northwest CleanAir agency
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Original issuance: April 9, 1992
Revision 1: March 6, 1996
Revision 2: August 2, 1999
Revision 3: September 23, 1999
Revision 4: June 7, 2001
Revision 5: April 12, 2002
Revision f: May 14, 2007
Revision g: June 6, 2022

Northwest Clean Air Agency (NWCAA) hereby issues Order of Approval to Construct (OAC) 330g

Project Summary: Construct and operate a cogeneration station that includes two GE Frame 7EA oil/gas fired combustion turbines and two gas fired 250 MMBtu/hour duct burners.

Approved Emission Units:

- Two GE Frame 7EA oil/gas fired combustion turbines and two gas fired 250 MMBtu/hour duct burners.

Owner/Operator	Facility Name and Location
PSE Ferndale Generating Station 5105 Lake Terrell Road Ferndale, WA 98248 Contact: Steve Feller	PSE Ferndale Generating Station 5105 Lake Terrell Road Ferndale, WA 98248

Permit History

- As of the date of issuance, this Order supersedes NWCAA OAC 330f, issued May 14, 2007.

Note that in addition to other applicable rules and regulations, the approved emission units are subject to applicable portions of the following federal regulations:

New Source Performance Standards (NSPS)

- 40 CFR 60 Subpart A - General Provisions
- 40 CFR 60 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
- 40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines

As authorized by the Northwest Clean Air Agency Regulation Section 300, this order is issued subject to the following restrictions and conditions[1]:

(1) The gas turbines shall burn either pipeline natural gas, or number 2 distillate oil with a sulfur

[1] Nothing in this permit is intended to, or shall, alter or waive any applicable law [including but not limited to defenses, entitlements, challenges or clarifications related to the Credible Evidence Rule, 62 FR 8315 (Feb. 27, 1997)] concerning the use of data for any purpose under the Act, generated by the reference method specified herein or otherwise.

Pursuant to Section 300.10 of the NWCAA Regulation and ch 43.21B RCW, this Order may be appealed to the Pollution Control Hearings Board (PCHB). To appeal to the PCHB, a written notice of appeal must be filed with the PCHB and a copy content not to exceed 0.05 weight percent. The HRSG duct burners shall burn only pipeline natural gas.

(2) Pollutant concentrations for each gas turbine/heat recovery steam generator stack shall not exceed the following:

Cond.	Pollutant	Ave.	Natural Gas	# 2 Distillate Oil
a.	Nitrogen Oxides	24 hr	7 ppmvd @ 15% O_2 - – fogger off 6 ppmvd @ 15% O_2 – fogger on	12 ppmvd @ 15% O_2
b.	Carbon Monoxide	1 hr	20 ppmvd @ 15% O_2	20 ppmvd @ 15% O_2
c.	Ammonia	1 hr	9 ppmvd @ 15% O_2	9 ppmvd @ 15% O_2
d.	Particulate Matter (PM-10)	1 hr	0.0022 gr/dscf @ 15% O_2	0.0022 gr/dscf @ 15% O_2
e.	Opacity	6 min	5 %	5 %

(3) Pollutant emissions rates from each gas turbine/heat recovery steam generator stack not exceed the following:

Cond.	Pollutant	Natural Gas	# 2 Distillate Oil
a.	Nitrogen Oxides (24 hr. average)	33 lbs./hr	60 lbs./hr
b.	Carbon Monoxide	44 lbs./hr	44 lbs./hr
c.	Ammonia	15 lbs./hr	16 lbs./hr
d.	Volatile Organic Compounds	15 lbs./hr	15 lbs./hr
e.	Particulate Matter (<10 microns)	13 lbs./hr	13 lbs./hr
f.	Sulfur Dioxide	12 lbs./hr	59 lbs./hr

In determining compliance with nitrogen oxides emission limits contained in conditions 2 and 3 during 24-hour periods (on a daily basis) when more than one fuel type was combusted, the source shall calculate and comply with a single prorated emission standard. This prorated standard shall be based on the number of hours that each fuel was combusted during the 24-hour period. For any period when natural gas and distillate fuel are simultaneously combusted, the NO_x limit, for the purpose of calculating a 24-hour prorated NO_x limit, shall be 12 ppmvd @ 15% O_2 (60 lb/hr).

(4) Continuous emission monitors shall be installed and operated in each turbine/heat recovery steam generator stack for the following:

(A) Oxygen - in accordance with Performance Specification 3 (40 CFR 60 Appendix B)

(B) Nitrogen Oxides - in accordance with Performance Specification 2 (40 CFR 60 Appendix B)

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served upon the NWCAA within 30 days of the date the applicant receives this Order. Additional information regarding appeal procedures can be found at: http://www.eluho.wa.gov/ under PCHB.

All monitoring systems shall be approved by the NWCAA prior to installation. All monitoring records shall be kept on site for a minimum of two years and made available to the NWCAA for inspection. All continuous emission monitors shall be certified within 180 days of startup of commercial operation. Continuous emission monitors shall be used for continuous compliance determinations and shall be installed and operated in accordance with NWCAA 367 and NWCAA Appendix A.

(5) An annual source test for carbon monoxide (CO) and ammonia emissions shall be completed for each gas turbine/HRSG stack using the following test methods. Tests shall be conducted while burning natural gas and shall be completed within thirteen months of the anniversary date of the previous test.

(A) CO: EPA Method 10

(B) Ammonia: BAAQMD Method ST-1B or other method approved in advance by NWCAA in writing

All source testing shall be conducted, and plans and test results submitted in accordance with NWCAA Section 367 and NWCAA Appendix A.

(6) The following information shall be reported to the NWCAA on a calendar month basis within 30 days after the end of the previous month:

(A) Daily average concentration of NOx in ppmvd corrected to 15% O2 and NOx emissions in lb/day for each gas turbine/HRSG stack.

(B) Standard cubic feet of natural gas burned in each of the turbines and the duct burners.

(C) Total gallons of Number 2 distillate oil burned in each of the turbines. Sulfur content of oil shall be determined by vendor receipt or lab analysis on each occasion that fuel is transferred to the storage tank from any source and records shall be maintained on site for a period of at least five years.

(D) The number of hours each of the turbines and duct burners operates.

(E) The duration and nature of any continuous emission monitor downtime, excluding daily calibration and drift tests.

(F) The highest sulfur content weight percent in the Number 2 distillate oil burned.

(G) The results of any monitor audits or accuracy checks.

(H) The results of any stack tests.

(I) Total pounds of SO_2 emitted on a monthly basis.

(J) Number of hours each fogger was in use.

(7) An air compliance operation and maintenance manual that identifies acceptable operation and maintenance (O&M) procedures that will ensure compliance with applicable air pollution rules and regulations shall be submitted to and approved by NWCAA prior to start-up. Failure to follow the procedures outlined shall be considered proof that the equipment was not properly maintained and operated.

(8) Foggers shall not be used when ambient temperatures are below 50°F or when burning distillate oil.

(9) PSE Ferndale shall maintain records of hourly time periods when foggers are used. Records of fogger use shall be available on-site for inspection by the NWCAA.

C.S. Christoforou

Christos Christoforou, P.E.
Engineer

Agata McIntyre P.E.

Agata McIntyre, P.E.
Engineering Manager

Revision 1, March 01, 1996: Remove permit requirements for equipment that was not installed (requirements 6, 11, 12-19). Averaging period for NOx emission limit defined as 24-hour average to be consistent with PSD permit

Revision 2, August 02, 1999: Revise to reflect changes made to PSD 91-04. Monitoring requirements for ammonia and carbon monoxide revised to eliminate continuous emission monitors and require annual performance testing. Permit condition number one removed.

Revision 3, September 23, 1999: Remove sulfur dioxide concentration limits. Remove reference to ISO correction.

Revision 4, June 07, 2001: Fogger device installed, PSD analysis based on WEPCO. Amend condition 2a by reducing NOx limit from 7 to 6 ppm when foggers in use. Amend condition 6 to require annual source test reports to include a net emissions increase calculation for fogger use and, added conditions 6c, 7j, 12, 13 and 14.

Revision 5, February 27, 2002: 2002 major inspection and minor turbine upgrades. PSD analysis based on WEPCO. "Tosco" property changed to "Phillips" property and slightly reworded. Add clarification of prorated emission standard to condition 3. Change ammonia test method. Amend condition 6 to modify calculation of net emissions increase. Add condition 6d to test for PM/PM-10. Remove references to initial permit fees paid by Tenaska. Replace ISO footnote (unneeded) with footnote 2 as written above. The time to deliver source test reports in condition 6 increased from 30 days to 45 days.

