
6.1

PSD Application (WAC 463-42-385)

WAC 463-42-385 PSD APPLICATION.

The applicant shall include a complete prevention of significant deterioration permit application.

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW.
81-21-006 (Order 81-5), §463-42-385, filed 10/8/81.]*

6.1 PSD PERMIT APPLICATION (WAC 463-42-385)

This section is an application for a modification to the existing PSD permit for the Satsop CT Project. This application covers proposed modifications to the current facility under construction (Phase I) and proposes a new power generation project (Phase II). As demonstrated below, the proposed modifications are “major” and therefore subject to PSD review. The analyses contained in this Section 6.1 address the combined emissions and operations of Phase I and Phase II, which will be referred to in this section as the Satsop CT Project.

6.1.1 INTRODUCTION

Duke Energy Grays Harbor, LLC, and Energy Northwest (the Certificate Holder) is proposing to construct and operate a second set of power generation units (PGUs) and associated equipment at the Satsop CT Project to generate additional electricity to help supply growing regional electrical loads. The proposed Phase II project will be a natural gas combined cycle power generation facility located on the site housing Phase I of the Satsop CT Project near the town of Elma, Washington, in Grays Harbor County.

This amended section of the Application for site certification includes the application for a PSD permit in accordance with the New Source Review (NSR) regulations codified in the Washington State Administrative Code (WAC) 173-400-050, and in Title 40, Code of Federal Regulations, Part 52. The Energy Facility Site Evaluation Council (EFSEC) will coordinate the review and permitting process with the Washington Department of Ecology (Ecology) and the Environmental Protection Agency (EPA).

This document includes the necessary information for EFSEC and Ecology to review the proposed emitting source in order to issue a revised Prevention of Significant Deterioration permit. The following information and documentation are included in this document:

- Section 6.1.2 describes the applicable regulatory requirements involved in permitting the proposed project.
- Sections 6.1.3 and 6.1.4 present location maps, site plan maps, and process flow diagrams as well as information about the proposed project including the facility location, owner and operator, a description of existing site conditions, the proposed system design, the estimated maximum potential pollutant emission rates, and proposed control equipment.
- Section 6.1.5 describes project compliance with New Source Performance Standards (NSPS) and Acid Rain Provisions.
- Section 6.1.6 provides an engineering analysis of air emission control systems proposed to meet the Best Available Control Technology (BACT) approach as defined in WAC

173-400-030(10). The conclusions presented are based upon the top-down evaluation process specified in Chapter B of EPA's draft *New Source Review Workshop Manual* (October 1990).

- Section 6.1.7 provides the modeling methodology and results of the ambient air quality impact analyses demonstrating compliance with PSD Class II increments, National Ambient Air Quality Standards (NAAQS) and Washington Ambient Air Quality Standards (WAAQS), significance levels, pre-construction ambient monitoring *de minimus* levels, and Acceptable Source Impact Levels (ASILs).
- Section 6.1.8 provides the Class I area impact determination and impacts to visibility, soil, vegetation, and aquatic resources.

6.1.2 APPLICABLE REGULATORY REQUIREMENTS

This section presents the regulatory requirements for submitting a PSD permit application for the proposed Phase II project. EFSEC will coordinate the application review process for the PSD application with Ecology. Also presented are the requirements for complying with air quality standards and the BACT to be utilized at the facility.

As with Phase I of the Satsop CT Project being constructed near Elma, Washington, Phase II is rated at 600 megawatts (MW), nominal, with a maximum output of 650 MW. The major components of each power generation unit (PGU) are a GE 7FA combustion turbine generator and a heat recovery steam generator (HRSG) with supplementary duct burner. Each turbine will have a maximum rating of 1,671 million British thermal units per hour (MMBtu/hr) and each supplementary duct burner will have a maximum rating of 505 MMBtu/hr. Other major components of the project include one steam turbine generator, one auxiliary boiler, and one forced draft cooling tower system. Two emergency backup diesel generators and two diesel engine-driven fire water pumps are also included as part of the facility.

With four PGUs (including duct burners and 130 startup/shutdown cycles per year for each PGU) operating 8,760 hours per year each, two auxiliary boilers operating 2,500 hours per year each, two emergency backup diesel generators operating 500 hours per year each, and two cooling towers operating 8,760 hours per year each, the proposed project has the potential to emit 588 tons per year of nitrogen oxides (NO_x), 883 tons per year of carbon monoxide (CO), 195 tons per year of volatile organic compounds (VOCs), 436 tons per year particulate matter (PM₁₀), and 23 tons per year of sulfur dioxide (SO₂). Thus, the revised facility has a potential to emit pollutants in excess of the PSD major source and major modification thresholds. The Satsop CT Project is located within an attainment area for all criteria pollutants. The above source description is the basis for determining applicable federal, state, and local regulations.

6.1.2.1 New Source Review (NSR)

The Clean Air Act requires that new major stationary sources of air pollution, or major sources proposing a major modification, obtain air pollution permits and/or approvals prior to commencing construction. Sources located in attainment areas (areas where all NAAQS have been met) are required to perform New Source Review for compliance with NAAQS and PSD requirements.

All applicable pre-construction review programs have been delegated to Ecology as stated in the Washington Administrative Code (WAC) 173-400. For most projects, Ecology is the permitting authority for the PSD permit program, and for a project at the proposed site, the Olympic Air Pollution Control Agency (OAPCA) will be the local authority for permits enforcement. Because (1) the Satsop CT Project is located at a site already subject to a Site Certification Agreement (SCA) administered by EFSEC and the proposed project has an SCA, and (2) the facility will produce at least 350 MW of power, EFSEC will issue and administer all state permits for the project in accordance with RCW 80.50. As stated in RCW 80.50.040(12), this includes "...applicable provisions of the federally approved implementation plan adopted in accordance with the Federal Clean Air Act, as now existing or hereafter amended, for the new construction, reconstruction or enlargement or operation of energy facilities." The regulatory requirements that will usually be included in a PSD permit are included in the existing amended SCA issued by EFSEC.

Phase II of the Satsop CT Project will be a modification to a major stationary source located in an area that is in attainment for all criteria pollutants. The applicant must demonstrate that the proposed project is in compliance with applicable federal and state ambient air quality standards, NSPS, and BACT, acid rain, visibility, and toxic air pollutant requirements.

6.1.2.2 Prevention of Significant Deterioration (PSD)

PSD regulations are promulgated in federal regulations under 40 CFR, Part 52.21. The State of Washington has adopted the federal regulations, with minor changes, in WAC 173-400-141. The PSD program is designed to ensure that air quality will not significantly deteriorate in areas where ambient standards are being met, i.e., in attainment areas. An area must be in attainment for at least one criteria pollutant for PSD requirements to apply. The PSD regulations specify that any major new stationary source or major modification to an existing major source within an air quality attainment area must undergo a PSD review and obtain all applicable federal and state preconstruction permits prior to commencement of construction.

"Potential emissions" are defined as the emissions of any pollutant at maximum design capacity or less than maximum design capacity with a permit restriction, including the control efficiency of air pollution control equipment. A major source is defined as a source whose potential to emit is (1) greater than 100 tons per year if the source is listed as one of EPA's PSD major source categories, or (2) greater than 250 tons per year if not listed. Combustion turbine combined-cycle plants are considered a listed source and, therefore, are subject to the 100 tons-per-year threshold. If the

source is considered to be a major source and the appropriate PSD threshold criteria are exceeded for any one regulated pollutant, then emissions of other regulated pollutants that exceed specified significant emission rates are also subject to PSD review, and PSD review requirements must be met for each pollutant with an emission rate exceeding the appropriate threshold criteria. These significant emission rates are shown in Table 6.1-1.

**TABLE 6.1-1
PSD SIGNIFICANT THRESHOLD EMISSION RATES**

Pollutant	Significant Emission Rate (tons/yr)
Carbon monoxide (CO)	100
Nitrogen oxide (NO _x)	40
Sulfur dioxide (SO ₂)	40
Total suspended particulates (TSP)	25
Particulate matter (PM ₁₀)	15
Volatile organic compounds (VOC)	40

PSD increments are defined as the maximum allowable increase in concentration allowed to occur above a “baseline concentration” for a pollutant. Significant deterioration is said to occur when the increase from the source or modification exceeds the applicable PSD increment. Air quality cannot deteriorate beyond the applicable ambient air quality standards, even if all of the PSD increment has not been consumed.

A source which has the potential to exceed PSD significant emission rates for criteria pollutants must comply with the following for each criteria pollutant:

- Emissions from the source cannot significantly deteriorate the air quality in the attainment area where ambient standards are being met as measured by PSD increments for air quality deterioration.
- Emissions from the source cannot adversely impact the soils and vegetation in the area.
- If ambient concentrations due to emissions from the source are predicted to exceed significance levels, impacts and controls must be evaluated under PSD.
- Emissions from the source cannot result in exceedance of PSD increments in Class I or Class II areas.
- Visibility impacts must be evaluated at Class I areas and may be evaluated for both local areas and for other federally managed areas.

The Phase II project is subject to PSD review because Phase I of the Satsop CT Project is a major source and at least one criteria pollutant from the proposed modifications has the potential to be emitted in excess of the significant emission rate.

6.1.2.3 New Source Performance Standards (NSPS)

NSPS are nationally uniform emissions standards established by EPA and set forth in 40 CFR Part 60. The State of Washington has adopted these standards in WAC 173-400-115. NSPS apply to every qualifying new source and are based on the category of industrial source and on the pollution control technology available to that category of source. Federal NSPS provide a starting point to evaluate required controls; however, the BACT analysis will usually be more stringent in specifying the type of control technology required.

EFSEC regulations incorporate the following federal NSPS (40 CFR Part 60) by reference:

Subpart	Description
A	General Provisions
D	Fossil Fuel-Fired Steam Generators (not applicable, exempts facilities covered under Subpart Da)
Da	Electric Utility Steam-Generating Units (applicable, duct firing)
GG	Stationary Gas Turbines (applicable)
J	Petroleum Refineries (not applicable)
K	Storage Vessels for Petroleum Liquids (not applicable; does not apply to fuel oils (e.g. No. 2 distillate fuel oil). This regulation focuses primarily on crude oil storage.
Kb	Volatile Organic Liquid Storage Vessels (not applicable; applies to vessels with capacities greater than 40 cubic meters and vapor pressures greater than 3.5 kPa)

The Satsop CT Project is considered an “Electrical Utility Stationary Gas Turbine” because more than one-third of its potential electric output capacity will be required for power distribution. The NSPS for Steam Generating Units, 40 CFR Part 60 Subparts Db and Dc, are not applicable to the Satsop CT Project either due to the type of fuel utilized or the size of the turbines. However, the Satsop CT Project will utilize duct burners for firing the gas turbines and will be subject to Subpart Da limiting nitrogen oxides, sulfur dioxide, and particulates. The NSPS for turbines, 40 CFR Part 60 Subpart GG, in this classification limit nitrogen oxides, sulfur dioxide, percentage of sulfur in fuel burned, and require continuous monitoring of operating parameters

and fuel characteristics. Compliance demonstration for NSPS requirements for the Satsop CT Project is presented in Subsection 6.1.5.

6.1.2.4 Best Available Control Technology (BACT)

Ecology and OAPCA require BACT be evaluated for the construction of a new source or modification of an existing source. Further, a BACT determination is required as part of a PSD permit application. A BACT analysis is conducted to ensure that all technically feasible control technologies are evaluated. The BACT evaluation ensures that air pollutant emissions are mitigated while limiting the impacts on available energy, the economy, and the environment within an affected area. This analysis ultimately determines the allowable emissions from a source and is the basis for demonstrating emission rates, ambient air impacts, and compliance with applicable regulations. The application of BACT must result in emissions which comply with the federal, state, and local ambient impact standards. BACT is defined in 40 CFR Part 52.21 as:

“...an emissions limitation based on the maximum degree of reduction, which the Agency, on a case-by-case basis, taking into account energy, environmental, and economic impacts other costs, determines is achievable for such source through application of production process and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each pollutant.”

Ecology and OAPCA recommend that each project adhere to EPA’s top-down approach for BACT analyses. This approach ranks all feasible and available control technologies in descending order of control effectiveness. The most stringent or “top” alternative is examined first. This alternative is established as BACT unless the applicant demonstrates to the satisfaction of the permitting authority that due to other considerations such as technical, energy, environmental, or economic reasons, it can be justified that a less stringent control technology is appropriate. If the most stringent technology is eliminated, then the process is repeated for the next most stringent alternative, and so on.

6.1.2.5 Ambient Air Quality Standards (AAQS)

EPA established NAAQS for six criteria pollutants: sulfur dioxide, carbon monoxide, particulate matter, nitrogen dioxide, ozone, and lead. There are two types of standards: primary and secondary. Primary standards were established to protect public health and secondary standards were developed to protect public welfare.

Ecology has adopted their own set of ambient air quality standards (WAAQS) which are at least as stringent as the NAAQS. The Satsop CT Project must demonstrate compliance with the NAAQS and WAAQS. These federal and state standards are presented in Table 6.1-2.

**TABLE 6.1-2
AIR QUALITY STANDARDS AND SIGNIFICANCE LEVELS**

Pollutant	Averaging Period	National Ambient Air Quality Standards ($\mu\text{g}/\text{m}^3$)		PSD Increments ($\mu\text{g}/\text{m}^3$)		Washington Ambient Air Quality Standards ($\mu\text{g}/\text{m}^3$)	Significant Impact Levels ($\mu\text{g}/\text{m}^3$)	Monitoring <i>DeMinimus</i> Concentrations ($\mu\text{g}/\text{m}^3$)
		Primary	Secondary	Class I	Class II			
Total Suspended Particulate Matter (TSP)	Annual	--	--	--	--	60	--	--
	24-Hour	--	--	--	--	150	--	10
Particulate Matter Less than 10 μm (PM_{10})	Annual	50	^(a)	4	17	50	1	--
	24-Hour	150 ^(b)	^(a)	8	30	150	5	10
Particulate Matter Less than 2.5 μm ($\text{PM}_{2.5}$)	Annual	15 ⁽ⁱ⁾	^(a)	--	--	--	--	--
	24-Hour	65 ⁽ⁱ⁾	^(a)	--	--	--	--	--
Sulfur Dioxide (SO_2)	Annual	80	--	2	20	52 ^(c)	1	--
	24-Hour	365 ^(b)	--	5 ^(b)	91 ^(b)	262 ^(d)	5	13
	3-Hour	--	1300 ^(b)	25 ^(b)	512 ^(b)	^(e)	25	--
	1-Hour	--	--	--	--	1048 ^(e)	--	--
Nitrogen Dioxide (NO_2)	Annual	100	^(a)	2.5	25	94 ⁽ⁱ⁾	1	14
Lead (Pb)	Quarterly	1.5	^(a)	--	--	--	--	--
Ozone (O_3)	8-Hour	157 ^{(g)(i)}	^(a)	--	--	^(h)	--	--
	1-Hour	235 ^(b)	^(a)	--	--	235	--	^(f)
Carbon Monoxide (CO)	8-Hour	10,000 ^(b)	--	--	--	10,000	500	575
	1-Hour	40,000 ^(b)	--	--	--	40,000	2000	--

^(a)Same as primary NAAQS.

^(b)Concentration not to be exceeded more than once per year.

^(c)40 CFR 50.3; Washington standard is 0.02 ppm.

^(d)40 CFR 50.3; Washington standard is 0.1 ppm.

^(e)No Washington 3-hour standard. Washington 1-hour standards are 0.4 ppm (not to be exceeded more than once per year) and 0.25 ppm (not to be exceeded more than twice in a consecutive 7-day period).

^(f)Increase in volatile organic compound emissions of more than 100 tons/year.

^(g)Limited implementation. Three year average of the annual 4th highest daily maximum 8-hour concentration.

^(h)No standard.

⁽ⁱ⁾40 CFR 50.3; Washington standard is 0.05 ppm.

^(j)A 1999 federal court ruling blocked implementation. EPA has requested the U.S. Supreme Court to reconsider the decision.

To demonstrate compliance with NAAQS and WAAQS requirements, emissions of each air pollutant must be quantified for the source. Air dispersion models aid in determining the proposed source's impact on the air quality in the region based on these emissions. Worst-case

controlled emission rates are modeled for each averaging period of concern based on the highest emitting fuels, materials, and operating conditions that the source will be permitted to employ.

6.1.2.6 Visibility

New sources subject to the PSD program are required to evaluate potential visibility impairment to Class I areas located within a radius of 160 kilometers (100 miles) from the new source. Class I areas include National Parks and Wilderness Areas, which are areas where air quality is afforded a higher degree of protection than other areas. Four Class I areas fall within a 160-kilometer (100-mile) radius of the proposed site: Olympic National Park, Mt. Rainier National Park, Goat Rocks Wilderness Area, and Alpine Lakes Wilderness Area, all of which are in the state of Washington.

Following proposed revisions to Ecology's guidance on visibility and other "regional" modeling analyses, the modeling domain for this project also includes Pasayten Wilderness, Glacier Peak Wilderness, Mt. Adams Wilderness, Mt. Hood Wilderness, Mt. Baker Wilderness, and the Columbia River Gorge National Scenic Area.

Figure 6.1-1 shows the PSD Class I and special significance areas in Washington.

6.1.2.7 Good Engineering Practice (GEP) Stack Height

GEP requirements are codified in WAC 173-400-200, "Creditable Stack Height and Dispersion Technique Regulations." The GEP analysis is used as to determine whether the proposed stack height is at or below GEP stack height and whether building downwash is likely to occur due to the proposed stack height. Stack heights greater than GEP cannot be used to reduce ground-level impacts of a source or to demonstrate compliance with ambient air quality standards.

6.1.2.8 Toxic Air Pollutants (TAPs)

New sources of toxic air pollutants are regulated at the state level by WAC 173-460, "Controls for New Sources of Toxic Air Pollutants." Under these regulations, new sources of toxic air pollutants must "demonstrate that emissions from the source are sufficiently low to protect human health and safety from potential carcinogenic and/or other toxic effects." Additionally, new sources must use Best Available Control Technology for toxics (T-BACT). T-BACT applies to each toxic air pollutant (TAP) or a mixture of TAPs that is emitted, taking into account the potency, quantity, and toxicity of each TAP. Sources of TAPs are allowed two methods for demonstrating compliance with WAC 173-460: comparison with a Small Quantity Emission Rate (SQER) and dispersion modeling.

New sources must demonstrate compliance through dispersion modeling unless the TAP emitted has an annual average Acceptable Source Impact Level (ASIL) equal to or greater than $0.001 \mu\text{g}/\text{m}^3$. If the ASIL for the TAP is above this level, its SQER may be used to demonstrate compliance. For each TAP emitted at levels less than the SQER, no further analysis is required.

For those TAPs that have emission rates in excess of the SQERs, dispersion modeling is required.

With dispersion modeling, an initial evaluation, known as a First Tier Analysis, is performed. This analysis compares the maximum incremental ambient air impacts for each TAP from the new source with an acceptable ambient concentration. ASILs are TAP-specific and are divided into two classes: Class A and Class B. Class A TAPs are known or probable carcinogens and Class B TAPs are non-carcinogens.

If maximum impacts from the source are shown to exceed an ASIL then a Second Tier Analysis is necessary. The Second Tier Analysis is performed after T-BACT is applied and uses a health impact or risk assessment approach rather than ASIL comparison.

6.1.2.9 Impacts on Nearby Nonattainment Areas

The proposed project is not located in or near any nonattainment areas. Figure 6.1-1 shows the nonattainment areas in Washington.

6.1.3 PROJECT LOCATION AND OWNER

6.1.3.1 Introduction

The Satsop CT Project is located at the Satsop Development Park, on property owned by Duke Energy Grays Harbor, LLC (DEGH), as shown in Figure 6.1-2. The Satsop Development Park is located near the town of Elma, Washington.

This property is located along a plateau approximately 290 to 315 feet in elevation situated about 0.5 mile south of the Chehalis River, and 3 miles southeast of Satsop, Washington. Terrain in the vicinity is complex toward the south and east with elevations reaching above 1,200 feet mean sea level. To the north and west is farmland and the valley terrain of the Chehalis River.

6.1.3.2 Applicant

The facility will be owned by DEGH and will be co-operated by DEGH and Energy Northwest.

Address: P.O. Box 26
Satsop, Washington 99583

Phone: (360) 482-7700

Contact: Mr. Michael J. Sotak, Duke Energy
Ms. Laura Schinnell, Energy Northwest

6.1.4 PROJECT DESIGN

This section provides a description of the Satsop CT Project's major process equipment and the emissions from the project. Phase I and Phase II each have two identical power generation units (PGUs) consisting of a combustion turbine generator (CTG) and a heat recovery steam generator (HRSG) with a duct burner. Phase I and Phase II each have a single steam turbine generator (STG). Figure 6.1-3 presents a plot plan of the proposed project, while Figure 6.1-4 and Figure 6.1-5 present an elevation drawing and a conceptual isometric view of the project, respectively. The CTGs and the duct burner will be fueled by natural gas. The CTGs and the duct burner are the primary sources of air containment emissions. Other emissions result from ammonia slip from the selective catalytic reduction (SCR) control systems, drift from the cooling towers, natural gas combustion from the auxiliary boilers (limited to 2,500 hours per year operation each), and distillate fuel oil combustion from the emergency backup diesel generators (limited to 500 hours per year operation each).

6.1.4.1 Process Flow Diagram

Each CTG will be fired by natural gas, delivered at a maximum pressure of 560 pounds per square inch gauge (psig). The gas will be fired in the turbine's combustion section using dry low-NO_x combustors to minimize the formation of NO_x.

Feedwater from the condensing system (with make-up water added as necessary) will enter the HRSG at the section where the exhaust gas has lost most of its heat energy. In successive stages the feedwater will be converted to steam and pass out of the HRSG for use in the steam turbine. These stages will be sequentially located up-stream in the exhaust gas flow in successively high-temperature exhaust gas. In this way, the maximum amount of heat energy will be extracted from the turbine exhaust gas before it will be released from the HRSG stack to the atmosphere. The turbine exhaust gas will enter the HRSG at approximately 1,035°F and leave the stack at approximately 181°F. The thermal energy represented by this exhaust gas temperature differential will be utilized for steam production.

Prior to entering the HRSG and converting to steam, feedwater will pass through a deaerator which will remove dissolved gases (oxygen and carbon dioxide). The feedwater will then be divided into separate circuits, one for high pressure steam, the second for intermediate pressure steam, and the third for low pressure steam. The separate feedwater circuits will pass through the economizer and evaporator stages in the HRSG where they will be converted to steam, then through a superheater stage where the temperature and pressure will increase to the desired output levels. The high pressure circuit will produce 400,000 lb/hr of steam at 1,000°F; the intermediate circuit will produce 75,000 lb/hr of steam at 575°F; the low pressure circuit will produce 50,000 lb/hr of steam at 410°F.

At the evaporator stages of the HRSG, blowdown or waste liquids will be collected and transferred to the cooling tower basin for use as makeup water in the cooling water system.

High-pressure, intermediate-pressure, and low-pressure steam produced by the HRSG will be collected in separate manifolds and directed to various stages of the STG. The steam turbine will have ports for reheat steam. The high-pressure steam from the HRSG will first be expanded in the high pressure casing of the steam turbine. The full volume of this “spent” steam will be exhausted out of the casing. The remaining steam will be sent to the HRSG where it will be reheated from 580°F to over 1,000°F. The reheated steam will be sent back to the STG where it will be injected into the low pressure casing and its energy will be transformed into more electrical power. The remaining steam will be exhausted to the condenser where it will eventually be recycled as boiler feedwater.

Various elements of the steam turbine electrical generator will be cooled using hydrogen cooling.

The use of a highly efficient HRSG and STG converts more than 30 percent waste energy into useful energy in the form of electrical power.

The SCR for reduction of NO_x emissions and the oxidation catalyst for reduction of CO emissions will be located within the HRSG.

The auxiliary boiler will provide steam for heating and PGU warmup purposes.

Each PGU will be supported by a 500 kW backup diesel generator for standby power and lighting during extended utility outages.

A general process flow diagram is provided in Figure 6.1-6.

6.1.4.2 Operating Schedule

The facility will operate up to 24 hours per day, up to 365 days per year. Table 6.1-3 presents the details of the operating scenarios for the PGUs, auxiliary boilers, cooling towers, and diesel generators.

**TABLE 6.1-3
OPERATING SCENARIOS**

Emission Unit	Maximum Hours/Year/Unit	Operating Percent Load	Total Number of Units
PGUs With Duct Firing	8,760	50-100	4
Auxiliary Boilers	2,500	100	2
Cooling Towers	8,760	100	2
Diesel Generators	500	100	2

6.1.4.3 Maintenance Schedule

Based on the maintenance schedule in Table 6.1-4, and allowing for occasional forced outages, each PGU is expected to be available for operation 93 percent of the hours in an operating year.

