NTIS # PB 80-225279

United States
Environmental Protection
Agency

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

EPA-600/2-80-075c
April 1980

Research and Development

EPA

Assessment of Atmospheric Emissions from Petroleum Refining:

Volume 3. Appendix B

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by

R.G. Wetherold, L.P. Provost, and C.D. Smith

Radian Corporation
P.O. Box 9948
Austin, Texas 78766

Contract No. 68-02-2147, Exhibit B
Program Element No. 1AB604

EPA Project Officer: Bruce A. Tichenor

Industrial Environmental Research Laboratory
Office of Environmental Engineering and Technology
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Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
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EPA 600/2-80-075c, "Assessment of Atmospheric Emissions from Petroleum
Refining: Volume 3. Appendix B"

Errata

Page 130	Change fourth value in column one of Table B2-16 from 1400 to 9400.
Page 306	Change upper limit of the next to the last confidence interval in the last column from 0.000261 to 0.00036.
Page 321	Change "Worst Case Estimate" for Purge Method from 0.0003 to 0.0004.

APPENDIX B: DETAILED RESULTS

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SECTION 1

INTRODUCTION

This appendix contains a detailed summary of the results obtained while measuring emissions to the atmosphere at 13 petroleum refineries. These refineries were located throughout the continental United States. The emissions sampling program was performed for the U.S. Environmental Protection Agency under Contracts 68-02-2665 and 68-02-2147, Exhibit B.

The data and results of the sampling program are displayed in tables and figures. The results have been explained and discussed in the main body of the report. For that reason, discussions have been minimized in this appendix.

Section 2 of this appendix contains the results obtained during the screening and sampling of baggable emission sources in refineries. These sources include valves, flanges, pump seals, compressor seals, drains, and relief valves. Emission factors, screening relationships, and correlations are presented.

The results of measuring hydrocarbon emissions from non-baggable sources such as cooling towers and units of the wastewater treating system are given in Section 3.

Several stacks were sampled in refineries. These included sulfur recovery unit stacks, process heater stacks, and flue gas stacks of the fluid catalytic cracking regenerator system. The data are tabulated in Section 4.

Individual species were identified in several samples of representative liquid streams and gaseous emissions. The results are presented in Section 5.

The effect of valve maintenance operations on the leak rate from valves was studied. The results are contained in Section 6 of this appendix.

Refiners were surveyed to obtain qualitative information concerning atmospheric emissions which might be caused by refinery operations such as sampling, maintenance, turnarounds, and blending. This information is summarized in Section 7.

SECTION 2

FUGITIVE HYDROCARBON EMISSIONS FROM BAGGABLE SOURCES

The data obtained during the screening and sampling of baggable sources (valves, flanges, pump seals, compressor seals, drains, and relief valves) are presented and analyzed in this section. The emissions sources were most conveniently grouped for analyses into twelve categories of source types and process stream classifications.

Section 2.1 contains a summary of the leak rate data. The results of the screening program are presented in Section 2.2. Included in this section are distributions of the total leak rate as a function of the screening value ranges.

The relationships between leak rates and screening values as functions of source types and process stream groups are presented in Section 2.3. Also included in this section are nomographs which relate screening values to predicted leak rates of the various source types.

Section 2.4 includes the distributions of emissions and sources as a function of screening values. The leak rates of the various source types were correlated with process variables. These results are presented in Section 2.5.

The emission factors for the six baggable source types are given in Section 2.6. Finally, the number and distribution of baggable emission sources in various refinery process units are presented and discussed in Section 2.7.

Information on the correlating variables presented in Section 2 could not be obtained, in some cases, for all sources. Therefore, the total number of each source type may differ slightly from one tabulation to the next.

2.1 LEAK RATE DATA

The baggables emission data have been grouped into the 12 categories in Table B2-1 for presentation and emission factor development.

Table B2-2 gives the distribution (by order-of-magnitude categories) of the leak rates for each of the above categories. The leak rates for sources screened but not included in these tabulations are assumed to be negligible. The leak rate data include all sampled emission rates as well as additional rates estimated from screening measurements. (This estimation of leak rates is discussed in Appendix C, Section 6.1.) Figures B2-1 through B2-12 give the frequency histograms for the leak rates for each of the twelve categories.

It is obvious from these tables and figures that the bulk of emissions emanate from a small percentage of the fittings. For example, 93 percent of the total measured leakage for valves in gas/vapor streams is attributable to 4.4 percent of the screened sources. Eighty-nine percent of the leakage from flanges comes from less than 1 percent of the screened flanges, while 95 percent of the emissions from pump seals in light liquid streams comes from 20 percent of the screened seals.

TABLE B2-1. CATEGORIES OF BAGGABLE SOURCES

Category	Source Description	Number of Sources Screened
1	Valves, Gas/Vapor Streams	563
2	Valves, Light Liquid/Two-Phase Streams	913
3	Valves, Heavy Liquid Streams	485
4	Valves, Predominantly Hydrogen Streams	135
5	Open-ended Valves (all streams)	129
6	Pump Seals, Light Liquid Streams	470
7	Pump Seals, Heavy Liquid Streams	292
8	Compressor Seals, Hydrocarbon Service	142
9	Compressor Seals, Hydrogen Service	83
10	Flanges (all streams)	2094
11	Drains (all streams)	257
12	Relief Valves (venting to atmosphere)	148

TABLE B2-2. DISTRIBUTION OF NONMETHANE LEAK RATES FROM SAMPLED SOURCES

	Leaking Sources Within Range			Total Leakage Within Range	
Leak Range (lb/hr)	No.	% of Leaking Sources	% of Total Sources Screened	Total Leakage (lb/hr)	% of Total Source of Leakage
		Valves, Gas/Vapor Streams = 563 Screened			
>1.0	7	4.6	1.2	17.7654	70.0
0.1 - 1.0	18	11.7	3.2	5.9187	23.3
0.01 - .1	43	27.9	7.6	1.4867	5.9
0.001 - 0.01	49	31.8	8.7	0.2052	0.8
0.00001 - 0.001	37	24.0	6.6	0.0133	0.1
	154	100%	20.3%	25.3893	100%
		Valves, Light Liquid/Two-Phase Streams = 913 Screened			
>1.0	1	0.3	0.1	2.2297	14.4
0.1 - 1.0	31	9.4	3.4	9.3351	60.3
0.01 - .1	105	31.8	11.5	3.3877	21.9
0.001 - 0.01	121	36.7	13.3	0.5028	3.2
0.00001 - 0.001	72	21.8	7.8	0.0266	0.2
	330	100%	36.1%	15.4819	100%
		Valves, Heavy Liquid Streams = 485 Screened			
>1.0	0	0.0	0.0	0.0	0.0
0.1 - 1.0	0	0.0	0.0	0.0	0.0
0.01 - .1	5	15.6	1.0	0.1773	74.1
0.001 - 0.01	13	40.6	2.7	0.0569	23.8
0.00001 - 0.001	14	43.8	2.9	0.0051	2.1
	32	100%	6.6%	0.2393	100%

Continued

TABLE B2-2. Continued

Leak Range (lb/hr)	Leaking Sources Within Range No.	% of Leaking Sources	% of Total Sources Screened	Total Leakage Within Range Total Leakage (lb/hr)	% of Total Source of Leakage
Valves, Predominantly Hydrogen Streams = 135 Screened					
>1.0	0	0.0	0.0	0.0	0.0
0.1 - 1.0	3	5.1	2.2	0.3789	34.2
0.01 - .1	19	32.2	14.1	0.6691	60.5
0.001 - 0.01	18	30.5	13.3	0.0532	4.8
0.00001 - 0.001	19	32.2	14.1	0.0059	0.5
	59	100%	43.7%	1.1071	100%
Open-Ended Valves, All Streams = 129 Screened					
>1.0	0	0.0	0.0	0.0	0.0
0.1 - 1.0	1	3.3	0.8	0.1242	23.3
0.01 - .1	9	30.0	7.0	0.3475	65.3
0.001 - 0.01	12	40.0	9.3	0.0576	10.8
0.00001 - 0.001	8	26.7	6.2	0.0033	0.6
	30	100%	23.3%	0.5326	100%
Flanges = 2094 Screened					
>1.0	0	0.0	0.0	0.0	0.0
0.1 - 1.0	4	6.4	0.19	0.8655	63.2
0.01 - .1	12	19.4	0.57	0.4117	30.1
0.001 - 0.01	28	45.2	1.33	0.0820	6.0
0.00001 - 0.001	18	29.0	0.86	0.0096	0.7
	62	100%	2.95%	1.3688	100%

Continued

TABLE B6-1. Continued

Process Stream Classifications

Liquid Streams

Stream	Stream Description
BCAX	C_1 - C_2 Hydrocarbons
BCBX	C_3 - C_4 Hydrocarbons
BCCX	C_5 - C_6 Hydrocarbons
BCDX	C_7 - C_9 Hydrocarbons
BCEX	Naphtha
BCFX	Kerosene/Diesel/Heating Oil
BCGX	Gas Oil
BCHX	Atmospheric Bottoms/Vacuum Gas Oil
BCIX	Vacuum Residual/Asphalt
BCJA	Low Molecular Weight Aromatics
BCJB	Polynuclear Aromatics
BDAX	Streams Containing >50% H_2O
BDBX	Streams Made up of Mixed Molecular Weight Components
BDCA	Hydrochloric Acid
BDCB	Methyl Ethyl Ketone
BDCC	Sulfolane
BDCD	Monoethanolamine
BDCE	Sulfuric Acid
CAAX	Two-Phase Stream containing methane gas and light liquid hydrocarbons
CBAB	Two-Phase Stream Containing >50% Hydrogen

TABLE B2-2. Continued

	Leaking Sources Within Range			Total Leakage Within Range	
Leak Range (lb/hr)	No.	% of Leaking Sources	% of Total Sources Screened	Total Leakage (lb/hr)	% of Total Source of Leakage
		Relief Valves = 148 Screened			
>1.0	5	8.6	3.4	15.5383	76.0
0.1 - 1.0	15	25.9	10.1	3.9313	19.2
0.01 - .1	22	37.9	14.7	0.9121	4.5
0.001 - 0.01	12	20.7	8.1	0.0580	0.3
0.00001 - 0.001	4	6.9	2.7	0.0022	0.0
	58	100%	39.0 %	20.4419	100%
		Compressor Seals, Hydrocarbon Service = 142 Screened			
>1.0	23	21.9	16.2	67.9440	74.3
0.1 - 1.0	48	45.7	33.8	22.2482	24.3
0.01 - .1	24	22.9	16.9	1.3014	1.4
0.001 - 0.01	7	6.6	4.9	0.0224	0.0
0.00001 - 0.001	3	2.9	2.1	0.0013	0.0
	105	100%	73.9 %	91.5172	100%
		Compressor Seals, Hydrogen Service = 83 Screened			
>1.0	0	0.0	0.0	0.0	0.0
0.1 - 1.0	14	20.3	16.9	3.3954	75.6
0.01 - .1	22	31.9	26.5	1.0105	22.5
0.001 - 0.01	21	30.4	25.3	0.0794	1.8
0.00001 - 0.001	12	17.4	14.5	0.0064	0.1
	69	100%	83.2	4.4917	100%

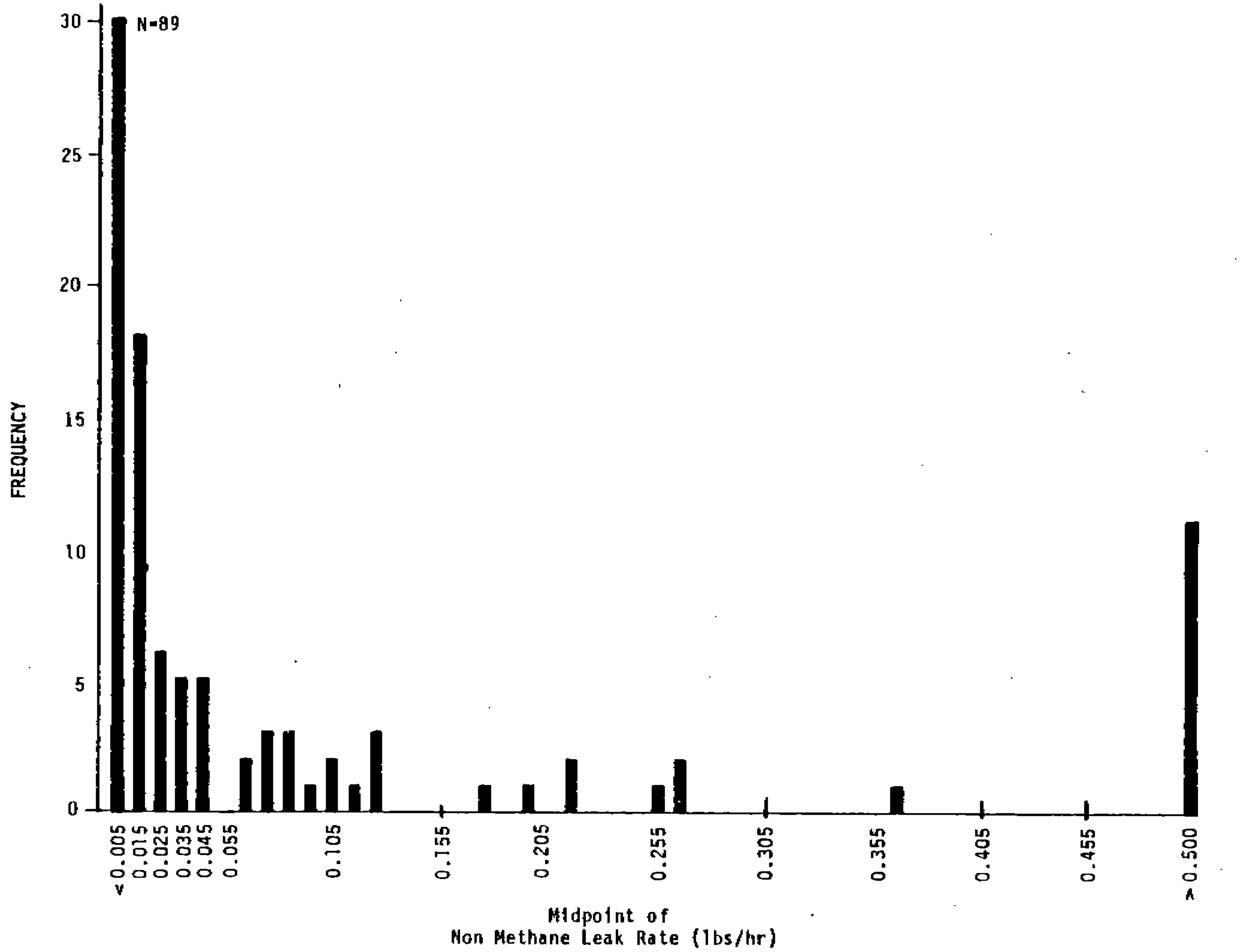


Figure B2-1. Distribution of leak rates for valves - gas/vapor streams.

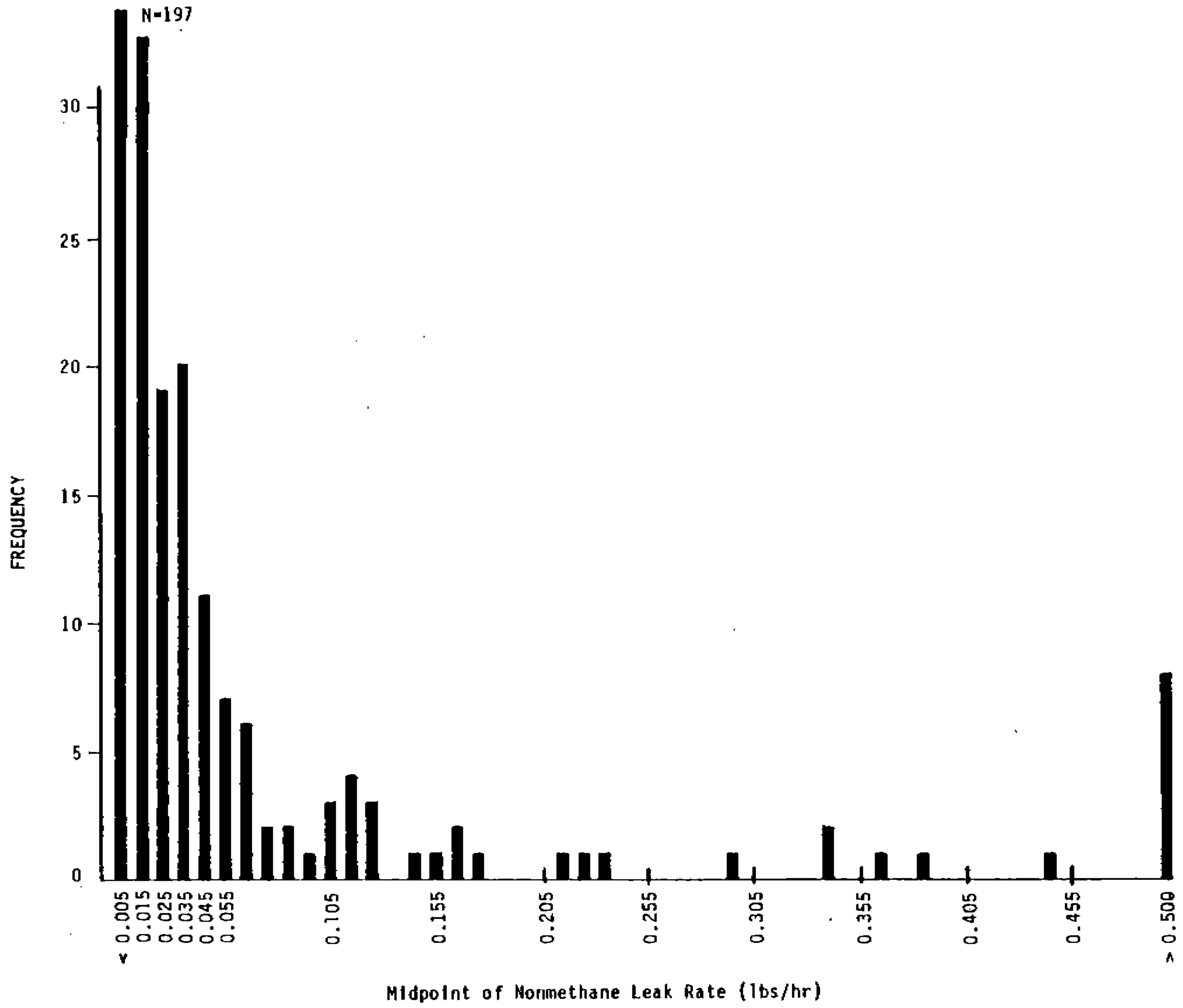


Figure B2-2. Distribution of leak rates for valves - light liquid/two-phase streams.

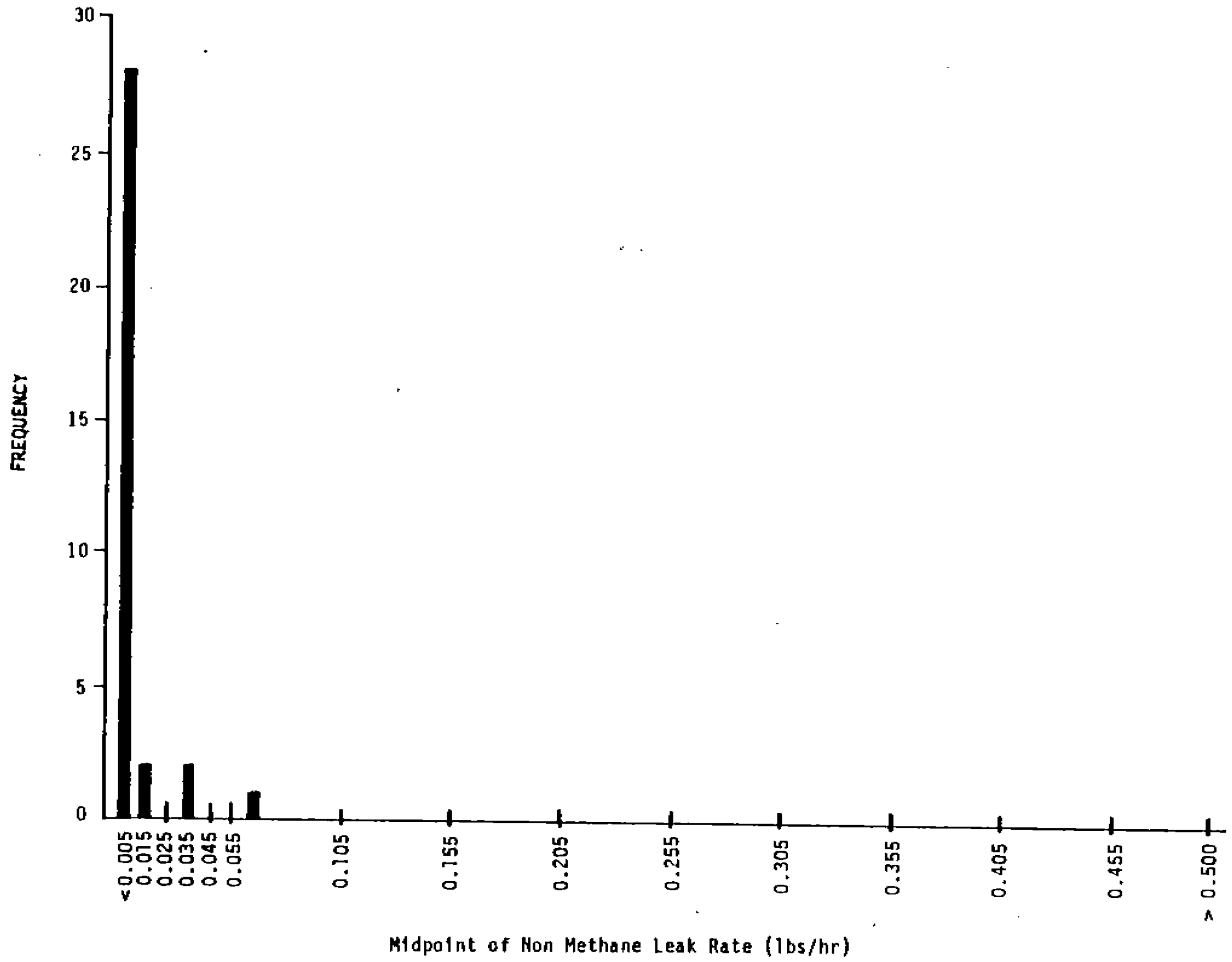


Figure B2-3. Distribution of leak rates for valves - heavy liquid streams.

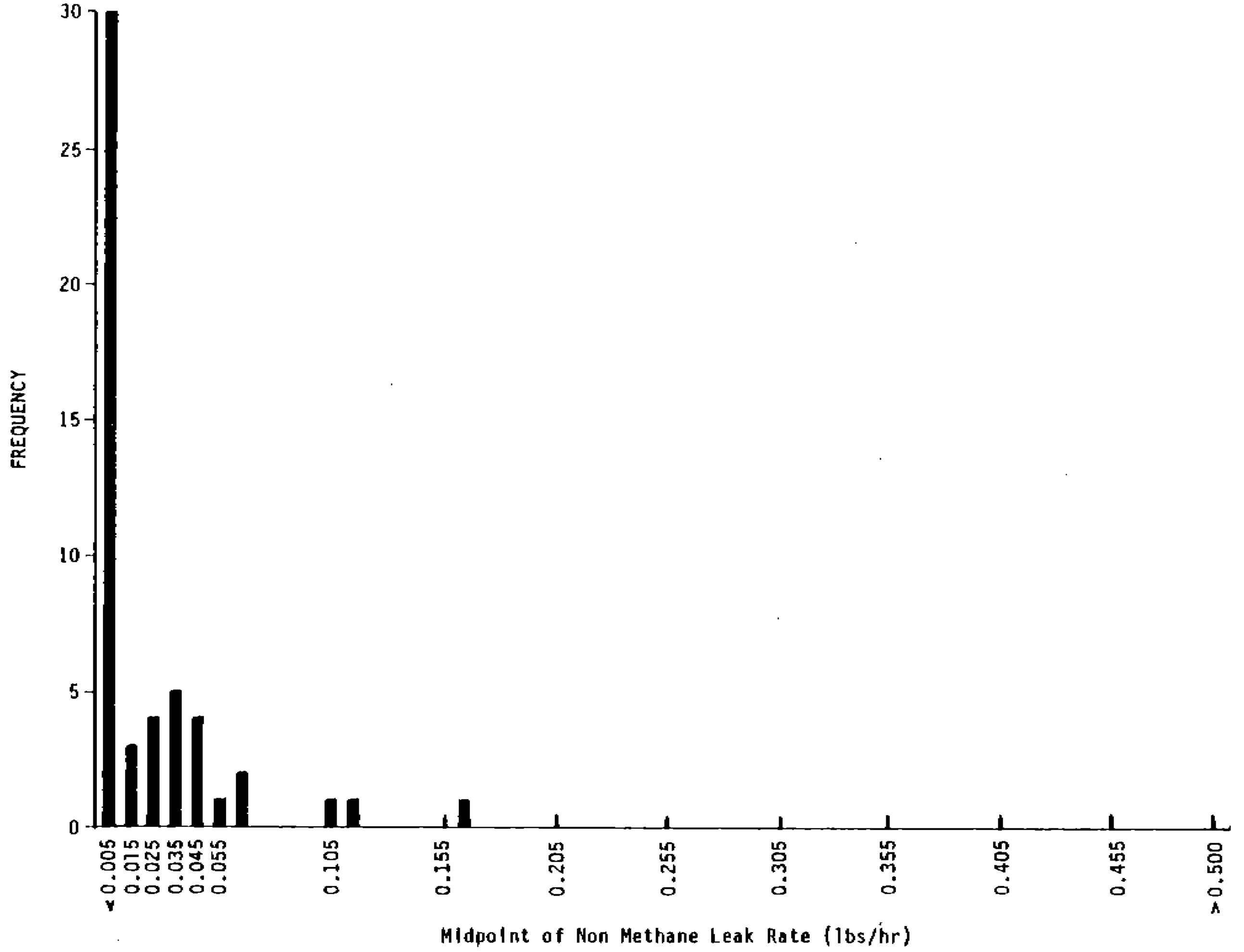


Figure B2-4. Distribution of leak rates for valves - hydrogen service.

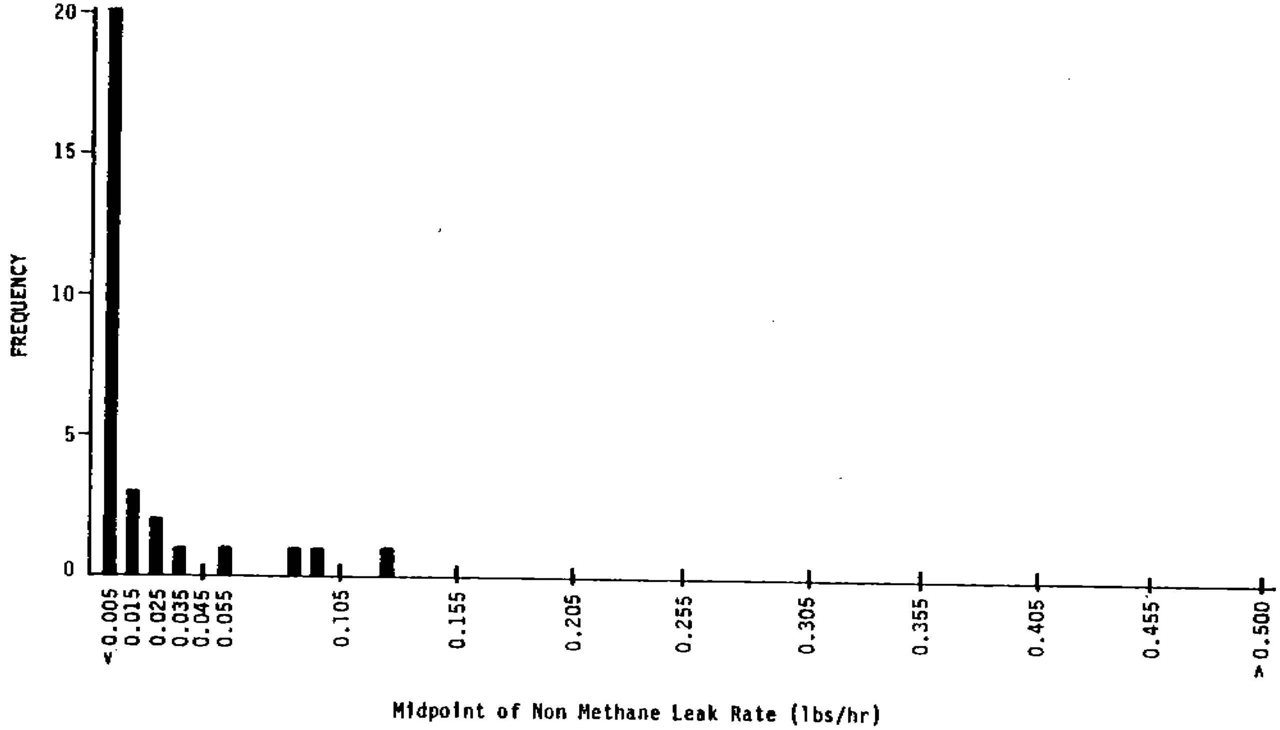


Figure B2-5. Distribution of leak rates for open-ended valves.

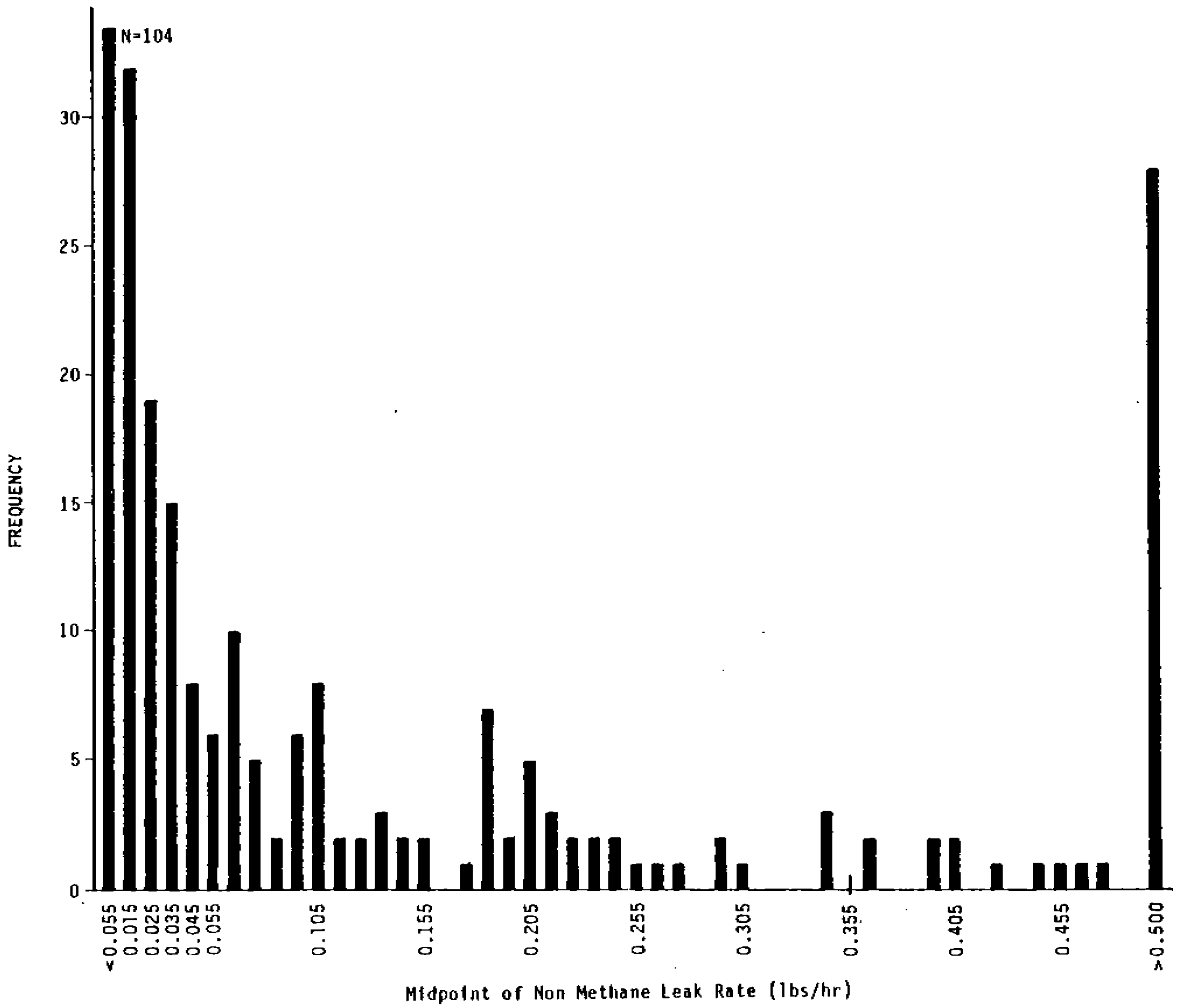


Figure B2-6. Distribution of leak rates for pumps - light liquid streams.

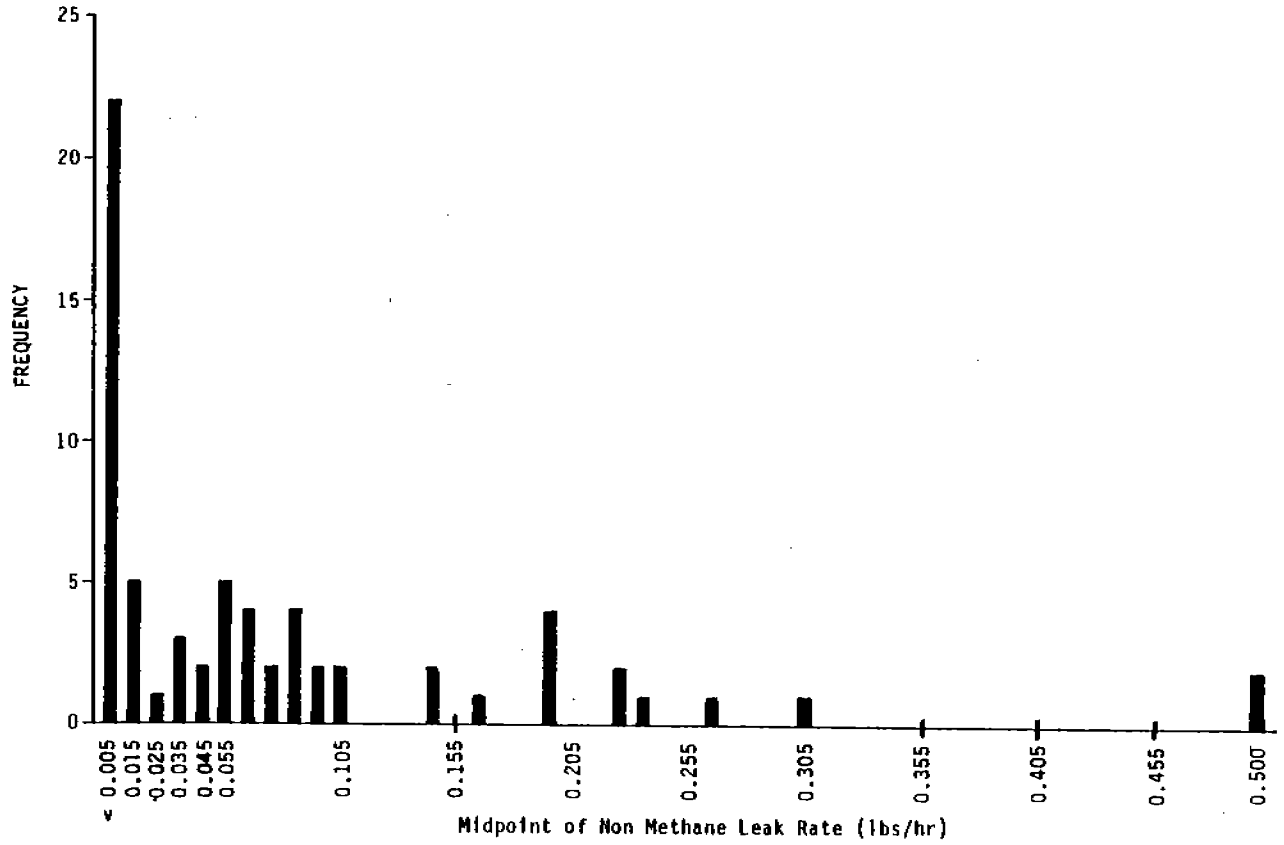


Figure B2-7. Distribution of leak rates for pumps - heavy liquid streams.

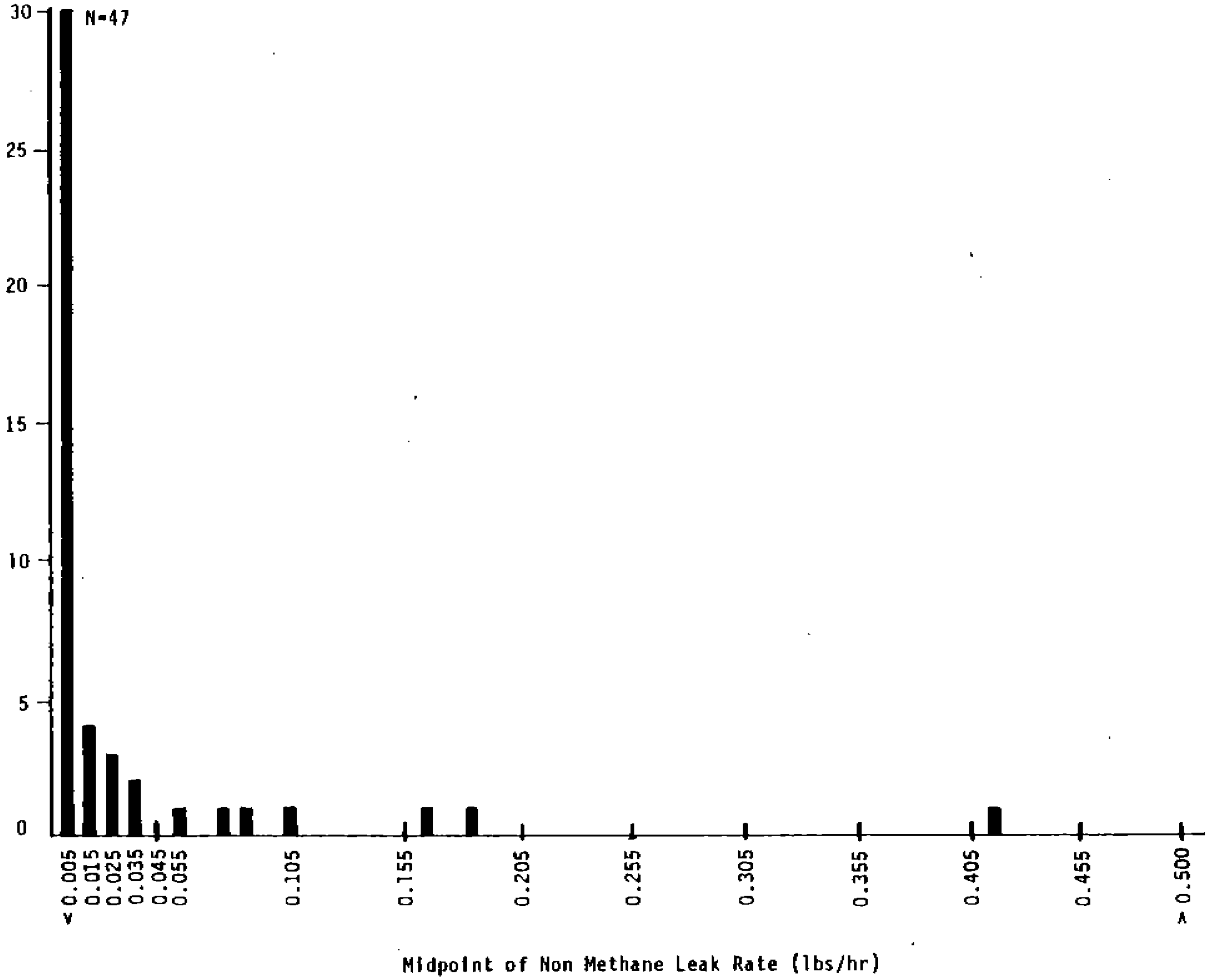


Figure B2-8. Distribution of leak rates for flanges.

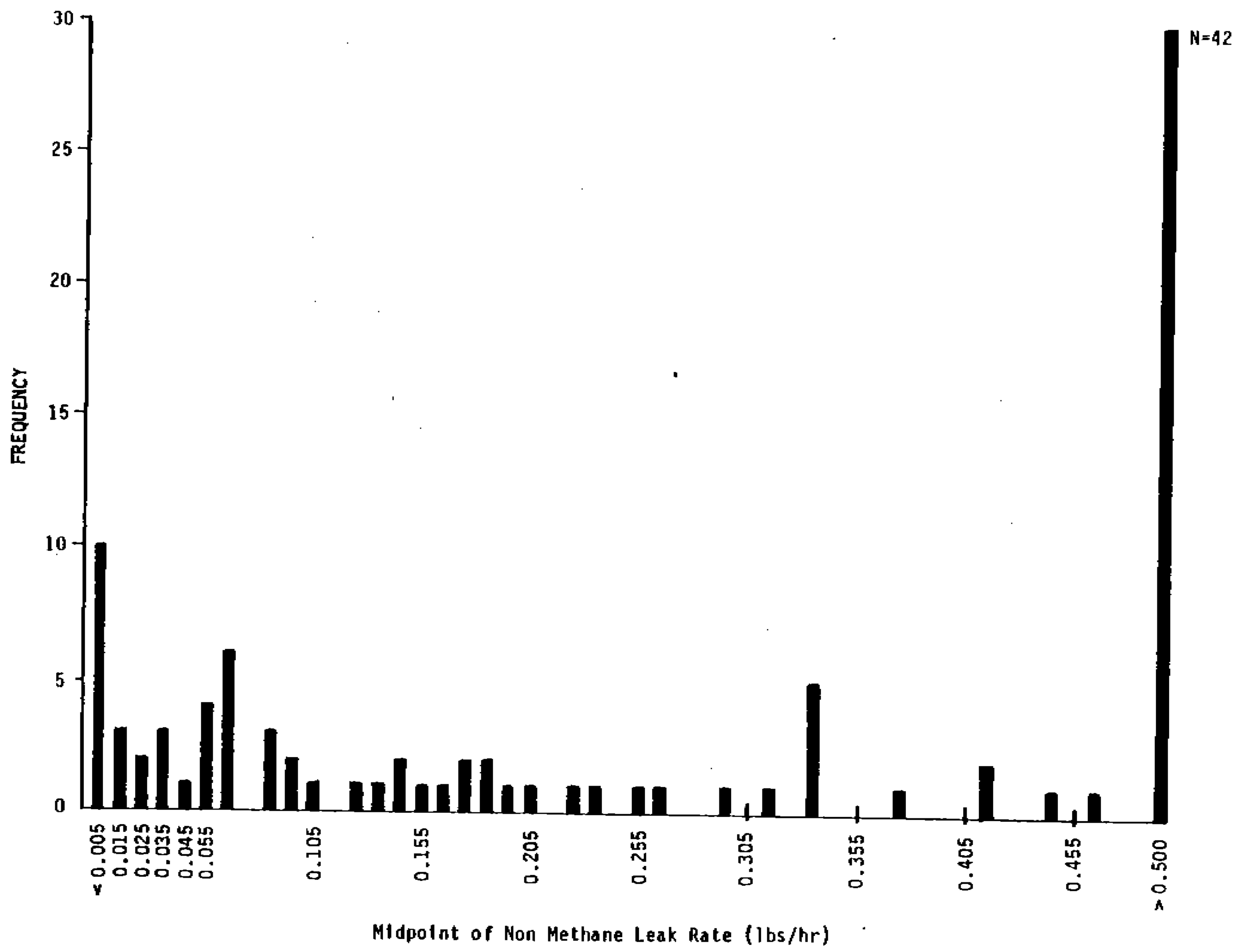


Figure B2-9. Distribution of leak rates for compressors - hydrocarbon streams.

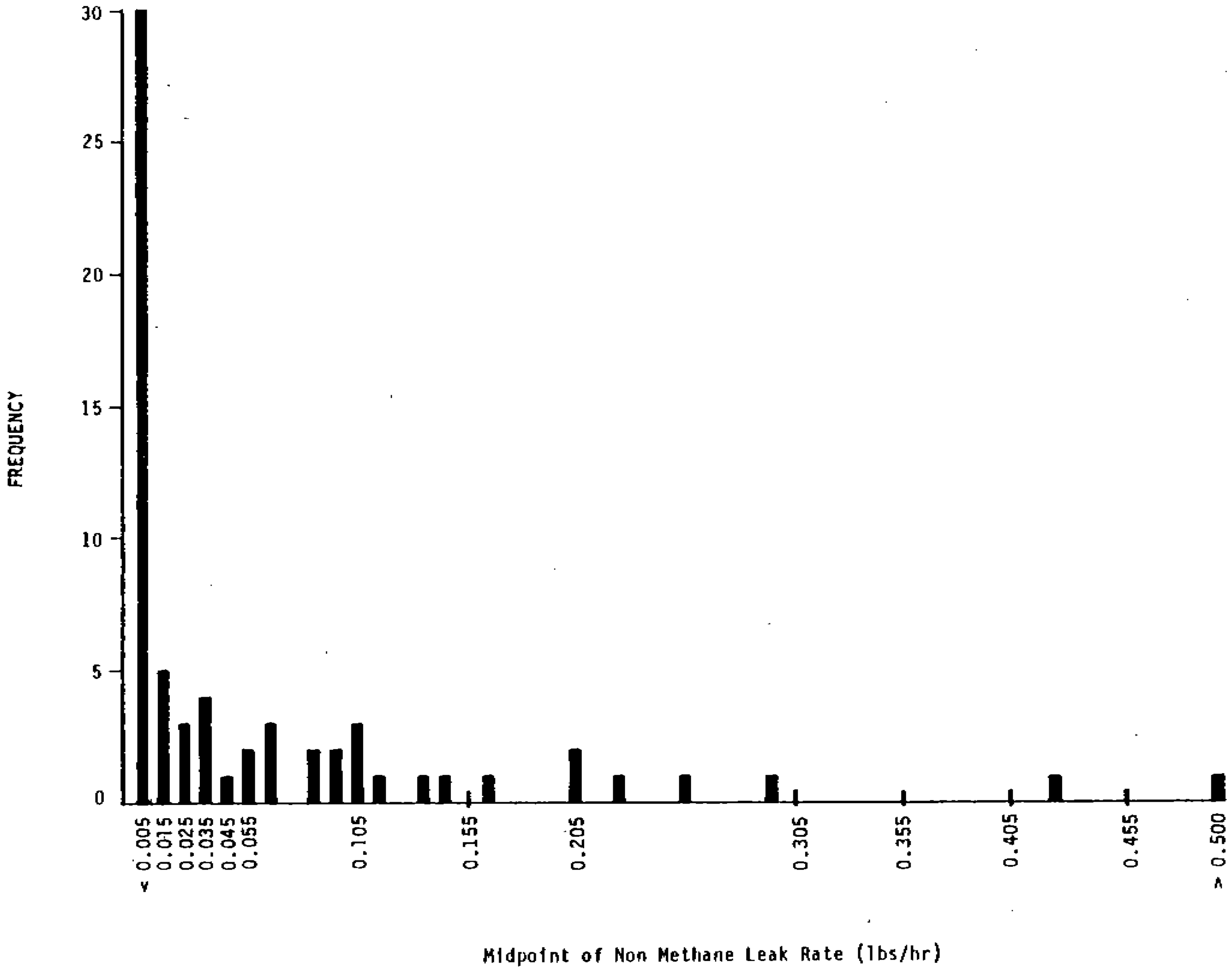


Figure B2-10. Distribution of leak rates for compressors - hydrogen service.

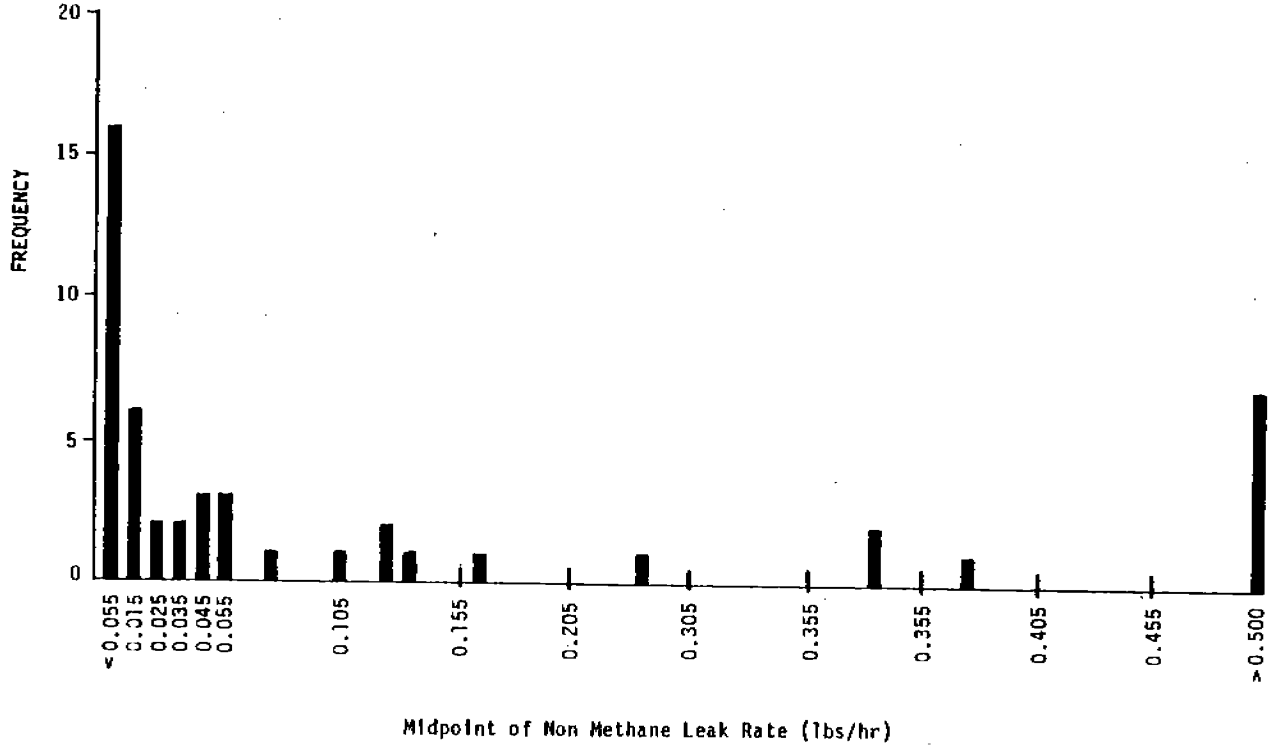


Figure B2-11. Distribution of leak rates for drains.

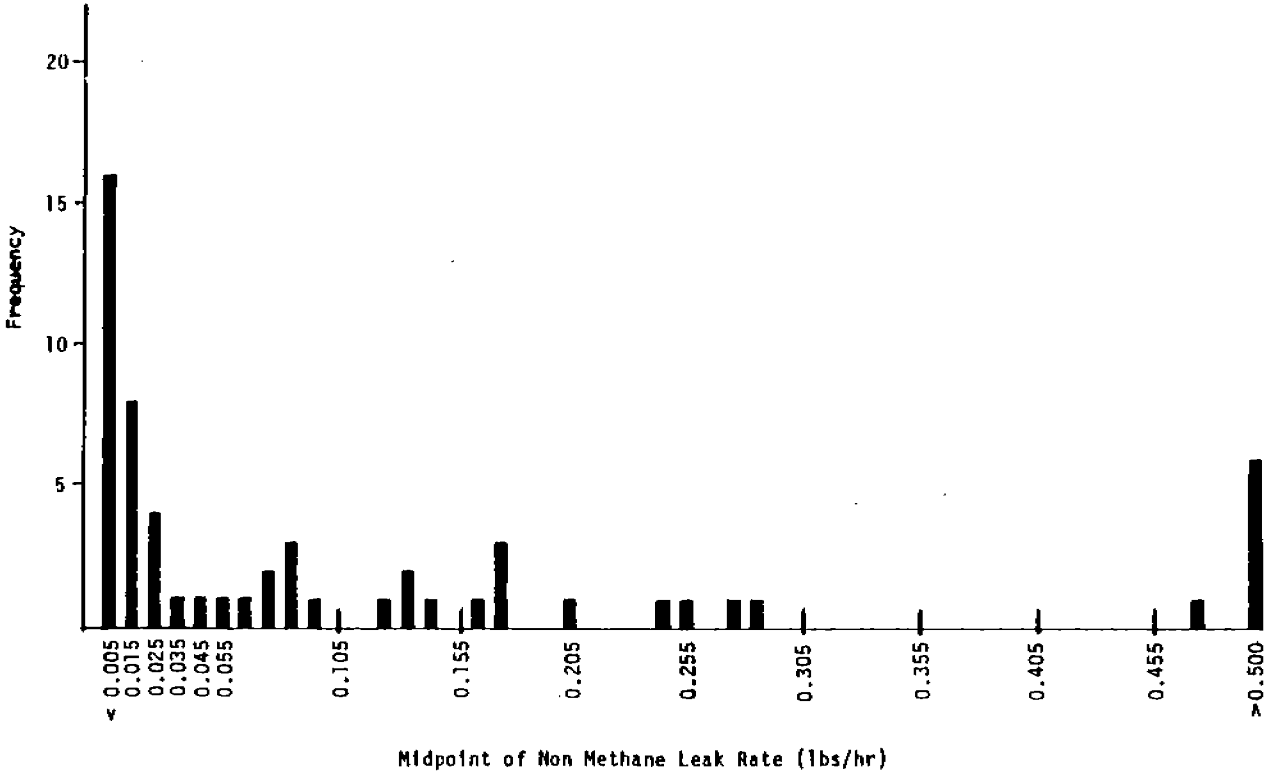


Figure B2-12. Distribution of leak rates for relief valves.

This highly skewed distribution of leak rates, which spans more than five orders of magnitude, has many implications concerning the measurement and control of fugitive emissions from these sources.

2.2 SCREENING DATA

The screening of sources during this program was accomplished with sensitive portable hydrocarbon detectors. The principal device used in this study was the J.W. Bacharach Instrument Co. "TLV Sniffer". The Century Instrument Co. Organic Vapor Analyzer (Model OVA-108) was used for some screening, but these readings were not included in the correlations which follow. The instruments were calibrated with standard mixtures of hexane in air. The OVA-108 and TLV Sniffer give direct readings of hydrocarbon concentrations in ppm by volume. In this report, the terms "screening values" and "TLV screening values" refer to the maximum hydrocarbon concentration detected at selected baggable sources.

Section 2.3 of this report discusses the relationship between leak rates and screening values for the various source types. Table B2-3 shows the distribution of screening values grouped into five screening value ranges. The distribution of the total leak rate (both measured and estimated) as a function of the screening value ranges is also given.

As can be seen from the table, a large percentage of the total leakage can be attributed to the small percentage of sources with screening values greater than 10,000 ppmv. For example, those 13 percent of the valves in gas/vapor streams with

TABLE B2-3. DISTRIBUTION OF MAXIMUM SCREENING VALUES AMONG SCREENED SOURCES

Screening range (ppmv)	Screened Sourced Within Range Number	Percent	Number Sampled or Estimated	Total Leakage (lbs/hr)	Percent of Total Leakage
Valves - Gas/Vapor Streams					
Missing[a]	1	0.2	0	-	-
0	277	49.3	1	0.0011	0.0
1 - 200	134	23.8	5	0.0007	0.0
201 - 1000	33	5.8	31	0.0689	0.3
1001 - 10000	47	8.3	46	3.9395	15.5
>10000	71	12.6	71	21.3791	84.2
	563	100%	154	25.3893	100%
Valves - Light Liquid/Two-Phase Streams					
Missing[a]	1	0.1	0	-	-
0	385	42.2	4	0.0053	0.0
1 - 200	211	23.1	13	0.0086	0.1
201 - 1000	70	7.7	68	0.1312	0.8
1001 - 10000	142	15.5	141	5.7437	37.1
>10000	104	11.4	104	9.5931	62.0
	913	100%	330	15.4819	100%
Valves - Heavy Liquid Streams					
0	335	69.1	2	0.0045	1.9
1 - 200	121	25.0	2	0.0466	19.5
201 - 1000	21	4.3	20	0.0748	31.3
1001 - 10000	7	1.4	7	0.1133	47.3
>10000	1	0.2	1	0.0001	0.0
	485	100%	32	0.2392	100%
Valves - Hydrogen Service					
0	47	34.8	1	0.00015	0.0
1 - 200	30	22.2	1	0.00076	0.1
201 - 1000	8	5.9	7	0.00694	0.6
1001 - 10000	22	16.3	22	0.13455	12.2
>10000	28	20.8	28	0.96477	87.1
	135	100%	59	1.10717	100%

Continued

TABLE B2-3. Continued

Screening range (ppmv)	Screened Sourced Within Range Number	Screened Sourced Within Range Percent	Number Sampled or Estimated	Total Leakage (lbs/hr)	Percent of Total Leakage
Valves - Open-ended (All Streams)					
0	74	57.4	0	-	-
1 - 200	26	20.2	1	0.0013	0.2
201 - 1000	7	5.4	7	0.0220	4.1
1001 - 10000	12	9.3	12	0.2985	56.1
>10000	10	7.7	10	0.2108	39.6
	129	100%	30	0.5326	100%
Flanges (All Streams)					
Missing[a]	64	3.1	-	-	-
0	1748	83.5	2	0.0050	0.4
1 - 200	225	10.7	4	0.0338	2.5
201 - 1000	29	1.4	29	0.1265	9.2
1001 - 10000	17	0.8	17	0.1818	13.3
>10000	11	0.5	10	1.0216	74.6
	2094	100%	62	1.3687	100%
Pumps Seals - Light Liquid Streams					
0	67	14.3	0	-	-
1 - 200	107	22.8	7	0.0375	0.0
201 - 1000	79	16.8	75	3.0242	3.4
1001 - 10000	104	22.1	104	8.2424	9.2
>10000	113	24.0	110	78.2010	87.4
	470	100%	296	89.5051	100%
Pump Seals - Heavy Liquid Streams					
0	114	39.0	0	-	-
1 - 200	115	39.4	4	0.0020	0.0
201 - 1000	24	8.2	23	0.6123	10.4
1001 - 10000	28	9.6	28	3.5191	59.7
>10000	11	3.8	11	1.7660	29.9
	292	100%	66	5.8995	100%

Continued

TABLE B2-3. Continued

Screening range (ppmv)	Screened Sourced Within Range Number	Screened Sourced Within Range Percent	Number Sampled or Estimated	Total Leakage (lbs/hr)	Percent of Total Leakage
Compressor Seals - Hydrocarbon Service					
Missing[a]	16	11.3	16	20.5337	-
0	23	16.2	0	-	-
1 - 200	7	4.9	0	-	-
201 - 1000	11	7.7	7	2.7960	3.9
1001 - 10000	13	9.2	10	15.1347	21.3
>10000	72	50.7	72	53.0528	74.8
	142	100%	105	91.5172	100%
Compressor Seals - Hydrogen Service					
Missing[a]	9	10.9	9	1.1626	-
0	8	9.6	1	0.0042	0.1
1 - 200	8	9.6	2	0.1066	3.1
201 - 1000	8	9.6	8	0.0187	0.5
1001 - 10000	17	20.5	17	1.2701	38.4
>10000	33	39.8	32	1.9296	57.9
	83	100%	69	4.4918	100%
Drains (All Streams)					
Missing[a]	2	0.8	0	-	-
0	138	53.7	1	0.1076	0.9
1 - 200	73	28.4	4	0.0098	0.1
201 - 1000	18	7.0	18	0.6436	5.3
1001 - 10000	14	5.4	14	2.6864	22.4
>10000	12	4.7	12	8.5681	71.3
	257	100%	49	12.0154	100%
Relief Valves (All Streams)					
Missing	8	5.4	0	-	-
0	61	41.2	0	-	-
1 - 200	33	22.3	11	0.2326	1.1
201 - 1000	11	7.4	11	0.5705	2.8
1001 - 10000	23	15.5	23	4.9156	24.1
>10000	12	8.1	12	14.7180	72.0
	148	100%	57	20.4369	100%

[a] Missing TLV value - Screening data are not available. Emissions from sampled sources with missing TLV data have been included in the total leakage column totals. These emissions, however, have been omitted from the total for calculating the percent of total leakage for each screening range.

screening values greater than 10,000 ppmv contributed 84 percent of the total emissions. Seventy-five percent of the measured emissions from flanges was attributable to the one-half percent of flanges with screening values greater than 10,000.

Histograms displaying the distribution of screening values for the various sources can be seen in Figures B2-13 through B2-24. The large spike at 10,000 ppmv for most graphs is due to the limited range of the screening device prior to obtaining dilution probes.

As described in Appendix C, a quality control plan was implemented to identify sources of variation in screening methods. At most refineries, one or more sources were screened once a day by at least one screening team for several days. Figures B2-25 through B2-27 show the screening results from the three "best case" sources screened. TLV Sniffer measurements generally stayed within one order of magnitude, and no distinct pattern is apparent in the data. More typical results from the daily screenings can be seen in Figures B2-28 through B2-31. The range of the screening values may be as great as 3 orders of magnitude. Reasons for these variations in the daily screening values could not be determined from the data obtained during this program. However, factors which might possibly affect the screening value include changing of the valve position by plant personnel, the continuous stem movement associated with control valves, and changes in process conditions such as temperature, pressure, or fluid type inside the valve. In addition, external factors such as wind velocity and direction may also affect the screening values to some degree.

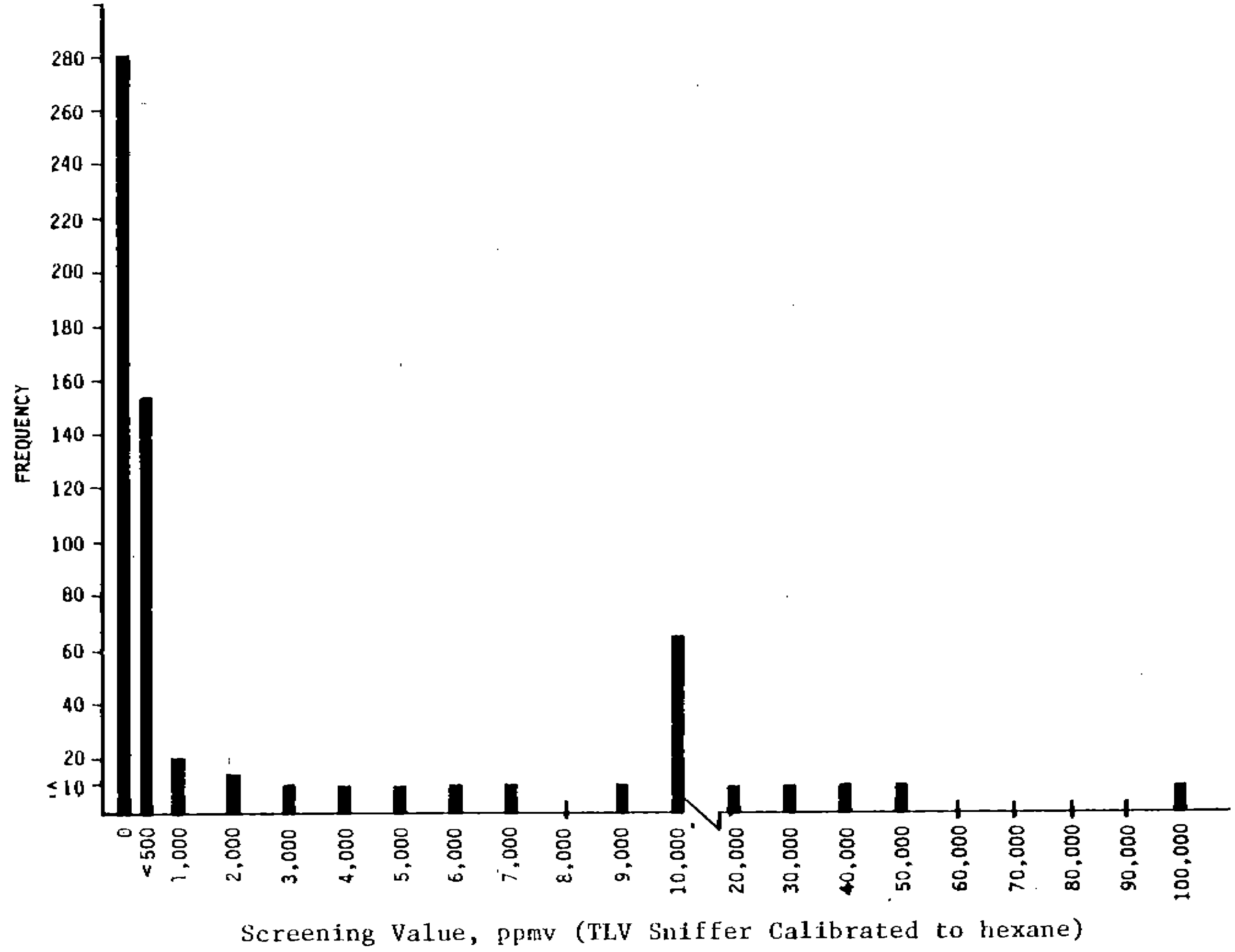


Figure B2-13. Distribution of screening values for valves - gas/vapor streams.

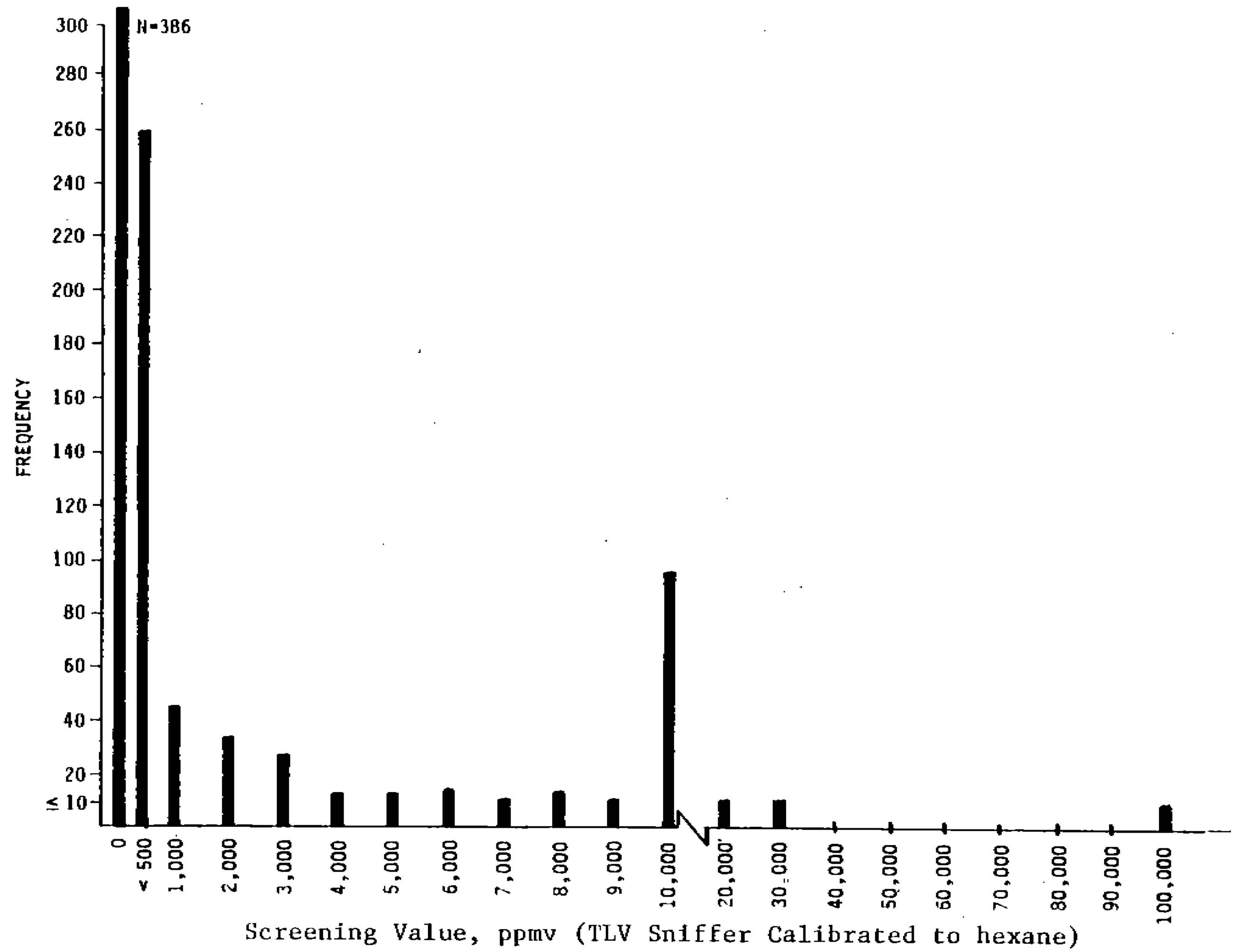


Figure B2-14. Distribution of screening values for valves - light liquid streams.

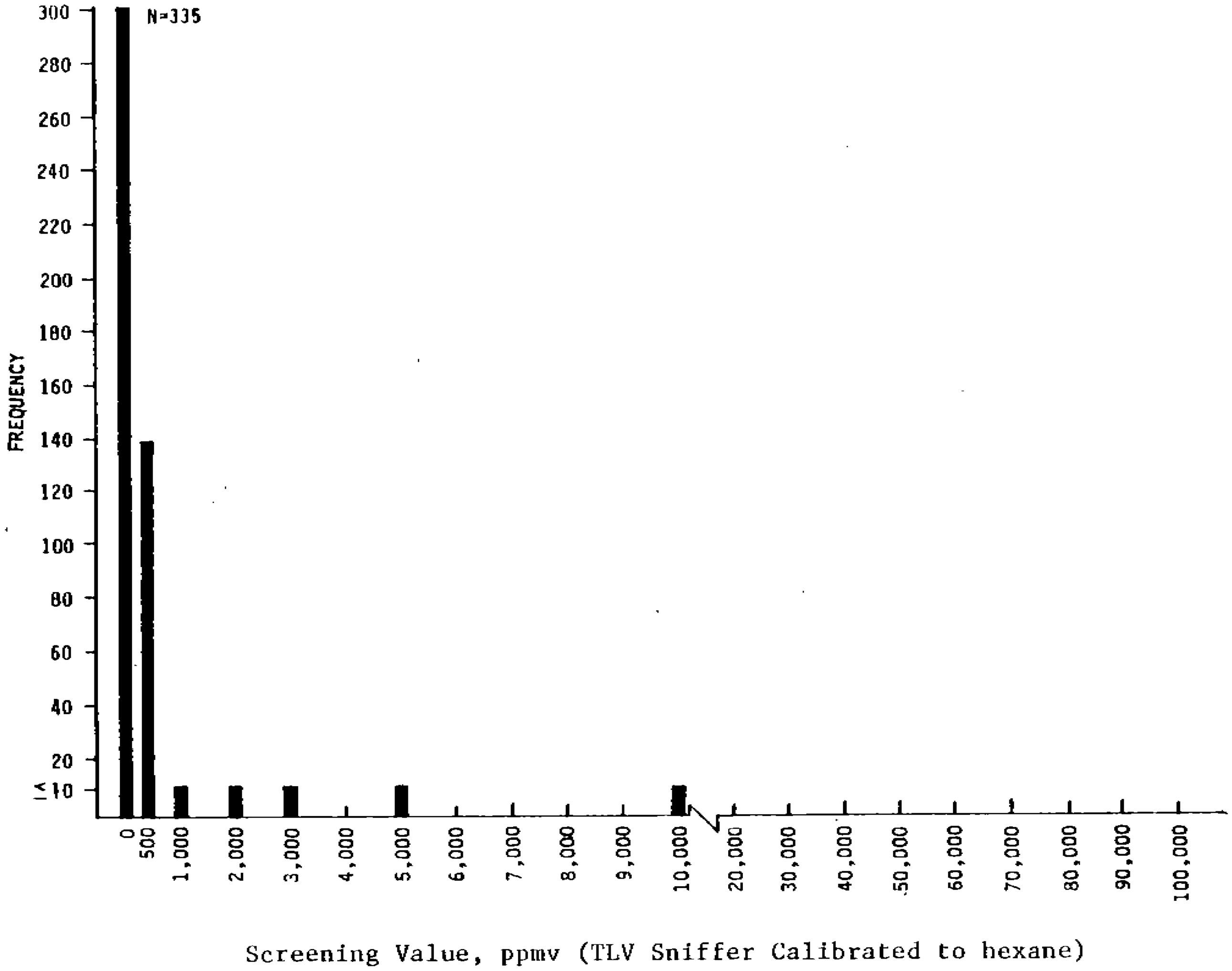


Figure B2-15. Distribution of screening values for valves - heavy liquid streams.

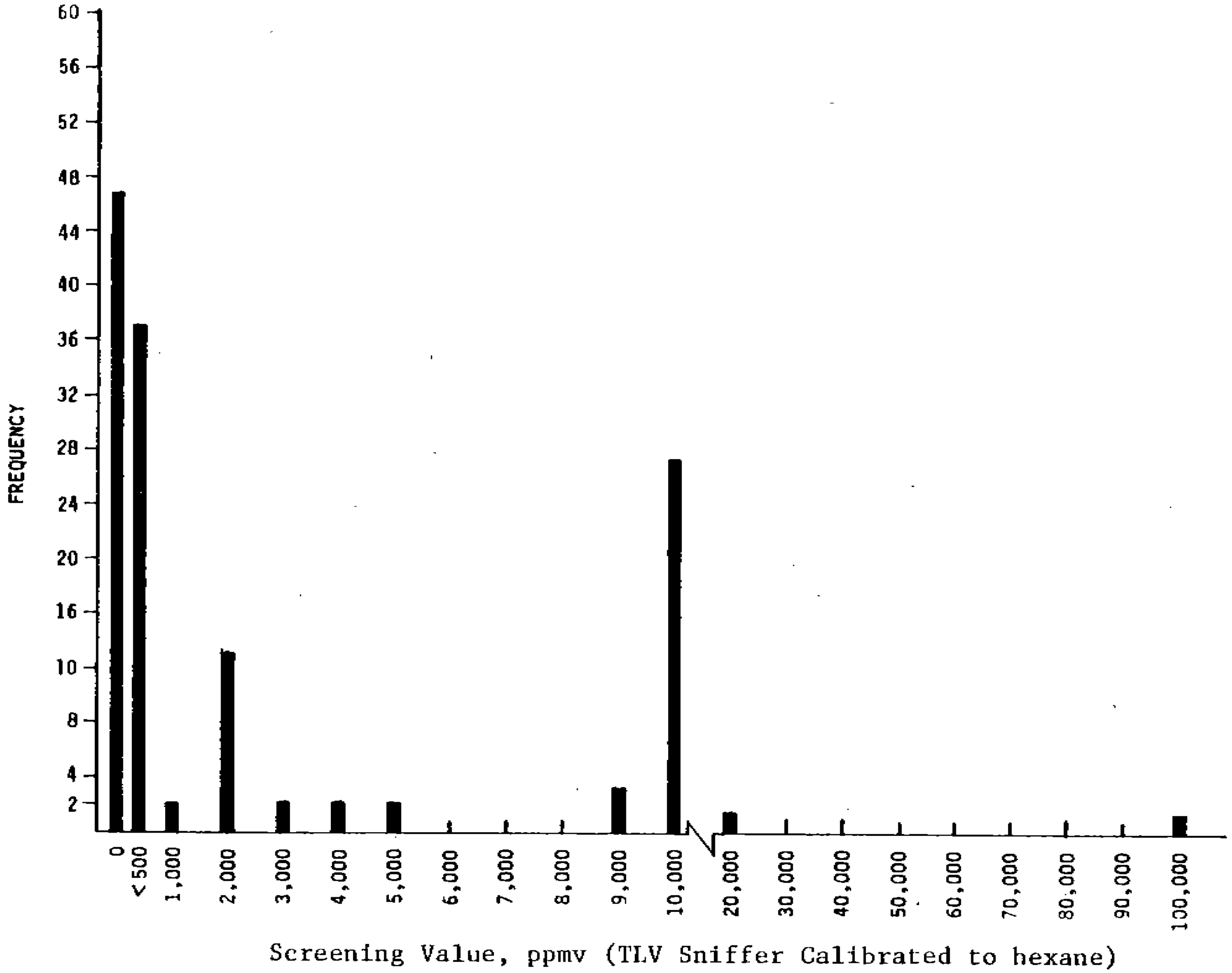


Figure B2-16. Distribution of screening values for valves - hydrogen streams.

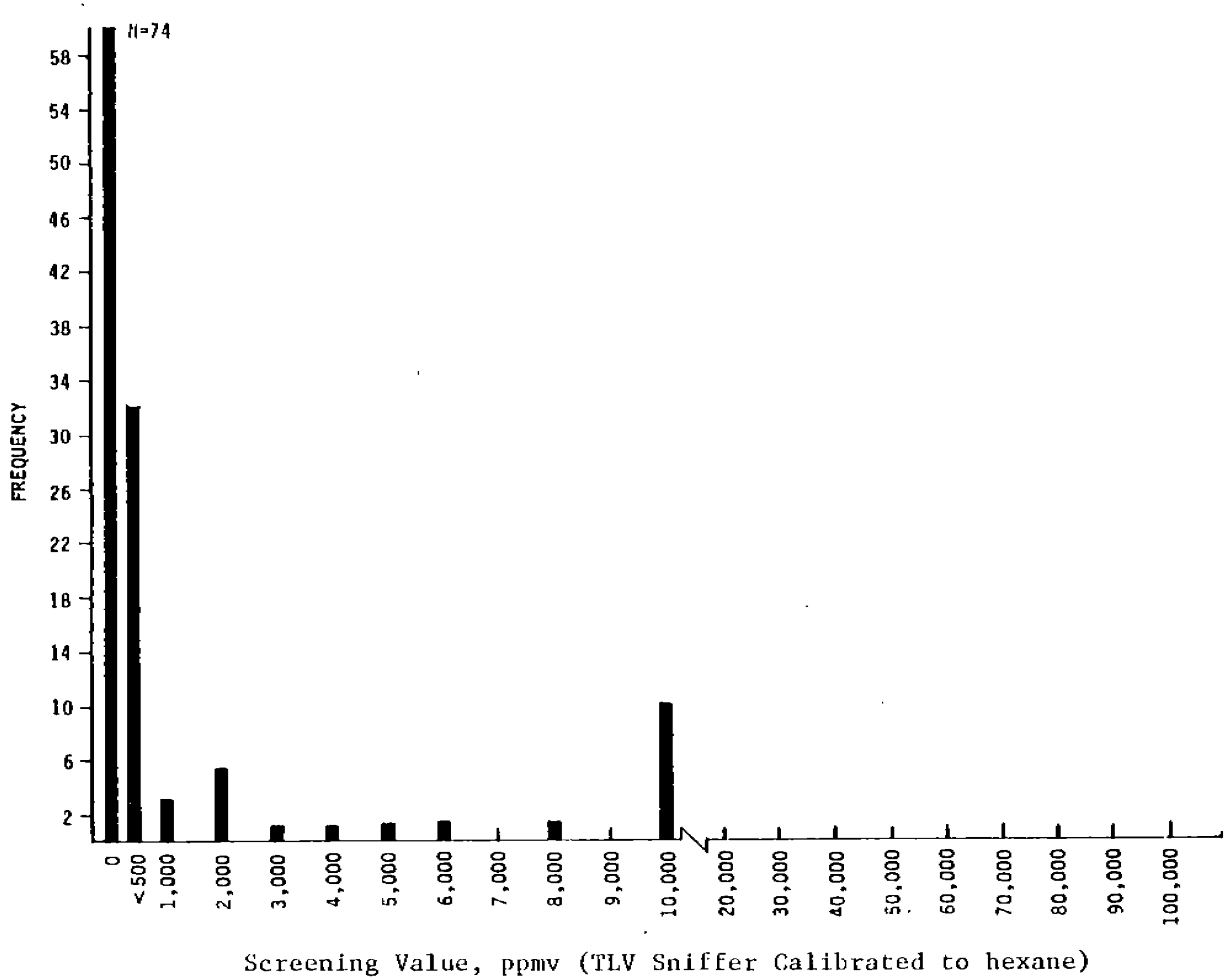


Figure B2-17. Distribution of screening values for valves - open-ended valves.

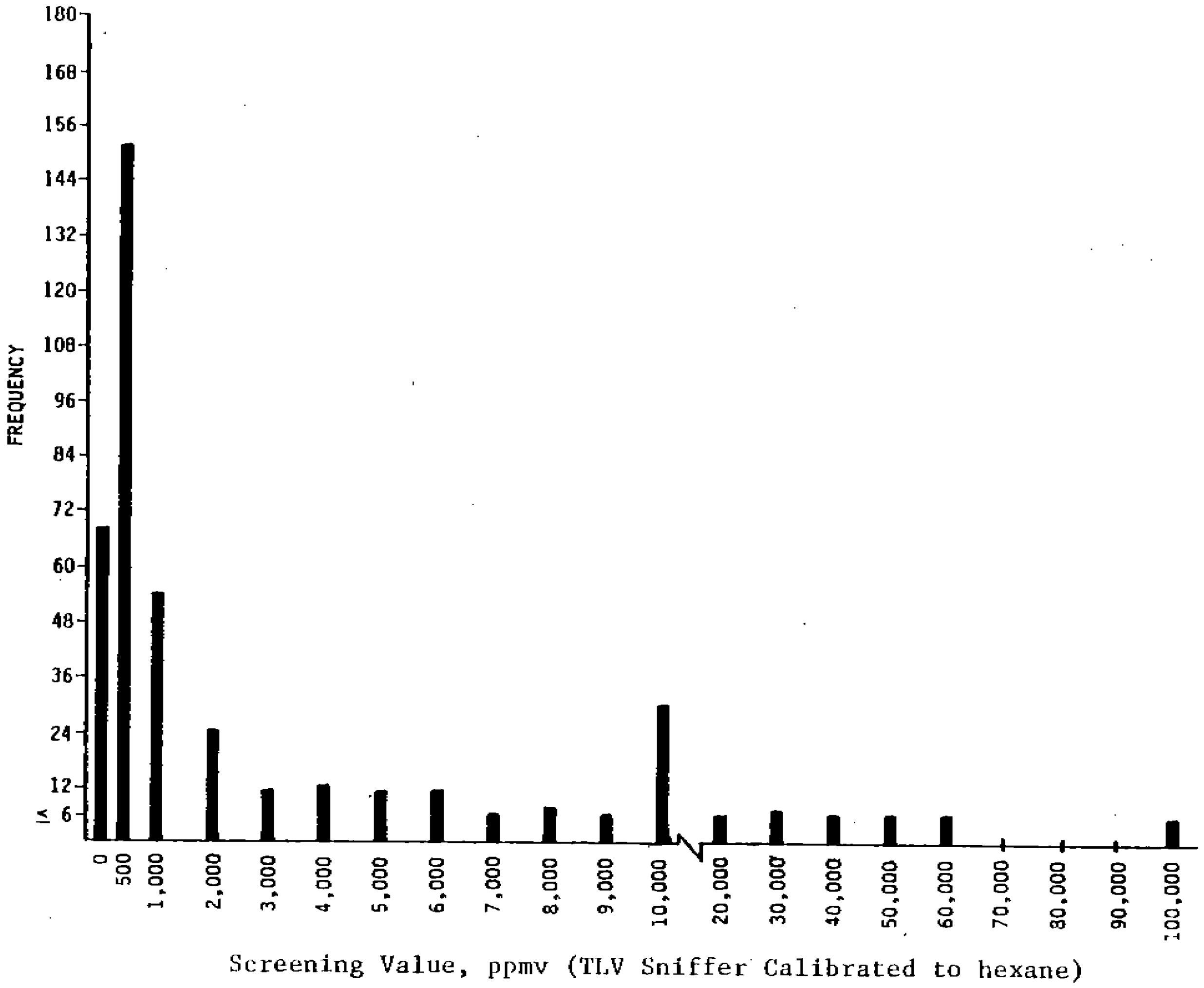


Figure B2-18. Distribution of screening values for pumps - light liquid streams.

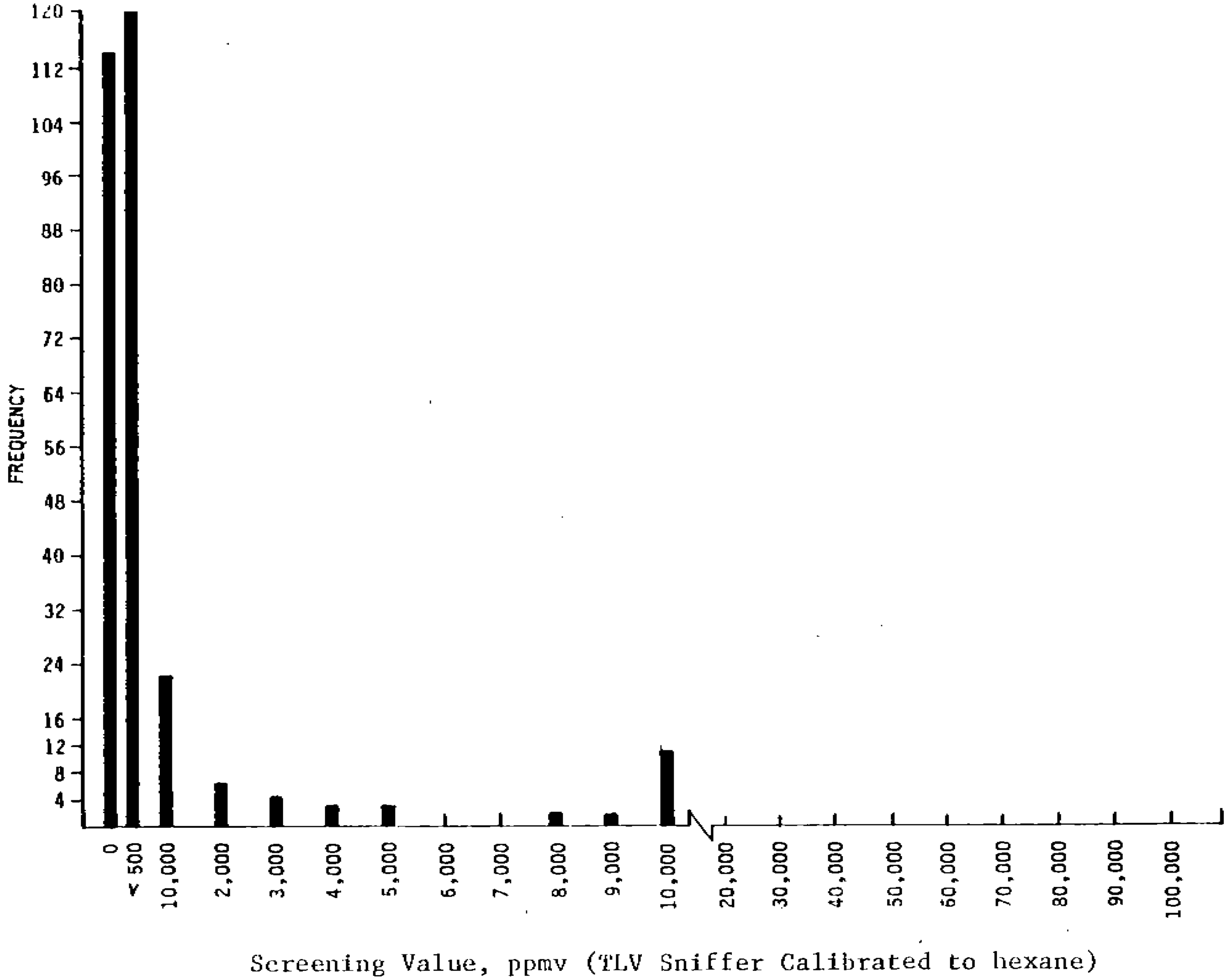


Figure B2-19. Distribution of screening values for pumps - heavy liquid streams.

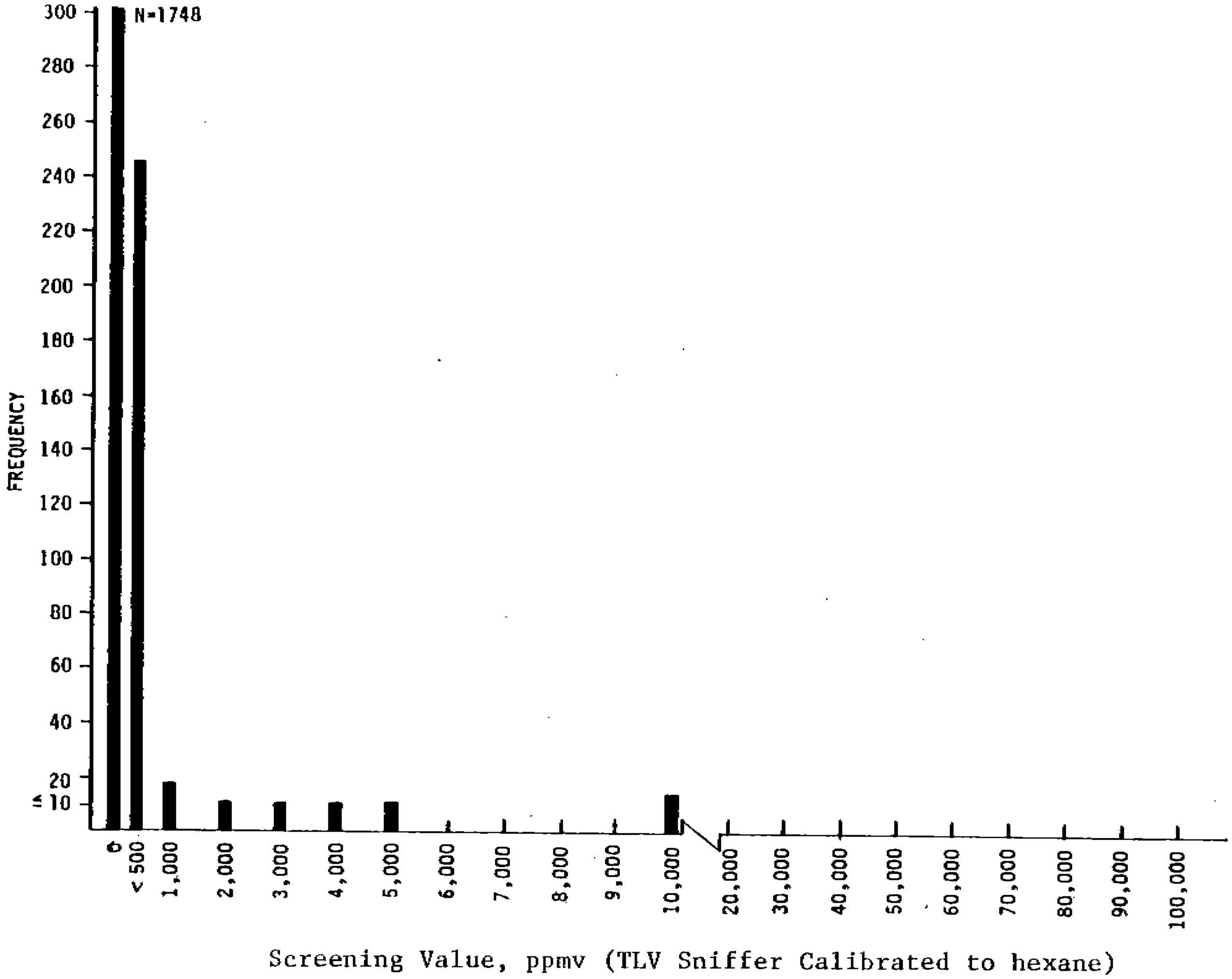


Figure B2-20. Distribution of screening values for flanges.

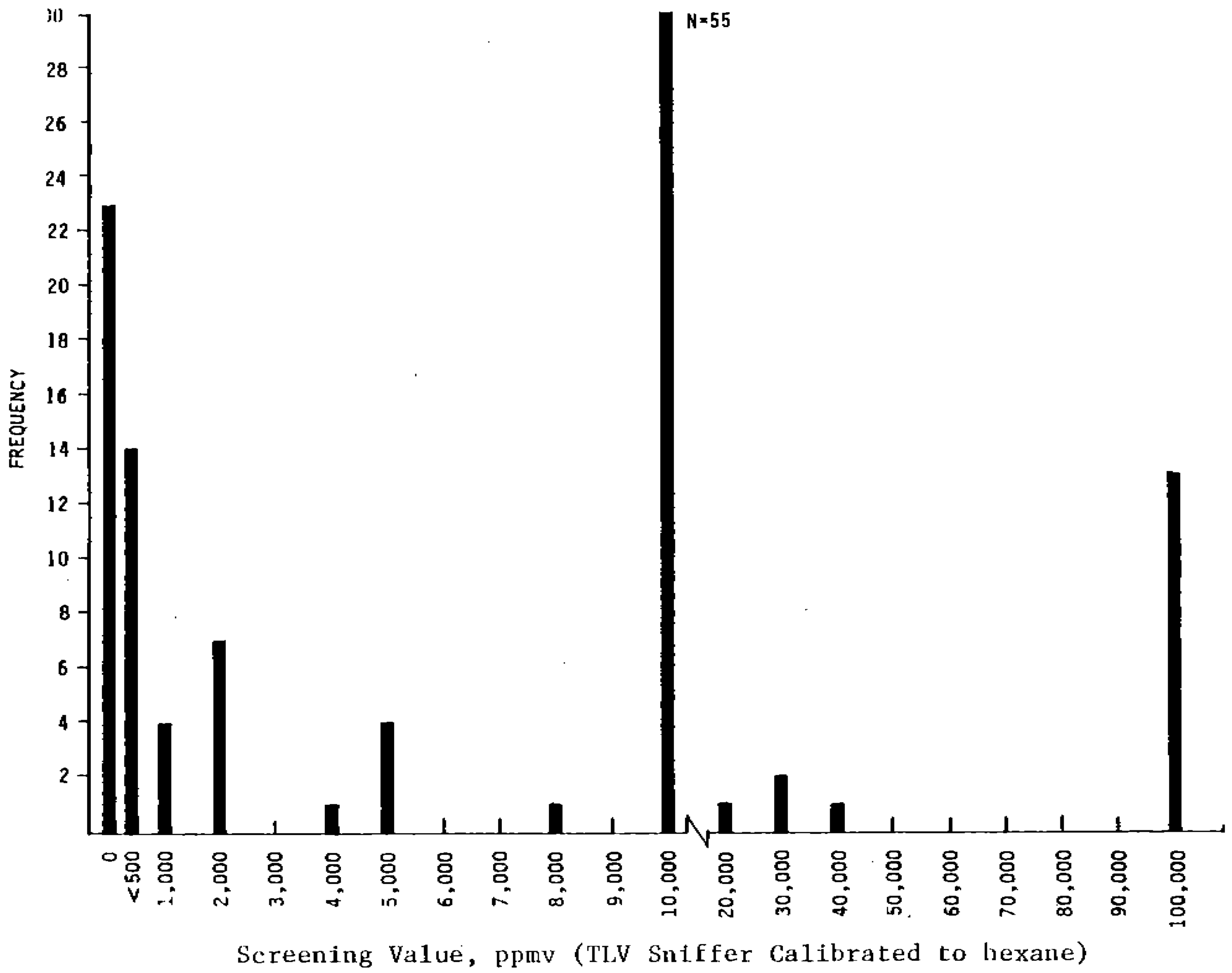


Figure B2-21. Distribution of screening values for compressors - hydrocarbon streams.

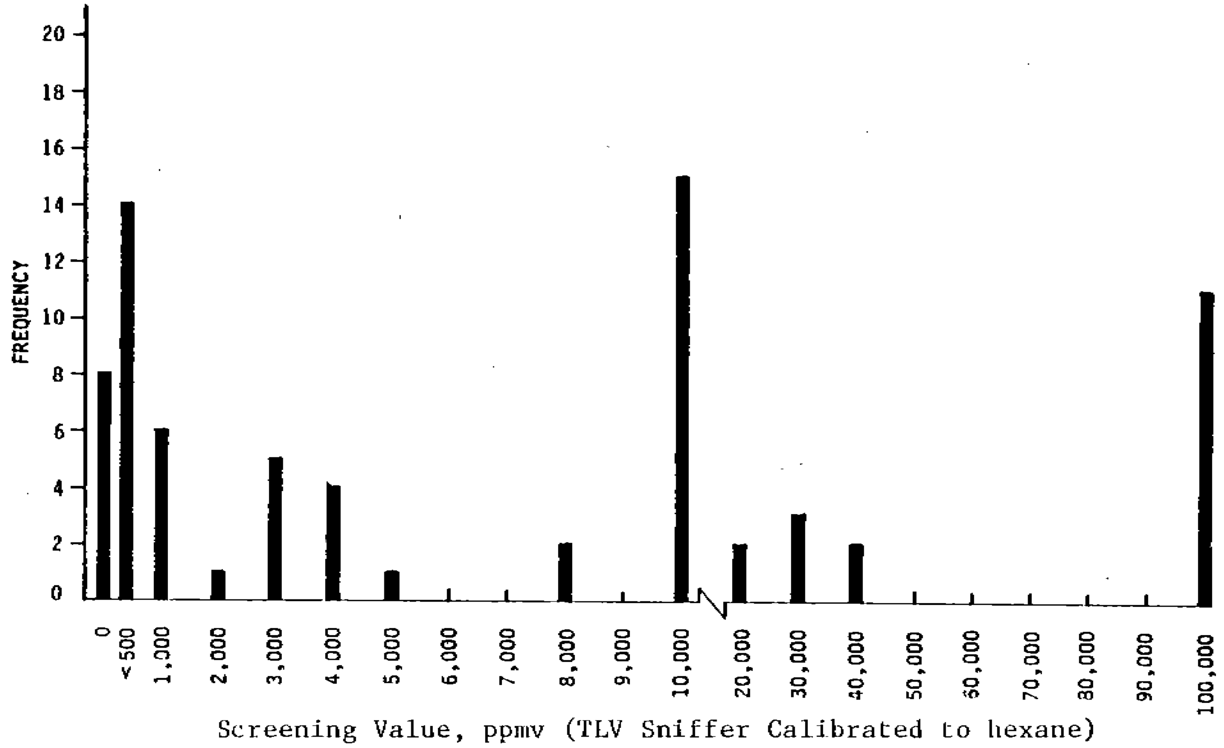


Figure B2-22. Distribution of screening values for compressors - hydrogen streams.

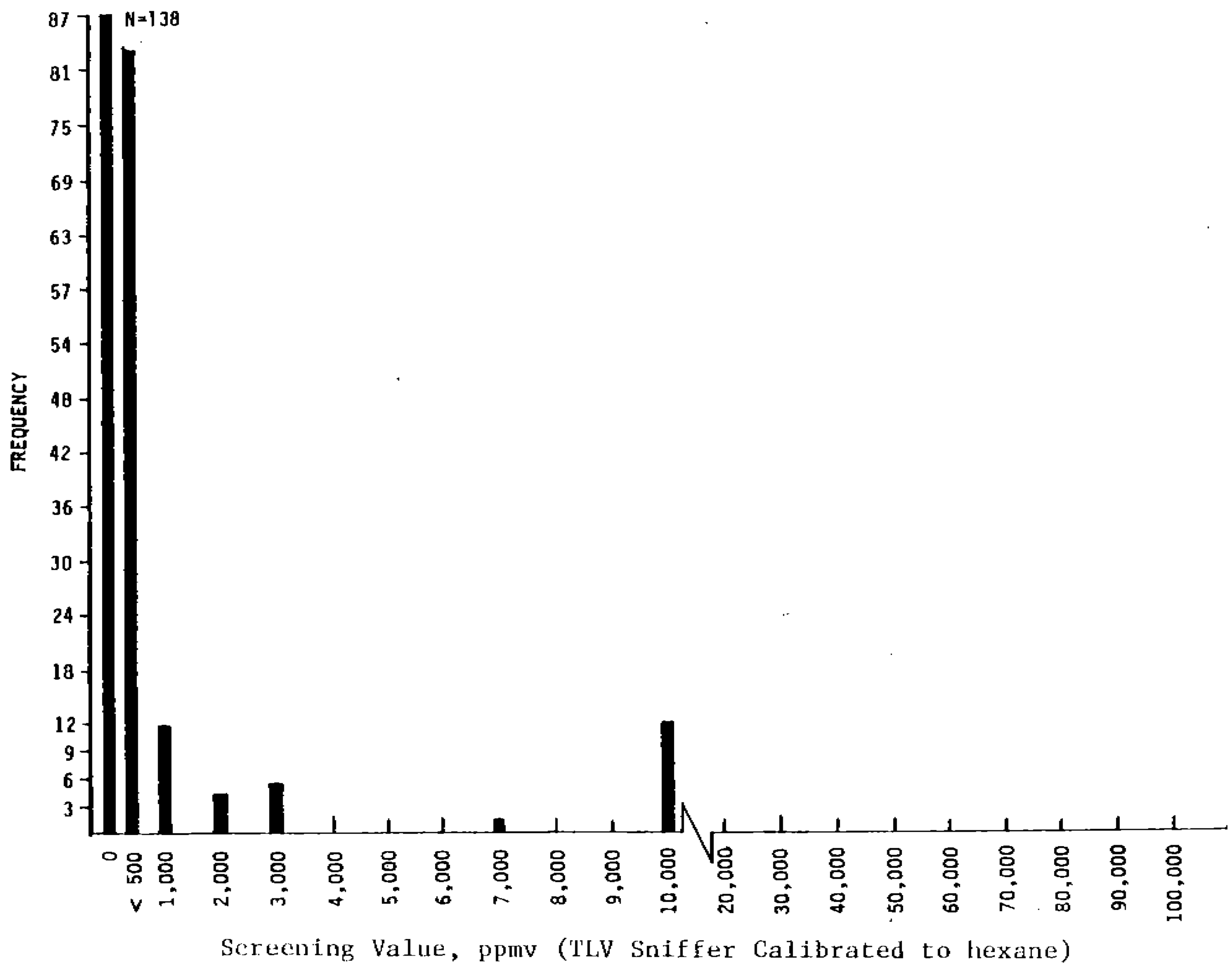


Figure B2-23. Distribution of screening values for drains.

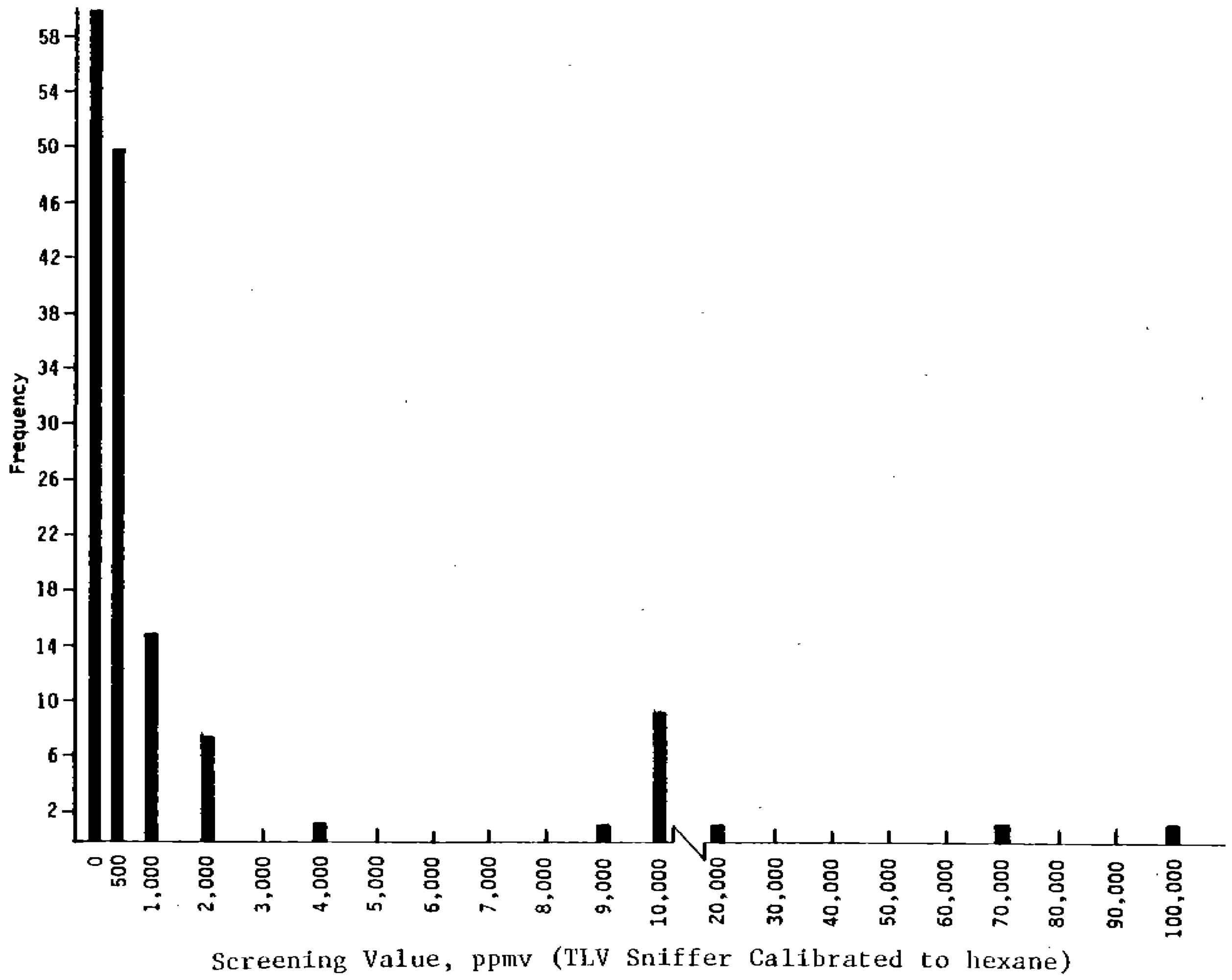


Figure B2-24. Distribution of screening values for relief valves.

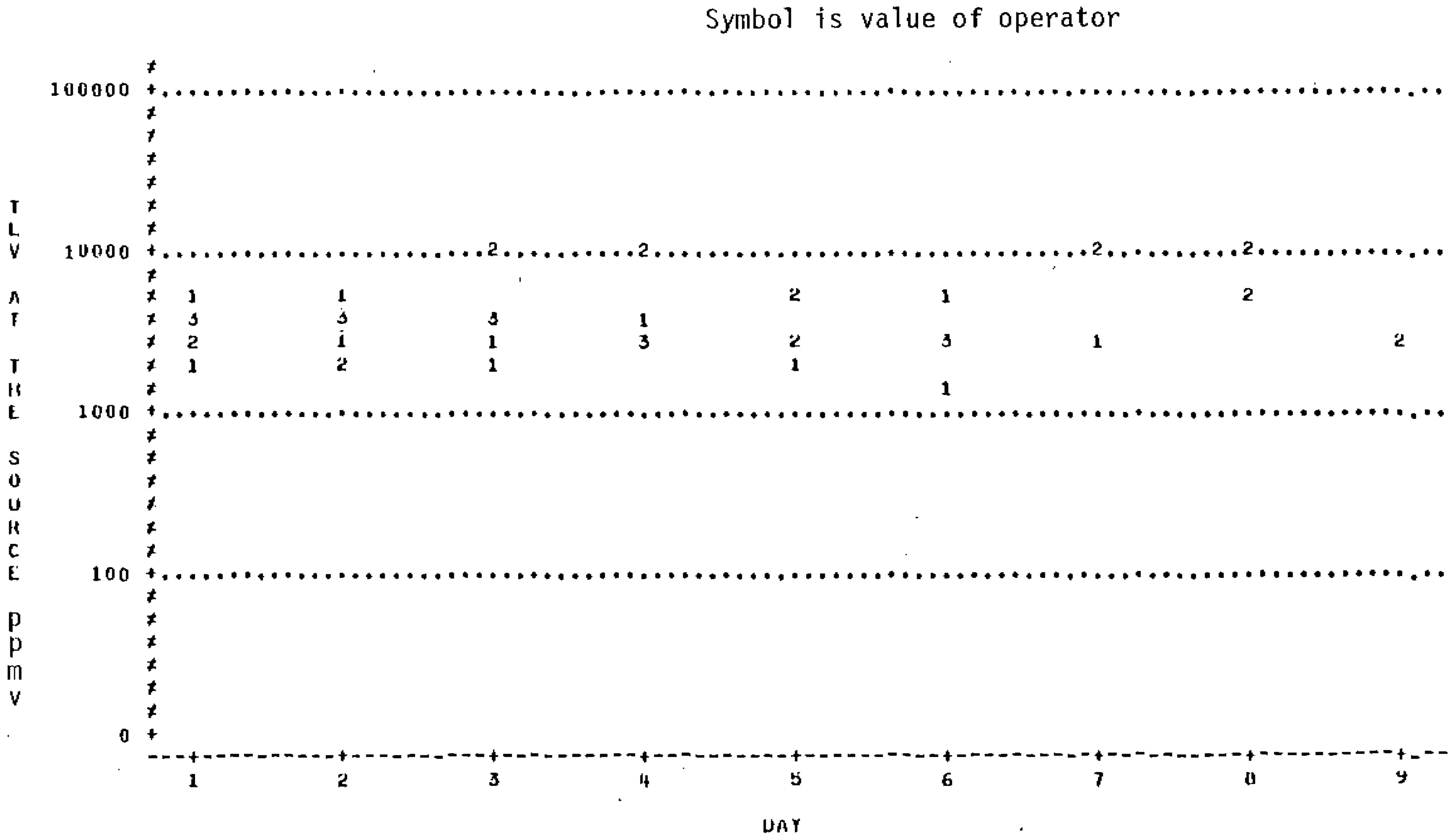


Figure B2-25. Quality control daily TLV Sniffer readings at the source - valve 82.

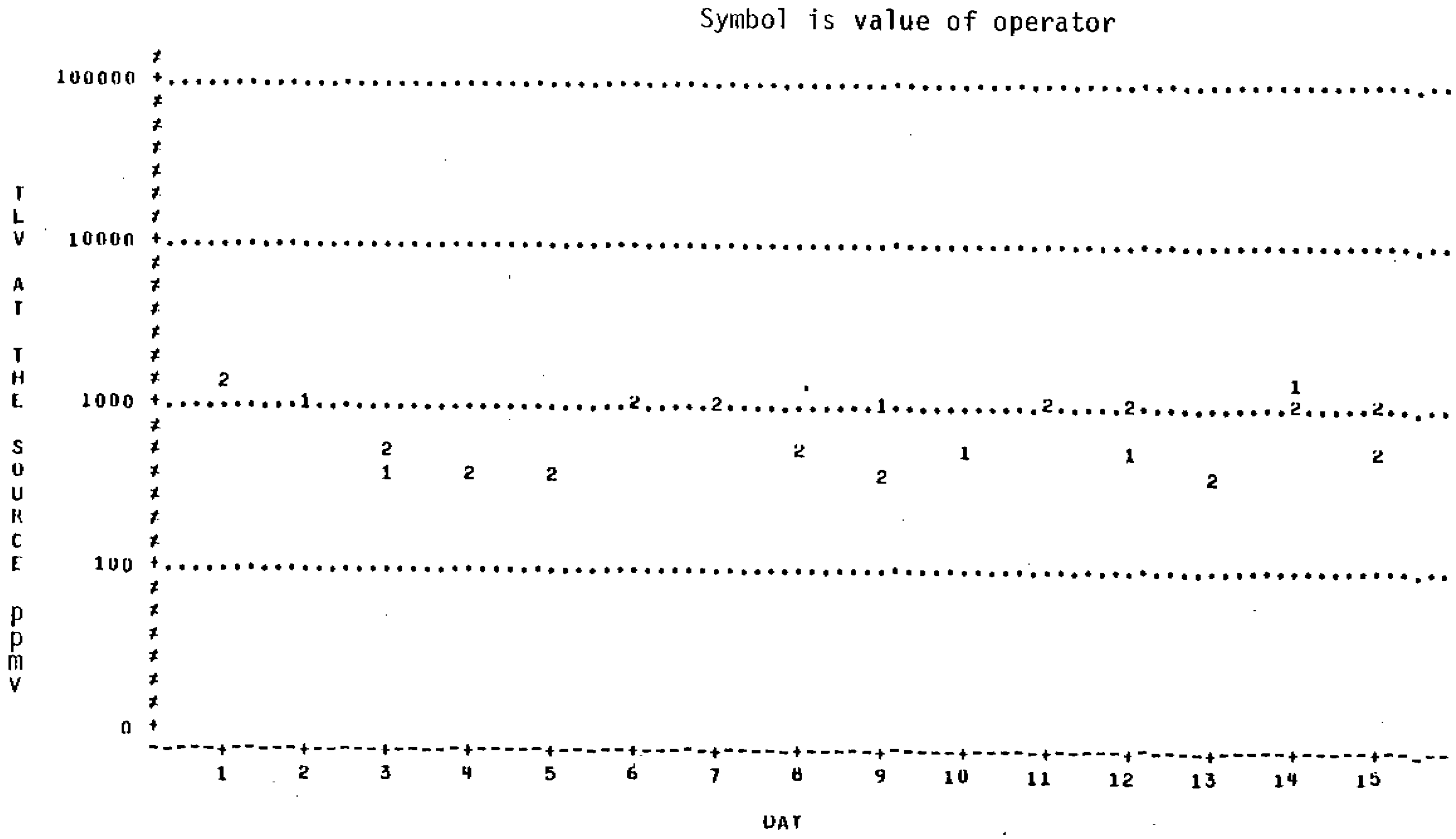


Figure B2-26. Quality control daily TLV Sniffer readings at the source - pump seal 75.

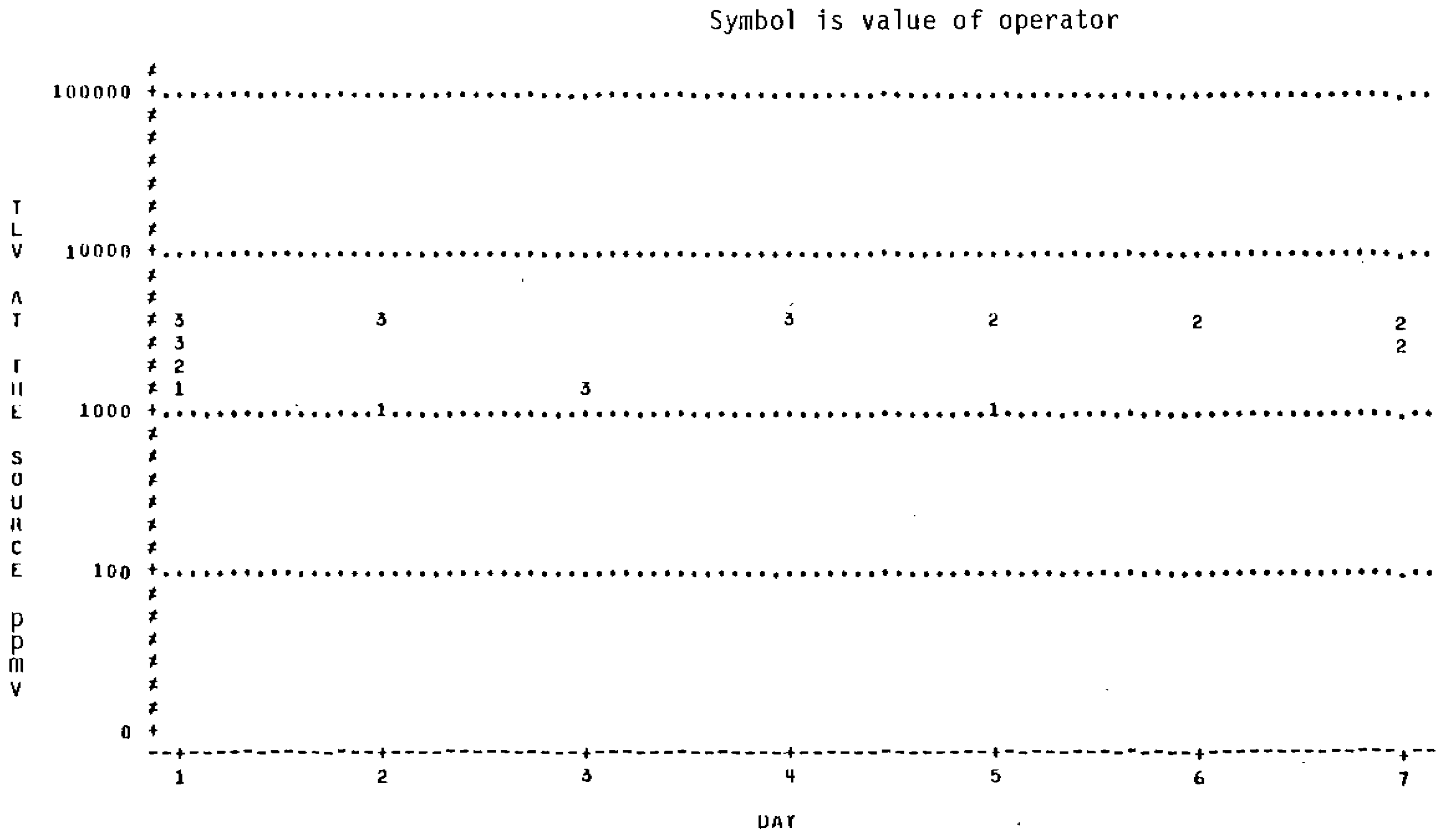


Figure B2-27. Quality control daily TLV Sniffer readings at the source - valve 78.

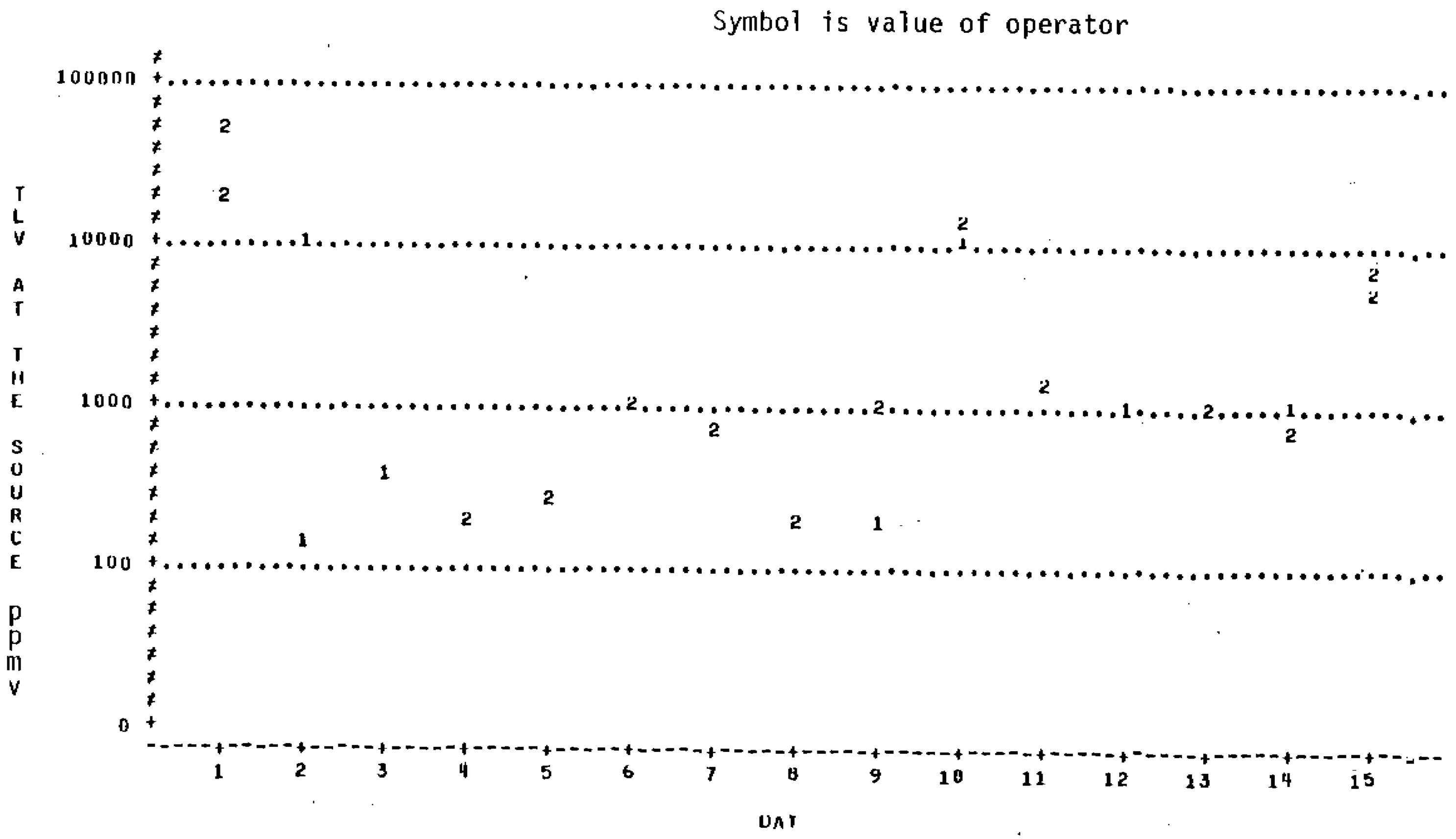


Figure B2-28. Quality control daily TLV Sniffer readings at the source - valve 212.

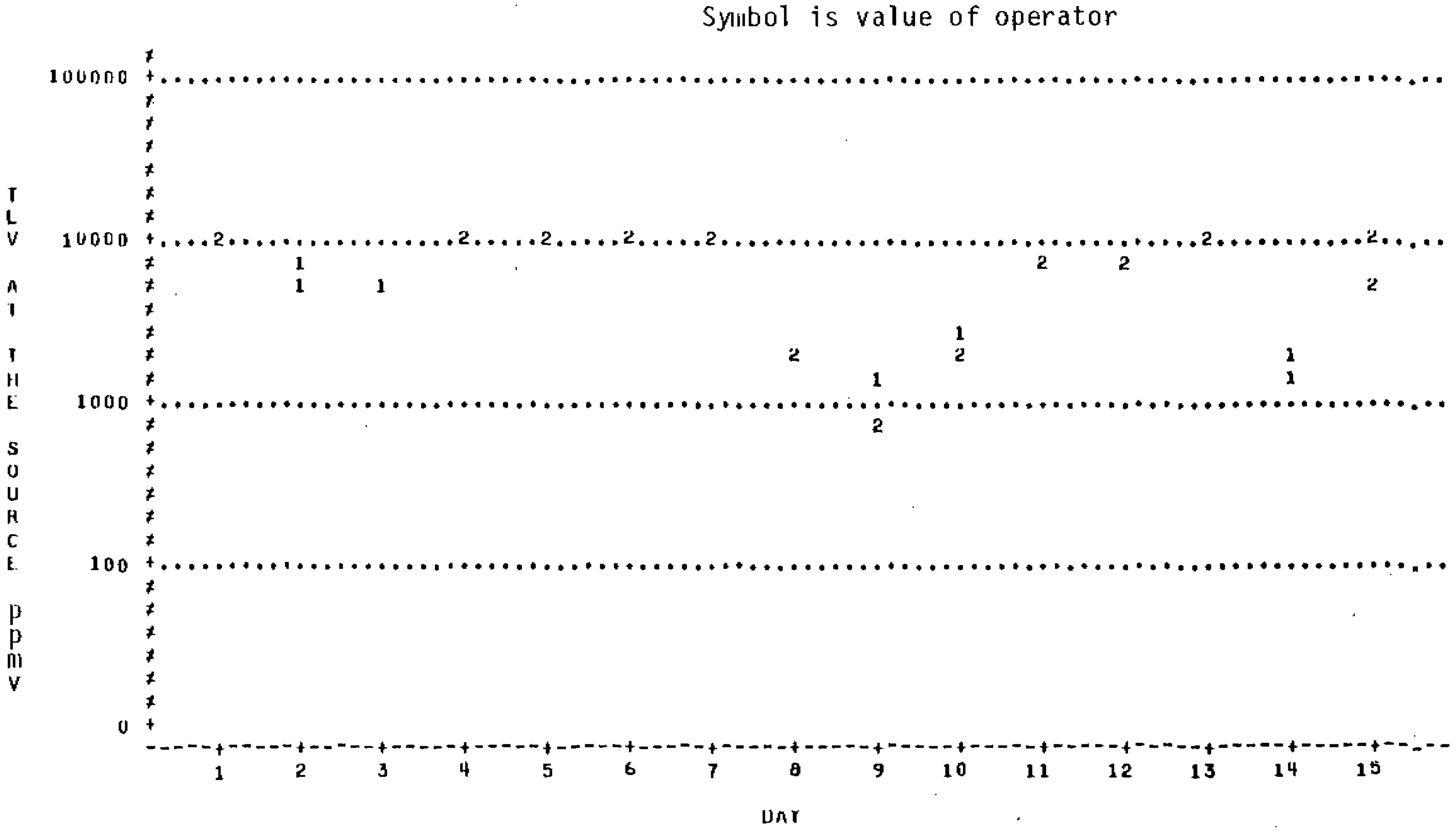


Figure B2-29. Quality control daily TLV Sniffer readings at the source - valve 231.

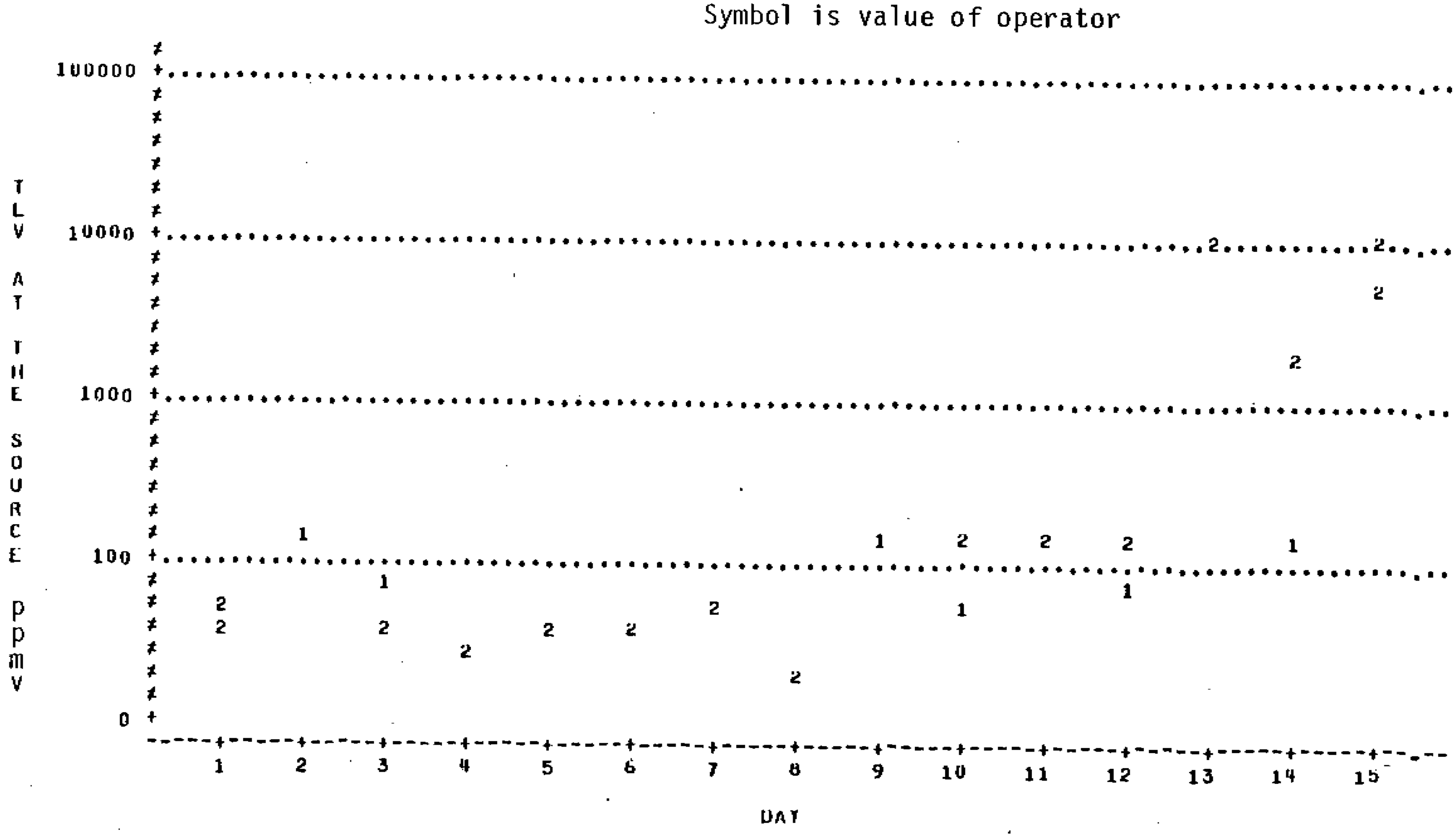


Figure B2-30. Quality control daily TLV Sniffer readings at the source - valve 263.

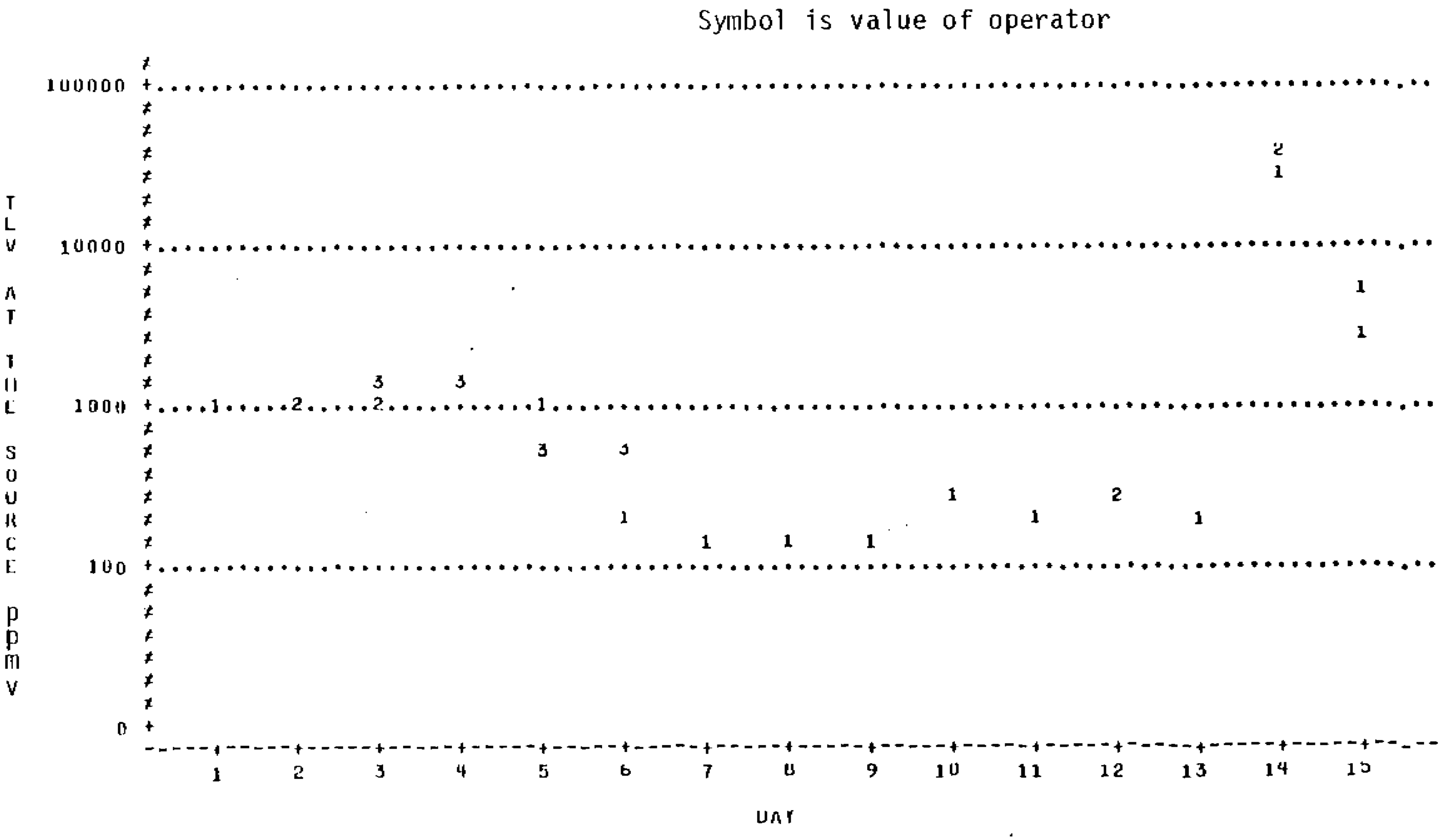


Figure B2-31. Quality control daily TLV Sniffer readings at the source - valve 999.

Observation variance within a source type can be resolved into independent components. Component variance may result from both the true differences in emission rates and from observational error. Specifically, differences may result due to emission rate differences between different sources, from daily changes in emissions from the same source, from observational differences due to variations between screening instruments, and from observational errors for replicate screenings. A variance component analysis was done on the daily screening values to determine the sources and percentages of variation (Table B2-4).

In Table B2-4, the degrees of freedom represent the number of independent comparisons available from the data to estimate the variance component. The variance component is calculated from the natural logs of the screening values within each set of individual comparisons. And, each variance component can be expressed as a percentage of the total variance. Repeatability and reproducibility are estimates of the variation inherent in multiple screenings of individual sources. Both are statistical functions based on the variance component of specific variance sources. The 90 percent repeatability is proportional to the square root of the "repeat" variance component and is defined as the maximum difference expected between two screenings by the same operator within a short period of time. A difference greater than the repeatability statistic would be expected less than 10 percent of the time. The 90 percent reproducibility is proportional to the square root of the sum of the "repeat" and "operator" variance components and is defined as the maximum difference between two screenings by different operators within a short period of time.

TABLE B2-4. VARIANCE COMPONENTS FOR TLV SNIFFER READINGS MEASURED AT THE SOURCE

Variance Source	Degrees of Freedom	Variance Component	Percent
	Valves		
Individual Valves	5	1.384	48.6
Day	70	1.134	39.8
Operator	39	0.060	2.1
Repeat	41	0.269	9.5
Total	155	2.847	100.0
	90% Repeatability - 121%		
	90% Reproducibility - 134%		
	Pump Seals		
Individual Pumps	1	-0.0008	0.0
Day	27	0.192	44.9
Operator	10	0.068	15.9
Repeat	8	0.167	39.2
Total	46	0.427	100.0
	90% Repeatability - 95%		
	90% Reproducibility - 113%		

2.3 LEAK RATES/SCREENING RELATIONSHIPS

This section describes the relationship between leak rate and screening values. Screening values were obtained when the source was first located, and rescreening values were taken at the time each source was sampled. The rescreening values are generally more highly correlated with leak rates than are the original screening results. For example, the correlation coefficient for the original screening values and nonmethane hydrocarbon leak rates of all valves is 0.63. A correlation coefficient of 0.72 is obtained for the maximum rescreening values and nonmethane hydrocarbon leak rates of valves. Tables B2-5 and B2-6 give correlation coefficients for various screening values for valves and pump seals.

Appendix C contains detailed descriptions of the least-squares linear regression equations developed for predicting leak rates from unsampled sources in the data base. For potential prediction purposes outside this data base, a statistical analysis of covariance was done to determine whether different linear equations are required for each baggable source and stream type. The first step was to develop separate regression equations for each source-process stream combination. These regressions are presented in Table B2-7. Separate results are given for gas/vapor, light liquid/two-phase, hydrogen, and heavy liquid streams, and also for cases in which the stream information was missing.

It can be seen that the results for flanges, drains, and pump seals for heavy liquid streams are based on small sample sizes. For this reason, equations for these three cases were developed from the original maximum screening

TABLE B2-5. CORRELATIONS OF SCREENING VARIABLES AND NONMETHANE LEAK RATES (lb/hr) - VALVES (All Correlations Based on Log of Variable)

Variable	(2) Max SC	(3) Max RSC	(4) Avg RSC	(5) 5-CM	(6) N. STM	(7) N. GL
1. Nonmethane Leak (lb/hr)	.628(584)	.715(260)	.739(260)	.685(246)	.703(251)	.511(195)
2. Maximum Screening Value	-	.745	.748	.593	.677	.434
3. Maximum Rescreening Value		-	.978	.804	.858	.633
4. Average Rescreening Value			-	.837	.890	.693
5. Avg of Maximum 5-CM Reading				-	.733	.722
6. North Stem Reading					-	.545
7. North Gland Reading						-

Tabulated values are r (m)

r = Simple correlation coefficient = $\frac{\Sigma(Xi - \overline{X})(Yi - \overline{Y})}{\sqrt{\Sigma(Xi - \overline{X})^2 \; \Sigma(Yi - \overline{Y})^2}}$

where X and Y are the paired variables

m = number of pairs of data observations used in computing correlation coefficient

SC = Screening value, ppmv (TLV Sniffer Calibrated to hexane)
RSC = Rescreening vlue, ppmv (TLV Sniffer Calibrated to hexane)
STM = Stem reading, ppmv (TLV Sniffer Calibrated to hexane)
GL = Gland reading, ppmv (TLV Sniffer Calibrated to hexane)

TABLE B2-6. CORRELATIONS OF SCREENING VARIABLES AND NONMETHANE LEAK RATES (lb/hr) - PUMPS (All Correlations Based on Log of Variable)

Variable	(2) Max SC	(3) Max RSC	(4) Avg RSC	(5) 5-CM	(6) N.Shaft
1. Nonmethane Leak Rate (lb/hr)	.636(418)	.678(169)	.700(169)	.731(160)	.716(164)
2. Maximum Screening Value	-	.766	.753	.618	.765
3. Maximum Rescreening Value		-	.987	.825	.940
4. Average Rescreening Value			-	.858	.958
5. Avg of Maximum 5-CM Reading				-	.835
6. North Shaft Reading					-

Tabulated values are r (m)

$$r = \text{Simple correlation coefficient} = \frac{\Sigma(Xi - \overline{X})(Yi - \overline{Y})}{\sqrt{\Sigma(Xi - \overline{X})^2 \; \Sigma(Yi - \overline{Y})^2}}$$

where X and Y are the paired variables

m = number of pairs of data observations used in computing correlation coefficient

SC = Screening value (TLV Sniffer Calibrated to hexane)
RSC = Rescreening value (TLV Sniffer Calibrated to hexane)

TABLE B2-7. REGRESSION OF LOG LEAK RATE ON LOG MAXIMUM RESCREENING VALUE BY SOURCE AND STREAM TYPE

Process Stream Type[a]		Valves	Flanges	Pump Seals	Compressor Seals	Drains	Relief Valves
Gas/Vapor	B_0	-7.04			-3.97		-4.41
	$SE(B_0)$	0.56			0.74		0.45
	B_1	1.23			0.71		0.87
	$SE(B_1)$	0.12			0.16		0.10
	R^2	0.57			0.23		0.58
	N	79			69		54
Light Liquid/ Two-Phase	B_0	-4.90	-2.93	-4.59		-2.38	
	$SE(B_0)$	0.22	1.01	0.32		1.64	
	B_1	0.80	0.22	0.89		0.60	
	$SE(B_1)$	0.06	0.31	0.08		0.55	
	R^2	0.63	0.05	0.48		0.10	
	N	119	12	136		13	
Hydrogen	B_0	-7.45			-5.30		
	$SE(B_0)$	0.90			0.72		
	B_1	1.14			0.72		
	$SE(B_1)$	0.20			0.36		
	R^2	0.51			0.24		
	N	32			15		
Heavy Liquid	B_0	-9.82		-3.08		-3.35	
	$SE(B_0)$	1.12		0.77		0.31	
	B_1	2.26		0.57		0.51	
	$SE(B_1)$	0.34		0.23		0.11	
	R^2	0.96		0.29		0.60	
	N	4		17		17	
Stream Information Missing	B_0	-5.68	-5.08	-4.77			
	$SE(B_0)$	0.54	0.88	1.50			
	B_1	0.95	0.89	0.70			
	$SE(B_1)$	0.17	0.24	0.45			
	R^2	0.75	0.78	0.13			
	N	21	6	18			

---

[a] $\log_{10}(\text{leak rate}) = B_0 + B_1 \log_{10}(\text{max rescreening value})$

$SE(B_0)$ = standard error of B_0

$SE(B_1)$ = standard error of B_1

N = number of data pairs

R^2 = coefficient of determination or correlation coefficient squared values rather than the maximum rescreening values. A small sample size (less than 20) was available for valves handling heavy liquids with either type of screening data; hence, an equation was not developed for this case.

Analyses of covariance were performed to determine which source and process stream types would be combined for prediction purposes. It was found that the source and stream types could be grouped such that seven equations were adequate for predicting leak rates from screened sources. The seven groups are as follows:

- Pumps in light liquid/two-phase streams, compressors and relief valves in gas/vapor streams
- Valves and compressor seals in hydrogen service
- Valves in gas/vapor streams
- Valves in light liquid/two-phase streams
- Flanges
- Drains
- Pump seals in heavy liquid streams.

The equations for flanges, drains, and pump seals in heavy liquid streams were developed from the original maximum screening values. This is because small sample sizes (less than 20) would have been available in each of the three cases if the rescreening values had been used. No equation was developed for valves in heavy liquid streams; a sample size of less than 20 was available with either the maximum screening or maximum rescreening values.

The resulting seven equations are summarized as follows (NMLEAK = leak rate in lb/hr):

A. Pump Seals (Light Liquid/Two-Phase Streams) Compressors and Relief Valves (Gas/Vapor Streams)

Log_{10} (NMLEAK) = -4.4 + 0.83 Log_{10} (Max Rescreening)
Correlation Coefficient = 0.68
Number of Data Pairs = 259
Standard Error Estimate = 0.76 Log_{10} (NMLEAK)
95% Confidence Interval for Intercept = (-4.9, -3.9)
95% Confidence Interval for Slope = (0.72, 0.94)
Scale Bias Correction Factor = 4.58

B. Valves and Compressor Seals, Hydrogen Streams

Log_{10} (NMLEAK) = -7.0 + 1.06 Log_{10} (Max Rescreening)
Correlation Coefficient = 0.67
Number of Data Pairs = 47
Standard Error of Estimate = 0.98 Log_{10} (NMLEAK)
95% Confidence Interval for Intercept = (-8.5, -5.5)
95% Confidence Interval for Slope = (0.72, 1.40)
Scale Bias Correction Factor = 10.67

C. Valves, Gas/Vapor Streams

Log_{10} (NMLEAK) = -7.0 + 1.23 Log_{10} (Max Rescreening)
Correlation Coefficient = 0.76

Number of Data Pairs = 79

Standard Error of Estimate -.78 Log_{10} (NMLEAK)

95% Confidence Interval for Intercept = (-8.1, -5.9)

95% Confidence Interval for Slope = (0.99, 1.47)

Scale Bias Correction Error = 4.81

D. Valves, Light Liquids/Two-Phase

Log_{10} (NMLEAK) = -4.9 + 0.80 Log_{10} (Max Rescreening)

Correlation Coefficient = 0.79

Number of Data Pairs = 119

Standard Error of Estimate = 0.60 Log_{10} (NMLEAK)

95% Confidence Interval for Intercept = (-5.3, -4.5)

95% Confidence Interval for Slope = (0.69, 0.91)

Scale Bias Correction Factor = 2.53

E. Drains

Log_{10} (NMLEAK) = -4.9 + 1.10 Log_{10} (Screening)

Correlation Coefficient = 0.68

Number of Data Pairs = 61

Standard Error of Estimate = 0.86 Log_{10} (NMLEAK)

95% Confidence Interval for Intercept = (-5.8, -4.0)

95% Confidence Interval for Slope (0.80, 1.40)

Scale Bias Correction Factor = 6.53

F. Flanges

Log_{10} (NMLEAK) = -5.2 + 0.88 Log_{10} (Screening)

Correlation Coefficient = 0.77

Number of Pairs = 52

Standard Error of Estimate = 0.52 Log_{10} (NMLEAK)

95% Confidence Interval for Intercept = (-5.9, -4.5)

95% Confidence Interval for Slope (0.68, 1.08)

Scale Bias Correction Factor = 2.02

G. Pump Seals, Heavy Liquid Streams

Log_{10} (NMLEAK) = -5.1 + 1.04 Log_{10} (Screening)
Correlation Coefficient = 0.75
Number of Data Pairs = 61
Standard Error of Estimate = 0.59 Log_{10} (NMLEAK)
95% Confidence Interval for Intercept = (-5.8, -4.3)
95% Confidence Interval for Slope = (0.80, 1.27)
Scale Bias Correction Factor = 2.44

The data used to develop these equations are shown in Figures B2-32 through B2-38. The one obvious outlier at the bottom right in the graph of flange data (Figure B2-37) was eliminated.

The equations were used to develop nomographs which relate the predicted leak rate to the screening values for the various source and stream types. These nomographs are shown in Figures B2-39 through B2-45.

Each nomograph gives the predicted mean leak rate as a function of the maximum TLV Sniffer screening readings taken directly at the source of the leak with the TLV Sniffer calibrated to hexane.

Although the equations were developed on a logarithmic scale, the nomographs are shown on an arithmetic scale for ease in reading and interpolation. Predicting the arithmetic mean leak rate for a given screening value is similar to predicting the mean from a lognormal distribution (as discussed in Appendix C). The mean leak rate for a given screening value on the nomograph was computed as follows:

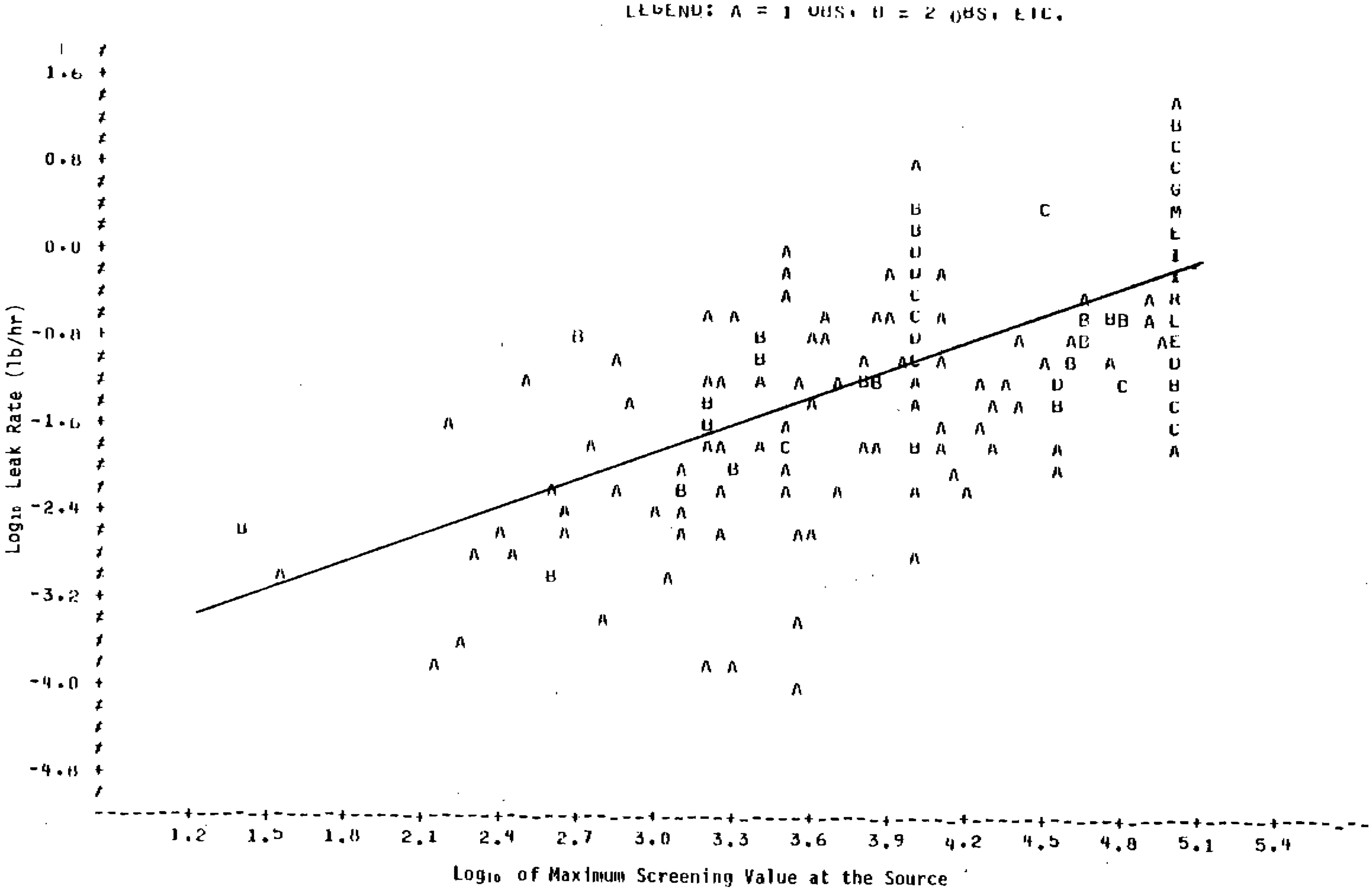


Figure B2-32. Leak Rate/screening relationship - pump seals (light liquid streams), compressor seals and relief valves (gas/vapor streams).

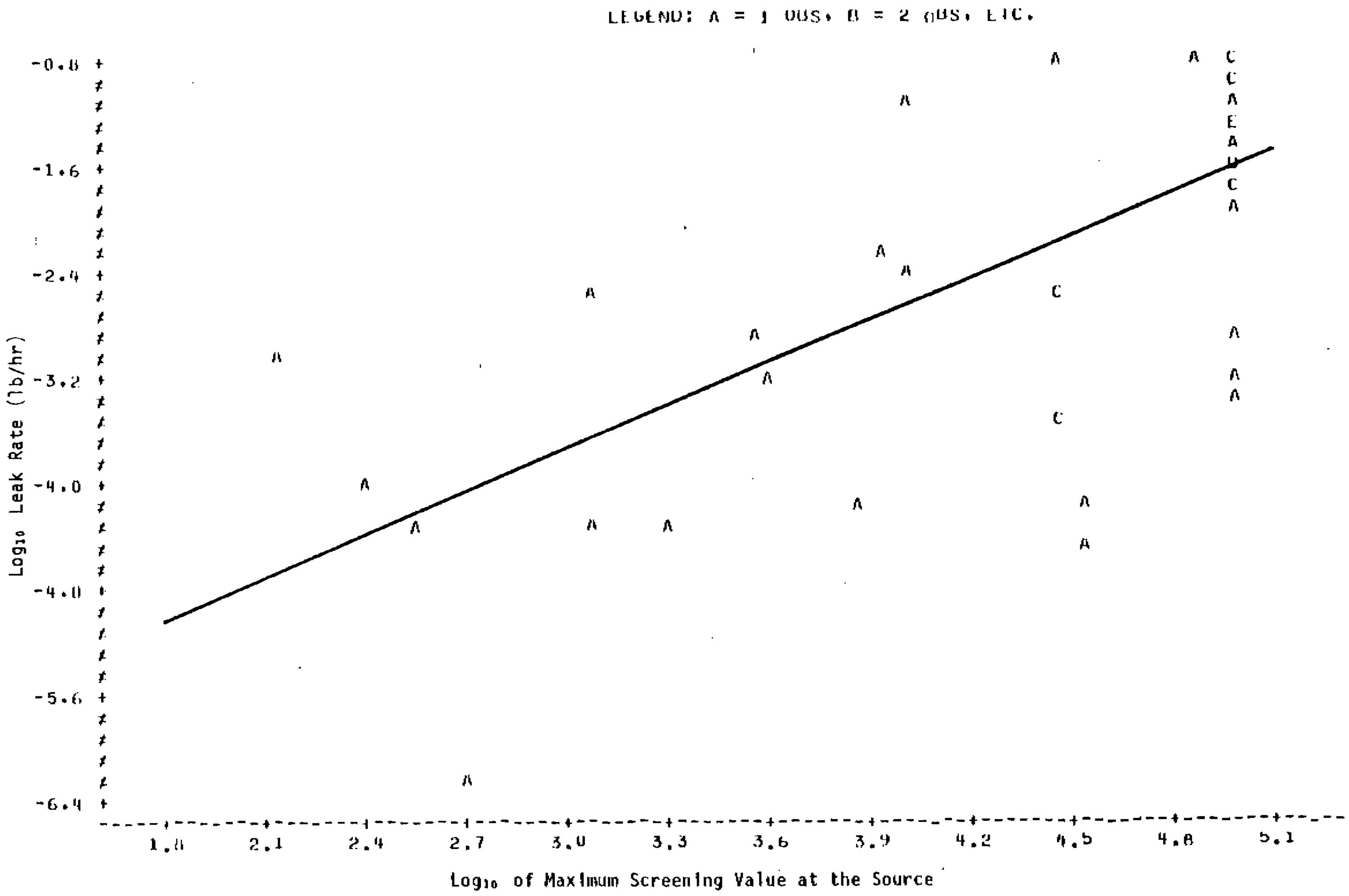


Figure B2-33. Leak rate/screening relationship - valves and compressor seals, hydrogen streams.

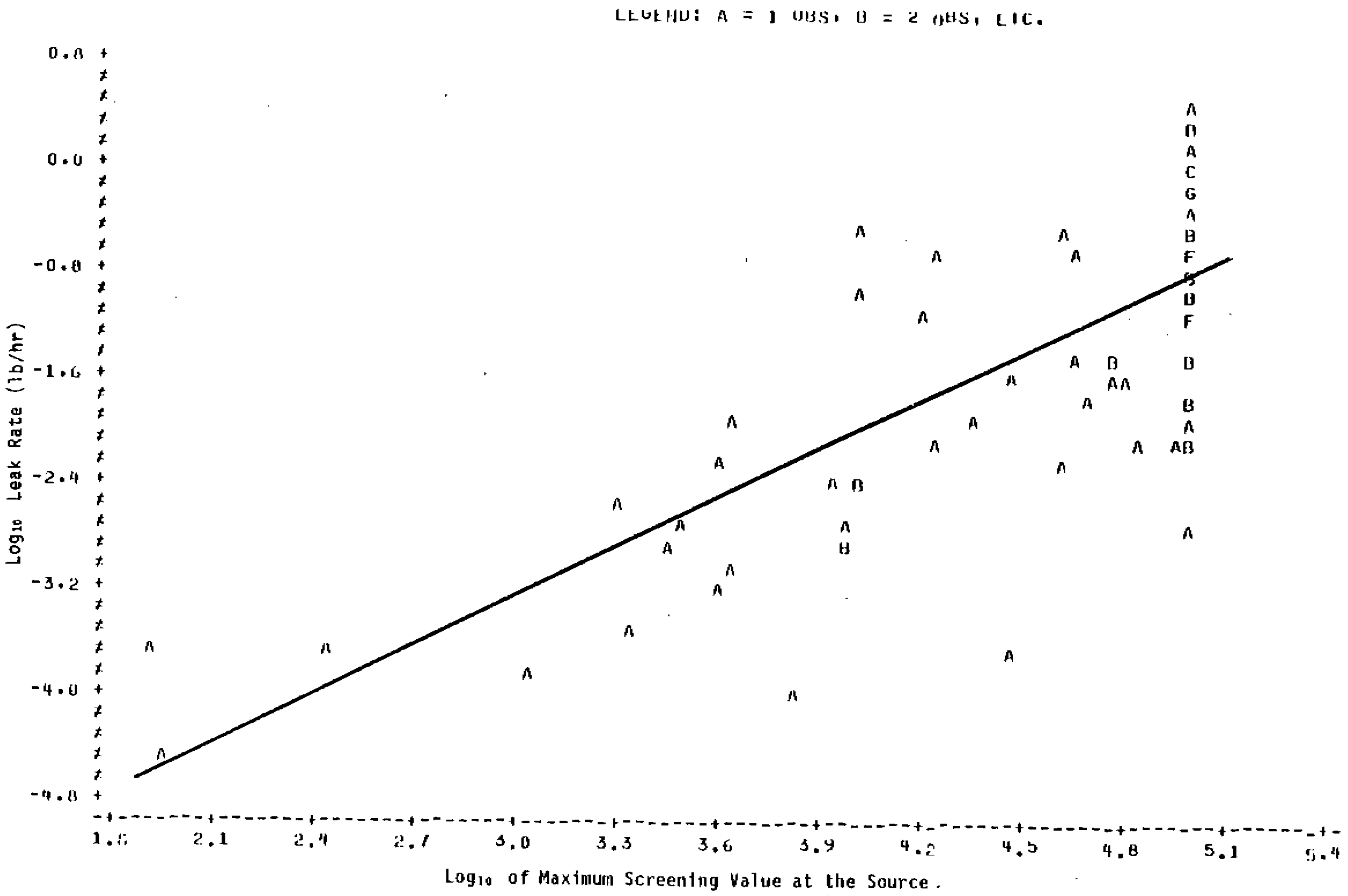


Figure B2-34. Leak rate/screening relationship - valves, gas/vapor streams.

