State of Utah

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Department of
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DIVISION OF AIR QUALITY
Bryce C. Bird
Director

RN103270030

September 29, 2022

Jon Finlinson
Intermountain Power Service Corporation
850 West Brush Wellman Rd
Delta, UT 846249546
Mike.Utley@ipsc.com

Dear Jon Finlinson,

Re: Engineer Review:
Modification to DAQE-AN103270029-22 to Correct a NO_x Limit Averaging Period
Project Number: N103270030

The DAQ requests a company representative (Title V Responsible Official for enhanced Approval Order application) review and sign the attached Engineer Review (ER). This ER identifies all applicable elements of the New Source Review permitting program. Intermountain Power Service Corporation should complete this review within **10 business days** of receipt.

Intermountain Power Service Corporation should contact **John Jenks** at (385) 306-6510 if there are questions or concerns with the review of the draft permit conditions. Upon resolution of your concerns, please email jjenks@utah.gov the signed cover letter to John Jenks. Upon receipt of the signed cover letter, the DAQ will prepare an ITA for a 30-day public comment period. At the completion of the comment period, the DAQ will address any comments and will prepare an AO for signature by the DAQ Director.

If Intermountain Power Service Corporation does not respond to this letter within **10 business days,** the project will move forward without source concurrence. If Intermountain Power Service Corporation has concerns that cannot be resolved and the project becomes stagnant, the DAQ Director may issue an Order prohibiting construction.

Approval Signature ____

(Signature & Date)

☐ By (Title V responsible official) initialing this box and signing this document, this document serves as an enhanced application and the public comment period will serve as the required comment period for Title V purposes.

The Title V responsible official certifies: based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

UTAH DIVISION OF AIR QUALITY
ENGINEER REVIEW

SOURCE INFORMATION

Project Number	N103270030
Owner Name	Intermountain Power Service Corporation
Mailing Address	850 West Brush Wellman Rd Delta, UT, 846249546
Source Name	Intermountain Power Service Corporation- Intermountain
Generation Station	
Source Location	850 West Brush Wellman Road Delta, UT 84624-9546
UTM Projection	364136.12 m Easting, 4374604.80 m Northing
UTM Datum	NAD27
UTM Zone	UTM Zone 12
SIC Code	4911 (Electric Services)
Source Contact	Mike Utley
Phone Number	(435) 864-6489
Email	Mike.Utley@ipsc.com
Project Engineer	John Jenks, Engineer
Phone Number	(385) 306-6510
Email	jjenks@utah.gov
Notice of Intent (NOI) Submitted	August 29, 2022
Date of Accepted Application	August 30, 2022

SOURCE DESCRIPTION

General Description

Intermountain Power Agency (IPA) operates the Intermountain Generating Station facility in Delta, Utah. Intermountain Generating Station consists of two (2) coal-fired electric utility steam generating units and the ancillary facilities to support their normal operation. The units are dry bottom, wall-fired boilers with a nominal capacity of 9,225 MMBtu/hr each. These units will be replaced with two 487 MW natural-gas/hydrogen fueled CCCT units controlled with selective catalytic reduction (SCR). The plant is a Phase II Acid Rain source and is a major source of SO_2, NO_x, PM_{10}, $PM_{2.5}$, CO, HAP, and HCl emissions.

NSR Classification:

Minor Modification at Major Source

Source Classification

Located in Attainment Area,
Millard County
Airs Source Size: A

Applicable Federal Standards

NSPS (Part 60), A: General Provisions
NSPS (Part 60), Da: Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978
NSPS (Part 60), Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
NSPS (Part 60), Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
NSPS (Part 60), Y: Standards of Performance for Coal Preparation and Processing Plants
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
NSPS (Part 60), TTTT: Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units
MACT (Part 63), A: General Provisions
MACT (Part 63), ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
MACT (Part 63), DDDDD: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
MACT (Part 63), UUUUU: National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units
MACT (Part 63), JJJJJ: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources
Title IV (Part 72 / Acid Rain)
Title V (Part 70) Major Source

Project Proposal

Modification to DAQE-AN103270029-22 to Correct a NO_x Limit Averaging Period

Project Description

When AO DAQE-AN103270029-22 was issued, an inadvertent error was included in the averaging period for the NO_x limit on the new combustion turbines. Rather than including the correct 30-day rolling period established as BACT, an erroneous averaging period of 3-hours was listed. This permitting action is to rectify this error. As this could potentially be viewed as a relaxation of a permit term, a 30-day public comment period is required prior to making this change. No other changes are anticipated as part of this permitting action.

EMISSION IMPACT ANALYSIS

This permitting action does not represent a change in emissions. The only change taking place is a change in the averaging period for demonstrating compliance with the NO_x limit. As there is not change in emissions no modeling is required. [Last updated August 30, 2022]

SUMMARY OF EMISSIONS

The emissions listed below are an estimate of the total potential emissions from the source. Some rounding of emissions is possible.

