December 4, 1992

Mr. John Brown, Jr., P.E.
Air Permitting and Standards
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED
DEC 7 1992
Bureau of
Air Regulation

Re: AC50-219413/PSD-FL-196, Flo-Energy, Inc.

Dear Mr. Brown:

This correspondence contains the responses to the Florida Department of Environmental Regulation (FDER) letter dated November 3, 1992, concerning the above-referenced permit application. Responses for the Flo-Energy application are presented in Attachment A. In the attachment, each response is referenced in numerical order according to the Department's letter.

In addition to the responses to FDER comments, Flo-Energy is providing the following additional information concerning the facility.

Ammonia Slip

The vendors have indicated that a higher ammonia slip than originally proposed may be required to meet the proposed NO_x limit when burning coal. This is due to the higher levels of uncontrolled NO_x when burning coal and the higher ammonia (or urea) injection rate required for control. The proposed revised ammonia slip emission rate is based on 65 ppmv slip in the exhaust gases. We recognize that the PG&E/Bechtel Indiantown PSD permit, issued in March 1992, limited ammonia slip to 50 ppmv, but this permit was for a pulverized coal-fired boiler. The Flo-Energy boilers will be of the spreader stoker type, which have a somewhat higher uncontrolled NO_x emission rate. Thus, a higher rate of ammonia slip is expected for Flo-Energy's spreader stoker boilers.

Attached are revised tables from the PSD permit application reflecting the changes in the ammonia emissions. The ammonia emission calculation is also presented. Based on the ammonia impacts, which are well below the FDER no-threat level, no adverse environmental impacts are expected from the higher ammonia emissions.

Mercury Testing for Existing Facilities

In response to the suggestions made during our meeting with FDER on September 17, 1992, Okeelanta developed a proposed plan for investigating actual mercury emissions from the existing bagasse fired boilers at Okeelanta and Osceola. These investigations would be for the purpose of better quantifying actual baseline mercury emissions. As we discussed, the county zoning conditions and our proposed PSD permit conditions for the Flo-Energy and Sol-Energy facilities require that future mercury emissions not exceed the emissions from the existing facilities (in tons per year).

Okeelanta has conducted only one in-house mercury emission test on one boiler at their facility. This test was conducted during the past crop season using EPA Method 101A. The results of the tests are shown in the attached Table 1. The boiler was fired with bagasse and No. 6 fuel oil, with the fuel oil ranging from 15-20 percent of the total heat input. The average mercury emission rate for the boiler was 0.0020 lb/hr or 6.5×10^{-6} lb/MM Btu. The range of emissions was from 0.6×10^{-6} to 14.9×10^{-6} lb/MMBtu.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

These test results are helpful for establishing a range of approximate emission rates, but they are much too limited to use alone for direct comparisons or for the establishment of absolute permit limits. In order to obtain more data concerning mercury emissions from bagasse boilers, Okeelanta proposes to conduct mercury emission testing on four boilers during the coming crop year. Two boilers at Okeelanta and two at Osceola Farms would be tested. Two different boiler types would be tested at each facility (i.e., fuel cell and traveling grate). In addition, bagasse, ash, and scrubber water samples will be obtained and analyzed for mercury content. Based on these data, the baseline mercury emissions for the two facilities can be determined more accurately, and the future mercury limits for the two cogeneration facilities can then be adjusted, if necessary.

In order to minimize the cost of this testing, Okeelanta may prefer to perform the mercury tests during the annual PM compliance tests run each year on the boilers. If possible, the compliance tests to be conducted in the first quarter of 1993 will be performed earlier in order to obtain the data sooner.

Due to the critical timing of obtaining the air construction permits for the facilities, it is requested that the review of the permit applications not be delayed because of Okeelanta's voluntary effort to gather additional mercury data. Flo-Energy and Sol-Energy have already proposed permit conditions which allow further testing to better quantify the baseline mercury emissions (refer to proposed Condition 26 for Flo-Energy and Condition 25 for Sol-Energy).

Construction Emissions

Little information exists concerning air emissions due to construction activities. EPA Publication AP-42, Section 11.2.4 (12/75), presents an estimate of 1.2 tons of PM per acre per month of construction activity, applicable to a medium activity level and semi-arid climate. This factor is very general, has no correction factors, and has a very high degree of uncertainty. Therefore, this emission factor is not considered appropriate for application to Flo-Energy. Actual emissions due to construction activities would be dependent upon a number of factors, including vehicle types, speeds, operating hours, rainfall, soil moisture, meteorological conditions, control measures, and the types of construction activities. In the case of Flo-Energy, emissions due to construction will be controlled as specified in proposed Specific Condition 10 contained in the application. In summary, construction emissions for Flo-Energy cannot be readily quantified, but they will be temporary in nature. Due to the remote nature of the plant site, no significant off-site impacts due to construction activities are expected.

We are confident that this information will adequately respond to your questions, allowing a determination to be made on the acceptability of the application. Please call me at (904) 331-9000 if you have any questions concerning this information.

Sincerely,

David A. Buff

David A. Buff, ME, PE
Principal Engineer
Florida Registration No. 19011

SEAL

Enclosure
cc: Gus Cepero, Okeelanta
Don Schaberg, Okeelanta
David Dee, Carlton-Fields
Jewell Harper, EPA
H. Hanks
C. Halladay

John Bunyak, NPS
Frank Gargiulo, PBCHD
David Knowles, FDER
File (2)
I. Goldman, SE Dist

12118C4/RTC1/1

REVISED AMMONIA SLIP EMISSIONS FOR COAL BURNING

Maximum NH_3 slip will be 65 ppm based on vendor information.

Maximum flow rate per boiler when burning coal = 210,300 acfm

MW NH_3 = 17

PV = mRT   M = PV/RT

$M = 2{,}116.8\ lb_f/ft^2 \times 210{,}300\ ft^3/min \times 60\ min/hr \times 17\ lb_m\text{-}^0R/1{,}545\ ft\text{-}lb_f \div (460 + 350)^0R \times 65/10^6 = 23.6\ lb/hr$ each boiler

$23.6\ lb/hr \div 490 \times 10^6\ Btu/hr = 0.048\ lb/MMBtu$

Table 2-10. Maximum Hourly Emissions of Non-Regulated Pollutants for the Flo-Energy Cogeneration Facility (per boiler) (Revised 11/25/92)

Non Regulated Pollutant	Biomass				No. 2 Fuel Oil				Coal				Maximum Hourly Emission[a] (lb/hr)
	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	
Ammonia	0.0148	8	715	10.6	0.0148	8	490	7.3	0.048	8	490	23.6	23.6
Antimony	UD	3	715	–	2.32E-06	5	490	0.0011	3.49E-05	5	490	0.017	0.017
Arsenic	1.62E-04	10	715	0.116	5.00E-07	1	490	0.0002	2.64E-05	4	490	0.013	0.116
Barium	1.06E-04	3	715	0.076	6.69E-06	5	490	0.0033	7.44E-04	5	490	0.36	0.36
Bromine	1.47E-03	7	715	1.05	6.97E-06	5	490	0.00342	7.90E-04	5	490	0.387	1.05
Cadmium	5.43E-06	2	715	0.0039	1.58E-06	1	490	0.0008	1.36E-06	4	490	0.001	0.0039
Chromium	1.54E-04	10	715	0.110	1.39E-05	1	490	0.0068	1.66E-05	4	490	0.008	0.110
Chromium^{+6}	3.81E-05	9	715	0.027	2.78E-06	9	490	0.0014	3.32E-06	9	490	0.002	0.027
Cobalt	4.98E-04	7	715	0.356	1.17E-05	5	490	0.0058	7.20E-05	5	490	0.035	0.356
Copper	1.45E-04	10	715	0.104	4.20E-05	1	490	0.021	1.71E-04	4	490	0.084	0.104
Dioxin	6.93E-12	2	715	5.0E-09	–		490	–	–		490	–	5.5E-09
Furan	3.62E-10	2	715	2.6E-07	–		490	–	–		490	–	2.6E-07
Formaldehyde	6.56E-04	2	715	0.469	4.05E-04	1	490	0.20	2.20E-04	4	490	0.108	0.47
Hydrogen Chloride	3.70E-02	3	715	26.5	6.37E-04	6	490	0.312	7.90E-02	6	490	38.7	38.7
Indium	1.27E-04	7	715	0.091	–		490	–	–		490	–	0.091
Manganese	7.98E-04	2	715	0.57	3.08E-06	1	490	0.0015	3.10E-05	4	490	0.015	0.57
Molybdenum	2.54E-04	7	715	0.18	4.88E-06	5	490	0.0024	8.83E-05	5	490	0.043	0.18
Nickel	4.41E-05	2	715	0.032	4.76E-05	1	490	0.023	1.02E-03	4	490	0.50	0.50
Phosphorus	3.53E-04	3	715	0.25	5.81E-06	5	490	0.0028	8.60E-04	5	490	0.42	0.42
Selenium	UD	3	715	–	4.60E-06	1	490	0.0023	5.34E-05	5	490	0.026	0.026
Silver	2.94E-05	3	715	0.021	–		490	–	–		490	–	0.021
Thallium	UD	3	715	–	–		490	–	–		490	–	–
Tin	1.62E-04	7	715	0.12	3.30E-05	5	490	0.016	8.83E-05	5	490	0.043	0.12
Zinc	4.24E-04	2	715	0.30	6.69E-06	5	490	0.0033	3.49E-04	5	490	0.17	0.30
Zirconium	9.29E-05	7	715	0.066	–		490	–	–		490	–	0.066

Note: UD = undetectable levels in gas stream.

[a] Denotes maximum for any fuel.

References

1: Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and Sources, Second Edition EPA-450/2-90-011 (1990).
2: Based on "Air Toxic Emissions from Wood Fired Boilers", C. Sassenrath, 1991 TAPPI Proceedings.
3: Based on stack test results of wood fired boilers and fuel analysis at Seminole Kraft Corporation (1990) equipped with wet scrubbers.
4: Estimating Emissions from Oil and Coal Combustion Sources EPA-450/2-89-001 (1989).
5: Emissions Assessment of Conventional Stationary Combustion Systems Volume V, 1981. Based on an uncontrolled spreader stoker design and then assuming 90% control from ESP.
6: Emissions Assessment of Conventional Stationary Combustion Systems Volume V, 1981. Based on an uncontrolled spreader stoker design.
7: EPA PM/VOC Speciation Database, updated October, 1989.
8: Based on maximum 20 ppm NH_3 in exhaust gases for biomass and No. 2 fuel oil; 65 ppm for coal.
9: Based upon stack test data at Dade County RRF, 1992, which indicated less than 20% of total chromium was chromium^{+6}.
10: Same as reference 2; includes 3% treated wood burning.

Source: KBN, 1992.

Table 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for the Flo-Energy Cogeneration Facility (total all boilers) (Page 1 of 2) (Revised 11/25/92)

	Biomass			No. 2 Fuel Oil			Coal			
Non Regulated Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Total Annual Emission (TPY)
Normal Operations										
Ammonia	0.0148	11.500	85.1	–	–	–	–	–	–	85.1
Antimony	UD	11.500	–	–	–	–	–	–	–	–
Arsenic	5.58E-05	11.500	0.32	–	–	–	–	–	–	0.32 [a]
Barium	1.06E-04	11.500	0.61	–	–	–	–	–	–	0.61
Bromine	1.47E-03	11.500	8.45	–	–	–	–	–	–	8.5 [a]
Cadmium	5.43E-06	11.500	0.031	–	–	–	–	–	–	0.031 [a]
Chromium	5.54E-05	11.500	0.32	–	–	–	–	–	–	0.32 [a]
Chromium^{+6}	1.35E-05	11.500	0.078	–	–	–	–	–	–	0.078 [a]
Cobalt	4.98E-04	11.500	2.86	–	–	–	–	–	–	2.86 [a]
Copper	7.23E-05	11.500	0.42	–	–	–	–	–	–	0.42
Dioxin	6.93E-12	11.500	4.0E-08	–	–	–	–	–	–	4.0E-08 [a]
Furan	3.62E-10	11.500	2.1E-06	–	–	–	–	–	–	2.1E-06 [a]
Formaldehyde	6.56E-04	11.500	3.77	–	–	–	–	–	–	3.8 [a]
Hydrogen Chloride	3.70E-02	11.500	212.75	–	–	–	–	–	–	212.8
Indium	1.27E-04	11.500	0.73	–	–	–	–	–	–	0.73 [a]
Manganese	7.98E-04	11.500	4.59	–	–	–	–	–	–	4.6 [a]
Molybdenum	2.54E-04	11.500	1.46	–	–	–	–	–	–	1.5 [a]
Nickel	4.41E-05	11.500	0.25	–	–	–	–	–	–	0.25
Phosphorus	3.53E-04	11.500	2.03	–	–	–	–	–	–	2.03
Selenium	UD	11.500	–	–	–	–	–	–	–	–
Silver	2.94E-05	11.500	0.169	–	–	–	–	–	–	0.169 [a]
Thallium	UD	11.500	–	–	–	–	–	–	–	–
Tin	1.62E-04	11.500	0.93	–	–	–	–	–	–	0.93 [a]
Zinc	4.24E-04	11.500	2.44	–	–	–	–	–	–	2.44 [a]
Zirconium	9.29E-05	11.500	0.53	–	–	–	–	–	–	0.53 [a]
25% Oil Firing										
Ammonia	0.0148	8.118	60.1	0.0148	2.706	10.01	–	–	–	70.1
Antimony	UD	8.118	–	2.32E-06	2.706	0.0031	–	–	–	0.0031
Arsenic	5.58E-05	8.118	0.23	5.00E-07	2.706	0.0007	–	–	–	0.23
Barium	1.06E-04	8.118	0.43	6.69E-06	2.706	0.0091	–	–	–	0.44
Bromine	1.47E-03	8.118	5.967	6.97E-06	2.706	0.0094	–	–	–	5.976
Cadmium	5.43E-06	8.118	0.022	1.58E-06	2.706	0.0021	–	–	–	0.024
Chromium	5.54E-05	8.118	0.22	1.39E-05	2.706	0.0188	–	–	–	0.24
Chromium+6	1.35E-05	8.118	0.055	2.78E-06	2.706	0.0038	–	–	–	0.059
Cobalt	4.98E-04	8.118	2.02	1.17E-05	2.706	0.0159	–	–	–	2.04
Copper	7.23E-05	8.118	0.29	4.20E-05	2.706	0.0568	–	–	–	0.35
Dioxin	6.93E-12	8.118	2.8E-08	–	2.706	–	–	–	–	2.8E-08
Furan	3.62E-10	8.118	1.5E-06	–	2.706	–	–	–	–	1.5E-06
Formaldehyde	6.56E-04	8.118	2.7	4.05E-04	2.706	0.55	–	–	–	3.21
Hydrogen Chloride	3.70E-02	8.118	150.18	6.37E-04	2.706	0.8616	–	–	–	151.04

Table 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for the Flo-Energy Cogeneration Facility (total all boilers) (Page 2 of 2) (Revised 11/25/92)

	Biomass			No. 2 Fuel Oil			Coal			
Non Regulated Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Total Annual Emission (TPY)
Indium	1.27E-04	8.118	0.52	–	2.706	–	–	–	–	0.52
Manganese	7.98E-04	8.118	3.24	3.08E-06	2.706	0.0042	–	–	–	3.2
Molybdenum	2.54E-04	8.118	1.03	4.88E-06	2.706	0.0066	–	–	–	1.0
Nickel	4.41E-05	8.118	0.18	4.76E-05	2.706	0.0644	–	–	–	0.24
Phosphorus	3.53E-04	8.118	1.43	5.81E-06	2.706	0.0079	–	–	–	1.44
Selenium	UD	8.118	–	4.60E-06	2.706	0.0062	–	–	–	0.0062
Silver	2.94E-05	8.118	0.119	–	2.706	–	–	–	–	0.119
Thallium	UD	8.118	–	–	2.706	–	–	–	–	–
Tin	1.62E-04	8.118	0.66	3.30E-05	2.706	0.045	–	–	–	0.70
Zinc	4.24E-04	8.118	1.72	6.69E-06	2.706	0.0091	–	–	–	1.7
Zirconium	9.29E-05	8.118	0.38	–	2.706	–	–	–	–	0.38
<u>25% Coal Firing</u>										
Ammonia	0.0148	8.118	60.1	–	–	–	0.048	2.706	64.9	125.0 [a]
Antimony	UD	8.118	–	–	–	–	3.49E-05	2.706	0.047	0.047 [a]
Arsenic	5.58E-05	8.118	0.23	–	–	–	2.64E-05	2.706	0.036	0.27
Barium	1.06E-04	8.118	0.43	–	–	–	7.44E-04	2.706	1.01	1.44 [a]
Bromine	1.47E-03	8.118	5.97	–	–	–	7.90E-04	2.706	1.069	7.04
Cadmium	5.43E-06	8.118	0.022	–	–	–	1.36E-06	2.706	0.0018	0.024
Chromium	5.54E-05	8.118	0.22	–	–	–	1.66E-05	2.706	0.022	0.24
Chromium^{+6}	1.35E-05	8.118	0.055	–	–	–	3.32E-06	2.706	0.004	0.059
Cobalt	4.98E-04	8.118	2.02	–	–	–	7.20E-05	2.706	0.097	2.1
Copper	7.23E-05	8.118	0.29	–	–	–	1.71E-04	2.706	0.23	0.52 [a]
Dioxin	6.93E-12	8.118	2.8E-08	–	–	–	–	2.706	–	2.8E-08
Furan	3.62E-10	8.118	1.5E-06	–	–	–	–	2.706	–	1.5E-06
Formaldehyde	6.56E-04	8.118	2.7	–	–	–	2.20E-04	2.706	0.30	2.96
Hydrogen Chloride	3.70E-02	8.118	150.183	–	–	–	7.90E-02	2.706	106.89	257.1 [a]
Indium	1.27E-04	8.118	0.52	–	–	–	–	2.706	–	0.52
Manganese	7.98E-04	8.118	3.24	–	–	–	3.10E-05	2.706	0.042	3.3
Molybdenum	2.54E-04	8.118	1.03	–	–	–	8.83E-05	2.706	0.119	1.2
Nickel	4.41E-05	8.118	0.18	–	–	–	1.02E-03	2.706	1.38	1.56 [a]
Phosphorus	3.53E-04	8.118	1.43	–	–	–	8.60E-04	2.706	1.16	2.60 [a]
Selenium	UD	8.118	–	–	–	–	5.34E-05	2.706	0.072	0.072 [a]
Silver	2.94E-05	8.118	0.119	–	–	–	–	2.706	–	0.119
Thallium	UD	8.118	–	–	–	–	–	2.706	–	–
Tin	1.62E-04	8.118	0.66	–	–	–	8.83E-05	2.706	0.119	0.78
Zinc	4.24E-04	8.118	1.72	–	–	–	3.49E-04	2.706	0.47	2.2
Zirconium	9.29E-05	8.118	0.38	–	–	–	–	2.706	–	0.38

Note: UD = undetectable levels in gas stream.

[a] Denotes maximum annual emissions for any fuel scenario.

Table 6-18. Maximum Impacts of Toxic Pollutants for Flo-Energy Cogeneration Facility (total all boilers) (Revised 11/25/92)

Pollutant	Maximum Hourly Emissions[a] (lb/hr)	Concentrations ($\mu g/m^3$) 8-Hour Impact	8-Hour NTL	24-Hour Impact	24-Hour NTL	Annual Impact	Annual NTL
Ammonia	70.8	3.9	180	3.0	43.2	–	–
Antimony	0.051	0.0028	5	0.002	1.2	0.0002	0.3
Arsenic	0.35	0.0163	2	0.01	0.48	0.000226[b]	0.000230
Barium	1.08	0.0594	5	0.05	1.2	0.0033	50
Beryllium	0.0087	0.0005	0.02	0.0004	0.0048	0.00003	0.00042
Bromine	3.15	0.15	7	0.11	1.68	–	–
Cadmium	0.012	0.0005	0.5	0.0004	0.12	0.00003	0.00056
Chromium metals	0.33	0.0154	5	0.012	1.2	0.00087	1000
Chromium^{+6}	0.081	0.0041	0.5	0.003	0.12	0.000059[c]	0.000083
Cobalt	1.07	0.05	0.5	0.04	0.12	–	–
Copper	0.31	0.01	10	0.01	2.4	–	–
Dioxins/Furans	8.0E-07	–	–	–	–	2.1E-09	2.2E-08
Fluoride	35.4	1.95	25	1.48	6	–	–
Formaldehyde	1.41	0.07	4.5	0.05	1.08	0.004	0.077
Hydrogen Chloride	116.1	6.39	70	4.84	16.8	0.360	7.0
Indium	0.27	0.01	1	0.01	0.24	–	–
Manganese	1.71	0.08	50	0.06	12	–	–
Mercury	0.0123	0.0007	0.5	0.0005	0.12	0.00004	0.3
Molybdenum	0.54	0.03	50	0.02	12	–	–
Nickel	1.50	0.08	0.5	0.06	0.12	0.0011[d]	0.0042
Phosphorus	1.26	0.07	1	0.05	0.24	–	–
Selenium	0.08	0.004	2	0.003	0.48	–	–
Silver	0.06	0.003	0.1	0.002	0.024	0.0002	3
Thallium	–	–	–	–	–	–	–
Tin	0.36	0.02	1	0.01	0.24	–	–
Zinc	0.90	0.04	10	0.03	2.4	–	–
Zirconium	0.20	0.009	50	0.01	12	–	–

Note: NTL = no-threat level.
Maximum concentrations determined with ISCST2 model and West Palm Beach meteorological data for 1982 to 1986.
Highest predicted concentration ($\mu g/m^3$) for a 10 g/s (79.365 lb/hr) emission rate:
8-hour = 4.369
24-hour = 3.310
Annual = 0.2459

[a] Total all three boilers.
[b] Based on maximum annual average emission rate of 0.32 TPY total all three boilers (avg. of 0.073 lb/hr).
[c] Based on maximum annual average emission rate of 0.078 TPY total all three boilers (avg. of 0.018 lb/hr).
[d] Based on maximum annual average emission rate of 1.56 TPY total all three boilers (avg. of 0.356 lb/hr).

Table 1. Results of Mercury Stack Tests at Okeelanta - Boiler No. 12

Run #		µg Hg/l	Vol. (ml)	µg Hg	DSCFM	Meter SCF	Hg (lb/hr)	Heat Input (MMBtu/hr)	Hg (lb/MMBtu)
1)	P/N/I	23.12	1,000	23.12					
	Filter	4.06	102	0.414					
	Blank	0.82	101	-0.0828	58,228	39.120	0.00462	310.45	14.9 x 10^{-6}
	Total			23.451					
2)	P/N/I	0.79	1,050	0.830					
	Filter	2.04	99	0.202					
	Blank	0.82	101	-0.0828	57,942	38.161	0.000191	315.81	0.605 x 10^{-6}
	Total			0.949					
3)	P/N/I	5.06	1,065	5.389					
	Filter	5.47	101	0.552					
	Blank	0.82	101	-0.083					
	Total			5.858	58,823	38.240	0.00119	304.49	3.91 x 10^{-6}
						Avg.	0.0020		6.47 x 10^{-6}

Note: P/N/I = Probe, Nozzle and Impingers.
EPA method 101A used for testing.

ATTACHMENT A

FLO-ENERGY, INC.

NOTE: FINAL VENDOR SELECTION HAS NOT BEEN COMPLETED FOR THE FLO-ENERGY FACILITY. INFORMATION PROVIDED REPRESENTS THE DESIGN FOR ONE OF THE TWO VENDORS BEING CONSIDERED. THE EQUIPMENT FINALLY SELECTED WILL BE OF THE DESIGN SPECIFIED, OR EQUIVALENT

FDER Comment 1: Please provide the make, model, drawing, brochure, or general specifications for each steam generation unit. What is the generating capacity of each plant, 74.9 or 44 MW?

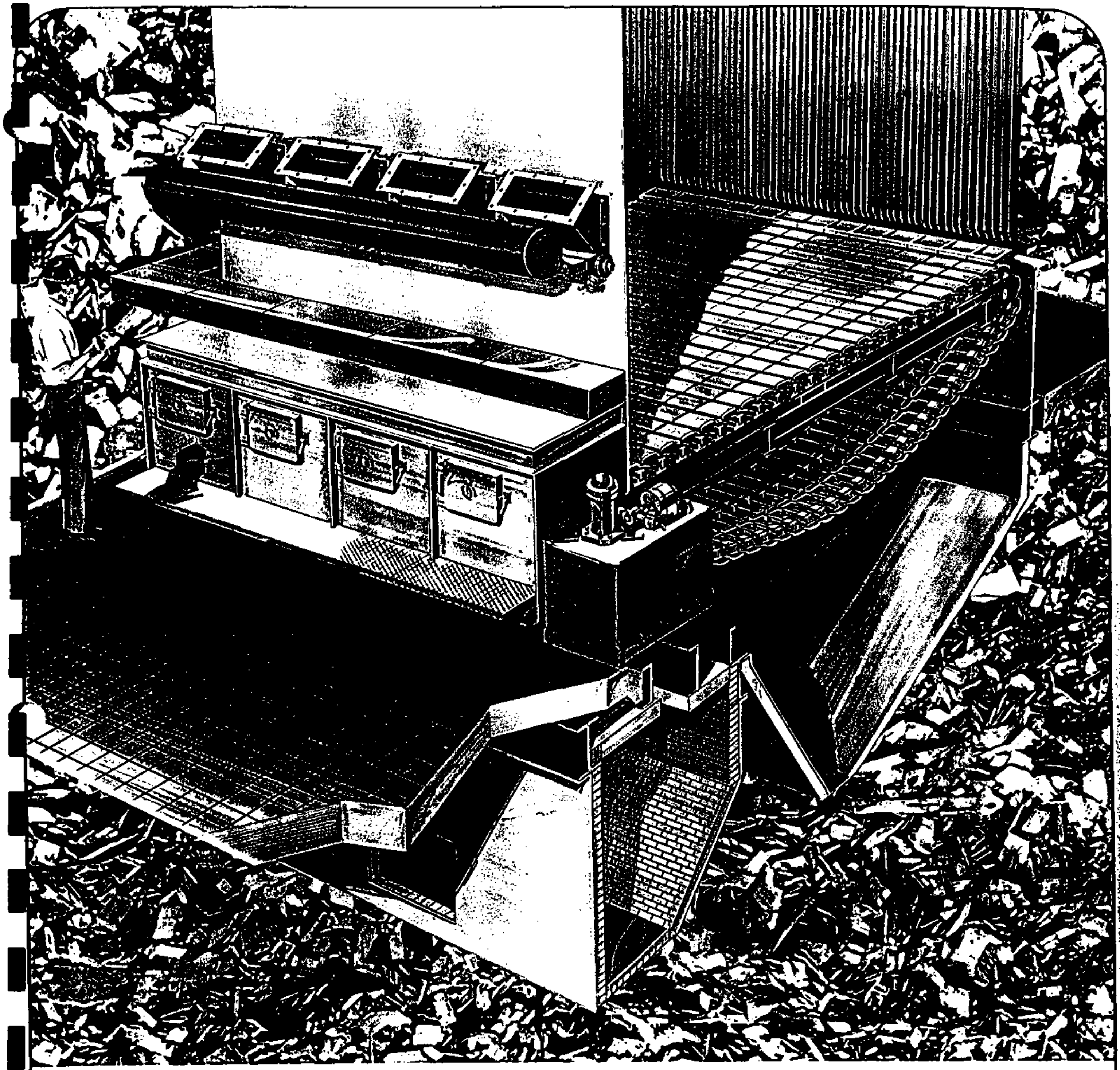
Response 1: The boilers will be manufactured by Zurn Industries, Inc. Design features of the boilers include the following:

- Two-drum, field erected, open pass, balanced draft steam generators
- Water cooled furnace with electrical resistance welded steel boiler tubes
- Superheater section
- Economizer section
- Primary air preheater
- Overfire air preheater
- Plenum hoppers, boiler hoppers and airheater hoppers for collection of fly ash
- Forced draft and induced draft fans
- Primary and overfire air systems
- Zurn Model SAO-32 No. 2 fuel oil burner; steam atomizing
- Spreader stoker; continuous traveling (Travagrate), front ash discharge, grate area of 585 sq. ft.

