OVERVIEW OF EXPLORATION AND PRODUCTION WASTE VOLUMES AND WASTE MANAGEMENT PRACTICES IN THE UNITED STATES

Based on

API Survey of Onshore and Coastal Exploration and Production Operations for 1995

and

API Survey of Natural Gas Processing Plants for 1995

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EXECUTIVE SUMMARY

During 1996, the American Petroleum Institute (API) conducted a survey of onshore oil and gas exploration and production (E&P) operations and natural gas processing plant operations for the year 1995. The survey sought data on current waste volumes and waste management practices, produced water management, and drilling practices. The 1995 survey was designed to update a similar survey of producers' waste management practices that was published by API in 1987, and was based on data for 1985. This report provides an evaluation of the results of the 1995 survey pertaining to E&P waste volumes and waste management practices. The survey covers the three primary categories of wastes produced by the oil and gas exploration and production industry:

- *Produced water* – the saline water brought to the surface with oil and gas;
- *Drilling waste* – the rock cuttings and fluids that are produced from drilling a new wellbore into the subsurface; and
- *Associated wastes* – a broad category of a variety of small volume waste streams that encompasses all other types of wastes "associated" with oil and natural gas production.

The total volume of wastes generated annually by the oil and gas industry has decreased substantially over the past decade. In 1995, the onshore oil and gas E&P industry generated an estimated 17,900 million barrels of produced water, 149 million barrels of drilling wastes, and 20.5 million barrels of associated wastes. In addition, natural gas processing contributed an estimated 9.5 million barrels of produced water and 0.10 million barrels of dehydration wastes. A decade earlier, in 1985, the E&P industry generated 21,000 million barrels of produced water, 361 million barrels of drilling wastes, and 12 million barrels of associated wastes.[1] The decreased volume of wastes generated by E&P operations in 1995 is consistent with the general decline in E&P industry activity between 1985 and 1995 (lower oil production, fewer producing wells, fewer new wells drilled) which affects the two largest waste streams – produced water and drilling wastes.

Table ES-1 summarizes the total estimated volumes of E&P wastes disposed in 1995 by waste disposal method. Because E&P wastes are predominately liquid wastes, over 90 percent of E&P wastes are injected. Another 2 percent of E&P wastes are reused or reclaimed. A brief discussion of the 1995 results for each category of E&P waste follows in Table ES-1.

Table ES.1. 1995 Estimated Volume of Oil and Gas E&P Wastes Disposed by Method (million barrels)

Disposal Method	Produced Water[1]	Drilling Wastes	Associated Wastes[2]	Total Waste Volume	% Disposed by Method
Injection (includes EOR[3])	16,386.5	19.3	7.9	**16,413.7**	**90.7 %**
Evaporation	0	69.9	2.3	**72.2**	**0.4 %**
Burial Onsite	0	31.2	0	**31.2**	**0.2 %**
Commercial E&P Waste Facility	90.3	3.0	3.1	**96.4**	**0.5 %**
Reuse, Recycle, Reclaim	358.1	10.4	3.9	**372.4**	**2.1 %**
Discharge	537.0	1.5	0	**538.5**	**3.0 %**
Land Spread	0	10.4	1.0	**11.4**	**>0.1 %**
Road Spread	1.8	0b	0.5	**2.3**	
All Other	537.0	3.0	1.9	**541.9**	**3.0 %**
Total	**17,910.7**	**148.7**	**20.6**	**18,080.0**	**100.0 %**

[1] Includes produced water removed at gas plants.
[2] Includes wastes from gas processing plants.
[3] Enhanced oil recovery

[1] The 1985 survey excluded completion fluids from the associated wastes volume, while the 1995 survey includes these wastes in the total volume of associated wastes.

Produced Water. In 1995, E&P operations produced an estimated 17,900 million barrels of water, of which 92 percent was injected. Seventy-one percent of the total volume of produced water was injected for enhanced oil recovery (EOR) in 1995. Another 21 percent of produced water was disposed in Class II injection wells.[2] In 1985, 62 percent of produced water was injected for EOR and 30 percent was disposed in Class II injection wells. An estimated 6 percent of produced water was discharged under NPDES permits in 1985. By 1995, only 3 percent of produced water was discharged, with almost all of the discharged volume from coalbed methane operations. In 1995, 2 percent of the total volume of produced water was put to beneficial use and 3 percent was disposed by various "other" disposal methods such as percolation pits, onsite evaporation, and public water treatment works.

Drilling Wastes. The total volume of drilling wastes estimated in 1995 was based on the calculation of waste volume per foot varied by well depth that was developed during the 1985 survey, and subsequently confirmed by later analyses. Consequently, the volume of drilling wastes estimated for 1995 is consistent with the 1985 estimate, adjusted for the substantial decline in drilling activity. Nonetheless, other improvements in drilling practice between 1985 and 1995 are indicated by the 1995 E&P operations survey. By 1995, 69 percent of reserve pits were lined, up from 35 percent lined in 1985. Moreover, an estimated 25 percent of new wells were drilled with a closed mud system and did not require reserve pits. An estimated 92 percent of onshore drilling wastes in the most recent survey were derived from freshwater based mud systems, compared to 64 percent of drilling wastes in 1985. In 1995, 68 percent of drilling wastes were disposed onsite through evaporation and burial, compared to 41 percent in 1985. Disposal by surface discharge and landspreading decreased from an estimated 17 percent of drilling wastes in 1985 to 8 percent in 1995.

Associated Wastes. Associated wastes represent only about 0.11 percent of E&P wastes estimated nationwide. Although, the estimated volume of associated wastes increased from 1985 to 1995, this may be attributed to general characteristics of the survey (inclusion of certain waste streams and exclusion of other waste streams), as well as industry trends toward better tracking and reporting of E&P wastes. A key factor in the difference is the exclusion of completion fluid volumes from the 1985 survey to avoid potential double counting of those wastes with produced water (with which they are typically co-mingled). The 1995 survey explicitly addressed completion fluid volumes so that they could be included. In addition, a marked increase in the volume of workover/stimulation wastes (from operators' attempts to keep older wells operating profitably) likely contributed to the increase in associated wastes. In 1995, an estimated 89 percent of associated wastes were aqueous fluid. The remaining 11 percent of associated wastes consist of oily solids and glycol-based wastes from dehydration. In 1995, the estimated volume of tank bottoms and oily sludge declined by 21 percent, from 2.5 million barrels in 1985 to less than 2 million barrels in 1995. Over 68 percent of associated wastes were disposed by a combination of injection into Class II wells, evaporation, re-use and reclamation. Disposal by surface discharge and land/road spreading dropped from 24 percent in 1985 to less than 8 percent in 1995.

Natural Gas Processing Plants Natural gas processing plants contribute only a small fraction of E&P wastes, and were not covered by the 1985 waste survey. Gas plants managed an estimated 10 million barrels of produced water in 1995, 93 percent of which were disposed by injection into Class II wells. In 1995, gas plants produced 0.1 million barrels of associated wastes, an average of 167 barrels of waste per plant. Seventy-nine percent of gas processing plant wastes consist of scrubber liquids and sludge, 3 percent consist of glycol compounds and used filter media, and the remaining 18 percent consist of miscellaneous other waste streams. Seventy-six percent of gas processing plant wastes were disposed by injection and 13 percent were disposed at commercial E&P waste facilities and industrial or municipal disposal facilities.

The results of API's 1995 E&P operations survey demonstrate increased use of improved drilling practices and improved waste management practices.[3] The survey results suggest a trend towards overall reduction of oily tank bottoms and sludges, glycol dehydration wastes, and drilling wastes from operations

[2] Class II injection wells are those associated with the oil and gas industry, using a numbering scheme described in the Safe Drinking Water Act.

[3] For more information about how advanced exploration and production technologies are producing waste reductions and other environmental benefits, see "Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology," issued by the U.S. Department of Energy, Office of Fossil Energy, 1999.

using oil based mud. Over 90 percent of E&P wastes continue to be disposed by injection, and underground injection continues to offer the best method to safely and efficiently dispose of liquid E&P wastes.

1. INTRODUCTION

Exploring for and producing oil and natural gas results in the production of substantial volumes of wastes, the largest portion of which is naturally occurring material removed from the subsurface. Because exploration and production in the United States takes place at nearly 900,000 separate sites across the country, no mechanism exists for tabulating the total volume of wastes produced and managed by the industry. Nevertheless, it is important to the industry to understand its waste volumes and how they are managed. In the past, the American Petroleum Institute (API) has used statistical surveys of industry operations to estimate waste volumes and characterize management practices. The oil and gas industry's wastes are characterized in three primary categories:

- *Produced water* – the saline water brought to the surface with oil and gas;
- *Drilling waste* – the rock cuttings and fluids that are produced from drilling a new wellbore into the subsurface; and
- *Associated wastes* – a broad category of a variety of small volume waste streams that encompasses all other types of wastes "associated" with oil and natural gas production.

In the fall of 1995, API conducted a survey of onshore oil and gas exploration and production (E&P) operations and natural gas processing plant operations. The survey collected data on current waste volumes and waste management practices, field equipment and facilities, produced water management, and drilling practices.[4] The purpose of the survey was to update current understanding of waste management practices in the oil and gas exploration and production industry. The last comprehensive survey of industry waste management practices was API's *1985 Production Waste Survey.* During the decade between 1985 and 1995, substantial changes occurred in the U.S. oil and gas industry as illustrated in Table 1.1. In 1995, API determined that an update of the 1985 waste management survey was needed to understand how waste management had changed in response to the other changes in the industry. The management and disposal of oil and gas exploration and production wastes continues to be an important concern to states, industry, and the public. The survey results presented here demonstrate how the industry has responded to internal and external concerns about waste management, as well as highlighting some of the challenges that can be undertaken to further enhance protection of human health and the environment.

Section 2 of this report discusses survey results pertaining to production pits, tanks, land treatment operations, and produced water. Section 3 discusses survey results pertaining to associated wastes, drilling practices, drilling wastes and waste management. Section 4 provides a summary of the survey results. Appendix G provides a discussion of the survey methodology including design of the survey forms, design of the survey sample, and methodology for extrapolation of reported data. A brief summary of the survey methodology is provided below. Throughout the report, the 1995 survey results are compared to API's *1985 Production Waste Survey* wherever possible.

[4] The survey form was modified just prior to mailing to include some questions related to equipment such as engines, turbines, and boilers. These data were collected to provide input to a data collection effort by the U.S. Environmental Protection Agency for some specific air emission control related rulemakings. The data collected were provided to EPA on an aggregated basis. The focus of this report, like the primary focus of the survey, is on wastes, and thus the other data collected are not reported here.

Table 1.1. Comparison of U.S. Exploration and Production Activity, 1985 and 1995

	1985	1995	Percent Change
Total U.S. Crude Oil Production	3,274.6 million barrels	2,394.3 million barrels	-27%
Total U.S. Natural Gas Production	17.2 trillion cubic feet	19.5 trillion cubic feet	+13%
Total U.S. Natural Gas Liquids Prod.	753 million barrels	791 million barrels	+5%
Total U.S. Production	7,093.6 MMboe[c]	6,661.2 MMboe[c]	-6%
Producing Oil Wells[a]	642,408 oil wells	569,508 oil wells	-11%
Stripper Oil Wells[b]	452,543 stripper oil wells	434,422 stripper oil wells	-4%
Producing Gas & Condensate Wells	243,344 gas wells	298,541 gas wells	+23%
New Wells Completed	71,108 wells	21,695 wells	-69%
Total Footage Drilled	316,778,000 feet	117,886,366 feet	-63%

[a] Federal offshore wells are not included.
[b] Stripper wells are a subset of total producing oil wells, and includes those wells that produce 10 barrels of oil per day or less.
[c] Million barrels of oil equivalent – converts natural gas to oil equivalent based on heating values.
Source: API, Basic Petroleum Data Book, January 1999, Volume XIX, Number 1: Tables III-2, III-10, III-12, III-14, III-15; Table IV-4; Table XIII-3, XIII-9.

1.1. Overview of Survey Methodology

Two forms were developed for API's 1995 survey: *API Survey of Onshore and Coastal Exploration and Production Operations for 1995 and API Survey of Natural Gas Processing Plants for 1995.* The onshore operations survey form is included as Appendix H and the gas processing plant survey form is included as Appendix I. A detailed discussion of survey methodology is included as Appendix G.

The operations survey form was designed to focus on all the facilities operated by an E&P company within a single field. An E&P company selected for the survey was asked to complete one survey form per selected field. Participating companies were selected for the survey sample from databases maintained by Petroleum Information (PI) Corporation. For a given geological basin/state/company size combination, a company's probability of being included in the sample was proportional to its 1994 production in the basin/state combination. The PI database that served as a sampling frame for the 1995 Onshore and Coastal E&P Operations survey did not contain production information for the Appalachian states. For these states, API contacted the Oil and Gas Associations of each state and asked for a list of member companies. API sent survey forms to a selection of the member companies and asked the companies to complete the forms for any two of their fields in the designated state.

All of the responses received for a state were aggregated. The total responses received for each state were used to generate a single extrapolation factor for the state, such as number of tanks per oil production facility or volume of completion fluids generated per well completion. Reported data from the operations survey were extrapolated on production, estimated number of production facilities, or number of wells, as appropriate to the survey question under consideration. Similarly, reported data from the gas plants survey were extrapolated on gas throughput or number of gas plants as appropriate.

1.2. Estimated Production Facilities, 1995 Production, Active Wells, and Other Supplemental Data

Appendix A contains two tables which summarize the supplemental data used in this report to estimate total state values for various elements of the operations survey – waste volumes, produced water volumes, waste management practices, drilling practices, and production facilities. Appendix A, Table 1 lists the 1995 producing wells and estimated number of production facilities for each state. Appendix A, Table 2 provides 1995 oil, gas, and natural gas liquids production by state.[5] The bases for extrapolation for all the survey elements discussed in this report are the following:

- Production Pits – extrapolated on the estimated number of 1995 production facilities; supplemented by state estimates and reported data
- Oil Tank Batteries – estimated to be equivalent to the number of oil production facilities
- Condensate Tank Batteries – extrapolated on the number of active gas wells.[6] Extrapolation factor determined from survey data.
- Total Tanks – extrapolated on the estimated number of tank batteries
- Produced Water Volume – extrapolated on 1995 oil and gas production; supplemented by state estimates, reported data and estimates from Petroleum Information
- Associated Wastes: Completion Fluids – extrapolated on 1995 completed wells
- Associated Wastes: Workover/Stimulation Fluids – extrapolated on 1995 active wells
- Associated Wastes: Tank Bottoms/Oil Sludge – extrapolated on 1995 production
- Associated Wastes: Dehydration/Sweetening Wastes – extrapolated on 1995 gas production
- Drilling Wastes – extrapolated on 1995 footage drilled using drilling waste extrapolation factors identified in API's *1985 Production Waste Survey*

For the gas processing plant survey, the following survey elements were extrapolated to regional and nationwide values:

- Production Pits – extrapolated on number of gas plants in a region provided by the *Oil and Gas Journal (OGJ), Gas Processing Survey.*
- Non-pressurized tanks – extrapolated on number of gas plants in a region
- Produced water – extrapolated on total gas throughput for a region provided by the *OGJ*, *Gas Processing Survey*
- Dehydration wastes – extrapolated on gas throughput.

[5] A consulting engineer with over 30 years of experience in the industry estimated the number of production facilities in each state. He based his estimates on data from PI, as well as prior analyses, engineering relationships, and professional experience.

[6] Although the total number of oil tank batteries is estimated as the number of oil production facilities, this estimation cannot be used for condensate tank batteries because condensate is not always associated with gas production. If all condensate tank batteries are estimated as the number of gas production facilities, the result is an unreasonably large number of condensate tank batteries and associated tanks. As an alternative, the number of condensate tank batteries is estimated using a national extrapolation factor of six gas wells per tank battery determined from the reported data.

2. SURVEY RESULTS: PRODUCTION PITS, TANKS, LAND TREATMENT OPERATIONS, AND PRODUCED WATER

2.1. Production Pits

2.1.1. E&P Operations - Pits

Production pits include all types of pits operated except those associated with drilling operations. Examples of production pits include evaporation, blowdown, produced water, percolation, workover, and emergency pits. These types of pits are used when needed to enhance the safety or efficiency of field operations. Active pits are defined as pits currently in service as part of field operations, whether or not they contain fluids. Inactive pits are pits that are no longer part of the field operating system but have not been closed. Reported data on production pits are presented in Appendix B, Table 1. Survey respondents reported a total of 2,444 production pits of which 97 percent are active and 59 percent are lined. Several states have encouraged operators to close production pits and phase out the use of many types of pits in E&P operations. Louisiana has ordered the closure of pits in many areas of the state since 1986. Texas and Oklahoma report a very small number of pits relative to the size of the E&P industry in these states and none of the respondents from Appalachian states report production pits.

Appendix B, Table 2 shows estimated total production pits extrapolated based on the number of production facilities. (The estimated number of oil and gas production facilities for each state is shown in Appendix A, Table 1.) For selected states, the numbers of pits estimated in Table B.2 are based on data collected by state regulatory agencies. These state data were used to represent certain states because they are believed to be more accurate than the estimates extrapolated from the survey responses. Generally, one production pit is assumed per oil production facility. If survey respondents for a given state reported production pits associated with gas production, then one production pit was assumed for each gas production facility as well. No production pits were extrapolated for states that did not report pits for the E&P operations survey. Due to relatively low survey response rates on this question, the extrapolated number of pits for individual states is highly uncertain. The estimated total numbers of pits from Table B.2 are best interpreted as an estimate of the potential order of magnitude of production pits in an individual state. Nationwide, an estimated 55,000 pits are associated with production operations. Based on the survey data reported in Table B.1, 97 percent of the 55,000 estimated pits are assumed to be active pits and 60 percent are assumed to be lined pits.

2.1.2. Gas Plants - Pits

Gas plant pits include all types of pits operated at the plant except small collection sumps. The pits included are identical to many types of production pits for E&P operations, namely: evaporation, blowdown, produced water, and emergency pits. Table 2.1 summarizes the reported numbers of gas plant production pits as well as the extrapolated number of gas plant pits. Survey respondents reported a total of 78 pits of which 97 percent are active and 62 percent are lined. The estimated number of pits was extrapolated on the number of gas plants in a region. No pits were estimated for regions that did not report pits for the survey. Approximately 875 gas plant pits are estimated to be associated with gas processing plants. The total of gas plant pits plus production pits from E&P operations are estimated to be about 56,000 pits nationwide.

Table 2.1. Gas Processing Plants – Pits

Region	# Plants in Region[a]	Reported Data from Survey				Estimated Number of Active Pits[b]
		Number of Pits Operated	Number of Active Pits	Number of Inactive Pits	% Active Pits with Liners	
Alaska	3	11	11	0	45%	11
California	25	0	0	0	0	0
Eastern U.S.	47	0	0	0	0	0
Mid-West	92	0	0	0	0	0
New Mexico	27	8	8	0	63%	43
Rockies	104	14	14	0	64%	208
Southeast	68	4	4	0	0%	18
Texas	233	41	39	2	72%	606
Total	**599**	**78**	**76**	**2**	**62%**	**875**

[a] Based on 1996 OGJ Survey.
[b] Extrapolated based on number of plants.

2.2. Tank Batteries and Total Tanks

2.2.1. Tanks and Tank Batteries – E&P Operations

Survey respondents were asked to report either tank batteries on individual leases, or the number of central or primary separation facilities in unitized fields where storage tanks are present. Produced water injection facilities and produced water disposal facilities are not included in the count of tank batteries/central facilities. Survey respondents were also asked to report the numbers and types of tanks at the tank batteries. The E&P operations survey forms sent to operators in the Appalachian states asked only for the number of tanks in operation and did not ask for an estimate of tank batteries or central facilities.

Appendix B, Table 3 summarizes the reported data for oil tank batteries, oil tanks and other tanks associated with oil production. Appendix B, Table 4 summarizes the reported data for condensate tank batteries, condensate tanks, and other tanks associated with gas production. Table B.3 indicates that the typical oil tank battery contains two oil tanks, one produced water tank, and an emergency tank and/or “waste” tank. For condensate tank batteries, the data reported in Table B.4 suggest that the typical condensate tank battery contains one condensate tank, one or two produced water tanks, and may include an emergency or “waste” tank.[7] Combining the reported data from Tables B.3 and B.4, suggests that the typical tank battery services five to six wells and is comprised of four tanks: two oil or condensate tanks, one produced water tank, and one emergency tank or waste oil/water tank.

Because no survey data were collected on tank batteries for Appalachian operations, it cannot be determined whether the reported components of a typical tank battery represent Appalachian operations. The combined data from Tables B.3 and B.4 for Appalachian operations suggests that the ratio of product tanks to produced water tanks for Appalachian operations is 1:2 (i.e., one oil or condensate tank to two produced water tanks). Also, only about one-third of oil or condensate tanks in Appalachian operations appear to be associated with either a waste tank or emergency tank.

Estimated total numbers of tank batteries and tanks associated with E&P operations for individual states were extrapolated from the reported data. Appendix B, Table 5 summarizes the estimated oil tank

[7] Reported data for condensate tank batteries includes some responses for Arkansas and Kansas that report very large numbers of produced water tanks per tank battery. Although these responses are outliers compared to the other reported data, they are not necessarily invalid responses. If the outlying responses are removed from the reported data, the typical condensate tank battery appears to include only two to three tanks: one condensate tank, one produced water tank, and possibly a waste or emergency tank.

batteries associated with oil production and Appendix B, Table 6 summarizes the estimated condensate tank batteries associated with gas production. The number of oil tank batteries was estimated as the number of oil production facilities (as illustrated in Appendix A). The number of condensate tank batteries was estimated by applying the ratio of six gas wells per tank battery to the number of active gas wells. The number of tank batteries estimated for each state was then multiplied by the average number of tanks per tank battery determined for that state from the survey responses received for the state (shown in Tables B.3 and B.4). If a state had no survey data, a national average of four tanks per oil tank battery or two tanks per condensate tank battery was assumed.[8]

Table 2.2. summarizes the national estimate of tank batteries and tanks associated with E&P operations. A typical ratio of oil or condensate tanks, produced water and "other" tanks can be determined from the survey data in Appendix Tables B.3 and B.4. If these ratios are applied to the estimated total number of tanks in Table 2.2, the total number of oil tanks is estimated to be approximately 627,500 and the total number of condensate tanks is estimated to be 204,300. Therefore, the estimated total number of tanks associated with E&P operations (oil tanks plus condensate tanks) is approximately 831,800 tanks. About 75 percent of these tanks are estimated to be associated with oil production operations. The remaining 25 percent are estimated to be associated with gas production operations.

Table 2.2. National Estimate of Total Tank Batteries and Tanks Associated with E&P Operations

	Estimated Oil Tank Batteries	Associated Tanks (Oil Production)	Estimated Condensate Tank Batteries	Associated Tanks (Gas/ Condensate Production)	Total Tanks (oil plus gas/condensate production)
All States Excluding Appalachian Region	144,100	517,800	27,800	109,600	627,400
Appalachian Region Only	27,400	109,700	20,500	94,700	204,400
Estimated National Total (includes Appalachian Region)	**171,500**	**627,500**	**48,300**	**204,300**	**831,800**

2.2.2. Non-pressurized Tanks – Gas Plants

The number of tanks reported includes all non-pressurized tanks used at the plant for storage of produced water, condensate, and liquid products and all tanks used for emergency conditions. Table 2.3 shows the estimated number of tanks associated with gas plants. The reported data for gas plant tanks is summarized in Appendix B, Table 7. Nationwide, gas plants are estimated to have about five associated non-pressurized tanks. The typical gas plant has approximately two liquid product tanks per plant, one condensate tank, and one or two produced water tanks. About 40 percent of plants are estimated to have an emergency tank. Table 2.3 also indicates the regional variation from the national estimate. For example, the New Mexico region is estimated to have about six to seven tanks per gas plant. A typical gas plant in New Mexico is estimated to have three liquid product tanks, two condensate tanks, and one emergency tank. About 60 percent of New Mexico plants are estimated to have a produced water tank as well.

[8] Alternate estimates of total tanks for the Appalachian states were obtained by applying a survey-derived ratio of six oil wells per tank to a state's total active oil wells and 1.3 gas wells per tank to a state's total active gas wells. The alternate estimates for the Appalachian states are included in Appendix Tables B.5 and B.6. The alternate estimate of tanks associated with oil production appears to be quite low and is not included in Table 2.2. The alternate estimate of tanks associated with condensate production is reasonably close to the estimate obtained from applying the method used for non-Appalachian states. The alternate estimate of tanks associated with condensate production is included in Table 2.2 because this estimate incorporates survey reported data for the Appalachian region.

Table 2.3. Estimate of Total Non-Pressurized Tanks Associated with Gas Plants

Region	# Plants in Region[a]	Estimated Number of Produced Water Tanks[b]	Estimated Number of Condensate Tanks[b]	Estimated Number of Liquid Product Tanks[b]	Estimated Number of Emergency Tanks[b]	Estimated Total Non-Pressurized Tanks[b]
Alaska	3	0	0	18	1	19
California	25	no data	no data	no data	no data	0
Eastern U.S.	47	20	94	275	27	416
Mid-West	92	153	123	92	0	368
New Mexico	27	16	54	81	22	173
Rockies	104	134	149	401	89	773
Southeast	68	59	59	59	5	181
Texas	233	466	186	342	124	1,118
Total	**599**	**848**	**665**	**1268**	**267**	**3,048**

[a] Based on 1996 OGJ survey.
[b] Extrapolated based on number of plants.

