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Evaluation of Emissions from Onshore Drilling, Producing, and Storing of Oil and Gas

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by

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1.0 ABSTRACT

This study provides an estimate of current HC, NO_x, CO, SO_x, and H_2S emissions from the drilling, production, and storage of oil and natural gas. Values used in this estimate are based on a combination of published information, acquired field inventory data and a series of model algorithms. Information presented includes number of wells drilled in 1976, a methodology to predict the type and amount of surface processing equipment expected in a specific field, and an estimation of the number and size mix of storage tanks in each state. Adjustments to the processing and storage tank emission estimates are made to eliminate emissions associated with stripper well activities. Projected emission levels for each year through 1987 are presented for each process. Various control options and their cost effectiveness are discussed. These include retrofitting existing storage tanks with internal floating roofs and applying various sulfur recovery processes to natural gas processing plants.

2.0 INTRODUCTION

The purpose of this project was to evaluate the HC, SO_x, NO_x, CO, and H_2S emissions from the drilling, production and storage of oil and natural gas in the United States. These activities are currently being conducted in 32 states. These states are listed in Table 2-1.

2.1 EMISSION ESTIMATES

Drilling emissions were calculated for each state. For reasons of data quality and type of activity, production and processing, and storage emissions were not calculated for seven states: Maryland, Missouri, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Disregarding these states removes from the evaluation less than 1 percent of the national totals for 1975 for both oil and gas. Sulfur emissions from natural gas processing were presented on a nationwide basis. Each activity is discussed separately with drilling practices discussed in Section 3.0, production and processing (including natural gas) presented in Section 4.0 and storage tanks appearing in Section 5.0.

2.2 PROJECTION OF EMISSIONS THROUGH 1987

Projected levels of drilling activities for each state through 1987 were estimated using figures presented in the September 19, 1978 edition of The Oil and Gas Journal. For the purpose of projecting state by state oil and gas production levels for each year through 1987, the services of Dr. Floyd Preston, Chairman of the Chemical and Petroleum Engineering Department, University of Kansas were retained. Dr. Preston presented growth or decline values for each state by year based on a series of assumptions. These values were used to calculate emission estimates from production and processing

Table 2-1. STATES ENGAGED IN THE PETROLEUM PRODUCTION INDUSTRY

ALABAMA	MONTANA
ALASKA	NEBRASKA
ARIZONA	NEVADA
ARKANSAS	NEW MEXICO
CALIFORNIA	NEW YORK
COLORADO	NORTH DAKOTA
FLORIDA	OHIO
ILLINOIS	OKLAHOMA
INDIANA	PENNSYLVANIA
KANSAS	SOUTH DAKOTA
KENTUCKY	TENNESSEE
LOUISIANA	TEXAS
MARYLAND	UTAH
MICHIGAN	VIRGINIA
MISSISSIPPI	WEST VIRGINIA
MISSOURI	WYOMING

equipment and storage tanks for the years 1978-1987. Sulfur emissions from the processing of natural gas were also projected from 1974-1987 based on the values prepared by Dr. Preston. Each projection scenario is discussed in the section relating to its activity.

2.3 COSTS AND ANALYSES OF CONTROL OPTIONS

Various possible control options for specific types of equipment or processes are discussed with special emphasis being placed on establishing the cost effectiveness of each system. This discussion appears as Section 6.0.

3.0 DRILLING OPERATIONS

During 1976, a total of 39,348 wells were drilled in the United States, requiring the operation of 1,658 drilling rigs (Reference 1). Wells being drilled are typically classified as either an exploratory (wildcat) or development type. An exploratory well is searching for new hydrocarbon formations. A development well is drilled into a known field in an effort to improve the recovery efficiency of the extraction operation. The majority of wells drilled (between 75 and 80 percent) are of the development type.

There are two basic drilling methods available for use in the United States today, the cable tool and the rotary.

3.1 CABLE TOOL DRILLING

Cable tool drilling is an old technique used for centuries to drill water wells which has been applied to the search for new oil and gas. The well is produced by successive strikes of a steel bit against the formation rock. A "spudder" is commonly used, working off an eccentric that alternately raises and drops the bit $\pm$ 3 feet to impact the bit on the bottom.

Components of a cable tool drilling rig consist of the drilling string, rig lines, walking beam, prime movers, bailers, and sand pumps. The drilling string is composed of a drill bit, drill stem, jars and tool joints. The drill bit is a heavy steel bar, generally 1.2 (4) to 2.4 m (8 ft) long, which can be sharpened to different degrees depending on the formation being penetrated. Additional weight for the downward blow is furnished by the drill stem, a cylindrical steel bar which is attached to the string directly above the bit. Jars are heavy steel links which form directly above the bit. Jars are heavy steel links which form a chain. Their function is to assist in extracting the tools from soft, sticky formations. Tool joints are metallic connectors which attach such items as the bit and drill stem to each other.

The prime mover for a cable tool drill rig is commonly an internal combustion engine although electric and steam drive applications are available. The prime mover drives a belt which rotates the band wheel. Using a series of connections, including a walking beam, the rotating band wheel imparts the reciprocating motion to the drilling line necessary for the operation.

The debris formed in the bottom of the hole as the well is being drilled is called cuttings. Accumulated volumes of this material can interfere with the drilling process. To remove the cuttings, at periodic intervals the drilling string must be lifted from the hole and a bailer sent down. The bailer acts as a scoop to remove the debris. A valve in the bottom of the bailer is opened and closed by a protruding stem as the bailer is alternately raised and lowered. Often the debris is too coarse to be collectable using the bailer. When this happens, a vacuum pump termed a sand pump is lowered into the hole to collect the material.

The rig has three different cables: drilling line, sand line and calf line. The drilling line connects the drilling string to a large surface spool which controls the raising and lowering of the apparatus. The sand line is normally attached to a bailer, which is alternately raised and lowered to remove the accumulated cuttings periodically from the well. The calf line is used to run casing into the well.

3.2 ROTARY DRILLING

The drilling method now almost exclusively in use in the United States is rotary drilling. In the rotary drilling method, a downward force is applied to a rotating bit which is fastened to and rotated by a drill string. The drill string is composed of high quality drill pipe and drill collars with new sections or joints being added as drilling progresses. Drilling fluid or mud continuously circulates down the inside of the drilling string through nozzles in the bit and upward in the annular space between the drill pipe and the bore hole lifting cuttings from the bottom to the well surface. At the surface, the returning fluid is diverted through a series of tanks or pits to allow cutting separation and necessary treating. Then, the mud is picked up by the pump suction and repeats the cycle.

The basic rotary rig components include a derrick or a mast and substructure, draw works, mud pumps, prime movers, drilling string, bits, drilling line and miscellaneous rig equipment. The derrick or mast and substructure provide the necessary raising and lowering vertical clearance of the drilling string during drilling operations.

The draw works is the key piece of equipment. It functions as a control center from which the driller operates the rig. The draw works retains the drum which stores the drilling line during hoisting and drilling operations. For the circulation of drilling fluid, a mud pump is employed to ensure the desired pressure and volume. A prime mover is necessary to generate power for operations such as circulation of drilling fluid and hoisting. Although the internal combustion engine is the most commonly used prime mover, the electric motor and steam engine are also employed.

An extremely expensive rig component is the drilling string which must be replaced periodically. The rotary bit can be classified into three general types: drag type, rolling cutter and diamond type. The drag and rolling cutter types are generally used for drilling through soft, sticky formations, and the diamond type is normally used in hard formations. The rotary drilling line functions as a means of handling the loads suspended from the hook. The rotary table transmits the rotation to the drilling string and suspends the pipe weight connections and trips. The traveling block connects the drilling line to the hook and swivel.

The drilling fluid is an important feature of the rotary drilling method. It functions as bit coolant, drill cutting lifter, remover of any entrained formation gases, provider of a hydrostatic column that will overcome the pressure in the formation drilled and preventor of fluid encroachment into the well bore.

The first rotary drilling fluid was water. Since water could not adequately support the borehole and prevent caving in of the quicksand encountered during drilling progression through softer formation, a muddy drilling fluid was devised.

When selecting the drilling fluid, the specific requirements of the geologic area in question and the fluid's ability to perform the function necessary in that area have to be considered. In soft rock areas, a precise control of mud properties is required, while in hard rock areas plain water may be a satisfactory and even superior drilling fluid.

The drilling fluid is mostly composed of prepared bentonitic clays, caustic soda, starch, lignin or lignocellulose and barium sulfate, a weight additive. Water or oil may be used as the fluid constituent of the mud. Since the bottom hole temperature affects the property of the mud in deep well drilling, drilled material is added constantly to the drilling fluid as temperature changes.

When the formation pressure exceeds that of the drilling fluid, the resevoir fluid will begin to flow into the well bore and cause either a controlling kick or blowout. If a wellhead is equipped with special heavy-duty equipment, it can be shut off during periods when adverse pressure differences are encountered.

3.3 RELATIVE USAGE

There are advantages attached to each technique. The cable tool method has lower equipment costs, daily operating expenses, and transportation costs. The drilling rig set-up time and expenses are also lower for a cable tool rig. Disadvantages of the cable tool method include slower drilling rates (about half that of a rotary rig), inability to provide an automatic control over high pressure, unconsolidated or caving formations, high failure rates of the drilling line, and increased danger of blowouts.

Current application of the cable tool method is generally restricted to shallow holes into known formations. It is estimated that wells drilled by the cable tool method numbered between 1 and 10 percent in the United States with the trend being toward lower usage rates. Therefore, for the purpose of estimating emissions from drilling activities, the evaluation will be directed toward the rotary drilling method.

3.4 ROTARY DRILLING EMISSION SOURCES

The important emission sources associated with rotary drilling operations are mud degassing, blowouts, and power generation. Only power generation and its related combustion contaminants is a continuous source of significant air pollution emissions. The drilling rig prime mover is commonly an internal combustion engine. While there are several fuels which can be used in these engines, the most popular seems to be diesel fuel.

Emissions from mud degassing have a more intermittent character. As the drilling bit passes through a gas producing formation, a small amount of the gas may seep into the well bore and become entrained in the drilling mud. Normally, gases encountered in this manner are unexpected and of small volumes. Consequently, after separation from the mud in a mud-gas separator (degasser), the gases are vented to the atmosphere. In rare instances where large volumes of gases are anticipated or toxic gases (containing H_2S) are expected, the mud degassing will be performed in a fully enclosed system and all gases released are captured and flared. Due to the high variability in frequency and volume discharges of such occurrences, no calculations of emissions from mud degassing are attempted in this report. However, the amount of gas escaping to the atmosphere from these operations is expected to be small.

A similar situation exists for blowouts. By properly maintaining blowout preventors in the well hole as drilling progresses, the frequency of a blowout can be expected to be small. Since a blowout is an upset condition and does not represent normal operations, emission estimates are not made. Again, the overall relative contribution of blowout emissions to the atmosphere can be expected to be small.

3.5 EMISSION ASSUMPTIONS

The size of rotary drilling rigs employed for oil and gas drilling varies with the type of formation being drilled and the drilling depth. Variables include the required engine power output, size of derrick, substructure, draw work and mud pump. According to the "Histogram of Land Rigs in the United States During March 1978" obtained from the American Petroleum Institute (Figure 3-1), the average drilling rig rating is approximately 3,048 m (10,000 ft). The basic rig components and sizes for the average rig are listed in Table 3-1.

Calculable emissions from drilling then arise only from the internal combustion diesel engine of 708.4 kW selected as typical. The reported fuel use associated with this engine of 2,650 ℓ (70 gal)[2] per hour results in an engine load factor of between 55 and 60 percent.

In order to attach drilling emission values to rig activities in a particular state, the most desirable means would be to use Table 3-1 to establish the total footage drilled in each state during 1976 and then attach an energy requirement (Btu of hp per footage drilled) to this value. Several factors arose during this evaluation which made this methodology unrealistic. No individual contacted was willing to assign specific values to the amount of energy necessary to drill a foot. Reasons for this reluctance were the high variability in formation hardness which could be expected to be found. Evaluators next attempted to verify a value of 147 kWh/m (60 hph/ft) drilled which appears on page 83 of Atmospheric Emissions From Offshore Oil and Gas Development and Production (Reference 2). Again, drilling contractors contacted were unable to satisfactorily apply this value to onshore activities.

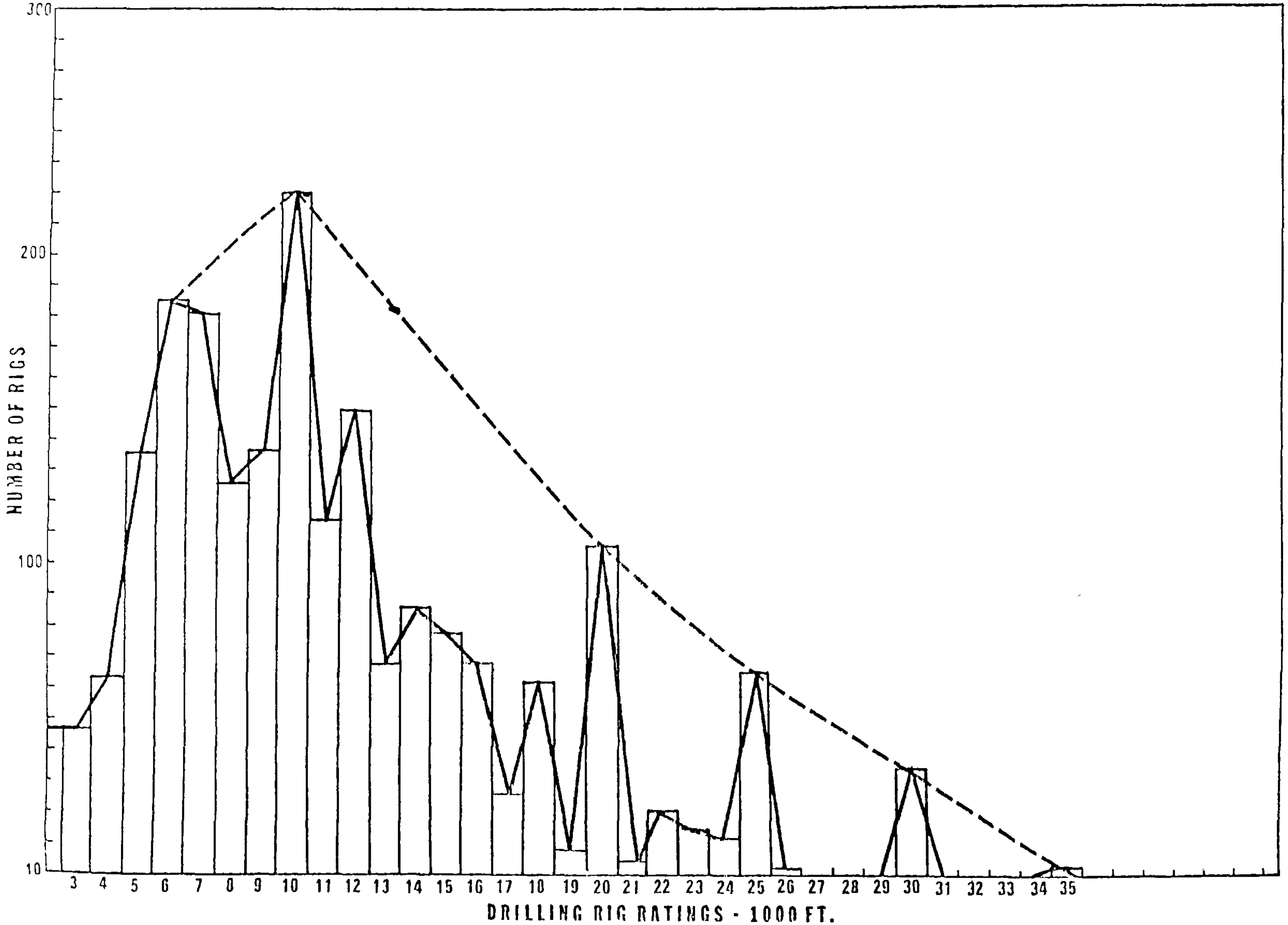

Figure 3-1. Histogram of Land Rigs in the United States During March 1978
(Provided Courtesy of the American Petroleum Institute

Table 3-1. TYPICAL 3,048m DRILLING RIG COMPONENTS[a]

Prime mover - 2 diesel fired reciprocating engines totaling up to 708.4 kW (950 hp) at 2,100 rpm

Power takeoff pump - Driven from prime mover transmission

Drawworks - Hoisting drum (diameter x length) - 59.0 cm x 111.8 cm ($23\frac{1}{4}$ in x 44 in)
- Line size - 2.9 cm (1-1/8 in)
- Brake rims (diameter x width) - 116.8 cm x 31.8 cm (46 in x $12\frac{1}{2}$ in)
- Effective brake area - 21,445 cm^2 (3,324 in^2)
- Brake cooling mechanism - Circulating water
- Hoisting speeds - 5 forward, 1 reverse
- Rotary speeds - 5 forward, 1 reverse
- Hydromatic drive chain - 3.2 cm ($1\frac{1}{4}$ in) quadruple
- Rotary drive chain - 3.8 cm ($1\frac{1}{2}$ in) double
- Drum drive chain - Two 3.2 cm ($1\frac{1}{4}$ in) triple

Mast - Clear height (with 13 ft floor) - 30.4 m (99 ft 7 in)
- Leg spread - 2.6 m (8 ft 6 in)
- Hook load capacity - 8 lines - 158.8 MT (350,000 lb)
  (API Standard 4E) 10 lines - 165.6 MT (365,000 lb)
- Racking capacity - 11.4 cm ($4\frac{1}{2}$ in) outside diameter drill pipe - 3,505.2 m (11,500 ft)
  (Range 2 doubles) 10.2 cm (4 in) outside diameter drill pipe - 3,901.4 m (12,800 ft)

Substructure - Floor height - 3.4 m, 4.0 m, and 4.6 m (11 ft, 13 ft, and 15 ft)
- Floor size (length x width) - 4.2 m x 5.5 m (13 ft 8 in x 18 ft)
- Ground overall dimensions (length x width) - 12.2 m x 3.7 m (40 ft x 12 ft)
- Rotary capacity - 158.8 MT (175 ton)
- Setback capacity - 90.7 MT (100 ton)
- Total simultaneous capacity - 249.5 MT (275 ton)

Rig field weights - Front - 27.2 MT (30.0 ton)
Rear - 27.2 MT (30.0 ton)
Total - 54.4 MT (60.0 ton)

[a] Reference 3

Project engineers were forced to abandon this methodology in favor of a different evaluation. A total of 1,660 rotary drilling rigs were reported in operation in 1976 (Reference 1). Table 3-2 shows the average number of rigs active in each producing state during 1976. Due to the downtime for logging, running electrical surveys, cementing, waiting on cement to set, rigging down, moving and rigging up, it is estimated that each of these average rigs operates 65 percent of the time. Combining all of these factors, drilling emissions for each state can be calculated.

3.6 1976 EMISSION ESTIMATES

The 1976 drilling emission totals for each state are shown in Table 3-3. The method of calculation is as follows (the discussion is presented in English units to be consistent with emission factor units).

$$(70 \text{ gal/hr})(8{,}760 \text{ hr/yr})(.65) = 398{,}580 \text{ gal/yr/rig}$$

By then multiplying by the average number of rigs active in a state in 1976, the total amount of diesel fuel burned in drilling operations in that state are made.

Emission estimates for these figures are made based on the following emission factors from Compilation of Air Pollution Emission Factors, AP-42, Part A, Second Edition, Table 3.3.3-1 (refer to Table 3-4).

3.7 PROJECTED EMISSIONS THROUGH 1987

Drilling projections were made based on figures appearing in The Oil and Gas Journal, September 18, 1978 (Reference 4). In the report it is estimated that the U.S. rotary rig count

Table 3-2. ACTIVE ROTARY DRILLING RIGS IN EACH STATE IN 1976[a]

Alabama	17	Montana	28
Alaska	14	Nebraska	8
Arizona	1	Nevada	2
Arkansas	15	New Mexico	54
California	89	New York	9
Colorado	38	North Dakota	19
Florida	5	Ohio	26
Illinois	22	Oklahoma	186
Indiana	2	Pennsylvania	10
Kansas	51	South Dakota	2
Kentucky	1	Tennessee	1[b]
Louisiana	231	Texas	653
Maryland	1	Utah	19
Michigan	24	Virginia	1[b]
Mississippi	32	West Virginia	12
Missouri	1[b]	Wyoming	86

[a] Reference 1

[b] Assumed a minimal level of activity if wells were drilled during 1976, even if reported average was zero

Table 3-3. DRILLING EMISSIONS FOR THE YEAR 1976
(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	96	1,442	115	314
Alaska	79	1,187	95	258
Arizona	6	85	7	18
Arkansas	85	1,272	102	277
California	502	7,547	603	1,641
Colorado	214	3,222	258	701
Florida	28	424	34	92
Illinois	124	1,866	149	406
Indiana	11	170	14	37
Kansas	288	4,325	346	941
Kentucky	6	85	7	18
Louisiana	1,303	19,587	1,566	4,260
Maryland	6	85	7	18
Michigan	135	2,035	763	443
Mississippi	181	2,713	217	590
Missouri	6	85	7	18
Montana	158	2,374	190	516
Nebraska	45	678	54	148
Nevada	11	170	14	37
New Mexico	305	4,579	366	996
New York	51	763	61	166
North Dakota	107	1,611	129	350
Ohio	147	2,205	176	480
Oklahoma	1,049	15,772	1,261	3,430
Pennsylvania	56	848	68	184
South Dakota	11	170	14	37
Tennessee	6	85	7	18
Texas	3,684	55,370	4,427	12,042
Utah	107	1,611	129	350
Virginia	6	85	7	18
West Virginia	68	1,018	81	221
Wyoming	485	7,292	583	1,586
TOTAL	9,366	140,761	11,857	30,611

Table 3-4. EMISSIONS FROM DRILL RIG ENGINE[a]

Pollutants	Emission Factor		Emission Rate	
	$lb/10^3$ gal	g/hphr	kg/hr	lb/hr
Carbon monoxide	102	3.03	3.22	7.1
Hydrocarbons	37.5	1.12	1.18	2.6
Oxides of nitrogen	469	14.0	14.88	32.8
Oxides of sulfur	31.2	0.931	1.00	2.2

[a] Basis: 950 hp diesel engine using 70 gph fuel. The load factor is between 55 and 60 percent

has grown at a pace of about 170 rigs per year. While the trend has accelerated over the past 18 months, the value of 170 additional rigs per year for the years through 1987 presents a representative scenario for future activities which is consistent with the modest increasing trend over the next 5 years expected by API drilling experts.

Figure 3-2 presents a graphic illustration of the projected drilling activities for the years through 1987. Using the number of rotary rigs active in each state during the base year 1976 (see Table 3-2), the 170 additional active rigs each year were assigned proportionally to each state and emission estimates calculated. The results of applying this projection procedure to the 1976 data are presented in Table 3-5. Using the assumption that drilling activities will increase by an average of 170 rotary rigs per year through 1987, an approximate 111 percent increase in drilling emissions can be expected. State by state emission estimates for each projected year are presented in Appendix I.

