ENERGY FACILITY SITE EVALUATION COUNCIL
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IN THE MATTER OF: **Satsop Combustion Turbine Project** **Electrical Generating Facility** **Elma, Washington**	]]]]]]	**NO. EFSEC/2001-01 Amendment 2** **FINAL DETERMINATION** **NOTICE OF CONSTRUCTION** **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 WAC 463-42-385, the Washington Department of Ecology (Ecology) regulations for new source review WAC 173-400-110 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 Notices of Construction Application (NOC), submitted by Duke Energy Grays Harbor, LLC., and Energy Northwest, the Administrative Order on Consent, Docket No. CAA-10-2001-0097, between the Satsop Combustion Turbine (Satsop CT) Project and the U.S. Environmental Protection Agency, Region 10, dated March 30, 2001, and the technical analysis performed by Ecology for EFSEC, EFSEC now finds the following:

FINDINGS

1 Duke Energy Grays Harbor, LLC., and Energy Northwest (jointly "Duke Energy") applied to construct the Satsop Combustion Turbine Project located near Elma, Washington. EFSEC has previously approved the construction of this project (also known as Satsop Phase I), which is designed to produce a maximum of 650 megawatt (MW) of electrical power. This project received final approval on November 2, 2001 (NO. EFSEC/2001-01). Amendment 1 to the original approval was issued on January 2, 2003.

This Amendment 2 is to extend the expiration of the authorization to construct the project previously approved and to make certain modifications to the monitoring requirements and BACT emission limitations based on recently available information. Duke Energy did not request to change or add any emission units that were either proposed for installation or already installed at the facility in their amendment request.

Amendment 1 modified the operating requirements and emission limitations in the original approval. In addition in their request for Amendment 1, Duke Energy also proposed the inclusion of additional equipment as part of the project. This new equipment was not part of the original the project description or included in the original approval. The Amendment also reflected a request to remove certain operational restrictions in the original approval.

As currently requested the total project is proposed to consist of the following major components:

a) Two General Electric gas combustion turbines (GE 7FA); each turbine having a maximum rating of 1,671 million British thermal units per hour (mmBtu/hr), and each turbine will have a supplementary duct burner with a maximum rating of 505 mmBtu/hr.;
b) Two heat recovery steam generators (HRSG);

c) One steam turbine generator (STG) rated 300 MW each;
d) One auxiliary boiler;
e) One forced draft cooling tower system;
f) One emergency backup diesel generator ; and
g) One diesel engine-driven fire water pump.

These components are configured in a "power island" comprised of 2 gas turbine/duct burner/HRSG units, one steam turbine, one cooling tower, one auxiliary boiler, one emergency generator, and one emergency fire water pump. Each gas turbine/duct burner/HRSG unit is known as a combined cycle gas turbine (CGT). Each CGT has its own exhaust stack.

2 Duke Energy's NOC/PSD application for amendment 1 to PSD No: EFSEC/2001-01 was filed on December 24, 2001. After submittal of additional information on January 30, 2002, and in March, April and May, 2002, the application for the amendment was determined to be complete on May 12, 2002.

3 Duke Energy's NOC/PSD application for Amendment 2 and request for extension of the begin construction time period was filed on January 21, 2004. After submittal of additional information on February 27, 2004 and on March 11, 2004, the application for amendment was determined to be complete on April 10, 2004. In accordance with EFSEC procedures and draft EPA guidance, the application/extension request included a review of the BACT technologies applicable to the facility, requests for modifications to specific monitoring and operational requirements in the approval and a request to identify which NOx emission limitations are the result of a BACT analysis and which are due to protection of Class I area air quality related values and visibility protection. The Technical Support document developed for this amendment includes details of the changes requested and how the requests were dealt with.

4 The request for Amendment 1 to the PSD approval included a Phase II project which would have doubled the capacity of the facility. During the public comment period on the amendment, Duke Energy requested that EFSEC stop processing of the Phase II project request. The Amendment 1 final determination only included the minor changes requested to the Phase I project.

5 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 Satsop CT Project has the potential to emit 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).

6 The project is subject to permitting under the requirements of WAC 463-39-005(1) and 005(4) (adopting Chapters 173-400 and 173-460 WAC respectively) for ammonia (NH_3). NH_3 emissions are limited in this permit in its role as in controlling emissions of NO_x.

7 The combustion turbines, duct burners and auxiliary boilers will only use natural gas received from the Northwest Pipeline. The fuel for the diesel engines powering the emergency generators and emergency fire water pumps is to be on-road specification diesel fuel.