2.3. Landspreading/Land Treatment Operations

Landspreading/land treatment operations dispose of solid wastes through application to the land or incorporation into the soil. This process uses the physical, chemical, and biological capabilities of the soil to decompose constituents of the wastes. Nutrients and water may be added to enhance biodegradation and the treatment area may be tilled periodically to improve aeration. In this context, “landspreading” or “land treatment” excludes the practice of landspreading or burying drill cuttings and other drilling wastes. An example of the type of land treatment operation included here might be land treatment or bioremediation of hydrocarbon contaminated soil on leased land surrounding a production facility. Land treatment operations typically require a state permit but some states prohibit land treatment. Question 18 of the E&P operations survey simply asked operators if on-site landspreading or land treatment operations are carried out in the field for which they were reporting. Thirty respondents (19 percent) report on-site land treatment operations and 127 respondents (81 percent) report no land treatment operations:

	On-site Land Treatment - Yes	On-site Land Treatment – No
Total Responses:	30 (19%)	127 (81%)

2.4. Produced Water

2.4.1. Estimated Volume of Produced Water – E&P Operations

The estimated total volume of produced water by state is shown in Appendix C, Table 1. An estimated national total of 17.9 billion barrels of water was produced in 1995. As indicated in Table C.1, the estimated total produced water for most states was obtained from state data, state estimates, or industry sources (Petroleum Information estimates). Where indicated, a produced water volume was extrapolated based on 1995 oil production using extrapolation factors estimated from survey responses for question six on the E&P operations survey form.

The API *1985 Production Waste Survey* reports two estimates for produced water. The first estimate, 16.3 billion barrels, was obtained from state records, operator inventories and EPA estimates. The second estimate, 20.9 billion barrels, was based on statistical analysis of data received from a supplemental survey form sent to individual companies. The 1985 estimates suggest that, on average, 5.0 barrels to 6.4 barrels of water were produced per barrel of oil. The 1995 estimate indicates that, a decade later, the produced water cut increased to approximately 7.5 barrels of water per barrel of oil. The 1995 estimate of produced water, 17.9 billion barrels, represents a 14 percent decline from the 1985 estimate of 20.9 billion barrels. This corresponds to the 27 percent decline in U.S. oil production over the same period. The apparent decline in produced water volume was not as great as the decline in oil production for two reasons. First, declining oil production between 1985 and 1995 was offset, in part, by a 13 percent increase in gas production. Although, gas wells generally produce less water than oil wells, water production associated with gas production can be substantial in some regions. Second, as oil production declined, associated water production increased on a per barrel basis, reflecting a growing population of aging oil wells

2.4.2. Produced Water Disposal – E&P Operations

The reported volumes of produced water and reported disposal methods are tabulated in Appendix C, Table 2. Survey respondents reported the production of approximately 4.8 million barrels of water per day or 1,750 million barrels annually. The survey respondents represent about 10 percent of the estimated national total volume of produced water. Table 2.4 below summarizes the frequency of produced water disposal methods estimated from the aggregate survey response. Nationwide, 71 percent of produced water is injected into producing reservoirs to enhance recovery of oil and natural gas. Another 21 percent of produced water is injected for disposal. Subsurface formation water and waste fluids produced by the oil and gas industry are injected into Class II wells as required under the Safe Drinking Water Act. Thus, approximately 92 percent of produced water is managed through Class II well injection into subsurface reservoirs, generally considered the safest and most effective method for handling these type fluids. Although only 3 percent of produced water is discharged; almost all of the discharged volume is obtained from coalbed methane operations in Alabama and is discharged under NPDES permits. Less than half of one percent of produced water is disposed at commercial disposal facilities.

Table 2.4. 1995 Produced Water Disposal Method – Reported Data

Produced Water Disposal Method	Percentage of Produced Water Disposed by Method
Inject for Enhanced Oil Recovery (EOR)	71.0 %
Inject for Disposal Onsite	18.0 %
Treat and Discharge [a]	3.0 %
Inject for Disposal Offsite	2.5 %
Beneficial Reuse [b]	2.0 %
Inject at Commercial Disposal Facility	< 0.5%
Road Spread	< 0.01%
Other [c] ("percolation ponds")	3.0 %

[a] Over 99 percent of surface discharged water originates from coalbed methane operations in Alabama. The remaining discharged water is comprised of small volumes reported from gas production operations in Appalachian states.
[b] Beneficial reuse takes place under NPDES permits and allows produced water to be used for irrigation, livestock watering, and similar uses in the Western U.S.
[c] Almost the entire volume in the "Other" category is reported by operators in California and appears to represent a produced water management method unique to California.

The percentage of produced water disposed by the methods summarized in Table 2.4 was applied to the 17,900 million barrels total volume estimated in Appendix C.1. An estimated 16,500 million barrels were injected into Class II wells in 1995, of which 12,700 million barrels were used for enhanced oil recovery and 3,800 million barrels were disposed. Approximately 500 million barrels were discharged via NPDES permit, an estimated 400 million barrels were re-used for beneficial purposes, and 500 million barrels were disposed by other methods.

As Appendix C, Table 2 indicates, there is significant regional variation from the nationwide aggregate produced water disposal methods presented in Table 2.4 above. For example, surface discharge of produced water is permitted for large coalbed methane operations in Alabama. Consequently, the percentage of water disposed by NPDES discharge in Alabama is quite large relative to other states, and represents a special case resulting from the coalbed methane operations in that state. The Appalachian States (KY, OH, PA, NY, VA, WV) and the Rocky Mountain States (CO, WY, UT, MT) provide further examples of regional variation in produced water disposal methods. In the Appalachian states, 85 percent of produced water is injected, 15 percent is reported as being surface discharged, and 6 percent of produced water is disposed at commercial facilities. Only 30 percent of injected produced water is used for enhanced oil recovery operations in the Appalachian states. In contrast, 85 percent of produced water is injected for EOR in the Rocky Mountain States, 7 percent is injected onsite for disposal, but less than 1 percent of produced water is disposed at offsite commercial facilities. In the Rocky Mountain States approximately 7 percent of produced water is reused for beneficial purposes (e.g., livestock watering, irrigation).

Table 2.5 compares the produced water disposal methods reported in API's *1985 Production Waste Survey* with the disposal methods reported in API's 1995 E&P operations survey. While the total percentage of produced water injected remained constant between 1985 and 1995; the percentage injected for enhanced recovery increased significantly by 1995. Disposal by injection was not distinguished as onsite, offsite, or commercial disposal in the 1985 survey. The percentage of produced water disposed by NPDES surface discharge decreased by half between 1985 and 1995. This was mainly due to a prohibition of coastal discharges in Louisiana and Texas, which was phased in during the early 1990s. In 1995, disposal by NPDES surface discharge is limited to a few unique, regional operations.

Table 2.5. Comparison of 1985 and 1995 Produced Water Disposal Methods

Produced Water Disposal Method	**% Produced Water Disposed by Method 1985**	**% Produced Water Disposed by Method 1995**
Inject for Enhanced Oil Recovery (EOR)	62 %	71 %
Injected for Disposal	30 %	21 %
NPDES Discharge	6 %	3 %[a]
Reuse	0 %	2 %
Other (percolation, evaporation, public treatment works)	2 %	3 %
Total	**100%**	**100%**

[a] Nearly all surface discharge is from coalbed methane operations in Alabama.

2.4.3. Produced Water – Gas Processing Plants

Gas plant survey respondents reported the removal of over 6,000 barrels of produced water per day. This is water that was not separated from the gas in the field but must be removed prior to processing. When extrapolated on gas throughput, the total volume of produced water from gas processing plants is estimated to be at least 9.5 million barrels per year. Table 2.6 summarizes the reported data and extrapolated volume of produced water for each gas plant region. The Alaskan region reported no volume of produced water. If an estimated volume of produced water is assumed for Alaska, then the total estimated volume of produced water from gas plants may be as much as 10.9 million barrels per year.

Table 2.6. Gas Plants, Produced Water Volume – Reported Data and Estimated Volumes

Region	# Plants in Region[a]	Gas Plant Throughput for Region [a] (MMcfd)	Reported Gas Throughput for Region (MMcfd)	Reported Volume Produced Water (barrels/day)	Vol. Produced Water per Vol. Gas Throughput (bbl/MMcf)	Estimated Volume Produced Water (barrels/day)
Alaska	3	8,600	7,900	0	b	b
California	25	700	300	201	0.67	**460**
Eastern U.S.	47	2,000	990	247	0.25	**500**
Mid-West	92	5,900	110	71	0.66	**3,900**
New Mexico	27	2,100	1,100	148	0.13	**300**
Rockies	104	4,400	2,700	328	0.12	**530**
Southeast	68	12,900	6,200	520	0.08	**1,100**
Texas	233	11,500	2,700	4,532	1.69	**19,400**
Total (excl. Alaska)	**596**	**39,500**	**14,100**	**6,047**	**0.62**	**26,190[b]**

[a] Based on 1996 Oil & Gas Journal survey.
[b] Due to processes used in Alaska, all produced water may be removed before it reaches the gas plant. If we assume a volume of 0.43 bbl/MMcf for Alaska, total estimated produced water volume is 29,890 bbl/d.

Appendix F, Table 1 shows the reported volumes of produced water disposed from gas plants by method for each gas plant region. The national results are summarized in Table 2.7 which shows that 93 percent of produced water from gas plants is reported to be disposed by injection into Class II wells. Approximately 38 percent of the injected volume is disposed onsite. About 46 percent of the injected volume is disposed offsite into Class II wells with 9 percent going to commercial well disposal facilities. The remaining produced water not injected is disposed by other miscellaneous methods.

Table 2.7. Gas Plants; Produced Water Disposal Method – Reported Data

Produced Water Disposal Method	Percentage of Produced Water Disposed by Method	Volume of Produced Water Disposed by Method (barrels/day)
Inject for Disposal Offsite	46 %	2,781
Inject for Disposal Onsite	38 %	2,306
Inject at Commercial Disposal Facility	9 %	534
Reuse	1 %	50
Treat and Discharge	0 %	0
Road Spread	0 %	0
Other	6 %	376
Total	100 %	6,047

“Other” methods include: co-mingle w/ oil product, treat & evaporate, evaporation pits, inject for EOR in adjacent oil fields, steam vent to atmosphere

3. SURVEY RESULTS: ASSOCIATED WASTES, GAS DEHYDRATION/SWEETENING WASTES, DRILLING WASTES, AND WASTE MANAGEMENT PRACTICES

3.1. Associated Wastes and Waste Management

3.1.1. Types of Associated Wastes

Associated wastes include a wide range of small volume waste streams that are associated with exploration and production of oil and natural gas. These wastes are often grouped under the term "associated wastes" as the third category of wastes (along with produced water and drilling wastes) that are exempt from regulation as hazardous wastes under the Resource Conservation and Recovery Act.[9] The 1995 E&P operations survey considered four categories of wastes that together comprise the majority of associated wastes:

- Completion Fluids – All fluids from initial well completion activities, including any initial acid stimulation or hydraulic fracturing.
- Workover/Stimulation Fluids – All fluids from subsequent workover and stimulation operations.
- Tank Bottoms/Oily Sludges – Tank sediment and water, produced sand and other tank bottoms.
- Dehydration/Sweetening Wastes – Includes glycol-based compounds, glycol filters, molecular sieves, amines, amine filter, precipitated amine sludge, iron sponge, scrubber liquids and sludge, backwash, filter media and other wastes associated with the dehydration and sweetening of natural gas.

Appendix D, Table 1 lists the 1995 reported volumes of associated wastes by state. Completion fluids and workover fluids comprise 91 percent of the reported volume of associated wastes. Tank bottoms and sludge comprise almost 9 percent of the reported volumes, and dehydration/sweetening wastes comprise only 0.25 percent.

The associated waste streams considered in the 1995 E&P operations survey differ somewhat from the API *1985 Production Waste Survey*. The types and volumes of associated wastes considered in the *1985 Production Waste Survey* are summarized in Table 3.1. The 1*985 Production Waste Survey* estimated the total volume of associated wastes generated in 1985 to be 11.76 million barrels; the 1995 survey estimates the total volume of associated wastes generated annually to be about 20.5 million barrels. The most significant difference is the 1995 survey defined completion fluids and workover/stimulation fluids as two separate categories of associated wastes, whereas the 1985 survey combined the two waste streams into a single category. In the 1985 survey, workover fluids were described as: *"…workover, swabbing, unloading, and completion fluids recovered from a well bore that are not recombined with the production stream. They include spent acid or stimulation fluids and swab tank fluids sent directly to disposal. They exclude fluids sent down flow lines, hauled to field batteries or NPDES permitted pits because these fluids are captured in other waste categories or under produced water disposal statistics."* Unlike the 1985 survey, the 1995 survey captures the volume of completion and workover fluids injected into Class II wells as associated waste. Consequently, the large percentage of completion and workover fluids that were reported disposed by injection in 1995 were not captured as associated waste in the 1985 survey, but were instead included in the estimated volume of produced water. For this reason, the percentage of associated wastes comprised of aqueous liquids in 1995 is almost twice the percentage of aqueous liquid associated waste in 1985. The 1985 survey also includes oil-contaminated soil as associated waste, as well as a number of other small waste streams such as solvents, cooling tower blowdown water, and used oils that were not

[9] A fourth category of wastes, 'industrial wastes' includes wastes generated at E&P sites that are not uniquely associated with oil and gas E&P operations and thus are not exempt from regulation as hazardous under RCRA. These include wastes such as paint and used solvents. Industrial wastes were not addressed by the survey.

included in the 1995 survey. Approximately 25 percent of the total associated wastes estimated in 1985 were contributed by waste streams not considered in the 1995 E&P operations survey.

Table 3.1. Summary of Total Estimated Associated Wastes from 1985 Production Waste Survey (barrels)

Associated Waste	% Waste	Est. Waste Volume (bbls./yr.)
Workover Fluids	48 %	5,656,000
Produced Sand	11 %	1,276,000
Oily Debris (contaminated soil, rags, etc.)	11 %	1,261,000
Tank Bottoms	10%	1,232,000
Dehydration/Sweetening Unit Wastes	4 %	460,000
Untreatable Emulsions	3 %	355,000
Used Solvents/Degreasers	2 %	252,000
Cooling Water	2 %	219,000
Used Oils	2 %	212,000
Spent Iron Sponge	< 1 %	54,000
Other Liquid Wastes	5 %	591,000
Other Solid Wastes	2 %	192,000
Total		**11,760,000**

3.1.2. Estimated Volume of Associated Wastes – 1995 E&P Operations Survey

Appendix D, Table 2 shows the estimated volumes of associated wastes by state. Completion fluids were extrapolated based on the number of completed wells, workover/stimulation fluids were extrapolated on the number of active wells, tank bottoms were extrapolated on total production, and dehydration/sweetening wastes were extrapolated on gas production. Table 3.2 summarizes the national total volume of associated wastes estimated from the 1995 E&P operations survey.

Table 3.2. 1995 E&P Operations Survey – Total Estimated Volume of Associated Wastes

Associated Waste	% Waste	Est. Waste Volume (bbls./yr.)
Completion Fluids	43 %	8,778,000
Workover/Stimulation Fluids	46 %	9,527,000
Tank Bottoms/Oily Sludge	10 %	1,987,000
Dehydration/Sweetening Unit Wastes	1 %	193,000
Total		**20,485,000**
Total (excluding completion fluids as in the 1985 Survey)		(11,707,000)

In 1985, the injected volume of workover and completion fluids was largely counted with the 1985 volume of produced water. Consequently, the total 1995 volume of associated wastes minus the 1995 volume of completion fluids provides an estimate of the total 1995 volume of associated wastes, 11.7 million barrels, that is directly comparable to the total 1985 volume of 11.76 million barrels (illustrated in Tables 3.1 and 3.2). The 1995 volume of associated wastes may be underestimated because oily debris and other miscellaneous waste streams were not included in the 1995 data. For example, in 1985 oily debris contributed approximately 11 percent of associated wastes, or about 1.3 million barrels, but this waste stream is not included in 1995. Another 1.0 million barrels, or about 9 percent of the 1985 total associated wastes, were contributed by miscellaneous solid and non-aqueous waste streams that were not included in 1995.

There are several other noteworthy differences between the 1995 estimated volumes of associated wastes and the 1985 estimated volumes. Aqueous fluids comprise 89 percent of associated wastes in 1995. The remaining 11 percent of associated wastes are solids, sludges, and glycol compound wastes. In 1985, solids, sludges, and non-aqueous liquids were estimated to comprise 45 percent of associated wastes, and workover fluids, cooling tower blowdown water, and miscellaneous other liquid wastes comprised the remaining 55 percent of associated wastes. In 1995, the estimated total volume of workover fluid was 68 percent greater than the total volume of workover fluid estimated in 1985. This increase probably reflects a substantial increase in the number of well workovers, recompletions, and well stimulations between 1985 and 1995. In 1995, the estimated volume of tank bottoms/oily sludge (includes produced sand) was about 21 percent less than the 1985 estimated volume of 2.51 million barrels (produced sand plus tank bottoms). Because tank bottoms were extrapolated on production, the decreased volume of tank bottoms/oily sludge between 1985 and 1995 reflects the 27 percent decline in crude oil production during the period. The estimated total volume of dehydration/sweetening wastes in 1995 is less than half the volume of dehydration/sweetening wastes estimated in 1985. The 1995 estimated volume of dehydration wastes is surprisingly low considering that total U.S. gas production increased by 13 percent between 1985 and 1995 and the number of active gas wells increased by 23 percent. The apparent decline in the estimated volume of dehydration wastes may be the result of a combination of factors: 1) Recycled glycol waste fluids were not reported in the survey; 2) By 1995, the percentage of production that is "new" gas increased relative to total gas production, and new production tends to be dry gas that does not require dehydration; 3) The survey response was insufficient to characterize gas dehydration wastes for the total United States.[10]

In comparing the estimated volumes of associated wastes between 1985 and 1995, another factor to consider is better record keeping. At the time of the 1985 survey, the term "associated wastes" was new and many companies simply did not keep track of these waste streams (which tend to be only a few barrels per well annually). By 1995, increased environmental awareness and the availability of better information management systems enhanced the accuracy of the data reported on the survey forms. Thus, a portion of the apparent "increase" in associated wastes may simply be due to better tracking and reporting of these waste streams within companies.

3.1.3. Associated Waste Disposal

Table 3.3. reports the estimated associated waste disposal practices for the aggregate associated waste stream for the total United States. The disposal practices reported in Table 3.3 reflect the large volume of aqueous liquid associated wastes that were identified in the 1995 survey. In 1995, the most common disposal practice was injection, 7.78 million barrels, followed by recycling, reclamation or beneficial reuse, 3.89 million barrels. Approximately, 3 million barrels were disposed at commercial E&P waste facilities and 2.25 million barrels were evaporated.

[10] In the 1995 survey, only 17 respondents reported dehydration waste in a total of 11 states. It is possible that the sample reporting gas dehydration wastes were not representative of gas dehydration operations in the U.S. as a whole.

Table 3.3. Estimated Associated Waste Disposal Practices for the Total U.S.; Total Associated Waste Stream – 1995 E&P Operations Survey

Associated Waste Disposal Method	% Waste	Total Estimated Waste Volume (bbls./year)
Disposal by Injection	38 %	7,784,000
Recycle, Reuse, Oil Reclamation	19 %	3,892,000
Commercial E&P Waste Facility	15 %	3,073,000
Evaporate from Pits	11 %	2,253,000
Land Spread	5 %	1,024,000
Road Spread	2.5 %	512,000
Incinerate	0.4%	82,000
Municipal or Industrial Landfill	<0.1 %	20,500
Other: (land treatment, burial onsite, disposal pits, other commercial disposal)	9%	1,844,000
Total (Bbls./Yr.)	**100%**	**20,484,500**

Table 3.4 shows the total volume of associated wastes by disposal practice estimated in the *1985 Production Waste Survey.* In 1985, the largest volume of associated wastes, 6.1 million barrels, was disposed in offsite commercial facilities. In 1995, only half this volume, 3.1 million barrels was estimated to be disposed at commercial E&P facilities. It is possible that the additional 3 million barrels disposed at offsite commercial facilities in 1985 includes some of the associated waste streams and volumes not identified in the 1995 survey, such as oil contaminated soil, spent solvents, emulsions, and miscellaneous oily debris. Between 1985 and 1995, the estimated volume of associated wastes disposed by land spreading or road spreading declined by over 40 percent from 2.7 million barrels to 1.5 million barrels. In 1995, 10 million barrels were estimated disposed by injection and evaporation compared to 1.18 million barrels in 1985. This reflects the inclusion of completion fluids as an associated waste in 1995, as well as the significant increase in workover/stimulation fluids between 1985 and 1995.

Table 3.4. Estimated Volume of Associated Wastes by Disposal Techniques From 1985 Production Waste Survey

Associated Waste Disposal Method	% Waste	Total Estimated Waste Volume (bbls./year)
Offsite Commercial Facility	52 %	6,114,000
Road Spread	14 %	1,646,000
Land Spread	9 %	1,058,000
Injection	7 %	823,000
Recycle	7 %	823,000
Onsite Burial	5 %	588,000
Evaporation/Onsite Pit	3 %	353,000
Surface Discharge	1 %	116,000
Other: (incinerate, burned as fuel)	2%	235,000
Total (Bbls./Yr.)	**100.0%**	**11,756,000**

Table 3.5 and Table 3.6 show the estimated volume of wastes disposed by waste disposal practice for each of the associated waste streams considered in the 1995 E&P operations survey. Appendix D, Table 3 and Table 4 contain the reported data on which Table 3.5 and Table 3.6 are based. Associated waste disposal practices vary significantly depending upon the type of waste stream. Appendix D, Table 5 and Table 6 show the reported volumes of associated wastes disposed by state. These tables indicate variations in associated waste disposal practices between states and regions.

Table 3.5. Estimated Volumes of Associated Wastes by Disposal Method; Completion Fluids and Workover Fluids, 1995 E&P Operations Survey

Associated Waste Disposal Methods	% Completion Fluids	Est. Volume Completion Fluids (bbls/yr.)	% Workover Fluids	Est. Volume Workover Fluids (bbls./yr.)
Disposal by Injection	21 %	1,843,000	59 %	5,621,000
Recycle, Beneficial Reuse, Oil Reclamation	33 %	2,897,000	<0.1 %	10,000
Commercial E&P Waste Facility	29 %	2,546,000	4 %	381,000
Evaporate from Pits	8 %	702,000	16 %	1,524,000
Land Spread	6 %	527,000	2 %	191,000
Road Spread		0	0.4%	38,000
Incinerate		0	1 %	95,000
Municipal or Industrial Landfill		0		0
Other: (land treatment)	3 %	263,000	17.5 %	1,667,000
Total	**100%**	**8,778,000**	**100%**	**9,527,000**

Table 3.6. Estimated Volumes of Associated Wastes by Disposal Method; Tank Bottoms/Oily Sludge and Dehydration Wastes, 1995 E&P Operations Survey

Associated Waste Disposal Methods	% Tank Bottoms	Est. Volume Tank Bottoms/ Sludge (bbls./yr.)	% Dehydration Wastes	Est. Volume Dehydration Wastes (bbls./yr.)
Disposal by Injection	24 %	477,000	4 %	7,700
Recycle, Beneficial Reuse, Oil Reclamation	37 %	735,000	7 %	13,500
Commercial E&P Waste Facility	2 %	40,000	32 %	61,700
Evaporate from Pits	0.2 %	4,000		0
Land Spread	16.5 %	328,000	8 %	15,400
Road Spread	18 %	358,000	48.5 % [a]	93,500
Incinerate	<0.1 %	2,000	0.1 %	200
Municipal or Industrial Landfill	<0.1 %	2,000		0
Other: (onsite burial, other commercial disposal, disposal pits)	2 %	40,000	0.5 %	1,000
Total	**100%**	**1,986,000**	**100%**	**193,000**

[a] Of the 17 survey respondents reporting gas dehydration waste, a single respondent accounted for almost half the total reported volume of dehydration waste. This same respondent reported all dehydration waste was roadspread in 1995. If this response is excluded from the reported data, then the total extrapolated volume of dehydration/sweetening waste is 99,000 barrels with an estimated 62.5 percent disposed at commercial E&P waste disposal facilities.

Comparison of the associated waste disposal practices and waste volumes reported in 1985 and 1995 suggest that significant changes occurred over the decade:

- The estimated total volume of associated wastes did not decrease between 1985 and 1995 despite the decline in oil production during that period. Between 1985 and 1995 the volume of aqueous liquid wastes increased relative to the volume of solid and oily wastes, with a corresponding increase in the volume of associated wastes disposed by Class II injection and evaporation.

- The volume of workover/stimulation fluids increased between 1985 and 1995, possibly reflecting an increase in workovers, recompletions, and well stimulations during that time.

- The volume of tank bottoms/oily sludge declined between 1985 and 1995. The decreased volume of oily wastes may, in part, be the result of the decline in oil production during that time, as well as improved waste minimization and waste treatment efforts.