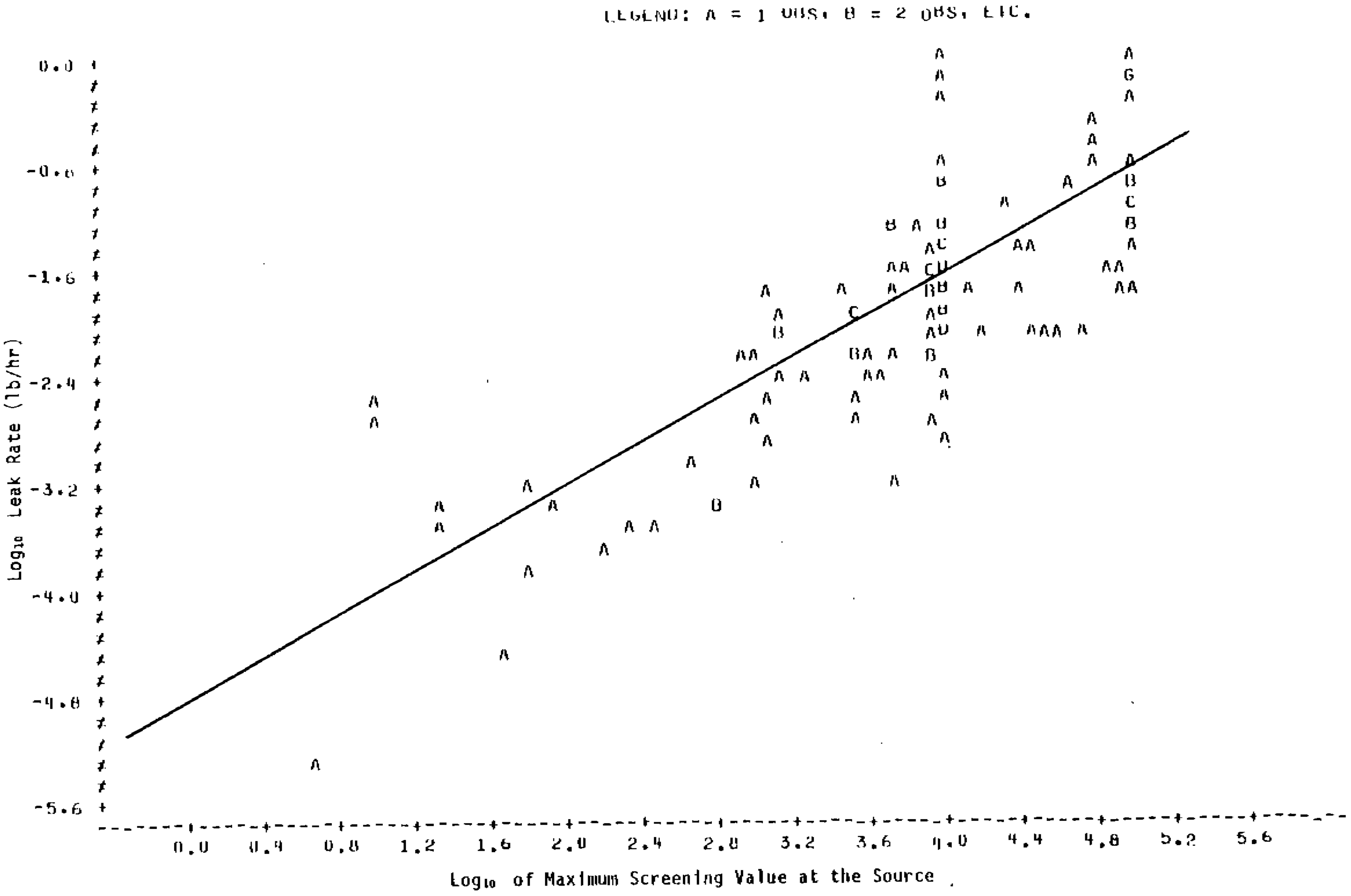


Figure B2-35. Leak rate/screening relationship - valves, light liquid/ two-phase streams.

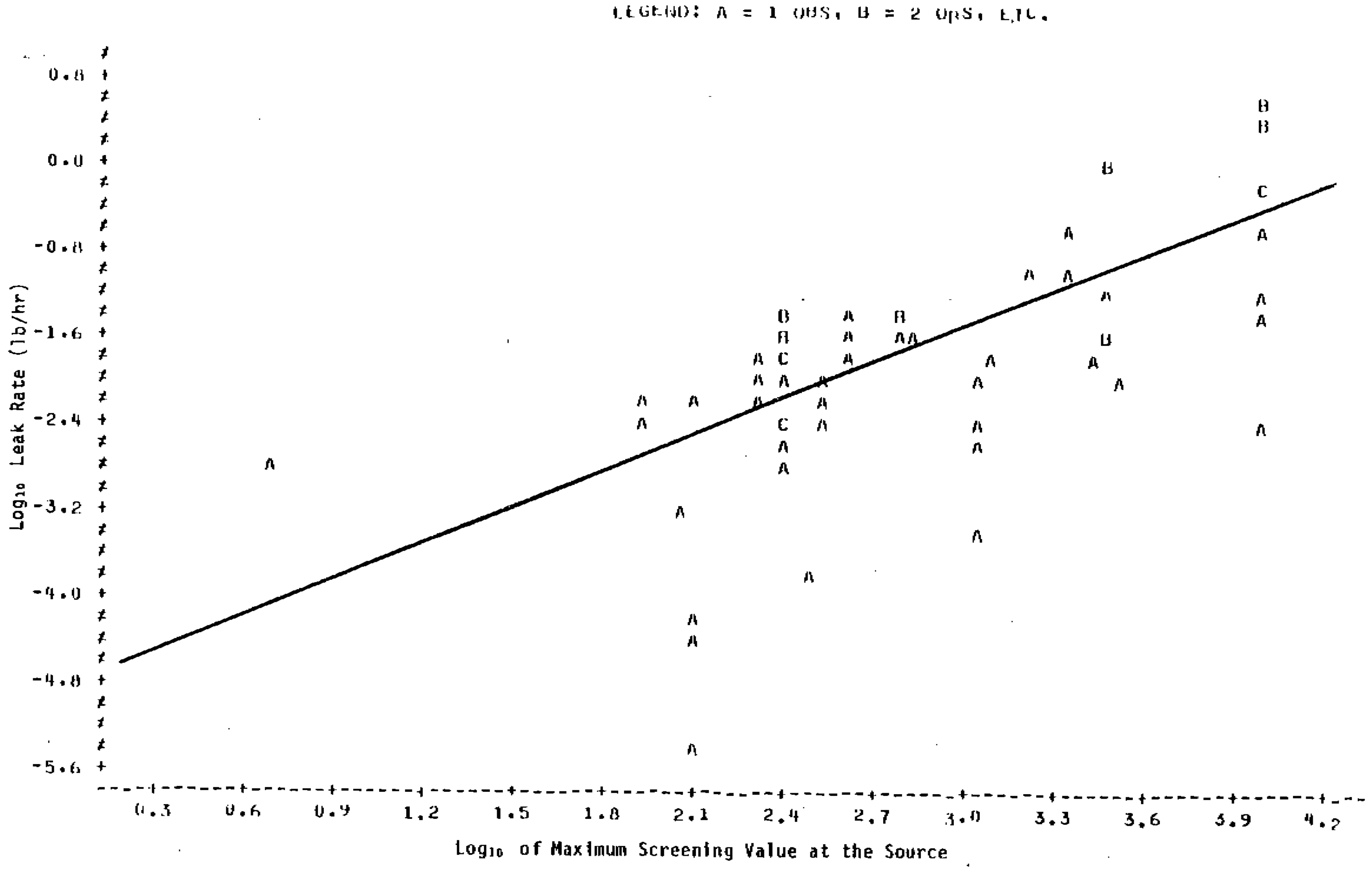


Figure B2-36. Leak rate/screening relationship - drains.

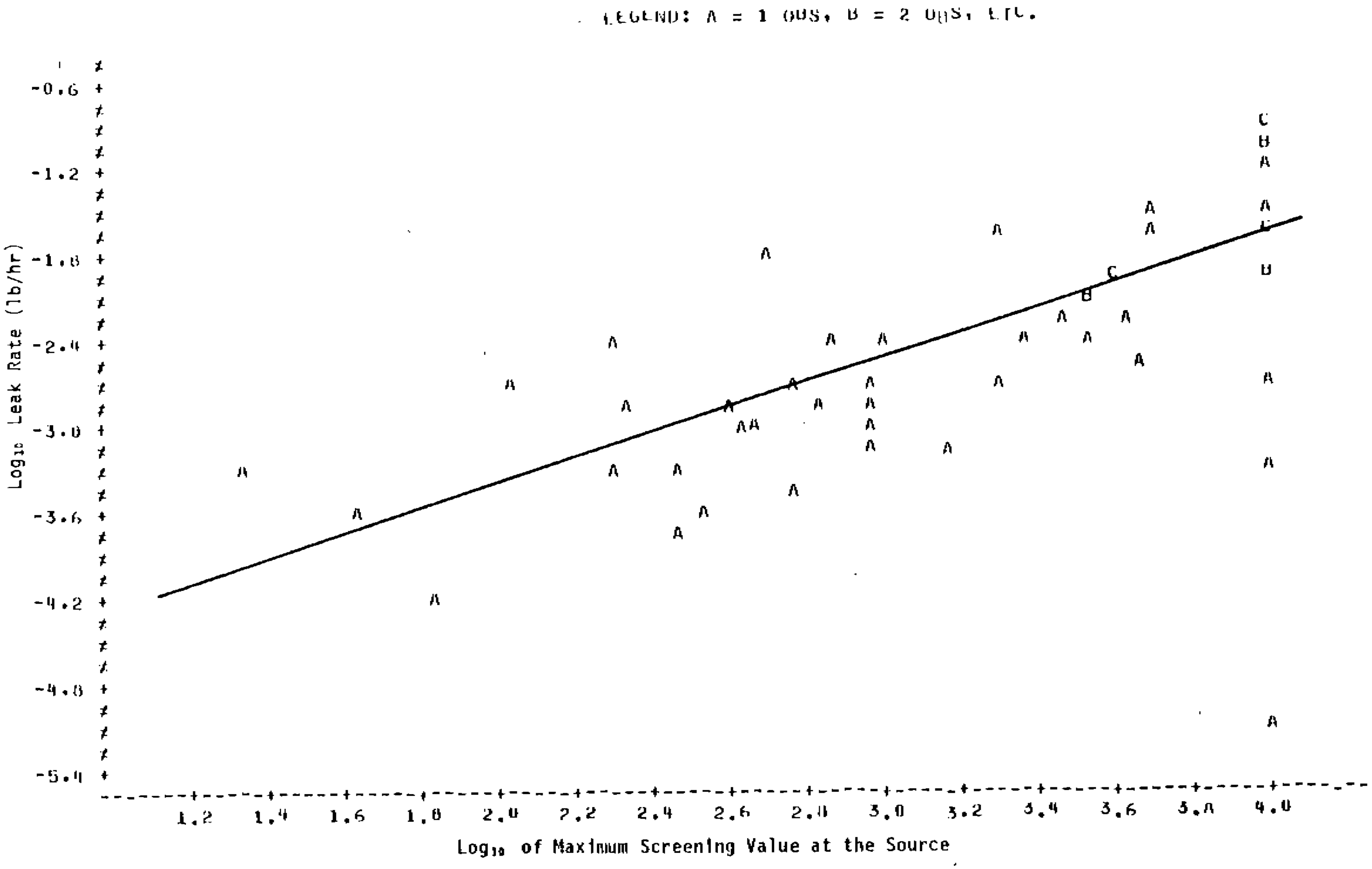


Figure B2-37. Leak rate/screening relationship - flanges.

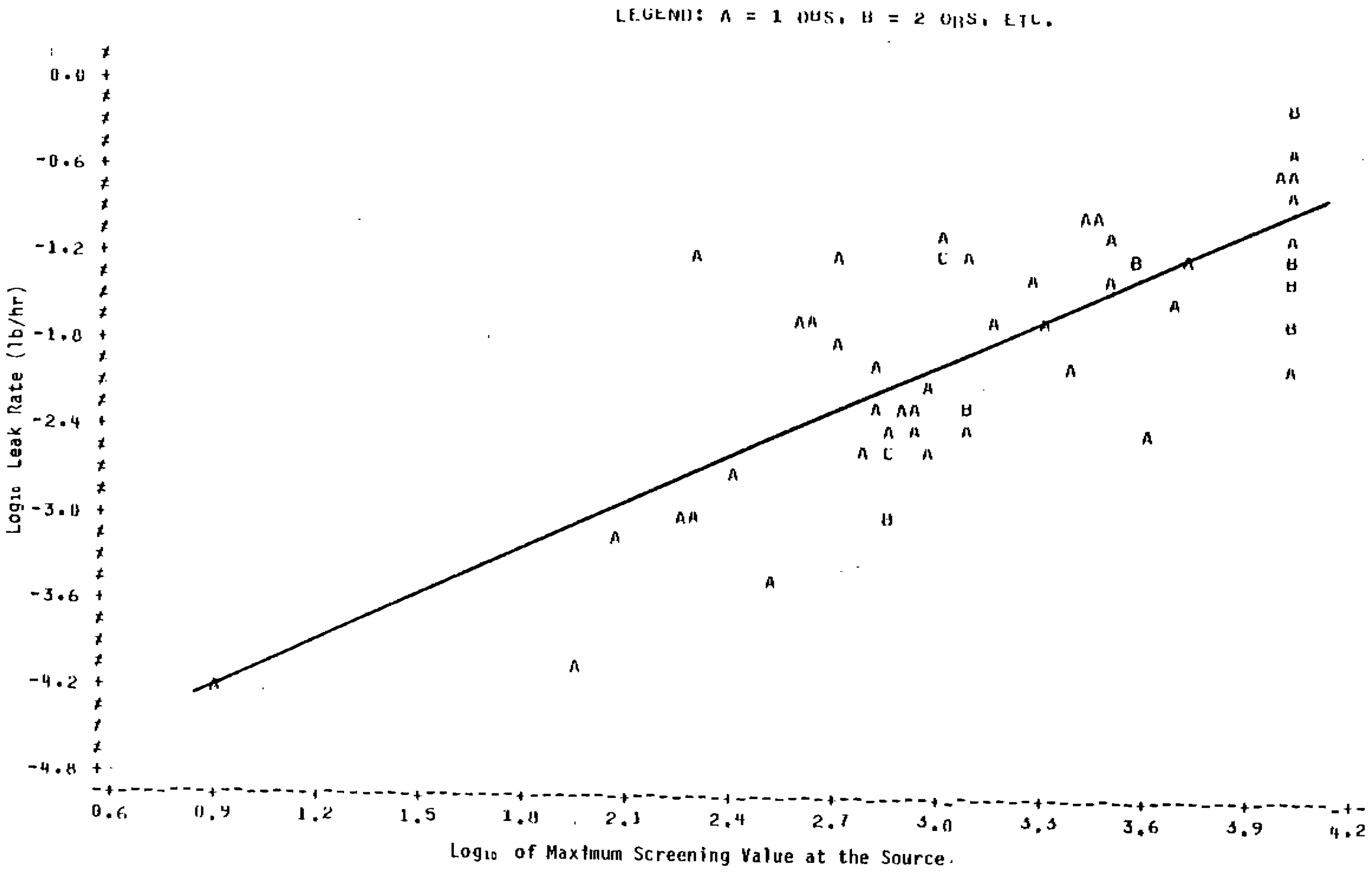


Figure B2-38. Leak rate/screening relationship - pump seals, heavy liquid streams.

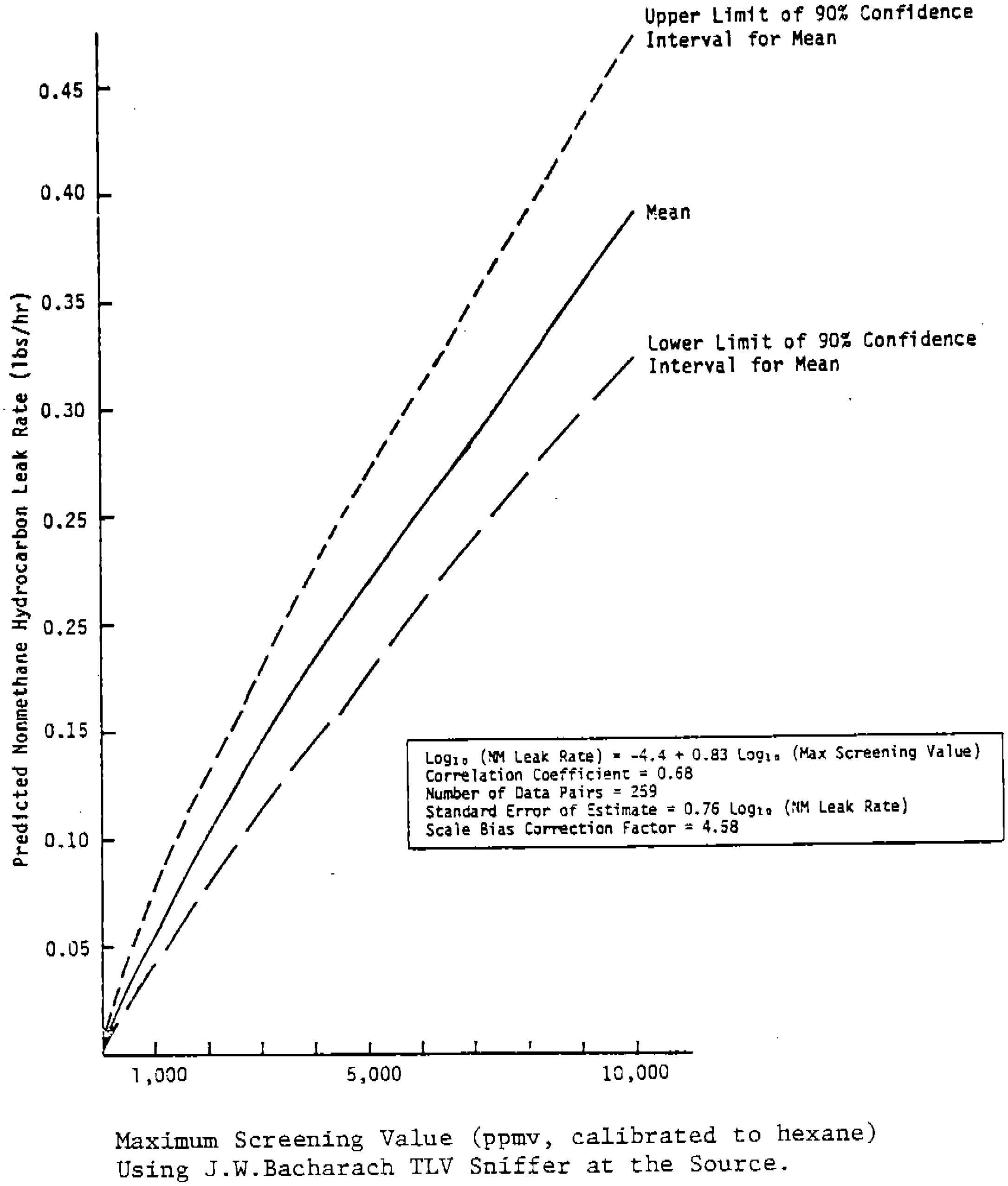


Figure B2-39A. Nomograph for predicting total hydrocarbon leak rates from maximum screening values - pumps (light liquids), compressors, relief valves (gas/vapor streams) (Part I: Screening values from 0-10,000 ppm).

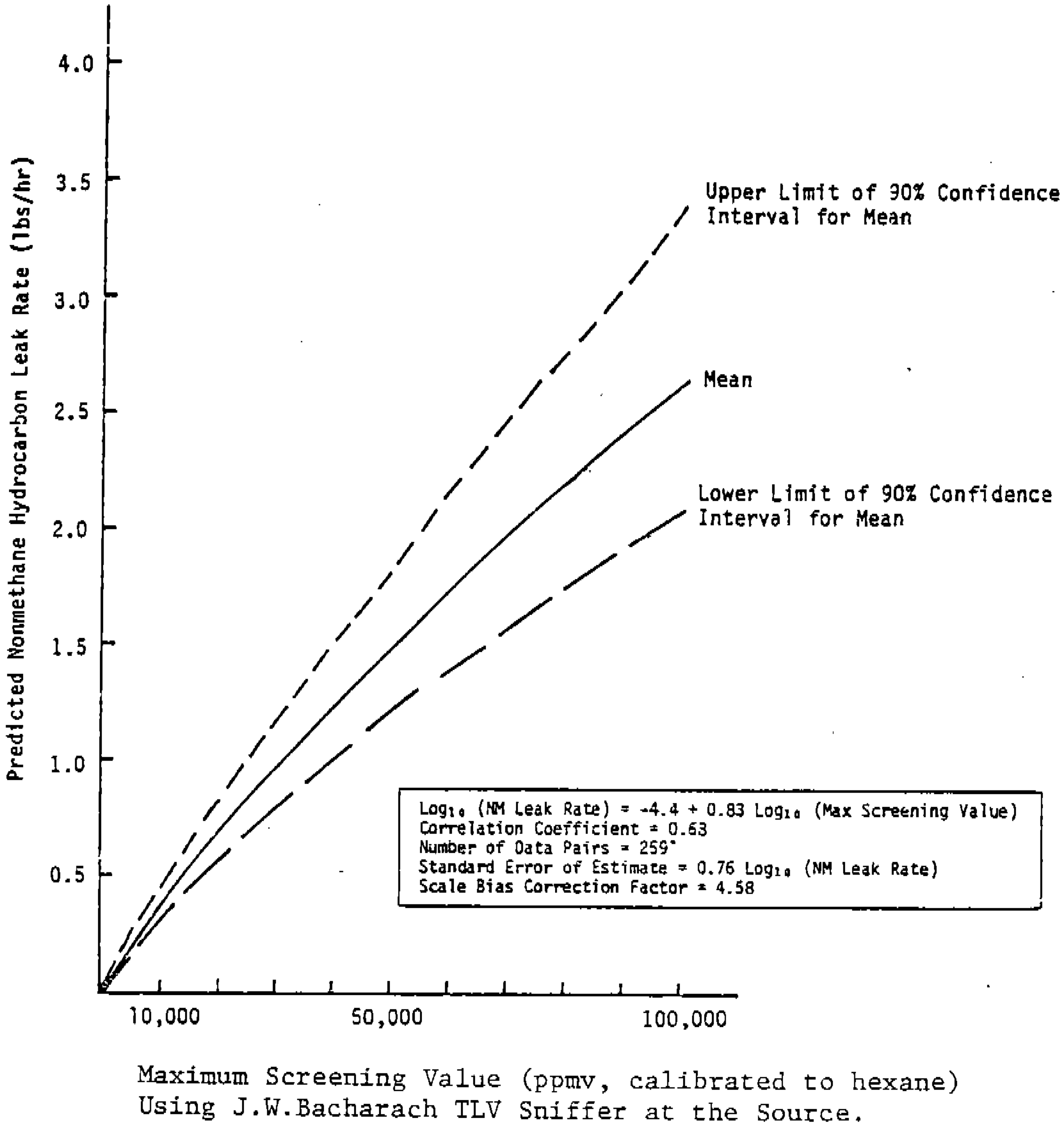


Figure B2-39B. Nomograph for predicting total hydrocarbon leak rates from maximum screening values - pumps (light liquids), compressors, relief valves (gas/vapor streams)(Part II: Screening values from 0-100,000 ppm).

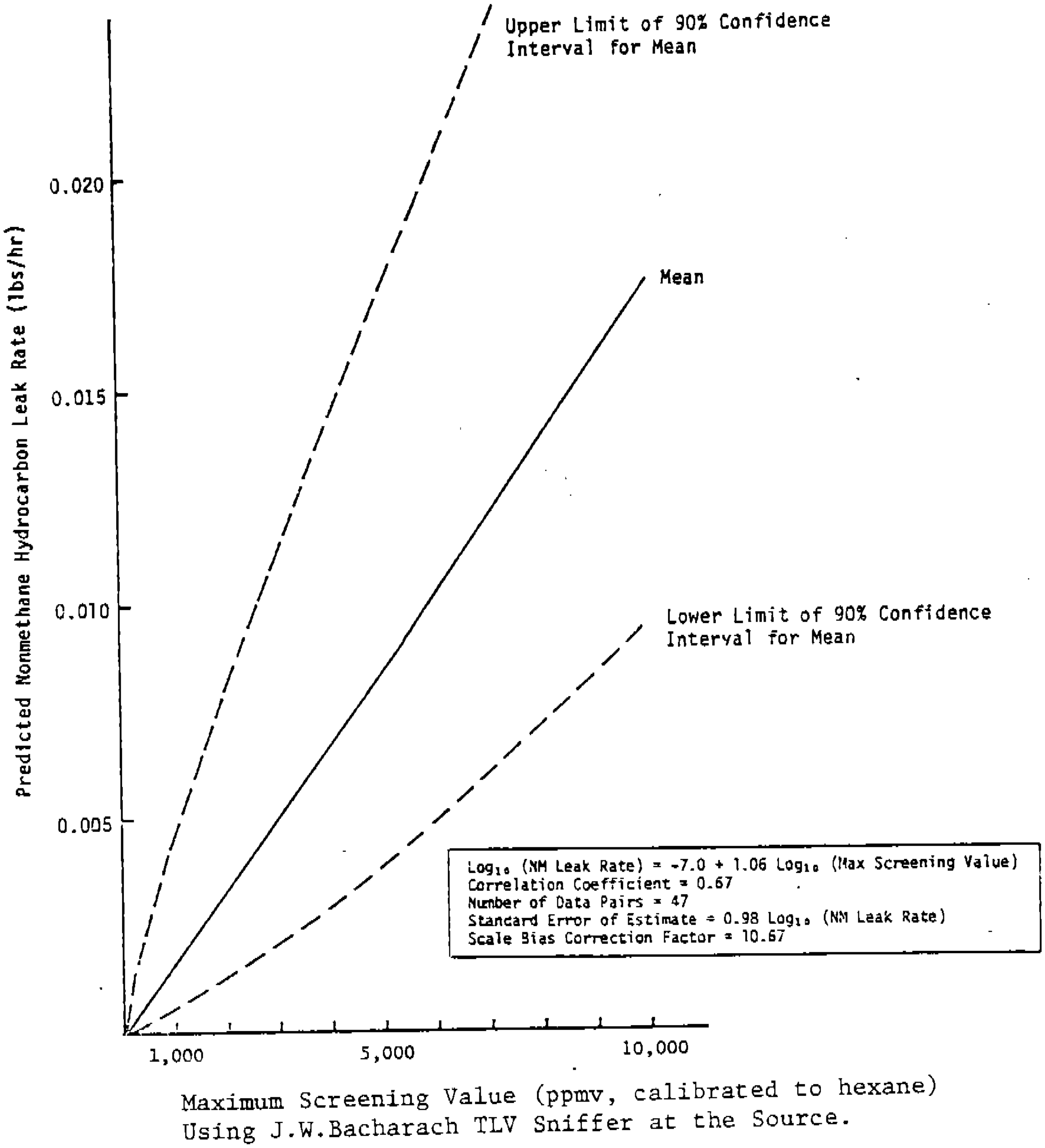


Figure B2-40A. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - valves and compressors in hydrogen service (Part I: Screening values from 0-10,000 ppm).

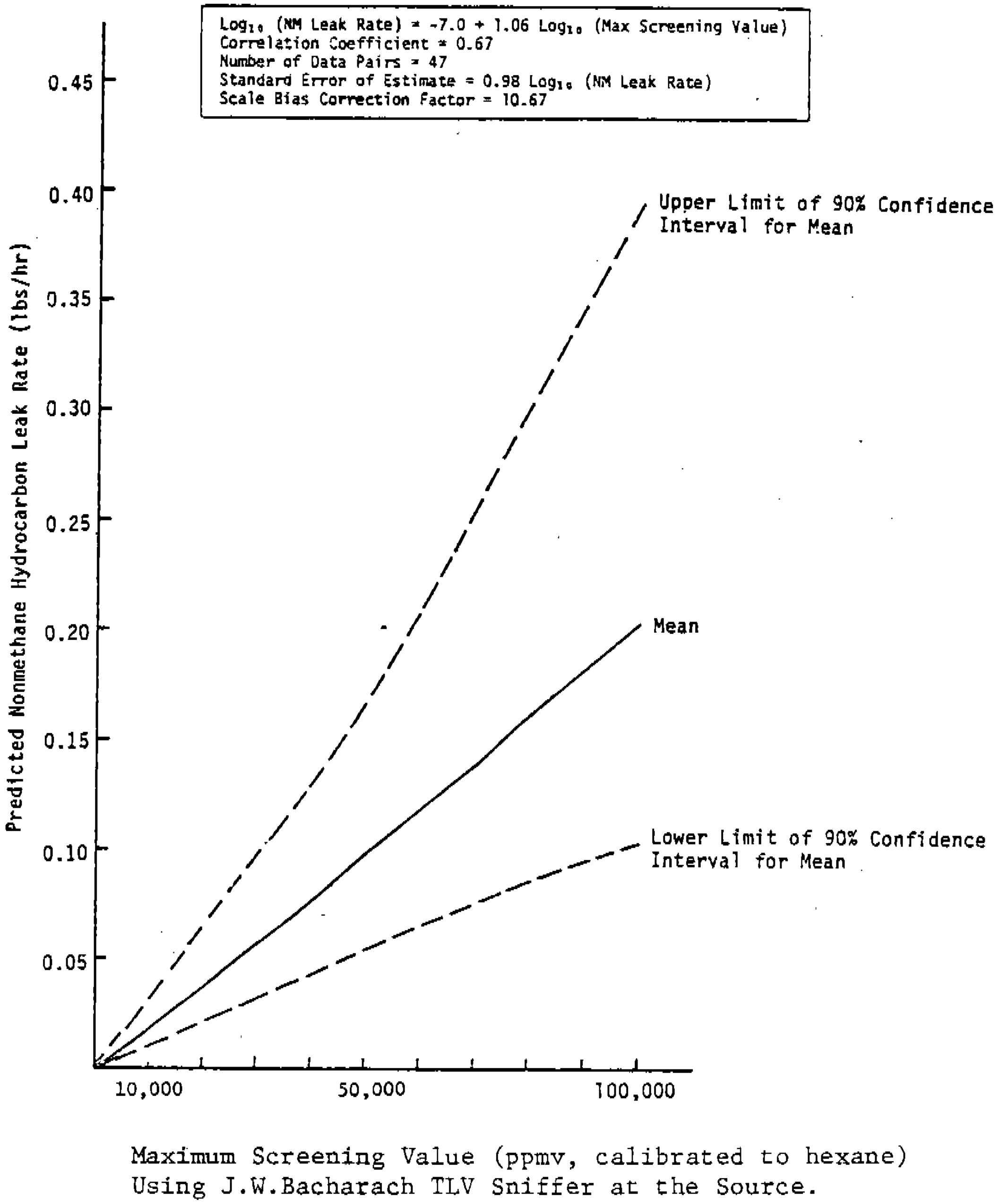


Figure B2-40B. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - valves and compressors in hydrogen service (Part II: Screening values from 0-100,000 ppm).

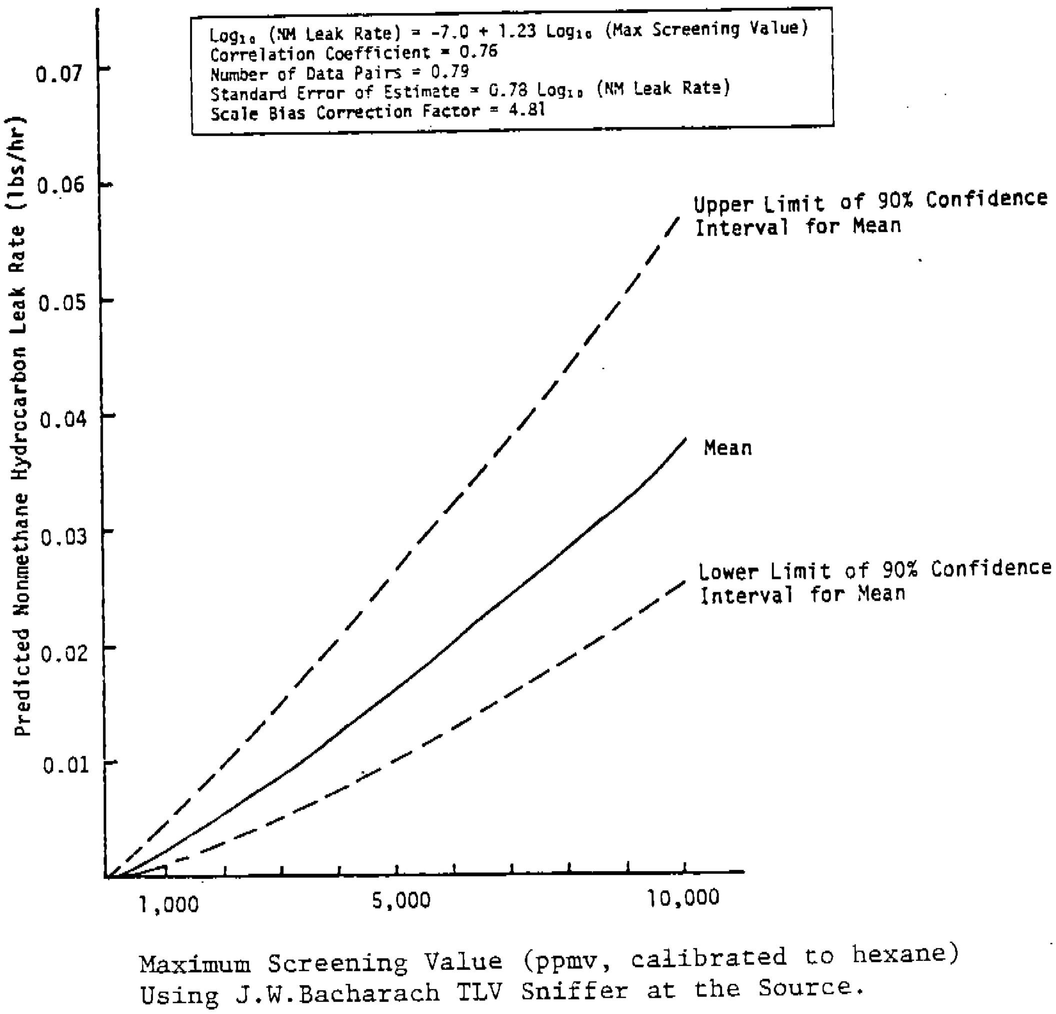


Figure B2-41A. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - valves, gas/vapor streams (Part I: Screening values from 0-10,000 ppm).

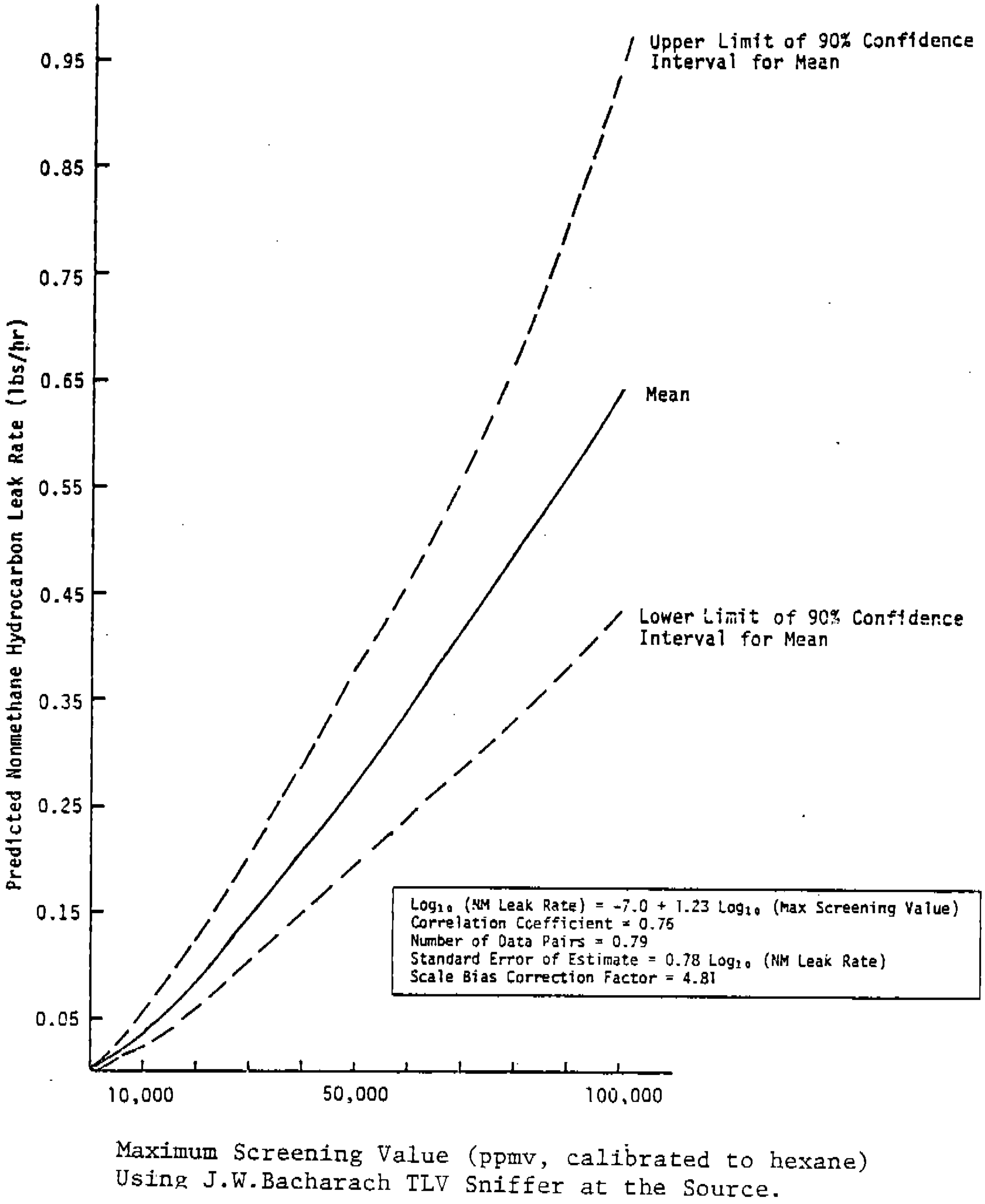


Figure B2-41B. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - valves, gas/vapor streams (Part II: Screening values from 0-100,000 ppm).

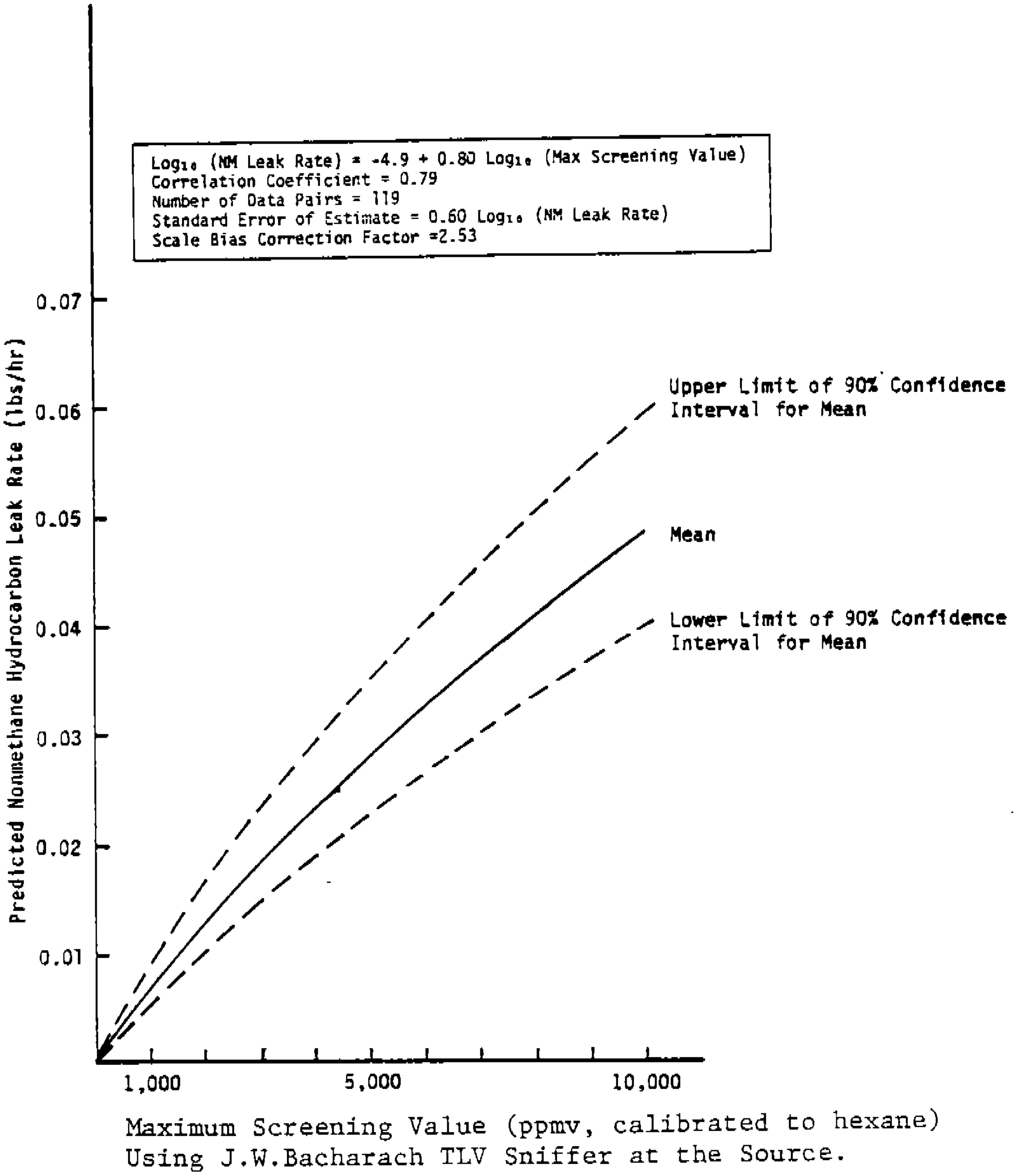


Figure B2-42A. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - valves, light liquid/two-phase streams (Part I: Screening values from 0-10,000 ppm).

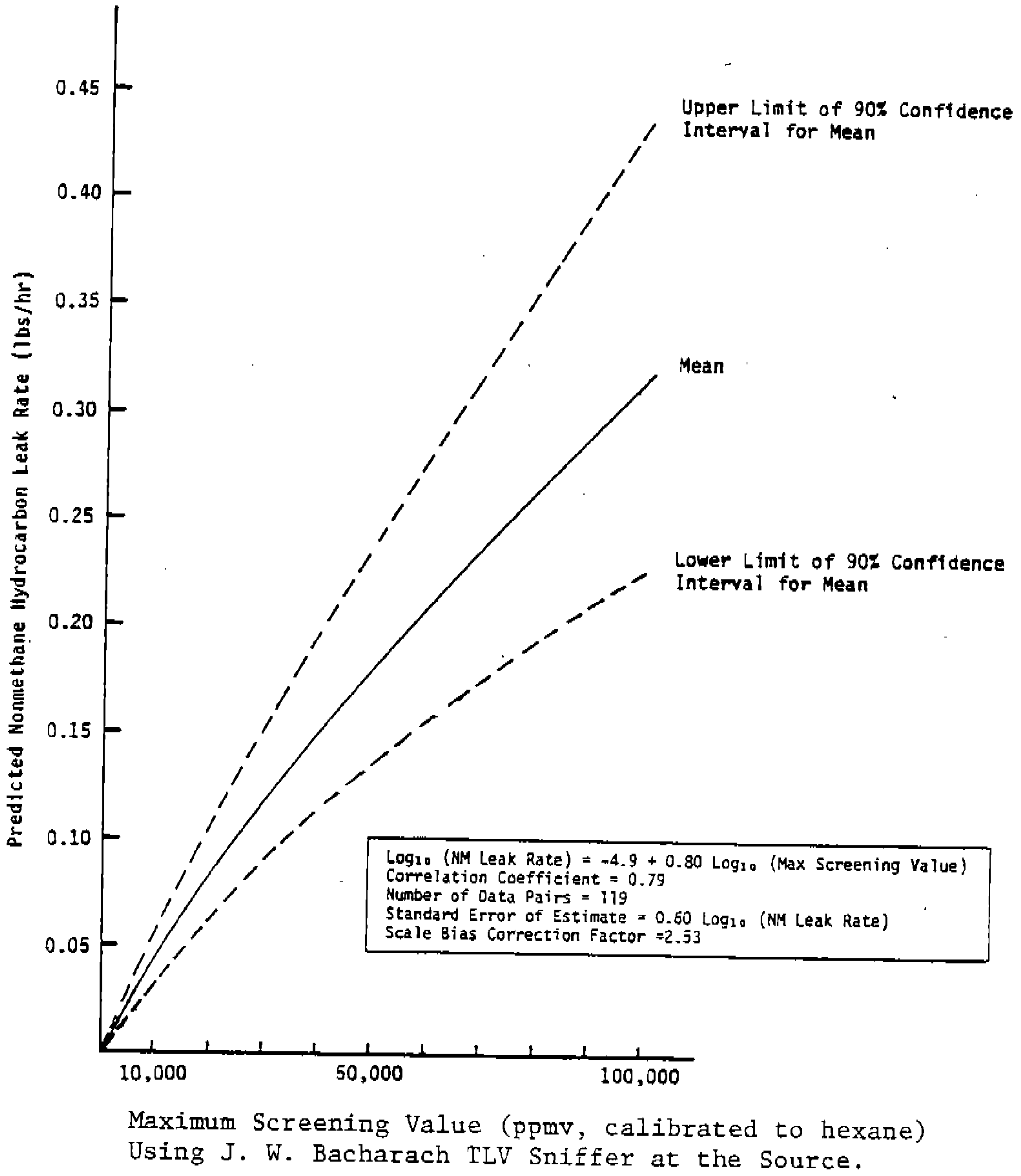


Figure B2-42B. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - valves, light liquid/two-phase streams (Part II: Screening values from 0-100,000 ppm).

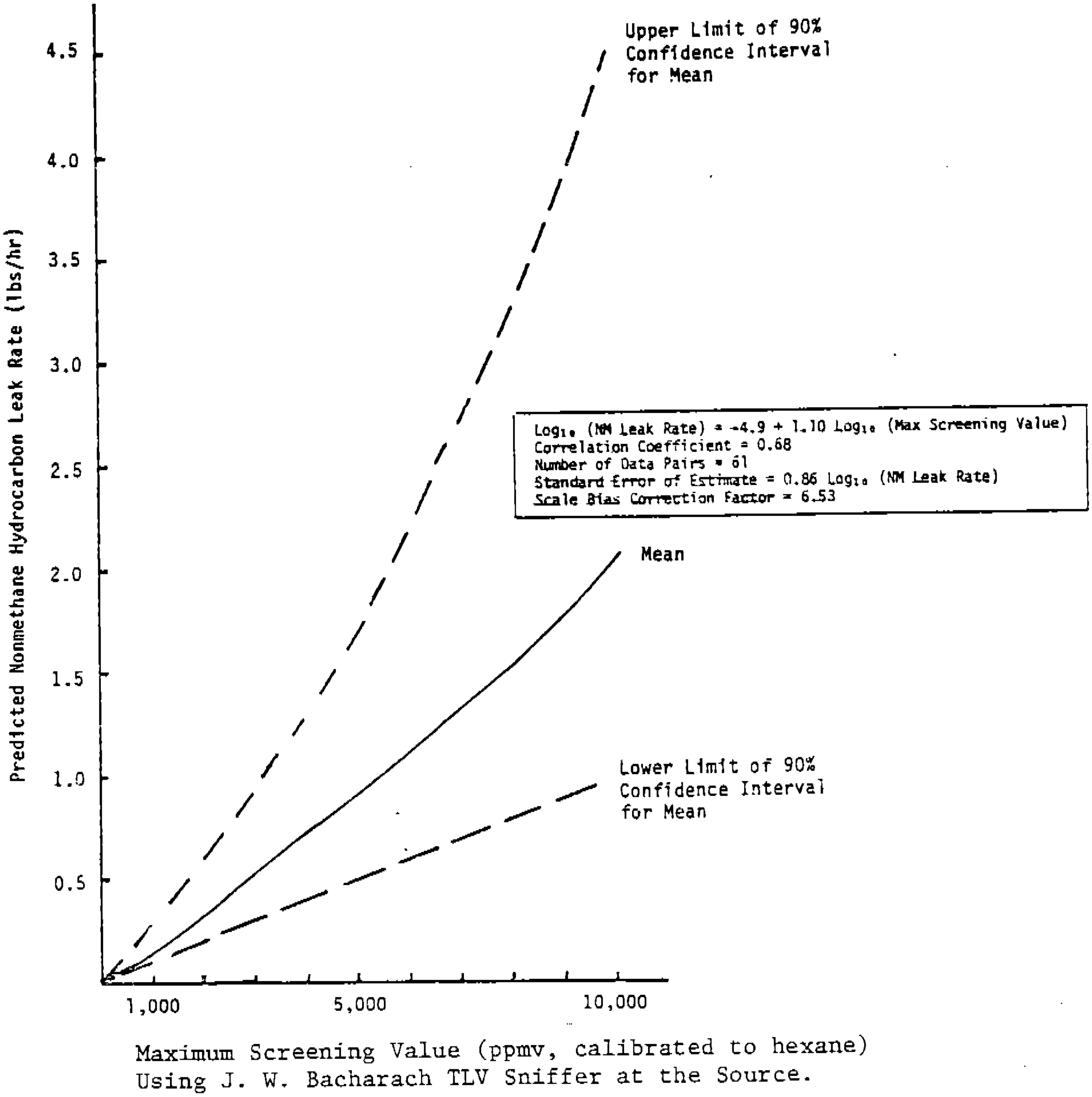


Figure B2-43. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - drains.

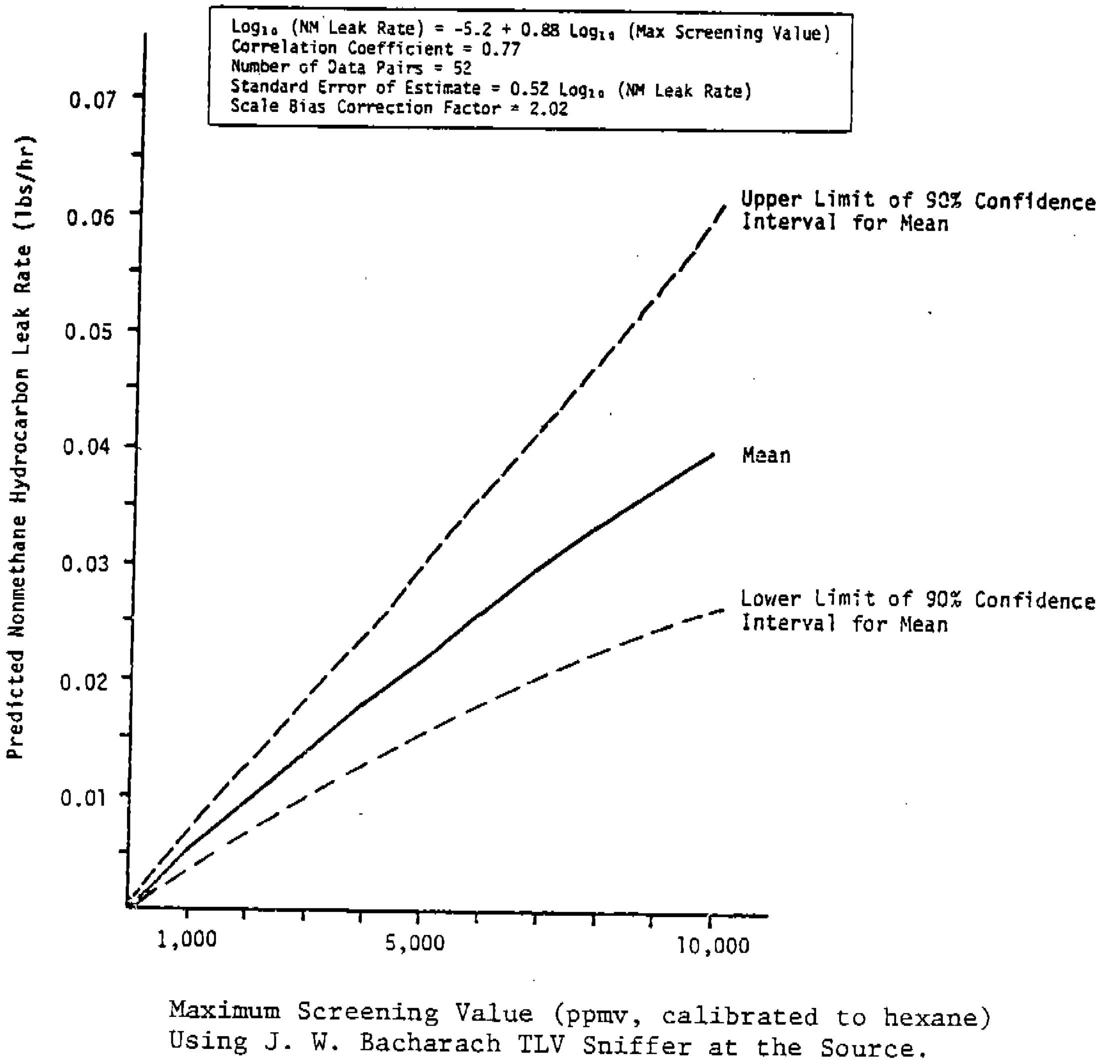
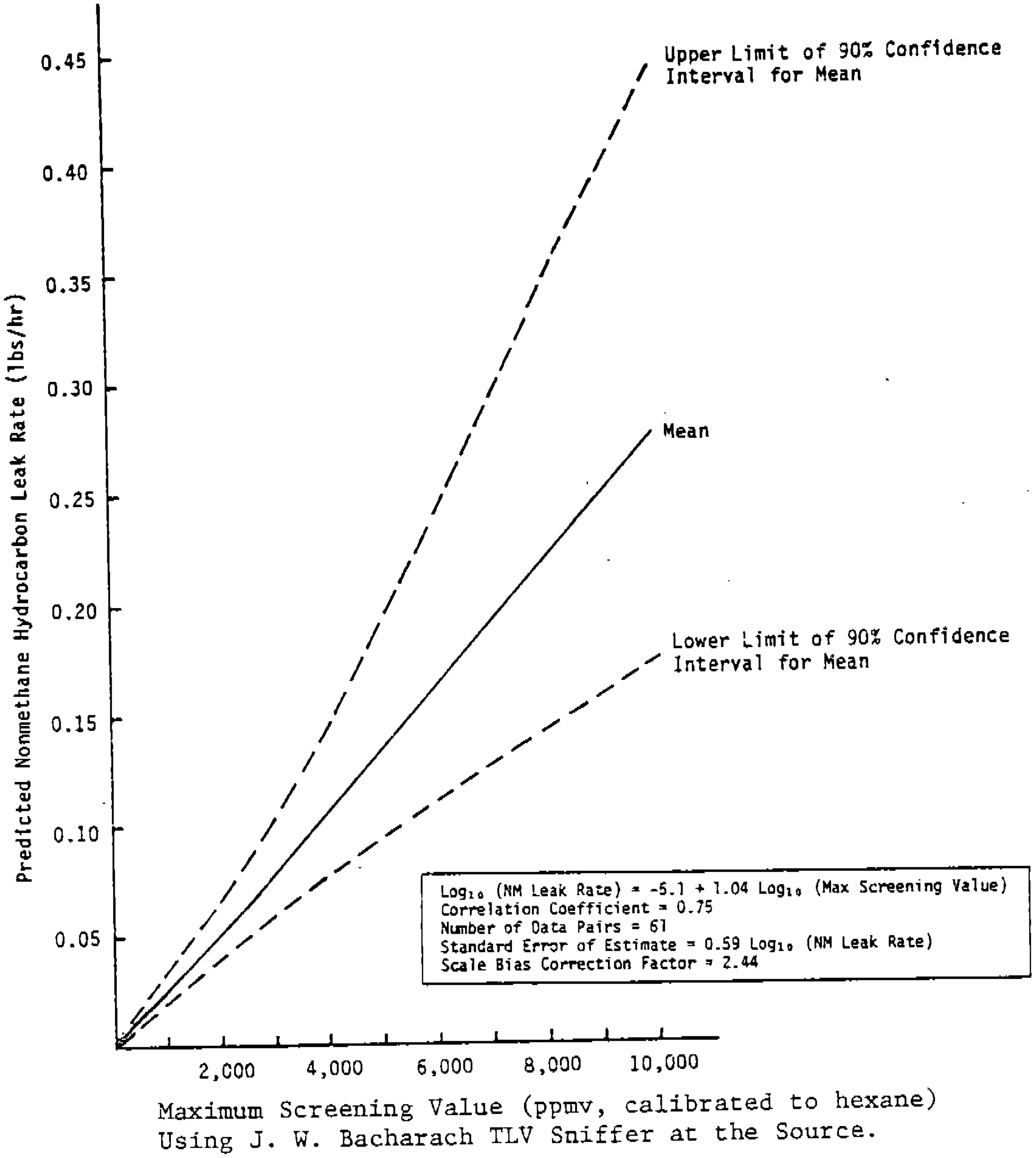
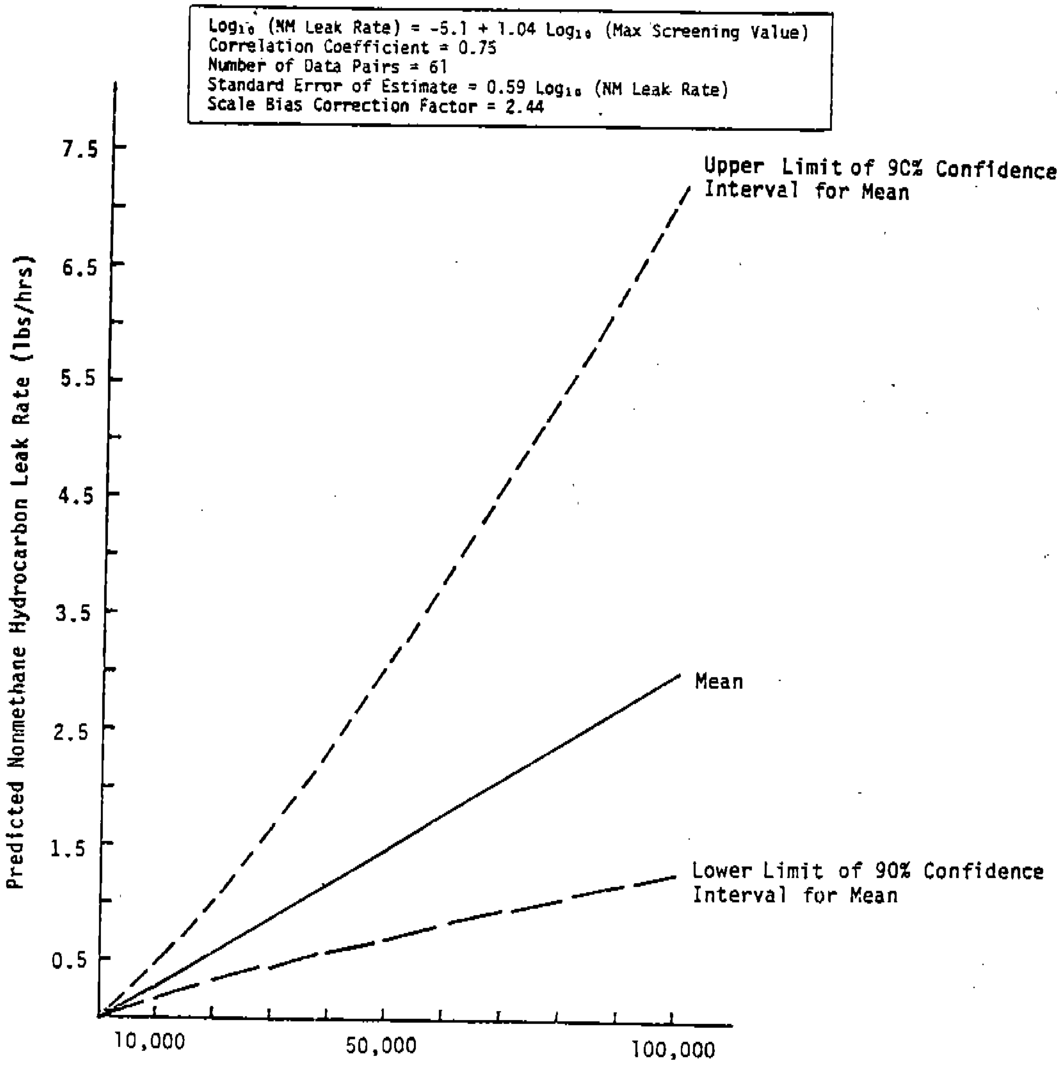


Figure B2-44. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - flanges.



$\log_{10}$ (NM Leak Rate) = -5.1 + 1.04 $\log_{10}$ (Max Screening Value)
Correlation Coefficient = 0.75
Number of Data Pairs = 61
Standard Error of Estimate = 0.59 $\log_{10}$ (NM Leak Rate)
Scale Bias Correction Factor = 2.44

Figure B2-45A. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - pumps, heavy liquid streams (Part I: Screening values from 0-10,000 ppm).



Maximum Screening Value (ppmv, calibrated to hexane)
Using J. W. Bacharach TLV Sniffer at the Source.

Figure B2-45B. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - pumps, heavy liquid streams (Part II: Screening values from 0-100,000 ppm).

$$\text{Mean} = \exp_{10}\ [B_0 + B_1\ \text{Log}_{10}\ (\text{screening})]\ g\ (SE^2_{Ln}/2)$$

$$= (10)^{B_0}\ (\text{screening value})^{B_1}\ (\text{scale bias correction factor}) \quad ,$$

where B_0 = Log regression intercept,

B_1 = Log regression slope,

SE_{Ln} = Standard error of estimate in natural log scale, and

$g(t)$ = Series described in Appendix C.

The 90 percent confidence intervals shown on the nomographs for the predicted mean leak for a given screening value were computed in a similar manner to the confidence intervals for the mean leak rate as described in Appendix C. These confidence limits are for the mean leak rate and should not be confused with confidence intervals for individual leak rates for given screening values. Tables B2-8 through B2-14 compare the 90 percent confidence intervals for the mean leak rate and the 90 percent confidence intervals for individual leaks for selected screening values for each of the seven equations.

Figures B2-46A and B graphically compare the confidence intervals for individual leak rates with the confidence interval for the mean leak rate for valves (light liquid/two-phase streams).

TABLE B2-8. CONFIDENCE INTERVALS FOR MEAN AND INDIVIDUAL LEAK RATES - PUMP SEALS (LIGHT LIQUID/TWO-PHASE STREAMS), COMPRESSOR SEALS AND RELIEF VALVES (GAS/VAPOR STREAMS)

Value (ppmv) [1]	Predicted Mean Leak Rate (lb/hr)	90% Confidence Interval	
		Mean Leak (lb/hr)	Individual Leak (lb/hr)
1	0.00018	(7.3x10^{-5}, 0.00045)	(8.8x10^{-6}, 0.0037)
200	0.015	(0.0096, 0.023)	(0.00081, 0.28)
500	0.032	(0.022, 0.047)	(0.0018, 0.59)
1,000	0.057	(0.042, 0.078)	(0.0032, 1.0)
3,000	0.14	(0.11, 0.18)	(0.0079, 2.6)
5,000	0.22	(0.18, 0.27)	(0.012, 3.9)
10,000	0.39	(0.32, 0.47)	(0.222, 7.0)
20,000	0.70	(0.58, 0.83)	(0.039, 12.5)
50,000	1.5	(1.2, 1.8)	(0.083, 27.0)
100,000	2.7	(2.1, 3.4)	(0.15, 48.0)

[1] TLV Sniffer Screening Value, ppmv (calibrated to hexane)

TABLE B2-9. CONFIDENCE INTERVALS FOR MEAN AND INDIVIDUAL LEAK RATES - VALVES AND COMPRESSOR SEALS (HYDROGEN STREAMS)

Value (ppmv)[1]	Predicted Mean Leak Rate (lb/hr)	90% Confidence Interval	
		Mean Leak (lb/hr)	Individual Leak (lb/hr)
1	10^{-6}	(10^{-7}, $2.0x10^{-5}$)	(0.0, 0.00012)
200	0.00028	($6.2x10^{-5}$, 0.0013)	($5.1x10^{-6}$, 0.015)
500	0.00074	(0.00021, 0.0026)	($1.5x10^{-5}$, 0.037)
1,000	0.0015	(0.00052, 0.0045)	($3.2x10^{-5}$, 0.073)
3,000	0.0049	(0.0022, 0.011)	(0.00011, 0.22)
5,000	0.0085	(0.0041, 0.017)	(0.00019, 0.37)
10,000	0.018	(0.0096, 0.032)	(0.00041, 0.75)
20,000	0.037	(0.021, 0.064)	(0.00087, 1.6)
50,000	0.097	(0.055, 0.17)	(0.0023, 4.1)
100,000	0.20	(0.10, 0.40)	(0.0047, 8.8)

[1] TLV Sniffer Screening Value, ppmv (calibrated to hexane)

TABLE B2-10. CONFIDENCE INTERVALS FOR MEAN AND INDIVIDUAL LEAK RATES - VALVES (GAS/VAPOR STREAMS)

Value (ppmv) [1]	Predicted Mean Leak Rate (lb/hr)	90% Confidence Interval	
		Mean Leak (lb/hr)	Individual Leak (lb/hr)
1	$4x10^{-7}$	(10^{-7}, $3.6x10^{-6}$)	(0.0, $1.67x10^{-5}$)
200	0.00030	(0.00010, 0.00089)	($1.3x10^{-5}$, 0.0071)
500	0.00094	(0.00038, 0.00023)	($4.3x10^{-5}$, 0.021)
1 000	0.0022	(0.0010, 0.0048)	(0.00010, 0.047)
3,000	0.0085	(0.0048, 0.015)	(0.00042, 0.17)
5,000	0.016	(0.0097, 0.026)	(0.00080, 0.32)
10,000	0.038	(0.025, 0.057)	(0.0019, 0.75)
20,000	0.089	(0.063, 0.13)	(0.0045, 1.75)
50,000	0.27	(0.19, 0.39)	(0.014, 5.4)
100,000	0.64	(0.43, 0.96)	(0.032, 13.0)

[1] TLV Sniffer Screening Value, ppmv (calibrated to hexane)

TABLE B2-11. CONFIDENCE INTERVALS FOR MEAN AND INDIVIDUAL LEAK RATES - VALVES (LIGHT LIQUID/TWO-PHASE STREAMS)

Value (ppmv)[1]	Predicted Mean Leak Rate (lb/hr)	90% Confidence Interval	
		Mean Leak (lb/hr)	Individual Leak (lb/hr)
1	3.2x10^{-5}	(1.4x10^{-5}, 7.5x10^{-5})	(2.9x10^{-6}, 0.00036)
200	0.0022	(0.0015, 0.0032)	(0.00022, 0.022)
500	0.0046	(0.0033, 0.0063)	(0.00047, 0.045)
1,000	0.0079	(0.0061, 0.010)	(0.00082, 0.077)
3,000	0.019	(0.015, 0.024	(0.0020, 0.19)
5,000	0.029	(0.023, 0.035)	(0.0030, 0.28)
10,000	0.050	(0.040, 0.062)	(0.0052, 0.48)
20,000	0.087	(0.069, 0.11)	(0.0090, 0.84)
50,000	0.18	(0.14, 0.24)	(0.019, 1.8)
100,000	0.31	(0.23, 0.44)	(0.032, 3.1)

[1] TLV Sniffer Screening Value, ppmv (calibrated to hexane)

TABLE B2-12. CONFIDENCE INTERVALS FOR MEAN AND INDIVIDUAL LEAK RATES - DRAINS

Value (ppmv)[1]	Predicted Mean Leak Rate (lb/hr)	90% Confidence Interval	
		Mean Leak (lb/hr)	Individual Leak (lb/hr)
1	8.1x10^{-5}	(1.5x10^{-5}, 0.00045)	(2.0x10^{-6}, 0.0032)
200	0.028	(0.016 0.048)	(0.0010, 0.76)
500	0.077	(0.050 0.12)	(0.0029, 2.1)
1,000	0.16	(0.11, 0.25)	(0.0061, 4.4)
3,000	0.55	(0.32, 0.95)	(0.020, 15.0)
5,000	0.97	(0.51, 1.8)	(0.035, 27.0)
10,000	2.1	(0.96, 4.5)	(0.073, 59.0)

[1] TLV Sniffer Screening Value, ppmv (calibrated to hexane)

TABLE B2-13. CONFIDENCE INTERVALS FOR MEAN AND INDIVIDUAL LEAK RATES - FLANGES

Value (ppmv)[1]	Predicted Mean Leak Rate (lb/hr)	90% Confidence Interval Mean Leak (lb/hr)	90% Confidence Interval Individual Leak (lb/hr)
1	$1.2\text{x}10^{-5}$	($3.4\text{x}10^{-6}$, $4.5\text{x}10^{-5}$)	($1.2\text{x}10^{-6}$, 0.00013)
200	0.0013	(0.00083, 0.0020)	(0.00017, 0.0099)
500	0.0029	(0.0021, 0.0041)	(0.00039, 0.022)
1,000	0.0053	(0.0040, 0.0071)	(0.00072, 0.040)
3,000	0.014	(0.010, 0.019)	(0.0019, 0.10)
5,000	0.022	(0.016, 0.031)	(0.0029, 0.16)
10,000	0.040	(0.027, 0.061)	(0.0053, 0.30)

[1] TLV Sniffer Screening Value, ppmv (calibrated to hexane)

TABLE B2-14. CONFIDENCE INTERVALS FOR MEAN AND INDIVIDUAL LEAK RATES - PUMP SEALS (HEAVY LIQUID STREAMS)

Valve (ppmv)[1]	Predicted Mean Leak Rate (lb/hr)	90% Confidence Interval Mean Leak (lb/hr)	90% Confidence Interval Individual Leak (lb/hr)
1	$2.0\text{x}10^{-5}$	($4.6\text{x}10^{-6}$, $8.4\text{x}10^{-5}$)	($1.4\text{x}10^{-6}$, 0.00028)
200	0.0048	(0.0030, 0.0077)	(0.00049, 0.047)
500	0.012	(0.0087, 0.018)	(0.0013, 0.12)
1,000	0.025	(0.019, 0.034)	(0.0027, 0.24)
3,000	0.079	(0.058, 0.11)	(0.0083, 0.75)
5,000	0.13	(0.093, 0.20)	(0.014, 1.3)
10,000	0.28	(0.17, 0.44)	(0.028, 2.7)

[1] TLV Sniffer Screening Value, ppmv (calibrated to hexane)

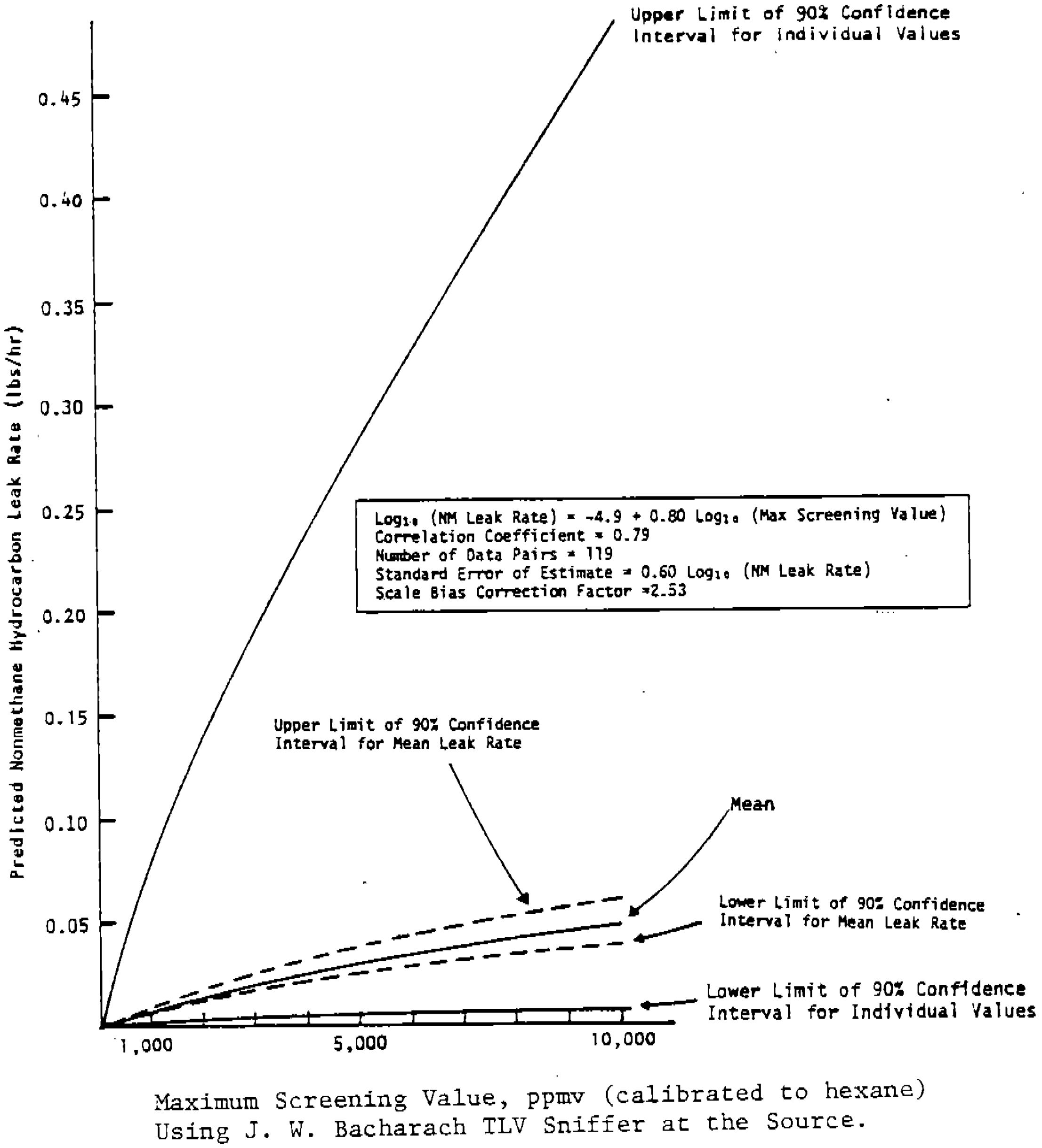


Figure B2-46A. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - valves, light liquid/two-phase streams (Part I: Screening values from 0-10,000 ppm).

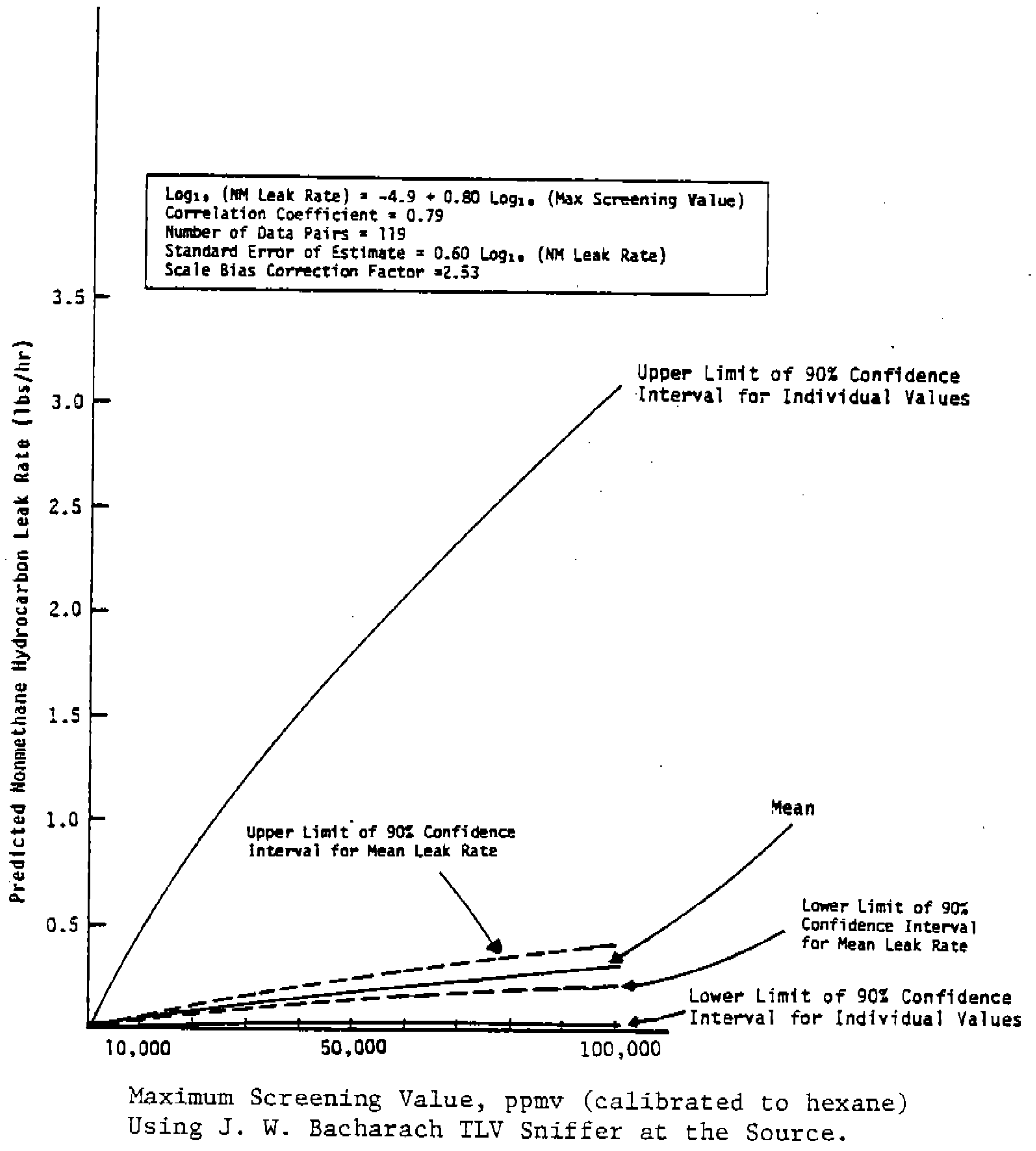


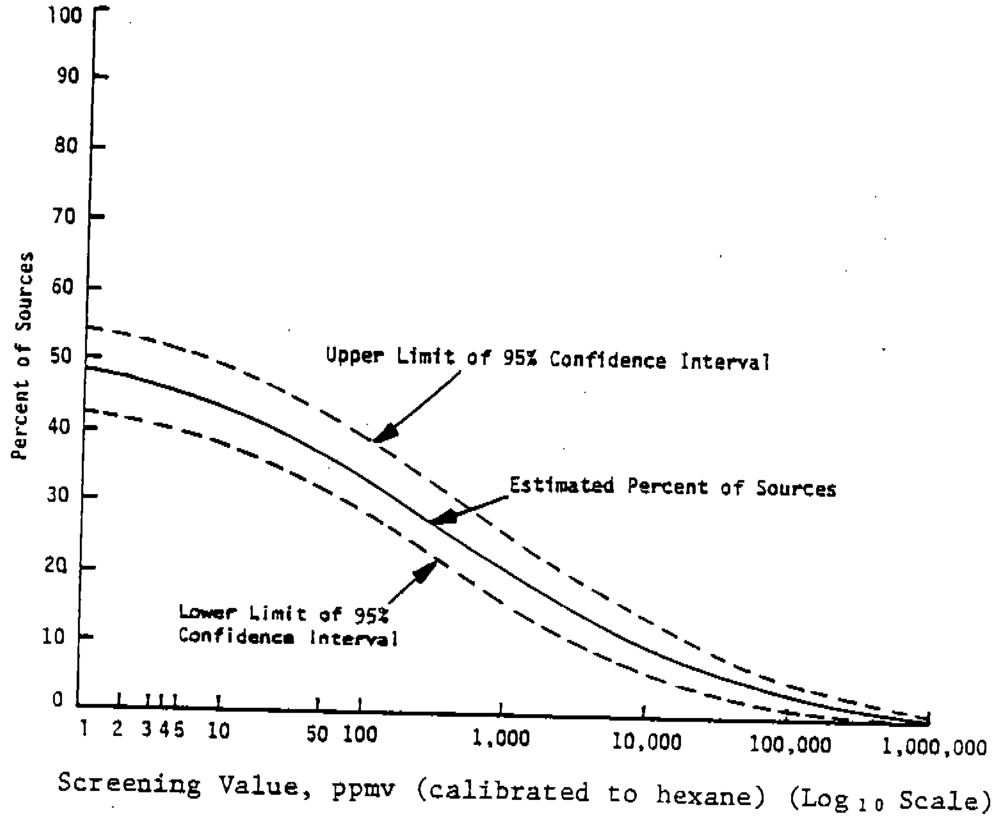
Figure B2-46B. Nomograph for predicting total nonmethane hydrocarbon leak rates from maximum screening values - valves, light liquid/two-phase streams (Part II: Screening values from 0-100,000 ppm).

2.4 DISTRIBUTION OF EMISSIONS AND SOURCES BASED ON SCREENING VALUES

A convenient tool both for monitoring hydrocarbon emission sources and estimating source leak rates is the portable hydrocarbon detector. From the results of this study, nomographs have been prepared relating hydrocarbon concentration at the source (screening value) to the percentage of each source type expected to have screening values above any selected value. Other nomographs have been prepared relating screening values to the percentage of total mass emissions which can be expected from sources with screening values greater than any given value. (See Appendix C for a discussion of nomograph development.)

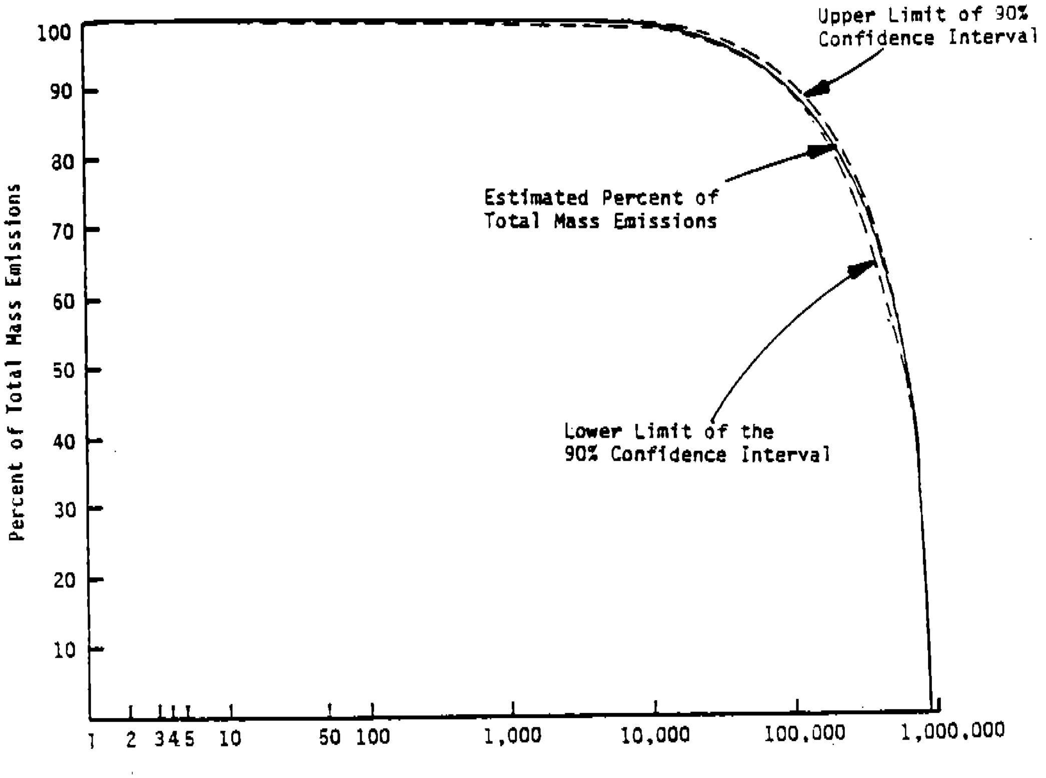
These nomographs for the six source types (and stream groups for valves, compressors, and pump seals) are presented in Figures B2-47 through B2-57. The "A" figures relate the percent of sources to screening values. The "B" figures relate the percent of total mass emissions for a given source category to screening values. The "C" and "D" figures are the same curves as in the "A" and "B" figures except the actual data are also included.

Confidence intervals are included on each of these nomographs. The statistical procedures used to develop these intervals are discussed in Section 6.3 of Appendix C. The confidence intervals for both types of nomographs indicate how well the cumulative function has been estimated from the data collected in this program.



Percent of Sources - indicates the percent of sources with screening values greater than the selected value.

Figure B2-47A. Cumulative distribution of sources and total emissions by screening values for valves - gas/vapor streams.



Screening Value, ppmv (calibrated to hexane) (Log_{10} Scale)

Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-47B. Cumulative distribution of source and total emissions by screening values for valves - gas/vapor stream.

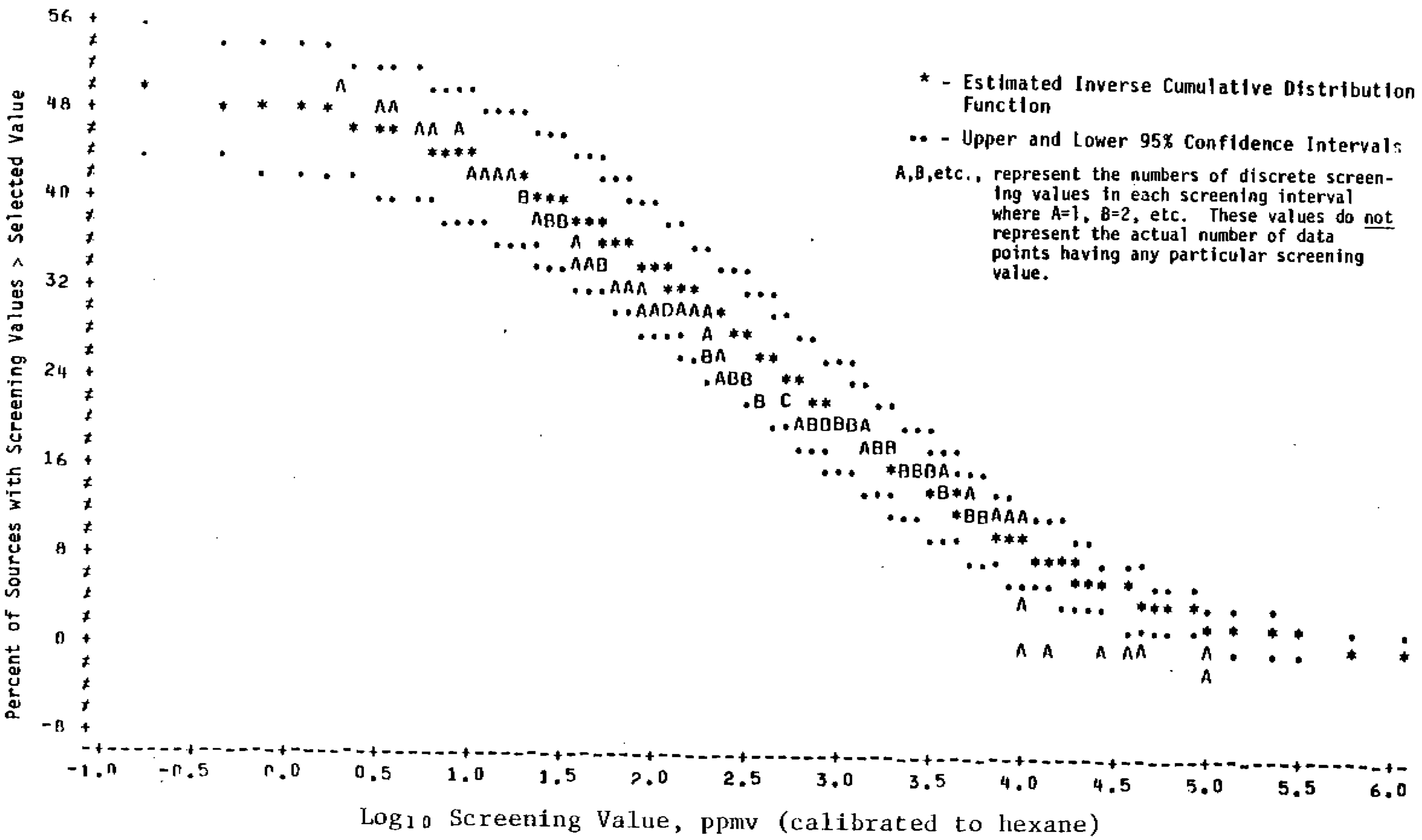


Figure B2-47C. Inverse cumulative distribution function for valves - gas/vapor streams.

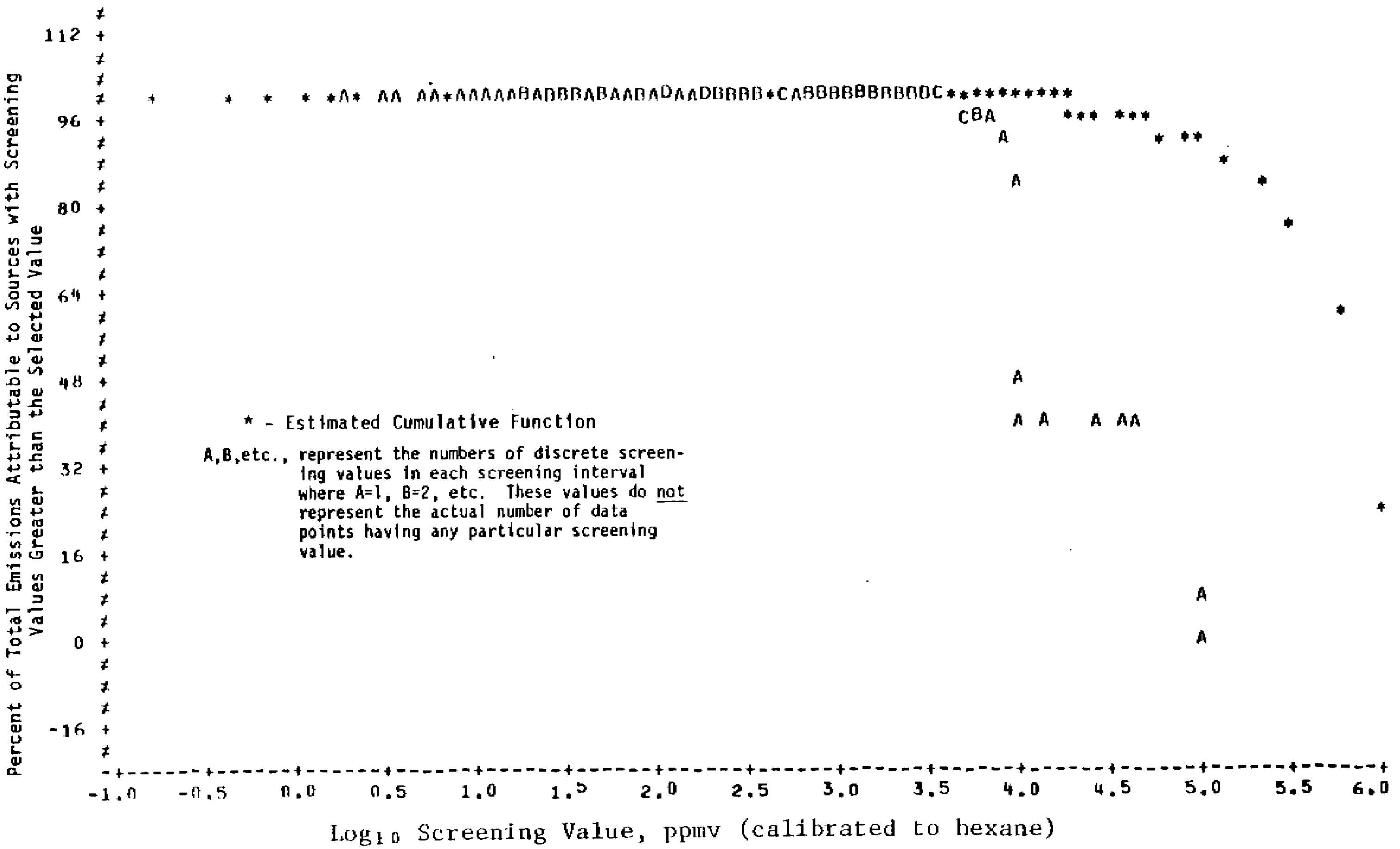


Figure B2-47D. Cumulative distribution of total emissions by screening values for valves - gas/vapor streams.

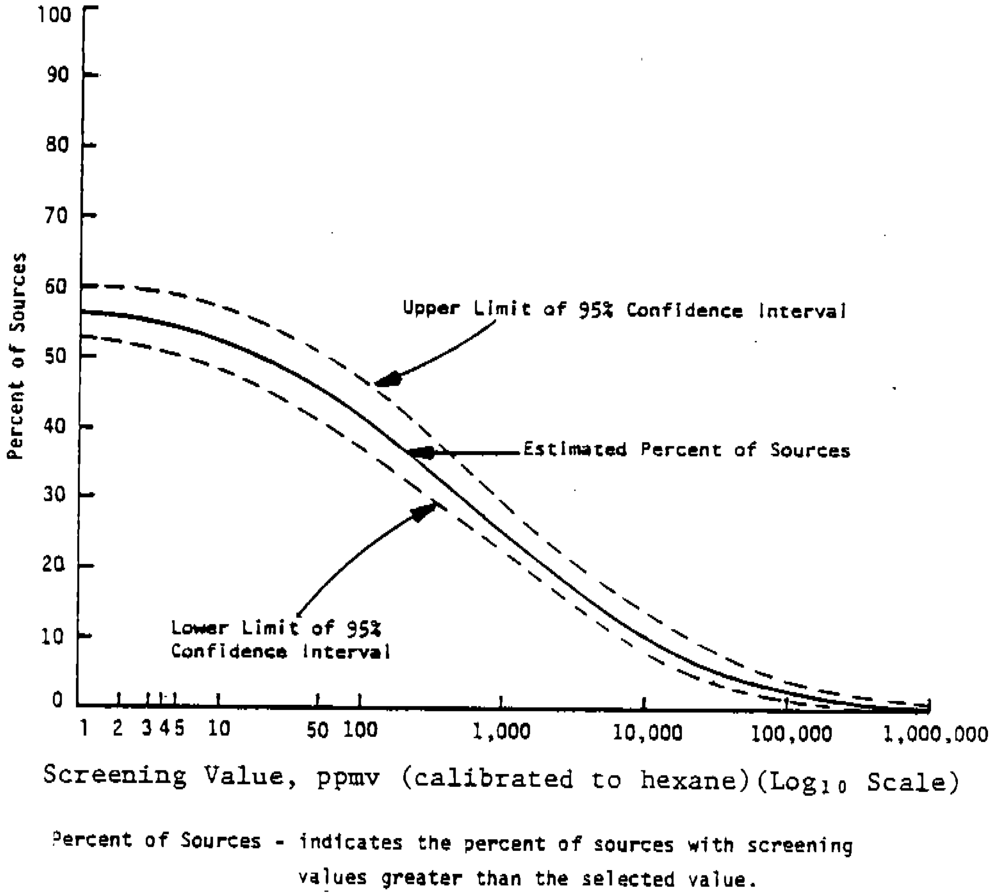
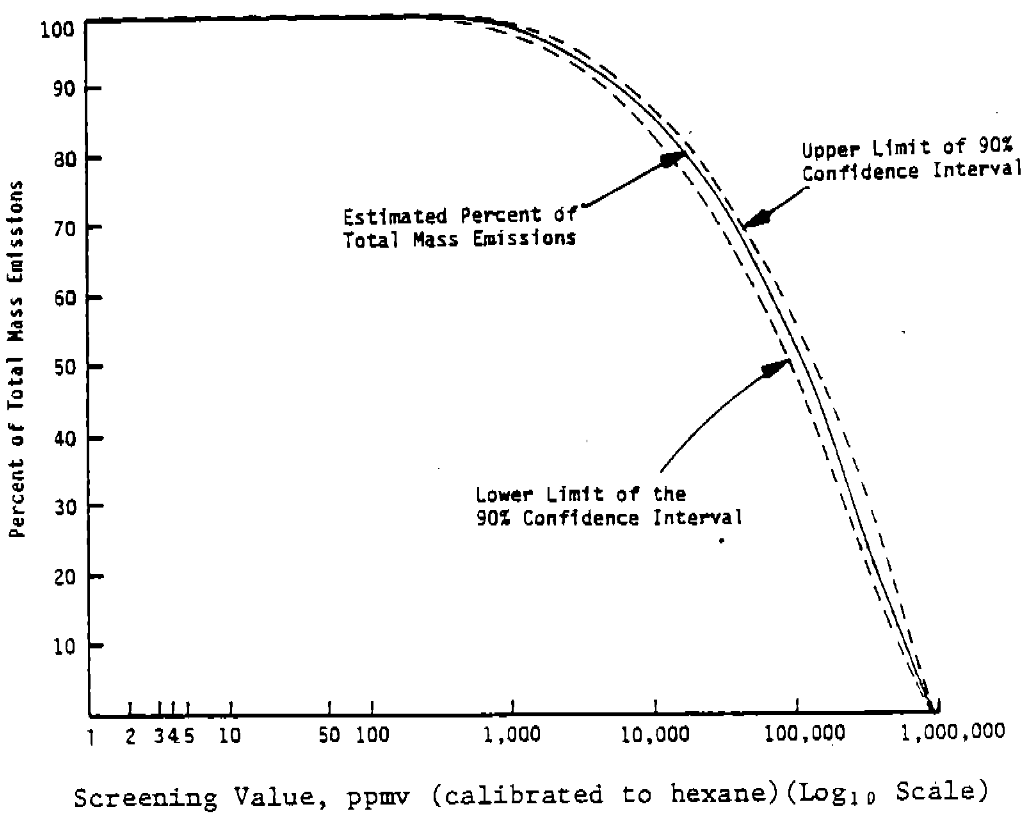


Figure B2-48A. Cumulative distribution of source and total emissions by screening values for valves - light liquid/two-phase streams.



Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-48B. Cumulative distribution of source and total emissions by screening values for valves - light liquid/two-phase streams.

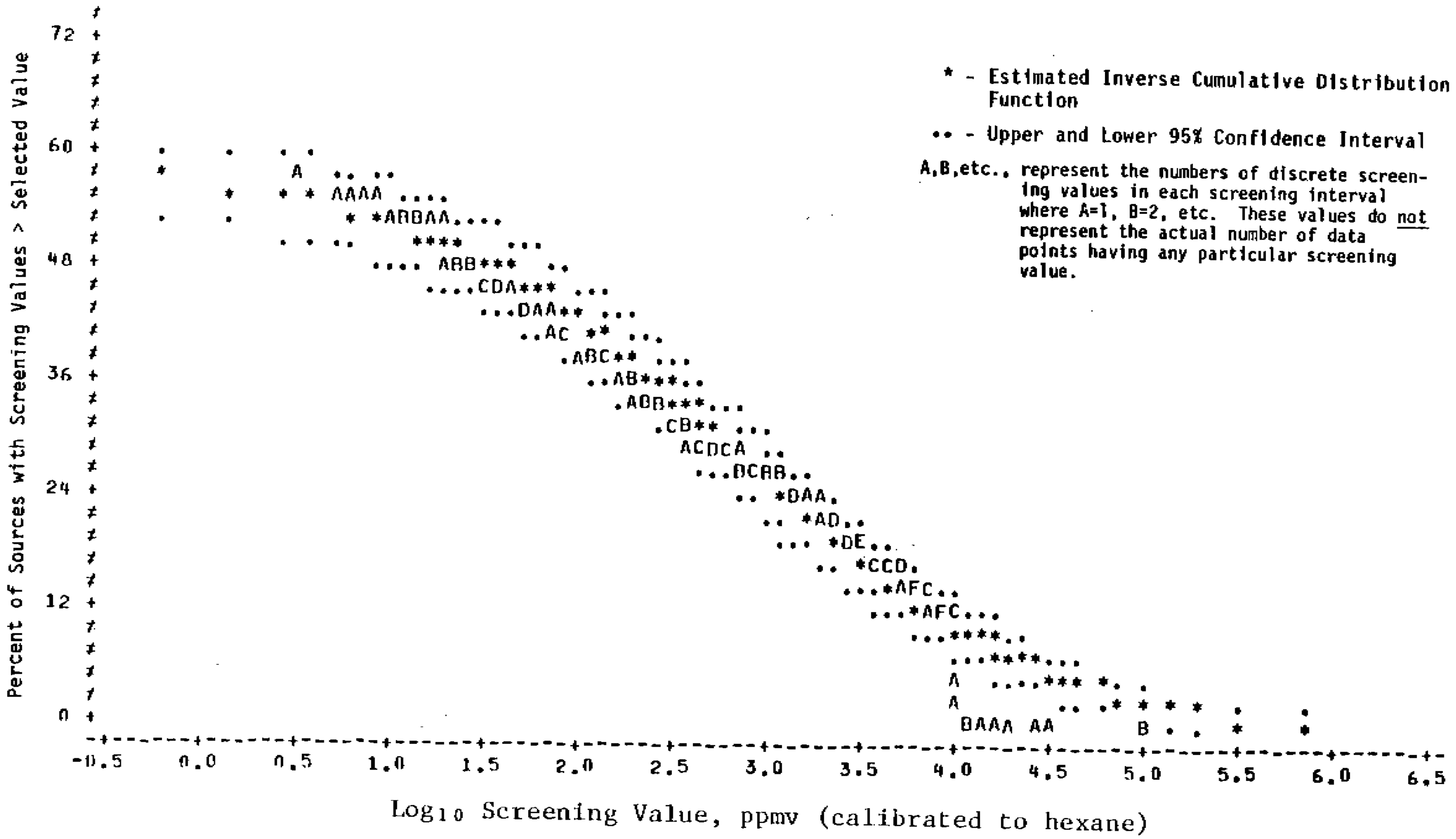


Figure B2-48C. Inverse cumulative distribution function for valves - light liquid/two-phase streams.

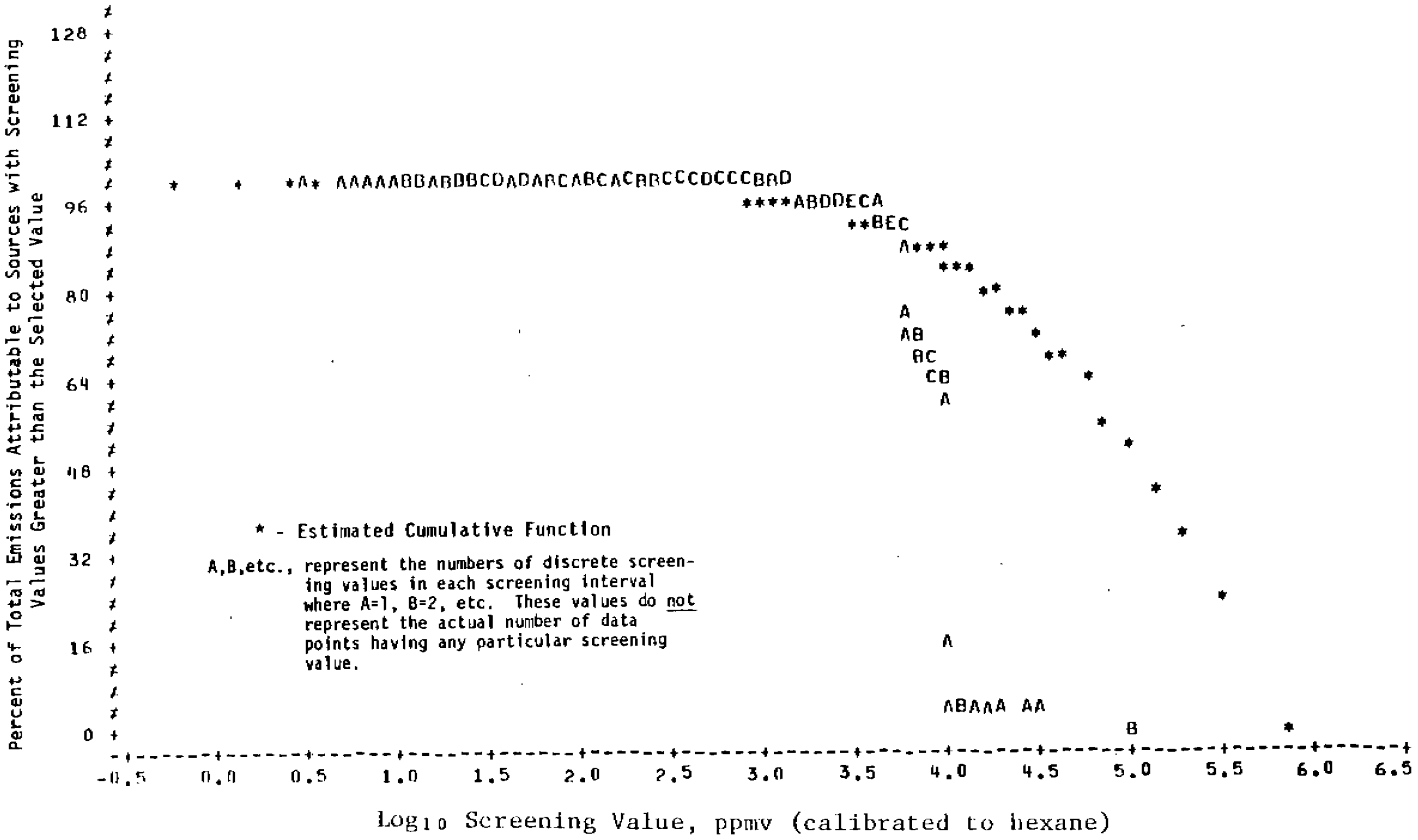
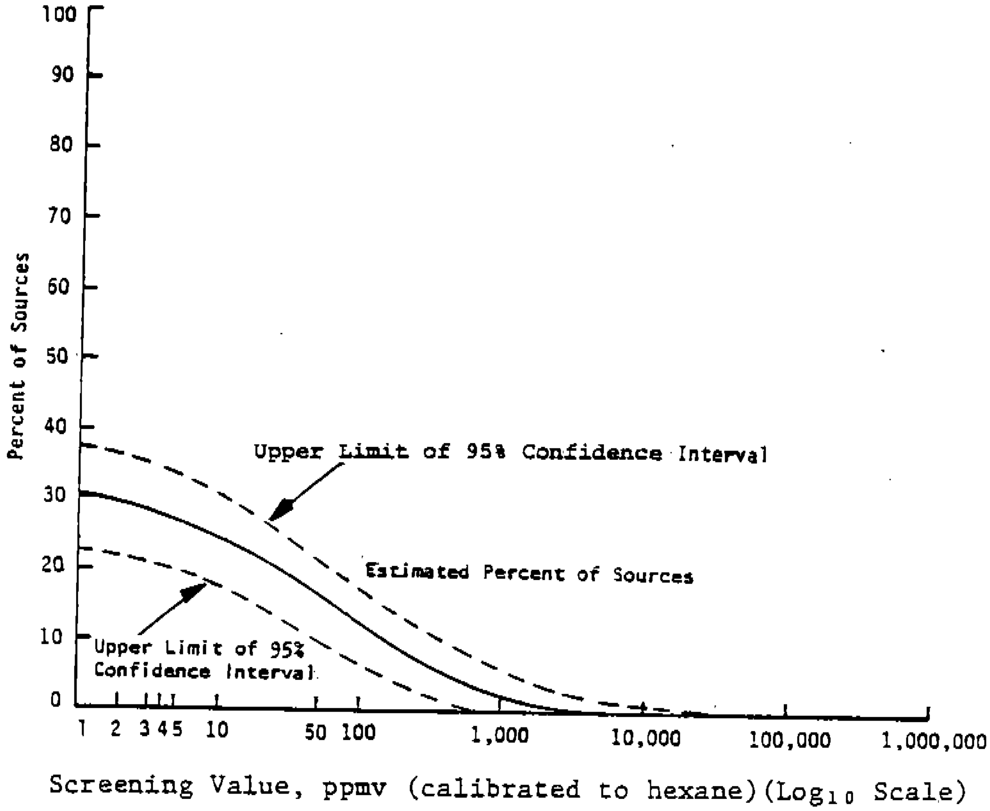
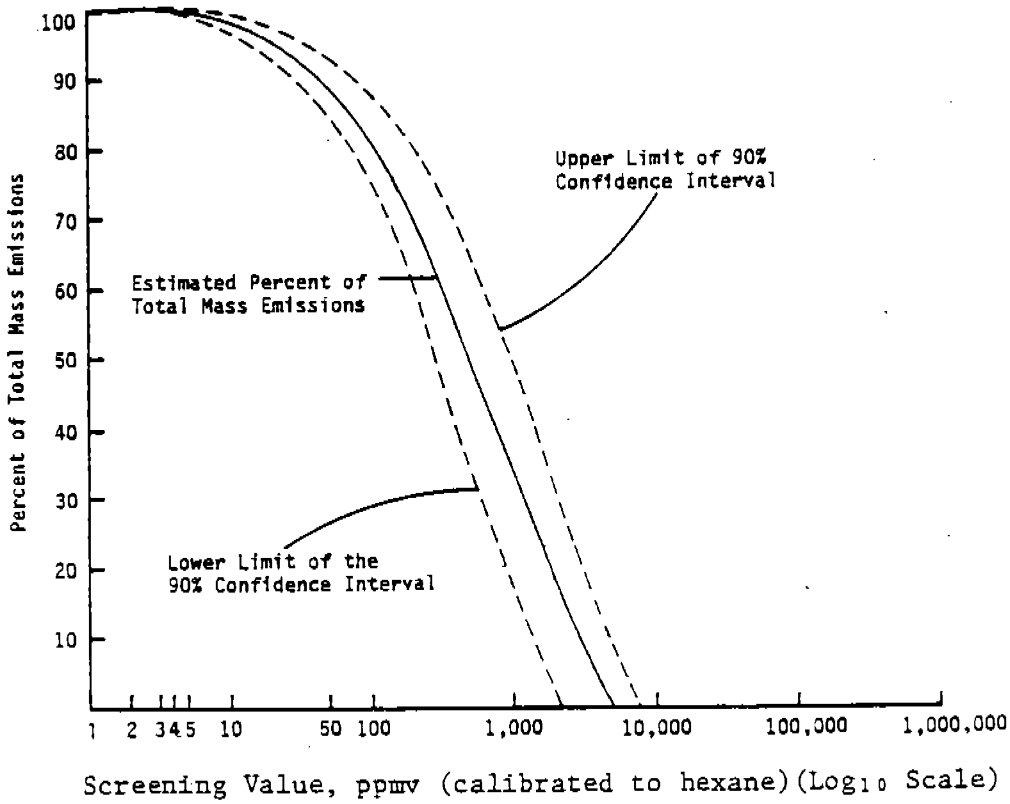


Figure B2-48D. Cumulative distribution of total emissions by screening values for valves - light liquid/two-phase streams.



Percent of Sources - indicates the percent of sources with screening values greater than the selected value.

Figure B2-49A. Cumulative distribution of sources and total emissions by screening values for valves - heavy liquids stream.



Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-49B. Cumulative distribution of source and total emissions by screening values for valves - heavy liquid streams.

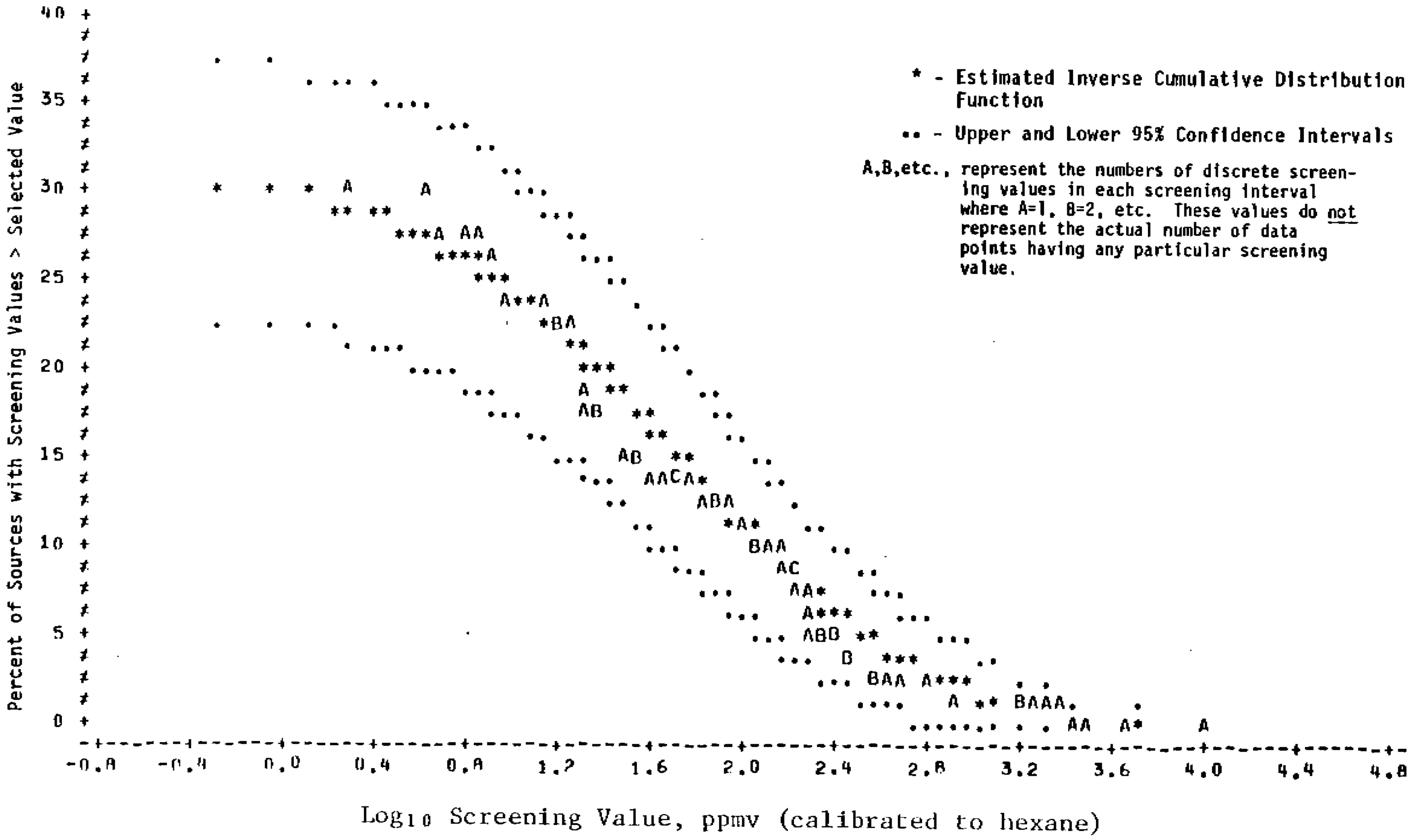


Figure B2-49C. Inverse cumulative distribution function for valves - heavy liquid streams.

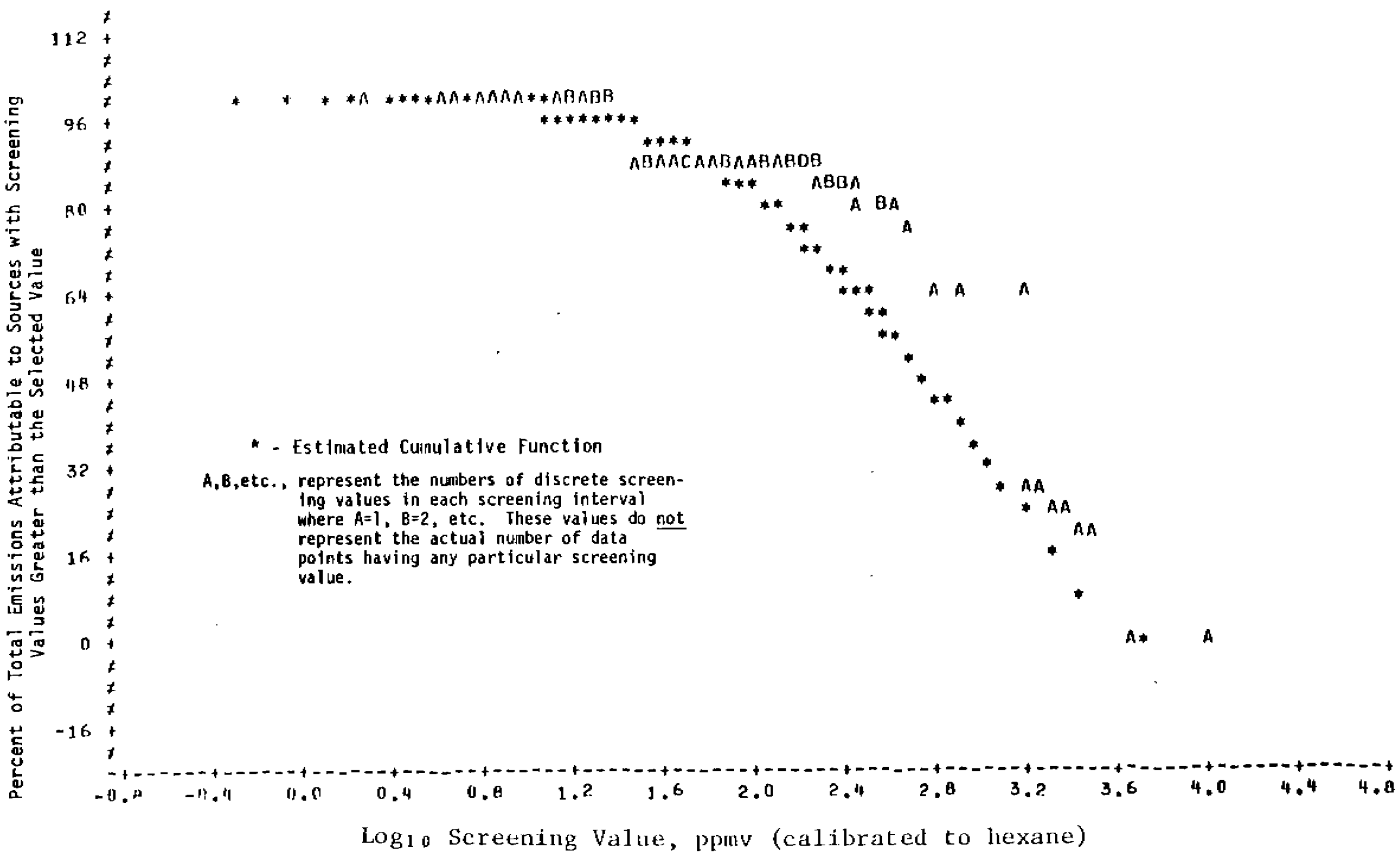
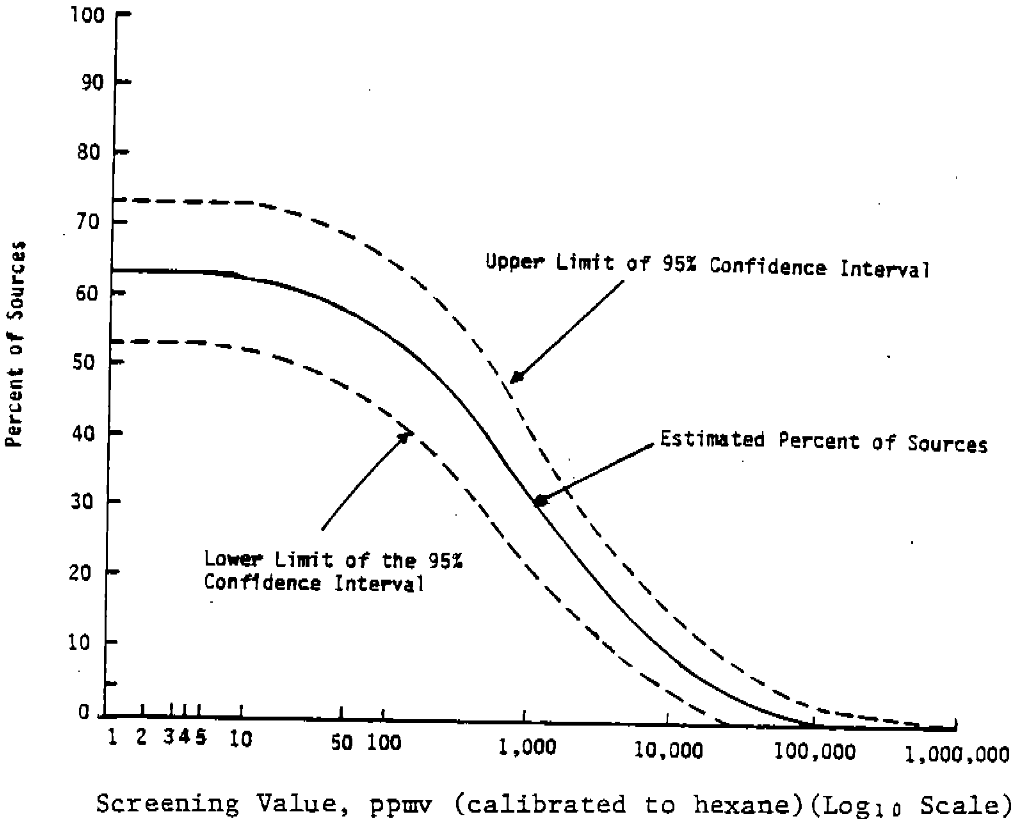
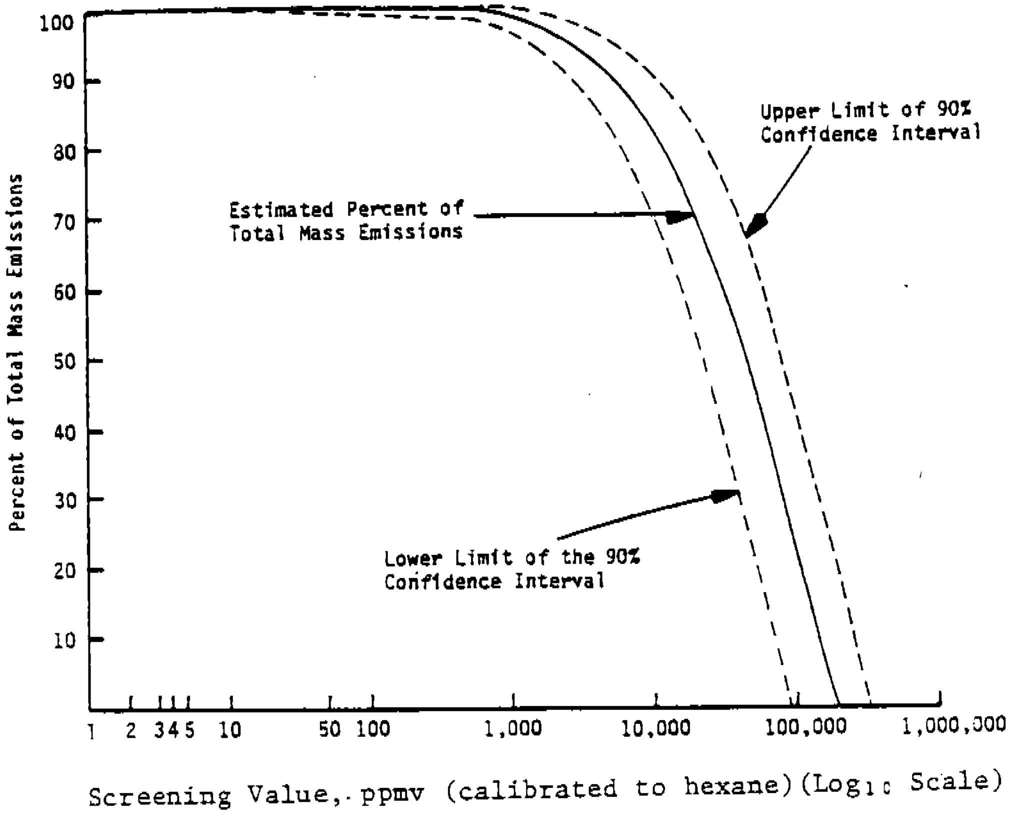


Figure B2-49D. Cumulative distribution of total emissions by screening values for valves - heavy liquid streams.



Percent of Sources - indicates the percent of sources with screening values greater than the selected value.

Figure B2-50A. Cumulative distribution of sources and total emissions by screening values for valves - hydrogen service.



Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-50B. Cumulative distribution of source and total emissions by screening values for valves - hydrogen service.

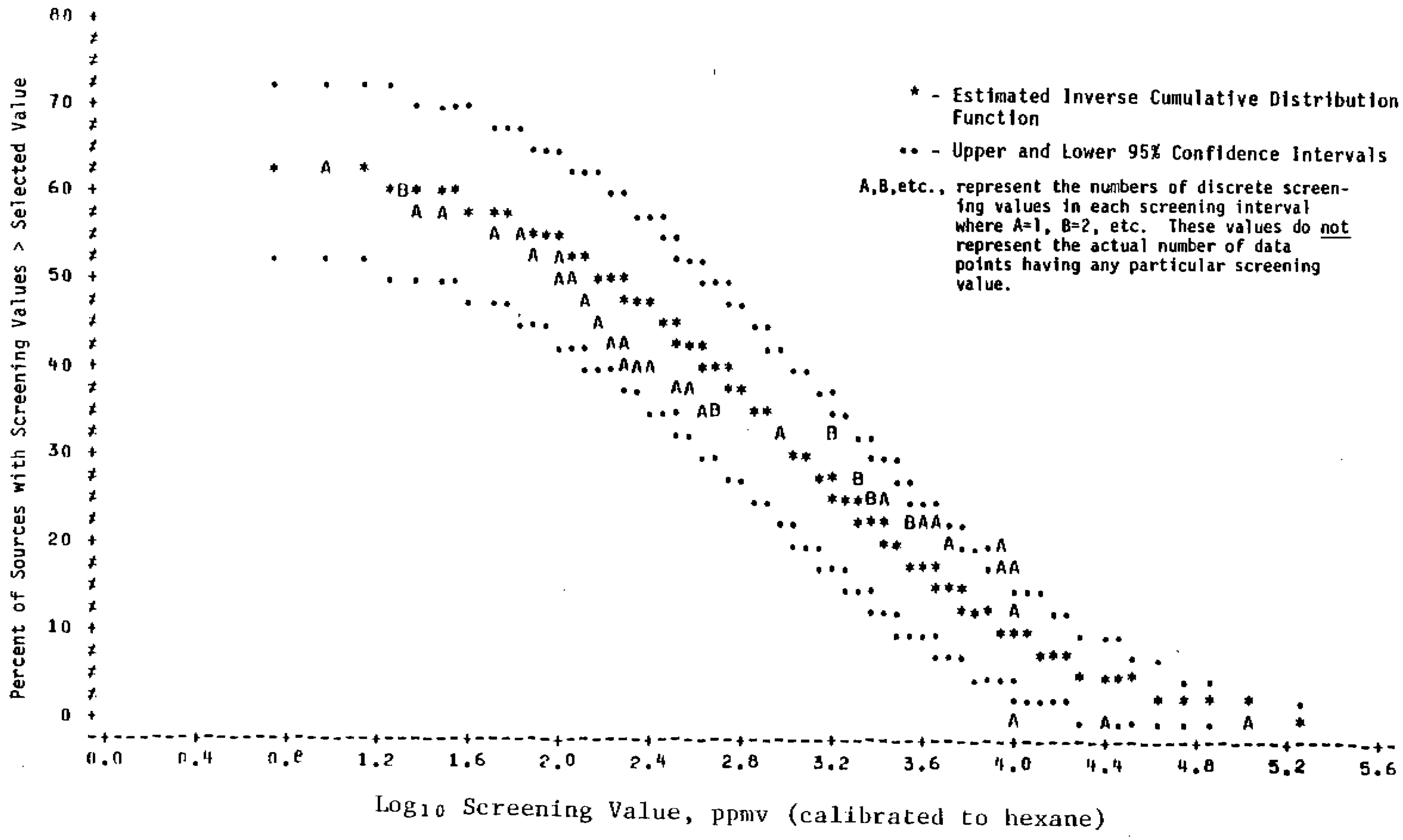


Figure B2-50C. Inverse cumulative distribution function for valves - hydrogen service.

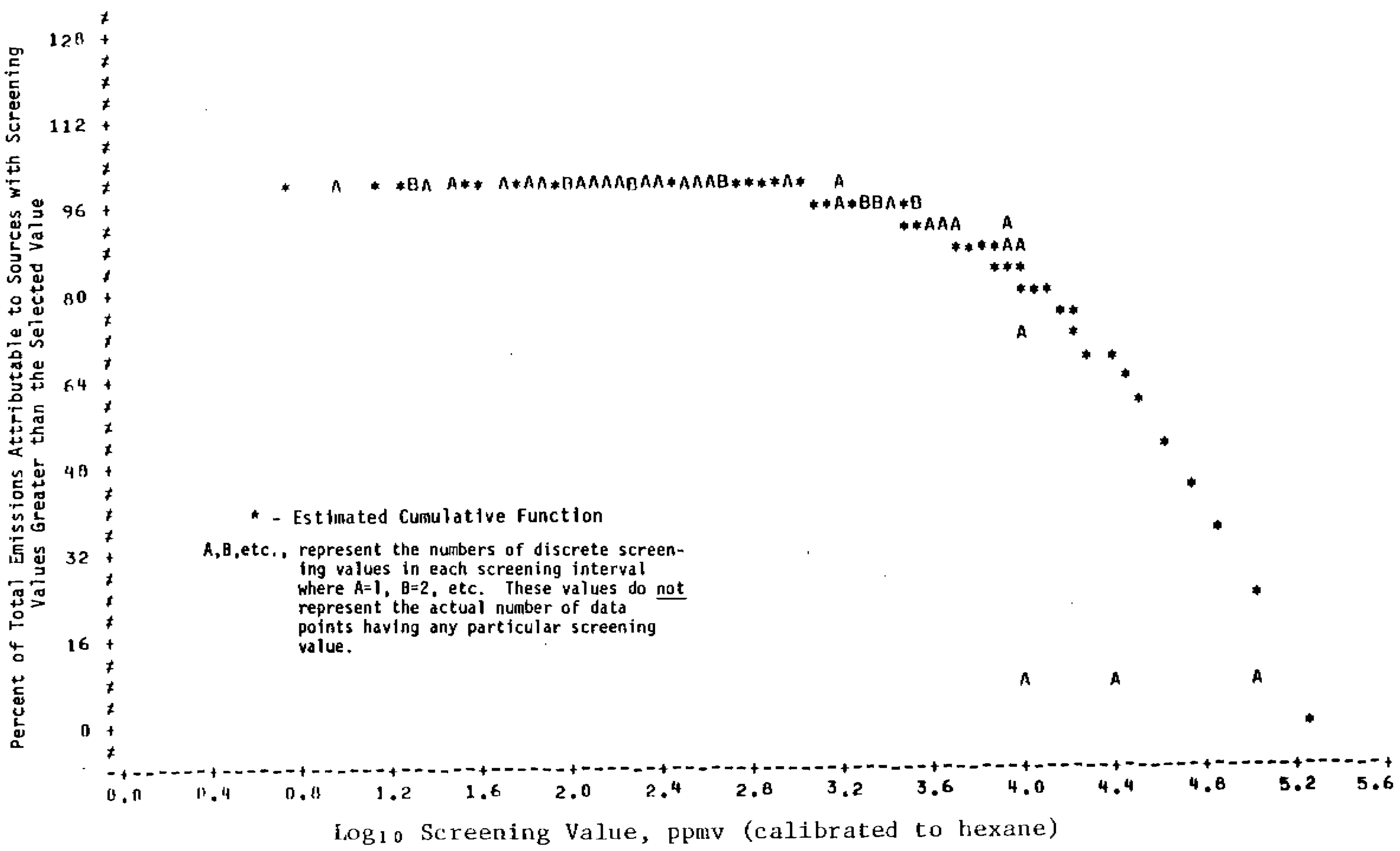
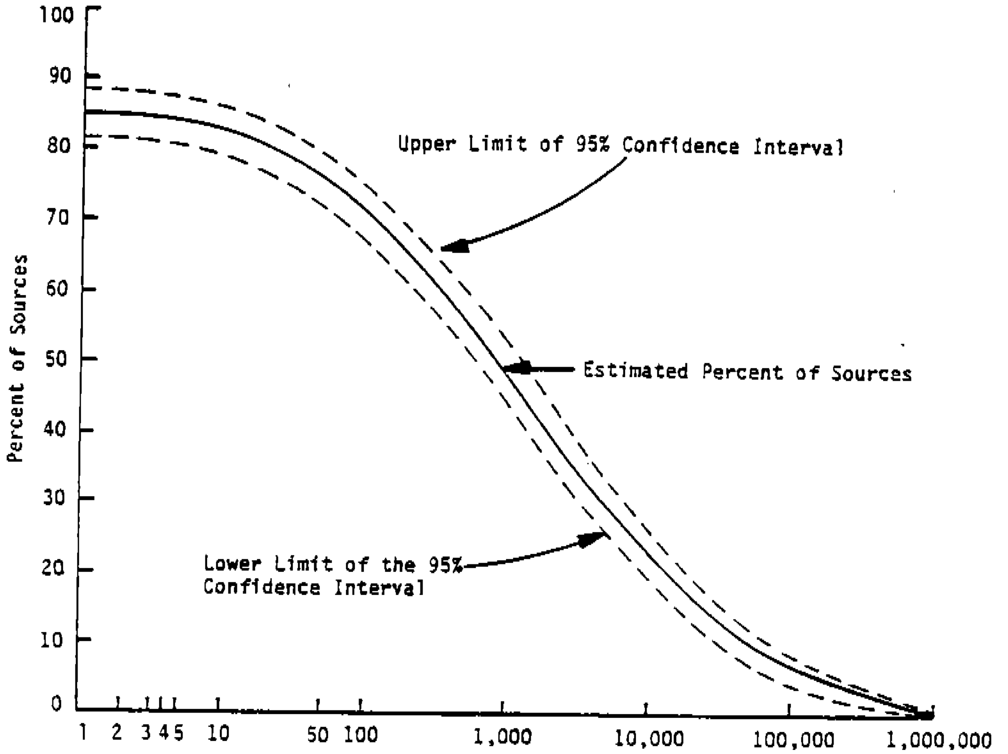


Figure B2-50D. Cumulative distribution of total emissions by screening values for valves - hydrogen service.



Screening Value, ppmv (calibrated to hexane)(Log_{10} Scale)

Percent of Sources - indicates the percent of sources with screening values greater than the selected value.

Figure B2-51A. Cumulative distribution of sources and total emissions by screening values for pump seals - light liquid streams.

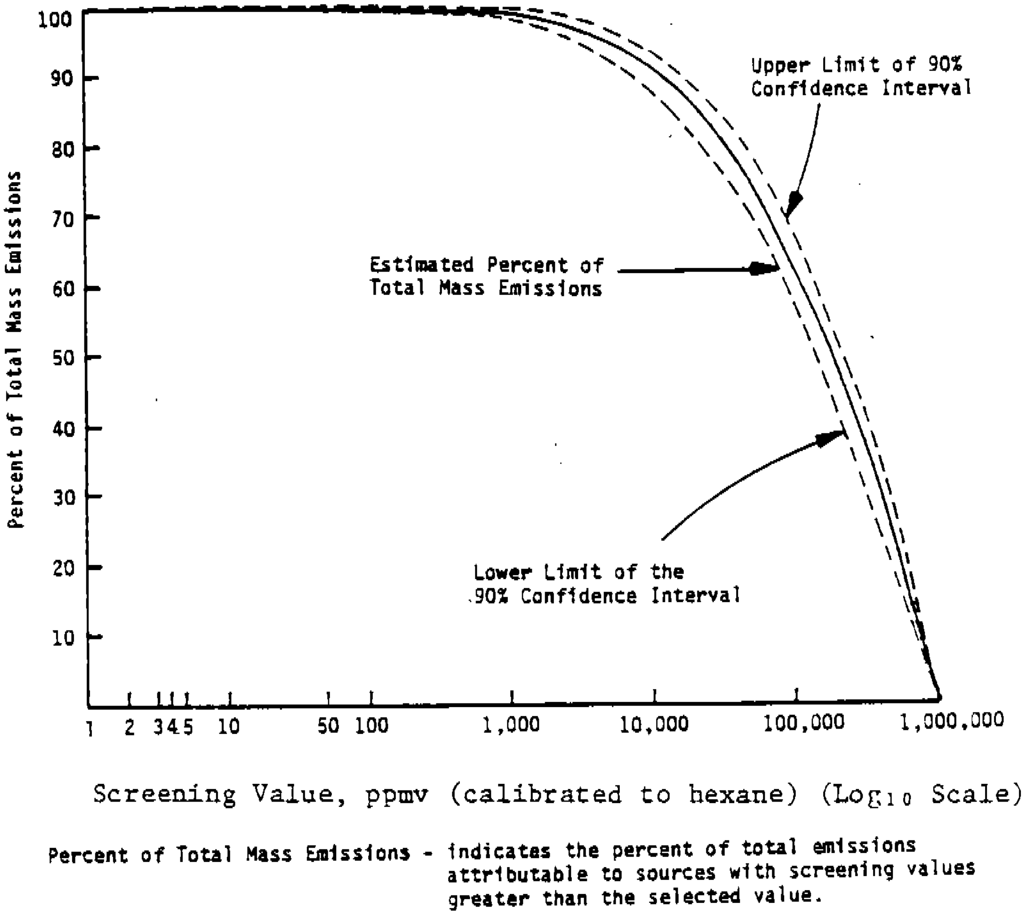


Figure B2-51B. Cumulative distribution of source and total emissions by screening values for pump seals - light liquid streams.

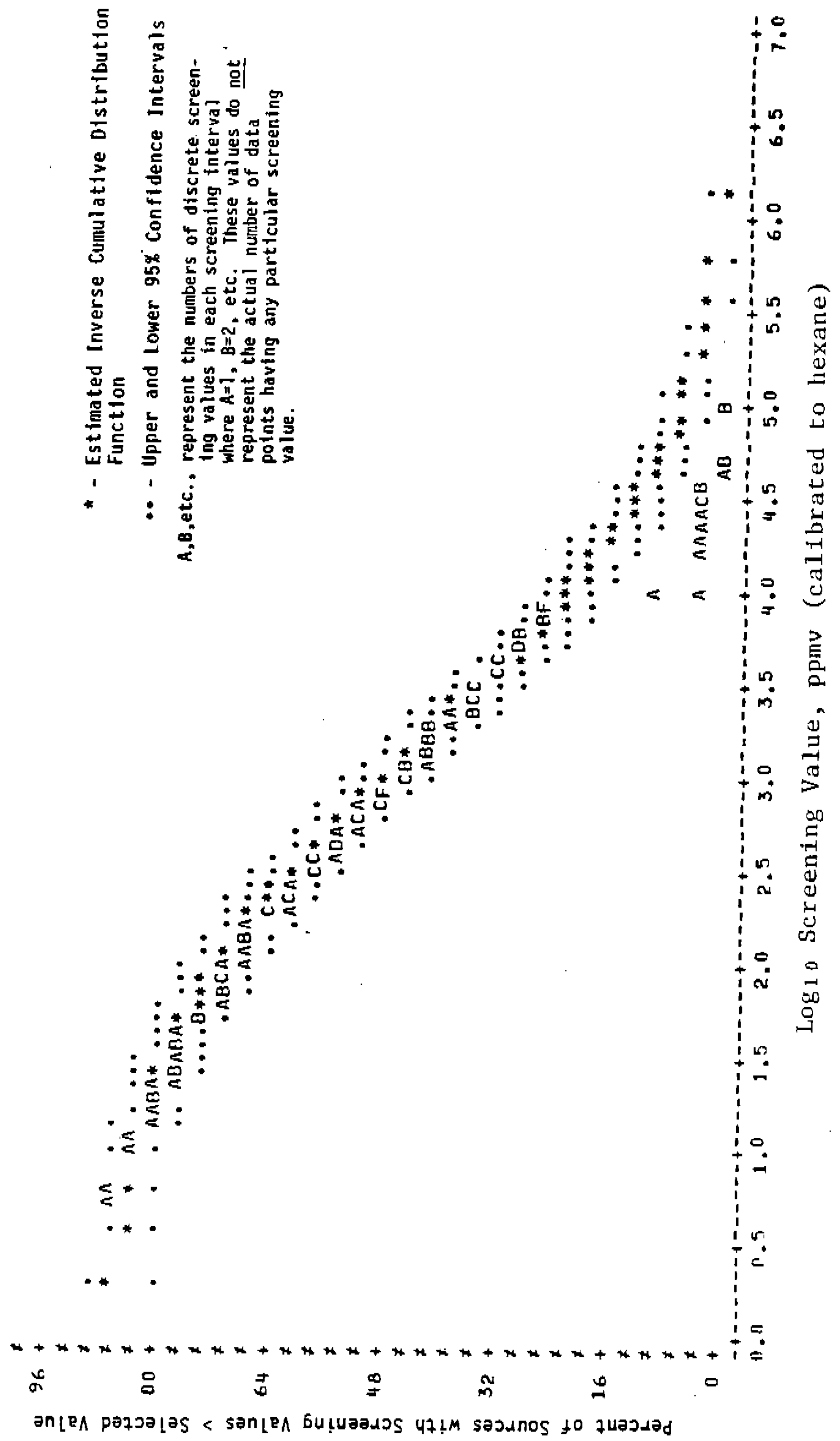


Figure B2-51C. Inverse cumulative distribution function for pump seals - light liquid streams.

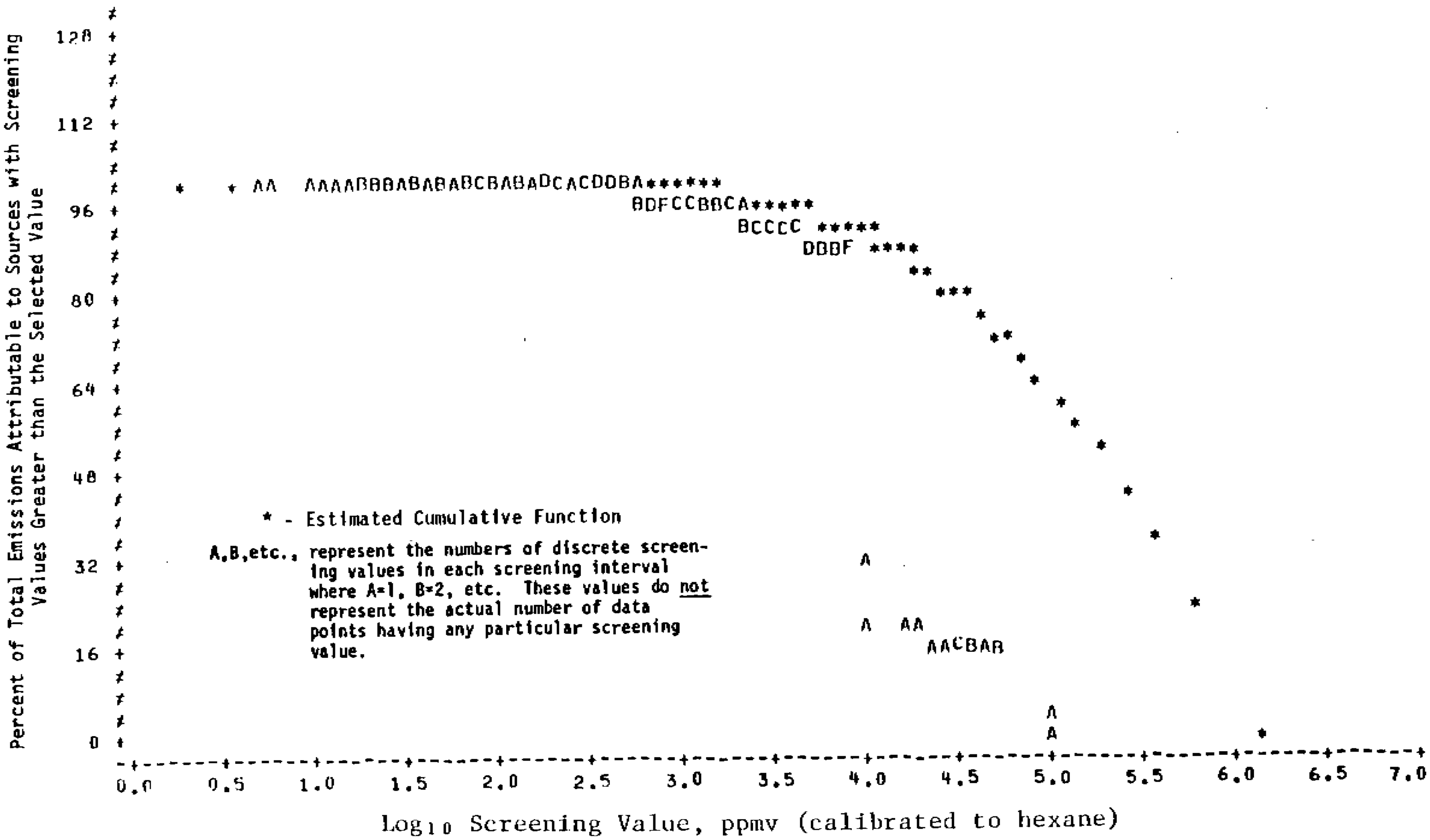


Figure B2-51D. Cumulative distribution of total emissions by screening values for pump seals - light liquid streams.

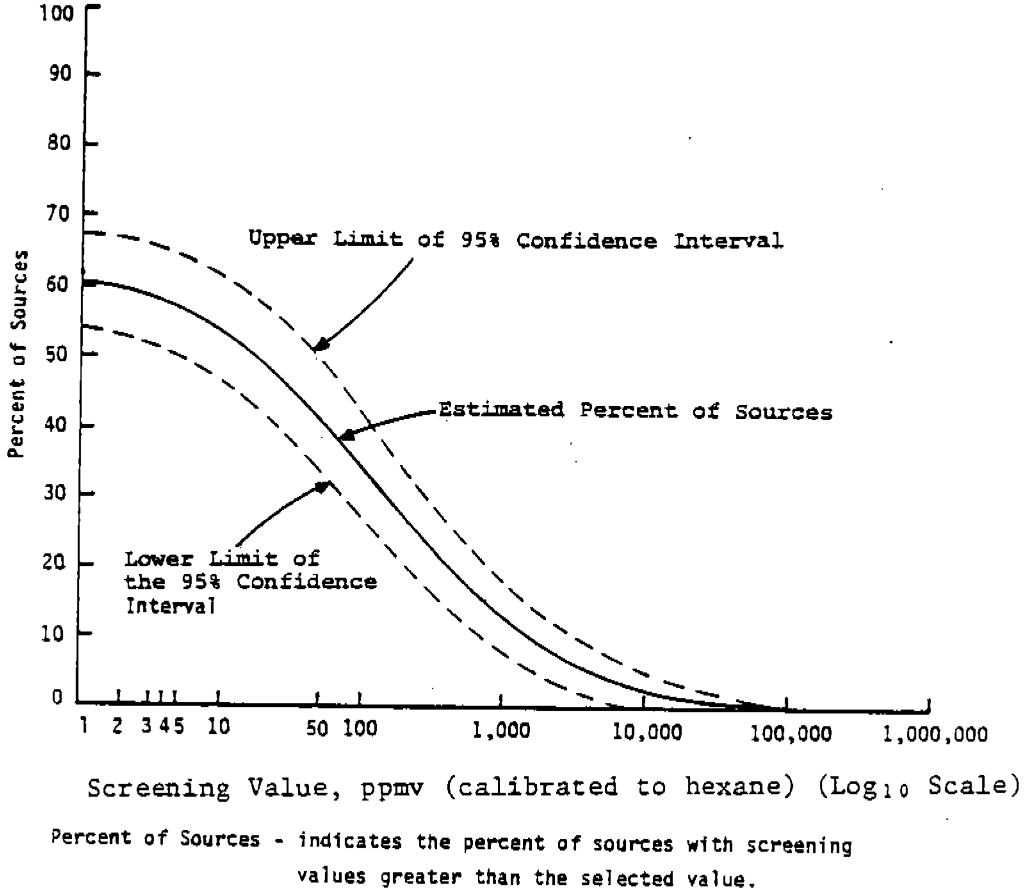
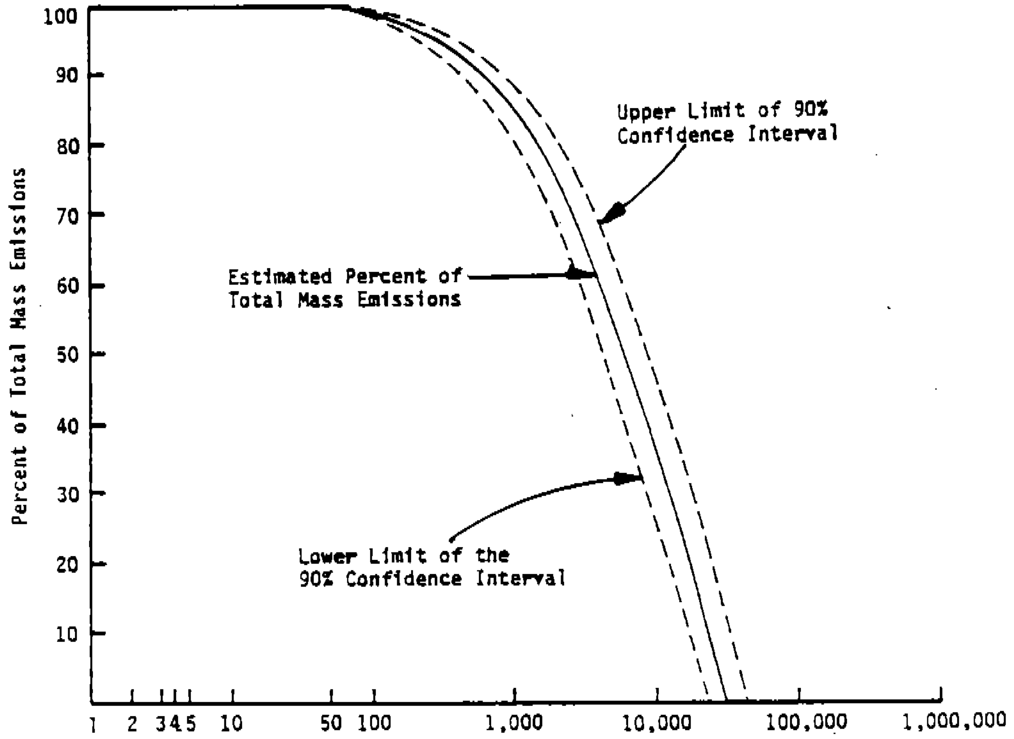


Figure B2-52A. Cumulative distribution of sources and total emissions by screening values for pump seals - heavy liquids.



Screening Value, ppmv (calibrated to hexane) (Log_{10} Scale)

Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-52B. Cumulative distribution of source and total emissions by screening values for pump seals - heavy liquids.

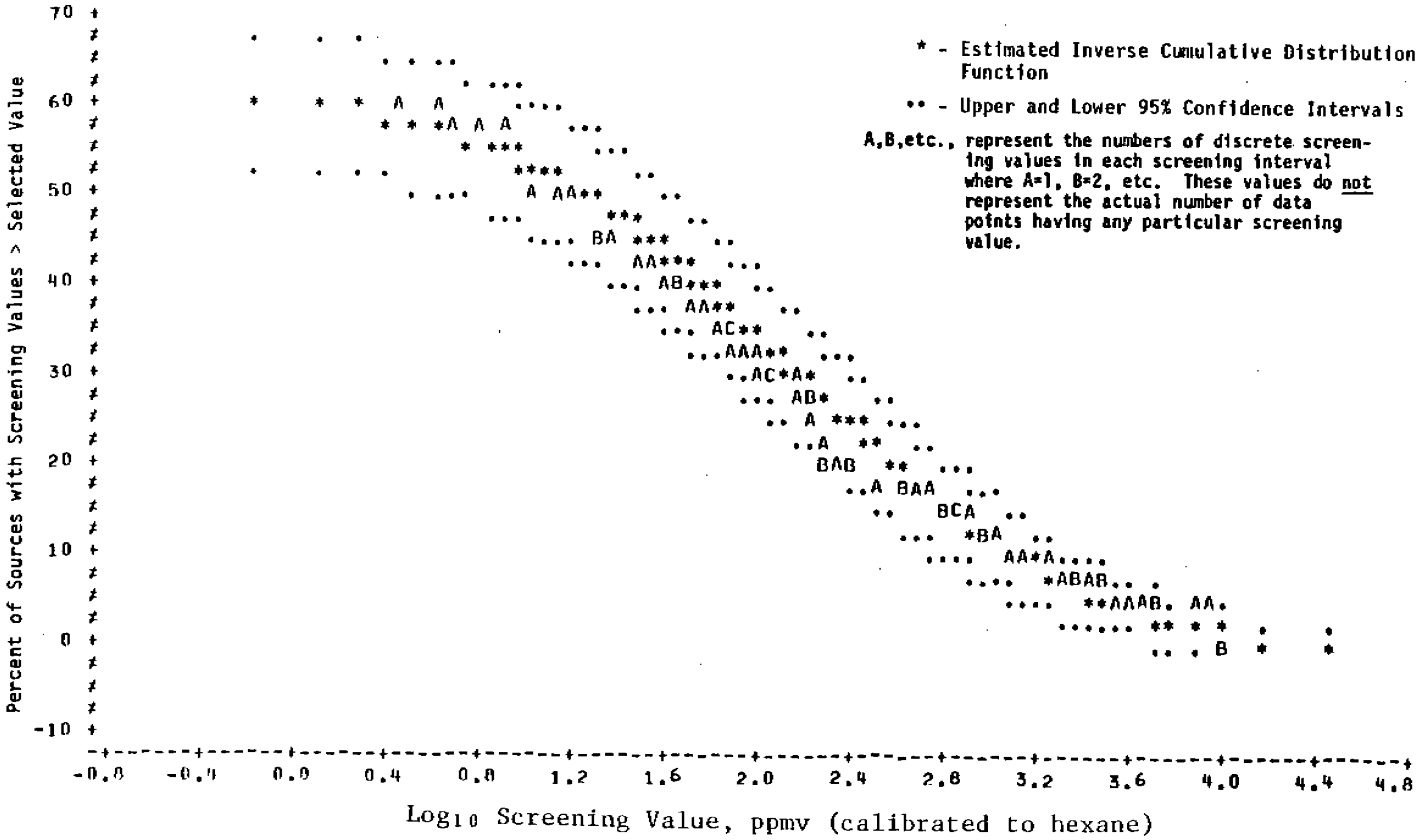


Figure B2-52C. Inverse cumulative distribution function for pump seals - heavy liquids.

