ENERGY FACILITY SITE EVALUATION COUNCIL
P.O. BOX 43172
OLYMPIA, WASHINGTON 98504-3172

IN THE MATTER OF:	]	**NO. EFSEC/2002-01**
BP Cherry Point Cogeneration Project	]	**FINAL APPROVAL**
BP West Coast Products, LLC	]	**NOTICE OF CONSTRUCTION**
Whatcom County, Washington	]	**AND PREVENTION OF**
	]	**SIGNIFICANT DETERIORATION**

Pursuant to the Energy Facility Site Evaluation Council (EFSEC) Permit Regulations for Air Pollution Sources Chapter 463-39 Washington Administrative Code (WAC), regulation for air permit applications Chapter 463-42-385 WAC, the Washington Department of Ecology (Ecology) regulations for new source review Chapter 173-400 WAC and Chapter 174-460 WAC, the federal Prevention of Significant Deterioration regulations Code of Federal Regulations (CFR) Title 40 Subpart 52.21, and based upon the Notice of Construction Application (NOC) submitted by BP West Coast Products, LLC (BP) on June 10, 2002, supplemental information submitted on July 3, 2002, and August 29, 2002, the April 2003 revised application, and the technical analysis performed by Ecology for EFSEC, EFSEC now finds the following:

FINDINGS

1. BP West Coast Products, LLC (BP) is proposing to build a 720 megawatt (MW) natural gas fired, combined cycle combustion turbine cogeneration facility (Project) on 33 acres of land adjacent to the BP Cherry Point Refinery (Refinery). The Project is located in Whatcom County approximately 6 miles (9.6 km) northwest of Ferndale and 7 miles (11 km) southeast of Blaine, Washington. The coordinates are UTM 10 520300E and 5415000N.
2. The Project site is located within a Class II area that is currently designated in attainment for all national and state air quality standards
3. The Project will consist of:
   - 3.1. Three General Electric 7FA combustion gas turbines (CGTs), each with its own 174 MW electric generator. Each turbine will have an annual average capacity rating of 1,614 million British thermal units per hour (mm Btu/hr).
   - 3.2. Three heat recovery steam generators (HRSG) each with a supplemental duct firing burner with a maximum rating of 105 mm Btu/hr.
   - 3.3. One steam driven turbine with a 243 MW electric generator (STG).
   - 3.4. One 1,500 kW diesel fueled emergency generator.
   - 3.5. One 265 hp diesel fueled firewater pump.
   - 3.6. The Project is designed to provide base load electric service and operate year round except for maintenance.
4. The Project will supply approximately 510,000 pounds per hour (lb/hr) of steam and about 85 MW of power to the Refinery.
5. Natural gas will be the only fuel for the combustion turbines and duct burners.
6. On-road specification diesel will be the only fuel for the emergency generator and firewater pump.
7. The Project will use a water cooled steam condensation system.

8. The Project is subject to permitting requirements under the federal requirements of 40 CFR 52.21 as a fossil fuel fired steam electric generator, one of 28 listed industries that becomes a "major source" when emitting more than 100 tons per year (tpy) of any regulated pollutant. The Project has the potential to emit Prevention of Significant Deterioration (PSD) significant quantities of nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), particulate matter (PM), particulate matter less than 10 micrometers (PM_{10}), and volatile organic compounds (VOC).

9. The Project is subject to emission limitation, monitoring and reporting requirements of New Source Performance Standards (NSPS) 40 CFR 60 Subpart Db, 40 CFR 60 Subpart GG, Chapter 173-400 WAC, 40 CFR 60 Appendices A, B, and F, and 40 CFR 75; and to gas fuel monitoring requirements under 40 CFR 60.334(b)(2) and 40 CFR Part 75 Appendix D.

10. Ammonia (NH_3) emissions from the Project are subject to permitting under the requirements of WAC 463-39-005(1) and 005(4), which adopt Chapters 173-400 and 173-460 WAC respectively.

11. The Project is subject to 40 CFR Part 70 and is required to file a Title V air operating permit application within 12 months after the facility operations commence.

12. Best available control technology (BACT) as required under 40 CFR 52.21(j) and WAC 173-113(2), and toxic best available control technology (T-BACT) as required under WAC 173-460-040(4) will be used for the control of all air pollutants which will be emitted by the Project. The following table lists the Project's potential emissions and the turbine BACT control technologies.