Design data for each boiler are as follows:

Furnace volume = 39,917 ft^3
Steam temperature = 975°F
Steam pressure = 1,800 psig (design); 1,500 psig (operating)
Steam output = 455,418 lb/hr
Heat input = 715 x 10^6 Btu/hr (biomass)
= 490 x 10^6 Btu/hr (coal)

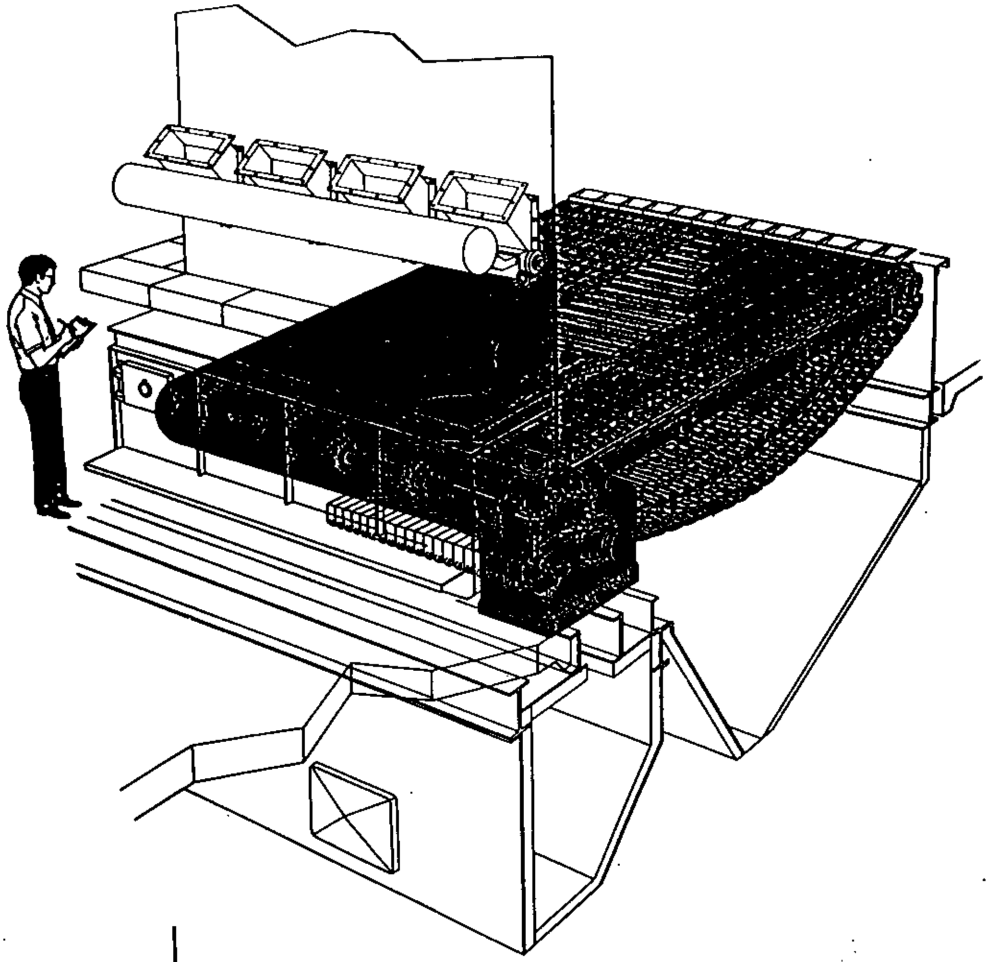
The maximum electric generating capacity of the Flo-Energy facility will be 74.9 MW.



ZURN SPREADER STOKERS

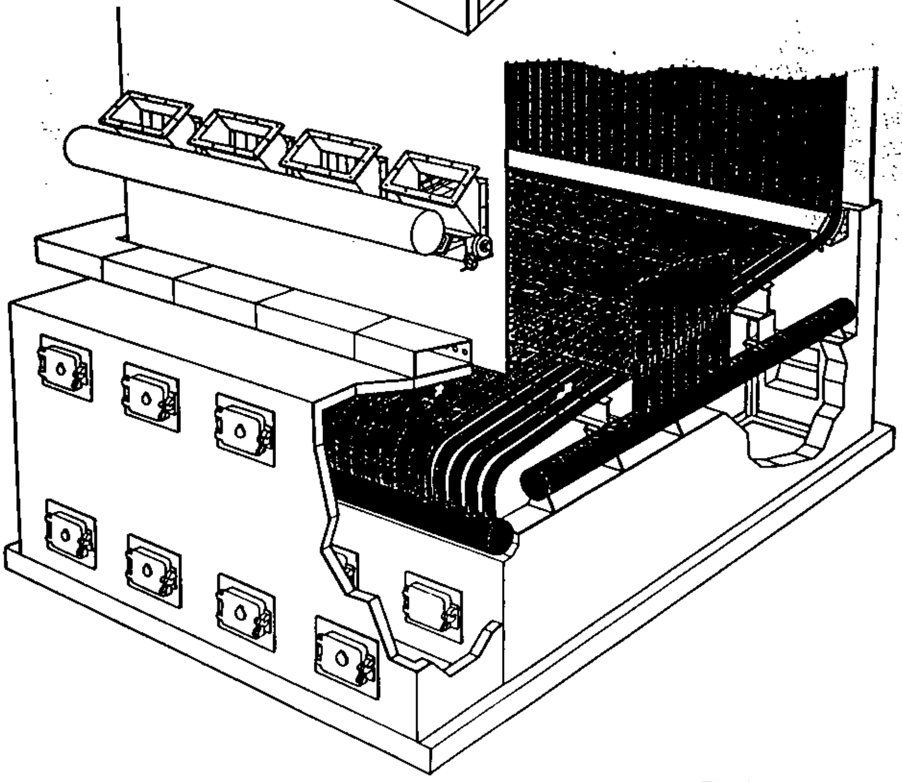
FOR WOOD, WOOD WASTE, MUNICIPAL REFUSE, AND OTHER BIOMASS FUELS

ZURN | *a step ahead of tomorrow*



The Zurn TRAVAGRATE® spreader stoker is an overfeed-type stoker designed for continuous ash discharge in steam generators with capacities ranging from 10,000 to 50,000 lbs/hr factory-assembled and 30,000 to 500,000 lbs/hr field-constructed. Fuel is burned in suspension as well as on the forward-traveling grate surface.

Zurn TRAVAGRATE spreader stokers consist of single or dual drive grate assemblies complete with hydraulic grate drive(s) and necessary pneumatic fuel distributors.



The Zurn stationary, water-cooled grate spreader stoker is also an overfeed stoker designed for intermittent zoned cleaning in steam generators with capacities ranging from 10,000 to 40,000 lbs/hr factory-assembled and 30,000 to 300,000 lbs/hr field-constructed. Fuel is burned in suspension as well as on the grate surface.

Zurn stationary, water-cooled grate spreader stokers can be automatically cleaned by intermittent air or steam by zones while maintaining full load operation. Pneumatic fuel distributors provide continuous feed of a variety of non-fossil solid fuels.

SPREADER STO
A RESOURCEFUL ENERGY ALTERNATIVE

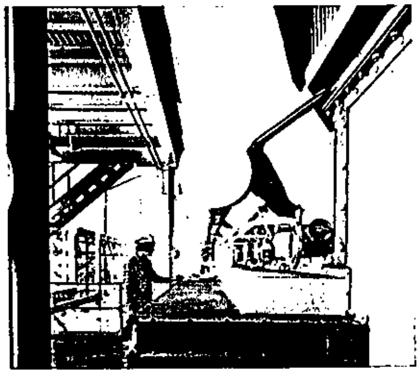
Renewable energy resources such as wood, refuse and other biomass wastes are receiving greater consideration as primary energy sources by industry and utilities.

In the early 1900's, wood was the major source of energy in the United States. Today, wood, agricultural wastes and other biomass supply almost 2% (1.5 *Quads/year) of U.S. energy, 7% of industrial energy. Government analysts estimate bioenergy resources could supply 15 to 20% (12-17 Quads/yr.) of U.S. energy by the year 2000. The combustible portion of municipal solid waste, now generated at 135 million tons/year has the potential of providing another 2%.

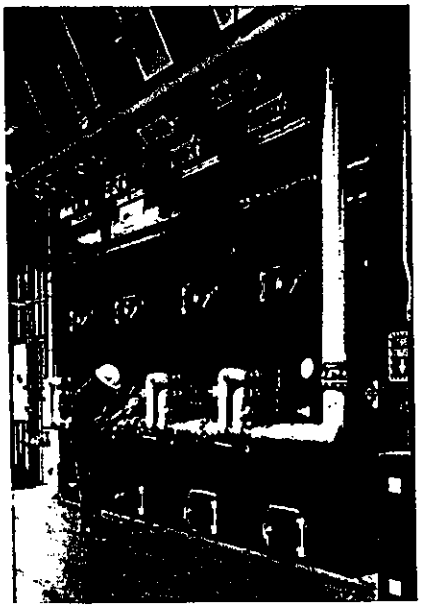
Higher costs for basic fossil fuels coupled with favorable legislation have greatly increased the financial viability of using alternate fuels. Stoker-fired systems are an excellent way to capitalize on these valuable energy resources.

The Energy Division of Zurn Industries, Inc. designs, engineers, manufactures and installs spreader stokers for burning a wide variety of wood, refuse and biomass fuels in boilers produced by Zurn or by any other boiler manufacturer.

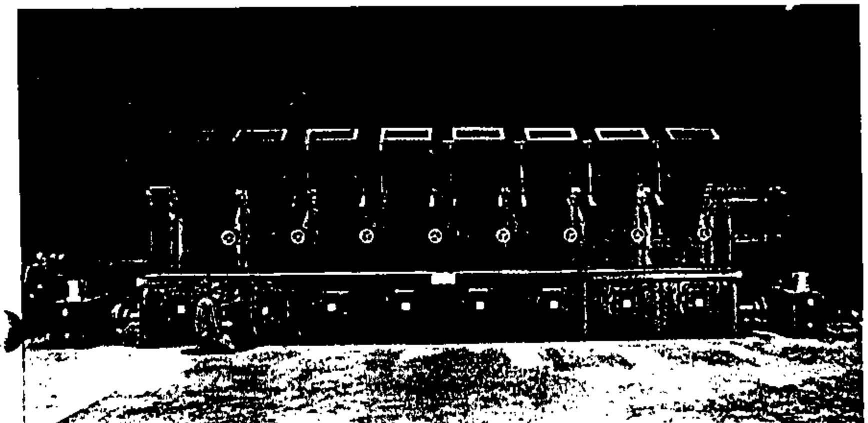
*A Quad equals 1 quadrillion (10^{15}) Btu. It equals the energy of approximately 464,000 bbl/d of oil for 1 year, 50 million tons of coal, or the typical annual energy output of eighteen 1,000 Mw power plants. Energy consumption in the U.S. totalled 70.45 Quads in 1983.



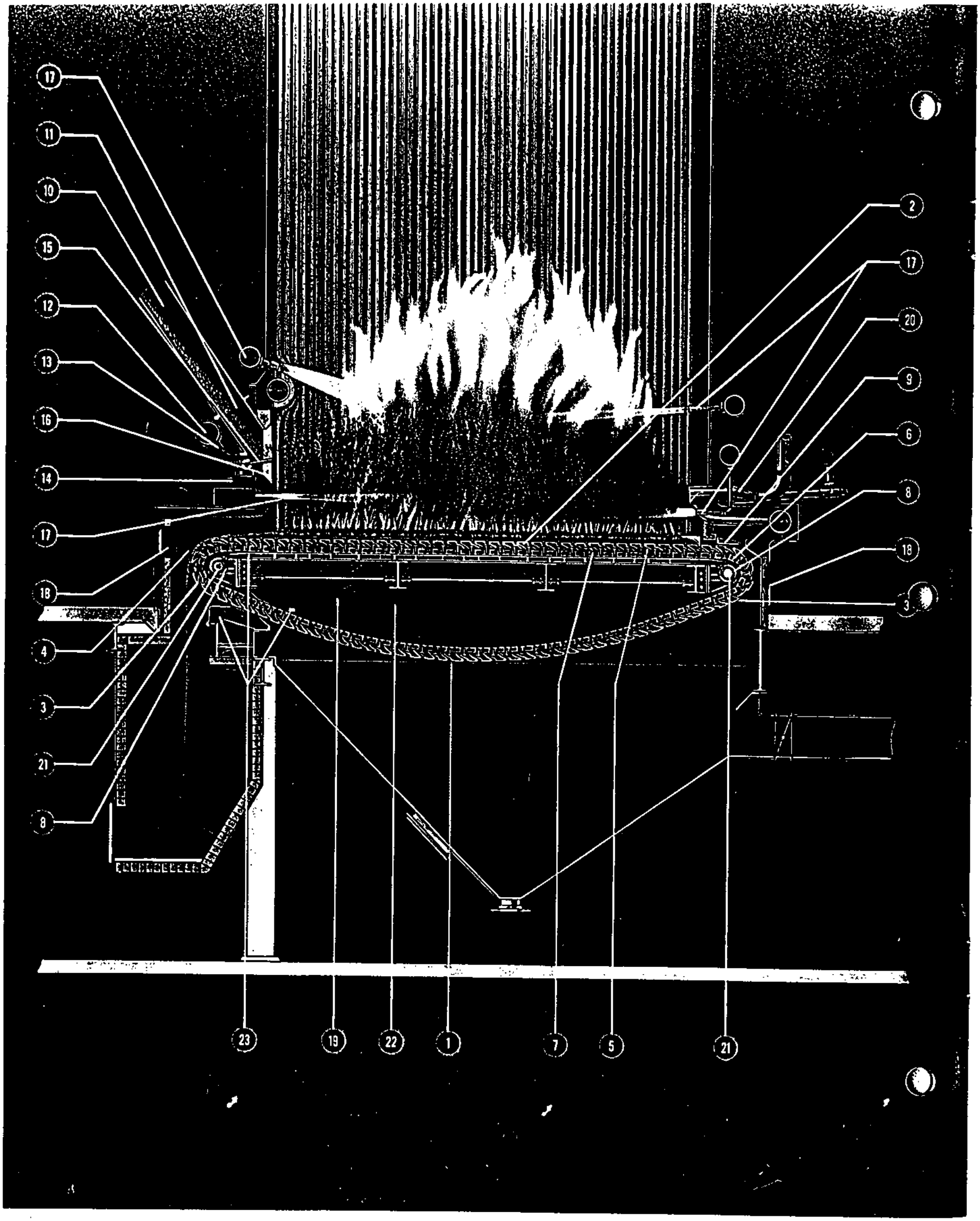
◀ *Zurn TRAVAGRATE spreader stoker provides continuous-ash-discharge for a 140,000 lb/hr wood-fired unit in a Texas forest-products producing plant. System was designed for future lignite firing and future cogeneration.*



◀ *Zurn stationary water-cooled-grate spreader stoker allows intermittent zoned cleaning of grates in a 120,000 lbs/hr unit at a Georgia paper plant.*



◀ *Zurn pneumatic fuel distributor assembly, TRAVAGRATE spreader stoker and hydraulic grate drives were pre-assembled at Zurn Energy Div. fabrication facility to assure component fit and alignment. System is installed and providing 480,000 lbs/hr steam to produce electricity for a 50 Mw wood-fired municipal power plant.*


17
11
10
15
12
13
16
14
17
18
4
3
21
8
2
17
20
9
6
8
18
3
23
19
22
1
7
5
21

ZURN TRAVAGRATE SPREADER STOKER FOR CONTINUOUS OPERATION

FEATURES

① **Catenary design** provides for automatic take-up or tensioning of grate chains to prevent jamming. Effective catenary is maintained by gravity, thus making external shaft adjustments unnecessary.

② **Grate surface** consists of a series of grates specifically designed for spreader stoker firing. The grates are constructed of high-quality, heat-resistant, ductile iron.

③ **Grate curvature** design keeps the grates closed without the aid of auxiliary weights when making the turn around the sprockets.

④ **Grate removal** is easily achieved via a grate access door. On removal of one bolt, any grate section can be replaced while the stoker is in operation.

⑤ **The chain grate assembly** consists of forged-steel chain clips and hardened link pins and rollers. The chain clips avoid chain breakage while the hardened link pins and rollers reduce stress and wear on shaft bearings and sprockets.

⑥ **Hardened link pins** that make up the grate chain assembly are held in place by the grate carrier bars, thereby eliminating cotter pins and assuring locked pin position.

⑦ **Grates are full-bearing-supported** the entire width of the grate on carrier bars, avoiding possible grate damage from falling slag and grate warpage from too little ash on the grate.

⑧ **Oversize split sleeve bronze bearings** are strategically located for both drive and idler shaft support. Bearing sleeves can be reversed for additional life.

⑨ **Rear fuel and air seal** enables the rear water wall to expand while maintaining tightness, thus reducing air leakage and preventing fuel carry-over into the stoker plenum.

⑩ **The refuse feeding chute** for the fuel distributor is constructed for large capacity, continuous flow.

⑪ **Air-swept fuel distributors** direct the volume of fuel being fired.

⑫ **A high pressure air duct** continually supplies transport air to the solid fuel being fed.

⑬ **A metering damper** allows adjustment of air flow for proper front-to-rear fuel distribution.

⑭ **A distributor setting device** determines the positioning of the fuel trajectory plate.

⑮ **The distributor deflector plate** allows for lateral and longitudinal fuel distribution into the furnace.

⑯ **The fuel distributor opening** located adjacent to the boiler front, is completely air-cooled.

⑰ **An overfire air system** is strategically located to provide turbulence and thorough mixing of the volatile gases, thus enhancing the combustion process. Two rows are located in the front wall and two rows in the rear wall.

⑱ **Front and rear access doors,** normally a pair for each distributor, provide for stoker inspection at the ash discharge extension housing (front) and at the rear stoker housing.

⑲ **Undergrate access doors,** located on each side of the stoker housing, provide inspection of and access to grate assembly.

⑳ **A char recovery system** of the straight-through, pneumatic type is furnished with all necessary inner-hardened steel pipe and reinjection nozzles.

㉑ **Front and rear grate shafts** carry the grate chains on hardened sprockets. Bearings and sprockets are strategically located along the shafts for maximum load-bearing efficiency.

㉒ **The air pressure chamber,** completely sealed both front and rear to prevent air leakage, directs and distributes hot combustion air through the active grate surface.

㉓ **Three front undergrate air seals** limit air by-passing to the ash discharge end.

OPERATION

Fuel is continuously and automatically fed from the fuel chute into the air-swept fuel distributors where it is advanced across a specially-designed trajectory plate into the furnace. Fuel distribution, front-to-rear and laterally within the furnace, is controlled by combination setting of high-pressure transport air and trajectory plate angle setting.

Strategically-located, high-pressure overfire air jets provide turbulence and thorough mixing of fuel/air to enhance the combustion process. As a further aid to complete combustion, hot combustion air is evenly distributed through the active grate surface. Fine particles of fuel are rapidly burned in suspension while coarser, heavier particles are spread evenly on the grate surface.

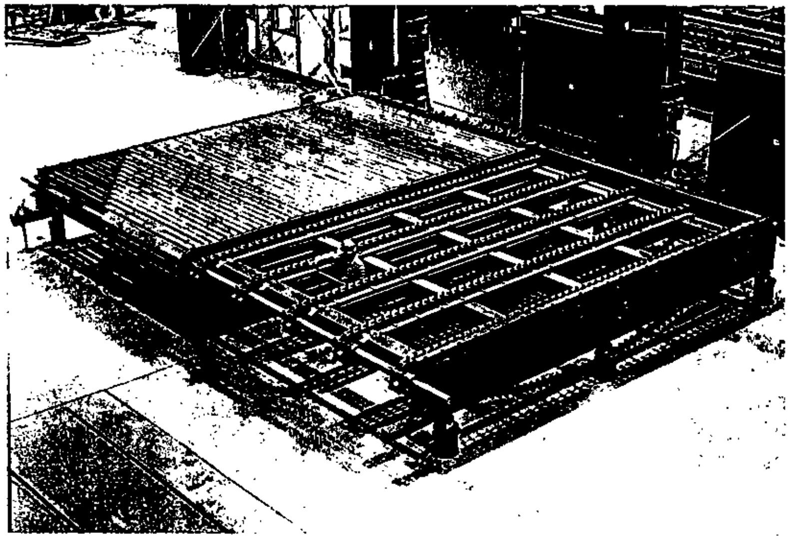
To compensate for variations in ash content, grate speed is adjustable from 0 to 24 feet per hour. The ash is continuously discharged over the front end of the grate into an ash pit or hopper.

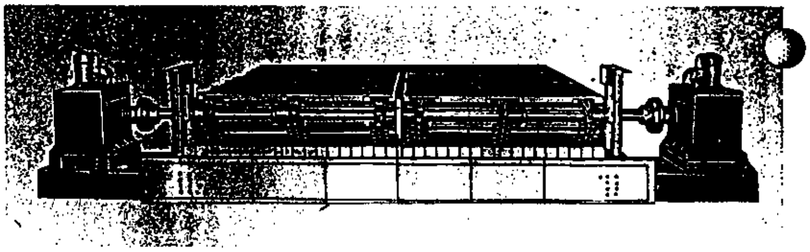
STOKER

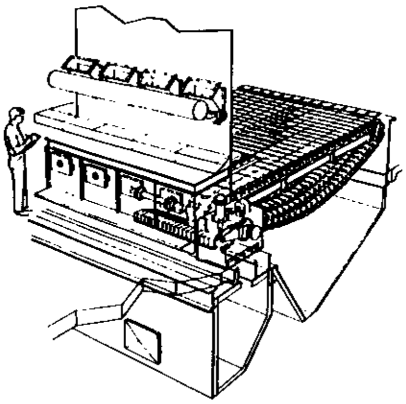
DRIVE COMPONENTS PROVIDE MAXIMUM PERFORMANCE

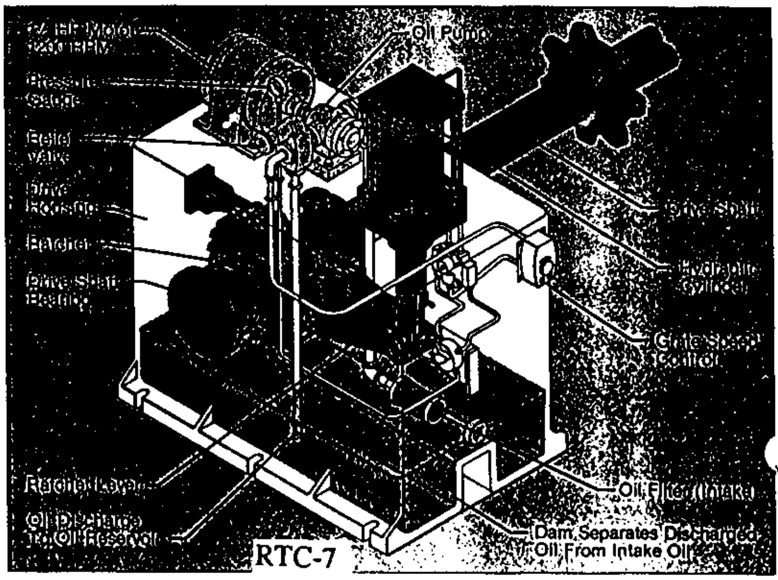
Zurn TRAVAGRATE spreader stokers are designed to provide continuous ash discharge. Grate sections mounted on carrier bars are pulled forward by forged steel chain links on skid rails. Heavy-duty, hardened sprockets specially designed for the roller chain pin design, reduce stress and provide longer life. Sprockets, located on the drive shaft, pull the chain assembly toward the front while sprockets on the idler shaft align the grate assembly at the rear.

Grates are driven by one or two hydraulic grate drives which can develop up to 30,000 ft-lbs of torque each. Grate speeds can be infinitely regulated from 0 to 24 feet per hour.





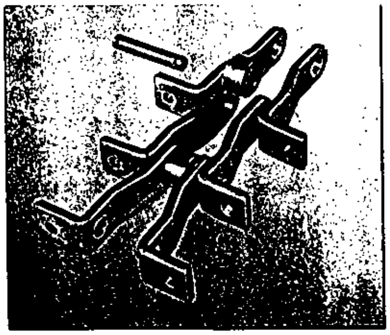




Overall view of TRAVAGRATE stoker assembly. Grate sections have been removed to show carrier bars, chains, sprockets and shaft assemblies. Shafts, bearings, sprockets and chains are pre-assembled at Zurn Energy Div. to assure component fit and alignment.

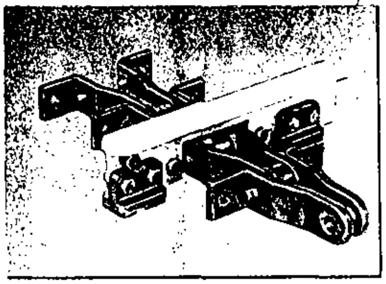
Front view of grate assembly showing a typical dual-drive application. Grate sections have been removed to show the center grate divider and dual shafts, chain sprockets, bearings and carrier bars.

The TRAVAGRATE hydraulic grate drive is a self-contained unit in a single housing with no external piping. Hydraulic pump and control regulate the flow, and pressure to the hydraulic cylinder which is connected through linkage to a ratchet gear that drives the main shaft. The hydraulic drive and main shaft are connected by a heavy-duty flange coupling. No shear pins are used in connection with the unit drive since the hydraulic unit is equipped with a factory-set relief valve to protect the grates should the need arise. To compensate for variation of the ash content in the fuel, the drive can be infinitely regulated to control the grate speed from 0 to 24 feet per hour.

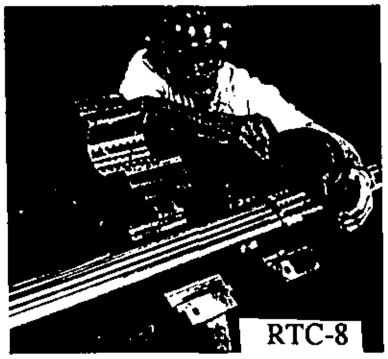


The Zurn TRAVAGRATE stoker is furnished with forged steel chain links, avoiding chain breakage and downtime. The chain is also furnished with hardened rollers and pins which reduce stress and reduce friction to the sprockets, thereby extending the sprocket life. Other manufacturers provide cast iron chain links, and use the drag-chain principle without rollers.

Close-up view of the grate chain assembly clearly shows the rugged construction required to make a traveling grate stoker a continuous-ash-discharge stoker.



Hardened link pins that make up the grate chain assembly are held in place by the grate carrier bars, thereby eliminating cotter pins and assuring locked pin position.



Oversize, split-sleeve, graphite-plugged bronze bearings are strategically located for both drive and idler shaft support. Bearings can be reversed for additional life. Bearings are manually-lubricated via grease lines conveniently located on stoker side housing.

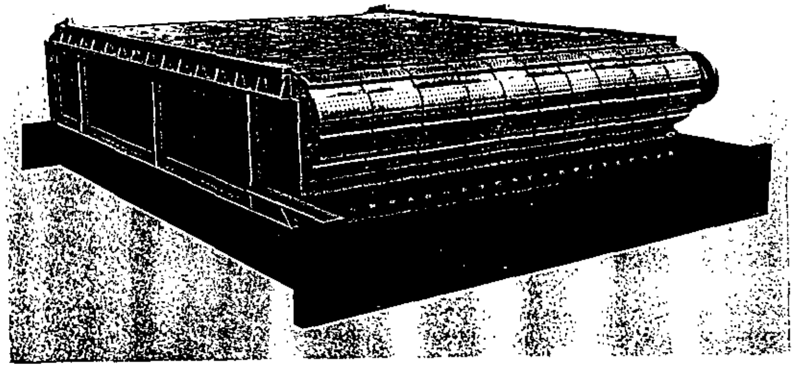
TRAVAGRATE STOKERS FIT ANY BOILER, ARE EASY TO MAINTAIN

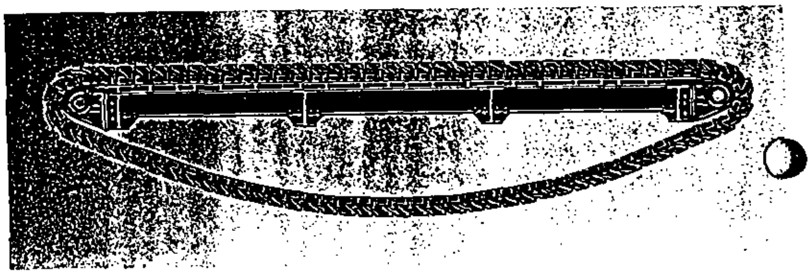
The Zurn TRAVAGRATE stoker is designed and manufactured for years of continuous operation with minimum maintenance.

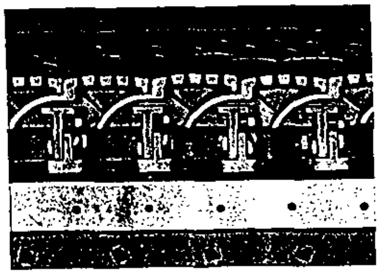
The TRAVAGRATE spreader stoker is available in various sizes to fit virtually any furnace. Stoker widths range from 7 feet to 34 feet wide, and shaft centers range from 11 feet to 25 feet.

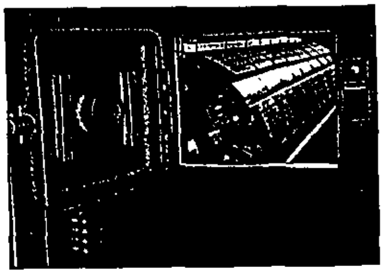
The various components are arranged for maximum efficiency and unnecessary parts have been eliminated. All sections directly exposed to the furnace are constructed of best-quality, heavy-duty, heat-resisting ductile cast iron for long service life.

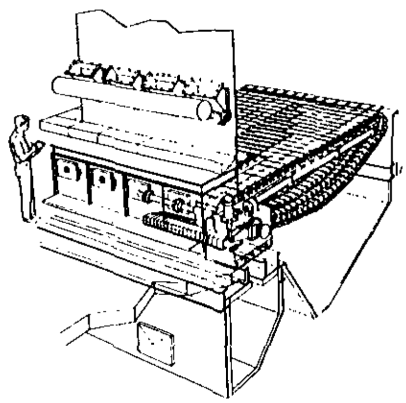
Maintenance is simplified by convenient access to all areas and external grease fittings.