**TABLE 6.1-4
MAINTENANCE SCHEDULE FOR EACH PGU**

Maintenance Type	Interval	
	Hours	Starts
Combustor Inspection	8,000	130
Hot Gas Path Inspection	24,000	260
Major Inspection	48,000	520

6.1.4.4 Process Fuels

Natural gas will be used to operate the PGUs and auxiliary boilers. Using the higher heating value of 23,358 Btu/lb, and noting the heat consumption rate of 2,407 million Btu/hr for each PGU with duct firing, the maximum gas consumption rate to operate all PGUs will be approximately 3.6 billion lb/yr based on 8,760 hours of operation each year for each PGU and duct burner. The auxiliary boilers are rated at 29.3 million Btu/hr at 100 percent load (700 Hp) resulting in an annual consumption rate for natural gas of 6.3 million lb/yr based on 2,500 hours of operation each year per auxiliary boiler.

Distillate fuel oil will be used to operate the emergency backup diesel generators. Each diesel generator uses 40.4 gallons of distillate fuel per hour of operation resulting in a maximum annual consumption rate to operate the diesel generators of 40,400 gallons of fuel oil per year based on 500 hours of operation for each diesel generator.

6.1.4.5 Process Products

The maximum electrical output from the Satsop CT Project is approximately 1300 MW (each PGU contributes 175 MW and each STG contributes 300 MW). Electrical power will be stepped up from 13.8 to 230 kilovolts for exportation through BPA's high voltage transmission system.

The auxiliary boilers will produce steam to assist in startup situations, reducing the amount of CO emitted from the PGUs during the startup period.

The diesel generators will provide standby power and lighting in the event of an electrical outage at the facility.

6.1.4.6 Project Emissions

NSR regulations require an estimate of source's "potential to emit," which is the maximum capacity of a stationary source to emit a pollutant under its physical limitations and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, provided the limitation is federally enforceable, is to be treated as part of its design. The calculations presented in this section are based on each PGU with duct burner operating 8,760 hours per year, each auxiliary boiler operating 2,500 hours per year, each cooling tower operating 8,760 hours per year, and each diesel generator operating 500 hours per year.

Project Emissions Methodology

Maximum potential to emit emissions for the Satsop CT Project is based on turbine load, ambient temperature, BACT control technology, and operating hours.

Emissions data for the PGUs were prepared by Duke/Fluor Daniel (D/FD) for natural gas combustion across a range of ambient temperatures and possible CT load levels. Worst-case (31°F and 100 percent load) conditions were used in all analyses.

Criteria Pollutants

Table 6.1-5 presents a summary of the hourly maximum potential emissions and stack gas concentrations for the PGUs, based on the worst-case ambient temperature, turbine load, and BACT control technology as presented in Subsection 6.1.6. Data is provided for the auxiliary boilers and diesel generators as well. Additional assumptions are outlined below.

- Typically, emissions of PM₁₀ are a portion of the TSP emission rate. However, to be conservative, emissions of PM₁₀ and PM_{2.5} were assumed to equal the TSP emission rate. Similarly, emissions of NO₂ were assumed to be the same as those for NO_x.
- Emissions of NO_x and CO are controlled emission rates. However, even though emissions of VOCs will be reduced by the CO catalyst, for this analysis VOC emissions were assumed to be uncontrolled.

Maximum annual emission rates are calculated based on 8,760 hours of PGU operations including duct firing and 130 startup/shutdown cycles per PGU.

All emissions rates are based on worst-case ambient temperature of 31°F and 100 percent load and are presented in Table 6.1-6. Also included in Table 6.1-6 are estimates of fugitive emissions from the cooling tower. The cooling tower emissions are a result of cooling tower drift, small droplets of water which do not evaporate in the cooling tower. The "drift" can contain small quantities of impurities from the water softening agents added to the cooling water. Although the cooling towers designed for this project are equipped with drift eliminators, a small amount of drift loss will occur.

**TABLE 6.1-5
MAXIMUM HOURLY EMISSION RATES^(a)**

Pollutant	Each Power Generation Unit With Duct Firing		Each Diesel Generator		Each Auxiliary Boiler	
	Stack Exhaust Concentration 100% Load (ppmvd) (gr/dscf for PM)	Maximum Emission Rate 100% Load (lb/hr)	Stack Exhaust Concentration 100% Load (ppmvw) (gr/scf for PM)	Maximum Emission Rate 100% Load (lb/hr)	Stack Exhaust Concentration 100% Load (ppmvd)	Maximum Emission Rate 100% Load (lb/hr)
NO _x	2.5	21.7	976	10.19	30	1.03
NO _x (startup & shutdown)	--	1536 lb/4-hr	--	--	--	--
SO ₂	0.11	1.3	19	0.27	1	0.029
PM ^(b)	0.0037	24.3	0.048	0.59	--	0.293
CO	2	10.6	1975	12.55	50	1.07
CO (startup & shutdown)	--	5288 lb/4-hr	--	--	150 ^(d)	0.80 ^(d)
VOC ^(c)	2.78	8.4	407	1.48	40	0.469
VOC (startup & shutdown)	--	354 lb/4-hr	--	--	40 ^(d)	0.117 ^(d)

^(a) Predicted emissions after reduction due to proposed controls (information provided by D/FD).

^(b) TSP, PM₁₀, and PM_{2.5} conservatively assumed to be equal. Includes ammonium sulfate and bisulfate compounds. Emissions as measured by EPA Reference Method 201/201a and Method 8.

^(c) VOC emission rate does not account for any reduction by the CO catalyst.

^(d) Emission rate at 25% load.

^(e) Startup/shutdown emissions are anticipated worst-case emissions associated with cold start of both PGUs. PM and SO₂ emissions are a function of fuel usage; therefore, emissions during startup/shutdown will be less than those during 100% load operations.

**TABLE 6.1-6
 MAXIMUM POTENTIAL TO EMIT ESTIMATES FOR CRITERIA POLLUTANTS
 FOUR PGUs, TWO AUXILIARY BOILERS, TWO DIESEL GENERATORS,
 AND TWO COOLING TOWERS^{(a)(c)}**

Pollutant	Power Generation Units (tons/yr)	Auxiliary Boilers (tons/yr)	Diesel Generators (tons/yr)	Cooling Towers (tons/yr)	Total Potential to Emit (tons/yr)
NO _x	580.2	2.6	5.1	--	588
SO ₂	22.8	0.1	0.1	--	23
PM ^(b)	425.7	0.7	0.3	9.02	436
CO	873.4	2.7	6.3	--	883
VOC	193.2	1.2	0.7	--	195 ^(d)

^(a) Based on 8,760 hours with duct firing for each PGU, 2,500 hours for each auxiliary boiler, 8,760 hours for each cooling tower, and 500 hours for each diesel generator.

^(b) TSP, PM₁₀, and PM_{2.5} conservatively assumed to be equal. Includes ammonium sulfate and bisulfate compounds. Emissions as measured by EPA Reference Method 201/201a and Method 8.

^(c) Includes emissions from the startup and shutdown cycles.

^(d) Includes emissions from two diesel fuel oil storage tanks.

Appendix C of this SCA amendment request contains a worksheet outlining these potential to emit calculations.

Toxic Air Pollutants (TAPs)

With the exception of ammonia slip from the operation of the SCR system, the emissions of toxic air pollutants from the various emission sources are minimal. Emissions of toxic air pollutants, other than ammonia, were estimated using emission factors from EPA's Factor Information Retrieval (FIRE) Data System (Version 6.23). Table 6.1-7 presents emissions for TAPs as defined in WAC 173-460 for the four PGUs, two auxiliary boilers, and two diesel generators. The cooling towers do not emit any TAPs.

**TABLE 6.1-7
TOXIC AIR POLLUTANT EMISSIONS**

	Phase I Turbines w/DF (lg/yr)	Phase II Turbines w/DF (lb/yr)	Auxiliary Boilers (lb/yr)	Diesel Generators (lb/yr)	Total (lb/yr)
Class A Taps (a)(b)					
Acetaldehyde	1171.037	1171.037	na	4.07	2346.14
Arsenic	1.735	1.735	0.029	na	3.50
Benzene	369.527	369.527	0.302	5.21	744.57
Benzo (a) pyrene	0.010	0.010	0.000	na	0.02
Benzo (b) fluoranthene	0.016	0.016	0.000	na	0.03
Benzo (k) fluoranthene	0.016	0.016	0.000	na	0.03
Beryllium	0.104	0.104	0.002	na	0.21
Cadmium	9.542	9.542	0.158	na	19.24
Chromium	12.144	12.144	0.201	na	24.49
Dibenzo (a,h) anthracene	0.010	0.010	0.000	na	0.02
Dichlorobenzene	10.409	10.409	0.172	na	20.99
Formaldehyde	21436.462	21436.462	10.772	6.25	42889.95
Indeno (1,2,3-cd) pyrene	0.016	0.016	0.000	na	0.03
Lead	0.000	0.000	0.000	na	0.00
Nickel	18.216	18.216	0.302	na	36.73
PAH ^a	64.490	64.490	0.001	0.89	129.87
Class B Taps (a)(b)					
Acrolein	93.68	93.68	na	na	187
Ammonia	141036.00	141036.00	35.19	na	282107
Barium	19.08	19.08	0.32	na	38
Butane	9107.82	9107.82	150.81	na	18366
Cobalt	0.36	0.36	0.01	na	1
Copper	3.69	3.69	0.06	na	7
Ethylbenzene	468.41	468.41	na	0.12	937
Manganese	1.65	1.65	0.03	na	3
Mercury	1.13	1.13	0.02	0.00	2
Molybdenum	4.77	4.77	0.08	na	10
n-Hexane	7806.71	7806.71	129.26	na	15743
n-Pentane	11276.35	11276.35	186.72	na	22739
Naphthalene	21.67	21.67	0.04	0.52	44
Selenium	0.10	0.10	0.002	na	0
Sulfuric Acid Mist	20562.73	20562.73	na		
Toluene	1917.68	1917.68	0.24	2.17	3838
Vanadium	9.98	9.98	0.17	na	20
Xylenes	936.83	936.83	na	1.51	1875
Zinc	125.77	125.77	2.08	na	254

^(a)Class A TAPs are known or probable carcinogens and Class B TAPs are non-carcinogens.

^(b)Class A TAP emission rates are based on 8,760 hours with duct firing for each PGU, 2,500 hours for each auxiliary boiler, 8,760 hours for each cooling tower, and 500 hours for each diesel generator.

6.1.5 NEW SOURCE PERFORMANCE STANDARDS (NSPS) AND ACID RAIN PROVISIONS

NSPSs are nationally uniform emission standards established by EPA and set forth in 40 CFR Part 60. The State of Washington has adopted these standards in WAC 173-400-115. The Satsop CT Project will comply with the NSPS emission limits for NO_x and SO₂ established in 40 CFR Part 60, Subparts Da and GG. Acid rain requirements and standards are contained within Title IV of the Clean Air Act Amendments of 1990. These standards limit potential emissions of NO_x and SO₂ from certain classes of stationary gas turbines and represent the minimum level of control that is required.

6.1.5.1 40 CFR Part 60 Subpart Da

Subpart Da applies to electric utility steam generating units with heat input from fuel combustion greater than 250 MMBtu/hr. When the duct burners are firing, this NSPS would apply as the heat input from each duct burner is approximately 505 MMBtu/hr. Because the duct burners will only fire natural gas, only those sections of this NSPS will apply to the Satsop CT Project.

Subpart Da limits particulate matter emissions to 0.03 lb/MMBtu and SO₂ and NO_x emissions to 0.20 lb/MMBtu. With a firing rate of 505 MMBtu/hr for each duct burner, the NSPS limits become 15 lb/hr for PM and 101 lb/hr for SO₂ and NO_x. The proposed emission rates for each duct burner are 5.5 lb/hr for PM, 0.31 lb/hr for SO₂, and 44 lb/hr NO_x. All proposed emission rates are less than the NSPS limits.

6.1.5.2 40 CFR Part 60 Subpart GG

Stationary gas turbines with a heat input from fuel combustion exceeds 100 million BTU/hr, 40 CFR Part 60.332(a)(1) requires that that NO_x concentrations in gaseous discharges from stationary gas turbines do not exceed concentrations calculated as follows:

$$\text{STD} = 0.0075 ((14.4)/y) + F$$

where

STD = allowable NO_x emissions, percent by volume at 15 percent O₂ on a dry basis
y = manufacturer's rated heat rate, kilojoules per watt-hour (kJ/watt-hr)
F = NO_x emission allowance for fuel-bound nitrogen

Using (1) a conservative assumption that there is no fuel-bound nitrogen in the natural gas (as natural gas contains primarily methane, ethane, and propane) and (2) the manufacturer's rated heat rate of 9570 Btu/kw-hr, the allowable emission rate calculated using the above equation is 119 parts per million by volume, dry (ppmvd). The proposed NO_x concentration for each Satsop CT Project PGU is 2.5 ppmvd at 15 percent O₂. Consequently, the Satsop CT Project will comply with the NO_x emission standard.

Subpart GG of 40 CFR Part 60.333(a) limits SO₂ emissions to 0.015 percent by volume at 15 percent O₂. This equates to 150 ppmvd and the Satsop CT Project is proposing 0.11 ppm. Consequently, the Satsop CT Project will comply with the SO₂ emission standard.

The project's continuous emissions monitoring system (CEMS) will be designed, operated, and maintained in accordance with 40 CFR Part 60, Appendix B, Performance Specifications 2, 3, and 4. A data acquisitions system will also be used to determine and record compliance with the air quality permits.

As required, continuous emission monitors (CEMs) for the stack exhaust gas will be installed to monitor compliance with the air contaminant discharge rates allowed during operations in the permit. NO_x and O₂ monitors will be used to aid in controlling operations of the SCR and the CT dry low-NO_x combustors.

6.1.5.3 Acid Rain Provisions

Title IV of the Clean Air Act Amendments of 1990 requires all facilities with gas turbines rated with an electric output greater than 25MW which provide at least one third of the output to a distribution system must comply with the Part 75 regulations. The Satsop CT Project will be required to monitor NO_x, SO₂, O₂, and flow rate. The continuous emission monitors required under the NSPS regulations are similar to those required by Part 75; however, the accuracy limits during the annual relative accuracy test audits are more stringent.

6.1.6 BACT TOP-DOWN ANALYSIS

Criteria air pollutant emissions from the Satsop CT Project will include NO₂, SO₂, PM, CO, and VOCs. The technologies available for controlling these emissions are discussed in this section. A "top-down" BACT analysis approach has been used to evaluate BACT for the Satsop CT Project.

6.1.6.1 Methodology

The five steps of a typical "top-down" BACT process consist of the following:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies
4. Evaluate the most effective control technology
5. Select BACT

A brief description of each step is presented below.

Step 1 - Identify All Control Technologies

The first step in a “top-down” BACT analysis is to identify all available control options. Air pollution controls include available technologies, methods, systems, and techniques for control of the regulated pollutant, as well as alternate production processes that may reduce the generation of pollutants. The control alternatives should not only include existing controls for the source category or piece of equipment in question, but also innovative technologies and controls applied to similar source categories.

Step 2 - Eliminate Technically Infeasible Options

In the second step of the “top-down” BACT evaluation, the technical feasibility of the control options identified in Step 1 are evaluated with respect to source-specific factors. The list of technically infeasible control options must be clearly documented. The applicant must demonstrate that, based on physical, chemical, and/or engineering principles, technical difficulties will preclude the successful use of the control option. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 - Rank Remaining Control Technologies

In Step 3, all remaining control alternatives not eliminated in Step 2 are ranked in order of control effectiveness for the pollutants under review. The most effective control alternative is ranked at the top. A list of control alternatives is prepared for each pollutant and for each emission unit subject to the BACT analysis. The list presents the array of control technology alternatives and includes the following types of information:

- Range of control efficiencies (percentage of pollutant removed)
- Expected emission rate (tons per year, pounds per year)
- Expected removal efficiency at the Satsop CT Project (tons per year)
- Economic impacts (cost effectiveness)
- Environmental impacts (includes significant or unusual impacts on other media, water or solid waste)
- Energy impacts

A detailed analysis of costs and other impacts is not required if the applicant chooses the most stringent emissions control technology. The applicant must document that the control option is the most stringent alternative and briefly explain the environmental impacts.

Step 4 - Evaluate Most Effective Control Technology

After the available and technically feasible control technology options have been identified, potential impacts such as energy, environmental, and economic impacts are considered to determine the best available level of control (Step 4). For each control option, the applicant must present an objective evaluation of each impact. Both beneficial and adverse impacts are described and, where possible, quantified. In general, BACT analyses focus on the direct impact of the control alternative.

In this analysis, the technology with the highest control efficiency is evaluated first. If this technology is found to have no adverse environmental, energy, or economic impacts, it is selected as BACT and no further analysis is necessary. If the most stringent technology is shown to be inappropriate because of energy, environmental, or economic reasons, the applicant must fully document the rationale for this conclusion. Then, the next most effective control alternative on the list becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated due to potential source-specific reasoning.

Step 5 - Select BACT

The most effective control option not eliminated in Step 4 is proposed as BACT for the pollutant(s) and emission unit(s) under review.

6.1.6.2 Combustion Turbines

The EPA maintains a database of technologies that have been implemented as Reasonably Achievable Control Technology (RACT), BACT, or Lowest Achievable Emission Rate (LAER) (known as the RACT/BACT/LAER Clearinghouse or RBLC database). This database was accessed to identify control strategies implemented to date, on turbines. The RBLC was searched for all “turbine” entries with Standard Industrial Classification (SIC) 4911 (Electric Services) where permits or latest updates were made after January 1, 1995. From the initial search results, the data set was further reduced by eliminating sources smaller than 90 MW and greater than 550 MW. Also, sources known, but not found in the RBLC, are included. Table 6.1-8 presents a summary of permit determinations for power generation projects comparable to the Satsop CT Project.

Other facilities have been permitted and/or built in Washington State that are not part of the RBLC; typically because these facilities utilized non-BACT rationales in selecting their control technology. Each of these facilities utilized a PSD-avoidance and/or modeling constraint strategy to determine their emission rates. At the time of their application preparation, each of these facilities were influenced by or located within a nonattainment region and would have needed offsets in order to permit 100 tons or more of any nonattainment pollutant or precursor. Consequently, these facilities have had no impact upon any BACT analyses, to date. Table 6.1-9 presents the pertinent information on these facilities.

**TABLE 6.1-8
RBLC SEARCH RESULTS FOR RECENT POWER GENERATION PROJECTS**

Facility	Location	EPA Region	Permit Date or Last Update	Size (each turbine)	
Alabama Power Company	McIntosh, AL	4	04/24/1998	100	MW
Alabama Power Company - Theodore Cogeneration	Theodore, AL	4	06/23/1999	170	MW
Alabama Power Plant Barry	Bucks, AL	4	08/05/1999	510	MW (Total)
Blue Mountain Power, LP	Richland, PA	3	01/12/1999	153	MW
Bridgeport Energy, LLC	Bridgeport, CT	1	01/21/1999	260	MW/HRSG per turbine
Calpine Corporation	Yuba City, CA	9	7/23/1999	500	MW (Total)
Casco Ray Energy Co	Veazie, ME	1	04/19/1999	170	MW (Each)
Champion International Corp. & Champ. Clean Energy	Bucksport, ME	1	04/19/1999	175	MW
Duke Energy Luna Energy Facility	Deming, NM	6	12/29/00	640	MW (Total)
Duke Energy New Smyrna Beach Power Co. LP	Charlotte NC (Headquarters) Facility is located in FL	4	11/11/1999	500	MW (2 Units)
Ecoelectrica, L.P.	Penuelas, PR	2	05/06/1998	461	MW
Gorham Energy Limited Partnership	Gorham, ME	1	04/19/1999	900	MW (Total)
La Paloma Generating Co. LLC	McKittrick, CA	9	2/11/2000	1048	MW (Total)
Lordsburg L.P.	Lordsburg, NM	6	09/29/1997	100	MW
Mid-Georgia Cogen.	Kathleen, GA	4	08/19/1996	116	MW
Oleander Power Project	Baltimore (Headquarters) Facility is located in FL	4	11/11/1999	190	MW
Public Service Of Colo.- Fort St Vrain	Platteville, CO	8	05/19/1998	471	MW
Puerto Rico Electric Power Authority (PREPA)	Arecibo, PR	2	05/06/1998	248	MW
Santa Rosa Energy LLC	Northbrook, FL	4	04/16/1999	241	MW
Seminole Hardee Unit 3	Fort Green, FL	4	05/31/1996	140	MW
Southern Energy, Inc.	Zeeland, MI	5	08/22/2000	9000	Gigajoules
Southwestern Public Service Co/Cunningham Station	Hobbs, NM	6	12/30/1996	100	MW
Southwestern Public Service Company/Cunningham Station	Hobbs, NM	6	03/31/1997	100	MW
Tenuska Georgia Partners, L.P.	Franklin, GA	4	06/23/1999	160	MW each
Tiverton Power Associates	Tiverton, RI	1	02/08/1999	265	MW
TN Valley Authority Lagoon Creek Combustion Turbine	Brownsville, TN	4	08/16/2000	194400	MMBtu/hr
Westbrook Power LLC	Westbrook, ME	1	04/19/1999	528	MW (Total)
Wyandotte Energy	Wyandotte, MI	5	04/19/1999	500	MW

**TABLE 6.1-9
OTHER FACILITIES IN WASHINGTON STATE**

Facility	Size (each turbine)	Fuel	Allowable NO_x Emissions	Type of Control	Permit Date	Status
Chehalis Generation Facility, Chehalis	460 MW	Natural Gas	9.9 ppm @ 15% O ₂	Advanced Dry Low-NO _x Combustors	1997	Under Construction
Clark Public Utilities, Vancouver	248 MW	Natural Gas, No. 2 Oil	4 ppm @ 15% O ₂ 9 ppm @ 15% O ₂ (24-hour average)	LAER for PSD-avoidance dry low-NO _x and SCR	1995	Operational
Cowlitz Co-generation Project, Longview	395 MW	Natural Gas	6 ppm A@ 15% O ₂	SCR	1993	Not Built
Frederickson Power, Frederickson	248 MW	Natural Gas, No. 2 Oil	3 ppm @ 15% O ₂ 8 ppm @ 15% O ₂	LAER for PSD-avoidance duct burner and SCR	2000	Under Construction
Florida Power & Light, Everett	235 MW	Natural Gas, No. 2 Oil	3.5 ppm @ 15% O ₂ 3.5 ppm @ 15% O ₂ (8-hour average)	LAER for PSD-avoidance SCR	1997	Not Built
Florida Power & Light - Delta II, Everett	247.4 MW	Natural Gas, No. 2 Oil	3.5 ppm @ 15% O ₂ 42 ppm @ 15% O ₂ (8-hour average)	PSD-avoidance SCR	1999	Not Built
Goldendale, Goldendale	248 MW	Natural Gas	2 ppm	SCR	2001	Under Construction
Mint Farm, Longview	248 MW	Natural Gas	3 ppm @ 15% O ₂	SCR	2001	Not Built
Northwest Region Power Facility, Creston	838 MW	Natural Gas	9 ppm @ 15% O ₂	Advanced Dry Low-NO _x Combustors	1996	Not Built
Starbuck, Starbuck	1,200 MW	Natural Gas	2 to 5 ppm @ 15% O ₂	SCR	—	Applied for Permit
Sumas Energy Sumas	660 MW	Natural Gas	2 ppm @ 15% O ₂	SCR	—	Applied for Permit
Wallula, Wallula	1,300 MW	Natural Gas	3 ppm @ 15% O ₂	SCR	—	Applied for Permit

Nitrogen Oxides

The formation of nitrogen oxides is the result of thermal oxidation of diatomic nitrogen in the combustion chamber. The rate of formation is dependent upon combustion temperature, residence time of combustion products at high temperatures, and the availability of oxygen in the flame zone of a combustion turbine generator. This section addresses the available control alternatives for NO_x emissions.

Available Control Technologies

Control technologies for NO_x emissions can be classified as combustion modifications or post-combustion controls. The RBLC search completed for NO_x is summarized in Table 6.1-10. The available NO_x control technologies for natural gas-fired combustion turbines are briefly described below.

