# 3.2 Air Quality

## 3.2.1 Introduction

### 3.2.1.1 Cogeneration Project

The proposed Cogeneration Project will be a 720-megawatt (MW) combined-cycle natural-gas-fired combustion turbine cogeneration facility located adjacent to the BP Cherry Point Refinery (Refinery). The Cogeneration Project will allow the Refinery to shut down existing boilers and modify its operations to reduce emissions. The Cogeneration Project will use highly effective emission control systems and good operating practices to minimize air emissions. BP expects that this will result in ~~The result will be~~ an overall reduction in cumulative criteria pollutant emissions from the Cherry Point site.

BP has performed extensive evaluations of the Cogeneration Project's emissions on ambient air quality without regard to corresponding reductions in emissions at the Refinery. BP then compared the predicted ambient air impacts to the most stringent regulatory standards in the United States and Canada. In the United States, the maximum predicted ambient impacts from the Cogeneration facility emissions will be below "significant impact levels" (SILs) established by the United States Environmental Protection Agency (USEPA). While state and federal law does not require a source to be below the SIL levels, these levels are set so low that, if a source is below the SILs, the USEPA considers impacts to be so inconsequential that no further evaluation is required. These SILs are significantly lower (more restrictive) than the U.S. Ambient Air Quality Standards and Canadian Ambient Air Quality Objectives and Canada-Wide Standards.

Dispersion modeling also indicates that even without consideration of the Refinery emission reductions, the Cogeneration Project's emissions will not cause any significant change in air quality in Canada and will not cause Canadian air quality objectives or standards to be exceeded. The analysis also indicates that the operation of the Cogeneration Project will not cause any significant degradation in the air quality levels or visibility at any of the sensitive National Park Service (NPS) or U.S. Forest Service (USFS) areas.

The Cogeneration facility will be configured with three combustion turbines (CTs) and generators (CTGs). Each of the CT exhaust outlets will be equipped with a heat recovery steam generator (HRSG) that will also have supplemental firing capability (duct burners) to augment steam production. Steam will be produced at high pressure in the HRSG and sent to a single steam turbine-driven electric generator (STG). The adjacent BP Refinery will also serve as a "steam host" for a portion of the steam produced by the HRSG. This integration with Refinery operations will allow BP to curtail or eliminate some existing operations at the Refinery with a resulting reduction in overall Refinery air emissions.

### 3.2.1.2 Sources of Information

In preparing the air quality analysis, several sources of information were used and significant coordination with local and regional air quality jurisdictions was undertaken. The type and quantity of air pollutant emissions related to the proposed project were based on data provided by BP, Duke Fluor Daniel (DFD), Bechtel, the combustion equipment suppliers, and the catalyst manufacturers. BP, ~~and~~ DFD and Bechtel provided other engineering and design criteria. Established emission calculation procedures, including AP-42 emission factors, were from USEPA publications or other accepted publications.

A BP sponsored meteorological measurements program has existed at the Refinery since the 1980's. The monitoring site is located on Safsten Road and about 1,500 feet north of Grandview Road and is approximately one-mile west-northwest of the project site. This site is operated within the strict guidelines of the USEPA On-Site Meteorological Program Guidance for Regulatory Modeling Applications (EPA-450/4-87-013, Revised June 1987). Summarized data for temperature, wind direction and speed, and precipitation were obtained from this program. Data are available for this site for the years 1995 through 2001. Data collected from this site have been used in several regulatory modeling applications for the Refinery. Wind speed and direction data from this site are considered representative of the project site.

Existing air quality in the vicinity of the project site was evaluated using summarized data collected by the Greater Vancouver Regional District (GVRD), the British Columbia Ministry of Water, Land, and Air Pollution (MWLA), the state of Washington Department of Ecology (WDOE), and the Northwest Air Pollution Authority (NWAPA).

USEPA-approved dispersion models were used to prepare an air quality impact assessment of the proposed project. The air quality impact assessment also involved extensive coordination with technical staff from the British Columbia MWLA and the GVRD regarding their input to the modeling protocols and methodologies.

#### 3.2.1.3 Regulatory Authorities

Under Washington State statute Chapter 80.50, the authority for permit review and issuance of the subsequent air permits is granted to EFSEC for thermal generating power plants capable of generating 350 MW or more of electricity. This authority has been promulgated in WAC 463-39. If the project did not fall under the authority of the EFSEC, it would require a Notice of Construction from the NWAPA. A Prevention of Significant Deterioration (PSD) permit is required and, if not under EFSEC jurisdiction, the permit would be issued by the WDOE prior to the commencement of construction of the project. By reference in WAC 463-49-005, EFSEC has adopted the PSD regulations that are contained in WAC 173-400. However, the USEPA, as provided in the Clean Air Act (CAA), retains permit co-signing authority to address the emissions of oxides of nitrogen ($NO_X$).

The PSD regulations are applicable to emission sources to be located in areas where the existing ambient air quality does not exceed the ambient air quality standards and are intended to ensure that new emission sources do not significantly deteriorate ambient air quality. The PSD regulations list ambient air increments that limit increases in the pollutant concentration over baseline conditions for fine particulate matter ($PM_{10}$), sulfur dioxide ($SO_2$) and nitrogen dioxide ($NO_2$). The air quality increments currently apply to three land classifications designated as Class I, Class II, and Class III. The most stringent of the increments applies to Class I. There are no Class III areas near the project site. All areas within 50 kilometers of the project site are Class II. Several Class I areas exist within a 200 kilometer radius of the project site.

For more information on the regulatory standards see Section 3.2.2.3 below.

### 3.2.2 Existing Conditions

3.2.2.1 Climate

The general project area is the Puget Sound Lowlands, a north-south trending topographical depression feature bordered on the east by the Cascade Mountains and the west by the Olympic Mountains and Vancouver Island. The project site is an area known as the Mountain View Upland. The climate at the Cogeneration Project site is influenced by marine air that flows easterly from the Pacific Ocean and through the Straits of Georgia and Juan De Fuca. Occasionally, cold dry continental air flows from the east-northeast through the Fraser River canyon.

The average annual temperature ranges in the region are shown below in Table 3.2-1. Monthly average temperature data presented in Table 3.2-1 are from the BP Cherry Point Refinery meteorological monitoring program. According to data from the BP measurements program, the maximum high temperature recorded was 86°F (1998) and the record low temperature was about 10°F (1996). Other published information exist on the Weather Channel web site that indicates that the record low temperature for Blaine, Washington, is -1°F (1950, 1951, 1968) with a record high temperature of 92°F (1973, 1976).

Total precipitation, by month and year, summarized from the BP meteorological measurements program is shown in Table 3.2-2. Precipitation data for this station show that about 75 percent of the annual precipitation occurs during the months of October through April. Annual precipitation amounts over the 3-year monitoring period ranged from a low of about 29 inches to a high of about 39 inches. The maximum hourly total precipitation amount since the BP precipitation measurements were established was 0.29 inches (March 2000).

Predominant wind directions at the site are from the south to south-southwest and from the east-northeast. On an annual basis, winds from the south and south-southwest occur with a frequency of about 24 percent. Winds with an easterly or east-northeasterly component occur about 21 percent of the time and winds from the west through northwest occur about 20 percent of the time.

Winds from the west-northwest through northwest become more prominent during the summertime as the Pacific sub-tropical high-pressure zone moves further north in the eastern Pacific and influences the summertime wind pattern at the site. Wintertime winds tend to have more of a southerly component, as influenced by the frequent passage of migratory storm systems from the west. Winds with easterly components are frequent and these winds occur during periods of high atmospheric pressure existing over eastern British Columbia and eastern Washington that causes an outflow of winds through the Fraser River Canyon.

Wind speeds can vary significantly, but the highest recorded hourly average wind speed at the BP monitoring site was 33.6 miles per hour (mph) that occurred in November 1998. A summary of the collected hourly average wind speeds is presented in Table 3.2-3.

In January 1999, the datalogger at the BP meteorological measurements site was reprogrammed to also collect and store the maximum wind gust for each hour.

Table 3.2-4 presents a summary of the maximum wind gusts recorded at the site since that time.

A series of wind rose plots for each year of available data are presented as Figures 3.2-1 through 3.2-7. These wind roses represent the distribution of the wind direction frequency and wind speed class on an annual basis for each year from 1995 through 2001. A cumulative wind rose for the 7-year period is presented as Figure 3-2-8.

Relative humidity is not measured at the BP meteorological measurements program. However, other published data demonstrate the influence of the marine climate at the project site. Afternoon humidity readings are typically in the 60 percent range during the summer months and in the mid to upper 80 percent range during the winter months (PNWRBC 1968). Higher relative humidity can be expected with the passage of migratory storm systems from the west. Lower humidity can be expected with high pressure over eastern British Columbia and eastern Washington. During these periods of dry outflow through the Fraser River Canyon, the relative humidity can be much lower than average.

3.2.2.2 Existing Air Quality

The NWAPA operates monitoring sites for a variety of air pollutants in the Whatcom County area. Pollutants monitored by or reported to the NWAPA include $SO_2$, particulates ($PM_{10}$, $PM_{2.5}$) and ozone ($O_3$).

NWAPA reports data for a $PM_{10}/PM_{2.5}$ monitor in the Lynden-Custer area and in downtown Bellingham. These data are reported as an “air quality index” where the levels are characterized as “good,” “moderate,” or “unhealthful.” Data from the Lynden-Custer site indicates that no moderate or unhealthful days occurred in calendar year 2001 (all 365 days were in the “good” range). At the more urban Bellingham site, there were no moderate or unhealthful days for $PM_{10}$ (all 365 days were in the “good” range) and 6 days where the $PM_{2.5}$ air quality index was in the moderate range. The Lynden-Custer site is representative of a rural “background” area while the Bellingham site is representative of a more mixed urban and rural area, where higher pollution levels are typically expected.

In Bellingham (Yew Street), $PM_{10}$ is collected continuously by a Rupprecht and Patashnick TEOM 1400 sampler. These~~is~~ data are~~is~~ summarized and reported by the NWAPA. A table showing the most recent three-year period (1999, 2000, 2001) of the~~is~~ summarized $PM_{10}$ data is presented in Table 3.2-5. For the years summarized, the maximum 24-hour $PM_{10}$ concentration is 53 $\mu g/m^3$. According to the three-year data presented, the maximum annual average $PM_{10}$ concentration in Bellingham was 13.7 $\mu g/m^3$. In March 1999, this $PM_{10}$ sampler was moved to its current Yew Street location from its previous location on Iowa Street.