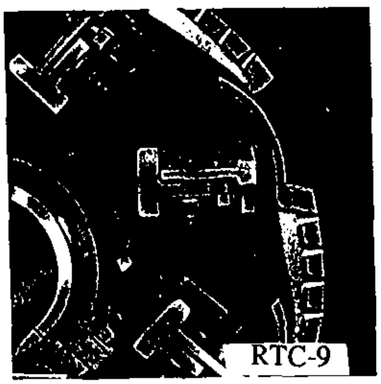


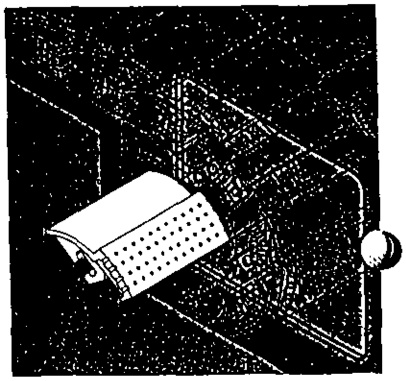




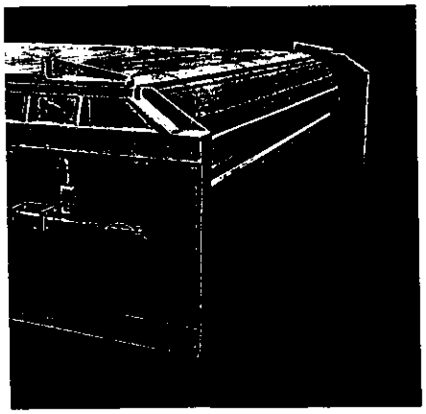






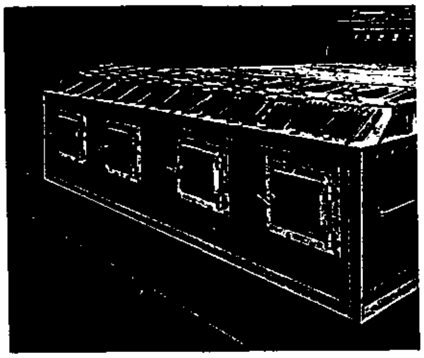


◀*The stoker front has been removed to show the grate assembly and supporting structures. Curvature design of the grates keeps the grates closed without the aid of auxiliary weights when making the turn around the sprockets. With this design, no gaps appear between the grates, thereby directing all foreign materials into the ash pit and not into the driven shaft mechanism.*



◀*A grate alarm system, built into the rear end of the grate assembly, is designed so that any foreign material or obstruction in the grates will come in contact with the alarm and immediately stop the stoker. An alarm is usually connected to an annunciator in the control room to alert the operator.*

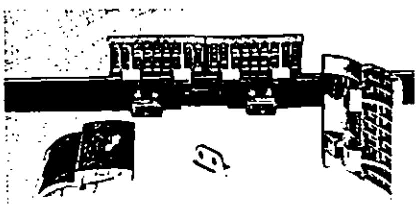
◀*Zurn catenary design provides for automatic take-up or tensioning of grate chains to prevent jamming. Effective catenary is automatically maintained by gravity thus making external shaft adjustments unnecessary.*



◀*TRAVAGRATE stoker from the rear clearly shows convenient location of access doors for ease of inspection.*

◀*(Far left) Side view of grate assembly showing the level and uniform grate support, hardened skids and skid rails. Note that each grate section is individually supported by its own series of skid shoes.*

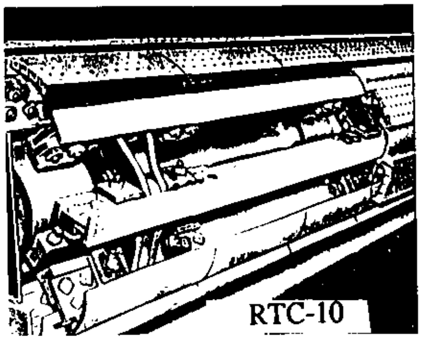
◀*(Near left) A view through the side access door at the ash discharge end of the grate assembly shows how easily grates can be removed.*



◀*To reduce maintenance costs, grate surface is made in short sections (12" to 15" long) of best quality, heavy-duty, heat-resisting ductile iron with uniformly-spaced, tapered, self-cleaning, air-metering openings, and with close-fitting, overlapping edges to reduce air leakage at the joints.*

◀*(Far left) Close-up view through the side access door of the grate assembly as it makes its gapless turn around the ash discharge end (front). View clearly shows single bolt, nut and washer for grate removal.*

◀*(Near left) Any grate section can be replaced without taking the steam generator or stoker out of service. Simply remove a single bolt, nut and washer and slide the grate off the carrier bar.*

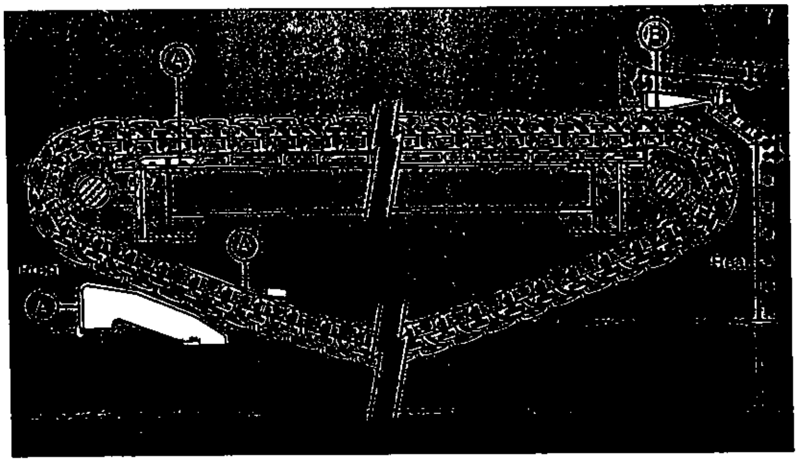


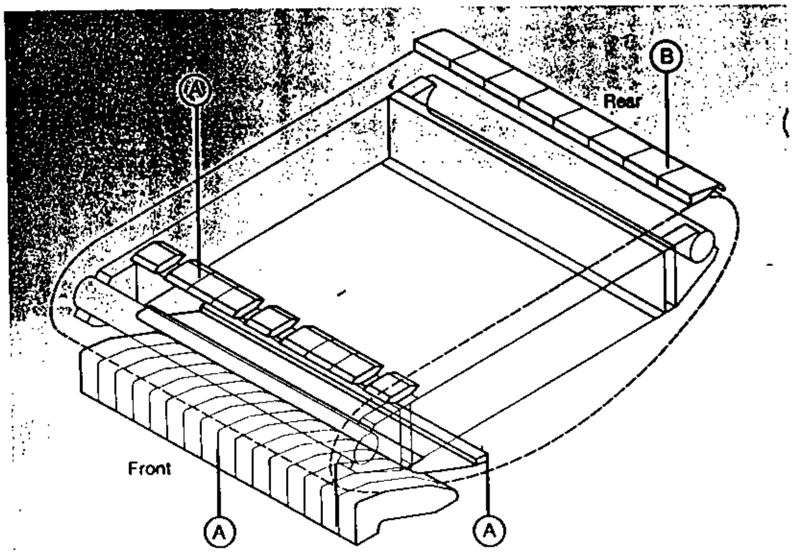
◀*Close-up view of grate assembly as it makes the turn around the ash discharge end. Grates are completely supported the full width of the stoker by carrier bars, thereby avoiding possible grate damage from falling slag and grate warpage due to too little ash on the grate surface.*

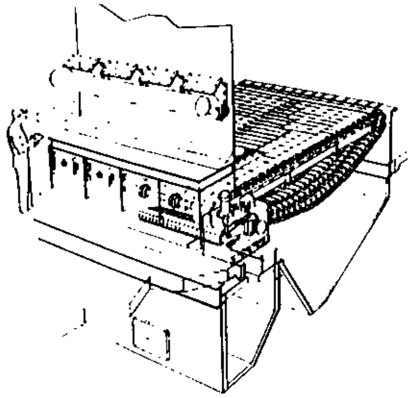
DESIGNED FOR INTEGRAL BOILER/STOKER EFFICIENCY

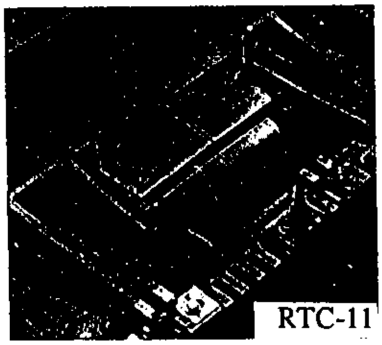
Zurn TRAVAGRATE spreader stokers are designed to operate within a variety of boiler designs. Every effort is made to merge the stoker operation and the boiler operation into an integrated system.

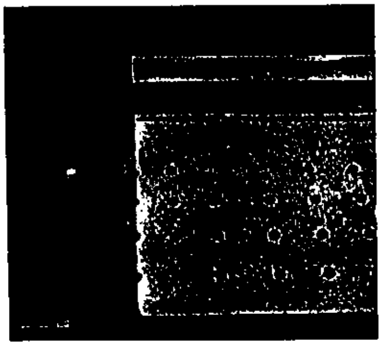
TRAVAGRATE stoker front and rear air seals automatically keep excess air to a minimum within the furnace. These front and rear seals are ruggedly constructed for long service and are automatically self-adjusting to maintain continuous close sealing contact.











◄ *TRAVAGRATE stoker air/fuel seals —*

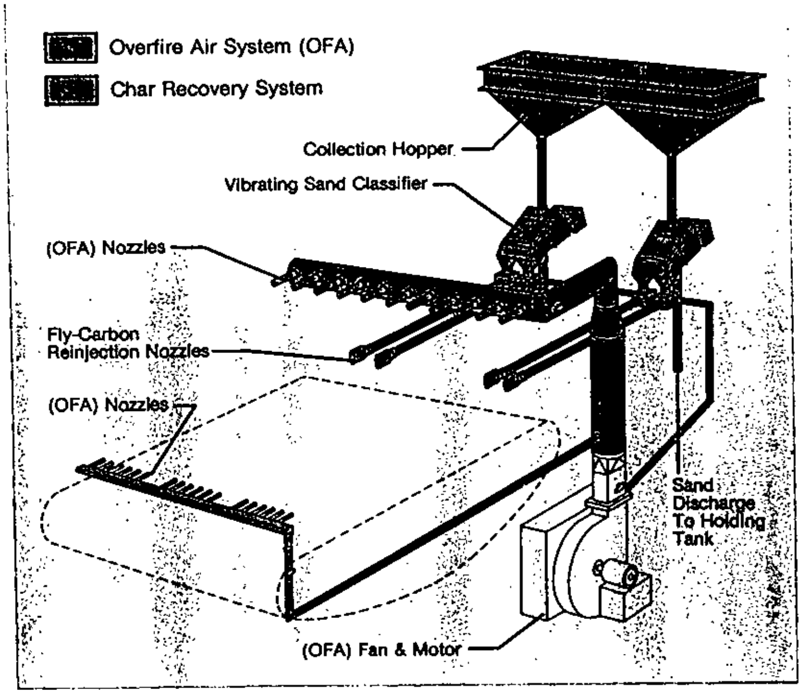
A. Three front undergrate seals limit air by-pass to the ash-discharge section and reduce excess air to a minimum within the furnace.

B. Rear fuel and air seal enables the rear water wall to expand while maintaining tightness, thus reducing air leakage and preventing fuel carryover into the stoker plenum.

◄ *Location of air/fuel seals relative to grate assembly.*

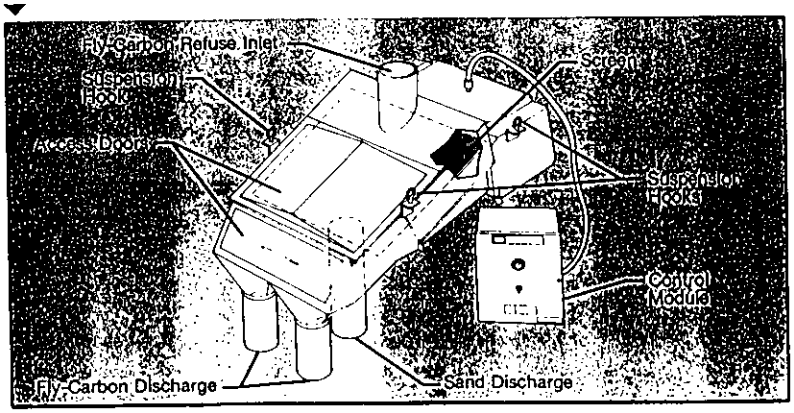
◄ *(Far left) Close-up view of rear air/fuel seal.*

◄ *(Near left) The side fuel seals enable the grates to expand while preventing fuel carryover into the stoker plenum.*

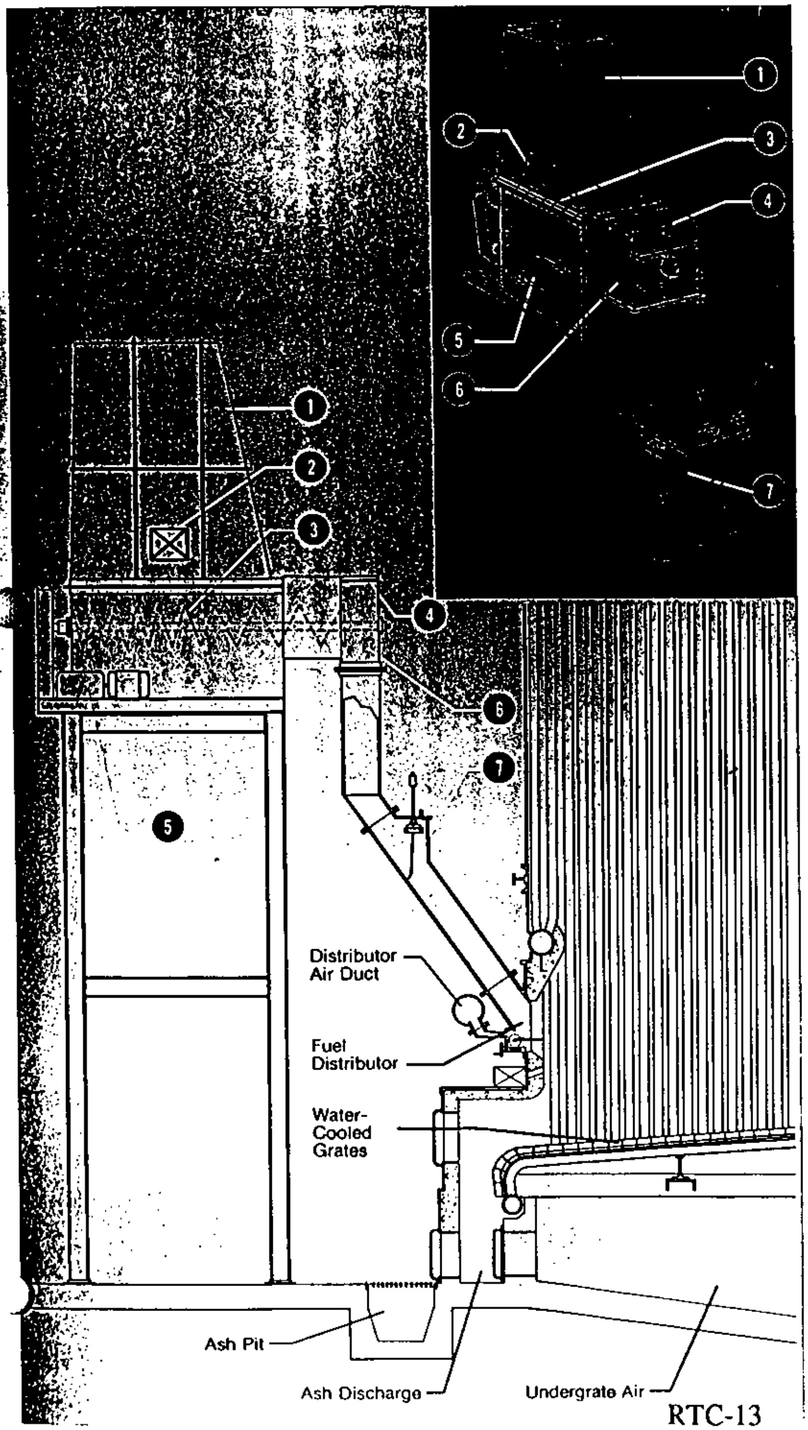


▲
Each Zurn TRAVAGRATE spreader stoker is provided with an overfire air and char recovery system. The overfire air system must be located to provide turbulence and thorough mixing of the volatile gases, thus enhancing the combustion process. Zurn overfire air systems are designed for 30% of the total air for combustion at 80°F and 30 inches W.C. of static pressure for successful combustion of the fuel. The high pressure overfire air fan, in addition to supplying air to the overfire system, also provides the air supply for the char recovery system. Reinjection of the fly-carbon into the furnace in the high temperature zone just above the fuel bed results in an increase in boiler efficiency.

Wood bark in some regions is impregnated with sand. When reinjected with the fly-carbon, damage to the convection surface may occur. To reduce this erosion, the sand is effectively separated from the fly-carbon by vibrating sand classifiers shown below. Each sand classifier is furnished with a control module.
▼



ZURN HOGGED WOOD FUEL FEEDERS PROVIDE A CONTINUOUS, CONTROLLED SUPPLY OF FUEL



Zurn fuel feeders are designed to meter hogged wood and other waste fuels to the distributor and into a stoker-fired steam generator. Fuel metering is achieved by driving the auger screw with a direct-current motor, the speed of which is regulated by combustion control signals. Both double and single-screw designs are available in a variety of sizes and drive-motor capacities according to feed requirements.

Features of the Zurn fuel feeder include:

❶ **A large storage hopper, sized to site conditions, incorporates expanding sides and ends to avoid fuel hangup.**

❷ **Access doors and observation ports are provided for inspection.**

❸ **A variable-pitch screw auger virtually eliminates jamming.**

❹ **An inspection door allows viewing and access to the feeder discharge chute.**

❺ **A variable-speed drive unit, also sized to feed requirements, provides fuel metered in response to boiler demand.**

❻ **The feeder discharge chute is sized** for maximum feed, minimum hangup.

❼ **A back-draft, shutoff damper protects** the fuel supply if the furnace should go positive. An access door is provided for inspection.

ZURN WOOD/REFUSE/BIOMASS-FIRED STOKER INSTALLATIONS: THE LARGE AND SMALL OF IT

Zurn TRAVAGRATE spreader stokers . . . and Zurn water-cooled grate spreader stokers . . . can be installed in a variety of steam generating systems. They are applicable to new or retrofit installations for heat, process, electric power or cogeneration in Zurn or non-Zurn boiler designs.

Zurn also designs, engineers and constructs a complete line of non-fossil fuel steam generators ideally suited for utilizing Zurn spreader stoker designs. Typical Zurn boiler/stoker combinations (illustrated at right) include:

Ⓐ Zurn 2DR-OP watertube steam generator with TRAVAGRATE spreader stoker for wood firing only. Steam capacities range from 50,000 through 500,000 lbs/hr.

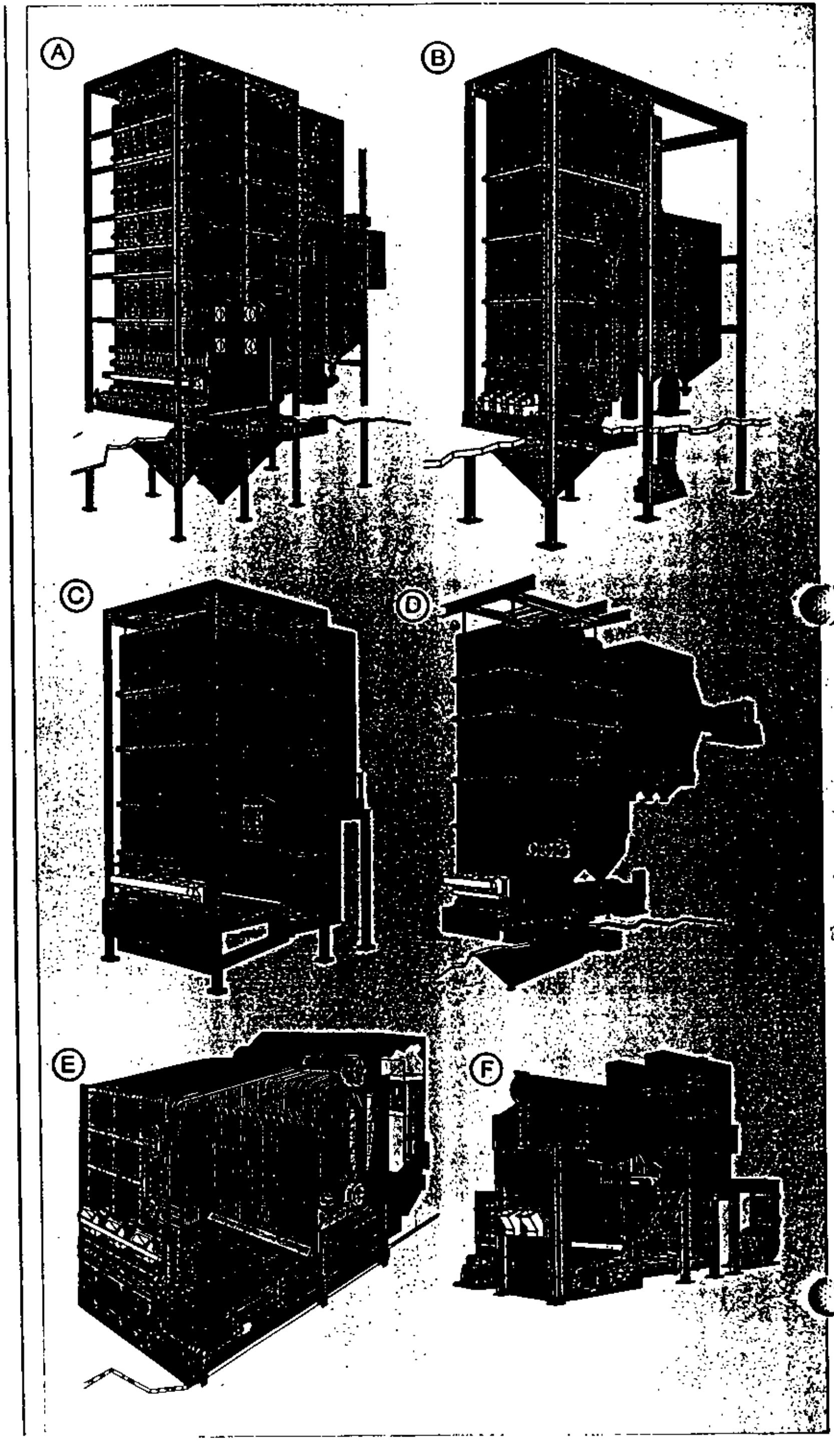
Ⓑ Zurn 2DR-OP watertube steam generator with TRAVAGRATE spreader stoker for combination firing of wood and coal. Steam capacities range from 50,000 through 500,000 lbs/hr.

Ⓒ Zurn 2DR-OP watertube steam generator with water-cooled grate spreader stoker for wood firing. Steam capacities range from 50,000 through 300,000 lbs/hr.

Ⓓ Zurn 2DR-OP watertube steam generator with TRAVAGRATE spreader stoker for refuse-derived-fuel (RDF) firing. Steam capacities range from 50,000 through 250,000 lbs/hr.

Ⓔ Zurn VC-MP watertube steam generator with water-cooled grate spreader stoker for wood firing. Steam capacities range from 30,000 through 150,000 lbs/hr.

Ⓕ Zurn VL-MP watertube steam generator with water-cooled grate spreader stoker for wood firing. Units are modularly factory-assembled for steam capacities ranging from 10,000 through 50,000 lbs/hr.



ZURN a step ahead of tomorrow

ZURN INDUSTRIES, INC.
ENERGY DIV.
1422 EAST AVE.
ERIE, PA, U.S.A. 16503-1592
PHONE: 814/452-6421
TELEX: 91-4473

Form No [illegible]

FDER Comment 2: Will these boilers operate under negative pressure?

Response 2: The boilers are balanced draft boilers and will operate under a slight negative pressure (about 0.15 inches H_2O). A balanced draft furnace prevents leakage of flue gas out of the unit. Any air movement through the boiler walls will be in the form of air in-leakage.

FDER Comment 3: What is the range in temperature, pressure, and steam production for the 350 psig/650°F and 20 psig/280°F steam sources?

Response 3: The boilers are designed for a pressure of 1,800 psig. The actual operating pressure will be approximately 1,500 psig with a steam temperature of approximately 975°F. Maximum steam production for each boiler will be 455,418 lb/hr. The lower pressure and temperature steam production figures presented in the application represent the steam extracted from the steam turbine and sent to the sugar mill for use in the process. The process steam conditions will normally be controlled within a ±10 percent range. During normal operating conditions, the process steam flow can be expected to fluctuate within a ±25 percent range from flows stated in the application. During startup, shutdown, upset, or transient conditions, steam flow could diminish to zero.

<u>FDER Comment 4</u>: How will the heat input by the various fuels to the boilers be monitored? What parameters of the fuels will be monitored and at what frequency? What test methods will be used? Where will the samples be collected? How often will a sample be collected on each fuel used at the proposed facilities. How will this data be used to show compliance with the various sulfur dioxide standards?

<u>Response 4</u>: The heat input to the boilers will be measured in two separate ways. The first method is by continuously monitoring steam production, pressure and temperature and using the design heat transfer efficiencies (refer to Table 2-2 of the application). Using this information and the enthalpies of the steam, the heat input can be calculated. The second method will consist of the continuous measurement of the fuel input to each boiler. Each boiler will be fitted with belt scales which will measure the weight of biomass and coal and provide an integrated hourly total. Separate metering devices will be provided for coal so that the heat input due to coal can be determined even when burning a combination of coal and biomass fuels. Utilizing fuel quality data (i.e., heating value), the heat input to each boiler can be calculated.

Fuel quality measurements will be made on all fuels in order to provide information for heat input and emission calculations. Biomass fuels (bagasse and wood waste) are very low in sulfur content, and the heating value of these fuels are well established. Therefore, a rigorous sampling program is not necessary. It is proposed to collect daily biomass samples at a location along the conveying system, prior to the boiler, whenever biomass fuels are fired during a day. These daily samples will be composited into one weekly sample each calendar week. This composite sample will be analyzed for sulfur, moisture, ash and heating value. These data will be used to calculate heat input and SO_2 emissions due to biomass fuels. This sampling program is proposed to be conducted for 1-year duration in order to develop a database for biomass fuels. After the initial 1-year period, the sampling frequency will be reduced to a reasonable level agreeable to FDER. Flo-Energy will present the data to FDER in order to justify the reduced sampling frequency.

For coal, each coal shipment, which will typically consist of a 50 to 60 car unit train, will be accompanied by a coal analysis representative of the shipment. The analysis will include heating value and sulfur content.

Flo-Energy has determined that the most accurate, cost-effective method to determine SO_2 emissions from the facility is to install a continuous SO_2 emission monitor (that meets EPA reference method specifications). This will allow the direct determination of hourly SO_2

emissions on a continuous basis, for determining compliance with the hourly, 24-hour average, and annual average emission limits for the facility.

<u>FDER Comment 5</u>: Please provide plans, drawings, brochures, or specifications for all air pollution control equipment that will be used in these projects. Include base line operating parameters such as temperatures, feed rates, pressure drops, flow rates, voltages, etc., as well as an operation and maintenance plan for the recommended air pollution control equipment.