Revision f: May 14, 2007: Reformat. Remove conditions requiring initial source testing. Remove conditions requiring five years of periodic source testing for PM/PM-10 and VOC emissions to demonstrate WEPCO compliance from the fogger and turbine upgrade projects. Remove other associated WEPCO conditions. Updated ammonia source test method. Remove odor enforcement condition. Remove condition to submit a quality assurance manual for CEM prior to commercial startup. Revised text for source testing and CEM operation to reflect consistency with NWCAA 367 and NWCAA Appendix A.

Revision g: June 6, 2022: Reformat. Amend Condition 5(B) to allow other testing methods for ammonia. Recurrence of testing revised from "between 11 and 13 months" to "within 13 months" of the previous test.

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
P.O. Box 47600 • Olympia, Washington 98504-7600
(360) 407-6000 • TDD Only (Hearing Impaired) (360) 407-6006

June 10, 1996

Mr. Michael C. Lebens
Tenaska Washington Partners, L.P.
1044 North 115th Street, Suite 400
Omaha, Nebraska 68154-4446

Dear Mr. Lebens:

Re: PSD 91-04, Administrative Change of Permit Condition
Tenaska Washington Partners, L.P.
Ferndale Cogeneration Facility

Your letter requesting an administrative modification of the Ferndale Cogeneration Facility PSD 91-04 has been received by Ecology. The requested change in Approval Condition 25 will involve no increase in either emissions or impacts and no fundamental change in the source, so it qualifies under EPA guidance as an acceptable administrative change. The change will also make this condition's wording more consistent with other PSD permits issued by Washington State.

Approval Condition 25 of the permit is hereby changed by deleting the words "or operation" to read:

25. This approval shall become void if construction of the project is not commenced within eighteen (18) months after receipt of final approval, or if construction of the project is discontinued for a period of eighteen (18) months.

Please note that the general policy to determine whether or not a source which has been shut down is subject to NSPS and PSD review upon reactivation is based on whether the shutdown is considered permanent or temporary. In order to determine permanence, a source must be either shut down for two years or more or result in the removal of the source from the state emissions inventory. Not fulfilling the terms of the unit's operating permit, or letting its operating permit lapse will also indicate permanence. If the unit is shut down for more than two years, maintenance of a valid operating permit, continued inclusion in the state emissions inventory, and continued efforts to maintain the unit in anticipation of reactivation can be used to refute a presumption of permanent shutdown.

RECEIVED
JUN 13 1996
Northwest Air Pollution Authority

Please file this letter with your original permit. If you have any questions, feel free to call the staff engineer who drafted this administrative change, Bob Burmark, at (360) 407-6812.

Sincerely,

Joseph R. Williams
Program Manager
Air Quality Program

JW:km

cc: Ms Valerie Lagen, Northwest Air Pollution Authority

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
Northwest Regional Office, 3190 - 160th Ave S.E. • Bellevue, Washington 98008-5452 • (206) 649-7000

file Tenaska

June 10, 1992

Mr. Michael C. Lebens
Tenaska Washington, Inc.
407 North 117th Street
Omaha, NE 68154

Dear Mr. Lebens:

The Department of Ecology has approved Tenaska's Prevention of Significant Deterioration application for the new cogeneration facility to be located in Ferndale, Washington.

Enclosed is a copy of the final approval. Ecology received comments from four organizations during the public review period. I have included Ecology's response to the comments. Also included is a revised fact sheet.

If I can be of any further assistance on the matter, please feel free to contact me at (206) 649-7106.

Sincerely,

John Drabek

John Drabek, P.E.
Technical and Engineering Services
Air Quality Program

Enclosure

cc: Terry Nyman, NWAPA
Ann Pontius, EPA
Shirley Clark, National Park Service
Bob Bachman, National Forest Service
Myron Saikewicz, Ecology
Shirley Van Zanten, Whatcom County

RECEIVED
JUN 1 2 1992
Northwest Air Pollution Authority

FACT SHEET FOR
PREVENTION OF SIGNIFICANT DETERIORATION
TENASKA WASHINGTON, INC.
COGENERATION PROJECT, FERNDALE
May 18, 1992

1. INTRODUCTION

1.1 THE PSD PROCESS

The Prevention of Significant Deterioration (PSD) procedure is established in Title 40, Code of the Federal Regulations, Part 52.21. Federal rules require PSD review of all new or modified air pollution sources that meet certain criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a proposed new source. The program limits degradation of air quality. It also sets up a mechanism for evaluating the effect that the proposed emissions might have on environmentally related areas such as visibility, soils, and vegetation. PSD rules also require the utilization of the most effective air pollution control equipment and procedures, after considering environmental, economic, and energy factors.

1.2 THE PROJECT

Tenaska Washington, Inc. is proposing to construct and operate a combined cycle cogeneration facility located at BP Oil's refinery near Ferndale. Two General Electric Frame 7 EA combustion turbines, two heat recovery steam generators with supplemental firing capability and one steam turbine will produce a total output of 245 megawatts. Heat input to the turbines will be 1,830 million BTU's per hour (MMBtu/hr) and heat input to the duct burners will be 500 MMBtu/hr. The gas turbines will burn natural gas as a primary fuel, with 0.05 weight percent sulfur No. 2 diesel fuel oil as backup.

Tenaska also proposes to construct two 90,000 pounds of steam per hour auxiliary boilers for standby service. Maximum heat input to each boiler will be 143 MMBtu/hr. The auxiliary boilers will also burn natural gas as a primary fuel with low sulfur No. 2 diesel fuel oil as backup. Refinery fuel gas, a byproduct of BP Oil's operations, will provide up to 3,400 million BTUs per day of total heat input to the duct burners and auxiliary boilers which is about 18 percent of the total gas burned.

A standby 8.5 MMBtu emergency diesel generator will generate 750 kilowatt or about 1106 horsepower emergency power. It will only burn 0.05 percent sulfur diesel oil.

Electrical power will be sold to Puget Sound Power and Light (Puget Power) and up to 300,000 pounds of steam will be provided to BP Oil. Scheduled startup is October 1, 1993.

Although Tenaska is constructing on land leased from and adjacent to BP Oil, the facility will be under separate control and ownership and is not dedicated to BP Oil. Therefore, under PSD rules it is permitted as a separate new air pollution source. The Tenaska cogeneration facility will be a major source of air pollution because it will emit more than 250 tons per year of nitrogen oxides and carbon monoxide. Emissions of nitrogen oxides, carbon monoxide, sulfur dioxide, particulate matter, and volatile organic compounds will exceed the significance levels for major sources and therefore the Tenaska project is subject to review under PSD rules.

Tenaska is proposing to control nitrogen oxides (NO_x) emissions from the gas turbines and heat recovery steam generators by steam injection and selective catalytic reduction (SCR), combuster controls to control carbon monoxide (CO) and volatile organic compounds (VOC) emissions and to burn low ash fuels to control particulate matter. They also propose to control sulfur dioxide (SO_2) emissions by burning natural gas to the maximum extent possible with only low sulfur No. 2 diesel fuel oil as a backup fuel.

Tenaska is proposing to control emissions of NO_x from the auxiliary boilers by using flue gas recirculation in conjunction with a low NO_x burner and to control CO, VOC, SO_2 and particulate matter by proper combustion of natural gas and using only No. 2 diesel fuel oil as backup.

2. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

2.1 DEFINITION

Best available control technology (BACT) is defined as an emission limitation based on the most stringent level of emission control available or applied at an identical or similar source. Tenaska must achieve this level of control or prove it is technically or economically infeasible before a less stringent level of control is allowed.

2.2 BACT FOR GAS TURBINE/HEAT RECOVERY STEAM GENERATOR SYSTEMS

Air for the two turbines will be compressed and mixed with natural gas or low sulfur No. 2 fuel oil in combustion chambers. Exhaust gas from the combustion chambers will be expanded through power turbines to recover energy released from combustion. The power turbines drive both the inlet air compressors and electric power generators.

Heat from the 1,000^{0}F exhaust will be recovered by generating steam. This arrangement is called a combined cycle gas turbine. Natural gas and up to 28 percent refinery fuel gas will be fired in duct burners within the heat recovery steam generators. This will boost steam production to 450,000 lbs/hr. High pressure steam will be expanded in a steam turbine, intermediate-pressure steam will be injected into the combusters of the gas turbine for NO_x control and low pressure steam will also be injected into the steam turbine or be used for deaerator feed water heating.

2.2.1 NITROGEN OXIDES CONTROL

Federal new source performance standards limit nitrogen oxides from stationary gas turbines to less than 125 parts per million (ppm) corrected to 15 percent oxygen.

New source performance standards for industrial steam generating units limit nitrogen oxide emissions from the duct burners to 0.20 lbs/hr (about 51 ppm) on gas and 0.40 lbs/hr (about 102 ppm) on distillate oil.

The most stringent emission control available for NO_x control is a combination of steam injection and selective catalytic reduction (SCR).

