Appendix A

NO_x Controls Analysis

A.1 Vendor Information

A.2 Cost Calculations

A.1 Vendor Information

The following vendor information is contained in Appendix A.1.

- Teleconference between Jason Huckaby, ERG, Inc. and H. Van Alstine, Koch Industries (John Zink Company), October 20, 1999 and November 9, 1999.

- Letter from Russell Goerlich, CRI Catalysts, Inc. to Roy Oommen, ERG, Inc. November 24, 1999.

- Teleconference between Roy Oommen, ERG, Inc. and Tim Shippey, Peerless Mfg. Co. December 3, 1999.

- E-mail message "Up Fired heater burners" from Jim Thornton, Carolina Combustion Resources, Inc. to Jason Huckaby, ERG, Inc. October 28, 1999.

Copies of vendor submitted information are not available electronically. Hard copies may be obtained from Roy Oommen at Eastern Research Group (919) 468-7888.

A.2 Cost Calculations

Appendix A.2.1 ULNB and LNB Cost Calculations

Heater Size (MMBtu)	Number of Burners[a]	Standard Burner – Capital Costs: Standard Burner Price ($)[h]	Purchased Equipment Cost ($)[c]	Total Capital Cost ($)[d]	Annual Costs ($/yr)[e]
10	1	3,333	3,333	3,433	489
50	5	2,838	14,189	14,615	2,081
75	7	2,744	19,207	19,784	2,817
150	15	2,543	38,138	39,282	5,593
350	35	2,336	81,760	84,213	11,990

		ULNB					LNB				
		Capital Costs					Capital Costs				
Heater Size (MMBtu)	Number of Burners[a]	Price per Burner ($)[b]	Purchased Equipment Cost ($)[c]	Total Capital Cost ($)[d]	Annual Costs ($/yr)[e]	Annual Cost Differential ($/yr)[f]	Price per Burner ($)[g]	Purchased Equipment Cost ($)[c]	Total Capital Cost ($)[d]	Annual Costs ($/yr)[e]	Annual Cost Differential ($/yr)[f]
10	1	5,000	5,000	5,150	733	244	3,533	3,533	3,639	518	29
50	5	4,257	21,283	21,922	3,121	1,040	3,008	15,040	15,492	2,206	125
75	7	4,116	28,811	29,675	4,225	1,408	2,909	20,360	20,971	2,986	169
150	15	3,814	57,207	58,924	8,389	2,796	2,695	40,427	41,639	5,929	336
350	35	3,504	122,640	126,319	17,985	5,995	2,476	86,665	89,265	12,709	719

[a] As per vendor advice.

[b] See Appendix A.1 for vendor supplied information. Burner price was calculated by multiplying the single burner price by: [(# burners)^0.9/(# burners)] to account for economy of scale pricing, per vendor data.

[c] Calculated by multiplying price per burner and number of burners. Assumes no installation in excess of standard burner installation costs.

[d] Calculated assuming 3% tax rate on purchased equipment cost (PEC).

[e] The only annual costs expected for LNBs and ULNBs are capital recovery costs (e.g., no additional operating and maintenance costs over a standard burner). Capital recovery costs were calculated assuming 7% interest rate over 10 year life.

[f] The difference in total annualized cost between ULNB and standard burner costs for ULNB (or, for LNB, the difference in total annualized cost between LNB and standard burner costs).

[g] Calculated assuming that standard burner costs 2/3 the price of ULNBs, and LNBs would cost 6% more than a standard burner per vendor information.

[h] Calculated assuming that standard burner price is equivalent to 2/3 the cost of ULNB, per vendor advice.

Appendix A.2.2 FGR and FGR+LNB Cost Calculations

Heater Size (MMBtu/hr)	Capital Cost (July 1999 $)[a]	Annual Costs				
		Electricity Costs ($/yr)[b]	Maintenance Costs ($/yr)[c]	Capital Recovery ($/yr)[d]	FGR Total Annual Costs ($/yr)	FGR+LNB Total Annual Costs ($/yr)[e]
10	57,078	855	1,570	8,127	10,551	10,581
50	149,917	4,276	4,123	21,345	29,743	29,868
75	191,208	6,414	5,258	27,224	38,896	39,065
150	289,817	12,828	7,970	41,263	62,061	62,397
350	481,847	29,931	13,251	68,604	111,786	112,505

[a] Capital costs were calculated using the algorithm in "Alternative Control Techniques Document-Nox emissions from Process Heaters" (EPA-453-/R-93-034)(ACT). Costs were scaled from 1991 dollars to 1999 dollars using Chemical Engineering (CE) index.

