# INTRODUCTION

Duke Energy Grays Harbor, LLC, and Energy Northwest (referred to collectively as the Certificate Holder) is proposing to expand the existing Satsop Combustion Turbine (CT) Project by constructing and operating a second phase similar to the permitted Phase I facility. As with Phase I, Phase II will consist of a combined-cycle plant and will generate approximately 650 MW to supply growing regional electrical demand.

Phase II will be constructed on the Satsop CT Project site. A Site Certification Agreement (SCA) (Application 94-1) was previously approved by the State of Washington. Phase II will be entirely within the boundaries of the previously permitted site. As a result, the Certificate Holder is applying to the Energy Facility Site Evaluation Council (EFSEC) for an amendment to the existing SCA to allow construction and operation of Phase II. This amendment is the fourth amendment to the SCA that was originally issued for the Satsop nuclear power plants.

## PROJECT SUMMARY

The expansion will consist of two gas turbines and one steam turbine, and have an estimated output of approximately 650 megawatts.

Phase II will be located within the previously permitted site, on land that has already been disturbed and developed for industrial use. The project will be fueled by natural gas, and no backup fuel source is proposed. Phase II will utilize the natural gas pipeline being installed for Phase I.

Power produced by Phase II will be routed through transmission lines that are being installed as part of Phase I and that will connect to the BPA system at BPA's Satsop substation. No new transmission lines will be required to serve Phase II.

The Council has already issued an SCA that permits development of the entire site, and the Council has already considered the impacts associated with site development in connection with permitting Phase I. As a result, the additional impacts associated with construction and operation of the proposed Phase II facility are principally limited to: (1) air emissions, (2) water use and discharge, and (3) sound emissions.

## SUMMARY OF ENVIRONMENTAL CONSIDERATIONS

Phase II incorporates many environmental design features that will eliminate or minimize environmental impacts. The remainder of this section presents a summary of key environmental considerations in the design, construction and operation of Phase II.

### Air

- Phase II will utilize the same air emission control technology installed for Phase I. This technology represents the “state of the art” and consists of General Electric (GE) Frame 7FA combustion turbines in a 2-x-1 combined cycle configuration with a GE D11 steam turbine with dry low-$NO_x$ combustor and selective catalytic reduction (SCR).

- Atmospheric emissions will be in compliance with all applicable federal and state air quality regulations.
- Each combustion turbine unit will incorporate best available control technologies (BACT).
- Air emissions and the resulting effect on ambient air quality are addressed in Sections 2.11, 3.2 and 6.1 of the application.

**Water Use and Discharge**

- Water for cooling will be obtained through the existing Ranney wells, and delivered through water lines originally constructed for the Satsop nuclear plants.
- Like Phase I, Phase II will utilize a mechanical draft (wet) cooling system and will require the same amount of water (a peak flow of 9.5 cfs) as required for Phase I.
- Grays Harbor Public Development Authority will provide the water from its existing 20 cfs water authorization. No new water rights will be required.
- Water discharge from Phase II will meet the discharge limitations of the existing National Pollutant Discharge Elimination System (NPDES) permit and will meet the state's applicable acute and chronic water quality criteria for Class A waters for discharge to the Chehalis River.
- The requirements of the Erosion and Sediment Control Plan (approved by EFESEC on September 19, 2001) are will apply to the construction and operation of Phase II as well. This plan was implemented to protect water quality with the start of Phase I construction, and will minimize erosion, sedimentation, and contaminated runoff. During construction and operation, the Certificate Holder and its contractors will adhere to the procedures, methods and other requirements presented in this plan.
- Water use and water quality issues are addressed in Sections 2.8, 2.8 and 3.3 of the application.

**Noise**

- Phase II is designed to ensure that its operation will not result in significant changes in noise levels at nearby industrial areas or at the nearest residential properties.
- Sound attenuation has been included in the project design through the proper selection of materials and equipment, as well as in the overall layout of the plant.

- The sound emissions from Phase II and the proposed noise mitigation measures are addressed in Section 4.1 of the application.

**Plants and Animals**

- Phase II will fit entirely within the previously permitted and developed Satsop CT site. Construction of Phase II on a disturbed and developed site will minimize impacts to vegetation and wildlife. The project site does not contain vegetation, wetlands or open water.

- The Certificate Holder has designed Phase II so that it will fit entirely within the boundaries of the existing developed site. In particular, the Certificate Holder has selected a mechanical draft (wet) cooling system, identical to that being used for Phase I, in part because alternative cooling systems would necessitate encroaching upon the wildlife mitigation area located directly to the east of the site.

- Phase II will utilize the natural gas pipeline and electrical transmission lines being installed for Phase I, and the existing water supply line and discharge that were originally built for the Satsop nuclear power plants and utilized by Phase I. The use of existing utilities avoids impacts to plants and animals that would otherwise result from the creation of new utility corridors.

**Land Use, Cultural Resources and Recreation**

- Phase II complies with Grays Harbor County's current land use plan and zoning ordinance. The site is zoned for industrial use and is designated Industrial 2 (I-2).

- The use of the site for industrial use is consistent with Grays Harbor Public Development Authority's planned use of the surrounding Satsop Development Park.

- Cultural resource surveys were conducted prior to the original development of the site. The construction and operation of Phase II will not impact cultural resources.

- Construction and operation of Phase II will not result in any direct impacts to recreational resources in the area. Indirect impacts will be temporary due to the possible the use of recreational facilities by construction workers during the 22-month construction period.

**Visual Resources**

- Expansion of the Satsop CT Project will be consistent with the visual character of the surrounding area. Phase II will be constructed immediately adjacent to the permitted Phase I power plant and will be surrounded by industrial and commercial development in the Satsop Development Park.

- There are few residents near the plant site, with the nearest residents located more than 2,000 feet west of the site. A 25-foot-high noise wall with a 12-foot-high landscaped berm on the street side are currently being constructed as part of the Phase I development along Keys

Road. Phase II will be located further to the east, behind the Phase I project. The berm and noise wall will screen both phases of the project from travelers along Keys Road and will screen portions of the facilities from the views of nearby residents.

- Topography and vegetation obstruct views of the site from more distant locations. Phase II emission stacks (200 feet) will be 50 percent shorter than the existing cooling towers constructed for the Satsop nuclear project. The existing stacks, at 496 feet, will remain the dominant landmark in the area. A computer simulation of the Phase II silhouette provided in Section 5.1 indicates that Phase II will not be visible from prominent viewpoints, such as along State Route 12 or from residences in the Chehalis River Valley.

**Socioeconomics and Public Services**

- Phase II construction will occur the end of the Phase I construction period, extending the positive economic benefits of both jobs and income to the local economy. Construction jobs will peak at approximately 500 jobs for a period of 4 months.

- Like Phase I, operation of the Phase II project will have positive impacts in terms of jobs, taxes, and purchase of goods and services.

- The proposed expansion of the Satsop CT Project will have minor impacts on existing public services.

**Transportation**

- During construction, delays at the intersection of Keys Road and State Route 12 during the evening commuting period are possible. A traffic and transportation plan for construction, in accordance with a Grays Harbor County Public Works Division letter dated July 2, 2001, was approved by EFSEC on September 19, 2001. This plan will be applicable to the Phase II construction period.

- During operation of both phases of the Satsop CT Project, 42 people will be employed and a maximum of 42 employees will be on site at any time. Negative impacts on transportation during normal operation are unlikely.

# 1.1
# Description of Applicant (WAC 463-42-015)

**WAC 463-42-015 GENERAL — DESCRIPTION OF APPLICANT.**
*The applicant shall provide an appropriate description of the applicant's organization and affiliations for this proposal. [Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-015, filed 10/8/81. Formerly WAC 463-42-170.]*

# 1.1 DESCRIPTION OF APPLICANT
# (WAC 463-42-015)

This application for an amendment to the existing Satsop Combustion Turbine (CT) Project Site Certification Agreement is being submitted for construction and operation of the Satsop CT Project Phase II (Phase II), which consists of two electrical generation plants and associated facilities. The applicant for this expansion project is the current Certificate Holder, Duke Energy Grays Harbor, LLC, and Energy Northwest.

## 1.2

# Designation of Agent (WAC 463-42-025)

**WAC 463-42-025 GENERAL - DESIGNATION OF AGENT.**

*The applicant shall designate an agent to receive communications on behalf of the applicant.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW.*
*81-21-006 (Order 81-5), §463-42-025, filed 10/8/81.*
*Formerly WAC 463-42-090.]*

## 1.2 DESIGNATION OF AGENT
## (WAC 463-42-025)

The Agents acting on behalf of the applicant shall be:


DEGH:

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# 1.3
# Assurances (WAC 463-42-075)

**WAC 463-42-075 GENERAL — ASSURANCES.**

*The application shall set forth insurance, bonding or other arrangements proposed in order to mitigate for damage or loss to the physical or human environment caused by project construction, operation, abandonment, termination, or when operations cease at the completion of a project's life.*

*[Statutory Authority: RCW 80.50.040(1). 87-05-017 (Order 87-1), §463-42-075, filed 2/11/87. Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-075, filed 10/8/81.]*

## 1.3 ASSURANCES
## (WAC 463-42-075)

Duke Energy Grays Harbor, LLC, and Energy Northwest, collectively the Certificate Holder, is proposing to construct and operate an expansion (Phase II) of the Satsop Combustion Turbine (CT) Project within the site already approved through a Site Certification Agreement. As with the existing project, the applicant will establish and maintain several forms of insurance during construction and operation of the Phase II Project as are required by law, customary business practice, or third-party participants such as lenders. The following coverages will be included:

- <u>Comprehensive General Public Liability</u> – The Certificate Holder will carry Comprehensive General Public Liability insurance including coverage for bodily injury (including death), property damage, independent contractors, products, and completed operations with a limit of liability of $50 million per occurrence.

- <u>Employer's Liability</u> – The Certificate Holder will carry Employer's Liability insurance with a limit of liability of $1 million per occurrence.

- <u>Comprehensive Automobile Liability</u> – The Certificate Holder will carry Comprehensive Automobile Liability insurance including coverage for all owned, hired, or non-owned automobiles with a limit of liability of $50 million per occurrence.

- <u>Workers Compensation</u> – Duke Energy Grays Harbor, LLC will carry Worker's Compensation and other insurance as required by law for all employees of the CT Phase II project.

Consistent with the existing Site Certification Agreement, the Certificate Holder will be responsible as required by law for acts of environmental impairment and expects to compensate for adjudicated damages from operating funds. Consistent with the terms of the approved Initial Site Restoration Plan, the Certificate Holder will retain responsibility for damages or loss and, to the extent site facilities are not otherwise removed, recycled or salvaged, will maintain ongoing responsibility for site facilities and site integrity.

## 1.4

# Mitigation Measures (WAC 463-42-085)

**WAC 463-42-085 GENERAL — MITIGATION MEASURES.**

*The application shall describe the means to be utilized to minimize or mitigate possible adverse impacts on the physical or human environments.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-085, filed 10/8/81.]*

# 1.4 MITIGATION MEASURES (WAC 463-42-085)

## 1.4.1 INTRODUCTION

This section describes the environmental design features that will be included in the Phase II project to eliminate or reduce adverse impacts. As a result of the mitigation measures that will be included in project design, there are no significant impacts associated with construction or operation of the project. More detailed information on existing conditions, environmental design features of the project, potential mitigation measures, and impact analyses are presented in Sections 3.1 through 3.4, Section 4.1, Sections 5.1 through 5.3, and Section 6.1.

In addition to the environmental design features of the project, for some elements of the environment this section describes other potential mitigation measures that could minimize adverse impacts. Where appropriate, the Certificate Holder will incorporate potential mitigation measures into the project to further reduce impacts at specific locations or for specific project-related activities. The decision regarding the incorporation of specific additional mitigation measures will be made in consultation with EFSEC. The Certificate Holder anticipates that the addition of mitigation measures, if appropriate, will be stipulated in the amendment to the Site Certification Agreement (SCA) or in EFSEC Resolutions associated with the amended SCA.

Both the environmental design features and potential mitigation measures are presented by element of the environment in the following sections.

## 1.4.2 GEOLOGY AND SOILS

- The plant will include seismic design criteria specific to the anticipated seismic risks in the area and will be designed to conform to the Uniform Building Code Seismic Zone 3.

- Construction activities will be controlled to help limit erosion. Clearing, excavation and grading will be limited to those areas of the project absolutely necessary for construction of the project. Areas outside the construction limits will be marked in the field and equipment will not be allowed to enter areas or to disturb existing vegetation.

- The construction contractors will implement the EFSEC-approved Erosion and Sedimentation Control Plan during construction to minimize soil loss due to surface water flows.

- The EFSEC-approved Environmental Protection Control Plan will be implemented to provide adequate maintenance and inspection of the erosion and sediment control system. The plan specifies that control structures will be inspected at a frequency sufficient to provide adequate environmental protection. Such inspections will increase in frequency during rainfall periods. In addition, supplies including sandbags and channel-lining materials will be stored on site for emergency use.

- Surface runoff will be diverted around and away from cut and fill slopes and conveyed in pipes or protected channels. If the runoff is from disturbed areas, it will be directed to a sediment trap prior to discharge.

## 1.4.3 AIR QUALITY

- Mitigation of potential impacts to air quality will be accomplished with the use of best available control technology (BACT). BACT analysis is provided in Subsection 6.1.6. Proposed BACT for pollutants associated with the proposed project are shown in Table 1.4-1. Project emissions to the atmosphere will be in compliance with applicable state and federal regulations.

- The Certificate Holder will maintain and operate equipment in accordance with vendor recommendations and generally accepted practices in order to prevent excessive emissions and minimize fuel consumption.

- To control dust during construction, water will be applied as necessary, and access roads will be graveled or paved.

## 1.4.4 HYDROLOGY AND WATER QUALITY

### 1.4.4.1 Surface Water

**Construction**

- To minimize impacts on surface water, contractors will use best management practices (BMPs) for erosion and sediment control during construction of Phase II and will implement a plan that complies with the requirements of the existing Erosion and Sedimentation Control Plan. BMPs will include limiting certain construction activities and installing temporary control structures such as sediment traps, silt fences, and diversion ditches.

- Runoff from the northern portion of the site will be routed through existing ditches and culverts to the C-1 pond, which is located on Satsop Development Park property to the west. If necessary, surface water runoff from the site can be pumped through a series of ditches and culverts to the existing Equalization Pond on the main Satsop Development Park property. This pond would provide additional storage capacity during construction if surface water runoff is unusually high. With implementation of this plan, surface water impacts due to construction of the plant will be temporary and minor.

## TABLE 1.4-1
## PROPOSED AIR POLLUTION CONTROL TECHNOLOGIES

| Pollutant | Proposed BACT |
|---|---|
| $NO_x$ | Power Generation Units:<br>Dry Low-$NO_x$ combustor<br>Selective catalytic reduction (SCR)<br>Natural gas firing only |
| | Auxiliary Boilers:<br>Flue gas recirculation<br>Low-NOx burners |
| | Emergency Backup Diesel Generators:<br>Turbocharging/aftercooling<br>Variable fuel injection timing retard |
| CO | Power Generation Units:<br>Catalytic Oxidation |
| $SO_2$ | Power Generation Units:<br>Natural gas firing only |
| | Emergency Backup Diesel Generators:<br>Limited fuel oil use<br>Low sulfur fuel |
| VOC | Power Generation Units:<br>Proper combustion<br>Turbine design<br>(additional reduction due to CO Catalyst) |
| $PM_{10}$ | Power Generation Units:<br>Proper combustion<br>Natural gas firing only |
| | Emergency Backup Diesel Generators:<br>Limited fuel oil use<br>Low sulfur fuel |
| | Cooling Towers:<br>Two-stage, low-drift eliminators |
| Ammonia | Power Generation Units:<br>Proper combustion<br>Adequate mixing |
| Other toxics | Power Generation Units:<br>Proper combustion |
| | Auxiliary Boilers:<br>Proper combustion |
| | Emergency Backup Diesel Generators:<br>Limited fuel oil use |

- The Certificate Holder currently has an approved NPDES permit that covers stormwater discharges, including stormwater discharges from the proposed plant site. In addition, the SCA addresses stormwater management during construction, and includes the following requirements:

  - The project must comply with all pertinent industry standards for control of any unforeseen surface water runoff event during construction, and must notify EFSEC of surface water runoff problems.

  - The project must abide by turbidity criteria for construction-related runoff as established in the State of Washington Water Quality Standards.

  - The existing NPDES permit establishes water quality limits and monitoring schedules for total suspended solids, settleable solids, and pH in collected stormwater runoff. These limits are applicable for material storage runoff and construction runoff within the 100-year, 24-hour rainfall event (5.5 inches per 24 hours).

**Operation**

- Runoff from the plant site will be directed toward the perimeter ditches and routed as described in Subsection 2.10.2.2. The Environmental Protection Control Plan will be modified if necessary to include specifications for any commitments made for Phase II plant operations. BMPs consistent with those in the *Stormwater Management Manual for the Puget Sound Basin* (WSDOE 2000) will be employed during operation of Phase II.

- At least annually, facility employees will also receive training in the pollution control laws and regulations, and the specific features of the facility which are intended to prevent releases of oil and petroleum products. Employees at the site will be trained in the following spill response measures:

  - Identifying areas that may be affected by a spill and potential drainage routes
  - Reporting of spills to appropriate individuals
  - Employing appropriate material handling and storage procedures
  - Implementing spill response procedures

- Stormwater catchbasins and detention systems will be inspected at least annually as part of the site preventive maintenance program. Stormwater catchbasins will be cleaned if the collected deposits fill more than one-third of the depth from the basin to the invert of the lowest pipe leading into or out of the basin.

- Inspections will be conducted to confirm that non-permitted discharges are not entering the stormwater system. A summary of each inspection will be retained, along with any notifications of noncompliance and reports on incidents such as spills.

- To meet the temperature requirements of the discharge, either heat exchangers and/or flow augmentation will be used to quench the temperature of the cooling water discharge.

1.4.4.2 Groundwater

- The design of the on-site septic system will include a professional engineer's report on site conditions, schedule for development, water balance analysis, overall effects of the proposed system on the surrounding area, and any local zoning requirements.

- The placement and design of the system will allow infiltration of effluent but inhibit its direct release to surface and/or groundwater bodies.

### 1.4.5 VEGETATION, WILDLIFE AND WILDLIFE HABITAT

Because the plant site was previously developed and no new utility corridors are required for Phase II, there will be no impacts to vegetation or wildlife from the construction or operation of Phase II.

### 1.4.6 AQUATIC RESOURCES

- As described in Section 2.10 - Surface Water Runoff, WAC 463-42-215, the construction contractors will implement the EFSEC-approved Erosion And Sediment Control Plan that will provide erosion control measures during both construction and operation of the proposed project, and an Environmental Protection Control Plan will be implemented to control surface water runoff during operation.

- In addition, as described in Section 2.9 - Spillage Prevention and Control, WAC 463-42-205, the Certificate Holder has an existing Spill Prevention Control and Countermeasures (SPCC) Plan for Phase I of the Satsop CT Project that will also be applicable to Phase II. The existing SPCC Plan describes the oil, fuel, and hazardous material storage facilities; reporting systems; prevention requirements; and spill response procedure.

- The existing Hazardous Waste Management procedure establishes a program for the handling, storage, and disposal of wastes from the Satsop site.

- Revisions of the SPCC Plan and Hazardous Waste Management procedure were most recently submitted to EFSEC in August 2001 and approved by EFSEC on September 19, 2001. Revisions are required a minimum of every 2 years, but will be made sooner to respond to changing site organizations or conditions, or changes in regulations. The revision process will include an engineer's review, an updated organizational structure, and updated procedures specifying locations and what checks need to be made.

### 1.4.7 ENERGY AND NATURAL RESOURCES

No impacts to energy resources are expected and no mitigation is necessary.

### 1.4.8 NOISE

1.4.8.1 Construction Sound Abatement Measures

- Construction will not be performed within 1,000 feet of an occupied dwelling unit on Sundays, legal holidays, or between the hours of 10:00 P.M. and 6:00 A.M. on other days.

- All construction equipment will have sound control devices no less effective than those provided on the original equipment. Equipment will not be operated with unmuffled exhaust systems.

- Pile driving or blasting operations, if required, will not be performed within 3,000 feet of an occupied dwelling unit on Sundays, legal holidays, or between the hours of 8:00 P.M. and 8:00 A.M. on other days.

- Despite inclusion of the measures described above, areas adjacent to the project will be exposed to increased sound levels during active periods of construction. This will be a short-term impact. The Certificate Holder will notify nearby residents in advance of the anticipated schedule for construction activities.

1.4.8.2 Acoustical Attenuation Features

- Major sources of sound will be located inside an acoustically treated building.

- Acoustically absorptive silencers will be installed on the combustion turbine inlet system, enclosure ventilation systems, and emergency relief valves.

- Separate acoustical enclosures will be installed for major noise sources, including the combustion turbine and generator.

- Acoustically absorptive insulation will be installed in duct walls of the combustion turbine inlet air and exhaust systems.

### 1.4.9 LAND USE

No impacts to land uses are expected and no mitigation is necessary.

### 1.4.10 LIGHT AND GLARE

1.4.10.1 Environmental Design Features

- The 25-foot-high noise wall, vegetation located on the berm and scattered existing vegetation between the project site and residences will screen most of the lights.

- Additional screening is provided by high trees located along the residential road since the residences are set back an estimated 50 to 75 feet.

1.4.10.2 Potential Mitigation Measures

- In specific locations where glare or light spillover would impact Keys Road or be obtrusive to nearby residences, lighting angles could be adjusted to minimize glare impacts, or supplemental light shields/vegetation could be used for extra screening.

### 1.4.11 AESTHETICS

- The Phase II will be constructed on an industrialized, developed site as part of the Satsop Combustion Turbine project. There are few nearby residences and few travelers using the adjacent Keys Road.

- The Phase II project will be located further east of the Phase I project. A screening berm is being built between the power plants and Keys Road as part of the Phase I construction, with a 25-foot high noise wall behind the berm. This berm and noise wall will screen the plant from viewers using Keys Road, and will screen all but the tallest portions of the plants from viewers at nearby residences.

- Equipment enclosure buildings and exterior tanks will be painted beige and gray to reduce contrasts.

- Two 200-foot high emission stacks, painted a light color, will be constructed.

### 1.4.12 RECREATION RESOURCES

No impacts to recreational resources are expected and no mitigation is necessary.

### 1.4.13 HISTORIC AND CULTURAL PRESERVATION

No impacts to cultural resources are expected and no mitigation is necessary.

### 1.4.14 AGRICULTURAL CROPS/ANIMALS

No impacts to agricultural crops or animals are expected and no mitigation is necessary.

### 1.4.15 TRAFFIC AND TRANSPORTATION

- EFSEC has approved the Certificate Holder's traffic control plan implemented for the Phase I construction. This plan was prepared in accordance with a letter from Grays Harbor County's Department of Public Works dated July 2, 2001. The plan is also applicable to the Phase II construction.

### 1.4.16 PUBLIC HEALTH AND SAFETY

- Engineering and design of the proposed Phase II project will ensure that the project's water discharges, air emissions, and noise generation will be in compliance with state and federal regulations (see Subsections 1.4.3 and 1.4.4).

No significant impacts are anticipated on schools or public service providers, and no mitigation is required.

### 1.4.17 SOCIOECONOMICS AND PUBLIC SERVICES

The proposed project is expected to have a positive effect on the local and state economy and significant impacts on population, housing, property values and public services are not anticipated. Therefore, the project does not include design features associated with potential socioeconomic impacts.

# 1.5
# Sources of Information (WAC 463-42-095)

**WAC 463-42-095 GENERAL — SOURCES OF INFORMATION.**
*The applicant shall disclose sources of all information and data and shall identify all preapplication studies bearing on the site and other sources of information.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-095, filed 10/8/81. Formerly WAC 463-42-120.]*

## 1.5 SOURCES OF INFORMATION (WAC 463-42-095)


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# 1.6

# Pertinent Federal, State and Local Requirements (WAC 463-42-685)

*(1) Each application submitted to the council for site certification shall include a list of all applicable federal, state and local codes, ordinances, statutes, rules, regulations and permits that would apply to the project if it were not under council jurisdiction. For each listed code, ordinance, statute, rule, regulation and permit, the applicant shall describe how the project would comply or fail to comply with each requirement. If the proposed project does not comply with a specific requirement, the applicant shall discuss why such compliance should be excused.*

*(2) Inadvertent failure to discover a pertinent provision after a reasonable search shall not invalidate the application, but may delay processing the application as necessary to gather and consider relevant information. (Statutory Authority: RCW 80.50.040(1). 92-10-001 § 463-42-685, filed 4/23/92, effective 5/24/92.)*

## 1.6 PERTINENT FEDERAL, STATE, AND LOCAL REQUIREMENTS (WAC 463-42-685)

Federal, state, and local permits and requirements applicable to the Satsop CT Phase II Project are listed in Table 1.6-1. This table also summarizes the regulatory compliance plans for the project. State and local permits listed are those that would apply to the proposed project if it were not under Energy Facility Site Evaluation Council (EFSEC) jurisdiction.

### TABLE 1.6-1
### PERTINENT FEDERAL, STATE, AND LOCAL REQUIREMENTS

| Permit or Requirement | Agency/Regulation | Compliance Plan |
|---|---|---|
| NEPA Compliance | **Bonneville Power Administration (BPA):** National Environmental Act; Power purchase by BPA. | The Satsop CT Project was one of three projects in BPA's Resource Contingency Program (RCP). Bonneville published a Final Environmental Impact Statement (EIS) and Record of Decision in 1995.<br><br>Phase II does not require federal action, and no NEPA action is required. |
| Federal Aviation Administration Approval | **Federal Aviation Administration (FAA):** Federal Aviation Regulations, Part 77; determination whether structure will affect navigable air space. | In August 2001, applications were submitted to the FAA for the exhaust stacks for Phase I. We do not expect that the FAA will require lighting. Similar applications will be filed for Phase II in 2002. |
| Endangered Species Act Consultation | **U.S. Fish and Wildlife Service (USFWS):** Endangered Species Act of 1973; determination that actions will not affect or jeopardize threatened or endangered species or their habitats. | Consultation with both USFWS and Washington Department of Fish and Wildlife was completed as part of the NEPA compliance process for Phase I. Phase II will not trigger the need for new consultation. |
| State Environmental Policy Act (SEPA) | **Grays Harbor County:** RCW 43.21C, 173-802 WAC; project development. | EFSEC performs SEPA compliance for the Phase II project as a part of its review of the Certificate Holder's request for an amendment to their Site Certification Agreement (SCA). It is anticipated that EFSEC will prepare and issue a limited scope Supplemental EIS tiered to the BPA NEPA EIS issued in 1995. |
| Air Quality (PSD Permit) | **Washington Department of Ecology:** 173-400, 403 WAC; Control Requirements for Air Pollutants. | This request for an amendment to the SCA includes a PSD Permit Amendment Application for EFSEC review and approval. The SCA amendment is expected to include a PSD Permit amendment that will stipulate limits on emission levels from both Phase I and Phase II. |
| Water Right | **Washington Department of Ecology:** RCW 90.44, RCW 80.50, 173-154 WAC; water supply. | Water for Phase II will be obtained from Grays Harbor Public Development Authority pursuant to the PDA's existing water rights. Additional water rights will not be required. |

## TABLE 1.6-1 (CONTINUED)
## PERTINENT FEDERAL, STATE, AND LOCAL REQUIREMENTS

| Permit or Requirement | Agency/Regulation | Compliance Plan |
|---|---|---|
| Wastewater Disposal (NPDES) | **Washington Department of Ecology:** Clean Water Act, RCW 90.48, 173-220 WAC, 173-201 WAC, 173-240 WAC, 173-03-070 WAC; cooling water discharge. | The discharge from the Phase II project will comply with the stipulations of the existing NPDES permit and will use the existing discharge pipeline and outfall. An amendment to add Phase II discharge as a waste stream to the existing NPDES permit will be submitted. It is anticipated that the amended NPDES permit will be included in the amended SCA issued by EFSEC. |
| Stormwater Discharge (NPDES) | **Washington Department of Ecology:** Clean Water Act, RCW 90.48, 90.50, 90.52 173-220 WAC; stormwater discharge associated with industrial activities. | All stormwater drainage from the CT site is routed to the C-1 erosion control pond, which is designed and maintained to handle a 100-year storm. This pond has not discharged since the West Park (formerly Cooley Laydown) area was stabilized in the early 1980's, even during a 100-year rainfall event. In the unlikely event discharge appears possible, EFSEC and Ecology will be notified. Drainage to the pond will be monitored in accordance with the existing Environmental Protection Control Plan. |
| Spill Prevention Control and Countermeasures (SPCC) Plan | **Washington Department of Ecology:** 40 CFR 112 RCW 80.50; plan to prevent, control and contain accidental petroleum discharges into surface waters. | The SPCC plan for the Satsop CT Project was approved by EFSEC on September 19, 2001, and is applicable to Phase II. |
| Notification of Dangerous Waste Activities | **Washington Department of Ecology:** 173-303 WAC, RCW 80.50; identification of dangerous waste activities. | An active state identification number has been issued for the CT project. This request for an amendment to the SCA provides EFSEC with information on (1) waste streams, compositions, and volumes, and (2) hazardous waste activities. Stipulations on methods of handling dangerous wastes are expected to be included in the amended SCA issued by EFSEC and are expected to be similar to those included in the existing SCA. |
| Temporary Modification of Water Quality Criteria | **Washington Department of Ecology:** RCW 90.48, 1730201 and 173-222 WAC; to address impacts associated with construction activities that unavoidably violate state water quality criteria. | The variance will be requested for the application of construction activities that unavoidably violate state water quality criteria on a short-term basis. |
| Consultation with State Historic Preservation Office | **Washington Department of Community Development:** State Historic Preservation Officer Approval; National Historic Preservation Act (Section 106); Executive Order RCW 80.50; protection of archaeological and historic resources. | Construction of Phase II is in areas previously disturbed by nuclear plant construction and/or Phase I construction and no further action is required. |
| On-Site Sewage System | **Grays Harbor County:** RCW 90.48, 173-240 WAC, RCW 80.50; to construct system septic system and to permit disposal of sanitary wastes. | This request for an amendment to the SCA provides EFSEC with relevant information on the proposed septic system for the CT project. Following current EFSEC requirements, design details will be submitted to EFSEC and Grays Harbor County for final approval. Design will meet Grays Harbor County requirements. |

## TABLE 1.6-1 (CONTINUED)
## PERTINENT FEDERAL, STATE, AND LOCAL REQUIREMENTS

| Permit or Requirement | Agency/Regulation | Compliance Plan |
|---|---|---|
| Building Approval | **Grays Harbor County:** County Ordinance No 137; RCW 80.50; to comply with County Building Code. | Building plans will be in compliance with the Grays Harbor County Building Code. Following current EFSEC requirements, drawings and specifications related to public health and safety will be submitted to Grays Harbor County for review and approval. |
| Shoreline Substantial Development Approval | **Grays Harbor County:** Shoreline Management Act, RCW 90.58, WAC 173-14, RCW 80.50, Grays Harbor County Shoreline Management Master Plan (Resolution No. 7419). | Phase I was shown to be consistent with Grays Harbor County Shoreline Master Management Plan. This consistency determination was required because auxiliary features (natural gas pipeline and transmission lines) crossed areas subject to the Shoreline Act. Phase II is entirely within the Phase I plant site, which is outside the boundaries of the Shoreline Master Management Plan. |
| Land Use and Zoning Compliance | **Grays Harbor County:** Ordinance 38, County Title 13, RCW 80.50; demonstration of compliance with county land use and zoning ordinances. | As part of the SCA amendment for Phase I, the location of energy facilities at the Satsop CT site was found to be consistent with the Grays Harbor County Zoning Code. The site has since been rezoned to I-2 expressly to permit energy facilities. No new determination of consistency is required for Phase II. |
| County Road Permit | **Grays Harbor County:** County Ordinance | When needed, county road permits will be obtained from Grays Harbor County for hauling of materials to the site. Road access and work in county road right-of-way permits will also be obtained if needed. |

## 2.1
## Site Description (WAC 463-42-125)

**WAC 463-42-125 PROPOSAL — SITE DESCRIPTION.**

*The application shall contain a description of the proposed site indicating its location, prominent geographic features, typical geological and climatological characteristics, and other information necessary to provide a general understanding of all sites involved, including county or regional land use plans and zoning ordinances.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-125, filed 10/8/81. Formerly WAC 463-42-180.]*

# 2.1 SITE DESCRIPTION
# (WAC 463-42-125)

## 2.1.1 PROJECT SUMMARY

Duke Energy Grays Harbor, LLC, and Energy Northwest (the Certificate Holder) is proposing to expand the existing Satsop Combustion Turbine (CT) Project by constructing and operating the Phase II power plant. As with Phase I, the project is to generate electricity to help supply growing regional electrical loads. Phase II will consist of a combined-cycle plant with a nominal average output of 600 megawatts per year.

Phase II will be constructed on the approximately 22-acre Satsop CT project site for which a Site Certification Agreement has already been approved by the State of Washington. The Phase II project will be entirely within the boundaries of the permitted site.

The fuel will be natural gas that will be supplied by a pipeline constructed as part of the Phase I development.

Power produced by Phase II will be routed through transmission lines that will connect to the BPA system at BPA's Satsop substation, approximately 4,000 feet east of the project site. As a part of Phase I, new transmission lines will be installed in the existing BPA right-of-way (on land owned by the Grays Harbor Public Development Authority) from the site to the substation. No new transmission lines for the connection to the substation will be required to serve Phase II.

## 2.1.2 PROJECT LOCATION

### 2.1.2.1 Plant Site

The approved site is located south of the Chehalis River near the town of Elma (see Figure 2.1-1). The 1600-acre Satsop Development Park surrounds the site on all four sides. The site is located approximately 0.5 mile southwest of the river. Fuller Creek is approximately 0.5 mile to the east, and Workman Creek is located approximately 2 miles to the east.

The site is currently under construction for Phase I. To the north and northwest of the proposed site are various field offices, storage buildings, and stockpiled building materials (see Figure 2.1-2). Similar items and facilities are located on the west side of the existing laydown area west of Keys Road. To the south and east, respectively, are the BPA transmission line right-of-way and a strip of forested land. A fire water tank and pump house are located in the northeast corner of the laydown area adjacent to the proposed site.

As part of the construction of Phase I, the site has been cleared of structures, discarded construction materials, and unneeded utilities. No additional clearing is required for Phase II construction.

#### 2.1.2.2 Transmission Line Corridor

The existing transmission line corridor from the plant site to the BPA substation is shown on Figure 2.1-1. This corridor contains two high voltage transmission lines and one distribution line and is maintained with only grass and low vegetation except within the Fuller Creek drainage channel. The creek is incised approximately 120 feet below the surrounding ground surface, and there is a small concrete and rock dam and drain pipe within the creek in the right-of-way.

#### 2.1.2.3 Pipeline

Phase II's gas supply will be provided by the natural gas pipeline being constructed for Phase I. No additional pipelines are required for Phase II.

### 2.1.3 TYPICAL GEOLOGICAL AND CLIMATOLOGICAL CHARACTERISTICS

The following sections summarize the geological and climatological characteristics of the project. A more detailed description of geological characteristics relevant to the proposed project is presented in Section 3.1 - Earth, WAC 463-42-302.

#### 2.1.3.1 Geology

The geologic setting of the project vicinity is the result of depositional processes and tectonic forces that have produced the bedrock geology of the Pacific Northwest and its subsequent modification by volcanoes, glaciers, and rivers. Data were obtained from review of literature, topographic maps, and geological maps of the region and project vicinity. (See Section 3.1 - Earth, WAC 463-42-302, for geology and structure maps.)

The proposed plant site is located in the Chehalis Lowlands section of the Pacific Border physiographic province. Provinces are defined by areas which possess similar surface topography, river drainage patterns, have common subsurface geology and recent geologic history. The Chehalis Lowlands section is characterized by low rolling hills and broad river valleys flanked by river terraces or flat narrow benches. Elevations within the Chehalis Lowlands range from 150 to 300 meters (480 to 1,000 feet). The plant site is a Quaternary river terrace founded on flat-lying Helm Creek glaciofluvial deposits which lie on Miocene age fine sands and silts of the Astoria Formation.

#### 2.1.3.2 Climate

The climate of the lowlands of western Washington is dominated by two large-scale influences. These are the mid-latitude westerly winds and the 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. The Grays Harbor County climate is strongly influenced by the Pacific Ocean because the winds and storms tend to move eastward from the ocean to the land, carrying the moderating affects 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, winters tend 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 degrees F range, with little daily variation.

The summer climate in this area reflects the 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 generally in the 70 to 80 degrees F range. This climate is a classic example of a west coast marine type environment.

Mean annual precipitation near Satsop is 70 inches (PNRBC 1970). Approximately 85 percent of the annual precipitation occurs between October and April.

Additional climate and air quality discussion and analysis can be found in Section 3.2 – Air, WAC 463-42-312.

### 2.1.4 ZONING ORDINANCES

The plant site is located in unincorporated Grays Harbor County near the town of Elma and surrounded by the property boundary of the Satsop Development Park (see Figure 2.1-1).

The plant site is located in areas zoned as Industrial District 2 (I-2) under Grays Harbor County Comprehensive Zoning Ordinance No. 38 (Title 13). The intent of the industrial zoning is to "provide for the location of industrial uses and activities involving the processing, handling and creating of products, and research and technological processes, all as distinguished from major fabrication, and which uses are largely devoid of nuisance-factors, hazards and exceptional demands upon public facilities and services, to establish a land-use pattern advantageous to the specialized needs of the uses permitted in this District" (Grays Harbor Zoning Ordinance, 13.06.080). Uses permitted outright include industrial uses and industrial development facilities as defined by RCW 39.84.020 Part 6. Energy facilities are included within this definition.

In passing the rezone at a Grays Harbor Planning Commission meeting on November 2, 1998, the Planning Commission found that the utilization of the infrastructure originally built for the Satsop Nuclear Plant and the reuse of existing sites for industrial purposes will promote job creation and economic diversification, expressed purposes of the Grays Harbor County Comprehensive Plan.

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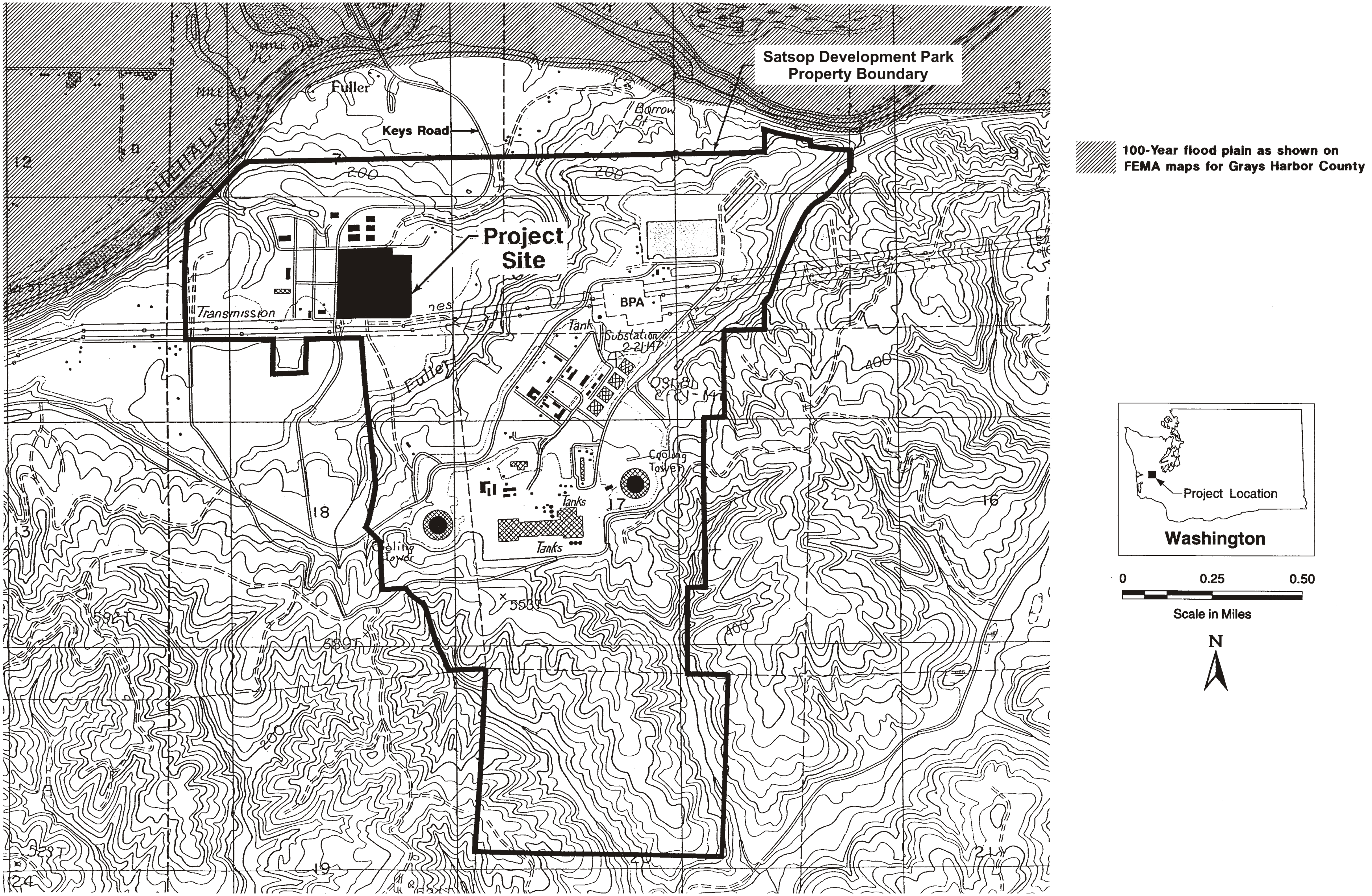


Figure 2.1-1
**Project Location**

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Phase II Expansion
Satsop CT Project

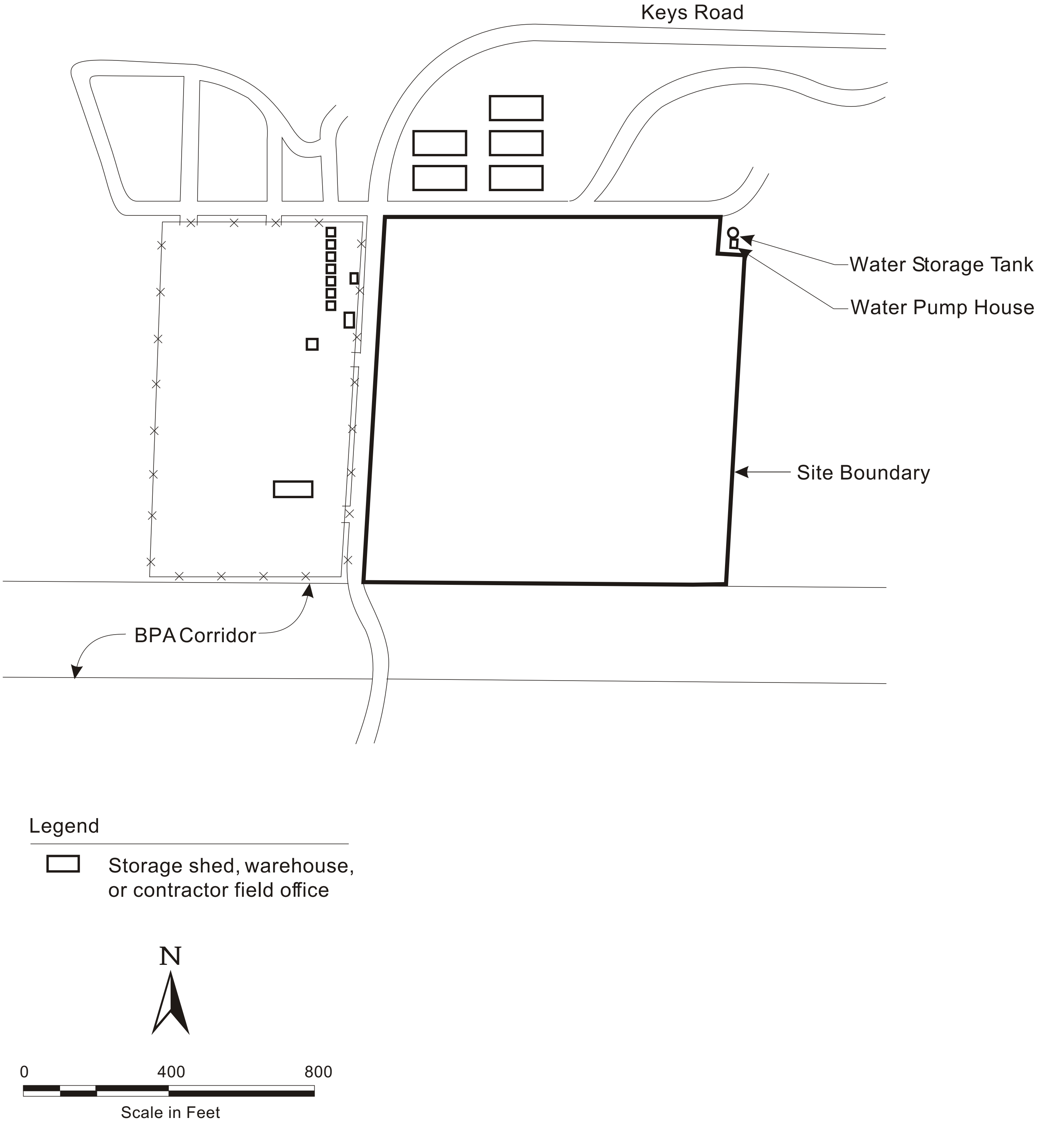


Figure 2.1-2
**Project Site**

## 2.2

# Legal Descriptions and Ownership Interests (WAC 463-42-135)

**WAC 463-42-135 PROPOSAL — LEGAL DESCRIPTIONS AND OWNERSHIP INTERESTS.**
*(1) Principal facility: the application shall contain a legal description of the site to be certified and shall identify the applicants and all nonprivate ownership interests in such land.*

*(2) Ancillary facilities: For those facilities described in RCW 80.50.020(6) and (7) the application shall contain the legal metes and bounds description of the preferred centerline of the corridor necessary to construct and operate the facility contained therein, the width of the corridor, or variations in width between survey stations if appropriate, and shall identify the applicant's and others ownership interests in lands over which the preferred centerline is described and of those lands lying equidistant for 1/4 mile either side of such center line. [Statutory Authority: RCW 80.50.040(1). 83-01-128 (Order 82-6), §463-42-135, filed 12/22/82. Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-135, filed 10/8/81. Formerly WAC 463-42-190.]*

## 2.2 LEGAL DESCRIPTION AND OWNERSHIP INTERESTS (WAC 463-42-135)

### 2.2.1 LEGAL DESCRIPTION - PRINCIPAL FACILITIES

Phase II will be located entirely within the approximately 22-acre site approved by Site Certification Agreement (SCA) for the Satsop Combustion Turbine (CT) Project. See Attachment I to the SCA. No change to the legal description is proposed.

### 2.2.2 DESCRIPTION OF ANCILLARY FACILITIES

#### 2.2.2.1 Natural Gas Pipeline

The natural gas pipeline serving Phase II is being constructed as part of the approved Phase I project.

#### 2.2.2.2 Transmission Line

Power from the plants will be exported to the Bonneville Power Administration (BPA) substation located approximately 4000 feet east of the plant site. This right-of-way is located on property owned by the Grays Harbor Public Development Authority and use of the right-of-way by BPA has been addressed in the SCA issued by the Energy Facility Site Evaluation Committee (EFSEC).

### 2.2.3 OWNERSHIP INTERESTS - PRINCIPAL FACILITIES

The approximately 22-acre is owned by the Certificate Holder.

### 2.2.4 OWNERSHIP INTERESTS - ANCILLARY FACILITIES

#### 2.2.4.1 Natural Gas Pipeline

The natural gas pipeline is expected to be constructed by, and will be owned by, Williams Pipeline Company.

#### 2.2.4.2 Transmission Line

BPA will own the transmission tower structures and the transmission line, constructed as part of Phase 1. No new transmission lines will be required for Phase II between the plant and the Satsop switchyard.

# 2.3

# Construction on Site (WAC 463-42-145)

**WAC 463-42-145 PROPOSAL — CONSTRUCTION ON SITE.**

*The applicant shall describe the characteristics of the construction to occur at the proposed site including the type, size, and cost of the facility; description of major components and such information as will acquaint the council with the significant features of the proposed project.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW.*
*81-21-006 (Order 81-5), §463-42-145, filed 10/8/81. Formerly WAC 463-42-210.]*

# 2.3 CONSTRUCTION ON SITE
# (WAC 463-42-145)

This section provides information on the proposed project and construction of the project in the following sections:

- Project Summary (Section 2.3.1)
- Power Plant Description (Section 2.3.2)
- Power Plant Construction (Section 2.3.3)

## 2.3.1 PROJECT SUMMARY

Duke Energy Grays Harbor, LLC, and Energy Northwest (the Certificate Holder) is proposing to expand the Satsop Combustion Turbine (CT) Project by 600 megawatts (MW), doubling the generating capacity of the project. Like Phase I, Phase II will consist of two combustion turbine generators and a single steam turbine generator. Certain facilities installed for Phase I, such as the operations and control office, warehouse, workshops and stores, gas regulation and treatment, and the water treatment building are adequately sized to serve both Phase I and Phase II, and new facilities of this type are not required.

A combined cycle plant uses exhaust gases from the combustion turbine that might otherwise be exhausted into the atmosphere without recapturing any of the heat content. In the proposed project, natural gas and air will be mixed and ignited in a combustion turbine. The combustion turbines produce about one-half of the plant's electrical output, and emit hot gases as a byproduct. The hot gases exhausted by the combustion turbines will be used to produce steam in a heat recovery steam generator (HRSG). The high-energy steam from the HRSG will be piped into a steam turbine that generates the remaining one-half of the unit's electrical output.

The total estimated value of Phase II at the completion of the construction is approximately $400 million for construction of the plant. The Certificate Holder estimates that the annual operating and maintenance costs will be approximately $12 million, including the following:

- Wages and salaries of operation, maintenance, and administrative personnel
- Procurement of goods and services
- Insurance
- Sales, property and other state and local taxes

Figures 2.3-1 and 2.3-2 present conceptual isometric diagrams of the proposed project (Phase I and Phases I and II, respectively). Figure 2.3-3 is a plant configuration diagram for Phase II, showing the major component systems for the plant. Figure 2.3-3 shows the major facilities/systems that will support the turbine trains, including the steam condensing/cooling system and the electrical interconnection system.

Process water will be purchased from the Grays Harbor Public Development Authority and supplied from the existing Ranney collectors via the existing Satsop Development Park water supply line that services Phase I facilities. This water is transported to Phase II through an existing water pipeline that passes adjacent to the site (see Figure 2.3-4). The existing outfall structure to the Chehalis River will be used for discharge of the Satsop CT Project's process effluent.

Potable water will be obtained from the existing Satsop Development Park raw water well. This system includes a supply tank and pump house located contiguous to the northeast corner of the site and will provide high-quality water that will be treated as necessary for potable uses. Sanitary wastewater will be discharged through an on-site septic system and leach field constructed for the plant.

Fuel for Phase II will be provided by the natural gas pipeline constructed as part of Phase I.

Power produced by Phase II will be routed through transmission lines that will connect to the BPA system at the Satsop substation. The lines will be constructed by BPA as part of Phase I.

## 2.3.2 POWER PLANT DESCRIPTION

### 2.3.2.1 Overview

The Certificate Holder is proposing to construct and operate Phase II to help supply growing regional electrical loads. This plant will be a combined cycle power plant with a nominal average output of 600 MW to be constructed on the site already certified for Phase I.

Like Phase I, Phase II will use the General Electric (GE) Frame 7FA combustion turbines in a 2-x-1 combined cycle configuration with a GE D11 steam turbine. Each GE 7FA combustion turbine generates a nominal gross power output of 175 MW, while the steam turbine generates approximately 300 MW gross with inlet chilling and maximum duct firing at annual average temperature. Phase II also features GE 7H2 hydrogen-cooled generators for the combustion turbine and stream turbine.

A basic description of Phase II is presented in Section 2.3.2.2. Detailed power plant design and specification information was provided as Appendix B to the original SCA application; as a convenience to the reader, that appendix is reproduced here as Appendix A to this amendment. A detailed description of the cooling systems is provided in Section 2.6 - System of Heat Dissipation, WAC 463-42-175. The basic building structures can be found on Figures 2.3-2, 2.3-3, and 2.3-4. Plant elevations are illustrated in Figure 2.3-5. The approximate heights of the major plant components are listed in Table 2.3-1.

2.3.2.2 Plant Components

Figure 2.3-3 shows the equipment configuration of the CT Project. The project is made up of the following components:

- Combustion turbine generator (CTG) (two)
- Heat recovery steam generator (HRSG) (two)
- Steam turbine generator (STG) (one)
- Fuel supply
- Process water and wastewater treatment
- Cooling system
- Electrical interconnection
- Fire protection

**TABLE 2.3-1**
**APPROXIMATE HEIGHTS OF MAJOR COMPONENTS**

| Component [a] | Approximate Height (ft) |
|---|---|
| Gas Turbine (1) | 57 |
| HRSG (2) | 80 |
| Exhaust Stack (3) | 200 |
| Cooling Tower (4) | 52 |

[a] Numbers in parentheses refer to key on Figure 2.3-4, Site Plan.

The following is a summary description of the major components of each unit.

**Combustion Turbine Generator (CTG)**

The configuration incorporates two GE 7FA turbine generators, each with a gross capacity of approximately 175 MW. The GE 7FA is an industrial combustion gas turbine, including dry low-NOx burners, that represents the state of the art in combustion turbine technology. This turbine has been specified as the basis for the heat and material balance, fuel use, and emissions calculations.

**Heat Recovery Steam Generator (HRSG)**

The high temperature exhaust produced by the combustion turbines will flow directly to an HRSG. The HRSG will produce output steam at three pressure levels, all of which will supply steam directly to the steam turbine.

Emissions control (air pollution control) equipment is integrated within the HRSG. The selective catalytic reduction (SCR) control equipment for removal of oxides of nitrogen ($NO_x$) and the oxidation catalyst for removal of carbon monoxide (CO) are located within the HRSG.

**Steam Turbine Generator (STG)**

Steam from the HRSG will be delivered to the STG which will have a gross capacity of approximately 300 MW (base load).

An auxiliary boiler will be installed with a low-NOx burner to produce steam at approximately 25,000 pounds per hour to provide sealing steam to the STG. It can also be used to maintain temperature in the HRSG and STG during long idle time to reduce startup duration.

**Fuel Supply**

The fuel for Phase II fuel will be natural gas. The natural gas supply will connect at T-connections and to the metering station on site that is being constructed as part of Phase I. Fuel will be supplied at an average of 450 psig.

**Process Water and Wastewater Discharge**

Process water requirements will be purchased from the Grays Harbor Public Development Authority. The water will be obtained through the existing Ranney collectors, located west of the plant site (see Figure 2.3-6). Ranney well water will be delivered to the Satsop CT Project plant site via the existing supply water line. The Phase II Project will send its effluent back to the existing water pipeline via another connection downstream of the project intake, from where it will be transported and discharged to the Chehalis River through the existing outfall structure. The discharge will comply with the limitations of the existing National Pollutant Discharge Elimination System (NPDES) permit. The NPDES permit will, however, require amendments to reflect the increased wastewater flow and the new waste stream.

**Cooling System**

The proposed cooling system consists of two major components: (1) a circulating water system that will carry cold water from the cooling tower through the steam turbine condenser and back to the cooling tower, and (2) an auxiliary cooling water system that will be tied into the circulating water system to provide water for cooling major equipment within the combined cycle facility. The evaporative cooling tower will consist of a 10-cell structure approximately 276 feet long, 114 feet wide, and 52 feet high.

**Electrical Interconnection**

Power generated by Phase II will be delivered to the BPA's existing high-voltage transmission system at 230 kV at the breakers constructed on site. The power will be exported on lines constructed for Phase I from the project site to the BPA Satsop substation located approximately 4,000 feet to the east of the project site (see Figure 2.1-1).

A switchyard containing necessary breakers, switching and transformer equipment will be constructed for Phase II.

**Fire Protection**

The fire protection system, including the fire water system, fixed suppression systems, detection systems, and portable fire extinguishers, will provide the required fire protection for each plant and will consist of the following major components:

- Sprinkler systems
- Yard loop hydrant system
- Preaction spray/sprinkler system for the steam turbine generator bearings and lube oil equipment
- Independent smoke detection system
- Portable fire extinguishers
- Standpipes and fire hose stations at various locations throughout the buildings
- Instrumentation and control equipment for alarm, indication of equipment status, and actuation of fire protection equipment
- Combined raw/fire water storage tank
- Fire water pumps

Fire water will be stored in the on-site 1,000,000 gallon storage tank. This tank will also serve as a reservoir for raw water. This storage capacity will be sufficient to provide the maximum automatic system demand plus 500 gallons per minute (as recommended by NFPA 850) for a 2-hour period. The fire water pumping system will consist of a primary motor-driven pump, a diesel-driven backup pump with independent fuel supply, and a pressure-maintaining jockey pump.

2.3.2.3 Project Layout

Figure 2.3-4 presents the site plan layout for the project. Buildings located on the site are shown on Figure 2.3-2. The locations of key components of each plant are described below.

The combustion turbine and generator, the steam turbine and generator, and their associated support equipment will be located within standard GE enclosures. The HRSGs will be located outside of the generation building.

The CT-HRSG will be laid out in an in-line design parallel to the STG in a north-south orientation. Within the CTG-HRSG, the combustion turbine and the generator will be located at the north end within the generation building and adjacent to the electrical switchyard. The northernmost structures will be the exhaust stacks, with the HRSG (and emission control equipment within the HRSG) located between the stack and the combustion turbine.

An electrical switchyard will be located adjacent to the generator ends of the combustion turbines on the southernmost end of the site. Transmission lines will extend from the switchyard to the Olympia-Aberdeen transmission line right-of-way that extends along the southern edge of the plant site (see Figure 2.3-3).

The natural gas pipeline will enter the center of the plant site from the east (see Figure 2.3-4).

## 2.3.3 POWER PLANT CONSTRUCTION

### 2.3.3.1 Construction Summary

The Phase II site was previously graded and a layer of gravel was placed to prepare the site for use as a construction storage area for the Phase I project.