- There appears to be an almost 50 percent decrease in the use of offsite commercial E&P facilities for associated waste disposal between 1985 and 1995. The estimated volume of associated wastes disposed at commercial facilities was 3 million barrels in 1995, down from 6 million barrels in 1985. This result suggests that a greater percentage of associated wastes were managed onsite in 1995 than in 1985.

- The estimated volume of associated waste disposed by surface disposal methods such as surface discharge, land spreading, and road spreading declined between 1985 and 1995.

3.2. Gas Processing Plant Wastes and Waste Management

3.2.1. Types of Gas Processing Plant Wastes

Like other types of wastes uniquely associated with oil and natural gas production, gas processing plant wastes are exempt from regulation as hazardous under the Resource Conservation and Recovery Act (RCRA). Exempt gas plant wastes include glycol and glycol-based compounds, glycol filters, molecular sieves, amines, amine filters, precipitated amine sludge, iron sponge, scrubber liquids and sludge, backwash, filter media, and miscellaneous other wastes associated with dehydration or sweetening of natural gas. The 1995 survey of gas processing plant wastes considered four categories of wastes that represent the primary exempt waste streams from gas processing operations. The waste streams considered include:

- Spent glycol/glycol compounds
- Used filters and filter media
- Scrubber liquids and sludge
- All other dehydration and sweetening wastes.

Detailed survey data reported for each gas plant dehydration waste stream are presented by region in Appendix F, Tables 2, Table 3, Table 4, and Table 5. Appendix F, Table 6 summarizes the reported volumes of gas processing plant wastes for the total United States.

3.2.2. Gas Processing Plant Waste Disposal Methods and Estimated Volumes of Waste

The total estimated volume of gas processing plant wastes for the United States is shown in Table 3.7. No wastes were extrapolated for the Alaska region because no wastes were reported for that region. The total estimated volume of wastes from gas processing plants is less than 1 percent of the estimated national total volume of associated wastes. Scrubber liquids and sludge comprise an estimated 79 percent of the waste stream from gas plants. Glycol compounds and used filters/filter media each contribute 1 percent to 2 percent of the gas plant dehydration waste stream. The remaining 18 percent of the wastes include other unspecified dehydration wastes.

Table 3.7. Gas Processing Plant Wastes – Estimated Volumes (extrapolated on gas throughput)

Region	Gas Throughput for Region (MMcfd)	Est. Volume Spent Glycol/ Glycol Compounds (bbls./yr.)	Est. Volume Used Filters/ Filter Media (bbls/yr.)	Est. Volume Scrubber Liquids & Sludge (bbls./yr.)	Est. Volume All Other Dehydration/ Sweetening Wastes (bbls./yr.)	Est. Total Reported Volume of Gas Plant Wastes (bbls./yr.)
Alaska	8,637	0	0	0	0	**0**
California	679	50	60	460	0	**570**
Eastern U.S.	2,005	220	1	120	0	**340**
Mid-West	5,894	0	10	0	830	**840**
New Mexico	2,122	0	50	40	2,140	**2,230**
Rockies	4,384	710	420	70	1,950	**3,150**
Southeast	12,864	210	150	66,370	9,280	**76,010**
Texas	11,502	10	820	13,470	4,090	**18,390**
Total	**48,087**	**1,200**	**1,510**	**80,530**	**18,290**	**101,530**

Table 3.8. lists the estimated volume of gas processing plant wastes by disposal method. The reported volumes of gas plant wastes by disposal method are summarized in Appendix F, Table 7. Table 3.8 suggests that scrubber liquids comprise the largest component of gas processing plant wastes. Consequently, most gas plant wastes, 78.5 percent, are disposed by injection or evaporation. Thirteen percent of gas plant wastes are disposed offsite at commercial E&P waste facilities or landfills. Data were not collected on gas processing plant wastes in the 1985 production survey, so no comparison can be made with 1985 waste volumes and disposal practices.

Table 3.8. Gas Processing Plants; Estimated Volume of Wastes by Disposal Method

Waste Disposal Method	Percentage of Gas Processing Plant Wastes Disposed by Method	Estimated Volume of Wastes Disposed by Method (barrels/year)
Disposal by Injection	76 %	77,200
Commercial E&P Waste Disposal Facility	9 %	9,100
Land Spread Onsite	6 %	6,100
Industrial or Municipal Landfill	4 %	4,100
Evaporate from Pits	2.5 %	2,500
Recycle or Reuse	1 %	1,000
Incinerate	0.25%	300
Road Spread Onsite	0.01 %	10
Other	1 %	1,000
Total	**100%**	**101,310**
"Other" methods include: "co-mingle w/ oil product, waste disposal contractor, onsite burial w/ permit, incineration in "waste-to energy" plant"		

3.3. Drilling and Drilling Waste Management

3.3.1. Drilling Techniques

Traditionally, wells are drilled using one of two techniques. Most wells are drilled using a rotary rig with drilling mud to cool the bit and lubricate the hole. Wells drilled with a rotary rig generally have a reserve pit to store and dispose the used drilling fluids and cuttings. An older drilling technique, common in Appalachia, uses a truck-mounted cable tool drilling rig. But new technologies have made in-roads. In sensitive areas, reserve pits are increasingly replaced with storage tanks in what is termed as a "closed system." Certain types of wells are drilled using pneumatic tools and air, gas, or foam in place of drilling mud. The survey requested information on drilling techniques to better understand the percentage of wells drilled with techniques other than a rotary rig and open mud systems. Appendix E, Table 1 summarizes the reported data on drilling techniques used for new wells in 1995.

Survey respondents reported a total of 1,244 new wells drilled. Operators from the Appalachian states reported 124 new wells, or approximately 10 percent of the total. With a few regional exceptions, the 1995 E&P operations survey indicates that the majority of new wells in the onshore U.S. were drilled using a reserve pit to store and dispose used drilling muds and cuttings. The primary regional exceptions are Alaska (100 percent wells reported drilled with closed system), New Mexico (73 percent of new wells drilled with air or gas), and Appalachia (96 percent drilled with air, gas, or pneumatics).

Table E.1 shows that for the total United States, 66 percent of new wells were reported drilled with a mud system discharging to reserve pits, 23 percent of new wells were drilled with a closed system (no reserve pits), 11 percent were drilled with air or gas (no drilling mud), and less than 0.1 percent were reported drilled with a cable tool.[11] Sixty-nine percent of mud reserve pits was reported to be lined. For the Appalachian states reporting, 96 percent of new wells were drilled with air and the remaining 4 percent were drilled using a reserve pit. No respondents from Appalachian states reported wells drilled with a cable tool. If the Appalachian component is removed from the reported data in Table E.1, for the remaining states, 74 percent of new wells were drilled using a reserve pit, 25 percent with a closed system, and only 1 percent was drilled with air or gas.

A significant improvement in drilling practices between 1985 and 1995 is indicated by the difference in drilling techniques reported in the 1995 E&P operations survey and the drilling techniques inferred from the 1985 survey.[12] Between 1985 and 1995, the percentage of lined reserve pits increased from 35 percent to 69 percent. By 1995, one quarter of new wells were drilled with a closed system and did not require reserve pits.

3.3.2. Percentage of Drilling Wastes by Base Drilling Fluid

Appendix E, Table 2 contains reported percentages of drilling wastes by base drilling fluid. Table E.2 indicates that most of the new wells, with a few local exceptions, are drilled with freshwater base mud. Alaska is the only state that reports a significant percentage of new drilling with synthetic based drilling mud (30 percent). Most drilling with oil based mud is reported only in Louisiana and Oklahoma. Drilling with saltwater-based mud is reported in only six states known to have salt bearing formations.

In Appendix E, Table 3, the percentage of drilling wastes by base drilling fluid (from Table E.2) were applied to reported drilling waste volumes to estimate a national percentage of drilling wastes by base drilling fluid. Table E.3 shows that in 1995, 92.5 percent of drilling wastes were derived from freshwater based drilling fluid, 5.5 percent of drilling wastes were derived from saltwater based drilling fluids, oil based drilling fluid produced less than 1.5 percent of wastes, and the remaining 0.5 percent were derived from

[11] Only one well was reported drilled with a cable tool.

[12] In the API *1985 Production Waste Survey,* 91 percent of wells were reported drilled with a mud system. The remaining 9 percent of new wells reported as "other" in 1985 is inferred to represent air- or gas-drilled wells. Of the 91 percent of new wells drilled with mud systems in 1985, 2 percent were drilled with a polymer mud system, which are inferred to be closed systems. Nationwide, an estimated 35 percent of reserve pits was estimated to be lined.

synthetic based drilling fluid. The *1985 Production Waste Survey* reported that 64 percent of drilling wastes were derived from freshwater based mud systems; 23 percent of drilling wastes were derived from saltwater based muds; oil based muds produced 7 percent of drilling wastes; and polymer or "other" muds produced the remaining 6 percent of drilling wastes. The decline in drilling waste from oil-based drilling reflects the availability of better water-based and synthetic-based drilling formulas, along with industry practice to substitute more environmentally friendly materials where feasible.

3.3.3. Volume of Drilling Wastes

Table 3.9 provides an estimate of the volume of drilling wastes generated within each state during 1995. Drilling waste volumes for the 1995 survey were estimated by multiplying the total 1995 footage drilled by the average waste extrapolation factor determined for the state (by depth category) in the *API 1985 Production Waste Survey*.[13] The estimated national total volume of drilling wastes for 1995 is 148.7 million barrels or approximately 1.21 barrels of waste per foot drilled. This estimated 1995 volume is less than half the 361 million barrels of drilling wastes estimated in 1985. Because the approach used to estimate the 1995 volume of drilling wastes does not account for improvements in the efficiency of drilling systems between 1985 and 1995, the actual volumes of drilling wastes may be over stated.

Appalachian States The 1995 E&P operations survey form sent to operators in the Appalachian states asked respondents to report volumes of drilling waste. This information had not been collected for the Appalachian states in the *1985 Production Waste Survey*. Appendix E, Table 4 shows the reported drilling waste volumes and reported footage drilled for the Appalachian region. Only eight respondents in the region reported drilling in 1995 and almost 97 percent of the reported footage was drilled with air rather than a mud system. The remaining 3 percent of reported footage was drilled with a mud system.

The reported data collected for the Appalachian region (0.07 barrels waste/foot) may represent typical waste volumes generated by air drilling, and may not be representative of typical drilling waste volumes generated for the Appalachian region as whole. In Appendix E, Table 5 the estimated waste extrapolation factor for air drilling, 0.07 barrels/foot, (from Table E.4) is applied to the Appalachian states, as well as other states, which report significant air drilling in the 1995 survey (New Mexico, Oklahoma, and Utah). Table E.5 provides alternative estimates of drilling wastes for these states (NM, OK, UT, KY, NY, OH, PA, TN, VA, WV) that are considerably lower than the drilling waste volumes estimated in Table 3.9. If the alternative drilling waste volumes estimated for the selected states in Table E.5 are substituted for the drilling waste volume estimated in Table 3.9, the estimated national total volume of drilling waste for 1995 becomes 132.8 million barrels, or approximately 1.08 barrels of waste per foot drilled.

[13] *API 1985 Production Waste Survey*, Table 90, Total Drilling Waste Volumes Discharged to the Reserve Pit.

Table 3.9. Estimated Total Volume of Drilling Wastes

STATE	Est. Total Footage Drilled in 1995 – Survey Reported Data [a] (feet)	Est. Volume Total Drilling Waste per Foot Drilled [b] (bbls/ft)	Est. Vol. Drilling Waste for 1995 Drilling - Survey Reported Data [c] (barrels)	1995 Total Footage Drilled [d] (Completed Wells)	Est. Total Volume Drilling Wastes for State [e] (barrels)
AK	132,000	0.84	110,880	1,911,300	**1,605,492**
AL	0	3.26	0	1,087,500	**3,545,250**
AR	0	2.05	0	1,289,500	**2,643,475**
AZ		1.92	0	5,400	**10,368**
CA	830,325	0.61	506,498	2,994,100	**1,826,401**
CO	72,000	0.87	62,640	4,117,600	**3,582,312**
FL		3.71	0	15,500	**57,505**
IL	55,800	0.51	28,458	749,100	**382,041**
IN		0.62	0	172,200	**106,764**
KS	1,024,428	0.9	921,985	5,344,700	**4,810,230**
KY	83,500	1.43	119,405	1,465,100	**2,095,093**
LA	175,390	1.95	342,011	11,526,800	**22,477,260**
MI	11,900	1.1	13,090	1,573,900	**1,731,290**
MO		1.13		0	**0**
MS	0	2.94		1,370,100	**4,028,094**
MT	58,616	1.52	89,096	898,500	**1,365,720**
ND	0	1.05		841,500	**883,575**
NE	0	0.55		159,800	**87,890**
NM	60,911	1.29	78,575	5,752,500	**7,420,725**
NV		1.57		104,600	**164,222**
NY	18,200	1.28	23,296	108,000	**138,240**
OH	44,650	0.56	25,004	3,073,700	**1,721,272**
OK	133,600	1.11	148,296	11,857,800	**13,162,158**
OR		0.36		0	**0**
PA	98,600	1.03	101,558	2,357,100	**2,427,813**
SD		1.03		9,300	**9,579**
TN		2.39		93,000	**222,270**
TX	2,488,209	1.13	2,811,676	57,847,100	**65,367,223**
UT	100,250	1.68	168,420	929,400	**1,561,392**
VA	93,793	0.41	38,455	139,900	**57,359**
WV	254,160	0.54	137,246	1,585,000	**855,900**
WY	24,000	1.27	30,480	3,443,900	**4,373,753**
Total	**5,760,332**	**1.2**	**5,757,070**	**122,823,900**	**148,720,666**

[a] Extrapolated from survey form question 22a: reported # new wells drilled in each depth zone x average drilling depth reported for each depth zone
[b] Average for state from API 1985 Production Waste Survey
[c] (Column 2) x (Column 3)
[d] Oil and Gas Journal, Energy Statistics Sourcebook, 12th edition, Table "Footage Drilled by State"
[e] (Column 3) x (Column 5)

3.3.4. Types of Drilling Wastes and Drilling Waste Disposal

Appendix E, Table 6 summarizes the disposal methods reported for liquid drilling wastes. The percentage of liquid wastes disposed by each method is expressed as a percentage of total drilling wastes. In California for example, survey respondents report that 19 percent of total drilling wastes are liquid wastes disposed by evaporation. Appendix E, Table 7 summarizes the disposal methods reported for solid drilling wastes. The percentage of solid wastes disposed by each method is expressed as a percentage of total drilling wastes. In Texas for example, survey respondents report that 13 percent of total drilling wastes are solid wastes disposed by burial onsite.

Table 3.10 illustrates that, for the total United States, almost 74 percent of drilling wastes were characterized as liquid wastes and 26 percent were characterized as solid drilling wastes. The estimated waste volumes disposed by various disposal methods are summarized in Appendix E, Table 8 for liquid drilling wastes and in Appendix E, Table 9 for solid drilling wastes.

Table 3.10. Summary of Estimated Drilling Wastes by Type of Waste From 1995 E&P Operations Survey (barrels)

Estimated Total Liquid Wastes	109,443,000	73.6 %[a]
Estimated Total Solid Wastes	39,257,000	26.4 %
Estimated Total Drilling Waste Volume	148,700,000	100 %

[a] Estimated relative percentages of solid and liquid drilling waste are derived from Appendix E, Tables 8 and 9, "Estimated Volumes of Liquid and Solid Drilling Waste for States with Reported Data."

The relative volumes of solid and liquid drilling wastes reported in Table 3.10. were derived in the following manner. The estimated volume of drilling wastes for each state (shown in Table 3.9.) was multiplied by the reported percentage of wastes disposed by each method (shown in Appendix E, Table 6 and Appendix E, Table 7). This was done only for states that reported drilling wastes in the 1995 survey. This exercise produced an estimate of the volume of drilling wastes disposed by each method for each state with reported data. These estimated volumes were aggregated to obtain an estimate of the relative volume of solid and liquid drilling wastes for the total United States, and an estimate of the aggregate drilling waste disposal practices for the total United States.

In the 1985 waste survey, liquid drilling wastes were estimated to comprise almost 90 percent of drilling wastes. Ten percent of drilling wastes were estimated to be solids, primarily drill cuttings. Table 3.11 summarizes the types of drilling wastes identified in the API *1985 Production Waste Survey*. Comparison of Tables 3.10 and Table 3.11 indicate a significant increase in the relative volumes of solid drilling wastes to liquid wastes from 1985 to 1995.

Table 3.11. Summary of Estimated Drilling Wastes by Type of Waste From 1985 Production Waste Survey (barrels)

Mud and Completion Fluid	226,801,000	62.75%
All Other Water	87,724,000	24.3 %
Formation Testing Fluids	916,000	0.25 %
Other Fluids	8,222,000	2.3 %
Total Liquid Wastes	**323,663,000**	**89.6 %**
Drill Cuttings	35,674,000	9.9%
Circulated Cement	1,876,000	0.5 %
Other Solids	196,000	
Total Solid Wastes	**37,746,000**	**10.4 %**
Total Volume	361,409,000	

Two factors may contribute to the apparent increase in solid drilling wastes relative to liquid drilling wastes in the 1995 survey:

1. There appears to be more air drilling represented in the 1995 E&P operations survey relative to the 1985 survey due, in part, to an increase in air-drilled coalbed methane wells by 1995 and in part, to greater representation of Appalachian operations in the 1995 survey. If Appalachian states are omitted from total drilling waste estimate, the percentage of solid drilling wastes are estimated to be 25 percent.

2. In the 1985 survey, drilling mud was characterized as a liquid waste, and a significant portion of drilling mud was reported hauled offsite for disposal as a liquid waste. In the 1995 survey, most drilling wastes were reported disposed onsite through evaporation of the liquid portion and burial of the solid portion. The 1995 E&P operations survey may have more effectively captured the solid component of drilling mud as a solid drilling waste. The mud solids remaining after onsite evaporation of freshwater based liquid drilling waste would generally be incorporated with drill cuttings and disposed through onsite burial. This would increase the volume of solid drilling wastes relative to liquid drilling wastes in the 1995 E&P operations survey.

Table 3.12 shows the aggregate nationwide drilling waste disposal practices estimated from the 1995 E&P waste survey. Nationwide, over two-thirds of drilling wastes (68 percent) were disposed onsite through evaporation and burial. Injection and reuse of liquid wastes account for another 20 percent of drilling wastes. Approximately 8 percent of drilling wastes were disposed on the land surface through land spreading and surface discharge. Disposal at commercial E&P waste facilities appears to be a minor disposal practice used for less than 3 percent of onshore drilling wastes.

Table 3.12. Estimated Drilling Waste Disposal Practices - 1995 E&P Operations Survey

Evaporate On or Offsite	47 %	Liquid Drilling Waste
Burial Onsite	21 %	Solid Drilling Waste
Injection (includes injection down annulus)	13 %	Liquid Waste
Reuse for Drilling	7 %	Liquid Waste
Land Spread Onsite	6 %	Solid and Liquid Waste
Land Spread Offsite	1 %	Solid and Liquid Waste
Commercial Disposal Facility	2 %	Solid Waste
Treat and Discharge	1 %	Liquid Waste
Recycle, Road Spread, Municipal Landfill	<0.5 %	Solid and Liquid Waste
Other	< 1.5 %	Includes: grind and inject – solid waste; commercial disposal – liquid waste; onsite remediation – solids & liquid waste; disposal pits – solid waste.
Total	**100%**	

The greatest change in drilling waste disposal practices between 1985 and 1995 appears to be a marked increase in onsite disposal and a decrease in surface discharge of liquid drilling wastes. In the *1985 Production Waste Survey,* 28 percent of drilling wastes were estimated to be hauled offsite for disposal. By 1995, less than 3 percent of drilling wastes were disposed at offsite commercial facilities. This increase in onsite disposal, particularly onsite evaporation, may be a function of the increased use of lined reserve pits. The estimated drilling waste disposal practices from the *1985 Production Waste Survey* are summarized in Table 3.13 for comparison with the 1995 E&P operations survey results.

Table 3.13. Comparison of 1985 and 1995 Estimated Drilling Waste Disposal Practices

Drilling Waste Disposal Method	% Drilling Wastes Disposed by Method	
	1985	1995
Evaporate Onsite	29 %	47 %
Hauled Offsite	28 %	2 %
Injection	13 %	13 %
Buried Onsite	12 %	21 %
Discharge to Surface	10 %	1 %
Land Spread	7 %	7 %
Reuse for Other Drilling	0 %	7 %
Other (includes solidification, incineration)	1 %	2 %
Total	**100%**	**100%**

4. SUMMARY OF RESULTS

Following is a summary of the extrapolated results of the survey questions evaluated in this report. The results presented here are national totals estimated for onshore operations for the total United States. The detailed survey results presented in the foregoing sections demonstrate that there is significant regional variation in E&P operations, the volume of wastes generated, and waste management practices.

- **Production Pits – E&P Operations**

  Nationwide, an estimated 55,000 pits are associated with production operations; 97 percent of production pits are estimated to be active. An estimated 60 percent of production pits are lined.

- **Production Pits – Gas Plants**

  An estimated 875 production pits are associated with gas plants in the total United States; 97 percent of pits are estimated to be active. An estimated 62 percent of gas plant pits are lined.

- **Tank Batteries and Tanks – E&P Operations and Gas Plants**

  The estimated total number of oil tank batteries is 171,500 batteries. The estimated total number of condensate tank batteries is 48,300 batteries. The estimated total number of tanks associated with E&P operations is approximately 832,000 tanks. Over 3,000 additional non-pressurized tanks are estimated to be associated with gas processing plants.

- **Produced Water – E&P Operations**

  An estimated national total of 17,900 million barrels of water was produced in 1995. This volume represents approximately 7.5 barrels of produced water per barrel of oil. Most produced water, an estimated 92 percent, was injected into Class II wells for enhanced oil recovery or disposal. Three percent of produced water, primarily from coal bed methane wells in Alabama, was treated and discharged under NPDES permits. Two percent of produced water was beneficially reused, and 3 percent was disposed by other methods.[14]

- **Produced Water – Gas Plants**

  An estimated 9.5 million barrels of water was produced by gas plants in 1995. Ninety-three percent of produced water from gas plants was disposed by injection into Class II wells. Only 1 percent was reused, and 6 percent was disposed by a variety of miscellaneous methods including co-mingling with oil production, evaporation, EOR injection into adjacent oil fields, and steam venting to the atmosphere.

- **Associated Wastes**

  The total estimated volume of associated wastes produced in 1995 was 20.5 million barrels. This total is comprised of 8.9 million barrels of completion fluids, 9.5 million barrels of workover/stimulation fluids, 2.0 million barrels of tank bottoms/oily sludge, and 0.2 million barrels of dehydration/sweetening wastes. Of the aggregate associated wastes, 38 percent were disposed by injection, 19 percent were recycled, reused, or reclaimed, 15 percent were disposed at offsite commercial E&P waste facilities, 11 percent were evaporated, and 8 percent were land spread or road spread.

- **Gas Processing Plant Wastes**

  The total estimated volume of gas processing plant wastes produced in 1995 was 0.1 million barrels. This total is comprised of approximately 80,500 barrels of scrubber liquids and sludge, 1,200 barrels of spent glycol compounds, 1,500 barrels of used filters and filter media, and 18,300 barrels of miscellaneous other dehydration wastes. Seventy-six percent of gas processing plant wastes were disposed by injection, 1 percent were recycled or reused, 9 percent were disposed at commercial E&P waste facilities, 3 percent were evaporated, 6 percent were land spread, and 4 percent were sent to landfills.

[14] "Other" produced water disposal methods include percolation ponds, which are used only in California.

- **Drilling Technique**

Drilling practices improved significantly between 1985 and 1995. In 1995, 66 percent of wells nationwide were drilled with reserve pits compared to 89 percent of wells drilled with reserve pits in 1985. In 1995, 69 percent of reserve pits were lined compared to 35 percent in 1985. Almost 25 percent of wells were drilled with a closed system in 1995 compared to an inferred 2 percent of wells in 1985.

- **Drilling Wastes**

The results from the 1995 E&P waste survey indicate an apparent decline in the use of oil and saltwater based drilling fluids since 1985. In 1995, an estimated 93 percent of drilling wastes were derived from freshwater based mud systems compared to 64 percent of drilling wastes in 1985. In 1995, 6 percent of drilling wastes were produced from saltwater-based mud systems compared to 23 percent in 1985. Finally, only 2 percent of drilling wastes were derived from oil based muds in 1995 compared to 7 percent of wastes in 1985. Polymer and "other " drilling fluids produced the remaining 6 percent of drilling wastes in 1985. In 1995, synthetic based drilling fluids produced less than 0.5 percent of drilling wastes from onshore operations.

In 1995, almost 74 percent of drilling wastes were characterized as liquid wastes and 26 percent were characterized as solid wastes. The total drilling wastes generated in 1995 are estimated to be 148.7 million barrels or about 1.21 barrels/wastes per foot drilled. An alternative drilling waste estimate incorporates the survey-derived waste estimation factor for air-drilled wells of 0.07 barrels of waste per foot drilled. This alternative national estimate of the total volume of drilling wastes is 132.8 million barrels or about 1.08 barrels of waste per foot drilled. Most drilling wastes in 1995 were disposed onsite. Forty-seven percent of drilling wastes was evaporated, 21 percent were buried onsite, 13 percent of drilling wastes were injected and 7 percent were reused for drilling other wells. Seven percent of drilling wastes were land spread and only 2 percent were disposed at commercial E&P waste facilities.