NWAPA has operated a $PM_{2.5}$ sampler in Bellingham since February 1999 (Yew Street). Data recorded for this site are presented in Table 3.2-6. This site is currently co-located with the Bellingham $PM_{10}$ measurements.

The NWAPA also reports ozone data for a Lynden-Custer site. For calendar year 2001, no moderate or unhealthful days were experienced (all 365 days were in the “good” range).

BP also operates an $SO_2$ monitor at the Refinery. According to the NWAPA data summary for $SO_2$ at Blaine, all 356 days in calendar year 2001 were in the "good" range.

In addition to monitoring stations in Washington State, the GVRD operates air quality monitoring stations in the Lower Fraser Valley of British Columbia. The GVRD data are also presented as an "air quality index (AQI)." Based on the index criteria, an "AQI" of less than 25 indicates "good" air quality. An AQI of 25 to 50 represents "fair" air quality levels. From 50 to 100, the AQI level is considered to be "poor " and above 100 the air quality is considered to be "very poor." In order to characterize the existing air quality for the areas closest to the US/Canada border, summarized data for a selection of the monitoring stations were evaluated (Surrey, Richmond, Langley, and Abbotsford).

Calendar year 2000 is the latest data available from GVRD and is summarized in Table 3.2-7. From the data, it is evident that the air quality in areas of British Columbia immediately north of the Cogeneration Project site is characterized as generally being in the "good" range with some days characterized as "fair." On no day during 2000 were "poor" air quality conditions observed at these locations.

Ambient air quality data has also been summarized by pollutant for the closest ambient monitoring stations in Canada. The Surrey and Langley sites are the closest sites in Canada to the project that monitor $PM_{10}$, carbon monoxide (CO), $NO_X$, and $O_3$. They are located approximately 26 kilometers to the north and northeast, respectively from the Cogeneration Project site. The Richmond and Abbotsford sites are the closest sites in Canada that monitor $SO_2$ and they are located 37 kilometers to the northwest and 36 kilometers to the northeast, respectively, from the Cogeneration Project site. Pitt Meadows and Vancouver Airport are the closest sites in Canada to the Cogeneration Project site that measure $PM_{2.5}$ and they are located 39 kilometers to the north and 43 kilometers to the northwest, respectively, from the Project site. A summary of the ambient monitoring sites is shown in Table 3.2-8.

For the Canadian air quality data, the maximum and 98$^{th}$ percentile concentrations for each pollutant and averaging time are summarized in Table 3.2-9. Concentrations are listed for 1999 through 2001 for the closest two ambient monitoring stations for each pollutant. The maximum values of the three years and the two stations are also listed.

3.2.2.3 Ambient Air Quality Standards

The USEPA is authorized by the CAA amendments of 1970 to establish National Ambient Air Quality Standards (NAAQS) and air concentration limits for six "criteria" air pollutants. The NAAQS include a primary standard that is designed to protect human health and a secondary standard that set to protect the public welfare. The USEPA lists the following six criteria pollutants:

- Ozone ($O_3$)
- Carbon monoxide (CO)
- Lead (Pb)
- Nitrogen dioxide ($NO_2$)
- Particulates ($PM_{10}$)
- Sulfur dioxide ($SO_2$)

WDOE has also adopted similar standards, but in addition includes air quality standards for radionuclides and fluorides. The state standards are listed in WAC 173-470 through 481 and, at a minimum, must be equivalent to the federal standards, although they can be more stringent.

Based on air quality monitoring information, WDOE and the USEPA designate regions as being in "attainment" or "nonattainment" for air pollutants. If a region is in compliance with the health-based NAAQS, then it is determined to be in "attainment." Whatcom County is in attainment for all air pollutants regulated by the NAAQS and the state air quality standards.

Table 3.2-10 summarizes the ambient air quality standards established by the USEPA and WDOE as well as presenting the significant impact level (SIL) values appropriate for each pollutant and averaging time. The SILs are typically 1 to 5 percent of the NAAQS and are well below any levels that could lead to adverse health or welfare impacts. Dispersion modeling for PSD applications typically focus first on comparing the dispersion modeling results for the new source to the established SILs and then conducting further modeling (PSD increment and multi-source cumulative) only if it is required because SILs are exceeded.

The SILs are a conservative screening tool used to determine the extent of air quality analysis required. According to USEPA and WDOE guidance, if the modeled maximum concentrations are below the SILs, no significant impact area exists and no further modeling, taking into account other nearby increment consuming or existing sources of air emissions, is required to demonstrate compliance with the PSD increments and the NAAQS. Projected (modeled) pollutant concentrations below the SILs are considered to be inconsequential relative to the PSD increments and the maintenance of the ambient air quality standards. For the Cogeneration Project, all modeled concentrations are below their respective SILs.

In addition to the ambient air quality standards established in the United States, the Canadian Environmental Protection Act provides for three levels of air quality objectives: Desirable, Acceptable and Tolerable. The Province of British Columbia has also established air quality objectives that are similar to the Canadian national objectives and where no comparable federal objectives exist, the GVRD has proposed objectives for pollutants of concern within its jurisdiction. There are also Canada-wide Standards for $PM_{2.5}$ and $O_3$ established by the Canadian Ministers of Environment. These Standards establish goals hoped to be achieved by the year 2010, rather than regulatory limits. Table 3.2-11 summarizes the Canadian air quality Objectives and Standards.

### 3.2.2.4 Odor

Generally, the air in the vicinity of the project site is free of unpleasant odors.

### 3.2.2.5 Dust

The air in the vicinity of the project site is generally free of dust. The area around the site is predominantly rural, agricultural land with some populated areas within a few kilometers of the site. The agricultural land is predominantly grass covered and is used for cattle grazing. Typical farming activities, such as soil tilling that create dust clouds, occur infrequently.

### 3.2.2.6 Existing Sources of Air Emissions

Existing emission sources in the vicinity of the Cogeneration Project site include the adjacent BP Refinery, the Alcoa Intalco Works aluminum smelter (approximately 3 miles south-southeast of the Project site), the Conoco-Phillips Refinery (approximately 5 miles south-southeast), and the Tenaska Washington Cogeneration power plant (approximately 5 miles to the south-southeast). All of these sources are regulated by NWAPA or by WDOE.

### 3.2.2.7 Air Quality Designations

As indicated above, NWAPA, other regional air quality authorities, and WDOE maintain air quality monitoring stations at various locations around the state. Data from these stations are used to establish whether an area is in attainment for criteria pollutants. Based on the closest monitoring stations in Whatcom County, the air quality at the project site is in attainment.

The USEPA and WDOE regulations specify three types of areas for consideration in air quality analyses. These areas are Class I areas, Class II areas, and Class III areas. Each of these area types has specific ambient air quality standards and PSD increments. The requirements for the Class I areas are the most stringent with the Class III requirements being the least stringent.

A PSD Class I area is one in which the area has been defined as having special sensitivities and are generally limited to certain National Parks Service (NPS) Areas, U.S. Forest Service (USFS) Wilderness Areas, and Fish and Wildlife Areas. The Class I areas within Washington State are listed in WDOE's regulations and are listed below.

A Class II area covers all other areas that are not designated as Class I or Class III. There are no Class III areas within the state of Washington, therefore, all other areas of the state are classified as Class II.

Impacts to air quality values must also consider the designated PSD Class I areas within a 200-kilometer radius of the project site. The Class I areas included in the BP air quality evaluations include:

- North Cascades National Park
- Olympic National Park
- Glacier Peak Wilderness Area
- Alpine Lakes Wilderness Area
- Pasayten Wilderness Area

Figure 3.2-9 shows the location of the Class I areas.

### 3.2.2.8 Greenhouse Gas Emissions

The issue of how emissions from human activities may affect the global climate has been the subject of extensive international research over the past several decades. The most recent report by the United Nations Intergovernmental Panel on Climate Change (IPCC) concludes that the concentrations of greenhouse gases in the atmosphere continue to increase as a result of human activities, and that there is strong evidence that these greenhouse gases are contributing to global warming (IPPC 2001a). The National Academy of Sciences has generally agreed with the IPCC's conclusion that greenhouse gases are accumulating in the atmosphere as a result of human activities and that they are causing surface temperature to rise (NAS 2001).

In 1999, annual greenhouse gas emissions in the United States totaled approximately 6,746 million metric tons of $CO_2$ equivalent (EPA 2001). Annual greenhouse gas emission in Washington State total approximately 92 million metric tons of $CO_2$ equivalent (OTED 2001, Kerstetter 1999). In Washington, about 75% of the total greenhouse gas emissions are attributable to transportation (OTED 2001).

### 3.2.3 Environmental Impacts of the Proposed Action

3.2.3.1 Construction Impacts

Equipment Emissions

Heavy construction equipment will be used for site excavation and preparation as well as for installation of equipment. These vehicles will emit a variety of pollutants from the combustion of diesel fuel or gasoline in the internal combustion engines. The emission of these pollutants will be limited to the daily construction period. It is not anticipated that these emissions will cause an associated ambient air quality standard to be exceeded.

Odor

Some odors may occasionally occur that will be associated with the use of diesel fuel and gasoline powered vehicles on the Project site. These odors would be unlikely to extend outside of the BP property.

Dust

The movement of vehicles on site during the Project construction phase will generate some dust. BP will minimize dust emissions by watering of the construction area and limiting the speed of the construction vehicles. It is not anticipated that any of the dust generated will cause a relevant ambient air quality standard to be exceeded.

3.2.3.2 Operation and Maintenance Impacts

Overview

Air quality impact assessments (AQIA) were conducted to determine the potential worst-case impacts of the project within the United States and Canada. The AQIA consisted of 5 elements:

- A Class II area criteria pollutant maximum concentration analysis in the United States;
- An analysis of the concentration, visibility, and deposition in Class I areas in the United States;

- A toxic pollutants analysis in the United States;
- A maximum concentration analysis in Canada; and,
- A visibility analysis in Canada.

The first three elements listed above were conducted as part of the PSD process required in the United States. The additional two elements were conducted at the request of Canadian regulatory agencies.

Computer dispersion modeling was used to simulate the dispersion of pollutant releases from the proposed facility. The methodologies used in the AQIA follow USEPA guidelines (40 CFR Part 51, Appendix W), the requirements of WDOE, the Federal Land Managers (FLMs), and requests by the GVRD. Additional details on the modeling protocols and results of the PSD elements can be found in Part III, Appendix E.

