State of Utah
GARY R. HERBERT
Governor
GREG BELL
Lieutenant Governor

Department of Environmental Quality
Amanda Smith
Executive Director
DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQE-IN105720026-11

September 12, 2011

Chris Kaiser
Kennecott Utah Copper LLC
4700 Daybreak Parkway
South Jordan, UT 84095

Dear Mr. Kaiser:

Re: Intent to Approve: Modify Approval Order DAQE-AN0105720022-09 to Replace Boilers (Units 1, 2 and 3) with a New Combined-Cycle Turbine
Project Number: N10572-0026

The attached document is the Intent to Approve for the above-referenced project. The Intent to Approve is subject to public review. Any comments received shall be considered before an Approval Order is issued. The Division of Air Quality is authorized to charge a fee for reimbursement of the actual costs incurred in the issuance of an Approval Order. An invoice will follow upon issuance of the final Approval Order.

Future correspondence on this Intent to Approve should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. The project engineer for this action is John Jenks, who may be reached at (801) 536-4459.

Sincerely,

Martin D. Gray, Manager
New Source Review Section

MDG:JJ:kw

cc: Mike Owens
Salt Lake Valley Health Department

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

INTENT TO APPROVE: Modify Approval Order DAQE-AN0105720022-09 to Replace Boilers (Units 1, 2 and 3) with a New Combined-Cycle Turbine

Prepared by: John Jenks, Engineer
Phone: (801) 536-4459
Email: jjenks@utah.gov

INTENT TO APPROVE NUMBER

DAQE-IN105720026-11

Date: September 12, 2011

Kennecott Utah Copper LLC
Power Plant/ Lab/ Tailings Impoundment

Source Contact:
Ray Gottling
Phone: (801) 569-7110

Martin D. Gray, Manager
New Source Review Section
Utah Division of Air Quality

ABSTRACT

On December 15, 2010 Kennecott Utah Copper, LLC (KUC) submitted a NOI to install and operate a new combined-cycle, natural gas-fired combustion turbine (CT) to replace three existing coal-fired boilers (identified as Units 1, 2 and 3 boilers). The new CT will have a nominal generating capacity of approximately 275 megawatts (MW) and will limit emissions through a combination of dry low-NOx combustors, selective catalytic reduction (SCR) and catalytic oxidation (CatOx). The CT will be located at KUC's existing power plant in Salt Lake County. Salt Lake County is a non-attainment area of the National Ambient Air Quality Standards (NAAQS) for PM10, PM2.5 (a subset of PM10) and SO2, and is a maintenance area for ozone. Title V of the 1990 Clean Air Act applies to this source and this modification will result in a Title V amendment. The requirements for Title V shall be followed until the operating permit for this source has been amended. Current potential to emit for the facility are estimated at: PM10 = 256; PM2.5 = 256; NOx = 4,160; SO2 = 6,522; CO = 384; and VOC = 33. Using a two-year average of KUC's actual emissions from Units 1, 2 and 3 boilers as a baseline, the change in emissions from this project, in tons per year (tpy), is as follows: PM10 -100; PM2.5 -20; NOx -1,543; SO2 -1,961; CO +93; VOC +19 and GHG (CO2e) +278,703. The facility-wide potential to emit totals following the installation of the new CT and after the shut-down of Units 1, 2 and 3 boilers are as follows (again in tpy): PM10 = 248, PM2.5 = 248, NOx = 1,641, SO2 = 2,577, CO = 328, VOC = 41 and total HAPs = 9. Potential GHG emissions for the new CT are estimated to be 1,162,552 tpy (expressed as CO2e). While classified as a minor modification for the criteria pollutants listed above, this project represents a major modification for GHG emissions.

The NOI for the above-referenced project has been evaluated and has been found to be consistent with the requirements of UAC R307. Air pollution producing sources and/or their air control facilities may not be constructed, installed, established, or modified prior to the issuance of an AO by the Executive Secretary of the Utah Air Quality Board.

A 30-day public comment period will be held in accordance with UAC R307-401-7. A notification of the intent to approve will be published in the Salt Lake Tribune and Deseret News on September 13, 2011. During the public comment period the proposal and the evaluation of its impact on air quality will be available for the public to review and provide comment. If anyone so requests a public hearing within 15 days of publication, it will be held in accordance with UAC R307-401-7. The hearing will be held as close as practicable to the location of the source. Any comments received during the public comment period and the hearing will be evaluated. The proposed conditions of the AO may be changed as a result of the comments received.

