NITROGEN OXIDE EMISSION TESTS

BOILERS NUMBER 4 AND 5

WHITEMAN AIR FORCE BASE

August 20 and 21, 1990

RECEIVED
NATURAL RESOURCES
1990 DEC -3 PM 3:26
AIR POLLUTION CONTROL

shell engineering and associates, inc.

2503 west ash columbia, mo 65203 314-445-0106

September 26, 1990

Mr. John G. Hart
The Gibson Hart Company
700 Mulberry Street
Kansas City, Missouri
64101

Re: Nitrogen Oxides Emissions Tests
at ADAL Steam Generation Plant
Whiteman Air Force Base
Contract Number DACA41-89-C-0038

Dear Mr. Hart:

Attached is our report entitled "Nitrogen Oxides Emission Tests, Boilers Number 4 and 5, Whiteman Air Force Base, Knob Noster, Missouri". The report describes the emissions testing program conducted at that facility for Boilers Number 4 and 5 during the period August 20-21, 1990, and details the results of the three USEPA Method 7 tests performed to determine the nitrogen oxide emissions as stated in the US Army Corps of Engineers' "Specifications for the ADAL Steam Generation Plant", published in October 1988. The specifications state a maximum NOx production of 0.12 pounds per million Btu for combustion of natural gas and 0.14 pounds per million Btu for number 2 fuel oil.

The results do demonstrate compliance with the Corps of Engineer Specifications for Boilers Number 4 and 5 on natural gas and fuel oil. The nitrogen oxide emissions were 0.088 (lb/mmBtu) for number 4 on natural gas, 0.085 for Number 5 on natural gas, 0.103 for Number 4 on fuel oil, and 0.125 for Number 5 on fuel oil.

Sincerely,

Charles A Shell

Charles A. Shell, P.E.
Vice-President

Attachment

TEST CERTIFICATION

We certify that the enclosed test results are true, accurate, and authentic. We were personally responsible for all phases of the testing to determine the nitrogen oxides emissions from the Boiler Number 4 and Boiler Number 5 at the ADAL Steam Generation Plant, Whiteman Air Force Base at Knob Noster, Mo.

The sampling equipment and procedures conformed to USEPA Method 7 for nitrogen oxides emissions from stationary sources. The results of this testing are the basis for this report.

SHELL ENGINEERING & ASSOCIATES, INC.

Charles A. Shell, P.E.
Vice-President

Tom Scheppers

Tom Scheppers, P.E.
Project Engineer

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I. INTRODUCTION

On June 13, 1988, the Missouri Department of Natural Resources (Mo DNR) issued a construction permit to Whiteman Air Force Base providing permission, with conditions, to construct a new Boiler Number 5 at the ADAL Steam Generation Plant at Whiteman AFB at Knob Noster, Missouri.

By regulation, the State of Missouri does not restrict nitrogen oxides emissions from fuel burning equipment used for indirect heating in the outstate area. However, as a condition of the permit for the construction of Boiler Number 5, the state has imposed a condition to test the nitrogen oxide emissions (NOx) by a performance test in accordance with USEPA Method 7 while burning natural gas and Number 2 fuel oil. Furthermore, an additional condition was listed in the permit. The state has limited the increase of annual emissions of NOx to 40 tons per year by limiting fuel usage. This limitation is enforced by placing restrictions on the amount of fuel usage of both natural gas and fuel oil for Boilers Number 4 and 5 at this plant.

Performance Standards published by the US Army Corps of Engineers, specify a limit of 0.12 pounds of nitrogen oxides per million Btu for natural gas and 0.14 pounds of nitrogen oxides per million Btu for number 2 fuel oil. Shell Engineering & Associates, Inc., of Columbia, Missouri, has been retained by Gibson Hart, Incorporated to determine the nitrogen oxides emissions from Boilers 4 and 5 at the Steam Generation Plant, at Whiteman Air Force Base at Knob Noster, Missouri. The Power Plant is located south of Highway 50 on the Air Force Base.

One test port on each stack was installed for testing these units since no tests had been performed previously. Testing for nitrogen oxides was performed on Monday, August 20 and Tuesday, August 21, 1990.

The nitrogen oxides emissions were evaluated by application of the United States Environmental Protection Agency's Method 7 - Determination of Nitrogen Oxides Emissions from Stationary Sources (Published in 40 CFR, Part 60, Appendix A).

Three individual Method 7 test runs were used for each evaluation of emissions. Each test run consisted of four samples extracted at approximately 15 minute intervals to total one hour for each run.

The Project Supervisor in charge of the test program for Shell Engineering & Associates was Mr. Tom Scheppers. Mr. Scheppers was assisted by Mr. Terry Shackelford at the test locations on the roof and Mr. Joe Grosvenor who collected operating data in the boiler areas.

Mr. Doug Elley, Environmental Specialist, Missouri Department of Natural Resources, Air Pollution Control Program was present for portions of the test program.

The compliance tests and operation of the boilers were performed in accordance with conditions discussed at a pretest meeting held onsite on July 27, 1990. At this meeting, fuel analysis of the natural gas was declared to be unnecessary due to the use of commercial natural gas. Fuel analysis of the fuel oil was obtained from a routine sample taken from the bulk storage tank prior to the tests by Whiteman personnel. The results of this analysis is available from Whiteman personnel and will be retained onsite.

II. SUMMARY OF RESULTS

The nitrogen oxides results are summarized in Table I. Actual emissions based on the test data is listed. The nitrogen oxides emissions have been calculated using "F factors" as described in the Code of Federal Regulations under the New Source Performance Standards (Title 40, Part 60).

Three sets of nitrogen oxides samples were collected during the first day (8/20/90) of testing from Boiler 5 on natural gas and Boiler 4 on natural gas. Each set consist of four samples.

The test results for both Boilers Number 4 and 5 on both natural gas and Number 2 fuel oil show the emission rates to comply with the performance standards set in the Corps of Engineer specifications.

During the test runs, no abnormalities were noted that would contribute to errors in the results of the tests. The results are accurate within the variations described by USEPA Method 7.

TABLE I

Whiteman Air Force Base
Summary of Nitrogen Oxides Emission Tests
ADAL Steam Generation Plant

(lb/mmBtu)

Boiler	Fuel	Run 1	Run 2	Run 3	Ave.
4	Natural Gas	0.0751	0.0798	0.0823	0.0791
4	Fuel Oil	0.105	0.103	0.102	0.103
5	Natural Gas	0.0944	0.0906	0.0885	0.0911
5	Fuel Oil	0.125	0.124	0.125	0.125

The determination of emissions on a "pounds/million BTU" (lb/mmBtu) basis is dependent upon the "F-Factor" of the fuel in use at the time of each test run. For purposes of these tests, the standard F-Factors found in the New Source Performance Standards - Subpart D, were used for each fuel. The dimensions of the F-Factor are "Dry Standard Cubic Feet/million BTU." The standard F-Factor for the two fuels are 8740 SCF/million BTU for natural gas and 9220 SCF/million BTU for number 2 fuel oil.

III. SOURCE DESCRIPTION

Boiler Number 5 at the Whiteman Air Force Base's ADAL Steam Generation Plant is a watertube boiler manufactured by Nebraska Boiler. The boiler has a Coen burner, Kentube Economizer, and Bailey controls. Number 5 boiler is rated at 60,000 lb of steam per hour at 250 psi and 406°F. This boiler is the most recently installed of a total of 5 boilers. The boiler is permitted by the Air Pollution Control Program (APCP) under permit numbers 0688-004A and 0688-005A.

Boiler Number 4 is also a watertube boiler manufactured by Nebraska Boiler. The boiler is equipped similar to Boiler Number 5 but smaller in size. Number 4 boiler is rated at 35,000 lb of steam per hour at 250 psi and 406°F. This boiler was was permitted under (APCP) permit number 1083-003. The boiler was recently modified with new controls as part of the construction program for Boiler Number 5.

Boiler Number 5 was permitted by the Air Pollution Control Program under permit numbers 0688-004A and 0688-005A, with operating restrictions on both Boilers Number 4 and 5. Boiler Number 4 is considered as part of the emissions review since Whiteman has applied for a "De minimis" permit, and Boiler Number 4 had previously been issued a "De minimis" permit. The new permit requires testing of both the Number 4 and Number 5 boilers to verify NOx emissions assumptions made in the permit.

Both boilers are operated year round on either either fuel at partial load, or full load, or standby (except for routine maintenance).

Number 2 fuel oil is trucked to the site, and natural gas is piped to the Power Plant. Every shipment of fuel oil is sampled and analyzed for compliance with the performance specifications of the purchasing contract.

No emission collection or reduction control equipment is used to control the gaseous emissions produced by either boiler. The NOx emissions are lower than most commercial boilers due to efficient burner design. The gases discharge to the atmosphere through separate stacks above roof level.

One 2-inch diameter test port was installed in each stack at 90° to the centerline of stack gas flow. This port was installed above the rooftop several feet below the stack exit. The test port locations were easily reached by climbing through an access cover to the rooftop over each of the boilers.

The ports were ideal for nitrogen oxides testing, providing access to uniformly mixed stack gasses. The results should be representative of actual conditions with no interferences.

IV. PLANT OPERATING CONDITIONS

Each boiler was fired and tested at base load with both natural gas and Number 2 fuel oil. Steam load was maintained near 60,000 lb/hr for #5 and 35000 lb/hr for #4 by venting excess unusable steam. These steam rates are approximately the maximum continuous rates that the boilers can be operated. The boilers do have the capability to exceed this rate by 10%, but only for peaking operation.

The testing was limited to the operation of only one boiler at a time due to the high demand for make-up water as a result of continuous venting of the steam. Normally, steam and condensed steam is recycled. The need for make-up water during normal operation never approaches the rated steam capacity of Boilers Number 4 and 5 combined. Since the equipment used to supply make-up water was not designed to accommodate such unrealistic operating conditions, the equipment was inadequate to provide enough water to run both boilers at their rated capacities.

The "Boiler Operations Data" for the periods of August 20 and 21, 1990, are included in Appendix F. This data includes the time, steam pressure, steam produced, fuel usage, feedwater heater pressure and temperature, make-up water, condensate return temperature, and feedwater pump pressure. Log entries were made at 15 minute intervals throughout the test periods. The operation data was collected by Joe Grosvenor of Shell Engineering.

V. TEST CONDITIONS

The Method 7 test samples were drawn from a single sample point on each of the two stacks. (The test port locations were selected by referring to USEPA regulation Method 1 - Selection of Sampling Port Locations.) The port locations meet the recommendations for an ideal sampling location.

Samples were collected according to USEPA Method 7 for a total of one hour for each of three runs (15 minutes/sample).

Boiler Number 5 was tested first on August 20. Testing began with run number 1 at approximately 0745 hours. The boiler was to be tested on natural gas, and then switched to Number 2 fuel oil. After the conclusion of testing on natural gas, difficulties were encountered during the fuel switch over. The boiler could not be operated on fuel oil despite several attempts. Therefore, all of the test equipment was moved to Boiler Number 4. Testing of boiler 4 also started on natural gas and extended through the afternoon. Testing of Boiler Number 4 on natural gas was completed on August 20.

On the morning of August 21, testing resumed on Boiler Number 4 while firing Number 2 fuel oil. After completion of the tests on fuel oil, the test equipment was moved back to the Boiler Number 5 stack and testing resumed on Boiler Number 5 using Number 2 fuel oil. All testing was completed on the afternoon of August 21, 1990.

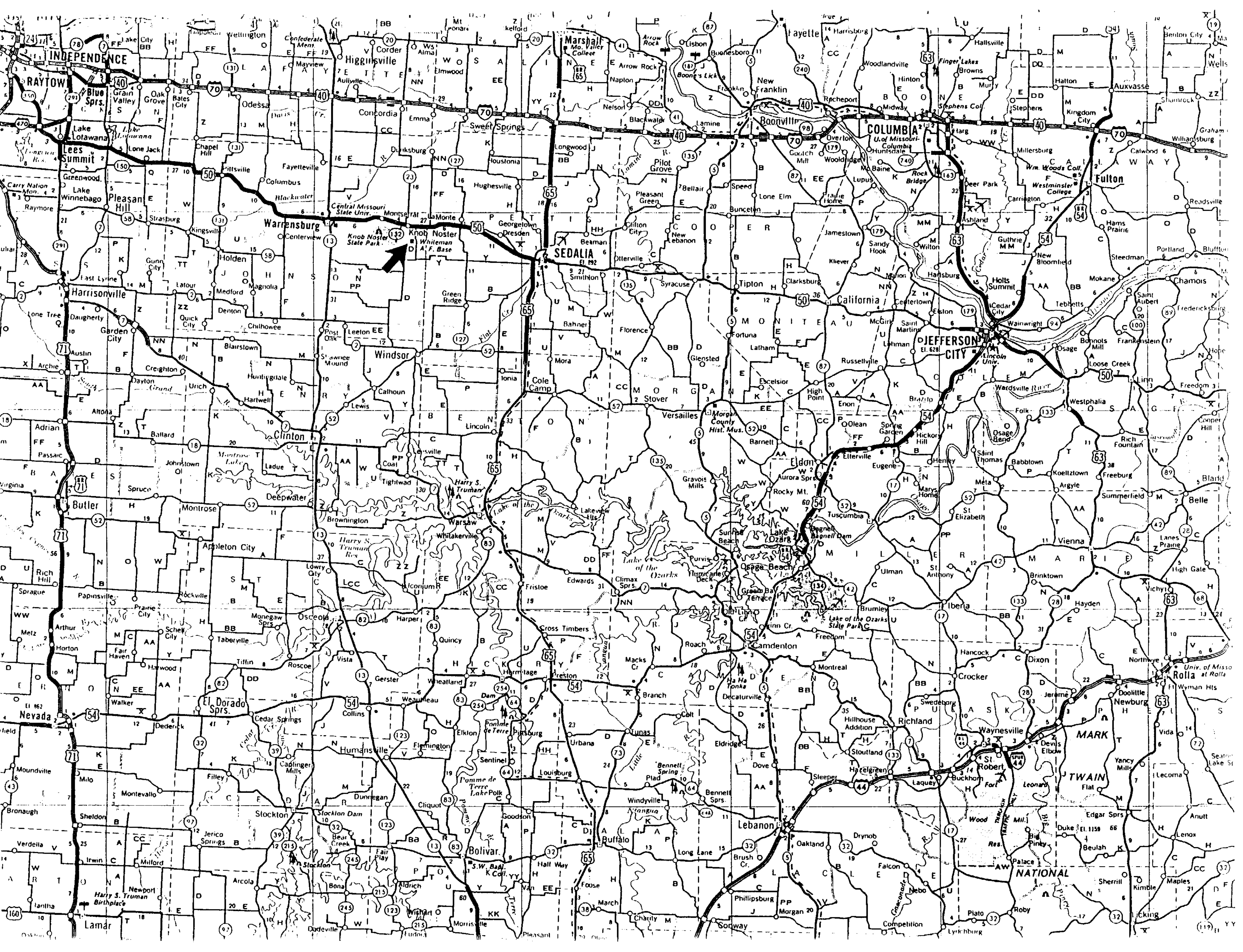
No operational problems were encountered during an emissions sampling run . The boilers were operated at steady state and near maximum normal load. Fuel combusted in the boilers was representative of fuel normally used in routine operations.

VI. TEST EQUIPMENT AND METHODS

The test procedures and equipment used to determine the nitrogen oxides concentrations in the stack gases of the Whiteman Air Force Base boilers are described in Appendix G of this report. In brief, a grab sample is collected in an evacuated flask containing a dilute sulfuric acid- hydrogen peroxide absorbing solution, and the nitrogen oxides (except nitrous oxide), are measured colorimetrically using the phenoldisulfonic acid (PDS) procedure. Four grab samples make-up one run. Three runs make up one test. Testing was done in accordance with USEPA Reference Method 7, as published in 40 CFR, Part 60, Appendix A. (See Appendix I of this report.)