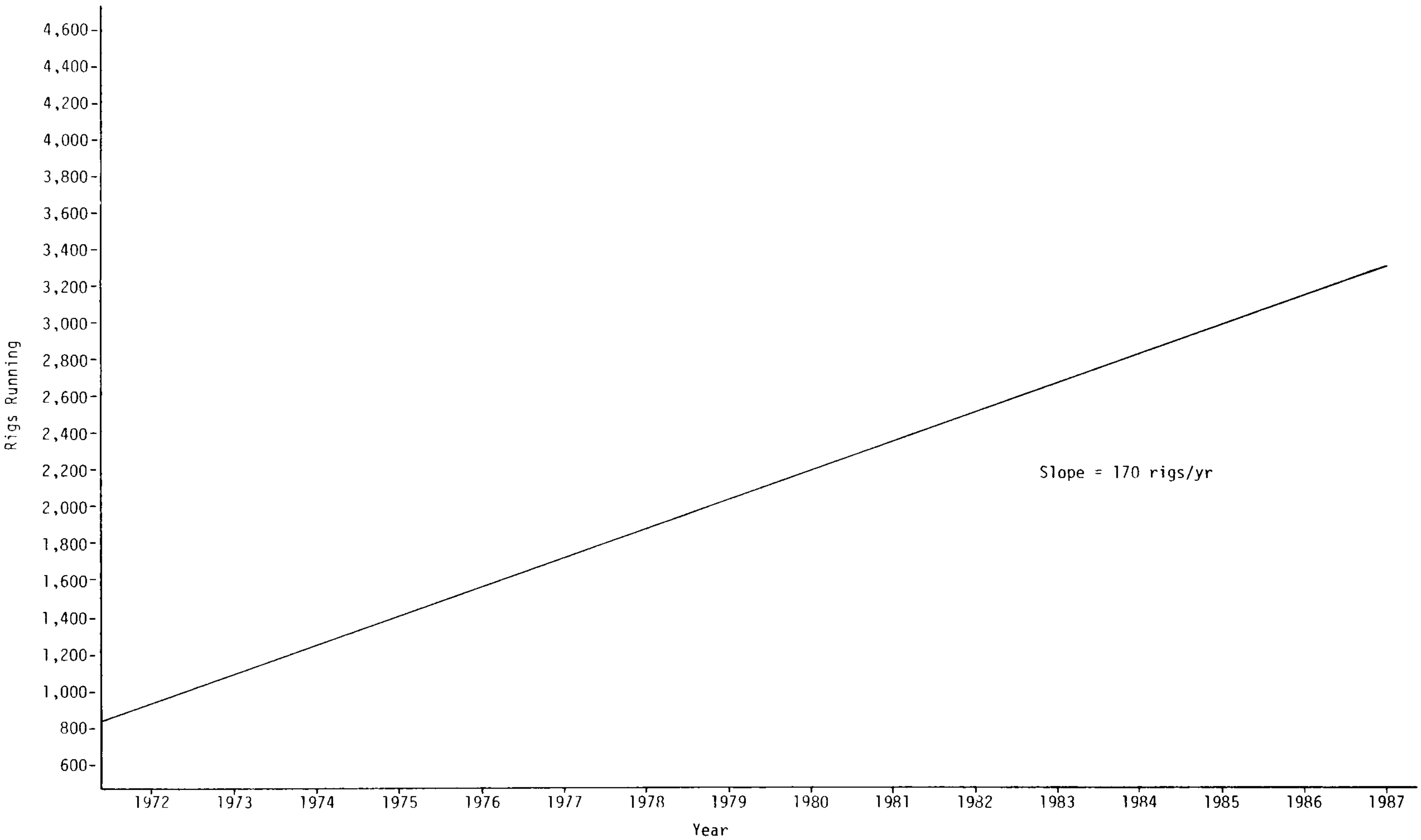

Figure 3-2. Drilling Rig Projected Increases Through 1987

Table 3-5. NATIONWIDE DRILLING EMISSIONS FOR YEARS 1976-1987 (10^3 kg)

Year	SO_x	NO_x	HC	CO
1976	9,366	140,761	11,857	30,611
1977	10,324	155,098	14,027	33,752
1978	11,265	164,100	15,159	36,805
1979	12,238	183,678	16,327	39,980
1980	13,185	198,538	17,463	43,053
1981	14,158	212,448	18,642	46,272
1982	15,103	226,530	19,780	49,338
1983	16,075	239,353	20,947	52,485
1984	17,025	255,124	22,087	55,553
1985	17,973	269,216	23,220	58,661
1986	18,907	283,291	24,352	61,728
1987	19,855	297,548	25,499	64,835

4.0 PRODUCTION AND PROCESSING

A three step process proved necessary to estimate emissions from oil and gas field production and processing operations: (1) identification and data collection for oil and gas fields on a state-by-state basis; (2) assignment of production methods to each oil and gas field; and (3) prediction of the types and numbers of processing equipment which could be expected to be found in each field.

4.1 COLLECTION OF INDIVIDUAL OIL AND GAS FIELD STATISTICS

The first step in the identification of petroleum producing fields involved contacting the related state agency in each producing state. Information from each of these states was reviewed for suitability to project needs. In some cases, the information received was inadequate. In those instances, the International Oil and Gas Development (Reference 5) published by the International Oil Scouts served as a supplementary document and accuracy check.

By combining the two sources of information, it was possible to compile a fairly detailed list of petroleum fields in most states. However, there were exceptions. Data were not available on an individual field basis for activities in Maryland, Ohio, and Virginia. Since the combined contribution to the national production totals for these states in 1975 amounted to less than 0.5 percent for oil and less than 0.6 percent for gas (Reference 6) they were excluded from this study.

Under the Scope of Work of the contract which generated this report, the study was to disregard stripper well activity. A stripper well is defined as any well which produces 10 barrels a day or less. The National Stripper Well Association in Tulsa, Oklahoma was contacted in an attempt to identify and geographically locate stripper activities. After consultation with Mr. Frank B. Taylor of that organization and review of the National Stripper Well Survey, January 1, 1977 (Reference 7), it was judged that production activities in Missouri, New York, Pennsylvania, and West Virginia were 100 percent stripper in nature and were not included in this study.

Field information was encoded for the remaining 25 states on forms similar to the one in Figure 4-1. Often, a field extracts oils of distinctly different characteristics from different levels of formation. These specific zones of oil are termed pools. In some instances, the state data were detailed enough to allow individual pool information to be recorded. For many fields and/or pools in a state, the production value for the Year of Record was zero. Since the method of calculating emissions was totally dependent on the production value, these fields were ignored. Table 4-1 presents the number of fields encoded for each producing state and whether or not pool information was also available. The specific information used to establish the data base for each state is presented in Appendix II.

The field information was entered onto the sheets using a series of numerical codes. Specific oil or gas characteristics were unavailable for most field cases. One supplemental source used to improve the oil sulfur content statistics was a publication titled Sulfur Content of Crude Oils (Reference 8).

4.2 PRODUCTION TECHNIQUE IDENTIFICATION

The second step in the generation of production and processing operation emission estimates is the identification of the production technique used in each field. A complex combination

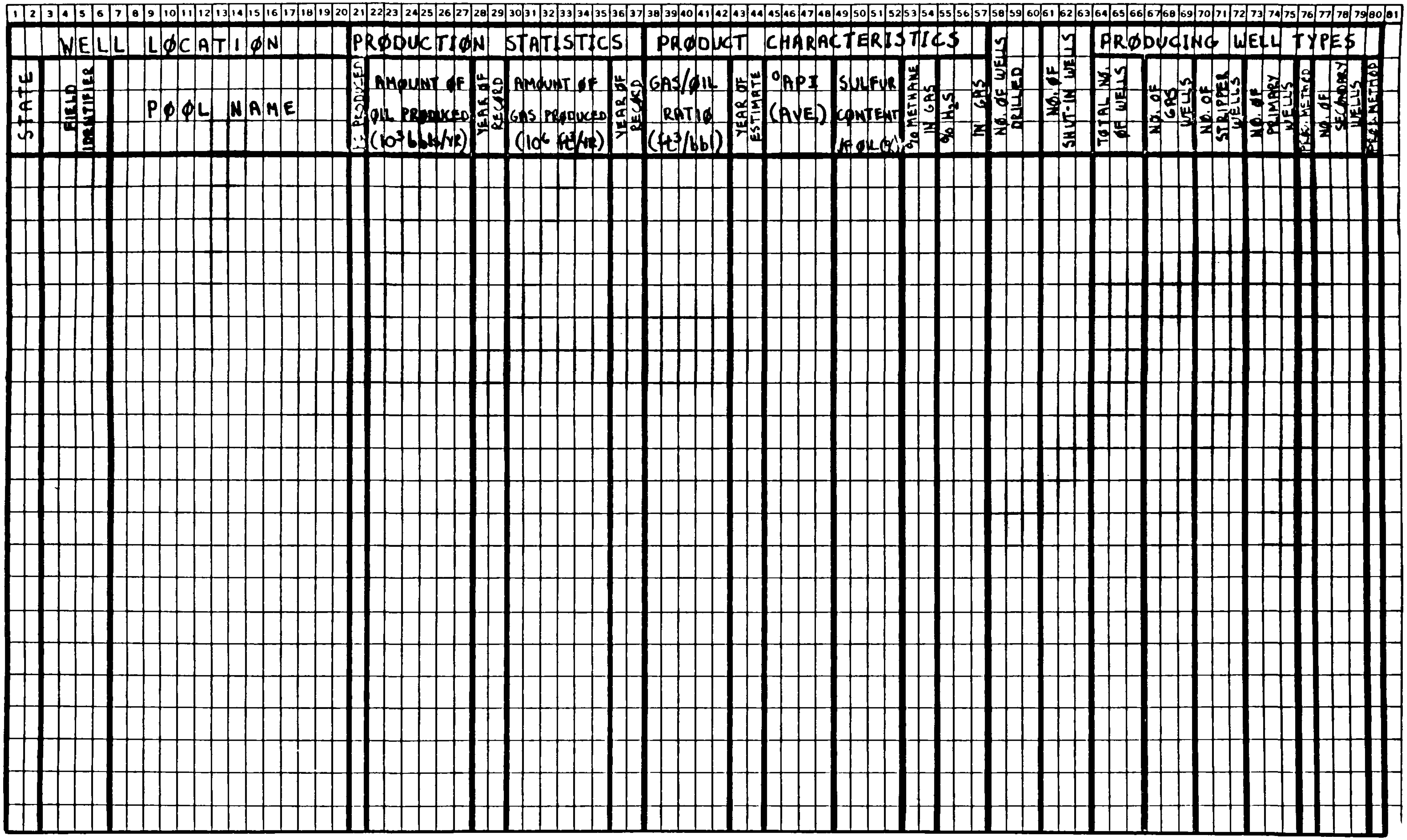

Figure 4-1. Sample Chart for Encoding Field Information

Table 4-1. NUMBER OF FIELDS ENCODED FOR EACH STATE

State	Number of Fields	Individual Pool Information Exists
Alabama	33	No
Alaska	21	Yes
Arizona	4	No
Arkansas	254	Yes
California	395	Yes
Colorado	534	Yes
Florida	11	No
Illinois	342	No
Indiana	210	No
Kansas	2,049	No
Kentucky	268	No
Louisiana	1,182	No
Michigan	455	No
Mississippi	363	Yes
Montana	219	Yes
Nebraska	349	No
Nevada	2	No
New Mexico	830	No
North Dakota	132	Yes
Oklahoma	1,948	No
South Dakota	12	No
Tennessee	46	No
Texas	18,612	No
Utah	109	No
Wyoming	681	No
Total	29,061	

Not Encoded

Maryland	Pennsylvania
Missouri	Virginia
New York	West Virginia
Ohio	

of formation and petroleum fluid characteristics will determine the necessary method of extraction. While individual fields often utilize a combination of techniques, in general, a new field will begin production using one of the natural lift primary production methods, move to artificial lift as pressure losses decrease the field's natural ability to force the fluids to the surface and finally resort to secondary recovery techniques requiring injection or flooding to encourage the oil to flow to production wells.

4.2.1 PRIMARY PRODUCTION METHODS

Two types of production methods are categorized as primary, natural lift (also termed flowing) or artificial lift. Oil cannot move and lift itself from reservoirs through wells to the surface. Natural lift production methods utilize the energy of formation in the gas or salt water (or both) occurring under high pressures with the oil to force oil through and from the pores of the reservoir into the wells.

When the reservoir pressure drops to the point where it is not possible for a well to flow naturally, or the desired production rate is greater than the actual production rate, it becomes necessary to install artificial lift to supplement the reservoir energy for lifting fluids from a well.

Artificial lifts used for this purpose are the gas lift, plunger lift and well pumps, the last of which can be classified according to the type of pump installed at the bottom of the hole. Although plunger pumps are the most commonly used oil-well pump, electric and hydraulic pumps are also used.

4.2.1.1 Natural Lift Methods

4.2.1.1.1 Dissolved Gas Drive

In nearly all reservoirs, varying quantities of gas are dissolved in the oil. Well completion into such a formation results in a reduction in pressure in the reservoir causing the gas to emerge and expand. As the gas escapes from the oil and expands, it drives oil through the reservoir toward the wells and assists in lifting it to the surface. For the fields where the reservoir is at or below the bubble point pressure, the recovered oil is replaced by an equal amount of expanding gas as the reservoir depletion begins. This process accelerates as the reservoir pressure decreases, requiring more gas expansion per unit volume of oil produced. Consequently, this production method is generally considered the least effective type, yielding maximum recoveries of between 15 and 25 percent of the oil originally present in the reservoir.

4.2.1.1.2 Expanding Gas Cap Drive

In many cases there exists more gas with the oil in a reservoir than the existing conditions of temperature and pressure will allow to be held dissolved in the oil. This extra gas, being lighter than the oil, exists in the form of a cap of gas over the oil. Such a gas cap is an important additional source of energy, for, as production of oil and gas proceeds and the reservoir pressure is lowered, the gas cap expands to help fill the pore spaces formerly occupied by the oil and gas produced. Also, when conditions are favorable, some of the gas coming out of the oil is conserved by moving upward into the gas cap to further enlarge the gas cap. This method is more effective than dissolved gas drive alone, yielding oil recoveries from 25 to 50 percent.

4.2.1.1.3 Natural Water Drive

The natural water drive process is effective when there is a vast quantity of salt water existing under pressure in the surrounding parts of the oil and gas formation. As the pressure in the reservoir is reduced by production of oil and gas, energy is generated by the expansion of the water*. This energy in turn supplies the required driving forces to move the water into the regions of lowered pressure and displace the oil and gas in an upward direction toward the wells. This process is capable of yielding up to 50 percent of the oil originally present in the reservoirs.

4.2.1.2 Artificial Lift Methods

4.2.1.2.1 Plunger Lift

Plunger lift is also known as free piston lift. The production of oil and gas is accomplished by a steel plunger, or swab, which utilizes the reservoir pressure for lifting and gravity for returning it to the producing zone. During the production operation, the force of gravity pulls the plunger

* Water actually will compress, or expand, to the extent of about one part in 2,500 per 690,000 pascal (100 psi) change in pressure. This effect is slight for any small quantity, but becomes of great importance when changes in reservoir pressure affect enormous volumes of salt water that are often contained in the same porous formation adjoining or surrounding a reservoir (Reference 9).

from the top to the bottom of the well. As the plunger strikes the footpiece, its bottom valve closes. A column of fluid is collected. The casing pressure is then gradually built up to its peak, and the plunger starts lifting its fluid column to the surface where it is discharged into the flow line. The plunger continues to rise until it strikes the bumper which opens the plunger valve. Then, the process repeats itself.

4.2.1.2.2 Gas Lift

Gas lift is a process of lifting fluids from a well by the injection of relatively high pressure gas between the casing and tubing strings. The injected gas from the annulus enters the tubing through the installed gas lift valves, where energy is being generated by the expansion of high pressure gas. When this energy builds to a level exceeding the bottom hole pressure, it begins to lift fluids to the well surface. The production rate of the fluids is a function of the gas injection rate, which can be stabilized by fixing it at some pre-determined injection point. In the case of slow production wells, an intermittent gas lift method is employed to provide the necessary energy to lift oil and gas to the surface at a more desirable rate.

4.2.1.2.3 Electric Pumps

Electric submersible pumps are centrifugal pumps with their shafts connected directly to an electric motor. The required power for this submerged unit is supplied by an insulated cable, which runs from the power source at the surface to the motor at the well bottom. As a result of the revolving motion of the impellers in the pump, the applied pressure forces the fluid through the tubing to the surface. The capacity of this type of pump is generally high and depends upon the depth and size of the well being lifted, varying from 250 to 26,000 barrels of fluid per day.

4.2.1.2.4 Subsurface Hydraulic Pumping

Hydraulic pumping is accomplished by a hydraulic engine directly connected to a rodless reciprocating pump, which is powered by a fluid (termed power oil). Surface power is supplied from a standard engine-driven pump.

There are several types of hydraulic pumping systems. The first type consists of two strings of tubing along side one another or a small string inside the other. Power oil is forced through the larger size tubing by the high pressure pump at the surface, triggering the submerged hydraulic engine, which in turn moves a power piston connected to the production plunger in the bottom hole pump. The exhausted power oil becomes mixed with the well fluid and returns to the surface via the smaller tubing. The second pumping system requires only one string of tubing set on a casing packer. Power oil is forced down through the tubing string as in the first type of system. The power oil mixes with well fluids and passes through the submersible pump and is transported to the surface using the space between the tubing and the casing string. The third type of system is the closed power fluid system. This system is being used where there is limited surface area or where clean power oil is unavailable. The system is termed closed because exhausted power oil returns to the surface through a separate string of tubing than the produced well fluid.

4.2.1.2.5 Mechanical Lift

This type of artificial lift utilizes pumps at the bottom of the hole, run by a string of rods. The drive mechanism for these plunger pumps is provided at the surface. Energy from the prime mover is transferred to the well using the familiar pumping unit shown in Figure 4-2.

Pumping wells need a means of packing or sealing off the pressure inside the tubing to prevent leakage of fluid and gas outside the polished rod. Stuffing boxes consist of flexible material or packing housed in a box which provides a method of compressing the packing. When the stuffing box becomes worn and loses its seal, it is replaced by the fluid pump operator. Generally speaking, the atmospheric emissions from stuffing box packings are considered to be negligible. Gases diverted into the casing are also a potential source of hydrocarbon emissions. These gases commonly are being disposed of as field fuel or sales when a large enough quantity of gas is available. Otherwise, it is vented directly to the atmosphere or flared.

Subsurface equipment consists of sucker rods and the plunger pump. Sucker rods are solid high-grade steel rods that are run inside of the producing tubing string to connect the subsurface pump to the pumping unit. Plunger pumps are cylindrical pumps consisting of the following basic parts: the working barrel, the plunger, a standing valve, and a traveling valve. These pumps can be categorized into three groups: tubing pumps, rod pumps, and casing pumps.

Tubing pumps utilize a working barrel that is attached to the lower end of the well tubing, while the plunger is suspended on the lower end of the sucker rods. Rod pumps have their working barrel and plunger assembled together as a single unit, which may be installed or withdrawn by the rods. Casing pumps are those with no auxiliary tubing used and a packer is set against

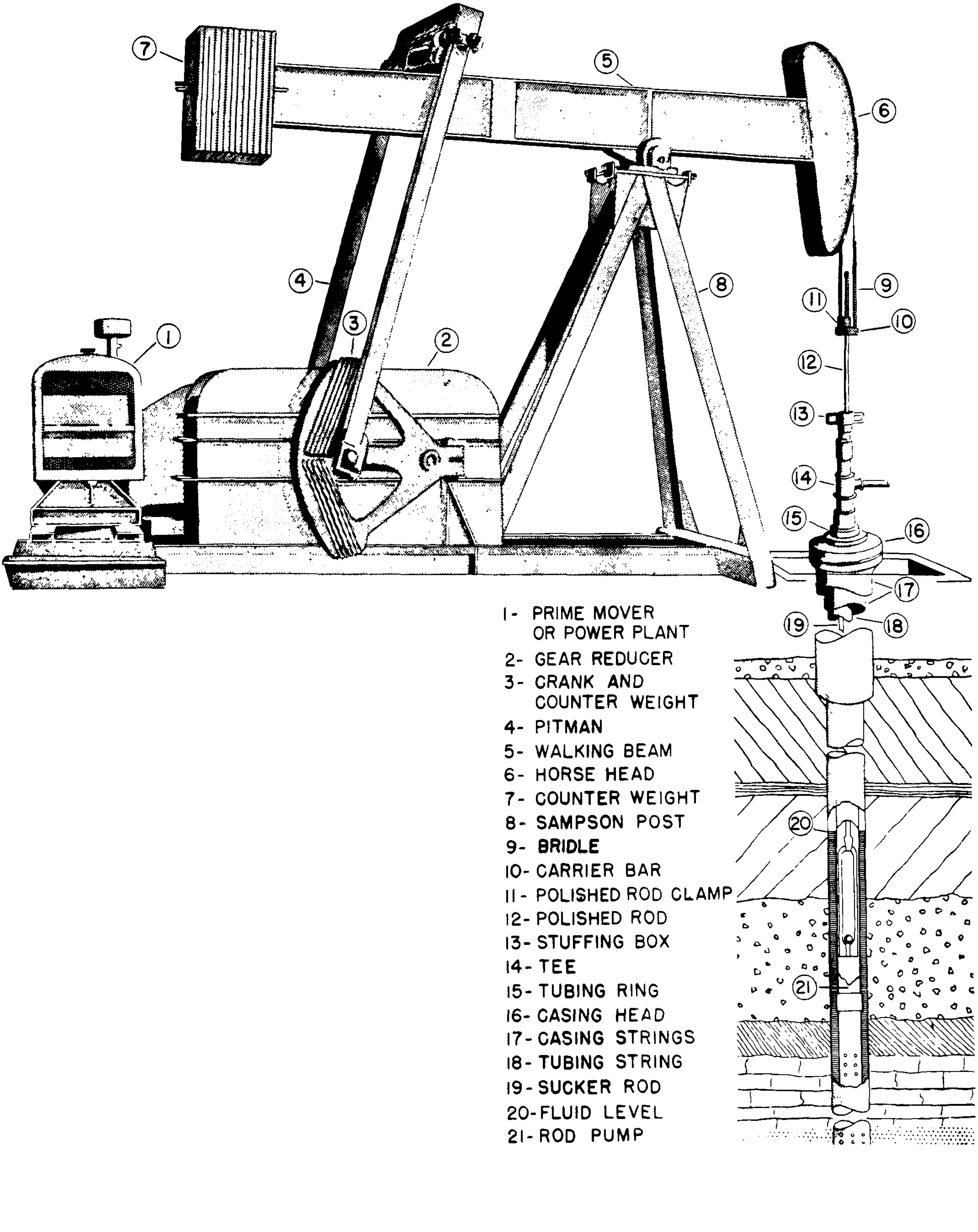

Figure 4-2. Mechanical Lift Pumping Unit (Reference 9)

the tubing string to support the rod pump.

The plunger pump is set at a depth in the well at which the pump will stay covered by fluid during the pumping operation. The upward stroke of the rod pulls the plunger up through the working barrel. This action causes the traveling valve to close, which permits the column of fluid above to rise with the plunger, while the standing valve opens to admit fluids from the well to the working barrel. On the downward stroke, the traveling valve opens, while the standing valve closes and the rod pushes the plunger down through the working barrel, forcing the fluid from the working barrel into the tubing. The result is fluid being lifted to the surface through the tubing on each upstroke of the plunger.

4.2.2 SECONDARY PRODUCTION METHODS

In primary recovery, naturally occurring forces, such as those associated with gas and liquid expansion are utilized to produce the oil. However, the possibility of a field producing in this manner for its entire lifetime is exceedingly small. In almost all cases, primary production accounts for less than 50 percent of the total recoverable reserves. In recent years, the high cost of oil and gas has made it more profitable to recover this additional oil by enhanced recovery methods. The most widely applied techniques to recover oil once primary methods are no longer economically satisfactory are secondary recovery methods, a term applied to processes which restore or inject the needed producing energy back into the well. Secondary recovery can be broken down into three categories: (1) waterflooding, (2) repressurization and pressure maintenance, and (3) thermal methods (steam soak and steam drive).

Thermal methods technically belong to a category of production types termed tertiary. Their inclusion in this report as a secondary method is made to make this discussion consistent with contract requirements.

4.2.2.1 Pattern Waterflooding

Pattern waterflooding is a technique employed whereby additional oil is recovered from reservoirs following depletion of the natural reservoir energy. In a program of this type, the wells to be used for water injection are interspersed between producing wells. The injection of water into the alternative wells forces oil into the well bores of adjoining producers that would otherwise remain in the sand unrecovered. There are many injection patterns that can be used. A common type of waterflooding is one in which each oil well is surrounded by four water-injection wells (located at the four corners of a square).

4.2.2.2 Water and Gas Injection, and Pressure Maintenance Projects

The production of oil from a reservoir usually causes a decline in pressure. Since in most instances the produced oil is accompanied by significant amounts of gas and water, the decline in pressure for a given amount of oil production may be much greater than if only the oil itself had been withdrawn from the reservoir. Maintaining this pressure will permit greater oil recovery and more economical operation of the wells. Pressure maintenance is the application of fluid injection early in the producing life of a reservoir to extend a field's production life.

In certain fields, there is a plentiful supply of water, usually called an aquifer, in direct contact with the oil reservoir and connected by means of a highly permeable channel to allow replacement of the oil as it is withdrawn. In fields having such a natural active water drive, the pressure may be maintained simply by replacing the produced fluids with aquifer water. In a field of this type, pressure maintenance by water injection is never required because natural conditions are such as to accomplish the end that a man-made project would be designed to accomplish.

In a field where such a condition does not exist, it is necessary to inject water or gas back into the reservoir as a means of replacing the reservoir fluids withdrawn while producing oil.

4.2.2.3 Thermal Methods (Steam Injection)

The utilization of steam for increased oil recovery is called steam injection. There are two steam injection processes, steam soak and steam drive.

4.2.2.3.1 Steam Soak

Steam soak is also known as the "huff and puff" method. Steam is injected into a reservoir at the location of the producing well head. This is termed the huff stage. The well head is subsequently closed for a period of from 1 week up to 2 months. This period allows the heat of the steam to be transferred to the crude oil in the reservoir. Hence, the viscosity of the oil decreases to the point where it can flow more easily. The puff stage begins when the well head is opened and the well starts producing. The produced fluid is a combination of oil and water.