**TABLE 6.1-10
RBLC SEARCH RESULTS FOR NO_x - TURBINES**

Facility ^(a)	Emissions	Pollution Control	Basis
Alabama Power Company	15 ppm	Dry low NO _x burners	BACT-PSD
Alabama Power Company - Theodore Cogeneration	0.013 lb/MMBtu	DLN combustor in CT, LNB in duct burner, SCR	BACT-PSD
Alabama Power Plant Barry	0.013 lb/MMBtu	Natural gas, CT-DLN combustors, ductburner, low NO _x burner, combined stack SCR	BACT-PSD
Blue Mountain Power, LP	4 ppm @ 15% O ₂	Dry LNB with SCR. Water injection in place when firing oil. Oil firing limits set to 8.4 ppm @15% O ₂	LAER
Bridgeport Energy, LLC	6 ppm	Dry low NO _x burner with SCR	BACT-PSD
Calpine Corporation	2.5 ppm	Dry low-NO _x burner with SCR	
Casco Ray Energy Co	3.5 ppm @15% O ₂	SCR	BACT-PSD
Champion International Corp. & Champ. Clean Energy	9 ppmvd @15% O ₂	Dry low NO _x burner 1 option is considered for oil and is selected	BACT-Other
Chehalis Generation Facility	9.9 ppm	Advanced dry low-NO _x combustors	BACT-PSD
Duke Energy New Smyrna Beach Power Co. LP	9 ppm @ 15% O ₂	DLN GE DLN2.6 burners	BACT-PSD
Ecoelectrica, L.P.	60 lb/hr	Steam/water injection and SCR.	BACT-PSD
Gorham Energy Limited Partnership	2.5 ppm @ 15% O ₂	SCR	LAER
La Paloma Generating Co. LLC	2.5 ppm	Dry low-NO _x burners with SCR on three units and SCONO _x TM or SCR on the fourth unit	

TABLE 6.1-10 (Continued)
RBLC SEARCH RESULTS FOR NO_x - TURBINES

Facility^(a)	Emissions	Pollution Control	Basis
Lordsburg L.P.	74.4 lbs/hr	Dry low-NO _x technology which adopts staged or scheduled combustion.	BACT-PSD
Mid-Georgia Cogen.	9 ppmvd	Dry low NO _x burner with SCR	BACT-PSD
Oleander Power Project	9 ppm @ 15% O ₂	DLN 2.6 GE advanced dry low NO _x burners	BACT-PSD
Public Service Of Colo.- Fort St Vrain	15 ppmvd	Dry low-NO _x combustion systems for turbines and duct burners	BACT-PSD
Puerto Rico Electric Power Authority (PREPA)	35 lb/hr as NO ₂	Steam injection plus SCR. Use of no. 2 fuel oil with nitrogen content not to exceed 0.10% by weight.	BACT-PSD
Santa Rosa Energy LLC	9.8 ppm@15% O ₂	Dry low NO _x burner	BACT-PSD
Seminole Hardee Unit 3	15 ppm @ 15% O ₂	Dry LNB staged combustion	BACT-PSD
Southern Energy, Inc.	0.013 lb/MMBtu	Limit is for each CT alone or with its DB. Ammonia injection, SCR. Limit based on 3.5 ppm.	BACT-PSD
Southwestern Public Service Co/Cunningham Station	15 ppm	Dry low NO _x combustion	BACT-PSD
Southwestern Public Service Company/Cunningham Station	No Data Available	Dry low-NO _x combustion	BACT-PSD
Tenuska Georgia Partners, L.P.	15 ppmvd @ 15% O ₂	Using 15% excess air.	BACT-PSD
Tiverton Power Associates	3.5 ppm @ 15% O ₂	Selective Catalytic Reduction (SCR)	LAER
TN Valley Authority Lagoon Creek Combustion Turbine	12 ppm	Dry low NO _x combustion (gas), wet injection (oil), and annual production limits	BACT-PSD
Westbrook Power LLC	2.5 ppm @15% O ₂	SCR and dry low-NO _x burners.	LAER
Wyandotte Energy	4.5 ppm	SCR	BACT

^(a)See Table 6.1-8 for locations.

Combustion Modifications:

- Steam/Water Injection:** Steam/water injection has been widely used as a gas turbine NO_x emission control. Steam or water is injected into the combustion zone to lower the combustion zone temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to (1) vaporize the water (latent heat of vaporization), and (2) raise the vaporized water temperature to the combustion temperature. High-purity water must be used to prevent

turbine corrosion and deposition of solids on the turbine blades. This normally requires installation of a water purification system if water of sufficient purity is not already available. Steam injection employs the same mechanisms as water injection to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO_x reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 pounds of water and 0.5 to 2.0 pounds of steam per pound of fuel. Water/steam injection will not reduce the formation of fuel NO_x. The maximum amount of water/steam that can be injected depends on the CT combustor design. Excessive rates of water/steam injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold-spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of wet injection to reduce NO_x emissions also depends on turbine combustor design. For a given turbine design, the maximum water/fuel ratio (and maximum NO_x reduction) will occur up to the point where cold-spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine.

- **Dry Low-NO_x Combustor:** The modern, dry low-NO_x (DLN) combustor is typically a three-staged, lean, premixed design, which utilizes a central diffusion flame for stabilization. The lean, premixed approach burns a lean fuel-to-air mixture for a lower combustion flame temperature resulting in lower thermal NO_x formation. The combustor operates with one of the lean premixed stages and the diffusion pilot at lower loads and the other stages at higher loads. This provides efficient combustion at lower temperatures, throughout the combustor-loading regime. The dry low-NO_x combustor reduces NO_x emissions by up to approximately 87 percent over a conventional combustor.
- **XONONTM:** Catalytica Combustion Systems' XONONTM combustion system improves the combustion process by lowering the peak combustion temperature to reduce the formation of NO_x while also providing further control of CO and unburned hydrocarbon emissions that other NO_x control technologies (such as water injection and DLN) cannot provide. Most gas turbine emission control technologies remove air contaminants from exhaust gas prior to release to the atmosphere. In contrast, the overall combustion process in the XONONTM system is a partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. In the catalyst module, a portion of the fuel is combusted without a flame (i.e., at relatively low temperature) to produce a hot gas. A homogeneous combustion region is located immediately downstream where the remainder of the fuel is combusted.

The key feature of the XONONTM combustion system is a proprietary catalytic component, called the XONONTM Module, which is integral to the gas turbine combustor. XONONTM combusts the fuel without a flame, thus eliminating the peak flame temperatures that lead to NO_x formation. Turbine performance is not affected.

XONON™ is an innovative technology that is currently being commercialized on smaller-scale projects with support from the U.S. Department of Energy, the California Energy Commission (CEC), and the California Air Resources Board (CARB). CARB has reported on the pilot effort underway in Santa Clara where the XONON™ system is operating at a 1.5-MW simple-cycle pilot facility. CARB indicated in its June 1999 report that “Emission levels from 1.33 to 4.04 ppmvd NO_x at 15 percent oxygen (O₂) have been achieved at Silicon Valley Power utilizing the XONON™ technology” (CARB 1999). However, it further indicates that “there is not sufficient operating experience to ensure reliable performance on large gas turbines.”

XONON™ does not currently represent an available control technology for any 300 MW turbine. According to Catalytica, a joint venture agreement is in place with General Electric (GE) to eventually develop XONON™ as original equipment manufacturer and retrofit equipment for the entire GE turbine line. GE does not currently offer a XONON™ combustor option for 7FA or any other large industrial turbine. An Application for Certification was recently approved by CEC for the Pastoria Energy Facility Project (December 20, 2000) which proposes to install XONON™ on F-Class Turbines, if the technological issues can be resolved. The NO_x emission limit proposed for the Pastoria Project is being evaluated under LAER criteria. DLN/SCR is proposed as the back-up control technology in the event that the XONON™ technology proves infeasible for this project. XONON™ does not represent a currently available control technology for the Satsop CT Project under BACT evaluation criteria.

Post-Combustion Controls:

- **Selective Catalytic Reduction:** In the SCR process, a reducing agent, such as aqueous ammonia, is introduced into the turbine’s exhaust, upstream of a metal or ceramic catalyst. As the exhaust gas mixture passes through the catalyst bed, the reducing agent selectively reduces the nitrogen oxide compounds present in the exhaust to produce elemental nitrogen (N₂) and water (H₂O). Ammonia is the most commonly used reducing agent. Adequate mixing of ammonia in the exhaust gas and control of the amount of ammonia injected (based on the inlet NO_x concentration) are critical to obtaining the required reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum O₂ concentrations and remain within a specified temperature range (typically between 580°F and 650°F), with the range dictated by the type of catalyst. Exhaust gas temperatures greater than the upper limit (850°F) will pass the NO_x and unreacted ammonia through the catalyst. The most widely used catalysts are vanadium, platinum, titanium, or zeolite compounds impregnated on metallic or ceramic substrates in a plate of honeycomb configuration. The catalyst life expectancy is typically 3 to 6 years, at which time the vendor can recycle the catalyst to minimize waste.

The SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical “poisoning”. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium.

One concern when using the SCR catalyst on fuels containing sulfur is the oxidation of flue gas SO_2 to SO_3 which will then combine with H_2O vapor to form H_2SO_4 . Accordingly, corrosion of downstream piping and heat transfer equipment (which will operate at temperatures below the H_2SO_4 dew point) will be of concern when using SCR with sulfur-bearing fuels. Also, SO_3 will combine with unreacted ammonia to form ammonium bisulfate and ammonium sulfate. Ammonium bisulfate is a hygroscopic solid at approximately 300°F and can deposit on equipment surfaces below this temperature as a white solid. Both ammonium bisulfate and ammonium sulfate will be expected to deposit on HRSG heat transfer equipment when temperatures below 300°F occur. Because ammonium bisulfate is hygroscopic, the material will absorb H_2O , forming a sticky substance which can cause fouling of heat transfer equipment. Ammonium bisulfate cannot be easily removed due to its sticky nature; a unit shutdown will be required to clean fouled equipment. Problems associated with ammonium salt deposition can be ameliorated, to some extent, by reducing the ammonia/ NO_x molar ratio when firing sulfur-containing fuels.

- **Selective Non-Catalytic Reduction (SNCR):** Similar to the SCR process, SNCR uses ammonia or a urea-based reagent to chemically react with the NO_x in the exhaust gas stream, forming diatomic nitrogen and steam. Because no catalyst is used for SNCR, the temperature required for the reaction ranges from 1,600°F to 1,750°F for ammonia, and from 1,000°F to 1,900°F for urea-based reagents. The NO_x conversion efficiency declines below these temperature ranges and the concentration of unreacted reagent in the emissions (“slip”) increases. Above these temperatures, the reagent will tend to react with the excess oxygen in the exhaust gas instead of the NO_x forming additional NO. At optimum temperatures, NO_x destruction efficiencies range from 75 percent to greater than 90 percent. However, SNCR is very dependent on adequate mixing and on adequate residence times.
- **SCONO_x™:** SCONO_x™ is a new, innovative post-combustion control system produced by EmeraChem, LLC. (formerly Goal Line Environmental Technologies). Commercial operation of SCONO_x™ began with an installation at the Federal Plant in Vernon, California in December 1996. The Federal Plant is owned by Sunlaw Cogeneration Partners (a part owner in Goal Line) and consists of an LM2500 combustion turbine (approximately 28 MW) with a HRSG. The unit is roughly one-tenth the size of the proposed GE 7FA combustion turbines. The SCONO_x™ system uses a coated oxidation catalyst installed in the flue gas to remove both NO_x and CO without a reagent such as ammonia. The NO emissions are oxidized to NO_2 and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to de-absorb the NO_2 from

the catalyst and reduce it to N₂ prior to exit from the stack. CO is oxidized to CO₂ and exits the stack, and VOC is reduced as well.

SCONO_xTM operates in a temperature range between 300°F and 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, NO₂ is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regenerative gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. As a result, each section of the catalyst is regenerated about once every 15 minutes.

The system is advertised to achieve NO_x levels below current LAER and BACT levels, and CO levels of 6 ppmvd (at 15 percent O₂) for turbine load conditions greater than 73 percent (10 ppmvd at 15 percent O₂ for low load conditions). Current emissions data show that the Federal Plant is controlling NO_x emissions to 2 ppmvd (at 15 percent O₂) on a periodic basis for the LM2500 application (excluding startup, shutdown, and frequent maintenance).

ABB and the former Goal Line Technologies representatives entered into an agreement to make SCONO_xTM commercially available for an F-Class ABB turbine at a guaranteed emissions level of 2.5 ppmvd NO_x (at 15 percent O₂). To date, due to company restructuring and other issues, SCONO_xTM has not been placed on an F-Class turbine.

The La Paloma Generating Project in California initially proposed to demonstrate the viability of SCONO_xTM on one ABB KA-24 (150 MW) turbine at that facility, assuming that the technological and commercial availability issues could be resolved. The NO_x emission limit to be met by either SCONO_xTM or DLN/SCR was approved under LAER criteria. Commercial, warranty, and operational issues of concern for SCONO_xTM were not resolved by the final engineering design deadline.

Otay Mesa Generating Company LLC, an affiliate of Umatilla Generating Company, LP, submitted an Application for Certification to the CEC for the Otay Mesa Project on August 2, 1999, which proposes to install SCONO_xTM anticipating that commercial, warranty, and operational issues of concern may be resolved in time for that facility's construction. The NO_x emission limit proposed for the Otay Mesa Project is being evaluated under LAER criteria. DLN/SCR is proposed as the back-up control technology if the SCONO_xTM technology proves infeasible for this project.

Evaluation of Technical Feasibility

The following section addresses the technical feasibility of the NO_x control technologies described above with respect to the Satsop CT Project.

Combustion Modifications:

- **Steam/Water Injection:** This technology is capable of reducing exhaust gas NO_x concentrations from natural gas firing to a concentration of 25 ppmvd, assuming combustion is at 15 percent oxygen. This reduction will not satisfy regulatory requirements without a post-combustion control. This technology could be implemented on the Satsop CT Project.
- **Dry Low-NO_x Combustor:** Dry low-NO_x combustors will be an integral part of the PG units designed for the Satsop CT Project. This technology is guaranteed by the manufacturer to reduce NO_x emissions from the PG units to 9 ppmvd for natural gas firing. This reduction will not satisfy current regulatory requirements without a post-combustion control. This technology is evaluated below.
- **XONON™:** Catalytica has been conducting field tests to verify the emission performance of the XONON™ technology. However, the current field tests are being run using a 1.5 MW engine (emitting less than 3.0 ppm NO_x and less than 10 ppm CO), which is the first use of the XONON™ technology on a full-scale engine. Because this innovative technology has not been proven on a turbine within an equivalent size range as that proposed for the Satsop CT Project, this technology is deemed technologically infeasible, until further results show the application is successful on larger engines.

Post-Combustion Controls:

- **Selective Catalytic Reduction:** This technology is readily available for many applications, including combustion turbines. Typically, SCR is an integral element of the HRSG unit on combined cycle plants, where the exhaust gas is at the optimum temperature.
- **Selective Non-Catalytic Reduction:** SNCR, although commercially available for many applications, has not fared well in the market place. There are no recent applications of SNCR to combustion turbines. Furthermore, adequate performance of SNCR is very dependent on residence time, which is very short in the high flow exhaust of a turbine. As indicated in the RBLC search, SNCR is not demonstrated on turbines. Consequently, this technology is considered technically infeasible for this project.
- **SCONO_x™:** This technology has not been proven technically feasible for projects of the size proposed with the Satsop CT Project. However, this technology has been utilized in two facilities, providing evidence that the process is technically feasible at small power

plants. Only one large source in California has a permit which includes SCONO_xTM as a control for three of four turbines. The fourth turbine can be controlled using either SCONO_xTM or SCR; however, the project was built using SCR due to problems obtaining the SCONO_xTM system. This facility will be in an ozone nonattainment area. Therefore, SCONO_xTM is considered technically feasible but unproven for large power plants such as the Satsop CT Project.

Control Technology Hierarchy

As noted above, NO_x controls include combustion modifications, post-combustion controls, or combination of these controls. Within each category, control technologies are ranked according to their pollutant removal efficiencies, with a higher ranking given to control methods with higher removal efficiencies.

The dry low-NO_x combustors and steam/water injection methods are the only technically feasible combustion modification options for the PGUs at the Satsop CT Project. Only SCR and SCONO_xTM are considered technically feasible as a post-combustion control for this project.

Combining the combustion modifications with the post-combustion controls has the potential to yield even higher overall NO_x removal efficiencies. NO_x emissions as low as 2.5 ppmvd can be achieved using SCR in conjunction with dry low-NO_x combustors. The combination of dry low-NO_x combustors with the SCR ranks as the most efficient and proven combination of control technologies. The combination of steam/water injection and SCR is ranked the second most effective proven control technology. The SCONO_xTM system has cited NO_x emissions as low as 2.0 ppmvd can be achieved on smaller turbine systems.

The technology ranking from highest (most effective) to lowest for the Satsop CT Project is as follows:

1. SCONO_xTM
2. Dry low-NO_x combustors with SCR
3. Water/steam injection with SCR
4. Conventional combustors with SCR
5. Dry low-NO_x combustors
6. Water/steam injection

Table 6.1-11 provides a comparison of estimated control efficiencies for dry low-NO_x combustors, dry low-NO_x combustors with SCR, and SCONO_xTM.

**TABLE 6.1-11
NO_x EMISSION CONTROL EFFICIENCIES FOR EACH PGU**

Emission Control Mechanism	CT Load	NO_x Emission Concentration (ppmvd @15% O₂ and ISO)	NO_x Emission Rate (lb/hr)	Control Efficiency (Ratio to No Control)
Conventional Combustor	Base	72.4	628.8 ^(a)	--
Dry Low NO _x (DLN) Combustor	Base	9 ^(b)	78.1	87.6%
DLN w/SCR (with duct burner firing)	Base	2.5 ^(b)	21.7 ^(b)	96.5%
SCONO _x TM	Base	2.0 ^(c)	17.4 ^(d)	97.2%

^(a)Based on AP-42, Section 3.1, Table 3.1-1, April 2000, for turbine emissions and AP-42, Section 1.4, Table 1.4-1, September 1998, for duct burner emissions (USEPA 1985b).

^(b)Emissions provided by GE.

^(c)Emissions provided by EmeraChem.

^(d)Emission rate estimated as ratio of 2.0/2.5*21.7 lb/hr.

BACT Determination

The environmental, energy, and economic impacts of the above-ranked NO_x control technologies for the Satsop CT Project are presented in this section. The highest ranked proven control for NO_x is a combination of the dry low-NO_x combustor and SCR with an emission limit of 2.5 ppm. SCONO_xTM with an emission limit of 2.0 ppm will be assessed as well.

Dry Low-NO_x Combustors:

- **Environmental Impacts:** Dry low-NO_x combustors pose no identified negative environmental impacts when implemented on a GE 7FA combustion turbine. The emission reduction is the same as with steam injection, but without increasing CO emissions and water consumption.
- **Energy Impacts:** There is no energy impact associated with dry low-NO_x combustors when firing natural gas. The power output for a gas turbine using dry low-NO_x combustors is the same as the output for a turbine with conventional combustors.
- **Economic Impacts:** An assessment of economic impacts was not performed for dry low-NO_x combustors because the dry low-NO_x combustors are an integral part of the GE 7FA combustion turbine.

SCR:

- **Environmental Impacts:** There are several environmental concerns associated with SCR control technology. The primary concern is that ammonia emissions are released when ammonia passes through the catalyst unreacted, and is exhausted through the stack. Most SCR manufacturers guarantee very small amounts of ammonia slip (less than 10 ppm). However, ammonia slip can increase significantly during start-ups, upsets/failures of the ammonia injection system, or due to catalyst degradation. In instances where such events have occurred, ammonia exhaust concentrations of 50 ppmv, or greater, have been measured.

Ammonia is most frequently shipped by highway or rail and the potential exists for a spill due to an accident, although the likelihood is low. Spills may occur during the transfer of the aqueous ammonia from one container or vessel to another. In addition, the SCR catalyst has the negative side effect of forming SO₃ from some of the SO₂ entering the system in the exhaust stream. SO₃ reacts with the unreacted ammonia in the exhaust stream to produce ammonium sulfate and ammonium bisulfate salts. As these sticky particles buildup on the HRSG boiler tubes, they diminish the heat transfer qualities of the HRSG turbine which reduces the efficiency of the plant. Also, these salt particles create corrosion problems within the HRSG. As a result, the use of an SCR requires additional HRSG maintenance in addition to increasing emissions of particulate matter.

- **Energy Impacts:** The greater the catalyst volume, the higher the pressure drop. The presence of the SCR system in the HRSG introduces added resistance to the turbine exhaust, which increases the combustion turbine backpressure. This results in more energy being expended to force air through the turbine, thus reducing the turbine power output. According to EPA, the backpressure from SCR reduces turbine output by approximately 0.5 percent of the turbines design output (USEPA 1993c).
- **Economic Impacts:** The annualized cost of a SCR system is \$1,227,962 resulting in a cost per ton of NO_x removed of \$3,402.

SCONO_xTM:

- **Environmental Impacts:** Unlike the SCR system, there are no ammonia emissions associated with the SCONO_xTM system.
- **Energy Impacts:** As with SCR, the greater the catalyst volume, the higher the pressure drop. The presence of the SCONO_xTM system in the HRSG introduces added resistance to the turbine exhaust, which increases the combustion turbine backpressure. This results in more energy being expended to force air through the turbine, thus reducing the turbine power output. The pressure drop associated with the SCONO_xTM system is greater than that associated with the proposed SCR and oxidation catalyst systems.

- Economic Impacts:** The annualized cost of a SCONOX™ system is \$4,757,834 resulting in a cost per ton of NO_x removed of \$12,521. The costs for SCONOX™ are unreasonably high and the Satsop CT Project is proposing to use proven pollution control technologies that achieve an emission rate nearly equivalent to those targeted with SCONOX™.

Appendix C contains worksheets with the details of the cost analyses.

Selected BACT

Although there can be adverse effects using SCR control technology, previous BACT determinations in Washington state indicate that SCR is required to reduce NO_x emissions to levels of 2.5 ppmvd or lower. The Satsop CT Project is located in an attainment area for ozone, and the implementation of this technology should not significantly contribute to ozone levels. Using a combination of the most advanced dry low-NO_x combustor technology with SCR control technology provides a significant amount of NO_x reduction to a level of 2.5 ppmvd at 15 percent O₂. The proposed NO_x emission limits are shown in Table 6.1-12.

**TABLE 6.1-12
PROPOSED BACT NO_x EMISSION LIMITS FOR EACH PGU^{(a), (b)}**

Pollutant	Emissions (ppmvd) at 15% O₂	Emissions (lb/hr)
NO _x	2.5	21.7

^(a)These emission limits apply to CT loads ≥ 50%.

^(b)Emissions provided by Duke/Fluor-Daniel.

Sulfur Dioxide

SO₂ emissions from gas turbines are a function of the sulfur content of the fuel, with virtually all fuel sulfur converted to SO₂. Coal generally has the highest sulfur content, followed by crude oils, sewage gas, waste fuels, and refined fuel oils (including No. 2). Natural gas has only trace amounts of sulfur. This section describes available control equipment and the BACT analysis for sulfur dioxide.

Available Control Technologies

The RBLC search completed for SO₂ is summarized in Table 6.1-13. Other technically feasible control technologies are two typical flue gas desulfurization processes: wet and dry scrubbing. These control technologies are described below.

**TABLE 6.1-13
RBLC SEARCH RESULTS FOR SO₂ - TURBINES**

Facility^(a)	Emissions	Pollution Control	Basis
Calpine Corporation	1 ppmvd, calendar day average	Natural gas fuel	
Casco Ray Energy Co	0.006 lb/MMBtu		BACT-PSD
Champion International Corp. & Champ. Clean Energy	12 lb/hr		BACT-OTHER
Duke Energy New Smyrna Beach Power Co. L.P.	0.02 gr/dscf gas	Natural gas only	BACT-PSD
Ecoelectrica, L.P.	No Data Available	Fuel spec: LNG/LPG as primary fuel, 0.04% sulfur no. 2 oil as backup fuel.	BACT-PSD
La Paloma Generating Co. LLC	3.73 lb/hr	Natural gas fuel, 0.75 grains of sulfur per 100 dscf	
Lordsburg L.P.	2.8 lb/hr	Use of sweet natural gas and no.2 diesel fuel with less than 0.05% by wt. of sulfur	BACT-PSD
Oleander Power Project	0.01 gr/dscf gas	Natural gas or low sulfur diesel	BACT-PSD
Tiverton Power Associates	0.006 lb/MMBtu	Fuel spec: natural gas fired	BACT-PSD
TN Valley Authority Lagoon Creek Combustion Turbine	0.0006 lb/MMBtu	Low sulfur fuels and annual production limits	BACT-PSD
Seminole Hardee Unit 3	1 gr/100 scf gas	Fuel spec: low sulfur fuel oil or natural gas fuel; combustion of clean fuels	BACT-PSD
Southwestern Public Service Co/Cunningham Station	No Data Available	Sweet pipeline natural gas	BACT-PSD
Southwestern Public Service Company/Cunningham Station	No Data Available	Sweet pipeline natural gas	BACT-PSD
Westbrook Power LLC	0.006 lb/MMBtu		BACT-PSD

^(a) See Table 6.1-8 for locations.

Wet Scrubbing

In this process, the exhaust gas is passed through a spray tower scrubber. Wet scrubbing devices work on the principle of reacting a liquid-phase reagent with the SO₂ in the exhaust stream to form various end products (depending on the type of reagent used). Optimum process temperatures are approximately 100°F to 140°F. Thus, some type of gas cooling is usually required upstream of the spray tower scrubber. Because some of the slurry is entrained by the gas as small droplets, the exhaust stream leaving the scrubber is normally passed through a mist eliminator to remove the droplets and return them to the scrubber. The exhaust gas is then directed to a stack.

Limestone is the most frequently used reagent in wet scrubbing systems as the cost is much less than that of either lime or sodium carbonate. Wet scrubbing devices are predominately used in coal-fired boiler facilities as well as some chemical plants and kraft pulp mills.

Dry Scrubbing

A dry scrubber removes SO₂ by mixing the flue gas with an atomized slurry in a spray dry scrubber. The water in the slurry evaporates, and the SO₂ is subsequently absorbed by the remaining fine solids. Reaction temperatures are maintained slightly above the gas dew point by controlling the amount of water in the slurry. The cleaned gases are then routed to the exhaust stack or particulate capturing/collection device.

This technology is mainly used in large coal-fired utility boilers. The reagent used in these systems is usually lime since it is more readily available and cheaper than sodium carbonate.