Criteria Pollutant	Change (TPY)	Total (TPY)
CO_2 Equivalent	0	3,952,225
Carbon Monoxide	0	236.51
Lead	0	0.00
Nitrogen Oxides	0	286.92
Particulate Matter - PM_{10}	0	112.57
Particulate Matter - $PM_{2.5}$	0	108.29
Sulfur Dioxide	0	128.90
Volatile Organic Compounds	0	82.09

Hazardous Air Pollutant	Change (lbs/yr)	Total (lbs/yr)
Beryllium (TSP) (CAS #7440417)	0	0
Generic HAPs (CAS #GHAPS)	0	35560
Hydrochloric Acid (Hydrogen Chloride) (CAS #7647010)	0	0
Lead (CAS #7439921)	0	0
Mercury (Organic) (CAS #22967926)	0	0
	Change (TPY)	**Total (TPY)**
Total HAPs	0	17.78

Note: Change in emissions indicates the difference between previous AO and proposed modification.

Review of BACT for New/Modified Emission Units

1. **BACT review regarding NO_x emissions (original review excerpt).**
The following represents the original BACT review for the combustion turbines NO_x emissions:

BACT review regarding CCCT NO_x Emissions
NO_x control for CTGs are limited compared to coal-fired units. Selective non-catalytic reduction (SNCR) systems are not technically feasible for CTGs due to the temperature regime. OFA is specific to use in a coal-fired boiler. The SNCR and OFA technologies are therefore not discussed further.

Step 1: Identify All Control Technologies
Dry low NO_x burners (DLNBs) mitigate thermal NO_x formation without the use of water or steam, hence the term dry. DLNBs uses a lean mixture of fuel and air (a lower fuel per air ratio, which is also more excess air) to lower the combustion flame temperature, which in turns dampens NO_x formation. Water injection and DLNBs typically are not installed with one another.

Selective Catalytic Reduction (SCR) system injects ammonia in the presence of a catalyst. The catalyst operates best around 600 to 750°F. Outside of this temperature range, the catalyst activity drops and at high temperatures, the catalyst structure can degrade. Thus, SCRs have been commonly installed in combined cycle applications and not for bypass stacks or simple cycle operations.

Step 2: Eliminate Technically Infeasible Options
DLNBs and SCRs are both technically feasible as control technology alternatives.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
SCRs can achieve over 90 percent control in certain applications. For the natural gas scenario in this project, a greater than 95 percent control can be achieved. DLNBs are a standard offering with many CTGs and it is not further discussed here due to its implicit application.

Step 4: Evaluate Most Effective Controls
Energy Impacts
The use of an SCR system has significant energy impacts on a CTG. The additional backpressure on the turbine will result in less energy output. In addition to the backpressure, the SCR system requires an ammonia storage, handling, and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. The pumps and vaporizers will require energy.

Environmental Impacts
The environmental impacts of the SCR system are many. The vanadium content of the catalyst classifies it as a hazardous waste. The use of ammonia in an SCR system introduces an element of environmental risk. However, the storage and use of ammonia is a relatively routine practice. Ammonia slip from an SCR system is one of the major design considerations that establishes catalyst life. The SCR catalyst will oxidize approximately 2 to 3% of the SO_2 in the flue gas to SO_3. The SO_2 may react with ammonia or moisture present in the flue gas to form ammonium sulfate and bisulfate salts and H_2SO_4. These in turn will increase the amount of PM_{10} emitted in the flue gas. As the catalyst gradually deactivates, more ammonia must be injected to compensate and maintain the desired NO_x reduction. This results in an increased amount of ammonia slip.

Economic Impacts

An economic impact analysis was not performed as the installation of a SCR is included in the design of the CCCT system.

Step 5: Select BACT
The installation of a SCR is considered BACT. The SCR will control the NO_x emissions to 2 ppmvd (at 15% O_2) while firing natural gas or a combination of natural gas and hydrogen gas during normal operation. The emission rate will be monitored with a CEMS and it is proposed that compliance with this limit be achieved based on a 30-day rolling average.

[Last updated August 30, 2022]

SECTION I: GENERAL PROVISIONS

The intent is to issue an air quality AO authorizing the project with the following recommended conditions and that failure to comply with any of the conditions may constitute a violation of the AO. **(New or Modified conditions are indicated as "New" in the Outline Label):**

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 Director or Director'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. [R307-401-8]
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 Director 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 UAC R307-107. General Requirements: Breakdowns. [R307-107]

I.7	The owner/operator shall comply with UAC R307-150 Series. Emission Inventories. [R307-150]
I.8	The owner/operator shall submit documentation of the status of construction of the new Combustion Turbine Plant equipment (II.A.3 through II.A.9) to the Director by December 22, 2023. This AO may become invalid if construction is not commenced within 18 months from the date of this AO or if construction is discontinued for 18 months or more. To ensure proper credit when notifying the Director, send the documentation to the Director, attn.: NSR Section. [R307-401-18]