After excavation, foundations will be installed, as will the drainage system for the construction stage. Materials to be used during construction are expected to be staged on the construction storage areas located adjacent to and west of the project site (see Figure 2.1-2), just west of Keys Road. During construction, the plant site will remain fenced to provide site security.

The Certificate Holder will purchase electricity needed for construction and startup. Approximately 1.5 megavolts (MVA) of 480-volt, 3-phase temporary power will be installed at a single location within the project site boundary. Startup power will be obtained by back-feeding from the 230-kilovolt (kV) utility system.

Conventional construction equipment, including bulldozers, front-end loaders, trucks, tractor-scrapers, and graders will be used to final grade the site. During construction, dust will be controlled as needed by spraying water on dry, exposed soil. Prior to leaving the site during construction, vehicles will be sprayed with water and required to drive over a gravel pad to remove mud from the tires.

Site clearing and grading has been completed during Phase I construction. Phase II construction erosion control measures will be used in accordance with the requirements of the Certificate Holder's existing Erosion and Sedimentation Control Plan. The Erosion and Sediment Control Plan was approved by EFSEC on September 19, 2001.

After site preparation is completed, the Phase II contractors will install the combustion turbine, steam turbine, generators, electrical and other equipment. Once these facilities are in place, the site landscaping will be initiated.

Field toilets and temporary holding tanks will be placed on site for use by construction personnel. During construction, potable water from the water supply system will supply the contractor's needs. Parking will be provided on the construction laydown area located west of Keys Road.

### 2.3.3.2 Site Preparation

There will be approximately 80,000 cubic yards of excavation for foundations, buried pipes (circulating water and fire loop), and the electrical duct banks. This material will be retained in the construction area west of Keys Road and later used for backfill.

A Phase I Environmental Site Assessment completed in April 1994 (Dames & Moore 1994) indicated that there is no evidence of contamination with hazardous materials at the site and that the likelihood of such contamination being present in subsurface soils is low. If contamination is encountered during excavation and grading, the Certificate Holder will notify EFSEC and take the appropriate remedial actions.

During site preparation, the Phase II contractor will install a storm drainage system. This system will consist of a series of swales that will convey surface water runoff into the existing Satsop Development Park storm drainage control system (see Section 2.10 - Surface-Water Runoff, WAC 463-42-215).

A 6-foot high enclosure (chain link fence) was constructed as part of Phase I surrounding the plant site to provide security, and will be maintained during construction of Phase II.

### 2.3.3.3 Foundations and Roadways

Foundations, including a pedestal for the steam turbine generator and foundations for the gas turbine generator and heat recovery steam generator equipment, will be installed. As a part of final design studies, geotechnical investigations will be conducted to determine the appropriate types of foundations for the facilities. Based on currently available data, the Certificate Holder anticipates that foundations will be Category 1 facilities (non-essential facilities) in accordance with ASCE document 7-88 ("Minimum Design Loads for Buildings and Other Structures"). Foundations and buildings will be designed for Seismic Zone 3.

Construction of the project foundations will require the use of a number of types of heavy equipment, including excavation equipment, concrete-pumping equipment, and concrete finishing equipment. In addition, light- and medium-duty trucks, air compressors, generators, and other internal combustion engine driven equipment are anticipated.

On-site roadways and parking areas will be constructed with asphaltic concrete over a compacted subbase.

An on-site concrete batch plant will not be required.

### 2.3.3.4 Equipment Installation

A number of the component systems of the Phase II facility will be fabricated and delivered to the site. This includes the combustion turbine, CTG, HRSG, STG, major pumps, and electrical equipment. Fabrication and delivery of these components will be scheduled to coincide with their requirement in the construction sequence. Heavy and large equipment components will be delivered to the site by truck. Various sized cranes will be required to lift and place many of the pieces of component equipment into the required position.

In sequence with the installation of component equipment, support systems will be installed, including electrical equipment, control equipment, piping instrumentation, wiring cable, and conduits. Typical construction activities onsite will include mechanical fastening, welding, preparation, and painting.

Cathodic protection will be provided on all underground gas lines within the site boundary.

2.3.3.5 Startup Testing

At the completion of the construction sequence, the plant system will be energized and operational testing undertaken. This will include testing each of the major component systems in a predetermined sequence and completion of quality assurance and quality control checks to ensure that each system is ready for full operation. After the total plant is fully operational, emission compliance testing will be conducted. At the end of the startup testing phase, each unit will be separately certified for commercial operation. The quality assurance and quality control checks are described in detail in Section 2.12 - Construction and Operation Activities, WAC 463-42-235.

Source: 3DScape

Figure 2.3-1
**Existing Phase I Isometric View**

URS

Phase II Expansion
Satsop CT Project

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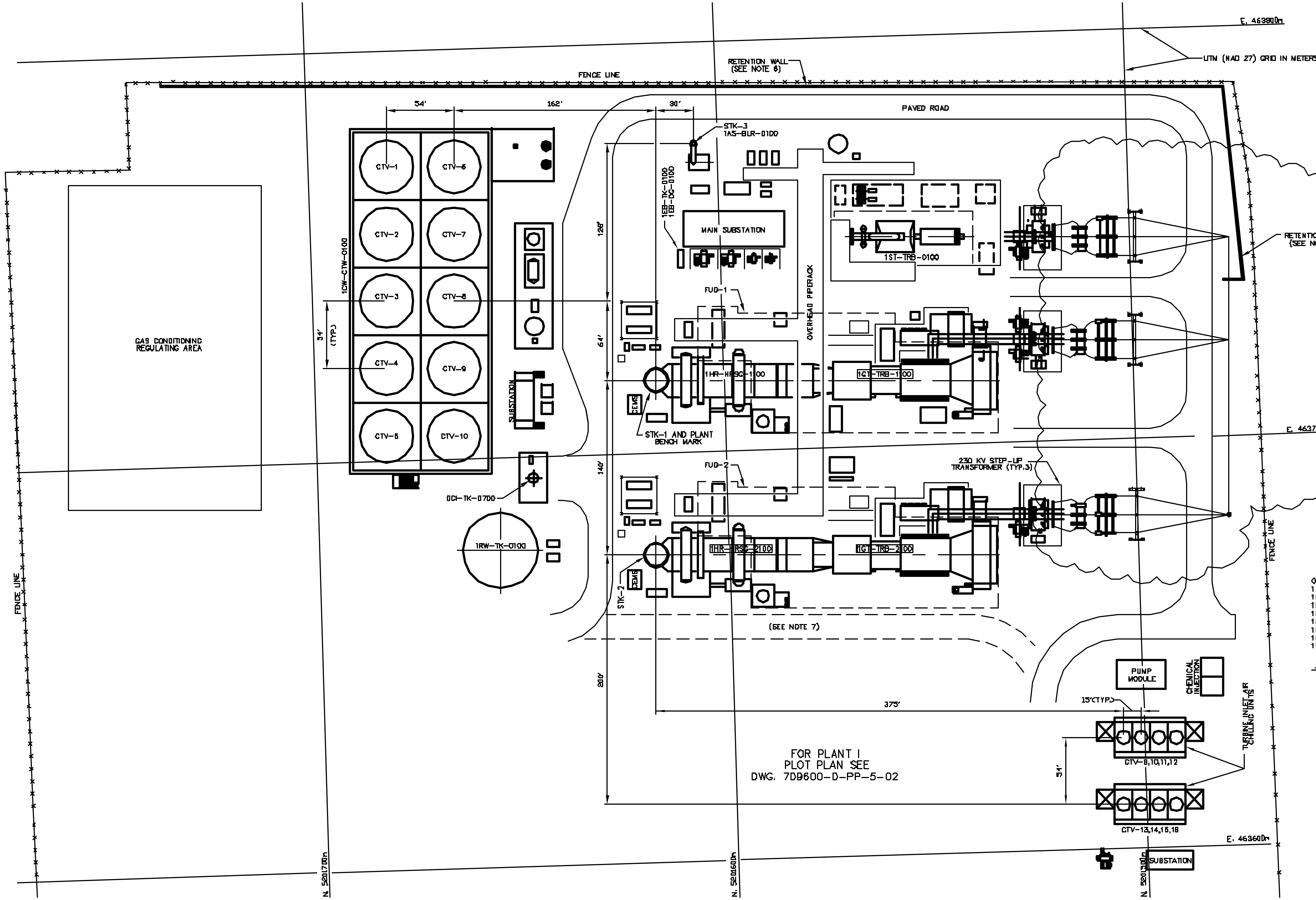
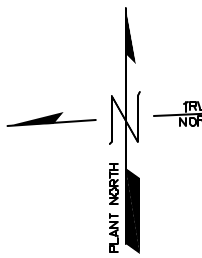
Source: 3DScape

Figure 2.3-2
**Proposed Phase II Conceptual Isometric View**

URS

Phase II Expansion
Satsop CT Project




EMISSION POINT COORDINATES

| DESCRIPTION | NORTHING | EASTING |
|---|---|---|
| STK-1 | N. 5201617m | E. 463718m |
| STK-2 | N. 5201610m | E. 463673m |
| STK-3 | N. 5201606m | E. 463775m |

EQUIPMENT LIST

| | |
|---|---|
| 0CI-TK-0700 | AMMONIA TANK |
| 1AS-BLR-0100 | AUXILIARY BOILER |
| 1CW-CTW-0100 | COOLING TOWER |
| 1EB-DG-0100 | BACKUP DIESEL GENERATOR |
| 1EB-TK-0100 | DIESEL DAY TANK {DIESEL GENERATOR} |
| 1CT-TRB-1100/2100 | COMBUSTION TURBINE GENERATORS |
| 1HR-HRSG-1100/2100 | HEAT RECOVERY STEAM GENERATORS |
| 1RW-TK-0100 | RAW WATER TANK |
| 1ST-TRB-0100 | STEAM TURBINE GENERATOR |

NOTES:

1. POST-CONSTRUCTION ELEVATION OF SITE = 305' ABOVE MSL.
2. FUG-X DENOTES FUGITIVE EMISSIONS AREAS.
3. CTV-X DENOTES COOLING TOWER CELLS.
4. STK-X DENOTES HRSG AND AUX. BOILER EXHAUST STACKS.
5. ALL COORDINATES SHOWN ARE UTM ZONE 10 GRID, NAD27, AND ARE GIVEN IN METERS.
6. RETENTION WALL AND EARTHWORK TO BE BY PLANT II.
7. EXISTING ROAD TO BE REMOVED DURING PLANT II CONSTRUCTION.

PRELIMINARY

GRAPHIC SCALE IN FEET

0 20 40 60 80 100

GRAPHIC SCALE IN METERS

0 5 10 20 30 40 50

Figure 2.3-3

## Plant Configuration

URS

Phase II Expansion
Satsop CT Project

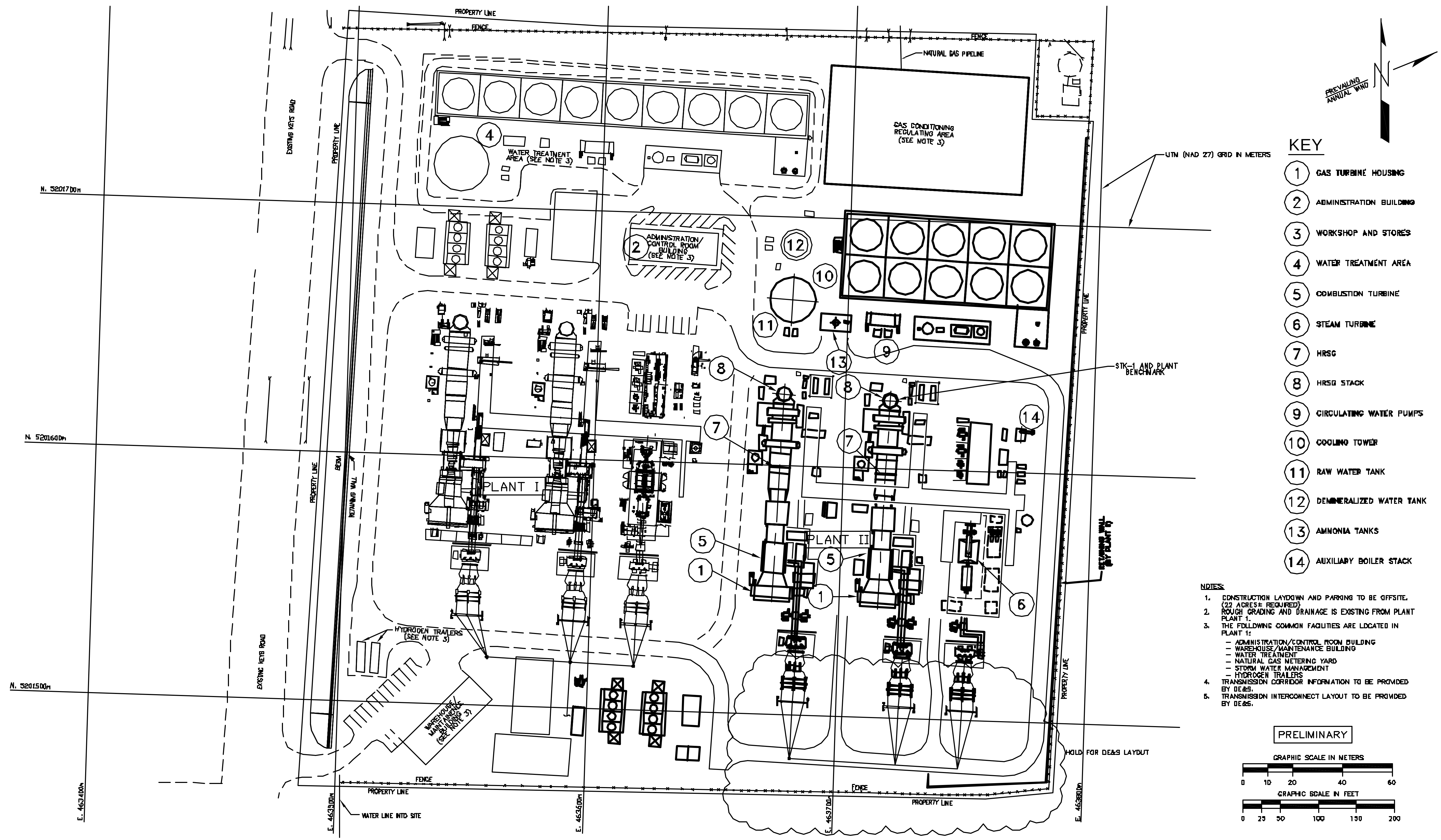
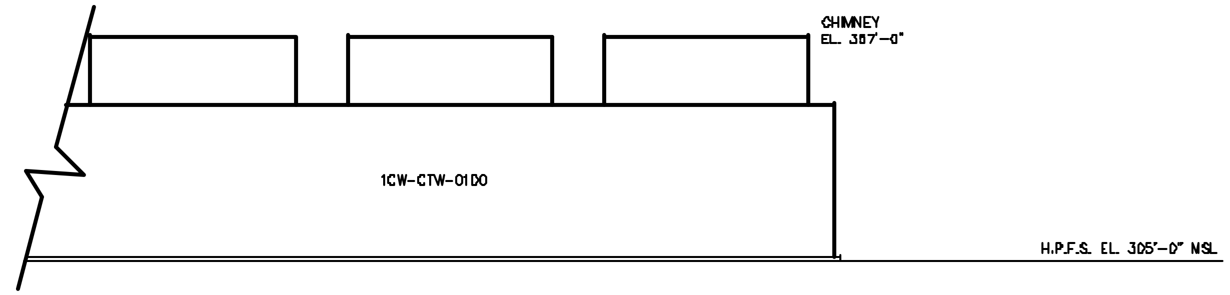
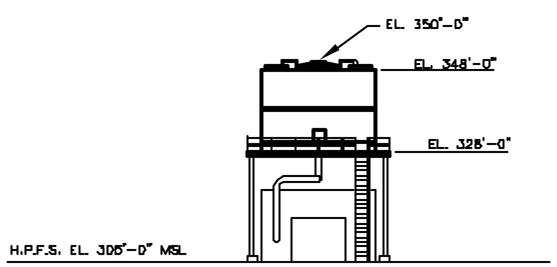


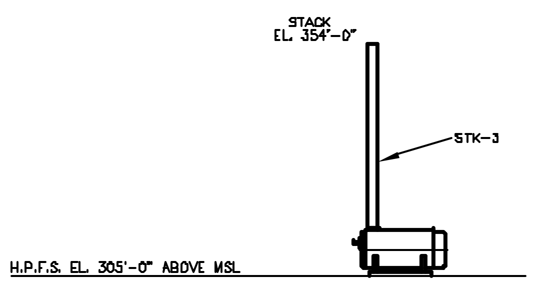

Figure 2.3-4
Site Plan



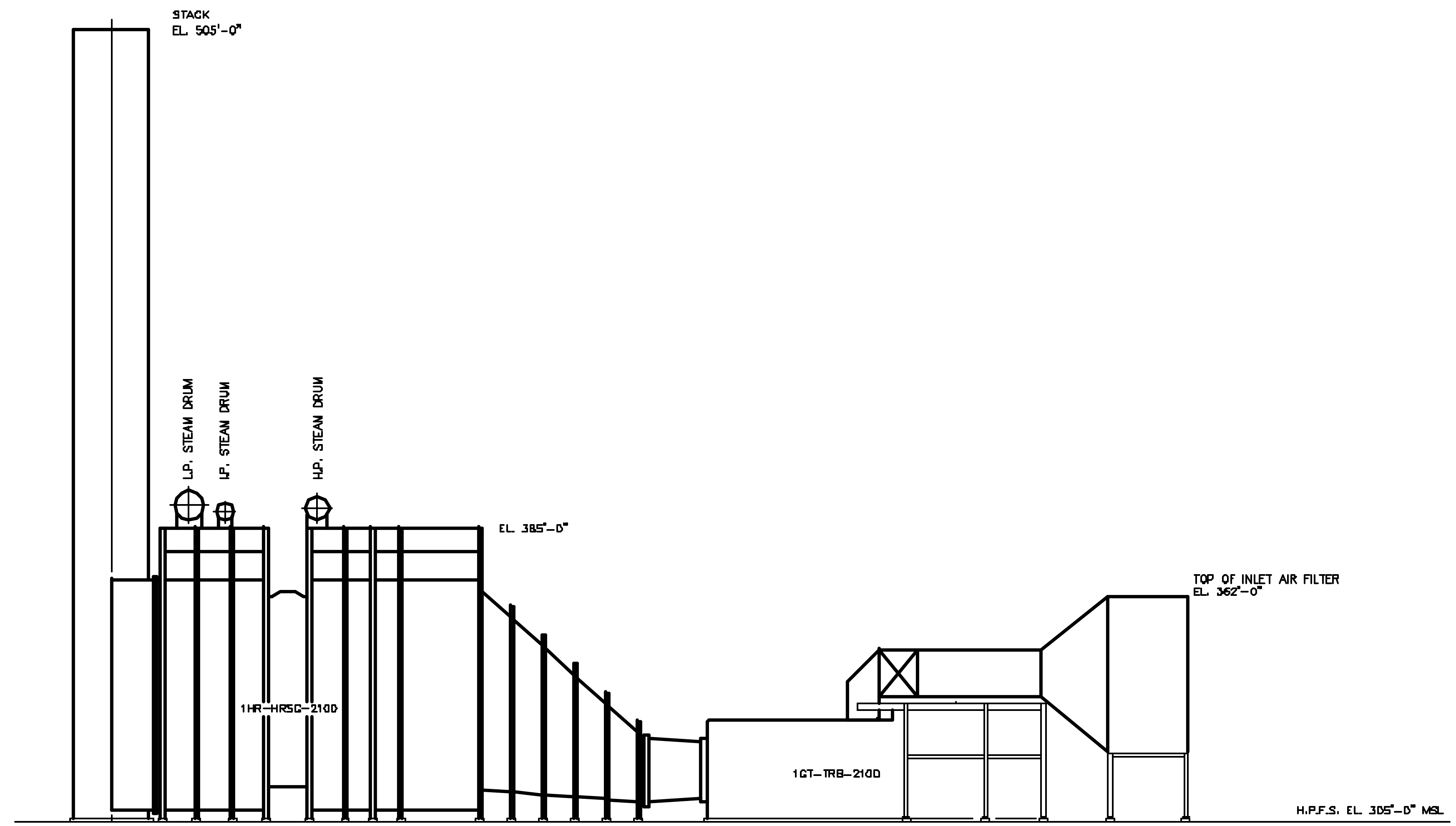

COOLING TOWER ELEVATION
VIEW LOOKING WEST




TURBINE INLET AIR CHILLING UNIT
VIEW LOOKING EAST




AUXILIARY BOILER ELEVATION
VIEW LOOKING NORTH




POWER TRAIN ELEVATION
VIEW LOOKING NORTH

PRELIMINARY

GRAPHIC SCALE IN FEET
0 10 20 30 40 50

Last Printed: P:\ACAD\PROJECT\DukeEnergy\Satsop\R04\8860020100003R04.dwg 10/23/01 at 16:36

Figure 2.3-5
Plant Elevation

URS

Phase II Expansion
Satsop CT Project

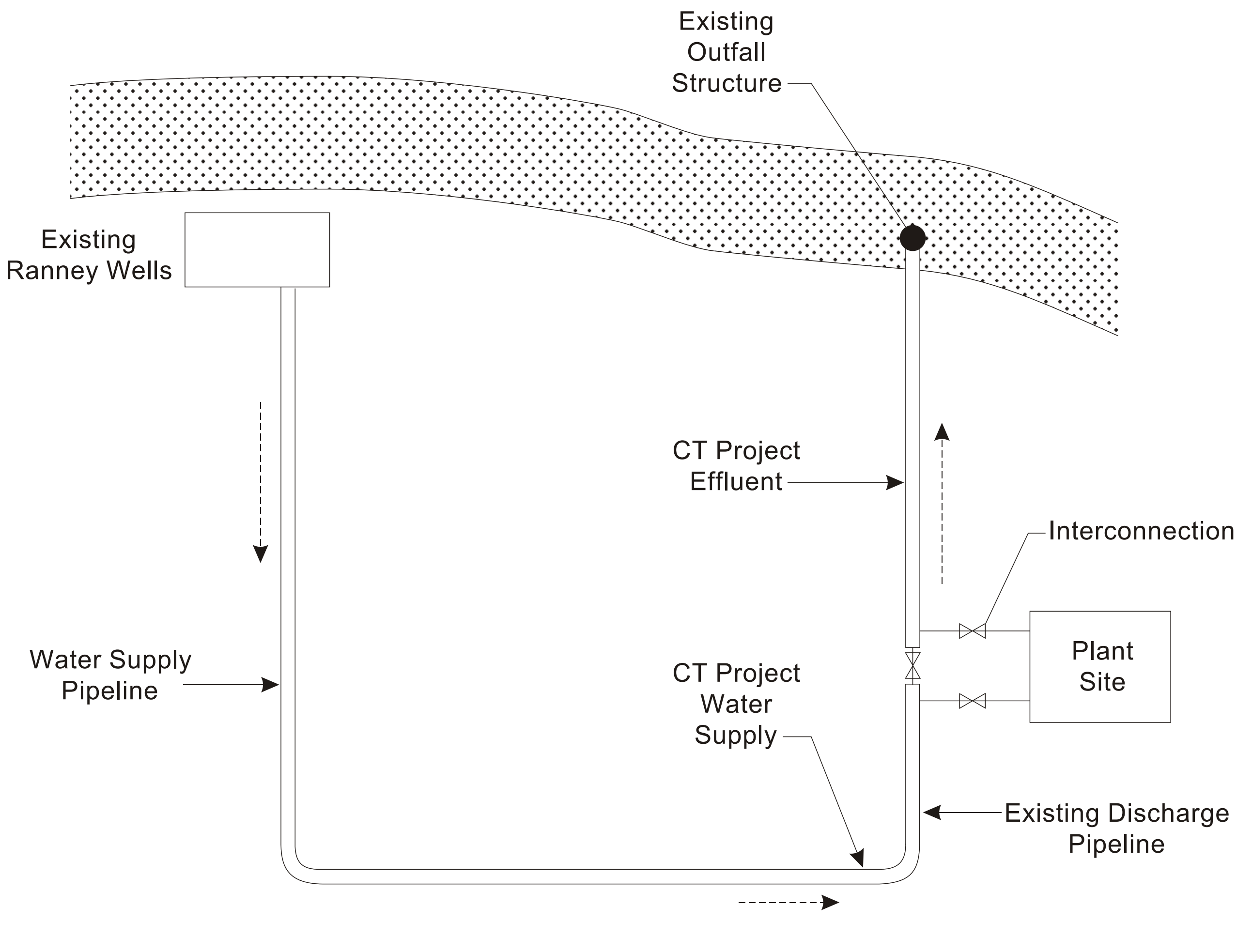



Figure 2.3-6
**Process Water**
**Conceptual Flow Diagram**

## 2.4

# Energy Transmission Systems (WAC 463-42-155)

**WAC 463-42-155 PROPOSAL — ENERGY TRANSMISSION SYSTEMS.**

*The applicant shall discuss the criteria utilized as well as describe the routing, the conceptual design, and the construction schedule for all facilities identified in RCW 80.50.020 (6) and (7) which are proposed to be constructed.*

*[Statutory Authority: RCW 80.50.040(1). 83-01-128 (Order 82-6), §463-42-155, filed 12/22/82. Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-155, filed 10/8/81. Formerly WAC 463-42-240.]*

# 2.4 ENERGY TRANSMISSION SYSTEMS (WAC 463-42-155)

## 2.4.1 INTRODUCTION

The Phase II project will be fueled by natural gas that is supplied by the natural gas pipeline being constructed as part of Phase I, and thus not subject to this section. Also as part of Phase I, there will be new electrical transmission lines extending approximately 4,000 feet east of the plant site to the Bonneville Power Administration (BPA) Satsop substation.

### 2.4.1.1 Phase I Power Line Construction

BPA has an existing transmission line right-of-way, south of and directly adjacent to the plant site and extending in an east-west direction. There are currently two 230-kilovolt (kV) transmission lines, both located on the same double-circuit structure. There is a separate 115-kV transmission line located on its own set of poles.

As part of construction for Phase I, the 115-kV line and its poles are being removed, and a new set of double-circuit structures are being installed. Three new transmission lines will be installed. Two of these lines will be 230-kV transmission lines. As shown on Figure 2.4-1, one line will be used to connect Phase I to the Satsop substation, and the other will remain idle until Phase II comes on line. The remaining line will be a 115-kV transmission line to replace the existing line.

The lines will be owned and operated by BPA.

### 2.4.1.2 Phase II Power Transmission

Power produced by Phase II project will connect to the BPA system via the transmission lines constructed as part of Phase I.

The Certificate Holder will coordinate with BPA to ensure that one of the new transmission lines constructed during Phase I is available to be tied in to the BPA substation when Phase II is ready for startup.

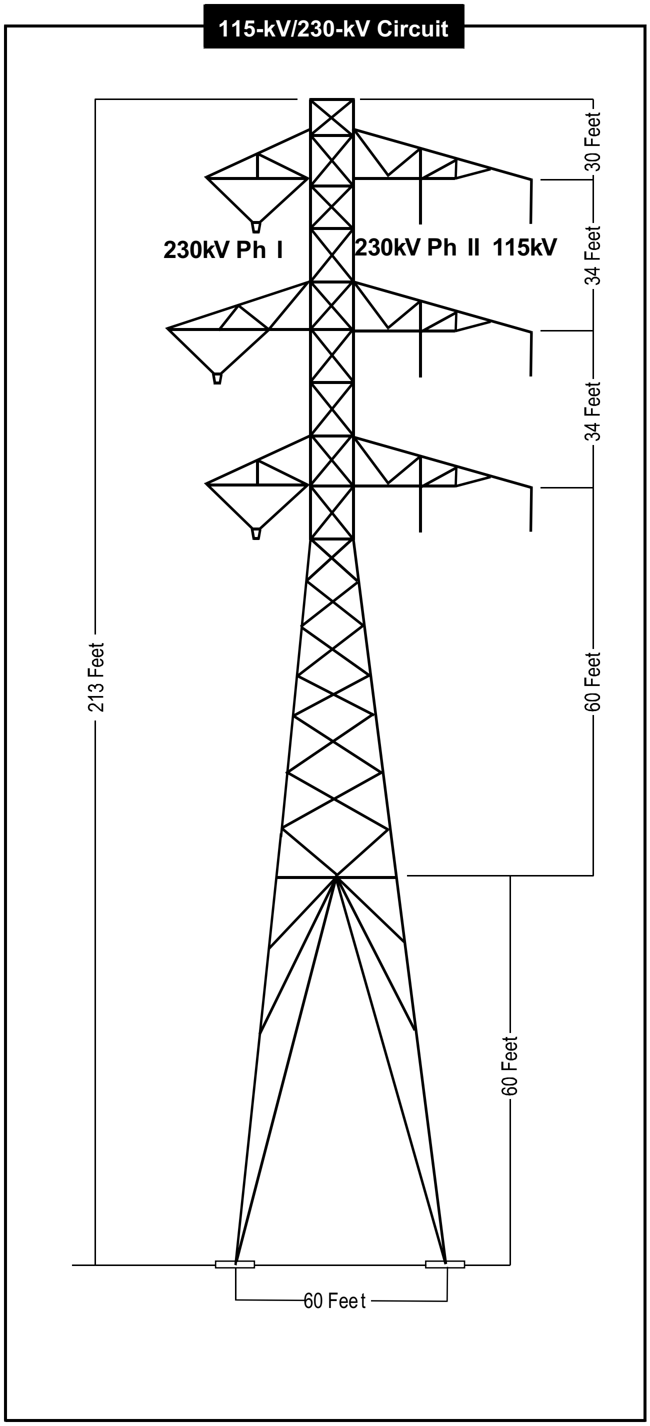



Figure 2.4-1

## BPA's Phase I Transmission Tower Design

# 2.5
# Water Supply (WAC 463-42-165)

**WAC 463-42-165 PROPOSAL — WATER SUPPLY.**
*The applicant shall describe the location and type of water intakes and associated facilities.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW.*
*81-21-006 (Order 81-5), §463-42-165, filed 10/8/81. Formerly WAC 463-42-400.]*

## 2.5 WATER SUPPLY SYSTEM (WAC 463-42-165)

### 2.5.1 PROCESS WATER SUPPLY

Process water will be supplied from the existing Ranney wells and transported through the existing supply water line (see Figure 2.5-1). The Ranney wells are located on the southern bank of the Chehalis River, approximately 4 miles downriver of the plant site near the river's confluence with Elizabeth Creek. The wells penetrate to a depth of approximately 120 feet into the alluvial aquifer associated with the Chehalis River. The Ranney wells obtain approximately 88 percent of their water from the Chehalis River via drawdown, with the remaining 12 percent drawn from groundwater in the surrounding river alluvium. Groundwater availability in river alluvium of the Chehalis River valley from each Ranney well is as high as 40 cfs (18,000 gpm). Additional information on water quality and quantity associated with the Ranney wells is presented in Section 3.3 – Water, WAC 463-42-322, and Appendix B.

Water from the Ranney wells will be transported to the Satsop CT Project plant site via the existing supply water line and the existing discharge (blowdown) line. A connection between the supply water line and the blowdown line will be made in the vicinity of the WNP-5 cooling tower. At the Satsop CT Project plant site, a pipe will be connected to the blowdown line to transport process supply water to the project. Detailed design, location, and connection information on the Ranney wells and on the existing distribution system to be used to supply water to the Satsop CT Project is presented in the WPPSS application for a Site Certification Agreement (SCA), in the SCA issued by EFSEC, in documents subsequently submitted to EFSEC, and in the WPPSS Environmental Report - Operating Licensing Stage (WPPSS 1982) and Final Safety Analysis Report (WPPSS 1984).

As part of this application, the Certificate Holder is requesting an amendment to the existing SCA to allow the Phase II project to use 9.5 cfs of the Public Development Authority's (PDA's) existing permitted water right.

### 2.5.2 POTABLE WATER SUPPLY

Water for potable uses at the proposed project will be supplied by the Satsop Development Park's raw water well. The raw water well is located at the confluence of the Satsop and Chehalis Rivers, and the distribution pipeline extends to a water storage tank located adjacent to the northeastern corner of the plant site. The Certificate Holder will construct pipeline connections from this distribution system to the power plants.

The well extends to a depth of 80 feet in the shallow sand and gravel aquifer in the area extending north of the Chehalis River and east of the Satsop River. Detailed design, location, and construction information on the raw water well and the associated water distribution system is presented in the WPPSS application for the SCA, the SCA issued by EFSEC, and documents subsequently submitted to EFSEC.

Anticipated potable and service water demand for the Phase II is approximately 50 gpm maximum, and will average less than 20 gpm. Water supplied by the Satsop Development Park is chlorinated, and if needed, additional treatment will be made prior to delivery to Phase II.

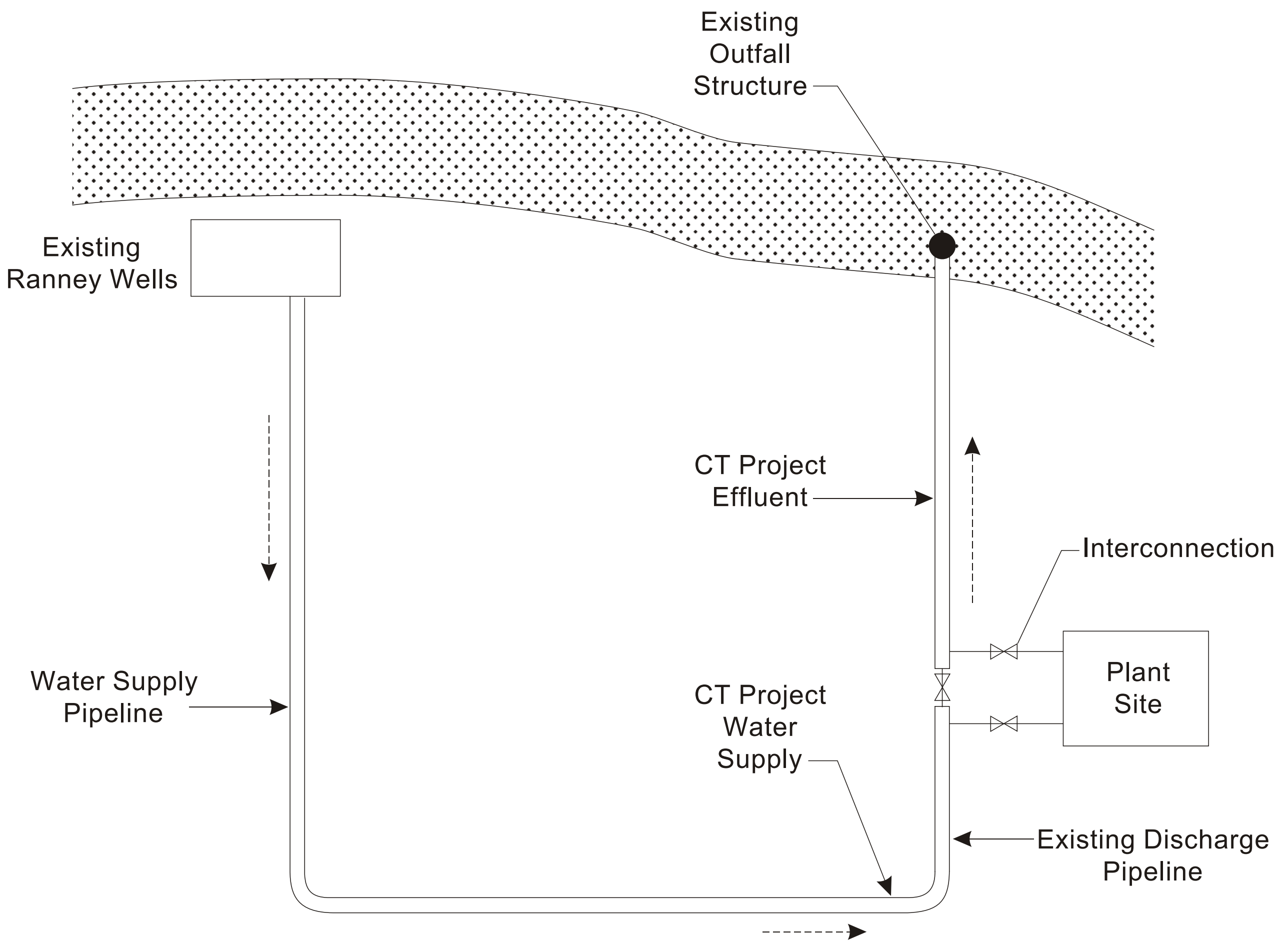



Figure 2.5-1

**Process Water**
**Conceptual Flow Diagram**

URS

Phase II Expansion
Satsop CT Project

46866002.01_38.cdr

# 2.6
# System of Heat Dissipation (WAC 463-42-175)

**WAC 463-42-175 PROPOSAL — SYSTEM OF HEAT DISSIPATION.**
*The applicant shall describe both the proposed and alternative systems for heat dissipation from the proposed facilities.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-175, filed 10/8/81. Formerly WAC 463-42-430.]*

## 2.6 SYSTEM OF HEAT DISSIPATION (WAC 463-42-175)

### 2.6.1 PROPOSED SYSTEM OF HEAT DISSIPATION

The proposed cooling system consists of two primary components: (1) a circulating cooling water system, and (2) a mechanical draft cooling tower. Steam supplied to the steam turbine generators (STG) will be exhausted from the steam turbine and condensed in the steam condenser. The circulating cooling water system, operating at a flow of approximately 66,000 gallons per minute (gpm), will route cool water to the condenser and auxiliary cooling system. The auxiliary cooling system will provide cooling for the generator cooling circuit, boiler feed pump, sampling/analysis panel, and the lubrication oil cooling circuit. At the condenser and the auxiliary cooling system, heat will be transferred to the circulating water. The warmed water will then be routed to the cooling tower, where the temperature will be reduced, before being returned to the cooling system.

The cooling tower will continuously receive the heated cooling water from the plant. The heated water will enter the tower near the top and will be sprayed downward through the tower. A large fan on top of the tower will pull air through openings in the bottom of the tower, moving air counter to the water sprays and cooling the water through evaporation. The temperature of the water will be reduced to approximately 90 degrees F when it reaches the cooling water basin where will be collected and returned to the cooling system. This cycle will be repeated until the circulating water needs to be replaced as described below.

Evaporation in the cooling tower will result in a loss of cooling water, and the constituents of the cooling water will be concentrated due to evaporation. At high concentrations, some of these constituents could cause scaling in the heat exchanger surfaces. Therefore after cooling water has circulated through the cooling cycle the appropriate number of times, a small portion will be removed from the cooling tower basin and discharged in accordance with the NPDES permit. (This discharge is termed cooling tower "blowdown.") To replenish the circulating cooling water, additional Ranney well water and the neutralized plant waste streams will be added to the cooling water. The three wastewater streams are the water treatment regeneration discharge, the cooling tower blowdown, and the plant sump discharge as described in Section 2.8 - Wastewater Treatment, WAC 463-42-195.

Since the cooling water will be repeatedly circulated before being discharged, several of the constituents of the cooling water will be concentrated to a point that could result in corrosion. Therefore, an alkaline phosphate treatment is necessary. Chemicals proposed for use in the cooling tower include an acrylic polymer (dispersant), tolyltriazole (copper corrosion inhibitor), phosphonocarboxylate (iron corrosion inhibitor), phosphonate (iron corrosion inhibitor), and sulfuric acid (alkalinity control). Because the circulating water is exposed to atmospheric microbiological contaminants, sodium hypochlorite will be used as a biocide to minimize microbiological growth. During treatment with sodium hypochlorite, the blowdown discharge valve will remain closed to prevent the release of chlorine. The majority of chlorine will dissipate from the cooling tower basin while the blowdown valve is closed. The retained wastewater will be sampled and analyzed prior to discharge as blowdown. If chlorine is detectable, sodium bisulfite will be added to dechlorinate the residual chlorine prior to discharge. As a result, chlorine will be at or below the detection level (0.05 milligrams per liter, see Note 4 in the existing NPDES permit) in the discharge.

The types of chemicals used and their anticipated usage rates are listed in Table 2.6-1.

**Table 2.6-1**
**TYPICAL CHEMICALS USED IN COOLING WATER SYSTEM (PER UNIT)**

| Chemical | Description and Use | Estimated Usage Rate (pounds per day) |
|---|---|---|
| Nalco - Dynacool - 8301D or equivalent (dispersant: acrylate polymer) | Liquid polymeric dispersant used in circulating water treatment system. | 58 |
| Nalco - Dynacool - 8308 or equivalent (corrosion inhibitor: phosphonate, phosphonocarboxylate, tolyltriazole) | Liquid phosphate-based corrosion inhibitor used in circulating water treatment system. | 116 |
| Sodium hypochlorite | Liquid water treatment chemical for the cooling tower. | 111 |
| Sulfuric acid | Liquid water treatment chemical used in demineralizer and in neutralization tank. | 335 |

### 2.6.2 ALTERNATIVE FORMS OF HEAT DISSIPATION

The Certificate Holder intends to install a mechanical draft cooling tower system, identical to that being installed for Phase I. The alternative forms of cooling technologies that were considered are described in Section 9.1 - Analysis of Alternatives, WAC 463-42-645. Please see Subsection 9.1.2 Alternative Cooling Technologies for a description of the alternatives considered and the reason for the selection of the mechanical draft cooling tower (wet) system for Phase II cooling.

# 2.7
# Characteristics of Aquatic Discharge Systems (WAC 463-42-185)

**WAC 463-42-185 PROPOSAL — CHARACTERISTICS OF AQUATIC DISCHARGE SYSTEMS.**
*Where discharges into a watercourse are involved, the applicant shall identify outfall configurations and show proposed locations.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-185, filed 10/8/81. Formerly WAC 463-42-440.]*

## 2.7 CHARACTERISTICS OF AQUATIC DISCHARGE SYSTEMS (WAC 463-42-185)

The Phase II project will use the same blowdown line and outfall that Phase I will use. The outfall includes a diffuser, which was designed to disperse the effluents as required to comply with the National Pollutant Discharge Elimination System (NPDES) permit (NPDES Permit #WA-002496-1). Detailed information on the design, location, and construction, of the outfall is presented in documents previously submitted to EFSEC as a part of the application for the Site Certification Agreement for the nuclear projects and in subsequent related documents.

The existing blowdown line and outfall are owned by the Grays Harbor Public Development Authority. The transfer agreement between Energy Northwest and the Satsop Redevelopment Project guarantees the use of the blowdown line and outfall for Satsop CT Project discharges. Currently, there are no process discharges entering the blowdown line.

An existing NPDES permit governs wastewater discharges from the Satsop CT and stormwater discharges from the Satsop Development Park. As described in Section 2.8 - Wastewater Treatment, WAC 463-42-195, effluent from the CT project will meet the stipulations of the existing NPDES permit. (See Section 7.1.)

Cooling tower blowdown will enter the Chehalis River at river mile 20.5 through an existing blowdown diffuser structure. The blowdown pipe is buried beneath the river bottom, and connects about 150 feet from the south river bank to a 30-foot-long multiport diffuser, which is also buried beneath the river bottom. The original design for the diffuser includes an 18-inch-diameter pipe perforated with 46 discharge ports (or nozzles) that project 1 foot above the river bottom and discharge in a downstream direction at a 12-degree angle above the horizontal. The ports are 2 inches in diameter and are spaced at 8-inch intervals. It has been determined that the diffuser structure has been damaged by snags catching on the discharge ports. An engineering review will be made to determine if modifications to the existing diffuser will be needed for Satsop CT discharges.

## 2.8

# Wastewater Treatment (WAC 463-42-195)

**WAC 463-42-195 PROPOSAL — WASTEWATER TREATMENT.**

*The applicant shall describe each wastewater source associated with the facility and for each source, the applicability of all known, available, and reasonable methods of wastewater control and treatment to ensure it meets current waste discharge and water quality regulations. Where wastewater control involves collection and retention for recycling and/or resource recovery, the applicant shall show in detail the methods selected, including at least the following information: Waste source(s), average and maximum daily amounts and composition of wastes, storage capacity and duration, and any bypass or overflow facilities to the wastewater treatment system(s) or the receiving waters. Where wastewaters are discharged into receiving waters, the applicant shall provide a detailed description of the proposed treatment system(s), including appropriate flow diagrams and tables showing the sources of all tributary waste streams, their average and maximum daily amounts and composition, individual treatment units and their design criteria, major piping (including all bypasses), and average and maximum daily amounts and composition of effluent(s). [Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-195, filed 10/8/81. Formerly WAC 463-42-470.]*

## 2.8 WASTEWATER TREATMENT (WAC 463-42-195)

This section provides information on the proposed process wastewater discharge streams and alternative systems in the following subsections:

- Process Wastewater Streams (Subsection 2.8.1)
- Wastewater Analyses (Subsection 2.8.2)
- Regulatory Compliance (Subsection 2.8.3)
- Bypass and Overflow Facilities (Subsection 2.8.4)
- Alternative Methods (Subsection 2.8.5)

### 2.8.1 PROCESS WASTEWATER STREAMS

The Satsop CT Project has been designed to minimize wastewater discharges, with only a single waste stream to be discharged from each phase. The design for each phase includes waste streams that will be treated as necessary and co-mingled prior to discharge. These waste streams consist of cooling tower blowdown and oil/water-separator decant. The co-mingled waste streams from each phase will be discharged to the Satsop Development Park's blowdown line in accordance with the NPDES permit (Permit No. WA-002496-1; see Section 2.8.2) for the Satsop CT Project. As shown on Figure 2.8-1, the outfall discharges to the Chehalis River. Figures 2.8-2, 2.8-3, and 2.8-4 illustrate maximum, minimum, and average daily composition of waste streams.

#### 2.8.1.1 Water Treatment System Units and Discharge

**Cooling Tower Blowdown**

The cooling towers will continuously receive the heated cooling water from the plants. Heated water will enter the tower near the top and will be sprayed downward through each tower. Evaporation in the cooling towers will result in a loss of cooling water, and the constituents of the cooling water will be concentrated due to evaporation. At high concentrations, some of these constituents could cause scaling in the heat exchanger surfaces. Therefore, after cooling water has repeatedly circulated through the cooling cycle, a small portion will be removed from each cooling tower basin and discharged in accordance with the NPDES permit. (This discharge is termed cooling tower “blowdown”.)

Since the cooling water will be repeatedly circulated before being discharged, several of the constituents of the cooling water will be concentrated to a point that could result in corrosion. Therefore, an alkaline phosphate treatment is necessary. Chemicals proposed for use in the cooling tower include an acrylic polymer (dispersant), tolytriazole (copper corrosion inhibitor), phosphonocarboxylate (iron corrosion inhibitor), phosphonate (iron corrosion inhibitor), and sulfuric acid (alkalinity control). Because the circulating water is exposed to atmospheric microbiological contaminants, sodium hypochlorite will be used as a biocide to minimize microbiological growth. During treatment with sodium hypochlorite, the blowdown discharge valve will remain closed to prevent the release of chlorine. The majority of chlorine will dissipate from the cooling tower basin while the blowdown valve is closed. The retained wastewater will be sampled and analyzed prior to discharge as blowdown. If chlorine is detectable, sodium bisulfite will be added to dechlorinate the residual chlorine. As a result, chlorine will be at or below the detection level. However, if the Certificate Holder can demonstrate to EFSEC that the facility can not operate without a residual discharge, the monthly average free available residual chlorine may be 0.2 mg/l and the daily maximum may be 0.5 mg/l (see NPDES permit).

The types of chemicals used for treatment are listed in Table 2.8-1. The constituents of these chemicals used for treatment of the cooling tower water system are not on the list of toxic substances regulated under WAC 173-201A-040 (Water Quality Standards for Surface Waters in Washington State). The chemicals used for treatment of the cooling water will either be precipitated out of the effluent stream or will be at undetectable concentrations.

**TABLE 2.8-1**
**CHEMICALS USED IN COOLING WATER SYSTEM**

| Chemical | Description and Use |
|---|---|
| Scale inhibitor | Liquid phosphate-based corrosion inhibitor used in circulating water treatment system |
| Sodium hypochlorite | Liquid water treatment chemical for the cooling tower |
| Hydrochloric acid | Liquid water treatment chemical |
| Oxygen scavenger | Liquid water treatment chemical |

The cooling tower blowdown water from each phase will be co-mingled with the waste stream from each phase's oil-water separator and discharged to the blowdown line to the Chehalis River. The expected flow will be a maximum of 640 gpm for each phase.

Discharges through the blowdown line and outflow structure are regulated by the NPDES permit, which will be amended to include Phase II. As described below (Subsection 2.8.2), the cooling tower discharge will meet the limitations of the NPDES permit and will be in compliance with applicable state water quality criteria (WAC 173-201A). The temperature of the discharge will be below the 18$^{o}$C specified in the NPDES permit, using either heat exchangers and/or quench water.

### Oil-Water Separator

The oil-water separator will be designed to produce an effluent concentration of less than or equal to 15 ppm of oil.

The oil-water separator will be provided for waste streams that potentially may contain oily water such as the steam turbine oil purification system and floor and equipment drains. The oil-water separator will receive and separate water and oil mixtures. Water from the separator will be co-mingled with the cooling tower blowdown prior to discharge to the Satsop Development Park's blowdown line, while the oil is retained for eventual removal and disposal. The oil-water separator will be a prefabricated modular fiberglass reinforced plastic, cast-in-place concrete structure, or a packaged steel tank type system. The discharge piping will be designed with a leg extending below the maximum design oil depth, which will allow only oil-free water to be discharged. A reservoir included with the oil/water separator will collect the waste oil for off-site recycling or disposal by a licensed contractor.

Large tanks containing oil will be diked and valved to "retain-in-place" any large oil spills for mitigation and cleanup in place.

**Sanitary Wastes**

Sanitary wastes will be treated at on-site septic tank systems constructed and operated in accordance with the applicable state and Grays Harbor County codes.

#### 2.8.1.2 Internal Waste Streams

**HRSG Blowdown (Internal Stream)**

A small stream (90 gpm) from the HRSG of each phase will be drained to remove the constituents of the make-up water that become more concentrated due to evaporative losses during operation (steam production). This "blowdown" from the HRSG will be routed to a blowdown tank before being piped to the cooling tower for use as make-up water. The purpose of the tank is to absorb the "flashing" (the rapid and forceful decrease in temperature and pressure during blowdown release) as blowdown water is released from the boiler.

**Regeneration Waste (Internal Stream)**

Approximately 8 gpm of regeneration waste will be discharged from the boiler feed water treatment system to the cooling tower basin.

**Plant Sump Discharge (Internal Stream)**

Each plant sump will receive minor wastewater streams from the steam turbine oil purification system, the transformer containment structure drains, and the generator building floor drains. Wastewater in the plant sump will be routed to an oil-water separator.

### 2.8.2 WASTEWATER ANALYSES

Wastewater modeling and analyses were conducted to determine the expected concentration of constituents of the discharge from the Satsop CT Phase I Project and to evaluate potential impacts to the receiving water (Chehalis River) from the process water discharge. Discharges to the river were evaluated in comparison to the water quality criteria specified in WAC 173-201A (Water

Quality Standards for Surface Waters of the State of Washington). Phase II discharge will be identical.

Two approaches were used to evaluate impacts to the river. The first approach used a simple mixing equation applied to 25 percent of the flow rate, assuming a low flow in the Chehalis River (550 cfs) and a 7-day, 10-year low flow of 416 cfs. This flow rate includes the low flow from the Satsop River Station at Satsop and the Chehalis River Station at Porter to estimate low flows in the vicinity of the outfall which is downstream of the confluence of the two rivers. The results of these calculations, along with discharge characteristics, are presented in Table 2.8-2.

## TABLE 2.8-2
## WATER QUALITY STANDARDS AND ANALYSES

| Parameters | WAC 173-201A Standards[a] Acute Criteria (mg/L) | Chronic Criteria (mg/L) | NPDES[b] Permit | Influent Concentration (Ranney Wells) (mg/L) | Chehalis River Concentration[c] 550 cfs (mg/L) | CT Project Discharge Concentration[d] (mg/L) | Receiving Water Concentration Minimum Flow Concentration[e] (mg/L) | Low Flow Concentration[f] (mg/L) | Plume Analysis Results (mg/L) |
|---|---|---|---|---|---|---|---|---|---|
| Arsenic | 0.36 | 0.19 | NA | 0.0025[g,h] | 0.0005[g] | 0.016 | 0.00066 | 0.00071 | 0.001751 |
| Cadmium | 0.00084 | 0.00037 | NA | 0.00005[g,i] | 0.00005[g] | 0.00032 | 0.00005 | 0.00005 | 3.5E-05 |
| Chromium$^{+3}$ | 0.63 | 0.075 | 0.1[j] | 0.0005[i] | 0.0006 | 0.00635 | 0.00066 | 0.00068 | 0.000695 |
| Copper | 0.00476 | 0.00354 | 0.03 | 0.0005[g,i] | 0.0005 | 0.00635 | 0.00056 | 0.00058 | 0.000695 |
| Iron | NA | NA | 1 | 0.008[i] | 0.107 | 0.1016 | 0.10694 | 0.10693 | 0.011121 |
| Mercury | 0.0024 | 0.000012 | NA | 0.0001[g,i] | 0.0004 | 0.00064 | 0.00040 | 0.00040 | 7.01E-05 |
| Nickel | 0.473 | 0.052 | 0.065 | 0.0005[g,i] | 0.0005[g] | 0.00635 | 0.00056 | 0.00058 | 0.000695 |
| Lead | 0.0116 | 0.00045 | NA | 0.00005[g,i] | 0.0005[g] | 0.00032 | 0.00050 | 0.00050 | 3.5E-05 |
| Selenium | 0.02 | 0.005 | NA | 0.001[g,i] | 0.001[g] | 0.0064 | 0.00106 | 0.00107 | 0.000701 |
| Temperature (°F) | NA | 64.4 | 68 | 51[i] | 52.3 | 68[k] | 52.5 | 52.5 | NA |
| Zinc | 0.0365 | 0.0331 | 0.0025 | 0.0025[g,i] | 0.0025[g] | 0.03175 | 0.00280 | 0.00290 | 0.003475 |

(a) Acute: In general, refers to a 1-hour average concentration not to be exceeded more than once every three years on the average.
Chronic: In general, refers to a 4-hour average concentration not to be exceeded more than once every three years on the average.
(b) NPDES permit (effluent limitations, recalculating cooling water blowdown).
(c) Chehalis River at intake area (Envirosphere, 1982)
(d) For constituents stipulated in the NPDES permit only, CT Project discharge concentration - assume 12.7 increase at point of discharge into blowdown line. CT Project discharge of 1.43 cfs (640 gpm) based on preliminary water balance assumptions.
For constituents not stipulated in the NPDES permit, a concentration factor of 6.4 was used.
(e) Receiving water minimum flow rate is the minimum base flow rate specified by WAC 173-522-020 in Chehalis River at Satsop

$$\text{Receiving water concentration} = \frac{(\text{CT Project Discharge} \times 1.43\text{ cfs}) + (\text{river concentration} \times 550/4\text{ cfs})}{1.43\text{ cfs} + 550/4\text{ cfs}}$$

(f) Receiving water low flow rate is the combined 7-day 10-year low flow in Chehalis River at Porter and Satsop River at Satsop (416 cfs).

$$\text{Receiving water concentration} = \frac{(\text{CT Project Discharge} \times 1.43\text{ cfs}) + (\text{river concentration} \times 416/4\text{ cfs})}{1.43\text{ cfs} + 416/4\text{ cfs}}$$

(g) -Based on estimated values calculated to equal 1/2 non-detectable analytical limit.
(h) -Ranney Well water data (Supply System).
(i) -Well APW (5 Nov, 1980 - 29 Oct 1981) mean annual dissolved concentration (all ND = 1/2 detection limit)(Evirosphere, 1982)
(j) -NPDES permit limitation for chromium.
(k) -The temperature at the point of discharge will be maintained at or below 18°C (68°F) by the addition of quench water, as required by the existing NPDES permit which states the following:
"The discharge temperature shall be such that the applicable Water Quality Standards for temperature shall be complied with at the edge of the dilution zone. Temperature shall not exceed 18.0 degrees Centigrade. The temperature increases shall not, at any time, exceed t=28/(T+7), as described in WAC 173-201A-030 for Class A waters. For purposes hereof, "t" represents the maximum permissible temperature increase measured at a mixing zone boundary and "T" represents the background temperature as measured at a point unaffected by the discharge and representative of the highest water temperature in the vicinity of the discharge. When natural conditions exceed 18.0 degrees Centigrade, no temperature increase will be allowed which will raise the receiving water temperature by greater than 0.3 degrees Centigrade."

The second approach applied a plume model to the discharge using the existing diffuser designed for the Washington Public Power Supply System (WPPSS) WNP-3 facility. This approach enabled evaluation of mixing and resultant concentrations of water quality parameters of concern (identified in the initial approach) within a specified mixing zone.

The following subsections present the methods used in the mixing analysis (Subsection 2.8.2.1) and the methods used in the plume model analysis (Subsection 2.8.2.2).

### 2.8.2.1 Mixing Equation Analysis

Concentrations of selected water quality parameters which would occur after mixing the discharge water with Chehalis River water were calculated. Constituents of the influent process water (concentrations of chemical constituents of Ranney well water), receiving water concentrations (Chehalis River water concentrations), discharge concentrations (concentrations in process water to be discharged from the plants), and resultant water quality concentrations are presented in Table 2.8-2. Water quality data are provided in Appendix B.

Table 2.8-2 also presents acute and chronic criteria for toxic substances introduced above background levels into state waters (WAC 173-201A, Water Quality Standards for Surface Waters of the State of Washington). Assumptions made to calculate acute and chronic concentrations were as follows: (1) a river water hardness concentration of 29 mg/l, (2) a temperature of 11.3°C, and (3) a pH level of 7.0, which are average annual levels for these parameters measured weekly by Envirosphere (1982) at the Chehalis River “intake” area. If natural levels of a toxic compound in the receiving stream exceed the criteria, the natural level serves as the standard.

Water quality data for Well APW (part of the Ranney well collector system) were assumed to represent influent water quality. Metal constituents and other water quality parameters were measured weekly by Envirosphere (1982) in Well APW. The metals concentrations used for the analysis were the dissolved fraction. Total metal concentrations include the desiment fraction which would be expected to be insignificant as the Ranney well gravel pack is developed by pumping, and sediment is removed due to settling in the cooling tower basin. For chemical constituents not measured in Well APW, the analytical data from Ranney well sampling conducted by the Supply System were used. Concentrations of selected constituents in the receiving water (Chehalis River) were assumed to be those concentrations measured at the “intake” area in the Chehalis River (Envirosphere 1982).