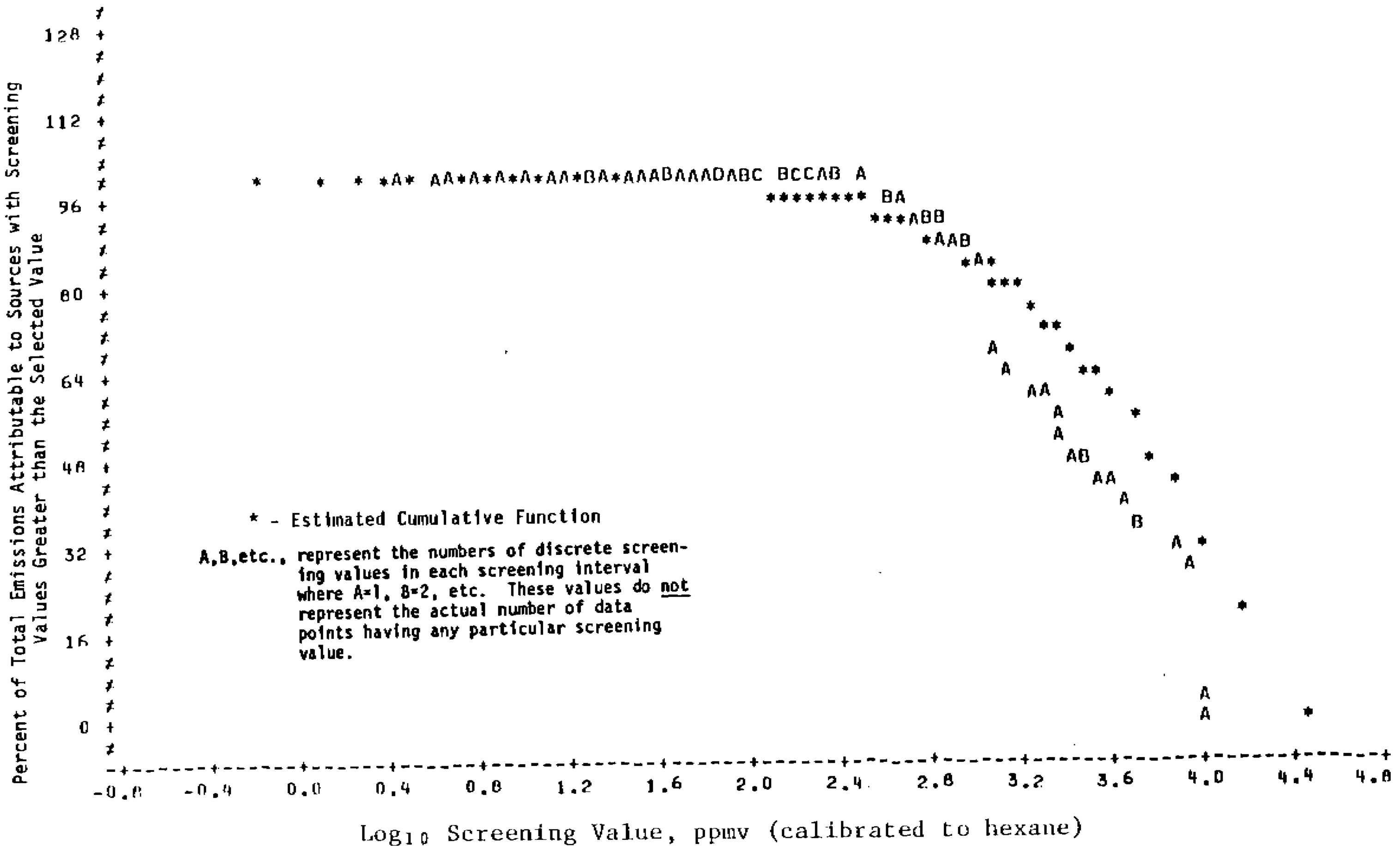


Figure B2-52D. Cumulative distribution of total emissions by screening values for pump seals - heavy liquids.

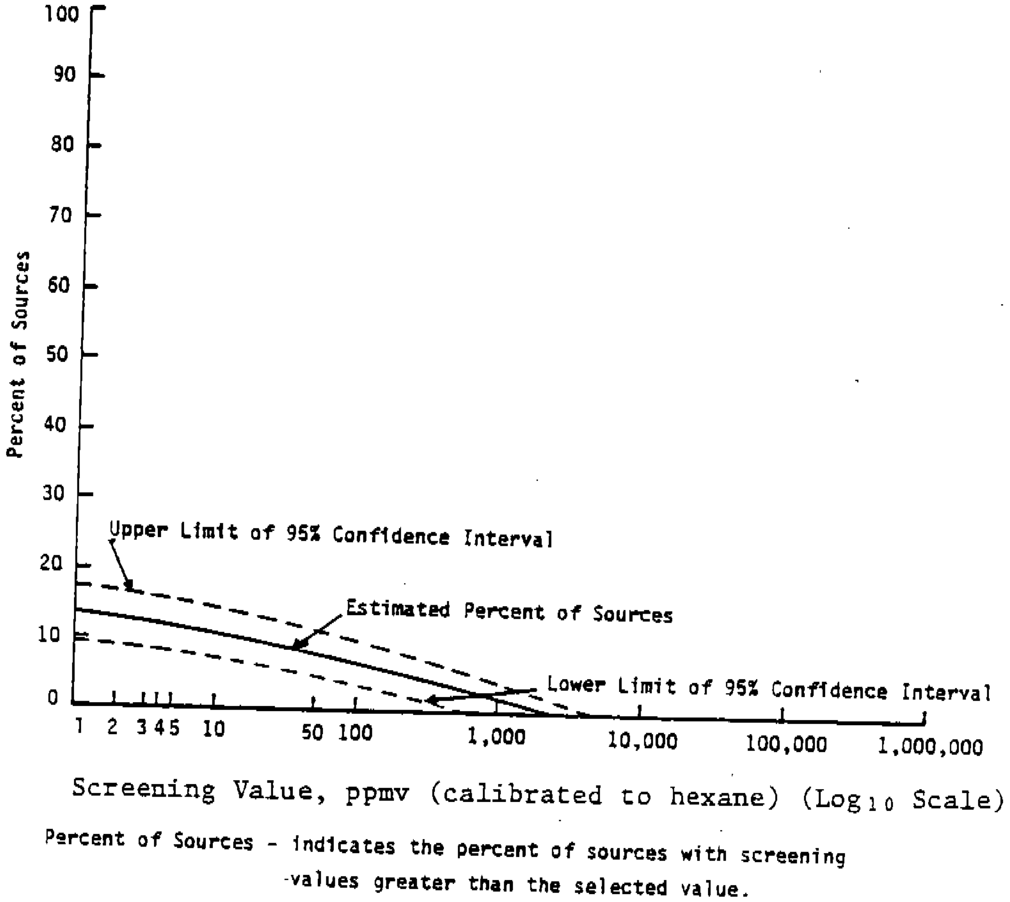
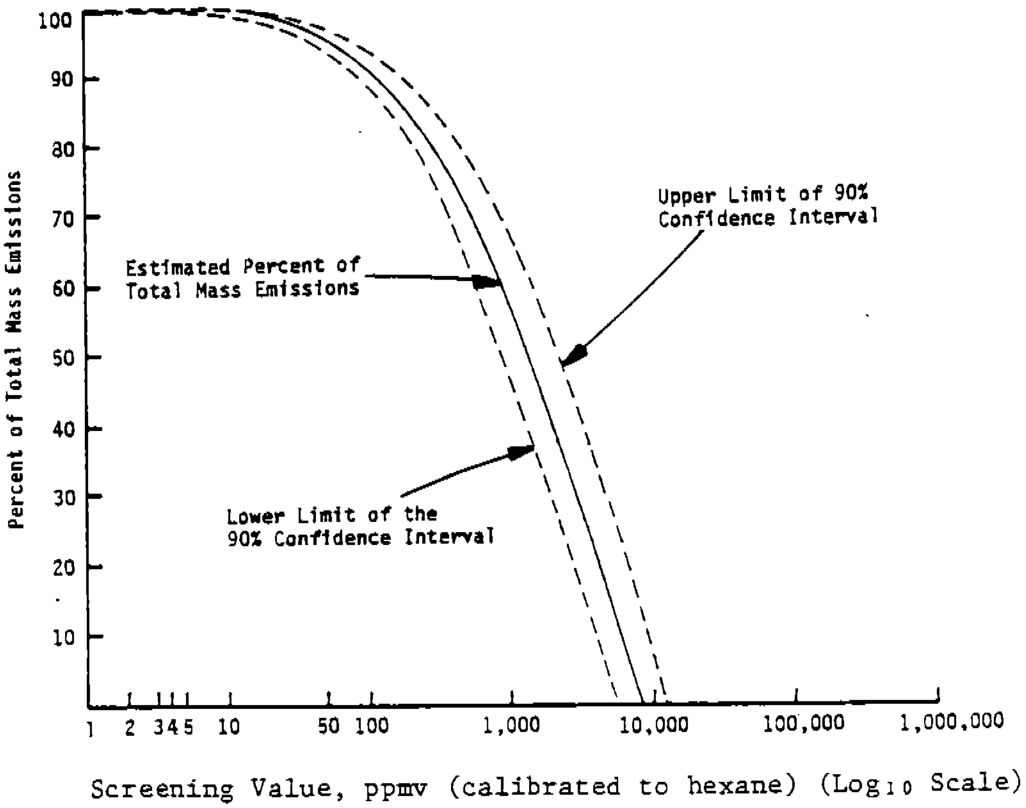


Figure B2-53A. Cumulative distribution of sources and total emissions by screening values for flanges.



Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-53B. Cumulative distribution of source and total emissions by screening values for flanges.

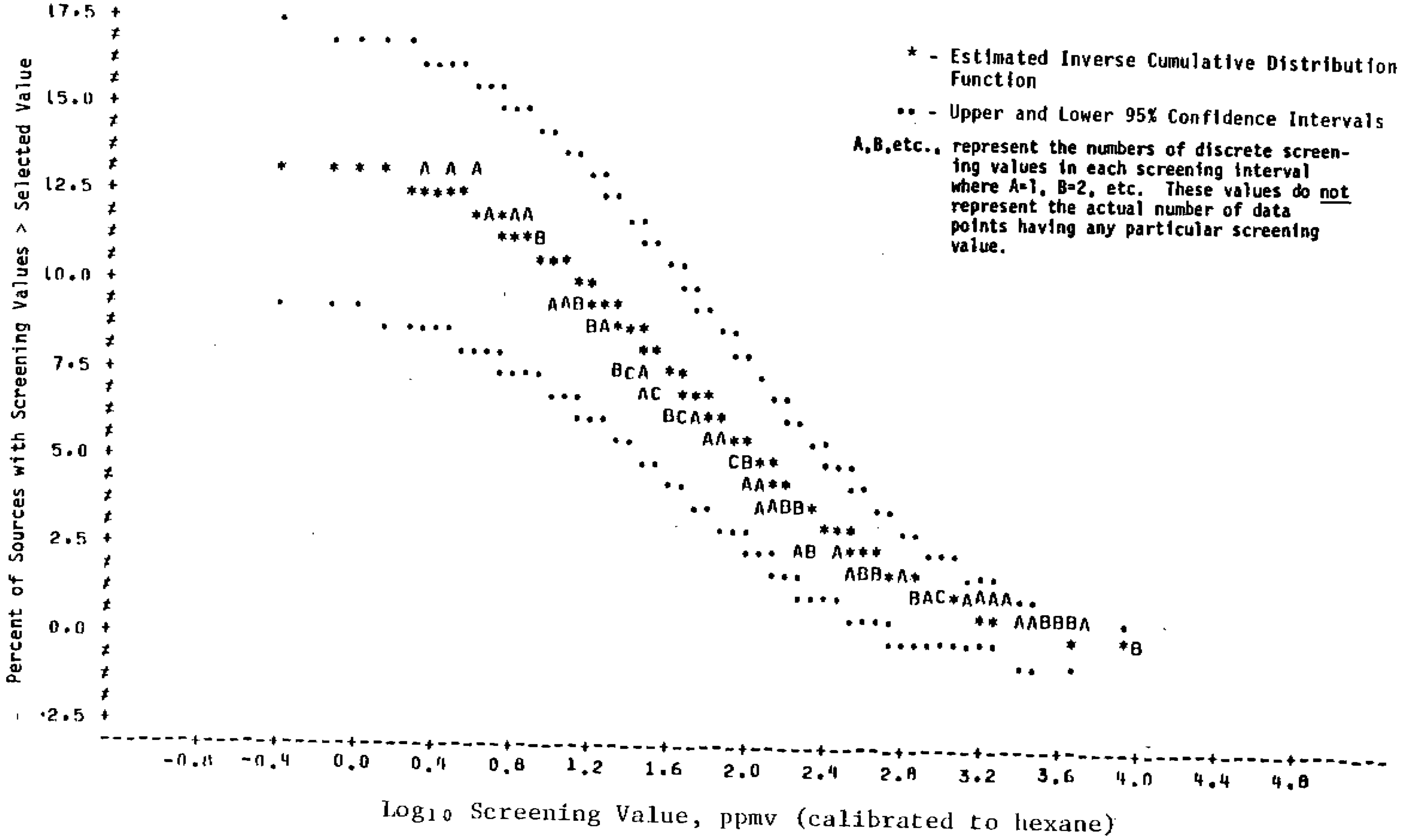


Figure B2-53C. Inverse cumulative distribution function for flanges.

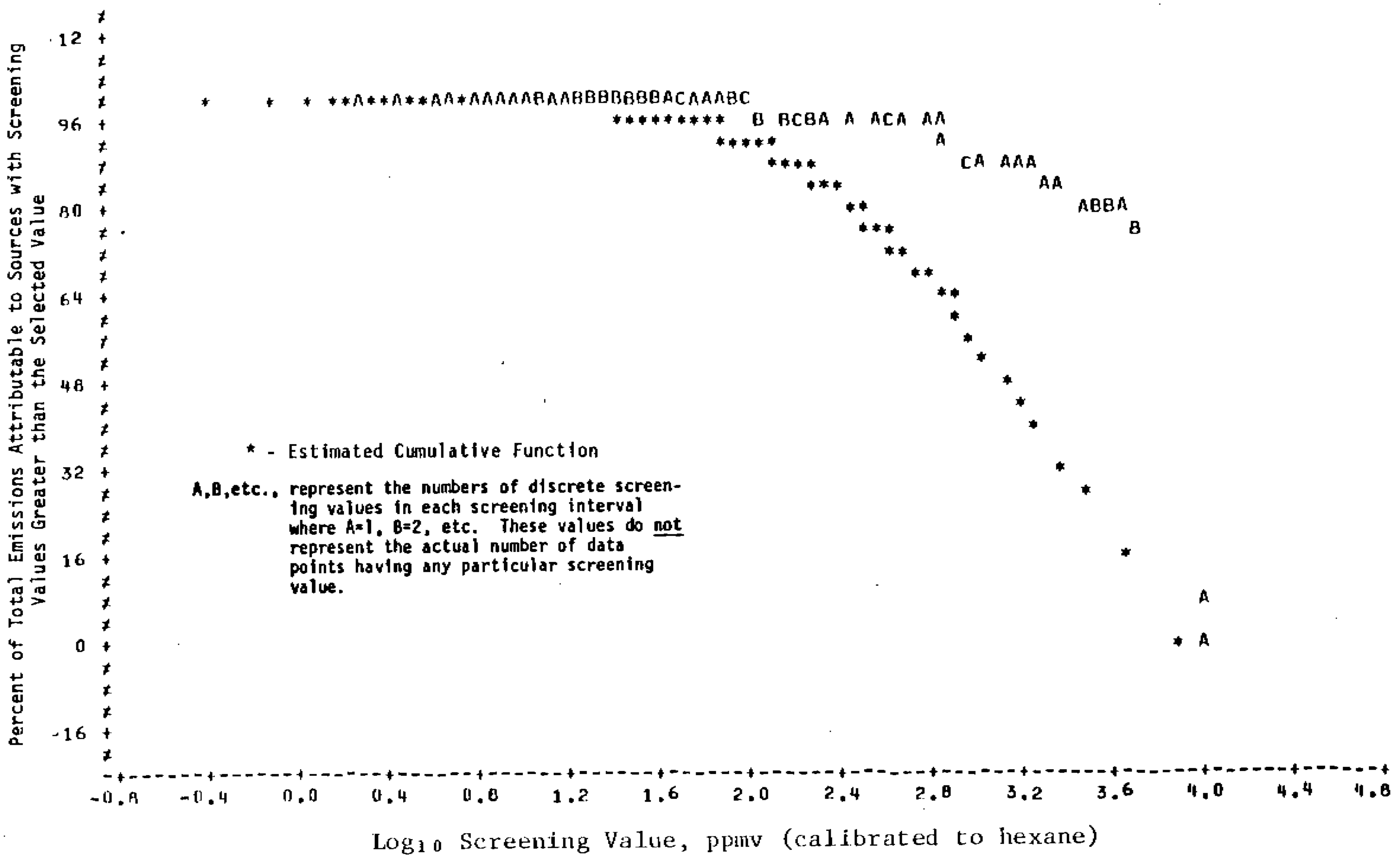


Figure B2-53D. Cumulative distribution of total emissions by screening values for flanges.

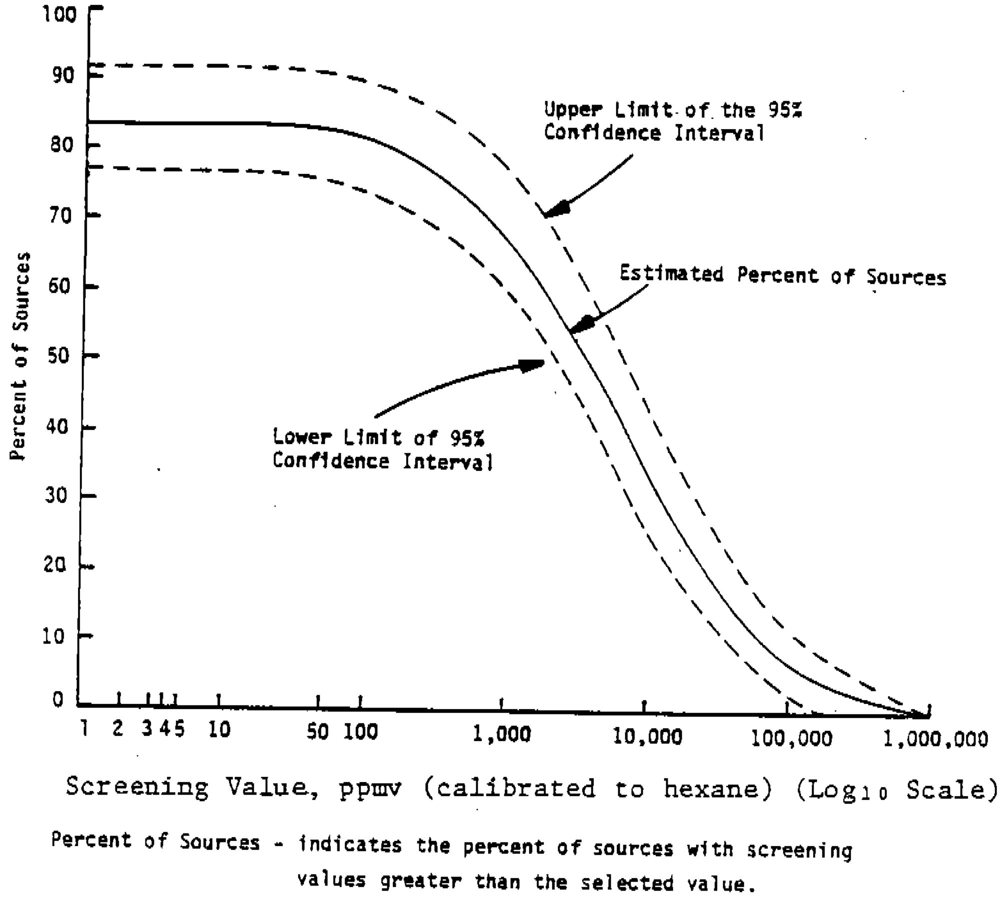
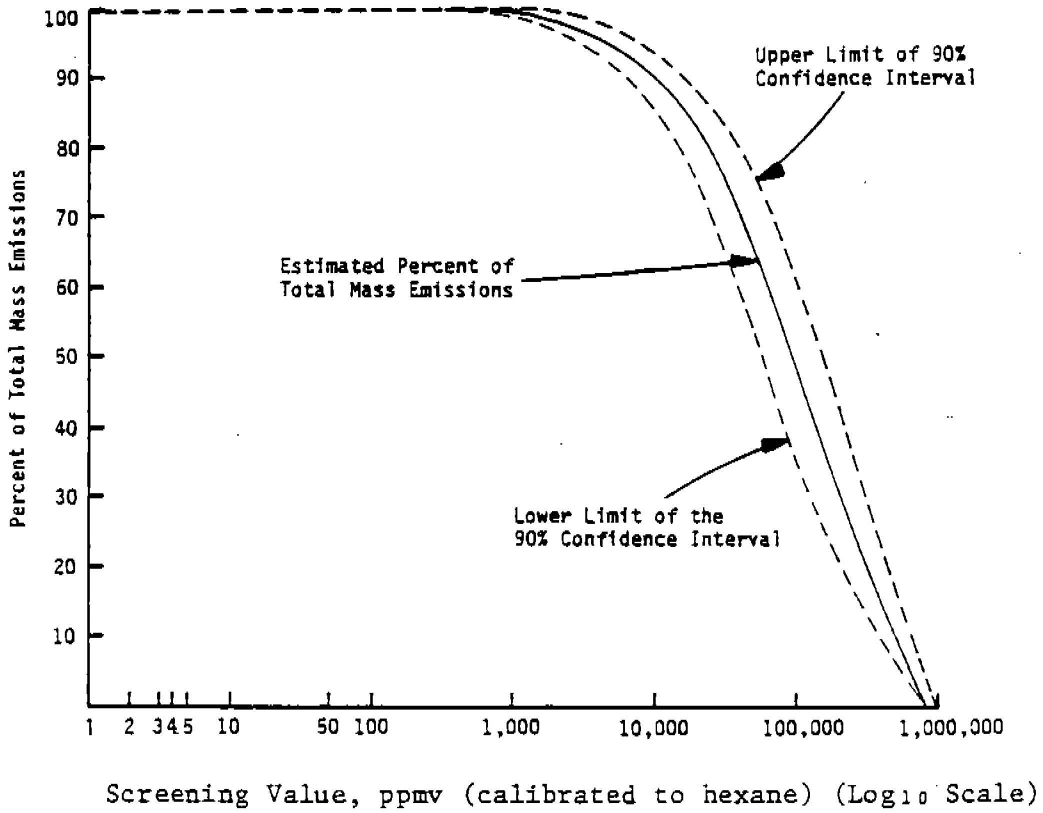


Figure B2-54A. Cumulative distribution of sources and total emissions by screening values for compressor seals - hydrocarbon service.



Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-54B. Cumulative distribution of source and total emissions by screening values for compressor seals - hydrocarbon service.

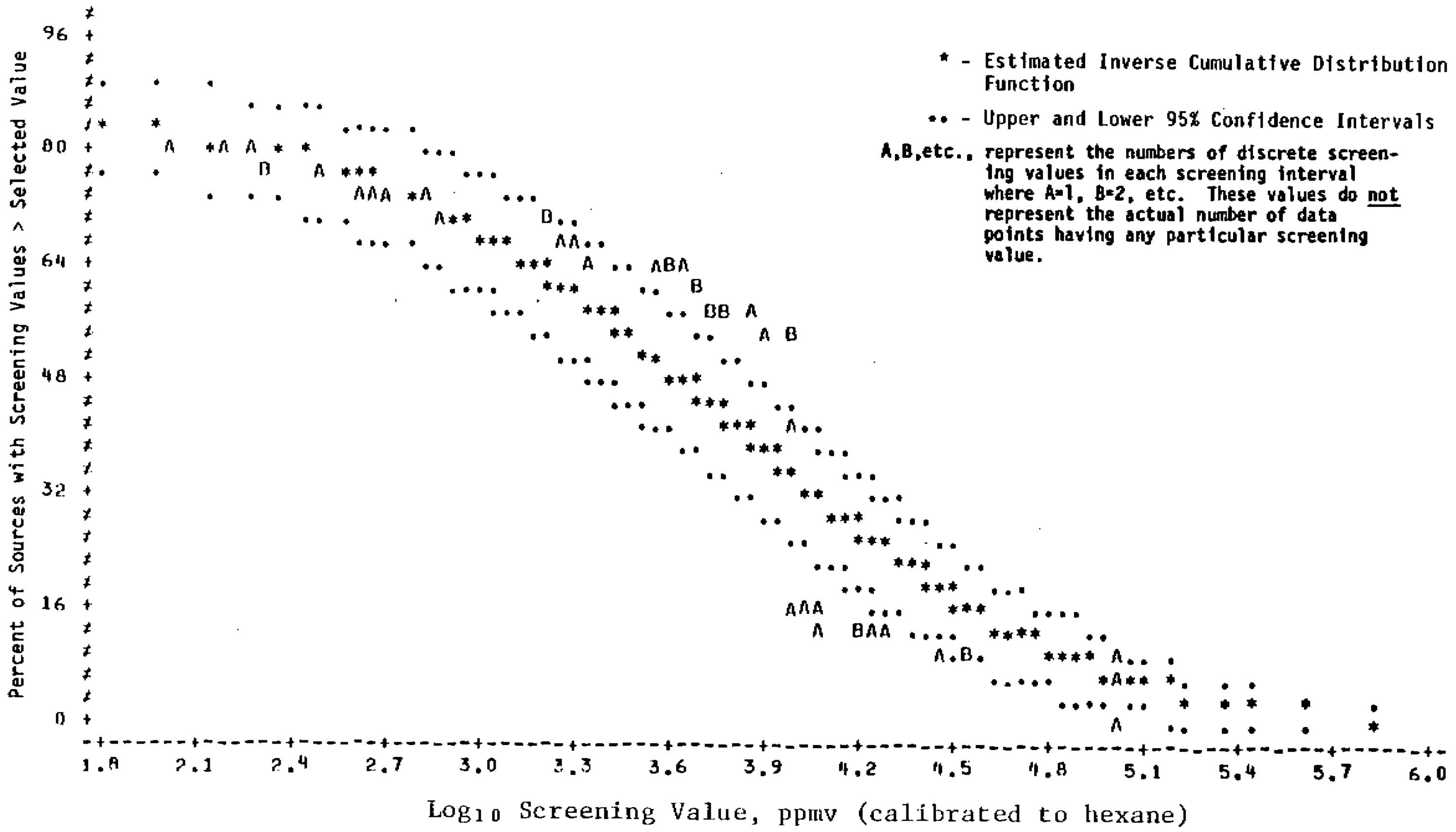


Figure B2-54C. Inverse cumulative distribution function for compressor seals - hydrocarbon service.

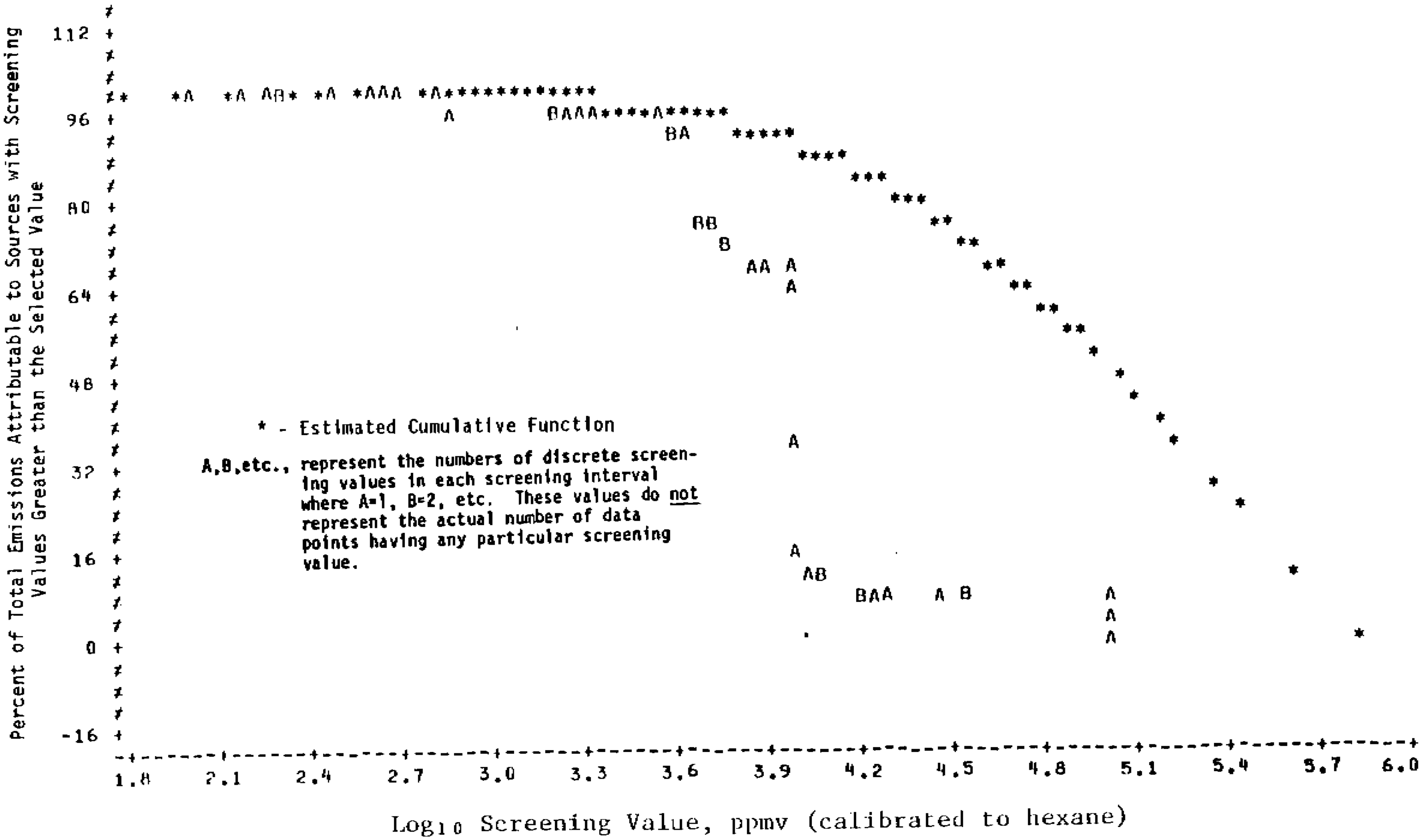
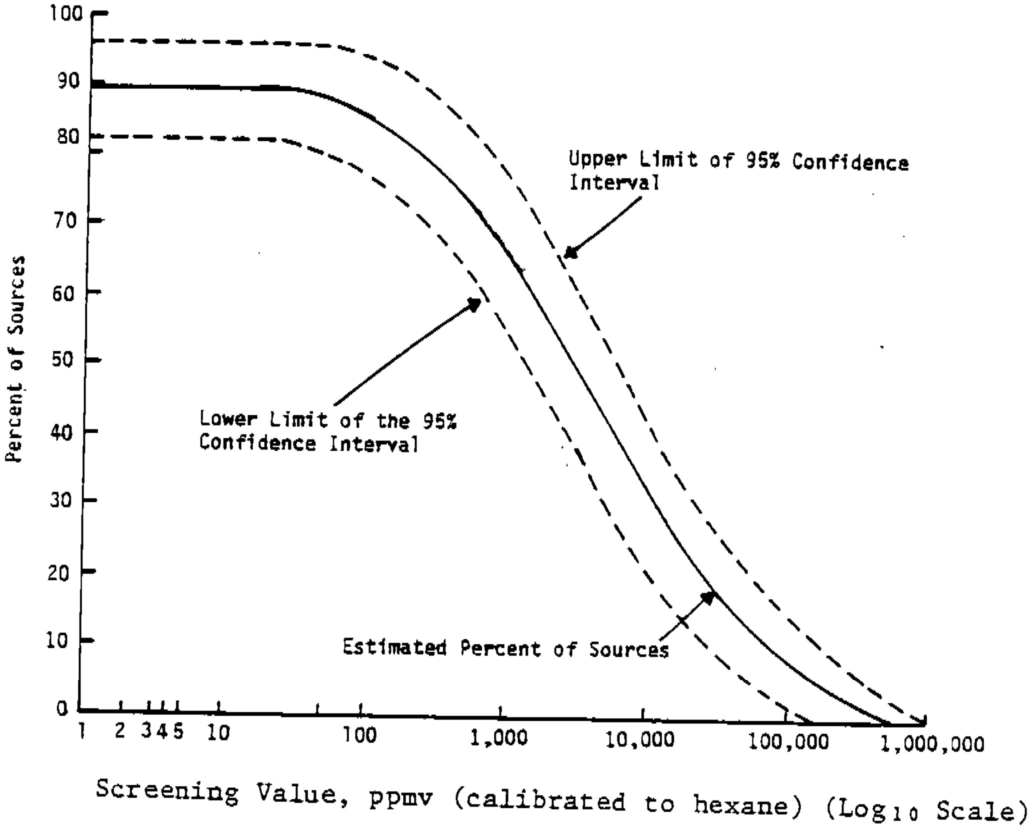
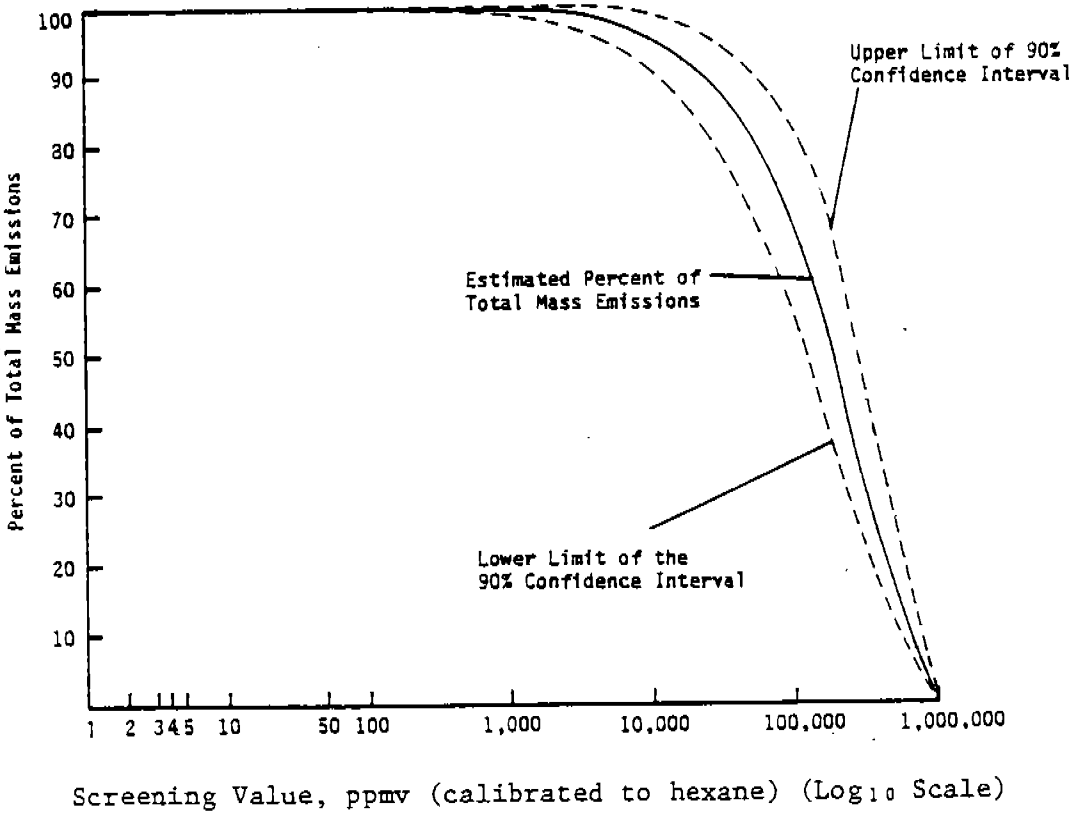


Figure B2-54D. Cumulative distribution of total emissions by screening values for compressor seals - hydrocarbon service.



Percent of Sources - indicates the percent of sources with screening values greater than the selected value.

Figure B2-55A. Cumulative distribution of sources and total emissions by screening values for compressor seals - hydrogen service.



Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-55B. Cumulative distribution of source and total emissions by screening values for compressor seals - hydrogen service.

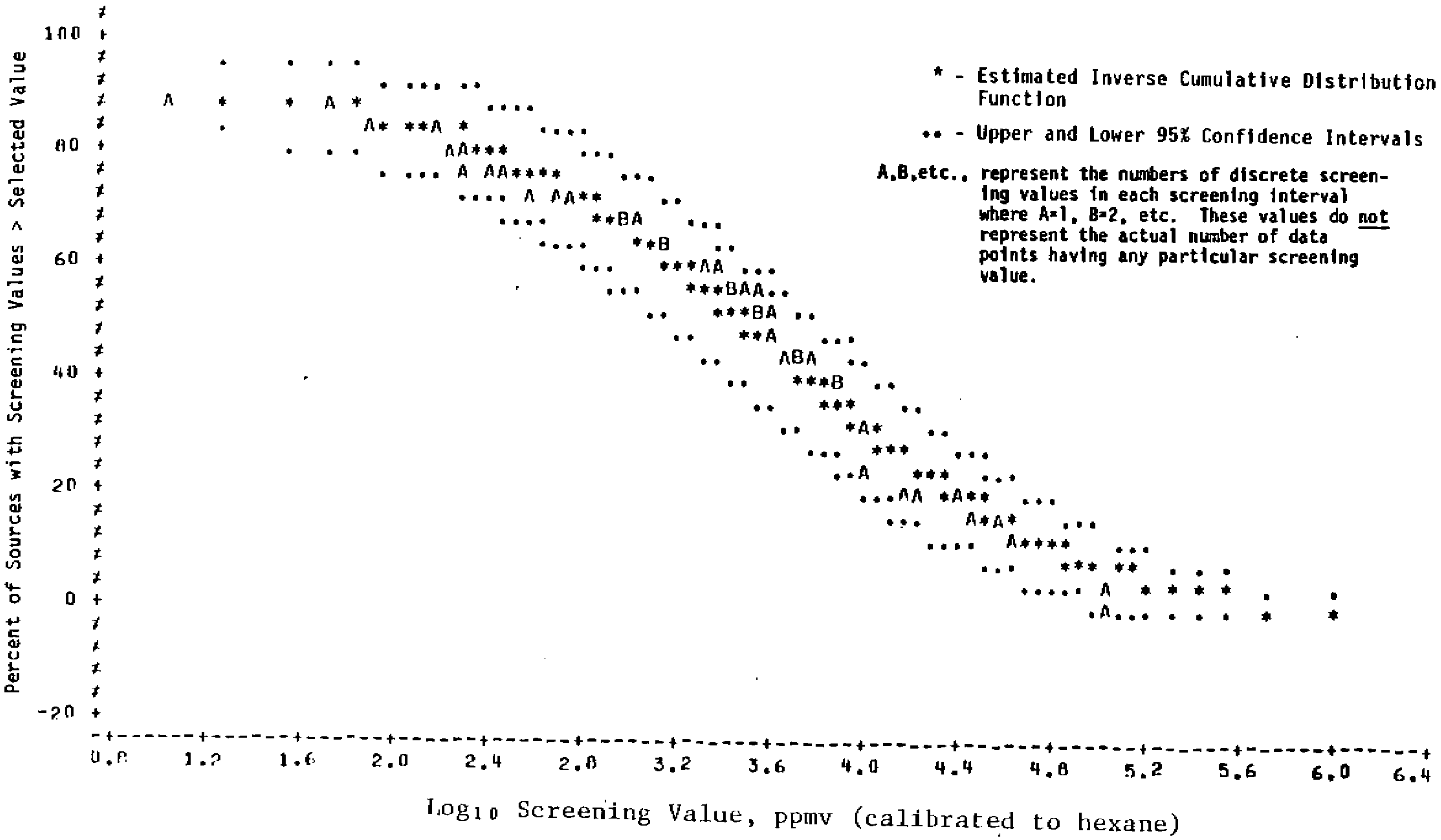


Figure B2-55C. Inverse cumulative distribution function for compressor seals - hydrogen service.

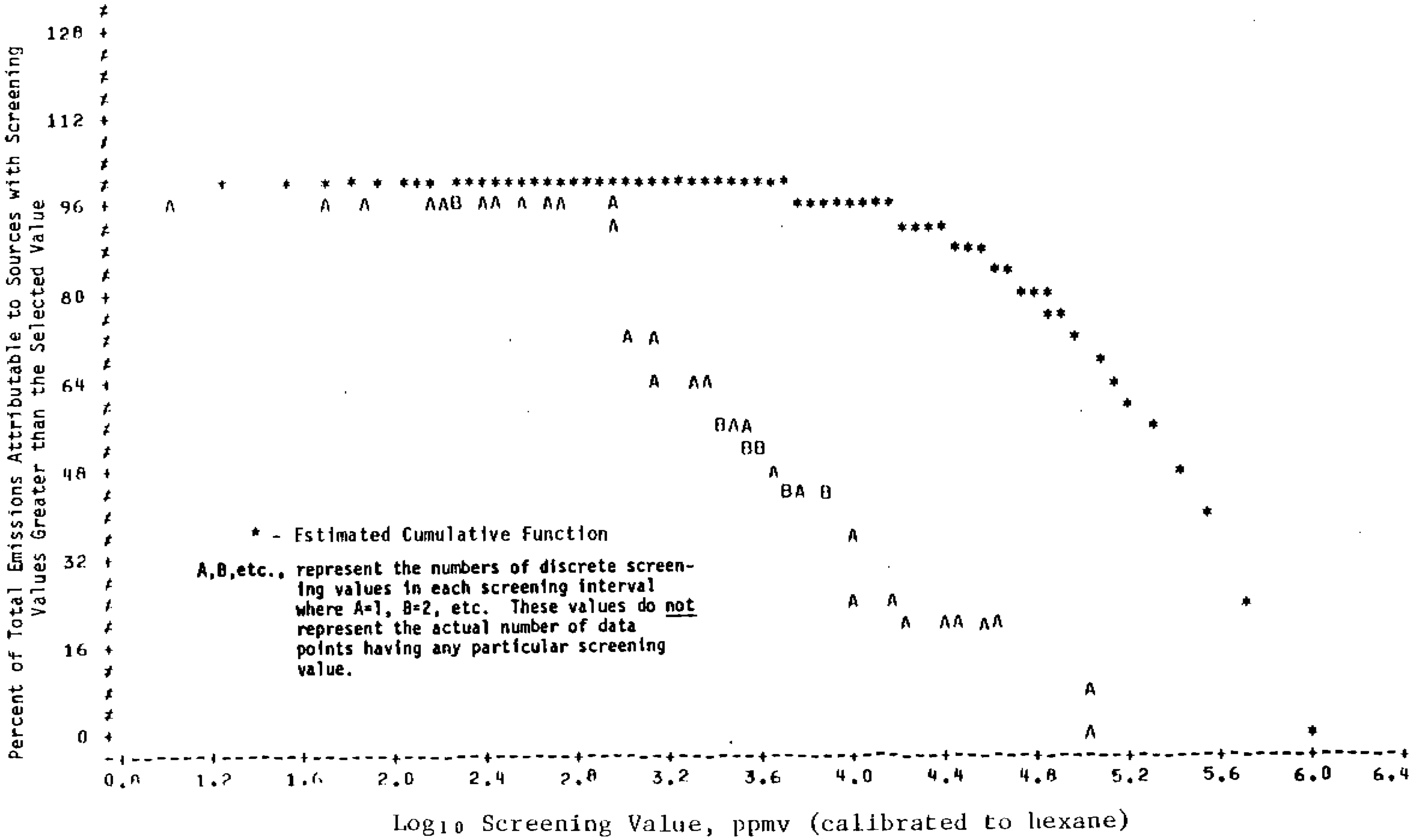
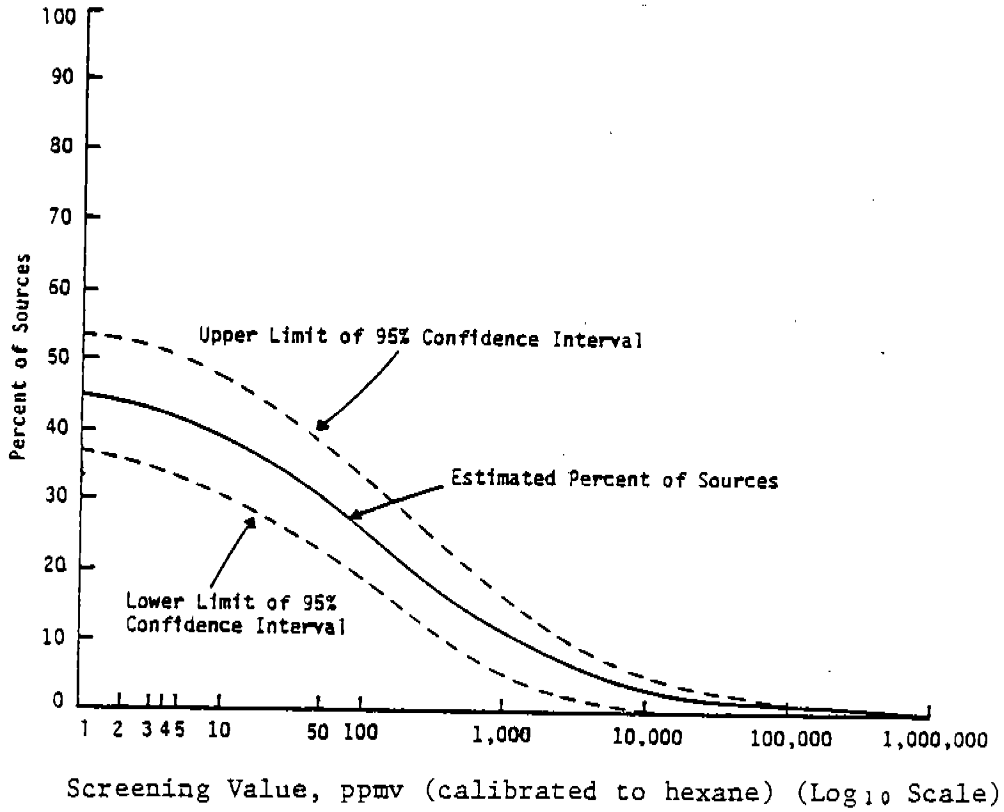
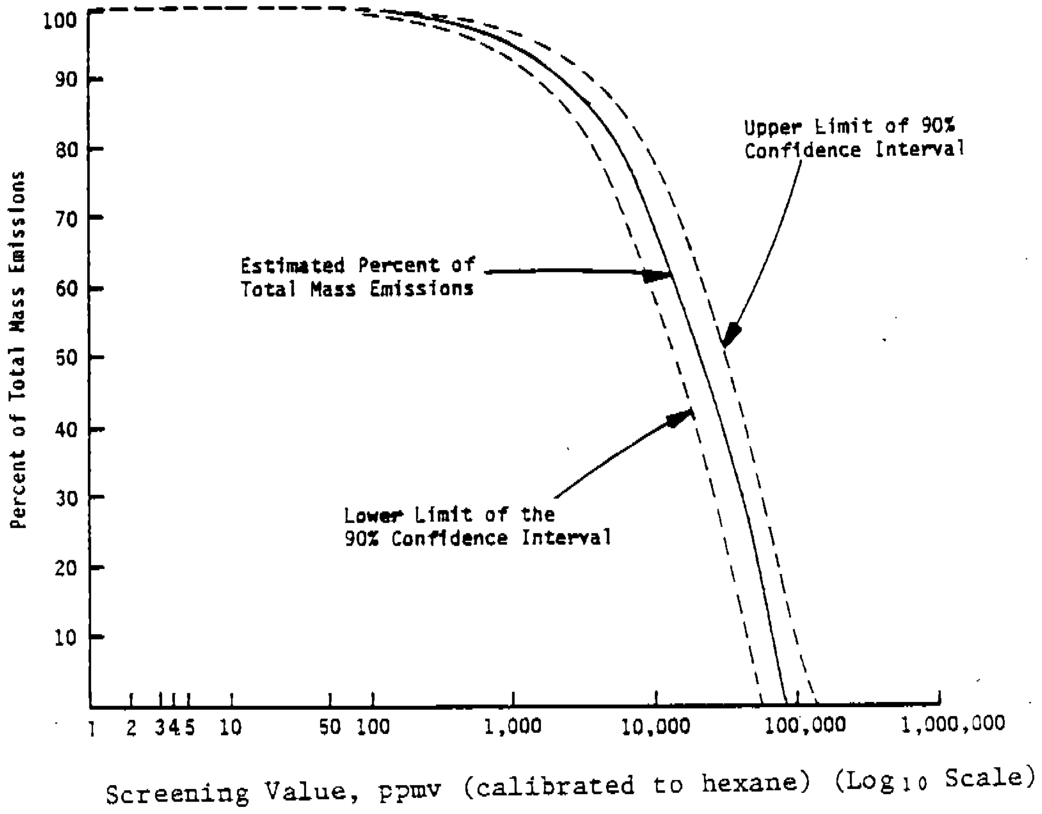


Figure B2-55D. Cumulative distribution of total emissions by screening values for compressor seals - hydrogen service.



Percent of Sources - indicates the percent of sources with screening values greater than the selected value.

Figure B2-56A. Cumulative distribution of sources and total emissions by screening values for drains.



Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-56B. Cumulative distribution of source and total emissions by screening values for drains.

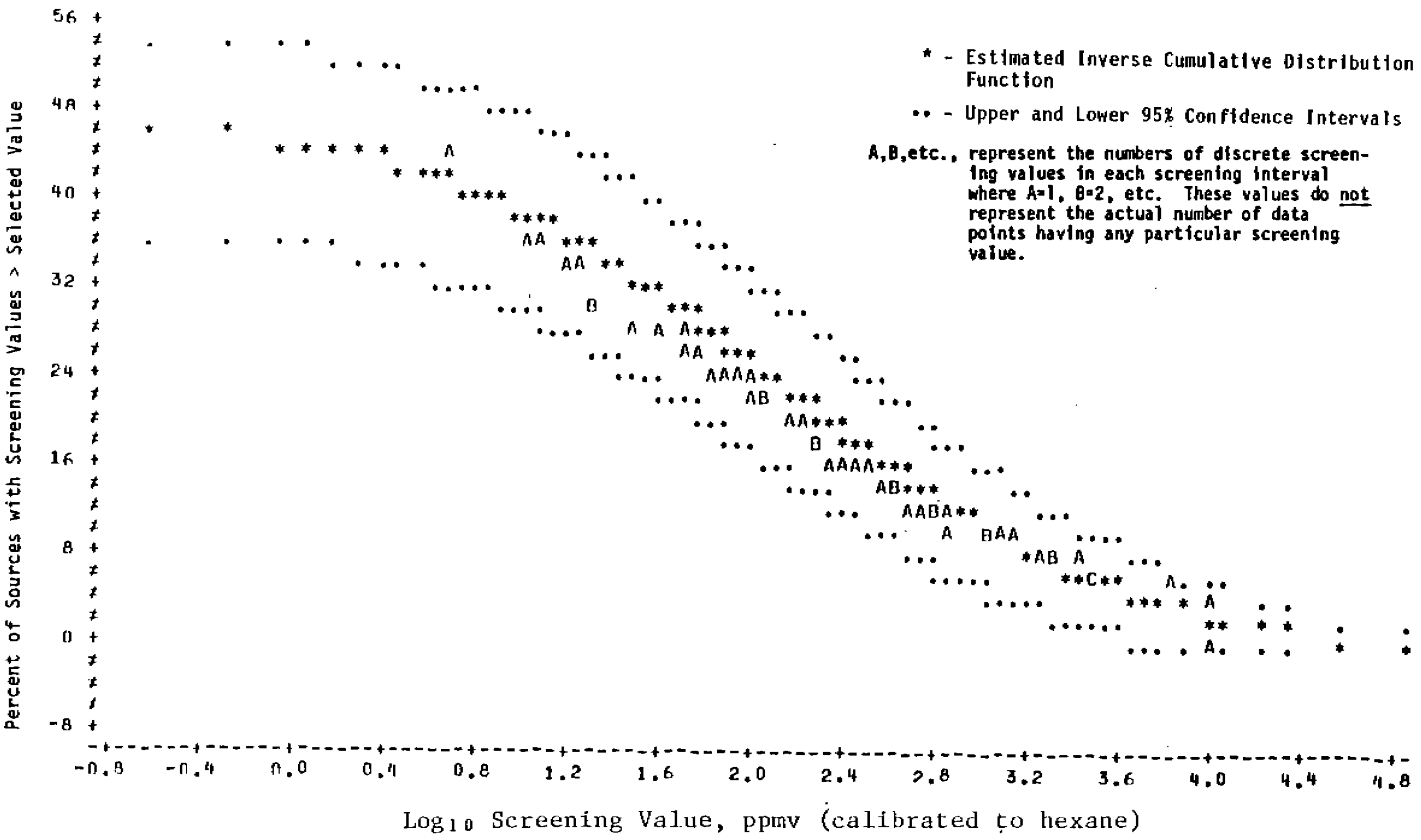


Figure B2-56C. Inverse cumulative distribution function for drains.

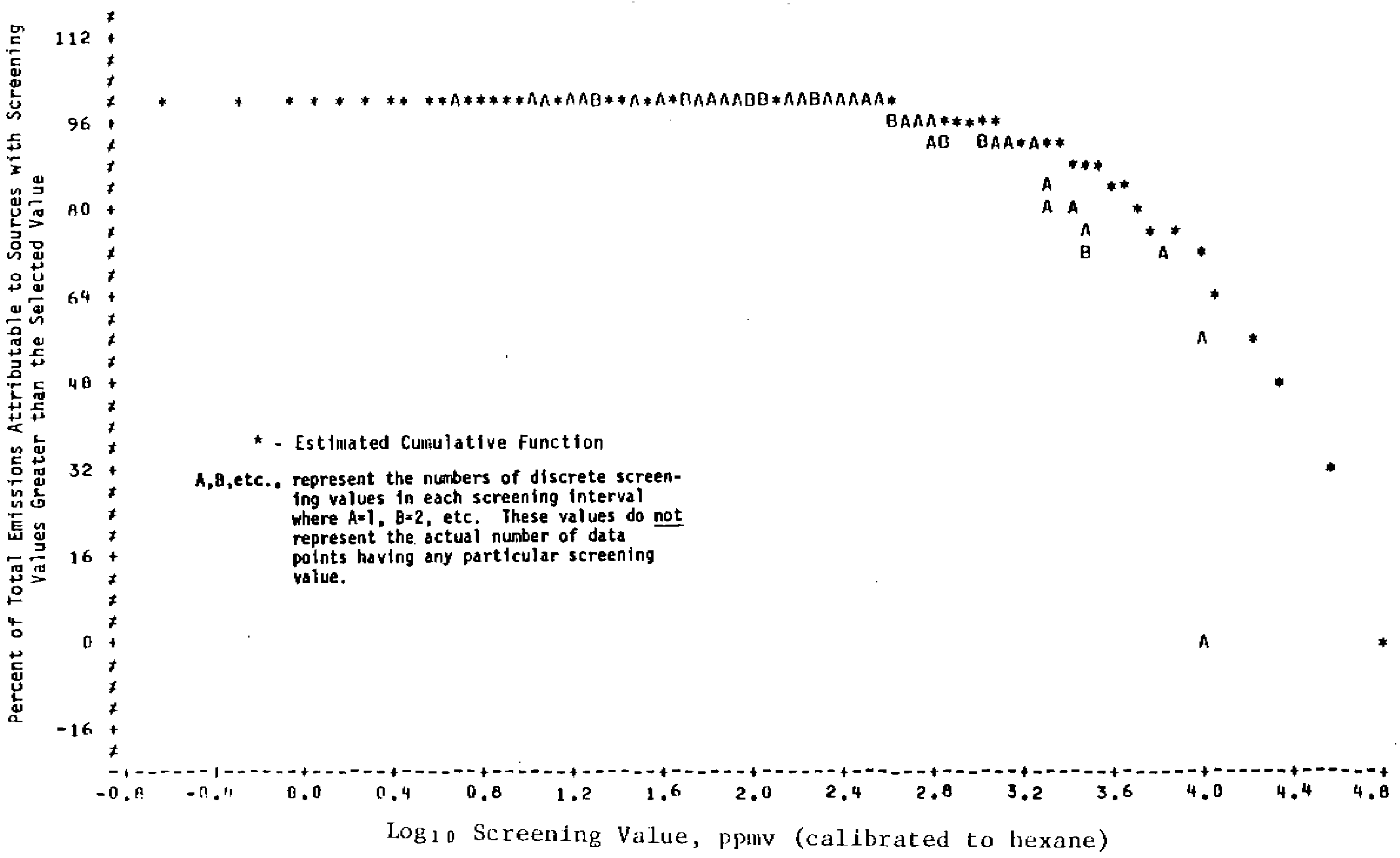
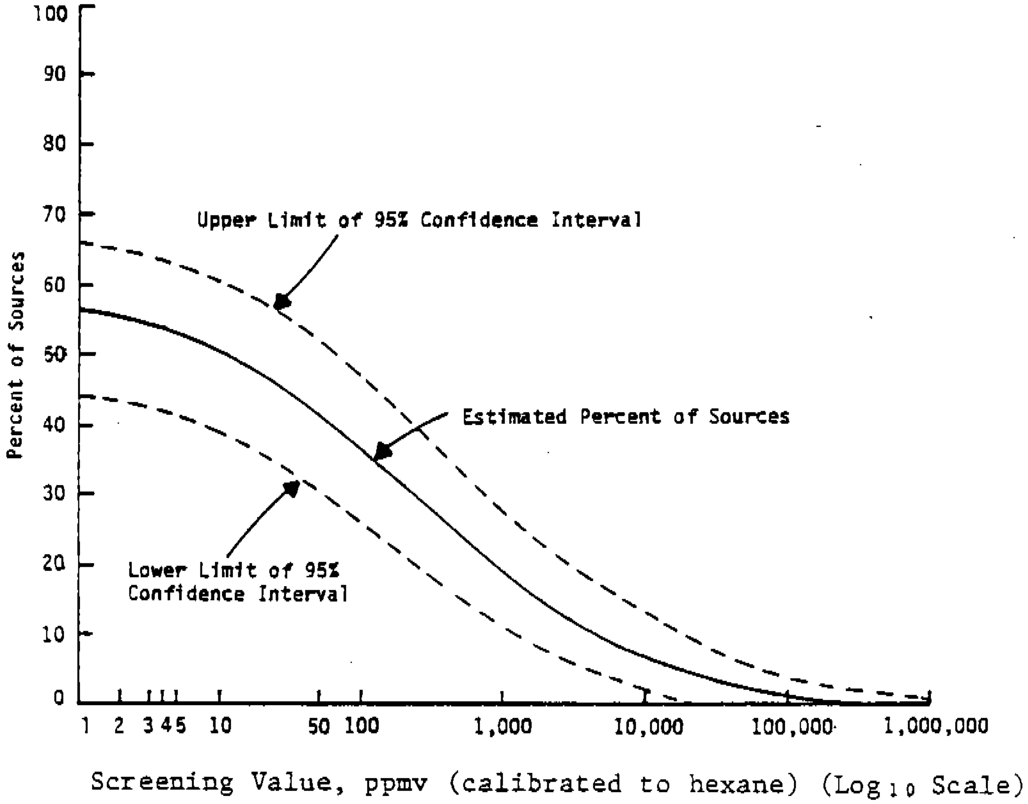
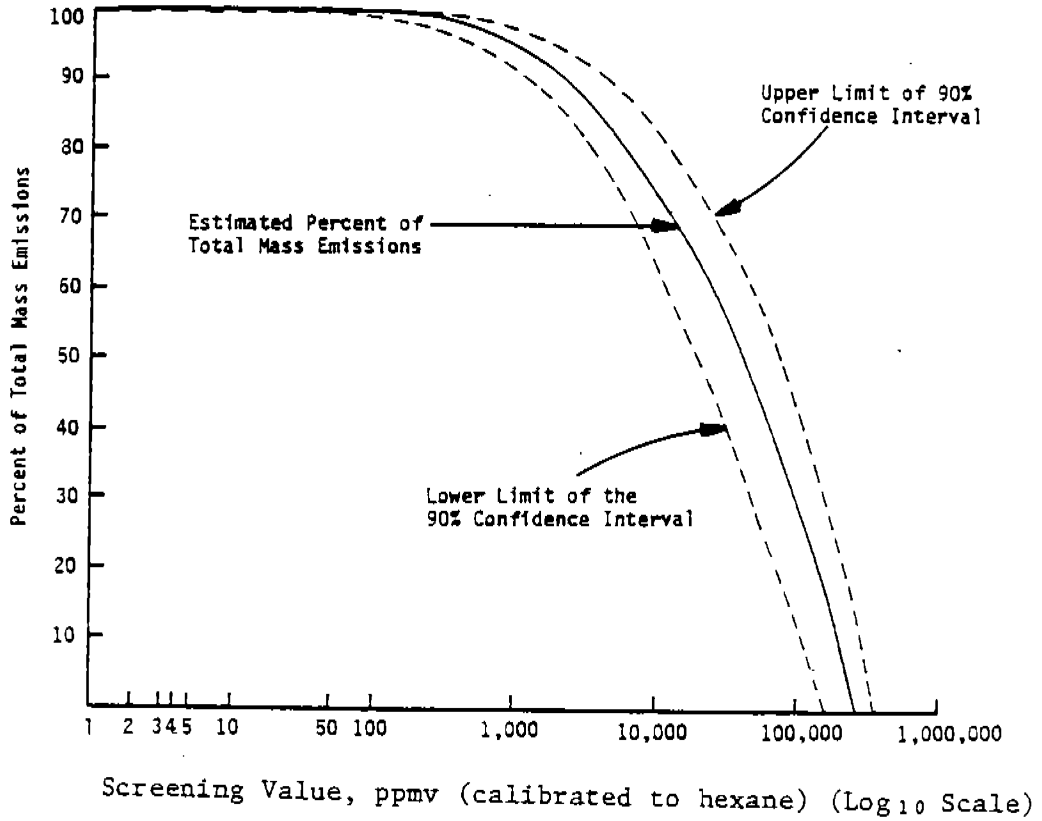


Figure B2-56D. Cumulative distribution of total emissions by screening values for drains.



Percent of Sources - indicates the percent of sources with screening values greater than the selected value.

Figure B2-57A. Cumulative distribution of sources and total emissions by screening values for relief valves.



Percent of Total Mass Emissions - indicates the percent of total emissions attributable to sources with screening values greater than the selected value.

Figure B2-57B. Cumulative distribution of source and total emissions by screening values for relief valves.

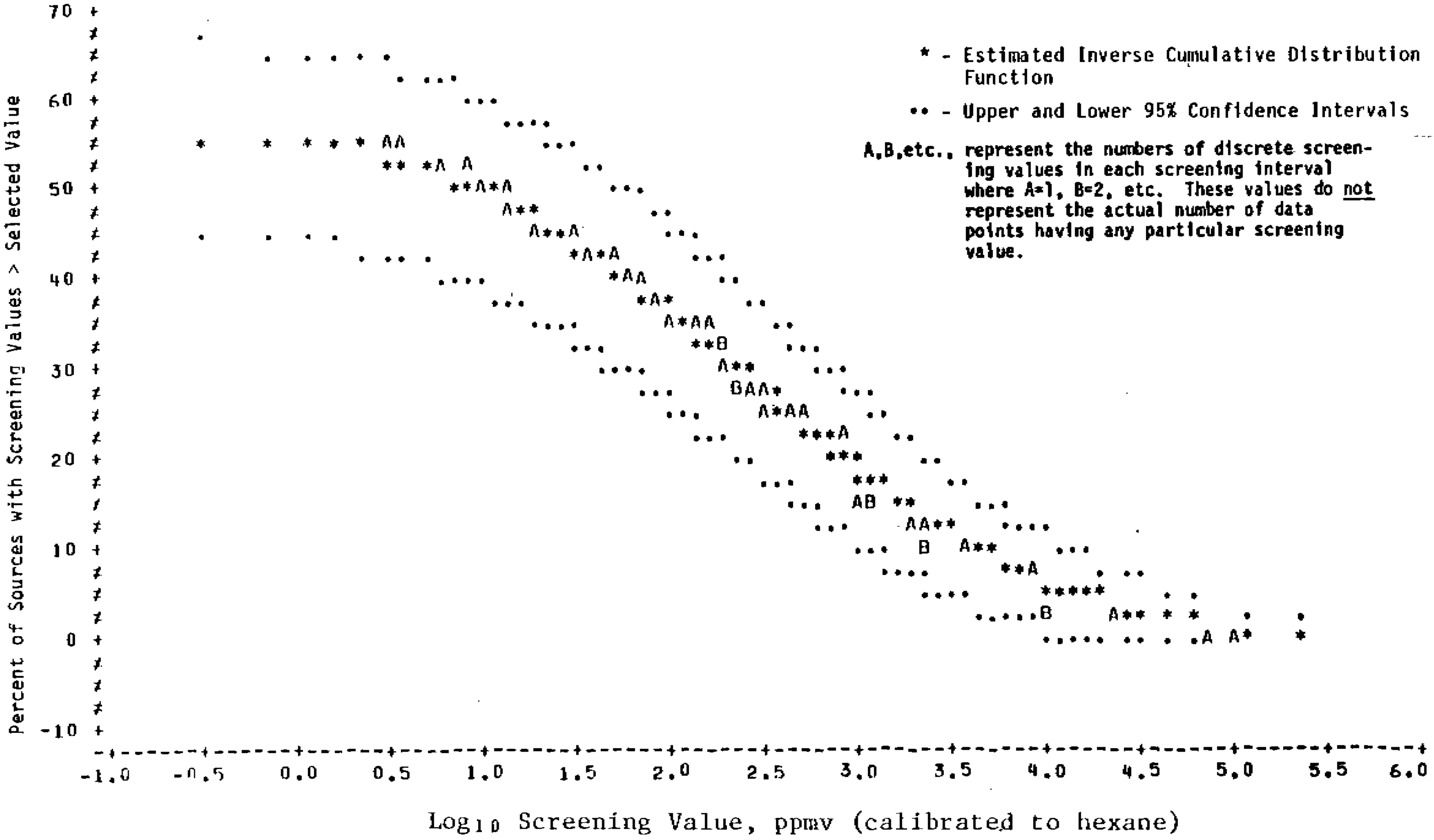


Figure B2-57C. Inverse cumulative distribution function for relief valves.

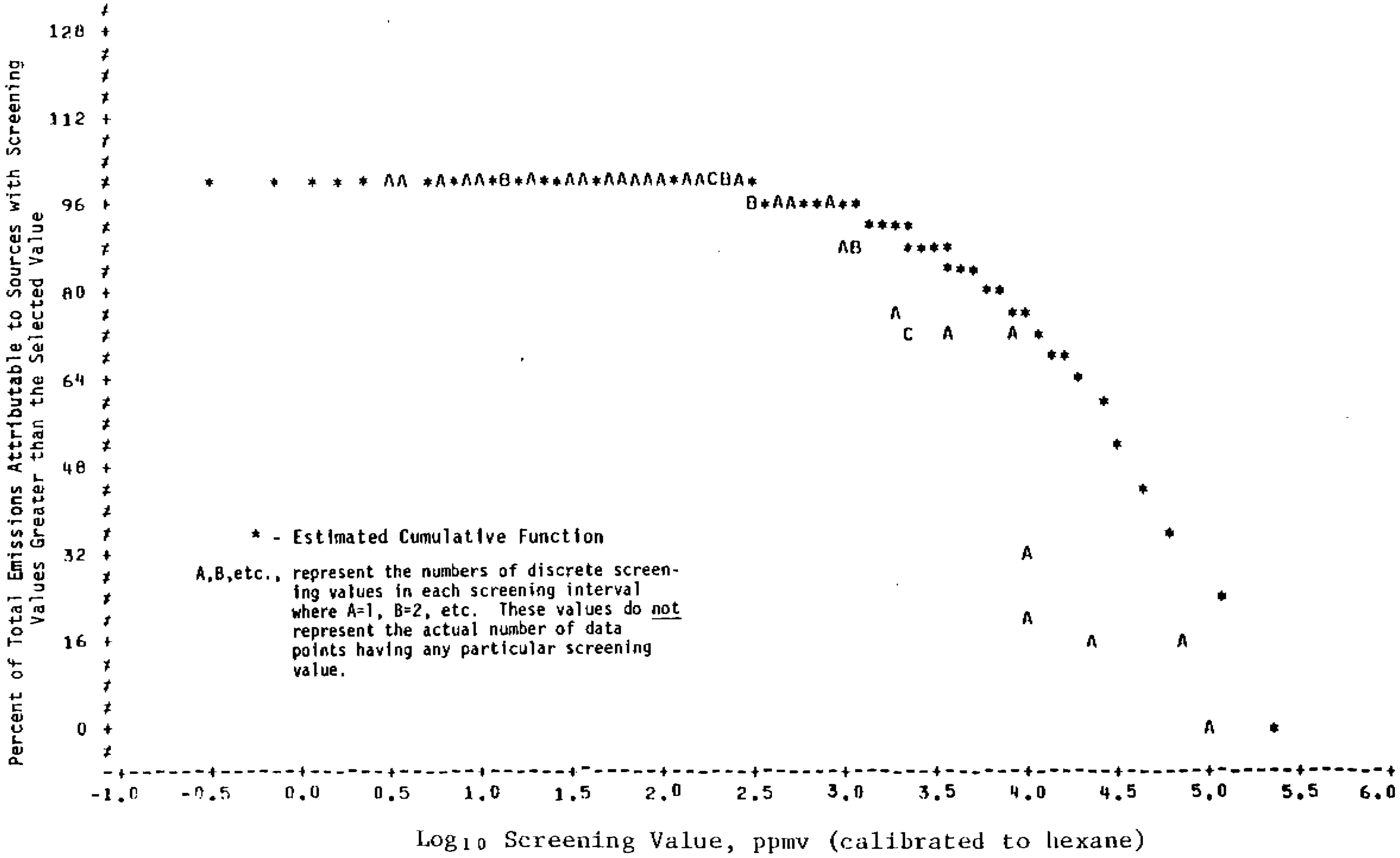


Figure B2-57D. Cumulative distribution of total emissions by screening values for relief valves.

The 95 percent confidence intervals for the cumulative percent of sources can be interpreted as ranges of values which contain the actual percent from the population of sources studied. Note that these intervals apply to the entire population of sources (i.e., a composite of all United States refineries), and are not necessarily applicable to a finite number of sources at any particular refinery. Because of the nature of the function, the confidence intervals will be approximately valid any time a random sample of greater than 100 sources is being considered.

The 90 percent confidence intervals for the cumulative percent of total emissions function can be interpreted as ranges of values which contain the actual percent of total emissions function for the entire population of sources. Again, these intervals describe how well the function has been estimated for the entire population and are not directly applicable to a particular refinery situation with a finite number of sources. The variation of the function for a particular sample of sources is a complex function of the number of sources.

The nomographs must be used with caution when comparing these estimates to actual measured emissions (sampled sources). As discussed earlier, the correlation between screening values and actual leak rates is imperfect. Because of this, values obtained from the nomographs for percent of total emissions caused by a specific percent of total sources may not exactly match similar values for measured leak rates as in Table B2-2. Table B2-15 gives a summary of measured leak rates. In most cases, the nomographs will indicate a higher percentage of sources being responsible for a given percentage of total emissions. In this sense, when actual leak rates can be measured, the nomographs are conservative (i.e., they will identify more sources than necessary to achieve a given level of reduction of total emissions). In a practical sense, however, it is unreasonable to expect that every source

TABLE B2-15. SUMMARY OF DISTRIBUTION OF MEASURED LEAK RATES[a]

Leak Range (lb/hr)	Valves									
	Gas/Vapor Streams		Light Liquid Two-Phase Streams		Heavy Liquid Streams		Hydrogen Streams		Open-Ended Valves	
	A	B	A	B	A	B	A	B	A	B
>1.0	1.2	70.0	0.1	14.4	0.0	0.0	0.0	0.0	0.0	0.0
0.1-1.0	3.2	23.3	3.4	60.3	0.0	0.0	2.2	34.2	0.8	23.3
0.01-0.1	7.6	5.8	11.5	21.9	1.0	74.1	14.1	60.5	7.0	65.3
0.001-0.01	8.7	0.8	13.3	3.2	2.7	23.8	13.3	4.8	9.3	10.8
0.00001-0.001	6.6	0.1	7.8	0.2	2.9	2.1	14.1	0.5	6.2	0.6
>0.00001	20.3	100.0	36.1	100.0	6.6	100.0	43.7	100.0	23.3	100.0

Leak Range (lb/hr)	Pump Seals				Compressor Seals			
	Light Liquid Streams		Heavy Liquid Streams		Hydrocarbon Service		Hydrogen Service	
	A	B	A	B	A	B	A	B
>1.0	4.0	70.6	0.0	0.0	16.2	74.3	0.0	0.0
0.1-1.0	15.5	24.6	5.5	73.2	33.8	24.3	16.9	75.6
0.01-0.1	22.7	4.4	9.6	25.6	16.9	1.4	26.5	22.5
0.001-0.01	16.4	0.4	5.8	1.2	4.9	0.0	25.3	1.8
0.00001-0.001	4.3	0.0	1.7	0.0	2.1	0.0	14.5	0.1
>0.00001	62.9	100.0	22.6	100.0	73.9	100.0	83.2	100.0

Leak Range (lb/hr)	Flanges All Stream Groups		Drains All Stream Groups		Relief Valves All Stream Groups	
	A	B	A	B	A	B
>1.0	0.0	0.0	1.6	61.6	3.4	76.0
0.1-1.0	0.2	63.2	4.7	33.0	10.1	19.2
0.01-0.1	0.6	30.1	6.6	4.9	14.7	4.5
0.001-0.01	1.3	6.0	5.1	0.5	8.1	0.3
0.00001-0.001	0.9	0.7	1.1	0.0	2.7	0.0
>0.00001	3.0	100.0	19.1	100.0	39.0	100.0

A = Percent of total sources screened with sampled leak rates within leak range.
B = Percent of total mass emissions attributable to sources within leak range.

[a] Most sources were bagged and sampled to obtain leak rates; some were estimated using procedures described in Section 6 of Appendix C.

with a screening value exceeding a specific level could be bagged and sampled. Since at this time there is no better method than screening for identifying sources for maintenance, the nomographs are appropriate for evaluating maintenance and control options.

The nomographs are therefore useful in evaluating the potential effectiveness of maintaining and repairing sources for reducing emissions. For example, approximately 5 percent of valves in gas vapor stream service can be expected to have screening values above 50,000 ppmv (Figure B2-47A). However, these 5 percent of the valves are responsible for an estimated 95 percent of the mass emissions (Figure B2-47B). Similarly, for a screening value of 10,000 ppmv, the percent of sources and percent of emissions are 9 percent and 99 percent, respectively.

Analyses, using the nomographs, can also be done for other sources and process streams. For example, Table B2-16 shows the percent of emissions for various sources and process streams when the upper 10 percent of screened sources are considered. Confidence intervals are also shown. Table B2-16 is presented only to illustrate the use of the nomographs and to emphasize the fact that a small fraction of the sources within any one source category account for the majority of emissions in that category. There is no intent here to prejudge that a reasonable level of control is 10 percent of sources, or any other specific number. Ultimately, the decision regarding reasonable control will be based on relative levels of emission reduction and the cost of achieving these levels. Therefore, percentage reduction goals for each source category may be different.

TABLE B2-16. PERCENT OF TOTAL MASS EMISSIONS RELEASED BY THE UPPER[a] TEN PERCENT OF SCREENED SOURCES

	Minimum Screening Value (ppmv)[b]	95% Confidence Interval for Percent of Sources	Percent of Total Emissions	
			Mean	90% Confidence Interval
Valves				
Gas/Vapor	9,200	(6, 13)	99	(98, 100)
Light Liquid/Two-Phase	11,000	(7, 13)	85	(82, 87)
Heavy Liquid	120	(5, 15)	80	(74, 87)
Hydrogen Service	1,400	(3, 16)	83	(70, 91)
Pump Seals				
Light Liquid	47,000	(7, 13)	75	(71, 79)
Heavy Liquid	1,100	(5, 15)	81	(76, 86)
Compressor Seals				
Hydrocarbon Service	68,000	(4, 15)	59	(46, 72)
Hydrogen Service	76,000	(3, 17)	77	(64, 87)
Flanges	14	(6, 14)	99	(98, 100)
Drains	1,100	(4, 16)	94	(92, 96)
Relief Valves	4,700	(3, 17)	83	(78, 90)

[a] The upper ten percent of screened sources is defined as the ten percent of sources having the highest screening values.

[b] Screening Value with TLV Sniffer calibrated to hexane.

In summary, Figures B2-47 through B2-57 present continuous distributions of the percent of emissions and sources versus specific screening values. These figures can be used to estimate the reduction in emissions which could ideally occur if, after screening, the emissions from a selected percentage of leaking sources were reduced to zero after repair. It is emphasized that these figures represent an amalgamation of data from nine refineries (thirteen for compressor seals and relief valves) and do not represent any single refinery. Therefore, these results must be used with caution when analyzing a specific refinery or process unit.

2.5 CORRELATION OF VARIABLES

2.5.1 Correlation of Leak Rate with Continuous Process Variables

At the beginning of this program it was hypothesized that the leak rates from baggable sources would be affected by process variables such as temperature, pressure, and size. The study of the correlation of process variables is complicated by three factors:

1) The degree of skewness in the leak rate data and the inherent variability of the leak rate measurement procedures,

2) The dominating effect on leak rate of the composition of the process stream, and

3) Inaccuracies and missing information when "measuring" process variables.

To examine the correlations, the logarithm (base 10) of the leak rate (lb/hr) was related to the process variables to minimize the effect of skewness and variability of the leak rate measurement. The data were grouped by the important process stream classifications to minimize the effect of the stream composition.

The inaccuracies in determining some of the process variables reduce the sensitivity of the correlation analysis. For instance, the variable "age" recorded was usually the age of the unit. A more useful age determination would have been the years in service of each individual source, or possibly the time since last maintenance was done, but it was impractical to obtain this information for the large number of sources studied. Therefore, the conclusions concerning process variables pertain to the variables as measured or determined in this study.

Table B2-17 lists the simple correlation coefficients between the log leak rate and the appropriate independent variables for each source type and stream classification. Correlations significantly different than zero are noted. The simple correlation coefficient is a statistical measure of the linear relationship between two variables. The correlation between "X" and "Y" is computed as:

$$r_{XY} = \frac{\Sigma(Xi-\overline{X})(Yi-\overline{Y})}{\sqrt{\Sigma(Xi-\overline{X})^2 \ \Sigma(Yi-\overline{Y})^2}}$$

and is bounded:

TABLE B2-17. CORRELATIONS BETWEEN CONTINUOUS VARIABLES AND LOG$_{10}$ LEAK RATE

	Pressure	Temperature	Age	Line Size	Diameter	Area	RPM	Capacity	Load	Stroke Length
Valves										
Gas/Vapor Streams	.230*	.077	.263*	.150*	-	-	-	-	-	-
Light Liquid Streams	.103*	.051	.096	.143*	-	-	-	-	-	-
Heavy Liquid Streams	-.351*	.144	.220	.046	-	-	-	-	-	-
Hydrogen Service	-.088	.129	-.531*	.288*	-	-	-	-	-	-
Open-Ended	.236	.242	.230	-.078	-	-	-	-	-	-
Pump Seals										
Light Liquid Service	.088	-.012	.062	-	.021	-	-.064	-	-	-
Heavy Liquid Service	.097	-.098	.237	-	.128	-	-.182	-	-	-
Flanges	.072	.021	-.180	.336*	-	-	-	-	-	-
Compressor Seals										
Hydrocarbon Service	.346*	.218*	.105	-	.278*	-	-.143[a]	-.138	-.087	-.012
Hydrogen Service	.398*	.312*	.052	-	.343*	-	-.034	.218	-.099	-.074
Drains	-	-.408*	-	-	-.039	-.191	-	-	-	-
Relief Valves	.045	.096	-	-.075	-	-	-	-	-	-

* Correlation Coefficient statistically different from zero ($P > .90$).

[a] Log$_{10}$ RPM was correlated with log$_{10}$ leak rate.

$$-1 < r_{XY} < 1.$$

Figure B2-58 is a schematic diagram which shows typical data associated with various values of the correlation coefficient, r. For values of r near +1, as one variable increases, the other increases. For values of r nearly -1, as one variable increases the other decreases. For data which show a random scatter pattern, the value of r will be zero.

The value of r^2 indicates the approximate percentage of the total variation in the log leak rate that is accounted for by the relationship of the leak rate with the correlating variable. For instance if $r = 0.50$, then $r^2 = 0.25$ and about 25 percent of the variation in the leak rate is attributable to the relationship with the process variable. The remaining 75 percent of the variation is due to other variables and random variation.

The sampling distribution of values of r is highly dependent on the sample size. Small values of r (0.1-0.2) may be statistically significant for large sample sizes while large values of r (0.4-0.7) may not be significant for small sample sizes. Statistically significant refers to a statistical test of the hypothesis that the correlation is equal to zero, i.e., no relationship between the variables. A significant correlation therefore does not imply a large value of r, since values of $r < 0.2$ may be significant for large sample sizes.

The correlation coefficient, r, can sometimes be misleading for the following reasons:

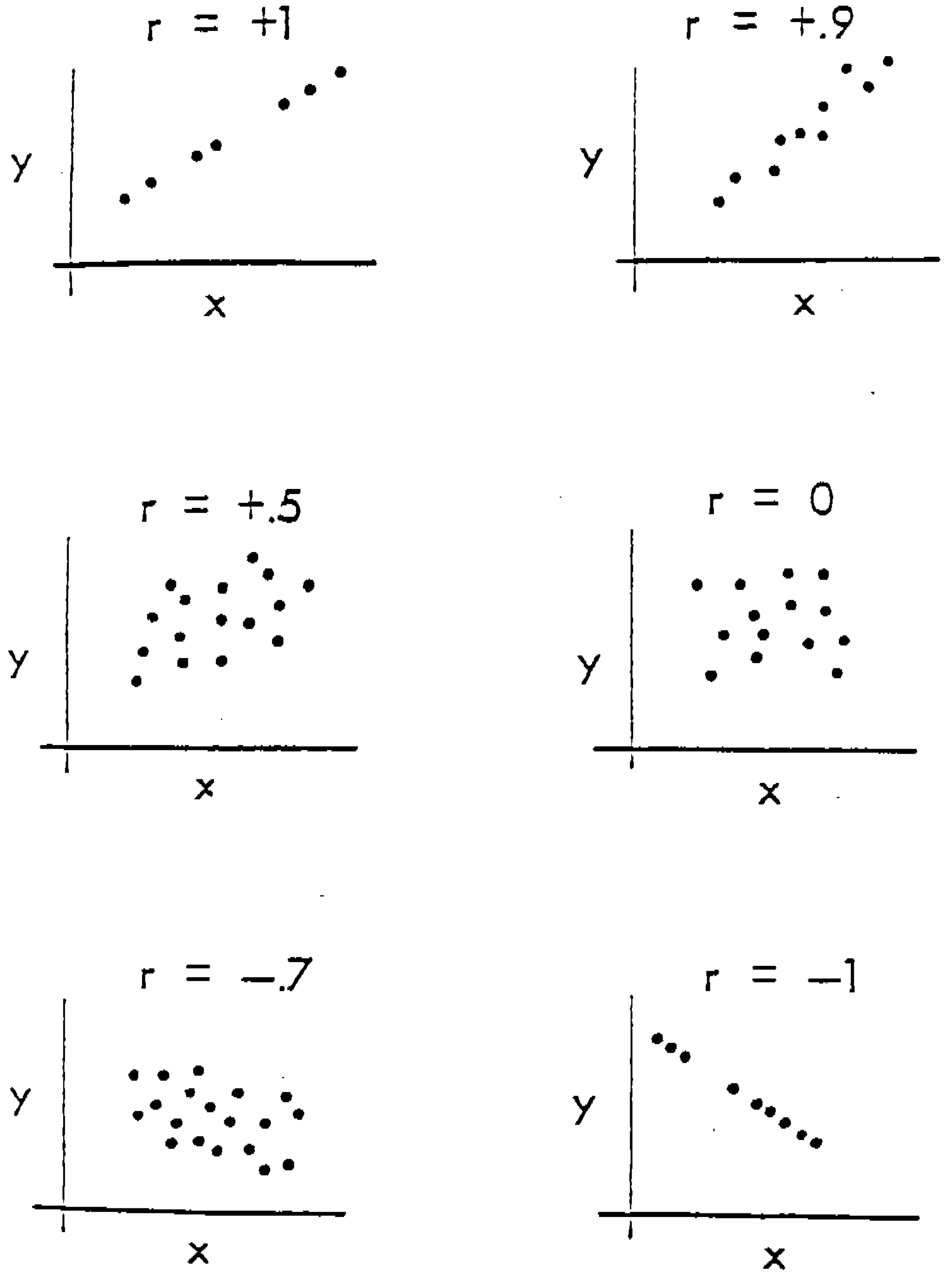


Figure B2-58. Scatter diagrams and correlation coefficients.

- r does not describe how much Y changes for a given change in X, what the shape of the curve connecting Y and X is, or how accurately Y can be predicted from X.
- A correlation between X and Y may be due to their common relation to other variables.
- Outliers and highly skewed data can distort the frequency distribution of r.
- Selecting values of X at which Y is measured can distort the frequency distribution of r.
- r may be unduly high because of sampling from two different populations instead of one.

In order to examine the actual data used in calculating the correlations presented here, scatter plots of the log leak rate data (in pounds per hour) and the process variables are shown in Figures B2-59 through B2-114. The correlation coefficient (r) and the number of data pairs are shown on each plot. Statistically significant correlations are noted with a "*".

2.5.2 Relationships Between Discrete Variables and Leak Rates

Unlike continuous variables, correlation coefficients are not easily interpreted for discrete variables, i.e., manufacturer, material, and seal type versus leak rate. A visual method for comparing the relationships between levels of the variable and leak rate is the schematic plot. Figures

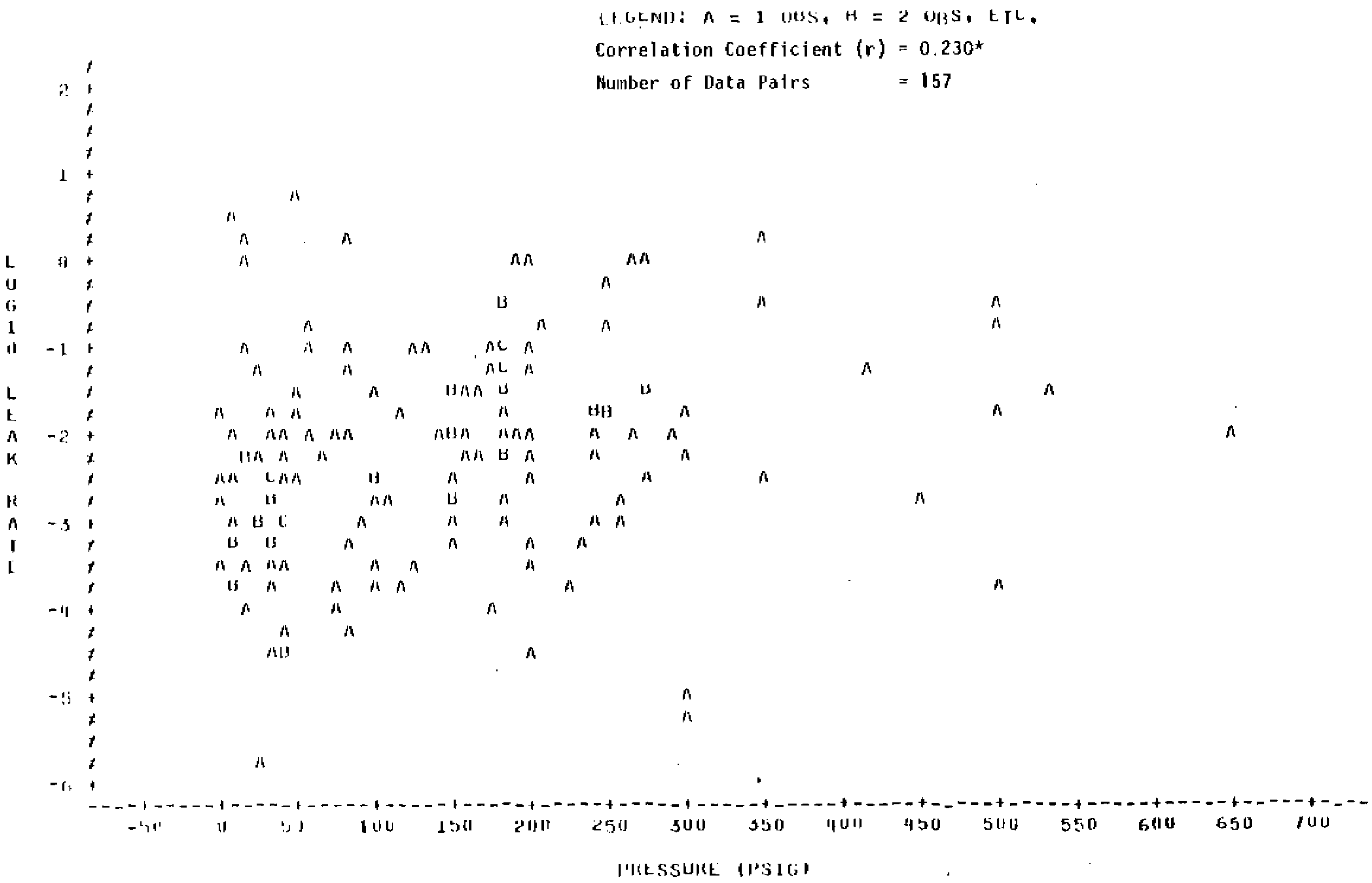


Figure B2-59. Leak rate vs. pressure - valves, gas/vapor streams.

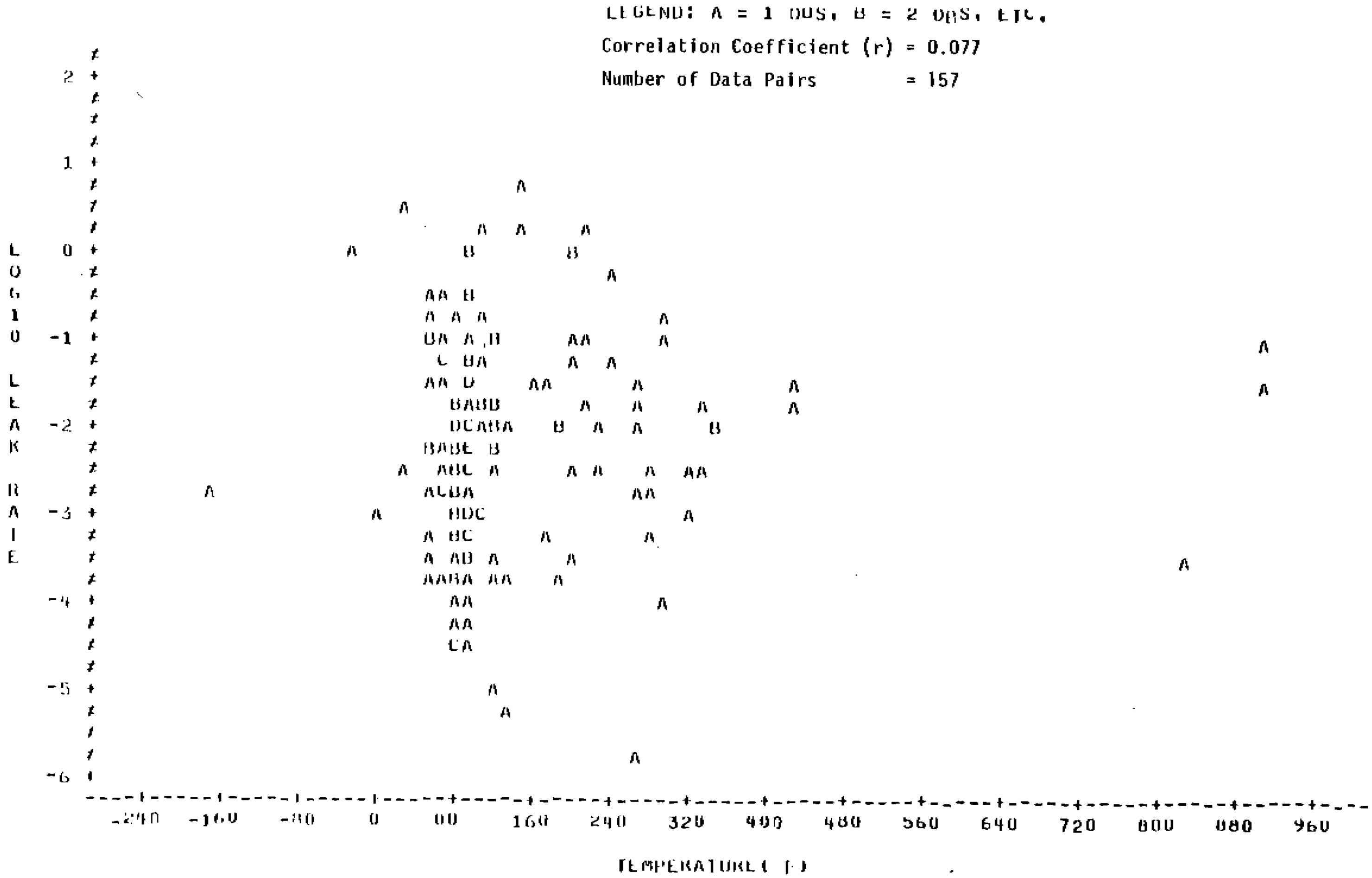


Figure B2-60. Leak rate vs. temperature - valves, gas/vapor streams.

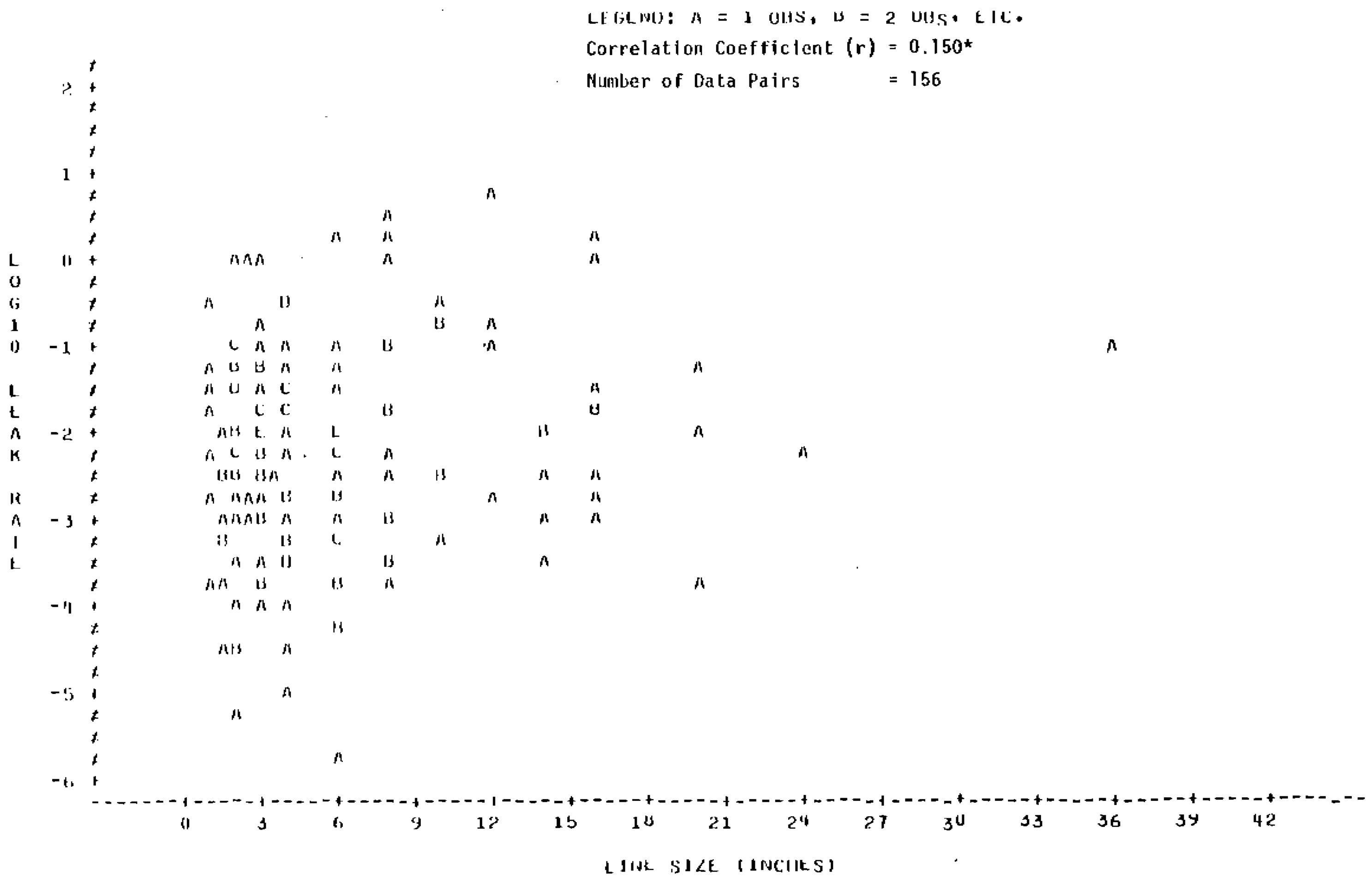


Figure B2-61. Leak rate vs. line size - valves, gas/vapor streams.

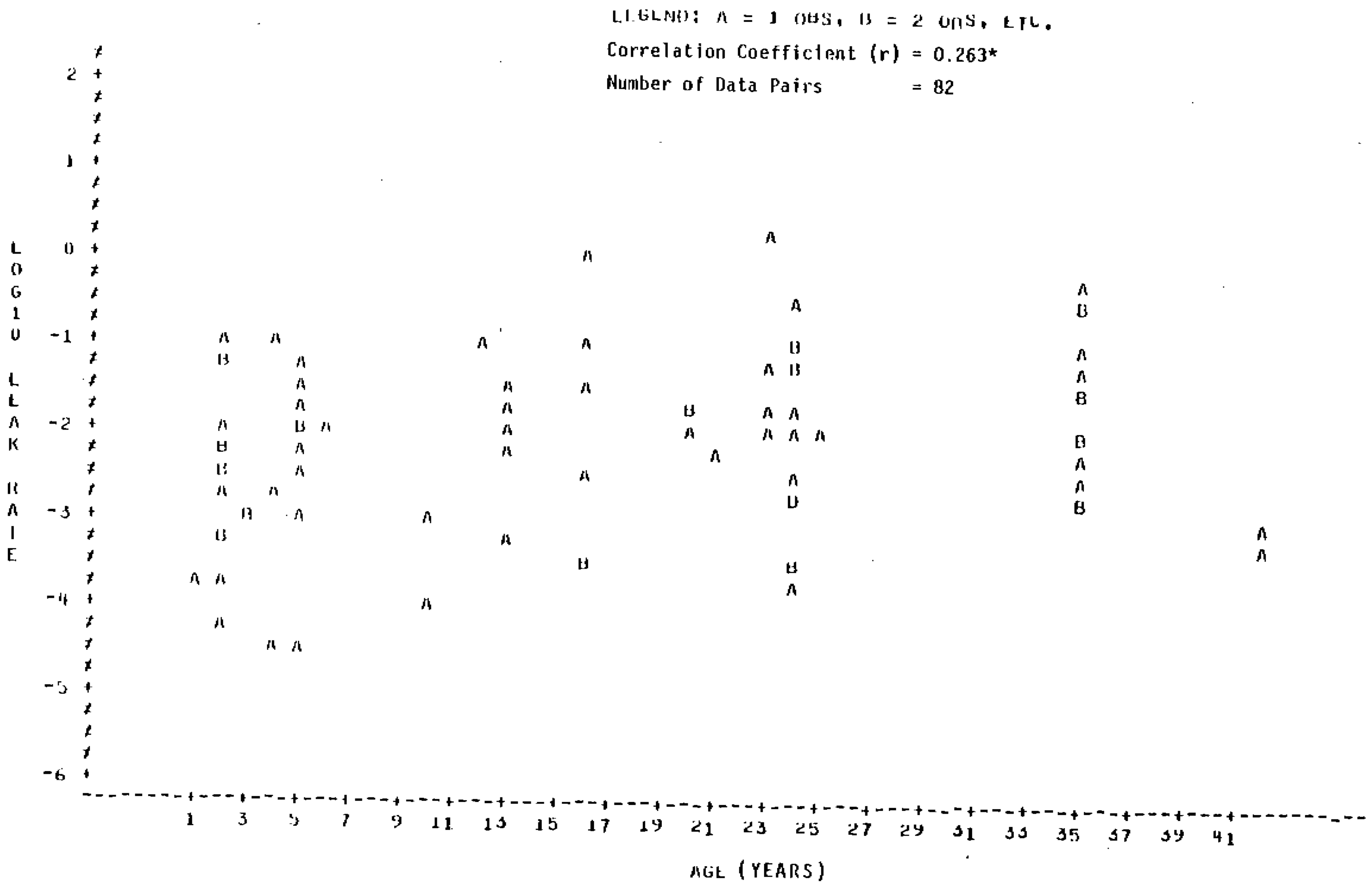


Figure B2-62. Leak rate vs. age - valves, gas/vapor streams.

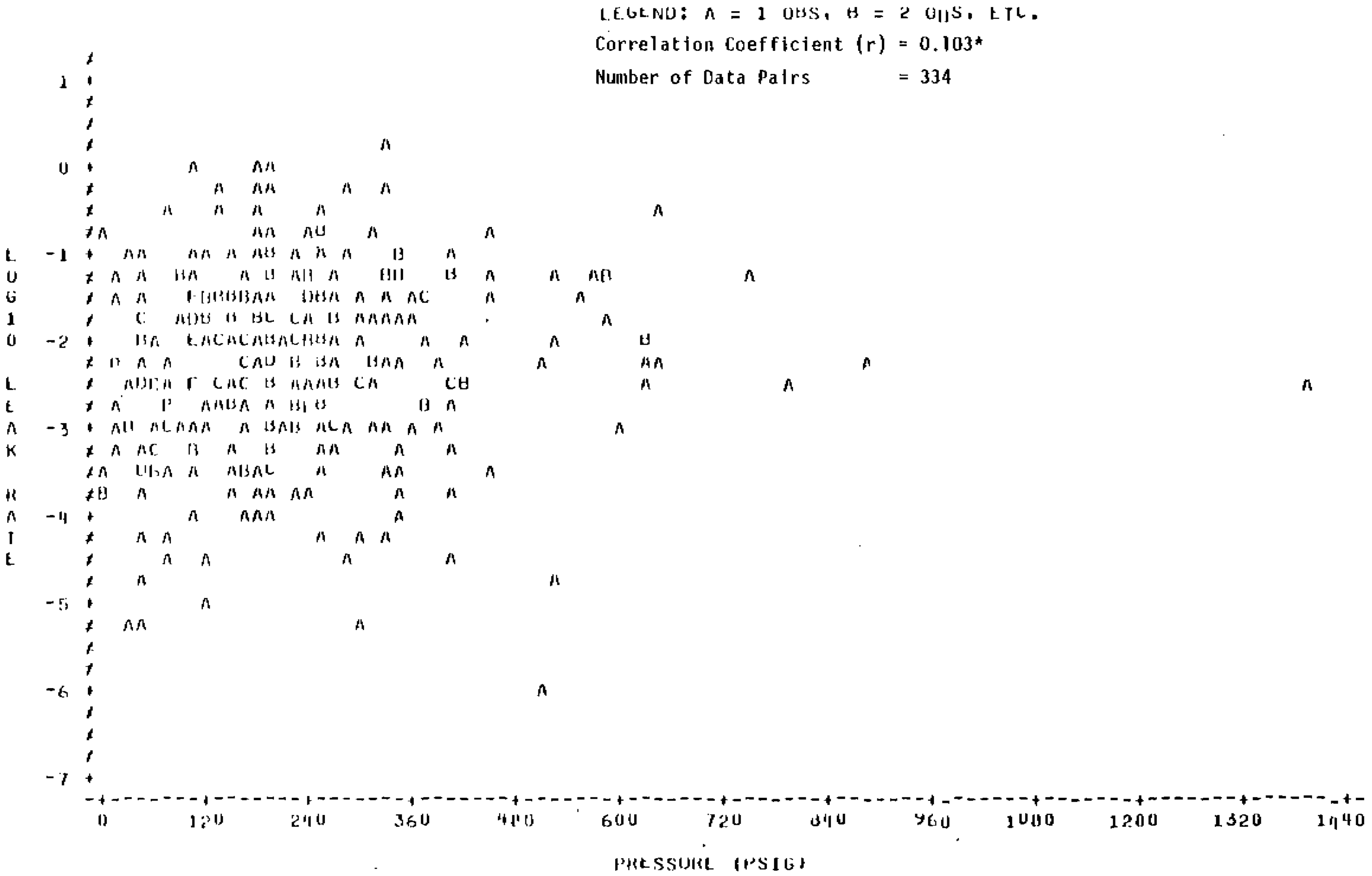


Figure B2- 63. Leak rate vs. pressure - valves, light liquid/two phase streams.

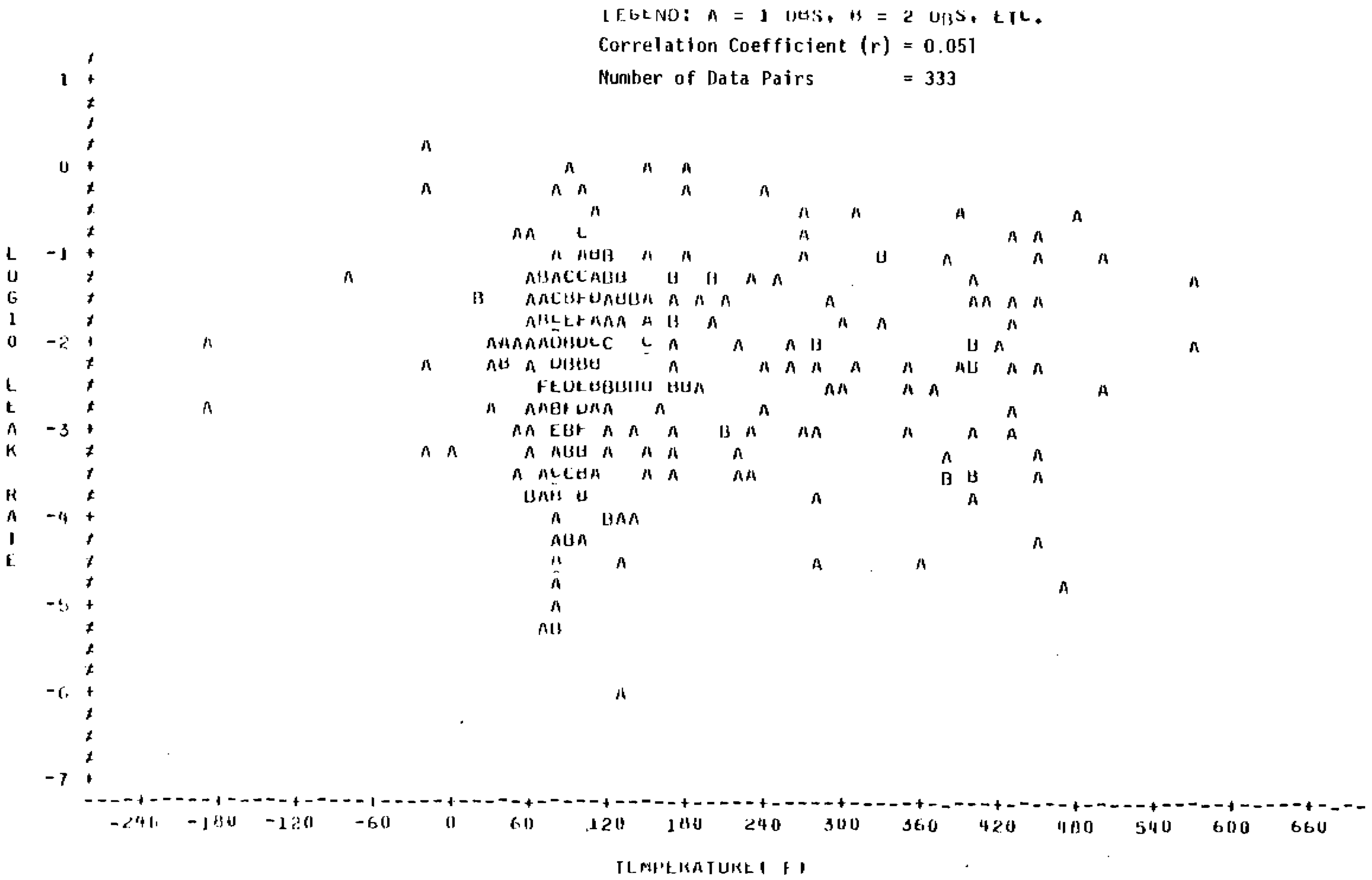


Figure B2-64. Leak rate vs. temperature - valves, light liquid/two phase streams.

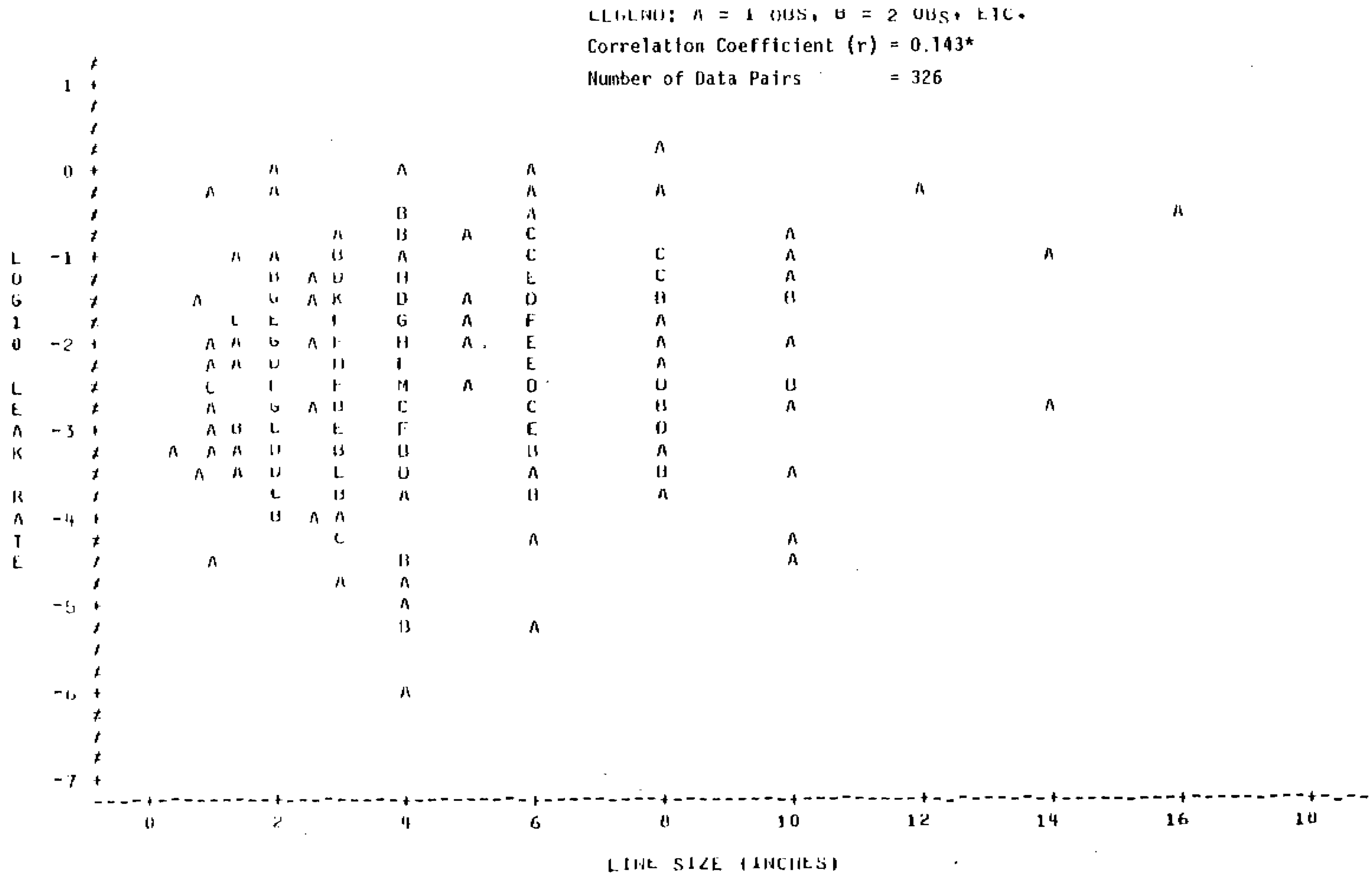


Figure B2-65. Leak rate vs. line size - valves, light liquid/two phase streams.

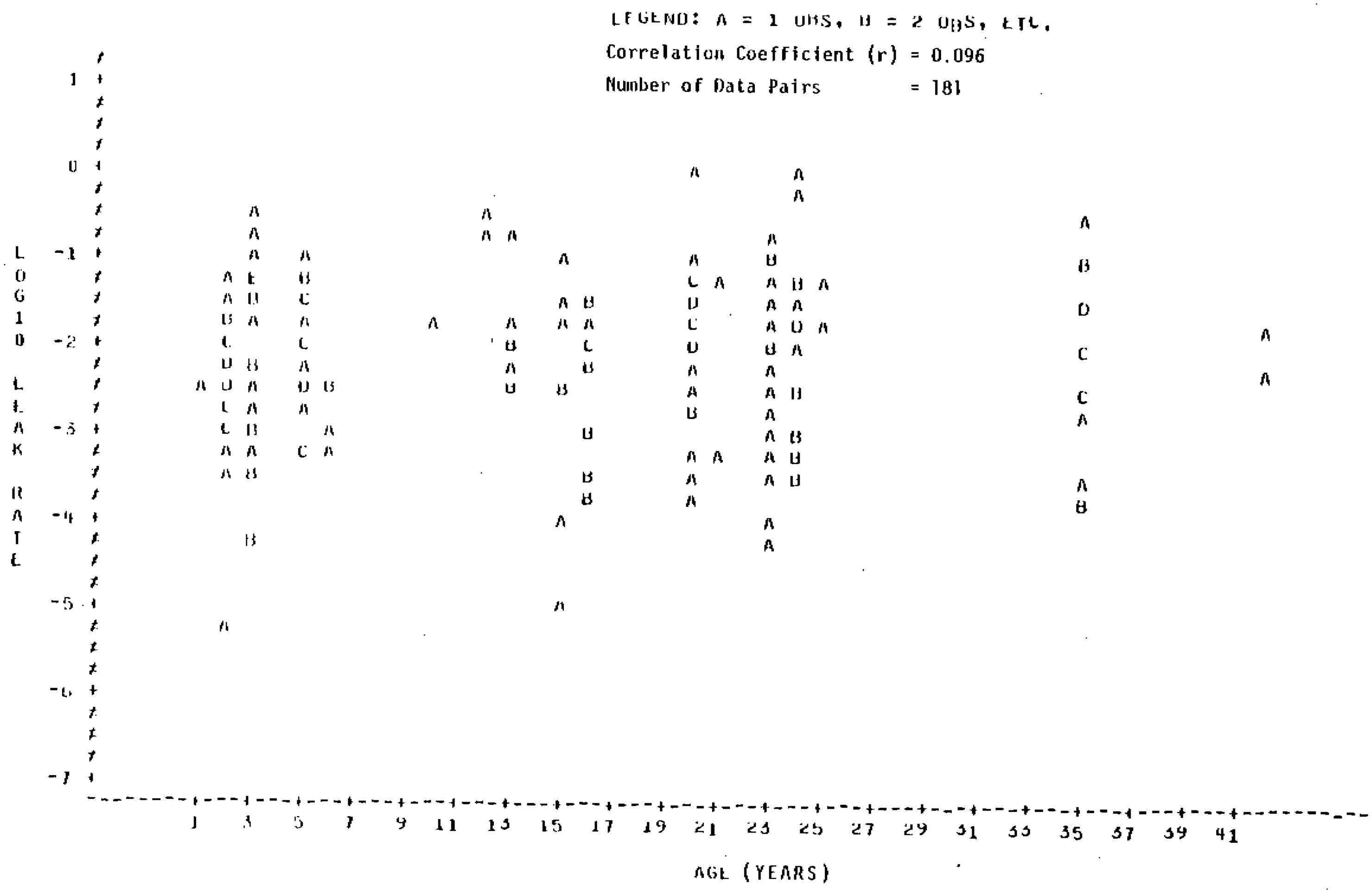


Figure B2- 66. Leak rate vs. age - valves, light liquid/two phase streams.

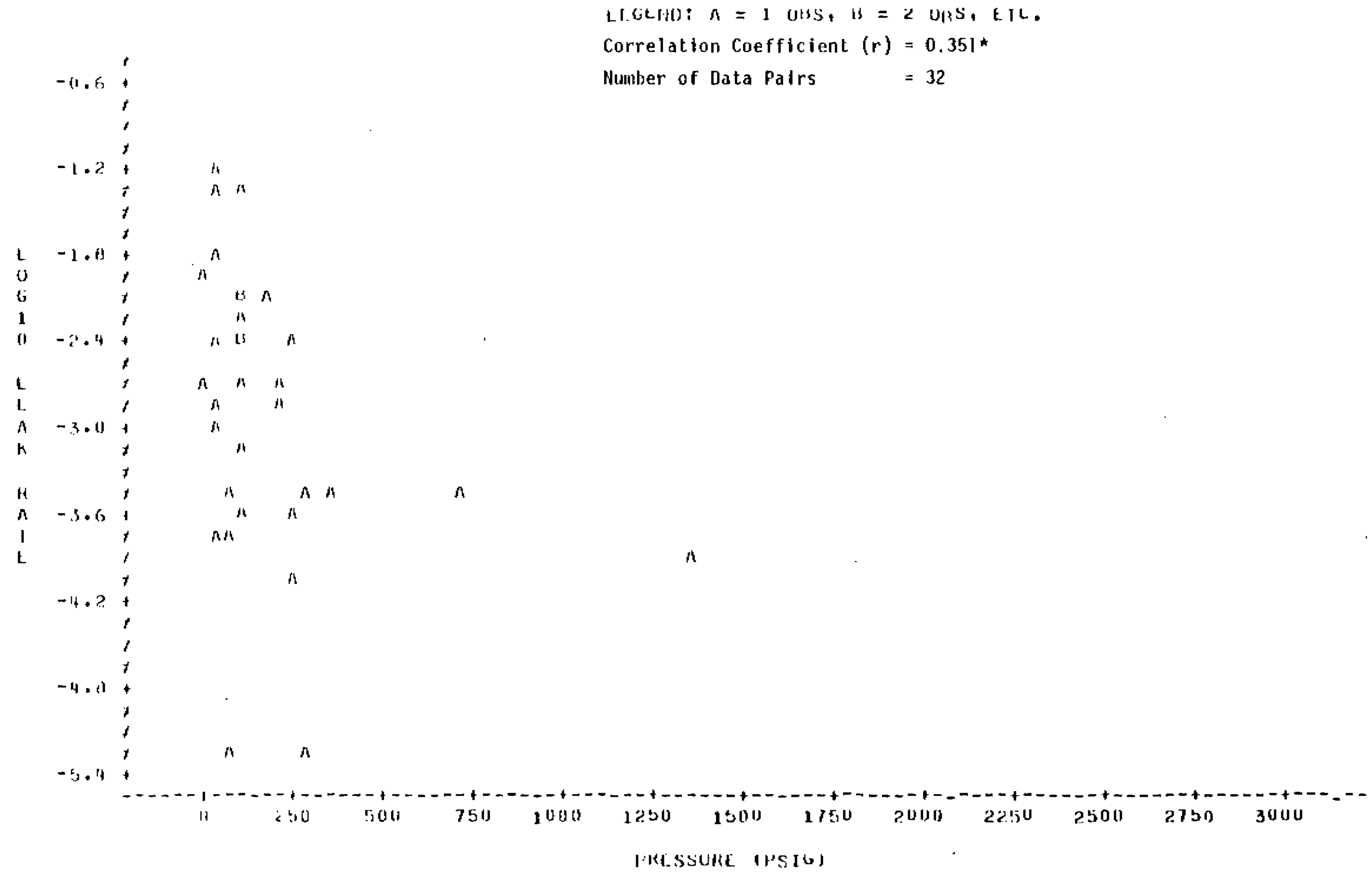


Figure B2-67. Leak rate vs. pressure - valves, heavy liquid streams.

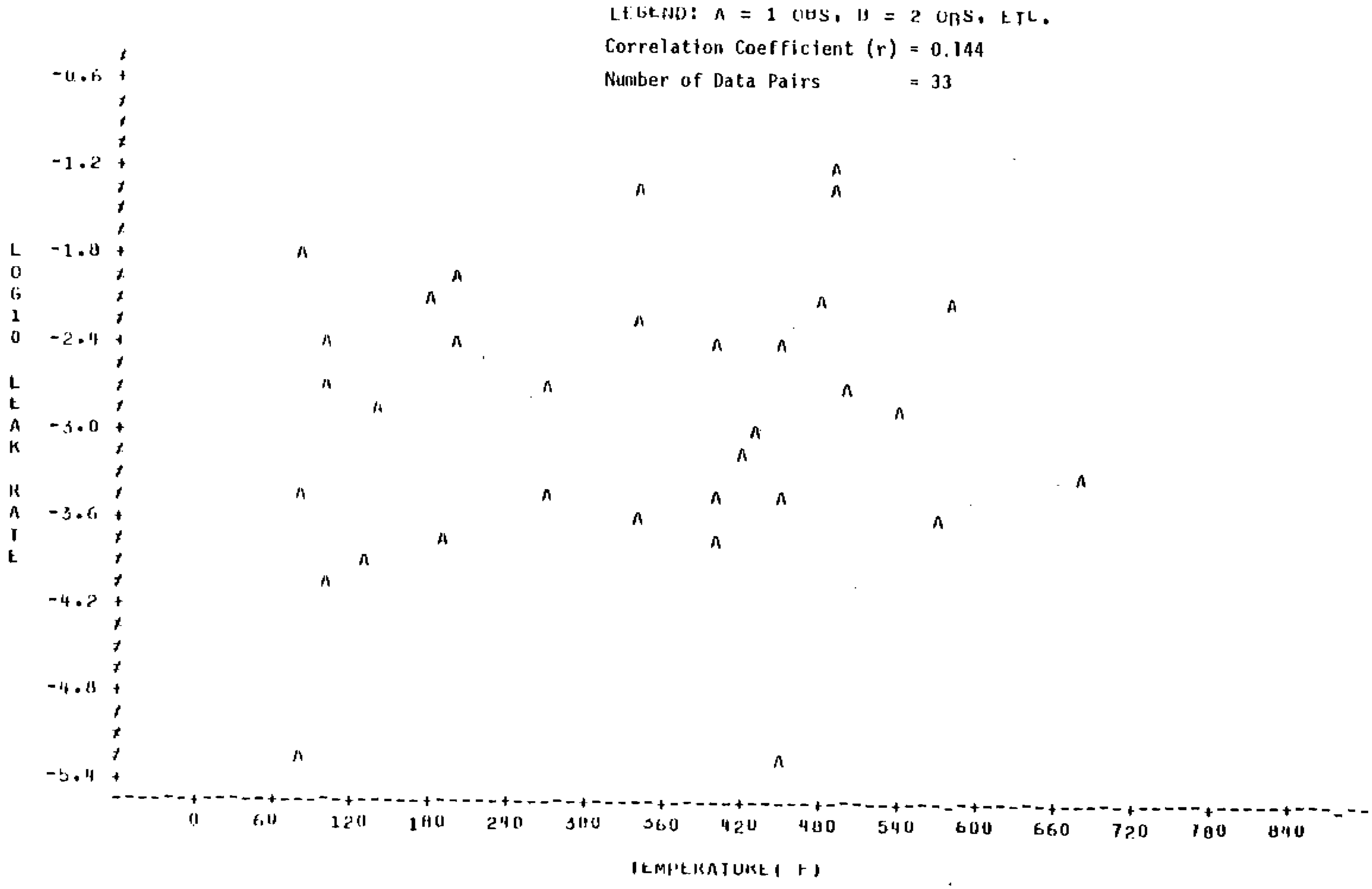


Figure B2-68. Leak rate vs. temperature - valves, heavy liquid streams.

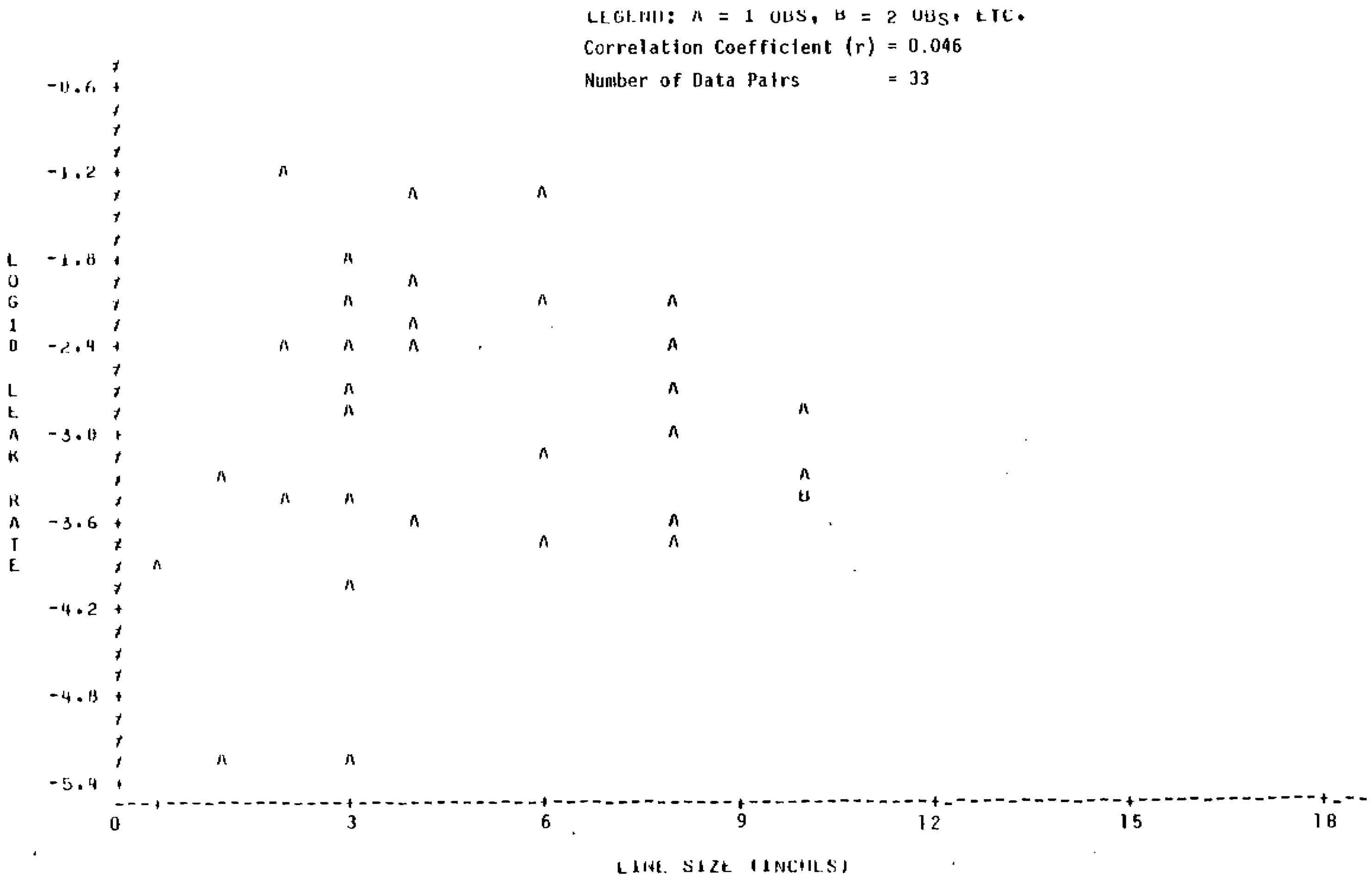


Figure B2-69. Leak rate vs. line size - valves, heavy liquid streams.

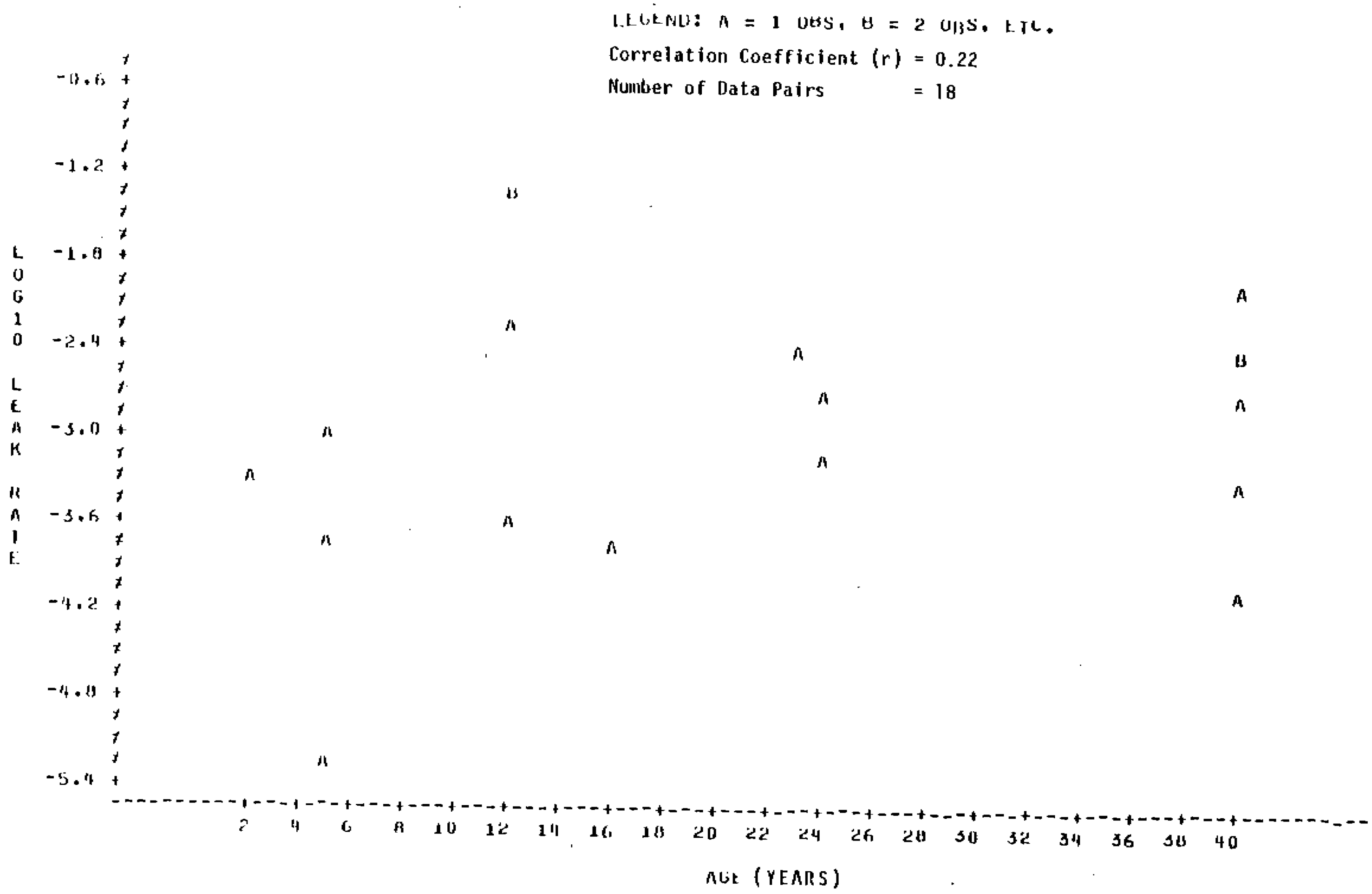


Figure B2-70. Leak rate vs. age - valves, heavy liquid streams.

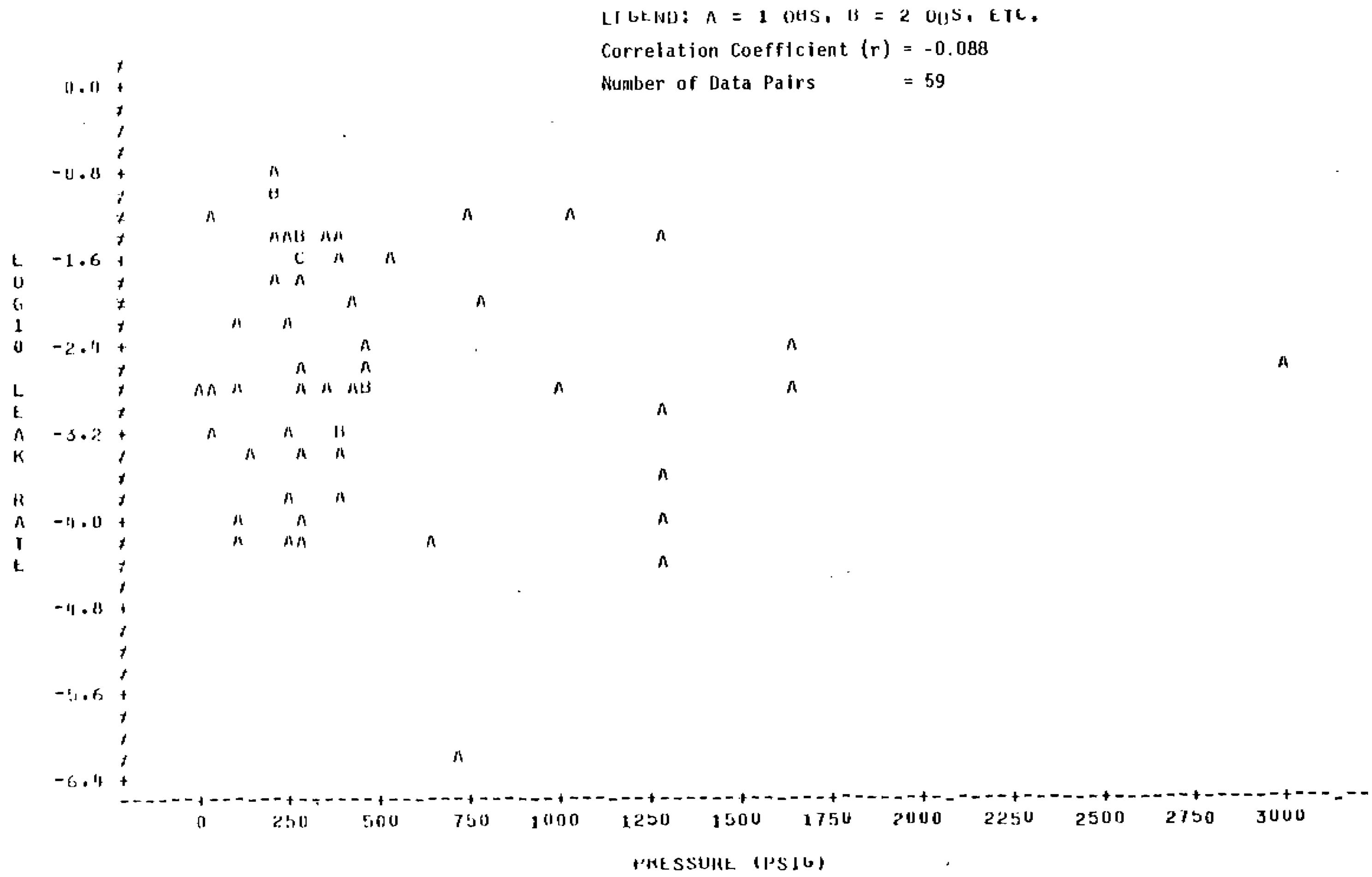


Figure B2-71. Leak rate vs. pressure - valves, hydrogen service.

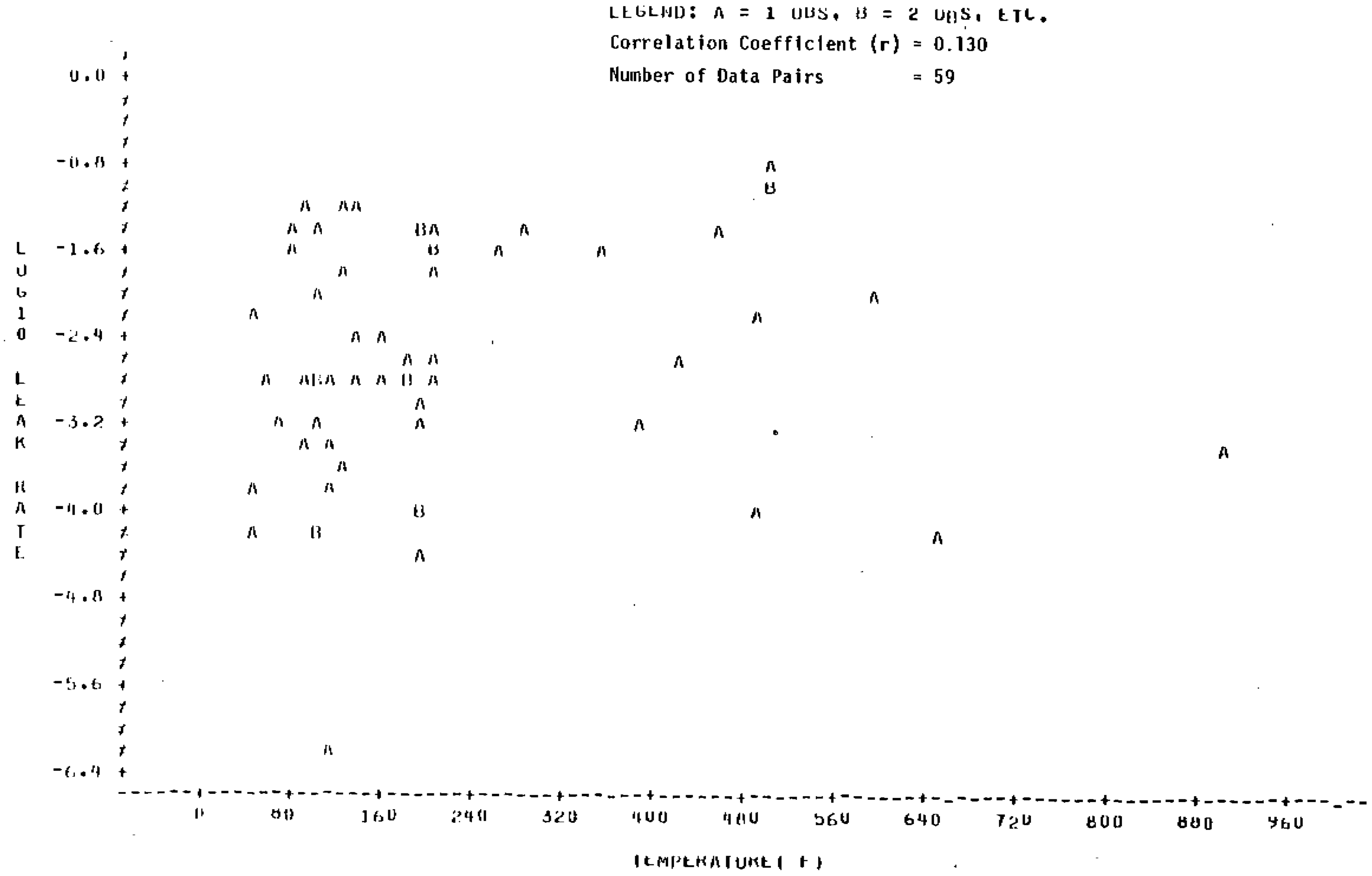


Figure B2-72. Leak rate vs. temperature - valves, hydrogen streams.

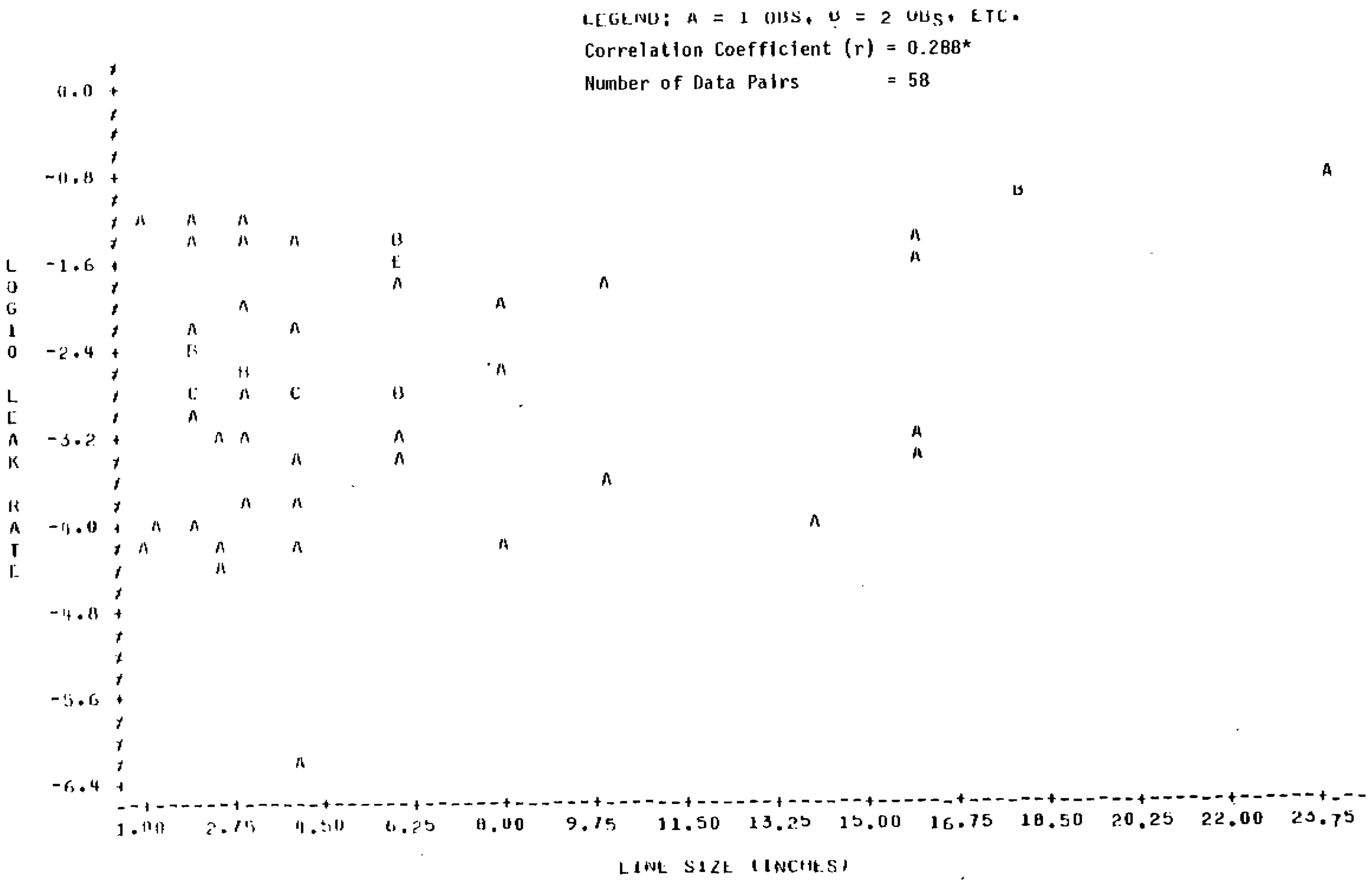


Figure B2-73. Leak rate vs. line size - valves, hydrogen streams.

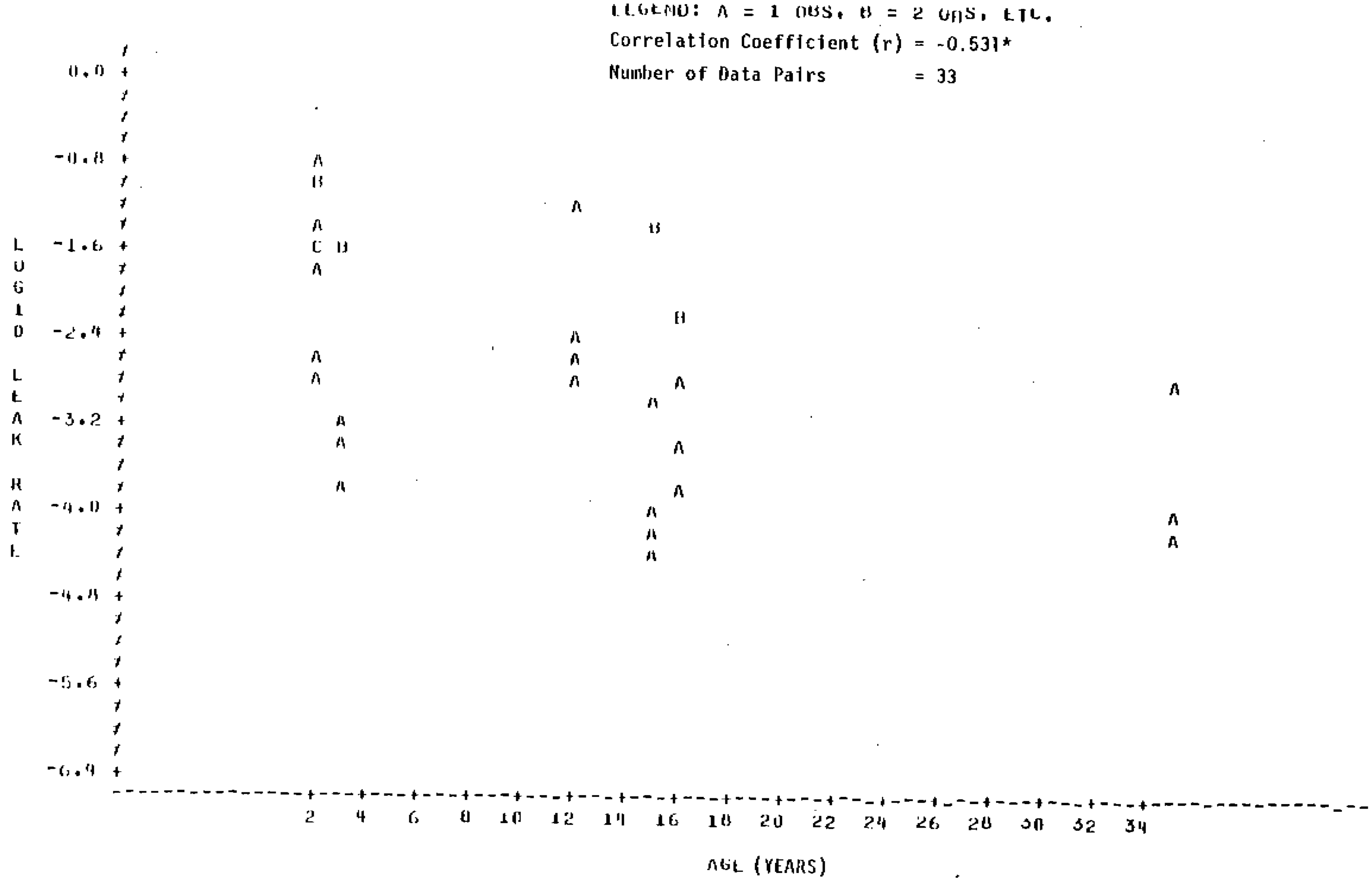


Figure B2-74. Leak rate vs. age - valves, hydrogen streams.

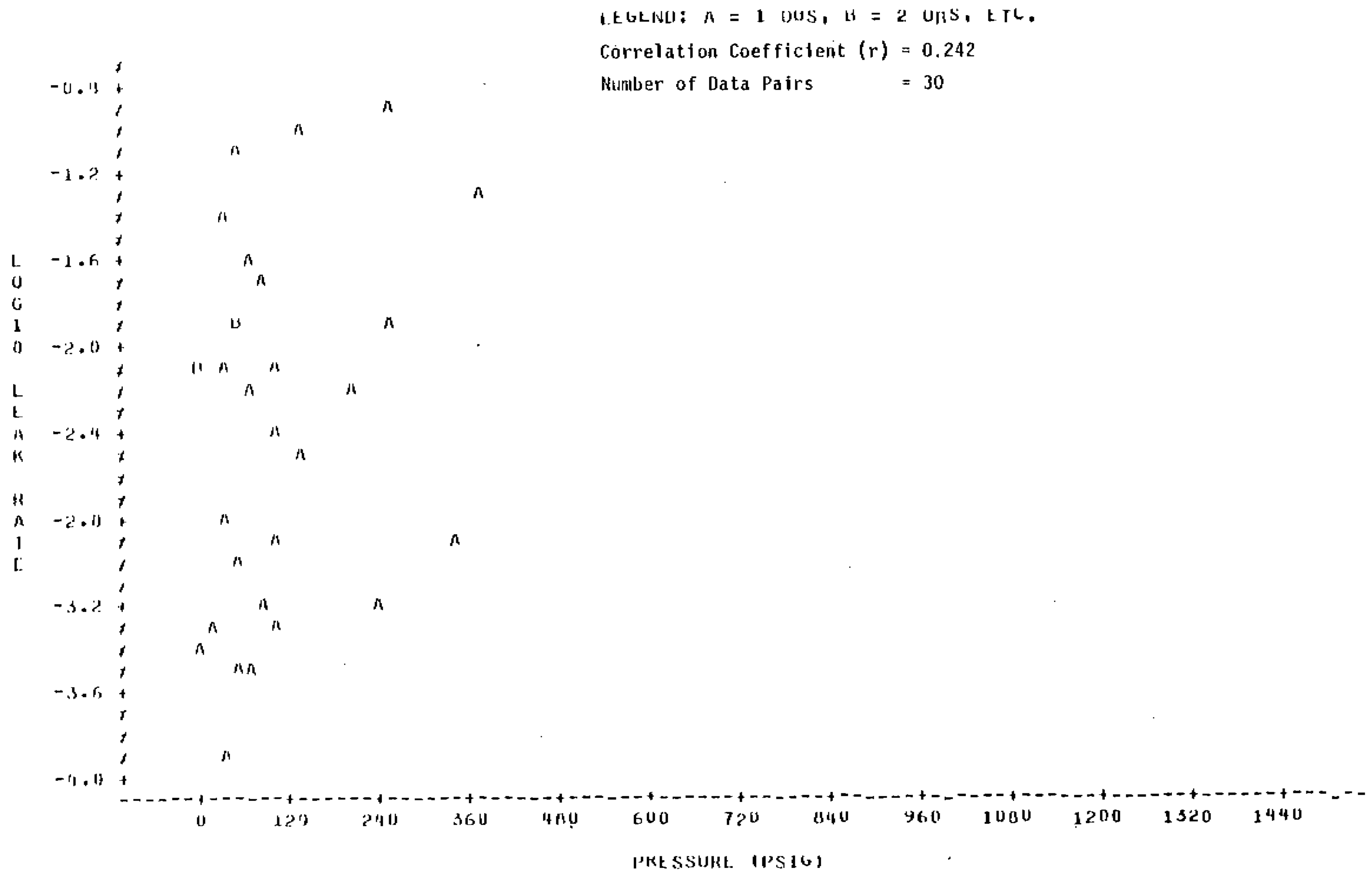


Figure B2-75. Leak rate vs. pressure - open-ended valves.

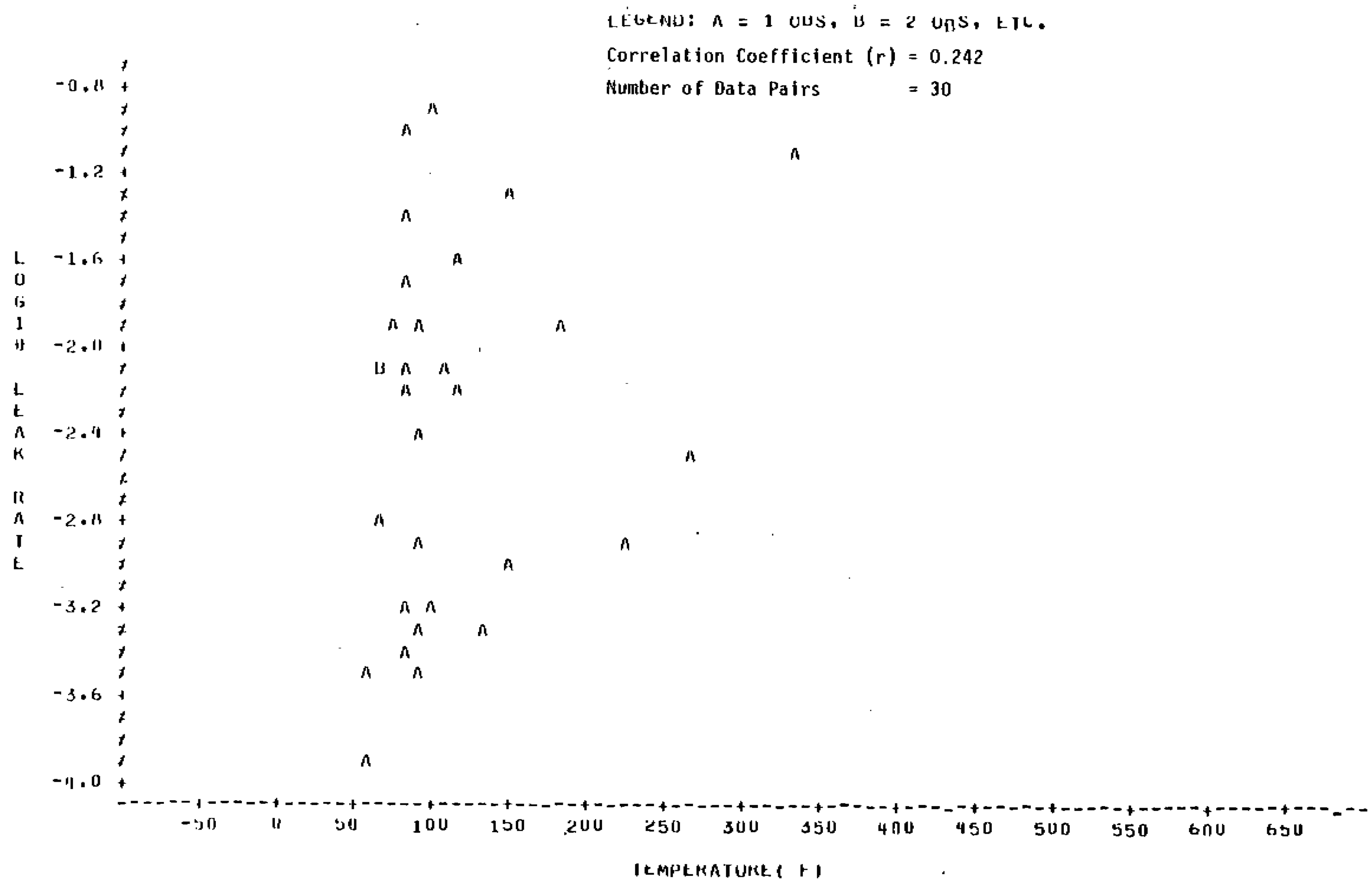


Figure B2-76. Leak rate vs. temperature - open-ended valves.

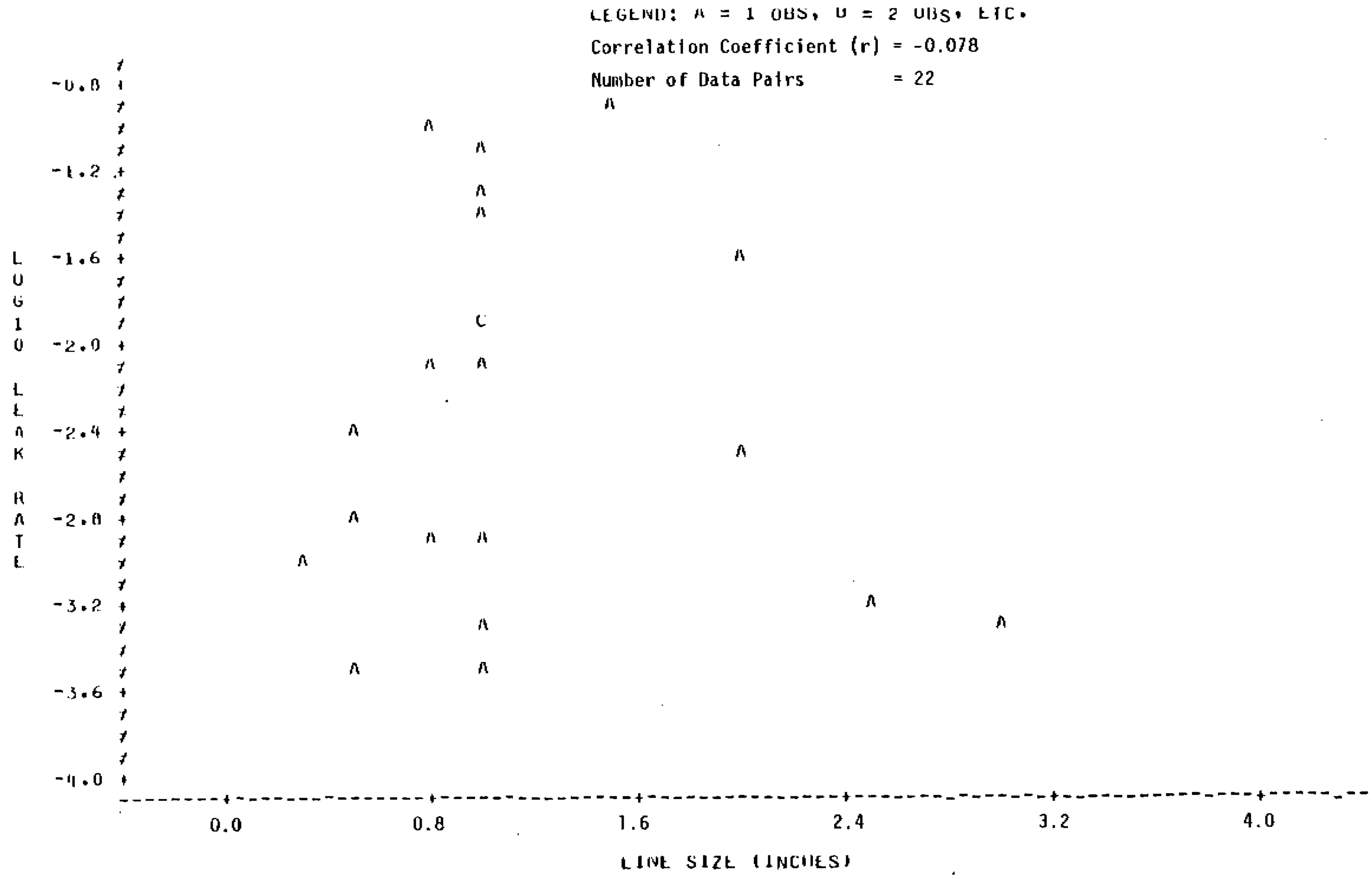


Figure B2-77. Leak rate vs. line size - open-ended valves.