Name of Permittee:

Kennecott Utah Copper LLC
4700 Daybreak Parkway
South Jordan, UT 84095

Permitted Location:

Power Plant/ Lab/ Tailings Impoundment
9600 West 2100 South
Magna, UT 84044-6001

UTM coordinates: 405000 m Easting, 4507000 m Northing, UTM Zone 12
SIC code: 4911 (Electric Services)

Section I: GENERAL PROVISIONS

I.1 All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]

I.2 The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]

I.3 Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]

I.4 All records referenced in this AO or in other applicable rules, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the two-year period prior to the date of the request. Unless otherwise specified in this AO or in other applicable state and federal rules, records shall be kept for a minimum of five years. [R307-401]. [R307-415-6b]

I.5 At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded. [R307-401-4]

I.6 The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring. [R307-150]

I.7 The owner/operator shall comply with UAC R307-107. General Requirements: Unavoidable Breakdowns. [R307-107]

Section II: SPECIAL PROVISIONS

II.A The approved installations shall consist of the following equipment:

II.A.1 **Plant Wide**
Power Plant

II.A.2 **Power Plant Boiler #1**
Rated at:
431 MMBtu/hr maximum heat input when burning coal
453 MMBtu/hr maximum heat input when burning natural gas

II.A.3 **Power Plant Boiler #2**
Rated at:
431 MMBtu/hr maximum heat input when burning coal
453 MMBtu/hr maximum heat input when burning natural gas

II.A.4 **Power Plant Boiler #3**
Rated at:
431 MMBtu/hr maximum heat input when burning coal
453 MMBtu/hr maximum heat input when burning natural gas

II.A.5 **Power Plant Boiler #4**
Rated at:
838 MMBTU/hr maximum heat input when burning coal
872 MMBTU/hr maximum heat input when burning natural gas

II.A.6 **Power Plant Turbine (Unit #5)**
Nominal 275 MW combustion turbine and HRSG unit, SCR and CatOx

II.A.7 **Hot Water Boiler**
7.133 MMBTU/hr natural gas fired boiler, located in the laboratory

II.A.8 **Cold Solvent Parts Washers**
25 gal. of solvent per washer and approximately 200 gal. or less of solvent used every year for maintenance cleaners at various locations throughout the source.

II.A.9 **Wet Cooling Towers**
Five Non-contact water-cooling towers

II.A.10 **Natural Gas Generator**
1.2 MMBTU/hr natural gas fired generator, located in the Power Plant

II.A.11 **Hydraulic Coal Unloader System with Diesel Engine**
Manufacturer: John Deere
Maximum Rating: 170 Hp

II.A.12 **Coal and Ash Handling Equipment**
Wet and closed fly ash capture system, handles ash from the electrostatic precipitators

II.A.13 **Diesel Engine**
175 Hp diesel engine located in the Power Plant, to operate an emergency fire water pump

II.B Requirements and Limitations

II.B.1 **<u>Plantwide Conditions</u>**

II.B.1.a 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 KUC to measure at least 95% of the required increments in any one month shall constitute a violation of this provision.

D. KUC 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 II.B.1.a.A, II.B.1.a.B, and II.B.1.a.C above may be replaced by an alternative testing plan for use with a given source of coal in accordance with R307-203-1. [R307-401]

II.B.1.b 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 R307-201 and R307-305:

Natural Gas Fuel	10% opacity
Coal and Oil Fuel	20% opacity

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 and Diesel Engines	20% opacity

[R307-201]

II.B.2 **<u>Conditions on combined-cycle CT/HRSG unit (Unit #5)</u>**

II.B.2.a The height of the turbine/HRSG stack shall be no less than 185 feet, as measured from ground level at the base of the stack. [R307-401-8]

II.B.2.b Emissions from the CT/HRSG stack shall not exceed the following values:

NO_x: 2.0 ppmvd at 15% O_2*
CO: 2.0 ppmvd at 15% O_2*
VOC: 2.0 ppmvd at 15% O_2*
$PM_{10}/PM_{2.5}$: 18.8 lb/hr with duct firing

* Under steady state operation. Steady state operation means all periods of combustion turbine operation, except for periods of startup and shutdown as defined below, and periods of transient load conditions.