Dividing maximum process influent flow by outflow and assuming no loss of naturally occurring chemical constituents through scaling or other means, the naturally occurring chemical constituent concentration of the outflow was estimated to be approximately 6.4 times greater than that of the inflow.

To calculate the concentration factor for the discharge from Phase II to the blowdown line, the cycles of operation, or concentration factor (6.25) in the cooling tower is added to the concentration factor of the naturally occurring chemical constituent concentration.

The 6.4 concentration factor was used in the analysis to estimate the resultant concentrations of regulated inorganic constituents (including trace metals) discharged to the river. The 12.7 factor was used to estimate constituent concentrations regulated by the NPDES permit at the point of discharge to the blowdown line. As required by WAC 173-201A-100, the mixing analysis assumed the flowrate in the receiving water was 25 percent of the 550 cfs (247,000 gpm) minimum permitted flow in the Chehalis River. Similarly, receiving water concentrations during a low-flow event in the Chehalis River were estimated using 25 percent of the 7-day, 10-year low flow rate of 416 cfs (187,000 gpm) in the Chehalis River below the confluence of the Satsop River, where the existing discharge is located. This mixing analysis did not consider dimensions of the mixing zone.

Resultant constituent concentrations in the Chehalis River (at the point of discharge) after mixing with effluent from the project were calculated using the mixing equation below:

$$[C] = \frac{[C_R]\ x\ Q_R + [C_D]\ x\ Q_D}{Q_R + Q_D} \qquad (1)$$

where,

$C$ = resultant concentration in the river after mixing
$C_R$ = concentration in receiving water (river)
$C_D$ = concentration in discharge
$Q_R$ = flow in receiving water
$Q_D$ = flow in discharge

Values for each variable are presented in Table 2.8-2.

#### 2.8.2.2 Plume Model Analysis

A plume model was used to evaluate the efficiency of mixing and dilution within a specified mixing zone. This model used the diffuser dimensions of the existing outfall structure and river data previously described.

Water discharged from the project is estimated to contribute 426 to 640 gpm per phase to the Chehalis River. Average annual flow in the Chehalis River at a point 2.2 miles downstream of its confluence with the Satsop River was 5,109 cfs (2,293,000 gpm) from 1980 to 1982. The anticipated discharge amount for the project will add minimally to the streamflow quantity in the Chehalis River and will not measurably affect average streamflow rates. During low flow periods, streamflow in the Chehalis River may be minimally supplemented by discharge from the project. Mean low flows in the Chehalis River downstream of the Satsop River for 1-, 7-, 30-, 60-, and 90-day return periods range from 538 to 805 cfs (241,500 gpm to 361,300 gpm). Maximum estimated discharge from Phase II will increase low flows in the Chehalis River by approximately 0.27 percent.

The existing diffuser at the outfall in the Chehalis River (see Figure 3.3-1 for the proposed discharge location) consists of a 30-foot diffusion manifold with 46, 2-inch ports on risers spaced every 8 inches. As designed, the ports discharge horizontally, approximately 12 inches from the bottom of the river and approximately 6 feet below Mean Higher High Water (MHHW). An estimate was made of the dispersion capabilities of this diffuser arrangement by modeling the turbulent mixing capability of the Chehalis River at the location of the diffuser. This type of analysis is preferable to the more commonly used plume modeling method because of the relatively shallow depth of the diffuser. In this case, the turbulent characteristics of the river dominate the mixing process.

Using a transverse mixing coefficient developed by Fischer (1979), the dilution factor was estimated at a point 100 feet downstream of the diffuser. This location represents the regulatory limits for the mixing zone as defined in the existing NPDES permit. The regulation also requires that the dilution meet the regulated standard at a point not to exceed 25 percent of the river width transversely. The dilution calculation depended on certain assumptions concerning the river morphology in this area. Specifically, it was assumed that the depth, average velocity, bottom slope, and width of the river were constant over the 100-foot zone. In addition, it was assumed that the diffuser acted as a point source. These assumptions are conservative in nature due to the added turbulence typical of changing river morphology and the dispersed discharge of the existing diffuser. Both of these characteristics tend to increase mixing potential.

### 2.8.3 REGULATORY COMPLIANCE

As shown in Table 2.8-2, at the point of Phase II's discharge, the dissolved chemical constituents listed in the NPDES permit are below the concentrations in the permit. In addition to the chemical concentrations presented in Table 2.8-2, the NPDES permit specifies effluent limitations on total residual halogens, pH, and flow rate. Water quality data are not available on total residual halogens in the Ranney wells; therefore, it is not possible to predict concentrations in the Phase II discharge water. However, the facility will be operated to meet limitations on residual chlorine levels in the NPDES permit.

Influent pH measured in the Ranney wells (Well APW) ranged from 6.6 to 7.5 (Envirosphere 1982), which is within the NPDES permit limitation (6.5 to 8.5). Concentration effects on pH in the process water are not predictable. However, changes are not likely to be major, and if minor changes are encountered a buffer will be added to remain within the compliance range.

The process water discharge temperature will be maintained at 18$^{o}$C or lower at the point of discharge to the river. The temperature of the project discharge to the river will be in compliance with the limitations of the NPDES permit, the Site Certification Agreement, and the requirements of WAC 173-201A.

The NPDES permit does not specify limits for many elements that are present in the Ranney well water and which will be concentrated due to evaporation during operation of the Satsop CT Project. All constituents not specified in the NPDES permit must be compared to the state's acute and chronic criteria levels. However, the NPDES permit allows a dilution zone for effluent constituents of toxic compounds specified in WAC 173-201 but not specified in the permit.

Discharges from the project will be below the state acute toxicity criteria at the point of discharge to the 001 blowdown pipeline, and therefore, will not exceed the state acute criteria in the river. These conclusions hold even if the constituents are concentrated by a factor of 10 (rather than 6.4), indicating that the proposed operating scenario for discharge includes flexibility to meet acute toxicity requirements at the point of discharge.

The results of the plume model analysis indicate that under the worst conditions for mixing, a dilution factor of 50-fold for the effluent concentrations is reached 100 feet downstream from the diffuser. This analysis was based on assumed values for river depth and velocity at the point of discharge and the permitted mixing distance. The depth and velocity estimates have not been field-verified but are within the range typical for low-flow conditions in the portion of the river receiving the discharge.

The concentrations of effluent constituents after transverse mixing are also presented in Table 2.8-2. The plume model results indicate that trace metals concentrated by evaporative losses during the cooling process, and then discharged, will be adequately diluted within the mixing zone. This is evidenced by the fact that the dilution factor is larger than the concentrating factor.

In conducting the comparison of project discharges to the state's chronic water quality criteria, existing data for the Chehalis River were used as described in Section 3.3 – Water, WAC 463-42-322. Reported concentrations of trace metals in the Chehalis River (receiving water) are listed as non-detectable, and were therefore assumed to be half of the lowest potential detection value. Using this assumption, concentrations of two toxic constituents in the river, mercury and lead, are above the applicable chronic criteria during periods of minimum and low flow conditions in the river. However, the Department of Ecology (Paul Pickett, personal communication, 1994) indicated that the sampling and analysis methods used for the Chehalis River data are in some cases questionable and that reported background concentrations of metals in the Chehalis River may not be accurate.

The plume model analysis of concentrations of mercury and lead in the effluent indicates that the concentrations of these constituents will be essentially the same or lower than the reported background concentrations in the Chehalis River. As noted above, the background levels in the river are above chronic toxicity levels, and since the discharge from Phase II will not alter the concentrations of these constituents in the river, the discharge of Phase II will not affect toxicity in the river.

The results also indicate that the diffuser and mixing conditions in the river, within the NPDES specified mixing zone, will be adequate to dilute regulated water quality parameters in the Phase II discharge such that all Class A water quality criteria for toxic substances will be met.

### 2.8.4 BYPASS AND OVERFLOW FACILITIES

Bypass facilities for wastewater would be limited to use in emergencies only. If a major fire were to occur, the capacities of floor and equipment drains would be greatly exceeded by water used to extinguish the fire, and the oil-water separator would likely overflow. Therefore, plant design includes a bypass around the oil-water separator to avoid overflow. This bypass will direct flows to a containment area specifically designed for each plant site and sized for a 30-minute event. The location of this facility will be shown in the final site plan.

No other bypass facilities would be included in plant design. All tanks would be equipped with overflow drains to prevent catastrophic losses. The discharge from overflow drains would be directed to a containment basin around each tank; each containment basin would be designed to hold 110 percent of the contents of the tank. The containment basin would be used to retain the collected fluids until a manual valve in the discharge piping is opened. Discharge from chemical tank containment basins would be routed to the neutralization tank for treatment; discharge from the fuel tank containment basin in each plant would be collected and disposed of off-site or routed to the oil-water separator for treatment. Administrative procedures require inspection of containment basin contents before opening the manual valve to discharge contents into the wastewater treatment system.

### 2.8.5 ALTERNATIVE METHODS

The infrastructure and permit for discharge into the Chehalis River already exist, are to be used for Phase I and, thus provide the most cost-effective and efficient approach to wastewater treatment for Phase II.

Zero discharge is another alternative approach. Zero discharge systems recycle and evaporate the water portion of wastewater and concentrate the solids for eventual off-site disposal. In this process, no wastewater is discharged. The zero discharge system was rejected for the following reasons: (1) no water would be returned to the river to supplement flows, and (2) the high cost of installing a zero discharge system.

The approach selected for the Phase II project minimizes plant wastewater discharges by recycling internal wastewater streams as make-up water for the cooling towers. However, some wastewater (up to 3.1 cfs for the entire Satsop CT Project) would be discharged to the Chehalis River, returning a portion of the water pumped from the Ranney wells (which obtain 88 percent of their water from the river). This is considered a beneficial condition since the wastewater returned to the river meets both NPDES permit criteria and state water quality standards.

Use of a deep well injection system represents another alternative method of wastewater handling. However, this approach is rarely used in power generation facilities. Deep well injection systems are dependent on the nature of the site's underlying aquifer, and are typically very difficult to permit. In addition, the water would not be recharged to the aquifer from which it is extracted. Due to the many risks associated with deep well injection, this alternative was not considered for the Phase II project.

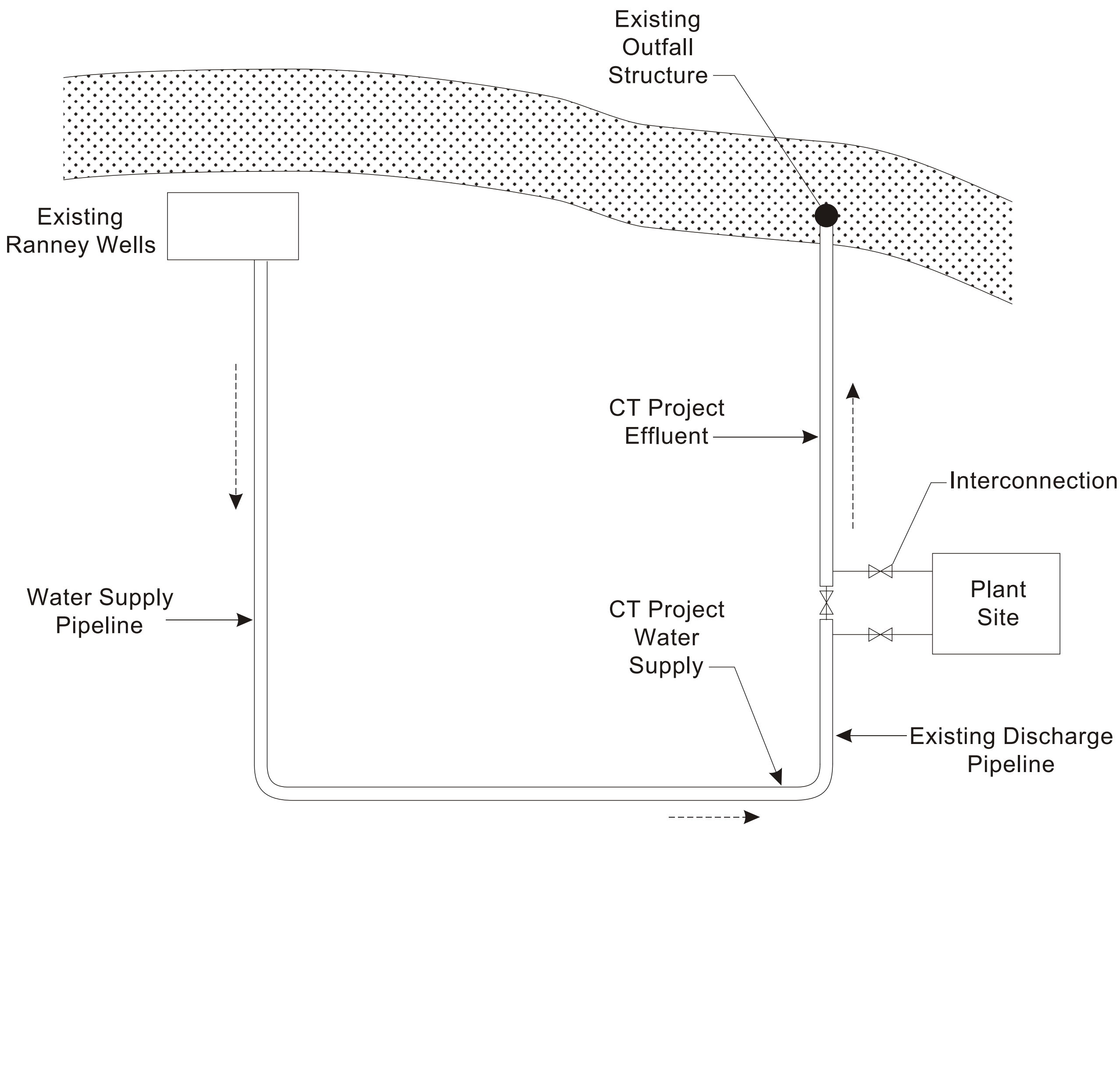
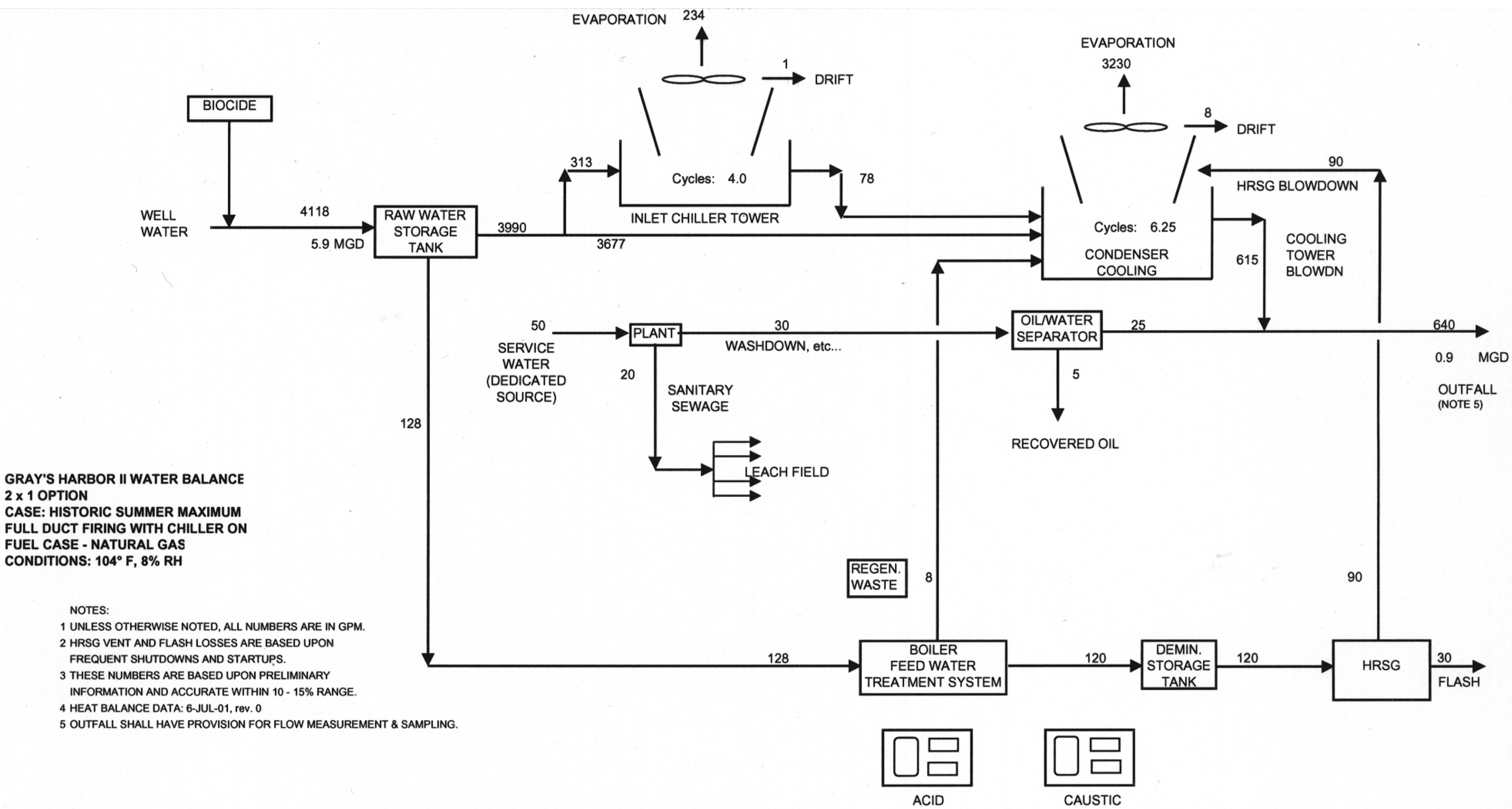



Figure 2.8-1
**Process Water**
**Conceptual Flow Diagram**

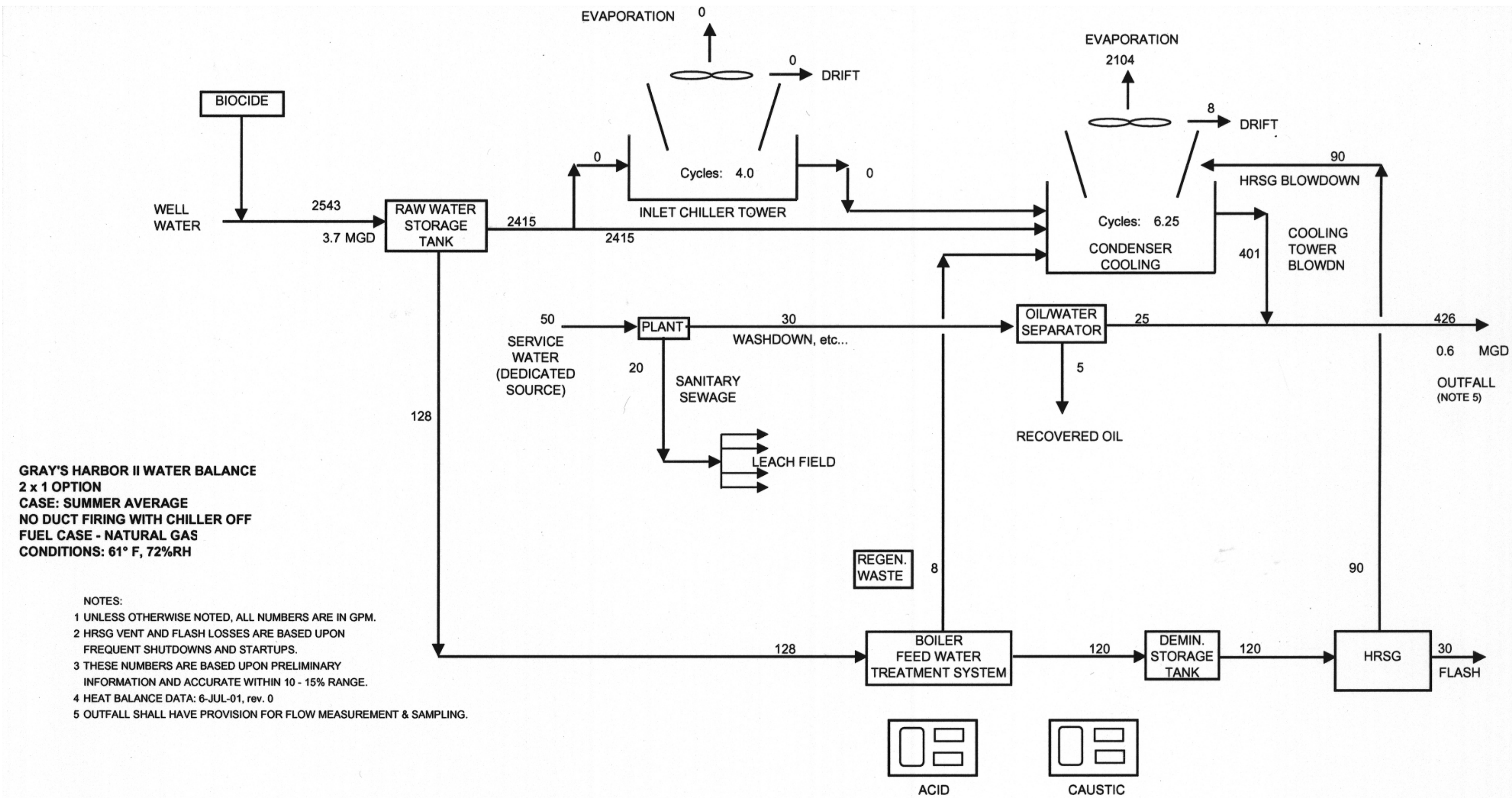



**GRAY'S HARBOR II WATER BALANCE**
**2 x 1 OPTION**
**CASE: HISTORIC SUMMER MAXIMUM**
**FULL DUCT FIRING WITH CHILLER ON**
**FUEL CASE - NATURAL GAS**
**CONDITIONS: 104° F, 8% RH**

NOTES:
1 UNLESS OTHERWISE NOTED, ALL NUMBERS ARE IN GPM.
2 HRSG VENT AND FLASH LOSSES ARE BASED UPON FREQUENT SHUTDOWNS AND STARTUPS.
3 THESE NUMBERS ARE BASED UPON PRELIMINARY INFORMATION AND ACCURATE WITHIN 10 - 15% RANGE.
4 HEAT BALANCE DATA: 6-JUL-01, rev. 0
5 OUTFALL SHALL HAVE PROVISION FOR FLOW MEASUREMENT & SAMPLING.

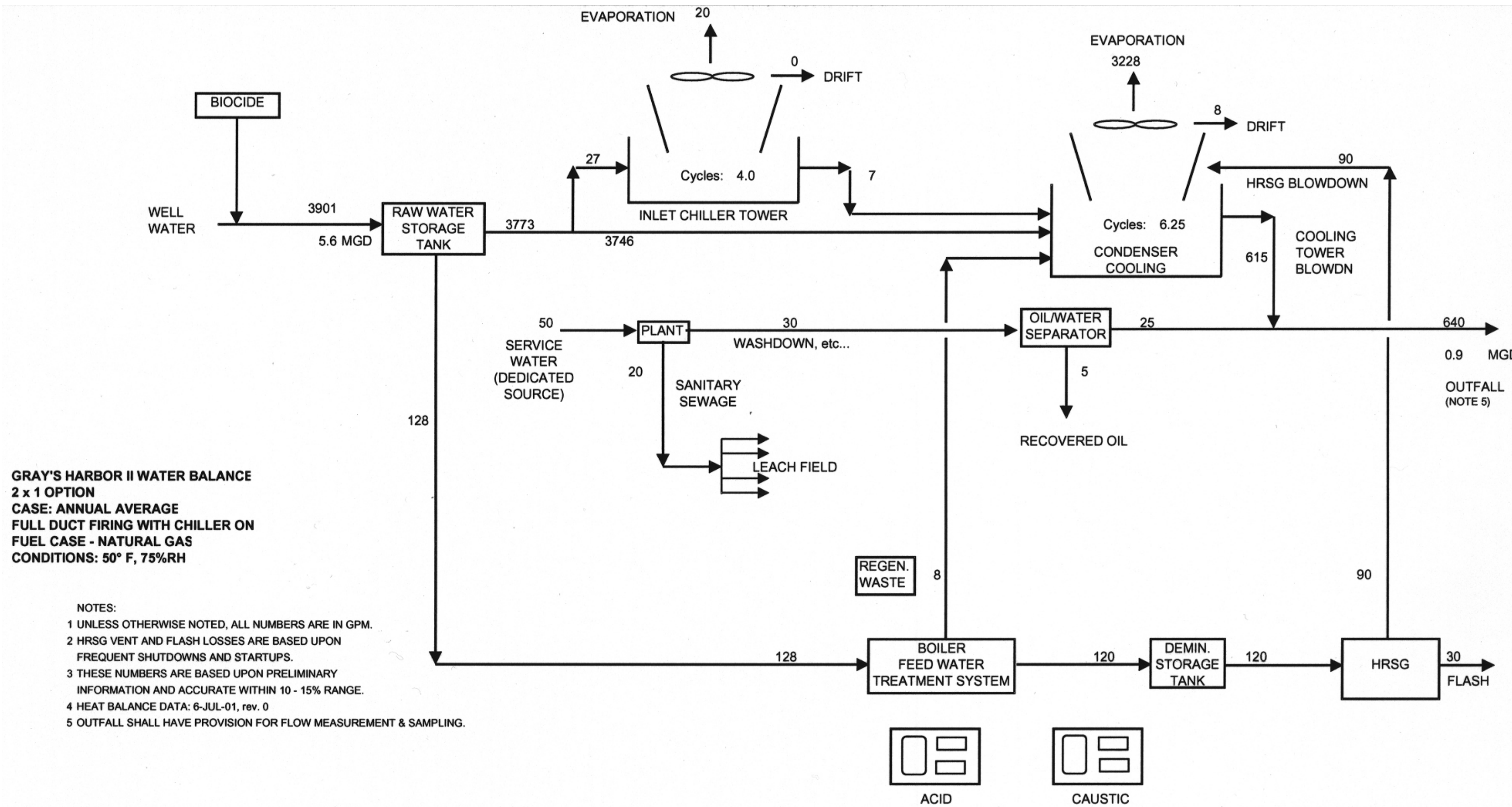
Source: Duke/Fluor Daniel

Figure 2.8-2
**Process Water Maximum**




Source: Duke/Fluor Daniel

Figure 2.8-3
**Process Water Maximum**




Source: Duke/Fluor Daniel

Figure 2.8-4

**Process Water Average Annual**

## 2.9

# Spillage Prevention and Control (WAC 463-42-205)

**WAC 463-42-205 PROPOSAL - SPILLAGE PREVENTION AND CONTROL.**

*The applicant shall describe all spillage prevention and control measures to be employed regarding accidental and/or unauthorized discharges or emissions, relating such information to specific facilities, including but not limited to locations, amounts, storage duration, mode of handling, and transport.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW.*
*81-21-006 (Order 81-5), §463-42-205, filed 10/8/81. Formerly WAC 463-42-420.]*

## 2.9 SPILLAGE PREVENTION AND CONTROL (WAC 463-42-205)

### 2.9.1 MATERIALS STORED ON SITE

Chemicals to be used and stored for the Phase II project are the same as those used and stored for Phase I. They consist of specialty and bulk/commodity chemicals and a minimal amount of fuel oil for small backup generators. Table 2.9-1 lists the typical types of specialty and bulk/commodity chemicals used at combustion turbine facilities and typical ways of storing these chemicals. The specific chemicals, the specific manufacturer, and storage methods have not yet been determined. Not included in the following table are the continuous emission monitoring (CEM) gases and incidental chemicals used for maintenance work at the site

### 2.9.2 SPILL PREVENTION CONTROL AND COUNTERMEASURES (SPCC) PLAN

The Certificate Holder has an existing Spill Prevention Control and Countermeasures (SPCC) Plan for Phase I of the Satsop CT Project that will also be applicable to Phase II. Revisions of the SPCC Plan and Hazardous Waste Management procedure were most recently submitted to EFSEC in August 2001 and approved by EFSEC on September 19, 2001. Revisions are required a minimum of every 2 years, but will be made sooner to respond to changing site organizations or conditions, or changes in regulations. The revision process will include an engineer's review, an updated organizational structure, and updated procedures specifying locations and what checks need to be made.

The existing SPCC Plan describes the oil, fuel, and hazardous material storage facilities; reporting systems; prevention requirements; and spill response procedure. The Hazardous Waste Management procedure establishes a program for the handling, storage, and disposal of wastes from the Satsop site.

## TABLE 2.9-1
## TYPICAL LIST OF PROCESS CHEMICALS

| Chemical | Description and Use | Storage |
|---|---|---|
| Aqueous ammonia | Used in selective catalytic reduction (SCR) for $NO_x$ control. | 20,000-gallon tank |
| Sodium hydroxide | Liquid water treatment chemical used in demineralizer and in neutralization tank. | 15,000-gallon tank inside water treatment building |
| Sulfuric acid | Liquid water treatment chemical used in demineralizer and in neutralization tank. | 15,000-gallon tank inside water treatment building |
| Scale inhibitor | Liquid phosphate-based corrosion inhibitor used in circulating water treatment system. | 5,000-gallon tank |
| Oxygen scavenger | Liquid oxygen scavenger that also maintains passive metal surfaces. Used in the HRSG. | 5,000-gallon tank |
| Rust inhibitor | Neutralizing corrosion inhibitor designed to protect metal surfaces from carbonic acid attack in steam condensate systems. Used in HRSG. | 5,000-gallon tank |
| Hydrochloric acid | Liquid water treatment chemical used in demineralizer and in neutralization tank. | 5,000-gallon tank |
| Amine solution | | 5,000-gallon tank |
| Fuel Oil | Used for backup diesel generators and fire-water pumps. | 1,640-gallon tank for generator<br>350-gallon tank for fire-water pump |

# 2.10

# Surface Water Runoff (WAC 463-42-215)

**WAC 463-42-215 PROPOSAL — SURFACE-WATER RUNOFF.**
*The applicant shall describe how surface-water runoff and erosion are to be controlled during construction and operation to assure compliance with state water quality standards.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-215, filed 10/8/81. Formerly WAC 463-42-330.]*

# 2.10 SURFACE WATER RUNOFF (WAC 463-42-215)

## 2.10.1 INTRODUCTION

The Certificate Holder has an Erosion and Sedimentation Control Plan and an Environmental Protection Control Plan that were approved by EFSEC on September 19, 2001. These plans provide surface water runoff controls during both construction projects and operational activities and are applicable for Phase II construction and operation. The following sections summarize the procedures that the Certificate Holder anticipates using to control erosion and surface water runoff during construction and operation of the proposed project.

## 2.10.2 EROSION CONTROL DURING CONSTRUCTION

This section presents information on the erosion control practices to be generally followed during construction (Subsection 2.10.2.1) and additional information on erosion control during construction at the plant site (Subsection 2.10.2.2).

### 2.10.2.1 General Practices

Erosion control measures will be used in accordance with the requirements of the approved Erosion and Sedimentation Control Plan. The Certificate Holder does not anticipate the need to modify this plan. However, the Certificate Holder will do so should conditions of the Site Certification Agreement amendment require modifications.

The Environmental Protection Control Plan establishes a monitoring and control program that documents all site environmental activity, including events or activities that do not comply with environmental commitments. The plan establishes administrative procedures to communicate such events or activities to site management and to bring about corrective action. Stop-work steps are given in the event that an activity is observed to be in violation of permits or environmental regulations. The plan also outlines steps for obtaining an environmental review of proposed activities. An Environmental Checklist will be modified to include specifications for commitments made as relates to Phase II prior to construction.

Erosion and sediment control best management practices (BMPs) consistent with those in the *Stormwater Management Manual for the Puget Sound Basin* (WSDOE 2000) will be employed during construction of Phase II and will comply with the requirements of the existing Erosion and Sedimentation Control Plan. BMPs will include limiting certain construction activities and installing temporary control structures such as sediment traps and silt fences. Generally, erosion control measures will include measures such as silt fences, diversion ditches, hydroseeding, and sediment traps.

Construction activities will be controlled to the extent possible to help limit erosion. Clearing, excavation, and grading will be limited to areas absolutely necessary for construction of the project.

Areas outside the construction limits will be identified and clearly marked, and equipment operators will be instructed to avoid these areas.

#### 2.10.2.2 Power Plant Site

The Phase II site was previously graded and covered with a layer of gravel for use as an equipment and material laydown area during construction of Phase I. Additional grading will be required to prepare the site for construction of Phase II.

Runoff from the northern portion of the site will be routed through existing ditches and culverts to the C-1 pond, which is located on Satsop Development Park property to the west. If necessary, surface water runoff from the site can be pumped through a series of ditches and culverts to the existing Equalization Pond on the main Satsop Development Park property. This pond would provide additional storage capacity during construction if surface water runoff is unusually high.

### 2.10.3 STORMWATER POLLUTION PREVENTION

The existing Site Certification Agreement provides the basis for the stormwater pollution control program. Used in conjunction with the existing Erosion and Sedimentation Control Plan, the existing NPDES permit, and implementing EFSEC resolutions, will ensure compliance with water quality standards.

#### 2.10.3.1 Construction

The Certificate Holder currently has an approved NPDES permit that covers stormwater discharges, including stormwater discharges from the proposed plant site. In addition, the SCA addresses stormwater management during construction, and includes the following requirements:

- The project must comply with all pertinent industry standards for control of any unforeseen surface water runoff event during construction, and must notify EFSEC of surface water runoff problems.

- The project must abide by turbidity criteria for construction-related runoff as established in the State of Washington Water Quality Standards.

The existing NPDES permit establishes water quality limits and monitoring schedules for total suspended solids, settleable solids, and pH in collected stormwater runoff. These limits are applicable for material storage runoff and construction runoff within the 100-year, 24-hour rainfall event (5.5 inches per 24 hours).

#### 2.10.3.2 Operation

Runoff from the plant site will be directed toward the perimeter ditches and routed as described in Section 2.10.2.2. The Environmental Protection Control Plan will be modified if necessary to include specifications for any commitments made for Phase II plant operations. BMPs consistent with those in the *Stormwater Management Manual for the Puget Sound Basin* (WSDOE 2000) will be employed during operation of Phase II.

At least annually, facility employees will also receive training in the pollution control laws and regulations, and the specific features of the facility which are intended to prevent releases of oil and petroleum products. Employees at the site will be trained in the following spill response measures:

- Identifying areas that may be affected by a spill and potential drainage routes
- Reporting of spills to appropriate individuals
- Employing appropriate material handling and storage procedures
- Implementing spill response procedures

Stormwater catchbasins and detention systems will be inspected at least annually as part of the site preventive maintenance program. Stormwater catchbasins will be cleaned if the collected deposits fill more than one-third of the depth from the basin to the invert of the lowest pipe leading into or out of the basin.

Inspections will be conducted to confirm that non-permitted discharges are not entering the stormwater system. A summary of each inspection will be retained, along with any notifications of noncompliance and reports on incidents such as spills.

# 2.11

# Emission Control (WAC 463-42-225)

**WAC 463-42-225 PROPOSAL — EMISSION CONTROL.**

*The applicant shall demonstrate that the highest and best practicable treatment for control of emissions will be utilized in facility construction and operation. In the case of fossil fuel power plants and petroleum refineries, the applicant should deal with products containing sulphur, $NO_X$, volatile organics, CO, $CO_2$, aldehydes, particulates, and any other emissions subject to regulation by local, state, or federal agencies. In the case of a nuclear-fueled plant, the applicant should deal with optional plant designs as these may relate to gaseous emissions.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-225, filed 10/8/81. Formerly WAC 463-42-520.]*

## 2.11 EMISSION CONTROL (WAC 463-42-225)

Proposed emission controls for the Phase II project are discussed in detail in Section 6.1 - PSD Application, WAC 463-42-385.

# 2.12

# Construction and Operation Activities (WAC 463-42-235)

**WAC 463-42-235 PROPOSAL — CONSTRUCTION AND OPERATION ACTIVITIES.**

*The applicant shall: Provide the proposed construction schedule, identify the major milestones, and describe activity levels versus time in terms of craft and noncraft employment; and describe the proposed operational employment levels.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-235, filed 10/8/81.]*

# 2.12 CONSTRUCTION AND OPERATION ACTIVITIES (WAC 463-42-235)

## 2.12.1 POWER PLANT

### 2.12.1.1 Construction Schedule and Milestones

Construction and final design of the power plant will be accomplished over a 22-month period, which begins at Construction Financial Closing. Prior to Construction Financial Closing, equipment specifications, and fabrication of major plant equipment will be initiated. The estimated construction schedule in Figure 2.12-1 will remain the same for either winter startup or summer startup.

The date of initiation of construction will be dependent on the needs of the Certificate Holder's customers. Based on the anticipated permitting schedule, including the amendment to the Site Certification Agreement, construction could begin as early as October of 2002. Since the date of initiation of on-site construction activities is not known, the information regarding construction schedules presented below is based on duration of activities over the 19-month on-site construction period.

Figure 2.12-1 identifies the major schedule milestones for design and construction of the power plant and associated facilities. The majority of the site preparation work has been completed as part of Phase I. Following the engineering and design studies, construction activities will begin with the preparation of the site, which will include final grading and road construction. Site preparation is expected to take 3 months. Construction will generally occur 5 days per week (Monday through Friday), with a 10-hour work day (7 a.m. to 5 p.m.).

Site preparation will be followed by the installation of underground utilities and foundation work. As soon as possible after the completion of foundation work, the erection of the combustion and steam turbine generator trains and the heat recovery steam generator will begin. The cooling tower, pumps, transformers, mechanical and electrical and other equipment will be installed next.

### 2.12.1.2 Construction Workforce

It is anticipated that the construction of the Phase II project will overlap with the construction of Phase I by approximately 8 months. The construction staff used for Phase I would transition to Phase II as their crafts were no longer needed on Phase I. The estimated number of construction workers (craft and non-craft) for the Phase II project by month is shown in Table 2.12-1 and Figure 2.12-2.

## TABLE 2.12-1
## POWER PLANT CONSTRUCTION WORKFORCE LOADING

| Month | Craft | Non-Craft (Project Management) | Total Staff |
|---|---|---|---|
| 1 | 19 | 11 | 30 |
| 2 | 28 | 17 | 45 |
| 3 | 52 | 20 | 72 |
| 4 | 78 | 22 | 100 |
| 5 | 98 | 28 | 126 |
| 6 | 130 | 30 | 210 |
| 7 | 162 | 36 | 198 |
| 8 | 196 | 37 | 233 |
| 9 | 225 | 42 | 267 |
| 10 | 288 | 42 | 330 |
| 11 | 376 | 42 | 418 |
| 12 | 438 | 43 | 481 |
| 13 | 480 | 50 | 530 |
| 14 | 487 | 52 | 539 |
| 15 | 505 | 52 | 557 |
| 16 | 487 | 48 | 535 |
| 17 | 433 | 48 | 481 |
| 18 | 306 | 45 | 351 |
| 19 | 203 | 42 | 245 |
| 20 | 105 | 34 | 139 |
| 21 | 16 | 27 | 43 |
| 22 | 0 | 27 | 27 |

The peak workforce during the 22-month construction period will range from over 400 to over 500 construction personnel from about Month 12 through Month 17 of construction (see Figure 2.12-2). During the construction phase there will be craft workers (welders, electricians, etc.) and non-craft workers (engineers, inspectors, etc.). As stated above, most if not all of these workers would come from workers hired for the construction of Phase I.

The types of crafts that will be required for construction include the following: boilermakers, carpenters, cement finishers, electricians, equipment operators and oilers, fire sprinkler installers, laborers, millwrights, painters, pile drivers, pipefitters, plumbers, rodmen, structural steel workers, and, welders.

The estimated number of non-craft workers for the construction and start-up phase is based on the sum of project management staff needed by function plus the administrative staff (on-site construction inspectors and project engineers) associated with the anticipated volume of work.

### 2.12.1.3 Operation

Operation of the project would involve approximately 22 employees working either two 12-hour shifts or three 8-hour shifts, with a maximum of 26 employees working on site at any time (see Table 2.12-2). The operational labor force would include the following positions: plant manager, operations supervisor/engineer, control operators, auxiliary operators, maintenance supervisor, mechanical and electrical technicians, and clerks. Efforts would be made to hire local individuals to staff the project as much as practicable. After the load needs of the Certificate Holder's customers are identified, the Certificate Holder will select the most appropriate number of shifts to meet the power needs. The two possible shift schedules currently under consideration for each unit are shown in Table 2.12-2.

**TABLE 2.12-2**
**POSSIBLE PLANT SHIFT SCHEDULES**

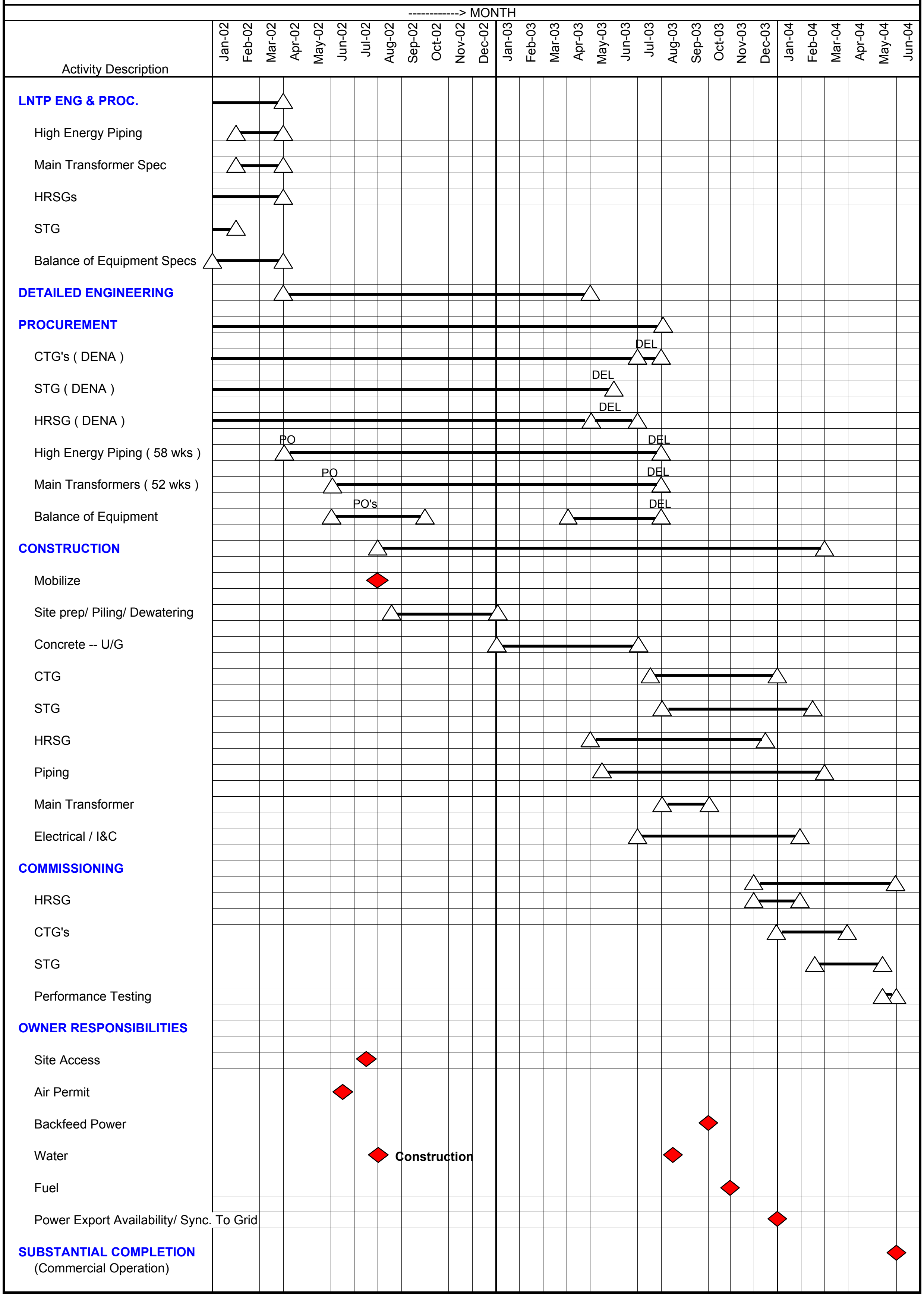
| Schedule | Shifts | Personnel and Hours |
|---|---|---|
| Option 1 | Two 12-hour shifts | 26 people working from 6:00 a.m. to 6:00 p.m. |
| | | 4 people working from 6:00 p.m. to 6:00 a.m. |
| Option 2 | Three 8-hour shifts | 26 people working from 8:00 a.m. to 4:00 p.m. |
| | | 4 people working from 4:00 p.m. to 12:00 a.m. |
| | | 4 people working from 12:00 a.m. to 8:00 a.m. |

Major maintenance is expected to take place in Year 6 of operation. During this work, 50 additional people will be on site for 28 days during the day shift.

Initiation of commercial operation for the plant will be dependent on the needs of the Certificate Holder's customers. If construction is initiated in October of 2002 immediately after the Certificate Holder obtains all required permits, the earliest anticipated date for the initiation of commercial operation is approximately mid-2004.

DUKE / FLUOR DANIEL

## Figure 2.12-1 Construction Schedule



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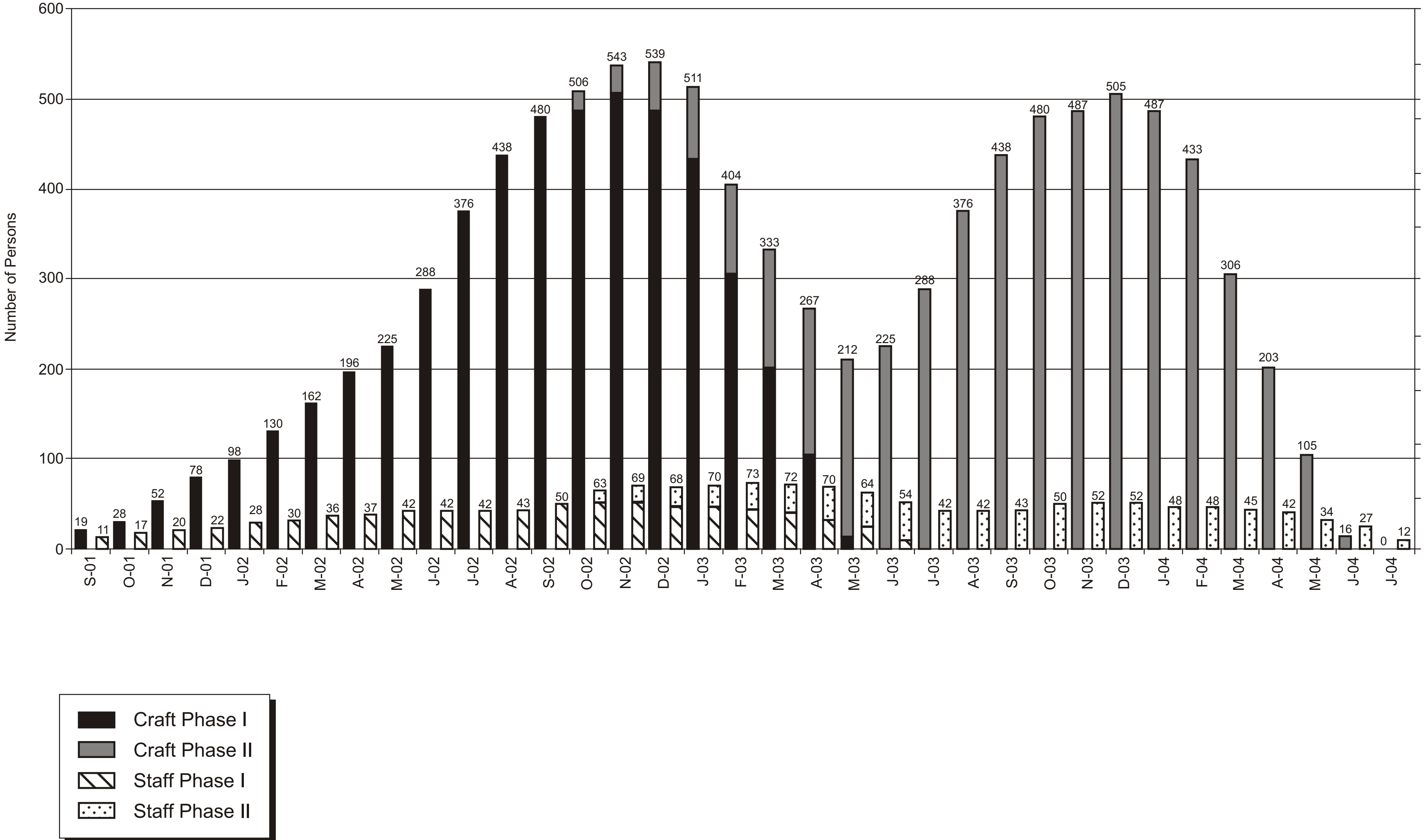


Figure 2.12-2

**Projected Craft and Staff Requirements for Phase II (Shown Overlapped with Phase I)**

## 2.13
# Construction Management (WAC 463-42-245)

**WAC 463-42-245 PROPOSAL — CONSTRUCTION MANAGEMENT.**
*The applicant shall describe the organizational structure including the management of project quality and environmental functions.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-245, filed 10/8/81.]*

## 2.13 CONSTRUCTION MANAGEMENT (WAC 463-42-245)

### 2.13.1 CONSTRUCTION MANAGEMENT - ORGANIZATION

Duke Energy Grays Harbor, LLC (DEGH) will be the contracting entity for the entire project and will contract for the turnkey engineering, procurement and construction (EPC) of the project with the EPC contractor. DEGH will assemble and maintain a staff of professional engineering and construction personnel to monitor the EPC contractor's performance and to ensure adherence to all contract specifications and requirements throughout the execution of the work.

Organization charts depicting the project's anticipated DEGH construction oversight organization and the EPC contractor's engineering and construction organization are shown on Figures 2.13-1 and 2.13-2, respectively. The EPC contractor will be responsible for the design, engineering, and construction of the entire project, for field quality assurance and quality control (QA/QC), and for environmental compliance. Where appropriate, subcontractors will be used to accomplish portions of the work. As shown on Figure 2.13-2, the DEGH Project Manger will be responsible for all work accomplished on the project, with subcontractors reporting to the Project Manager or the Project Manager's designee.

### 2.13.2 QUALITY ASSURANCE AND QUALITY CONTROL

DEGH will implement QA/QC procedures throughout the project. A formal QA/QC Program will be in place during all phases of the project to ensure that the equipment suppliers deliver their components as designed and specified and the installation of the equipment is completed as specified. DEGH will prepare a Project Procedures Manual that describes project activities from the initiation of final design activities through startup of the plant. This document will include a Project QA/QC Plan to be used during all phases of the work. The QA/QC Plan will address key aspects of the project such as vendor shop and field work activities and the activities each contractor will use to ensure and document that work accomplished for the project is of acceptable quality.

DEGH's engineering and construction personnel will periodically audit the EPC contractor, including reviews of documentation and surveillances of field activities to ensure compliance with the project specifications and with the requirements of the QA/QC Plan. For the installation and alignment of major equipment, the acceptance of DEGH’s field inspectors will be required prior to final sign-off of the project. The audits, inspections, and surveillances of DEGH will be described in a written plan that will include the checks listed below.

#### 2.13.2.1 Gas Turbine Generator

- Verify drawings and weld procedure specification (WPS) review/accepted status
- Verify materials
- Review all applicable non-destructive examination (NDE) records
- Witness or review results of hydrostatic, operational, performance, rotor balance, rotor runout, hi-pot, overspeed testing
- Check flange finish/protection
- Check painting/marking/preparation for shipment

#### 2.13.2.2 Steam Turbine Generator

- Verify drawings and weld procedure specification (WPS) review/accepted status
- Verify materials for casting(s) and appurtenances
- Review all applicable non-destructive examination (NDE) records
- Review all casting repair procedures and witness repairs
- Witness or review results of hydrostatic, operational, performance, rotor balance, rotor runout, hi-pot, overspeed testing
- Check flange finish /protection
- Check painting/marking/preparation for shipment

#### 2.13.2.3 Heat Recovery Steam Generator

- Verify drawings and WPS review/accepted status
- Verify materials
- Review all applicable NDE records
- Verify dimension
- Witness hydrostatic, performance and run testing
- Witness control panel operational testing
- Check overall visual (including welding)
- Inspect refractory
- Check flange finish/protection
- Check painting/marking/preparation for shipment
- Inspect all associated subordered equipment (e.g., stacks, ladders, platforms, and expansion joints)

#### 2.13.2.4 Pumps

- Verify drawings and WPS review/accepted status
- Verify materials
- Review all applicable NDE records
- Dimension verification
- Witness or review hydrostatic, performance, net positive suction head (NPSH) test results
- Check overall visual (including welding)

- Check flange finish/protection
- Check painting/marking/preparation for shipment

2.13.2.5 Water Treating System

- Verify drawings and WPS review/accepted status
- Verify materials
- Review all applicable NDE records
- Verify dimensions
- Witness hydrostatic (piping) and operational testing
- Check visual (including welding)
- Check flange finish/protection
- Check painting/marking/preparation for shipment
- Inspect associated subordered equipment (e.g., pumps, vessels, and vessel lining installations)

2.13.2.6 Piping and Piping Specialties

- Verify materials
- Verify dimensions
- Witness, or review results of pressure testing and NDE
- Check flange finish/protection
- Check visual (including welding)
- Check painting/tagging/preparation for shipment

2.13.2.7 Pressure Vessels

- Verify drawings and WPS review/accepted status
- Verify materials
- Review all applicable NDE records
- Review hardness test records
- Review post-weld heat treatment (PWHT) records
- Verify dimensions
- Witness hydrostatic and nozzle reinforcing pad air/soap testing
- Check overall visual (including welding)
- Check flange finish/protection
- Check painting/marking/preparation for shipment

2.13.2.8 Control Valves 6 Inches and Larger, Displacer Level Instruments and Special Relief Valves

- Verify compliance to engineering specifications
- Verify materials
- Witness pressures and operational test

- Check flange finish/protection
- Check painting/marking/preparation for shipment

2.13.2.9 Distributed Control System

- Review hardware and software engineering
- Review materials and assemblies per specifications
- Witness selected subsystem tests
- Witness full system functional testing
- Verify tagging/wiring/preparation for shipment

2.13.2.10 Main Transformers

- Witness and/or review winding resistance measurements
- Witness and/or review polarity and phase displacement tests
- Witness and/or review no load losses and excitation current at rated voltage and frequency
- Witness and/or review high potential and induced potential tests
- Witness and/or review impulse tests, reduced full wave, chopped wave and full wave
- Witness and/or review regulation and efficiency calculations
- Verify compliance to engineering specifications
- Check painting/tagging/preparation for shipment

2.13.2.11 Main Breakers

- Witness and/or review rated continuous current
- Witness and/or review short circuit current rating
- Witness and/or review dielectric withstand tests
- Witness and/or review switching tests
- Witness and/or review insulator tests
- Witness and/or review mechanical life tests
- Witness and/or review terminal loading tests
- Witness and/or review partial discharge tests
- Witness and/or review sound level limits
- Witness and/or review insulation coordination tests
- Verify compliance to engineering specifications
- Check painting/tagging/wiring/preparation for shipment

2.13.2.12 Environmental Compliance

The Certificate Holder has an active Environmental Protection Control Plan for the Satsop Combustion Turbine (CT) Project that was approved by EFSEC on September 19, 2001. Where appropriate, this plan will be revised to include environmental protection procedures specific to the Phase II Project, including revisions necessary to comply with the stipulations of the amended Site Certification Agreement (SCA).