8 The site of the proposed project is within an area that is in attainment with regard to all pollutants

regulated by the National Ambient Air Quality Standards (NAAQS) and state air quality standards. The site is approximately 60 kilometers from the nearest Class I Area, Olympic National Park.

9 The project is subject to new source review requirements under Chapter 463-39 WAC, which adopts by reference Chapter 173-400 WAC, Chapter 173-460 WAC, and 40 CFR 52.21. The facility is also subject to emission limitation, monitoring and reporting requirements in 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 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 proposed project. The following table lists the plant wide, allowable emissions and BACT control technologies.

Pollutant	Plant-wide Potential to Emit kg/yr (tpy)	Control Technology
Nitrogen oxides (NOx)	223,617 (246)	Selective Catalytic Reduction plus dry low NOx turbine burners and low NOx duct burners meeting a limitation of 2.5 ppm NOx, 1 hr average
Carbon monoxide (CO)	425,935 (470)	Dry low NOx turbine burners and low NOx duct burners
Sulfur dioxide (SO_2)	26,420 (29)[1]	Natural gas fuel
Sulfuric acid mist (H_2SO_4)	17,246 (19)	Natural gas fuel
Volatile organic compounds (VOC)	84,702 (93.2)	Selective Catalytic Reduction plus dry low NOx turbine burners and low NOx duct burners
Particulate matter (PM) and Particulate matter ≤ 10 micrometers (PM_{10})	192,044 (211.2)	Natural gas fuel
Ammonia (NH_3)	128,214 (141)	5 ppm ammonia slip limitation

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

11.1 Any state or national ambient air quality standard;
11.2 Any applicable PSD increment

The following Table indicates the maximum Class I and Class II increment consumed by this project.

[1] Based on an annual average natural gas total sulfur content of 0.5 grains/100 scf

POLLUTANT	Maximum ambient Class II area impact concentration (μg/m³)	Class II area allowable increment (μg/m³)	Maximum ambient Class I Area impact concentration (μg/m³)	Class I area allowable increment (μg/m³)
Particulate (PM_{10})*				
Annual	0.27	17	0.00476	4
24-Hour	2.41	30	0.166	8
Nitrogen dioxide*				
Annual	0.35	25	0.00391	2.5
Sulfur dioxide				
Annual	0.17	20	0.00051	2
24-Hour	2.10	91	0.0159	5
3-Hour	4.80	512	0.1281	25
1-Hour	12.18	-	-	-

*Evaluated at a higher emission rate than proposed to be permitted see fact sheet and application materials for details.

11.3 Ammonia is the significant toxic air pollutant emitted by this facility. The emissions of ammonia and all other toxic air pollutants from this facility will not exceed an acceptable source impact level established under WAC 173-460-150 and 160.

12 Ambient Impact Analysis indicates that there will be no significant impacts resulting from pollutant deposition on soils and vegetation in either of the closest Class I areas, Olympic and Mt. Rainier National Parks. The deposition of nitrogen within Olympic National Park for the 4 turbine proposal was modeled to be slightly above the level established by the National Park Service for concern. The National Park Service has informed EFSEC that the predicted deposition from the 4 turbine project was acceptable. The current 2 turbine project will have deposition levels significantly below the National Park Service's level of concern.

13 Ambient air quality analysis indicates that there will be no adverse impacts resulting from pollutant deposition in the Class II areas surrounding the project site.

14 Ambient Impact Analysis indicates that degradation of regional visibility or vistas from Olympic National Park due to the Satsop project is acceptable to the National Park Service based on an emission limitation of 2.0 ppm NOx, 24 hr average on the facility.

15 No significant effect on industrial, commercial, or residential growth in the Elma area is anticipated due to the project.

16 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 application is granted subject to the following conditions:

APPROVAL CONDITIONS

1 This Amendment supercedes air quality PSD approval EFSEC 2001-01, Amendment 1 dated January 2, 2003.

2 The CGTs and auxiliary boilers shall use only natural gas.

3 The diesel emergency generators shall:
3.1 Use only on-road specification diesel oil with a sulfur content of 0.05% by weight or less.
3.2 Not exceed 500 hours per engine per year of operating time.

4 Nitrogen oxide emissions limitations
4.1 Each CGT exhaust stack shall not exceed the following:
4.1.1 9.86 kilograms/hour (kg/hr) (21.7 pounds/hour (lb/hr)), 1-hour (1-hr.)average when duct firing,
4.1.2 7.89 kg/hr (17.4 lb/hr), 24-hour moving average
4.1.3 2.5 parts per million by volume, dry (ppm), 1-hr average, corrected to 15.0% oxygen (O_2)
4.1.4 2.0 ppm, 24-hour moving average, corrected to 15% O_2
4.1.5 Initial compliance shall be determined in accordance with 40 CFR Subpart GG and EPA Reference Method 20, except that the instrument span shall be set between zero and 25 ppm, and
4.1.6 Routine compliance will be indicated by continuous emission monitors for NO_X and O_2. The continuous emission monitoring system (CEMS) must meet the requirements of Approval Condition 20.1.