SCR is the injection of ammonia into the gas turbine exhaust in the presence of oxygen and a platinum, vanadium or titanium catalyst to reduce nitrogen oxides to nitrogen and water. Steam injection will act as a heat sink slowing combustion and reducing flame temperatures which reduces NO_x emissions from 154 ppm to 42 ppm. SCR will further reduce emissions by 80 percent to 9 ppm, according to the vendor.

NO_x emissions will be minimized in the HRSGs because the duct burners will be staged low NO_x burners. Staged air burners split the combustion flame by diverting a portion of the combustion air downstream of the primary fuel injection point. Staged fuel burners split the combustion flame by dividing the fuel flow into two zones.

In both cases the rate of the combustion reaction is reduced lowering peak flame temperatures and formation of NO. Also combustion products from the primary zone act as reducing agents to further suppress NO_x formation. Emissions are reduced by at least 50% over conventional burners.

Tenaska proposes SCR, steam injection and low NO_x HRSG burners as BACT with an emission limit of 9 ppm corrected to 15 percent oxygen on gas, and 12 ppm at 15 percent oxygen when operated on oil. Similar large combined cycle gas turbines with these controls have achieved and been permitted at 7 ppm NO_x when operated on gas. Therefore Ecology determines BACT to be steam injection, SCR and low NO_x HRSG burners and an emission limit of 7 ppm corrected to 15% O_2 and 31 lbs per hour when operated on gas. BACT is 12 ppm and 60 pounds per hour when each turbine is operated on oil.

Continuous monitoring effectively makes the NOx limit more stringent than periodic manual compliance testing. A continuous emission monitoring system (CEMS) will be required to insure 24 hour per day compliance.

2.2.2 CARBON MONOXIDE CONTROL

There are no federal new source performance standards for CO from turbines or duct burners.

The most stringent means to control carbon monoxide is catalytic oxidation. Excess air in the presence of a catalyst oxidizes CO to carbon dioxide. The incremental cost of this control is $6,000 per ton of CO removed. This is considered economically infeasible.

The next most stringent level of control is combustion control. This limits CO by ensuring proper oxygen level, high temperature and adequate residence time. About 22 pounds per hour of CO (10 ppm) will come from each turbine and 20 lbs/hour (10 ppm) will come from each duct burner. The duct burner will use only the oxygen exhausted from the turbine for combustion. Therefore, the stack concentration will increase to 20 ppm. Tenaska proposes and Ecology concludes combustion controls, 20 ppm CO corrected to 15% O_2 and 44 lbs/hr are BACT for each turbine and heat recovery steam generator stack. A CO monitor will continuously determine compliance.

2.2.3 VOLATILE ORGANIC COMPOUNDS (VOC)

There are no federal new source performance standards for VOC from gas turbines or duct burners.

The most stringent means to control VOCs is catalytic oxidation. About twice as much catalyst is required for VOC control than is required for CO control. The incremental cost of control is $55,000 per ton of VOC removed. Ecology considers this to be economically infeasible.

The next most stringent level of control is combustion control. Tenaska proposes and Ecology agrees combustion controls and an emission limit of 15 lbs/hr VOC from each turbine HRSG stack represents BACT.

2.2.4 SULFUR DIOXIDE CONTROL

Federal new source performance standards for turbines limit sulfur dioxide emissions to 150 ppm at 15 percent O_2 and by limiting sulfur content of any fuel to 0.8 percent by weight.

New source performance standards for industrial steam generating units limit sulfur dioxide emissions from the duct burners by limiting fuel to gas or low sulfur fuel oil.

Tenaska is proposing to burn only these fuels.

The most stringent method to control SO_2 is by burning low sulfur fuels. Tenaska has proposed burning natural gas in the turbines to the maximum extent possible. When it is not possible, such as during natural gas supply curtailments, low sulfur fuel oil will be burned not to exceed 1500 hours per year. Ecology agrees burning low sulfur fuels is BACT for sulfur dioxide from the turbines.

The heat recovery steam generator (HRSG) duct burners will be capable of burning only natural gas or refinery fuel gas. Refinery fuel gas has approximately 700 ppm hydrogen sulfide (H_2S which will be converted to SO_2). Natural gas has about 20 ppm H_2S.

Tenaska proposes to limit refinery fuel gas burning in the duct burners, auxiliary boilers and turbines to less than 142 million BTUs heat input per hour. This will result in refinery fuel gas composing a maximum of 28 percent of total heat input to the duct burners. This will result in less than 4 ppm SO_2 at 15% O_2 from each gas turbine/HRSG. Tenaska will be able to duct all the refinery fuel gas to just one of the gas turbines. Therefore the emission limit is proposed as 24 lbs/hr from both stacks combined when gas is burned.

When low sulfur oil is burned 9 ppm at 15% O_2 from each turbine and 59 lbs/hr from both stacks combined will be emitted.

Ecology determines these emission limits and these fuels represent BACT for the gas turbines/HRSG. Fuel meters, heating value measurements and a continuous emission monitor will ensure continuous compliance and that only these fuels and quantities will be burned.

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2.2.5 PARTICULATE AND PM_{10} CONTROL

There are no federal new source performance standards for particulate nor for particulate matter less than 10 microns (PM_{10}) from turbines or duct burners.

State standards limit particulate emissions to 0.10 gr/DSCF at 7% O_2.

The most stringent means of particulate control is low ash fuels. Tenaska proposes to burn only natural gas, refinery fuel gas or No. 2 diesel oil which are all low ash fuels. Ecology concludes limiting combustion to these fuels and an emission limit of 0.0022 gr/DSCF at 15% O_2 and 13 pounds per hour represents BACT for particulate emissions from each gas turbine/HRSG.

Compliance will be determined by federal Reference Method 5 under the assumption all the collected particulate matter is PM_{10}. Compliance can also be determined by promulgated federal reference methods for PM_{10}.

2.3 BACT FOR THE AUXILIARY BOILERS

The two 90,000 pounds of steam per hour auxiliary boilers will provide uninterrupted steam to the BP oil refinery during unscheduled outages of the cogeneration facility and during periods when Puget Power requires operation to be interrupted for system purposes. The auxiliary boilers will fire natural gas and up to 18 percent refinery fuel gas with low sulfur No. 2 fuel oil as backup.

2.3.1 NITROGEN OXIDES CONTROL

New source performance standards for industrial steam generating units limit nitrogen oxides emissions from the auxiliary boilers to 0.10 lbs/hr or 87 ppm on gas and 0.20 lbs/hr or 174 ppm on distillate oil.

The most stringent emission control available for NO_x control is selective catalytic reduction (SCR). The incremental cost of this control is $8,400 per ton of NO_x removed. This is based on operating all year. These are standby boilers to be run only when the turbines are down for maintenance. They will run only about two months per year. This would increase the cost to about $40,000 per ton. Ecology determines SCR is economically infeasible.

The next most stringent level of control is burning the fuel using low NO_x burners in combination with flue gas recirculation.

Natural gas, refinery fuel gas or oil will be burned by combined staged air and staged fuel burners. Staged air burners split the combustion flame by diverting a portion of the combustion air downstream of the primary fuel injection point. Staged fuel burners split the combustion flame by dividing the fuel flow into two zones.

In both cases the rate of the combustion reaction is reduced lowering peak flame temperatures and formation of NO. Also combustion products from the primary zone act as reducing agents to further suppress NO_x formation. Emissions are reduced by at least 50% over conventional burners.

Flue gas recirculation (FGR) is extracting flue gas and returning it to the boiler through the burner. This reduces peak flame temperature in the burner through absorption of the heat by the relatively inert flue gas. Also, less oxygen in the combustion air is available for NO_x formation.

The incremental cost of control is $522 per ton NO_x removed. Tenaska proposes and Ecology concurs BACT for NO_x control on the auxiliary boilers is flue gas recirculation and low NO_x burners.

This will reduce NO_x emissions when gas is burned to 33 ppm at 7% O_2 and 7 lbs per hour from each boiler. The two boilers will emit through one common stack therefore the stack CO emission limit will be 33 ppm at 7% O_2 and 15 lbs per hour.

When fuel oil is burned emissions with this control technology will be 60 ppm at 7% O_2 and 28 pounds per hour from the common stack.

2.3.2 CARBON MONOXIDE CONTROL

There are no federal new source performance standards for CO emitted from boilers.

The most stringent means to control carbon monoxide is catalytic oxidation. Excess air in the presence of a catalyst oxidizes CO to carbon dioxide. This is based on operating all year. These are standby boilers to be run only when the turbines are down for maintenance. They will run only about two months per year. This would increase the cost to about $25,000 per ton. Ecology determines catalytic oxidation is economically infeasible.

The next most stringent level of control is proper combustion control. The high efficiency burners will provide nearly complete combustion of the fuel. Ecology concludes combustion controls and 150 ppm at 7% O_2 and 14 pounds per hour CO are BACT for each auxiliary boiler. The common stack emission limit will be 100 ppm and 28 lbs/hr.

