State of Utah
DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY

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DAQE-433-94

May 27, 1994

Fred Fox
Kennecott, Utah Copper
P.O. Box 525
Bingham Canyon, Utah 84006-0525

Re: Approval Order For RACT Analysis
Salt Lake County CDS A1 NA Title V Major

Dear Mr. Fox:

The attached document is an Approval Order for the above referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right hand corner of this letter. Please direct any technical questions you may have on this project to Mr. Tim Blanchard. He may be reached at (801) 536-4057.

Sincerely,

Russell A. Roberts, Executive Secretary
Utah Air Quality Board

RAR:JTB:dn

Abstract

Kennecott Utah Copper (KUC) submitted a Notice of Intent dated February 25, 1994, in order to comply with the NO_x Reasonably Available Control Technology (RACT) requirement of Utah State Implementation Plant (SIP) Section IX.D.2.g as it applies to KUC's Utah Power Plant (UPP). KUC proposes to install low-NO_x burners in one of the three older boilers (Boiler #1, #2, or #3) at the UPP, and test the performance of the boiler with the low-NO_x burners. If that boiler performs satisfactorily in terms of both operation and NO_x and NO_x emission reduction, then KUC will install identical low-NO_x burners in the other two boilers. If the first boiler does not perform satisfactorily, then RACT for these three boilers will need to be reevaluated. No other changes are proposed.

The NO_x emissions shall be reduced by 1,324 tons/year by May 31, 1995, if the low-NO_x burners operate as the manufacturer guaranteed.

The above-referenced project has been evaluated and found to be consistent with the requirements of the Utah Air Conservation Rules (UACR) and the Utah Air Conservation Act. A 30-day public comment period was held and all comments received were evaluated. The conditions of this Approval Order (AO) reflect any changes to the proposed conditions which resulted from the evaluation of the comments received. This air quality AO authorizes the project with the following conditions, and failure to comply with any of the conditions may constitute a violation of this order.

General Conditions

1. This AO applies to the following plant:

   Operation Offices

   Kennecott Utah Copper Corporation
   P. O. Box 525
   Bingham Canyon, Utah 84006-0525

   Facility Street Address

   Kennecott Utah Power Plant
   9600 West 2100 South
   Magna, Utah 84044

   Facility Approximate Universal Transverse Mercator (UTM) Coordinate System Coordinates

   405,000 meters East, 4,507,000 meters North

2. Definitions of terms, abbreviations, and references used in this AO conform to those used in the UACR, Utah Administrative Codes (UAC), and Series 40 of the Code of

Federal Regulations (40 CFR). These definitions take precedence unless specifically defined otherwise herein.

3. Kennecott Utah Copper Corporation (KUC) shall install six new low-NO_x burners in either Boiler #1, Boiler #2, or Boiler #3, according to the information submitted in the Notice of Intent dated February 25, 1994. If initial testing demonstrates that the boiler operates as guaranteed by the manufacturer of the burners, both in terms of operation and emissions, then KUC shall install six new low-NO_x burners in each of the other two boilers and operate all three boilers (#1, #2, and #3) according to the information submitted in the Notice of Intent dated February 25, 1994.

4. As provided by R307-1-3.2.4, UAC, this AO shall take precedence in the event of any inconsistency between conditions of this AO and Section IX, Part H.2.a and Section IX, Part H.2.b.Z of the SIP for Salt Lake and Davis Counties.

5. A copy of this AO shall be posted on site. This AO shall be available to the employees who operate the air emission producing equipment. These employees shall receive instruction as to their responsibilities in operating the equipment according to all of the relevant conditions listed below.

6. The approved installations shall consist of only the following emissions points:

   A. Boilers No. 1, No. 2, and No. 3, <u>each</u> rated at:

      431.4 MMBtu/hr maximum heat input when burning coal
      453 MMBtu/hr maximum heat input when burning natural gas

   B. Boiler No. 4, rated at:

      838 MMBtu/hr maximum heat input when burning coal
      872 MMBtu/hr maximum heat input when burning natural gas

   C. Other associated equipment, such as coal and ash handling equipment, and maintenance equipment.

<u>Limitations and Test Procedures</u>

7. During the period from November 1, to the last day in February, inclusive, the following conditions shall apply:

   A. The four boilers shall use only natural gas as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. The power plant may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment. The Executive Secretary shall be notified of the curtailment within 48 hours of when it begins and within 48 hours of when it ends.