4.2.2.3.2 Steam Drive

Steam drive is very similar to waterflooding. The main difference being that steam is used instead of water. Steam is generally injected at the perimeter of a reservoir, similar to pattern operations used in waterflooding. This essentially drives the oil into the producing zone where it is recoverable. The technique is generally employed in formations containing heavy (low API gravity) oil. The steam lowers the viscosity of the oil and permits it to flow.

4.2.3 PRODUCTION METHOD ASSIGNMENT

Each field identified was assigned a production technique. Since it is common to find more than one production method employed in a single field, provisions were made for multiple entries into the data base. The quality of information obtained was such that a determination could only be made between natural flowing wells, artificial lift wells, and the three specific secondary production methods. Numerical well assignments to each of these five production categories were made for each field. Referring to Figure 4-1, the following numerical coding scheme was applied to wells in each field:

- Primary production method — Column 76
  - Natural flowing wells — 1
  - Artificial lift wells — 2
- Secondary production methods — Column 80
  - Waterflood — 1
  - Repressurization — 2
  - Steam injection — 3

4.2.4 WELL TREATMENT

Wells often may be treated to improve the natural drainage pattern, or to remove barriers within the oil-bearing formation which prevent easy passage of fluids into the well bore. Such processes are classified as well stimulation treatments. Stimulation treatments are classified primarily as fracturing, acidizing, or use of other special chemicals. These processes are often used in combination since they frequently help each other. Programs for individual wells vary according to well characteristics and conditions, economics, and end result desired.

4.2.4.1 Fracturing

Fracturing is a process by which fluid pressure at the bottom of a well is developed by high pressure pumps to the extent necessary to counterbalance the weight of rock above it, plus sufficient additional pressure to crack the formation. This makes possible the introduction of fluids carrying sand, walnut hulls, or other small particles of material into the new crevices created to keep the fractures open.

4.2.4.2 Acidizing

Acidizing is a process by which acids are applied to the producing formation to enlarge existing crevices, or are forced into the pores of the formation to increase the flow capacity of the drainage system.

4.2.4.3 Special Chemical Treatments

Special chemical treatments are those in which acid is not a material part. Although many of the materials in this group often are used in conjunction with fracturing and acidizing, they have definite application in their own right.

Water can sometimes create a block when present in the tiny pore spaces of a formation. Certain chemicals may be applied to lower surface tension. By contact, the chemicals break large drops of water into several smaller ones thus, allowing fluid trapped behind the surface tension to be released to flow to the well bore.

In many instances, when oil and water become intimately mixed they form an emulsion. With continued agitation, the emulsion may form a very thick mass which impairs flow of fluids to the well bore. Chemicals may be used to break this emulsion. The resulting decrease in viscosity frees the fluids to move to the well bore.

4.2.4.4 Exclusion Justification

Emission estimations from well treatment activities have been excluded from this study. These practices are normally handled by contractors who bring their own equipment to the site. Since injection is commonly done under extremes of pressure, it is important to minimize leaks from the equipment. The only major potential source of emission would occur if combustion materials were used to generate needed energy requirements. The most common fuel consumed is diesel in an internal combustion engine. Since the well treatment processes are intermittant and vary with the geographical area, these sources have been disregarded from this study.

4.3 SURFACE EQUIPMENT DESCRIPTION

The third step necessary before emission estimates can be made involves the identification of the surface equipment used in a given field. Once oil has been extracted from the ground using one of the previously mentioned production techniques, it is the very rare case in which that oil can be transported directly to the refinery. Sediments and water produced with the oil necessitates the presence of equipment in the field that cleans the oil and removes most of the water. The most commonly found activities and pieces of equipment are described below.

4.3.1 OIL AND GAS SEPARATORS

There are many types of separation systems including low pressure and high pressure systems, and free water knockout (FWKO) units. In each case, the separator is a pressure vessel used for the purpose of separating well fluids into gaseous and liquid components.

The FWKO unit is a two phase separator that sets apart the gas and liquid petroleum from water. Low pressure and high pressure separators can be a two or three phase vessel. They are usually sized to handle high instantaneous rates of flow. Generally, FWKO's or other separation equipment such as gun barrels or wash tanks (see next section) are added to the field treating system when the system becomes overloaded because of increasing water production. The additional equipment eliminates this water and saves energy requirements and treatment capacity. The gas coming off from these separators is usually vented to the atmosphere. However, if sufficiently high quantities are generated, they will be compressed for uses such as field fuel, gas lift, gas re-injection or sales. This report will not discuss the handling of this associated produced gas.

4.3.2 GUN BARREL

A gun barrel is a cylindrical tank used to separate oil from water when oil characteristics make the differentiation easy to accomplish. The tank is equipped with a flume which routes the fluids received either directly from the well or from the separators downward to a level below the oil-water interface. Released at this level, the oil and water separate with the lighter oil floating to the upper level of the tank, where it is withdrawn to storage by means of a pipe. Water exits through piping with a dump valve or water siphon controlled flow. The water siphon has a closed equalizer loop back into the tank for gases breaking free of the water. Any gases entrained in the fluids would be liberated directly to the atmosphere. Gun barrel applications are made only when the difference in densities between the oil and water is great enough to allow easy separation.

4.3.3 WASH TANK AND SETTLING TANKS

A wash tank is commonly used when a combination of low gas quantities and emulsified mixtures of oil and water are present. The wash tank is a large vessel equipped with a low-pressure liquid separator (located atop the tank), a spreader, level control, and heating coil. Mixtures of oil and water first enter the separator where any entrained gas in the liquid is removed and vented to the atmosphere. When vapor amounts are substantial, a vapor recovery system may be employed. The liquid is then gravitationally brought through a large diameter vertical pipe to be dispersed uniformly by the spreader below the level of the oil-water interface. In order to break the oil-water emulsion, heat is applied to this zone of the tank by hot water or steam circulated in heating coils. Clean oil is skimmed at the top of the oil layer and water is drawn off at the bottom of the tank.

A settling tank is a fixed roof tank used to assist in the reduction of the water content in the oil. The tank is commonly used in conjunction with a wash tank if large quantities of water are produced at the well head. By placing the settling tank ahead of the wash tank, it can serve both as flow regulator and reduce the separation time required in the wash tank.

4.3.4 HEATER TREATER

A heater treater is a pressure vessel equipped with a heating capability to break emulsions that basic separation cannot achieve. The most commonly used treaters are the direct-gas-fired vessel for oil treating and the indirect-gas-fired vessel for gas treating. The flow in the treaters is essentially the same as that in the wash tank. The main difference is that the treaters operate under pressure, which separates substantial volumes of gas. Although an indirect treater can also be used for treating oil emulsions at lower pressures with minor amounts of gas, its use is usually for heating gas at elevated pressures. It raises the temperature of the gas so that hydrates will not form when pressure is reduced.

Often used in place of or in combination with heat to break the emulsion are chemicals. A great variety of chemicals can be used for this purpose, but no one material has proved effective for all emulsions.

After being heated and/or chemically treated, the emulsion is allowed to enter a tank where the water can separate from the oil. The separated liquids are then drawn off — the oil going to the stock tanks, and the water going to the disposal system.

4.3.5 EQUIPMENT SPECIFIC TO CERTAIN PRODUCTION PROCESSES

Each of the types of equipment just discussed is generally utilized in a field as a result of fluid characteristics instead of the production method used. However, several secondary production techniques do require specific pieces of equipment to be effective.

4.3.5.1 Water Injection and Flooding

In general, field equipment employed in secondary water injection projects is similar to that used in primary production. Mechanical lift pumping units and submersible pumping units are extremely common in a typical water injected field. Techniques used to separate the crude oil from the water (i.e., heater treaters, wash tanks, etc.) are identical with those techniques used in primary production. The basic difference is that provisions for injection of water into the reservoir must be provided. The heart of a system of this type is the water injection pump station. Here, water usually transported from the formation is pumped to the water injection well. The water injection well sometimes is an old shut-in well that was previously producing. It can also be a newly drilled hole made solely to be used as a water injection well. The water injected has generally been reclaimed at the production site from the crude oil. After separation from the crude oil and removal of any residual oil, the water is usually softened and then either reinjected into the formation or routed to disposal.

4.3.5.2 Thermal Operations

The heart of a steam injection field or a steam drive field is the steam generator. This unit is generally fueled by crude oil or natural gas. The steam is produced on-site and transported to the injection wells in heated or highly insulated pipelines. In the case of steam drive, it commonly takes four to five barrels of water as injected steam to produce one barrel of oil. For steam injection, the amount of steam used can vary greatly. Once the oil has been produced, the surface treatment procedures are similar to those used in other production systems in which the produced fluid contains water.

4.3.6 WATER TREATMENT FACILITIES

The water leaving the free water knockout unit, the wash and surge tanks, the gun barrels, and heater treaters must be properly treated to reduce the oil and sediment content before discharging into sewers, the ocean, or injecting into the injection wells.

Gravity settling basins are commonly used when a high degree of water cleaning is not necessary. Otherwise, filters are installed as a secondary cleaning method, especially for waterflood systems, where the water must be thoroughly cleaned of oil and sediment.

Another treatment method employs flotation cells. When this system is employed, air or gas is injected upstream of the main process pumps of the system. Some waste waters require chemical treatment for control of basic oxygen demand, microorganisms, and certain gases. The chemical is mixed with air and the water inside the pump and discharged to the retention tank, where the pressure is approximately 203,000 (2) to 304,000 pascal (3 atmospheres).

As the water enters the flotation cell, the air is released as the pressure drops to atmospheric. This causes small sludge and oil particles to be pushed to the top of the flotation cell where a rotating skimming arm sweeps the oil sludge into a compartment for removal. The settled solids at the bottom of the cell are removed by a bottom grit scraper which is also rotated by the same drive shaft as the skimming arm. The clean water effluent is then discharged into the environment or used for repressurizing the well.

4.3.7 CUSTODY TRANSFER

After the produced fluids have been separated, the resulting crude oil must be transported to the refinery. For many years, the oil industry handled this problem by storing the crude in tanks on or near the field. This oil was eventually transported to the refinery using trucks. During the last decade, concentrated engineering efforts have developed pipeline deliveries and automatic devices for handling and measuring oil. Lease automatic custody transfer (LACT) units now exist at most major fields, with oil still being tank gauged in the remaining fields.

A typical LACT unit uses several surge tanks for "averaging" deliveries to the pipeline. In some cases, compressors are tied directly into surge tanks to recover gas and stabilize oil and materially aid overall vapor recovery.

An automatic detector monitors the amount of basic sediment and water (BS & W) flowing and diverts oil for further treatment if the content exceeds a preset maximum. This is another advantage to using LACT units. Some pipelines will not accept more than 0.2 percent BS & W content although 0.3 percent is a more common limit.

In order to properly evaluate emissions due to custody transfer it is necessary to ascertain how common LACT units and pipeline systems and their associated negligible hydrocarbon emissions are used as opposed to tank gauging and trucking of oil with their higher emission potential. A telephone survey to a number of pipeline companies throughout the United States (see Appendix III) revealed that in almost any field producing significant quantities of oil, LACT units (and by assumption, a pipeline) will be employed. Trucking and tank gauging is more common in fields containing a majority of stripper wells. Since this study excludes stripper well activities, it is assumed that all transport is achieved via LACT units and pipelines.

4.3.8 ARTIFICIAL LIFT POWER

The vast majority of production pumping units are powered by electricity. Pumping units were originally powered by gas produced at the field. The introduction of electricity as the primary power source took place many years ago. The primary reason for the switchover to electric motors was to reduce maintenance costs. Electrical motors are far more dependable under a variety of climatic conditions. The old-fashioned gas driven motors inevitably freeze up during periods of cold weather. Production time and money are lost. Another reason for preferring electricity over gas is that many wells are not allowed or are unable to oil 24 hours a day. Wells of this nature are called "on clock." An electric driven pump can easily be put "on clock" automatically. However, a gas driven pump requires a field operator present to turn the pumping unit on or off.

Today, the occurrence of gas powered pumping equipment is often limited to isolated well locations where electricity is not available. Due to the maintenance and operation costs, the installation of gas powered pumping units at an "on clock" well is impractical.

Investigators concluded that the occurrence of gas powered pumping can be expected to be very infrequent. By assuming that power will be supplied by purchased electricity, the emission levels in the fields from power generation will be zero. What will not be considered here is the impact of this electrical demand on powerplant emissions.

4.4 FIELD SPECIFIC SURFACE EQUIPMENT IDENTIFICATION

The technique used to remove water from produced oil varies greatly with the location of the field and the type of oil being produced. To be able to estimate emissions from surface activities, it was necessary to predict what type of equipment could be found in each field. A limiting condition for this prediction was the field parameters available. After evaluation of the data base, it was concluded that the only field parameters which were consistently available from state to state were the oil and gas production statistics for each field, the API gravity of the oil in each field, and the number of wells.

In some cases, the decisions were relatively easy and straightforward. All fields were assumed to utilize water treatment facilities. Thermal operations had been specifically defined in the data base, making fields containing steam generators easy to identify. While it would also be an easy matter to identify water injection fields requiring an additional pumping station, since this only results in increased power consumption, a fact which is disregarded, no special emphasis was placed on these fields.

The major effort in this area was concentrated on utilizing available field parameters to predict the types of oil-gas-water separation systems which would be found in a field. Primary emphasis was placed on the API gravity, a parameter that describes the specific gravity of the produced oil. The higher the API gravity of a certain oil, the lighter it is and hence the easier it separates from water (with an API gravity of 10). After careful study and field investigations in California, Colorado, Louisiana, New Mexico, and Texas, it was found that generally, an oil with an API gravity of 35 or greater could easily be separated from water in a gun barrel. Since a gun barrel operates at atmospheric pressure, if gases were present in fluids passing through a gun barrel, they would be lost. Therefore, in fields which produce gas as well as oil with a high API gravity, a FWKO unit was assumed to be online ahead of the gun barrel to remove the gas.

Oils with an API gravity less than 35 were found to have a tendency to emulsify, making separation more difficult. Treatment of these oils required the more involved systems of heater treaters or wash tanks and surge tanks. Wash tanks and heater treaters both perform the same function, the difference being that a heater treater is pressurized and a wash tank is not. Any oil containing gas which passed through a wash tank would lose that gas to the atmosphere. Fields which produce gas as well as oil with an API gravity of less than 35 were expected to utilize a FWKO unit followed by a pressurized heater treater. Fields which produce oil with negligible quantities of gas only were assumed to treat the fluids through a settling tank followed by a wash tank.

A great many fields produce gas and/or condensate without any oil. These fields utilize the indirect fired heater treater to separate these two products. It was assumed that any field which produced one or both of these products without oil would require this "special" heater treater.

All fields identified in the nationwide inventory have been assigned a numerical code to describe the petroleum products recovered.

The numerical code is:

Oil production	-	1
Oil and condensate production only	-	2
Oil, condensate and gas production	-	3
Condensate and gas production only	-	4
Oil and gas production only	-	5
Gas production only	-	6
Condensate only	-	7

A computer program was written to apply the equipment prediction model to each field based on the numerical code for that field. Figure 4-3 presents the steps used in the model to describe field surface equipment.

4.4.1 COLD CLIMATE MODIFICATION

In field investigations of operations in Colorado it was discovered that in certain northern states the climatic conditions necessitate heating the produced fluids regardless of how light the oil. These states are summarized in Table 4-2. In such a state

Table 4-2 COLD CLIMATE STATES

Alaska	North Dakota
Colorado	South Dakota
Michigan	Utah
Montana	Wyoming
Nebraska	

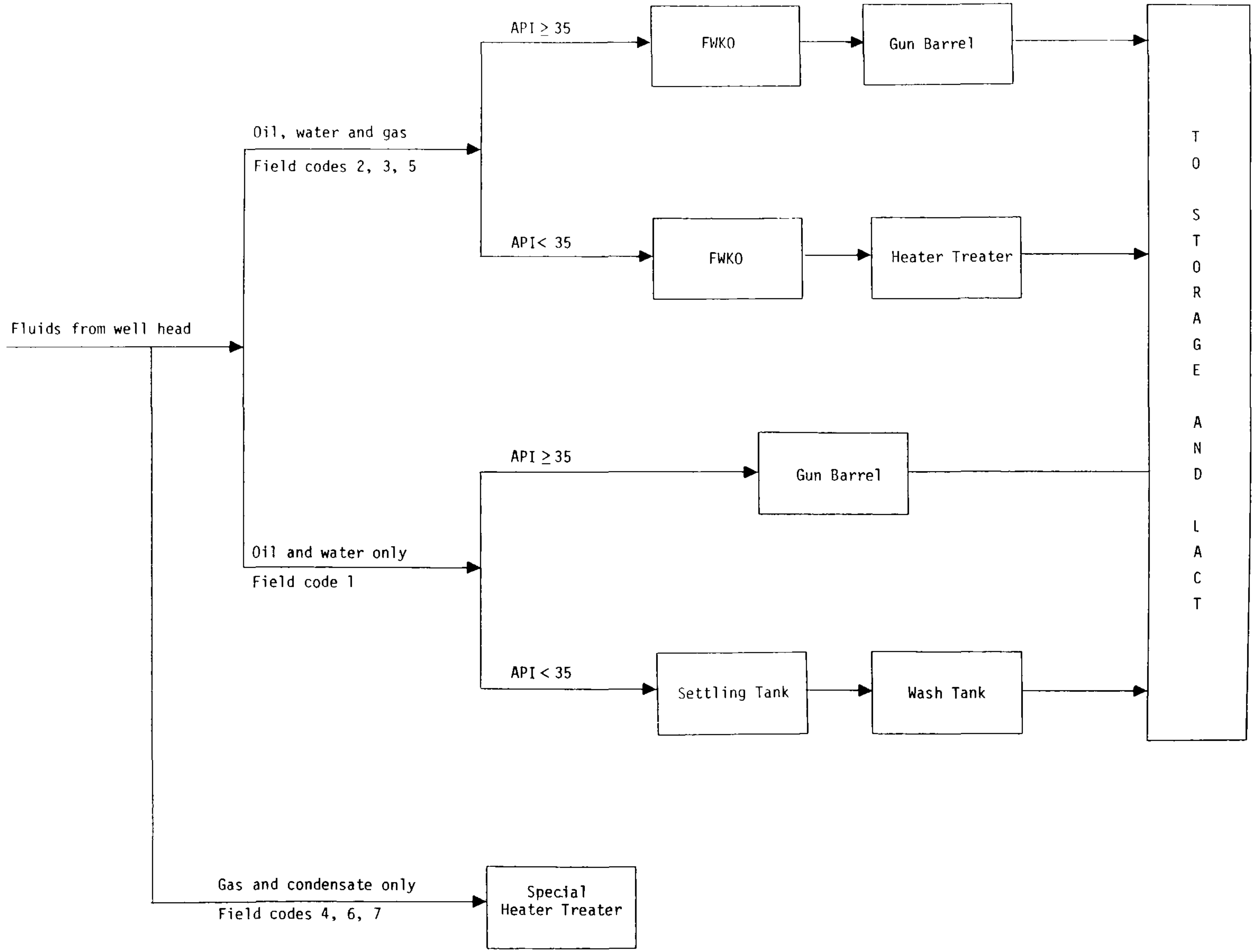

Figure 4-3. Field Equipment Prediction Model

it became necessary to modify the Field Equipment Prediction Model. Basically, the gun barrel was eliminated from consideration. For fields in these states which produce gas in conjunction with any type of oil, surface treatment would consist of a FWKO unit followed by a heater treater. For fields which produce oil only, a surge tank followed by a wash tank would be used. The modified model is shown in Figure 4-4.

4.5 LEVELS OF ACTIVITY AND EMISSION ESTIMATION ASSUMPTIONS

Once the Field Equipment Prediction Model has been applied to a field and expected surface equipment identified, it is necessary to assign levels of activity to each field so that emission estimates can be made. Due to the nature of the field data encoded, levels of activities and emission estimates were modified to be expressed in terms of barrels of throughput per year.

4.5.1 FWKO UNITS

These units are pressurized vessels which do not utilize combustion. The only sources of emissions would be any control valves associated with routing fluids into or around the process and the occasional venting of gases during an overpressurized situation. It is not possible to quantify emergency pressure relief valve ventings but the amount is expected to be small. Control valve emissions are assumed to be handled in a general production field fugitive hydrocarbon emission factor which is applied to each field. Number of units and emissions from FWKO units were not calculated.

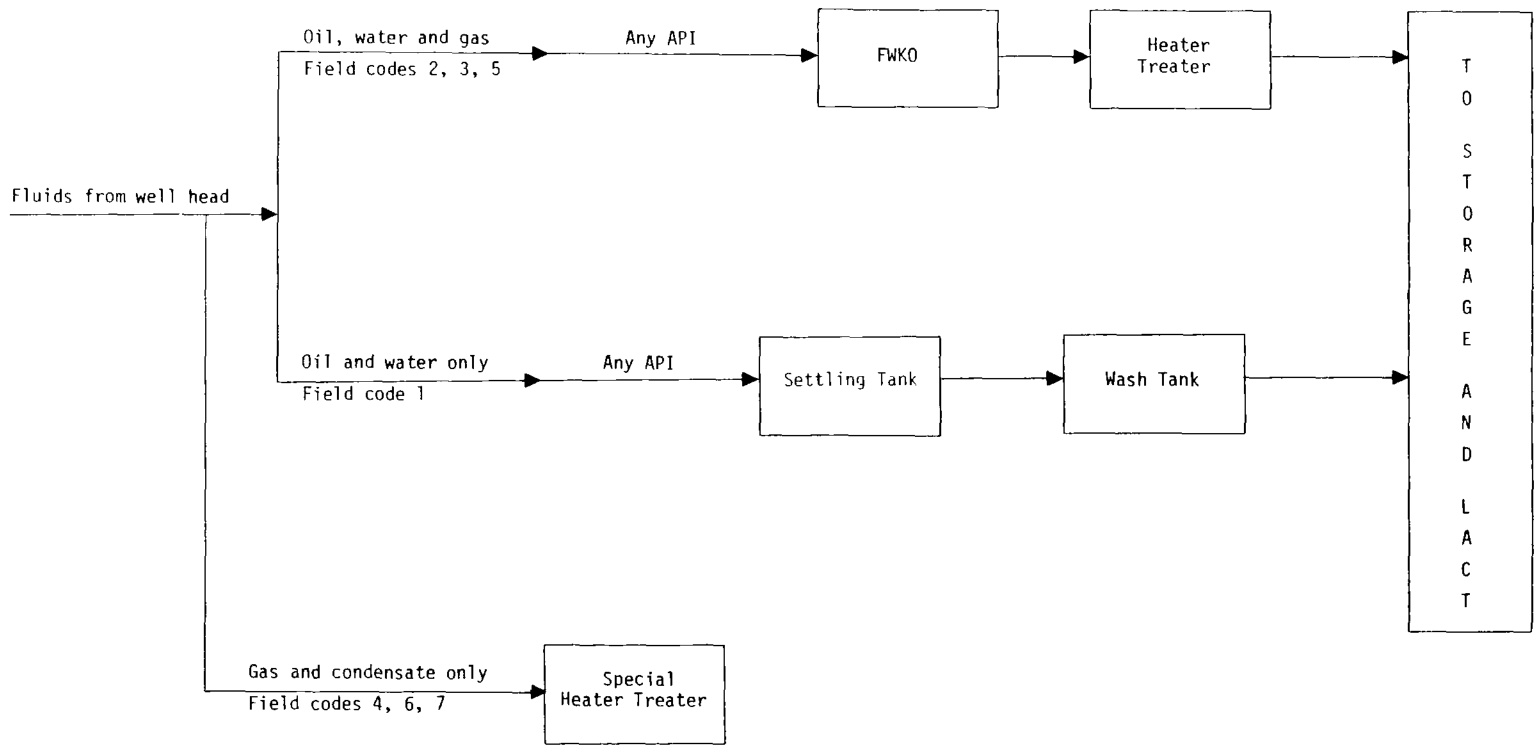

Figure 4-4. Field Equipment Prediction Model Adjusted for Cold Climates

4.5.2 GUN BARREL

Data used in predicting the number of gun barrels present in a field were obtained in field visits to New Mexico and Texas. The standard size of a gun barrel is 280 barrels capacity with dimensions of 3 m (10 ft) diameter by 6.1 m (20 ft) high. Since the unit operates at atmospheric pressure it was assumed to have emission characteristics similar to a fixed roof tank with a flat roof. Calculated emissions from each tank are 96.8 kg of HC/year (see Appendix IV).