Fuel Specification

Natural gas is considered a clean fuel containing only trace amounts of sulfur (USEPA 1985b). Natural gas is the only fuel for this project.

Evaluation of Technical Feasibility

Wet Scrubbing

Wet scrubbing is widely used in large coal-fired boilers, kraft pulp mill, and other large chemical processing plants. However, it has never been implemented on a natural gas-fired combustion turbine facility. Most combustion turbine facilities are small and the pressure drops imposed by wet scrubbing applications would be a severe operational constraint. An induced draft fan or similar device would be required to overcome the pressure drop in the exhaust system. This may cause PGU operation problems with a fan drawing exhaust gas from the turbine and with the air/fuel ratio controls in the combustor. There is no commercial experience with exhaust gas blowers in natural gas-fired combustion turbine equipment trains. For these reasons, wet scrubbing is considered technically infeasible for this project.

Dry Scrubbing

Dry scrubbing is also primarily used with large utility coal-fired boilers and has never been implemented on a natural gas-fired combustion turbine system. As with wet scrubbing, this technology would impose excessive pressure drop constraints on a combustion turbine facility. Thus, this technology is considered technically infeasible for the same reason as presented for wet scrubbers and is not evaluated any further in this BACT analysis.

Fuel Specification

Natural gas fuel will be the only fuel used for the PGUs.

Control Technology Hierarchy

The only SO₂ control remaining in this BACT analysis, and the only one known to be implemented on natural gas-fired combustion turbines, is fuel specification. Natural gas is the only fuel that will be used at the Satsop CT Project.

Selected BACT

The exclusive use of natural gas for the combustion turbines is considered BACT for controlling SO₂ emissions. The proposed SO₂ emissions for the Satsop CT Project are representative of RACT/BACT/LAER determinations. The proposed SO₂ emission limits are shown in Table 6.1-14.

**TABLE 6.1-14
PROPOSED BACT SO₂ EMISSION LIMITS FOR EACH PGU^{(a), (b)}**

Pollutant	Emissions (ppmvd) at 15% O₂	Emissions (lb/hr)
SO ₂	0.11	1.3

^(a)These emission limits apply to CT loads \geq 50%.

^(b)Emissions provided by Duke/Fluor-Daniel.

Carbon Monoxide and Volatile Organic Compounds

CO is a product of incomplete combustion, where oxygen is not present in sufficient quantities to fully oxidize the fuel. In addition, CO emission levels are a direct function of the air/fuel ratio. Combustion inefficiencies introduced by combustion modifications for NO_x control increase the generation of CO. VOC emissions are also products of incomplete combustion. Some VOCs are involved in the process of ozone formation.

Available Control Technologies

Control technologies for CO and VOC can be classified as combustion modifications or post-combustion controls. Tables 6.1-15 and 6.1-16 list the control technologies available for the control of CO and VOC, respectively. This section describes each technology and its technical feasibility for controlling these contaminant emissions from a natural gas-fired combustion turbine.

**TABLE 6.1-15
RBLC SEARCH RESULTS FOR CO - TURBINES**

Facility^(a)	Emissions	Pollution Control	Basis
Alabama Power Company - Theodore Cogeneration	0.086 lb/MMBtu	Efficient combustion	BACT-PSD
Alabama Power Plant Barry	0.057 lb/MMBtu	Efficient combustion	BACT-PSD
Blue Mountain Power, LP	3.1 ppm @ 15% O ₂	Oxidation catalyst, 16 ppm @ 15% O ₂ when firing No. 2 oil. At 75% NG Limit Set To 22.1 ppm	OTHER
Bridgeport Energy, LLC	10 ppm	Pre-mix fuel fair to optimize efficiency. Actual emissions expected between 5-7 ppm	BACT-PSD
Calpine Corporation	4 ppm	Oxidation catalyst	
Casco Ray Energy Co	20 ppm @ 15% O ₂	15% excess air	BACT-PSD
Champion International Corp. & Champ. Clean Energy	9 ppmvd @15% O ₂		BACT-OTHER
Duke Energy Luna Energy Facility	17.2 ppm	Natural gas only and good combustion practices	BACT-PSD
Duke Energy New Smyrna Beach Power Co. LP	12 ppm	Good combustion	BACT-PSD
Ecoelectrica, L.P.	33 ppmvd	Combustion controls.	BACT-PSD
La Paloma Generating Co. LLC	6 ppm	Catalytic oxidizer	
Lordsburg L.P.	27 lbs/hr	Dry low-NO _x technology by maintaining proper air-fuel ratio.	BACT-PSD
Mid-Georgia Cogen.	10 ppmvd, Gas	Complete combustion	BACT-PSD
Oleander Power Project	12 ppm @ 15% O ₂	Good combustion	BACT-PSD
Puerto Rico Electric Power Authority (PREPA)	20 lb/hr	Maintain each turbine in good working order and implement good combustion practices.	BACT-PSD
Public Service Of Colo.- Fort St Vrain	15 ppmvd	Good combustion control practices. Commitment to a pattern of operation (load variations, etc.) to minimize operation at high emissions.	BACT-PSD
Santa Rosa Energy LLC	Data Not Available	Dry low NO _x burner good combustion practice	BACT-PSD
Seminole Hardee Unit 3	20 ppm	Dry LNB good combustion practices	BACT-PSD
Southern Energy, Inc.	0.042 lb/MMBtu	Good combustion practice required.	BACT-PSD
Southwestern Public Service Company/Cunningham Station	Data Not Available	Good combustion practices	BACT-PSD
Tenuska Georgia Partners, L.P.	15 ppmvd @ 15% O ₂		BACT-PSD
Tiverton Power Associates	12 ppm @ 15% O ₂	Good combustion	BACT-PSD
TN Valley Authority Lagoon Creek Combustion Turbine	25 ppm @ 15% O ₂	Annual production limits	BACT-PSD
Westbrook Power LLC	15 ppm @15% O ₂	Using 15% excess air	BACT-PSD
Wyandotte Energy	3 ppm	Catalytic oxidizer	LAER

^(a)See Table 6.1-8 for locations

**TABLE 6.1-16
RBLC SEARCH RESULTS FOR VOCs - TURBINES**

Facility	Emissions	Pollution Control	Basis
Alabama Power Company - Theodore Cogeneration	0.016 lb/MMBtu	Efficient combustion	BACT-PSD
Alabama Power Plant Barry	0.015 lb/MMBtu	Efficient combustion	BACT-PSD
Blue Mountain Power, LP	4 ppm @ 15% O ₂	Oxidation catalyst when firing No. 2 oil emission limit = 4.4 ppmvd @ 15% O ₂ . @ 75% load, alternate gas limit 7.6 ppm	LAER
Calpine Corporation	1 ppmvd		BACT
Casco Ray Energy Co	1 ppm	Low NO _x burner	BACT-PSD
Champion International Corp. & Champ. Clean Energy	3 lb/hr		BACT-Other
Commonwealth Chesapeake Corporation	38.9 tpy	Good combustion operating practices	BACT/NSPS
Duke Energy Luna Energy Facility	19.7 lb/hr	Good combustion design and control	BACT-PSD
Ecoelectrica, L.P.	5 ppmvd	Combustion controls.	BACT-PSD
La Paloma Generating Co. LLC	2.8 lb/hr		BACT
Mid-Georgia Cogen.	6 ppmvd	Complete combustion	BACT-PSD
Public Service Of Colo.- Fort St Vrain	1.4 ppmvd	Good combustion control practices.	BACT-PSD
Puerto Rico Electric Power Authority (PREPA)	13 lb/hr (as methane)	Maintain each turbine in good working order and implement good combustion practices.	BACT-PSD
Puerto Rico Electric Power Authority (PREPA)	11 lb/hr (as methane)	Maintain each turbine in good working order and implement good combustion practices.	BACT-PSD
TN Valley Authority Lagoon Creek Combustion Turbine	1.4 ppm @ 15% O ₂	Annual production limits	BACT-PSD
Southern Energy, Inc.	0.008 lb/MMBtu	Good combustion practice.	BACT-PSD
Southwestern Public Service Co/Cunningham Station	Data Not Available	Good combustion practices	BACT-PSD
Southwestern Public Service Company/Cunningham Station	Data Not Available		BACT-PSD
Tiverton Power Associates	2 ppm @ 15% O ₂	Good combustion	BACT-PSD
Tenuska Georgia Partners, L.P.	0.03 lb/MMBtu		BACT-PSD
Westbrook Power LLC	0.4 ppm @ 15% O ₂		BACT-PSD

^(a)See Table 6.1-8 for locations.

Combustion Modifications

The most practical approach for reducing CO and VOC emissions is maximizing the efficiency of fuel combustion by proper design, installation, operation, and maintenance of the turbine combustor. Efficient combustion reduces the amount of fuel required to generate a given amount of power, thereby decreasing the generation of CO and VOC.

Steam/water injection for NO_x emission control increases the generation of CO emissions. Using the dry low-NO_x combustors will not increase the formation of CO at base load.

Post-Combustion Controls

CO and VOC generated during combustion can be reacted with excess oxygen in the exhaust gas (oxidized), forming CO₂ and H₂O. There are two general post-combustion control methods: thermal oxidation and catalytic oxidation. Thermal oxidation uses a flame to incinerate the pollutants. Catalytic oxidation uses a catalyst to effect oxidation at the lower temperatures of the exhaust gases. In addition to oxidation, organic contaminants can be removed from gas streams using adsorption, condensation, or absorption technologies. However, these technologies are suited for gas streams containing much larger concentrations of hydrocarbons than found in the PGU exhaust streams.

- **Thermal Oxidation:** Thermal oxidation, also called direct-flame or direct-fired afterburners, uses an afterburner to combust the CO and VOC in the exhaust steam. Since the exhaust gas from PG units contains insufficient VOCs to sustain incineration, supplemental fuel is required in the afterburner. The gas is passed through the combustion zone of the flame at a typical temperature range of 1000°F to 1500°F. As with other combustion systems, thermal oxidation combustors must be designed to provide sufficient residence times at high temperatures with adequate turbulence for efficient combustion. The high combustion temperatures used in the thermal oxidation process produce more NO_x emissions than with catalytic oxidation. Thermal oxidation units are usually located prior to heat recovery process equipment to recover some of the energy released by the supplementary fuel. Organic contaminant removal efficiencies in excess of 95 percent can be achieved; however, emissions of CO₂ and NO_x increase. Although capital costs are relatively low, supplementary fuel costs drive operating costs up.
- **Catalytic Oxidation:** Catalytic oxidation also uses heat to oxidize CO and VOCs. This approach promotes the oxidation of CO to CO₂ without the use of reagents. Effective CO conversion occurs in the range of 700°F to 1200°F. The temperature of turbine exhaust gas is sufficient for catalytic oxidation without requiring supplemental fuel. The reduced residence time required for catalytic oxidation eliminates the need for an afterburner combustion chamber, and a flame is not generated since the gas temperatures are below the auto-ignition temperature. Other forms of catalysts such as metal mesh or pellets are

available but are not as effective as the monolithic form and introduce high pressure drops to the exhaust duct system.

Capital costs are about 40 percent higher than those of thermal oxidation, while operating costs are lower since supplementary fuel is not required. Catalysts generally require regeneration or cleaning every 3 to 6 years. However, commercial experience with oxidation catalysts installed on natural gas-fired combustion turbines reveals that catalyst cleaning or regeneration is seldom required. Since oxidation occurs on the catalyst sites, fouling of the sites by sulfur combustion products or significant amounts of particulates will reduce the catalyst removal efficiency.

- **Carbon Adsorption:** Carbon adsorption is a process by which organics are captured on the surface of granular solids. Common adsorbents include activated carbon, silica gel, and alumina. Adsorbents can be regenerated in place using steam or hot air, producing a secondary waste stream. The adsorption process is not effective, however, at temperatures below 100°F, and high concentrations of volatile organic compounds (>1,000 ppm) are required to achieve removal efficiencies on the order of 95 percent.
- **Condensation:** Condensation is another technology used to separate and remove organic contaminants from gas streams. This process involves reducing the temperature of the gas stream to below the saturation temperature of the contaminants, allowing the organics to condense, and collecting the liquid phase. Like the adsorption process, condensation is only effective for gases with high concentrations of organics, capable of achieving 95 percent removal for concentrations above 5,000 ppm. This process is used primarily for product recovery in chemical process lines.
- **Absorption:** Absorption is another removal technology developed for gas streams containing high concentrations of organics (>500 ppm). Water or organic liquids serve as the liquid absorbent used in packed towers, spray chambers, or venturi scrubbers. The gradient between the actual and the equilibrium concentration of the organics in the absorbent drives the migration of the organics in the gas stream to the absorbent liquid, and is typically enhanced at lower temperatures. The saturated liquid becomes a secondary waste stream.

Evaluation of Technical Feasibility

Both thermal and catalytic oxidation are considered technically feasible for the removal of CO and VOCs from the exhaust gas stream of a combustion turbine. The expected concentrations of organic compounds are too low for adsorption, condensation, or absorption to be considered technically feasible.

Control Technology Hierarchy

Both thermal and catalytic oxidation are considered technically feasible for the control of CO and VOCs emitted from a combustion turbine. Both technologies can achieve over 95 percent total organic contaminant removal efficiencies given optimum inlet concentrations, oxidation temperatures, and combustor or catalytic design. Catalysts are susceptible to poisoning or fouling by certain compounds in the exhaust gas which will reduce control efficiency. Sulfur compounds have been the most troublesome in the combustion of some fuel oils, solid fuels, and sewer gas. However the combustion products from burning clean fuels such as natural gas are not expected to affect the performance of an oxidation catalyst. Using an oxidation catalyst, 80 to 90 percent removal efficiencies can be achieved for CO removal from the combustion turbine's exhaust gas, and 30 to 90 percent for VOCs emitted from a combustion turbine. Catalyst vendors normally do not guarantee VOC removal rates. Specific hydrocarbon destruction efficiencies are unique to each installation as they are influenced by temperature, concentration, and exhaust gas composition; however, destruction efficiencies of 80 to 90 percent can be achieved for benzene and formaldehyde in gas turbine installations.

Comparable destruction efficiencies can be obtained using thermal oxidation, although there are environmental and economic disadvantages to thermal oxidation. Because the VOC concentration in turbine exhaust gas is too low to sustain combustion, supplemental fuel must be supplied, which increases costs and produces additional combustion products, including CO₂ and NO_x. In comparison to catalytic oxidation, thermal oxidation produces higher NO_x emissions as a combustion product since the oxidation (flame) temperature is much higher. Because of these environmental impacts, catalytic oxidation is ranked as the more effective control technology.

BACT Determination

The highest ranking control technology for CO and VOCs is catalytic oxidation. Because the conversion efficiency is tied directly to residence time, it can be increased by adding more catalyst material. Limitations to destruction efficiencies, therefore, become integral with the design of the exhaust system including space limitations. Economics ultimately limit the volume of catalytic material for a given project.

Catalytic Oxidation:

- **Environmental Impacts:** Environmental impacts of using catalytic oxidation involve the disposal of the catalyst and additional products of combustion. The catalyst used to control CO in a gas turbine installation can become masked by compounds in the exhaust gas and may require thermal or chemical cleaning to expose the clogged reaction sites. Catalyst cleaning or regeneration, instead of disposal and replacement, minimizes waste associated with declining performance. As with other combustion processes, NO and other compounds containing nitrogen are converted to NO_x during catalytic oxidation. However, this is minimized by catalytic oxidation since oxidation occurs at low

temperatures. Because the SCR process injects ammonia into the exhaust stream, the oxidation catalyst is typically located upstream of the SCR unit to avoid unnecessary NO_x generation. In summary, there are only minor environmental impacts associated with catalytic oxidation.

- **Energy Impacts:** The application of catalytic oxidation technology to a gas turbine will result in an increase in backpressure on the combustion turbine due to pressure drop across the catalyst bed. The increase in backpressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate.
- **Economic Impacts:** An economic evaluation of a standard catalytic oxidation installation as compared with the SCONO_xTM oxidation is provided in Appendix C. The standard catalytic oxidation system has an annualized cost of \$500,000 and with 80 percent control efficiency, the cost per ton of CO removed is \$1,792. For VOC control, the annualized cost of \$500,000 with 80 percent control efficiency yields a cost per ton of VOC removed of \$21,739. While the cost for CO control is within the range of acceptable costs, the costs for VOC control are excessive.

The SCONO_xTM system contains an oxidation catalyst which theoretically achieves a 90% reduction in CO and VOC emissions. The SCONO_xTM system has an annualized cost of \$4,757,834. Although a "total pollutant" comparison is not usually performed for a BACT costing analysis, one is provided here to demonstrate the cost effectiveness of the proposed control systems with the SCONO_xTM system. The total of pollutants (CO, VOC, and NO_x) that can theoretically be controlled by a single SCONO_xTM system is 715 tons per year. Additionally, 70 tons of ammonia, each year, would not be emitted; hence, the total tons of pollutants removed is 785 tons. This yields a cost per ton of pollutant removed of \$6,061 for the SCONO_xTM system. This cost is outside the range of acceptable costs as previously determined by Ecology and EPA. The proposed control systems (SCR and CO oxidation catalyst) can remove 640 tons per year yielding a cost per ton of pollutant removed of \$2,700 which is within the range of acceptable costs.

Selected BACT

Catalytic oxidation, the most effective proven control technology, has been selected as BACT for the Satsop combustion turbines. Table 6.1-17 presents the control efficiencies for catalytic oxidation. The proposed CO emission limits are shown in Table 6.1-18.

Particulate Matter

Particulate matter (PM) emissions arise primarily from non-combustible metals present in trace quantities in liquid fuels. Other sources of particulate matter include condensable unburned organics and particles in the combustion air and ammonium bisulfate and ammonium sulfate compounds from the SCR/CO catalyst. These are included in PM emission estimates.

TABLE 6.1-17
CO REMOVAL EFFICIENCY FOR CATALYTIC OXIDATION FOR EACH PGU^(a)

	Uncontrolled Emissions	Catalytic Oxidation
CO ppmvd @ 15% O ₂	9 ^{(b)(c)}	2 ^(b)
CO emitted (lb/hr)	47.7	10.6 ^(b)

^(a)Based on 100 percent CT load.

^(b)Emissions provided by GE and Duke/Fluor-Daniel.

^(c)Based on turbine with dry low-NO_x combustors.

TABLE 6.1-18
PROPOSED BACT CO AND VOC EMISSION LIMITS FOR EACH PGU^{(a), (b)}

Pollutant	Emissions (ppmvd) at 15% O₂	Emissions (lb/hr)
CO	2	10.6
VOC ^(c)	2.78	8.4

^(a)These emission limits apply to CT loads ≥ 50%.

^(b)Emissions provided by Duke/Fluor-Daniel.

^(c)VOC emissions consider no reduction due to catalytic oxidation.

Available Control Technologies

This section describes control technologies available for the control of particulate matter emissions and their technical feasibility specific to a natural gas-fired combustion turbine. Table 6.1-19 presents the results of the RBLC search for particulate matter control technologies for projects similar to the proposed Satsop CT Project. Control methods can be grouped into two categories: (1) pre-combustion and combustion controls, and (2) post-combustion controls. As described below, pre-combustion and combustion controls include the use of clean-burning fuels and post-combustion controls include electrostatic precipitators and fabric filters.

Clean Fuels and Combustion Control

The use of clean burning fuels such as natural gas limits the presence of non-combustible metals in the fuel, consequently fewer particulates are formed during combustion. Efficient combustion, maintained by controlling (1) the air/fuel ratio and combustor staging sequences, and (2) the ambient conditions of the inlet air and plant loading requirements, ensure the minimum amount of condensable unburned organics are emitted. Combustion controls enable the combustion turbines to minimize fuel consumption as well, which in turn minimizes particulate emissions.

**TABLE 6.1-19
RBLC SEARCH RESULTS FOR PARTICULATE MATTER - TURBINES**

Facility^(a)	Emissions	Pollution Control	Basis
Alabama Power Company - Theodore Cogeneration	0.012 lb/MMBtu	Combustion of natural gas only	BACT-PSD
Alabama Power Plant Barry	0.011 lb/MMBtu	Natural gas only, efficient combustion	BACT-PSD
Champion International Corp. & Champ. Clean Energy	0.06 lb/MMBtu		BACT-Other
Champion International Corp. & Champ. Clean Energy	9 lb/hr		BACT-Other
Casco Ray Energy Co	0.06 lb/MMBtu		BACT-PSD
Duke Energy Luna Energy Facility	34.2 lb/hr front and back half emissions	Natural gas firing only	BACT-PSD
Ecoelectrica, L.P.	12 lb/hr	Maintain each turbine in good working order and implement good combustion practices. Fuel spec: use of NG/LPG.	BACT-PSD
La Paloma Generating Co. LLC	17.2 lb/hr	Combusting natural gas	
Lordsburg L.P.	5.3 lb/hr	High combustion efficiency use of No.2 low sulfur fuel oil (less than 0.05% by wt.)	BACT-PSD
Mid-Georgia Cogen.	18 lb/hr	Clean fuel	BACT-PSD
Public Service Of Colo.- Fort St Vrain	9 lb/hr	Fuel spec: combustion of pipeline quality gas. Close monitoring and control of the combustion process.	BACT-PSD
Puerto Rico Electric Power Authority (PREPA)	55 lb/hr	Maintain each turbine in good working order and implement good combustion practices.	BACT-PSD
Seminole Hardee Unit 3	7 lb/hr	Dry LNB fuel spec: low sulfur oil, limited operation on oil. Good combustion	BACT-PSD
Southern Energy, Inc.	14.7 lb/hr	Equivalent to 0.007 ppm @ 15% O ₂ . Rate is per turbine. 10% Opacity.	BACT-PSD
Southwestern Public Service Company/Cunningham Station	No Data Available		BACT-PSD
Southwestern Public Service Co/Cunningham Station	No Data Available	Good combustion practices	BACT-PSD
Tenuska Georgia Partners, L.P.	0.01 lb/MMBtu		BACT-PSD
Tiverton Power Associates	0.0089 lb/MMBtu	Good combustion	BACT-PSD
TN Valley Authority Lagoon Creek Combustion Turbine	7.35 lb/hr	Annual production limit(s).	BACT-PSD
Westbrook Power LLC	0.06 lb/MMBtu		BACT-PSD
Westplains Energy	No Data Available	Fuel spec: use of pipeline quality natural gas and good combustion controls to minimize PM emissions.	BACT-PSD
Westbrook Power LLC	0.06 lb/MMBtu		BACT-PSD

^(a)See Table 6.1-8 for locations.

Post-Combustion Controls

Electrostatic precipitators and fabric filters are used on solid fuel boilers and incinerators to remove large quantities of particulate matter and ash from the flue gas of solid fuel combustion. Electrostatic precipitators use a high voltage direct current corona to electrically charge particles in the gas stream. The suspended particles are attracted to collecting electrodes of opposite polarity. These electrodes are typically plates suspended parallel with the gas flow. Particles are collected and disposed of by mechanically rapping the electrodes and dislodging the particles into the hoppers below.

Baghouses are used to collect particulate matter by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags which are periodically shaken to release the particulates into hoppers.

Both technologies impose a significant pressure drop through the exhaust gas stream, requiring fans to blow the hot gases through the particulate control device and out the stack. Because particulate emissions from gas turbines are below the BACT control levels achievable using fabric filters and electrostatic precipitators (0.01 grains per standard cubic foot [gr/scf]), particulate control equipment has not been proposed for the back end of a combustion turbine.

Control Technology Hierarchy

The use of clean fuels and combustion control are technically feasible for particulate emissions from natural gas-fired combustion turbines. Particulate emissions from natural gas are much less than the levels of particulate control possible using control technologies such as electrostatic precipitators and fabric filters. The combination of clean burning fuels with combustion control is considered the most effective particulate control technology for natural gas-fired combustion turbines.

BACT Determination

Minimizing particulate emissions is achieved by operating on natural gas only and utilizing the most fuel-efficient combustion conditions.

Selected BACT

A review of the comparable gas turbine installations in the RBLC identifies combustion control as the only control technology required. The proposed particulate matter emissions for the Satsop CT Project are representative of RACT/BACT/LAER determinations. The estimated particulate emissions for the Satsop CT Project are listed in Table 6.1-20.

**TABLE 6.1-20
PROPOSED BACT PM₁₀ EMISSION LIMITS FOR EACH PGU^(a)**

Pollutant	Emissions (lb/day)
PM ₁₀	583.2 (front and back half)

^(a)This emission limit applies to loads \geq 50%.

6.1.6.3 Cooling Towers

Wet cooling towers utilize air passage through the cooling water to cool the water for reuse. This direct contact between the cooling water and the air passing through the tower results in entrainment of some of the liquid water in the air stream. The entrained water is carried out of the tower as “drift” droplets. The drift droplets generally contain the same chemical impurities and additives as the water circulating through the tower. These impurities and additives can be converted to airborne emissions as the water in the drift droplets evaporate and leaves fine particulate matter formed by crystallization of dissolved solids.