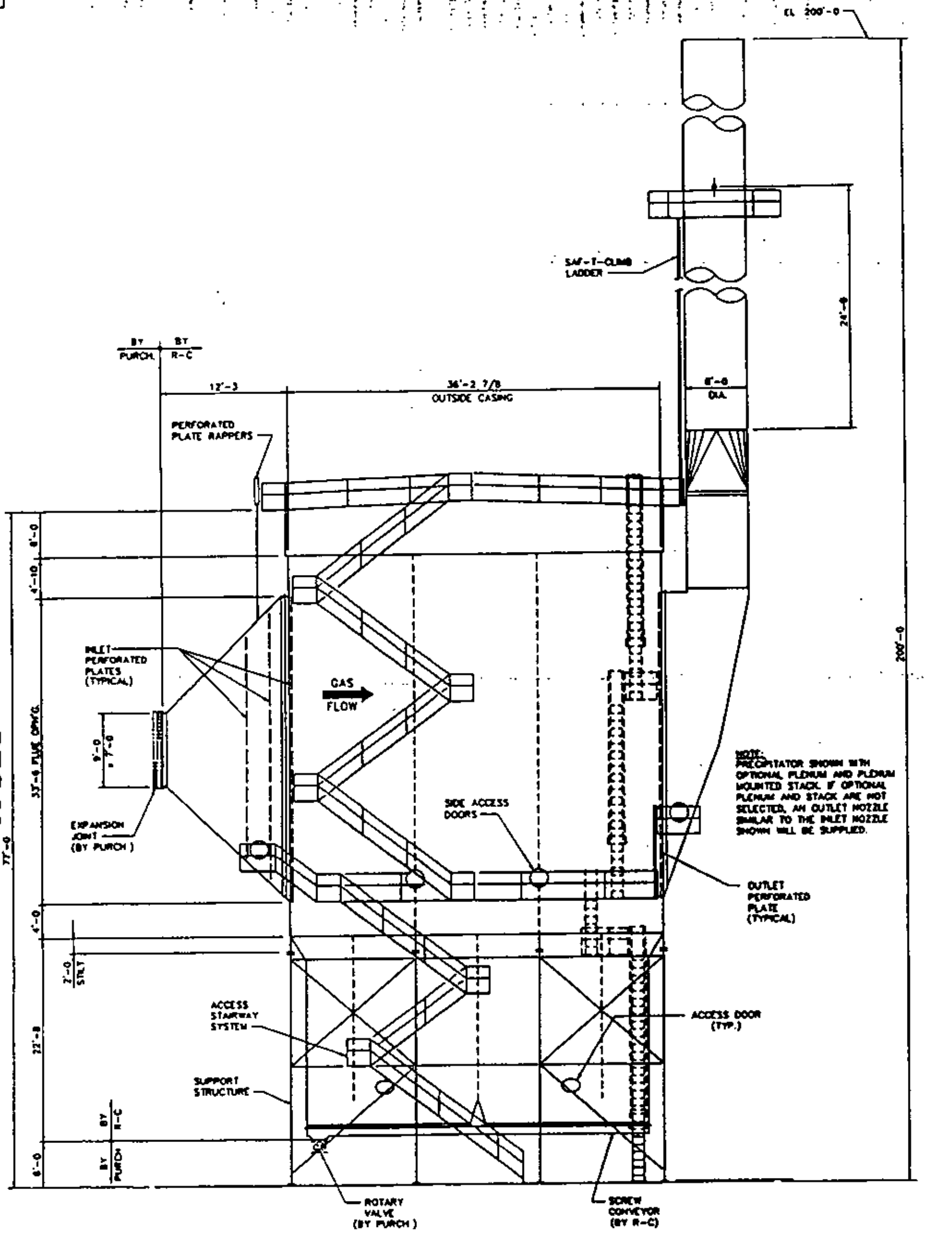
<u>Response 5</u>:

<u>Electrostatic Precipitator</u>

The electrostatic precipitator (ESP) for the Flo-Energy facility will be manufactured by Research-Cottrell. A drawing of the proposed ESP and stack is attached. Design specifications for the ESP (one per boiler) are provided below:

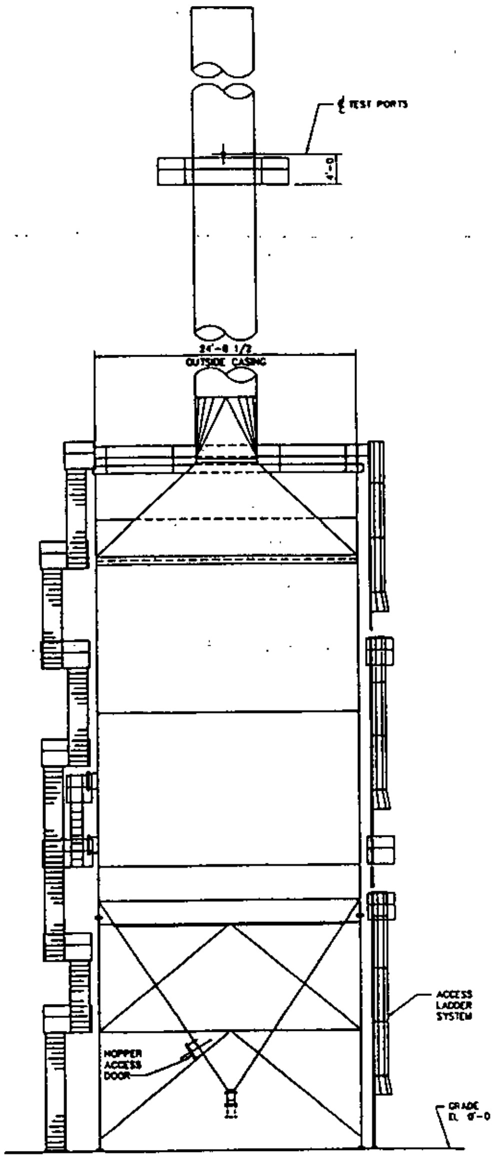
Chambers = 1
Gas Passages/Chamber = 18
Plate Spacing = 16 inches
Collecting Plate = 10.8 ft L x 36.0 ft H
Fields/Chamber = 3
Collecting Electrode Area = 44,323 ft^2
Specific Collection Area = 145 ft^2/1,000 acfm (minimum)
Pressure Drop = less than 2.0 inches H_2O
Operating Temperature = 350°F
Aspect Ratio = 0.90
Discharge Electrode = Durà-Trade, 18 gauge
Rapping System = Microprocessor controlled
Transformer Rectifier = 2 @ 105 kVp/500 mA
= 1 @ 105 kVp/750 mA
= microprocessor control
Ash Handling = Trough hopper with screw conveyor

RTC-20



NOTE:
PRECIPITATOR SHOWN WITH OPTIONAL PLENUM AND PLENUM MOUNTED STACK. IF OPTIONAL PLENUM AND STACK ARE NOT SELECTED, AN OUTLET NOZZLE SIMILAR TO THE INLET NOZZLE SHOWN WILL BE SUPPLIED.

SIDE ELEVATION



OUTLET END ELEVATION

NOTES.
ALL DETAILS AND DIMENSIONS ARE SUBJECT TO CHANGE PENDING FINAL ENGINEERING.
ONE PRECIPITATOR SHOWN, OTHER TWO ARE SIMILAR

ZURN NEPCO
OKEELANTA COGEN
SOUTH BAY, FLORIDA
PRECIPITATOR

RESEARCH–COTTRELL
EXPERIENCED ENVIRONMENTAL PEOPLE
P. O. BOX 1500 SOMERVILLE NEW JERSEY 08876

Research-Cottrell Hi-R ESP Installations
Partial Listing - Woodwaste Applications

CUSTOMER	LOCATION	APPLICATION	DATE SOLD	NO. ESP	GAS VOLUME (ACFM)	EFF. (%)
Alternative Energy	Ashland, ME	Woodwaste	Mar-92	1	296,334	98.77
Alternative Energy	Cadillac, MI	Woodwaste	Mar-92	1	305,225	98.77
Alternative Energy	Livermore Falls, ME	Woodwaste	Jun-91	1	296,334	98.77
Willamette Ind.	Campti, LA	Woodwaste	Sep-90	1	392,750	98.87
James River Corp.	Camas, WA	Woodwaste	Jul-90	1	202,000	99.33
Smurfit Newsprint	Newberg, OR	Woodwaste/Tires	Jun-90	1	354,000	99.50
Tasman Pulp #3	Kawerau, N.Z.	Woodwaste	Jan-90	1	135,610	93.30
Celgar Pulp	Castlgar, B.C.	Woodwaste	Jan-90	1	148,300	95.50
Tasman Pulp #2	Kawerau, N.Z.	Woodwaste	Jan-90	1	115,590	93.30
Simpson Tacoma Kraft	Tacoma, WA	Woodwaste	Sep-89	1	260,000	99.50
Alberta Pacific Forest Ind.	Alberta, Canada	Woodwaste	Jun-89	1	464,040	97.77
Zurn/Nepco	New Bern, NC	Woodwaste	May-89	1	282,350	99.00
S.D.Warren	Skowhegan, ME	Woodwaste	Apr-89	2	310,730	99.43
Tracy Constructors	Tracy CA	Woodwaste	Feb-89	1	140,000	99.60
Yanke Energy Inc.	Soledad, CA	Woodwaste	Sep-88	1	100,000	98.18
Honey Lake Power	Susanville, CA	Woodwaste	Mar-88	1	285,012	99.00
P.H.Glatfelter	Spring Grove, PA	CFB-Wood,Coal	Mar-87	1	236,000	99.91
Yanke Energy Inc.	North Fork, CA	Woodwaste	Jan-87	1	82,000	98.19
Ultrasystems	Fresno, CA	CFB Woodwaste	Sep-86	1	171,600	99.65
Ultrasystems	Rocklin, CA	CFB Woodwaste	Sep-86	1	171,600	99.65
Whitefield Power & Light	Whitefield, N. H.	Woodwaste	May-86	1	95,390	98.26
Gorbell Power & Light	Athens, ME	Woodwaste	Mar-86	1	101,730	98.26
Hemphill Power & Light	Springfield, NH	Woodwaste	Mar-86	1	95,390	98.26
Duluth, City of	Duluth, MN	Wood/Coal Stoke	Feb-86	2	257,870	99.00
Georgia Pacific	Palatka, FL	Woodwaste	Aug-85	1	230,000	98.30
Container Corp.	Fernandia Beach, FL	Woodwaste	Jun-85	1	282,000	94.33
Georgia Pacific	Palatka, FL	Woodwaste	Jun-85	1	230,000	96.00
Yanke Energy Inc.	Auberry, CA	FFB Woodwaste	Apr-85	1	82,000	98.19
Union Camp Corp.	Franklin, Va	Wood/Coal Stoke	Apr-85	1	95,500	98.86
Atlantic Gulf Co.	Martell, CA	Woodwaste	Jan-85	1	153,300	98.75
Yanke Energy Inc.	Dinuba Station, CA	Woodwaste	Nov-84	1	103,000	95.08
Ultrapower #4	Chinese Sta., CA	FFB Woodwaste	Jul-84	1	193,750	96.44
Ultrapower #3	Blud Lake, CA	Woodwaste	May-84	1	78,000	98.00
Appleton Power	Combined Locks, WI	Woodwaste,Coal	Jun-83	1	175,000	98.00
Union Camp Corp.	Savannah, GA	Comb.(Bark,Coal)	Oct-80	2	441,360	99.59
Weyerhauser Corp.	Plymouth, NC	Woodwaste,Coal	May-79	1	318,000	99.00

Dura-Trode™ Rigid Discharge Electrodes

The Dura-Trode rigid discharge electrode is comprised of two roll-formed steel sections welded together along their emitting edges with provisions for rigid attachment to the high voltage structural framework. The configuration provides uniform corona distribution while maximizing equipment reliability. Completely shop fabricated, no field assembly of the electrode is required.

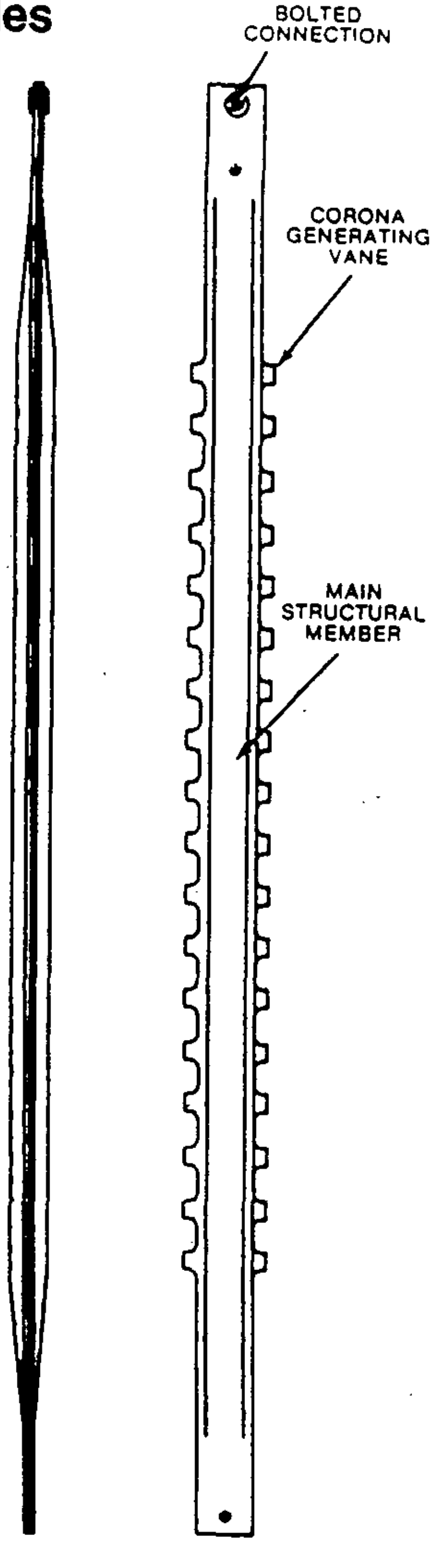
Principal design features:

Inherently rigid—No wires, thin metal strips or framework; the design incorporates electrical energization and mechanical integrity into a single member.

Self-aligning—Each electrode is individually supported from a single bolt, and guided at the bottom by a lower alignment frame.

Maintenance-free—The electrode is virtually unbreakable, and is resilient to operational upsets.

Uniform corona—The scalloped vanes, which tend to force corona to form at the sharpest points, combined with the flattened ellipsoidal shape, simultaneously provide well distributed corona and high field strength.



G-Opzel™ Collecting Surfaces

Research-Cottrell's G-Opzel collecting surfaces are designed to provide maximum accelerations normal to the collecting surface with minimum rapper energy input. The surfaces have aerodynamically designed baffles which provide quiescent zones to aid particulate collection and reduce re-entrainment. These baffles also provide the necessary structural rigidity to prevent bellying and bowing of the collecting surface.

Principal design features:

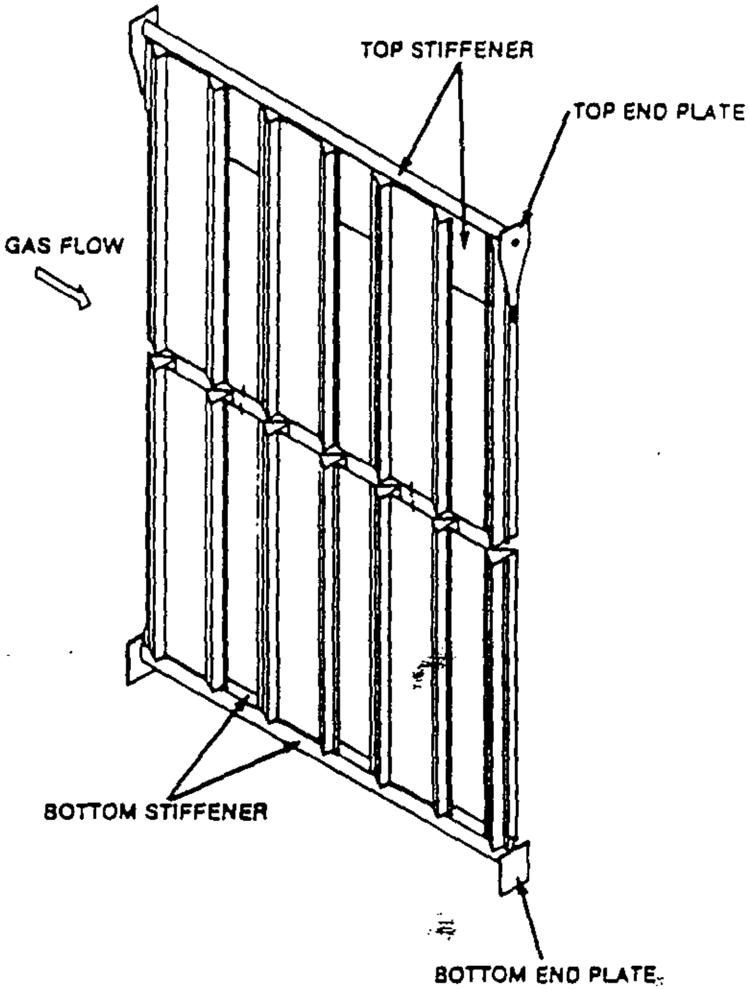
Shop assembly—Cold-rolled sheet steel is roll-formed into panel plates. Panels are then shop-welded together into full field assemblies.

Gas baffles—Vertical, triangular baffles provide plate rigidity and quiescent zones.

Top suspension—Bolted and welded to collecting surface hanger channel.

Alignment—Alignment guides provided at all four corners.

Spark suppression—The rolled tubes, attached to the top and bottom edges of the collecting surface, provide increased rigidity and suppress sparking at these edges by eliminating sharp corners.



Research-Cottrell

Air Pollution Control Division

MIGI™ Drop-hammer Rappers for Collecting Surfaces and Discharge Electrodes

The Magnetic Impulse Gravity Impact (MIGI) rapper is an electromagnetic device utilizing only one moving part. Intensity, sequence and cycle time of the rapping blows are electrically controlled from a central cabinet, enabling adjustment while the precipitator is in operation.

Principal design features:

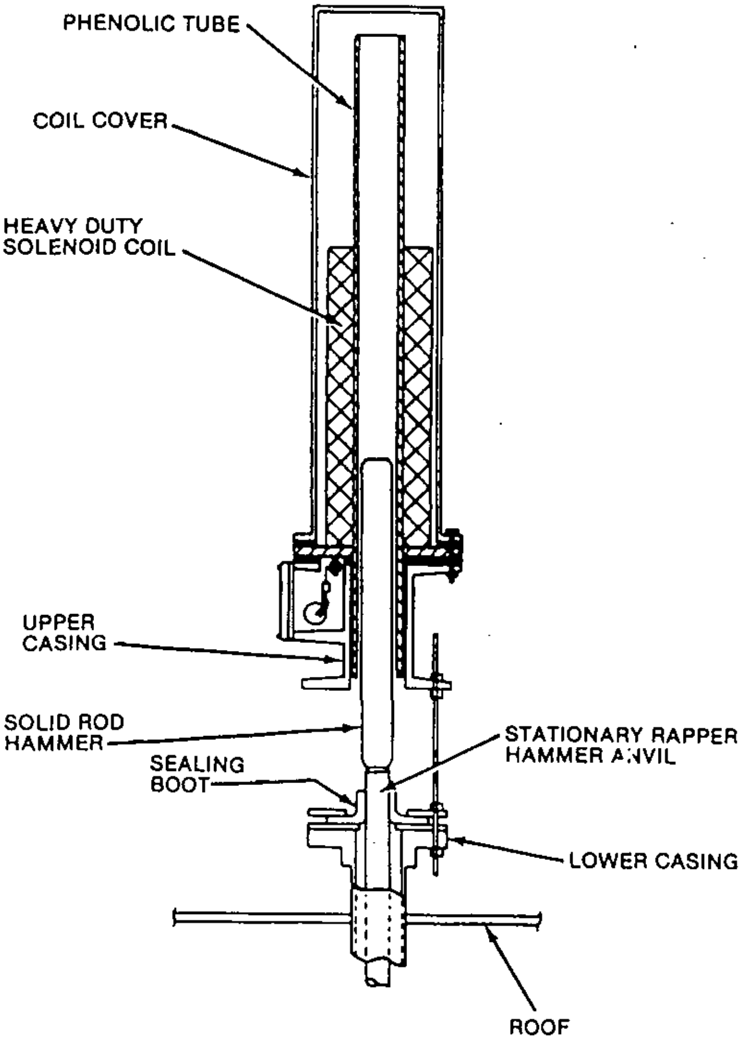
Operation—Controlled single impact; electromagnetic lift by heavy duty solenoid, gravity drop.

Accessibility—Located outside of gas stream, on precipitator roof. Inspection, maintenance and adjustments can be made during on-line operation.

Mounting—vertically mounted on three adjustable studs for easy and rapid maintenance.

Operating temperature—60°C maximum continuous ambient temperature.

Lubrication—Not required.



CONTENTS (Continued)

TABLES

FDER Comment 9: One application currently being processed by the Bureau is proposing 0.05% sulfur in No. 2 fuel oil. What is the lowest percent sulfur in No. 2 fuel oil available in your area?

Response 9: Many suppliers of diesel and fuel oil in southeast Florida were contacted to obtain the latest information on fuel oil availability and price. All of these suppliers, including the fuel oil supplier for Okeelanta (Star Enterprises/Texaco; Gene Tauches, 404-903-1559), stated that they were aware of the EPA mandate of 0.05 percent sulfur maximum in over-the-road diesel fuel by October 1993. However, the Department of Energy has not made a determination on the sulfur limit for off-road No. 2 fuel oil, which would also be sold as home heating oil. Fuel oil suppliers believe there may be two different fuels, with one identified with a dye. It is impossible to predict at this time what the sulfur content of the off-road diesel might be. It also is impossible to state what the cost of such a new fuel would be, or whether it will be available in sufficient quantity to be used for industrial purposes. Given these significant uncertainties, at this time Flo-Energy cannot commit to a lower sulfur No. 2 fuel oil than is currently available (i.e., 0.5 percent maximum).

FDER Comment 10: What are the specifications for the wood waste and biomass? Will either contain asphalt shingles, tar paper, or plastics?

Response 10: The specifications for the wood waste and biomass are those contained in the proposed Specific Condition 12 described in Section 8.0 of the Flo-Energy application (pg 8-3 of the application). This condition states "any wood waste materials burned as fuel shall be substantially free from painted wood, chemically treated wood, household garbage, toxic or hazardous materials or waste, and special waste." All contracts for biomass issued by Flo-Energy will contain this wording. Asphalt shingles, tar paper, and plastics, will not knowingly be accepted by Flo-Energy.

FDER Comment 11: Will the existing boiler No. 16, designated for standby service at the Flo-Energy facility, be used when all 3 of the proposed boilers are in operation?

Response 11: Boiler No. 16 will only be operated when one or more of the cogeneration boilers is shutdown (refer to proposed Specific Condition 18 on page 8-3 of the application).

FDER Comment 12: Please explain why only 30% of the mercury but 90% of the other metals will be removed from the emissions. Will the presence of ammonia in the flue gas effect the mercury removal?

Response 12: Nearly all the metals in the flue gas just prior to the ESP (temperature approximately 350°F) will be in the solid phase. The ESP will be designed for 98% removal of particulate matter; thus these metals will be controlled to approximately 98% or greater. Mercury, however, exists primarily in the vapor phase at 350°F. Research has shown that as the flue gas temperature is reduced downstream of the boiler, some mercury will be condensed and/or adsorbed onto carbon-containing particulate in the gas stream. At certain MSW resource recovery facilities, it has been demonstrated that mercury control of 30% and greater may be achievable by injection of additional carbon into the gas stream ahead of the particulate control device. The level of control is dependent upon a number of factors, including mercury concentration in the flue gas, flue gas temperature, carbon injection rate, and type of particulate control device. For a biomass/coal fueled facility, the initial mercury concentration is very low. As a result, the removal efficiency achievable in this case is not certain; however Flo-Energy's proposed mercury emission limits are based on a conservative assumption of 30 percent control efficiency.

FDER Comment 13: What is the basis of assuming that 20% of the chromium is Cr+6 in Appendix A?

Response 13: No data was found in the literature regarding the form of chromium (Cr) emissions from biomass/coal combustion sources. The estimate of 20 percent of total chromium emissions existing as hexavalent chromium is based in part on actual source testing of the Dade County Resources Recovery (DCRR) facility. The data are shown in the attached table. As shown, the results are somewhat inconclusive due to many of the measurements being below the detectable limit of the measurement method. The 20 percent factor was derived using a value equal to one-half the detectable limit for measurements which were below the detectable limit.

Data regarding Cr^{+6} emissions are available from a few other sources. Test data from an MSW combustion unit equipped with ESP control only (city of Baltimore) showed a Cr^{+6} concentration of 0.5 μg/g particulate at the inlet to the ESP, and 465 μg/g of total chromium (Municipal Waste Combustion Study, EPA, 1988). This would result in a Cr^{+6}/Cr ratio of 0.001, or 0.1 percent.

A summary of medical waste incinerator test data was recently published in the Journal of Air and Waste Management (Walker and Cooper, Vol. 42, No. 6, June 1992). The compilation showed the following for uncontrolled emissions from general medical waste:

Cr (total) - 422 μg/g waste input (average of 27 tests)
Cr^{+6} - 32 μg/g waste input (average of 9 tests)
Ratio = 32/422 = 0.076 = 7.6%

For pathological waste, the test data were as follows:

Cr (total) - 3,900 μg/g waste (average of 6 tests)
Cr^{+6} - 680 μg/g waste (average of 4 tests)
Ratio = 680/3,900 = 0.174 = 17.4%

A recent study of municipal wastewater sludge incinerator emissions (EPA, 1992) in the U.S. investigated both total Cr and Cr^{+6} emissions. At five test sites, all equipped with wet venturi scrubbers, the Cr^{+6}/Cr ratio was found to range from <1.8 percent to 11.9 percent.

Based on the limited data available, the factor of 20 percent Cr^{+6} used in the permit application appears to be very conservative.

Hexavalent Chromium Emissions from Dade County Resources Recovery Facility

Unit	Date	Total Chromium (lb/hr)	Hexavalent Chromium (lb/hr)	$\mathrm{Cr}^{+6}/\mathrm{Cr}$ (%)
1	11/15/88	<0.00134	<0.000437	--
		0.00146	<0.000531	<36.4
		<0.00131	<0.000434	--
2	05/10/89	0.00244	<0.000671	<27.5
		0.00243	<0.00108	<44.4
		0.00181	<0.00054	<29.8
3	11/16/89	<0.00360	<0.00111	--
		<0.00351	<0.00115	--
		<0.00354	<0.00112	--
4	11/07/89	<0.00330	<0.00102	--
		<0.00328	<0.00092	--
		<0.00348	<0.000747	--
			Average =	<34.5

Source: Entropy, Inc.

FDER Comment 14: What does the term "black start purposes" mean (page 2-5)?

Response 14: A "Black Start" refers to the situation where the facility has electricity, but all equipment (i.e., boilers, pumps, turbine generators, etc.) are shutdown. Boiler No. 16 may be used in this situation to provide steam to operating equipment until such time as one or more of the cogeneration boilers is brought on line. As stated previously, Boiler No. 16 will not be operated when all three of the cogeneration boilers are operating.

FDER Comment 15: What is "special waste" that was referred to in proposed Specific Condition No. 12?

Response 15: The term special waste is used to describe toxic or hazardous non-biomass and non-combustible waste materials.

FDER Comment 16: Please respond to the National Park Service FAX dated October 8, 1992.

Response 16: The NPS comment concerns the ownership of the Flo-Energy facility and its relationship to the Okeelanta sugar mill. This relationship will determine if the emission reductions from the existing Okeelanta facility will be creditable reductions for PSD purposes. KBN has discussed this issue with EPA through correspondence (attached) and during a recent meeting at EPA Region IV in Atlanta. The two factors which will render the reductions creditable are as follows:

1. Okeelanta owns the existing facility, and will own 50% or more of the voting rights in Flo-Energy. Thus, both facilities will be under "common control" and constitute a single "facility" under the PSD regulations.
2. The Okeelanta sugar mill will be totally dependent upon the cogeneration facility for steam; thus the cogeneration facility and sugar mill will be considered as the same facility (i.e., same primary SIC code) for PSD purposes.

EPA has indicated in the attached correspondence and in our recent meeting that the emission reductions will be creditable for PSD purposes.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

4APT-AEB

OCT 9 1991

Mr. David A. Buff, P.E.
KBN Engineering and Applied Sciences, Inc.
1034 Northwest 57th Street
Gainesville, FL 32605

Dear Mr. Buff:

This letter is in response to your letter dated July 18, 1991, concerning several questions related to Prevention of Significant Deterioration (PSD) source applicability for cogeneration facilities. The answers to your questions are as follows:

-- What criteria must be met for the cogeneration facility to use the emission reductions from the industrial facility in determining PSD source applicability?

The pertinent PSD criteria for emissions increases and <u>decreases</u> to be creditable for netting transactions is outlined in CFR 40 Part 52.21 (b)(3) or Part 51.166 (b)(3). Referring to (b)(3)(iii), emissions increases and decreases are creditable:

> "...if the Administrator has not relied on it (e.g., an emissions decrease) in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs." (NOTE: EPA's policy is to interpret the permit to be a PSD permit).

In order to be creditable, a decrease in actual emissions must meet three criteria. These criteria are stated in (b)(3)(vi)(a), (b), and (c):

> (a) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;
> (b) It is federally enforceable at and after the time that actual construction on the particular change begins; and
> (c) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

It is important to note that the proposed source shutdowns, as well as all other decreases, must be federally enforceable in order to be creditable. If the source nets out of review, no PSD permit is issued. Where a source is not able to net out of review, any emissions increase or decrease used in the netting equation to determine source applicability must also be used in its entirety in the subsequent air quality impact analysis. In this manner, a reviewing authority relies on the full emissions increase or decrease in determining whether the proposed project would or would not cause, or contribute to, a violation of an increment or ambient standard. At this point, these increases and decreases are no longer creditable.

-- What if the industrial facility is a joint owner of the power plant, but not the operator? Is there a certain percent ownership in the power plant necessary to qualify as "persons under common control?"

Common control or ownership has been defined by precedent in previous EPA applicability determinations. In a memorandum dated March 16, 1979, from the Director of Stationary Source Enforcement to the Director of the Enforcement Division of Region VI, the following assertion was made:

> If the International Paper Company has 50% voting interest in the Arizona Chemical Company, it can be considered "in control" for PSD (and IR*) purposes, and the International Paper mill and Arizona Chemical plant, both located at the Springhill, Louisiana complex, can be considered a single source. *(Interpretative Ruling, see Federal Register, December 21, 1976, pages 55524-55530)

-- For the power plant to be included in the same SIC code as the industrial facility, must it supply a certain portion of its total steam capacity to the industrial facility? Must the power plant not sell more than 33% of its electrical generating capacity to the electric grid, or else it would automatically be classified under SIC Major Group 49, Electric Services?

This is addressed in comments and responses on proposed PSD regulations published in the Federal Register, dated August 7, 1980, page 52695. Where a single unit is used to support two otherwise distinct sets of activities, the unit is to be included within the source which relies most heavily on its support. In this case, as long as the industrial facility required over 50% of the total steam capacity, then the power plant could be included in the same SIC group, and the remainder of its steam capacity could be sold to other users (in this instance, the electric grid).

-- What if essentially all of the steam needed by the industrial facility comes from the power plant, i.e., the industrial facility is totally dependent upon the power plant for steam?

The power plant and industrial facility would be classified as under the same source because one source classification encompasses both primary and support facilities, even when the latter includes units with a different two-digit SIC Code (reference Federal Register, August 7, 1980, page 52695).

-- Must both the "common control" criteria and SIC code criteria be met before any offsets from the industrial facility are available to the power plant?