4.2 Each auxiliary boiler exhaust stack shall not exceed the following:
4.2.1 0.468 kg/hr (1.03 lb/hr), 1-hr. average,
4.2.2 30 ppm at 3% O_2, 1-hr. average,
4.2.3 Initial compliance shall be determined in accordance with 40 CFR Subpart GG and EPA Reference Method 20, except that the instrument span shall be set between zero and 75 ppm, and
4.2.4 Routine compliance will be indicated through
4.2.4.1 Boiler operating records indicating hours of operation and fuel flow and the application of an emission factor derived from stack testing of the installed boilers, and
4.2.4.2 Periodic stack tests taken at 5 year intervals after the initial compliance test.

5 Nitrogen oxides plus nonmethane hydrocarbons emissions
5.1 Each diesel generator exhaust stack shall not exceed:
5.1.1 2.38 kg/hr (5.26 lb/hr) or 6.4 grams per kilowatt-hour,
5.1.2 Initial compliance shall be determined and certified by the engine manufacturer in accordance with the methods in 40 CFR Part 89, and
5.1.3 Routine compliance will be indicated through diesel generator operating hour, maintenance, and fuel records and certification of the engine meeting the applicable new engine standards for engines sold in 2002.

5.2 Each emergency fire water pump engine shall meet the emission standard requirements in 40 CFR 89 applicable to a new engine of its engine size for 2002.
5.2.1 Initial and routine compliance shall be demonstrated by demonstration/certification by the engine manufacturer that the engine meets the applicable emission standard in 40 CFR 89.

6 Ammonia (free NH_3 and combined measured as NH_3) emissions
6.1 Each CGT exhaust stack shall not exceed the following:
6.1.1 5.0 ppm, 24-hour average corrected to 15.0 percent O_2,
6.1.2 7.3 kg/hr (16.1 lb/hr), 24-hour average,
6.1.3 Initial compliance for each CGT shall be determined by Bay Area Air Quality Management

District Source Test Procedure ST-1B, "Ammonia, Integrated Sampling," EPA Conditional Test Method 027, or an equivalent method approved in advance by EFSEC, and

6.1.4 Routine compliance determinations will be determined through use of a CEMS which meets the requirements of Approval Condition 20.2 or Duke Energy may propose alternative means for continuous assessment and reporting of NH_3 emissions for approval by EFSEC. Any proposed alternative NH_3 reporting shall be at a minimum equivalent to a CEMS meeting the requirements of Approval Condition 20.2.

6.2 The SCR catalyst system treating the exhaust from one CGT shall be repaired, replaced or have additional catalyst bed installed at the next scheduled outage, following a calendar month when ammonia slip can not be maintained at or below 4.5 ppm, 1 hour average corrected to 15.0 percent oxygen, based on the actual operating hours of the CGT. No month with less than 200 hours of actual operation (excluding start-up and shutdown hours) will be used for this evaluation. The outage to repair or replace or install additional catalyst to the SCR system shall be no later than 12 months after the month the ammonia slip exceeds the 4.5 ppm ccriteria given above.

6.3 The permit limitations outlined in this section shall not apply to startup, shutdown and scheduled maintenance conditions.

7 Carbon monoxide emissions

7.1 Each CGT exhaust stack shall not exceed the following:

7.1.1 3 ppm corrected to 15.0 percent oxygen, 3-hr. average

7.1.2 6.62 kg/hr (14.6 lb/hr) at 100% load, 3-hr. average

7.1.3 Initial compliance for each CGT shall be determined by EPA Reference Method 10 or an equivalent method agreed to in advance by EFSEC. The span and linearity calibration gas concentrations in Method 10 shall be appropriate to the CO concentration limits specified in this condition, and

7.1.4 Routine compliance determinations will be determined through use of a continuous emission monitor meeting the requirements of Approval Condition 16.3.