[R307-401-8]

II.B.2.c Stack testing to show compliance with the above Unit #5 emission limitations shall be performed for 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:

	Pollutant	Method	Retest every
A.	$PM_{10}/PM_{2.5}$	201/201a/202**	3 years
B.	NO_x	7	3 years
C.	VOC	25/25a	3 years
D.	CO	10	3 years

** or other testing methods approved by the Executive Secretary

The heat input during all compliance testing shall be no less than 90% of the design rate, which is 1,725 MMBTU/hr. The limited use of natural gas during startup, for maintenance firings and break-in firings does not constitute operation and does not require stack testing.

E. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary. The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Executive Secretary.

F. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location

[R307-401]

G. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or other testing methods approved by the Executive Secretary.

H. $PM_{10}/PM_{2.5}$

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201a, 202, or other testing methods approved by the Executive Secretary, such as the OTM 28 Dry Impinger Method. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered $PM_{10}/PM_{2.5}$ as appropriate.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered $PM_{10}/PM_{2.5}$ as appropriate.

I. NO_x

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by the Executive Secretary.

J. CO

40 CFR 60 Appendix A, Method 10, or other testing methods approved by the Executive Secretary.

K. Calculations

To determine mass emission rates (lb/hr, etc.) 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

[R307-150, R307-401]

II.B.2.d Emissions of GHG from Unit 5 shall not exceed 1,162,552 short tons of CO_2e per rolling 12-month period. GHG emissions shall include combined emissions of CO_2, CH4 and N2O. Compliance with the rolling 12-month period shall be determined as follows:

KUC shall multiply the actual rolling 12-month heat input for Unit 5 by the appropriate emissions factor and global warming potential listed below to estimate emissions of each GHG. Total CO_2e emissions equals the sum of all GHG emissions.

GHG	Emission Factor	Global Warming Potential
CO_2	53.02 kg/MMBtu	1
CH4	0.001 kg/MMBtu	21
N2O	0.0001 kg/MMBtu	310

[R307-401-8]

II.B.3 **Boiler Conditions**

II.B.3.a The following conditions as applicable to the Unit #1 Boiler, Unit #2 Boiler and Unit #3 Boiler shall only apply until Unit #5 becomes operational. Upon commencing operation of Unit #5, KUC shall not operate Unit #1, #2 and #3 Boilers. [R307-401]

II.B.3.b During the period from November 1, to the last day in February of the following year, 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. If the power plant is in operation using natural gas when the curtailment is imposed, 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 consumption limits on fuel usage shall not be exceeded:

1) 42,706 MMBTU per day for natural gas usage
2) 31,510 MMBTU per day for coal usage

Compliance with the consumption limits on fuel usage above shall be determined by calculating the MMBTU used per day. The BTU limit shall be determined by monitoring the daily natural gas, and/or coal consumption and multiplying that value with the BTU rating of the fuel consumed. The natural gas BTU used shall be that value supplied by the natural gas vendor from the previous month's bill. The BTU limit for coal shall be determined by monitoring the daily coal consumption and multiplying that value with the coal BTU rating. Appendix A outlines how the coal BTU rating is calculated. KUC shall provide test certification for each load of coal received. Test certification for each load received shall be defined as test once per day for coal received that day from each supplier. Certification shall be either by their own testing or test reports from the coal marketer. Records of BTU fuel usage shall be kept on a daily basis. [R307-401]

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 (68oF, 29.92 in Hg)
   b) NO_x: 159 lb/hr and 336 ppmdv (measured at 3% oxygen)

2) For boiler no. 4:
   a) PM_{10}: 0.004 grain/dscf (68oF, 29.92 in Hg)
   b) NO_x: 306 lb/hr and 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 and 0.029 grain/dscf (68oF, 29.92 in Hg)
   b) NO_x: 216 lb/hr and 426.5 ppmdv (measured at 3% oxygen)

2) For boiler no. 4:
   a) PM_{10}: 33.5 lb/hr and 0.029 grain/dscf (68oF, 29.92 in Hg)
   b) NO_x: 377 lb/hr and 384 ppmdv (measured at 3% oxygen)

E. KUC 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.

[R307-401]

II.B.3.c During each annual period from March 1 to October 31, inclusive, the following conditions shall apply:

A. KUC shall use coal, natural gas, and/or 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. Fuel usage shall not exceed 50,400 MMBTU per day of heat input.