2.3.3 VOLATILE ORGANIC COMPOUNDS (VOC)

There are no federal new source performance standards for VOCs from boilers.

The most stringent means to control VOCs is catalytic oxidation. About twice as much catalyst is required for VOC control than for CO control. The incremental cost of control is $128,700 per ton of VOC removed. Ecology considers this to be economically infeasible.

The next most stringent level of control is proper combustion control. Tenaska proposes and Ecology agrees combustion controls and an emission limit of 1.5 pounds per hour from each boiler represents BACT for VOC. The common stack limit will be 3 pounds per hour.

2.3.4 SULFUR DIOXIDE CONTROL

New source performance standards for industrial steam generating units limit sulfur dioxide emissions from the auxiliary boilers by limiting fuel to gas or low sulfur fuel oil.

Tenaska is proposing to burn only these fuels.

The most stringent method to control SO_2 is burning low sulfur fuels. Tenaska has proposed burning whenever possible natural gas and up to 18 percent refinery fuel gas in the auxiliary boilers. When this is not possible only low sulfur fuel oil will be burned. Ecology has determined burning only low sulfur fuels and limiting fuel oil to less than 1500 hours per year is BACT for the auxiliary boilers. This will result in emissions of 12 ppm at 7% O_2 and 3.5 lbs per hour from each boiler when gas is burned and 23 ppm and 7 lbs/hr from each boiler when oil is burned. The common stack emission limit will be 12 ppm at 7% O_2 and 7 lbs/hr on gas and 23 ppm at 7% O_2 and 14 lbs/hr on oil.

2.3.5 PARTICULATE AND PM_{10} CONTROL

There are no federal new source performance standards for particulate emissions from gas or oil fired industrial boilers.

State standards limit emissions to 0.1 grain per dry standard cubic foot corrected to 7 percent oxygen (gr/DSCF at 7% O_2).

The most stringent means of particulate control is burning low ash fuels. Tenaska proposes to burn only low ash fuels which are natural gas, refinery fuel gas and No. 2 fuel oil. Ecology concludes limiting combustion to these fuels and a PM_{10} emission limit of 0.020 gr/DSCF at 7% O_2 and 5.5 lbs per hour from each auxiliary boiler represents BACT for particulate emissions. The common stack emission limit will be 0.020 gr/DSCF at 7% O_2 and 11 lbs/hr. Compliance will be determined by federal Reference Method 5 under the assumption all the collected particulate matter is PM_{10}. Compliance can also be determined by promulgated federal reference methods for PM_{10}.

Opacity will not exceed five percent at this level. Therefore, an opacity limit of five percent is also BACT for the auxiliary boilers.

3. AMBIENT AIR QUALITY ANALYSIS

3.1 REGULATED POLLUTANTS

PSD rules require an assessment of ambient air quality impacts from any facility emitting pollutants in significant quantities. Significant deterioration of air quality is prevented by limiting increases in ambient concentrations to maximum allowable increments. The only pollutant causing a significant ambient air quality impact is NO_x.

Nitrogen dioxide impacts will consume up to 1.30 micrograms per cubic meter (ug/m^3) of the allowable PSD NO_2 25 ug/m^3 increment. The impact when added to existing NO_x sources will be well below the 100 ug/m^3 National Ambient Air Quality Standard.

3.2 TOXIC AIR CONTAMINANTS

The Department of Ecology requires an ambient air quality analysis of toxic air contaminant (TAC) emissions. All TACs that will be emitted from the turbines, duct burners and auxiliary boilers and emergency diesel generator were analyzed to determine the potential impacts on ambient air quality. Ambient concentrations of all TACs will be below acceptable source impact levels (ASILs) contained in the regulation WAC 173-460 "Controls for New

Sources of Toxic Air Pollutants". Therefore, no adverse health impacts will occur due to toxics emitted from the Tenaska facility.

The reaction between ammonia and NO_x in the gas turbine heat recovery steam generators will not be complete and a small quantity of unreacted ammonia will escape to the atmosphere. This ammonia slip can be visible and is also an air toxic. However, limiting ammonia slip by reducing the ammonia reactant will decrease the NO_x control efficiency and increase NO_x emissions.

Similar gas turbines have achieved 10 ppm ammonia slip. GE has guaranteed the ammonia slip will be less than 9 ppm from the Tenaska gas turbines. Therefore, Ecology determines BACT for ammonia is an emission limit of 9 ppm. At this ammonia concentration and at the particulate concentration emission limit opacity will be no greater than five percent. An emission limit of five percent is BACT for the gas turbines.

4. AIR QUALITY RELATED VALUES

The PSD regulations require an evaluation of the effects of the anticipated emissions on soils, vegetation, growth and visibility in any class I area. A Level II screening analysis using procedures in the EPA "Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015) demonstrated visibility will not be reduced in the Olympic National Park nor the North Cascades National Park which are the nearest Class I areas. Initially Tenaska used a 60 mile background visual range in a Level I screening analysis. Level I screening is designed to provide conservative worst case estimates of plume visual impacts. Thee are stable meteorological conditions, very low wind speeds persisting for 12 hours and wind transport in a constant direction. Ecology required a reanalysis using a 160 mile visual range that is more representative of the western United States. The analysis showed visibility degradation. In this case EPA procedures require a level 2 screening analysis using extensive measured meteorological data. Using BP Oil meteorological data Tenaska demonstrated no visibility impact.

Ozone, nitrogen oxides, nitrates and sulfur dioxide impacts from the Tenaska project on soils and vegetation will not harm even the most sensitive species in the Class I areas. Nitrate concentrations of 0.27 ug/m_3 have been measured at Marblemont in the North Cascades Park during one three day period. Tenaska under worst case conditions will increase nitrate concentrations less than 0.01 ug/m^3. Reducing this concentration beyond the stringent controls already required is unjustified. Since oil firing is limited and natural gas which contains almost no sulfur will be the principle fuel sulfur dioxide emissions will have little impact.

Tenaska found ozone concentrations above 0.06 ppm will affect plants in the North Cascades National Park. These plants include ponderosa pine, douglas fir, sitka spruce and lichens. The cumulative impacts from all sources impacting the area is estimated to be below 0.06 ppm ozone. This is supported by ozone measured near the North Cascades National Park. Ozone levels are generally below 0.06 ppm as measured at the Everson and Lyman sites operated by the Northwest Air Pollution Control Authority, the Abbotsford and Chilliwack sites in British Columbia operated by Environment Canada and the Greater Vancouver Regional district and in a special study by Edmonds.

Although modeling is difficult Tenaska estimated ambient ozone increases from the project to be less than 0.0004 parts per million (0.4 parts per billion). This increase is insignificant and not measurable.

However, because of the uncertainties in estimating impacts and since ozone and many air quality related values in the park have not been measured Tenaska has agreed to participate in a study related to air quality in the Class I area. The study will be directed by the Forest Service in consultation with Ecology.

During the construction phase of the project up to 275 construction workers will be employed. It is expected that the majority will come from the local area. About 30 new employees will be hired to operate the project.

RESPONSIVENESS SUMMARY FOR THE TENASKA COGENERATION PROJECT

Ecology received comments from four organizations concerning the Tenaska Cogeneration Project prevention of significant deterioration draft permit.

John Williams, JW Research
Consultant for the TAME TIC Committee, an affiliate of the Plumbers and Steamfitters Union.

1. Selective Catalytic Reduction (SCR) is best available control technology for nitrogen oxides (NO_x) control but the emission limit should be reduced from 7 parts per million (ppm) to 4 ppm based on other cogeneration projects.

Response: The Department of Ecology determined BACT based on balancing the increase in CO and ammonia emissions with decreases in NO_x. Reducing nitrogen oxides emissions generally increases carbon monoxide and ammonia emissions. A higher flame temperature could reduce CO but could increase NO_x. This can be found in NO_x versus CO curves published by turbine manufacturers. Williams quoted only NO_x emissions without the CO emissions. Ecology researched similar cogeneration facilities throughout the country and found when carbon monoxide and ammonia emissions are taken into account 7 ppm NO_x and 20 ppm CO are BACT. In fact, sources quoted by the respondent confirm that 7 ppm NO_x and 20 ppm are BACT.

2. Combustion controls are not BACT for combustion gas turbines as determined by Ecology for carbon monoxide (CO) and volatile organic compounds (VOC). The Sumas Energy Cogeneration plant and some other cogeneration plants control CO emissions using catalytic oxidation. The catalyst's cost at about $6,000 per ton of CO controlled is economically feasible.

   VOC reductions from the catalyst should be included in the cost analysis.

   The cost should also be compared to the market value of VOC in the Seattle and Everett ozone non-attainment area since Tenaska will be able to sell VOC reductions as offsets to sources at that location.