[b] Electricity costs were calculated using the algorithm in the ACT.

[c] Maintenance costs were calculated using the ACT factor of 2.75% of SNCR capital costs.

[d] Capital recovery costs were calculated assuming the same inputs used for LNBs and ULNBs systems:
7% interest rate and a 10 year life.

[e] Total annual costs are the sum of the FGR annual costs and annual costs for control combinations. See Appendix A.2.1 for LNB and ULNB costs.

Appendix A.2.3 SCR Cost Calculations

Annual Cost Calculated from Vendor Data

Vendor[a]	NOx Inlet Level[b]	Heater Capacity (MMBtu/hr)	Total Capital Cost ($)[c]	Annual Cost: Capital Recovery($/yr)[d] Equipment	Catalyst	Total	Ammonia Cost ($/yr)[e]	Taxes, Ins, Admin ($/yr)[f]	Total Annual Cost ($/yr)
Vendor 1	179 ppmv	10	264,875	15,001	25,840	40,842	1,055	10,595	52,492
		50	313,775	17,771	30,611	48,382	5,276	12,551	66,209
		75	370,825	21,002	36,176	57,178	7,915	14,833	79,926
		150	431,950	24,464	42,139	66,603	15,829	17,278	99,710
		350	550,125	31,157	53,668	84,825	36,935	22,005	143,764
	33 ppmv	10	264,875	15,001	25,840	40,842	195	10,595	51,631
		50	313,775	17,771	30,611	48,382	973	12,551	61,905
		75	370,825	21,002	36,176	57,178	1,459	14,833	73,470
		150	431,950	24,464	42,139	66,603	2,918	17,278	86,799
		350	550,125	31,157	53,668	84,825	6,809	22,005	113,639
Vendor 2	179 ppmv	10	120,910	11,035	976	12,011	1,055	3,627	16,694
		50	204,530	17,513	4,634	22,147	5,276	6,136	33,559
		75	262,160	21,820	7,561	29,380	7,915	7,865	45,160
		150	393,240	31,456	14,633	46,089	15,829	11,797	73,715
		350	561,610	40,363	32,681	73,045	36,935	16,848	126,827
	33 ppmv	10	119,780	10,976	854	11,830	195	3,593	15,618
		50	201,140	17,382	4,146	21,528	973	6,034	28,535
		75	257,640	21,865	6,341	28,206	1,459	7,729	37,395
		150	386,460	31,759	12,195	43,954	2,918	11,594	58,466
		350	531,100	40,221	25,608	65,829	6,809	15,933	88,571

Summary of Total Annual Costs for Control Technology Combinations

Heater Capacity (MMBtu/hr)	SCR[g]	SCR+LNB: SCR Cost[h]	LNB Cost[i]	Total	SCR+ULNB: SCR Cost[j]	ULNB Cost[k]	Total
10	34,593	34,021	29	34,050	33,624	244	33,869
50	49,884	47,025	125	47,149	45,220	1,040	46,260
75	62,543	58,254	169	58,423	55,432	1,408	56,841
150	86,713	78,135	336	78,471	72,633	2,796	75,429
350	135,296	115,281	719	116,000	101,105	5,995	107,100

[a] Information from vendors is provided in Appendix A.1.

[b] Inlet levels correspond to uncontrolled NOx from process heaters (179 ppmv) and controlled using an ULNB (33 ppmv).

[c] Total capital cost components include purchased equipment, installation, taxes and freight, and ammonia storage. Purchased equipme

[d] Capital recovery was calculated assuming 7% interest rate over life of equipment and life of catalyst. Based on vendor data equipment life was assumed to be 20 years and catalyst life was assumed to be 5 years. Catalyst costs for vendor 1 are 40% of capital costs and equipment costs are 60%, based on vendor 1 data. Catalyst costs for vendor 2 were provided for each heater size.

[e] Ammonia costs are calculated in Appendix A.2.4.

[f] Taxes, insurance, and administration costs were assumed to be 4 % of the total capital cost.

[g] SCR costs are the average of the costs provided by vendors for inlet NOx levels of 179 ppmv (uncontrolled).

[h] SCR costs are the costs of the SCR system with the ammonia costs for the LNB level of control instead of the uncontrolled level of control.