This Environmental Protection Control Plan covers all construction activities. The DEGH Project Manager or the Project Manager's designee will be responsible for complying with the requirements of the Environmental Protection Control Plan. Both Energy Northwest and DEGH will audit the project for environmental compliance, including periodic reviews of documentation and surveillance of field activities, as follows:

- Review erosion control plan
- Review spill prevention plan
- Witness construction implementation
- Witness erosion control performance
- Observe spills and cleanup
- Review spill reports

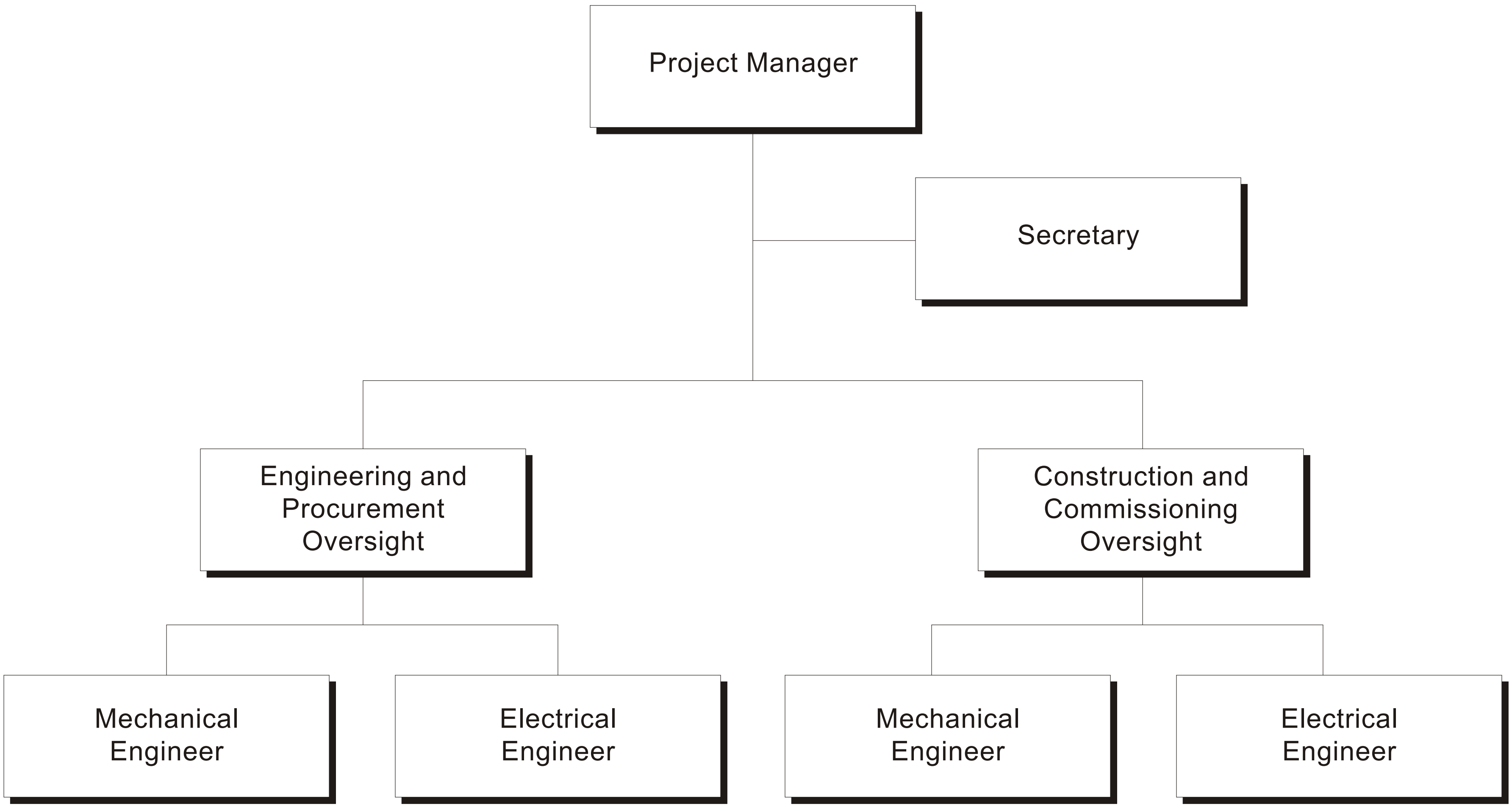


Figure 2.13-1

**Duke Energy Grays Harbor Construction Organization**

URS

Phase II Expansion
Satsop CT Project

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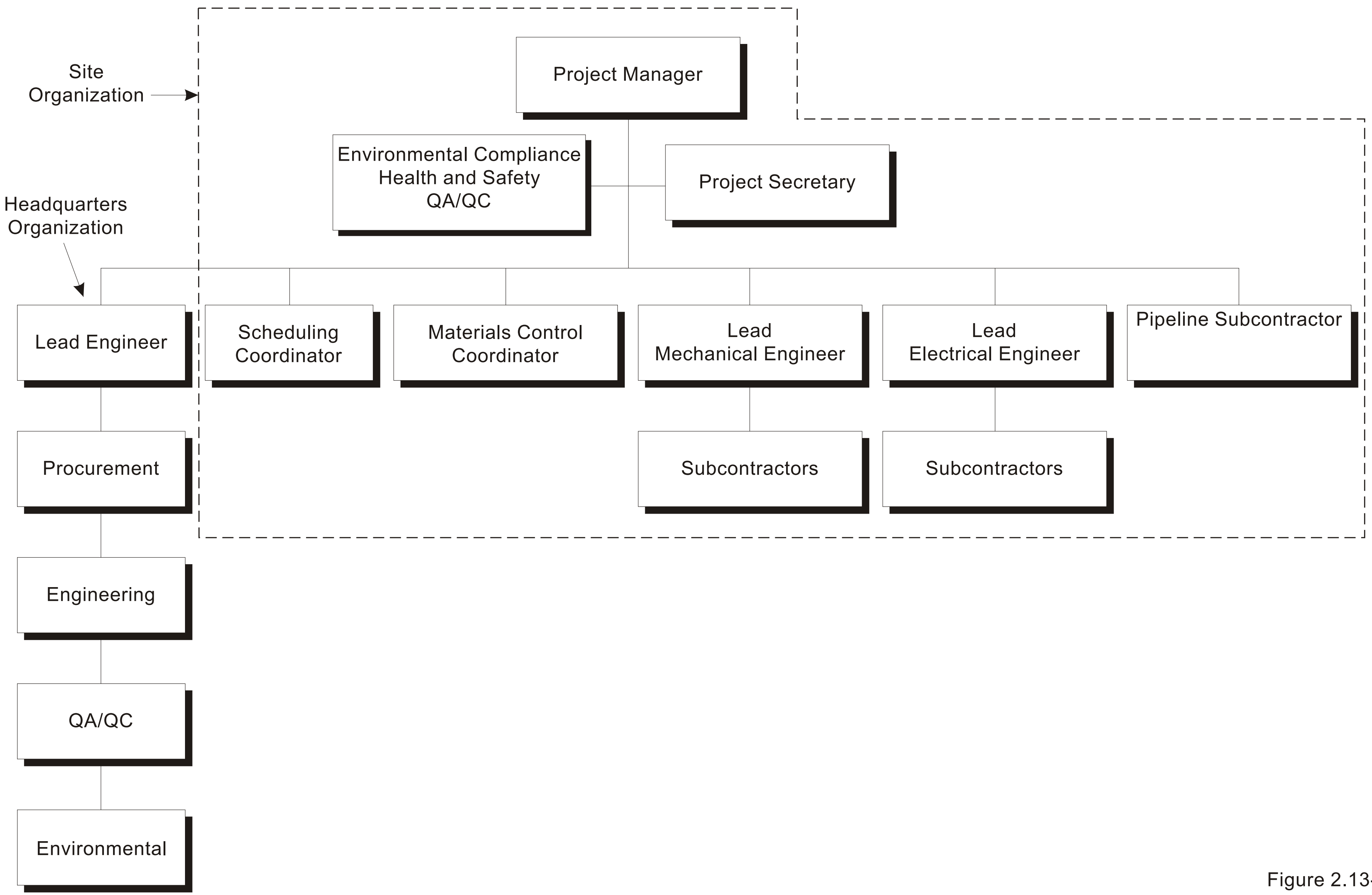


Figure 2.13-2

**EPC Contractor Anticipated Organization**

# 2.14
# Construction Methodology (WAC 463-42-255)

**WAC 463-42-255 PROPOSAL — CONSTRUCTION METHODOLOGY.**
*The applicant shall describe in detail the construction procedures, including major equipment, proposed for any construction activity within watercourses, wetlands and other sensitive areas.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-255, filed 10/8/81.]*

## 2.14 CONSTRUCTION METHODOLOGY (WAC 463-42-255)

Section 463-42-255 of the Washington Administrative Code (WAC) addresses the construction procedures to be used within watercourses, wetlands, and other sensitive areas. There are no watercourses, wetlands, or other sensitive areas on or adjacent to the proposed plant site. Therefore, no construction methodology descriptions are required. Construction procedures related to activity in terrestrial areas are addressed in Section 2.3 - Construction on Site, WAC 463-42-145.

# 2.15

# Protection from Natural Hazards (WAC 463-42-265)

**WAC 463-42-265 PROPOSAL — PROTECTION FROM NATURAL HAZARDS.**

*The applicant shall describe the means employed for protection of the facility from earthquakes, volcanic eruption, flood, tsunami, storms, avalanche or landslides, and other major natural disruptive occurrences.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-265, filed 10/8/81. Formerly WAC 463-42-290.]*

## 2.15 PROTECTION FROM NATURAL HAZARDS (WAC 463-42-265)

The following section describes natural hazards that may impact the proposed project and briefly describes environmental design measures included in the project to mitigate these potential impacts.

### 2.15.1 EARTHQUAKE HAZARDS

Earthquake-related damage to industrial facilities such as the planned Phase II facility typically arises from surface fault rupture, ground motion, or liquefaction of soils. See Section 3.1 - Earth, WAC 463-42-302, for additional details. The potential for seismically induced slope failure is addressed in Section 2.15.5.

2.15.1.1 Surface Fault Rupture

Surface fault rupture is highly unlikely at the plant site because of the absence of known faults beneath the site and the absence of evidence of faults with historical or geologically recent surface rupture in the site area. No surface fault rupture has been recorded in Washington within historic time (McCrumb et al. 1989). In general, faults that have had a surface rupture during the Holocene epoch (last 10,000 years) or multiple ruptures during the Pleistocene epoch of the Quaternary period (last 10,000 to 1.8 million years) are considered to have a potential for future surface rupture. The few known faults with Holocene or late Pleistocene surface displacement within the region are distant from the site (see Section 3.1 – Earth, WAC 463-42-302). No Quaternary faults have been previously mapped or inferred within the project boundaries (WPPSS 1988; Noson et al. 1988; and Rogers et al. 1996).

2.15.1.2 Strong Ground Motion

Western Washington, where the proposed plant is located, is characterized as a region of high seismic hazard due to the potential for strong earthquake ground motion (see Section 3.1.2.1). The site is in seismic Zone 3 of the 1997 Uniform Building Code (UBC). The UBC designates a total of six different seismic zones in the United States (i.e., Zones 0, 1, 2a, 2b, 3, and 4). The location of the boundaries of the zones are based on scientific studies of the intensity of ground motion (i.e., ground acceleration levels), the damage patterns produced in past earthquakes, and the locations of the fault zones where these earthquakes have occurred. Zone 0 represents areas with the lowest seismic activity and the least expected damage, and Zone 4 represents areas with highest seismic activity and the greatest expected damage.

The largest rational and believable seismic event that appears capable of occurring in the region within the current geologic epic, also known as maximum credible earthquake (MCE), is in the range of magnitude (M) 8.0 to 9.5 (Heaton and Hartzell, 1986). According to the probabilistic National Seismic Hazard Maps published by the USGS (Frankel, et al., 1996), the estimated peak ground acceleration (g) for the site is on the order of 0.25 to 0.30 g for a 2,475-year return period earthquake (10 percent chance of not being exceeded in 50 years). For a 2475-year return period earthquake (2 percent of not being exceeded in 50 years), the estimated peak acceleration for the site is 0.55 to 0.60 g. Design of facilities for the USGS estimated levels of ground shaking, and potentially higher levels, can be accommodated within the current level of seismic engineering design practice. As with Phase I, Phase II will be designed in accordance with the seismic design requirements for UBC Zone 3.

#### 2.15.1.3 Liquefaction

Liquefaction is a phenomenon in which loose to medium-dense, saturated sands lose their shear strength during dynamic loading (usually during an earthquake) and behave as a fluid. Liquefaction induces soil settlements, loss of foundation support, and sometimes, lateral spreading or flow failure of a soil mass. These movements can have significant adverse effects on facilities built on or near areas experiencing liquefaction. Due to the depth of groundwater and the lack of loose soils in the shallow subsurface, the soils of the power plant site do not appear to be susceptible to liquefaction. Therefore, plant design does not include measures to protect the plant from the adverse effects of liquefaction.

### 2.15.2 FLOOD

The plant site is over 300 feet above the flood plain of the Chehalis River and thus will not require dikes or other flood protection devices other than the normal storm water control system.

#### 2.15.2.1 Flood Hazards

Please see Subsection 2.15Flood hazards were delineated for the plant site area according to the Federal Emergency Management Agency's (FEMA) flood insurance rate maps. The site is outside of any flood zone listed on the FEMA maps.

Flood potential at the Satsop CT project site was estimated and presented in the Final Safety Analysis Report (FSAR) for the WPPSS's nuclear plant WNP-3 (WPPSS 1988a). The FSAR analysis utilized historical flood data to estimate probable maximum floods on streams and rivers in the site vicinity using the HEC-1 Flood Hydrography Package developed by the U.S. Army Corp of Engineers. The probable maximum flood (PMF) was computed to be 53.1 feet mean sea level (MSL). The elevation of the plant site ranges from about 290 to 315 feet MSL and therefore the plant site is not within the flood hazard area.

The FSAR provided additional analysis on water levels at the site assuming coincident wind wave activity, seismically induced dam failure in a nearby dam, and tsunami flooding. Conclusions indicated the PMF resultant from coincident wind wave activity is 76.2 feet MSL and water elevation from seismically induced dam failure is 39.6 feet MSL. Both levels are below the elevation of the plant site. The rise in water level as a result of a tsunami occurring and entering into Grays Harbor at the mouth of the Chehalis River is estimated to be 3.5 feet. This rise would only produce a negligible rise in the river's water level and would not affect the plant site.

### 2.15.3 TSUNAMIS

The plant site is approximately 20 miles from the coast at an elevation of approximately 290 to 315 feet above sea level. As a result, tsunamis are not a potential hazard at the site.

### 2.15.4 STORMS

The plant will be constructed in accordance with current building codes and designed to withstand wind and rain conditions associated with a 100-year storm event. Erosion and sedimentation control measures will be incorporated in all stages of construction and operation, and will also be designed, when appropriate, for the 100-year event. In the Satsop area, cumulative precipitation amounts for a 24-hour period of the 100-year storm event would be between 0.65 and 0.7 inches (Miller, et al. 1973).

### 2.15.5 AVALANCHES OR LANDSLIDES

The power plant site is generally flat, with about 25 feet of elevation change across the site. The areas adjacent to and near the site are also relatively flat, and avalanches and landslides (including seismically induced slope failures) are not considered to be a potential hazard at power plant site. The nearest identified landslide deposits to the site are two 1-acre failures located in Helm Creek glacial deposits on Fuller Creek, approximately 1,500 feet southeast of the site. None of the identified slope failures were judged to be recent. New slides or reactivation of old landslides in these areas would not affect the proposed power plant.

### 2.15.6 VOLCANOES

The power plant site is approximately 80 miles from both Mt. St. Helens and Mt. Rainier (Figure 2.15-1). Both volcanoes have erupted within the historic record, with Mt. St. Helens most recently erupting in 1980 (Harris 1980). Based on the effects of past eruptions both observed and in the geologic record, an eruption of either volcano would not directly affect the power plant and there is a low potential for deposition of significant air fall at the site (Waldron 1989). However, it is possible that a shift in the prevailing wind direction could cause airborne ash to reach the site and require a temporary shut down of the combustion turbines. No additional mitigation efforts are anticipated for the plant from these causes.

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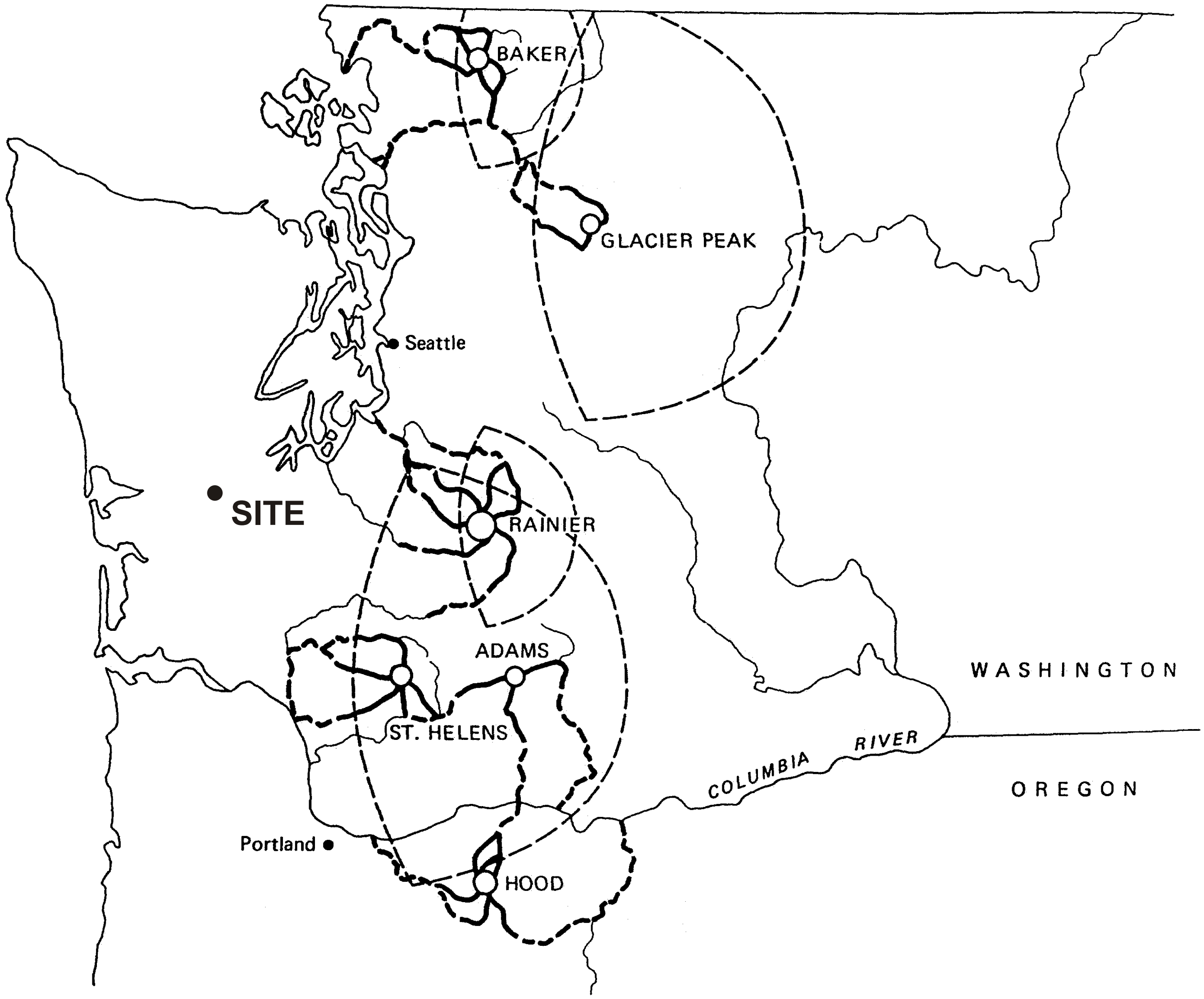



MAP EXPLANATION

LARGE VOLCANO - FLANKS SUBJECT TO LAVA FLOWS AND OTHER KINDS OF VOLCANIC HAZARDS.

VALLEY FLOORS SUBJECT TO BURIAL BY HOT AVALANCHES OR SMALL- TO MODERATE-SIZED MUDFLOWS.

VALLEY FLOORS SUBJECT TO FLOODS AND RELATIVELY LARGE BUT INFREQUENT MUDFLOWS.

ASHFALL-HAZARD ZONE SUBJECT TO DEPOSITION OF 5 cm OR MORE DURING A MODERATE ERUPTION. MOST ASHFALL (75-80%) EXPECTED TO FALL IN AREA RANGING FROM NNE TO SSE OF VOLCANO.

*SOURCE: Waldron 1989*

Figure 2.15-1

**Distribution of Ash**

URS

Phase II Expansion
Satsop CT Project

## 2.16

# Security Concerns (WAC 463-42-275)

**WAC 463-42-275 PROPOSAL — SECURITY CONCERNS.**

*The applicant shall describe the means employed for protection of the facility from sabotage, vandalism and other security threats.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-275, filed 10/8/81. Formerly WAC 463-42-300.]*

## 2.16 SECURITY CONCERNS (WAC 463-42-275)

The Satsop CT Project site is enclosed by a 6-foot-high chain link fence with locking gates to provide ingress and egress; 24-hour security is provided.

The Emergency Plan, which was approved by EFSEC on September 19, 2001, applies to all project personnel and provides the guidelines necessary to ensure timely notification and rapid response in the event of emergencies occurring on the property. Specific emergency modification procedures include contacting the following agencies:

- Fire Emergency
  - 911 (response will be by the Satsop or Elma Fire Departments)

- Medical Emergency
  - On-site personnel
  - Elma Fire Department if transport by ambulance required
  - If on-site fatality, Grays Harbor County sheriff contacted

- Bomb Threat Emergency
  - Grays Harbor County Sheriff

- Demonstration Emergency
  - Grays Harbor County Sheriff

- Hazardous Materials Accidents
  - Energy Facility Site Evaluation Council
  - Department of Ecology
  - Others who could be notified include National Response Center, Elma Fire Department

# 2.17

# Study Schedules (WAC 463-42-285)

**WAC 463-42-285 PROPOSAL — STUDY SCHEDULES.**

*The applicant shall furnish a brief description of all present or projected schedules for additional environmental studies. The studies descriptions should outline their scope and indicate projected completion dates.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-285, filed 10/8/81. Formerly WAC 463-42-130.]*

## 2.17 STUDY SCHEDULES (WAC 463-42-285)

On September 19, 2001, EFSEC approved the following plans for the Satsop Combustion Turbine (CT) Project site:

- Spill Prevention Control and Countermeasure (SPCC) Plan
- Hazardous Waste Management Procedure
- Environmental Protection Control Plan
- Erosion Control Procedure
- Safety Program Procedure
- First Aid and Emergency Medical Response Procedure
- Emergency Plan
- Traffic and Transportation Plan

All of these plans are applicable to the Phase II project. While the Certificate Holder does not anticipate the need to update any of these plans specifically for the Phase II project, the plans would be modified should the amended Site Certification Agreement include conditions that require changes to the approved plans.

# 2.18

# Potential for Future Activities at Site (WAC 463-42-295)

**WAC 463-42-295 PROPOSAL — POTENTIAL FOR FUTURE ACTIVITIES AT SITE.**
*The applicant shall describe the potential for any future additions, expansions, or further activities which might be undertaken by the applicant on or contiguous to the proposed site.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-295, filed 10/8/81. Formerly WAC 463-42-140.]*

## 2.18 POTENTIAL FOR FUTURE ACTIVITIES AT SITE (WAC 463-42-295)

Duke Energy Grays Harbor, LLC, and Energy Northwest (the Certificate Holder) proposes to construct and own a second, combined cycle, combustion turbine power plant at its Satsop Combustion Turbine (CT) Project property. This Application to Amend the existing Site Certification Agreement is for the expansion of the existing use within the previously approved approximately 22-acre site. With this expansion, all available land within the approved site will be used, and no future activities at this site are planned.

The Satsop Development Park, owned by the Grays Harbor Public Development Authority, encompasses over 1,600 acres. Because of its size, and the many advantages that the location offers for power production, it is conceivable that other future power or related industrial projects will be investigated and proposed for the Satsop Development Park property. At this time, the Certificate Holder has no detailed plans for future activities at the Satsop Development Park beyond those described in this Application for Amendment.

# 3.1
# Earth (WAC 463-42-302)

**WAC 463-43-302 NATURAL ENVIRONMENT — EARTH.**
*The applicant shall provide detailed descriptions of the existing environment, project impacts, and mitigation measures for the following:*

*(1) Geology - The applicant shall include the results of a comprehensive geologic survey showing conditions at the site, the nature of foundation materials, and potential seismic activities.*

*(2) Soils - The applicant shall describe all procedures to be utilized to minimize erosion and other adverse consequences during the removal of vegetation, excavation of borrow pits, foundations and trenches, disposal of surplus materials, and construction of earth fills. The location of such activities shall be described and the quantities of material shall be indicated.*

*(3) Topography - The applicant shall include contour maps showing the original topography and any changes likely to occur as a result of energy facility construction and related activities. Contour maps showing proposed shoreline or channel changes shall also be furnished.*

*(4) Unique physical features - The applicant shall list any unusual or unique geologic or physical features in the project area or areas potentially affected by the project.*

*(5) Erosion/enlargement of land area (accretion) - The applicant shall identify any potential for erosion, deposition, or change of any land surface, shoreline, beach, or submarine area due to construction activities, placement of permanent or temporary structures, or changes in drainage resulting from construction or placement of facilities associated with construction or operation of the proposed energy project.*

## 3.1 EARTH
## (WAC 463-42-302)

The proposed Satsop CT Project is located in Satsop, Grays Harbor County. Existing conditions and potential impacts are discussed below, including evaluation of geology, soils, topography, unique physical features, and erosion/enlargement of the land area. With standard and site-specific mitigation measures, impacts on the natural earth environment from the construction and operation of the Phase II project are expected to be minor (URS 2001).

This section presents information on "Earth" in the following subsections, including information on existing conditions, potential impacts, and where appropriate, mitigation measures.

- Geology (Subsection 3.1.1)
- Seismicity (Subsection 3.1.2)
- Soils (Subsection 3.1.3)
- Topography (Subsection 3.1.4)
- Unique Physical Features (Subsection 3.1.5)
- Erosion/Enlargement of Land Area (Accretion) (Subsection 3.1.6)

### 3.1.1 GEOLOGY

3.1.1.1 Regional Setting

Western Washington and the adjacent continental margin have been divided into four major tectonic terranes reflecting the regional tectonic setting at the margin of two converging plates. These terranes are the continental margin, the fore-arc, the volcanic arc, and the back-arc. The Satsop site is located within the Willapa Hills tectonic province of the fore-arc (Figure 3.1-1).

The geologic units in the site region consist of Tertiary age sedimentary and volcanic rocks overlain by Quaternary glacial, glaciofluvial, and alluvial deposits (Figures 3.1-2 and 3.1-3). In addition, landslide deposits in the Astoria Formation and Helm Creek deposits have been mapped by Gower and Pease (1965) in the nearby Montesano Quadrangle and were mapped near the site during preparation of the Final Safety Analysis Report (FSAR) for the construction of WNP-3 (WPPSS 1988). The slides are composed of broken, distorted and dislocated parent material and range in areal extent from 0.4 to 40 hectares (1 to 100 acres) (Figure 3.1-3). The largest appear to be located in the Astoria sandstone.

Geologic structures in the site vicinity consist of several broad uplifts, folds, and faults that generally trend northwest (Figure 3.1-3). These structures are interpreted to result from northeast-directed compression caused by convergence of the Juan de Fuca and North American plates during the Tertiary. The shortening of the crust caused by the compression that was taken up by the structures.

Three basement uplifts occur within 20 miles (30 kilometers) of the site: the Minot Peak Uplift, the Blue Mountain Uplift, and the Black Hills Uplift. These uplifts are broad, open domes and typically have faulted margins. The Crescent Formation is often exposed at the core of the uplifts. Faults mapped in the site vicinity include the Gibson Creek and Welkswood Canyon faults. The site is located on the northern nose of a broad, poorly defined anticline that is the northern extension of the Minot Peak Uplift (Figure 3.1-3).

The faults mapped within the site vicinity are interpreted as being associated with the uplifts and are rooted in the Crescent Formation basalts. FSAR field investigations discovered no previously unmapped faults in the site vicinity and no faults cutting the Quaternary deposits such as the Helm Creek (WPPSS 1988). This indicates that the age of the structures is pre-Helm Creek and that these are not considered to be active structures.

3.1.1.2 Plant Site Area

The plant site is situated on a Quaternary river terrace formed on flat-lying Helm Creek glaciofluvial deposits (Figure 3.1-4). The deposits are regionally correlated with other similar deposits dated at 250,000 to 320,000 years old (WPPSS 1988b). The deposits are reworked glacial materials carried downstream by the ancestral Chehalis River. The sediments are fine- to medium-grained sands, silts, and clayey silts. Gravel lenses are locally present and a peat horizon was intercepted in one of the borings completed for the discontinued nuclear project. The deposits range in thickness from 100 to 200 feet (30 to 60 meters).

The Helm Creek deposits lie on Miocene age fine sands and silts of the Astoria Formation (Figure 3.1-4). This marine deposit is 2,500 to 3,000 feet (800 to 900 meters) thick and overlies Lincoln Creek in the regional stratigraphy (Pease and Hoover 1957). The sandstone is thick, bedded to massive, light olive-gray, poorly sorted silty to fine to medium-grained sand (Pease and Hoover 1957). Other rock types included in the Astoria Formation are tuff and tuffaceous sandstone beds 1 to 12 feet thick, thin lenses of siltstone and conglomerate, and seams of carbonaceous material (WPPSS 1988).

Loess, or wind-blown glacial silt, can be found in local accumulations from 5 to 15 feet (1.5 to 5 meters) thick overlying the terrace deposits of the Helm Creek. The thicker loess is found in closed depressions on the site. Recent alluvium and colluvium represent the most recent deposits in the immediate site area. Carbon-14 age dating of charcoal in the deposits have given a date of up to 37,000 years before present (WPPSS 1998). Information on the site-specific subsurface conditions is presented in Subsection 3.1.3.

### 3.1.2 SEISMICITY

Strong ground motions that could potentially affect the site can be generated from earthquakes on several regional seismic sources. Earthquakes are the result of sudden releases of built-up stress within the tectonic plates that make up the earth's surface. The stresses accumulate because of friction between the plates as they attempt to move past one another. The movement can be between plates such as when one plate moves over another, as in subduction zones or within the plates themselves. Earthquakes in the Pacific Northwest can originate from four different types of seismic sources: (1) interplate earthquakes on the Cascadia Subduction Zone (CSZ) between the Juan de Fuca plate and the overriding North American plate, (2) intraplate earthquakes within the subducting Juan de Fuca plate as it sinks and breaks up, (3) shallow crustal earthquakes on faults within the North American plate, and (4) volcanic earthquakes such as those associated with the eruption of Mount St. Helens. These sources are depicted on Figures 3.1-5 and 3.1-6. The largest historical earthquakes in Washington, southern British Columbia, and northern Oregon are shown on Figure 3.1-7 and summarized in Table 3.1-1.

The historic record of seismicity in the Pacific Northwest (approximately 150 years) is insufficient to indicate whether the CSZ has generated or is capable of generating a great earthquake of magnitude (M8 or greater). This type of event apparently occurs every several hundred years and results in major earthquakes at depths of approximately 6 to 25 miles beneath coastal and offshore Washington. Geologic and geodetic studies during the last 10-plus years indicate that great (M8+) earthquakes have occurred on the CSZ during the Holocene and could occur during the project lifetime (Adams 1996; Atwater 1996, 1987a, 1987b, 1992; Atwater and Hemphill-Haley 1997; Carver and Burke 1987; Darienzo and Peterson 1990, 1987; Grant and McLaren 1987; Peterson and Darienzo 1996; Savage and Lisowski 1991; Nelson and Personious 1996). Geologic evidence for the most recent great earthquake (approximately 300 years before present [b.p.]) has been found at many coastal locations in Washington and Oregon. It is uncertain whether a single earthquake or several separate earthquakes closely spaced in time caused the geologic effects recorded at these locations. However there is a general consensus that the CSZ has generated earthquakes of M8 or larger in the past few thousand years (Atwater et al. 1996; Nelson and Personius 1996; and Weaver and Shedlock 1996).

In the FSAR (WPPSS 1988), theoretical arguments are presented that: (1) the CSZ has three discrete segments, (2) that great earthquakes would be confined within each segment and (3) because of the limited length (less than 300 km) each segment is capable of generating earthquakes of only M8.5 or less. Rogers (1988) and Heaton and Hartzell (1986) suggest that a moment magnitude M9.1 CSZ earthquake could occur that would rupture the entire 900-km length of the Juan de Fuca plate between the Explorer and Gorda plates (offshore from Vancouver Island, British Columbia to northern California near Eureka). Analysis of historical records of tsunamis in Japan support the interpretation that the most recent great earthquake on the CSZ was about M9 (Satake and Tanioka 1996). This type of event would generate long period ground motions for a relatively long duration at the Satsop site.

## TABLE 3.1- 1
## LARGEST KNOWN EARTHQUAKES FELT IN WASHINGTON(a)

| Year | Date | Time (PST) | North Latitude | West Longitude | Depth (km) | Mag (felt)(b) | Mag (inst)(c) | Max. Mod. Mercalli Intensity | Felt Area (sq km) | Location |
|---|---|---|---|---|---|---|---|---|---|---|
| 1872 | 12-14 | 2140 | 48°48'00" | 121°24'00" | shallow | 7.3 | None | IX | 1010000 | North Cascades |
| 1877(d) | 10-12 | 1353 | 45°30'00" | 122°30'00" | shallow | 5.3 | None | VII | 48000 | Portland, Oregon |
| 1880 | 12-12 | 2040 | 47°30'00" | 122°30'00" | | | None | VII | | Puget Sound |
| 1891 | 11-29 | 1521 | 48°00'00" | 123°30'00" | | | None | VII | | Puget Sound |
| 1893 | 3-6 | 1703 | 45°54'00" | 119°24'00" | shallow | 4.7 | None | VII | 21000 | Southeastern Washington |
| 1896 | 1-3 | 2215 | 48°30'00" | 122°48'00" | | 5.7 | None | VII | | Puget Sound |
| 1904 | 3-16 | 2020 | 47°48'00" | 123°00'00" | | 5.3 | None | VII | 50000 | Olympic Peninsula, eastside |
| 1909 | 1-11 | 1549 | 48°42'00" | 122°48'00" | deep | 6 | None | VII | 150000 | Puget Sound |
| 1915 | 8-18 | 605 | 48°30'00" | 121°24'00" | | 5.6 | none | VI | 77000 | North Cascades |
| 1918(d) | 12-6 | 41 | 49°37'00" | 122°55'00" | | 7 | 7 | VIII | 650000 | Vancouver Island |
| 1920 | 1-23 | 2309 | 48°36'00" | 123°00'00" | | 5.5 | none | VII | 70000 | Puget Sound |
| 1932 | 7-17 | 2201 | 47°45'00" | 121°50'00" | shallow | 5.2 | none | VII | 41000 | Central Cascades |
| 1936 | 7-15 | 2308 | 46°00'00" | 118°18'00" | shallow | 6.4 | 5.75 | VII | 270000 | Southeastern Washington |
| 1939 | 11-12 | 2346 | 47°24'00" | 122°36'00" | deep | 6.2 | 5.75 | VII | 200000 | Puget Sound |
| 1945 | 4-29 | 1216 | 47°24'00" | 121°42'00" | | 5.9 | 5.5 | VII | 128000 | Central Cascades |
| 1946 | 2-14 | 1918 | 47°18'00" | 122°54'00" | 40 | 6.4 | 6.3 | VII | 270000 | Puget Sound |
| 1946(d) | 6-23 | 913 | 49°48'00" | 125°18'00" | deep | 7.4 | 7.3 | VIII | 1096000 | Vancouver Island |
| 1949 | 4-13 | 1155 | 47°06'00" | 122°42'00" | 54 | 7 | 7.1 | VIII | 594000 | Puget Sound |
| 1949(d) | 8-21 | 2001 | 53°37'20" | 133°16'20" | | 7.8 | 8.1 | VIII | 2220000 | Queen Charlotte Isl., B.C. |
| 1959 | 8-5 | 1944 | 47°48'00" | 120°00'00" | 35 | 5.5 | 5 | VI | 64000 | North Cascades, east side |
| 1959(d) | 8-17 | 2237 | 44°49'59" | 111°05' | 10-12 | 7.6 | 7.5 | X | 1586000 | Hebgen Lake, Montana |
| 1962(d) | 11-5 | 1936 | 45°36'30" | 122°35'54" | 18 | 5.3 | 5.5 | VII | 51000 | Portland, Oregon |
| 1965 | 4-29 | 728 | 47°24'00" | 122°24'00" | 63 | 6.8 | 6.5 | VIII | 500000 | Puget Sound |
| 1981 | 2-13 | 2209 | 46°21'01" | 122°14'66" | 7 | 5.8 | 5.5 | VII | 104000 | South Cascades |
| 1983(d) | 10-28 | 606 | 44°03'29" | 113°51'25" | 14 | 7.2 | 7.3 | VII | 800000 | Borah Peak, Idaho |
| 1990(g) | 4-14 | | | | 3 | | 5.2 | VI | | Deming |
| 1993(d) | 3-25 | 535 | 45°02'00" | 122°36'26" | 16 | | 5.6 | VII | | Scotts Mills, Oregon |
| 1995(f) | 1-29 | 1511 | 47°23'24" | 121°21'36" | 20 | | 5 | V | | Robinson Pt., Vashon Island |
| 1996(e) | 5-02 | 2104 | 47°45'36" | 121°51'00" | 7 | | 5.3 | | | Duvall |
| 1999(e) | 7-02 | 0543 | 47°'33 | 123°'49" | 41 | | 5.5 – 5.9 | VI | | Satsop |
| 2001(e) | 2-28 | 1054 | 47° 9'9" | 122° 43'11" | 52 | | 6.8 | VIII | | Nisqually |
| 2001(e) | 6-10 | 0519 | 47° 9'58" | 123 °30'21" | 41 | | 5.0 | V | | Satsop |

(a) Data from Noson et al. (1988); EERI (1993) except where noted otherwise
(b) Mag (felt) = an estimate of magnitude, based on felt area; unless otherwise indicated, it is calculated from Mag (felt) = -1.88 + 1.53 log A, where A is the total felt area in km²; from Toppozada (1975).
(c) Mag (inst) = instrumentally determined magnitude; refer to references listed in the original Table 2 of Noson et al. (1988), or (e) below, for magnitude scale used.
(d) Earthquakes with epicenters outside Washington.
(e) Data from University of Washington Geophysics Program via http://www.geophys.washington.edu/seis/.
(f) Dewberry and Crosson (1996)
(g) Dragovich et al. (1997)

Intraplate seismic events result from rupture within the subducted plate at depths of 20 to 55 miles. Based primarily on the historical intraplate earthquakes in western Washington and other subduction zones of the world, the intraplate zone is considered capable of generating earthquakes as large as M7.5. Because intraplate earthquakes do not cause deformation at the ground surface that can be distinguished from other types of earthquakes, the typical frequency of these earthquakes cannot be readily assessed. However, these types of earthquakes have historically caused the greatest amount of damage in western Washington. This source has generated three of the largest historical seismic events to affect the Pacific Northwest, the 1949 Olympia earthquake of magnitude M7.1, the 1965 M6.5 Seattle earthquake, and the 2001 Nisqually M6.8 earthquake. These earthquakes caused substantial damage in central and southern Puget Sound and were strongly felt in Satsop, but damage in the Satsop area was relatively minor (Thorsen 1986; UW 2001). In addition to these large intraplate events, there have been two moderate magnitude (M5.0 to 5.9) events centered in the Satsop area (Table 3.1-1). The July 2, 1999 event (M5.7 to 5.9) was strongly felt in Satsop and caused some building damage in the site area (UW 2001 and WDNR 1999).

There is increasing geologic evidence that other regional seismic sources have the potential to produce shallow continental crust earthquakes. Shallow crustal seismic events appear to be more widespread geographically relative to the other sources of historical seismicity, and often occur along mapped or postulated faults exposed at the earth's surface. Based primarily on historic and paleo-seismicity, Quaternary shallow crustal faults are considered capable of generating earthquakes greater than M6 and potentially as large as M7.0 to M7.5, such as the 1872 North Cascade event which was estimated to be a M7.3 (Noson et al. 1988). The largest instrumentally recorded shallow crustal earthquake in the region is the 1996 M5.3 Duvall earthquake, which has not been associated with a recognized Quaternary fault.

Known faults within 70 miles (113 km) of the plant site were identified in the studies conducted for the FSAR. These mapped faults, postulated faults, and lineaments are shown on Figure 3.1-8. The closest faults suspected to have been active in the late Quaternary are the Olympia fault and Doty fault, located 20 to 25 miles from the site. The Canyon River fault is the closest fault with documented Holocene age displacement and is located approximately 30 miles north of the site (Walsh et al. 1997).

Based on the magnitude and intensities reported for the moderate to large Pacific Northwest earthquakes listed in Table 3.1-1, strong ground accelerations greater than 0.2 gravity (g) are estimated to have occurred near the epicenters of these events. Peak ground accelerations (PGA) measured in Olympia during the large intraplate earthquakes in Puget Sound were 0.28g (1949), 0.20g (1965), 0.18g (2001). Larger PGA have likely been generated in western Washington during great prehistoric earthquakes inferred to have occurred on the CSZ.

The historical earthquake estimated to have generated the strongest ground motion near the proposed site was the 1949 Olympia earthquake with an epicenter about 37 miles (60 km) from the site. Peak ground accelerations (PGA) of 0.1g to 0.15g are estimated to have occurred at the site during this event based on computations developed by Crouse (1991a, 1999b) and the WPPSS (1988b). The PGA recorded near Satsop during the 2001 Nisqually earthquake was 0.08g. A value was not obtained from this station during the 1999 Satsop earthquake.

Values of PGA were also computed at the site for use in the design of the existing plant. The FSAR reports calculations of median value for PGA obtained from several published ground-motion attenuation equations. In that analysis, the postulated earthquake estimated to produce the largest ground motion at the site was a M7.5 event on the Olympia lineament at a distance of 22 miles (35 km) from the site. The resulting median PGA values computed for this event were 0.16 to 0.17g.

### 3.1.3 SOILS

Naturally occurring, surficial soils have been modified or removed as a result of the prior grading and construction activities at the site. The gravel-covered ground surface at the site is sparsely vegetated in the western half, while the eastern half is covered with small coniferous trees. The subsurface strata and engineering properties of the Helm Creek deposits in the site area have been assessed in conjunction with work completed for WNP-3 and Satsop CT Phase I. Site-specific conditions of the proposed Phase II project have been investigated by URS (2001). Subsurface conditions were investigated by drilling 9 borings, advancing 27 electric cone penetrometer probes, and excavating 5 test pits. The locations of these explorations are shown on Figure 3.1-9. Borings were drilled to depths of 60 to 120 feet, the cone probes were pushed to depths of 40 to 133 feet, and the test pits were excavated to depths of 10 to 12 feet.

Generally, the soils encountered at the site consisted of up to approximately 75 feet of alluvial soils interpreted as Helm Creek deposits, overlying decomposed sandstone from the Astoria Formation. Interpreted cross sections of the subsurface soils are illustrated on Figures 3.1-10 and 3.1-11. The engineering properties of these strata are summarized in Table 3.1-2. The specific description of each soil unit, proceeding downward from the ground surface, is as follows:

- <u>Gravel Surfacing</u> - The site is covered with a gravel fill approximately 1.5 to 2.5 feet in thickness. The gravel is subrounded, reasonably well graded and contains some silt and sand as well as cobbles. At the base of this fill cover is a geotextile.

- <u>Stratum 1</u> - Reddish Brown Medium Stiff to Stiff SILT

  This soil layer is typically 5 to 12 feet thick, and medium stiff to stiff in character based on N-values, cone tip resistances, pocket penetrometer test values and unconfined compression test values. Other laboratory tests indicate that this silt is moderately to highly plastic (liquid limit of 54) and moderately compressible. Moisture contents were usually in the range of 38 to 44 percent.

- <u>Stratum 2</u> - Yellowish Brown Silty SAND to Sandy SILT

  This soil layer grades between a fine sand and a silt, and typically exhibits the character of a fine-grained soil. The layer is only 4 to 10 feet thick along the western 200 feet of the site, but is typically 20 to 30 feet thick elsewhere. The soil would be characterized as stiff based on N-values and cone tip resistance values. Laboratory tests indicate that the fines content of the layer ranges from 39 to 65 percent for the samples tested. The fines appear to be non-plastic. Consolidation tests indicate that the soil is moderately compressible but drains quickly. High natural moisture contents in the range of 40 to 50 percent were measured.

**TABLE 3.1-2**
**SUMMARY OF SOIL CONDITIONS AND DESIGN PARAMETERS**

| Item | Stratum 1 Silt | Recompact. Stratum 1 Silt | Stratum 2 Silty Sand Sandy Silt | Stratum 3 Gravelly Sand | Stratum 4 Silty Sand |
|---|---|---|---|---|---|
| Average Thickness (ft) | 10 | | 20 | 40 | 40+ |
| Typical Uncorrected N-values (bpf) | 2 to 5 | | 3 to 10 | 14 to 35 | 20 to 40 |
| Typical Cone Tip Resistance (tsf) | 6 to 10 | | 30 to 60 | 100 to 200 | 50 to 100 |
| Ave. Shear Wave Velocity Vs (fps) | 640 | 680 | 870 | 1,590 | 1,320 |
| Ave. Compr. Wave Velocity Vp (fps) | 1,560 | 1,700 | 1,800 | 3,300 | 2,750 |
| Total Unit Weight $\gamma$ (pcf) | 110 | 110 | 110 | 130 | 120 |
| Friction Angle $\phi$ (degrees) | 0 | 0 | 0 | 40 | 36 |
| Cohesion c (psf) | 900 | 1,200 | 1,200 | 0 | 50 |
| Dynamic Elastic Modulus Emax (ksf) | 3,800 | 4,400 | 7,000 | 27,000 | 17,000 |
| Static Elastic Modulus E (ksf) | 300 | 3,20 | 250 | 800 | 600 |
| Dynamic Shear Modulus Gmax (ksf) | 1,400 | 1,600 | 2,600 | 10,200 | 6,500 |
| Poisson's Ratio v | 0.4 | 0.4 | 0.35 | 0.35 | 0.35 |
| Active Earth Pressure Coeff Ka | 0.36 | 0.36 | 0.31 | | |
| At-Rest Earth Pressure Coeff Ko | 0.53 | 0.53 | 0.47 | | |
| Passive Earth Pressure Coeff Kp | 2.7 | 2.7 | 3.2 | | |
| Soil-Concrete Friction Coefficient | 0.3 | 0.3 | 0.3 | | |
| California Bearing Ratio CBR | 5 | 6 | | | |
| Compression Index $Cc\varepsilon$ | 0.1 | 0.1 | 0.08 | | |
| Coeff of Consolidation cv ($ft^2$/day) | 1.5 | 1.5 | 8.5 | | |
| Permeability k (cm/sec) | $10^{-5}$ | $10^{-5}$ | $10^{-3}$ | | |
| Thermal Resistivity ($^oC$-cm/W) | 50 | 50 | 46 | | |

Notes:

1. The Vs values are measured (except for Recompacted Stratum 1); Vp values are estimated.
2. The Gmax and Emax values apply to a shear strain level of approximately $10^{-4}$ percent.
3. The $Cc\varepsilon$ Compression Index is from a percent strain versus log of applied load curve.
4. Values listed above generally represent average to the slightly conservative side of average values based on interpretation of available data. Natural variability of soil conditions and parameters are expected to occur throughout the site.
5. The water table is interpreted to be at a depth of at least 70 feet.

Source: URS 2001

- <u>Stratum 3</u> - Multi-colored Medium Dense to Dense Gravelly SAND

  This layer typically consists of well-graded sand with 15 to 50 percent gravel and 15 to 25 percent fines. The apparently re-worked sediments show color variations that include red, green, gray, brown and white. This layer is at least 25 feet thick, and more typically the thickness exceeds 35 feet. N-values and cone tip resistance values suggest that the layer is medium dense to dense in character.

- <u>Stratum 4</u> - Brown to Grayish Brown Silty SAND

  This layer is interpreted to be a residual soil derived from the Astoria Sandstone formation. It is primarily silty sand, but contains occasional zones that are primarily silt. N-values and cone tip resistance values suggest that the soil is dense in character. The last sample collected in boring B-3, at a depth of 111 feet bgs, appeared to be the weathered top of the Astoria sandstone.

### 3.1.4 TOPOGRAPHY

#### 3.1.4.1 Existing Conditions

The proposed plant site is located in the Chehalis Lowlands section of the Willapa Hills physiographic province (Figure 3.1-1). Provinces are defined by areas which possess similar surface topography, river drainage patterns, have common subsurface geology and recent geologic history. The Chehalis Lowlands section is characterized by low rolling hills and broad river valleys flanked by river terraces, or flat narrow benches. Elevations within the Chehalis Lowlands range from 480 to 1,000 feet (150 to 300 meters).

The proposed plant site is located on a flat terrace above the Chehalis River in a region characterized by finely dissected uplands cut by the valley of the Chehalis River. The terrace lies at an elevation of approximately 305 feet (93 meters) above mean sea level (MSL), 300 feet (91 meters) above the Chehalis River. The gravel-covered ground surface slopes gently downward to the west and north, with a total topographic relief across the site of about 30 feet (Figure 3.1-9). The low point of the site is at approximately Elevation 284 at the northwest corner. From the site, elevation drops 240 feet (73 meters) to the next lower river terrace in a steep, but short slope to the north. West of the site, approximately 3,000 feet (315 meters), the terrace drops to river level in a steep river cutbank.

The land surface rises to the south of the site in a finely dissected drainage pattern to a topographic high of over 1,760 feet (536 meters) at Minot Peak, 6 miles (10 km) to the southeast. Fuller Creek, less than 1,500 feet (450 meters) southeast, is the nearest surface drainage. It flows northeast to the Chehalis River in a 100-foot (30-meter) deep valley.

#### 3.1.4.2 Potential Impacts

The planned finished grade of the project will be approximately elevation 305 (Figures 3.1-9 through 3.1-11). Therefore construction of Phase II will require some cutting and filling that will have an insignificant impact on topography. The amount of material to be removed and replaced, as described in Subsection 2.3.3.2, is 80,000 cubic yards.

#### 3.1.4.3 Mitigation Measures

No mitigation measures are necessary.

## 3.1.5 UNIQUE PHYSICAL FEATURES

There are no unusual or unique geological or physical features in the project area that could potentially be affected by the project.

## 3.1.6 EROSION/ENLARGEMENT OF LAND AREA (ACCRETION)

### 3.1.6.1 Existing Conditions

As part of the soil surveys of Grays Harbor County, the State of Washington Department of Natural Resources (DNR) conducted a survey that evaluated the erosion potential in an area that includes the proposed plant site. The rating for erosion potential is based on the interaction of the following conditions:

- Soil properties, including texture, structure, and porosity
- Rainfall rate and storm intensity
- Slope

The soil property is represented in the commonly used Universal Soil Loss Equation as the K factor. The K factor and slope conditions of the project are further evaluated in other sections of this report in an effort to more specifically characterize the separate parts of the project. In summary, the larger the K factor of a soil, the higher the potential for erosion, given that all other factors remain constant.

Rainfall rate is readily available from government agencies and slope is a function of the rise in elevation over a horizontal distance expressed as a percentage. Slopes greater than 15 percent are classified as having high potential for erosion, slopes from 5 to 15 percent have medium potential, and less than 5 percent have a low potential.

The evaluation is summarized on Figure 3.1-12 by classifying the areas into three categories to qualitatively describe the erosion potential. The categories are low, medium, and high erosion potential. In areas with the low designation the potential for erosion is insignificant. In areas with the medium designation, the potential for erosion is significant and extensive erosion can occasionally occur, but can be reduced or limited by avoiding unnecessary surface disturbance. In areas with the high designation, erosion can frequently be expected to occur on all bare surfaces.

The soils underlying the proposed plant site and in the immediate vicinity of the site have been assigned K factors of between 0.15 to 0.32 at the depths expected to be disturbed during construction (Soil Conservation Service, no date). These values correspond to a high potential for soil erosion. The slope at the plant site itself has a rating of 1 (low); slopes adjacent to Fuller Creek to the east have a slope rating of 3 (high). It is anticipated that the majority of disturbance during the plant construction and operation will occur on the relatively flat bench away from the creek. Table 3.1-3 presents a slope rating system that was established to quantitatively describe the terrain features in the site area.

**TABLE 3.1-3**
**SLOPE RATING SYSTEM**

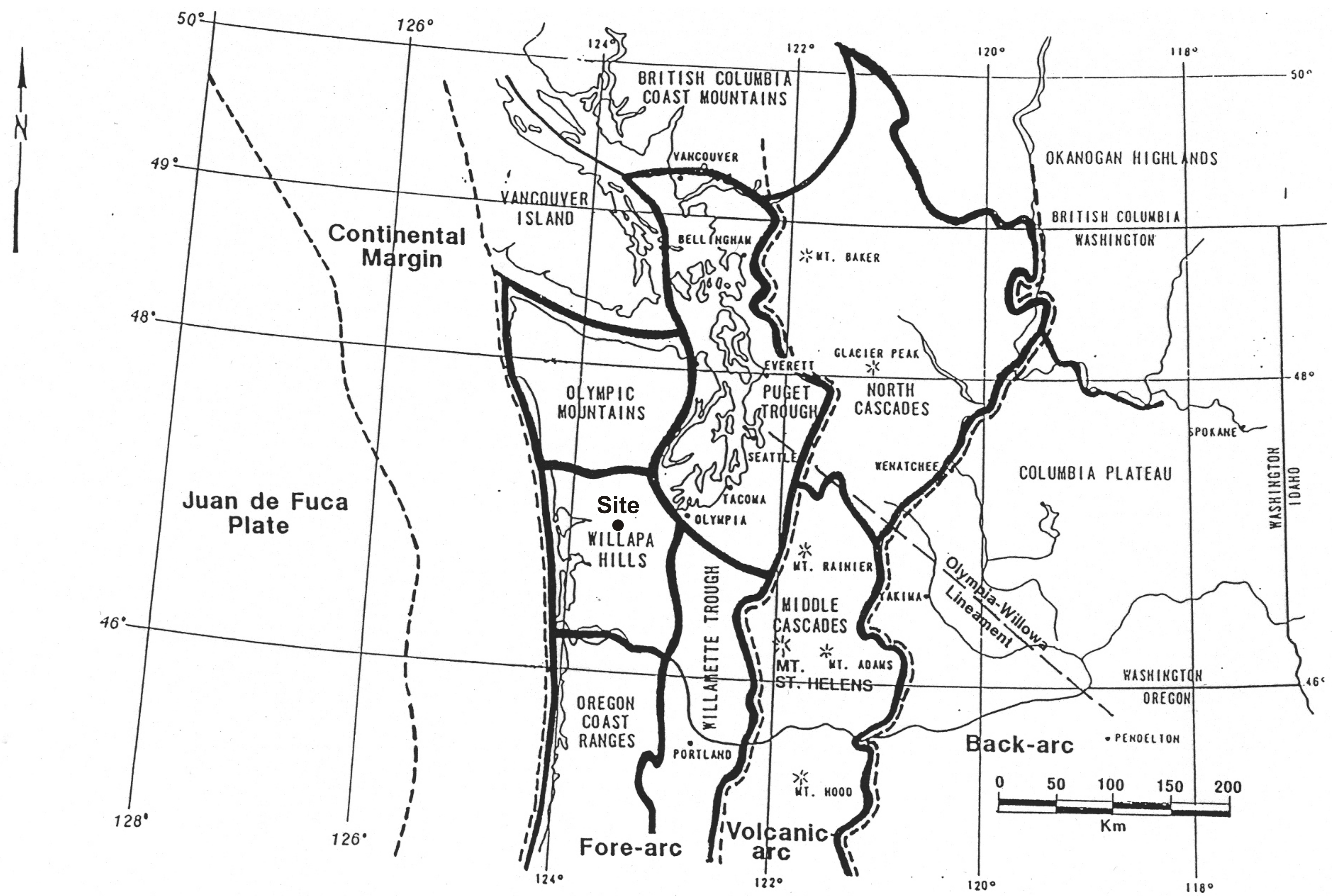
| Slope Rating | Description | Slope Range (percent) |
|---|---|---|
| 1 | Low | 0-5 |
| 2 | Moderate | 5-15 |
| 3 | High | greater than 15 |

### 3.1.6.2 Potential Impacts

The Certificate Holder has an EFSEC-approved Erosion Control and Sedimentation Plan for the Phase I project which covers the entire site, including the area proposed for Phase II project. This plan is applicable to Phase II and is designed to prevent and/or minimize the potential for erosion. See Environmental Commitments Book, August 2001 for a description of the approved measures. Implementation of the plan will result in minimal if any erosion impacts.

### 3.1.6.3 Mitigation Measures

No additional mitigation measures are warranted beyond proper implementation of the EFSEC-approved Erosion Control and Sedimentation Plan.




LEGEND:

Tectonic Terrane

Tectonic Province

Geo-Political Boundary

*Source: Fugro Northwest, Inc., 1979 and McCrumb and others, 1989.*

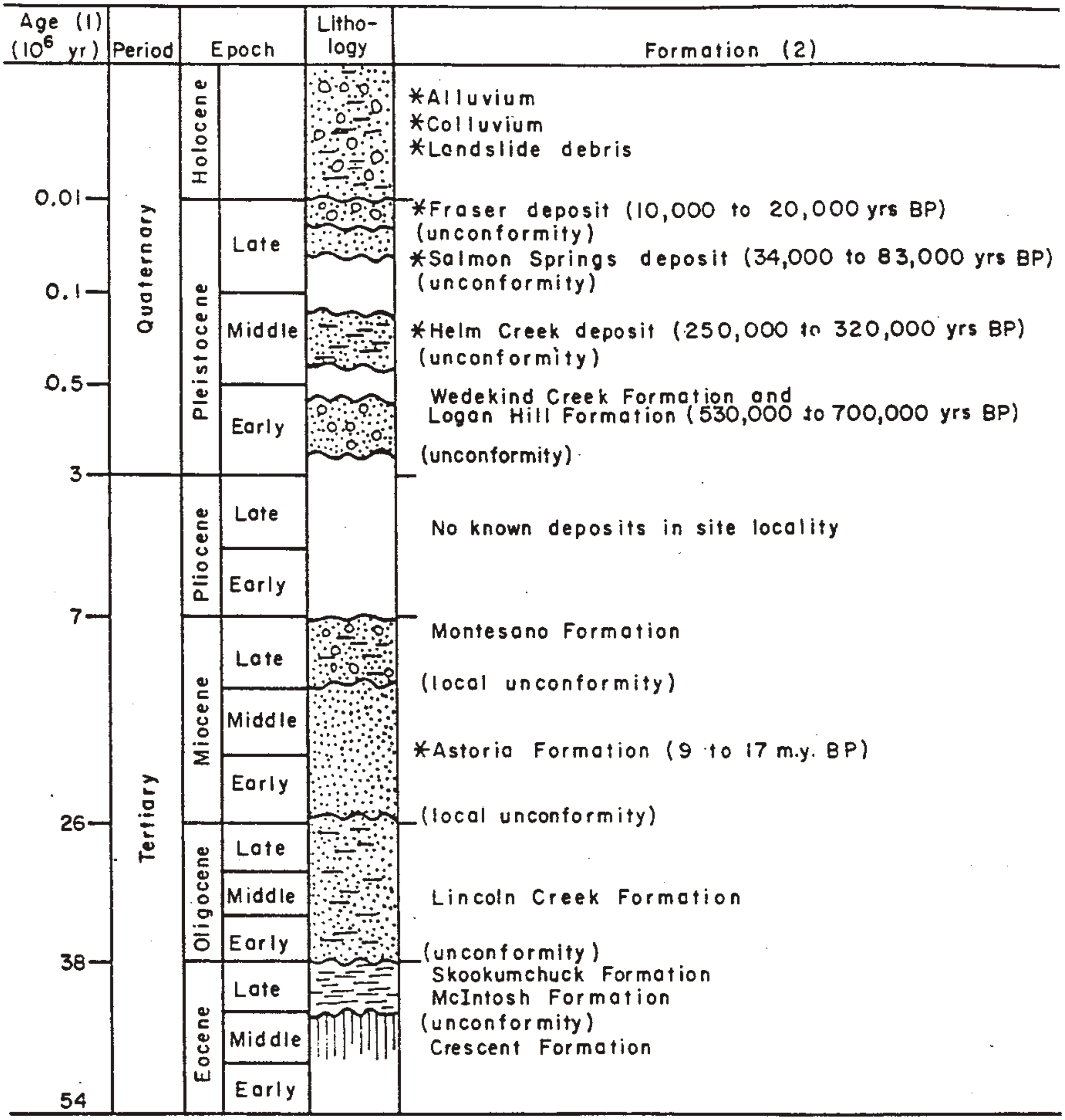
Figure 3.1-1

**Tectonic Terranes and Province of the Pacific Northwest**

URS

Phase II Expansion
Satsop CT Project

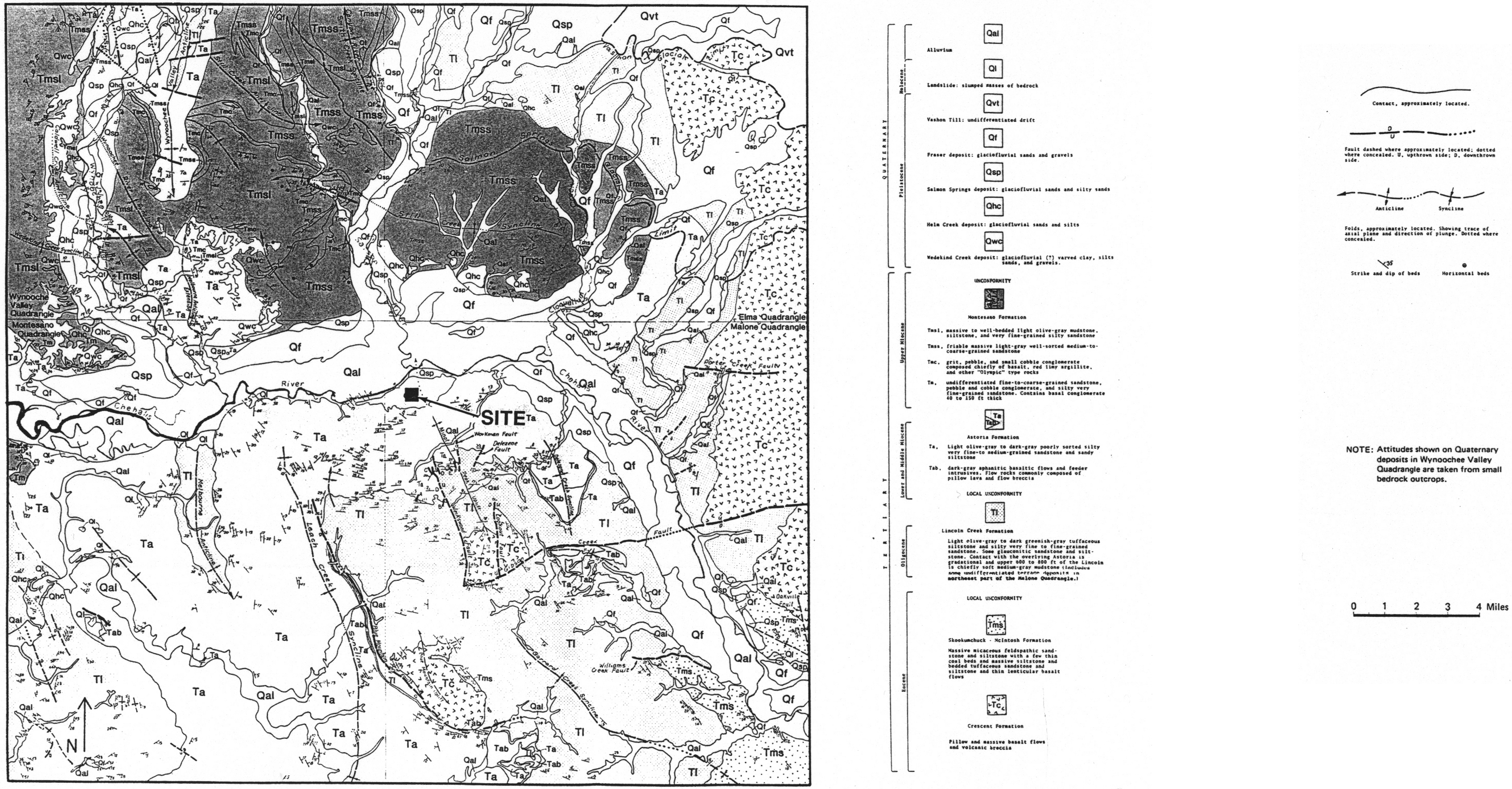
46866002.01_23.cdr




*Formations present within 1.5mi of plant location

Source: Washington Public Power Supply System,
Nuclear Projects 3 & 5, Final Safety Analysis Report.