B. The following limits on fuel usage shall not be exceeded without prior approval in accordance with Section R307-1-3.1:

1) 40 million cubic feet per day of natural gas

2) 1370 tons per day of coal, only during curtailment of natural gas supply

C. Natural gas used as fuel:

Except during a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

1) For each of boilers no. 1, 2, & 3:

a) PM_{10} - 0.004 grain/dscf (68°F, 29.92 in Hg)

b) NO_x - 159 lb/hr
336 ppmdv (measured at 3% oxygen)

2) For boiler no. 4:

a) PM_{10} - 0.004 grain/dscf (68°F, 29.92 in Hg)

b) NO_x - 306 lb/hr
336 ppmdv (measured at 3% oxygen)

D. Coal used as fuel:

During a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

1) For each of boilers no. 1, 2, & 3:

a) PM_{10} - 17.3 lb/hr
- 0.029 grain/dscf
(68°F, 29.92 in Hg)

b) On or before May 31, 1995
NO_x - 278 lb/hr
- 597 ppmdv (measured at 3% oxygen)

After May 31, 1995, if the low-NO_x burners operate in the initial trial as guaranteed by the manufacturer,
NO_x - 216 lb/hr
- 426.5 ppmdv (measured at 3% oxygen)

If the low-NO_x burners fail the initial trial, then the post-May 31, 1995, NO_x limit for Boilers #1, #2, and #3 must be reevaluated and revised by a subsequent AO.

2) For boiler no. 4:

a) PM_{10} - 33.5 lb/hr
- 0.029 grain/dscf (68°F, 29.92 in Hg)

b) On or before May 31, 1995

NO_x - 637 lb/hr
- 597 ppmdv (measured at 3% oxygen)

After May 31, 1995

NO_x - 377 lb/hr
- 384 ppmdv (measured at 3% oxygen)

E. Owner/operator shall provide monthly reports to the Executive Secretary showing daily total emission estimates based upon boiler usage, fuel consumption and previously available results of stack tests.

8. During each annual period from March 1 to October 31, inclusive, the following conditions shall apply:

A. The owner/operator shall use coal, natural gas, oils that meet all the specifications of 40 CFR 266.40(e) and contains less than 1000 ppm total halogens, and/or number two fuel oil or lighter in the boilers.

B. The following limit on fuel usage shall not be exceeded without prior approval in accordance with Subsection R307-1-3.1, UAC:

50,400 million Btu per day of heat input

C. Emissions to the atmosphere from each emission point shall not exceed the following rates and concentrations:

1) For each of boilers no. 1, 2, & 3:

a) PM_{10} - 17.3 lb/hr
- 0.029 grain/dscf (68°F, 29.92 in Hg)

b).1 On or before May 31, 1995

NO_x - 562 lb/hr
- 1208 ppmdv (measured at 3% oxygen)

.2 After May 31, 1995, if the low-NO_x burners operate in the initial trial as guaranteed by the manufacturer

NO_x - 216 lb/hr
- 426.5 ppmdv (measured at 3% oxygen)

If the low-NO_x burners fail the initial trial, then the post-May 31, 1995, NO_x limit for Boilers #1, #2, and #3 must be reevaluated and revised by a subsequent AO.

2) For boiler no. 4:

a) PM_{10} - 33.5 lb/hr
- 0.029 grain/dscf (68°F, 29.92 in Hg)

b).1 On or before May 31, 1995

NO_x - 796 lb/hr
- 746 ppmdv (measured at 3% oxygen)

.2 After May 31, 1995

NO_x - 377 lb/hr
- 384 ppmdv (measured at 3% oxygen)

9. Stack testing to show compliance with the above emission limitations shall be performed for all four boilers and the following air contaminants, as determined by the following test methods in accordance with 40 CFR 60, Appendix A, 40 CFR 51, Appendix M (see Section IX, Part H.2.a for more details), and as directed by the Executive Secretary:

		Method	Retest every
A.	NO_x	7	1 year
B.	PM_{10}	201/201a	1 year

The heat input during all compliance testing shall be no less than 90% of the design rate, which is 388 MMBTU/hr for boilers 1, 2, and 3, and 754 MMBTU/hr for boiler #4.

Notification

The applicant shall provide a notification of the test date at least 45 days prior to the test. A pretest conference shall be held if directed by the Executive Secretary. It shall be held at least 30 days prior to the test between the owner/operator, the tester, and the Executive Secretary. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approvable access shall be provided to the test location.