[i] LNB costs are from LNB calculations in Appendix A.2.1.

[j] SCR costs are the average of the costs provided by vendors for an inlet NOx level of 33 ppmv (ULNB level of control).

[k] ULNB costs are from ULNB calculations in Appendix A.2.1.

Appendix A.2.4 Calculation of Ammonia Cost for SCR and SNCR Control Cases

SCR / SNCR Inlet Case	Heater Size (MMBtu/hr)	NOx Inlet Level (ppmv)	NOx Inlet Level (lb/MMBtu)	feedrate (lb NH3/hr)[a]	Cost ($/yr)[b]
Uncontrolled	10	179	0.217	0.80	1,055
	50	179	0.217	4.02	5,276
	75	179	0.217	6.02	7,915
	150	179	0.217	12.05	15,829
	350	179	0.217	28.11	36,935
LNB level	10	82	0.100	0.37	483
	50	82	0.100	1.84	2,417
	75	82	0.100	2.76	3,626
	150	82	0.100	5.52	7,251
	350	82	0.100	12.88	16,920
ULNB level	10	33	0.040	0.15	195
	50	33	0.040	0.74	973
	75	33	0.040	1.11	1,459
	150	33	0.040	2.22	2,918
	350	33	0.040	5.18	6,809

[a] Calculated assuming 1:1 ratio of NOx to ammonia, ammonia molecular weight (MW) of 17, and NOx MW of 46. This calculation assumes that additional ammonia will be injected beyond the amount that would react with NOx to achieve the estimated emission reduction. This was done to account for ammonia slip and incomplete mixing of ammonia and flue gas.

[b] Calculated using $300/ton cost for annhydrous ammonia. This value is the midpoint of the range of costs as reported in the "Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers," NESCAUM/MARAMA, June 1998.

Appendix A.2.5 SNCR and Control Combinations- Capital and Annual Cost Calculations

Controls	Heater Size (MMBtu/hr)	Capital Cost (July 1999 $)[a]	Annual Costs: Ammonia Cost ($/yr)[b]	Annual Costs: Electricity Cost ($/yr)[c]	Annual Costs: Maintenance Cost ($/yr)[d]	Annual Costs: Capital Recovery[e]	Annual Costs: SNCR Total Annual Cost ($/yr)	Total Annual Cost ($/yr)[f]
SNCR	10	123,501	1,055	0	3,396	11,658	16,109	16,109
	50	324,379	5,276	0	8,920	30,619	44,816	44,816
	75	413,721	7,915	0	11,377	39,052	58,345	58,345
	150	627,083	15,829	1	17,245	59,192	92,267	92,267
	350	1,042,584	36,935	2	28,671	98,413	164,020	164,020
SNCR + LNB	10	123,501	483	0	3,396	11,658	15,537	15,567
	50	324,379	2,417	0	8,920	30,619	41,957	42,082
	75	413,721	3,626	0	11,377	39,052	54,056	54,225
	150	627,083	7,251	0	17,245	59,192	83,689	84,024
	350	1,042,584	16,920	1	28,671	98,413	144,004	144,724
SNCR + ULNB	10	123,501	195	0	3,396	11,658	15,248	15,493
	50	324,379	973	0	8,920	30,619	40,512	41,553
	75	413,721	1,459	0	11,377	39,052	51,889	53,297
	150	627,083	2,918	0	17,245	59,192	79,355	82,152
	350	1,042,584	6,809	0	28,671	98,413	133,893	139,888

[a] Capital costs were calculated using the algorithm in "Alternative Control Techniques Document-Nox emissions from Process Heaters" (EPA-453-/R-93-034)(ACT). Costs were scaled from 1991 dollars to 1999 dollars using CE index.

[b] Ammonia costs were taken from calcuation in Appendix A.2.4.

[c] Electricity costs were calculated using the algorithm in the ACT.

[d] Maintenance costs were calculated using the ACT factor of 2.75% of SNCR capital costs.

[e] Capital recovery costs were calculated assuming the same inputs used for SCR systems: 7% interest rate and a 20 year life.

[f] Total annual costs are the sum of the SNCR annual costs and annual costs for control combinations.