SECTION II: PERMITTED EQUIPMENT

The intent is to issue an air quality AO authorizing the project with the following recommended conditions and that failure to comply with any of the conditions may constitute a violation of the AO. **(New or Modified conditions are indicated as "New" in the Outline Label):**

II.A **THE APPROVED EQUIPMENT**

II.A.1	**Electric Plant** Combustion turbine plant, coal-fired boiler plant, emergency equipment, etc.
II.A.2	**Combustion Turbine Plant Equipment** The following items are located at the new combustion turbine plant
II.A.3	**Combined Cycle Combustion Turbines** Two 487 MW natural gas and hydrogen-fired combined-cycle combustion turbines Control: SCR and oxidation catalyst
II.A.4	**Fuel Gas Heaters** Two 9.9 MMBtu/hr natural gas-fired heaters
II.A.5	**Auxiliary Boiler** 136 MMBtu/hr natural gas-fired auxiliary boiler Control: Low-NO_x Burner (0.14 lb/MMBtu)
II.A.6	**Cooling Towers** Two six-cell linear mechanical draft cooling towers (LMDCTs) 88,341 gpm of cooling water per tower
II.A.7	**Emergency Generators** Three diesel-fired emergency generators Rating: 2,500 kW Each NSPS Applicability: Subpart IIII MACT Applicability: Subpart ZZZZ
II.A.8	**Firewater Pump** One 425 bhp diesel-fired emergency firewater pump engine

II.A.9	**Miscellaneous Fugitive Sources** Natural gas piping components (pipes, flanges, valves, etc.) New circuit breakers located at switchyard - SF6 insulated, air cooled.
II.A.10	**Existing Equipment** The following existing equipment (II.A.11 through II.A.31) will remain available for operation at the site following installation of the new turbine plant
II.A.11	**#1 Lime Dust Collector** Dust collector controlling the lime silo
II.A.12	**#2 Lime Dust Collector** Dust collector controlling the lime hopper
II.A.13	**#3 Soda Ash Dust Collector** Dust collector controlling the soda ash silo
II.A.14	**#4 Soda Ash dust Collector** Dust collector controlling the soda ash hopper
II.A.15	**Paved Haul Roads**
II.A.16	**Landfill** Class III Industrial Waste Landfill
II.A.17	**Gasoline Tank** Capacity: 500 gallons
II.A.18	**Diesel Tank** Capacity: 10,000 gallons
II.A.19	**Diesel Day Tanks** Maximum capacity: Not to exceed 560 gallons per tank
II.A.20	**Mobile Oil Storage Tanks** Maximum capacity: Not to exceed 12,000 gallons per tank
II.A.21	**Used Oil Tank** Capacity: 10,000 gallons
II.A.22	**On-Road Diesel Tank** Non-commercial, ultra low sulfur, highway diesel fuel tank Capacity: 500 gallons
II.A.23	**Paint booth/shops**
II.A.24	**Solvent Washer**
II.A.25	**Bulb recycling crusher**

II.A.26	**Emergency diesel-driven fire pump** Diesel fire pump located at the Intermountain Community Center, but operated by IPP. Rating: 290 HP
II.A.27	**Engine Driven Equipment** Compressors, generators, hydraulic pumps and diesel fire pumps
II.A.28	**Unpaved Haul Roads**
II.A.29	**#1B Fire Pump** Diesel driven fire pump Rating: 290 hp
II.A.30	**#1C Fire Pump** Diesel driven fire pump Rating: 290 hp
II.A.31	**ICS Cooling Towers** 8 cooling towers used at the Intermountain Convertor Station and auxiliary equipment
II.A.32	**Coal-fired Boiler Plant Equipment** The following equipment (II.A.32 - II.A.87) is considered part of the coal-fired boiler plant and will be removed from service once the combustion turbine plant is operational
II.A.33	**Unit #1 Coal Fired Boiler** Equipped with low NO_x burners with a maximum heat input of 248 MMBtu/hr per burner. Rating - 9,225,000,000 MMBtu/yr
II.A.34	**Unit #2 Coal Fired Boiler** Equipped with low NO_x burners with a maximum heat input of 248 MMBtu/hr per burner. Rating - 9,225,000,000 MMBtu/yr
II.A.35	**Over-Fire Air-Port System** Boiler #1 & #2 over-fire air-ports system, 16 per boiler
II.A.36	**#1A Dust Collector** Dust collector controlling coal railcar unloading
II.A.37	**#1B Dust Collector** Dust collector controlling coal railcar unloading
II.A.38	**#1C Dust Collector** Dust collector controlling coal railcar unloading
II.A.39	**#1D Dust Collector** Dust collector controlling coal railcar unloading
II.A.40	**#4 Coal Dust Collector** Dust collector controlling Coal transfer building #1