7.2 Each auxiliary boiler exhaust stack shall not exceed the following:

7.2.1 50.0 ppm, 1- hour average corrected to 3.0% O_2, 3-hr. average

7.2.2 0.485 kg/hr (1.07 lb/hr) at 100% load, 3-hr. average

7.2.3 Initial compliance for each auxiliary boiler shall be determined by EPA Reference Method 10 or an equivalent method agreed to in advance by the EFSEC. The span and linearity calibration gas concentrations in Method 10 shall be appropriate to the CO concentration limits specified in this condition, and

7.2.4 Routine compliance will be indicated through:

7.2.4.1 Boiler operating records indicating

7.2.4.1.1 Hours of operation and

7.2.4.1.2 Fuel flow

7.2.4.2 The application of an emission factor derived from stack testing of the installed boilers, and

7.2.4.3 Periodic stack tests taken at 5 year intervals after the initial compliance test.

7.3 Each diesel generator exhaust stack shall not exceed the following:

7.3.1 1.75 kg/hr (3.86 lb/hr) or 3.5 grams per kilowatt-hour,

7.3.2 Initial compliance shall be determined and certified by the engine manufacturer in accordance with

the methods in 40 CFR Part 89, and
Routine compliance will be indicated through diesel generator operating hour records and certification of the engine meeting the applicable new engine standards for engines sold in 2002.

7.4 Each emergency fire water pump engine shall meet the emission standard requirements in 40 CFR 89 applicable to a new engine of its engine size for 2002.

7.4.1 Initial and routine compliance shall be demonstrated by demonstration/certification by the engine manufacturer that the engine meets the applicable emission standard in 40 CFR 89.

8 Sulfur dioxide emissions

8.1 Each CGT exhaust stack shall not exceed the following:

8.1.1 1.5 kg/hr (3.3 lb /hr), rolling annual-average calculated monthly,

8.1.2 9.0 kg/hr (19.8 lb/hr), 1-hr. average,

8.1.3 Initial compliance for each CGT shall be determined by EPA Reference Method 8, or an equivalent method approved in advance by EFSEC. Duke Energy shall conduct source testing for sulfur dioxide once per calendar quarter for the first year of operation at each CGT exhaust stack,

8.1.4 Routine compliance shall be determined through:

8.1.4.1 Annual stack test on each CGT stack using the above Reference Method. The timing of the annual stack test will coincide with the annual RATA testing for the installed CEM systems,

8.1.5 Routine compliance shall be indicated through:

8.1.5.1 Monthly calculation of the SO_2 emissions based on

8.1.5.1.1 The quantity of natural gas used by each turbine

8.1.5.1.2 The total sulfur content of the natural gas consumed

8.1.5.1.3 Subtracting the quantity of potential SO_2 converted to H_2SO_4. The conversion rate of potential SO_2 to H_2SO_4 is determined through the information provided by the Method 8 stack tests required in Approval Conditions 8.1 and 9.1.

8.1.5.2 Duke Energy shall report to EFSEC on a monthly basis the quantity and average sulfur content of the natural gas burned by the CGT units at the facility. Total sulfur content on the natural gas shall be substantiated by purchase records and vendor's reports or total sulfur content monitoring performed by Duke Energy on the gas used at this facility.

8.1.6 Fuel sulfur determination shall follow the more stringent of the procedures in 40 CFR 60.335(d) and (e) and 40 CFR Part 75, Appendix D.

8.2 Each auxiliary boiler exhaust stack shall not exceed:

8.2.1 0.032 kg/yr (0.07 lb/hr) annual average, calculated monthly,

8.2.2 1 ppm at 3% O_2, 3- hr. average

8.2.3 Initial compliance for each auxiliary boiler shall be determined by EPA Reference Method 8, or an equivalent method approved in advance by EFSEC,

8.2.4 Routine compliance shall be determined by

8.2.4.1 Fuel consumption records for each auxiliary boiler and

8.2.4.2 Total sulfur content of the natural gas consumed in the boilers, and

8.2.5 Natural gas sulfur content shall be measured and reported through the methods defined in Approval Condition 8.1.

8.3 Each diesel generator exhaust stack shall not exceed:

8.3.1 2.93 kg/day (6.56 lb/day), 1-day average,

8.3.2 Initial compliance shall be determined and certified by the engine manufacturer in accordance with the methods in 40 CFR Part 89, and

8.3.3 Routine compliance will be indicated by calculating the sulfur dioxide emissions based on

8.3.3.1 Generator fuel usage, and

8.3.3.2 Fuel sulfur content records.

9 Sulfuric acid mist emissions

9.1 Each CGT exhaust stack shall not exceed the following:

9.1.1 0.984 kg/hr (2.17 lb H_2SO_4/hr), rolling annual average calculated monthly,

9.1.2 Initial compliance with the sulfuric acid emissions limits shall be determined by EPA Reference Method 8, or an equivalent method approved by EFSEC. Duke Energy shall conduct source testing for sulfuric acid mist once per calendar quarter for the first year of operation at each exhaust stack.