Appendix B

VOC Equipment Leaks Analysis

Calculation of Costs and Emission Reductions

Table B-1A. Uncontrolled Emissions from Hydrotreating Units

Component	Service	Large Refineries (crude capacities >50,000 bbl/sd) Count[1]	VOC Emission Factor[2] (kg/hr/comp)	VOC Emissions (tpy)[3]	HAP[4] Percent	HAP Emissions (tpy)[5]	Small Refineries (crude capacities < 50,000 bbl/sd) Count[1]	VOC Emission Factor[2] (kg/hr/comp)	VOC Emissions (tpy)[3]	HAP[4] Percent	HAP Emissions (tpy)[5]
Valves	Gas	200	0.0268	52	15%	8	100	0.0268	26	15%	4
	Heavy liquid	218	0.00023	0	5%	0	181	0.00023	0	5%	0
	Light liquid	252	0.0109	27	23%	6	202	0.0109	21	23%	5
Pumps	Heavy liquid	7	0.021	1	5%	0	5	0.021	1	5%	0
	Light liquid	7	0.114	8	23%	2	5	0.114	6	23%	1
Compressors	Gas	2	0.636	12	15%	2	2	0.636	12	15%	2
Connectors	Gas	520	0.00025	1	15%	0	282	0.00025	1	15%	0
	Heavy liquid	610	0.00025	1	5%	0	519	0.00025	1	5%	0
	Light liquid	1361	0.00025	3	23%	1	443	0.00025	1	23%	0
Pressure relief	Gas	10	0.16	15	15%	2	4	0.16	6	15%	1
devices	Heavy liquid	7	0	0	5%	0	4	0	0	5%	0
	Light liquid	17	0	0	23%	0	3	0	0	23%	0
Open-ended lines		329	0.0023	7	23%	2	15	0.0023	0	23%	0
Samplng connections		26	0.015	4	23%	1	6	0.015	1	23%	0
Total		3566		133	18%	23	1771		77	18%	13

Table B-1B. Uncontrolled Emissions from Hydrogen Units

Component	Service	Large refineries (>50,000 bbl/sd) Count[1]	VOC Emission Factor[2] (kg/hr/comp)	VOC Emissions (tpy)[3]	Small refineries (<50,000 bbl/sd) Count[1]	VOC Emission Factor[2] (kg/hr/comp)	VOC Emissions (tpy)[3]
Valves	Gas	317	0.0268	82	168	0.0268	43
	Heavy liquid	0	0.00023	0	0	0.00023	0
	Light liquid	105	0.0109	11	41	0.0109	4
Pumps	Heavy liquid	0	0.021	0	0	0.021	0
	Light liquid	10	0.114	11	3	0.114	3
Compressors	Gas	2	0.636	12	2	0.636	12
Connectors	Gas	252	0.00025	1	304	0.00025	1
	Heavy liquid	0	0.00025	0	0	0.00025	0
	Light liquid	148	0.00025	0	78	0.00025	0
Pressure relief	Gas	6	0.16	9	4	0.16	6
devices	Heavy liquid	0	0	0	0	0	0
	Light liquid	139	0	0	2	0	0
Open-ended lines		59	0.0023	1	8	0.0023	0
Samplng connec.		21	0.015	3	4	0.015	1
Total		1059		131	614		71

1 Taken from memorandum "Development of the Petroleum Refinery Equipment Leaks Data Base", March 9, 1994. Item A-93-48, IV-B-16 from Petroleum Refinery NESHAP Docket
2 Taken from 1995 Protocol for Equipment Leak Emission Estimates. U.S. Environmental Protection Agency. Research Triangle Park, North Carolina, 1995
3 Calculated assuming 24 hours a day and 365 days a year of operation.
4 Taken from memorandum "Development of the Petroleum Refinery Equipment Leaks Data Base", March 9, 1994. Item A-93-48, IV-B-16 from Petroleum Refinery NESHAP Docket
5 HAP emissions from sampling connections and open-ended lines were calculated assuming HAP composition for light liquid streams.