II.A.41	**#5 Coal Dust Collector** Dust collector controlling coal transfer building #2
II.A.42	**#6 Coal Dust Collector** Dust collector controlling coal transfer building #4
II.A.43	**#11 Coal Dust Collector** Dust collector controlling coal crusher building
II.A.44	**#13A Coal Dust Collector** Dust collector controlling U1 Generation building coal dust
II.A.45	**#13B Coal Dust Collector** Dust collector controlling U1 Generation building coal dust
II.A.46	**#14A Coal Dust Collector** Dust collector controlling U2 Generation building coal dust
II.A.47	**#14B Coal Dust Collector** Dust collector controlling U2 Generation building coal dust
II.A.48	**#4 Limestone Dust Collector** Dust collector controlling limestone preparation
II.A.49	**#2 Coal Dust Collector** Dust collector controlling Coal truck unloading
II.A.50	**#3 Coal Dust Collector** Dust collector controlling coal reserve reclaim
II.A.51	**#1A Limestone Dust Collector** Dust collector controlling limestone unloading
II.A.52	**#1B Limestone Dust Collector** Dust collector controlling limestone unloading
II.A.53	**#1 Limestone Dust Collector** Dust collector controlling limestone transfer
II.A.54	**#2 Limestone Dust Collector** Dust collector controlling limestone reclaim
II.A.55	**Limestone silo bin vent filter**
II.A.56	**#3 Limestone Dust Collector** Dust collector controlling limestone crusher
II.A.57	**#1A Filter** Fly ash silo bin vent filter

II.A.58	**#1B Filter** Fly ash silo bin vent filter
II.A.59	**Coal sample preparation building dust collector**
II.A.60	**Sandblast facility dust collector**
II.A.61	**Dust Collector** Dust collector controlling U1 Generation building vacuum cleaning
II.A.62	**Dust Collector** Dust collector controlling U2 Generation building vacuum cleaning
II.A.63	**Dust Collector** Dust collector controlling U1 Fabric filter vacuum cleaning
II.A.64	**Dust Collector** Dust collector controlling U2 Fabric filter vacuum cleaning
II.A.65	**Dust Collector** Dust collector controlling GSB vacuum cleaning
II.A.66	**Coal Pile** Active and reserve
II.A.67	**Coal Stackout**
II.A.68	**#1A Tank** Fuel oil tank Capacity: 675,000 gallons
II.A.69	**#1B Tank** Fuel oil tank Capacity: 675,000 gallons
II.A.70	**Limestone storage pile**
II.A.71	**Combustion byproducts stackout & stockpile**
II.A.72	**Combustion byproducts landfill**
II.A.73	**#1A Cooling Tower** Unit 1 cooling tower
II.A.74	**#1B Cooling Tower** Unit 1 cooling tower
II.A.75	**#1A Cooling Tower** Unit 2 cooling tower

II.A.76	**#1B Cooling Tower** Unit 2 cooling tower
II.A.77	**#1A Generator** Emergency generator Rating:* 4,000 hp
II.A.78	**#1B Generator** Emergency generator Rating: 4,000 hp
II.A.79	**#1C Generator** Emergency generator, Rating: 4,000 hp
II.A.80	**Engine Driven Equipment** Compressors and hydraulic pumps
II.A.81	**Coal Conveyors**
II.A.82	**Coal Truck Unloading Grating**
II.A.83	**Laboratory fume hoods**
II.A.84	**Turbine Lube Oil Units** Maximum capacity: Not to exceed 40,000 gallons per tank
II.A.85	**Diesel Tank** Underground storage diesel tank Capacity: 20,000 gallons
II.A.86	**Gasoline Tank** Underground storage gasoline tank Capacity: 6,000 gallons
II.A.87	**Two Helper Cooling Towers**

SECTION II: SPECIAL PROVISIONS

The intent is to issue an air quality AO authorizing the project with the following recommended conditions and that failure to comply with any of the conditions may constitute a violation of the AO. **(New or Modified conditions are indicated as "New" in the Outline Label):**

II.B REQUIREMENTS AND LIMITATIONS

II.B.1	**Intermountain Generating Station**
II.B.1.a NEW	Visible emissions from the following emission point sources shall not exceed the listed values:

	A. All abrasive blasting - 40% opacity (grandfathered equipment) B. All other points - 20% opacity Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9. For sources that are subject to NSPS, except for the units equipped with continuous opacity monitoring system, opacity shall be determined by conducting observations in accordance with 40 CFR 60.11(b) and 40 CFR 60, Appendix A, Method 9. [R307-201-3]
II.B.1.b	The owner/operator shall abide by the latest FDCP submitted to the Director for control of all dust sources associated with the Intermountain Power Generation site. Any haul road speeds established in the plan shall be posted. [R307-205]
II.B.1.c	The facility shall abide by all applicable requirements of R307-205 for Fugitive Emission and Fugitive Dust sources. [R307-205]
II.B.2	**Stack Testing Requirements**
II.B.2.a	The owner/operator shall conduct any stack testing required by this AO according to the following conditions. [R307-401-8]
II.B.2.a.1	**Notification** At least 30 days prior to conducting a stack test, the owner/operator shall submit a source test protocol to the Director. The source test protocol shall include the items contained in R307-165-3. If directed by the Director, the owner/operator shall attend a pretest conference. [R307-165-3, R307-401-8]
II.B.2.a.2	**Testing & Test Conditions** The owner/operator shall conduct testing according to the approved source test protocol and according to the test conditions contained in R307-165-4. [R307-165-4, R307-401-8]
II.B.2.a.3	**Access** The owner/operator shall provide Occupational Safety and Health Administration (OSHA)- or Mine Safety and Health Administration (MSHA)-approved access to the test location. [R307-401-8]
II.B.2.a.4	**Reporting** No later than 60 days after completing a stack test, the owner/operator shall submit a written report of the results from the stack testing to the Director. The report shall include validated results and supporting information. [R307-165-5, R307-401-8]
II.B.2.a.5	**Possible Rejection of Test Results** The Director may reject stack testing results if the test did not follow the approved source test protocol or for a reason specified in R307-165-6. [R307-165-6, R307-401-8]
II.B.2.b	**Test Methods** When performing stack testing, the owner/operator shall use the appropriate EPA-approved test methods as acceptable to the Director. Acceptable test methods for pollutants are listed below. [R307-401-8]