Table 1. Project Emissions and Turbine BACT Control Technology

Pollutant	Project Potential to Emit tons per year, (tpy)	Turbine BACT Control Technology
Nitrogen Oxides (NO_X)	234	Selective Catalytic Reduction (SCR) plus lean premix dry low NO_X turbine burners and low NO_X duct burners
Carbon monoxide (CO)	158	Oxidation catalyst plus lean premix turbine burners
Sulfur dioxide (SO_2)	51	Natural gas fuel
Sulfuric acid mist (H_2SO_4)	36	Natural gas fuel
Volatile organic compounds (VOC)	43	BACT same as CO
Particulate matter (PM) and Particulate matter less than 10 microns (PM_{10})	262	Natural gas fuel
Ammonia (NH_3)	174	5 ppm ammonia slip

13. BACT for the emergency generator and firewater pump engines is that the engine be new and meet the 40 CFR 89 federal engine standards for the year of engine purchase, use of diesel fuel that meets the sulfur content specification of on road diesel fuel at the time of fuel purchase, and operation of no more than 250 hours per year for each unit.

14. BACT for the cooling tower is installation of a demister guaranteed to have a drift loss of less than 0.001% of the recirculating water flow rate.

15. Allowable emissions from the new emissions units will not cause or contribute to air pollution in violation of:

    15.1. Any state or national ambient air quality standard;

    15.2. Any applicable PSD increment. Table 2 indicates the maximum Class I and Class II increment consumed by this Project.

Table 2: Increment Impact Summary

Pollutant	Maximum Ambient Class I Area Impact		Class I Area Allowable Increment (µg/m³)	Maximum Ambient Class II Area Impact (µg/m³)	Class II Area Allowable Increment (µg/m³)
	Class I Area With Maximum Impact	µg/m³			
Sulfur dioxide					
Annual	Alpine Lakes Wilderness	0.001	2	0.03	20
24-Hour	Olympic National Park	0.021	5	4.3	91
3-Hour	Olympic National Park	0.048	25	8.4	512
Particulate (PM_{10})					
Annual	Alpine Lakes Wilderness	0.0054	4	0.25	17
24-Hour	Olympic National Park	0.087	8	4.3	30
Nitrogen Dioxide					
Annual	Alpine Lakes Wilderness	0.0053	2.5	0.6	25

16. The emissions of toxic air pollutants from this facility will not exceed any acceptable source impact level (ASIL) established under WAC 173-460-150 or 160.
17. Ambient Impact Analysis indicates the Project will have no adverse impact from pollutant deposition on soils and vegetation in the following Class I areas: the North Cascades National Park (50 miles east of the site), the Glacier Peak Wilderness Area (71 miles southeast), the Pasayten Wilderness Area (81 miles east), and the Alpine Lakes Wilderness Area (105 miles southeast). The Federal Land Managers (FLMs) use a 5% visibility impact as their threshold for possible concern. A 6% visibility impact was predicted for the Olympic National Park (66 miles southwest) on one day per year. The National Park Service considered this acceptable.
18. Ambient Air Quality modeling indicates that projected concentrations of pollutants will be below levels that require further impacts analysis or air monitoring.
19. Use of cogeneration steam is expected to result in emissions reductions at the refinery. These refinery emissions reductions are not relied upon for the cogeneration power plant's emissions impacts analysis or emissions permitting.
20. No significant effect on industrial, commercial, or residential growth in the Whatcom County area is anticipated due to the Project.
21. EFSEC finds that all requirements for new source review (NSR) and PSD are satisfied and that as approved below, the new emissions units comply with all applicable federal new source performance standards. Approval of the NOC/PSD application is granted subject to the following conditions:

APPROVAL CONDITIONS:

1. For the combustion turbines (CGTs) and duct burners :
   - 1.1. Natural gas shall be the only fuel.
   - 1.2. Compliance shall be monitored by written affirmation once per quarter of the type of fuel burned in the combustion turbines and duct burners per Condition 17.
2. For the emergency generator and fire pump:
   - 2.1. On road specification diesel shall be the only fuel.
   - 2.2. Compliance shall be monitored by written affirmation from the fuel supplier.