With the exception of the Class I area visibility analyses, BP's air quality modeling did not take into account the substantial reduction in emissions due to modifications at the Refinery associated with the Cogeneration Project. These reductions were not taken into account in the modeling because the modeled impacts were already well below all the regulatory significance criteria. Modeling results are compared to appropriate significance criteria for each AQIA element. These significance criteria are:

- Published significant impact levels (SILs) for Class I and Class II concentration analyses.
- Published acceptable source impact levels (ASILs) for the toxic air pollutant (TAP) concentration analyses.
- Air quality related values (AQRV) for the Class I visibility and deposition analyses.
- The Canadian air quality objectives and standards after incorporating appropriate background values.
- The Canadian visibility criteria recommended by the GVRD.

The maximum results for all of these evaluations are less than the appropriate significant criteria listed above. Generally, the short-term impacts from all combined facility emissions sources are at their maximum ground-level concentration just outside the Cogeneration Project site's northern property line~~, and the maximum annual impacts are approximately 7 miles to the north of the site~~. The results and comparisons are further explained below.

Cogeneration Project Emissions

The sources of air emissions in the Cogeneration Project are the three natural gas-fired combustion turbines, the cooling tower, the emergency diesel generator and the emergency diesel firewater pump.

Emissions associated with the combustion turbines will vary with operating modes. The emission rates for criteria pollutants are provided in Table 3.2-12. Criteria pollutant emissions associated with the cooling tower, emergency diesel generator and the emergency firewater pump are provided in Table 3.2-13. The emission rates for toxic pollutants are provided in Table 3.2-14.

Table 3.2-15 provides the maximum potential annual emissions of criteria pollutants, taking into account all potential sources and operating scenarios associated with the Cogeneration Project. These maximum potential emissions are based upon very conservative assumptions that the facility would operate at maximum capacity (with duct firing) for 7,960 hours per year, and that each turbine would be started up and shut down 100 times annually.

Table 3.2-16 also provides what BP believes to be a much more realistic estimate of expected emissions from the Cogeneration Facility. This estimate was based upon several assumptions. First, BP used an average operating scenario that was developed based on six years of expected operation (a typical operational/maintenance cycle for turbines) while taking into account market conditions and required maintenance. Under this average operating scenario, the plant is expected to operate as follows:

- 55% of the time at 100% turbine load and no duct firing
- 39% of the time at 100% turbine load and variable duct firing sufficient to maintain the Refinery steam header pressure
- 2% of the time in a forced outage mode where one turbine is down for maintenance for eight hours while the other two are operating at 100% turbine load
- 1% of the time in an economic dispatch mode where all three turbines are down for eight hours
- 3% of the time in a planned outage mode where all three turbines are shut down for more than 72 hours for planned maintenance.

Second, BP assumed that average actual $NO_X$ emissions would be no more than 90% of the proposed permit limit. In order to ensure constant compliance with the short-term permit limits, these types of facilities would expect to maintain average emissions somewhat below their permit limits. Based on its operating experience, BP indicated that it would be reasonable to expect actual $NO_X$ emissions to average ten percent below the permit limit.

Third, BP assumed that average actual CO emissions would be no more than 80% of the proposed permit limit in order to ensure constant compliance with the short-term permit limits. Since oxidation catalyst performance is more efficient when new and degrades over time, it is reasonable to expect that the CO concentration will be very low initially and then increase over time. The long-term average CO concentration will always be below the permit limit.

Finally, BP assumed that the project's actual $PM_{10}$ emissions would be approximately 60% below the proposed permit limit. BP's assumptions regarding the $PM_{10}$ emissions follow.

PSD permit limits are set at levels deemed appropriate in light of the EPA testing method that permit holders are required to use to test for $PM_{10}$ emissions. That testing method

(EPA Method PRE-4/202) was designed to measure both filterable (front half) particulate and condensable (back half) particulate. Filterable particulate is particulate present in the hot exhaust gas. Condensable particulate is that which forms as the exhaust gas cools, either in the stack or immediately after exiting the stack. The filterable particulate is measured by pulling a sample of the exhaust through a filter and the condensable particulate is estimated using an instrument that forces the turbine exhaust gas into an icewater bath.

In recent years, $PM_{10}$ concentrations detected in gas-fired combustion turbine exhaust using the EPA test method have raised questions about the accuracy of the test method. Extensive research has been conducted in an effort to determine the source and type of the particulate matter in the exhaust gas and to determine whether the EPA test method is accurate (GE 2002; Sierra Research 2001).

This research shows that up to 90% of the particulate reported by this test method in exhaust from natural gas-fueled combustion turbines is condensable particulate. Of this condensable particulate, about 90% is inorganic and comprised of sulfates, chlorides, ammonia, sodium, and calcium.

This research shows that the EPA test method significantly exaggerates $PM_{10}$ emissions. By far, the largest source of error in the EPA test method is generated by condensable particulate measured by the test. Sulfur dioxide ($SO_2$) gas, a constituent of the stack gas, is drawn into the test apparatus. As expected of a gas, $SO_2$ passes through the filterable portion of the test apparatus and into an icewater bath, where it is “bubbled” through the cold water. The $SO_2$ dissolves in the cold water. Since gas turbines operate with a large excess of oxygen, oxygen is also dissolved in the cold water. During the testing, virtually all of the $SO_2$ is slowly oxidized to form sulfate ($SO_4$.), which is measured as a particulate. This results in the test method significantly overestimating the particulate emissions because, during normal operation, only a relatively small portion of the $SO_2$ in the exhaust would form $SO_4$ in the stack.

The test method also overstates the particulate emissions by including particulates already present in the ambient air. These particulates were identified in the research as sodium, chloride, and calcium.

The EPA test method suffers from measurement error due to the small amount of particulate sample collected from the gas turbine exhaust. The EPA method was intended to collect samples over a one hour period of time, however, the research shows that gas turbine tests must be run for up to 6 hours to collect enough material.

Based on the information contained in the GE and Sierra Research studies, the actual particulate emissions from the plant are expected to be at least 60% less than the particulate emissions measured by the EPA reference method test (see Table 3.2-16).

Total emissions of criteria pollutants from the Cogeneration Project are expected to be offset by reductions in emissions from the Refinery. These reductions will be accomplished by the Cogeneration Project providing steam to the Refinery. This will allow the Refinery to discontinue the use of utility boilers that currently provide steam for Refinery operations. This will also allow the Refinery to reduce the use of Refinery gas-fired heaters. Utility boilers and gas-fired heaters are emission sources at the

Refinery. Table 3.2-17 compares BP's expected annual emissions of criteria pollutant emissions to the emission reductions that will occur at the BP Refinery.

The air quality impact analysis discussed below does not take into account the emissions reductions at the Refinery unless specifically indicated.

Impact Analysis

The Class II area analysis was conducted using the USEPA-approved Industrial Source Complex ~~Short Term, Version 3~~ (ISC~~ST3~~) computer dispersion model that has been updated to include more recent treatment of building-induced downwash calculations to predict the maximum concentration of the criteria and toxic air pollutants. This model is called ISC-Prime and is approved for use by the WDOE. Five years of on-site meteorological data were used. The analysis covered a square area ~~12~~ 50 kilometers in distance from the project site in the north-south and east-west directions, including into Canada.~~up to the Canadian border.~~ Three operating scenarios were modeled;

- Normal turbine operations without duct burners operating
- Operation with duct burners operating at a normal firing rate
- Operation with duct burners operating at a maximum firing rate

Operation at base-load and part-load were modeled to determine the worst-case operating conditions. The duct burners would only be fired when the turbines are operating at full load. Since gas turbine operations vary with ambient temperature, operations at three ambient temperatures were modeled.

The modeling also included the emissions from the emergency diesel generator and the firewater pump, estimated to be 1,500 kW and 265 bhp in size, respectively, and the multi-cell cooling tower. While the cooling tower will operate on a continuous basis, the emergency generator and firewater pump will only operate up to 2 hours per week (104 hours per year) for readiness testing and maintenance. Annual impacts were conservatively modeled for 250 hours per year. The diesel engines will also operate as needed in emergency situations.

Predicted concentrations of $NO_X$, CO, $SO_2$, and $PM_{10}$ in the Class II areas are compared to the SILs presented in Table 3.2-18~~2~~. As shown in this table, all Class II impacts are well below their respective SILs. Since this is the case, PSD guidance stipulates that no comparison with NAAQS, WAAQS, or Class II PSD increments needs to be performed to demonstrate compliance with the ambient air quality standards and the maintenance of the public health and welfare.

The analyses for the Class I areas were conducted using the CalPuff computer dispersion modeling system. CalPuff was used to predict $NO_X$, $SO_2$, and $PM_{10}$ concentrations, nitrogen and sulfur deposition, and visibility in five Class I areas and one additional wilderness area as requested by the U.S. Forest Service (USFS). The wind field used in the CalMet meteorological processing program covers an area that extends 50 kilometers beyond the Class I areas and is approximately 504 kilometers by 408 kilometers in size. One year of MM5 meteorological data was obtained from WDOE for this study. The same three operating scenarios used in the Class II concentration analyses and previously described were used for the Class I area analyses. The full-load and minimum temperature scenarios were modeled because they are associated with the highest emissions.

Additional modeling was performed for the Class I visibility analysis to account for some of the reduction of emissions resulting from proposed modifications at the Refinery. This additional modeling is presented to show a more realistic analysis of the potential effects on visibility for this Project.

Predicted concentrations of $NO_X$, $SO_2$, and $PM_{10}$ in the Class I areas are compared to the SILs shown in Table 3.2-19~~13~~. As shown in the table, all Class I impacts are below their respective SILs.

The predicted visibility change and nitrogen and sulfur deposition are compared to the AQRV significance levels presented in Table 3.2-20~~14~~. All deposition results are well below their respective significance levels. The predicted visibility change is less than the 5 percent significance level in all Class I areas for all three operating scenarios and including the reduction of the emissions from the three utility boilers.

The TAP analyses were conducted using similar methods as the Class II area criteria pollutant analyses previously described. The maximum toxic emissions were used to achieve conservative, maximum impacts. A comparison to the small quantity emission rates listed in WAC 173-460 was performed (included in the PSD Application - Appendix E of this document) to determine which TAPs should be modeled. Predicted concentrations of the modeled TAPs are compared with to the ASILs shown in Table 3.2-21~~15~~. As shown in this table, all TAP concentrations are below the WDOE-specified ASILs.