9.1.3 Routine compliance shall be indicated through:

9.1.3.1 An annual emissions test on each CGT exhaust stack using the methods indicated above. After the initial 3 years of tests on each CGT stack have been completed, each CGT stack shall be tested once every 5 years unless the initial 3 years of testing indicates noncompliance with the limitations, then the testing frequency remains annual until 3 consecutive years of testing indicating compliance is achieved. If a once every 5 year test indicates noncompliance, the testing frequency reverts to yearly until 3 consecutive years of testing indicating compliance is achieved. The timing of these annual emissions tests shall coincide with the annual RATA testing, and

9.1.3.2 Monthly calculation of the sulfuric acid mist emissions based on

9.1.3.2.1 The quantity of natural gas used by each turbine

9.1.3.2.2 The total sulfur content of the natural gas consumed

9.1.3.2.3 Subtracting the quantity of potential SO_2 converted to H_2SO_4. The conversion rate of potential SO_2 to H_2SO_4 determined through the Method 8 stack tests required in Approval Conditions 8.1 and 9.1 and updated annually.

9.1.4 Fuel sulfur determination shall follow procedures outlined in Approval Condition 8.1.

10 Volatile organic compound emissions

10.1 Each CGT exhaust stack shall not exceed the following:

10.1.1 2.86 kg/hr (6.3 lb /hr), 1-hr average, reported as carbon equivalent,

10.1.2 2.8 ppm, 1-hr average, reported as carbon equivalent

10.1.3 Initial compliance for each CGT shall be determined by EPA Reference Method 25A or 25B, South Coast Air Quality Management District Method 25.3, or an equivalent method agreed to in advance by EFSEC, and

10.1.4 Routine compliance will be indicated through boiler operating records indicating

10.1.4.1 Hours of operation

10.1.4.2 Fuel flow, and

10.1.4.3 Application of an emission factor derived from stack testing of the installed boilers

10.1.4.4 An annual stack test using one of the above referenced methods. After 3 consecutive years of stack testing indicating compliance, Duke Energy may request and EFSEC may approve an alternative testing frequency. At no time shall stack testing be less frequent than once every 5 years.

10.2 Each auxiliary boiler exhaust stack shall not exceed the following:

10.2.1 0.213 kg/hour (0.469 lb /hr), 1-hour average, reported as carbon equivalent,

10.2.2 Initial compliance for each auxiliary boiler shall be determined by EPA Reference Method 25A or 25B, or an equivalent method agreed to in advance by EFSEC, and

10.2.3 Routine compliance will be indicated through boiler operating records indicating

10.2.3.1 Hours of operation

10.2.3.2 Fuel flow, and

10.2.3.3 Application of an emission factor derived from stack testing of the installed boilers

10.2.3.4 Periodic stack tests, using one of the above referenced methods, taken at 5 year intervals after the initial compliance test.

11 Particulate Matter and Particulate Matter less than or equal to 10 micrometer (PM_{10}) emissions

11.1 Each CGT exhaust stack shall not exceed the following:

11.1.1 246.0 kg/24 hours (542.4 lb/24 hours), filterable plus condensable PM,

11.1.2 0.003 grains/dry standard cubic foot(gr/dscf), filterable plus condensable PM at 15% O_2,

11.1.3 Initial compliance for each CGT exhaust stack shall be determined by use of EPA Reference Methods 5, 201, or 201A, plus Reference Method 202, or an equivalent method agreed to in advance by EFSEC. Use of EPA Reference Method 5 assumes all filterable particulate is PM10. Use of EPA Reference Method 201 or 201A assumes that the mass of filterable PM is equal to the mass of filterable PM_{10}. If Method 201 or 201A is used, the mass of particulate retained in the cyclone shall be determined and reported.

11.1.4 The results of the filterable and condensable particulate analyses shall be reported as total particulate, filterable particulate and condensable particulate.

11.1.5 Routine compliance shall be the following:

11.1.5.1 An annual emissions test on each CGT exhaust stack using the methods indicated above. After the initial 3 years of tests on each CGT stack have been completed, each CGT stack shall be tested once every 5 years unless the initial 3 years of testing indicates noncompliance with the limitations, then the testing frequency remains annual until 3 consecutive years of testing indicating compliance is achieved. If a once every 5 year test indicates noncompliance, the testing frequency reverts to yearly until 3 consecutive years of testing indicating compliance is achieved. The timing of these annual emissions tests shall coincide with the annual RATA testing, and

11.1.6 When PM_{10} stack test data is not available, routine compliance shall be indicated by the use of natural gas for fuel and through operating records and the application of a source test derived emission factor.