3. The emergency generator shall:
   3.1. Not exceed NO_X emissions of 3.4 tons per year, 12 month rolling average.
   3.2. Be operated only as needed for its maintenance, for training, and for emergency power.
   3.3. Not exceed 250 hours operation in any consecutive 12 month period.
   3.4. Meet applicable Federal new engine standards (40 CFR 89) for engines sold in 2004 or for the year of purchase which ever is later.
   3.5. Compliance with Condition 3.1 shall be by calculation of NO_X emissions using hours of operation and an emission factor approved by EFSEC. Until a factor is approved, the emission factor assumed for modeling is acceptable.
   3.6. Compliance with Conditions, 3.2 and 3.3 shall be monitored by installing and operating a nonresetable hour meter with monthly recording of the operating hour meter reading to determine the operating hours, or by automated data collection. The reason for operation shall be logged.
   3.7. NO_X and SO_2 emissions shall be calculated and reported using operating data such as hours of operation, NO_X emission factors, and fuel data. Reporting shall be per Condition 17.
   3.8. Compliance with Condition 3.4 shall be by initial certification of the engine manufacturer.
4. The fire pump shall:
   4.1. Be operated only as needed for its maintenance, for training, and for emergency fire suppression.
   4.2. Not exceed 250 hours operation in any consecutive 12 month period.
   4.3. Meet applicable new standards for new engines of its size sold in 2004 or in the year of purchase, which ever is later.
   4.4. Compliance with Conditions, 4.1, and 4.2 shall be by a log of hours of operation, reason for operation, and reported per Condition 17. SO_2 emissions shall be calculated and reported using fuel and operating data.
   4.5. Compliance with Condition 4.3 shall be by initial certification of the engine manufacturer.
5. The sulfur content of the diesel fuel must conform with the on-road diesel specification valid at the time of fuel purchase. At the time of issuance of this permit, this is defined in 40 CFR § 80.29(a)(i).
6. Nitrogen oxides (NO_X) emissions:
   6.1. NO_X emissions from each CGT exhaust stack shall not exceed:
      6.1.1. 2.5 parts per million by volume, dry (ppmdv), three hour average, corrected to 15% oxygen (O_2).
      6.1.2. 8.6 kilograms per hour (kg/hr), (19 pounds/hour (lb/hr)) on a three hour average.
   6.2. Compliance shall be determined in accordance with 40 CFR 60 Subpart GG and EPA Reference Method 20, except that the instrument span shall be reduced appropriately for accuracy.
   6.3. Continuous compliance shall be monitored by continuous emission monitors for NO_X and O_2. The continuous emission monitoring system (CEMS) must meet the requirements of Approval Condition 16.1.
7. Carbon monoxide (CO) emissions:
   7.1. CO emissions from each CGT exhaust stack shall not exceed:
      7.1.1. 2.0 ppmdv, three hour average, corrected to 15% oxygen (O_2).
      7.1.2. 4.2 kg/hr, (9.2 lb/hr) on a three hour average.

7.2. Compliance shall be determined by use of EPA Reference Method 10, except that the instrument span shall be reduced appropriately for accuracy.

7.3. Continuous compliance shall be monitored by continuous emission monitors for CO and O_2. The CEMS must meet the requirements of Approval Condition 16.

8. Particulate Matter (PM) and Particulate Matter less than or equal to ten microns (PM_{10}) shall be considered equal for this permit, and referenced and reported as PM_{10}.

8.1. PM_{10} emissions from each CGT exhaust stack shall not exceed 9.4 kg/hr (20.6 lb/hr), filterable plus condensable, averaged over 24 hours.

8.2. Compliance shall be determined by use of EPA Methods 5, 201, or 201A for filterable particulate, and Method 202 for condensable particulate, or equivalent methods agreed to in advance by EFSEC.

8.2.1. Use of EPA Method 5 assumes all filterable particulate is PM_{10}.

8.2.2. Use of Method 201 or 201A assumes that the mass of filterable PM is equal to the mass of filterable PM_{10}. The mass of particulate retained in the cyclone shall be determined and reported.

8.3. Continuous compliance shall be demonstrated by an annual emissions test on a CGT exhaust stack using the methods indicated in Condition 8.2. After 3 consecutive years of annual tests on each CGT stack have demonstrated compliance, testing of each CGT stack may be reduced to once every 5 years. If a test demonstrates noncompliance, a retest along with resumption of annual testing is required for the unit until 3 consecutive years demonstrate compliance.

8.4. Routine emissions shall be determined using emission factors determined from source test data. If no source test data is available, emission factors approved by EFSEC shall be used until source test data can be developed.