The Canadian areas concentration analyses were conducted using similar methods as the U.S. Class II area analyses previously described. The analyses covered an area into Canada extending to 50 kilometers from the project site (the limit of the approved use of the ISC-Prime~~ST3~~ dispersion model). The predicted concentrations are added to the maximum background concentrations provided by the Canadian regulatory agencies and compared to the Canadian objectives and standards given in Table 3.2-22~~16~~. The $PM_{2.5}$ emissions are not specifically modeled and are conservatively assumed to be equal to the $PM_{10}$ emissions. In reality, the $PM_{2.5}$ emissions are a subset of the $PM_{10}$ emissions and should, therefore, be lower than reported. The modeled maximum concentration is significantly less than the background concentration for all pollutants. The total concentration (modeled concentration plus background concentration) is significantly less than the objectives and standards for all pollutants.

The visibility analyses for the Canadian areas were conducted using similar methods as the Class I visibility analyses conducted for the United States areas. The analyses were conducted along lines of sight recommended by the GVRD (listed in Table 3.2-23~~17~~). The visibility extinction was averaged along each line of sight to achieve a day-by-day account of whether visibility is impaired with and without the impacts from the proposed BP Cogeneration Project. The maximum visibility change due to the emissions from the BP Cogeneration Project was also calculated.

Background data from Abbotsford for 1995 was used in these analyses since this is the best available data for nitrate and sulfate concentrations. The $10^{th}$ percentile concentrations were used to simulate good visibility conditions. A visual range of less than 60 kilometers was used to determine impaired visibility.

The results of the Canada visibility analyses are summarized in Table 3.2-24~~18~~. As shown in this table, Cogeneration Project impacts will not increase the number of days with impaired visibility at any of the seven specified lines of sight. In addition, the maximum visibility change is only 2.7 percent, which is significantly below the 5 percent threshold of perceptibility used by the Federal Land Managers in the United States.

Startup and shutdown conditions were not modeled for any of the five analyses. ISC-Prime~~ST3~~ and CalPuff are designed to model emissions from steady-state emissions sources. Startup and shutdown conditions are dynamic (not steady-state) with the emissions and, more importantly, the stack exhaust gas exit velocity and exhaust gas temperature changing rapidly and highly dependent on how long the turbine has been shut down (cold start, warm start, hot start).

Short-Term Criteria Pollutants

The criteria air pollutants with short-term averaging periods (24-hours or less) for which air quality modeling analyses studies were conducted are $SO_2$, $PM_{10}$, and CO. Table 3.2-18~~2~~ presents the results of the modeling analyses conducted for these pollutants. As can be seen from this table, no concentrations were found to be in excess of any of the respective SILs.

Long-Term Criteria Pollutants

The criteria pollutants with long-term averaging periods (greater than a 24-hour period) are $NO_X$, $SO_2$, $PM_{10}$, and lead (Pb). Tables 3.2-18~~0~~ and 3.2-19 present~~s~~ the results of the modeling analyses conducted for these pollutants, with the exception of lead, which did not require modeling. As can be seen from this table, no concentrations were found to be in excess of any of the respective SILs.

PSD Analysis

The complete text of the PSD Application for this Project is included as Appendix E of this document.

Green House Gas Emissions

Electricity generated from coal, oil or natural gas results in the emission of greenhouse gases. However, different types of electrical generation technologies produce different amounts of greenhouse gases per kilowatt-hour of electricity generated. In the United States, coal-fired generation produces an average of 2.10 lbs of $CO_2$ per kWh, oil-fired generation produces an average of 1.97 lbs of $CO_2$ per kWh, and natural gas-fired generation produces an average of 1.32 lbs of $CO_2$ per kWh (DOE/EPA 2000). A state-of-the-art natural-gas-fired combined-cycle combustion turbine facility produces approximately 0.87 lbs of $CO_2$ per kWh of electricity generated (EFSEC 2002).

The Cogeneration Project is more efficient than all of the other fuel alternatives or the non-cogeneration gas fired power plant. . It will produce approximately 0.83 lbs of $CO_2$ per kWh of electricity. Assuming the Cogeneration Project operates at 85% capacity, it would emit approximately 2,016 Ktonnes of $CO_2$ annually to produce electricity.

In addition to efficient production of electricity, the Refinery would realize a ~~net~~ reduction in $CO_2$ emissions due to the production of steam by the Cogeneration Project and the reduction in steam produced at the Refinery. The total annual $CO_2$ reduction at the refinery would be about 400 Ktonnes/year.

To the extent that the Cogeneration Project produces electricity that would otherwise be produced by a less efficient generating facility, its operation will result in an overall reduction in greenhouse gas emissions. For this reason, every major authority on global warming recommends the increased reliance on natural-gas-fired combined cycle generating technology and cogeneration in particular (IEA 2001; DOE/EPA 2000; EAI 1998; IPPCb).

Odors

Offensive odors are not typically observed with natural-gas-fired combustion turbine cogeneration facilities and the operation of this proposed facility is not expected to create any nuisance odor conditions. No odors are typically associated with the combustion of natural gas in CTs.

Anhydrous ammonia will be used in the selective catalytic reduction (SCR) system as a reaction agent for the control of $NO_X$ emissions. Unreacted ammonia will be present in the HRSG exhaust gas flow. Ammonia is commonly perceived as having an odor (e.g., household cleaners, etc.). However, in the quantity to be released through the HRSG stack, an ammonia odor is not expected to be detectable. In fact, the dispersion modeling conducted for ammonia at a rate of 5~~10~~ ppm (a maximum of 13.2~~34.8~~ lbs/hour per turbine and about 173~~181~~ tons/year total) from the HRSG stacks indicates that the public exposure to ammonia (approximately 2.8~~5.817.75~~ µg/m³ or 0.004~~825~~ ppm) will be well below the accepted range where an ammonia odor could be detected (5 to 53 ppm) (Clayton, 1993). Ammonia emissions will be limited to ~~an annual average of~~ a 24-hour average of no more than 5 ppm at 15% $O_2$~~, with maximum concentrations of no more than 10 ppm at 15% $O_2$ at any time~~. Relative to the public health exposure of ammonia, the maximum projected ground-level impact of the ammonia emissions, based on the 5~~10~~ ppm level, is about 3~~618~~ percent of the 100 µg/m³ 24-hour health-based standard identified in WAC 173-460.

No other odors are anticipated from the cogeneration facility.

Dust

Significant quantities of dust will not be generated during the operation of this proposed facility. All facility roads will be paved to minimize the potential for fugitive dust emissions from vehicle traffic.

Fogging and Icing from Cooling Tower

A cooling tower water vapor plume fogging and icing analysis was performed using the Seasonal/-Annual Cooling Tower Impact Model (SACTI), version 11-01-90. SACTI was created by the Argonne National Laboratory to predict the seasonal and annual impacts of cooling tower plumes, including plume fogging and icing.

The objective of this study was to determine if the cooling tower would~~ill~~ contribute to fogging and/or icing on Grandview Road on the north side of the project boundary. The analysis shows that fogging may occur for a total of 2.5 hours a year in the NE or NW directions. The area affected by fogging extends from 200 to 500 meters from the center of the cooling tower. Grandview road is approximately 400 meters in these directions and, therefore, may be affected by the edge of the plume for these few hours of the year. Icing is not expected to occur.

### 3.2.4 Environmental Impacts of the No Action Alternative

Under the No Action Alternative, increasing demands for electricity in the Pacific Northwest would be satisfied by the construction of other natural gas fired power plants. No new hydroelectric generating capacity is being added and the development of nuclear power plants has been halted. Wind and solar power do not have the generating availability needed to meet continuous electricity demand. Fuel cell technologies are being developed but remain relatively small and expensive. Natural-gas-fired combined-cycle combustion turbine plants will meet the increasing demand for electricity generation. If the Cogeneration Project is not built and operated, the Refinery and others in the region will use electricity produced by existing sources of generation and new gas-fired combined-cycle power plants.

Under the No Action Alternative, BP would also be unable to implement the proposed modifications at the Refinery, and therefore, would not achieve the criteria pollutant and $CO_2$ emission reductions anticipated in connection with the Cogeneration Project. Other new gas-fired facilities would be less efficient than the Cogeneration Project and so would generate additional greenhouse gases.

Under the No Action Alternative, existing gas-fired power plants employing older, less effective emission control technology would be more likely to continue operations. These facilities emit higher rates of both regulated pollutants and greenhouse gases than would the Cogeneration Project.

### 3.2.5 Mitigation Measures

3.2.5.1 Construction Impacts

During construction, dust will be controlled as needed by spraying water on dry, exposed soil.

3.2.5.2 Operation Impacts

Regulated Air Emissions

BP will mitigate the air emissions from the facility by burning only natural gas in the combustion turbines and duct burners and only low-sulfur diesel fuel in the emergency generator and firewater pump. Over and above the CT vendor's 9.0 ppm dry Low-$NO_X$ technology, $NO_X$ emissions from the CTs and duct burners will be controlled to the BACT level (2.5 ppm annual average at 15% $O_2$) through the use of selective catalytic reduction (SCR). Although clearly more expensive than BACT requires, a catalytic oxidation system will be installed for the control of CO emissions to an annual level of 2.0 ppm (at 15% $O_2$). This catalytic oxidation system will also provide the added benefit of controlling about 30 percent of the VOC emissions, including toxics. Other pollutants will be controlled using good combustion technology and good operating practices and the combustion of low-sulfur natural gas as a fuel.

BP will control dust on~~pave~~ all Cogeneration Project roads and will provide necessary maintenance and housekeeping to minimize the amount of dust that could be generated from vehicle traffic.

Greenhouse Gases

In 1997, BP became concerned about the influence of man-made greenhouse gas (GHG) emissions on changes in the world's climate. Rather than wait for proof that such a linkage existed, BP took action by targeting a 10% reduction in the company's worldwide GHG emissions from 1990 levels to be achieved by the year 2010. In early 2002, BP met this target, receiving independent verification of a reduction in annual GHG emissions of 9.5 million metric tonnes. Having met this target, BP set a new objective to hold net GHG emissions at the same level through the year 2012, while absorbing all new growth in company operations.

Because it is possible for the Cogeneration Project to change ownership, the GHG mitigation proposal must be able to accommodate such changes. As long as the Cogeneration Project is owned by BP, the Project's GHG emissions would be a part of BP's new GHG objective and the Project's emissions would be offset by GHG emission reductions within BP's worldwide operations. If, at some point in the future, BP did not own the Cogeneration Project, mitigation for Cogeneration Project GHG emissions would be provided as described below:

1. The proposed CO2 emission standard will be 0.675 lbs CO2/kWh calculated on the basis of Cogeneration Project Fuel Charged to Power in Btu/kWh.
    a. Fuel Charged to Power equals (Total Fuel Consumed by the Cogeneration Unit less Fuel Charged to Steam) divided by net kWh generated.

   b. Fuel Charged to Steam is equal to the steam energy used by the Refinery divided by a conversion factor of 0.901~~9~~ (LHV/HHV).