As part of certain processes, water is used to remove heat from hydrocarbon-carrying streams. Equipment (e.g., leaking heat exchangers) can introduce small quantities of VOCs into the cooling water stream. These VOCs are then emitted from the cooling towers as a result of the direct contact air passage through the towers. The Satsop CT Project, however, does not have any hydrocarbon-carrying streams. Consequently, no quantifiable VOC emissions are expected from this source. Thus, the BACT analysis for cooling towers focuses on PM₁₀ emissions only.

A review of EPA’s RBLC database was conducted cooling towers. The source type “miscellaneous sources” was searched for all entries where permits or latest updates were made after January 1, 1990. The RBLC review revealed that the control technique for PM₁₀ emissions from cooling towers is drift eliminators, as shown in Table 6.1-21.

**TABLE 6.1-21
RBLC SEARCH RESULTS FOR COOLING TOWERS**

Facility ^(a)	Emissions	Pollution Control	Basis
Duke Energy Luna Energy Facility	0.001% of Flow	High Efficiency Drift Eliminators	BACT-Other
Ecoelectrica, L.P.	0.0015% of Flow	Two Stage Mist Eliminator To Restrict Drift.	BACT-Other

^(a)Table 6.1-8 for locations.

Drift eliminators are usually incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower. The drift eliminators used in cooling towers rely on the inertial separation caused by directional changes in the airflow while passing through the eliminators. Types of drift eliminator configurations include herringbone (blade-type), wave form, and cellular (or honeycomb) designs. The cellular units generally are the most efficient. Drift eliminators may include various materials, such as ceramics, fiber reinforced cement, fiberglass, metal, plastic, and wood installed or formed into closely spaced slats, sheets, honeycomb assemblies, or tiles. The materials may include other features, such as corrugations and water removal channels, to enhance the drift removal further.

Two-stage, low-drift eliminators (0.001 percent of flow) have been selected as BACT for the proposed cooling tower. Because the PM₁₀ emissions from the cooling tower cannot be measured, it is proposed that the requirement to install and operate drift eliminators constitute BACT for the cooling tower.

6.1.6.4 Auxiliary Boiler

Air emissions from natural gas-fired boilers include NO_x, CO, PM₁₀, SO₂, and VOCs. A BACT analysis was performed for each of these pollutants.

A review of EPA's RBLC database was conducted for the proposed auxiliary boiler. The source types "boilers," "heaters," and "furnaces" were searched for all entries where permits or latest updates were made after January 1, 1995. The proposed auxiliary boiler is rated at 29.3 MMBtu/hr. Therefore, boilers, heaters, or furnaces rated at greater than 100 MMBtu/hr were not considered to be applicable to the BACT review; this approach is consistent with the emission calculation approach for boilers provided in AP-42, Section 1.4 (USEPA 1985b). Lastly, only those control technologies installed on the basis of BACT were evaluated; control technologies installed as the result of LAER were not considered. Table 6.1-22 presents a summary of permit determinations for natural gas-fired boilers comparable to the auxiliary boiler proposed for the Satsop CT Project.

The results of the BACT analysis for each pollutant are described below.

Nitrogen Oxides

This section addresses the available control alternatives for NO_x emissions.

Available Control Technologies

The RBLC search completed for NO_x is summarized in Table 6.1-23. The available NO_x control technologies for natural gas-fired boilers are briefly described below.

**TABLE 6.1-22
RBLC SEARCH RESULTS FOR RECENT PROJECTS INCLUDING
BOILERS, HEATERS, AND FURNACES**

Facility	Location	EPA Region	Permit Date or Last Update	Size (each unit)
Air Liquide America Corporation	Geismar, LA	6	1/20/1999	95 MMBtu/hr
American Soda, LLP	Parachute, CO	8	5/6/1999	80.8 MMBtu/hr
Anniston Army Depot	Anniston, AL	4	5/17/2000	13.4 MMBtu/hr
Anniston Army Depot	Anniston, AL	4	5/17/2000	11.7 MMBtu/hr
Boise Cascade Corporation - Yakima Complex	Yakima, WA	10	8/22/1997	800 hp
Cargill Inc - Sioux City	Sioux City, IA	7	12/10/1999	77 MMBtu/hr
Champion International	Courtland, AL	4	3/24/1995	5.83 MMBtu/hr
Chem Process Incorporated	Norco, LA	6	3/24/1995	5.83 MMBtu/hr
Doctors Medical Center	Modesto, CA	9	8/17/1999	3.78 MMBtu/hr
Doswell Limited Partnership	VA	3	3/24/1995	40 MMBtu/hr
Duke Energy Luna Energy Facility	Deming, NM	6	12/29/2000	44.1 MMBtu/hr
Exxon Company, Usa Santa Ynez Unit Project	CA	9	8/19/1996	95 MMBtu/hr
H&H Heat Treating	Santa Fe Springs, CA	9	4/19/1999	7 MMBtu/hr
I/N Kote	Carlisle, IN	5	3/24/1995	70.8 MMBtu/hr
Indeck Energy Company	Silver Springs, NY	2	3/31/1995	0 MMBtu/hr
Indeck-Yerkes Energy Services	Tonawanda, NY	2	3/31/1995	99 MMBtu/hr
Indelk Energy Services Of Otsego	MI	5	4/5/1995	99 MMBtu/hr
Intel Corporation	Chandler, AZ	9	3/24/1995	50 MMBtu/hr
International Flavors And Fragrances	Union Beach, NJ	2	2/11/1999	96 MMBtu/h
JVC Magnetics America Co.	Tuscaloosa, AL	4	5/29/1995	5.2 MMBtu/hr
Kalkan Foods Inc.	Vernon, CA	9	2/25/2000	78.59 MMBtu/hr
Kamine/Besicorp Syracuse LP	Solvay, NY	2	4/27/1995	2.5 MMBtu/hr
Kamine/Besicorp Syracuse LP	Solvay, NY	2	4/27/1995	33 MMBtu/hr
Louisiana Land and Exploration Company - Lost Cabin	Lost Cabin, WY	8	5/12/1999	2,280 scfh
Louisiana Land and Exploration Company - Lost Cabin	4 miles E-NE of Lysite, WY	8	5/12/1999	22.89 MMBtu/hr
Mid-Georgia Cogen.	Kathleen, GA	4	8/19/1996	60 MMBtu/hr
Milagro, Williams Field Service	Bloomfield, NM	6	5/29/1995	0
Minnesota Corn Processors	Marshall, MN	5	5/31/1996	0

TABLE 6.1-22 (Continued)
RBLC SEARCH RESULTS FOR RECENT PROJECTS INCLUDING
BOILERS, HEATERS, AND FURNACES

Facility	Location	EPA Region	Permit Date or Last Update	Size (each unit)
Montana Refining Company	Great Falls, MT	8	6/17/1999	0.75 MMBtu/hr
Orange Cogeneration Lp	Bartow, FL	4	1/13/1995	100 MMBtu/hr
Paramount Farms	Lost Hills, CA	9	3/24/1995	0.29 MMBtu/hr
Proctor and Gamble Paper Products Co (Charmin)	Mehoopany, PA	3	11/27/1995	69.7 MMBtu/hr
Qualitech Steel Corp.	Pittsboro, IN	5	5/31/1997	67.5 MMBtu/hr
Quincy Soybean Company Of Arkansas	Helena, AR	6	3/10/1999	68 MMBtu/hr
Sitix Of Phoenix, Inc.	Phoenix, AZ	9	2/27/1996	42 MMBtu/hr
Solvay Soda Ash Joint Venture Trona Mine/Soda Ash	Green River, WY	8	2/17/1999	100 MMBtu/hr
Stafford Railsteel Corporation	West Memphis, AR	6	3/24/1995	46.5 MMBtu/hr
Sunland Refinery	Bakersfield, CA	9	3/24/1995	12.6 MMBtu/hr
Toyota Motor Corporation Svcs Of N.A.	Princeton, IN	5	10/21/1996	58 MMBtu/hr
Transamerican Refining Corporation	Norco, LA	6	4/17/1995	95 MMBtu/hr
Transamerican Refining Corporation (Tarc)	New Sarpy, LA	6	3/24/1995	0 MMBtu/hr
Transamerican Refining Corporation (Tarc)	New Sarpy, LA	6	3/24/1995	1.2 MMBtu/hr
Waupaca Foundry - Plant 5	Tell City, IN	5	5/31/1996	93.9 MMBtu/hr

Low NO_x Burners

Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. Utilizing low NO_x burners is a combustion control method that reduces the peak temperature in the combustion zone, reduces the gas residence time in the high-temperature zone, and provides a rich fuel/air ratio in the primary flame zone. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emissions levels) have been observed with low NO_x burners.

**TABLE 6.1-23
RBLC SEARCH RESULTS FOR NO_x - BOILERS**

Facility	Emissions	Pollution Control	Basis
Air Liquide America Corporation	0.05 lb/MMBtu	Low NO _x burners	BACT-PSD
American Soda, LLC	0.05 lb/MMBtu	Low NO _x combustion system	BACT-PSD
Anniston Army Depot	0.03 lb/MMBtu	Clean fuel, low NO _x burners	BACT-PSD
Anniston Army Depot	0.03 lb/MMBtu	Clean fuel, low NO _x burners	BACT-PSD
Champion International	0.05 lb/MMBtu	Flue gas recirculation (FGR)	BACT-PSD
Chem Process Incorporated	0.07 lb/MMBtu	Low NO _x burners	BACT-PSD
Doctors Medical Center	30 ppmv @ 3% O ₂	Industrial combustion burner as FGR	BACT
Doswell Limited Partnership	0.12 lb/MMBtu	Burner design	Other
Duke Energy Luna Energy Facility	21.4 lb/hr	SCR and DLN (?)	BACT-PSD
Exxon Company, USA Santa Ynez Unit Project	27 ppmvd @ 3% O ₂	FGR, steam injection	BACT-Other
H&H Heat Treating	No Data Available	Low NO _x burners	BACT-Other
I/N Kote	0.05 lb/MMBtu	Fuel spec: use of natural gas & FGR	BACT-PSD
Indeck Energy Services Of Otsego	0.06 lb/MMBtu	FGR	BACT-Other
Intel Corporation	No Data Available	Low NO _x burners	BACT
JVC Magnetics America Co.	40 tpy or < potential	Fuel spec: natural gas w/ max 0.5% sulfur fuel oil as backup	BACT-PSD
Kamine/Besicorp Syracuse Lp	0.035 lb/MMBtu 1.17 lb/hr	Induced FGR	BACT-Other
Mid-Georgia Cogen.	0.1 lb/MMBtu	Dry low NO _x burner with FGR	BACT-PSD
Milagro, Williams Field Service	0.08 lb/MMBtu	Low NO _x burners; fuel induced recirculation	BACT-PSD
Minnesota Corn Processors	24.1 lb/hr	Use of low NO _x multistage combustion combined with induced FGR	BACT-PSD
Orange Cogeneration Lp	0.13 lb/MMBtu	Low NO _x burners	BACT-PSD
Paramount Farms	0.22 lb/d	Fuel spec: natural gas firing	
Quincy Soybean Company Of Arkansas	25 ppm @ 15% O ₂	Low NO _x combustors	BACT-PSD
Sitix Of Phoenix, Inc.	49 tpy	FGR, NO _x not to exceed 30 ppm	BACT-PSD
Stafford Railsteel Corporation	7.1 tpy	Fuel spec: use of natural gas & low NO _x burners	BACT-PSD
Sunland Refinery	0.036 lb/MMBtu	FGR/low NO _x burner	BACT-Other
Toyota Motor Corporation Sves Of N.A.	0.1 lb/MMBtu	Low NO _x burners & fuel spec: use of natural gas as fuel	BACT-PSD
Transamerican Refining Corporation (95 MMBtu/hr)	7.7 lb/hr	Low NO _x burner/combustion control	BACT-PSD
Transamerican Refining Corporation (Tarc) (0 MMBtu/hr)	4.9 lb/hr	Low NO _x burners	BACT-PSD
Transamerican Refining Corporation (Tarc) (1.2 MMBtu/hr)	0.14 lb/hr	Good Combustion Practices	BACT-PSD
Waupaca Foundry - Plant 5	6.94 lb/hr	Low NO _x burner	BACT-PSD

Flue Gas Recirculation (FGR)

In a FGR system, a portion of the flue gas is recycled from the stack to the primary combustion zone. Upon entering the primary combustion zone, the re-circulated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. Primarily, the re-circulated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of re-circulated flue gas is a key operating parameter influencing NO_x emission rates for these systems. FGR systems are capable of reducing NO_x emissions by 49 to 68 percent.

An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NO_x burners and FGR are used in combination, these techniques are capable of reducing NO_x emissions by 60 to 90 percent.

Staged Air/Fuel Combustion

Staged air combustion, or off-stoichiometric combustion, combusts the fuel in two or more steps. A percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. The total amount of combustion air fed to the boiler remains unchanged. Initially, fuel is combusted in a primary, fuel-rich, combustion zone. Combustion is completed at lower temperatures in a secondary, fuel-lean, combustion zone. The sub-stoichiometric oxygen introduced with the primary combustion air into the high temperature, fuel-rich zone reduces fuel and thermal NO_x formation. Combustion in the secondary zone is conducted at a lower temperature, reducing thermal NO_x formation. In staged combustion, the degree of staging is a key operating parameter influencing NO_x emission rates. Staged combustion can reduce emissions by 5 to 20 percent.

Evaluation of Technical Feasibility

Each of the three NO_x control technologies described above are considered technically feasible with respect to the auxiliary boiler proposed for the Satsop CT Project. Combining FGR with low NO_x burners provides the most effective control of NO_x emissions. The technology ranking from highest (most effective) to lowest for the auxiliary boilers proposed for the Satsop CT Project is as follows:

1. FGR with low NO_x burners
2. Low-NO_x burners
3. FGR
4. Staged air/fuel combustion

BACT Determination

A cost-effectiveness analysis was not performed since the most efficient control technology identified (FGR with low-NO_x burners) will be installed on the auxiliary boiler for the Satsop CT Project.

Selected BACT

A combination of FGR and low-NO_x burners has been selected as the NO_x emissions control technology for the auxiliary boiler. The proposed BACT emission limit for NO_x is shown in Table 6.1-24.

**TABLE 6.1-24
PROPOSED BACT NO_x EMISSION LIMITS FOR THE AUXILIARY BOILERS^(a)**

Pollutant	Emissions (ppmvd) at 15% O₂	Emissions (lb/MMBtu)	Emissions (lb/hr)
NO _x	30	0.035	1.03

^(a)Based on 100% load.

Carbon Monoxide, Particulate Matter, Sulfur Dioxide, and Volatile Organic Compounds

The RBLC search identified the use of natural gas as an exclusive fuel in combination with good combustion practices as representing the most stringent control available for CO, PM₁₀, SO₂, and VOC. No post-combustion controls for these pollutants were identified during the review.

6.1.6.5 Emergency Diesel Generators

The RBLC was searched for all “diesel” and internal combustion (IC) entries. Eliminating all units not listed as “emergency”, “standby”, or “fire water pump” reduced the initial data set. Fire water pumps are expected to see even less service than emergency diesel generators. From the initial search results, eliminating sources that listed no specific control technology or were for clearly unrelated equipment further reduced the data set. Table 6.1-25 presents a summary of permit determinations for emergency or standby diesel IC generators.

**TABLE 6.1-25
RBLC SEARCH RESULTS FOR RECENT DIESEL GENERATORS**

Facility	Location	EPA Region	Permit Date or Last Update	Size (Each Generator)	
City of Unalaska	Unalaska, AK	10	6/21/1996	300	KW
Grain Processing Corp.	Washington, IN	5	6/10/1997	115	HP
Hartford Insurance Co.	Simsbury, CT	1	8/30/1989	10.2	MMBtu/hr
Kamine/Besicorp Syracuse L.P.	Solvay, NY	2	12/10/1994	1.5	MMBtu/hr
LSP-Cottage Grove, L.P.	Cottage Grove, MN	5	3/1/1995	2.7	MMBtu/hr
LSP - Cottage Grove, L.P.	Cottage Grove, MN	5	11/10/1998	2.7	MMBtu/hr
OXY NGL, Inc.	Johnson Bayou, LA	6	11/14/1989	3.2	MMBtu/hr
OXY NGL, Inc.	Johnson Bayou, LA	6	11/14/1989	1.4	MMBtu/hr
PASNY/Holtsville Combined Cycle Plant	Holtsville, NY	2	9/1/1992	1.3	MMBtu/hr
Multitrade Limited Partnership	Hurt, VA	3	4/8/1991	14.7	MMBtu/hr
UPF Corporation	Bakersfield, CA	9	12/2/1991	410	HP
Vaughan Furniture Company	Stuart, VA	3	8/28/1996	231	HP

Nitrogen Oxides

The formation of nitrogen oxides is the result of thermal oxidation of diatomic nitrogen in the combustion chamber. The rate of formation is dependent upon combustion temperature, residence time of combustion products at high temperatures, and the availability of oxygen in the flame zone of a combustion turbine generator. This section addresses the available control alternatives for NO_x emissions.

Available Control Technologies

Control technologies for NO_x emissions can be classified as combustion modifications or post-combustion controls. The RBLC search completed for NO_x is summarized in Table 6.1-26. The available NO_x control technologies for natural gas-fired combustion turbines are briefly described below.

Turbocharging/Aftercooling

Turbocharging and aftercooling lowers NO_x emissions by running the turbocharged intake air past a heat exchanger. This lowers the temperature of combustion, resulting in less NO_x formation. Most new stationary diesel engines are equipped with a turbocharger and aftercooling system.

**TABLE 6.1-26
RBLC SEARCH RESULTS FOR NO_x - DIESEL GENERATORS**

Facility^(a)	Pollution Control	Basis
City of Unalaska	Limit of Operation Hours and Aftercoolers	BACT-PSD
Cummins Cal Pacific, Inc.	No Control	BACT-PSD
Grain Processing Corp.	Limited to 1,128 Gal/Yr Diesel Fuel	BACT-PSD
Hartford Insurance Co.	Limit Hrs of Operation	BACT-PSD
Kamine/Besicorp Syracuse L.P.	No Controls	BACT-Other
LSP - Cottage Grove, L.P.	Retardation of Engine Timing; Turbocharger Aftercooling	BACT-PSD
LSP - Cottage Grove, L.P.	Limited to Burn Diesel 150 H/Yr.	BACT-PSD
Multitrade Limited Partnership	Operation Restriction & Good Combustion	BACT-PSD
OXY NGL, Inc.	Limit Operating Hours	Other
PASNY/Holtsville Combined Cycle Plant	Lean Burn Engine	BACT-Other
UPF Corporation	Turbocharger With Aftercooler, Timing Retard > Or = To 4 Degrees	BACT-PSD
Vaughan Furniture Company	300 Hours/Year Limit	BACT

^(a) See Table 6.1-25 for locations.

Fuel Injection Timing Retard and Variable Fuel Injection Timing Retard

Fuel injection timing retard (FITR) lowers NO_x emissions by moving the ignition event to later in the power stroke. Because the combustion chamber volume is greater at the time of ignition, the peak flame temperature will be reduced, thus reducing NO_x formation. Variable FITR (VFITR) adjusts the timing continuously for optimum emission reduction. Most modern computer controlled fuel injection systems implement VFITR.

Proposed BACT for NO_x is VFITR and turbocharging/aftercooling.

Sulfur Dioxide

SO₂ emissions from diesel IC generators are a function of the sulfur content of the fuel. Virtually all fuel sulfur is converted to SO₂. The RBLC listed no SO₂ emission controls for emergency diesel IC engine other than fuel sulfur specifications. Current on-road No. 2 fuel oil contains no greater than 0.05 percent sulfur. Proposed BACT for SO₂ for the emergency diesel IC generator is fuel oil containing a maximum of 0.05 percent sulfur by weight.

Carbon Monoxide and Volatile Organic Compounds

CO is a product of incomplete combustion, where oxygen is not present in sufficient quantities to fully oxidize the fuel. In addition, CO emission levels are a direct function of the air/fuel ratio. Combustion inefficiencies introduced by combustion modifications for NO_x control increase the generation of CO. VOC emissions are also products of incomplete combustion. Some VOCs are involved in the process of ozone formation.

The RBLC did not list any available control technologies for emergency use diesel generators. For non-emergency use an oxidation catalyst can be used to reduce both CO and VOCs. However, due to the nature of emergency power-generation oxidation catalysts are not demonstrated technologies for emergency use. Proposed BACT is no control.

Particulate Matter

PM₁₀ emissions arise primarily from non-combustible metals present in trace quantities in liquid fuels. Other sources of PM₁₀ include condensable unburned organics and particles in the combustion air.

The RBLC search for particulate matter control technologies for emergency use diesel generators produced no listing of available particulate matter controls. For non-emergency use, combustion controls include the use of clean-burning fuels and post-combustion controls include fabric filters. However, due to the nature of emergency power-generation fabric filters are not demonstrated technologies for emergency use. BACT for Particulate Matter is using clean-burning fuels.

Table 6.1-27 presents the summary of the BACT findings.

**TABLE 6.1-27
PROPOSED BACT EMISSION LIMITS FOR DIESEL GENERATORS**

Pollutant	Proposed BACT
CO	No control
NO _x	Turbocharging/Aftercooling & VFITR
PM ₁₀	No greater than 0.05% sulfur fuel
SO ₂	No greater than 0.05% sulfur fuel
VOC	No control

6.1.6.6 Toxic Air Pollutants

Washington Administration Code (WAC) 173-460 requires that all sources that apply for a Notice of Construction (NOC), and may potentially increase emissions of regulated toxic air pollutants (TAPs), conduct a best available control technology for toxics (T-BACT) analysis.

The T-BACT analysis ensures that the best available technology is utilized to control TAP emissions. Therefore, a T-BACT analysis was conducted for the Satsop CT Project emission sources.

The T-BACT requirements apply to all applicable stationary sources at the facility. Consequently, for the Satsop CT Project the following sources will be included in the T-BACT analysis:

- Four PGUs with one steam generator rated at 1300 MW total, maximum
- Two auxiliary natural gas-fired boilers
- Two forced draft cooling tower systems
- Two emergency backup diesel generators

Due to the similarities between a BACT and T-BACT analysis, a review of all traditional BACT resources was conducted to identify potential T-BACT emission information. Although minimal supporting material was discovered, information in the Factor Information Retrieval (FIRE) Data System (Version 6.23) provided some pollutant-by-pollutant emission data. The FIRE database is a management system containing EPA's recommended emission estimation factors for criteria and hazardous air pollutants. FIRE includes information about industries and their emitting processes, the chemicals emitted, and the emission factors themselves.

FIRE listed several regulated toxic air pollutants of interest, and identified the pollution control equipment that would have impacts on the emissions. Although the pollution control equipment reviewed was not installed to reduce the TAP emissions, it did reveal that in some cases the TAP emissions were also reduced, and in other cases the TAP emissions actually increased. Table 6.1-28 summarizes the information obtained from FIRE.

As shown in Table 6.1-28, several of the TAPs emission rates were reduced by pollution control equipment, although the pollution control equipment was not installed to reduce the TAP emissions. The equipment was originally installed to reduce other targeted pollutants, e.g. nitrogen oxides, but due to the nature of the TAP, some TAP removal resulted.

Gas Turbines

There are no specific controls for TAP emissions on existing turbines. The control technologies typically installed on turbines are utilized to control other non-TAP pollutants, such as NO_x, or CO. These controls in some cases decrease certain TAP emissions while increasing other TAP emissions. For instance, TAP emission reductions occur when control technologies such as afterburners, CO catalytic reduction, and SCR systems are employed. Reductions in the range of 47 percent to 97 percent have been reported for TAP emissions such as acetaldehyde and formaldehyde. Although there is very limited data regarding the reduction of other TAP

**TABLE 6.1-28
TAP EMISSION CONTROL TECHNOLOGIES**

Emission Source	Toxic Air Pollutant (TAP)	Uncontrolled Emission Rate	Controlled Emission Rate	Percent Reduction or (Increase)	Control Technology
Natural Gas Fired Turbine	Acetaldehyde	4.00 x 10 ⁻⁵ lb/MMcf	2.13 x 10 ⁻⁵ lb/MMcf	47%	Afterburner
	Acetaldehyde	4.00 x 10 ⁻⁵ lb/MMcf	4.29 x 10 ⁻⁶ lb/MMcf	89%	SCR
	Benzene	1.20 x 10 ⁻⁵ lb/MMBtu	9.10 x 10 ⁻⁷ lb/MMBtu	92%	Catalytic reduction
	Formaldehyde	7.10 x 10 ⁻⁴ lb/MMBtu	2.00 x 10 ⁻⁵ lb/MMBtu	97%	Catalytic reduction
	Naphthalene	1.30 x 10 ⁻⁶ lb/MMBtu	1.03 x 10 ⁻⁵ lb/MMBtu	(691%)	SCR
Natural Gas Fired Boiler 10 - 100 MMBtu/hr	Ammonia	4.90 x 10 ⁻¹ lb/MMcf	9.10 x 10 ⁰ lb/MMcf	(1757%)	SNCR
Natural Gas Fired Boiler >100 MMBtu/hr (Duct Burner)	Ammonia	3.20 x 10 ⁰ lb/MMcf	1.80 x 10 ¹ lb/MMcf	(463%)	SNCR
		3.20 x 10 ⁰ lb/MMcf	9.10 x 10 ⁰ lb/MMcf	(184%)	SCR
	Formaldehyde	7.50 x 10 ⁻² lb/MMcf	3.95 x 10 ⁻⁵ lb/MMBtu	46%	Flue Gas Recirculation
	Mercury	2.60 x 10 ⁻⁴ lb/MMcf	2.27 x 10 ⁻⁶ lb/MMBtu	(791%)	Wet Scrubber

emissions, it can be anticipated that other TAP emissions of similar characteristics to acetaldehyde and formaldehyde would also result in emission reductions. As noted above, some TAP emissions may actually increase as a result of certain control technologies. Namely, emissions of naphthalene and ammonia will increase, if using ammonia injection as part of the SCR technology. (Ammonia emissions are a result of ammonia slip, or carryover, when ammonia is injected.)