9. Volatile organic compound (VOC) emissions:

9.1. VOC emissions from each CGT exhaust stack shall not exceed: 1.4 kg/hr, (3.0 lb/hr) averaged over 24 hours, reported as carbon equivalent.

9.2. Compliance shall be determined by EPA Method 25A or 25B, or an equivalent method agreed to in advance by EFSEC.

9.3. Continuous compliance shall be demonstrated by an annual emissions test on each CGT exhaust stack using the methods indicated in Condition 9.2. After 3 consecutive years of annual tests on a CGT stack have demonstrated compliance, testing of each CGT stack may be reduced to once every 5 years. If a test demonstrates noncompliance, a retest along with resumption of annual testing is required for that unit until 3 consecutive years demonstrate compliance.

9.4. Routine emissions shall be determined using emission factors determined from source test data. If no source test data is available, emission factors approved by EFSEC shall be used until source test data can be developed.

10. Sulfur dioxide (SO_2) emissions:

10.1. SO_2 emissions from each CGT exhaust stack shall not exceed 8.8 lb/hr averaged over 24 hours.

10.2. Compliance for each CGT shall be determined by EPA Method 6, 6C, 8, or an equivalent method agreed to in advance by EFSEC.

10.3. Continuous compliance shall be demonstrated by an annual emissions test on each CGT exhaust stack using the methods indicated in Condition 10.2. After 3 consecutive years of annual tests on a CGT stack have demonstrated compliance, testing of each CGT stack may be reduced to once every 5 years. If a test demonstrates noncompliance, a retest along with resumption of annual testing is required for that unit until 3 consecutive years demonstrate compliance.

10.4. Continuous compliance shall be indicated by calculation of daily SO_2 emissions. This calculation may be based on daily fuel usage, daily fuel sulfur content determined by information supplied by the natural gas fuel supplier, odorant addition into the Ferndale pipeline, and any other applicable information approved by EFSEC. Conversion of SO_2 to H_2SO_4 may be estimated by information provided by the Method 8 stack tests required in Approval Condition 11.

11. Sulfuric acid mist (H_2SO_4) emissions:

11.1. H_2SO_4 emissions from each CGT exhaust stack shall not exceed 1.3 kg/hr (2.8 lb/hr) averaged over 24 hours.

11.2. Compliance shall be determined by EPA Method 8, or an equivalent method agreed to in advance by EFSEC.

11.3. Continuous compliance shall be demonstrated by an annual emissions test on each CGT exhaust stack using the method indicated in Condition 11.2. After 3 consecutive years of annual tests on each CGT stack have demonstrated compliance, testing of each CGT stack may be reduced to once every 5 years. If a test demonstrates noncompliance, a retest along with resumption of annual testing is required for that unit until 3 consecutive years demonstrate compliance.

11.4. Continuous compliance shall be indicated by calculation of daily H_2SO_4 emissions based on fuel usage and daily fuel sulfur content. Conversion of SO_2 to H_2SO_4 may be estimated by information provided by the Method 8 stack tests required in Approval Condition 11.2.

12. Cooling Tower:

12.1. Particulate emissions shall not exceed 6,440 kg/yr (7.2 tpy) 12 month rolling average, calculated monthly.

12.2. Compliance shall be determined by methodology proposed to and approved by EFSEC prior to the operation of the cooling tower. The methodology may involve factors such as cooling tower recirculation rate, cooling tower total dissolved solids (TDS), fan operation effects, and manufacturer's information on drift losses.

12.3. BP shall obtain an affirmative report by the cooling tower drift eliminator manufacturer, based on an onsite inspection of the completed installation, that its product has been installed in accordance with its specifications and has a drift loss of less than 0.001% of the re-circulating water flow rate.

13. Within 90 days of initial startup, BP shall prepare Operating and Maintenance Manuals and an equipment Start-up, Shutdown, and Malfunction Procedures Manual for all equipment that has the potential to affect emissions to the atmosphere.

13.1. The manuals shall be reviewed annually, and updated as needed. EFSEC shall be notified whenever the manuals are updated.

13.2. Copies of the manuals shall be available to EFSEC or the authorized representative of EFSEC, or the EPA.

13.3. Emissions that result from a failure to follow the requirements of the manuals may be considered credible evidence that emission violations have occurred.