II.B.2.b.1	**Standard Conditions** A. Temperature - 68 degrees Fahrenheit (293 K) B. Pressure - 29.92 in Hg (101.3 kPa) C. Averaging Time - As specified in the applicable test method [40 CFR 60 Subpart A, 40 CFR 63 Subpart A, R307-401-8]
II.B.2.b.2	**PM_{10}** Total PM_{10} = Filterable PM_{10} + Condensable PM Filterable PM_{10} 40 CFR 60, Appendix A, Method 5; 40 CFR 51, Appendix M, Method 201; Method 201A; or other EPA-approved testing method as acceptable to the Director. If other approved testing methods are used which cannot measure the PM_{10} fraction of the filterable particulate emissions, all of the filterable particulate emissions shall be considered PM_{10}. Condensable PM 40 CFR 51, Appendix M, Method 202 or other EPA-approved testing method as acceptable to the Director. [R307-401-8]
II.B.2.b.3	**NO_x** 40 CFR 60, Appendix A, Method 7; Method 7E; or other EPA-approved testing method as acceptable to the Director. [R307-401-8]
II.B.2.b.4	**SO_2** 40 CFR 60, Appendix A, Method 6; Method 6C; or other EPA-approved testing method as acceptable to the Director. [R307-401-8]
II.B.2.b.5	**CO** 40 CFR 60, Appendix A, Method 10 or other EPA-approved testing method as acceptable to the Director. [R307-401-8]
II.B.2.b.6	**VOC** 40 CFR 60, Appendix A, Method 18; Method 25; Method 25A; 40 CFR 63, Appendix A, Method 320; or other EPA-approved testing method as acceptable to the Director. [R307-401-8]
II.B.2.b.7	**Existing Source Operation:** For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years. [R307-401-8]
II.B.3	**Combustion Turbine Plant**
II.B.3.a	The owner/operator shall install, calibrate, maintain, and operate a continuous emissions monitoring system on each of the HRSG stacks. The owner/operator shall record the NO_x and CO emissions. The monitoring system shall comply with all applicable sections of R307-170;

	40 CFR 13; and 40 CFR 60, Appendix B. The NO_x monitor shall comply with 40 CFR 75, Appendix A and B. All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed prior to placing the affected source in operation. These devices shall be certified within 90 days of achieving full load, not to exceed 180 days after startup. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13. [40 CFR 60.13, R307-170]
II.B.3.b NEW	The owner/operator shall use natural gas or hydrogen (H2) as fuel in the combustion turbines. The owner/operator shall use natural gas as fuel in the auxiliary boiler. [R307-401-8(1)(a)]
II.B.3.c	The owner/operator shall not exceed 535 million standard cubic feet (SCF) natural gas consumption at the 136 MMBtu/hr Auxiliary Boiler (II.A.5) per rolling 12-month period. [R307-401-8(1)(a)]
II.B.3.c.1	Natural gas consumption shall be monitored through use of a flow meter on the natural gas supply line to the Auxiliary Boiler. Fuel usage shall be determined and recorded monthly. By the 20th day of each month a new rolling 12-month total shall be calculated by summing the monthly fuel usage values for the previous 12 months. Monthly and total 12-month fuel usage shall be recorded in an operations log. [R307-401-8]
II.B.3.d NEW	Emissions to the atmosphere from each Turbine/HRSG Stack shall not exceed the following rates and concentrations: Pollutant — Limitations — Averaging Period NO_x — 2.0 ppmvd at 15% O_2 * — 30-day rolling CO — 2.0 ppmvd at 15% O_2 * — 3-hour VOC — 1.0 ppmvd at 15% O_2 * — 3-hour * Under steady state operation. [R307-401-8(1)(a)]
II.B.3.d.1	Stack testing to demonstrate compliance with the emission limitations stated in the above condition shall be performed on the following schedule: Each turbine/HRSG stack NO_x: compliance shall be demonstrated by CEM as outlined in condition II.B.3.a. The Director may require testing at any time. CO: compliance shall be demonstrated by CEM as outlined in condition II.B.3.a. The Director may require testing at any time. VOC: initial testing is required within 180 days of beginning operation, subsequent testing to be conducted at least once annually. Testing may be replaced with parametric monitoring if approved by the Director. [R307-165, R307-170]