In order to correlate this value for one gun barrel to a producing field utilizing several tanks, a relationship must be formed between gun barrel and field throughputs. Field investigations revealed that a settling tank of 280 barrels capacity has a maximum daily throughput of 125 barrels of oil. A field correlation can be developed using the following procedure. The relationship:

$$\frac{\text{(field production in net bbl/yr)}}{\text{(125 net bbl/day/gun barrel)(365 day/yr)}}$$

establishes the number of gun barrels expected in a field. Multiplying this number by 96.8 kg of HC/year/gun barrel will give the annual emissions from this field due to gun barrel activities. Correlating this directly to field size as reported in thousand barrels per year yields:

$$\text{(field size in } 10^3 \text{ bbl/yr)} \left[\frac{\text{(96.8 kg of HC/yr/gun barrel)}(10^3)}{\text{(125 net bbl/day/gun barrel)(365 day/yr)(1,000 kg/MT)}}\right]$$

$$\text{(field size in } 10^3 \text{ net bbl/yr)(0.00212 MT/}10^3\text{ bbl) = HC emissions from gun barrels}$$

4.5.3 HEATER TREATER LIQUID SEPARATION

To predict the amount of energy needed to treat given amounts of oil, the following relationship was used:

$$Q = (\omega)(Cp)(\Delta t)$$

where Q = heat gain, Btu/yr

ω = production weight rate, lb/yr

Cp = heat content of oil, Btu/lb-°F

Δt = necessary temperature change of oil, °F

Production weight rate information in the data base is in 10^3 bbl/yr. To convert ω to allow use of this value, the following modification is made:

$$\omega = [(X)\text{bbl/yr}](350{,}000 \text{ lb}/10^3 \text{ bbl of water})(0.85 \text{ lb of oil/lb of water})$$

$$= 297{,}500\ (x)\ \text{lb/yr} \qquad \text{where } x = \text{annual oil production in } 10^3 \text{ bbl}$$

The temperature change (Δt) needed to bring the crude oil to treating temperature will vary from field to field and with the season. Little or no heat may be required in the summer with up to 60 to 80°F required in the winter. For the purpose of this study, a mid-range value of 40°F for Δt was used. Combining this value with the figure 0.5 for Cp (provided by the American Petroleum Institute), the heat gain necessary to treat a given amount of oil can be calculated as:

$$Q = [297{,}500\ (x)\ \text{lb/yr}](0.5\ \text{Btu/lb-°F})(40\text{°F})$$

$$= 5.95 \times 10^6\ (x)\ \text{Btu/yr}$$

If it is assumed that no heat is lost to the heater's surroundings, then the heat gained by the fluid is equal to the burner heat release. Conversion of heat input to burner heat release will not be 100 percent efficient. If the overall heater treater efficiency is 60 percent, the necessary heat input will be:

$$\frac{5.95 \times 10^6 \text{ (x) Btu/yr}}{0.6} = 9.917 \times 10^6 \text{ (x) Btu/yr}$$

Assuming the heat input to be provided by the combustion of natural gas with a heat content of 1,050 Btu/ft^3 (AP-42, Appendix A, page A-4), the amount of fuel required will be:

$$\frac{9.917 \times 10^6 \text{ (x) Btu/yr}}{1{,}050 \text{ Btu/ft}^3} = 9{,}444 \text{ (x) ft}^3\text{/yr}$$

The combustion of natural gas in the heater treater is expected to produce emission characteristics similar to indirect fired units. Corresponding emission factors from AP-42, page 1.4-2 are:

$$SO_x = 0.0006 \text{ lb/10}^3 \text{ ft}^3 \text{ of gas burned}$$

$$NO_x = 0.23 \text{ lb/10}^3 \text{ ft}^3 \text{ of gas burned}$$

$$HC = 0.003 \text{ lb/10}^3 \text{ ft}^3 \text{ of gas burned}$$

$$CO = 0.017 \text{ lb/10}^3 \text{ ft}^3 \text{ of gas burned}$$

Therefore, to calculate heater treater emission totals from a given field for each of these four pollutants in terms of metric tons (MT) per year, the values used are:

$$SO_x = \frac{(0.0006 \text{ lb/10}^3 \text{ ft}^3)[9.444\text{(x)} \times 10^3 \text{ ft}^3\text{/yr}]}{2{,}204.6 \text{ lb/MT}}$$

$$= 2.6 \times 10^{-6}\text{(x) MT/yr}$$

$$NO_x = 9.9 \times 10^{-4}\text{(x) MT/yr}$$

$$HC = 1.3 \times 10^{-5}\text{(x) MT/yr}$$

$$CO = 7.3 \times 10^{-5}\text{(x) MT/yr}$$

4.5.4 WASH AND SETTLING TANKS

As with the heater treater, the wash tank utilizes heat to separate oil and water emulsions. No information was available concerning heat inputs from these units. Although the heat input to a wash tank may generally be less than a heater treater, it was assumed that the combustion relationship for the heater treater also applies to the wash tank.

Unlike the heater treater, both the settling tank and the wash tank operate at atmospheric pressure. This will result in fugitive hydrocarbon losses. An inventory of wash tanks in California showed the representative size of the units to be 1,000 barrels and emissions from each tank to be 550.2 kg/yr (see Appendix V).

To relate the emissions of hydrocarbons per wash tank to a field predicted to engage in that activity, it is necessary to calculate the number of wash tanks expected in each field. Data presented in Appendix VI can be correlated into the following relationship:

$$y = 139 - 7.99(x)$$

where y = expected wash tank capacity per 10^3 barrels of annual throughput

x = annual production in 10^3 barrels

Once (y) has been calculated for a field, by multiplying that value by the field size, an expression for the wash tank capacity in that field can be made. Dividing this number by 1,000 and rounding up to the nearest whole number to account for partial storage will determine the number of wash tanks in a field.

It was assumed that one settling tank of identical size would be associated with each wash tank. By multiplying the number of wash tanks by two and then by 0.5502 MT/yr/tank, the hydrocarbon emissions from a field's wash tank and settling tank activities can be predicted.

4.5.5 "SPECIAL" HEATER TREATER

From consultation with various equipment manufacturers (Reference 10) it was found that the most commonly used indirect field heater treater for separating gas and condensate is a 0.6 (2) by 1.8 m (6 ft) unit utilizing eight (8) coils, each with a surface area of 2.7 m^2 (29 ft^2). Coil working pressure is 23.2 mega pascal (3,372 psig). The heater treater utilizes 264 mega joule (250,000 Btu) per hour of heat input, usually in the form of natural gas, and is capable of processing 1 mega m^3 (35 million ft^3) of gas per day.

The value 35 million ft^3 per day corresponds to 12,776 million ft^3 per year. To determine the number of heater treaters being used in a gas field it is only necessary to divide the reported value from the data base by 12,776 million ft^3 per year and round upward to the nearest whole number to account for partial capacity. Using the value of 1,050 Btu/ft^3 for the heat content of natural gas, the generation of 250,000 Btu/hr will require the consumption of 238.1 ft^3/hr of gas.

Emission factors used are from AP-42, page 1.4-2.

SO_x = 0.6 lb/10^6 ft^3 burned
CO = 17 lb/10^6 ft^3 burned
HC = 3 lb/10^6 ft^3 burned
NO_x = 230 lb/10^6 ft^3 burned

These values correspond to:

SO_x = 5.6 x 10^{-4} MT/yr/heater treater
CO = 1.6 x 10^{-2} MT/yr/heater treater

$HC = 2.8 \times 10^{-3}$ MT/yr/heater treater

$NO_x = 2.2 \times 10^{-1}$ MT/yr/heater treater

4.5.6 STEAM GENERATORS

The secondary recovery methods termed Thermal Operations utilize a steam generation system to inject heated fluids into the reservoir. Data obtained in field visits to Long Beach and Kern County, California thermal operations, as well as the American Petroleum Institute, indicate that a good rule of thumb in steam operations is that one barrel of crude oil is used for fuel for each four barrels of crude oil produced.

Recently published reports have identified emission factors for the combustion of crude oil. Data from these reports were supplied to project investigators by the Western Oil and Gas Association and are presented in Table 4-3. The last column of the table represents the average of the other two sets of factors. Evaluators used the average values for crude oil combustion.

Since annual production figures are only available in 10^3 barrels, it is necessary to adjust the emission factors to this number. A total of 250 barrels of oil will be combusted to recover one thousand barrels.

$$\left(\frac{\text{250 barrels of oil burned}}{10^3 \text{ barrels of oil produced}}\right)(\text{42 gallons/barrel})$$

$$= 10.5 \times 10^3 \text{ gallons of oil burned}/10^3 \text{ barrels of oil produced}$$

Emissions factors in terms of metric tons (MT) of pollutant per thousand barrels of oil produced are therefore:

$$SO_x = \frac{(10.5 \times 10^3 \text{ gal}/10^3 \text{ bbl})(150.5 \text{ lb}/10^3 \text{ gal})}{2{,}204.6 \text{ lb/MT}} = 0.717 \text{ MT}/10^3 \text{ bbl}$$

Table 4-3. COMPARISON OF FUEL OIL EMISSION FACTORS
($lb/10^3$ gal)

Pollutant	High Sulfur Crude[1] Oil (1.5%)	Low Sulfur Crude[1] Oil (0.5%)	Average Value (1%)
Sulfur Dioxide	137.5(S)[2]	164.4(S)	150.5[3]
Sulfur Trioxide	5.3(S)[2]	9.4(S)	
Carbon Monoxide	5.0	3.1	4.1
Hydrocarbons	0.8	1.6	1.2
Nitrogen Oxides (NO_2)	36.3	30.7	33.5

[1]Data from: Air Pollutant Emissions Testing Report, Oil Field Steam Generators. Performed at the Midway-Sunset Oil Field, Kern County, California; Ryckman/Edgerly/Tomlinson & Associates; July, 1977.

[2](S) = weight percent of sulfur

[3]SO_x weighted average calculated as follows for SO_2: $\frac{137.5(1.5) + 164.4(0.5)}{2} = 144.2(1.0)$

$= 144.2$

for SO_3: $\frac{5.3(1.5) + 9.4(0.5)}{2} = 6.3(1.0) = 6.3$

$$CO = 0.020\ MT/10^3\ bbl$$

$$HC = 0.006\ MT/10^3\ bbl$$

$$NO_x = 0.160\ MT/10^3\ bbl$$

Not all oil in a field can be assumed to be produced using Thermal Operations. In order to establish the portion of the annual production in a field associated with this activity, a proportioning routine is followed. Fields identified as engaged in steam projects will have a certain number of secondary wells (injection and production) associated with the activity. These wells will be designated in Columns 77-79 of the coded information for that field (see Figure 4-1). Dividing this number by the total wells in the field (Columns 64-66) will provide an estimate of the percentage of total production attributable to the Thermal Operations.

4.5.7 FUGITIVE HYDROCARBON SOURCES

A significant source of hydrocarbon emissions from a production field come from what are considered to be "fugitive" sources. Types of equipment usually categorized as sources of fugitive hydrocarbon emissions include: compressor seals, relief valves, wastewater separators, pipeline valves, and pumps. Table 4-4 presents emission factors for each of these sources based on barrels of oil produced. Several studies are now under way to revise these fugitive emission factors, however, these studies are not complete so the value of 107 lb of HC/10^3 bbl of oil produced was used to calculate fugitive loses from production activities.

4.6 YEAR OF RECORD ESTIMATES

Using the equipment prediction model and the estimation procedures just discussed, state estimates of emissions were made for

Table 4-4. FUGITIVE HYDROCARBON EMISSION FACTORS[a]
($lb/10^3$ bbl)

Unit	Crude Oil Production
Compressor seals	4
Relief valves	8
Wastewater separator	8
Pipeline valves	12
Pumps	75
Total	107

[a] Burklin, C.E., R.L. Honerkamp, Revision of Evaporative Hydrocarbon Emission Factors, for U.S. EPA-450/3-76-039, August 1976.

the base year of activity (between 1974 and 1977, depending on the state). These emissions are presented in Table 4-5. As stated earlier, stripper well activities were to be disregarded. It was not possible in most cases to identify the location of the stripper wells with regard to individual fields and pools. Instead, the National Stripper Well Survey (Reference 7) summary totals for each state were used. In addition to Missouri, New York, Pennsylvania and Virginia having 100 percent stripper activity, it was discovered that Alaska, Florida and Nevada have no wells which can be classified as stripper.

To adjust the Year of Record estimates to take into account stripper well activities, a percentage factor for each state during that year has been calculated. This value represents the portion of that state's production activities that are stripper in nature. The annual totals are adjusted downward by these percentages. Table 4-6 summarizes the revised values.

4.7 PROJECTED EMISSIONS THROUGH 1987

In order to effectively estimate the growth of crude production by state to the year 1987 and use those estimates to predict emissions, the services of Dr. Floyd Preston, a consultant from the University of Kansas, were retained. A description of his analysis follows.

4.7.1 PROJECTION ASSUMPTIONS

Prediction of future oil production on a state by state basis cannot be done with high precision or accuracy. The few extent methods for extrapolating production from wells, leases, fields or states all rely upon past data to establish the pattern for the future. To the extent that the future contains unexpected events such as discovery of large new fields (Alaska for instance) or dramatic

Table 4-5. YEAR OF RECORD SURFACE PROCESSING EMISSIONS (10^3 kg/yr)

State	Year of Record	HC	NO_x	SO_x	CO
Alabama	1976	774	2	Neg.	Neg.
Alaska	1976	3,881	79	Neg.	6
Arizona	1977	22	Neg.	Neg.	Neg.
Arkansas	1976	12,899	118	Neg.	9
California	1976	15,593	13,264	58,169	1,644
Colorado	1976	2,002	64	Neg.	5
Florida	1975	2,104	4	Neg.	Neg.
Illinois	1975	1,411	2	Neg.	Neg.
Indiana	1976	291	1	Neg.	Neg.
Kansas	1975	3,419	59	Neg.	4
Kentucky	1975	349	5	Neg.	Neg.
Louisiana	1974	16,147	226	1	17
Michigan	1975	1,203	44	Neg.	3
Mississippi	1976	2,634	34	Neg.	3
Montana	1976	1,818	40	Neg.	3
Nebraska	1975	254	5	Neg.	Neg.
Nevada	1976	44	1	Neg.	Neg.
New Mexico	1975	4,798	78	Neg.	6
North Dakota	1976	1,018	19	Neg.	1
Oklahoma	1975	12,501	113	Neg.	8
South Dakota	1976	20	Neg.	Neg.	Neg.
Tennessee	1976	68	2	Neg.	Neg.
Texas	1976	58,707	2,344	322	175
Utah	1976	1,794	39	Neg.	3
Wyoming	1976	6,948	511	1,632	56
Total		150,699	17,054	60,124	1,943

Table 4-6. STRIPPER WELL ADJUSTMENT TO YEAR OF RECORD SURFACE PROCESSING EMISSION TOTALS (1,000 kg/hr)

State	Year of Record Production (bbl)	Year of Record Stripper Well Production* (bbl)	Stripper Well Adjustment Factor	HC	NO_x	SO_x	CO
Alabama	10,140,000*	162,399	0.0160	762	2	Neg.	Neg.
Alaska	-----------	-----------	------	3,881	79	Neg.	6
Arizona	519,000*	5,723	0.0134	22	Neg.	Neg.	Neg.
Arkansas	18,097,000*	5,198,866	0.287	9,197	84	Neg.	6
California	326,392,000*	52,245,703	0.160	13,097	11,142	48,862	1,381
Colorado	38,992,000*	2,012,511	0.0516	1,899	61	Neg.	5
Florida	-----------	-----------	------	2,104	4	Neg.	Neg.
Illinois	26,487,000	25,214,700	0.952	68	Neg.	Neg.	Neg.
Indiana	4,609,000*	4,470,827	0.970	9	Neg.	Neg.	Neg.
Kansas	57,156,000	43,706,695	0.765	803	14	Neg.	1
Kentucky	7,555,821	6,182,821	0.818	64	1	Neg.	Neg.
Louisiana	323,234,000	7,501,798	0.0232	15,772	221	1	17
Michigan	24,321,000	4,760,253	0.196	967	35	Neg.	2
Mississippi	46,072,000*	1,214,582	0.0264	2,564	33	Neg.	3
Montana	32,814,000*	2,947,320	0.0898	1,655	36	Neg.	3
Nebraska	4,774,000	1,545,430	0.324	171	3	Neg.	Neg.
Nevada	-----------	-----------	------	44	1	Neg.	Neg.
New Mexico	90,753,522	11,082,540	0.122	4,213	68	Neg.	5
North Dakota	21,725,000*	1,075,074	0.0495	967	18	Neg.	1
Oklahoma	157,118,000	73,459,288	0.468	6,651	60	Neg.	4
South Dakota	447,000*	20,516	0.0459	19	Neg.	Neg.	Neg.
Tennessee	598,000*	140,436	0.235	52	2	Neg.	Neg.
Texas	1,153,941,000*	129,699,764	0.112	52,132	2,081	286	155
Utah	37,317,000*	261,823	0.00702	1,781	39	Neg.	3
Wyoming	134,148,000	4,790,719	0.0357	6,700	493	1,574	54
Total				125,594	14,477	50,723	1,646

*Reference 9 values.

changes in economic conditions (for instance the oil embargo of 1972-73) then the past is not a good estimator of the future production. In the selection of the method for extrapolation of past data it was recognized that the purpose of the prediction of future oil production for this study was a secondary objective to the primary one of estimating future statewide pollution levels from oil field production. The method used was the time-honored one of decline curve analysis.

The data were the most recent (1976) API historical records of oil production by state and within Texas by the Railroad Commission District.

The annual oil production from this compilation was plotted on semi-log paper (log of annual oil production) versus year. By visual analysis, the curves for each state, and for Texas, each district, were classified into two categories, (a) those curves for which three or more years of production counting from 1976 backward could be said to follow a linear decline pattern, and (b) those for which this was not true. Particular significance was placed on whether the production of the most recent years (1976 or 1977) seemed to be establishing a new trend.

For those states or districts in which a linear decline was evident [category (a) above], a qualitative choice was made as to how many years to include in the linear least-squares analysis of the data. A computer program calculated the linear least-squares of future production and predicted values for the years 1977 through 1987.

For those states whose production data did not follow a semi-log (constant rate) decline over the past several years, a subjective estimate of the decline was made under the following assumptions.

Where the recent history (one to several years) was one of actual increase (Arkansas, Michigan, Nebraska, North Dakota, Ohio, and Texas District 1) then the trend was allowed to continue to 1977. Beyond that period, the decline was taken to be that established earlier for the state before the increase started. The estimate of that earlier rate was obtained through visual estimation of the most applicable constant decline rate.

Two states, Alaska and Florida, and Texas District 8A presented special problems. Alaskan production from 1970 through 1976 declined at approximately 4.5 percent per year. Extrapolation of this rate for the future would be entirely inappropriate because of the present production increase associated with opening of the Alaskan pipeline. The data used to estimate this future production was taken from a Lewin and Associates study for ERDA (Reference 11). The report displayed graphically (no tabular data given) the Alaskan production from 1976 through 1995 as an increment above expected United States (non-Alaskan) production.

Florida has recently experienced a sharp increase in oil production because of the recent discovery (1970) of the prolific Jay field. However, production for the period 1972-1976 though increasing, indicates that the state's annual production rate is nearing a peak. For this state, the production for 1976 was taken to be the peak and the decline was figured at the overall U.S. decline rate (3.85 percent figured over the last 5 years). This is a somewhat arbitrary process but no other data were available.

Texas District 8A presents a somewhat analogous situation to that of Florida, although the production rate was considerably higher (for 1976, 360,776,000 barrels versus 43,680,000 barrels). Here again the U.S. decline rate of 3.85 percent was applied starting in 1976.

It is widely recognized that additional drilling will discover future oil. However, the rate of drilling and the consequent rate of discovery and rate of production from such activity is extremely uncertain. Very approximate predictions of future national oil production for 1976 through 1990 have been made by FEA (Reference 12) under various scenarios of decontrol of oil prices, continuation of present controls and various expectations as to future discoveries of oil. No state by state predictions were made by FEA and no attempt was made in this study to incorporate such estimates because of their highly uncertain nature. The extrapolations in the present report are therefore dependent in large measure on the continuance of current pricing and other economic policies.

An additional factor that can influence future oil production is the extent to which future enhanced oil recovery methods (also called tertiary oil recovery, and improved oil recovery methods) will be employed in the future. For the purposes of the present study, one prediction for future oil production rate from enhanced oil recovery processes was chosen. This was from the Office of Technology Assessment (OTA) (Reference 13) study assuming high process performance and current (1976) upper tier oil price ($11.62 per barrel).

The method to proportion these annual rates to each state was to assume that the rates in each state will be proportional to the expected ultimate recoveries in each state as given in the OTA study. This is a highly oversimplified assumption since each process is in a somewhat different state of technological development and the mixture of enhanced oil recovery processes is not the same for all states. Neither will any given enhanced process be developed at the same rate in all states. However, without an extensive study such factors could not be considered.

4.7.2 PROJECTION CALCULATIONS

The results of Dr. Preston's analysis was a table presenting the expected annual production rate for each state through 1987 (see Appendix VII). For calculation purposes, these production figures were converted into annual percent changes for each state. Table 4-7 shows the projection matrix used to calculate emissions. For the 1978 values, it was necessary to apply the percentage change to the year of record. The projected annual nationwide emissions for the years 1978-1987 appear in Table 4-8. State by state emission estimates for each projected year are presented in Appendix VIII. Values in these tables reflect the stripper well adjustments shown in Table 4-6.

4.8 SULFUR COMPOUND EMISSIONS FROM NATURAL GAS PRODUCTION

A problem arose in the identification and quantification of sources of H_2S. The only consistently recorded measure of sulfur in crude oil is the organic sulfur content. It was not possible to correlate the presence of H_2S to this value. Discussions with the U.S. Geological Survey and specific state agencies did not uncover any information or statistics for sulfur reported as H_2S. Without specific field or state information, the emission discussion will have to be general in nature.

4.8.1 YEAR OF RECORD ESTIMATES

Data used in this discussion comes from Sulfur Compound Emissions of the Petroleum Production Industry (Reference 14). Table 4-9 reproduces combined information from two tables in that document (Table 5, page 77 and Table 7, page 87) concerning sulfur emissions from natural gas production. The numbers presented are for the amount of sulfur emitted. The actual amount produced is approximately 1,400,000 MT/yr but the major portion (1,000,000 MT/yr) is recovered.

Table 4-7. DECLINE OR GROWTH PROJECTIONS FOR EACH STATE AS A PERCENTAGE CHANGE FROM THE PREVIOUS YEAR

State	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Alabama	- 3.75	- 3.68	-3.82	- 3.74	- 3.65	- 3.78	- 3.80	- 3.68	- 3.68	- 3.82
Alaska	+46.7	+88.1	+39.9	+ 4.73	0	0	- 4.51	- 4.91	- 2.39	- 5.10
Arizona*	- 1.31	+ 2.76	+ 2.27	- 2.24	- 0.85	- 5.17	- 3.54	- 3.83	- 1.35	- 2.03
Arkansas	- 1.97	- 1.34	- 1.36	- 2.76	- 2.13	- 2.17	- 2.96	- 2.29	+ 2.34	+ 2.29
California	- 0.32	0	- 0.32	- 1.27	- 1.29	- 1.31	- 1.32	- 1.01	+ 3.01	+ 2.63
Colorado	- 3.86	- 3.72	- 4.17	- 3.73	- 6.77	- 0.69	- 3.83	- 3.99	- 3.77	- 3.92
Florida	- 3.81	- 3.96	- 3.87	- 3.75	- 3.90	- 6.67	- 0.93	- 4.08	- 3.59	- 3.73
Illinois	- 7.62	- 6.80	- 6.77	- 7.82	- 7.27	- 7.19	- 7.04	- 6.06	- 0.81	0
Indiana	- 8.55	- 8.78	- 8.70	- 8.84	- 8.96	- 8.61	- 8.97	- 8.37	- 9.14	- 8.28
Kansas	- 3.30	- 3.04	- 2.74	- 4.23	- 3.99	- 3.94	- 3.87	- 3.55	+ 3.69	+ 3.79
Kentucky	- 8.79	- 8.76	- 8.83	- 8.63	- 8.76	- 8.84	- 8.86	- 8.51	- 8.97	- 8.76
Louisiana	- 9.46	- 9.03	- 9.14	- 9.48	- 9.21	- 9.09	- 9.23	- 9.32	- 7.94	- 8.12
Michigan	- 4.75	- 4.72	- 4.68	- 4.91	- 4.60	- 4.78	- 4.68	- 4.91	- 4.80	- 4.65
Mississippi	- 6.07	- 6.20	- 6.06	- 6.16	- 6.25	- 6.33	- 6.05	- 6.06	- 4.44	- 4.64
Montana	- 1.88	- 1.92	- 1.63	- 1.99	- 1.69	- 2.06	- 1.75	- 1.79	- 2.18	- 1.86
Nebraska	-12.5	-13.0	-13.4	-13.8	-14.0	-11.6	-13.2	-13.6	-12.3	-12.0
Nevada*	- 1.31	+ 2.76	+ 2.27	- 2.24	- 0.85	- 5.17	- 3.54	- 3.83	- 1.35	- 2.03
New Mexico	- 3.61	- 6.63	- 3.21	- 0.83	- 4.04	- 3.92	- 3.78	- 3.77	- 0.16	- 0.16
North Dakota	+ 6.98	- 3.48	- 5.41	- 5.71	- 5.05	- 4.79	- 5.03	- 2.94	- 6.06	- 5.81
Oklahoma	- 4.29	- 4.48	- 3.91	- 5.69	- 4.31	- 5.41	- 4.76	- 4.30	+ 1.78	+ 2.16
South Dakota	- 6.30	- 6.20	- 6.34	- 6.18	- 6.27	- 6.35	- 6.43	- 6.11	- 6.50	- 6.09
Tennessee	-11.8	-11.8	-12.0	-11.6	-11.9	-11.7	-12.1	-11.5	-11.9	-11.8
Texas	- 1.75	- 1.79	- 1.82	- 1.85	- 2.83	- 1.94	- 1.78	- 2.02	- 1.13	- 1.14
Utah	- 7.53	- 4.81	- 3.11	- 2.41	- 1.23	- 0.83	- 2.94	- 0.43	- 2.61	- 1.79
Wyoming	- 1.60	- 2.44	- 2.50	- 1.71	- 2.61	- 2.68	- 1.83	- 2.80	- 0.96	- 0.97

*No specific state data available, so used nationwide figures.