14. Turbine Startup and Shutdown:

14.1. Startup is defined as any operating period that is ramping up to normal operation (60%), and ends when the earlier of one of these events occurs:

14.1.1. The turbine(s) are operating above 60% load, and normal operating temperatures have been reached in both the catalytic oxidation and selective catalytic reduction modules as indicated by the manufacturer's operating manual.

14.1.2. One of the following time limits have been reached, as applicable:

14.1.2.1. Six hours have elapsed since fuel was first introduced to the applicable turbine on a cold startup. A cold startup is any startup occurring after the applicable turbine has been shut down for seventy two hours or more.

14.1.2.2. Four hours have elapsed since fuel was first introduced to the applicable turbine on a warm startup. A warm startup is any startup occurring after the applicable turbine has been shut down for more than eight but less than seventy two hours.

14.1.2.3. Two hours have elapsed since fuel was first introduced to the applicable turbine on a hot startup. A hot startup is any startup occurring after the applicable turbine has been shut down for less than eight hours.

14.2. Shutdown is defined as any operating period when the system is ramping down from normal operation. Normal operation is defined as operation between 60% and 100% turbine power generation capacity. Shutdown ends when the fuel feed to the system ceases.

14.3. All turbine emissions during startups and shutdowns shall be counted towards annual mass emissions.

14.4. Emission limits for NOx during startup and shutdown:

14.4.1. For purposes of compliance with NO_X emission limits, startup or shutdown operation exists only when the turbines are operating below 60% load or when the selective catalytic reduction system is below the normal operating temperature range indicated by the manufacturer's operating manual. Time in startup mode is limited by Condition 14.1.2.

14.4.2. The limit on the three hour average NO_X concentration and daily NO_X mass emissions from each HRSG stack exhaust are relieved.

14.4.3. The continuous emissions monitor (CEM) for NO_X shall be operated during startup and shutdown periods. If the CEM cannot effectively measure emissions during startup, factors acceptable to EFSEC shall be substituted. Emission factors used for the permit application preparation are acceptable initially.

14.5. Emission limits for CO during startup and shutdown:

14.5.1. For purposes of compliance with CO emission limits, startup or shutdown operation exists only when the turbines are operating below 60% load or when the catalytic oxidation system is below the normal operating temperature range indicated by the manufacturer's operating manual. Time in startup mode is limited by Condition 14.1.2.

14.5.2. The limits on the three hour average CO concentration and mass emissions from each HRSG stack exhaust are relieved.

14.5.3. The continuous emissions monitor (CEM) for CO shall be operated during startup and shutdown periods. If the CEM cannot effectively measure emissions during startup, factors acceptable to EFSEC shall be substituted. Emission factors used for the permit application preparation are acceptable initially.

14.6. Emission limits for VOC during startup and shutdown:

14.6.1. For purposes of compliance with VOC emission limits, startup or shutdown operation exists only when the turbines are operating below 60% load or when the catalytic oxidation system is below the normal operating temperature range indicated by the manufacturer's operating manual. Time in startup mode is limited by Condition 14.1.2.

14.6.2. The limits on twenty four hour average VOC concentration and mass emissions are relieved.

14.6.3. VOC emissions shall be estimated using an emission factor. An initial factor of thirty (30) pounds/hour/turbine may be used until a more representative factor is determined by testing or other reputable sources approved by EFSEC.

14.7. During each turbine's initial start up and commissioning after construction, excess emissions shall be reported and justified. Justified excess emissions shall not be considered violations or be counted toward annual emission limits. This initial commissioning period ends upon successful completion of initial performance testing or 180 days after initial startup of the turbine, which ever is first.

15. Annual emissions shall not exceed the limits in the following table. The annual limits are 12 month rolling totals calculated each month, using the procedure approved for monitoring continuous compliance for the pollutant.

Unit	NO_X	CO	PM_{10}	SO_2	VOC
Each CT G/HRSG, tons/yr	77	53	85	17	14
Cooling Tower, tons/yr	na[1]	na[1]	7.2	na[1]	na[1]
Emergency Generator	3.4	na[1]	na[1]	na[1]	na[1]

1. na means "not applicable." The cooling tower has no NO_X, CO, SO_2, or VOC emissions. The emergency generator's NO_X emissions are the only emissions from the generator or the firewater pump estimated to be more than one ton per year.