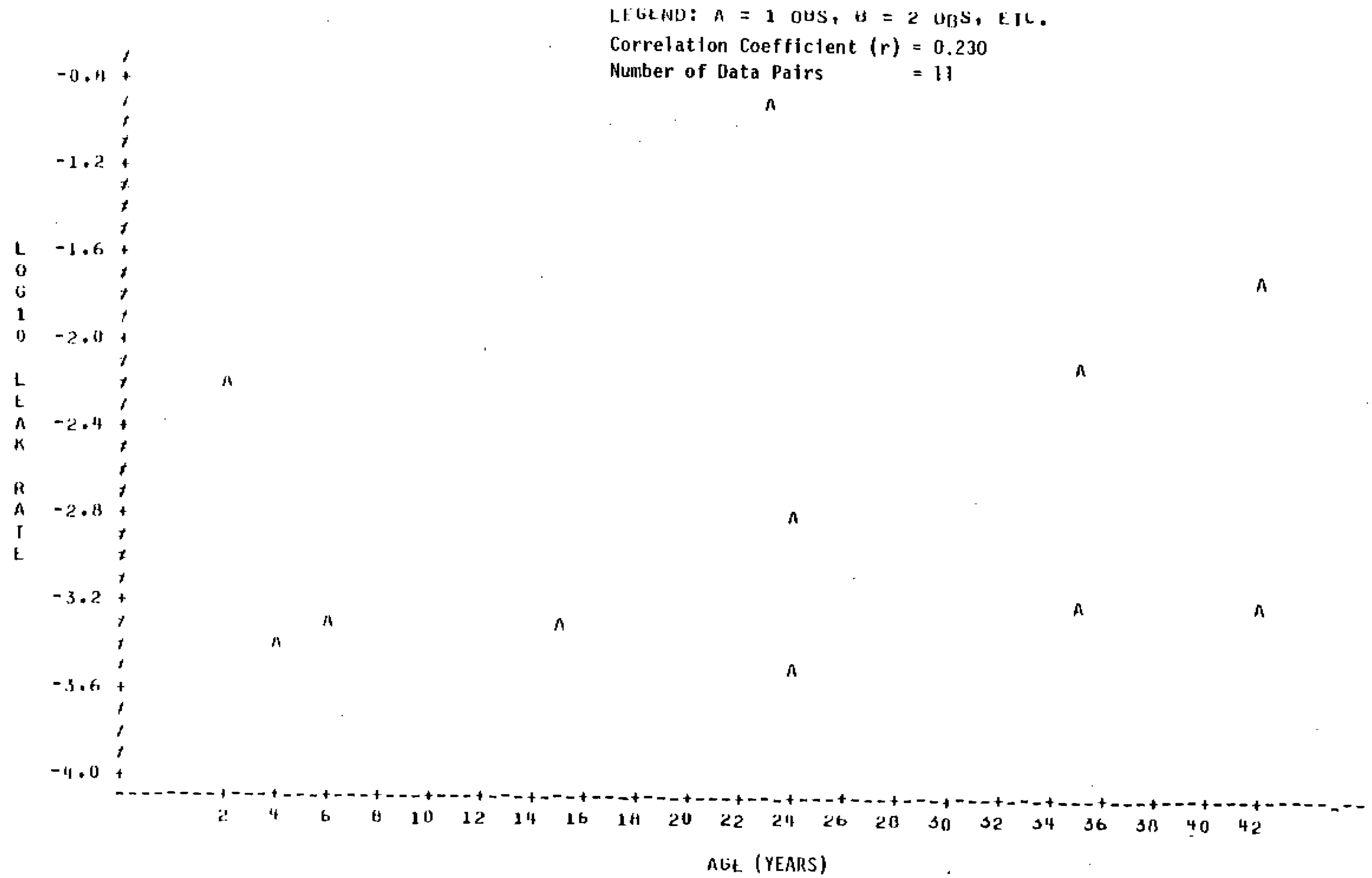


Figure B2-78. Leak rate vs. age - open-ended valves.

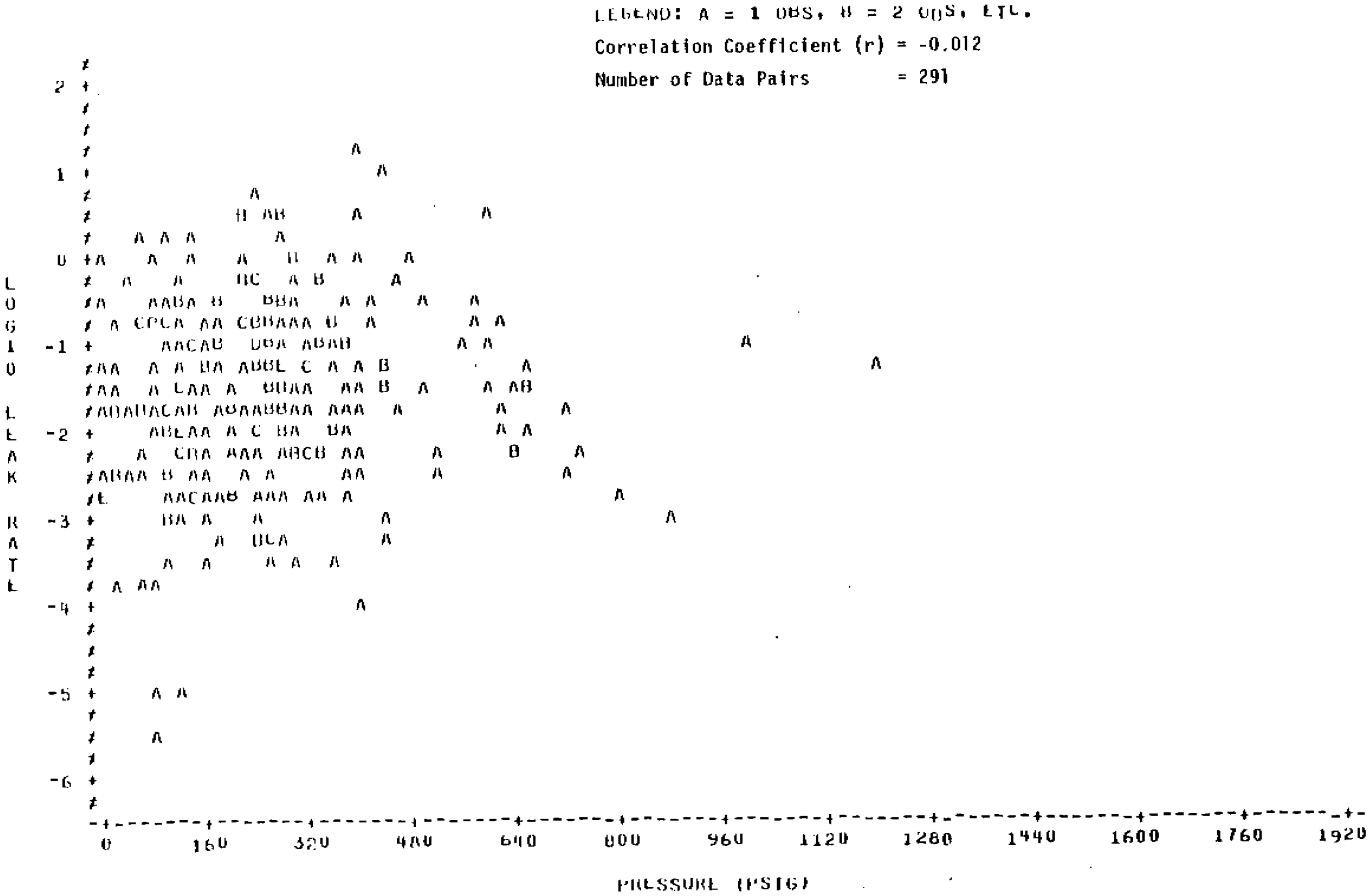


Figure B2-79. Leak rate vs. pressure - pump seals, light liquid service.

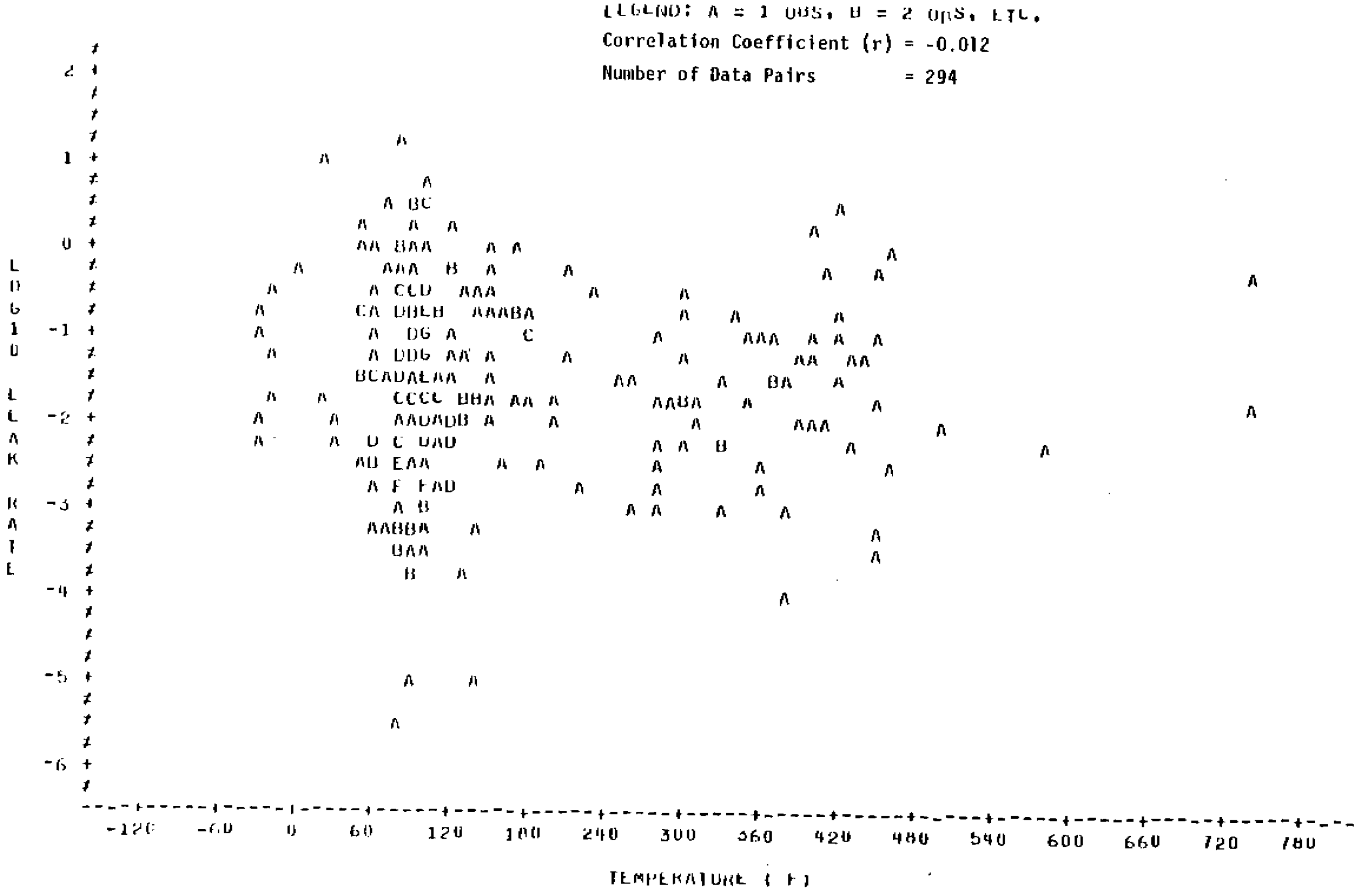


Figure B2-80. Leak rate vs. temperature - pump seals, light liquid service.

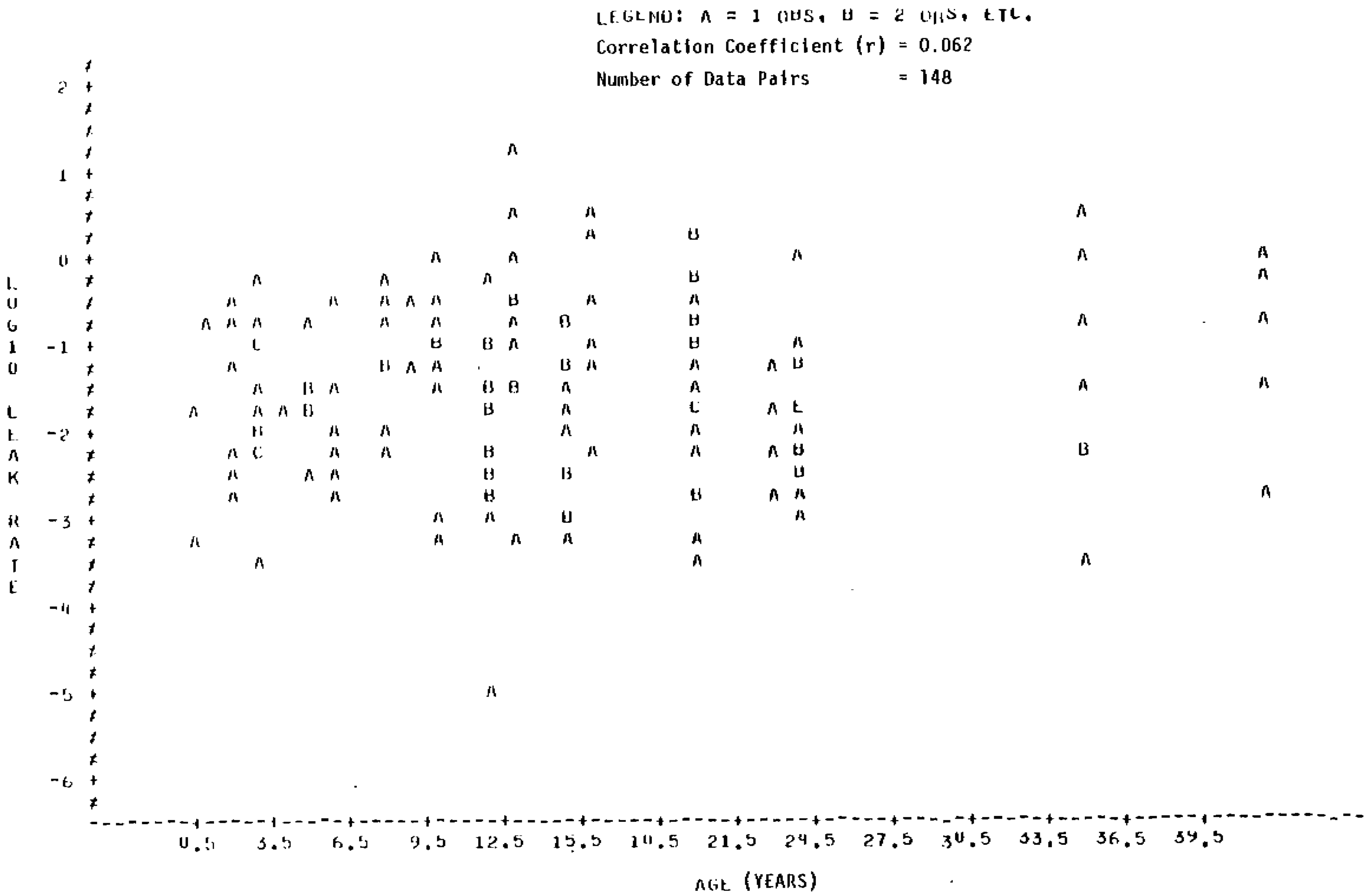


Figure B2-81. Leak rate vs. age - pump seals, light liquid service.

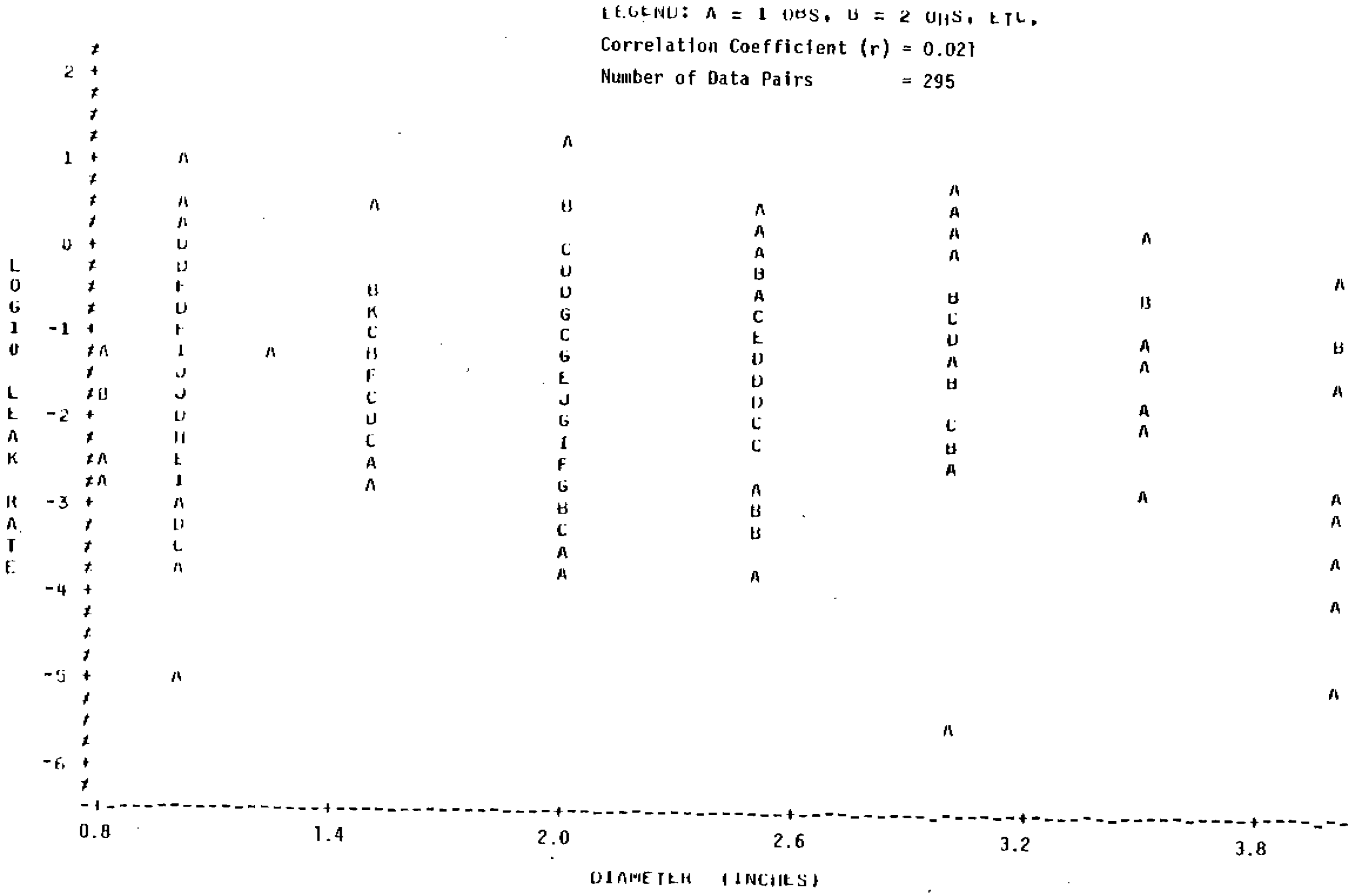


Figure B2-82. Leak rate vs. diameter - pump seals, light liquid service.

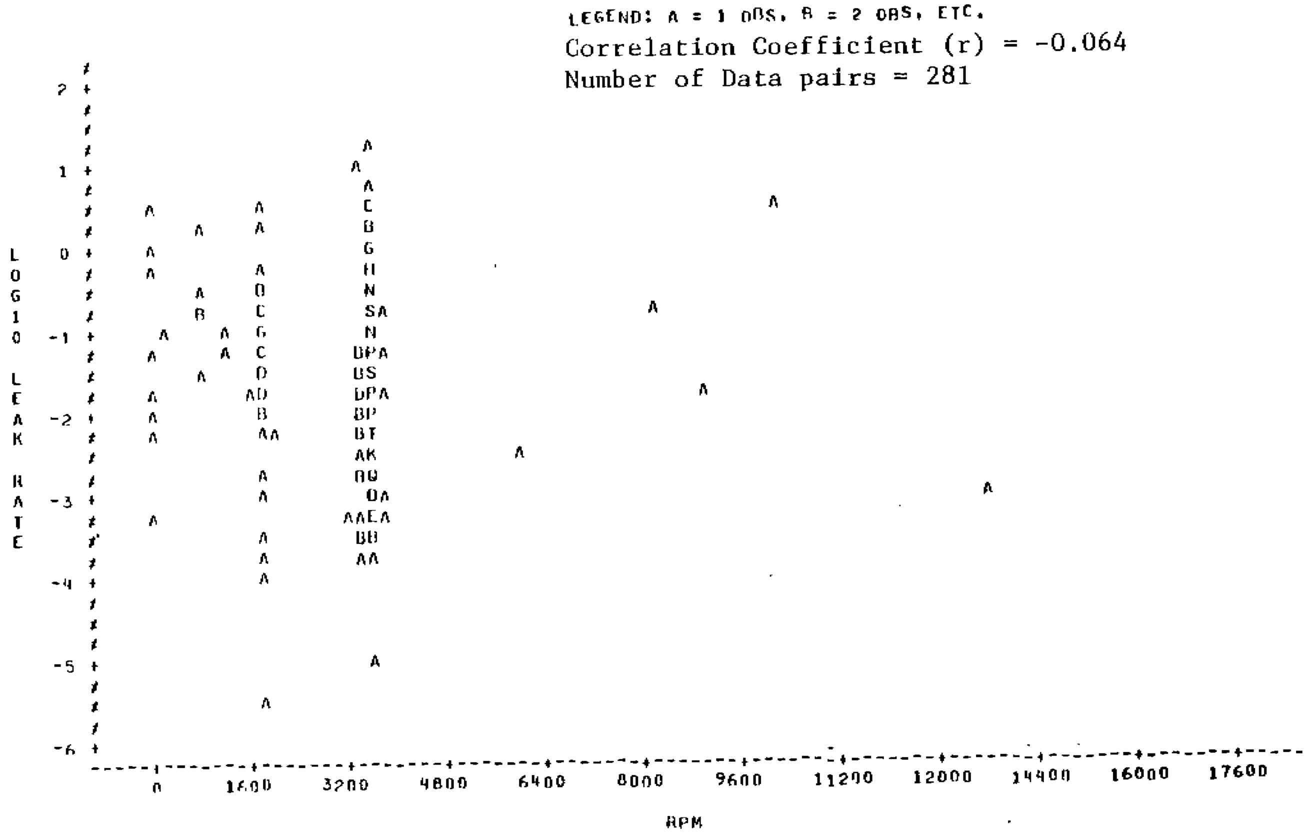


Figure B2-83. Leak rate vs. RPM - pump seals, light liquid service.

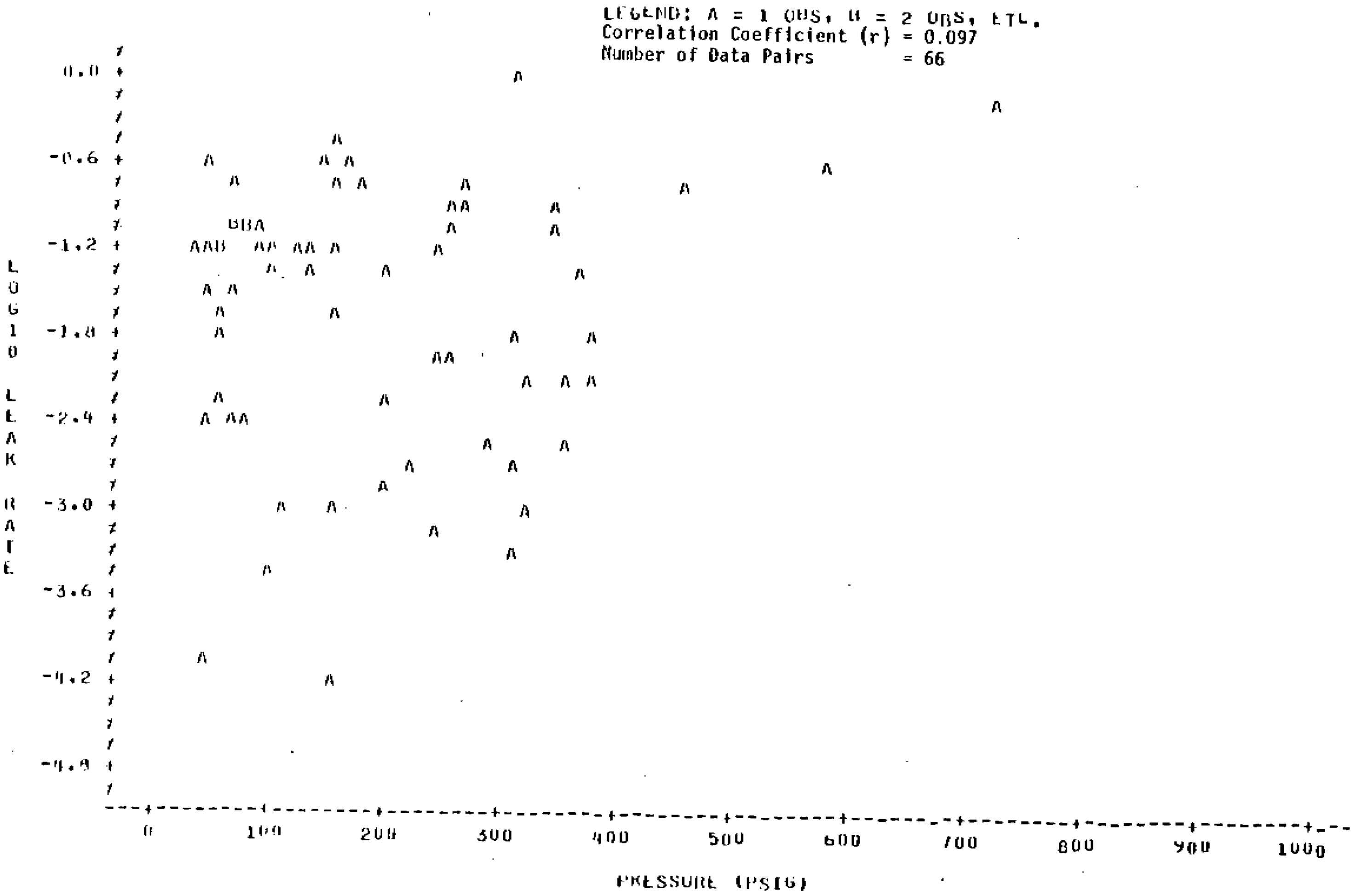


Figure B2-84. Leak rate vs. pressure - pump seals, heavy liquid service.

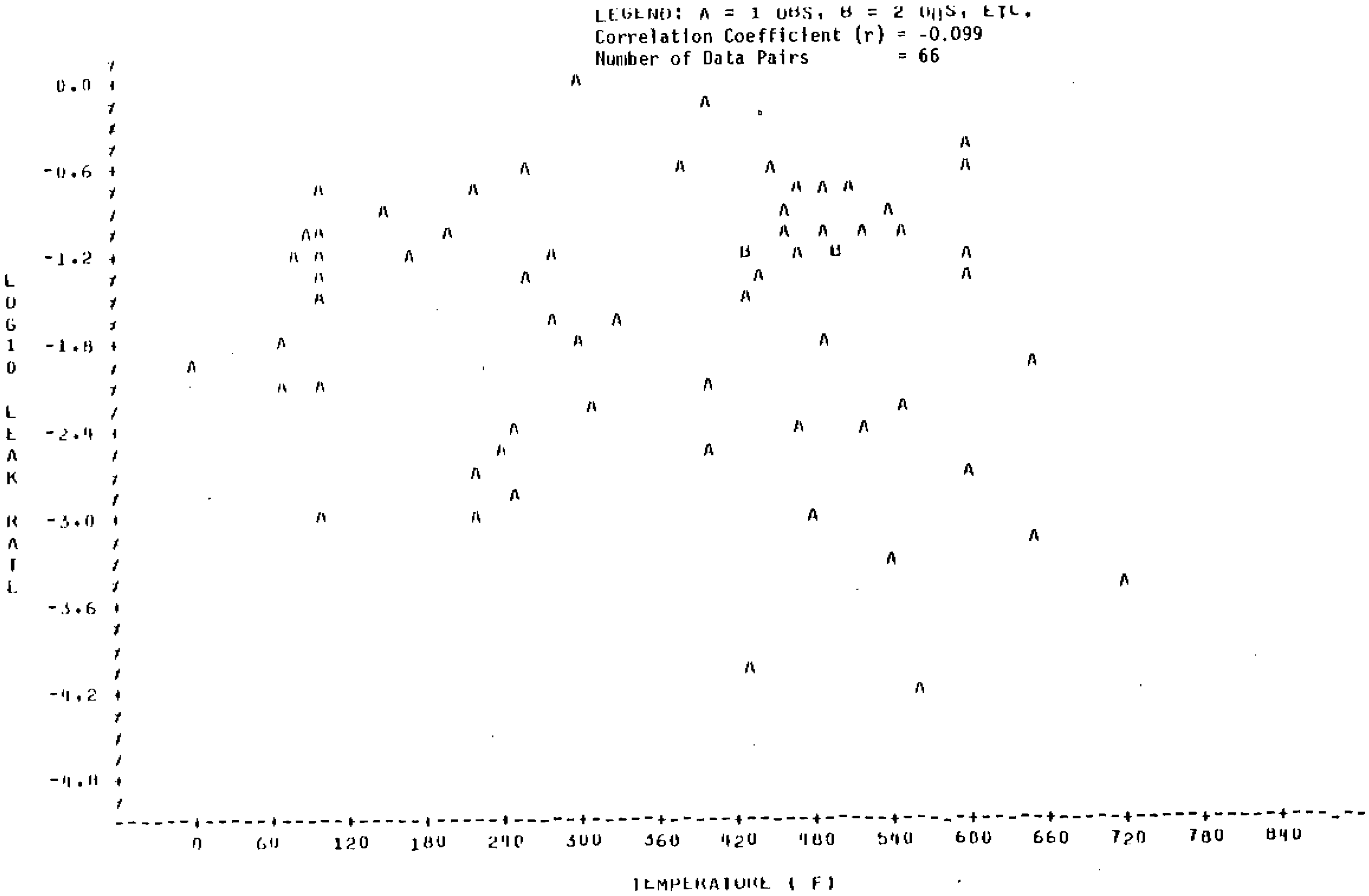


Figure B2-85. Leak rate vs. temperature - pump seals, heavy liquid service.

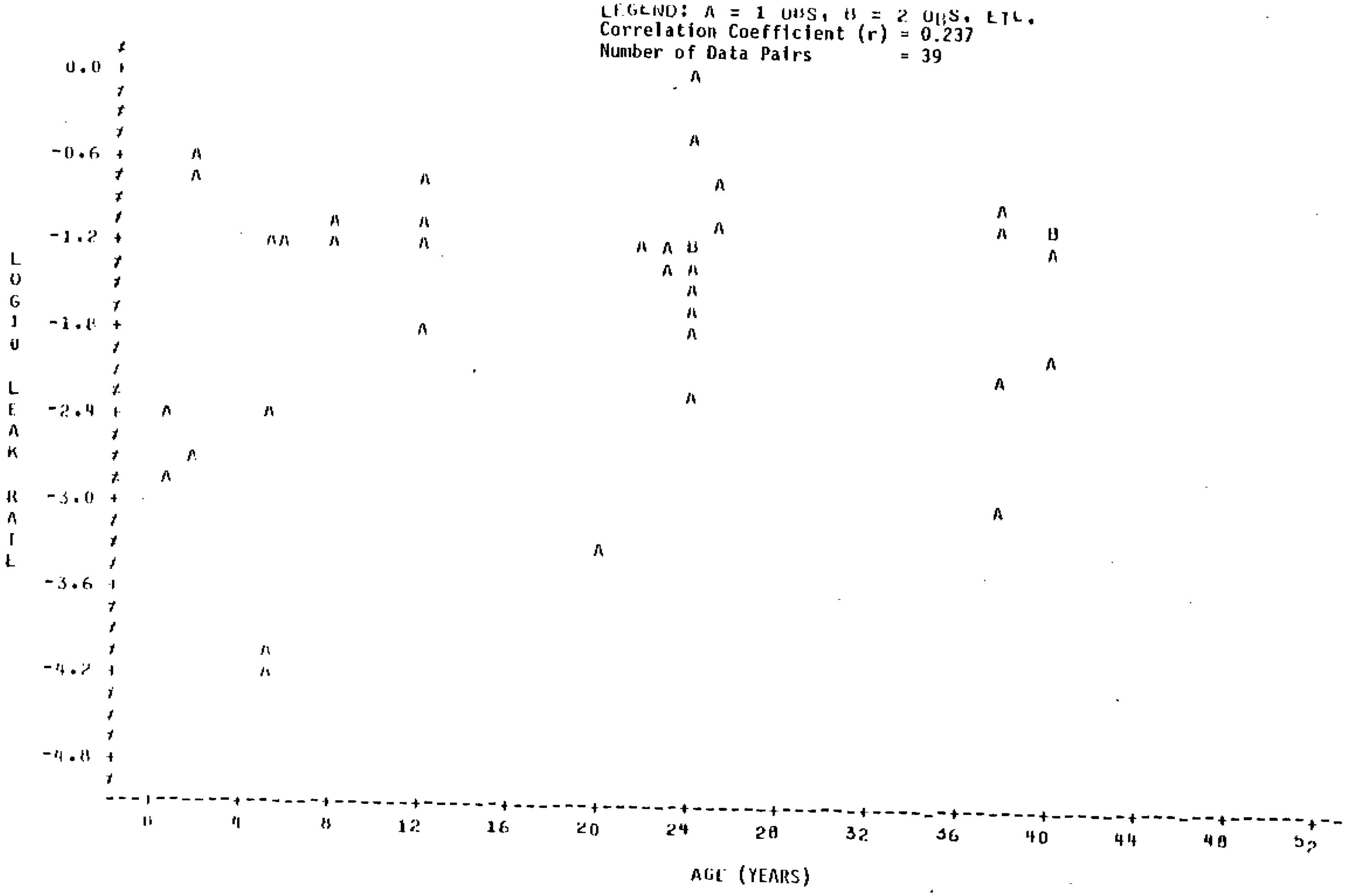


Figure B2-86. Leak rate vs. age - pump seals, heavy liquid service.

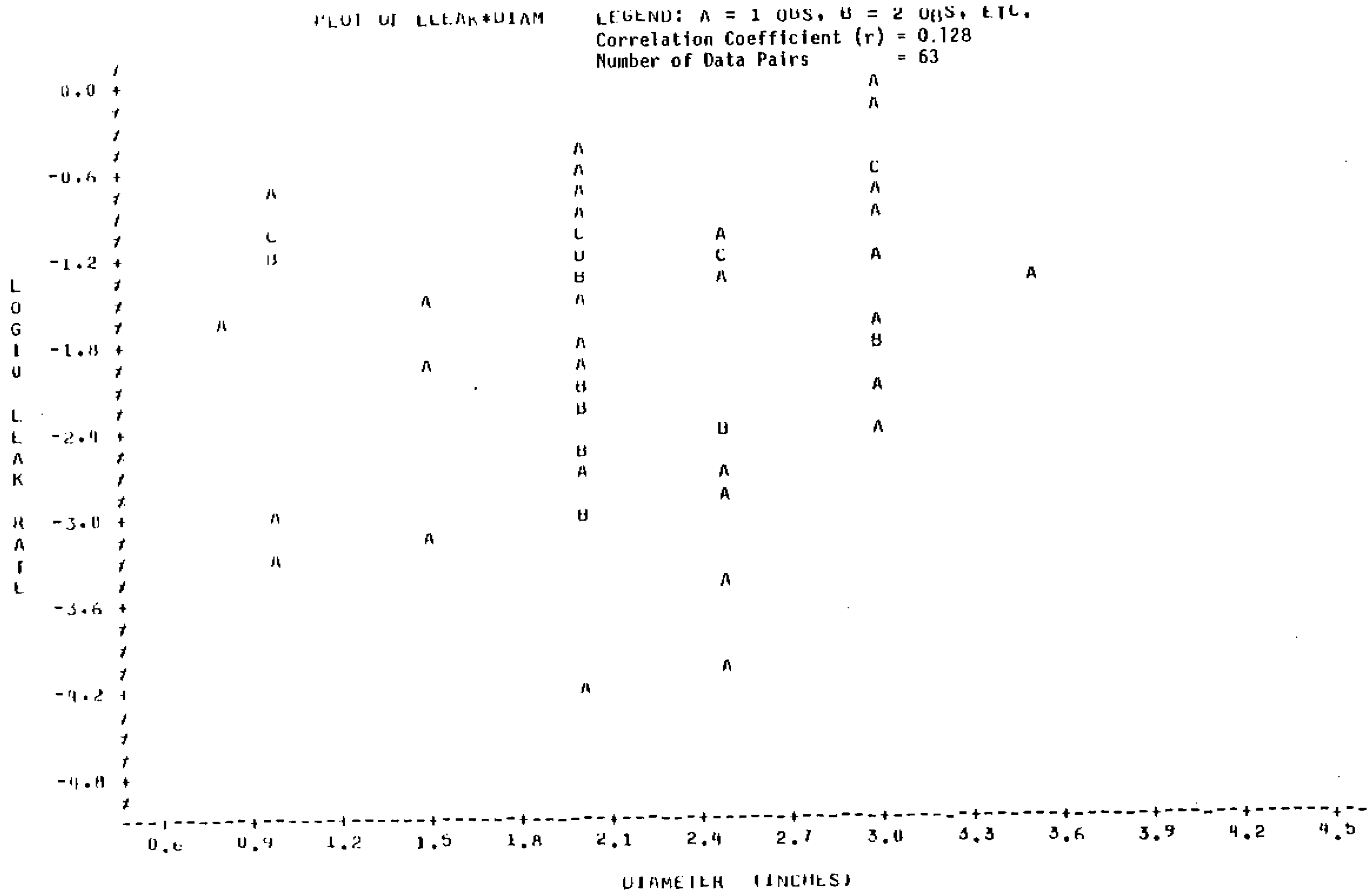


Figure B2-87. Leak rate vs. diameter - pump seals, heavy liquid service. *

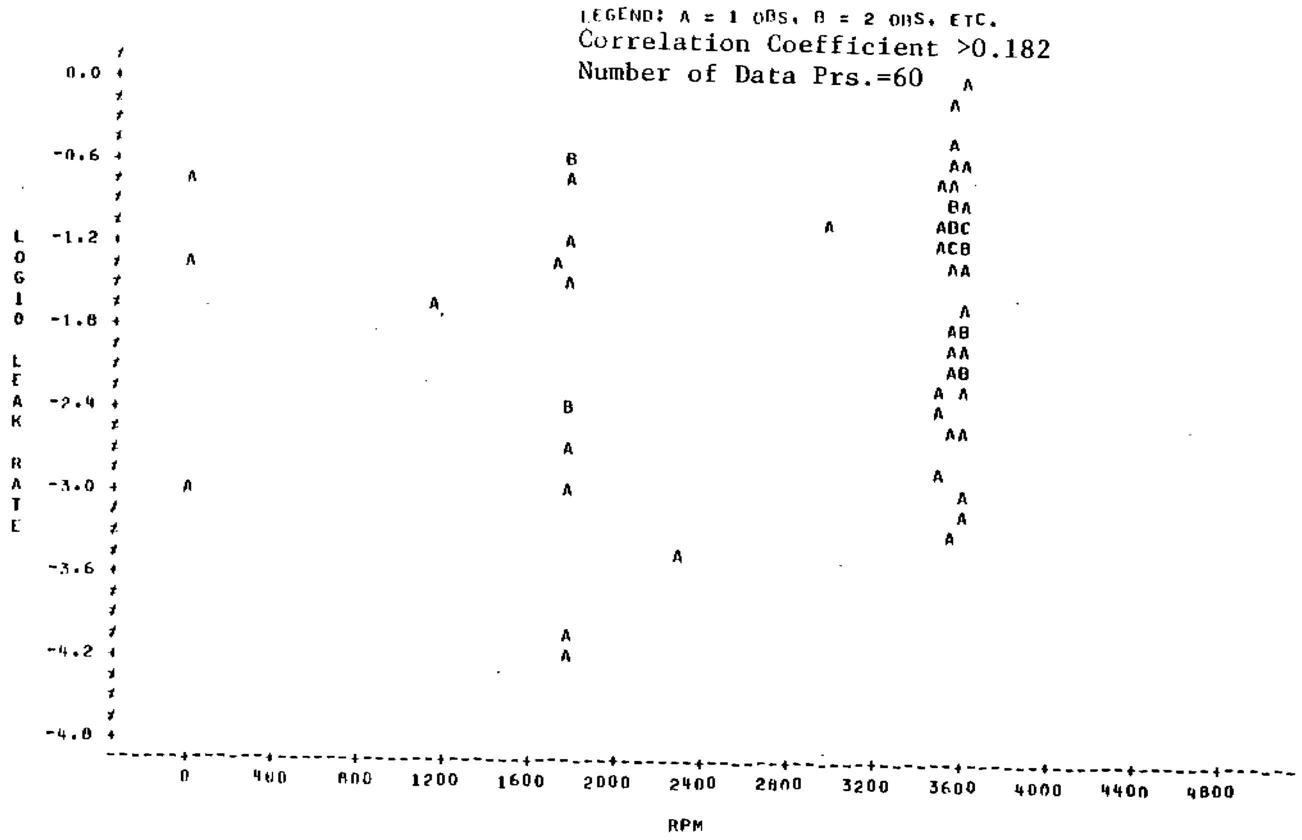


Figure B2-88. Leak rate vs. RPM - pump seals, heavy liquid service.

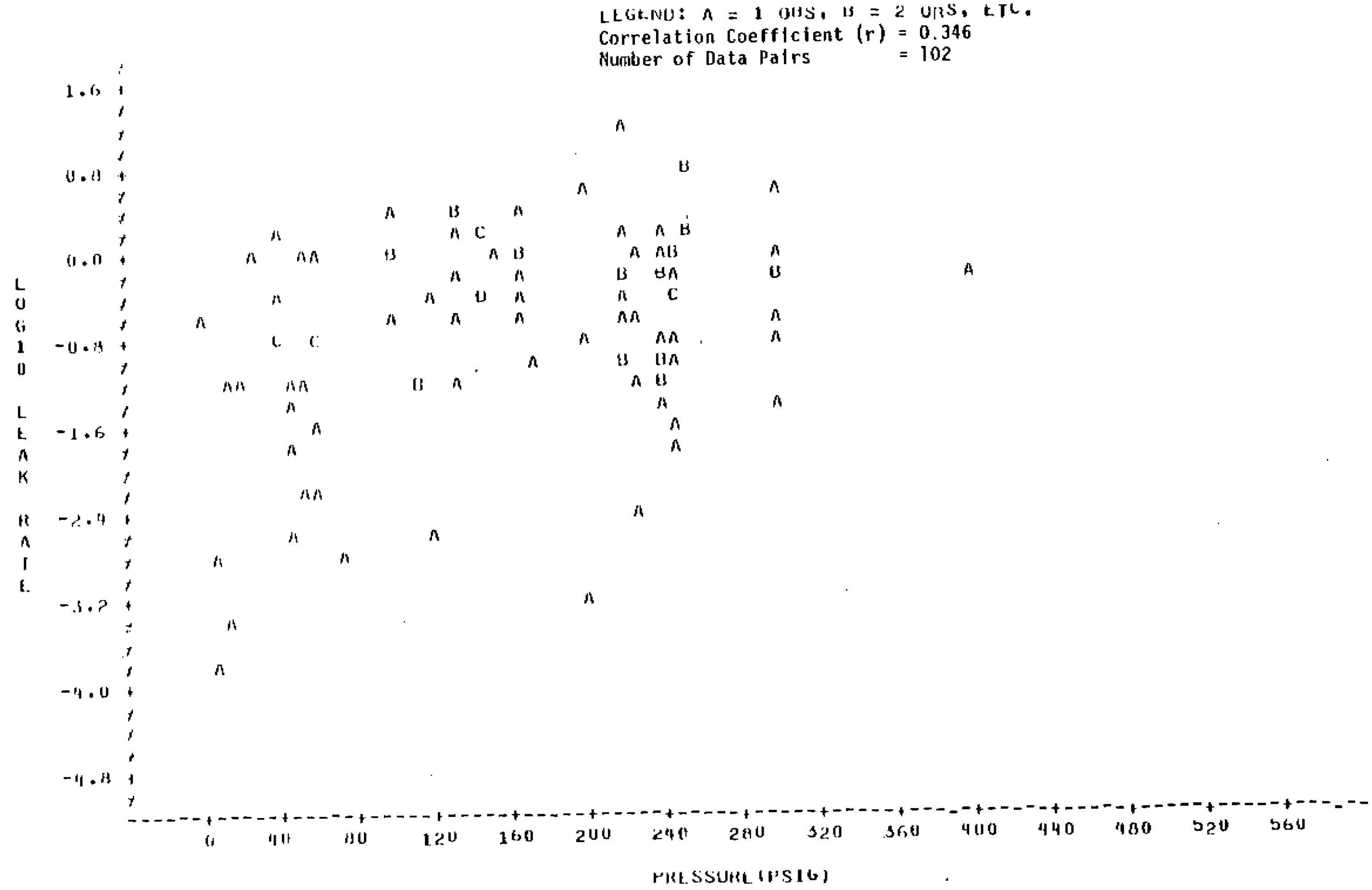


Figure B2-89. Leak rate vs. pressure - compressor seals, hydrocarbon service.

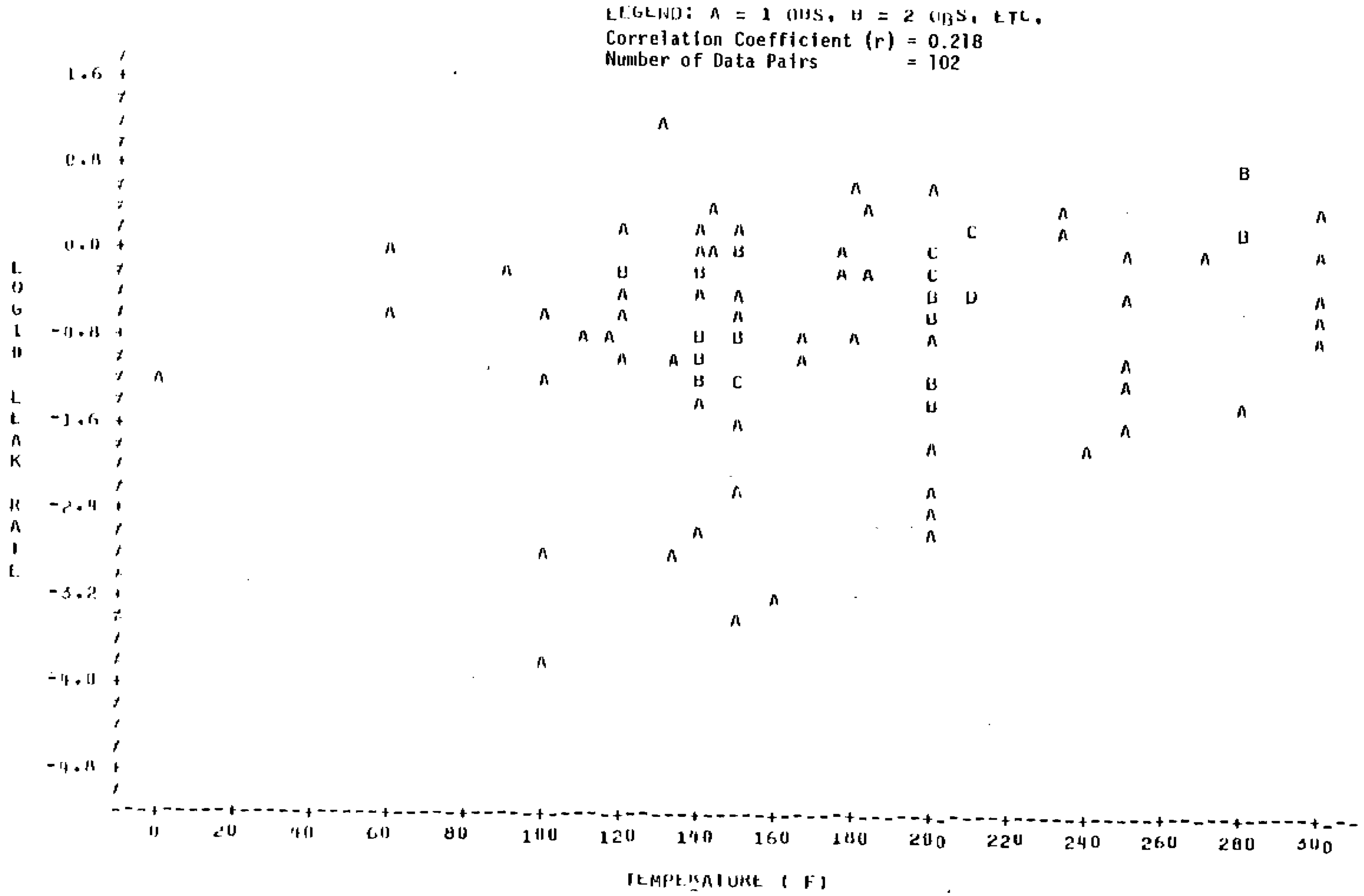


Figure B2- 90. Leak rate vs. temperature - compressor seals, hydrocarbon service.

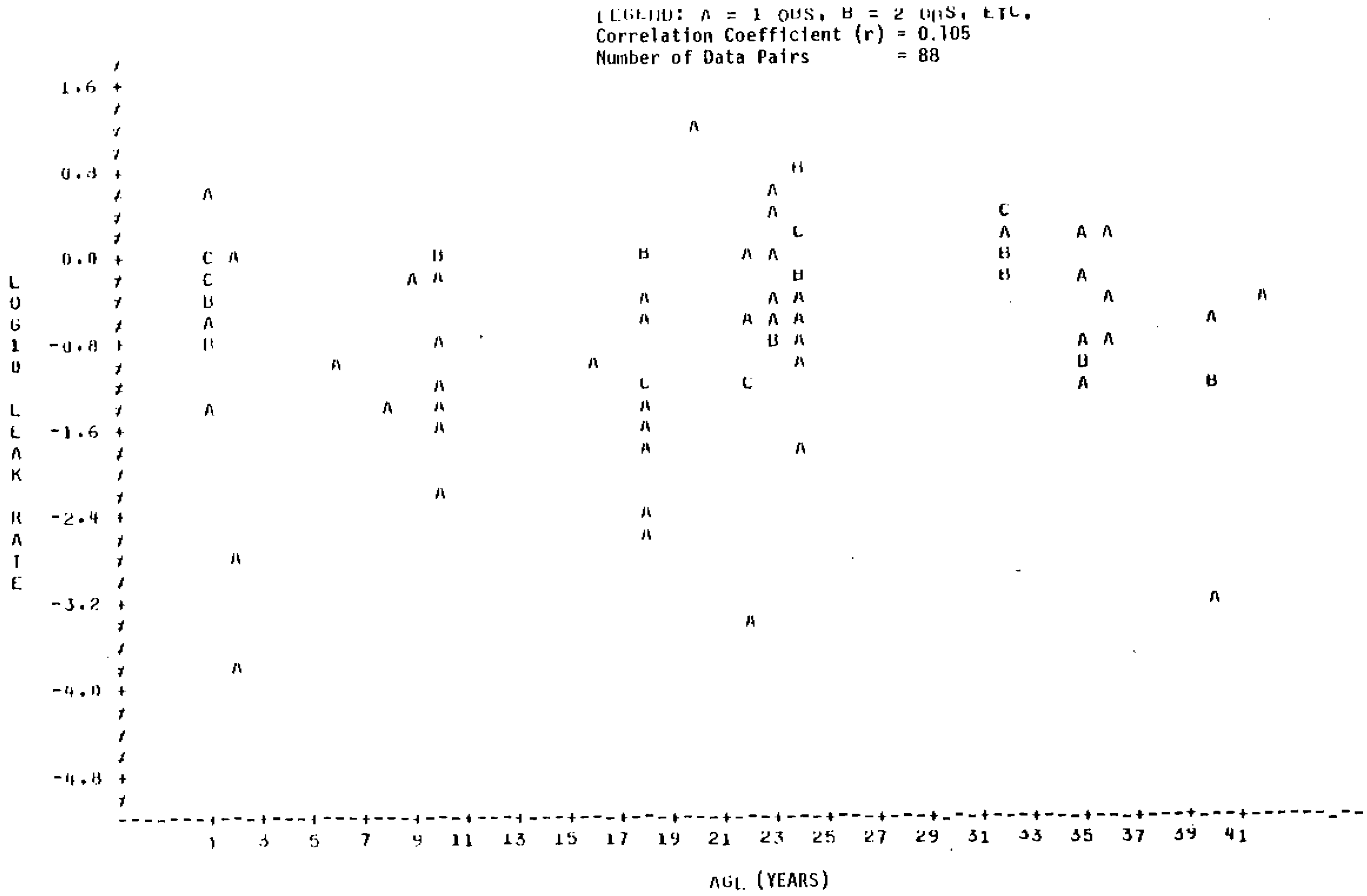


Figure B2-91. Leak rate vs. age - compressor seals, hydrocarbon service.

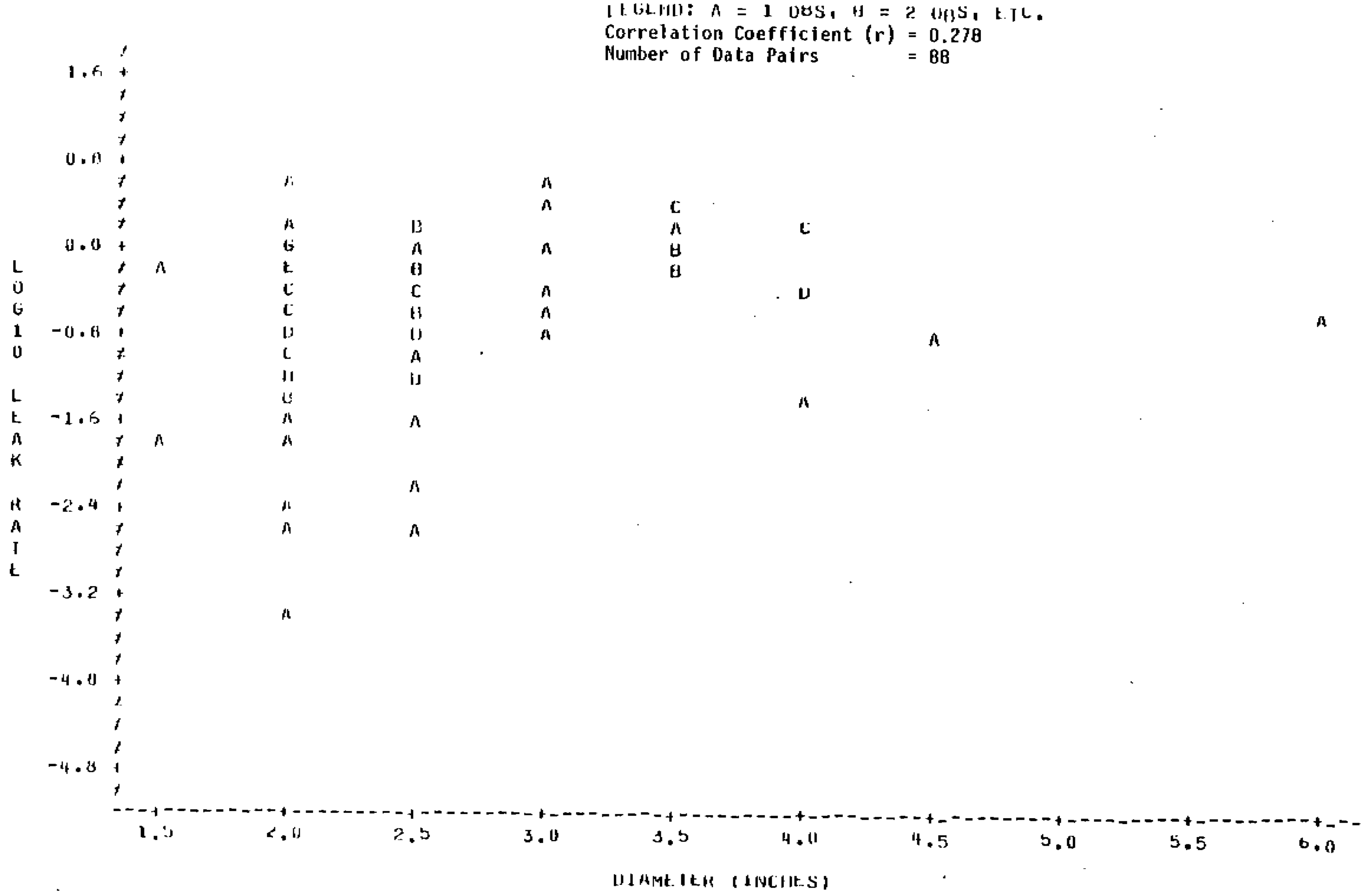


Figure B2-92 Leak rate vs. diameter - compressor seals, hydrocarbon service.

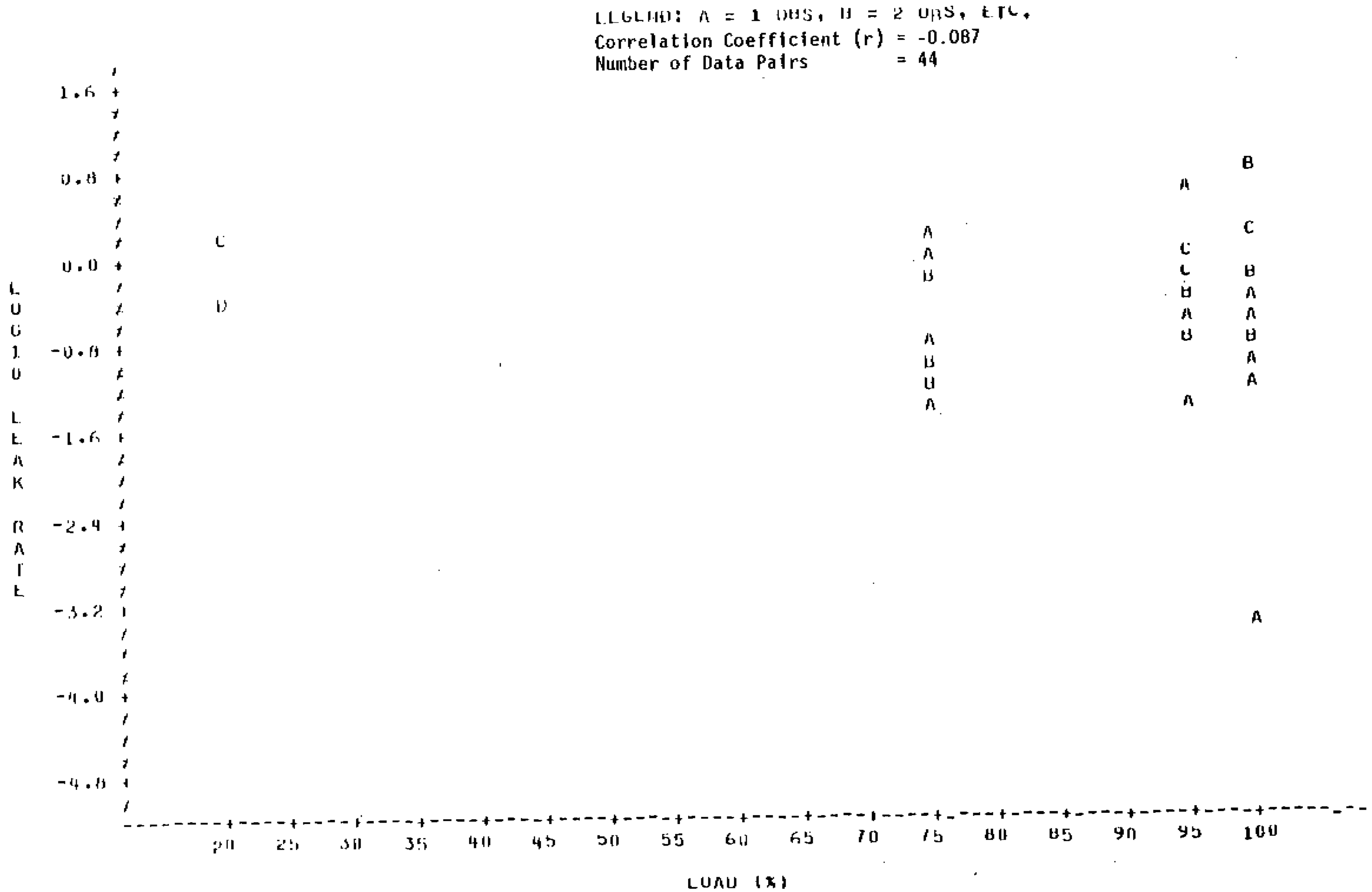


Figure B2-93. Leak rate vs. load - compressor seals, hydrocarbon service.

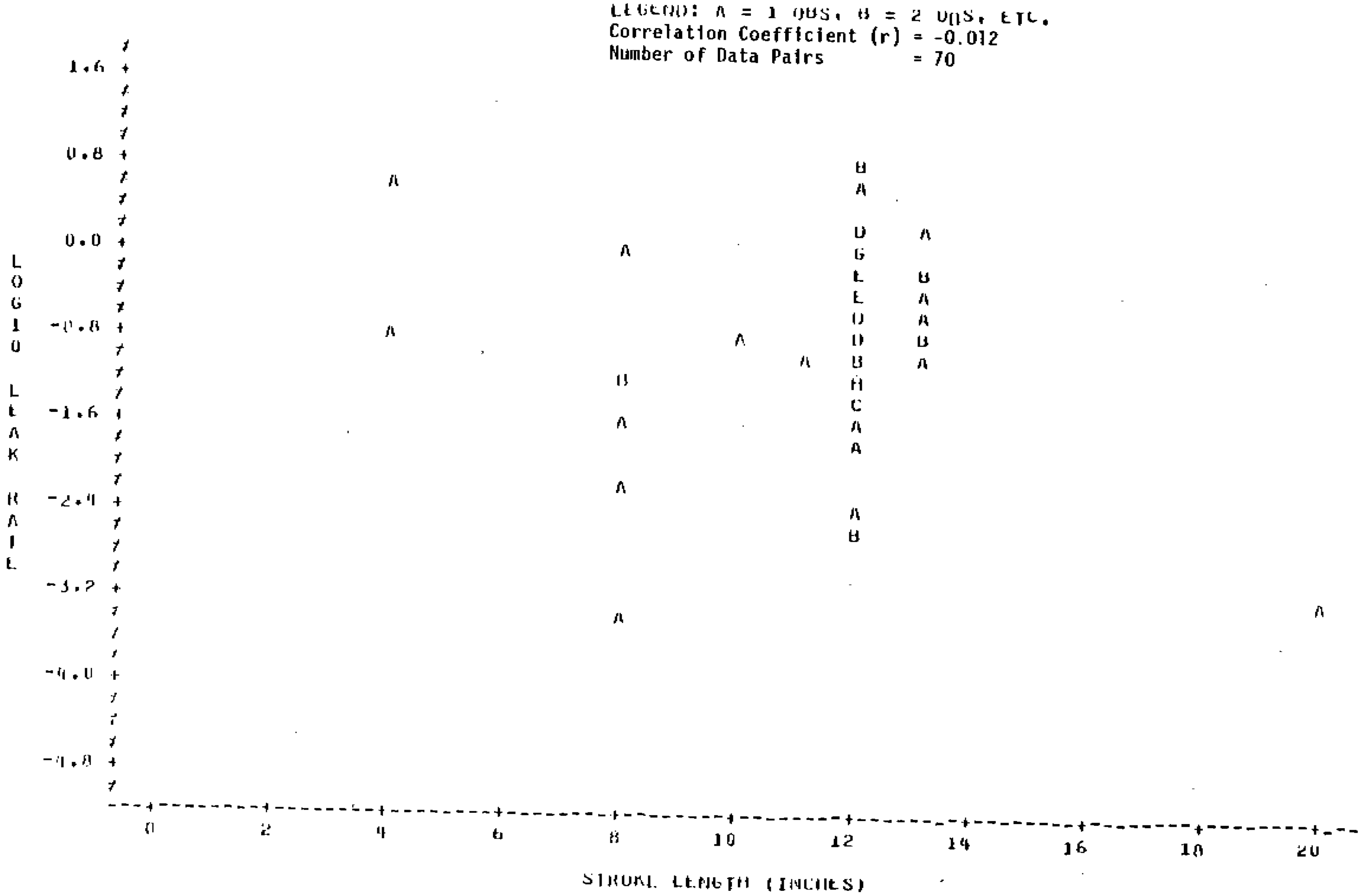


Figure B2- 94. Leak rate vs. stroke length - compressor seals, hydrocarbon service.

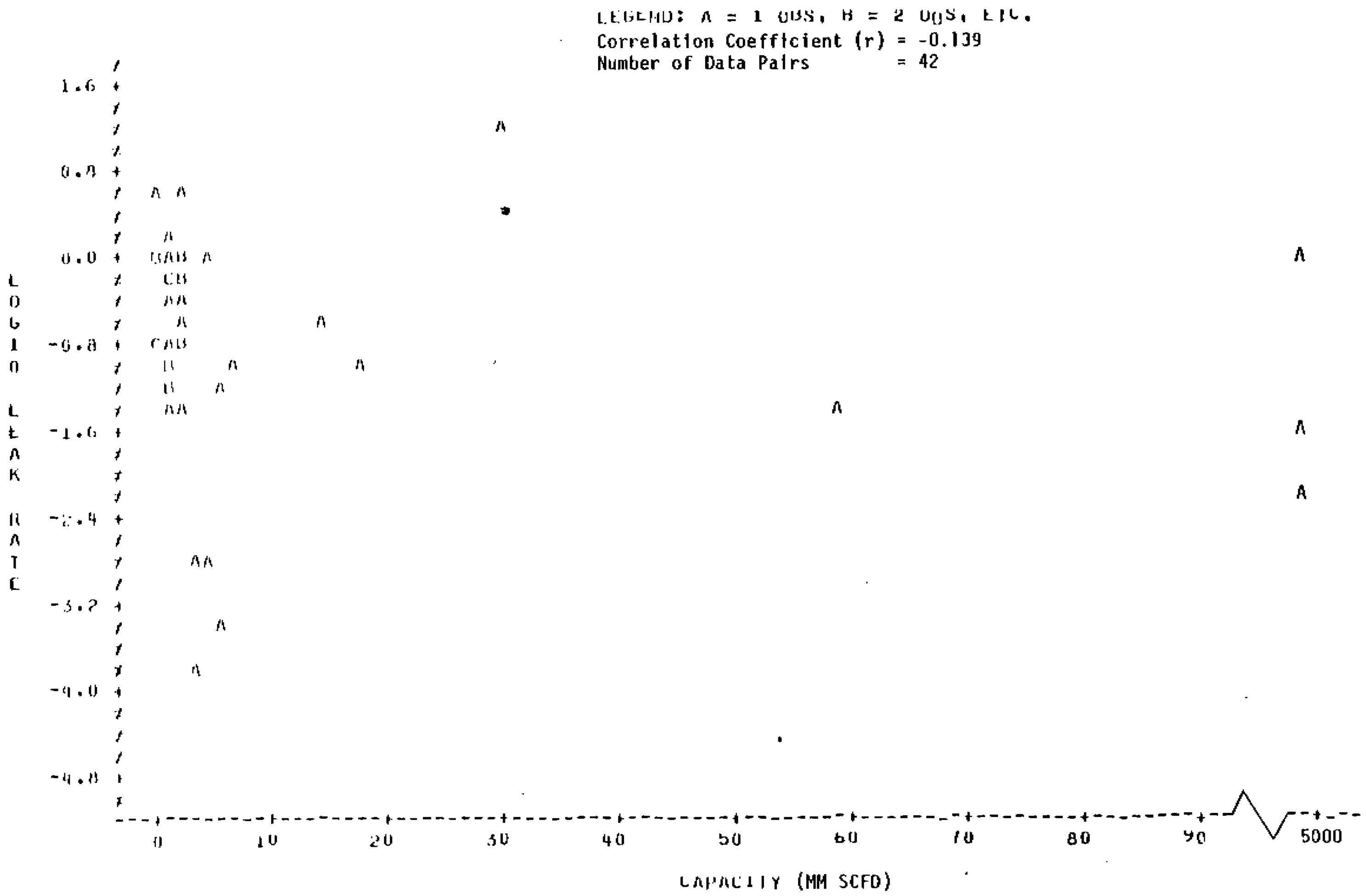


Figure B2-95. Leak rate vs. capacity - compressor seals, hydrocarbon service.

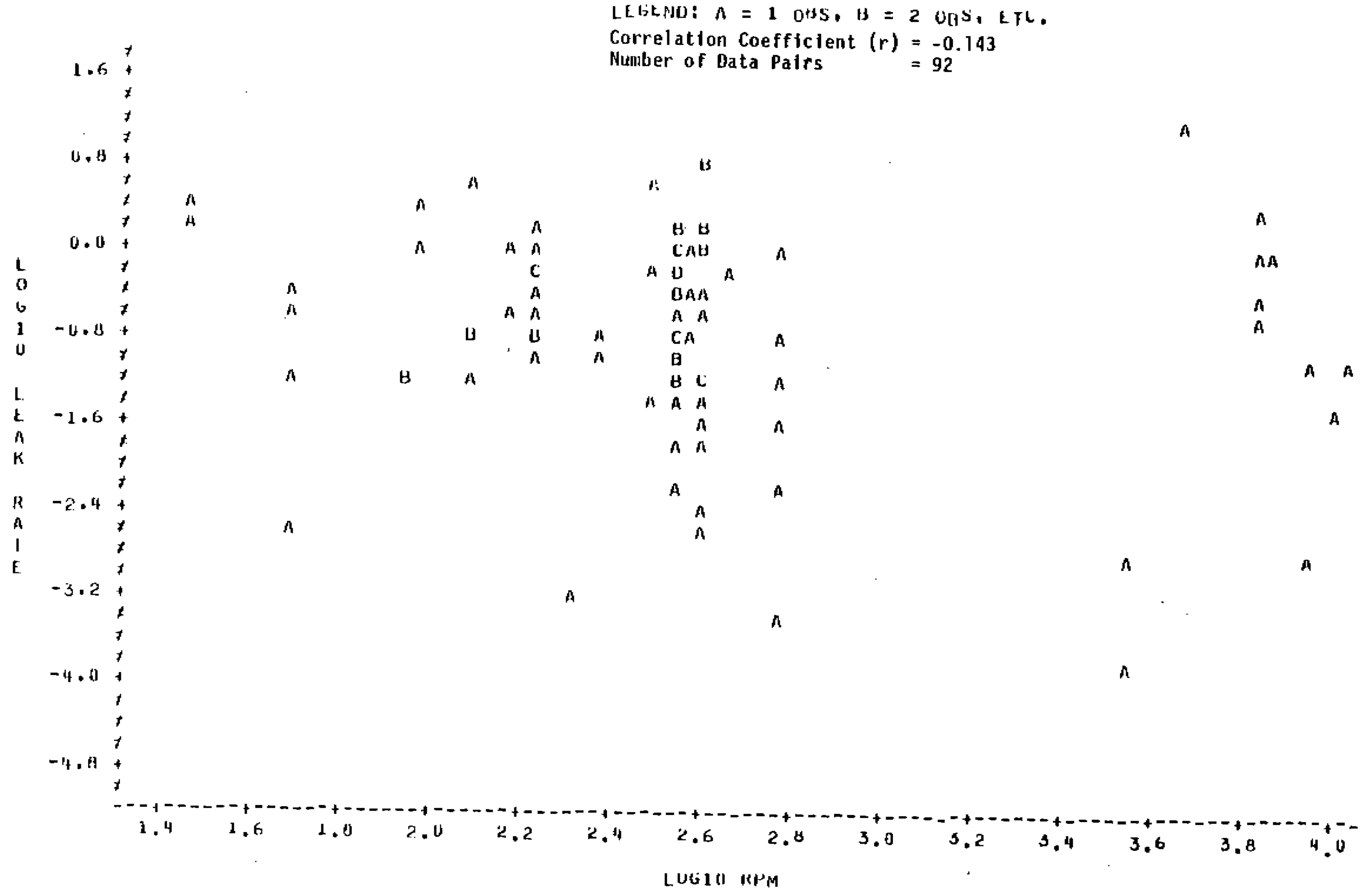


Figure B2-96. Leak rate vs. log 10 RPM - compressor seals, hydrocarbon service.

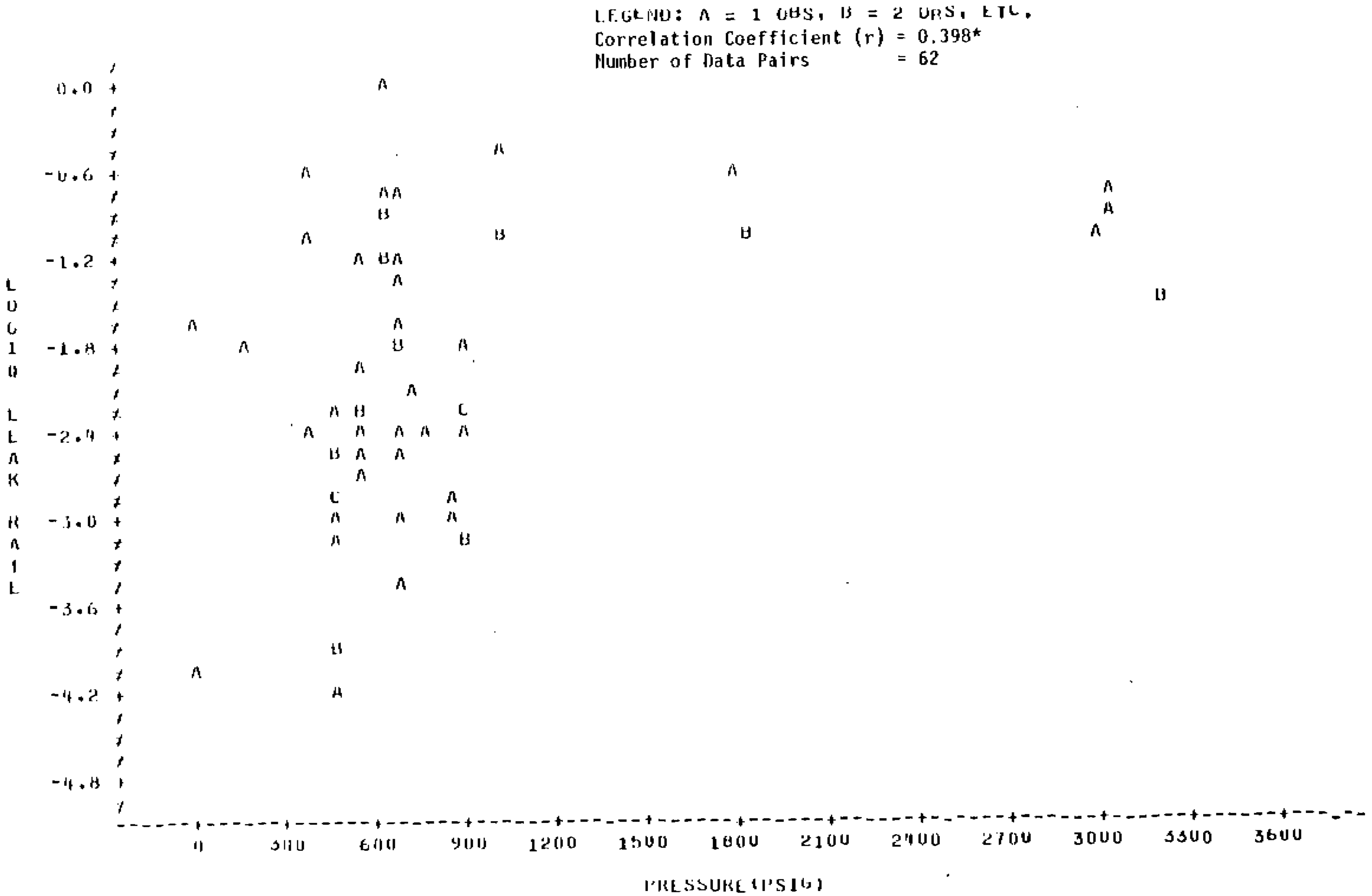


Figure B2-97. Leak rate vs. pressure - compressor seals, hydrogen service.

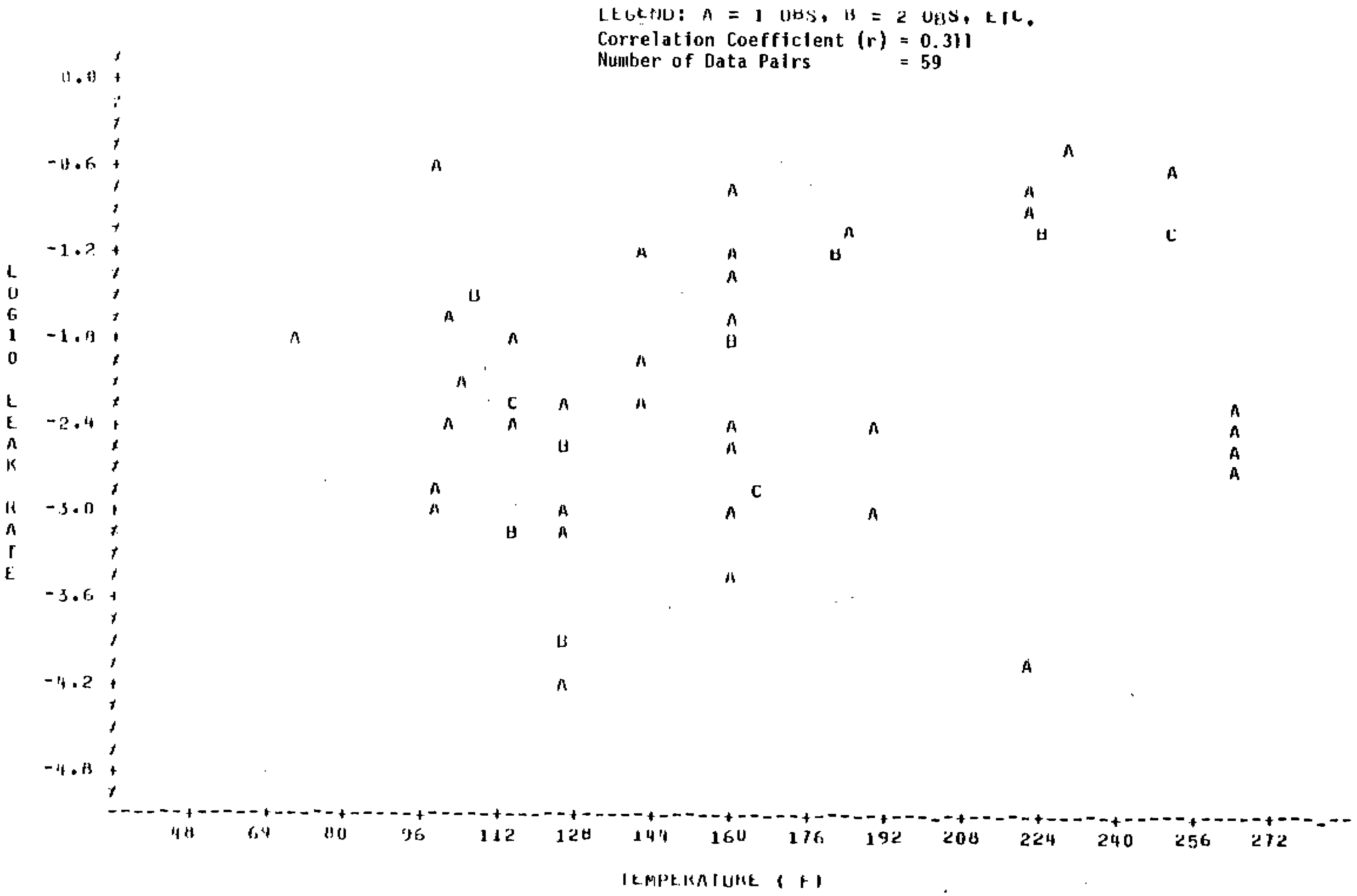


Figure B2-98. Leak rate vs. temperature - compressor seals, hydrogen service.

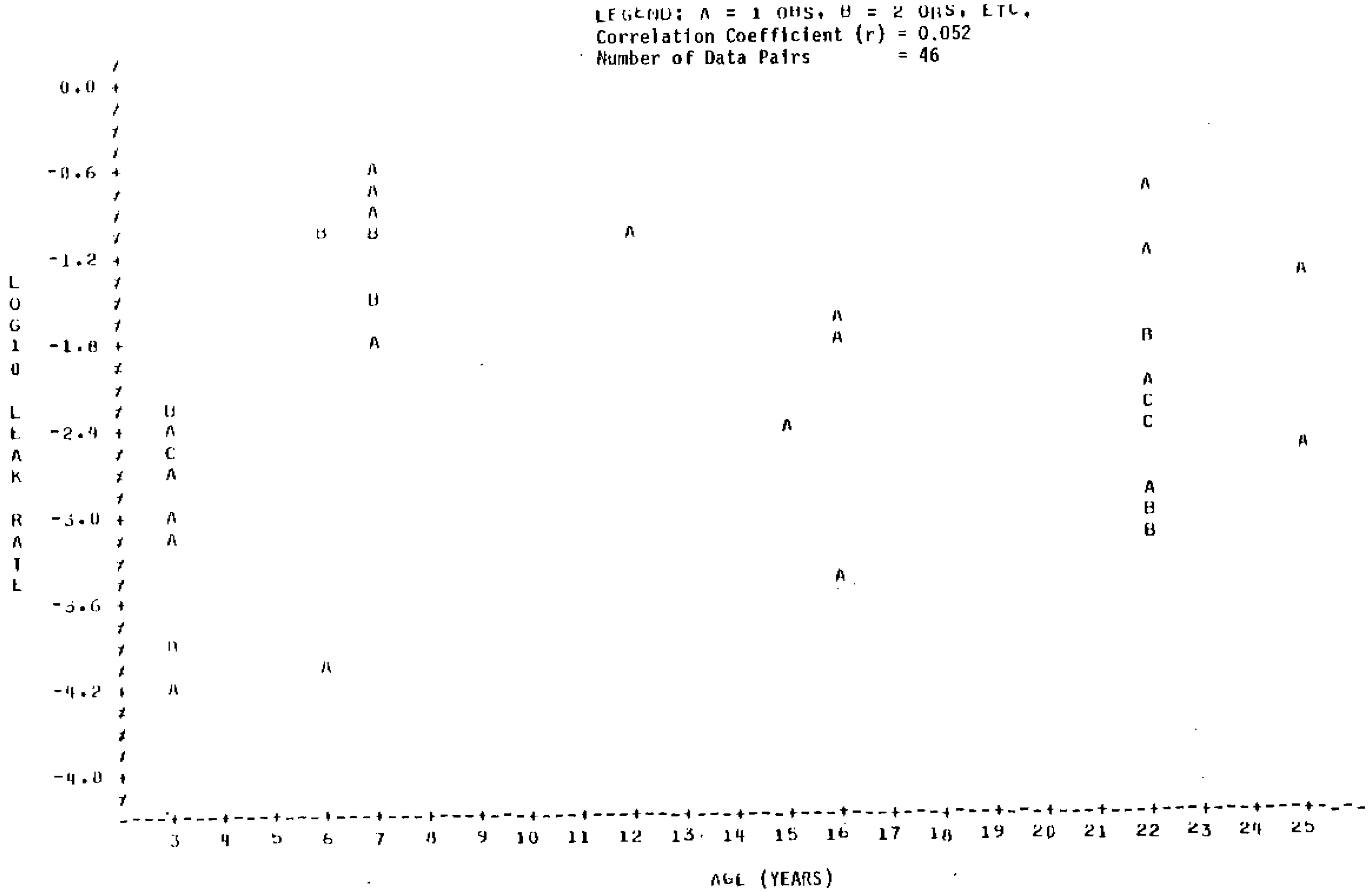


Figure B2-99. Leak rate vs. age - compressor seals, hydrogen service.

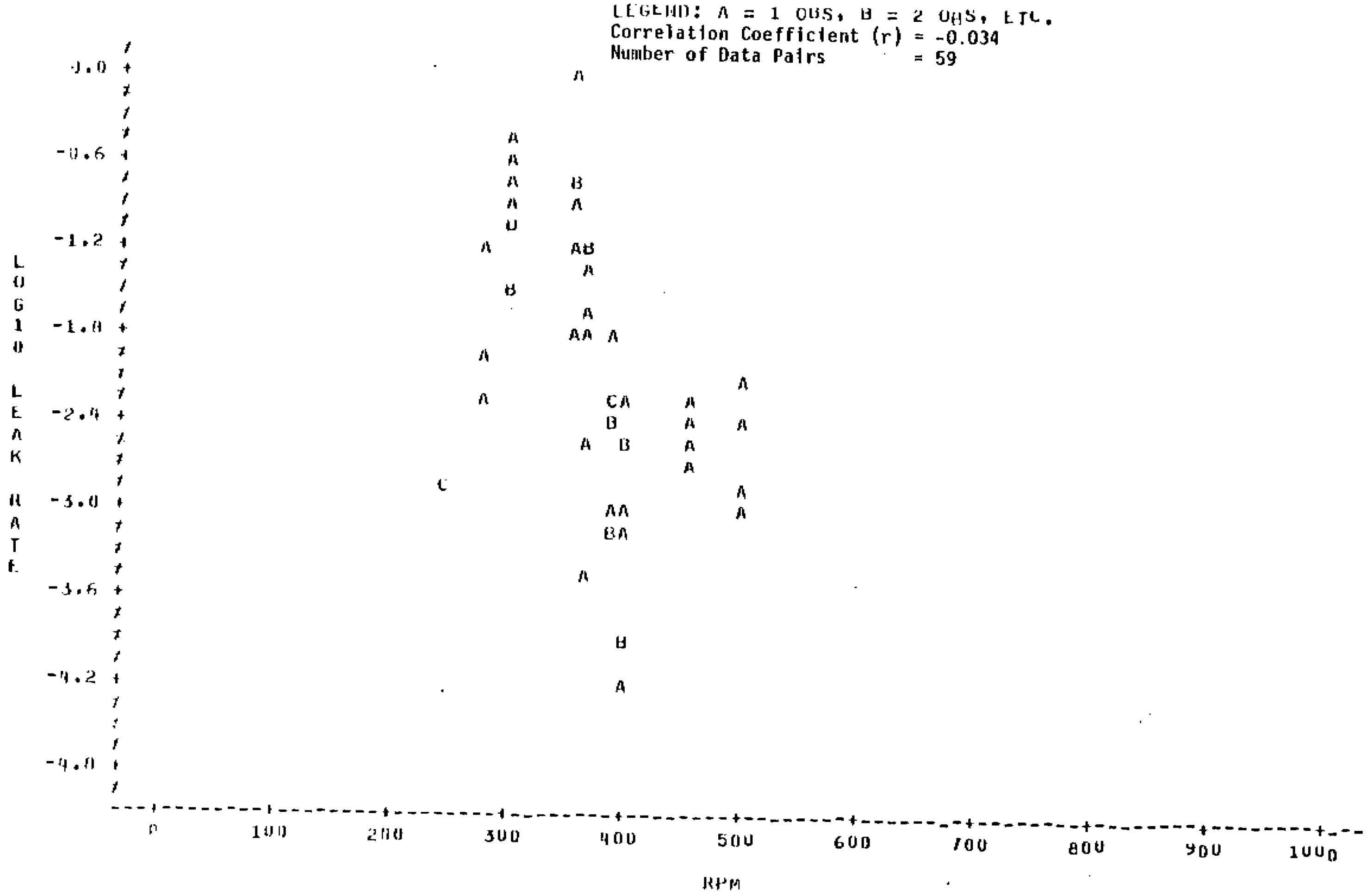


Figure B2-100. Leak rate vs. RPM - compressor seals, hydrogen service.

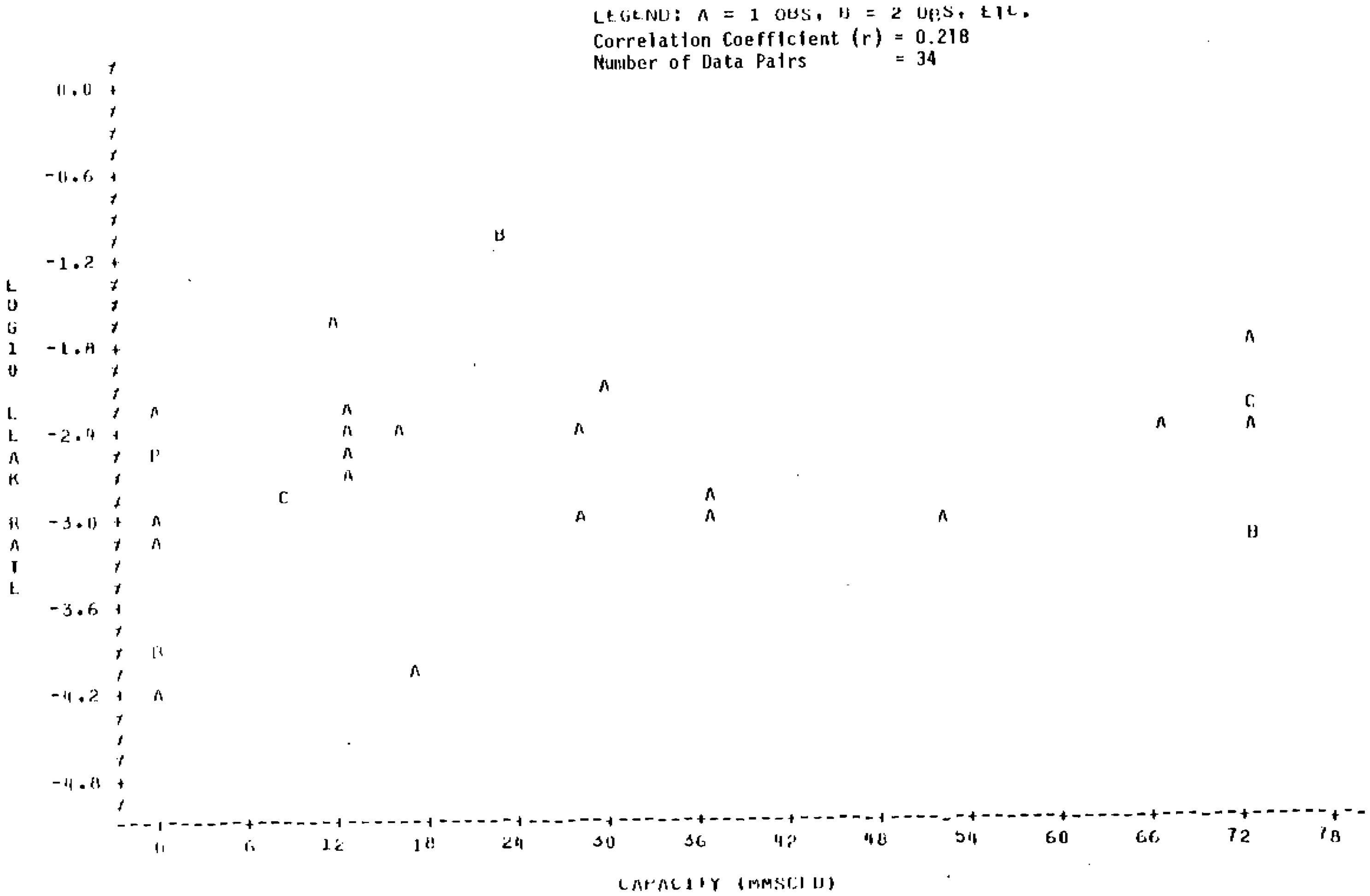


Figure B2-101. Leak rate vs. capacity - compressor seals, hydrogen service.

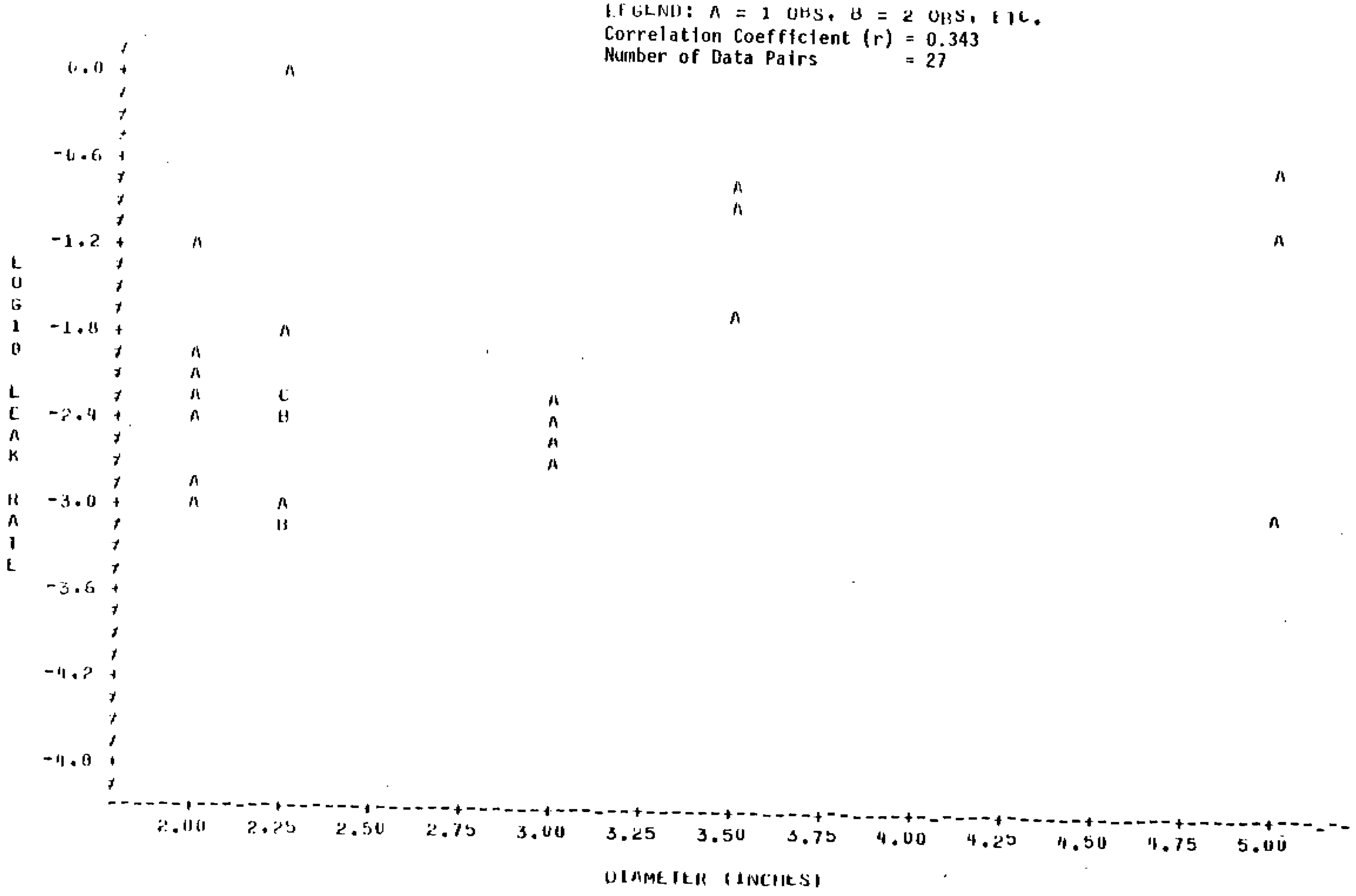


Figure B2-102. Leak rate vs. diameter - compressor seals, hydrogen service.

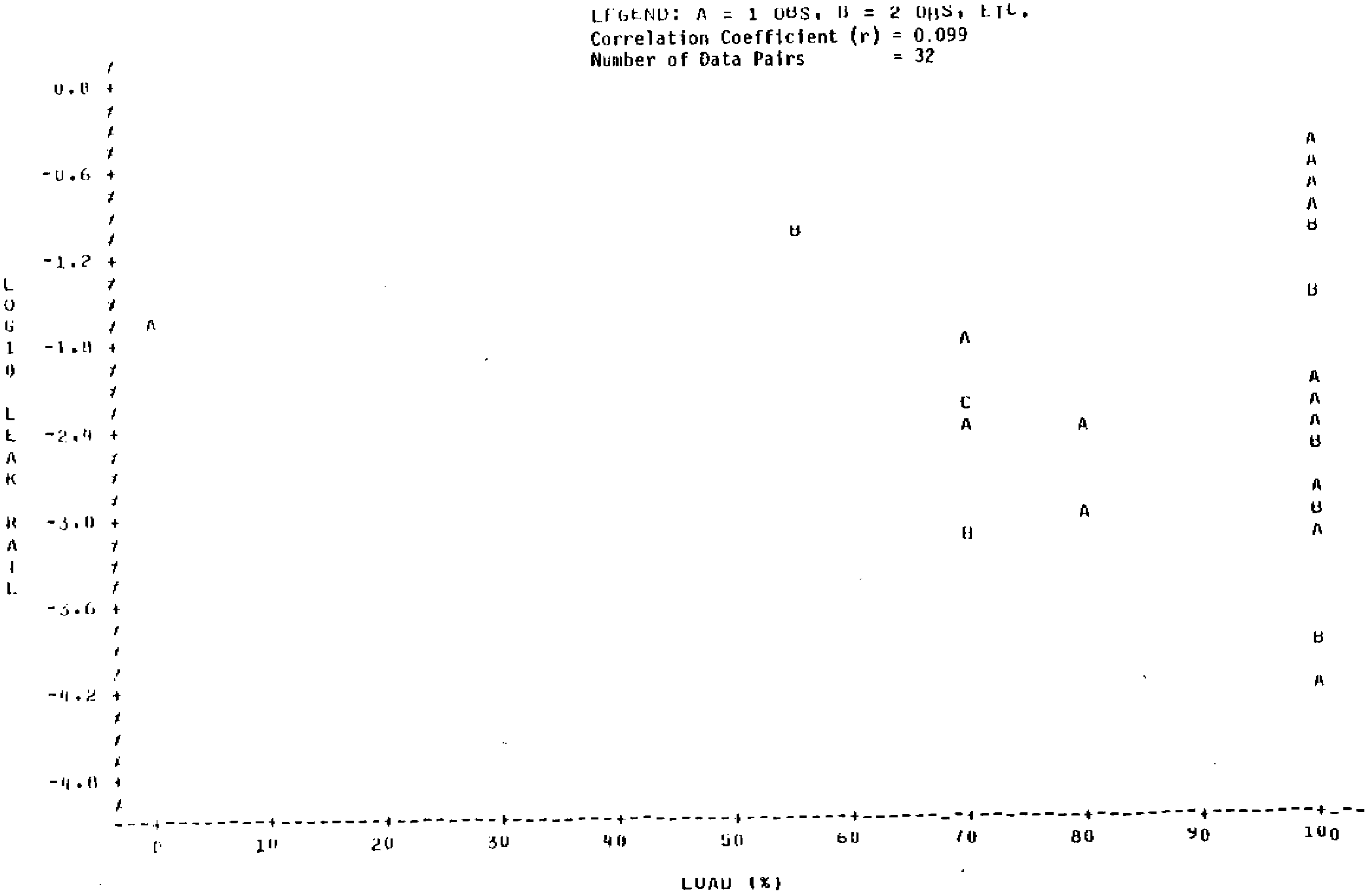


Figure B2-103. Leak rate vs. load - compressor seals, hydrogen service.

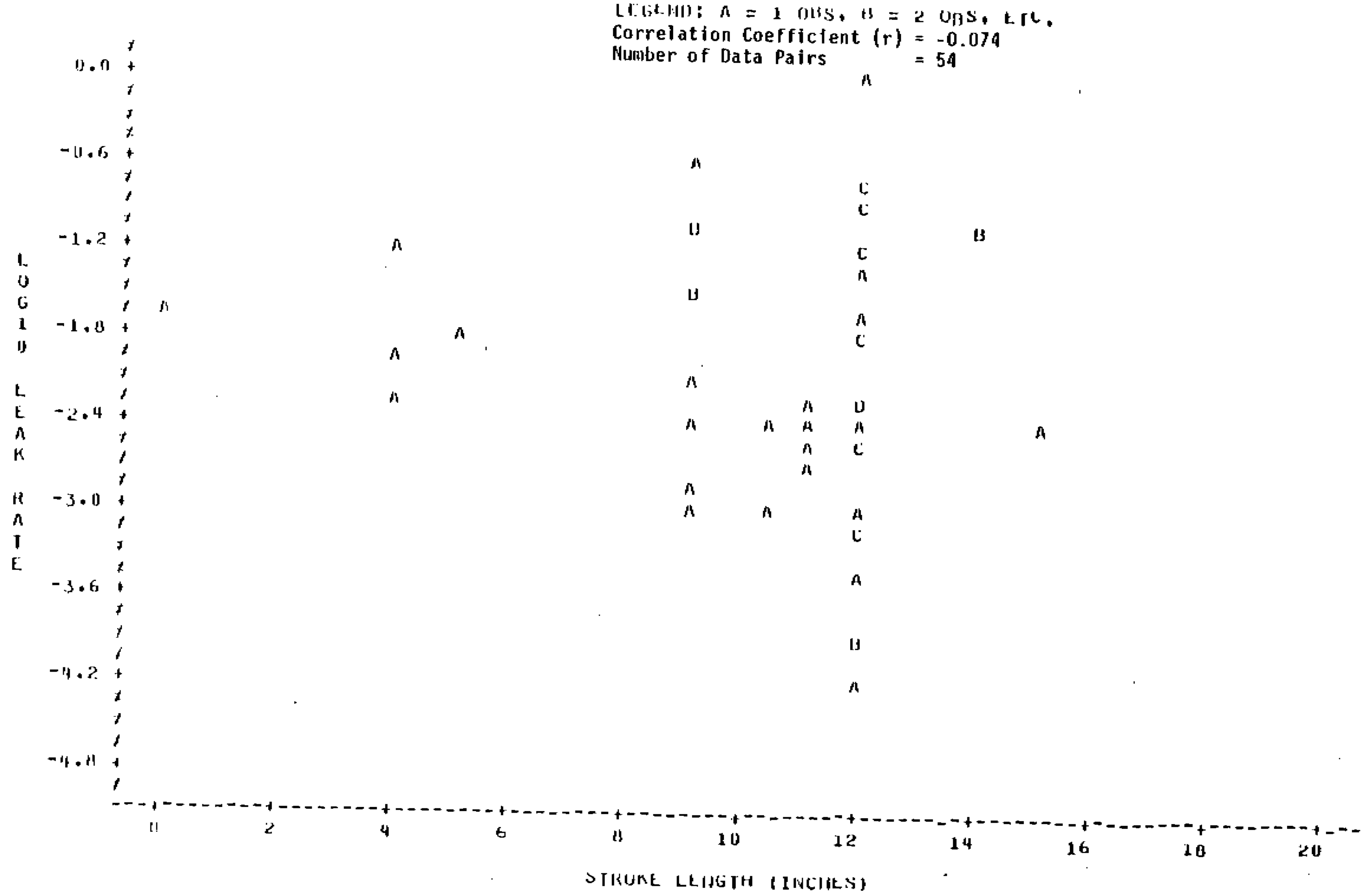


Figure B2-104. Leak rate vs. stroke length - compressor seals, hydrogen service.

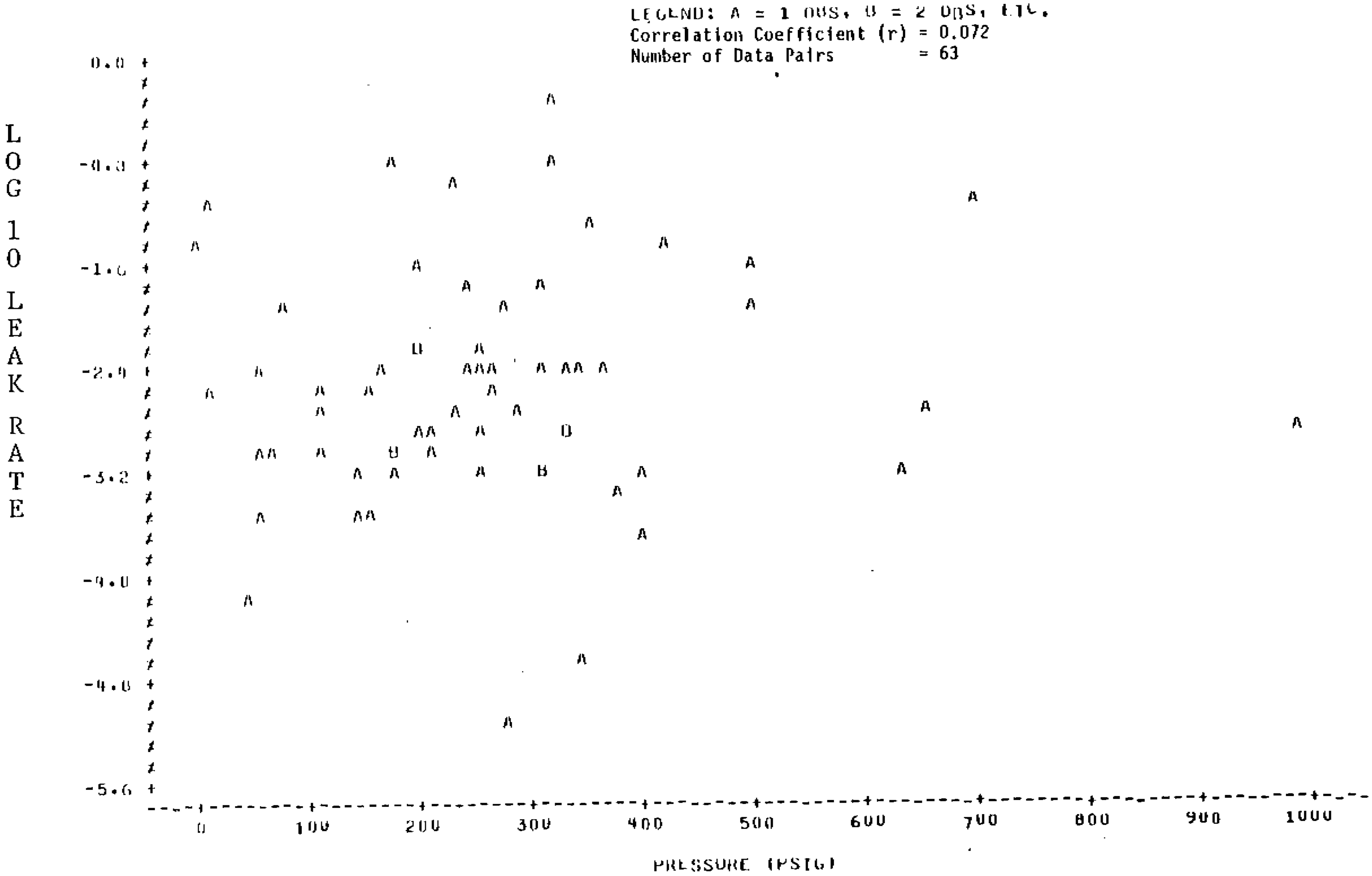


Figure B2-105 . Leak rate vs. pressure - flanges.

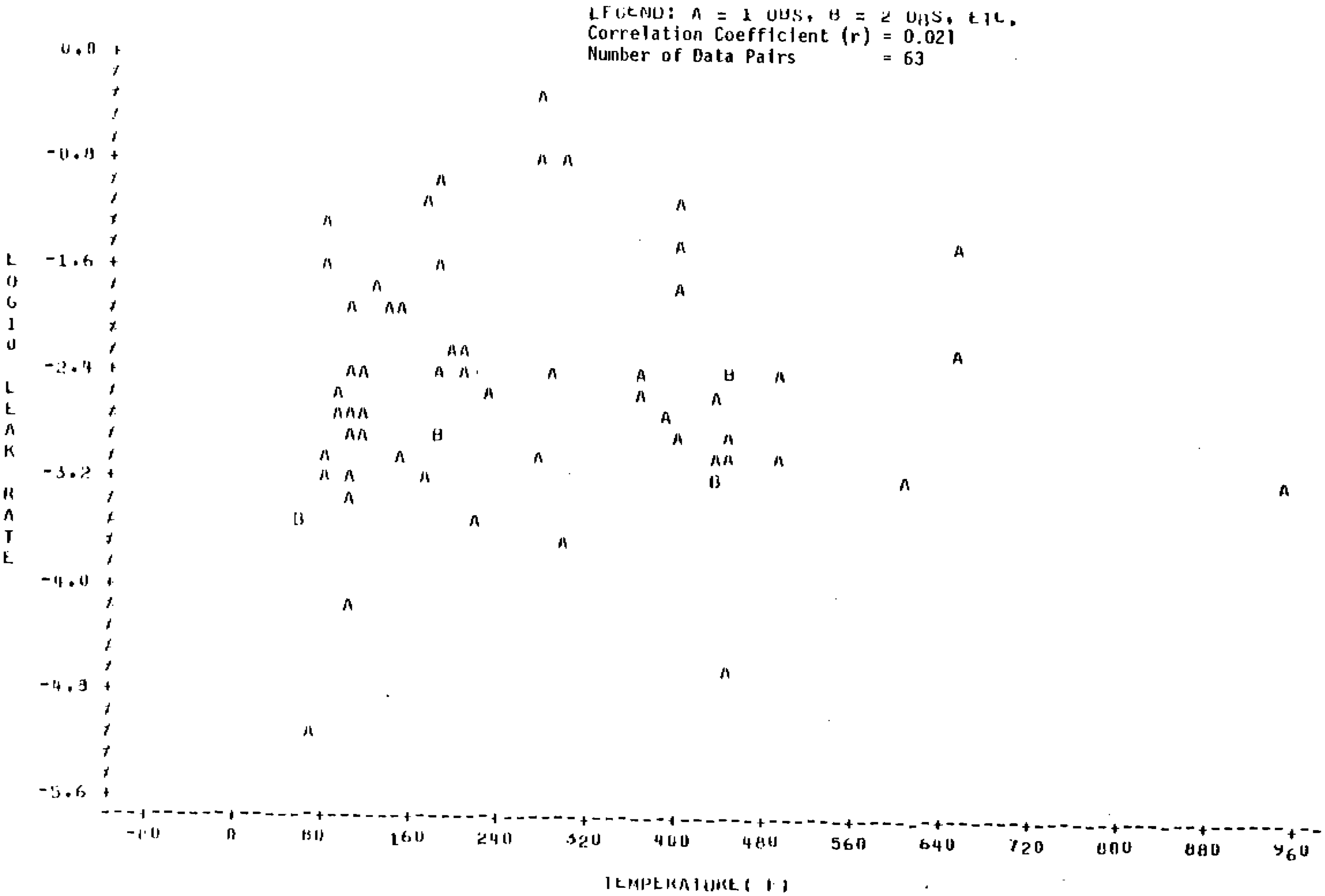


Figure B2-106. Leak rate vs. temperature - flanges.

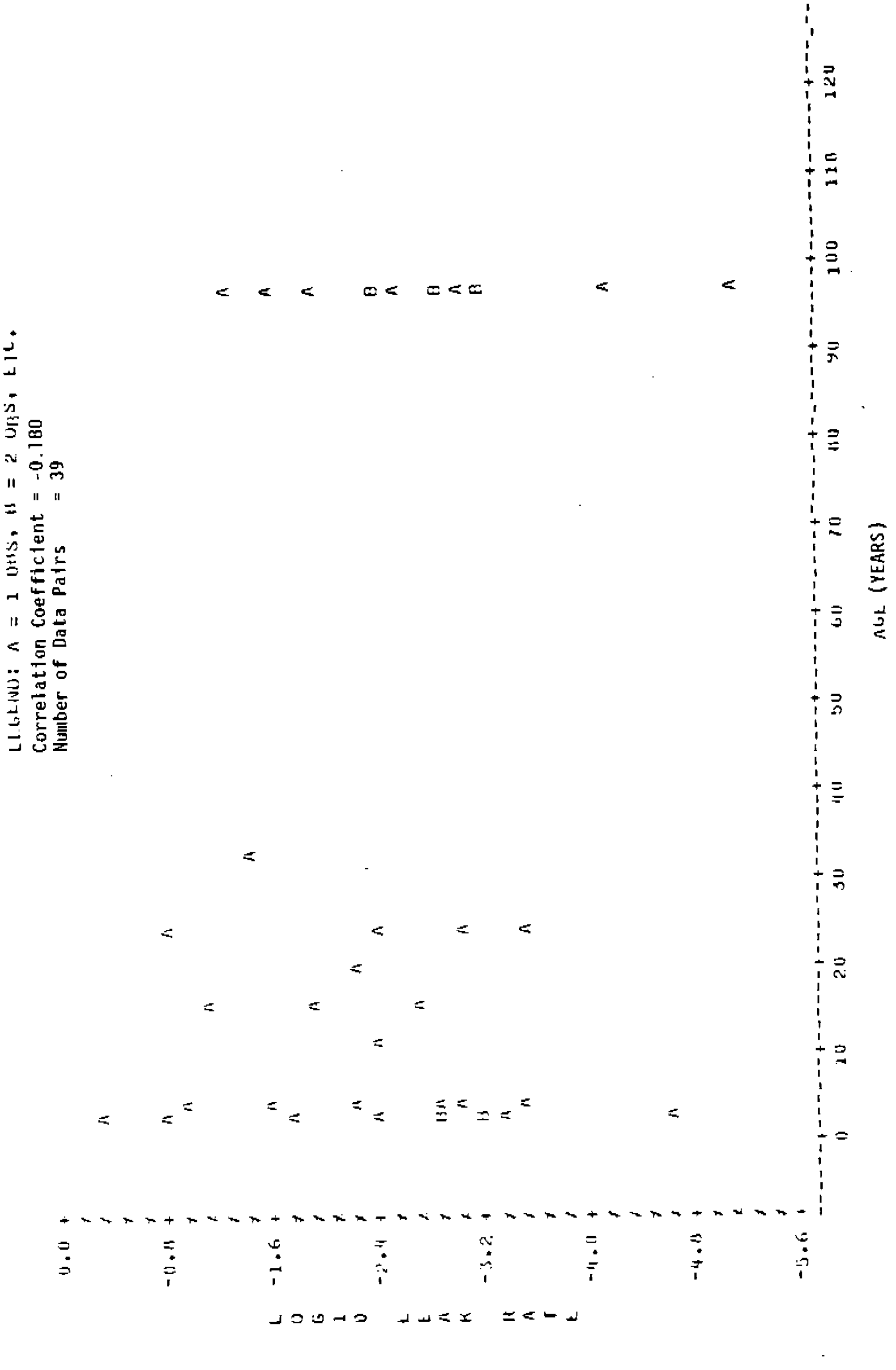


Figure B2-107. Leak rate vs. age - flanges.

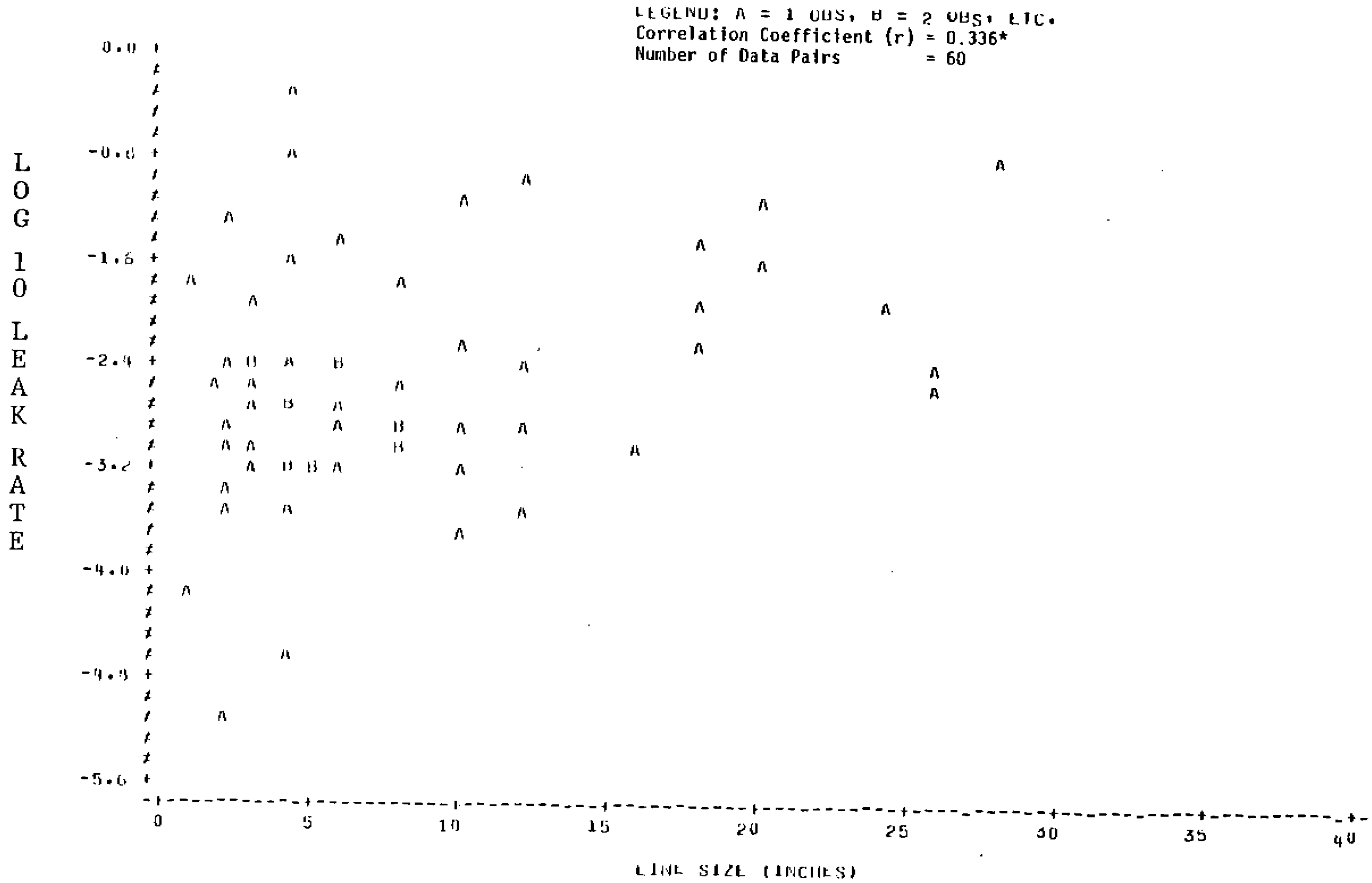


Figure B2-108. Leak rate vs. line size - flanges.

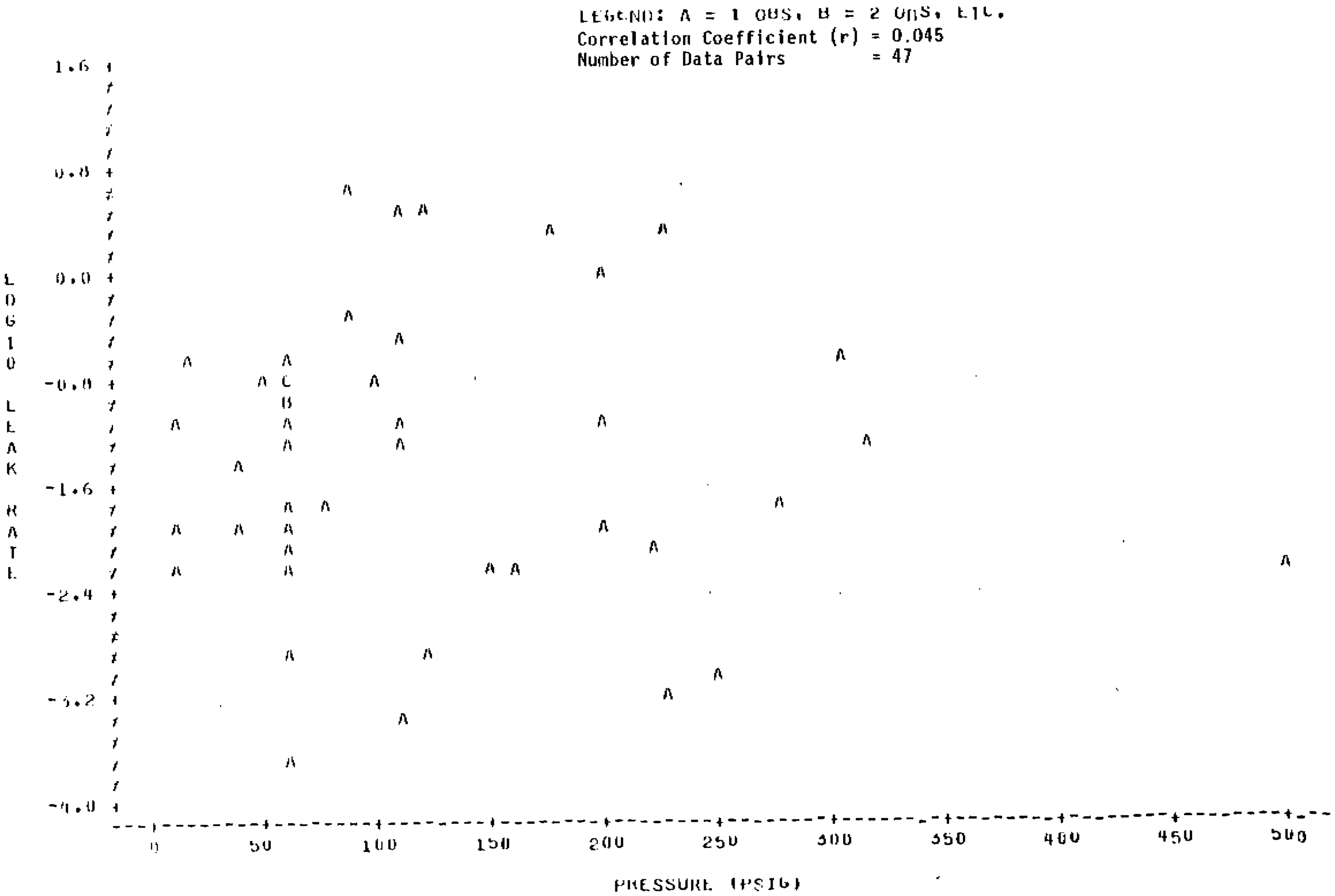


Figure B2-109. Leak rate vs. pressure - relief valves.

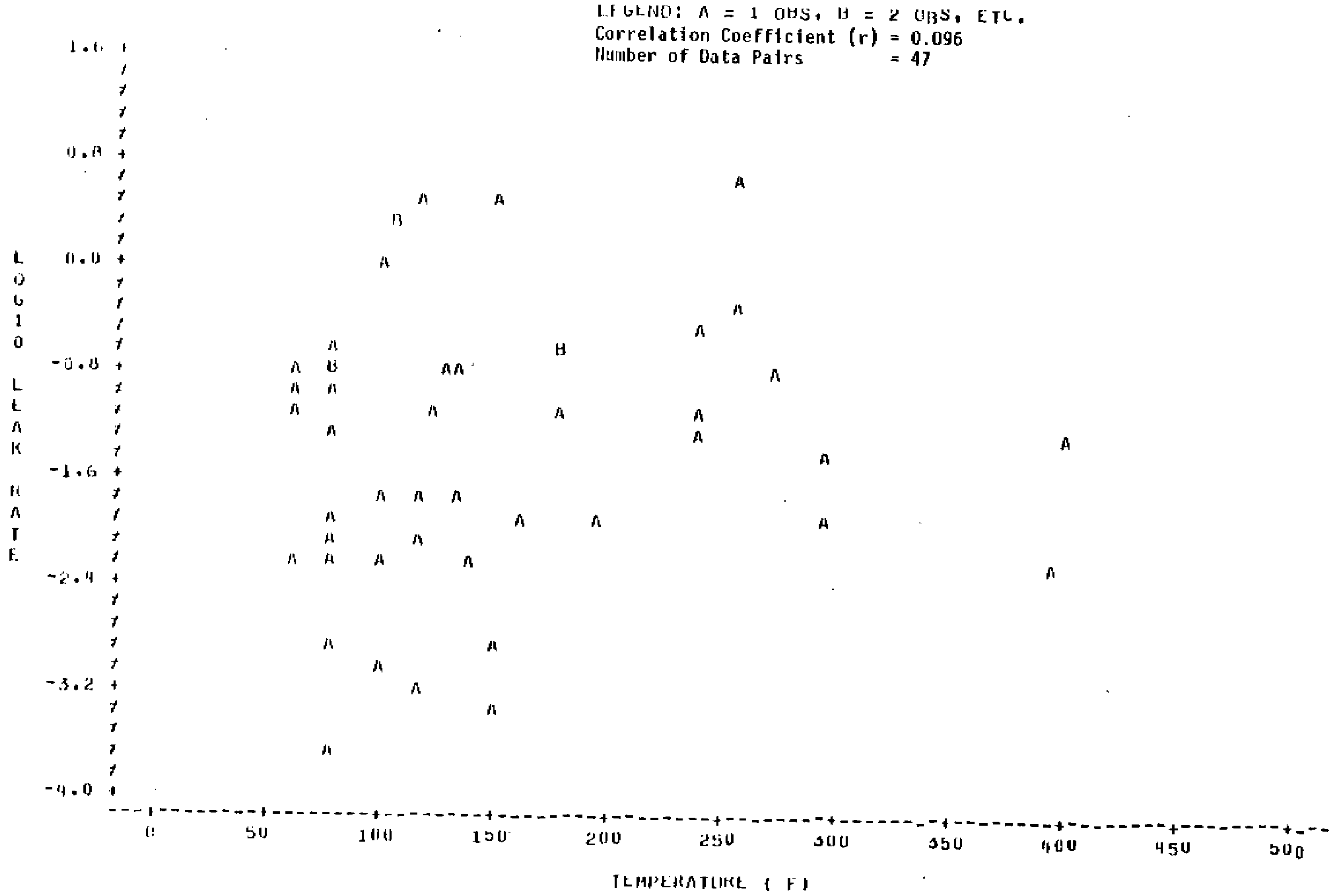


Figure B2-110. Leak rate vs. temperature - relief valves.

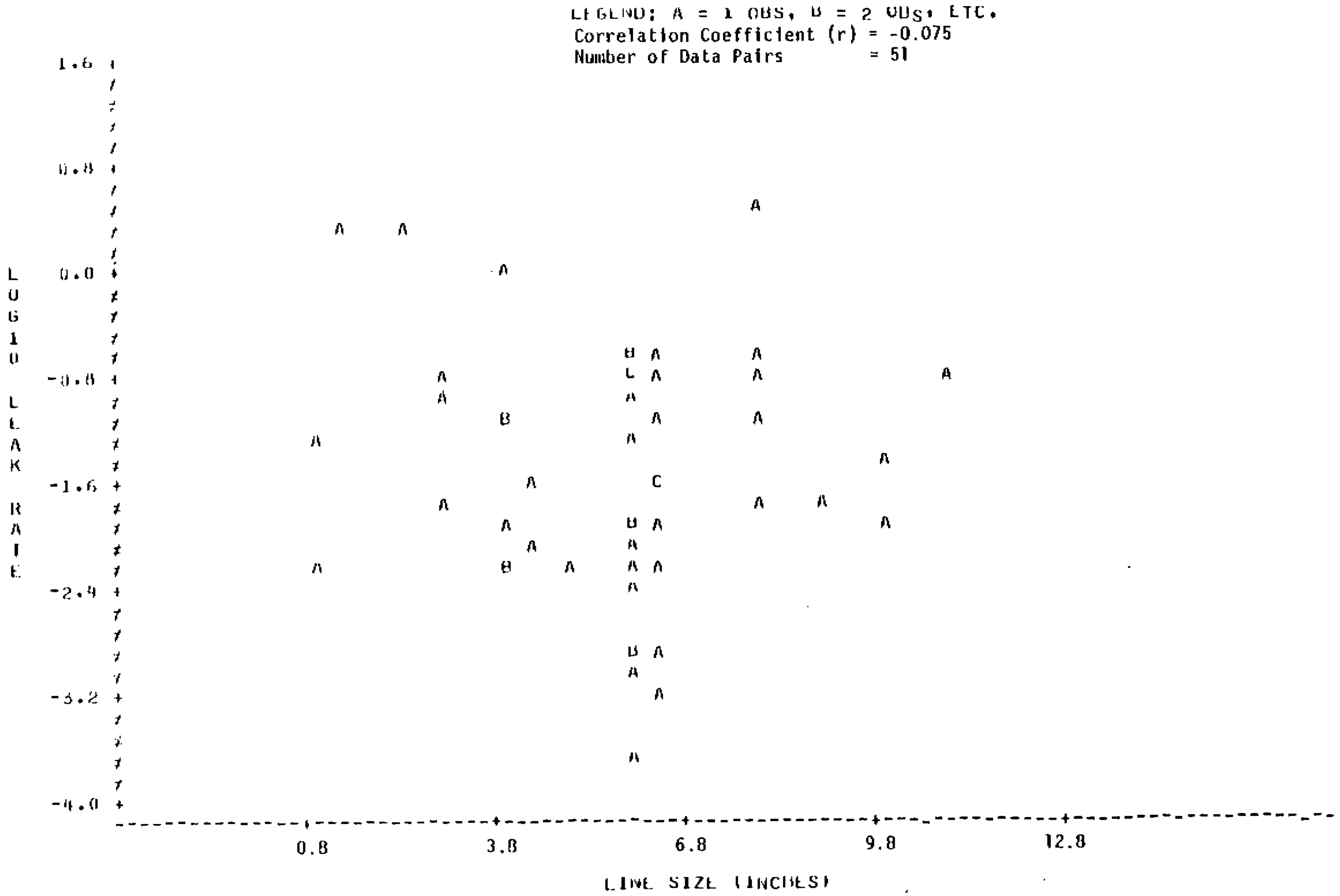


Figure B2-111. Leak rate vs. line size - relief valves.

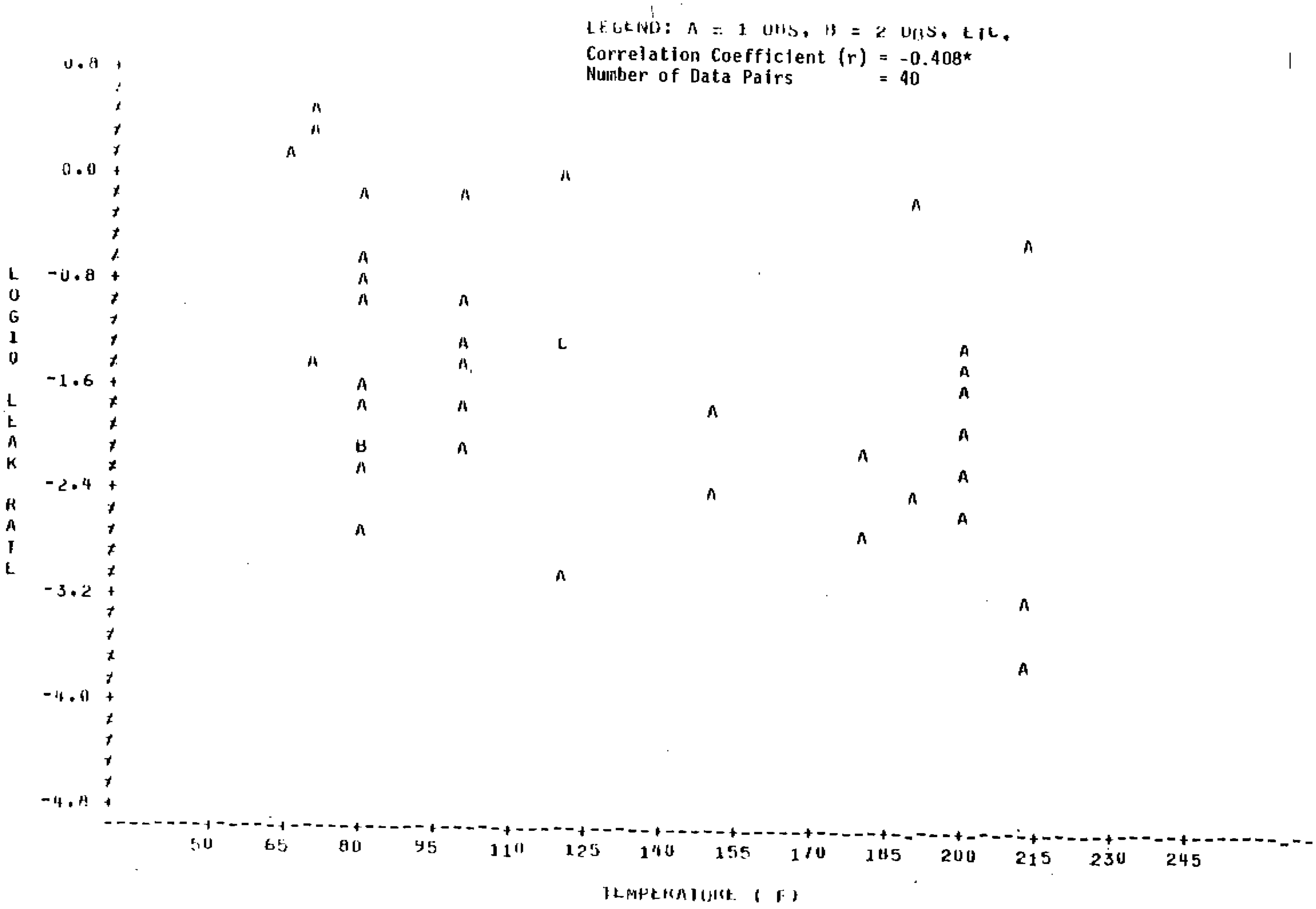


Figure B2-112. Leak rate vs. temperature - drains.

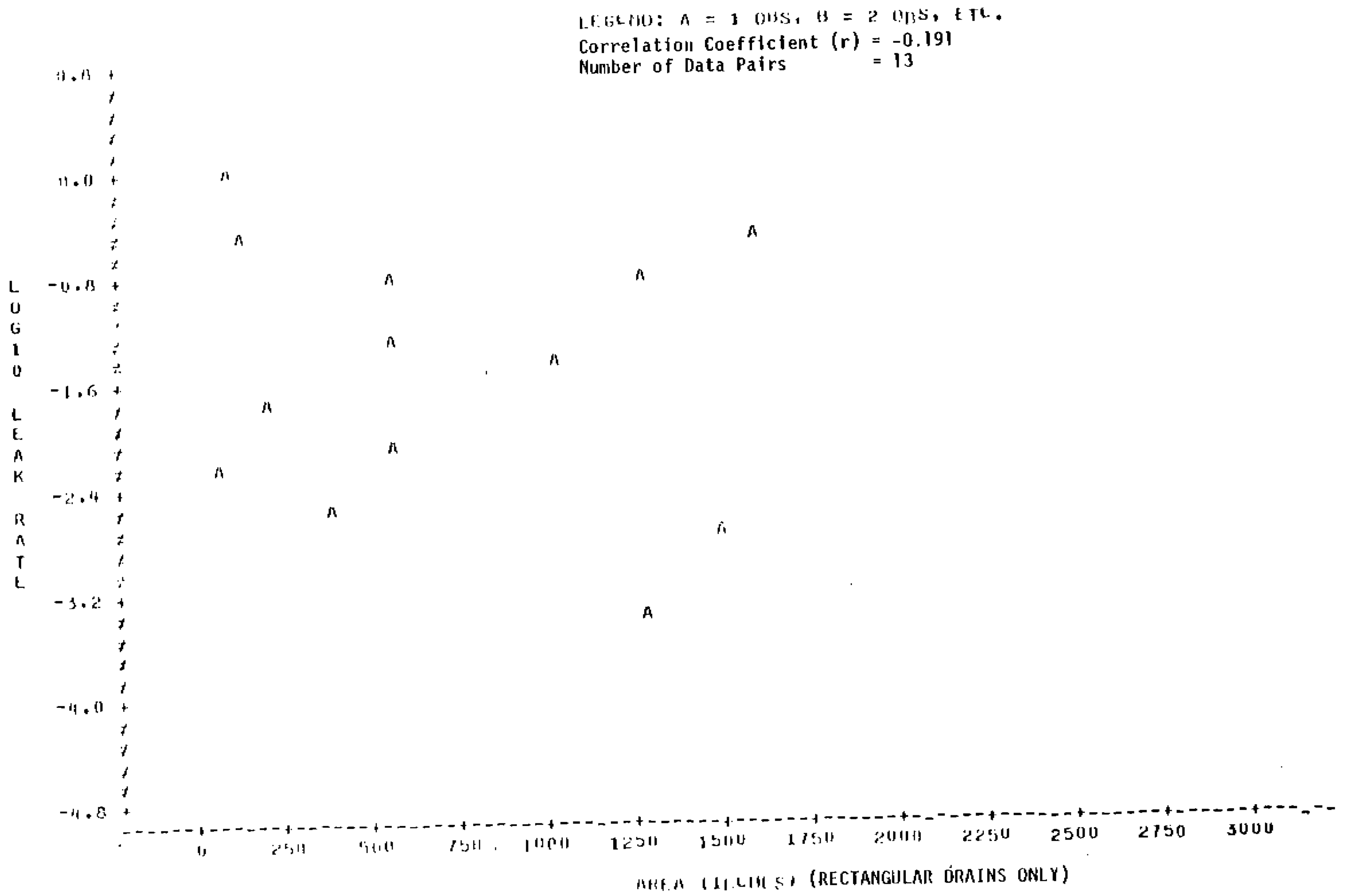


Figure B2-113 . Leak rate vs. area - drains.

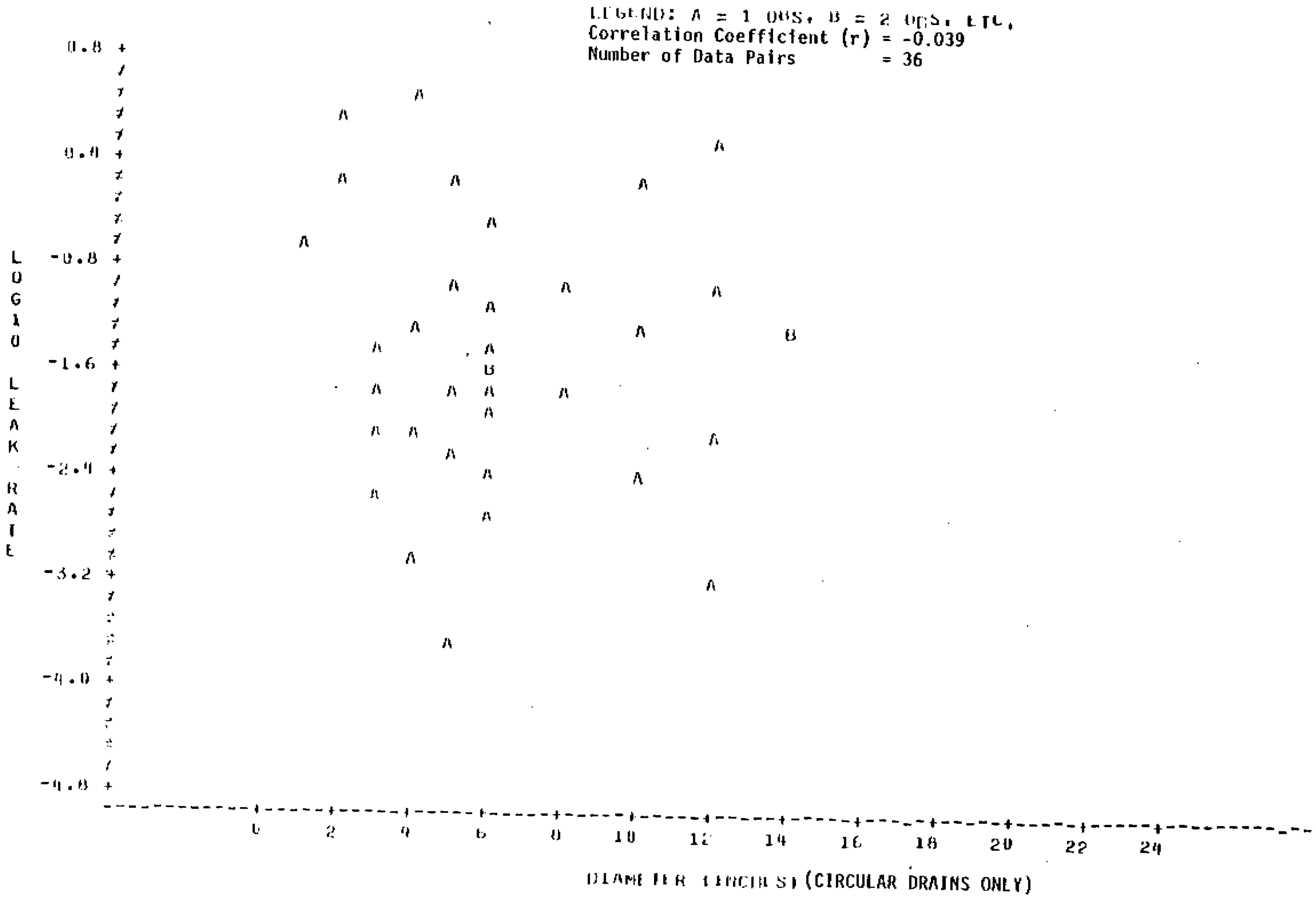


Figure B2-114. Leak rate vs. diameter - drains.

B2-115 through B2-120 are schematic plots for valves describing the variables block/control, in line/open-ended, valve type, stem movement, vibration, and manufacturer. On any particular plot, each level of the variable is represented by a "box and whisker" figure that identifies the mean, median, upper and lower quartile, and range of values. The number of leaking sources is also listed. Taking sample size into consideration, there appears to be no significant difference in leak rate between the levels of any of the variables.

Figures B2-121 through B2-128 describe the discrete variables for pumps: pump type, single/double seal, in service/out of service, quench, inboard/outboard, lubricant, attitude, and manufacturer. Differences can be seen between single and double seals for heavy liquid streams (Figure B2-122); however, the small sample sizes prevent any firm conclusions from being drawn.

Discrete variables for flanges are displayed in Figures B2-129 through B2-133. Small differences can be seen between the leak rates of flange types, special service, and vibration. Because of small sample sizes, these differences cannot be considered significant.

Figures B2-134 through B2-139 describe discrete variables for compressors; Figures B2-140 and B2-141, discrete variables for drains; and Figure B2-142, single or double configuration for relief valves. A slight difference between variables appears in Figure B2-140 for drains where drains without visible vapor emissions tend to have higher leak rates than those with visible vapor.

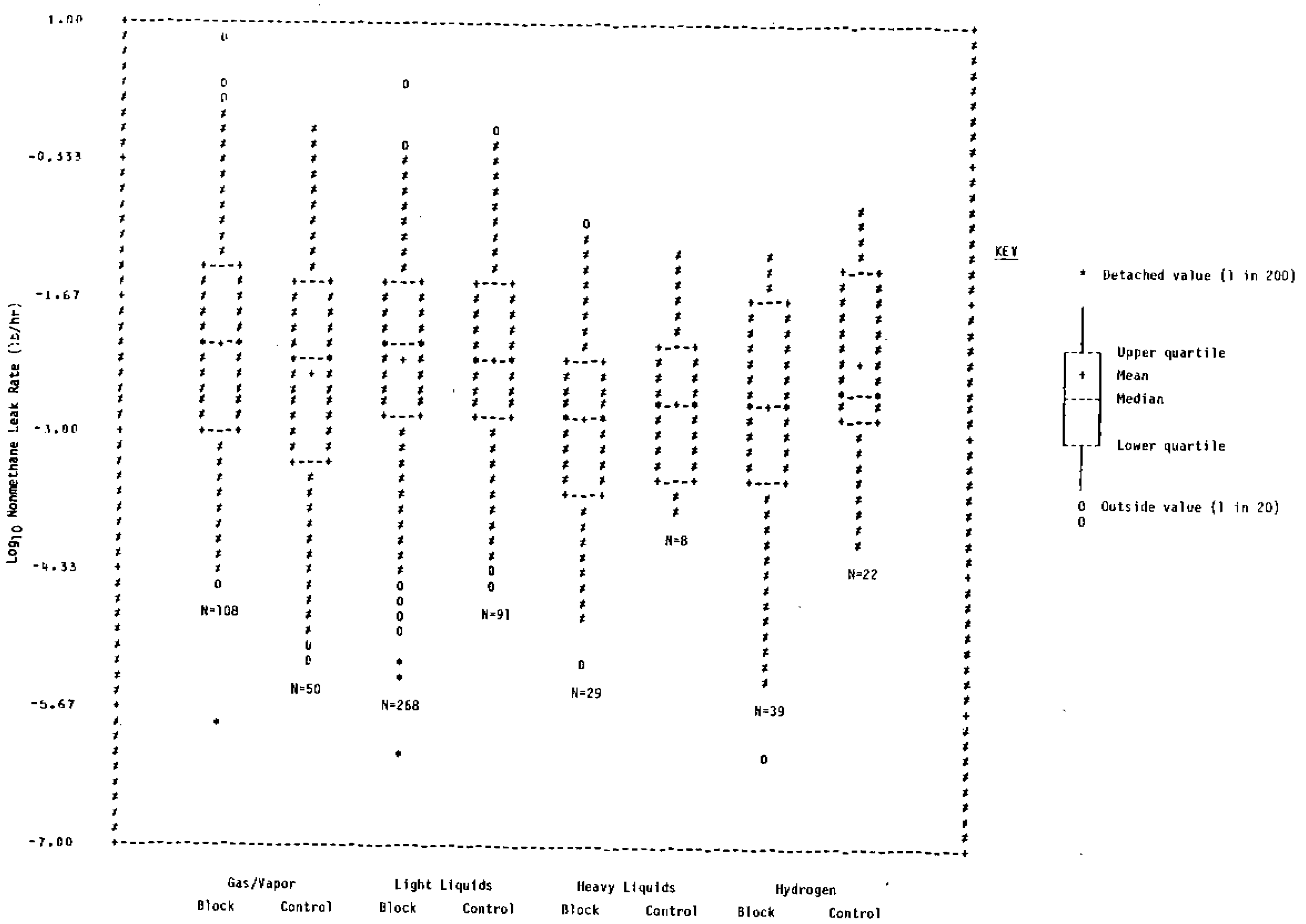


Figure B2-115. Schematic plot for valves by block/control variable.

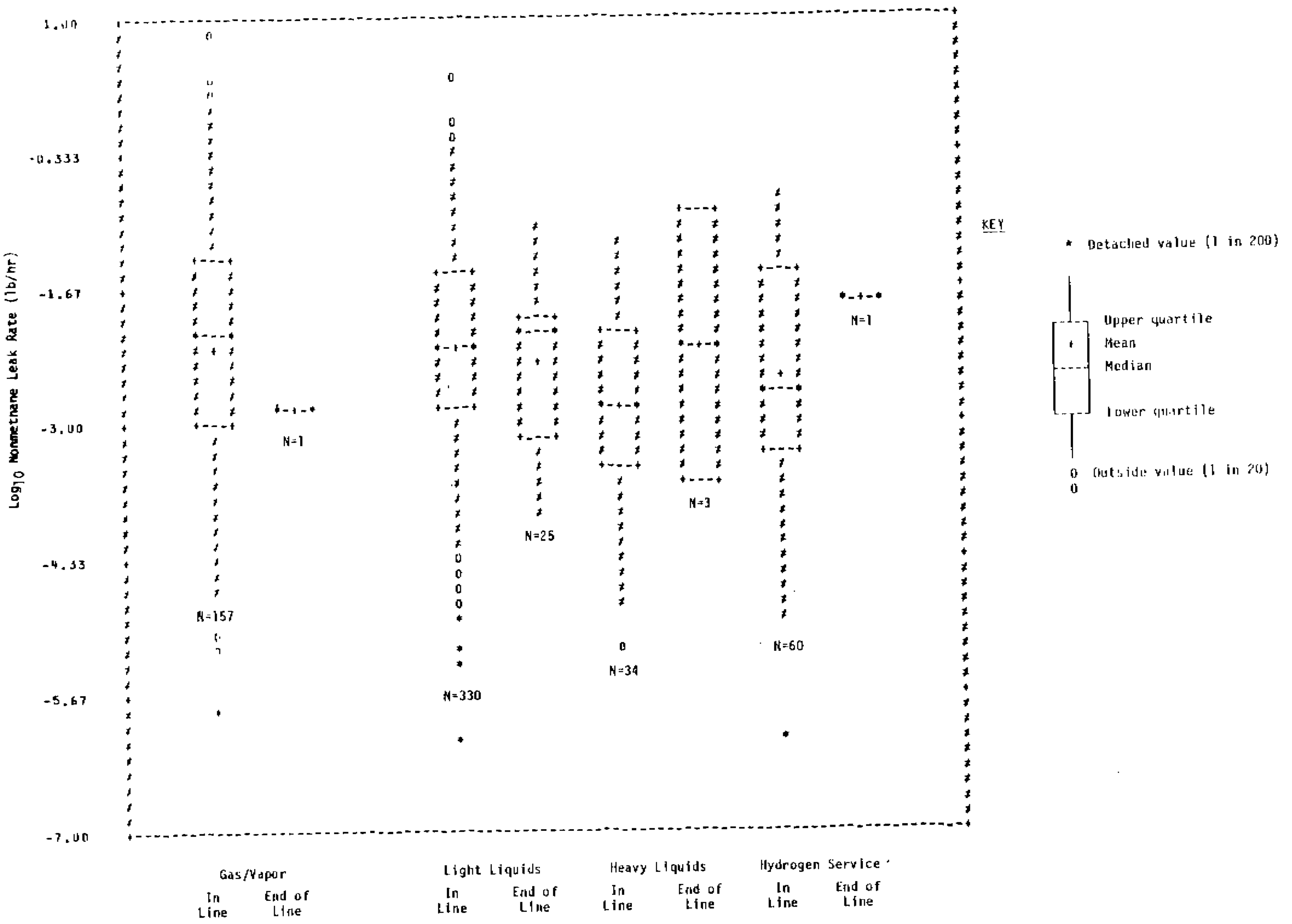


Figure B2-116. Schematic plot for valves by in line/end of line variable.

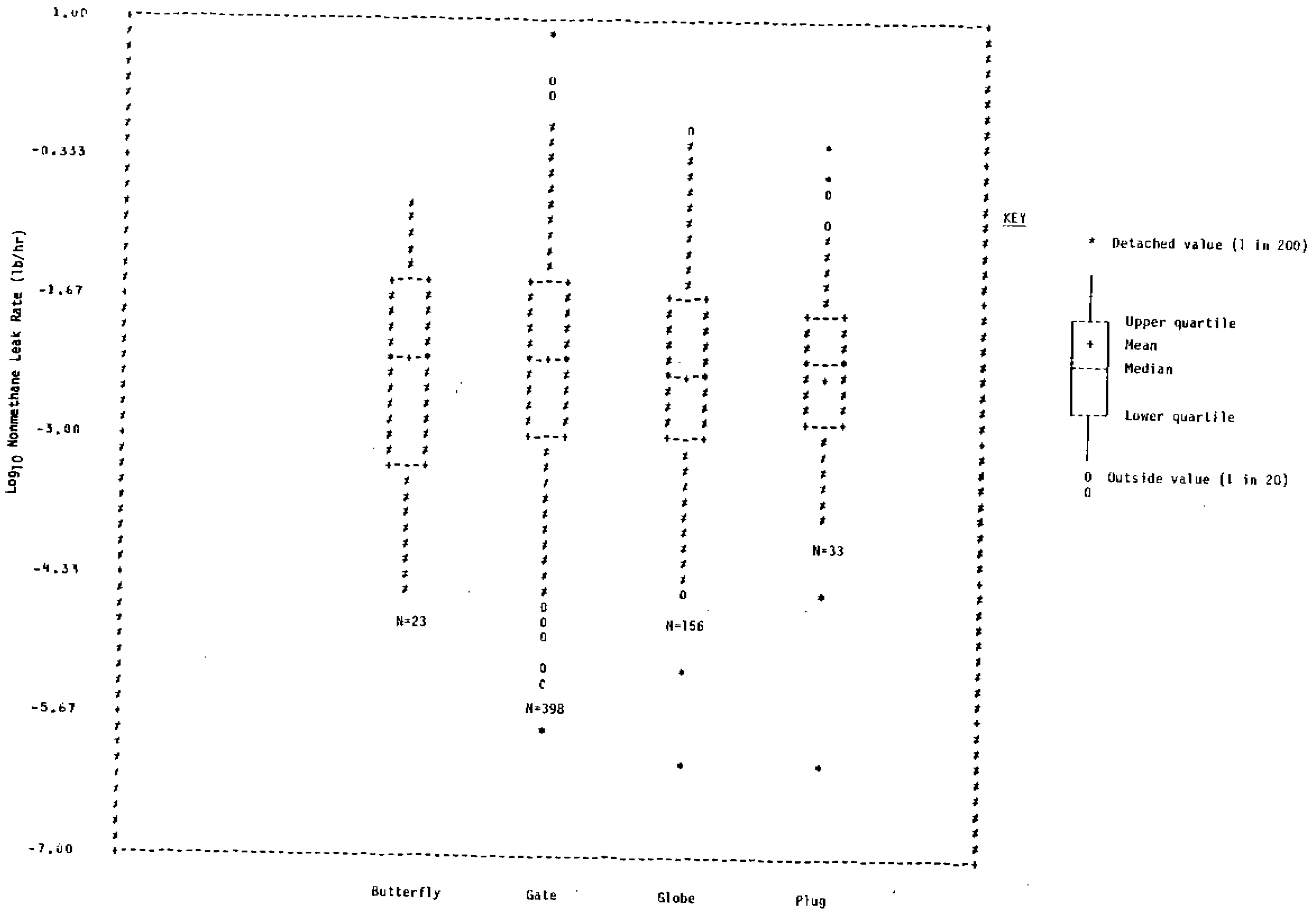


Figure B2-117. Schematic plot for valves by valve type variable.