Additional TAP emission reductions will occur with the exclusive use of natural gas. Natural gas is a “cleaner” fuel as compared to fuel oil, i.e., less air pollutants are emitted when burning natural gas. Consequently, the use of natural gas is considered T-BACT.

Therefore, based on the T-BACT technology review, the proposed T-BACT for the gas turbines is no control, besides the use of natural gas. Note, that the proposed gas turbines will have SCR and CO oxidation systems for the control of non-TAP pollutants. As noted above, these technologies will result in some reduction of selected TAPs but should not be considered as T-BACT for the TAPs; these technologies are beyond established T-BACT thresholds.

Duct Burners

The turbine duct-firing feature is rated at 505 MMBtu per hour. Therefore, the associated air pollutant emissions would be similar to natural gas fired boilers rated greater than 100 MMBtu per hour. No data was found for turbine duct-firing processes, however, FIRE did provide information regarding TAP emissions from natural gas fired boilers greater than 100 MMBtu per hour. This information was then used to characterize and evaluate the TAP emissions from the duct burners.

Table 6.1-28 shows three TAPs that were affected by the installed pollution control equipment. The data shows that only one technology resulted in a reduction of emissions, namely formaldehyde. Formaldehyde emissions were reduced when flue gas recirculation was employed. This technology is not available for gas turbines. Of the two remaining TAPs, both resulted in emission increases when the control equipment was utilized. Ammonia emissions increased when SCR was applied, and mercury emissions increased when a scrubber was used. Consequently, these control technologies would not be recommended as a method to reduce these TAP emissions.

Auxiliary Boilers

The auxiliary boilers are rated at 29.3 MMBtu per hour. Therefore, emission data from FIRE version 6.23 for boilers rated in the 10 to 100 MMBtu per hour range was used to characterize the toxic air pollutants. As shown in Table 6.1-28, the FIRE data only provided toxic emission data for ammonia emissions. Ammonia emissions resulted in an increase due to the use of SCR.

There was no other references information regarding toxic emission data for the auxiliary boiler. However, similar to the turbine generators, the exclusive use of natural gas will maintain the toxic air emissions at a minimum. Therefore, the use of natural gas is considered T-BACT for the auxiliary boiler.

Cooling Towers

There are no TAP emissions data for water cooling towers. However, as found in AP-42, TAP emissions would be related to the chemicals impurities that are found in the water (USEPA 1985b, Section 13.4 regarding "Wet Cooling Towers"). Since there are no chemical additives, such as biocides being added, and no carryover chemicals from the turbine condensers, there should not be any TAP emissions from the cooling tower. Therefore, T-BACT for the water cooling tower is no control.

Diesel Generators

There are no specific controls for TAP emissions on emergency backup diesel generators. Proposed T-BACT is an annual limit of 500 hours of operations for each diesel generator.

A summary of the proposed T-BACT for the sources at the Satsop CT Project are summarized in Table 6.1-29 below.

**TABLE 6.1-29
PROPOSED T-BACT**

Emission Source	Proposed T-BACT
Gas Turbine	Exclusive use of natural gas.
Turbine Duct Firing	Exclusive use of natural gas.
Auxiliary Boiler	Exclusive use of natural gas.
Water Cooling Tower	No TAPs; therefore, no control.
Diesel Generator	500 hours per year operational limit.

6.1.7 LOCAL AIR QUALITY IMPACT ASSESSMENT (AQIA)

Air quality impact assessments (AQIAs) are performed using dispersion modeling techniques in accordance with the EPA’s *Guidelines on Air Quality Models (Revised)* (1986). The results of a modeling analysis can exempt the applicant from ambient air monitoring or cumulative source modeling.

A local AQIA was conducted for the four PGUs, the two auxiliary boilers, and the two emergency diesel generators to assess potential impacts on air quality in the area surrounding the proposed Satsop CT Project. Computer-based dispersion modeling techniques were applied to simulate criteria and toxic air pollutant releases from the facility to assess compliance with the Class I and Class II Prevention of Significant Deterioration (PSD) Increments, the National and Washington Ambient Air Quality Standards (NAAQS and WAAQS), and Ecology’s Acceptable Source Impact Levels (ASILs) for toxic air pollutants. This section describes the techniques and the results of the AQIA. The AQIA focused on the prediction of concentrations for pollutants directly emitted by the PGUs. Dispersion techniques were also used to assess potential secondary impacts to Class I areas including degradation of visibility and other air-quality-related values (AQRVs). This “regional” AQRV analysis is described in Subsection 6.1.8.

The organization of the local AQIA follows the outline typically used to address PSD regulations (40 CFR 52.21 and WAC 173-400-141). Subsections 6.1.7.1 and 6.1.7.2 summarize stack parameters used for the simulation of exhaust gases from the PGUs and auxiliary boilers. Subsection 6.1.7.3 describes the topography, climate, meteorology, and land use classification at the site. The dispersion model selection and application are described in Subsection 6.1.7.4, followed by Significant Impact Level assessment, PSD Class II Increment and de minimus monitoring comparison, ambient air quality standard assessments, and toxic air pollutant analysis, in Subsections 6.1.7.5 through 6.1.7.9.

6.1.7.1 Stack Parameters

The AQIA required estimates of the stack heights, building dimensions, and other exit parameters that define the characteristics of the exhaust flow from the sources. Stack parameters provided for modeling are listed in Table 6.1-30.

**TABLE 6.1-30
STACK AND MODEL INPUT PARAMETERS**

Parameter	Phase I PGU Stacks	Phase II PGU Stacks	Auxiliary Boilers	Diesel Generators
Stack Height	54.86 meters	60.96 meters	14.9 meters	24.38 meters
Stack Diameter	5.5 meters	5.5 meters	0.54 meters	0.2 meters
Stack Exhaust Gas Velocity	20.1 meters/sec	20.1 meters/sec	19.3 meters/sec	49 meters/sec
Stack Temperature	356 K	356 K	476 K	915 K

6.1.7.2 Good Engineering Practice Analysis

A good engineering practice (GEP) stack height design analysis was conducted based on the latest design specifications for the project's buildings according to EPA procedures (EPA 1985a). Releases below the GEP stack height are potentially subject to building wake effects, which can result in relatively high ground level predictions from the EPA's regulatory models. For the purposes of PSD review, the EPA does not allow credit for the added dispersion associated with releases above the GEP stack height and restricts the simulated heights in the modeling to the GEP stack height.

A GEP stack height determination was made for the proposed turbine exhaust stack for each plant. GEP stack height is equal to the height of the building which has the dominant wake effect ("zone of influence") on the stack plume plus 1.5 times the lesser of (1) that building's maximum projected width, or (2) the building height. This GEP stack height is expressed in the following equation:

$$H_g = H + 1.5 L \quad (\text{Equation 1})$$

where

H_g = GEP stack height

H = Building height

L = Lesser of the maximum projected building width or the building height

Use of a stack with this height removes the plume completely from the wake zone.

The cavity height is the stack height required to prevent the stack plume from entering the cavity region of the building. Pollutant plumes which are entrained into the cavity region of a building often produce extremely high concentrations. EPA defines cavity height by the following equation:

$$H_c = H + 0.5 L \quad \text{(Equation 2)}$$

where

H_c = Cavity height

H = Building height

L = Lesser of the maximum projected building width or the building height

Additionally, EPA modeling recommendations for estimating ground level pollutant concentrations at receptors in the cavity region of a building direct the use of a screening procedure contained in EPA's SCREEN3 dispersion model. Alternatively, the ISC-PRIME model provides downwash computations for both the cavity and wake regions.

Based upon site plans, the HRSG has the dominant wake effect for the Satsop CT Project. Exhaust stacks built to a GEP height will minimize downwind air pollution impacts. EPA regulations define GEP stack height as either 65 meters (213 feet) or the calculated height from Equations (1) and (2), whichever is greater. Based on the GEP and cavity analysis, stack heights of 180 feet for the Phase I PGUs, stack heights of 200 feet for the Phase II PGUs, stack heights of 49 feet, with the effects of plume rise, for the auxiliary boilers, and stack heights of 80 feet, with the effects of plume rise, for the diesel generators are sufficient enough to remove the plumes from the building cavity zone; however, building "far" wake is required to be assessed. EPA's ISC3 and ISC-PRIME dispersion models assess impacts due building wake and the results of the modeling are presented in Subsection 6.1.7.5.

6.1.7.3 Topography, Climate, Meteorology, and Land Use Classification

Topography

The Satsop CT Project is located just south of the edge of the broad Chehalis River Valley at an elevation ranging from about 290 to 315 feet above sea level. The area south of the plant has terrain higher than 1,200 feet above the site, while the Chehalis River Valley floor is approximately 300 feet below the site. The channeling influences of the valley floor and the larger scale topography act to give the site location a prevailing wind direction from the east and are evident in the figure.

Climate

The climate of the lowlands of western Washington is dominated by two large-scale influences. These are the mid-latitude westerly winds and proximity of the Pacific Ocean. The westerlies carry

with them a recurring progression of storm systems, or low pressure systems which develop, move toward the east, and dissipate in these latitudes. The westerlies and their associated storms are most intense in the winter months, and they weaken and shift northward in the summer months. The Pacific Ocean exerts a powerful influence on the climate of the lands which surround it. This huge mass of water acts to moderate the seasonal and daily variability in climate throughout the year. Winters are warmer and summers cooler than at other locations at similar latitudes, and cloudiness and high humidities are also persistent features. Grays Harbor County is strongly influenced by the Pacific Ocean because the winds and storms tend to move eastward from the ocean to the land, carrying the moderate effects of the ocean with them. The topography of Grays Harbor County does little to obstruct this influence, especially at locations in the Chehalis River Valley. In Grays Harbor County winter tends to have the most severe weather of any season. Synoptic storms move repeatedly through the area, bringing continuous rain, cloudiness, and windy conditions to exposed locations. Often, there is little relief from the cloudiness for several weeks at a time. Heavy snows do occur, but are rare. Freezing conditions are only occasionally observed with rare occurrences of sleet or freezing rain. Winter's daily low temperatures are generally in the 30 to 40°F range, with little daily variation. The summer climate in this area reflects weakening of the westerly winds and storms. Skies are often fair to partly cloudy and precipitation generally comes in the form of brief, rarely intense showers. Stormy cloudy conditions can dominate for several days in succession, but these conditions are generally less pervasive or severe than in the winter months. The summertime climate is generally mild, with daily afternoon high temperatures in the 70 to 80°F range. This climate is a classic example of a west coast marine type environment.

Meteorology and Land Use Parameters

The AQIA required sequential hourly meteorological data to characterize conditions at the site. The dispersion modeling techniques used to simulate transport and diffusion required an hourly meteorological database which included wind speed, wind direction, temperature, atmospheric stability class, and mixing height. Representative meteorological data was obtained from a meteorological monitoring station located just east of the Satsop CT Project property boundary. The monitoring station was in operation from 1979 through 1982. The meteorological data from the monitoring station was submitted to Ecology for approval for use in the modeling analysis for the Satsop CT Project. Ecology reviewed and approved 1 year of data for input into the models. The data chosen was from February 1, 1980 through January 31, 1981. However, the AIQA for the combined Phase I and Phase II projects used more current and refined EPA models: ISC-PRIME and AERMOD. The AERMOD model requires meteorological data formatted in a different manner than ISC3 or ISC-PRIME; consequently, a new meteorological data file was created for AERMOD using AERMET.

For AERMET, onsite surface observations recorded from October 1, 1979 through September 30, 1980 at the site were combined with coincident National Weather Service (NWS) surface observations recorded at Olympia, Washington, and Seattle-Tacoma International

Airport, Washington, in order to create a set of data with all necessary variables for the AERMOD dispersion model. The ONSITE pathway in the preprocessor AERMET was used to combine a hybrid Satsop/Olympia data set with the NWS data. The NWS upper air soundings required by the model were taken at Quillayute, Washington. The methodology used in the creation of the data set, the completeness and quality of the data, and its applicability to the project location are also discussed.

Coincident meteorological observations recorded at four locations were used to construct the surface and profile input files for the AERMOD dispersion model. Onsite observations were used whenever possible and missing values were filled with observations from two offsite NWS surface stations. Pertinent information regarding the meteorological stations used in AERMET can be found in Table 6.1-31.

**TABLE 6.1-31
METEOROLOGICAL STATIONS**

Station	WBAN Number	Type of Observation	Anemometer Height (meters)	Latitude (degrees)	Longitude (degrees)
Satsop (on site)	N/A	Surface	10, 60	46.97	123.47
Olympia	24227	Surface	6.1	46.97	122.90
Seattle-Tacoma	24233	Surface	6.1	47.46	122.31
Quillayute	94240	Upper Air	N/A	47.93	124.56

The onsite data set was recorded hourly at the Satsop site during 1979 and 1980. Meteorological observations were taken at 10 and 60 meter tower heights. Three variables, wind direction, wind speed and dry bulb temperature from the two observation heights were combined and placed into two FORTRAN readable files. One full year of data was prepared by using observations taken from October 1, 1979 through September 30, 1980. Because 1980 was a leap year, a total of 8784 hourly observations were processed. Olympia Airport surface observations (SAMSON format) were then used to fill some of the missing onsite values. The two files were rewritten and checked for quality and completeness using the STAGE1N2 program. Because the coincident data from Olympia were very incomplete, Seattle-Tacoma International Airport surface observations, the next most proximate NWS surface station, were also used to fill the surface station inputs required by AERMET. The SAMSON format surface data files for 1979 and 1980 were extracted and checked for quality and completeness by the STAGE1N2 program.

The upper air soundings from Quillayute, Washington, were extracted and checked for quality and completeness by the STAGE1N2 program. The MODIFY keyword was used to direct the STAGE1N2 processor to delete mandatory sounding levels within one percent of a significant

level (with respect to pressure), set non-zero wind directions to zero when associated with zero wind speeds, and fill missing temperatures by linear interpolation.

The second step in the creation of the AERMET meteorological data set used the STAGE1N2 program to merge the onsite surface observations (Satsop/Olympia), NWS surface observations (Seattle-Tacoma) and the upper air soundings (Quillayute) into two files, one for October 1, through December 31, 1979 and one for January 1 through September 30, 1980.

Stage three of AERMET produced the surface and profile input files used to represent the meteorology in the AERMOD dispersion model. The inclusion of the METHOD REFLEVEL SUBNWS keywords in the STAGE3 program gave priority to the onsite data; however, whenever the program encountered a variable for which no onsite value could be found, the appropriate value was substituted from the Seattle-Tacoma NWS data. The program selects onsite values measured at the lowest elevation when more than one level is available. If a value is missing from a required parameter at the lowest elevation, the AERMET model will try to fill the value with a measurement taken at the higher elevation. Once AERMET is satisfied that a parameter can not be filled with onsite data, it attempts to fill the parameter with a coincident NWS value.

Albedo, bowen ratio and surface roughness values were selected based on the land use categories within a 3-mile radius of the proposed Satsop facility. USGS aerial photographs taken on July 30, 1991, and topographic maps were examined in order to determine landuse classifications and corresponding site values. Site parameters were defined by season. Autumn values were used in place of winter values for all three parameters since lower elevation areas of western Washington do not possess typical winter characteristics. The ground remains unfrozen and persistent snowfall is uncommon. The Pacific Ocean's influence tends to moderate the climate and maintain an overall high level of moisture. Bowen ratios for wet conditions were used for all seasons and land use categories.

The land use around the project site was divided into two sectors, each having different properties. Figure 6.1-7 depicts the surrounding land area examined as a circle with a radius of three kilometers, centered around the project location. Sector 1, which begins at 60 degrees and ends at 270 degrees, is a mosaic of clear cuts and coniferous forest. Sector 2 is composed of 68 percent cultivated cropland and 32 percent coniferous forest intermingled with clear cuts. The triangles labeled 1a and 1b in Figure 6.1-7 represent the portion of land designated as coniferous forest, while the remaining land was classified as cultivated cropland. Site specific values for this sector were determined based upon the percentage of each land use category. For example, the summertime surface roughness is 0.20 meters for cultivated cropland and 1.30 meters for coniferous forest. The surface roughness value used in AERMET for this sector and season was determined using:

$$\text{surface roughness} = (0.32*1.30) + (0.68*0.20) = 0.55$$

Tables 6.1-32 and 6.1-33 list the sector-specific site properties used in AERMET.

**TABLE 6.1-32
AERMET LAND USE VALUES FOR SECTOR ONE (60° – 270°)**

	Albedo	Bowen Ratio	Roughness
Spring	0.12	0.30	1.30
Summer	0.12	0.20	1.30
Fall	0.12	0.30	1.30
Winter	0.12	0.30	1.30

**TABLE 6.1-33
AERMET LAND USE VALUES FOR SECTOR TWO (270° – 60°)**

	Albedo	Bowen Ratio	Roughness
Spring	0.13	0.30	0.44
Summer	0.17	0.44	0.55
Fall	0.16	0.57	0.45
Winter	0.16	0.57	0.45

Each set of data used by AERMET were checked for quality and completeness. A summary of the missing data at each station is provided in Table 6.1-34. Due to the lack of valid data from Olympia, Seattle-Tacoma data was also used in the preparation of AERMET surface and profile meteorological data files. Although the onsite data was greater than 90 percent complete for temperature, wind direction and wind speed; other required parameters were not recorded. The NWS surface station at Olympia was a logical choice to provide the missing data, however, due to the low frequency of data collection, the AERMET output files were of poor quality. While on a grand scale the wind vectors observed at Seattle-Tacoma are not likely to be similar to those observed at Satsop, the low percentage of hours substituted when onsite or Olympia vectors were unavailable did not significantly alter the resulting AERMET output files. It was assumed that Seattle-Tacoma cloud cover, temperature and pressure observations were similar to those found at Satsop and, therefore substitution of those variables, when necessary, was appropriate.

The wind directions from the AERMET surface file compared favorably with the expected wind flows based on the Satsop area topography. The predominant wind vector for the period proceeded in a east-northeast direction. This wind flow pattern occurred 18.8 percent of the time and is in agreement with the valley topography and an onshore airflow pattern. The offshore flow, with a west-southwest vector, occurred 11.5 percent of the time. In general, the wind vectors proceeded in a westerly direction the majority of the time. A wind flow vector plot for the data set is shown in Figure 6.1-8. There were 122 hours with a zero wind speed.

**TABLE 6.1-34
SUMMARY OF METEOROLOGICAL DATA COMPLETENESS**

Parameter/Station	Percentage/Number of Observations ¹			
	Satsop	Olympia	Seattle-Tacoma	Quillayute ²
Temperature	97.0	100	100	100
Wind Direction ³	95.4	33.3	100	N/A
Wind Speed	97.3	33.3	100	612
Cloud Cover	N/A	100	100	N/A
Pressure	N/A	100	100	N/A

¹ All surface variables are presented as percent complete based on 8784 hours. Upper air wind speeds are presented as total number missing for the coincident period of time.

² Quillayute upper air soundings.

³ Upper air wind directions are not used by AERMET and are therefore not checked.

This AERMET data set was found to be similar to the ISC meteorological data set approved for use in previous Satsop CT Project dispersion modeling efforts. The ISC data set encompassed the period of time from February 1, 1980 through January 31, 1981. Wind flow vectors from this data set are shown in Figure 6.1-9. As found in the AERMET data set, the predominant wind vector in the ISC data set was east-northeast. This pattern occurred 18.1 percent of the time. The west-southwest wind vector occurred 11.3 percent of the time, again showing agreement with the AERMET data set. The overall westerly direction of the wind vectors was again apparent.

A comparison of the stability classes between the two sets of meteorological data also attest to their similarity. A comparison of the stability class frequency distribution between the two sets of data is provided in Table 6.1-35.

**TABLE 6.1-35
STABILITY CLASS FREQUENCY**

Stability Class	Frequency of Occurrence	
	AERMET Data Set	ISC Data Set
A	0.00434	0.00148
B	0.0568	0.0335
C	0.103	0.0743
D	0.553	0.594
E	0.124	0.100
F	0.143	0.0972

Rural/Urban Land Use Classification for ISC

A technique was developed by Irwin (1979) to classify a site area as either rural or urban for purposes of using rural or urban dispersion coefficients. The classification can be based on either land use or population density within 3 kilometers of an emission sources. Of these, EPA has specified that land use is the most definitive criterion (USEPA 1993b).

Using the meteorological land use typing scheme established by Auer (1978) for an area within a 3 kilometer radius from a site, an urban classification of the site area requires more than 50 percent of the following land use types: Heavy industrial (I1), light-moderate industrial (I2), commercial (C1), single family compact residential (R2), and multi-family compact residential (R3). Otherwise, the site area is considered rural. Because rural land use types comprise greater than 90 percent of the total area in the vicinity of the generating facility, rural dispersion coefficients were employed in the model to calculate plume dispersion.

6.1.7.4 Dispersion Model Selection and Application

This section discusses the dispersion modeling methods that were applied to evaluate the potential impacts of criteria and toxic air pollutant emissions. The rationale for the dispersion modeling approach was based on EPA guidelines (USEPA 1986), considerations of the local terrain, and the source characteristics. EPA recommends the use of specific dispersion models for the evaluation of air quality impacts in a regulatory setting. These recommended models are generally referred to as “guideline” models. The “guideline” dispersion models chosen for the local AQIA were EPA’s Industrial Source Complex (ISC3) model and EPA’s SCREEN3 model. Additionally, two proposed “guideline” models were used to assess the combined Phase I and Phase II emissions: ISC-PRIME and AERMOD.

The Industrial Source Complex (ISC3) model has historically been the preferred regulatory model for assessments involving stationary sources requiring analysis of aerodynamic downwash, particle deposition, volume sources, area sources. ISC3 is based on the steady-state Gaussian plume formulation with modifications to allow for simulations of complex industrial sources in both rural and urban settings. Major features of these models are the special algorithms that have been included to simulate point sources subject to building wake effects. In these calculations the vertical and horizontal dimensions of the Gaussian plume are specified by atmospheric stability class as functions of downwind distance. For rural conditions, conventional Pasquill-Gifford dispersion curves are applied, while for urban conditions the Briggs urban dispersion curves are utilized. On-site meteorological data can also be used in ISC3.

ISC3 was applied using the recommended defaults for rural conditions including options for calm processing, buoyancy-induced dispersion, final plume rise, stack-tip downwash, default terrain adjustment coefficients and other options specified by the “guideline.” Rural Conditions reflect the current nonindustrial land use and low population density surrounding the site.

EPA's SCREEN3 dispersion model was used to approximate the distance from the source where maximum concentrations were likely to occur and to assess plume rise and building cavity effects.

More refined modeling made use of the newest EPA dispersion models. ISC-PRIME is EPA's Industrial Source Complex model with Plume Rise Model Enhancements. These enhancements characterize the effects of building downwash more accurately and provides computations for both the cavity and the wake regions. AERMOD is EPA's AMS/EPA Regulatory Model which utilizes "state-of-the-science" representation of the physics of the planetary boundary layer. The modeling domain for AERMOD is characterized by roughness length, albedo, and Bowen ratio parameters rather than a simple rural/urban classification. Additionally, AERMOD utilized horizontal and vertical turbulence profiles that vary with height rather than simple stability class categories.

The cartesian receptor grid used in the dispersion modeling analysis included receptor points as follows:

- Receptors were located using approximately 50-foot spacing along the fenceline of the facility site.
- Off-site receptors were located at 1,000-foot intervals.
- ISC-PRIME was used to assess receptors out to approximately 5 kilometers from the facility and AERMOD was used to assess receptors from approximately 2 kilometers out from the facility to approximately 11.5 kilometers out from the facility.

Receptor elevations were taken from the 1:24,000 scale USGS topographic maps of the area surrounding the site using USGS Digital Elevation Modules. AERMAP was used to process the terrain parameters.

6.1.7.5 Criteria Pollutant Significant Impact Level Assessment

Ambient concentrations of criteria pollutants due to emission releases from the four PGUs, two auxiliary boilers, and two diesel generators were predicted using ISC-PRIME and AERMOD. Maximum short-term concentrations and annual average concentrations were obtained for the emission rates presented in Table 6.1-36.

**TABLE 6.1-36
MODELED EMISSION RATES**

Pollutant	Each Power Generation Unit With Duct Firing	Each Auxiliary Boiler	Each Diesel Generator
	Maximum Emission Rate (gram/second)	Maximum Emission Rate (gram/second)	Maximum Emission Rate (gram/second)
PM ^(a)	3.06	0.037	0.07
SO ₂	0.16	0.004	0.03
NO _x	2.74	0.037 ^(b)	1.28 ^(b)
NO _x SU/SD	1.44	0	0
CO	1.34	0.13	1.58
CO SU/SD 1-hour	166.6	0	0
CO SU/SD 8-hour	41.7	0	0

^(a)TSP, PM₁₀, and PM_{2.5} conservatively assumed to be equal. Includes ammonium sulfate and bisulfate compounds. Emissions include backhalf CT emission estimates.