PM_{10}

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201 or 201a. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

Sample Location

40 CFR 60, Appendix A, Method 1, if required by test method used.

Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2, if required by test method used.

Nitrogen Oxides

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, or 7E

Calculations

To determine mass emission rates (lb/hr) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary to give the results in the specified units of the emission limitation.

10. A. Visible emissions from the boiler stacks shall not exceed the associated opacity on a six-minute average, based on 40 CFR 60, Appendix A, Method 9, or as measured by a CEM, except as provided for in R307-1-4.1.7:

Natural Gas Fuel	10% opacity
Coal Fuel	20% opacity

B. Visible emissions from the following types of stationary sources shall not exceed the associated opacity on a six minute average, based on 40 CFR 60, Appendix A, Method 9:

Baghouses	10% opacity
Fugitive Emissions	~~15% opacity~~
Fugitive Dust	20% opacity

Fuels

11. The sulfur content of any fuel burned shall not exceed 0.52 lb of sulfur per million Btu (annual running average), nor shall any one test exceed 0.66 lb of sulfur per million Btu.

A. Coal increments will be collected using ASTM 2234, Type I conditions A, B, or C and systematic spacing.
Fuel lot size is defined as the weight of fuel consumed during three operational hours.

B. Percent sulfur content and gross calorific value of the coal on a dry basis will be determined for each gross sample using ASTM D methods 2013, 3177, 3173, and 2015.

C. Failure of the owner/operator to measure at least 95% of the required increments in any one month shall constitute a violation of this provision.

D. The owner/operator shall submit monthly reports of sulfur input to the boilers. The reports shall include sulfur content, gross calorific value and moisture content of each gross coal sample; the gross calorific value of all coal and gas; the total amount of coal and gas burned; and the running annual average sulfur input calculated at the end of each month of operation.

Conditions 11.A, 11.B, and 11.C may be replaced by an alternative testing plan for use with a given source of coal in accordance with R307-1-4.2.1.E, UAC.

12. Natural gas consumption shall be determined by metering the gas as it is fed into the boilers with gauges, which shall be installed if necessary. Records shall be kept on a daily basis. Coal consumption shall be determined by examination of purchase records and electricity production records. Records of fuel consumption shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request.

Records & Miscellaneous

13. All installations and facilities authorized by this AO shall be adequately and properly maintained. All pollution control vendor recommended equipment shall be installed, maintained, and operated. Instructions from the vendor or established maintenance practices that maximize pollution control shall be used. All necessary equipment control and operating devices, such as pressure gauges, amp meters, volt meters, flow rate indicators, temperature gauges, CEMs, etc., shall be installed and operated properly and easily accessible to compliance inspectors. A copy of all manufacturers' operating instruction for pollution control equipment and pollution emitting equipment shall be kept on site. These instructions shall be available to all employees who operate the equipment and shall be made available to compliance inspectors upon their request.

14. The owner/operator shall comply with R307-1-3.5, UAC. This rule addresses emission inventory reporting requirements.

15. The owner/operator shall comply with R307-1-4.7, UAC. This rule addresses unavoidable breakdown reporting requirements. The owner/operator shall calculate/estimate the excess emissions whenever a breakdown occurs. The total of excess emissions shall be reported to the Executive Secretary as directed for each calendar year.

Any future modifications to the equipment approved by this order must also be approved in accordance with R307-1-3.1.1, UAC.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including the UACR.

Annual emissions for this source (the entire power plant) are currently calculated at the following values:

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Pollutant	Emissions
PM_{10}	257 tons/yr

SO_2	6219 tons/yr
NO_x	5085 tons/yr, on or before May 31, 1995
NO_x	3761 tons/yr, after May 31, 1995, if the low NO_x burners operate in the initial trial as guaranteed by the manufacturer.

These calculations are for the purposes of determining the applicability of Prevention of Significant Deterioration and nonattainment area major source requirements of the UACR. They are not to be used for the purposes of determining compliance.

If the low-NO_x burners fail the initial trial, or if, for any reason, KUC is unable to comply with the NO_x emission levels referred to in this AO, after May 31, 1995, then the State must make the appropriate revisions to the Ozone SIP in accordance with the rulemaking process, including a redefinition of NO_x RACT for the power plant, and the NO_x emission limits for the power plant shall be recalculated and revised by the issuance of a subsequent AO.

~~Approved By:~~

Russell A. Roberts, Executive Secretary
Utah Air Quality Board