Table B-2. Controls Required by Equipment Leak Control Programs

Equipment Type	Service	Petroleum Refinery NSPS	Petroleum Refinery NESHA for New Sources	HON Negotiated Rule
Valves	Gas	Monthly LDAR @10,000; Decreasing frequency with good performance	Same as HON	Monthly LDAR with > 2% leakers; Quarterly LDAR with < 2% leakers; Decreasing frequency with good performance; Initially @10,000 ppm, annually @500 ppm
	Light liquid	Monthly LDAR @10,000; Decreasing frequency with good performance	Same as HON	Monthly LDAR with > 2% leakers; Quarterly LDAR with < 2% leakers; Decreasing frequency with good performance; Initially @10,000 ppm, annually @500 ppm
Pumps	Light liquid	Monthly LDAR @10,000 ppm; Weekly visual inspection; or dual mechanical seals with controlled degassing vents	Same as HON	Monthly LDAR; Weekly visual inspection; Leak definition decreases from 10,000 ppm; or dual mechanical seals closed-vent system
Compressors	Gas	Daily visual inspection; Dual mechanical seal with barrier fluid and closed-vent system or maintained at a higher pressure than the compressed gas	Same as HON	Daily visual inspection; Dual mechanical seal with barrier fluid and closed-vent system or maintained at a higher pressure than the compressed gas
Connectors	Gas and light liquid	None	None	Annual LDAR @500 ppm with > 0.5% leakers; Decreasing frequency with good performance
Pressure relief devices	Gas	No detectable emissions	Same as HON	No detectable emissions or closed-vent system
Sampling connections	All	Closed-loop or in situ sampling	Same as HON	Closed-loop, closed-purge, closed-vent or in situ sampling
Open-ended lines	All	Cap, blind flange, plug, or second valve	Same as HON	Cap, blind flange, plug, or second valve

Table B-3A. Emissions and Reductions from Hydrotreating Units for Large Refineries (crude capacities >50,000 bbl/sd)

		Refinery NSPS				Refinery NESHAP for New Sources				HON Negotiated Rule			
			VOC				VOC				VOC		
		LDAR[1]	Emission	Emissions post control		LDAR[1]	Emission	Emissions post control		LDAR[1]	Emission	Emissions post control	
		Reduction	Reduction	VOC	HAP	Reduction	Reduction	VOC	HAP	Reduction	Reduction	VOC	HAP
Component	Service	Efficiency	(Mg/yr)	(Mg/yr)	(Mg/yr)	Efficiency	(Mg/yr)	(Mg/yr)	(Mg/yr)	Efficiency	(Mg/yr)	(Mg/yr)	(Mg/yr)
Valves	Gas	88	46	6	1	96	50	2	0	96	50	2	0
	Heavy liquid	0	0	0	0	0	0	0	0	0	0	0	0
	Light liquid	76	20	6	1	95	25	1	0	95	25	1	0
Pumps	Heavy liquid	0	0	1	0	0	0	1	0	0	0	1	0
	Light liquid	68	5	2	1	88	7	1	0	88	7	1	0
Compressors	Gas	100	12	0	0	100	12	0	0	100	12	0	0
Connectors	Gas	0	0	1	0	0	0	1	0	81	1	0	0
	Heavy liquid	0	0	1	0	0	0	1	0	0	0	1	0
	Light liquid	0	0	3	1	0	0	3	1	81	3	1	0
Pressure relief	Gas	100	15	0	0	100	15	0	0	100	15	0	0
devices	Heavy liquid	0	0	0	0	0	0	0	0	0	0	0	0
	Light liquid	0	0	0	0	0	0	0	0	0	0	0	0
Open-ended lines		100	7	0	0	100	7	0	0	100	7	0	0
Samplng connec.		100	4	0	0	100	4	0	0	100	4	0	0
Total		100	110	23	4	100	120	12	2	100	124	9	1

Table B-3B. Emissions and Reductions from Hydrotreating Units for Small Refineries (crude capacities <50,000 bbl/sd)

		Refinery NSPS				Refinery NESHAP for New Sources				HON Negotiated Rule			
			VOC				VOC				VOC		
		LDAR[1]	Emission	Emissions post control		LDAR[1]	Emission	Emissions post control		LDAR[1]	Emission	Emissions post control	
		Reduction	Reduction	VOC	HAP	Reduction	Reduction	VOC	HAP	Reduction	Reduction	VOC	HAP
Component	Service	Efficiency	(Mg/yr)	(Mg/yr)	(Mg/yr)	Efficiency	(Mg/yr)	(Mg/yr)	(Mg/yr)	Efficiency	(Mg/yr)	(Mg/yr)	(Mg/yr)
Valves	Gas	88	23	3	0	96	25	1	0	96	25	1	0
	Heavy liquid	0	0	0	0	0	0	0	0	0	0	0	0
	Light liquid	76	16	5	1	95	20	1	0	95	20	1	0
Pumps	Heavy liquid	0	0	1	0	0	0	1	0	0	0	1	0
	Light liquid	68	4	2	0	88	5	1	0	88	5	1	0
Compressors	Gas	100	12	0	0	100	12	0	0	100	12	0	0
Connectors	Gas	0	0	1	0	0	0	1	0	81	1	0	0
	Heavy liquid	0	0	1	0	0	0	1	0	0	0	1	0
	Light liquid	0	0	1	0	0	0	1	0	81	1	0	0
Pressure relief	Gas	100	6	0	0	100	6	0	0	100	6	0	0
devices	Heavy liquid	0	0	0	0	0	0	0	0	0	0	0	0
	Light liquid	0	0	0	0	0	0	0	0	0	0	0	0
Open-ended lines		100	0	0	0	100	0	0	0	100	0	0	0
Samplng connec.		100	1	0	0	100	1	0	0	100	1	0	0
Total		100	62	14	3	100	70	7	1	100	71	6	1