2. Emissions in excess of the emission standard would be mitigated either by (a) an annual payment to a qualifying organization such as the Climate Trust of \$0.85~~57~~/ton $CO_2$, or (b) GHG reductions obtained by the Cogeneration Project owner, or (c) a combination of the two.

3. Mitigation would be satisfied annually for 30 years, which is the assumed economic life of the project. Mitigation would be reported to EFSEC annually.

### 3.2.6 Cumulative Impacts

BP has evaluated the cumulative effect of existing sources and the proposed Cogeneration Project by summing the modeled impact of the Cogeneration Project emissions and the existing (background) levels then comparing that total to established ambient air quality standards~~.~~ (see Tables 3.2-22 and 3.2-25). All of the projected cogeneration facility impacts are well below the existing levels and the total concentrations are well below the respective ambient air quality standards. In fact, the cumulative effects would be even less than these results show, because the modeling did not take into account the emission reductions at the Refinery as a result of the Cogeneration Project.

### 3.2.7 Unavoidable Significant Adverse Impacts

There are no unavoidable significant air quality impacts associated with this project. The proposed cogeneration facility will emit criteria air pollutants and some toxic pollutants into the atmosphere. However, it will also enable BP to implement significant emissions reductions at the Refinery. In fact, with these emissions reductions implemented, there is likely to be no observable changes in the ambient air quality levels either in the U.S. or in Canada. The various analyses conducted for the PSD application and for other sensitive areas of interest indicate that, even though air emissions associated with the cogeneration facility will occur and will have an impact on the overall air quality of the region, those impacts are almost negligible and are not likely to cause any adverse impacts to the protection of human health and welfare, to any soils or vegetation, to any flora or fauna, or to any other sensitive areas identified by the NPS or USFS or by the Canadian air quality regulatory agencies.

The expected emission reductions from the Refinery are not required to achieve this low level of impact, except to reduce the visibility change at Olympic National Forest from 6% one day per year to below 2.5%.

## Table 3.2-1

## Average Temperature by Month (°F)

| Month | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 7-Year Average |
|---|---|---|---|---|---|---|---|---|
| January | 40.6 | 35.8 | 39.2 | 39.9 | 41.3 | 38.6 | 40.9 | 39.5 |
| February | 43.1 | 40.3 | 41.0 | 45.4 | 42.8 | 41.0 | 37.6 | 41.6 |
| March | 44.2 | 44.0 | 43.9 | 45.3 | 43.1 | 35.2 | 44.1 | 42.8 |
| April | 47.9 | 49.9 | 47.3 | 48.1 | 46.5 | 47.1 | 47.3 | 47.7 |
| May | 55.4 | 51.2 | 55.4 | 54.0 | 50.6 | 52.1 | 52.7 | 53.1 |
| June | 58.2 | 57.0 | 57.6 | 58.4 | 56.3 | 53.5 | 56.0 | 56.8 |
| July | 62.0 | 62.0 | 61.3 | 63.0 | 59.5 | 53.1 | 60.1 | 60.1 |
| August | 58.8 | 61.5 | 63.1 | 62.7 | 61.4 | 54.3 | 61.2 | 60.4 |
| September | 58.2 | 54.4 | 57.9 | 58.1 | 54.5 | 59.4 | 55.8 | 56.9 |
| October | 49.7 | 49.3 | 49.7 | 48.7 | 47.8 | 48.1 | 49.2 | 48.9 |
| November | 47.2 | 39.9 | 45.9 | 46.3 | 46.3 | 48.7 | 45.9 | 45.7 |
| December | 40.2 | 33.7 | 41.6 | 39.9 | 41.4 | 40.4 | 40.3 | 39.6 |
| Annual | 50.6 | 48.2 | 50.3 | 50.8 | 49.3 | 47.6 | 49.2 | 49.4 |

Source: BP meteorological program

## Table 3.2-2

## Precipitation by Month (Inches)

| Month | 1998 | 1999 | 2000 | 2001 | Monthly Average |
|---|---|---|---|---|---|
| January | N/A | 5.94 | 2.58 | 3.20 | 3.91 |
| February | N/A | 4.84 | 2.66 | 0.80 | 2.77 |
| March | N/A | 3.42 | 3.49 | 3.28 | 3.40 |
| April | N/A | 1.48 | 1.80 | 3.19 | 2.16 |
| May | N/A | 1.96 | 3.55 | 1.35 | 2.29 |
| June | N/A | 2.31 | 2.37 | 1.89 | 2.19 |
| July | N/A | 0.93 | 1.30 | 0.78 | 1.00 |
| August | N/A | 1.84 | 0.69 | 2.12 | 1.55 |
| September | 0.33 | 0.44 | 2.04 | 1.42 | 1.06 |
| October | 0.99 | 4.03 | 2.76 | 4.72 | 3.13 |
| November | 6.58 | 6.10 | 2.72 | 4.18 | 4.89 |
| December | 5.19 | 5.32 | 3.03 | 4.81 | 4.59 |
| Annual | 13.09 | 38.61 | 28.99 | 31.74 | 33.11 |

Note: The precipitation measurements were established in September of 1998.
Source: BP meteorological measurements program.

## Table 3.2-3

## Maximum Hourly Average Wind Speed by Month (Miles Per Hour)

| Month | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | Maximum |
|---|---|---|---|---|---|---|---|---|
| January | 26.9 | 25.5 | 23.9 | 25.1 | 28.5 | 27.8 | 22.3 | 28.5 |
| February | 27.1 | 27.0 | 19.2 | 25.9 | 30.8 | 19.1 | 22.6 | 30.8 |
| March | 25.1 | 22.3 | 31.3 | 22.8 | 32.6 | 22.3 | 22.1 | 32.6 |
| April | 20.2 | 26.9 | 21.4 | 13.5 | 18.7 | 19.4 | 25.0 | 26.9 |
| May | 14.4 | 18.8 | 15.5 | 17.1 | 16.2 | 14.9 | 18.8 | 18.8 |
| June | 16.6 | 15.4 | 15.5 | 14.1 | 15.7 | 15.4 | 14.6 | 16.6 |
| July | 15.9 | 16.8 | 14.8 | 13.6 | 14.5 | 14.3 | 14.7 | 16.6 |
| August | 15.4 | 17.6 | 14.7 | 13.2 | 14.5 | 12.6 | 17.5 | 17.6 |
| September | 13.1 | 15.5 | 21.5 | 12.8 | 21.3 | 15.9 | 15.4 | 21.5 |
| October | 25.4 | 25.2 | 24.3 | 18.7 | 23.2 | 21.8 | 21.3 | 25.4 |
| November | 30.1 | 24.1 | 24.1 | 33.6 | 26.3 | 17.8 | 24.6 | 33.6 |
| December | 31.9 | 24.1 | 26.5 | 29.4 | 25.3 | 26.9 | 27.2 | 31.9 |
| Maximum | 31.9 | 27.0 | 31.3 | 33.6 | 32.6 | 27.8 | 27.2 | 33.6 |

Source: BP meteorological measurements program

## Table 3.2-4

## Peak Wind Gusts by Month (Miles Per Hour)

| Month | 1999 | 2000 | 2001 | Maximum |
|---|---|---|---|---|
| January | 53.0 | 51.0 | 41.0 | 53.0 |
| February | 60.8 | 37.3 | 53.2 | 60.8 |
| March | 60.7 | 44.5 | 42.4 | 60.7 |
| April | 33.5 | 34.6 | 48.3 | 48.3 |
| May | 33.1 | 29.2 | 37.6 | 37.6 |
| June | 29.2 | 28.5 | 30.1 | 30.1 |
| July | 29.2 | 29.2 | 29.5 | 29.5 |
| August | 26.1 | 25.0 | 35.7 | 35.7 |
| September | 42.3 | 35.8 | 29.8 | 42.3 |
| October | 48.3 | 42.9 | 45.3 | 48.3 |
| November | 50.7 | 43.4 | 52.4 | 52.4 |
| December | 48.0 | 52.0 | 56.8 | 56.8 |
| Maximum | 60.8 | 52.0 | 56.8 | 60.8 |

Source: BP meteorological measurements program

**Table 3.2-5**
**(REVISED)**
**Summarized Bellingham Maximum 24-Hour $PM_{10}$ Data ($\mu g/m^3$)**

| Month | 1999 | 2000 | 2001 | Maximum |
|---|---|---|---|---|
| January | 53 | 18 | 30 | 53 |
| February | 15 | 22 | 29 | 29 |
| March | ND | 18 | 25 | 25 |
| April | 30 | 28 | 29 | 30 |
| May | 21 | 27 | 23 | 27 |
| June | 27 | 21 | 16 | 27 |
| July | 31 | 17 | ND | 31 |
| August | 23 | 22 | 21 | 23 |
| September | 31 | 26 | 19 | 31 |
| October | 43 | 25 | 16 | 43 |
| November | 40 | 27 | 25 | 27 |
| December | 18 | 29 | 26 | 29 |
| Maximum | 53 | 29 | 30 | 53 |
| Annual Average | 13.7 | 12.3 | 11.9 | 13.7 |

ND = No Data
Source: NWAPA

## Table 3.2-6

## Summarized Bellingham Maximum 24-Hour $PM_{2.5}$ Data ($\mu g/m^3$)

| Month | 1999 | 2000 | 2001 | Maximum |
|---|---|---|---|---|
| January | ND | 20 | 21 | 21 |
| February | 16 | 15 | 24 | 24 |
| March | 25 | 9 | 11 | 11 |
| April | 13 | 15 | 10 | 15 |
| May | 9 | 9 | 9 | 9 |
| June | 12 | 8 | 9 | 9 |
| July | 11 | 17 | 10 | 17 |
| August | 12 | 10 | 16 | 16 |
| September | 14 | 13 | 9 | 14 |
| October | 21 | 19 | 11 | 21 |
| November | 19 | 26 | 18 | 26 |
| December | 25 | 21 | 16 | 25 |
| Maximum | 25 | 26 | 24 | 26 |
| Annual Average | 8.1 | 8.4 | 7.2 | 8.4 |

ND = No Data
Source: NWAPA

## Table 3.2-7

## Summarized GVRD Air Quality Index (AQI) Information for 2000 (REVISED, APRIL 2003)

| Station | $PM_{10}$ (24-hour) | $SO_2$ (1-hour) | $SO_2$ (24-hour) | CO (1-hour) | CO (8-hour) | $O_3$ (1-hour) | $NO_2$ (1-hour) |
|---|---|---|---|---|---|---|---|
| Hours with good air quality | | | | | | | |
| Surrey | 8657 | N/A | N/A | 8760 | 8760 | 8728 | 8760 |
| Richmond | 8476 | 8760 | 8760 | 8760 | 8760 | 8748 | 8760 |
| Langley | 8557 | N/A | N/A | 8760 | 8760 | 8720 | 8760 |
| Abbotsford | 8525 | 8760 | 8760 | 8760 | 8760 | 8741 | 8760 |
| Hours with fair air quality | | | | | | | |
| Surrey | 103 | N/A | N/A | 0 | 0 | 32 | 0 |
| Richmond | 284 | 0 | 0 | 0 | 0 | 12 | 0 |
| Langley | 203 | N/A | N/A | 0 | 0 | 40 | 0 |
| Abbotsford | 235 | 0 | 0 | 0 | 0 | 19 | 0 |
| Hours with poor or very poor air quality | | | | | | | |
| Surrey | 0 | N/A | N/A | 0 | 0 | 0 | 0 |
| Richmond | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Langley | 0 | N/A | N/A | 0 | 0 | 0 | 0 |
| Abbotsford | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Note: An AQI below 25 represents "good" air quality. An AQI between 25 and 50 represents "fair" air quality. An AQI between 50 and 100 represents "poor" air quality. An AQI over 100 represents "very poor" air quality.
There are no hours with the AQI greater than 50.
$SO_2$ is not measured at the Surrey and Langley monitoring stations.