^(b)Annually averaged emission rate used for auxiliary boilers and diesel generators based on maximum annual operating hours of 2500 hours for each auxiliary boiler and 500 hours for each diesel generator.

Significant Impact Levels (SILs) have been established for various criteria pollutants. If pollutant concentrations exceed the SILs, then further evaluation is required to compare the project's concentrations to the Class II PSD Increment and the NAAQS and WAAQS. However, all ambient impact concentrations modeled for facility operations are less than the SILs; therefore, no further analysis is required. Additionally, under PSD regulations, only facilities with impacts in excess of SILs are required to include the impacts of other facilities or consider collecting background ambient air quality information. Table 6.1-37 presents the results of the AQIA. Figures 6.1-10 through 6.1-18 present the concentration contours for each pollutant and averaging period listed in Table 6.1-37.

**TABLE 6.1-37
AIR QUALITY MODELING RESULTS SIGNIFICANT IMPACT LEVELS**

Pollutant	Maximum Ambient Impact Concentration ($\mu\text{g}/\text{m}^3$)	Significant Impact Levels ($\mu\text{g}/\text{m}^3$)
PM ₁₀ annual	0.91	1
PM ₁₀ 24-hour	4.86	5
SO ₂ annual	0.29	1
SO ₂ 24-hour	1.52	5
SO ₂ 3-hour	6.14	25
NO ₂ annual	0.898	1
CO 8-hour	122.3	500
CO 1-hour	504.0	2,000

6.1.7.6 Criteria Pollutant PSD Increment and Monitoring De Minimus Concentration Assessment

As stated in the previous section, all criteria pollutant impacts are less than the Significant Impact Levels (SILs) defined under the PSD regulations. Consequently, no impacts exceed PSD Increment Levels or monitoring de minimus concentrations. Table 6.1-38 presents the results of the AQIA as compared with PSD Class II Increments and de minimus monitoring concentrations. Because the facility has ambient air quality impacts less than the SILs, no modeling of neighboring facilities is required.

TABLE 6.1-38
AIR QUALITY MODELING RESULTS PSD CLASS II INCREMENTS AND
MONITORING DE MINIMUS CONCENTRATIONS

Pollutant	Maximum Ambient Impact Concentration ($\mu\text{g}/\text{m}^3$)	PSD Class II Increment ($\mu\text{g}/\text{m}^3$)	Monitoring <i>De Minimus</i> Concentrations ($\mu\text{g}/\text{m}^3$)
PM ₁₀ annual	0.80	17.0	--
PM ₁₀ 24-hour	4.72	30.0	10
SO ₂ annual	0.08	20.0	--
SO ₂ 24-hour	0.40	91.0	13
SO ₂ 3-hour	1.55	512	--
NO ₂ annual	0.18	25.0	14
CO 8-hour	32.26	---	575
CO 1-hour	74.51	---	--

6.1.7.7 Criteria Pollutant Ambient Air Quality Standards Assessment

National and Washington ambient air quality standards (NAAQS and WAAQS) have been established by EPA and Ecology, respectively. Some of the criteria pollutants are subject to both “primary” and “secondary” federal standards. Primary standards are designed to protect human health with a margin of safety. Secondary standards are established to protect the public welfare from any known or anticipated adverse effects associated with these pollutants, such as soiling, corrosion, or damage to vegetation.

As ambient impact concentrations are below SILs, no exceedances of the WAAQS or NAAQS are predicted. Table 6.1-39 presents a comparison between the maximum predicted concentration and each ambient air quality standard. Startup/shutdown (SU/SD) modeling results are also provided in Table 6.1-39.

TABLE 6.1-39
AIR QUALITY MODELING RESULTS
NAAQS AND WAAQS

Pollutant	Averaging Period	Maximum Ambient Impact Concentration ($\mu\text{g}/\text{m}^3$)	National Ambient Air Quality Standards ($\mu\text{g}/\text{m}^3$)		Washington Ambient Air Quality Standards ($\mu\text{g}/\text{m}^3$)
			Primary	Secondary	
Total Suspended Particulate Matter (TSP)	Annual	0.91	--	--	60
	24-Hour	4.86	--	--	150
Particulate Matter Less than 10 μm (PM ₁₀)	Annual	0.91	50	(a)	50
	24-Hour	4.86	150 ^(b)	(a)	150
Particulate Matter Less than 2.5 μm (PM _{2.5})	Annual	0.91	15 ^(k)	(a)	--
	24-Hour	4.86	65 ^(k)	(a)	--
Sulfur Dioxide (SO ₂)	Annual	0.29	80	--	52 ^(c)
	24-Hour	1.52	365 ^(b)	--	262 ^(d)
	3-Hour	6.14	--	1300 ^(b)	(e)
	1-Hour	10.93	--	--	1048 ^(e)
Nitrogen Dioxide (NO ₂)	Annual	0.898	100	(a)	94 ^(h)
Nitrogen Dioxide (NO ₂) from SU/SD	Annual	0.16	100	(a)	94 ^(h)
Lead (Pb)	Quarterly	0.00002 ⁽ⁱ⁾	1.5	(a)	--
Ozone (O ₃)	8-Hour	(g)	157 ^{(f)(k)}	(a)	(i)
	1-Hour	(g)	235 ^(b)	(a)	235
Carbon Monoxide (CO)	8-Hour	122.3	10,000 ^(b)	--	10,000
	1-Hour	504.0	40,000 ^(b)	--	40,000
Carbon Monoxide (CO) from SU/SD	8-Hour	144.1	10,000 ^(b)	--	10,000
	1-Hour	2,754.6	40,000 ^(b)	--	40,000

^(a)Same as primary NAAQS.

^(b)Concentration not to be exceeded more than once per year.

^(c)40 CFR 50.3; Washington standard is 0.02 ppm.

^(d)40 CFR 50.3; Washington standard is 0.1 ppm.

^(e)No Washington 3-hour standard. Washington 1-hour standards are 0.4 ppm (not to be exceeded more than once per year) and 0.25 ppm (not to be exceeded more than twice in a consecutive 7-day period).

^(f)Limited implementation. Three year average of the annual 4th highest daily maximum 8-hour concentration.

^(g)Grays Harbor County is designated as an attainment area for ozone.

^(h)40 CFR 50.3; Washington standard is 0.05 ppm.

⁽ⁱ⁾No Standard.

^(j)Conservatively based on maximum 1-hour impact concentration.

^(k)A 1999 federal court ruling blocked implementation. EPA has requested the U.S. Supreme Court to reconsider the decision.

6.1.7.8 Toxic Air Pollutant Small Quantity Emission Rate Assessment

New sources of toxic air pollutants are regulated on the state level by WAC 173-460. Under these regulations, emissions of toxic air pollutants (TAPs) from new sources must be evaluated to ensure compliance with WAC 173-460-070. Additionally, new sources must use Best Available Control Technology for toxics (T-BACT). T-BACT applies to each TAP or a mixture of TAPs that is discharged, taking into account the potency, quantity, and toxicity of each TAP.

Under these air toxic regulations, an initial evaluation known as a Small Quantity Emission Rate is to be performed, and TAPs exceeding the Small Quantity Emission Rate (SQER) are then required to undergo air dispersion modeling (i.e., an ASIL analysis). In addition, if a TAP does not have a SQER, it must be modeled. Table 6.1-40 presents the estimated TAP emission rates for the Satsop CT Project and compares them to the SQERs.

**TABLE 6.1-40
TOXIC AIR POLLUTANT
SMALL QUANTITY EMISSION RATE COMPARISON^(a)**

Toxic Air Pollutant	Emission Rate (lb/yr)	SQER (lb/yr) ^a	Dispersion Modeling Req'd? ^b
Acetaldehyde	2,346.14	50	Y
Acrolein	187.37	175	Y
Ammonia	28,2107.19	17,500	Y
Arsenic	3.50	na	Y
Barium	38.48	175	
Benzene	744.57	20	Y
Benzo (a) Pyrene*	0.02	na	Y
Benzo (b) fluoranthene*	0.03	na	Y
Benzo (k) fluoranthene*	0.03	na	Y
Beryllium	0.21	na	Y
Butane	18,366.46	43,748	
Cadmium	19.24	na	Y
Chromium	24.49	na	Y
Cobalt	0.37	175	
Copper	7.43	175	
Dibenzo (a,h) anthracene*	0.02	na	Y
Dichlorobenzene	20.99	500	
Ethylbenzene	468.41	43,748	
Formaldehyde	42,889.95	20	Y
Indeno (1,2,3-cd) pyrene*	0.03	na	Y
Lead	10.71	na	Y

TABLE 6.1-40 (Continued)
TOXIC AIR POLLUTANT
SMALL QUANTITY EMISSION RATE COMPARISON^(a)

Toxic Air Pollutant	Emission Rate (lb/yr)	SQER (lb/yr) ^a	Dispersion Modeling Req'd? ^b
Manganese	3.32	5,250	
Mercury	2.28	175	
Molybdenum	9.62	1,750	
n-Hexane	15,742.68	22,750	
n-Pentane	22,739.42	43,748	
Naphthalene	43.91	22,750	
Nickel	36.73	0.5	Y
Polycyclic Aromatic Hydrocarbons (PAH) ^c	129.87	na	Y
Selenium	0.21	175	
Sulfuric Acid Mist	41,125.46	175	Y
Toluene	3,837.78	43,748	
Vanadium	20.12	175	
Xylenes	1,875.17	43,748	
Zinc	253.63	1,750	

^(a) na = not applicable as ASIL is < 0.001 µg/m³ or TAP ASIL is not established.

^(b) Dispersion modeling required if TAP emissions exceed SQER, TAP ASIL is < 0.001 µg/m

^(c) Polycyclic Aromatic Hydrocarbons (PAH) includes all TAPs labeled with * and chrysene.

6.1.7.9 Toxic Air Pollutant Acceptable Source Impact Level Assessment

For those TAPs that require modeling, the ambient impact concentrations for each TAP are compared with an Acceptable Source Impact Level (ASIL) as found in WAC 173-460. If maximum impacts from the source are shown to exceed an ASIL, a Second Tier Analysis is necessary; however, no impacts are in excess of the ASILs. Table 6.1-41 presents a summary of the ASIL comparison.

**TABLE 6.1-41
TOXIC AIR POLLUTANT
ACCEPTABLE SOURCE IMPACT LEVEL COMPARISON**

Pollutant	Class ^(a)	Maximum Ambient Impact Concentration (µg/m ³)	ASIL ₃ (µg/m ³)	Further Analysis Required?
Acetaldehyde	A	0.00214	0.45	N
Acrolein	B	0.0034	0.02	N
Ammonia	B	5.17	100	N
Arsenic	A	0.00001	0.00023	N
Benzene	A	0.00168	0.12	N
Beryllium	A	0.000001	0.00042	N
Cadmium	A	0.00005	0.00056	N
Chromium	A	0.00006	0.000083	N
Formaldehyde	A	0.0638	0.077	N
Sulfuric Acid Mist	B	0.108	3.3	N
Lead	A	0.00002	0.5	N
Nickel	A	0.00009	0.00210	N
PAH ^(b)	A	0.00028	0.00048	N

^(a) Class A TAPs are known or probable carcinogens and Class B TAPs are non-carcinogens.

^(b) Polyaromatic hydrocarbons (PAH) includes all TAPs labeled with * and chrysene

6.1.8 “REGIONAL” AIR QUALITY RELATED VALUES ASSESSMENT

PSD regulations require an assessment of the proposed Satsop CT Project’s impact to AQRVs in Class I areas. AQRVs include regional visibility or haze; the effects of primary and secondary pollutants on sensitive plants; the effects of pollutant deposition on soils and receiving water bodies; and other effects associated with secondary aerosol formation. Through the PSD program, the Clean Air Act provides special protection for Class I areas and as the federal land managers (FLMs) for the Class I areas, the National Park Service (NPS), and U.S. Forest Service (USFS) have the responsibility of ensuring AQRVs in the Class I areas are not adversely affected. This section provides the FLMs with information necessary to assess potential air quality impacts of the combined Phase I and Phase II of the proposed project on Pacific Northwest Class I areas.

6.1.8.1 Modeling Procedures

The CALPUFF modeling system was used to examine potential AQRV impacts from Phase I and Phase II of the proposed Satsop CT Project. EPA, Ecology, and the FLMs currently recommend the CALPUFF system for long-range transport assessments and for evaluating potential impacts to AQRVs in Class I areas. Features of the CALPUFF modeling system include the ability to

consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; complex three-dimensional wind regimes; and the effects of humidity on regional visibility. The modeling procedures used follow the recommendations of the Interagency Agency Workgroup on Air Quality Modeling (IWAQM) (IWAQM 1998) and the Federal Land Managers Air Quality Related Values Workgroup (FLAG) (FLAG 1999).

6.1.8.2 Study Domain

The domain of the regional modeling study is shown in Figure 6.1-19. The 378-km by 414-km modeling domain includes the Olympic Mountains, Cascades Mountains, southern Vancouver Island, western Washington lowlands, portions the Lower Fraser Valley, and northwest Oregon. Olympic National Park is the closest Class I area to the Satsop CT Project and is about 60 km north-northwest of the proposed site. Other Class I areas considered in the modeling analysis include Mt. Rainier National Park, Pasayten Wilderness, Glacier Peak Wilderness, Alpine Lakes Wilderness, Goat Rocks Wilderness, Mt. Adams Wilderness, and the Mt. Hood Wilderness. At the request of the USFS, the analysis also considers impacts to the Mt. Baker Wilderness and the Columbia River Gorge National Scenic Area (CRGNSA). These areas are not subject to special protection under the Clean Air Act and model estimates are provided for information purposes only.

6.1.8.3 Emission Rates and Stack Parameters

The emission rates and stack parameters used in the CALPUFF simulations are shown in Table 6.1-42 and Table 6.1-43, respectively. Emissions and stack parameters are conservatively based on 100 percent load with supplemental duct firing and a 31°F ambient temperature. The parameters in Table 6.1-42 and Table 6.1-43 were assumed for all hours of the year in the CALPUFF simulations. The facility also has emissions associated with two emergency diesel generators. These sources would not operate concurrently with the PGUs for prolonged periods.

Data characterizing the chemical composition and size distribution of the PM₁₀ emitted are needed for the regional haze assessment. The PM₁₀ is divided into the components shown in Table 6.1-42 based on a recent paper by Corio and Sherwell (2000) summarizing stack test results from a number of combustion sources including turbines fired by natural gas and oil. Corio and Sherwell found filterable PM₁₀ averaged 23 percent for gas-fired turbines. In the stack tests summarized by Corio and Sherwell, the condensable (non-filterable) fraction of the PM₁₀ was further broken down into two components: organic and inorganic matter. Inorganic matter comprised 67 percent of the condensable fraction for gas-fired turbines.

**TABLE 6.1-42
EMISSION RATES AND PM₁₀ SPECIES**

Species Emitted	Emission Rates Per Each of Four PGUs (lb/hr) ^(a)	Emission Rates Per Each of Two Auxiliary Boilers (lb/hr)
SO ₂ ^(b)	0.91	0.03
Sulfate ^(b)	0.59	0.00
NO _x	21.7	1.03
Nitrate	0.0	0.00
PM ₁₀ ^(b)	23.5	0.03
PM ₁₀ as EC ^(c)	5.4	0.01
PM ₁₀ as OC ^(d)	6.0	0.00
PM ₁₀ as Fine Mass ^(e)	12.1	0.02
PM ₁₀ as Coarse Mass	0.0	0.00

- (a) Based on 100 percent load, duct firing, and 31°F.
- (b) Based on 30 percent conversion of SO₂ in the HRSG. Note, SO₂ and PM₁₀ emission rates were reduced accordingly to avoid double counting of emissions.
- (c) All filterable matter was conservatively assumed to be EC. The filterable portion of the PM₁₀ emission was assumed to be 23 percent.
- (d) The organic portion of the non-filterable PM₁₀ was assumed to be OC.
- (e) Sixty-seven percent of the non-filterable PM₁₀ was assumed to be inorganic fine particle mass of unknown composition.

**TABLE 6.1-43
STACK PARAMETERS ^(a)**

Variable	PGUs	Auxiliary Boilers
Stack Height (ft)	180 – 200 ^(b)	49
Stack Diameter (ft)	18	1.8
Exit Velocity (ft/s)	61.3	63.3
Exit Temperature (F)	181	398

- (a) Stack parameters based on 100 percent peak load, duct firing, and an ambient temperature of 31°F.
- (b) Phase I stacks are 180 ft and Phase II stacks are 200 ft.

The elemental carbon (EC) fraction was assumed to be 23 percent of the PM₁₀ or equivalent to the average filterable portion found by Corio and Sherwell for gas-fired turbines. The remaining non-filterable organic component was assumed to be organic carbon (OC) and the inorganic component was “generic PM_{2.5}” of unknown composition. For the latter, scattering efficiency properties were assumed to be equivalent to crustal material, the default used by the CALPUFF modeling system for fine particulate matter of unknown composition.

6.1.8.4 CALPUFF Modeling System Overview

The CALPUFF (Version 5.4) modeling system was used to estimate primarily pollutant concentrations, secondary aerosol concentrations, deposition fluxes, and changes to regional haze that might occur as the result of emissions from Phase I and Phase II of the Satsop CT Project. The CALPUFF system contains many modeling components that are more realistic than the conventional modeling techniques used to evaluate impacts in Class II areas. Specifically, the CALPUFF system includes:

- A Gaussian puff dispersion formulation: Plumes are treated as a series of Gaussian puffs that move and disperse according to local conditions that vary in time and space.
- Three-dimensional meteorology: Wind and other meteorological variables are allowed to vary three-dimensionally.
- Wet and dry deposition mechanisms: Deposition processes are included for both particles and gaseous pollutants that depend on the characteristics of the pollutant, the local surface and meteorology. The model accounts for the mass removed from the plume when deposition occurs.
- Aerosol chemistry: Secondary aerosol formation is treated according to a first-order mechanism that depends on the time of day, relative humidity, meteorology, background ozone concentration, and background ammonia concentration.
- Post-processing specifically designed to assess regional haze: Visibility is characterized using extinction coefficients that vary with the concentrations of the aerosol species present, extinction characteristics of each aerosol species, and relative humidity.

The IWAQM Phase 2 Recommendations were followed for the application of CALPUFF to this project. Some of the key options included in these recommendations are as follows:

- Pasquill-Gifford dispersion curves and other default dispersion options
- CALPUFF partial path treatment of terrain
- MESOPUFF-II daytime chemistry with default conversion rates at night
- Default wet and dry deposition parameters for the particle and gaseous species

The NO_x chemistry in CALPUFF depends on the ammonia concentration. Ammonia is not explicitly simulated by CALPUFF and the user must select an appropriate background concentration. The IWAQM Phase 2 Recommendations suggest typical ammonia concentrations are: 10 ppb for grasslands, 0.5 ppb for forests, and 1 ppb for arid lands during warmer weather. Because land use with the study domain is mixed, a conservative ammonia background concentration of 10 ppb was used for the modeling simulations. Such a conservative concentration ensures the conversion of NO_x to ammonium nitrate is not ammonia limited.

Reaction rates in the CALPUFF chemistry algorithms are also influenced by background ozone concentrations. Hourly ozone data were collected from the stations located within the study area shown in Figure 6.1-20. Ozone data were obtained for nineteen stations within Washington, three stations from the NPS, eleven stations from the Greater Vancouver Regional District, and two stations on Vancouver Island from the Ministry of Environment, Land and Parks. Many of these stations do not operate outside of the ozone season and it is still necessary to establish a background ozone concentration. For periods of missing data outside the ozone season, a conservative background ozone concentration of 40 ppb was used.

6.1.8.5 Meteorological Data Set Construction

Wind regimes in the Pacific Northwest typically have complex three-dimensional qualities that can be important for assessments of regional air quality. Although the number of surface observation sites is gradually increasing in the Northwest, the stations tend to be located at airports, near populated areas and the network is not adequate to characterize flow within the region's more rugged terrain. The observational database also lacks sufficient upper air measurements to describe wind patterns aloft that can be important in transporting the buoyant turbine plumes to the Class I areas.

A numerical model is believed to characterize winds within the study area better than wind fields constructed solely from the network of existing observations. An important component of the study is the incorporation of a meteorological data set from the University of Washington (UW) based on numerical simulations of Pacific Northwest weather with the Penn State and National Center of Atmospheric Research Mesoscale Model (MM5). The UW MM5 data were obtained from Ecology after the archive had been converted with CALMM5. This program reformats the binary MM5 output files into the format expected by the CALPUFF modeling system. The AQRV analysis used hourly MM5 output fields from April 1998 through mid March 1999, with 32 vertical levels and a 12-km grid mesh size.

CALMET, the meteorological preprocessor component of the CALPUFF system, was used to combine the MM5 simulation data, surface observations, terrain elevations, and land use data into the format required by the dispersion modeling component CALPUFF. In addition to specifying the three-dimensional wind field, CALMET also estimates the boundary layer

parameters used to characterize diffusion and deposition by the dispersion model. Major features of the CALMET application and input data preparation were as follows:

- 12-km MM5 winds were used to initialize the three-dimensional wind field predictions. The data recovery for the MM5 archive is 93 percent. Periods of missing data were filled with interpolation and for longer periods by repeating the previous day.
- CALMET objective procedures were used with local terrain and land use data to increase the horizontal resolution of the wind fields using a mesh size of 6 km. The pressure based 32 vertical level MM5 fields were also reduced and layer averaged resulting in 10 vertical levels from the surface to 4000 m.
- Land use and terrain data were prepared from the USGS 1:250,000 scale data sets on the Internet. Terrain data for British Columbia were based on the 900-m resolution data set included with the CALPUFF modeling system. Land use categories in British Columbia were from subjective interpretation of topographic maps. Figure 6.1-21 shows the terrain data provided to the CALPUFF modeling system using a horizontal mesh size of 6 km.
- Surface observations from 95 stations within the study domain were used to provide hourly cloud cover, ceiling height, temperature and relative humidity data. The locations of these stations are shown in Figure 6.1-22. Local wind speed and direction data were not used in the preparation of the wind fields. The wind fields used in the AQRV analysis depend solely on the MM5 winds and the objective procedures applied by CALMET.
- Upper air temperature lapse rate data for CALMET were taken from the MM5 archives as opposed to the limited observations within the model domain. Soundings within or near the domain are only taken twice daily at Quillayute and Salem. The NWS also operates a 915-MHz radar wind profiler with a radio acoustic sounding system in Seattle. In contrast, the MM5 archives provide better spatial coverage with hourly profiles available at every 12-km grid point. Twenty “pseudo” upper air stations were constructed by extracting the necessary data from the MM5 archives. The locations of these sites are shown in Figure 6.1-23.
- Hourly precipitation data were also extracted from the MM5 archives. Stations with hourly precipitation in the study area tend to be located at low elevations and conventional interpolation of these data will likely under estimate precipitation and wet deposition in the mountain regions. As an alternative, the precipitation forecasts from every other grid point on MM5’s 12-km grid were used. The UW has shown precipitation forecasts from MM5 are slightly biased towards over prediction, but generally compare favorably with available observations.

Hourly three-dimensional wind fields and two-dimensional fields were constructed for surface meteorological variables for April 1, 1998 through March 15, 1999. The resulting wind fields were assessed subjectively by preparing vector plots of the wind fields for days selected at random and by constructing wind roses from the surface wind predictions to compare against observations.

Examples of the vector plots on June 1, 1998 at 0400 PST are provided in Figure 6.1-24, Figure 6.1-25, and Figure 6.1-26 for winds at the surface, 300 m, and 3000 m, respectively. In this example, surface winds are light and variable with drainage winds on the slopes of some of the terrain features and stronger winds over the water. Note the relatively good agreement between the model predictions and the available surface observations displayed in Figure 6.1-24. At 300 m above the surface, the predicted winds begin to show signs of a wind jet (maximum in wind velocity) in the Straits of Georgia and on the lee side of the Cascades. A small low-pressure eddy or convergence zone is also predicted in the south Puget Sound, near Olympia. On the western slopes of the Cascades the winds are lighter and show the damming effects of the Cascades. In Figure 6.1-26, the winds at 3000 m above the surface are more uniform with slightly higher winds over the major terrain features. In this example, the surface level winds are uncoupled from the winds aloft and at many locations wind directions vary by 180 degrees between the surface (Figure 6.1-24) and 3000 m (Figure 6.1-26). These plots demonstrate the complexity of the winds within the study domain and are typical of those examined throughout the year.

Wind rose plots of predictions and observations for selected surface stations within the study domain were examined. Figure 6.1-27 and Figure 6.1-28 are examples of these wind roses and compare predicted and observed winds near the Satsop CT Project site. Note, the wind data for the site are from the Class II modeling data set used in the PSD permit and correspond to a different annual period. Considering different periods are compared, the agreement between model predictions and observations at the Satsop CT Project site is good. The model predicts more frequent westerly winds, but the predicted average wind speed of 3.2 m/s agrees with the observed annual wind speed of 3.0 m/s.