Response: The Department of Ecology has consistently agreed catalytic oxidation is economically unjustified for combustion gas turbines. The catalytic oxidizer was voluntarily installed by Sumas and was not determined to be BACT.

The cost benefit of VOC control was included in the cost analysis. About twice as much catalyst is required for VOC control than is required for CO control. The incremental cost to control VOC using a catalyst is $55,000 per ton. This is economically unjustified.

BACT is determined by comparing control costs to similar facilities in attainment areas. The lowest achievable emission rate (LAER) is compared to sources permitted in nonattainment areas. Tenaska is in an attainment area and its emissions will not effect the Seattle and Everett ozone non-attainment areas. Since offsets can only be granted for emissions that affect nonattainment areas Tenaska cannot sell offsets in the Seattle or Everett areas. The cost of VOC offsets in nonattainment areas is therefore irrelevant.

3. Formaldehyde was not correctly modeled. A catalyst is BACT for formaldehyde.

Response: Williams mistakenly used stack height in place of plume height in determining ambient concentrations. The buoyancy of the plume must be included. He also compared a one hour concentration to the annual concentration acceptable ambient impact level (ASIL). Using measured meteorological conditions Tenaska estimated formaldehyde levels one fifth of the ASIL.

Ecology does not know of a combustion turbine that uses a catalyst to control formaldehyde. Proper combustion control techniques has been determined to be BACT for toxic air pollutants including formaldehyde.

4. BACT forbids the use of low sulfur fuel oil as a backup fuel during natural gas curtailment.

Response: The Department of Ecology and BACT determinations throughout the country have consistently agreed limited use of very low sulfur oil as a backup fuel is BACT. The predicted ambient impact caused by the burning of oil is below the 13 microgram per cubic meter significant air quality concentration for sulfur dioxide listed in the PSD rules.

5. The North County Resource Recovery Associates PSD Remand requires consideration of air toxics in BACT determination.

Response: The remand requires considering the effects on toxics in BACT determinations for PSD pollutants. In this case Ecology considered the toxic ammonia in determining NO_x controls. In addition the Northwest Air Pollution Authority considered toxics under 173-460 Washington Administrative Code.

6. Selective Catalytic Reduction is BACT for NO_x from the auxiliary boilers even if operated only part time.

Response: The PSD permit and the notice of construction limits operation of the auxiliary boilers to about two months per year. The Department of Ecology concluded the cost of $40,000 per ton to control NO_x from the boilers by selective catalytic reduction was economically unjustified.

7. Pre and post construction monitoring of ozone should be required in Bellingham and the North Cascades as recommended by the U.S. Forest Service.

Response: Emissions of volatile organic compounds are below the PSD significant level of 100 tons per year. That is, emissions are not significant enough to require pre or post construction monitoring under PSD. Also, monitoring could not distinguish between the impacts of Tenaska and other sources in the area.

Ozone is monitored reasonably close to the North Cascades National Park at Lyman and Lynden. The NAAQS standard has not been exceeded.

8. Other facilities in Northern Washington should have been included in the modeling.

Response: Tenaska demonstrated impacts of carbon monoxide, particulate matter (PM_{10}) and sulfur dioxide are below the PSD significant impact levels. Under prevention of significant deterioration rules expanded ambient impact analysis is not required for these pollutants. The impact area above the 1.0 ug/m^3 significance level extends about 0.6 mile north of the Tenaska site. The sources contributing to nitrogen oxides emissions within the nearby area were included in this expanded modeling. These sources include the ARCO Cherry Point Refinery, BP Oil, Georgia Pacific and Encogen Northwest Cogeneration Project. Sources beyond this will not have a significant impact.

9. PM10 should be modeled in the Class I areas. The PM_{10} standard is threatened at 44 ug/m^3 during winter.

Response: Impacts of particulate matter (PM_{10}) are below the PSD significant impact levels. Expanded ambient impact analysis is therefore not required for PM_{10}. The particulate standards are averaged both annually and daily. The annual PM_{10} concentration in the Bellingham area has been between 25 and 30 ug/m^3. The standard is 50. The 24 hour standard of 150 ug/m^3 has not been exceeded. The impacts on Class I areas will be less.

10. More pre construction meteorological monitoring should take place at locations other than the BP Oil Ferndale Station. Meteorological monitoring should be done in the Class I area.

Response: The meteorological station at BP Oil meets the PSD modeling criteria.

11. Mobile sources should be included in the modeling.

Response: The Encogen cogeneration PSD application and other inventories have demonstrated Interstate 5 and other mobile sources contribute little NO_x in this area.

12. The cumulative increases in nitrate and NO_x from Tenaska, Encogen and Sumas Energy will damage vegetation and lakes in the North Cascades.

Response: See Response No. 2 to Park Service.

13. VOC emissions from the fuel oil storage tanks added pipelines compressors and construction fugitive dust were not evaluated.

Response: The one fuel oil storage tank on site will be an equipped with a floating roof and a vapor recovery system, or their equivalents. No additional compressors will be added to the pipeline. The construction site will be watered to suppress dust.

14. Tenaska will contribute to ozone in Seattle.

Response: The analysis showed that the project will not significantly contribute to ozone anywhere. Also, Seattle is outside the boundary for PSD review.

15. Tenaska will import many construction workers who will cause increases in air pollution.

Response: This is beyond the scope of PSD review. The State Environmental Policy Act (SEPA) is the proper forum for such concerns. PSD does not require considerations of site work forces which will be less than 30.

<u>REBOUND</u>

REBOUND is an association of building trade unions.

1. The PSD fact sheet and BACT determination rely too much on the Tenaska application.

Response: Ecology and the Northwest Air Pollution Authority researched similar facilities in their BACT determination independent of the application.

2. The PSD NO_x increment consumption was not shown in the Section 3.1 of the Ecology fact sheet.

Response: The NO_x increment consumption is shown in Section 3.1 of the Ecology fact sheet as "1.30 micrograms per cubic meter (ug/m^3) of the allowable PSD NO_2 25 ug/m^3 increment."

3. Insufficient information was submitted by Tenaska concerning ozone and nitrogen oxide levels.

Response: Tenaska satisfied Ecology in their responses on August 2 and August 30, 1991 to Ecology requests for additional information on impacts to the North Cascades. Although modeling ozone is difficult Tenaska estimated increases from the project to be less than 0.0004 parts per million (0.4 parts per billion). The cumulative impacts are estimated to be below the level 0.06 ppm where ozone will harm plant lichens and other plant species listed for the North Cascades. However, because of uncertainties in estimating impacts since ozone and many other air quality related values have not been measured in the Class I areas, Tenaska will participate in a study related to air quality in the Class I area.

4. Ecology has not responded to Forest Service comments.

Response: Ecology included Forest Service comments in additional information requests sent to Tenaska. Ecology is satisfied Tenaska will have little impact on Class I areas.

5. The fact sheet does not sufficiently discuss impacts on visibility, soils and vegetation.

Response: The fact sheet has been expanded to include the analyses of impacts on visibility, soils and vegetation.

6. The analysis of impacts on Class I areas did not consider summertime low level winds transport of pollutants to wilderness areas.

Response: Tenaska considered short term, summertime and annual impacts of emissions on Class I areas. Visibility, nitrate deposition, and ozone will have little impact.

7. The nitrate concentrations and pH at Marblemount were not considered.

Response: Episodic acidification was addressed in Tenaska's response to Ecology's request for additional information. The increase in nitrate concentration will be less than 0.01 ug/m^3 under worst case conditions. This is much less than the peak three day concentration of 0.27 ug/m^3 measured at Marblemount.

8. Control of air toxics was not considered in the BACT determination of criteria pollutants.

Response: See Response No. 5 to Williams.

9. Tenaska did not analyze impacts on drinking water.

Response: See Response No. 2 to Park Service.

J. A. Kendall Snell, Regional Air Resource Manager, U.S. Forest Service, Pacific Northwest Region.

1. Tenaska did not analyze impacts on Northwest Class I Wildernesses (Glacier Peak, Alpine Lakes and Pasayten).

Response: See Response No. 2 and 3 to REBOUND.

2. Episodic acidification of lakes and streams are not addressed.

Response: Episodic acidification was addressed in Tenaska's response to Ecology's request for additional information. The increase in nitrate concentration is less than 0.01 ug/m^3. This is much less than the highest three day concentration of 0.27 ug/m^3 measured in any Class I area. Since oil firing is limited and natural gas which contains almost no sulfur will be the principle fuel impacts from sulfate formation will be negligible.