11.2 Each auxiliary boiler exhaust stack shall not exceed:

11.2.1 3.175 kg/day (7.0 lb/day), annual average, filterable plus condensable PM_{10},

11.2.2 0.005 gr/dscf, filterable plus condensable PM at 15% O_2.

11.2.3 Initial compliance for each auxiliary boiler exhaust stack shall be determined by either EPA Reference Methods 5, 201, or 201A, or an equivalent method agreed to in advance by EFSEC. Use of EPA Reference Method 5 assumes all particulate is in the form of PM_{10}. Use of EPA Reference Method 201 or 201A assumes that the mass of filterable PM is equal to the mass of filterable PM_{10}.

11.2.4 The results of the filterable and condensable particulate analyses shall be reported as total particulate, filterable particulate and condensable particulate.

11.2.5 Routine compliance will be indicated through:

11.2.5.1 Boiler operating records indicating

11.2.5.1.1 Hours of operation,

11.2.5.1.2 Fuel flow, and

11.2.5.1.3 Application of an emission factor derived from stack testing of the installed boilers.

11.2.5.2 Periodic stack tests, using the above specified methods, taken at 5 year intervals after the initial compliance test.

11.3 Each diesel generator exhaust stack shall not exceed:

11.3.1 2.4 g/day (5.28 lb/day) or 0.20 grams particulate per kilowatt-hour,

11.3.2 Initial compliance shall be determined and certified by the engine manufacturer in accordance with the methods in 40 CFR Part 89, and

Routine compliance will be indicated through diesel generator operating hour records and certification of the engine meeting the applicable new engine standards for engines sold in 2002.

11.4 Each emergency fire water pump engine shall meet the emission standard requirements in 40 CFR 89 applicable to a new engine of its engine size for 2002.

11.4.1 Initial and routine compliance shall be demonstrated by demonstration/certification by the engine manufacturer that the engine meets the applicable emission standard in 40 CFR 89.

11.5 Each cooling tower shall not exceed:

11.5.1 11.11 kg/day (24.5 lb/day), annual average,

11.5.2 4062 kg/yr (4.5 tpy), rolling total, calculated monthly,

11.5.3 Initial compliance shall be determined by:

11.5.3.1 A total solids mass balance across each cooling tower. The analysis shall incorporate factors involving the :

11.5.3.1.1 Cooling tower recirculation rate,

11.5.3.1.2 Cooling tower total dissolved solids (TDS),

11.5.3.1.3 Fan operation effects, and

11.5.3.1.4 Manufacturer's information on drift losses

11.5.3.1.5 The methodology shall be submitted to and accepted by EFSEC prior to the first operation of any cooling tower.

11.5.3.2 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 accompanied by the results of a test or analysis of the cooling tower drift eliminator material indicating that the material has a drift loss of less than 0.001% of the recirculating water flow rate. The required test could be performed on a full size mist eliminator module under laboratory conditions that match the worst case operations scenario of the actual cooling tower,

11.5.4 Routine compliance using the same calculation methodology used for the initial compliance test, once each quarter estimate the PM emissions from each cooling tower.

11.5.5 Prior to operation of the cooling tower, Duke Energy shall submit to EFSEC, a report describing the manufactures recommendations for installing, operating and testing the drift eliminators.

12 Opacity

12.1 Each CGT exhaust stack shall not exceed a six minute average of 5 percent,

12.2 Each auxiliary boiler exhaust stack shall not exceed a six minute average of 5 percent,

12.3 Each diesel generator exhaust stack shall not exceed a six minute average of 10 percent,

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

12.5 Installation of a Continuous Opacity Monitoring system on each CGT can be substituted for use of EPA Reference Method 9 readings for the CGTs. If installed, the continuous opacity monitor must meet the requirements of Approval Condition 20.

13 Annual emissions shall not exceed the limits in the following table. The annual limits are 12 month rolling totals.

Pollutant	Each CGT kg/year (tons/yr)	Auxiliary boiler kg/year (tons/yr)	Cooling tower kg/year (tons/yr)	Diesel emergency generator kg/year (tons/yr)
NO_x	110,625.5 (121.7)**	1,170 (1.3)	--	1,195 (1.35)*
CO	227,776.5 (251.0)**	1,216 (1.3)	--	877.3 (1.0)
SO_2	13,140 (14.5)	79.5 (0.088)	--	61.1 (0.1)
H_2SO_4	8623 (9.5)	--	--	--
PM/PM_{10}***	89,989.1 (99.0)	7954 (8.8)	4061 (4.5)	50 (0.1)
VOC	41,916.4 (46.1)**	533 (0.6)	--	Included in generator NO_x
NH_3	64,107 (70.5)	--	--	--

*Limit for diesel generators is Nonmethane hydrocarbons plus NO_x. In this presentation the assumption is that all of the emissions are as NO_x.