1 Taken from memorandum " Comparison of Emission Reduction Efficiencies for Equipment Leak Control Programs", July 26, 1995. Item A-93-48, IV-B-9 from Petroleum Refinery NESHAP Docket

Table B-3C. Emissions and Reductions from Hydrogen Units for Large Refineries (crude capacities >50,000 bbl/sd)

		Refinery NSPS			Refinery NESHAP for New Sources			HON Negotiated Rule		
Component	Service	LDAR[1] Reduction Efficiency	VOC Emission Reduction (tpy)	VOC Emissions post control (tpy)	LDAR[1] Reduction Efficiency	VOC Emission Reduction (tpy)	VOC Emissions post control (tpy)	LDAR[1] Reduction Efficiency	VOC Emission Reduction (tpy)	VOC Emissions post control (tpy)
Valves	Gas	88	72	10	96	79	3	96	79	3
	Heavy liquid	0	0	0	0	0	0	0	0	0
	Light liquid	76	8	3	95	10	1	95	10	1
Pumps	Heavy liquid	0	0	0	0	0	0	0	0	0
	Light liquid	68	7	4	88	10	1	88	10	1
Compressors	Gas	100	12	0	100	12	0	100	12	0
Connectors	Gas	0	0	1	0	0	1	81	0	0
	Heavy liquid	0	0	0	0	0	0	0	0	0
	Light liquid	0	0	0	0	0	0	81	0	0
Pressure relief	Gas	100	9	0	100	9	0	100	9	0
devices	Heavy liquid	0	0	0	0	0	0	0	0	0
	Light liquid	0	0	0	0	0	0	0	0	0
Open-ended lines		100	1	0	100	1	0	100	1	0
Samplng connec.		100	3	0	100	3	0	100	3	0
Total		87	114	17	95	125	6	96	126	5

Table B-3D. Emissions and Reductions from Hydrogen Units for Small Refineries (crude capacities <50,000 bbl/sd)

		Refinery NSPS			Refinery NESHAP for New Sources			HON Negotiated Rule		
Component	Service	LDAR[1] Reduction Efficiency	VOC Emission Reduction (tpy)	VOC Emissions post control (tpy)	LDAR[1] Reduction Efficiency	VOC Emission Reduction (tpy)	VOC Emissions post control (tpy)	LDAR[1] Reduction Efficiency	VOC Emission Reduction (tpy)	VOC Emissions post control (tpy)
Valves	Gas	88	38	5	96	42	2	96	42	2
	Heavy liquid	0	0	0	0	0	0	0	0	0
	Light liquid	76	3	1	95	4	0	95	4	0
Pumps	Heavy liquid	0	0	0	0	0	0	0	0	0
	Light liquid	68	2	1	88	3	0	88	3	0
Compressors	Gas	100	12	0	100	12	0	100	12	0
Connectors	Gas	0	0	1	0	0	1	81	1	0
	Heavy liquid	0	0	0	0	0	0	0	0	0
	Light liquid	0	0	0	0	0	0	81	0	0
Pressure relief	Gas	100	6	0	100	6	0	100	6	0
devices	Heavy liquid	0	0	0	0	0	0	0	0	0
	Light liquid	0	0	0	0	0	0	0	0	0
Open-ended lines		100	0	0	100	0	0	100	0	0
Samplng connec.		100	1	0	100	1	0	100	1	0
Total		88	63	8	95	68	3	96	69	3

1 Taken from memorandum " Comparison of Emission Reduction Efficiencies for Equipment Leak Control Programs", July 26, 1995. Item A-93-48, IV-B-9 from Petroleum Refinery NESHAP Docket