II.B.3.d.2 NEW	Steady state operation means all periods of combustion turbine operation, except for periods of startup and shutdown as defined below. Startup is defined as the period beginning with turbine initial firing until the unit meets the ppmvd emission limits listed in condition II.B.3.d for steady state operation. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine. The owner/operator shall ensure the following limitations: 1.Startup and shutdown events shall not exceed 114.9 hours per turbine per rolling 12-month period and are counted toward the applicable annual emission limitations. 2. Emissions of NO_x from either turbine/HRSG stack shall not exceed 100.8 lb/hr during startup or shutdown operations. 3. Emissions of CO from either turbine/HRSG stack shall not exceed 624.0 lb/hr during startup or shutdown operations. Compliance with the hours of operation limitation shall be determined though maintenance of an operations log detailing the mode of operation and total hours of operation in each mode. Compliance with the NO_x and CO emission limits shall be determined by CEM as outlined in II.B.3.a. [R307-401-8(1)(a)]
II.B.4	**Emergency Engine Requirements**
II.B.4.a	The owner/operator shall install emergency engines (II.A.7) that are certified to meet a NO_x emission rate of 7.29 g/kW-hr or less. [R307-401-8(1)(a)]
II.B.4.a.1	To demonstrate compliance with the emission rate, the owner/operator shall keep a record of the manufacturer's certification of emission standards. The record shall be kept for the life of the equipment. [R307-401-8]
II.B.4.b	The owner/operator shall not operate each emergency engine on site for more than 100 hours per rolling 12-month period during non-emergency situations. There is no time limit on the use of the engines during emergencies. [40 CFR 63 Subpart ZZZZ, R307-401-8]
II.B.4.b.1 NEW	To determine compliance with a rolling 12-month total, the owner/operator shall calculate a new 12-month total by the 20th day of each month using data from the previous 12 months. Records documenting the operation of each emergency engine shall be kept in a log and shall include the following: A. The date the emergency engine was used B. The duration of operation in hours C. The reason for the emergency engine usage. [40 CFR 60 Subpart ZZZZ, R307-401-8]
II.B.4.b.2	To determine the duration of operation, the owner/operator shall install a non-resettable hour meter for each emergency engine (generator or fire water pump). [40 CFR 60 Subpart ZZZZ, R307-401-8]

II.B.4.c	The owner/operator shall only use diesel fuel (e.g. fuel oil #1, #2, or diesel fuel oil additives) as fuel in each emergency engine (generator or fire water pump). [R307-401-8]
II.B.4.c.1	The owner/operator shall only combust diesel fuel that meets the definition of ultra-low sulfur diesel (ULSD), which has a sulfur content of 15 ppm or less. [R307-401-8]
II.B.4.c.2	To demonstrate compliance with the ULSD fuel requirement, the owner/operator shall maintain records of diesel fuel purchase invoices or obtain certification of sulfur content from the diesel fuel supplier. The diesel fuel purchase invoices shall indicate that the diesel fuel meets the ULSD requirements. [R307-401-8]
II.B.5	**Coal Plant Sunset Provisions**
II.B.5.a NEW	The equipment listed in Section II.A.32 under the heading Coal-fired Boiler Plant Equipment shall remain in operation until such time as the new combustion turbines are installed and operational. The new Combustion Turbine Plant will become operational only after a reasonable shakedown period, not to exceed 180 days. At that time the listed Coal Boiler Plant Equipment shall cease operations and be removed from service. Conditions II.B.6 through II.B.7.a, shall not apply to the owner/operator once the equipment has been removed from service. [R307-401]
II.B.6	**Unit #1 & Unit #2 Main Boilers**
II.B.6.a	The owner/operator shall combust only bituminous, subbituminous coals, non-limited synthetic coal-derived fuels and refined coal (synfuels), as primary fuels and shall only use diesel oil or natural gas during the startups, shutdowns, maintenance, performance tests, upsets and for flame stabilization in the 9,225 MMBtu/hr boilers. The owner/operator may fuel-blend self-generated used oil with coal at the active coal pile reclaim structure provided that self-generated used oil has not been mixed with hazardous waste. [R307-401]
II.B.6.a.1	The sulfur content of any fuel oil combusted shall not exceed 0.85 lb/MMBtu heat input in the main boilers. The sulfur content shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of fuel oil shall either be by IPSCs own testing or test reports from the fuel oil marketer. [R307-203]
II.B.6.b	The owner/operator shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) on the main boiler stacks and SO_2 removal scrubber inlets. The owner/operator shall record the output of the system, for measuring the opacity, SO_2, NO_x, and CO_2 emissions. The monitoring system shall comply with all applicable sections of R307-170, UAC; and 40 CFR 60, Appendix B. All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed and operational prior to placing the affected source in operation. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring devices and shall meet minimum frequency of operation requirements as outlined in 40 CFR 60.13 and Section UAC R307-170. [R307-150]
II.B.6.c	Unit #1 & Unit #2 Main Boiler Stack

