State of Oregon Department of Environmental Quality

OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY
OREGON TITLE V OPERATING PERMIT

Eastern Region
475 NE Bellevue Dr., Suite 110
Bend, OR 97701
Telephone: 541-388-6146

Issued in accordance with provisions of ORS 468A.040
and based on the land use compatibility findings included in the permit record.

ISSUED TO:

Klamath Energy LLC
1125 NW Couch Street, Suite 700
Portland, OR 97209

INFORMATION RELIED UPON:

Application Number: 32643
Received: 08/18/2020

PLANT SITE LOCATION:

Klamath Cogeneration Project (KCP) and
Klamath Generation Peakers (KGP)
4940 Hwy. 97 South
Klamath Falls, OR 97603

LAND USE COMPATIBILITY STATEMENT:

Pursuant to ORS 469, Oregon Department of Energy's Energy Facility Siting Council, in their orders, determined that the proposed land use complies with state wide planning goals.

ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY

Mark W. Bailey, Eastern Region Air Quality Manager

DEC - 8 2020
Date

Nature of Business	SIC	NAICS
Electric power generation, natural gas fired, 25 MW or more	4911	221112

Acid Rain Program Information:

Plant Name	State	ORIS Code	NADB#
Klamath Cogeneration Project	OR	55103	CT-1, CT-2
Klamath Generation Peakers	OR	55544	CT-3, CT-4, CT-5, CT-6

RESPONSIBLE OFFICIAL and
Acid Rain Designated Representative

Title: Managing Director

FACILITY CONTACT PERSON

Name: Jay Schindler
Title: EH & S
Phone: 541-850-6131

Addendum No. 1
Minor Permit Modification

In accordance with OAR 340-218-0170(1), Condition 31 of Oregon Title V Operating Permit 18-0003-TV-01 is revised to read as follows: (Changes are shown with highlight)

EMISSIONS UNIT (EU) AND POLLUTION CONTROL DEVICE (PCD) IDENTIFICATION

3. The emissions units regulated by this permit are the following: [OAR 340-218-0040(3)]

Table 1: Emission Units and Pollution Control Device Identification

Emission Unit (EU) Description	EU ID	Pollution Control Device (PCD)	PCD ID
Turbine/duct burners/heat recovery steam generator (HRSG)	CT-1	Ultra Low-NOx Combustor with Selective catalytic reduction (SCR)	SCR-1
Turbine/duct burners/HRSG	CT-2	Ultra Low-NOx Combustor with SCR	SCR-2
Pratt & Whitney combustion turbine #3	CT-3	Water injection, SCR, CO catalyst	WI#3, SCR#3, CO#3
Pratt & Whitney combustion turbine #4	CT-4	Water injection, SCR, CO catalyst	WI#4, SCR#4, CO#4
Pratt & Whitney combustion turbine #5	CT-5	Water injection, SCR, CO catalyst	WI#5, SCR#5, CO#5
Pratt & Whitney combustion turbine #6	CT-6	Water injection, SCR, CO catalyst	WI#6, SCR#6, CO#6
Auxiliary boiler – natural gas/oil fired	BR	None	NA
Aggregate insignificant activities – dust emissions from vehicle traffic on paved and unpaved roads	AI	None	NA

3.a. Ultra Low-NOx Combustors are to be installed and operational on Combustion Turbines (CT-1 & CT-2) by January 1, 2022.