## Table 3.2-8

## Ambient Monitoring Stations in Canada used in study

| Station | Station ID | Distance from project site (km) | Direction from project site | Pollutants |
|---|---|---|---|---|
| Surrey | T15 | 26.6 | N | $PM_{10}$, CO, $NO_2$, O3 |
| Richmond | T17 | 37.1 | NW | $SO_2$ |
| Pitt Meadows | T20 | 39.4 | N | $PM_{2.5}$ |
| Langley | T27 | 26.2 | NE | $PM_{10}$, CO, $NO_2$, O3 |
| Vancouver Airport | T31 | 43.3 | NW | $PM_{2.5}$ |
| Abbotsford | T33 | 35.9 | NE | $SO_2$ |

## Table 3.2-9

## Background concentrations in Canada (μg/m$^3$)
## (REVISED, APRIL 2003)

| Pollutant | | Ambient Monitoring Station 1 | | | Ambient Monitoring Station 2 | | | Maximum |
|---|---|---|---|---|---|---|---|---|
| | | 1999 | 2000 | 2001 | 1999 | 2000 | 2001 | |
| Maximum Concentration | | | | | | | | |
| $SO_2$ | Annual | 3 | 3 | 3 | 3 | 1 | 3 | 3 |
| | 24-hour | 11 | 13 | 8 | 5 | 5 | 8 | 13 |
| | 3-hour | 19 | 27 | 16 | 19 | 21 | 13 | 27 |
| | 1-hour | 29 | 35 | 29 | 27 | 27 | 29 | 35 |
| $PM_{10}$ | Annual | 12 | 13 | 12 | 12 | 13 | 12 | 13 |
| | 24-hour | 34 | 31 | 35 | 32 | 34 | 33 | 35 |
| $PM_{2.5}$ | Annual | 8 | 9 | 5 | 9 | 9 | 5 | 9 |
| | 24-hour | 24 | 22 | 19 | 23 | 29 | 17 | 29 |
| CO | 8-hour | 2,436 | 1,740 | 1,624 | 2,668 | 1,740 | 1,508 | 2,668 |
| | 1-hour | 2,900 | 2,900 | 2,900 | 2,900 | 2,784 | 4,060 | 2,900 |
| $NO_X$ | Annual | 23 | 27 | 21 | 17 | 17 | 17 | 27 |
| | 24-hour | 69 | 67 | 55 | 52 | 48 | 42 | 69 |
| | 1-hour | 107 | 99 | 90 | 84 | 88 | 73 | 107 |
| Ozone | 24-hour | 88 | 84 | 76 | 94 | 86 | 82 | 94 |
| | 1-hour | 140 | 138 | 166 | 142 | 134 | 160 | 168 |
| 98th Percentile Concentrations for short-term averaging times | | | | | | | | |
| $SO_2$ | 24-hour | 5 | 8 | 5 | 5 | 5 | 5 | 8 |
| | 3-hour | 8 | 11 | 8 | 5 | 8 | 5 | 11 |
| | 1-hour | 21 | 24 | 16 | 19 | 19 | 11 | 24 |
| $PM_{10}$ | 24-hour | 24 | 25 | 25 | 26 | 27 | 24 | 27 |
| $PM_{2.5}$ | 24-hour | 17 | 19 | 15 | 17 | 21 | 15 | 21 |
| CO | 8-hour | 1,276 | 1,044 | 1,044 | 1,160 | 1,044 | 928 | 1,276 |
| | 1-hour | 1,276 | 1,160 | 1,740 | 1,276 | 1,160 | 1,624 | 1,740 |
| $NO_X$ | 24-hour | 50 | 52 | 46 | 34 | 32 | 36 | 52 |
| | 1-hour | 61 | 69 | 78 | 48 | 46 | 63 | 78 |
| Ozone | 24-hour | 72 | 68 | 70 | 76 | 72 | 68 | 76 |
| | 1-hour | 90 | 88 | 112 | 94 | 88 | 114 | 112 |

Notes: Ambient Monitoring Station 1 is Surrey for $PM_{10}$, CO, $O_3$, and $NO_2$, Richmond for $SO_2$, and Pitt Meadows for $PM_{2.5}$.
Ambient Monitoring Station 2 is Langley for $PM_{10}$, CO, $O_3$, and $NO_2$, Abbotsford for $SO_2$, and Vancouver Airport for $PM_{2.5}$.
The $PM_{2.5}$ Canada-wide standard is based on the 98th percentile averaged over 3 years.

## Table 3.2-10

## U.S. Criteria Pollutant Ambient Air Quality Standards and SILs (REVISED, APRIL 2003)

| Pollutant | Averaging Period | Standards | | | SILs | |
|---|---|---|---|---|---|---|
| | | National (μg/m3) | | Washington | Class I | Class II |
| | | Primary | Secondary | (μg/m3) | (μg/m3) | (μg/m3) |
| Sulfur Dioxide | Annual | 80 | None | 53 | 0.1 | 1 |
| | 24-hour | 365 | None | 260 | 0.2 | 5 |
| | 3-hour | None | 1,300 | None | 1.0 | 25 |
| | 1-hour | None | None | 1,065 | None | None |
| Total Suspended Particulates | Annual | None | None | 60 | None | None |
| | 24-hour | None | None | 150 | None | None |
| $PM_{10}$ | Annual | 50 | 50 | 50 | 0.2 | 1 |
| | 24-hour | 150 | 150 | 150 | 0.3 | 5 |
| $PM_{2.5}$[1] | Annual | 15 | 15 | None | None | None |
| | 24-hour | 65 | 65 | None | None | None |
| Carbon Monoxide | 8-hour | 10,000 | 10,000 | 10,000 | None | 500 |
| | 1-hour | 40,000 | 40,000 | 40,000 | None | 2.000 |
| Ozone | 1-hour | 235 | 235 | 235 | None | None |
| | 8-hour | 157 | 157 | None | None | None |
| Nitrogen Dioxide | Annual | 100 | 100 | 100 | 0.1 | 1 |
| Lead | Quarterly | 1.5 | 1.5 | 1.5 | None | None |

1. As of April, 2003, the $PM_{2.5}$ and ozone 8-hour standards are not being enforced until a nation-wide assessment of which areas are in attainment and non-attainment is made.

## Table 3.2-11

## Canadian Air Quality Objectives and Standards (REVISED, APRIL 2003)

| Pollutant | Averaging Period | Canada Objectives [1] (µg/m3) | | B.C. and GVRD Objectives [2] (µg/m3) | | Canada-Wide Standard |
|---|---|---|---|---|---|---|
| | | Desirable | Acceptable | Level A | Level B | |
| Sulfur Dioxide | Annual | 30 | 60 | 25 | 50 | --- |
| | 24-hour | 150 | 300 | 160 | 260 | --- |
| | 3-hour | --- | --- | 375 | 665 | --- |
| | 1-hour | 450 | 900 | 450 | 900 | --- |
| Total Suspended Particulate (TSP) | Annual | 60 | 70 | 60 | 70 | --- |
| | 24-hour | --- | 120 | 150 | 200 | --- |
| Inhalable Particulate ($PM_{10}$) [3] | Annual | --- | --- | --- | 30 | --- |
| | 24-hour | --- | --- | --- | 50 | --- |
| Fine Particulate ($PM_{2.5}$) [4,5] | 24-hour | --- | --- | --- | --- | 30 |
| Carbon Monoxide | 8-hour | 6,000 | 15,000 | 5,500 | 11,000 | --- |
| | 1-hour | 15,000 | 35,000 | 14,300 | 28,000 | --- |
| Ozone | 24-hour | 30 | 50 | --- | --- | --- |
| | 8-hour [4] | --- | --- | --- | --- | 127 |
| | 1-hour | 100 | 160 | --- | --- | --- |
| Nitrogen Dioxide | Annual | 60 | 100 | --- | --- | --- |
| | 24-hour | --- | 200 | --- | --- | --- |
| | 1-hour | --- | 400 | --- | --- | --- |
| Total Reduced Sulfur | 24-hour | --- | --- | 3 | 6 | --- |
| | 1-hour | --- | --- | 7 | 28 | --- |
| Lead | Annual | --- | --- | 2 | 2 | --- |
| | 24-hour | --- | --- | 4 | 4 | --- |
| Zinc | Annual | --- | --- | 3 | 3 | --- |
| | 24-hour | --- | --- | 5 | 5 | --- |

1. Federal Objective unless otherwise noted.
2. British Columbia Provincial Objective unless otherwise noted
3. GVRD Objective
4. Canada-Wide Standard to be achieved by year 2010
5. 98th percentile averaged over 3 years