Yes, and in addition a third basic test must be met. In order for offsets to be available, the affected facilities must be located on adjacent or contiguous property.

Thank you for the opportunity to respond to your questions regarding PSD applicability and netting. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 347-5014.

Sincerely yours,

Jewell A. Harper, Chief
~~Air~~ Enforcement Branch
Air, Pesticides, and Toxics
Management Division

KBN

July 18, 1991

Mr. Jewell A. Harper, Chief
Air Enforcement Branch
U.S. Environmental Protection Agency
345 Courtland Street, N.E.
Atlanta, GA 30365

Re: PSD Source Applicability for Cogeneration Facilities

Dear Mr. Harper:

In November 1989 the EPA issued a letter response to questions regarding PSD source applicability and emissions netting for cogeneration facilities (copy of letter attached). The letter stated that for an independently owned and operated power plant located at the same site as an industrial facility (such as a paper mill), the power plant could not use any offsets from the industrial source in its source applicability determination. The power plant and industrial source would have different SIC codes and would not be under common control, and therefore would not meet the definition of "facility" contained in the federal PSD rules.

KBN is now performing a feasibility study for locating a cogeneration facility adjacent to an industrial facility. The industrial facility will be shutting down all of its steam boilers and would receive all of its steam needs from the cogeneration facility. This cogeneration facility would also produce excess steam and electric power for sale to the grid.

What criteria must be met for the cogeneration facility to use the emission reductions from the industrial facility in determining PSD source applicability?

What if the industrial facility is a joint owner of the power plant, but not the operator? Is there a certain percent ownership in the power plant necessary to qualify as "persons under common control?"

Obviously, many industrial facilities utilize steam and power. For the power plant to be included in the same SIC code as the industrial facility, must it supply a certain portion of its total steam capacity to the industrial facility? Must the power plant not sell more than 33% of its electrical generating capacity to the electric grid, or else it would automatically be classified under SIC Major Group 49, Electric Services?

What if essentially all of the steam needed by the industrial facility comes from the power plant, i.e., the industrial facility is totally dependent upon the power plant for steam?

Must both the "common control" criteria and SIC code criteria be met before any offsets from the industrial facility are available to the power plant?

91088A1/1

KBN ENGINEERING AN D SCIENCES, INC.
1034 Northwest 57th Street Gainesville, 904/331-9000 FAX: 904/332-4189
EQUAL EMPLOYMENT OPPORTU IVE ACTION EMPLOYER

I would like to obtain EPA's current policy on these questions. If you have any questions concerning this request, please call. If possible, I would greatly appreciate a response within the next two weeks.

Sincerely,

David A. Buff

David A. Buff, M.E., P.E.
Principal Engineer

cc: Mike Sewell, EPA/RTP

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

NOV 3 1989

4APT-APB-cdw

Mr. David A. Buff, M.E., P.E.
Principal Engineer
KBN Engineering and Applied
Sciences, Inc.
Post Office Box 14288
5700 S.W. 34th Street
Gainesville, Florida 32604

Dear Mr. Buff:

We have received your October 2, 1989, letter in which you requested our position regarding the use of leftover netting credits from a modification at Seminole Kraft's pulp mill located in Jacksonville, Florida. To fully address your questions, we have requested the assistance of the New Source Review Section at our Headquarters Office of the Environmental Protection Agency (EPA). Enclosed with this letter, please find a copy of our October 27, 1989, memorandum to EPA Headquarters. Also note that we have requested Headquarters to answer other related questions in addition to the ones raised in your October 2 letter.

On a related issue, we would like to express our concerns with the proposed modification in general. As our information indicates, Seminole Kraft has jointly applied with AES Cedar Bay, Inc., (Cedar Bay) to perform several modifications: Namely, to construct a new kraft recovery boiler and smelt tank (while simultaneously shutting down three old recovery boilers and smelt tanks) and also to construct a new power facility using circulating fluidized bed (CFB) boilers. The new recovery boiler/smelt tank would be owned and operated by Seminole Kraft while the new power facility would be owned and operated by Cedar Bay. Our review of the application for the Site Certification submitted jointly by Seminole kraft and Cedar Bay indicates that netting credits from the shutdown of existing pulp mill sources are being used for both the new recovery boiler/smelt tank and the new power facility modifications. EPA Region IV disagrees with this action because netting credits can only be applied within a "facility", which is defined under federal regulations as: "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively.)"

The modifications to the Seminole Kraft pulp mill are categorized under the "Major Group" 26-Paper and Allied Products. The cogeneration project is categorized under the "Major Group" 49-Electric, Gas, and Sanitary Services. Moreover, it is clearly stated in the Site Certification Application that the new recovery boiler/smelt tank will be owned and operated by Seminole Kraft, and the new power facility will be owned and operated by Cedar Bay. Based on these facts, we have concluded that Seminole Kraft and Cedar Bay are two separate and distinct facilities and may not "net" interchangeably under the Prevention of Significant Deterioration (PSD) rules. However, for purposes of nonattainment new source review (NSR) requirements, offset credit may be used by either facility as long as the reductions in volatile organic compound (VOC) emissions are made federally enforceable. Offset credit should not be confused with "netting" as defined under both sets of regulations, i.e., in determining applicability.)"

In summary, please be advised that we are attempting to obtain a written determination from our Headquarters Office in answering your question. We will transmit a copy of their response to you upon our receipt.

If you have any questions concerning this matter, please call Mark Armentrout of my staff at (404) 347-2864.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
  Management Division

Enclosure

cc: Clair Fancy
    Florida DER

FDER Comment 17: Please note which information for the following sources used for the modeling analysis is correct.

a. Source 50PMB500086 Glades Corr Institute:

	Qs	Hs	Ts	Vs	Ds	Xs	Ys
Table 6-4:	2.82	9.8	389	11.28	0.40	8400	15800
Model:	2.82	9.1	477	1.22	1.04	8400	15800

b. Source 50PMB500021 Pratt & Whitney:

Table 6-4:	34.2 (km)	38.9 (km)
Model:	35800 (m)	-23100 (m)

c. Source 52FTM500061 US Sugar-Bryant

	Unit 5 PSD (3hr)	Unit 1,2,3 (3hr)	Unit 5 PSD (24hr)	Unit 1,2,3 (24hr)
FOL: Table 6-4 & Model:	81.36	204.53	79.97	79.69
SOL: Table 6-4 & Model:	68.07	174.36	67.38	63.66

d. OKCOGEN Stack Height	60.66 in Maximum Impact Analysis, PSD Class I and II Analysis 65.2 in AAQS Analysis

Response 17:

a. For Glades Correctional Institute, the source information used in the modeling runs is correct. The source information provided in Table 6-4 has been revised to match the model input for this facility. A revised table is attached.

b. The location for Pratt & Whitney as presented in Table 6-4 is the correct location. The modeling location for this facility is not correct. This facility was modeled only in the AAQS analysis. Therefore, the AAQS impacts were remodeled with the correct information, and Tables 6-8, 6-9, and 6-10 were revised (attached). Re-modeling with this change does not significantly change any of the maximum impacts shown in the application (i.e., Table 6-11 of the application is not affected).

c. The facility information for US Sugar-Bryant, as presented in the Sol-Energy PSD application is the more accurate information. The source information for US Sugar-Bryant, as presented in the Flo-Energy application reflects higher SO_2 emissions and therefore, re-modeling for the Flo-Energy application is not necessary.

d. The OKCOGEN stack height should be 60.66 meters. The stack height of 65.2 meters, as presented in the AAQS analysis, was in error. As a result, the AAQS impacts have been revised (attached Tables 6-8, 6-9, and 6-10). As shown, this error does not have a discernable affect on maximum predicted concentrations. The maximum AAQS impacts as shown in Table 6-11 of the application are not affected.

Table 6-4. Summary of Non-Okeelanta Source Data Used in Modeling Analysis (Page 1 of 2) (Revised 11/25/92)

APIS Number	Facility	Stack		Temp (K)	Velocity (m/s)	SO_2 3-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in		
		Height (m)	Diameter (m)					AAQS	Class II	Class I
52FTM500016	Atlantic Sugar									
	Unit 1[a]	18.9	1.92	346	12.7	17.24		Yes	No	No
	Unit 2[a]	18.9	1.92	342	10.9	22.50		Yes	No	No
	Unit 3[a]	21.9	1.83	341	17.5	16.88		Yes	No	No
	Unit 4[a]	18.3	1.83	344	15	16.88		Yes	No	No
	Unit 5[a] PSD	27.4	1.68	339	15.7	11.80	CON	Yes	Yes	Yes
50WPB43????	Bechtel Indiantown PSD	150.9	4.88	333.2	30.5	75.64	CON	Yes	Yes	Yes
50DAD130348	Dade County RRF PSD									
	Units 1&2 proposed mod.	64.9	3.66	405.4	15.86	12.30	CON	No	No	Yes
	Units 3&4 proposed mod.	64.9	3.66	405.4	15.86	12.30	CON	No	No	Yes
	Units 5&6 proposed	76.2	4.2	399.8	15.74	17.20	CON	No	No	Yes
52FTM260001	Everglades Sugar[a]	21.9	1.1	477	10.1	11.80		Yes	No	No
50BRO060037	FPL - Lauderdale									
	CTs 1-4 PSD	45.7	4.88	411	10.97	271.10	CON	Yes	Yes	Yes
	4&5 PSD Baseline	46	4.27	422	14.63	-457.00	EXP	No	Yes	Yes
50WPB430001	FPL Martin									
	Units 1&2	152.1	7.99	420.9	21.03	1743.79		Yes	No	No
	Aux Blr PSD	18.3	1.1	535.4	15.24	12.90	CON	Yes	Yes	Yes
	Diesl Gens PSD	7.6	0.3	785.9	39.62	0.51	CON	Yes	Yes	Yes
	Units 3&4 PSD	64.9	6.1	410.9	18.9	470.40	CON	Yes	Yes	Yes
50BRO060036	FPL - Port Everglades									
	GT 1-2	15.5	5.49	733	21.34	488.39		Yes	No	No
	Units 1&2	104.9	4.27	416	18.59	637.54		Yes	No	No
	Units 3&4	104.5	5.52	108	19.2	1067.16		Yes	No	No
50PMB500042	FPL - Riviera Beach									
	Unit 2	45.7	4.57	430.2	7.62	124.86		Yes	No	No
	3&4	90.8	4.88	408	18.9	846.33		Yes	No	No
50PMB500086	Glades Corr Institute	9.1	1.04	477	1.22	2.82		Yes	No	No
50PMB500045	Lake Worth									
	Units 1&2	18.23	1.52	434.1	6.19	72.58		Yes	No	No
	Units 3&4	38.1	2.29	408	9.69	237.90		Yes	No	No
	Unit 5	22.9	0.95	450.2	18.29	11.59		Yes	No	No
NA	Lee County RRF PSD	83.8	1.88	388.5	19.81	14.00	CON	No	No	Yes
NA	North Broward RRF PSD	58.5	3.96	381	18.01	35.40	CON	Yes	Yes	Yes
52FTM500019	Osceola Farms									
	Unit 1 PSD Baseline[a]	22	1.52	342	8.18	-5.07	EXP	No	No	Yes
	Unit 2 PSD Baseline[a]	22	1.52	341	18.1	-16.32	EXP	No	No	Yes
	Unit 3 PSD Baseline[a]	22	1.93	341	14.5	-7.26	EXP	No	No	Yes

Table 6-4. Summary of Non-Okeelanta Source Data Used in Modeling Analysis (Page 2 of 2) (Revised 11/25/92)

APIS Number	Facility	Stack		Temp (K)	Velocity (m/s)	SO_2 3-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in		
		Height (m)	Diameter (m)					AAQS	Class II	Class I
	Unit 4 PSD Baseline[a]	22	1.83	341	18.8	-13.61	EXP	No	No	Yes
	Cogenerator Units 1&2	54.9	2.13	449	26.05	139.20	CON	Yes	Yes	Yes
50WPB500234	Palm Beach RRF 1&2 PSD	76.2	2.04	505.2	24.9	85.05	CON	Yes	Yes	No
50PMB500021	Pratt & Whitney									
	ACHR-1	1.8	0.91	500	40.23	16.02		Yes	No	No
	ACHR-2	15.2	0.91	500	40.23	47.92		Yes	No	No
	ACHR-3	4.6	3.38	700	13.44	23.46		Yes	No	No
	BO-12	4.6	0.76	500	6.92	9.08		Yes	No	No
	LI-1 MW	8.2	0.67	2000	8.35	6.18		Yes	No	No
NA	South Broward RRF PSD	59.4	3.96	381	18.01	37.91	CON	Yes	Yes	Yes
52FTM260015	Southern Gardens PSD	22	0.64	479.8	17.48	4.99	CON	Yes	Yes	Yes
52FTM500026	Sugar Cane Growers									
	Unit 3[a]	24.4	1.6	344	15.6	4.40		Yes	No	No
	Unit 4 PSD[a]	33.5	1.63	344	10.6	24.20	CON	Yes	Yes	Yes
	Unit 4 PSD Baseline[a]	25.9	2.82	344	10.6	-24.20	EXP	No	Yes	Yes
	Unit 5[a]	24.4	1.4	344	15.2	16.20		Yes	No	No
	Unit 8 PSD[a]	47.2	3.05	344	10.6	26.70	CON	Yes	Yes	Yes
	Unit 1&2[a]	24.4	1.4	344	11.4	24.20		Yes	No	No
	Unit 6&7[a]	12.2	2.13	606	11.2	51.00		Yes	No	No
50DAD130020	Tarmac									
	Kiln 2 PSD Baseline	61	2.44	465	12.84	-5.71	EXP	No	No	Yes
	Kiln 3 PSD Baseline	61	4.57	472	10.78	-2.76	EXP	No	No	Yes
	Kiln 2 PSD	61	2.44	422	9.1	24.50	CON	No	No	Yes
	Kiln 3 PSD	61	4.57	450	11.04	51.40	CON	No	No	Yes
52FTM260003	US Sugar Clewiston									
	Unit 3[a]	27.4	2.29	340	14.54	28.16[b]		Yes	No	No
	Unit 4 PSD[a]	45.7	2.51	334	19.66	16.26[b]	CON	Yes	Yes	Yes
	Units 1&2[a]	22.9	1.86	339	35.54	95.22[b]		Yes	No	No
	Units 5&6[a]	19.8	1.83	340	9.78	4.48		Yes	No	No
52FTM500061	US Sugar-Bryant									
	Unit 5 PSD[a]	42.7	2.9	345	11.49	81.36[b]	CON	Yes	Yes	Yes
	Unit 1,2&3[a]	19.8	1.64	342	36.4	204.54[b]		Yes	No	No
50BRO062094	Waste Management PSD	11.3	1.22	721.9	36.82	5.39	CON	Yes	Yes	No

[a] These sources operate only during the crop season, October 1 through April 30.

[b] The following sources were modeled under 24 hour and annual averaging times with the following emission rates (g/s):

US Sugar Clewiston Unit 3: 22.99
US Sugar Clewiston Unit 4: 14.78
US Sugar Clewiston Unit 1&2: 80.68
US Sugar Bryant Unit 5 PSD: 79.97
US Sugar Bryant Unit 1,2&3: 79.69

Table 6-8. Maximum Predicted SO_2 Concentrations for the AAQS Screening Analysis, Near-Field Receptors (Revised 11/25/92)

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	36	30.	17000.	82——
	30	30.	17000.	83——
	31	30.	17000.	84——
	28	30.	17000.	85——
	28	30.	17000.	86——
24-Hour[b]	162	30.	17000.	82070824
	183	30.	17000.	83040624
	176	30.	17000.	84041224
	181	30.	17000.	85010124
	173	30.	17000.	86081224
3-Hour[b]	446	30.	17000.	82070909
	381	30.	17000.	83040609
	424	30.	17000.	84072015
	442	30.	17000.	85060318
	360	30.	17000.	86080909

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-9. Maximum Predicted SO_2 Concentrations for the AAQS Screening Analysis, Far-Field Receptors (Revised 11/25/92)

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	23	40.	50000.	82-----
	20	40.	50000.	83-----
	24	40.	50000.	84-----
	23	40.	50000.	85-----
	21	20.	30000.	86-----
24-Hour[b]	146	130.	80000.	82011824
	153	130.	80000.	83081024
	213	130.	80000.	84050224
	188	130.	80000.	85052124
	124	90.	70000.	86032124
3-Hour[b]	631	130.	80000.	82011815
	613	130.	80000.	83081018
	634	130.	80000.	84063015
	835	130.	80000.	85101112
	622	130.	80000.	86010212

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 6-10. Maximum Predicted SO_2 Concentrations for the AAQS Detailed Screening Analysis Grid[a], Annual and 24-Hour Averaging Time Only (Revised 11/25/92)

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (m)	Period Ending (YYMMDDHH)
Annual	35	30.	17000.	82------
	30	30.	17000.	83------
	33	30.	16000.	84------
	31	30.	16000.	85------
	33	30.	16000.	86------
24-Hour[c]	168	30.	16000.	82112624
	183	30.	17000.	83040624
	199	35.	16000.	84092624
	181	30.	17000.	85010124
	205	30.	16000.	86110724

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Centered on screening grid receptor location (17,000 m, 30°).

[b] All receptor coordinates are reported with respect to the Boiler No. 16 stack location.

[c] All short-term concentrations indicate highest, second-highest concentrations.

FDER Comment 18: What is the worst case total maximum hourly sulfur dioxide emission rate for all three boilers when they are running concurrently? Modeling for maximum short-term impacts is based on worst case maximum hourly emissions.

Response 18: The worst-case maximum hourly SO_2 emission rate for each boiler, as shown in Table 2-5 and on page 8-4 of the application, will be 588.0 lb/hr. This emission rate was used in the modeling analysis for all averaging times.

FDER Comment 19: Please explain the last three footnotes (a, b, c in the Sol-Energy application and b, c, d in the Flo-Energy application) in Table 6-18 of both applications. The annual impact values due to arsenic, chromium VI and nickel emissions appear to exceed the annual no threat levels (NTL) when the impact values are computed by multiplying the hourly emissions in column 1 by the highest predicted annual concentration given in the information below the table.

Response 19: The maximum estimated hourly emissions for all non-regulated pollutants were initially used to conservatively estimate the maximum 8-hour, 24-hour and annual air quality impacts. Based on this analysis, the annual NTL level for arsenic, hexavalent chromium, and nickel were predicted to be exceeded. Therefore, the estimated maximum annual emissions for each of these pollutants were used to more realistically predict impacts, as indicated in the footnotes to Table 6-18 of the application. The maximum annual emissions for each of these pollutants is shown in Table 2-11 of the application, and the derivation of the emissions is presented in Appendix A of the application. The annual emissions in tons per year were converted to lb/hr based on 8,760 hr/yr operation.

REFERENCES

Entropy Environmentalists Inc. 1989. Stationary Source Sampling Final Report, Reference No. 6488. Research Triangle Park, NC.

U.S. Environmental Protection Agency (EPA). 1988. Municipal Waste Combustion Study. Washington, DC. EPA/530-SW-87-021b.

U.S. Environmental Protection Agency (EPA). 1992. Emissions of Metals, Chromium and Nickel Species, and Organics from Municipal Wastewater Sludge Incinerators. Cincinnati, OH. EPA/600/R-92/003a.

Walker, B.L. and C.D. Cooper. 1992. Air Pollution Emission Factors for Medical Waste Incinerators. Journal of the Air & Waste Management Association, Vol. 42, No. 6:784-791.

Table 2-8. Flo-Energy Cogeneration Facility Maximum Annual PM Emission Rates for Fugitive Dust Sources (Revised 11/25/92)

Source	Uncontrolled Emission Factor (lb/ton)	Control	Control Efficiency (%)	Controlled Emission Factor (lb/ton)	Maximum Annual Thruput (tons/yr)	Maximum Annual PM(TSP) Emissions (tons/yr)	PM10 Size Mult.	Maximum Annual PM10 Emissions (tons/yr)
<u>Coal Handling</u>								
Railcar Unloading	0.00234	Enclosure	70	0.00070	112,750	0.040	0.35	0.014
Conveyor-to-Coal Pile	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Underpile Reclaim Hopper	0.00234	Enclosure	90	0.00023	112,750	0.013	0.35	0.005
Conveyor-to-Crusher	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Coal Crusher	0.02	Enclosure	70	0.00600	112,750	0.338	0.45	0.152
Crusher-to-Conveyor	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Conveyor-to-Boiler Feeders	0.00234	None	0	0.00234	112,750	0.132	0.35	0.046
Storage Pile	–	None	0	–	–	0.211[a]	0.5	0.105[a]
Coal Storage Pile Maintenance	0.90328[b]	Watering	50	0.45164[b]	14,600[c]	3.297	0.35	1.154
<u>Biomass Handling</u>								
Truck Dump	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Conveyor-to-Conveyor	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Conveyor-to-Hog Tower	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Hogger	0.02	Enclosed	95	0.00100	1,352,941	0.676	0.35	0.237
Hogger-to-Conveyor	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Transfer Tower	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Conveyor-to-Stacker	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Stacking	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Underpile Reclaim	0.00012	Enclosed	90	0.00001	1,352,941	0.008	0.35	0.003
Reclaimer-to-Conveyor	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Transfer Tower	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Conveyor-to-Boiler Feeders	0.00012	None	0	0.00012	1,352,941	0.083	0.35	0.029
Biomass Storage Pile	–	None	0	–	–	0.160	0.5	0.080
Biomass Storage Pile Maintenance	0.90328[b]	Watering	50	0.45164[b]	21,900[c]	4.945	0.35	1.731
<u>Fly Ash Handling</u>								
Fly Ash Transfer	0.00727	Enclosure or Watering	50	0.00364	43,294[d]	0.079	0.35	0.028
	TOTAL					11.122		3.982

---

[a] Refer to Appendix A and text for derivation.

[b] lb/VMT.

[c] Vehicle miles traveled per year.

[d] 1,352,941 TPY biomass at 3.20 percent ash; assumes all ash is flyash.

BIOMASS STORAGE PILE EMISSIONS DUE TO WIND EROSION

Inventory area: Okeelanta Cogenerati
Source ID: Bagasse Pile Filename: A:\BagsPil.epc

Emissions estimate year: 91
Based on wind data year: 91
Fastest mile filename: WESTP91.MET
System of units: English
Source life (inclusive days of year)
Start day: 1
End day: 365
F=flat area, PC=conical pile, PO=oval pile: PC
Pile height (ft) : 30
Pile diameter (ft) : 767
Area (sq ft): 463217.7
Material description: Bagasse/WW
Percent moisture content: 37
Percent silt content: 2.2
Threshold friction velocity, U*t, (cm/sec): 112
Roughness height (cm): .3
Mode (mm) of size distribution 3.533677# (# denotes calculated value)
Lc value (cf. Fig. 6-3 of reference manual):

Frequency of disturbance information :
Us/Ur = .9 -- subarea # 1 -- 20 % of regime disturbed every 1 day(s)
Us/Ur = .6 -- subarea # 1 -- 20 % of regime disturbed every 1 day(s)
Us/Ur = .2 -- subarea # 1 -- 20 % of regime disturbed every 1 day(s)

Total emissions emitted over the period: 145150.4 g

Table 3-3. PSD Source Applicability Analysis for the Flo-Energy Cogeneration Facility (revised 12/1/92)

Regulated Pollutant	Baseline Emissions (TPY)	Cogeneration Facility Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	473.7	183.6[b]	-290.1	25	No
Particulate (PM10)	426.3	176.4[c]	-249.9	15	No
Sulfur Dioxide	748.3	1,700	951.7	40	Yes
Nitrogen Oxides	888.7	862.5	-26.2	40	No
Carbon Monoxide	10,388.0	2,012.5	-8,375.5	100	No
VOC	401.9	345.0	-56.9	40	No[a]
Lead	0.28	0.19	-0.09	0.6	No
Mercury	0.0256[d]	0.0262	0.0006	0.1	No
Beryllium	0.0004	0.0080	0.0076	0.0004	Yes
Fluorides	0.04	32.5	32.5	3	Yes
Sulfuric Acid Mist	22.4	51.2	28.8	7	Yes
Total Reduced Sulfur	–	–	0	10	No
Asbestos	–	–	0	0.007	No
Vinyl Chloride	–	–	0	0	No

---

[a] Nonattainment review does not apply since there is no increase in VOC emissions.

[b] Includes 172.5 TPY from boilers and 11.1 TPY from fugitive dust sources.

[c] Includes 172.5 TPY from boilers and 3.9 TPY from fugitive dust sources.

[d] The estimated average annual emission rate for the most recent 2 years is 0.0256 TPY. The highest annual emission rate for either of the last 2 years is 0.0262 TPY.

FDER Comment 7: Gypsum recovered from the lime/limestone injection FGD system may be of value to the sugar cane industry as a soil conditioner. FGD should also reduce fluoride and sulfuric acid emissions. Please revise your BACT determination by eliminating the cost of the disposal of the material captured by the ESP and calculate the cost per ton of air pollutant removed. Also address the use of other emerging sulfur dioxide control technologies for the BACT determination such as furnace sorbent or duct sorbent injection.

Response 7: Gypsum ($CaSO_4 \cdot 2H_20$) is a source of elemental calcium (Ca) for plant nutrition and could potentially be a benefit to crop growers. However, organic soils and surface waters in the sugar cane growing area are Ca dominated. Thus, enough plant available Ca is already present, making additional gypsum unnecessary. Hypothetically, gypsum amendments to sugar cane soils may require additional phosphorous (P) fertilizer to compensate for the P fixation by the gypsum supplied Ca. Thus, adding gypsum to the sugar cane fields as a soil conditioner may actually have detrimental effects. Therefore, Flo-Energy cannot consider the use of FGD waste products as a soil conditioner.

Emerging Sulfur Dioxide Control Technologies

INTRODUCTION

This discussion focuses on dry sorbent injection (DSI) processes as an emerging technology for SO_2 control. The DSI process for SO_2 removal was first investigated in England in the 1930's, and was experimented with in the U.S. in the early 1960's with little success and low removal rates. With the development of the low NO_x burner technology in the 1970's, better SO_2 removal rates were obtained compared to experiments performed with conventional burners. However, little interest was shown in this technology in the U.S. until the early 1980's when concerns over acid rain in the eastern region of the U.S. prompted the need for more practical and economical alternatives for reducing SO_2 emissions from existing coal-fired power plants. Standard flue gas desulfurization (FGD) processes such as wet limestone scrubbing or spray dryer scrubbing are well-proven for controlling SO_2 emissions; however, many existing power plants are not able to apply these FGD processes because of physical constraints or the high cost associated with these technologies. A number of technologies based on DSI have been developed as low-cost SO_2 control alternatives to the standard FGD processes for retrofitting purposes.

The DSI process involves the injection of dry sorbents into a gas stream upstream from the particulate collection system. Typical sorbents include finely ground limestone, hydrated lime, sodium carbonate, and sodium sesquicarbonate. The sorbent reacts with the SO_2 emissions to form a solid material such as calcium sulfate or sodium sulfate which are then captured by the particulate control system, typically an electrostatic precipitator (ESP) or baghouse.

The DSI process includes two basic configurations which differ based on the point of injection of the sorbent into the flue gases. Initial developments concentrated on the injection of calcium sorbent directly into the furnace equipped with a low NO_x burner system (i.e., the limestone injection multistage burner or LIMB process). This process can utilize either limestone or lime as the sorbent. The second process, developed more recently, injections sorbent into the duct between the boiler and the downstream particulate collection device, termed duct injection. This latter process is designed to utilize either lime or sodium-based sorbent materials.

Both furnace DSI and duct injection DSI processes are considered demonstration technologies because their application is not yet commercially demonstrated on a long-term basis. Also, the achievable SO_2 emission reduction levels range from 30 to 70 percent, which are modest when compared to the well proven wet and dry FGD processes which can achieve over 90 percent SO_2 removal.

Since mid-1987, U.S. EPA's Clean Coal program has been conducting full-scale demonstrations of furnace injection technology in different boiler configurations. These are EPA-sponsored demonstrations at Ohio Edison's Edgewater Station in Lorrain, Ohio, using Babcock & Wilcox's front wall-fired boiler; Richmond Power and Light's Whitewater Valley Generating Station in Richmond, Indiana; and Virginia Power's Yorktown Power Station in Yorktown, Virginia. The latter two units are tangentially-fired pulverized coal boilers manufactured by ABB-Combustion Engineering.

Lime duct injection has also been studied at the Ohio Edison Edgewater power plant. Sodium sorbent duct injection has been investigated by Colorado Springs Department of Utilities (CSDU) at its R.D. Nixon Unit 2 and by Public Service Company of Colorado (PSCC) at the Cherokee power station in Denver.

TECHNICAL DESCRIPTIONS OF THE DSI PROCESS

Brief descriptions of the three different DSI processes (i.e., lime furnace injection, lime duct injection, and sodium duct injection) are described in this section.

Lime Furnace Injection-- In the lime furnace injection process, lime is injected as a sorbent directly into the upper part of the boiler where it is calcined into active calcium oxide, and then reacts with SO_2 and oxygen in the flue gas to produce calcium sulfate. The by-product is a solid placed in the upper furnace section where the temperature is in the range of 1,600 to 2,300°F. At Edgewater, a flexible sorbent injection scheme has been installed consisting of three injection grids placed 4 feet apart vertically on the front wall. Hydrated lime is fed through two sets of feeders to either one or two levels of injectors at a time.