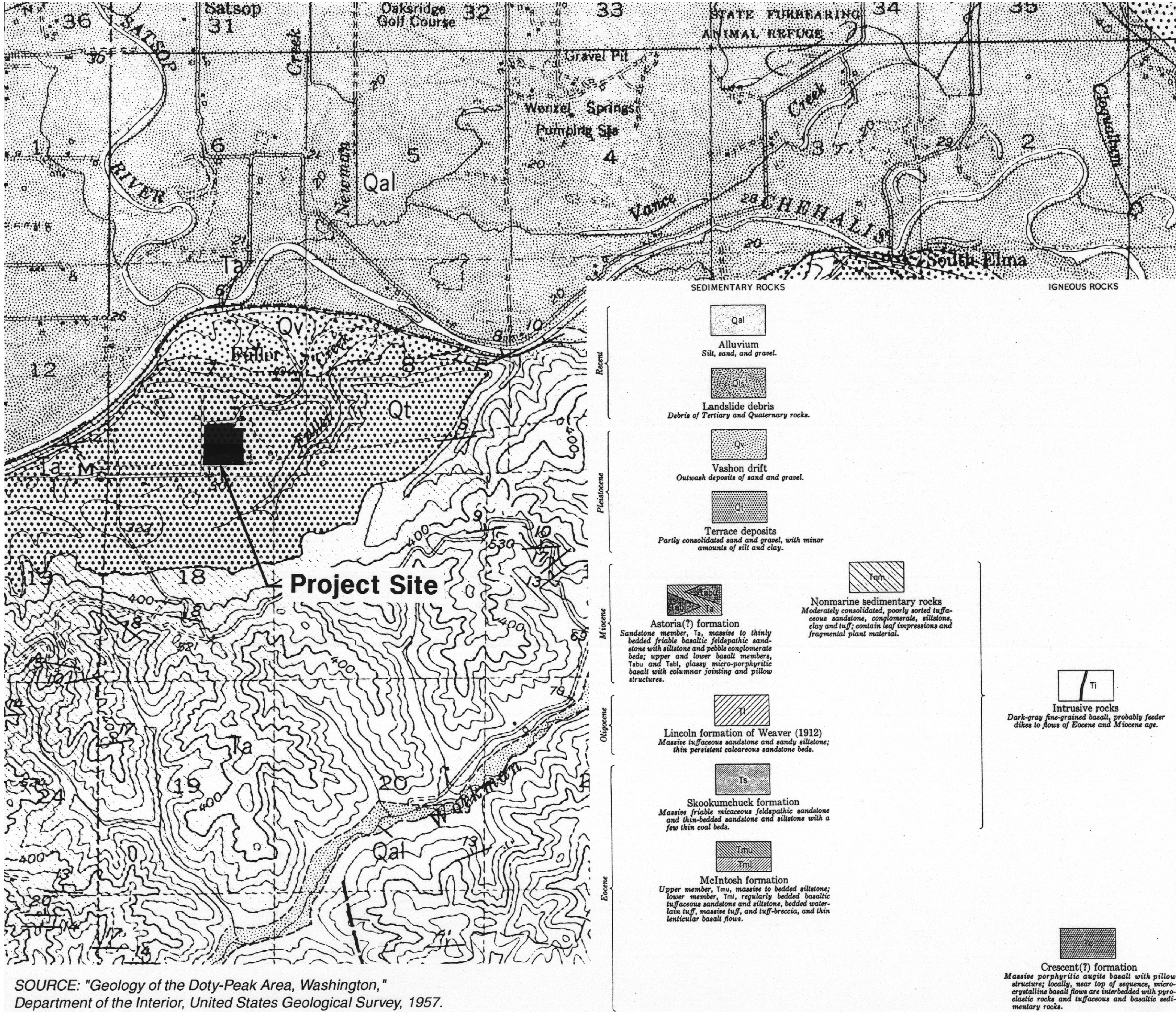
Figure 3.1-2
**Local Stratigraphic Column**

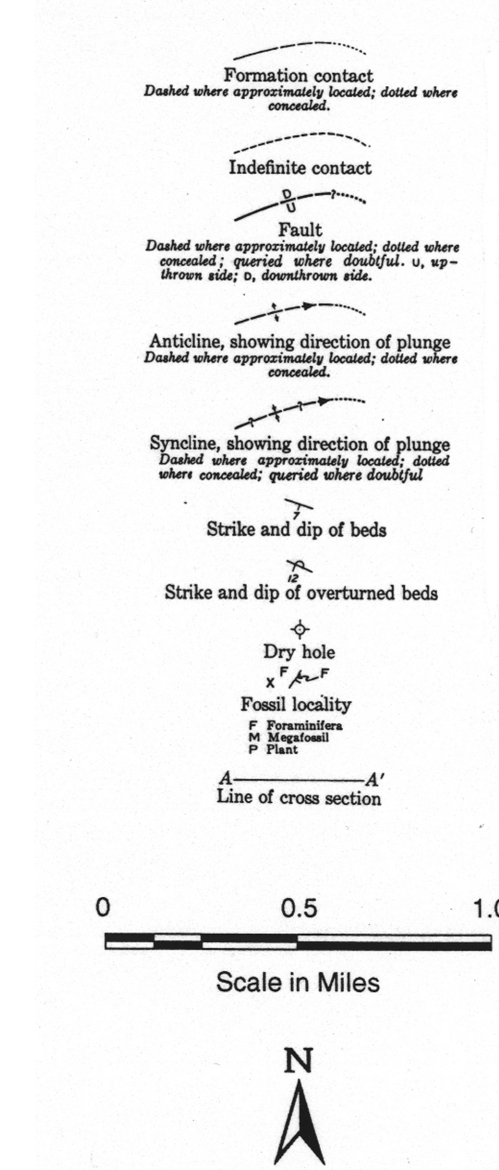



Source: Washington Public Power Supply System, Nuclear Projects 3 & 5, Final Safety Analysis Report.

Figure 3.1-3

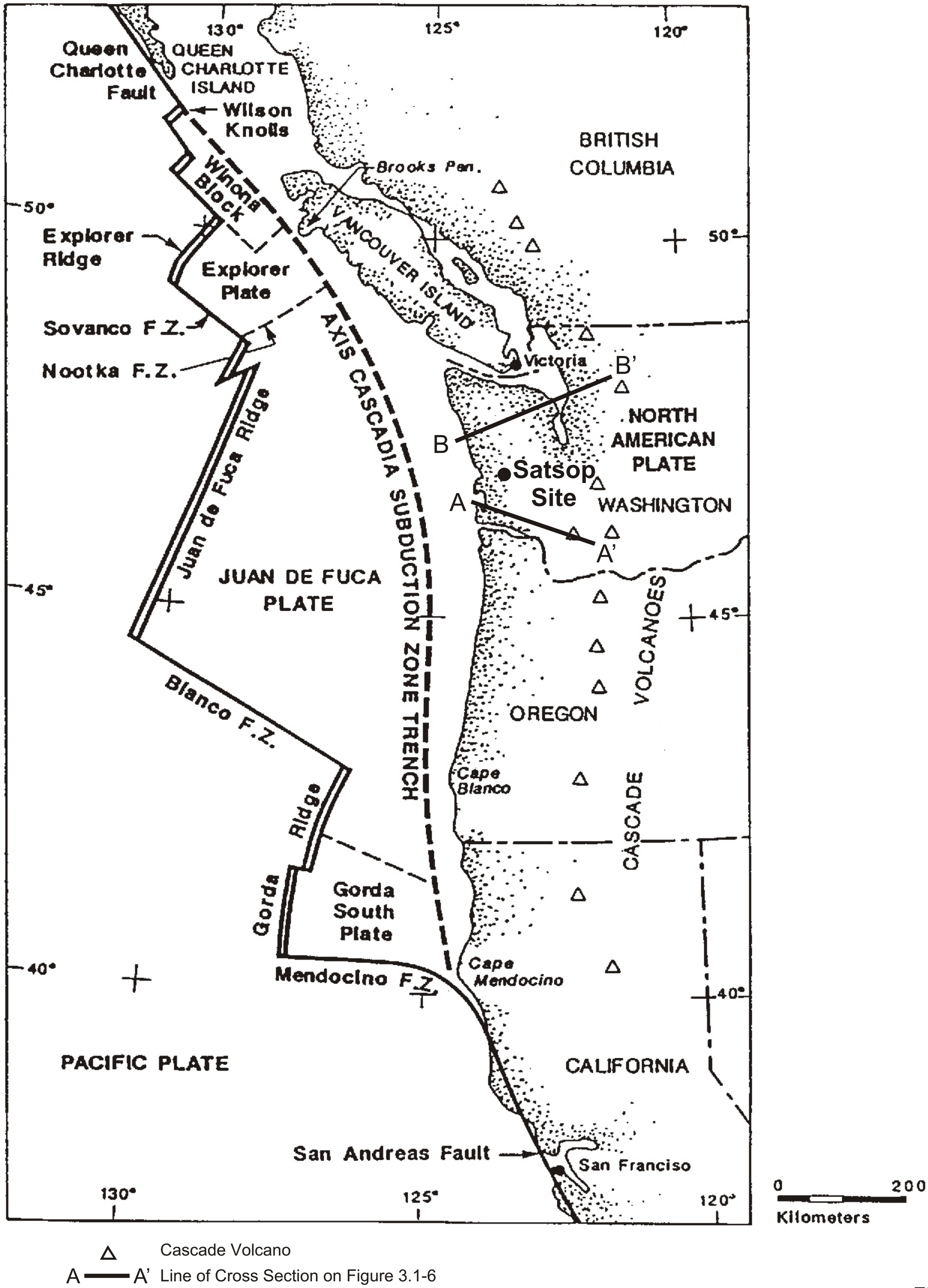
**Regional Geology and Structure Map**




*SOURCE: "Geology of the Doty-Peak Area, Washington," Department of the Interior, United States Geological Survey, 1957.*

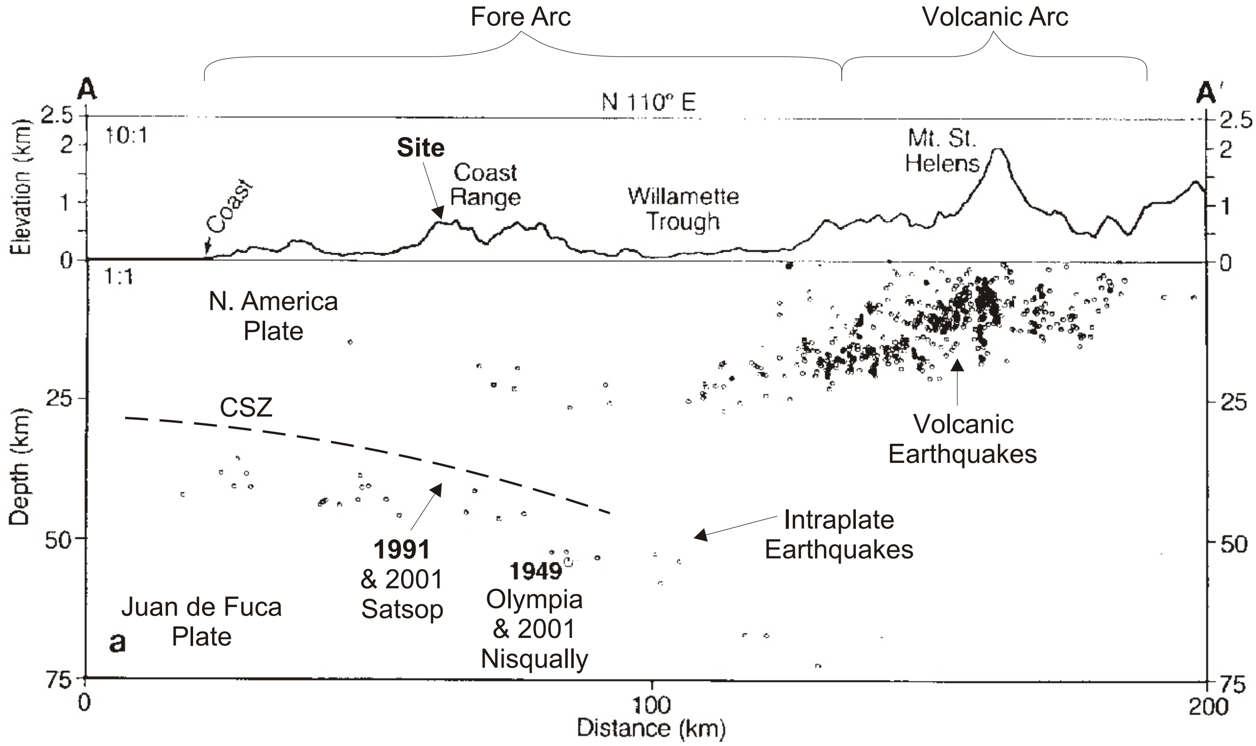
Figure 3.1-4
**Site Geology Map**



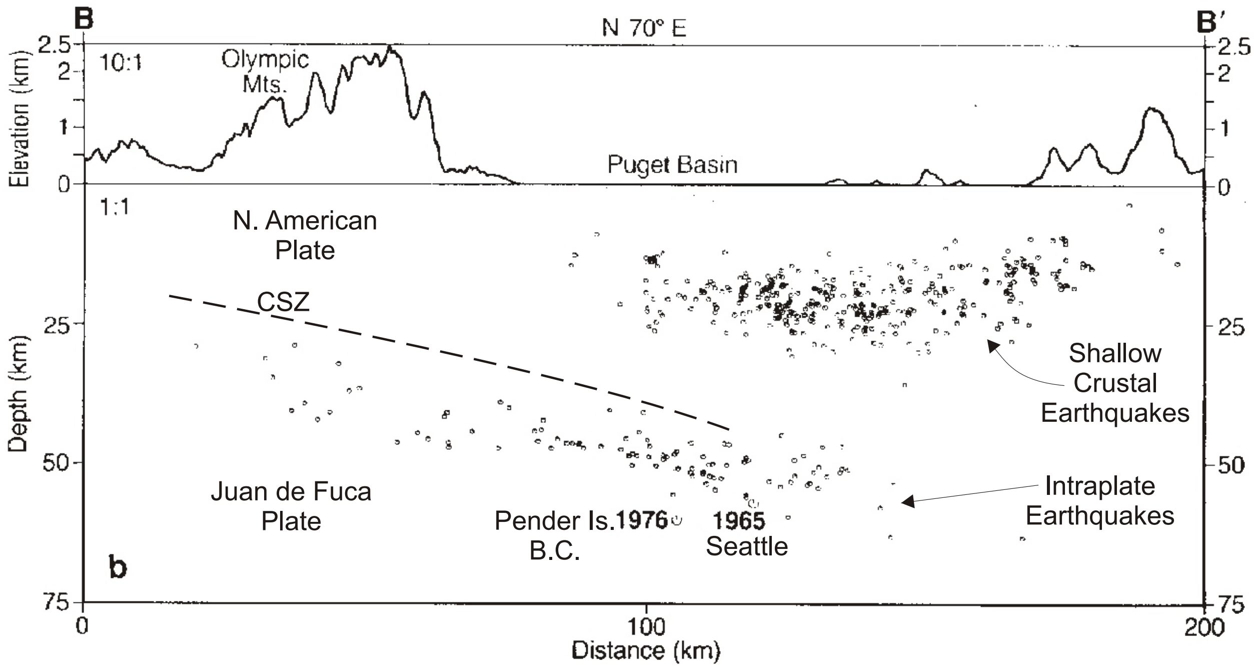

Modified from Washington Public Power Supply System (1988) (after Riddihough, 1984).

Figure 3.1-5

**Tectonic Setting of the Cascadia Subduction Zone**




a. Southwestern Washington Cross Section A-A'



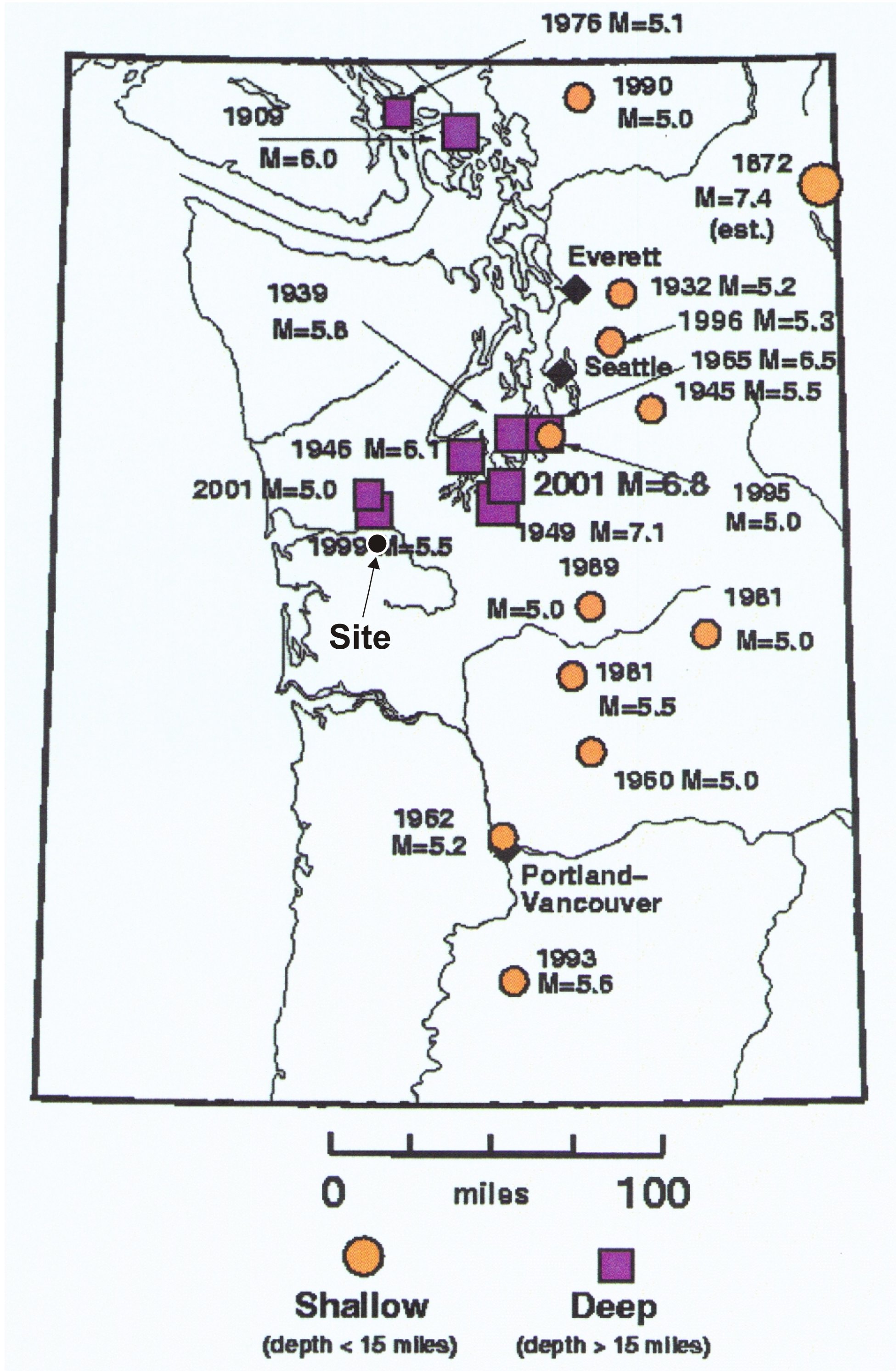

b. Northwestern Washington Cross Section B-B'

CSZ = Cascadia Subduction Zone

See Figure 3.1-5 for cross section locations.

Figure 3.1-6

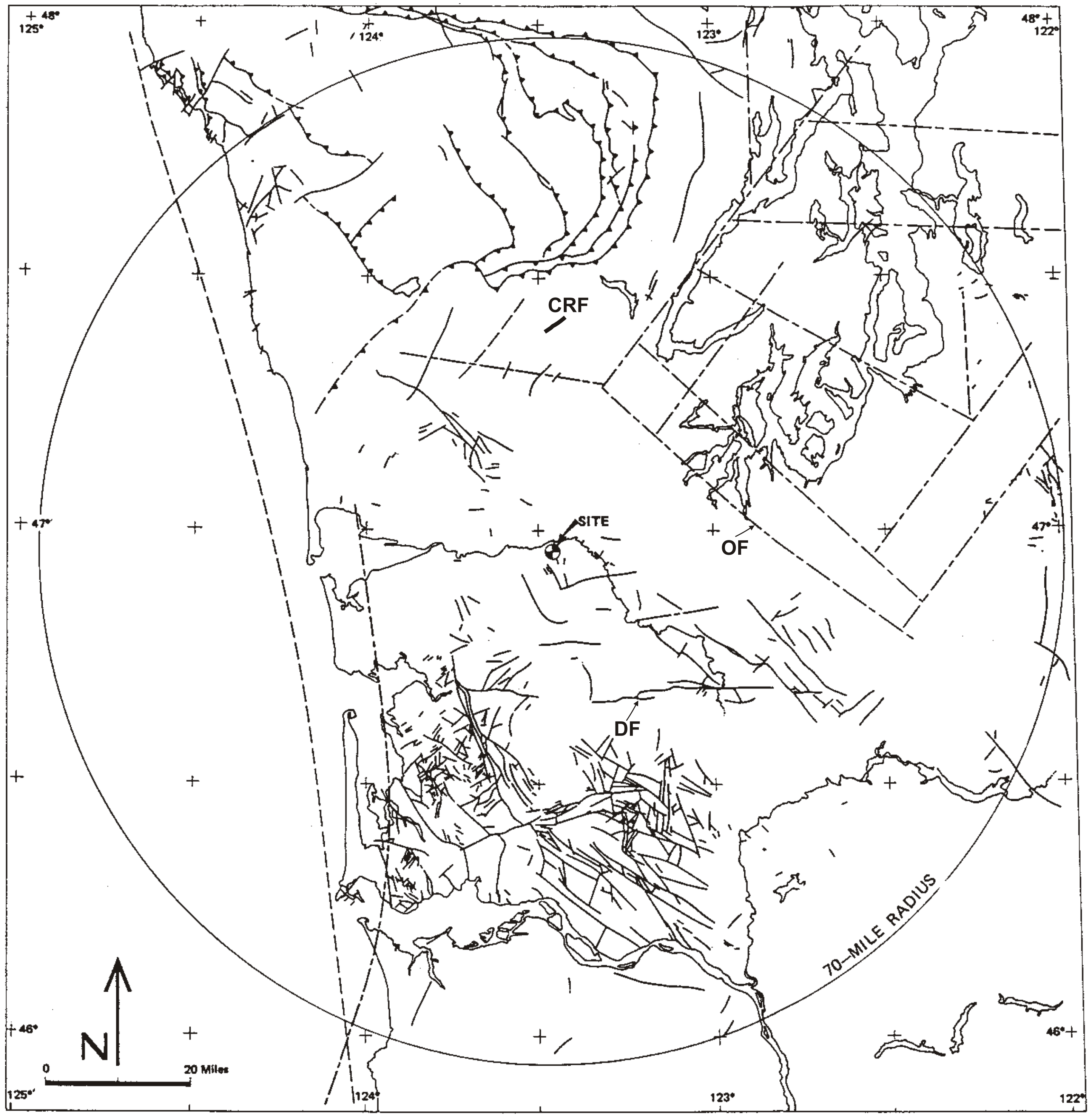
**Cross Sections of Earthquake Hypocenters Beneath Western Washington**




Source: University of Washington

Figure 3.1-7

**Epicenters and Dates of Larger Pacific Northwest Earthquakes**




EXPLANATION

KNOWN FAULTS:
High Angle
Thrust (barbs indicate upper plate)

POSTULATED FAULTS:
Based on minimal evidence

PUBLISHED LINEAMENTS:
Based mainly on geophysical and physiographical evidence

**CRF** Canyon River Fault

**OF** Olympia Fault

**DF** Doty Fault

Source: Washington Public Power Supply System, Nuclear Projects 3 & 5, Final Safety Analysis Report.

Figure 3.1-8

**Known Faults, Postulated Faults, and Published Lineaments Within 70 Miles of Site**

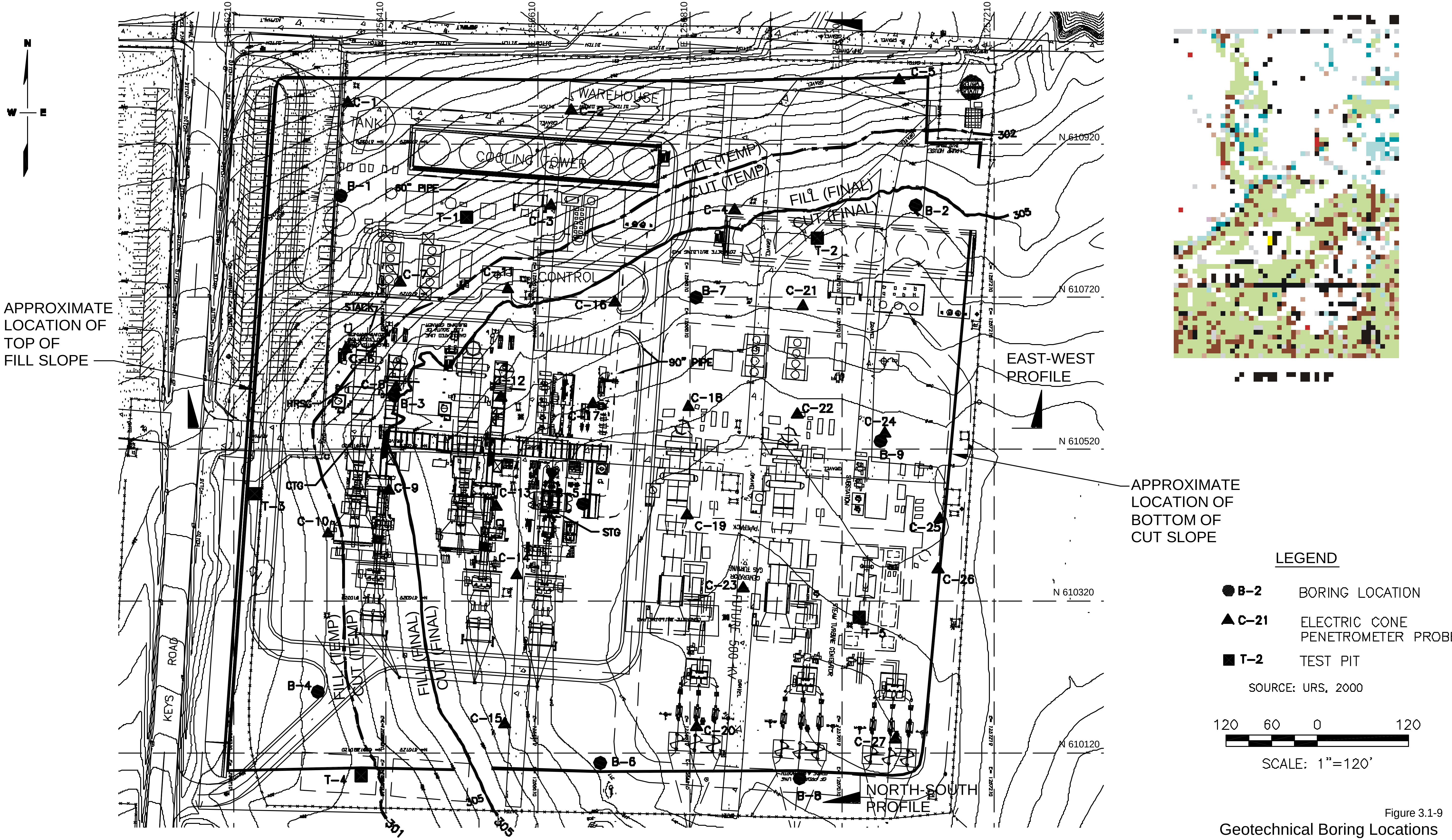
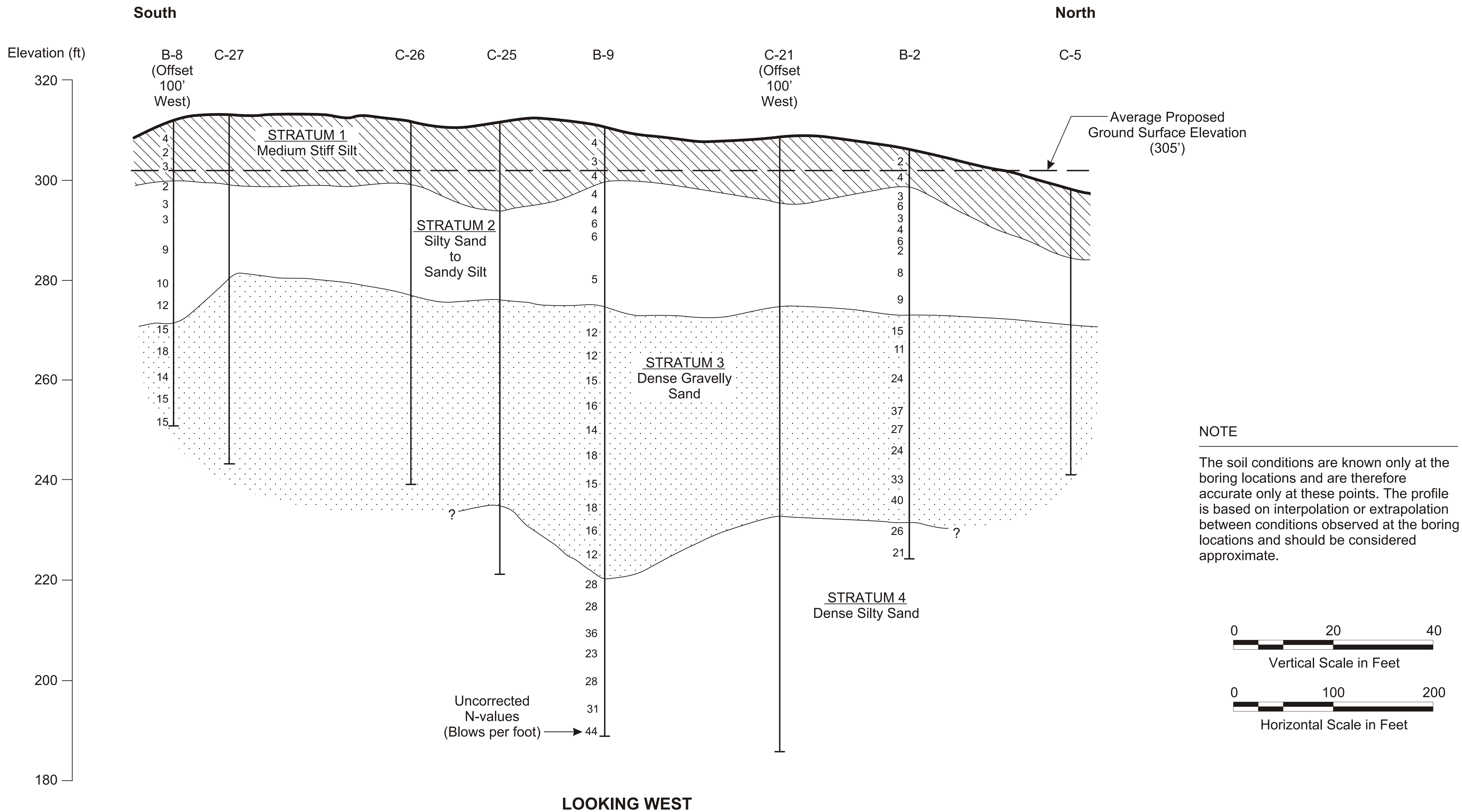



Figure 3.1-9
Geotechnical Boring Locations
And Site Plan

46866002.01_27.cdr

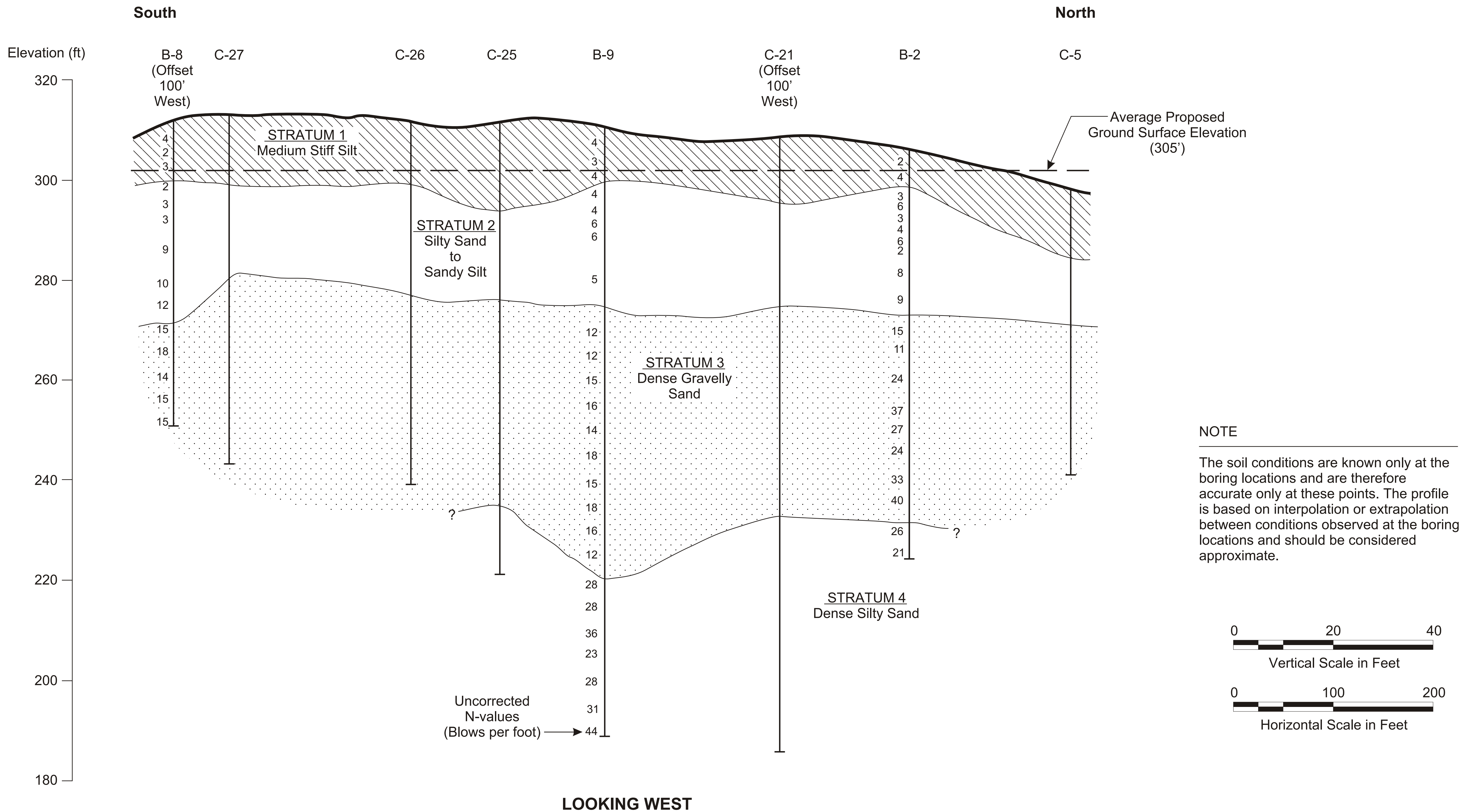



Source: URS 2001

Figure 3.1-10

**East-West Cross Section**

46866002.01_28.cdr



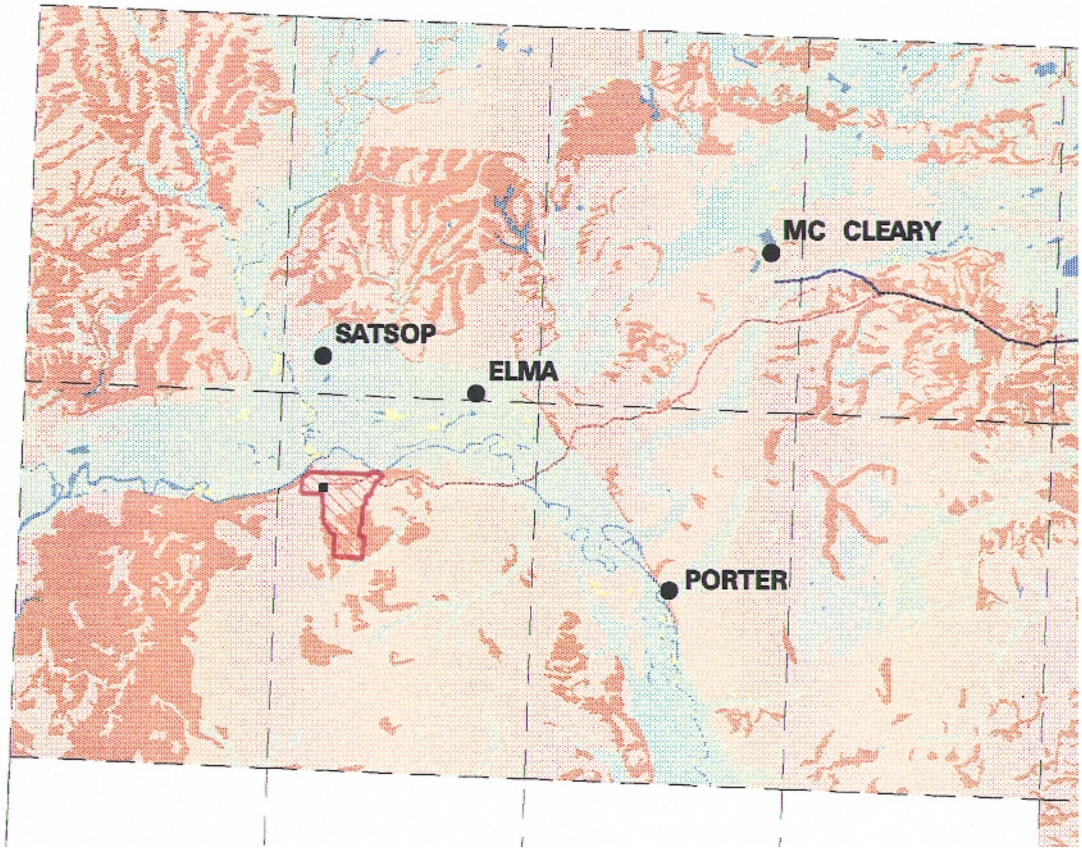

Source: URS 2001

Figure 3.1-11
**North-South Cross Section**

URS

Phase II Expansion
Satsop CT Project

46866002.01_35.cdr




LEGEND:

Existing Gas Pipeline

Property Boundary

Project Site

Water/Wet

Low

Medium

High

Variable

N

0 4 8

Scale in Miles

Source: Washington State DNR GIS (1990).

Figure 3.1-12

## Erosion Potential

# 3.2

# Air (WAC 463-42-312)

**WAC 463-42-312 NATURAL ENVIRONMENT — AIR.**

*The applicant shall provide detailed descriptions of the affected environment, project impacts, and mitigation measures for the following:*

*(1) Air quality - The applicant shall identify all pertinent air pollution control standards. The application shall contain adequate data showing air quality and meteorological conditions at the site. Meteorological data shall include, at least, adequate information about wind direction patterns, air stability, wind velocity patterns, precipitation, humidity, and temperature. The applicant shall describe the means to be utilized to assure compliance with applicable local, state, and federal air quality and emission standards.*

*(2) Odor - The applicant shall describe for the area affected, all odors caused by construction or operation of the facility, and shall describe how these are to be minimized or eliminated.*

*(3) Climate - The applicant shall describe the extent to which facility operations may cause visible plumes, fogging, misting, icing, or impairment of visibility, and changes in ambient levels caused by all emitted pollutants.*

*(4) Dust - The applicant shall describe for any area affected, all dust sources created by construction or operation of the facility, and shall describe how these are to be minimized or eliminated.*

## 3.2 AIR
## (WAC 463-42-312)

### 3.2.1 AMBIENT AIR QUALITY

Detailed information regarding air quality, required under WAC 463-42-312, is provided in Section 6.1 - PSD Application, WAC 463-42-385. As required for the Prevention of Significant Deterioration (PSD) permit, the discussion of air impacts in both this Section 3.2 and in Section 6.1 addresses the combined emissions and operations of Phase I and Phase II.

#### 3.2.1.1 Ambient Air Quality Standards

The distinction between emissions and concentrations is important in the review of air quality issues. Emission regulations (New Source Performance Standards) limit the amount of a particular pollutant that can be emitted into the atmosphere from a stack or facility, measured in pounds per hour (lb/hr). Air quality standards limit the concentration of certain pollutants (such as criteria pollutants) in the ambient air, measured in parts per million (ppm).

The Washington Ambient Air Quality Standards (WAAQS) and National Ambient Air Quality Standards (NAAQS) limit the concentrations of air pollution that are permissible in all air basins. These regulations govern six pollutants known as criteria pollutants (sulfur dioxide, carbon monoxide, particulate matter, nitrogen dioxide, ozone, and lead). Each criteria pollutant has primary and secondary standards. Primary standards define air quality levels judged necessary to protect public health with a margin of safety while secondary standards protect public welfare from any known or anticipated adverse effects associated with these pollutants. Grays Harbor County, where the project area is located, is governed by the Olympic Air Pollution Control Agency (OAPCA). Grays Harbor County has had no demonstrated violations of air quality standards and therefore areas adjacent to the project site are currently designated as being in attainment with ambient air quality standards for each criteria pollutant. PSD increments are limits established to maintain air quality levels in attainment areas. All relevant standards that would apply to the proposed project are presented in Table 3-2.1. OAPCA has adopted the same ambient air quality standards as Ecology.

**TABLE 3.2-1**
**AIR QUALITY STANDARDS AND SIGNIFICANCE LEVELS**

| Criteria Pollutant | Averaging Period | National Ambient Air Quality Standards ($\mu g/m^3$) | | PSD Increments ($\mu g/m^3$) | | Washington Ambient Air Quality Standards ($\mu g/m^3$) | Significant Impact Levels ($\mu g/m^3$) | Monitoring DeMinimus Concentrations ($\mu g/m^3$) |
|---|---|---|---|---|---|---|---|---|
| | | Primary | Secondary | Class I | Class II | | | |
| Total Suspended Particulate Matter (TSP) | Annual | -- | -- | -- | -- | 60 | -- | -- |
| | 24-Hour | -- | -- | -- | -- | 150 | -- | 10 |
| Particulate Matter Less than 10 $\mu$m ($PM_{10}$) | Annual | 50 | [a] | 4 | 17 | 50 | 1 | -- |
| | 24-Hour | 150[b] | [a] | 8 | 30 | 150 | 5 | 10 |
| Particulate Matter Less than 2.5 $\mu$m ($PM_{2.5}$) | Annual | 15[j] | [a] | -- | -- | -- | -- | -- |
| | 24-Hour | 65[j] | [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 | -- | 1,300[b] | 25[b] | 512[b] | [e] | 25 | -- |
| | 1-Hour | -- | -- | -- | -- | 1,048[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][j] | [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 | 2,000 | -- |

[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] 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.

### 3.2.1.2 Climate

The climate of western Washington is dominated by two large-scale influences: the mid-latitude westerly winds and proximity of the Pacific Ocean. Temperature data available from the National Climatic Data Center, measured over a 30-year period in Elma, indicate that monthly temperatures average 51°F, with an average maximum of 67°F, and an average minimum of 34°F. Temperature extremes were recorded ranging from the high 20s for the minimum temperatures up to the high 90s as the maximum temperatures recorded. Few days below 32°F are recorded for the project area. Meteorological data indicate that precipitation totals about 60 inches annually, with the wettest months from November to April. Approximately 5 inches of snow falls annually, primarily from December to March. Mean annual mixing heights for the morning hours are approximately 600 meters, while afternoon or evening hour mixing heights are approximately 1,000 meters for the Northwest Pacific Coastal region. Relative humidity ranges from about 30 percent during the summer months, and winter months average about 60 percent.

#### 3.2.1.3 Meteorology

Representative meteorological data for the project site and vicinity was obtained from a meteorological monitoring station located within the Satsop power plant boundary. Additional meteorological parameters were obtained from Olympia and Seattle-Tacoma International Airport National Weather Service stations. The data indicate a predominant east and east-northeast wind direction. Calm periods were recorded for 1.5 percent of the collection period. Wind speeds averaged 3.0 meters per second (m/s), with the strongest winds 5 to 7 m/s from the east. Westerly winds were also recorded with milder wind speeds of 3 to 5 m/s.

### 3.2.2 AIR QUALITY IMPACTS

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. A demonstration that the proposed project is in compliance with applicable federal and state ambient air quality standards, New Source Performance Standards (NSPS), best available control technology (BACT), air toxics standards, opacity, and visibility is required. Please refer to Section 6.1 – PSD Application, WAC 463-42-385, for detailed description of analysis of methodology, calculated concentrations, and air quality impact assessments.

#### 3.2.2.1 New Source Review (NSR)

The Clean Air Act requires that new major stationary sources of air pollution 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 (NSR) for compliance with NAAQS and PSD requirements.

NSR regulations require an estimate of a new or modified 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. Table 3.2-2 presents the potential to emit estimates for the Satsop CT Project.

**TABLE 3.2-2**
**MAXIMUM POTENTIAL TO EMIT ESTIMATES FOR CRITERIA POLLUTANTS FOUR PGUs, TWO AUXILIARY BOILERS, TWO DIESEL GENERATORS, AND TWO COOLING TOWERS[a][c]**

| Criteria 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 power generation unit, 2,500 hours for each auxiliary boiler, 8,760 hours for each cooling tower, and 500 hours for each diesel generator.
[b] TSP, $PM_{10}$, 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.

To demonstrate compliance with NAAQS and WAAQS requirements, the uncontrolled and controlled emissions of each air pollutant must be quantified for the source. These emissions are calculated for use in air dispersion models which will determine the proposed source's impact on the air quality in the region. Air quality impact assessments (AQIAs) are performed using dispersion modeling techniques in accordance with the EPA's *Guidelines on Air Quality Models* (USEPA 1986). The dispersion models chosen for this air quality analysis were the EPA's SCREEN3, ISC-PRIME, and AERMOD dispersion models. Particulate matter (TSP, $PM_{10}$, and $PM_{2.5}$), $NO_2$, CO, and $SO_2$ were modeled based on time intervals of regulatory concern. There are no background sources within the project's significant impact area; therefore only the Satsop CT Project's modeled concentrations were compared with applicable standards to evaluate the project's impact on ambient air quality. Further information on the models and analyses is presented in Section 6.1. Table 3.2-3 summarizes the results from the air quality modeling analysis. The technologies available for controlling these emissions are discussed in Section 6.1. All concentrations were below federal and state standards and increments for the listed criteria pollutants.

**TABLE 3.2-3**
**AIR QUALITY MODELING RESULTS**
**WAAQS AND NAAQS**

| Pollutant | Averaging Period | Maximum Ambient Impact Concentration ($\mu g/m^3$) | National Ambient Air Quality Standards ($\mu g/m^3$) Primary | National Ambient Air Quality Standards ($\mu g/m^3$) Secondary | Washington Ambient Air Quality Standards ($\mu g/m^3$) |
|---|---|---|---|---|---|
| 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(j) | 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.

### 3.2.2.2 New Source Performance Standards, Acid Rain Provisions, and BACT

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 $SO_2$ 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 $SO_2$ from certain classes of stationary gas turbines and represent the minimum level of control that is required.

**40 CFR Part 60 Subpart Da**

Subpart Da applies to electric utility steam generating units with heat input from fuel combustion greater than 250 million British thermal units per hour (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 fire only 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 $SO_2$ 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 $SO_2$ and $NO_x$. The proposed emission rates for each duct burner are 5.5 lb/hr for PM, 0.31 lb/hr for $SO_2$, and 44 lb/hr $NO_x$. All proposed emission rates are less than the NSPS limits.

**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:

$$STD = 0.0075 ((14.4)/y) + F$$

where

STD = allowable $NO_x$ emissions, percent by volume at 15 percent $O_2$ 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 power generation unit (PGU) is 2.5 ppmvd at 15 percent $O_2$. Consequently, the Satsop CT Project will comply with the $NO_x$ emission standard.

Subpart GG of 40 CFR Part 60.333(a) limits $SO_2$ emissions to 0.015 percent by volume at 15 percent $O_2$. This equates to 150 ppmvd and the Satsop CT Project is proposing 0.11 ppm. Consequently, the Satsop CT Project will comply with the $SO_2$ 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 $O_2$ monitors will be used to aid in controlling operations of the SCR and the CT dry low-$NO_x$ combustors.

**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 25 MW that 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 $NO_x$, $SO_2$, $O_2$, 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.

**Best Available Control Technology**

Ecology and OAPCA require that BACT be evaluated for the construction of a new source or modification of an existing source. Additionally, as the Satsop CT Project will be a modification to a major source, a BACT determination is required as part of the 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 emission rates, and demonstrating compliance with ambient air impacts and applicable regulations. The application of BACT must result in emissions which comply with the federal, state, and local ambient impact standards. Ecology and OAPCA recommend a "top-down" approach for BACT be used to determine BACT. 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.

#### 3.2.2.3 Toxic Air Pollutants

New sources of air toxics 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 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 (SQER) analysis is to be performed, and TAPs exceeding the SQER are then required to undergo air dispersion modeling (i.e., an acceptable source impact level [ASIL] analysis). In addition, if a TAP does not have a SQER, it must be modeled. Table 3.2-4 presents the estimated TAP emission rates for the Satsop CT Project and compares them to the SQER.

**Acceptable Source Impact Level (ASIL) Evaluation**

An ASIL analysis compares the maximum incremental ambient air impacts for each TAP from the new source with an ASIL. ASILs are compound-specific and are classified into two categories: 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, a second tier analysis is necessary. TAPs which were identified in Table 3.2-4 as requiring air dispersion modeling were modeled to estimate the maximum ambient impact. The results of these analyses are presented in Table 3.2-5. These data show that all TAP concentrations are below the Washington ASILs.

#### 3.2.2.4 Opacity

Washington regulations [WAC 174-400-040 (4)] specify that visible emissions of an air contaminant exceeding 20 percent opacity, for more than 3 minutes in any 1 hour, are prohibited. Project emissions will be significantly lower than 20 percent opacity restriction. Operation of the Satsop CT Project is not expected to cause fugitive dust emissions. However, emissions of regulated pollutants, including fugitive dust may occur from construction activities during the construction period. The primary sources of pollution will be vehicle exhaust and fugitive dust caused by equipment movement and excavation. Incremental vehicular emissions will occur as site workers commute to and from the construction site, but will not represent a significant increase in emissions. Excavation, trenching, backfilling, grading, and similar activities may generate dust during construction of the power plants, pipeline, transmission towers, and associated facilities. When these activities and similar activities are in progress, dry soil in the active construction area will be sprayed with water to minimize fugitive dust emissions. Construction impacts are for a limited term and are not expected to result in significant air quality impacts.

### 3.2.3 ODOR

Washington regulations [WAC 174-400-040 (4)] restrict odors from any source that may "unreasonably interfere with any property owner's use and enjoyment of his property." Good operating practice and procedures must be used to reduce odors as deemed reasonable. The only chemical to be used as part of the project operations that has an identified odor detection limit is anhydrous ammonia (detection limit = 17 ppm; Hesketh and Cross 1988.) Any concentrations of anhydrous ammonia resulting from project operations are expected to be well below the detection threshold at the site boundary and therefore not a potential impact on the surrounding environment.

## TABLE 3.2-4
## SMALL QUANTITY TOXIC AIR POLLUTANT EMISSION RATE COMPARISON

| 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 |
| 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 |
| Polyaromatic 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 $\mu g/m^3$ or TAP ASIL is not established.
(b) Dispersion modeling required if TAP emissions exceed SQER, TAP ASIL is < 0.001 $\mu g/m$
(c) Polyaromatic hydrocarbons (PAH) includes all TAPs labeled with * and chrysene.

**TABLE 3.2-5**
**TOXIC AIR POLLUTANT**
**ACCEPTABLE SOURCE IMPACT LEVEL COMPARISON**

| Pollutant | Class[a] | Maximum Ambient Impact Concentration ($\mu g/m^3$) | ASIL ($\mu g/m^3$) | 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

## 3.2.4 AIR-QUALITY-RELATED VALUES ASSESSMENT

PSD regulations require an assessment of the proposed Satsop CT Project's impact to air-quality-related values (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 for the Class I areas, the National Park Service, and U.S. Forest Service (USFS) have the responsibility of ensuring AQRVs in the Class I areas are not adversely affected.

### 3.2.4.1 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 federal land managers 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 Workgroup on Air Quality Modeling (IWAQM) and the Federal Land Managers Air Quality Related Values Workgroup (FLAG).

The 378-kilometer (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.

### 3.2.4.2 Model Results

**Class I Area Increment Consumption**

The effects of emissions from the proposed facility on Class I area increment consumption were assessed by comparing predicted pollutant concentrations to Class I modeling significance levels proposed by the EPA. Concentration predictions for $SO_2$, $NO_x$, and $PM_{10}$ 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 federal land managers for these Class II areas of interest.

Table 3.2-6 displays the highest predicted $SO_2$, $NO_x$, and $PM_{10}$ concentrations for the Class I areas, CRGNSA, and the Mt. Baker Wilderness. $PM_{10}$ concentrations include primary $PM_{10}$ 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 3.2-6
## CALPUFF CLASS I INCREMENT ANALYSIS RESULTS

| Area | Maximum Concentration Predictions ($\mu g/m^3$) | | | | | |
|---|---|---|---|---|---|---|
| | $NO_2$ | $SO_2$ | | | $PM_{10}$ | |
| | Annual | Annual | 24-hr | 3-hr | Annual | 24-hr |
| **Class I** | | | | | | |
| 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 $NO_2$. $PM_{10}$ 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 3.2-6 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 federal land managers have recommended significant impact levels that are more restrictive than those proposed by the EPA. The federal land manager-recommended levels are also presented in Table 3.2-6. All maximum predictions are lower than both the EPA and federal land managers 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 federal land managers 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 $SO_2$ concentrations not exceed 40 to 50 ppb (105 to 130 $\mu g/m^3$), and annual $SO_2$ concentrations should not exceed 8 to 12 ppb (21 to 31 $\mu g/m^3$). 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 $SO_2$ concentrations in the range of 5 to 15 parts per billion (ppb) (13 to 39 $\mu g/m^3$). The USFS also indicates that no significant amount of injury to plants species in the Pacific Northwest are expected for annual $NO_2$ concentrations less than 15 ppb (28 $\mu g/m^3$).

The 24-hour maximum and annual predictions displayed in Table 3.2-6 are several orders of magnitude less than USFS criteria established to protect vegetation in Pacific Northwest 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.

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. 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 $SO_2$ 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 3.2-7 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.

## TABLE 3.2-7
## CALPUFF ANNUAL DEPOSITION ANALYSIS RESULTS

| Area | 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** | | | | | | | | |
| 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 percent load operation with supplemental duct firing.
Nitrogen deposition includes ammonium ion.