## Table 3.2-12

## Hourly Criteria Pollutant Emission Rates – Turbine (NEW)

| Operating Scenario | Operating Parameters | | | Hourly Emissions (lb/hr) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Inlet Temperature (°F) | Load (%) | Duct Burning (mmBtu/hr) | $NO_X$ | CO (2 ppm annual average) | CO (5 ppm short-term average) | VOC | $PM_{10}$ | $SO_2$ (0.8 gr S annual average) | $SO_2$ (1.6 gr S short-term average) |
| 1AA | 5 | 100 | 0 | 17.5 | 8.5 | 21.3 | 2.2 | 18.7 | 4.2 | 8.3 |
| 1AB | 50 | 100 | 0 | 16.3 | 8.0 | 20.0 | 2.0 | 18.6 | 3.9 | 7.7 |
| 1AC | 85 | 100 | 0 | 15.0 | 7.3 | 18.3 | 1.9 | 18.5 | 3.5 | 7.1 |
| 1BA | 5 | 75 | 0 | 14.1 | 6.8 | 17.0 | 1.7 | 18.4 | 3.4 | 6.7 |
| 1BB | 50 | 75 | 0 | 13.1 | 6.4 | 16.0 | 1.6 | 18.3 | 3.1 | 6.3 |
| 1BC | 85 | 75 | 0 | 12.2 | 5.9 | 14.8 | 1.5 | 18.2 | 2.9 | 5.8 |
| 1CA | 5 | 50 | 0 | 11.0 | 5.4 | 13.5 | 1.4 | 18.1 | 2.7 | 5.3 |
| 1CB | 50 | 50 | 0 | 10.4 | 5.1 | 12.8 | 1.3 | 18.0 | 2.5 | 5.0 |
| 1CC | 85 | 50 | 0 | 9.6 | 4.7 | 11.8 | 1.3 | 18.0 | 2.3 | 4.7 |
| 2A | 5 | 100 | 28.3 | 17.9 | 8.7 | 21.8 | 2.4 | 19.2 | 4.2 | 8.4 |
| 2B | 50 | 100 | 28.3 | 16.7 | 8.1 | 20.4 | 2.2 | 19.1 | 3.9 | 7.9 |
| 2C | 85 | 100 | 28.3 | 15.3 | 7.5 | 18.7 | 2.1 | 19.0 | 3.6 | 7.2 |
| 6A | 5 | 100 | 105 | 18.7 | 9.1 | 22.8 | 3.0 | 20.6 | 4.4 | 8.8 |
| 6B | 50 | 100 | 105 | 17.5 | 8.5 | 21.3 | 2.8 | 20.4 | 4.1 | 8.3 |
| 6C | 85 | 100 | 105 | 16.1 | 7.9 | 19.6 | 2.7 | 20.3 | 3.8 | 7.6 |

## Table 3.2-13

## Hourly Criteria Pollutant Emission Rates – Auxiliary Equipment (NEW)

| Operating Unit | Hourly Emissions (lbs/hr) | | | | |
|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_2$ |
| Emergency Generator | 27.5 | 6.9 | 1.3 | 0.7 | 0.80 |
| Firewater Pump | 3.33 | 0.17 | 0.14 | 0.05 | 0.105 |
| Cooling Tower | N/A | N/A | N/A | 1.63 | N/A |

Notes:
N/A = No Emissions

## Table 3.2-14

## Toxic Emissions that Require Modeling
## (NEW)

| Toxic Compound | Emission Rate for 3 CTs (lbs/hr) | Emission Rate for Emergency Generator (lbs/hr) | Emission Rate for Firewater Pump (lbs/hr) | Total Annual Emissions (lbs/yr) | Total Hourly Emissions (lbs/hr) | SQER (lbs/yr) | SQER (lbs/hr) | ASIL (µg/m³) | Class A or B Toxic Compound | |
|---|---|---|---|---|---|---|---|---|---|---|
| Acetaldehyde | 0.0210 | 0.00039 | 0.001553 | 184.8 | 0.023 | 50 | NA | 0.45 | A | Annual |
| Acrolein | 0.0373 | 0.000121 | 0.0001872 | 327.1 | 0.038 | 175 | 0.02 | 0.02 | B | 24-hr |
| Ammonia[1] | 39.5 | 0 | 0 | 346,247 | 39.5 | 17,500 | 2.0 | 100 | B | 24-hr |
| Benzene | 0.0705 | 0.01192 | 0.001889 | 621.4 | 0.084 | 20 | NA | 0.12 | A | Annual |
| 1,3-Butadiene | 0.0025 | 0 | 0.0000791 | 22.0 | 0.0026 | 0.5 | NA | 0.0036 | A | Annual |
| Formaldehyde | 0.5876 | 0.00121 | 0.00239 | 5,148 | 0.59 | 20 | NA | 0.077 | A | Annual |
| PAH | 0.0129 | 0.00326 | 0.000034 | 113.5 | 0.016 | NA | NA | 0.00048 | A | Annual |
| Arsenic | 0.000052 | 0.00371 | 0.000265 | 1.5 | 0.00403 | NA | NA | 0.00023 | A | Annual |
| Beryllium | 0.000003 | 0 | 0 | 0.03 | 0.000003 | NA | NA | 0.00042 | A | Annual |
| Cadmium | 0.000287 | 0.00035 | 0.000025 | 2.6 | 0.00066 | NA | NA | 0.00056 | A | Annual |
| Chromium | 0.0259 | 0.00371 | 0.000265 | 227.6 | 0.030 | 175 | 0.02 | 1.7 | B | 24-hr |
| Cobalt | 0.0255 | 0 | 0 | 223.6 | 0.026 | 175 | 0.02 | 0.33 | B | 24-hr |
| Copper[1] | 0.0257 | 0 | 0 | 225.3 | 0.026 | 175 | 0.02 | 0.3 | B | 24-hr |
| Manganese | 0.0256 | 0 | 0 | 224.2 | 0.026 | 175 | 0.02 | 0.4 | B | 24-hr |
| Nickel | 0.0260 | 0.00035 | 0.000025 | 228.3 | 0.026 | 0.5 | NA | 0.0021 | A | Annual |
| Zinc[1] | 0.0331 | 0.00385 | 0.000275 | 290.7 | 0.037 | 175 | 0.02 | 7 | B | 24-hr |
| Sulfuric Acid[1] | 8.1 | 0.2437 | 0.0321 | 71,040 | 8.38 | 175 | 0.02 | 3.3 | B | 24-hr |

NOTES:
1. Not an USEPA Classified hazardous air pollutant (HAP)

SQER = Small Quantity Emission Rate
ASIL = Acceptable Source Impact Level
The maximum hourly toxics emissions are calculated from Case 6A. These represent worst-case toxic emissions.

## Table 3.2-15

## Maximum Potential Annual Emissions (Criteria Pollutants) (NEW)

| Operating Scenario | Maximum Annual Emissions (tons/yr) | | | | | |
|---|---|---|---|---|---|---|
| | Hours per year | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_2$ |
| 100% load, maximum duct firing (Case 6B) | 7,960 | 209.1 | 101.8 | 33.8 | 244.0 | 49.3 |
| 50% load (Case 1CB) | 300 | 4.7 | 2.3 | 0.6 | 8.1 | 1.1 |
| Hot Start | 100 | 12.8 | 35.6 | 5.9 | 1.5 | 0.4 |
| Shutdown | 100 | 2.9 | 17.1 | 2.0 | 0.8 | 0.2 |
| Offline | 300 | 0 | 0 | 0 | 0 | 0 |
| Total Turbines | 8,760 | 229.4 | 156.8 | 42.2 | 254.4 | 50.9 |
| **Auxiliary Equipment** | | | | | | |
| Emergency Generator | 250 | 3.4 | 0.9 | 0.16 | 0.09 | 0.0995 |
| Firewater Pump | 250 | 0.42 | 0.021 | 0.018 | 0.006 | 0.0131 |
| Cooling Tower | 8,760 | N/A | N/A | N/A | 7.1 | N/A |
| Total | | 233.3 | 157.7 | 42.3 | 261.6 | 51.0 |

Notes:
N/A = No emissions
Totals may not equal sum of individual components due to rounding.

## Table 3.2-16

## Expected Annual Emissions (Criteria Pollutants) (NEW)

| Operating Scenario | Annual Emissions (tons/yr) | | | | | |
|---|---|---|---|---|---|---|
| | Average hours per year | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_2$ |
| 100% load with no duct firing (Case 1AB) | 4,766 | 104.9 | 45.8 | 14.4 | 133.0 | 27.7 |
| 100% load with minimal duct firing (Case 2B) | 3,451 | 65.7 | 28.2 | 11.6 | 95.2 | 20.4 |
| Forced Outage | 175 | 3.9 | 2.8 | 0.7 | 4.6 | 0.9 |
| Economic Dispatch | 98 | 2.3 | 2.9 | 0.5 | 2.3 | 0.4 |
| Planned Outage | 272 | 0.4 | 0.6 | 0.1 | 0.1 | 0.02 |
| **Auxiliary Equipment** | | | | | | |
| Emergency Generator | 250 | 3.44 | 0.86 | 0.16 | 0.09 | 0.10 |
| Firewater Pump | 250 | 0.42 | 0.021 | 0.018 | 0.006 | 0.013 |
| Cooling Tower | 8,760 | N/A | N/A | N/A | 7.1 | N/A |
| Total (unadjusted) | | 181.1 | 81.2 | 27.5 | 242.4 | 49.6 |
| $PM_{10}$ adjustments due to source test method[1] | | | | | -148.5 | |
| Total | | 181.1 | 81.2 | 27.5 | 93.9 | 49.6 |

Notes:
N/A = No emissions
Totals may not equal sum of individual components due to rounding.
1. Approximately 60% of the PM10 emissions are subtracted due to source test exaggerations of sulfates and the inclusion of compounds associated with background, ambient air.

## Table 3.2-17

## Expected Annual Emissions With Refinery Emission Reductions (RENUMBERED/REVISED, APRIL 2003)

| | NOx | CO | VOC | PM10 | SO2 | Total |
|---|---|---|---|---|---|---|
| Expected Emissions | 181 | 81 | 28 | 94 | 50 | 433 |
| Refinery Emission Reductions | -499 | -54 | -3 | -10 | -7 | -573 |
| Total Change in Emissions | -318 | 27 | 25 | 84 | 43 | -140 |
| Totals may not equal sum of individual components due to rounding. | | | | | | |

## Table 3.2-18

## Significant Impact Level Modeling Analysis Results – U.S. Class II Areas (RENUMBERED/REVISED, APRIL 2003)

| Pollutant | Averaging Period | Maximum Predicted Concentration[1,2] (µg/m³) | SIL[3] (µg/m³) |
|---|---|---|---|
| Sulfur Dioxide | Annual[4,6] | 0.03 | 1 |
| | 24-hour[5,7] | 4.3 | 5 |
| | 3-hour[5,7] | 8.4 | 25 |
| $PM_{10}$ | Annual[6] | 0.25 | 1 |
| | 24-hour | 4.3 | 5 |
| Carbon Monoxide | 8-hour[7] | 50.4 | 500 |
| | 1-hour[7] | 81.4 | 2,000 |
| Nitrogen Dioxide | Annual[6] | 0.60 | 1 |

1. Highest of all cases for 1995, 1996, 1998, 1999,2000.
2. Excludes the effect of refinery emissions reductions.
3. Significant Impact Level (SIL) for criteria pollutants.
4. Value represents a maximum sulfur content in natural gas of 0.8 gr/100 scf annual average.
5. Value represents a maximum sulfur content in natural gas of 1.6 gr/100 scf.
6. Based on annual average ambient temperature of 50°F.
7. Due to emergency use of diesel generator.