This furnace injection design was first tested in July 1987, and by August 1988 the demonstration included a downstream flue gas humidification process for the purpose of restoring lost efficiency of the electrostatic precipitator (ESP) due to the dry sorbent injection. The humidification step also increased SO_2 removal. Without the humidification process, the dry condition of the flue gas may produce back corona in the ESP due to the high resistivity of the carbon ash, thus resulting in increased stack opacity beyond allowable levels. The humidifier was designed to quench the flue gas to within 20°F above the adiabatic saturation temperature.

The lime furnace injection process requires a Ca/S ratio of at least 2 to 1, which results in a 40 to 60 percent utilization rate. Although limestone was first proposed as sorbent, only quick lime has been used because limestone could only achieve up to 25 percent SO_2 removal. An oversize ESP was used in the demonstration project in order to handle the increased particulate loading. Particulate loading was expected to increase by a factor of two to three for the LIMB process. Changes in the particulate properties have also made the ash more difficult to collect by the ESP, potentially increasing particulate emissions. For new applications, the ESP for particulate control would have to be sized larger to account for these concerns.

Lime Duct Injection-- The lime duct injection process uses a sorbent injection system and auxiliary equipment similar to the furnace injection process. In the duct injection process, however, the hydrated lime is injected at a point that is downstream from the boiler air preheater unit. The humidifier is arranged upstream from the point of injection. The flue gas temperature entering the humidifier is about 300°F and is quenched down to approximately 20° above the adiabatic saturation condition (about 145°F). Here, humidification activates the sorbent to enhance SO_2 removal and conditions the ash for removal by the ESP.

At Edgewater, a sodium hydroxide solution was added to the humidification water to enhance SO_2 removal. An ash recycle system is used to reinject unspent sorbent into the duct for improved sorbent reactivity. To prevent condensation in the ESP and stack, the flue gas is reheated using a steam reheater unit prior to entering the stack. The lime duct injection process at Edgewater was able to achieve a SO_2 removal efficiency of up to 70 percent.

Dry-Sodium Duct Injection-- Sodium-based sorbents are also used for the duct injection process pioneered by EPRI, PSCC, and CSDU. These initial studies were performed with sodium sesquicarbonate and sodium bicarbonate supplied from the main U.S. sodium mine in the Wyoming area. Of these two sorbents, sodium bicarbonate provides slightly higher reactivity at the same normal stoichiometric ratio since it is a refined chemical. In general, sodium-based sorbents are much more reactive in nature than calcium-based (lime or limestone) sorbents, and perform best when injected in the 285-300°F flue gas temperature range. Similar to the lime duct injection process, the sodium powder is injected between the air preheater unit and the particulate collection device. In all of the dry sodium injection process demonstrations, a fabric filter has been used as the particulate control device.

Demonstrations of the dry sodium injection process on utility boilers, conducted mainly in Colorado, demonstrated that up to 70 percent SO_2 emission reduction is achievable. However, an existing unit at the PSCC's Cherokee power station has been limited to 30 percent SO_2 removal due to a brown plume effect associated with higher removal efficiencies. The reagent utilization is about 80 percent. The dry sodium utilization was shown to be insensitive to minor fluctuations in the flue gas temperature during normal boiler operation, but declined significantly when flue gas temperatures dropped below approximately 260°F. Applications of the dry sodium injection process to date has been mainly confined to the Rocky Mountain region because of the readily available sodium sorbent, and only in cases where a low level of SO_2 removal is required on low-sulfur coal (less than 0.5 percent sulfur coal).

In terms of SO_2 removal efficiency, the most consistent data indicate that the lime furnace injection process is capable of achieving 40 percent removal. Both lime and dry sodium duct injection processes can achieve between 40 to 70 percent SO_2 removal. As in the case of furnace injection, new applications would require a larger ESP to account for the increased particulate loading to the ESP.

BACT EVALUATION OF THE DSI PROCESS

Technical Issues-- The furnace injection process has been developed mainly for the retrofit of existing pulverized-coal-fired utility boilers. Thus far all furnace injection demonstration projects have been performed on pulverized-coal (PC) boilers only, with none being applied to stoker boilers. However, performance test results for PC boilers may be applicable to stoker boilers because the dry sorbent injection takes place at the upper furnace section, and thus is relatively independent of the firing mechanism in newly designed boiler systems.

The critical parameters for the furnace injection process lie in the flow pattern of the flue gas inside the furnace. The rate of SO_2 removal is directly related to the reactivity of lime, which in turn is a function of temperature, humidity, flow distribution, residence time, and contact surface area. Potential problems encountered due to lime injection result from the tendency of the sorbent to take up moisture in the flue gas. The wet sorbent may then form deposits on the outer surfaces of steam tubes, superheaters, and air preheaters. Therefore, more frequent soot blowing is required to prevent a build up of material on these components. On the average, lime furnace injection systems have about a 1 percent steam penalty.

The lime furnace injection process results in additional particulate loading to the control device. If an ESP is used, increasing the size of the ESP will be required in order to maintain the same level of particulate emissions. The dry condition of the flue gases at temperatures above 300°F also degrades the performance of the ESP unit; therefore, a humidification process is usually required to cool the flue gas temperature to approximately 275°F to enhance the ESP performance.

The lime duct injection process shares similar technical issues as the lime furnace injection process. Duct injection can achieve somewhat better SO_2 removal efficiency than the furnace injection process. The higher SO_2 removal efficiency is achieved by adding a sodium additive to the humidification water. Sodium hydroxide solution is generally recommended for use as an additive. At the Edgewater demonstration project, the Babcock & Wilcox process operated at a reduced temperature of approximately 20° above the adiabatic temperature of the flue gas, or about 145°F. The result was that additional heating was required to raise the temperature of the stack gas to above 200°F to prevent condensation in the ESP and the stack. A larger ESP is also required to handle the increased particulate loading.

Both lime furnace and duct injection processes have low reagent utilization. Approximately 40 to 60 percent of the lime injected is utilized; therefore, both processes produce large amounts of free lime in the solid waste.

For the dry-sodium duct injection process, a larger ESP unit will also be required to handle the additional particulate loading. This process has only been demonstrated on very low-sulfur coal of less than 0.4 percent sulfur by PSCC at the Cherokee power station in Denver.

As for the availability of the sodium-based sorbents, most of the sodium chemicals are being mined exclusively in sodium mines in Wyoming and processed mainly for the glass manufacturing industry. Approximately 90 percent of the sodium is converted into soda ash for this purpose, and historically sodium suppliers have not sold their products in alternative markets. Therefore, availability and pricing of sodium-based sorbents are considered to be uncertain in the future.

The DSI process has been used in several demonstration projects, but there are no commercially operating systems in the U.S. Based on the demonstration projects, the DSI process is considered technically feasible. However, the lack of long-term commercial operating experience with systems achieving greater than 30 percent SO_2 control efficiency introduces significant uncertainties concerning the economics and effectiveness of the DSI system.

Environmental Effects-- While the waste materials from the sorbent injection technologies differ from conventional pulverized coal combustion, they are similar to wastes generated by spray dryers or fluidized bed combustors. The lime furnace injection process tends to form calcium sulfate and substantial quantities of unreacted free lime (up to 50 percent); the reactivity and exothermicity of the free lime require special handling because of the associated safety hazards. On the other hand, waste from the lime duct injection process contains less free lime, but large amounts of calcium sulfite, which can cause compaction problems during disposal. If the lime duct injection process uses a sodium additive such as sodium hydroxide, the ash has to be handled as hazardous solid waste.

The sodium-containing wastes from the dry sodium injection process are a concern with respect to surface runoff and leachate entering the groundwater. The wastes must be disposed of in a landfill with a liner. In addition, a brownish plume may be produced when the injection system is operated at higher than 30 percent SO_2 removal efficiency. Through a complex chemical reaction, NO_2 is produced by the oxidation of NO which occurs at a high level of depletion of SO_2 from the flue gas. Therefore, visible emissions will be expected to increase when a sodium-based DSI process is operated at above 30 percent SO_2 removal efficiency.

Energy Requirements and Impacts-- Both the furnace and duct injection processes require additional electricity to drive various mechanical equipment, including conveyor belts, feeder systems, pulverizers, and air pumps. Additional energy is required for operating a larger ESP unit as well as larger ash handling equipment. The estimated energy requirement is approximately 1,765 megawatt-hours per year (MW-hr/yr) for both the furnace and duct injection processes. These estimated energy requirements are calculated assuming the maximum allowable coal-firing for the Flo-Energy facility, and that the DSI system would be operating only during coal firing.

In the furnace injection process, the sorbent is injected into the flue gas prior to the superheater section of the boiler. Some of the sorbent will undergo pozzolanic reactions with the fly ash and may deposit on boiler internal components, forming a coating and resulting in a small steam penalty (approximately 1 percent of the total steam production).

In the lime duct injection process, reheat of the flue gas may be required prior to discharge at the stack. More electricity will be required for a larger ESP unit, and for the operation of auxiliary equipment. Additional water usage is required for the humidification system for both lime injection processes.

The dry sodium process will also require additional electricity to operate a larger ESP unit and the auxiliary equipment associated with the injection system and ash handling system.

Economic Analysis-- The capital cost factors for the DSI system were developed from vendor information and published literature. The estimated factors are $4,000/MMBtu heat input for the lime furnace injection system, $3,500/MMBtu for the lime duct injection system, and $3,000/MMBtu for the dry sodium duct injection process. The capital, operating and annualized cost estimates for the DSI systems are presented in the attached Table A. The estimates include the costs of upsizing the ESP units and the ash handling systems.

The total capital investment for the three DSI processes are estimated at $7.08 million, $6.00 million, and $4.98 million for the lime furnace injection process, the lime duct injection process, and the dry sodium duct injection process, respectively. The annualized costs for these three DSI processes are approximately $3.06 million, $2.76 million, and $2.56 millon, respectively. The cost effectiveness values for these DSI processes are $4,709 per ton of SO_2 removed for the lime furnace injection process, \$3,396 per ton of SO_2 removed for the lime duct injection process, and \$3,155 for the dry sodium duct injection process.

A review of the cost tables presented in the Flo-Energy application for the spray dryer SO_2 control system revealed that ESP upsizing was not included in the costs. Therefore, Tables 5-3 and 5-4 from the original application have been revised and are attached.

A revised BACT summary table (Table 5-5 from the original permit application) is attached which incorporates all of the FGD technologies considered. The dry-sodium duct injection process is used to represent all DSI processes in the revised BACT summary table because this process has the lowest cost effectiveness, reflected in the lowest annualized cost at 50 percent SO_2 removal efficiency as shown in Table A.

BACT CONCLUSIONS

In conclusion, the three DSI processes (lime furnace injection, lime duct injection, and dry-sodium injection) are considered technically feasible for application to Flo-Energy. However, the lack of any long-term operating experience renders these DSI processes uncertain in terms of economics and SO_2 removal efficiency. In actual operations, all SO_2 removal efficiencies have been reported at lower rates than those projected thus far in all existing demonstration projects in the U.S. Other concerns related to lime injection DSI systems include solids buildup on heat transfer surfaces, increased particulate emissions and/or solid waste disposal, and increased water and energy usage. The dry-sodium injection process has several areas of concern that include:

- Brown plume visible emissions,
- Disposal of highly soluble sodium ash, and
- Long-term cost and availability of sodium-based sorbent for the proposed project.

The total cost effectiveness for the lime furnace injection, the lime duct injection, and the dry sodium duct injection processes are \$4,709; \$3,396; and \$3,155 per ton of SO_2 removed, respectively. Thus, the dry sodium process is the most effective of these three emerging control technologies.

With the addition of the DSI process to the revised BACT summary table (Table 5-5) for the Flo-Energy facility, the total cost effectiveness for the wet limestone scrubber, the spray dryer, and the dry-sodium duct injection process are \$3,155, \$2,794, and \$4,698 per ton of SO_2 removed, respectively, based on the worst-case annual emissions. The total cost effectiveness for these same options for the combined Flo-Energy and Sol-Energy facilities is at least two times higher for each option (i.e., \$8,342; \$6,912; and \$12,666 per ton for the wet limestone scrubber, the spray dryer, and the dry-sodium duct injection process, respectively) based on the combined average SO_2 emissions from the two facilities of 1,000 TPY.

The incremental cost effectiveness of the dry sodium injection process, above the baseline case of low sulfur coal firing, is \$3,155/ton SO_2 removed. This value is far above the incremental cost effectiveness considered to be unreasonable in previous BACT determinations for SO_2, i.e., greater than \$2,000/ton. The incremental cost of the spray dryer, over the DSI process, is \$2,365/ton, and the incremental cost of the wet scrubber option, above the spray dryer process cost, is \$63,090/ton. In the case of the combined Flo-Energy and Sol-Energy projects, these incremental costs are more than doubled.

These high costs render all SO_2 control alternatives considered as economically infeasible. Therefore, the firing of low sulfur coal is BACT for the proposed Flo-Energy Cogeneration facility.

Table A. Capital, Operating, and Annualized Cost Estimates for Sorbent Injection Systems, Flo–Energy Cogenration.

Cost Items	Basis	Furnace Injection Lime Sorbent	Duct Injection Lime Sorbent	Duct Injection Sodium Sorbent
TOTAL CAPITAL INVESTMENT (TCI)				
(1) Dry Sorbent Injection System	See Note 1	$5,880,000	$4,704,000	$4,410,000
(a) Flue Gas Humidification System		Included	Included	--
(2) Upsizing ESP for Particulate Control				
(a) Percent Increase in Size	Based on ESP's Vendor Estimate	55%	60%	25%
(b) Cost of Upsizing for 3 Boilers	$7,000 per 1% Increase per boiler	$1,155,000	$1,260,000	$525,000
(3) Upsizing Ash Handling System				
(a) Cost of Upsizing for 3 Boilers	10% of current system cost. See Note 2.	$40,000	$40,000	$40,000
Subtotal of TCI	(1) + (2b) + (3a)	$7,075,000	$6,004,000	$4,975,000
DIRECT OPERATING COSTS (DOC):				
(1) Labor				
Operator[2]	$22/hr; 4,706 hr/yr total	$129,425	$129,425	$129,425
Supervisor[1]	15% of operator cost	$19,414	$19,414	$19,414
(2) Maintenance[2]	5% of direct capital cost	$237,013	$201,134	$166,663
(3) Replacement Parts	3% of direct capital cost	$142,208	$120,680	$99,998
(4) Utilities				
(a) Electricity for ESP	$85 per MW–hr	$159,115	$164,247	$128,318
for Auxiliary Equipment	$85 per MW–hr	$42,431	$43,799	$34,218
(b) Water	$0.27 / 1,000 gal	$10,726	$10,726	--
(c) Steam Lost or Reheat	$6.19/$10^9$ lb	$32,749	--	--
(5) Raw Chemicals				
(a) Limestone (97% purity)	$32 / ton including freight	--	--	--
(b) Hydrated Lime (74% purity)	$140 / ton including freight	$568,874	$568,874	--
(c) Sodium Bicarbonate	$230 / ton including freight	--	--	$602,762
(6) Solid Disposal	$27 / ton for Lime; $50 /ton for Sodium	$98,721	$123,402	$204,979
Total DOC		$1,440,674	$1,381,701	$1,385,776
INDIRECT OPERATING COSTS (IOC):				
(7) Overhead[1]	60% of operating labor & maintenance	$231,511	$209,983	$189,301
(8) Property Taxes[1]	1% of total capital investment	$58,800	$47,040	$44,100
(9) Insurance[1]	1% of total capital investment	$58,800	$47,040	$44,100
(10) Administration[1]	2% of total capital investment	$117,600	$94,080	$88,200
Total IOC		$466,711	$398,143	$365,701
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	$1,151,103	$976,851	$809,433
ANNUALIZED COST (AC):	DOC + IOC + CRC	$3,058,487	$2,756,696	$2,560,909
TOTAL SO2 REMOVED, TPY [3]	40% for Furnace Inj.; 50% for Duct Inj.	649	812	812
COST EFFECTIVENESS		$4,709	$3,396	$3,155

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

[2] Based on maximum of 25% coal firing for the Flo–Energy cogeneration facility.

[3] Uncontrolled SO2 emissions from coal firing for the worst–case year are 1,623.6 TPY.

Note 1: Capital cost factors are $4,000/MMBtu of heat input for Furnace Injection and $3,500/MMBtu of heat input for Duct Injection (both using lime) projecting from Babcock and Wilcox's cost analysis summary for Ohio's Edison Power Plant located at Edgewater, Ohio. The capital cost factor for the sodium sorbent injection process is $3,000/MMBtu of heat input based on estimations from Colorado Springs Utilities Company and Public Service Company of Colorado. Total Capital Investment for the dry sorbent injection process was calculated using these cost factors for a total of three 490–MMBtu boilers for the proposed Flo–Energy facility.

Note 2: Capital cost estimates of the ash handling system prior to the upsizing in order to handle the additional ash generated from the DSI process are approximately $400,000.

Table 5-3. Capital Cost Estimates for Alternative SO2 Control Systems for Flo-Energy (Revised 11/30/92).

Cost Items	Cost Factors	Spray Dryer	Wet FGD
DIRECT CAPITAL COSTS (DCC):			
(1) Purchased Equipment			
(a) Basic Equipment*	Vendor Quote	$3,990,000	$8,618,400
(b) Auxiliary Equipment	included	included	included
(c) Structure Support	0.10 x (1a)	$399,000	$861,840
(d) Instrumentation & Controls	0.10 x (1a)	$399,000	$861,840
(e) Freight[1]	0.05 x (1a-1d)	$239,400	$430,920
(f) Sales Tax (Florida)	0.06 x (1a-1d)	$287,280	$517,104
(g) Subtotal	(1a-1f)	$5,314,680	$11,290,104
(2) Direct Installation[1]	0.30 x (1g)	$1,594,404	$3,387,031
(3) Upsizing ESP for Particulate Control			
(a) Percent Increase in Size	Based on ESP's Vendor Estimate	40%	--
(b) Cost of Upsizing for 3 Boilers	$7,000 per 1% Increase per boiler	$840,000	--
(4) Upsizing Ash Handling System			
(a) Cost of Upsizing for 3 Boilers	See Note 1.	$40,000	--
Total DCC:	(1) + (2) + (3) + (4)	$7,789,084	$14,677,135
INDIRECT CAPITAL COSTS (ICC):			
(3) Indirect Installation			
(a) Engineering & Supervision[1]	0.10 x (DCC)	$778,908	$1,467,714
(b) Construction & Field Expenses[1]	0.10 x (DCC)	$778,908	$1,467,714
(c) Contruction Contractor Fee[1]	0.05 x (DCC)	$389,454	$733,857
(d) Contigencies[1]	0.20 x (DCC)	$1,557,817	$2,935,427
(4) Other Indirect Costs			
(a) Startup & Testing[1]	0.03 x (DCC)	$233,673	$440,314
(b) Working Capital	30-day DOC**	$125,642	$188,150
Total ICC:	(3) + (4)	$3,864,403	$7,233,175
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	$11,653,487	$21,910,311

* For the spray dryer, the basic equipment cost is the average of budgetary quotations from ABB-Flakt, Joy Environmental Systems, and United McGill. The basic equipment cost for the wet limestone scrubbers were estimated as 2.16 times the cost for the spray dryer scrubbers. The cost factor was determined from vendor estimates and comparative costs between the wet scrubber and the dry scrubber processes as as presented in similar analysis.

** 30 days of direct operating costs, calculated from the annualized cost Table 5-4 (i.e., total DOC/12 months).

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition (1990).

Note 1: Capital cost estimates of the ash handling system prior to the upsizing in order to handle the additional ash generated from the spray dryer process are approximately $400,000. The upsizing of the ash handling system will add an additional 10% cost or approximately $40,000 to the spray dryer option. The wet FDG option does not involve any upsizing of the ESP ash handling system.

Table 5-4. Annualized Cost Estimates for the Alternative SO2 Control Systems for Flo-Energy (Revised 11/30/92).

Cost Items	Basis	Spray Dryer	Wet FGD
DIRECT OPERATING COSTS (DOC):			
(1) Labor			
Operator[2]	$22/hr; 4,706 and 7,087 hr/yr total	$103,540	$155,905
Supervisor[1]	15% of operator cost	$15,531	$23,386
(2) Maintenance[2]	5% of direct capital cost	$389,454	$733,857
(3) Replacement Parts	3% of direct capital cost	$233,673	$440,314
(4) Utilities			
(a) Electricity	$85 per MW-hr	$320,901	$670,312
(b) Water	$0.27 / 1,000 gal	$6,129	$15,323
(5) Raw Chemicals			
(a) Limestone (97% purity)	$32 / ton including freight	--	$101,313
(b) Hydrated Lime (74% purity)	$140 / ton including freight	$329,591	--
(6) Solid Disposal	$27 / ton	$108,892	--
(7) Sludge Disposal	$27 / ton	--	$117,397
Total DOC		$1,507,709	$2,257,806
INDIRECT OPERATING COSTS (IOC):			
(7) Overhead[1]	60% of operating labor & maintenance	$305,115	$547,888
(8) Property Taxes[1]	1% of total capital investment	$116,498	$219,103
(9) Insurance[1]	1% of total capital investment	$116,498	$219,103
(10) Administration[1]	2% of total capital investment	$232,995	$438,206
Total IOC		$771,105	$1,424,301
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	$1,895,415	$3,564,808
ANNUALIZED COST (AC):	DOC + IOC + CRC	$4,174,230	$7,246,914

---

[1] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

[2] Based on maximum of 25% coal firing for the Flo-Energy cogeneration facility.

Table 5-5. Summary Results of the Top-Down BACT Analysis for SO2 for Flo-Energy Cogeneration Facility (Revised 11/30/92).

				Environmental Impacts		Energy Impacts	Economic Impacts			
Control Alternative	Total SO2 Emissions (TPY)	Total Emission Reduction (TPY)*	Incremental Emission Reduction (TPY)	Potential toxic air impact?	Potential adverse enviromental impacts?	Additional Energy Requirements Electricity (MW-hr/yr)	Total Annualized Cost ($/yr)*	Incremental Annualized Cost ($/yr)	Total Cost Effectiveness ($/ton)*	Incremental Cost Effectiveness ($/ton)
Flo-Energy Facility Only- Worst Case Year										
Wet Limestone Scrubber	81.2	1,542.4	48.7	No	Yes	7,900	$7,247,000	$3,073,000	$4,698	$63,090
Spray Dryer	129.9	1,493.7	681.9	No	Yes	3,800	$4,174,000	$1,613,000	$2,794	$2,365
Dry-Sodium Duct Injection	811.8	811.8	811.8	No	Yes	2,000	$2,561,000	$2,561,000	$3,155	$3,155
Baseline (0.7 Wt% S Coal Uncontrolled)	1,623.6	--	--	--	--	--	---	---	---	---
Flo-Energy and Sol-Energy Facilities Combined- Average SO2 Emissions										
Wet Limestone Scrubber	50	950	30	No	Yes	12,900	$12,033,000	$5,674,000	$12,666	$189,133
Spray Dryer	80	920	420	No	Yes	6,200	$6,359,000	$2,188,000	$6,912	$5,210
Dry-Sodium Duct Injection	500	500	500	No	Yes	3,300	$4,171,000	$4,171,000	$8,342	$8,342
Baseline (0.7 Wt% S Coal Uncontrolled)	1,000	--	--	--	--	--	---	---	---	---

* Total emission reduction, total annualized cost, and total cost effectiveness are based on comparison to the baseline case.

FDER Comment 8: Please provide an operation and maintenance plan to minimize emissions during filling and storage of ammonia. What controls will be used to capture any ammonia escaping from the storage tank's pressure relief valve?

Response 8: The filling and storage of ammonia will be performed according to the American National Standards Institute (ANSI) K-61.1-1989 guideline (title page and table of contents attached). This document contains safety procedures and basic rules for the storage and handling of anhydrous ammonia. Minimum construction specifications are included for the tank, piping, tubing, fittings, and the pressure relief valve. Safety procedures for filling and handling are included. Safety procedures for a spill, rupture or relief valve opening are also specified.

The pressure relief valve on the ammonia storage tank will open only during emergency conditions when the pressure in the tank exceeds specified levels. Under such conditions, the ANSI guideline recommends the use of water spray directed at the vapor cloud. The water spray can be applied via a fire hose.

Since ammonia is not considered a toxic or health related air pollutant, no further controls on the pressure relief valve are proposed. The potential for any emergency ammonia releases to cause nuisance odors is extremely low due to the remote location of the Flo-Energy site in regard to any residences or commercial development. Water sprays can adequately control any emergency ammonia releases.

ANSI
K-61.1-1989
Revision of
K61.1-1981

American National Standard
Safety Requirements for the Storage and Handling of Anhydrous Ammonia

Secretariat

Compressed Gas Association, Inc.
1235 Jefferson Davis Highway
Arlington, VA 22202

CGA Pamphlet G-2.1 — 1989

Approved March 17, 1989
American National Standards Institute, Inc.

RTC-67

CONTENTS

Improved
ER&E THERMAL DeNO$_X$ Process

Exxon Research and Engineering Company (ER&E) has developed, and is offering for license, a non-catalytic process called THERMAL DeNO$_X$ for removing oxides of nitrogen (NO$_X$) from flue gas in stationary combustion sources. Recent improvements in the process now permit the attainment of higher deNO$_X$, better load following and lower equipment cost.

U.S. patents covering the THERMAL DeNO$_X$ process have been granted to ER&E. Applications for counterparts of these patents have been filed in a number of foreign countries and additional patents on related technology are pending.

	Completed	Under Construction
Japanese Industrial Boilers	4	
Japanese Utility Boilers	5	
Japanese Petroleum Heaters	4	
California Oil Field Steamers	5	
California Flat Glass Melting Furnace	1	2
California Petroleum Heaters	30	
California Utility Boiler	1	
California Industrial Boilers	3	
California Incinerators	3	11
California Wood-Fired Boilers	3	
German Coal-Fired Boilers	2	

Table I—THERMAL DeNO$_X$ Experience Summary

Table I summarizes the commercial-scale field experience that has been acquired to date with this process. NO$_X$ reductions of up to 90% have been demonstrated on an oil field steamer where favorable process conditions exist. DeNO$_X$ performance using earlier technology ranges from 50% to 70% for most oil- and gas-fired process heaters and steam boilers. Successful results have also been obtained on a municipal incinerator, a glass furnace and coal-fired utility boilers.

Development of an accurate kinetic model of the process chemistry has significantly expanded the understanding of the interaction of all parameters affecting performance, and permits accurate calculation of NO$_X$ reduction and unreacted ammonia. Substantially greater performance is now achieved through the use of an inexpensive wall injection system. These advances have resulted in deNO$_X$ performance of 70% to over 80% and better load following capability without the use of hydrogen. Lower cost installations are being accomplished by replacement of grid injectors with the new injection system design. In effect, THERMAL DeNO$_X$ now offers performance approaching that of competing flue gas treatment processes for many types of fired equipment, at lower cost and with reduced space requirements.

This brochure is intended to provide an overview of THERMAL DeNO$_X$, to assist those companies that may be concerned with their present or projected NO$_X$ emission levels, in the evaluation of NO$_X$ reduction options currently available commercially. A list of relevant publications is appended for those seeking additional background information on this general subject.

Readers desiring specific technical assistance, or those interested in exploring the possibility of licensing ER&E THERMAL DeNO$_X$ technology, are invited to contact ER&E either by mail or phone as follows:

Technology Sales Division
Exxon Research and Engineering Company
P.O. Box 390, Florham Park, N.J. 07932 Phone: (201) 765-2615

Process Description

THERMAL DeNO$_X$ is a non-catalytic process based on the gas phase homogeneous reaction between NO$_X$ in flue gas and ammonia (NH_3) which produces nitrogen and water. In general, NH_3 is injected into the hot flue gas by means of either air or steam carrier gas at a point in the flue specifically selected to provide optimum reaction temperature and residence time. The following two equations describe the reactions which govern the overall process:

$$NO_X + NH_3 + O_2 + H_2O + (H_2) \rightarrow N_2 + H_2O \qquad (1)$$

$$NH_3 + O_2 \rightarrow NO_X + H_2O \qquad (2)$$

Equation (1) is the deNO$_X$ reaction. In the temperature range of 1600F (870C) to 2200F (1200C), the reaction occurs through the injection of NH_3 alone. Hydrogen (H_2) can also be injected along with NH_3 to extend the effectiveness of the deNO$_X$ reaction down to the range of 1300F (700C). As indicated by equation (2), NH_3 injected into high temperature flue gas above the range of the deNO$_X$ reaction, results in increased NO$_X$ and is thus counterproductive.

Detailed laboratory experiments have shown that there are no reactions between the THERMAL DeNO$_X$ process components and sulfur compounds in high temperature flue gas regions. Also, the injection of NH_3 does not cause SO_2 to undergo additional oxidation to SO_3.

Ammonia breakthrough in the THERMAL DeNO$_X$ process is extremely complicated because it depends upon the interaction of numerous factors. Because of its complexity, ammonia breakthrough must be evaluated for a particular fired equipment apparatus, and there are very few generalizations which can be made. Since breakthrough is linked to a certain degree to deNO$_X$ performance, fired equipment in which the time-temperature relationship is favorable to achieving high deNO$_X$ performance will also typically exhibit low NH_3 breakthrough. In cases where favorable conditions exist, it has been possible for ER&E to predict NH_3 breakthrough as low as 5 ppm. In any case, the placement of the injectors for a given time-temperature relationship and their mixing effectiveness are of prime importance in minimizing NH_3 breakthrough, and this is within the control of the deNO$_X$ system design which can be prepared by ER&E.