16. Continuous Emission Monitoring Systems (CEMS):

16.1. CEMS for NO_X and O_2 compliance shall meet the requirements contained in 40 CFR 75, Emissions Monitoring.

16.2. CEMS for CO shall meet the requirements contained in 40 CFR, Part 60, Appendix B, Performance Specification 4 or 4A, and 40 CFR, Part 60, Appendix F, Quality assurance Procedures.

16.3. Use of velocity factors from 40 CFR, Part 60, Method 19 will satisfy the requirements for determining exhaust gas flow rate or velocity compliance contained in 40 CFR 75, Emissions Monitoring.

17. CEMS and process data shall be submitted quarterly, in written form (or electronic if permitted by the EFSEC) within thirty days of the end of each calendar quarter to EFSEC, its authorized representative (if any), and to the EPA Region X Office of Air Quality. A different schedule may be approved by EFSEC.

18. The format of the reporting described in Approval Condition 17 shall match that required by EPA for demonstrating compliance with the Title IV Acid Rain program reporting requirements. Pollutants not covered by that format shall be reported in a format approved by EFSEC that shall include at least the following:

18.1. Process or control equipment operating parameters.

18.2. The hourly maximum and average concentration or emission rate, in the units of the permitted limit, for each pollutant monitored.

18.3. The duration and nature of any monitor down time.

18.4. Results of any monitor audits or accuracy checks.

18.5. Results of any required stack tests.

18.6. Results of any other stack tests performed after the initial performance tests.

19. For each occurrence of monitored emissions in excess of the permitted limit, the quarterly emissions report shall include the following:

    19.1. For parameters subject to monitoring and reporting under the Title IV Acid Rain program, the reporting requirements in that program shall govern excess emissions report content.

    19.2. For all other pollutants:

        19.2.1. The time of the occurrence.

        19.2.2. Magnitude of the emission or process parameters excess.

        19.2.3. The duration of the excess.

        19.2.4. The probable cause.

        19.2.5. Corrective actions taken or planned.

        19.2.6. Any agency contacted.

20. BP shall maintain monitoring records on site for at least five years.

21. Operating Records for Emitting Equipment:

    21.1. Unless otherwise specified, operating records shall be information necessary to determine the operational status of the equipment. Specific parameters and acceptable ranges of those parameters shall be specified in the Operation and Maintenance Manual. Example operating record information includes, but is not limited to:

        21.1.1. Fuel quality.

        21.1.2. Fuel consumption during the period (hourly, monthly, etc.).

        21.1.3. Unit operating parameters such as:

            21.1.3.1. Exhaust temperature.

            21.1.3.2. Percent excess air.

            21.1.3.3. Output rate (pounds of steam/hour, kW output, etc.).

            21.1.3.4. Operating hours during the reporting period and cumulative for the year.

22. Within 180 days after initial start-up of each turbine, BP shall conduct performance tests for NOx, CO, PM_{10}, VOC, SO_2, and H_2SO_4 on each combustion turbine.

    22.1. The performance tests shall be performed by an independent testing firm.

    22.2. A test plan shall be submitted for EFSEC's approval at least 30 days prior to the testing.

23. Initial start-up for determining the initial compliance testing, CEM system performance testing, and similar purposes is defined as the earlier of the following dates:

    23.1. Beginning of commercial operation, or

    23.2. 180 days after the first fire occurs.

24. BP shall notify EFSEC in writing at least thirty days prior to:

    24.1. Initial start-up of any permitted emissions unit for operational testing and manufacturer's certification purposes.

    24.2. Initial start up of the Project as in Condition 23.

    24.3. The date any emissions testing required by this permit will be performed.

    24.4. The date(s) CEMS performance testing or Relative Accuracy Test Audits will be performed.

25. Sampling ports and platforms shall be provided on each stack, after the final pollution control device. The ports shall meet the requirements of 40 CFR 60 Appendix A, Method 20.
26. Adequate permanent and safe access to the test ports shall be provided. Other arrangements may be acceptable if approved by EFSEC prior to installation.
27. Any activity which is undertaken by the company or others in a manner which is inconsistent with the application and this determination shall be subject to EFSEC enforcement under the applicable regulations. Nothing in this determination shall be construed so as to relieve BP of its obligations under any state, local, or federal laws or regulations.
28. Access to the source, by EFSEC, the authorized representative of EFSEC, or the EPA, shall be permitted upon request for the purposes of compliance assurance inspections. Failure to allow such access is grounds for enforcement action under the federal Clean Air Act or the Washington Clean Air Act.
29. This approval shall become invalid if construction of the Project is not commenced within eighteen (18) months after receipt of final approval, or if construction of the facility is discontinued for a period of eighteen (18) months, unless EFSEC extends the 18 month period upon a satisfactory showing that an extension is justified, pursuant to 40 CFR 52.21(r)(2) and applicable EPA guidance.