### Regional Haze

The CALPUFF modeling system using the MM5 initialized wind fields were used to calculate 24-hour average extinction coefficients for each day of the year. 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 $PM_{10}$ fraction of the emissions, with hygroscopic aerosols becoming more important further downwind.

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.

The episodes affecting the Olympic National Park occur on a 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 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 3.2-8 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, $PM_{10}$, and to a lesser extent sulfates. Sulfates did contribute significantly to the extinction budget for the October 29-30, 1998, 2-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.

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 2 days in Olympic National Park and 1 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.

## TABLE 3.2-8
## CALPUFF REGIONAL HAZE ANALYSIS RESULTS

| | Maximum Change to 24-hour Background Extinction | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Bext (1/Mm) | | | Del Bext | | Bext by Component (1/Mm) | | |
| **Area** | **Date** | **SCTP** | **Back** | **Total** | **(%)** | **F(RH)** | **bx$SO_4$** | **bx$NO_3$** | **bxPMF** |
| **Class I** | | | | | | | | | |
| 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 percent).

### 3.2.5 CARBON DIOXIDE AND WATER VAPOR

#### 3.2.5.1 Carbon Dioxide

Carbon dioxide ($CO_2$) is a by-product of efficient combustion processes. It is also considered to be a factor in global warming. Deforestation, fossil-fueled power plants, and transportation are the primary sources of carbon dioxide emissions. Table 3.2-9 presents a compilation of carbon dioxide emitters in Washington State.

**TABLE 3.2-9**
**WASHINGTON STATE $CO_2$ EMISSION INVENTORIES FROM FOSSIL FUEL COMBUSTION (MMTCE)**

| | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|
| Commercial | 0.88 | 0.88 | 0.72 | 0.80 | 0.78 | 0.81 | 0.85 | 0.84 |
| Electric Utilities | 2.02 | 2.12 | 2.65 | 2.42 | 2.61 | 1.72 | 2.33 | 2.00 |
| Distillate Fuel | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| Bituminous Coal and Lignite | 2.01 | 2.11 | 2.56 | 2.34 | 2.57 | 1.62 | 2.22 | 1.95 |
| Residual Fuel | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Petroleum Coke | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Anthracite | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Natural Gas | 0.00 | 0.00 | 0.08 | 0.07 | 0.04 | 0.10 | 0.10 | 0.04 |
| Industrial | 4.76 | 4.41 | 5.10 | 4.70 | 5.23 | 5.27 | 5.43 | 5.24 |
| Residential | 1.00 | 1.05 | 0.93 | 1.05 | 1.05 | 1.06 | 1.20 | 1.19 |
| Transportation | 11.26 | 11.37 | 12.67 | 11.54 | 11.85 | 12.44 | 12.11 | 12.42 |
| TOTAL | 19.91 | 19.82 | 22.06 | 20.50 | 21.54 | 21.31 | 21.92 | 21.69 |

Source:

http://yosemite.epa.gov/globalwarming/ghg.nsf/emissions/CO2EmissionsBasedOnStateEnergyData?OpenDocument&Start=30&Count=30&Expand=48.2

Notes:

This table provides state carbon dioxide emission inventories from fossil fuel combustion that were developed by EPA, using (1) fuel consumption data from the DOE/EIA State Energy Data Report (SEDR) and (2) emission factors from Chapter 1 of the *Emissions Inventory Improvement Program, Volume VIII: Estimating Greenhouse Gas Emissions*. The inventories present annual emissions of CO2 by sector (e.g., industry, transportation, etc.) and by fuel type (e.g., distillate fuel, natural gas, etc.). State totals are reported in million metric tons of carbon equivalent (MMTCE).

These CO2 emissions were calculated using fuel consumption data from the Combined State Energy Data System (CSEDS). The most recently published data from the CSEDS can be found in *State Energy Data Report 1997* DOE/EIA-0214(97). The report and the spreadsheets containing the background fuel consumption data may be found on the Energy Information Administration’s Website.

The Satsop CT Project has the potential to emit carbon dioxide from the power generation units, auxiliary boilers, and backup diesel generators as follows:

- 2.2 million tons of $CO_2$ per year from each power generation unit (8,760 hours of operation with duct firing)

- 4,284 tons of $CO_2$ per year from each auxiliary boiler (2,500 hours of operation)

- 214 tons of $CO_2$ per year from each diesel generator (500 hours of operation)

#### 3.2.5.2 Water Vapor

The Satsop CT project will have several sources of water vapor emissions. These sources include:

- Moisture in the natural gas that is combusted, moisture in the aqueous ammonia that is used to control nitrogen oxides, and moisture in the combustion air. These sources of moisture result in water vapor that is emitted from the Heat Recovery Steam Generator (HRSG) stacks of the facility.

- Water vapor is emitted from the combustion of natural gas in the auxiliary boilers and emergency backup diesel generators.

- Water vapor is emitted from the cooling towers. While the cooling towers utilize drift eliminators to restrict drift droplets, a water vapor plume will be present at times. Typically the plume can range in size up to 40 to 50 meters in length.

The water vapor emitted through any of these sources poses no adverse impact to the environment, nor to human health.

Most water will be emitted when the plant is operated at full load with all duct burners fired. The emissions from the three sources listed above will be:

- HRSG exhaust stack: 238,000 lb/hr or 118 tons/hr

- Auxiliary boiler water vapor emissions: 3,100 lb/hr or 1.5 tons/hr

- Cooling tower water vapor emissions: 1,624,000 lb/hr or 812 tons/hr, and cooling tower drift droplets: 4,000 lb/hr

Minimal to no water vapor emissions are expected from the diesel generators as these are used only on an emergency basis (less than 500 hours per year each).

Some particulate matter will be emitted in the cooling tower drift droplets, at a rate of 1.03 lbs/hr per cooling tower (4.51 tons per year per cooling tower). These particulate emissions were included and analyzed in the permit application, and are included in the total particulate matter emissions reflected in the permit conditions.

### 3.2.6 DUST

Dust generated by construction activities will be short term. Dust from these activities will be controlled by applying gravel or paving to the access road. Water will be applied as necessary.

### 3.2.7 MITIGATION

The following mitigation measures will be employed:

- To control dust during construction, water will be applied as necessary, and access roads will be graveled or paved.

- To reduce air pollutant emissions from the PGUs, auxiliary boilers, backup diesel generators, and cooling towers, Best Available Control Technology will be utilized at the Satsop CT Project.

# 3.3
# Water (WAC 463-42-322)

**WAC 436-42-322 NATURAL ENVIRONMENT — WATER.**

*The applicant shall provide detailed descriptions of the affected natural water environment, project impacts and mitigation measures and shall demonstrate that facility construction and/or operational discharges will be compatible with and meet state water quality standards. The applicant shall indicate the source and the amount of water required during construction and operation of the plant and show that it is available for this use and describe all existing water rights, withdrawal authorizations, or restrictions which relate to the proposed source.*

*(1) Surface water movement/quality/quantity - The application shall set forth all background water quality data pertinent to the site, and hydrographic study data and analysis of the receiving waters within one-half mile of any proposed discharge location with regard to: Bottom configuration; minimum, average, and maximum water depths and velocities; water temperature and salinity profiles; anticipated effluent distribution and dilution, and plume characteristics under all discharge conditions; and other relevant characteristics which could influence the impact of any wastes discharged thereto.*

*(2) Runoff/absorption - The applicant shall describe how surface water runoff and erosion are to be controlled during construction and operation, how runoff can be reintroduced to the ground for retention to the ground water supply, and to assure compliance with state water quality standards.*

*(3) Floods - The applicant shall describe potential for flooding, identify the five, one hundred, and five hundred year flood boundaries, and all protective measures to prevent possible flood damage to the site and facility.*

*(4) Ground water movement/quantity/quality - The applicant shall include the results of a comprehensive hydrologic survey, describe the ground water conditions on and near the site and any changes in ground water movement, quantity, or quality which might result from project construction or operation.*

*(5) Public water supplies - The applicant shall provide a detailed description of any public water supplies which may be used or affected by the project during construction or operation of the facility.*

# 3.3 WATER
# (WAC 463-42-322)

## 3.3.1 EXISTING CONDITIONS

This section summarizes existing information on surface water and groundwater resources in the vicinity of the proposed plant site and describes the proposed water supply sources for the proposed project. This information is included in the following subsections:

- Subsection 3.3.1 Existing Conditions
- Subsection 3.3.2 Impacts
- Subsection 3.3.3 Mitigation Measures

### 3.3.1.1 Surface Water

The Satsop CT Project site is located in the lower Chehalis River Valley near Elma, Washington (Figure 3.3-1). The site is situated along the southern bank of the Chehalis River with Fuller Creek approximately 0.5 miles to the east and Workman Creek 2 miles to the east. Both Fuller and Workman creeks drain into the southern side of the Chehalis River. Fuller Creek's drainage basin faces northeast and covers approximately 2 square miles. The Workman Creek drainage basin, which drains into the Chehalis River east of the plant site, faces northeast and covers approximately 16 square miles. The Satsop River basin, approximately 2.5 miles from the site, faces south and covers an area of 299 square miles (PNRBC 1970). A small drainage basin between Workman Creek and Fuller Creek is drained by Purgatory Creek.

Mean annual precipitation near Satsop is approximately 70 inches (Western Regional Climate Center 2001). The Chehalis River system is principally fed by rainfall. Approximately 85 percent of the annual precipitation occurs between October and April, whereas water resource demand is greatest during July and August (WSDOE 1975). Annual precipitation quantities recorded at Elma, Washington, and at the Satsop site are listed in Table 3.3-1.

**Stream Flow**

In accordance with Chapter 173-522, Washington Administrative Code (WAC), and general rules of the Department of Ecology (Ecology), the base flows for the Satsop CT Project were established at monitoring station 12.0350.02, and are presented in Table 3.3-2. On those days not specifically identified in the table, Ecology plots a straight-line graph between the dates and flows shown in the table to determine base flow. This monitoring station, located at the outfall for the Satsop CT Project, has not been in operation since the early 1980's; however the USGS is in the process of re-establishing the station.

**TABLE 3.3-1**
**ANNUAL PRECIPITATION[a]**

| Year | Elma, Washington (inches) | Satsop Site (inches) |
|---|---|---|
| 2000 | 45.11 | 55.83 |
| 1999 | 86.33 | 95.68 |
| 1998 | 77.43 | 82.12 |
| 1997 | 93.24 | 92.63 |
| 1996 | 87.83 | 90.05 |
| 1995 | 75.23 | 79.38 |
| 1994 | 74.37 | 86.64 |
| 1993 | 48.12 | 55.11 |
| 1992 | 52.20 | 57.05 |
| 1991 | 75.03 | 70.65 |
| 1990 | 80.91 | 96.86 |
| 1989 | 57.60 | 64.49 |
| 1988 | 63.86 | 69.26 |
| 1987 | 53.12 | 59.32 |

[a] Data from NOAA 1987-2000; Energy Northwest 2001

In the meantime, Ecology estimates flow at this monitoring station by taking the flow in the Satsop River near Satsop and adding the flow of the Chehalis River as measured at Porter, approximately 10 miles upstream of the confluence of the Satsop, and a calculated flow for Cloquallem Creek based on historical data. Figures 3.3-2, 3.3-3, and 3.3-4 are Ecology's exceedance hydrographs for the Chehalis River at Porter, the Satsop River at Satsop, and Cloquallem Creek, respectively.

**TABLE 3.3-2**
**BASE FLOW FOR MONITORING STATION 12.0350.02**
**(CHEHALIS RIVER AT OUTFALL)**

| Month | Day | Base flow (cfs) | Month | Day | Base flow (cfs) |
|---|---|---|---|---|---|
| January | 1 | 3800 | July | 1 | 1085 |
| January | 15 | 3800 | July | 15 | 860 |
| February | 1 | 3800 | August | 1 | 680 |
| February | 15 | 3800 | August | 15 | 550 |
| March | 1 | 3800 | September | 1 | 550 |
| March | 15 | 3800 | September | 15 | 550 |
| April | 1 | 3800 | October | 1 | 640 |
| April | 15 | 3800 | October | 15 | 750 |
| May | 1 | 2910 | November | 1 | 1305 |
| May | 15 | 2300 | November | 15 | 2220 |
| June | 1 | 1750 | December | 1 | 3800 |
| June | 15 | 1360 | December | 15 | 3800 |

Source: Chapter 173-522, Washington Administrative Code

A review of the exceedance data shows that low flow conditions in the Chehalis River at Satsop typically occurs from July to September, but also may occur at any time of the year. Annual peak discharge typically occurs in November through March. This annual peak discharge is a result of winter storms, which produce excess rainfalls. During periods when flows are below the base flow requirement, some withdrawals may be restricted by Ecology. However, water rights issued prior to 1973 are not subject to flow restrictions.

**Water Quality in the Site Vicinity**

General water quality and flow data for the Chehalis River at the Porter station upstream from the site are presented in Table 3.3-3. This station is the closest station to the site to have analytical water quality testing for general chemistry parameters and study of water flow. Most of the parameters vary seasonally; concentrations of suspended solids, turbidity, and dissolved oxygen levels are highest during high flow events and lowest during low flow periods. Seasonal water temperature data for the Porter station are presented in Table 3.3-4. River water temperature ranged between 0.6°C on 1/8/73 to slightly greater than 24°C on 7/20/71. Average seasonal river water temperature ranged between 4.0°C to 22°C annually.

River water quality in the Chehalis River is considered Class A in the vicinity of the site (Chapter 173-201A WAC). Water quality of this class must meet requirements for many uses, including water supply, stock watering, fish and shellfish existence, wildlife habitat, recreation, commerce, and navigation. Water quality requirements for Class A waters include limits on fecal coliform organisms, dissolved oxygen, total dissolved gas, temperature, pH, toxic substances, and impacts to aesthetic values.

**TABLE 3.3-3**
**CHEHALIS RIVER WATER QUALITY DATA AND FLOW RATE**

| | 1997 | | | 1998 | | | 1999 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Mean | Range | n[(b)] | Mean | Range | n[(b)] | Mean | Range | n[(b)] |
| Flow (cfs) | 3593 | 450 - 9460 | 12 | 1970 | 439 - 6050 | 12 | 4406 | 344 - 14100 | 9 |
| Specific Conductivity (µmhos/cm) | 84 | 60 - 132 | 12 | 87.3 | 56 - 109 | 12 | 81 | 50 - 108 | 12 |
| pH (S.U.) | 7.4 | 6.9 - 7.9 | 12 | 7.5 | 7.0 – 7.7 | 12 | 7.3 | 7.0 - 7.6 | 12 |
| Temperature (°C) | 10.6 | 2.5 – 18.7 | 12 | 11.1 | 2.7 – 21.8 | 12 | 10.0 | 4.5 – 17.7 | 12 |
| Turbidity (NTU) | 6.8 | 1.9 - 19 | 12 | 7.5 | 1.3 - 23 | 12 | 9.7 | 1.3 - 32 | 11 |
| Dissolved Oxygen (mg/l) | 9.9 | 8.0 - 11.7 | 12 | 9.7 | 7.1 – 11.3 | 12 | 10.1 | 8.0 - 11.2 | 12 |
| Ammonia Nitrogen (mg/l) | 0.019 | 0.010 – 0.033 | 12 | 0.016 | 0.010 – 0.031 | 12 | 0.027 | 0.010 – 0.04 | 11 |
| Total Phosphorus (mg/l) | 0.062 | 0.039 – 0.104 | 12 | 0.043 | 0.016 – 0.08 | 12 | 0.056 | 0.036 – 0.101 | 11 |
| Total Suspended Solids (mg/l) | 10.6 | 4 - 28 | 12 | 13.1 | 3 - 44 | 12 | 19.6 | 3 - 77 | 11 |
| Nitrites and Nitrates (mg/l) | 0.6 | 0.4 - 0.8 | 12 | 0.7 | 0.4 – 1.4 | 12 | 0.6 | 0.4 – 0.8 | 11 |
| Fecal Coliform (colonies/100 ml) | 53 | 11 - 140 | 12 | 58 | 10 - 170 | 12 | 61 | 3 - 360 | 11 |

[(a)] Data are for Porter Station (Washington Department of Ecology)
[(b)] n = Total number of data values

## TABLE 3.3-4
## CHEHALIS RIVER TEMPERATURE DATA FROM PORTER STATION
## (USGS, 1970 - 1991)

| Date | Temperature (°C) | Date | Temperature (°C) |
|---|---|---|---|
| 10/5/70 | 14.0 | 7/5/72 | 21.0 |
| 10/20/70 | 10.5 | 7/17/72 | 21.0 |
| 11/5/70 | 7.0s | 7/31/72 | 21.0 |
| 11/20/70 | 7.0 | 8/14/72 | 17.8 |
| 12/5/70 | 5.0 | 9/5/72 | 18.4 |
| 12/20/70 | 9.5 | 9/18/72 | 15.0 |
| | | 10/3/72 | 12/6 |
| 1/5/71 | 3.0 | 10/16/72 | 10.2 |
| 1/20/71 | 5.5 | 10/30/72 | 6.2 |
| 2/5/71 | 5.5 | 11/13/72 | 7.2 |
| 2/20/71 | 4.5 | 11/27/72 | 5.8 |
| 3/5/71 | 4.5 | 12/19/72 | 6.4 |
| 3/20/71 | 8.5 | 12/26/72 | 7.6 |
| 4/5/71 | 11.0 | | |
| 4/20/71 | 10.0 | 1/8/73 | 0.6 |
| 5/5/71 | 13.5 | 1/22/73 | 4.5 |
| 5/20/71 | 13.0 | 2/5/73 | 4.4 |
| 6/5/71 | 17.0 | 2/20/73 | 5.4 |
| 6/20/71 | 15.0 | 3/5/73 | 7.7 |
| 7/5/71 | 15.5 | 3/19/73 | 6.2 |
| 7/20/71 | 24.0 | 4/2/73 | 7.7 |
| 8/5/71 | 22.0 | 4/16/73 | 11.5 |
| 8/20/71 | 20.0 | 5/17/73 | 8.2 |
| 95/71 | 15.5 | 5/14/73 | 16.6 |
| 9/20/71 | 15.0 | 6/5/73 | 16.7 |
| 10/4/71 | 13.5 | 6/18/73 | 15.5 |
| 10/26/71 | 9.0 | 7/10/73 | 18.7 |
| 11/2/71 | 6.3 | 7/23/73 | 17.5 |
| 11/29/71 | 8.0 | 8/13/73 | 19.6 |
| 12/6/71 | 5.9 | 8/27/73 | 15.4 |
| 12/20/71 | 5.8 | 9/10/73 | 17.5 |
| | | 9/24/73 | 14.6 |
| 1/3/72 | 3.8 | | |
| 1/7/72 | 5.5 | 10/15/74 | 13.2 |
| 2/1/72 | 2.2 | 10/28/74 | 10.3 |
| 2/14/72 | 5.6 | 10/30/74 | 10.2 |
| 3/6/72 | 6.7 | 11/12/74 | 9.9 |
| 3/20/72 | 8.7 | 11/18/74 | 9.2 |
| 3/28/72 | -- | 11/19/74 | 8.4 |
| 4/3/72 | 8.7 | 12/9/74 | 7.8 |
| 4/17/72 | 7.4 | 12/16/74 | 7.9 |
| 5/1/72 | 9.5 | 12/20/74 | 10.8 |
| 5/15/72 | 15.5 | | |
| 6/5/72 | 16.9 | | |
| 6/19/72 | 18.1 | | |

## TABLE 3.3-4 (Continued)
## CHEHALIS RIVER TEMPERATURE DATA FROM PORTER STATION
### (USGS, 1970 - 1991)

| Date | Temperature (°C) | Date | Temperature (°C) |
|---|---|---|---|
| 1/13/75 | 5.4 | 1/21/80 | 6.3 |
| 1/22/75 | 6.4 | 2/28/80 | 9.6 |
| 1/27/75 | 4.5 | 3/27/80 | 8.2 |
| 2/18/75 | 5.9 | 4/22/80 | 11.4 |
| 2/20/75 | 5.5 | 5/28/80 | 13.8 |
| 2/24/75 | 6.0 | 6/24/80 | 16.8 |
| 3/10/75 | 6.3 | 7/15/80 | 18.2 |
| 3/12/75 | 7.3 | 8/13/80 | 17.8 |
| 3/24/75 | 6.2 | | |
| 4/9/75 | 8.9 | 11/9/81 | 8.0 |
| 4/14/75 | 9.1 | | |
| 4/28/75 | 9.4 | 1/5/82 | 3.5 |
| 5/12/75 | 14.2 | 3/8/82 | 8.5 |
| 5/21/75 | 14.4 | 5/11/82 | 10.0 |
| 5/26/75 | 14.1 | 7/13/82 | 19.5 |
| 6/9/75 | 16.6 | 9/23/82 | 14.5 |
| 6/23/75 | 14.8 | 11/15/82 | 4.0 |
| 7/14/75 | 18.3 | | |
| 7/16/75 | 17.6 | 1/10/83 | 9.0 |
| 7/28/75 | 20.6 | 3/15/83 | 10.0 |
| 8/12/75 | 18.4 | 5/24/83 | 19.0 |
| 8/14/75 | 18.2 | 7/22/83 | 19.0 |
| 8/25/75 | 15.7 | 9/22/83 | 14.5 |
| 9/2/75 | 15.4 | 11/18/83 | 8.5 |
| 9/15/75 | 16.6 | | |
| 9/16/75 | 15.9 | 1/10/84 | 7.5 |
| | | 3/1/84 | 8.0 |
| 10/19/77 | 11.2 | 5/24/84 | 9.5 |
| 11/14/77 | 10.2 | 7/18/84 | 20.5 |
| | | 9/20/84 | 15.0 |
| 1/17/78 | 7.2 | 11/16/84 | 7.0 |
| 2/6/78 | 8.0 | | |
| 3/7/78 | 7.5 | 1/28/85 | 4.0 |
| 4/10/78 | 10.2 | 3/18/85 | 8.5 |
| 5/9/78 | 14.2 | 5/20/85 | 15.5 |
| 6/5/78 | 10.3 | 7/22/85 | 22.6 |
| 7/5/78 | 6.6 | 9/23/85 | 15.0 |
| 8/7/78 | 21.0 | 11/12/85 | 4.5 |
| | | | |
| 10/16/79 | 12.2 | | |
| 11/20/79 | 5.5 | | |
| 12/19/79 | 8.9 | | |
| 1/23/86 | 6.5 | 1/13/89 | 4.5 |
| 3/24/86 | 8.0 | 3/24/89 | 7.5 |
| 5/30/86 | 18.5 | 6/7/89 | 12.0 |

## TABLE 3.3-4 (Continued)
## CHEHALIS RIVER TEMPERATURE DATA FROM PORTER STATION
**(USGS, 1970 - 1991)**

| Date | Temperature (°C) | Date | Temperature (°C) |
|---|---|---|---|
| 7/22/86 | 19.0 | 7/18/89 | 18.0 |
| 9/23/86 | 13.0 | 9/20/89 | 10.5 |
| 11/18/86 | 7.0 | 11/30/89 | 6.5 |
| | | | |
| 1/27/87 | 6.0 | 4/4/90 | 11.0 |
| 3/25/87 | 8.5 | 5/24/90 | 10.5 |
| 5/6/87 | 14.5 | 7/25/90 | 17.5 |
| 7/8/87 | 17.0 | 8/20/90 | 20.5 |
| 9/10/87 | 18.0 | 12/12/90 | 6.5 |
| 11/18/87 | 4.5 | | |
| | | 1/23/91 | 4.0 |
| 1/28/88 | 6.0 | 3/21/91 | 8.0 |
| 3/30/88 | 7.5 | 6/6/91 | 13.0 |
| 5/25/88 | 14.0 | 7/18/91 | 17.0 |
| 7/21/88 | 20.5 | 9/19/91 | 17.5 |
| 9/27/88 | 12.5 | | |
| 11/17/88 | 7.5 | | |

### 3.3.1.2 Groundwater

**Groundwater Occurrence**

Significant groundwater aquifers in the plant site vicinity occur in the alluvial valleys of the Chehalis, Satsop and tributary rivers and in smaller perched aquifers in the marginal terrace deposits. Little useable water occurs in the underlying Tertiary bedrock (WPPSS 1982). The alluvial deposits are approximately 100 feet thick north of the site vicinity, and extend to depths of as much as 200 feet in the lower Chehalis River valley (See Figure 3.3-5). The alluvial aquifer under the Satsop Power Plant property consists of alluvial sediments including sand, gravel, and silt and is confined by a thin layer of silt flood deposits, approximately 11 feet thick. Groundwater flow in the alluvial aquifer is likely to generally parallel the flow the Chehalis River, toward the west. During periods of low river flow, the flow direction in the aquifer would likely be skewed toward the river, where it would discharge; during high river flow periods, flow direction would be skewed toward the valley walls due to aquifer recharge from the river. According to aquifer tests performed prior to installation of the Ranney collector system, the gradient of the potentiometric surface is estimated to be approximately 15 foot per mile in a down-valley direction, (WPPSS 1974). The alluvial aquifer extends north approximately 2 miles across the Chehalis River Valley, about 14 miles downstream to Grays Harbor, and about 15 miles upstream to the eastern limit of Grays Harbor County. The northern, southern, and basal boundaries of the alluvial aquifer are formed by a Tertiary sandstone formation that occurs at the southern portion of the site, and contains little groundwater.

Groundwater depths in the alluvium may range from near-surface in slough and wetland areas to greater than 20 feet below ground surface. Reported groundwater withdrawal rates from wells in the eastern Grays Harbor County area range from 5 gallons per minute (gpm) for domestic supplies to over 900 gpm for irrigation purposes (WSDOE 2001). Wells screened at depths of less than 100 feet typically yield lower quantities whereas those screened below 100 feet potentially yield up to 3,000 gpm. The interconnection between shallow and deep groundwater in the alluvial aquifer and surface water sources such as the Chehalis River is known to be high. Groundwater wells screened in the alluvium typically draw upon both groundwater and surface water sources. Recharge to the alluvial aquifer is from direct precipitation as well as from surface water sources (e.g., Chehalis River).

As a part of investigations related to the nuclear projects, a pumping test of the aquifer was performed in anticipation of installing the Ranney wells in alluvial deposits at the confluence of the Satsop and Chehalis Rivers (current raw water well location). Test results indicated that average transmissivity of the aquifer is 1,242,000 gallons per day per foot (gpd/ft) and the aquifer is hydraulically connected with the Satsop River (WPPSS 1974). Pumping tests after the Ranney wells' installation in 1980 yielded an aquifer transmissivity of approximately 560,000 gpd/foot. Natural groundwater flow conditions are governed by the transmissivity and gradient of the aquifer. Based on the pumping test data from the Ranney collector system, the calculated natural underflow in the alluvial aquifer is approximately 8 to 18 million gallons per day per one mile of aquifer width. More accurate calculation of this value is difficult due to the Ranney wells' interaction with both the aquifer and surface water systems and limitations in separating the ground and surface water components of the flow.

Smaller, discontinuous perched aquifers, which occur in the unconsolidated terrace deposits on Satsop CT Project and Satsop Development Park property, lie above the alluvial valley (WPPSS 1982). The groundwater level in the terrace deposits beneath the property varies from 15 to 50 feet below ground surface. The flow of water through the perched aquifers is locally controlled by topography. Flow will likely tend toward the Chehalis river valley, where it will join the regional groundwater system (See Figure 3.3-5). Recharge to the terrace deposits is by direct infiltration.

Limited groundwater quality analyses for samples taken at the Ranney collector system are included as part of Appendix B. A comparison between groundwater and surface water quality is discussed below.

### Groundwater Wells in the Site Vicinity

There are no groundwater wells on the Satsop CT property. Groundwater wells on Satsop Development Park property include a groundwater collection system referred to as the Ranney collector system (makeup water well), the raw (potable and construction) water well, and a small domestic well. Other domestic wells occur in the area (within several miles of the site), and are generally located to the west of the site or on the north side of the river. Three domestic wells are known to be screened in the terrace deposits.

The Ranney wells consist of two vertically placed caissons which penetrate beneath the Chehalis River bed within the alluvial gravel beneath the river. The caissons are connected to a tier of horizontal collector laterals that extend in a radial pattern from the caisson (see Appendix B Figures 2.4-40 and 2.4-41. Each caisson potentially yields 26 million gallons per day (mgd) (40 cfs) (WPPSS 1984). Pump tests completed in the collector system indicate the wells draw surface water from the Chehalis River as well as groundwater in the alluvium. It was determined that the Ranney wells derive up to 88 percent of their supply from the Chehalis River via infiltration, with the remaining 12 percent drawn from the surrounding alluvial aquifer (WPPSS 1982). Drawdown effects resultant from pumping 20,833 gpm were estimated to lower water levels in surrounding farm and irrigation wells 1 to 2.5 feet. Withdrawals for Phase I and Phase II (4,264 gpm each, or a total of 8,528 gpm for both phases) will be substantially less than those projected for the nuclear plants, and therefore the impact to surrounding farm and irrigation wells is expected to be negligible.

3.3.1.3 Comparison Between Surface and Groundwater Quality

WPPSS initiated a 1-year sampling program (November 1980 to October 1981) to determine metal concentrations in the Chehalis River at an intake area, a discharge area, at the South Elma Bridge area, and at a well at the plant intake area (Well APW) (Envirosphere 1982). Water quality data provided by WPPSS are available for the Chehalis River, the Ranney collector system (Ranney wells, also referred to as Wells #1 and #3, Makeup Well, and Well APW), the raw water well, and regional groundwater wells. Analytical findings are presented in Appendix B. Descriptions and comparisons of surface and groundwater quality as identified by the 1-year sampling program are provided below according to water quality categories.

**Metals**

Metal concentrations in Well APW were very low for the majority of measured constituents (barium, cadmium, chromium, copper, iron, lead, manganese, mercury, nickel, selenium, and zinc) except calcium, magnesium, potassium, and sodium (Envirosphere 1982). Metal concentrations in the Chehalis River were low except for iron and mercury. Total and dissolved metal concentrations in Well APW were generally similar, with the exception of iron which showed higher total concentration compared to dissolved. The higher total concentration likely represents particulate iron or iron associated with sediment that would settle out in the cooling tower basin prior to use at the facility. In river water, total metal concentrations were often greater than dissolved concentrations. Generally, metal concentrations were lower in groundwater than surface water, except for concentrations of calcium, magnesium, potassium, and sodium which were somewhat higher in groundwater than surface water. Metals concentrations in the Chehalis River did not appear affected by streamflow rates or turbidity levels and groundwater quality did not appear to be affected seasonally.

**Hardness**

Average hardness levels at Porter ranged between 24.3 to 31 milligrams per liter (mg/l) as $CaCO_3$ whereas in groundwater, maximum hardness levels were measured at 92 mg/l as $CaCO_3$ (groundwater well number 17/7-7P1). Hardness levels in the Ranney wells (Wells #1 and #3) were 32 and 77 mg/l as $CaCO_3$, respectively.

**Conductivity**

Average values of specific conductance in the Chehalis River at Porter ranged from 77 to 96.6 micromhos per centimeter (umho/cm) whereas groundwater concentrations ranged from nondetectable levels to 140 umho/cm in the raw water well and from 112 to 225 umho/cm in the domestic well. Conductivity levels in the Ranney wells ranged from 110 to 160 umhos/cm.

**Nitrate/Nitrite**

Nitrate/nitrite concentrations in groundwater and surface water sources in the site vicinity were generally less than 1 mg/l. Detectable nitrate in both Well #1 and #3 was 0.9 mg/l, whereas nitrate/nitrite levels in the Chehalis River at Porter ranged from 0.50 to 0.68 mg/l, as reported by Envirosphere (1982).

**Turbidity**

Chehalis River at Porter had relatively low turbidity levels. Average turbidity levels ranged from 1.9 to 10 nephelometric turbidity units (NTU) whereas levels in the domestic well ranged from 1.2 to 46 NTU. The turbidity level in Well #1 (Ranney well) was 1 NTU (sampled September 13, 1993).

**pH**

Groundwater pH was slightly higher than in the river. Average pH in Well APW was 7.2, whereas average pH in the Chehalis River ranged from 7.0 to 7.1 (Envirosphere 1982).

**Temperature**

Water temperature data (Envirosphere 1982) for the Ranney wells collected during the period November 1980 to October 1981 (49 samples total) are summarized below:

- mean temperature = 10.6 °C (51°F)
- range = 10.4 - 10.8 °C (50 to 51.4°F)

Groundwater temperatures were relatively constant, whereas surface water temperatures fluctuated seasonally. Water temperatures in the Ranney wells were similar to the mean water temperature in the Chehalis River (Table 3.3-6). The difference between the high and low temperatures in the wells was less than in the Chehalis River. Changes in water temperature in the wells apparently lags approximately 2 months behind river water temperature (personal communication, Laura Schinnell 1994) and the high and low temperatures are significantly attenuated in magnitude. The difference in temperature is probably due to the lag time and thermal storage within the aquifer beneath the river.

#### 3.3.1.4 Existing Water Appropriations

Existing surface water right appropriations in the Chehalis Basin include water for domestic, municipal, irrigation/agricultural, power, commercial, and fish propagation purposes. Critical periods for potential impacts of water withdrawals to the environment and to existing surface water rights occur during low flow periods, typically from July through October.

A water right provides legal authorization to use a certain amount of surface water or groundwater for specific beneficial purposes. Diversion of surface or groundwater requires a water right except for minimal diversions. The proposed water use must satisfy statutory requirements in order for Ecology to issue a water right permit. Statutes require beneficial use of the water, the use must not cause impairment of existing rights, there must be water available for appropriation, and issuance of the water right must not be deemed detrimental to the public's interest.

A review of current surface and groundwater appropriations filed with Ecology indicates that industry is the largest appropriator in the basin (42 percent of the total consumptive use appropriations) followed by municipal (44 percent), irrigation (1.2 percent), and domestic use (1.1 percent). Municipal supply uses both surface and groundwater resources. In-stream flows are necessary to maintain anadromous fish populations which attract sport and commercial fishing interests. In-stream flow appropriations are also pursued for subsistence fishing and aesthetic concerns.

Ecology has established a water resources program for the Chehalis River basin in order to establish base flow, provide protection for future allocations, establish a priority scheme for future rights during water shortage periods, and identify streams closed to further consumptive appropriations (WAC 173-522). No streams in the near-site vicinity are closed to appropriations. Base flow requirements for the Chehalis River below the confluence with the Satsop River (Station Number 12.0350.02) have been developed by Ecology for maintenance of instream flows (See Table 3.3-2).

The Chehalis River basin is divided into two Water Resources Inventory Areas (WRIA) which divide the drainage area into an upper basin (WRIA-23) and lower basin (WRIA-22). The site is located in the upper portion of the lower basin. Specific water resource management goals are assigned to each separate WRIA including base flow regulations. Base flows are in-stream flow limits which allow “preservation of wildlife, fish, scenic, aesthetic, and other environmental values, and navigational values” (WSDOE 1975). While existing water right permits are not affected by base flow restrictions, future water right permits and certificates will not allow appropriation of surface water from the Chehalis River and its tributaries below the base flow levels specified by regulation. In addition, future groundwater appropriations will be affected by base flow provisions if the groundwater in question is determined to be in hydraulic continuity with the affected stream section.

Several surface water and groundwater users have been identified in the area of the Ranney wells. The intended use for is for domestic, stockwater, and irrigation purposes. Ecology's listing of water right permits for the Ranney well area include withdrawal quantities ranging from 300 gpm to 800 gpm.

## 3.3.2 IMPACTS

This section addresses potential impacts to surface water and groundwater due to construction and operation of the Phase II project. Surface water runoff controls during operation are presented below and in the approved Erosion Control Plan.

### 3.3.2.1 Surface Water

Runoff from the site will be routed to the C-1 erosion control pond, located on Satsop Development Park property to the west of the site. The C-1 pond is designed and maintained to store runoff from the 100-year rainfall event. If necessary, surface water runoff from the site can be pumped through a series of ditches and culverts to the Satsop Development Park's existing Equalization Pond. This pond would provide additional storage capacity during construction if surface water runoff is unusually high. As a result of implementation of this plan, surface water impacts due to construction of the plant will be temporary and minor.

### 3.3.2.2 Groundwater

The Phase II project is situated on terrace deposits with smaller, discontinuous perched aquifers which may contribute little recharge to adjacent surface water bodies. In addition, the gravel fill currently on the site is underlain by a liner which restricts water infiltration. As a result, plant construction will not have a significant impact on groundwater resources.

### 3.3.2.3 Impacts of Process Water Withdrawal

**Process Water Supply**

Process water will be supplied from the existing Ranney wells and transported through the existing make-up water line to the Satsop Development Park (see Figure 3.3-6). The make-up water line was originally designed and constructed for the nuclear plants, and is capable of carrying 80 cfs of water. Phase I is authorized to use 9.5 cfs from the Ranney wells, and the Grays Harbor Public Development Authority (PDA) has a permitted water right to withdraw an additional 20 cfs from the Ranney wells. The Certificate Holder is proposing to use 9.5 cfs of the PDA's permitted water right and has negotiated an agreement with the PDA to purchase this water. Therefore, the capacity of the Ranney wells and make-up water line are more than sufficient for the permitted uses. In the vicinity of WNP-5, water for the Satsop CT Project (both phases) will be diverted to the existing blowdown line, which will carry the water to the Satsop CT site, where a valve will allow diversion of the water to Phase II.

The estimated maximum instantaneous water requirement for Phase II is 9.5 cfs (4,264 gpm). This maximum includes process water and water to cool the temperature of the discharge to a temperature below that specified in the existing NPDES permit. However, the amount of process water used by Phase II annually will average 3,901 gpm with full duct firing and the chiller on. The lowest anticipated process water use is 2,543 gpm, which assumes typical summer conditions with no duct firing and the chillers off.

The Ranney wells are located on the southern bank of the Chehalis River, approximately 4 miles downriver of the plant site near the river's confluence with Elizabeth Creek. The wells penetrate to a depth of approximately 120 feet into the alluvial aquifer associated with the Chehalis River. The estimated radius of groundwater influence for the Ranney wells is 2,000 feet after 30 days of pumping. Ecology well records do not show groundwater wells within 2,000 feet of either Ranney well. However, if a groundwater well screened in the alluvial deposits were within 2,000 feet of the Ranney wells, it would experience some drawdown in water level due to the pumping at the Ranney wells. Because Phase II is intended to operate using an existing permitted water right, Phase II will not draw additional ground water from the alluvial aquifer system. Therefore, change to the local and regional water levels due to pumping is not expected.

### 3.3.2.4 Potable Water Supply Withdrawal

**Potable Water Supply**

Water for potable uses at the Satsop CT Project site will be supplied by the Satsop Development Park's raw water well. The raw water well is located at the confluence of the Satsop and Chehalis Rivers. The PDA chlorinates the water prior to use. The raw water well extends to a depth of 80 feet in the shallow sand and gravel aquifer in the area extending north of the Chehalis River and east of the Satsop River. The PDA presently withdraws water from their raw water well at a rate of 300 gpm on an as-needed basis. The maximum anticipated demand for water from this source for Phase I and Phase II is expected to be 100 gpm, and the average use will be less than 40 gpm.

Due to the low potable water requirements for the project, withdrawals for potable uses are not expected to impact surface water or groundwater availability. A WPPSS study of the affected aquifer concluded that the aquifer could produce approximately 21,000 gpm with minimal reduction in streamflow in the Satsop River during low flow periods and a slight drop in water levels in wells within the pumping range of influence (WPPSS 1974a).

### 3.3.2.5 Process Water Discharge

**Discharge Summary**

The proposed Satsop CT Project has been designed to minimize wastewater discharges. The design for each Phase includes waste streams that will be treated as necessary and co-mingled prior to discharge. These waste streams consist of cooling tower blowdown and oil/water-separator decant. The co-mingled waste streams from each Phase will be discharged to the Satsop Development Park's blowdown line in accordance with the NPDES permit (Permit No. WA-002496-1; see Section 2.8.2) for the Satsop CT Project. As shown on Figure 3.3-6, the outfall discharges to the Chehalis River. Figures 3.3-7, 3.3-8, 3.3-9 illustrate maximum, minimum, and average daily composition of waste streams. This combined waste stream will be discharged to the blowdown line (see Figure 3.3-6) in accordance with the existing NPDES permit (Permit No. WA-002496-1). The NPDES permit will be modified to allow the additional discharge from Phase II. For each Phase, discharge of process water to the river will be at a maximum rate of approximately 640 gpm when operating with duct firing and the chillers on.

The temperature of the cooling tower blowdown at the point of discharge from the Satsop CT Project to the blowdown line will be below the limit of 18$^{o}$C, the temperature limitation in the existing NPDES Permit, as required by the Site Certification Agreement.

Based on preliminary water balances for the project with both Phases operating, evaporative losses and other flow reduction losses from the combustion turbine process range from 2,104 to 3,230 gpm for each plant.

The impact analysis presented below regarding process water discharges includes an assessment of impacts in relation to regulatory guidelines for operation and the NPDES permit. In addition to the discharge requirements of the NPDES permit, each phase of the CT Project must comply with the state's nondegradation standards specific to Class A water bodies and state standards for discharges of toxic substances. These later standards specify maximum acute and chronic levels permitted.

Concerns regarding water quality of the Chehalis River are most pronounced during the dry season, particularly the months of July, August, and September, when on average, the lowest flows in the river occur. During low-flow periods, instream flows are the most critical because of water appropriations from the river for irrigation (although most appropriations are upstream of the discharge point) and to maintain habitat for migrating anadromous fish as well as for resident aquatic species. In addition, due to the lower flows during the dry months, potential water quality impacts can be greater because of less attenuation in the river.

Habitat conditions in the Chehalis River are sensitive to regulated water quality parameters which may exhibit acute or chronic toxicity to aquatic species. The habitat, particularly with regard to migrating anadromous fish, is also sensitive to water temperature. In general, the cooler the water temperature, the better the habitat conditions. The Total Maximum Daily Load (TMDL) study for the Chehalis River, prepared in 1994 by Ecology, provides baseline information on current water quality problems in the river (WDOE 1994). The TMDL study includes recommendations that address problems relating to flow, temperature, dissolved oxygen, fecal coliform, and other compounds.

**Wastewater Analyses**

Wastewater modeling and analyses were conducted to determine the expected concentration of constituents of the discharge from the Satsop CT Project and to evaluate potential impacts to the receiving water (Chehalis River) from the Satsop CT Project process water discharge. Discharges to the river were evaluated in comparison to the water quality criteria specified in WAC 173-201A (Water Quality Standards for Surface Waters of the State of Washington). The discharges for Phase II would be the same.

Two approaches were used to evaluate impacts to the river. The first approach used a simple mixing equation applied to 25 percent of the flow rate, assuming the base low flow in the Chehalis River of 550 cfs, and a 7-day, 10-year low flow of 416 cfs. This flow rate includes the low flow from the Satsop River Station at Satsop and the Chehalis River Station at Porter to estimate low flows in the vicinity of the outfall, which is downstream of the confluence of the two rivers. The results of these calculations, along with discharge characteristics, are presented in Table 3.3-5.

The second approach applied a plume model to the discharge using the existing diffuser designed for the nuclear plants. This approach enabled evaluation of mixing and resultant concentrations of water quality parameters of concern (identified in the initial approach) within a specified mixing zone.

The following sections present the methods used in the mixing analysis and the methods used in the plume model analysis.

<u>Mixing Equation Analysis</u>

Concentrations of selected water quality parameters which would occur after mixing the discharge water with Chehalis River water were calculated. Constituents of the influent process water (concentrations of chemical constituents of Ranney well water), receiving water concentrations (Chehalis River water concentrations), discharge concentrations (concentrations in water to be discharged from the plants), and resultant water quality concentrations are presented in Table 3.3-5. Water quality data are provided in Appendix B.

Table 3.3-5 also presents acute and chronic criteria for toxic substances introduced above background levels into state waters (WAC 173-201A, Water Quality Standards for Surface Waters of the State of Washington). Assumptions made to calculate acute and chronic concentrations were as follows: (1) a river water hardness concentration of 29 mg/l, (2) a

**TABLE 3.3-5**
**WATER QUALITY STANDARDS AND ANALYSES**

| Parameters | WAC 173-201A Standards[a] Acute Criteria (mg/L) | WAC 173-201A Standards[a] Chronic Criteria (mg/L) | NPDES[b] Permit | Influent Concentration (Ranney Wells) (mg/L) | Chehalis River Concentration[c] 550 cfs (mg/L) | CT Project Discharge Concentration[d] (mg/L) | Receiving Water Concentration Minimum Flow Concentration[e] (mg/L) | Receiving Water Concentration Low Flow Concentration[f] (mg/L) | Plume Analysis Results (mg/L) |
|---|---|---|---|---|---|---|---|---|---|
| Arsenic | 0.36 | 0.19 | NA | 0.0025[g,h] | 0.0005[g] | 0.016 | 0.00066 | 0.00071 | 0.001751 |
| Cadmium | 0.00084 | 0.00037 | NA | 0.00005[g,i] | 0.00005[g] | 0.00032 | 0.00005 | 0.00005 | 3.5E-05 |
| Chromium$^{+3}$ | 0.63 | 0.075 | 0.1[j] | 0.0005[i] | 0.0006 | 0.00635 | 0.00066 | 0.00068 | 0.000695 |
| Copper | 0.00476 | 0.00354 | 0.03 | 0.0005[g,i] | 0.0005 | 0.00635 | 0.00056 | 0.00058 | 0.000695 |
| Iron | NA | NA | 1 | 0.008[i] | 0.107 | 0.1016 | 0.10694 | 0.10693 | 0.011121 |
| Mercury | 0.0024 | 0.000012 | NA | 0.0001[g,i] | 0.0004 | 0.00064 | 0.00040 | 0.00040 | 7.01E-05 |
| Nickel | 0.473 | 0.052 | 0.065 | 0.0005[g,i] | 0.0005[g] | 0.00635 | 0.00056 | 0.00058 | 0.000695 |
| Lead | 0.0116 | 0.00045 | NA | 0.00005[g,i] | 0.0005[g] | 0.00032 | 0.00050 | 0.00050 | 3.5E-05 |
| Selenium | 0.02 | 0.005 | NA | 0.001[g,i] | 0.001[g] | 0.0064 | 0.00106 | 0.00107 | 0.000701 |
| Temperature (°F) | NA | 64.4 | 68 | 51[i] | 52.3 | 68[k] | 52.5 | 52.5 | NA |
| Zinc | 0.0365 | 0.0331 | 0.0025 | 0.0025[g,i] | 0.0025[g] | 0.03175 | 0.00280 | 0.00290 | 0.003475 |

(a) Acute: In general, refers to a 1-hour average concentration not to be exceeded more than once every three years on the average.
Chronic: In general, refers to a 4-hour average concentration not to be exceeded more than once every three years on the average.
(b) NPDES permit (effluent limitations, recalculating cooling water blowdown).
(c) Chehalis River at intake area (Envirosphere, 1982)
(d) For constituents stipulated in the NPDES permit only, CT Project discharge concentration - assume 12.7 increase at point of discharge into blowdown line. CT Project discharge of 1.43 cfs (640 gpm) based on preliminary water balance assumptions.
For constituents not stipulated in the NPDES permit, a concentration factor of 6.4 was used.
(e) Receiving water minimum flow rate is the minimum base flow rate specified by WAC 173-522-020 in Chehalis River at Satsop

$$\text{Receiving water concentration} = \frac{\text{(CT Project Discharge x 1.43 cfs) + (river concentration x 550/4 cfs)}}{\text{1.43 cfs + 550/4 cfs}}$$

(f) Receiving water low flow rate is the combined 7-day 10-year low flow in Chehalis River at Porter and Satsop River at Satsop (416 cfs).

$$\text{Receiving water concentration} = \frac{\text{(CT Project Discharge x 1.43 cfs) + (river concentration x 416/4 cfs)}}{\text{1.43 cfs + 416/4 cfs}}$$

(g) -Based on estimated values calculated to equal 1/2 non-detectable analytical limit.
(h) -Ranney Well water data (WPPSS).
(i) -Well APW (5 Nov, 1980 - 29 Oct 1981) mean annual dissolved concentration (all ND = 1/2 detection limit)(Evirosphere, 1982)
(j) -NPDES permit limitation for chromium.
(k) -The temperature at the point of discharge will be maintained at or below 18°C (68°F) by the addition of quench water, as required by the existing NPDES permit which states the following:
"The discharge temperature shall be such that the applicable Water Quality Standards for temperature shall be complied with at the edge of the dilution zone. Temperature shall not exceed 18.0 degrees Centigrade. The temperature increases shall not, at any time, exceed t=28/(T+7), as described in WAC 173-201A-030 for Class A waters. For purposes hereof, "t" represents the maximum permissible temperature increase measured at a mixing zone boundary and "T" represents the background temperature as measured at a point unaffected by the discharge and representative of the highest water temperature in the vicinity of the discharge. When natural conditions exceed 18.0 degrees Centigrade, no temperature increase will be allowed which will raise the receiving water temperature by greater than 0.3 degrees Centigrade."

temperature of 11.3°C, and (3) a pH level of 7.0, which are average annual levels for these parameters measured weekly by Envirosphere (1982) at the Chehalis River "intake" area. If natural levels of a toxic compound in the receiving stream exceed the criteria, the natural level serves as the standard.

Water quality data for Well APW (part of the Ranney well collector system) were assumed to represent influent water quality. Metal constituents and other water quality parameters were measured weekly by Envirosphere (1982) in Well APW. For chemical constituents not measured in Well APW, the analytical data from Ranney well sampling conducted by the WPPSS were used. Concentrations of selected constituents in the receiving water (Chehalis River) were assumed to be those concentrations measured at the "intake" area in the Chehalis River (Envirosphere 1982).

Preliminary water estimates for process water include an inflow of 2,543 gpm to 4,118 gpm and an outflow rate of 426 to 640 gpm. Using the maximum summer conditions with inflow of 4,118 gpm and outflow of 640 gpm, and dividing influent flow by outflow and assuming no loss of naturally occurring chemical constituents through scaling or other means, the naturally occurring chemical constituent concentration of the outflow was estimated to be approximately 6.4 times greater than that of the inflow.

To calculate the concentration factor for the discharge from Phase II to the blowdown line, the cycles of operation (6.25) in the cooling tower is added to the concentration factor of the naturally occurring chemical constituent concentration. At the point of discharge to the blowdown line, the concentration factor is therefore 12.7.

The 6.4 concentration factor was used in the analysis to estimate the resultant concentrations of regulated inorganic constituents (including trace metals) discharged to the river. The 12.7 factor was used to estimate constituent concentrations regulated by the NPDES permit at the point of discharge to the blowdown line. As required by WAC 173-201A-100, the mixing analysis assumed the flowrate in the receiving water was 25 percent of the 550 cfs (247,000 gpm) minimum base flow in the Chehalis River. Similarly, receiving water concentrations during a low-flow event in the Chehalis River were estimated using 25 percent of the 7-day, 10-year low flow rate of 416 cfs (187,000 gpm) in the Chehalis River below the confluence of the Satsop River, where the existing discharge is located. This mixing analysis did not consider dimensions of the mixing zone.

Resultant constituent concentrations in the Chehalis River (at the point of discharge) after mixing with effluent from the project were calculated using the mixing equation below:

$$[C] = \frac{[C_R]\ x\ Q_R + [C_D]\ x\ Q_D}{Q_R + Q_D} \qquad (1)$$

where,

$C$ = resultant concentration in the river after mixing
$C_R$ = concentration in receiving water (river)
$C_D$ = concentration in discharge
$Q_R$ = flow in receiving water
$Q_D$ = flow in discharge

Values for each variable are presented in Table 3.3-5.

Plume Model Analysis

A plume model was used to evaluate the efficiency of mixing and dilution within a specified mixing zone. This model used the diffuser dimensions of the existing WNP-3 outfall structure and river data previously described.

Average annual discharge in the Chehalis River at a point 2.2 miles downstream of its confluence with the Satsop River was 5,109 cfs (2,293,000 gpm) from 1980 to 1982. The anticipated discharge amount for the project will add minimally to the streamflow quantity in the Chehalis River and will not measurably affect average streamflow rates. During low flow periods, streamflow in the Chehalis River may be minimally supplemented by discharge from the project. Mean low flows in the Chehalis River downstream of the Satsop River for 1-, 7-, 30-, 60-, and 90-day return periods range from 538 to 805 cfs (241,500 gpm to 361,300 gpm). Maximum estimated discharge from Phase II will increase low flows in the Chehalis River by approximately 0.27 percent.

The diffuser at the outfall in the Chehalis River (see Figure 3.3-1 for the proposed discharge location) is designed with a 30-foot diffusion manifold with 46, 2-inch ports on risers spaced every 8 inches. An estimate was made of the dispersion capabilities of this diffuser arrangement by modeling the turbulent mixing capability of the Chehalis River at the location of the diffuser. This type of analysis is preferable to the more commonly used plume modeling method because of the relatively shallow depth of the diffuser. In this case, the turbulent characteristics of the river dominate the mixing process.

Using a transverse mixing coefficient developed by Fischer (1979), the dilution factor was estimated at a point 100 feet downstream of the diffuser. This location represents the regulatory limits for the mixing zone as defined in the existing NPDES permit. The regulation also requires that the dilution meet the regulated standard at a point not to exceed 25 percent of the river width transversely. The dilution calculation depended on certain assumptions concerning the river morphology in this area. Specifically, it was assumed that the depth, average velocity, bottom slope, and width of the river were constant over the 100-foot zone. In addition, it was assumed that the diffuser acted as a point source. These assumptions are conservative in nature due to the added turbulence typical of changing river morphology and the dispersed discharge of the existing diffuser. Both of these characteristics tend to increase mixing potential.

**Regulatory Compliance**

As shown in Table 3.3-5, at the point of the Satsop CT Project's discharge, the dissolved chemical constituents are below the concentrations in the permit. Chemical parameters presented in Table 3.3-10 address WAC 173-201A and NPDES chemical parameter monitoring requirements that govern the facility application for discharge to the Chehalis River. The eleven water quality parameters contained in Table 3.3-10 are those that will be present in the discharge and which are regulated by WAC 173-201A and/or the NPDES permit. Other regulated parameters will either be controlled by the facility prior to discharge, including temperature control by flow augmentation and pH adjustment, or will not be affected by the Satsop CT Project operation. The water discharge temperature will be maintained below 18°C at the point of discharge to the river.

The NPDES permit does not specify limits for many elements that are present in the Ranney well water and which will be concentrated due to evaporation during operation of the Satsop CT Project. All constituents not specified in the NPDES permit must be compared to the state's acute and chronic criteria levels. However, the NPDES permit allows a dilution zone for effluent constituents of toxic compounds specified in WAC 173-201 but not specified in the permit.

Discharges from the project will be below the state acute toxicity criteria at the point of discharge to the 001 blowdown pipeline, and therefore, will not exceed the state acute criteria in the river. These conclusions hold even if the constituents are concentrated by a factor of 10 (rather than 6.4), indicating that the proposed operating scenario for discharge includes flexibility to meet acute toxicity requirements at the point of discharge.

The results of the plume model analysis indicate that under the worst conditions for mixing, a dilution factor of 50-fold for the effluent concentrations is reached 100 feet downstream from the diffuser. This analysis was based on assumed values for river depth and velocity at the point of discharge and the permitted mixing distance. The depth and velocity estimates have not been field-verified but are within the range typical for low-flow conditions in the portion of the river receiving the discharge.

The concentrations of effluent constituents after transverse mixing are also presented in Table 3.3-5. The plume model results indicate that trace metals concentrated by evaporative losses during the cooling process, and then discharged, will be adequately diluted within the mixing zone. This is evidenced by the fact that the dilution factor is larger than the concentrating factor.

In conducting the comparison of project discharges to the state's chronic water quality criteria, existing data for the Chehalis River were used. Reported concentrations of trace metals in the

Chehalis River (receiving water) are listed as non-detectable, and were therefore assumed to be half of the lowest potential detection value. Using this assumption, concentrations of two toxic constituents in the river, mercury and lead, are above the applicable chronic criteria during periods of minimum and low flow conditions in the river. However, the Department of Ecology (personal communication, Paul Pickett 1994) indicated that the sampling and analysis methods used for the Chehalis River data are in some cases questionable and that reported background concentrations of metals in the Chehalis River may not be accurate.

The plume model analysis of concentrations of mercury and lead in the effluent indicates that the concentrations of these constituents will be essentially the same or lower than the reported background concentrations in the Chehalis River. As noted above, the background levels in the river are above chronic toxicity levels, and since the discharge from either phase of the Satsop

CT Project will not alter the concentrations of these constituents in the river, the discharge of the Satsop CT Project will not affect toxicity in the river.

The results also indicate that the diffuser and mixing conditions in the river, within the revised NPDES specified mixing zone, will be adequate to dilute regulated water quality parameters in the Phase II discharge such that all Class A water quality criteria for toxic substances will be met.

#### 3.3.2.6 Sanitary Water Discharge

Sanitary water effluent will be released to a constructed on-site septic system. Conservatively estimating the number of people on site (staff and visitors) per day, and using a sanitary waste flow typical for an operating plant, the estimated flow to the onsite system would be less than 3,500 gallons per day per phase. Therefore, the system will be designed to Grays Harbor County standards. Normal flowrate will likely be somewhat less.

Grays Harbor County requires that the design of the system include a preliminary report prepared by a professional engineer licensed in the state of Washington. The report will include: site conditions, schedule for development, water balance analysis, overall effects of the proposed system on the surrounding area, and any local zoning requirements.

At this time, a septic system has not been designed.

### 3.3.3 MITIGATION MEASURES

#### 3.3.3.1 Surface Water

To minimize impacts on surface water, contractors will use Best Management Practices (BMPs) for erosion and sediment control during construction of Phase II and will implement a plan that complies with the requirements of the existing Erosion and Sedimentation Control Plan. BMPs will include limiting certain construction activities and installing temporary control structures such as sediment traps, silt fences, and diversion ditches.

To meet the temperature requirements of the discharge, either heat exchangers and/or flow augmentation will be used to quench the temperature of the cooling water discharge.

#### 3.3.3.2 Groundwater

The design of the on-site septic system will include a professional engineer’s report on site conditions, schedule for development, water balance analysis, overall effects of the proposed system on the surrounding area, and any local zoning requirements.

The placement and design of the system will allow infiltration of effluent but inhibit its direct release to surface and/or groundwater bodies.