- **Summary of Total Waste Volumes Disposed by Method in the United States**

Table 5.1. 1995 Estimated Volume of E&P Wastes Disposed by Method (million barrels)

Disposal Method	Produced Water [a]	Drilling Wastes	Associated Wastes [b]	Total Waste Volume	% Total Wastes Disposed by Method
Injection (includes EOR)	16,386.5	19.0	7.9	**16,413.7**	**90.8 %**
Evaporation	0	69.9	2.3	**72.2**	**0.4 %**
Burial Onsite	0	31.2	0	**31.2**	**0.2 %**
Commercial E&P Waste Facility	90.3	3.0	3.1	**96.4**	**0.5 %**
Reuse, Recycle, Reclaim	358.1	10.4	3.9	**372.4**	**2.1 %**
Discharge	537.0	1.5	0	**538.5**	**3.0 %**
Land Spread	0	10.4	1.0	**11.4**	**>0.1 %**
Road Spread	1.8	-	0.5	**2.3**	
All Other	537.0	3.0	1.9	**541.9**	**3.0 %**
Total	**17,910.7**	**148.7**	**20.6**	**18,080.0**	**100.0%**

[a] Includes produced water removed at gas plants.
[b] Includes associated wastes generated at gas plants.

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1995 PRODUCTION FACILITIES AND OIL AND GAS PRODUCTION

Table A.1. 1995 Producing Wells and Estimated Production Facilities by State

STATE	1995 Producing Oil Wells [a]	1995 Producing Gas Wells [b]	1995 Total Producing Wells	1995 Oil Production Facilities [c]	1995 Gas Production Facilities [c]	1995 Well Completions [d]
AK	2,086	100	2,186	417	44	165
AL	913	3,526	4,439	302	1,728	176
AR	7,834	3,988	11,822	2,611	2,659	215
AZ	22	7	29	6	0	7
CA	39,365	997	40,362	8,610	421	1,293
CO	9,022	7,017	16,039	3,007	6,049	868
FL	85	0	85	21	0	1
IL	31,128	372	31,500	10,376	248	365
IN	7,135	1,347	8,482	2,162	806	106
KS	44,235	22,020	66,255	14,745	9,919	1,495
KY	23,538	13,311	36,849	7,846	8,874	763
LA	24,430	14,169	38,599	8,143	9,446	1,307
MI	4,079	5,258	9,337	1,360	3,081	873
MO	518	15	533	64	0	0
MS	1,516	535	2,051	444	304	155
MT	3,100	2,918	6,018	1,033	2,000	217
ND	3,171	99	3,270	1,057	63	150
NE	1,489	87	1,576	496	52	47
NM	17,976	23,510	41,486	5,753	18,069	1,005
NV	72	0	72	18	0	26
NY	3,670	6,134	9,804	918	3,008	33
OH	29,622	34,380	64,002	7,406	11,500	786
OK	91,289	29,733	121,022	22,822	14,669	1,797
OR	0	17	17	0	3	0
PA	18,157	31,792	49,949	5,295	18,094	570
SD	150	56	206	45	29	7
TN	701	0	701	186	258	52
TX	174,527	54,635	229,162	56,498	33,999	7,957
UT	1,851	1,127	2,978	617	571	230
VA	23	1,671	1,694	0	805	53
WV	17,436	35,148	52,584	5,784	23,978	385
WY	10,368	4,196	14,564	3,456	2,433	530
Total	**569,508**	**298,165**	**867,673**	**171,498**	**173,110**	**21,634**

[a] *API Basic Petroleum Data Book*, Vol.18, No. 1, Table III-19.
[b] *API Basic Petroleum Data Book,* Vol. 18, No. 1, Table III-17.
[c] Memorandum from M.A. Brown, Gruy and Associates, Inc. to Glenda Smith, API dated March 10, 1998. Status report for work performed under contract to American Petroleum Institute
[d] API Basic Petroleum Data Book, Vol. 18, No.1, Table III –15.

A.1. Estimated Oil and Gas Production Facilities

Table A.1 contains an estimated number of oil and gas production facilities by state. This estimate of 1995 oil and gas production facilities was developed by Gruy and Associates for API to provide supplemental data for extrapolation of API's 1995 waste survey data. The estimate of 1995 production facilities/tank batteries is compiled from several sources including standard industry data, a custom 1990 report prepared for API and Gruy Associates by the Petroleum Information Corporation (PI), other proprietary company data, plus specific industry knowledge of contributing individuals.[15]

[15] M.A. Brown, Gruy and Associates, March 10 1998 memorandum to Glenda Smith, American Petroleum Institute and Bill Freeman, Shell E & P Technology Center.

APPENDIX A

1995 PRODUCTION FACILITIES AND OIL AND GAS PRODUCTION

The 1990 PI report lists all active producing wells and “reporting entities” for each state categorized by producing rate and depth of production. A reporting entity usually corresponds to a lease or production unit and is the point of product measurement and custody transfer. Stock tanks, separators, and other treating equipment are usually located at the same site. Each lease must have separate metering and treating facilities because the ownership of each lease is usually different. For states that require production reported by lease, unit, or other custody transfer point, the number of production facilities/tank batteries can be estimated fairly accurately.

Some states require oil production to be reported by well. For these states, the number of oil production facilities/tank batteries is estimated with considerably less certainty. In areas where production is shallow and the leases are relatively small, there are fewer producing wells per facility. In western states, the leases tend to be larger and may have more wells per producing facility/tank battery. Deep wells are generally widely spaced (up to one mile apart) and often have a production facility/tank battery for each well. Shallow wells are more closely spaced and have more wells per producing facility/tank battery.

Gas wells are usually more widely spaced than oil wells. Overall, there are fewer gas wells per gas facility than there are oil wells per oil facility. Most states require gas production to be reported by well or by “gas unit”. When gas fields are first drilled there is usually only one gas well per unit and each unit has its own facility. However, as gas fields mature and are infill drilled, several gas wells may be tied into the gas unit facility. If a field has both oil wells and gas wells, the facilities may be located at the same site. This case is considered to represent two facilities.

This document contains two different estimates for the number of gas production facilities, which were derived differently. This appendix includes a large estimated number of facilities, based on PI data, as described above. In Table 3-2 and Appendix B, figures are provided for condensate tank batteries, which are essentially analogous to gas production facilities. The estimated number of condensate tank batteries was derived from survey data. Comparing the two numbers and the number of gas wells per facility that each represents, it seems likely that the actual number of gas production facilities/tank batteries is somewhere between these two estimates.

1995 PRODUCTION FACILITIES AND OIL AND GAS PRODUCTION

Table A.2. Total 1995 Oil, Gas, and Natural Gas Liquids Production by State

STATE	Total 1995 Oil Production [a] (Mbbl)	Total 1995 Gas Production [b] (MMcf)	Total 1995 Natural Gas Liquids Production [c] (estimated) (Mbbl)
AK	541,654	469,550	8,395
AL	18,731	519,661	33,945
AR	8,910	187,242	460
AZ	71	558	-
CA	350,686	279,555	8,030
CO	27,976	523,084	14,600
FL	5,693	6,463	1,260
IL	16,190	335	145
IN	2,778	249	-
KS	43,767	721,436	35,309
KY	3,492	74,754	1,582
LA	426,322	5,108,366	93,425
MI	11,383	238,203	4,597
MO	120	16	-
MS	19,911	95,533	304
MT	16,529	50,264	322
ND	29,335	49,468	2,804
NE	3,794	2,240	9
NM	64,508	1,625,837	59,651
NV	1,342	13	-
NY	304	18,400	-
OH	8,258	126,336	84
OK	87,491	1,811,734	63,501
OR	0	1,923	-
PA	1,939	111,000	104
SD	1,344	1,252	-
TN	382	1,820	-
TX	600,527	6,330,048	264,512
UT	19,988	241,290	2,329
VA	12	49,818	
WV	1,948	186,231	7,891
WY	78,884	673,775	10,368
Total	**2,394,269**	**19,506,454**	**613,627**

[a] *API Basic Petroleum Data Book,* Vol. 18, No. 1, Table IV-5.
[b] *API Basic Petroleum Data Book,* Vol. 18, No. 1, Table XIII-9.
[c] IPAA, *The Oil and Gas Industry in Your State, 1996-1997.*

Appendix B

Production Pits, Tank Batteries, Tanks

Table B.1. Production Pits – Reported Data

State	Total Production Pits Reported	Total Workover Pits	Total Active Pits	Total Inactive Pits	Total Lined Pits	Percentage of Total Pits			
						Workover	Active	Inactive	Lined
AK	7	0	7	0	7		100%		100%
AL	48	0	48	0	48		100%		100%
AR	0	0	0	0	0				
CA	234	27	209	25	87	12%	89%	11%	37%
CO	884	6	881	3	846	1%	100%		96%
FL	5	0	5	0	5		100%		100%
IL	1	0	1	0	1		100%		100%
KS	7	0	7	0	0		100%		0%
LA	22	0	17	5	0		77%	23%	0%
MI	0	0	0	0	0				
MS	2	0	2	0	2		100%		100%
MT	39	1	38	1	5	3%	97%	3%	13%
ND	8	0	8	0	0		100%		0%
NE	4	0	2	2	0		50%	50%	0%
NM	5	0	0	5	0			100%	0%
OK	0	0	0	0	0				
TX	310	282	307	3	300	91%	99%	1%	97%
UT	498	38	468	30	143	8%	94%	6%	29%
WY	370	253	369	1	1	68%	100%		0%
Total	**2,444**	**607**	**2,369**	**75**	**1,445**	**25%**	**97%**	**3%**	**59%**

Table B.2. Estimated Number of Production Pits

State	Estimated Total Number of Pits	State Data[a] (Where Available) Workover Pits	Active Pits	Inactive Pits	Total Number of Lined Pits	Comments
AK	400					Assumes 1 pit per oil production facility
AL	2,000					Assumes 1 pit per oil and gas production facility
AR						no pits reported
CA	8, 600					Assumes 1 pit per oil production facility
CO	9, 271	"unknown"	9, 271	"unknown"	588	1998 data from state
FL	20					Assumes 1 pit per oil production facility
IL	10,400					Assumes 1 pit per oil production facility
KS	14,700					Assumes 1 pit per oil production facility
LA	8,099	5,339 "reserve"	1,795 "open prod."	965 "orphan prod."	402	1997/ 98 State data [b]
MI						no pits reported
MS	48		48		48	1997/ 98 State data [b]
MT	3,000					Assumes 1 pit per oil and gas production facility
ND	1,100					Assume 1 pit per oil production facility
NE	500					Assume 1 pit per oil production facility
NM	5,800					Assume 1 pit per oil production facility
OH	0					1998 data from state
OK	93					1998 data from state
TX	4,830[c]	"unknown"	4,830	"unknown"	2,490	1998 data from state
UT	1,200					Assume 1 pit per oil and gas production facility
WY	3,500	800	3,500			1997/ 98 State estimate [b]
Total [d]	**55,690**					

[a] Where data was available from a state agency, either estimates or reported data, these have been provided.
[b] Source: Gruy memorandum, 1998.
[c] This likely understates the total number of production pits in the state. In Texas, certain types of pits require permits, while some types of production pits do not require permits. This includes permitted pits only.
[d] Assumes zero pits in the Appalachian states. No survey respondents from Appalachian states reported pits. Recent state data from Ohio (6/99) indicates that Ohio has no active production pits.

Table B.3. Oil Tank Batteries and Oil Tanks – Reported Data

State	Active Oil Wells Reported	Oil Tank Batteries	Oil Tanks	Oil Tanks per Tank Battery	Waste Oil/ Water Tanks	Produced Water Tanks	Produced Water Tanks per Tank Battery	Emergency Tanks	Total Tanks per Oil Tank Battery
AK	355	11	9	1	6	7	1	11	3
AL	140	24	135	6	3	49	2	0	8
AR	5	5	10	2	0	7	1	0	3
CA	6,570	152	308	2	73	101	1	70	4
CO	437	67	101	2	3	44	1	4	2
FL	50	1	2	2	0	2	2	0	4
IL	291	14	29	2	2	26	2	3	4
KS	497	174	343	2	5	112	1	9	3
LA	330	79	190	2	8	74	1	28	4
MI	6	1	2	2	0	1	1	0	3
MS	125	41	183	4	2	66	2	0	6
MT	425	41	129	3	3	22	1	11	4
ND	8	8	20	3	0	8	1	0	4
NE	3	3	7	2	0	1	0	0	3
NM	16	10	19	2	0	3	0	0	2
OK	72	52	113	2	15	16	0	9	3
TX	5,599	1,647	3,475	2	508	1,209	1	926	4
UT	486	264	416	2	6	346	1	18	3
WY	1,064	114	351	3	7	136	1	0	4
Total (excluding Appalachian States)	**16,479**	**2,708**	**5,842**	**2**	**641**	**2,230**	**1**	**1,089**	**4**
Appalachian States:	**Active Oil Wells Reported**	**Oil Tanks**	**Oil Wells per Oil Tank**	**Produced Water Tanks**	**Oil Wells per Produced Water Tank**	**Waste Oil/ Water Tanks**	**Emergency Tanks**	**Total Tanks Reported**	**Total Oil Wells per Tank**
KY	340	15	23	3	113	0	0	18	19
NY	125	11	11	4	31	0	0	15	8
OH	8	17	0.5	9	1	0	0	26	0.3
PA	8	0		0		0	0	0	
VA	1	2	0.5	0	0	0	0	2	1
WV	230	41	6	13	18	0	0	54	4
Total - Appalachian States	**712**	**86**	**8**	**29**	**24**	**0**	**0**	**115**	**6**

APPENDIX B

PRODUCTION PITS, TANK BATTERIES, TANKS

Table B.4. Condensate Tank Batteries and Condensate Tanks – Reported Data

State	Active Gas Wells Reported	Condensate Tank Batteries	Condensate Tanks	Condensate Tanks per Battery	Waste Oil/ Water Tanks	Produced Water Tanks	Produced Water Tanks per Battery	Emergency Tanks	Total Tanks per Condensate Tank Battery
AK	15	1	0	0	2	1	1	3	6
AL	976	2	2	1	26	15	8	0	22
AR	152	3	9	3	0	33	11	0	14
CA	47	1	0	0	1	1	1	0	2
CO	1,516	816	974	1	8	212	0	1	1
FL	0	0	0	0	0	0	0	0	0
IL	0	0	0	0	0	0	0	0	0
KS	4,960	40	60	2	2	2,269	57	1	58
LA	89	51	118	2	6	15	0	2	3
MI	45	1	1	1		3	3	0	4
MS	15	2	2	1			0	0	1
MT	23	0	0	0	0	0	0	0	0
ND	0	0		0			0		0
NE	0	0		0			0		0
NM	878	251	278	1	1	611	2	583	6
OK	226	58	70	1	6	148	3	0	4
TX	413	61	84	1	4	78	1	0	3
UT	361	322	322	1	0	0	0	2	1
WY	32	20	29	1	3	24	1	13	3
Total (excluding Appalachian States)	**9,748**	**1,629**	**1,949**	**1**	**59**	**3,410**	**2**	**605**	**4**

Appalachian States:	Active Gas Wells Reported	Condensate Tanks	Gas Wells per Condensate Tank	Produced Water Tanks	Gas Wells per Produced Water Tank	Waste Water Tanks	Emergency Tanks	Total Tanks Reported	Total Active Gas Wells per Tank
KY	4,127	1,038	4	1,776	2	15	0	2,829	1
NY	108	0	0	113	1	1	0	114	1
OH	333	351	1	116	3	0	0	467	1
PA	1,124	19	59	981	1	51	4	1,055	1
VA	908	39	23	443	2	11	0	493	2
WV	1,062	32	33	353	3	395	0	780	1
Total - Appalachian States	**7,662**	**1,479**	**5**	**3,782**	**2**	**473**	**4**	**5,738**	**1**

Table B.5. Estimated Oil Tank Batteries and Total Tanks Associated With Oil Production Facilities

State	1995 Active Oil Wells	Estimated Oil Tank Batteries [a]	Estimated Total Tanks per Tank Battery [b]	Estimated Total Tanks (Associated w/ Oil Production Facilities)
AK	2,086	417	3	1,251
AL	913	302	8	2,416
AR	7,834	2,611	3	7,833
AZ	22	6	4	24
CA	39,365	8,610	4	34,440
CO	9,022	3,007	2	6,014
FL	85	21	4	84
IL	31,128	10,376	4	41,504
IN	7,136	2,162	4	8,648
KS	44,235	14,745	3	44,235
LA	24,430	8,143	4	32,572
MI	4,079	1,360	3	4,080
MO	518	64	4	256
MS	1,516	444	6	2,664
MT	3,100	1,033	4	4,132
ND	3,171	1,057	4	4,228
NE	1,489	496	3	1,488
NM	17,976	5,753	2	11,506
NV	72	18	4	72
OK	91,289	22,822	3	68,466
OR	0	0	4	0
SD	150	45	4	180
TX	174,527	56,498	4	225,992
UT	1,851	617	3	1,851
WY	10,368	3,456	4	13,824
Estimated Total (excluding Appalachian States)	**476,362**	**144,063**		**517,760**
Appalachian States:	**1995 Active Oil Wells**	**Estimated Oil Tank Batteries [a]**	**Estimated Total Tanks (based on wells) [c]**	**Estimated Total Tanks (based on facilities) [d]**
KY	23,538	7,846	3,923	31,384
NY	3,670	918	459	3,672
OH	29,622	7,406	4,937	29,624
PA	18,157	5,295	3,026	21,180
TN	701	186	117	744
VA	0	0	0	0
WV	17,436	5,784	4,359	23,136
Estimated Appalachian Total	**93,124**	**27,435**	**16,821**	**109,740**
Estimated National Total	**569,486**	**171,498**		**627,500**

[a] Equals estimated number of oil production facilities
[b] Based on reported data for state
[c] Based on reported survey data for Appalachian States; average 6 oil wells per tank
[d] Based on national estimate of 4 tanks per production facility or oil tank battery.

Table B.6. Estimated Condensate Tank Batteries and Total Tanks Associated with Gas Production Facilities

State	1995 Gas Wells	Estimated Number of Gas Production Facilities [a]	Estimated Condensate Tank Batteries [b]	Estimated Total Tanks per Tank Battery [c]	Estimated Total Tanks at Gas Production Facilities
AK	109	44	18	6	109
AL	3,455	1,728	576	22	12,668
AR	3,988	2,659	665	2[d]	1,329
AZ	0	0	0	2	0
CA	962	421	160	2	321
CO	7,259	6,049	1,210	1	1,210
FL	0	0	0	2	0
IL	372	248	62	2	124
IN	1,330	806	222	2	443
KS	14,878	9,919	2,480	3[d]	7,439
LA	14,169	9,446	2,362	3	7,085
MI	4,621	3,081	770	4	3,081
MO	0	0	0	2	0
MS	518	304	86	1	86
MT	3,000	2,000	500	2	1,000
ND	94	63	16	2	31
NE	78	52	13	2	26
NM	28,231	18,069	4,705	6	28,231
NV	0	0	0	2	0
OK	29,337	14,669	4,890	4	19,558
OR	18	3	3	2	6
SD	49	29	8	2	16
TX	49,639	33,999	8,273	3	24,820
UT	1,142	571	190	1	190
WY	3,649	2,433	608	3	1,825
Estimated Total (excluding Appalachian States)	**166,898**	**106,593**	**27,816**		**109,598**
Appalachian States:	**1995 Gas Wells**	**Estimated Number of Gas Production Facilities [a]**	**Estimated Condensate Tank Batteries [b]**	**Estimated Total Tanks (based on wells) [e]**	**Estimated Total Tanks (based on facilities) [f]**
KY	13,311	8,874	2,219	10,239	8,874
NY	6,016	3,008	1,003	4,628	4,011
OH	34,501	11,500	5,750	26,539	23,001
PA	31,025	18,094	5,171	23,865	20,683
TN	485	258	81	373	323
VA	1,610	805	268	1,238	1,073
WV	36,144	23,978	6,024	27,803	24,096
Estimated Appalachian Total	**123,092**	**66,517**	**20,515**	**94,686**	**82,061**
Estimated National Total	**289,990**	**173,110**	**48,332**	**204,284**	**191,659**

[a] From Appendix G [b] Based on 6 gas wells per tank battery (from reported data)
[c] Based on reported data for state [d] When outliers in Kansas and Arkansas are removed (responses reporting unusually large number of produced water tanks), national estimate of tanks per condensate tank battery is 2 to 3 tanks per battery. [e] Based on survey reported data; average 1.3 gas wells per tank
[f] Based on estimated number of tank batteries and national estimate of 4 tanks per gas production facility/tank battery.

Table B.7. Gas Plants, Non-Pressurized Tanks – Reported Data

Region	# Plants in Region [a]	Reported No. Produced Water Tanks	Reported No. Condensate Tanks	Reported No. Liquid Product Tanks	Reported No. Emergency Tanks
Alaska	3	0	0	18	1
California	25	0	0	0	0
Eastern U.S.	47	3	14	41	4
Mid-West	92	5	4	3	0
New Mexico	27	3	10	15	4
Rockies	104	9	10	27	6
Southeast	68	13	13	13	1
Texas	233	30	12	22	8
Total	**599**	**63**	**63**	**139**	**24**

[a] Based on 1996 Oil and Gas Journal survey.

APPENDIX C

PRODUCED WATER

Table C.1. Estimated Volume of Produced Water by State (1,000 barrels/year)

State	Estimated Volume of Produced Water [a]	NOTES
AK	1,090,000	Estimated from survey response & 1995 production
AL	320,000	Estimated from survey response & 1995 production for state
AR	110,000	Estimated from survey response & 1995 production
AZ	100	Estimated from survey response & 1995 production for state
CA	1,684,200	PI estimate
CO	210,600	PI estimate
FL	76,500	PI estimate
IL	285,000	state estimate
IN	48,900	Based on bbl PW/bbl oil ratio for IL
KS	683,700	State estimate
KY	3,000	Estimated from survey response
LA	1,346,400	State estimate adjusted for onshore/coastal production only
MI	52,900	PI estimate
MO	100	Estimated from survey response
MS	234,700	PI estimate
MT	103,300	State estimate
ND	79,800	State estimate
NE	61,200	PI
NM	706,000	Estimated from survey response
NV	6,700	State
NY	300	Estimated from survey response
OH	7,900	State estimate
OK	1,642,500	State estimate
OR	40	State estimate
PA	2,100	State estimate
SD	4,000	State estimate
TN	400	Estimated from survey response
TX	7,630,000	State estimate
UT	124,600	PI estimate
VA	300	Estimated from survey response
WV	6,000	Estimated from survey response
WY	1,401,000	PI estimate
Total	**17,922,240**	

[a] State data were used where available. PI estimate is from the Petroleum Information Corp. produced water database. If state or PI estimates for 1995 were not available, the produced water volume for a state was estimated from 1995 production for the state using extrapolation factors developed from the 1995 survey responses.

APPENDIX C

PRODUCED WATER

Table C.2. Produced Water Volumes Disposed by Method – Reported Data (Barrels/day and Percentages)

State	Reported Volume Produced Water (b/d)	Inject for EOR (b/d)	% PW Inject for EOR	Injected for Disposal Onsite (b/d)	% PW Inject Onsite	Injected Offsite (b/d)	% PW Inject Offsite	Injected @ Commercial Facility (b/d)	% PW Inject @ Comm. Facility	Treat and Discharge (b/d)	% PW Treat and Discharge	Reuse (b/d)	% PW Reuse
AK	797,037	787,500	99%	9,500	1%					37	<0.01%		
AL	151,897	206	0.1%	8,087	5%	1,710	1%			141,894[a]	93%		
AR	302			276	91%	1	0.3%						
CA	713,904	365,844	51%	179,573	25%	5,050	0.7%						
CO	322,505	269,525	84%	52,828	16%	11	<0.01%	141	0.04%				
FL	190,550	190,550	100%										
IL	79,650	79,650	100%										
KS	75,533	3,646	5%	64,302	85%	7,356	10%	225	0.3%				
KY	518	34	7%			465	90%	19	4%				
LA	131,645			131,645	100%								
MI	1,838			1,708	93%	130	7%						
MS	74,045			74,045	100%								
MT	137,616	119,735	87%	2,302	2%	555	0.4%	22	0.02%			15,000	11%
ND	29					29	100%						
NE	524			44	8%								
NM	7,086			5,405	76%	507	7%	1,175	17%				
NY	213									210	99%		
OH	107					96	90%	11	10%				
OK	6,575	4,706	72%	997	15%	10	0.2%	862	13%				
PA	198							61	31%	86	43%		
TX	1,226,786	831,820	68%	276,872	23%	97,652	8%	17,478	1%			2,964	0.2%
UT	113,214	65,000	57%	36,368	32%	7,533	7%	4,313	4%				
VA	568			550	97%	18	3%						
WV	736	661	90%	6	1%	10	1%	59	8%				
WY	775,879	689,206	89%	6,600	1%			21	<.01%			80,000	10%
Survey Total	**4,808,955**	**3,408,083**	**71%**	**851,108**	**18%**	**121,133**	**2.5%**	**24,386**	**0.5%**	**142,227**	**3%**	**97,964**	**2%**

[a] In Alabama, surface discharge of produced water is allowed under NPDES permits for coalbed methane operations.