This Prevention of Significant Deterioration Permit has been Prepared by:

__________________________ ____________________

Robert C. Burmark, P.E. Date
Technical, Information, and Engineering Services
Air Quality Program
Washington State Department of Ecology

This Prevention of Significant Deterioration Permit has been Approved by:

__________________________ ____________________

James O. Luce Date
Chair
Energy Facility Site Evaluation Council

This Prevention of Significant Deterioration Permit has been Approved by:

__________________________ ____________________

Richard Albright Date
Director
Office of Air, Waste and Toxics
U.S. Environmental Protection Agency, Region 10

NOTICE OF CONSTRUCTION APPROVAL CONDITIONS

1. BP will comply with all Prevention of Significant Deterioration Approval Conditions.

2. Ammonia (free NH_3 and combined measured as NH_3) emissions from each combustion turbine exhaust stack shall not exceed 5.0 ppmdv corrected to 15% O_2 and 6.0 kg/hr (13.2 lb/hr), both 24 hour average.

   2.1. Compliance shall be determined by either Bay Area Air Quality Management District Source Test Procedure ST-1B, EPA Conditional Test Method CTM-027, or an equivalent method approved in advance by EFSEC. Tests are to be done at several operating rates such as 70%, 85%, and 100% load to establish a correlation between the heat input rates of the gas turbine and its associated HRSG, the SCR ammonia injection rate, and the corresponding NH_3 emission concentration at the exhaust point.

   2.2. Continuous compliance shall be demonstrated by annual testing in accordance with Condition 2.1.

   2.3. Continuous compliance shall be indicated by the correlation established in Condition 2.1, and updated annually per Condition 2.2.

   2.4. An ammonia CEMS system may be used to indicate continuous compliance and satisfy Condition 2.2. The CEMS must meet the requirements of Approval Condition 5.1.

3. Opacity:

   3.1. Each CGT exhaust stack shall not exceed a six minute average of 5%.

   3.2. Opacity shall be determined by use of EPA Reference Method 9, or an equivalent method approved in advance by EFSEC. A certified opacity reader shall read and record the opacity of each operating unit once per week.

   3.3. An opacity CEMS system may be used to indicate continuous compliance and satisfy condition 3.1. The opacity CEMS must meet the requirements of Condition 5.2.

   3.4. The limit for opacity is relieved during start up and shutdown periods.

4. BP shall determine applicability of the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbine Combustion Turbines, 40 CFR 63 Subpart YYYY, within 180 days after initial startup.

   4.1. Testing of each turbine shall be done after the oxidation catalyst using Test Method 320 of 40 CFR Part 63, Appendix A including the additional testing provisions of 40 CFR 63 Subpart YYYY, or using other methods approved by EFSEC.

   4.2. If Subpart YYYY is not applicable, then BP shall:

      4.2.1. Monitor and maintain the 4-hour rolling average of the oxidation catalyst inlet temperature within the range suggested by the catalyst manufacturer, and

      4.2.2. Performance test for formaldehyde once every five years as specified in Condition 4.1.

5. Continuous Emission Monitoring Systems (CEMS)

   5.1. CEMS for ammonia (if used) shall meet the requirements contained in 40 CFR, Part 63, Appendix A, Reference Method 301, Validation Protocol, and 40 CFR, Part 60, Appendix F, Quality Assurance Procedures, or other EFSEC approved performance specifications and quality assurance procedures.

   5.2. CEMS for opacity (if used) shall meet the requirements contained in 40 CFR Part 60, Appendix B, Performance Specification 1, and in 40 CFR, Part 60, Appendix F, Quality Assurance Procedures.

6. CEMS and process data shall be submitted quarterly, in written form (or electronic if permitted by the EFSEC) within thirty days of the end of each calendar quarter to EFSEC, its authorized representative (if any), and to the EPA Region X Office of Air Quality. A different schedule and format may be approved by EFSEC.