Table 4-8. NATIONWIDE PRODUCTION AND PROCESSING EMISSIONS FOR YEARS 1978-1987 (1,000 kg/yr)

Year	HC	NO_x	SO_x	CO
1978	123,686	14,397	50,537	1,639
1979	125,091	14,412	50,494	1,642
1980	126,041	14,384	50,295	1,636
1981	123,327	14,182	49,648	1,613
1982	119,567	13,937	48,984	1,587
1983	116,402	13,726	48,321	1,564
1984	112,787	13,504	47,675	1,542
1985	109,221	13,313	47,166	1,522
1986	108,041	13,581	48,523	1,558
1987	106,536	13,814	49,743	1,590

Table 4-9. EMISSIONS OF SULFUR COMPOUNDS IN THE UNITED STATES IN 1973 (1,000 kg/yr)

Location	Estimated Sulfur Emissions	Actual Emissions	
		Sulfur Dioxide	Hydrogen Sulfide
Study Area:			
Alabama, Arkansas South, Florida, Louisiana North, Mississippi, New Mexico East, Texas	309,000	603,000	8,000
Outside Study Area:			
Arkansas (N)	0	0	0
California	5,080	10,026*	75*
Colorado	1,016	2,006*	15*
Kansas	5,080	10,206*	75*
Kentucky	0	0	0
Louisiana (S)	2,032	4,010*	30*
Michigan	5,080	10,026*	75*
Montana	3,048	6,016*	45*
North Dakota	20,321	40,110*	299*
New Mexico (NW)	10,061	19,858*	149*
Oklahoma	27,435	54,152*	404*
Utah	0	0	0
Wyoming	25,401	50,136*	375*
TOTAL	413,554	809,336	1,542

Note: Ohio values disregarded since activities are not being considered.

*Estimated ratio based on study area relationship.

4.8.2 PROJECTED EMISSIONS THROUGH 1987

To calculate emissions for the years 1974-1977, the U.S. petroleum production decline rate over the last five years (as reported by Dr. Preston) was used. For the years 1978-1987, nationwide percentage changes based on Dr. Preston's own work are used (see Appendix VII). The results are shown in Table 4-10. This projection assumes a uniform H_2S concentration in natural gases processed during that period.

Table 4-10. PROJECTED SULFUR COMPOUND EMISSIONS IN THE UNITED STATES 1974-1987
(1,000 kg/yr)

Year	Percentage Change As A Function of Previous Year	Sulfur Dioxide	Hydrogen Sulfide
1974	-3.85	778,177	1,483
1975	-3.85	748,217	1.426
1976	-3.85	719,411	1,371
1977	-3.85	691,713	1,318
1978	-1.31	682,652	1,301
1979	+2.76	701,493	1,337
1980	+2.27	717,417	1,367
1981	-2.24	701,347	1,336
1982	-0.85	695,386	1,325
1983	-5.17	659,435	1,256
1984	-3.54	636,091	1,212
1985	-3.83	611,729	1,166
1986	-1.35	603,471	1,150
1987	-2.03	591,221	1,127

5.0 PRODUCTION STORAGE

Produced oil and condensate must be stored prior to custody transfer (pipeline or truck). Such storage is commonly performed in a series of tank batteries usually situated at or near the various production and processing facilities spread about a field. The tank itself commonly has a fixed roof, and is of either welded or bolted construction. Hydrocarbon emissions from these tanks can be expected to constitute one of the more significant sources of pollution from the oil and gas production industry. This section discusses the methodology used by the investigators to estimate the number of storage tanks in each state, the tank size mix and the hydrocarbon emission estimates for both the year of record and each projected year through 1987.

5.1 STORAGE TANK DATA BASE

For a variety of reasons including lack of applicable regulations, very few extensive inventories of production field tankage have been completed. Project investigators were able to discover only two. One inventory was produced by the Kern County, California, Air Pollution Control District and contained tankage data by company for all fields in the county. The second inventory was of all tanks in Texas fields. This information was gathered by the Texas Mid-Continent Oil and Gas Association and relayed to PES by Mr. C.R. Kreuz of Mobil Oil Corporation in Houston, Texas.

5.2 ESTABLISHMENT OF STORAGE CAPACITY — FIELD RELATIONSHIPS

In each inventory case, the first step involved the grouping of storage tanks by individual fields. Once all possible individual field and tank assignments had been made, a storage capacity ratio was calculated. This number was obtained by dividing the total field storage capacity in barrels by the field size expressed as thousands of barrels of annual production. A total of 61 such relationships could be calculated for California fields and 1,028 ratios were calculated for Texas.

The relationships for each state were plotted separately on natural log-log paper to determine if a linear correlation of data existed. A least-square analysis of each set of data was performed, resulting in an expression for the relationship in each state. Figure 5-1 shows the relationships calculated for each set of information. The mathematical expression for each is:

California expression $y = 3{,}837\ (x)^{-0.29}$,

Texas expression $y = 28{,}519\ (x)^{-0.605}$

where: x is the field annual production in barrels and

y is the storage capacity ratio in barrels per thousand barrels of annual production.

The expected field storage capacity can then be calculated by multiplying the storage capacity ratio by the field production in thousands of barrels.

Close examination of the California and Texas ratios show that they are based on two very different field storage tank densities, especially in large field situations. Investigators undertook to discover if either or both expressions were representative and in what recognizable field situations. The solution was provided by Dr. Preston, who stated that the Texas data reflect the process of unitization, a condition not generally in effect in the Kern County fields. Unitization is a system of operating a certain oil and condensate reservoir in order to conduct some form of pressure maintenance, repressurizing, waterflood, or other cooperative form to increase ultimate recovery. By utilizing unitization, field operators are able to combine resources, reducing the total number of

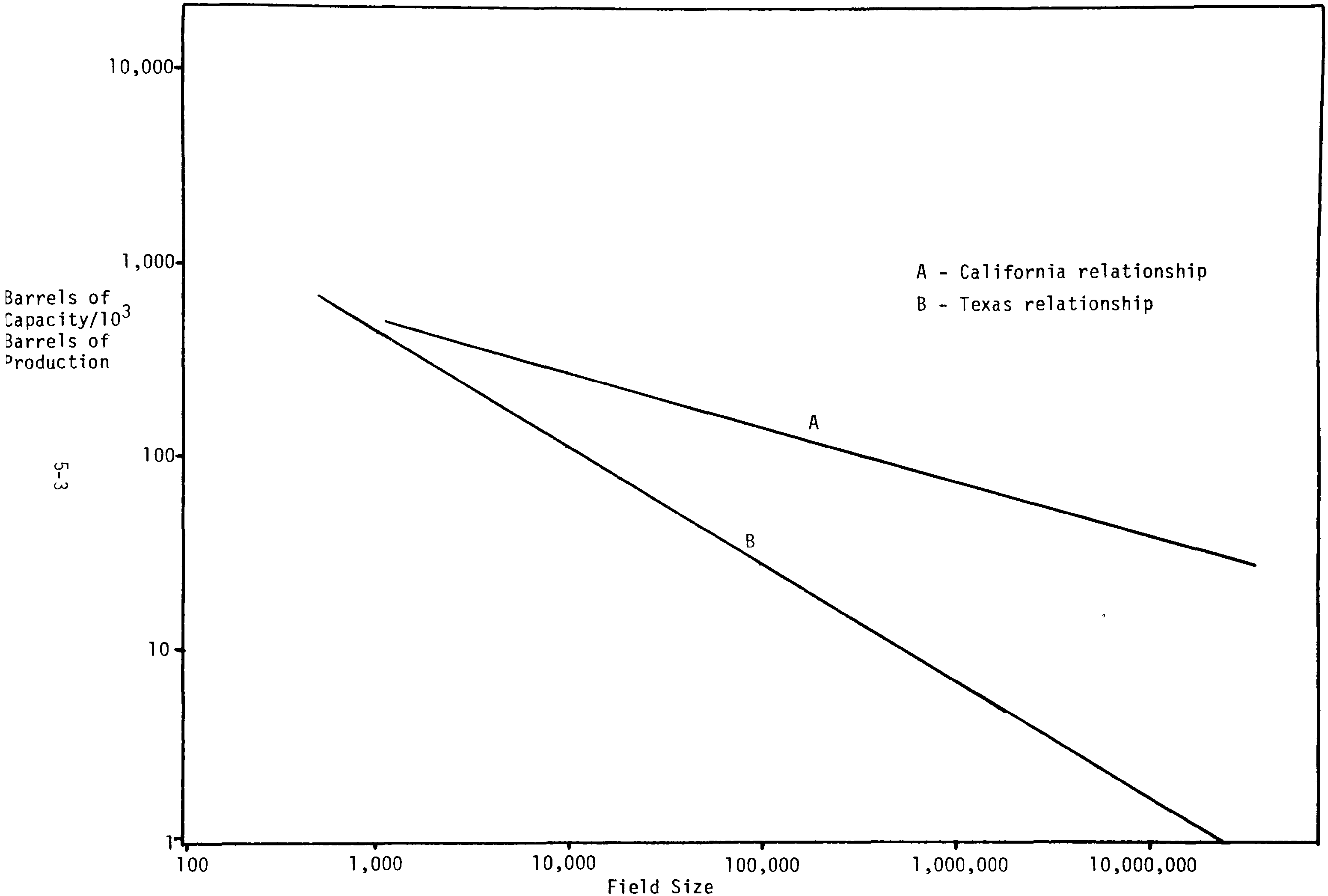

Figure 5-1. Storage Capacity Relationships

tanks found in a field. Project engineers decided to apply the Texas storage tank ratio to any field exhibiting secondary production activities and the California ratio to any field without secondary activities.

5.3 TANK SIZE ASSIGNMENTS

To predict emissions from storage of crude oil, it is necessary to establish the number of tanks and the size mixture to be assigned to the calculated field storage capacity value. The Texas and California inventories indicated three dominant tank sizes: 210 barrels, 500 barrels, and 1,000 barrels capacity. All of the inventoried fields had the various assigned tanks categorized by size into three groups: (1) 250 barrels or less, (2) 250 to 500 barrels, and (3) more than 500 barrels. Table 5-1 summarizes the tank categorization distributions for different field sizes.

Table 5-1. TANK INVENTORY SUMMARY

Field Size (10^3 bbl/yr)	Number of Tanks in Survey	Percent of Tanks in Each Size Category		
		≥ 250 bbl	250 to 500 bbl	7,500 bbl
0-10	1,009	48.86(27.16)*	47.27(62.59)	3.87(10.25)
10-100	2,309	36.68(18.06)	56.74(66.51)	6.58(15.43)
100-1,000	3,179	20.89(8.27)	60.82(57.34)	18.24(34.39)
1,000-and greater	3,157	5.83(2.22)	80.52(73.02)	13.65(24.76)

*Values in parentheses represent the percent of total capacity stored in each size category.

The table indicates that for fields producing 10,000 barrels per year or less, 48.86 percent of the tanks inventoried were in the size category of 250 barrels or less, 47.27 percent in the 250 through 500 barrel category, and 3.87 percent in the greater than 500 barrel category. All tanks in each of these size categories were assumed to be the same size. The smallest tanks were all assumed to be 210 barrel units, with the medium size being 500 barrels, and the largest tanks all 1,000 barrels in size. The tank percentages cannot be directly applied to a field storage capacity ratio, since the first number concerns numbers of tanks and the second is in terms of field capacity (bbl/10^3 bbl of production). Using the tank distribution and specific tank size assumptions, Table 5-1 indicates that for a field of 10,000 barrels per year or less, the following distribution of storage capacities among the various tank sizes will be available:

$$
\begin{aligned}
& (0.4886)(0.21 \times 10^3 \text{ bbl}) && = 0.1026 \\
+ \; & (0.4727)(0.5 \times 10^3 \text{ bbl}) && = 0.2364 \\
+ \; & (0.0387)(1.0 \times 10^3 \text{ bbl}) && = \underline{0.0387} \\
& \qquad \text{Total} && = 0.3777 \times 10^3 \text{ bbl}
\end{aligned}
$$

Of this total of 0.3777 x 10^3 bbl, the 210 barrel tanks while comprising nearly 50 percent of the number of tanks, only represent 27.16 percent of the available capacity. This conversion to capacity relationships has been performed for each tank size and field category and appears as the values in parentheses in Table 5-1. With these values, tank assignments can be made to specific fields.

Based on the size and type of field, the calculated storage capacity relationship is multiplied by the specific tank capacity distribution percentages and then divided by the appropriate tank size to assign the number of each size tank to that field. A sample calculation is demonstrated in Table 5-2.

Table 5-2. CALCULATION OF NUMBER OF TANKS IN OIL FIELDS PRODUCING 150,000 BBL/YR AND NOT EMPLOYING SECONDARY PRODUCTION

Step 1	Step 2	Step 3		
		Calculate Number of Tanks of Each Size		
Calculate field storage capacity ratio	Calculate total field storage capacity	210	500	1,000
$3{,}837(150{,}000)^{-0.29}$ $= 121\ \text{bbl}/10^3$ bbl of production	$(121\ \text{bbl}/10^3\ \text{bbl})(150 \times 10^3\ \text{bbl})$ = 18,150 bbl	(0.0827)(18,150 bbl) = 1,501 bbl $\frac{1{,}501\ \text{bbl}}{210\ \text{bbl/tank}} = 7.15$ tanks	(0.5734)(18,150 bbl) = 10,407 bbl $\frac{10{,}407\ \text{bbl}}{500\ \text{bbl/tank}} = 20.8$ tanks	(0.3439)(18,150 bbl) = 6,242 bbl $\frac{6{,}242\ \text{bbl}}{1{,}000\ \text{bbl/tank}} = 6.2$ tanks

5.4 EMISSION ESTIMATES AND TANK INVENTORY

Several recent studies have been performed which indicate that hydrocarbon losses from fixed roof storage tanks may be significantly lower than those calculated using the traditional relationships. However, much of this work has still to be finalized. For the purpose of this study, the emission factors presented in Compilation of Air Pollutant Emission Factors, AP-42, Part A, Second Edition, Section 4.3, "Storage of Petroleum Liquids", April, 1977, were used.

Emissions from each of the three tank types were calculated to be (see Appendix IX):

210 barrel unit:	0.49 MT/yr/tank
500 barrel unit:	1.273 MT/yr/tank
1,000 barrel unit:	2.61 MT/yr/tank

All tanks were assumed to utilize a fixed roof, to experience 30 turnovers per year (AP-42 assumption), and to vent uncontrolled to the atmosphere. Evaluators are aware that a certain proportion of existing crude oil storage tanks employ vapor recovery as a control measure. However, inquiries of state and local air control agencies could not produce figures for the level of activity in any state. Without accurate information, evaluators did not include a vapor recovery adjustment in the emission estimates.

Table 5-3 presents the calculated tank mix and hydrocarbon estimates for each state during the year of record.

5.5 PROJECTED EMISSIONS

The amount of oil being extracted and processed from a given field will vary from year to year based on a variety of conditions specific to both that field and the total industry. It is felt that as these production fluctuations are experienced, tank usage will be affected both in throughput and number of tanks in

Table 5-3. YEAR OF RECORD STORAGE TANK SUMMARY

State	Number of Tanks				Hydrocarbon Estimation (1,000 kg/yr)	Stripper Well Estimation (1,000 kg/yr)
	210 bbl	500 bbl	1,000 bbl	Total		
Alabama	245	755	185	1,185	1,565	1,540
Alaska	10	82	14	106	147	147
Arizona	26	57	14	97	121	119
Arkansas	1,525	7,325	1,268	10,118	13,337	9,509
California	2,260	6,146	1,282	9,688	12,269	10,306
Colorado	1,501	2,576	398	4,475	4,985	4,728
Florida	85	283	72	440	590	590
Illinois	642	998	141	1,781	1,910	92
Indiana	299	403	56	758	780	23
Kansas	4,423	6,305	856	11,584	12,155	2,856
Kentucky	612	914	133	1,659	1,800	328
Louisiana	5,411	19,517	4,146	29,074	38,272	37,384
Michigan	1,601	2,994	561	5,156	6,028	4,847
Mississippi	2,827	6,094	1,128	10,049	11,986	11,670
Montana	626	1,613	329	2,568	3,184	2,898
Nebraska	741	952	103	1,796	1,772	1,198
Nevada	23	68	20	111	151	151
New Mexico	2,424	5,580	1,086	9,090	11,076	9,725
North Dakota	744	1,584	357	2,685	3,307	3,143
Oklahoma	4,178	9,834	1,691	15,703	18,848	10,027
South Dakota	46	74	12	132	148	141
Tennessee	58	98	20	176	205	157
Texas	33,131	70,567	12,143	115,841	136,380	121,105
Utah	280	1,559	279	2,118	2,853	2,833
Wyoming	2,262	6,434	1,324	10,020	12,717	12,263
TOTAL	65,980	152,812	27,618	246,410	296,586	247,780

service. Decisions to operate solely by varying tank throughputs or to either add or decrease tankage will be an individual decision and cannot be predicted within the scope of this project. For the purpose of predicting future tankage and emissions, it has been assumed that state production fluctuations will be reflected in corresponding tank usage modifications. To provide these anticipated changes, the projection matrix developed from Dr. Preston's data will be used. Table 5-4 shows the projected hydrocarbon emissions from storage tanks for the years 1978-1987. Table 5-5 presents the final estimation when adjustments are made assuming a stable statewide level of stripper well activities for the years in question.

Table 5-4. STORAGE TANK HYDROCARBON EMISSIONS FOR THE YEARS 1978-1987
(1,000 kg/yr)

State	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Alabama	1,506	1,451	1,396	1,344	1,295	1,246	1,198	1,154	1,112	1,070
Alaska	215	404	566	593	593	593	566	538	526	499
Arizona	119	122	125	122	121	115	111	107	106	104
Arkansas	13,074	12,900	12,724	12,372	12,109	11,846	11,495	11,232	11,494	11,758
California	12,230	12,230	12,191	12,037	11,881	11,726	11,571	11,453	11,798	12,108
Colorado	4,793	4,614	4,422	4,257	3,969	3,949	3,798	3,646	3,509	3,372
Florida	567	545	523	504	484	452	448	429	414	398
Illinois	1,765	1,644	1,533	1,413	1,311	1,216	1,131	1,062	1,053	1,053
Indiana	713	650	594	541	492	450	409	375	340	313
Kansas	11,754	11,396	11,084	10,615	10,191	9,790	9,411	9,077	9,412	9,769
Kentucky	1,641	1,498	1,366	1,249	1,140	1,039	948	868	790	721
Louisiana	34,651	31,522	28,641	25,926	23,539	21,399	19,424	17,613	16,215	14,898
Michigan	5,741	5,470	5,215	4,959	4,731	4,504	4,293	3,871	3,686	3,515
Mississippi	11,259	10,561	9,921	9,310	8,728	8,176	7,681	7,215	6,895	6,575
Montana	3,124	3,063	3,014	2,954	2,904	2,844	2,794	2,744	2,684	2,635
Nebraska	1,551	1,349	1,169	1,007	867	766	665	575	505	444
Nevada	149	153	156	152	151	143	138	133	131	128
New Mexico	10,676	9,969	9,649	9,569	9,183	8,823	8,489	8,169	8,157	8,144
North Dakota	3,538	3,415	3,230	3,046	2,892	2,754	2,616	2,539	2,385	2,247
Oklahoma	18,039	17,231	16,557	15,616	14,942	14,134	13,461	12,882	13,111	13,394
South Dakota	138	130	122	114	107	101	94	88	82	77
Tennessee	181	160	141	125	110	97	86	76	68	59
Texas	133,993	131,595	129,200	126,810	123,221	120,830	118,680	116,282	114,968	113,658
Utah	2,638	2,511	2,433	2,375	2,346	2,326	2,258	2,248	2,190	2,151
Wyoming	12,514	12,208	11,903	11,699	11,394	11,088	10,885	10,580	10,479	10,378
TOTAL	286,569	276,791	267,875	258,709	248,701	240,407	232,650	224,956	222,110	219,468

Table 5-5. STRIPPER WELL ADJUSTMENTS TO STORAGE TANK ESTIMATES FOR THE YEARS 1978-1987 (1,000 kg/yr)

State	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Alabama	1,481	1,427	1,373	1,322	1,274	1,226	1,179	1,135	1,094	1,053
Alaska	215	404	566	593	593	593	566	538	526	499
Arizona	117	120	123	120	119	113	109	106	105	103
Arkansas	9,321	9,198	9,072	8,822	8,633	8,446	8,196	8,008	8,196	8,383
California	10,273	10,273	10,240	10,111	9,981	9,850	9,720	9,620	9,910	10,170
Colorado	4,545	4,376	4,194	4,037	3,764	3,746	3,602	3,458	3,328	3,198
Florida	567	545	523	504	484	452	448	429	414	398
Illinois	85	79	74	68	62	59	54	51	50	50
Indiana	21	19	18	16	15	14	12	11	10	9
Kansas	2,762	2,678	2,605	2,494	2,395	2,300	2,212	2,133	2,212	2,296
Kentucky	299	272	248	227	207	189	173	158	144	131
Louisiana	33,847	30,791	27,977	25,325	22,992	20,902	18,974	17,205	15,839	14,553
Michigan	4,616	4,399	4,192	3,987	3,803	3,621	3,452	3,113	2,964	2,826
Mississippi	10,961	10,282	9,660	9,064	8,497	7,960	7,478	7,025	6,713	6,401
Montana	2,844	2,788	2,743	2,688	2,643	2,588	2,543	2,498	2,443	2,398
Nebraska	1,048	912	790	681	586	518	449	389	341	300
Nevada	149	153	156	152	151	143	138	133	131	128
New Mexico	9,374	8,753	8,472	8,402	8,063	7,747	7,454	7,173	7,161	7,151
North Dakota	3,362	3,246	3,070	2,895	2,749	2,618	2,486	2,413	2,267	2,136
Oklahoma	9,596	9,167	8,809	8,307	7,950	7,519	7,161	6,853	6,975	7,126
South Dakota	132	124	116	109	103	96	90	84	78	74
Tennessee	138	123	108	95	84	74	66	58	51	45
Texas	118,986	116,855	114,729	112,608	109,421	107,297	105,388	103,259	102,092	100,928
Utah	2,619	2,494	2,416	2,358	2,329	2,310	2,242	2,233	2,174	2,135
Wyoming	12,067	11,772	11,477	11,282	10,987	10,692	10,496	10,203	10,105	10,007
TOTAL	239,425	231,250	223,751	216,267	207,885	201,073	194,688	188,286	185,323	182,498

6.0 COSTS AND ANALYSES OF CONTROL OPTIONS

The types of operations in use in the petroleum production industry present several important control options. The most important emission sources to be considered are: (1) hydrocarbon emissions from storage tanks, (2) control of H_2S removed from natural gas, (3) fugitive hydrocarbon emissions from surface valves and seals, and (4) use of alternate fuels in specific combustion sources.

6.1 CONTROL OF HYDROCARBON EMISSIONS FROM FIXED ROOF STORAGE TANKS

6.1.1 VAPOR RECOVERY USING COMPRESSION

Vapor recovery, a control technique commonly applied in petroleum refineries, has had only limited applications in production operations. While its use in very large tank battery situations in California and Texas cannot be overlooked, the control strategy is not considered to have general application to the petroleum production industry.

The recovered compressed gas must be disposed of by either combustion or removal. Due to the small volumes considered [10.6 m^3/day/tank (375 ft^3/day/tank)]*, routing the gases to a flare or fuel-fired unit would not be practical. Compression and removal would require the availabilty of a pipeline. Therefore, the first limiting factor is the need for a field utilizing a pipeline for custody transfer.