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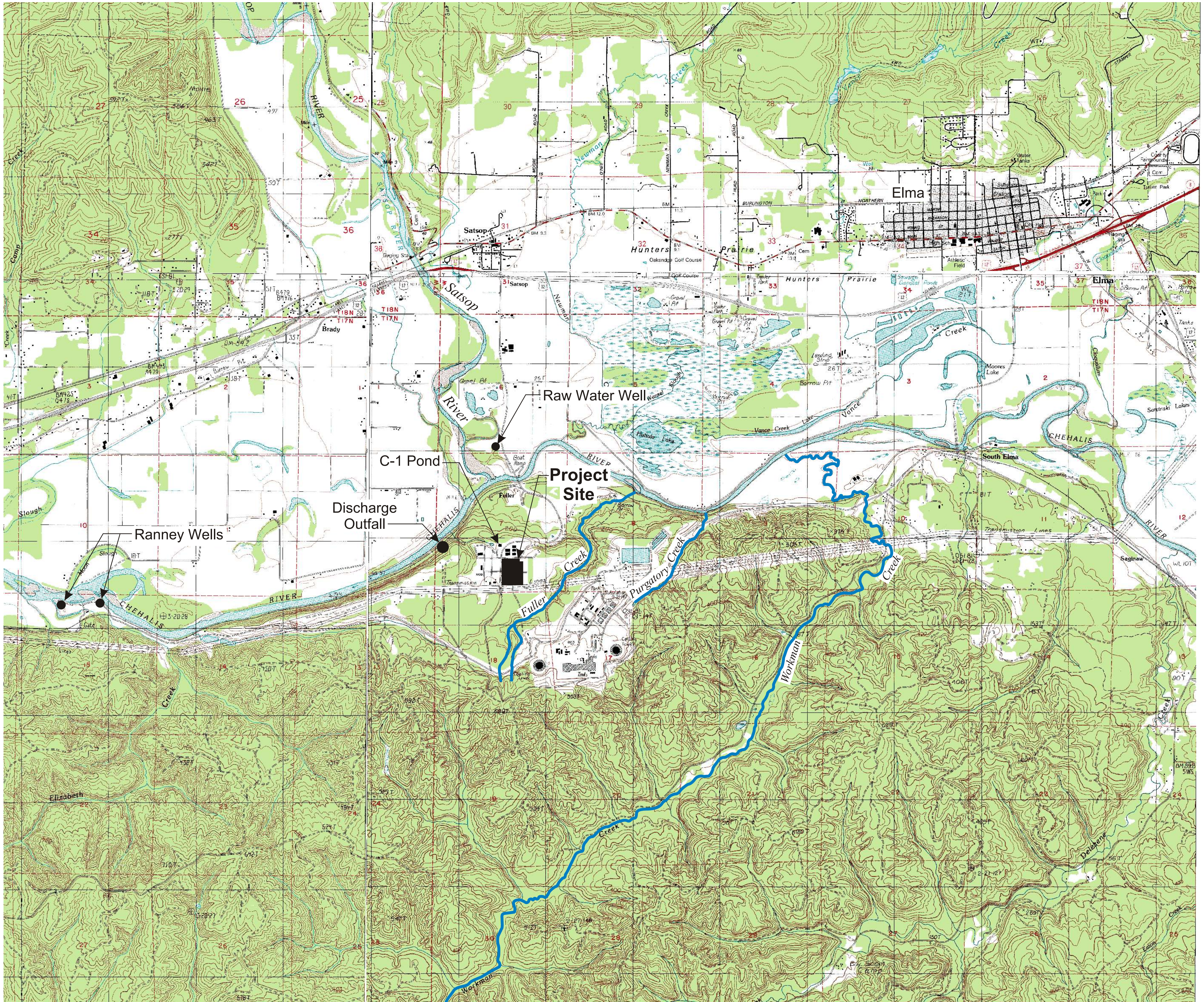


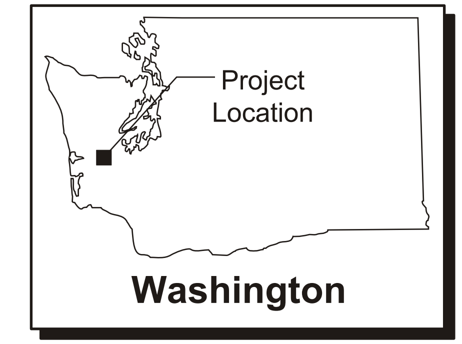


Figure 3.3-1
**Area Map**

URS

Phase II Expansion
Satsop CT Project

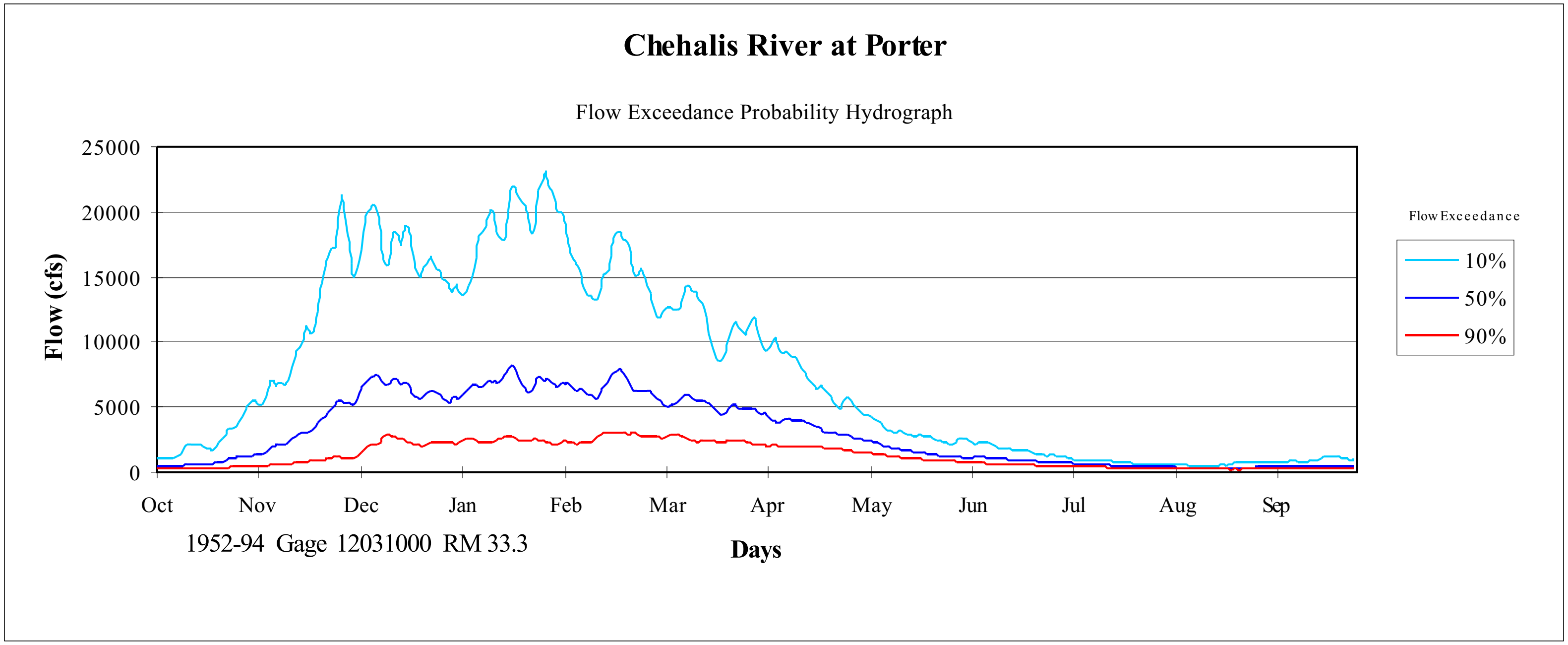


Figure 3.3-2

**Chehalis River at Porter Flow Exceedance**

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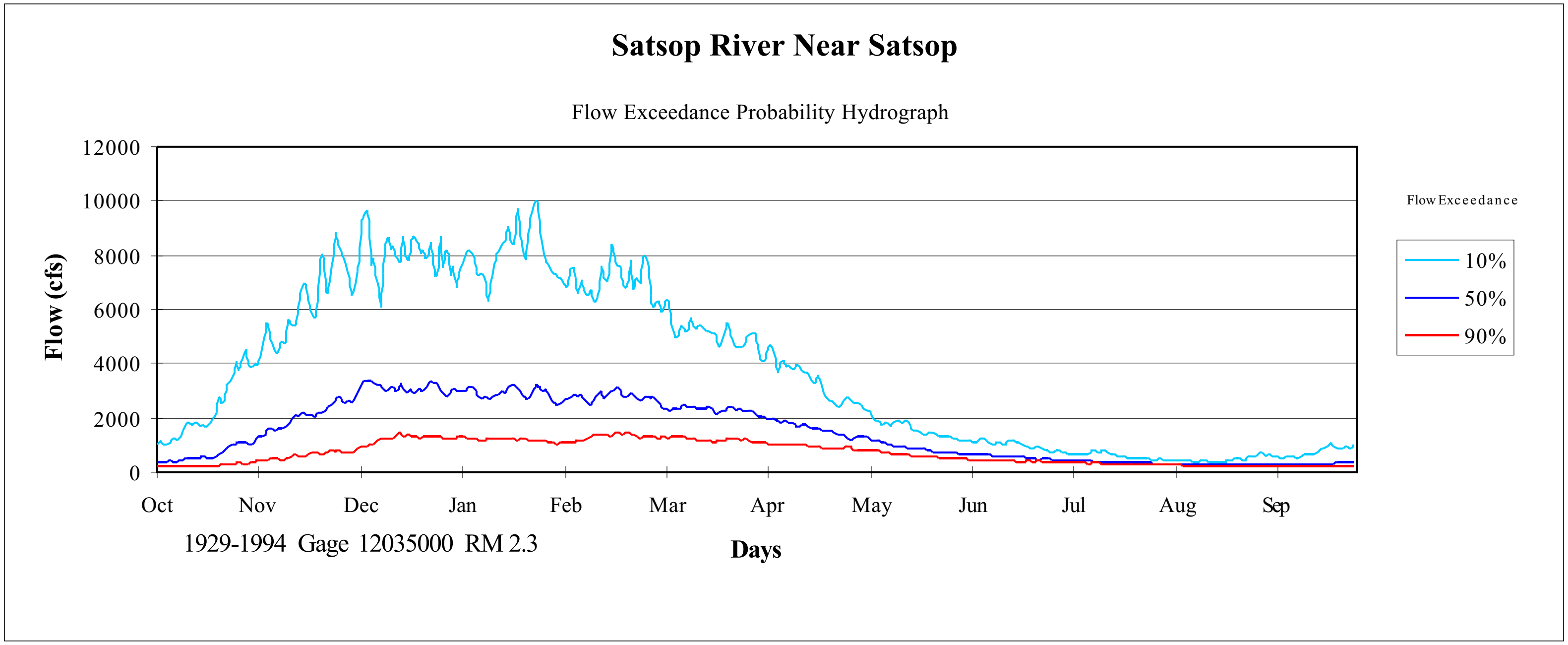


Figure 3.3-3

**Satsop River Near Satsop Flow Exceedance**

URS

Phase II Expansion
Satsop CT Project

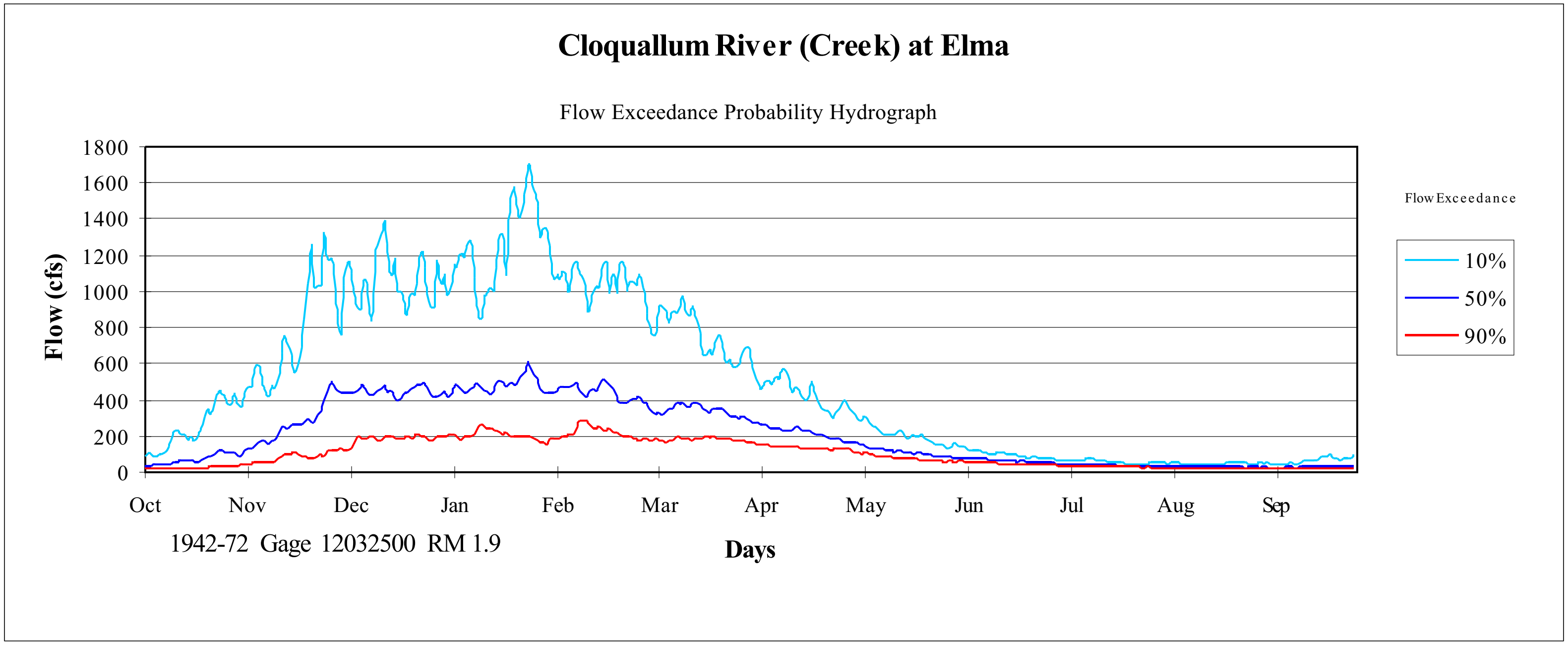


Figure 3.3-4

**Cloquallem Creek Flow Exceedance**

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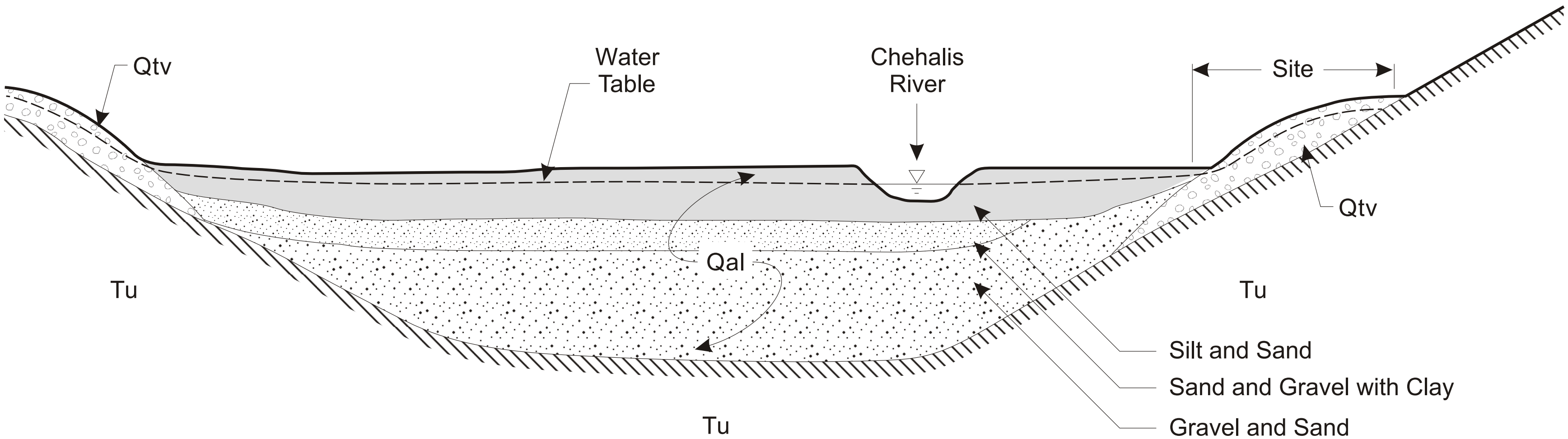


LEGEND

| | |
|---|---|
| Qal | Alluvium: unconsolidated, interbedded fluvial silt, sand, and gravel |
| Qtv | Terrace deposits: glaciofluvial outwash of sand, gravel, and clay |
| Tu | Tertiary rocks: undifferentiated siltstones, sandstones, conglomerates, and basalt flows |

Not to Scale

*SOURCE: Adapted from Eddy, 1966*

Figure 3.3-5

**Generalized Geologic Cross Section through Site Location and Chehalis River Valley**

URS

Phase II Expansion
Satsop CT Project

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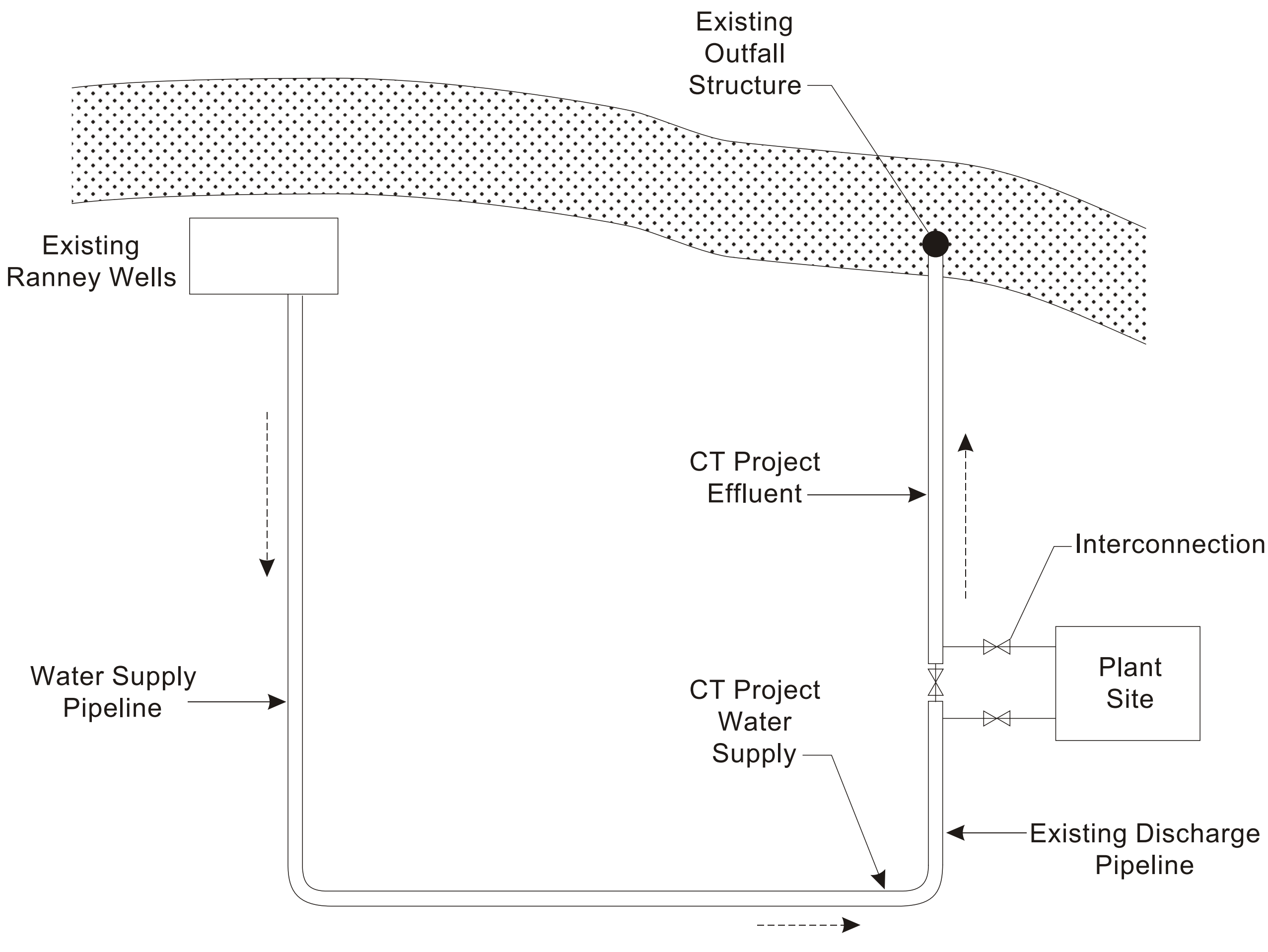
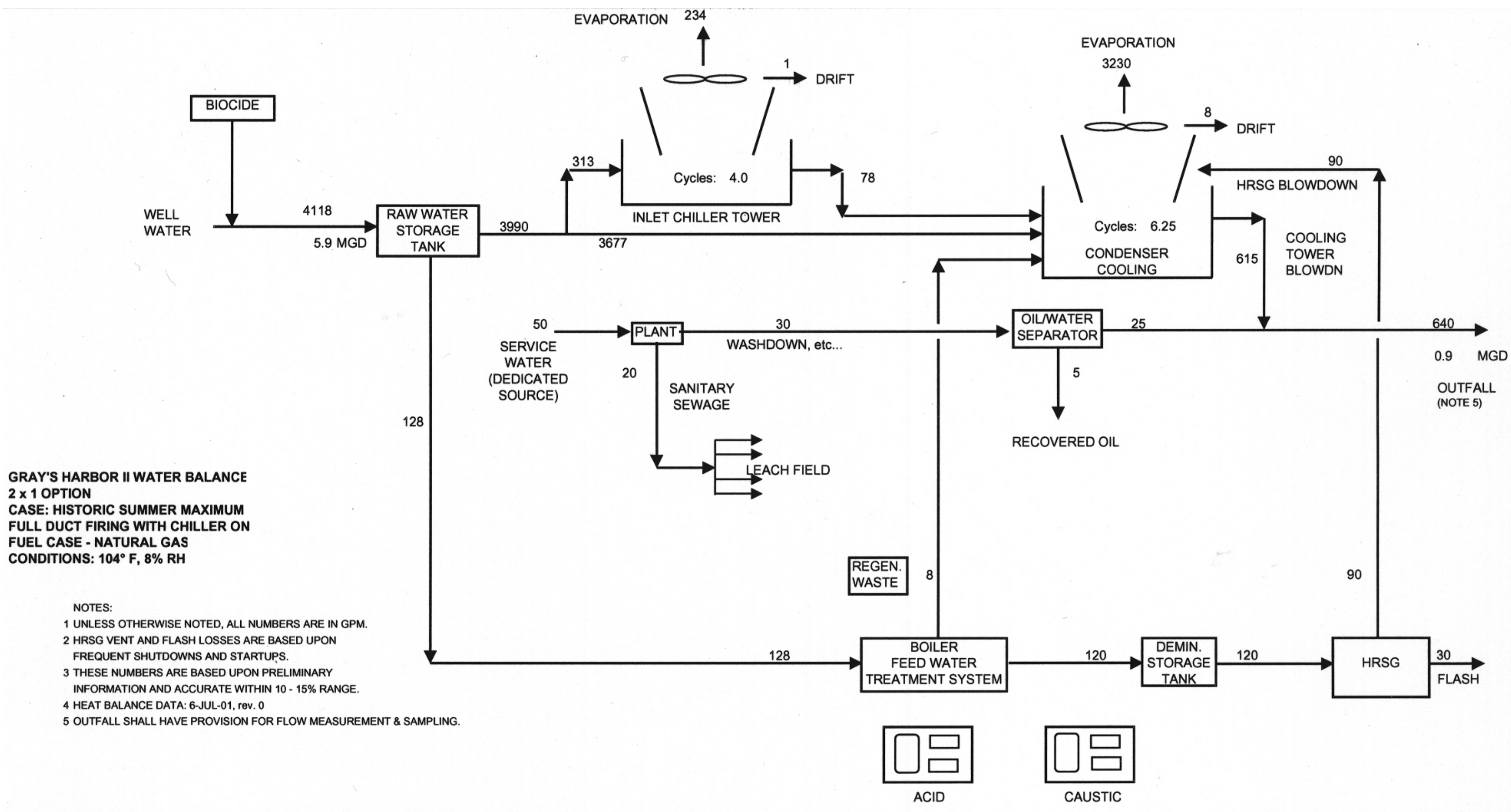



Figure 3.3-6

**Process Water**
**Conceptual Flow Diagram**

URS

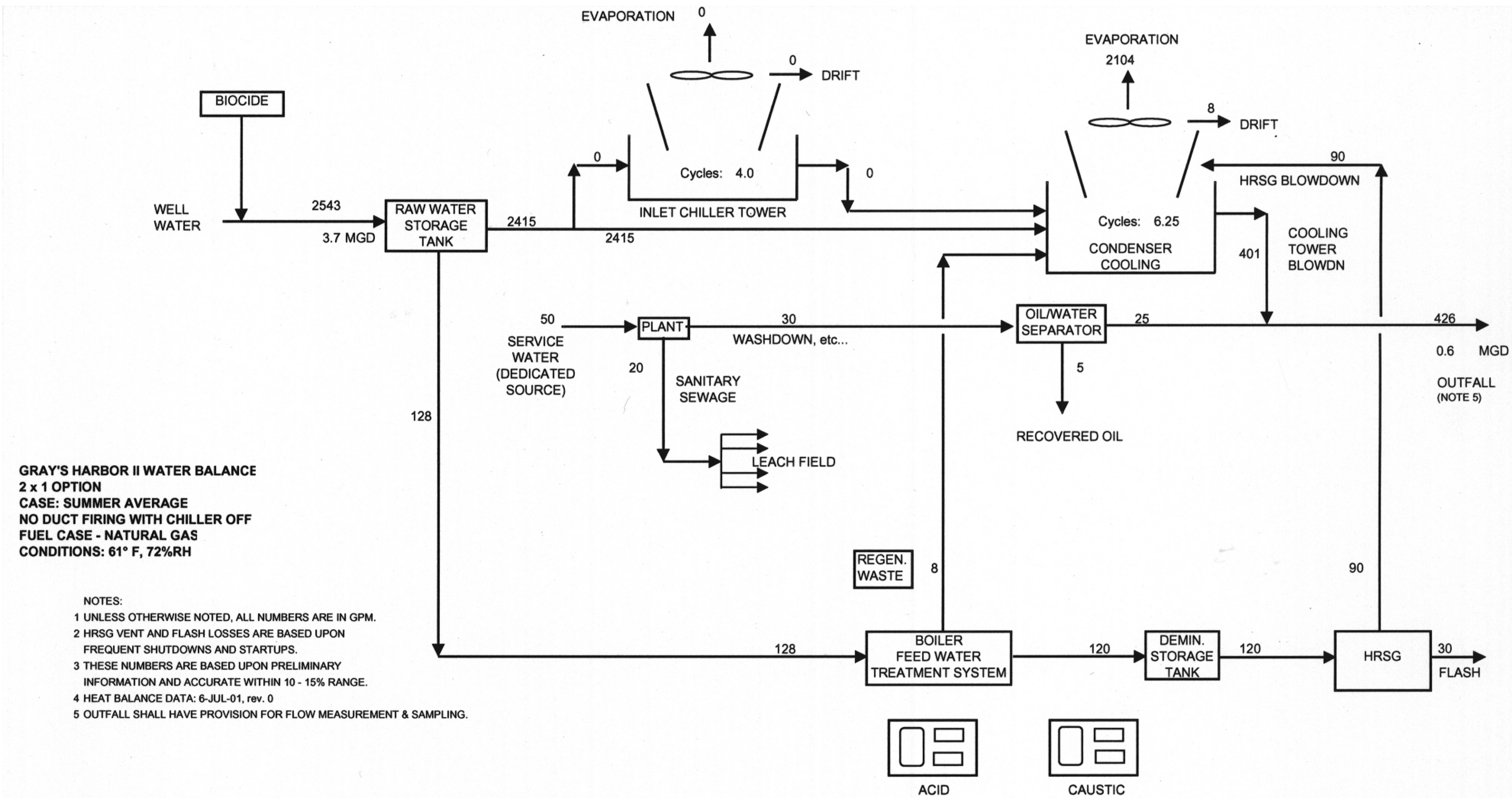
Phase II Expansion
Satsop CT Project




Source: Duke/Fluor Daniel

Figure 3.3-7

**Process Water Maximum**




Source: Duke/Fluor Daniel

Figure 3.3-8
**Process Water Minimum**

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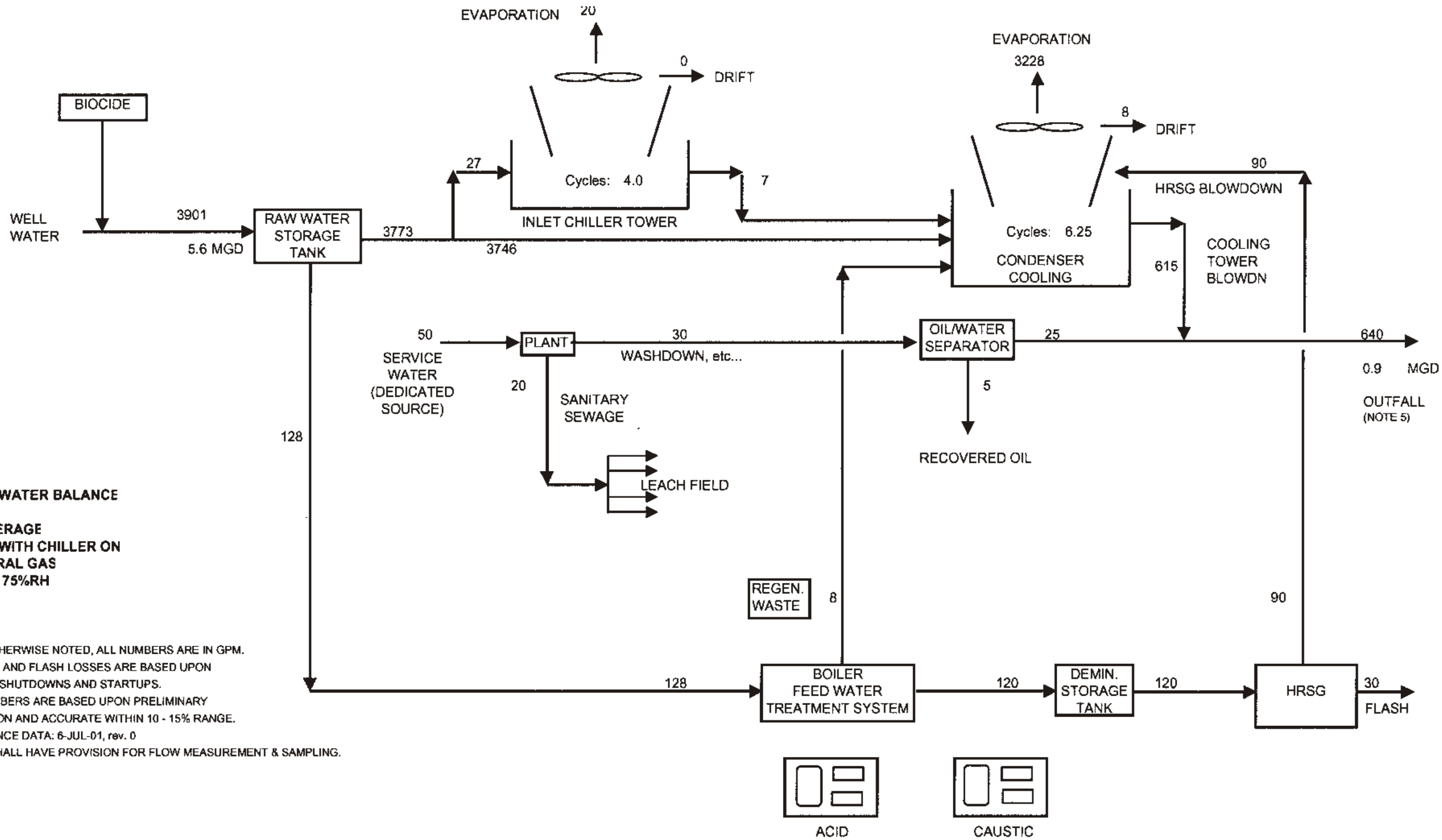
Phase II Expansion
Satsop CT Project




**GRAY'S HARBOR II WATER BALANCE**
**2 x 1 OPTION**
**CASE: ANNUAL AVERAGE**
**FULL DUCT FIRING WITH CHILLER ON**
**FUEL CASE - NATURAL GAS**
**CONDITIONS: 50° F, 75%RH**

NOTES:
1 UNLESS OTHERWISE NOTED, ALL NUMBERS ARE IN GPM.
2 HRSG VENT AND FLASH LOSSES ARE BASED UPON FREQUENT SHUTDOWNS AND STARTUPS.
3 THESE NUMBERS ARE BASED UPON PRELIMINARY INFORMATION AND ACCURATE WITHIN 10 - 15% RANGE.
4 HEAT BALANCE DATA: 6-JUL-01, rev. 0
5 OUTFALL SHALL HAVE PROVISION FOR FLOW MEASUREMENT & SAMPLING.

Source: Duke/Fluor Daniel

Figure 3.3-9
**Process Water Average Annual**

URS

Phase II Expansion
Satsop CT Project

## 3.4

# Plants and Animals (WAC 463-42-332)

**WAC 463-42-332 NATURAL ENVIRONMENT — PLANTS AND ANIMALS.**

*(1) Habitat for and number or diversity of species of plants, fish, or other wildlife - The applicant shall describe all habitat types, vegetation, wetlands, animal life, and aquatic life which might reasonably be affected by construction, operation, or cessation of construction or operation of the energy facility and any associated facilities. Assessment of these factors shall include density and distribution information. The application shall contain a full description of each measure to be taken by the applicant to protect all habitat types, vegetation, wetlands, animal life, and aquatic life from the effects of project construction, operation, abandonment, termination, or cessation of operations.*

*(2) Unique species - Any endangered species or noteworthy species or habitat shall receive special attention.*

*(3)Fish or wildlife migration routes - The applicant shall identify all fish or wildlife migration routes which may be affected by the energy facility or by any discharge to the environment.*

# 3.4 PLANTS AND ANIMALS (WAC 463-42-332)

This section presents information on existing conditions and impacts related to plants and animals, including the following sections:

- Habitats and Species Present (Subsection 3.4.1)
  - Upland Vegetation (Subsection 3.4.1.1)
  - Habitat Types and Wildlife Use (Subsection 3.4.1.2)
  - Fisheries and Aquatic Resources (Subsection 3.4.1.3)
- Unique Species (Subsection 3.4.2)
  - Federal Threatened, Endangered, and Sensitive Plant Species (Subsection 3.4.2.1)
  - Federal Threatened, Endangered, and Sensitive Wildlife Species (Subsection 3.4.2.2)
  - Federal Threatened, Endangered, and Sensitive Fish Species (Subsection 3.4.2.3)
  - State-Listed Fish and Wildlife Species and Habitats (Subsection 3.4.2.4)
- Fish or Wildlife Migration Routes (Subsection 3.4.3)

## 3.4.1 HABITATS AND SPECIES PRESENT

The areas defined below describe the plant site and the study area applicable to the vegetation, wildlife, and wetland studies conducted for the project.

- The plant site is defined as the construction site upon which the proposed plant will be built. This site was used as a construction laydown area remaining from the previously built nuclear facilities. The site has been graded several times, is scarcely vegetated, and covered in gravel.

- The study area is defined as the proposed plant site and 500 feet around it. The study area provides a basis for describing existing conditions within a regional context.

Biologists surveyed the vegetation focusing primarily on the areas potentially impacted by construction activities. Three teams (two biologists per team) conducted the field surveys. Mapping of vegetation types in the vicinity of the proposed site was based primarily on Energy Northwest Habitat Evaluation maps.

### 3.4.1.1 Upland Vegetation

This subsection describes the upland vegetation resources occurring in the vicinity of the Satsop CT Project study area. The study area was evaluated to identify upland plant communities occurring in the project vicinity.

Vegetation studies were conducted by Dames & Moore biologists during May and June 1994. These surveys of the study area consisted of reviewing and assessing aerial photographs, National Wetland Inventory Maps, and county soil surveys. Vegetation types were mapped and entered into a Geographic Information System.

**Existing Conditions**

Regional Conditions

The study area is located within the Puget Trough Province (Franklin and Dyrness 1988). Relief is moderate, with elevations seldom exceeding 525 feet. The majority of the soils were formed in glacial materials under the influence of coniferous forest vegetation.

The study area is also within the *Tsuga heterophylla* (Western hemlock) Zone (Franklin and Dyrness 1988). This zone is the most extensive zone in western Washington and is named for the potential climax species (Western hemlock). This zone has a wet, mild, maritime climate, although climatic variation is widespread. The greatest amount of precipitation occurs in the winter, with only 6 to 9 percent of the total precipitation during the summer. The climatic variation and precipitation patterns create moisture stresses that result in distinct community patterns along moisture gradients.

Plant Site

Prior to Phase I of the Satsop CT Project, most of the proposed power plant site had been filled and graded with several feet of compacted gravel (Parametrix 1993), lacked vegetation, and a portion of the site was covered with asphalt. The site was used as a construction laydown area and had stockpiles of concrete forms, steel reinforcing bars, and other materials remaining from construction of the nuclear facilities located on the Satsop Power Plant property. Currently, the site is under construction for Phase I and has been completely regraded including the portion of the site that would be used for Phase II.

The area immediately surrounding the plant site is a mix of developed and undeveloped mitigation areas. The area to the north of the Phase II project site is industrial with some conifers to the northeast. The area to the south of Phase II project consists of the transmission line corridor and is mostly brush, followed by conifers further south. The area immediately to the west of Phase II project is the Phase I plant, which is currently under construction. The area to the east of Phase II project is part of a mitigation area and consists of thinned conifers managed as a mature forest. Continuing east is an area managed for pasture that is mowed every year. Beyond the pasture there is a zoned preservation area.

The original nuclear power plant site composed 1,600 acres, of which 400 acres were developed, and 1,200 acres were left as mitigation land. Developed areas include land that is essentially cleared of all vegetation, such as roads, industrial parks, and other buildings and facilities. Planted grasses, forbs, shrubs, and trees typically dominate these areas. These areas also have a higher proportion of ornamentals. The mitigation areas were chosen based on the existing habitat types that would provide beneficial features for different life stages of wildlife species.

**Impacts**

Since the proposed plant site is not vegetated, there will not be any impacts to upland vegetation due to construction or operation of the plant. Construction of the plant will not affect wetlands, because there are no wetlands on site. The forested and pasture areas surrounding the plant site will not be impacted by construction. However, noise from the operation of the plant will be detectable in areas immediately adjacent to the site.

3.4.1.2 Habitat Types and Wildlife Use

This subsection describes the habitat resources and wildlife within the vicinity of the Phase II study area. Habitat surveys were conducted by Dames & Moore biologists during winter (January 1994) and spring (May and June 1994) to document existing habitat conditions at the proposed plant site and in surrounding areas. Surveys completed in 1994 were for the Phase I project (which included the study area for the Phase II project), as well as the pipeline corridor, and the transmission line corridor (which were part of Phase I only). A bald eagle survey conducted in February 2001 focused on bald eagle nesting habitat within 0.5 mile of the study area for Phase II. The bald eagle survey consisted of recording evidence of the species (e.g., sign, vocalizations, and direct observations).

**Existing Conditions**

As previously discussed, the plant site itself has been highly disturbed by previous activities and contains minimal vegetation. The area surrounding the plant site consists of developed land, coniferous forest, regenerating coniferous forest, grassland, and shrubland.

<u>Habitat Types</u>

*Developed*

Although there are varying levels of development, these areas generally provide low-quality habitat because of the lack of native vegetation and the level of human disturbance. Species observed in developed areas during field reconnaissance in 1994 included European starlings, rock doves, American crows, house sparrows, and opossums, all of which are highly adapted to human-modified environments.

*Coniferous Forest*

Forest habitat consists of areas dominated by coniferous and/or deciduous tree cover, and associated forest understory vegetation. Coniferous forest is the predominant habitat in the areas around the study area to the northeast, south past the transmission lines, and immediately to the east of the project site. Deciduous and mixed forest occurs in smaller patches, generally interspersed with coniferous forest stands.

The quality of forest habitat for wildlife varies depending on the age or successional stage of the stand, the presence of several vegetative layers (i.e., shrub/midstory and herbaceous/understory vegetation), the presence of snags and downed logs, and the size of the stand. A stand along Fuller Creek on the Public Development Authority (PDA) property is over 80 years old and is classified as mature coniferous forest. This stand is defined as a "Preservation Area" and is being managed to create structural characteristics of old-growth forest. The intent of the management is to provide thermal cover for deer, habitat for cavity-nesting wildlife such as pileated woodpeckers, and large snags for raptor nesting and perching.

Wildlife occurring in forest habitat in the study area is typical of wildlife occurring in second-growth forest stands throughout western Washington. Common forest songbirds observed in the 1994 surveys throughout the study area included Pacific slope flycatchers, Steller's jays, chestnut-backed chickadees, red-breasted nuthatches, brown creepers, winter wrens, golden-crowned kinglets, varied thrushes, solitary vireos, Townsend's warblers, Wilson's warblers, western tanagers, and black-headed grosbeaks. Sign of black-tailed deer, mountain beaver, and Douglas' squirrel also was observed in many forested areas.

*Regenerating Coniferous Forest*

Regenerating coniferous forest is defined as areas that were clearcut up to 20 years ago and where successional advancement is moving rapidly toward forest development. For the first few years after clearcutting, these stands are dominated by a mix of forbs, ferns, and shrubs, such as salal, Oregon grape, trailing blackberry, vine maple, sword fern, bracken fern, and red alder. The diversity of plant species is higher in regenerating stands than during later stages of forest succession because the open space following clearcutting allows many plant species to invade. Within 5 to 10 years after clearcutting, the conifer seedlings (primarily Douglas fir) become the dominant vegetation. Herbs, ferns, and shrubs become overtopped by young trees and often die under the taller growing species. By age 20, the stands have developed closed canopies and are classified as forest habitat. Regenerating forest is interspersed with forest habitat in the study area.

Many wildlife species are found in regenerating forest stands since the variety of plants and seeds provides an abundance and diversity of food. The young plants are fairly palatable, are accessible to ground-foraging animals (i.e., deer), and provide hiding cover for songbirds and other wildlife. Wildlife commonly observed in regenerating coniferous forest during the 1994 field surveys included ruffed grouse, mourning doves, rufous hummingbirds, Swainson's thrushes, orange-crowned warblers, MacGillivray's warblers, Wilson's warblers, rufous-sided towhees, song sparrows, white-crowned sparrows, dark-eyed juncos, and American goldfinches. Red-tailed hawks occasionally were observed circling over the open stands. Sign of coyote, black-tailed deer, and elk was observed within regenerating forest habitat and on logging roads through the regenerating stands. Garter snakes were common along the edges of logging roads. Mountain beaver sign also was prevalent throughout many of the stands.

*Grassland/Agricultural*

Grasslands and agricultural areas include pastures, croplands, orchards, hayfields, and untended fields. Some of the low-lying fields become flooded during winter and provide habitat for numerous species of waterfowl where they rest and feed on grains. Species observed in flooded fields near the Chehalis River during the 1994 field surveys included trumpeter swans, Canada geese, mallards, northern pintails, American wigeons, green-winged teal, common goldeneyes, killdeer, and common snipe. Open areas also provide foraging habitat for raptors. Red-tailed hawks and northern harriers occur year-round in open agricultural areas. American kestrels occur in open areas in the study area during winter. Songbirds occurring in this habitat type include violet-green swallows, savannah sparrows, and American robins.

*Shrubland*

Shrub habitat is the primary habitat type in existing rights-of-way for the BPA transmission line to the south of the project site. Shrub habitat is not a forest successional stage. Shrub habitat is dominated primarily by Scotch broom, but also includes trailing blackberry, Himalayan blackberry, salmonberry, thimbleberry, and young red alder.

<u>Wildlife Species</u>

There are 148 species of birds that potentially occur within habitats in the vicinity of the study area and adjacent lands (DeGraaf et al. 1991). Of these, 46 species are most likely to occur in forest habitat, 25 in shrub habitat, 31 in open agricultural areas and grasslands, and 46 in wetland, riparian, and aquatic habitats. Approximately 75 of the bird species are year-round residents, 45 are summer breeding residents, 23 are winter residents, and 5 occur only during spring and/or fall migration periods. A total of 32 species of mammals potentially occur within habitats traversed by Phase I of the project, with a smaller total utilizing the area immediately adjacent to Phase II. Small mammals, including rodents, shrews, bats, and rabbits are the most numerous although they are not readily observed. Large mammals include deer, elk, coyotes, and black bears.

Prior to the February 2001 bald eagle survey, Washington Department of Fish and Wildlife (WDFW) biologists were contacted for information about nest sites and bald eagle activity near the study area. There are no nests mapped by the WDFW Priority Habitat and Species (PHS) Division in the study area. The closest mapped nests are approximately 1.5 miles northeast of the study area. The location and status of these nests were confirmed by personal communication with the WDFW area biologist (Zahn 2001). Also confirmed was that there are no known bald eagle nests in the study area or the vicinity (Zahn 2001). The field survey found no bald eagles or bald eagle nests within 0.5 mile of the study area. The field survey focused on two areas of potential nesting habitat identified from the review of aerial photographs; a small creek corridor between the study area and the Chehalis River, and a steep slope along the south bank of the river. The weather at the time of the survey permitted good visibility.

A small creek flows to the Chehalis River, approximately 0.3 mile to the northwest. Although the creek was dry most of its length at the time of investigation, a distinct channel is evident by the presence of gravelly substrate, eroded banks, and lack of vegetation. The creek's riparian corridor is mainly composed of deciduous forest, but does contain some patches of coniferous trees. The creek corridor was surveyed from Keys Road northwest to the edge of the terrace where the creek discharges down a steep slope to the river, crossing underneath an abandoned railroad bed via three metal culverts. The tops of large conifer trees along the creek and in the forested area to the north of the creek were surveyed. No bald eagles or nests were observed in this area.

The Chehalis River is bordered to the south by a steep slope with mature deciduous and conifer trees. The southern riverbank is lined with large deciduous trees that could be used as perch trees for foraging. Some of the largest trees are rooted on a fairly large terrace located on the slope. Agricultural farm fields dominate the north side of the river with only sparse trees along the riverbanks. There is no habitat suitable for bald eagle nesting on the north side of the river in the area surveyed. The south side of the river was surveyed by walking the abandoned railroad bed that borders the river and by both focusing on perch trees overlooking the river and searching for nests in the mature trees on the terrace edge. No observations of foraging or nesting bald eagles were made between the beginning of the railroad bed, at the bridge crossing near Fuller Creek, and approximately 1.5 miles southwest along the riverbank.

**Impacts**

Construction of the Phase II project will result in no impacts to habitat or wildlife onsite because habitat conditions at the plant site are highly disturbed and provide minimal value for wildlife. Human activity and noise generated from construction of the plant will be temporary and result in temporary disturbance of wildlife in immediately surrounding habitat areas. Wildlife tends to habituate, so only minor impacts are expected to occur.

Noise in the wildlife area to the east of the Satsop CT Project site will increase from 61 dB(A) with Phase I operating, to 75 dB(A) with both plants in operation. This is a considerable increase in noise, however given the scarcity for definitive criteria for noise level impacts to wildlife and the assumption that wildlife tends to habituate, the increase in noise from the addition of Phase II is not likely to permanently impact wildlife in the surrounding areas.

The then-named Washington Department of Wildlife management recommendations (Milner and Roderick 1991) include a site-specific approach to designating buffers for bald eagle nests. In general, buffers for active nests range from 1,300 to 2,600 feet (0.25 to 0.5 mile) during the nesting period (January through August 15). There were no bald eagle nests found near the study area, therefore no buffers or timing restrictions are needed.

No special wildlife use areas, such as fawning areas, seasonal congregation areas, or critical seasonal use habitats have been reported adjacent to the study area, and none were noted during fieldwork. It is possible that fawning areas may exist and are unknown.

Construction and maintenance vehicle traffic may cause mortality among some individual animals as they cross the access roads. These impacts generally will affect a very small percentage of the existing animal populations, and therefore the impacts will not be significant.

3.4.1.3 Fisheries and Aquatic Resources

The plant will use 9.5 cfs of water from the existing Ranney well. Eighty percent of the water in the well comes from the Chehalis River. This section describes the fisheries and aquatic resources important to the Satsop CT Project study area, which includes portions of the Chehalis River Basin. The study area is defined as the streams and rivers potentially affected by the construction and operation of the power plant facility and would include Fuller Creek and the Chehalis River.

Data sources, including USFWS, WDFW, Washington Department of Natural Resources (WDNR), Lewis County Conservation District (LCCD), and monitoring program studies conducted for the WPPSS, were reviewed in the preparation of this section. Maps from the then-named Washington Department of Fisheries (WDF) stream catalog (WDF 1975) were used to obtain information about the locations of cascades and falls. WDF and Washington Rivers Information System (WARIS) maps (WDW 1992a) were used to delineate stream use by fish.

**Existing Conditions**

<u>Fisheries</u>

The focus of this subsection is on salmonids (salmon and trout) because of their economic, cultural, and biological importance, their well-documented sensitivity to a wide range of environmental stresses, and their position near the top of the aquatic food chain. Streams that support anadromous species (fish which ascend rivers from the sea to spawn) are emphasized. Important species include fall chinook salmon, coho salmon, sockeye salmon, pink salmon, chum salmon, bull trout, and Dolly Varden. Also discussed are the anadromous gamefish species, winter and summer steelhead trout, coastal cutthroat trout, and resident species, including largemouth bass and resident cutthroat trout. Table 3.4-1 lists all fish species that occur within the study area. Primary and secondary producers (such as plankton and invertebrates) are a critical food source for fish populations and are discussed later in this section.

Nine species of anadromous salmonids (chinook, coho, sockeye, pink, and chum salmon; steelhead trout; coastal cutthroat trout, bull trout, and Dolly Varden) potentially utilize waters within the study area (WDF 1975; Willa et al. 1991; WDW 1992a; WDW 1992b, USFWS 2001). Most anadromous species in the Chehalis River system are hatchery-produced, outnumbering native stocks (Willa et al. 1991).

**TABLE 3.4-1**
**RESIDENT AND ANADROMOUS FISH SPECIES IN THE PROJECT AREA**

| Common Name | Scientific Name |
|---|---|
| **Anadromous Fishes** | |
| Chinook Salmon | *(Oncorhynchus tshawytscha)* |
| Coho Salmon | *(Oncorhynchus kisutch)* |
| Sockeye Salmon | *(Oncorhynchus nerka)* |
| Pink Salmon | *(Oncorhynchus gorbuscha)* |
| Chum Salmon | *(Oncorhynchus keta)* |
| Steelhead Trout | *(Oncorhynchus mykiss)* |
| Coastal Cutthroat Trout | *(Oncorhynchus clarki clarki)* |
| Bull trout | *(Salvelinus confluentus)* |
| Dolly Varden | *(Salvelinus malma)* |
| Pacific Lamprey | *(Entosphenus tri)* |
| River Lamprey | *(Lampetra ayresi)* |
| **Resident Fishes** | |
| Cutthroat Trout | *(Oncorhynchus clarki)* |
| Bull Trout | *(Salvelinus confluentus)* |
| Dolly Varden | *(Salvelinus malma)* |
| Largemouth Bass | *(Micropterus salmoides)* |
| Sculpin | *(Cottus* spp.*)* |
| Threespine Stickleback | *(Gasterosteus aculeatus)* |
| Olympic Mudminnow | *(Novumbra hubbsi)* |
| Northern Squawfish | *(Ptychocheilus oregonensis)* |
| Speckled Dace | *(Rhinichthys osculus)* |
| Redside Shiner | *(Richardsonius balteatus)* |
| Bridgelip Sucker | *(Catostomus columbianus)* |
| Western Brook Lamprey | *(Lampetra richardsoni)* |

Chinook salmon are the least abundant of the salmon species which occur on the west coast of the United States, but are nevertheless important to both the commercial and sport catches in Washington. Chinook salmon are most abundant in large rivers in the northwest and typically use the main channels of these rivers for spawning and rearing. Juvenile fall chinook salmon can spend extended periods of time in larger estuarine areas.

Coho salmon are a highly sought-after sport and commercial species in Washington. They typically spawn in tributary channels and rear in pools and backwater areas associated with good cover. Coho salmon juveniles typically spend 1 to 2 years rearing in streams before out-migrating to the sea. Off-channel areas are often used for overwintering habitat (Groot and Margolis 1991).

Sockeye salmon are the least-abundant salmon species occurring in the study area but are highly prized by sport and commercial fishermen on the west coast.

Pink salmon are the most abundant of the Pacific salmon, comprising more than 50 percent of the commercial catch on the west coast and a major portion of the commercial catch in odd years in

Puget Sound. Chum salmon are also a major species in Puget Sound. Both pink and chum salmon typically spawn near the mouths of streams but can also be found far upstream in major rivers. The out-migration patterns of pink salmon and chum salmon fry are similar. Fry emerge from the gravel and migrate downstream immediately to the estuary, where they spend an extended period of time before gradually moving offshore (Groot and Margolis 1991).

Steelhead trout (the sea-run form of rainbow trout) are one of the most sought-after sport species in Washington. Steelhead trout spawn in mainstream and tributary stems. Juveniles rear in tributaries and large river mainstreams. The coastal subspecies of cutthroat trout is widely distributed in western Washington drainages, spawning in small headwater streams and tributaries and usually remaining there at least a year before migrating down to larger streams. The sea-run form occurs in most sea-accessible drainages. The non-anadromous form is found in many coastal lakes and most streams. Cutthroat trout is considered a good sport fish.

Bull trout and Dolly Varden are difficult to distinguish in the field and are managed as a single species (native char) by the WDFW (WDF 1992b, WDFW 1998a). Anadromous (sea-run), fluvial (living in mainstem streams), lacustrine (lake-dwelling), and stream resident (living in tributary streams) populations of bull trout/Dolly Varden are found in coastal drainages from the Chehalis River to the Canadian border (WDF 1992b, WDFW 1998b). Dolly Varden are typically anadromous except where migration is blocked. Some anglers consider Dolly Varden an excellent game fish (Wydoski and Whitney 1979).

Resident game fish species inhabiting waters in the vicinity of the project include resident cutthroat trout, largemouth bass, and pumpkinseed (sunfish family). Important resident nongame fish species include three-spine stickleback, Northern squawfish, dace, shiner, sucker, and the Olympic mudminnow.

<u>Primary and Secondary Producers</u>

Aquatic primary producers (plankton and algae) and secondary producers (aquatic invertebrates) are important contributors to the freshwater environment. These organic aquatic organisms combined with terrestrial organisms, provide food for fish. The distribution patterns of aquatic insects are influenced by a variety of physical factors including stream flow, temperature, water quality, substrate, and hydrography, and biological factors such as predation and competition. Studies of various aquatic organisms were conducted within the study area from 1973 through 1980 (WPPSS 1974b; Envirosphere 1978a, 1978b, 1978c, 1979, 1980, 1981). Because invertebrate fauna of the study area have not been studied in detail, general regional aspects will be discussed.

Nineteen diatom genera were identified in the Chehalis River, predominantly *Navicula*, *Nitzchia*, *Cocconeis*, and *Melosira*. Surveys of macrophytes in the Chehalis River indicated that during spring and summer macrophyte growth was sparse, with most species only appearing from July to October. Twelve species were widely dispersed and occurred in relatively small groups in the river. *Potamogeton* spp., *Elodea canadensis*, and *Fontinalis antipyretica* were the predominant species collected.

Periphyton (algae that attach to substrates) consisted mainly of diatoms and blue-green algae. The most abundant diatom genera collected were *Cocconeis*, *Achnenthes*, *Cymbella*, *Gomphonema*, *Synedra* and *Navicula*. *Chamaesiphon* and *Lyngbya* were the dominant blue-green genera collected. Zooplankton densities collected in June and July were consistently low. *Canthocamptus* and *Cyclops* were the dominant copepoda genera while Dipterans (Tendipedidae) were the most abundant non-crustaceans. Chehalis River macroinvertebrate densities were generally highest in the spring and lowest for the autumn exposure period. Midges (Chironmidae) were dominant in most of the samples. Other abundant groups included scuds (*Gammarus* sp.), true flies (Diptera), may-flies (Ephemeroptera), caddisflies (Trichoptera), stoneflies (Plecoptera), beetles (Coleoptera), snails (Gastropoda), and worms (Oligohaeta).

<u>Aquatic Resources</u>

This section discusses aquatic resources near the plant site potentially affected by the proposed project. The study area lies within the Chehalis Basin and includes the Chehalis River and Fuller Creek.

*Chehalis Basin*

The Chehalis Basin is composed mainly of the Chehalis River watershed. The Chehalis River forms near Pe Ell, Washington and flows generally northward to Grays Harbor. Grays Harbor is an important estuary area that provides rearing and feeding areas for juvenile salmonids produced in the Chehalis Basin (WDF 1975). Salmon enter Grays Harbor to feed on abundant smaller marine fishes which school in the western portion of the harbor (WDF 1975). Eleven species of anadromous fish use the Chehalis Basin, including the River lamprey, Pacific lamprey, coastal cutthroat, steelhead trout, bull trout, Dolly Varden, and chinook, coho, chum, pink, and sockeye salmon. Pink salmon and sockeye salmon occur in small numbers and are assumed to be strays from other areas as they are not indigenous to the Chehalis Basin (WDF 1975). Forestry and farming are the primary commercial land uses in the Chehalis basin. Over time, habitat loss and degradation have reduced the diversity of fish species in the basin.

*Chehalis River and Vicinity*

The Chehalis River supports chinook, coho, and chum salmon, steelhead, bull trout, Dolly Varden, coastal cutthroat trout, River lamprey, and the Pacific lamprey. Pink and sockeye salmon have been reported in the Chehalis River in insignificant numbers.

Outside of the Columbia River system, the Chehalis River is the largest watershed in the state of Washington (Seiler 1989). The Chehalis River is classified as Class A (excellent), as are most of the water bodies of the Chehalis Basin. Beneficial uses of Class AA and Class A waters include water supply, fish spawning and rearing, recreation, and navigation (LCCD 1992a, LCCD 1992b). The Chehalis River flows into Grays Harbor, the fourth largest estuary in the western United States.