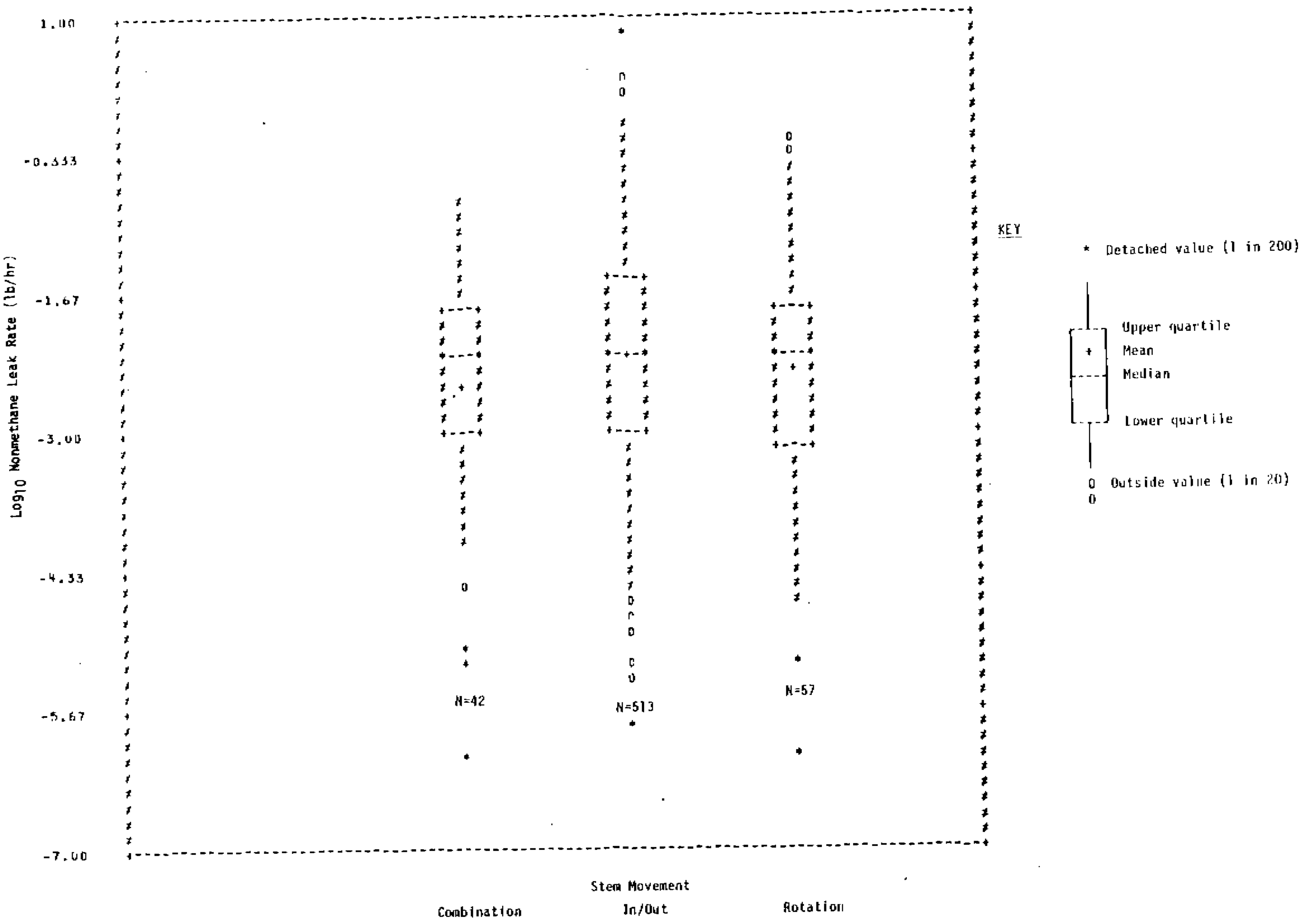


Figure B2-118. Schematic plot for valves by stem movement variable.

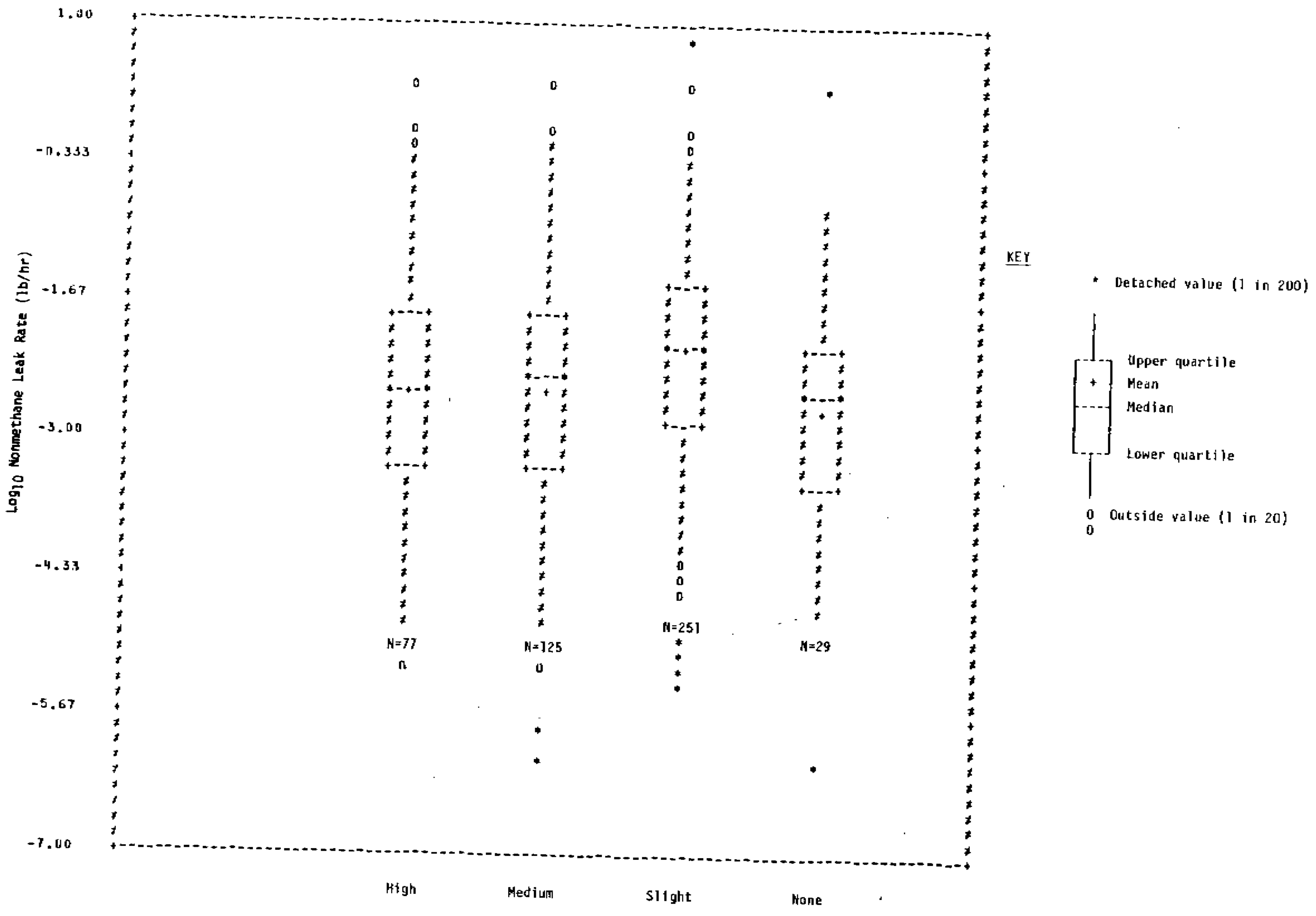


Figure B2-119. Schematic plot for valves by vibration variable.

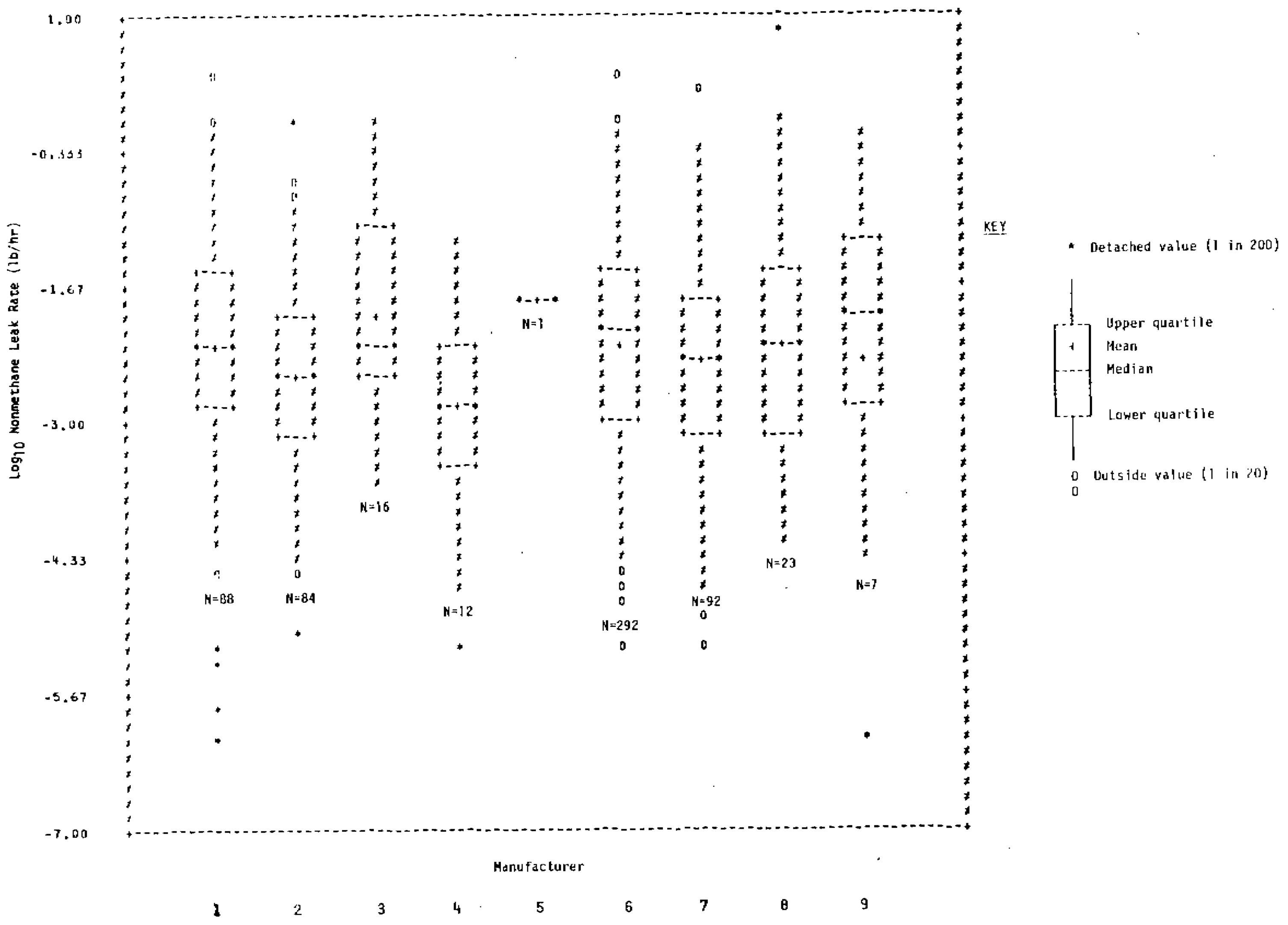


Figure B2-120. Schematic plot for valves by manufacturer variable.

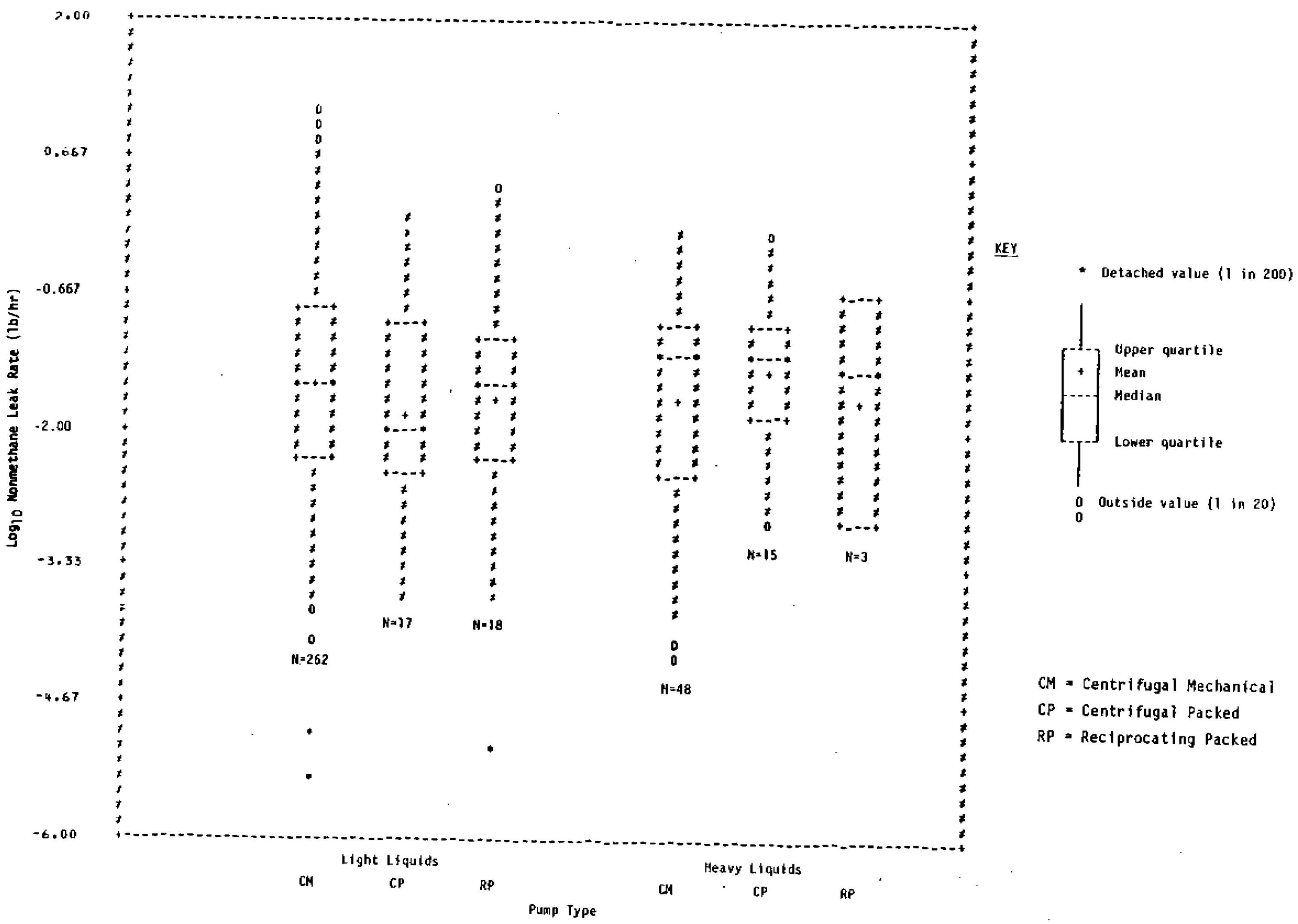


Figure B2-121. Schematic plot for pumps by pump type variable.

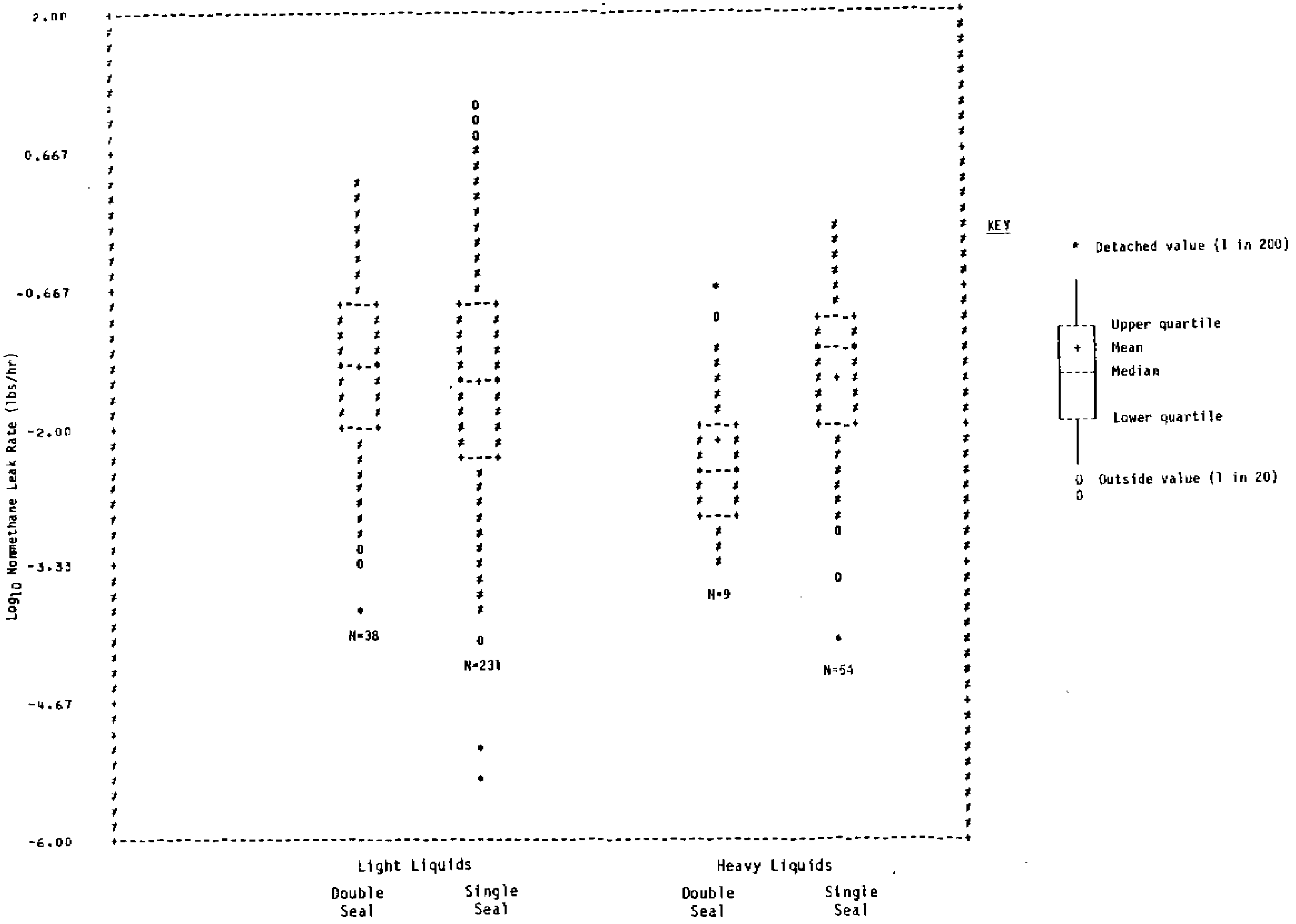


Figure B2-122. Schematic plot for pumps by seal variable.

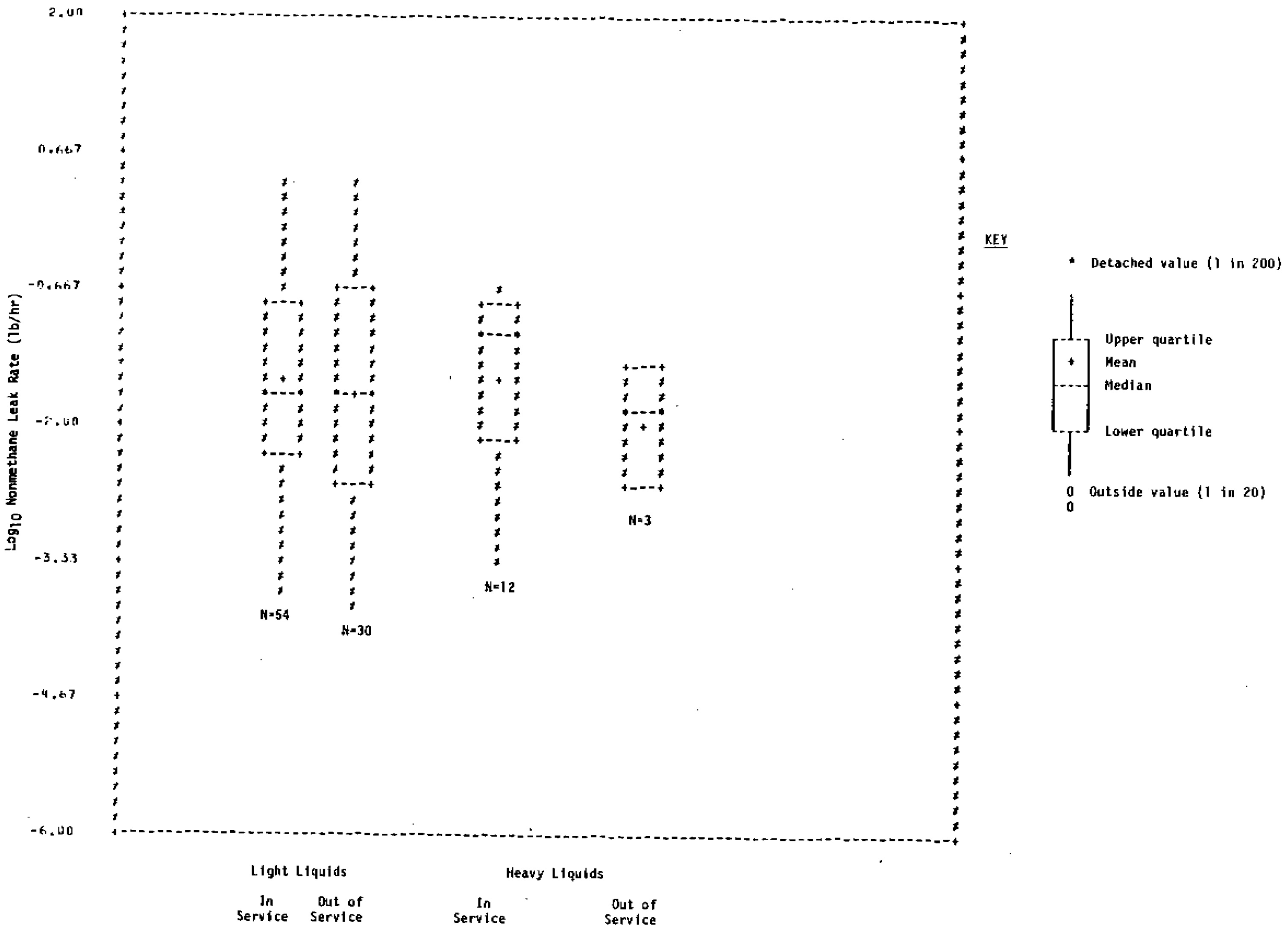


Figure B2-123. Schematic plot of pumps by service variable.

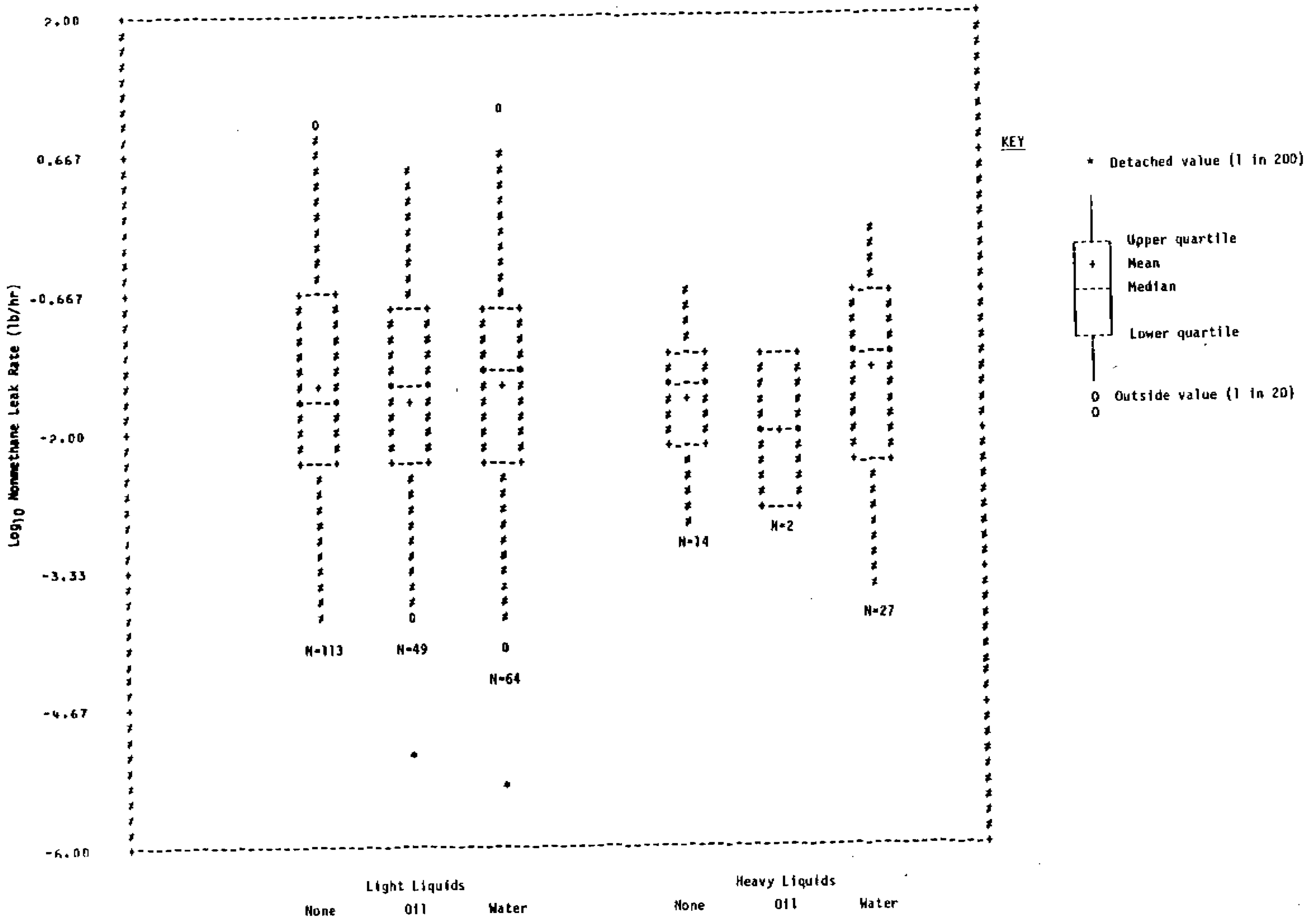


Figure B2-124. Schematic plot for pumps by quench liquid variable.

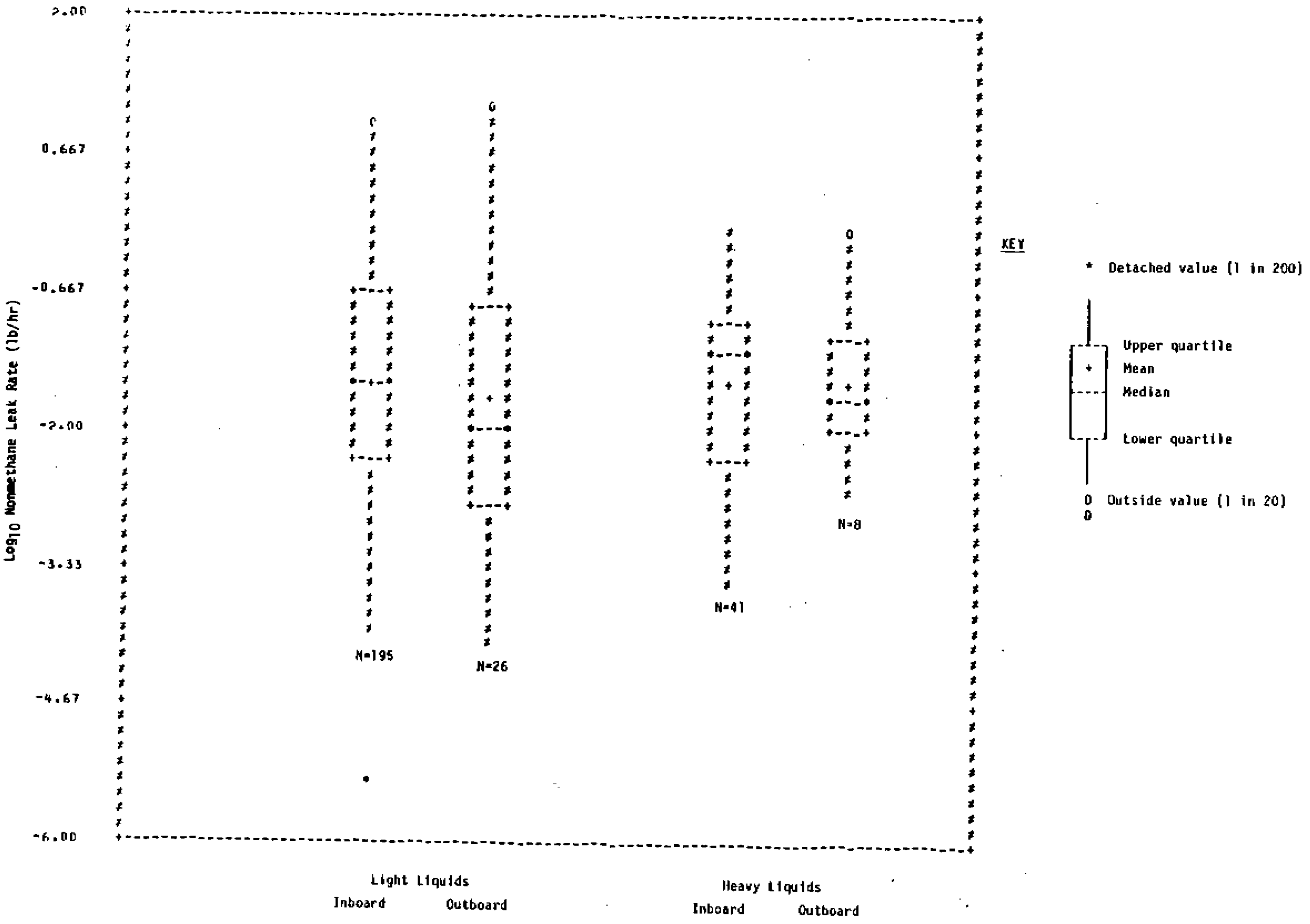


Figure B2-125. Schematic plot of pumps by inboard/outboard seal variable.

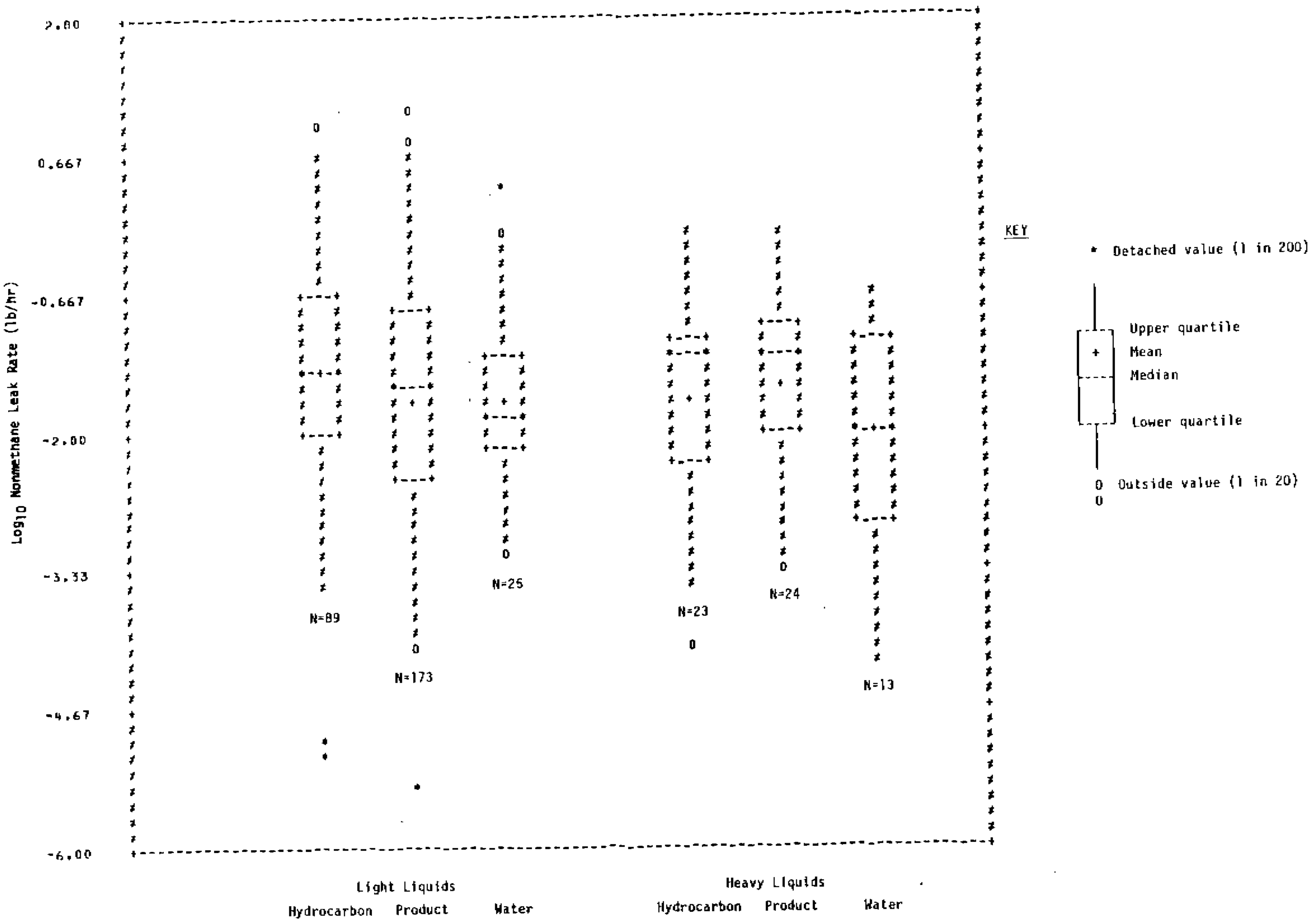


Figure B2-126. Schematic plot for pumps by lubricant variable.

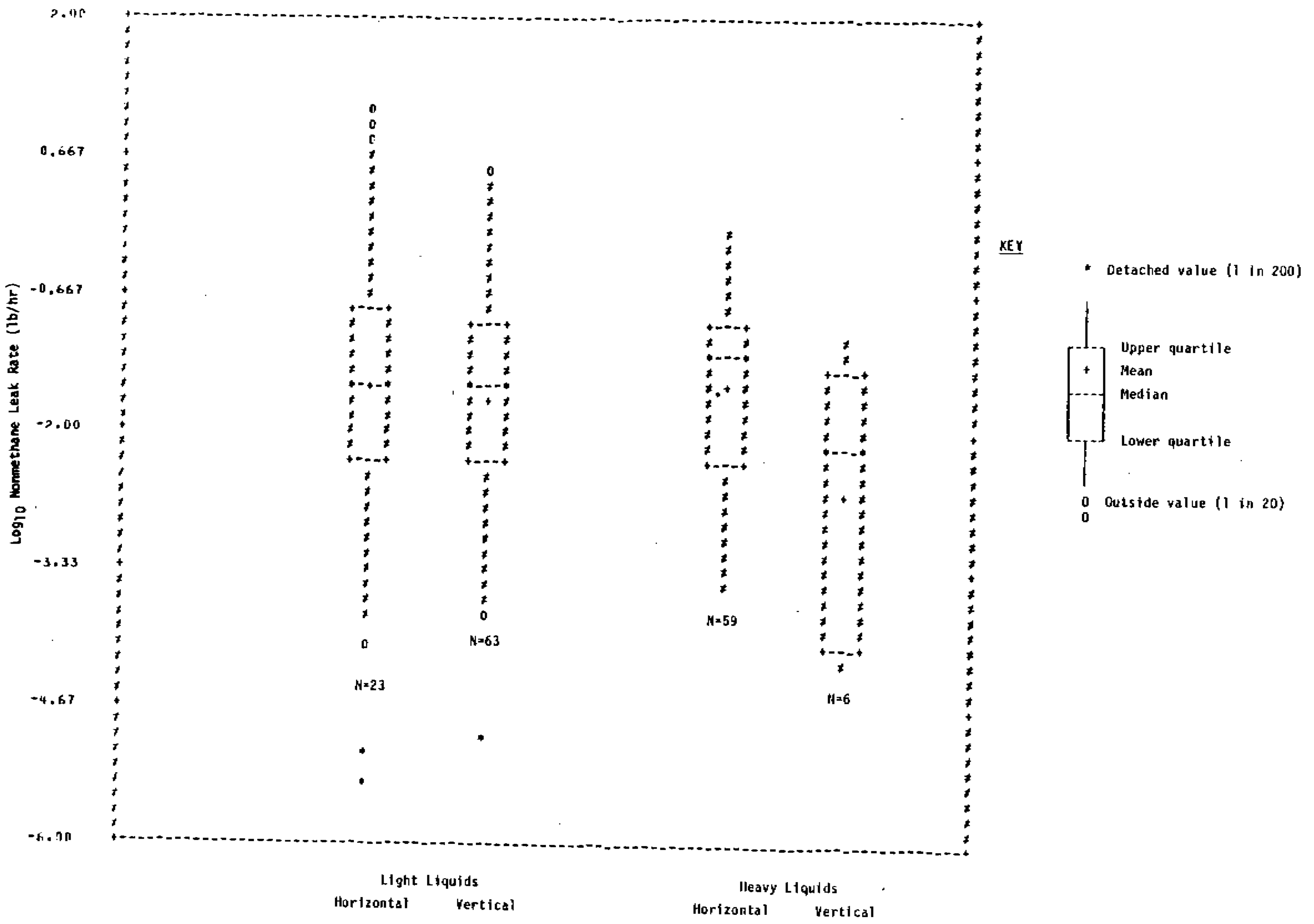


Figure B2-127. Schematic plot of pumps by attitude variable.

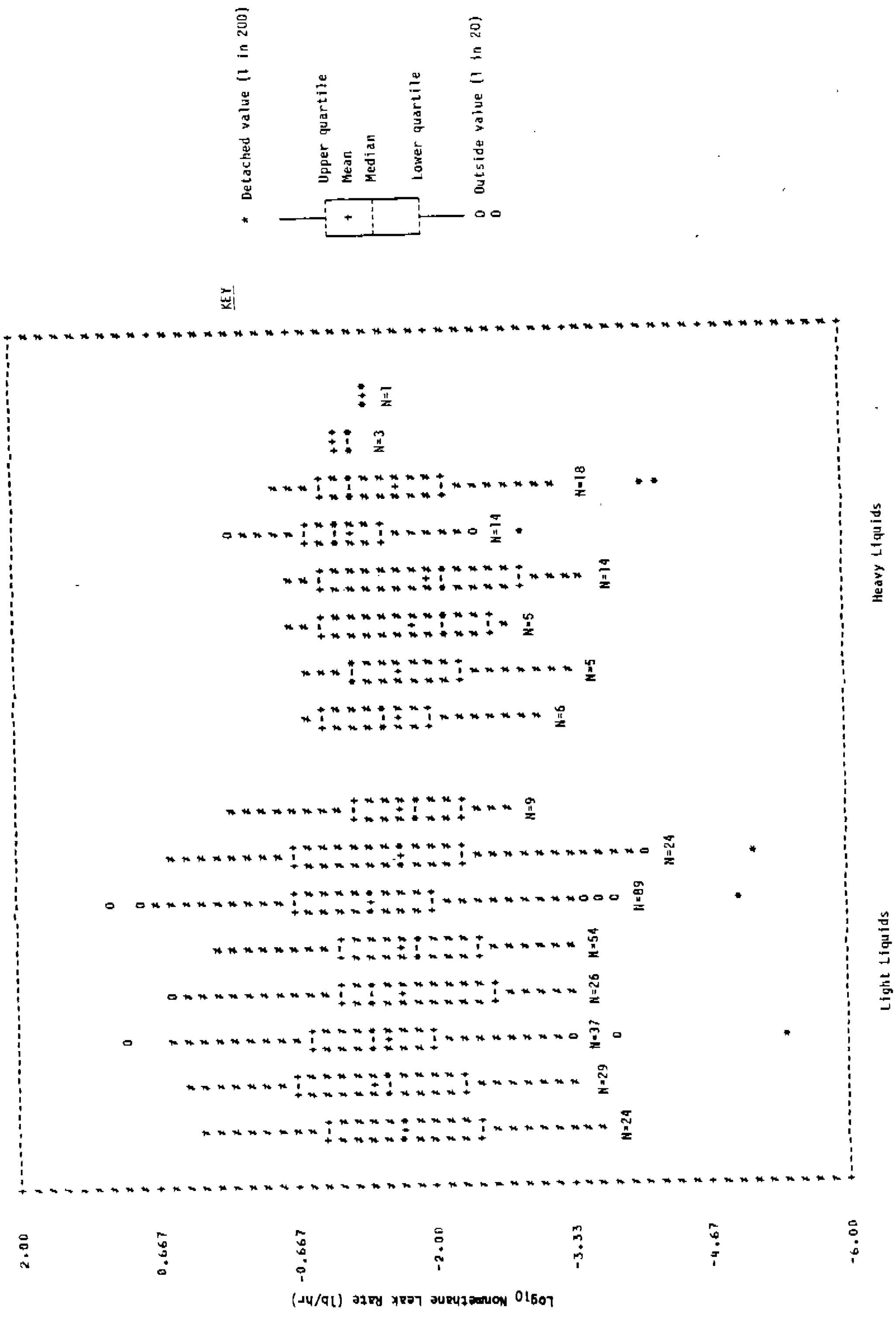


Figure B2-128. Schematic plot for pumps by manufacturer variable.

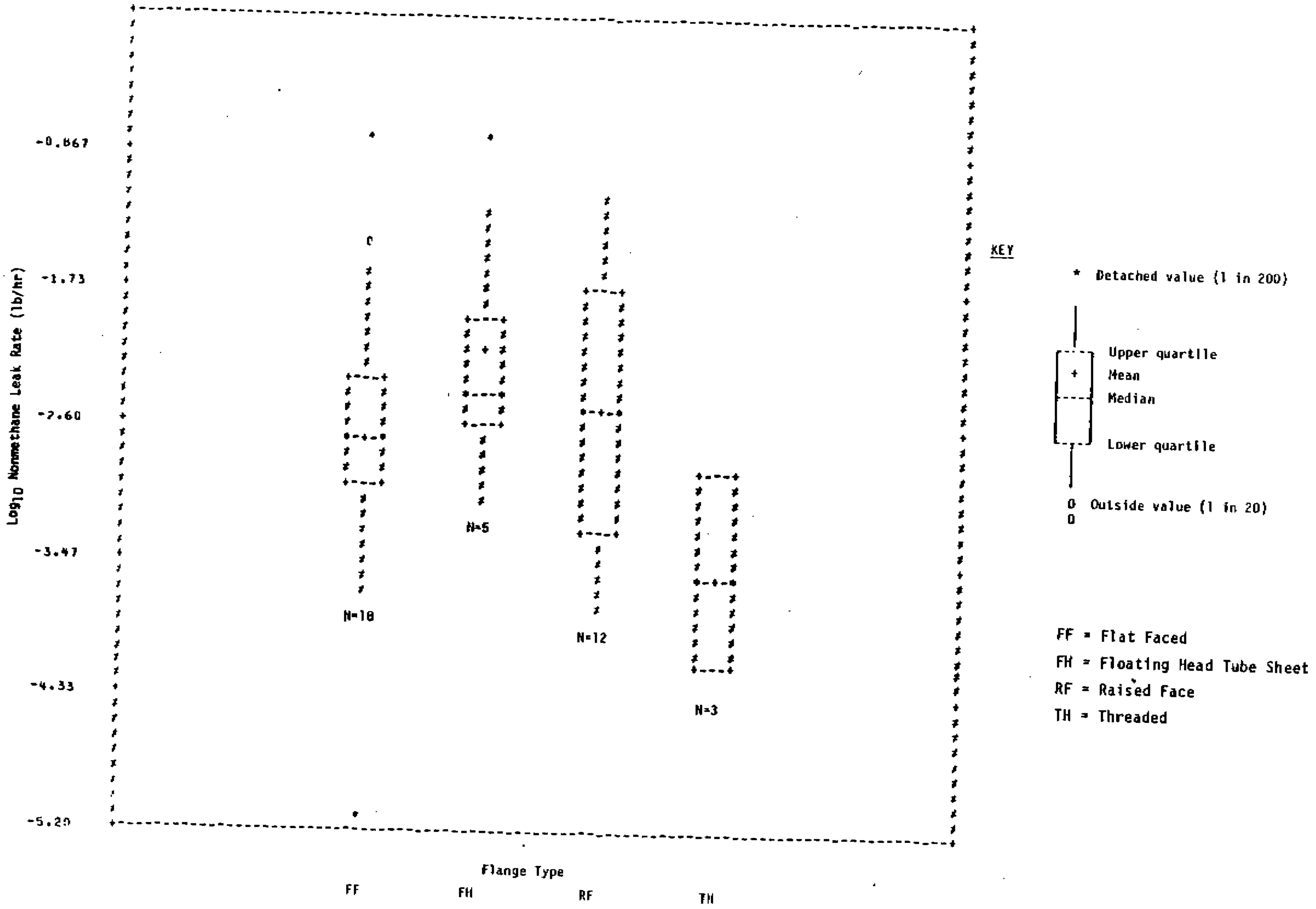


Figure B2-129. Schematic plot of flanges by flange type variable.

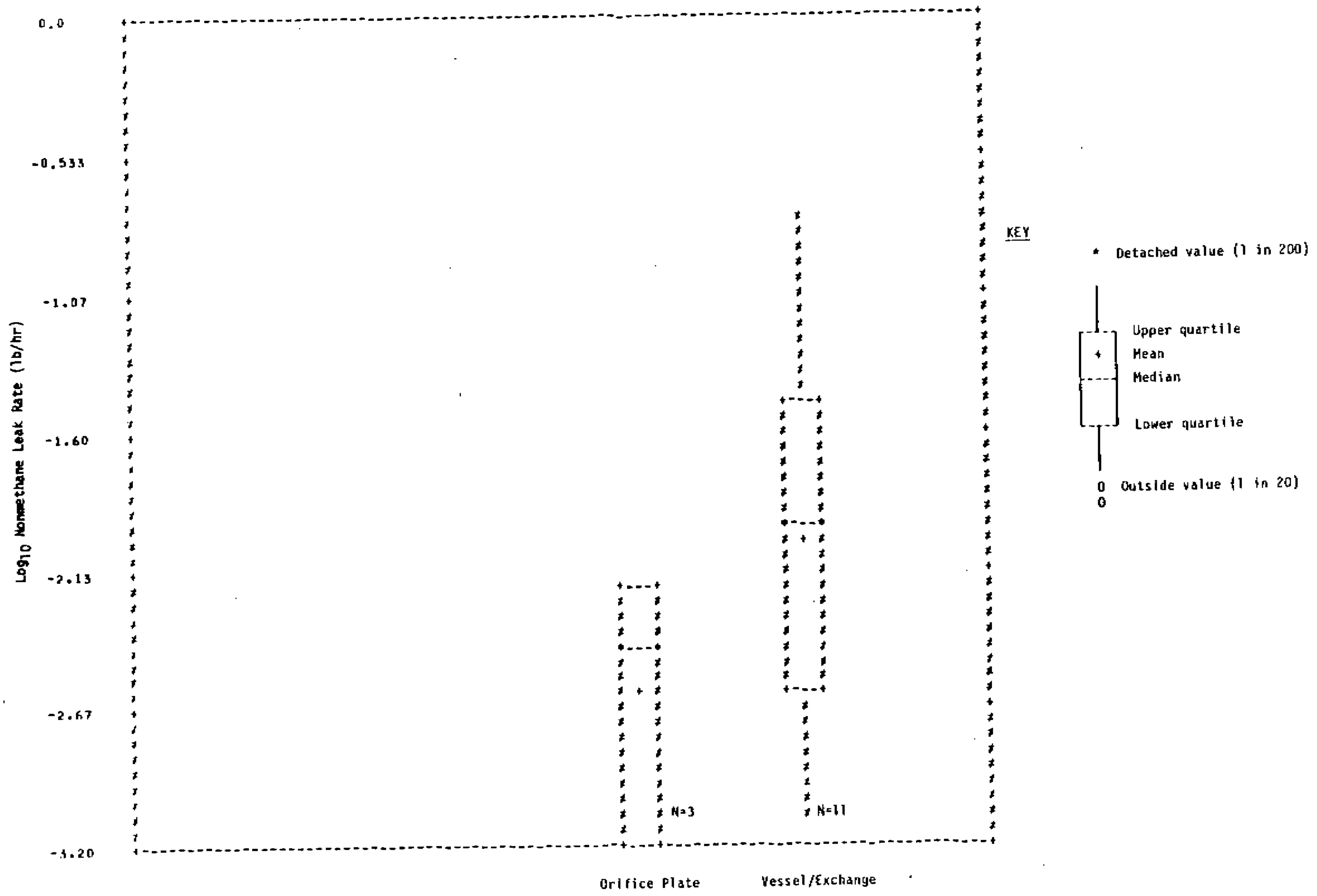


Figure B2-130. Schematic plot for flanges by special service variable.

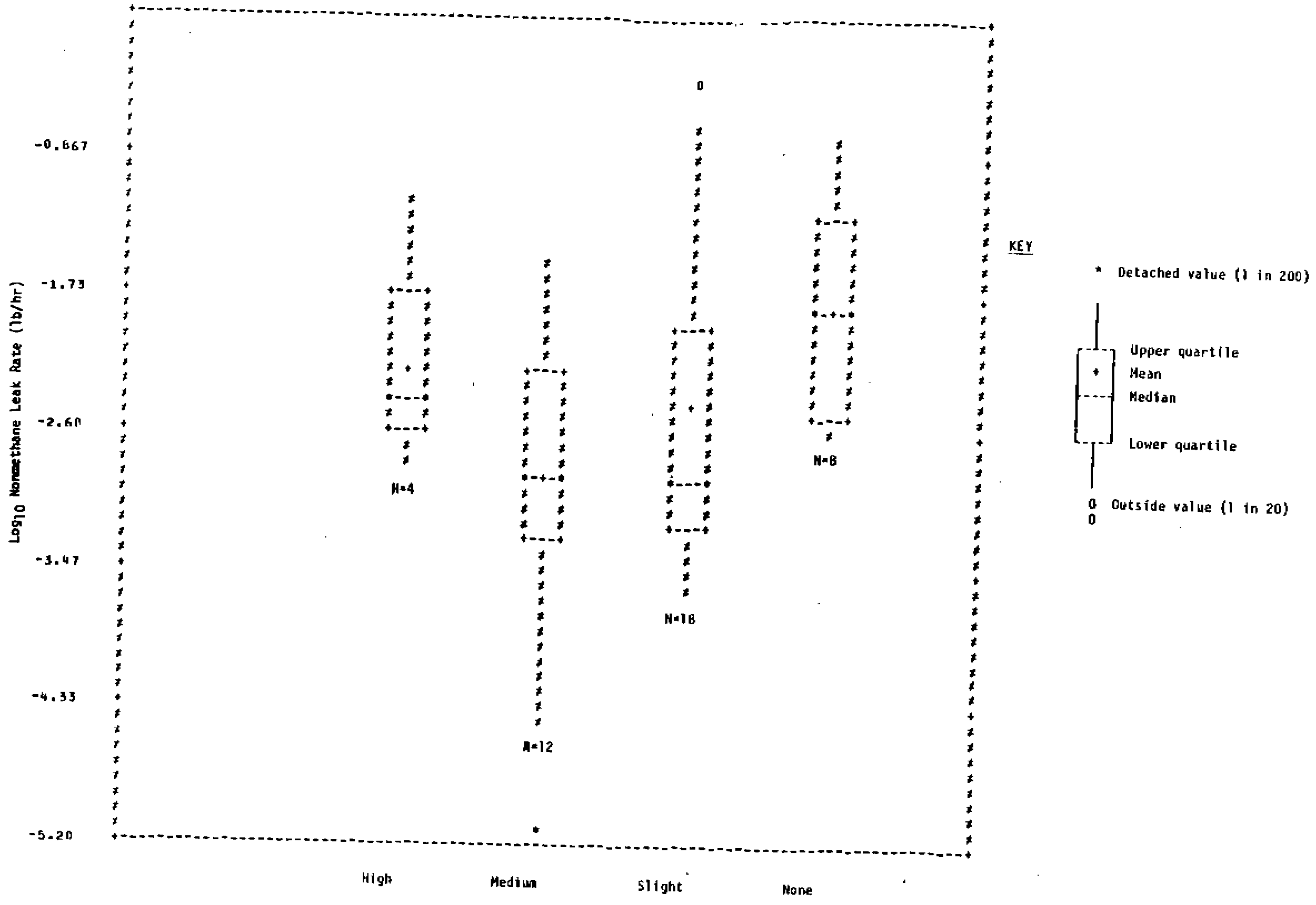


Figure B2-131. Schematic plot of flanges by vibration variable.

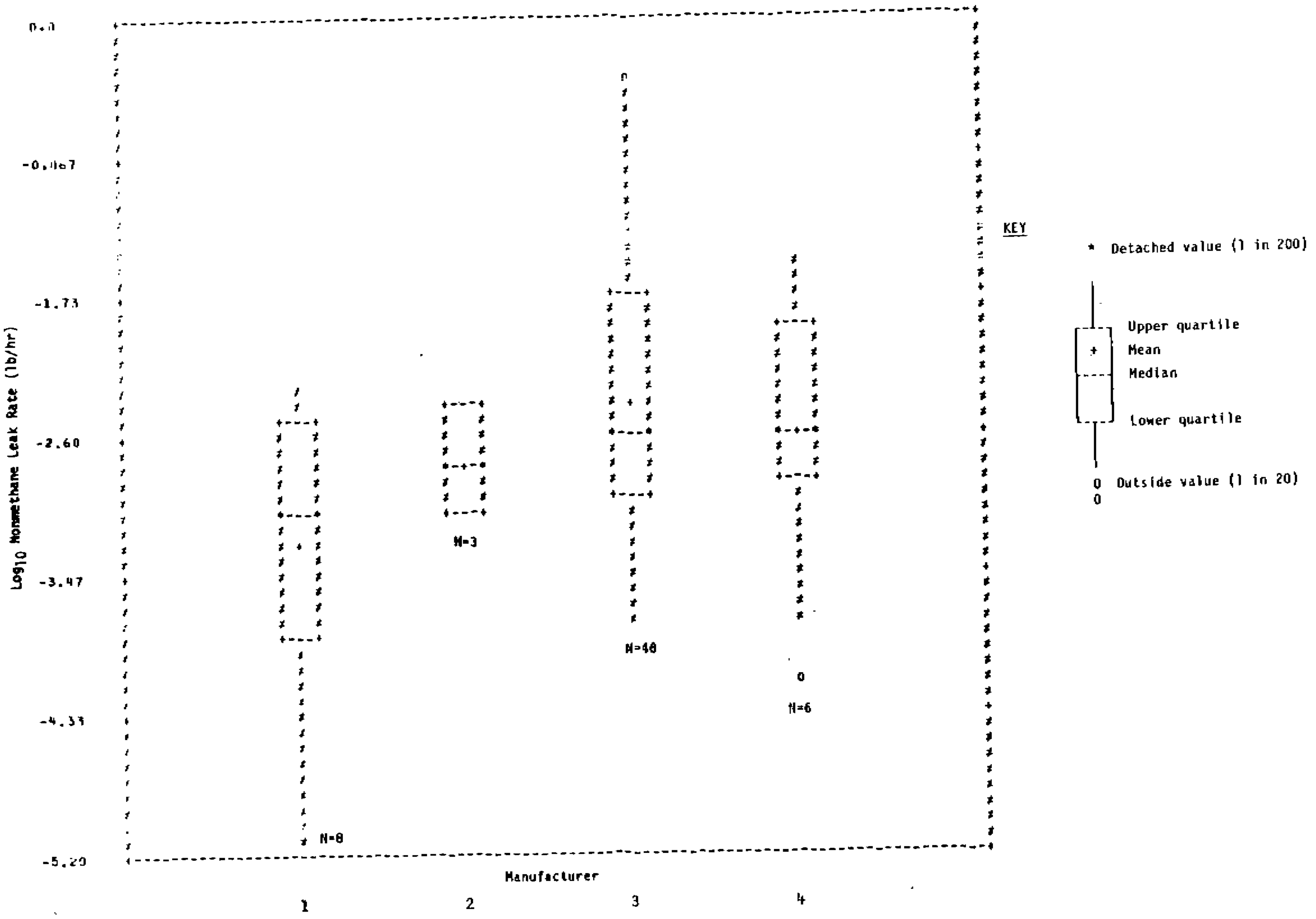


Figure B2-132. Schematic plot for flanges by manufacturer variable.

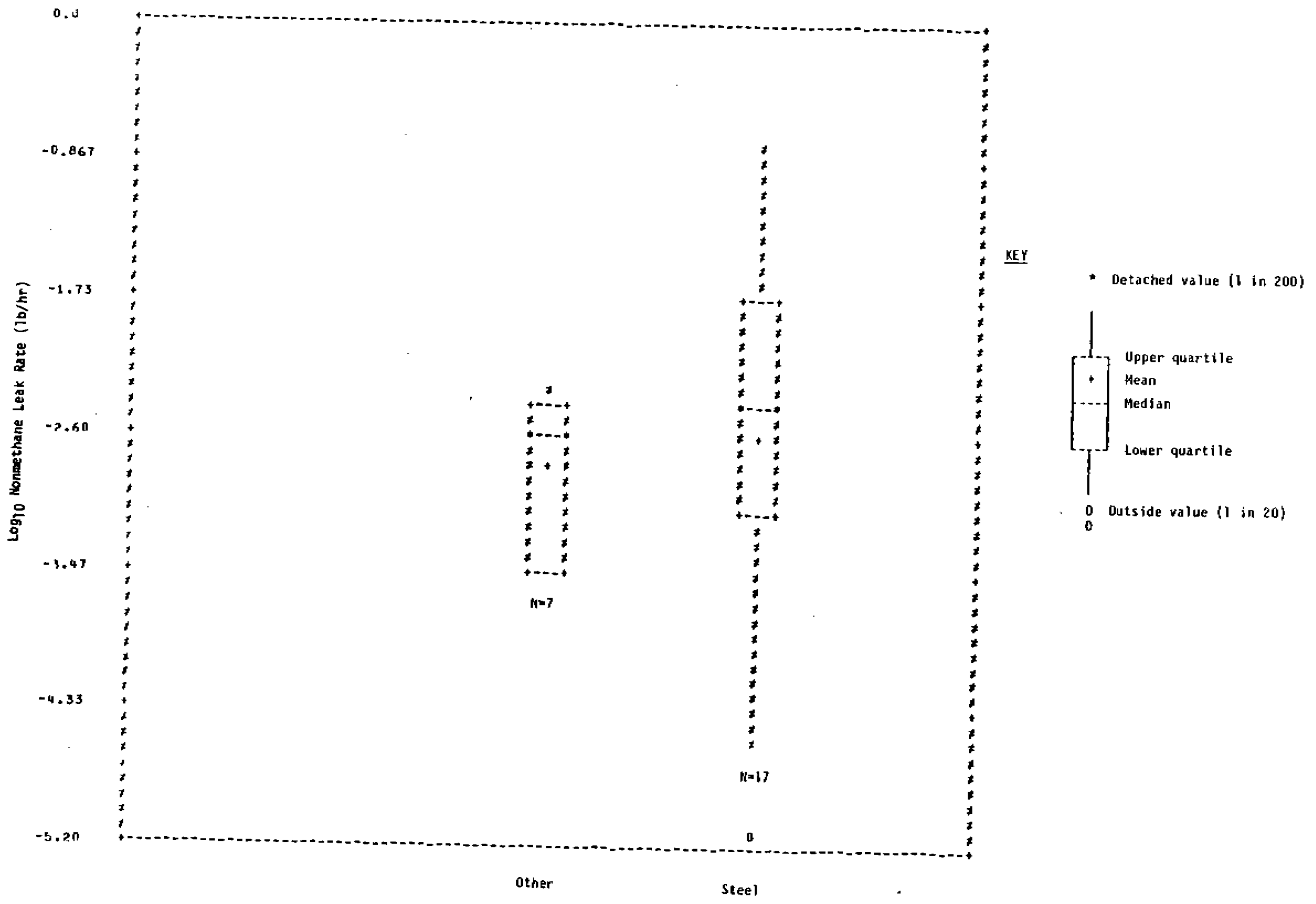


Figure B2-133. Schematic plot for flanges by gasket material variable.

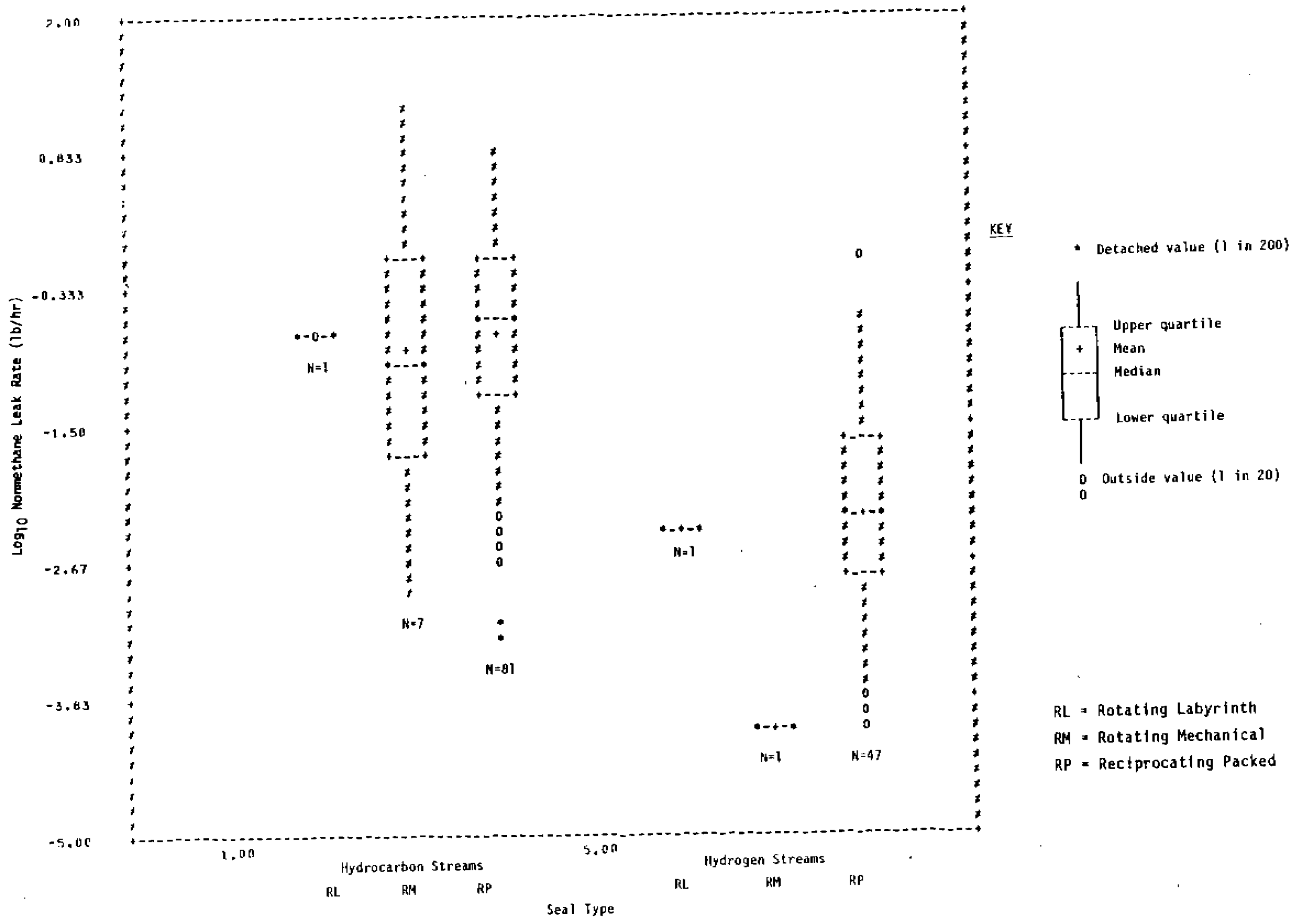


Figure B2-134. Schematic plot for compressor seals by seal type variable.

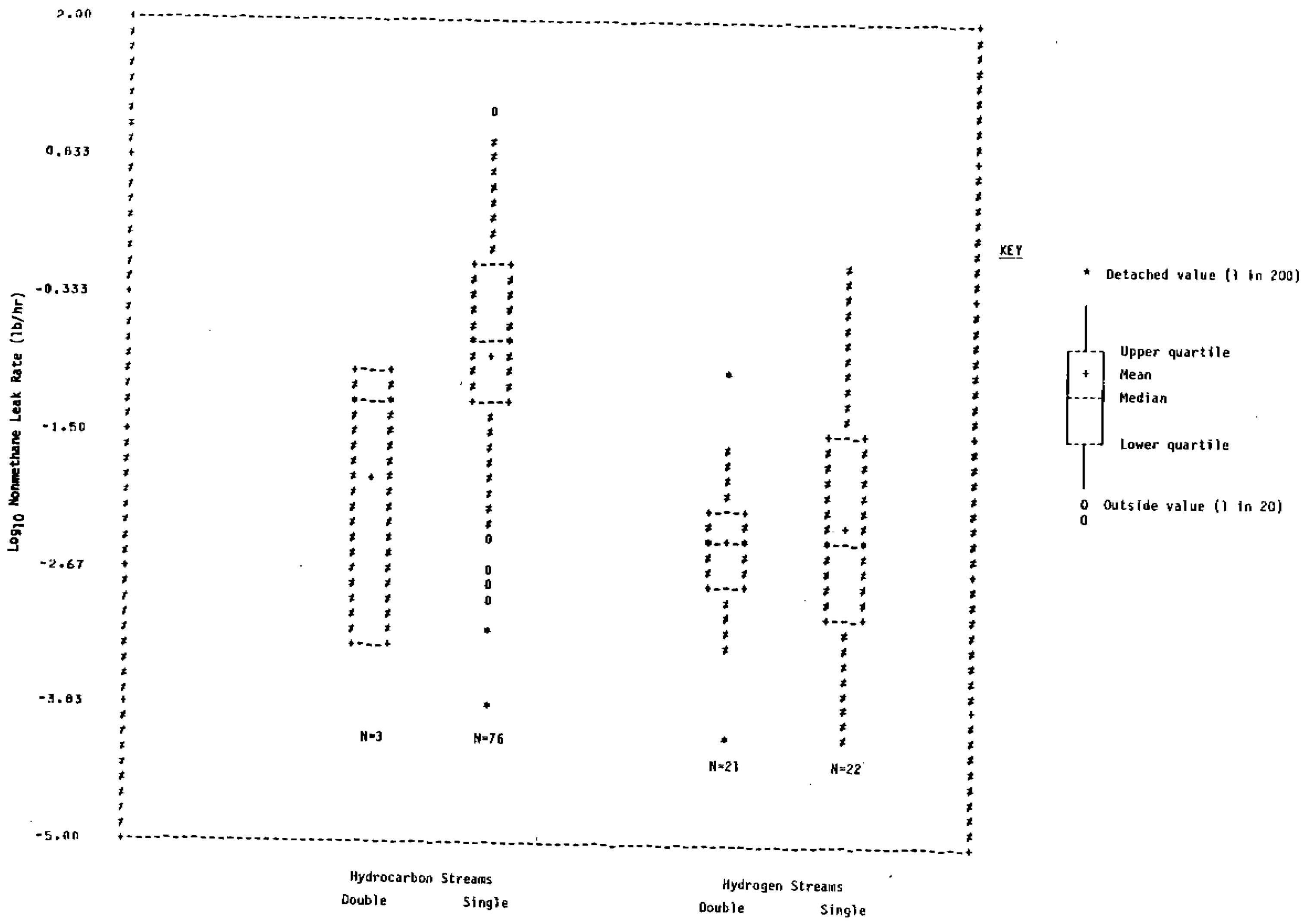


Figure B2-135. Schematic plot for compressor seals by single/double seal variable.

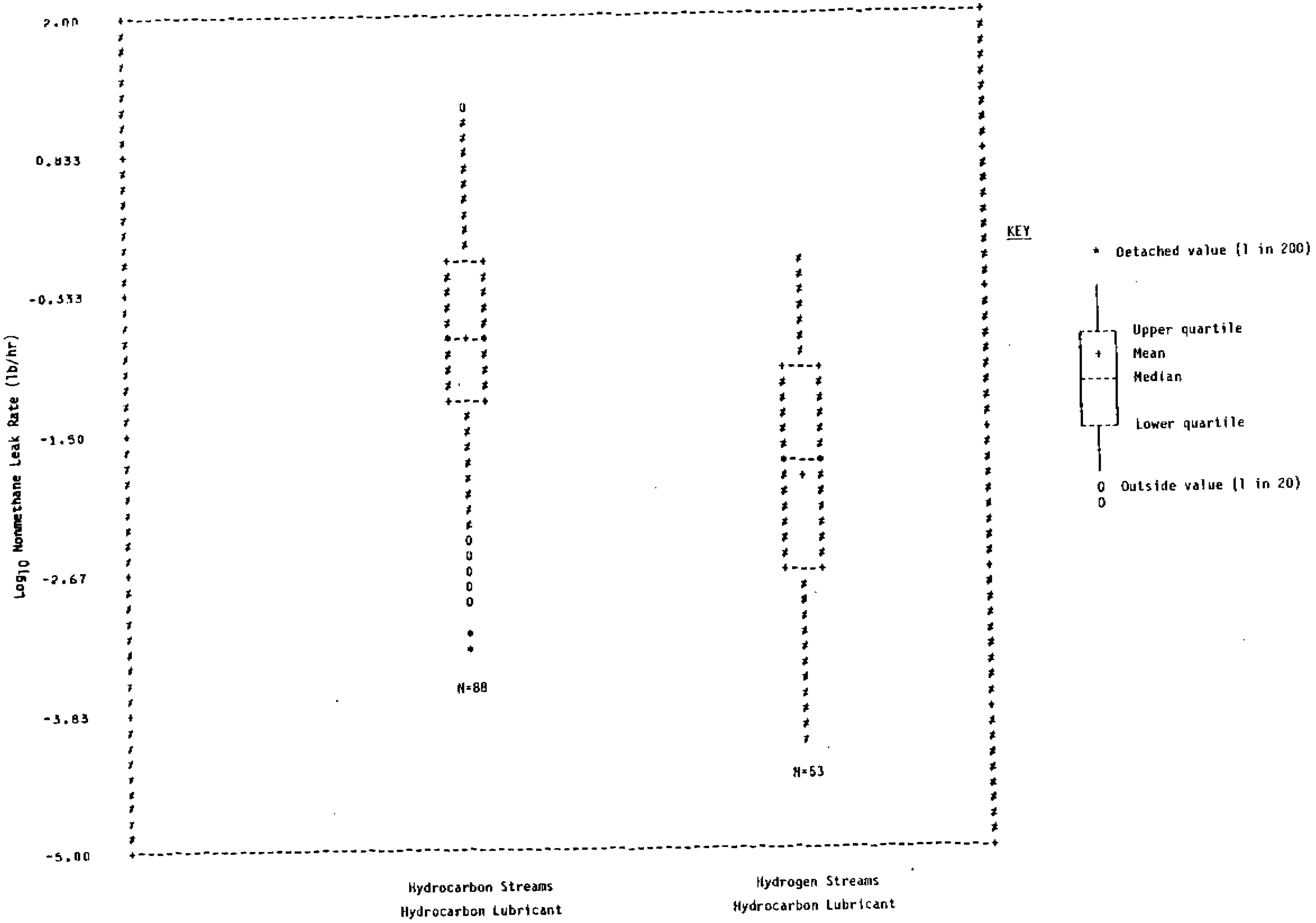


Figure B2-136. Schematic plot for compressor seals by lubricant variable.

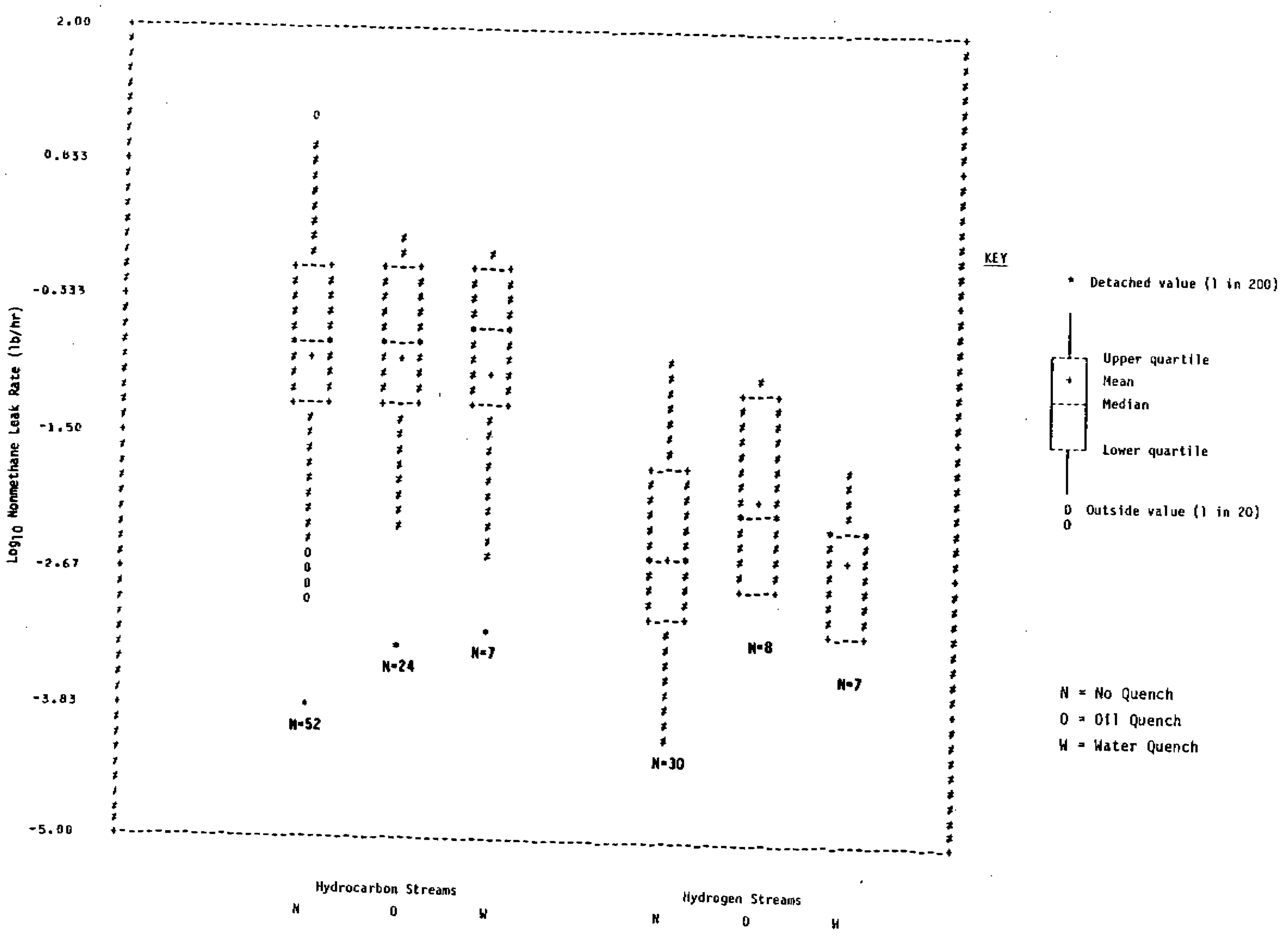


Figure B2-137. Schematic plot for compressor seals by gland type variable.

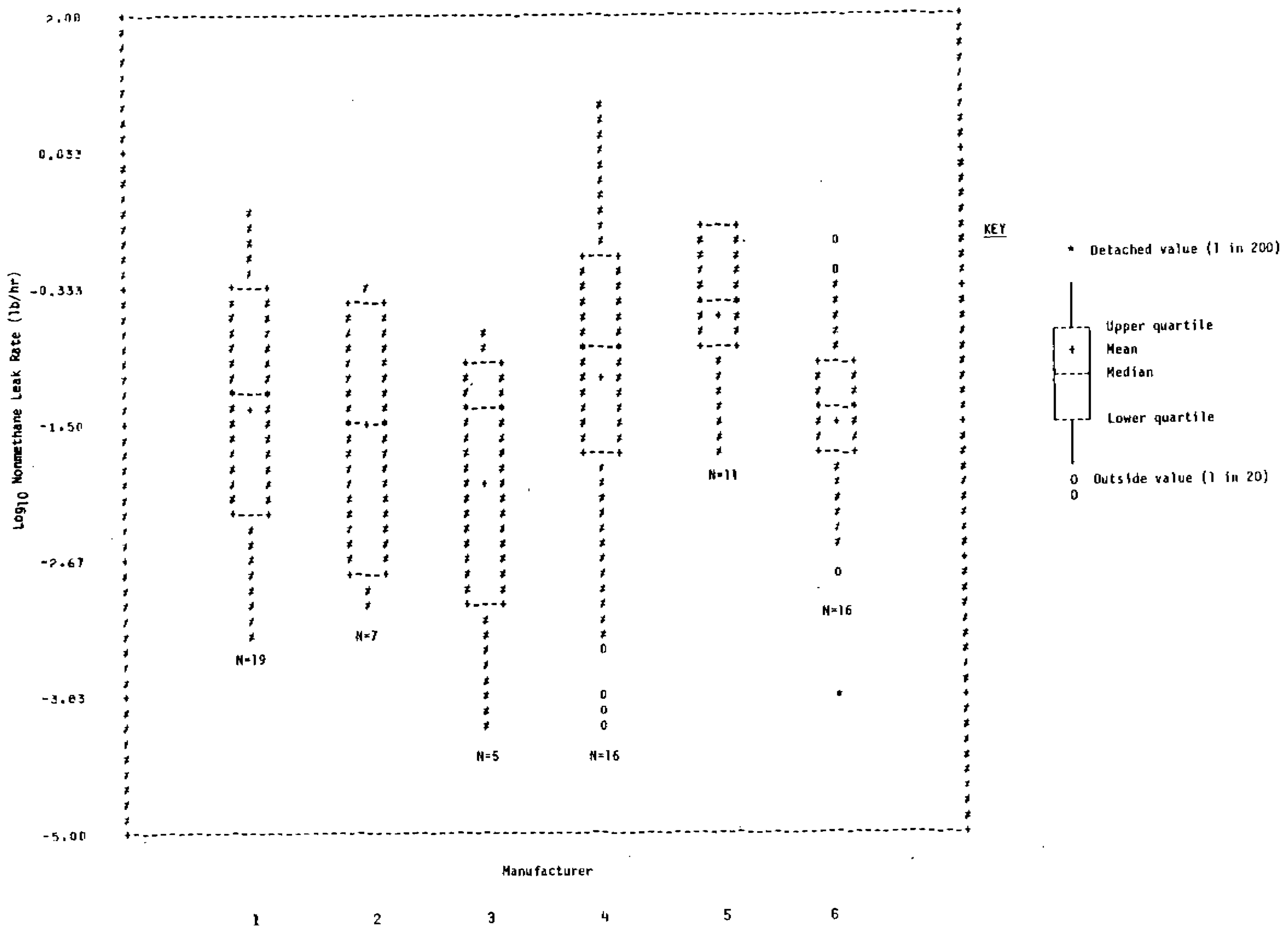


Figure B2-138. Schematic plot for compressor seals by manufacturer variable.

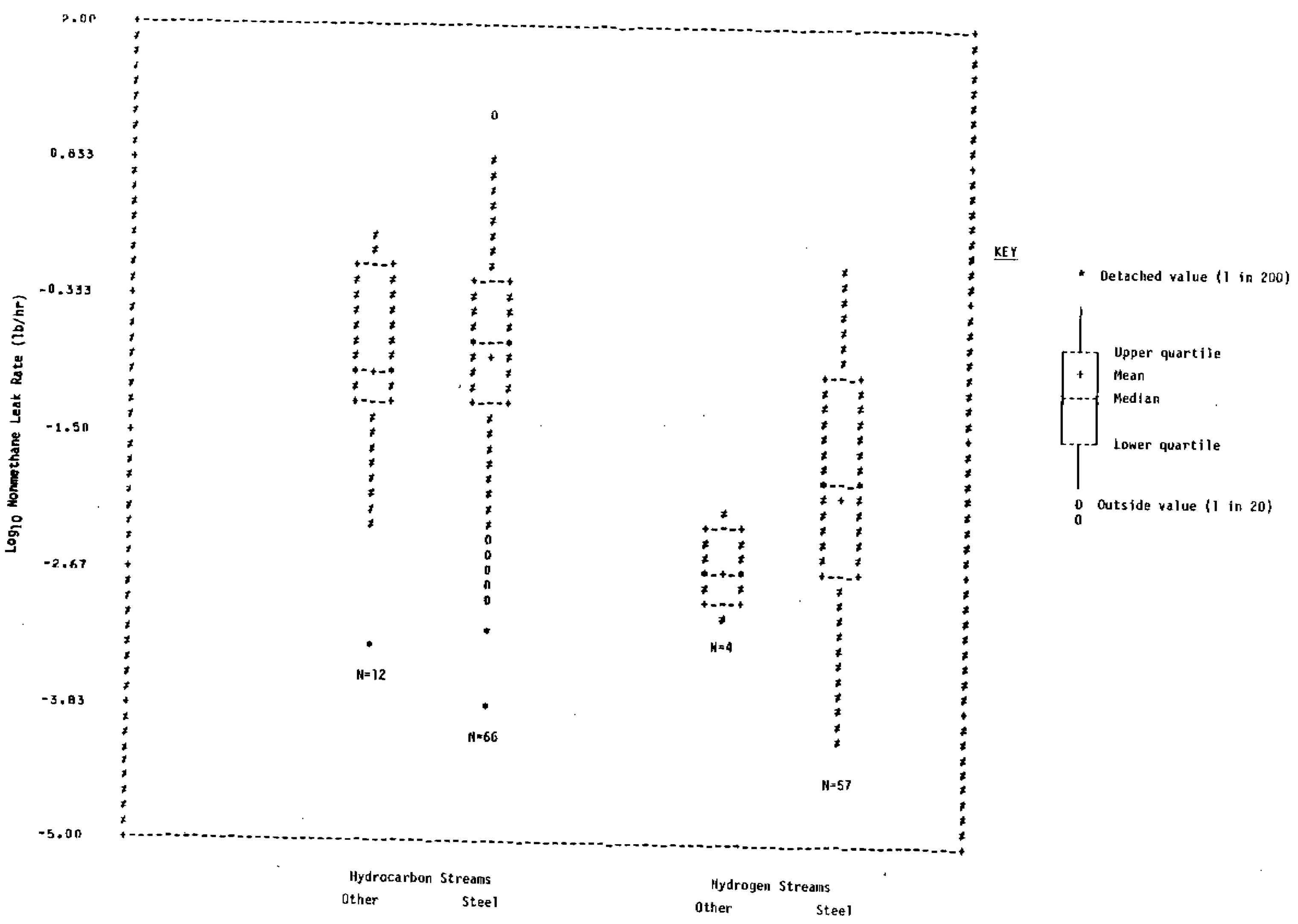


Figure B2-139. Schematic plot for compressor seals by material variable.

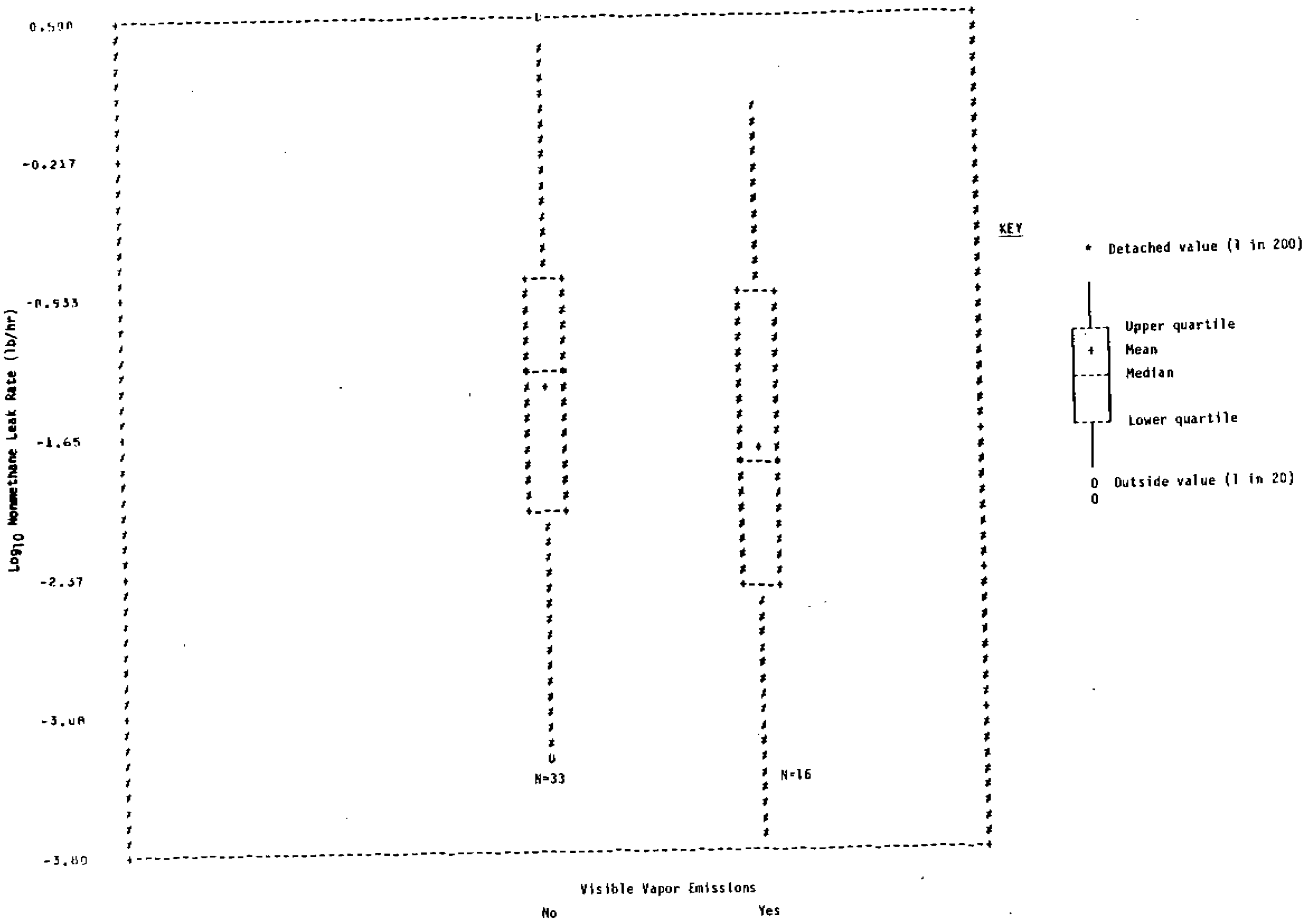


Figure B2-140. Schematic plot of drains by visible vapor variable.

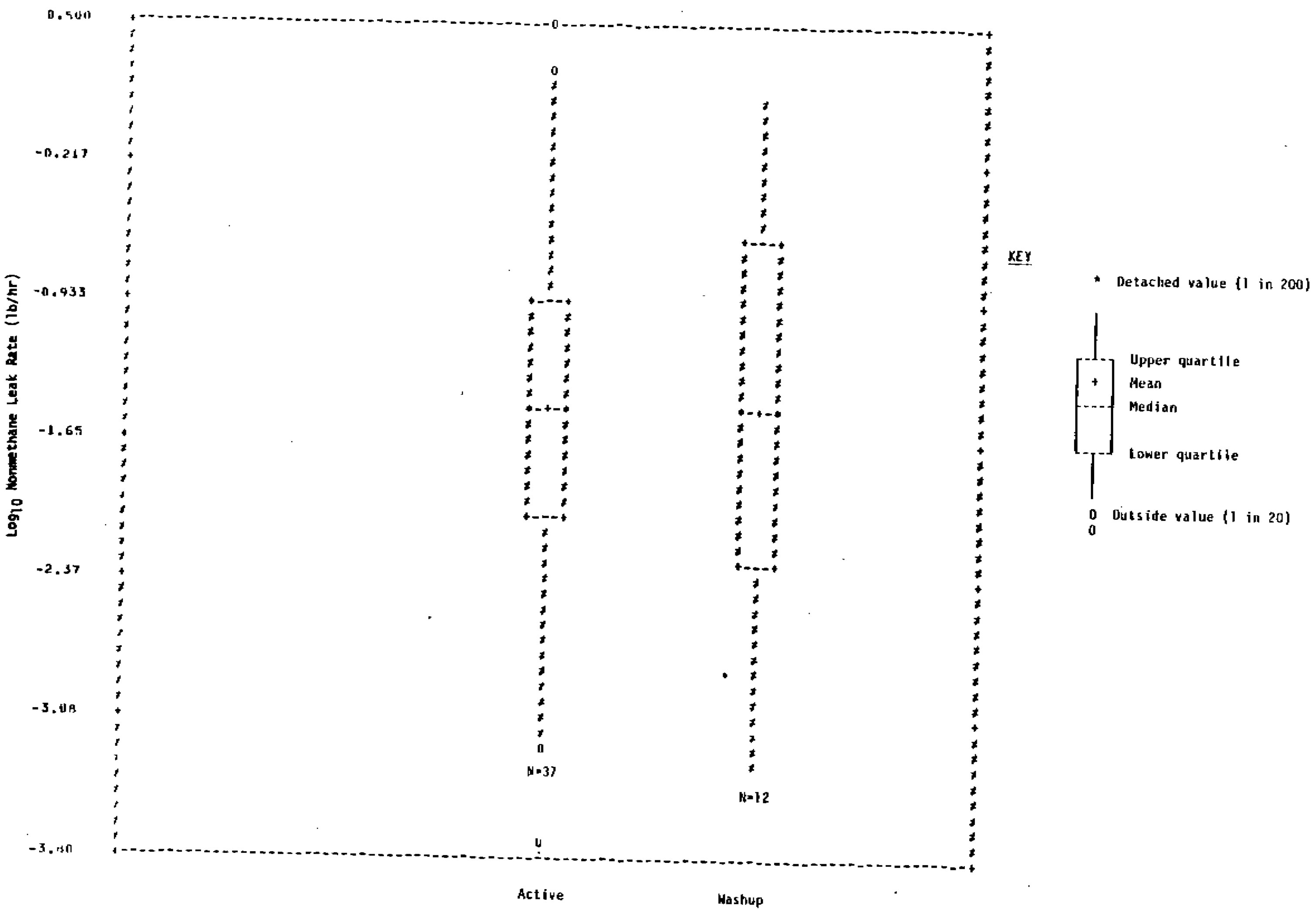


Figure B2-141. Schematic plot of drains by active/washup variable.

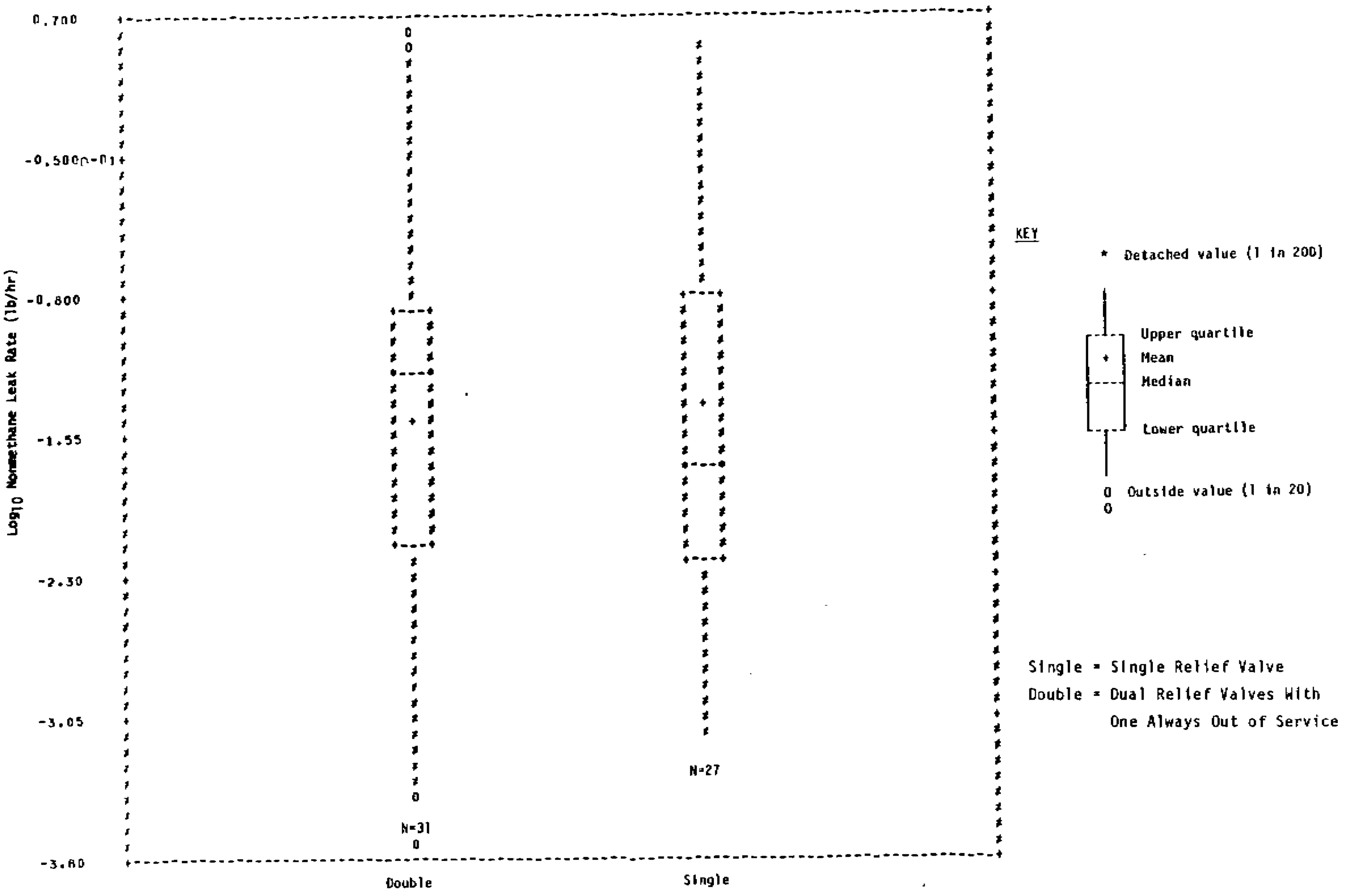


Figure B2-142. Schematic plot for relief valves by single/double variable.

2.5.3 Effect of Process Variables on Percent of Sources Leaking

Previous analysis has shown that the percent of sources leaking varies due to source type and process stream composition. This subsection examines the effect of other process variables on the percent of sources leaking. A leaking source is defined, for the purpose of this report, as a source with a screening value greater than 200 ppmv and/or a measured leak rate of greater than 10^{-5} lb/hr.

Tables B2-18 through B2-22 give the percent of sources leaking for the baggable source types grouped by the various process variables recorded during the study. The data are grouped by process stream type whenever appropriate. Note that the sum of the sources listed for each variable is not the same for all variable groups due to missing data for some sources. In some cases, the hydrogen stream data were omitted because of the small number of data points.

The data in Tables B2-18 through B2-22 are presented graphically for selected variables in Figures B2-143 through B2-183. Ninety-five percent confidence intervals are included in these graphs to define the precision of the percent leaking estimates. Source groupings with overlapping confidence intervals should not be considered statistically different in percent of sources leaking. A dotted line connecting the percent leaking estimate is shown on the graphs whenever it is appropriate to examine the trends portrayed.

TABLE B2-18. EFFECT OF PROCESS VARIABLES ON PERCENT OF VALVES LEAKING

Variable	Gas/Vapor Streams			Light Liquid/Two-Phase			Heavy Liquid Streams			Hydrogen Streams			Open End Valves		
	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking
Discrete Variables															
Manufacturer Code -															
1	53	16	30.2	131	62	47.3	92	1	1.1	8	5	62.5	6	0	0.0
2	102	25	24.5	142	43	30.2	62	4	6.4	24	11	45.8	1	0	0.0
3	12	3	25.0	21	8	38.1	12	1	8.3	7	4	57.1	0		
4	7	3	42.9	19	6	31.6	8	0	0.0	3	2	66.7	0		
5	23	9	39.1	46	19	41.3	31	1	3.2	8	4	50.0	0		
6	10	1	5.2	5	0	0.0	3	0	0.0	2	0	0.0	0		
7	226	61	27.0	367	129	35.2	182	16	8.9	56	25	44.6	102	26	25.4
8	87	25	28.7	137	50	36.5	76	7	9.2	13	5	38.5	16	4	25.0
9	22	6	27.3	35	13	37.1	18	2	11.1	2	2	100.0	3		
10	12	5	41.7	10	0	0.0	1	0	0.0	12	1	8.3	1		
Vibration -															
High	54	22	40.7	99	37	37.4	67	6	9.0	7	3	42.9	12	8	66.7
Moderate	104	19	18.3	235	77	32.7	84	7	8.3	32	13	40.6	21	6	28.6
Slight	269	69	25.6	374	127	34.0	196	11	5.6	78	34	43.6	12	4	33.3
None	48	14	29.1	20	7	35.0	26	2	7.7	6	1	16.7	61	7	11.5
Type of Valve -															
Butterfly	20	8	40.0	15	5	33.3	7	0	0.0	11	10	90.9	0		
Gate	309	91	29.4	593	223	37.6	331	1	0.3	70	32	45.7	102	22	21.5
Globe	156	41	26.3	262	89	34.0	110	4	3.6	36	15	41.7	6	3	50.0
Plug	72	14	19.4	35	9	25.7	23	0	0.0	17	2	11.8	19	5	26.3
Stem Type -															
Combination	37	5	13.5	70	21	30.0	24	0	0.0	6	1	16.7	46	12	26.1
In/Out	425	128	30.1	781	291	37.3	423	30	7.1	102	47	46.1	62	12	19.4
Rotation	94	21	22.3	53	15	28.3	29	2	6.9	26	11	42.3	20	6	30.0
Material -															
Other	43	15	34.9	60	24	40.0	21	3	14.3	6	4	66.7	3	0	0.0
Steel	518	138	26.6	847	304	35.9	460	29	6.3	129	55	42.6	126	30	23.8
Purpose -															
Block	390	105	26.9	650	237	36.5	353	24	6.8	114	47	41.2	128	30	23.4
Control	172	48	27.9	258	91	35.3	129	8	6.2	21	12	57.1	1	0	0.0

Continued

TABLE B2-18. Continued

Variable	Gas/Vapor Streams			Light Liquid/Two-Phase			Heavy Liquid Streams			Hydrogen Streams			Open End Valves		
	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking
Continuous Variables															
Pressure Range (psig) -															
0-50	247	49	19.3	161	35	26.7	172	9	5.2	9	4	44.4	53	13	24.5
51-100	71	20	28.2	156	41	26.3	76	6	7.9	19	3	15.8	19	8	42.1
101-150	44	16	36.4	111	46	41.4	79	5	6.3	5	2	40.0	11	3	27.3
151-200	91	35	38.5	131	59	45.0	43	2	4.7	0	0	0.0	13	1	7.7
201-250	37	12	32.4	97	44	45.4	28	4	14.3	11	9	81.8	10	1	10.0
251-300	31	11	35.5	77	31	40.3	22	1	4.6	19	12	63.2	8	2	25.0
301-400	16	3	18.8	96	46	47.9	20	1	5.0	13	8	61.5	7	2	28.6
401-500	21	6	28.6	23	8	34.8	5	0	0.0	13	6	46.2	1	0	0.0
>500	3	2	66.7	59	20	33.9	26	2	7.7	45	4	8.9	5	0	0.0
Temperature Range (°F) -															
<30	8	5	62.5	28	10	35.7	3	0	0.0	0	0	0.0	1	0	0.0
31-80	207	45	21.7	204	69	33.8	39	1	2.6	16	5	31.3	37	12	32.4
81-100	130	40	30.7	278	82	29.5	56	4	7.1	27	9	33.3	35	8	22.9
101-150	107	24	22.4	198	69	34.9	39	2	5.1	21	12	57.1	18	6	33.3
151-200	38	12	31.6	57	23	40.4	44	4	9.1	39	12	30.8	12	1	8.3
201-300	48	17	35.4	54	29	53.7	60	2	3.3	9	8	88.9	12	2	16.7
301-500	17	8	47.1	91	45	49.5	153	14	9.2	14	9	64.3	7	1	14.3
>500	8	3	37.5	2	2	100,0	88	4	4.6	8	3	37.5	5	0	0.0
Age Range (years) -															
<2	19	13	68.4	39	23	59.0	25	1	4.0	10	10	100.0	5	1	20.0
2.1-10	63	17	21.0	91	46	50.6	22	2	9.1	8	5	62.5	9	2	22.2
10.1-22	80	16	20.0	175	55	31.4	61	5	8.2	48	15	31.3	23	1	4.4
>22	142	35	24.6	123	55	44.7	106	9	8.5	8	3	37.5	25	7	28.0
Line Size Range (inches) -															
0-1.0	47	7	14.9	51	13	25.5	31	2	6.5	6	2	33.3	76	17	22.4
1.1-2.0	121	31	25.6	221	67	30.3	93	3	3.2	35	11	31.4	19	3	15.8
2.1-3.0	91	28	30.8	216	70	32.4	96	7	7.3	38	11	29.0	8	2	25.0
3.1-5.0	79	22	27.9	182	77	42.3	87	5	5.8	14	8	57.1	1	0	0.0
5.1-9.0	114	37	32.5	171	79	46.2	119	10	8.4	27	15	55.6	0		
9.1-13.0	33	10	30.3	40	13	32.5	45	4	8.9	2	2	100.0	0		
>13.1	43	18	41.9	5	3	60.0	7	0	0.0	9	8	88.9	0		

TABLE B2-19. EFFECT OF PROCESS VARIABLES ON PERCENT OF PUMP SEALS LEAKING

Variable		Light Liquid Streams			Heavy Liquid Streams		
		Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking
Discrete Variables							
Pump Seal Attitude -	Horizontal	378	237	62.7	253	59	23.3
	Vertical	90	63	70.0	31	6	19.4
Type of Seal -	Centrifugal/Mechanical	404	264	65.4	217	48	22.1
	Centrifugal/Packed	37	17	46.0	50	15	30.0
	~~Centrifugal~~/Packed Reciprocating	25	17	68.0	23	3	13.0
Seal -	Double Seal	73	38	52.0	69	9	13.0
	Single Seal	356	233	65.4	198	54	27.3
Seal Lubricant -	Hydrocarbon	122	87	71.3	112	23	20.5
	Product Leakage	285	176	61.8	107	24	22.4
	Water	42	25	59.5	57	13	22.8
Manufacturer Code -	A	39	24	61.5	14	6	42.9
	B	43	29	67.4	20	5	25.0
	C	68	36	52.9	45	5	11.1
	D	87	54	62.1	59	14	23.7
	E	117	88	75.2	68	18	26.5
	F	49	23	46.9	22	3	13.6
	G	13	9	69.2	23	1	4.4
	H	8	7	87.5	3	0	0.0
Seal -	Inboard Seal	327	198	60.6	187	41	21.9
	Outboard Seal	45	26	57.8	42	8	19.0
Gland Type -	No Quench Gland	186	115	61.8	59	14	23.7
	Oil Quench	84	50	59.5	35	2	5.7
	Water Quench	103	63	61.2	125	27	21.6

Continued

TABLE B2-19. Continued

Variable		Light Liquid Streams			Heavy Liquid Streams		
		Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking
<u>Continuous Variables</u>							
Discharge Pressure Range (psig) -	0-50	73	27	37.0	61	11	18.0
	51-100	54	31	57.4	49	13	26.5
	101-150	59	42	71.2	53	10	18.9
	151-200	39	23	59.0	34	6	17.6
	251-300	47	33	70.2	18	5	27.8
	301-350	67	50	74.6	21	5	23.8
	351-400	64	47	73.4	25	13	52.0
	401-500	18	14	77.8	4	1	25.0
	>500	40	25	62.5	21	2	9.5
Temperature Range (°F) -	<80	138	78	56.5	29	4	13.8
	81-100	127	86	67.7	24	8	33.3
	101-150	86	49	57.0	27	1	3.7
	151-300	55	37	67.3	43	14	32.6
	301-500	54	42	77.8	79	23	29.1
	>500	4	3	75.0	85	16	18.8
Capacity Range (GPM) -	0-100	64	35	54.7	29	6	20.7
	101-200	39	27	69.2	27	5	18.5
	201-400	109	69	63.3	20	9	45.0
	401-800	84	51	60.7	42	11	26.2
	801-1000	20	12	60.0	45	8	17.8
	1001-1500	33	25	75.8	19	4	21.0
	1501-2500	28	19	67.9	0	2	22.2
	>2500	26	22	84.6	30	9	30.0
Shaft Diameter Range (inches) -	0-0.5	142	98	69.0	63	9	14.3
	0.6-1.0	59	40	67.8	25	3	12.0
	1.1-1.5	148	82	55.4	81	26	32.1
	1.6-2.0	83	60	72.3	108	24	22.2
	>2.0	24	16	66.7	4	1	25.0

Continued

TABLE B2-19. Continued

Variable		Light Liquid Streams			Heavy/Liquid Streams		
		Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking
RPM or Strokes PM Range –	0-1000	9	9	100.0	20	3	15.0
	1001-2000	46	33	71.7	35	10	28.6
	2001-4000	232	154	66.4	145	34	23.4
	4001-7000	1	1	100.0	0		
	7001-10,000	2	2	100.0	0		
	>10,000	2	2	100.0	0		
Age Range (years)	0-2.0	23	9	39.1	18	5	27.8
	2.1-3.0	16	13	81.2	0		
	3.1-8.0	36	20	55.6	30	7	23.3
	8.1-15	137	94	68.6	68	19	27.9
	>15	16	12	75.0	17	8	47.1

TABLE B2-20. EFFECT OF PROCESS VARIABLES ON PERCENT OF COMPRESSOR SEALS LEAKING

Variable		Hydrocarbon Streams Number Screened	Hydrocarbon Streams Number Leaking	Hydrocarbon Streams Percent Leaking	Hydrogen Streams Number Screened	Hydrogen Streams Number Leaking	Hydrogen Streams Percent Leaking
Material -	Other	12	12	100.0	4	4	100.0
	Steel	103	66	64.1	68	55	80.9
Lubricant -	Hydrocarbon	125	88	70.4	61	51	83.6
Gland Type -	No Quench	62	52	83.9	34	28	82.4
	Oil Quench	44	24	54.6	9	8	88.9
	Water Quench	14	7	50.0	10	7	70.0
Seal -	Double	5	3	60.0	27	20	74.1
	Single	111	76	68.5	26	21	80.8
In/Out Service -	In-Service	85	74	87.1	40	36	90.0
	Out-of-Service	2	2	100.0	9	8	88.9
Seal Type -	Rotating/Labyrinth	10	1	10.0	1	1	100.0
	Rotating/Mechanical	21	7	33.3	2	0	0.0
	Reciprocal/Packed	93	81	87.1	52	46	88.5
Cylinder Load Range (%) -	0-85	17	17	100.0	13	6	46.2
	86-95	13	13	100.0	0		
	96-100	15	14	93.3	21	0	0.0
RPM or Strokes PM Range -	0-200	33	28	84.9	0		
	201-400	50	46	92.0	48	45	93.8
	401-600	8	7	87.5	8	8	100.0
	601-800	0	0	0.0	1	0	0.0
	>800	31	12	38.7	11	4	36.4

Continued

TABLE B2-20. Continued

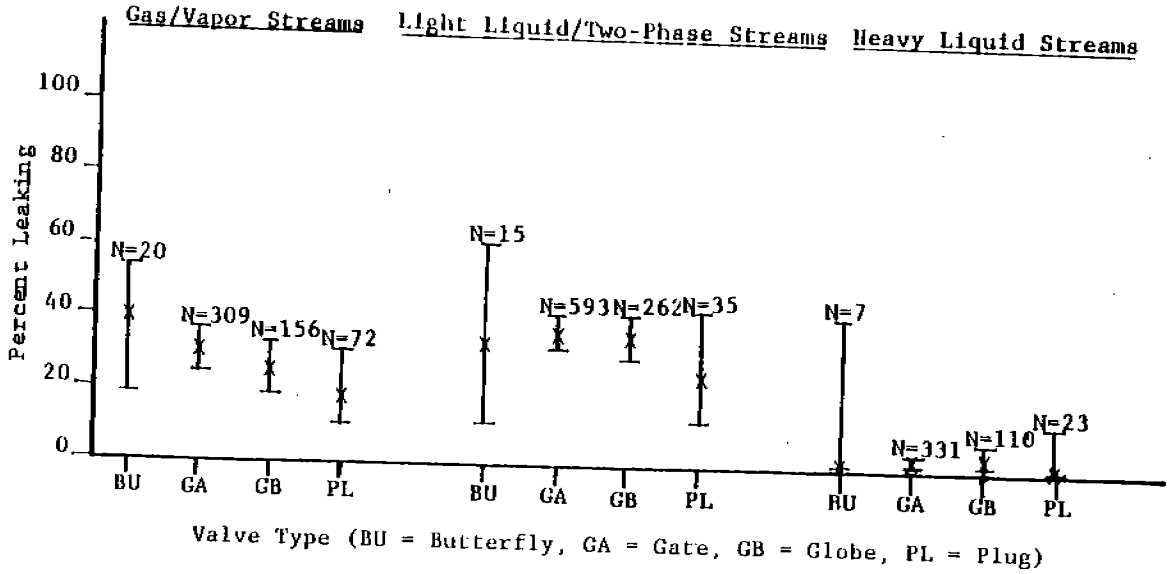
Variable		Hydrocarbon Streams			Hydrogen Streams		
		Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking
Shaft Diameter Range (inches)	<1.5	2	2	100.0	0		
	1.6-2.0	50	42	84.0	9	7	77.8
	2.1-3.0	27	26	96.0	15	14	93.3
	>3.1	21	18	85.7	7	6	85.7
Capacity Range (MM SCFD)	0-20	52	37	71.2	20	16	80.0
	21-40	4	1	25.0	9	7	77.8
	41-60	3	1	33.3	3	1	33.3
	61-80	0			9	8	89.9
	>80	3	3	100.0	0		
Pressure Range (psig)	0-100	44	30	68.2	2	1	50.0
	101-200	38	28	73.7	1	1	100.0
	201-300	53	43	81.1	0		
	301-500	1	1	100.0	15	13	86.7
	501-700	1	0	0.0	24	23	95.8
	>700	0			28	22	78.6
Temperature Range (°F)	0-100	17	8	47.1	7	6	85.7
	101-150	45	39	86.7	23	20	87.0
	151-200	39	29	74.4	25	18	72.0
	>200	38	26	68.4	14	13	92.9
Age Range (years)	0.-3.0	16	16	100.0	13	11	84.6
	3.1-20	32	25	78.1	18	15	83.3
	20-30	30	25	83.3	19	18	94.7
	>30	22	22	100.0	0		

TABLE B2-21. EFFECT OF PROCESS VARIABLES ON PERCENT OF FLANGES LEAKING

Variable	Gas/Vapor Streams			Light Liquid/Two-Phase			Heavy Liquid Streams		
	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking
Special Service -									
Orifice Plate	6	0	0.0	29	2	6.9	14	1	7.1
Vessel/Exchange	33	2	6.1	74	6	8.1	30	0	0.0
Vibration -									
High	27	1	3.7	20	2	10.0	9	1	11.1
Moderate	54	3	5.6	197	8	4.1	52	0	0.0
Slight	200	3	1.5	305	9	3.0	203	1	0.5
None	72	1	1.4	46	5	10.9	43	1	2.3
Type -									
Flat Face	182	2	1.1	273	13	4.8	192	1	0.5
Floating Head	3	0	0.0	33	5	15.2	17	0	0.0
Raised Face	124	5	4.0	182	5	2.8	64	2	3.1
Threaded	29	1	3.5	78	2	2.6	30	0	0.0
Weld	2	0	0.0	9	0	0.0	1	0	0.0
Gasket Material -									
Other	167	0	0.0	160	6	3.8	222	1	0.5
Steel	73	2	2.7	277	12	4.3	32	1	3.1
Manufacturer Code -									
A	40	0	0.0	101	3	3.0	40	0	0.0
B	13	1	7.7	15	0	0.0	13	0	0.0
C	4	0	0.0	22	0	0.0	15	0	0.0
D	12	0	0.0	7	0	0.0	3	0	0.0
E	12	0	0.0	54	0	0.0	35	1	2.9
F	14	0	0.0	0			0		
G	15	0	0.0	32	0	0.0	15	0	0.0
H	0			17	0	0.0	15	0	0.0
I	13	0	0.0	3	0	0.0	2	0	0.0
J	14	0	0.0	0			1	0	0.0
K	30	2	6.7	111	4	3.6	62	0	0.0
L	23	0	0.0	11	0	0.0	8	0	0.0

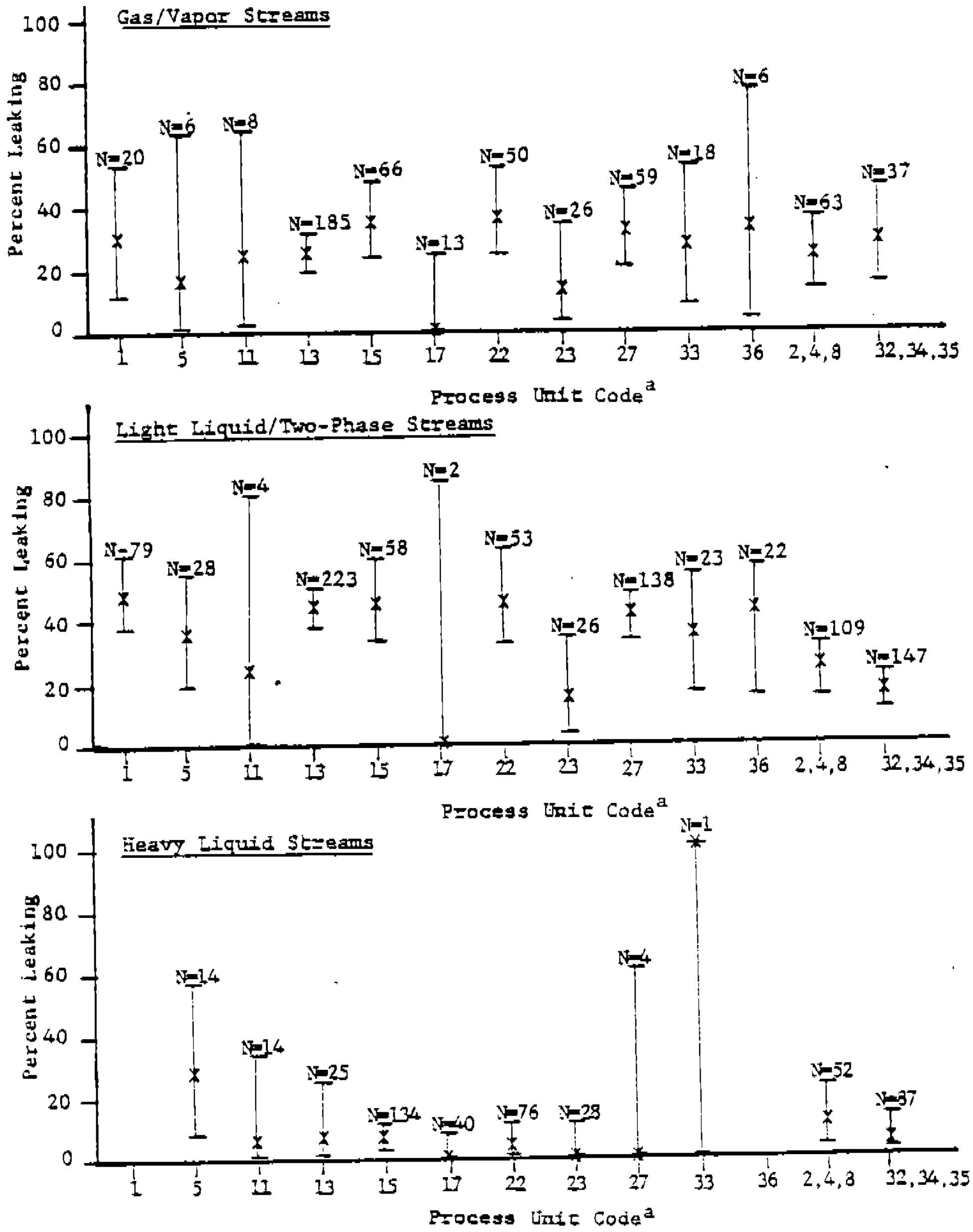
TABLE B2-22. EFFECT OF PROCESS VARIABLES ON PERCENT OF RELIEF VALVES LEAKING

Variable	Number Screened	Number Leaking	Percent Leaking
All Stream Types			
Vent to Atmosphere	109	53	48.6
Vent to Flare	16	2	12.5
Gas/Vapor Streams			
Dual Valve	26	21	80.8
Single Valve	66	21	31.8
Light Liquid/Two-Phase Streams			
Dual Valve	8	2	25.0
Single Valve	20	5	25.0
Heavy Liquid Streams			
Dual Valve	17	8	47.1
Single Valve	6	0	0.0
Pressure Range (psig)			
0-50	39	7	18.0
51-100	29	16	55.2
101-200	26	12	46.2
>200	25	9	36.0
Temperature Range (°F)			
0-100	43	17	39.5
101-200	36	19	52.8
>200	37	10	27.0
Line Size Range (inches)			
<4.0	53	13	24.5
>4.0	82	37	45.1



N = Number of Sources Screened

Figure B2-143. Selected Categories of Valves - effect of valve type on percent leaking.



N = Number of Sources Screened

Figure B2-144. Selected Categories of Valves - effect of process unit type on percent leaking.

[a]See Table B2-24 for unit codes.

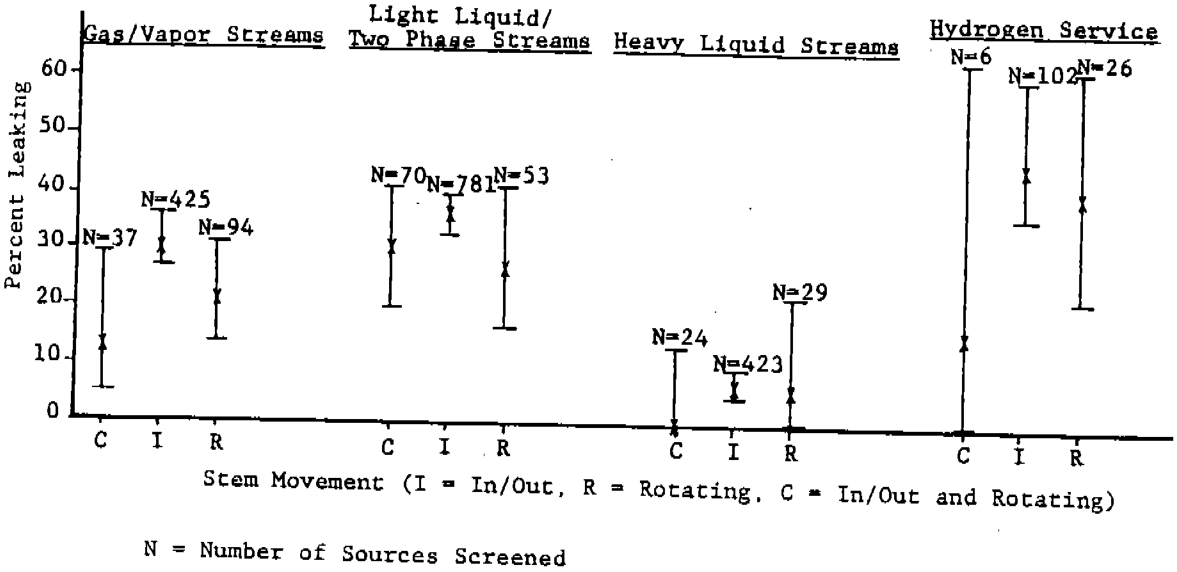


Figure B2-145. Selected Categories of Valves - effect of stem movement on percent of valves leaking

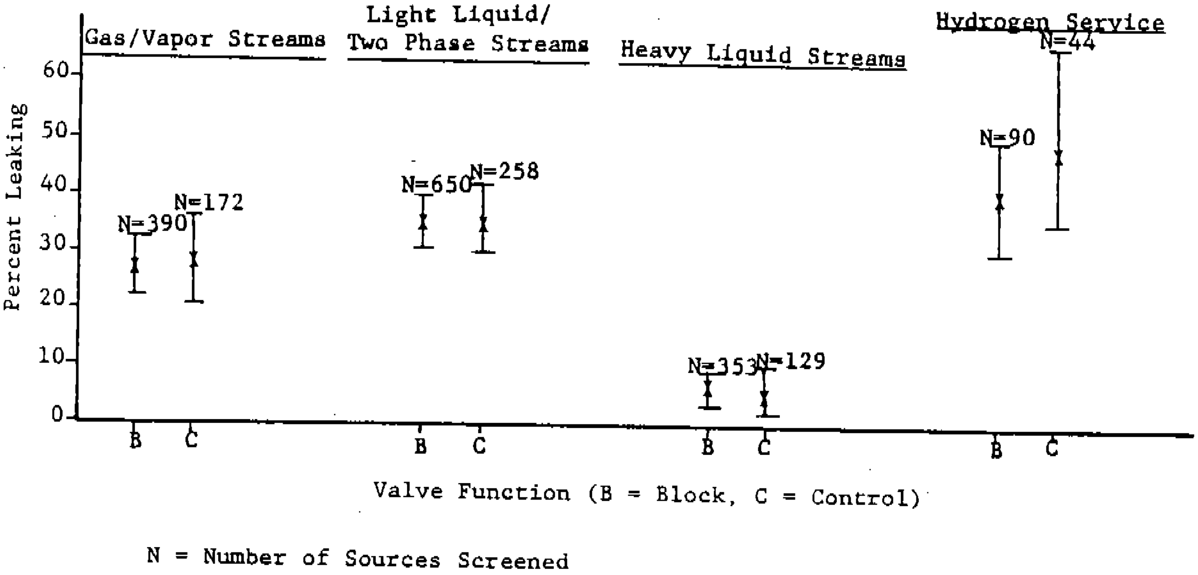
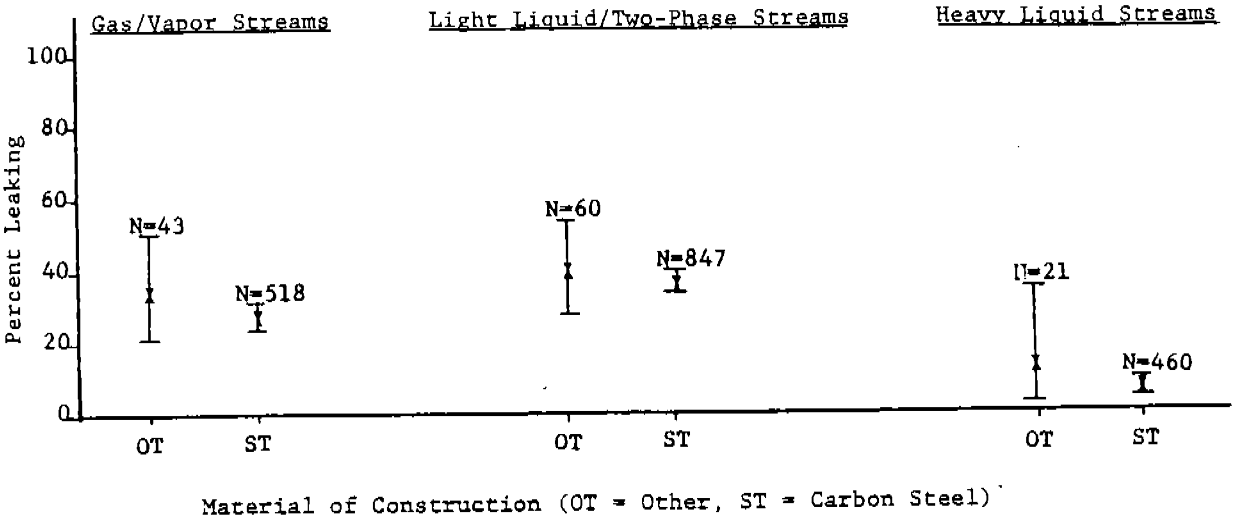
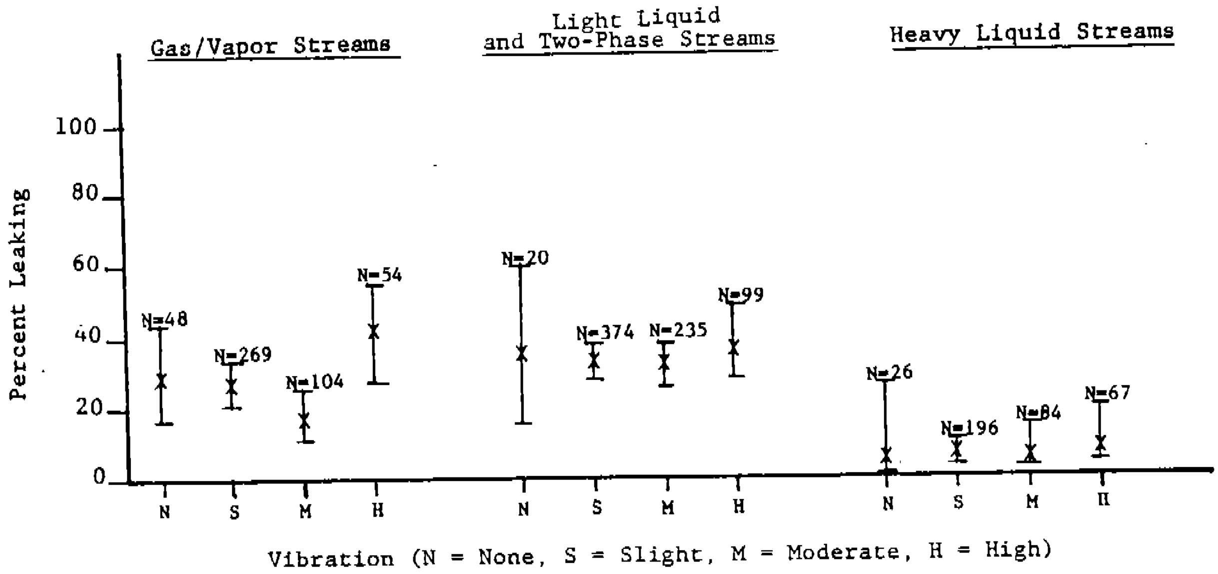


Figure B2-146. Selected Categories of Valves - effect of valve function on percent of valves leaking



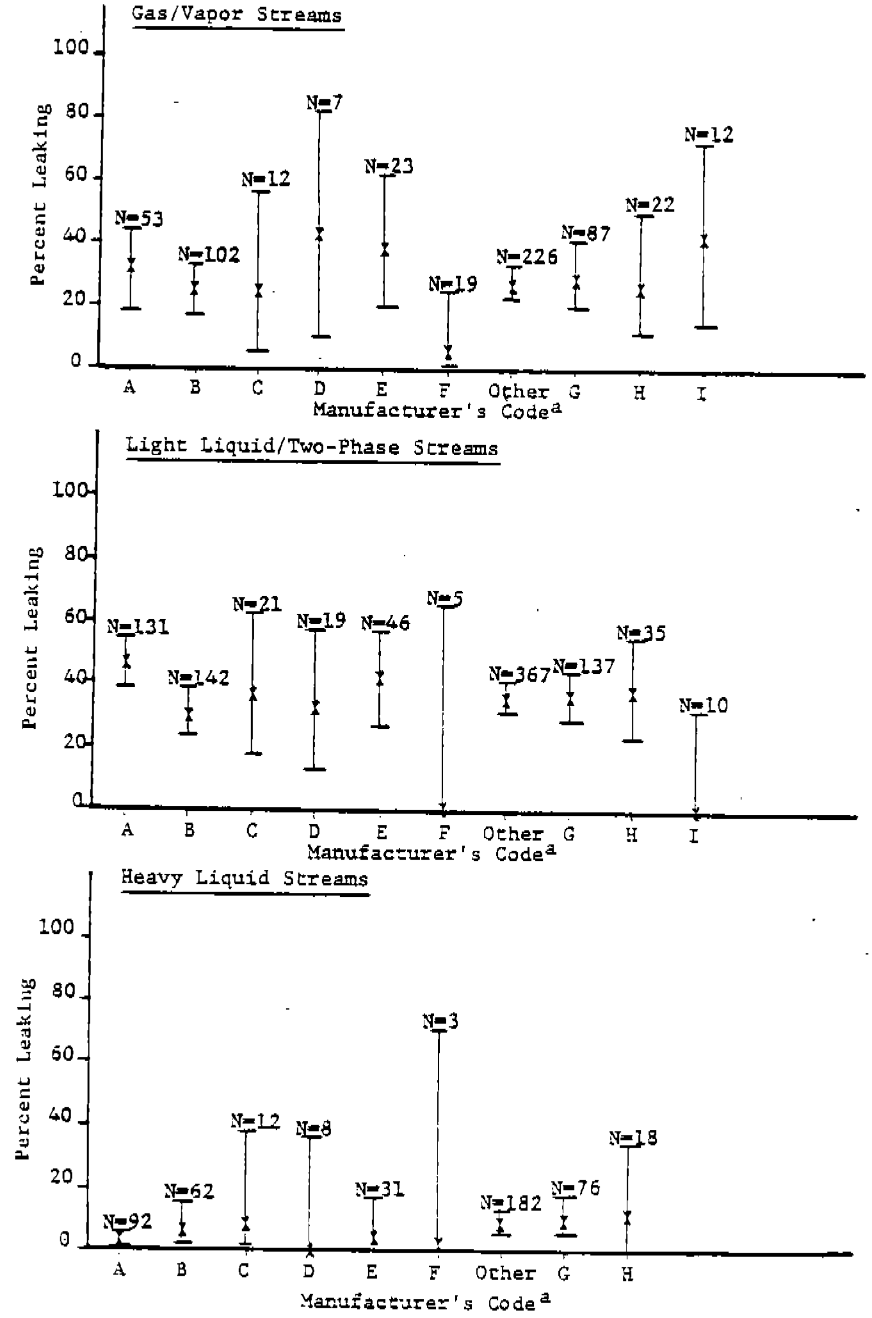
N = Number of Sources Screened

Figure B2-147. Selected Categories of Valves - effect of materials of construction on percent of valves leaking.



N = Number of Sources Screened

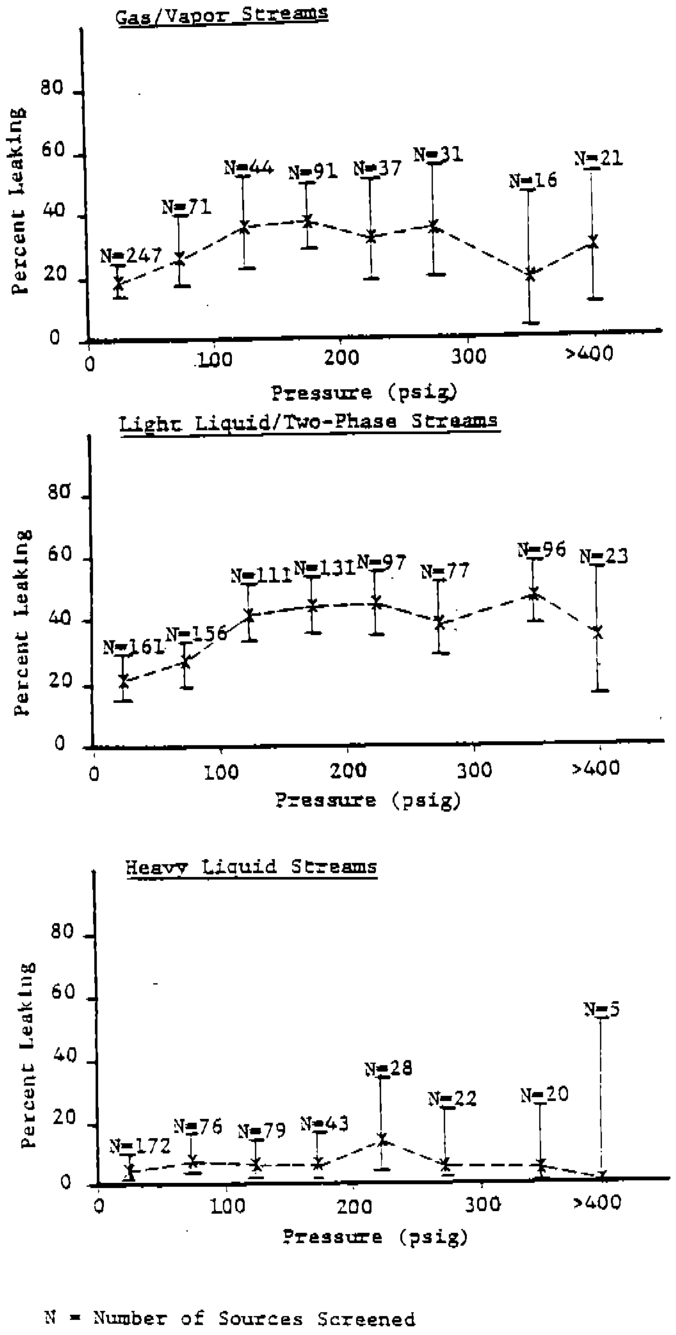
Figure B2-148. Selected Categories of Valves - effect of valve vibration on percent of valves leaking.



N = Number of Sources Screened

Figure B2-149. Selected Categories of Valves - effect of valve brand on percent of valves leaking.

[a] Codes are arbitrary as to not identify particular manufacturers. Only manufacturers with a significant number of valves are broken out.



Gas/Vapor Streams

Light Liquid/Two-Phase Streams

Heavy Liquid Streams

N = Number of Sources Screened

Figure B2-150. Selected Categories of Valves - effect of pressure on percent of valves leaking.

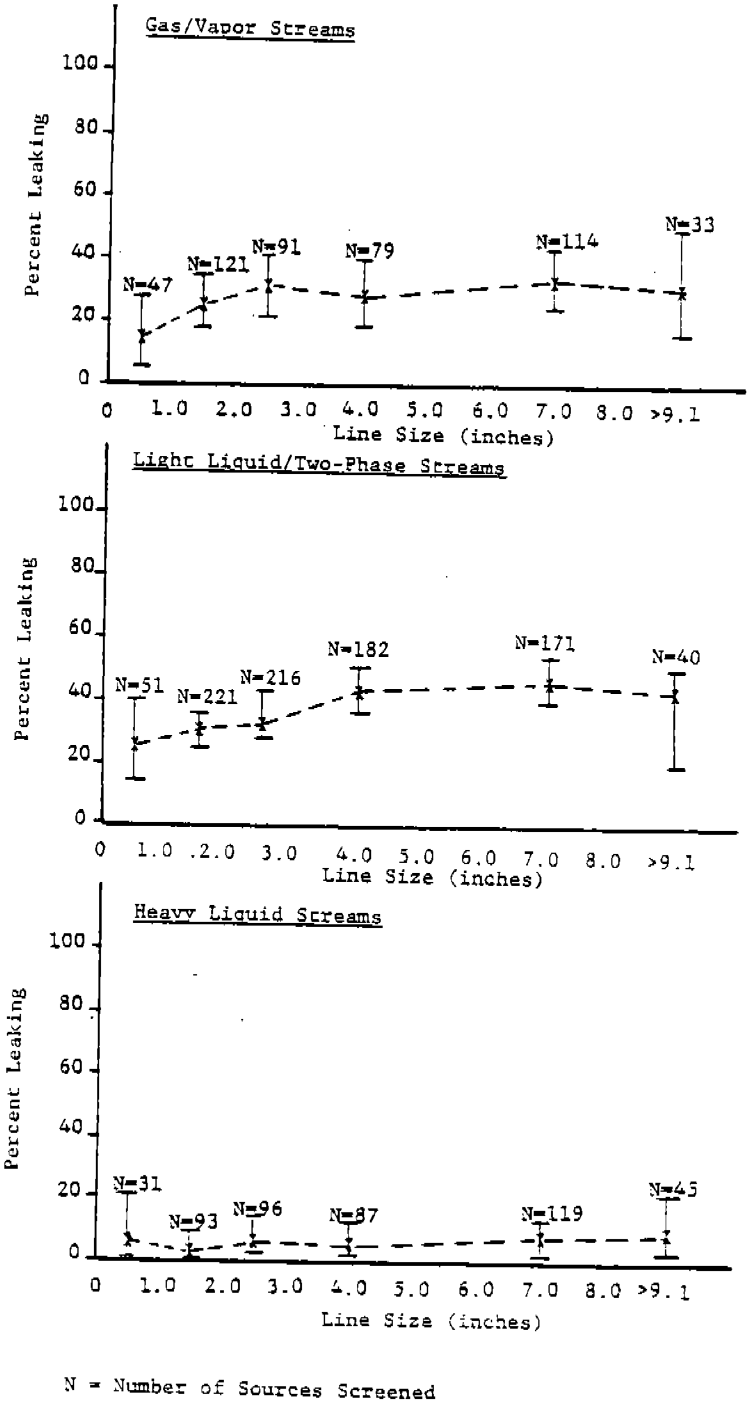


Figure B2-151. Selected Categories of Valves - effect of line size on percent of valves leaking.

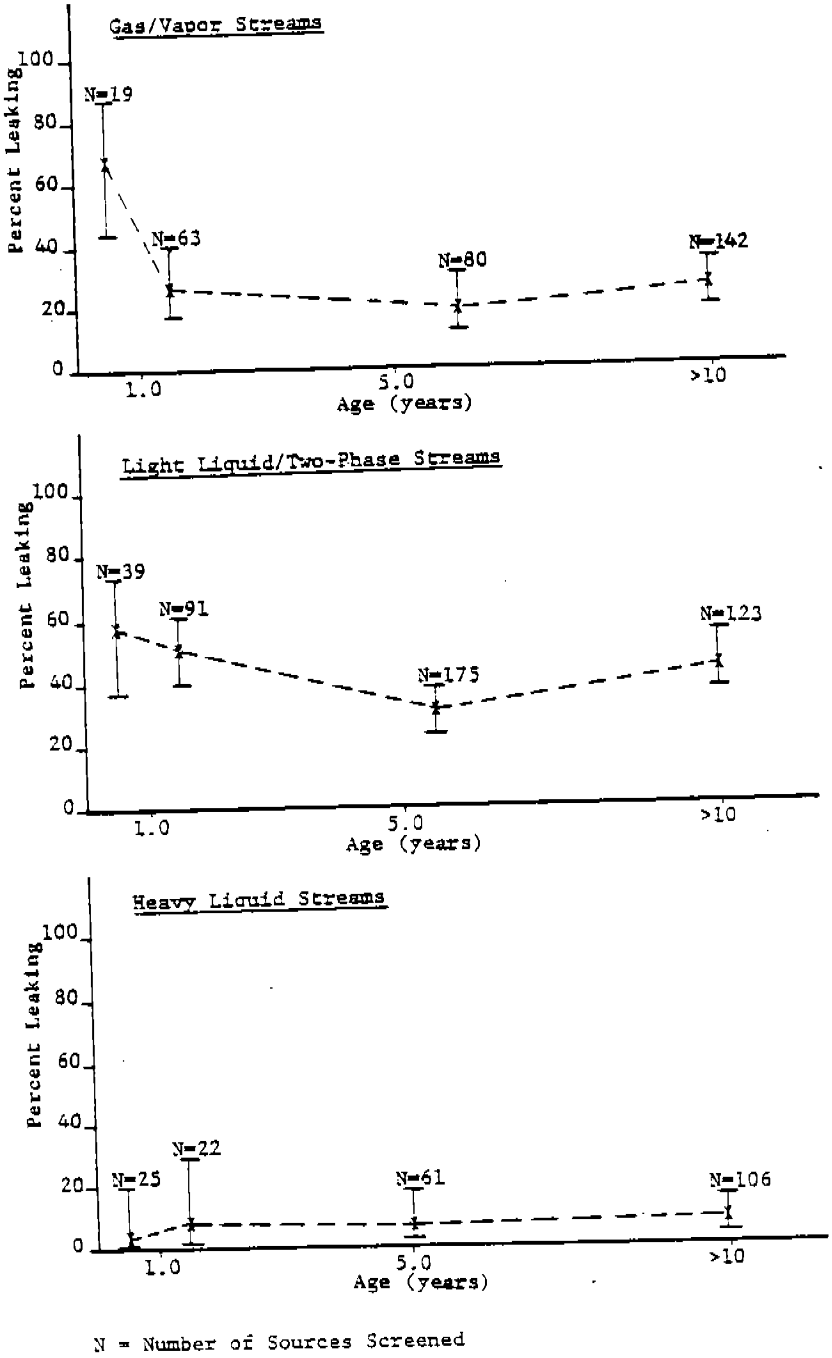


Figure B2-152. Selected Categories of Valves - effect of age on percent of sources leaking.

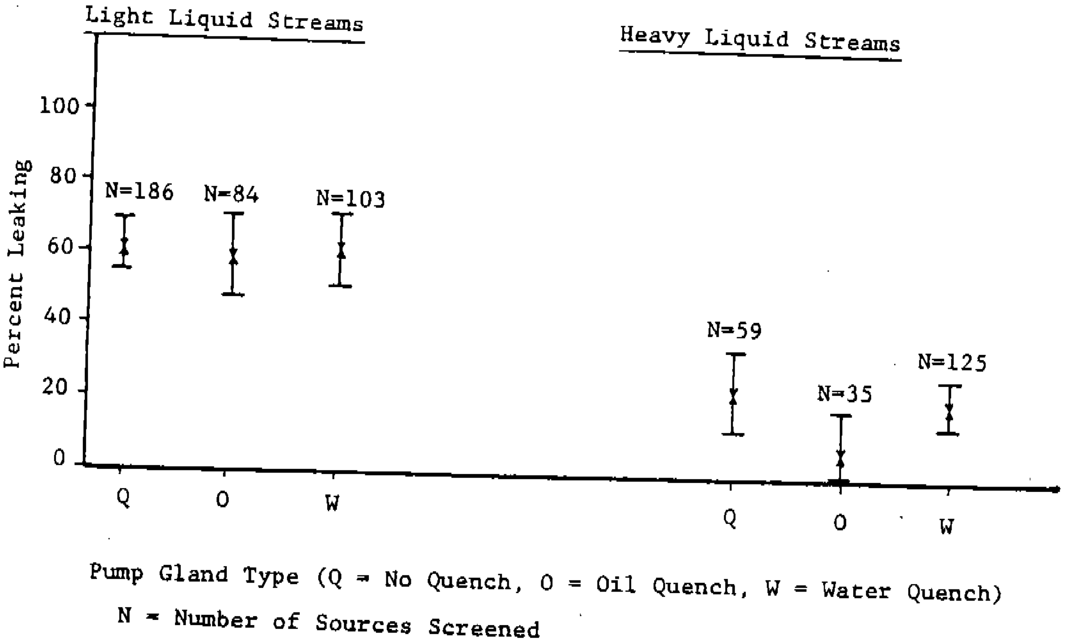


Figure B2-153. Pumps - effect of gland type on percent of pump seals leaking.

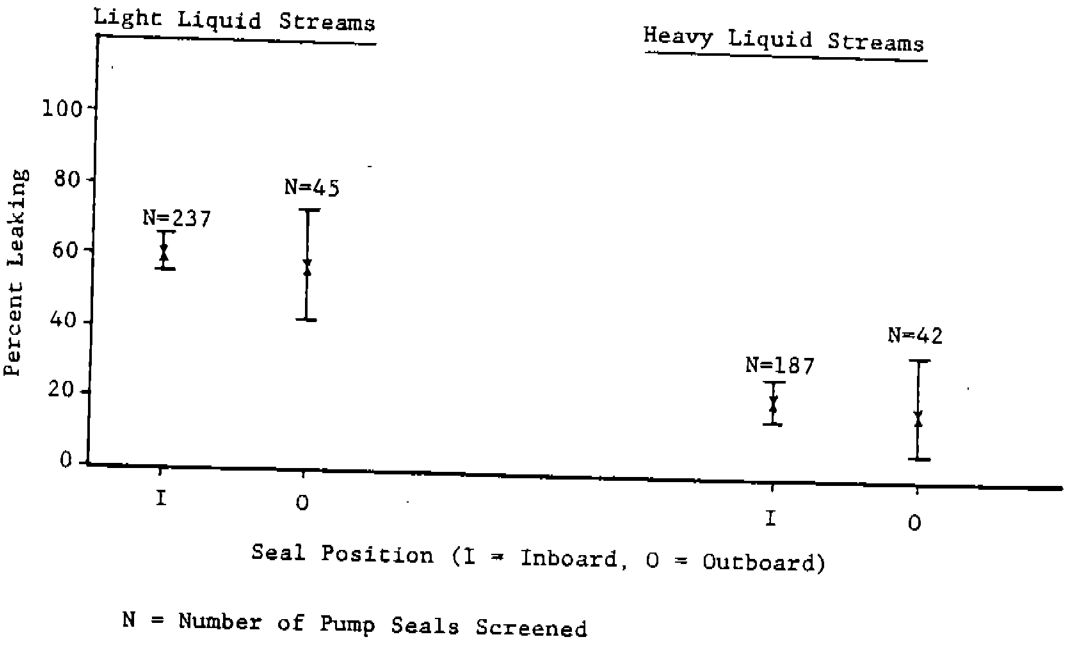
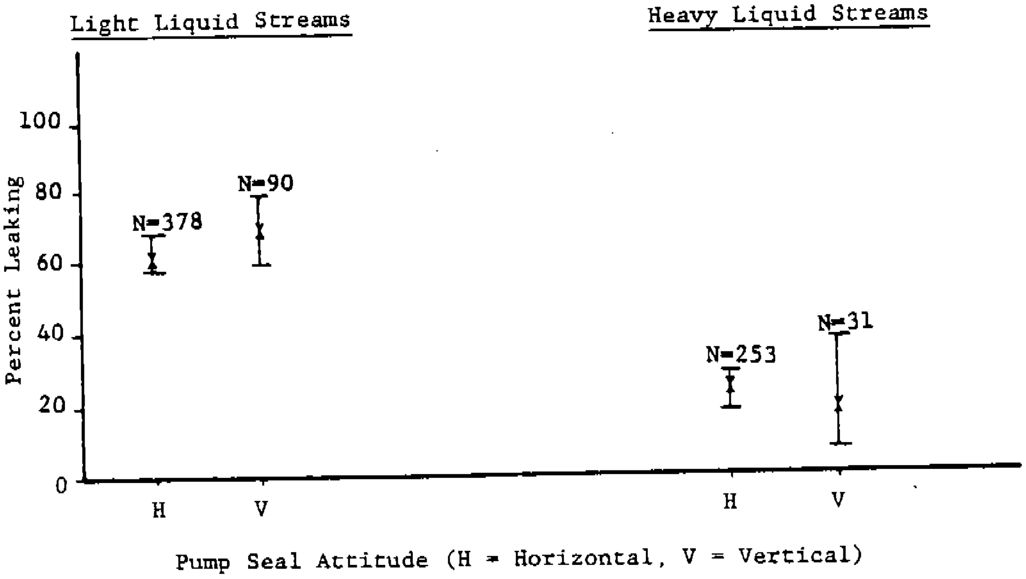
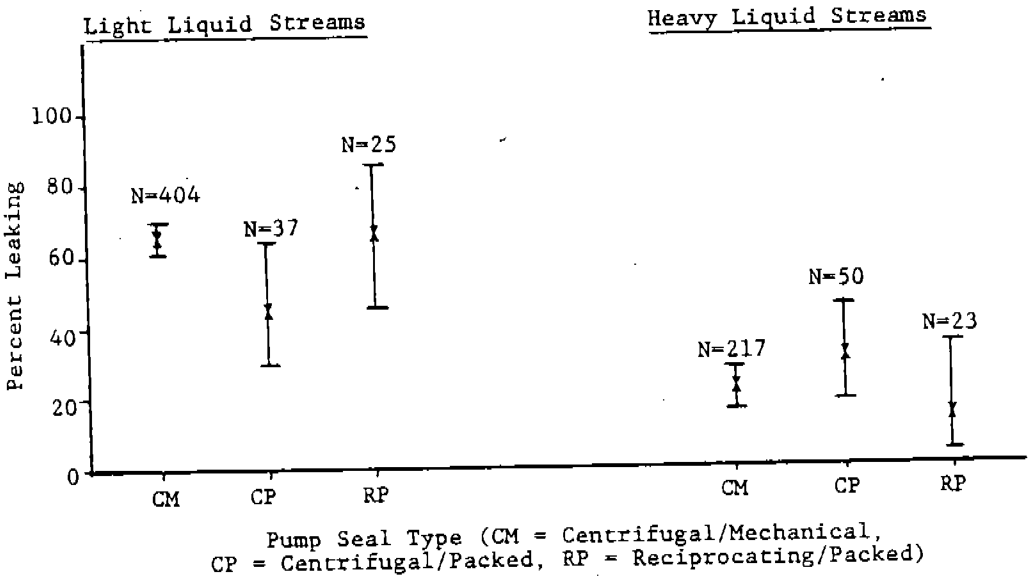


Figure B2-154. Pumps - effect of seal position on percent of pump seals leaking.



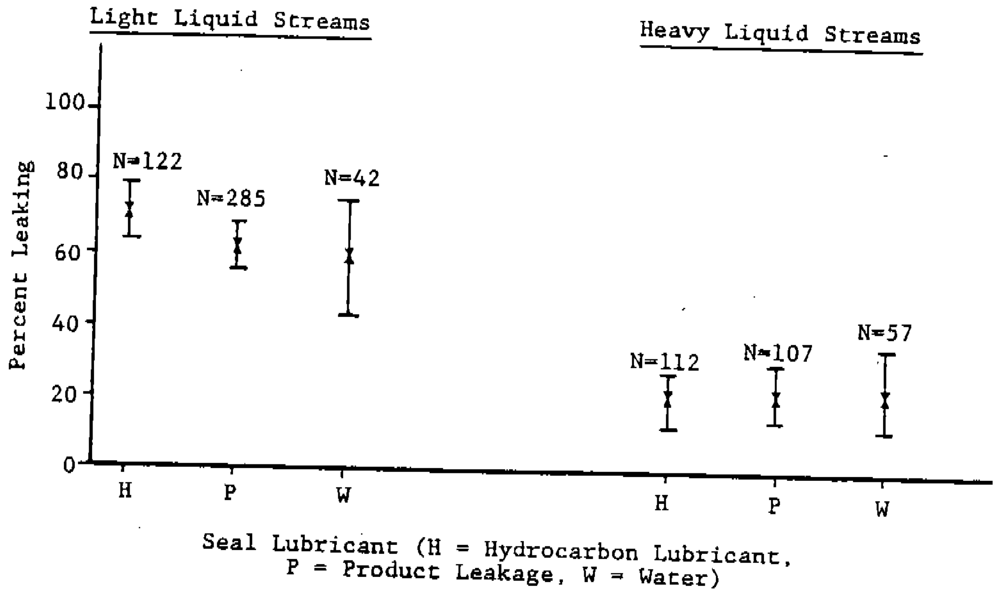
N = Number of Sources Screened

Figure B2-155. Pumps - effect of pump attitude on percent of seals leaking.



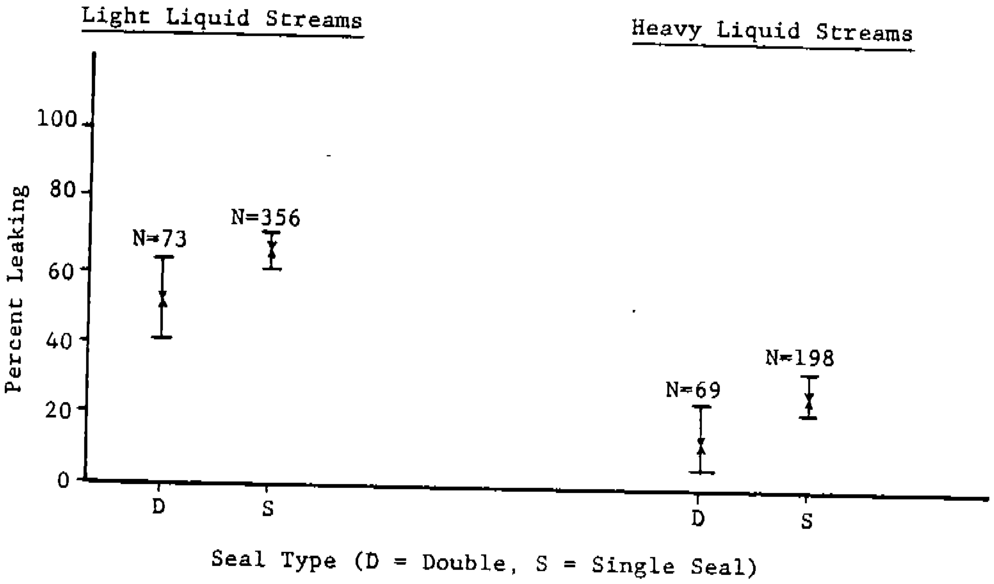
N = Number of Sources Screened

Figure B2-156. Pumps - effect of pump seal type on percent of seals leaking.



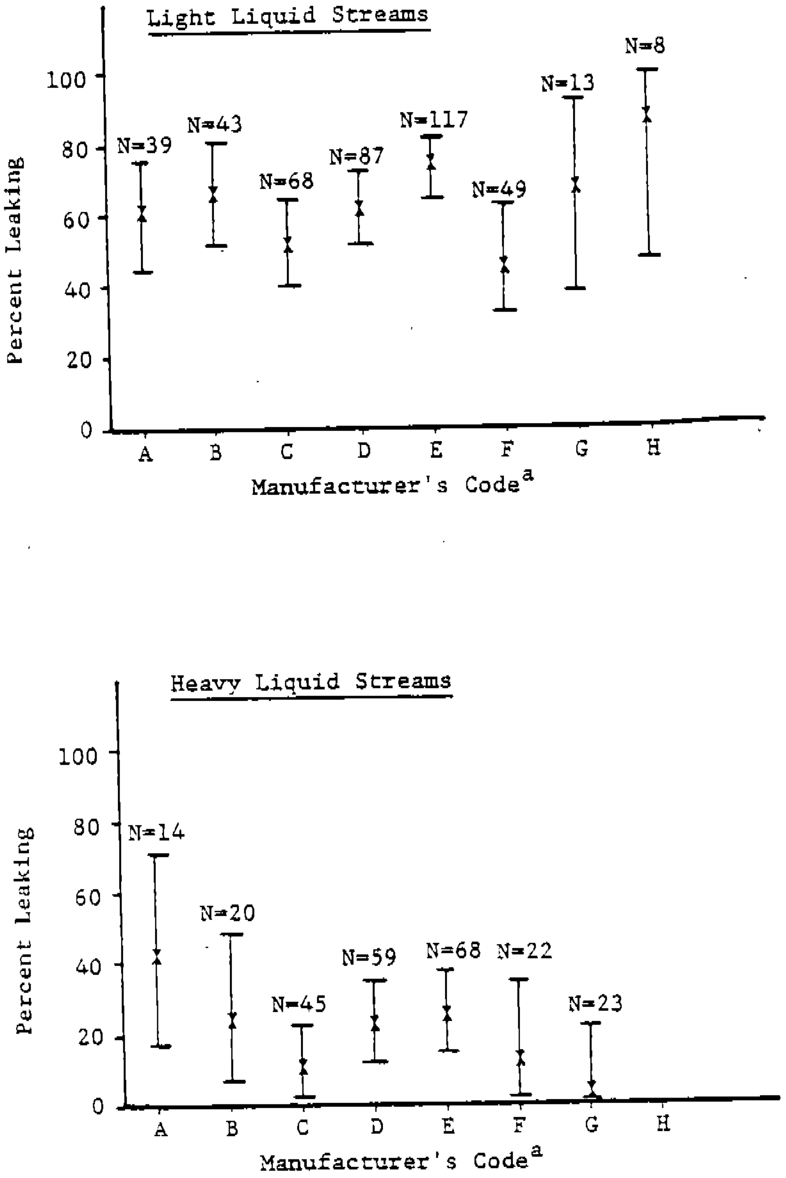
N = Number of Sources Screened

Figure B2-157. Pumps - effect of seal lubricant type on percent of seals leaking.