In practice, some of the injected NH_3 escapes reaction with the NO$_X$ and, as it cools with the combustion gases, it reacts with SO_3 and H_2O to form NH_4HSO_4, and $(NH_4)_2SO_4$. Laboratory as well as full-scale commercial test results show these sulfates to be harmless with respect to both corrosion and preheater fouling when the THERMAL DeNO$_X$ process is operated within the prescribed design specifications. Long-term tests conducted in two oil-fired boilers in Japan showed that these sulfate deposits are readily removed by periodic water washing.

Tests to determine the THERMAL DeNO$_X$ process applicability to coal burning boilers gave performance similar to oil and gas burning boilers. These tests were made on a 3M Btu/hr (0.9 MW) combustion system under the joint sponsorship of EPRI and ER&E and represented the first development step in the application of THERMAL DeNO$_X$ to coal-fired utility boilers. Subsequent installation of the process in two coal fired utility boilers in Germany have substantiated the application to coal fired units.

Process Modeling

Equations (1) and (2) summarize the overall effect of the deNO$_X$ reaction, but they do not reveal the complexity of interaction of numerous intermediate chain branching reactions involving certain key free radicals. A recently developed kinetic model has been successful in assessing the process chemistry and reaction rate constants for each of the intermediate chain branching reactions. The model has been verified by an extensive laboratory data bank and also agrees well with pilot plant data and commercial plant performance. This technology has enabled extension of the temperature window using NH$_3$ alone from under 1600F (870C) to over 2200F (1200C) under certain conditions of the other kinetic parameters. The model is being used to pinpoint the optimum flue gas temperature zone and ammonia injection rate for specific applications. The model also permits accurate prediction of unreacted ammonia.

The kinetic model calculations represent the maximum possible deNO$_X$ performance for the process under a given set of flue gas conditions. Performance may be lowered in a real system due to one or more of the engineering design or unit specific parameters including mixing, carrier rate, flue gas temperature and velocity gradients, and staged injection. The influence of each of these parameters has been the subject of considerable research and development. Mixing effectiveness of grid injectors has been increased such that it is possible to achieve 95-100% of the kinetic limit performance. Wall injector mixing can now be optimized for a specific geometry by utilizing a recently field-validated three-dimensional flow modeling technique.

Application Engineering

The original THERMAL DeNO$_X$ applications involved positioning an injection grid within the flue gas stream at the proper flue gas temperature for injecting a mixture of NH$_3$ and carrier steam or air. Sometimes, multiple grids and/or hydrogen were employed to achieve some load following, but this increased the complexity and cost of the installation. Also, there was concern over the long term operability of the grid, particularly in corrosive, erosive or heavy fouling flue gas streams such as occur with coal-firing. In most applications today, the injection grids are being superseded by wall injectors consisting of large jets located at or near the boundary walls of the injection zone. The advantages of wall injectors are listed in Table II.

- Higher Performance
- Lower Investment Cost
- Better Load Following
- Lower Fouling Tendency
- No Cooling Requirement
- Simple Installation
- Easily Retrofitted
- Greater Cost Effectiveness

Table II—Advantages of Wall Injectors

The wall injectors are simple and relatively inexpensive, but require careful design and placement in order to achieve optimum process results. They are not subject to overheating upon loss of carrier, corrosive attack, or collection of fuel ash deposits such as may result with a grid injector design when firing heavy fuel oil, coal or refuse. These factors permit location of the injectors at the optimum flue gas temperature, even within the combustion zone of fired equipment. To accommodate turndown operation, two sets of injectors may be used with little impact on overall cost. Through proper location of the injectors to cover the load range, the need for hydrogen injection to promote low temperature performance is eliminated. In addition, if flue gas temperatures during operation of a unit are substantially different from those anticipated in the design, the wall injectors may be relocated during a short outage. Wall injectors may be retrofitted to an existing boiler without relocating ducting, air preheaters, stacks, etc. and with minimal impact on the boiler structure. All of these factors contribute to a THERMAL DeNO$_X$ technology which is practical, highly efficient and cost effective.

While the wall jet injectors do offer substantial benefits over injection grids, they also pose a challenging problem in achieving adequate mixing, especially in very large fired equipment. This has spurred development of a three-dimensional, turbulent flow modeling technique. Use of this tool, coupled mathematically with the kinetic model, permits the direct calculation of deNO$_X$ performance for any geometry, flow condition and temperature profile.

The modeling technique has been validated by field testing of a boiler located in Kawasaki, Japan. The test unit is a 440,000 lb/hr (200 ton/hr) oil- and gas-fired power boiler. This is a typical front-fired, waterwall boiler where flue gases exit the burners in the lower part of the combustion chamber, pass upward over a small arch and into the superheater zone. Flue gases then turn downward through the steam generating tube bank and exit to the air preheater.

The ammonia injectors are arranged in three zones. Zone 1 enters through the roof upstream of the primary superheater. Zone 2 enters through the roof in the cavity between the primary and secondary superheater. Zone 3 enters the lower part of this same cavity through the sidewalls.

Field data and calculated performance results for this boiler are illustrated in Figures 1, 2, 3 and 4. In Figure 1 performance results are provided for 80, 90 and 100% load. Performance results were obtained by first testing individual injection zones and then testing combinations of zones to determine which operating conditions yield optimum performance. Zone settings for NH$_3$ and carrier rates were guided by performance calculations and modeling results.

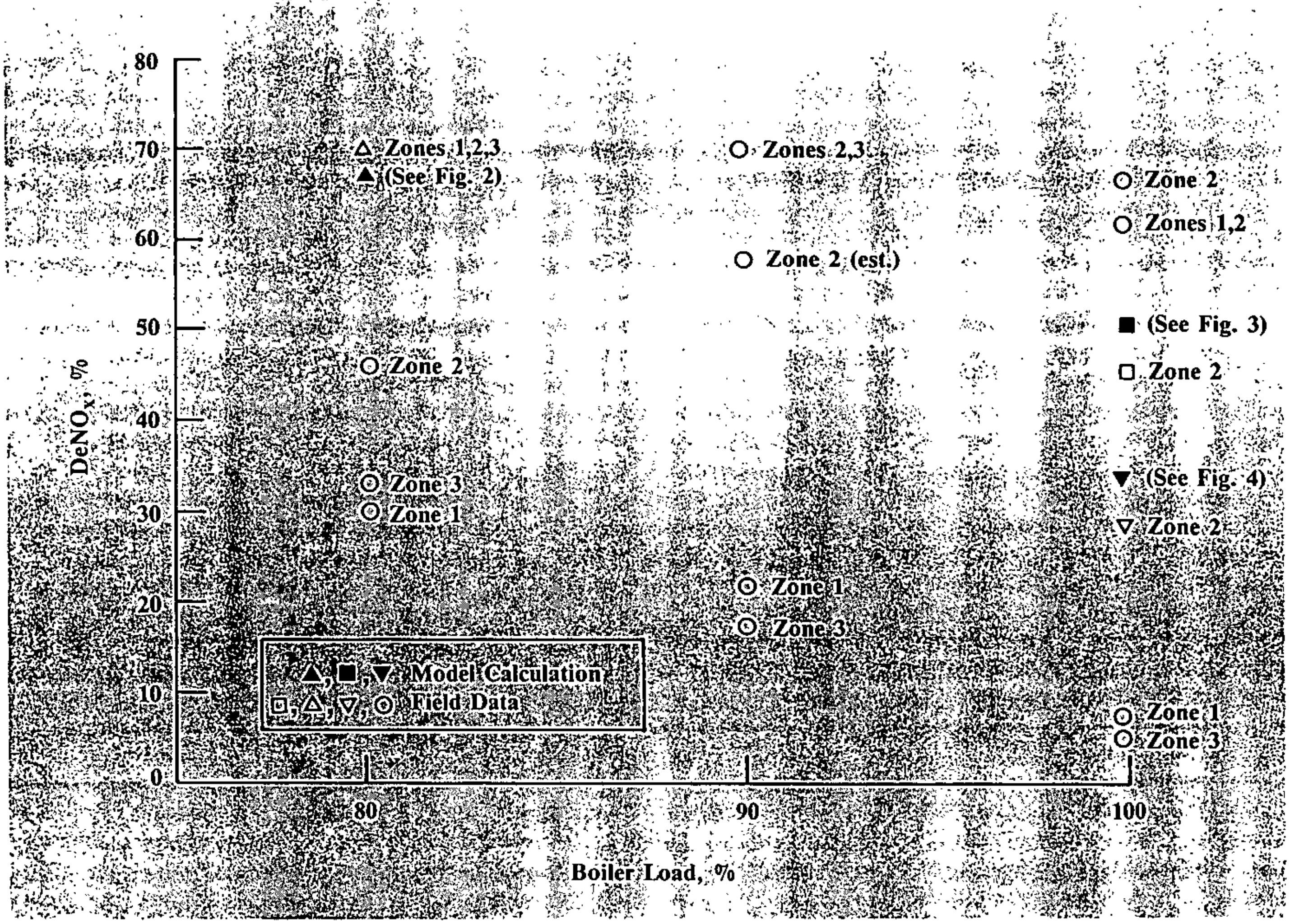


Figure 1. THERMAL $DeNO_x$ Test Results for Kawasaki Boiler

Optimized performance for the three test loads of 80, 90 and 100% are 70, 70 and 65% $deNO_x$, respectively. At 100% load optimized performance is achieved by operating Zone 2 alone. At 90% load optimized performance is achieved by simultaneously operating Zones 2 and 3, and at 80% load optimized performance is obtained by operating all three zones. The individual zone data show that Zone 2 achieves its maximum effectiveness at full load and decreases in effectiveness as load is reduced. On the other hand, Zones 1 and 3 are ineffective at full load, but increase in effectiveness as load is reduced. This multizone design technique can be utilized to achieve essentially constant performance over a wide load range. Figure 2 is a modeling result for the 3-zone operation at 80% load which predicts 67.5% $deNO_x$ vs. the 70% indicated by field data.

It was desirable to optimize performance in the range of 30-50% $deNO_x$ since it is unnecessary to achieve high NO_x reduction except during pollution emergencies. Figures 3 and 4 illustrate modeling results at 100% load for 50% and 30% $deNO_x$ respectively, utilizing only the Zone 2 injectors. The Figure 3 results are for a relatively high injection velocity which yields an outlet NO_x concentration of 92 vppm (184 mg/m^3). In Figure 4 the
jection velocity is relatively low and the indicated outlet conc
tration is 126 vppm (252 mg/m^3). These modeling results w
verified by field testing with a maximum variation betwe
calculated results and field data of ±7%. Thus, in the 80-10
load range, this boiler may operate with a single zone of inj
tors making adjustments to carrier and NH_3 rate as required
meet emission targets.

Generally, the first step in determining the feasibility of a pot
tial THERMAL $DeNO_x$ installation is the preliminary estim
tion of overall applicability, cost and NO_x reducing capabili
ER&E's application engineers can provide these prelimina
estimates from a review of the original equipment design specifi
tions. More accurate estimates can be obtained on the basis
measured temperature profiles and other field data. Individual p
cess designs are also derived from such data. ER&E person
can provide recommendations for designing new equipment
well as for modifying existing equipment in order to maxim
overall process efficiency.

Cost Effectiveness

In order to illustrate the cost effectiveness of the THERMAL $DeNO_x$ process, a 200,000 lb/hr (91 ton/hr) oil- or gas-fired industrial boiler has been selected for detailed analysis. Figure 5 shows the corresponding flow schematic of the THERMAL $DeNO_x$ supply system, which is sized on the basis of the values presented in Table III. It is assumed that the boiler has an uncontrolled NO_x effluent of 200 vppm (400 mg/m^3) corrected to 3% O_2 dry and that it will be equipped with two sets of injectors for injecting NH_3 via a steam carrier. Provision for a one-month NH_3 supply storage facility is also assumed in this analysis.

The total erected capital investment for these facilities is estimated to be $470k as outlined in Table IV. Direct costs include the material and labor for equipment outlined in Table III plus interconnecting piping. Indirect costs include field labor overheads, construction supervision and equipment, labor wage taxes, erection fee and engineering costs. Costs are expressed on 3Q86 basis at Southern California location. Excluded from these costs are such items as land, owners' charges and licensing royalty.

Cost effectiveness for the sample boiler installation is also shown in Table IV for three different bases. Annualized costs are obtained by assuming a five-year payout on investment plus annual operating costs. On a heat-fired basis, cost effectiveness of the process is $0.13 per MBtu (0.44 $/MWh). The cost effectiveness based on NO_x removed is 1.22k$/US ton (1.34 $/kg) NO_2 for a $deNO_x$ efficiency of 70% and 1.06k$/US ton (1.17 $/kg) NO_2 for 80% $deNO_x$. This cost compares favorably with some combustion modification techniques, such as burners out of service and flue gas recirculation, and is substantially lower than selective catalytic reduction.

Annual operating costs are shown in Table V. These costs are based on a 65% annual load factor and include values for NH_3, power and steam consumption, and maintenance material and labor.

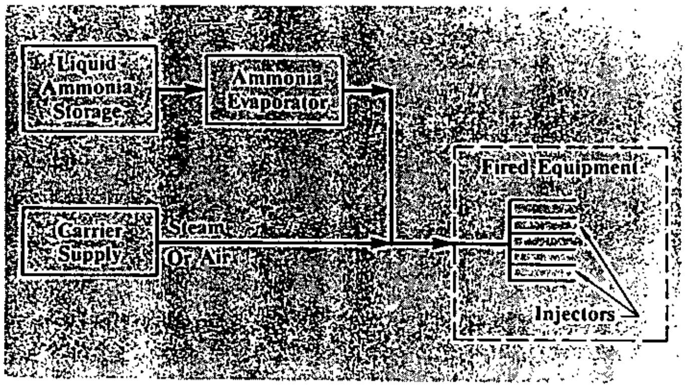


Figure 5—Simplified THERMAL $DeNO_x$ Supply System Flow Diagram

Boiler Design Conditions
200,000 lb/hr, 615 PSIG, 700F

Fuel	Oil or Gas
Initial NO_x	200 vppm (400 mg/m^3)
NH_3/NO_x	2.0 = 0.174 lb NH_3/lb NO_x
Carrier Requirement	Steam, 1500 lb/hr (680 kg/hr)
NH_3 Storage Tank	30 Day Storage Capacity (8000 US gallons = 30.3 m^3)
NH_3 Vaporizor	(1) Electric Element; Direct Contact
Injectors	Two Locations
Instrumentation	As Required

Table III—Equipment Sizing Basis for Permanent THERMAL $DeNO_x$ Facilities For Sample Industrial Boiler

Capital Investment(1)	
Material and Labor(2)	$190k
Indirect Costs(3)	$280k
	$470k
Cost Effectiveness	
$/MBTU Fired ($/MWh)	0.13 (0.44)
k$/US Ton ($/kg) NO_x Removed @ 70% $DeNO_x$	1.22 (1.34)
k$/US Ton ($/kg) NO_x Removed @ 80% $DeNO_x$	1.06 (1.17)

Notes:
(1) Investment costs are expressed at 3Q84 Southern California level
(2) Includes equipment items listed in Table III plus interconnecting piping
(3) Includes field labor overheads, construction supervision and equipment, labor wage taxes, erection fee, contractor engineering and Exxon Research and Engineering Co. charges. Excluded are such items as land, owners charges and licensing royalty.

Table IV—THERMAL $DeNO_x$ Investment Cost and Cost Effectiveness for Sample Industrial Boiler

Item	Annual Consumption(1)	Unit Cost	Annual Cost
Ammonia(2)	181 US Tons	$250/Ton	$45,250
Electric Power(3)	55 MWh	$75/MWh	4,125
Steam(4)	4290 US Tons	$12/Ton	51,480
Maintenance Material and Labor(5)			13,300
		Total	$114,155

Notes:
(1) Assumes 65% load factor
(2) Includes ammonia for direct injection
(3) Includes power requirement for ammonia vaporizer
(4) Low pressure steam (15 psig = 1 barg minimum) for carrier
(5) Assumed to be 7% of direct investment cost

Table V—THERMAL $DeNO_x$ Annual Operating Cost for Sample Industrial Boiler

Summary

In summary, the THERMAL DeNO$_x$ process offers one of the most practical and cost-effective approaches to significant NO$_x$ reduction from stationary fired equipment of any [illegible] NO$_x$ removal process currently on the market. This is due to the fact that the process is far less capital intensive and its NO$_x$ reduction capability approaches that of other, more costly processes.

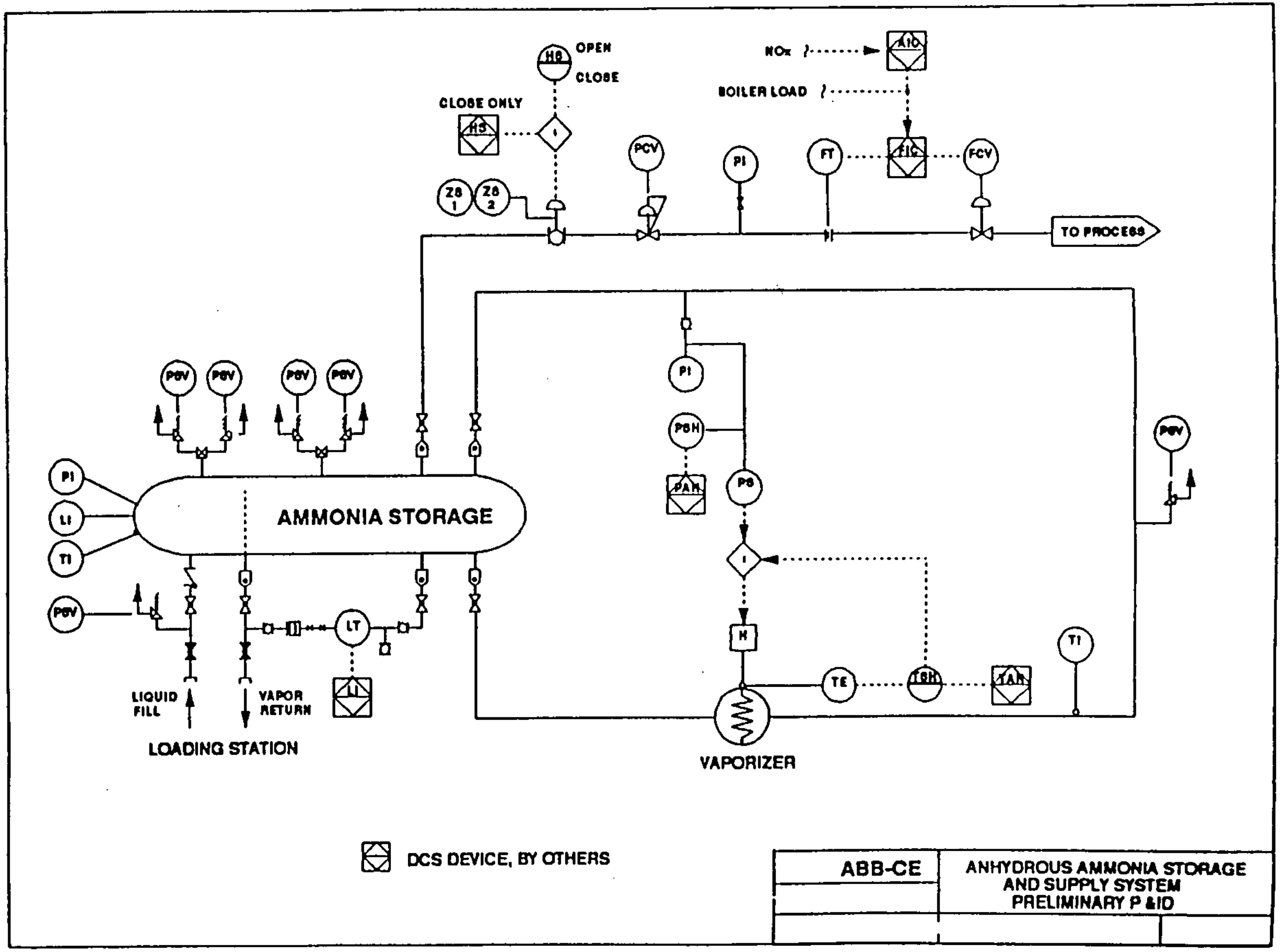
Recent technological advances have resulted in significant increases in THERMAL DeNO$_x$ performance along with decreases in equipment cost, thus further improving its cost effectiveness. No technological difficulties are foreseen in applying the THERMAL DeNO$_x$ process to all types of fired equipment, including those that are coal-fired. Exxon stands ready to work with potential users of this technology and/or their consultants to evaluate specific application situations.

References

Basic Chemistry

1. U.S. Patent 3,900,554.
2. A.M. Dean, et al., "A Mechanistic Analysis of the THERMAL DeNO$_x$ Reaction," 7th International Symposium on Gas Kinetics, Gootingen, W. Germany, August, [illegible]
3. G. M. Varga, M.E. Tomsho, B.H. Ruterbories, G.J. Smith and W. Bartok, "Applicability of the THERMAL DeNO$_x$ Process to Coal-Fired Utility Boilers," EPA-[illegible], March, 1979.
4. B.E. Hurst and C.E. Schleckser, Jr., "Applicability of THERMAL DeNO$_x$ to Large Industrial Boilers," 1980 Joint Symposium on Stationary Combustion NO$_x$ Control, Denver, October, 1980 (Vol. 5).
5. "Champlin Petroleum Using New System to Reduce NO$_x$ Emissions from Boilers," *Hydrocarbon Processing*, November, 1980.
6. B.E. Hurst, "Exxon THERMAL DeNO$_x$ Process for Utility Boiler Applications," Joint Power Generation Conference, St. Louis, October, 1981 ASME 81-JPGC-[illegible]
7. B.E. Hurst, "Exxon THERMAL DeNO$_x$ Process for Stationary Combustion Sources," US-Dutch International Symposium on Air Pollution by Nitrogen Oxides, Maastricht, The Netherlands, May, 1982.
8. B.E. Hurst, "Improved THERMAL DeNO$_x$ Process for Refinery Heaters and Boilers," 38th Petroleum Mechanical Engineering Workshop and Conference, Philadelphia, September, 1982.
9. B.E. Hurst, "THERMAL DeNO$_x$: The Practical Approach to Deep NO$_x$ Reduction," 32nd Canadian Chemical Engineering Conference, Vancouver, October, 1982.
10. H.T. Dziegiel, et al., "The THERMAL DeNO$_x$ Demonstration Project," 1982 Joint Symposium on Stationary Combustion NO$_x$ Control, Dallas, November, 1982.
11. R.W. Scheck, et al., "Technical and Economic Feasibility of Ammonia-Based Post Combustion NO$_x$ Control," EPRI CS 2713, November, 1982.
12. B.E. Hurst, "Technology Advances in Selective Non-Catalytic NO$_x$ Reduction (THERMAL DeNO$_x$)," 6th Annual Energy-Sources Technology Conference and Exhibition, Houston, January, 1983.
13. B.E. Hurst. "The Non-Catalytic Denitrification Process (THERMAL DeNO$_x$) for Glass Melting Furnaces," *Glass Technology*, April, 1983.
14. B.E. Hurst, "Improved THERMAL DeNO$_x$ Process Verified by Field Testing," APCA Annual Meeting, San Francisco, June, 1984.
15. B.E. Hurst, "The Improved THERMAL DeNO$_x$ Process—A Non-Catalytic Approach to NO$_x$ Emission Reduction," The International Clean Energy Technology Conference, Rotterdam, The Netherlands, November, 1984.
16. B.E. Hurst, "THERMAL DeNO$_x$ Technology Update," 1985 Joint Symposium on Stationary Combustion NO$_x$ Control, Boston, May, 1985.
17. G. Mittelbach and H. Voje, "Application of SNCR Process to Cyclone Firing," German Power Industry Association, June, 1986.
18. B.E. Hurst and C.M. White, "THERMAL DeNO$_x$: A Commercial Selective Non-catalytic NO$_x$ Reduction Process for Waste-to-Energy Applications," ASME 12th Biennial National Waste Processing Conference, Denver, June, 1986.

PRODUCED BY
GRAPHIC DESIGN
ER&E


HS
OPEN
CLOSE
NOx
AIC
BOILER LOAD
CLOSE ONLY
HS
I
PCV
PI
FT
FIC
FCV
ZS 1
ZS 2
TO PROCESS
PSV
PSV
PSV
PSV
PI
PSH
PAH
PS
I
H
PSV
PI
LI
TI
AMMONIA STORAGE
PSV
LT
LI
LIQUID FILL
VAPOR RETURN
LOADING STATION
TE
TSH
TAH
TI
VAPORIZER
DCS DEVICE, BY OTHERS
ABB-CE
ANHYDROUS AMMONIA STORAGE AND SUPPLY SYSTEM PRELIMINARY P &ID

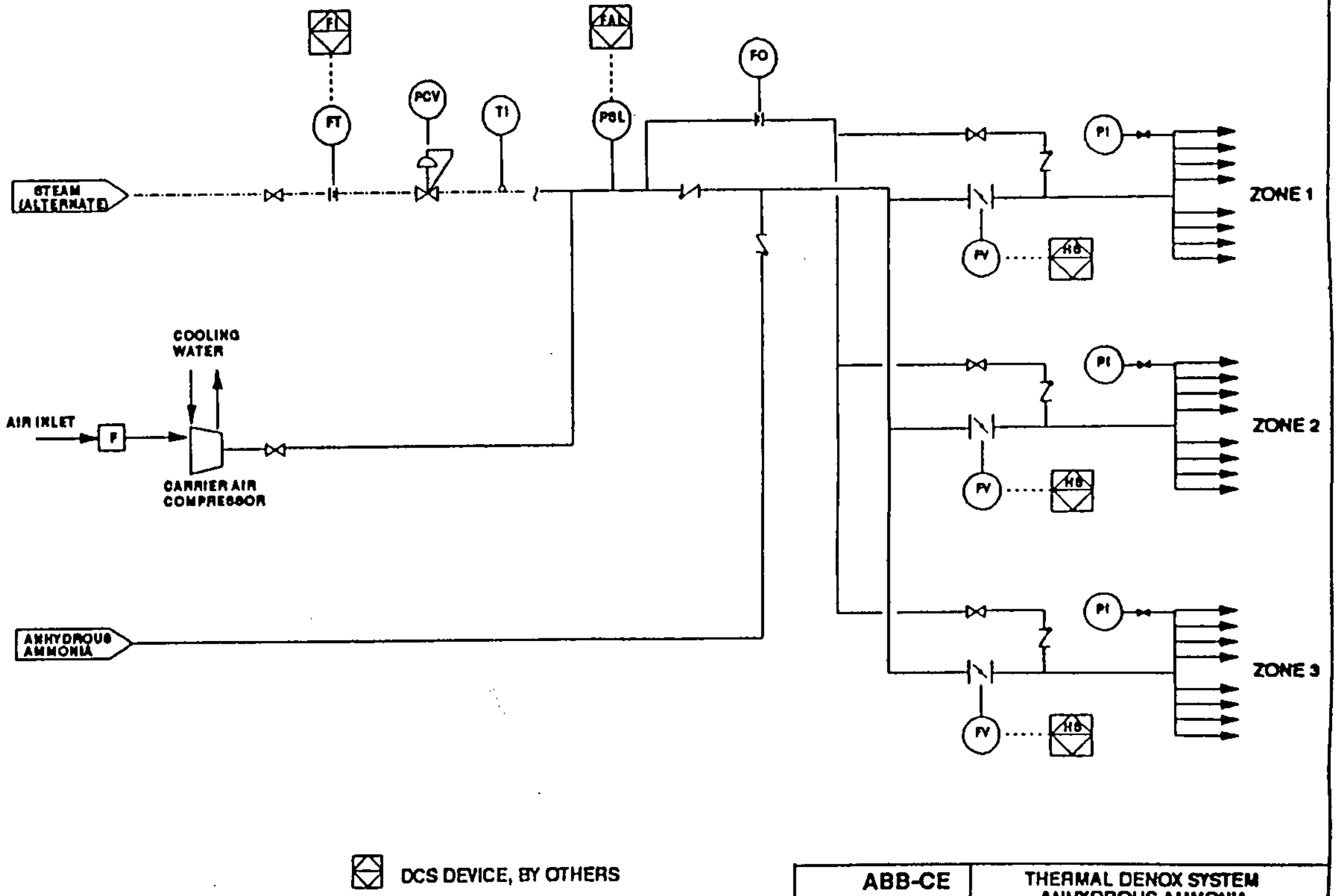


ABB-CE

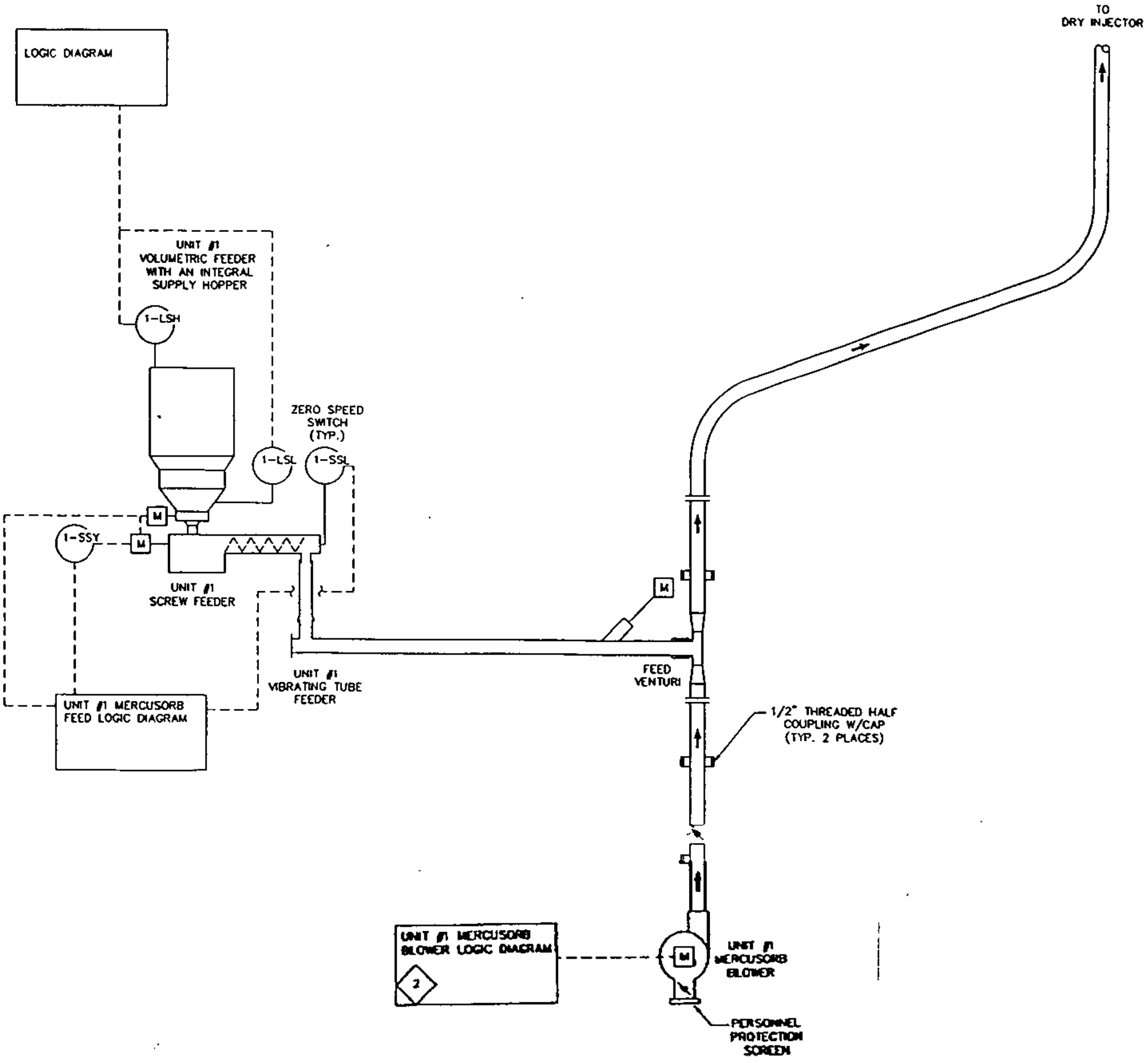
THERMAL DENOX SYSTEM
ANHYDROUS AMMONIA
PRELIMINARY P & ID

Mercury Control System

A schematic of a proposed mercury control system from Research-Cottrell is attached. The system would be similar to that installed on municipal waste incinerators. A volumetric feeder with integral supply hopper would meter activated carbon for injection at a point upstream of the ESP and ID fan to promote turbulent mixing and provide adequate residence time. A blower system would transport the carbon to the injection point. The ESP will effectively capture the activated carbon particles along with the boiler flyash (which also contains some carbon). No adjustment to the size of the ESP is envisioned since the activated carbon particles will be relatively large in size and small in amount compared to the flyash. No increase in stack particulate emissions is expected.