Differences between modeled surface winds and observations are expected. The modeled surface winds are based on 6-km mesh size and will not resolve terrain features influencing winds near some local stations. The model predictions represent a larger spatial area and will smooth out small local variations in the wind field. The regional transport modeling depends on atmospheric flow with scales much larger than 6 km and the differences encountered should not bias the AQRV analysis.

6.1.8.6 Regional Haze Calculation Procedures

The potential for Phase I and Phase II of the Satsop CT Project's emissions to contribute to regional haze was assessed using the CALPUFF modeling system, MM5-driven three-

dimensional wind fields, IWAQM Phase 2 recommendations for long-range transport modeling (IWAQM 1998), and background aerosol concentrations for days with very good visibility. The analysis assessed the potential for direct fine particle emissions and secondary aerosols formed from the gases emitted by the Satsop CT Project to reduce visual ranges in Class I areas. At the request of the FLMs, the CRGNSA and Mt. Baker Wilderness are also included in the assessment. The procedure assumes regional visibility degradation is primarily due to light extinction caused by scattering by fine particles including sulfates and nitrates, and by light absorption from soot particles. This section describes the methods used to calculate the extinction coefficient.

Twenty-four hour average extinction coefficients were used as a measure of regional haze. Increased extinction causes reduced visual range. The FLMs recommend that a 5 percent change in extinction be used to indicate a “just perceptible” change to a landscape (FLAG 1999). Extinction coefficients were calculated from the CALPUFF output files using the post-processing program CALPOST. CALPOST calculates extinction coefficients from concentrations of aerosols directly emitted, sulfate concentrations, nitrate concentrations, and relative humidity. CALPOST can also summarize expected changes to background extinction as a function of hourly relative humidity at each receptor and assumed background aerosol concentrations.

The general equation applied in CALPOST divides the extinction coefficient into two components as follows:

$$b_{ext} = b_{SN}f(RH) + b_{dry} \quad \text{(Equation 3)}$$

where

b_{ext} = the extinction coefficient (1/Mega-m or Mm^{-1})

$f(RH)$ = the relative humidity adjustment factor

b_{SN} = the sulfate and nitrate or hygroscopic portion of the extinction coefficient (Mm^{-1})

b_{dry} = the non-hygroscopic portion of the extinction coefficient (Mm^{-1})

The hygroscopic portions of the extinction budget are calculated from the sulfate and nitrate concentrations predicted by CALPUFF according to:

$$b_{SN} = 3[(NH_4)_2SO_4 + NH_4NO_3] \quad \text{(Equation 4)}$$

where the sulfate and nitrate concentrations have units $\mu g/m^3$ and are converted for the change in molecular weight due to the assumed chemical form of the aerosol. The portion of the extinction coefficient that does not vary with humidity is calculated from:

$$b_{dry} = 4[OC] + 1[Soil Mass] + 0.6[Coarse Mass] + 10[EC] + b_{Ray} \quad \text{(Equation 5)}$$

where

$[OC]$ = the organic carbon portion of the $PM_{2.5}$

$[Soil\ Mass]$ = the crustal portion of the $PM_{2.5}$

$[Coarse\ Mass]$ = the portion of the mass between $PM_{2.5}$ and PM_{10}

$[EC]$ = the elemental carbon (soot) portion of PM_{10}

b_{Ray} = extinction due to Rayleigh scattering assumed to be $10\ Mm^{-1}$

Concentrations in Equation 5 also have units of $\mu g/m^3$.

6.1.8.7 Background Extinction

The hygroscopic and non-hygroscopic aerosol components of background extinction are shown in Table 6.1-44 based on data provided by the USFS for the Class I areas, CRGNSA and Mt. Baker Wilderness. The assessment used these background data for comparison with the contributions predicted for Satsop CT Project sources and used the FLM recommended criteria of a 5 percent change as an indicator of a just perceptible difference. The background data provided by the USFS in Table 6.1-44 are based on the average aerosol sampling data taken from the days with the best visibility (top 5 percent) in each season. In the CALPUFF simulations such low background aerosol concentrations are assumed for all hours of the year. Thus the results of the regional haze analysis in this assessment are conservative and likely overstate the actual influence of Satsop CT Project emissions on regional visibility.

6.1.8.8 Background Deposition Fluxes

Soils, vegetation and aquatic resources in Class I areas are potentially influenced by nitrogen and sulfur deposition. Nitrogen and sulfur deposition occur through both wet and dry processes and both direct emissions and secondary aerosols formed during transport from the source to the Class I area can contribute to total deposition. The FLMs believe the effects of pollutant loading on these AQRVs are nonlinear and request model predictions be added to conservative background estimates. The FLMs assess potential effects on a case-by-case basis using cumulative total deposition flux estimates.

Table 6.1-45 compares background Class I area deposition fluxes obtained from the USFS and NPS for each Class I area to deposition criteria established to protect soils, vegetation, and aquatic resources. The USFS indicates annual sulfur deposition fluxes below 3 kg/ha/yr are unlikely to significantly affect terrestrial ecosystems of Pacific Northwest forests. The USFS also suggests total nitrogen deposition below 5 kg/ha/yr should cause no injury, and a rate of 3-20 kg/ha/yr has the potential for some injury to plants and forest ecosystems. The background data in Table 6.1-45 suggest several Class I areas are receiving nitrogen and sulfur deposition at rates near, or above, criteria established to protect these areas.

TABLE 6.1-44
SEASONAL EXTINCTION COEFFICIENTS
FOR CLASS I AREAS AND OTHER AREAS OF INTEREST

Area of Interest		Seasonal Non-Hygroscopic and Hygroscopic Extinction (Mm^{-1})			
		Autumn	Spring	Summer	Winter
Mt. Rainier National Park	b_{dry}	13.76	14.10	17.48	12.25
	b_{SN}	0.46	0.61	1.94	0.27
Olympic National Park	b_{dry}	13.93	14.13	16.68	13.11
	b_{SN}	0.93	1.13	1.99	0.74
North Cascades National Park	b_{dry}	13.93	14.13	16.68	13.11
	b_{SN}	0.93	1.13	1.99	0.74
Pasayten Wilderness	b_{dry}	13.93	14.13	16.68	13.11
	b_{SN}	0.93	1.13	1.99	0.74
Glacier Peak Wilderness	b_{dry}	13.93	14.13	16.68	13.11
	b_{SN}	0.93	1.13	1.99	0.74
Alpine Lakes Wilderness	b_{dry}	13.40	13.36	15.11	13.05
	b_{SN}	0.65	0.93	2.93	0.47
Goat Rocks Wilderness	b_{dry}	13.93	14.13	16.68	13.11
	b_{SN}	0.93	1.13	1.99	0.74
Mt. Adams Wilderness	b_{dry}	13.93	14.13	16.68	13.11
	b_{SN}	0.93	1.13	1.99	0.74
Mt. Hood Wilderness	b_{dry}	13.93	14.13	16.68	13.11
	b_{SN}	0.93	1.13	1.99	0.74
CRGNSA	b_{dry}	14.97	17.38	19.36	18.26
	b_{SN}	1.14	1.41	3.05	1.37
Mt. Baker Wilderness	b_{dry}	13.93	14.13	16.68	13.11
	b_{SN}	0.93	1.13	1.99	0.74

Note: b_{dry} refers to the non-hygroscopic portion of extinction and includes Rayleigh scattering of 10 Mm^{-1} . b_{SN} refers to the hygroscopic component. Background coefficients provided by the USFS using aerosol data from days with the top 5 percent best visibility (Bachman 2000).

**TABLE 6.1-45
PACIFIC NORTHWEST CLASS I AREA BACKGROUND DEPOSITION FLUXES**

Area of Interest	Total Nitrogen Deposition (kg/ha/year)	Total Sulfur Deposition (kg/ha/year)
North Cascades National Park	4.0	3.5
Olympic National Park	2.0	5.6
Mt. Rainier National Park	2.4	3.1
Alpine Lakes Wilderness	5.2	7.2
Eagle Cap Wilderness	1.6	1.6
Glacier Peak Wilderness	5.8	8.0
Goat Rocks Wilderness	9.0	11.8
Mt. Adams Wilderness	9.0	10.8
Mt. Hood Wilderness	5.4	8.6
Pasayten Wilderness	5.2	7.2
CRGNSA	Assume the same as the Mt. Adams Wilderness	
Mt. Baker Wilderness	Assume the same as the Glacier Peak Wilderness	
USFS/NPS Criteria	5.0	3.0

Note: Background fluxes for USFS areas provided by Bachman (1999). These data were developed using a scientific consensus process in a workshop in 1990. These data are considered to represent a conservative upper limit for these areas – they are not average values spatially or temporally. The deposition fluxes are based on the high end of the ranges reported in Table 11 in Peterson et al. (1992).

The USFS has not adjusted these deposition flux estimates since 1990, but still considers these estimates as an adequate basis for conservative assessments.

National Park deposition flux estimates based on 1995 - 1999 National Acid Deposition Program monitoring data collected at Marblemount, Hoh Ranger Station and Pack Forest.

For all USFS and NPS areas, total background deposition is conservatively assumed to be double the measured wet deposition flux to account for additional dry and occult (cloud water) deposition processes.

6.1.8.9 Model Results

Class I Area Increment Consumption

The effects of emissions from the proposed facility on Class I area increment consumption was assessed by comparing predicted pollutant concentrations to Class I modeling significance levels proposed by the EPA (Federal Register Vol. 61, No. 142, p. 38292). Concentration predictions for SO₂, NO_x, and PM₁₀ were obtained using the CALPUFF modeling system, MM5-driven wind

fields, and other techniques outlined above. Additionally, predictions within Mt. Baker Wilderness and the CRGNSA were extracted to provide information to the FLMs for these Class II areas of interest.

Table 6.1-46 displays the highest predicted SO₂, NO_x, and PM₁₀ concentrations for the Class I areas, CRGNSA, and the Mt. Baker Wilderness. Figures 6.1-28 through Figure 6.1-34 show contour plots constructed using maximum model predictions for SO₂, NO_x, and PM₁₀ concentration for each Class I increment averaging period. PM₁₀ concentrations include primary PM₁₀ emitted by the Satsop CT Project, as well as ammonium sulfate and ammonium nitrate formed downwind of the facility. All predictions are based on a worst-case emission scenario assuming Satsop CT Project sources are operating at 100 percent load with supplemental duct firing.

**TABLE 6.1-46
CALPUFF CLASS I INCREMENT ANALYSIS RESULTS**

	Maximum Concentration Predictions (µg/m ³)					
	NO ₂ Annual	SO ₂			PM ₁₀	
		Annual	24-hr	3-hr	Annual	24-hr
Class I Area						
Mt. Rainier National Park	0.00140	0.00010	0.00172	0.00606	0.00426	0.07583
Goat Rocks Wilderness	0.00073	0.00005	0.00114	0.00446	0.00235	0.04452
Mt. Adams Wilderness	0.00044	0.00004	0.00082	0.00315	0.00218	0.03078
Mt. Hood Wilderness	0.00023	0.00003	0.00079	0.00193	0.00203	0.03984
Olympic National Park	0.00790	0.00034	0.00899	0.03883	0.00905	0.22298
Alpine Lakes Wilderness	0.00160	0.00012	0.00195	0.00354	0.00538	0.09014
Glacier Peak Wilderness	0.00095	0.00006	0.00076	0.00242	0.00290	0.03745
North Cascades National Park	0.00065	0.00004	0.00073	0.00212	0.00156	0.03153
Pasayten Wilderness	0.00033	0.00002	0.00034	0.00098	0.00066	0.01401
EPA Proposed Class I SIL	0.10	0.10	0.20	1.00	0.20	0.30
FLM Proposed Class I SIL	0.03	0.03	0.07	0.48	0.08	0.27
Class II Area of Interest						
CRGNSA (All Areas)	0.00092	0.00009	0.00132	0.00475	0.00463	0.05905
Mt. Baker Wilderness	0.00104	0.00006	0.00095	0.00335	0.00239	0.05224
EPA Class II Significance Level	1.00	1.00	5.00	25.00	1.00	5.00

Note: All NO_x conservatively assumed to be converted to NO₂. PM₁₀ concentrations include sulfates and nitrates. Emissions based on continuous operation with supplemental duct firing.

The highest model concentration predictions within the study domain typically occur on the elevated terrain several kilometers east of the site in an area known as the Black Hills. These elevated receptors are downwind for the prevailing westerly winds at the site and are also occasionally impacted during light wind conditions. Under westerly winds, the Satsop CT Project plumes once past the Black Hills typically are advected north into Puget Sound.

Table 6.1-46 lists EPA's proposed significant impact levels for Class I areas. When predicted concentrations are less than the Class I area significant impact levels, pollutant impacts are considered insignificant, and a comprehensive Class I increment analysis is not required for a given pollutant. However, these levels of significance have not, at this time, been adopted and FLMs have recommended significant impact levels that are more restrictive than those proposed by the EPA. The FLM-recommended levels are also presented in Table 6.1-46. All maximum predictions are lower than both the EPA and FLM proposed criteria. While these are not adopted regulatory criteria, they are used here to provide a measure of assurance that the Satsop CT Project contributions predicted by the model are not significant.

Pollutant Concentrations Effects on Plants

The FLMs have the responsibility of ensuring AQRVs in the Class I areas are not adversely affected, regardless of whether the Class I increments are maintained. In order to protect plant species, the USFS recommends maximum SO₂ concentrations not exceed 40 to 50 ppb (105 to 130 µg/m³), and annual SO₂ concentrations should not exceed 8 to 12 ppb (21 to 31 µg/m³) (Peterson et al. 1992). Lichens and bryophytes are found in the subalpine and alpine regions of several of the Class I areas. Some of these species may be sensitive to SO₂ concentrations in the range of 5 to 15 ppb (13 to 39 µg/m³). The USFS also indicates that no significant amount of injury to plants species in the Pacific Northwest are expected for annual NO₂ concentrations less than 15 ppb (28 µg/m³).

The 24-hour maximum and annual predictions displayed in Table 6.1-46 are several orders of magnitude less than USFS criteria established to protect vegetation in Pacific Northwest Class I areas. While cumulative effects of other existing sources in this analysis were not considered in this assessment, the magnitude of the predictions from the Satsop CT Project are not significant and are not expected to cause or contribute to the injury of plant species within the Class I areas.

Nitrogen and Sulfur Deposition

The CALPUFF modeling system was used to estimate the Satsop CT Project's potential contribution to total nitrogen and sulfur deposition in the Class I areas. Soils, vegetation, and aquatic resources in Class I areas are potentially influenced by nitrogen and sulfur deposition. As shown in Table 6.1-45, existing total nitrogen and sulfur deposition are already above FLM levels of concern. Total annual nitrogen and sulfur deposition fluxes were calculated by summing the contributions of the gases directly emitted with the secondary aerosol products formed as predicted by CALPUFF's chemistry and deposition algorithms. Note, in the nitrogen deposition

estimates, the nitrogen from the ammonium ion was included. The simulations used chemical-dependent default parameters for all reaction rate and deposition rate variables according to the IWAQM Phase 2 Recommendations. Precipitation data for wet deposition estimates are from the MM5 model, allowing a more realistic treatment of precipitation in mountain areas than could be obtained through the sparse observation network.

Contour plots of total nitrogen and sulfur deposition constructed from the CALPUFF simulations are shown in Figure 6.1-33 and Figure 6.1-36, respectively. Predicted annual nitrogen and sulfur deposition patterns are similar, with the highest deposition predicted near the site, on the Black Hills, and in southern Puget Sound. Wet deposition plays an important role in both nitrogen and sulfur deposition from the proposed project. Figure 6.1-37 and Figure 6.1-38 display the fraction of overall deposition attributed to wet deposition for nitrogen and sulfur, respectively. Wet deposition dominates north of the facility, especially in the mountain areas. Dry deposition is more important south of the site, and for nitrogen, along the western foothills of the Olympic Mountains. Annual sulfur deposition is dominated by the meteorology that accompanies rainfall and removal of SO₂ from the plume. Total nitrogen deposition depends primarily on dry deposition of NO_x and wet deposition of nitrate.

Maximum annual deposition fluxes predicted by the CALPUFF modeling system are presented in Table 6.1-47 for each Class I area, CRGNSA, and the Mt. Baker Wilderness. The highest predicted deposition fluxes and changes to existing deposition are in the southeastern corner of the Olympic National Park. However, the deposition fluxes predicted are many times lower than the USFS criteria and existing background levels. Although existing background levels may be of concern, the CALPUFF modeling analysis predicts the proposed project will not significantly add to nitrogen or sulfur deposition in the Class I areas.

Regional Haze

The CALPUFF modeling system using the MM5 initialized wind fields, and the CALPOST procedures described above were used to calculate 24-hour average extinction coefficients for each day of the year. Figures 6.1-39 through 6.1-42 display contour plots of maximum 24-hour extinction coefficients predicted for each of the four seasons from the four Satsop CT Project PGUs and two auxiliary boilers. For all seasons, the highest extinction coefficients are predicted relatively close to the Satsop CT Project in the Black Hills, east of the proposed site. The higher extinction coefficients close to the site are primarily driven by the PM₁₀ fraction of the emissions, with hygroscopic aerosols becoming more important further downwind.

**TABLE 6.1-47
CALPUFF ANNUAL DEPOSITION ANALYSIS RESULTS**

Total Annual Wet Plus Dry Deposition								
	Nitrogen Deposition (kg/ha/yr)				Sulfur Deposition (kg/ha/yr)			
	SCTP	Back	Total	Change	SCTP	Back	Total	Change
Class I Area								
Mt. Rainier National Park	0.0011	2.40	2.4011	0.0440%	0.0002	3.10	3.1002	0.0054%
Goat Rocks Wilderness	0.0006	9.00	9.0006	0.0063%	0.0001	11.80	11.8001	0.0007%
Mt. Adams Wilderness	0.0004	9.00	9.0004	0.0042%	0.0001	10.80	10.8001	0.0005%
Mt. Hood Wilderness	0.0003	5.40	5.4003	0.0047%	0.0000	8.60	8.6000	0.0004%
Olympic National Park	0.0051	2.00	2.0051	0.2559%	0.0015	5.60	5.6015	0.0268%
Alpine Lakes Wilderness	0.0020	5.20	5.2020	0.0381%	0.0003	7.20	7.2003	0.0042%
Glacier Peak Wilderness	0.0015	5.80	5.8015	0.0257%	0.0002	8.00	8.0002	0.0028%
North Cascades National Park	0.0012	4.00	4.0012	0.0308%	0.0002	3.50	3.5002	0.0056%
Pasayten Wilderness	0.0005	5.20	5.2005	0.0098%	0.0001	7.20	7.2001	0.0010%
USFS Level of Concern			5.0				3.0	
Class II Area of Interest								
CRGNSA (All Areas)	0.0005	9.00	9.0005	0.0055%	0.0001	10.80	10.8001	0.0007%
Mt. Baker Wilderness	0.0018	5.80	5.8018	0.0306%	0.0003	8.00	8.0003	0.0040%

Note: Emissions based on continuous 100% load operation with supplemental duct firing.
Nitrogen deposition includes ammonium ion.

Maximum extinction coefficient contours in all seasons follow the lowlands. Conditions conducive to aerosol formation and relatively high concentrations of fine particles are light winds, high relative humidity, and fair weather. During these conditions, high pressure and subsidence inversions are sometimes present to restrict the vertical movement of fine particles. Aerosols remain trapped until a precipitation event removes them or until winds increase sufficiently to allow vertical mixing and transport out of the lowlands.

Contour plots constructed from the 24-hour average extinction coefficients for the four days with the greatest change to background extinction are shown in Figure 6.1-43 (October 29, 1998), Figure 6.1-44 (October 30, 1998), Figure 6.1-45 (September 24, 1998), and Figure 6.1-46 (May 8, 1998). The episodes affecting the Olympic National Park occur on day with southerly flow. During these episodes the highest changes to extinction in the Park are predicted in the lower elevations as the Satsop CT Project's plumes are diverted around the mountainous areas. The episodes affecting the Mt. Rainier National Park (Figure 6.1-44) and Alpine Lakes Wilderness occur during days with high humidity as the Satsop CT Project's plumes enter the lower elevations of these areas.

Table 6.1-48 displays the maximum predicted change in 24-hour extinction coefficient for each Class I area, CRGNSA, and Mt. Baker Wilderness. Changes to extinction are based on seasonal background data for good visibility days and are adjusted with hourly humidity using the techniques described above. The extinction budgets for the higher episodes in most Class I areas are influenced by nitrates, PM₁₀, and to a lesser extent sulfates. Sulfates did contribute significantly to the extinction budget for the October 29-30, 1998, two-day episode affecting the nearby Olympic National Park. With the exception of three days, predicted changes to extinction are less than the 5 percent criterion suggested by the FLMs and Ecology for all seasons and Class I areas. According to this criterion, changes to visual conditions in the Class I areas would usually not be perceptible even when the four Satsop CT Project's PGUs and two auxiliary boilers are emitting at their short-term peak rates.

**TABLE 6.1-48
CALPUFF REGIONAL HAZE ANALYSIS RESULTS**

Maximum Change to 24-hour Background Extinction									
	Date	Bext (1/Mm)			Del Bext (%)	F(RH)	Bext by Component (1/Mm)		
		SCTP	Back	Total			bxSO ₄	bxNO ₃	bxPMF
Class I Area									
Mt. Rainier National Park	09/24/98	1.181	18.49	19.67	6.39	10.30	0.123	0.846	0.213
Goat Rocks Wilderness	09/25/98	0.213	16.45	16.66	1.29	2.71	0.014	0.081	0.118
Mt. Adams Wilderness	09/24/98	0.200	20.78	20.98	0.96	7.37	0.021	0.121	0.058
Mt. Hood Wilderness	07/02/98	0.288	24.71	24.99	1.17	4.03	0.022	0.147	0.119
Olympic National Park	10/29/98	1.673	22.17	23.85	7.55	8.86	0.222	0.705	0.746
	10/30/98	1.298	25.29	26.58	5.13	12.21	0.202	0.591	0.504
Alpine Lakes Wilderness	05/08/98	1.203	27.11	28.32	4.44	14.78	0.125	0.814	0.265
Glacier Peak Wilderness	05/08/98	0.428	30.82	31.25	1.39	14.78	0.043	0.302	0.083
North Cascades National Park	01/05/99	0.271	19.11	19.38	1.42	8.12	0.021	0.181	0.069
Pasayten Wilderness	01/05/99	0.127	19.29	19.42	0.66	8.35	0.010	0.087	0.030
Class II Area of Interest									
CRGNSA (All Areas)	04/23/98	0.547	29.01	29.55	1.89	8.25	0.050	0.365	0.133
Mt. Baker Wilderness	01/05/99	0.694	21.52	22.21	3.23	11.36	0.061	0.484	0.149

Note: Emissions are based on continuous operation with supplemental duct firing.
Background extinction derived from aerosol data on days with the best visibility (top 5%).

Emissions from combined Phase I and Phase II of the Satsop CT Project are predicted to change background extinction by more than 5 percent on two days in Olympic National Park and one day in Mt. Rainier National Park. Note, this analysis did not consider whether meteorological

conditions causing the greatest impacts actually coincide with good “natural” background visibility. Background aerosol concentrations will likely be higher and fog, low clouds, precipitation and other obscuring weather phenomena may reduce visual ranges so in some instances the impacts of the sources considered in this analysis would not be perceptible.

6.1.8.10 Summary

Class I PSD increment consumption and AQRVs, including regional haze, the effects of primary and secondary pollutants on sensitive plants and soils, and other effects associated with secondary aerosol formation, were assessed for Class I areas within 250 km of the Satsop CT Project. A regional modeling analysis designed to provide realistic estimates of secondary aerosol formation, deposition flux, and extinction coefficients for visual range was conducted.

Satsop CT Project Phase I and Phase II related PM₁₀, SO₂ and NO₂ concentrations predicted for the Class I areas are small fractions of applicable PSD increments and USFS recommended levels for the protection of sensitive vegetation. The deposition of gaseous pollutants, primary aerosols, and secondary aerosols from the facility are also many times lower than existing levels and the USFS criteria for significant impacts to soils and aquatic resources in these areas. While existing sulfur and nitrogen deposition in several Class I areas are of concern, the magnitude of the predictions from the combined Phase I and Phase II of the Satsop CT Project are not significant and are not expected to cause or contribute to the injury of the terrestrial ecosystems within the Class I areas.

The proposed facility’s impacts to regional haze in Class I areas were assessed. Perceptible changes in visual range were estimated by examining the potential increase in light scattering due to the presence of primary and secondary aerosols from the project. Concentrations of primary and secondary aerosols in Class I areas attributable to Satsop CT Project were calculated using a regional modeling approach that incorporated realistic meteorology. With the exception of three days, predicted changes to extinction are less than the 5 percent criterion suggested by the FLMs and Ecology for all seasons and Class I areas. The conservative methodologies applied in this analysis assume low background aerosol concentrations and maximum short-term project emissions occur simultaneously in the absence of weather obscuring visual conditions. Thus, the results likely over estimate actual regional haze impacts from combined Phase I and Phase II of the Satsop CT Project to Class I areas, CRGNSA, and the Mt. Baker Wilderness.