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* This value is obtained by dividing the figure of 15.77 lb of HC/day/tank (see Appendix IX) by the value of 0.042 lb/ft^3 of methane at 60°F.

The second problem involves the minimum available size for the compression unit. The stated minimum size for the necessary compression system is approximately 122 m^3 (4,300 ft^3) per day (Reference 15). Using the calculated value for hydrocarbon vapor loss volumes from the largest 1,000 barrel tanks of 375 ft^3/day/tank, to utilize such a compression system would require a battery of 12 such tanks in close enough proximity to be connected to the one compressor. Review of the tank inventory revealed only a small number of fields where these requirements could possibly be met. The project staff concluded that this system was not viable on an industry-wide basis.

6.1.2 INTERNAL FLOATING ROOF

A hydrocarbon control technique with a wider application to the total industry is the installation of an internal floating cover to existing tanks. As with the vapor recovery system, there are limits to its use. Many of the smaller bolted tanks as well as tanks containing other internal obstructions such as heating coils would be unavailable for installation of internal covers. However, the potential application and emission reduction is felt to be significant enough to warrant consideration. The cost parameters for the three tank sizes under consideration are presented in Table 6-1. The installed capital cost is an average of quotes obtained from three different manufacturers (References 16, 17, 18). Uncontrolled emissions are the calculated values using AP-42 fixed roof equations. The controlled value was obtained by applying the AP-42 floating roof equation to each tank.

Control cost estimates for retrofitting existing fixed roof tanks with an internal floating roof are presented in Table 6-2. The net annual cost subtracts a petroleum credit

Table 6-1. COST PARAMETERS FOR CONTROL OF HC EMISSIONS FROM FIXED ROOF TANKS (INTERNAL FLOATERS)

Tank Size bbl (liters)	210 (33×10^3)	500 (79×10^3)	1,000 (159×10^3)
Installed Capital Cost ($)[a]	3,890	4,880	6,130
Annual Operational Cost (% of installed capital)[b]	6	6	6
Replacement Life (yrs)[b]	30	30	30
Uncontrolled Emissions (kg/yr)	490	1,270	2,610
Controlled Emissions (kg/yr)	200	320	480
Percent Control	59	75	82
Petroleum Value ($/kg)[b]	.136	.136	.136

[a] References 16, 17,18

[b] EPA 450/2-77-036, December 1977, Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed Roof Tanks.

Table 6-2. CONTROL COST ESTIMATES FOR EXISTING FIXED ROOF TANKS[a]

Control Device	Internal Floating Roof		
Tank Size bbl (liters)	210 (33×10^3)	500 (79×10^3)	1,000 (159×10^3)
Installed Capital Cost ($)	3,890	4,880	6,130
Operating and Maintenance ($/yr)	230	290	370
Capital Charges ($/yr)[b]	570	710	890
Petroleum Credit ($/yr)	(40)	(130)	(290)
Net Annual Cost or (Credit)($/yr)	760	870	970
VOC Reduction (kg/yr)	290	950	2,130
Cost (Credit) per kg ($/kg)	2.62	0.92	0.46

[a] See Table 6-1.

[b] Capital recovery factor for 30 year life, and 10 percent interest plus 4 percent for taxes, insurance and administration (see Reference b, Table 6-1).

associated with the reduced hydrocarbon losses experienced when an internal floater is installed. The final value is an expression for the amount of money necessary to recover a kilogram of hydrocarbon.

6.1.3 POTENTIAL EMISSION REDUCTION ACHIEVEMENT

Table 6-3 demonstrates the amount of hydrocarbon reduction that can be achieved when internal floating roofs are installed on all existing tanks. Estimates are presented for both the year of record and 1987. An effort was made to quantify the percentage of tanks which would have heating coils and therefore be unavailable for the retrofit. Insufficient information existed in the data base to make such a determination. The frequency of such tanks will be higher in colder states and areas where heavy crudes having a pour point of approximately 38°C (100°F) or less are processed.

6.2 H_2S EMISSIONS FROM NATURAL GAS

The production of pipeline grade natural gas requires the removal of large quantities of H_2S from the reservoir gas. Currently (1973), approximately 70 percent of the sulfur removed in this manner is reduced to elemental sulfur. The remainder is either burned to SO_2, allowed to leak or vent to the atmosphere as H_2S, or is emitted as H_2S, SO_2, COS, or CS_2 from a sulfur recovery operation.

Table 4-8 shows that for the year 1973, after sulfur recovery, an additional 413,554 MT/yr of sulfur were emitted to the atmosphere. This figure was assumed to be represented by 809,336 MT/yr of SO_2 and 1,542 MT/yr of H_2S. Of the sulfur value, it was reported that 172,000 MT/yr represented Claus plant tail gas

Table 6-3. POTENTIAL HYDROCARBON REDUCTIONS DUE TO RETROFIT OF TANKS WITH INTERNAL FLOATING ROOFS (1,000 kg/yr)

State	Year of Record*		1987	
	Uncontrolled	Controlled	Uncontrolled	Controlled
Alabama	1,540	373	1,053	255
Alaska	147	35	499	119
Arizona	119	30	103	26
Arkansas	9,509	2,323	8,383	2,048
California	10,306	2,549	10,170	2,515
Colorado	4,728	1,248	3,198	844
Florida	590	142	398	96
Illinois	92	25	50	14
Indiana	23	6	9	2
Kansas	2,856	778	2,296	625
Kentucky	328	87	131	35
Louisiana	37,384	9,102	14,553	3,543
Michigan	4,847	1,244	2,826	725
Mississippi	11,670	2,976	6,401	1,632
Montana	2,898	727	2,398	602
Nebraska	1,198	340	300	85
Nevada	151	36	128	31
New Mexico	9,725	2,451	7,151	1,802
North Dakota	3,143	786	2,136	534
Oklahoma	10,027	2,550	7,126	1,812
South Dakota	141	37	74	19
Tennessee	157	40	45	11
Texas	121,105	31,112	100,928	25,929
Utah	2,833	684	2,135	515
Wyoming	12,263	3,034	10,007	2,476
TOTAL	247,780	62,715	182,498	46,295

* Based on Tables 5-3 and 5-5 which utilize stripper well adjustments.

emissions, (since the average recovery efficiency was 85.3 percent for these plants, it was assumed that tail gas cleanups were not in use).

The remaining 241,554 MT/yr of sulfur emitted was assumed to be uncontrolled. To recover the sulfur, it will be necessary to utilize either the Stretford Process for low H_2S concentration streams or the Claus-Beavon system.

6.2.1 STRETFORD PROCESS

The Stretford Process has been used in Great Britain for many years to recover hydrogen sulfide from natural gas and convert it to sulfur. The feed gas is passed through an absorption tower which removes the H_2S. The absorbent is an organic liquid which also serves to oxidize the dissolved H_2S to sulfur. The sulfur is removed from the liquid by filtration, and the solvent is regenerated by air oxidation. Very high conversions of H_2S to sulfur are possible with this process.

The advantages of the Stretford process are that it functions well at atmospheric pressure, is unaffected by any carbon dioxide present, purifies the gas to a very high degree and does not require special operator skills. Several United States engineering firms have produced operational units of this process — Parsons and Pritchard primarily.

Table 6-4 presents the cost parameters for a Stretford system as estimated by engineers at J.F. Pritchard and Company. The control efficiency estimation was also supplied by Pritchard personnel. Control cost estimates for the installation of a Stretford Process unit are presented in Table 6-5. The final value is an expression for the amount of money necessary to recover a kilogram of hydrogen sulfide.

Table 6-4. COST PARAMETERS FOR CONTROL OF H_2S FROM NATURAL GAS AT WELLHEAD

(Stretford Process for Low H_2S)

Flow Rate Megaliters per day (MMSCFD)	1,557 (55)
Inlet Sulfur (ppmv)	1,490
Uncontrolled H_2S Emissions (kg/yr)	1.20×10^6
Outlet Sulfur (ppmv)	2.97
Controlled H_2S Emissions (kg/yr)	2.4×10^3
Capital Cost Installed ($)	1,270,000
Annual Operating Cost	
Chemicals	3,600
Electricity	15,900
Maintenance	38,100
Total	57,600
Sulfur Recovery	none
Percent Emissions Control (%)	99.8

Table 6-5. CONTROL COST ESTIMATES FOR CONTROL OF H_2S FROM NATURAL GAS AT WELLHEAD[a]

Control Technique	Stretford Process
Installed Capital Cost ($)	1,270,000
Operating Cost ($/yr)	57,600
Capital Charges ($/yr)[b]	257,400
Net Annual Cost ($/yr)	315,000
Controlled Emissions (kg/yr)	2.5×10^3
Percent Reduction (%)	99.8
Cost per kg of H_2S Controlled ($/kg)	0.26

[a] See Table 6-4

[b] Capital recovery factor for 10 year life and 10% interest plus 4% for taxes, insurance and administration.

6.2.2 CLAUS PLANT AND BEAVON TAIL GAS TREATMENT

In the Claus reaction, hydrogen sulfide is converted to elemental sulfur in two steps according to the following reactions:

$$H_2S + 3/2\ O_2 \rightarrow SO_2 + H_2O$$

$$2H_2S + SO_2 \longrightarrow 2H_2O + 3S$$

In the first step, H_2S is partially burned to SO_2 using air. The H_2S/SO_2 mixture is then reacted over a catalyst to produce sulfur and water. This reaction is known as the shift conversion and is carried out in one to three stages with sulfur removal after each stage. The design of a sulfur recovery plant depends upon the inlet H_2S concentration. If the concentration of H_2S in the feed is high, a "straight-through" process is used. In the straight-through configuration, all of the H_2S and air are fed to the burned (boiler). If the H_2S concentration in the feed is low, a "split-flow" or "sulfur recycle" process is used.

The Beavon unit simply hydrogenates the sulfur compounds, SO_2, COS, and CS_2 to H_2S under moderate temperature and pressure conditions using a cobalt-molybdate catalyst. After the reactor, the hydrogenated stream is cooled, water is condensed out, and vapor, containing H_2S, is ready for processing to eliminate the sulfide. It would be desirable to return this H_2S to the Claus plant feed but, unfortunately, the stream contains so much CO_2 that cannot be easily removed that the build-up of inert gas in the Claus unit could not be tolerated.

Since the H_2S concentration is about 10,000 ppm and must ultimately be reduced to 1 ppm, a Stretford section is added. This H_2S stream id directed into a column and contacted with sodium carbonate to convert it to sodium hydrosulfide. This is oxidized to sulfur by sodium vanadate. Subsequently, vanadium is oxidized back to the penta valent state by blowing in air with sodium anthraquinone disulfonate working as an oxidation catalyst. Sulfur particles are finely divided, and appear as a froth which is skimmed, filtered and returned to the Claus plant to be included in the elemental sulfur product. The tail gas will now contain less than 250 ppm SO_2 and 10 ppm H_2S.

Table 6-6 presents the cost estimates for two 100 long ton (102 MT) per day Claus reactors, one having a sulfur conversion efficiency of 90 percent and the other 95 percent. The use of the 102 MT/day unit was suggested by engineers at Ralph W. Parsons, who prepared the estimate, as the most representative size. This value was confirmed as reasonable by project engineers from data appearing on pages 5-3 through 5-17 of Reference 17. A total of 55 gas processing plants utilizing the Claus process had a daily average recovery rate of 49.8 LT (50.6 MT). Table 6-6 also presents an analysis of the addition of a Beavon tail gas cleanup system to the Claus reactor. The cost per kg of H_2S controlled for the Claus plus the Beavon unit is given as \$40/MT. This value does not demonstrate the incremental cost of the addition of the Beavon unit. To go from a 95 percent efficient Claus plant to a 99 percent efficiency Beavon system will result in an 800,000 kg additional emission reduction. The difference in the net annual cost of installing such a system will be \$480,000. Therefore the cost per kg H_2S for this <u>additional</u> control will be \$600/MT.

Table 6-7 presents the cost parameters for the Claus plant and the Beavon unit.

6.2.3 POTENTIAL EMISSION REDUCTION ACHIEVEMENT

As of 1973, a total of 413,554 MT of sulfur were being emitted to the atmosphere. Of this total, 172,000 MT was the result of Claus conversion. Insufficient information is available to differentiate between lean and heavy H_2S streams and determine the

Table 6-6. COST ESTIMATES FOR CONTROL OF H_2S

Control Technique	Claus (95%)	Claus (90%)	Claus & Beavon
Installed Capital Cost ($)	1.67×10^6	1.67×10^6	3.17×10^6
Operating Cost ($/yr)	0.10×10^6	0.10×10^6	0.28×10^6
Capital Charges ($/yr)	0.34×10^6	0.34×10^6	0.64×10^6
Sulfur Credit ($/yr)	(0.125×10^6)	(0.12×10^6)	(0.13×10^6)
Net Annual Cost ($/yr)	0.31×10^6	0.32×10^6	0.79×10^6
H_2S Controlled (kg/yr)	18.7×10^6	17.7×10^6	19.5×10^6
% Controlled	95	90	99
Cost per kg H_2S Controlled ($/kg)	0.017	0.018	0.040

Table 6-7. COST PARAMETERS FOR CONTROL OF H_2S FROM HIGH SULFUR CONTENT NATURAL GAS

Control Technique	Claus Plant	Beavon Process
Installed Capital Cost ($)	1.67×10^6	1.50×10^6
Operating Cost ($/yr)	0.100×10^6	0.177×10^6
Power		0.087×10^6
Fuel		0.095×10^6
Soft Water		0.004×10^6
Chemicals		0.066×10^6
Catalyst		0.006×10^6
Steam Credit		$(0.081) \times 10^6$
Uncontrolled H_2S Emissions (kg/yr)*	19.7×10^6	------
Controlled Emissions for Claus as H_2S		
at 95% (kg/yr)	0.99×10^6	------
at 90% (kg/yr)	1.97×10^6	------
Controlled Emissions from Beavon as H_2S (kg/yr)		1.97×10^5
Sulfur Recovered		
at 95% (kg/yr)	17.6×10^6	18.4×10^6
at 90% (kg/yr)	16.7×10^6	
Sulfur Credit ($/kg)	0.0071	0.0071

*Assumes 92.5 percent conversion efficiency.

relative applicability of the Stretford versus the Claus and Beavon units to existing field conditions. Project investigators have decided to apply each system to the total 1973 values to show the relative merits of each system.

The 1973 sulfur emissions can be distributed in the following manner. A total of 413,554 MT of sulfur were emitted as 809,336 MT of SO_2 and 1,542 MT of H_2S. Elminating 172,000 MT of sulfur emitted as SO_2 from tail gas combustion in existing Claus plants, leaves 241,554 MT of sulfur generated as H_2S which is either converted to SO_2 or remains as H_2S without passing through a Claus plant.

Applying the Stretford process to all this remaining sulfur will produce 483 MT of sulfur as H_2S. Passing all of the remaining sulfur through either a 90 percent of 95 percent efficient Claus plant without any further treatment other than incineration will result in 24,155 MT or 12,078 MT of sulfur as SO_2. By adding a tail gas cleanup system to both the new Claus facilities and the existing units, the complete sulfur recovery system will have an efficiency of 99 percent with an efficiency of 97.3 percent attributed to the Beavon system. This will result in the 241,554 MT being reduced to 2,415 MT of sulfur emitted as SO_2 and an additional 4,644 MT as SO_2 from controlling the 172,000 MT of sulfur currently leaving existing Claus plants. Table 6-8 summarizes these results.

6.3 FUGITIVE HYDROCARBON EMISSIONS

Several recent studies conducted in petroleum refineries have determined that fugitive emission factors are a direct function of maintenance. Experimental results indicate that by initiating a comprehensive inspection and maintenance program,

Table 6-8. IMPACT OF SULFUR CONTROL STRATEGIES ON 1973 EMISSION ESTIMATES (1,000 kg/yr)

Situation	Atmospheric Emissions as Sulfur	Actual Emissions	
		SO_2	H_2S
Existing situation	413,554	809,336	1,542
Adding Stretford to non-Claus emissions	172,483	334,000	543
Adding 90 percent efficient units for non-Claus emissions	196,155	392,310	—
Adding 95 percent efficient Claus units for non-Claus emissions	184,078	368,156	—
Placing Beavon tail gas treatment systems on all new and existing Claus units	7,060	14,120	—

existing emission from valves, flanges, and seals can be reduced up to ten-fold (References 19 and 20). The problem stems from defining what constitutes such a program. There is a great deal of discussion currently as to what amount of resources in the form of manpower is required to initiate and maintain such a program. Until a conclusion is reached, it will not be possible to evaluate the cost effectiveness of these actions.

6.4 ALTERNATE FUELS IN STEAM GENERATORS

Thermal operations utilize a steam generator which commonly burns crude oil. The emission reduction which can be achieved by combusting diesel fuel or natural gas instead is shown in Table 6-9. A great many variables concerning transportation costs and storage will make the relative cost effectiveness for each of these fields different in each situation. For this reason, no further analysis is considered representative.

Table 6-9. EMISSION ESTIMATES FROM THE COMBUSTION OF VARIOUS FUELS

Fuel	Emissions [kg/giga joule (lb/10^6 Btu)]			
	SO_x	CO	HC	NO_x
Crude Oil	2.167 (1.037)	0.059 (0.028)	0.017 (0.008)	.482 0.231
Diesel* (Distillate)	1.04 (0.496)	0.071 (0.034)	.015 (0.007)	0.316 (0.151)
Natural Gas*	.002 (0.001)	0.033 (0.016)	.006 (0.003)	0.458 (0.219)

* Based on values appearing in AP-42, Second Edition, Part A.

7.0 CONCLUSIONS

The primary goal of this study was to estimate existing annual HC, SO_x, NO_x, CO, and H_2S emissions from drilling, production, and storage of oil and gas and project these emissions through the year 1987. The scope of the project called for the exclusion of stripper well activities. Disregarding these activities called for modification of production and processing as well as storage tank estimates. Projected emission levels for production and processing activities were made only for the stripper well adjusted values. The most recent data available concerning individual oil fields were obtained. The years this information pertained to ranged from 1974-1977, with the majority occurring in 1976. The base year was termed the Year of Record. Table 7-1 summarizes the nationwide production and processing and storage emissions for the Year of Record and drilling and sulfur extraction values for the year 1976.

Table 7-2 presents the expected nationwide emissions levels in 1987 without initiation of controls. The installation of internal floating roofs on all storage tanks would reduce nationwide emissions from these sources by approximately 75 percent (see Table 6-3). The routing of all H_2S and SO_2 streams generated by the processing of natural gas through Claus recovery units and/or tail gas cleanup systems would reduce sulfur emissions from these sources by over 98 percent (see Table 6-8).

Table 7-1. EXISTING ANNUAL EMISSIONS FROM DRILLING, PRODUCTION AND PROCESSING, AND STORAGE ACTIVITIES FOR YEAR 1976 (1,000 kg/yr)

Activity	Without Stripper Well Adjustment					With Stripper Well Adjustment				
	HC	NO_x	CO	SO_x	H_2S	HC	NO_x	CO	SO_x	H_2S
Drilling	11,857	140,761	30,611	9,366	-	11,857	140,761	30,611	9,366	-
Production and Processing	150,699	17,054	1,943	60,124	-	125,594	14,477	1,646	50,723	-
Sulfur Emissions From Natural Gas Processing	-	-	-	719,411	1,371	-	-	-	719,411	1,371
Storage	296,586	-	-	-	-	247,780	-	-	-	-
TOTAL	459,142	157,815	32,554	788,901	1,371	385,114	155,238	32,257	779,500	1,371

Table 7-2. 1987 PROJECTED EMISSIONS
(1,000 kg/yr)

Activity	Without Stripper Well Adjustment					With Stripper Well Adjustment				
	HC	NO_x	CO	SO_x	H_2S	HC	NO_x	CO	SO_x	H_2S
Drilling	25,499	297,548	64,835	19,855	-	25,499	297,548	64,835	19,855	-
Production and Processing	127,831*	16,273*	1,877*	58,962*	-	106,536	13,814	1,590	49,743	-
Sulfur Emissions From Natural Gas Processing	-	-	-	591,221	1,127	-	-	-	591,221	1,127
Storage	219,468	-	-	-	-	182,498	-	-	-	-
TOTAL	372,798	313,821	66,712	670,038	1,127	314,533	311,362	66,425	660,819	1,127

*Estimated

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APPENDIX I

STATE BY STATE EMISSION ESTIMATES FOR EACH PROJECTED YEAR

DRILLING EMISSIONS FOR THE YEAR 1977

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	107	1,611	129	350
Alaska	85	1,193	101	263
Arizona	6	85	7	18
Arkansas	96	1,442	115	332
California	553	8,310	664	1,807
Colorado	237	3,561	285	775
Florida	34	509	41	111
Illinois	135	2,035	1,879	443
Indiana	11	170	14	37
Kansas	316	4,749	380	1,033
Kentucky	6	85	7	18
Louisiana	1,438	21,622	1,729	4,703
Maryland	6	85	7	18
Michigan	147	2,205	176	480
Mississippi	197	2,968	237	645
Missouri	6	85	7	18
Montana	175	2,629	210	572
Nebraska	51	763	61	166
Nevada	11	170	14	37
New Mexico	338	5,088	407	1,106
New York	56	848	68	184
North Dakota	119	1,781	142	387
Ohio	164	2,459	197	535
Oklahoma	1,156	17,383	1,390	3,781
Pennsylvania	62	933	75	203
South Dakota	11	170	14	37
Tennessee	6	85	7	18
Texas	4,061	61,051	4,881	13,278
Utah	119	1,781	142	387
Virginia	6	85	7	18
West Virginia	73	1,102	88	240
Wyoming	536	8,055	546	1,752
TOTAL	10,324	155,098	14,027	33,752

DRILLING EMISSIONS FOR THE YEAR 1978

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	113	1,696	136	369
Alaska	96	1,204	112	275
Arizona	6	85	7	18
Arkansas	102	1,526	122	350
California	604	4,073	725	1,973
Colorado	260	3,901	312	848
Florida	34	509	41	111
Illinois	147	2,205	1,893	480
Indiana	11	170	14	37
Kansas	344	5,173	414	1,125
Kentucky	6	85	7	18
Louisiana	1,568	23,573	1,885	5,127
Maryland	6	85	7	18
Michigan	164	2,459	197	535
Mississippi	220	3,307	264	719
Missouri	6	85	7	18
Montana	192	2,883	230	627
Nebraska	56	848	68	184
Nevada	11	170	14	37
New Mexico	367	5,512	441	1,199
New York	62	933	75	203
North Dakota	130	1,950	156	424
Ohio	175	2,629	210	572
Oklahoma	1,264	18,994	1,519	4,131
Pennsylvania	68	1,018	81	221
South Dakota	11	170	14	37
Tennessee	6	85	7	18
Texas	4,434	66,732	5,336	14,513
Utah	130	1,950	156	424
Virginia	6	85	7	18
West Virginia	79	1,187	95	258
Wyoming	587	8,818	607	1,918
TOTAL	11,265	164,100	15,159	36,805

DRILLING EMISSIONS FOR THE YEAR 1979

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	124	1,866	149	406
Alaska	102	1,210	117	281
Arizona	6	85	7	18
Arkansas	113	1,696	136	387
California	654	9,836	786	2,139
Colorado	282	4,240	339	922
Florida	39	594	48	129
Illinois	164	2,459	1,913	535
Indiana	17	254	20	55
Kansas	378	5,681	454	1,236
Kentucky	6	85	7	18
Louisiana	1,704	25,608	2,047	5,569
Maryland	6	85	7	18
Michigan	175	2,629	210	572
Mississippi	237	3,561	285	775
Missouri	6	85	7	18
Montana	209	3,137	251	682
Nebraska	56	848	68	184
Nevada	17	254	20	55
New Mexico	400	6,020	481	1,309
New York	68	1,018	81	221
North Dakota	141	2,110	170	461
Ohio	192	2,883	231	627
Oklahoma	1,371	20,605	1,648	4,481
Pennsylvania	73	1,102	88	240
South Dakota	17	254	20	55
Tennessee	6	85	7	18
Texas	4,806	72,329	5,783	15,730
Utah	141	2,120	170	461
Virginia	6	85	7	18
West Virginia	90	1,357	109	295
Wyoming	632	9,497	661	2,065
TOTAL	12,238	183,678	16,327	39,980