APPENDIX D

ASSOCIATED WASTES

Table D.1. Associated Waste Volume by State – Reported Data (Barrels per year)

State	Reported Volume Completion Fluids	Reported Volume Stimulation Fluids	Reported Volume Tank Bottoms/ Oily Sludge	Reported Volume Dehydration/ Sweetening Wastes	Total Reported Volume Associated Waste
AK	0	110	15,051	16	15,177
AL	0	5,600	1,955	0	7,555
AR	0	0	0	0	0
CA	262,300	155,020	39,600	1,042	457,962
CO	156,071	177,157	6,800	0	340,028
FL	0	595	1,051	0	1,646
IL	3,650	8,600	460	0	12,710
KS	66,670	26,620	1,430	1,600	96,320
KY	2,250	850	70	0	3,170
LA	3,242	55,700	258	18	59,218
MI	0	200	0	80	280
MS	0	0	4,600	0	4,600
MT	37,000	9,635	2,300	0	48,935
ND	0	0	100	0	100
NE	0	0	0	0	0
NM	11,800	17,000	0	238	29,038
NY	500	250	10	2	762
OH	1,200	2,000	0	0	3,200
OK	3,900	20,000	825	270	24,995
PA	14,000	3,200	0	0	17,200
TX	19,580	19,375	29,699	20	68,674
UT	0	32,895	888	0	33,783
VA	5,050	530	0	10	5,590
WV	20,800	13,262	2,670	0	36,732
WY	700	26,000	6,700	0	33,400
Survey Total	**608,713**	**574,599**	**114,467**	**3,296**	**1,301,075**

APPENDIX D

ASSOCIATED WASTES

Table D.2. Estimated Volume of Associated Wastes by State (Barrels/Year)

State	Completion Fluids [a]	Workover/ Stimulation Fluids [b]	Tank Bottoms/ Oily Sludges [c]	Dehydration/ Gas Sweetening Wastes [d]	Total Estimated Associated Wastes
AK	72,800	18,500	217,800	5,130	314,230
AL	77,600	22,300	25,200	5,670	130,770
AR	94,800	201,000	9,900	2,040	307,740
AZ	2,300	700	100	10	3,110
CA	431,300	945,600	220,300	29,290	1,626,490
CO	382,800	305,000	35,900	5,710	729,410
FL	400	1,000	400	10	1,810
IL	57,900	931,000	15,800	320	1,005,020
IN	16,900	144,200	14,300	2,070	177,470
KS	939,200	366,600	207,300	7,880	1,520,980
KY	65,000	24,600	19,400	1,840	110,840
LA	571,400	656,200	217,300	9,080	1,453,980
MI	385,000	143,600	12,600	8,560	549,760
MO	0	9,100	3,600	30	12,730
MS	68,400	34,900	10,800	1,040	115,140
MT	95,700	135,800	9,500	550	241,550
ND	66,200	75,200	12,600	540	154,540
NE	20,700	26,800	1,500	80	49,080
NM	494,600	788,900	80,900	2,150	1,366,550
NV	8,700	1,700	400	20	10,820
NY	1,200	10,500	2,000	490	14,190
OH	295,900	375,400	12,800	3,200	687,300
OK	1,427,300	968,200	121,000	19,780	2,536,280
OR	0	300	0	10	310
PA	443,300	308,600	10,000	4,990	766,890
SD	3,100	3,500	1,000	90	7,690
TN	17,600	2,800	200	40	20,640
TX	2,152,900	1,882,200	619,900	69,110	4,724,110
UT	101,400	115,700	10,400	2,630	230,130
VA	9,400	1,500	200	540	11,640
WV	195,300	539,800	10,500	2,630	748,230
WY	279,200	485,500	83,100	7,360	855,160
Total	**8,778,300**	**9,526,700**	**1,986,700**	**192,890**	**20,484,590**

[a] Extrapolated on number of completed wells
[b] Extrapolated on number of active oil and gas wells
[c] Extrapolated on oil and gas production
[d] Extrapolated on gas production.

Appendix D

Associated Wastes

Table D.3. Volume of Completion Fluids and Workover/Stimulation Fluids by Disposal Method – Reported Data

Associated Waste Disposal Method	% Completion Fluids	Volume-Completion Fluids (Bbls./Year)	% Workover/ Stimulation Fluids	Volume – Workover/ Stimulation Fluids (Bbls./Year)
Disposal by injection	21.3%	129,605	59.1%	339,714
Landspread within field	6.0%	36,275	1.9%	11,130
Landspread outside field	0%	0	0%	0
Roadspread w/in field	0%	0	< 0.1%	100
Roadspread outside field	0.4%	2,500	0.3%	1,500
Commercial E&P waste facility	28.8%	175,142	3.9%	22,380
Industrial or municipal landfill	0%	0	0%	0
Crude oil reclamation	0.1%	500	0%	45
Recycling/beneficial reuse	32.9%	200,450	< 0.1%	3
Incinerate	0%	0	1.0%	5,503
Evaporate from pits or tanks	8.0%	48,441	16.3%	93,833
Other:	2.6%	15,800[a]	17.5%	100,392[b]
Total (Bbls./Yr.)	100%	**608,713**	100.0%	**574,599**

[a] Land treatment disposal site within field
[b] Land treatment and onsite burial

ASSOCIATED WASTES

Table D.4. Volume of Tank Bottoms/Oily Sludge and Dehydration/Sweetening Wastes by Disposal Method – Reported Data

Associated Waste Disposal Method	% Tank Bottoms/ Oily Sludge	Volume- Tank Bottoms/ Oily Sludge (Bbls./Year)	% Dehydration/ Sweetening Wastes	Volume – Dehydration/ Sweetening Wastes (Bbls./Year)
Disposal by injection	23.9%	27,311	4.2%	140
Landspread within field	9.0%	10,256	8.2%	270
Landspread outside field	7.5%	8,621	0%	0
Roadspread within field	17.4%	19,885	0%	0
Roadspread outside field	0.3%	400	48.5%	1,600[a]
Commercial E&P waste facility	2.0%	2,327	31.7%	1,045
Industrial or municipal landfill	< 0.1%	3	0%	0
Crude oil reclamation	18.3%	20,973	0%	0
Recycling/beneficial reuse	19.0%	21,738	6.8%	223
Incinerate	<0.1%	44	0.1%	2
Evaporate from pits or tanks	0.2%	200	0%	0
Other:	2.4%	2,709[b]	0.5%	16[c]
Total (Bbls./Yr.)	**100.0%**	**114,467**	**100.0%**	**3,296**

[a] Volume is reported by a single respondent. If this volume is excluded from total, 62.5% of dehydration wastes are disposed at commercial disposal facility.
[b] Respondents noted this as oil containment berms and working pits.
[c] Respondent noted this as commercial disposal.

APPENDIX D

ASSOCIATED WASTES

Table D.5. Total Associated Waste; Percentage Waste Disposed by Method – Reported D

State	% Disposal by Injection	% Land Spread within Field	% Land Spread outside of Field	% Road Spread within Field	% Road Spread outside of Field	% Comm. E&P Waste Disposal	% to Landfill	% Crude Oil Reclaim.	% Recycle/ Beneficial Use	Inc
AK	98.8%					1.1%				
AL	76.7%			13%				0.1%	10.0%	
AR	No waste volumes reported									
CA	1.5%	3%	1.0%	2%		0.2%		0.7%	48.3%	
CO	52.0%	2%				46.0%		0.2%		
FL										
IL	99.2%				1%					
KS	77.8%				6%	1.6%		1.5%		
KY	15.8%	82%	1.3%	1%						
LA	12.0%					32.3%				
MI	100.0%									
MS								97.8%	2.0%	
MT	87.8%					0.2%		0.6%		
ND						100.0%				
NE										
NM	55.1%					8.0%				
NY	13.1%	3%		13%			0.4%	6.6%	59.6%	
OH	100.0%									
OK	89.6%	1%		1%	1%	6.1%		0.8%		
PA	18.6%					81.4%				
TX	63.7%		3.0%	12%		5.7%		14.2%	0.1%	
UT	96.9%					2.5%				
VA		100%				0.2%				
WV	16.1%	84%								
WY	78.8%		6.0%	10%		0.6%		4.5%		
Survey Total	**38.2%**	**4%**	**0.7%**	**2%**	**0.5%**	**15.4%**	**< 0.10%**	**1.7%**	**17.1%**	

APPENDIX D

ASSOCIATED WASTES

Table D.6. Total Associated Waste; Volume of Waste Disposed by Method – Reported Da
(Barrels per Year)

State	Disposed by Injection	Land Spread within Field	Land Spread outside of Field	Road Spread within Field	Road Spread outside of Field	Comm. E&P Waste Disposal	Landfill	Crude Oil Reclaim.	Recycle/ Beneficial Use	Incinerated
AK	15,000					161				
AL	5,796			1,000				4	755	
AR	No waste volumes reported									
CA	7,060	12,400	4,500	7,300		800		3,000	221,000	2
CO	176,908	6,000				156,320		770	30	
FL										42
IL	12,610				100					
KS	74,899				5,600	1,500		1,430		
KY	500	2,600	42	28						
LA	7,100					19,105			13	5,500
MI	280									
MS		10						4,500	90	
MT	42,985					100		300		
ND						100				
NE										
NM	16,000					2,330			8	0
NY	100	25		100		0	3	50	454	5
OH	3,200									
OK	22,400	270		300	300	1,525		200		
PA	3,200					14,000				
TX	43,730	246	2,079	8,057	0	3,910	0	9,764	63	
UT	32,750					833				
VA		5,580				10				
WV	5,932	30,800								
WY	26,320		2,000	3,200		200		1,500		
Survey Total	**496,770**	**57,931**	**8,621**	**19,985**	**6,000**	**200,894**	**3**	**21,518**	**222,413**	**5,549**

APPENDIX E

DRILLING WASTES

Table E.1. Percentage of New Wells Drilled by Technique - Reported Data

State	No. Of New Wells	% With Mud Reserve Pits	% With Closed System	% With Air, Gas, or Pneumatic Drilling	% With Cable Tool	% Of Mud Reserve Pits - Lined	Number of Responses
AK	11		100%				1
CA	349	79%	21%			0%	8
CO	9	78%	22%			0%	2
IL	25	96%			4%	0%	2
KS	306	39%	61%			17%	6
LA	21	100%				71%	4
MI	7	100%				100%	1
MT	7	100%				86%	2
NM	11	27%		73%		100%	3
OK	14	64%		36%		22%	2
TX	349	99%	1%			87%	8
UT	9	22%	56%	22%		100%	3
WY	2	100%				100%	1
Survey Total	**1,120**	**74%**	**25%**	**1%**	**< 0.1%**	**69%**	**43**
Appalachian States:							
KY	22	5%		95%		0%	3
NY	14			100%		Not reptd.	1
OH	3	38%		62%		33%	3
PA	26			100%		Not reptd.	2
VA	16			100%		Not reptd.	2
WV	38	3%		97%		100%	4
Appalachian Total	**124**	**4%**	**0%**	**96%**	**0%**		**15**
Nationwide Total	**1,244**	**66%**	**23%**	**11%**	**< 0.1%**	**69%**	**58**

APPENDIX E

DRILLING WASTES

Table E.2. Percentage of Drilling Wastes by Base Drilling Fluid – Reported Data

State	Percentage of Wastes by Base Fluid				No. Of Responses
	Freshwater	Saltwater	Oil	Synthetic	
AK	70%			30%	1
CA	98%		1.5%	0.5%	8
CO	100%				2
IL	100%				2
KS	99%	1%			6
LA	93%		7%		4
MI	100%				1
MT	14%	86%			2
NM	82%	16%		2%	3
OK	63%		37%		2
TX	93%	7%			8
UT	100%				3
WY	100%				1
Appalachian States:					
KY					Air drill only
NY					Air drill only
OH	67%	33%			3
PA					Air drill only
VA					Air drill only
WV	83%	17%			1

Table E.3. Estimated Percentage of Drilling Wastes by Base Drilling Fluid

State	Estimated Volume Drilling Wastes Reported by Respondents [a] (barrels)	Percentage of Wastes by Base Fluid				No. of Responses
		Freshwater	Saltwater	Oil	Synthetic	
AK	111,000	70%			30%	1
CA	506,000	98%		1.5%	0.5%	8
CO	63,000	100%				2
IL	28,000	100%				2
KS	922,000	99%	1%			6
LA	342,000	93%		7%		4
MI	13,000	100%				1
MT	89,000	14%	86%			2
NM	21,000	82%	16%		2%	3
OK	95,000	63%		37%		2
TX	2,812,000	93%	7%			8
UT	131,000	100%				3
WY	30,000	100%				1
Estimated Survey Total	**5,163,000**	**92.5%**	**5.5%**	**1.3%**	**< 0.6%**	**43**

[a] Estimated volume of drilling waste for rotary drilling w/ open mud system. Air/pneumatic drilling is excluded. Estimate is based on reported footage drilled multiplied by appropriate factors for drilling waste volume per foot by depth category. This is not, and should not be interpreted as, a total volume of drilling waste (see Table 3.9). This is based on the respondents only and was used solely to calculate national average distribution of drilling wastes by base fluid.

Table E.4. Appalachian States, Volumes of Drilling Wastes – Reported Data

State	Footage Drilled – Rotary w/ mud	Footage Drilled – Air Drilling	Volume of Drilling Wastes to Mud Reserve Pits	Volume of Drilling Wastes – Air/Pneum. Drilling	Drilling Wastes to Reserve Pit: Approx. Volume per Foot Drilled (bbl waste/ft)	Air Drilling Wastes: Approx. Volume per Foot Drilled (bbl waste/ft.)	Total Number of Responses
KY	0	80,000	0	2,000	N/A	0.025	1
OH	11,890	32,760	1,900	2,800	0.16	0.085	3
PA	0	55,800	0	2,900	N/A	0.052	1
WV	1,740	232,920	800	20,300	0.46	0.087	3
TOTAL	**13,630**	**401,480**	**2,700**	**28,000**	**0.20**	**0.070**	**8**

Table E.5. Alternative Estimation of Total Drilling Waste for Appalachian States and Other States with Significant Air Drilling

State	1995 Total Footage Drilled for State [a] (ft)	Estimated 1995 Footage Drilled w/ Mud [b] (ft)	Estimated 1995 Footage Drilled w/ Air [b] (ft)	Estimated 1995 Volume of Drilling Wastes - Rotary Drill w/ Mud [c] (bbls)	Estimated 1995 Volume of Drilling Wastes – Air Drill [d] (bbls)	Total Alternative Estimated Volume of Drilling Wastes for State (bbls)
NM	5,752,500	1,553,175	4,199,325	2,003,596	293,953	2,297,549
OK	11,857,800	7,588,992	4,268,808	8,423,781	298,817	8,722,598
UT	929,400	724,932	204,468	1,217,886	14,313	1,232,199
Appalachian States:						
KY	1,465,100	73,255	1,391,845	104,755	97,429	202,184
NY	108,000	4,320	103,680	5,530	7,258	12,788
OH	3,073,700	1,168,006	1,905,694	654,083	161,984	816,067
PA	2,357,100	94,284	2,262,816	97,113	158,397	255,510
TN	93,000	3,720	89,280	8,891	6,250	15,141
VA	139,900	0	139,900	0	9,793	9,793
WV	1,585,000	47,550	1,537,450	25,677	133,758	159,435
Appalachian Total:	**8,821,800**	**1,391,135**	**7,430,665**	**896,049**	**574,869**	**1,470,918**

[a] From Table 3.9, "Estimated Total Volume of Drilling Wastes"
[b] From Table E.1, "Percentage of New Wells Drilled by Technique." (Total for all the Appalachian States is applied to PA, NY, TN)
[c] (Column 3) x (waste extrapolation factor, bbl waste per foot drilled, from API 1985 Production Waste Survey)
[d] (Column 4) x (estimated extrapolation factor for air drilling, 0.07 bbl waste per foot drilled, from Table E.4)

APPENDIX E

DRILLING WASTES

Table E.6. Liquid Drilling Waste Disposal- Reported Data (as % of Total Drilling Wastes)

State	Percentage of Total Drilling Waste Disposed by Method									Response
	Injection	Down Annulus	Treat & Discharge	Road Spread	Evaporate On or Offsite	Land Spread Onsite	Land Spread Offsite	Reuse for Drilling	Other	
AK	50%									1
AR	70%									1
CA					19%	44%	<0.1%	1.2%	14%[a]	8
CO	36%				52%					2
IL	83%									2
KS	1%				19%			37%		6
LA	7%	45%			1%	10%		0.5%		4
MI						80%				1
MT	51%							10%		2
NM	4%				78%	3%				3
OK					1%			49%		2
TX	1%			0.1%	82%		0.9%	2%		8
UT					39%			5%		3
WY					50%					1
Appalachian States:										
KY			64%			6%				3
NY	No liquid wastes reported; air drilling only									1
OH	74%									3
PA	7%								32%[b]	2
VA						56%	4%			2
WV			22%			13%				4

[a] liquids and solids remediated onsite
[b] commercial disposal facility

Appendix E

Drilling Wastes

Table E.7. Solid Drilling Waste Disposal- Reported Data (As % of Total Drilling Wastes)

State	Percentage of Total Drilling Waste Disposed by Method							Response
	Buried Onsite	Land Spread Onsite	Land Spread Offsite	Commercial Disposal Facility	Industrial or Municipal Landfill	Reuse or Recycle	Other	
AK							50%[a]	1
AR	30%							1
CA	21%	0.3%	0.1%	0.2%	0.1%			8
CO		3%	9%					2
IL	1%	16%						2
KS	42%							6
LA	20%	4%		13%				4
MI	20%							1
MT	39%							2
NM	13%	3%						3
OK	50%							2
TX	13%	0.3%	0.1%			0.6%	0.1%[b]	8
UT	56%							3
WY	50%							1
Appalachian States:								
KY	28%	2%						3
NY		100%						1
OH	26%							3
PA	2%	59%						2
VA	40%							2
WV	66%							4

[a] grind and inject in Class II well
[b] pit

Table E.8. Estimated Volume of Liquid Drilling Wastes Disposed by Method; Estimated for States with Reported Data (Barrels)

State	Est. Total Volume Drilling Wastes for State	Injection	Injected Down Annulus	Treat & Discharge	Road Spread	Evaporate On or Offsite	Land Spread Onsite	Land Spread Offsite	Reuse for Drilling	Other
AK	1,605,000	803,000								
AR	2,643,000	1,850,000								
CA	1,826,000					347,000	804,000	1,000	22,000	256,000
CO	3,582,000	1,290,000				1,863,000				
IL	382,000	317,000								
KS	4,810,000	48,000				914,000			1,780,000	
LA	22,477,000	1,573,000	10,115,000			225,000	2,245,000		112,000	
MI	1,731,000						1,385,000			
MT	1,366,000	697,000							137,000	
NM	7,421,000	297,000				5,788,000	223,000			
OK	13,162,000					132,000			6,449,000	
TX	65,367,000	654,000			65,000	53,601,000		588,000	1,307,000	
UT	1,561,000					609,000			78,000	
WY	4,374,000					2,187,000				
Total Volume (excludes Appalachian States):	132,307,000	7,529,000	10,115,000	0	65,000	65,666,000	4,657,000	589,000	9,885,000	256,000
Appalachian States:										
KY	2,095,000			1,341,000			126,000			
NY	138,000									
OH	1,721,000	1,274,000								
PA	2,428,000	170,000								777,000
VA	57,000						32,000	2,000		
WV	856,000			188,000			111,000			
Total Volume (Appalachian States Only):	7,295,000	1,444,000	0	1,529,000	0	0	269,000	2,000	0	777,000
National Est. Total Volume [a]:	**139,602,000**	**8,973,000**	**10,115,000**	**1,529,000**	**65,000**	**65,666,000**	**4,926,000**	**591,000**	**9,885,000**	**1,033,000**
National Total, % by Disposal Method	Liquid Wastes = 73.6%	**6%**	**7%**	**1%**	**0.05%**	**47%**	**3.5%**	**0.4%**	**7%**	**0.7%**

[a] Table only includes states with reported data. Therefore, the estimated total volume of drilling waste is less than the 148.7 million barrels discussed in the text. The estimated total volume reported in the text, 148.7 million barrels, includes drilling waste volumes estimated for states for which no responses to drilling related questions were received on the 1995 survey.

Table E.9. Estimated Volume of Solid Drilling Wastes Disposed by Method; Estimated for States with Reported Data (Barrels)

State	Estimated Total Volume Drilling Wastes for State [a]	Buried Onsite	Land Spread Onsite	Land Spread Offsite	Commercial Disposal Facility	Industrial or Municipal Landfill	Reuse or Recycle	Other
AK	1,605,000							803,000
AR	2,643,000	793,000						
CA	1,826,000	383,000	5,000	2,000	4,000	2,000		
CO	3,582,000		107,000	322,000				
IL	382,000	4,000	61,000					
KS	4,810,000	2,020,000						
LA	22,477,000	4,495,000	899,000		2,922,000			
MI	1,731,000	346,000						
MT	1,366,000	533,000						
NM	7,421,000	965,000	223,000					
OK	13,162,000	6,581,000						
TX	65,367,000	8,533,000	197,000	65,000			394,000	65,000
UT	1,561,000	874,000						
WY	4,374,000	2,187,000						
Total Volume (excludes Appalachian States):	**132,307,000**	28,060,000	1,492,000	389,000	2,926,000	2,000	394,000	868,000
Appalachian States								
KY	2,095,000	587,000	42,000					
NY	138,000		138,000					
OH	1,721,000	448,000						
PA	2,428,000	49,000	1,432,000					
VA	57,000	23,000						
WV	856,000	565,000						
Total Volume (Appalachian States Only):	**7,295,000**	1,672,000	1,612,000					
National Est. Total Volume [a]:	**139,602,000**	**29,732,000**	**3,104,000**	**389,000**	**2,926,000**	**2,000**	**394,000**	**868,000**
National Total, % by Disposal Method	Solid Wastes = 26.4 %	**21%**	**2.2%**	**0.3%**	**2%**	**0.001%**	**0.3%**	**0.6%**

[a] Table only includes states with reported data. Therefore, the estimated total volume of drilling waste is less than the 148.7 million barrels discussed in the text. The estimated total volume reported in the text, 148.7 million barrels, includes drilling waste volumes estimated for states for which no responses to drilling related questions were received on the 1995 survey.

APPENDIX F

GAS PROCESSING PLANTS; PRODUCED WATER AND ASSOCIATED WASTES

Table F.1. Gas Plants: Produced Water Disposal by Method and Region – Reported Da
(Barrels/day and Percentages)

	Alaska	California	Eastern U.S.	Mid-West	New Mexico	Rockies
Number of Plants Responding	3	3	7	3	5	7
Reported Volume of Produced Water (Bbl/day)	0	201	246.9	70.9	147.95	328
Injected Onsite for Disposal (Bbl/day)	0	0	246	0	0	0
% Injected Onsite	NA		99.6%			
Injected Offsite for Disposal (Bbl/day)	0	1	0.9	0	0	230
% Injected Offsite	NA	0.5%	0.4%	0%		70%
Injected at Commercial Disposal Facility (Bbl/day)	0	0	0	70.9	0.25	20
% Injected at Commercial Disposal Facility	NA			100%	0.2%	6%
Treat/Discharge (Bbl/day)	0	0	0	0	0	0
% Treat/Discharge	NA					
Reuse (Bbl/day)	0	0	0	0	0	50
% Reuse	NA					15%
Road spread (Bbl/day)	0	0	0	0	0	0
% Road spread	NA					
Other Disposal Method (Bbl/day)	0	200[a]	0	0	147.7[b]	28[c]
% Other Disposal Method	NA	99.5%			99.8%	9%

[a] Respondent noted this method as “commingle with crude oil”
[b] Respondents noted this method as “re-injected for enhanced recovery” and “evaporation ponds”
[c] Respondents noted this method as “evaporation pit (lined)” and “treated/evaporated”
[d] Respondent noted this method as “steam vent to atmosphere”

APPENDIX F

GAS PROCESSING PLANTS; PRODUCED WATER AND ASSOCIATED WASTES

Table F.2. Gas Plants: Disposal of Glycol Wastes by Method and Region – Reported Da

	Alaska	**California**	**Eastern U.S.**	**Mid-West**	**New Mexico**	**Rockies**	**S**
Spent Glycol/ Glycol Compounds (Bbls/yr)	0	20	108	0	0	437	
Volume Disposed by Method (Barrels/yr):							
Dispose by Injection	0	0	28	0	0	61.64	
Land spread Onsite	0	0	0	0	0	0	
Road spread Onsite	0	0	0	0	0	0	
E&P Waste Facility	0	0	5	0	0	0	
Industry or Municipal Landfill	0	0	0	0	0	0	
Recycle or Reuse	0	0	39	0	0	375	
Incinerate	0	0	36	0	0		
Evaporate from pits	0	0	0	0	0	0.36	
Other method	0	20[a]	0	0	0	0	
Percentage Disposed by Method:							
% Injection			26%	0%		14%	
% Land Spread Onsite							
% by Road Spread Onsite							
% Commercial Disposal Facility			5%				
% Landfill							
% Recycle/ Reuse			36%			86%	
% Incinerate			33%				
% Evaporate from Pits						0.08%	
% Other		100%					

[a] Respondent listed method as "commercial disposal contractor"
[b] Respondent listed method as "mix with crude oil being sold"

APPENDIX F

GAS PROCESSING PLANTS; PRODUCED WATER AND ASSOCIATED WASTES

Table F.3. Gas Plants: Disposal of Used Filters/Filter Media by Method and Region – Reporte

	Alaska	California	Eastern U.S.	Mid-West	New Mexico	Rockies	S
Spent Used Filters/Filter Media (Bbls/yr)	0.04	24.96	0.35	0.25	25.66	259.65	
Volume Disposed by Method (Barrels/yr):							
Dispose by Injection	0	0	0	0	0	0	
Land spread Onsite	0	0	0	0	0	0	
Road spread Onsite	0	0	0	0	0	0	
E&P Waste Facility	0	0.19	0	0.10	0.14	7.62	
Industry or Municipal Landfill	0	0.00	0.35	0.15	25.53	252.03	
Recycle or Reuse							
Incinerate	0.04						
Evaporate from pits	0	0	0	0	0	0	
Other method	0	24.77[a]	0	0	0	0	
Percentage Disposed by Method:							
% Injection							
% Land Spread Onsite							
% by Road Spread Onsite							
% Commercial Disposal Facility		1%		38%	1%	3%	
% Landfill			100%	61%	99%	97%	
% Recycle/ Reuse	0%	0%					
% Incinerate	100%						
% Evaporate from Pits							
% Other		99%					

[a] Respondent listed method as "commercial disposal contractor"
[b] Respondents listed method as "waste to energy plant" and "burial with permit."