	Except for time of start-up, shut-down, malfunction (NO_x or PM_{10} only), or emergency conditions (SO_2 only), emissions to the atmosphere at all times from the indicated emission points shall not exceed the following rates and concentrations: Pollutant lb/MMBtu heat input PM_{10} 0.0184* SO_2 0.138 ** (based on 30-day rolling average) NO_x 0.461 ** (based on 30-day rolling average) * Test once a year. The Director may require testing at any time. ** Compliance for NO_x and SO_2 emissions shall be demonstrated through use of a continuous emissions monitoring system as outlined in Condition II.B.6.b. [R307-401]
II.B.6.c.1	Calculations for Test Results: Unit #1 & Unit #2 Boiler Stacks 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 Director, to give the results in the specified units of the emission limitation. Pollutant lbs/hr (Compliance demonstration) CO 1320 lb/hr rate (monthly block average) Combustion flue gas percent O_2 shall be monitored and recorded at least once per 15 minutes at the exit path of each boiler. Measurements are weighted average results collected from several sensors located in each boiler exit flue path. Calibrations shall be maintained within manufacturer's recommendations. Over-Fire Air (OFA) operating condition shall be monitored and recorded at least once per 15 minutes. Monitoring shall include OFA position and status: i.e., No OFA, 1/3 OFA, 2/3 OFA, throttled or open. Operational status is measured by OFA system damper position. Using the data above and this formula, CO concentration (ppmdv) shall be calculated and averaged hourly, except for periods of calibration, maintenance, or malfunction of the instrumentation or data system. For periods of calibration, maintenance, or malfunction of instrumentation or data collection system, missing data shall be back filled following procedures similar to 40 CFR Part 75 Subpart D, and used for compliance determinations. [Cppmvd] = n * (O_2%)^a Where: [Cppmvd] = concentration of CO in parts per million volume dry n = curve specific factor obtained from the table below O_2% = percent O_2 measured at the boiler stack exit a = curve specific exponent obtained from the table below Values for n and a factors: n a No. OFA 47259 -7.6817

	1/3 OFA 66265 -7.9824 2/3 OFA (Throttled) 4029.2 -4.0112 2/3 OFA (full open) 1372.4 -3.0919 The hourly mass emission rates in lb per hour shall be calculated using the following formula or any necessary conversion factors determined by the Director, to give the results in the specified units of the emission limitation. [Clb/hr] = [Cppmvd] * 2.59 * 10E-9 * MW * Fd * 20.9/(20.9-O_2%) * HI Where: [Clb/hr] = pound per hour emission rate [Cppmvd] = hourly average of CO emissions in parts per million 2.59*10E-9 = conversion factor for pound per standard cubic feet MW = molecular weight of CO Fd= F factor to convert standard cubic feet per MMBtu heat input. O_2% = hourly average of excess combustion oxygen, in percent HI = heat input, in MMBtu per hour By the 15th day of each month, the monthly average of CO emissions in lb/hr shall be calculated by using the hourly average CO emission values in lb/hr. [R307-401]
II.B.6.d	The owner/operator shall comply with R307-424 Permits: Mercury Requirements for Electric Generating Units. [R307-424-4]
II.B.7	**Dust Collectors**
II.B.7.a	Except for times of start-up, shut-down, or malfunction, differential pressure at the indicated emission points, at all times, shall be within the following limits: Pollutant/Source Differential Pressure Range Across the Dust Collector PM_{10} (Inches of water gage) (4) Rail car unloading units 0.5 to 12 Transfer building #1 0.5 to 12 Transfer building #2 0.5 to 12 Transfer building #4 0.5 to 12 Crusher building #1 0.5 to 12 Unit one 13A 0.5 to 12 Unit one 13B 0.5 to 12 Unit two 14A 0.5 to 12 Unit two 14B 0.5 to 12 Limestone preparation building 0.5 to 12 If any differential pressure is less than 2 inches or greater than 10 inches, work orders will be written to investigate. Dust collector may run in the 0.5 to 2 or 10 to 12 range if reason is known. Intermittent recording of the reading is required on a monthly basis. The instrument shall be calibrated against a primary standard annually. Preventive maintenance shall be done quarterly on each baghouse. [R307-401]

PERMIT HISTORY

When issued, the approval order shall supersede (if a modification) or will be based on the following documents:

Is Derived From	Source Submitted NOI dated August 29, 2022
Supersedes	DAQE-AN103270029-22 dated June 22, 2022