N = Number of Sources Screened

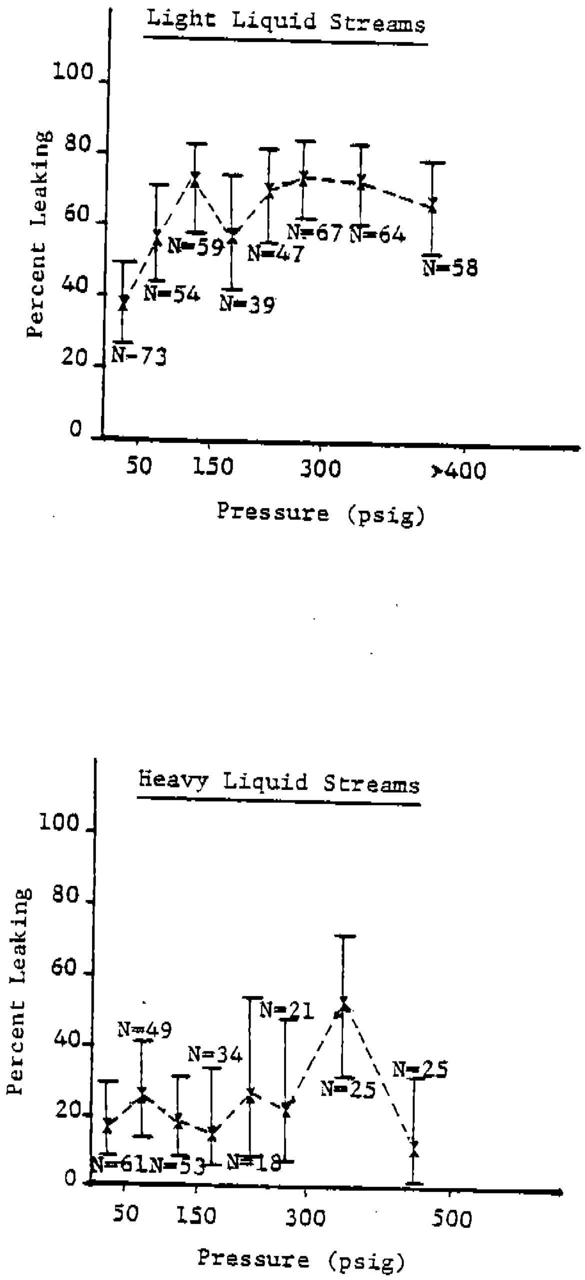
Figure B2-158. Pumps - effect of seal type on percent of seals leaking.



N = Number of Sources Screened

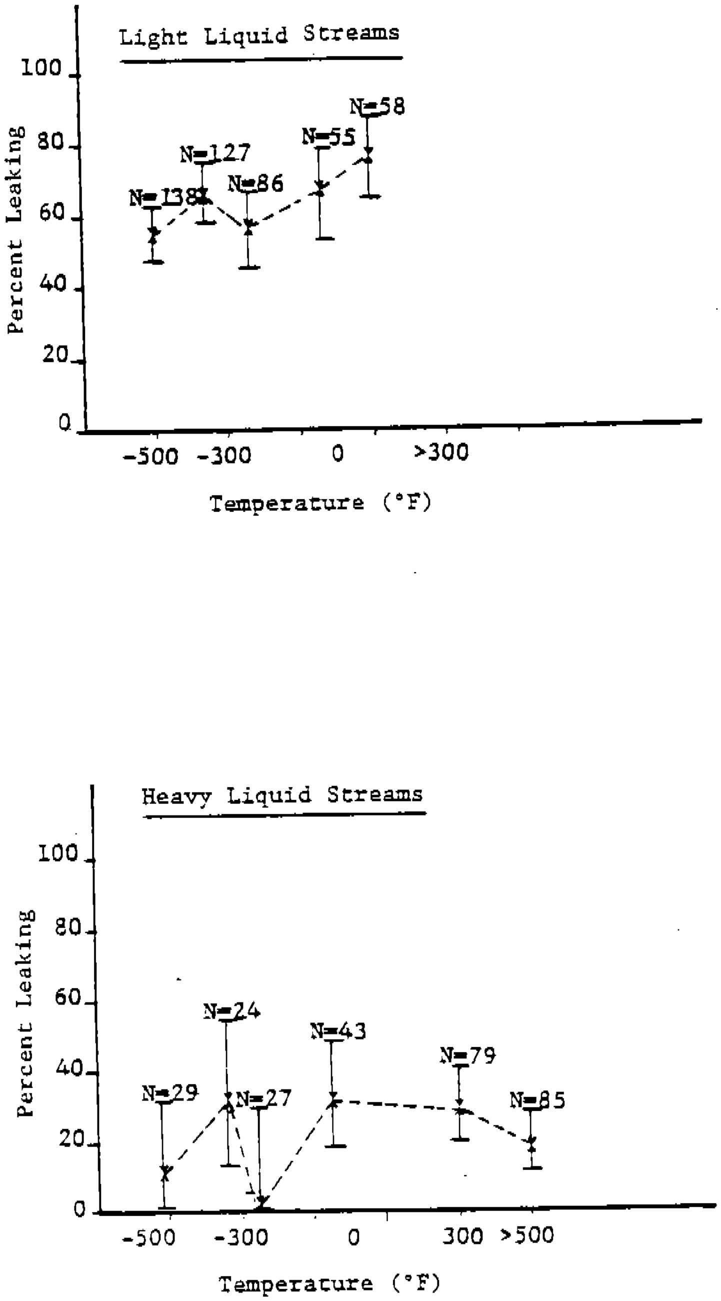
Figure B2-159. Pumps - effect of manufacturer on percent of pump seals leaking.

[a] Codes are arbitrary as to not identify particular manufacturers.



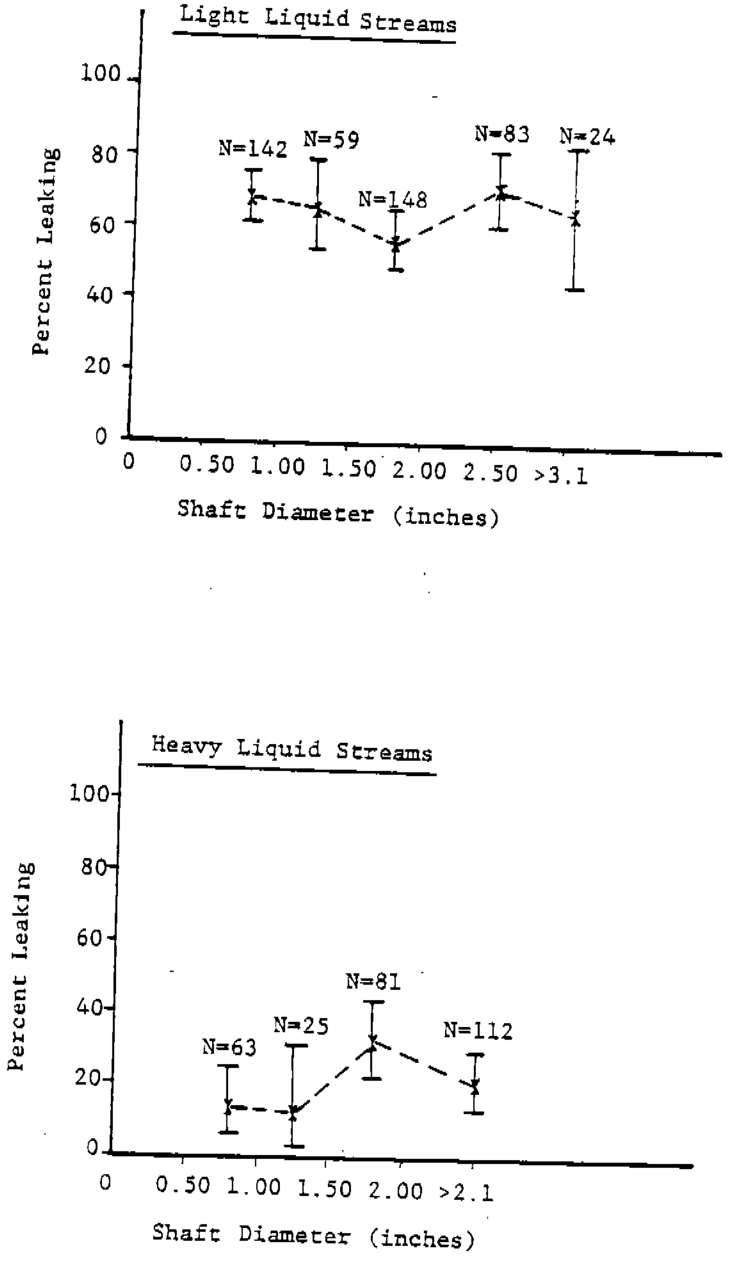
N = Number of Sources Screened

Figure B2-160. Pumps - effect of discharge pressure on percent of pump seals leaking.



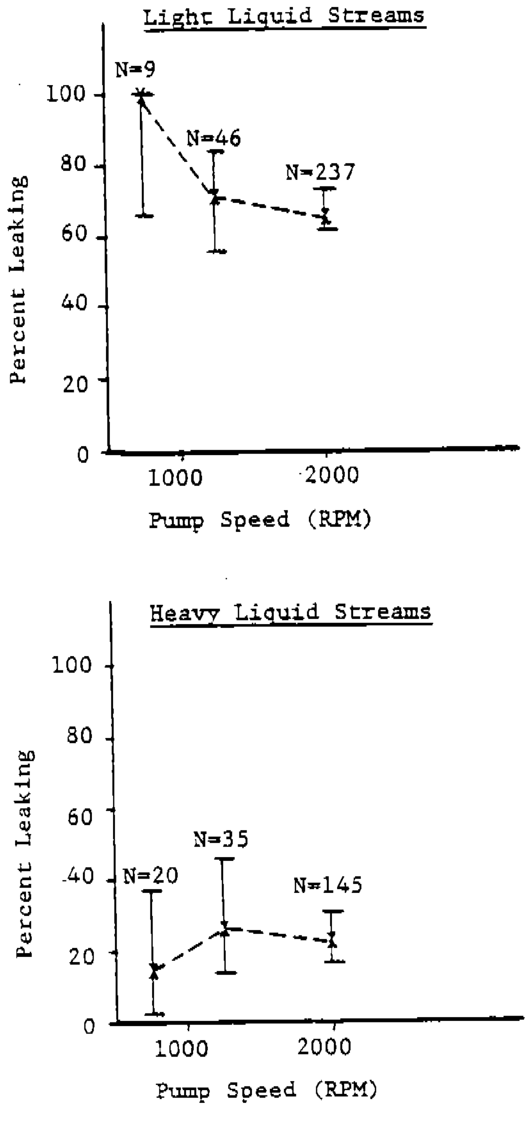
N = Number of Sources Screened

Figure B2-161. Pumps - effect of operating temperature on percent of seals leaking.



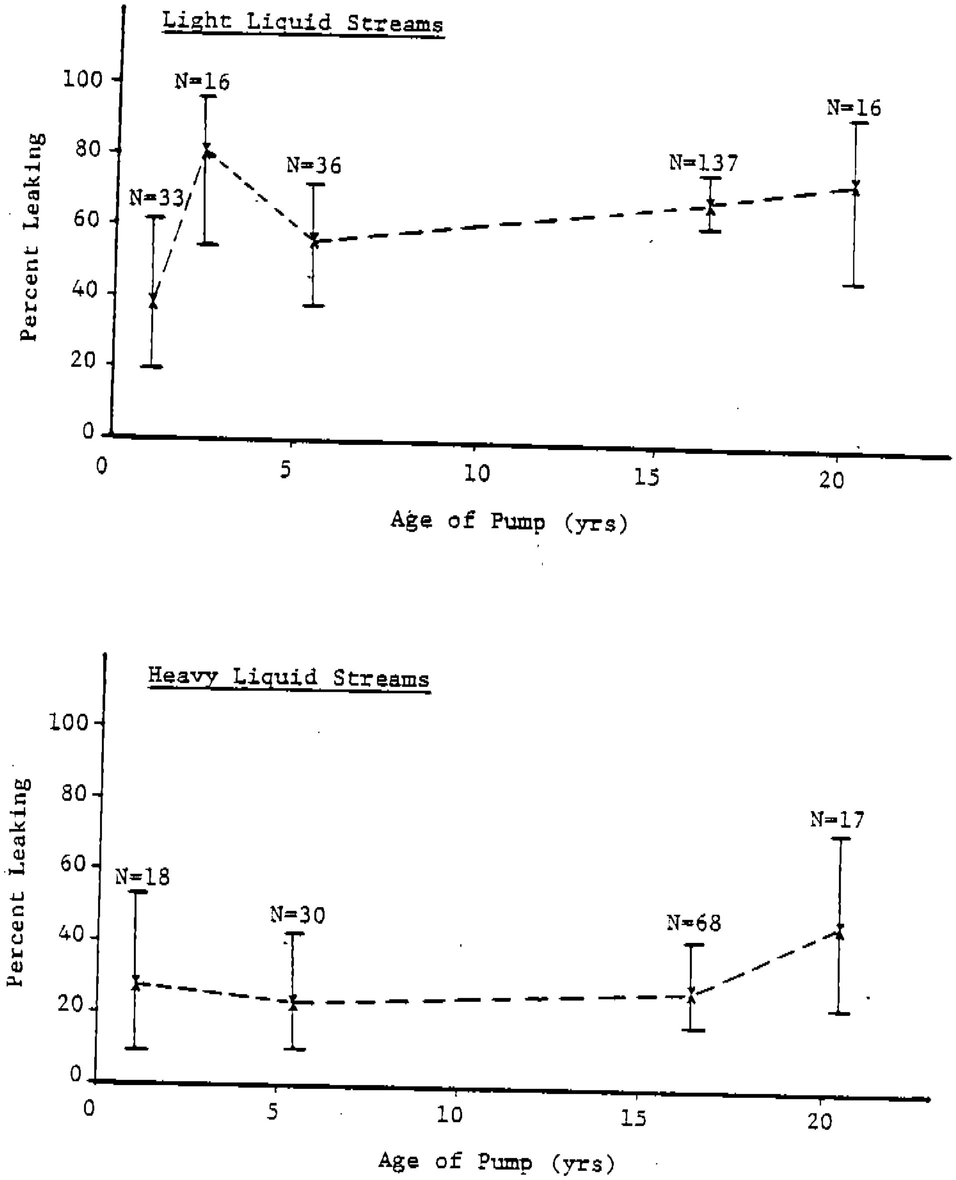
N = Number of Sources Screened

Figure B2-162. Pumps - effect of shaft diameter on percent of seals leaking.



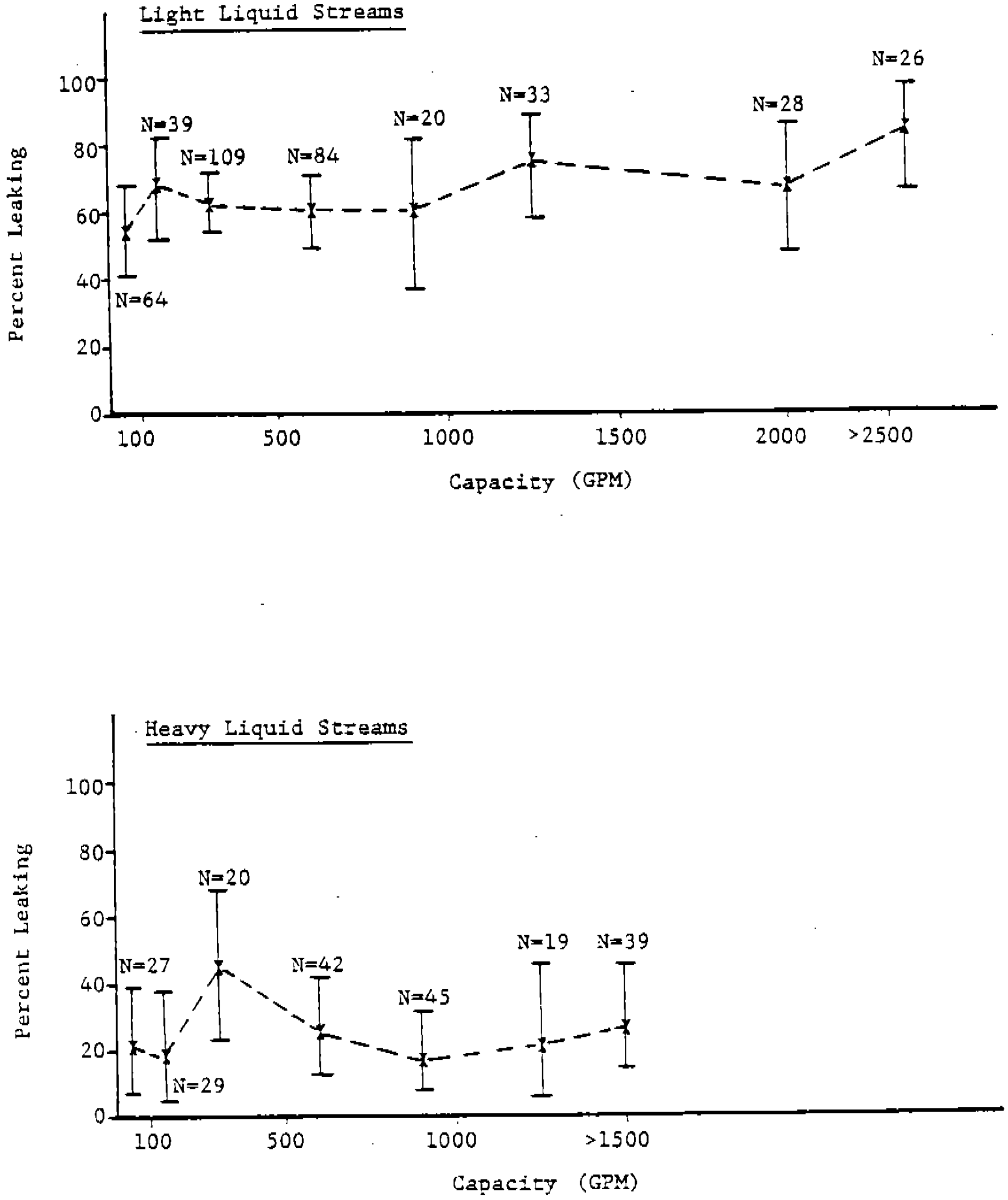
N = Number of Sources Screened

Figure B2-163. Pumps - effect of pump speed on percent of pump seals leaking.



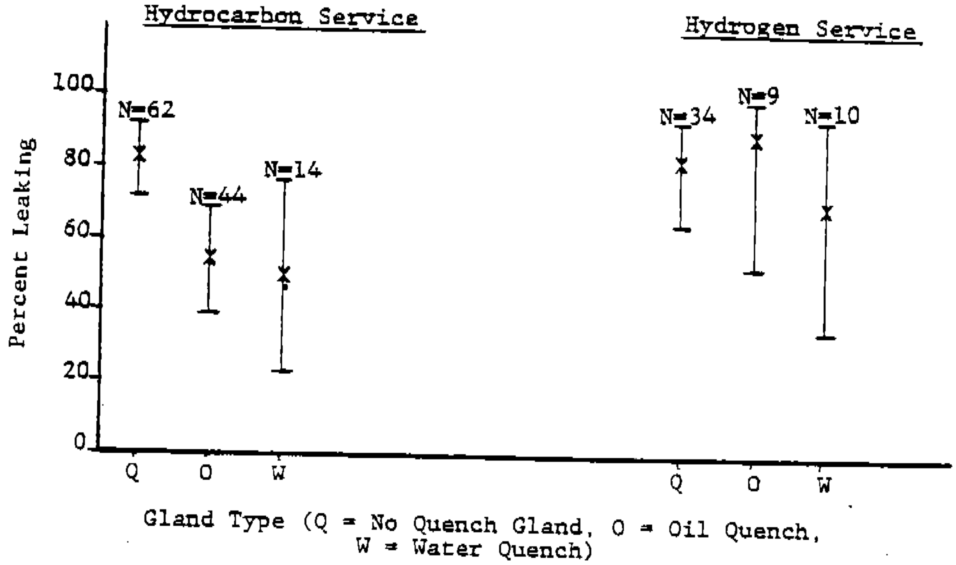
N = Number of Sources Screened

Figure B2-164. Pumps - effect of age on percent of seals leaking.



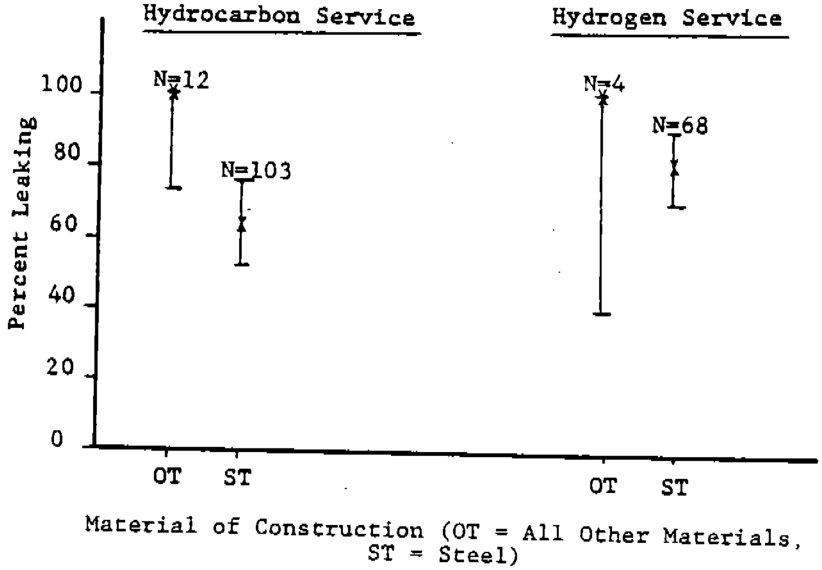
N = Number of Sources Screened

Figure B2-165. Pumps - effect of size (capacity) on percent of pump seals leaking.



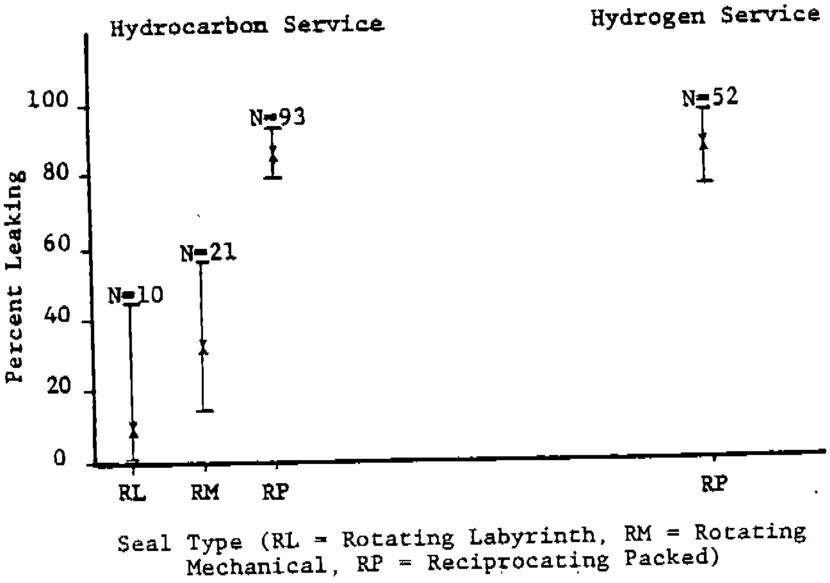
N = Number of Sources Screened

Figure B2-166. Compressors - effect of gland type on percent of seals leaking.



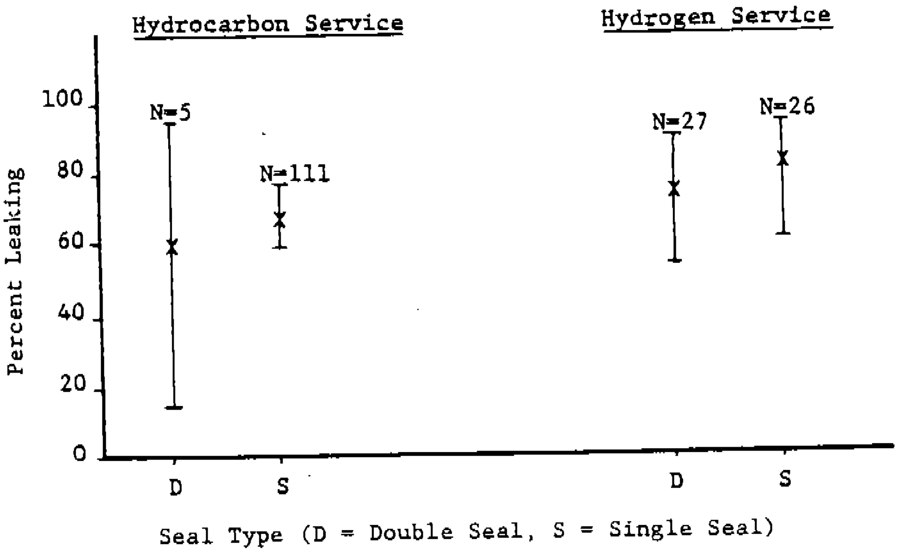
N = Number of Sources Screened

Figure B2-167. Compressors - effect of material of construction on percent of seals leaking.



N = Number of Sources Screened

Figure B2-168. Compressors - effect of seal type on percent of seals leaking.



N = Number of Sources Screened

Figure B2-169. Compressors - effect of seal number on percent of seals leaking.

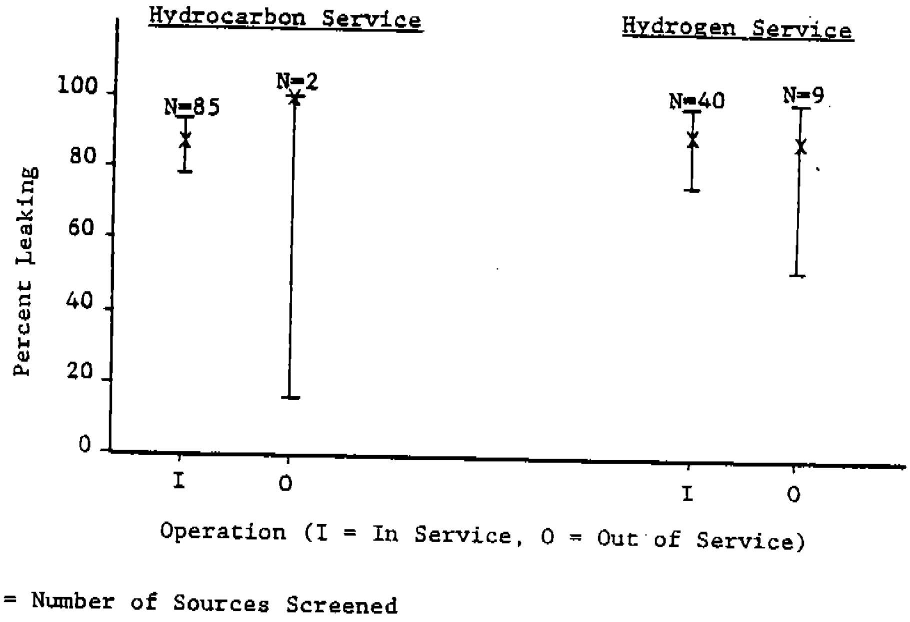
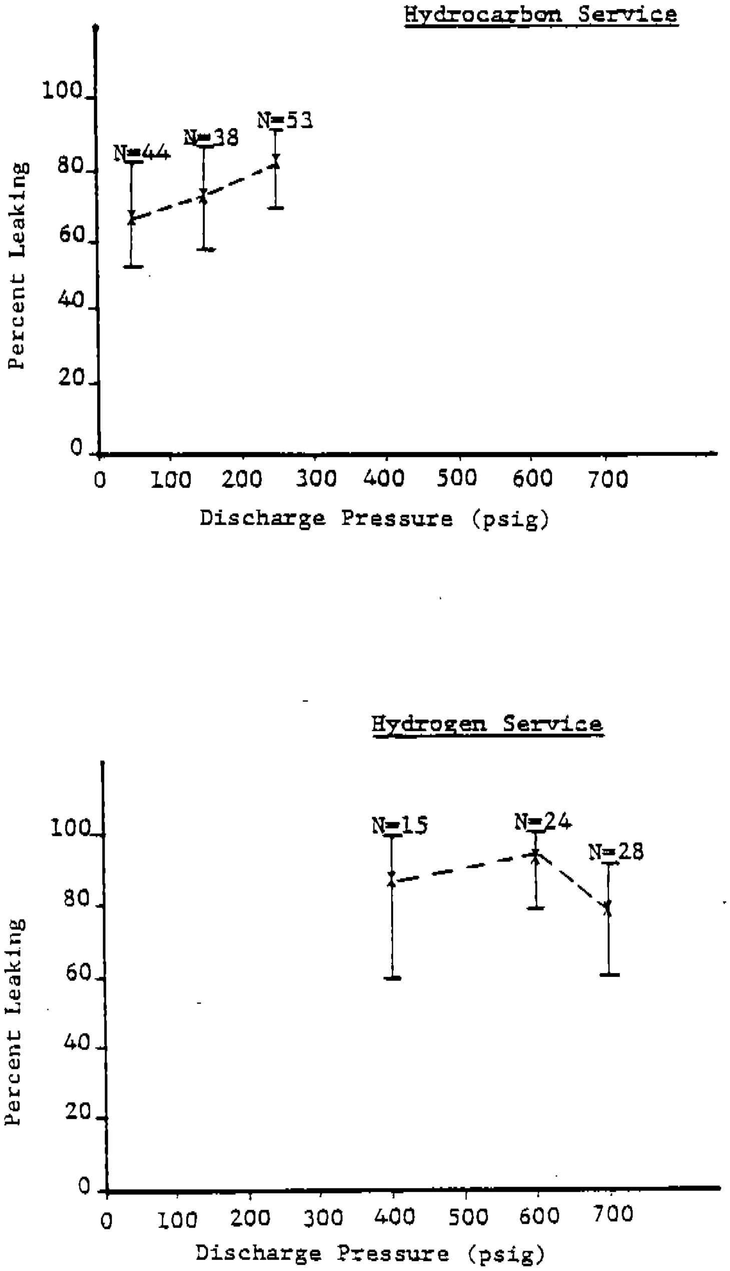
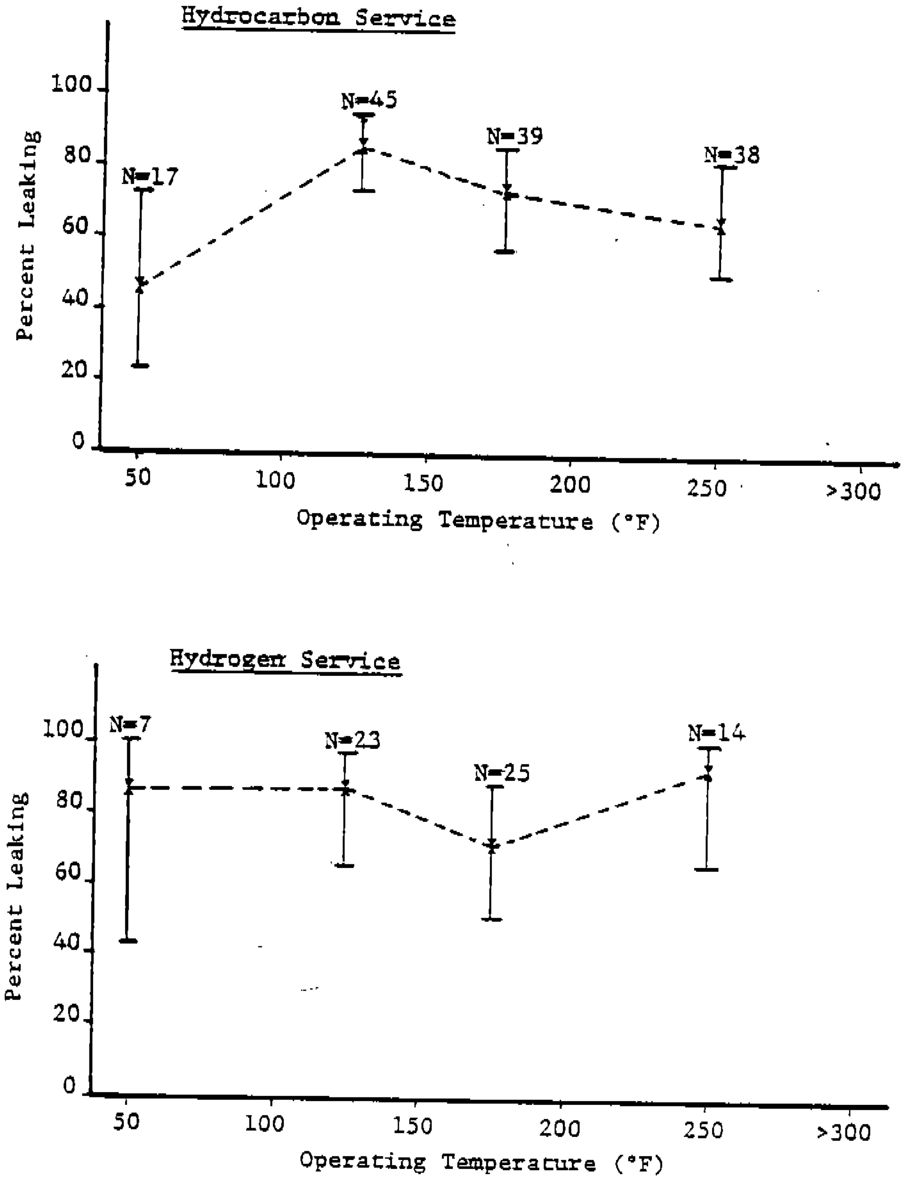


Figure B2-170. Compressors - effect of operation on percent of seals leaking.



N = Number of Sources Screened

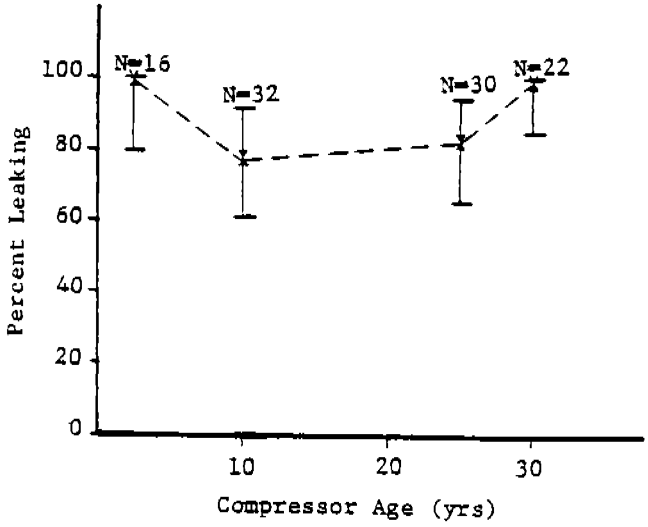
Figure B2-171. Compressors - effect of compressor discharge pressure on percent of seals leaking.



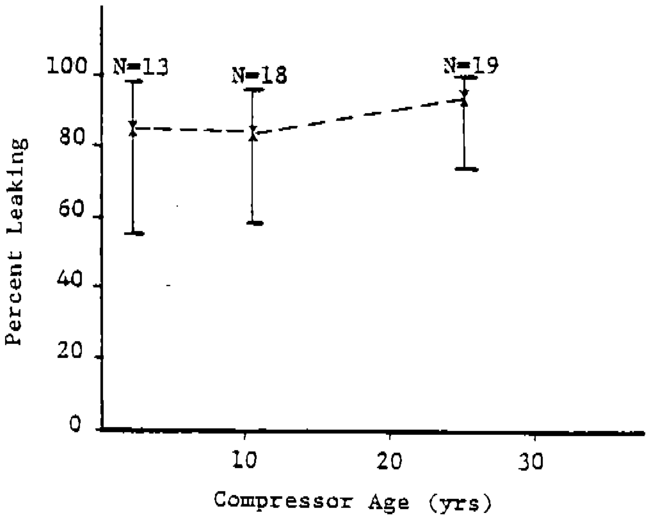
N = Number of Sources Screened

Figure B2-172. Compressors - effect of operating temperature on percent of seals leaking.

Hydrocarbon Service

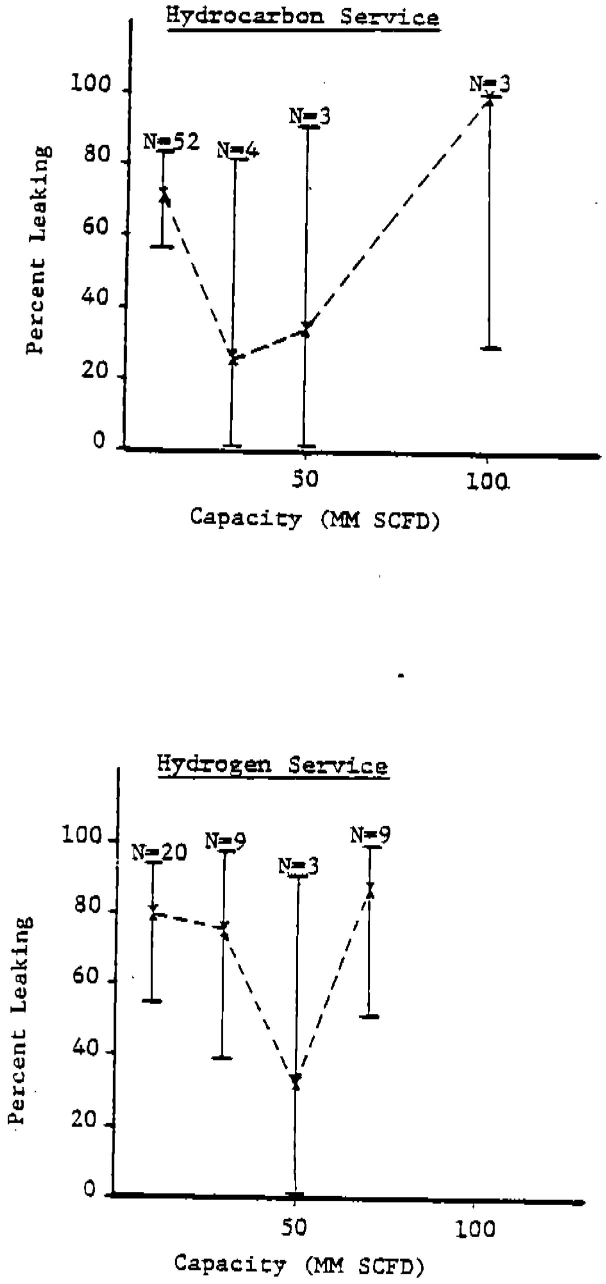


Hydrogen Service



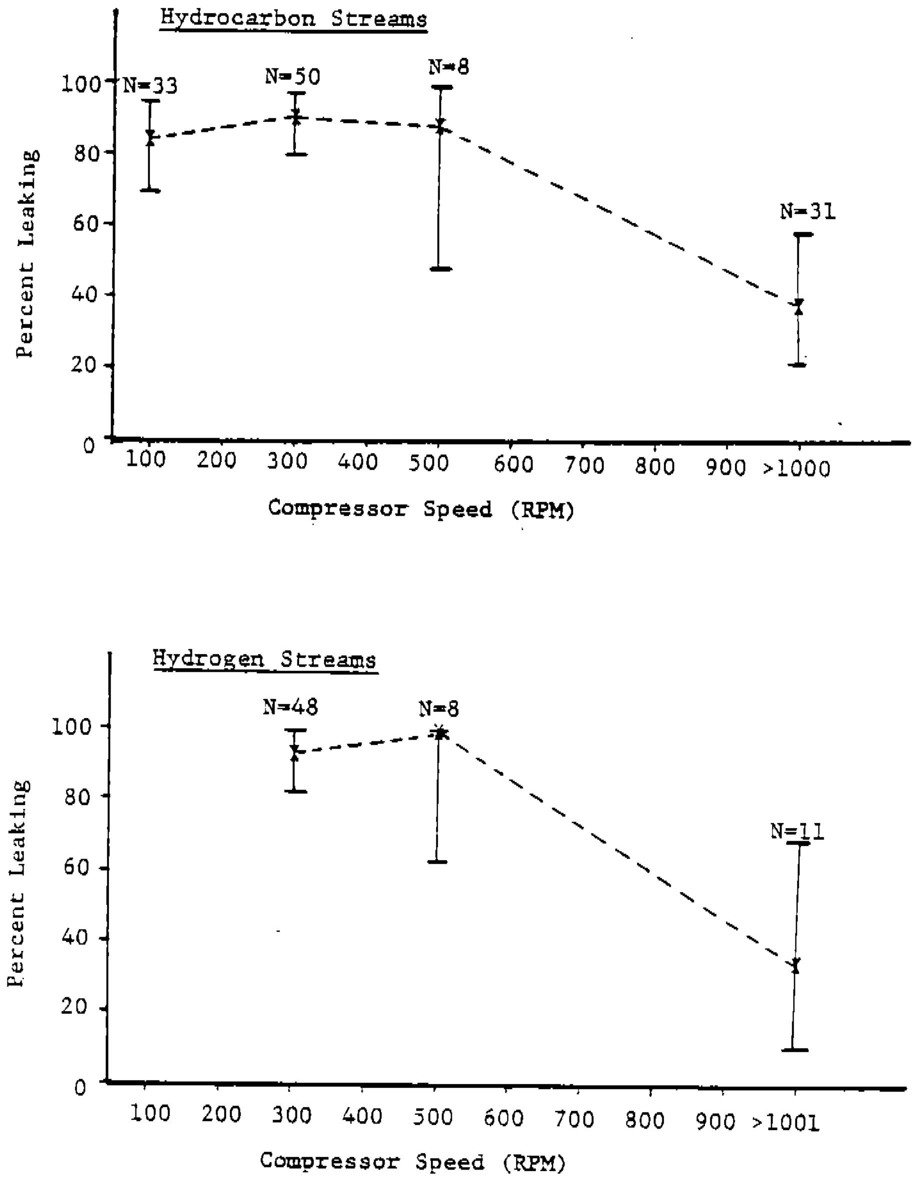
N = Number of Sources Screened

Figure B2-173. Compressors - effect of age on percent of seals leaking.



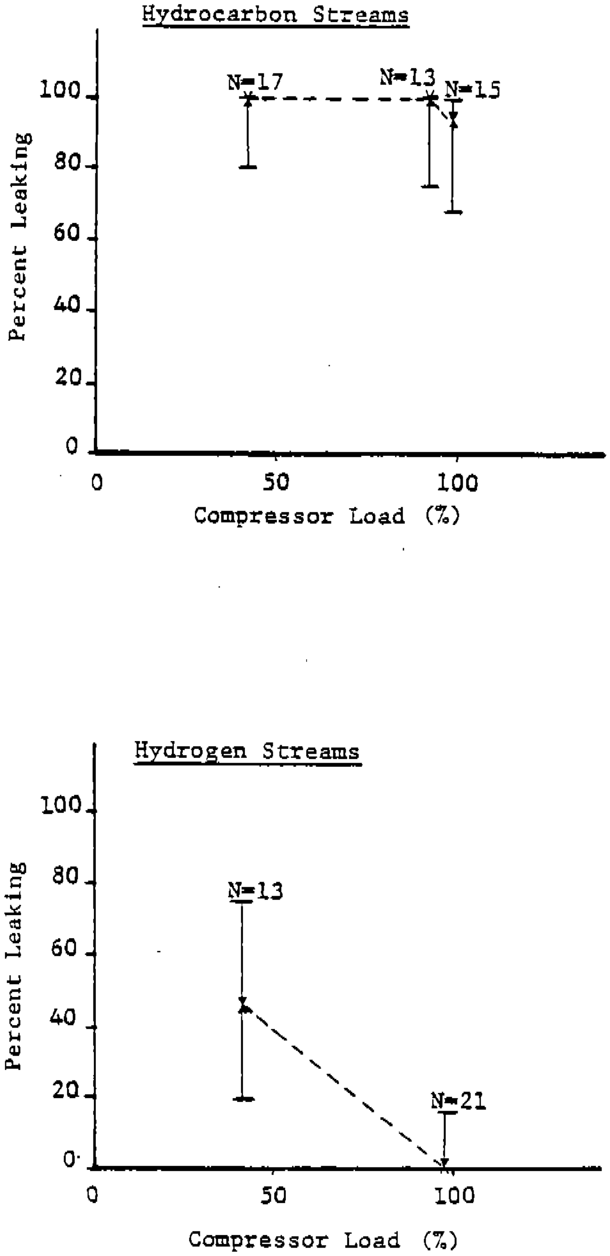
N = Number of Sources Screened

Figure B2-174. Compressors - Effect of capacity on percent of compressor seals leaking.



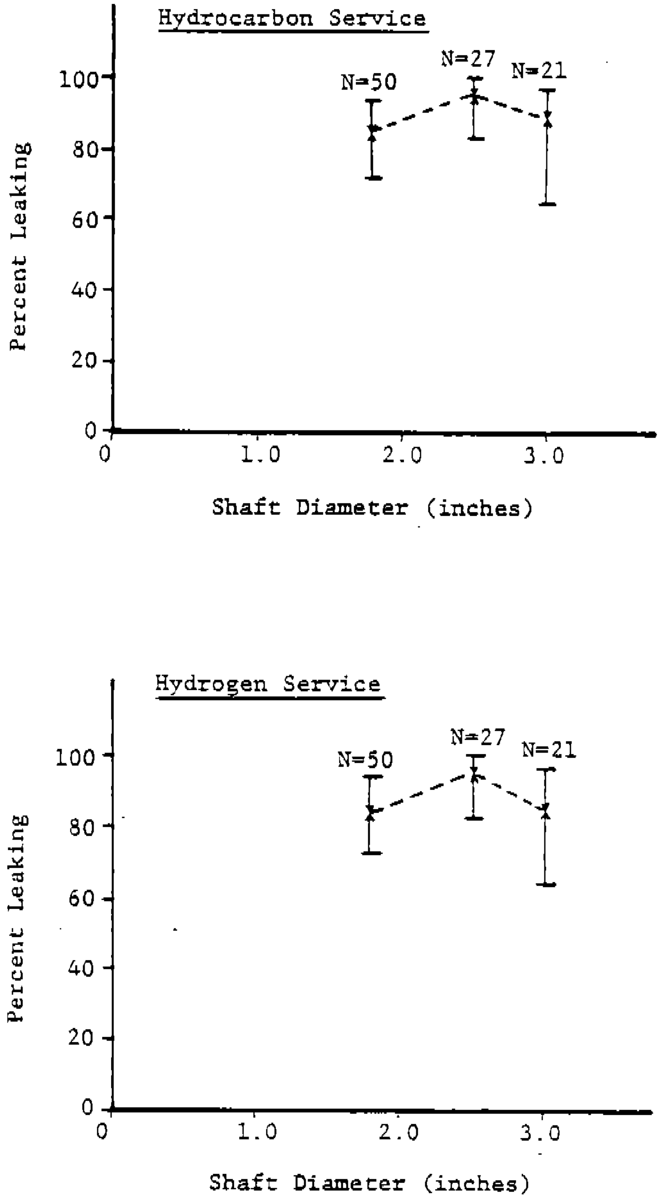
N = Number of Sources Screened

Figure B2-175. Compressors - effect of compressor speed on percent of seals leaking.



N = Number of Sources Screened

Figure B2-176. Compressors - effect of compressor loading on percent of seals leaking.



N = Number of Sources Screened

Figure B2-177. Compressors - effect of shaft diameter on percent of seals leaking.

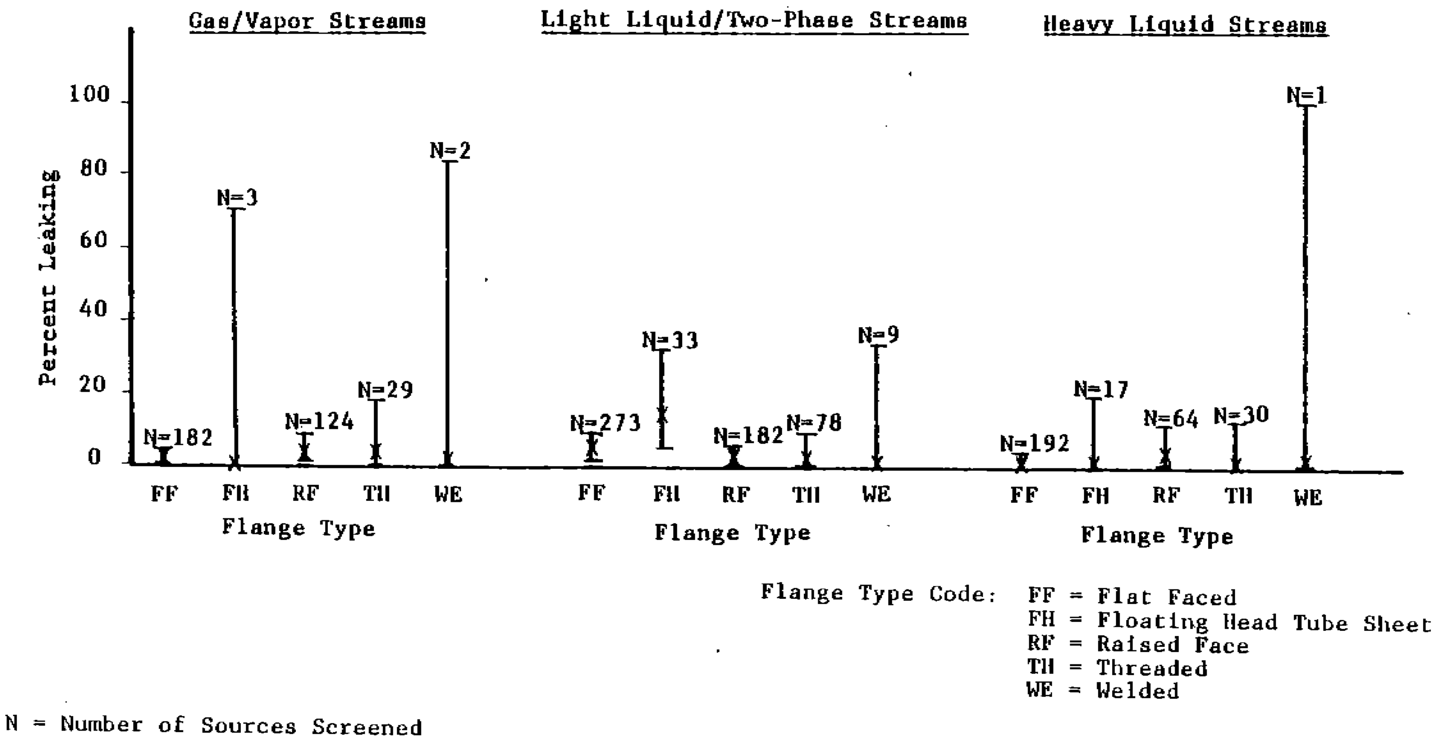
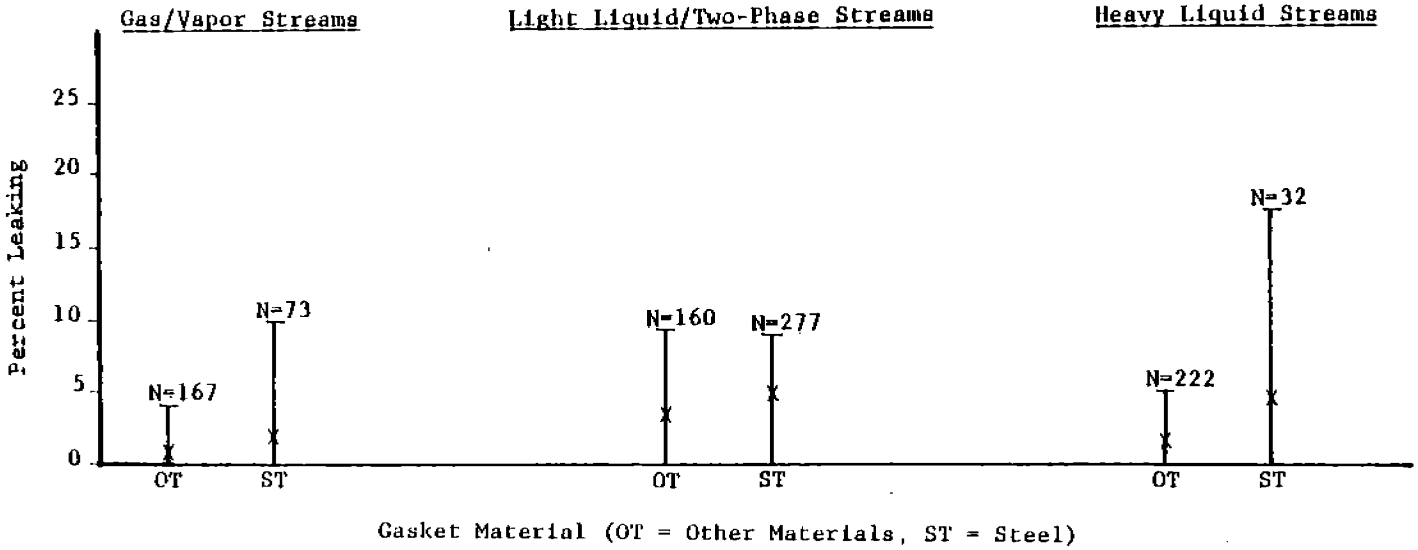
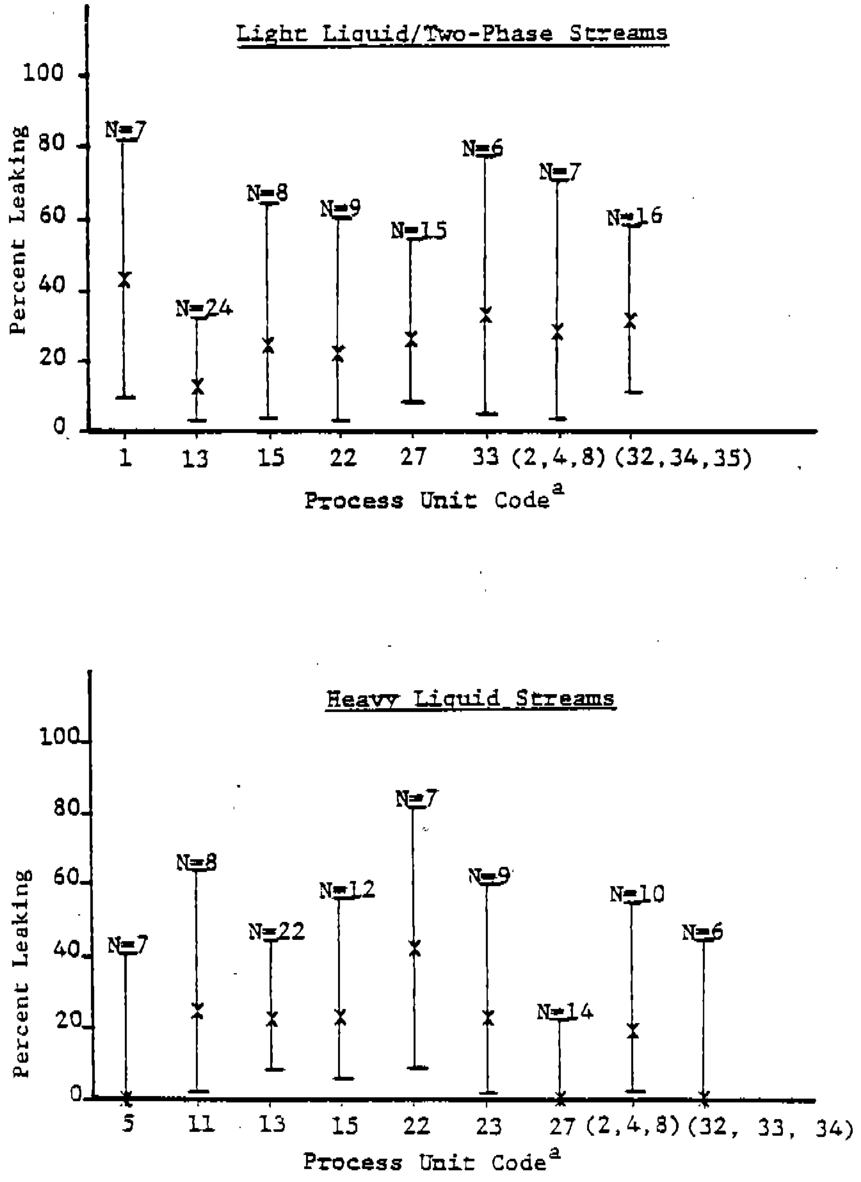


Figure B2-178. Flanges - effect of flange type on percent of flanges leaking.



N = Number of Sources Screened

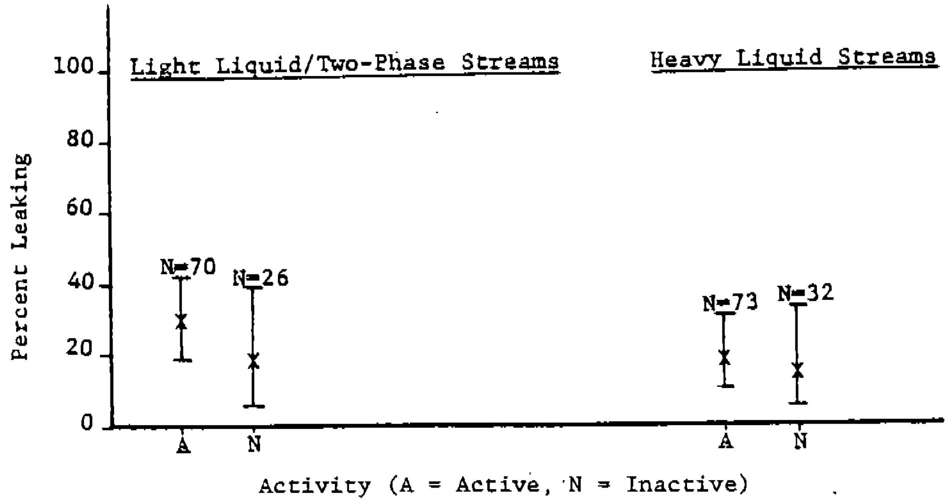
Figure B2-179. Flanges - effect of gasket material on percent leaking.



N = Number of Sources Screened

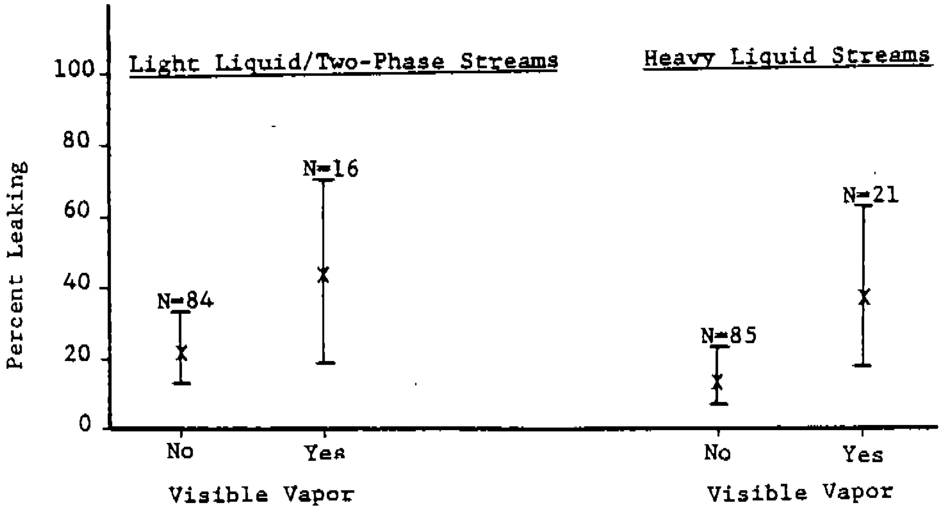
Figure B2-180. Drains - effect of process unit type on percent of drains leaking.

[a] See Table B2-24 for process unit code definitions.



N = Number of Sources Screened

Figure B2-181. Drains - effect of drain activity on percent leaking.



N = Number of Sources Screened

Figure B2-182. Drains - effect of vapor visibility on percent of drains leaking.

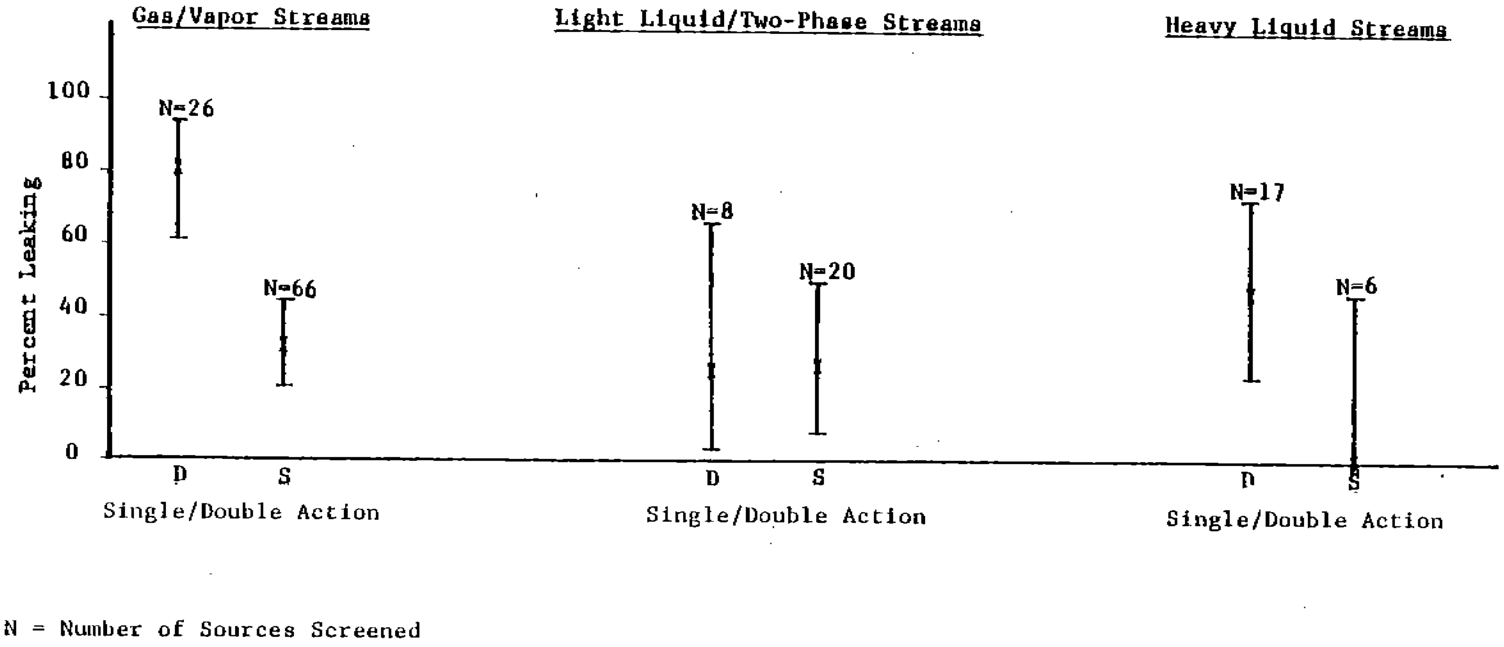


Figure B2-183. Relief valves - effect of single versus double action on percent of relief valves leaking to atmosphere.

Some significant differences in percent leaking are noted for valves due to age and unit type and vibration. Valves less than one year old have a higher percent leaking for gas/vapor and light liquid streams, but not for heavy streams. A trend of increasing percent leaking with larger line sizes is indicated for all stream groupings. No significant differences are noted for the different valve manufacturers.

For pump seals in light liquid service, the percent of seals leaking appears to increase as the pressure and temperature increase. No significant differences are noted for the discrete variables, including manufacturer. Single seals have a higher percent leaking than double seals for both light and heavy liquid streams, although the confidence intervals do overlap.

For compressors in hydrocarbon service, significant differences in the percent of seals leaking were noted for gland type and seal type. The percent leaking also appeared to be increasing as discharge pressure increased.

2.6 EMISSION FACTORS

2.6.1 Emission Factors for Baggable Sources

The estimated emission factors for nonmethane hydrocarbon emissions for the six types of baggable sources are summarized in Table B2-23. Twelve emission factors are presented representing the twelve cases discussed in Section 2.1. Confidence intervals are given in each case for both the percent of sources leaking and the estimated emission

TABLE B2-23. ESTIMATED VAPOR EMISSION FACTORS FOR NONMETHANE HYDROCARBONS FROM BAGGABLE SOURCES

Source Category	Emission Factor Estimate (lb/hr/source)[1]	95% Confidence Interval for Emission Factor (lb/hr/source)[2]
Valves		
Gas Vapor Streams	0.059	(0.030, 0.110)
Light Liquid/Two-Phase	0.024	(0.017, 0.036)
Heavy Liquid	0.0005	(0.0002, 0.0015)
Hydrogen	0.018	(0.007, 0.045)
Open-Ended ~~[illegible]~~ Lines	0.005	(0.0016, 0.016)
Pump Seals		
Light Liquid Streams	0.25	(0.16, 0.37)
Heavy Liquid Streams	0.046	(0.019, 0.11)
Drains	0.070	(0.023, 0.20)
Flanges	0.00056	(0.0002, 0.0025)
Relief Valves	0.19	(0.070, 0.49)
Compressor Seals		
Hydrocarbon Service	1.4	(0.66, 2.9)
Hydrogen Service	0.11	(0.05, 0.23)

---

[1] The estimated mean level of emissions from all sources of this type in United States refineries. This factor is an average and incorporates the fact that a significant number of sources have no emissions.

[2] The statistical procedures used to construct these intervals account for both systematic and random errors in experimental design, sampling, chemical analysis, and statistical analysis. The procedures used are such that at least 95% of the intervals will include the true emission factor.

factor. The confidence interval for the percent leaking gives the range of values expected with 95 percent confidence to include actual average percent leaking from all U.S. refineries if they could be tested. The confidence interval for the emission factors represents the range of values which is expected with 95 percent confidence to include the average emission rate for all sources of the particular type in all U.S. refineries. The confidence intervals include consideration of both potential biases and random variation as discussed in Appendix C.

The emission factors listed in Table B2-23 are slightly different than those published in a previous report (EPA 600/2-79-044).[4] The results given here are based on further refinements of the data base and the formation of emission factors for values in hydrogen service which were previously incorporated in other valve service categories.

Tables B2-24 through B2-29 contain a division of the emissions data by process unit type. The data within each unit are the composite of data collected for that unit during the sampling program. Since a random sample of sources was not selected within each unit, the emission factors and estimated percent leaking may be biased. This is particularly true because of the influence of process stream composition as previously discussed. Tables B2-24 through B2-29 should be considered as a summary of the emissions data collected in this program. The unit emission factor should be used with caution.

TABLE B2-24. SUMMARY OF EMISSIONS DATA BY PROCESS UNIT - VALVES

Unit Code	Unit Identification	Number Screened	Number Leaking	Percent Leaking	95% Confidence Interval for Percent Leaking	Nonmethane Hydrocarbons	
						Estimated Emission Factor (lb/hr/source)	95% Confidence Interval for Emission Factor (lb/hr/source)
15	Atmospheric Distillation	278	62	22.3	(17, 27)	0.0023	(0.001, 0.005)
13	Fuel Gas/Light Ends Processing	460	158	34.3	(30, 39)	0.046	(0.026, 0.084)
22	Catalytic Cracking	190	49	25.8	(20, 33)	0.047	(0.015, 0.14)
1	Catalytic Reforming	153	86	56.2	(46, 67)	0.029	(0.015, 0.059)
27	Alkylation	227	85	37.4	(31, 44)	0.031	(0.015, 0.065)
17	Vacuum Distillation	57	0	0.0	(0, 6)	neg	(neg, 0.009)
2,4,8	Catalytic Hydrotreating/ Refining	285	69	24.2	(19, 29)	0.0051	(0.002, 0.012)
33	Aromatics Extraction	45	15	33.3	(20, 49)	0.0053	(0.001, 0.03)
23	Delayed Coking	86	9	10.5	(5, 19)	0.0019	(0.001, 0.02)
32, 34,35	Dewaxing, Treating	289	44	15.2	(11, 19)	0.011	(0.003, 0.04)
18	Sulfur Recovery	10	0	0.0	(0, 31)	*	*
5	Hydrocracking	83	27	32.5	(23, 44)	0.057	(0.01, 0.30)
11	Hydrogen Production	49	9	18.4	(9, 32)	0.0013	(neg, 0.02)
36	Hydrodealkylation	36	14	38.9	(23, 57)	0.013	(0.001, 0.09)
	Other[1]	11	0	0.0	(0, 28)	*	*

* Insufficient data

[1] Unit identification of "other" includes all valves for which the unit identification data were missing.

TABLE B2-25. SUMMARY OF EMISSIONS DATA BY PROCESS UNIT - COMPRESSOR SEALS

Unit Code	Unit Identification	Number Screened	Number Leaking	Percent Leaking	95% Confidence Interval for Percent Leaking	Nonmethane Hydrocarbons Estimated Emission Factor (lb/hr/source)	Nonmethane Hydrocarbons 95% Confidence Interval for Emission Factor (lb/hr/source)
15	Atmospheric Distillation	6	6	100.0	(54, 100)	*	*
13	Fuel Gas/Light Ends Processing	59	34	57.6	(44, 70)	1.28	(.3, 4.6)
22	Catalytic Cracking	34	26	76.5	(59, 89)	1.233	(0.335, 4.154)
1	Catalytic Reforming	42	37	88.1	(74, 96)	0.064	(0.022, 0.186)
27	Alkylation	10	9	90.0	(56, 100)	*	*
17	Vacuum Distillation	-	-	-	-	-	-
2,4,8	Catalytic Hydrotreating/ Refining	25	19	76.0	(57, 91)	*	*
33	Aromatics Extraction	5	5	100.0	(48, 100)	*	*
23	Delayed Coking	14	14	100.0	(77, 100)	*	*
32, 34,35	Dewaxing/Treating	19	19	100.0	(82, 100)	*	*
18	Sulfur Recovery	-	-	-	-	-	-
5	Hydrocracking	9	7	77.8	(40, 97)	*	*
11	Hydrogen Production	-	-	-	-	-	-
36	Hydrodealkylation	2	1	50.0	(13, 99)	*	*
29	Blending	2	2	100.0	(16, 100)		

* Insufficient data

TABLE B2-26. SUMMARY OF EMISSIONS DATA BY PROCESS UNIT - RELIEF VALVES

						Nonmethane Hydrocarbons	
Unit Code	Unit Identification	Number Screened	Number Leaking	Percent Leaking	95% Confidence Interval for Percent Leaking	Estimated Emission Factor (lb/hr/source)	95% Confidence Interval for Emission Factor (lb/hr/source)
15	Atmospheric Distillation	17	2	14.3	(1.5, 36)	*	*
13	Fuel Gas/Light Ends Processing	67	37	55.2	(43, 67)	0.107	(0.035, 0.299)
22	Catalytic Cracking	19	3	15.8	(3, 40)	*	*
1	Catalytic Reforming	7	2	28.6	(3.7, 71)	*	*
27	Alkylation	20	10	50.0	(27, 73)	*	*
17	Vacuum Distillation	1	0	0.0	(0, 99)	*	*
2,4,8	Catalytic Hydrotreating/ Refining	7	2	28.6	(4, 71)	*	*
33	Aromatics Extraction	4	1	25.0	(1, 81)	*	*
23	Delayed Coking	4	1	25.0	(1, 81)	*	*
32, 34,35	Dewaxing, Treating	0	-	-	-	*	*
18	Sulfur Recovery	0	-	-	-	*	*
5	Hydrocracking	4	0	0.0	(0, 60)	*	*
11	Hydrogen Production	2	0	0.0	(0. 84)	*	*
36	Hydrodealkylation	0	-	-	-	*	*

* Insufficient data

TABLE B2-27. SUMMARY OF EMISSIONS DATA BY PROCESS UNIT - PUMP SEALS

Unit Code	Unit Identification	Number Screened	Number Leaking	Percent Leaking	95% Confidence Interval for Percent Leaking	Nonmethane Hydrocarbons: Estimated Emission Factor (lb/hr/source)	Nonmethane Hydrocarbons: 95% Confidence Interval for Emission Factor (lb/hr/source)
15	Atmospheric Distillation	149	65	43.6	(36, 52)	0.022	(0.001, 0.023)
13	Fuel Gas/Light Ends Processing	156	83	53.2	(45, 61)	0.19	(0.09, 0.40)
22	Catalytic Cracking	77	31	40.3	(29, 52)	0.081	(0.02, 0.29)
1	Catalytic Reforming	41	32	78.0	(62, 89)	0.18	(0.06, 0.51)
27	Alkylation	76	60	78.9	(68, 87)	1.3	(0.51, 3.5)
17	Vacuum Distillation	25	3	12.0	(3, 31)	*	*
2,4,8	Catalytic Hydrotreating/ Refining	61	23	37.7	(26, 51)	0.033	(0.01, 0.13)
33	Aromatics Extraction	43	25	58.1	(42, 73)	0.20	(0.05, 0.73)
23	Delayed Coking	37	10	27.0	(14, 44)	0.020	(0.002, 0.15)
32, 34,35	Dewaxing, Treating	65	26	40.0	(26, 56)	0.056	(0.02, 0.20)
5	Hydrocracking	40	20	50.0	(34, 66)	0.053	(0.01, 0.20)
11	Hydrogen Production	7	0	0.0	(0, 41)	*	*
36	Hydrodealkylation	5	4	80.0	(28, 99)	*	*
	Other[1]	5	0	0.0	(0, 52)	*	*

* Insufficient data

[1] Unit identification of "other" includes all pump seals for which unit identification data were missing.

TABLE B2-28. SUMMARY OF EMISSIONS DATA BY PROCESS UNIT - FLANGES

Unit Code	Unit Identification	Number Screened	Number Leaking	Percent Leaking	95% Confidence Interval for Percent Leaking	Nonmethane Hydrocarbons: Estimated Emission Factor (lb/hr/source)	Nonmethane Hydrocarbons: 95% Confidence Interval for Emission Factor (lb/hr/source)
15	Atmospheric Distillation	407	6	1.47	(0, 3.0)	0.0001	(neg, 0.001)
13	Fuel Gas/Light Ends Processing	148	11	7.43	(3.0, 12)	0.00085	(neg, 0.005)
22	Catalytic Cracking	224	0	0.00	(0, 1.5)	neg	(neg, 0.0005)
1	Catalytic Reforming	245	19	7.76	(4.0, 11)	0.0034	(0.0005, 0.019)
27	Alkylation	264	8	3.03	(1.0, 5.0)	0.00014	(neg, 0.001)
17	Vacuum Distillation	77	0	0.00	(0, 4.6)	neg	(neg, 0.0020)
2,4,8	Catalytic Hydrotreating/ Refining	245	9	3.67	(1.0, 6.0)	0.00042	(neg, 0.004)
33	Aromatics Extraction	15	1	6.67	(0.2, 32)	*	*
23	Delayed Coking	32	0	0.00	(0, 11)	neg	(neg, 0.004)
32, 34,35	Dewaxing, Treating	300	5	1.67	(0, 30)	0.00003	(neg, 0.001)
18	Sulfur Recovery	6	0	0.00	(0, 46)	*	
5	Hydrocracking	33	2	6.06	(1.0, 20)	0.0028	(neg, 0.25)
11	Hydrogen Production	19	1	5.26	(0.1, 26)	*	*
36	Hydrodealkylation	15	0	0.00	(0, 22)	*	*

* Insufficient data

TABLE B2-29. SUMMARY OF EMISSIONS DATA BY PROCESS UNIT - DRAINS

Unit Code	Unit Identification	Number Screened	Number Leaking	Percent Leaking	95% Confidence Interval for Percent Leaking	Nonmethane Hydrocarbons Estimated Emission Factor (lb/hr/source)	Nonmethane Hydrocarbons 95% Confidence Interval for Emission Factor (lb/hr/source)
15	Atmospheric Distillation	23	5	21.7	(7, 44)	*	*
13	Fuel Gas/Light Ends Processing	57	8	14.0	(6, 26)	0.026	(0.001, 0.45)
22	Catalytic Cracking	18	5	27.8	(9, 53)	*	*
1	Catalytic Reforming	21	4	19.0	(4, 42)	*	*
27	Alkylation	33	4	12.1	(3, 29)	0.027	(0.0004, 0.98)
17	Vacuum Distillation	2	2	100.0	(16, 100)	*	*
2,4,8	Catalytic Hydrotreating/ Refining	27	5	18.5	(6, 38)	*	*
33	Aromatics Extraction	7	2	2.7	(4, 71)	*	*
23	Delayed Coking	11	3	27.3	(6, 61)	*	*
32, 34,35	Dewaxing, Treating	26	5	19.2	(7, 39)	*	*
18	Sulfur Recovery	3	0	0.0	(0, 71)	*	*
5	Hydrocracking	12	3	25.0	(5, 57)	*	*
11	Hydrogen Production	8	2	25.0	(3, 65)	*	*
36	Hydrodealkylation	5	1	20.0	(5, 72)	*	*
	Other[1]	2	0	0.0	(0, 84)	*	*

* Insufficient data

[1] Unit identification of "other" includes all drains for which unit identification data were missing.

2.6.2 Effect of Process Variables on Emission Factors

Section 2.5 presented a breakdown of the emissions data by the various process variables measured or recorded at the time that emissions data were obtained from each source. Both the effect on the percentage of sources leaking and the leak rate of the leaking sources was discussed. Any discussion of the effect of process variables is complicated by the confounding between variables in the data base. This confounding is due to the lack of independence between process variables as they naturally occur and the fact that all combinations of levels of many variables could not be obtained in the study.

A fractional factorial experimental design was followed in selecting sources with selection based on key process variables. The design allowed the estimation of the main effects of important variables, but not all variable interaction effects could be estimated. Most second order interactions (e.g., stream type by line size by source type) and higher order interactions are either confounded or there are not enough replicate data to quantify their effects with any precision. This means that it is difficult to break sources down by more than two variables at a time to determine emission factors or effects.

Tables B2-30 through B2-34 give emission factors and confidence intervals for selected classifications of the baggable sources. Emission factors for valves, pump seals and compressor seals have previously been given for

TABLE B2-30. VALVE TYPES DATA SUMMARY - PERCENT LEAKING AND EMISSION FACTORS

Valve Function	Valve Type	Number Screened	Number Leaking	Percent Leaking	95% Confidence Interval for Percent Leaking	Emission Factor (lb/hr/source)	95% Confidence Interval for Emission Factor (lb/hr/source)
Block	Butterfly	14	5	35.7	(13, 65)	0.0060	(neg, 0.19)
	Gate	1390	384	27.6	(25, 30)	0.023	(0.016, 0.034)
	Globe	81	22	27.2	(17, 37)	0.0057	(0.011, 0.023)
	Plug	123	21	17.1	(10, 24)	0.0077	(0.0016, 0.030)
Control	Butterfly	39	18	46.1	(30, 62)	0.019	(0.003, 0.09)
	Gate	17	7	41.2	(18, 67)	0.014	(0.0005, 0.25)
	Globe	499	136	27.2	(23, 31)	0.020	(0.01, 0.04)
	Plug	43	11	25.6	(13, 39)	0.0077	(0.0007, 0.06)

TABLE B2-31. PUMP SEAL TYPES DATA SUMMARY - PERCENT LEAKING AND EMISSION FACTORS

Pump Seal	Number Screened	Number Leaking	% Leaking (95% Confidence Interval)	Estimated Emission Factor (lb/hr/seal)	95% Confidence Interval for Emission Factor (lb/hr/seal)
All Stream Service					
Centrifugal/Mechanical	621	312	51.0 (46.5, 55.5)	0.20	(0.13, 0.29)
Centrifugal/Packed	87	32	36.8 (24.6, 47.8)	0.07	(0.02, 0.22)
Reciprocating/Packed	48	20	41.7 (24.8, 60.0)	0.15	(0.06, 0.69)
Light Liquid Service					
Centrifugal/Mechanical	404	264	65.3 (59.9, 70.6)	0.27	(0.18, 0.41)
Centrifugal/Packed	37	17	45.9 (26.3, 66.6)	0.08	(0.01, 0.34)
Reciprocating/Packed	25	17	68.0 (41.9, 87.8)	0.26	(0.04, 1.20)
Heavy Liquid Service					
Centrifugal/Mechanical	217	48	22.1 (15.7, 28.4)	0.05	(0.02, 0.12)
Centrifugal/Packed	50	15	30.0 (15.6, 47.9)	0.04	(0.008, 0.17)
Reciprocating/Packed	23	3	13.0 (1.8, 38.5)	0.01	(neg, 7.2)

(Continued)

TABLE B2-31. Continued

Pump Seal	Number Screened	Number Leaking	% Leaking (95% Confidence Interval)	Estimated Emission Factor (lb/hr/seal)	95% Confidence Interval for Emission Factor (lb/hr/seal)
Light Liquid Streams					
In-Service	86	54	62.8 (52, 73)	0.17	(0.06, 0.4)
Out-of-Service	69	30	43.5 (32, 56)	0.29	(0.06, 1.2)
Heavy Liquid Streams					
In-Service	48	12	25.0 (14, 40)	0.05	(0.005, 0.26)
Out-of-Service	28	3	10.7 (2, 28)	0.002	(neg., 0.16)
Centrifugal/Mechanical					
In-Service	95	51	53.7	0.13	(0.05, 0.3)
Out-of-Service	68	23	33.8 (23, 46)	0.14	(0.02, 0.7)
Double Seal	106	41	38.7 (30, 49)	0.15	(0.05, 0.4)
Single Seal	474	247	52.1 (46, 58)	0.19	(0.12, 03)

(Continued)

TABLE B2-31. Continued

Pump Seal	Number Screened	Number Leaking	% Leaking (95% Confidence Interval)	Estimated Emission Factor (lb/hr/seal)	95% Confidence Interval for Emission Factor (lb/hr/seal)
Centrifugal/Packed					
In-Service	35	13	37.1 (21, 55)	0.05	(0.006, 0.3)
Out-of-Service	21	7	33.3 (15, 57)	0.06	(0.001, 1.5)
Double Seal	23	5	21.7 (5, 39)	0.005	(neg., 0.17)
Single Seal	62	26	41.9 (30, 55)	0.07	(0.02, 0.2)

TABLE B2-32. COMPRESSOR SEAL TYPES DATA SUMMARY - PERCENT LEAKING AND EMISSION FACTORS

Compressor Seal Type	Number Screened	Number Leaking	Percent Leaking (95% Confidence Interval)	Estimated Emission Factor (lb/hr/seal)	95% Confidence Interval for Emission Factor (lb/hr/seal)
All Streams:					
Reciprocal Packed	153	136	88.9 (83, 94)	1.24	(0.70, 2.3)
Rotating Mechanical	24	8	33.3 (15, 55)	0.21	(0.01, 3.0)
Rotating Labyrinth	11	2	18.2 (2, 52)	0.02	(0.01, 6.5)
Seal Type Not Identified	42	32	76.2 (60, 88)	2.86	(0.77, 9.8)
Hydrocarbon Streams:					
Reciprocal Packed	93	81	87.1 (78, 93)	1.10	(0.59, 2.03)
Rotating Mechanical	21	7	33.3 (14, 57)	1.03	(0.018, 40.9)
Seal Type Not Identified	16	14	87.5 (61, 98)	8.88	(1.21, 49.2)
Hydrogen Streams:					
Reciprocal Packed	52	47	90.4 (78, 97)	0.038	(0.016, 0.084)
Seal Type Not Identified	25	18	72.0 (50, 88)	0.79	(0.13, 4.06)

TABLE B2-33. RELIEF VALVE DATA SUMMARY - PERCENT LEAKING AND EMISSION FACTORS

Relief Valve Category	Number Screened	Number Leaking	Percent Leaking	95% Confidence Interval for Percent Leaking	Emission Factor (lb/hr/valve)	95% Confidence Interval for Emission Factor (lb/hr/valve)
Type:						
Single Relief Valve	68	31	45.6	(34, 57)	0.22	(0.06, 0.77)
Double Relief Valve	189	27	14.3	(9.3, 19)	0.067	(0.01, 0.28)
Venting:						
To Atmosphere	155	54	34.8	(27, 42)	0.19	(0.07, 0.51)
To Header or Flare	16	2	12.5	(0.1, 40)	0.002	(neg, 2.0)
Process Stream:						
Gas/Vapor	92	42	45.6	(35, 56)	0.36	(0.10, 1.30)
Light Liquid/Two-Phase	28	7	25.0	(11, 45)	0.013	(0.001, 0.23)
Heavy Liquid	23	8	34.8	(16, 59)	0.019	(0.001, 0.20)

TABLE B2-34. FLANGES DATA SUMMARY - PERCENT LEAKING AND EMISSION FACTORS

	Number Screened	Number Leaking	Number Leaking	95% Confidence Interval for Percent Leaking	Emission Factor (lb/hr/flange)	95% Confidence Interval for Emission Factor (lb/hr/flange)
Process Stream Type:						
Gas/Vapor	369	10	2.7	(0.8, 4.6)	0.0005	(10^{-5}, 0.005)
Light Liquid/Two-Phase	616	33	5.4	(3.3, 7.4)	0.0005	(0.0002, 0.001)
Heavy Liquid	325	6	1.9	(0.2, 3.5)	0.0007	(8×10^{-5}, 0.02)
Line Size:						
<2 inches	247	30	12.1	(7.5, 17)	0.0019	(0.0005, 0.006)
2 - 4.9 inches	1189	23	1.9	(1.2, 2.8)	0.00039	(10^{-5}, 0.002)
5 - 9.9 inches	340	14	4.1	(2.0, 6.2)	0.00016	(3×10^{-5}, 0.0005)
10 - 16.9 inches	86	10	11.6	(4.9, 18)	0.0017	(0.0001, 0.013)
≥17 inches	118	9	7.6	(2.8, 13)	0.0030	(0.0003, 0.018)

process stream groups. An important observation from these tables is the width of most of the emission factor confidence intervals. Because leak rates in any category span three or more orders of magnitude, it is impossible to precisely estimate the emission factor with a relatively small number of sources screened and sampled. Hence, these values should not be used as emission factors. Since most of the confidence intervals overlap, differences between emission factors for the various categories of a source may not be real. Differences between emission factors with overlapping confidence intervals should be treated only as trends and not absolute differences.

The effect of a process variable on emissions rate is difficult to study because of the distribution of leak rates. The effect of line size on flange emissions is a good example. In Section 2.5.1, line size was shown to have a significant positive correlation with leak rate. In Section 2.5.2, the percent of flanges leaking was significantly different for different line sizes. Figure B2-184 summarizes these findings and shows emission factors for five different line size ranges. Although there are significant differences in percent leaking and a significant effect of line size on leak rate, the confidence intervals for the emission factors all overlap.

Table B2-35 demonstrates the other difficulty in developing emission factors for subgroups of the data. The amount of data for valves is broken down by process stream

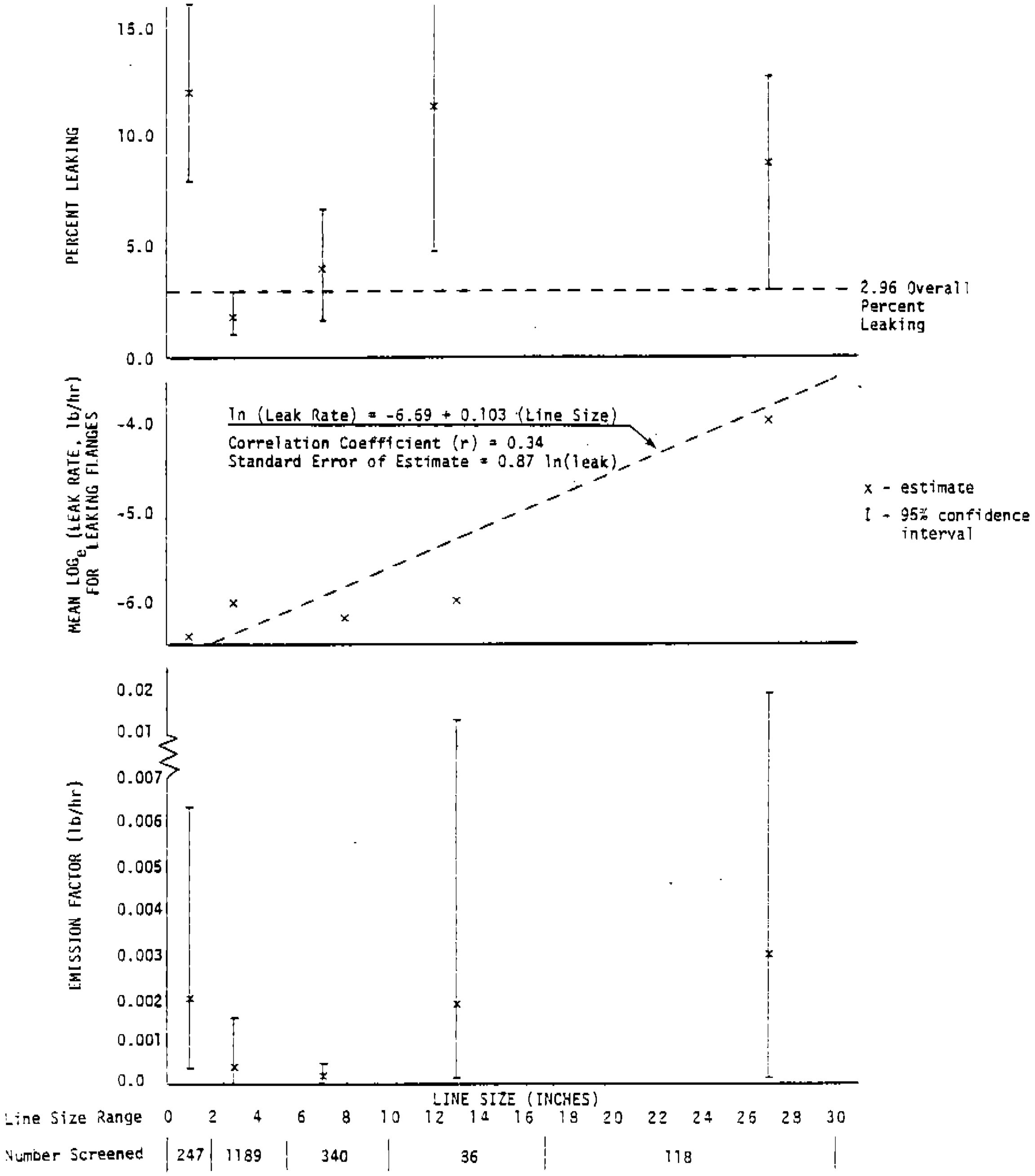


Figure B2-184. Effect of line size on emissions from flanges.

TABLE B2-35. DISTRIBUTION OF VALVES BY UNIT AND STREAM GROUPING

Unit	Gas Streams			Light Liquid/Two-Phase			Heavy Streams			
	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking	Number Screened	Number Leaking	Percent Leaking	All Streams Percent Leaking
Catalytic Reforming	36	19	52.8	104	56	53.8	0	0	0.0	56.2
Catalytic Hydrotreating/ Refining	107	32	30.0	121	30	24.8	57	7	12.3	24.2
Hydrocracking	34	11	32.4	32	11	34.4	15	4	26.7	32.5
Hydrogen Production	30	7	23.3	4	1	25.0	15	1	6.7	18.4
Fuel Gas/Light Ends Processing	185	46	24.9	246	109	44.3	27	2	7.4	34.3
Atmospheric Distillation	68	23	33.8	63	28	44.4	143	11	7.7	22.3
Vacuum Distillation	13	0	0.0	2	0	0.0	42	0	0.0	0.0
Catalytic Cracking	50	19	38.0	59	26	44.1	80	4	5.0	25.8
Delayed Coking	27	4	14.8	29	5	17.2	30	0	0.0	10.5
Alkylation	59	20	33.9	151	62	41.1	4	0	0.0	37.4
Dewaxing/Treating	37	11	29.7	159	26	16.3	93	7	7.5	15.2
Aromatics Extraction	18	5	27.8	24	8	33.3	2	1	50.0	33.3
Hydrodealkylation	12	4	33.3	24	10	41.7	0	0	0.0	38.9
All Units	676	203	30.0	1018	372	32.3	508	37	7.3	27.8

group (hydrogen streams and open-ended valves are not broken out) and unit. This categorization is desirable in order to ascertain unit effects beyond that due to the distribution of process streams within a unit. In only eight of the 39 cases do the categories have 100 or more valves screened, so obtaining precise emission factor estimates for these categories is not possible.

2.7 THE NUMBER AND DISTRIBUTION OF BAGGABLE FUGITIVE EMISSION SOURCES

The analyses of the emission rate data showed that the emission rates of hydrocarbons from valves, pump seals, and compressor seals were functions of the process stream properties. To estimate total hydrocarbon emissions from these sources in a complete refinery or in individual process units within refineries, the distributions and number of the sources among the various types of process streams must be available.

As part of the refinery assessment program, three objectives were achieved. These were:

- To count the number of fugitive hydrocarbon emission sources in a number of selected refinery process units,
- To estimate the relative number of each source type that is associated with selected process streams, and
- To estimate the total fugitive hydrocarbon emissions from the six baggable source types in a hypothetical refinery.

The results of this work are described in this section.

2.7.1 The Number of Sources in Selected Refinery Units

The total number of individual sources of fugitive hydrocarbon emissions were counted in various types of refinery process units. The number of individual sources were estimated in those units where actual counting was not done.

2.7.1.1 Source Counting

Individual fugitive emission sources were physically counted in a number of process units within five different refineries. Valves, flanges, pumps, compressors, drains, and relief valves (only those venting directly to the atmosphere) were counted. The counted sources are listed in Table B2-36. The capacities of each unit in which sources were counted are also presented.

Some sources are not included in this tabulation. Only those valves in hydrocarbon service on process, vent, or fuel lines were counted. Valves in auxiliary services such as steam, water, air, compressor lubrication, and pump seal flushing were not included in the source numbers listed in Table B2-36.

Pumps and compressors operating on non-hydrocarbon streams such as water and air were not counted. Only those relief valves that were venting directly to the atmosphere were included as emission sources. Those relief valves venting into blowdown and flare systems were not included in the numbers given in Table B2-36. All drains in a unit were counted.

TABLE B2-36. SUMMARY OF HYDROCARBON EMISSION SOURCES COUNTED IN SELECTED REFINERY PROCESS UNITS

Process Unit	Unit Capacity BPSD	Valves	Flanges	Pumps	Compressors	Relief Valves[1]	Drains
Atmospheric Distillation: Unit A	50,000	1032	3720	33	0	0	102
Unit B	10,000	754	4274	28	1	4	36
Fuel Gas/Light Gas Processing: Unit A	--	152	658	0	4	30	7
Unit B	--	210	630	5	0	3	14
Catalytic Hydroprocessing: Unit A	16,000	632	3410	11	2	16	24
Unit B	10,000	658	2076	8	3	0	--
Fluid Catalytic Cracking: Unit A	9,000	1314	4212	30	4	16	65
Hydrocracking: Unit A	14,000	931	1955	22	3	4	58
Catalytic Reforming: Unit A	11,000	660	2279	18	4	0	70
Unit B	5,000	943	3334	16	3	-	54
Unit C	3,000	470	3270	8	3	0	23
Alkylation: Unit A	6,000	571	1992	11	0	1	28
Unit B	2,000	782	2821	14	0	15	54
Fluid Coking: Unit A	7,000	304	1047	9	4	6	28
Dewaxing/Treating: Unit A	≈4,000	380	1950	16	0	4	43
Unit B	≈4,000	855	3435	19	4	0	43
Unit C	≈4,000	700	--	25	0	-	45
Unit D	--	459	1481	11	0	0	--
Hydrogen Plant: Unit A	20 MMCFD	182	635	5	-	4	17

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[1] Relief valves venting to the atmosphere.

All the counting was done solely within the battery limits of each process unit.

The relationship between the capacity or size of a process unit and the number of sources in the unit was investigated. The pump counts from this study, as well as an EPA study,[3] were correlated with the volumetric capacities of crude distillation, catalytic hydroprocessing, catalytic reforming, and alkylation units. The correlation coefficients were all very low indicating that the degree of correlation was insignificant. Thus, the number of pumps in a process unit is not directly related to the size of the unit. This is not surprising. The leak rates from all sources including pump seals and valves are effectively independent of the size of the source. Larger process units will have larger sizes of the individual leak sources. However, the larger units do not necessarily have more sources. The number of sources is a function of the complexity of the refinery unit rather than the unit capacity.

The number of valves (and other sources) are related to the number of pumps. This was identified in this current study and by EPA.[3] Therefore, the number of valves, flanges, and drains also appear to be unrelated to the capacity of a process unit.

2.7.1.2 Estimation of Source Numbers in Selected Refinery Units

The visual source counts were used as a basis for estimating the total source populations in some of the major types of refinery process units. These estimated source populations are presented in Table B2-37.

TABLE B2-37. ESTIMATED NUMBER OF INDIVIDUAL EMISSION SOURCES[2] IN 15 SPECIFIC REFINERY PROCESS UNITS

Process Unit	Estimated Number of Sources Within Battery Limits of Process Units					
	Valves	Flanges	Pumps[3]	Compressors[4]	Drains	Relief Valves
Atmospheric Distillation	893	3997	31	1	69	6
Vacuum Distillation[1]	500	1785	16	0	42	6
Fuel Gas/Light Ends Processing	181	644	3	2	11	6
Catalytic Hydroprocessing	645	2743	10	3	24	6
Catalytic Cracking	1314	4212	30	4	65	6
Hydrocracking	931	1955	22	3	58	6
Catalytic Reforming	691	2961	14	3	49	6
Aromatics Extraction[1]	600	2142	18	0	47	6
Alkylation	677	2407	13	0	41	6
Delayed Coking[1]	300	1071	9	0	23	6
Fluid Coking	304	1047	9	4	28	6
Hydroealkylation[1]	690	2463	14	3	36	6
Treating/Dewaxing	599	2289	18	1	44	6
Hydrogen Production	182	635	5	3[1]	17	6
Sulfur Recovery[1]	200	714	6	0	16	6

---

[1] Sources were not counted in process units of this type. The number of sources was estimated.

[2] Only those sources in hydrocarbon (or organic compound) service.

[3] Number of pump seals = 1.4 × number of pumps.

[4] Number of compressor seals = 2.0 × number of compressors.

Sources were not counted in some types of process units including vacuum distillation, aromatics extraction, delayed coking, hydrodealkylation, and sulfur recovery units. The number of valves, pumps, and compressors in these units were estimated from source counts obtained in similar types of units.

The number of flanges and drains in uncounted process units were based on the average number of valves and pumps, respectively, in counted process units. Specifically, the ratio of flanges to valves for counted units was 3.6. This ratio was multiplied by the estimated number of valves in each uncounted unit to obtain estimates of the number of flanges. The ratio of drains to pumps for all counted process units was 2.6. This ratio was multiplied by the estimated number of pumps in each uncounted process unit to obtain an estimate of the number of drains.

Table B2-36 shows that the number of relief valves venting to the atmosphere varies widely among counted process units. These differences are noted between different types of process units as well as units of the same type. This appears to be the result of individual refinery practice; that is, the degree to which emission are collected from relief valves varies from one refinery to the next. Therefore, the average of six atmospherically vented relief valves, determined from the counted units listed in Table B2-36, was used as the estimate for the number of relief valves for all of the process units.

Open-ended valves were not counted during this program and no estimate for the number of these fittings is offered.

2.7.2 Distribution of Fugitive Emission Sources

Emission factors for fugitive hydrocarbon sources have been developed. These are given in Section 2.6 of this Appendix. These factors are a function of the process stream service of the individual sources. An estimate of the number of valves, pump seals, and compressor seals in various process stream services is required to develop total hydrocarbon emission rates from refinery process units. These source distributions were determined for pumps and compressors during the field sampling program in refineries. Stream service distributions were not established for valves, however. Thus, the valve distributions were estimated by indirect means.

2.7.2.1 Estimation of Valve and Pump Stream Service Distributions

The number of valves in any given refinery process unit should be related to the total number of pumps and compressors. Consequently, the total number of valves in each of the counted process units were divided by the total number of counted pumps. These values are shown in Table B2-38. The average valve-to-pump ratio determined from field counts was 41 with a standard deviation of ± 10. In the Los Angeles Joint Study in 1958,[1] approximately 45 valves were counted for each pump.

In the Los Angeles Joint Study, it was found that 23.6 percent of all refinery valves were in hydrocarbon gas service. Similarly, 44.8 percent of the valves were in liquid service processing gasoline and lighter liquids (Radian's "light liquid" stream designation). About 31.6 percent of the

TABLE B2-38. AVERAGE NUMBER AND ESTIMATED DISTRIBUTION OF VALVE AND PUMP SEALS IN REFINERY PROCESS UNITS

Process Unit	Average No. of Valves	Average No. of Pumps	Average No. of Compressors	Valve To Pump Ratio	Pump Service Distribution		Estimated Distribution of Valves, Number/Unit				Estimated Distribution of Pump Seals, Number/Unit[2]			Estimated Distribution of Compressor Seals, Number/Unit[3]	
					Light Liquid Service, %	Heavy Liquid Service, %	Gas Vapor Service	Hydrogen Service	Light Liquid Service	Heavy Liquid Service	Light Liquid Service	Heavy Liquid Service	Total Pump Seals	Hydrocarbon Service	Hydrogen Service
Atmospheric Distillation	893	31	1	29	35	65	89	0	281	521	15	28	43	2	0
Vacuum Distillation	500[1]	16[1]	0[1]	31	10	90	50[1]	0[1]	45[1]	405[1]	2[1]	20[1]	22[1]	0[1]	0[1]
Fuel Gas/Light Ends Processing	181	3	2	60	83	17	88	0	77	16	3	1	4	4	0
Catalytic Hydroprocessing	645	10	3	65	67	33	235	101	208	102	9	5	14	0	6
Catalytic Cracking	1314	30	4	44	44	56	384	0	409	521	18	24	42	8	0
Hydrocracking	931	22	3	42	55	45	174	75	375	307	17	14	31	0	6
Catalytic Reforming	691	14	3	49	90	10	180	77	391	43	18	2	20	0	6
Aromatics Extraction	600[1]	18[1]	0[1]	33	90[1]	10[1]	60[1]	0[1]	486[1]	54[1]	23[1]	3[1]	25[1]	0[1]	0[1]
Alkylation	677	13	0	52	100	0	274	0	403	0	18	0	18	0	0
Delayed Coking	300[1]	9[1]	0[1]	33	21[1]	79[1]	30[1]	0[1]	57[1]	213[1]	3[1]	10[1]	13[1]	0[1]	0[1]
Fluid Coking	304	9	4	34	21	79	30	0	58	216	3	10	13	8	0
Hydrodealkylation	690[1]	14[1]	3[1]	49	90[1]	10[1]	179[1]	77[1]	391[1]	43[1]	18[1]	2[1]	20[1]	0[1]	6[1]
Dewaxing/Treating	599	18	1	33	39	61	60	0	210	329	10	15	25	2	0
Hydrogen Production	182	5	3	36	60	40	15	8	93	62	4	3	7	0	6
Sulfur Recovery	200[1]	6[1]	0[1]	33	84[1]	16[1]	20[1]	0[1]	151[1]	29[1]	7	1	8	0	0

[1] Estimated values.

[2] Number of pump seals = 1.4 × number of pumps.

[3] Number of compressor seals = 2.0 × number of compressors.

valves handled hydrocarbon liquids that were heavier than gasoline. This latter valve service corresponds to Radian's "heavy liquid" stream category.

The distribution between light and heavy liquid service was determined for all pump seals screened in this current study. These distributions were developed as a function of the type of process unit. The pump stream service distribution are presented in Table B2-38. For some types of units, the data were insufficient and the distributions were estimated using the information from similar process units.

The overall ratio of pump seals to pumps was 1.4 in the Joint Study. This ratio was used to estimate the number of seals associated with the pumps for the various process units. The estimated number of pump seals in each type of refinery process unit and stream service is shown in Table B2-38.

In the current study it was found that 62 percent of all of the screened pump seals were in light liquid service and 38 percent of the seals were in heavy liquid service. The valve liquid service distribution was assumed to be the same as that of the pumps. In the Los Angeles Joint Study Report the stream services of pumps were not reported. However, it was found that 59 percent of the valves in liquid service were in lines processing light hydrocarbon liquids (lighter than kerosene) and 41 percent were in heavy liquid service. This valve liquid stream service compares favorably with the Radian pump service distribution.

The number and stream group distributions of valves in each process unit were estimated using the procedure described below. Since 24 percent of all valves were found to be in gas service in the Joint Study, 76 percent of the average of 41 valves per pump or 31 valves per pump were assumed to be in liquid service.

The remaining valve distribution for hydrocarbon vapor service, hydrogen service and light and heavy liquid service was determined as follows:

1) Valves in liquid service = 31 × (number of pumps in the process unit).

2) Valves in gas service = Total counted valves--valves in liquid service (Step 1). It was assumed that at least 10% of the valves in a process unit are in gas stream service. The number of valves calculated in this step can amount to less than 10% of the total valves. If so, the number of gas valves is set at 10% of the total number of valves.

3) Valves in hydrogen service = 30% of the total number of valves in gas service for units which utilize significant quantities of hydrogen (reforming, HDS, hydrocracking).

4) Valve liquid distribution = Ratio of pump liquid stream service as determined from this study.

2.7.2.2 Estimation of Compressor Seal Distribution

The compressor seal emission factors have been developed for two stream types; predominantly hydrogen streams and predominantly hydrocarbon streams. All compressors and seals were counted and screened in those refineries involved in the current study. Of the screened compressor seals, 63 percent were processing hydrocarbons and 37 percent were compressing a gas consisting primarily of hydrogen.

The distribution of hydrocarbon and hydrogen service was done on a unit basis. That is, the compressors in process units utilizing substantial amounts of hydrogen in the processing scheme generally are in hydrogen service. Thus, for each unit, the compressors have been classified as either hydrocarbon service or hydrogen service.

In the Los Angeles Joint Study, a ratio of 2.14 compressor seals per compressor was noted. In this report, a ratio of 2.0 seals per compressor was used to estimate the number of seals in the various refinery process units.

2.7.3 Fugitive Hydrocarbon Emissions from a Hypothetical Refinery

An estimate was made of the total fugitive hydrocarbon emissions from six source types in a hypothetical refinery. The Texas Gulf Coast Cluster Model Refinery, developed by Arthur D. Little, Inc.[2], was used for this purpose. The major process units are shown in Table B2-39. These process units were developed from the block flow diagram of the ADL Gulf Coast Model Refinery. Two atmospheric distillation units, two reformers, and a hydrogen plant are included in the list of process units. The capacities of each unit are also shown in Table B2-39; however, they have been included only for completeness and have little if any bearing on total emissions.

An estimate of the total number of each source type and their total hydrocarbon emissions are given in Table B2-40. Where applicable, the number of sources and the total emissions from sources in the various stream services are also presented.

TABLE B2-39. MAJOR PROCESS UNITS IN HYPOTHETICAL REFINERY

ADL - Texas Gulf Cluster Model: 330,000 BPCD

Refinery Process Unit	Capacity, BPCD
Atmospheric Distillation #1	200,000
Atmospheric Distillation #2	131,000
Vacuum Distillation	134,000
Light Ends/Gas Processing	12,000
HDU: Reformer Feed	57,000
HDU: Light Gas Oil	11,000
HDU: Heavy Gas Oil	15,000
HDU: Light Cycle Oil	15,000
HDU: Vacuum Gas Oil	17,000
HDU: Coker Naphtha	3,000
Hydrocracker	15,000
FCCU	93,000
Catalytic Reformer: #1	41,000
Catalytic Reformer: #2	30,000
Aromatics Extraction	16,000
Alkylation	18,000
Coker	17,000
Hydrogen Plant	---

TABLE B2-40. HYPOTHETICAL REFINERY: NON-METHANE HYDROCARBON EMISSIONS[1]

	Number of Valves in Units					Valve Emissions, lb./hr.					Relief Valves		Flanges	
Process Unit	Gas Vapor Service	Hydrogen Service	Light Liquid Service	Heavy Liquid Service	Total	Gas Vapor Service	Hydrogen Service	Light Liquid Service	Heavy Liquid Service	Total	Total R.V.	Emissions lb./hr.	Total Flanges	Emissions lb./hr.
Atmospheric Distillation #1	89	0	281	523	893	5.25	0.0	6.74	0.26	12.25	6	1.14	3997	2.24
Atmospheric Distillation #2	89	0	281	523	839	5.25	0.0	6.74	0.26	12.25	6	1.14	3997	2.24
Vacuum Distillation	50	0	45	405	500	2.95	0.0	1.08	0.20	4.23	6	1.14	1785	1.00
Light Ends/Gas Processing	88	0	77	16	181	5.19	0.0	1.85	0.01	7.05	6	1.14	644	0.36
HDU: Reformer Feed	235	101	208	102	645	13.9	1.82	4.99	0.05	20.76	6	1.14	2743	1.54
HDU: Light Gas Oil	235	101	208	102	645	13.9	1.82	4.99	0.05	20.76	6	1.14	2743	1.54
HDU: Heavy Gas Oil	235	101	208	102	645	13.9	1.82	4.99	0.05	20.76	6	1.14	2743	1.54
HDU: Light Cycle Oil	235	101	208	102	645	13.9	1.82	4.99	0.05	20.76	6	1.14	2743	1.54
HDS: Vacuum Gas Oil	235	101	208	102	645	13.9	1.82	4.99	0.05	20.76	6	1.14	2743	1.54
HDS: Coker Naphtha	235	101	208	102	645	13.9	1.82	4.99	0.05	20.76	6	1.14	2743	1.54
FCCU	384	0	409	521	1314	22.7	0.0	9.82	0.26	32.78	6	1.14	4212	2.36
Hydrocracking	174	75	375	307	931	10.3	1.35	9.00	0.15	20.80	6	1.14	1955	1.09
Catalytic Reformer No. 1	180	77	391	43	691	10.6	1.39	9.38	0.02	21.39	6	1.14	2961	1.66
Catalytic Reformer No. 2	180	77	391	43	691	10.6	1.39	9.38	0.02	21.39	6	1.14	2961	1.66
Aromatics Extraction	60	0	486	54	600	3.54	0.0	11.7	0.03	15.27	6	1.14	2142	1.20
Alkylation	274	0	403	0	677	16.2	0.0	9.67	0.0	25.87	6	1.14	2407	1.35
Coking	30	0	57	213	300	1.77	0.0	1.37	0.11	3.25	6	1.14	1071	0.60
Hydrogen Production	19	8	93	62	182	1.12	0.14	2.23	0.03	3.52	6	1.14	635	0.36
	3027	843	4537	3322	11723	178.87	15.19	108.90	0.11	304.61	108	20.52	45225	25.36

defined as the difference between the inlet and outlet hydrocarbon concentrations, for these towers is given in Table B3-1. Raw data for the above values are given in Table B3-2 and calculations for the above in Tables B3-3 through B3-11.

The magnitude of the sampling/analytical variation caused some problems in quantifying the low levels of emissions from the towers. In Appendix B it was reported that the standard deviation for replicate TOC analyses was 4.2 ppm. If two tests were run each day the standard deviation for the average would be 3.0 ppm. The between day standard deviation (after averaging replicate samples and analyses) reported here using the TOC analyses was 3.61 ppm. Since this is close to the analytical standard deviation when replicate samples are averaged, it appears most of the variation in the TOC data is due to the analytical technique in the homogenity of replicate samples.

The analytical standard deviation for the purge method was reported in Appendix B as 80 percent of the concentration (averaging about 0.1 ppm). The between day standard deviation calculated here was 0.12 ppm so again most of the variation in the purge data is due to the analytical method. But, since the levels reported by the purge method were at least an order of magnitude smaller than the TOC values, the absolute variation is much smaller for towers evaluated using the purge technique.

Since sampling was only done over five to seven days for most towers, and emissions from the towers were found to be relatively low, it was not surprising to get some negative values as estimates of emissions for a particular tower. The negative estimates are as follows:

It must be emphasized that all of the source counts and stream service distributions given in Section 2.7 are, at best, rough estimates. Even those values based on actual source count data should be considered rough estimates since only a small number of process units were counted. In addition, source counts for similar types of process units showed large variations. Therefore, reliable estimates for emissions source counts and distributions should be obtained for the particular process unit in question rather than using the estimates which are designed to characterize typical refinery operation.

2.8 REFERENCES

1. Air Pollution Control District, County of Los Angeles, Emissions to the Atmosphere from Petroleum Refineries in Los Angeles County, Final Report No. 9, 1958.

2. Arthur D. Little, Inc., The Impact of SO_x Emissions Control on the Petroleum Refining Industry. EPA Contract No. 68-02-1332, 1976.

3. Powell, D., et al., Development of Petroleum Refinery Plot Plans, EPA-450/3-78-025, Pacific Environmental Services, June 1978.

4. Wetherold, R. G., and Provost, L. P., Emission Factors and Frequency of Leak Occurrence for Fittings in Refinery Process Units. Interim Report, EPA-600/2-79-044, Radian Corporation, Austin, Texas, February 1979.

SECTION 3

COOLING TOWERS AND WASTEWATER TREATMENT SYSTEMS

3.1 COOLING TOWERS

3.1.1 Methodology

Hydrocarbon emissions from cooling towers were determined from hydrocarbon material balances around each tower. Water from two sources enters a cooling tower: make-up water and the hot water from process heat exchangers. Water leaves the tower as vapor from the top of the tower, as cooled water returning to the process heat exchangers, and as blowdown. Drift and windage losses also occur but they are insignificant in relation to these other factors. The water balance is schematically illustrated in Figure B3-1. The hydrocarbon balance is therefore:

$$HC_{\text{Inlet}} + HC_{\text{Makeup}} = HC_{\text{Outlet}} + HC_{\text{Blowdown}} + HC_{\text{Evaporation}}$$

The make-up rate is controlled to exactly balance blowdown plus evaporation; however, the hydrocarbon content of the make-up water was negligible. The above balance may therefore be written:

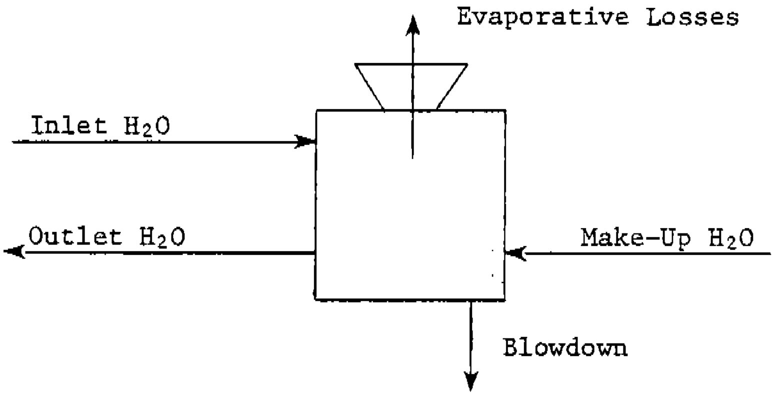

Figure B3-1. Cooling tower water balance.

$$HC_{Evaporation} = (HC_{Inlet} - HC_{Outlet}) - HC_{Blowdown}$$

or, to be more specific:

$$\begin{aligned}\text{Evaporative Emissions, lb/hr} = {} & (\text{Circulation,GPM})(8.33\ \tfrac{\text{lb}}{\text{gal}})(\text{ppm}_{in}-\text{ppm}_{out}) \\ & (10^{-6})(60\ \tfrac{\text{min}}{\text{hr}}) \\ & - (\text{Blowdown,GPM})(8.33\ \text{lb/gal})(\text{ppm}_{out}) \\ & (10^{-6})(60\ \tfrac{\text{min}}{\text{hr}})\end{aligned}$$

At some refineries, the blowdown rate was not available, and was therefore eliminated from the calculations.

Two analysis methods were used to determine the hydrocarbon content of the inlet and outlet streams. With the first method, the total organic carbon content (TOC) was determined with the use of a Dohrman Total Organic Carbon Analyzer. Quality control studies reported in Appendix C questioned the accuracy of this technique. Accuracy at low TOC levels is important since a difference of 1 ppm in the organic carbon content of the inlet and outlet streams can be equivalent to as much as 2 - 5 lb/hr of hydrocarbon emissions.

All nonmethane hydrocarbons were represented as hexane. Since the readout of the TOC analyzer is in ppm organic carbon, the following conversion was used;

$$\text{Total Hydrocarbons}_{ppm} = \text{Total Organic Carbon}_{ppm}\ (\frac{86}{72})$$

where the ratio (86/72) represents the molecular weight of hexane over the molecular weight of the carbon contained in the hexane.

With the second analytical method, water samples were analyzed by purging only volatile organics from the water. Values obtained by the purge method were found to be much more precise in absolute value than those obtained by TOC analysis although a bias of about - 15 percent of the concentration was observed. Both methods were used on the water samples from one of the refineries.

In order to compensate for the difference in precision of the two analytical methods and the different number of samples analyzed for each tower, a weighting technique was used to determine mean values for groups of tower estimates. The technique used is as follows:

$$\text{Mean Value} = \frac{W_A\overline{X}_A + W_B\overline{X}_B + W_C\overline{X}_C + \ldots\ldots}{W_A + W_B + W_C + \ldots\ldots}$$

where, $W_a = \dfrac{\text{Number of Analyses for Tower A}}{\text{(Variance for Analytical Method used for Tower A)}}$ = Weighting Factor, and

$\overline{X}_A$ = Average value reported for Tower A.

The variance for each analytical method was estimated by pooling the between-day variances for the individual towers evaluated using each method. These variances include variability due to analysis, sampling, and process variations. The pooled values were as follows:

Method	Standard Deviation	Variance
TOC	3.61 ppm	13.0
Purge	0.118 ppm	0.014

The confidence intervals for the average emission estimates were computed by first calculating the variance between towers for each method and then pooling these calculated variances (σ^2) as follows:

$$\hat{\sigma}^2 = \frac{W_{TOC}\ (\sigma^2_{TOC}) + W_{Purge}\ (\sigma^2_{Purge})}{W_{TOC} + W_{Purge}}$$

where, W_{TOC} = Sum of weighting factors for TOC towers.

W_{Purge} = Sum of weighting factors for purge towers

Confidence intervals for the estimated mean values were then calculated using:

$$\text{Mean Value} \pm 2\sqrt{\frac{\hat{\sigma}^2}{\text{number of towers}}}$$

3.1.2 Results

Thirty-one cooling towers were sampled, eight of which had statistically significant emissions. Streams from a total of 21 towers were analyzed by TOC and streams from 15 towers were analyzed by purging. Therefore, streams from five towers were analyzed by both TOC analysis and purge analysis. The purge values were judged to be the more precise of the two methods used and they were chosen to represent the towers analyzed by both methods in the calculations of mean emissions for all towers. A summary of the emissions and the Δ ppm values, defined as the difference between the inlet and outlet hydrocarbon concentrations, for these towers is given in Table B3-1. Raw data for the above values are given in Table B3-2 and calculations for the above in Tables B3-3 through B3-11.

The magnitude of the sampling/analytical variation caused some problems in quantifying the low levels of emissions from the towers. In Appendix B it was reported that the standard deviation for replicate TOC analyses was 4.2 ppm. If two tests were run each day the standard deviation for the average would be 3.0 ppm. The between day standard deviation (after averaging replicate samples and analyses) reported here using the TOC analyses was 3.61 ppm. Since this is close to the analytical standard deviation when replicate samples are averaged, it appears most of the variation in the TOC data is due to the analytical technique in the homogenity of replicate samples.

The analytical standard deviation for the purge method was reported in Appendix B as 80 percent of the concentration (averaging about 0.1 ppm). The between day standard deviation calculated here was 0.12 ppm so again most of the variation in the purge data is due to the analytical method. But, since the levels reported by the purge method were at least an order of magnitude smaller than the TOC values, the absolute variation is much smaller for towers evaluated using the purge technique.

Since sampling was only done over five to seven days for most towers, and emissions from the towers were found to be relatively low, it was not surprising to get some negative values as estimates of emissions for a particular tower. The negative estimates are as follows:

TABLE B3-1. SUMMARY OF COOLING TOWER EMISSIONS

Cooling Towers Sampled	31	
Cooling Towers Having Statistically Significant Emissions	8	
Range of Cooling Tower Circulation Rates	714 to 58,000 GPM	
	Results (estimate with 95% confidence interval)	
Mean Cooling Tower Δ HC Concentration		
From Emitting Towers		
Both Analyses	0.101 ± 0.19 ppm	(negligible, 0.29 ppm)
From All Towers Sampled		
TOC Analysis	1.25 ± 1.24 ppm	(0.01, 2.5 ppm)
Purge Analysis	0.0130 ± 0.0299 ppm	(negligible, 0.043 ppm)
Both Analyses[a]	0.0173 ± 0.058 ppm	(negligible, 0.075 ppm)
Mean Cooling Tower Emissions		
From Emitting Towers		
Both Analysis	0.00088 ± 0.0016 lb/1000 gal	(negligible, 0.0025 lb/1000 gal)
From All Towers Sampled		
TOC Analysis	0.0124 ± 0.0123 lb/1000 gal	(0.0001, 0.025 lb/1000 gal)
Purge Analysis	0.000108 ± 0.00025 lb/1000 gal	(negligible, 0.000261 lb/1000 gal)
Both Analyses[a]	0.000151 ± 0.00051 lb/1000 gal	(negligible, 0.00066 lb/1000 gal)
Range of Measurable Emissions	0.36 to 8.46 lb/hr	

[a] Calculated for 15 towers analyzed by TOC only plus 16 towers analyzed by purge. The 5 towers analyzed by both methods were represented only by the purge values, considered more accurate than TOC values.

TABLE B3-2. RAW DATA FOR COOLING TOWER CALCULATIONS

Number	Service	Analytical Method	Day 1		Day 2		Day 3		Day 4		Day 5		Day 6		Day 7	
			n*	Δ PPM	n	Δ PPM	n	Δ PPM	n	Δ PPM	n	Δ PPM	n	Δ PPM	n	Δ PPM
1	Catalytic Cracker	Purge	1	0.030	1	0.014	1	-0.020	1	-0.010	1	-0.002				
2	Catalytic Cracker	Purge	1	0.040	1	0.011	1	0.012	1	0.007						
3	Isomax	TOC	2	-2.7	2	3.4	2	0.3	2	0.4						
		Purge	1	-0.021	1	0.060	1	-0.047	1	0.012	1	0.299				
4	MEK Dewaxing	TOC	2	0	4	3.6	2	2.6	2	3.6	2	0.9				
5	Atmospheric Distillation	TOC	2	2.0	2	1.7	4	1.0	2	-6.7**	2	2.9	2	1.5	2	-1.6
6	Aromatics Extraction	TOC	1	-0.1	1	1.0	1	-1.4	1	-1.4	1	-4.4	1	-0.7		
7	Alkylation	TOC	1	4.3	1	3.6	1	2.3	1	0.4	1	2.5	1	-1.4	1	0.4
8	Aromatics Reformer	TOC	1	1.2	1	0.5	1	1.4	1	-2.3	1	1.7	1	1.9	1	-0.1
9	Hydrotreating	TOC	2	-2.7	2	-1.6	3	5.3	2	4.3	2	-3.5	1	0.5		
10	Alkane	TOC	2	-6.4	2	-9.8	-	-	2	-9.9	2	6.0				
		Purge	1	0.049	1	0.009	1	0.063	1	0.020	1	0.043				
11	Vacuum Distillation	TOC	2	-1.2	2	4.5	2	6.5	2	28.4	2	14.7	2	0.8	2	16.9
12	Fuel Reformer	TOC	1	3.4	1	1.9	1	-1.5	1	1.6	1	-0.9	1	-2.9	1	0.4
13	Crude Distillation	TOC	2	3.2	4	4.0	4	5.6	2	5.3	2	1.6				
14	Gas Hydrogenation	Purge	3	0.076	1	0.013	1	0.00	1	-0.012	1	-0.003				
15	Gas Hydrogenation	Purge	1	0.034	1	0.052	2	0.019	2	0.018	1	0.047				
16	Hydrotreating	TOC	2	-1.1	2	-0.1	3	2.1	1	7.7**	2	-1.4	1	-0.2		
17	Crude Distillation	TOC	1	-	1	0.8	1	0.3	1	3.9	1	0.2	1	0.4	1	0.6
18	Hydrogen Plant and Hydrocracker	Purge	1	0.013												
19	Catalytic Cracker	TOC	1	0.7	1	0.6	1	0.5	1	0.8	1	0.3	1	-1.0	1	0.5
20	Catalytic Cracker	TOC	3	3.8	2	1.9	2	-4.2	2	4.4	1	5.2				
		Purge	1	-0.026	1	0.149	1	0.160	1	0.176	2	0.197				
21	Phenol Treating	TOC	-	-	2	0.5	4	2.1	2	1.8	2	1.4				
22	Gas Plant and Crude Distillation	Purge	1	0.019												
23	Hydrotreating	TOC	2	-1.4	2	5.2	2	0.4	2	-0.1	2	3.2				
		Purge	1	-0.012	1	0.007	1	-0.712	1	0.097	1	-0.156				
24	Naphtha Hydrotreating	TOC	1	-	1	0.6	1	0.8	1	-2.7	1	0.3	1	-1.3	1	-1.3
25	Cat Reformer	TOC	-	-	2	5.4	2	3.3	2	-3.3	2	8.4				
		Purge	-	-	1	-0.037	1	-0.083	1	0.016	1	0.006				
26	Alkylation	Purge	1	0.082	1	-0.001	1	-0.010	1	0.009	1	0.002				
27	TCC Cracking,	Purge	1	0.006												
28	Fluid Coker,	Purge	1	0.011												
29	Crude	Purge	1	0.024												
30	Cat Cracker	TOC	2	1.9	3	1.5	2	-1.6	2	-2.9	5	-2.1	2	-6.0	2	-5.4
31	Distillation	TOC	1	-3.4	1	0.6	1	1.4	1	-0.6	1	-1.0	1	0.2	1	1.1

* n = Number of analyses per sample

** = outliers

TABLE B3-3. CALCULATION OF EMISSIONS FOR INDIVIDUAL TOWERS

Tower Number	Analysis Method	Average Δ PPM	Standard Deviation	Student t Test	Circulation (GPM)	Blowdown (GPM)	Emissions (lb/hr)
1	Purge	0.002	0.020	0.24	1,000		
2	Purge	0.018	0.015	2.00	5,000		
3	TOC	0.35	2.49	0.24	58,000	155.0	
	Purge	0.061	0.139	0.87	58,000	155.0	
4	TOC	2.14	1.63	2.63**	5,250	28.5	6.47±4.44
5	TOC	1.25	1.53	1.82**	5,000	10.0	3.73±3.27
6	TOC	-1.17	1.82	-1.43	5,500	15.7	
7	TOC	1.61	2.12	1.86**	5,900	12.5	5.56±5.24
8	TOC	0.61	1.46	1.03	6,900	24.8	
9	TOC	0.38	3.69	0.23	9,000		
10	TOC	-5.03	7.53	-1.16	1,800	30.0	
	Purge	-0.008	0.046	-0.35	1,800	30.0	
11	TOC	10.09	10.49	2.35**	714	1.4	4.30±3.20
12	TOC	0.29	2.19	0.32	6,200	23.3	
13	TOC	3.94	1.63	4.83**	3,597	9.7	8.46±3.15
14	Purge	0.015	0.035	0.84	2,850		
15	Purge	0.034	0.016	4.36**	21,150		0.36±0.18
16	TOC	-0.14	1.37	-0.20	25,000		
17	TOC	0.83	1.57	1.19	6,700	14.3	
18	Purge	0.013					
19	TOC	-0.03	0.72	-0.10	3,900	15.4	
20	TOC	2.22	3.79	1.17	48,000	131.7	
	Purge	0.131	0.090	2.92**	48,000	131.7	3.14±2.32
21	TOC	1.45	0.70	3.61**	3,500		3.03±1.56
22	Purge	0.019					
23	TOC	1.46	2.68	1.09	5,000	50.0	
	Purge	-0.155	0.324	-0.96	5,000	50.0	
24	TOC	-0.80	1.26	-1.42	10,000	16.9	
25	TOC	3.45	4.96	1.20	15,000	106.7	
26	Purge	-0.025	0.045	-0.94	15,000	106.7	
26	Purge	0.016	0.037	0.88	29,600		
27	Purge	0.006					
28	Purge	0.011					
29	Purge	0.024					
30	TOC	-2.09	3.05	-1.67	8,570	17.1	
31	TOC	-0.24	1.64	-0.36	8,300	106.0	

** Statistically significant

TABLE B3-4. CALCULATION OF AVERAGE DIFFERENCE IN HYDROCARBON CONCENTRATION (ΔPPM) FOR EMITTING TOWERS

Emitting Tower	Total Number of Analyses	Analysis Method	Δ PPM	Weighting Factor W_i	$(\Delta \text{ PPM})(W_i)$
4	12	TOC	2.14	.02	2.33
5	16	TOC	1.25	1.23	1.54
7	7	TOC	1.61	0.54	0.87
11	14	TOC	10.09	1.08	10.90
13	14	TOC	3.94	1.08	4.2
15	7	Purge	0.034	500.	17.0
20	6	Purge	0.131	428.6	56.1
21	10	TOC	1.45	0.77	1.12
Total				934.2	94.06

$$\text{Estimated Emission} = \frac{\Sigma(\Delta \text{ PPM})(W_i)}{\Sigma W_i} = \frac{94.06}{934.2} = 0.101 \text{ ppm}$$

Average Weighted Δ PPM for Emitting Towers = 0.101 ± 0.19 ppm

TABLE B3-5. CALCULATION OF AVERAGE HYDROCARBON CONCENTRATION DIFFERENCE (Δ PPM) FOR TOC ANALYSIS SAMPLES

Tower Number	Total Number of Analyses	Δ PPM	Weighting Factor W_i	(Δ PPM)(W_i)
3	8	0.35	.62	0.22
4	12	2.14	.92	1.98
5	16	1.25	1.23	1.54
6	6	-1.17	.46	-0.54
7	7	1.61	.54	0.87
8	7	0.61	.54	0.33
9	12	0.38	.92	0.35
10	8	-5.03	.62	-3.09
11	14	10.09	1.08	10.90
12	7	0.29	.54	0.16
13	14	3.94	1.08	4.26
16	11	-0.14	.85	-0.12
17	7	0.83	.54	0.45
19	7	-0.03	.54	0.02
20	10	2.22	.77	1.71
21	10	1.45	.77	1.12
23	10	1.46	.77	1.12
24	7	-0.80	.54	-0.43
25	8	3.45	.62	2.12
30	18	-2.09	1.38	-2.88
31	7	-0.24	.54	-0.13
Total			15.84	19.88

$$\text{Estimated Emissions} = \frac{\Sigma(\Delta\ \text{PPM})(W_i)}{\Sigma W_i} = \frac{19.88}{15.84} = 1.25$$

Average Weighted Δ PPM for All Towers = 1.25 ± 1.24

TABLE B3-6. CALCULATION OF AVERAGE HYDROCARBON CONCENTRATION DIFFERENCE (Δ PPM) FOR PURGE ANALYSIS SAMPLES

Tower Number	Total Number of Analyses	Δ PPM	Weighting Factor W_i	(Δ PPM)(W_i)
1	5	0.002	357.14	.71
2	4	0.018	285.71	5.14
3	5	0.061	357.14	21.78
10	5	-0.008	357.14	-2.86
14	7	0.015	500.00	7.50
15	7	0.034	500.00	17.00
18	1	0.013	71.43	.93
20	6	0.131	428.57	56.14
22	1	0.019	71.43	1.36
23	5	-0.155	357.14	-55.36
25	4	-0.025	285.71	-7.14
26	5	0.016	357.14	5.71
27	1	0.006	71.43	.43
28	1	0.011	71.43	.79
29	1	0.024	71.43	1.71
Total			4142.8	53.84

$$\hat{\mu} = \frac{\Sigma(\Delta \text{ PPM})(W_i)}{\Sigma W_i} = \frac{53.84}{4142.8} = 0.0130$$

Average Weighted Δ PPM for All Towers = 0.0130 ± .0299

TABLE B3-7. CALCULATION OF AVERAGE HYDROCARBON CONCENTRATION DIFFERENCE (Δ PPM) FOR TOC ANALYSIS AND PURGE ANALYSIS SAMPLES

Tower Number	Total Number of Analyses	Analysis Method	Δ PPM	Weighting Factor W_i	(Δ PPM)(W_i)
1	5	Purge	0.002	357.14	.71
2	4	Purge	0.018	285.71	5.14
3	5	Purge	0.061	357.14	21.78
4	12	TOC	2.14	.923	1.98
5	16	TOC	1.25	1.23	1.54
6	6	TOC	-1.17	.46	-.54
7	7	TOC	1.61	.54	.87
8	7	TOC	0.61	.54	.33
9	12	TOC	0.38	.92	.35
10	5	Purge	-0.008	357.14	-2.86
11	14	TOC	10.09	1.08	10.90
12	7	TOC	0.29	.54	.16
13	14	TOC	3.94	1.08	4.26
14	7	Purge	0.015	500.00	7.50
15	7	Purge	0.034	500.00	17.00
16	11	TOC	-0.14	.85	-.12
17	7	TOC	0.83	.54	.45
18	1	Purge	0.013	71.43	0.93
19	7	TOC	-0.03	.54	.02
20	6	Purge	-0.131	428.57	56.14
21	10	TOC	1.45	.77	1.12
22	1	Purge	0.019	71.43	1.36
23	5	Purge	-0.155	357.14	-55.36
24	7	TOC	-0.80	.54	-.43
25	4	Purge	-0.025	285.71	-7.14
26	5	Purge	0.016	357.14	5.71
27	1	Purge	0.006	71.43	.43
28	1	Purge	0.011	71.43	.79
29	1	Purge	0.024	71.43	1.71
30	18	TOC	-2.09	1.38	-2.88
31	7	TOC	-0.24	.54	-.13
				4155.31	71.72

$$\hat{\mu} = \frac{\Sigma(\Delta\ PPM)(W_i)}{\Sigma W_i} = \frac{71.72}{4155.31} = 0.173$$

Average Weighted Δ PPM for All Towers = 0.0173 ± .0585

TABLE B3-8. CALCULATION OF EMITTING TOWER EMISSION RATE

Tower Number	Analysis Method	Δ PPM	lb/1000 gal
4	TOC	2.14	0.0213
5	TOC	1.25	0.0124
7	TOC	1.61	0.0160
11	TOC	10.09	0.1004
13	TOC	3.94	0.0392
15	Purge	0.034	0.00028
20	Purge	0.131	0.00110
21	TOC	1.45	0.0144

$\overline{X}$ = Weighted Δ PPM for emitting towers = 0.101 ± 0.19 PPM

$$\text{Mean Emission Rate} = (\overline{X})\left(\frac{\Sigma(\Delta\ \text{PPM})(W_i)\ \text{for TOC samples}}{\Sigma(\Delta\ \text{PPM})(W_i)\ \text{for all samples}}\right)\left(\begin{matrix}\text{TOC Conversion}\\ \text{Factor}\end{matrix}\right)^{a}$$

$$+\left(\frac{\Sigma(\Delta\ \text{PPM})(W_i)\ \text{for purge samples}}{\Sigma(\Delta\ \text{PPM})(W_i)\ \text{for all samples}}\right)\left(\begin{matrix}\text{Purge Conversion}\\ \text{Factor}\end{matrix}\right)^{b}$$

$$= (0.101 \pm 0.19)\left(\frac{20.96}{94.06}\right)(9.946) + (0.101 \pm 0.19)$$

$$\left(\frac{73.1}{94.06}\right)(8.33\text{E-}3)$$

$$= 0.000878 \pm .00165\ \text{lb/1000 gal}$$

---

[a] TOC Conversion Factor = $(8.33)(1.194)(10^{-3})$ = 9.946E-3

[b] Purge Conversion Factor = $(8.33)(10^{-3})$ = 8.33E-3

TABLE B3-9. CALCULATION OF EMISSION RATE FOR TOC ANALYSIS SAMPLES

Tower Number	Δ PPM	Emission Rate (lb/1000 gal)
3	0.35	0.0035
4	2.14	0.0213
5	1.25	0.0124
6	-1.17	-0.0116
7	1.61	0.0160
8	0.61	0.0061
9	0.38	0.0038
10	-5.03	-0.0500
11	10.09	0.1004
12	0.29	0.0028
13	3.94	0.0392
16	-0.14	-0.0014
17	0.83	0.0083
19	-0.03	-0.0003
20	2.22	0.0221
21	1.45	0.0144
23	1.46	0.0145
24	-0.80	-0.0080
25	3.45	0.0343
30	-2.09	-0.0208
31	-0.24	-0.0024

$\overline{X}$ = Weighted Δ PPM for TOC Analysis Samples = 1.25 ± 1.24

Mean Emission Rate = $(\overline{X})$(TOC Conversion Factor)[a]

= (1.25 ± 1.24)(9.946E-3)

= .0124 ± .0123 lb/1000 gal

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[a] TOC Conversion Factor = (8.33)(1.194)(10^{-3}) = 9.946E-3

TABLE B3-10. CALCULATION OF EMISSION RATE FOR PURGE ANALYSIS SAMPLES

Tower Number	Δ PPM	Emission Rate (lb/1000 gal)
1	0.002	0.000017
2	0.018	0.00015
3	0.061	0.00051
10	-0.008	0.000067
14	0.015	0.00013
15	0.034	0.00028
18	0.013	0.00011
20	0.131	0.00110
22	0.019	0.00016
23	-0.155	-0.00130
25	-0.025	-0.00021
26	0.016	0.00013
27	0.006	0.00005
28	0.011	0.000092
29	0.024	0.00020

$\overline{X}$ = Weighted Δ PPM for Purge Analysis Samples = 0.0198 ± 0.000219

Mean Emission Rate = $(\overline{X})$(Purge Conversion Factor)[a]

= (0.0130 ± 0.0299)(8.33E-3)

= 0.000108 ± 0.00025 lb/1000 gal

TABLE B3-11. CALCULATION OF EMISSION RATE FOR TOC ANALYSIS AND PURGE ANALYSIS SAMPLES

Tower Number	Analysis Method	Δ PPM	lb/1000 gal
1	Purge	0.002	0.000017
2	Purge	0.018	0.00015
3	Purge	0.061	0.00051
4	TOC	2.14	0.0213
5	TOC	1.25	0.0124
6	TOC	-1.17	-0.0116
7	TOC	1.61	0.0160
8	TOC	0.61	0.0061
9	TOC	0.38	0.0038
10	Purge	-0.008	0.000067
11	TOC	10.09	0.1004
12	TOC	0.29	0.0028
13	TOC	3.94	0.0392
14	Purge	0.015	0.00013
15	Purge	0.034	0.00028
16	TOC	-0.14	-0.0014
17	TOC	0.83	0.0083
18	Purge	0.013	0.00011
19	TOC	-0.03	-0.0003
20	Purge	0.131	0.00110
21	TOC	1.45	0.0144
22	Purge	0.019	0.00016
23	Purge	-0.155	-0.00130
24	TOC	-0.80	-0.0080
25	Purge	-0.025	-0.00021
26	Purge	0.016	0.00013
27	Purge	0.006	0.00005
28	Purge	0.011	0.000092
29	Purge	0.024	0.00020
30	TOC	-2.09	-0.0208
31	TOC	-0.24	-0.0024

$\overline{X}$ = Weighted Δ PPM for All Towers = 0.0207 ± 0.325

$$\text{Mean Emission Rate} = (\overline{X})\left(\frac{\Sigma(\Delta\ \text{PPM})(W_i)\ \text{for TOC samples}}{\Sigma(\Delta\ \text{PPM})(W_i)\ \text{for all samples}}\right)\left(\begin{matrix}\text{TOC Conversion}\\ \text{Factor}\end{matrix}\right)^{a}$$

$$+\left(\frac{\Sigma(\Delta\ \text{PPM})(W_i)\ \text{for purge samples}}{\Sigma(\Delta\ \text{PPM})(W_i)\ \text{for all samples}}\right)\left(\begin{matrix}\text{Purge Conversion}\\ \text{Factor}\end{matrix}\right)^{b}$$

$$= (0.0173 \pm .00585)\left(\frac{17.88}{71.72}\right)(9.946\text{E-}3) + (0.0173 \pm 0.0585)$$

$$\left(\frac{53.84}{71.72}\right)(8.33\text{E-}3) = 0.000151 \pm 0.00051\ \text{lb/1000 gal}$$

---

[a] TOC Conversion Factor = $(8.33)(1.194)(10^{-3}) = 9.946\text{E-}3$

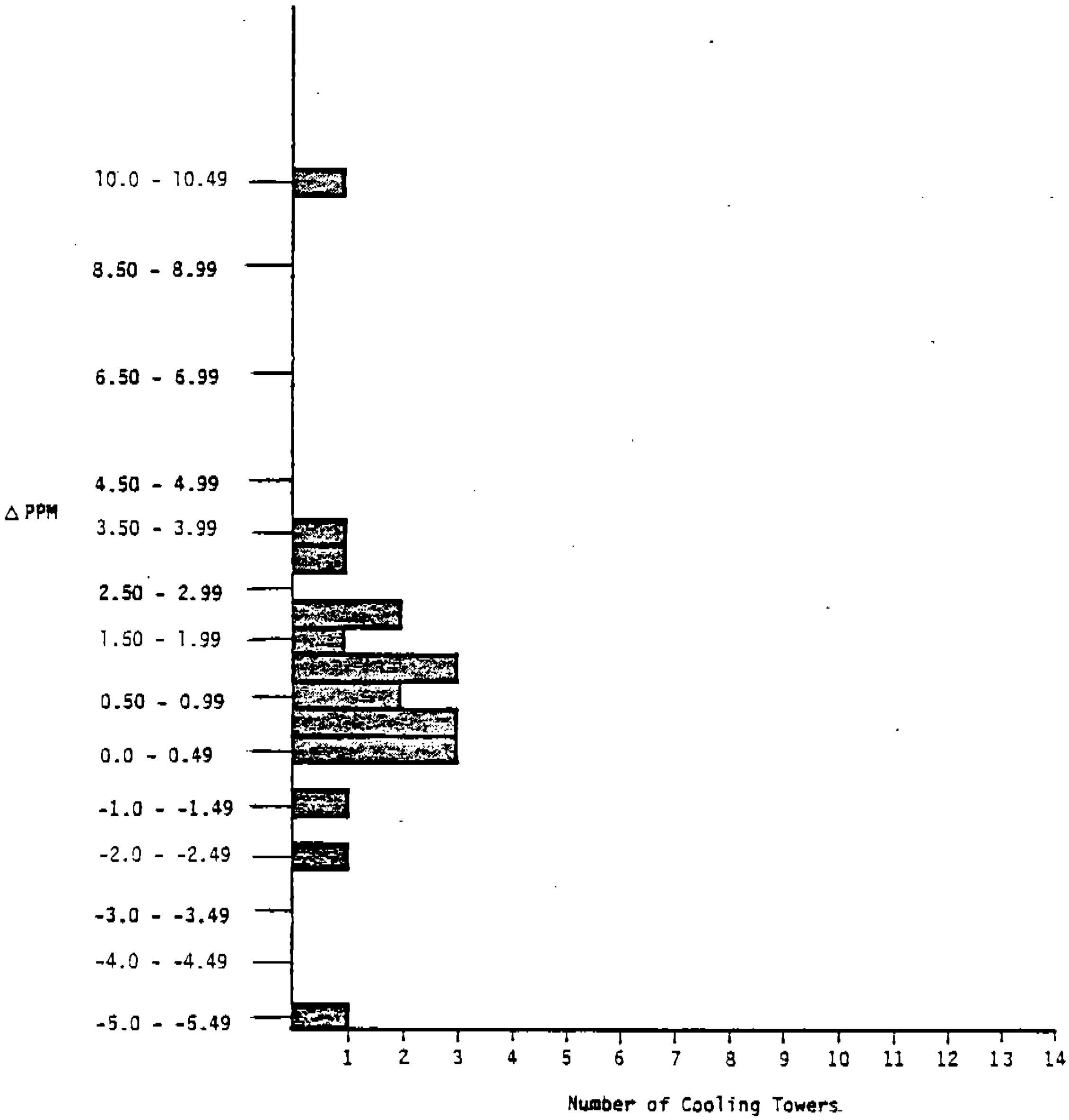
[b] Purge Conversion Factor = $(8.33)(10^{-3}) = 8.33\text{E-}3$

Analytical Method	Number of Towers	Towers with Negative Estimate	
		Number	Percent
TOC	21	7	33.3
Purge	15	2	13.3
Combined	31	8	25.8

The negative estimates are due primarily to the analytical variation. In order not to bias the average emission calculation for cooling towers, these negative values have been used rather than setting the estimate to zero.

The mean emissions for the 16 towers analyzed by TOC only and the 15 analyzed by purge were 0.00015 lb/1000 gal with 95% confidence interval of ± 0.00051 (negligible, 0.00066 lb/1000 gal). Mean emissions for the eight towers with statistically significant emissions were 0.00088 ± 0.0016 lb/1000 gal (negligible, 0.0025 lb/1000 gal). Mean emissions for the 21 towers analyzed by TOC were 0.0124 ± 0.0123 lb/1000 gal (0.0001, 0.025 lb/1000 gal). For the 15 towers analyzed by the purge method, mean emissions were 0.000108 ± 0.00025 lb/1000 gal (negligible, 0.00026 lb/1000 gal).

Values obtained by the purge method were much more precise than those obtained from TOC measurements. This fact is illustrated in Figures B3-2 through B3-4. Figure B3-2 is a graph of the results of the TOC analyses; Figure B3-3, the results of the purge analyses. When the results are combined on Figure B3-4, the difference in precision of the two methods is apparent.



02-5210-1

Figure B3-2. Display of Δ ppm hydrocarbon concentration from TOC analyses.

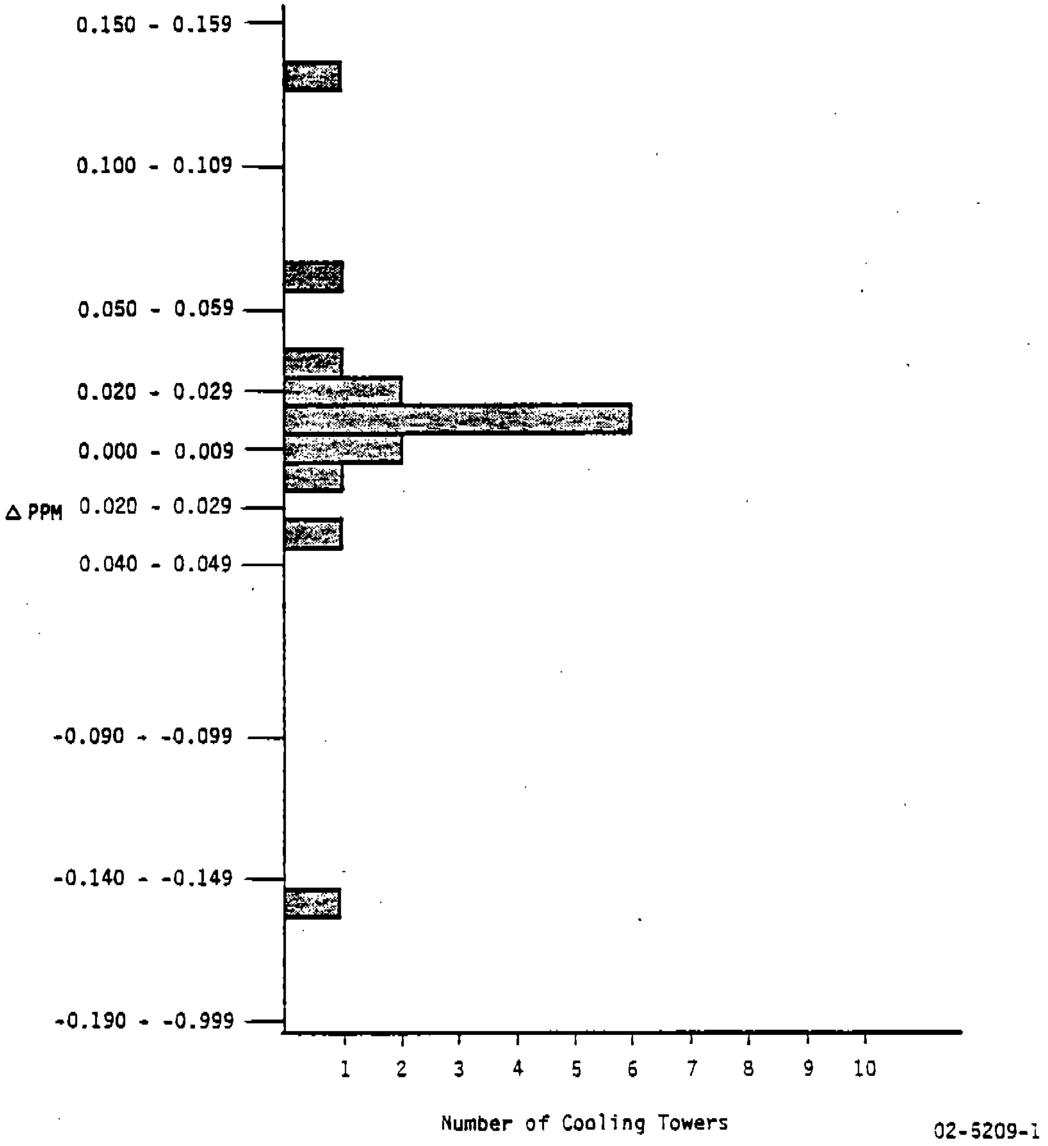
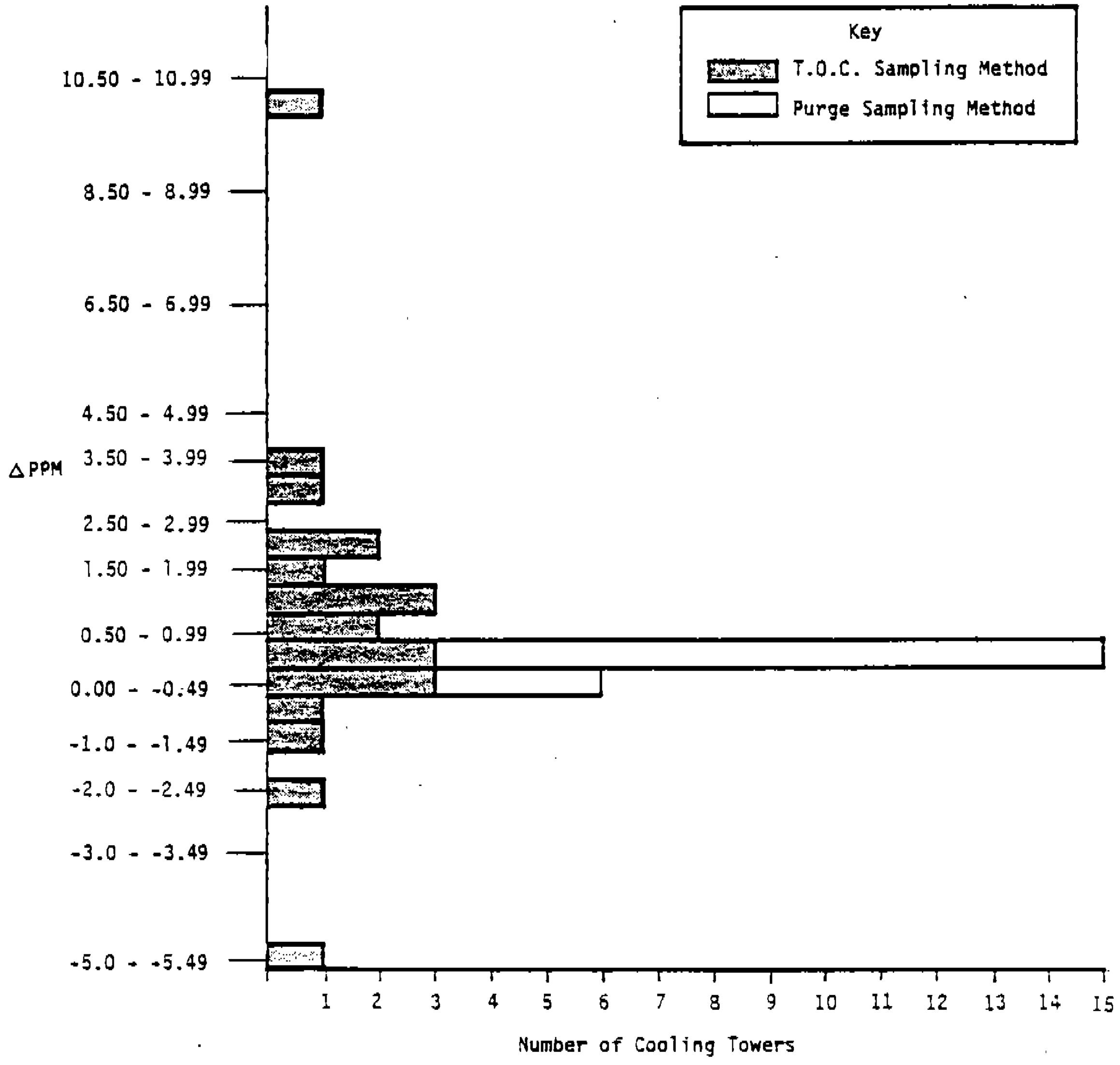


Figure B3-3. Display of Δ ppm hydrocarbon concentration from purge analyses.



02-5211-1

Figure B3-4. Display of Δ ppm hydrocarbon concentration from all analyses.

Because of the varying precision of the methods, the upper confidence limit for each estimate may be a more useful value than the estimated average for many purposes. These values which give a "worst-case" estimate for the magnitude of hydrocarbon emissions from cooling towers are as follows:

Analytical Method Used	"Worst-case" Estimate of Average Emissions from Cooling Towers
TOC	0.025 lb/1000 gal
Purge	0.0003 lb/1000 gal
Combined	0.0007 lb/1000 gal

We recommend the use of the combined emission factor (0.0007 lb/1000 gal) for estimating cooling tower hydrocarbon emissions. Thus, a cooling tower with a circulation rate of 50,000 GPM would have the following emissions rate.

$$\left(\frac{0.0007 \text{ lb}}{1000 \text{ gal}}\right)\left(\frac{50{,}000 \text{ gal}}{\text{min}}\right)\left(\frac{60 \text{ min}}{\text{hr}}\right) = 2.1 \text{ lb/hr}$$

This emissions rate is relatively small compared to other sources of emissions from refineries.

3.2 WASTEWATER SYSTEMS

Wastewater treatment is usually accomplished in three stages: primary, secondary, and tertiary treatment. Primary treatment facilities are principally involved in physically upgrading the wastewater by removal of oil, oily sludge, and grit. Thus, primary treatment facilities will be the principal sources of fugitive hydrocarbon emissions from the waste treatment plant. Oil removal equipment includes API separators, corrugated plate interceptors, flocculation units, and dissolved air flotation units. The latter are also used for suspended solids removal.

API separators, corrugated plate interceptors, and dissolved sir flotation (DAF) units were sampled to determine atmospheric emissions of hydrocarbon. The emissions were estimated from a hydrocarbon material balance around each unit. There is a great deal of scatter and uncertainty in the data and results, particularly in the determination of emissions from the oil phase. Negative values are even indicated for some emissions. The one conclusion that can be made regarding these results is that the material balance approach, as implemented in this program, is inadequate for defining emission rates. The composition of the incoming stream varies widely, and grab samples are not generally representative. For this reason, emission factors for oil-water separators and DAF units were not developed from experimental results.

Table B3-12 summarizes the average emissions per gallon of material throughput for all sampled devices by refinery. Tables B3-13 through B3-20 show daily emissions for each device sampled at individual refineries.

TABLE B3-12. DESCRIPTION OF SAMPLED DEVICES - WASTE OIL/WATER SYSTEMS

Refinery	Device	Refinery Size[1]	Covered/ Uncovered	Average Hydrocarbon Emissions	
				Losses from Oil Phase, lb/gal slop oil	Losses from Water Phase, lb/gal water
1	Rectangular API Separator	Large	C	1.6 ± 2	$2.7\text{x}10^{-4} \pm 1.8\text{x}10^{-4}$
	Circular DAF		U	0.073 ± 0.4	$8.2\text{x}10^{-5} \pm 1.5\text{x}10^{-4}$
2	Rectangular API Separator	Large	C	1.84 ± 1.11	$-3.01\text{x}10^{-6} \pm 1\text{x}10^{-5}$
3	Corrugated Plate Interceptor	Large	C	-1.5 ± 0.08	--
	Corrugated Plate Interceptor		C	-0.11 ± 0.06	--
4	Rectangular API Separator Forebay Covered	Large	U	0.12 ± 1.3	$2.2\text{x}10^{-4} \pm 2.7\text{x}10^{-4}$
5	Surge Tank	Large	U	0.45	
	Two Rectangular Separators		U	--	$1.6\text{x}10^{-5} \pm 3\text{x}10^{-6}$
	Rectangular DAF		U	--	$-2.4\text{x}10^{-5} \pm 2.7\text{x}10^{-5}$
6	Rectangular API Separator	Small	U	-1.1 ± 0.74	$1.5\text{x}10^{-4} \pm 2.4\text{x}10^{-4}$
7	Rectangular API Separator	Large	U	0.14 ± 0.4	$6.5\text{x}10^{-4} \pm 1.9\text{x}10^{-4}$
	Rectangular DAF		U	--	$1.1\text{x}10^{-4} \pm 1.3\text{x}10^{-4}$
8	Circular Separator	Small	U	0.48 ± 0.61	$3.4\text{x}10^{-4} \pm 1.8\text{x}10^{-4}$
	Circular DAF		U	--	$1.4\text{x}10^{-5} \pm 1.7\text{x}10^{-5}$

[1] Small refinery ≤ 50,000 bbl/day capacity. Large refinery > 50,000 bbl/day capacity.