Table F.4. Gas Plants: Disposal of Scrubber Liquids/Sludge by Method and Region – Report

	Alaska	**California**	**Eastern U.S.**	**Mid-West**	**New Mexico**	**Rockies**	**S**
Scrubber Liquids and Sludge (Bbls/yr)	0	200	57	0	20	40	
Volume Disposed by Method (Barrels/yr):							
Dispose by Injection	0	0	7	0	0	0	
Landspread Onsite	0	0	0	0	0	0	
Roadspread Onsite	0	0	0	0	0	0	
E&P Waste Facility	0	0	50	0	20	40	
Industry or Municipal Landfill	0	0	0	0	0	0	
Recycle or Reuse	0	0	0	0	0	0	
Incinerate	0	0	0	0	0	0	
Evaporate from pits	0	0	0	0	0	0	
Other method	0	200[a]	0	0	0	0	
Percentage Disposed by Method:							
% Injection			12%				
% Land Spread Onsite							
% by Road Spread Onsite							
% Commercial Disposal Facility			88%		100%	100%	
% Landfill							
% Recycle/ Reuse							
% Incinerate							
% Evaporate from Pits							
% Other		100%					

[a] Respondent listed method as “commercial disposal contractor”

APPENDIX F

GAS PROCESSING PLANTS; PRODUCED WATER AND ASSOCIATED WASTES

Table F.5. Gas Plants: Disposal of Other Dehydration/Sweetening Wastes by Method and Region –

	Alaska	California	Eastern U.S.	Mid-West	New Mexico	Rockies	S
Other Dehydration/Sweetening Wastes (Bbls/yr)	0	0	0	195	1,117	1,203	
Volume Disposed by Method (Barrels/yr):							
Dispose by Injection	0	0	0	0	0	0	
Land spread Onsite	0	0	0	0	207	0	
Road spread Onsite	0	0	0	0	0	0	
E&P Waste Facility	0	0	0	0	25	58	
Industry or Municipal Landfill	0	0	0	195	841	50	
Recycle or Reuse	0	0	0	0	0	0	
Incinerate	0	0	0	0	44	0	
Evaporate from pits	0	0	0	0	0	1095	
Other method	0	0	0	0	0	0	
Percentage Disposed by Method:							
% Injection							
% Land Spread Onsite					19%		
% by Road Spread Onsite							
% Commercial Disposal Facility					2%	5%	
% Landfill				100%	75%	4%	
% Recycle/ Reuse							
% Incinerate					4%		
% Evaporate from Pits						91%	
% Other							

[a] Respondent listed method as “onsite burial with permit of mole sieve, charcoal”

Table F.6. Gas Processing Plant Wastes – Reported Data

Region	Reported Gas Throughput (MMcfd)	Spent Glycol/ Glycol Compounds (bbls./yr.)	Used Filters/ Filter Media (bbls./yr.)	Scrubber Liquids & Sludge (bbls./yr.)	All Other Dehydration/ Sweetening Wastes (bbls./yr.)	Total Reported Volume of Gas Plant Wastes (bbls./yr.)
Alaska	7,938	0	0.04	0	0	0.04
California	298.38	20	24.96	200	0	244.96
Eastern U.S.	992.4	108	0.35	57	0	165.35
Mid-West	108	0	0.25	0	195	195.25
New Mexico	1,109	0	25.66	20	1,117	1,162.66
Rockies	2,699	437	259.65	40	1,203	1,939.65
Southeast	6,159	102	69.82	31,775	4,442	36,388.82
Texas	2,689.8	3	192.35	3,150	957	4,302.35
Total	**21,994**	**670**	**573.08**	**35,242**	**7,914**	**44,399.08**

Table F.7. Gas Processing Plants; Reported Volume of Wastes Disposed by Method

Waste Disposal Method	Percentage of Gas Plant Wastes Disposed by Method	Reported Volume of Wastes Disposed by Method (barrels/day)
Disposal by Injection	76 %	33,717
Commercial E&P Waste Disposal Facility	9 %	4,102
Land Spread Onsite	6%	2,854
Industrial or Municipal Landfill	4 %	1,606
Evaporate from Pits	2.5 %	1,095
Recycle or Reuse	1 %	587
Incinerate	0.3 %	113
Road Spread Onsite	0.01 %	5
Other	1 %	320
Total	100 %	44,399
“Other” methods include: co-mingle w/ oil product, waste disposal contractor, onsite burial w/ permit, incineration in “waste-to energy” plant		

Appendix G

Survey Methodology

G.1. Survey Forms

Two forms were developed for API's 1995 survey: API Survey of Onshore and Coastal Exploration and Production Operations for 1995 and API Survey of Natural Gas Processing Plants for 1995. The onshore operations survey form is included in Appendix H and the gas processing plant survey form is included in Appendix I. The survey form was originally intended to collect data only on waste volumes and waste management practices. However, following a beta test of the survey forms but prior to distribution of the survey, a need arose to collect data on equipment that produces air emissions at E&P sites. This resulted in the addition of several pages of questions to the survey form. Although this data collection effort was needed, it increased the length and complexity of the survey form and may have reduced the rate of response to the survey. Although the survey forms were beta tested, in analyzing the results it was apparent that the wording of some questions was unclear to the respondents. API and its contractor made follow-up phone calls to survey respondents to clarify responses as needed.

A separate version of the onshore E&P operations survey was developed for operators in the Appalachian states. The Appalachian version of the 1995 survey form did not collect data on tank batteries/central facilities (question 10). The Appalachian version of the 1995 survey form also asked respondents to specify volumes of drilling waste generated because this data was not collected for the Appalachian states in API's 1985 survey. The 1995 survey form developed for states outside the Appalachian region did not ask operators to report drilling waste volumes. This data was collected in the 1985 survey and the relationship between footage drilled (by depth category) and drilling waste volume was not believed to have changed substantially between 1985 and 1995.

G.2. Design of Survey Sample

The survey was conducted using a representative statistical sample of industry operations. Two survey samples were designed for the 1995 Onshore and Coastal E&P Operations Survey. The first sample was designed to characterize E&P industry facilities and wastes for the entire U.S. excluding the Appalachian states. The second sample was designed to characterize the Appalachian states, Kentucky, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. It was necessary to separate out Appalachia because the population frame used to draw the samples did not contain data for those states. The following section describes the survey sample design for both the E&P operations survey and the gas processing plant survey.

G.2.1. 1995 E&P Operations Survey excluding Appalachia

The survey questionnaire was designed to focus on all the facilities operated by an E&P company within a single field. A selected E&P company was only asked to complete one survey form per selected field. The participating companies were selected as follows.

The United States can be divided into 50 geological basins. Because geological basins cross state boundaries, a single state can contain parts of several basins. This results in 71 unique onshore basin/state combinations. If the Appalachian states are excluded, the number of basin/state combinations with oil or natural gas production is 59. The E&P companies operating in each of the 59 basin/state combination were classified as either large or small companies. If a publicly traded company's 1994 combined oil and gas production exceeded 20 million barrels of oil equivalent (BOE), the company was designated as 'large'. This method yielded a group of thirty-one large companies, with the remaining companies considered 'small'. Stratification by company size ensured that a cross-section of the types and sizes of oil and gas operators were included in the sample. The fifty-nine basin/state combinations were grouped into, high, medium, or low producing areas, based on the 1994 production of oil and gas. The production range of these three categories is shown in Table G.1 below. The total 1994 production in the basin/state combinations is summarized in Table G.5.

APPENDIX G

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Table G.1. Operations Survey Sample Design - Basin/State Categories

Basin/State Categories	1994 Production (barrels of oil equivalent)	Number of Basin/State Combinations in Category
High Producing	>100 Million BOE	12
Medium Producing	10 Million – 100 Million BOE	28
Low Producing	<10 Million BOE	19

Participating companies were selected for the survey sample from databases maintained by Petroleum Information (PI) Corporation using the selection method termed "probability proportional to size with replacement". For a given basin/state/company size combination, a company's probability of being included in the sample was proportional to its 1994 production in that basin/state combination. For example, if company A had twice as much production as company B, company A was twice as likely to be selected as company B. For each selected company in a basin/state location, one of the company's fields was selected with probability proportional to the production from that field. The selected company was then asked to respond with information for all its leases in that field. Previous beta test experience indicated that small operating companies were less likely to respond to the survey questionnaire. To account for possible non-response by small companies, the sample size for these companies was increased by a factor of two. Under this sampling methodology, a company could receive survey forms for a field in more than one basin/state, but only one field in each basin/state. The final composition of the sample in each basin/state category is shown in Table G.2 below.

Table G.2. Operations Survey Sample Design - No. Of Large and Small Companies in Sample by Basin/State Category

Basin/State Categories	Large Companies in Sample	Small Companies in Sample	Number of Basin/States	Total Sample Size
High Producing	3	6	12	96
Medium Producing	2	4	28	156
Low Producing	1	2	19	44
				Total = 296

Three large and six small companies were selected from each basin/state category in a high producing area. Two large and four small companies were selected from each basin/state category in a medium producing area. One large and two small companies were selected from each category in a low producing area. The final sample size contained 296 survey forms. A total of 131 operators responded to the survey, approximately 44 percent of the fields sampled. Sixty-eight percent of large companies responded and 33 percent of small/independent operators responded. Table G.6 tabulates the respondent coverage by state and by basin/state combination.

G.2.2. 1995 E&P Operations Survey – Appalachian States

The PI database that served as a sampling frame for the 1995 Onshore and Coastal E&P Operations survey did not contain production information for the Appalachian states, Kentucky, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. For these states, API contacted the Oil and Gas Associations of each state and asked for a list of member companies. API sent survey forms to a selection of the member companies and asked the companies to complete the forms for any two of their fields in the designated state. Companies in Appalachia were chosen for their likelihood of response, rather than based on a statistical sampling. Participating companies were asked to select one large field and one medium/small field in the assigned state. Thirty-three responses were received from seven states. Table G.3 below lists the number of respondents for each state.

Table G.3. Appalachian State Respondents

State	Respondents
Kentucky	8
New York	3
Ohio	4
Pennsylvania	5
Tennessee	0
Virginia	4
West Virginia	9
Appalachia Total	**33**

G.2.3. 1995 Natural Gas Processing Plant Survey

For sampling purposes, the United States was divided into eight regions shown in Table G.4. The sampling frame used for the gas plants waste management survey was obtained from the July 1, 1996, *Oil and Gas Journal* Gas Processing Survey. The original *Oil and Gas Journal* 1996 survey list contains 623 gas plants operating in the United States in 1995. Twenty-four plants listed had missing capacity information and were removed from the population frame for the wastes survey. This left a total of 599 gas plants in the population.

A stratified random sample design was used, with an individual gas plant facility being the primary sampling unit. One hundred two gas plants were to be included in the nationwide survey. The country was first divided into 8 regions. Each region was divided into three strata, small, medium, and large, by gas plant capacity and all "large" gas plants were included in the sample. Some regions had zero facilities in some of the strata. For example, Alaska had only three facilities in the region and all three were in the "large" stratum. After including all the "large" plants and all the Alaska plants, eighty-three "non-large" plants (facilities not classified in the large stratum) remained to be randomly selected.

Proportional allocation was used to determine the sample sizes (total sample size for the small and medium strata) for each region. Proportional allocation was also used to distribute the non-certainty sample between the strata within each region. Table G.7 lists the population, sample, and respondent number of gas plants by region and stratum (gas plant capacity and gas throughput).

Table G.4. Gas Plants Survey - Regions and Sample Size

Region	State	Population Size	Sample Size	Respondents
Alaska	Alaska	3	3	3
California	California	25	4	3
Eastern U.S.	Alabama, Florida, Kentucky, Michigan, Ohio, Pennsylvania, West Virginia	47	10	7
Mid-West	Arkansas, Kansas, Oklahoma	92	14	3
New Mexico	New Mexico	27	6	5
Rockies	Colorado, Montana, North Dakota, Utah, Wyoming	104	11	7
Southeast	Louisiana, Mississippi	68	27	15
Texas	Texas	233	27	15
Total		**599**	**102**	**85**

G.3. Survey Data Analysis

The 1995 E&P operations survey and gas plants survey collected data on a range of facilities and their operational practices. This report evaluates only the survey questions pertaining to waste volumes and waste management practices:

- numbers of production pits and non-pressurized tanks,
- produced water volumes and produced water management,
- drilling practices, drilling waste volumes and waste management,
- associated production waste volumes and waste management, and
- gas processing plant dehydration waste volumes and waste management.

Although survey samples were designed on a basin/state basis for the E&P operations survey, the survey responses are aggregated, reported and extrapolated by state. The objective of the analysis presented here is to provide reported data and data extrapolations that can be meaningfully compared with other oil and gas data that are typically reported by state. Table G.8 shows the number of responses by state for the E&P operations survey. The response rate for the onshore operations survey was 44 percent (131 responses were received from a sample size of 296). Thirty-three additional responses were received from seven Appalachians states. For the 32 states included in the survey sample design, the number of responses ultimately received for each state range from zero to 22, with an average of five responses per state. The gas processing plant data is reported and extrapolated by the regions defined in the survey sample design. The responses received for the gas plant regions are shown in Table G.4 and range from three to fifteen responses per region.

G.3.1. Survey Data Extrapolation

For most questions, a ratio estimation method is used to extrapolate the reported data for a given state to an estimated total for that state. Different extrapolation methods were applied to the data received for the E&P operations survey in an attempt to find a method that produced state by state estimates that were reasonable when compared to known data.[16] However, because most states are represented by a small

[16] For example, large states with a greater number of respondents, such as California and Texas, had enough responses for some questions that regression analysis could be used. The survey responses were examined on a respondent-by-respondent basis for individual survey questions to determine whether any trend or relevant clustering occurred. For example, did responses tend to cluster by oil production vs. gas production, large operator vs. small operator? Individual responses were also examined to

number of responses, straightforward ratio estimation produced the most consistent and reasonable estimated values. Reported data from the operations survey are extrapolated on production, estimated number of production facilities, or number of wells, as appropriate to the survey question under consideration. Similarly, reported data from the gas plants survey are extrapolated either on gas throughput or on number of gas plants, as appropriate.

All of the responses received for a state were aggregated. Depending upon the survey question under consideration, the individual survey responses were designated as predominately representing gas production or predominately representing oil production. The total responses received for the state were used to generate a single extrapolation factor for the state such as number of tank batteries per oil production facility or volume of completion fluids generated per well completion. The extrapolation factor was then applied to state data such as number of well completions or volume of gas production, in order to generate a total estimated survey response for the state. Depending upon the nature of the survey question, "zero" responses received from survey responses were either incorporated into the state extrapolation factor or omitted. For example, for some questions related to facilities, "zero" responses are treated as questionable data and are omitted. Consider the example below:

State "A"

Response 1	10 wells	2 tank batteries
Response 2	100 wells	0 tank batteries
Response 3	37 wells	10 tank batteries

It is unlikely that a field with 100 wells has no tank batteries, so "Response 2" is considered questionable data and is omitted from the state extrapolation factor:

$$\text{Extrapolation Factor for State "A"} = \frac{\text{10 wells + 37 wells}}{\text{2 tank batteries + 10 batteries}} = \frac{\text{4 wells}}{\text{tank battery}}$$

For most questions related to volumes of produced water or waste, the "zero" responses are appropriately treated as valid data and are incorporated into the state extrapolation factor. The example shown below illustrates the case in which a volume of workover waste is generated intermittently depending upon field operations. In this example, "zero" responses represent valid data that should be incorporated into the state extrapolation factor.

State "A"

Response 1	10 oil wells	20 barrels waste
Response 2	100 oil wells	280 barrels waste
Response 3	37 oil wells	0 barrels waste

$$\text{Extrapolation Factor for State "A"} = \frac{\text{20 bbls. + 280 bbls. + 0 bbls.}}{\text{10 wells + 100 wells + 37 wells}} = \frac{\text{2.04 bbls. waste}}{\text{oil well}}$$

For some of the survey questions evaluated in this report, a statewide value for wastes or facilities is estimated for states that have no reported data. Either these states were not sampled (Oregon, Missouri), or the states were sampled but no response was received (Nevada, South Dakota). Also, in a few instances for both the operations survey and the gas plants survey, the survey response received appears to be an "outlier", or in some way is a non-representative respondent. In these cases, either a value is estimated for the state using a "national" extrapolation factor based upon the total survey response or an extrapolation factor or survey response from a similar neighboring state is applied. For example, an extrapolation factor based upon gas

(..continued)

determine the most reasonable way to treat "zero" responses and outliers. Depending upon the type of question, a zero response was treated as valid response, or was considered an "unlikely" response and omitted.

production in West Virginia might be applied to gas production in Virginia, or an extrapolation factor for an associated waste volume reported for Montana might also be applied to North Dakota. It was apparent that the wording of some survey questions was unclear to respondents. This contributed to a poor response rate on some questions, and to results that were difficult to interpret. Follow-up calls were made to respondents by API and its contractors to clarify responses where needed. Also, for some questions such as produced water volumes, the results extrapolated from the survey responses are supplemented by estimates from other sources.

Table G.5. E&P Operations Survey Sample Design
Total 1994 Production (Mboe) in Basin/State Combinations

State	Basin/ State	Total 1994 Production (Mboe)	State	Basin/ State	Total 1994 Production (Mboe)	State	Basin/ State	Total 1994 Production (Mboe)
Alabama	AL1	21,211	Louisiana	LA1	78,029	Oklahoma	OK1	57,699
Alabama	AL2	68,813	Louisiana	LA2	303,705	Oklahoma	OK2	93,813
AL - Total		**90,024**	**LA - Total**		**381,734**	Oklahoma	OK3	238,136
Alaska	AK1	1,018,672	**Michigan**	**MI1**	**46,097**	**OK - Total**		**389,648**
Alaska	AK2	67,408	Mississippi	MS1	1,598	SD	SD1	2,474
AK-Total		**1,086,080**	Mississippi	MS2	25,675	SD	SD2	191
Arizona	AZ1	191	Mississippi	MS3	12,874	**SD - Total**		**2,665**
Arkansas	AR1	24,725	**MS - Total**		**40,147**	Texas	TX1	318,382
Arkansas	AR2	12,122	Montana	MT1	18,795	Texas	TX2	2,603
AR - Total		**36,847**	Montana	MT2	700	Texas	TX3	97,963
California	CA1	46,110	Montana	MT3	4,242	Texas	TX4	218,914
California	CA2	258,198	Montana	MT4	1,334	Texas	TX5	212,916
California	CA3	13,330	**MT - Total**		**25,071**	Texas	TX6	607,207
CA - Total		**317,638**	Nebraska	NE1		Texas	TX7	69,390
Colorado	CO1	37,064	Nebraska	NE2	2,594	**TX - Total**		**1,527,375**
Colorado	CO2	2,291	Nebraska	NE3	42	Utah	UT1	12,486
Colorado	CO3	36,425	Nebraska	NE4	2,043	Utah	UT2	66,145
Colorado	CO4	23,694	**NE- Total**		13	Utah	UT3	0
Colorado	CO5	7,630	**Nevada**	**NV1**	**4,692**	**UT - Total**		**78,631**
CO - Total		**107,104**	New Mexico	NM1	**1,699**	Wyoming	WY1	13,340
Florida	**FL2**	**5,964**	New Mexico	NM2	151,280	Wyoming	WY2	2,416
Illinois	**IL1**	**15,704**	New Mexico	NM3	130,894	Wyoming	WY3	40,067
Indiana	**IN1**	**2,590**	**NM –Total**		0	Wyoming	WY4	161,192
Kansas	KS1	17,513	**ND - total**	**ND1**	**282,174**	Wyoming	WY5	45,178
Kansas	KS2	124,547			**37,357**	**WY - Total**		**262,193**
Kansas	KS3	19,919						
KS - Total		**161,979**						

Table G.6. E&P Operations Survey Design – Number of Survey Respondents by State, Company Size, and by Basin/State Combination

State	Basin/ State	Basin/ State Category	Large Companies Sample Size	Large Companies Responses	Small Companies Sample Size	Small Companies Responses	Total Companies Sample Size	Total Companies Responses
Alabama	AL1	M	2	1	4	2	6	3
Alabama	AL2	M	1	1	3	2	4	3
AL - Total			**3**	**2**	**7**	**4**	**10**	**6**
Alaska	AK1	H	2	1	1	0	3	1
Alaska	AK2	M	2	2	1	0	3	2
AK-Total			**4**	**3**	**2**	**0**	**6**	**3**
Arizona	AZ1	L	**0**	**--**	**2**	**0**	**2**	**0**
Arkansas	AR1	M	2	1	4	2	6	3
Arkansas	AR2	M	2	1	4	1	6	2
AR - Total			**4**	**2**	**8**	**3**	**12**	**5**
California	CA1	M	2	0	4	3	6	3
California	CA2	H	2	3	4	3	6	6
California	CA3	M	2	0	4	2	6	2
CA - Total			**6**	**3**	**12**	**8**	**18**	**11**
Colorado	CO1	M	2	1	4	1	6	2
Colorado	CO2	L	1	1	2	0	3	1
Colorado	CO3	M	2	2	4	1	6	3
Colorado	CO4	M	1	1	4	0	5	1
Colorado	CO5	L	1	1	2	1	3	2
CO - Total			**7**	**6**	**16**	**3**	**23**	**9**
Florida	**FL1**	**L**	**0**	**--**	**2**	**0**	**2**	**0**
Florida	**FL2**	**L**	**1**	**1**	**1**	**0**	**2**	**1**
Illinois	**IL1**	**M**	**2**	**1**	**4**	**1**	**6**	**2**
Indiana	**IN1**	**M**	**1**	**0**	**2**	**0**	**3**	**0**
Kansas	KS1	M	1	1	4	2	5	3
Kansas	KS2	H	3	3	6	4	9	7
Kansas	KS3	M	2	1	5	3	7	4
KS - Total			**6**	**5**	**15**	**9**	**21**	**14**
Louisiana	LA1	M	2	2	4	2	6	4
Louisiana	LA2	H	3	3	6	2	9	5
LA - Total			**5**	**5**	**10**	**4**	**15**	**9**
Michigan	**MI1**	**M**	**2**	**2**	**3**	**1**	**5**	**3**
Mississippi	MS1	L	0	--	2	0	2	0
Mississippi	MS2	M	1	1	4	0	5	1
Mississippi	MS3	M	2	1	3	0	5	1
MS - Total			**3**	**2**	**9**	**0**	**12**	**2**
Montana	MT1	M	2	1	4	3	6	4
Montana	MT2	L	1	0	2	2	3	2
Montana	MT3	L	1	0	2	1	3	1
Montana	MT4	L	1	1	2	2	3	3
MT - Total			**5**	**2**	**10**	**8**	**15**	**10**
Nebraska	NE1	L	1	0	2	1	3	1
Nebraska	NE2	L	0	--	2	0	2	0
Nebraska	NE3	L	1	1	1	0	2	1
Nebraska	NE4	L	0	--	1	0	1	0
NE- Total			**2**	**1**	**6**	**1**	**8**	**2**