**Includes the emissions from startup and shutdown events of the CGTs and diesel generators. CGT start up emissions are equally apportioned among the 2 turbines.

***PM and PM_{10}, conservatively assumed to be equal.

14 Routine equipment startup and shut down

14.1 Each CGT is limited to 130 cold startup and shutdown events per calendar year. A cold startup event is when more than 48 hours has elapsed since the turbines were last fired or heat applied to the HRSG system.

14.2 Each CGT is limited to 2 warm startup and shutdown events per calendar day. This limitation does not apply during the period between initial firing of a combustion turbine for testing purposes and the start-up condition specified in Approval Condition 16.

14.3 A warm or cold startup period begins when fuel is first fired in the combustion turbine,

14.4 The warm startup period ends when the earlier of these two operating events occurs:

14.4.1 The proper operating temperature of the oxidation and SCR catalysts serving an operating CGT has been achieved and the combustion turbine achieves operational Mode 6, or

14.4.2 A maximum of 3 hours has elapsed since fuel was first combusted in that CGT.

14.5 The cold startup period ends when the earlier of these two operating events occurs:

14.5.1 The proper operating temperature of the oxidation and SCR catalysts serving one CGT has been achieved and the combustion turbine achieves operational Mode 6, or

14.5.2 4 hours maximum for each turbine in a single power island has elapsed since fuel was first combusted in the first turbine.

14.6 The Shutdown period begins when the combustion turbine leaves operational Mode 6 and ends when fuel is no longer being introduced to any burner.

14.7 Operational Mode 6 is defined by the turbine manufacturer as the low emission mode during which all 6 of the burner nozzles are in use, burning a lean premixed gas for steady-state operation.

14.8 The proper operating temperature of the oxidation and SCR catalysts and the point at which all dry-low-NO_x burners for each combustion turbine are operational shall be determined from the manufacturer's design specifications and must be reported in writing to EFSEC before commercial operation of the combustion turbines,

14.9 Compliance with short-term emission limits (during startup and shutdown periods) shall be determined using manufacturer's emission factors or source test data using the EPA Reference Methods noted above. Where source test data and manufacturer's emission factors conflict, source test data shall be used to determine compliance,

14.10 Emissions resulting from these startup and shutdown events shall be included in the quarterly emissions reporting of Approval Condition 21.

14.11 The following emission factors may be used for calculating the emissions generated during cold startup of the CGTs in a single power island until emissions test data is developed by Duke Energy, submitted to and approved by EFSEC that demonstrates a different value is appropriate:

Pollutant	Cold Startup Emission Factor (per pair turbines in one power island)
Nitrogen oxides	1536 lb/startup
Carbon monoxide	5288 lb/startup
Volatile organic compounds	354 lb/startup

15 Within 180 days after formal, initial start-up of each combustion turbine, auxiliary boiler, and installation of the diesel generators, Duke Energy shall conduct the initial performance tests for NOx, ammonia, SO_2, opacity, VOC, CO, PM_{10} and H_2SO_4 noted above. The initial performance testing shall be performed by an independent testing firm. A test plan shall be submitted to EFSEC for approval at least 30 days prior to the testing. The initial compliance tests and all subsequent compliance tests shall be made at maximum load.

16 Initial start-up for determining when the initial compliance testing, CEM system performance testing, and other, non acid rain program purposes is the earlier of the following dates:

16.1 The earliest date that electrical power is offered for sale (not test generation) from a CGT and its associated steam turbine, or

16.2 180 days after the first CGT in the power island has been synchronized to the electrical distribution grid.

17 Duke Energy Energy shall notify EFSEC in writing at least thirty days prior to

17.1 Initial start-up of any permitted emissions unit for operational testing and manufacturers certification purposes.

17.2 Formal, initial start-up defined in Approval Condition 16.

17.3 The date any emissions testing required by this permit will be performed when the time between tests is specified to be longer than 30 days.

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

18 Sampling ports and platforms shall be provided on each CGT stack, after the final pollution control device. The ports shall meet the requirements of 40 CFR, Part 60, Appendix A, Method 20. Sampling ports and platforms for each auxiliary boiler and diesel engine shall meet the requirements of 40 CFR Part 60, Appendix A, Method 1.