WASHINGTON DEPARTMENT OF ECOLOGY
MAILSTOP PV-11
OLYMPIA, WASHINGTON 98504

IN THE MATTER OF:	
Tenaska Washington, Inc.	NO. PSD 91-04
177 Telegraph Road No. 679	FINAL APPROVAL
Bellingham, WA. 98226	OF PSD APPLICATION

Pursuant to the U.S. Environmental Protection Agency (EPA) regulations for the Prevention of Significant Deterioration (PSD) set forth in Title 40, Code of the Federal Regulations, Part 52 and regulations set forth in the Washington Administrative Code 173-400-141 and based on the complete Prevention of Significant Deterioration application submitted by Tenaska Washington Inc. and the technical analysis performed by the Department of Ecology (the department), dated May 18, 1992 the department now finds the following:

FINDINGS

1. Tenaska Washington Inc. proposes to build a new combined cycle cogeneration facility adjacent to BP Oil's refinery near Ferndale. The project would consist of two natural gas fired combustion turbines, two heat recovery steam generators with supplemental firing capability and one steam turbine. Two auxiliary boilers would be constructed for standby service. The facility would provide electrical power to Puget Sound Power and Light (Puget Power) and steam to BP Oil.
2. The Tenaska Washington project qualifies as a major source because it will emit more than 250 tons per year of nitrogen oxides and carbon monoxide. It is located in an area which is designated Class II for the purposes of PSD evaluation under 40 CFR 52.21 dated July 1, 1990.

3. The emissions of NO_x, SO_2, and particulate matter from the duct burners and auxiliary boilers are subject to new source performance standards in Title 40 Code of Federal Regulations (CFR) Part 60, Subpart Db as of July 1,1990. The emissions from the combustion turbines is subject to 40 CFR Part 60 Subpart GG as of July 1, 1990.

4. The proposed site is within an area which is in attainment with regards to the state and national air quality standards.

5. The facility would generate up to 491 tons per year of nitrogen oxides.

6. The facility would generate up to 473 tons per year of carbon monoxide.

7. The facility would generate up to 188 tons per year of sulfur dioxide.

8. The facility would generate up to 91 tons per year of volatile organic compounds (VOC).

9. The facility would generate up to 95 tons per year of total suspended particulate matter (TSP).

10. The facility would generate up to 87 tons per year of particulate matter less than 10 micrometers(PM_{10}).

11. The emissions of nitrogen oxides, carbon monoxide, sulfur dioxide, VOC, TSP and PM_{10} are subject to PSD review.

12. Best available control technology (BACT) will be used to control air pollutants from the proposed project.

13. The project nitrogen oxides (as NO_2) emissions will consume up to 1.3 ug/M^3 of the 25 ug/M^3 PSD increment. The project will have no other significant adverse impact on air quality.

14. The project is anticipated to have no noticeable affect on industrial, commercial or residential growth.

15. Visibility will not be impaired in any Class I area due to the proposed emissions.

16. Ambient pollutant concentrations in any Class I area are not predicted to change due to the project.

17. The department finds that all requirements for PSD have been satisfied. Approval of the PSD application is granted subject to the following conditions.

APPROVAL CONDITIONS

1. NO_x emissions from each gas turbine/heat recovery steam generator system stack when gas is fired shall not exceed 7 parts per million on a dry volume basis (ppmdv) corrected to 15 percent oxygen and ISO (ISO standard dry conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilo Pascals pressure) conditions and also shall not exceed 31 pounds per hour (lbs/hr) corrected to ISO conditions on a daily average.

NO_x emissions from each gas turbine/heat recovery steam generator system stack when oil is fired shall not exceed 12 ppmdv at 15% O_2 and ISO conditions and also shall not exceed 60 pounds per hour corrected to ISO conditions on a daily average. Initial compliance shall be determined by EPA Reference Method 20 of 40 CFR Part 60, Appendix A as of July 1, 1990.

Compliance shall also be determined for each stack by a continuous emission monitoring system (CEMS) which meets the requirements of Condition 17.

2. CO emissions from each gas turbine/heat recovery steam generator system stack shall not exceed 20 ppmdv corrected to 15% O_2 and ISO conditions on an hourly average. CO emissions from each gas turbine/heat recovery steam generator system stack shall not exceed 44 pounds per hour corrected to ISO conditions. Initial compliance shall be determined by EPA Reference Method 10 or 10A of 40 CFR Part 60, Appendix A as of July 1, 1990. Compliance shall also be determined for each stack by a continuous monitoring system which meets the requirements of Condition 17.

3. The gas turbines and auxiliary boilers shall burn either pipeline natural gas mixed with refinery fuel gas or shall burn No. 2 fuel oil with sulfur content of no more than 0.05 weight percent. The heat recovery steam generator duct burners shall burn only pipeline natural gas, refinery fuel gas or a mixture of both. Total heat input from refinery fuel gas burned in the gas turbines, heat recovery steam generator duct burners and auxiliary boilers shall be no more than 142 million BTUs per hour. Each gas turbine shall burn low sulfur No. 2 fuel oil no more than 1500 hours per calendar year. Tenaska shall measure and maintain records of the hours and volumes of refinery fuel gas and oil firing. Tenaska shall maintain fuel receipts from the fuel supplier which certify that the fuel oil meets the fuel sulfur limit.

4. SO_2 emissions from each gas turbine/heat recovery steam generator system stack when gas is burned in the turbines shall not exceed 4 ppmdv corrected to 15 percent oxygen and ISO conditions. Total SO_2 emissions from the gas turbine/heat recovery steam generator system stacks when

gas is burned in the turbines shall not exceed 24 lbs/hr corrected to ISO conditions on an hourly average .

SO_2 emissions from each gas turbine/heat recovery steam generator system stack when fuel oil is burned in the turbines shall not exceed 9 ppmdv corrected to 15 percent oxygen and ISO conditions and 59 lbs/hr corrected to ISO conditions on an hourly average.

Initial compliance shall be determined by EPA Reference Method 6 of 40 CFR Part 60 Appendix A as of July 1, 1990 or an equivalent method approved by Ecology. Compliance shall also be determined for each stack by a continuous monitoring system which meets the requirements of Condition 17.

5. PM_{10} emissions from each gas turbine/heat recovery steam generator system stack when gas or fuel oil is burned in the turbines shall not exceed 0.0022 grains per dry standard cubic foot corrected to 15 percent oxygen (gr/DSCF at 15% O_2) and ISO conditions and shall not exceed 13 lbs/hr on an hourly average. Compliance shall be determined by EPA Reference Method 5 of 40 CFR Part 60 Appendix A as of July 1, 1990, EPA Method 201 or 201A of 40 CFR Part 51, Appendix M as of July 1, 1990 or an equivalent method approved by Ecology.

6. VOC emissions from each gas turbine/heat recovery steam generator system stack shall not exceed an hourly average of 15 pounds at ISO condtions. Compliance shall be determined by EPA Reference Method 25A or Method 18 of 40 CFR Part 60, Appendix A as of July 1, 1990.

7. Ammonia (NH_3) emissions from each gas turbine/heat recovery steam generator system stack shall not exceed 9 ppm corrected to 15 percent oxygen and ISO conditions on an hourly average. Initial compliance

shall be determined by EPA Reference Method 5 of 40 CFR Part 60 Appendix A as of July 1, 1990 with modifications to the impingers or an equivalent method approved by Ecology. Compliance shall also be determined by a continuous emission monitoring system approved by Ecology.

8. Opacity from each gas turbine/heat recovery steam generator system stack shall not exceed 5 percent as measured by EPA Reference Method 9 of 40 CFR Part 60, Appendix A as of July 1, 1990.

9. NO_x emissions from the auxiliary boiler common stack when gas is burned in the boilers shall not exceed 33 ppmvd corrected to 7% O_2 and 15 pounds per hour on an hourly average. NO_x emissions from the auxiliary boiler common stack when fuel oil is burned in the boilers shall not exceed 60 ppmvd corrected to 7% O_2 and 28 pounds per hour on an hourly average. Compliance shall be determined by EPA Method 7A, 7E of 40 CFR Part 60, Appendix A as of July 1, 1990 or an equivalent method approved by Ecology.

10. SO_2 emissions from the auxiliary boiler common stack when gas is burned shall not exceed 12 ppmvd at 7% O_2 and 7 pounds per hour on an hourly average.

SO_2 emissions from the auxiliary boiler common stack when fuel oil is burned shall not exceed 23 ppmvd at 7% O_2 and 14 pounds per hour on an hourly average. Compliance shall be determined by EPA Reference Method 6 of 40 CFR Part 60, Appendix A as of July 1, 1990 or an equivalent method approved by Ecology.

11. CO emissions from the auxiliary boiler common stack shall not exceed 150 ppm at 7% O_2 and 28 pounds per hour on an hourly average. Compliance shall be determined by EPA Reference Method 10 or 10A of 40 CFR Part 60, Appendix A as of July 1, 1990 or equivalent method approved by Ecology.

12. VOC emissions from the auxiliary boiler common stack shall not exceed 3 pounds per hour. Compliance shall be determined by EPA Reference Method 25A or Method 18 of 40 CFR Part 60 Appendix A as of July 1, 1990 or equivalent method approved by Ecology.