3.b. The permittee must notify DEQ in writing when the ultra Low-NOx combustors are brought into operation. The notification must be submitted no later than seven (7) days after the initial startup of the ultra Low-NOx combustors. [OAR 340-214-0110]

Source Specific Recordkeeping Requirements

61. Source specific recordkeeping requirements:

61.a. Monthly total plant production (electricity, by unit);
61.b. Hourly and 12-month total auxiliary boiler steam production;
61.c. Operating time of each turbine, duct burner and auxiliary boiler;
61.d. Hourly and 12-month rolling total amount of natural gas burned in each combustion turbine, duct burner and auxiliary boiler;
61.e. Hourly and 12-month rolling total amount of oil burned in the auxiliary boiler, CT-3, CT-4, CT-5 and CT-6 (gallons);
61.f. Number of hours each day and calendar month that oil is burned in the Auxiliary Boiler, CT-3, CT-4, CT-5 and CT-6;
61.g. Hourly and 12-month rolling total heat input for each combustion turbine, duct burner and auxiliary boiler (MMBtu/hr, MMBtu/yr);
61.h. HHV of natural gas as measured by the permittee;
61.i. Oil sulfur content records, HHV and certifications from the oil supplier;
61.j. Valid purchase contract, tariff sheet or transportation contract for the gaseous fuel and/or sulfur content of the natural gas fuel;
61.k. Amount of time CT-1, CT-2, the duct burners and auxiliary boiler are operated simultaneously;
61.l. Total operating time that CT-1 or CT-2 operated broken down to periods within the normal operating range (60 – 100%) and periods within the partial load range (50 - 60%);
61.m. Number of CT-1 and CT-2 start-up and shut-downs and duration of each start-up and shut-down;
61.n. CT-1 and CT-2 hourly NO_x emissions data (ppmdv corrected to 15% O_2, lb/MMBtu, lb/hr, and

lb/MWh, if complying with the lb/MWh limit);

61.o. CT-1 and CT-2, 30 unit operating day rolling average NO_x emissions data (ppmdv corrected to 15% O_2 and lb/MWh, if complying with the lb/MWh limit);

61.p. CT-1 and CT-2, 24-hour rolling average NO_x concentration (ppmdv, corrected to 15% O_2);

61.q. CT-1 and CT-2 hourly CO emissions data (ppmdv corrected to 15% O_2 and lb/hr);

61.r. CT-1 and CT-2, 8-hour rolling average CO concentration (ppmdv, corrected to 15% O_2);

61.s. CT-1 and CT-2 CO and VOC emissions during less than full load operation (lbs/hr);

61.t. Auxiliary boiler hourly NO_x emissions data (ppmdv corrected to 15% O_2, lb/MMBtu, and lb/hr);

61.u. Auxiliary boiler 30 unit operating day rolling average NO_x emissions data (lb/MMBtu);

61.v. Auxiliary boiler 24-hour rolling average NO_x concentration (ppmdv corrected to 3% O_2);

61.w. CT-3, CT-4, CT-5 and CT-6 hourly NO_x emissions data (ppmdv, corrected to 15% O_2 and lb/hr);

61.x. CT-3, CT-4, CT-5 and CT-6, 4-hour rolling average NO_x data (ppmdv, corrected to 15% O_2);

61.y. CT-3, CT-4, CT-5 and CT-6 hourly CO emissions data (ppmdv, corrected to 15% O_2 and lb/hr);

61.z. CT-3, CT-4, CT-5 and CT-6, 4-hour rolling average CO data (ppmdv, corrected to 15% O_2);

61.aa. Dates the Aux Boiler burned distillate oil and the amount of distillate oil burned and hours the boiler operated on oil (date, gal/yr, hr/yr);

61.bb. Auxiliary boiler visible emission observations while burning oil;

61.cc. Number of hours each calendar day oil is burned in CT-3, CT-4, CT-5 and CT-6;

61.dd. CT-3, CT-4, CT-5, CT-6 visible emission observations while burning oil;

61.ee. CEMS quality assurance/quality control records (including, but not limited to daily zero and span calibration checks, weekly inspection and maintenance activities, quarterly linearity and cylinder gas audits, annual relative test accuracy audits);

61.ff. Occurrence and length of downtime for all pollution control devices;

61.gg. Permit deviations;

61.hh. Excess emissions;

61.ii. 12-month rolling total pollutant emissions;

61.jj. Auxiliary boiler visible emissions observations according to 40 CFR 60.49b(f);

61.kk. Auxiliary boiler NO_x CEMS data according to 40 CFR 60.49b(g)

61.ll. Fuel receipts according to 40 CFR 60.49b(r)(1); and

61.mm. NSPS records in accordance with 40 CFR 60.7(b), including:

- 61.mm.i. Occurrence and duration of any startup, shutdown or malfunction in operation;
- 61.mm.ii. Any malfunction of the air pollution control equipment; or
- 61.mm.iii. Any periods during which a continuous monitoring system or monitoring device is inoperative.