 6.1. For ammonia:

  6.1.1. Any reference tests performed, along with the correlation used to estimate ammonia emissions.

  6.1.2. Daily hourly average ammonia emissions in the unit of the standard.

 6.2. For opacity:

  6.2.1. Daily opacity readings

 6.3. For formaldehyde emissions:

  6.3.1. The daily hourly average, maximum, and minimum oxidation catalyst inlet temperature in the units of the standard.

  6.3.2. Any performance test results.

 6.4. For each occurrence of the monitored emissions or process parameters in excess of the standard, the quarterly emissions report shall include the following:

  6.4.1. The time of the occurrence.

  6.4.2. Magnitude of the emissions or process parameters excess.

  6.4.3. Duration of the excess.

  6.4.4. The probable cause.

  6.4.5. Corrective actions taken or planned.

  6.4.6. Any agency contacted.

This Notice of Construction Approval has been Prepared by:

____________________________ _____________________

Robert C. Burmark, P.E. Date
Engineering and Technical Services
Air Quality Program
Washington State Department of Ecology

This Notice of Construction has been Approved by:

____________________________ _____________________

James O. Luce Date
Chair
Energy Facility Site Evaluation Council.

Appendix A – Summary of Emission Limitations for EFSEC/2002-01 PSD and NOC Approval

Note: 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.

COMBUSTION TURBINE WITH ADVANCED DRY LOWNOX TECHNOLOGY, SCR, AND OXIDATION CATALYST (PER TURBINE)				
Pollutant	**Limit**	**Averaging Time**	**Test Method (or equivalent approved by EFSEC)**	**Stack Testing or Certification Frequency**
NO_x @15% O_2	2.5 ppmdv 18.7 lb/hr 77 tpy	3 hour 24 hour 12 month rolling average	RM 20 and CEMs	Initial and Annual CEM RATA
CO @ 15% O_2	2.0 ppmdv 9.2 lb/hr 53 tpy	3 hour 3 hour 12 month rolling average	RM 10 and CEMs	Initial and Annual CEM RATA
SO_2	8.8 lb/hr 17 tpy	24 hour 12 month rolling average	RM 6 or 6C or 8, and fuel monitoring	Initial and annual for 3 years[1]
PM_{10}	20.6 lb/hr 85 tpy	24 hour 12 month rolling average	RM 5 or 201 or 201A, and 202	Initial and annual for 3 years[1]
VOC	3.0 lb/hr 14 tpy	24 hour 12 month rolling average	RM 25A or 25B	Initial and annual for 3 years[1]
Sulfuric Acid Mist	2.8 lb/hr	24 hour	RM 8	Initial and annual for 3 years[1]
Ammonia	5.0 ppmdv 13.2 lb/hr	24 hour 24 hour	Conditional Test Method CTM -027, or Bay Area Air Quality Management District Source Test Procedure ST-1B	Initial and Annual according to agreed protocol[2]
Opacity	5%	6 minute (one weekly reading)	RM 9	Initial and 6 month reader certification
COOLING TOWER				
PM_{10}	7.2 tpy	12 month rolling average	Calculation method approved by EFSEC	Initial certification of drift eliminator installation
EMERGENCY GENERATOR				
Operating Hours	250 hours	12 month rolling average	Hour meter or automatic data system	Engine manufactured to meet Federal new engine standards
NO_X	3.4 tpy	12 month rolling average	Emission factor	Emission factor approved by EFSEC
SO_2	On road specification diesel SO_2	Report quarterly	Analysis of fuel by supplier	Certification by fuel supplier at time of fuel purchase
FIREWATER PUMP				
Operating Hours	250 hours	12 month rolling average	Log of hours of operation	Engine manufactured to meet Federal new engine standards
SO_2	On road specification diesel SO_2	Report quarterly	Analysis of fuel by supplier	Certification by fuel supplier at time of fuel purchase

1. After 3 consecutive years of annual tests on each CGT stack have demonstrated compliance, testing of each CGT stack may be reduced to once every 5 years. If a test demonstrates noncompliance, a retest along with resumption of annual testing is required for the unit until 3 consecutive years demonstrate compliance.

2. Tests are to be done at several operating rates such as 70%, 85%, and 100% load to establish a correlation between the heat input rates of the gas turbine and its associated HRSG, the SCR ammonia injection rate, and the corresponding NH_3 emission concentration at the exhaust point.