13. PM_{10} emissions from the auxiliary boiler common stack shall not exceed 0.020 gr/DSCF corrected to 7% O_2 and 11 pounds per hour on an hourly basis. Compliance shall be determined by EPA Reference Method 5 of 40 CFR Part 60 Appendix A as of July 1, 1990, EPA Method 201 or 201A of 40 CFR Part 51, Appendix M as of July 1, 1990 or an equivalent method approved by Ecology.

14. Each auxiliary boiler shall operate no more than 1500 hours per year when burning 0.05 weight percent No. 2 fuel oil.

15. Opacity from the auxiliary boiler common stack shall not exceed 5 percent as measured by EPA Reference Method 9 of 40 CFR Part 60, Appendix A as of July 1, 1990.

16. The standby emergency diesel generator shall burn only No. 2 fuel oil with a sulfur content no more than 0.05 percent sulfur by weight. Tenaska shall maintain fuel receipts from the fuel supplier which certify that the fuel oil meets the fuel sulfur limit.

The standby diesel generator shall operate no more than 2000 hours per year. Operating hours shall be measured and a record maintained for a running two year period.

17. With the exception of particulate, PM-10, sulfur dioxide, carbon monoxide, volatile organic compounds, nitrogen oxides and ammonia emissions of any pollutant regulated under the Clean Air Act shall be less than the significant levels in 40 CFR 52.21(b)(23)(i) as of July 1, 1991.

18. Any continuous emission monitoring system (CEMS) used by Tenaska to measure NO_x, SO_2, CO or O_2 emissions shall, at a minimum, conform with EPA Title 40 Code of the Federal Regulations, Part 60, Appendix B Performance Specifications as of July 1, 1990. Any CEMS or alternative used by Tenaska to determine NH_3 emissions shall be evaluated for acceptability by means equivalent in stringency to EPA Title 40 Code of the Federal Regulations, Part 60, Appendix B Performance Specifications as of July 1, 1990. In addition, before initial start-up a continuous emission monitoring quality control plan conforming with 40 CFR 60 Appendix F and acceptable to Ecology shall be submitted and Ecology may require the plan to be periodically updated.

19. CEMS and process data shall be reported in written form to the Northwest Air Pollution Authority (NWAPA) at least monthly (unless a different testing and reporting schedule has been approved by Ecology) within thirty days of the end of each calendar month and in a format approved by Ecology which shall include but not be limited to the following:

19.1 Process or control equipment operating parameters.
19.2 The daily maximum and average concentration, in the units of the standard, for each pollutant monitored.
19.3 The duration and nature of any monitor downtime.
19.4 Results of any monitor audits or accuracy checks.
19.5 Results of any stack tests.

20. For each occurrence of monitored emissions in excess of the standard the report shall include the following:

20.1 The time of the occurrence.
20.2 Magnitude of the emission or process parameters excess.
20.3 The duration of the excess.
20.4 The probable cause.
20.5 Corrective actions taken or planned.
20.6 Any other agency contacted.

21. Operating and maintenance manuals for all equipment that has the potential to affect emissions to the atmosphere shall be developed and followed. Copies of the manuals shall be available to Ecology or NWAPA. Emissions that result from a failure to follow the requirements of the manuals may be considered proof that the equipment was not properly operated and maintained.

22. Within 60 days after achieving maximum production, but not later than 180 days after startup, Tenaska shall conduct performance tests for NO_x, SO_2, CO, VOC, PM_{10}, opacity, and ammonia on each combustion turbine, to be performed by an independent testing firm. Within 60 days after achieving maximum production, but not later than 180 days after startup, Tenaska shall conduct performance tests for NO_x, SO_2, CO, VOC, PM_{10}, and opacity the auxiliary boilers common stack to be performed by an independent testing firm. A test plan shall be submitted for Ecology approval at least 30 days prior to testing.

23. Tenaska must participate in an ambient air monitoring program directed by the U. S. Forest Service in consultation with Ecology.

24. Operation of the equipment must be conducted in compliance with all data and specifications submitted as part of the PSD application unless otherwise approved by Ecology.

25. This approval shall become void if construction of the project is not commenced within eighteen (18) months after receipt of final approval,

or if construction or operation of the project is discontinued for a period of eighteen (18) months.

26. Any activity which is undertaken by Tenaska Washington or others, in a manner which is inconsistent with the application and this determination, shall be subject to department enforcement under applicable regulations. Nothing in this determination shall be construed so as to relieve Tenaska Washington of its obligations under any state, local, or federal laws or regulations.

27. Tenaska Washington shall notify the department in writing at least thirty days prior to startup.

28. Access to the facility by the U.S. Environmental Protection Agency (EPA), department, state or local regulatory personnel shall be permitted upon request for the purpose of compliance assurance inspections. Failure to allow access is grounds for enforcement under federal and state law.

Reviewed by:

John Drabek, P.E. — 5/18/92 Date

Engineering and Technical Services

Washington Department of Ecology

Approved by:

Joseph R. Williams — 5/19/92 Date

Manager, Air Quality Program

Washington Department of Ecology

Jim ~~John~~ McCormick, Director — 5/29/92 Date

Air and Toxics Division

United States Environmental Protection Agency

Region 10

WASHINGTON DEPARTMENT OF ECOLOGY
PO Box 47600
OLYMPIA, WASHINGTON 98504-7600

IN THE MATTER OF:	]	
	]	
Tenaska Washington Partners, L.P.	]	**NO. PSD 91-04 AMENDMENT 1**
5105 Lake Terrell Road	]	**FINAL APPROVAL**
Ferndale, WA 98248	]	

Pursuant to the U.S. Environmental Protection Agency (EPA) regulations for the Prevention of Significant Deterioration (PSD) set forth in Title 40, Code of the Federal Regulations, Part 52 and regulations set forth in the Washington Administrative Code 173-400-141 and based on the complete PSD application submitted by Tenaska Washington Inc., the technical analysis performed by the Washington State Department of Ecology (Ecology), dated May 18, 1992, and the June 12, 1998, application to amend the May 1992 permit, the department now finds the following:

FINDINGS

1. In May 1992, Tenaska Washington Inc. obtained PSD Permit 91-04 to build a new combined cycle cogeneration facility adjacent to the Tosco (formerly BP Oil) refinery near Ferndale. The project consisted of two natural gas fired combustion turbines, two heat recovery steam generators with supplemental firing capability, and one steam turbine. Two auxiliary boilers and an auxiliary power generator were planned to be constructed for standby service. The facility would provide electrical power to Puget Sound Energy (formerly Puget Sound Power and Light) and steam to the Tosco refinery.

2. In June 1998, several permit changes were requested. These included eliminating references to equipment never installed (two auxiliary boilers, one standby diesel generator) and a fuel never used (refinery gas), clarifying permit language, clarifying reporting requirements, and allowing an alternative monitoring method for ammonia and CO if emission levels are well below permitted limits.

3. The Tenaska Washington Project qualified as a major source because it would emit more than 100 tons (90.7 megagrams) per year of nitrogen oxides, carbon monoxide, and sulfur dioxide. It is located in an area which is designated Class II for the purposes of PSD evaluation under 40 CFR 52.21 dated July 1, 1990.

4. The emission of NO_X from the duct burners is subject to new source performance standards in Title 40 Code of Federal Regulations (CFR) Part 60, Subpart Db as of July 1, 1990. The emissions from the combustion turbines are subject to 40 CFR Part 60 Subpart GG as of July 1, 1990.

5. The site is within an area that is in attainment with regards to the state and national air quality standards.

6. The facility has the potential to emit (PTE) up to 342 tons (310 megagrams) per year of nitrogen oxides. PTE of equipment that was originally permitted but not installed has been deleted from the original 491 tons (445 megagrams) per year PTE value.

7. The facility has the potential to emit up to 366 tons (332 megagrams) per year of carbon monoxide. PTE of equipment that was originally permitted but not installed has been deleted from the original 473 tons (429 megagrams) per year PTE value.

8. The facility has the potential to emit up to 100 tons (90.7 megagrams) per year of sulfur dioxide. PTE of equipment that was originally permitted but not installed has been deleted from the original 188 tons 171 megagrams) per year PTE value.

9. The facility has the potential to emit up to 82 tons (74 megagrams) per year of volatile organic compounds (VOC). PTE of equipment that was originally permitted but not installed has been deleted from the original 91 (83 megagrams) tons per year PTE value.

10. The facility has the potential to emit up to 74 tons (67 megagrams) per year of total particulate matter (PM). PTE of equipment that was originally permitted but not installed has been deleted from the original 95 tons (86 megagrams) per year PTE value.

11. The facility has the potential to emit up to 70 tons (64 megagrams) per year of particulate matter less than 10 micrometers (PM_{10}). PTE of equipment that was originally permitted but not installed has been deleted from the original 87 tons (80 megagrams) per year PTE value.