REVIEWER COMMENTS

1. **<u>Comment regarding correction to condition II.B.3.d:</u>**
   When originally issued, AO DAQE-AN103270029-22 contained an error in condition II.B.3.d. The averaging period for demonstrating compliance with the NO_x limit on the combustion turbines was incorrectly stated as a 3-hr period, rather than what had been established as BACT in the engineering review. BACT for the combustion turbines was established as a 30-day rolling average, to be monitored by CEM. The relevant portion of the original BACT analysis has been re-included in this engineering review for clarity (see the BACT section above for details). This permitting action corrects that error. As the change represents a relaxation of a permit term, a 30-day public comment period is required. No other changes in any conditions or requirements of AO are anticipated by this permitting action. [Last updated September 1, 2022]

ACRONYMS

The following lists commonly used acronyms and associated translations 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
CMS	Continuous monitoring system
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/UDAQ	Division of Air Quality
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
LB/YR	Pounds per year
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
VOC	Volatile organic compounds

John Jenks <jjenks@utah.gov>

Re: Intermountain Power Service Corporation - Project Number N103270029 Update

1 message

John Jenks <jjenks@utah.gov> Tue, Aug 30, 2022 at 10:49 AM
To: "Rinkol, Michael J." <RinkolMJ@bv.com>

Mike,
Well the follow up is that unfortunately we have to go back out for public comment. Since the AO was already issued, changing the averaging period back to 30-days would be a relaxation of a permit term - even though it was issued in error. In the meantime, The company can still build the units without issue, and the new AO should be issued well before the new units go online. Sorry about the inconvenience, but we're stuck with the process. I'll finish the new engineering review and get a copy out to you this afternoon. We should be able to make the first publication next week without issue.
- John

On Tue, Aug 30, 2022 at 10:29 AM Rinkol, Michael J. <RinkolMJ@bv.com> wrote:

> Thanks John, really appreciate your quick response to this issue. Please let me know what they say and if you need anything from us.
>
> Best regards,
>
> **Mike**
>
> ---
>
> **Michael Rinkol, P.E.***
>
> Subject Matter Lead – Air Regulations & Sciences
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> Environmental & Land Services
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> *Licensed in Michigan
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> **E** RinkolMJ@BV.com
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>

From: John Jenks <jjenks@utah.gov>
Sent: Tuesday, August 30, 2022 11:03 AM
To: Rinkol, Michael J. <RinkolMJ@bv.com>
Subject: Re: Intermountain Power Service Corporation - Project Number N103270029 Update

Mike,

No it sounds like that error crept back in on the final version. Let's get it corrected. I'll contact management on my end, using your email as the catalyst to start an administrative change project and we'll get it fixed. I'll also let them know that it was our error and that you guys shouldn't be charged for it. Hopefully that will work. I'll let you know what they say.

- John

On Mon, Aug 29, 2022 at 3:34 PM Rinkol, Michael J. <RinkolMJ@bv.com> wrote:

> John,
>
> Going through some work with the contractors and I happened to notice the permit states the NOX emission limit of 2.0 ppmvd at 15% O2 should be on a 3-hour averaging period (See Condition II.B.3.d). However, the BACT analysis discussion for NOX on page 7 states compliance shall be achieved based on a 30-day rolling average. If I remember correctly, we had a discussion about this in March and thought we came to a conclusion that NOX should be on a 30-day rolling average basis. Please let me know which averaging period is correct when using the CEMS data.
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From: John Jenks <jjenks@utah.gov>
Sent: Wednesday, June 22, 2022 9:38 AM
To: Rinkol, Michael J. <RinkolMJ@bv.com>
Subject: Re: Intermountain Power Service Corporation - Project Number N103270029 Update

In case you haven't yet seen a copy mailed to you, the final AO was signed yesterday afternoon, and should have been emailed to source early this morning.

Please let me know if you have any questions.

- John

On Mon, Jun 20, 2022 at 4:07 PM Rinkol, Michael J. <RinkolMJ@bv.com> wrote:

John,

I did not see the final AO document last week, can you please provide a status update on this? Thanks.

Mike

Michael Rinkol, P.E.*

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From: John Jenks <jjenks@utah.gov>
Sent: Tuesday, June 7, 2022 11:40 AM
To: Rinkol, Michael J. <RinkolMJ@bv.com>
Subject: Re: Intermountain Power Service Corporation - Project Number N103270029 Update

Caution - External Email: This email originated outside of Black & Veatch. Please do not click links or open attachments unless you recognize the sender and know the content is safe.

Michael,

Actually, we didn't receive any comments, and I just approved the final AO document for processing yesterday. It should be heading through for management approval in the next few days, and I expect you will see a final version early next week.

- John

On Tue, Jun 7, 2022 at 10:34 AM Rinkol, Michael J. <RinkolMJ@bv.com> wrote:

John,

Just wondering if you can provide any update on the status of the Approval Order for the reference project in the subject line? Were there in public comments UDEQ received and if so, does UDEQ require any assistance from us to provide support in preparing responses?

Thanks for any information you can provide.

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UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY

John D. Jenks

Environmental Engineer | NSR Major Source

New Phone #: (385) 306-6510

airquality.utah.gov

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