APPENDIX A

Location Map of Whiteman Air Force Base, Knob Noster, Missouri



Independence
Raytown
Blue Sprs.
Grain Valley
Oak Grove
Bates City
Lake City
Lake Lotawana
Lees Summit
Lone Jack
Greenwood
Lake Winnebago
Carry Nation Mon.
Raymore
Pleasant Hill
Strasburg
Kingsville
Holden
Chapel Hill
Pittsville
Columbus
Fayetteville
Odessa
Wellington
Mayview
Higginsville
Corder
Alma
Aullville
Concordia
Emma
Elmwood
Sweet Springs
Houstonia
Hughesville
Dunksburg
Confederate Mem.
Marshall
Mo. Valley College
Napton
Arrow Rock
Nelson
Blackwater
Lamine
Boonville
New Franklin
Franklin
Boonesboro
Boone's Lick
Lisbon
Fayette
Harrisburg
Rocheport
Woodlandville
Hinton
Midway
Columbia
U. of Missouri-Columbia
Huntsdale
Overton
Gooch Mill
Wooldridge
McBaine
Rock Bridge
Stephens Coll.
Finger Lakes
Browns
Murry
Hallsville
Harg
Deer Park
Ashland
Hartsburg
Guthrie
Millersburg
Wm. Woods Coll.
Westminster College
Fulton
Carrington
Kingdom City
Hatton
Auxvasse
Benton City
Wells
Shamrock
Williamsburg
Calwood
Readsville
Hams Prairie
Portland
Steedman
Mokane
Chamois
New Bloomfield
Holts Summit
Tebbetts
Cedar City
Wainwright
Jefferson City
Lincoln Univ.
Saint Aubert
Bonnots Mill
Frankenstein
Fredericksburg
Osage
Loose Creek
Linn
Freedom
Westphalia
Wardsville
Folk
Osage Bend
Saint Thomas
Babbtown
Rich Fountain
Koeltztown
Freeburg
Argyle
Belle
Bland
Summerfield
Meta
St. Elizabeth
Vienna
Lanes Prairie
High Gate
Brinktown
Vichy
Hayden
Iberia
St. Anthony
Ulman
Brumley
Dixon
Hancock
Crocker
Northwye
Rolla
Univ. of Missouri at Rolla
Wyman Hts.
Doolittle
Newburg
Jerome
Swedeborg
Richland
Hillhouse Addition
Stoutland
Waynesville
St. Robert
Fort Leonard Wood
Devils Elbow
Laquey
Buckhorn
Hazelgreen
Sleeper
Mark Twain National
Yancy Mills
Flat
Vida
Lecoma
Edgar Sprs.
Duke
Beulah
Big Piney
Palace
Lenox
Anutt
Kimble
Maples
Licking
Sherrill
Roby
Plato
Lynchburg
Competition
Nebo
Falcon
Drynob
Oakland
Lebanon
Brush Cr.
Phillipsburg
Morgan
Conway
Long Lane
Bennett Sprs.
Bennett Spring
Plad
Windyville
Buffalo
Charity
March
Fosse
Half Way
Bolivar
S.W. Bapt. Coll.
Van
Morrisville
Pleasant Hope
Aldrich
Bona
Dadeville
Fair Play
Stockton
Stockton Dam
Bear Creek
Jerico Springs
Arcola
Milford
Newport
Harry S. Truman Birthplace
Lamar
Iantha
Sheldon
Bronaugh
Milo
Moundville
Verdella
Irwin
Nevada
Walker
Dederick
El Dorado Sprs.
Cedar Springs
Caplinger Mills
Filley
Montevallo
Humansville
Flemington
Collins
Dunnegan
Cliquot
Polk
Pomme de Terre Lake
Sentinel
Pittsburg
Louisburg
Elkton
Wheatland
Hermitage
Preston
Weaubleau
Gerster
Vista
Roscoe
Tiffin
Taberville
Schell City
Fair Haven
Harwood
Rockville
Prairie City
Papinsville
Sprague
Rich Hill
Metz
Arthur
Horton
Osceola
Monegaw Sprs.
Appleton City
Lowry City
Iconium
Harper
Quincy
Cross Timbers
Macks Cr.
Camdenton
Roach
Branch
Urbana
Tunas
Eldridge
Dove
Decaturville
Ha Ha Tonka
Montreal
Freedom
Linn Cr.
Lake of the Ozarks State Park
Green Bay Terrace
Old Linn
Hurricane Deck
Osage Beach
Purvis
Climax Sprs.
Edwards
Fristoe
Lakeview Hts.
Lake of the Ozarks
Sunrise Beach
Lake Ozark
Bagnell
Bagnell Dam
Tuscumbia
Marys Home
Rocky Mt.
Aurora Sprs.
Eldon
Etterville
Eugene
Henley
Hickory Hill
Spring Garden
Olean
Enon
Brazito
High Point
Excelsior
Barnett
Morgan County Hist. Mus.
Versailles
Gravois Mills
Stover
Glensted
Latham
Fortuna
Russellville
Lohman
Saint Martins
Centertown
McGirk
Elston
California
Tipton
Clarksburg
Syracuse
Otterville
Smithton
Sedalia
Beaman
Clifton City
New Lebanon
Pilot Grove
Bellair
Speed
Lone Elm
Bunceton
Prairie Home
Jamestown
Sandy Hook
Lupus
Klever
Marion
Wilton
Georgetown
Dresden
La Monte
Knob Noster
Whiteman A.F. Base
Knob Noster State Park
Montserrat
Central Missouri State Univ.
Warrensburg
Centerview
Green Ridge
Bahner
Florence
Mora
Cole Camp
Ionia
Lincoln
Windsor
Calhoun
Lewis
Leeton
Post Oak
Shawnee Mound
Chilhowee
Blairstown
Huntingdale
Hartwell
Urich
Clinton
Leesville
Coal
Tightwad
Harry S. Truman Res.
Warsaw
Whitakerville
Brownington
Deepwater
Montrose
Ladue
Johnstown
Spruce
Butler
Passaic
Adrian
Ballard
Altona
Archie
Austin
Garden City
Creighton
Dayton
Daugherty
Lone Tree
Harrisonville
East Lynne
Gunn City
Latour
Medford
Magnolia
Denton
Quick City
Amsterdam
Virginia

APPENDIX B

Nitrogen Oxides Test Results

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		1A	1B	1C	1D
Data set		(01)	(02)	(03)	(04)
Date		8-20-90	8-20-90	8-20-90	8-20-90
Location		BOILER 4 NAT GAS	BOILER 4 NAT GAS	BOILER 4 NAT GAS	BOILER 4 NAT GAS
Start time		12:35	12:50	13:05	13:20
Flask Number		50	63	37	53
Volume of Flask	Mls	2055	2005	2053	2050
Initial Temperature	Deg. F	106	106	101	113
Final Temperature	Deg. F	97	87	94	94
Initial Pressure	In Hg	0.93	1.23	0.93	1.13
Final Pressure	In Hg	28.27	28.17	27.97	28.27
NOX in sample	Micro G	255.20	214.30	228.80	197.50
Percent O2	%	1.6	1.5	1.4	1.5
F Factor	DSCF/MBtu	8740	8740	8740	8740
Volume Sampled	DSCC	1759	1723	1747	1752
NOX Concentration	Lbs/DSCF	9.059E-06	7.765E-06	8.177E-06	7.036E-06
Parts Per Million	PPM	75.83	65.00	68.44	58.89
NOX Emissions	Lbs/MBtu	8.57E-02	7.31E-02	7.65E-02	6.62E-02

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		2A	2B	2C	2D
Data set		(05)	(06)	(07)	(08)
Date		8-20-90	8-20-90	8-20-90	8-20-90
Location		BOILER 4 NAT GAS	BOILER 4 NAT GAS	BOILER 4 NAT GAS	BOILER 4 NAT GAS
Start time		13:35	13:50	14:05	14:20
Flask Number		58	19	64	28
Volume of Flask	Mls	2045	2065	2009	2052
Initial Temperature	Deg. F	109	111	107	109
Final Temperature	Deg. F	85	85	84	86
Initial Pressure	In Hg	1.13	1.13	1.13	0.93
Final Pressure	In Hg	29.17	27.07	27.67	27.57
NOX in sample	Micro G	231.20	217.90	255.20	252.80
Percent O2	%	1.8	1.3	1.4	1.3
F Factor	DSCF/MBtu	8740	8740	8740	8740
Volume Sampled	DSCC	1836	1716	1710	1747
NOX Concentration	Lbs/DSCF	7.859E-06	7.926E-06	9.314E-06	9.033E-06
Parts Per Million	PPM	65.79	66.35	77.97	75.61
NOX Emissions	Lbs/MBtu	7.51E-02	7.38E-02	8.72E-02	8.41E-02

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		3A	3B	3C	3D
Data set		(09)	(10)	(11)	(12)
Date		8-20-90	8-20-90	8-20-90	8-20-90
Location		BOILER 4 NAT GAS	BOILER 4 NAT GAS	BOILER 4 NAT GAS	BOILER 4 NAT GAS
Start time		14:35	14:50	15:05	15:20
Flask Number		6	67	56	61
Volume of Flask	Mls	2065	2009	2094	2040
Initial Temperature	Deg. F	107	101	104	119
Final Temperature	Deg. F	85	85	89	93
Initial Pressure	In Hg	1.33	1.23	1.13	1.23
Final Pressure	In Hg	28.67	27.27	27.87	27.67
NOX in sample	Micro G	244.40	226.40	217.90	284.10
Percent O2	%	1.8	1.6	1.3	1.6
F Factor	DSCF/MBtu	8740	8740	8740	8740
Volume Sampled	DSCC	1809	1674	1780	1703
NOX Concentration	Lbs/DSCF	8.436E-06	8.441E-06	7.643E-06	1.041E-05
Parts Per Million	PPM	70.61	70.65	63.98	87.17
NOX Emissions	Lbs/MBtu	8.06E-02	7.98E-02	7.12E-02	9.85E-02

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		1A	1B	1C	1D
Data set		(13)	(14)	(15)	(16)
Date		8-20-90	8-20-90	8-20-90	8-20-90
Location		BOILER 5 NAT GAS	BOILER 5 NAT GAS	BOILER 5 NAT GAS	BOILER 5 NAT GAS
Start time		07:47	08:05	08:20	08:35
Flask Number		87	11	74	10
Volume of Flask	Mls	2098	2047	2043	1985
Initial Temperature	Deg. F	83	86	86	86
Final Temperature	Deg. F	83	74	74	75
Initial Pressure	In Hg	0.83	0.63	0.93	0.93
Final Pressure	In Hg	28.27	28.07	28.97	27.97
NOX in sample	Micro G	252.80	263.70	267.30	249.20
Percent O2	%	3.8	3.9	3.8	4.0
F Factor	DSCF/MBtu	8740	8740	8740	8740
Volume Sampled	DSCC	1848	1834	1871	1749
NOX Concentration	Lbs/DSCF	8.540E-06	8.977E-06	8.921E-06	8.896E-06
Parts Per Million	PPM	71.48	75.14	74.67	74.47
NOX Emissions	Lbs/MBtu	9.12E-02	9.64E-02	9.52E-02	9.61E-02

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		2A	2B	2C	2D
Data set		(17)	(18)	(19)	(20)
Date		8-20-90	8-20-90	8-20-90	8-20-90
Location		BOILER 5 NAT GAS	BOILER 5 NAT GAS	BOILER 5 NAT GAS	BOILER 5 NAT GAS
Start time		09:00	09:15	09:30	09:45
Flask Number		71	2	4	30
Volume of Flask	Mls	2028	2043	2110	2045
Initial Temperature	Deg. F	87	100	99	106
Final Temperature	Deg. F	75	75	75	75
Initial Pressure	In Hg	0.93	1.33	1.43	1.03
Final Pressure	In Hg	27.97	27.37	27.87	27.47
NOX in sample	Micro G	238.40	234.80	243.20	239.60
Percent O2	%	4.0	4.4	3.8	3.9
F Factor	DSCF/MBtu	8740	8740	8740	8740
Volume Sampled	DSCC	1787	1737	1822	1765
NOX Concentration	Lbs/DSCF	8.327E-06	8.441E-06	8.333E-06	8.476E-06
Parts Per Million	PPM	69.71	70.65	69.75	70.95
NOX Emissions	Lbs/MBtu	9.00E-02	9.34E-02	8.90E-02	9.10E-02

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		3A	3B	3C	3D
Data set		(21)	(22)	(23)	(24)
Date		8-20-90	8-20-90	8-20-90	8-20-90
Location		BOILER 5 NAT GAS	BOILER 5 NAT GAS	BOILER 5 NAT GAS	BOILER 5 NAT GAS
Start time		10:00	10:15	10:30	10:45
Flask Number		1	17	25	20
Volume of Flask	Mls	2085	2037	2058	1960
Initial Temperature	Deg. F	93	100	96	97
Final Temperature	Deg. F	88	89	86	89
Initial Pressure	In Hg	0.73	0.53	1.03	0.83
Final Pressure	In Hg	29.37	28.37	28.77	28.97
NOX in sample	Micro G	237.20	228.80	255.20	258.90
Percent O2	%	3.5	3.9	3.4	3.5
F Factor	DSCF/MBtu	8740	8740	8740	8740
Volume Sampled	DSCC	1900	1800	1823	1750
NOX Concentration	Lbs/DSCF	7.795E-06	7.933E-06	8.738E-06	9.234E-06
Parts Per Million	PPM	65.25	66.40	73.14	77.29
NOX Emissions	Lbs/MBtu	8.18E-02	8.52E-02	9.12E-02	9.69E-02

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		4A	4B	4C	4D
Data set		(25)	(26)	(27)	(28)
Date		8-21-90	8-21-90	8-21-90	8-21-90
Location		BOILER 4 FUEL OIL	BOILER 4 FUEL OIL	BOILER 4 FUEL OIL	BOILER 4 FUEL OIL
Start time		08:20	08:35	08:50	09:05
Flask Number		46	12	29	27
Volume of Flask	Mls	2043	1965	1995	2034
Initial Temperature	Deg. F	74	77	79	80
Final Temperature	Deg. F	83	85	83	83
Initial Pressure	In Hg	0.67	0.87	0.87	0.77
Final Pressure	In Hg	28.74	28.14	29.34	28.74
NOX in sample	Micro G	271.70	300.70	290.30	298.40
Percent O2	%	3.2	3.2	3.4	3.4
F Factor	DSCF/MBtu	9220	9220	9220	9220
Volume Sampled	DSCC	1839	1712	1822	1825
NOX Concentration	Lbs/DSCF	9.221E-06	1.096E-05	9.949E-06	1.020E-05
Parts Per Million	PPM	77.18	91.81	83.27	85.43
NOX Emissions	Lbs/MBtu	.10	.11	.10	.11

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		5A	5B	5C	5D
Data set		(29)	(30)	(31)	(32)
Date		8-21-90	8-21-90	8-21-90	8-21-90
Location		BOILER 4 FUEL OIL	BOILER 4 FUEL OIL	BOILER 4 FUEL OIL	BOILER 4 FUEL OIL
Start time		09:20	09:35	09:50	10:05
Flask Number		9	87	11	74
Volume of Flask	Mls	2071	2098	2047	2043
Initial Temperature	Deg. F	79	77	80	86
Final Temperature	Deg. F	84	83	83	83
Initial Pressure	In Hg	0.77	0.87	0.77	0.67
Final Pressure	In Hg	28.54	28.34	28.34	27.94
NOX in sample	Micro G	275.20	284.40	285.60	313.50
Percent O2	%	3.0	3.6	2.5	2.2
F Factor	DSCF/MBtu	9220	9220	9220	9220
Volume Sampled	DSCC	1842	1849	1811	1788
NOX Concentration	Lbs/DSCF	9.327E-06	9.601E-06	9.846E-06	1.094E-05
Parts Per Million	PPM	78.07	80.36	82.42	91.62
NOX Emissions	Lbs/MBtu	.10	.10	.10	.11

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		6A	6B	6C	6D
Data set		(33)	(34)	(35)	(36)
Date		8-21-90	8-21-90	8-21-90	8-21-90
Location		BOILER 4 FUEL OIL	BOILER 4 FUEL OIL	BOILER 4 FUEL OIL	BOILER 4 FUEL OIL
Start time		10:20	10:35	10:50	11:05
Flask Number		10	71	2	4
Volume of Flask	Mls	1985	2028	2043	2110
Initial Temperature	Deg. F	91	91	87	98
Final Temperature	Deg. F	83	83	83	83
Initial Pressure	In Hg	0.87	0.67	0.67	0.67
Final Pressure	In Hg	27.54	28.14	27.94	27.24
NOX in sample	Micro G	299.50	290.30	289.10	276.30
Percent O2	%	2.6	2.6	2.5	2.4
F Factor	DSCF/MBtu	9220	9220	9220	9220
Volume Sampled	DSCC	1699	1788	1788	1801
NOX Concentration	Lbs/DSCF	1.100E-05	1.013E-05	1.009E-05	9.578E-06
Parts Per Million	PPM	92.12	84.83	84.49	80.17
NOX Emissions	Lbs/MBtu	.11	.10	.10	9.97E-02

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		4A	4B	4C	4D
Data set		(37)	(38)	(39)	(40)
Date		8-21-90	8-21-90	8-21-90	8-21-90
Location		BOILER 5 FUEL OIL	BOILER 5 FUEL OIL	BOILER 5 FUEL OIL	BOILER 5 FUEL OIL
Start time		12:05	12:20	12:35	12:50
Flask Number		67	19	6	64
Volume of Flask	Mls	2009	2065	2065	2009
Initial Temperature	Deg. F	83	102	122	125
Final Temperature	Deg. F	84	83	83	85
Initial Pressure	In Hg	0.77	1.17	1.27	1.07
Final Pressure	In Hg	27.64	27.44	27.54	28.74
NOX in sample	Micro G	304.20	333.20	319.30	318.10
Percent O2	%	2.4	3.4	4.4	3.3
F Factor	DSCF/MBtu	9220	9220	9220	9220
Volume Sampled	DSCC	1729	1744	1747	1782
NOX Concentration	Lbs/DSCF	1.098E-05	1.193E-05	1.141E-05	1.114E-05
Parts Per Million	PPM	91.96	99.86	95.53	93.30
NOX Emissions	Lbs/MBtu	.114	.131	.133	.122

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		5A	5B	5C	5D
Data set		(41)	(42)	(43)	(44)
Date		8-21-90	8-21-90	8-21-90	8-21-90
Location		BOILER 5 FUEL OIL	BOILER 5 FUEL OIL	BOILER 5 FUEL OIL	BOILER 5 FUEL OIL
Start time		13:05	13:20	13:35	13:50
Flask Number		58	28	50	37
Volume of Flask	Mls	2045	2052	2115	2053
Initial Temperature	Deg. F	99	112	104	108
Final Temperature	Deg. F	83	83	83	83
Initial Pressure	In Hg	0.97	1.07	0.97	1.07
Final Pressure	In Hg	28.94	27.04	26.44	27.04
NOX in sample	Micro G	310.00	313.50	314.60	328.60
Percent O2	%	3.4	3.1	3.2	3.6
F Factor	DSCF/MBtu	9220	9220	9220	9220
Volume Sampled	DSCC	1837	1714	1732	1714
NOX Concentration	Lbs/DSCF	1.053E-05	1.142E-05	1.134E-05	1.196E-05
Parts Per Million	PPM	88.17	95.59	94.93	100.18
NOX Emissions	Lbs/MBtu	.115	.123	.123	.133

Total Source Analysis, Inc.
NOX - Nitrogen Oxide

SHELL ENGINEERING
WHITEMAN AFB
STEAM PLANT
90-122

Run Number		6A	6B	6C	6D
Data set		(45)	(46)	(47)	(48)
Date		8-21-90	8-21-90	8-21-90	8-21-90
Location		BOILER 5 FUEL OIL	BOILER 5 FUEL OIL	BOILER 5 FUEL OIL	BOILER 5 FUEL OIL
Start time		14:05	14:20	14:35	14:50
Flask Number		61	1	25	53
Volume of Flask	Mls	2040	2085	2058	2050
Initial Temperature	Deg. F	109	104	100	98
Final Temperature	Deg. F	83	83	83	83
Initial Pressure	In Hg	1.07	0.97	1.07	1.07
Final Pressure	In Hg	26.94	28.74	28.74	26.44
NOX in sample	Micro G	326.20	333.20	326.20	321.60
Percent O2	%	2.8	2.4	3.7	3.6
F Factor	DSCF/MBtu	9220	9220	9220	9220
Volume Sampled	DSCC	1697	1861	1830	1671
NOX Concentration	Lbs/DSCF	1.200E-05	1.117E-05	1.113E-05	1.201E-05
Parts Per Million	PPM	100.46	93.57	93.16	100.58
NOX Emissions	Lbs/MBtu	.127	.116	.124	.133

APPENDIX C

Nitrogen Oxides Field Data Sheets

NO$_x$ Field Test Sheet

Client Whiteman AFB
Project No., 90-122
Plant Site Steam Plant - Knob Noster, Mo
Final Barometric Pressure (in. of Hg) 29.37

Run By T. Shackelford
Date 8/20/90
Sampling Location Stack - Boiler 4
Sample Recovery Date 8-21-90

(Natural Gas)

Test No.	Repit. Letter	Flask No.	Start Time	Flask Volume (ml)	Leak Rate (in.of Hg)	Initial Barometric Pressure (in. of Hg)	Initial Pressure (in. of Hg)	Initial Temperature °F	Final Pressure (in. of Hg)	Final Temperature °F	CO_2	$+O_2$	O_2	CO
1	A	50	1235	2055	0	29.23	-28.3	106	-1.1	97	10.8	12.4	1.6	0
1	B	63	1250	2005	0	"	-28.0	106	-1.2	87	11.0	12.5	1.5	0
1	C	37	1305	2053	0	"	-28.3	101	-1.4	94	11.2	12.6	1.4	0
1	D	53	1320	2050	0	"	-28.1	113	-1.1	94	10.9	12.4	1.5	0
2	A	58	1335	2045	0	29.23	-28.1	109	-0.2	85	11.0	12.8	1.8	0
2	B	19	1350	2065	0	"	-28.1	111	-2.3	85	11.2	12.5	1.3	0
2	C	64	1405	2009	0	"	-28.1	107	-1.7	84	11.6	12.0	1.4	0
2	D	28	1420	2052	0	"	-28.3	109	-1.8	86	11.4	12.7	1.3	0
3	A	6	1435	2065	0.1	29.23	-27.9	107	-0.7	85	11.0	12.8	1.8	0
3	B	67	1450	2009	0	"	-28.0	101	-2.1	85	11.0	12.6	1.6	0
3	C	56	1505	2094	0	"	-28.1	104	-1.5	89	11.2	12.5	1.3	0
3	D	61	1520	2040	0	"	-28.0	119	-1.7	93	11.2	12.8	1.6	0

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Client Whiteman AFB
Project No. 90-122
Plant Site Steam Plant-Knob Noster, MO
Final Barometric Pressure (in. of Hg) 29.34

Run By T. Shackelford
Date 8/21/90
Sampling Location Stack-Boiler 4
Sample Recovery Date 8-24-80

(No. 2 Fuel Oil)

Test No.	Repit. Letter	Flask No.	Start Time	Flask Volume (ml)	Leak Rate (in.of Hg)	Initial Barometric Pressure (in. of Hg)	Initial Pressure (in. of Hg)	Initial Temperature °F	Final Pressure (in. of Hg)	Final Temperature °F	CO_2	$+O_2$	O_2	CO
			0820								12.8	16.0	3.2	0
4	A	46	~~0850~~	2043	0	29.37	-28.7	74	-0.6	83	~~11.2~~	~~17.0~~	~~5.4~~	~~0~~
4	B	12	0835	1965	0	"	-28.5	77	-1.2	85	12.9	16.1	3.2	0
4	C	29	0850	1995	0	"	-28.5	79	0	83	12.9	16.3	3.4	0
4	D	27	0905	2034	0	"	-28.6	80	-0.6	83	12.8	16.2	3.4	0
											~~13~~			
5	A	9	0920	2071	0	29.37	-28.6	79	-0.8	84	13.0	16.0	3.0	0
5	B	87	0935	2098	0	"	-28.5	77	-1.0	83	13.8	16.4	3.6	0
5	C	11	0950	2047	0	"	-28.6	80	-1.0	83	13.5	16.0	2.5	0
5	D	74	1005	2043	0	"	-28.7	86	-1.4	83	13.8	16.0	2.2	0
6	A	10	1020	1985	0	29.37	-28.5	91	-1.8	83	13.4	16.0	2.6	0
6	B	71	1035	2028	0	"	-28.7	91	-1.2	83	13.5	16.1	2.6	0
6	C	2	1050	2043	0	"	-28.7	87	-1.4	83	13.8	16.2	2.5	0
6	D	4	1105	2110	0	"	-28.7	98	-2.1	83	13.6	16.0	2.4	0

NO_x Field Test Sheet

Client Whiteman AFB

Project No. 90-122

Plant Site Steam Plant-Knob Noster, MO

Final Barometric Pressure (in. of Hg) 29.37

Run By T. Shackelford

Date 8/20/90

Sampling Location Stack-Boiler 5

Sample Recovery Date 8-21-90

(Natural Gas)

Test No.	Repit. Letter	Flask No.	Start Time	Flask Volume (ml)	Leak Rate (in.of Hg)	Initial Barometric Pressure (in. of Hg)	Initial Pressure (in. of Hg)	Initial Temperature °F	Final Pressure (in. of Hg)	Final Temperature °F	CO_2	$+O_2$	O_2	CO
1	A	87	~~[illegible]~~ 0747	2098	0	29.23	-28.4	83	-1.1	74	9.2	13.0	3.8	0
1	B	11	0805	2047	0	"	-28.6	86	-1.7	74	9.0	12.9	3.9	0
1	C	74	0820	2043	0	"	-28.3	86	-0.4	74	9.0	12.8	3.8	0
1	D	10	0835	1985	0	"	-28.3	86	-1.4	73	9.4	13.4	4.0	0
2	A	71	0900	2028	0	29.23	-28.3	87	-1.4	75	9.2	13.2	4.0	0
2	B	2	0915	2043	0	"	-27.9	100	-2.0	75	9.2	13.6	4.4	0
2	C	4	0930	2110	0	"	-27.8	99	-1.5	75	9.6	13.4	3.8	0
2	D	20	0945	2045	0	"	-28.2	106	-1.9	75	9.8	13.7	3.9	0
											~~9.9~~	~~13.4~~	~~3.5~~	~~0~~
3	A	1	1000	2085	0	29.23	-28.5	93	-0	88	9.9	13.4	3.5	0
3	B	17	1015	2037	0	"	-28.8	100	-1.0	89	9.9	13.8	3.9	0
3	C	25	1030	2058	0.1	"	-28.2	96	-0.6	86	9.8	13.2	3.4	0
3	D	10	1045	1960	0	"	-28.4	97	-0.4	89	9.2	13.2	3.5	0

NO$_X$ Field Test Sheet

Client Whiteman AFB
Project No. 90-122
Plant Site Steam Plant - Knob Knoster, MO
Final Barometric Pressure (in. of [illegible]) 29.34

Run By T. Shackelford
Date 8/23/90
Sampling Location Stack-Boilers
Sample Recovery Date 8-24-90

(No. 2 Fuel Oil)

Test No.	Repit. Letter	Flask No.	Start Time	Flask Volume (ml)	Leak Rate (in.of Hg)	Initial Barometric Pressure (in. of Hg)	Initial Pressure (in. of Hg)	Initial Temperature °F	Final Pressure (in. of Hg)	Final Temperature °F	CO_2	$+O_2$	O_2	CO
4	A	67	1205	2009	0	29.37	-28.6	83	-1.7	84	14.0	16.4	2.4	0
4	B	19	1220	2065	0	"	-28.2	102	-1.9	83	10.2	13.6	3.4	0
4	C	6	1235	2065	0	"	-28.1	122	-1.8	83	12.6	17.0	4.4	0
4	D	64	1250	2009	0	"	-28.3	125	-0.6	85	12.7	16.0	3.3	0
5	A	58	1305	2045	0	29.37	-28.4	99	-0.4	83	13.4	16.8	3.4	0
5	B	28	1320	2052	0	"	-28.3	112	-2.3	83	13.5	16.6	3.1	0
5	C	50	1335	2115	0	"	-28.4	104	-2.9	83	14.4	17.6	3.2	0
5	D	37	1350	2053	0	"	-28.3	108	-2.3	83	13.0	16.6	3.6	0
						"								
6	A	61	1405	2040	0	29.37	-28.3	109	-2.4	83	14.0	16.8	2.8	0
6	B	1	1420	2085	0	"	-28.4	104	-0.6	83	14.0	16.4	2.4	0
6	C	25	1435	2058	0	"	-28.3	100	-0.6	83	13.0	16.7	3.7	0
6	D	53	1450	2050	0	"	-28.3	98	-2.9	83	13.2	16.8	3.6	0

APPENDIX D

Analytical Laboratory Reports

NO_x Analysis Sheet

Client WHITEMAN AFB Analysis Run By A. BEHESHTI Date 9/4/90

Project No. 90-122 Plant Site STeam PlanT - Knob KnosTer, MO

% Absorbance:

0 ml 0.000 2 ml 0.171

4 ml 0.333 6 ml 0.466

8 ml 0.685

Flask No.	Absorbance %	Dilution of Sample	Kc	NO_2/Sample m (Ug)
BLanK	0.005	1:1	602.0	6.0
4-1-50	0.212			255.2
4-1-63	0.178			214.3
4-1-37	0.190			228.8
4-1-53	0.164			197.5
4-2-58	0.192	1:1		231.2
4-2-19	0.181			217.9
4-2-64	0.212			255.2
4-2-28	0.210			252.8
4-3-6	0.203	1:1		244.4
4-3-67	0.188			226.4
4-3-56	0.181			217.9
4-3-61	0.236			284.1

NO_x Analysis Sheet

Client WHITEMAN AFB

Analysis Run By A. BEHESHTI

Date 9/4/90

Project No. 90-122

Plant Site STeam PlanT - Knob KnosTer, MO

% Absorbance:

0 ml 0.000

2 ml 0.171

4 ml 0.333

6 ml 0.466

8 ml 0.685

Flask No.	Absorbance %	Dilution of Sample	Kc	NO_2/Sample m (Ug)
Blank	0.005	1:1	602.0	6.0
5-1-87	0.210			252.8
5-1-11	0.219			263.7
5-1-74	0.222			267.3
5-1-10	0.207			249.2
5-2-71	0.198	1:1		238.4
5-2-2	0.195			234.8
5-2-4	0.202			243.2
5-2-30	0.199			239.6
5-3-1	0.197	1:1		237.2
5-3-17	0.190			228.8
5-3-25	0.212			255.2
5-3-20	0.215			258.9

NO_x Analysis Sheet

Client WHITEMAN AFB
Analysis Run By A. BEHESHTI
Date 8/28/90
Project No. 90-122
Plant Site STeam PlanT - Knob KnosTer, MO

% Absorbance:
0 ml 0.000
2 ml 0.171
4 ml 0.360
6 ml 0.501
8 ml 0.693

Flask No.	Absorbance %	Dilution of Sample	Kc	NO_2/Sample m (Ug)
Blank	0.009			10.4
4-4-46	0.234	1:1	580.5	271.7
4-4-12	0.259			300.7
4-4-29	0.250			290.3
4-4-27	0.257			298.4
4-5-9	0.237	1:1		275.2
4-5-87	0.245			284.4
4-5-11	0.246			285.6
4-5-74	0.270			313.5
4-6-10	0.258	1:1		299.5
4-6-71	0.250			290.3
4-6-2	0.249			289.1
4-6-4	0.238			276.3

NO$_x$ Analysis Sheet

Client WHITEMAN AFB
Analysis Run By A. BEHESHTI
Date 8/28/90
Project No. 90-122
Plant Site STeam Plant - Knob Knoster, MO

% Absorbance:

0 ml 0.000
2 ml 0.171
4 ml 0.360
6 ml 0.501
8 ml 0.693

Flask No.	Absorbance %	Dilution of Sample	Kc	NO_2/Sample m (Ug)
Blank	0.009			10.4
5-4-67	0.262	1:1	580.5	304.2
5-4-19	0.287			333.2
5-4-6	0.275			319.3
5-4-64	0.274			318.1
5-5-58	0.267	1:1		310.0
5-5-28	0.270			313.5
5-5[illegible]-50	0.271			314.6
5-5-37	0.283			328.6
5-6-61	0.281	1:1		326.2
5-6-1	0.287			333.2
5-6-25	0.281			326.2
5-6-53	0.277			321.6

APPENDIX E

Test Equipment Calibrations

NO_X FLASK CALIBRATIONS

BY: BIW

BAROMETRIC PRESSURE: 29.80

FLASK NO.	FLASK VOLUME
1	2085
2	2043
4	2110
5	2095
6	2085
7	2085
8	2066
9	2071
10	1985
11	2047
12	1965
14	2100
15	2080
16	2085
17	2037
19	2065
20	1990
21	2055
23	2085
24	2068
25	2035
26	2060
27	2034
28	2060
34	2020
37	2038
38	2014
46	2043
50	2055
53	2050
54	2058
56	2094
57	2070
58	2069
61	2040
62	2049
63	2005
64	2005
65	2028
67	2009
68	2024
69	2006
70	2020
71	2028
74	2010
87	2080

APPENDIX F

Boiler Operating Data

DAILY STEAM BOILER PLANT OPERATING LOG

1. COMMAND

2. BASE AND LOCATION

3. BUILDING NO. AND NAME

4. DATE 9-21-90

	TIME HOUR	STEAM PRESS (PSIG)	STEAM PRODUCED (1000 Pounds) C				FUEL USED D COAL - BTU/LB [✓ OIL] - BTU/GAL GAS - BTU/1000CF				FLUE GAS E O₂ OR CO₂ (Avg %)				FLUE GAS E TEMP (Degree F)				FUEL OIL F		FEEDWATER HEATER G		FEEDWATER FLOW (Gals) H			MAKE-UP WATER FLOW (Gals) I			CONDENSATE RETURN TEMP (°F) J	FEEDWATER PUMP PRESSURES (PSIG) K		OUTSIDE TEMPERATURE (°F) L
			BOILER NO.				BOILER NO.				BOILER NO.				BOILER NO.				PRESS (PSIG)	TEMP (°F)	PRESS (PSIG)	TEMP (°F)	START	STOP	GALS	START	STOP	GALS		SUCT.	DISCH.	
	A	B	1	~~2~~ 5	3	4	1	~~2~~ 5	3	4	1	2	3	4	1	2	3	4														
FIRST SHIFT	11,55	122																			5.4	225				17820100			178	11.2	211	
	12:10	103		1130				78													5.2	225					17820200	100	182	1128	197	
	12:25	110		1661				108													5.6	225					17821300	1100	175	11.2	200	
	12:40	99		1782				114													5.5	225					17822600	1300	176	11.2	205	
	12:55	101		1499				96													5.5	225					17823800	1200	177	11.2	200	
	13,10	105		1624				109													5.5	225					17825000	1200	178	11.2	199	
	13:25	106		1891				127													5.5	225					17825800	800	177	11.2	198	
	13:40	107		1228				83													5.5	225					17826500	700	177	11.2	200	
	TOTAL																															
	AVG.																															
SECOND SHIFT	13:55	106		1652				110													5.5	225					17827500	1000	178	11.2	200	
	14:10	107		1648				110													5.5	225					17828100	600	179	11.2	201	
	14:25	105		1604				108													5.5	225					17828200	100	181	11.4	200	
	14:40	105		1545				102													5.6	225					17828300	100	180	11.4	201	
	14:55	103		1665				110													5.5	225					17828700	400	178	11.2	202	
	TOTAL																															
	AVG.																															
THIRD SHIFT																																
	TOTAL																															
	AVG.																															
DAILY	TOTAL																															
	AVG.																															

5. OPERATING DATA

	FIRST SHIFT		SECOND SHIFT		THIRD SHIFT		TOTAL
A. STEAM FLOW FINAL (Integrator)							
B. STEAM FLOW START							
C. TOTAL STEAM PRODUCED							
D. LBS. STEAM PER UNIT OF FUEL							
E. SOOT BLOWN							
F. BLOW DOWN	TIME:	GALS.	TIME:	GALS.	TIME:	GALS.	
G. DEGREE DAY							
H. OPERATOR							
I. FIREMAN							
J. TOTAL MANHOURS OPERATION							

6. PLANT COMBUSTION EFFICIENCY (Percent)

7. PLANT BTU OUTPUT (Millions)

8. PLANT BTU INPUT (Millions)

9. OVERALL EFFICIENCY (Percent)

10. PEAK DEMAND FACTOR (Percent)

11. MAKEUP WATER (Percent)

12. TOTAL FUEL USED

COAL - LBS. ______

OIL - GALS. ______

GAS - MCF ______

13. REMARKS (Continue on reverse)

DATE	SIGNATURE OF CHIEF OPERATING ENGINEER

AF FORM OCT 82 1458 PREVIOUS EDITION WILL BE USED.

DAILY STEAM BOILER PLANT OPERATING LOG

1. COMMAND

2. BASE AND LOCATION

3. BUILDING NO. AND NAME

4. DATE 8-21-90

	TIME HOUR	STEAM PRESS (PSIG)	STEAM PRODUCED (1000 Pounds)				FUEL USED COAL – BTU/LB [✓ OIL] – BTU/GAL GAS – BTU/1000CF				FLUE GAS O2 OR CO2 (Avg %)				FLUE GAS TEMP (Degree F)			
	A	B	C BOILER NO. 1	2	3	[✓ 4]	D BOILER NO. 1	2	3	[✓ 4]	E BOILER NO. 1	2	3	4	BOILER NO. 1	2	3	4
FIRST SHIFT	7:20	124																
	7:35	101				3.34				23								
	7:50	107				7.31				42								
	8:05	118				7.54				45								
	8:20	112				9.74				57								
	8:35	113				7.32				43								
	8:50	119				8.10				47								
	9:05	104				8.57				49								
	TOTAL																	
	AVG.																	
SECOND SHIFT	9:20	109				9.06				51								
	9:35	119				8.06				50								
	9:50	105				9.31				53								
	10:05	103				8.19				46								
	10:20	113				8.57				50								
	10:35	113				8.28				48								
	10:50	115				10.50				62								
	11:05	110				6.13				35								
	TOTAL																	
	AVG.																	
THIRD SHIFT	11:20	99				9.24				51								
	TOTAL																	
	AVG.																	
DAILY	TOTAL																	
	AVG.																	

	TIME HOUR	FUEL OIL		FEEDWATER HEATER		FEEDWATER FLOW (Gals)			MAKE-UP WATER FLOW (Gals)			CONDENSATE RETURN TEMP (°F)	FEEDWATER PUMP PRESSURES (PSIG)		OUTSIDE TEMPERATURE (°F)
	A	F PRESS (PSIG)	TEMP (°F)	G PRESS (PSIG)	TEMP (°F)	H START	STOP	GALS	I START	STOP	GALS	J	K SUCT.	DISCH.	L
FIRST SHIFT	7:20			5.4	225				17812000			180	11.2	200	
	7:35			5.3	225					17812000	0	182	11.0	245	
	7:50			5.5	225					17812000	0	182	11.0	241	
	8:05			5.5	225					17812000	0	181	11.2	242	
	8:20			5.3	225					17812400	400	179	11.2	233	
	8:35			5.5	225					17813500	1100	178	11.2	241	
	8:50			5.4	225					17814300	800	180	11.7	240	
	9:05			5.2	225					17814800	500	193	11.7	240	
	TOTAL														
	AVG.														
SECOND SHIFT	9:20			5.5	225					17815600	800	184	11.6	240	
	9:35			5.5	225					17815600	0	181	11.4	240	
	9:50			5.4	225					17815900	300	179	11.2	240	
	10:05			5.6	225					17816800	900	177	11.6	240	
	10:20			5.4	225					17817200	400	172	11.2	241	
	10:35			5.4	225					17817800	600	171	11.2	240	
	10:50			5.5	225					17818400	600	175	11.2	243	
	11:05			5.5	225					17818800	400	176	11.2	235	
	TOTAL														
	AVG.														
THIRD SHIFT	11:20			5.4	225					17819500	700	173	11.2	240	
	TOTAL														
	AVG.														
DAILY	TOTAL														
	AVG.														

5. OPERATING DATA

	FIRST SHIFT		SECOND SHIFT		THIRD SHIFT		TOTAL
A. STEAM FLOW FINAL (Integrator)							
B. STEAM FLOW START							
C. TOTAL STEAM PRODUCED							
D. LBS. STEAM PER UNIT OF FUEL							
E. SOOT BLOWN							
F. BLOW DOWN	TIME:	GALS.	TIME:	GALS.	TIME:	GALS.	
G. DEGREE DAY							
H. OPERATOR							
I. FIREMAN							
J. TOTAL MANHOURS OPERATION							

13. REMARKS (Continue on reverse)

6. PLANT COMBUSTION EFFICIENCY (Percent)

7. PLANT BTU OUTPUT (Millions)

8. PLANT BTU INPUT (Millions)

9. OVERALL EFFICIENCY (Percent)

10. PEAK DEMAND FACTOR (Percent)

11. MAKEUP WATER (Percent)

12. TOTAL FUEL USED

COAL - LBS. ______

OIL - GALS. ______

GAS - MCF ______

DATE

SIGNATURE OF CHIEF OPERATING ENGINEER

DAILY STEAM BOILER PLANT OPERATING LOG

1. COMMAND

2. BASE AND LOCATION Whiteman AFB

3. BUILDING NO. AND NAME

4. DATE 8-20-70

	TIME HOUR	STEAM PRESS (PSIG)	STEAM PRODUCED (1000 Pounds) C				FUEL USED D COAL - BTU/LB OIL - BTU/GAL [✓ GAS] - BTU/1000CF				FLUE GAS E O2 OR CO2 (Avg %)				FLUE GAS E TEMP (Degree F)				FUEL OIL F		FEEDWATER HEATER G		FEEDWATER FLOW (Gals) H			MAKE-UP WATER FLOW (Gals) I			CONDENSATE RETURN TEMP (°F) J	FEEDWATER PUMP PRESSURES (PSIG) K		OUTSIDE TEMPERATURE (°F)
			BOILER NO.				BOILER NO.				BOILER NO.				BOILER NO.				PRESS (PSIG)	TEMP (°F)	PRESS (PSIG)	TEMP (°F)	START	STOP	GALS	START	STOP	GALS		SUCT.	DISCH.	
	A	B	1	x5	3	4	1	x5	3	4	1	2	3	4	1	2	3	4											J			
FIRST SHIFT	7:00	124																			5.5	225				17788600			177	11.5	201	
	7:15	116		14.87				4.65													5.2	225					17788600	0	174	11.0	193	
	7:30	98		14.31				15.28													5.1	225					17789100	500	169	10.5	201	
	7:45	115		16.79				18.68													5.5	225					17790100	1000	172	11.0	204	
	8:00	120		14.64				17.13													5.5	225					17790800	700	172	11.2	201	
	8:15	119		16.40				19.43													5.5	225					17792100	1300	178	11.1	200	
	8:30	120		15.80				18.59													5.5	225					17793200	1100	174	11.2	203	
	8:45	121		14.22				16.66													5.4	225					17794200	1000	174	11.2	202	
	TOTAL																															
	AVG.																															
SECOND SHIFT	9:00	117		14.52				17.04													5.5	225					17795300	1100	173	11.0	195	
	9:15	116		16.50				19.09													5.5	225					17796500	1200	173	11.2	200	
	9:30	115		14.59				16.92													5.5	225					17797800	1300	172	11.0	200	
	9:45	115		15.37				17.80													5.5	225					17798400	600	171	11.2	202	
	10:00	115		15.62				18.13													5.5	225					17799200	500	169	11.2	196	
	10:15	115		15.71				18.06													5.5	225					17799900	700	166	11.2	201	
	10:30	115		15.37				17.83													5.5	225					17800600	700	166	11.0	200	
	10:45	115		17.59				20.06													5.6	225					17800700	100	169	11.2	194	
	TOTAL																															
	AVG.																															
THIRD SHIFT																																
	TOTAL																															
	AVG.																															
DAILY	TOTAL																															
	AVG.																															

5. OPERATING DATA

	FIRST SHIFT		SECOND SHIFT		THIRD SHIFT		TOTAL
A. STEAM FLOW FINAL (Integrator)							
B. STEAM FLOW START							
C. TOTAL STEAM PRODUCED							
D. LBS. STEAM PER UNIT OF FUEL							
E. SOOT BLOWN							
F. BLOW DOWN	TIME:	GALS.	TIME:	GALS.	TIME:	GALS.	
G. DEGREE DAY							
H. OPERATOR							
I. FIREMAN							
J. TOTAL MANHOURS OPERATION							

6. PLANT COMBUSTION EFFICIENCY (Percent)

7. PLANT BTU OUTPUT (Millions)

8. PLANT BTU INPUT (Millions)

9. OVERALL EFFICIENCY (Percent)

10. PEAK DEMAND FACTOR (Percent)

11. MAKEUP WATER (Percent)

12. TOTAL FUEL USED

COAL - LBS. ________

OIL - GALS. ________

GAS - MCF ________

13. REMARKS (Continue on reverse)

DATE

SIGNATURE OF CHIEF OPERATING ENGINEER

AF FORM OCT 62 1458 PREVIOUS EDITION WILL BE USED.

DAILY STEAM BOILER PLANT OPERATING LOG

1. COMMAND
2. BASE AND LOCATION
3. BUILDING NO. AND NAME
4. DATE 8-20-90

	TIME HOUR	STEAM PRESS (PSIG)	STEAM PRODUCED (1000 Pounds) C				FUEL USED D COAL – BTU/LB OIL – BTU/GAL [✓ GAS] – BTU/1000CF				FLUE GAS E								FUEL OIL F		FEEDWATER HEATER G		FEEDWATER FLOW (Gals) H			MAKE-UP WATER FLOW (Gals) I			CONDENSATE RETURN TEMP (°F)	FEEDWATER PUMP PRESSURES (PSIG) K		OUTSIDE TEMPERATURE (°F)
			BOILER NO.				BOILER NO.				O2 OR CO2 (Avg %) BOILER NO.				TEMP (Degree F) BOILER NO.				PRESS (PSIG)	TEMP (°F)	PRESS (PSIG)	TEMP (°F)	START	STOP	GALS	START	STOP	GALS	J	SUCT.	DISCH.	L
	A	B	1	2	3	④	1	2	3	④	1	2	3	4	1	2	3	4														
FIRST SHIFT	12:30	100																			5.5	225				17802600			169	11.9	226	
	12:45	104				9.23				1080											5.7	225					17803400	800	171	11.6	226	
	13:00	110				8.34				1011											5.5	225					17803700	300	175	11.3	237	
	13:15	112				8.37				1016											5.5	225					17804400	700	178	11.3	240	
	13:30	113				8.11				990											5.5	225					17804900	500	177	11.2	240	
	13:45	125				9.23				1154											5.6	225					17805300	400	172	11.2	240	
	14:00	113				7.95				968											5.3	225					17805700	400	173	11.3	230	
	14:15	108				9.24				1061											5.5	225					17806700	1000	175	11.2	233	
	TOTAL																															
	AVG.																															
SECOND SHIFT	14:30	121				7.95				921											5.5	225					17807700	1000	176	11.2	235	
	14:45	118				8.51				1052											5.5	225					17808600	900	175	11.0	237	
	15:00	90				8.64				968											5.7	225					17809400	800	174	11.2	240	
	15:15	101				9.47				1075											5.5	225					17809900	500	175	11.2	237	
	15:30	126				7.80				979											5.5	225					17810400	500	176	11.2	236	
	TOTAL																															
	AVG.																															
THIRD SHIFT																																
	TOTAL																															
	AVG.																															
DAILY	TOTAL																															
	AVG.																															

5. OPERATING DATA

	FIRST SHIFT	SECOND SHIFT	THIRD SHIFT	TOTAL
A. STEAM FLOW FINAL (Integrator)				
B. STEAM FLOW START				
C. TOTAL STEAM PRODUCED				
D. LBS. STEAM PER UNIT OF FUEL				
E. SOOT BLOWN				
F. BLOW DOWN	TIME: GALS.	TIME: GALS.	TIME: GALS.	
G. DEGREE DAY				
H. OPERATOR				
I. FIREMAN				
J. TOTAL MANHOURS OPERATION				

6. PLANT COMBUSTION EFFICIENCY (Percent)

7. PLANT BTU OUTPUT (Millions)

8. PLANT BTU INPUT (Millions)

9. OVERALL EFFICIENCY (Percent)

10. PEAK DEMAND FACTOR (Percent)

11. MAKEUP WATER (Percent)

12. TOTAL FUEL USED

COAL - LBS. ______

OIL - GALS. ______

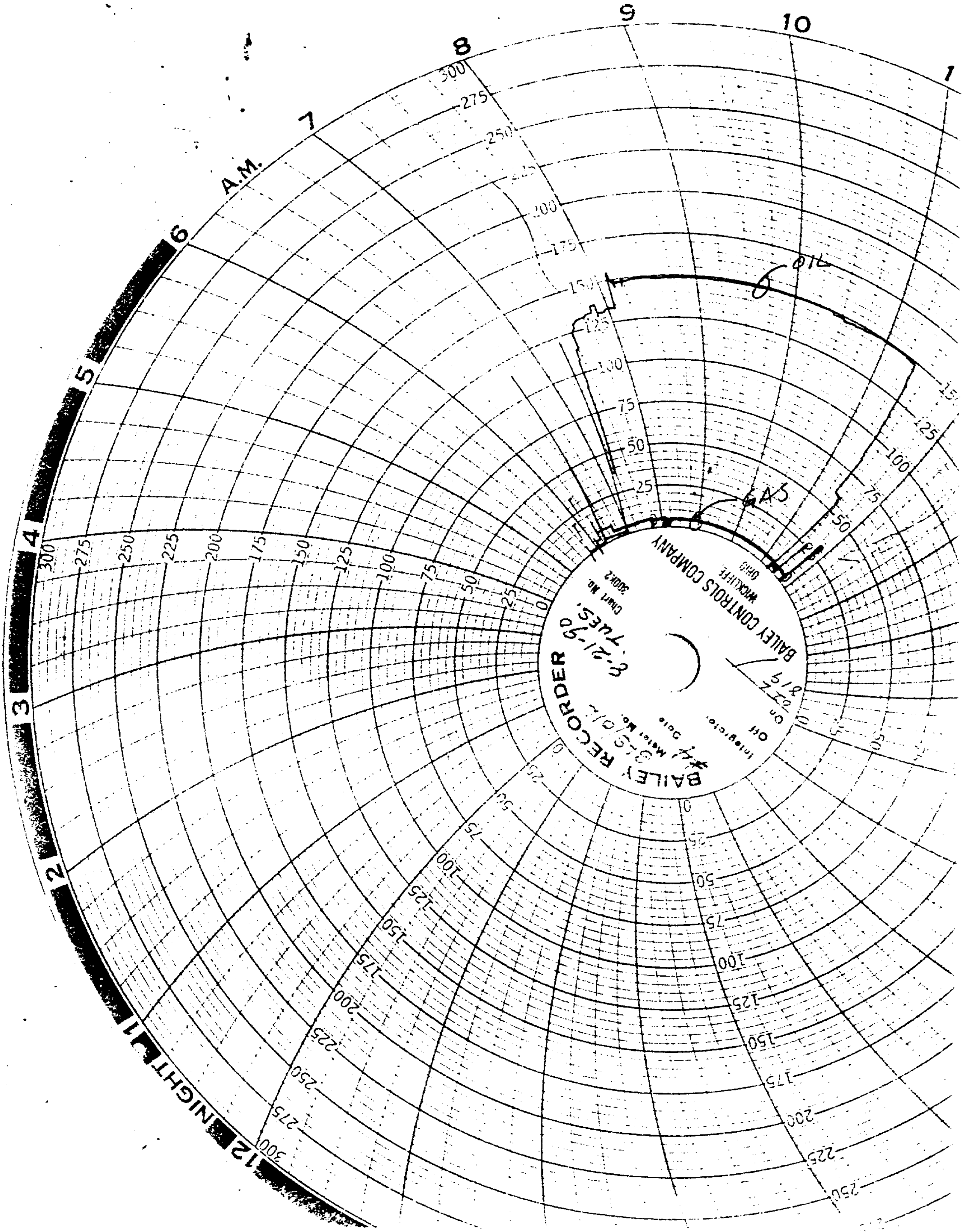
GAS - MCF ______

13. REMARKS (Continue on reverse)

DATE

SIGNATURE OF CHIEF OPERATING ENGINEER

AF FORM OCT 82 1458 PREVIOUS EDITION WILL BE USED.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BAILEY CONTROLS COMPANY
WICKLIFFE OHIO
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Date 6-21-60 Tues.
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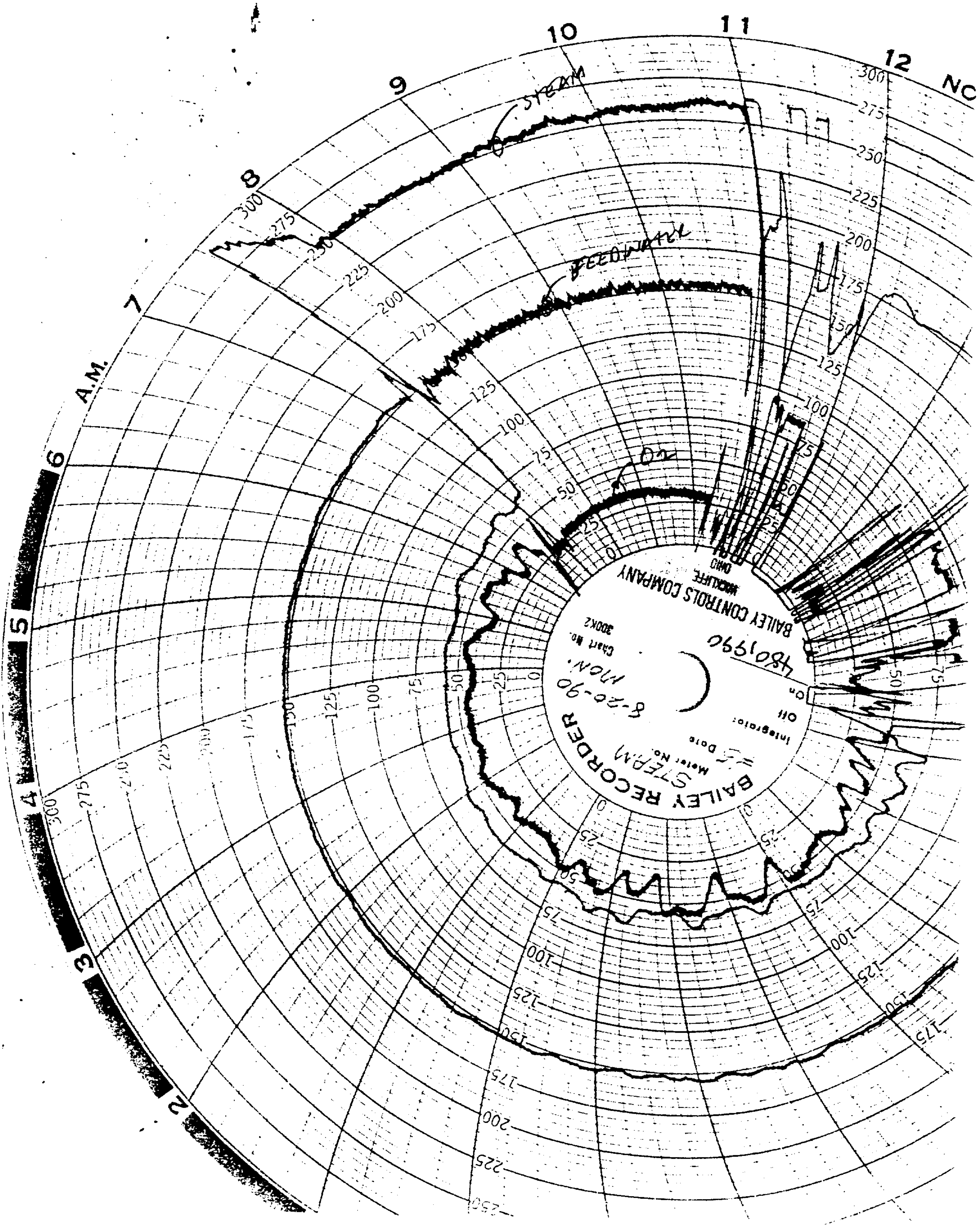
5 4 3 2 1 NIGHT 12
0 25 50 75 100 125 150 175 200 225 250 275 300
6 on
6A5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11
12
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9
8
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A.M.
6
5
4
3
2
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FEEDWATER
O2
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250
225
200
175
150
125
100
75
50
25
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BAILEY RECORDER
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On
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WICKLIFFE, OHIO
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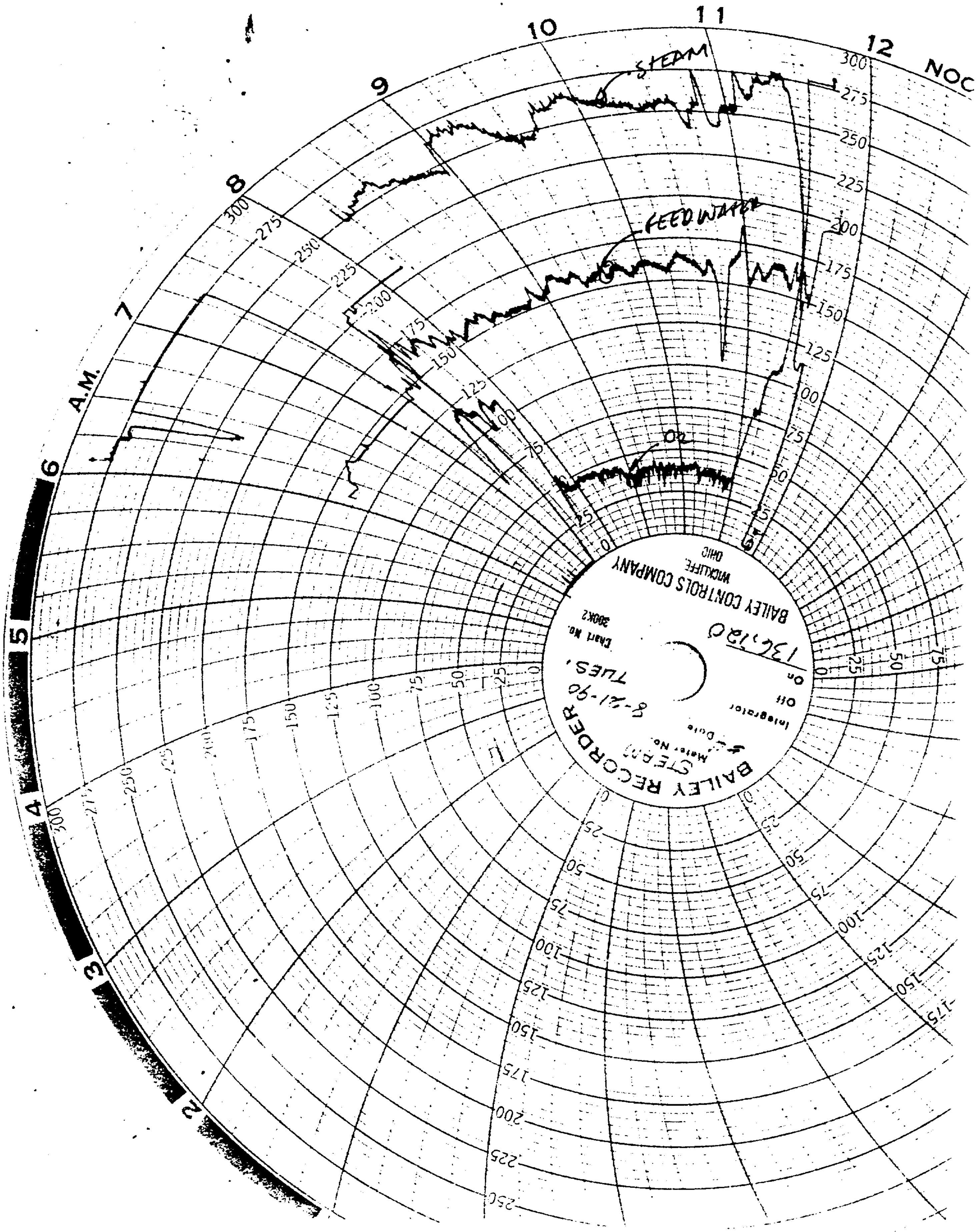

6
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A.M.
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STEAM
FEEDWATER
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BAILEY CONTROLS COMPANY
WICKLIFFE, OHIO
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On
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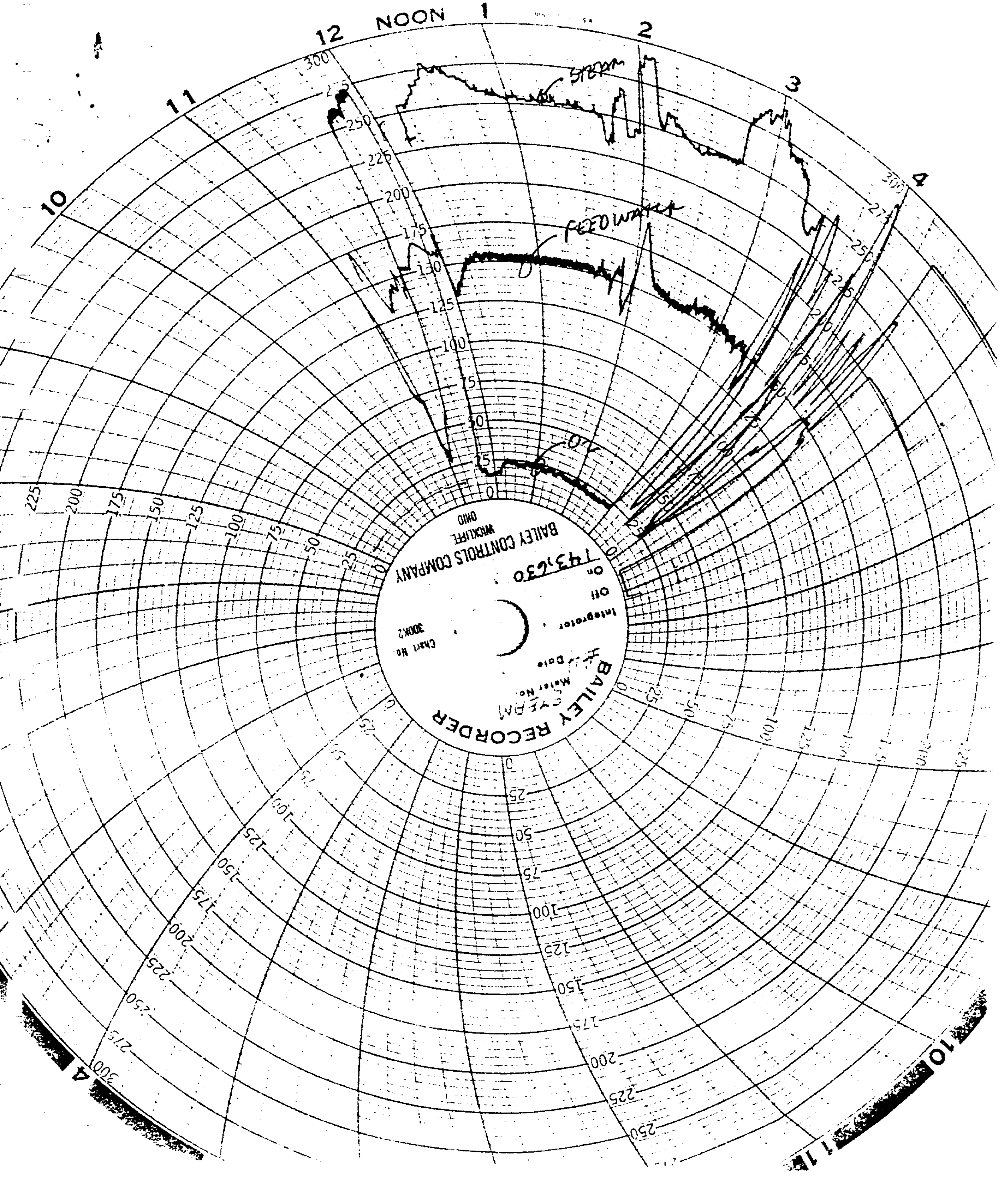
Integrator
Date 8-21-90 TUES.
Meter No. STEAM
BAILEY RECORDER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STEAM
FEEDWATER
OIL
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WICKLIFFE
OHIO
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Date
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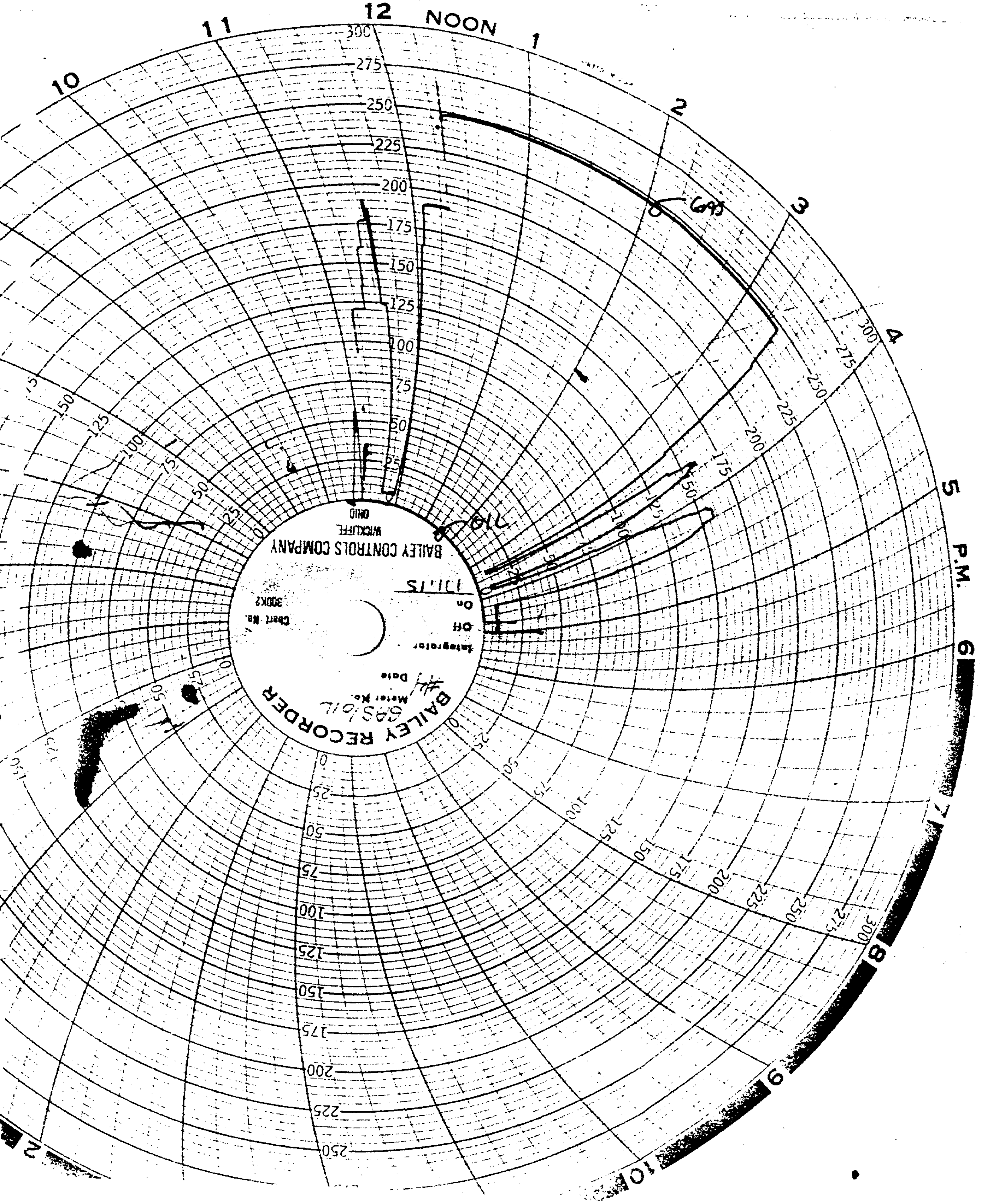

12 NOON
1
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P.M.
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200
225
250
275
300
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Meter No. 6AS1612
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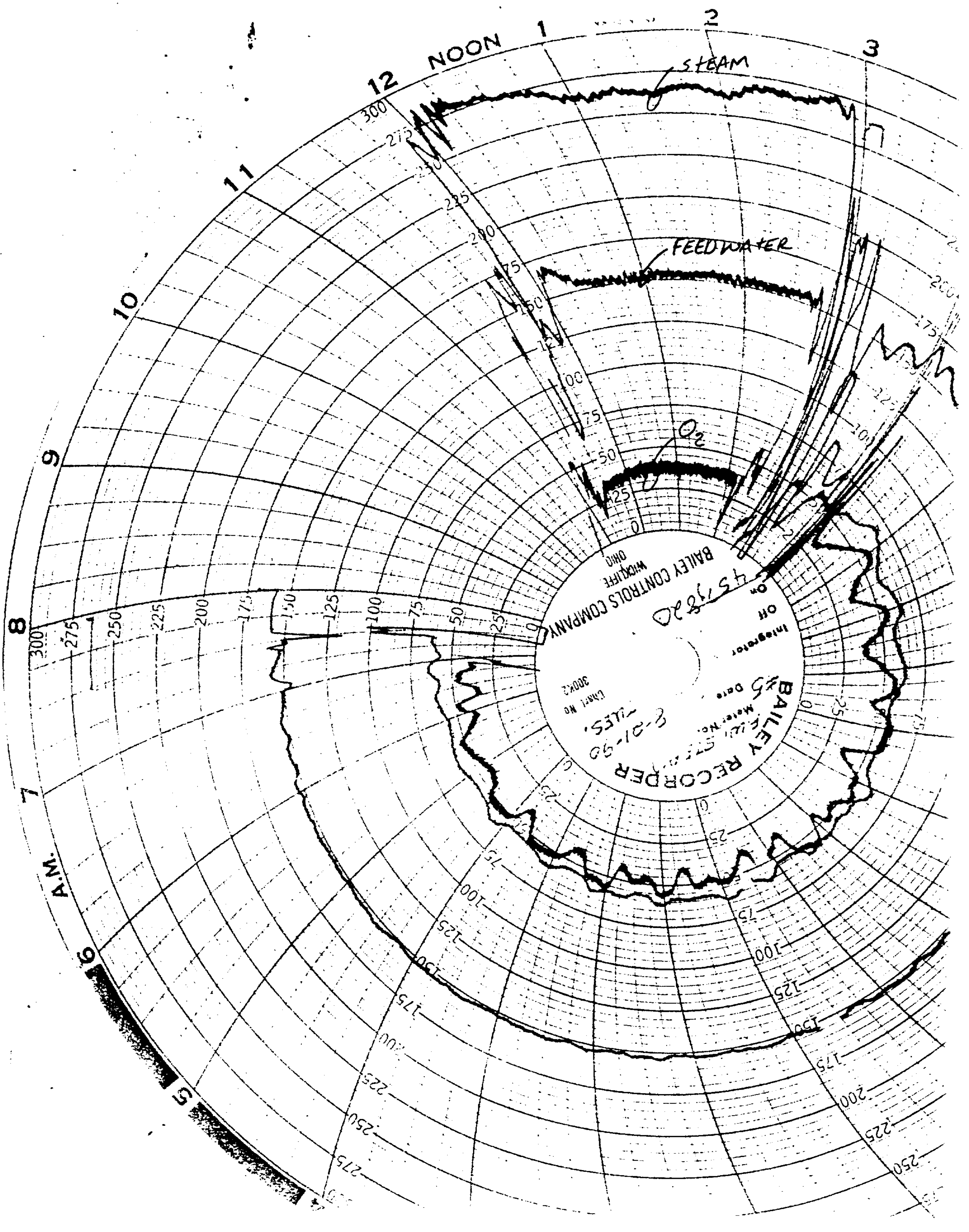
BAILEY CONTROLS COMPANY
WICKLIFFE
OHIO
(6A)
710


NOON
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175
150
125
100
75
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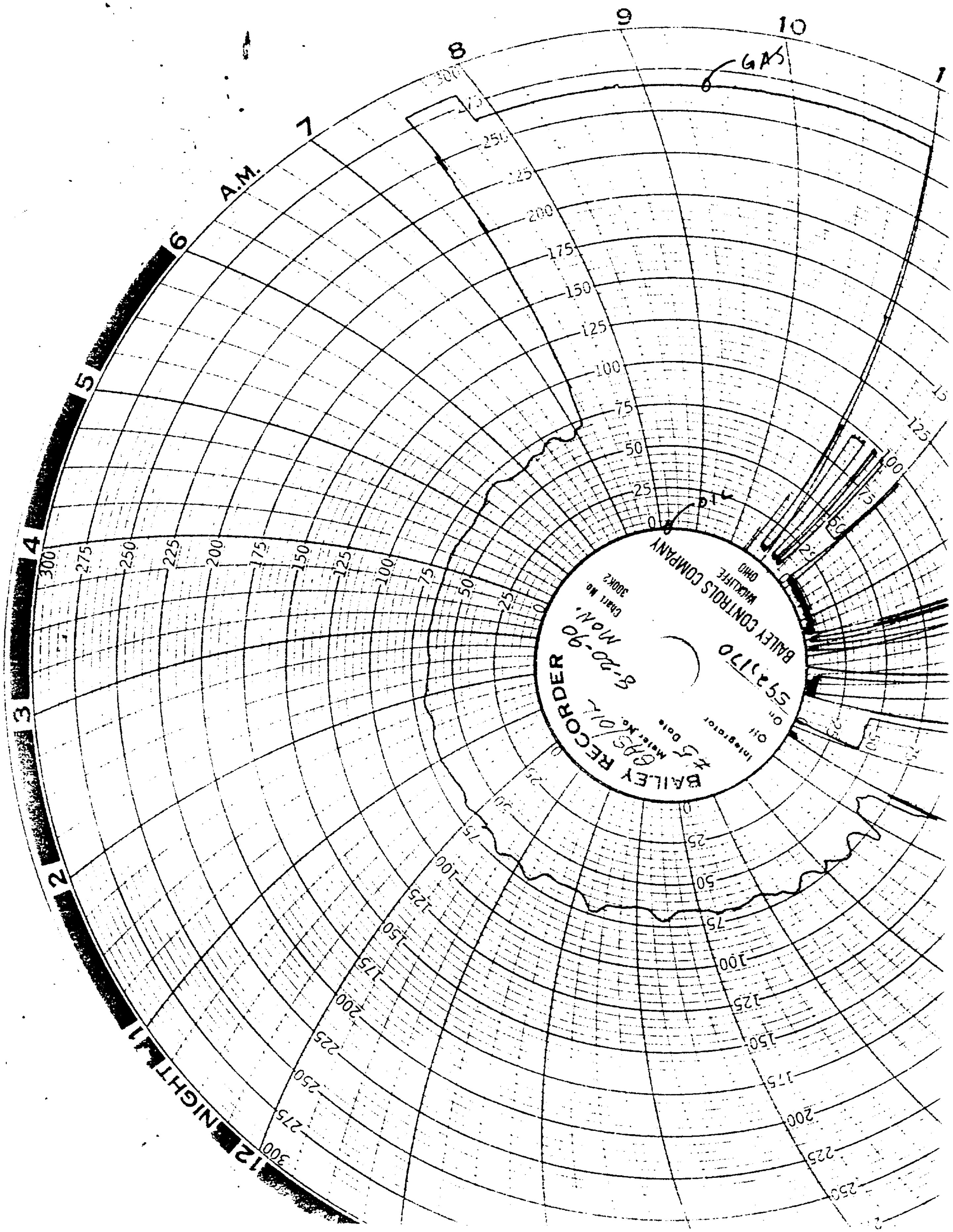
25
0
STEAM
FEEDWATER
O_2
BAILEY CONTROLS COMPANY
WICKLIFFE
OHIO
BAILEY RECORDER
Meter No.
Date
Chart No.
300K2
Integrator
Off
On
45,920
8-21-90
Tues.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OIL
A.M.
NIGHT
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225
250
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300
BAILEY CONTROLS COMPANY
WICKLIFFE
OHIO
Chart No.
300K2
BAILEY RECORDER
Integrator
On
Off
Date
Meter No.
5592170
8-20-90
Mon.
#5
OBS012

APPENDIX G

Test Procedures

TESTING EQUIPMENT - EPA REFERENCE METHOD 7 (NOx)

NITROGEN OXIDE SAMPLING TRAIN:

A Scientific Glass & Instruments Company NOx Sampler was used at the sampling location(s). The NOx sampling train consisted basically of a heated probe; a 2-liter borosilicate, round-bottom, short-neck boiling flask with a Pyrex 3-way, T-bore stopcock valve; a mercury-in-glass thermometer; a Dwyer U-tube mercury manometer; a Gast 3/4 hp carbon vane vacuum pump; a stop watch; and various interconnecting hoses, fittings and valves.

The U-tube manometer was used to monitor internal pressures in the collection flask.

SAMPLING PROCEDURES - EPA REFERENCE METHOD 7 (NOx)

Prior to the field testing, all instruments were checked and calibrated, and the chemical reagents prepared as follows:

A. Sampling Reagents:

1. Absorbing Solution - 2.8 milliliters of concentrated sulfuric acid were mixed with 1 liter of deionized, distilled water. 6 milliliters of reagent grade hydrogen peroxide solution, were added to the diluted sulfuric acid mixture.

B. Sample Recovery Reagents:

1. Sodium Hydroxide - 40 grams of sodium hydroxide (1N) were dissolved in deionized, distilled water and diluted to 1 liter.

C. Analytical Reagents:

1. Standard Potassium Nitrate Solution - 2.198 grams of dried potassium nitrate were dissolved in deionized, distilled water and diluted to 1 liter.

2. Working Standard Potassium Nitrate Solution - 10 milliliters of the standard potassium nitrate solution are diluted to 100 milliliters with deionized, distilled water.

3. Phenoldisulfonic Acid Solution - 25 grams of pure white phenol were dissolved in 150 milliliters of concentrated sulfuric acid on a steam bath. The solution was then cooled and 75 milliliters of fuming sulfuric acid were added and heated to 212 degrees Fahrenheit for two hours.

The sampling procedures were performed in accordance with the Environmental Protection Agency's Reference Method 7 - "Determination of Nitrogen Oxide Emissions form Stationary Sources" in the July 1, 1989 Federal Register - Standards of Performance for New Stationary Sources", and subsequent revisions.

A NOx sampling train was prepared at the sampling location in the following manner: 25 milliliters of absorbing solution were added to a collection flask. A sufficient quantity of the absorbing solution was retained for later use in preparing the calibration standards. A 3-way stopcock valve was inserted into the collection flask and the valve turned to the "purge" position. Glass wool was placed into the inlet end of the heated sampling probe. The probe was then placed into the flue and connected to the collection flask. The probe heater was turned on and the probe heated to approximately 250 degrees Fahrenheit.

A U-tube manometer and a vacuum pump were connected to the outlet of the collection flask with a Teflon tee fitting. The stopcock valve and the pump valve were then turned to the "evacuate" positions.

The collection flask was evacuated to 3 inches of mercury absolute pressure, or less. As soon as the flask evacuation was completed, the pump valve was turned to the "off" position and the pump turned off. A leak-check was performed on the collection flask by observing the manometer for one minute to determine if the pressure varied by more than 0.4 inches of mercury. If the pressure did not fluctuate more than the allowable tolerance, the leak-check was considered acceptable.

After the NOx sampling train was assembled, the probe temperature stabilized and the collection flask leak-checked, the nitrogen oxides sampling was performed.

As soon as the leak-check was completed, the stopcock valve and the pump valve were turned to the "purge" positions and the pump turned on. After an adequate amount of time for purging, the pump valve was turned to the "off" position and the stopcock valve was turned to the "evacuate" position. The difference in the mercury levels in the U-tube manometer was recorded. Immediately after recording the flask pressure the stopcock valve was turned to the "sample" position for approximately 15 seconds permitting the flue gas to enter the flask until the pressures in the flask and the flue attained equilibrium.

After the completion of each 15 second sampling period, the following procedures were performed: The stopcock valve was turned to the "purge" position and the collection flask was disconnected from the sampling probe, U-tube manometer and the vacuum pump. The sampling probe was left in the flue with the probe heater on and ready for the next sampling period. The flask was then shaken by hand for a minimum of 5 minutes.

One point was sampled at the sample location from one sample port. Three test runs were performed, each consisted of four - 15 second sampling periods with intervals of approximately 15 minutes between periods. The collection flask and stopcock valve volume, collection flask temperature and barometric pressure were recorded on a field test form prior to each 15 second sampling period.

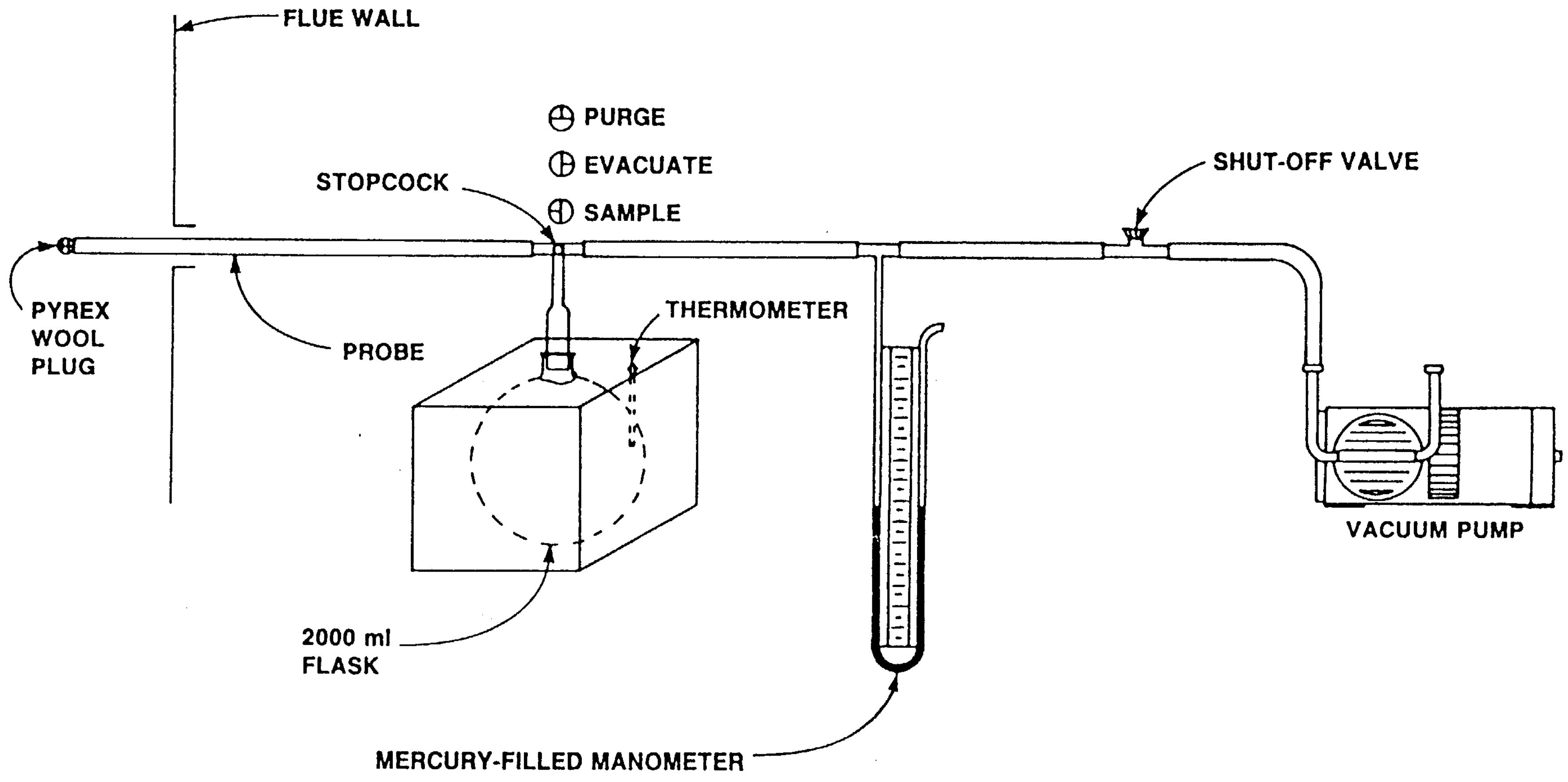
ANALYTICAL PROCEDURES - EPA METHOD 7 (NOx)

After the field testing was completed, the following procedures were performed:

The collection flask was transferred to a protective transport case and allowed to set for a minimum of 16 hours to stabilize. At the end of the 16 hour stabilization period, the contents in the flask was shaken for two minutes. The flask was then connected to a U-tube manometer and the pressure differential recorded. The contents of the flask were transferred to a leak-free polypropylene sample bottle. The flask was rinsed twice with 5 milliliters of deionized, distilled water and the rinsings added to the contents in the sample bottle. Sodium hydroxide (1N) was added to the sample dropwise, to adjust the pH between 9 and 12.

Each nitrogen oxides sample was transferred from its sample bottle to a 50 milliliter volumetric flask and diluted to the mark with deionized, distilled water. One 25 milliliter aliquot of each diluted sample was pipetted into separate porcelain evaporating dishes, evaporated to dryness on a steam bath and allowed to cool. Two milliliters of phenoldisulfonic acid were added to the dried residue and triturated thoroughly. One milliliter of deionized, distilled water and four drops of concentrated sulfuric acid were added to each sample and heated on a steam bath for 3 minutes. After each solution cooled, 20 milliliters of deionized, distilled water were added to each solution and mixed.

Concentrated ammonium hydroxide was added dropwise until the pH of the sample was 10. Each sample was then transferred directly to a 100 milliliter volumetric flask and diluted to the mark with deionized, distilled water. The solution in each flask was mixed thoroughly and the absorbance of each solution measured at the optimum wave length on a spectrophotometer calibrated against a working standard using a blank solution as a zero reference.



Exhibit

NITROGEN OXIDE
SAMPLING TRAIN

APPENDIX H

Permit & Review for Boiler 5

JOHN ASHCROFT
Governor

FREDERICK A. BRUNNER
Director

STATE OF MISSOURI
DEPARTMENT OF NATURAL RESOURCES

Division of Energy
Division of Environmental Quality
Division of Geology and Land Survey
Division of Management Services
Division of Parks, Recreation,
and Historic Preservation

OFFICE OF THE DIRECTOR
P.O. Box 176
Jefferson City, Missouri 65102
Telephone 314-751-4422

June 13, 1988

Mr. Randall B. White
Department of the Air Force
Headquarters 351st Combat Support Group (SAC)
Whiteman Air Force Base, MO 65305-5000

Re: Permit Number 0688-004A & 005A
Johnson County

Dear Mr. White:

Your application, received January 15, 1988, to the Air Pollution Control Program, for Authority to Construct a boiler in your heating plant in Johnson County, Missouri, has been reviewed by my staff and found to qualify as a "De minimis" source by meeting our permit requirements.

You are hereby granted permission to construct as described in your application, subject to the following conditions:

1. The maximum aggregate amount of No. 2 fuel oil combusted in Boilers Number 4 and 5 shall not exceed 500,000 gallons per year, with a sulfur content not to exceed 0.4 percent. Records shall be kept on-site recording the amount of No. 2 fuel oil combusted in Boiler Number 4 and Boiler Number 5 on a monthly basis, together with the sulfur content of the fuel oil. These records shall be made available to inspectors of the Missouri Department of Natural Resources.

2. The maximum aggregate amount of natural gas combusted in Boilers Number 4 and 5 shall not exceed 540 million cubic feet per year. Records shall be kept on-site recording the amount of natural gas combusted in Boiler Number 4 and Boiler Number 5 on a monthly basis. These records shall be made available to inspectors of the Missouri Department of Natural Resources.

3. The emission rate of nitrogen oxides from the operation of Boilers Number 4 and 5 shall not exceed a rate of 0.12 pounds of nitrogen oxides per million BTU firing rate.

4. In order to demonstrate that the emission limit contained in Condition Number 3 of this permit will be met, performance testing shall be conducted in accordance with EPA Test Method 7,

"Determination of Nitrogen Oxide Emissions from Stationary Sources." This testing shall be conducted in accordance with the requirements of 40 CFR Part 60, Subparagraph 60.8.

5. Boilers Number 4 and 5 shall burn only natural gas or distillate fuel oil.

6. This source must continue to emit, on an annual basis, below the emission rates established in 10 CSR 10-6.060 subsection (7)(A), Table 1, De minimis Emission Levels.

7. A notification of the anticipated date of initial start-up of the source not more than 60 days or less than 30 days prior to such date; and,

8. A notification of the actual date of initial start-up of the source within 15 days after such date.

Pursuant to RSMo 643.075, the applicant may appeal to the Commission from any condition in any permit by filing notice of appeal with the Commission within thirty days of this notice of conditional approval.

The notices should be mailed to: Air Pollution Control Program, PO Box 176, Jefferson City, MO 65102.

You may consider this letter and the enclosed review to be your permit to construct. This permit is only to allow you to construct and start-up this facility, and in no way relieves you of your obligation to meet all air pollution control regulations or other federal, state, or local regulations.

If you have questions regarding this air pollution permit contact: Mike Tharpe, Air Pollution Control Program (314) 751-4817.

Sincerely,

DEPARTMENT OF NATURAL RESOURCES

Frederick A. Brunner, Ph.D., P.E.
Director

FAB/msb

cc: Kansas City Regional Office
John R. Mills - Lutz, Daily, & Brain

REVIEW OF APPLICATION FOR AUTHORITY TO CONSTRUCT
Permit Numbers (0688 - 004A and 0688 - 005A)

Department of the Air Force
Headquarters, 351st Combat Support Group
Whiteman Air Force Base, MO 65305-5000

Sec 33, T46N, R34W
Johnston County

Received: January 15, 1988
Reviewed: May 5, 1988

ABSTRACT

The emissions from this new source are estimated to be 1.9 tons per year of particulate matter, 14.2 tons per year of sulfur dioxide, 39 tons per year of nitrogen oxides, 11 tons per year of carbon monoxide, and 0.9 tons per year of volatile organic compounds.

Approval of this permit application is recommended.

ANALYSIS

Whiteman Air Force Base in Johnson County currently has four boilers at its base heating plant, Boiler No.'s 1 through 4, which are used primarily for space heating. These boilers are each rated at 35,000 lb/hr of steam (52 MMBTU/hr) heat input, and are fueled primarily by natural gas, with No. 6 fuel oil used as backup. Boilers 1 through 3 were installed in 1953, while Boiler No. 4 was installed in 1984. Whiteman AFB made application on July 6, 1983 for authority to install Boiler No. 4, and was granted Permit Number 1083-003. Boiler No. 4 was added, not to increase total steam production capability, but to provide standby capacity so that the heating plant could operate at its current capacity with one boiler out of operation for maintenance. In order that no net increase in plant emissions would occur with the installation of this fourth boiler, a condition was made a part of the permit which limited the total steam production from the plant to 105,000 pounds of steam per hour, which was the plants steaming capacity with the three original boilers. Whiteman AFB chose this course of action in order to expedite issuance of the permit for Boiler No. 4.

Whiteman AFB now desires to expand its heating plant through the addition of a fifth boiler, with a heat input rate of 75 MMBTU/hr, and through the removal of the steam production cap of 105,000 pounds steam per hour, which was imposed at the time that Boiler No. 4 was added to the facility. These changes at this facility will be conditioned so that the net emissions increase will be below the de minimis emissions limits. The applicant desires that the net emissions increases from the proposed modifications at this facility be below the de minimis levels because the present facility has a potential emission rate of more that 250 tons per year of sulfur dioxide, meaning that it is presently an existing major source of air contaminant emissions. Any additions or modifications at this facility which would result in a net emissions increase over the de minimis emissions limits would require that this source undergo a review under the Prevention of Significant Deterioration (PSD) requirements.

EMISSIONS ANALYSIS - EXISTING FACILITY

The existing facility consists of the three boilers which were installed in 1953, and Boiler No. 4, which was installed under Permit Number 1083-003. Assuming the heat content for natural gas to be 1050 BTU/cf, the heat content for No. 6 fuel oil to be 150,000 BTU/gallon with a sulfur content of 1%, an ash content of 0.1%, and taking into account the limitation imposed by Permit No. 1083-003, the potential annual emission rate from the existing heating plant is:

POTENTIAL ANNUAL EMISSIONS, FOUR EXISTING BOILERS
subject to a cap on steam production of 105,000 lbs/hr

Pollutant	Natural Gas (tons/yr)	No. 6 Fuel Oil (tons/yr)
Particulate Matter	3.3	123.8
Sulfur Dioxide	0.4	694.3
Nitrogen Oxides	91.1	22.1
Carbon Monoxide	22.8	243.2
Volatile Organic Compounds	1.8	1.2

It is apparent that this facility currently meets the definition of an existing major source, as the potential emissions rate is in excess of 250 tons per year. Of course, the actual emissions are well below these levels, as it is the No. 6 fuel oil combustion which pushes this facility above the major source levels, and No. 6 is used only as a backup fuel - however, there is no federally enforceable condition limiting the use of No. 6 oil, so no credit can be taken in calculating potential to emit.

State Regulation 10 CSR 10-3.060 imposes a particulate emissions limit of 0.36 lb/MMBTU on the three boilers which were installed in 1953, equivalent to a particulate emission rate of 18.5 pounds per hour per boiler, and a particulate emissions limit of 0.22 lb/MMBTU on Number 4 boiler, equivalent to a particulate emissions rate from Number 4 boiler of 11.2 pounds per hour. The uncontrolled particulate emission rate from these boilers, when combusting No. 6 fuel oil, is 9.42 pounds per hour; these boilers therefore operate in compliance with 10 CSR 10-3.060 while combusting No. 6 fuel oil.

One avenue for insuring that a given addition or modification at an existing installation will not result in a net emissions increase of more than the de minimis emissions levels is to use internal offsets from the installation in question. These offsets must be obtained from measures which serve to reduce the actual emissions at an installation, and can serve to keep the net emissions increase at the facility below the de minimis emissions levels. These offsets can frequently be obtained by the applicant by its agreeing to limit the operation of sources within a facility, or by changing the fuels used within an installation. The average actual emissions from the operation of this facility over the past three years is estimated to be:

ACTUAL ANNUAL EMISSIONS, FOUR EXISTING BOILERS
calendar years 1985 through 1987 inclusive

Pollutant	Emissions (tons/yr)
Particulate Matter	0.9
Sulfur Dioxide	3.9
Nitrogen Oxides	16.7
Carbon Monoxide	4.1
Volatile Organic Compounds	0.3

It can be seen by the above table that the applicant cannot realistically use emissions offsets obtained by agreeing to reduce the existing actual emissions at this facility, as actual emissions are already very low. The applicants only other recourse is to accept permit conditions on Boilers No. 4 and 5 which will serve to limit the emissions of these boilers together to less than the de minimis levels.

EMISSIONS ANALYSIS - BOILERS No. 4 & 5

Whiteman AFB desires to remove the steam production limitation of 105,000 pounds per hour which was imposed at the time that Boiler No. 4 was added to this facility, and desires to add a fifth boiler to its heating plant. Boiler No. 4 has a heating capacity of 52 MMBTU/hr, and will be modified from its present status to fire either natural gas or No. 2 fuel oil, but will not have the capability to fire No. 6 fuel oil. Boiler No. 5 will have a heating capacity of 60,000 pounds per hour steam at 150 psig and saturated steam condition, equivalent to 75 MMBTU/hr, and will also fire either natural gas or No. 2 fuel oil. In order that the emission rate of nitrogen oxides not exceed 40 tons per year (the de minimis emission rate) this permit will be conditioned such that the natural gas burners be a low NOx design, that no more than 540 million cubic feet of natural gas may be combusted in Boilers No. 4 and 5 in any calendar year, and that no more than 500,000 gallons of No. 2 oil may be combusted in Boilers No. 4 and 5 in any calendar year. Assuming that the heat content for natural gas is 1050 BTU/cf and the heat content for No. 2 oil is 139,000 BTU per gallon with a sulfur content of 0.4%, the potential annual emissions rate from the combination of Boilers No. 4 & 5 would be:

POTENTIAL EMISSIONS, BOILERS No. 4 & 5
SUBJECT TO CONDITION NUMBER 1

Pollutant	Natural Gas (lb/hr)	Natural Gas (tons/yr)	No. 2 Fuel Oil (lb/hr)	No. 2 Fuel Oil (tons/yr)
Particulate Matter	0.6	1.4	1.9	0.5
Sulfur Dioxide	0.07	0.2	51.9	14.2
Nitrogen Oxides	15.2	34.0	18.3	5.0
Carbon Monoxide	4.2	9.7	4.6	1.3
Volatile Organic Compounds	0.3	0.8	0.2	0.1

State Regulation 10 CSR 10-3.060 will impose a particulate emissions limit of 0.19 lb/MMBTU on Boilers No. 4 & 5. This is equivalent to a particulate emission rate of 10.1 pounds per hour from Boiler No. 4; as this boiler will emit particulate matter at a rate of 0.8 pounds per hour while combusting No. 2 oil, it will operate in compliance with this regulation. This regulation imposes a particulate emission limit of 14.3 pounds per hour on particulate emissions from Boiler No. 5; as this boiler will emit particulate matter at a rate of 1.1 pounds per hour while combusting No. 2 oil, it will also operate in compliance with this regulation.

In order that the deminimis rate not be exceeded by the operation of Boilers No. 4 & 5, the emissions rates of all pollutants must remain below the de minimis emissions rates. This is done by limiting the usage of natural gas to 540 million cubic feet (MMCF) per calendar year, and limiting the usage of No. 2 fuel oil to 500,000 gallons per calendar year. Usage at these maximum rates will result in the emission of 34 tons of nitrogen oxides while combusting natural gas, and 5 tons of nitrogen oxides while burning the No. 2 fuel oil. Obviously, the use of natural gas can be increased if there is a proporportionate decrease in the usage of fuel oil, or vice-versa. However, for purposes of enforceability, the above usage rates have been chosen; should the applicant wish a different split on the usage rates, a suitable agreement can be entered into between the applicant and this department. Should the applicant wish the removal in their entirety of these fuel usage limitations, the applicant must undergo a review under the Prevention of Significant Deterioration (PSD) regulations.

It can be seen from the table below that the average annual consumption of natural gas over the past several years has been approximately 238 million cubic feet per year. Fuel oil consumption over the same time period has averaged 125,538 gallons of No. 6 oil annually, and in no case has it exceeded 630,000 gallons; for Boilers No. 4 and 5 to be restricted to 540 million cubic feet of natural gas and 500,000 gallons of No. 2 oil should prove no hardship. The following table shows historical fuel use data at Whiteman AFB.

WHITEMAN AIR FORCE BASE
HISTORICAL FUEL USAGE AND EMISSIONS DATA

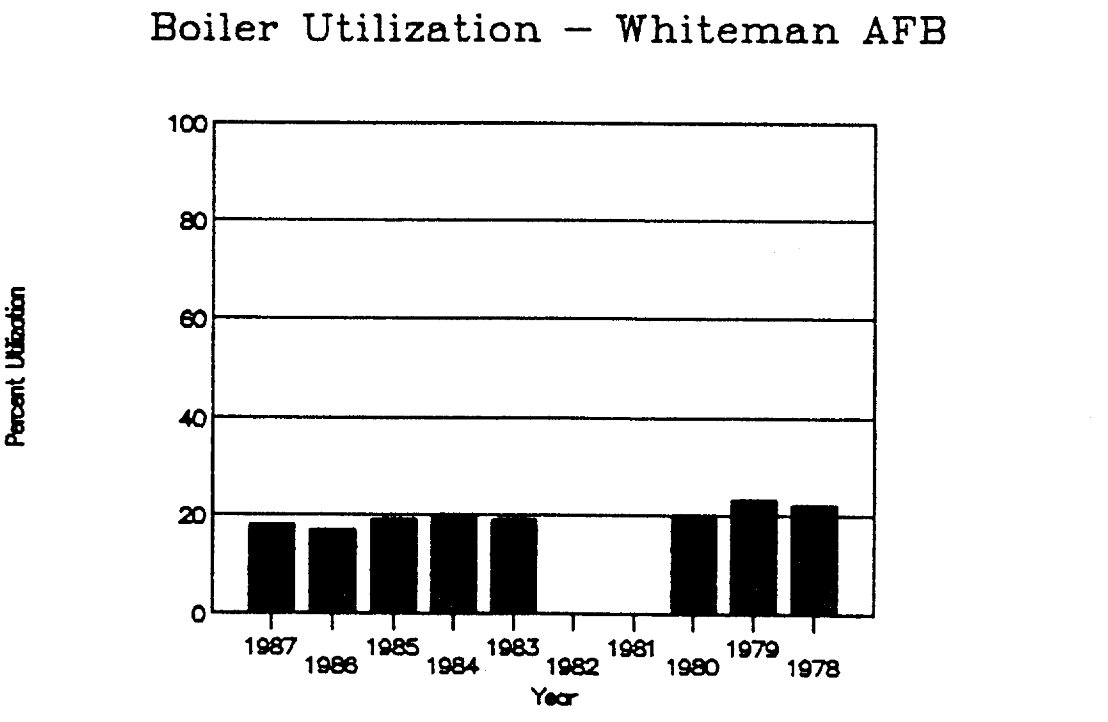
Year	Gas (MCF)	Oil (gal)	TSP	SO2	NOx	CO	VOC	Heat Usage	
					(tons)			Gas (MMBTU/yr)	Oil (MMBTU/yr)
1987	233,624	30	0.58	0.08	16.35	4.09	0.33	245,305	4.35
1986	215,475	60728	1.36	11.46	16.75	3.92	0.31	226,249	8805.6
1985	240,887	0	0.60	0.07	16.86	4.22	0.34	252,931	0
1984	254,106	400	0.64	0.15	17.80	4.45	0.36	266,811	58
1983	250,081	5900	0.70	1.18	17.67	4.39	0.35	262,585	855.5
1982		Data is unavailable for this year							
1981		Data is unavailable for this year							
1980	257,502	0	0.64	0.08	18.03	4.51	0.36	270,377	0
1979	206,211	626964	8.95	117.69	31.68	5.18	0.38	216,522	90910
1978	245,735	310282	4.79	58.29	25.73	5.08	0.39	258,022	44991

The restrictions imposed on these boilers have the effect of only allowing a 57 percent utilization of these two boilers, where percent utilization is calculated by dividing the allowable rate of usage of the boilers against a possible usage of 8760 hours per year. The following table shows that the past rates of boiler utilization at this facility have been much lower than the utilization rate allowed by the fuel use conditions in this permit, and in fact the boilers at Whiteman AFB have only been utilized at an average of only 15.3 percent during 1986.

Boiler Utilization as a Percentage of Capacity
Calendar Year 1986

Month	Boiler 1	Boiler 2	Boiler 3	Boiler 4	Total
January	24.94%	0.00%	53.33%	0.00%	19.57%
February	24.54%	0.00%	52.38%	0.00%	19.23%
March	6.20%	0.00%	46.59%	0.00%	13.20%
April	0.00%	0.00%	0.00%	25.80%	6.46%
May	0.18%	0.00%	0.00%	153.30%	38.38%
June	0.00%	1.27%	0.00%	31.40%	8.19%
July	0.00%	0.00%	0.00%	32.80%	8.22%
August	0.00%	8.06%	17.63%	22.70%	12.11%
September	0.00%	36.37%	2.21%	0.00%	9.65%
October	0.00%	7.33%	0.18%	35.10%	10.65%
November	0.00%	19.57%	0.00%	53.30%	18.22%
December	0.00%	29.89%	0.00%	46.65%	19.13%
Totals	4.54%	8.55%	14.20%	33.78%	15.27%

The following graph indicates that this rate of utilization has not varied significantly over the last several years. No data is available for the years 1981 and 1982.



These utilization rates support the contention that fuel limitations which will in effect limit the utilization of Boilers No. 4 & 5 will not have a deleterious effect on the operation of the base heating plant. However, the applicant does have the option, if it so chooses, to undergo a PSD review, which will allow it to remove the fuel usage restrictions.

AMBIENT AIR QUALITY IMPACT ANALYSIS

Ambient air quality modeling, using the ISCST model in a screening mode, indicates that the ambient air quality impact due to the operation of these two boilers will be:

AMBIENT AIR QUALITY IMPACT
Concentrations in micrograms per cubic meter

Pollutant	1-hr	3-hr	8-hr	24-hr	De Minimis Levels	NAAQS Standards
Particulate Matter	2.5	2.2	1.7	1.4	10 24-hr	150 24-hr
Sulfur Dioxide	68.1	61.4	47.8	38.0	13 24-hr	365 24-hr
Nitrogen Oxides	23.8	21.4	16.7	13.3	14 annual	100 annual
Carbon Monoxide	6.0	5.4	4.2	3.3	575 8-hr	10,000 8-hr
Volatile Organic Compounds	0.2	0.2	0.2	0.1	-	235 1-hr

The concentrations of all pollutants with the exception of sulfur dioxide are well under the de minimis ambient air quality impact levels. While the concentration of sulfur dioxide is predicted to be approximately 3 times the de minimis impact levels, these concentrations are still only 10 percent of the National Ambient Air Quality Standards. While a de minimis source may exceed the de minimis ambient air quality impact levels, it may not exceed the National Ambient Air Quality Standards.

CONCLUSIONS AND RECOMMENDATIONS

Summary

The potential annual emissions from the modifications proposed at this facility are:

Particulate Matter = 1.9 tons per year
Sulfur Dioxide = 14.4 tons per year
Nitrogen Oxides = 39.0 tons per year
Carbon Monoxide = 11.0 tons per year
Volatile Organic Compounds = 0.9 tons per year

Conditions

1. The maximum aggregate amount of No. 2 fuel oil combusted in Boilers Numbers 4 and 5 shall not exceed 500,000 gallons per year, with a sulfur content not to exceed 0.4 percent. Records shall be kept on-site recording the amount of No. 2 fuel oil combusted in Boiler Number 4 and Boiler Number 5 on a monthly basis, together with the sulfur content of the fuel oil. These records shall be made available to inspectors of the Missouri Department of Natural Resources.

2. The maximum aggregate amount of natural gas combusted in Boilers Numbers 4 and 5 shall not exceed 540 million cubic feet per year. Records shall be kept on-site recording the amount of natural gas combusted in Boiler Number 4 and Boiler Number 5 on a monthly basis. These records shall be made available to inspectors of the Missouri Department of Natural Resources.

3. The emission rate of nitrogen oxides from the operation of Boilers Numbers 4 and 5 shall not exceed a rate of 0.12 pounds of nitrogen oxides per million BTU firing rate.

4. In order to demonstrate that the emissions limit contained in Condition Number 3 of this permit will be met, performance testing shall be conducted in accordance with EPA Test Method 7, <u>Determination of Nitrogen Oxide Emissions From Stationary Sources</u>. This testing shall be conducted in accordance with the requirements of 40 CFR Part 60, Subparagraph 60.8.

5. Boilers Number 4 and 5 shall burn only natural gas or distillate fuel oil.

Recommendations

Approval of this permit application, subject to the above conditions, is recommended.

Michael Stansfield
Environmental Engineer
Air Pollution Control Program

Mike
Chief of Enforcement
Air Pollution Control Program