12. The emissions of nitrogen oxides, carbon monoxide, sulfur dioxide, VOC, PM, and PM_{10} are subject to PSD review.

13. Best available control technology (BACT) will be used to control air pollutants from the proposed project.

14. The project nitrogen oxides (as NO_2) emissions will consume up to 1.3 $\mu g/m^3$ of the 25 $\mu g/m^3$ PSD increment. The project will have no other significant adverse impact on air quality.

15. The project is anticipated to have no noticeable affect on industrial, commercial, or residential growth.

16. Visibility will not be impaired in any Class I area due to the proposed emissions.

17. Ambient pollutant concentrations in any Class I area are not predicted to change due to the project.

18. Ecology finds that all requirements for PSD have been satisfied. Approval of the PSD application is granted subject to the following conditions.

APPROVAL CONDITIONS

1. NO_X emissions from each gas turbine/heat recovery steam generator system stack when gas is fired shall not exceed 7 parts per million on a volume basis (ppmdv) corrected to 15 percent oxygen on a daily average, and also shall not exceed 33 pounds (15 kilograms) per hour on a daily average. NO_X emissions from each gas turbine/heat recovery steam generator system stack when oil is fired shall not exceed 12 ppmdv corrected to 15% O_2 on a daily average, and also shall not exceed 60 pounds (27 kilograms) per hour on a daily average. Initial compliance shall be determined by EPA Reference Method 20 of 40 CFR Part 60, Appendix A as of July 1, 1990. Compliance shall also be determined for each stack by a continuous emission monitoring system (CEMS) which meets the requirements of Condition 8.

2. CO emissions from each gas turbine/heat recovery steam generator system stack shall not exceed 20 ppmdv corrected to 15% O_2 on an hourly average. CO emissions from each gas turbine/heat recovery steam generator system stack shall not exceed 44 pounds (20 kilograms) per hour. Compliance shall be determined by annual EPA Reference Method 10 or 10A of 40 CFR Part 60, Appendix A as of July 1, 1990. A test plan shall be submitted for Ecology approval at least 30 days prior to annual testing.

3. The gas turbines shall burn either pipeline natural gas or No. 2 fuel oil with sulfur content of no more than 0.05 weight percent. The heat recovery steam generator duct burners shall burn only pipeline natural gas. The facility may burn no more than 20.4 million gallons (77.2 million liters) of low sulfur No. 2 fuel oil per calendar year. Tenaska shall maintain records of fuel oil usage and sulfur content as required by Ecology.

4. SO_2 emissions from each gas turbine/heat recovery steam generator system stack when gas is burned in the turbines shall not exceed 12 pounds (5.4 kilograms) per hour on an hourly average. SO_2 emissions from each gas turbine/heat recovery steam generator system stack when fuel oil is burned in the turbines shall not exceed 59 pounds (27 kilograms) on an hourly average. Initial compliance shall be determined by EPA Reference Method 6 of 40 CFR Part 60 Appendix A as of July 1, 1990, or an equivalent method approved by Ecology.

5. PM_{10} emissions from each gas turbine/heat recovery steam generator system stack when gas or fuel oil is burned in the turbines shall not exceed 0.0022 grain per dry standard cubic foot (0.0050 grams per dry cubic meter) corrected to 15 percent oxygen (gr/DSCF at 15% O_2) and shall not exceed 13 pounds (5.9 kilograms) on an hourly average. Compliance shall be determined by EPA Reference

Method 5 of 40 CFR Part 60 Appendix A as of July 1, 1990, EPA Method 201 or 201A of 40 CFR Part 51, Appendix M as of July 1, 1990, or an equivalent method approved by Ecology.

6. VOC emissions from each gas turbine/heat recovery steam generator system stack shall not exceed 15 pounds (6.8 kilograms) per hour on an hourly average. Compliance shall be determined by EPA Reference Method 25A of 40 CFR Part 60, Appendix A as of July 1, 1990 or an equivalent method approved by Ecology.

7. Opacity from each gas turbine/heat recovery steam generator system stack shall not exceed 5 percent as measured by EPA Reference Method 9 of 40 CFR Part 60, Appendix A as of July 1, 1990.

8. Any CEMS used by Tenaska to measure NO_X or O_2 emissions shall, at a minimum, conform to EPA Title 40 Code of the Federal Regulations, Part 60, Appendix B Performance Specifications as of July 1, 1990. In addition, before initial start-up a continuous emission monitoring quality control plan conforming with 40 CFR 60 Appendix F and acceptable to Ecology shall be made available and Ecology may require the plan to be periodically updated.

9. CEMS and process data shall be reported in written form to the Northwest Air Pollution Authority (NWAPA) and Ecology at least monthly (unless a different testing and reporting schedule has been approved by Ecology) within thirty days of the end of each calendar month and in a format approved by Ecology. For each occurrence of monitored emissions in excess of the standard the report shall include the following:

   9.1. The time of the occurrence.
   9.2. Magnitude of the emission or process parameters excess.
   9.3. The duration of the excess.
   9.4. The probable cause.
   9.5. Corrective actions taken or planned.

10. Within 60 days after achieving maximum production, but not later than 180 days after startup, Tenaska shall conduct performance tests for NO_X, SO_2, CO, VOC, PM_{10}, opacity, and ammonia on each combustion turbine, to be performed by an independent testing firm. A test plan shall be submitted for Ecology approval at least 30 days prior to testing.

11. Tenaska must participate in an ambient air monitoring program directed by the U. S. Forest Service in consultation with Ecology.

12. Operation of the equipment must be conducted in compliance with all data and specifications submitted as part of the PSD application unless otherwise approved by Ecology.

13. This approval shall become void if construction of the project is not commenced within eighteen (18) months after receipt of final approval, or if construction of the project is discontinued for a period of eighteen (18) months.

14. Any activity undertaken by Tenaska Washington or others, in a manner that is inconsistent with the application and this determination, shall be subject to enforcement under applicable regulations. Nothing in this determination shall be construed so as to relieve Tenaska Washington of its obligations under any state, local, or federal laws or regulations.

15. Tenaska Washington shall notify the department in writing at least thirty days prior to startup.

16. Access to the facility by the U.S. Environmental Protection Agency (EPA), department, state or local regulatory personnel shall be permitted upon request for the purpose of compliance assurance inspections. Failure to allow access is grounds for enforcement under federal and state law.

Reviewed by:

Robert C. Burmark — 11/12/99

Robert C. Burmark, P.E.
Engineering and Technical Services
Washington Department of Ecology

Date

ROBERT C. BURMARK
STATE OF WASHINGTON
29848
REGISTERED
PROFESSIONAL ENGINEER
EXPIRES 1-4-02

Approved by:

Mary E. Burg — 11·17·99

Mary E. Burg
Program Manager, Air Quality Program
Washington Department of Ecology

Date

Barbara McAllister — 1/19/00

Barbara McAllister
Director, Office of Air Quality
US Environmental Protection Agency Region 10

Date

Summary of Permit Conditions for each Gas Turbine/Heat Recovery Steam Generator Stack[3]					
Pollutant	**Permit Limit**	**Averaging Time**	**Approved Test Method**	**Source Test Frequency**	**Reporting Frequency**
NO_X	Natural Gas Fired[1]: 7 ppmdv @ 15% O_2 and 33 lb/hr (15 Kg/hr) (Duct burners may burn gas only, not oil) Oil Fired[2]: 12 ppmdv @ 15% O_2 and 60 lb/hr (27 Kg/hr)	Daily	RM 20 , CEM	Initial Annual RATA	Monthly
CO	20 ppmdv @ 15% O_2 44 lb/hr (20 Kg/hr)	Hourly	RM 10 or 10A,	Annual	Annual
SO_2	Natural Gas Fired: 12 lb/hr (5.4 Kg/hr) Oil Fired: 59 lb/hr (27 Kg/hr)	Hourly	RM 6 , Fuel monitoring	Initial test and fuel monitoring	Monthly
PM_{10}	0.0022 grains per dry standard cubic foot (0.0050 grams per standard cubic meter) @ 15% O_2 13 lb/hr (5.9 Kg/hr)	Hourly	RM 5, RM 201 or 201A, or equivalent method approved by Ecology	Initial	Annual
VOC	15 lb/hr (6.8 Kg/hr)	Hourly	RM 25A or equivalent method approved by Ecology	Initial	Annual
Opacity	5%		RM 9		Monthly

1. "Natural Gas fired" means combusting pipeline quality natural gas only
2. "Oil Fired" means combusting No. 2 fuel oil with sulfur content of no more than 0.05 weight percent The two turbines in total are limited to combusting 20.4 million gallons (77.2 million liters) of oil per calendar year.
3. This table is a summary of the permit's conditions. If there is a conflict between this table and a permit provision, the written permit provision takes precedence.