Semi-Annual and Annual Reports

66. The permittee must submit three (3) copies of reports of any required monitoring at least every 6 months, completed on forms approved by DEQ. Six month periods are January 1 to June 30, and July 1 to December 31. One copy of the report must be submitted to the EPA and two copies to the DEQ regional office. All instances of deviations from permit requirements must be clearly identified in such reports: [OAR 340-218-0050(3)(c)(A) and 340-218-0080(6)(d)]]

66.a. The first semi-annual report is due on **July 30** and must include the semi-annual compliance certification, OAR 340-218-0080.

66.b. The annual report is due on **February 15** and must consist of the following:

- 66.b.i. The emission fee report; [OAR 340-220-0100]
- 66.b.ii. A summary of the excess emissions upset log; [OAR 340-214-0340]
- 66.b.iii. The second semi-annual compliance certification; [OAR 340-218-0080]
- 66.b.iv. Annual greenhouse gas emissions in accordance with OAR 340, Division 215;
- 66.b.v. The annual certification that the risk management plan is being properly implemented; OAR 340-244-0230: [OAR 340-218-0080(7)]
- 66.b.vi. Calendar year operating time for each unit;
- 66.b.vii. Calendar year production (electricity) for each unit;

66.b.viii. Calendar year steam production from the auxiliary boiler;
66.b.ix. Calendar year natural gas burned in each unit;
66.b.x. Calendar year distillate oil burned in each unit; and
66.b.xi. 12-month rolling total emissions.
66.b.xii. Starting January 1, 2023, the combined rolling 12-month annual emissions for PM_{10}, SO_2, and NO_x as tons per year.

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OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY
OREGON TITLE V OPERATING PERMIT
MINOR PERMIT MODIFICATION
REVIEW REPORT
Addendum 1

Klamath Energy LLC
1125 NW Couch Street, Suite 700
Portland, OR 97209

PERMITTING ACTION

1. On June 12, 2017, Oregon Title V Operating Permit No. 18-0003-TV-01 was renewed to Klamath Energy LLC. DEQ received an application for this minor permit modification on August 13, 2020. In this minor permit modification, the permittee has requested authorization to replace the existing dry low NO_x (DLN) combustors on the Combustion Turbines (CT-1 & CT-2) with ultra-low NOx combustors and to clarify the recordkeeping requirements identified in PC 61.l. of the current Title V Operating Permit.

2. In accordance with OAR 340-218-0120(1)(f), this Review Report is intended to provide the legal and factual basis for the draft permit conditions. In most cases, the legal basis for a permit condition is included in the permit by citing the applicable regulation. In addition, the factual basis for the requirement may be the same as the legal basis. However, when the regulation is not specific and only provides general requirements, this Review Report is used to provide a more thorough explanation of the factual basis for the permit conditions.

DISCUSSION

3. Klamath Cogeneration Project (KCP): KCP is a cogeneration power plant generating electricity to the grid and supplying steam to a wood products facility. The facility has a 2-turbine system with a 484 MW output. The combustion turbines (CT-1 & CT-2) are used to generate electricity with energy in the exhaust gas from the turbines recovered in a Heat Recovery Steam Generator (HRSG). The combustion turbines are fired on a natural gas and compressed air mixture which is combusted and expanded through the power turbine to recover the released energy. The power turbine drives both the inlet air compressor and the generator to produce electrical power. The exhaust gas is then routed to the HRSG to produce steam, which is converted to additional electrical energy in a steam turbine generator. Medium-pressure steam is extracted from the steam turbine for supply to off-site industry for use as process steam. The system is capable of generating up to 275,000 pounds per hour of steam for off-site use. The output of the system can be enhanced through the use of natural gas-fired duct burners located between the turbine and HRSG. Oxides of Nitrogen (NO_x) are controlled by selective catalytic reduction (SCR). An auxiliary boiler that can burn natural gas or distillate oil is available as a back-up method of generating steam for distribution in the event of natural gas curtailment or downtime of the turbine systems.