TABLE B3-13. WASTEWATER SYSTEM HYDROCARBON EMISSIONS AT REFINERY 1

Day Sampled	Separator Emissions		DAF Emissions
	Oil Phase, lb/gal slop oil	Water Phase, lb/gal water	Water Phase lb/gal
1	0.20	$2.6x10^{-4}$	$-1.0x10^{-4}$
2	0.36	$4.2x10^{-4}$	$2.7x10^{-5}$
3	-0.34	$1.2x10^{-4}$	$2.0x10^{-4}$
4	--[a]	--[c]	$2.0x10^{-4}$
5	--[b]	--[c]	--[b]

[a] Day not sampled

[b] Points eliminated by Dixon's Outlier Criteria.

[c] Invalid samples.

TABLE B3-14. WASTEWATER SYSTEM HYDROCARBON EMISSIONS AT REFINERY 2

Day Sampled	Separator	
	Oil Phase, lb/gal slop oil	Water Phase, lb/gal water
1	0.75	$-3.4x10^{-7}$
2	2.23	$2.6x10^{-6}$
3	2.54	$-1.8x10^{-5}$
4	0.59	$3.7x10^{-6}$
5	3.07	--[a]

[a] Day not sampled.

TABLE B3-15. WASTEWATER SYSTEM HYDROCARBON EMISSIONS AT REFINERY 3

Day Sampled	Corrugated Plate Interceptor Emissions from Oil Phase[a]	
	CPI A (lb/gal slop oil)	CPI B (lb/gal slop oil)
1	-1.5	-0.05
2	-1.46	-0.15
3	-1.52	-0.12

[a] Average of two analyses.

TABLE B3-16. WASTEWATER SYSTEM HYDROCARBON EMISSIONS AT REFINERY 4

Day Sampled	Separator[a]	
	Oil Phase, lb/gal slop oil	Water Phase, lb/gal water
1	-0.056	-1.8×10^{-5}
2	--[b]	4.6×10^{-4}
3	-1.27	5.4×10^{-4}
6	1.84	9.9×10^{-5}
7	-0.04	2.3×10^{-5}

[a] Average of multiple analyses.
[b] Points eliminated by Dixon's Outlier Criteria.

TABLE B3-17. WASTEWATER SYSTEM HYDROCARBON EMISSIONS AT REFINERY 5

Day Sampled	Surge Tank Emissions, lb/gal slop oil	Separator Water[a] Phase Emissions lb/gal	DAF Water Phase Emissions lb/gal
1	--[b]	1.9×10^{-5}	5.2×10^{-6}
2	--[b]	--[b]	-2.1×10^{-5}
5	--[b]	--[c]	-1.7×10^{-5}
6	--[b]	1.6×10^{-5}	-6.5×10^{-5}
7	--[b]	1.2×10^{-5}	-6.2×10^{-5}
8	--[b]	1.6×10^{-5}	1.3×10^{-5}
16	0.45		

[a] Sum of two separators.
[b] Day not sampled.
[c] Points eliminated by Dixon's Outlier Criteria.

TABLE B3-18. WASTEWATER SYSTEM HYDROCARBON EMISSIONS AT REFINERY 6

	Separator Emissions	
Day Sampled	Oil Phase[a] lb/gal slop oil	Water Phase[a] lb/gal water
1	--[b]	7.6×10^{-4}
2	--[b]	1.04×10^{-4}
3	--[b]	2.6×10^{-5}
4	--[b]	5.9×10^{-5}
5	--[b]	-1.6×10^{-5}
6	--[b]	-8.0×10^{-6}
16	-1.3	--[b]
17	0.24	--[b]
18	-0.93	--[b]
19	-2.4	--[b]

[a] Average of two analyses.
[b] Day not sampled.

TABLE B3-19. WASTEWATER SYSTEM HYDROCARBON EMISSIONS AT REFINERY 7

Day Sampled	Separator Emissions Oil Phase, lb/gal slop oil	Separator Emissions Water Phase, lb/gal water	DAF Water[a] Phase Emissions lb/gal
1	--[b]	$-3.4x10^{-4}$	$5.27x10^{-5}$
3	0.5	--[b]	$2.37x10^{-5}$
4	-0.22	$1.2x10^{-5}$	$-6.6x10^{-5}$
5	--[b]	$8.4x10^{-5}$	$-1.3x10^{-5}$
6	0.13	$-1.6x10^{-5}$	$2.2x10^{-4}$
19	--[b]	--[b]	$4.32x10^{-4}$
22	--[b]	--[b]	$1.2x10^{-4}$

[a] Average of multiple analyses.
[b] Day not sampled.

TABLE B3-20. WASTEWATER SYSTEM HYDROCARBON EMISSIONS AT REFINERY 8

Day Sampled	Separator Emissions Oil Phase, lb/gal slop oil	Separator Emissions Water Phase, lb/gal water	DAF Water Phase Emissions lb/gal
1	-0.22	$8.9x10^{-5}$	$3.5x10^{-5}$
3	1.58	$3.3x10^{-4}$	$3.5x10^{-5}$
4	0.5	$2.3x10^{-4}$	$5.8x10^{-6}$
5	0.11	$3.9x10^{-4}$	$-5.8x10^{-6}$
6	0.4	$6.4x10^{-4}$	$1.9x10^{-6}$

SECTION 4

STACK EMISSIONS

Table B4-1 lists the stacks sampled during this program along with a brief description of the associated refinery process or unit. Tables B4-2 through B4-56 contain the detailed results of analyses for specific components in the gas streams. These are grouped according to the kind of processing units the stacks are associated with.

TABLE B4-1. SUMMARY OF SAMPLED STACKS

Stack Number	Description
1	Resin Fume Oxidation Unit Stack
2	Crude Process Heater Stack
3	Crude Process Heater Stack
4	Crude Process Heater Stack
5	Crude Process Heater Stack
6	Crude Process Heater Stack
7	Tail Gas Treating Unit (SRU) Stack
8	Sulfur Recovery Unit Stack
9	TCC CO Boiler Stack
10	Fluid Coker CO Boiler Stack
11	FCCU CO Boiler Stack
12	FCCU CO Boiler Scrubber Stack
13	FCCU CO Boiler Stack
14	FCCU CO Boiler Stack
15	FCCU CO Boiler Stack
16	FCCU CO Boiler Stack
17	FCCU CO Boiler Scrubber Stack
18	FCCU CO Boiler Stack
19	Fluid Coker Scrubber
20	FCCU Compressor Exhaust Stack

Tables B4-2 through B4-5 include the sampling results of emissions from a resin fume oxidation unit.

The sampling results for five heater stacks are given in Tables B4-6 through B4-11. These units were fired with mixed refinery fuel gas and fuel oil. No external emission controls were in use during any of the sampling activities.

The stack gases from the tail gas treating processes of two sulfur recovery units were sampled and analyzed. And, the results are given in Tables B4-12 through B4-17. The accuracy of the hydrocarbon and SO_x analyses of the gas from Stack No. 7 is uncertain. The concentration of hydrocarbons in the gas is very high. At the same time, almost no SO_2 was found. No satisfactory explanation of these results has been put forward.

Tables B4-18 through B4-23 give the sampling results for emissions from the CO boiler stack of a Thermofor Catalytic Cracking (TCC) unit.

Tables B4-24 through B4-29 show the sampling results from the CO boiler of a fluid coking unit. This unit was also equipped with a scrubber upstream of the CO boiler. And, sampling results for the inlet and outlet of the scrubber are given in Tables B4-30 through B4-35. Hydrocarbon samples were the only results obtained at the scrubber outlet. Hence, the effect of the scrubber or the CO boiler alone cannot be evaluated for any species except hydrocarbons. A comparison of data from these tables does, however, show the combined effect of the scrubber and the CO boiler on reducing emissions of particulates, methane and nonmethane hydrocarbons, aldehydes, HCN, and NH_3. NO_x emissions, however, were higher at the CO boiler outlet.

TABLE B4-2. STACK GAS AND PARTICULATES[a] - RESIN FUME OXIDATION UNIT

Stack	Time	Total Gas Sample[b] Meter (ft^3)	Total Gas Sample[b] STP[c] (SCF)	Avg Meter Temp (°F)	Avg Stack Temp (°F)	Avg Dry (MW)	Moisture Collected (g)	Fraction	Particulates Filter	Particulates Probe	Particulates Imp. #1	Particulates Total	Grain Loading (gr/SCF)	Avg Stack Velocity (ft/sec)	% Isokin.
1	1907-2007	32.74	30.79	84	500	27.94	36.1	0.053	0.0029	0.0046	0.0110	0.0185	0.0093	56.27	104
	2103-2203	36.47	34.16	87	500	27.94	44.7	0.058	0.0044	0.0033	0.0000	0.0077	0.0033	57.82	102

[a] Sampled with LSI EPA-5 train.

[b] Total gas flow rate is 3.09 x 10^5 SCFM.

[c] Corrected to 70°F and 29.92 inches Hg.

TABLE B4-3. METHANE/NONMETHANE HYDROCARBONS[a] AND FIXED GASES[b] - RESIN FUME OXIDATION UNIT

		Methane Concentrations[c]				Nonmethane Concentrations[c] (As Hexane)				Fixed Gases (Dry Basis)				
Stack	Time	By Weight (ppm)	By Weight (μg/l)	(lb/SCF)[d]	By Volume (ppm)	By Weight (ppm)	By Weight (μg/l)	(lb/SCF)[d]	By Volume (ppm)	CO$_2$ (%)	O$_2$ (%)	N$_2$ (%)	CO (%)	Mol. Wt. (Dry)
1	2030	2.84	3.26	2.04x10^{-7}	4.92	1547	1777	1,11x10^{-4}	498,6					
	2035	--	--	--	--	--	--	--	--	2.0	16.3	78.0	0.0	27.94
	2155	--	--	--	--	--	--	--	--	1,25	16.4	78.0	0.0	27.64
	2212	0.99	1.14	7.10x10^{-8}	1.72	8.21	9.43	5,89x10^{-7}	2.63					
	2250	--	--	--	--	--	--	--	--	1.3	16.4	78.0	0.0	27.66
	2304	1.03	1.18	7,39x10^{-8}	1.78	12.56	14.43	9.01x10^{-7}	4.05					
	1401	--	--	--	--	--	--	--	--	1.2	16.5	78.0	0.0	27.65
	1412	0.68	0.78	4.88x10^{-8}	1,18	4,89	5.62	3;5x10^{-7}	1,58					
	1513	0,85	0,98	6.10x10^{-8}	1.47	3.06	3,52	2,20x10^{-7}	0,99					

[a] Byron hydrocarbon analyzer using flame ionization detector.

[b] Fischer Model 1200 partitioner.

[c] Dry basis.

[d] Corrected to 70°F and 29.92 inches Hg.

TABLE B4-4. SULFUR SPECIES - RESIN FUME OXIDATION UNIT

		SO_3[a]		SO_2[b]		SO_2[d]		H_2S		COS		CS_2	
Stack	Time	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]
1	1907-2007	0.29	6.11×10^{-8}	27.97	4.63×10^{-6}	--	--	--	--	--	--	--	--
	1930	--	--	--		23.99	3.97×10^{-6}	--	--	--	--	--	--
	2103-2203	0.56	1.15×10^{-7}	19.44	3.22×10^{-6}	--	--	--	--	--	--	--	--
	2150	--	--	--	--	19.05	3.15×10^{-6}	--	--	--	--	--	--
	2246	--	--	--	--	12.59	2.09×10^{-6}	--	--	--	--	--	--
	1443	--	--	--	--	10.47	1.74×10^{-6}	--	--	--	--	--	--
	1610	--	--	--	--	15.14	2.51×10^{-6}	--	--	--	--	--	--

[a] IPA Impinger, $Ba(ClO_4)_2$ Titration.
[b] 6% H_2O Impingers, $Ba(ClO_4)_2$ Titration.
[c] Corrected to 70°F and 29.92 inches Hg, dry basis.
[d] GC analysis of grab samples yielded comparable results for SO_2; other species not detected.

TABLE B4-5. ALDEHYDES[a] - RESIN FUME OXIDATION UNIT

		Gas Sample Volume (ℓ)		Aldehyde Collected	Gaseous Ald. Volume @ STP	Concentrations[c]		
							By Weight @ STP	
Stack	Time	(55°F)	(STP)[b]	(μg)	(μℓ)	ppm(Vol.)	(μg/ℓ)	(lb/SCF)
1	2016-2116	12.0	11.82	1275	1025.5	86.76	107.86	6.74×10^{-6}
	2215-2240 2305-2340	12.0	11.82	300	241.3	20.41	25.38	1.59×10^{-6}

[a] Sample Rate - 200 mℓ/min. Bisulfite method used.

[b] Corrected to 70°F and 29.92 inches Hg.

[c] Dry basis.

TABLE B4-6. STACK GAS AND PARTICULATES[a] - CRUDE UNIT PROCESS HEATERS

		Total Gas Sample[b]		Avg	Avg				Particulates					Avg	
Stack	Time	Meter (ft^3)	STP (SCF)[c]	Meter Temp (°F)	Stack Temp (°F)	Avg Dry (MW)	Moisture Collected (g)	Fraction	Filter	Probe	Imp. #1	Total	Grain Loading (gr/SCF)	Stack Velocity (ft/sec)	% Isokin.
4	1319-1446	36.68	36.13	84	418	27.56	87.7	0.103	0.0993	0.0374	0.0272	0.1639	0.070	58.01	102.6
	1742-1916	35.42	35.12	81	420	26.04	78.5	0.094	0.0807	0.0490	0.0000	0.1297	0.057	58.03	99.0
5	1255-1730	39.17	37.82	100.1	492	28.06	219.6	0.214	0.0247	0.1092	0.0182	0.1521	--[d]	17.20	19.6
	1155-1433	54.17	52.74	95.4	490	28.87	273.9	0.196	0.0181	0.3925	0.0090	0.4196	--[d]	26.39	30.1
2	1342-1532	33.21	33.18	89	345	27.59	139.3	0.166	0.0049	0.0290	0.0592	0.0931	0.0433	16.63	97.6
2	1230-1424	24.14	24.57	78	344	27.92	96.5	0.157	0.0049	0.0165	0.0420	0.0634	0.0398	11.05	107.5
3	1929-1943[e]	5.83	5.83	80	350	30.11	24.8	0.168	0.0016	0.0127	0.0002	0.0143	0.0378	10.19	114.6

[a] Sampled with LSI EPA-5 train.

[b] Total gas flow rates: Stack No. 2 - 3.26 x 10^6 SCFM; Stack No. 3 - 2.34 x 10^6 SCFM; Stack No. 4 - 7.03 x 10^6 SCFM; Stack No. 5 - 2.78 x 10^6 SCFM; Stack No. 6 - Undetermined.

[c] Corrected to 70°F and 29.92 inches Hg.

[d] Particulate sampling done under nonisokinetic conditions. Grain loading not reported.

[e] Electrical problems curtailed sampling.

TABLE B4-7. METHANE/NONMETHANE HYDROCARBONS[a] AND FIXED GASES[b] - CRUDE UNIT PROCESS HEATERS

		Methane Concentrations[c]			Nonmethane Concentrations[c] (As Hexane)			Fixed Gases (Dry Basis)					
		By Weight		By Volume	By Weight		By Volume						
Stack	Time	(ppm)	(lb/SCF)[d]	(ppm)	(ppm)	(lb/SCF)[d]	(ppm)	CO_2 (%)	O_2 (%)	N_2 (%)	CO (%)	H_2 (%)	Mol. Wt. (Dry)
4	1458	--	--	--	--	--	--	7.6	9.2	76.0	0.0	--[e]	27.56
	1730	0.08	5.55×10^{-9}	0.13	3.55	2.46×10^{-7}	1.11						
	1955	--	--	--	--	--	--	5.5	9.5	73.5	0.0	--	26.04
	1957	0.10	6.94×10^{-9}	0.17	0.51	3.54×10^{-8}	0.16						
	1439	0.47	3.26×10^{-8}	0.78	5.30	3.68×10^{-7}	1.65						
	1453	0.44	3.05×10^{-8}	0.74	4.33	3.00×10^{-7}	1.35						
6	1803	0.25	1.9×10^{-8}	0.45	5.78	3.91×10^{-7}	1.76						
	1813							10.0	5.3	80.1	0.0	--[e]	28.53
	2127	--[f]	--	--	5.50	4.07×10^{-7}	1.83						
	2130							10.3	4.8	80.7	0.0	--[e]	28.67
6 Ambient	2130	3.64	2.73×10^{-7}	6.59	8.11	6.08×10^{-7}	2.73						
5	1145	2.60	1.92×10^{-7}	4.7	21.0	1.55×10^{-6}	7.07	12.0	2.0	79.4	--	--[e]	28.15
	1520	0.90	6.68×10^{-8}	1.63	24.6	1.82×10^{-6}	8.28	8.3	5.8	80.2	--	--[e]	27.96
	1100	1.80	1.33×10^{-7}	3.26	10.0	7.40×10^{-7}	3.37	14.5	2.5	79.5	--	--[e]	29.44
	1230	0.59	4.37×10^{-8}	1.07	18.8	1.39×10^{-6}	6.33	11.2	3.5	79.5	--	--[e]	28.31
3	1612	0.038	2.37×10^{-9}	0.057	4.74	2.96×10^{-7}	1.33	11.7	6.2	82.1	0.0	0.0	30.12
	1921	0.0	0.0	0.0	1.54	9.61×10^{-8}	0.432	11.7	6.0	82.0	0.0	0.0	--
3 Ambient	1927	0.867	5.41×10^{-8}	1.31	0.305	1.90×10^{-8}	0.086	--	--	--	--	--	--
2	1608	0.0	0.0	0.0	2.76	1.72×10^{-7}	0.774	11.1	6.3	82.6	0.0	0.0	28.29

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[a] Byron hydrocarbon analyzer using flame ionization detector.

[b] Fischer Model 1200 gas partitioner.

[c] Dry basis.

[d] Corrected to 70°F and 29.92 inches HG.

[e] Results questionable, not reported.

[f] Not detectable, less than 0.01 ppm by weight.

TABLE B4-8. SULFUR SPECIES - CRUDE UNIT PROCESS HEATERS

Stack	Time	SO$_3$[a] ppm (Vol)	SO$_3$[a] lb/SCF[c]	SO$_2$[b] (EPA-5) ppm (Vol)	SO$_2$[b] (EPA-5) lb/SCF[c]	SO$_2$ (HP)[e] ppm (Vol)	SO$_2$ (HP)[e] lb/SCF[c]	H$_2$S[e] ppm (Vol)	H$_2$S[e] lb/SCF[c]	COS[e] ppm (Vol)	COS[e] lb/SCF[c]	CS$_2$[e] ppm (Vol)	CS$_2$[e] lb/SCF[c]
2	1342-1532	0.51	1.063×10^{-7}	2.33	3.854×10^{-7}								
	1230-1424	0.70	1.436×10^{-7}	1.97	3.248×10^{-7}								
3	1923-1943	0.146	3.03×10^{-8}	2.11	3.479×10^{-7}								
	1616					0.0	0.0	No Data					
6	1637					0.2	3.0×10^{-8}	--[d]	--	--[d]	--	--[d]	--
	1918					0.04	7.0×10^{-9}	--[d]	--	--[d]	--	--[d]	--
	2000					0.3	5.0×10^{-8}	--[d]	--	--[d]	--	--[d]	--
5	1255-1730	34.14	7.06×10^{-6}	82.62	1.4×10^{-5}		--						
	1520												
	1155-1433	8.25	1.68×10^{-6}	108.84	1.8×10^{-5}								
4	1319-1446	0.93	1.93×10^{-7}	328.3	5.4×10^{-5}								
	1510	--	--	--	--	302.0	5.01×10^{-5}	--	--	--	--	--	--
	1742-1916	0.51		314.1	5.2×10^{-5}								
	1959	--	1.05×10^{-7}	--	--	302.0	5.01×10^{-5}	--	--	--	--	--	--
	1310	--	--	--	--	251.2	4.17×10^{-5}	--	--	--	--	--	--
	1445	--	--	--	--	275.4	4.56×10^{-5}	--	--	--	--	--	--

[a] IPA Impinger, Ba(ClO$_4$)$_2$ Titration.
[b] 6% H$_2$O$_2$ Impinger Ba(ClO$_4$)$_2$ Titration.
[c] STP = 70°F and 29.92 inches Hg.
[d] No species detected.
[e] Gaseous SO$_2$ determined using a Hewlitt Packard Gas Chromatograph equipped with a flame photometric detector.

TABLE B4-9. ALDEHYDES - CRUDE UNIT PROCESS HEATERS

Stack	Time	Gas Volume (ℓ) @ STP[b]	μg Aldehyde	Concentration[c] ppm(Vol.)	Concentration[c] lb/SCF
2[a]	1453-1553	12.0	98.7	6.62	5.12×10^{-7}
3[a]	1620-1723	12.0	102.0	6.84	5.29×10^{-7}
6[a]	1646-1746	12.0	120.79	8.10	6.29×10^{-7}
	2021-2121	12.0	145.66	9.76	7.58×10^{-7}
4[d]	1149-1255	12.88	0.79	0.049	3.83×10^{-9}
	1326-1426	11.70	0.385	0.026	2.06×10^{-9}
	1524-1624	11.68	0.94	0.065	5.03×10^{-9}
5[d]	1620-1720	10.55	1.84	0.14	1.086×10^{-8}
	1223-1328	12.47	2.95	0.19	1.480×10^{-8}
	1400-1500	11.51	0.0	0.0	0.0

[a] Bisulfite method.

[b] STP = 70°F and 29.92 inches Hg.

[c] Dry Basis. Calculated as formaldehyde.

[d] MBTH method.

TABLE B4-10. OXIDES OF NITROGEN - CRUDE UNIT PROCESS HEATERS

Stack	Time	NO_x (as NO_2) Concentration[a]	
		ppm (Vol.)	lb/SCF[b]
6	1825	98.0	1.17×10^{-5}
	2136	87.7	1.04×10^{-5}

[a] Dry basis.

[b] STP = 70°F and 29.92 inches Hg.

TABLE B4-11. HCN AND NH_3 - CRUDE UNIT PROCESS HEATERS

		HCN Concentration[a]		NH_3 Concentration[a]	
Stack	Time	ppm (Vol.)	lb/SCF[b]	ppm (Vol.)	lb/SCF[b]
5[c]	1630	0.8	5.49×10^{-8}	0.95	4.12×10^{-8}
	1000	0.9	6.18×10^{-8}	1.5	6.49×10^{-8}
2[d,e]	0951-1112	$<1 \times 10^{-3}$	6.5×10^{-11}	<0.3	$<1 \times 10^{-8}$
	1452-1621	4.16×10^{-2}	2.91×10^{-9}	<0.3	$<1 \times 10^{-8}$
3[d,e]	1541-1825	$<1 \times 10^{-3}$	6.5×10^{-11}	<0.3	$<1 \times 10^{-8}$

[a] Dry basis.

[b] STP = 70°F and 29.92 inches Hg.

[c] Infrared analysis at 3.01μ(HCN) and 10.4μ(NH_3). Path length = 20.25m; cell temperature = 75°C.

[d] NH_3 sampling performed using LSI train with impingers containing 0.1N H_2SO_4.

[e] HCN sampling performed using LSI train with 3 impingers containing 250 ml of 2N NaOH each.

TABLE B4-12. METHANE/NONMETHANE HYDROCARBONS[a] AND FIXED GASES[b] - SULFUR RECOVERY UNITS

		Methane Concentration[c]			Nonmethane Concentration[c] (As Hexane)			Fixed Gases (Dry Basis)					
Stack	Time	By Weight (ppm)	lb/SCF[d]	By Volume (ppm)	By Weight (ppm)	lb/SCF[d]	By Volume (ppm)	CO (%)	O (%)	N (%)	CO (%)	H (%)	Mol. Wt. (Dry)
8	1455	.213	1.33×10^{-8}	.321	4.745	2.96×10^{-7}	1.35	5.1	8.7	86.2	0.0	0.0	27.03
	1140	1.30	8.11×10^{-8}	1.96	51.065	3.19×10^{-6}	14.32	4.9	9.3	85.8	0.0	0.0	
	1515	0.062	3.87×10^{-9}	0.094	4.87	3.04×10^{-7}	1.37	5.1	8.6	86.3	0.0	0.0	
Ambient	1505	0.822	5.13×10^{-8}	1.24	1.155	7.21×10^{-8}	0.324						
	1556							14.0	1.4	83.2	1.4	--[e]	30.30
	1613	3135	2.10×10^{-4}	5075	7170	4.81×10^{-4}	2159						
7	1645	4120	2.76×10^{-4}	6669	6650	4.46×10^{-4}	2003						
Ambient	1908	0.43	3.22×10^{-8}	0.78	1.40	1.05×10^{-7}	0.47						

NOTE: Gas flow rate from Stack No. 8 = 2.02×10^5 SCFM; this value provided by plant personnel.

[a] Byron hydrocarbon analyzer using flame ioization detector.

[b] Fischer Model 1200 gas partitioner.

[c] Dry basis.

[d] STP = 70°F and 29.92 inches Hg.

[e] Results questionable, not reported.

[f] Not detectable, less than 0.01 ppm by weight.

TABLE B4-13. SULFUR SPECIES - SULFUR RECOVERY UNITS

		SO_3[a]		SO_2[b]		SO_2		H_2S		COS		CS_2	
Stack	Time	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]
8	1005-1035	0.61	1.263×10^{-7}	319.72	5.282×10^{-5}								
	1115-1145	0.72	1.481×10^{-7}	315.18	5.207×10^{-5}								
	1316					444.0	7.34×10^{-5}	- Not	Detected -	0.6	9.30×10^{-8}	1.3	2.55×10^{-7}
	1452					491.0	8.11×10^{-5}	- Not	Detected -	0.5	7.75×10^{-8}	2.9	5.69×10^{-7}
	1553					528.0	8.72×10^{-5}	- Not	Detected -	0.4	6.0×10^{-8}	2.6	5.1×10^{-7}
	1020					582.0	9.62×10^{-5}	- Not	Detected -	0.45	7.0×10^{-8}	1.1	2.2×10^{-7}
	1055					509.0	8.41×10^{-5}	- Not	Detected -	Not Run	Not Run	Not Run	Not Run
	1238					510.0	8.42×10^{-5}	- Not	Detected -	0.5	8.0×10^{-8}	1.4	2.7×10^{-7}
7	1644					--[d]	--	--[e]	--	8.6	1.3×10^{-6}	15.0	2.95×10^{-6}
	1700					0.2	3.0×10^{-8}	--[e]	--	3.0	5.0×10^{-7}	0.04	8.0×10^{-9}
	1540					0.2	3.0×10^{-8}	--	--	7.7	1.2×10^{-6}	12.0	2.36×10^{-6}

[a] IPA Impinger, $Ba(ClO_4)_2$ Titration.

[b] 6% H_2O_2 Impinger, $Ba(ClO_4)_2$ Titration

[c] STP = 70°F and 29.92 inches Hg, dry basis.

[d] No species detected.

[e] Results questionable, not reported.

TABLE B4-14. ALDEHYDES[a] - SULFUR RECOVERY UNITS

Stack	Time	Gas Sample Volume (ℓ) @ STP[b]	Aldehyde Collected (μg)	Concentration[c]	
				ppm(Vol.)	lb/SCF
8	1525-1625	12.0	59.7	4.01	3.11×10^{-7}
	1120-1220	12.0	61.5	4.13	3.20×10^{-7}
	1315-1415	12.0	57.0	3.83	2.97×10^{-7}

[a] Sample Rate = 200 mℓ/min. Bisulfite Method

[b] STP = 70°F and 29.92 inches Hg.

[c] Dry basis. Calculated as formaldehyde.

TABLE 4-15. OXIDES OF NITROGEN - SULFUR RECOVERY UNITS

Stack	Time	NO_x (as NO_2) Concentration[a] ppm (Vol.)	NO_x (as NO_2) Concentration[a] lb/SCF[b]
8	1732	16.7	1.98×10^{-6}
7	1626	15.0	1.70×10^{-6}

[a] Dry basis.

[b] STP = 70°F and 29.92 inches Hg.

TABLE B4-16. HCN[a] - SULFUR RECOVERY UNITS

Stack	Time	HCN Concentrations[b]	
		ppm (Vol.)	lb/SCF[c]
8	1551-1625	$<1 \times 10^{-3}$	$<6.5 \times 10^{-11}$
	1305-1340	$<1 \times 10^{-3}$	$<6.5 \times 10^{-11}$

[a] Sampling performed using LSI train with 3 impingers containing 250 ml of 2N NaOH each.

[b] Dry basis.

[c] STP = 70°F and 29.92 inches Hg.

TABLE B4-17. NH_3[a] - SULFUR RECOVERY UNITS

Stack	Time	NH_3 Concentration[b]	
		ppm(vol.)	lb/SCF[c]
8	1505-1540	<0.3	$<1 \times 10^{-8}$
	1405-1440	<0.3	$<1 \times 10^{-8}$

[a] Sampling performed using LSI train with impingers containing 0.1 N H_2SO_4.

[b] Dry Basis.

[c] STP = 70°F and 29.92 inches Hg.

TABLE B4-18. STACK GAS AND PARTICULATES[a] - TCCU CO BOILER STACK

Stack	Time	Total Gas Sample Meter (ft^3)	Total Gas Sample STP[b] (SCF)[c]	Avg Meter Temp (°F)	Avg Stack Temp (° F)	Avg Dry (MW)	Moisture Collected (g)	Fraction	Particulates Filter	Particulates Probe	Particulates Imp. #1	Particulates Total	Particulates Grain Loading (gr/SCF)	Avg Stack Velocity (ft/sec)	% Isokin.
9	1338-1450	40.38	39.27	82	446	28.47	106.0	0.113	0.0363	0.0484	0.0000	0.0847	0.0333	51.67	105.6
	1013-1125	40.32	38.80	81	458	28.38	107.9	0.116	0.0402	0.0028	0.0000	0.0430	0.0171	54.77	101.3
	1018-1130	27.14	26.73	76	474	28.56	78.3	0.122	0.0305	0.0457	0.0220	0.0982	0.0567	36.69	105.1
	1503-1615	31.90	31.25	79	458	28.17	68.9	0.095	0.0282	0.0099	0.0284	0.0665	0.0328	40.96	104.9

[a] Sampled with LSI EPA-5 train.

[b] Total gas flow - 3.10 x 10^6 SCFM

[c] Corrected to 70°F and 29.92 inches Hg.

TABLE B4-19. METHANE/NONMETHANE HYDROCARBONS[a] AND FIXED GASES[b] - TCCU CO BOILER STACK

		Methane Concentration[a]			Nonmethane Concentration[c] (As Hexane)			Fixed Gases					
Stack	Time	By Volume (ppm)	lb/SCF[d]	By Volume (ppm)	By Weight (ppm)	lb/SCF[d]	By Volume (ppm)	CO_2 (%)	O_2 (%)	N_2 (%)	CO (%)	H_2 (%)	Mol. Wt. (Dry)
9	1345							10.8	7.0	76.3	0.0	0.0	28.35
	1405	4.6	3.4×10^{-7}	8.2	30.7	2.26×10^{-6}	10.2						
	1525							11.4	6.6	76.6	0.0	0.0	28.58
	1535	2.32	1.71×10^{-7}	4.13	27.83	2.05×10^{-6}	9.21						
Ambient													
9	1710	6.22	4.66×10^{-7}	11.3	9.36	7.01×10^{-7}	3.15						
9	1415							10.5	7.4	75.7	0.0	0.0	28.19
	1425	0.24	1.8×10^{-8}	0.43	1.38	1.01×10^{-7}	0.455						
	1535	0.0	0.0	0.00	0.0	0.0	0.0						
	1545							11.5	6.6	76.4	0.0	0.0	28.56
	0930							11.3	6.9	76.7	0.0	0.0	28.66
	1050							10.8	7.3	76.3	0.0	0.0	28.45
	1410							10.0	6.7	76.3	0.0	0.0	27.90
	1415	0.0	0.0	0.00	1.96	1.44×10^{-7}	0.646						
	1520							11.4	6.5	76.2	0.0	0.0	28.44
	1525	0.0	0.0	0.00	0.85	6.2×10^{-8}	0.28						
Ambient													
9	1530	0.87	6.5×10^{-8}	1.6	0.99	7.4×10^{-8}	0.33						

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[a] Byron hydrocarbon analyzer using flame ionization detector.

[b] Fischer Model 1200 gas partitioner.

[c] Dry basis.

[d] STP - 70° and 29.92 inches Hg.

TABLE B4-20. SULFUR SPECIES - TCCU CO BOILER STACK

		SO_3[a]		SO_2[b]		SO_2[d]		H_2S		COS		CS_2	
Stack	Time	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]
9	1338-1450	--	--	603.5	9.99×10^{-5}								
	1013-1125	0.66	1.4×10^{-7}	923.6	1.53×10^{-4}								
	1018-1130	1.5	3.1×10^{-7}	670.4	1.11×10^{-4}								
	1503-1615	0.48	9.9×10^{-8}	464.3	7.68×10^{-5}								

[a] IPA Impinger, $Ba(ClO_4)_2$ Titration. SO_2 not reported on Run #1 (2/6/78) due to transfer of impinger contents yielding higher than expected SO_2 results. Results calculated as SO_2.

[b] 6% H_2O_2 Impinger, $Ba(ClO_4)_2$ Titration.

[c] STP = 70°F and 29.92 inches Hg.

[d] Sulfur species (SO_2, H_2S, COS, and CS_2) not reported due to problems with Hewlett Packard GC.

TABLE B4-21. ALDEHYDES[a] - TCCU CO BOILER STACK

Stack	Time	Gas Sample Volume (ℓ) @ STP[b]	Aldehyde Collected (μg)	Concentration[c]	
				ppm(Vol.)	lb/SCF[b]
9	1415-1515	12.0	121.9	8.17	6.34×10^{-7}
	1605-1705	12.0	121.8	8.16	6.34×10^{-7}
	1430-1530	12.0	117.0	7.84	6.08×10^{-7}
	0940-1040	12.0	129.0	8.65	6.71×10^{-7}
	1120-1220	12.0	204.0	13.70	1.06×10^{-6}
	1415-1515	12.0	231.0	15.50	1.20×10^{-6}

[a] Sample rate = 200 mℓ/min. Bisulfite Method Used.

[b] STP = 70°F and 29.92 inches Hg.

[c] Dry basis. Calculated as formaldehyde.

TABLE B4-22. OXIDES OF NITROGEN - TCCU CO BOILER STACK

Stack	Time	NO_x (as NO_2) Concentration[a] ppm (Vol.)	NO_x (as NO_2) Concentration[a] lb/SCF[b]
9	1543	120	1.43×10^{-5}
	1308	123	1.46×10^{-5}
	1405	121	1.44×10^{-5}
	1555	125	1.48×10^{-5}
	1137	126	1.51×10^{-5}

[a] Dry basis.

[b] STP = 70°F and 29.92 inches Hg.

TABLE B4-23. HCN[a] AND NH_3[a] - TCCU CO BOILER STACK

		HCN[b] Concentration			NH_3 Concentration[b]	
Stack	Time	ppm (Vol.)	lb/SCF[c]	Time	ppm (Vol.)	lb/SCF[c]
9	1645-1715	[d]--	--	1603-1634	1.96	8.61×10^{-8}
	1431-1502	--	--	1330-1440	2.75	1.21×10^{-7}
	1336-1406	--	--	1251-1322	2.21	9.72×10^{-8}
	1112-1142	--	--	1155-1225	2.70	1.19×10^{-7}

[a] Sampling performed using LSI Method 5 train and acidic or basic impinger solutions, as required.

[b] Dry basis.

[c] Corrected to 70°F and 29.92 inches Hg.

[d] Not detectable, less than 0.005 ppm in solution.

TABLE B4-24. STACK GAS AND PARTICULATES[a] - FLUID COKER CO BOILER STACK

		Total Gas Sample[b]		Avg Meter Temp	Avg Stack Temp	Avg Dry	Moisture Collected		Particulates					Avg Stack Velocity	%
Stack	Time	Meter (ft³)	STP (SCF)[c]	(°F)	(°F)	(MW)	(g)	Fraction	Filter	Probe	Imp. #1	Total	Grain Loading (gr/SCF)	(ft/sec)	Isokin.
10	2035-2145	38.33	37.36	115	572	29.61	207.0	0.208	0.0242	0.6500	0.0187	0.6929	0.2862	72.47	108.2
	1135-1245	38.99	38.41	109	570	30.17	206.4	0.203	0.0263	0.1531	0.0000	0.1794	0.0721	72.13	109.9

[a] Sampled with LSI EPA-5 train.

[b] Total gas flow - 2.44 x 10^6 SCFM.

[c] Corrected to 70°F and 29.92 inches Hg.

TABLE B4-25. METHANE/NONMETHANE HYDROCARBONS[a] - AND FIXED GASES[b] - FLUID COKER CO BOILER STACK

		Methane Concentrations[c]			Nonmethane Concentrations[c] (As Hexane)			Fixed Gases (Dry Basis)					
Stack	Time	(ppm)	By Weight (lb/SCF)[d]	By Volume (ppm)	(ppm)	By Weight (lb/SCF)[d]	By Volume (ppm)	CO_2 (%)	O_2 (%)	N_2 (%)	CO (%)	H_2 (%)	Mol. Wt. (Dry)
10	1255	7.78	6.02×10^{-7}	14.5	73.9	5.72×10^{-6}	25.7						
	1600	3.7	2.9×10^{-7}	6.9	19.5	1.51×10^{-6}	6.78	11.5	5.49	81.4	0.0	--	29.61
	1820	1.62	1.25×10^{-7}	3.03	32.9	2.55×10^{-6}	11.4						
	1330	--	--	--	--	--	--	11.7	4.79	83.9	0.00	--	30.17
	1515	2.7	2.1×10^{-7}	5.0	6.04	4.63×10^{-7}	2.08						
	1630	24.0	1.84×10^{-6}	44.4	3.93	3.01×10^{-7}	1.35	12.2	4.9	81.0	0.0	--	29.62

[a] Byron hydrocarbon analyzer using flame ionization detector.

[b] Fischer Model 1200 gas partitioner.

[c] Dry basis.

[d] STP - 70° and 29.92 inches Hg.

TABLE B4-26. SULFUR SPECIES - FLUID COKER CO BOILER STACK

		SO_3[a]		SO_2[b]		SO_2		H_2S		COS		CS_2	
Stack	Time	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]
10	1400	--	--	--	--	306	5.07×10^{-5}	--[d]	--	--[d]	--	--[d]	--
	1605	--	--	--	--	314	5.20×10^{-5}	--[d]	--	--[d]	--	--[d]	--
	2035-2145	0.31	6.5×10^{-8}	233	3.86×10^{-5}								
	1135-1245	1.9	4.0×10^{-7}	229	3.79×10^{-5}								

[a] IPA Impinger, $Ba(ClO_4)_2$ Titration.
[b] 6% H_2O Impingers, $Ba(ClO_4)_2$ Titration.
[c] Corrected to 70°F and 29.92 inches Hg, dry basis.
[d] No species detected.

TABLE B4-27. ALDEHYDES - FLUID COKER CO BOILER STACK

Stack	Time	Gas Sample Volume (ℓ)[a] @ STP[b]	Aldehyde Collected (μg)	Concentration[c]	
				ppm(Vol.)	lb/SCF[b]
10	1500-1600	25.0	91.4	2.94	2.28×10^{-7}
	1610-1710	25.0	70.4	2.27	1.76×10^{-7}
	1710-1810	25.0	106.5	3.43	2.66×10^{-7}

[a] CO Boiler Stack samples flow ≅ 417 mℓ/min. Bisulfite method used.

[b] STP = 70°F and 29.92 inches Hg.

[c] Dry basis. Calculated as formaldehyde.

TABLE B4-28. OXIDES OF NITROGEN - FLUID COKER CO BOILER

Stack	Time	NO_x (as NO_2) Concentration[a]	
		ppm (Vol.)	lb/SCF[b]
10	1515	209	2.49×10^{-5}
	1630	239	2.85×10^{-5}

[a] Dry basis.

[b] STP = 70°F and 29.92 inches Hg.

TABLE B4-29. HCN AND NH_3 - FLUID COKER CO BOILER STACK

		HCN Concentration[a,b]			NH_3 Concentration[a,b]	
Stack	Time	ppm (Vol.)	lb/SCF[c]	Time	ppm (Vol.)	lb/SCF[c]
10	1515-1545	3.15	2.20×10^{-7}	1701-1733	<0.05	$<2.3 \times 10^{-9}$
	1540-1610	2.56	1.78×10^{-7}	1705-1735	1.79	7.85×10^{-8}

[a] Sampling performed using LSI Method 5 train and acidic or basic impinger solutions, as required.

[b] Dry basis.

[c] Corrected to 70°F and 29.92 inches Hg.

TABLE B4-30. STACK GAS AND PARTICULATES[a] - FLUID COKER SCRUBBER - INLET AND OUTLET

		Total Gas Sample		Avg	Avg				Particulates					Avg	
Stack	Time	Meter (ft^3)	STP[b] (SCF)[c]	Meter Temp (°F)	Stack Temp (°F)	Avg Dry (MW)	Moisture Collected (g)	Fraction	Filter	Probe	Imp. #1	Total	Grain Loading (gr/SCF)	Stack Velocity (ft/sec)	% Isokin.
19 Inlet B	2015-2115	24.25	23.86	86	1089	29.09	115.9	0.187	0.8165	0.1013	0.0403	0.9601	0.6209	113.18	102.0
	1130-1230	37.59	37.53	79	1098	29.09	199.1	0.201	1.0528	0.1972	0.6720	1.9220	0.7902	174.19	106.7

[a] Sampled with LSI EPA-5 train.

[b] Total gas flow • (scrubber inlet) - 1.77×10^6 SCFH

[c] Corrected to 70°F and 29.92 inches Hg.

TABLE B4-31. METHANE/NONMETHANE HYDROCARBONS[a] AND FIXED GASES[b] - FLUID COKER SCRUBBER - INLET AND OUTLET

	Methane Concentrations[a,c]			Nonmethane Concentrations[a,c] (As Hexane)			Fixed Gases (Dry Basis)					
Source	(ppm)	By Weight (lb/SCF)[d]	By Volume (ppm)	(ppm)	By Weight (lb/SCF)[d]	By Volume (ppm)	CO_2	O_2 (%)	N_2 (%)	CO (%)	H_2 (%)	Mol. Wt. (Dry)
19 - Inlet A	3360	2.53×10^{-4}	6110	394	2.54×10^{-5}	113						
	3310	2.49×10^{-4}	6020	402	3.03×10^{-5}	136						
19 - Outlet A	3400	2.56×10^{-4}	6180	382	2.88×10^{-5}	129						
	3350	2.52×10^{-4}	6090	366	2.76×10^{-5}	124						
19 - Inlet B	--	--	--	--	--	--	9.5	2.11	81.6	6.9	--	29.64
	2050	1.54×10^{-4}	3730	285	2.15×10^{-5}	96.4						
	3292	2.48×10^{-4}	5985	318	2.39×10^{-5}	108						
	--	--	--	--	--	--	9.46	2.45	78.9	7.22	--	29.05
	--	--	--	--	--	--	10.05	2.13	76.8	7.06	--	28.58
	3250	2.45×10^{-4}	5910	636	4.79×10^{-5}	215						

[a] Byron hydrocarbon analyzer using flame ionization detector.

[b] Fischer Model 1200 gas partitioner.

[c] Dry basis.

[d] STP - 70°F and 29.92 inches Hg.

TABLE B4-32. SULFUR SPECIES - FLUID COKER SCRUBBER - INLET AND OUTLET

		SO_3[a]		SO_2[b]		SO_2[d]		H_2S		COS		CS_2	
Source	Time	ppm (Vol)	lb/SCF @ STP	ppm (Vol)	lb/SCF @ STP	ppm (Vol)	lb/SCF @ STP	ppm (Vol)	lb/SCF @ STP	ppm (Vol)	lb/SCF @ STP	ppm (Vol)	lb/SCF @ STP
19	2015-2115	--	--	--	--								
	1130-1230	--	--	--	--								
Inlet	1633	--	--	--	--	--	--	--	--	--	--	--	--
B	1824	--	--	--	--	--	--	--	--	--	--	--	--
	2018	--	--	--	--	--	--	--	--	--	--	--	--

[a] IPA Impinger, $Ba(ClO_4)_2$ Titration.
[b] 6% H_2O_2 Impingers, $Ba(ClO_4)_2$ Titration.
[c] Corrected to 70°F and 29.92 inches Hg, dry basis.
[d] No species detected.

TABLE B4-33. ALDEHYDES - FLUID COKER SCRUBBER - INLET AND OUTLET

Stack	Time	Gas Sample Volume (ℓ)[a] @ STP[b]	Aldehyde Collected (μg)	Concentration[c] ppm(Vol.)	Concentration[c] lb/SCF
19 - Inlet B	1644-1744	12.0	180.0	12.10	9.37×10^{-7}
	1838-1938	12.0	102.0	6.84	5.31×10^{-7}

[a] Gas flow through impingers = 200 mℓ/min. Bisulfite method used.

[b] STP = 70°F and 29.92 inches Hg.

[c] Dry basis. Calculated as formaldehyde.

TABLE B4-34. OXIDES OF NITROGEN - FLUID COKER SCRUBBER - INLET AND OUTLET

Stack	Time	NO_x (as NO_2) Concentration[a]	
		ppm (Vol.)	lb/SCF @ STP[b]
19 - Inlet B	1645	4.8	5.70×10^{-7}
	1650	22.6	2.69×10^{-6}

[a] Dry basis

[b] STP = 70°F and 29.92 inches Hg.

TABLE B4-35. HCN AND NH_3 - FLUID COKER SCRUBBER - INLET AND OUTLET

		HCN Concentration [a,b]			NH_3 Concentration [a,b]	
Stack	Time	ppm (Vol.)	lb/SCF @ STP[c]	Time	ppm (Vol.)	lb/SCF @ STP[c]
19	1530-1600	141.3	9.87×10^{-6}	1700-1730	175.4	7.71×10^{-6}
Inlet B	1530-1600	102.5	7.16×10^{-6}	1700-1730	195.8	8.61×10^{-6}

[a] Sampling performed using LSI Method 5 train and acidic or basic impinger solutions, as required.

[b] Dry Basis.

[c] Corrected to 70°F, and 29.92 inches Hg.

Sampling results from six stacks in five different Fluid Catalytic Cracking (FCC) units are given in Tables B4-36 through B4-41. The units were all equipped with electrostatic precipitatiors and CO boilers. Stack No.'s 13 and 18 were from separate CO boilers on the same FCC unit.

Tables B4-42 through B4-46 give the sampling results obtained from an FCC unit whose flue gases passed through a CO boiler and then through a scrubber. Two scrubber units were utilized, each handling one-half of the flue gas. Both particulates and SO_x were removed in the scrubbers.

The results for FCC unit CO boiler Stack No. 15 were given in Tables B4-36 through B4-41. However, grab samples were obtained from this unit upstream of the ESP-CO boiler control devices. These results are listed, together with the results from the CO boiler stack, in Tables B4-47 through B4-52. These results show the CO boiler is effective in removing carbon monoxide, aldehydes, and HCN.

Tables B4-53 through B4-56 show the sampling results for a FCC unit compressor exhaust stack. The emissions from these internal combustion engines were relatively low compaired to other refinery process emissions sources.

Many of the sampling results listed in this section compare favorably with published emission factors. However, these results should not be used in updating or developing new emission factors due to the low number of samples obtained from each stack.

TABLE B4-36. STACK GAS AND PARTICULATES[a] - FCCU CO BOILER STACKS

		Total Gas Sample[b]		Avg Meter Temp	Avg Stack Temp	Avg Dry	Moisture Collected		Particulates					Avg Stack Velocity	%
Stack	Time	Meter (ft^3)	STP (SCF)[c]	(°F)	(°F)	(MW)	(g)	Fraction	Filter	Probe	Imp. #1	Total	Grain Loading (gr/SCF)	(ft/sec)	Isokin.
13	1427-1854	70.99	73.79	78	391	29.95	293.3	0.159	0.1296	0.0629	0.0110	0.2035	0.0426	47.57	105.3
	0859-1230	28.96	29.16	94	392	28.65	103.3	0.144	0.0654	0.0122	0.0027	0.0803	0.0425	44.21	90.4
18	1130-1536	29.13	30.55	75	386	29.46	126.4	0.163	0.0728	0.0174	0.0075	0.0977	0.0493	43.12	98.8
14	1000-1300	46.60	40.10	117	585	30.94	88.4	0.0944	0.1864	0.3001	--[d]	0.4865	--[e]	49.24	59.3
	1945-2133	57.50	51.25	97	577	30.94	106.8	0.0897	0.1767	0.3239	--	0.5006	--	52.37	50.8
16	1605-1755	37.41	37.14	90	719	28.47	213.3	0.214	0.0214	0.0166	0.0060	0.0440	0.0183	49.97	106.8
	1415-1625	35.69	34.92	98	727	28.21	218.21	0.228	0.0154	0.0127	0.0020	0.0281	0.0124	49.24	104.5
15	1745-1857	31.68	31.81	96	538	30.58	185.0	0.216	0.0425	0.0282	0.1290	0.1997	0.0969	48.98	112.0
	1015-1127	32.71	32.03	107	540	30.58	186.2	0.216	0.0372	0.0384	0.0081	0.0837	0.0403	51.93	107.1
11	1045-1245	36.61	36.56	81.4	460	29.13	112.7	0.127	0.0624	0.0773	0.0113	0.510	0.064	66.29	115.4
	1500-1700	30.92	30.20	93.6	460	30.39	85.1	0.117	0.0880	0.5007	0.0071	0.5958	0.304	68.94	90.6

[a] Sampled with LSI EPA-5 train.

[b] Total gas flow rates: Stack No. 11 - 2.70 x 10^6 SCFM; Stack No. 13 - 9.15 x 10^6 SCFM; Stack No. 14 - 1.26 x 10^6 SCFM; Stack No. 15 - 6.53 x 10^6 SCFM; Stack No. 16 - 8.97 x 10^6 SCFM; Stack No. 18 - 8.58 x 10^6 SCFM

[c] Corrected to 70°F and 29.92 inches HG.

[d] Not determined.

[e] Particulate sampling conducted under nonisokinetic conditions. Grain loading not required.

TABLE B4-37. METHANE/NONMETHANE HYDROCARBONS[a] AND FIXED GASES[b] - FCCU CO BOILER STACKS

		Methane Concentrations[c] By Weight			Nonmethane Concentrations[c] (As Hexane)			Fixed Gases (Dry Basis)					
Stack	Time	(ppm)	lb/SCF[d]	By Volume (ppm)	By Weight (ppm)	lb/SCF[d]	By Volume (ppm)	CO_2 (%)	O_2 (%)	N_2 (%)	CO (%)	H (%)	Mol. Wt. (Dry)
13	1440							15.1	3.5	79.2	0.0	--[e]	29.95
	1711	--[f]	--	--	1.94	1.50×10^{-7}	0.68						
	1335							14.8	3.8	79.0	0.0	--[e]	29.85
	1614	--[f]	--	--	19.95	1.54×10^{-6}	6.92						
	1500	3.98	2.98×10^{-7}	7.20	19.92	1.49×10^{-6}	6.71						
	1508	0.49	3.7×10^{-8}	0.89	19.73	1.48×10^{-6}	6.64						
Ambient 13	0844							14.3	3.5	73.9	0.0	--[e]	28.10
	0936							14.4	3.3	73.8	0.0	--[e]	28.06
	1042							15.0	5.0	77.1	0.0	--[e]	29.79
18	1533	--[f]	--	--	10.63	7.88×10^{-7}	3.54						
	1035							15.6	3.7	77.4	0.0	--[e]	29.71
	1150							15.5	3.5	77.7	0.0	--[e]	29.70
	1328							13.5	3.4	78.4	0.0	--[e]	28.98
	1559	--[f]	--		0.83	6.3×10^{-9}	0.28						
14	2000	--	--	--	--	--	--	14.1	7.0	77.0	1.0	--[e]	30.24
	2020	4.10	3.22×10^{-7}	7.78	66.00	5.19×10^{-6}	23.31	16.1	6.7	77.5	0.0	--[e]	30.94
	0900	0.22	1.73×10^{-8}	0.42	32.62	2.56×10^{-6}	11.52	14.1	6.3	77.3	0.0	--[e]	29.76
	1000	0.50	3.9×10^{-8}	0.95	4.20	3.30×10^{-7}	1.48	14.2	6.3	77.5	0.0	--[e]	29.93
	1030	0.15	1.18×10^{-8}	0.28	4.87	3.83×10^{-7}	1.72						
Ambient 14	1030	1.15	8.62×10^{-8}	2.08	13.59	1.01×10^{-6}	5.45						
16	1034	0	0	0	23.775	1.48×10^{-6}	6.67	14.5	4.2	81.4	0.0	0.0	28.47
	1323	0	0	0	2.655	1.66×10^{-7}	0.745	13.6	5.0	81.4	0.0	0.0	
	1531	0	0	0	1.446	9.02×10^{-8}	0.406	14.9	3.2	81.9	0.0	0.0	
Ambient 16	1537	0.898	5.6×10^{-8}	1.35	1.986	1.24×10^{-7}	0.557	14.9	3.3	81.7	0.0	0.0	
16	1722	0.248	1.55×10^{-8}	0.374	8.065	5.03×10^{-7}	2.26						
	2150	0	0	0	13.9	8.67×10^{-7}	3.90						
	1950	0	0	0	10.58	6.60×10^{-7}	2.97						

Continued

TABLE B4-37. Continued

		Methane Concentrations[c]			Nonmethane Concentrations[c] (As Hexane)			Fixed Gases (Dry Basis)					
		By Weight											
Stack	Time	(ppm)	lb/SCF[d]	By Volume (ppm)	By Weight (ppm)	lb/SCF[d]	By Volume (ppm)	CO_2 (%)	O_2 (%)	N_2 (%)	CO (%)	H (%)	Mol Wt. (Dry)
15	1615							14.89	3.55	81.98	0.0	0.0	
	1915							15.23	3.39	81.21	0.0	0.0	
	1030							13.52	4.35	82.67	0.0	0.0	
	1215							14.01	3.75	81.63	0.0	0.0	
11	1530	0.30	2.25×10^{-8}	0.54	75.0	5.55×10^{-6}	25.25						
	1615	0.30	2.25×10^{-8}	0.54	17.0	1.26×10^{-6}	5.72	16.0	4.0	75.0	--	--[e]	29.32
	1740	0.98	7.24×10^{-8}	1.77	114.0	8.43×10^{-6}	38.38	15.0	4.0	75.5	--	--	28.88
	1100	0.10	7.49×10^{-9}	0.18	31.5	2.33×10^{-6}	10.60	15.5	7.0	77.0	--	--	30.62
	1230	0.20	1.50×10^{-8}	0.36	23.4	1.73×10^{-6}	7.88	15.0	6.5	77.0	--	--	30.24
	1625	0.12	8.74×10^{-9}	0.22	25.5	1.89×10^{-6}	8.58	15.0	6.7	77.0	--	--	30.30
Ambient 11	1730	3.20	2.37×10^{-7}	5.79	37.1	2.74×10^{-6}	12.49						

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[a] Byron hydrocarbon analyzer using flame ionization detector.

[b] Fischer Model 1200 gas partitioner.

[c] Dry basis.

[d] STP = 70°F and 29.92 inches Hg.

[e] Results questionable, not reported.

[f] Not detectable, less than 0.01 ppm by weight.

TABLE B4-38. SULFUR SPECIES - FCCU CO BOILER STACKS

		SO_3[a]		SO_2[b]		SO_2		H_2S		COS		CS_2	
Stack	Time	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF[c]
13	1427-1854	0.65	1.34×10^{-7}	368.5	6.10×10^{-5}								
	1720					416.0	6.89×10^{-5}	--[d]	--	--[d]	--	--[d]	--
	1346					330.0	5.47×10^{-5}	1.75	1.54×10^{-7}	--[d]	--	0.9	2.0×10^{-7}
	1622					390.0	6.46×10^{-5}	--[d]	--	--[d]	--	0.3	6.0×10^{-8}
	0859-1230	1.62	3.36×10^{-7}	528.7	8.75×10^{-5}								
18	1130-1536	1.89	3.90×10^{-7}	605.0	1.00×10^{-4}								
	1210					314.0	5.20×10^{-5}	--[d]	--	--[d]	--	0.4	8.0×10^{-8}
	1341					145.0	2.40×10^{-5}	--[d]	--	--[d]	--	--[d]	--
	1515					245.0	4.06×10^{-5}	--[d]	--	--[d]	--	--[d]	--
16	1605-1755	1.18	2.434×10^{-7}	14.4	2.374×10^{-6}								
	1415-1625	1.11	2.298×10^{-7}	20.9	3.446×10^{-6}								
	1045					<0.5	$<8.26 \times 10^{-8}$	<0.1	$<8.8 \times 10^{-9}$	0.2	3.0×10^{-8}	<0.2	$<4.0 \times 10^{-8}$
	1340					17.0	2.81×10^{-6}	0.0	0.0	0.0	0.0	<0.2	$<4.0 \times 10^{-8}$
	1550					14.0	2.31×10^{-6}	0.0	0.0	0.0	0.0	0.0	0.0
15	1745-1857	0.781	1.61×10^{-7}	289.0	4.78×10^{-5}								
	1015-1127	1.126	2.32×10^{-7}	708.0	1.17×10^{-4}								
	1040					841.0	1.39×10^{-4}	--[d]	--	--	--	--	--
	1115					871.0	1.44×10^{-4}	--	--	--	--	--	--
14	1000-1300	13.46	2.78×10^{-6}	644.09	1.06×10^{-4}	--	--	--	--	--	--	--	--
	1945-2133	1.07	2.21×10^{-7}	606.76	1.00×10^{-4}	--	--	--	--	--	--	--	--
	2020	--	--	--	--	251.0[e]	--	--	--	--	--	36.0[e]	--
11	1045-1245	9.21	1.87×10^{-6}	92.11	1.5×10^{-5}			--[f]	--	--	--	--	--
	1500-1700	7.39	1.52×10^{-6}	101.42	1.654×10^{-5}			--[f]					

[a] IPA Impinger, $Ba(ClO_4)_2^2$ Titration.
[b] 6% H_2O_2 Impinger, $Ba(ClO_4)_2$ Titration.
[c] STP = 70°F and 29.92 inches HG, dry basis.
[d] No species detected.
[e] GC results questionable due to moisture in samples.
[f] Results not reported because of questionable sampling techniques.

TABLE B4-39. ALDEHYDES[a] - FCCU CO BOILER STACKS

Stack	Time	Gas Sample Volume (ℓ) @ STP[b]	Aldehyde Collected (μg)	Concentration[c] ppm(Vol.)	Concentration[c] lb/SCF[b]
15	1050-1150	12.0	220.5	14.77	1.144×10^{-6}
	1245-1345	12.0	292.5	19.60	1.517×10^{-6}
13	1558-1658	12.0	111.91	7.50	5.82×10^{-7}
	1504-1604	12.0	113.68	7.62	5.92×10^{-7}
	1627-1727	12.0	101.25	6.79	5.27×10^{-7}
18	1544-1644	12.0	83.48	5.60	4.34×10^{-7}
	0920-1020	12.0	81.72	5.48	4.25×10^{-7}
16	1049-1149	12.0	147.0	9.87	7.65×10^{-7}
	1552-1652	12.0	52.5	3.52	2.73×10^{-7}
14	2045-2130	8.42	76.88	7.34	5.70×10^{-7}
	0855-0955	10.92	172.2	12.68	9.85×10^{-7}
11	1137-1237	11.51	1.58	0.11	8.52×10^{-9}
	1540-1640	11.51	1.18	0.08	6.43×10^{-9}
	1035-1135	11.51	0.12	0.008	6.243×10^{-10}
	1330-1430	11.51	--[d]	--[d]	--[d]
	1550-1650	11.51	--[d]	--[d]	--[d]

[a] Sample rate = 200 m /min. Bisulfite method used.

[b] Corrected to 70°F and 29.92 inches Hg.

[c] Dry basis.

[d] Blue color developed during sample collection; interference(s) unknown.

TABLE 40. OXIDES OF NITROGEN - FCCU CO BOILER STACKS

Stack	Time	NO_x (as NO_2) Concentration[a] ppm (Vol.)	NO_x (as NO_2) Concentration[a] lb/SCF[b]
13	1823	306	3.64×10^{-5}
	1406	297	3.53×10^{-5}
	1755	170	2.00×10^{-5}
18	1659	181	2.16×10^{-5}
	1047	269	3.20×10^{-5}
15	1125	94.1	1.12×10^{-5}
	1130	105.8	1.26×10^{-5}
16	1410	453	5.38×10^{-5}
	1517	378	4.49×10^{-5}
	1640	415	4.93×10^{-5}
14	2020	164.3	1.395×10^{-5}
	0900	190.0	1.514×10^{-5}
	1000	200.4	1.66×10^{-5}

[a] Dry basis.

[b] STP = 70°F and 29.92 inches Hg.

TABLE B4-41. HCN AND NH_3 - FCCU CO BOILER STACKS

Stack	Time	NH_3 Concentrations[b]		HCN Concentrations[b]	
		ppm (Vol.)	lb/SCF[c]	ppm (Vol.)	lb/SCF[c]
15[a]	1305-1336	15.36	6.76×10^{-7}		
	1515-1545			19.0	1.33×10^{-6}
	1315-1345	6.64	2.92×10^{-7}		
	1215-1247			19.1	1.33×10^{-6}
14[f]	1100	0.75	5.24×10^{-8}	1.00	6.96×10^{-8}
	1300	0.70	4.89×10^{-8}	1.05	7.31×10^{-8}
13[a]	1257-1331	0.511	2.25×10^{-8}		
	1425-1455			0.023	1.6×10^{-9}
	1613-1643	--[d]	--		
	1750-1820			--[e]	--
18[a]	0952-1052	--[d]	--		
	1706-1736			0.005	4.0×10^{-10}
16[a]	1345-1420	<0.3	$<1 \times 10^{-8}$		
	1115-1145	8.2	3.6×10^{-7}		
	1455-1525			$<1 \times 10^{-3}$	6.5×10^{-11}
	1015-1045			0.406	2.84×10^{-8}
11[a]	12:40 PM	1.0	43.7×10^{-8}	0.9	6.18×10^{-8}
	14:10 PM	0.6	2.62×10^{-8}	0.6	4.12×10^{-8}
	16:40 PM	1.0	4.37×10^{-8}	0.9	6.18×10^{-8}

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[a] Sampling performed using LSI Method 5 train and acidic or basic impinger solutions, as required.
[b] Dry Basis.
[c] Corrected to 70°F and 29.92 inches Hg.
[d] Not detectable, less than 0.01 ppm in solution.
[e] Not detectable, less than 0.005 ppm in solution.
[f] Infrared Analysis at 3.01 μ(HCN) and 10.4 μ(NH_3)

TABLE B4-42. STACK GAS AND PARTICULATES[a] - FCCU CO BOILER SCRUBBER STACKS

		Total Gas Sample[b]		Avg Meter Temp (°F)	Avg Stack Temp (°F)	Avg Dry (MW)	Moisture Collected (g)	Fraction	Particulates					Avg Stack Velocity (ft/sec)	% Isokin.
Stack	Time	Meter (ft³)	STP (SCF)[c]						Filter	Probe	Imp. #1	Total	Grain Loading (gr/SCF)		
12	1516-1643	41.67	41.09	78	185	29.13	251.2	0.225	0.0342		0.0180	0.0522	0.020	55.32	102.6
	1811-1922	42.08	41.77	75	185	29.19	261.1	0.229	0.0348	0.0131	0.0000	0.0479	0.018	55.88	103.6
17	1612-1741	40.55	39.22	93	180	29.71	260.3	0.239	0.0312	0.0084	0.0230	0.0626	0.025	52.57	100.7
	1821-1929	40.24	39.45	87	180	29.81	266.3	0.242	0.0300	0.0145	0.0107	0.0552	0.022	52.15	103.1

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[a] Sampled with LSI EPA-5 train.

[b] Total gas flow rates: Stack No. 12 - 9.08 x 10^5 SCFM; Stack No. 17 - 8.53 x 10^5 SCFM

[c] Corrected to 70°F and 29.92 Inches Hg.

TABLE B5-53. ALKYLATION UNIT: CRUDE ALKYLATE

Compound	Bulk Liquid, ppm[a]	Vapor on XAD, μg	Vapor on Tenax, μg
Benzene		0.69	0.0044
Toluene		3.3	0.067
Ethylbenzene		5.2	0.064
m,p-Xylene		42.0	0.20
o-Xylene		22.0	0.094
n-Propylbenzene		48.0	--
3-Ethyl toluene		36.0	0.86
1,2,3-Trimethylbenzene		96.0	--
1,3,5-Trimethylbenzene		54.0	--
2-Ethyl toluene		230.0	0.73
1,2,4-Trimethylbenzene		72.0	0.22
Diethylbenzene		6.0	0.14
Methylisopropylbenzene		2.6	0.0088
Methylpropylbenzene		26.0	0.35
Methylpropylbenzene		72.0	--
Methylpropylbenzene		47.0	--
Diethylbenzene		65.0	0.083
Diethylbenzene		22.0	--
Dimethylethylbenzene		72.0	0.15
Dimethylethylbenzene		66.0	0.11
Dimethylethylbenzene		17.0	--
Tetramethylbenzene		32.0	0.12
Tetramethylbenzene		48.0	0.15
Tetramethylbenzene		30.0	--
C_5-Alkylbenzene		10.0	--
C_5-Alkylbenzene		12.0	--
Naphthalene		140.0	0.57
C_5-Alkylbenzene		14.0	--
2-Methylnaphthalene		36.0	0.12

[a] None of the vapor species were found in the bulk liquid. The vapor species, therefore, must have been adsorbed from the ambient air or from cross-contamination with other samples from residue in the sampling train.

TABLE B4-44. SULFUR SPECIES - FCCU CO BOILER SCRUBBER STACKS

		SO_3[a]		SO_2[b]		SO_2[d]		H_2S		COS		CS_2	
Stack	Time	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF	ppm (Vol)	lb/SCF	ppm (Vol)	lb/SCF	ppm (Vol)	lb/SCF	ppm (Vol)	lb/SCF
12	1516-1643	0.19	4.01×10^{-8}	0.73	1.20×10^{-7}								
	1609	--	--	--	--	--	--	--	--	--	--	--	--
	1811-1922	0.13	2.65×10^{-8}	9.53	1.58×10^{-6}								
	1832	--	--	--	--	--	--	--	--	--	--	--	--
	1219	--	--	--	--	--	--	--	--	--	--	--	--
17	1612-1741	0.23	4.67×10^{-8}	11.98	1.98×10^{-6}								
	1710	--	--	--	--	--	--	--	--	--	--	--	--
	1821-1929	0.47	9.77×10^{-8}	13.10	2.17×10^{-6}								
	1949	--	--	--	--	--	--	--	--	--	--	--	--

[a] IPA Impinger, $Ba(ClO_4)_2$ Titration.
[b] 6% H_2O_2 Impingers, $Ba(ClO_4)_2$ Titration.
[c] Corrected to 70° and 29.92 inches Hg., dry basis.
[d] SO_2 only detected in samples from heater duct. Due to high moisture content in regenerator stack, no appreciable concentration of sulfur species detected in samples.

TABLE B4-45. ALDEHYDES[a] - FCCU CO BOILER SCRUBBER STACKS

Stack	Time	Gas Sample Volume (ℓ) (STP)[b]	Aldehyde Collected (μg)	Gaseous Ald. Volume @ STP (μℓ)	Concentrations[c] ppm(Vol.)	Concentrations[c] By Weight @ STP (μg/ℓ)	Concentrations[c] By Weight @ STP (lb/SCF)[b]
12	1438-1538	12.04	635.0	510.8	42.42	52.74	3.29×10^{-6}
	1707-1807	11.97	691.25	556.0	46.45	57.75	3.61×10^{-6}
	1229-1329	12.22	761.75	612.7	50.14	62.34	3.89×10^{-6}
17	1614-1714	11.87	582.5	468.5	39.47	49.07	3.06×10^{-6}
	1816-1916	12.25	497.5	400.2	32.67	40.61	2.54×10^{-6}

[a] Corrected to 70°F and 29.92 inches Hg.
[b] Dry basis.

TABLE B4-46. OXIDES OF NITROGEN[a] - FCCU CO BOILER SCRUBBER STACKS

Stack	Time	NO Concentration[b]			NO_2 Concentration[b]		
		Volume	By Weight		Volume	By Weight	
		(ppm)	(μg/l)	(lb/SCF)[c]	(ppm)	(μg/l)	(lb/SCF)[c]
12	1830	--	--	--	11.34	21.62	1.35×10^{-6}
	1158	--	--	--	--	--	--
	1359	--	--	--	70.89	135.14	8.44×10^{-6}
17	1845	--	--	--	77.98	148.65	9.28×10^{-6}
	1929	--	--	--	283.55	540.54	3.38×10^{-5}

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[a] A modified Phenoldisulfonic Acid method was used for analysis of NO_x as NO_2.

[b] Dry basis.

[c] Corrected to 70°F and 29.92 inches Hg.

[d] Not detected.

TABLE B4-47. STACK GAS AND PARTICULATES[a] - FCCU CO BOILER STACK - INLET AND OUTLET

		Total Gas Sample[b]		Avg	Avg				Particulates					Avg	
Stack	Time	Meter (ft³)	STP (SCF)[c]	Meter Temp (°F)	Stack Temp (°F)	Avg Dry (MW)	Moisture Collected (g)	Fraction	Filter	Probe	Imp. #1	Total	Grain Loading (gr/SCF)	Stack Velocity (ft/sec)	% Isokin.
15	1745-1857	31.68	31.81	96	538	30.58	185.0	.216	0.0425	0.0282	0.1290	0.1997	0.0969	48.98	112.0
	1015-1127	32.71	32.03	107	540	30.58	186.2	.216	0.0372	0.0384	0.0081	0.0837	0.0403	51.93	107.1

[a] Sampled with LSI EPA-5 train.

[b] Total gas flow rates: CO Boiler Outlet (Stack No. 15) - 6.53 x 10^6 SCFM; Precipitator Inlet - Undetermined

[c] Corrected to 70°F

TABLE B4-48. FIXED GASES[a] - FCCU CO BOILER STACK - INLET AND OUTLET

			% Composition[b]			
Stack	Time	CO_2	H_2	O_2	N_2	CO
15	1615	14.89	0.00	3.55	81.98	0.00
	1915	15.23	0.00	3.39	81.21	0.00
	1030	13.52	0.00	4.35	82.67	0.00
	1215	14.01	0.00	3.75	81.63	0.00
Precipitator Inlet	1600	10.88	0.49	3.21	77.64	7.78
	1945	10.11	0.69	3.31	78.14	7.74

[a] Fisher Model 1200 gas partitioner.

[b] Dry basis.

TABLE B4-49. SULFUR SPECIES - FCCU CO BOILER - INLET AND OUTLET

		SO_3[a]		SO_2[b]		SO_2		H_2S[d]		COS		CS_2	
Stack	Time	ppm (Vol)	lb/SCF[c]	ppm (Vol)	lb/SCF	ppm (Vol)	lb/SCF	ppm (Vol)	lb/SCF	ppm (Vol)	lb/SCF	ppm (Vol)	lb/SCF
15	1745-1857	0.781	1.61×10^{-7}	289	4.78×10^{-5}								
	1015-1127	1.126	2.33×10^{-7}	708	1.17×10^{-4}								
	1040					841	1.39×10^{-4}	n.d.[d]	n.d.	n.d.	n.d.	n.d.	n.d.
	1215					871	1.44×10^{-4}	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
Precipitator Inlet	1525					321	5.30×10^{-5}	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
	1530					344	5.68×10^{-5}	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.

[a] IPA Impinger, $Ba(ClO_4)_2$ Titration.

[b] 6% H_2O_2 Impinger, $Ba(ClO_4)_2$ Titration.

[c] STP = 70°F and 29.92 Inches Hg.

[d] n.d. = not detected.

TABLE B4-50. ALDEHYDES[a] - FCCU CO BOILER - INLET AND OUTLET

Stack	Time	Gas Sample Volume (ℓ) @ STP[b]	Aldehyde Collected (μg)	Concentration[c]	
				ppm(Vol.)	lb/SCF[b]
15	1050-1150	12.0	220.5	14.77	1.144×10^{-6}
	1245-1345	12.0	292.5	19.60	1.517×10^{-6}
Precipitator Inlet	1720-1820	12.0	3105	208.0	1.611×10^{-5}

[a] Sample rate = 200 mℓ/min. Bisulfite method used.

[b] STP = 70°F and 29.92 inches Hg.

[c] Dry basis. Calculated as formaldehyde.

TABLE B4-51. OXIDES OF NITROGEN - FCCU CO BOILER - INLET AND OUTLET

Stack	Time	NO_x (as NO_2) Concentration[a] ppm (Vol.)	NO_x (as NO_2) Concentration[a] lb/SCF[b]
15	1125	94.1	1.12×10^{-5}
	1130	105.8	1.26×10^{-5}
Precipitator Inlet	1700	36.4	4.32×10^{-6}
	1700	46.5	5.52×10^{-6}

[a] Dry basis.

[b] STP = 70°F and 29.92 inches Hg.

TABLE B4-52. HCN[a] AND NH_3[b] - FCCU CO BOILER CO BOILER STACK - INLET AND OUTLET

		HCN Concentration[c]			NH_3 Concentration[c]	
Stack	Time	ppm (Vol.)	lb/SCF[d]	Time	ppm (Vol.)	lb/SCF[d]
15	1515-1545	19.0	1.33×10^{-6}	1305-1336	15.36	6.76×10^{-7}
	1215-1247	19.1	1.33×10^{-6}	1315-1345	6.64	2.92×10^{-7}
Precipitator Inlet	1617-1645	109.5	7.65×10^{-6}	1530-1603	3.99	1.76×10^{-7}

[a] Sampling performed using LSI Method 5 train and 2 N H_2SO_4 impinger solutions.

[b] Sampling performed using LSI Method 5 train and 0.IN NaOH impinger solutions.

[c] Dry basis.

[d] Corrected to 70°F and 29.92" Hg.

TABLE B4-53. STACK GAS AND PARTICULATES[a] - FCCU COMPRESSOR EXHAUST STACK

Stack	Time	Total Gas Sample[b] Meter (ft³)	Total Gas Sample[b] STP (SCF)[c]	Avg Meter Temp (°F)	Avg Stack Temp (°F)	Avg Dry (MW)	Moisture Collected (g)	Fraction	Particulates Filter	Particulates Probe	Particulates Imp. #1	Particulates Total	Grain Loading (gr/SCF)	Avg Stack Velocity (ft/sec)	% Isokin.
20	1048-1248	62.92	59.18	114.9	600	28.39	185.8	0.129	0.0020	0.2674	0.0173	0.2867	0.075	89.32	105
	1500-1700	66.81	62.76	115.6	660	27.42	190.4	0.125	0.0033	0.0287	0.0047	0.0367	0.009	91.11	98

[a] Sampled with LSI EPA-5 train.

[b] Total gas flow - 0.055 x 10^6 SCFM

[c] STP = 70°F and 29.92 inches Hg.

TABLE B4-54. METHANE/NONMETHANE HYDROCARBONS[a] - AND FIXED GASES[b] - FCCU COMPRESSOR EXHAUST STACK

		Methane Concentrations				Nonmethane Concentrations (As Hexane)				Fixed Gases (Dry Basis)				
		By Weight			By Volume	By Weight			By Volume					
Stack	Time	(ppm)	(µg/l)	(lb/SCF)	(ppm)	(ppm)	(µg/l)	(lb/SCF)	(ppm)	CO_2 (%)	O_2 (%)	N_2 (%)	CO (%)	Mol. Wt. (Dry)
20	0930	--	--	--	--	--	--	--	--	4.0	10.3	76.5	0.5	26.62
	1145	--	--	--	--	--	--	--	--	4.0	12.5	77.0	0.5	27.46
	1530	--	--	--	--	--	--	--	--	6.8	10.0	75.3	0.5	27.42
	0830	NC	NC	NC	4.00	NC	NC	NC	75	9.0	7.0	76.5	0.5	27.76
	0945	NC	NC	NC	4.00	NC	NC	NC	68	9.0	6.5	76.0	0.5	27.46
	1045	--	--	--	--	--	--	--	--	8.0	8.0	77.0	0.4	27.75

[a] Byron hydrocarbon analyzer using flame ionization detector.

[b] Fischer Model 1200 gas partitioner.

[c] NC - Not Calculated.

TABLE B4-55. SULFUR SPECIES - FCCU COMPRESSOR EXHAUST STACK

Stack	Time	SO_3[a] ppm (Vol)	SO_3[a] lb/SCF @ STP	SO_2[b] ppm (Vol)	SO_2[b] lb/SCF @ STP
20	0930				--
	1048-1248	0.69	1.4×10^{-7}	0.66	1.08×10^{-7}
	1145				
	1500-1700	0.523	1.04×10^{-7}	0.33	5.29×10^{-8}
	1530				

[a] IPA Impinger, $BaClO_4$ Titration.
[b] 6% H_2O Impinger, $BaClO_4$ Titration.

TABLE B4-56. HCN AND NH_3[a] - FCCU COMPRESSOR EXHAUST STACK

Source	Time	Baseline (A)	Measured Absorb (A)	Net Absorb (A)	Concentration		
					Volume (ppm)	By Weight @ STP	
						(μg/1)	(1b/SCF)[b]
				HCN			
20	1200	0.0058	0.0600	0.0542	1.8	1.99	1.24×10^{-7}
	1515	0.0065	0.0720	0.0655	2.1	2.32	1.45×10^{-7}
	1710	0.0068	0.0850	0.0782	2.5	2.76	1.72×10^{-7}
				NH_3			
20	1200	0.0060	0.0320	0.0260	1.0	0.70	4.37×10^{-8}
	1515	0.0075	0.0550	0.0475	2.4	1.39	8.68×10^{-8}
	1710	0.0074	0.0310	0.0236	0.9	0.63	3.93×10^{-8}

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[a] Infrared analysis at 3.01μ(HCN) and 10.4μ(NH_3). Path length = 20.25m; cell temperature = 75°C.

[b] STP = 70°F and 29.92 inches Hg.

SECTION 5

SPECIES CHARACTERIZATION

5.1 ORGANIC AND INORGANIC SPECIES CHARACTERIZATION

The characterization and measurement of organic emissions from controlled and uncontrolled sources were conducted at several petroleum refineries. The controlled sources under study included the flue gas from carbon monoxide (CO) boilers (that are charged with flue gas from fluidized catalytic cracking regenerators) and from a fluidized coking unit. The uncontrolled sources included wastewater treatment systems, valves, pumps, flanges, compressors, and drains.

Tables B5-1 through B5-12 and Tables B5-60 and B5-61 list the aromatic species and inorganics contained in emissions from controlled sources.

Tables B5-13 through B5-59 present the species identified in various refinery process streams and/or the fugitive emissions from fittings in service on those process streams. Each of these sources is identified by the process unit name followed by the stream name. An effort was made to generalize these stream names so that similar streams from different refineries could be compared.

Each process source was sampled in two ways when possible. A sample of the material in the line was taken directly for analysis by GC-MS. For liquid streams, a small

TABLE B5-1. ORGANIC SPECIES IN FCCU CO BOILER FLUE GAS (STACK NO.11)

Compound	Concentration (ppb)		
	XAD-2	Particulates	Total
Acenaphthalene	0.06	0.0	0.06
Anthracene/Phenanthrene	0.1	0.0	0.1
C_3 - Benzene	0.0	0.009	0.009
Benzo(a)pyrene	0.005	0.0	0.005
Benzo(ghi)perylene	0.01	0.0	0.01
Chrysene	0.005	0.0	0.005
Fluoranthene	0.02	0.0	0.02
Fluorene	0.05	0.0009	0.05
Methyl Anthracene/Phenanthrene	0.1	0.0	0.1
Methyl-2,4-dichlorobenzoic acid	0.0	0.04	0.04
Methyl Fluorene	0.05	0.0	0.05
Methyl naphthalene	0.08	0.03	0.1
Naphthalene	0.1	0.03	0.1
C_2 - Naphthalene	0.1	0.0	0.1
Pyrene	0.04	0.001	0.04

TABLE B5-2. ORGANIC SPECIES IN FCCU CO BOILER FLUE GAS (STACK NO. 14)

Compound	Concentration (ppb)		
	XAD-2	Particulates	Total
Acenaphthene	0.048	0.0	0.048
Acetophenone	0.028	0.0	0.028
C_2-Alkyl acetophenone	0.015	0.0	0.015
C_2-Alkyl anisole	0.009	0.0	0.009
C_2-Alkylbenzaldehyde	0.002	0.0	0.002
C_3-Alkylbenzene	0.013	0.0	0.013
C_2-Alkylnaphthalene	0.13	0.0	0.13
Benzaldehyde	0.034	0.0	0.034
Benzoic acid	3.5	0.0	3.5
Biphenyl	0.34	0.0	0.34
Cresol	0.22	0.0	0.22
Cyclohexane diol	0.13	0.0	0.13
Cyclohexanol	0.12	0.0	0.12
Cyclohexanone	0.18	0.0	0.18
Cyclohexene oxide	0.80	0.0	0.80
Cyanobenzene	0.001	0.0	0.001
Diphenyl oxide	0.018	0.0	0.018
Fluoranthene	0.011	0.0	0.011
Fluorene	0.041	0.0	0.041
1-Methoxynaphthalene	0.063	0.0	0.063
Methylcyclohexanone	0.0	0.61	0.61
1-Methylnaphthalene	0.15	0.0	0.15
2-Methylnaphthalene	0.16	0.0	0.16
Naphthalene	0.43	0.0	0.43
Phenanthrene/Anthracene	0.061	0.0	0.061
Phenol	0.038	0.0	0.038
Phenyl benzoate	0.013	0.0	0.013

TABLE B5-3. ORGANIC SPECIES IN FCCU CO BOILER FLUE GAS (STACK NO. 15)

Compound	Concentration (ppb) XAD-2	Particulates	Total
Benzaldehyde	0.2	0.0	0.2
Cyclohexanone	0.0	0.13	0.13
Ethyl toluene	0.0	0.01	0.01
Naphthalene	0.04	0.006	0.046
Phthaldehyde[a]	0.01	0.0	0.01
Phenanthrane/Anthracene	0.01	0.0	0.01

[a] Sum of two or more isomeric species.

TABLE B5-4. ORGANIC SPECIES IN FCCU CO BOILER FLUE GAS (STACK NO. 16)

Compound	Concentration (ppb) XAD-2	Particulates	Total
Benzoic acid[a]	1.5	0.0	1.5
Naphthalene	0.02	0.0	0.02
Phenol[b]	0.003	0.0	0.003

[a] Based on identification of corresponding methyl ester.

[b] Based on identification of corresponding phenol ether.

TABLE B5.5. ORGANIC SPECIES IN FCCU CO BOILER FLUE GAS (STACK NO.13)

Compound	Concentration (ppb)		
	XAD-2	Particulate	Total
Acenaphthene	<0.001	0.0	<0.001
Biphenyl	0.003	0.0	0.003
Chrysene	0.0	0.002	0.002
Dibenzofuran	0.0	0.008	0.008
Dimethyl naphthalene[a]	0.02	0.0	0.02
Fluoranthene	0.006	0.006	0.012
Fluorene	0.008	0.009	0.017
Methyl dimethoxybenzoate			0.54
Naphthalene	0.02	0.08	0.10
Phenanthrene/Anthracene	0.025	0.05	0.075
Pyrene	0.02	0.003	0.023

[a] Sum of two or more isomeric species.

TABLE B5-6. ORGANIC SPECIES IN FCCU CO BOILER FLUE GAS FROM SCRUBBER (STACK NO. 12)

Compound	Concentration (ppb)		
	XAD-2	Particulates	Total
Acenaphthene	0.20	0.0	0.20
Acenaphthylene	0.42	0.0	0.42
Anthracene/Phenanthrene	0.46	0.0	0.46
Benzo(a)pyrene	0.07	0.0	0.07
Benzo(g,h,i)perylene	0.03	0.0	0.03
Benzofluorene	0.08	0.0	0.08
Benz(a)anthracene/Chrysene	0.10	0.0	0.10
C_2-Alkylnaphthalene	1.25	0.0	1.2
C_2-Alkyl phenols	0.29	0.0	0.29
C_3-Alkyl phenols	1.65	0.0	1.6
Dibenzofuran	0.29	0.0	0.29
Fluorene	0.18	0.0	0.18
Fluoranthene	0.25	0.0	0.25
Indanol	0.16	0.0	0.16
Methnaphthalene	1.14	0.0	1.1
Methyl phenols	0.20	0.0	0.20
Methyl indanol	0.07	0.0	0.07
Methyl epoxyoctadecanoate	2.68	0.0	2.7
Methyl hexadecanoate	3.20	0.0	3.2
Methyl octadecanoate	2.23	0.0	2.2
Methyl oleate	1.25	0.0	1.2
Naphthalene	1.43	0.0	1.4
n-Tridecane	0.09	0.0	0.09
n-Tetradecane	0.17	0.0	0.17
n-Pentadecane	0.19	0.0	0.19
n-Hexadecane	0.23	0.0	0.23
n-Heptadecane	0.44	0.0	0.44
n-Octadecane	0.56	0.0	0.56
n-Nonadecane	0.61	0.0	0.61
n-Eicosane	0.71	0.0	0.71
n-Uncosane	0.65	0.0	0.65
n-Docosane	0.63	0.0	0.63
n-Tricoscane	0.59	0.0	0.59
n-Tetracosane	0.60	0.0	0.60
n-Pentacosane	0.46	0.0	0.46
n-Hexacosane	0.38	0.0	0.38
n-Heptacosane	0.35	0.0	0.35
n-Octacosane	0.30	0.0	0.30
n-Nonacosane	0.28	0.0	0.28
n-Triacontane	0.18	0.0	0.18
n-Untriacontane	0.10	0.0	0.10
n-Dotriacontane	0.05	0.0	0.05

Continued

TABLE B5-6. CONTINUED

Compound	Concentration (ppb)		
	XAD-2	Particulates	Total
n-Tritriacontane	0.03	0.0	0.03
Nonyl phenol	0.66	0.0	0.66
Octyl Phenol	0.21	0.0	0.21
Pyrene	0.11	0.0	0.11

TABLE B5-7. ORGANIC SPECIES IN TCC CO BOILER FLUE GAS (STACK NO. 9)

	Concentration (ppb)		
Compound	XAD-2	Particulates	Total
C_2-Alkyl biphenyl	0.02	0.0	0.02
C_2-Alkyl naphthalene	0.03	0.0	0.03
C_3-Alkyl naphthalene	0.02	0.0	0.02
C_2-Alkyl phenanthrene	0.09	0.0	0.09
C_3-Alkyl phenol	0.56	0.0	0.56
Azulene	0.01	0.0	0.01
Benz(a)anthracene	0.003	0.0	0.003
Benzaldehyde	1.2	0.0	1.2
Benzofluoranthene	0.02	0.0	0.02
Benzo(g,h,i)perylene	0.005	0.0	0.005
Benzoic acid[c]	15.0	0.0	15.0
Benzopyrene	0.02	0.0	0.02
Biphenyl	0.01	0.0	0.01
Carbazole	0.01	0.0	0.01
Chlorocresol[b]	0.07	0.0	0.07
Chloroxylenol	0.02	0.0	0.02
Chrysene	0.03	0.0	0.03
Cresol[b]	0.02	0.0	0.02
Ethyl phenol	1.7	0.0	1.7
Ethyl toluene	0.036	0.0	0.036
Ethyl xylene	0.054	0.0	0.054
Fluoranthene	0.09	0.0	0.09
Fluorene	0.008	0.0	0.008
Indeo(1,2,3-c,d)pyrene	0.007	0.0	0.007
Methyl fluoranthene	0.01	0.0	0.01
Methyl naphthalene	0.02	0.0	0.02
Methyl phenanthrene	0.15	0.0	0.15
Methyl pyrene	0.07	0.0	0.07
Naphthalene	0.08	0.0	0.08
Phenanthrene/Anthracene	0.17	0.0	0.17
Phenol[b]	0.11	0.0	0.11
Phthaldehyde[a]	0.26	0.0	0.26
Phthalic acid[c]	0.20	0.0	0.20
Pyrene	0.06	0.0	0.06
Xylenol	1.3	0.0	1.3

[a] Sum of two or more isomeric species.

[b] Based on identification of corresponding phenol ether.

[c] Based on identification of corresponding methyl ester.

TABLE B5-8. ORGANIC SPECIES IN FLUID COKER SCRUBBER INLET (1), (STACK NO. 19)

Compound	Concentration (ppb)		
	XAD-2	Particulates	Total
C_2-Alkyl naphthalene	0.1	0.0	0.1
Azulene	5.0	0.0	5.0
Benzaldehyde	9.0	0.0	9.0
Benzamide	0.36	0.0	0.39
Benzofuran	9.8	0.0	9.8
Benzoic acid[c]	21.08	0.007	21.0
Benzonitrile	107.7	8.5	116.
Benzothiophene	5.5	0.16	5.7
Biphenyl	4.5	0.35	4.8
Butyl benzene	0.0	0.02	0.02
Cyanobenzothiophene[a]	7.28	0.03	7.3
Cyanothiophene	4.2	0.0	4.2
Cyclohexanone	1.3	0.0	1.3
n-Decane	0.0	1.1	1.1
Dibenzofuran	3.0	0.17	3.2
Dibenzothiophene	0.51	0.0	0.51
Diethyl benzene[a]	0.0	0.11	0.11
Dimethyl ethyl benzene	0.0	0.04	0.04
n-Dodecane	0.0	0.54	0.54
Dodecene	0.0	0.31	0.31
Ethyl quiniline[a]	0.0	0.12	0.12
Ethyl toluene[a]	0.03	1.46	1.5
Ethyl xylene	0.0	0.28	0.28
Hydroxymethyl quinoline	1.8	0.0	1.8
Methoxy dipehnyl ether	0.24	0.0	0.24
Methyl benzonitrile	3.5	0.0	3.5
Methyl indan[a]	0.0	0.02	0.02
Methyl naphthalene[a]	0.37	0.02	0.39
Methyl phenyl pyridine	0.0	0.06	0.06
Methyl quinoline[a]	1.1	0.0	1.1
Naphthalene	4.1	0.62	4.7
Naphthonitrile	10.5	0.29	11.
n-Nonane	0.0	2.0	2.0
Phenanthrene/Anthracene	0.83	0.08	0.91
Phenol[b]	6.0	0.0	6.0
Phthaldehyde[a]	0.10	0.0	0.10
Phthalic acid[d]	1.5	0.0	1.5
Phthalonitrile[a]	10.85	0.0	11.
Propyl benzene	0.0	0.30	0.30
Quinoline	1.7	0.0	1.7
Styrene	0.40	0.0	0.40
n-Tridecane	0.03	0.24	0.27
Tridecene	0.0	0.09	0.09
n-Undecane	0.0	0.87	0.87
Undecene	0.0	0.77	0.77
Xylene[a]	0.34	0.17	0.51

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[a] Sum of two or more isomeric species.

[b] Based on identification of corresponding phenol ether.

[c] Based on identification of corresponding methyl ester.

[d] Based on identification of corresponding dimethyl diester.

TABLE B5-9. ORGANIC SPECIES IN FLUID COKER SCRUBBER OUTLET (2) (STACK NO. 19)

Compound	Concentration (ppb)		
	XAD-2	Particulates	Total
Azulene	3.2	0.0	3.2
Benzofuran	3.4	0.0	3.4
Benzoic acid[c]	21.0	0.11	21.0
Benzonitrile	110.0	0.0	110.0
Benzothiophene	5.5	0.0	5.5
Biphenyl	3.4	0.0	3.4
Cresol[a]	0.11	0.0	0.11
Cyanobenzothiophene	0.06	0.0	0.06
Cyanothiophene	2.26	0.0	2.3
Cyclohexane	0.12	0.0	0.12
n-Decane	0.0	0.02	0.02
Dibenzofuran	1.0	0.0	1.0
Dibenzothiophene	0.03	0.0	0.03
Dimethyl naphthalene	0.02	0.0	0.02
Ethyl toluene[a]	0.20	0.06	0.26
Indan	0.02	0.0	0.02
Methyl benzonitrile[a]	1.6	0.0	1.6
Methyl indan[a]	0.05	0.0	0.05
Methyl naphthalene[a]	0.33	0.0	0.33
Naphthalene[a]	3.6	0.0	3.6
Naphthonitrile[a]	0.36	0.0	0.36
Pnenanthrene/Anthracene	0.03	0.0	0.03
Phenol[b]	3.04	0.0	3.0
Phthaldehyde[a]	0.59	0.0	0.59
Quinoline	0.40	0.0	0.40
Xylene	0.93	0.0	0.93
Styrene	0.61	0.0	0.61

[a] Sum of two or more isomeric species.

[b] Based on identification of corresponding phenol ether.

[c] Based on identification of corresponding methyl ester.

TABLE B5-10. ORGANIC SPECIES IN FLUID COKER SCRUBBER OUTLET (2) (STACK NO. 19)

Compound	Concentration (ppb)		
	XAD-2	Particulates	Total
C_2-Alkyl benzoic acid[c]	1.2	0.0	1.2
C_2- Alkyl naphthalene	0.03	0.0	0.03
Azulene	0.68	0.0	0.68
Benzaldehyde	2.3	0.0	2.3
Benzofuran	1.1	0.0	1.1
Benzoic acid[c]	11.0	0.0	11.0
Benzonitrile	37.0	0.65	37.6
Benzothiophene	1.87	0.02	1.9
Biphenyl	0.54	0.07	0.61
Butyl benzene	0.0	0.003	0.003
Cresol[b]	0.02	0.0	0.02
Cyanobenzothiophene	0.067	0.0	0.067
Cyanothiophene	1.57	0.0	1.57
Cyclohexanone	0.19	0.0	0.19
Dibenzofuran	0.41	0.07	0.48
Dibenzothiophene	0.0	0.008	0.008
Ethyl toluene	0.13	0.11	0.24
Ethyl xylene[a]	0.02	0.02	0.04
Indan	0.033	0.0	0.033
Isoquinoline	0.01	0.0	0.01
Methyl benzonitrile[a]	0.21	0.21	0.42
Methyl indan[a]	0.03	0.03	0.06
Methyl napthalene[a]	0.18	0.008	0.188
Methyl quinoline	0.13	0.0	0.13
Naphthalene	1.75	0.37	2.12
Naphthonitrile	0.16	0.06	0.22
Pehnanthrene/Anthracene	0.01	0.02	0.03
Phenol[b]	1.11	0.0	1.11
Phthaldehyde[a]	0.009	0.0	0.009
Phthalic acid[d]	0.05	0.0	0.05
Propyl benzene	0.02	0.02	0.04
Quinoline	0.27	0.0	0.27
Styrene	0.16	0.0	0.16
Xylene	0.16	0.02	0.18

[a] Sum of two or more isomeric species.

[b] Based on identification of corresponding phenol ether.

[c] Based on identification of corresponding methyl ester.

[d] Based on identification of corresponding dimethyl diester.

TABLE B5-11. ORGANIC SPECIES IN FLUID COKER CO BOILER FLUE GAS (2) (STACK NO. 10)

Compound	Concentration (ppb)		
	XAD-2	Particulates	Total
Benzaldehyde	9.8	0.0	9.8
Benzofuran	0.03	0.0	0.03
Benzoic acid[c]	58.0	0.0	58.1
Benzonitrile	3.2	0.55	3.8
Benzothiophene	0.04	0.0	0.04
Biphenyl	0.02	0.16	0.18
Chrysene	0.0	0.003	0.003
Cyclohexanone	0.11	0.22	0.33
Dibenzofuran	0.04	0.15	0.19
Fluoranthene	0.01	0.002	0.012
Fluorene	0.01	0.0	0.01
Methyl naphthalene[a]	0.05	0.006	0.011
Naphthalene	0.44	0.03	0.47
Naphthonitrile[a]	0.0	0.07	0.07
Phenanthrene/Anthracene	0.03	0.02	0.05
Phenol	0.009	0.0	0.009
Phthaldehyde[a]	0.02	0.0	0.02
Pyrene	0.008	0.005	0.013

[a] Sum of two or more isomeric species.

[b] Based on identification of corresponding phenol ether.

[c] Based on identification of corresponding methyl ester.

TABLE B5-12. ORGANIC SPECIES IN RESIN FUME OXIDATION FLUE GAS, (STACK NO. 1)

Compound	Concentration (ppb)		
	XAD-2	Particulates	Total
Biphenyl	0.017	0.0066	0.024
Methyl naphthalene	0.0011	0.0	0.001
Naphthalene	0.0059	0.0	0.006
Phenanthrene/Anthracene	0.0097	0.0	0.010
Pyrene	0.011	0.0	0.011

TABLE B-13. CRUDE DISTILLATION UNIT: FLASHED CRUDE

Compound	Bulk Liquid ppm	Vapor on XAD, μg	Vapor on Tenax, μg
Benzene	60	78	0.10
Toluene	680	600	0.47
Ethylbenzene	220	160	0.09
m,p-Xylene	640	460	0.24
o-Xylene	240	110	0.11
Isopropylbenzene	60	42	0.34
n-Propylbenzene	--	130	--
3 or 4-Ethyl toluene	580	370	0.15
1,3,5-Trimethylbenzene	400	220	
2-Ethyl toluene	310	160	0.14
1,2,4-Trimethylbenzene	680	320	0.13
Isobutylbenzene	80	18	0.08
1,2,3-Trimethylbenzene	280	84	0.08
Methylpropylbenzene	240	54	--
Methylpropylbenzene	160	154	0.05
Diethylbenzene	120	440	0.06
Diethylbenzene	200	66	--
Dimethylethylbenzene	290	78	0.05
Methyl indan	18	--	--
Dimethylethylbenzene	80	36	0.02
Tetramethylbenzene	120	32	0.15
Methyl indan	21	--	--
C_5-Alkylbenzene	90	--	--
Naphthalene	860	120	0.01
C_5-Alkylbenzene	40	--	--
C_5-Alkylbenzene	30	--	--
2-Methylnaphthalene	1000	50	--
1-Methylnaphthalene	860	25	--
Biphenyl	320	--	--
C_2-Alkylnaphthalene	160	--	--
C_2-Alkylnaphthalene	1100	--	--
C_2-Alkylnaphthalene	1700	--	--
C_2-Alkylnaphthalene	540	--	--
C_2-Alkylnaphthalene	160	--	--
C_3-Naphthalene	320	--	--
C_3-Naphthalene	860	--	--
C_3-Naphthalene	710	--	--
C_3-Naphthalene	390	--	--
Fluorene	80	--	--
Phenanthrene/Anthracene	140	--	--

TABLE B5-14. CRUDE DISTILLATION UNIT: ATMOSPHERIC TOWER OVERHEAD ACCUMULATOR GAS

Peak Number	Compounds (In Retention Order)	Vapor on XAD (μg)	Vapor on Tenax (μg)
1	Benzene	606.0	0.100
(IS)[a]	d_6-Benzene	--	(0.035)
2	$C_5H_{10}O$, possibly Tetrahydropyran	--	0.010
3	$C_6H_{12}O$, possibly a Dimethyl tetrahydrofuran	230.0	--
4	$C_6H_{12}O$, possibly a Methyl pentanol	210.0	--
5	$C_5H_{12}O_2$, or $C_6H_{12}O$	770.0	--
6	Toluene	1,220.0	0.036
7	$C_7H_{12}O$, possibly a Trimethyl dihydrofuran	690.0	--
8	Ethylbenzene	70.2	0.054
9	m- + p- Xylene	430.0	
10	o-Xylene	120.0	0.032
11	3- + 4- Ethyltoluene	7.5	0.065
12	1,3,5-Trimethylbenzene	18.0	
13	1,2,4-Trimethylbenzene	28.5	0.068
14	Isobutylbenzene	--	0.031
15	Indan	--	0.010
16	C_4-Alkylbenzene	--	0.052
17	C_4-Alkylbenzene	--	0.050
18	C_4-Alkylbenzene	--	0.046
19	C_5-Alkylbenzene	--	0.021
20	Naphthalene	--	0.140
(IS)	d_{10}-Anthracene	(600.0)	--

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[a] IS = Internal Standard

TABLE B5-15. CRUDE DISTILLATION UNIT: INTERMEDIATE NAPHTHA PRODUCT, BULK LIQUID

Compound	ppm
Benzene	26.3
Toluene	64.0
Ethylbenzene	153.0
m/p-xylenes	204.0
o-xylenes	40.3
i-propylbenzene	3.74
n-propylbenzene	45.9
m/p-ethyltoluene	236.0
o-ethyltoluene	47.6
1,2,4-Trimethylbenzene	105.0
1,2,3-Trimethylbenzene	9.52
C_4-Alkylbenzene	3.42
C_4- Alkylbenzene	70.0
n-butylbenzene	88.0
C_4-Alkylbenzene	24.0
C_4-Alkylbenzene	24.0
Methylindan	10.8
Methylindan	94.0
C_4-Alkylbenzene	60.0
C_4-Alkylbenzene	36.0
C_4-Alkylbenzene	3.04
C_5-Alkylbenzene	8.05
C_4-Alkylbenzene	13.6
C_5-Alkylbenzene	6.56
C_5-Alkylbenzene	20.8
C_5-Alkylbenzene	45.0
C_5-Alkylbenzene	70.0
Tetralin	74.0
C_5-Alkylbenzene	27.5
Naphthalene	24.2
C_2-Alkyl Indan/Methyltetralin	140.0
C_2-Alkyl Indan/Methyltetralin	115.0
2-Methyltetralin	96.1
C_2-Alkyl Indan/Methyltetralin	102.0
C_2-Alkyl Indan/Methyltetralin	112.0
C_2-Alkyl Indan/Methyltetralin	52.7
2-Methylnaphthalene	32.3
1-Methylnaphthalene	16.0
C_2-Alkyl naphthalene	5.25
C_2-Alkyl naphthalene	25.0
B.Phenyl	7.70
C_2-Alkyl naphthalene	23.8
C_2-Alkyl naphthalene	12.3

Continued

TABLE B5-15. Continued

Compound	ppm
Methylbiphenyls	13.6
C_3-Alkyl naphthalene	2.67
C_3-Alkyl naphthalene	9.28
C_3-Alkyl naphthalene	13.1
C_3-Alkyl naphthalene	9.86
C_3-Alkyl naphthalene	5.80
C_2-Alkyl biphenyls	36.0
Phenanthrene/anthracene	5.50
Methyl phenanthrene/anthracene	14.0
C_2-Alkyl phenanthrene/anthracene	14.8
Fluorenthene	3.10
Pyrene	7.50
Methyl fluoranthene/pyrene	10.8
Methyl fluoranthene/pyrene	15.6
C_2-Alkyl fluoranthene/pyrene	26.0
C_1-Alkyl chrysenes/Benzointhracines	0.533

TABLE B5-16. CRUDE DISTILLATION UNIT: FULL RANGE STRAIGHT RUN NAPHTHA, BULK LIQUID

Compound	PPM
Benzene	57.5
Toluene	139.0
Ethylbenzene	300.0
m/p-xylenes	229.0
o-xylene	228.0
i-propylbenzene	21.6
n-propylbenzene	63.8
m/p-ethyltoluene	284.0
1,3,5-Trimethylbenzene	74.8
o-ethyltoluene	49.3
1,2,4-Trimethylbenzene	257.0
sec-Butylbenzene	26.0
1,2,3-Trimethylbenzene	21.8
C_4-Alkylbenzene	28.8
Inden	4.38
C_4-Alkylbenzene	68.0
n-Butylbenzene	28.0
C_4-Alkylbenzene	72.0
C_4-Alkylbenzene	90.0
Methylindan	30.0
Methylindan	18.4
C_4-Alkylbenzene	26.0
C_4-Alkylbenzene	8.40
C_5-Alkylbenzene	47.31
C_5-Alkylbenzene	7.00
C_4-Alkylbenzene	24.0
C_5-Alkylbenzene	17.4
Methylindan	7.00
C_5-Alkylbenzene	8.25
C_5-Alkylbenzene	15.0
C_5-Alkylbenzene	37.5
Methylindan	9.10
C_5-Alkylbenzene	45.0
C_5-Alkylbenzene	11.5
C_5-Alkylbenzene	6.00
Naphthalene	12.1
C_2-Alkylindene/methyltetralin	17.4

TABLE B5-17. CRUDE DISTILLATION UNIT: VIRGIN MIDDLE DISTILLATE PRODUCT, BULK LIQUID

Compound	ppm
Toluene	4.48
Ethylbenzene	9.10
m/p-xylenes	40.3
o-xylene	11.7
n-propylbenzene	7.80
m/p-ethyltoluene	27.3
1,3,5-Trimethylbenzene	22.1
o-ethyltoluene	5.85
1,2,4-Trimethylbenzene	89.8
1,2,3-Trimethylbenzene	14.0
Indan	11.4
C_4-Alkylbenzene	48.0
C_4-Alkylbenzene	38.0
C_4-Alkylbenzene	106.0
Methylindan	28.0
C_4-Alkylbenzene	70.0
C_4-Alkylbenzene	80.0
Methylindan	26.0
C_5-Alkylbenzene	27.5
C_5-Alkylbenzene	65.0
Methylindan	29.9
C_5-Alkylbenzene	80.0
C_5-Alkylbenzene	32.5
Naphthalene	100.0
Benzothiophene	38.0
C_5-Alkylbenzene	25.0
Methylbenzothiophene	129.0
2-Methylnaphthelene	760.0
Methylbenzothiophene	114.0
1-Methylnaphthalene	89.9
C_2-Alkylbenzothiophene	80.0
C_2-Alkylbenzothiophene	36.0
C_2-Alkylnaphthalene	62.5
C_2-Alkylbenzothiophene	205.0
C_2-Alkylnaphthalene	400.0
C_2-Alkylbenzothiophene	64.0
C_2-Alkylnaphthalene	700.0
C_2-Alkylbenzothiophene	54.0
C_2-Alkylnaphthalene	143.0
C_2-Alkylnaphthalene	32.5
Acenaphthene	19.6
C_3-Alkylbenzothiophene	215.0
C_3-Alkylnaphthalene	241.0

Continued

TABLE B5-17. Continued

Compound	ppm
C_3-Alkylnaphthalene	249.0
C_3-Alkylnaphthalene	235.0
C_3-Alkylnaphthalene	171.0
Fluorene	34.5
C_3-Alkylnaphthalene	69.6
Methylacenaphthene	86.0
C_4-Alkylbenzothiophene	100.0
C_4-Alkylnaphthalene	348.0
Methylfluorene	18.7
C_2-Alkylacenapthene	126.0
Methylfluorene	30.6
Methylfluorene	10.4
Dibenzothiophene	32.0
Phenanthrene/Anthracene	56.1
C_2-Alkylfluorene	62.0
Methyldibenzothiophene	27.2
Methyldibenzothiophene	51.0
Methyl phenanthrene/anthracene	51.8
Methyl phenanthrene/anthracene	40.6
C_2-Alkyldibenzothiophene	12.6
C_2-Alkyl phenanthrene/anthracene	4.75
C_2-Alkyldibenzothiophene	4.60
C_2-Alkyl phenanthrene/anthracene	18.0
C_2-Alkyl phenanthrene/anthracene	40.0
C_2-Alkyldibenzothiophene	36.3
C_2-Alkyldibenzothiophene	22.0
C_2-Alkyl phenanthrene/anthracene	92.5
Fluoranthene	3.30
C_3-Alkyldibenzothiophene	65.0
C_3-Alkyl phenanthrene/anthracene	5.22
C_3-Alkyl phenanthrene/anthracene	4.93
C_3-Alkyl phenanthrene/anthracene	10.73
Pyrene	4.80
C_3-Alkyl phenanthrene/anthracene	24.9
C_4-Alkyldibenzothiophene	13.3
C_3-Alkyl phenanthrene/anthracene	8.41
Methyl fluoranthen/pyrene	2.99
Methyl fluoranthen/pyrene	3.51

TABLE B5-18. CRUDE DISTILLATION UNIT: ATMOSPHERIC GAS OIL, BULK LIQUID

Compound	ppm
Toluene	7.60
Ethylbenzene	5.46
m/p-xylenes	11.1
o-xylene	4.68
m/p-ethyltoluene	15.1
1,3,5-Trimethylbenzene	5.27
o-ethyltoluene	18.7
C_4-Alkylbenzene	4.40
C_4-Alkylbenzene	7.20
C_4-Alkylbenzene	4.80
C_5-Alkylbenzene	5.25
Naphthalene	3.52
2-Methylnaphthalene	4.75
1-Methylnaphthalene	3.48
C_2-Alkylnaphthalene	9.75
C_2-Alkylnaphthalene	0.750
C_2-Alkylnaphthalene	13.8
C_2-Alkylnaphthalene	8.25
C_2-Alkylnaphthalene	14.5
Phenanthrene/anthracene	3.30
Methyl phenanthrene/anthracene	10.6
Methyl phenanthrene/anthracene	14.0
C_2-Alkyl phenanthrene/anthracene	80.0
C_3-Alkyl phenanthrene/anthracene	60.9

TABLE B5-19. CRUDE DISTILLATION UNIT: LIGHT VACUUM GAS OIL, BULK LIQUID

Compound	ppm
Toluene	5.04
Ethylbenzene	5.85
m/p-xylene	9.88
o-xylene	11.6
n-propylbenzene	3.22
m/p-ethyltoluene	17.0
1,3,5-Trimethylbenzene	7.48
o-ethyltoluene	9.01
1,2,4-Trimethylbenzene	12.4
Indan	4.50
C_4-Alkylbenzene	10.2
C_4-Alkylbenzene	16.0
C_4-Alkylbenzene	6.80
Methylindan	5.20
Methylindan	5.00
C_4-Alkylbenzene	8.80
C_4-Alkylbenzene	80.0
Methylindan	4.20
C_5-Alkylbenzene	45.0
C_5-Alkylbenzene	3.5
C_5-Alkylbenzene	3.25
Methylindan	11.3
C_5-Alkylbenzene	5.00
C_5-Alkylbenzene	5.00
Tetralin	1.60
Naphthalene	27.5
C_2-Alkylindan/methyltetralin	27.3
C_5-Alkylbenzene	14.0
C_2-Alkylindan/methyltetralin	19.2
C_5-Alkylbenzene	15.3
C_2-Alkylindan/methyltetralin	15.2
C_2-Alkylindan/methyltetralin	18.3
2-Methylnaphthalene	68.4
1-Methylnaphthalene	18.9
C_2-Alkylnaphthalene	25.0
C_2-Alkylnaphthalene	72.5
Biphenyl	8.80
C_2-Alkylnaphthalene	113.0
C_2-Alkylnaphthalene	70.0
C_2-Alkylnaphthalene	18.0
Methylbiphenyls	13.6
C_3-Alkylnaphthalene	34.8
C_3-Alkylnaphthalene	43.5

TABLE B5-19. Continued

Compound	ppm
C_3-Alkylnaphthalene	55.1
C_3-Alkylnaphthalene	31.9
Fluorene	9.36
C_3-Alkylnaphthalene	4.93
Methylacenaphthalene	13.6
C_2-Alkylbiphenyls	28.0
Methylfluorene	9.35
Phenanthrene/anthracene	12.1
C_2-Alkylfluorene	9.40
Methyl phenanthrene/anthracene	6.30
Methyl phenanthrene/anthracene	5.18
C_2-Alkyl phenanthrene/anthracene	9.50
C_3-Alkyl phenanthrene/anthracene	2.9

TABLE B5-20. CRUDE DISTILLATION UNIT: VACUUM GAS OIL, BULK LIQUID

No Aromatic Species Detected.

TABLE B5-21. CRUDE DISTILLATION UNIT: VACUUM GAS OIL

Compound	Bulk Liquid, ppm[a]	Vapor on XAD, μg	Vapor on Tenax, μg
Benzene		1.5	0.00046
Toluene		29.0	0.0070
Ethylbenzene		8.9	0.0030
m,p-Xylene		42.0	0.0099
o-Xylene		34.0	0.0046
Isopropylbenzene		11.0	0.0017
3-Ethyl toluene		49.0	0.0096
4-Ethyl toluene		38.0	0.0052
1,2,3-Trimethylbenzene		30.0	0.0039
2-Ethyl toluene		73.0	0.0099
sec-Butylbenzene		17.0	0.0029
1,2,4-Trimethylbenzene		55.0	0.0062
Diethylbenzene		13.0	0.0031
Methylisopropylbenzene		10.0	--
Methylpropylbenzene		4.2	0.00049
Methylpropylbenzene		25.0	0.0068
Methylpropylbenzene		14.0	--
Diethylbenzene		19.0	0.0029
Diethylbenzene		17.0	0.0039
Dimethylethylbenzene		20.0	0.0044
Dimethylethylbenzene		11.0	--
Dimethylethylbenzene		10.0	--
Dimethylethylbenzene		5.6	--
C_5-Alkylbenzene		10.0	0.0034
Dimethylethylbenzene		4.7	
Tetramethylbenzene		7.0	
Tetramethylbenzene		17.0	0.0034
Tetramethylbenzene		4.9	0.0024
C_5-Alkylbenzene		31.0	0.0065
C_5-Alkylbenzene		5.8	0.0018
Naphthalene		59.0	0.014
C_5-Alkylbenzene		6.7	0.0016
C_5-Alkylbenzene		2.8	--
C_5-Alkylbenzene		2.6	--

[a] None of the listed vapor species were found in the bulk liquid. The vapor species, therefore, must have been adsorbed from the ambient air or resulted from cross-contamination with other samples due to residue in the sampling train.

TABLE B5-22. CRUDE DISTILLATION UNIT: HEAVY VACUUM GAS OIL, BULK LIQUID

No Aromatic Species Detected

TABLE B5-23. CRUDE DISTILLATION UNIT: VACUUM RESIDUE, BULK LIQUID

No Aromatic Species Detected.

TABLE B5-24. API SEPARATOR: SURFACE OIL SKIMMED FROM INLET BAY, BULK LIQUID

Peak No.	Compound	Concentration (ppm)
1	Benzene	230
2	Toluene	1800
3	Ethylbenzene	480
4	m,p-Xylene	1300
5	o-Xylene	390
6	Isopropylbenzene	100
7	n-Propylbenzene	240
8	3 or 4-Ethyl toluene	1000
9	1,3,5-Trimethylbenzene	500
10	2-Ethyl toluene	460
11	1,2,4-Trimethylbenzene	1000
12	Isobutylbenzene	60
13	1,2,3-Trimethylbenzene	330
14	Methylpropylbenzene	180
15	Indan	60
16	Methylpropylbenzene	470
17	Diethylbenzene	130
18	Diethylbenzene	300
19	Dimethylethylbenzene	370
20	Methyl indan	120
21	Dimethylethylbenzene	130
22	Tetramethylbenzene	140
23	Tetramethylbenzene	60
24	Methyl indan	150
25	C_5-Alkylbenzene	50
26	C_5-Alkylbenzene	160
27	Naphthalene	2000
28	C_5-Alkylbenzene	100
29	C_5-Alkylbenzene	80
30	2-Methylnaphthalene	2200
31	1-Methylnaphthalene	1700
32	Biphenyl	620
33	C_2-Alkylnaphthalene	390
34	C_2-Alkylnaphthalene	1800
35	C_2-Alkylnaphthalene	3000
36	C_2-Alkylnaphthalene	700
37	C_2-Alkylnaphthalene	240
38	C_2-Biphenyl	840
39	C_3-Naphthalene	390
40	C_3-Naphthalene	1200
41	C_3-Naphthalene	860
42	C_3-Naphthalene	470
43	Fluorene	160
44	Phenanthrene/Athracene	220
45	d_{10}-Anthracene	--

TABLE B5-25. API SEPARATOR: SURFACE OIL SKIMMED FROM INLET BAY, BULK LIQUID

Compound	Concentration (ppm)
Benzene	24
Toluene	460
Ethylbenzene	30
m,p-Xylene	350
o-Xylene	210
Isopropylbenzene	72
n-Propylbenzene	160
3 or 4-Ethyl toluene	710
1,3,5-Trimethylbenzene	490
2-Ethyl toluene	145
1,2,4-Trimethylbenzene	730
1,2,3-Trimethylbenzene	160
Methylpropylbenzene	79
Methylpropylbenzene	14
Diethylbenzene	31
Dimethylethylbenzene	170
Dimethylethylbenzene	78
Diethylbenzene	190
Dimethylethylbenzene	25
Dimethylethylbenzene	180
C_5-Alkylbenzene	140
C_5-Alkylbenzene	65
C_5-Alkylbenzene	90
C_5-Alkylbenzene	20
Dimethylethylbenzene	145
Tetramethylbenzene	250
C_5-Alkylbenzene	35
Tetramethylbenzene	260
C_5-Alkylbenzene	80
C_5-Alkylbenzene	100
C_5-Alkylbenzene	165
C_5-Alkylbenzene	120
C_5-Alkylbenzene	190
C_5-Alkylbenzene	55
C_5-Alkylbenzene	55
C_5-Alkylbenzene	165
C_5-Alkylbenzene	70
d_{10}-Anthracene	

TABLE B5-26. API SEPARATOR: SURFACE OIL SKIMMED FROM OUTLET END, BULK LIQUID

Peak No.	Compound	Concentration (ppm)
1	Toluene	280
2	Ethylbenzene	200
3	m,p-Xylene	2,400
4	o-Xylene	950
5	Isopropylbenzene	250
6	3-Ethyl toluene	2,500
7	4-Ethyl toluene	1,200
8	1,2,3-Trimethylbenzene	950
9	2-Ethyl toluene	3,800
10	sec-Butylbenzene	280
11	1,2,4-Trimethylbenzene	1,600
12	Diethylbenzene	210
13	Methylisopropylbenzene	85
14	Methylpropylbenzene	700
15	Diethylbenzene	600
16	Dimethylethylbenzene	900
17	Dimethylethylbenzene	850
18	Tetramethylbenzene	1,100
19	Tetramethylbenzene	120
20	C_5-Alkylbenzene	6,500
21	Naphthalene	1,200
22	C_5-Alkylbenzene	210
23	C_5-Alkylbenzene	430
24	C_5-Alkylbenzene	180
25	C_5-Alkylbenzene	120
26	C_5-Alkylbenzene	140
27	C_5-Alkylnaphthalene	160
28	2-Methylnaphthalene	23,000
29	C -Alkylbenzene	140
30	1-Methylnaphthalene	14,000
31	C_5-Alkylnaphthalene	70
32	Biphenyl	380
33	C_2-Alkylnaphthalene	4,100
34	C_2-Alkylnaphthalene	18,000
35	C_2-Alkylnaphthalene	22,000
36	C_2-Alkylnaphthalene	4,500
37	C_2-Alkylnaphthalene	1,100
38	Acenaphthene	600
39	C_3-Alkylnaphthalene	6,000
40	C_3-Alkylnaphthalene	10,000
41	C_3-Alkylnaphthalene	11,000
42	C_3-Alkylnaphthalene	3,200
43	Fluorene	1,200
44	C_3-Alkylnaphthalene	240

Continued

TABLE B5-26. Continued

Peak. No.	Compound	Concentration (ppm)
45	C_3-Alkylnaphthalene	500
46	Methylbiphenyl	4,600
47	C_4-Alkylnaphthalene	1,700
48	C_4-Alkylnaphthalene	1,600
49	C_4-Alkylnaphthalene	220
50	C_4-Alkylnaphthalene	800
51	C_4-Alkylnaphthalene	1,300
52	C_4-Alkylnaphthalene	850
53	Methyl fluorene	1,300
54	Methyl fluorene	240
55	C_4-Alkylnaphthalene	1,300
56	C_4-Alkylnaphthalene	380
57	Phenanthrene/Anthracene	1,800
58	d_{10}-Anthracene	

TABLE B5-27. API SEPARATOR: OIL FROM THE SKIM OIL SUMP, BULK LIQUID

Peak No.	Compound	Concentration (ppm)
1	Benzene	70
2	Toluene	1400
3	Ethylbenzene	540
4	m,p-Xylene	1600
5	o-Xylene	450
6	Isopropylbenzene	130
7	n-Propylbenzene	480
8	3 or 4-Ethyl toluene	1700
9	1,3,5-Trimethylbenzene	720
10	2-Ethyl toluene	630
11	1,2,4-Trimethylbenzene	1600
12	Isobutylbenzene	100
13	1,2,3-Trimethylbenzene	480
14	Methylpropylbenzene	240
15	Indan	120
16	Methylpropylbenzene	740
17	Diethylbenzene	220
18	Diethylbenzene	320
19	Dimethylethylbenzene	520
20	Methyl indane	220
21	Dimethylethylbenzene	240
22	Tetramethylbenzene	320
23	Tetramethylbenzene	60
24	Methyl indan	260
25	C_5-Alkylbenzene	280
26	C_5-Alkylbenzene	240
27	Naphthalene	690
28	C_5-Alkylbenzene	120
29	C_5-Alkylbenzene	130
30	2-Methylnaphthalene	4000
31	1-Methylnaphthalene	2700
32	Biphenyl	840
33	C_2-Alkylnaphthalene	390
34	C_2-Alkylnaphthalene	2400
35	C_2-Alkylnaphthalene	4500
36	C_2-Alkylnaphthalene	1200
37	C_2-Alkylnaphthalene	390
38	C_3-Naphthalene	760
39	C_3-Naphthalene	2000
40	C_3-Naphthalene	1400
41	C_3-Naphthalene	700
42	Fluorene	250
43	Phenanthrene/Anthracene	260
44	d_{10}-Anthracene	--

TABLE B5-28. CRUDE DESALTER: EFFLUENT WATER, BULK LIQUID

Peak No.	Compound	Concentration (ppb)
1	Benzene	6.6
2	Toluene	3.4
3	Ethylbenzene	7.3
4	m,p-Xylene	2.2
5	o-Xylene	9.9
6	Isopropylbenzene	1.4
7	n-Propylbenzene	4.8
8	3 or 4-Ethyl toluene	15.0
9	1,3,5-Trimethylbenzene	1.2
10	2-Ethyl toluene	5.9
11	1,2,4-Trimethylbenzene	18.0
12	1,2,3-Trimethylbenzene	12.0
13	Diethylbenzene	3.8
14	Naphthalene	450.0
15	Carbazole	51.0
16	2-Methylnaphthalene	150.0
17	1-Methylnaphthalene	140.0
18	Biphenyl	100.0
19	C_2-Alkylnaphthalene	20.0
20	C_2-Alkylnaphthalene	67.0
21	C_2-Alkylnaphthalene	120.0
22	C_2-Alkylnaphthalene	36.0
23	C_2-Alkylnaphthalene	10.0
24	C_3-Naphthalene	48.0
25	C_3-Naphthalene	37.0
26	C_3-Naphthalene	23.0
27	Fluorene	22.0
28	Phenanthrene/Anthracene	50.0
29	d_{10}-Anthracene	--
30	Acenaphthene	100.0

TABLE B-29. CRUDE DESALTER: EFFLUENT WATER, BULK LIQUID

Peak No.	Compound	Concentration (ppb)
1	Benzene	3.1
2	Toluene	11.0
3	Ethylbenzene	1.1
4	m-Xylene/p-Xylene	6.9
5	o-Xylene	2.4
6	Isopropylbenzene	0.10
7	n-Propylbenzene	0.12
8	3-Ethyl toluene	0.62
9	1,3,5-Trimethylbenzene	0.44
10	2-Ethyl toluene	0.25
11	1,2,4-Trimethylbenzene	0.14
12	C_4-Alkylbenzene	0.06
13	Indan	0.19
14	C_4-Alkylbenzene	0.05
15	C_4-Alkylbenzene	0.03
16	C_4-Alkylbenzene	0.14
17	C_4-Alkylbenzene	0.23
18	C_4-Alkylbenzene	0.14
19	Methyl indan	0.07
20	C_4-Alkylbenzene	0.14
21	Methyl indan	0.11
22	C_5-Alkylbenzene	0.15
23	C_4-Alkylbenzene	0.13
24	C_4-Alkylbenzene	0.04
25	C_4-Alkylbenzene	0.07
26	C_5-Alkylbenzene	0.10
27	C_5-Alkylbenzene	0.05
28	Naphthalene	8.1
29	C_4-Alkylbenzene	0.17
30	2-Methylnaphthalene	0.49
31	1-Methylnaphthalene	0.32
32	Biphenyl	0.02
33	Dimethylnaphthalene	0.02
34	Dimethylnaphthalene	0.07
35	Dimethylnaphthalene	0.15
36	Dimethylnaphthalene	0.05
37	Dimethylnaphthalene	0.01
38	C_3-Alkylnaphthalene	0.01
39	Methyl biphenyl	0.14
40	Methyl biphenyl	0.04
41	C_3-Alkylnaphthalene	0.03
42	Methyl biphenyl	0.03
43	C_3-Alkylnaphthalene	0.03
44	C_3-Alkylnaphthalene	0.03

Continued

TABLE B5-29. Continued

Peak No.	Compound	Concentration (ppb)
45	C_3-Alkylnaphthalene	0.04
46	C_3-Alkylnaphthalene	0.04
47	C_3-Alkylnaphthalene	0.01
48	Fluorene	0.004
49	Methyl fluorene	0.006
50	Methyl fluorene	0.006
51	Dibenzothiophene	0.03
52	Phenanthrene	0.01

TABLE B5-30. CRUDE DESALTER: EFFLUENT WATER, BULK LIQUID

Peak No.	Compound	Concentration (ppb)
1	Benzene	36
2	Toluene	2600
3	Ethylbenzene	290
4	m,p-Xylene	250
5	o-Xylene	130
6	Isopropylbenzene	24
7	1,3,5-Trimethylbenzene	120
8	Methylethylbenzene	110
9	1,2,4-Trimethylbenzene	60
10	sec-Butylbenzene	56
11	Methylpropylbenzene	100
12	Naphthalene	1200
13	2-Methylnaphthalene	220
14	1-Methylnaphthalene	210
15	Biphenyl	40
16	C_2-Alkylnaphthalene	140
17	Fluorene	21
18	d_{10}-Anthracene	--

TABLE B5-31. SOUR WATER STRIPPER: SOUR WATER FEED, BULK LIQUID

Peak No.	Compound	Concentration (ppm)
1	Dimethyldisulfide	100.0
2	Phenol[a]	120.0
3	Methylphenol[a]	14.0
4	Methylphenol[a]	46.0
5	Methylquinoline	4.8
6	Dimethylphenol[a]	5.6
7	Dimethylphenol[a]	3.6
8	Dimethylphenol[a]	2.1
9	Methylquinoline	3.3
10	d_{10}-Anthracene	

[a] Identification based on corresponding methyl ether.

TABLE B5-32. FLUID CATALYTIC CRACKER: COMPRESSOR DISCHARGE (GAS TO THE ABSORBERS)

Compound	Vapor on XAD Resin (μg)	Vapor on Tenax (μg)
Benzene	21.0	0.54
Toluene	93.0	2.5
Ethylbenzene	13.0	0.68
m,p-Xylene	46.0	1.6
o-Xylene	14.0	0.58
Isopropylbenzene	--	0.05
n-Propylbenzene	--	0.30
3 or 4-Ethyl toluene	12.0	0.74
1,3,5-Trimethylbenzene	6.0	0.55
2-Ethyl toluene	2.4	0.31
1,2,4-Trimethylbenzene	13.0	0.94
1,2,3-Trimethylbenzene	2.3	0.28
Methylpropylbenzene	3.8	0.40
Diethylbenzene	1.6	0.22
Dimethylbenzene	4.1	0.48
Dimethylethylbenzene	0.4	
Tetramethylbenzene	--	0.08
Tetramethylbenzene	2.0	0.26
C_5-Alkylbenzene	--	0.16
C_5-Aklybenzene	--	0.13
Naphthalene	23.0	0.01
2-Methylnaphthalene	1.9	--
1-Methylnaphthalene	0.3	--

TABLE B5-33. FLUID CATALYTIC CRACKER: LOW PRESSURE SEPARATOR GAS (COMPRESSOR SUCTION)

Compound	Vapor on XAD, μg	Vapor on Tenax, μg
Benzene	--	0.028
Toluene	8.5	0.054
Ethylbenzene	--	0.0085
m,p-Xylene	--	0.019
o-Xylene	--	0.059
Isopropylbenzene	0.55	0.0010
n-Propylbenzene	--	0.0049
3-Ethyl toluene	--	0.014
4-Ethyl toluene	--	0.0096
1,2,3-Trimethylbenzene	--	0.0065
2-Ethyl toluene	--	0.022
sec-Butylbenzene	--	0.0086
1,2,4-Trimethylbenzene	--	0.0052
Methylpropylbenzene	--	0.013
Dimethylethlybenzene	--	0.018
Diethylbenzene	--	0.0083
C_5-Alkylbenzene	--	0.0049
Tetramethylbenzene	--	0.014
C_5-Alkylbenzene	--	0.011
Naphthalene	--	0.059

TABLE B5-34. FLUID CATALYTIC CRACKER: LOW PRESSURE SEPARATOR LIQUID, BULK LIQUID

Peak No.	Compound	Concentration (ppb)
1	Benzene	4,300
2	Toluene	5,000
3	Ethylbenzene	7,300
4	m-Xylene/p-Xylene	55,000
5	o-Xylene	32,000
6	Isopropylbenzene	5,600
7	n-Propylbenzene	44,000
8	3-Ethyl toluene	66,000
9	1,3,5-Trimethylbenzene	14,000
10	2-Ethyl toluene	82,000
11	C_4-Alkylbenzene	1,300
12	1,2,4-Trimethylbenzene	20,000
13	C_4-Alkylbenzene	2,000
14	Indan	15,000
15	C_4-Alkylbenzene	15,000
16	C_4-Alkylbenzene	14,000
17	C_4-Alkylbenzene	19,000
18	C_4-Alkylbenzene	4,600
19	C_4-Alkylbenzene	24,000
20	Methyl indan	7,000
21	C_4-Alkylbenzene	24,000
22	Methyl indan	1,200
23	C_5-Alkylbenzene	2,200
24	C_4-Alkylbenzene	4,000
25	C_4-Alkylbenzene	20,000
26	C_4-Alkylbenzene	18,000
27	C_5-Alkylbenzene	4,700
28	Methyl indan	16,000
29	Methyl indan	16,000
30	C_4-Alkylbenzene	7,000
31	C_5-Alkylbenzene	14,000
32	C_5-Alkylbenzene	16,000
33	Naphthalene	15,000
34	C_5-Alkylbenzene	3,000
35	C_2-Alkyl indan	21,000
36	C_2-Alkyl indan	28,000
37	C_4-Alkylbenzene	13,000
38	C_2-Alkyl indan	15,000
39	C_5-Alkylbenzene	15,000
40	C_5-Alkylbenzene	4,300
41	C_6-Alkylbenzene	1,200
42	C_6-Alkylbenzene	2,100
43	C_5-Alkylbenzene	2,500
44	C_6-Alkylbenzene	8,800

Continued

TABLE B5-34. Continued

Peak No.	Compound	Concentration (ppb)
45	C_6-Alkylbenzene	5,200
46	C_6-Alkylbenzene	4,800
47	C_5-Alkylbenzene	1,300
48	C_2-Alkyl indan	11,000
49	C_6-Alkylbenzene	7,500
50	C_6-Alkylbenzene	8,100
51	C_2-Alkyl indan	11,000
52	C_6-Alkylbenzene	7,500
53	C_2-Alkyl indan	14,000
54	C_6-Alkylbenzene	3,900
55	C_6-Alkylbenzene	7,500
56	C_6-Alkylbenzene	5,000
57	C_2-Alkyl indan	9,700
58	Methyl benzothiophene	500
59	C_6-Alkylbenzene	2,500
60	C_2-Alkyl indan	5,000
61	Methyl benzothiophene	1,400
62	2-Methylnaphthalene	16,000
63	Methyl benzothiophene	1,400
64	Methyl benzothiophene	1,200
65	1-Methylnaphthalene	15,000
66	Methyl benzothiophene	1,600
67	C_2-Alkylnaphthalene	700
68	C_2-Alkylnaphthalene	1,400
69	C_2-Alkylnaphthalene	1,100
70	C_2-Alkylnaphthalene	300

TABLE B5-35. FLUID CATALYTIC CRACKER: LOW PRESSURE SEPARATOR LIQUID

Peak Number	Compounds (In Retention Order)	Bulk Liquid (ppm)	Vapor on XAD (μg)	Vapor on Tenax (μg)
1	Benzene	6,600	260	0.72
(IS)	d_6-Benzene	--	--	(0.035)
2	Toluene	47,700	8,100	25.3
3	Ethylbenzene	10,600	4,400	4.0
4	m-+p-Xylene	57,200	8,000	21.3
5	o-Xylene	21,300	7,500	8.7
6	Isopropylbenzene	--	130	0.21
7	n-Propylbenzene	3,000	850	19.8
8	3- + 4-Ethyltoluene	32,500	7,100	
9	1,3,5-Trimethylbenzene	15,100	2,800	
10	2-Ethyltoluene	7,100	1,280	
11	1,2,4-Trimethylbenzene	46,000	6,150	13.3
12	1,2,3-Trimethylbenzene	9,600	880	3.2
13	C_4-Alkylbenzene	--	72	0.33
14	Indan	4,000	250	1.2
15	C_4-Alkylbenzene	17,200	1,000	7.8
16	C_4-Alkylbenzene	19,600	960	
17	C_4-Alkylbenzene	2,400	210	
18	C_4-Alkylbenzene	13,200	520	4.1
19	C_4-Alkylbenzene	13,600	480	
20	2- +-Methylindan	2,500	85	0.41
21	C_4-Alkylbenzene	2,000	32	0.74
22	C_4-Alkylbenzene	19,600	340	2.3
23	Methylindan	2,500	10	0.22
24	Methylindan	2,800	30	0.24
25	C_4-Alkylbenzene	2,800	--	0.49
26	C_5-Alkylbenzene	27,000	--	1.2
27	C_5-Alkylbenzene	2,700	--	0.44
28	Naphthalene	15,600	66	0.03
29	C_4-Alkylbenzene	1,200	--	--
30	C_2-Alkylindane	2,400	--	0.11
31	C_4-Alkylbenzene	600	--	--
32	C_5-Alkylbenzene	4,000	--	1.2
33	C_5-Alkylbenzene	1,700	--	0.46
34	C_2-Alkylindan	400	--	--
35	C_2-Alkylindan	600	--	--
36	C_2-Alkylindan	400	--	--
37	C_2-Alkylbenzene	100	--	--
38	C_5- Alkylbenzene	1,000	--	--
39	2-Methylnaphthalene	8,700	--	0.03
40	1-Methylnaphthalene	3,600	--	0.01
(IS)	d_{10}-Anthracene (IS)	(100)	(1000)	--

TABLE B5-36. FLUID CATALYTIC CRACKER: LOW PRESSURE SEPARATOR LIQUID

	Bulk Liquid, ppm			Vapor, µg		
Compound	Fraction 1	Fraction 2	Total	Fraction 1	Fraction 2	Total
Toluene	160,000	2,400	160,000	300	19	320
Ethylbenzene	39,000	380	39,000	91	5	96
m,p-Xylene	250,000	7,800	260,000	220	93	310
o-Xylene	68,000	8,200	76,000	26	32	58
1,3,5-Trimethylbenzene	150,000	3,300	150,000	99	60	160
Methylethylbenzene	6,700	3,100	10,000	--	27	27
1,2,4-Trimethylbenzene	24,000	3,400	27,000	--	18	18
sec-Butylbenzene	84,000	11,000	95,000	--	42	42
Methylisopropylbenzene	22,000	5,600	28,000	--	--	--
C_4-Alkylbenzene	--	1,300	1,300	--	--	--
C_4-Alkylbenzene	--	620	620	--	--	--
C_4-Alkylbenzene	--	1,100	1,100	--	--	--
Naphthalene	6,000	8,600	15,000	--	--	--
2-Methylnaphthalene	320	3,600	3,900	--	--	--
1-Methylnaphthalene	170	590	760	--	--	--

TABLE B5-37. FLUID CATALYTIC CRACKER: LIGHT CYCLE GAS OIL, BULK LIQUID

Compound	ppm
Benzene	1.75
Toluene	13.6
Ethylbenzene	8.97
m/p-xylenes	19.5
o-xylene	8.58
i-propylbenzene	0.578
n-propylbenzene	11.9
m/p-ethyltoluene	76.5
1,3,5-Trimethylbenzene	22.1
o-ethyltoluene	4.08
1,2,4-Trimethylbenzene	30.1
Sec-Butylbenzene	18.4
Indan	15.0
C_4-Alkylbenzene	46.0
C_4-Alkylbenzene	34.0
C_4-Alkylbenzene	26.0
Methylindan	28.0
C_4-Alkylbenzene	32.0
C_4-Alkylbenzene	8.00
C_5-Alkylbenzene	41.5
Methylindan	30.0
C_5-Alkylbenzene	10.8
C_5-Alkylbenzene	20.0
Methylindan	32.5
C_5-Alkylbenzene	22.0
C_5-Alkylbenzene	27.5
Tetralin	1.6
Naphthalene	96.8
C_2-Alkylindan/methyltetralin	58.9
C_5-Alkylbenzene	45.0
C_2-Alkylindan/methyltetralin	55.8
C_2-Alkylindan/methyltetralin	96.1
C_2-Alkylindan/methyltetralin	19.2
Methylbenzothiophene	2.89
Methylbenzothiophene	25.5
2-Methylnaphthalene	616.0
Methylbenzothiophene	37.4
1-Methylnaphthalene	71.1
C_2-Alkylbenzothiophene	28.0
C_2-Alkylnaphthalene	485.0
C_2-Alkylbenzothiophene	65.0

Continued

TABLE B5-37. Continued

Compound	ppm
C_2-Alkylnaphthalene	825.0
Biphenyl	5.72
C_2-Alkylbenzothiophene	28.0
C_2-Alkylnaphthalene	550.0
C_2-Alkylbenzothiophene	17.3
C_2-Alkylnaphthalene	185.0
C_2-Alkylnaphthalene	87.5
Acenaphthene	8.40
Methylbiphenyls	15.5
C_3-Alkylbenzothiophene	92.5
C_3-Alkylnaphthalene	43.5
C_3-Alkylnaphthalene	218.0
C_3-Alkylnaphthalene	203.0
C_3-Alkylnaphthalene	249.0
Fluorene	18.2
C_2-Alkylnaphthalene	148.0
Methylacenaphthenes	62.0
C_2-Alkylbiphenyls	48.0
C_4-Alkylnaphthalene	328.0
Methylfluorene	17.0
Methylfluorene	23.8
Methylfluorene	7.14
Phenanthrene/anthracene	97.9
C_2-Alkylfluorenes	52.0
Methyldibenzothiophene	74.8
Methyldibenzothiophene	51.0
Methyl phenanthrene/anthracene	71.4
Methyl phenanthrene/anthracene	42.0
C_2-Alkyl dibenzothiophene	10.8
C_2-Alkyl phenanthrene/anthracene	2.35
C_2-Alkyl dibenzothiophene	70.0
C_2-Alkyl phenanthrene/anthracene	96.3
C_2-Alkyl dibenzothiophene	44.0
C_2-Alkyl dibenzothiophene	72.5
C_2-Alkyl dibensothiophene	30.0
C_2-Alkyl phenanthrene/anthracene	20.0
Fluoranthene	3.50
C_3-Alkyl dibenzothiophene	65.0
C_3-Alkyl phenanthrene/anthracene	1.45
C_3-Alkyl phenanthrene/anthracene	4.64
C_3-Alkyl phenanthrene/anthracene	11.6
Pyrene	4.30
C_3-Alkyl phenanthrene/anthracene	37.7

Continued

TABLE B5-37. Continued

Compound	ppm
C_4-Dibenzothiophene	13.0
C_3-Alkyl phenanthrene/anthracene	15.4
C_3-Alkyl phenanthrene/anthracene	6.67
Methyl fluorenthene/pyrene	0.429
Methyl fluorenthene/pyrene	0.871
Methyl fluorenthene/pyrene	1.82
Methyl fluorenthene/pyrene	1.82
C_4-Alkyl phenanthrene/anthracene	13.1

TALBE B5-38. FLUID CATALYTIC CRACKER: LIGHT CYCLE GAS OIL

Compound	Bulk Liquid, ppm			Vapor, μg		
	Fraction 1	Fraction 2	Total	Fraction 1	Fraction 2	Total
Benzene	--	--	--	--	2	2
Toluene	40	--	40	230	1	230
Ethylbenzene	--	--	--	250	--	250
p,m-Xylene	360	--	360	840	19	860
o-Xylene	270	--	270	270	24	290
Methylethylbenzene	1,400	--	1,400	--	7	7
1,3,5-Trimethylbenzene	950	--	950	800	22	820
Methylethylbenzene	470	--	470	210	9	220
1,2,4-Trimethylbenzene	--	--	--	68	68	140
sec-Butylbenzene	14,000	--	14,000	220	16	240
Methylisopropylbenzene	950	--	950	15	4	19
Diethylbenzene	1,800	--	1,800	22	11	33
Dimethylethylbenzene	1,100	--	1,100	63	6	69
C_4-Alkylbenzene	1,100	--	1,100	64	2	66
C_4-Alkylbenzene	1,500	--	1,500	--	2	2
C_4-Alkylbenzene	2,400	--	2,400	--	--	--
C_4-Alkylbenzene	940	--	940	--	--	--
1,2,3,5-Tetramethylbenzene	--	--	--	180	22	200
1,2,3,4-Tetramethylbenzene	--	--	--	8	--	8
Naphthalene	40,000	12,000	52,000	31	50	81
2-Methylnaphthalene	52,000	90,000	140,000	--	4	4
1-Methylnaphthalene	44,000	39,000	83,000	--	--	--
Biphenyl	--	4,600	4,600	--	--	--
C_2-Naphthalene	9,900	3,500	13,000	--	--	--
C_2-Naphthalene	20,000	69,000	89,000	--	--	--
C_2-Naphthalene	27,000	78,000	110,000	--	--	--
C_2-Naphthalene	8,100	28,000	36,000	--	--	--
C_1-Biphenyl	--	2,100	2,100	--	--	--
C_3-Naphthalene	--	8,800	8,800	--	--	--
C_3-Naphthalene	--	2,400	2,400	--	--	--
C_3-Naphthalene	--	19,000	19,000	--	--	--
C_3-Naphthalene	--	28,000	28,000	--	--	--
C_3-Naphthalene	--	18,000	18,000	--	--	--
Phenanthrene/Anthracene	--	7,400	7,400	--	--	--

TABLE B5-39. FLUID CATALYTIC CRACKER: HEAVY CYCLE GAS OIL, BULK LIQUID

Compound	ppm
Benzene	4.75
Toluene	15.4
Ethylbenzene	4.29
m/p-xylenes	27.0
o-xylene	13.1
n-propylbenzene	3.91
m/p-ethyltoluene	21.8
o-ethyltoluene	2.72
1,2,4-Trimethylbenzene	38.3
Sec-Butylbenzene	4.80
Indan	6.13
n-Butylbenzene	3.60
C_4-Alkylbenzene	6.80
C_4-Alkylbenzene	11.2
Methylindan	11.4
C_4-Alkylbenzene	16.2
C_4-Alkylbenzene	8.80
Methylindan	6.40
C_5-Alkylbenzene	4.00
C_5-Alkylbenzene	3.25
Methylindan	4.81
C_5-Alkylbenzene	15.5
Naphthalene	19.0
C_2-Alkylindan/methyltetralin	20.2
Benzothiophene	2.70
C_5-Alkylbenzene	5.50
C_2-Alkylindan/methyltetralin	10.2
C_5-Alkylbenzene	3.75
C_2-Alkylindan/methyltetralin	7.44
C_2-Alkylindan/methyltetralin	13.6
Methylbenzothiophene	6.29
C_5-Alkylbenzene	8.25
Methylbenzothiophene	6.29
2-Methylnaphthalene	45.4
Methylbenzothiophene	13.6
1-Methylnaphthalene	30.7
C_2-Alkylnaphthalene	25.0
C_2-Alkylnaphthalene	73.3
C_2-Alkylnaphthalene	82.0
C_2-Alkylnaphthalene	57.8
C_2-Alkylnaphthalene	21.8
Acenaphthene	3.08
C_3-Alkylnaphthalene	36.5

Continued

TABLE B5-39. Continued

Compound	ppm
C_3-Alkylnaphthalene	115.0
C_3-Alkylnaphthalene	52.2
C_3-Alkylnaphthalene	49.3
C_3-Alkylnaphthalene	10.4
Fluorene	8.97
C_3-Alkylnaphthalene	4.93
Methylacenaphthenes	51.0
C_4-Alkylnaphthalene	151.0
Methylfluorene	18.7
Methylfluorene	27.2
Methylfluorene	14.3
Dibenzothiophene	55.0
Phenanthrene/anthracene	143.0
C_2-Alkylfluorene	107.0
Methyldibenzothiophene	126.0
Methyldibenzothiophene	258.0
Methyl phenanthrene/anthracene	333.0
Methyl phenanthrene/anthracene	256.0
C_2-Alkyl dibenzothiophene	127.0
C_2-Alkyl phenanthrene/anthracene	25.0
C_2-Alkyl dibenzothiophene	306.0
C_2-Alkyl phenanthrene/anthracene	510.0
C_2-Alkyl phenanthrene/anthracene	943.0
C_2-Alkyl dibenzothiophene	232.0
C_2-Alkyl dibenzothiophene	173.0
C_2-Alkyl dibenzothiophene	49.0
C_2-Alkyl phenanthrene/anthracene	37.5
C_2-Alkyl phenanthrene/anthracene	35.0
C_3-Alkyl dibenzothiophene	818.0
C_3-Alkyl phenanthrene/anthracene	21.2
C_3-Alkyl phenanthrene/anthracene	26.4
Pyrene	5.60
C_3-Alkyl phenanthrene/anthracene	409.0
C_4-Alkyl dibenzothiophene	370.0
C_3-Alkyl phenanthrene/anthracene	87.0
C_3-Alkyl phenanthrene/anthracene	87.0
Methyl fluorenthene/pyrene	18.2
Methyl fluorenthene/pyrene	32.5
Methyl fluorenthene/pyrene	68.9
Methyl fluorenthene/pyrene	107.0
C_5-Alkyl dibenzothiophene	90.0
C_4-Alkyl phenanthrene/anthracene	334.0

Continued

TABLE B5-39. Continued

Compound	ppm
C_2-Alkyl fluorenthene/pyrene	78.0
C_2-Alkyl fluorenthene/pyrene	46.0
C_2-Alkyl fluorenthene/pyrene	64.0
Natphthabenzothiophene	10.0
C_2-Alkyl fluorenthene/pyrene	86.0
C_2-Alkyl fluorenthene/pyrene	58.0
C_3-Alkyl fluorenthene/pyrene	215.0
C_5-Phenanthrene/anthracene	128.0
C_4-Alkyl fluorenthene/pyrene	78.3
C_2-Alkyl chrysenes/benzanthracenes	2.0
C_3-Alkyl chrysenes/benzanthracenes	25.8

TABLE B5-40. FLUID CATALYTIC CRACKER: HEAVY CYCLE GAS OIL

Compound	Bulk Liquid, ppm	Vapor on XAD, μg	Vapor on Tenax, μg
Benzene	740	15.0	0.10
Toluene	10,000	34.0	0.83
Ethylbenzene	1,200	66.0	0.16
m,p-Xylene	8,800	190.0	0.54
o-Xylene	3,000	120.0	0.15
Isopropylbenzene	120	7.6	--
n-Propylbenzene	900	59.0	--
3-Ethyl toluene	6,900	250.0	0.25
4-Ethyl toluene	2,700	42.0	0.10
1,2,3-Trimethylbenzene	1,500	24.0	--
2-Ethyl toluene	7,200	140.0	0.057
1,2,4-Trimethylbenzene	1,800	34.0	0.19
Diethylbenzene	320	23.0	--
Methylisopropylbenzene	--	17.0	--
Methylpropylbenzene	2,100	9.8	0.036
Diethylbenzene	1,800	17.0	0.017
Diethylbenzene	440	7.6	--
Dimethylethylbenzene	2,300	20.0	--
Dimethylethylbenzene	2,000	14.0	--
Dimethylethylbenzene	320	--	--
Dimethylethylbenzene	1,700	--	--
C_5-Alkylbenzene	2,000	--	--
Tetramethylbenzene	390	1.4	0.0058
Tetramethylbenzene	200	--	0.016
C_5-Alkylbenzene	1,400	9.2	0.015
C_5-Alkylbenzene	360	--	--
Naphthalene	14,000	13.0	--
C_5-Alkylbenzene	500	--	--
C_5-Alkylbenzene	840	--	--
C_5-Alkylbenzene	200	--	--
C_5-Alkylbenzene	210	--	--
2-Methylnaphthalene	12,000	--	--
1-Methylnaphthalene	5,500	--	--
C_2-Alkylnaphthalene	5,000	--	--

TABLE B5-41. THERMOFOR CATALYTIC CRACKER: HEAVY CYCLE GAS OIL, BULK LIQUID

Peak No.	Compound	Concentration (ppb)
1	Benzene	80
2	Toluene	540
3	Ethylbenzene	200
4	m-Xylene/o-Xylene	1,100
5	3-Ethyl toluene	940
6	1,3,5-Trimethylbenzene	500
7	2-Ethyl toluene	200
8	1,2,4-Trimethylbenzene	200
9	Indan	350
10	C_4-Alkylbenzene	350
11	C_4-Alkylbenzene	500
12	C_4-Alkylbenzene	400
13	Methyl indan	250
14	Methyl indan	150
15	Methyl indan	250
16	Naphthalene	920
17	2-Methylnaphthalene	2,200
18	1-Methylnaphthalene	1,400
19	C_2-Alkylnaphthalene	2,700
20	C_2-Alkylnaphthalene	4,200
21	C_2-Alkylnaphthalene	1,700
22	C_2-Alkylnaphthalene	740
23	Acenaphthylene	200
24	C_2-Alkylnaphthalene	390
25	C_2-Alkylnaphthalene	1,300
26	C_2-Alkylnaphthalene	1,700
27	C_2-Alkylnaphthalene	1,900
28	C_3-Alkylnaphthalene	2,300
29	C_2-Alkylnaphthalene	1,600
30	C_2-Alkylnaphthalene	200
31	Fluorene	150
32	C_2-Alkylnaphthalene	500
33	Methyl fluorene	250
34	Methyl fluorene	250
35	Methyl fluorene	200
36	Dibenzothiophene	650
37	Anthracene	180
38	Methyl anthracene	4,800
39	Methyl anthracene	4,900
40	Methyl anthracene	5,200
41	Pyrene	5,200
42	Methyl pyrene	420
43	Methyl pyrene	2,900
44	Methyl fluoranthene	2,100

Continued

TABLE B5-41. Continued

Peak No.	Compound	Concentration (ppb)
45	Methyl fluoranthene	260
46	Chrysene	2,400
47	Methyl chrysene	200
48	Methyl chrysene	1,400
49	Methyl chrysene	1,600
50	Methyl chrysene	600
51	Methyl chrysene	900
52	Methyl chrysene	480
53	Dimethyl chrysene	190
54	Dimethyl chrysene	1,000
55	Dimethyl chrysene	900
56	Dimethyl chrysene	1,100
57	Dimethyl chrysene	620
58	Dimethyl chrysene	880
59	Dimethyl chrysene	1,100

TABLE B-5-42. CATALYTIC REFORMER: HYDROGEN (H_2) RECYCLE GAS

Compound	Vapor on XAD, μg	Vapor on Tenax, μg
Benzene	130.0	0.010
Toluene	350.0	0.34
Ethylbenzene	25.0	0.38
m,p-Xylene	100.0	
o-Xylene	36.0	0.38
Isopropylbenzene	4.8	0.38
n-Propylbenzene	18.3	0.38
3 or 4-Ethyl toluene	61.0	0.88
1,3,5-Trimethylbenzene	42.0	
2-Ethyl toluene	11.0	
1,2,4-Trimethylbenzene	63.0	
1,2,3-Trimethylbenzene	11.0	
Dimethylethylbenzene	5.0	0.88
Tetramethylbenzene	6.6	0.88

TABLE B5-43. CATALYTIC REFORMER: NAPHTHA FEED

Compound	Bulk Liquid (ppm)	Vapor on XAD, μg	Vapor on Tenax, μg
Benzene	1040	59	0.098
Toluene	1800	670	2.9
Ethylbenzene	550	88	0,55
m,p-Xylene	4500	640	2.6
o-Xylene	1700	260	1.6
Isopropylbenzene	420	48	0.38
n-Propylbenzene	690	90	0.52
3 or 4-Ethyl toluene	3200	330	2.70
1,3,5-Trimethylbenzene	2600	200	1.9
2-Ethyl toluene	520	33	0.24
1,2,4-Trimethylbenzene	2600	180	1.19
1,2,3-Trimethylbenzene	190	11	0.077
Methylpropylbenzene	65	-	-
Diethylbenzene	19	-	0.013

TABLE B5-44. CATALYTIC REFORMER: NAPHTHA FEED

Compound	Bulk Liquid, ppm			Vapor, µg		
	Fraction 1	Fraction 2	Total	Fraction 1	Fraction 2	Total
Toluene	2,400	4.8	2,400	95	2	97
Ethylbenzene	2,500	--	2,500	120	--	120
m,p-Xylene	6,600	3.9	6,600	280	3	280
o-Xylene	3,000	7.2	3,000	38	18	56
Isopropylbenzene	900	--	900	--	--	--
1,3,5-Trimethylbenzene	2,700	11	2,700	--	10	10
Methylethylbenzene	7,500	--	7,500	110	45	160
1,2,4-Trimethylbenzene	2,200	--	2,200	--	6	6
sec-Butylbenzene	8,300	58	8,400	19	58	77
Methylpropylbenzene	5,900	18	5,900	70	28	98
C_3-Alkylbenzene	4,000	--	4,000	--	7	7
C_3-Alkylbenzene	3,500	--	3,500	--	20	20
C_4-Alkylbenzene	--	--	--	--	8	8
C_4-Alkylbenzene	--	--	--	--	3	3
C_4-Alkylbenzene	--	--	--	--	5	5
C_4-Alkylbenzene	5,000	--	5,000	--	22	22
C_4-Alkylbenzene	2,600	--	2,600	00	7	7
Naphthalene	43,000	800	44,000	--	31	31
2-Methylnaphthalene	30,000	4,000	34,000	--	--	--
1-Methylnaphthalene	36,000	1,800	38,000	--	--	--
Biphenyl	--	1,300	1,300	--	--	--
C_2-Alkylnaphthalene	--	230	230	--	--	--
C_2-Alkylnaphthalene	6,400	1,600	4,000	--	--	--
C_2-Alkylnaphthalene	12,000	2,500	14,000	--	--	--
C_2-Alkylnaphthalene	27,000	920	28,000	--	--	--
C_2-Alkylnaphthalene	3,700	130	3,800	--	--	--
Methylbiphenyl	--	1,200	1,200	--	--	--
Methylbiphenyl	--	460	460	--	--	--
Methylbiphenyl	--	290	290	--	--	--
Anthracene/phenanthrene	--	19	19	--	--	--
C_3-Alkylnaphthalene	--	500	500	--	--	--
C_3-Alkylnaphthalene	--	1,500	1,500	--	--	--
C_3-Alkylnaphthalene	--	260	260	--	--	--
C_3-Alkylnaphthalene	--	260	260	--	--	--
C_2-Alkylbiphenyl	--	740	740	--	--	--
C_2-Alkylbiphenyl	--	410	410	--	--	--
C_4-Alkylnaphthalene	--	300	300	--	--	--
C_4-Alkylnaphthalene	--	110	110	--	--	--

TABLE B5-45. CATALYTIC REFORMER: PRODUCT NAPHTHA (DEPENTANIZER BOTTOMS)

	Bulk Liquid, ppm			Vapor, µg		
Compound	Fraction 1	Fraction 2	Total	Fraction 1	Fraction 2	Total
Benzene	—	—	—	21	0.3	21
Toluene	85,000	480	85,000	190	68	260
Ethylbenzene	15,000	49	15,000	140	4	140
m,p-Xylene	74,000	800	75,000	160	130	290
o-Xylene	30,000	570	30,000	95	72	170
Isopropylbenzene	—	—	—	5	—	5
Propylbenzene	—	—	—	20	—	20
Methylethylbenzene	18,000	78	18,000	82	15	97
Methylethylbenzene	11,000	78	11,000	22	19	41
Trimethylbenzene	3,600	45	3,600	16	10	26
Methylethylbenzene	15,000	440	15,000	24	55	79
Trimethylbenzene	5,900	140	6,000	—	—	—
Dimethylbenzene	—	14	14	—	—	—
Diethylbenzene	—	—	—	—	15	15
Indane	220	33	250	4	5	9
Dimethylethylbenzene	—	<1	—	1	3	4
Dimethylethylbenzene	—	9	60	—	—	—
Dimethylethylbenzene	51	14	65	—	5	—
Dimethylethylbenzene	—	11	11	—	3	—
Tetramethylbenzene	230	30	260	5	1	6
Tetramethylbenzene	180	15	300	—	8	8
Methyldiethylbenzene	—	23	23	2	6	8
Di-isopropylbenzene	—	14	14	—	—	—
Methyl indane	50	—	50	—	—	—
Methyl indane	70	8	80	1	2	3
Di-isopropylbenzene	—	14	14	—	—	—
Tetramethylbenzene	59	9	68	—	4	—
C_5-Alkylbenzene	14	—	—	—	—	—
C_5-Alkylbenzene	10	—	—	—	—	—
C_5-Alkylbenzene	20	—	—	—	—	—
Naphthalene	410	280	720	—	10	10
2-Methylnaphthalene	81	120	200	—	—	—
1-Methylnaphthalene	37	62	100	—	—	—
C_2-Alkylnaphthalene	6	—	6	—	—	—
C_2-Alkylnaphthalene	34	31	65	—	—	—
C_2-Alkylnaphthalene	40	41	81	—	—	—
C_2-Alkylnaphthalene	22	18	40	—	—	—
C_2-Alkylnaphthalene	13	14	27	—	—	—
C_2-Alkylnaphthalene	3	—	3	—	—	—
Biphenyl	—	54	54	—	—	—
Fluorene	—	54	54	—	—	—
Anthracene	—	4	4	—	—	—

TABLE B5-46. CATALYTIC REFORMER: PRODUCT NAPHTHA, BULK LIQUID

Compound	Bulk Liquid (ppm)	Vapor on XAD (μg)	Vapor on Tenax (μg)
Benzene	440	8.4	0.22
Toluene	4,900	74.0	1.0
Ethylbenzene	2,000	32.0	1.1
m, p-Xylene	7,000	120.0	0.81
o-Xylene	2,000	50.0	0.81
Isopropylbenzene	310	2.3	0.11
n-Propylbenzene	1,400	20.0	0.78
3-Ethyl toluene	5,500	48.0	2.4
4-Ethyl toluene	2,400	38.0	--
1,2,3-Trimethylbenzene	1,600	22.0	--
1,3,5-Trimethylbenzene	260	--	--
2-Ethyl toluene	6,500	74.0	1.1
sec-Butylbenzene	300	5.2	--
1,2,4-Trimethylbenzene	1,400	20.0	0.52
Diethylbenzene	95	1.6	--
Methylisopropylbenzene	120	2.2	--
Methylpropylbenzene	1,600	15.0	0.76
Methylpropylbenzene	1,300	10.0	--
Methylpropylbenzene	450	9.1	--
Diethylbenzene	960	11.0	0.52
Diethylbenzene	360	4.0	0.21
Dimethylethylbenzene	1,100	12.0	0.71
Dimethylethylbenzene	140	11.0	--
Dimethylethylbenzene	--	1.6	--
Dimethylethylbenzene	60	2.2	--
C_5-Alkylbenzene	330	0.8	--
Tetramethylbenzene	1,200	7.6	--
Tetramethylbenzene	1,100	7.4	0.35
Tetramethylbenzene	900	1.6	--
C_5-Alkylbenzene	350	3.2	--
C_5-Alkylbenzene	400	1.6	--
Naphthalene	2,800	7.4	0.65
C_5-Alkylbenzene	460	1.6	--
C_5-Alkylbenzene	310	1.0	--
2-Methylnaphthalene	2,200	--	--
1-Methylnaphthalene	2,600	--	--
C_2-Alkylnaphthalene	700	--	--
C_2-Alkylnaphthalene	1,300	--	--

TABLE B5-47. CATALYTIC REFORMER: PRODUCT NAPHTHA, BULK LIQUID

Peak No.	Compound	Concentration (ppb)
1	Benzene	80
2	Toluene	2,100
3	Ethylbenzene	440
4	m-Xylene/p-Xylene	4,100
5	o-Xylene	1,200
6	Isopropylbenzene	200
7	n-Propylbenzene	780
8	3-Ethyl toluene	620
9	1,3,5-Trimethylbenzene	180
10	2-Ethyl toluene	80
11	C_4-Alkylbenzene	140
12	1,2,4-Trimethylbenzene	230
13	Indan	86
14	C_4-Alkylbenzene	320
15	C_4-Alkylbenzene	69

TABLE B5-48. CATALYTIC REFORMER: PRODUCT NAPHTHA, BULK LIQUID

Compound	ppm
Benzene	83.8
Toluene	840.0
Ethylbenzene	142.0
m/p-xylenes	632.0
o-xylene	31.2
i-propylbenzene	35.7
n-propylbenzene	210.8
m/p-ethyltoluene	207.0
1,3,5-Trimethylbenzene	71.4
o-ethyltoluene	64.6
1,2,4-Trimethylbenzene	184.0
sec-Butylbenzene	46.0
i-Butylbenzene	56.0
Indan	17.5
C_4-Alkylbenzene	98.0
C_4-Alkylbenzene	11.8
C_4-Alkylbenzene	104.0
Methylindan	28.0
Methylindan	8.00
C_4-Alkylbenzene	11.2
C_4-Alkylbenzene	20.0
Methylindan	6.00
C_5-Alkylbenzene	18.3
C_5-Alkylbenzene	6.50
C_5-Alkylbenzene	13.0
Methylindan	5.20
Tetralin	4.60
Naphthalene	9.02
C_2-Alkylindan/methyltetralin	11.2
C_5-Alkylbenzene	2.50

TABLE B5-49. CATALYTIC REFORMER: PRODUCT NAPHTHA, BULK LIQUID

Compound	ppm
Benzene	826.0
Toluene	445.0
Ethylbenzene	581.0
m/p-xylenes	1160.0
o-xylene	315.0
i-propylbenzene	44.2
n-propylbenzene	182.0
m/p-ethyltoluene	1560.0
1,3,5-Trimethylbenzene	493.0
o-ethyltoluene	168.0
1,2,4-Trimethylbenzene	952.0
sec-Butylbenzene	32.0
Indan	58.8
C_4-Alkylbenzene	548.0
n-Butylbenzene	144.0
C_4-Alkylbenzene	322.0
C_4-Alkylbenzene	336.0
C_4-Alkylbenzene	284.0
C_4-Alkylbenzene	400.0
C_5-Alkylbenzene	166.0
C_5-Alkylbenzene	41.5
Methylindan	76.0
C_5-Alkylbenzene	90.0
C_5-Alkylbenzene	22.5
C_5-Alkylbenzene	92.5
Methylindan	107.0
Naphthalene	82.5
C_5-Alkylbenzene	87.5
C_5-Alkylbenzene	17.5
2-Methylnaphthalene	277.0
1-Methylnaphthalene	47.9
C_2-Alkylnaphthalene	5.25
C_2-Alkylnaphthalene	23.8
Biphenyls	0.660
C_2-Alkylnaphthalene	45.0
C_2-Alkylnaphthalene	15.75
C_2-Alkylnaphthalene	7.00
Methylbiphenyls	2.04
C_3-Alkylnaphthalene	1.74
C_3-Alkylnaphthalene	4.93
C_3-Alkylnaphthalene	3.48
C_3-Alkylnaphthalene	2.32
Fluorene	.13

TABLE B5-50. CATALYTIC REFORMER: PRODUCT NAPHTHA, BULK LIQUID

Compound	ppm
Benzene	150.0
Toluene	396.0
Ethylbenzene	451.0
m/p-xylenes	1950.0
o-xylene	85.8
i-propylbenzene	59.5
n-propylbenzene	204.0
m/p-ethyltoluene	1020.0
1,3,5-Trimethylbenzene	340.0
o-ethyltoluene	42.5
1,2,4-Trimethylbenzene	1390.0
sec-Butylbenzene	32.0
i-Butylbenzene	30.0
1,2,3-Trimethylbenzene	143.0
C_4-Alkylbenzene	56.3
Indan	36.3
C_4-Alkylbenzene	280.0
n-Butylbenzene	220.0
C_4-Alkylbenzene	300.0
C_4-Alkylbenzene	68.0
C_4-Alkylbenzene	300.0
Methylindan	70.0
Methylindan	44.0
C_4-Alkylbenzene	340.0
C_4-Alkylbenzene	32.0
C_4-Alkylbenzene	40.0
C_5-Alkylbenzene	83.0
C_4-Alkylbenzene	200.0
Methylindan	58.0
C_5-Alkylbenzene	100.0
C_5-Alkylbenzene	160.0
Methylindan	94.9
C_5-Alkylbenzene	75.0
C_5-Alkylbenzene	27.5
C_5-Alkylbenzene	100.0
C_5-Alkylbenzene	45.0
C_5-Alkylbenzene	125.0
C_5-Alkylbenzene	12.5
Naphthalene	228.0
C_2-Alkylindan/methyltetralin	7.13
C_5-Alkylbenzene	40.0
C_2-Alkylindan/methyltetralin	34.1
C_5-Alkylbenzene	27.5

Continued

TABLE B5-50. Continued

Compound	ppm
C_2-Alkylindan/methyltetralin	12.4
C_2-Alkylindan/methyltetralin	55.8
C_2-Alkylbenzene	21.0
2-Methylnaphthalene	106.4
1-Methylnaphthalene	81.2
C -Alkylnaphthalene	7.00
C -Alkylnaphthalene	32.5
C -Alkylnaphthalene	65.0
C -Alkylnaphthalene	21.0
Phenanthrene/Anthracene	0.924
Methyl phenanthrene/anthracene	1.18

TABLE B5-51. ALKYLATION UNIT: CRUDE ALKYLATE, ORGANIC SPECIES ON TENAX

No Aromatic Species Detected.