Compliance with the consumption limit on fuel usage shall be determined by calculating the MMBTU used per day. The BTU limit shall be determined by monitoring the daily natural gas, and/or coal consumption and multiplying that value with the BTU rating of the fuel consumed. The natural gas BTU used shall be that value supplied by the natural gas vendor from the previous month's bill. The BTU limit for coal shall be determined by monitoring the daily coal consumption and multiplying that value with the coal BTU rating. Appendix A outlines how the coal BTU rating is calculated. KUC shall provide test certification for each load of coal received. Test certification for each load received shall be defined as test once per day for coal received that day from each supplier. Certification shall be either by KUC's own testing or test reports from the coal marketer. Records of BTU fuel usage shall be kept on a daily basis.

[R307-401]

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 and 0.029 grain/dscf (68 degrees F, 29.92 in Hg)
   b) NO_x: 216 lb/hr and 426.5 ppmdv (measured at 3% oxygen)

2) For boiler no. 4:
   a) PM_{10}: 33.5 lb/hr and 0.029 grain/dscf (68 degrees F, 29.92 in Hg)
   b) NO_x: 377 lb/hr and 384 ppmdv (measured at 3% oxygen)

[R307-401]

II.B.3.d Stack testing to show compliance with the above emission limitations shall be performed for 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:

	Pollutant	Method	Retest every
A.	PM_{10}	201/201a	1 year
B.	NO_x	7	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 each of boilers 1, 2 & 3 and 754 MMBTU/hr for boiler #4. The limited use of natural gas during startup, for maintenance firings and break-in firings does not constitute operation and does not require stack testing.

C. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary. The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Executive Secretary.

D. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location

[R307-401]

E. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or other testing methods approved by the Executive Secretary.

F. PM_{10}

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201a, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM_{10}. The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the

EPA document, AP-42, or other data acceptable to the Executive Secretary. The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

G. NO_x

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by the Executive Secretary.

H. Calculations

To determine mass emission rates (lb/hr, etc.) 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

[R307-401]

Section III: APPLICABLE FEDERAL REQUIREMENTS

In addition to the requirements of this AO, all applicable provisions of the following federal programs have been found to apply to this installation. 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 UAC R307.

NSPS (Part 60), IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
NSPS (Part 60), KKKK: Standards of Performance for Stationary Combustion Turbines
MACT (Part 63), YYYY: National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines
MACT (Part 63), ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
Title V (Part 70) Major source

PERMIT HISTORY

The final AO will be based on the following documents:

Incorporates	Source Submitted NOI dated December 15, 2010
Incorporates	Additional Information Received dated January 20, 2011
Incorporates	Additional Information Received dated April 20, 2011
Incorporates	Additional Information Received dated July 20, 2011
Supersedes	DAQE-AN0105720022-09 dated May 14, 2009

ADMINISTRATIVE CODING

The following information is for UDAQ internal classification use only:

Salt Lake County
CDS A
Compliance Assurance Monitoring (CAM), MACT (Part 63), NSPS (Part 60), Nonattainment or Maintenance Area, PM_{10} SIP / Maint Plan, Title V (Part 70) Major source

ACRONYMS

The following lists commonly used acronyms as they apply to this document:

40 CFR	Title 40 of the Code of Federal Regulations
AO	Approval Order
BACT	Best Available Control Technology
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CDS	Classification Data System (used by EPA to classify sources by size/type)
CEM	Continuous emissions monitor
CEMS	Continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	Carbon monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent - 40 CFR Part 98, Subpart A, Table A-1
COM	Continuous opacity monitor
DAQ	Division of Air Quality (typically interchangeable with UDAQ)
DAQE	This is a document tracking code for internal UDAQ use
EPA	Environmental Protection Agency
FDCP	Fugitive Dust Control Plan
GHG	Greenhouse Gas(es) - 40 CFR 52.21 (b)(49)(i)
GWP	Global Warming Potential - 40 CFR Part 86.1818-12(a)
HAP or HAPs	Hazardous air pollutant(s)
ITA	Intent to Approve
LB/HR	Pounds per hour
MACT	Maximum Achievable Control Technology
MMBTU	Million British Thermal Units
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOI	Notice of Intent
NO_x	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM_{10}	Particulate matter less than 10 microns in size
$PM_{2.5}$	Particulate matter less than 2.5 microns in size
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
R307	Rules Series 307
R307-401	Rules Series 307 - Section 401
SO_2	Sulfur dioxide
Title IV	Title IV of the Clean Air Act
Title V	Title V of the Clean Air Act
TPY	Tons per year
UAC	Utah Administrative Code
UDAQ	Utah Division of Air Quality (typically interchangeable with DAQ)
VOC	Volatile organic compounds