19 Adequate permanent and safe access to the test ports shall be provided. Other arrangements may be acceptable if approved by EFSEC prior to installation.

20 Operating Records for Emitting Equipment.

20.1 Unless otherwise specified above, 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.

20.1.1 Example operating record information includes, but is not limited to:

20.1.1.1 Fuel quality

20.1.1.2 Fuel consumption during the period (hourly, monthly, etc.

20.1.1.3 Unit operating parameters such as

20.1.1.3.1 Exhaust temperature,

20.1.1.3.2 Percent excess air,

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

20.1.1.3.4 Operating hours during the reporting period and cumulative for the year,

21 Continuous Emission Monitoring Systems (CEMS)

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

21.2 CEMS for ammonia 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.

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

21.4 CEMS for opacity 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.

22 CEMS and process data shall be submitted quarterly, in written form (or electronic if permitted by the EFSEC) monthly 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.

23 The format of the reporting described in Approval Condition 21 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:

23.1 Process or control equipment operating parameters

23.2 The hourly maximum and average concentration, in the units of the standards, for each pollutant monitored

23.3 The duration and nature of any monitor down-time

23.4 Results of any monitor audits or accuracy checks

23.5 Results of any required stack tests

23.6 Results of any other stack tests performed after the initial performance test

23.7 The above data shall be retained at the Satsop CT Project site for a period of at least five years

24 For each occurrence of monitored emissions in excess of the standard, the quarterly emissions report (per Approval Conditions 21 and 22) shall include the following:

24.1 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.

24.2 For all other pollutants:

24.2.1 The time of the occurrence

24.2.2 Magnitude of the emission or process parameters excess

24.2.3 The duration of the excess
24.2.4 The probable cause
24.2.5 Corrective actions taken or planned
24.2.6 Any other agency contacted

25 Duke Energy shall have on site, and shall follow, an Operating and Maintenance manual, and an equipment Start-up, Shut-down, and Malfunction Procedures manual for all equipment that has the potential to affect emissions to the atmosphere. Copies of the manuals shall be available to EFSEC or the authorized representative of EFSEC at the facility. Emissions that result from a failure to follow the requirements of the manuals may be considered evidence that emission violations have occurred. The above manuals must be reviewed annually and updated as needed. EFSEC shall be notified whenever the manual is updated.

25.1 The Operating and Maintenance manual should contain equipment specific operating parameter and maintenance information. Examples of the operational information to include are:

25.1.1 Control equipment normal operating ranges such as:
25.1.1.1 Normal operating temperature range.
25.1.1.2 Normal pressure drop and acceptable range of pressure drops.
25.1.1.3 Fan speed range.
25.1.1.4 Reagent feed rate.
25.1.1.5 Scrubber liquor pH range.
25.1.1.6 Scrubber liquor feed rate and pressure.

25.1.2 Boiler operating parameters such as:
25.1.2.1 Fuel feed rate.
25.1.2.2 Steam pressure.
25.1.2.3 Combustion air flow rate.

25.1.3 Combustion turbine operating parameters such as:
25.1.3.1 Temperature ranges at inlet, combustors, turbine exhaust.
25.1.3.2 Allowable vibration range.
25.1.3.3 Inlet humidity.
25.1.3.4 Operating speed (rpm) range.
25.1.3.5 Turbine fuel feed rate.

25.1.4 Similar type operational measures for other emitting equipment, such as diesel generators and cooling towers.

25.2 The Start-up, Shut-down, and the Malfunction manual shall contain information on the proper procedures, and sequencing of actions for plant operations staff to follow in order to safely and efficiently start and stop the various equipment at the station under all reasonably ascertainable normal and abnormal start-up and shut-down situations.

26 Construction time

26.1 Construction of this project began under terms of Administrative Order on Consent, Docket No. CAA-10-2001-0097, dated March 30, 2001, and has continued under air quality approval EFSEC 2001-01, Amendment 1, and is allowed to continue under Amendment 2.

26.2 Amendment 2 allows for a suspension of construction on the approved facility and becomes void if construction is not restarted by January 20, 2006. Construction must be completed in a reasonable time after the restart of construction.

27 Any activity which is undertaken by Duke Energy, or others, in a manner which is inconsistent with the application and this determination, shall be subject to EFSEC enforcement under applicable regulations. Nothing in this determination shall be construed so as to relieve Duke Energy 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 U.S. Environmental Protection Agency (EPA), shall be permitted upon request for the purpose of compliance assurance inspections. Failure to allow access is grounds for action under the Federal Clean Air Act or the Washington Clean Air Act.

Prepared by:

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Date

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James O. Luce
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Date