DRILLING EMISSIONS FOR THE YEAR 1980

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	135	2,035	163	443
Alaska	113	1,221	129	292
Arizona	6	85	7	18
Arkansas	118	1,781	143	405
California	705	10,599	847	2,305
Colorado	305	4,579	366	996
Florida	39	594	48	129
Illinois	175	2,629	1,927	572
Indiana	17	254	20	55
Kansas	406	6,105	488	1,328
Kentucky	6	85	7	18
Louisiana	1,839	27,643	2,210	6,012
Maryland	6	85	7	18
Michigan	192	2,883	231	627
Mississippi	254	3,816	305	830
Missouri	6	85	7	18
Montana	220	3,307	264	719
Nebraska	62	933	75	203
Nevada	17	254	20	55
New Mexico	429	6,444	515	1,401
New York	73	1,102	88	240
North Dakota	152	2,290	183	498
Ohio	209	3,137	251	682
Oklahoma	1.478	22,216	1,776	4,832
Pennsylvania	79	1,187	95	258
South Dakota	17	254	20	55
Tennessee	6	848	7	18
Texas	5,184	78,010	6,237	16,966
Utah	152	2,290	183	498
Virginia	6	85	7	18
West Virginia	96	1,442	115	313
Wyoming	683	10,260	722	2,231
TOTAL	13,185	198,538	17,463	43,053

DRILLING EMISSIONS FOR THE YEAR 1981
(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	147	2,205	177	480
Alaska	118	1,227	134	298
Arizona	11	170	14	37
Arkansas	130	1,950	156	442
California	762	11,447	915	2,490
Colorado	322	4,833	386	1,051
Florida	45	678	54	147
Illinois	186	2,798	1,940	609
Indiana	17	254	20	55
Kansas	434	6,529	522	1,420
Kentucky	11	170	14	37
Louisiana	1,969	29,593	2,366	6,436
Maryland	11	170	14	37
Michigan	203	3,053	244	664
Mississippi	271	4,070	325	885
Missouri	11	170	14	37
Montana	237	3,561	285	775
Nebraska	68	1,018	81	221
Nevada	17	254	20	55
New Mexico	457	6,953	556	1,512
New York	79	1,187	95	258
North Dakota	164	2,459	197	535
Ohio	220	3,307	264	738
Oklahoma	1,585	23,827	1,905	5,182
Pennsylvania	84	1,272	102	276
South Dakota	17	254	20	55
Tennessee	11	170	14	37
Texas	5,562	83,691	6,692	18,202
Utah	164	2,459	197	535
Virginia	11	170	14	37
West Virginia	101	1,526	122	332
Wyoming	733	11,023	783	2,397
TOTAL	14,158	212,448	18,642	46,272

DRILLING EMISSIONS FOR THE YEAR 1982

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	152	2,290	183	498
Alaska	124	1,232	140	303
Arizona	11	170	14	37
Arkansas	135	2,035	163	460
California	812	12,210	976	2,656
Colorado	344	5,173	413	1,125
Florida	45	678	54	147
Illinois	198	2,968	1,954	646
Indiana	17	254	20	55
Kansas	463	6,953	556	1,512
Kentucky	11	170	14	37
Louisiana	2,104	31,628	2,529	6,879
Maryland	11	170	14	37
Michigan	220	3,307	264	719
Mississippi	293	4,409	352	959
Missouri	11	170	14	37
Montana	254	3,816	305	830
Nebraska	73	1,102	88	240
Nevada	17	254	20	55
New Mexico	485	7,377	590	1,604
New York	84	1,272	102	276
North Dakota	175	2,629	210	572
Ohio	237	3,561	285	775
Oklahoma	1,692	25,438	2,034	5,533
Pennsylvania	90	1,357	109	295
South Dakota	17	254	20	55
Tennessee	11	170	14	37
Texas	5,940	89,287	7,146	19,437
Utah	175	2,629	210	572
Virginia	11	170	14	37
West Virginia	107	1,611	129	350
Wyoming	784	11,786	844	2,563
TOTAL	15,103	226,530	19,780	49,338

DRILLING EMISSIONS FOR THE YEAR 1983

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	164	2,459	197	535
Alaska	135	1,243	151	315
Arizona	11	170	14	37
Arkansas	147	2,205	177	497
California	863	12,973	1,037	2,822
Colorado	367	5,512	441	1,199
Florida	51	763	61	166
Illinois	214	3,222	1,974	701
Indiana	17	254	20	55
Kansas	496	7,462	597	1,623
Kentucky	11	170	14	37
Louisiana	2,234	33,578	2,685	7,303
Maryland	11	170	14	37
Michigan	231	3,477	278	756
Mississippi	310	4,664	373	1,014
Missouri	11	170	14	37
Montana	271	4,070	325	885
Nebraska	79	1,187	95	258
Nevada	17	254	20	55
New Mexico	519	7,886	631	1,715
New York	84	1,272	102	276
North Dakota	186	2,798	224	609
Ohio	254	3,816	305	830
Oklahoma	1,800	27,049	2,163	5,883
Pennsylvania	96	1,442	115	313
South Dakota	17	254	20	55
Tennessee	11	170	14	37
Texas	6,318	94,968	7,600	20,673
Utah	186	2,798	224	609
Virginia	11	170	14	37
West Virginia	118	1,781	143	387
Wyoming	835	12,549	905	2,729
TOTAL	16,075	239,353	20,947	52,485

DRILLING EMISSIONS FOR THE YEAR 1984

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	175	2,629	211	572
Alaska	141	1,249	157	320
Arizona	11	170	14	37
Arkansas	152	2,290	183	515
California	914	13,736	1,098	2,988
Colorado	390	5,851	468	1,273
Florida	51	763	61	166
Illinois	226	3,392	1,988	738
Indiana	23	339	27	74
Kansas	525	7,886	631	1,715
Kentucky	11	170	14	37
Louisiana	2,369	35,613	2,847	7,745
Maryland	11	170	14	37
Michigan	248	3,731	298	811
Mississippi	327	4,918	393	1,070
Missouri	11	170	14	37
Montana	288	4,325	346	940
Nebraska	84	1,272	102	276
Nevada	23	339	27	74
New Mexico	547	8,310	665	1,807
New York	90	1,357	109	295
North Dakota	198	2,968	238	646
Ohio	265	3,985	319	885
Oklahoma	1,907	28,600	2,292	6,233
Pennsylvania	101	1,526	122	332
South Dakota	23	339	27	74
Tennessee	11	170	14	37
Texas	6,690	100,565	8,047	21,890
Utah	198	2,968	238	646
Virginia	11	170	14	37
West Virginia	124	1,866	149	406
Wyoming	880	13,227	960	2,877
TOTAL	17,025	255,124	22,087	55,553

DRILLING EMISSIONS FOR THE YEAR 1985

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	181	2,714	217	590
Alaska	152	1,260	168	331
Arizona	11	170	14	37
Arkansas	164	2,459	197	552
California	965	14,499	1,159	3,154
Colorado	412	6,190	495	1,347
Florida	56	848	68	184
Illinois	237	3,562	2,001	775
Indiana	23	339	27	74
Kansas	553	8,310	665	1,807
Kentucky	11	170	14	37
Louisiana	2,505	37,648	3,010	8,188
Maryland	11	170	14	37
Michigan	260	3,901	312	848
Mississippi	350	5,257	420	1,143
Missouri	11	170	14	37
Montana	304	4,579	366	996
Nebraska	84	1,272	102	276
Nevada	23	339	27	74
New Mexico	581	8,819	705	1,918
New York	96	1,445	115	313
North Dakota	203	3,053	244	664
Ohio	282	4,240	339	940
Oklahoma	2,014	30,272	2,420	6,584
Pennsylvania	107	1,611	129	350
South Dakota	23	339	27	74
Tennessee	11	170	14	37
Texas	7,068	106,246	8,502	23,126
Utah	203	3,053	244	664
Virginia	11	170	14	37
West Virginia	130	1,950	156	424
Wyoming	931	13,991	1,021	3,043
TOTAL	17,973	269,216	23,220	58,661

DRILLING EMISSIONS FOR THE YEAR 1986

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	192	2,883	231	627
Alaska	158	1,266	174	337
Arizona	11	170	14	37
Arkansas	169	2,544	204	570
California	1,016	15,262	1,220	3,320
Colorado	435	6,529	522	1,420
Florida	56	848	68	184
Illinois	248	3,731	2,015	812
Indiana	23	339	27	74
Kansas	581	8,734	698	1,899
Kentucky	11	170	14	37
Louisiana	2,634	39,598	3,166	8,612
Maryland	11	170	14	37
Michigan	276	4,155	332	904
Mississippi	367	5,512	440	1,199
Missouri	11	170	14	37
Montana	321	4,833	386	1,051
Nebraska	90	1,357	109	295
Nevada	23	339	27	74
New Mexico	609	9,243	739	2,010
New York	101	1,526	122	332
North Dakota	215	3,222	258	701
Ohio	299	4,494	359	996
Oklahoma	2,121	31,883	2,549	6,934
Pennsylvania	112	1,696	136	368
South Dakota	23	339	27	74
Tennessee	11	170	14	37
Texas	7,440	111,927	8,956	24,361
Utah	215	3,222	258	701
Virginia	11	170	14	37
West Virginia	135	2,035	163	442
Wyoming	982	14,754	1,082	3,209
TOTAL	18,907	283,291	24,352	61,728

DRILLING EMISSIONS FOR THE YEAR 1987

(10^3 kg)

State	SO_x	NO_x	HC	CO
Alabama	203	3,053	245	664
Alaska	163	1,272	179	343
Arizona	11	170	14	37
Arkansas	180	2,714	217	607
California	1,066	16,026	1,281	3.486
Colorado	457	6,869	549	1,494
Florida	62	933	75	203
Illinois	265	3,986	2,035	867
Indiana	23	339	27	74
Kansas	609	9,158	732	1,992
Kentucky	11	170	14	37
Louisiana	2,770	41,633	3,329	9,055
Maryland	11	170	14	37
Michigan	288	4,325	346	941
Mississippi	384	5,766	461	1,254
Missouri	11	170	14	37
Montana	333	5,003	400	1,088
Nebraska	96	1,442	115	313
Nevada	23	339	27	74
New Mexico	643	9,752	780	2,120
New York	107	1,611	129	350
North Dakota	226	3,392	272	738
Ohio	310	4,664	373	1,033
Oklahoma	2,228	33,494	2,678	7,285
Pennsylvania	118	1,781	143	387
South Dakota	23	339	27	74
Tennessee	11	170	14	37
Texas	7,812	117,608	9,410	25,597
Utah	226	3,392	272	738
Virginia	11	170	14	37
West Virginia	141	2,120	170	461
Wyoming	1,033	15,517	1,143	3,375
TOTAL	19,855	297,548	25,499	64,835

APPENDIX II

INDIVIDUAL STATE DATA BASE SOURCES

INDIVIDUAL STATE DATA BASE SOURCES

1. ALABAMA
   State of Alabama Oil and Gas Board
   a. Oil, Gas and Condensate Production for State of Alabama for 1976.
   b. Letter dated May 29, 1978 from Mark R. Wyatt, Geologist.

2. ALASKA
   State of Alaska, Department of Natural Resources, Division of Oil and Gas Conservation, Statistical Report for the Year 1976.

3. ARIZONA
   Oil and Gas Conservation Commission, State of Arizona, Oil, Gas and Helium Production, December 1977.

4. ARKANSAS
   Arkansas Oil and Gas Commission, Annual Oil and Gas Report, 1976.

5. CALIFORNIA
   Annual Review of California Air and Gas Production, 1976, Conservation Committee of California Oil Producers.

6. COLORADO
   State of Colorado Oil and Gas Conservation Commission, 1976 Oil and Gas Statistics.

7. FLORIDA
   International Oil and Gas Development (Reference 7), page 64.

8. ILLINOIS
   Petroleum Industry in Illinois, 1975, Illinois State Geological Survey.

9. INDIANA
   Oil Development and Production in Indiana During 1976, Department of Natural Resources.

10. KANSAS
    a. International Oil and Gas Development (Reference 7), pages 102-180.
    b. Enhanced Oil Recovery Operations in Kansas, 1976, for the Kansas Enhanced Oil Recovery Committee.

11. KENTUCKY
    International Oil and Gas Development (Reference 7), pages 181-196.

12. LOUISIANA
    a. Louisiana Annual Oil and Gas Report, 1974, Department of Conservation.
    b. Secondary Recovery and Pressure Maintenance Operating in Louisiana, 1976 Report, Department of Natural Resources, Office of Conservation.

13. MICHIGAN
    a. International Oil and Gas Development (Reference 7), pages 261-276.
    b. Michigan's Oil and Gas Fields, 1976, Department of Natural Resources, Geological Survey Division.

14. MISSISSIPPI
    Mississippi Oil and Gas Bulletin, Annual Report, 1976, Mississippi Oil and Gas Board.

15. MONTANA
    Oil and Gas Conservation Division, Annual Review for the Year 1976, Relating to Oil and Gas.

16. NEBRASKA
    a. International Oil and Gas Development (Reference 7), pages 297-305.
    b. Nebraska Oil and Gas Conservation Commission, Secondary Recovery Report, December 1976.

17. NEVADA
    International Oil and Gas Development (Reference 7), page 306

18. NEW MEXICO
    a. International Oil and Gas Development (Reference 7), pages 307-325.
    b. New Mexico Secondary Recovery Projects as of December 31, 1976, Oil Conservation Commission.

19. NORTH DAKOTA
    Production Statistics and Engineering Data, Oil in North Dakota, first and second half of 1976, North Dakota Geological Survey.

20. OKLAHOMA
    a. International Oil and Gas Development (Reference 7), pages 332-426.
    b. Secondary Recovery Operations, Oklahoma, last six months 1976, Petroleum Information Corporation.

21. SOUTH DAKOTA
International Oil and Gas Development (Reference 7), page 429.

22. TENNESSEE
Tennessee 1976 Oil and Gas Production, Tennessee Division of Geology.

23. TEXAS
  a. The Railroad Commission of Texas, Oil and Gas Division, Annual Report.
  b. Personal visit to Austin to obtain secondary information from Railroad Commission files.

24. UTAH
Monthly Oil and Gas Production Report, December 1976, Division of Oil and Gas Mining.

25. WYOMING
Wyoming Oil and Gas Statistics, 1976, The Wyoming Oil and Gas Conservation Commission.

APPENDIX III

COMPANIES CONTACTED TO DETERMINE EXTENT OF LACT ACTIVITIES VERSUS TRUCKING OF CRUDE OIL

COMPANIES CONTACTED TO DETERMINE EXTENT OF LACT AND PIPELINE ACTIVITIES VERSUS TRUCKING OF CRUDE OIL

1. Company: Arapahoe Pipe Line Company, Brush, Colorado

   Individual Contacted: D.W. Lee

   Telephone Number: (303) 842-2881

   Results of Conversation: 60 percent of oil received is by way of LACT units and pipelines with the remaining oil handled by truck. "The trend is toward more LACT units. As time goes on, treatment plants are becoming more centrally located. This makes LACT units more economically desirable."

2. Company: Exxon Pipeline Company, Houston, Texas

   Individual Contacted: L.J. Baube

   Telephone Number: (713) 656-5646

   Results of Conversation: 90 percent of oil received is by way of LACT and pipelines with the remaining oil handled by truck.

3. Campany: Jayhawk Pipeline Corporation, Wichita, Kansas

   Individual Contacted: Mike McCool

   Telephone Number: (316) 267-0361

   Results of Conversation: 60 percent of oil received is by way of LACT and pipelines with the remaining oil handled by truck.

4. Company: Lakehead Pipeline, Superior, Wisconsin

   Individual Contacted: Mr. Burley

   Telephone Number: (715) 392-5631

   Results of Conversation: 100 percent of oil is received by LACT and pipelines.

5.	Company:	National Transit Company Oil City, Pennsylvania
	Individual Contacted:	Mr. Dickenson
	Telephone Number:	(814) 645-1251
	Results of Conversation:	70 percent of oil received is gauged through pipelines with the remaining oil received by truck. No LACT units are used.
6.	Company:	Portal Pipeline Billings, Montana
	Telephone Number:	(406) 259-4521
	Results of Conversation:	100 percent of oil is received by LACT and pipelines.
7.	Company:	Sunniland Pipeline Company Fort Lauderdale, Florida
	Individual Contacted:	Mr. St. John
	Telephone Number:	(305) 467-0769
	Results of Conversation:	89 percent of oil received is by LACT and pipelines with the remainder received by truck.
8.	Company:	Texoma Pipeline Company Tulsa, Oklahoma
	Telephone Number:	(918) 749-0959
	Results of Conversation:	100 percent of oil is received by LACT and pipelines.

APPENDIX IV

GUN BARREL EMISSION CALCULATIONS

GUN BARREL EMISSION CALCULATIONS

Fixed roof emissions consist of breathing and working losses. Fixed roof breathing losses consist of: vapor expelled from a tank because of the thermal expansion of existing vapors; vapor expansion caused by barometric pressure changes; and/or an increase in the amount of vapors due to added vaporization in the absence of liquid-level change. Fixed roof working losses consist of vapor expelled from a tank as a result of filling and emptying operations. Filling loss is the result of vapor displacement by the input of liquid. Emptying loss is the expulsion of vapors subsequent to product withdrawal, and is attributable to vapor growth as the newly inhaled air is saturated with hydrocarbons.

A gun barrel has a very high volume of liquids passing through it with little or no fluctuation in the liquid level within the tank. Therefore, working losses are assumed to be essentially zero.

Fixed roof breathing losses are calculated using the relationship presented on page 4.3-6 of "Compilation of Air Pollutant Emission Factors," AP-42, Part A, Second Edition.

$$L_B \text{ (lb/day)} = 2.21 \times 10^{-4}\, M \left[\frac{P}{14.7-P}\right]^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_p C K_c$$

where M = molecular weight, presumed to be 50 from Table 4.3-1 of AP-42

P = true vapor pressure, assumed to be 2.8 psia at 60°F, from same table

D = tank diameter, 10 ft

H = vapor space height; gun barrel was assumed to be 85 percent full at all times, leaving (0.14)(20) = 3 ft for H

ΔT = average ambient temperature change from day to night, 15°F

F_p = paint factor 1.15 (white paint, poor condition)

C = adjustment factor for small diameter tanks, 0.52

K_C = crude oil factor, 0.65

$$L_B = 2.21 \times 10^{-4}(50)\left[\frac{2.8}{14.7-2.8}\right]^{0.68}(10)^{1.73}(3)^{0.51}(15)^{0.50}(1.15)(0.52)(0.65)$$

$$= 0.585$$

$$L_T = L_B = 0.585 \text{ lb/day} = 213.5 \text{ lb/yr} = \underline{96.8 \text{ kg/yr}}$$

APPENDIX V

THE EMISSIONS CALCULATIONS FROM A 1,000 BARREL WASH TANK

THE EMISSIONS CALCULATIONS FROM A 1,000 BARREL TANK

The wash tank was assumed to be a fixed roof storage tank with potential breathing and working losses. As with the gun barrel, (see Appendix IV), the wash tank has a high volume of liquids passing through it with little or no fluctuation in the liquid level within the tank. Therefore, working losses are assumed to be essentially zero.

Fixed roof breathing losses are calculated using the relationship presented on page 4.3-6 "Compilation of Air Pollutant Emission Factors," AP-42, Part A, Second Edition

$$L_B \text{ (lb/day)} = 2.21 \times 10^{-4} M \left[\frac{P}{14.7-P}\right]^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_p C K_c$$

as discussed and defined in Appendix IV, the following values are assigned:

M = 50 lb/lb mole
P = 2.8 psia at 60°F
D = 21.1
H = 15 percent of a 16 ft high tank is 2.4 ft
ΔT = 15°F
F_p = 1.15
C = 0.91
K_c = 0.65

$$L_B = 2.21 \times 10^{-4} (50) \left[\frac{2.8}{14.7-2.8}\right]^{0.68} (21.1)^{1.73} (2.4)^{0.51} (15)^{0.50}$$

$$(1.15)(0.91)(0.65)$$

$$= 3.323$$

$LT = L_B$ = 3.323 lb/day = 1,212.9 lb/yr = 550.2 kg/yr

APPENDIX VI

CALCULATION OF WASH TANK RELATIONSHIP

CALCULATION OF WASH TANK RELATIONSHIP

Data used to calculate the wash tank relationship were obtained from an inventory of tanks done in Kern County, California during 1977. The inventory was sorted by field and the number of wash tanks identified in each case. The data base obtained is presented in Table VI-A. The last column presents a value expressing the amount of wash tank capacity which is available in a specific field as a function of the annual capacity in 10^3 barrels.

In order to utilize this information to predict the number of wash tanks expected in a given field, it was necessary to attempt to find a correlation for these data. Figures VI-A and VI-B show the Wash Tank Coefficient for two size ranges of fields.

The next step in the calculation process involves assuming that the data presented represent a linear relationship.

Careful examination of Figures VI-A and VI-B will reveal that the field size is presented logarithmically (natural). Any linear relationship based on these data must utilize the natural log of the actual field size. Using this information, the data can be statistically correlated into the following relationship:

$$y = 139 - 7.99(x)$$

where x = natural logarithm of the field production in bbl/yr

y = Wash Tank Coefficient in bbl/10^3 bbl of production

This relationship is more easily presented as follows:

$$y = \frac{139 - \ln(x)}{7.99}$$

Table VI-A. KERN COUNTY INVENTORY OF WASH TANKS

Field Size	No. of Tanks	Total Capacity	Average Tank Size in Barrels	Wash Tank Coefficiency (bbl/10^3bbl of Annual Production)
172,897	1	1,600	1,600	9.25
152,490	9	8,000	889	52.5
357,673	4	3,250	813	9.09
526,292	16	18,500	1,156	35.2
75,412	2	2,500	1,250	33.2
33,537	1	300	300	8.95
556,729	13	29,750	2,288	53.4
11,056,269	20	41,972	2,099	3.80
3,163,729	24	30,400	1,267	9.61
117,076	1	2,000	2,000	17.1
69,079	7	9,350	1,336	135.4
2,412,737	2	6,500	3,250	2.69
269,471	1	1,500	1,500	5.57
3,279,896	25	20,070	803	6.12
1,382,132	81	68,470	845	49.5
13,793	1	1,000	1,000	72.5
1,009,769	31	48,050	1,550	47.6
547,000	4	5,250	1,313	9.60
561,420	40	43,250	1,081	77.0
100,481	3	2,050	683	20.4
3,961,312	48	131,400	3,738	33.2
30,669,002	76	224,500	2,954	7.32
2,212,466	22	32,090	1,459	14.5
564,220	4	4,000	1,000	7.09
5,590,364	24	51,343	2,139	9.18
38,270,880	175	325,678	1,861	8.51
3,858,816	55	254,601	4,629	66.0
529,347	53	43,000	811	81.3
28,486	6	6,850	1,142	240.8

Table VI-A. KERN COUNTY INVENTORY OF WASH TANKS (CONCLUDED)

Field Size	No. of Tanks	Total Capacity	Average Tank Size in Barrels	Wash Tank Coefficiency ($bbl/10^3 bbl$ of Annual Production)
124,462	3	1,600	533	12.9
131,807	2	1,250	625	9.48
1.446,379	21	33,350	1,588	23.1
91,462	2	5,000	2,500	54.7
49,783	1	300	300	6.03
584,471	23	57,150	2,485	97.8
364,819	4	6,700	1,675	18.4
29,906	1	1,500	1,500	50.2
204,426	2	3,000	1,500	14.7
634,798	17	21,078	1,240	33.2
419,729	3	1,750	583	4.17
825,069	7	8,750	1,250	10.6
4,690,890	6	9,750	1,625	2.08
123,844	4	2,250	563	18.2
2,263	1	200	200	88.4
2,616	1	250	250	95.6
21,020	3	740	247	35.2
20,478	1	300	300	14.6
1,388	1	500	500	36.0
14,489	1	500	500	34.5
13,347	4	2,150	538	161.1