TABLE B5-52. ALKYLATION UNIT: ALKYLATE GASOLINE, BULK LIQUID

No Aromatic Species Detected

TABLE B5-53. ALKYLATION UNIT: CRUDE ALKYLATE

Compound	Bulk Liquid, ppm[a]	Vapor on XAD, μg	Vapor on Tenax, μg
Benzene		0.69	0.0044
Toluene		3.3	0.067
Ethylbenzene		5.2	0.064
m,p-Xylene		42.0	0.20
o-Xylene		22.0	0.094
n-Propylbenzene		48.0	--
3-Ethyl toluene		36.0	0.86
1,2,3-Trimethylbenzene		96.0	--
1,3,5-Trimethylbenzene		54.0	--
2-Ethyl toluene		230.0	0.73
1,2,4-Trimethylbenzene		72.0	0.22
Diethylbenzene		6.0	0.14
Methylisopropylbenzene		2.6	0.0088
Methylpropylbenzene		26.0	0.35
Methylpropylbenzene		72.0	--
Methylpropylbenzene		47.0	--
Diethylbenzene		65.0	0.083
Diethylbenzene		22.0	--
Dimethylethylbenzene		72.0	0.15
Dimethylethylbenzene		66.0	0.11
Dimethylethylbenzene		17.0	--
Tetramethylbenzene		32.0	0.12
Tetramethylbenzene		48.0	0.15
Tetramethylbenzene		30.0	--
C_5-Alkylbenzene		10.0	--
C_5-Alkylbenzene		12.0	--
Naphthalene		140.0	0.57
C_5-Alkylbenzene		14.0	--
2-Methylnaphthalene		36.0	0.12

[a] None of the vapor species were found in the bulk liquid. The vapor species, therefore, must have been adsorbed from the ambient air or from cross-contamination with other samples from residue in the sampling train.

TABLE B5-54. ALKYLATION UNIT: CRUDE ALKYLATE, BULK LIQUID

Peak No.	Compound	Concentration (ppb)
1	Benzene	120
2	Toluene	200
3	Ethylbenzene	77
4	m-Xylene/p-Xylene	370
5	o-Xylene	370
6	Isopropylbenzene	280
7	n-Propylbenzene	160
8	3-Ethyl toluene	100
9	1,3,5-Trimethylbenzene	420
10	1,2,4-Trimethylbenzene	300
11	Indan	100
12	C_4-Alkylbenzene	100
13	C_4-Alkylbenzene	300
14	Methyl indan	100
15	Methyl indan	200
16	C_4-Alkylbenzene	450
17	Naphthalene	200
18	2-Methylnaphthalene	300
19	1-Methylnaphthalene	250
20	C_2-Alkylnaphthalene	50
21	C_2-Alkylnaphthalene	200
22	C_2-Alkylnaphthalene	450
23	C_2-Alkylnaphthalene	250

TABLE B5-55. NAPHTHA HYDRODESULFURIZATION: DESULFURIZED NAPHTHA PRODUCT, BULK LIQUID

Compound	ppm
Benzene	18.8
Toluene	5836.0
Ethylbenzene	299.0
m/p-xylenes	260.0
o-xylenes	195.0
i-propylbenzene	49.3
n-propylbenzene	51.0
m/p-ethyltoluene	272.0
1,3,5-Trimethylbenzene	150.0
o-ethyltoluene	170.0
1,2,4-Trimethylbenzene	136.0
i-Butylbenzene	24.0
1,2,3-Trimethylbenzene	98.0
C_4-Alkylbenzene	80.4
Indan	15.0
C_4-Alkylbenzene	174.0
C_4-Alkylbenzene	70.0
C_4-Alkylbenzene	42.0
Methylindan	24.0
Methylindan	22.0
C_4-Alkylbenzene	10.0
C_5-Alkylbenzene	55.6
C_4-Alkylbenzene	16.8
C_5-Alkylbenzene	23.2
Methylindan	13.4
C_5-Alkylbenzene	7.50
C_5-Alkylbenzene	27.5
Methylindan	16.9
C_5-Alkylbenzene	40.0
C_5-Alkylbenzene	42.5
Tetralin	44.0
C_5-Alkylbenzene	12.5
C_2-Alkyl indan/methyl tetralin	34.1
C_2-Alkyl indan/methyl tetralin	31.0
C_2-Alkyl indan/methyl tetralin	4.96
C_2-Alkyl indan/methyl tetralin	1.71

TABLE B5-56. HYDRODESULFURIZATION UNIT: DESULFURIZED GAS OIL, BULK LIQUID

Compound	ppm
Toluene	3.52
Ethylbenzene	10.9
m/p-xylenes	5.59
o-xylene	2.73
n-propylbenzene	4.08
m/p-ethyltoluene	6.46
1,3,5-Trimethylbenzene	2.21
o-ethyltoluene	2.72
1,2,4-Trimethylbenzene	4.93
C_4-Alkylbenzene	6.40
C_4-Alkylbenzene	2.60
C_4-Alkylbenzene	4.60
C_4-Alkylbenzene	1.84
C_4-Alkylbenzene	14.6
C_4-Alkylbenzene	2.00
Biphenyl	1.87
Phenanthrene/anthracene	1.43

TABLE B5-57. GASOLINE SWEETENING UNIT: MIXED NAPHTHA FEED, BULK LIQUID

Peak No.	Compound	Concentration (ppm)
1	Benzene	130
2	Toluene	8,500
3	Ethylbenzene	1,100
4	m,p-Xylene	7,000
5	o-Xylene	1,700
6	Isopropylbenzene	1,100
7	n-Propylbenzene	1,800
8	3-Ethyl toluene	4,200
9	4-Ethyl toluene	2,900
10	1,2,3-Trimethylbenzene	1,800
11	2-Ethyl toluene	5,000
12	sec-Butylbenzene	650
13	1,2,4-Trimethylbenzene	2,000
14	Diethylbenzene	800
15	Methylisopropylbenzene	130
16	Methylpropylbenzene	1,100
17	Methylpropylbenzene	550
18	Diethylbenzene	900
19	Diethylbenzene	230
20	Dimethylethylbenzene	900
21	Dimethylethylbenzene	650
22	Dimethylethylbenzene	340
23	C_5-Alkylbenzene	290
24	Dimethylethylbenzene	150
25	Tetramethylbenzene	600
26	Tetramethylbenzene	600
27	Tetramethylbenzene	600
28	C_5-Alkylbenzene	80
29	C_5-Alkylbenzene	200
30	Naphthalene	1,600
31	C_5-Alkylbenzene	200
32	C_5-Alkylbenzene	120
33	C_5-Alkylbenzene	160
34	Methylnaphthalene	300
35	C_2-Alkylnaphthalene	300
36	C_2-Alkylnaphthalene	190
37	d_{10}-Anthracene	

TABLE B5-58. GAS ABSORBTION UNIT: LEAN OIL (NAPHTHA), BULK LIQUID

Peak No.	Compound	Concentration (ppb)
1	Benzene	1,600
2	Toluene	10,000
3	Ethylbenzene	2,200
4	m-Xylene/p-Xylene	22,000
5	o-Xylene	5,000
6	Isopropylbenzene	980
7	n-Propylbenzene	9,500
8	3-Ethyl toluene	9,300
9	1,3,5-Trimethylbenzene	1,400
10	2,Ethyl toluene	3,500
11	C_4-Alkylbenzene	300
12	1,2,4-Trimethylbenzene	2,400
13	Indan	2,100
14	C_4-Alkylbenzene	1,200
15	C_4-Alkylbenzene	1,800
16	C_4-Alkylbenzene	400
17	C_4-Alkylbenzene	1,300
18	C_4-Alkylbenzene	1,300
19	Methyl indan	560
20	Methyl indan	1,100
21	C_4-Alkylbenzene	450
22	C_4-Alkylbenzene	600
23	C_4-Alkylbenzene	840
24	C_5-Alkylbenzene	250
25	Methyl indan	400
26	Methyl indan	500
27	C_5-Alkylbenzene	800
28	Naphthalene	100

TABLE B5-59. SOLVENT DEWAXING UNIT: SLACK WAX

Compound	Bulk Gas Liquid, ppm	Vapor on XAD,μg	Vapor on Tenax,μg
Benzene	73	-	0.022
Toluene	17000	4100	23.8
Ethylbenzene/m or p-Xylene	-	-	0.033
o-Xylene	-	-	0.064
3 or 4-Ethyl toluene	-	-	0.059
1,3,5-Trimethylbenzene	-	-	0.035
2-Ethyl toluene	-	-	0.013
1,2,4-Trimethylbenzene	-	-	0.071
1,2,3-Trimethylbenzene	-	-	0.024
Di-ethylbenzene	-	-	0.033
Di-methylethylbenzene	-	-	0.014
Di-methylethylbenzene	-	-	0.034
Tetramethylbenzene	-	-	0.020
Tetramethylbenzene	-	-	0.024

TABLE B5-60. ELEMENTAL ANALYSIS OF FCCU CO BOILER FLUE GAS PARTICULATES (STACK NO. 14)

Element	Conc.[a]	Element	Conc.	Element	Conc.	Element	Conc.
Uranium	5	Terbium	29	Ruthenium		Vanadium	150
Thorium	6	Gadolinium	150	Molybdenum	66	Titanium	MC
Bismuth[b]		Europium	14	Niobium	15	Scandium	17
Lead	54	Samarium	490	Zirconium	48	Calcium	MC
Thallium		Neodymium	MC[c]	Yttrium	240	Potassium	MC
Mercury		Praseodymium	MC	Strontium	120	Chlorine	22
Gold		Cerium	MC	Rubidium	≤0.5	Sulfur	MC
Platinum		Lanthanum	MC	Bromine	≤3	Phosphorus	MC
Iridium		Barium	790	Selenium	36	Silicon	MC
Osmium		Cesium	0.2	Arsenic	4	Aluminum	MC
Rhenium		Iodine		Germanium	≤0.7	Magnesium	MC
Tungsten	5	Tellurium		Gallium	10	Sodium	MC[c]
Tantalum	≤1	Antimony	0.9	Zinc	260	Fluorine	MC
Hafnium	3	Tin	5	Copper	40	Oxygen	NR[d]
Lutetium	1	Indium	STD	Nickel	300	Nitrogen	NR
Ytterbium	5	Cadmium	≤0.5	Cobalt	50	Carbon	NR
Thulium	0.9	Silver	0.5	Iron	MC	Boron	69
Erbium	22	Palladium		Manganese	300	Beryllium	1
Holmium	24	Rhodium		Chromium	840	Lithium	280
Dysprosium	230					Hydrogen	NR

[a] Concentration in ppm by weight.

[b] All elements not reported ≤0.3 ppm by weight.

[c] MC - major component.

[d] NR - not reported.

TABLE B5-61. ELEMENTAL ANALYSIS OF FCCU CO BOILER FLUE GAS PARTICULATES (STACK NO. 11)

Element	Conc.[a]	Element	Conc.	Element	Conc.	Element	Conc.
Uranium	5	Terbium	7	Ruthenium	--	Vanadium	100
Thorium	19	Gadolinium	94	Molybdenum	150	Titanium	MC[c]
Bismuth[b]	--	Europium	9	Niobium	80	Scandium	12
Lead	29	Samarium	930	Zirconium	260	Calcium	MC
Thallium	--	Neodymium	MC ≃ .4%	Yttrium	88	Potassium	MC
Mercury	NR	Praseodymium	MC ≃ .3%	Strontium	130	Chlorine	150
Gold	--	Cerium	MC ≃ 2%	Rubidium	≤ 8	Sulfur	MC
Platinum	--	Lanthanum	MC ≃ 4%	Bromine	≤ 3	Phosphorus	MC
Iridium	--	Barium	860	Selenium	5	Silicon	MC
Osmium	--	Cesium	1	Arsenic	4	Aluminum	MC
Rhenium	--	Iodine	0.4	Germanium	≤ 1	Magnesium	200
Tungsten	2	Tellurium	--	Gallium	53	Sodium	MC
Tantalum	1	Antimony	3	Zinc	130	Fluorine	MC
Hafnium	4	Tin	4	Copper	140	Oxygen	NR[d]
Lutetium	0.4	Indium	STD	Nickel	550	Nitrogen	NR
Ytterbium	2	Cadmium	≤0.3	Cobalt	60	Carbon	NR
Thulium	0.6	Silver	≤0.3	Iron	MC	Boron	8
Erbium	12	Palladium	--	Manganese	680	Beryllium	0.3
Holmium	10	Rhodium	--	Chromium	MC	Lithium	11
Dysprosium	30					Hydrogen	NR

[a] Concentration in ppm by weight.

[b] All elements not reported ≤0.2 ppm by weight.

[c] MC - major component.

[d] NR - not reported.

amber bottle was filled, sealed, and kept refrigerated until analyzed. The results of this type of sampling/analysis are labeled "Bulk Liquid." An attempt was made to get line material samples for vapor phase streams, but no reliable results were obtained because of leakage (glass bombs) or contamination (metal bombs). The fugitive emissions from fittings on these streams were also analyzed by adsorbing the organics on a solid resin. The resin packed tubed were then capped, refrigerated, and transported to Austin under refrigeration. The adsorbed organics were then extracted from the resin and analyzed by GC-MS. The results of this type of sampling/analysis are labeled either "Vapor on XAD" or "Vapor on Tenax," depending on which type of resin was used.

5.2 EXPERIMENTAL COMPARISON OF COMPOSITION OF LEAKING VAPOR WITH COMPOSITION OF LIQUID IN PIPES

The scope of the refinery program included the determination of the location and concentration of hazardous materials contained in fugitive hydrocarbon emissions. To meet this objective, corresponding liquid and fugitive vapor samples were obtained during the field portion of the program.

The liquid samples were obtained from selected process streams at locations such as sample lines, drain lines, or other appropriate equipment.

Corresponding fugitive vapor samples were obtained from leaking valves on the process line in question. The vapors were collected using either activated charcoal, Tenax resin, or XAD-2 resin adsorption medias. These materials were contained in packed tubes.

Both the liquid and the vapor samples were analyzed by Radian. The analysis procedures are discussed in detail in Appendix A.

The sampling and analyses of vapor samples is time-consuming. The analysis of liquid hydrocarbons is considerably simpler. Corresponding vapor and liquid samples were analyzed to compare their compositions. The results were inconclusive in defining the relationship between the liquid in the pipe and the leaking vapor.

5.2.1 Experimental System

An experiment was conducted to determine the relationship between the liquid and fugitive vapor compositions.

5.2.1.1 Experimental Equipment--

In the experiment, a valve, similar to those used in refineries, was installed in a system designed to duplicate conditions found within refinery process streams. The system consisted of equipment which circulated hydrocarbon liquid through the valve at elevated temperature and pressure. The valve packing material was adjusted to produce a relatively low vapor leak. Samples of this vapor were analyzed and compared to the liquid in the system.

Two different hydrocarbon mixtures were used during the experiment. The first consisted of roughly equivalent amounts of hexane and toluene. The selection of these materials was based on the following factors:

- Both materials are relatively volatile and would remain in the vapor phase. That is, as these hydrocarbons leave the seal, they do not condense on cooler surfaces at the low concentrations involved.

- There are considerable differences between the physical and chemical properties of hexane and toluene. And, separation of the materials by GC is not difficult.

- Both materials are available in bulk quantities at low cost.

The second hydrocarbon mixture used consisted of hexane, toluene, and naphthalene. This system was selected after the results of earlier testing indicated that the compositions of the liquid and vapor were identical. The boiling point of naphthalene (218°C) is considerably higher than either hexane or toluene. And, the presence of significant quantities of naphthalene in the vapor leak would provide additional evidence for a conclusion of identical composition.

A simplified diagram of the valve assembly used in this experiment is given in Figure B5-1. This diagram indicates important equipment and gives other information on the operation of the system.

Pressure within the system was maintained with a small gear pump. The pump was capable of producing pressures in excess of 100 psig at flow rates of approximately 5 GPM.

From the pump, the hydrocarbon liquid circulated through a section of 1" pipe wrapped with electrical heating tape. The heating tape was used to raise the hydrocarbon temperature of the pump. The liquid then entered a section of 6"

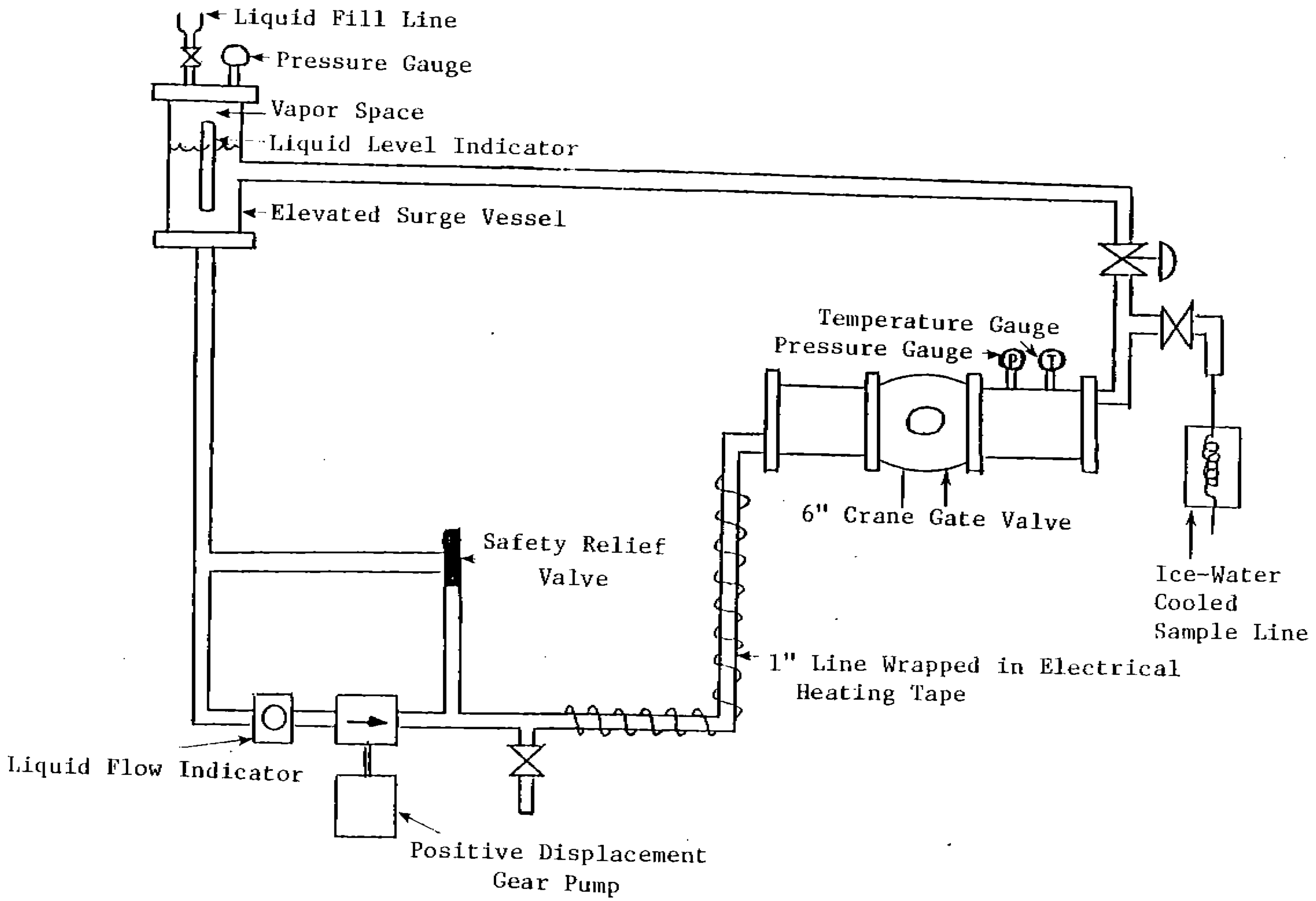


Figure B5-1. Diagram of experimental set-up.

pipe which contained the valve from which fugitive emission samples were obtained. Temperature and pressure indicators were also located on this section of pipe.

Liquid samples were obtained from a sample line located after the 6" valve assembly. Following the liquid sample line was a flow control globe valve. This valve was used to regulate the pressure within the 6" valve assembly. From the control valve, liquid passed to a small elevated surge tank from which the pump took suction.

5.2.1.2 Collection and Analysis of Vapor Samples--

The fugitive emission vapor samples were obtained from the 6" Crane gate valve. The packing gland was adjusted to give a leak rate of approximately 0.015 lb/hr. The leak rate was determined by measuring the gas concentration at the seal with a Bacharach "TLV Sniffer". The leak rate was estimated from the correlations presented in Section 2.4 of this appendix.

The packing gland and valve stem were enclosed within a small Mylar plastic shroud (or tent). Zero air (air with an extremely low concentration of hydrocarbons) was injected into the tent to keep the hydrocarbon concentration at low levels.

Vapor samples for the hexane-toluene system were taken from within the tent using a 1 ml gas-tight syringe. The sample was immediately injected into the sample port of an AID portable gas chromatograph.

Analysis of vapor samples for the hexane-toluene-naphthalene system was accomplished using a Hewlett-Packard temperature programmable gas chromatograph.

5.2.1.3 Collection and Analysis of Liquid Samples--

Liquid samples were taken from an ice-water cooled sample line. The sample line was cooled to prevent flashing of the liquid.

Liquid samples from the hexane-toluene system were analyzed on the portable AID gas chromatograph while samples from the hexane-toluene-naphthalene system were analyzed on the Hewlett-Packard temperature programmable gas chromatograph.

5.2.2 Testing Results

The following tests were conducted:

1) The response time of the system was determined, that is, the time required for the vapor composition to equilibrate after a change in the liquid composition.

2) Vapor and liquid compositions were determined for the hexane-toluene systems.

3) Vapor and liquid compositions were determined for the hexane-toluene-naphthalene system.

4) The effect of temperature and pressure on the vapor composition of the hexane-toluene system was investigated.

5.2.2.1 Equilibration Test Results

The response time of the system was determined to insure that adequate time was allowed for the system to reach equilibrium before testing was initiated.

The results of this test are shown graphically in Figure B5-2. The concentration of toluene in the vapor as a function of time in response to a step change in the concentration of toluene in the liquid is shown. The concentration values have been normalized to show the percentage of the total required concentration change. The actual toluene concentration was changed from 43.1 percent to 57.2 percent. These results indicated that at least eight hours were required after a change in the system composition before steady state operation was achieved.

5.2.2.2 Vapor-Liquid Compositions: Hexane-Toluene System--

After completion of the equilibration test, numerous vapor and liquid samples were taken. The results of this test are given in Table B5-62. Operating conditions for the test were:

Temperature = 200°F
Pressure = 80 psig

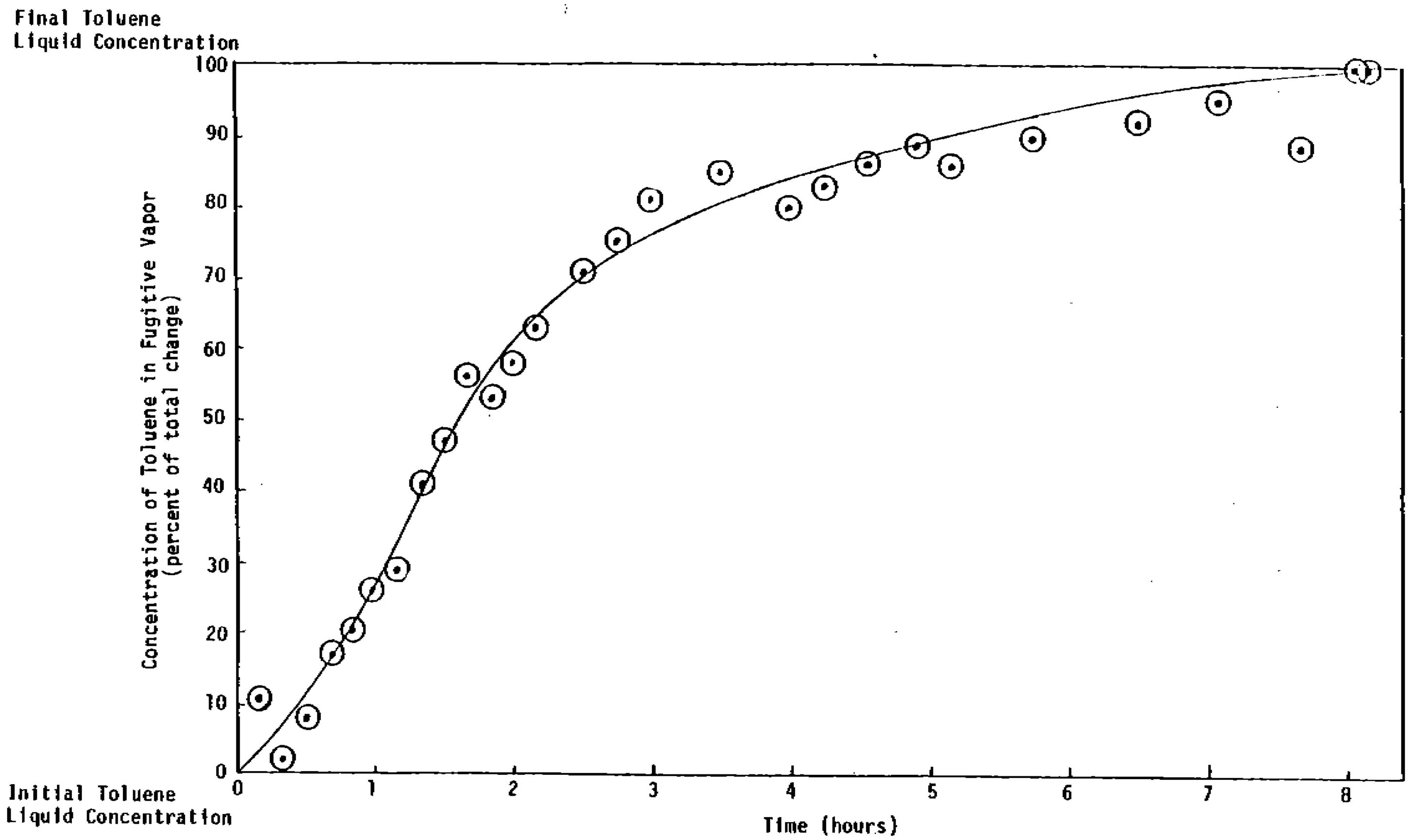


Figure B5-2. Change in the vapor toluene concentration versus time for a step change in liquid toluene concentration.

TABLE B5-62. COMPARISON OF VAPOR AND LIQUID COMPOSITIONS: HEXANE-TOLUENE SYSTEM

Sample Type	Concentration of Toluene (%)	Number of Samples
Vapor	56.9 ± 0.8	7
Liquid	57.2 ± 1.2	15

5.2.2.3 Vapor-Liquid Compositions: Hexane-Toluene-Naphthalene System--

Naphthalene was added to the hexane-toluene system to determine the emission characteristics of a much heavier component. A mixture of hexane and toluene containing 8 percent naphthalene was used. The naphthalene vapor concentrations obtained ranged from 2-6 percent, somewhat lower than the liquid concentration. It was observed, however, that small amounts of solid naphthalene had accumulated within the sampling syringe.

5.2.2.4 Effect of Temperature and Pressure--

Vapor and liquid concentrations were measured for the hexane-toluene system at the following operating conditions:

1) T = 130°F, P = 40 psig
2) T = 130°F, P = 100 psig
3) T = 200°F, P = 40 psig
4) T = 200°F, P = 100 psig

In all cases, the vapor and liquid concentrations remained constant at the levels given in Table B5-63.

5.2.3 Conclusions

Based on the results obtained during the course of this experiment, the following conclusions are offered:

1) The composition of fugitive emissions from refinery process equipment appears to be identical to the composition of the liquid within the leaking equipment.

2) The temperature and pressure of the process stream have no effect on the composition of the leak.

3) Heavier components within the liquid process stream may leak at concentrations equivalent to that of the line concentration. However, they may condense on cooler external surfaces. Hence, only a portion of these heavier components will constitute air emissions.

SECTION 6

MAINTENANCE STUDIES

To evaluate control technologies for valves and to develop parameters for "off-set" analyses using valve maintenance programs, data on the effectiveness of various types of maintenance activities are needed. In this section of the report, the short-term effects of maintenance are described. No long-term effects are available. However, an ongoing program is described.

6.1 SHORT-TERM MAINTENANCE RESULTS

A short-term maintenance study was performed on 86 valves at four refineries. Three variables were considered in selecting valves for the study: leak rate, process stream, and valve type. A selective experimental design based on categories of the above variables was used to minimize the number of required valves in the study.

Eligible valves were first located by screening with a TLV Sniffer. Variable information was recorded. Each valve was then rescreened and sampled. Routine maintenance, such as tightening the packing gland or adding grease, was performed on the valve. Maintenance was described as directed or undirected. Directed maintenance involved simultaneous maintenance and screening of the valve until no further reduction in TLV Sniffer reading could be obtained. Undirected maintenance was not monitored with the TLV Sniffer. Finally, the valve was rescreened or resampled after the maintenance had been performed. Table B6-1 summarizes all maintenance and leak rate information.

The effect of the type of maintenance performed, either directed or undirected, can be seen in Figures B6-1 and B6-2. The leak rate of the valve before maintenance is plotted against the leak rate for the valve after maintenance for both the directed and the undirected maintenance efforts. Valves that exhibited a reduction in leak rate are indicated by those points that fall below the diagonal line drawn in each figure. Those valves whose leak rate increased are shown as the points plotted above the line. Valves whose leak rates show no change after maintenance are represented by points on the line. It appears that the directed maintenance produces a greater reduction in leak rate in a larger percentage of valves. This indicates that the directed maintenance method is more effective than undirected maintenance in reducing emissions from valves.

The percentage reduction in leak rates after maintenance was calculated using the following equation:

$$\text{Percentage Reduction} = \frac{\text{Leak Rate Before Maint.} - \text{Leak Rate After Maint.}}{\text{Leak Rate Before Maint.}}$$

Negative percentage reductions are possible in cases where the leak rate increases after maintenance. The highest potential reduction in emissions is 100 percent. However, it is possible to get negative percentage reductions that are much greater than 100 percent, particularly if the original leak rate is very low.

TABLE B6-1. SUMMARY OF MAINTENANCE AND LEAK RATE INFORMATION

The data in this table are first sorted into directed and undirected maintenance groups. Within the type of maintenance group, the valves are first sorted by valve function (block or control) and then in descending order by percent reduction due to maintenance. The valves selected as "control sources" (no maintenance performed) are the last valves listed in each valve type group.

The following is a description of the variables listed on the printouts:

ID - Unit code and source number for each valve (refinery ID is not included so there may be some replication of ID).
BLK - B - Block valve
C - Control valve
PRSI- Process stream code (see below for description).
TLV - Maximum screening value when source was first located.
DATE- Date (month, day, year) when valve was sampled and/or screened.
SAMP- Sample type: BC - Sample for source selected as control.
BS - Sample before maintenance.
MI - Sample after maintenance
BQ - Quality control sample - before or after maintenance.
ES - Estimated leak rate based on maximum rescreening value.

Screening information:

MEAN STEM - Average of four screening values at the valve stem.
MAX STEM - Maximum of four screening values at the valve stem.
MEAN GLAND- Average of four screening values at the valve gland.
MAX GLAND - Maximum of four screening values at the valve gland.

NON-METH LK RATE - Measured or estimated nonmethane leak rate (lb/hr).
% REDUC - Percent reduction due to maintenance.

$$\% \text{ REDUC} = 100 \times \left(\frac{\text{Lk rate before maintenance - lk rate after maintenance}}{\text{Lk rate before maintenance}}\right)$$

Continued

TABLE B6-1. Continued

Process Stream Classifications

Gas/Vapor Streams

Stream	Stream Description*
AAAX	C_1 - C_2 Hydrocarbons
AABX	C_3 - C_4 Hydrocarbons
AACX	C_5 - C_9 Hydrocarbons
AADX	C_{10}+ Hydrocarbons
AAEX	Mixed Molecular Weight Hydrocarbons
AAFX	Aromatic Hydrocarbons
ABAA	Streams Containing 10 - 50% Hydrogen
ABAB	Streams Containing >50% Hydrogen
ABBA	Streams Containing 5 - 50% H_2S
ABBB	Streams Containing >50% H_2S
ABCX	Streams Containing >50% H_2O
ABDA	Hydrofluoric Acid
ABDB	Methyl Ethyl Ketone
ABDC	Sulfolane
ABDD	Monoethanolamine
ABDE	Sulfuric Acid
ABEX	Miscellaneous Gas Streams

*The most volatile stream component present at a concentration of 20% or more determines the stream classification.

Continued

TABLE B6-1. Continued

Process Stream Classifications

Liquid Streams

Stream	Stream Description
BCAX	$C_1 - C_2$ Hydrocarbons
BCBX	$C_3 - C_4$ Hydrocarbons
BCCX	$C_5 - C_6$ Hydrocarbons
BCDX	$C_7 - C_9$ Hydrocarbons
BCEX	Naphtha
BCFX	Kerosene/Diesel/Heating Oil
BCGX	Gas Oil
BCHX	Atmospheric Bottoms/Vacuum Gas Oil
BCIX	Vacuum Residual/Asphalt
BCJA	Low Molecular Weight Aromatics
BCJB	Polynuclear Aromatics
BDAX	Streams Containing >50% H_2O
BDBX	Streams Made up of Mixed Molecular Weight Components
BDCA	Hydrochloric Acid
BDCB	Methyl Ethyl Ketone
BDCC	Sulfolane
BDCD	Monoethanolamine
BDCE	Sulfuric Acid
CAAX	Two-Phase Stream containing methane gas and light liquid hydrocarbons
CBAB	Two-Phase Stream Containing >50% Hydrogen

TABLE B6-1. Continued

ID	BLK	PRST	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance												
21VA	14 B	AAAX	26	102678	BS	49750	100000	0	0	0.03207		½ turn top nut; ⅔ turn bottom nut.
21VA	14 B	AAAX	26	110678	M1	0	0	13	50	0.00001	99.97	
21VA	12 B	AAAX	120	102678	BS	66250	100000	0	0	0.04367		⅔ turn top nut; 1 turn bottom nut.
21VA	12 B	AAAX	120	110678	M1	13	50	8	30	0.00002	99.95	
21VA	13 B	AAAX	220	102678	BS	10500	24000	.	.	0.01582		⅔ turn top nut; ½ turn bottom nut.
21VA	13 B	AAAX	220	110678	M1	575	700	38	150	0.00028	98.25	
13VA	11 B	BCBX	100000	121278	BS	82500	100000	3275	5500	0.14761		
13VA	11 B	BCBX	100000	121478	M1	458	760	90	270	0.00507	96.57	1½ turn each, top and bottom nuts.
13VA	11 B	BCBX	100000	121778	ES	563	1000	869	2800	0.01752		
13VA	11 B	BCBX	100000	121878	ES	408	900	1030	3600	0.02186		
13VA	11 B	BCBX	100000	121978	ES	778	1000	280	900	0.00708		
13VA	6 B	BCBX	100000	121278	BS	79750	100000	10750	21000	0.65717		
13VA	6 B	BCBX	100000	121478	M1	420	500	4425	10000	0.02311	96.48	1½ turn each, top and bottom nuts.
13VA	6 B	BCBX	100000	121578	ES	1325	2400	4238	8800	0.04801		
13VA	6 B	BCBX	100000	121878	ES	2498	3700	3800	8400	0.04609		
13VA	6 B	BCBX	100000	121978	ES	1550	2300	1925	2700	0.01697		
13VA	3 B	AABX	100000	112278	BS	65000	100000	600	2000	0.58010		
13VA	3 B	AABX	100000	120178	M1	3950	10000	8400	14000	0.04810	91.71	1½ turn each, top and bottom nuts.
13VA	3 B	AABX	100000	120478	ES	1446	5000	2125	2900	0.02919		
13VA	38 B	BCBX	1600	110678	BS	1059	2600	1225	1400	0.00180		½ turn each nut (not much packing left).
13VA	38 B	BCBX	1600	110878	M1	133	200	50	120	0.00015	91.67	
13VA	49 B	BCBX	400	110678	BS	27750	100000	0	0	0.03265		⅔ turn each nut (packing very tight).
13VA	49 B	BCBX	400	110878	M1	705	1500	326	1100	0.00313	90.43	
13VA	1 B	AABX	10000	112278	BS	28250	100000	0	0	0.08712		
13VA	1 B	AABX	10000	120178	M1	1800	4000	3600	10000	0.00937	89.25	1 turn on both nuts.

Continued

TABLE B6-1. Continued

ID	BLK	PRSI	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
13VA	1 B	AABX	10000	120478	ES	825	2400	1688	3000	0.01862		
13VA	13 B	BLEX	100000	112278	BS	14000	30000	34250	70000	0.19625		
13VA	13 B	BLEX	100000	120178	M1	3325	8000	3265	7300	0.02875	85.35	1 turn on both nuts.
13VA	13 B	BLEX	100000	120478	ES	2360	3500	8200	13000	0.06769		
15VA	2 B	AAEX	100000	121278	BS	29750	100000	9125	12000	0.10709		
15VA	2 B	AAEX	100000	121478	M1	3350	7000	7500	17000	0.01679	84.32	1½ turn west nut; 1½ turn east nut.
15VA	2 B	AAEX	100000	121778	ES	1605	5000	4988	12000	0.06309		
15VA	2 B	AAEX	100000	121878	ES	1240	2500	1715	6000	0.03427		
15VA	2 B	AAEX	100000	121978	ES	1413	4200	5388	10000	0.05373		
21VA	15 B	AAAX	49000	121278	BS	.	.	.	.	0.00262		
21VA	15 B	AAAX	49000	121378	ES	10888	24000	43	90	0.11614		
21VA	15 B	AAAX	49000	121478	M1	21	25	41	90	0.00045	82.01	1 turn each, west and east nuts.
21VA	15 B	AAAX	49000	121778	ES	20	20	20	20	0.00023		
21VA	15 B	AAAX	49000	121878	ES	20	20	20	20	0.00023		
21VA	15 B	AAAX	49000	121978	ES	20	20	20	20	0.00023		
13VA	14 B	AABX	8000	121278	BS	5400	6400	3325	3800	0.01089		
13VA	14 B	AABX	8000	121478	M1	495	810	668	850	0.00191	82.46	2 turns each, top and bottom nuts.
13VA	14 B	AABX	8000	121778	ES	293	550	450	590	0.00445		
13VA	14 B	AABX	8000	121878	ES	553	1000	603	970	0.00708		
13VA	14 B	AABX	8000	121978	ES	578	980	623	840	0.00695		
3VA	83 B	BLEX	4500	102678	BS	2400	3600	3025	4500	0.16731		
3VA	83 B	BLEX	4500	102778	M1	.	.	.	.	0.03652	78.17	⅔ turn top nut; ⅓ turn bottom nut (could not tighten further).
3VA	83 B	BLEX	4500	103078	BO	38	100	380	600	0.01644		
3VA	83 B	BLEX	4500	110378	BO	420	700	1900	2400	0.01838		
15VA	4 B	BLEX	800	121278	BS	.	.	.	.	0.00192		
15VA	4 B	BLEX	800	121378	ES	498	790	20	20	0.00575		

Continued

TABLE B6-1. Continued

ID	BLK	PRS1	ILV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	* REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
15VA	4 B	BLEX	800	121478	M1	20	20	20	20	0.00047	75.65	¾ turn top nut; ¾ turn bottom nut.
15VA	4 B	BLEX	800	121778	LS	20	20	40	100	0.00093		
15VA	4 B	BLEX	800	121878	LS	27	28	34	55	0.00055		
15VA	4 B	BLEX	800	121978	LS	21	22	44	100	0.00093		
13VA	46 B	BLEX	10000	110678	BS	5300	9800	4825	8800	0.04488		
13VA	46 B	BLEX	10000	110878	M1	398	1000	508	1100	0.01744	61.14	1 turn each nut.
1VA	75 B	AABX	100000	101778	BS	.	.	.	.	0.03813		
1VA	75 B	AABX	100000	102778	M1	40250	100000	35000	70000	0.01916	49.75	1 turn top nut; ⅔ turn bottom nut.
1VA	75 B	AABX	100000	103078	BQ	6750	9800	2725	5200	0.01621		
1VA	75 B	AABX	100000	110378	BQ	67500	100000	35500	72000	0.02582		
13VA	15 B	BLEX	60000	112278	BS	2225	3300	4800	6200	0.02946		
13VA	15 B	BLEX	60000	120178	M1	428	560	1265	2400	0.01571	46.66	1½ turns on both nuts.
13VA	15 B	BLEX	60000	120478	LS	184	440	2908	5200	0.03021		
1VA	33 B	BLBX	9000	12078	BS	2550	3300	8200	10000	0.12563		
1VA	33 B	BLBX	9000	12378	BQ	1370	2200	10850	20000	0.08794		
1VA	33 B	BLBX	9000	20778	M1	1370	2200	10850	20000	0.07665	38.99	Tightened packing.
13VA	14 B	BDBX	4000	112278	BS	2600	8000	0	0	0.00233		
13VA	14 B	BDBX	4000	120178	M1	430	460	893	2300	0.00153	34.11	2 turns on both nuts.
13VA	14 B	BDBX	4000	120478	LS	183	380	315	1100	0.00770		
1VA	90 B	AACX	4000	102678	BS	3990	6000	6100	10000	0.19948		
1VA	90 B	AACX	4000	102778	M1	.	.	.	.	0.13540	32.12	⅓ turn each nut (no thread on packing nuts).
1VA	90 B	AACX	4000	103078	BQ	1113	2000	3525	7300	0.11420		
1VA	90 B	AACX	4000	110378	BQ	5625	10000	4000	4500	0.10514		
15VA	7 B	BLEX	1400	102678	BS	3550	4600	600	900	0.10191		1⅓ turn south nut; ⅔ turn north nut.
15VA	7 B	BLEX	1400	110478	M1	8	30	1750	2000	0.07138	29.96	

Continued

TABLE B6-1. Continued

ID	BLK	PRSI	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
4VA 64	B	BLFX	24	110678	BS	44	58	20	20	0.02640		⅓ turn each nut (not much packing left).
4VA 64	B	BLFX	24	110878	M1	22	24	41	54	0.01976	25.15	
1VA 26	B	AAAX	10001	12078	BS	46500	90000	8775	13800	0.17606		
1VA 26	B	AAAX	10001	12378	BU	51000	100000	44000	98000	0.18110		
1VA 26	B	AAAX	10001	20778	M1	100000	100000	4250	7000	0.13276	24.59	Tightened packing.
13VA 13	B	AABX	4600	121278	BS	1963	4800	20	20	0.00152		
13VA 13	B	AABX	4600	121478	M1	1395	2900	20	20	0.00118	22.46	1 turn each, top and bottom nuts.
13VA 13	B	AABX	4600	121778	ES	3250	5500	25	30	0.03174		
13VA 13	B	AABX	4600	121878	ES	1425	2300	29	34	0.01473		
13VA 13	B	AABX	4600	121978	ES	475	730	22	24	0.00536		
13VA 10	B	BLBX	14000	112278	BS	26500	96000	28325	100000	0.06147		
13VA 10	B	BLBX	14000	120178	M1	1100	2400	3575	5100	0.05083	17.32	1½ turn on right nut; 1 turn on left nut.
13VA 10	B	BLBX	14000	120478	ES	570	1400	7625	14000	0.07226		
13VA 10	B	BLFX	1600	121278	BS	143	380	24	30	0.00049		
13VA 10	B	BLFX	1600	121478	M1	20	20	20	20	0.00054	-10.4	½ turn each, north and south nuts.
13VA 10	B	BLFX	1600	121778	ES	40	54	23	26	0.00054		
13VA 10	B	BLFX	1600	121878	ES	43	98	21	23	0.00092		
13VA 10	B	BLFX	1600	121978	ES	24	34	20	20	0.00036		
22VA 25	B	AAAX	2000	113078	BS	.	.	.	.	0.00338		
22VA 25	B	AAAX	2000	120178	ES	240	400	325	500	0.00384		1½ turns on top nut; 1½ turns on bottom nut.
22VA 25	B	AAAX	2000	120278	M1	80	220	146	300	0.00436	-29	
13VA 9	B	BLBX	2000	112278	BS	1600	3000	388	1500	0.00828		
13VA 9	B	BLBX	2000	120178	M1	395	680	940	2000	0.01742	-110	1 turn on both nuts.
13VA 9	B	BLBX	2000	120478	ES	91	220	2958	6800	0.03826		
15VA 12	B	BLGX	1000	112178	BS	715	1200	100	120	0.01824		

Continued

TABLE B6-1. Continued

ID	BLK	PRSI	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
15VA	12 B	BCGX	1000	120278	MI	418	600	238	300	0.04623	-153	2 turns on both nuts, could not turn more (packing needs replacing).
3VA	85 B	BCBX	10000	102678	BS	56750	100000	20500	24000	0.02929		
3VA	85 B	BCBX	10000	102778	MI	25750	66000	87500	100000	0.13976	-377	⅓ turn top; 1 turn bottom.
3VA	85 B	BCBX	10000	103078		13750	32000	84500	100000			
3VA	85 B	BCBX	10000	110378	BO	30000	60000	81000	100000	0.12711		
22VA	3 B	BCGX	20	110678	BC	20	20	20	20	0.00020		
15VA	10 B	BDBX	650	110678	BC	163	500	330	650	0.00293		
15VA	11 B	BDBX	5600	102678	ES	1038	1100	1025	2200	0.01417		
15VA	11 B	BDBX	5600	110678	BC	323	450	2475	4000	0.01762		
13VA	33 B	BCBX	40000	110678	BC	15925	50000	2775	5400	0.04508		
13VA	35 B	BCHX	12000	110078	BC	9938	28000	373	800	0.02369		
15VA	2 B	AALX	100000	112178	BC	35000	100000	68	100	0.03053		
13VA	4 B	AAAX	100000	112278	BS	34000	80000	125	400	0.01314		
13VA	4 B	AAAX	100000	120478	ES	715	1700	64	120	0.01129		
15VA	2 B	BCEX	4600	112178	BC	863	1500	1175	1500	0.01973		
15VA	6 B	BCEX	4600	112278	ES	1000	1800	1325	1500	0.01187		
13VA	11 B	BCEX	6000	112278	BC	4350	8000	450	1400	0.04045		
13VA	11 B	BCEX	6000	120478	ES	3375	7200	295	580	0.04054		
13VA	16 B	BCHX	70000	112278	BC	38875	100000	43000	80000	0.04373		
13VA	16 B	BCBX	70000	120478	ES	9025	18000	31050	74000	0.31298		

Continued

TABLE B6-1. Continued

ID	BLK	PRSI	ILV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
13VA	20 B	AACX	6200	113078	BC	.	.	.	.	0.01163		
13VA	20 B	AACX	6200	120178	LS	1375	2600	1900	2800	0.01752		
22VA	26 B	AAAX	300	120278	BC	92	60	37	54	0.01065		
15VA	1 B	AAEX	43000	121278	BC	5875	9000	4925	12000	0.02802		
15VA	1 B	AAEX	43000	121478	LS	1525	2700	5250	9200	0.04993		
15VA	1 B	AAEX	43000	121778	LS	1138	2200	17600	50000	0.22162		
15VA	1 B	AAEX	43000	121878	LS	3625	6000	14728	50000	0.22162		
15VA	1 B	AAEX	43000	121978	LS	1975	3000	29563	100000	0.40798		
13VA	7 B	AABX	84000	121278	BC	10750	35000	3350	6300	0.03594		
13VA	7 B	AABX	84000	121478	ES	13200	45000	16263	60000	0.26021		
13VA	7 B	AABX	84000	121778	LS	2763	5400	1788	4300	0.03123		
13VA	7 B	AABX	84000	121878	LS	3350	8000	2425	5700	0.04415		
13VA	7 B	AABX	84000	121978	LS	9347	22000	2375	6600	0.10757		
13VA	12 B	BCCX	100	121278	BC	.	.	.	.	0.00052		
1VA	24 B	AABX	1000	121378	BC	630	1200	59	95	0.00376		
1VA	24 B	AABX	1000	121478	LS	828	2600	54	84	0.01641		
1VA	24 B	AABX	1000	121778	LS	91	230	20	20	0.00194		
1VA	24 B	AABX	1000	121878	LS	2675	7800	128	150	0.04318		
1VA	24 B	AABX	1000	121978	LS	3075	9000	00	120	0.04897		
13VA	22 C	AACX	100000	113078	BS	.	.	.	.	0.27031		
13VA	22 C	AACX	100000	120178	LS	80000	100000	1350	4000	0.40798		3 turns on south nut; 5 turns on north nut.
13VA	22 C	AACX	100000	120278	MI	56	50	73	140	0.00094	99.65	
13VA	94 C	BCCX	10000	12478	BS	65500	86000	100000	100000	0.62352		
13VA	94 C	BCCX	10000	12678	BQ	97500	100000	100000	100000	0.76380		
13VA	94 C	BCCX	10000	12678	BQ	97500	100000	100000	100000	1.01558		

Continued

TABLE B6-1. Continued

ID	BLK	PRSI	TEV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
13VA 94	C	BCCX	10000	20778	M1	3500	4800	11	14	0.00450	99.28	Tightened packing.
1VA 77	C	BCBX	9000	102678	BS	85000	100000	14250	30000	0.22534		
1VA 77	C	BCBX	9000	102778	BU	.	.	.	.	0.00581		
1VA 77	C	BCBX	9000	102778	M1	988	1400	613	1100	0.00173	99.23	¾ turn north nut; 1½ turn south nut.
1VA 77	C	BCBX	9000	103078	BU	1525	1800	300	400	0.00160		
1VA 77	C	BCBX	9000	110378	BU	8250	14000	350	500	0.00186		
13VA 24	C	BCBX	2000	113078	BS	.	.	.	.	0.09232		3 turns on west nut; 3 turns on east nut after it touched the packing.
13VA 24	C	BCBX	2000	120178	ES	30250	50000	1650	4000	0.22162		
13VA 24	C	BCBX	2000	120278	M1	20	20	20	20	0.00115	98.76	
13VA 5	C	AABX	100000	112278	BS	100000	100000	2033	4000	0.02266		
13VA 5	C	AABX	100000	120178	M1	378	480	1000	1800	0.00176	92.24	2 turns on both nuts.
13VA 5	C	AABX	100000	120478	ES	3000	3700	418	680	0.02239		
13VA 17	C	BCLX	8000	112278	BS	6700	8000	500	1200	0.02860		
13VA 17	C	BCLX	8000	120178	M1	413	430	340	340	0.00230	91.96	2 turns on both nuts.
13VA 17	C	BCLX	8000	120478	ES	87	110	68	150	0.00133		
13VA 19	C	BCLX	100000	112278	BS	100000	100000	100000	100000	0.58625		
13VA 19	C	BCLX	100000	120178	M1	5750	9400	10850	24000	0.05527	90.57	1½ turns on both nuts.
13VA 19	C	BCLX	100000	120478	ES	9525	26000	13050	36000	0.16596		
13VA 27	C	AAAX	400	110678	BS	20575	80000	128	160	0.00575		
13VA 27	C	AAAX	400	110878	M1	43	50	31	35	0.00078	86.45	½ turn each nut.
4VA 70	C	AAAX	.	102678	BS	54900	100000	74000	100000	0.00541		
4VA 70	C	AAAX	.	102778	M1	3950	5000	638	1200	0.00074	86.27	1 turn both nuts.
4VA 70	C	AAAX	.	103078	BU	11000	14000	3000	4000	0.00238		
19VA 16	C	BDAX	8000	121278	BS	.	.	.	.	0.01614		

Continued

TABLE B6-1. Continued

ID	BLK	PRS1	ILV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
19VA 16	C	BDAX	8000	121378	ES	973	1600	425	870	0.01070		
19VA 16	C	BDAX	8000	121478	M1	510	900	123	210	0.00290	82.06	1⅛ turns each, west and east nuts.
19VA 16	C	BDAX	8000	121778	ES	2250	4000	20	20	0.02398		
19VA 16	C	BDAX	8000	121878	ES	3775	7000	55	100	0.03925		
19VA 16	C	BDAX	8000	121978	ES	6875	23000	410	500	0.11187		
1VA 73	C	AABX	450	102678	BS	4775	6400	1375	2000	0.00628		
1VA 73	C	AABX	450	102778	M1	235	400	1090	1900	0.00126	79.93	1 turn both nuts.
1VA 73	C	AABX	450	103078	BQ	100	150	630	1000	0.00109		
1VA 73	C	AABX	450	110378	BQ	433	520	1575	2000	0.00099		
1VA 71	C	BCBX	16000	102678	BS	94000	100000	19500	30000	0.05137		
1VA 71	C	BCBX	16000	102778	M1	8200	22000	47750	86000	0.02022	60.64	1 turn both nuts.
1VA 71	C	BCBX	16000	103078	BQ	.	.	.	.	0.02626		
1VA 71	C	BCBX	16000	103078	BQ	.	.	.	.	0.02260		
1VA 71	C	BCBX	16000	110278	BQ	.	.	.	.	0.02297		
1VA 71	C	BCBX	16000	110378	BQ	.	.	.	.	0.02408		
1VA 71	C	BCBX	16000	110378	BQ	4325	7000	39500	68000	0.02633		
21VA 18	C	AAAX	13000	121378	BS	1225	1900	5725	9300	0.00385		
21VA 18	C	AAAX	13000	121478	M1	.	.	.	.	0.00175	54.52	1 turn each, west and east nuts.
21VA 18	C	AAAX	13000	121578	ES	25	27	26	27	0.00029		
21VA 18	C	AAAX	13000	121778	ES	21	23	20	20	0.00026		
21VA 18	C	AAAX	13000	121878	ES	21	25	21	24	0.00028		
21VA 18	C	AAAX	13000	121978	ES	33	66	23	30	0.00065		
13VA203	C	AABX	10000	11778	BS	52675	100000	31625	100000	0.16407		
13VA203	C	AABX	10000	12078	BQ	8100	12000	8600	16000	0.08950		
13VA203	C	AABX	10000	20778	M1	63750	100000	23000	30000	0.07579	53.81	Tightened packing.
1VA 19	C	AALX	100000	121378	BS	100000	100000	2130	5000	0.02758		1 turn each, west and east nuts.
1VA 19	C	AALX	100000	121478	M1	.	.	.	.	0.01407	48.99	

Continued

TABLE B6-1. Continued

						SCREENING INFORMATION						
ID	BLK	PRSI	ILV	DATE	SAMP	MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
1VA	19 C	AAEX	100000	121578	ES	19250	55000	38500	80000	0.33521		
1VA	19 C	AAEX	100000	121778	ES	16950	49000	17675	35000	0.21771		
1VA	19 C	AAEX	100000	121078	ES	36750	60000	72000	100000	0.40798		
1VA	19 C	AAEX	100000	121978	ES	1995	5000	20500	75000	0.31670		
13VA	8 C	AABX	100000	121278	BS	585	590	.	.	0.00037		
13VA	8 C	AABX	100000	121478	M1	.	.	.	.	0.00026	29.47	1½ turn each, west and east nuts.
13VA	8 C	AABX	100000	121578	ES	128	140	29	34	0.00125		
13VA	8 C	AABX	100000	121778	ES	763	950	28	34	0.00676		
13VA	8 C	AABX	100000	121878	ES	1300	1600	56	85	0.01070		
13VA	8 C	AABX	100000	121978	ES	558	640	81	120	0.00478		
13VA	24 C	BCBX	37	110678	BS	885	1400	20	20	0.00090		
13VA	24 C	BCBX	37	110878	M1	42	50	28	28	0.00065	27.94	¾ turn each nut.
15VA	9 C	BCEX	350	102678	ES	225	400	218	850	0.00613		
15VA	9 C	BCEX	350	110678	BS	138	350	180	500	0.00548		
15VA	9 C	BCEX	350	110878	M1	111	160	217	360	0.00403	26.56	½ turn each nut.
13VA	56 C	BCLX	38	110678	BS	218	250	0	0	0.00063		
13VA	56 C	BCLX	38	110878	M1	20	20	22	24	0.00049	21.55	1½ turn each nut.
1VA	21 C	AAEX	100000	121378	BS	56500	100000	2255	4200	0.01267		
1VA	21 C	AAEX	100000	121478	M1	.	.	.	.	0.01151	9.17	¼ turn each, west and east nuts; ½ turn west nut.
1VA	21 C	AAEX	100000	121578	ES	41000	100000	1235	2500	0.40798		
1VA	21 C	AAEX	100000	121778	ES	47000	100000	1525	2500	0.40798		
1VA	21 C	AAEX	100000	121878	ES	54000	100000	2113	4500	0.40798		
1VA	21 C	AAEX	100000	121978	ES	19000	35000	875	1000	0.16190		
1VA	20 C	AAEX	100000	121378	BS	63250	100000	35250	74000	0.02335		
1VA	20 C	AAEX	100000	121478	M1	.	.	.	.	0.02435	-4.20	1 turn each, west and east nuts.
1VA	20 C	AAEX	100000	121578	ES	30875	90000	28000	50000	0.37184		

Continued

TABLE B6-1. Continued

ID	BLK	PRSI	ILV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
1VA	20 C	AAEX	100000	121778	ES	7800	17000	43250	100000	0.40798		
1VA	20 C	AAEX	100000	121878	ES	53250	100000	66250	100000	0.40798		
1VA	20 C	AAEX	100000	121978	ES	21500	52000	55500	100000	0.40798		
1VA	22 C	AAEX	100000	121378	BS	30700	78000	16100	38000	0.01189		
1VA	22 C	AAEX	100000	121478	M1	.	.	.	.	0.01325	-11.5	¾ turn east nut; 1 turn west nut.
1VA	22 C	AAEX	100000	121578	ES	5000	6000	17250	45000	0.20199		
1VA	22 C	AAEX	100000	121778	ES	3025	4000	29125	85000	0.35359		
1VA	22 C	AAEX	100000	121878	ES	10750	23000	44850	100000	0.40798		
1VA	22 C	AAEX	100000	121978	ES	5875	10000	13000	27000	0.12883		
4VA	69 C	ABAB	95000	102678	BS	30750	66000	25000	26000	0.00269		
4VA	69 C	ABAB	95000	102778	M1	2075	5000	700	1000	0.00346	-28.5	¼ turn east nut; 1 turn west nut.
4VA	69 C	ABAB	95000	103078	BQ	11500	23000	1600	2000	0.00221		
4VA	69 C	ABAB	95000	110278	BQ	.	.	.	.	0.00112		
4VA	69 C	ABAB	95000	110378	BQ	1200	2200	2100	2200	0.00122		
33VA	23 C	AAFX	400	121378	BS	0	0	18	35	0.00154		
33VA	23 C	AAFX	400	121478	M1	.	.	.	.	0.00244	-58.4	¾ turn east nuts.
33VA	23 C	AAFX	400	121578	ES	20	20	20	20	0.00023		
33VA	23 C	AAFX	400	121778	ES	170	170	.	.	0.00149		
33VA	23 C	AAFX	400	121878	ES	20	20	20	20	0.00023		
33VA	23 C	AAFX	400	121978	ES	20	20	20	20	0.00023		
13VA	9 C	BCEX	1600	121278	BS	185	220	56	120	0.00106		
13VA	9 C	BCEX	1600	121478	M1	.	.	.	.	0.00265	-149	1 turn each, west and east nuts.
13VA	9 C	BCEX	1600	121578	ES	554	910	44	58	0.00651		
13VA	9 C	BCEX	1600	121778	ES	528	680	68	98	0.00504		
13VA	9 C	BCEX	1600	121878	ES	423	620	26	35	0.00465		
13VA	9 C	BCEX	1600	121978	ES	643	940	33	54	0.00670		
13VA	21 C	AAHX	400	113078	BS	.	.	.	.	0.00031		

Continued

TABLE B6-1. Continued

ID	BLK	PRSI	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
13VA	21 C	AABX	400	120178	ES	0	0	0	0	.		
13VA	21 C	AABX	400	120278	M1	23	28	26	32	0.00078	-152	3 turns on both nuts.
22VA	1 C	AAAX	24	110678	BS	20	20	20	20	0.00013		
22VA	1 C	AAAX	24	110878	M1	20	20	20	20	0.00085	-550	1 turn on each nut.
13VA	7 C	AABX	600	112278	BS	425	600	.	.	0.00189		
13VA	7 C	AABX	600	120178	M1	3325	5600	.	.	0.16734	-8745	3 turns on both nuts.
13VA	7 C	AABX	600	120478	ES	60000	100000	86000	100000	0.40798		
13VA	43 C	BCCX	6200	110678	BC	3600	4700	18	50	0.00510		
4VA	67 C	ABAB	62000	110678	BC	825	1000	36	40	0.00032		
15VA	6 C	AAEX	100000	112178	BS	.	.	.	.	1.04328		
15VA	6 C	AAEX	100000	112278	ES	100000	100000	12500	25000	0.40798		
13VA	18 C	BCLX	10000	112278	BC	2350	4400	18	50	0.02012		
13VA	18 C	BCLX	10000	120478	ES	4900	6500	405	610	0.03677		
13VA	23 C	BCEX	2000	120278	BC	7650	10000	700	1000	0.01779		
15VA	3 C	BCFX	510	121278	BC	.	.	.	.	0.00220		
15VA	3 C	BCFX	510	121378	ES	225	540	168	220	0.00274		
15VA	3 C	BCFX	510	121578	ES	205	240	155	160	0.00201		
15VA	3 C	BCFX	510	121778	ES	165	300	20	20	0.00245		
15VA	3 C	BCFX	510	121878	ES	178	230	88	90	0.00194		
15VA	3 C	BCFX	510	121978	ES	120	150	71	80	0.00133		
15VA	5 C	BCEX	380	121378	BC	423	490	174	290	0.00698		
15VA	5 C	BCEX	380	121478	ES	158	220	27	35	0.00107		
15VA	5 C	BCEX	380	121778	ES	380	540	173	210	0.00411		

Continued

TABLE B6-1. Continued

ID	BLK	PRST	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Undirected Maintenance (Continued)												
15VA	5 L	BLEX	380	121878	ES	60	130	32	47	0.00117		
15VA	5 L	BLEX	380	121978	ES	163	180	40	50	0.00156		
21VA	17 L	AAAX	2000	121378	UC	20	25	658	810	0.00167		
21VA	17 L	AAAX	2000	121478	ES	41	50	2125	3000	0.01862		
21VA	17 L	AAAX	2000	121778	ES	20	20	23	30	0.00032		
21VA	17 C	AAAX	2000	121878	ES	20	20	28	40	0.00042		
21VA	17 L	AAAX	2000	121978	ES	20	20	20	20	0.00023		

TABLE B6-1. Continued

ID	BLK	PRSI	ILV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Directed Maintenance												
13VA 2	B	BLBX	480	11179	BS	63	80	22	26	0.00108		
13VA 2	B	BLBX	480	11779	M1	28	50	13	40	0.00000	100	1 turn north nut; 1 turn south nut.
13VA 2	B	BLBX	480	11979	ES	65	200	20	20	0.00172		
13VA 2	B	BLBX	480	12279	ES	24	25	23	25	0.00028		
13VA 2	B	BLBX	480	12379	ES	20	20	27	48	0.00049		
13VA 7	B	BLBX	8000	11179	BS	4975	6600	35	42	0.01107		
13VA 7	B	BLBX	8000	11879	M1	.	.	.	.	0.00015	98.62	5¼ turns east nut; 5¼ turns west nut.
13VA 7	B	BLBX	8000	11979	ES	20	20	20	20	0.00023		
13VA 7	B	BLBX	8000	12279	ES	20	20	20	20	0.00023		
13VA 7	B	BLBX	8000	12379	ES	20	20	20	20	0.00023		
13VA 7	B	BLBX	8000	12479	ES	23	30	20	20	0.00032		
27VA 49	B	AABX	100000	11179	BS	87000	100000	1025	1200	0.08912		
27VA 49	B	AABX	100000	11779	M1	1688	2400	430	900	0.00168	98.12	½ turn top nut; ½ turn bottom nut.
27VA 49	B	AABX	100000	11979	ES	6525	9000	3100	5500	0.04897		
27VA 49	B	AABX	100000	12279	ES	750	1200	398	600	0.00831		
27VA 49	B	AABX	100000	12379	ES	1250	1600	463	600	0.01070		
13VA 27	B	AAAX	100000	11179	BS	82500	100000	265	400	0.13960		
13VA 27	B	AAAX	100000	11778	M1	.	.	.	.	0.00282	97.98	1 turn north nut; 1 turn south nut.
13VA 27	B	AAAX	100000	11779	ES	713	1400	663	900	0.00952		
13VA 27	B	AAAX	100000	11979	ES	411	700	838	1500	0.01011		
13VA 27	B	AAAX	100000	12279	ES	563	850	2250	3400	0.02078		
13VA 27	B	AAAX	100000	12379	ES	725	1200	1175	2200	0.01417		
13VA 3	B	BLCX	3200	11179	BS	90	120	863	1100	0.00750		
13VA 3	B	BLCX	3200	11879	M1	.	.	.	.	0.00019	97.45	3 turns top nut; 3½ turns bottom nut.
13VA 3	B	BLCX	3200	11979	ES	21	22	102	230	0.00194		
13VA 3	B	BLCX	3200	12279	ES	31	35	87	250	0.00209		
13VA 3	B	BLCX	3200	12379	ES	26	42	125	300	0.00245		
13VA 3	B	BLCX	3200	12479	ES	29	30	143	280	0.00231		

Continued

TABLE B6-1. Continued

ID	BLK	PRS1	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Directed Maintenance (Continued)												
13VA	9 B	BLCX	44000	11179	BS	17850	50000	2650	3500	0.03823		
13VA	9 B	BLCX	44000	12279	LS	19400	58000	4550	6800	0.25256		
13VA	9 B	BLCX	44000	12979	M1	1160	1620	373	530	0.00169	95.59	2 turns top nut; 2 turns bottom nut.
13VA	9 B	BLCX	44000	13079	LS	738	1600	520	770	0.01070		
13VA	9 B	BLCX	44000	13179	ES	1750	2300	900	1200	0.01473		
13VA	6 B	BCBX	4000	11179	BS	2400	3100	543	800	0.01260		
13VA	6 B	BCBX	4000	11079	M1	.	.	.	.	0.00087	93.07	5½ turns north nut; 5½ turns south nut.
13VA	6 B	BCBX	4000	11979	ES	169	540	550	1200	0.00831		
13VA	6 B	BCBX	4000	12279	ES	21	24	202	420	0.00330		
13VA	6 B	BCBX	4000	12379	ES	140	350	233	580	0.00438		
13VA	6 B	BCBX	4000	12479	ES	80	170	438	700	0.00517		
13VA	12 B		18000	11178	BS	.	.	.	.	0.01150		
13VA	12 B	AAAX	18000	11179	ES	2525	4000	.	.	0.02398		
13VA	12 B	AAAX	18000	11779	M1	20	20	20	20	0.00083	92.80	5 turns each nut.
13VA	12 B	AAAX	18000	11979	ES	2000	2000	2250	4000	0.02398		
13VA	12 B	AAAX	18000	12279	ES	37	50	49	55	0.00055		
13VA	12 B	AAAX	18000	12379	ES	25	30	155	400	0.00316		
27VA	54 B	BCBX	100000	11279	BS	905	2000	.	.	0.03069		
27VA	54 B	BCBX	100000	11679	M1	55000	100000	0	0	0.00254	91.72	38 pumps of grease.
27VA	54 B	BCBX	100000	11979	ES	265	600	.	.	0.00451		
27VA	54 B	BCBX	100000	12279	ES	33	60	.	.	0.00059		
27VA	54 B	BCBX	100000	12379	ES	23	25	.	.	0.00028		
13VA	10 B	BLCX	2300	11179	BS	525	900	271	720	0.00321		
13VA	10 B	BLCX	2300	11779	M1	33	70	15	20	0.00041	87.29	2½ turns north nut; 2½ turns south nut.
13VA	10 B	BLCX	2300	11979	ES	163	200	100	260	0.00216		
13VA	10 B	BLCX	2300	12279	ES	50	60	25	36	0.00059		
13VA	10 B	BLCX	2300	12379	ES	35	50	34	52	0.00052		

Continued

TABLE B6-1. Continued

ID	PLK	PRS1	TLV	DATE	SAMP	SCREENING INFORMATION				NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
						MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND			
Directed Maintenance (Continued)												
27VA	50 B	AAAX	100000	11279	BS	29750	100000	.	.	0.00446		
27VA	50 B	AAAX	100000	11679	M1	1850	2200	.	.	0.00066	85.16	95 pumps of grease.
27VA	50 B	AAAX	100000	11979	ES	54	100	.	.	0.00093		
27VA	50 B	AAAX	100000	12279	ES	28750	70000	.	.	0.29803		
27VA	50 B	AAAX	100000	12379	ES	22785	80000	.	.	0.33521		
27VA	46 B	BLBX	26000	11179	BS	15550	42000	40625	76000	0.07998		
27VA	46 B	BLBX	26000	11779	M1	15450	45000	6250	15000	0.01236	84.55	52 pumps of grease; 3 turns per nut.
27VA	46 B	BLBX	26000	11979	ES	4500	7000	5375	12000	0.06309		
27VA	46 B	BLBX	26000	12279	ES	1275	3500	843	1500	0.02132		
27VA	46 B	BLBX	26000	12379	ES	4500	6600	2725	8200	0.04512		
27VA	21 B	BLBX	24000	11179	BS	20	20	20	20	0.00066		
27VA	21 B	BLBX	24000	11779	M1	20	20	20	20	0.00013	80.40	¾ turns each nut.
27VA	21 B	BLBX	24000	11979	ES	20	20	20	20	0.00023		
27VA	21 B	BLBX	24000	12279	ES	20	20	20	20	0.00023		
27VA	21 B	BLBX	24000	12379	ES	285	500	13750	18000	0.09015		
13VA	13 B	AAAX	3600	11179	BS	825	1400	20	20	0.00136		
13VA	13 B	AAAX	3600	11779	M1	25	36	.	.	0.00039	71.70	40 pumps of grease; 1 turn each nut.
13VA	13 B	AAAX	3600	11979	ES	54	72	47	50	0.00070		
13VA	13 B	AAAX	3600	12279	ES	26	30	32	33	0.00035		
13VA	13 B	AAAX	3600	12379	ES	31	32	26	26	0.00034		
13VA	14 B	AAAX	7000	11179	BS	10300	29000	24500	34000	0.00078		
13VA	14 B	AAAX	7000	11779	M1	57	60	30	30	0.00032	59.38	35 pumps of grease.
13VA	14 B	AAAX	7000	11979	ES	73	150	.	.	0.00133		
13VA	14 B	AAAX	7000	12279	ES	101	200	.	.	0.00172		
13VA	14 B	AAAX	7000	12379	ES	20	20	.	.	0.00023		
13VA	26 B	AAAX	2500	11179	BS	845	1600	583	1000	0.00197		3 turns north nut; 3 turns south nut.
13VA	26 B	AAAX	2500	11779	M1	925	1100	790	2500	0.00186	45.97	

Continued

TABLE B6-1. Continued

ID	BLK		PRS1	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-MLTH LK RATE	% REDUC	MAINTENANCE PERFORMED
Directed Maintenance (Continued)													
13VA	28	B	AAAX	2500	11979	ES	1000	1600	1238	3200	0.01970		
13VA	28	B	AAAX	2500	12279	ES	425	1600	920	1500	0.01070		
13VA	28	B	AAAX	2500	12379	ES	450	800	1750	2200	0.01417		
27VA	53	B	CAAX	3500	11279	BS	399	650	.	.	0.00055		
27VA	53	B	CAAX	3500	11679	M1	288	600	1450	2000	0.00090	-62.5	48 pumps of grease.
27VA	53	B	CAAX	3500	11979	ES	24000	40000	.	.	0.18209		
27VA	53	B	CAAX	3500	12279	ES	1238	4400	.	.	0.02608		
27VA	53	B	CAAX	3500	12379	ES	214	600	.	.	0.00451		
27VA	51	B	CAAX	100000	11279	BS	51250	80000	1700	2800	0.00533		
27VA	51	B	CAAX	100000	11779	M1	4300	4500	3800	5600	0.01304	-145	⅓ turn north nut; ½ turn south nut.
27VA	51	B	CAAX	100000	11979	ES	7000	8000	5600	8800	0.04801		
27VA	51	B	CAAX	100000	12279	ES	3000	5000	2600	4000	0.02919		
27VA	51	B	CAAX	100000	12379	ES	1050	3200	1905	3100	0.01970		
13VA	1	B	BCBX	1200	11579	ES	20	20	22	26	0.00028		
13VA	1	B	BCBX	1200	11679	BC	48	100	0	0	0.00056		
13VA	1	B	BCBX	1200	11779	ES	123	200	29	36	0.00172		
13VA	1	B	BCBX	1200	11979	ES	120	160	24	31	0.00141		
13VA	1	B	BCBX	1200	12279	ES	31	35	22	22	0.00037		
13VA	4	B	AABX	55000	11579	ES	5000	7000	2300	2900	0.03925		
13VA	4	B	AABX	55000	11679	BC	6225	9200	3100	3000	0.02019		
13VA	4	B	AABX	55000	11779	ES	4875	7900	3450	5500	0.04366		
13VA	4	B	AABX	55000	11979	ES	5150	7300	4325	5600	0.04073		
13VA	4	B	AABX	55000	12279	ES	38250	98000	3125	4800	0.40079		
13VA	11	B	BCCX	7300	11579	ES	420	700	4500	8000	0.04415		
13VA	11	B	BCCX	7300	11679	BC	3700	4600	4350	6600	0.04270		
13VA	11	B	BCCX	7300	11779	ES	1403	4200	12875	41000	0.18609		
13VA	11	B	BCCX	7300	11979	ES	1975	4500	4925	10000	0.05373		

Continued

TABLE B6-1. Continued

ID	BLK	PRSI	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Directed Maintenance (Continued)												
13VA 11	B	BLCX	7500	12279	ES	2775	4600	4725	8800	0.04801		
13VA 25	B	AABX	9000	11579	ES	4063	8000	*	*	0.04415		
13VA 25	B	AABX	9000	11679	BC	1900	2600	20000	20000	0.04126		
13VA 25	B	AABX	9000	11779	ES	4250	7000	2500	5000	0.03925		
13VA 25	B	AABX	9000	11979	ES	8875	11000	12100	30000	0.14135		
13VA 25	B	AABX	9000	12279	ES	3550	10000	6375	17000	0.08575		
13VA 26	B	AABX	35000	11579	ES	5400	10000	3700	5000	0.05373		
13VA 26	B	AABX	35000	11679	BC	5225	7800	2300	3200	0.01881		
13VA 26	B	AABX	35000	11779	ES	8125	15000	3075	5800	0.07678		
13VA 26	B	AABX	35000	11979	ES	36250	60000	3225	3400	0.26021		
13VA 26	B	AABX	35000	12279	ES	5375	7000	2775	4000	0.03925		
27VA 48	B	AABX	58000	11279	BC	83750	100000	1425	2000	0.02682		
27VA 48	B	AABX	58000	11579	ES	35000	50000	950	2000	0.22162		
27VA 48	B	AABX	58000	11779	ES	12750	20000	430	700	0.09892		
27VA 48	B	AABX	58000	11979	ES	3350	5000	1050	1200	0.02919		
27VA 48	B	AABX	58000	12279	ES	10625	15000	1050	1400	0.07678		
27VA 48	B	AABX	58000	12379	ES	17750	40000	1325	1500	0.18209		
27VA 52	B	CAAX	45000	11279	BC	80000	100000	1600	2000	0.01870		
27VA 52	B	CAAX	45000	11579	ES	100000	100000	2000	4000	0.40798		
27VA 52	B	CAAX	45000	11779	ES	56250	100000	1150	2000	0.40798		
27VA 52	B	CAAX	45000	11979	ES	100000	100000	2800	4000	0.40798		
27VA 52	B	CAAX	45000	12279	ES	36500	100000	1000	1000	0.40798		
27VA 44	C	BLBX	100000	11179	BS	11250	20000	25	100	0.00951		
27VA 44	C	BLBX	100000	11779	MI	278	380	508	1200	0.00000	100	1 turn east nut; 1 turn west nut.
27VA 44	C	BLBX	100000	11979	ES	228	240	275	460	0.00357		
27VA 44	C	BLBX	100000	12279	ES	335	600	456	900	0.00645		
27VA 44	C	BLBX	100000	12379	ES	2050	3400	85	200	0.02078		

Continued

TABLE B6-1. Continued

						SCREENING INFORMATION						
ID	BLK	PRSI	FLV	DATE	SAMP	MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Directed Maintenance (Continued)												
13VA	5 L	BCCX	4200	11179	BS	4875	8000	1350	1800	0.01813		
13VA	5 L	BCCX	4200	12279	ES	5325	6300	2325	4500	0.03577		
13VA	5 L	BCCX	4200	12979	M1	46	90	228	310	0.00040	97.81	2½ turns north nut; 2½ turns south nut.
13VA	5 L	BCCX	4200	13079	ES	23	30	345	640	0.00478		
13VA	5 L	BCCX	4200	13179	ES	18	40	323	540	0.00411		
27VA	45 L	BCBX	20000	11179	BS	34000	73000	20	20	0.00653		
27VA	45 L	BCBX	20000	11779	M1	370	500	.	.	0.00033	95.00	⅛ turn west nut.
27VA	45 L	BCBX	20000	11979	ES	200	240	.	.	0.00201		
27VA	45 L	BCBX	20000	12279	ES	593	1000	.	.	0.00708		
27VA	45 L	BCBX	20000	12379	ES	47500	100000	.	.	0.40798		
15VA	41 L	BCBX	.	11279	BS	.	.	.	.	0.01734		
15VA	41 L	BCBX	92000	11279	ES	52500	58000	21750	32000	0.25256		
15VA	41 L	BCBX	92000	11979	ES	47	49	30	32	0.00050		
15VA	41 L	BCBX	92000	12279	ES	85	92	35	40	0.00087		
15VA	41 L	BCBX	92000	12379	ES	5225	5800	500	600	0.03326		
15VA	41 L	BCBX	92000	12479	ES	1200	1400	305	370	0.00952		
15VA	41 L	BCBX	92000	12979	M1	.	.	.	.	0.00096	94.46	1¼ turns each nut.
15VA	18 L	BCBX	3000	11279	BS	2675	2800	738	1000	0.01262		
15VA	18 L	BCBX	3000	11979	M1	20	20	20	20	0.00111	91.22	8 turns north nut; 8 turns south nut.
15VA	18 L	BCBX	3000	12279	ES	23	30	20	20	0.00032		
15VA	18 L	BCBX	3000	12379	ES	20	20	318	1000	0.00708		
15VA	18 L	BCBX	3000	12479	ES	21	24	20	20	0.00027		
13VA	8 L	BCBX	1400	11179	BS	1775	2000	61	100	0.00249		
13VA	8 L	BCBX	1400	11779	M1	245	400	13	30	0.00029	88.40	3½ turns north nut; 3½ turns south nut.
13VA	8 L	BCBX	1400	11979	ES	265	350	150	200	0.00281		
13VA	8 L	BCBX	1400	12279	ES	168	350	20	20	0.00201		
13VA	8 L	BCBX	1400	12379	ES	434	1200	29	42	0.00831		

Continued

TABLE B6-1. Continued

ID	BLK	PRSI	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	* REDUC	MAINTENANCE PERFORMED
Directed Maintenance (Continued)												
13VA	16 C	AAAX	100000	11279	BS	9500	20000	3350	5500	0.00214		
13VA	16 C	AAAX	100000	11979	M1	2550	2600	1500	2400	0.00049	77.19	½ turn east nut; ½ turn west nut.
13VA	16 C	AAAX	100000	12279	ES	118	200	1390	3000	0.01862		
13VA	16 C	AAAX	100000	12379	ES	1300	1800	1600	3400	0.02078		
13VA	16 C	AAAX	100000	12479	ES	2550	3200	1300	2500	0.01970		
13VA	15 C	AAAX	8000	11279	BS	850	1200	.	.	0.00050		
13VA	15 C	AAAX	8000	11979	M1	445	550	.	.	0.00027	45.71	1½ turn on nut.
13VA	15 C	AAAX	8000	12279	ES	425	700	.	.	0.00517		
13VA	15 C	AAAX	8000	12379	ES	1400	2200	.	.	0.01417		
13VA	15 C	AAAX	8000	12479	ES	1063	1300	.	.	0.00892		
15VA	42 C	BCEX	1100	11279	BS	760	1000	30	42	0.00159		
15VA	42 C	BCEX	1100	12279	ES	1525	1700	315	480	0.01129		
15VA	42 C	BCEX	1100	12979	M1	1225	1400	223	420	0.00348	-119	2½ turns west nut; 2½ turns east nut.
15VA	42 C	BCEX	1100	13079	ES	1050	1100	625	1000	0.00770		
15VA	42 C	BCEX	1100	13179	ES	768	1000	67	75	0.00708		
13VA	17 C	AAAX	2200	11279	BC	663	800	.	.	0.00105		
13VA	17 C	AAAX	2200	11579	ES	1925	3700	.	.	0.02239		
13VA	17 C	AAAX	2200	11779	ES	2850	5200	.	.	0.03021		
13VA	17 C	AAAX	2200	11879	ES	1850	2000	.	.	0.01303		
13VA	17 C	AAAX	2200	11979	ES	1425	1700	.	.	0.01129		
27VA	43 C	BCOX	1800	11579	ES	663	800	43	52	0.00501		
27VA	43 C	BCDX	1800	11679	BC	225	300	0	0	0.00209		
27VA	43 C	BCOX	1800	11779	ES	763	850	45	80	0.00613		
27VA	43 C	BCOX	1800	11979	ES	400	500	768	2200	0.01417		
27VA	43 C	BCOX	1800	12279	ES	233	360	71	100	0.00248		
27VA	47 C	AABX	26000	11178	BC	.	.	.	.	0.00934		
27VA	47 C	AABX	6000	11179	ES	2050	3000	4900	8200	0.04512		

Continued

TABLE B6-1. Continued

ID	BLK	PRS1	TLV	DATE	SAMP	SCREENING INFORMATION MEAN STEM	MAX STEM	MEAN GLAND	MAX GLAND	NON-METH LK RATE	% REDUC	MAINTENANCE PERFORMED
Directed Maintenance (Continued)												
27VA 47	C	AABX	6000	11579	ES	358	950	885	1000	0.00708		
27VA 47	L	AABX	6000	11779	ES	3300	3800	3155	5800	0.03326		
27VA 47	L	AABX	6000	11979	ES	530	700	768	2200	0.01417		
27VA 47	L	AABX	6000	12279	ES	150	220	1925	3700	0.02239		

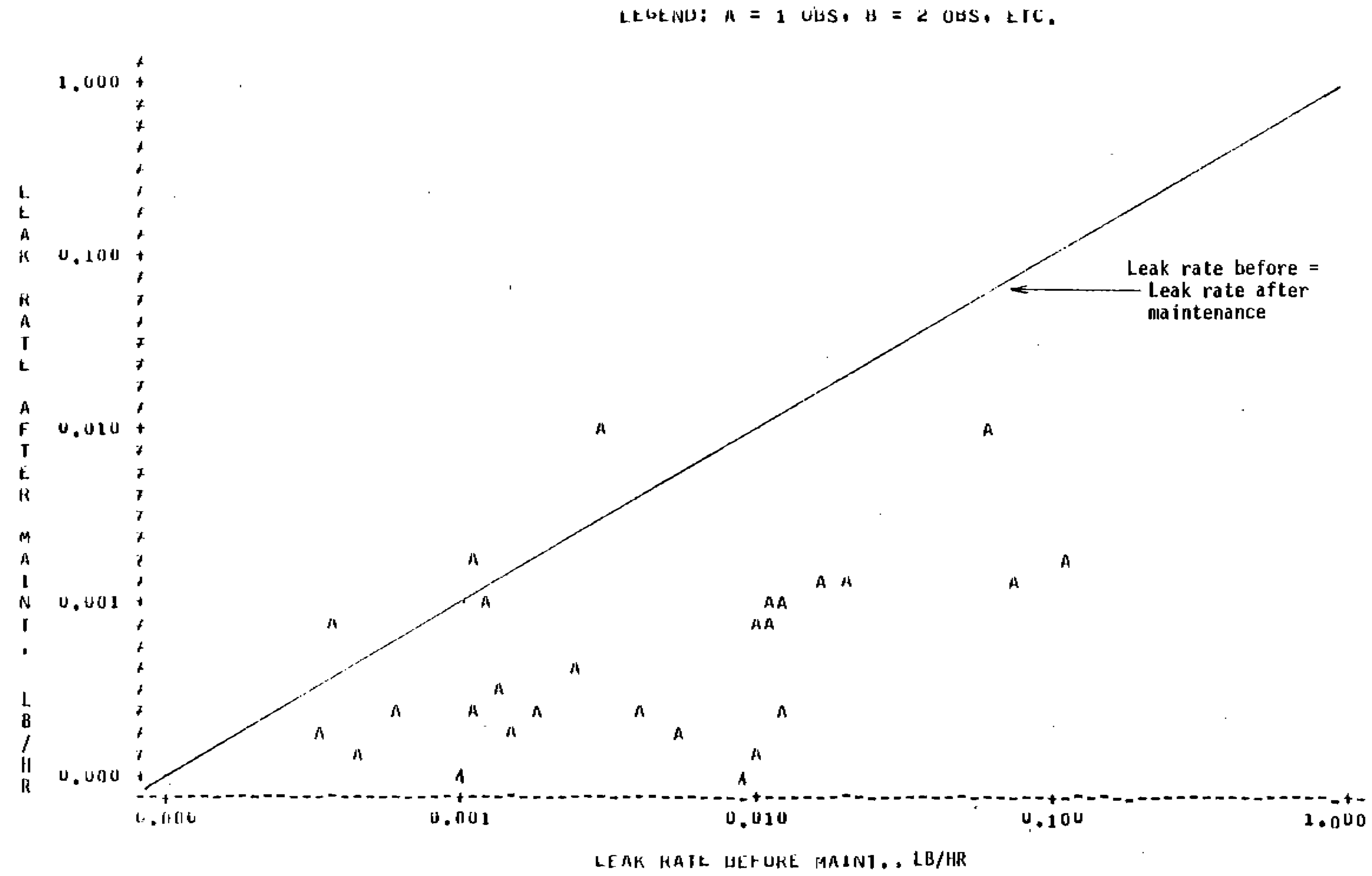


Figure B6-1. Directed maintenance - leak after maintenance versus leak before maintenance.

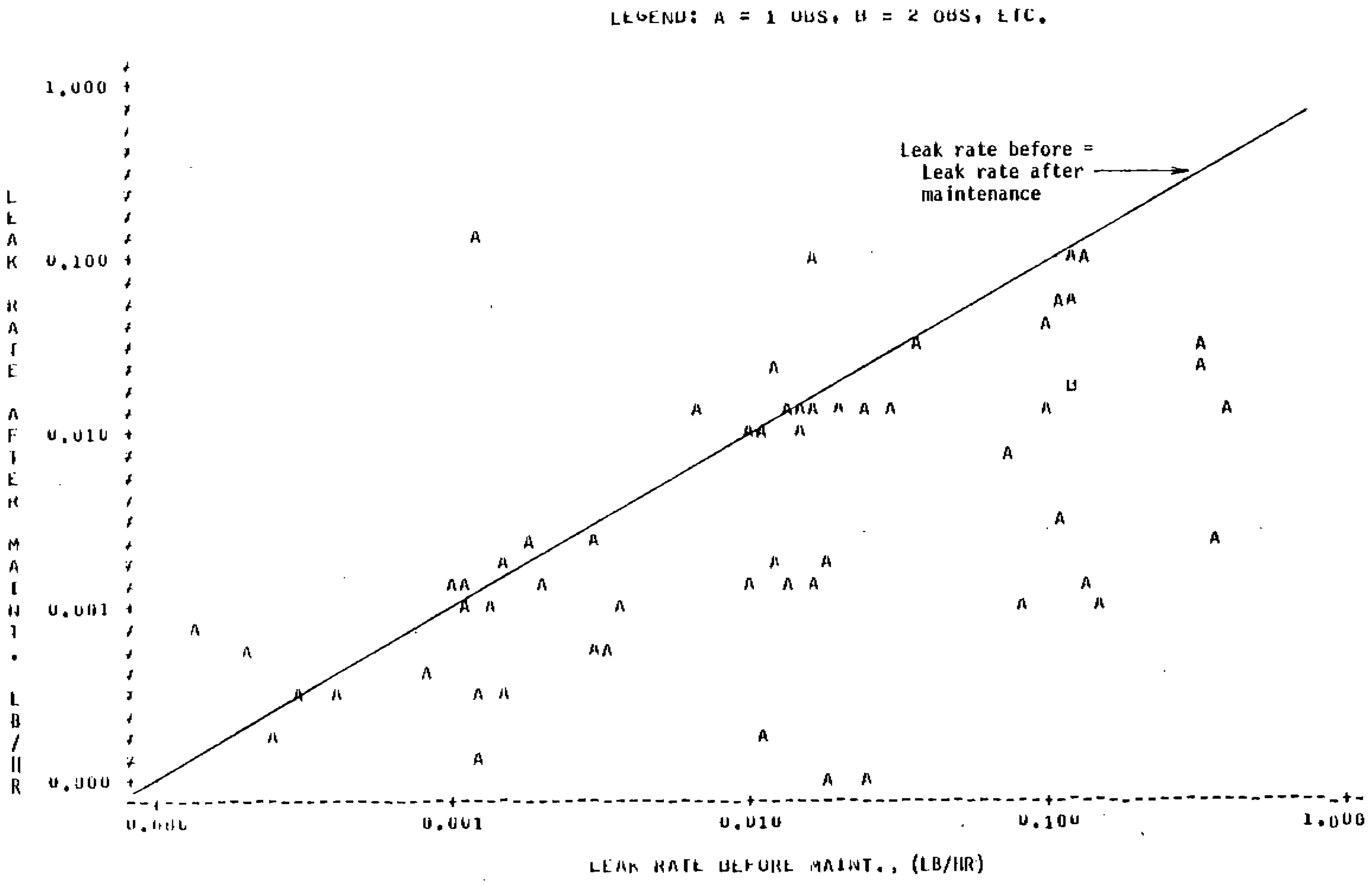


Figure B6-2. Undirected maintenance - leak after maintenance versus leak before maintenance.

Figure B6-3 summarizes the percent reduction data with histograms comparing directed and undirected maintenance. The effectiveness of directed versus undirected maintenance is obvious when comparing the distributions of percent reduction.

The effects of the valve maintenance studies are summarized in Table B6-2. The results are shown for both the directed and the undirected maintenance programs, and are grouped according to the level of emission rates. Two results are noteworthy. It is evident that the percentage leak reduction for those valves that were subjected to directed maintenance is considerably greater than that of the valves that had undirected maintenance. It is also apparent that the level of the initial leak rate has a marked effect on the percentage reduction in emission rate for both directed and undirected maintenance. The percentage reduction achieved by maintenance is lower for the initially small leak rates. In the very low initial leak range, $\leq$ 0.001 pounds per hour, the average and weight percent reduction was actually negative.

It should be noted that as the magnitude of the leak rate becomes smaller, both the mean percent reduction and weight percent reduction decrease rapidly. Both of these parameters are dependent on the magnitude of the leak rate and are highly influenced by extremes within the leak rate range. The median percent reduction, however, is a more robust measure of central tendency and cannot be affected by the very large negative values of percent reduction encountered at low leak rates with undirected maintenance.

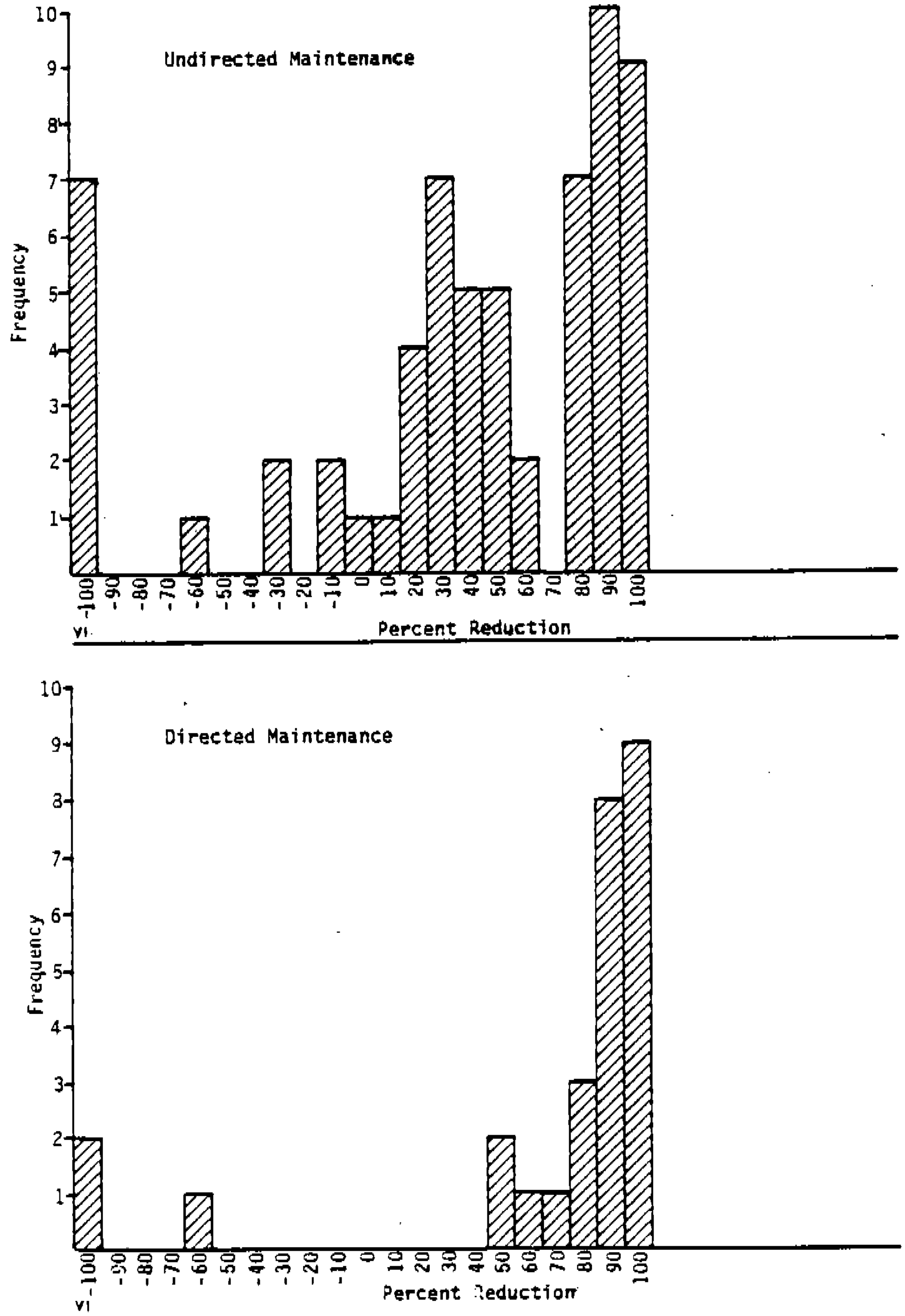


Figure B6-3. Histograms for percent reduction in leak rate directed vs. undirected maintenance.

TABLE B6-2. SUMMARY OF MAINTENANCE REDUCTION BY LEAK RATE LEVEL

Level	Original Leak Rate Range (lb/hr)		Directed Maintenance	Undirected Maintenance
1	≤0.001	n	4	6
		$\overline{p}$	30.7	-105.5
		pw	35.2	-26.3
		pm	52.6	5.6
2	0.001 - 0.01	n	12	16
		$\overline{p}$	48.7	-530.0
		pw	56.9	-276.4
		pm	86.2	30.4
3	0.01 - 0.1	n	10	22
		$\overline{p}$	93.8	31.7
		pw	93.0	45.1
		pm	93.8	60.9
4	>0.1	n	1	15
		$\overline{p}$	98.0	73.4
		pw	98.0	83.5
		pm	98.0	85.4

n = Number of valves maintained

$$\overline{p} = \text{Average percent reduction} = \Sigma P_i/n, \text{ where } P_i = \frac{\text{(leakage before - leakage after maintenance)}}{\text{leakage before maintenance}} \times 100$$

$$pw = \text{Weight percent reduction} = \frac{\Sigma\text{leakage before maintenance} - \Sigma\text{leakage after maintenance}}{\Sigma\text{leakage before maintenance}} \times 100$$

pm = Median percent reduction

The median percent reduction does show the same patterns as the average and weight percent reductions. The comparison between the median percent reductions for the two types of maintenance indicates that directed maintenance yields a higher reduction in leak rate. Undirected maintenance appears to be less reliable at low leak rate levels (0.001 lb/hr) with the potential for causing more increases in leakage.

The individual percent reduction from the two maintenance methods was plotted against the original screening value in Figures B6-4 and B6-5. It appears on these graphs that the positive percent reductions for directed maintenance are generally higher than for undirected maintenance. Also, a greater percentage of the undirected maintenance valves appears to have increased in leak rate after being maintained than for the directed maintenance. Table B6-3 bears out these observations. The median percent reduction for directed maintenance (91.2 percent) is significantly higher than that for undirected maintenance (53.8 percent).

In Table B6-3 the valves are grouped according to the categories of the three variables used in the experimental design for selecting valves. One of these variables was valve function (block or control). Control valves which had directed maintenance had a slightly higher median percent reduction in leak rate than block vlaves which had the same type of maintenance. However, the opposite is true for valves which underwent undirected maintenance. Again, even within the block/control groupings, directed maintenance appears to yield a higher percent reduction in leak rate than undirected maintenance.

The screening value range was also used in selecting valves for the study. For directed maintenance, the median percent reduction stays approximately constant across the screening value

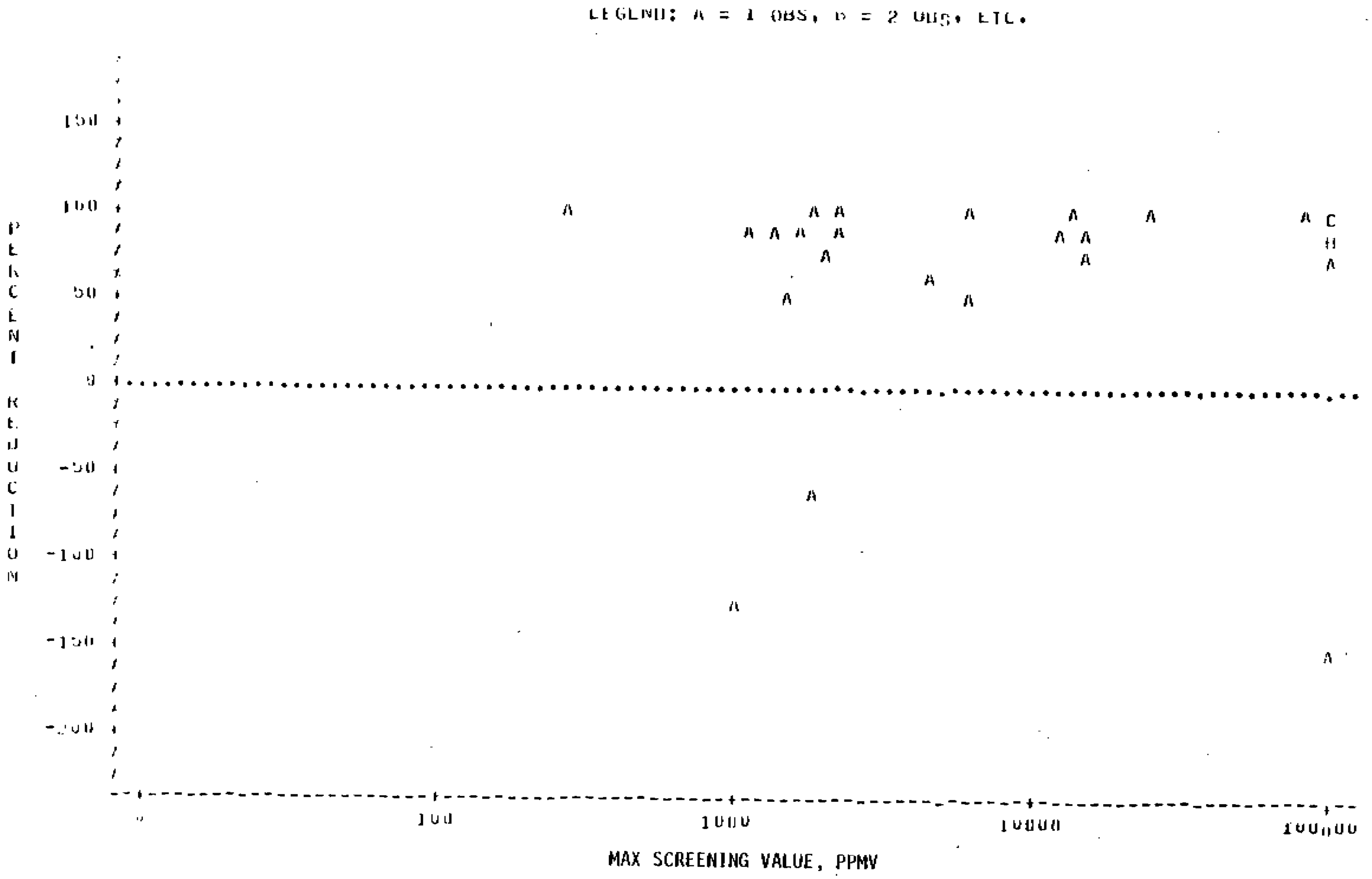
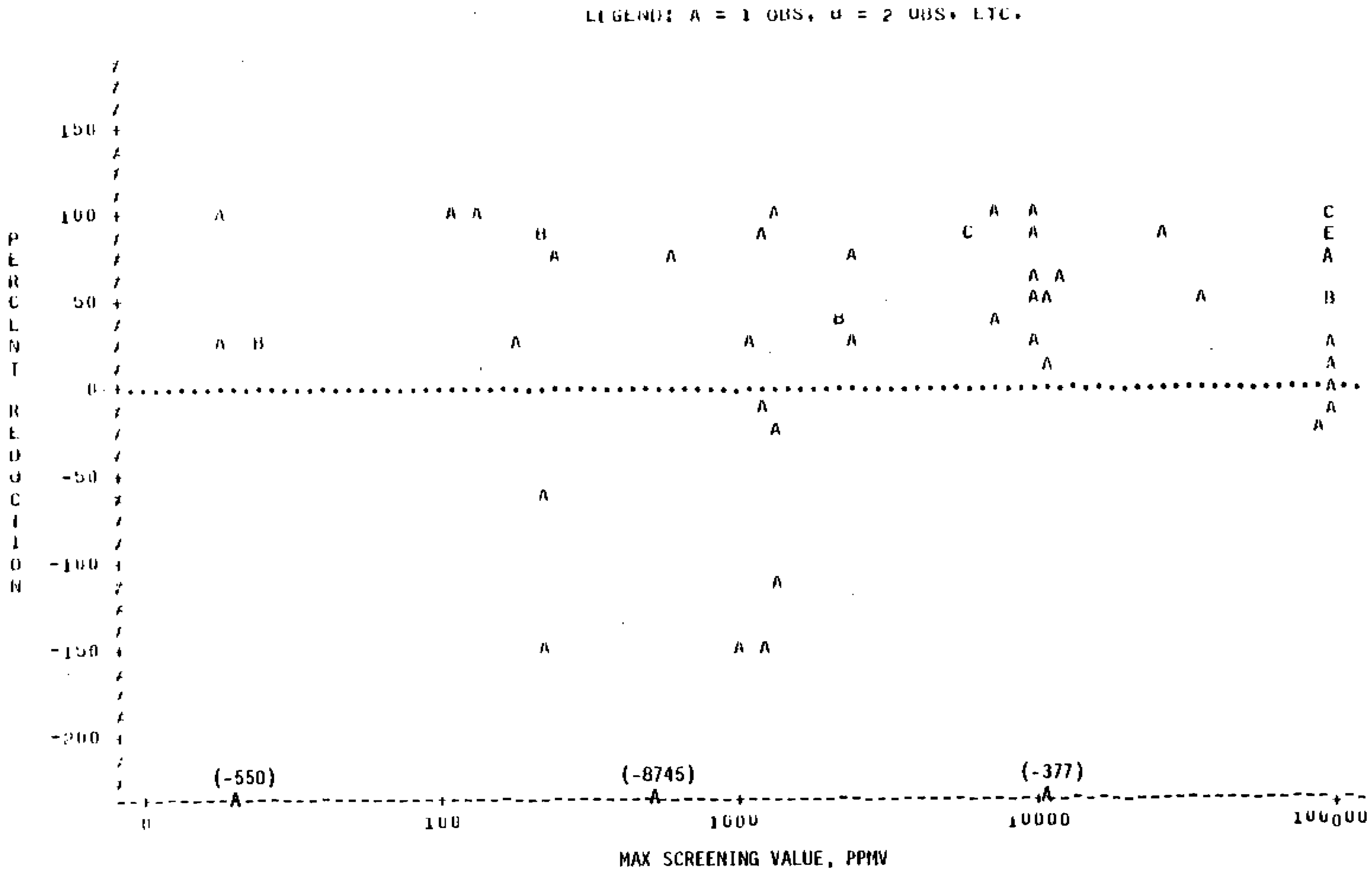


Figure B6-4. Directed maintenance - percent reduction versus screening values.



Note: 3 values were out of range

Figure B6-5. Undirected maintenance - percent reduction versus screening value.

TABLE B6-3. STATISTICAL SUMMARY OF MAINTENANCE DATA - PERCENT REDUCTION

	Directed Maintenance								
	Block Valves				Control Valves				
Screening Value Range (ppmv)	G/V Stream	LL Stream	HL Stream	Total* Block	G/V Stream	LL Stream	HL Stream	Total Control	Total* All Valves
<5K	2 58.8 56.5 58.8	5 63.1 90.5 93.1	0	7 61.8 86.5 87.3	0	4 39.5 84.9 89.8	0	4 39.5 84.9 89.8	11 53.74 (3.7,100) 85.6 (72,99) 88.4 (18,98)
5K-50K	2 76.1 90.7 76.1	4 89.8 89.0 90.1	0	6 85.2 89.1 88.7	1 45.7 45.7 45.7	1 95.0 95.0 95.0	0	2 70.4 91.5 70.4	8 81.5 (65,98) 89.2 (69,100) 88.7 (-55,96)
>50K	3 93.8 97.8 98.0	2 -26.4 56.7 -26.4	0	5 45.7 92.3 91.7	1 77.2 77.2 77.2	2 97.2 96.4 97.2	0	3 90.5 95.0 94.5	8 62.5 (-7.9,100) 92.6 (81,100) 93.1 (-33,99)
				18 64.2 (32,96) 91.0 (82,99) 86.2 (75,97)				9 66.8 (12,100) 89.7 (79,99) 91.2 (9.3,98)	27 64.6 (38,91) 90.7 (83,98) 91.2 (79,95)

(Continued)

*Numbers in parentheses indicate an approximate 95% confidence interval for the average reduction for the three different estimations.

Code for Each Cell in Table		
	1	2
		3
		4

1 = Number of valves maintained

2 = Average of percent reduction where percent reduction = $\frac{\text{100 x (leak before - leak after maintenance)}}{\text{Leak before maintenance}}$

3 = Weight percent reduction = $\frac{\Sigma\text{leak rate before maintenance} - \Sigma\text{leak rate after maintenance}}{\Sigma\text{leak rate before maintenance}}$

4 = Median percent reduction

TABLE B6-3. Continued

Undirected Maintenance

Screening Value Range (ppmv)	Block Valves				Control Valves				
	G/V Stream	LL Stream	HL Stream	Total* Block	G/V Stream	LL Stream	HL Stream	Total Control	Total* All Valves
<5K	6 54.0 52.2 65.2	6 42.6 58.9 76.9	4 -26.1 -43.4 7.37	16 29.7 48.5 33.1	7 -1320 - 717 -58.4	5 5.2 91.1 26.56	0	12 - 769 -50.5 24.1	28 -312 (-950,100) 33.0 (-39,100) 28.9 (-0.5,79)
5K-50K	4 69.8 47.8 82.6	4 -64.9 - 9.0 28.2	0	8 2.4 20.2 50.1	2 54.2 53.8 54.2	4 87.8 96.9 95.6	1 82.1 82.1 82.1	7 77.4 90.2 82.1	15 37.4 (-28,100) 67.4 (34,100) 82.1 (42,88)
>50K	3 75.3 88.4 84.3	4 81.3 93.0 90.9	0	7 78.7 91.1 85.4	8 29.4 81.3 19.3	1 90.6 90.6 90.6	0	9 36.2 87.0 29.5	16 54.8 (31,78) 89.6 (81,98) 67.0 (21,92)
				31 33.7 (-1.8,69) 68.7 (48,89) 61.1 (31,85)				28 298 (-940,100) 81.0 (64,98) 51.4 (13,85)	59 -124 (-410,100) 73.9 (69,88) 53.8 (29,82)

*Numbers in parentheses indicate an approximate 95% confidence interval for the average percent reduction for the three different estimations.

Code for Each Cell in Table		
	1	2
		3
		4

1 = Number of valves maintained

2 = Average of percent reduction where percent reduction $= \frac{100 \times (\text{leak before} - \text{leak after maintenance})}{\text{Leak before maintenance}}$

3 = Weight percent reduction $= \frac{\Sigma\text{leak rate before maintenance} - \Sigma\text{leak rate after maintenance}}{\Sigma\text{leak rate before maintenance}} \times 100$

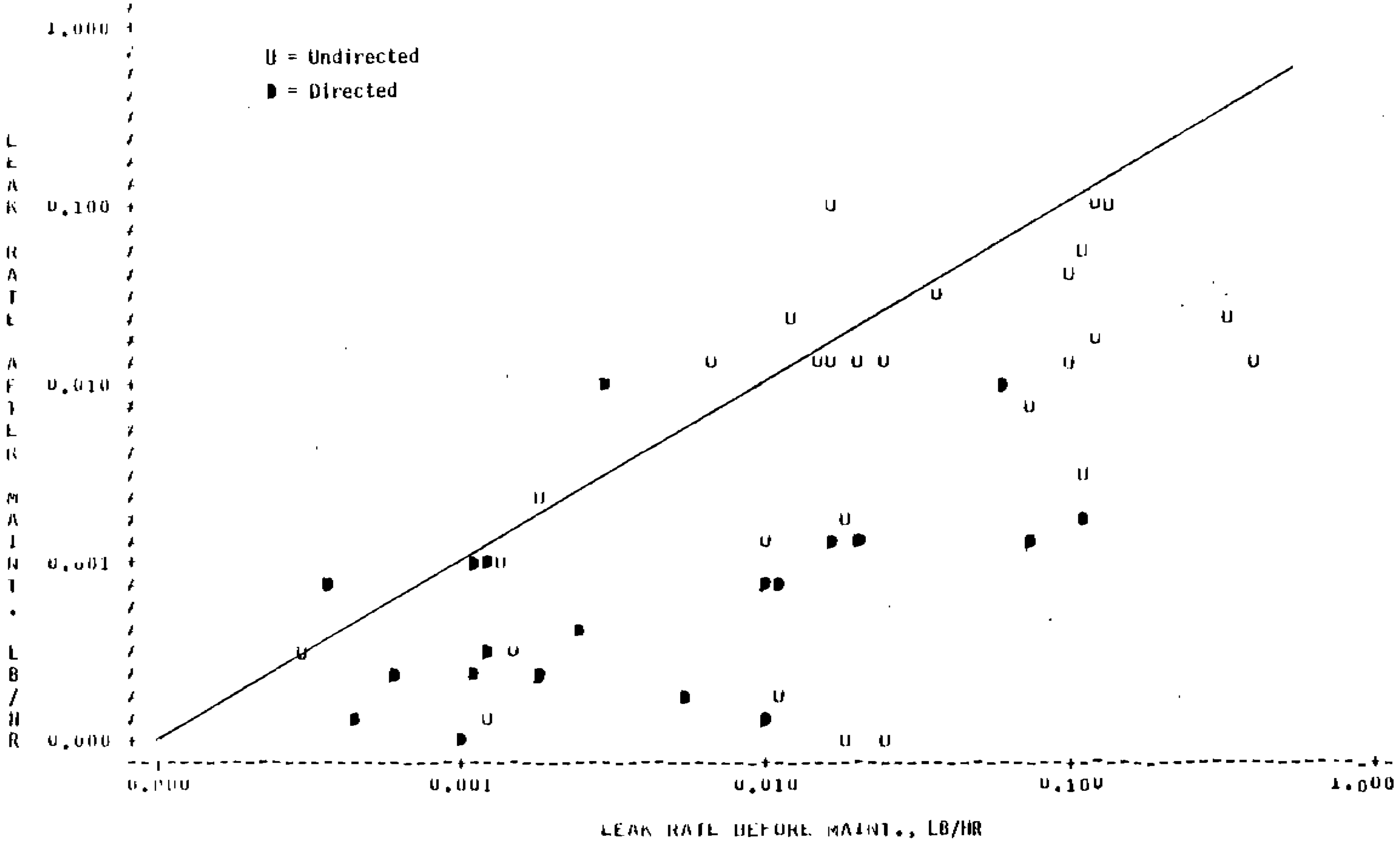
4 = Median percent reduction

range. However, for the undirected maintenance group the median percent reduction increases dramatically with increasing screening values. Within the low screening value range the median percent reduction is very low, only 28.9 percent. This may indicate that undirected maintenance at this screening level is not effective at all. For the middle screening value range, the median percent leak reduction increases to 82.1 percent, almost as high as the value for directed maintenance (88.7 percent). However, the median percent leak reduction drops again for the high screening value range (67.0 percent). The effectiveness of the maintenance program appears to be much more consistent when the directed method is used rather than the undirected method.

The differences in percent reduction discussed above should be considered as trends. Confidence intervals were calculated for the key values in Table B6-3. Differences in percent reduction cannot be considered statistically significant if confidence limits for the estimates overlap. The statistical procedures used to calculate the confidence intervals are discussed in subsection 6.3.

A graphic representation of the differences between the effect of maintenance on block and control valves is shown in the next several figures. The leak rates before and after maintenance are plotted for block and control valves in Figures B6-6 and B6-7. The percent reduction in leak rate for each valve is plotted against the original screening value for block and control valves in Figures B6-8 and B6-9.

Finally, Figures B6-10 and B6-11 are histograms of percent reduction for block and control valves for directed and undirected maintenance. The differences described in Table



NOTE: 1 OBS HIDDEN

Figure B6-6. Directed and undirected maintenance - leak after maintenance versus leak before maintenance - block valves.

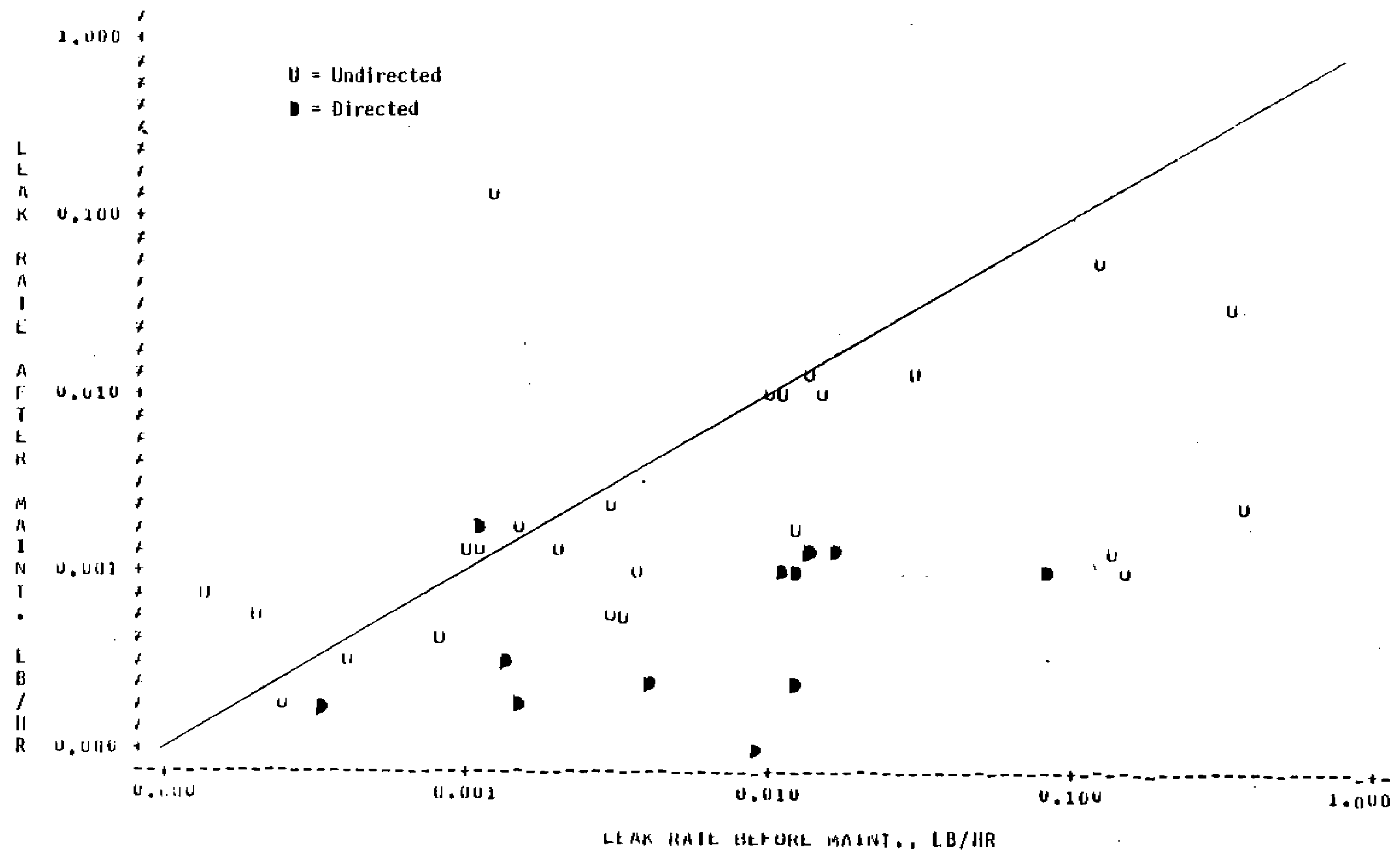


Figure B6-7. Directed and undirected maintenance - leak after maintenance versus leak before maintenance - control valves.

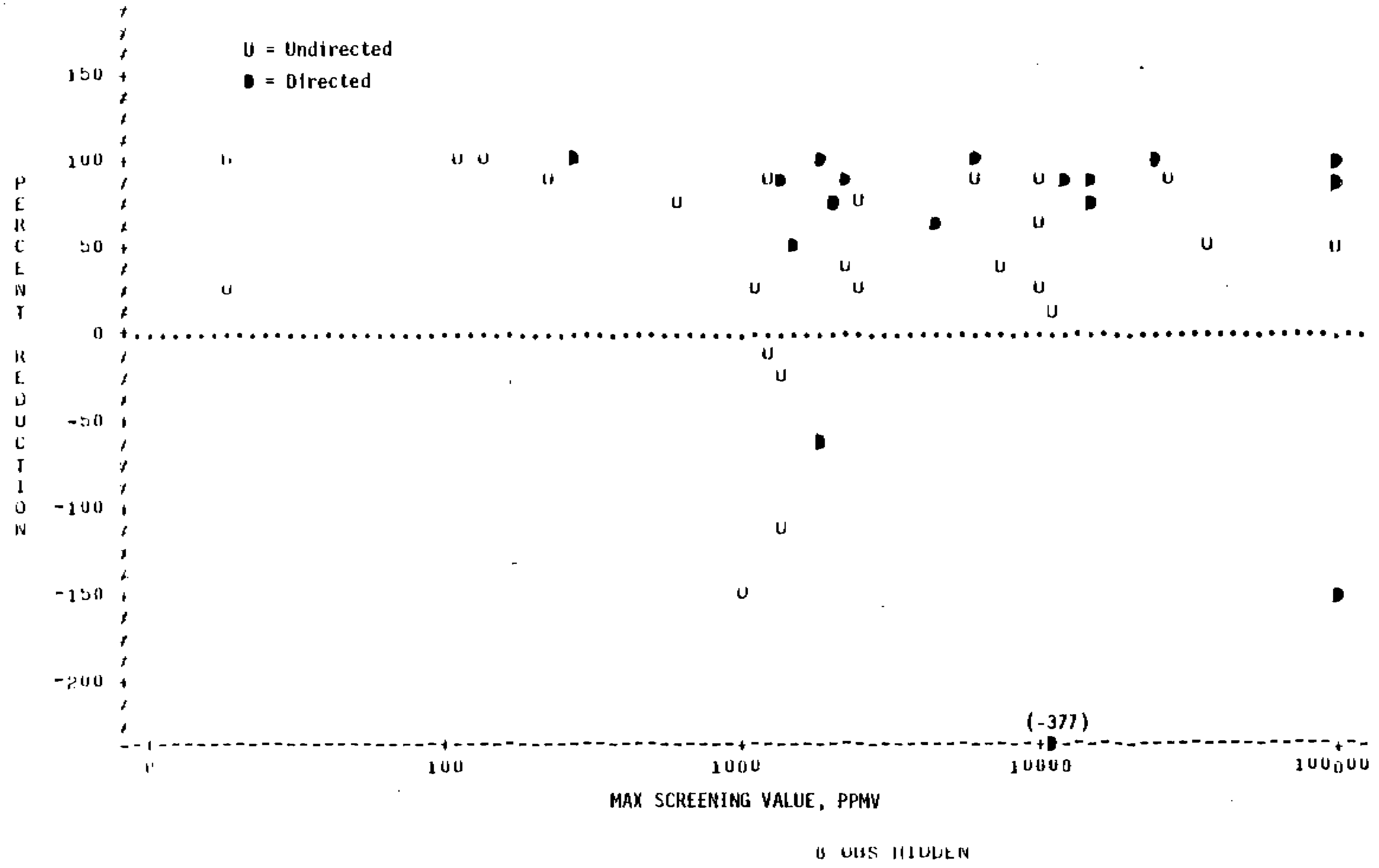


Figure B6-8. Directed and undirected maintenance - percent reduction versus screening value - block valves.

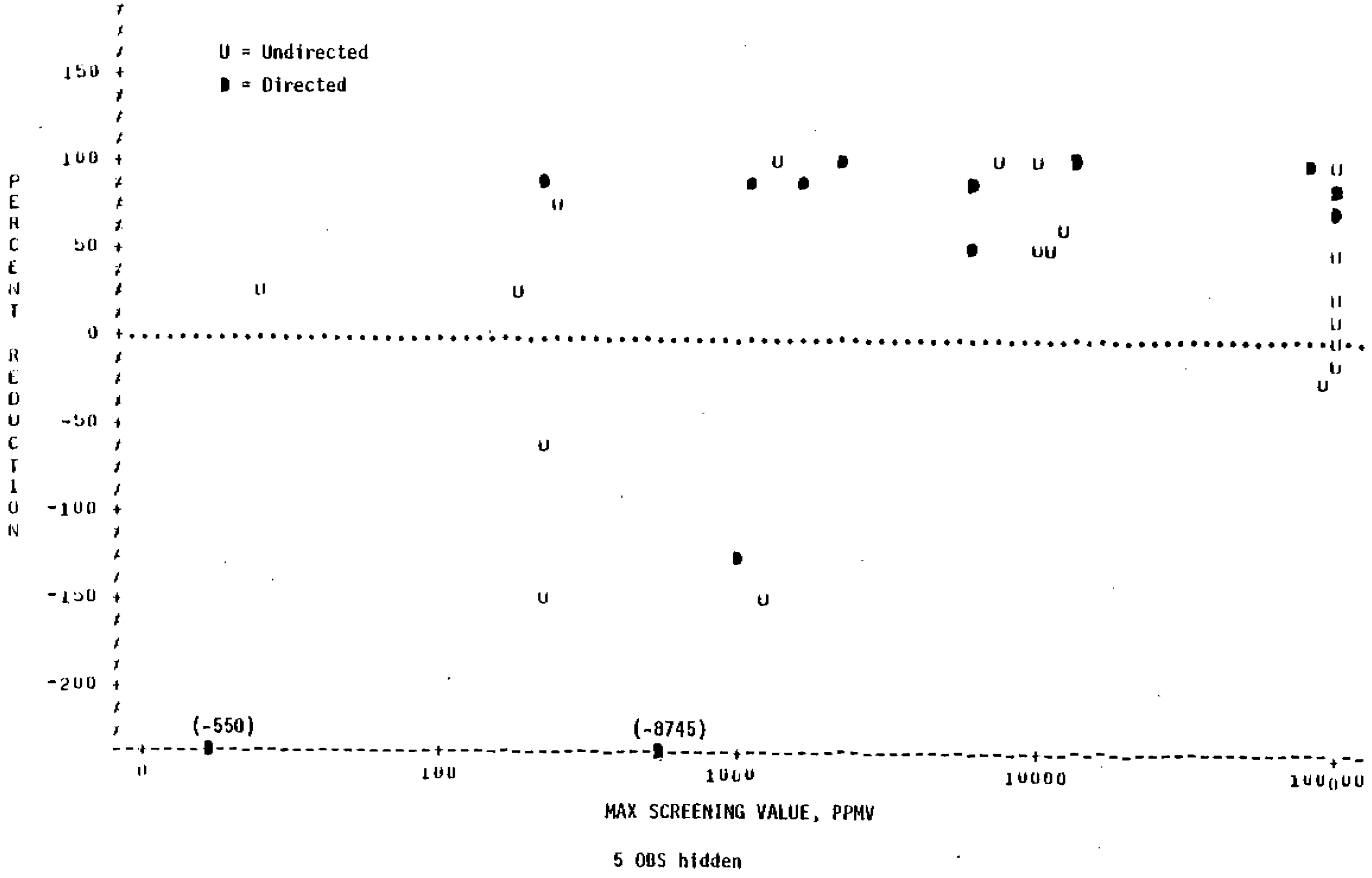
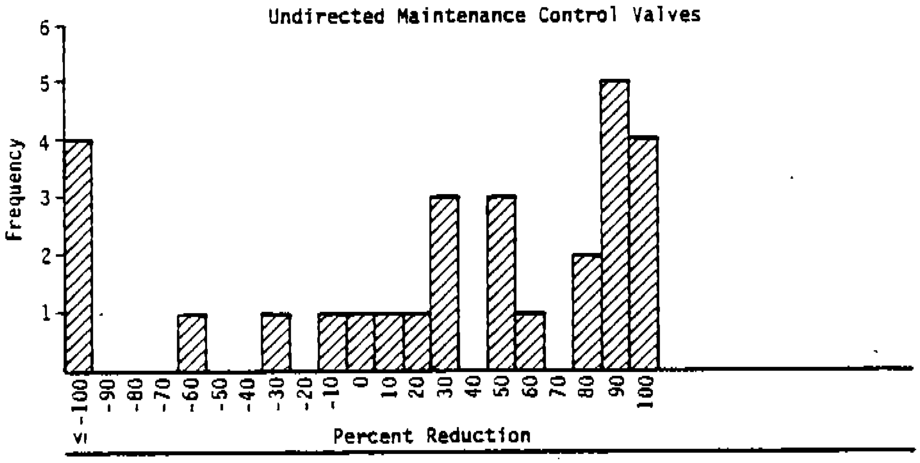


Figure B6-9. Directed and undirected maintenance - percent reduction versus screening value - control valves.



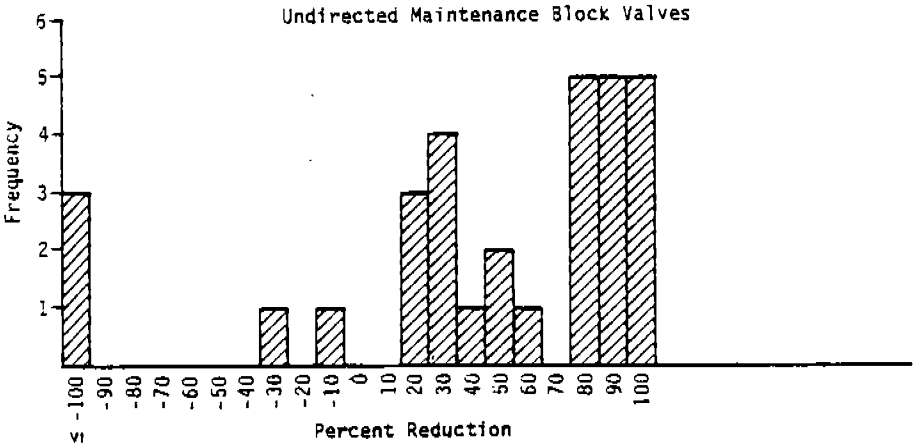
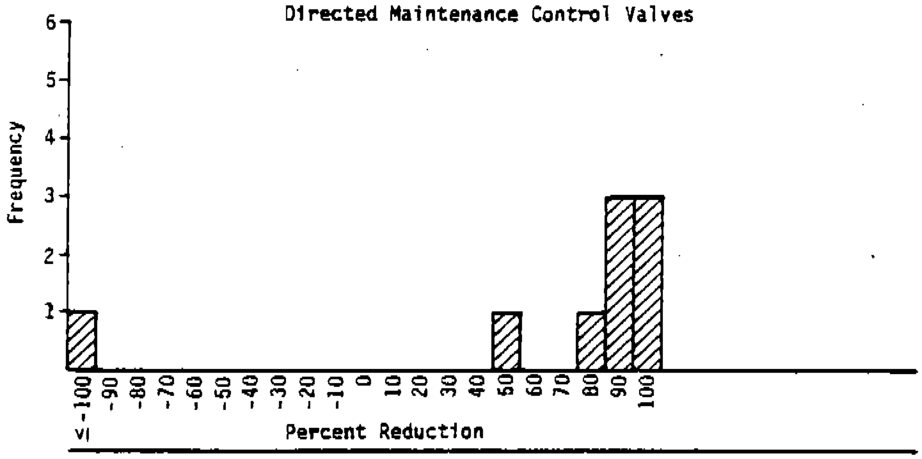


Figure B6-10. Histograms for percent reduction in leak rate - undirected maintenance.



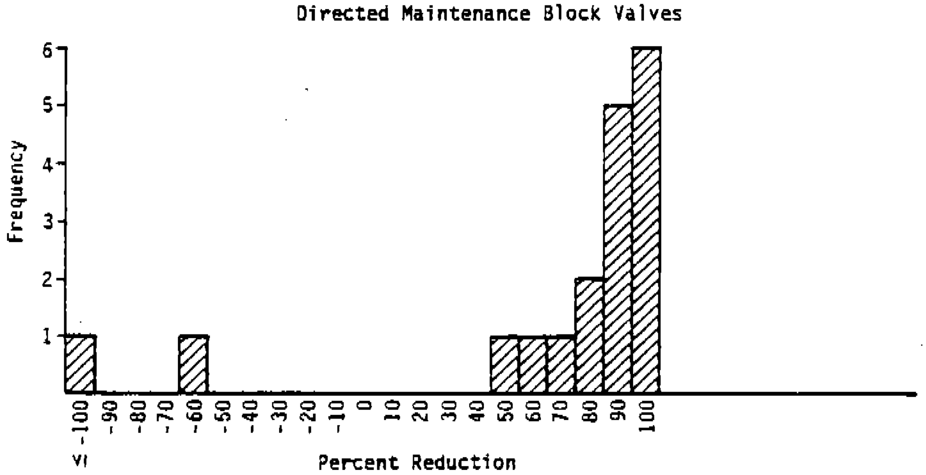


Figure B6-11. Histograms for percent reduction in leak rate - directed maintenance.

B6-2 can be seen on these histograms. While no large differences between valve function are obvious, the differences between the percent reduction in emissions for valves undergoing directed and undirected maintenance can be seen. The advantages of directed maintenance are usually apparent.

The data from this study can be used to assess the short term effectiveness of maintenance in a leak reduction program. In extrapolating the data from the study to a general population of valves, it is important to review how the valves were selected for study. The selection of valves was not random; rather, a specific experimental design was attempted. This design called for at least four valves in each cell in Table B6-3 (directed versus undirected maintenance was not considered in the original design).

In extrapolating the percent reduction estimates from this study to a general population of valves, the following factors must be considered:

- Will directed or undirected maintenance be employed?
- For what screening values will maintenance be required?

Note that the type of valve and the type of process fluid need not be considered since no consistent differences were found for these factors in this study.

Suppose directed maintenance for all valves with screening values greater than 5,000 ppmv is required. Estimates of the short term effectiveness of maintenance can be obtained by appropriately weighing the percent reduction statistics for valves in the 5k to 50K and >50K screening ranges which underwent maintenance.

From Table B6-3, the appropriate statistics for directed maintenance are as follows:

Screening range	Percent Reduction in Emissions		
	Average	Weight	Median
5,000 - 50,000	81.5	89.2	88.7
> 50,000	62.5	92.6	93.1

All three of the percent reduction statistics are potential estimates for the population percent reduction. Perhaps the most useful of these statistics, however, is the weight percent reduction since it allows an estimation of the total mass emissions reduction resulting from a valve maintenance program. Continuing the above example, assume that for a random sample of valves, 70 percent of all valves that will require maintenance are in the 5K to 50K screening range and 30 percent of the valves requiring maintenance are in the >50K screening range. Using the weight percent reduction statistics and the percentage of valves in each screening group, an estimate of the mass reduction for the the population would be:

Estimated effectiveness (total mass reductions)

$$= (0.7 \times 89.2\%) + (0.3 \times 92.6\%)$$

$$= 90.2\%$$

An appropriate confidence interval for this estimate would be (72%, 100%).

6.2 LONG-TERM MAINTENANCE STUDIES

The effect of maintenance procedures on the long-term reduction of emissions is currently being studied for a limited number of valves. The staffs of three refineries are monitoring several of those valves that were sampled and maintained as part of Radian's refinery field study. Approximately 60 valves are being screened with TLV Sniffers at intervals of one week to one month for a total period of 6 months. The program has not been completed. The results will be published in a separate Technical Note when they are available.

6.3 CONFIDENCE INTERVALS FOR PERCENT REDUCTION

Approximately 95 percent confidence intervals were calculated for the three types of estimates of percent reduction presented in Table B6-3. The statistical procedures used to develop these intervals are discussed below.

The mean percent reduction in leak rate, being an average of identically distributed random variables, was assumed to be approximately normally distributed by the central limit theorem. Thus, the 95 percent confidence limits are:

$$\bar{x} \pm t_c s_{\bar{x}}$$

where $\bar{x}$ is the mean,

$s_{\bar{x}}$ is the standard error of $\bar{x}$, and

t_c is the critical t-value obtained from a table.

The calculation of the confidence limits for the median percent reduction in leak rate did not require an assumption regarding the type of distribution. The method, which is valid for all continuous distributions, is described briefly as follows.

Suppose the data for which the median has been calculated are ordered so that

$$P_1 \leq P_2 \leq P_3 \leq \ldots \leq P_m$$

where P_i is the i^{th} value of percent reduction, and m is the number of values. Then the two points whose indices are

$$\frac{m+1}{2} \pm \frac{1.96\sqrt{m}}{2}$$

are the desired confidence limits. Since these two indices are actually not integers, interpolation between values was performed to achieve slightly increased accuracy.

Confidence limits were also computed for the percent total reduction in leak rate,

$$\frac{100\ (B-A)}{B}$$

where B is the total leak rate before maintenance, and A is the total leak rate after maintenance.

The expression for the variance of a ratio such as the above is not known exactly but can be approximated using a second-order Taylor's series expansion, as is discussed by Mood, et al.[1]

The type of distribution of this ratio is unknown. It was felt, however, that $\pm 2\hat{\sigma}$ confidence limits provide a reasonable indication of the uncertainty. If the ratio were normally distributed, these would be 95 percent confidence limits.

6.4 REFERENCES

1. Mood, et al. Introduction to the Theory of Statistics, Third Edition, 1974, p. 180-181.

SECTION 7

GENERAL SURVEY INFORMATION

There are many factors in a refinery which might contribute directly to the fugitive emission load or indirectly affect the overall emission level. However, they do not lend themselves to direct sampling. Among these factors are maintenance practices, laboratory techniques, unit shutdown procedures, blind changing procedures and blending operations. In order to evaluate these items, a general survey form for each of them was submitted to the refiner. In this way, the information necessary to compare these factors from one refinery to the next was obtained.

7.1 MAINTENANCE PRACTICES

It is widely acknowledged that good preventive maintenance is one of the best ways to minimize fugitive emissions. If the effectiveness of maintenance plans in reducing fugitive emissions can be characterized, a valuable correlation could be obtained. This correlation could be used when applying the results of this study to other refineries.

Generally speaking, the refineries used combinations of in-house and contract maintenance personnel. The in-house maintenance people did much of the routine maintenance, and supplemental contract labor was used during turnarounds and larger maintenance projects.

None of the refineries sampled during this study were utilizing an extensive valve maintenance program during the period when sampling was conducted. That is, routine screening of large numbers of valves for the purpose of preventing or reducing hydrocarbon emissions was not encountered.

Some form of preventive maintenance program was in force at five of the six refineries responding to this survey. The extent of these programs varied, however, among refineries. In one refinery an inspection of each unit is performed once a year. Piping, furnace tubes, etc., are replaced if it is felt that they might fail during the following year. Maintenance records are not kept for extended periods of time; work orders are held for one year. These work orders cover pump repairs and seal replacement. Pumps, valves, flanges, etc., are inspected and adjusted/replaced only when a problem is reported.

At another refinery, however, a preventive maintenance program is practiced on instrumentation, electric motors and pumps. This includes a prescribed maintenance schedule for each piece of equipment. The program is supplemented by an equipment file. These records are maintained of failures and service life of various equipment items. The packing and seals of pumps, valves, etc. are routinely inspected by operating personnel. Some minor adjustments may be made when the need is observed. More extensive work, as well as minor work on critical pieces of equipment, is done by maintenance personnel after they receive requirest by the operator.

In five of the six refineries, equipment files are kept on pumps and compressors. Seal failures and packing leaks are recorded. However, valve maintenance records were kept at only one refinery.

Maintenance personnel were generally not assigned permanently to a particular unit in the smaller refineries. They could be assigned to specific refinery areas which might include several process units. Some maintenance people are assigned to major process units in large refineries.

Three of the six refineries reported that 17 percent, 18 percent and 20 percent of the operating budget is devoted to maintenance. One reported that 44 percent of its manpower was devoted to maintenance. No information on the criteria used to establish these numbers was available.

Significant differences in emission rates were not found amont the refineries. This would indicate that the variations in maintenance programs found do not affect the emissions rates.

7.2 PROCESS UNIT TURNAROUND PROCEDURES

Most normal maintenance in a refinery can be performed while running, but some major items require that the unit be shut down and opened. Since maintenance personnel must physically enter the vessels to work, the entire unit must be purged of all hydrocarbons and tested to insure that it is "gas free". This large scale overhaul of a processing unit is called a "turnaround". A survey was made to determine the frequency of turnarounds on various process units as well as the disposition of the purged hydrocarbons.

The following purging procedure is typical of industry practice. The unit is shut down and process gases are vented to a vapor recovery system, if available, or to the flare. Then steam is charged to the unit to strip out the remaining hydrocarbons. Most of this steam is vented to a closed blowdown system which will remove condensed water and route the gases to the flare. A few "high-point" vents are opened to the atmosphere during the latter stages of steaming out, but it is felt that there is little significant hydrocarbon evolution by that time. Then the steam flow is stopped and the unit is cooled, thus condensing the steam. The condensate is drained off. Atmospheric vents must be open at this stage to prevent the formation of a destructive vacuum. Then the vessel manways are opened and the interiors are gas tested. This procedure is thorough and effective, and its overall impact on fugitive emissions is negligible, especially in light of the infrequent nature of its occurrence.

The frequency of shutdowns for various units at one refinery is presented below. These frequencies are typical of the refining industry.

TABLE B7-1. SHUTDOWN FREQUENCY

Unit	Times Down in Last 12 Months	Scheduled Period Between Turnarounds
Crude Unit	1	1 year
Crude Unit	1	1 year
Catalytic Cracker	1	1 year
Fuel Reformer	0	1 year
Naphtha HDS	0	3 years
Alkylation	1	1 year
Aromatics Reformer	2	1 year
Aromatics Extraction	1	3 years

Only the Aromatics Reformer had exceeded its scheduled down times with one unscheduled shutdown for catalyst regneration.

7.3 BLIND CHANGING

A blind changing survey was included in this study largely because of the results of the Los Angeles County study. It was initially believed that the practice of routinely changing pipeline blinds is unusual. This belief has been substantiated in Refineries "A" through "I". Only when handling very expensive and exotic materials, such as some lube oil stocks, would the use of blinds be warranted as a means of controlling direction of flow to prevent any cross-contamination. The refineries reported that they do not routinely change a significant number of blinds. Most blind changing takes place during the start-up or shutdown of a unit, and at these times, the unit has generally been purged of hydrocarbons. The refineries were unable to supply any detailed information on the times, the hydrocarbon properties, or amounts spilled during the limited amount of blind changing they did.

7.4 SAMPLING PROCEDURES

Quality control sampling in a modern refinery can potentially add significantly to the overall fugitive emissions. It is very difficult to quantify the emissions from sampling because of their irregular and transient nature. General surveys were made of sampling, flushing and sample waste disposal procedures. It was hoped that this information could be correlated into a sampling emission factor.

At one large refinery, laboratory personnel were observed while drawing routine liquid samples in the field. Line flushings were routed to a covered oily water drain system with a maximum of 18 inches free fall and minimum exposed retention time (i.e., less than 2 minutes). Readings were taken with the J. W. Bacharach "TLV Sniffer" at the drain entrance immediately before and after sampling. No significant difference in readings was discernible, and the absolute parts per million readings were below the selected sampling limit of 200 ppm. Thus, it was concluded that the flushing of liquid samples did not significantly contribute to the fugitive emission load at this refinery.

A common control test for light hydrocarbon fractionators, the reflux end-point, or "boil-away end-point", may cause significant emissions. In this test, 100 milliliters of column reflux are collected in a graduated vessel with a conical bottom. Since the reflux of these "stabilizer" towers is primarily butane and lighter hydrocarbons, the sample will begin to evaporate at ambient conditions. The vessel is then fitted with a two-hole stopper, one side of which held a thermometer. The sample is allowed to boil away, and the temperature noted when 5 milliliters remain. This value is the reflux end-point, or more precisely, the 95 percent point on the distillation curve. At one refinery, it was observed that approximately 400 milliliters were flushed to the atmosphere in order to obtain a sample representative of current operations. A survey of the operating units revealed that this test was routinely run 33 times per day at one large refinery. Therefore, 16.5 liters of light hydrocarbon were lost to the atmosphere per day. Assuming that this material may be characterized as butane, this would represent an emission of 0.87 pounds per hour or 21 pounds per day. The number of reflux end-point tests reported by the refineries varied from 6 to 33 per day. Thus, the losses from this test varied from 4 to 21 pounds per day.

The overall sample load at one large refinery was approximately 200 samples per day. Of these, about 40 percent were gas samples for chromatographic analysis, about 24 percent were volatile liquids (naphtha or lighter), and about 36 percent were nonvolatile liquids. Sample wastes were emptied into one of two slop oil collection systems, one for naphtha and one for heavier materials.

The six refineries responding to the survey reported sample loads of 50 to 200 samples per day.

7.5 BLENDING OPERATIONS

Although blending operations were not considered for sampling as a refinery process module, they do employ many of the same pieces of equipment and are therefore subject to fugitive emissions. The only unique piece of equipment would be the mechanical tank mixers. This emission source consists of a low-pressure seal on a rotating shaft. The pump emission factors should not be used as estimates of emissions from this source for two reasons: (1) only a few samples were obtained from these sources and there are no data to suggest that the pump emission factors would be appropriate, and (2) these seals are often exposed to vapor rather than liquid, particularly when vertical mixers are employed. A portion of the survey included questions to determine what facilities are allocated to blending at each refinery.

One large refinery uses only batch blending. This is done in two parallel systems, one for leaded gasolines and one for unleaded. These two share no common facilities. Agitation in the blending tanks is provided by side-entering mechanical mixers. Emissions control on the leaded system is by floating roof, while the unleaded system uses a vapor recovery system. This is a conventional compression-absorption-stripping system using light cycle gas oil from the catalytic cracker as the absorption medium. There are nine tanks involved in this operation, six in the leaded system and three in the unleaded.

Another large refinery blends all gasoline using in-line blending. Both pump-around loops and mechanical mixers are used to agitate tanks. There are eight tanks used in blending service, and they are all equipped with floating roofs. Two independent, parallel blending systems are employed.

A small refinery reported using batch blending. They employ only two tanks in blending service. Both are equipped with vapor recovery systems, and pump-around loops are used to agitate these tanks.

Another refiner employs six tanks in their single train, batch blending system. All six tanks are equipped with floating roofs.

7.6 CONVERSION FACTORS

To Convert From	To	Multiply By
Btu	kcal	0.252
bbl	ℓ	159.0
gal	ℓ	3.785
ton	kg	907.2
lbs	kg	0.454
cm	in	0.394
ft^3	m^3	0.0283
psi	kg/cm^2	14.223
g/gal	g/ℓ	0.264
Btu/bbl	kcal/ℓ	0.0016
kWh/bbl	kWh/ℓ	0.0063
lb/bbl	kg/ℓ	0.0285
$lb/10^6$ Btu	g/Mcal	18.0
$grain/ft^3$	g/m^3	2.29
gal/MMcf	$ℓ/(hm)^3$	133.7
gpm	m^3/hr	0.227
lb/1000 gal	mg/ℓ	119.8

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/2-80-075c	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Assessment of Atmospheric Emissions from Petroleum Refining: Volume 3. Appendix B		5. REPORT DATE April 1980 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) R.G.Wetherold, L.P.Provost, and C.D.Smith		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Radian Corporation P.O. Box 9948 Austin, Texas 78766		10. PROGRAM ELEMENT NO. 1AB604 11. CONTRACT/GRANT NO. 68-02-2147, Exhibit B
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final; 3/76-6/79 14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Bruce A. Tichenor, Mail Drop 62, 919/541-2547.

16. ABSTRACT

The report gives results of a 3-year program to assess the environmental impact of petroleum refining atmospheric emissions. This volume contains a detailed compilation of the data and a summary of the results obtained from measurements taken at 13 refineries throughout the U.S. The sampled sources included valves, flanges, pump and compressor seals, relief valves, drains, cooling towers, oil/water separators, dissolved air flotation units, and various process stacks. Nonmethane hydrocarbon emission factors for the various fugitive emission sources are presented. Nomographs illustrating the relationship between screening (monitoring) values and emission rates are included. Correlations of leak rates with various process and equipment parameters are graphically displayed. The frequency and distribution of emission sources in refineries are estimated. The effect of simple valve maintenance on valve leak rates is described. Many organic species present in liquid process streams and vapor emissions were identified and quantified. These species and their concentrations in the various streams are listed.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Maintenance	Pollution Control	13B	15E
Petroleum Refining	Organic Compounds	Stationary Sources	13H	
Assessments		Nonmethane Hydrocarbons	14B	
Sampling				
Analyzing				
Hydrocarbons			07C	

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 549
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE