Eastern Kern Air Pollution Control District

Rule 425.2
BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN)

FINAL STAFF REPORT

March 8, 2018

Prepared by

Wunna Aung
Air Quality Engineer

Reviewed by

Glen Stephens, P.E.
Air Pollution Control Officer

Eastern Kern Air Pollution Control District
2700 "M" Street, Suite 302
Bakersfield, California 93301
(661) 862-5250 ● www.kernair.org

Table of Contents

I. BOARD ADOPTION 1

II. INTRODUCTION 1

III. RULE OVERVIEW 2

IV. EMISSIONS FROM BOILERS, STEAM GENERATORS, AND PROCESS HEATERS 2

V. NOx EMISSIONS REDUCTIONS (CONTROL TECHNOLOGIES) 2

VI. COST-EFFECTIVENESS 4

VII. APPLICABILITY 4

VIII. CHANGES IN RULE 425.2 5

IX. IMPACTS 8

X. SOCIOECONOMIC IMPACTS 9

XI. RULE APPROVAL PROCESS 9

APPENDIX A	AMENDED RULE 425.2, BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN) CLEAN VERSION
APPENDIX B	AMENDED RULE 425.2, BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN) STRIKEOUT UNDERLINE VERSION
APPENDIX C	RULE DEVELOPMENT COMMENTS
APPENDIX D	RESPONSE TO COMMENTS

I. BOARD ADOPTION

Amendments to Rule 425.2, Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen) was adopted by the Eastern Kern Air Pollution Control District's Governing Board on March 8, 2018 at the Tehachapi Police Department Community Room, located at 220 West "C" Street, Tehachapi, California and at the Ridgecrest City Hall, located at 100 West California Avenue, Ridgecrest, California.

II. INTRODUCTION

This staff report presents the amendments made to Rule 425.2, Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen). Rule 425.2 was originally adopted October 13, 1994 and amended April 6, 1995 and July 10, 1997. The primary reason for amending Rule 425.2 is to update NOx emission limits promulgated by the EPA. NOx compounds are precursors in the formation of ground level ozone and particulate matter. The District has nonattainment status for the federal 8-hour ozone standard. This staff report presents an extensive revision of the Rule.

On November 2, 2017 the District held a public rule development workshop at the Mojave Veteran's Building in Mojave, CA to present the proposed amendments to Rule 425.3. A 30-day public review and comment period followed the workshop ending December 4, 2017. The District received comments from industries by the close of the 30-day review period. The District also requested assessments of costs for installing NOx control technologies and received the assessments of cost letter on January 29, 2018.

A majority of Rule 425.2 proposed amendments are modeled after California Air Resources Board (ARB)'s *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters*[1]. Similar rules can also be found in Bay Area, San Diego, and Santa Barbara Air Pollution Control Districts.

Appendix A is the clean version of proposed Rule 425.2, Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen).

Appendix B shows all changes made to proposed Rule 425.2, Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen) in strikeout underline form.

Appendix C are the comments made by U.S. Borax, Inc. and Edwards Air Force Base following the 30-day review period.

Appendix D is cost-effectiveness analysis of installing Low NOx Burner, SCR and SNCR for U.S. Borax's 150 MMBtu/hr Boilers.

[1] Complete Document can be found at: https://www.arb.ca.gov/ractbarc/boilers.pdf

III. RULE OVERVIEW

Amended rule lowers the current NOx limits for boilers, steam generators and process heaters with rated heat input of 5 million Btu per hour or more and fired with gaseous and/or liquid fuels. For units with annual heat input of 90,000 therms or more during one or more of the three preceding years of operation, NOx emission levels shall not exceed 30 parts per million by volume (ppmv) when operated on gaseous fuel and 40 ppmv when operated on liquid fuel. For units with annual heat inputs of less than 90,000 therms, the requirements will be unchanged. Additionally, carbon monoxide (CO) emissions limits of 400 ppmv will be unchanged.

IV. EMISSIONS FROM BOILERS, STEAM GENERATORS, AND PROCESS HEATERS

Boilers, steam generators, and process heaters emit NOx from combustion of fuels. NOx is one of two precursors in the formation of ozone which is the primary component of smog. The second precursor is volatile organic compounds (VOCs). Because the District has nonattainment status for federal 8-hour ozone standard, the District is required to implement all feasible State and Federal measures to reduce emissions of ozone precursors, including NOx. NOx reacts photochemically with VOCs to form ozone. Ozone irritates human respiratory systems and damages plant life and property. Exposure to ozone can be associated with hospitalization for cardiopulmonary causes, asthma episodes, restrictions in physical activity, and premature death. NOx emissions from boilers, steam generators, and process heaters can also react with other pollutants to form airborne particles smaller than 2.5 micrometer (microns) in diameter called $PM_{2.5}$. When inhaled, $PM_{2.5}$ can travel deep into the lungs and reduce lung function.

V. NOx EMISSIONS REDUCTION (CONTROL TECHNOLOGIES)

Reducing NOx emissions from boilers, steam generators, and process heaters can be achieved by applying control technologies and they can be broken down into four methods. These are

A. Retrofitting of low-NOx-emitting burners;
B. Retrofitting of flue-gas-recirculation systems;
C. Installation of ammonia injection systems for selective noncatalytic reduction; and
D. Installation of ammonia injection systems along with catalytic reactors for selective catalytic reduction.

A. Low-NOx Burner

Low-NOx burners employ low excess air combustion, air staging, fuel staging, or combustion product recirculation to lower NOx formation in the flame. Low excess air combustion and combustion product recirculation decrease the oxygen available for NOx formation. Combustion product recirculation also lowers the bulk flame temperature, and consequently lowers the NOx formation rate and equilibrium concentration. Stage-air burners lower available oxygen at points in the combustion chamber where the temperature is high. Staged-fuel burners lower the temperature at points in the combustion chamber where available oxygen is high. Retrofitting of low-NOx burners may require derating of equipment because flame lengths may be significantly increased.

Low-NOx burners are applicable to most gas-fired and oil-fired units. For gas-fired units, the control effectiveness ranges from 10 to 55 percent. For units fired with low-nitrogen oil, the control effectiveness is expected to be within the same range.

B. Flue Gas Recirculation

Flue gas recirculation (FGR) for NOx control consists of extracting a portion of the flue gas from the economizer outlet and returning it to the furnace, admitting the flue gas through the furnace windbox. Flue gas recirculation lowers the bulk furnace gas temperature and reduces oxygen concentration in the combustion zone. A retrofit installation of FGR consists of adding a fan, ductwork, dampers, and controls as well as possibly having to increase existing fan horsepower due to increased draft loss FGR is an effective control technique for both gas-fired and distillate oil-fired units. FGR is not effective at reducing NOx formation originating from fuel-bound nitrogen. The control effectiveness of flue gas recirculation ranges from 60 to 70 percent for gas-fired units. The control effectiveness of FGR for units firing low-nitrogen oil is expected to be within the same range.

C. Selective Noncatalytic Reduction

Exxon Research and Engineering Company has developed, patented, and is offering for license, a noncatalytic process called Thermal DeNOx for removing oxides of nitrogen from flue gas in stationary combustion sources. Thermal DeNOx is based on the gas phase homogeneous reaction between NOx 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. In the temperature range of 1,600 to 2,200 degrees Fahrenheit, 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 DeNOx reaction down to 1,300°F.

NOx reductions of up to 90 percent have been demonstrated on oil field steam generators where favorable process conditions exist. DeNOx performance using earlier technology ranges from 50 to 70 percent reduction for most oil-fired and gas-fired process heaters and steam boilers.

D. Selective Catalytic Reduction

Selective catalytic reduction (SCR) refers to a process that chemically reduces NOx with NH_3 over a heterogeneous catalyst in the presence of oxygen (O_2). The process is termed selective because the reducing agent NH_3 preferentially attacks NOx rather than O_2. However, the O_2 enhances the reaction and is a necessary part of the reaction scheme. Thus, SCR is potentially applicable to flue gas under oxidizing conditions with greater than one percent excess O_2.

In theory a 1:1 stoichiometric molar ratio of NH_3 to NO is sufficient to reduce NOx to molecular nitrogen (N_2) and water vapor (H_2O). In practice a NH_3: NO ratio of 1:1 has typically reduced NOx emissions by 80 to 90 percent with a residual NH_3 concentration of less than 20 ppmv. The optimum temperature range for the catalytic reaction is 570°F to 845°F.

Selective catalytic reduction retrofitting requires a reactor, which contains the catalytic material, and an ammonia storage and injection system. Due to the increased pressure drop across the reactor, some increase in boiler fan capacity, or possibly an additional fan, may be necessary. SCR has been extensively employed in Japan on gas-fired and oil-fired industrial and utility boilers.

VI. COST-EFFECTIVENESS

ARB's *Determination of Reasonably Available Control Technology (RACT) and Best Available Retrofit Control Technology (BARCT) for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, 1991*, listed cost effectiveness for control technologies mentioned above.

VII. APPLICABILITY

Rule 425.2 will apply to any boiler, steam generator or process heater with rated heat input of 5 million Btu per hour or more with gaseous and/or liquid fuels.

VIII. CHANGES IN RULE 425.2

The following requirements have been added to Rule 425.2:

- The purpose of this Rule is to limit oxides of nitrogen (NOx) emissions from boilers, steam generators, and process heaters.

- Section V.A.2 shall not apply to any unit while forced to burn liquid fuel during time of natural gas curtailment. NOx emission limit shall not exceed 150 ppmv or 0.215 pounds per million Btu of heat input when burning liquid fuel. This exemption shall not exceed 168 cumulative hours of operation per calendar year excluding equipment testing not to exceed 48 hours per calendar year.

- 30 parts per million by volume (ppmv) or 0.036 pound per million Btu of heat input when operated on gaseous fuel.

- 40 parts per million by volume (ppmv) or 0.052 pounds per million Btu of heat input when operated on liquid fuel.

- The heat-input weighted averaged of the limits specified in Section V.A.1 and V.A.2 above when operated on combination of gaseous and liquid fuel.

- The owner or operator of Union Iron Works CA B21841-68 and Combustion Engineering CA B35362-74 with Permit to Operate issued before January 1, 1983 shall have the following NOx emission limits:

  1. 70 parts per million by volume (ppmv) or 0.084 pound per million Btu of heat input when operated on gaseous fuel.

  2. 115 parts per million by volume (ppmv) or 0.150 pound per million Btu of heat input when operated on liquid fuel.

The following figures have been added to Rule 425.2:

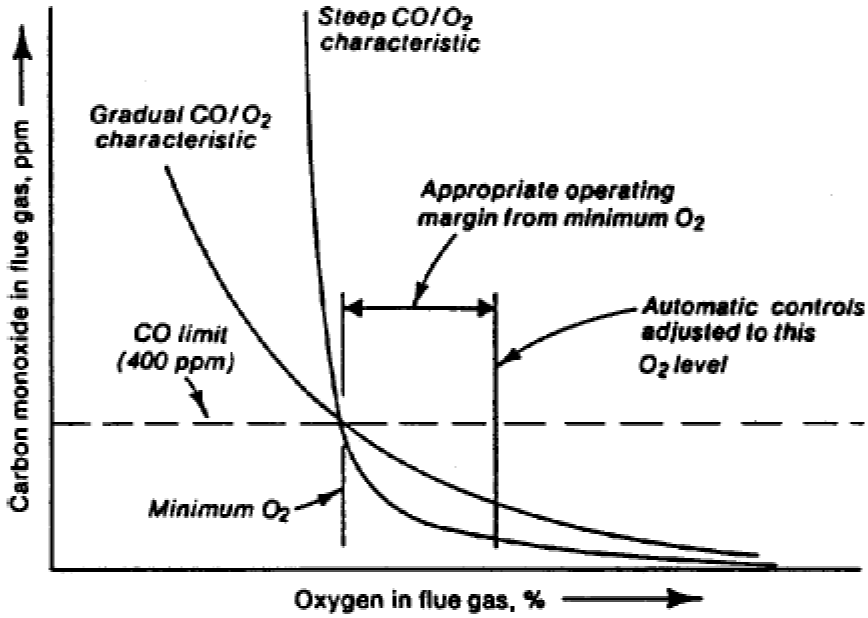

Figure 1: Oxygen/CO Characteristic Curve

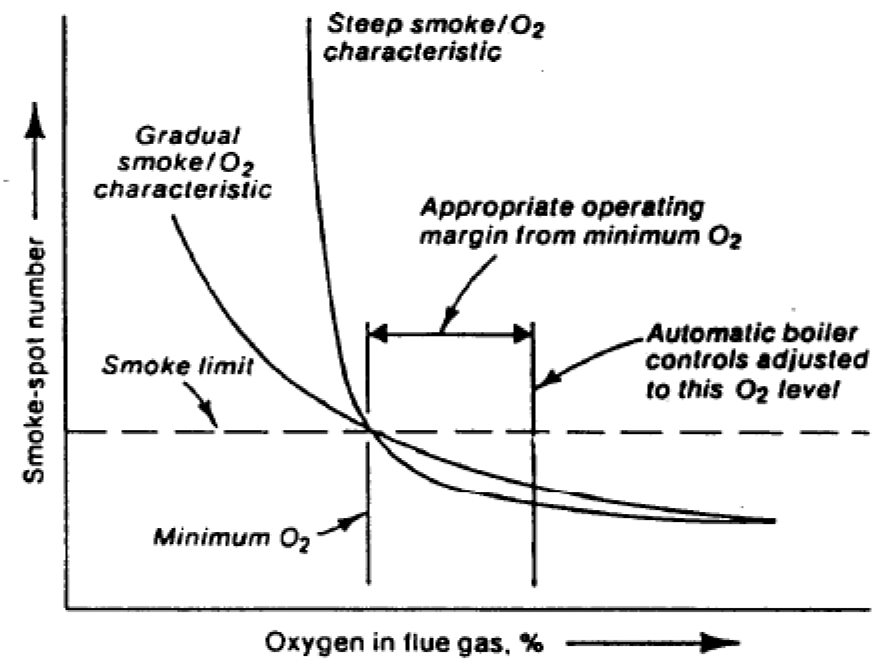

Figure 2: Oxygen/Smoke Characteristic Curve

The following requirements of Rule 425.2 have been revised:

- Definition of Natural gas curtailment has been revised from: ~~*loss of natural gas supply due to action of PUC-regulated supplier. For Section V curtailment limit to apply, curtailment must not exceed 168 cumulative hours of operation per calendar year, excluding equipment testing not to exceed 48 hours per calendar year.*~~ To: A shortage in the supply of natural gas, due solely to limitations or restrictions in distribution pipelines by the utility supplying natural gas, and not due to the cost of natural gas.

- Definition of Standard Conditions has been revised from: ~~*as defined in Rule 102, Subsection DD*~~. To: As defined in Rule 102, Subsection RR.

- Recordkeeping and reporting requirement (Section VI.A.4) has been revised from:

  ~~*Records shall be maintained for at least two calendar years on site and shall be made readily available to District personnel.*~~

  To:

  Records shall be maintained for a period of five (5) years and made available for District inspection at any time.

- Compliance testing requirement (Section VI.C.3) has been revised from:

  ~~*3. Test results from an individual unit may be used for other units at the same location provided manufacturer, model number, rated capacity, fuel type, and emission control provisions are identical and key operating parameters such as stack gas oxygen, fuel consumption, etc. are monitored and established to correlate with NOx emissions from unit tested.*~~

  To:

  3. Test results from an individual unit may be used for other units when the following criteria are met:

     a. Units are located at the same facility,
     b. Units are produced by the same manufacturer, have the same model number, and have the same rated capacity and operating specifications,
     c. Units are operated and maintained in a similar manner, and
     d. Based on documentation provided by the facility, District determines that the variability of emissions from tested unit is low enough for confidence that identical untested units will be in compliance.

4. An owner/operator utilizing Section VI.C.3 above is required to test all units at least once every thirty-six months. For example, testing one third of a fleet every year shall result in every unit being tested after three years, and not the same units being tested every year.

The following requirements of Rule 425.2 have been deleted:

- ~~*The purpose of this Rule is to limit oxides of nitrogen (NOx) emissions from boilers, steam generators, and process heaters to levels consistent with Reasonably Available Control Technology (RACT) to satisfy California Health and Safety Code Section 40918(b) and 1990 Federal Clean Air Act Amendments, Section 182(f). Carbon monoxide emissions are also limited to insure efficient combustion at reduced NOx levels.*~~

- ~~*Reasonably Available Control Technology (RACT) - lowest emission limitation a particular source is capable of meeting by application of control technology reasonably available considering technological and economic feasibility.*~~

-

	~~*Gaseous Fuel*~~	~~*Liquid Fuel*~~
~~*During Normal Operation*~~	~~*70 ppmv, or 0.09 lb/MMBtu*~~	~~*115 ppmv, or 0.15 lb/MMBtu*~~
~~*During Natural Gas Curtailment*~~	~~*----*~~	~~*150 ppmv, or 0.19 lb/MMBtu*~~

IX. IMPACTS

A. Economic

The potential economic impacts of this determination are the capital cost of emission control equipment and the increased operating cost associated with emission control equipment. If combustion equipment is operated with lower excess air after, or instead of, retrofitting control equipment; there will be a cost benefit due to increased thermal efficiency.

B. Air Quality

The most significant impact of this determination is the decrease in NOx emissions and resultant decrease in atmospheric ozone and PM_{10} formation. Other potential impacts include ammonia slip from SNCR and SCR systems and ammonia leakage from storage and handling systems, which will result in emissions of ammonia to the atmosphere. Ammonia emissions will increase the formation of PM_{10} in the atmosphere.

C. Hazards

Ammonia is a toxic, highly reactive compound and its use, storage, and transport can be hazardous, especially in the case of worker exposure to highly concentrated ammonia vapor or contact with liquid ammonia.

Occupational Safety and Health Administration (OSHA) regulations specify the methods for the use, storage, and transport of ammonia. There regulations were developed to reduce the hazards that could occur when handling ammonia.

The spent catalyst materials from the use of SCR commonly contain small amounts of hazardous materials, including vanadium pentoxide. This compound is toxic if inhaled. A majority of catalysts used in California are now reclaimed and recycled by the manufacturer, so that their disposal should pose no significant environmental impacts. For those facilities that do not recycle their catalysts, the spent material would have to be deposited in a Class I landfill. The only operational Class I disposal site in California is located in Kings County.

D. Energy

Additional fan energy will be required to operate FGR, SNCR, and SCR systems. All of the systems require additional mass flows and gas velocities, which will increase flow losses through the furnaces and downstream passages. The FGR ducting and SCR reactor are additional flow impedances.

X. SOCIOECONOMIC IMPACTS

CHSC Section 40728.5 exempts districts with a population of less than 500,000 persons from the requirement to assess the socioeconomic impacts of proposed rules. Eastern Kern County population is below 500,000 persons.

XI. RULE APPROVAL PROCESS

The District accepted written comments and concerns from persons interested in Rule 425.2 for a period of 30 days ending on December 4, 2017. Comments from U.S. Borax and Edward Air Force Base were received. They are addressed in Appendix C and D of this staff report. District adopted the amendments of Rule 425.2 at the March 2018 Board Hearing. Upon adoption, Rule 425.2 will be sent to ARB to be forwarded to EPA as revision to the SIP.

APPENDIX A:

AMENDED RULE 425.2

BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN)

CLEAN VERSION

RULE 425.2 <u>Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen)</u> – Adopted 10/13/94, Amended 4/6/95, 7/10/97, 3/8/18

I. Purpose

The purpose of this Rule is to limit oxides of nitrogen (NOx) emissions from boilers, steam generators, and process heaters.

II. Applicability

This Rule shall apply, as specified, to any boiler, steam generator or process heater operating in the Eastern Kern Air Pollution Control District (District) with rated heat input of 5 million Btu per hour or more and fired with gaseous and/or liquid fuels.

III. Definitions

A. <u>Annual Heat Input:</u> total heat released (therms) by fuel(s) burned in a unit during a calendar year as determined from higher heating value and cumulative annual fuel(s) usage.

B. <u>Boiler or Steam Generator:</u> any external combustion unit fired with liquid and/or gaseous fuel used to produce hot water or steam, but not including gas turbine engine exhaust gas heat recovery systems.

C. <u>British Thermal Unit (Btu):</u> amount of heat required to raise the temperature of one pound of water from 59°F to 60°F at one atmosphere.

D. <u>Gaseous Fuel:</u> any fuel existing as gas at standard conditions.

E. <u>Heat Input:</u> total heat released (Btu's) by fuel(s) burned in a unit as determined from higher heating value, not including sensible heat of incoming combustion air and fuel(s).

F. <u>Higher Heating Value (HHV):</u> total heat released per mass of fuel burned (Btu's per pound), when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to standard conditions.

G. <u>Liquid Fuel:</u> any fuel, including distillate and residual oil, existing as liquid at standard conditions.

H. <u>Natural Gas Curtailment</u>: a shortage in the supply of natural gas, due solely to limitations or restrictions in distribution pipelines by the utility supplying natural gas, and not due to the cost of natural gas.

I. <u>Oxides of Nitrogen (NOx):</u> total nitrogen oxides (expressed as NO_2).

J. <u>Process Heater</u>: any external combustion unit fired with liquid and/or gaseous fuel used to transfer heat from combustion gases to liquid process streams.

K. Rated Heat Input: heat input capacity (Btu's/hr) specified on nameplate of unit or by manufacturer for that model number, or as limited by District permit.

L. Standard Conditions: as defined in Rule 102, Subsection RR.

M. Therm: 100,000 British thermal units (Btu's).

N. Unit: any boiler, steam generator or process heater as defined in this Rule.

IV. Exemption

1. This Rule shall not apply to any unit with rated heat input less than 5 million Btu per hour.

2. Section V.A.2 shall not apply to any unit while forced to burn liquid fuel during time of natural gas curtailment. NOx emission limit shall not exceed 150 ppmv or 0.215 pounds per million Btu of heat input when burning liquid fuel. This exemption shall not exceed 168 cumulative hours of operation per calendar year excluding equipment testing not to exceed 48 hours per calendar year.

V. Requirements

A. An owner/operator of any unit subject to this Rule with annual heat input of 90,000 therms or more during one or more of the three preceding years of operation shall comply with following applicable NOx emission limit(s):

   1. 30 parts per million by volume (ppmv) or 0.036 pound per million Btu of heat input when operated on gaseous fuel.

   2. 40 parts per million by volume (ppmv) or 0.052 pound per million Btu of heat input when operated on liquid fuel.

   3. The heat-input weighted averaged of the limits specified in Section V.A.1 and V.A.2 above when operated on combination of gaseous and liquid fuel.

B. The owner/operator of Union Iron Works CA B21841-68 and Combustion Engineering CA B35362-74 with Permit to Operate issued before January 1, 1983 shall have the following NOx emission limit(s):

   1. 70 parts per million by volume (ppmv) or 0.084 pound per million Btu of heat input when operated on gaseous fuel.

   2. 115 parts per million by volume (ppmv) or 0.150 pound per million Btu of heat input when operated on liquid fuel.

For units subject to this Section, carbon monoxide (CO) emissions shall not exceed 400 parts per million by volume (ppmv).

NOx emission limit for any unit fired simultaneously with gaseous and liquid fuels shall be heat input-weighted average of applicable limits. Calculations shall be performed as prescribed in Section VIII.C.

NOx and CO emission limits in ppmv are referenced at dry stack gas conditions, adjusted to 3.00 percent by volume stack gas oxygen in accordance with Section VIII, and averaged over 15 consecutive minutes from no less than 5 data sets, recorded from sampling of no more than 3 minutes.

C. An owner/operator of any unit subject to this Rule with annual heat input rate of 90,000 therms or more shall comply, until March 8, 2021, and any unit with annual heat input rate of less than 90,000 therms shall comply with one of the following NOx minimization procedures:

1. Tune each unit at least once per year in accordance with Section IX.;

2. Operate each unit in a manner maintaining stack gas oxygen at no more than 3.00 percent by volume on dry basis; or

3. Operate each unit with an automatic stack gas oxygen trim system set at 3.00 (±0.15) percent by volume on dry basis.

D. Monitoring Requirements

1. An owner/operator of any unit simultaneously firing a combination of different fuels shall install and maintain a totalizing mass or volumetric flow rate meter in each fuel line.

2. An owner/operator of any unit utilizing equipment intended to reduce or control NOx shall install and maintain appropriate provisions to monitor operational parameters of unit and/or NOx control system that correlate to NOx emissions.

E. Compliance Demonstration

1. An owner/operator of any unit subject to Section V shall have the option of complying with either concentration (ppmv) emission limits or heat input basis (lb/MMBtu) emission limits as specified in Section V. All compliance demonstrations shall be performed using applicable test method(s) specified in Section VI.B and methods selected to demonstrate compliance shall be specified in Emission Control Plan required by Section VI.D.

2. All emission measurements shall be made with unit operating at conditions as close as physically possible to maximum firing rate allowed by the District Permit to Operate.

VI. Administrative Requirements

A. Recordkeeping and Reporting

1. An owner/operator of any unit subject to this Rule or limited by permit condition to firing less than 5 million Btu's/hr shall monitor and record HHV and cumulative annual use of each fuel.

2. An owner/operator of any unit operated under natural gas curtailment limit of Section V.A shall monitor and record cumulative annual hours of operation on liquid fuel during curtailment and during testing.

3. An owner/operator of any identical units wishing to limit emissions testing to one unit per group of units pursuant to Section VI.C shall establish correlation of NOx emissions and key operating parameters and keep records of these data for each affected unit.

4. Records shall be maintained for a period of five (5) years and made available for District inspection at any time.

5. Compliance test data and results collected to satisfy Section VI.C shall be submitted to District within 60 days of collection.

B. Test Methods

1. Fuel HHV shall be certified by third party fuel supplier or determined by:

    a. ASTM D 240-87 or D 2382-88 for liquid fuels; and

    b. ASTM D 1826-88 or D 1945-81 in conjunction with ASTM D 3588-89 for gaseous fuels.

2. Oxides of nitrogen (ppmv) - EPA Method 7E, or CARB Method 100.

3. Carbon monoxide (ppmv) - EPA Method 10, or CARB Method 100.

4. Stack gas oxygen - EPA Method 3 or 3A, or CARB Method 100.

5. NOx emission rate (heat input basis) - EPA Method 19, or CARB Method 100 and data from fuel flow meter.

6. Stack gas velocity - EPA Method 2.

7. Stack gas moisture content - EPA Method 4.

C. Compliance Testing

1. Units subject to requirements of Section V shall be tested to determine compliance with applicable requirements not less than once every 12 months. An owner/operator of gaseous fuel-fired units demonstrating compliance for two consecutive years can, if desired, demonstrate compliance once every thirty-six months.

2. An owner/operator of any unit subject to Section V.C.2 shall sample and record stack gas oxygen content at least monthly.

3. Test results from an individual unit may be used for other units when the following criteria are met:

   a. Units are located at the same facility,
   b. Units are produced by the same manufacturer, have the same model number, and have the same rated capacity and operating specifications,
   c. Units are operated and maintained in a similar manner, and
   d. Based on documentation provided by the facility, District determines that the variability of emissions from tested unit is low enough for confidence that identical untested units will be in compliance.

4. An owner/operator utilizing Section VI.C.3 above is required to test all units at least once every thirty-six months. For example, testing one third of a fleet every year shall result in every unit being tested after three years, and not the same units being tested every year.

D. Emission Control Plan

An owner/operator of any unit subject to this Rule shall submit to Control Officer an Emission Control Plan including:

1. List of units subject to Rule, including rated heat inputs, anticipated annual heat input, applicable Section V requirements, and control option chosen, if applicable;

2. Description of actions to be taken to satisfy requirements of Section V. Such plan shall identify actions to be taken to comply, including any type of emissions control to be applied to each unit and construction schedule, or shall include test results to demonstrate unit already complies with applicable requirements; and

3. Specification of proposed test methods.

VII. Compliance Schedule

A. An owner/operator of any unit subject to Section V shall comply with following schedule:

1. By October 1, 2018, submit to Control Officer an Emission Control Plan pursuant to Section VI.D, and a complete application for Authority to Construct emission control equipment, if necessary;

2. By January 31, 2019 demonstrate compliance with Section V.C; and

3. By March 8, 2021 demonstrate full compliance with all additional and applicable provisions of this Rule.

B. An owner/operator of any unit becoming subject to requirements of Section V.A by exceeding the annual heat input exemption threshold shall comply with following increments of progress:

1. On or before December 31st of calendar year immediately following year annual heat input threshold was exceeded, submit an Emission Control Plan containing information prescribed in Section VI.D; and

2. No later than three calendar years following submission of Emission Control Plan, demonstrate final compliance with all applicable standards and requirements of this Rule.

VIII. Calculations

A. All ppmv emission limits specified in Section V are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen as follows:

$$[\text{ppmv NOx}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O_2]_{\text{measured}}} \times [\text{ppmv NOx}]_{\text{measured}}$$

$$[\text{ppmv CO}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O_2]_{\text{measured}}} \times [\text{ppmv CO}]_{\text{measured}}$$

B. All lb/MMBtu NOx emission rates shall be calculated as pounds of nitrogen dioxide per million Btu's of heat input (HHV).

C. Heat input-weighted average NOx emission limit for combination of gaseous and liquid fuel shall be calculated as follows:

$$\text{NOx Emission Limit} = \frac{(30\text{ ppmv} \times X) + (40\text{ ppmv} \times Y)}{X + Y}$$

Where X = heat input from gaseous fuel and Y = heat input from liquid fuel.

IX. NOx Minimization Tuning Procedures

A. Purpose

The purpose of these procedures is to provide a reasonable, cost-effective method to minimize NOx emissions from smaller, or low-fire/low use-rate combustion units subject to this Rule. These procedures not only minimize NOx emissions, but also result in reduced operating costs.

B. Equipment Tuning Procedure[2] for Mechanical Draft Boilers, Steam Generators, and Process Heaters

Nothing in this Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, California Department of Industrial Relations (Occupational Safety and Health Division), Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate unit at firing rate most typical of normal operation. If unit experiences significant load variations during normal operation, operate at its average firing rate.

2. At this firing rate, record stack gas temperature, oxygen concentration, and CO concentration (for gaseous fuels) or smoke spot number[3] (for liquid fuels), and observe flame conditions after unit operation stabilizes at firing rate selected. If excess oxygen in the stack gas is at lower end of range of typical minimum values[4]; and if CO emissions are low and there is no smoke, unit is probably operating at near optimum efficiency - at this particular firing rate. However, complete remaining portion of this procedure to determine whether still lower oxygen levels are practical.

3. Increase combustion air flow to unit until stack gas oxygen levels increase by one to two percent over level measured in Step 2. As in Step 2, record stack gas temperature, CO concentration (for gaseous fuels) or smoke spot number (for liquid fuels), and observe flame conditions for these higher oxygen levels after unit operation stabilizes.

4. Decrease combustion air flow until stack gas oxygen concentration is at level measured in Step 2. From this level gradually reduce combustion air flow, in small increments. After each increment, record stack gas temperature, oxygen concentration, CO concentration (for gaseous fuels) and smoke-spot number (for liquid fuels). Also, observe flame and record any changes in its condition.

---

[2] This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for U.S. EPA.
[3] The smoke-spot number can be determined with ASTM Test Method D-2156 or with the Bacharach method.
[4] Typical minimum oxygen levels for boilers at high firing rates are:
For natural gas: 0.5% to 3% and For liquid fuels: 2% to 4%.

5. Continue to reduce combustion air flow stepwise, until one of these limits is reached:

    a. Unacceptable flame conditions- such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability,

    b. Stack gas CO concentrations greater than 400 ppmv,

    c. Smoking at the stack, or

    d. Equipment-related limitations such as low windbox/furnace pressure differential, built in air-flow limits, etc.

6. Develop O_2/CO curve (for gaseous fuels) or O_2/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2 using excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.

7. From curves prepared in Step 6, find stack gas oxygen levels where CO emissions or smoke-spot number equal following values:

Fuel	Measurement	Value
Gaseous	CO Emissions	400 ppmv
#1 and #2 Oils	smoke-spot number	number 1
#4 Oil	smoke-spot number	number 2
#5 Oil	smoke-spot number	number 3
Other Oils	smoke-spot number	number 4

    Above conditions are referred to as CO or smoke thresholds, or as minimum excess oxygen levels.

    Compare this minimum value of excess oxygen to expected value provided by combustion unit manufacturer. If minimum level found is substantially higher than value provided by combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mix, thereby allowing operations with less air.

8. Add 0.5 to 2.0 percent to minimum excess oxygen level determined in Step 7 and reset burner controls to operate automatically at this higher stack gas oxygen level. This margin above minimum oxygen level accounts for fuel variations, variations in atmospheric conditions, load changes, and nonrepeatability or "play" in automatic controls.

9. If load of unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent upper and lower limits of range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish optimum excess oxygen level at all firing rates. If this is the case, choose burner control settings that give best performance over range of firing rates. If one firing rate predominates, setting should optimize conditions at that rate.

10. Verify that new settings can accommodate sudden load changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing flame and stack. If any of conditions in Step 5 result, reset combustion control to provide slightly higher level of excess oxygen at affected firing rates. Next verify these new settings in a similar fashion. Then make sure that final control settings are recorded at steady-state operating conditions for future reference.

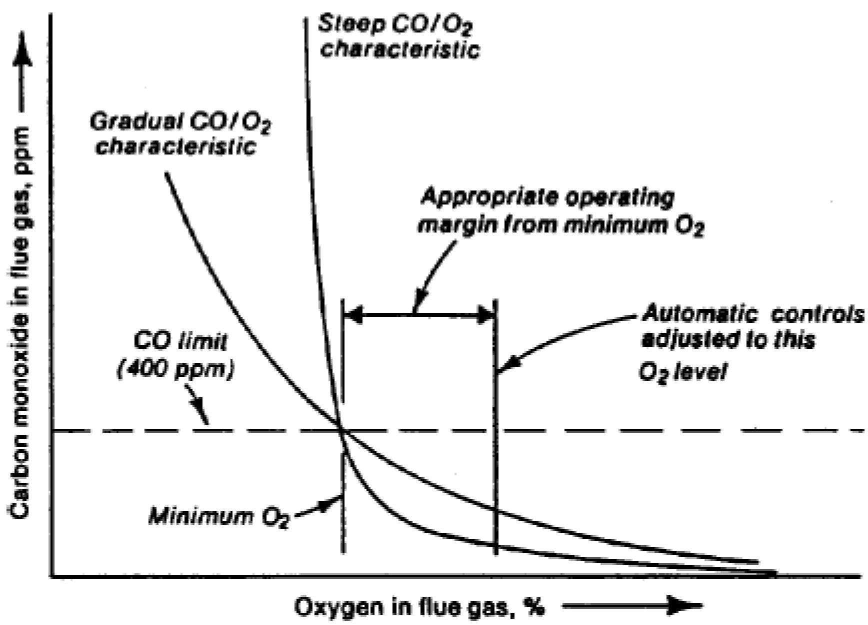

Figure 1: Oxygen/CO Characteristic Curve

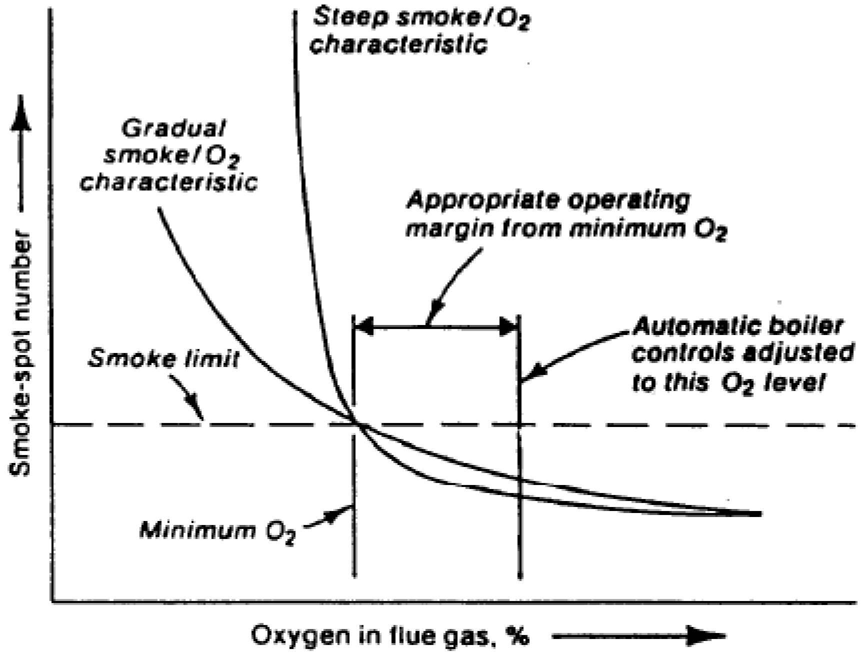

Figure 2: Oxygen/Smoke Characteristic Curve

C. Equipment Tuning Procedure[5] for Natural and Induced-Draft Boilers, Steam Generators, and Process Heaters

Nothing in this Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Preliminary analysis

   a. Check operating pressure or temperature. Operate unit at lowest acceptable pressure or temperature that will satisfy load demand. Determine pressure or temperature that will be used as basis for comparative combustion analysis before and after tune-up.

   b. Check operating hours. Plan workload so that unit operates only the minimum hours and days necessary to perform work required.

   c. Check air supply. Area of air supply openings must be in compliance with applicable codes and regulations. Air openings must be kept wide open when burner is firing and clean from restriction to flow.

[5] This tuning procedure is based on a tune-up procedure developed by Parker Boiler for South Coast AQMD.

d. Check vent. Check to be sure vent is in good condition, sized properly and with no obstructions.

e. Perform combustion analysis. Perform an "as is" flue gas analysis (O_2, CO, CO_2, etc.) at high and low fire, if possible. In addition to data obtained from combustion analysis, also record following:

1) Inlet fuel pressure at burner (at high and low fire),
2) Draft at inlet of draft hood or barometric damper at high, medium, and low settings, if applicable,
3) Steam pressure, water temperature, or process fluid pressure or temperature entering and leaving unit, and
4) Unit rate, if meter is available.

With above conditions recorded, make following checks and corrective actions as necessary.

2. Checks and Corrections

a. Check burner condition. Clean burners and burner orifices thoroughly. To clean burners effectively all burners must be removed, blown out with high pressure air and checked for obstructions. All accumulated sediment, dirt, and carbon must be removed. Check for smooth lighting and even flame. Also, ensure that fuel filters and moisture traps are in place, clean, and operating properly, to prevent plugging of gas orifices. Confirm proper location and orientation of burner diffuser spuds, gas canes, etc. Look for any burned-off or missing burner parts, and replace as needed.

b. Check for clean boiler, steam generator, or process heater tubes and heat transfer surfaces. Clean tube surfaces, remove scale and soot, assure proper fluid flow, and flue gas flow.

c. Check water treatment and blowdown program. Employ timely flushing and periodic blowdown to eliminate sediment and scale build-up in heat exchange tubes.

d. Check for steam hot water or process fluid leaks. Repair all leaks immediately. Be sure there are no leaks through the blow-off drains, safety valve, by-pass lines or at the feed pump, if used.

3. Safety Checks

a. Test primary and secondary low water level controls.

b. Check operating and limit pressure and temperature controls.

c. Check safety valve pressure and capacity to meet boiler, steam generator, or process heater requirements.

d. Check limit safety control and spill switch.

4. Adjustments

While taking combustion readings with unit at operating temperature and at high fire perform checks and adjustments as follows:

a. Adjust unit to fire at rated capacity. Record fuel manifold pressure.

b. Adjust draft and/or fuel pressure to obtain efficient, clean combustion at both high, medium and low fire. Carbon monoxide value should always be below 400 ppm at 3% O_2. If CO is high make necessary adjustment such as increasing draft. Check to ensure burner light offs are smooth and safe. A reduced fuel pressure test at both high and low fire should be conducted in accordance with manufacturer's instructions and maintenance manuals.

c. Check and adjust operation of modulation controller. Insure proper, efficient and clean combustion through range of firing rates. When above adjustments and corrections have been made, record all data.

5. Final Test

Perform final combustion analysis with unit at operating temperature and at high, medium, and low fire, whenever possible. In addition to data from combustion analysis, also check and record:

a. Fuel pressure at burner (high, medium, and low settings, if applicable).

b. Draft at inlet or above draft hood or barometric damper (high, medium, and low settings, if applicable).

c. Steam pressure or water temperature entering and leaving unit.

d. Unit rate, if fuel meter is available.

When above checks and adjustments have been made, record data and attach combustion analysis data to boiler, steam generator, or process heater records indicating name and signature of person, title, company name, company address and date tune-up was performed.

APPENDIX B:

AMENDED RULE 425.2

BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN)

STRIKEOUT UNDERLINE VERSION

RULE 425.2 **Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen)** – Adopted 10/13/94, Amended 4/6/95, 7/10/97, 3/8/18

I. Purpose

The purpose of this Rule is to limit oxides of nitrogen (NOx) emissions from boilers, steam generators, and process heaters. ~~to levels consistent with Reasonably Available Control Technology (RACT) to satisfy California Health and Safety Code Section 40918(b) and 1990 Federal Clean Air Act Amendments, Section 182(f). Carbon monoxide emissions are also limited to insure efficient combustion at reduced NOx levels.~~

II. Applicability

This Rule shall apply, as specified, to any boiler, steam generator or process heater operating in the Eastern Kern Air Pollution Control District (District) with rated heat input of 5 million Btu per hour or more and fired with gaseous and/or liquid fuels.

III. Definitions

A. Annual Heat Input: – total heat released (therms) by fuel(s) burned in a unit during a calendar year as determined from higher heating value and cumulative annual fuel(s) usage.

B. Boiler or Steam Generator: – any external combustion unit fired with liquid and/or gaseous fuel used to produce hot water or steam, but not including gas turbine engine exhaust gas heat recovery systems.

C. British Thermal Unit (Btu): – amount of heat required to raise the temperature of one pound of water from 59°F to 60°F at one atmosphere.

D. Gaseous Fuel: – any fuel existing as gas at standard conditions.

E. Heat Input: – total heat released (Btu's) by fuel(s) burned in a unit as determined from higher heating value, not including sensible heat of incoming combustion air and fuel(s).

F. Higher Heating Value (HHV): – total heat released per mass of fuel burned (Btu's per pound), when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to standard conditions.

G. Liquid Fuel: – any fuel, including distillate and residual oil, existing as liquid at standard conditions.

H. Natural G~~g~~as C~~c~~urtailment: a shortage in the supply of natural gas, due solely to limitations or restrictions in distribution pipelines by the utility supplying natural gas, and not due to the cost of natural gas. ~~– loss of natural gas supply due to action of PUC-regulated supplier. For Section V curtailment limit to apply, curtailment must~~

~~not exceed 168 cumulative hours of operation per calendar year, excluding equipment testing not to exceed 48 hours per calendar year.~~

I. Oxides of Nitrogen (NOx): - total nitrogen oxides (expressed as NO_2).

J. Process Heater: - any external combustion unit fired with liquid and/or gaseous fuel used to transfer heat from combustion gases to liquid process streams.

~~X. Reasonably Available Control Technology (RACT) - lowest emission limitation a particular source is capable of meeting by application of control technology reasonably available considering technological and economic feasibility.~~

~~XI.~~ K. Rated Heat Input: - heat input capacity (Btu's/hr) specified on nameplate of unit or by manufacturer for that model number, or as limited by District permit.

~~XII.~~ L. Standard Conditions: - as defined in Rule 102, Subsection RR~~DD~~.

~~XIII.~~ M. Therm: - 100,000 British thermal units (Btu's).

~~XIV.~~ N. Unit: - any boiler, steam generator or process heater as defined in this Rule.

IV. Exemption

1. This Rule shall not apply to any unit with rated heat input less than 5 million Btu~~'s~~ per hour.

2. Section V.A.2 shall not apply to any unit while forced to burn liquid fuel during time of natural gas curtailment. NOx emission limit shall not exceed 150 ppmv or 0.215 pounds per million Btu of heat input when burning liquid fuel. This exemption shall not exceed 168 cumulative hours of operation per calendar year excluding equipment testing not to exceed 48 hours per calendar year.

V. Requirements

A. An owner/operator of any unit subject to this Rule with annual heat input of 90,000 therms or more during one or more of the three preceding years of operation shall comply with following applicable NOx emission limit(s):

1. 30 parts per million by volume (ppmv) or 0.036 pound per million Btu of heat input when operated on gaseous fuel.

2. 40 parts per million by volume (ppmv) or 0.052 pound per million Btu of heat input when operated on liquid fuel.

3. The heat-input weighted averaged of the limits specified in Section V.A.1 and V.A.2 above when operated on combination of gaseous and liquid fuel.

B. The owner/operator of Union Iron Works CA B21841-68 and Combustion Engineering CA B35362-74 with Permit to Operate issued before January 1, 1983 shall have the following NOx emission limits(s):

1. 70 parts per million by volume (ppmv) or 0.084 pound per million Btu of heat input when operated on gaseous fuel.

2. 115 parts per million by volume (ppmv) or 0.150 pounds per million Btu of heat input when operated on liquid fuel.

	~~Gaseous Fuel~~	~~Liquid Fuel~~
~~During Normal Operation~~	~~70 ppmv, or 0.09 lb/MMBtu~~	~~115 ppmv, or 0.15 lb/MMBtu~~
~~During Natural Gas Curtailment~~	~~----~~	~~150 ppmv, or 0.19 lb/MMBtu~~

For units subject to this Section, carbon monoxide (CO) emissions shall not exceed 400 parts per million by volume (ppmv).

NOx emission limit for any unit fired simultaneously with gaseous and liquid fuels shall be heat input-weighted average of applicable limits. Calculations shall be performed as prescribed in Section VIII.C.

NOx and CO emission limits in ppmv are referenced at dry stack gas conditions, adjusted to 3.00 percent by volume stack gas oxygen in accordance with Section VIII, and averaged over 15 consecutive minutes from no less than 5 data sets, recorded from sampling of no more than 3 minutes.

~~B.~~C. An owner/operator of any unit subject to this Rule with annual heat input rate of 90,000 therms or more shall comply, until March~~November~~ 8~~3~~0, 2021~~1997~~, and any unit with annual heat input rate of less than 90,000 therms shall comply with one of the following NOx minimization procedures:

1. Tune each unit at least once per year in accordance with Section IX.;

2. Operate each unit in a manner maintaining stack gas oxygen at no more than 3.00 percent by volume on dry basis; or

3. Operate each unit with an automatic stack gas oxygen trim system set at 3.00 (±0.15) percent by volume on dry basis.

~~C.~~D. Monitoring Requirements

1. An owner/operator of any unit simultaneously firing a combination of different fuels shall install and maintain a totalizing mass or volumetric flow rate meter in each fuel line.

2. An owner/operator of any unit utilizing equipment intended to reduce or control NOx shall install and maintain appropriate provisions to monitor operational parameters of unit and/or NOx control system that correlate to NOx emissions.

~~D.~~E. Compliance Demonstration

1. An owner/operator of any unit subject to Section V.A shall have the option of complying with either concentration (ppmv) emission limits or heat input basis (lb/MMBtu) emission limits as specified in Section V.A. All compliance demonstrations shall be performed using applicable test method(s) specified in Section VI.B and methods selected to demonstrate compliance shall be specified in Emission Control Plan required by Section VI.D.

2. All emission measurements shall be made with unit operating at conditions as close as physically possible to maximum firing rate allowed by the District~~KCAPCD~~ Permit to Operate.

VI. Administrative Requirements

A. Recordkeeping and Reporting

1. An owner/operator of any unit subject to this Rule or limited by permit condition to firing less than 5 million Btu's/hr shall monitor and record HHV and cumulative annual use of each fuel.

2. An owner/operator of any unit operated under natural gas curtailment limit of Section V.A shall monitor and record cumulative annual hours of operation on liquid fuel during curtailment and during testing.

3. An owner/operator of any identical units wishing to limit emissions testing to one unit per group of units pursuant to Section VI.C shall establish correlation of NOx emissions and key operating parameters and keep records of these data for each affected unit.

4. Records shall be maintained for a period of five (5) years and made available for District inspection at any time~~for at least two calendar years on site and shall be made readily available to District personnel~~.

5. Compliance test data and results collected to satisfy Section VI.C shall be submitted to District within 60 days of collection.

B. Test Methods

1. Fuel HHV shall be certified by third party fuel supplier or determined by:

   a. ASTM D 240-87 or D 2382-88 for liquid fuels; and

   b. ASTM D 1826-88 or D 1945-81 in conjunction with ASTM D 3588-89 for gaseous fuels.

2. Oxides of nitrogen (ppmv) - EPA Method 7E, or CARB Method 100.

3. Carbon monoxide (ppmv) - EPA Method 10, or CARB Method 100.

4. Stack gas oxygen - EPA Method 3 or 3A, or CARB Method 100.

5. NOx emission rate (heat input basis) - EPA Method 19, or CARB Method 100 and data from fuel flow meter.

6. Stack gas velocity - EPA Method 2.

7. Stack gas moisture content - EPA Method 4.

C. Compliance Testing

1. Any unit subject to requirements of Section V.A shall be tested to determine compliance with applicable requirements not less than once every 12 months. An owner/operator of gaseous fuel-fired units demonstrating compliance for two consecutive years can, if desired, demonstrate compliance once every thirty-six months.

2. An owner/operator of any unit subject to Section V.B.2 shall sample and record stack gas oxygen content at least monthly.

3. Test results from an individual unit may be used for other units when the following criteria are met:~~at the same location provided manufacturer, model number, rated capacity, fuel type, and emission control provisions are identical and key operating parameters such as stack gas oxygen, fuel consumption, etc. are monitored and established to correlate with NOx emissions from unit tested.~~

   a. Units are located at the same facility,
   b. Units are produced by the same manufacturer, have the same model number, and have the same rated capacity and operating specifications,
   c. Units are operated and maintained in a similar manner, and
   d. Based on documentation provided by the facility, District determines that the variability of emissions from tested unit is low enough for confidence that identical untested units will be in compliance.

4. An owner/operator utilizing Section VI.C.3 above is required to test all units at least once every thirty-six months. For example, testing one third of a fleet every year shall result in every unit being tested after three years, and not the same units being tested every year.

D. Emission Control Plan

An owner/operator of any unit subject to this Rule shall submit to Control Officer an Emission Control Plan including:

1. List of units subject to Rule, including rated heat inputs, anticipated annual heat input, applicable Section V requirements, and control option chosen, if applicable;

2. Description of actions to be taken to satisfy requirements of Section V. Such plan shall identify actions to be taken to comply, including any type of emissions control to be applied to each unit and construction schedule, or shall include test results to demonstrate unit already complies with applicable requirements; and

3. Specification of proposed test methods.

VII. Compliance Schedule

A. An owner/operator of any unit subject to Section V shall comply with following schedule:

1. By October~~March~~ 1, 2018~~1995~~, submit to Control Officer an Emission Control Plan pursuant to Section VI.D, and a complete application for Authority to Construct emission control equipment, if necessary;

2. By January~~May~~ 31, 2019~~1995~~ demonstrate compliance with Section V.~~B~~C; and

3. By March~~November~~ 8~~3~~0, 2021~~1997~~ demonstrate full compliance with all additional and applicable provisions of this Rule.

B. An owner/operator of any unit becoming subject to requirements of Section V.A by exceeding the annual heat input exemption threshold shall comply with following increments of progress:

1. On or before December 31st of calendar year immediately following year annual heat input threshold was exceeded, submit an Emission Control Plan containing information prescribed in Section VI.D; and

2. No later than three calendar years following submission of Emission Control Plan, demonstrate final compliance with all applicable standards and requirements of this Rule.

VIII. Calculations

A. All ppmv emission limits specified in Section V.A are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen as follows:

$$[\text{ppmv NOx}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O_2]_{\text{measured}}} \times [\text{ppmv NOx}]_{\text{measured}}$$

$$[\text{ppmv CO}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O_2]_{\text{measured}}} \times [\text{ppmv CO}]_{\text{measured}}$$

B. All lb/MMBtu NOx emission rates shall be calculated as pounds of nitrogen dioxide per million Btu's of heat input (HHV).

C. Heat input-weighted average NOx emission limit for combination of ~~natural~~ gaseous and liquid fuel shall be calculated as follows:

$$\text{NOx Emission Limit} = \frac{(30\text{ ppmv} \times \text{X}) + (40\text{ ppmv} \times \text{Y})}{\text{X} + \text{Y}}$$

Where X = heat input from gaseous fuel and Y = heat input from liquid fuel.

IX. NOx Minimization Tuning Procedures

A. Purpose

The purpose of these procedures is to provide a reasonable, cost-effective method to minimize NOx emissions from smaller, or low-fire/low use-rate combustion units subject to this Rule. These procedures not only minimize NOx emissions, but also result in reduced operating costs.

B. Equipment Tuning Procedure[6] for Mechanical Draft Boilers, Steam Generators, and Process Heaters

Nothing in this Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, California Department of Industrial Relations (Occupational Safety and Health Division), Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate unit at firing rate most typical of normal operation. If unit experiences significant load variations during normal operation, operate at its average firing rate.

2. At this firing rate, record stack gas temperature, oxygen concentration, and CO concentration (for gaseous fuels) or smoke spot number[7] (for liquid fuels), and observe flame conditions after unit operation stabilizes at firing rate selected. If excess oxygen in the stack gas is at lower end of range of typical minimum values[8]; and if CO emissions are low and there is no smoke, unit is probably operating at near optimum efficiency - at this particular firing rate. However, complete remaining portion of this procedure to determine whether still lower oxygen levels are practical.

[6] This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for U.S. EPA.
[7] The smoke-spot number can be determined with ASTM Test Method D-2156 or with the Bacharach method.
[8] Typical minimum oxygen levels for boilers at high firing rates are:
For natural gas: 0.5% to 3% and For liquid fuels: 2% to 4%.

3. Increase combustion air flow to unit until stack gas oxygen levels increase by one to two percent over level measured in Step 2. As in Step 2, record stack gas temperature, CO concentration (for gaseous fuels) or smoke spot number (for liquid fuels), and observe flame conditions for these higher oxygen levels after unit operation stabilizes.

4. Decrease combustion air flow until stack gas oxygen concentration is at level measured in Step 2. From this level gradually reduce combustion air flow, in small increments. After each increment, record stack gas temperature, oxygen concentration, CO concentration (for gaseous fuels) and smoke-spot number (for liquid fuels). Also, observe flame and record any changes in its condition.

5. Continue to reduce combustion air flow stepwise, until one of these limits is reached:

   a. Unacceptable flame conditions- such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability,

   b. Stack gas CO concentrations greater than 400 ppmv,

   c. Smoking at the stack, or

   d. Equipment-related limitations such as low windbox/furnace pressure differential, built in air-flow limits, etc.

6. Develop O_2/CO curve (for gaseous fuels) or O_2/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2 ~~on Page 425-13~~ using excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.

7. From curves prepared in Step 6, find stack gas oxygen levels where CO emissions or smoke-spot number equal following values:

Fuel	Measurement	Value
Gaseous	CO Emissions	400 ppmv
#1 and #2 Oils	smoke-spot number	number 1
#4 Oil	smoke-spot number	number 2
#5 Oil	smoke-spot number	number 3
Other Oils	smoke-spot number	number 4

Above conditions are referred to as CO or smoke thresholds, or as minimum excess oxygen levels.

Compare this minimum value of excess oxygen to expected value provided by combustion unit manufacturer. If minimum level found is substantially higher than value provided by combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mix, thereby allowing operations with less air.

8. Add 0.5 to 2.0 percent to minimum excess oxygen level determined in Step 7 and reset burner controls to operate automatically at this higher stack gas oxygen level. This margin above minimum oxygen level accounts for fuel variations, variations in atmospheric conditions, load changes, and nonrepeatability or "play" in automatic controls.

9. If load of unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent upper and lower limits of range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish optimum excess oxygen level at all firing rates. If this is the case, choose burner control settings that give best performance over range of firing rates. If one firing rate predominates, setting should optimize conditions at that rate.

10. Verify that new settings can accommodate sudden load changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing flame and stack. If any of conditions in Step 5 result, reset combustion control to provide slightly higher level of excess oxygen at affected firing rates. Next verify these new settings in a similar fashion. Then make sure that final control settings are recorded at steady-state operating conditions for future reference.

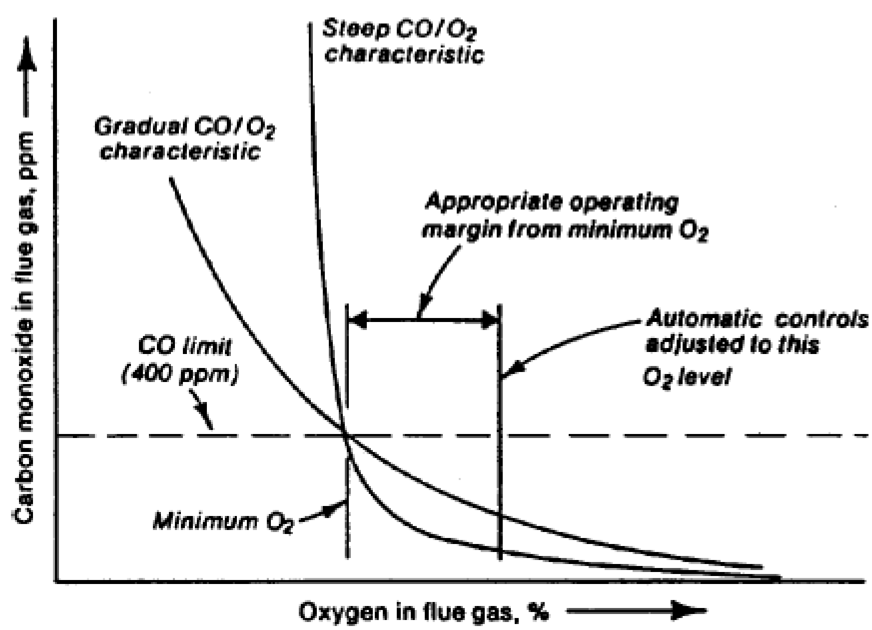

Figure 1: Oxygen/CO Characteristic Curve

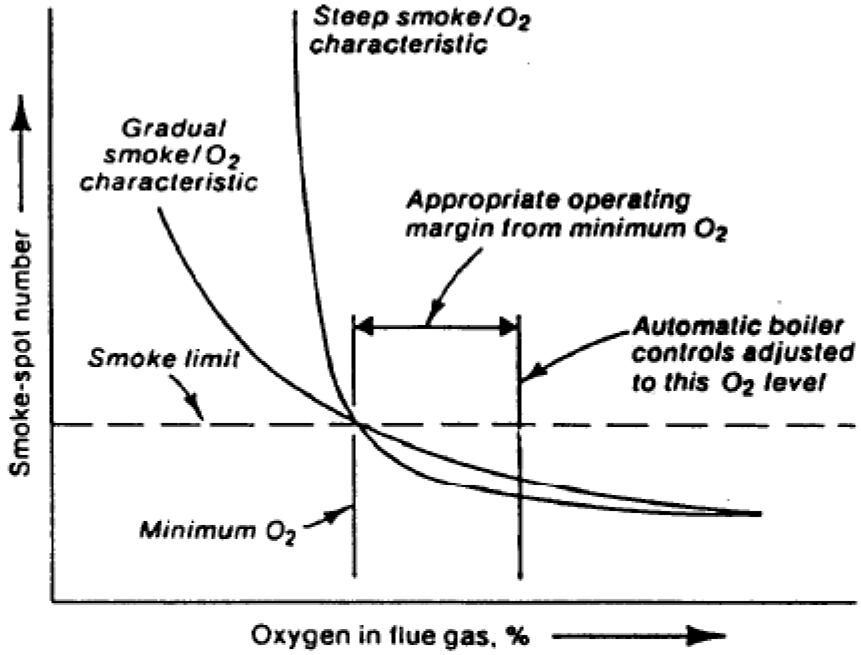

Figure 2: Oxygen/Smoke Characteristic Curve

C. Equipment Tuning Procedure[9] for Natural and Induced-Draft Boilers, Steam Generators, and Process Heaters

Nothing in this Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Preliminary analysis

   a. Check operating pressure or temperature. Operate unit at lowest acceptable pressure or temperature that will satisfy load demand. Determine pressure or temperature that will be used as basis for comparative combustion analysis before and after tune-up.

   b. Check operating hours. Plan workload so that unit operates only the minimum hours and days necessary to perform work required.

   c. Check air supply. Area of air supply openings must be in compliance with applicable codes and regulations. Air openings must be kept wide open when burner is firing and clean from restriction to flow.

[9] This tuning procedure is based on a tune-up procedure developed by Parker Boiler for South Coast AQMD.

d. Check vent. Check to be sure vent is in good condition, sized properly and with no obstructions.

e. Perform combustion analysis. Perform an "as is" flue gas analysis (O_2, CO, CO_2, etc.) at high and low fire, if possible. In addition to data obtained from combustion analysis, also record following:

1) Inlet fuel pressure at burner (at high and low fire),
2) Draft at inlet of draft hood or barometric damper at high, medium, and low settings, if applicable,
3) Steam pressure, water temperature, or process fluid pressure or temperature entering and leaving unit, and
4) Unit rate, if meter is available.

With above conditions recorded, make following checks and corrective actions as necessary.

2. Checks and Corrections

a. Check burner condition. Clean burners and burner orifices thoroughly. To clean burners effectively all burners must be removed, blown out with high pressure air and checked for obstructions. All accumulated sediment, dirt, and carbon must be removed. Check for smooth lighting and even flame. Also, ensure that fuel filters and moisture traps are in place, clean, and operating properly, to prevent plugging of gas orifices. Confirm proper location and orientation of burner diffuser spuds, gas canes, etc. Look for any burned-off or missing burner parts, and replace as needed.

b. Check for clean boiler, steam generator, or process heater tubes and heat transfer surfaces. Clean tube surfaces, remove scale and soot, assure proper fluid flow, and flue gas flow.

c. Check water treatment and blowdown program. Employ timely flushing and periodic blowdown to eliminate sediment and scale build-up in heat exchange tubes.

d. Check for steam hot water or process fluid leaks. Repair all leaks immediately. Be sure there are no leaks through the blow-off drains, safety valve, by-pass lines or at the feed pump, if used.

3. Safety Checks

a. Test primary and secondary low water level controls.

b. Check operating and limit pressure and temperature controls.

c. Check safety valve pressure and capacity to meet boiler, steam generator, or process heater requirements.

d. Check limit safety control and spill switch.

4. Adjustments

While taking combustion readings with unit at operating temperature and at high fire perform checks and adjustments as follows:

a. Adjust unit to fire at rated capacity. Record fuel manifold pressure.

b. Adjust draft and/or fuel pressure to obtain efficient, clean combustion at both high, medium and low fire. Carbon monoxide value should always be below 400 ppm at 3% O_2. If CO is high make necessary adjustment such as increasing draft. Check to ensure burner light offs are smooth and safe. A reduced fuel pressure test at both high and low fire should be conducted in accordance with manufacturer's instructions and maintenance manuals.

c. Check and adjust operation of modulation controller. Insure proper, efficient and clean combustion through range of firing rates. When above adjustments and corrections have been made, record all data.

5. Final Test

Perform final combustion analysis with unit at operating temperature and at high, medium, and low fire, whenever possible. In addition to data from combustion analysis, also check and record:

a. Fuel pressure at burner (high, medium, and low settings, if applicable).

b. Draft at inlet or above draft hood or barometric damper (high, medium, and low settings, if applicable).

c. Steam pressure or water temperature entering and leaving unit.

d. Unit rate, if fuel meter is available.

When above checks and adjustments have been made, record data and attach combustion analysis data to boiler, steam generator, or process heater records indicating name and signature of person, title, company name, company address and date tune-up was performed.

APPENDIX C:

AMENDED RULE 425.2

BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN)

RULE DEVELOPMENT COMMENTS

On December 4, 2017, U.S. Borax, Inc. provided the District a comment letter on proposed amendments to Rule 425.2. The letter states that the District's propose NOx limits present both cost and technological feasibility concerns for the U.S. Borax boilers, particularly Union Iron Works CA B21841-68 boiler and Combustion Engineering CA B35362-74 boiler. However, the letter did not include the cost of installing control technologies. The District requested U.S. Borax to address the cost of installing control technologies. On January 29, 2018, the District received a cost analysis for both boilers from U.S. Borax.

Additionally, on December 4, 2017, Edwards Air Force Base provided written comments in response to proposed Rule 425.2.

Written comments from U.S. Borax Inc. and Edwards Air Force Base are provided on the following pages.

Remainder of page Intentionally Left Blank

B&W

November 20, 2017

Rio Tinto Borates
14486 Borax Road
Boron, CA 93516

Attention: Mr. Mike Bonomo, PE
Energy Manager

Reference: B&W Proposal P063144 Rev 0

Subject: Low NOX Burner Retrofit B&W FM 201-2748

Dear Mr. Bonomo:

The Babcock & Wilcox Company (B&W) is pleased to provide a budgetary proposal in response to your e-mail Request for Quotation dated October 29, 2017 for a burner upgrade to reduce NOx from 60 ppm to 30 ppm.

The current budget price contains the following scope:

- Retention of the existing burner wallbox
- Replacement of (2) NG/Oil Burners with 30ppm NOx burners (on natural gas)
- Modification of or adding to the existing burner throat inside the furnace
- Adding windbox baffles
- Adding/welding burner guide rings to the boiler front plate
- Replacement of the ducting between the economizer outlet and stack inlet
- Addition of a stack/draft damper to the stack inlet for back pressure and burner stability
    - **NOTE**: Damper will need to be added to combustion controls and adjusted/tuned to enable 30 ppm NOx and stable flame
- Addition of FGR ducting, FGR damper, and FGR expansion joint
- Addition of FGR connection port to existing ducting between FD Fan and Silencer
- Replacement of FD Fan blower unit and FD Fan motor
    - **NOTE**: Existing fan produces 28 in H2O pressure using test block with 350-hp chassis motor. New configuration due to requirement of 18% FGR flow rate requires 34 in H2O pressure using test block and 450-hp chassis motor
    - Blower housing will be custom to meet existing inlet and outlet configuration to minimize impact to equipment configuration

Babcock & Wilcox
710 Airpark Road
Napa, CA 94558-7518 | USA
Phone: +1 800.382.2577 | Fax: +1 707.265.1000
www.babcock.com

Ronald Pon
Account Manager
Direct: +1 707.265.1055
Cell: +1 925.451.4272
rlpon@babcock.com

B&W

- EQUIPMENT NOT INCLUDED
  - Ducting of FD Fan supports
  - Control system modifications, Wiring or Electrical Devices
  - Demolition, Installation, or Installation Consumables
  - FD Fan Couplings or FD Fan Foundation Materials
- Material is FOB jobsite.

The burner updated price budget for the equipment listed above is $370,315 (+/-15%).

During a November 5 phone call you indicated a desire for budgetary pricing for SNCR and SCR technology as comparison against the Low NO_X Burner (LNB) retrofit. A review of the photos provided of the boiler and surrounding area indicates that there is not enough space in the surrounding area to accommodate a SCR or SNCR system. The magnitude of the modifications that would be required to make room for a SCR or SNCR could approximate the cost of the LNB retrofit and that would not include the equipment costs for a SCR or SNC system. Respectfully, as such we are refraining from pricing a SCR or SNCR system at this time.

B&W wishes to thank Rio Tinto for the invitation to submit this budgetary proposal. We look forward to the opportunity to discuss the merits of our proposal in more detail and answer any questions that you might have following your review.

If you should have any questions or comments regarding this proposal, please feel free to contact me in the Napa office at (800) 382-2577.

Very truly yours,

Babcock & Wilcox

Ronald Pon
Account Manager

P063144 Rev 0 11-20-17

Cc: S. E. Maykowski – B&W, West Point

TRANSFORMING OUR WORLD | 150 YEARS

Babcock & Wilcox
710 Airpark Road
Napa, CA 94558-7518 | USA
Phone: +1 800.382.2577 | Fax: +1 707.265.1000
www.babcock.com

Ronald Pon
Account Manager
Direct: +1 707.265.1055
Cell: +1 925.451.4272
rtpon@babcock.com

U.S. BORAX INC.

COMMENTS ON:

PROPOSED REVISION TO RULE 425.2 BOILERS,

STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN)

(STAFF REPORT OCT. 2, 2017)

SUBMITTED ELECTRONICALLY TO:

WUNNA AUNG, EASTERN KERN APCD

AUNGW@KERNCOUNTY.COM

DECEMBER 4, 2017

TABLE OF CONTENTS

I. Executive Summary 1

II. Applicability of Rule 425.2 to U.S. Borax's Boilers and Dryers 2

III. The District Must Assess the Technological Feasibility and Cost-Effectiveness of RACT on a Case-by-Case Basis. 3

- A. The District Must Consider the Technological Feasibility of Proposed Control Technologies. 3
- B. The District Must Assess Cost-Effectiveness on a Case-by-Case Basis. 4
- C. Potential Cost-Effectiveness of the District's RACT at U.S. Borax 6

IV. U.S. Borax Encourages the District to Consider the Applicability of the CAA Rural Transport Provision. 7

V. Conclusion 8

U.S. Borax Inc. ("U.S. Borax") appreciates the opportunity to provide comment on the Eastern Kern Air Pollution Control District's (the "District") proposed amendments to Rule 425.2: Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen) (the "Proposed Amendments"). U.S. Borax operates a borate mining and processing operation in Boron, California, in which boron-based minerals are dissolved, settled, crystallized, filtered, and dried. The refining operation relies heavily on steam generated by three natural-gas fired boilers, along with a separately regulated cogeneration unit.

I. Executive Summary

The Clean Air Act ("CAA") requires any area not attaining the ozone National Ambient Air Quality Standard ("NAAQS") to implement Reasonably Available Control Technology ("RACT") for existing stationary sources as a part of its nonattainment state implementation plan ("SIP"). 42 U.S.C. § 7502(c)(1). The Environmental Protection Agency ("EPA") has defined RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 Fed. Reg. 53,761, 53,762 (Sept. 17, 1979). RACT is assessed "on a case-by-case basis, considering the technological and economic circumstances of the individual source." *Id.*

The District's RACT SIP, adopted on May 11, 2017, includes a finding that the existing nitrogen oxides ("NO_x") limits for boilers, steam generators, and process heaters as reflected in Rule 425.2 are inadequate and do not constitute RACT. E. KERN AIR POLLUTION CONTROL DIST., REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) STATE IMPLEMENTATION PLAN (SIP) FOR THE OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS) (May 11, 2017). The Proposed Amendments, which significantly reduce the existing NO_x emission limits, from 70-ppmv to 30-ppmv for gaseous fuel and from 115-ppmv to 40-ppmv for liquid fuel, reflect the District's RACT determination for this source category. The District bases its proposal on a 1991 guidance document published by the California Air Resources Board ("CARB") and similar emission limitations promulgated by other California air pollution control districts.

The District's RACT SIP includes five U.S. Borax boilers and three heaters that the District asserts are subject to Rule 425.2. Two of the boilers and three of the heaters, however, are not properly included within the scope of the Proposed Amendments and the SIP. Furthermore, the District broadly references control equipment that would qualify as RACT without undertaking a meaningful technological feasibility or cost-effectiveness analysis for the U.S. Borax boilers as required under the CAA. As set forth in more detail in these comments, U.S. Borax would appreciate the opportunity to discuss the District's approach to its boilers prior to finalization of the Proposed Amendments.

Finally, as noted in the RACT SIP, the District is located in a rural area that is nonattainment primarily due to pollutant transport. The negative impacts associated with moving from marginal to moderate, and now serious, nonattainment are substantial, particularly in an area with limited opportunities for emission reductions. U.S. Borax, therefore, encourages the District to request status as a Rural Transport Area.

II. Applicability of Rule 425.2 to U.S. Borax's Boilers and Dryers

The District's RACT SIP identifies five U.S. Borax boilers and three heaters subject to Rule 425.2. Only three of the five boilers are permanent boilers, and the three heaters identified in the RACT SIP are not "process heaters" subject to Rule 425.2. For purposes of the Proposed Amendments and development of the RACT SIP, U.S. Borax requests that the District remove the two temporary boilers and three heaters from the scope of the rulemaking.

Table 5 of the NO_x RACT SIP provides that the following emission units at the U.S. Borax facility are subject to Rule 425.2 and therefore the Proposed Amendments.

Permit No.	Emission Unit
1004040	Boiler # 5
1004041	Boiler # 6
1004056	Boiler # 7
1004278	Boiler
1004284	Temporary Replacement Unit for Cogen Duct Unit
1004222A	Boric Acid Dryer
1004027B	Line 7 Fusing
10004005J	Neobor Rotary Drying Operation

As an initial matter, the dryers and the Line 7 Fusing dryers and curing belts are not "process heaters" as defined in the rule. Specifically, Rule 425.2(III)(J) defines a "process heater" as "any external combustion unit fired with liquid and/or gaseous fuel used to transfer heat from combustion gases to liquid process streams." The U.S. Borax dryers are direct-fired and are not designed to transfer heat to a liquid process stream; rather, the dryers and curing belts are used to apply heat to product in order to drive off moisture. For this reason, Rule 425.2 does not apply to the dryers and these units are not subject to the SIP.

Boiler Nos. 5, 6, and 7 are permanent boilers that provide steam for processing operations. The remaining two listed boilers, however, are temporary rental boilers occasionally brought to the site by a third-party contractor as a short-term replacement for the co-generation unit when it is off-line for outages and repairs. The boilers are transported to the site on a trailer, remain on the trailer, and stay on the site for approximately one month. Although U.S. Borax maintains permits for these units to provide flexibility, they are not appropriately subject to SIP controls and associated requirements. U.S. Borax would like to discuss with the District options for excluding these boilers from the Proposed Amendments and the nonattainment SIP.

III. The District Must Assess the Technological Feasibility and Cost-Effectiveness of RACT on a Case-by-Case Basis.

Under the CAA, an area designated as nonattainment for ozone must implement RACT for existing stationary sources as a part of its nonattainment SIP. 42 U.S.C. § 7502(c)(1). EPA has defined RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 Fed. Reg. 53,761, 53,762 (Sept. 17, 1979). NO_x control technology is "reasonably available" if it is both economically and technologically feasible. *Id.* RACT is assessed "on a case-by-case basis, considering the technological and economic circumstances of the individual source." *Id.* The District, however, relies on reference documents and does not assess the technological feasibility and cost-effectiveness of the Proposed Amendments, either for individual boilers or for categories of boilers within the District.

A. The District Must Consider the Technological Feasibility of Proposed Control Technologies.

EPA has determined that technological feasibility "should consider the source's process and operating procedures, raw materials, physical plant layout, and any other environmental impacts." 57 Fed. Reg. 18,070, 18,073 (Apr. 28, 1992). The physical layout of a regulated source may affect whether retrofitting a source or applying additional control equipment is technologically feasible as "[t]he space available in which to implement such changes may limit the choices and will also affect the costs of control." *Id.*

The District includes low-NO_x burners, as well as selective noncatalytic reduction ("SNCR") and selective catalytic reduction ("SCR") control devices, as RACT. SNCR and SCR, however, often present both technological (as well as economic) feasibility concerns. For example, retrofitting an existing unit to add SCR devices can increase a source's costs by more than 30% due primarily to "ductwork modification, the cost of structural steel, and reactor construction." U.S. EPA, AIR POLLUTION CONTROL TECHNOLOGY FACT SHEET 2, https://www3.epa.gov/ttncatc1/dir1/fscr.pdf (last visited Nov. 30, 2017). Applying SCR to existing sources may also require significant demolition at the site and equipment relocation in order to make space for the device. *Id.* Making a blanket assumption that SNCR and SCR qualify as RACT fails to consider these site-specific constraints.

Other California air pollution control districts have addressed the technological infeasibility of SCR by providing alternatives to installing the control technology. The Ventura County Air Pollution Control District (the "Ventura District"), in its 2014 RACT SIP, did not apply SCR where a source's "configuration and inability to cost-effectively install" such controls discouraged requiring its installation. VENTURA CTY. AIR POLLUTION CONTROL DIST., 2014 REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) STATE IMPLEMENTATION PLAN (SIP) REVISION 36 (June 10, 2014). The Ventura District instead applied a specific permit limit to that source. *Id.* The San Joaquin Air Pollution Control District (the "San Joaquin District") similarly determined, in its 2014 RACT SIP, that applying SCR to its boilers and process heaters "would not be feasible due [to] cost effectiveness and/or technological infeasibility because of physical limitations." SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DIST., 2014 REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) DEMONSTRATION FOR THE 8-HOUR OZONE STATE IMPLEMENTATION PLAN (SIP) 33 (June 19, 2014). Instead of requiring the installation of SCR, the San Joaquin District provided these units "an option allowing for the payment of an annual emissions fee based on total actual emissions." *Id.*

U.S. Borax has initiated a study of the feasibility of retrofitting its boilers. Based on an initial review by Babcock & Wilcox, neither SCR nor SNCR would be technologically feasible because of size constraints; specifically, the area where the boilers are housed does not have adequate space to install SNCR or SCR. Moreover, U.S. Borax is not confident that installation of low-NO_x burners on Boiler Nos. 5 and 6 is technologically feasible due to the age of the boilers and concerns regarding whether the existing structures could handle the weight of the low- NO_x burner assembly. U.S. Borax would like to discuss further with the District the possibility of alternatives to installation of control technology on Boiler Nos. 5 and 6 to address these concerns.

B. <u>The District Must Assess Cost-Effectiveness on a Case-by-Case Basis.</u>

The District does not undertake a cost-effectiveness analysis, relying instead on the 1991 CARB document *Determination of Reasonably Available Control Technology (RACT) and Best Available Retrofit Technology (BARCT) for Industrial, Institutional, and Commercial*

Boilers (the "CARB Guidance"). The CARB Guidance determines four methods of control technology for reducing NO_x emissions from regulated sources—low-NO_x burners, flue gas recirculation, SNCR, and SCR—and provides a cost-effectiveness assessment on each of the control technologies. The document represents the cost-effectiveness assessment as a range of 1986 dollars per ton of NO_x removed based on the annual capacity factor.

Without a case-by-case assessment of costs, it would be impossible to determine whether a control technology implemented at an individual source or across a source category within the District would be cost-effective based solely on the CARB Guidance. The CARB Guidance assessment does not distinguish between boiler types or fuel types. Further, the CARB Guidance assesses the cost-effectiveness for the recommended RACT based on extremely wide ranges, from $1,000 to $29,000 for flue gas recirculation, from $1,300 to $20,000 for SNCR, and from $4,000 to $66,000 for SCR.

EPA, in a 1994 guidance for determining RACT for NO_x from boilers, determined that "the cost effectiveness of [RACT] controls varies with boiler capacity...the larger the boiler size the more cost effective is the control...[and] costs increase much more rapidly for boilers below 50 MMBtu/hr in size." U.S. EPA, ALTERNATIVE CONTROL TECHNIQUES DOCUMENT—NO_x EMISSIONS FROM INDUSTRIAL/COMMERCIAL/INSTITUTIONAL (ICI) BOILERS 2-19 (Mar. 1994). The cost-effectiveness of a NO_x control technology implemented at a boiler, therefore, depends on the individual circumstances of the regulated boiler. The CARB Guidance does not assess the cost-effectiveness based on information specific to the regulated boilers within the District. Rather than rely entirely on the CARB Guidance, the District must consider the cost-effectiveness of the Proposed Amendments on a case-by-case basis that considers individual source circumstances, such as boiler size or cost factors associated with implementation at individual sources or across a category of sources.

The District further assumes that, by adopting NO_x emission limitations substantially similar to the rules found in the Bay Area, San Diego, and Santa Barbara Air Pollution Control District, which have proved capable of satisfying RACT, the Proposed Amendments will automatically satisfy the RACT requirement. Modeling a RACT determination after rules in other air pollution districts is insufficient to satisfy the CAA's RACT requirements, which require applicability assessments for individual or category sources. Further, the other air pollution districts have assessed the cost-effectiveness of their NO_x emission limitation to satisfy the RACT requirement, while the District has not undertaken this assessment.

C. Potential Cost-Effectiveness of the District's RACT at U.S. Borax

U.S. Borax has determined that it likely would be cost-effective to install low-NO_x burners on Boiler No. 7. As noted previously, the same is not true for the other two boilers; indeed, it is likely that even if it is technologically feasible to install low-NO_x burners, the cost to retrofit these boilers would be so high as to necessitate replacement of the boilers. We are continuing to assess these costs and would like to discuss with the District an alternative RACT scenario for these boilers.

The District is not required under the CAA to implement RACT at every source within its air pollution control district as long as it demonstrates that it can achieve RACT-level NO_x reductions across the area. 80 Fed. Reg. 12,264, 12,280 (Mar. 6, 2015). The CAA requires states to demonstrate emissions reductions from existing sources in a nonattainment area "as may be obtained" through the implementation of RACT. 42 U.S.C § 7502(c)(1). EPA interprets the CAA as permitting states to use area-wide averaging to achieve RACT-level reductions of NO_x emissions. 80 Fed. Reg. at 12,280. For example, states can meet RACT by including in their RACT SIP "a demonstration that the weighted average NO_x emissions rate from sources in the nonattainment areas subject to RACT achieves RACT-level reduction." *Id.*

EPA interprets the CAA's RACT requirement as "not necessarily call[ing] for implementation of controls at each and every source, but rather requir[ing] an area to achieve at least RACT-level reductions in emission." *Nat. Res. Def. Council v. EPA*, 571 F.3d 1245, 1257 (D.C. Cir. 2009). The D.C. Circuit Court of Appeals found *region-wide* averaging to be an impermissible interpretation of the CAA, but the Court did not find that EPA's interpretation of the CAA as allowing averaging across a *nonattainment area* to be an impermissible reading of the statute. *Id.* Thus, averaging NO_x emissions across a nonattainment area is a permissible method of demonstrating RACT compliance, and neither the CAA nor EPA requires each individual source in the nonattainment area to "employ RACT or achieve RACT-level reductions." 80 Fed. Reg. at 12,280.

The District has substantial flexibility in making RACT determinations, including the potential for averaging of emissions reductions across units and sources in the nonattainment area. In light of the aforementioned concerns regarding technological feasibility and cost effectiveness of control technology installation on Boiler Nos. 5 and 6, U.S. Borax would like to discuss further with the District application of RACT to these boilers.

IV. U.S. Borax Encourages the District to Consider the Applicability of the CAA Rural Transport Provision.

The District is rural, with limited anthropogenic sources and monitored ozone levels that are affected primarily by transport from metropolitan areas in coastal California. In light of the serious impacts of nonattainment on existing facilities like U.S. Borax, and the associated planning burdens placed on the District, U.S. Borax encourages the District to investigate the possibility of designation as a Rural Transport Area under the CAA. If designated, the District would be deemed to have fulfilled all ozone-related planning and control requirements if it meets the CAA's planning requirements for areas designated as Marginal nonattainment, regardless of whether the area meets the standard by any given deadline, and regardless of the design value of the area.

Section 182(h) of the CAA allows EPA to designate and treat a qualifying nonattainment area as a Rural Transport Area ("RTA"). 42 U.S.C. § 7511a(h). For a nonattainment area to qualify as a RTA, the area cannot contain emission sources of NO_x or volatile organic compounds ("VOCs") that make significant contributions to the ozone concentrations in the area or in other areas. *Id.* at § 7511a(h)(2). Generally, a qualifying RTA "has few or insignificant sources of ozone precursors [that] encompass a relatively small geographic area due to lack of emission sources." JANET G. MCCABE, U.S. EPA, AREA DESIGNATION FOR THE 2015 OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS 8 (Feb. 25, 2016), https://www.epa.gov/sites/production/files/2016-02/documents/ozone-designations-guidance-2015.pdf. In addition, a nonattainment area must not include and must not be adjacent to any Metropolitan Statistical Area to qualify as a RTA. 42 U.S.C. § 7511a(h)(1). The U.S. Bureau of the Census defines a Metropolitan Statistical Area as an area that has "a central county or counties with an urbanized area of at least 50,000 people, plus adjacent outlying counties having a high degree of economic integration with the central county, as measured through worker commuting ties." 80 Fed. Reg. at 12,292.

EPA has the discretion to determine whether a nonattainment area qualifies as a RTA, "recogniz[ing] that violations of ozone standards in some rural areas may be almost entirely attributable to emissions from upwind areas and/or sources of background ozone." U.S. EPA, AREA DESIGNATION FOR THE 2016 OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS, at 8. EPA may determine that a rural nonattainment area qualifies as a RTA if it "includes or is adjacent to, any part of a Micropolitan Statistical Area[1] that is too sparsely populated to be included in a statistical area." *Id.* Further, for certain rural nonattainment

[1] The Census Bureau defines a Micropolitan Statistical Area as an area "with central county or counties containing an urban cluster of 10,000–49,999 people plus adjacent counties having a high degree of economic and social integration as measured through worker commuting." 80 Fed. Reg. at 12,292.

areas, EPA may apply partial boundaries, which the agency considers "especially relevant in the western United States, where many of the counties are large." *Id.*

As noted in the RACT SIP, the District is separated from "populated valleys and coastal areas to the west and south by several mountain ranges." These mountain passes create "transport corridors" that direct ozone from coastal California to the portion of the Mojave Desert within the District. Indeed, as recognized by the District, it is the coastal valleys that "are the major source of O_2 precursor emissions affecting O_3 exceedances within Eastern Kern's part of the Mojave Desert." Furthermore, the District may be adjacent to Bakersfield (which is a Metropolitan Statistical Area), but there are none of these areas within the District itself as the area is rural and relatively sparsely populated.

The EPA has stated that it will respond to RTA requests during the designation process for initial area designations, but states also may request RTA treatment after initial area designations are completed. U.S. Borax therefore requests that the District consider designation as an RTA prior to development and implementation of the serious ozone nonattainment SIP.

V. Conclusion

U.S. Borax requests the opportunity to discuss the District's approach to regulating its boilers under the Proposed Amendments and the SIP. Two of U.S. Borax's boilers are temporary rental boilers and are not appropriately subject to SIP controls and associated requirements. Further, Rule 425.2 is not applicable to the U.S. Borax dryer units and these units are not subject to the SIP. U.S. Borax would like to discuss options for excluding these units from the Proposed Amendments and the nonattainment SIP.

Additionally, the District has not conducted a cost-effectiveness and technological feasibility assessment for RACT as applied to the U.S. Borax emission units as required by the CAA. The District's proposed RACT present both cost and technological feasibility concerns for the U.S. Borax boilers, particularly Boiler Nos. 5 and 6, and U.S. Borax would like to discuss further with the District the possibility of alternatives to installation of control technology for these units.

II. RULE 425.2 Boilers, Steam Generators, and Process heaters (Oxides of Nitrogen) Amended 10/2/2017

We appreciate the opportunity to comment drafts of proposed rules. Our comments are provided with a brief explanation and a quotation from the Rule with recommended additions shown in red and textual changes shown with a strikeout font.

1. We recommend reducing the cost and burden of source testing of boilers by refining the application of representative testing as stated in VI.C.3, by making allowances for using a class of boilers performing the same or similar operation. Limiting the boilers to the same manufacturer, model number defeats the purpose of representative testing and will increase the amount of source tests, subsequently increasing the cost and burden on the source and the District. As stated in this rule, this is a group of identical units aside from the year of manufacturer. Considering the recent improvements in low-NOx burners and environmental regulations, the year of manufacturer is more definitive of the emissions from a boiler than the manufacturer or model. A definition similar to "functionally-identical" should be used to classify the boilers which allows for a more practical application. Boilers that perform the same function, use the same fuel, are in the same capacity range and are constructed using the same control technology should all have emissions representative of each other regardless of the manufacturer or model.

   The advantage to representative testing is maximized as the size of boilers or process heaters decreases. A facility may have several (20 – 100) small process heaters (5-10 MMBTU/hr) all performing the same function and meeting the same engineering specification. It is doubtful that all units are the exact same manufacturer and model number. A rough estimate could be 10 out of 100 are the same model; possibly 50 out of 100 units are designed the same but are different models or different manufacturers. As the rule appears to be written, 4 of these 10 identical units can be tested every year and represent 6 other boilers. The remaining 90 boilers must all be tested as they are not identical. Broadening the range of units included in the representative testing to functionally identical can significantly reduce the burden of sourcing testing. In this example, 17 units out of the 50 similar units could be tested per year representing the other 33 units. This would reduce the total amount of source tests per year from 94 to 71, (which equates to much greater than 25% in financial savings).

   If all units are fired off natural gas and meet the 30 ppmv NOx requirement, NOx emissions for a group of boilers rated 5.0 – 10 MMBTU/hr used continuously throughout the year range from 0.81 – 1.62 tons/yr per unit. A 0.5 MMBTU/hr rated capacity change equals a variance in emissions of 0.08 tons/yr or less than 10% change in yearly emissions. Statistically, this difference in emissions between units rated within 10 % capacity is not significant, therefore units within this range can be grouped together and represent equivalent emissions to each other.

   We hope the above examples provide adequate explanation of the benefits and low risk of emissions increases for representative testing for boilers and heaters which are similar, but not identical. Of course the burden would be on the source to identify similar units, perform initial source testing, and justify compliance with emissions standards for each unit included in a representative source test program.

The recommended changes for representative testing to this proposed rule comply with the source testing requirements of 40 CFR Subpart DDDDD – *National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*. (Boiler NESHAPS). The source testing requirements of the Boiler NESHAPS allow for testing of an individual unit every 3 years after a compliance demonstration of 2 years in section 63.7515. The recommended change to representative testing does not relax an individual unit from testing once every 3 years. A suggestion to add the following to clarify the applicability is shown below:

"*3. Test results from an individual unit may be used for other units when the following criteria are met:*

a. Units are located at the same facility;

b. Units are fired off the same fuel. Units using public utility fuel (natural gas, propane, butane, or LPG) shall meet CARB low-sulfur fuel content.

~~*b*~~ *c. Units are manufactured to within 10% of the same design specifications, use the same control technology* ~~*by the same manufacturer, have the same model number*~~*, and have the same rated input/output capacity range and operating specifications,*

c. Units are operated and maintained in a similar manner, and

d. District, based on documentation submitted by the facility, determines that the variability of emissions for ~~*identical*~~ *representative tested units is low enough for confidence that the untested unit will be in compliance.*

APPENDIX D:

AMENDED RULE 425.2

BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN)

RESPONSE TO COMMENTS

I. INDUSTRY COMMENTS

U.S. Borax, Inc.

The letter received on January 29, 2018 from U.S. Borax states that installing low-NOx burners would cost $370,000. Based on that quote submitted by Babcock & Wilcox, the District examines installing low-NOx burner will be cost effective for Union Iron Works CA B21841-68 boiler and Combustion Engineering CA B35362-74 boiler located at U.S. Borax facility.

Per District Policy 92-01 (last update in 2000), a control technology shall be considered cost effective for a specific air pollutant, if total annual cost per ton (TACPT) of control does not exceed the cutoff below:

Pollutant	**Cutoff Cost ($/ton)**	
VOC	5,000	
NOx	10,000[10]	**14,324**[11]
PM10	6,000	
SOx	4,000	

Cost Effectiveness Determination Procedures

1. Calculate Capital Recovery Cost as follows:

$$\text{CRC} = \text{TCI} \times \frac{\text{I}\ (1+\text{I})^{n}}{(1+\text{I})^{n}-1} \quad \text{where}$$

CRC = Capital Recovery Cost. This is the cost of air pollution control equipment;

TCI = Total Capital Investment. This includes purchased equipment costs (primary control device, ancillary equipment, ductwork, instrumentation, sales tax, and freight); direct installation costs (foundations, and supports), handling and erection, electrical, piping, insulation, and finishing); and indirect installation costs (engineering, construction and field expenses, contractor fees, start-up, performance tests, and contingencies);

[10] The Policy was updated in 2000. Therefore, the cutoff cost of 10,000 is in Year 2000 U.S. Dollars
[11] According to the Bureau of Labor Statistics, prices in 2018 are 43.2% higher than prices in 2000.

I	=	Interest rate. Use 10% or demonstrate why alternate is more representative or appropriate; and
n	=	Equipment life. Assume 10 years, or demonstrate why alternate is more representative or appropriate.

2. Determine Annual Operating Cost (AOC) of control equipment, including direct costs such as raw materials, utilities (electricity, fuel, steam, water, and compressed air), water treatment/disposal, labor (operating, supervisory, and maintenance), maintenance materials, replacement parts and indirect costs (overhead, property taxes, insurance, and administrative charges), less recovery credits (value of material or energy recovered from control equipment).

3. Calculate Total Annual Cost (TAC) by summing CRC and AOC.

4. If control equipment reduces only one air pollutant, calculate total annual cost per ton (TACPT) of pollutant by dividing TAC by annual emission reduction. (The emission reduction is calculated from uncontrolled level to level achievable by technology under consideration.) If TACPT exceeds the applicable cutoff threshold, installing control technology is not cost effective.

Cost Effectiveness Calculation for 150 MMBtu/hr Union Iron Works CA B21841-68 natural gas fired boiler from U.S. Borax Facility

1.

$$\text{CRC} = \text{TCI} \times \frac{\mathrm{I}\ (1+\mathrm{I})^{n}}{(1+\mathrm{I})^{n} - 1}$$

TCI = 1,190,000 (Total Capital Investment)

1.	Equipment Costs ($)	370,000[12]
2.	Direct Installation Costs ($)	683,000[13]
3.	Indirect Installation Costs ($)	137,000[14]
	Total Capital Investment ($)	1,190,000

I = 10%

n = 10 years

[12] The cost of Low-NOx burner from the comment letter from U.S. Borax in Appendix C.
[13] Direct Installation Costs is assumed to be one tenth of direct capital cost calculated from Page 497 of EPA Air Pollution Control Cost Manual Sixth Edition. https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf
[14] Indirect Installation Costs is assumed to be one tenth of indirect installation cost calculated from Page 497 of EPA Air Pollution Control Cost Manual Sixth Edition.

$$CRC = 1{,}190{,}000 \times \frac{0.1\ (1+0.1)^{10}}{(1+0.1)^{10} - 1} = 194{,}600\ \$$$

2. Annual Operating Cost (AOC) = 145,300[15]

3. Total Annual Cost (TAC) = 194,600 + 145,300 = 339,900

Annual NOx Emission Reduction

NOx reduction	=	0.084 lb/MMBtu (70 ppmv) – 0.036 lb/MMBtu (30 ppmv)
	=	0.048 lb/MMBtu
Annual Mass Reduction	=	(0.048 lb/MMBtu) (150 MMBtu/hr) (4380 hr/yr)
	=	31536 lb/yr (15.77 ton/yr)
Total Annual Cost Per Ton	=	339,900/15.77
(TACPT)	=	**21,500**

TACPT of installing low-NOx burner ($21,500) exceeds NOx cutoff cost of $14,324. Additionally, installing other NOx control technologies such as Selective Catalytic Reduction (SCR) and Selective Noncatalytic Reduction (SNR) costs more than installing low-NOx burner.

Therefore, installing low-NOx burner or SCR or SNR to Union Iron Works CA B21841-68 boiler and Combustion Engineering CA B35362-74 boiler would not be considered cost effective.

Edwards Air Force Base

Edwards AFB commented: *To allow using a class of boilers performing the same or similar operation located at the same facility by refining the application of representative testing as stated in Rule 425.2 Section VI.C.3.*

District: According to Rule 425.2 Section VI.C.3, test results from an individual unit may be used for other units at the same location provided manufacturer, model number, rated capacity, fuel type, and emission control provision are the same.

[15] Annual Operating Cost is assumed to be one tenth of total annual cost calculated from Page 500 of EPA Air Pollution Control Cost Manual Sixth Edition.