Given that the inlet mercury concentration on a biomass and coal-fired boiler would be very low, it is difficult to estimate carbon requirements. At the Stanislaus County MSW incineration facility, EPA has conducted one of the most extensive studies to date on the injection of activated carbon for mercury control. Carbon feed rates were varied between 2.8 lb/hr and 12.1 lb/hr, which equated to approximately 25 to 110 pounds of carbon per pound of mercury in the incoming flue gas. Mercury removal rates ranged from 53 to 85 percent at the lower injection rate, and from 88 to 98 percent at the higher injection rate. Inlet mercury flue gas concentrations ranged from 300 to 1,300 μg/dscm at 7 percent O_2.

To conservatively estimate carbon injection design rates for the proposed facility, the maximum indicated carbon injection rate of 110 lb/lb of mercury from Stanislaus was used. For each boiler, the maximum mercury emissions occur when burning coal at 490 MMBtu/hr, and maximum mercury emissions based on 30 percent control are 0.0041 lb/hr. Therefore, uncontrolled mercury emissions would be 0.0059 lb/hr. The calculated carbon injection requirement would then be 0.6 lb/hr. Based on this calculation, the proposed system will be designed to inject at least 1.0 lb/hr of carbon into each boiler. Flo-Energy will continue to evaluate the status of research concerning carbon injection for mercury control. A larger injection system will be implemented if final engineering demonstrates higher carbon injection rates are needed.


LOGIC DIAGRAM
UNIT #1 VOLUMETRIC FEEDER WITH AN INTEGRAL SUPPLY HOPPER
1-LSH
1-LSL
ZERO SPEED SWITCH (TYP.)
1-SSL
M
1-SSY
M
M
UNIT #1 SCREW FEEDER
UNIT #1 MERCUSORB FEED LOGIC DIAGRAM
UNIT #1 VIBRATING TUBE FEEDER
M
FEED VENTURI
1/2" THREADED HALF COUPLING W/CAP (TYP. 2 PLACES)
TO DRY INJECTOR
UNIT #1 MERCUSORB BLOWER LOGIC DIAGRAM
2
M
UNIT #1 MERCUSORB BLOWER
PERSONNEL PROTECTION SCREEN

Operation and Maintenance Plan

Since final equipment selection has not been completed, it is premature to develop an operation and maintenance (O&M) plan for the air pollution control equipment. However, Flo-Energy would be agreeable to a permit condition which would require an O&M plan to be submitted at least 90 days prior to beginning operation, or within 6 months of final equipment selection, whichever occurs first.

FDER Comment 6: Please provide drawings of all storage and material handling equipment (biomass, coal, bagasse, fly ash, carbon, etc.) with notations of how fugitive particulate matter emissions from hauling the material to the plant to disposing of any waste will be controlled. Include a table similar to Table 2-8 to show the fugitive emissions from these materials. Clarify how the ash for coal will be kept separate from the ash produced by the biomass.

Response 6: A diagram of the biomass/coal handling facilities is presented in the attached figure, entitled, Schematic of Fuel Handling System. Elevation views of the conveyor belts and transfer points are shown in the second figure, entitled, Elevation View of Fuel Handling System. Biomass will be delivered to the facility by conveyor belt (directly from the sugar mill) or by truck. The trucks will discharge the material into a dump hopper. The truck dump hopper will be open, but all subsequent conveyor belts will be covered and transfer points will be partially enclosed. From the dump hoppers, the biomass will be placed on a conveyor belt, pass through the hogger (crusher), and be placed on another conveyor to the transfer tower. From the transfer tower, the material can be fed to the boilers or directed to the fuel storage yard. If directed to the boilers, the material will be transferred from a conveyor belt to the fuel flight conveyor and then to the boiler feeders. Fuel will be delivered to the fuel yard via a stacker, and reclaimed by underpile reclaimer or by an overpile reclaimer device. To estimate worst case emissions, underpile reclaiming is assumed, which maximizes vehicular traffic in the fuel yard.

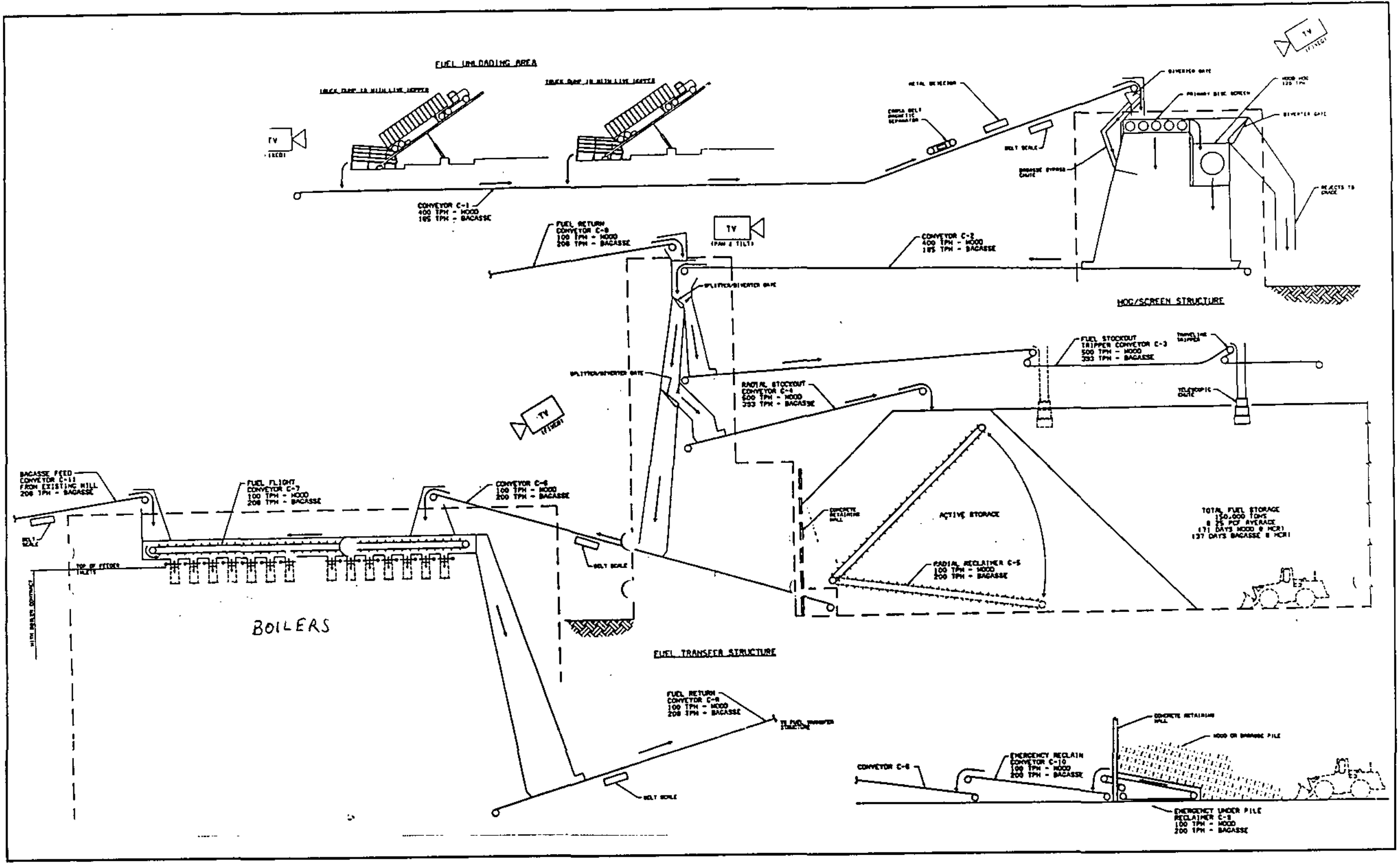
Bottom ash will be handled in a wet state and therefore emissions should not occur. Fly ash will be handled in an enclosed manner and will be delivered to enclosed dumpsters via a drop tube, or, as an alternative, will be first conditioned and then stored in open bins. Since the ash will be stored in dumpsters, it is very simple to segregate the coal ash from the biomass ash. Whenever coal firing commences, any ash placed in the dumpsters from that point on will be treated as coal ash. This will continue until such time as coal firing ceases and coal ash clears the system. Once specific ash handling equipment has been selected, the maximum time for ash to clear the system can be calculated. To provide assurance that coal ash is not mixed with biomass ash, Flo-Energy will continue to handle the ash during this time, plus an additional two hours, as coal ash.

All potential fugitive dust emission points are identified in Tables 2-7 and 2-8 attached. Table 2-7 and 2-8 have been revised to include the biomass transfer points. Worst case fugitive particulate emissions have been estimated by assuming the maximum amount of biomass to be burned is brought in by truck, proceeds to the fuel storage area (storage piles), and then is reclaimed and sent to the boilers. The estimated fugitive dust emissions do not consider any enclosures on the conveyor belts or transfer points (i.e., zero control efficiency has been assumed). Pile maintenance emissions are based on one vehicle operating 12 hours per day at an average speed of 5 mph (21,9000 VMT per year). Wind erosion emissions are based on the assumption that the entire fuel storage area contains biomass.

The fugitive emissions due to biomass handling are then added to the fugitive particulate emissions due to coal handling to estimate total emissions. Based on this very conservative methodology, the maximum estimated total fugitive PM (TSP) emissions are 11.122 TPY and the fugitive PM10 emissions are 3.982 TPY. Based on these changes, Table 3-3 of the permit application has been revised and is attached.

RTC-47

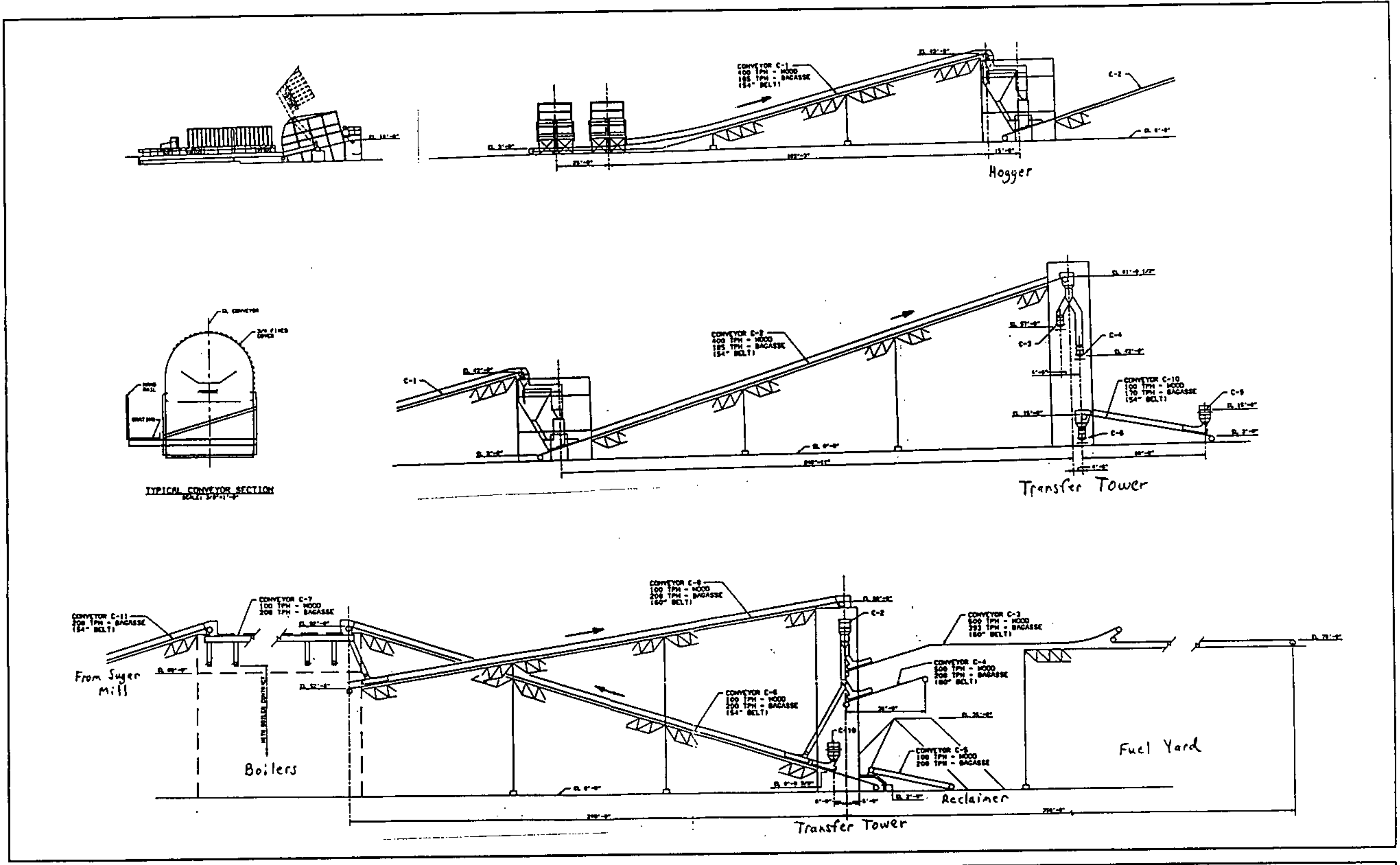
11-26-92



SCHEMATIC OF FUEL HANDLING SYSTEM

KBN

11-26-92



RTC-48

ELEVATION VIEW OF FUEL HANDLING SYSTEM

KBN

Table 2-7. Flo-Energy Cogeneration Facility Annual Average Uncontrolled Fugitive Emission Factors (Revised 11/17/92)

Source	Type of Operation[a]	M Moisture Content (%)	U Wind Speed (mph)	E Emission Factor (lb/ton)
<u>Coal Handling</u>				
Railcar Unloading	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Coal Pile	Batch Drop	4.5	9.4	0.00234
Underpile Reclaim Hopper	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Crusher	Batch Drop	4.5	9.4	0.00234
Coal Crusher	Coal Crushing	--	--	0.02 [b]
Crusher-to-Conveyor	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Boiler Feeders	Batch Drop	4.5	9.4	0.00234
Storage Pile	Wind Erosion	--	--	-- [c]
Coal Pile Maintenance	Vehicular Traffic	--	--	0.90328 [d]
<u>Biomass Handling</u>				
Truck Dump	Batch Drop	37	9.4	0.00012
Hopper-to-Conveyor	Batch Drop	37	9.4	0.00012
Conveyor-to-Hog Tower	Batch Drop	37	9.4	0.00012
Hogger	Crushing	--	--	0.02
Hogger-to-Conveyor	Batch Drop	37	9.4	0.00012
Transfer Tower	Batch Drop	37	9.4	0.00012
Conveyor-to-Stacker	Batch Drop	37	9.4	0.00012
Stacking	Batch Drop	37	9.4	0.00012
Underpile Reclaim	Batch Drop	37	9.4	0.00012
Reclaimer-to-Conveyor	Batch Drop	37	9.4	0.00012
Transfer Tower	Batch Drop	37	9.4	0.00012
Conveyor-to-Boiler Feeders	Batch Drop	37	9.4	0.00012
Biomass Storage Pile	Wind Erosion	--	--	--
Biomass Storage Pile Maintenance	Vehicular Traffic	--	--	0.90328 [d]
<u>Fly Ash Handling</u>				
Fly Ash Transfer	Batch Drop	2.0	9.4	0.00727

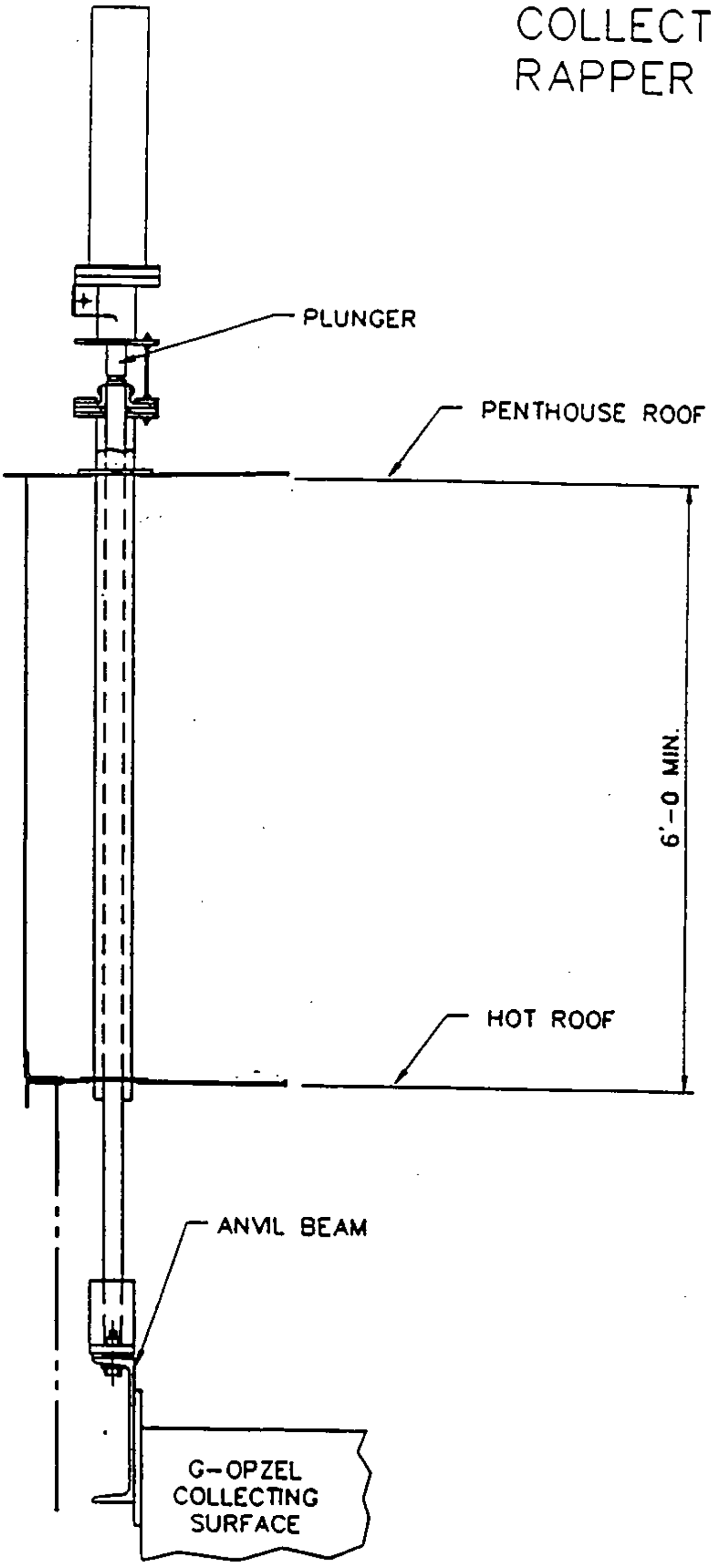
[a] Batch drop emission factors are computed from AP-42 (EPA, 1988) Section 11.2.3
$E = 0.0032 \times (U/5)^{1.3} / (M/2)^{1.4}$ lb/ton.

[b] Emission factor for coal crusher computed from AP-42 Table 8.23-1, for high moisture ore.

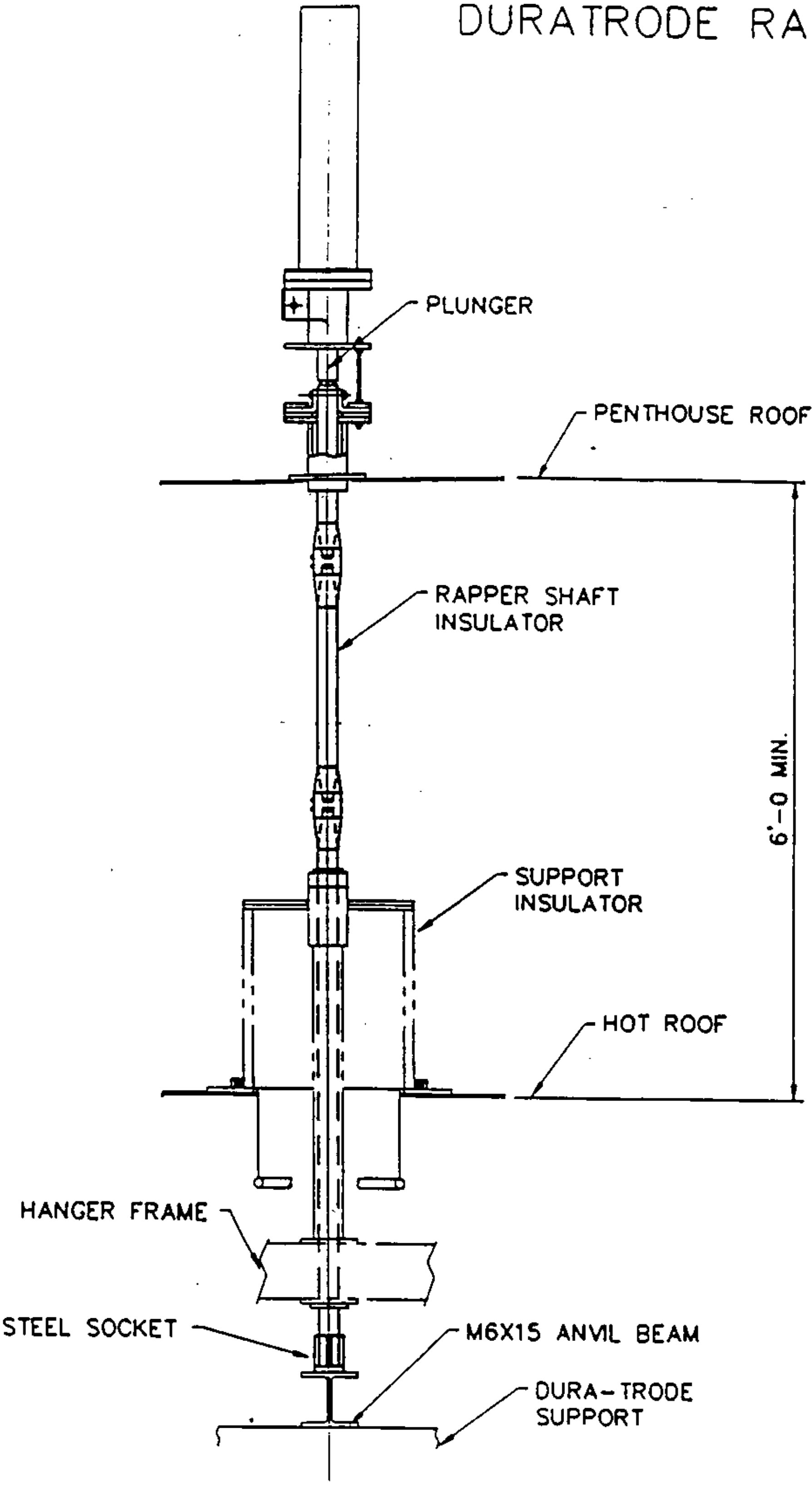
[c] Emission calculations provided in Appendix A.

[d] lb/vehicle mile traveled based on AP-42 Section 11.2.1. Silt = 2.2, W = 53.

COLLECTOR PLATE
RAPPER TRAIN



DURATRODE RAPPER TRAIN



Research-Cottrell

Air Pollution Control Division

Transformer-Rectifier

Research-Cottrell manufactures transformer-rectifier units specifically designed for electrostatic precipitator applications. In-house quality control, in which all units are tested prior to shipment, and a conservative rating have produced an outstanding record of operating reliability.

Description

Transformer type—Liquid immersed, convection cooled, designed for outdoor installation.

Dielectric fluid—Mineral oil RTEmp$^{\text{TM}}$ or silicone fluid, with visual indicator.

Rectifier type—Silicon diode, immersed in dielectric fluid, full wave or optional double half-wave bridge configuration.

Rectifier transient protection—Rectifier stack contains transient suppression voltage equalization networks. A high frequency choke in the high voltage output leg protects all components from connected load transients.

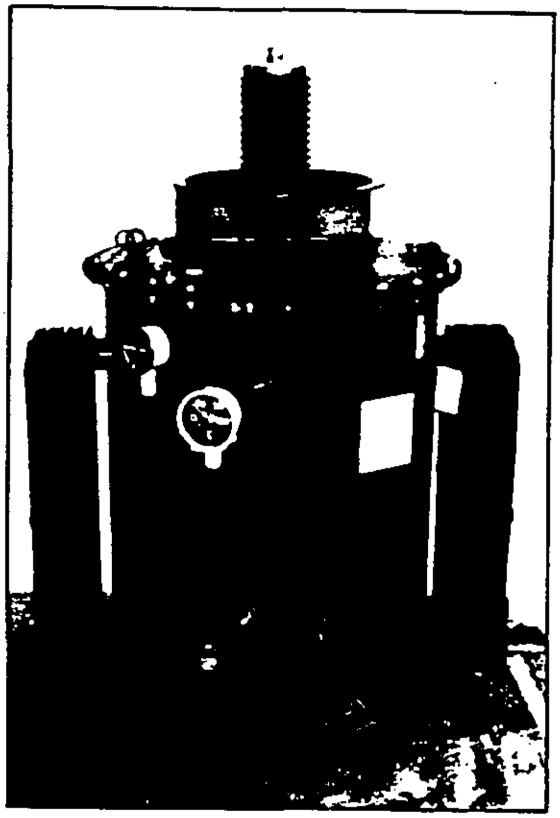
Temperature—Maximum continuous temperature range of −40°C to +50°C. Thermowell provided as standard.

Electrical connections—Molded epoxy low voltage and instrumentation bushings; glazed porcelain high voltage output bushing.

Inspection—Bolted hand hole provided for inspection and internal servicing.

Bushing enclosure—Steel weatherproof enclosure, with observation window. Externally mounted, key-interlocked ground switch prevents access to transformer-bushings and precipitator internals unless ground switch is in the grounded position. The transformer-rectifier is also key-interlocked with its control cabinet to prevent grounding when energized. A high voltage danger sign and a sign warning against operating without a load are provided.

High voltage bus—Black iron pipe completely enclosed in a grounded steel tubular guard. Conductor is terminated with gastight, glazed, feed-through insulators at output end. For inspection, there is a bolted access plate at each insulator location.



March 1986