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State	Basin/ State	Basin/ State Category	Large Companies Sample Size	Large Companies Responses	Small Companies Sample Size	Small Companies Responses	Total Companies Sample Size	Total Companies Responses
Nevada	**NV1**	**L**	**1**	**0**	**1**	**0**	**2**	**0**
New Mexico	NM1	H	3	3	4	0	7	3
New Mexico	NM2	H	3	2	6	2	9	4
New Mexico	NM3	--	0	--	0	--	0	--
NM – Total			**6**	**5**	**10**	**2**	**16**	**7**
North Dakota	**ND1**	**M**	**2**	**0**	**4**	**1**	**6**	**1**
Oklahoma	OK1	M	2	2	4	0	6	2
Oklahoma	OK2	M	2	2	4	3	6	5
Oklahoma	OK3	H	**3**	**1**	**6**	**0**	**9**	**1**
OK - Total			**7**	**5**	**14**	**3**	**21**	**8**
South	SD1	L	1	0	2	0	3	0
South	SD2	L	0	--	2	0	2	0
SD - Total			**1**	**0**	**4**	**0**	**5**	**0**
Texas	TX1	H	3	3	6	2	9	5
Texas	TX2	L	0	--	1	1	1	1
Texas	TX3	M	2	0	4	2	6	2
Texas	TX4	H	3	1	6	2	9	3
Texas	TX5	H	3	2	6	3	9	5
Texas	TX6	H	3	3	6	1	9	4
Texas	TX7	M	2	1	4	1	6	2
TX - Total			**16**	**10**	**33**	**12**	**49**	**22**
Utah	UT1	M	1	1	3	0	4	1
Utah	UT2	M	2	1	3	2	5	3
Utah	UT3	--	--	--	--	--	--	--
UT - Total			**3**	**2**	**6**	**2**	**9**	**4**
Wyoming	WY1	M	2	2	4	1	6	3
Wyoming	WY2	L	1	1	1	0	2	1
Wyoming	WY3	M	2	2	4	2	6	4
Wyoming	WY4	H	2	2	6	1	8	3
Wyoming	WY5	M	2	1	4	0	6	1
WY - Total			**9**	**8**	**19**	**4**	**28**	**12**
U. S. Total			**96**	**65**	**200**	**66**	**296**	**131**
Appalachian Responses: KY = 8, NY = 3, OH = 4, PA = 5, TN = 0, VA = 4, WV = 9								

Table G.7. Gas Plants Survey Sample Design – Range in Gas Plant Capacity and Throughput (mmcfd) for Survey Sample Strata

Region	Strata			Total
	Small	Medium	Large	
Alaska				
Stratum Size, MMcfd per plant	N/A	N/A	≤ 8200	
Population Size	0	0	3	
Sample Size	0	0	3	
No. of Responses	0	0	3	
Gas Capacity, MMcfd	0	0	8,975	
Gas Throughput, MMcfd	0	0	8,637	
California				
Stratum Size, MMcfd per plant	≤ 160	> 160	N/A	
Population Size	23	2	0	25
Sample Size	2	2	0	4
No. of Responses	1	2	0	3
Gas Capacity, MMcfd	718	320	0	1,038
Gas Throughput, MMcfd	379	300	0	679
Eastern U. S.				
Stratum Size, MMcfd per plant	≤ 500	> 500	N/A	
Population Size	46	1	0	47
Sample Size	9	1	0	10
No. of Responses	6	1	0	7
Gas Capacity, MMcfd	5,132	1,000	0	6,132
Gas Throughput, MMcfd	1,934	71	0	2,005
Mid West				
Stratum Size, MMcfd per plant	≤ 180	> 180 and ≤ 480	> 480	
Population Size	82	7	3	92
Sample Size	7	4	3	14
No. of Responses	2	1	0	3
Gas Capacity, MMcfd	3,773	2,012	2,600	8,385
Gas Throughput, MMcfd	2,579	1,285	2,030	5,894
New Mexico				
Stratum Size, MMcfd per plant	≤ 80	> 80 and ≤ 220	> 220	
Population Size	19	6	2	27
Sample Size	2	2	2	6
No. of Responses	2	1	2	5
Gas Capacity, MMcfd	784	894	1,094	2,772
Gas Throughput, MMcfd	585	679	858	2,122
Rockies				
Stratum Size, MMcfd per plant	≤ 120	> 120 and ≤ 350	> 350	
Population Size	91	10	3	104
Sample Size	4	4	3	11
No. of Responses	0	4	3	7

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Region	Strata			Total
	Small	Medium	Large	
Gas Capacity, MMcfd	2,125	2,255	1,965	6,345
Gas Throughput, MMcfd	1,253	1,649	1,482	4,384
Southeast				
Stratum Size, MMcfd per plant	≤ 300	> 300 and ≤ 950	> 950	
Population Size	51	13	4	68
Sample Size	10	13	4	27
No. of Responses	4	9	2	15
Gas Capacity, MMcfd	3,757	9,345	5,650	18,752
Gas Throughput, MMcfd	2,855	5,224	4,785	12,864
Texas				
Stratum Size, MMcfd per plant	≤ 140	> 140 and ≤ 375	> 375	
Population Size	208	21	4	233
Sample Size	15	8	4	27
No. of Responses	9	3	3	15
Gas Capacity, MMcfd per	8,354	4,580	3,300	16,234
Gas Throughput, MMcfd	5,873	3,415	2,214	11,502
Population Size (All)	**520**	**60**	**19**	**599**
Total Sample Size	**49**	**34**	**19**	**102**
Total Respondents	**24**	**21**	**13**	**58**

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Table G.8. Survey Response by State

State	Total Responses	No. of Oil and Gas Fields Represented by Respondents	Responses representing predominately OIL production	Responses representing predominately GAS production
AK	3	3	2	1
AL	6	6	2	4
AR	5	5	1	4
AZ	0			
CA	11	10	9	2
CO	9	7	4	5
FL	1	1	1	0
IL	2	2	2	0
IN	0			
KS	14	11	7	7
LA	9	9	2	7
MI	3	3	1	2
MS	2	2	2	0
MO	0			
MT	10	10	9	1
ND	1	1	1	0
NE	2	2	2	0
NM	7	6	1	6
NV	0			
OK	8	8	2	6
OR	0			
SD	0			
TX	22	21	13	9
UT	4	4	2	2
WY	12	12	8	4
Sub-Total	**131**	**123**	**71**	**60**
Appalachian States:				
KY	8	6	4	4
NY	3	3	1	2
OH	4	4	2	2
PA	5	5	0	5
TN	0			
VA	4	2	1	3
WV	9	9	2	7
Appalachian Total:	**33**	**29**	**10**	**23**
TOTAL	**164**	**152**	**81**	**83**

APPENDIX H

SURVEY FORM - API SURVEY OF ONSHORE AND COASTAL EXPLORATION AND PRODUCTION OPERATIONS FOR 1995

Please respond by ___________

American
Petroleum
Institute

API SURVEY OF ONSHORE AND COASTAL EXPLORATION AND PRODUCTION OPERATIONS FOR 1995

SURVEY FORM

Name of Field _________________________

County/Parish _____________ State __________

***ALL SURVEY RESPONSES WILL BE HELD CONFIDENTIAL*.**
Only aggregated results from the survey will be made publicly available. For API internal use, company names and field names will be replaced by codes to maintain confidentiality.

We hope that you will look at completing the survey not as an additional cost or inconvenience, but as an investment in the well-being of our industry.

Carl Giardini, Chairman
API General Committee on Exploration and Production

Estimated Time Required

Before sending out this survey, we asked several companies to complete the survey as a test both of its clarity and the length of time involved in its completion. The small companies participating reported spending between 30 minutes and 2 hours on completion of the survey. Larger companies reported spending up to 8 hours (spread over a week) to complete the survey form, due primarily to the need to coordinate with many different individuals throughout the company to gather the information. We hope that you will find this burden sufficiently light to complete this vitally important survey.

Please remember that the survey focuses on operations in a single field, not for your company as a whole. Several of the questions focus only on large pieces of equipment (e.g., heater treaters or boilers with > 10 million Btu/hour capacity) because they are possible targets of future regulatory activity. Many field operations will not have these large pieces of equipment — thus, those questions can be quickly answered; reducing the effort involved in responding to the survey.

Benefits to Completing the Survey

The primary benefit to you will be knowing that API and other industry organizations have an accurate characterization of industry operations that they can provide to regulators, legislators, and the general public to educate them about our industry. This will help to allow future requirements to be based on current conditions, and may result in compliance cost savings on future regulations that better reflect the real risks associated with industry activities.

In addition, the questions related to equipment that may produce air emissions are an attempt to avoid a mandatory data collection request from EPA that could be far more time-consuming than this survey.

Your response is crucial to our survey design (which has attempted to minimize the burden on companies). Given these benefits, and the importance of this effort, we hope that you will help and complete the survey form. It really is an investment in the well-being of our industry.

API SURVEY OF ONSHORE AND COASTAL EXPLORATION AND PRODUCTION OPERATIONS FOR 1995

Name of Field ____________________

County/Parish ____________________ State ____________________

Please complete this survey to cover all of your ***operated*** **leases/units in the field noted above**. If the field crosses county or parish boundaries, please provide data for the entire field, not just the portion in the county listed above. Please provide data for **calendar year 1995**. Do not include information about the leases within the field that you do not operate. Do not include data on gas plants located in the field. If you did not operate leases in this field during 1995, please complete questions 1-2 below, check here __________ and return this form to the address on the back page.

Instructions are enclosed that provide additional explanation about the completion of each question.

1. Operator/Company Name ____________________

2. Contact Person ____________________ Phone # ____________________

3. Number of months of 1995 you operated in this field: ____________________

FIELD/LEASE INFORMATION

4. Number of individual leases or units you operate in field ____________________

5. Number of active wells you operate in field by type (end of 1995):

	Oil Wells	Gas Wells	Disposal (Injection) Wells	Enhanced Recovery (Injection) Wells	Source Water Wells
Number of active wells at year end 1995					

6. Your gross daily production volumes from this field for 1994 and 1995:

	Oil Bbls/day	Natural Gas		Condensate Bbls/day	Produced Water Bbls/day
		From Oil Wells* 1,000 scf/day	From Gas Wells* 1,000 scf/day		
1994 production volume					
1995 production volume					

Please report **gross** daily production volumes from all operated wells in the field. Please use the units noted in each column.
* If you do not have a breakdown on gas from oil wells vs. gas from gas wells available, please put total gas production in gas wells column and label as both oil and gas wells.

7. Estimated distance from field to nearest town or city with population of 2,500 or more

_______ miles

8. a) Average API gravity of produced fluids:

Oil ____________________ degrees; Condensate ________________ degrees

b) Is gas production from this field sweet or sour? (Mark one) Sweet _________ Sour _________

FIELD EQUIPMENT/FACILITIES

9. **Production Pits**

Production pits include all types of pits operated, except those associated with drilling operations. Small collection sumps are not production pits, and should not be included in the total provided. Examples of production pits include evaporation, blowdown, produced water, percolation, workover, washout, skim, and emergency pits. If you use tanks rather than pits for emergency upsets, please report these tanks in question 10 below. Active pits are defined as those currently part of the operation, *whether or not* they currently contain fluids. Inactive pits are pits that are no longer part of the system but have not yet been closed.

a) Total number of production pits you operate in this field ____________________________
If zero, please place a zero in the blank above and proceed to question 10.

b) Number of these production pits that are workover pits ____________________________

c) Number of production pits that are: Active ________________ Inactive ______________

d) Number of *active* production pits you operate in field that are lined ___________________

10. **Tank Batteries/Central Facilities**

Central facilities are primary separation facilities in unitized fields where storage tanks are present. Do not include facilities for injection or disposal of produced water (covered in question 11 below) in your count of facilities (question 10a), but do include produced water storage tanks at these facilities in the count of tanks in question 10b. For this survey, please consider gun barrel tanks to be produced water tanks. Do not include pressurized vessels. Include only tanks currently in service (part of field operations, regardless of whether they currently contain fluids). Tanks used for emergency or upset conditions (e.g., blowdown tanks or tanks installed to replace a pit) should be reported as emergency tanks, even if they are not located at tank batteries or central facilities.

a) Number of tank batteries/central facilities you operate in this field:

Oil batteries/facilities ______________ Condensate batteries/facilities ____________

b) Number of tanks you operate in this field (both at tank batteries and elsewhere in the field) by type:

	Oil	Condensate	Waste Oil/Water	Produced Water	Emergency
Total number of tanks					

c) Percentage of oil and condensate tanks that route vapors directly to a flare _______________ %

d) Percentage of oil and condensate tanks with a floating roof _______________ %

e) Percentage of oil and condensate tanks with a vapor recovery unit installed _______________ %

f) Of oil and condensate tanks with a vapor recovery unit, percentage by vapor destination:

	Percentage
Incineration (flare)	
Sales (as product)	
Return to process	
Other (specify)	
Total	100%

g) Average operating pressure of high pressure separator _______________ psig

h) Average operating pressure of low pressure separator _______________ psig

i) Is gas from the low pressure separator vented? Yes _________________ No _________ ________

11. **<u>Produced Water Injection/Disposal Facilities</u>**

Produced water injection/disposal facilities include one or more wells injecting water for disposal or enhanced recovery, along with the associated treatment equipment. Storage tanks located at these facilities should be reported in question 10 above.

a) Number of facilities operated and water volumes injected in this field:
If zero, place a zero in the table below and proceed to question 12.

	Enhanced Recovery/Injection	Produced Water Disposal
Number of facilities operated in field		
Volume of water injected (barrels/day)		

b) Source of produced water disposed (disposal facilities only):

	Percentage
From company operations in this field	
From company operations in other fields	
From other companies in this field	
From other companies in other fields	
TOTAL	100%

12. **Gas Dehydration Units**

a) Total number of gas dehydration units you operate in field by dehydration method (do not include dehydration units located at a gas plant):
If zero, place a zero in the table below and proceed to question 13.

	Triethylene glycol (TEG)	Ethylene glycol (EG)	Diethylene glycol (DEG)	Dry bed desiccant or molecular sieve	Other
Number of dehydration units					

Note: Remaining parts of this question address TEG units only. If zero, proceed to question 13.

b) Number of triethylene glycol (TEG) dehydration units you operate in field by size:

Number of TEG Units	Design Capacity and Actual Throughput Ranges			
	≤ 1 million scf/d	1.01–3 million scf/d	3.01–10 million scf/d	> 10 million scf/d
Number of units with Design Capacity in range				
Number of units with Actual Throughput[1] in range				

[1] Annual average operating throughput for year 1995.

c) Percentage of TEG dehydration units with both flash tanks (fuel economizers) and condensers

____________________ %

d) Percentage of TEG dehydration units with a flash tank, but no condenser ______________ %

e) Percentage of TEG dehydration units with a condenser, but no flash tank ______________ %

f) Percentage of TEG units with a condenser which:

Incinerates the offgas in a unit burner ______________ %

Flares the offgas ______________ %

g) Percentage of TEG units that route emissions to a flare without prior condensation ____________%

h) Number of glycol reboiler fireboxes with maximum rated heat input capacity ≥ 10 million btu/hour

____

13. **Field Gas Compressor Drivers**

Field gas compressors are driven by engines or turbines, and are used to compress gas to prepare it for pipeline transportation, to inject CO_2 or natural gas to enhance oil and gas recovery, or to boost gas pressure to use in gas lift operations. Include only those compressor drivers of 150 Hp or larger (continuous design-rated Hp) operated by you. Include electric motors that are used to drive compressors. Do not include any compressors that are part of pipeline/transmission operations. Do not include compressors located at gas plants.

Size and physical location of field compressor drivers may affect whether they are covered by certain air regulations in the future. Two locations are of interest:

- Productionsite – a contiguous graded pad, gravel pad, foundation, platform, or other location upon which any combination of compressor(s), separator(s), pumps(s), storage tank(s), heater treater(s), and/or boiler(s) are physically affixed and comprise a field facility to process the produced fluids for sale and/or injection/discharge.
- Compressor site – a contiguous graded pad, gravel pad, foundation, platform, or other location upon which one or more compressors are physically affixed that is not located within a productionsite.

a) Total number of field gas compressor drivers (engines and turbines) larger than 150 continuous design-rated Hp _____
If zero, place a zero in the blank above and proceed to question 14.

b) Percentage and total horsepower of compressor drivers (engines and turbines) 150 Hp or larger by engine manufacturer:

Engine Manufacturer	Waukesha	Cooper-Bessemer	Clark	Ingersoll Rand	Ajax	Other
% of compressor drivers						
Total Horsepower						

c) Number, type, size and fuel source for compressor drivers (engines) at productionsites:

Horsepower (continuous design-rating)	Engine Type	Number of engines/motors				
		Electric powered motors	Rich[1] burn engines	% rich burn w/ catalytic controls[2]	Lean[3] burn engines	Clean[4] burn engines
150-300 Hp	2-Stroke					
	4-Stroke					
301-500 Hp	2-Stroke					
	4-Stroke					
501-750 Hp	2-Stroke					
	4-Stroke					
751-1,000 Hp	2-Stroke					
	4-Stroke					
>1,000 Hp	2-Stroke					
	4-Stroke					
Fuel Source[5]		electric				

1 Rich burn engines produce less than 4% oxygen in their exhaust. The manufacturer's original recommended operating air-fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1:1. Most 4-stroke engines installed prior to 1982 are rich burn engines.

2 Include the percentage of your rich burn engines that have had catalytic controls installed.

3 A lean burn engine produces greater than 4% oxygen in its exhaust. All 2-stroke engines are lean burn, along with some 4-stroke engines.

4 Clean burn engines are engines (typically 4-stroke) that have had the cylinder heads, combustion chamber, or other parts modified so that the engine is a low NOx emitter without catalytic controls .

5 Natural gas, diesel, gasoline, propane, or other (please specify).

d) Number of compressor sites in the field with *one* compressor ______________________ sites

e) Number of compressor sites with *more than one* compressor ______________________ sites

f) Number, type, and fuel source for compressor drivers (engines) at compressor sites:

Horsepower (continuous design-rating)	Engine Type	Number of engines/motors				
		Electric powered motors	Rich[1] burn engines	% rich burn w/ catalytic controls[2]	Lean[3] burn engines	Clean[4] burn engines
150-300 Hp	2-Stroke					
	4-Stroke					
301-500 Hp	2-Stroke					
	4-Stroke					
501-750 Hp	2-Stroke					
	4-Stroke					
751-1,000 Hp	2-Stroke					
	4-Stroke					
>1,000 Hp	2-Stroke					
	4-Stroke					
Fuel Source[5]		electric				

[1] Rich burn engines produce less than 4% oxygen in their exhaust. The manufacturer's original recommended operating air-fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1:1. Most 4-stroke engines installed prior to 1982 are rich burn engines.

[2] Include the percentage of your rich burn engines that have had catalytic controls installed.

[3] A lean burn engine produces greater than 4% oxygen in its exhaust. All 2-stroke engines are lean burn, along with some 4-stroke engines.

[4] Clean burn engines are engines (typically 4-stroke) that have had the cylinder heads, combustion chamber, or other parts modified so that the engine is a low NOx emitter without catalytic controls .

[5] Natural gas, diesel, gasoline, propane, or other (please specify).

g) Number, size, location, and fuel source of turbines to drive compressors:

Turbine Size	Location	
	Plant Site	Compressor Site
≤ 1,000 Hp		
1,001-5,000 Hp		
5,001-15,000 Hp		
15,001-25,000 Hp		
> 25,000 Hp		
Fuel Source[1]		

[1] Natural gas, diesel, gasoline, propane, or other (please specify).

h) Estimated average BTU content of natural gas used for fuel ________________ BTU/scf

14. **Field Internal Combustion Engines**

Please include all types of stationary field internal combustion engines, including drivers for pumping units, pumps, generators, and other equipment not included in question 13 above. Do not include engines on mobile sources (trucks, etc.)

a) Number of stationary internal combustion engines of 150 horsepower or more (excluding compressor drivers) you operate in this field by size:
If zero, place zeros in the table below and proceed to question 15.

Horsepower rating	Engine Type	Number of engines			
		Rich[1] burn engines	% rich burn w/ catalytic controls[2]	Lean[3] burn engines	Clean[4] burn engines
150-300 Hp	2-Stroke				
	4-Stroke				
301-500 Hp	2-Stroke				
	4-Stroke				
501-750 Hp	2-Stroke				
	4-Stroke				
751-1,000 Hp	2-Stroke				
	4-Stroke				
>1,000 Hp	2-Stroke				
	4-Stroke				
Fuel Source[5]					

1 Rich burn engines produce less than 4% oxygen in their exhaust. The manufacturer's original recommended operating air-fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1:1. Most 4-stroke engines installed prior to 1982 are rich burn engines.

2 Include the percentage of your rich burn engines that have had catalytic controls installed.

3 A lean burn engine produces greater than 4% oxygen in its exhaust. All 2-stroke engines are lean burn, along with some 4-stroke engines.

4 Clean burn engines are engines (typically 4-stroke) that have had the cylinder heads, combustion chamber, or other parts modified so that the engine is a low NOx emitter without catalytic controls .

5 Natural gas, diesel, gasoline, propane, or other (please specify).

b) Percentage and total horsepower of stationary internal combustion engines of 150 horsepower or more (excluding compressor drivers) by manufacturer:

Engine Manufacturer	Waukesha	General Electric	Detroit Diesel	Caterpillar	Ajax	Other
% of engines						
Total Horsepower						

15. **Field Heater Treaters and Boilers/Steam Generators**

This question covers only units with a maximum rated heat input capacity of 10 million Btu/hour or more. Do not include glycol reboilers, which were covered in question 12 above. Do not include heaters or boilers located at gas plants.

Size and physical location of heater treaters and boilers/steam generators may affect whether they are covered by certain air regulations in the future. Two locations are of interest:

- Productionsite – a contiguous graded pad, gravel pad, foundation, platform, or other location upon which any combination of separator(s), pumps(s), storage tank(s), compressor(s), heater treater(s), and/or boiler(s) are physically affixed and comprises a field facility to process the produced fluids for sale and/or injection/discharge.
- Heater/Steam Generator/Boiler site – a contiguous graded pad, gravel pad, foundation, platform, or other location upon which heater treater(s) and/or boiler/steam generator(s) are physically affixed that is not located within a productionsite.

a) Total number of heater treaters and boilers/steam generators with maximum heat input capacity of 10 million Btu/hour or more operated in the field:
If zero, place a zero in the table and proc eed to question 16.

	Capacity ≥ 10 million Btu/hour	
	Heater Treaters	Boilers/Steam Generators
Number of units		

b) List the number of heater treaters and boiler/steam generators with capacity of ≥ 10 million Btu/hour, by size and location, using a separate line of the table for each size unit:

	Productionsites		Heater/Boiler Sites	
Unit Capacity	Heater Treaters	Boilers/Steam Gen.	Heater Treaters	Boilers/Steam Gen.

c) Fuel used for heater treaters and boilers/steam generators:

	Natural gas	Diesel	Propane	Other (please specify)	Total
Percentage of BTUs generated using					100%

d) Percentage of heater treaters and boilers/steam generators with emission controls by type:

Control	Heaters using control (%)	Boilers using control (%)
No controls installed		
SO_2 scrubber[1]		
Low NOx burner[2]		
Selective catalytic reduction (SCR)[3]		
Selective non-catalytic reduction (SNCR)[4]		
Flue gas recirculation[5]		
Other (please specify)		
Total	100%	100%

1 SO_2 scrubbers are generally "wet scrubbers" that bring the SO_2-laden flue gases into contact with a liquid that selectively reacts with the SO_2.

2 Low NOx burners generally incorporate the principles of delayed fuel-air mixing, oxygen-deficient zones for initial combustion, lower flame turbulence, and lower flame temperatures.

3 SCR involves the use of ammonia and catalysts at a temperature of around 700 ^oF to reduce NOx to H_20 and N_2.

4 SNCR involves the injection of ammonia at a temperature of around 1,750 ^oF, which reacts with NO to form H_20 and N_2.

5 Recycling a portion of the flue gases back into the combustion zone can reduce both the flame temperature and the oxygen concentration, thus lowering NOx emissions.

e) Based on currently installed control equipment, estimated control efficiency for variou s pollutants from heater treaters and boilers/steam generators:

Pollutant	SO_2	NO_x	CO	VOCs	PM-10
Heater control efficiency (%)					
Boiler control efficiency (%)					

16. Gas Sweetening Units

Gas sweetening units remove hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) from natural gas by a variety of processes, including amine, Sulfinol, caustics, and iron sponge. Do not include gas sweetening units located at gas plants in the field.

a) Total number of gas sweetening units you operate in this fiel d ______________________

17. Pneumatic Devices

a) Percentage of pneumatic devices for control valve operation by type:

	Instrument Air	Instrument Gas*	Other	Total
Percentage by type				100%

* Use of natural gas to control the valve.

18. **Landspreading/Land Treatment Operations**

Landspreading/land treatment operations dispose of solid wastes through application to the land or incorporation into the soil. This process uses the physical, chemical, and biological capabilities of the soil to absorb and decompose waste constituents. Nutrients and/or water may be added to enhance biodegradation. The waste/soil mixture may be tilled for aeration. These operations typically require a state permit. Include both single and multiple applicationsites, but do not include drilling sites where wastes are spread when the reserve pit is closed. Do not include roadspreading operations.

a) Do you perform on-site landspreading/land treatment for waste disposal in this field?

Yes ___________ No ___________

PRODUCED WATER MANAGEMENT

19. **Produced Water Management**

a) Disposition of produced water:

	1995 Produced water volume[1] (Bbls/day)
Injected for enhanced recovery	
Injected for disposal onsite	
Injected for disposal offsite[2]	
Injected for disposal at commercial facility	
Treated[3] and discharged[4]	
Beneficial use[5]	
Roadspreading[6]	
Other (please specify):	

1 Total produced water volume should equal total provided in question 6 for 1995.

2 Offsite disposal wells operated by your company or as part o f a co-op, partnership, or communal disposal operation, not commercial facilities.