4. Combustion Turbines and Duct Burners (CT-1/DB-1 & CT-2/DB-2): Each combustion turbine is a Siemens/Westinghouse 501 with a rated design capacity of 1,653 million Btu per hour heat input. The units were placed into operation in July 2001. The units were later modified in 2009/2010 increasing the heat input for each unit to 1,825.3 MMBtu/hr. The modification was approved by the DEQ under a Notice of Approval (#23550). As a result of the modification, the turbines are now subject to 40 CFR Part 60, Subpart KKKK and are no longer subject to 40 CFR Part 60, Subpart GG. Each of the units includes an HRSG for generating steam to produce additional electricity and/or sell to nearby industries. A 191 million Btu per hour duct burner is installed between each combustion turbine and HRSG. Each of the turbines emissions are currently operate with a dry low NO_x (DLN) combustor and controlled with a SCR system downstream of the HRSG for reducing NO_x emissions. Major components of the SCR system are the

anhydrous ammonia flow control, injection system and catalyst bed. The catalyst bed consists of honeycombed ceramic elements designed to maximize stack gas contact with the catalyst surface. The combustion turbines burn only pipeline quality natural gas.

5. The permittee has applied for a minor permit modification to replace the dry low NO_x (DLN) combustor on each combustion turbine (CT-1 & CT-2) with ultra-low NOx combustors in mid-year 2021. The permittee proposed replacing the low NO_x (DLN) combustors with ultra-low NOx combustors to reduce the facility's actual emissions in any rolling 12-month period to a combined 122 tons per year for PM_{10}, SO_2, and NO_x. This reduction of combined emissions will enable the facility to screen out of the Round 2 Regional Haze Four Factor Analysis process based on reducing the facility's emission to below the screening threshold of Q/d of 5. The permittee has proposed an effective date of January 1, 2023 for the Regional Haze combined emission reduction to allow for a reasonable shakedown period for the new combustors and achieving the combined 12-month rolling emission requirement by December 31, 2022.

6. The permittee also requested that the source specific recordkeeping requirements identified in permit Condition 61.l. be clarified to identify the operational time for each Combustion Turbine (CT-1 & CT-2) during the periods within the normal operating range (60 – 100%) and periods within the partial load range (50 - 60%).

7. These revisions qualify as a minor permit modification because they: [OAR 340-218-0170(1)(a)]

   7.a. Do not violate any applicable requirement;
   7.b. Do not involve significant changes to existing monitoring, reporting or recordkeeping requirements in the permit;
   7.c. Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;
   7.d. Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:
      7.d.i. A federally enforceable emissions cap assumed to avoid classification as a Title I modification; and
      7.d.ii. An alternative emissions limit approved pursuant to OAR 340-244-0100 through 340-244-0180.
   7.e. Do not increase emissions over the PSEL;
   7.f. Are not Title I modifications; and,
   7.g. Are not required by OAR 340-218-0180 to be processed as a significant modification.

8. As a minor permit modification, the permittee was allowed to make the changes on the date that the application was submitted (08/18/20) in accordance with OAR340-218-0170(2)(d).

PUBLIC NOTICE

EPA and affected states were notified of the minor permit modification application on August 18, 2020. A proposed permit will be sent to EPA for a 45 day review period. DEQ will request, and EPA may agree to an expedited review of 5 days. The permit revision will be issued following EPA's review. The procedures for issuing minor permit modifications do not require public notice. The public will have an opportunity to comment on the changes at the next permit renewal.