## Table 3.2-19

## Significant Impact Level Modeling Analysis Results - Class I Areas (RENUMBERED/REVISED, APRIL 2003)

| Pollutant | Averaging Period | Maximum Predicted Concentration[1,2] (µg/m³) | SIL [3] (µg/m³) |
|---|---|---|---|
| Sulfur Dioxide | Annual | 0.001 | 0.1 |
| | 24-hour | 0.021 | 0.2 |
| | 3-hour | 0.048 | 1 |
| $PM_{10}$ | Annual | 0.0054 | 0.2 |
| | 24-hour | 0.087 | 0.3 |
| Nitrogen Dioxide | Annual | 0.0053 | 0.1 |

1. Highest of 1995, 1996, 1998, 1999, 2000.
2. Excludes the effect of refinery emissions reductions.
3. Significant Impact Level (SIL) for criteria pollutants.

**Table 3.2-20**

**AQRV Modeling Analysis Results**
**(RENUMBERED/REVISED, APRIL 2003)**

| Operating Scenario | Class I area | Maximum Nitrogen Deposition | Maximum Sulfur Deposition | Maximum Visibility Change | Number of days over 5% | Maximum Visibility Change including Boiler Emissions Reductions | Number of days over 5% |
|---|---|---|---|---|---|---|---|
| | | (g/ha/yr) | (g/ha/yr) | (%) | | (%) | |
| Normal Operation without duct burners operating | Olympic National Park | 0.09 | 0.11 | 5.5 | 1 | 1.6 | 0 |
| | North Cascades National Park | 0.44 | 0.31 | 2.5 | 0 | 1.4 | 0 |
| | Alpine Lakes Wilderness Area | 0.56 | 0.68 | 3.8 | 0 | 1.9 | 0 |
| | Glacier Peak Wilderness Area | 0.42 | 0.32 | 4.1 | 0 | 1.8 | 0 |
| | Pasayten Wilderness Area | 0.23 | 0.13 | 1.7 | 0 | 1.0 | 0 |
| | Mt. Baker Wilderness Area | 0.63 | 0.56 | 4.0 | 0 | 2.2 | 0 |
| Normal Operation with Duct Burners | Olympic National Park | 0.09 | 0.11 | 5.6 | 1 | 1.7 | 0 |
| | North Cascades National Park | 0.45 | 0.31 | 2.5 | 0 | 1.4 | 0 |
| | Alpine Lakes Wilderness Area | 0.57 | 0.70 | 3.9 | 0 | 2.0 | 0 |
| | Glacier Peak Wilderness Area | 0.42 | 0.32 | 4.2 | 0 | 1.9 | 0 |
| | Pasayten Wilderness Area | 0.23 | 0.13 | 1.7 | 0 | 1.1 | 0 |
| | Mt. Baker Wilderness Area | 0.64 | 0.57 | 4.0 | 0 | 2.3 | 0 |
| Operation with Duct Burners firing at a maximum rate | Olympic National Park | 0.09 | 0.12 | 6.0 | 1 | 1.9 | 0 |
| | North Cascades National Park | 0.47 | 0.32 | 2.6 | 0 | 1.5 | 0 |
| | Alpine Lakes Wilderness Area | 0.60 | 0.73 | 4.1 | 0 | 2.3 | 0 |
| | Glacier Peak Wilderness Area | 0.44 | 0.34 | 4.4 | 0 | 2.1 | 0 |
| | Pasayten Wilderness Area | 0.24 | 0.14 | 1.8 | 0 | 1.2 | 0 |
| | Mt. Baker Wilderness Area | 0.67 | 0.60 | 4.1 | 0 | 2.3 | 0 |
| Maximum | | 0.67 | 0.68 | 6.0 | 1 | 2.3 | 0 |

NOTES: Significance level for visibility is 5%.
Significance level for deposition is 5 g/ha/yr.

## Table 3.2-21

## Significant Impact Level Modeling Analysis Results - Toxic Compounds (RENUMBERED/REVISED, APRIL 2003)

| Pollutant | Maximum Predicted Concentration (μg/m³)[4] | | ASIL (μg/m³)[3] | ASIL Exceeded (Yes/No) |
|---|---|---|---|---|
| | Annual[1] | 24-hr[2] | | |
| Acetaldehyde | 0.00014 | NA | 0.45 | No |
| Acrolein | NA | 0.0027 | 0.02 | No |
| Ammonia | NA | 2.8 | 100 | No |
| Benzene | 0.00032 | NA | 0.12 | No |
| 1,3-Butadiene | 0.00001 | NA | 0.0036 | No |
| Formaldehyde | 0.00237 | NA | 0.077 | No |
| PAH | 0.00007 | NA | 0.00048 | No |
| Arsenic | 0.00007 | NA | 0.00023 | No |
| Beryllium | <0.00001[5] | NA | 0.00042 | No |
| Cadmium | 0.00001 | NA | 0.00056 | No |
| Chromium | NA | 0.0024 | 1.7 | No |
| Cobalt | NA | 0.0018 | 0.33 | No |
| Copper | NA | 0.0018 | 0.3 | No |
| Manganese | NA | 0.0018 | 0.4 | No |
| Nickel | 0.00011 | NA | 0.0021 | No |
| Zinc | NA | 0.0025 | 7 | No |
| Sulfuric Acid | NA | 0.57 | 3.3 | No |

1. Highest of cases 1AB, 1BB, 1CB, 2B, 6B (50°F)
2. Highest of all cases for 1995, 1996, 1998, 1999, and 2000.
3. Acceptable source impact levels (ASIL).
4. Excludes the effect of refinery emissions reductions.
5. Impacts are less than the sensitivity of the ISC-Prime model of 0.00001 ug/m³

## Table 3.2-22

## Maximum Concentration Modeling Analysis in Canada (RENUMBERED/REVISED, APRIL 2003)

| Pollutant | Averaging Time | Maximum Concentration in Canada (µg/m³) | | | Most Stringent Canadian Objective or Standard (µg/m³) |
|---|---|---|---|---|---|
| | | Modeled | Background | Total | |
| $SO_2$ | Annual | 0.03 | 3 | 3 | 25 |
| | 24-hour | 0.7 | 16 | 17 | 150 |
| | 3-hour | 3.3 | 27 | 30 | 374 |
| | 1-hour | 5.3 | 59 | 64 | 450 |
| $PM_{10}$ | Annual | 0.2 | 13 | 13 | 30 |
| | 24-hour | 2.5 | 35 | 38 | 50 |
| $PM_{2.5}$ | 24-hour | 0.9 | 18 | 19 | 30 |
| CO | 8-hour | 4.8 | 2,668 | 2,673 | 5,500 |
| | 1-hour | 13.6 | 2,900 | 2,914 | 14,300 |
| $NO_2$ | Annual | 0.2 | 27 | 27 | 60 |
| | 24-hour | 1.6 | 69 | 71 | 200 |
| | 1-hour | 16.7 | 107 | 124 | 400 |

Notes: $PM_{2.5}$ emissions are conservatively assumed to be equal to $PM_{10}$ emissions.
The $PM_{2.5}$ Canada-wide standard is based on the $98^{th}$ percentile averaged over 3 years, therefore, the modeled and background values indicated above are also based on these assumptions.
$NO_X$ is considered to be fully converted to $NO_2$.
Excludes the effect of Refinery emissions reductions.

## Table 3.2-23

## Lines of Sight Evaluated for Visibility Analysis in Canada (RENUMBERED)

| Line of Sight | Observer Location | Direction and Target |
|---|---|---|
| 1 | Victoria | ENE to Mount Baker |
| 2 | White Rock | ESE to Mount Baker |
| 3 | Tsawwassen | ESE to Mount Baker |
| 4 | Vancouver | N to North Shore Mountains (The Lions) |
| 5 | Langley | N to North Shore Mountains (Golden Ears) |
| 6 | Chilliwack | E to Mount Cheam |
| 7 | Abbotsford | SE to Mount Baker |

## Table 3.2-24

## Results of Visibility Analysis in Canada (RENUMBERED/REVISED, APRIL 2003)

| Line of Sight | Number of days with impaired visibility, background conditions | Additional days with impaired visibility due to Cogeneration Project | Maximum visibility change |
|---|---|---|---|
| 1 | 171 | 0 | 1.2% |
| 2 | 166 | 0 | 2.4% |
| 3 | 166 | 0 | 2.1% |
| 4 | 166 | 0 | 2.2% |
| 5 | 166 | 0 | 2.7% |
| 6 | 166 | 0 | 1.5% |
| 7 | 166 | 0 | 1.4% |
| Impaired visibility is defined as those days with a visibility range of less than 60 km.<br>Excludes the effect of refinery emissions reductions. | | | |

## Table 3.2-25

## Comparison with U.S. Ambient Air Quality Standards (RENUMBERED/REVISED, APRIL 2003)

| Pollutant | Averaging Time | Maximum Concentration (µg/m³) | | | Lower of WAAQS or NAAQS (µg/m³) |
|---|---|---|---|---|---|
| | | Modeled | Background | Total | |
| $SO_2$ | Annual | 0.03 | 3 | 3 | 53 |
| | 24-hour | 1.0 | 13 | 14 | 260 |
| | 3-hour | 5.1 | 27 | 32 | 1,300 |
| | 1-hour | 8.7 | 35 | 44 | 1,065 |
| $PM_{10}$ | Annual | 0.25 | 13 | 13 | 50 |
| | 24-hour | 4.3 | 35 | 39 | 150 |
| $PM_{2.5}$ | Annual | 0.25 | 9 | 9 | 15 |
| | 24-hour | 4.3 | 29 | 33 | 65 |
| CO | 8-hour | 12.6 | 2,668 | 2,681 | 10,000 |
| | 1-hour | 67.3 | 2,900 | 2,967 | 40,000 |
| $NO_2$ | Annual | 0.60 | 27 | 28 | 100 |

Background concentration is the maximum value for each pollutant and averaging time of the two nearest representative ambient measuring station (see tables 3.2-8 and 3.2-9).