3 Treated (if needed) to meet applicable discharge requirements.

4 Discharge may be to the land surface, or to a stream, lake, or other body of water as allowed by state or federal regulations.

5 Irrigation, livestock watering and other special uses allowable west of 98th meridian.

6 Spreading on roads for dust suppression or de-icing.

OTHER ASSOCIATED WASTES

Other associated wastes are wastes other than produced water and drilling wastes that are exempt from regulation as hazardous wastes under the Resource Conservation and Recovery Act. Of these, four waste streams are typically the largest by volume:

- *Completion fluids*. All fluids from initial completion activities including any acidizing or fracturing performed.
- *Workover and stimulation fluids*. All fluids from subsequent workover and stimulation activities.
- *Tank bottoms/oily sludges*. This includes basic sediment and water, produced sand, and other tank bottoms.
- *Dehydration/sweetening wastes*. This includes glycol-based compounds, glycol filters, molecular sieves, amines, amine filters, precipitated amine sludge, iron sponge, scrubber liquids and sludge, backwash, filter media and other wastes associated with the dehydration or sweetening of natural gas.

20. **Other Associated Waste Volume**

a) Volume of selected associated waste streams managed from operations in this field during 1995:

Waste stream	Units	Estimated volume
Completion fluids[1]	Barrels/Year	
Workover and stimulation fluids	Barrels/Year	
Tank bottoms/oily sludges[2]	Barrels/Year	
Dehydration/sweetening wastes	Barrels/Year	

[1] If your company does not differentiate completion activities from other workover and stimulation activities, please estimate based on the number of wells completed during 1995.

[2] If you did not clean out any tanks, and therefore manage any tank bottom wastes, during 1995, enter zero as the volume, even though tank bottoms did accumulate (which will be cleaned out and managed in a subsequent year).

21. **Other Associated Waste Disposal**

a) Disposal of other associated waste streams by method:

Please fill in the percentage of each waste stream disposed by each method listed at left. The percentages in each column should add to 100%.

	Tank bottoms/oily sludges	Completion fluids	Workover/ stimulation fluids	Dehydration/ sweetening wastes
Disposal by injection				
Landspreading within the field				
Landspreading outside the field[1]				
Roadspreading within the field				
Roadspreading outside the field[1]				
Commercial NOW[2] disposal				
Industrial or municipal landfill				
Crude oil reclamation				
Recycling/beneficial reuse				
Incinerated				
Evaporated from pits or tanks				
Other (specify):				
TOTAL	100%	100%	100%	100%

[1] Activities conducted directly by your company at another location, not through use of a commercial disposal location or contractor.

[2] Non-hazardous oilfield waste commercial disposal contractor.

DRILLING ACTIVITIES

If you did not perform any drilling in this field during 1995, check here _______ and return the completed survey to the address on the back page.

22. **New Wells Drilled**

a) Number and depth of new wells you drilled in field in 1995:

Wells drilled[1]	Zone 1[2]	Zone 2[2]	Zone 3[2]	Zone 4[2]
Number drilled for oil or gas[3,4]				
Number of these that are dual completions[4]				
Number drilled for injection or disposal				
Number drilled for source water				
Average well depth in zone[5]				

[1] Include all wells finished drilling in 1995, regardless of when they were spudded or completed.
[2] Since multiple pay zones may exist within the field, please use as many columns as needed to describe your drilling in this field. If a single pay zone, use only the first column. Source water wells and disposal wells would typically be from/to a separate zone from oil and gas production.
[3] Include all wells drilled for the purpose of finding oil or gas, including dry holes.
[4] Use 0.5 wells in each applicable zone to represent dual completions.
[5] For horizontal wells, consider measured hole depth.

b) Percentage of new wells drilled by technique:

	Mud Rotary Drilling		Cable Tool Drilling	Air, Gas, or Pneumatic Drilling	Total
	Reserve Pits	Closed System (Tanks)			
Percentage of new wells using					100%

c) Percentage of your reserve pits that were lined (clay or synthetic) ____________________ %

d) Percentage of drilling waste by base drilling fluid:

	Fresh-water base[1]	Salt-water base	Oil-base	Synthetic-base	Total
Percentage of waste					100%

[1] Mud made with fresh water would be classified as fresh water base even if the fluid later became "contaminated" with chlorides or other solids.

23. **<u>Drilling Waste Disposal</u>**

a) Disposal of drilling wastes by technique:

Drilling Waste Disposal Method	Percentage of Total Drilling Waste
LIQUID PORTION OF DRILLING WASTE	
Liquids extracted and disposed via injection (Class II well)	
Liquids extracted and disposed down well annulus between surface pipe and production casing	
Liquids extracted, treated, and discharged	
Liquids extracted and used for roadspreading	
Liquids evaporated from solids on-site or off-site	
Liquids removed from pit and landspread on-site	
Liquids removed from pit and landspread off-site [1]	
Liquids reused/recycled for drilling other wells	
Other (specify):	
SOLID PORTION OF DRILLING WASTE	
Backfilled/buried in reserve pit or trench following evaporation or extraction of liquids [4]	
Removed from pit and landspread on-site [4]	
Removed from pit and landspread off-site [1]	
Removed from pit and disposed at a commercial NOW [2] facility	
Removed from pit and disposed at industrial or municipal landfill	
Removed from pit and reused/recycled [3]	
Other (specify):	
TOTAL	100%

[1] Activities conducted by your company at another location, not use of a commercial disposal sit e.
[2] Nonhazardous oilfield waste commercial disposal contractor.
[3] Used for landfill cover, road bed construction, dike stabilization, or plugging and abandoning wells, etc.
[4] Includes practice of removing a section of pit wall, allowing pit contents to fl ow into a trench or onto the ground, then treating material like other burial or landspreading operations.

Thank you for your assistance with this important survey.

The information provided will help educate policy-makers about current practices within the oil and gas industry.

Please return the completed survey form to:

Amita Gopinath
Statistical Services Division
American Petroleum Institute
1220 L Street N.W.
Washington, DC 20005

For questions about completing the survey, please call (703) 934-3675 and leave a detailed message. Someone knowledgeable in the subject area of your question will return your call as soon as possible.

APPENDIX I

SURVEY FORM - API SURVEY OF NATURAL GAS PROCESSING PLANTS FOR 1995

Please respond by ____________

American
Petroleum
Institute

API SURVEY OF NATURAL GAS PROCESSING PLANTS FOR 1995

SURVEY FORM

Plant/Location ________________________________
______

***ALL SURVEY RESPONSES WILL BE HELD CONFIDENTIAL*.**
Only aggregated results from the survey will be made publicly available. For API internal use, company names and plant names will be replaced by codes to maintain confidentiality.

We hope that you will look at completing the survey not as an additional cost or inconvenience, but as an investment in the well-being of our industry.

Carl Giardini, Chairman
API General Committee on Exploration and Production

Estimated Time Required

Based on input from companies asked to review the survey form, we estimate that completion of the survey will require 2-4 hours for smaller plants. For larger plants, or larger companies, where coordination among more individuals may be required, the total time investment may be larger. We hope that you will find this burden sufficiently light to complete this vitally important survey.

Benefits to Completing the Survey

The primary benefit to you will be knowing that API and other industry organizations have an accurate characterization of industry operations that they can provide to regulators, legislators, and the general public to educate them about our industry. This will help to allow future requirements to be based on current conditions, and may result in compliance cost savings on future regulations that better reflect the real risks associated with industry activities.

In addition, the questions related to equipment that may produce air emissions are an attempt to avoid a mandatory data collection request from EPA that could be far more time-consuming than this survey.

Your response is crucial to our survey design (which has attempted to minimize the burden on companies). Given these benefits, and the importance of this effort, we hope that you will help and complete the survey form. It really is an investment in the well-being of our industry.

API SURVEY OF NATURAL GAS PROCESSING PLANTS FOR 1995

Plant/Location ____

Please complete this survey to cover operations at the natural gas processing plant listed above. Please provide data for **calendar year 1995**.

Instructions are enclosed that provide additional explanation about the completion of each question.

1. Operator/Company Name ____

2. Contact Person ______________________________ Phone # _______________

3. Number of months of 1995 you operated this plant: _______________

PLANT INFORMATION

4. Plant size, throughput data:

	Units	1995 Data
Processing Capacity	Million scf/day	
Gas Throughput	Million scf/day	
Total Liquids Recovered	Thousand gallons/day	
Total Sulfur Recovered	Metric tons/year	

5. Estimated distance from plant to nearest town or city with population of 2,500 or more

   __________________ miles

6. a) Is the plant currently subject to PSD (prevention of significant deterioration) requirements?

   Yes ________ No _________

   b) If so, which criteria pollutant(s) (SO_2, NOx, CO, VOCs, etc.) has caused plant to be subject to PSD requirements?

   ____

7. Percentage of gas processed at this plant by source (onshore fields/offshore fields):

   Onshore _____________ % Offshore ______________ %

PLANT EQUIPMENT/FACILITIES

8. **Pits**

Include all types of pits operated at the plant, except small collection sumps. Examples of pits include evaporation, blowdown, produced water, percolation, washout, skim, and emergency pits. If you use tanks rather than pits for emergency upsets, please report these tanks in question 9 below. Active pits are defined as those currently part of the operation, whether or not they currently contain fluids. Inactive pits are pits that are no longer part of the system but have not yet been closed.

a) Total number of pits you operate at this plant ______________________________
If zero, please place a zero in the blank above and proceed to question 9.

b) Number of pits that are: Active ____________ Inactive _______________

c) Number of *active* pits you operate at the plant that are lined __________________________

9. **Tanks**

Please include all tanks used for storage of produced water, condensate, or liquid products, and tanks used for emergency conditions. Do not include pressurized vessels. Include only tanks currently in service (part of plant operations, regardless of whether they currently contain fluids). Tanks used for emergency or upset conditions (e.g., blowdown tanks or tanks installed to replace a pit) should be reported as emergency tanks.

a) Number of tanks you operate at this plant by type:

	Produced Water	Condensate	Liquid Products	Emergency
Total number of tanks				

b) Percentage of condensate and product tanks that route vapors directly to a flare ______________ %

c) Percentage of condensate and product tanks with floating roofs ____________________________ %

d) Percentage of condensate and product tanks with a vapor recovery unit installed ______________ %

e) Of crude and product tanks with a vapor recovery unit, percentage by vapor destination:

	Percentage
Incineration (flare)	
Sales (as product)	
Return to process	
Other (specify)	
Total	100%

10. **Produced Water Disposal Wells**

a) Number of disposal wells operated by this plant ____________
If zero, place a zero in the table below and proceed to question 11.

b) Volume of water injected to these wells (barrels/day) _______________

11. **Gas Sweetening Units**

Gas sweetening units remove hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) from natural gas by a variety of processes, including amine, Sulfinol, caustics, and iron sponge.

a) Total number of gas sweetening units you operate in this plant ____________________

b) Total volume of gas sweetened (daily average) ____________________ Million scf/day

12. **Gas Dehydration Units**

a) Total number of gas dehydration units you operate at plant by dehydration method:
If zero, place a zero in the table below and proceed to question 13.

	Triethylene glycol (TEG)	Ethylene glycol (EG)	Diethylene glycol (DEG)	Dry bed desiccant or molecular sieve	Other
Number of dehydration units					
Gas volume dehydrated by method (million scf/d)					

Note: Remaining parts of this question address TEG and EG units only. If zero, proceed to question 13.
If zero TEG units, proceed to subpart h for questions on EG units.

Triethylene glycol (TEG) units

b) Number of triethylene glycol (TEG) dehydration units you operate at plant by size:

Number of TEG Units	Design Capacity and Actual Throughput Ranges			
	≤ 3 million scf/d	3.01–10 million scf/d	10.01–50 million scf/d	> 50 million scf/d
Number of units with Design Capacity in range				
Number of units with Actual Throughput[1] in range				

[1] Annual average operating throughput for year 1995.

c) Percentage of TEG dehydration units with both flash tanks (fuel economizers) and condensers

____________ %

d) Percentage of TEG dehydration units with a flash tank, but no condenser __________________ %

e) Percentage of TEG dehydration units with a condenser, but no flash tank __________________ %

f) Percentage of TEG units with a condenser which:

Incinerates the offgas in a unit burner _________________ %

Flares the offgas __________________ %

g) Percentage of TEG units that route emissions to a flare without prior condensation _____________%

Ethylene glycol (EG) units

h) Number of ethylene glycol (EG) dehydration units you operate at plant by size:

Number of EG Units	Design Capacity and Actual Throughput Ranges			
	≤ 10 million scf/d	10.01–100 million scf/d	100.01–500 million scf/d	> 500 million scf/d
Number of units with Design Capacity in range				
Number of units with Actual Throughput[1] in range				

[1] Annual average operating throughput for year 1995.

i) Percentage of EG dehydration units with condensers ________________________________%

j) For EG units with condensers, percentage by vapor destination:

	Percentage
Incineration (flare)	
Return to process	
Use as fuel	
Vented to atmosphere	
Other (please specify)	
Total	100%

Both triethylene glycol (TEG) and ethylene glycol (EG) units

k) Heat or fuel source for glycol reboiler, both TEG and EG units (percentage by source):

	Waste heat	Steam	Hot Oil	Natural gas	Propane	Other (specify)	Total
TEG units % by fuel							100%
EG units % by fuel							100%

l) Size of firebox for glycol reboilers (TEG and EG units - number):

Firebox capacity	Number of TEG units	Number of EG units
< 10 Million Btu/hour		
10-25 Million Btu/hour		
>25 Million Btu/hour		

m) Are emission controls installed on the glycol reboiler firebox? Yes _________ No ________

13. **Gas Compressor Drivers**

Gas compressors driven by engines or turbines compress the gas for processing or to prepare it for pipeline transportation. Include only those engines 150 Hp or larger (continuous design-rated) operated by you. Include any electric-powered motors that are used to drive compressors. Do <u>not</u> include any compressors that are part of pipeline/transmission operations or field operations.

Size and physical location of field compressor drivers may affect whether they are covered by certain air regulations in the future. Two locations are of interest:

- <u>Plant site</u> – one or more compressors physically located within the plant.
- <u>Compressor site</u> – one or more compressors located on a single pad or platform, <u>*operated and maintained by the plant*</u>, but located away from the plant site.

a) Total number of gas compressor drivers (engines and turbines) larger than 150 continuous design-rated Hp operated by the plant (both plant and compressor sites). If zero, place a zero in the blank and proceed to question 14.

____________________ compressor drivers

b) Percentage and total horsepower of compressor drivers (engines and turbines) 150 Hp or larger by engine manufacturer:

Engine Manufacturer	Waukesha	Cooper-Bessemer	Clark	Ingersoll Rand	Ajax	Other
% of compressor drivers						
Total horsepower						

c) Number, type, and fuel source for compressor drivers (engines) at <u>plant sites</u>:

Horsepower (continuous design-rating)	Engine Type	Number of engines/motors				
		Electric powered motors	Rich[1] burn engines	% rich burn w/ catalytic controls[2]	Lean[3] burn engines	Clean[4] burn engines
150-300 Hp	2-Stroke					
	4-Stroke					
301-500 Hp	2-Stroke					
	4-Stroke					
501-750 Hp	2-Stroke					
	4-Stroke					
751-1,000 Hp	2-Stroke					
	4-Stroke					
>1,000 Hp	2-Stroke					
	4-Stroke					
Fuel Source[5]		electric				

[1] Rich burn engines produce less than 4% oxygen in their exhaust. The manufacturer's original recommended operating air-fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1. <u>Most 4-stroke engines installed prior to 1982 are rich burn engines</u>.

[2] Include the percentage of your rich burn engines that have had catalytic controls installed.

[3] A lean burn engine produces greater than 4% oxygen in its exhaust. <u>All 2-stroke engines are lean burn</u>, along with some 4-stroke engines.

[4] Clean burn engines are engines (typically 4-stroke) that have had the cylinder heads, combustion chamber, or other parts modified so that the engine is a low NOx emitter without catalytic controls.

[5] Natural gas, diesel, gasoline, propane, or other (please specify).

d) Number of compressor sites with *one* compressor ____________________ sites

e) Number of compressor sites with *more than one* compressor _________________________ sites

f) Number, type, and fuel source for compressor drivers (engines) at compressor sites:

Horsepower (continuous design-rating)	Engine Type	Number of engines/motors				
		Electric powered motors	Rich[1] burn engines	% rich burn w/ catalytic controls[2]	Lean[3] burn engines	Clean[4] burn engines
150-300 Hp	2-Stroke					
	4-Stroke					
301-500 Hp	2-Stroke					
	4-Stroke					
501-750 Hp	2-Stroke					
	4-Stroke					
751-1,000 Hp	2-Stroke					
	4-Stroke					
>1,000 Hp	2-Stroke					
	4-Stroke					
Fuel Source[5]		electric				
For footnotes, see table above.						

g) Number, size, location, and fuel source of turbines to drive compressors:

Turbine Size	Location	
	Plant Site	Compressor Site
< 1,000 Hp		
1,000-5,000 Hp		
5,001-15,000 Hp		
15,001-25,000 Hp		
> 25,000 Hp		
Fuel Source [1]		
[1] Natural gas, diesel, gasoline, propane, or other (please specify).		

h) Estimated average BTU content of natural gas used for fuel ______________ BTU/scf

14. **Internal Combustion Engines and Turbines**

Please include all types of stationary internal combustion engines and turbines, including drivers for pumps, generators, and other equipment not included in question 13 above. Do not include engines on mobile sources (trucks, etc.)

a) Number of stationary internal combustion engines of 150 horsepower or larger (excluding compressor drivers) you operate in this plant by size:

Horsepower (continuous design-rating)	Engine Type	Number of engines			
		Rich[1] burn engines	% rich burn w/ catalytic controls[2]	Lean[3] burn engines	Clean[4] burn engines
150-300 Hp	2-Stroke				
	4-Stroke				
301-500 Hp	2-Stroke				
	4-Stroke				
501-750 Hp	2-Stroke				
	4-Stroke				
751-1,000 Hp	2-Stroke				
	4-Stroke				
>1,000 Hp	2-Stroke				
	4-Stroke				
Fuel Source[5]					

[1] Rich burn engines produce less than 4% oxygen in their exhaust. The manufacturer's original recommended operating air-fuel ratio divided by the stoichiometric air/fuel ratio is less than or equal to 1.1. Most 4-stroke engines installed prior to 1982 are rich burn engines.

[2] Include the percentage of your rich burn engines that have had catalytic controls installed.

[3] A lean burn engine produces greater than 4% oxygen in its exhaust. All 2-stroke engines are lean burn, along with some 4-stroke engines.

[4] Clean burn engines are engines (typically 4-stroke) that have had the cylinder heads, combustion chamber, or other parts modified so that the engine is a low NOx emitter without catalytic controls.

[5] Natural gas, diesel, gasoline, propane, or other (please specify).

b) Percentage and total horsepower of engines and turbines (excluding compressor drivers) 150 Hp or larger by engine manufacturer:

Engine Manufacturer	Waukesha	Cooper-Bessemer	Clark	Ingersoll Rand	Ajax	Other
% of compressor drivers						
Total horsepower						

c) Number, size, and fuel source of turbines (excluding compressor drivers):

Turbine Size	Number of Turbines
< 1,000 Hp	
1,000-5,000 Hp	
5,001-15,000 Hp	
15,001-25,000 Hp	
> 25,000 Hp	
Fuel Source[1]	
[1] Natural gas, diesel, gasoline, propane, or other (please specify).	

15. **Heaters and Boilers**

a) Total number of heaters with maximum rated heat input capacity of 10 million Btu/hour or more operated at the plant:
If zero, place a zero in the table and proceed to question 15b.

Heater capacity	Number of Heaters
10-25 million Btu/hour	
26-50 million Btu/hour	
51-75 million Btu/hour	
76-100 million Btu/hour	
> 100 million Btu/hour	

b) Total number of boilers (other than glycol reboilers) with maximum rated heat input capacit y of 10 million Btu/hour or more operated at the plant:
If zero, place a zero in the table and proceed to question 16.

Boiler capacity	Number of Boilers
10-50 million Btu/hour	
51-100 million Btu/hour	
101-150 million Btu/hour	
> 150 million Btu/hour	

c) Fuel used for heaters and boilers:

	Natural gas	Diesel	Propane	Other (please specify)	Total
Percentage of BTUs generated using					100%

d) Percentage of heaters and boilers with controls:

Control	Heaters using control (%)	Boilers using control (%)
No controls installed		
SO_2 scrubber[1]		
Low NOx burner[2]		
Selective catalytic reduction (SCR)[3]		
Selective non-catalytic reduction (SNCR)[4]		
Flue gas recirculation[5]		
Other (please specify)*		
Total	100%	100%

[1] SO_2 scrubbers are generally "wet scrubbers" that bring the SO_2-laden flue gases into contact with a liquid that selectively reacts with the SO_2.

[2] Low NOx burners generally incorporate the principles of delayed fuel-air mixing, oxygen-deficient zones for initial combustion, lower flame turbulence, and lower flame temperatures.

[3] SCR involves the use of ammonia and catalysts at a temperature of around 700 °F to reduce NOx to H_20 and N_2.

[4] SNCR involves the injection of ammonia at a temperature of around 1,750 °F, which reacts with NO to form H_20 and N_2.

[5] Recycling a portion of the flue gases back into the combustion zone can reduce both the flame temperature and the oxygen concentration, thus lowering NOx emissions.

e) Based on currently installed control equipment, estimated control efficiency for various pollutants from heaters and boilers:

Pollutant	SO_2	NO_x	CO	VOCs	PM-10
Heater control efficiency (%)					
Boiler control efficiency (%)					

16. **Pneumatic Devices**

a) Percentage of pneumatic devices for control valve operation by type:

	Instrument Air	Instrument Gas*	Other	Total
Percentage by type				100%
* Use of natural gas to control the valve.				

17. **Emissions Inventory**

If one is readily available, please enclose a copy of the emissions inventory for this plant.

This information will be treated as confidential. Availability of emission inventories may provide additional data/insights to assist in response to future rulemakings, since they provide more data than it is feasible to request as part of this survey.

WASTE VOLUMES AND MANAGEMENT

18. **Produced Water**

a) Volume of produced water removed from processed gas streams: ________ Barrels/day

b) Disposition of produced water removed:

	1995 produced water volume (Bbls/day)
Injected for disposal onsite	
Injected for disposal offsite[1]	
Injected for disposal at commercial facility	
Treated[2] and discharged[3]	
Beneficial use[4]	
Roadspreading[5]	
Other (please specify):	

1 Offsite disposal wells operated by your company or as part of a co-op, partnership, or communal disposal operation, not commercial facilities.
2 Treated (if needed) to meet applicable discharge requirements.
3 Discharge may be to the land surface, or to a stream, lake, or other body of water as allowed by state or federal regulations.
4 Irrigation, livestock watering and other special uses allowable west of 98th meridian.
5 Spreading on roads for dust suppression or de-icing.

19. **Dehydration/Sweetening Wastes**

Dehydration and sweetening wastes are typically exempt from regulation as hazardous wastes under the Resource Conservation and Recovery Act. Exempted wastes include: glycol-based compounds, glycol filters, molecular sieves, amines, amine filters, precipitated amine sludge, iron sponge, scrubber liquids and sludge, backwash, filter media, and other wastes associated with the dehydration or sweetening of natural gas.

a) Volume of selected dehydration/sweetening waste streams managed during 1995:

Waste stream[1]	Units	Estimated volume
Spent glycol/glycol compounds	Barrels/Year	
Used filters/filter media	Pounds/Year	
Scrubber liquids and sludge	Barrels/Year	
All other dehydration/sweetening wastes	Barrels/Year	

[1] Please provide a breakdown where possible. If separate estimates for each waste stream are not feasible, please provide estimated total waste volume in the category for "all other dehydration/ sweetening wastes," and write "included below" in the column for volume of the other waste streams.

20. **Dehydration/Sweetening Waste Disposal**

a) Disposal of dehydration/sweetening waste streams by method:

Please fill in the percentage of each waste stream disposed by each method listed at left. The percentages in each column should add to 100%.

	Spent glycol/ glycol compounds	Used filters/filter media	Scrubber liquids and sludge	All other dehydration/ sweetening wastes
Disposal by injection				
Landspreading onsite				
Roadspreading onsite				
Commercial NOW[1] disposal				
Industrial or municipal landfill				
Recycling/beneficial reuse				
Incinerated				
Evaporated from pits or tanks				
Other (specify):				
TOTAL	100%	100%	100%	100%

[1] Non-hazardous oilfield waste commercial disposal contractor.

Thank you for your assistance with this important survey.

The information provided will help educate policy-makers about current practices within the oil and gas industry.

Please return the completed survey form to:

Amita Gopinath
Statistical Services Division
American Petroleum Institute
1220 L Street N.W.
Washington, DC 20005

Please include a copy of your emissions inventory for this plant, if available.

For questions about completing the survey, please call (703) 934-3675 and leave a detailed message. Someone knowledgeable in the subject area of your question will return your call as soon as possible.