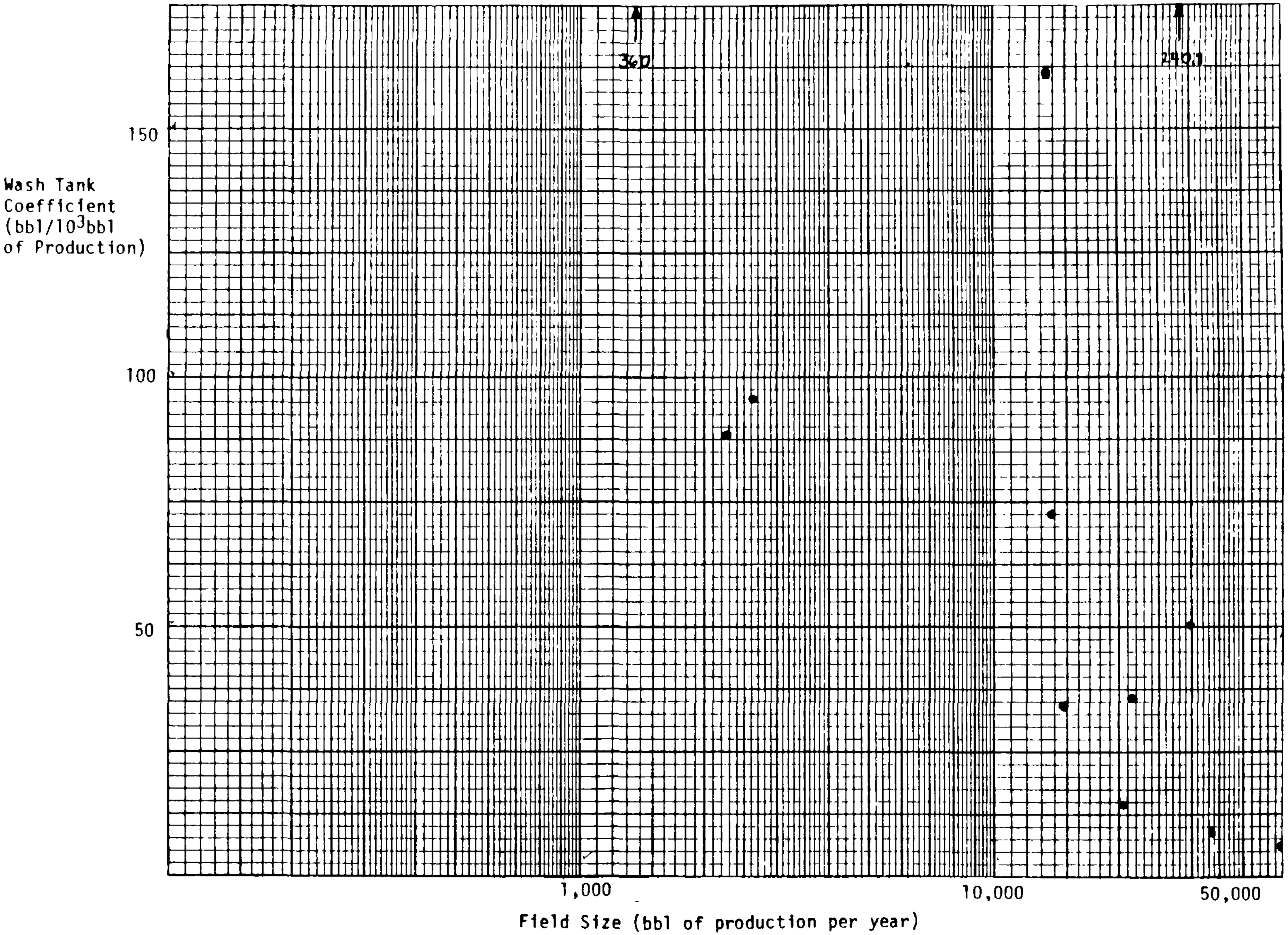

Figure VI-A. Wash Tank Data for Fields Less Than or Equal to 50,000 bbl/yr

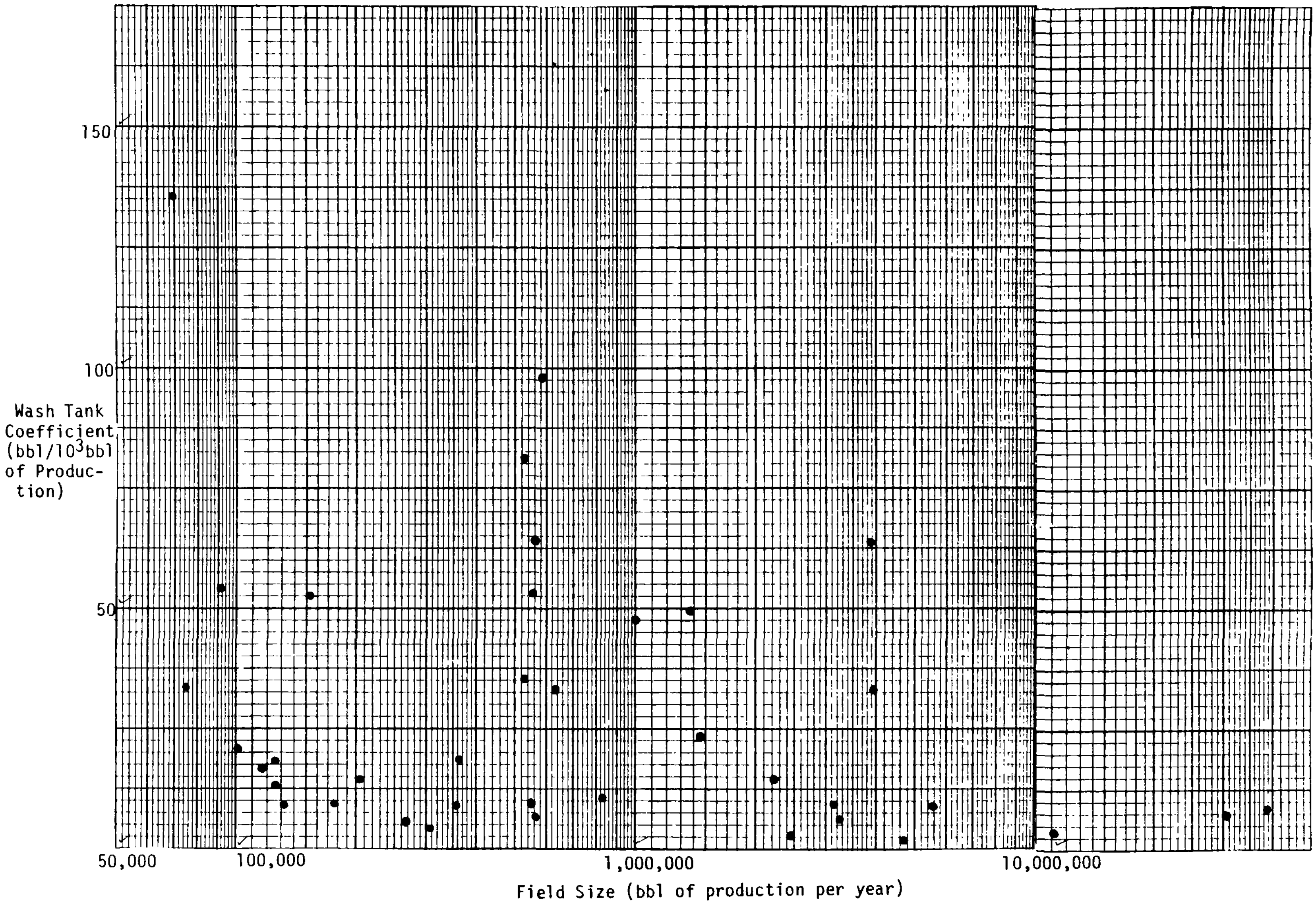

Figure VI-B. Wash Tank Data for Fields Greater Than 50,000 bbl/yr where x = annual production in bbl

y = Wash Tank Coefficient in bbl/10^3 bbl of production.

APPENDIX VII

ANNUAL OIL PRODUCTION RATES BY STATES AND RAILROAD COMMISSION DISTRICTS TO THE YEAR 1987

ANNUAL OIL PRODUCTION RATES BY STATES AND RAILROAD COMMISSION DISTRICTS (TEXAS) TO THE YEAR 1987 (IN THOUSANDS OF BARRELS)

State	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
United States	2865914	2828402	2906410	2972314	2905876	2881119	2732066	2635462	2534481	2500267	2449406
Alabama	9590	9230	8890	8550	8230	7930	7630	7340	7070	6810	6550
Alaska	137000	201000	378000	529000	554000	554000	554000	529000	503000	491000	466000
Arkansas	15200	14900	14700	14500	14100	13800	13500	13100	12800	13100	13400
California	316000	315000	315000	314000	310000	306000	302000	298000	295000	304000	312000
Colorado	36300	34900	33600	32200	31000	28900	28700	27600	26500	25500	24500
Florida	42000	40400	38800	37300	35900	34500	32200	31900	30600	29500	28400
Illinois	22300	20600	19200	17900	16500	15300	14200	13200	12400	12300	12300
Indiana	3860	3530	3220	2940	2680	2440	2230	2030	1860	1690	1550
Kansas	54500	52700	51100	49700	47600	45700	43900	42200	40700	42200	43800
Kentucky	6260	5710	5210	4750	4340	3960	3610	3290	3010	2740	2500
Louisiana	465000	421000	383000	348000	315000	286000	260000	236000	214000	197000	181000
Michigan	40000	38100	36300	34600	32900	31400	29900	28500	21700	25800	24600
Mississippi	41200	38700	36300	34100	32000	30000	28100	26400	24800	23700	22600
Montana	31900	31300	30700	30200	29600	29100	28500	28000	27500	26900	26400
Nebraska	88000	77000	67000	58000	50000	43000	38000	33000	28500	25000	22000
New Mexico	83000	80000	72300	74700	71700	68800	66100	63600	61200	61100	61000
New York	768	724	683	644	608	573	541	510	481	454	428
North Dakota	21500	23000	22200	21000	19800	18800	17900	17000	16500	15500	14600
Ohio	10400	9800	9800	8700	8200	7700	7200	6800	6400	6000	5700
Oklahoma	140000	134000	128000	123000	116000	111000	105000	100000	95700	97400	99500

State	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Pennsylvania	2970	3010	3050	3100	3050	3000	2970	2930	2900	3240	3560
South Dakota	413	387	363	340	319	299	280	262	246	230	216
Tennessee	527	465	410	361	319	281	248	218	193	170	150
Texas - Total	1140000	1120000	1100000	1080000	1060000	1030000	1010000	992000	972000	961000	950000
District 1	22700	22000	21800	19500	18700	17800	16900	16000	15300	14900	13600
District 2	58600	55400	52300	49400	46600	44000	41600	39300	37100	35000	33100
District 3	153000	149000	145000	141000	138000	134000	131000	127000	12400	121000	118000
District 4	25800	22000	18700	15900	13600	11500	9820	8360	7110	6050	5150
District 5	17900	17400	16800	16200	15700	15200	14700	14200	13700	13300	12800
District 6	136000	131000	125000	120000	115000	111000	106000	102000	97600	93600	89800
District 7B	32800	31900	31000	30200	29400	28600	27800	27100	26300	25600	24900
District 7C	24000	22200	20600	19100	17700	16400	15200	14000	13000	12000	11200
District 8	241000	234000	226000	219000	212000	205000	198000	192000	186000	180000	174000
District 8A	347000	333000	321000	308000	296000	285000	274000	264000	253000	244000	234000
District 9	34500	32300	30200	28300	26500	24900	23300	21800	20400	19100	17900
District 10	16000	14800	13800	12800	11900	11100	10300	9550	8870	8250	7660
Utah	29200	27000	25700	24900	24300	24000	23800	23100	23000	22400	22000
West Virginia	2390	2380	2380	2380	2330	2280	2240	2200	2170	2310	2460
Wyoming	125000	123000	120000	117000	115000	112000	109000	107000	104000	103000	102000
Miscellaneous	636	566	504	449	400	356	317	282	251	223	192

APPENDIX VIII

SURFACE PROCESSING EMISSIONS

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1978
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	733	2	-	-
Alaska	5,693	116	-	9
Arizona	22	-	-	-
Arkansas	9,016	82	-	6
California	13,055	11,106	48,706	1,377
Colorado	1,826	59	-	5
Florida	2,024	4	-	-
Illinois	63	-	-	-
Indiana	8	-	-	-
Kansas	777	14	-	1
Kentucky	58	1	-	-
Louisiana	14,280	200	1	15
Michigan	921	33	-	2
Mississippi	2,408	31	-	3
Montana	1,624	35	-	3
Nebraska	150	3	-	-
Nevada	43	1	-	-
New Mexico	4,061	66	-	5
North Dakota	1,034	19	-	1
Oklahoma	6,366	57	-	4
South Dakota	18	-	-	-
Tennessee	46	2	-	-
Texas	51,220	2,045	281	152
Utah	1,647	36	-	3
Wyoming	6,593	485	1,549	53
TOTAL	123,686	14,397	50,537	1,639

- = Negligible

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1979
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	706	2	-	-
Alaska	10,709	218	-	17
Arizona	23	-	-	-
Arkansas	8,895	81	-	6
California	13,055	11,106	48,706	1,377
Colorado	1,758	57	-	5
Florida	1,944	4	-	-
Illinois	59	-	-	-
Indiana	8	-	-	-
Kansas	753	13	-	1
Kentucky	53	1	-	-
Louisiana	12,991	182	1	14
Michigan	878	31	-	2
Mississippi	2,259	29	-	3
Montana	1,593	34		3
Nebraska	131	2	-	-
Nevada	44	1	-	-
New Mexico	3,792	62	-	5
North Dakota	998	18	-	1
Oklahoma	6,081	54	-	4
South Dakota	17	-	-	-
Tennessee	41	2	-	-
Texas	50,303	2,008	276	149
Utah	1,568	34	-	3
Wyoming	6,432	473	1,511	52
TOTAL	125,091	14,412	50,494	1,642

- = Negligible

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1980
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	679	2	-	-
Alaska	14,982	305	-	24
Arizona	23	-	-	-
Arkansas	8,774	80	-	6
California	13,013	11,070	48,550	1,373
Colorado	1,685	55	-	4
Florida	1,869	4	-	-
Illinois	55	-	-	-
Indiana	7	-	-	-
Kansas	732	13	-	1
Kentucky	48	1	-	-
Louisiana	11,804	165	1	13
Michigan	837	30	-	2
Mississippi	2,122	27	-	2
Montana	1,567	34	-	3
Nebraska	113	2	-	-
Nevada	45	1	-	-
New Mexico	3,670	60	-	4
North Dakota	944	17	-	1
Oklahoma	5,843	52	-	4
South Dakota	16	-	-	-
Tennessee	36	1	-	-
Texas	49,387	1,971	271	146
Utah	1,519	33	-	3
Wyoming	6,271	461	1,473	50
TOTAL	126,041	14,384	50,295	1,636

- = Negligible

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1981
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	654	2	-	-
Alaska	15,691	319	-	25
Arizona	23	-	-	-
Arkansas	8,532	78	-	6
California	12,848	10,929	47,933	1,356
Colorado	1,622	53	-	4
Florida	1,799	3	-	-
Illinois	51	-	-	-
Indiana	6	-	-	-
Kansas	701	12	-	1
Kentucky	44	1	-	-
Louisiana	10,685	149	1	11
Michigan	796	28	-	2
Mississippi	1,991	26	-	2
Montana	1,536	33	-	3
Nebraska	97	2	-	-
Nevada	44	1	-	-
New Mexico	3,640	60		4
North Dakota	890	16	-	1
Oklahoma	5,511	49	-	3
South Dakota	15	-	-	-
Tennessee	32	1		-
Texas	48,473	1,935	266	143
Utah	1,482	32	-	2
Wyoming	6,164	453	1,448	50
TOTAL	123,327	14,182	49,648	1,613

- = Negligible

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1982
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	630	2	-	-
Alaska	15,691	313	-	25
Arizona	22	-	-	-
Arkansas	8,350	76	-	5
California	12,682	10,788	47,315	1,339
Colorado	1,512	49	-	4
Florida	1,729	3	-	-
Illinois	47	-	-	-
Indiana	6	-	-	-
Kansas	673	12	-	1
Kentucky	40	1	-	-
Louisiana	9,701	135	1	10
Michigan	759	27	-	1
Mississippi	1,867	24	-	2
Montana	1,510	32	-	3
Nebraska	83	1	-	-
Nevada	44	1	-	-
New Mexico	3,493	57	-	4
North Dakota	845	15	-	1
Oklahoma	5,273	47	-	3
South Dakota	14	-	-	-
Tennessee	28	1	-	-
Texas	47,101	1,880	258	139
Utah	1,464	32	-	2
Wyoming	6,003	441	1,410	48
TOTAL	119,567	13,937	48,984	1,587

- = Negligible

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1983
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	606	2	-	-
Alaska	15,691	313	-	25
Arizona	21	-	-	-
Arkansas	8,167	74	-	5
California	12,516	10,647	46,695	1,321
Colorado	1,502	49	-	4
Florida	1,614	3	-	-
Illinois	44	-	-	-
Indiana	5	-	-	-
Kansas	646	11	-	1
Kentucky	37	1	-	-
Louisiana	8,819	123	1	9
Michigan	723	26	-	1
Mississippi	1,749	22	-	2
Montana	1,479	32	-	3
Nebraska	73	1	-	-
Nevada	42	1	-	-
New Mexico	3,356	55	-	4
North Dakota	805	15	-	1
Oklahoma	4,988	45	-	3
South Dakota	13	-	-	-
Tennessee	25	1	-	-
Texas	46,187	1,844	253	136
Utah	1,452	32	-	2
Wyoming	5,842	429	1,372	47
TOTAL	116,402	13,726	48,321	1,564

- = Negligible

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1984
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	583	2	-	-
Alaska	14,983	299	-	24
Arizona	20	-	-	-
Arkansas	7,925	72	-	5
California	12,351	10,506	46,079	1,304
Colorado	1,444	47	-	4
Florida	1,599	3	-	-
Illinois	41	-	-	-
Indiana	5	-	-	-
Kansas	621	11	-	1
Kentucky	33	1	-	-
Louisiana	8,005	112	1	9
Michigan	689	25	-	1
Mississippi	1,643	21	-	2
Montana	1,453	30	-	2
Nebraska	64	1	-	-
Nevada	40	1	-	-
New Mexico	3,229	53		4
North Dakota	765	14		1
Oklahoma	4,751	42	-	3
South Dakota	12	-	-	-
Tennessee	22	1	-	-
Texas	45,365	1,811	248	134
Utah	1,409	31	-	2
Wyoming	5,735	421	1,347	46
TOTAL	112,787	13,504	47,675	1,542

- = Negligible

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1985
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	562	2	-	-
Alaska	14,247	284	-	22
Arizona	20	-	-	-
Arkansas	7,744	71	-	5
California	12,226	10,400	45,614	1,291
Colorado	1,386	45	-	4
Florida	1,534	3	-	-
Illinois	38	-	-	-
Indiana	4	-	-	-
Kansas	599	11	-	1
Kentucky	31	-	-	-
Louisiana	7,259	102	-	8
Michigan	655	23	-	1
Mississippi	1,543	20	-	2
Montana	1,427	29	-	2
Nebraska	55	1	-	-
Nevada	38	1	-	-
New Mexico	3,107	51	-	4
North Dakota	743	14	-	1
Oklahoma	4,547	41	-	3
South Dakota	11	-	-	-
Tennessee	19	1	-	-
Texas	44,449	1,774	243	131
Utah	1,403	31		2
Wyoming	5,574	409	1,309	45
TOTAL	109,221	13,313	47,166	1,522

- = Negligible

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1986
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	541	1	-	-
Alaska	13,906	277	-	22
Arizona	19	-	-	-
Arkansas	7,925	72	-	5
California	12,594	10,713	46,987	1,330
Colorado	1,334	43	-	4
Florida	1,479	3	-	-
Illinois	38	-	-	-
Indiana	4	-	-	-
Kansas	621	11	-	1
Kentucky	28	-	-	-
Louisiana	6,683	94	-	7
Michigan	624	22	-	1
Mississippi	1,474	19	-	2
Montana	1,396	29	-	2
Nebraska	48	1	-	-
Nevada	38	1	-	-
New Mexico	3,102	51	-	4
North Dakota	698	13	-	1
Oklahoma	4,628	41	-	3
South Dakota	11	-	-	-
Tennessee	17	1	-	-
Texas	43,947	1,754	240	130
Utah	1,366	30	-	2
Wyoming	5,520	405	1,296	44
TOTAL	108,041	13,581	48,523	1,558

- = Negligible

SURFACE PROCESSING EMISSIONS FOR THE YEAR 1987
(1,000 kg/yr)

State	HC	NO_x	SO_x	CO
Alabama	520	1	-	-
Alaska	13,197	263	-	21
Arizona	19	-	-	-
Arkansas	8,106	74	-	5
California	12,925	10,995	48,223	1,365
Colorado	1,282	42	-	3
Florida	1,424	3	-	-
Illinois	38	-	-	-
Indiana	4	-	-	-
Kansas	645	11	-	1
Kentucky	25	-	-	-
Louisiana	6,140	86	-	7
Michigan	595	21	-	1
Mississippi	1,406	18	-	2
Montana	1,370	28	-	2
Nebraska	42	1	-	-
Nevada	37	1	-	-
New Mexico	3,097	51	-	4
North Dakota	657	12	-	1
Oklahoma	4,728	42	-	3
South Dakota	10	-	-	-
Tennessee	15	1	-	-
Texas	43,446	1,734	237	129
Utah	1,342	29	-	2
Wyoming	5,466	401	1,283	44
TOTAL	106,536	13,814	49,743	1,590

- = Negligible

APPENDIX IX

STORAGE TANK CALCULATIONS

1. <u>210 Barrel Unit</u>

As discussed when calculating the gun barrel emission estimate, hydrocarbon vapor losses from a fixed roof tank consist of breathing and working fractions. Unlike both the gun barrel and the wash tank, storage tank liquid levels are not expected to remain constant, meaning that working losses must be considered.

A. Breathing Losses

$$L_B(\text{lb/day}) = 2.21 \times 10^{-4} M \left[\frac{P}{14.7-P}\right]^{0.68} D^{1.73}\, H^{0.51}\, \Delta T^{0.50}\, F_p\, C K_c$$

where:
M = 50 lb/lb mole
P = 2.8 psia at 60°F
D = 10 ft
H = 50 percent of 15 ft or 7.5 ft
ΔT = 15°F
F_p = 1.14
C = 0.52
K_c = 0.65

$$L_B = 2.21 \times 10^{-4}\,(50)\left[\frac{2.8}{14.7-2.8}\right]^{0.68}(10)^{1.73}\,(7.5)^{0.51}\,(15)^{0.50}$$

$$(1.14)(0.52)(0.65)$$

= 0.92 lb of HC/day = 335.8 lb of HC/yr

B. Working Losses

$$L_W\ (\text{lb}/10^3\text{gal}) = 2.4 \times 10^{-2}\,(M)(P)(K_N)(K_c)$$

where:
M = 50 lb/lb mole
P = 2.8 psia at 60°F
K_N = 1
K_c = 0.84

$$L_W = 2.4 \times 10^{-2} (50)(2.8)(1)(0.84)$$
$$= 2.82 \text{ lb}/10^3 \text{ gal}$$

Assuming 30 turnovers per year for the tank (AP-42 value), annual losses are:

$$(2.82 \text{ lb}/10^3 \text{ gal})(30 \text{ turnovers/yr})(210 \text{ bbl/turnover})(0.042 \times 10^3 \text{ gal/bbl}) = 746.2 \text{ lb of HC/yr}$$

Total hydrocarbon losses are: 335.8 + 746.2 lb/yr = <u>1,082 lb of HC/yr</u>
= <u>0.49 MT/yr</u>

2. <u>500 Barrel Unit</u>

A. Breathing Losses

Different parameters include:

D = 15.43 ft

C = 0.75

$$L_B = 2.21 \times 10^{-4}(50)\left[\frac{2.8}{14.7-2.8}\right]^{0.68} (15.43)^{1.73} (7.5)^{0.51} (15)^{0.50} (1.14)(0.75)(0.65)$$
$$= 2.82 \text{ lb/day} = 1,029.3 \text{ lb/yr}$$

B. Working Losses

L_W is same as for 210 barrel tank: 2.82 lb/10^3 gal

$$(2.82 \text{ lb}/10^3 \text{ gal})(30 \text{ turnovers/yr})(500 \text{ bbl/turnover})(0.042 \times 10^3 \text{ gal/bbl}) = 1,776.6 \text{ lb/yr}$$

Total losses are: 1,029.3 + 1,776.6 = <u>2,805.9 lb/yr</u>
= <u>1.273 MT/yr</u>

3. 1,000 Barrel Unit

A. Breathing Losses

Different parameters include:

$D = 21.13$ ft

$H = 50$ percent of 16 ft, or 8 ft

$C = 0.90$

$$L_B = 2.21 \times 10^{-4}\ (50)\left[\frac{2.8}{14.7-2.8}\right]^{0.68}\ (21.13)^{1.73}\ (8)^{0.51}\ (1.14)$$

$$(0.90)(0.65) = 6.04 \text{ lb/day} = 2{,}204.6 \text{ lb/yr}$$

B. Working Losses

L_B is same as for 210 barrel tank: 2.82 lb/10^3 gal

$$(2.82 \text{ lb}/10^3 \text{ gal})(30 \text{ turnovers/yr})(1{,}000 \text{ bbl/turnover})$$

$$(0.042 \text{ gal/bbl}) = 3{,}553.2 \text{ lb/yr}$$

Total losses = 2,204.6 + 3,553.2 lb/yr = 5,757.8 lb/yr = <u>2.61 MT/yr</u>

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

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16. ABSTRACT

This report provides an estimate of current HC, NO_x, CO, SO_x, and H_2S emissions from the drilling, production, and storage of oil and natural gas. Projected emission estimates for each year through 1987 are presented. Various control options and their cost effectiveness are discussed.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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