Salmon produced or reared in the Chehalis basin are harvested by sport and commercial fishermen from northern California, Oregon, Washington, Canada, and Alaska (WDF 1975). Low wild runs of coho salmon, chinook salmon, and steelhead trout have been evident for over 50 years in the Chehalis River (Seiler 1989). The decrease in wild coho salmon originating from the Chehalis basin has led to restrictions on coho salmon ocean fisheries (WDF 1992a). Wild and hatchery coho salmon smolts from the Chehalis have a consistently lower survival rate than smolts from other coastal watersheds. In order to increase run sizes (out-migrating juvenile salmon) WDFW has planted up to 2 million coho salmon smolts and up to 5 million coho salmon fingerlings per year in the Chehalis River system. Total coho salmon smolt production in the Chehalis system is estimated at 2 to 3 million per year (Seiler 1989; WDF 1993).

Chinook salmon enter the Chehalis River from March through November, spawning mainly in areas downstream of Oakville (WDF 1975), a town about 39 miles south of Olympia. Fall chinook salmon fry remain in fresh water from 3 to 5 months, and spring chinook fry remain for more than 1 year (WDF 1975). Both spring and fall Chinook salmon stocks in the Chehalis River are considered healthy based on the present number of returning adults in recent years as compared to past returns (WDW 1992c).

A native stock is one that has not been substantially affected by genetic interactions with non-native stocks and is present in all or part of its original range. A mixed stock has individuals that have originated from the mating and/or commingling of native and non-native parents or undergone a substantial change in its genetic makeup. A non-native stock is one that has become established outside of its original range. Wild stocks are stocks sustained by natural spawning and rearing in the natural habitat, regardless of parentage (WDW 1992c). The origin of Chehalis River chinook salmon stocks are both native (Spring chinook salmon) and mixed (Fall chinook salmon), but both are sustained through wild population spawning (WDW 1992c).

Coho salmon adults use virtually all accessible streams in the Chehalis basin which offer suitable spawning habitat; juveniles use many non-spawning streams for rearing and refuge during high water periods (WDW 1992c; Bisson et al. 1982). Grays Harbor coho salmon runs enter fresh water beginning in September and continuing through February (WDF 1975).

Chum salmon spawning areas occur mainly in larger tributaries entering the north side of the Chehalis River, downstream of Cloquallum Creek (WDF 1975). Chum salmon runs in areas further upstream have suffered significant declines. The only stream within the study area with reported chum salmon use is the Chehalis River (WDW 1992a).

Steelhead trout occur in many of the larger streams within the Chehalis basin. However, in the vicinity of the project site, the Chehalis River itself is the only area where steelhead trout have been documented. Steelhead trout are taken by anglers every year from the Chehalis River. An estimated 21 summer run steelhead trout were harvested by sport fishermen in the Chehalis River during the 1992 summer fishery, and 1,091 winter run steelhead trout were harvested during the winter fishery (WDW 1993b). Indian treaty steelhead trout harvests (Chehalis and Quinault tribes combined) numbered about 95 summer run steelhead trout during the 1992 summer run fishery and 1,410 winter run steelhead trout during the 1992-1993 winter run fishery (WDW 1993b).

Bull trout/Dolly Varden in the Chehalis River/Grays Harbor system have been identified as a distinct stock based on the geographic distribution. Spawn timing and locations are unknown. Chehalis River bull trout/Dolly Varden are native and are maintained by wild production. The Chehalis River is closed to fishing for bull trout/Dolly Varden, but there may be some mortality from hook and release of bull trout/Dolly Varden in fisheries targeting other species (WDFW 1996b).

Coastal cutthroat trout are considered to be an excellent game fish and are harvested annually from the Chehalis system. They use most accessible areas with suitable habitat (WDFW 1994) and have been stocked in the Chehalis River and several tributary systems from the Black River downstream (WDW 1993; WDFW 1994). Approximately 4,200 coastal cutthroat trout were stocked in the Chehalis River mainstream in 1991 by WDFW (1994).

Pacific lamprey adults are parasitic on fish in the Pacific Ocean while the larvae are filter feeders that inhabit the fine silt deposits in backwaters and quiet eddies of streams. Upon reaching maturity the adults enter fresh water in the late spring and early summer to spawn. Newly metamorphosed individuals migrate from their parent stream to the Pacific Ocean from March to July, with a peak in April and June (Wydoski and Whitney 1979).

Little is known about the biology of the River lamprey. However, it does migrate to sea and is parasitic on fishes. After feeding in the Pacific Ocean for an unknown period of time, river lamprey migrate to freshwater to spawn (Wydoski and Whitney 1979).

Limiting factors are those factors excluding harvest that lead to a reduction or complete loss of the environment's capability to sustain fish production. In most streams in the Chehalis basin, limiting factors affecting fisheries resources may include seasonal low flows resulting in degradation of spawning and rearing areas and water quality (WDF 1975; WDW 1992a). A major limiting factor in the Chehalis basin is degraded water quality. Grays Harbor is reportedly degraded by fecal bacterial and unknown agents from sources including industrial, municipal, and pasture land uses, and from timber harvesting, residential wastewater, and other unknown sources (LCCD 1992a).

The Chehalis River from its mouth upstream to the Newaukum River confluence, River Mile (RM) 75.4, is reportedly impaired by fecal bacteria and low dissolved oxygen (LCCD 1992a). From its confluence with the Satsop River upstream to the city of Chehalis, the river has a history of fish kills associated with high temperatures and low dissolved oxygen levels. Elevated temperatures (in excess of 18°C) have been measured throughout the Chehalis River system in most years, resulting in water quality problems that restrict anadromous fisheries in this basin (LCCD 1992a, 1992b). Elevated temperatures and depressed dissolved oxygen levels typically occur during the summer season (LCCD 1992a). Despite the limiting factors associated with water quality in the lower Chehalis River, better fisheries habitat is found in the area downstream of the confluence of the Black River (RM 47.0), as compared to the upper Chehalis basin (Seiler 1989).

Although degraded water quality can be a seasonal limiting factor affecting fisheries production, rearing conditions in the Chehalis Basin are not the primary reason for the overall decrease in coho salmon and other anadromous fish survival (WDF 1992). High occurrences of the diagenic fluke

*Nanophyetus salmincola* are present in lower areas of the Chehalis River. Adult coho salmon migrating through the lower reaches become heavily infested with this parasite that places physiological burdens on the fish and increases their vulnerability to additional stress, and may increase mortality (WDF 1992).

The inner Grays Harbor area has degraded water quality that can stress coho salmon smolts (WDF 1992, Berg and Northcoat 1985, Bjornn et al. 1974). Fall chinook salmon may be more negatively impacted than coho salmon, due to a longer residence time in Grays Harbor (Seiler 1989; WDF 1992). Chum salmon production is comparable to other watersheds in the area, possibly due to the migration of juveniles during a time when flows are higher and water quality in Grays Harbor is better (Seiler 1989, WDF 1992). It appears that degraded water quality and heavy parasite infestation cause exceptionally high mortality in the Chehalis River coho salmon smolts (WDF 1992). Another factor that limits salmon production is the presence of a robust population of squawfish, known predators of juvenile salmonids, in the lower Chehalis River and many of its tributaries (WDF 1992).

Ground water helps sustain stream flow during low flow (basal flow) conditions, which typically occur during the summer months. Groundwater problem areas are evident in Grays Harbor County near Elma. Typical causes of ground water contamination include septic systems, agricultural waste (manure and pesticides), automotive waste, landfills, and industrial waste (LCCD 1992a). Contaminated ground water is probably a contributing factor in water quality impairment in the lower Chehalis River basin.

Based upon quantity and quality of spawning and rearing habitat available and historical data, the potential salmon production of the Chehalis River and its tributaries is similar to that of other systems throughout the state (Seiler 1989).

*Fuller Creek and Vicinity*

Fuller Creek flows into the Chehalis River from an area south and east of the proposed plant site. The creek has produced only a few coho and chum salmon in recent years (WDFW 1994). Fuller Creek maintains a population of resident cutthroat trout (WDFW 2000b) Coho and chum salmon have been planted in previous years, but few if any adults returned. Fuller Creek substrate is primarily sand in the lower reach, turning to a mixture of rubble, gravel, and sand in the mid and upper reaches. Where spawning habitat does exist, gravels are sub-optimal; in addition, river flows in this stream further restrict spawning. Rearing habitat and refuge areas are provided during high flow periods (WDFW 1994). The area near Fuller creek has been logged three times in recent history. Increased sedimentation and erosion from logging is reported to be the predominant factor contributing to the sand substrate of the creek (WDFW 1994). Spawning coho salmon adults have been observed in Fuller Creek (WDFW 1994) located immediately east of the plant site, although only limited numbers (107 adult spawners) have been observed during WDF spawning index counts since 1987 (WDF 1993).

## Impacts

Potential Plant Construction Impacts

Although there are no aquatic resources on the plant site, the Certificate Holder will implement the already approved erosion and sediment control plan to avoid sediment releases into nearby streams. Discharges from the Satsop CT Project will use the existing outfall structure, and therefore, construction of an outfall will not be necessary. Thus, there will not be a significant adverse impact due to construction of the power plant.

Potential Operational Impacts

*Plant Operations*

Water to be used in the facility will be withdrawn from existing Ranney wells and transported to the site through an existing pipeline infrastructure system (see Sections 3.3 - Water, WAC 463-42-322, and 2.5 - Water Supply System, WAC 463-42-165. Process water will be delivered to the plant site through a connection to the existing outflow line. The project will send its effluent back to the blowdown line via another connection downstream of the project intake. Effluent from the facility will be discharged through an existing outfall in the Chehalis River. The discharge will meet the limitations of the existing NPDES Permit; however, the permit will be amended to include the wastewater discharge of the Phase II project.

The alluvial aquifer in the Chehalis River valley, in which the Ranney wells draw water, is interconnected with surface water sources. Surface water recharges the alluvial aquifer and groundwater in the aquifer provides baseflow to the Chehalis River. Due to this interconnection between the alluvial aquifer and the Chehalis River, the Ranney wells draw on a mixture of Chehalis River water (88 percent) and groundwater (12 percent). Phase I is authorized to use 9.5 cubic feet per second (cfs) from the Ranney wells, and the Grays Harbor Public Development Authority (PDA) has a permitted water right to withdraw an additional 20 cfs from the Ranney wells. The Certificate Holder is proposing to use 9.5 cfs of the PDA's permitted water right for Phase II.

The estimated maximum instantaneous water requirement for Phase II is 9.5 cfs (4,264 gallons per minute [gpm]). This maximum includes process water and water to cool the temperature of the discharge to a temperature below that specified in the existing NPDES permit. Using 25 percent of the 7-day, 10-year Chehalis River flow of 416 cfs (predicted low flow), and conservatively estimating that all the flow comes from the river, at worst case Phase II would withdraw less than 2.3 percent of this flow. Phase I and Phase II together will require 19 cfs or 8528 gpm. This is less than 4.6 percent of the 25 percent, 7-day, 10-year low flow. The United States Geological Survey (USGS) considers that monitors for flow (river gauges) operate at plus or minus 10 percent accuracy (Wiggins 2001). Therefore, water withdrawal for the project will not have a measurable impact on the baseflow in the Chehalis River or surrounding creeks and there will not be a measurable impact on aquatic resources.

Process effluent will be discharged to the Chehalis River through the existing outfall. As described in Section 3.3 - Water, WAC 463-42-322, the effluent will meet discharge limitations set forth in the existing NPDES permit and the discharge will meet all Class A water quality criteria for toxic substances. The discharge temperature will be in compliance with the stipulations of the existing NPDES permit and Site Certification Agreement. Therefore, project related discharges will not significantly impact the river water quality or the aquatic resources of the area (see Section 3.3 - Water, WAC 463-42-322 for additional details on water quality).

Water for potable uses will be supplied to the plant by the PDA's raw water wells located near the confluence of Chehalis and Satsop Rivers on the north bank of the Chehalis River and east of the Satsop River. The maximum anticipated demand for Phase I and Phase II is expected to be 100 gpm, and the average use will be less than 40 gpm (0.08 cfs). No significant impacts to aquatic resources from the use of this well are anticipated.

<u>Mitigation</u>

Maintenance wastewater will be discharged under NPDES guidelines and solid waste and toxic waste (i.e., used lubricants) will be disposed of according to state and federal regulations. Storage and use of petroleum products will be controlled and trained personnel will be equipped to respond to large and small spills.

### 3.4.2 UNIQUE SPECIES

Federally listed threatened and endangered species are those plant and animal species formally listed by the USFWS and National Marine Fisheries Service (NMFS) under authority of the Endangered Species Act of 1973, as amended. An *endangered* species is defined as "one in danger of extinction throughout all or a significant portion of its range." A *threatened* species is defined as "one likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range." Species listed as *proposed* receive limited federal protection (i.e. Section 7 consultation requirement for federal actions). *Candidate* species are those being considered for listing as threatened or endangered by the USFWS and NMFS, but do not receive any federal protection.

The USFWS, NMFS, WDNR, and WDFW were contacted for information on threatened and endangered species potentially occurring in the study area. The WDNR's Natural Heritage Data Systems were searched for documented occurrences of species of concern in the study area. Local biologists with the WDFW were contacted to confirm specific information on bald eagles and other species of concern in the study area (USFWS 1986; Zahn 2001).

#### 3.4.2.1 Federal Threatened, Endangered and Sensitive Plant Species

The USFWS was contacted for information on the potential occurrence of threatened, endangered, and candidate plant species in or adjacent to the study area. The Washington Natural Heritage Program was also contacted for information on endangered, threatened, and sensitive plants; high quality native plant communities; and high quality natural areas and wetlands occurring in the vicinity of the study area. *Endangered, Threatened and Sensitive Vascular Plants of Washington* (WDNR 1990) and *An Illustrated Guide to the Endangered, Threatened and Sensitive Vascular Plants of Washington* (WDNR 1981) were reviewed for information on the distribution and status of plant species of special interest potentially occurring in the study area.

There are no threatened, endangered, candidate, or sensitive plant species on or adjacent to the study area (USFWS 2001; WDNR 2001).

**Impacts to Threatened, Endangered, or Candidate Plant Species**

There will be no impacts to threatened, endangered, candidate, or sensitive plant species in the study area because none are present.

3.4.2.2 Federal Threatened, Endangered and Sensitive Wildlife Species

Threatened, endangered, and candidate wildlife species potentially occurring near the vicinity of the study area are listed in Table 3.4-2.

**TABLE 3.4-2**
**THREATENED, ENDANGERED, AND CANDIDATE WILDLIFE SPECIES LIKELY TO OCCUR IN THE VICINITY OF THE STUDY AREA[a][b]**

| Common Name | Scientific Name | Federal Status[c] | State Status[d] |
|---|---|---|---|
| Bald eagle | *Haliaeetus leucocephalus* | T | ST |
| Northern spotted owl | *Strix occidentalis caurina* | T | SE |
| Streaked horned lark | *Eremophila alpestris strigata* | C | SC |
| Western pocket gopher | *Thomomys mazama* | C | SC |

[a] USFWS 2001
[b] The study area is defined as the proposed plant site and 500 feet around it.
[c] T = Threatened - A species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.
C = Candidate - A species that is being considered for listing as threatened or endangered.
[d] SE = State Endangered - A species, native to the state of Washington, that is seriously threatened with extirpation throughout all or a significant portion of its range within the state.
ST = State Threatened - A species, native to the state of Washington, that is likely to become endangered in the foreseeable future throughout a significant portion of its range within the state without cooperative management or the removal of threats.
SC = State Candidate - A species that is under review for possible listing as endangered, threatened, or sensitive.

The bald eagle is a state- and federally-listed threatened species. Wintering bald eagles occur in the vicinity of the study area from about October 31st through March 31st. The WDFW has conducted midwinter bald eagle surveys throughout the state. Fairly low numbers of bald eagles have been observed along the Chehalis River. Therefore, these areas are not considered to be high concentration areas for wintering bald eagles. There are no known bald eagle nests in the study area. The nearest known nests are approximately 1.5 miles northeast of the project site.

Perching habitat for wintering and nesting bald eagles consists of large trees and snags along the Chehalis River. Food stocks for bald eagles in the study area consist primarily of anadromous and resident fish in the Chehalis River and their tributaries. More detail on fish availability is presented in Subsection 3.4.1.3. Bald eagles also prey on waterfowl that concentrate in seasonally flooded fields, emergent wetlands, and ponds near the Chehalis River.

The northern spotted owl is a state-listed endangered species and a federally-listed threatened species. This species is dependent on large stands of mature and old-growth forest. Surveys for the northern spotted owl were conducted in mature forest habitat at the Satsop Development Park in 1993 and 1994 by qualified biologists from the WDNR. The surveys were designed to meet USFWS protocol. No spotted owls were detected during these surveys (Welker 1993; Schinnell 1994). There are no other stands of mature or old-growth forest in the vicinity of the study area; therefore, northern spotted owls are unlikely to occur in the study area.

Other federal candidate wildlife species potentially occurring near the study area include the streaked horned lark and the Western pocket gopher. The streaked horned lark historically occurred in prairies throughout the Puget Trough. Urbanization, conversion of prairies to agriculture, fire suppression, and introduction of exotic plants have evidently played a role in extirpating this subspecies from most of its Washington range. Currently, the only known breeding of the streaked horned lark occurs at Fort Lewis/McChord Air Force Base in Pierce County and Ocean Shores in Grays Harbor County (Smith et al. 1997).

The Western pocket gopher requires open, undisturbed tracts of prairie or meadows free of conifer encroachment, with a substantial growth of herbs and relatively dry soil loose enough for burrowing (Johnson and Cassidy 1997).

**Impacts to Threatened, Endangered, and Candidate Wildlife Species**

No bald eagles nests were found within 0.5 mile of the project site. The nearest bald eagle nests are 1.5 miles to the northeast of the study area. It is unlikely that the project would impact the known bald eagle nests due to the distance between the project site and the nearest nest location.

No spotted owls have been detected during surveys in mature forest habitat of the Satsop Development Park property. No other stands of mature or old-growth forest are located in the study area.

Due to the lack of suitable habitat in the study area and the adjacent vicinity, it is unlikely that the streaked horned lark or Western pocket gopher would be affected by this project.

3.4.2.3 Federal Threatened, Endangered and Sensitive Fish Species

The USFWS and NMFS were contacted for a list of threatened, endangered, proposed, and candidate species occurring in the Chehalis River in the vicinity of the proposed project. These species are listed in Table 3.4-3.

**TABLE 3.4-3**
**THREATENED, ENDANGERED, AND CANDIDATE FISH SPECIES LIKELY TO OCCUR IN THE VICINITY OF THE STUDY AREA[a][b]**

| Common Name | Scientific Name | Federal Status[c] | State Status[d] |
|---|---|---|---|
| Bull Trout | *Salvelinus confluentus* | T | SC |
| Dolly Varden | *Salvelinus malma* | PT | N/A |
| Coastal Cutthroat Trout | *Oncorhynchus clarki clarki* | PT | N/A |
| Coho Salmon (Lower Columbia/Southwest WA ESU) | *Oncorhynchus kisutch* | C | N/A |

(a) USFWS 2001, NMFS 2001.
(b) The *study area* is defined as the proposed plant site and 500 feet around it.
(c) T = Threatened - A species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.
PT = Proposed Threatened. Species receives limited federal protection (Section 7 consultation).
C = Candidate - A species that is being considered for listing as threatened or endangered.
(d SC = State Candidate - A species that is under state review for possible listing as endangered, threatened, or sensitive.
N/A = Not available, species has not yet been added to the state list.

Native char (bull trout and Dolly Varden) have been documented in the Chehalis River. The majority of the Chehalis River Basin is low gradient and low elevation, which is not ideal habitat for native char. Bull trout/Dolly Varden are generally associated with cool, clear mountain streams and lakes. The highest abundance has been found in streams dominated by gravel and cobble. In lakes and streams, these fish prefer regions of temperature less than 15°C (59°F). Bull trout/Dolly Varden require cool streams for spawning, typically in high elevation headwater streams that are fed by snow melt or springs. In western Washington spawning usually occurs above 2,000 feet elevation in low gradient reaches of snow-fed streams. Spring-fed reaches of bull trout/Dolly Varden spawning streams usually occur in recent volcanic formations that are fed by high-altitude snow run off. Spawning usually occurs when stream temperatures drop below 9°C (48°F) and successful incubation generally requires temperatures of less than 4°C (39°F) for most of the incubation period. Although some bull trout/Dolly Varden may spend their entire life in a small segment of a stream, most are highly migratory, traveling between headwater spawning streams and large stream reaches (fluvial populations) or lakes (adfluvial populations) to rear as adults and larger juveniles. In western Washington, anadromous populations occur that spend a portion of their life history in marine or estuarine environments. Consequently, part of their habitat requirement is interbasin migratory routes free of blockages. Because of the bull trout/Dolly Varden's characteristic of residing in the substrate or other protected areas as juveniles, they require clean, mostly sediment-free bottom areas, or an abundance of large woody debris for cover.

The Bonneville Power Administration environmental impact statement, dated November 1995, cited a letter from D. Frederick, USFWS, July 10, 1995, identifying the bull trout (*Salvelinus confluentis*) as Federal Candidate species of fish that occurs, or may occur in streams in the vicinity of the Chehalis River (page 3-35). Since that time, the Coastal/Puget Sound Distinct

Population Segment of bull trout has been listed by the USFWS as threatened and on January 9, 2001, the USFWS proposed to list Dolly Varden as threatened under the "Similarity of Appearance" provisions of the ESA (Federal Register Vol. 66, No. 6, p. 1629).

There is scant historical and current information about native char populations in the Chehalis River Basin, but native char in the Chehalis and other southwestern Washington coastal basins appear to be in low abundance based on anecdotal information. The little available current information on the status of native char in the Grays Harbor/Chehalis River drainage is available in the 1998 bull trout/Dolly Varden stock inventory (WDFW 1998b) and the 1998 bull trout coastal/Puget Sound population segment candidate and listing priority assignment form (USFWS 1998). Native char in the Chehalis River Basin have not been identified to the species level (bull trout or Dolly Varden) and the status of the Chehalis River/Grays Harbor sub-population was listed as "unknown" in the 1998 bull trout/Dolly Varden stock inventory (WDFW 1998b).

Native char are believed to be distributed in tributaries of the Chehalis River Basin west of and including the Satsop River. Because the Chehalis River is located near the southern extent of the coastal distribution of native char in North America, abundance of the species may be naturally low in the Chehalis River (USFWS 1998). Anglers in the anadromous zone of the Chehalis River have occasionally caught native char in the spring and fall during steelhead and salmon spawning runs. The anadromous zone refers to all portions of a stream that are accessible to anadromous fish. The Chehalis River is accessible to fish at least to RM 113 and above. These are adult fish, 457 mm in length or larger. A single juvenile was observed in a WDFW downstream migrant trap at RM 50 in 1997 (WDFW 1998a). A couple of native char have been caught in the Wynochee and Satsop rivers in the past by steelhead anglers and in smaller systems that flow into Grays Harbor, such as the Hoquiam and Humptulips Rivers. Although suitable spawning conditions may exist in the headwaters of the Humptulips and Satsop Rivers, the Wynoochee River is the only tributary of the Grays Harbor/Chehalis River drainage with extensive areas of snow melt fed streams in its headwaters.

Resident fish have not been documented in the Chehalis River and it has not been determined if the fish that have been caught by anglers in the anadromous zone of the river are anadromous, fluvial or both. Spawning populations of native char have not been documented in the Chehalis River Basin and it is possible that char found in the Grays Harbor/Chehalis River drainage are primarily or entirely composed of anadromous fish spawned in river systems to the north (Quinault, Hoh, and Queets Rivers) that enter the Grays Harbor Chehalis River drainage to forage and overwinter.

Cutthroat trout are present in virtually all perennial tributaries and mainstem reaches of this system in one or more of their life history forms. The anadromous and fluvial forms inhabit mainstem and accessible tributary reaches. The Chehalis coastal cutthroat stock is complex and considered distinct based on the geographic distribution of its spawning grounds (WDFW 2000a). River entry is from October through April and spawning occurs from January through mid-March.

Coho salmon are found throughout the Chehalis River watershed. Spawning occurs in the upper mainstem and all suitable accessible tributaries. Adults enter the river in October and spawning begins in November and continues into January and sometimes February (WDW 1992c). The Chehalis River coho stock is considered healthy (WDW 1992c).

**Impacts to Threatened, Endangered, and Candidate Fish Species**

Bull trout/Dolly Varden are not known to spawn in the Chehalis River. They could however use the river in the study area as a migration corridor, foraging area, and possibly a rearing area. Bull trout/Dolly Varden are known to follow runs of spawning salmon upstream to feed on the eggs and later on the rearing juvenile salmon. Coastal cutthroat trout and coho salmon spawn in smaller tributary streams and therefore could also use the Chehalis River in the vicinity of the study area as a migratory corridor, foraging area, or rearing area. No impacts are anticipated to any of these species by the construction of the plant or water discharge. Water withdrawals for the operational use of the plant are also not expected to impact the fish due to the negligible amount being withdrawn even during low flows.

### 3.4.2.4 State-Listed Wildlife Species and Habitats

The WDFW publishes a Priority and Habitat Species (PHS) list and a Species of Concern (SOC) list. The PHS list is a catalog of habitats and species considered to be priorities for conservation and management. Priority species require protective measures for their perpetuation due to their population status, sensitivity to habitat alteration, and/or recreational, commercial, or tribal importance. Priority Species include, but are not limited to state endangered, threatened, sensitive, and candidate species. Priority habitats are those habitat types or elements with unique or significant value to a diverse assemblage of species (WDFW 2001).

The SOC list published by the Wildlife Management Program includes only native Washington fish and wildlife species that are state-listed, as well as federal-listed endangered, threatened, sensitive, or candidates for these designations (WDFW 2001).

The PHS database was searched through the WDFW for documented occurrences of priority habitats and species in the study area (WDFW 2000b). There were several priority fish species documented in the immediate study area (see Table 3.4-3). A list of Species of Concern was obtained through the WDFW website and those species that may occur in the vicinity of the study area are also listed in Table 3.4-4.

**TABLE 3.4-4**
**PRIORITY SPECIES AND SPECIES OF CONCERN OCCURRING IN THE VICINITY OF THE STUDY AREA[(a)(b)]**

| Common Name | Scientific Name | PHS Species in Study Area | Federal SOC Status[(c)] | SOC State Status[(d)] |
|---|---|---|---|---|
| Yuma myotis | *Myotis yumanensis* | | SOC | N/A |
| Long-eared myotis | *Myotis evotis* | | SOC | N/A |
| Long-legged myotis | *Myotis volans* | | SOC | N/A |
| Keen's myotis bat | *Myotis keenii* | | NW | C |
| Townsend's big-eared bat | *Coryhorhinus townsendii* | | SOC | C |
| Mazama (Western) pocket gopher | *Thomomys mazama* | | C | C |
| Western gray squirrel | *Sciurus griseus griseus* | | SOC | T |
| Oregon vesper sparrow | *Pooectetes gramineus affinis* | | SOC | N/A |
| Pacific Fisher | *Martes pennanti pacifica* | | SOC | E |
| Bald eagle | *Haliaeetus leucocephalus* | | FT | T |
| Northern goshawk | *Accipiter gentiles* | | SOC | C |
| Spotted owl | *Strix occidentalis* | | FT | E |
| Vaux's swift | *Chaetura vauxi* | | NW | C |
| Pileated woodpecker | *Dryocopus pileatus* | | NW | C |
| Olive-sided flycatcher | *Contopus cooperi* | | SOC | N/A |
| Willow flycatcher | *Empidonax traillii* | | SOC | N/A |
| Streaked horned lark | *Eremophila alpestris strigata* | | C | C |
| Purple martin | *Progne subis* | | NW | C |
| Western toad | *Bufo boreas* | | SOC | C |
| Tailed frog | *Ascaphus truei* | | SOC | N/A |
| Pacific lamprey | *Entosphenus tridentatus* | | SOC | N/A |
| River lamprey | *Lampetra ayresi* | | SOC | C |
| Olympic mudminnow | *Novumbra hubbsi* | | NW | S |
| Bull trout | *Salvelinus confluentus* | Chehalis River | FT | C |
| Dolly Varden | *Salvelinus malma* | Chehalis River | PT | N/A |
| Chinook salmon | *Oncorhynchus tshawytscha* | Chehalis River | NW | N/A |
| Chum salmon | *Oncorhynchus keta* | Chehalis River | NW | N/A |
| Coho salmon | *Oncorhynchus kisutch* | Chehalis River | C | N/A |
| Sockeye salmon | *Oncorhynchus nerka* | Chehalis River | NW | N/A |
| Coastal Cutthroat | *Oncorhynchus clarki clarki* | Chehalis River | PT | N/A |
| Steelhead Trout | *Oncorhynchus mykiss* | Chehalis River | NW | N/A |
| Largemouth Bass | *Micropterus salmoides* | Chehalis River | NW | N/A |
| Resident Cutthroat | *Oncorhynchus clarki* | Fuller Creek | NW | N/A |

**TABLE 3.4-4 (Continued)**
**PRIORITY SPECIES AND SPECIES OF CONCERN**
**OCCURRING IN THE VICINITY OF THE STUDY AREA[(a)(b)]**

(a) The study area is defined as the proposed plant and 500 feet around it.
(b) Data from Natural Heritage Data Systems, WDFW 2000, and USFWS 2001
(c) SOC = Federal Species of Concern
FT = Federal Threatened Species
PT = Federal Proposed Threatened Species
C = Federal Candidate Species
N/W = Not warranted
(d) E = State Endangered - A species, native to the state of Washington, that is likely seriously threatened with extirpation throughout all or a significant portion of its range.
T = State Threatened - A species, native to the state of Washington, that is likely to become endangered in the foreseeable future throughout a significant portion of its range within the state without cooperative management or the removal of threats.
C = State Candidate - A species that is under review for possible listing as endangered, threatened, or sensitive.
S = State Sensitive - A species native to the state of Washington that is vulnerable or declining and likely to become endangered or threatened throughout a significant portion of its range within the state without cooperative management or removal of threats.
N/A = Not applicable, available

### Impacts to State-Listed Wildlife and Plant Species

There are no wetlands or waterbodies on the project site, therefore there would be no impacts to species relying on those habitats. The project site has minimal vegetation and marginal if any current habitat value. No woodlands would be impacted by the construction of the Phase II project. The state listed wildlife in the vicinity of the study area may be temporarily displaced due to either the construction or operational noise. Signs of pileated woodpecker foraging activity was observed in forested stands near Fuller Creek, but no long-term impacts are anticipated with either the construction or operation of the plant. None of the remaining listed wildlife have been documented onsite or within the study area by WDFW. The fish species documented in the Chehalis River and Fuller Creek are not expected to be impacted.

## 3.4.3 FISH OR WILDLIFE MIGRATION ROUTES

Concentrations of waterfowl, including Canada geese, mallards, gadwalls, pintails, wigeons, shovelers, and teal, are defined as a state priority species. Seasonally flooded fields along the Chehalis River provide wintering habitat for over 10,000 wigeons, mallards, pintails, and buffleheads, 250 Canada geese, and 80 trumpeter swans (WDNR 1994). Numerous waterfowl were observed in flooded fields and emergent wetlands in the study area during field surveys in January 1994. Construction and operation of the project will not affect the migration of these or other migrating species.

## 3.5

# Energy and Natural Resources (WAC 463-42-342)

**WAC 463-42-342 NATURAL ENVIRONMENT — ENERGY AND NATURAL RESOURCES.**

*(1) Amount required/rate of use/efficiency - The applicant shall describe the energy and natural resource consumption during both construction and operation of the proposed facilities as rate of use and efficiency that can be achieved during construction and operation.*

*(2) Source/availability - The applicant shall describe the sources of supply, locations of use, types, amounts, and availability of energy or resources to be used or consumed during construction and operation of the facility.*

*(3) Nonrenewable resources - The applicant shall describe all nonrenewable resource that will be used, made inaccessible or unusable by construction and operation of the facility.*

*(4) Conservation and renewable resources - The applicant shall describe conservation measures and/or renewable resources which will or could be used during construction and operation of the facility.*

*(5) Scenic resources - The applicant shall describe any scenic resources which may be affected by the facility or discharges from the facility.*

# 3.5 ENERGY AND NATURAL RESOURCES (WAC 463-42-342)

## 3.5.1 INTRODUCTION

Energy and natural resources are consumed during construction and operation of any facility. Because the Phase II project will generate electricity, it will produce many times more energy than is invested in its materials or is used to construct it. Thus, the focus of this section is on the operational aspect of the project.

## 3.5.2 ENERGY REQUIRED

### 3.5.2.1 Construction

Cranes, trucks, mobile equipment, and power tools will all consume energy during project construction. Similarly, energy is used during manufacturing of the combined cycle equipment and materials necessary for constructing the new combustion turbine facility. For example, the steel used in much of the equipment requires energy input during the foundry, rolling mill, and fabrication processes. Until the project's detailed design has been completed, estimates of materials content and manufacturing energy use cannot be made; however, the purpose of the combustion turbine facility will be to produce electrical and steam energy over a planned project lifetime of at least 30 years. During this time the Phase II project will produce approximately 171 million megawatt hours of electricity, an amount far in excess of the energy required for production of the materials used in the manufacture and fabrication of the equipment used in the project.

### 3.5.2.2 Operation

The Phase II project will be fueled by natural gas. A small amount of diesel fuel (#2 distillate) will be on site for the backup generators and fire-water pump. The Phase II project will contract for a firm, long-term (non-interruptible) gas supply and non-interruptible transportation.

Natural gas will be delivered to the Phase II project by the natural gas pipeline installed for Phase I. Natural gas will flow from the pipeline through a metering/pressure-regulating station located on the northern boundary of the project site.

The Satsop CT Project (both phases) will require a maximum of 103,048 pounds per hour of natural gas to fuel each combustion turbine and duct burner, for a maximum consumption of 412,192 pounds per hour for the Phase I and Phase II projects. Annually, a maximum of 3.6 billion pounds of natural gas will be used to fuel both phases, assuming 8,760 hours of operation per unit. The auxiliary boilers will use a maximum of 1,254 pounds per hour of natural gas. Annually, a maximum of 6.3 million pounds of natural gas will be used to fuel the auxiliary boilers assuming 2,500 hours of operation per boiler. Assuming a 30-year project life, the Satsop CT Project will require a maximum of 108 billion pounds of natural gas to generate a maximum of 342 million megawatt-hours of electricity.

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.

## 3.5.3 SOURCE AND AVAILABILITY OF ENERGY AND NATURAL RESOURCES

The project's fuel will be natural gas that will be supplied by a pipeline constructed as part of Phase I. An agreement has been negotiated with Williams Gas Marketing to provide natural gas to the facility. The agreement allows for supplies to be drawn from both domestic and Canadian sources. A final determination of the fuel source will be made when the fuel contract is finalized, after final commitment for construction. The suppliers have sufficient gas available to provide for the needs of the project and other customers over the 30-year life of the project.

## 3.5.4 NONRENEWABLE RESOURCES

### 3.5.4.1 Construction

The project will use a variety of natural resources, although in relatively small amounts. The largest quantities will be of steel (from iron ore) and concrete (from aggregate and sand from quarries and pits and cement). Diesel fuel and electrical power will also be consumed during construction.

### 3.5.4.2 Operation

The main resource consumed by operation of the facility will be natural gas.

In addition, operation of the plants will entail consumption of minor amounts of other materials, such as metals, petroleum-based lubricants, paints, and various chemicals used in the process of operation and normal maintenance of the plants.

## 3.5.5 CONSERVATION AND RENEWABLE RESOURCES

Compared with many other sources of electricity, the Phase II project will conserve energy. The facility is expected to operate at approximately 54 to 54.5 percent efficiency across the ambient temperature range, compared to 30 to 45 percent efficiency for other types of thermal plants. A discussion of water reuse can be found in Section 2.8.

## 3.5.6 SCENIC RESOURCES

Impacts to scenic resources are described in Section 5.1 - Land and Shoreline Use, WAC 463-42-362.

As discussed in Subsection 6.1.8 of the PSD Application, four Class I areas are located within 160 kilometers (100 miles) of the project site: Mt. Rainier National Park, Goat Rocks Wilderness Area, Alpine Lakes Wilderness Area, and Olympic National Park. The Class I area closest to the proposed Satsop CT Project is Olympic National Park, located approximately 58 kilometers (35 miles) to the northeast. Other Class I areas considered in the modeling analysis are Pasayten Wilderness, Glacier Peak 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 Are (CRGNSA). Results of the CALPUFF dispersion modeling performed for the proposed project show that concentrations of pollutants from both phases of the project are well below the Class I allowable increment for the nearest Class I area and thus are not expected to have a significant impact upon these scenic resources. Additionally, the regional haze analyses show minimal impact from the project.

Visual impacts of the facility upon the existing regional landscape are not expected to be significant. Even though project buildings and ancillary facilities will not be seen, a small portion of the emission stacks may be visible from some viewpoints in the Chehalis River Valley. The WNP-3 and WNP-5 cooling towers, juxtaposed against the horizontal profile of the background hills, are objects of attention for viewers looking across the open plain of the Chehalis River Valley. These cooling towers may be removed in the future. If visible, the presence of small portions of the project's emission stacks will be an additional, but minor, element to the west of the existing and taller cooling towers of WNP-3 and WNP-5. Depending on the time of year and weather conditions, attention to the stacks could be more pronounced when a vapor plume is present.

The impact to local residents adjacent to the site is expected to be slightly negative but not significant, due to the overall visual compatibility of the project with the existing conditions. Even though the emission stacks and the higher plant structures will be visible, the Phase II facility will be an expansion of the Satsop CT Project which already provides a context of low visual quality. The vegetated screening berm and turbine equipment enclosures will also reduce visual impacts.

# 4.1
# Environmental Health (WAC 463-42-352)

**WAC 463-42-352 BUILT ENVIRONMENT — ENVIRONMENTAL HEALTH.**

*(1) Noise - The applicant shall describe the impact of noise from construction and operation and shall describe the measures to be taken in order to eliminate or lessen this impact.*

*(2) Risk of explosion - The applicant shall describe any potential for fire or explosions during construction, operation, standby or nonuse, dismantling, or restoration of the facility and what measures will be made to mitigate any risk of fire or explosion.*

*(3) Releases or potential releases to the environment affecting public health, such as toxic or hazardous materials - The applicant shall describe any potential for release of toxic or hazardous materials to the environment and shall identify plans for complying with the federal Resource Conservation and Recovery Act and the state Dangerous waste regulations (Chapter 173-303 WAC). The applicant shall describe the treatment or disposition of all spent fuel, ash, sludge, and bottoms, and show compliance with applicable state and local solid waste regulations.*

*(4) Safety standards compliance - The applicant shall identify all federal, state, and local health and safety standards which would normally be applicable to the construction and operation of a project of this nature and shall describe methods of compliance therewith.*

*(5) Radiation levels - For facilities which propose to release any radioactive materials, the applicant shall set forth information relating to radioactivity. Such information shall include background radiation levels of appropriate receptor media pertinent to the site. The applicant shall also describe the proposed radioactive waste treatment process, the anticipated release of radionuclides, their expected distribution and retention in the environment, the pathways which may become sources of radiation exposure, and projected resulting radiation doses to human populations. Other sources of radiation which may be associated with the project shall be described in all applications.*

# 4.1 ENVIRONMENTAL HEALTH
# (WAC 463-42-352)

## 4.1.1 NOISE

### 4.1.1.1 Existing Conditions

**Characteristics of Noise Propagation and Attenuation**

Ambient sound levels can be generated by a number of noise sources, including mobile sources, such as automobiles, trucks, trains, and airplanes, and stationary sources, such as construction sites, machinery, or industrial operations. Often "background" sound sources can contribute substantially to ambient sound levels; background sources can include birds chirping, an occasional vehicle passing by, a television or radio, or leaves rustling in the wind. These background sources can determine the ambient sound levels in areas not dominated by a single major noise source.

Noise is any sound that is undesirable because it interferes with speech and hearing, or is otherwise annoying (unwanted sound). If present in high intensities, loud sounds have the potential to cause hearing damage. Sound is measured in decibels (dB), a logarithmic ratio between pressures caused by a given sound source and a reference sound pressure. The human ear is not equally sensitive to all frequencies in the sound spectrum. Thus, it is standard to represent sound levels using a scale corresponding to the range and characteristics most consistent with the way human ears perceive sounds: the A-weighted scale, dB(A). Because this scale is logarithmic and associated with the typical sensitivity response of the human ear, a dB(A) increase does not always result in a direct increase in perceived loudness. In fact, small fluctuations in A-weighted sound level (less than 3 dB) are not typically audible.

Using the A-weighted scale, sound levels at an average residence typically range from 45 dB(A) to 55 dB(A). Sounds associated with nearby freeway and highway traffic are generally louder, ranging from 65 dB(A) to 80 dB(A), depending on the type, number, and speeds of vehicles on the roadway, distance from noise-sensitive receptors to the noise source (traffic), and topographic conditions (attenuation effects). Because sounds do vary (depending, for example, on equipment type and duration of use), the equivalent average sound level (denoted as $L_{eq}$), is used to represent the acoustical energy equivalent, over a specified period of time, to the actual fluctuating sound over that same time span.

**Regulatory Controls**

Regulations applicable to the proposed Phase II expansion are codified in Washington Administrative Code (WAC) Chapter 173-60, Maximum Environmental Noise Levels. There are no community noise regulations in effect for Grays Harbor County.

The State of Washington has established noise regulations based on land use compatibility as shown in Table 4.1-1. Compliance with these regulatory limits is judged separately for each source. In other words, the regulations prohibit a source from generating more than the specified amount of sound at the receiving location. They do not require the cumulative sound generated by all sources to remain below the specified levels. For the purpose of this analysis, we have analyzed the impacts of Phase II, and then the cumulative impacts of Phases I and II as a single source.

Although not specifically stated in the code, the noise abatement criteria are assumed to be presented as equivalent sound levels ($L_{eq}$). For noise-sensitive areas or areas which fall under Class A (residential areas), the noise abatement criterion is an $L_{eq}$ of 60 dB(A) when the noise originates from a Class C site. For areas which fall under Class B (commercial areas), the noise abatement criterion is an $L_{eq}$ of 65 dB(A), when the noise originates from a Class C (industrial) site. And, for areas which fall under Class C, the noise abatement criterion is an $L_{eq}$ of 70 dB(A) when the noise originates from a Class C site. Between the hours of 10:00 P.M. and 7:00 A.M. the noise limitations in Table 4.1-1 are reduced by 10 dB(A) for receiving property within Class A areas. Additionally, at any hour of the day or night, the applicable noise limitations may not be exceeded in any 1-hour period by more than 5 dB(A) for a total of 15 minutes, 10 dB(A) for a total of 5 minutes, or 15 dB(A) for a total of 1.5 minutes. These correspond to the L25 (25 percent of 1 hour, or 15 minutes), L8.3, and L2.5 sound levels, respectively. Assuming the worst-case conditions of the proposed Phase II plant running 24 hours per day, these time-weighted adjustments would not apply for this project. Rather, the steady-state WAC 173-60 $L_{eq}$ limits are pertinent without adjustment.

**TABLE 4.1-1**
**MAXIMUM PERMISSIBLE ENVIRONMENTAL SOUND LEVELS[A]**

| EDNA of Noise Source[b] | Maximum Permitted Sound Level by EDNA of Receiving Source[c] | | |
|---|---|---|---|
| | **Class A** | **Class B** | **Class C** |
| Class A | 55 | 57 | 60 |
| Class B | 57 | 60 | 65 |
| Class C | 60 | 65 | 70 |

[a] Data from Washington State Department of Ecology, Noise Regulations, Chapter 173-60.
[b] EDNA =Environmental Designation for Noise Abatement.
[c] Sound levels in dB(A).

Class A = Residential areas or lands where human beings reside and sleep; such as residential areas, multiple family living areas, recreational and entertainment areas (e.g., camps, parks, resorts), community service areas (e.g., retirement homes, hospitals, health and correctional facilities).
Class B = Commercial areas or land uses requiring protection against noise interference with speech; such as commercial living and dining areas, motor vehicle services, retail services, banks, office buildings, and commercial and recreational areas not used for human habitation (e.g., theaters, stadiums, fairgrounds, amusement parks, and educational, religious, governmental, and cultural facilities).
Class C = Industrial areas or lands involving economic activities; such as agricultural, storage, warehouse, production, and distribution facilities.

The Phase II expansion site is located within Grays Harbor County's Industrial (I-2) zoning designation (see Figure 4.1-1). Based on this information, the plant site and the surrounding areas are categorized as Class C. Current existing residences are located in General Development District Five (GD-5), which, for purposes of this analysis, are assumed to be Class A. These applicable noise level limits, as well as the pertinent existing conditions are summarized in Table 4.1-2.

**TABLE 4.1-2**
**PERTINENT ALLOWABLE SOUND LEVELS FOR PROPOSED PHASE II PLANT**

| Location[a] | 2001 Nighttime Ambient Noise Level, $L_{eq}$ dB(A) | WAC 173-60 Nighttime Noise Level Limit, $L_{eq}$ dB(A) |
|---|---|---|
| Plant_W (#1) | 42.8 | **70** |
| Plant_S (#2) | 35.8 | **70** |
| Plant_N (#3) | 34.7 | **70** |
| Plant_E | No data | **70** |
| #4 | 42.4 | **50** |
| #5 | 32.4 | **50** |
| #6 | 41.2 | **50** |
| #7 | 35.0 | **50** |

[a] Locations are shown in Figure 4.1-2.

## Noise Evaluation and Analysis Methods

A computerized noise prediction program was used to simulate and model the noise propagation from the Phase II plant. The modeling program uses industry-accepted propagation algorithms based on standards written by CONCAWE[1]. The calculations account for classical sound wave divergence (spherical spreading loss with adjustments for source directivity from point sources) plus attenuation factors due to air absorption, minimal ground effects, and barrier/shielding (including reductions from vegetation/ forestation)[2].

Calculations are performed using octave band sound power levels (abbreviated PWL or Lw) as inputs from each noise source. The computer outputs are in terms of octave band and overall A-weighted noise levels (sound pressure levels, abbreviated SPL or $L_p$) at discrete receptor positions or at grid map nodes (in preparation for computing a contour map). The output listing is ranked by relative noise contribution from each noise source. This model has been validated over the years via noise measurements at several operating plants that had been previously modeled during the engineering design phases.

[1] CONCAWE is the oil companies' European organization for environment, health, and safety, headquartered in Brussels, Belgium. The noise propagation standard was originally published in 1981 under the title "The propagation of noise from petroleum and petrochemical complexes to neighboring communities." Parts of this method are also included in the ISO 9613, ISO 1913 (Part 1), ANSI 126, or ISO 3891 standards.
[2] For ease of use and computational efficiency, the model does not provide for advanced ground attenuation definitions, special screening effects, or complex meteorological variables.

The project site plan drawing, Figure 2.3-4, was used to establish the position of the noise sources. The plant configuration drawing, Figure 2.3-3, and previous 1995 application drawings were used to locate receptor locations with respect to the facility layout. The receptor locations were chosen to match, as closely as possible, the positions used in the 1995 application, and the 2001 ambient survey. These approximate receptor locations are shown in Figure 4.1-2. Both the source locations and receptor locations were translated into input x, y, z coordinates for the noise modeling program.

**Procedures, Inputs, and Assumptions**

For conservatism, and as is standard practice in the description of environmental noise, the modeling assumed stable atmospheric conditions suitable for reproducible measurements (under "standard day" conditions of 59°F and 70 percent relative humidity), that are favorable for propagation. These inherently conservative factors and assumptions result in a noise model that will tend be biased to higher predicted values than would be expected in the actual environment around the proposed project.

All continuous-operation equipment items that were deemed to be significant noise sources at the Phase II plant were included in the noise model. The set of modeled sources included turbines (gas and steam), heat recovery steam generators (HRSGs) pumps, motors (taken to be TEFC or WPII[3] type, depending on horsepower rating[4]), main transformers, air compressors, fans and blowers (including roof-top ventilators and HVAC units), cooling tower cells, and chiller modules. Only the currently planned Phase II set of power generation equipment was modeled.

The plant was assumed to operate 24 hours per day, which means its noise output would be constant regardless of time of day. Given the early stages of the project, project-specific vendor data is not available. The modeling inputs used noise emission values that were obtained from equipment vendors on several recent Duke/Fluor-Daniel (D/FD) design efforts for similar-sized plant configurations, and data used for the Phase I design.

No special noise control options were initially assumed. These "standard design" levels from the significant noise sources were converted into sound power levels (in decibels re 1 pico Watt) to serve as inputs for the noise modeling program. Major buildings were included as barriers, as were the HRSG's bodies and some large storage tanks. However, for conservatism, only the end caps of the cooling tower were considered as barriers. The analysis included the benefits of Phase I barriers and structures that will be in place prior to the start-up of Phase II. Specifically, the Keys Road sound wall along the entire length of the west site boundary, as well as several Phase I retaining walls, equipment, and buildings were included in the Phase II model.

Sound emissions values were modeled to calculate the expected noise levels at the selected receptor locations. For several receptors, initial noise estimates produced noise levels that were

[3] TEFC is totally-enclosed, fan-cooled and WPII is weather-proof, Type II

[4] Small equipment items, such as pumps less than 20 horsepower, were excluded since they were considered as insignificant sources.

above regulatory requirements. To achieve compliance, noise contributing equipment was evaluated. An iterative process of reducing the highest noise contributors, via the effective application of noise control treatments such as installing silencers on exhausts or using low-noise equipment, was performed. This process achieved an efficient, cost-effective, and reasonably achievable mix of noise source characteristics (see Subsection 4.1.1.3).

4.1.1.2 Impacts

**Construction**

Areas adjacent to the proposed project will be exposed to construction sounds produced by construction equipment and activities. Figure 4.1-3 shows the typical range of sound levels for construction equipment that may be used for this project.

Construction activities are excluded from Ecology noise ordinances. However, the following construction sound abatement measures which are included in the existing Phase I SCA, will be included in the project construction specifications to mitigate construction sound impacts:

- Construction will not be performed within 1,000 feet of an occupied dwelling unit on Sundays, legal holidays, or between the hours of 10:00 P.M. and 6:00 A.M. on other days.
- All construction equipment will have sound control devices no less effective than those provided on the original equipment. Equipment will not be operated with unmuffled exhaust systems.
- Pile driving or blasting operations, if required, will not be performed within 3,000 feet of an occupied dwelling unit on Sundays, legal holidays, or between the hours of 8:00 P.M. and 8:00 A.M. on other days.

Despite inclusion of the measures described above, areas adjacent to the project will be exposed to increased sound levels during active periods of construction. This will be a short-term impact. The Certificate Holder will notify nearby residents in advance of the anticipated schedule for construction activities.

**Operation**

<u>Model Results</u>

The site boundary and nearby community noise levels that are predicted from the Phase II plant operations (only) are summarized in Table 4.1-3 along with the pertinent noise level limit and information (for reference) on the ambient noise environment at each receptor location.

**TABLE 4.1-3**
**SUMMARY OF MODELING RESULTS FOR PROPOSED PHASE II PLANT**

| Location | 2001 Nighttime Ambient Noise Level, $L_{eq}$ dB(A) | Maximum Allowable Contribution from Proposed Phase II Plant, dB(A) | Predicted Contribution from Proposed Phase II Plant, dB(A) | Total Predicted Future Noise Environment (Measured Ambient plus Proposed Phase II Plant Contribution), dB(A) | Difference between Total Future Noise Environment and Allowable Noise Level Contribution, dB |
|---|---|---|---|---|---|
| Plant_W (#1) | 42.8 | 70 | 42 | 45 | -28 |
| Plant_S (#2) | 35.8 | 70 | 68 | 68 | -2 |
| Plant_N (#3) | 34.7 | 70 | 44 | 44 | -26 |
| Plant_E | No data | 70 | 75 | 75 | +5 |
| #4 | 42.4 | 50 | 36 | 43 | -7 |
| #5 | 32.4 | 50 | 37 | 38 | -12 |
| #6 | 41.2 | 50 | 35 | 42 | -8 |
| #7 | 35.0 | 50 | 38 | 40 | -10 |

Table 4.1-3 shows that the critical analysis locations are the adjacent properties to the south and east. This is because these locations are quite close to the GTG/HRSG, the STG, the chiller modules, and the cooling tower array. Further, these locations receive little benefit from barrier shielding from either Phase II equipment or from Phase I equipment, buildings, and/or walls (as do the receptor locations to the north and west). Therefore, the south and east property line locations served as the primary design points for controlling noise emissions from the Phase II project.

The set of Phase II noise sources was then used to create a noise contour map of the proposed facility. Figure 4.1-4 presents constant, A-weighted sound level contours in 5-dB increments on the currently planned project site from just the Phase II equipment (including the measured ambient environment). Note that this Phase II-only contour would be applicable only in the situation where Phase II was operating and Phase I was idle.

As with Phase I, the Certificate Holder is negotiating an agreement under which the neighboring property owner (Grays Harbor Public Development Authority) has consented to noise levels in excess of the otherwise applicable 70-db(A) noise limit.

Cumulative Impacts

Since the expectation is to generate power with both Phase I and Phase II in operation, an assessment of the combined noise emissions from the entire site was undertaken. The separate modeling files for the Phase I project and the Phase II project were combined such that the total allotment of site equipment with the common physical barriers could be analyzed. The results are as shown in Table 4.1-4.

## TABLE 4.1-4
## SUMMARY OF MODELING RESULTS FOR THE CUMULATIVE PHASE I AND PHASE II PLANTS

| Location | 2001 Nighttime Ambient Noise Level, $L_{eq}$ dB(A) | Maximum Allowable Contribution from Combined Project Site, dB(A) | Predicted Contribution from just Ph. I Project (for reference only), dB(A) | Predicted Cumulative Contribution from Combined Projects (Ph. I + Ph. II), dB(A) | Total Predicted Future Noise Environment (Measured Ambient plus Proposed Combined Projects, (Ph. I + Ph. II), dB(A) | Difference between Predicted Site Cumulative and Allowable Contribution, dB |
|---|---|---|---|---|---|---|
| Plant_W (#1) | 42.8 | 70 | 51 | 52 | 52 | -18 |
| Plant_S (#2) | 35.8 | 70 | 66 | 70 | 70 | -0 |
| Plant_N (#3) | 34.7 | 70 | 53 | 53 | 53 | -17 |
| Plant_E | No data | 70 | 61 | 75 | 75 | +5 |
| #4 | 42.4 | 50 | 37 | 40 | 44 | -6 |
| #5 | 32.4 | 50 | 38 | 41 | 42 | -8 |
| #6 | 41.2 | 50 | 34 | 37 | 43 | -7 |
| #7 | 35.0 | 50 | 36 | 40 | 41 | -9 |

Since the cumulative impacts would be due to the addition of the Phase II project, the relevant noise level limits for the combined facility are the WAC 173-60 nighttime limits as shown in Table 4.1-4. A noise contour map of this cumulative set of compliant site noise sources was created for the proposed facility. Figure 4.1-5 shows the constant, A-weighted sound level contours in 5-dB increments on the currently planned project site from the combined Satsop CT Project, Phase I plus Phase II (including the contributions from the measured ambient noise levels).

Figure 4.1-4 (Phase II only) shows that the project's contribution on the west side of the plant can be expected to be in the mid-40s dB(A), owing primarily to the benefit from the 25-foot-high sound wall along the west side and the cooling tower retaining walls along the north and west sides of the project site. The north and south sides of the plant are expected to be in the high 60s dB(A) due to the proximity of major equipment, coupled with the lack of significant barrier shielding. Likewise, the proximity of major equipment to the eastern boundary will result in noise levels, generally around 75 dB(A), with a small area around the circulating water pumps that may be expected to be approximately 80 dB(A). More importantly, the 70-dB(A) contour would protrude only marginally into the adjacent wooded land. The distant residential receptors are predicted to receive contributions from Phase II in the mid- to upper-30s dB(A), which is comparable to the contributions from just the Phase I project at these locations.

Figure 4.1-5 (cumulative of Phase I plus Phase II) shows combined site contributions in the mid-50 dB(A) range along the west property line and 70 dB(A) or just above along portions of the north and south property lines. The east boundary will generally have noise levels around 75 dB(A) with only a relatively small area in the adjacent wooded parcel exceeding 70 dB(A). The distant residential receptors are predicted to receive total site contributions in the upper-30s to low-40s dB(A).

The most notable noise sources include the HRSG, the GTG and STG casings and generators, the main cooling water pumps/motors, and the cooling tower fans (including water splash noise). Other sources that are nearly as important for community levels include the chiller modules, the boiler feedwater pumps/motors, and the main transformers.

#### 4.1.1.3 Indicated Equipment Noise Level Limits and Conceptual Mitigation Measures

The mitigated noise emission levels were calculated into near-field and far-field noise level specifications for individual equipment items. These individual levels will be used for specification requirements during equipment procurement to ensure that the aggregate plant noise levels are within the project's noise predictions. The equipment noise level specifications, as well as the associated noise control methodologies, are summarized in Table 4.1-5.

**TABLE 4.1-5**
**SUMMARY OF NOISE LEVELS AND POTENTIAL CONTROL MEASURES**

| Noise Source | Noise Level Specification and Proposed Noise Control Measure |
|---|---|
| Gas Turbine (including turbine casing, generator, accessory bay, load compartment, and support skids) | Near-Field Limit: 85 dB(A) at 3' |
| | Far-Field Limit: 60 dB(A) at 400' composed of the components:<br>Casing: 55 dB(A) at 400'<br>Generator: 55 dB(A) at 400'<br>Accessory Bay: 54 dB(A) at 400'<br>Exhaust Plenum: 49 dB(A) at 400'<br>Inlet Plenum: 47 dB(A) at 400'<br>Load Compartment: 45 dB(A) at 400'<br>Air Inlet: 44 dB(A) at 400' |
| | Noise Control: An acoustical enclosure on the turbine, noise treatment of the generator, and a local wall system around the outlet plenum. |
| Steam Turbine/Condenser (including turbine casing, generator, and support skids) | Near-Field Limit: 85 dB(A) at 3' |
| | Far-Field Limit: 60 dB(A) at 400' composed of the components:<br>Casing: 56 dB(A) at 400'<br>Generator: 55 dB(A) at 400'<br>Condenser: 53 dB(A) at 400' |
| | Noise Control: An acoustical enclosure on the turbine and noise treatment of the generator as well as acoustical insulation on the condenser and related piping. |
| HRSG | Near-Field Limit: 85 dB(A) at 3' |
| | Far-Field Limit: 58 dB(A) at 400' composed of the components:<br>Transition: 57 dB(A) at 400'<br>Boiler Section: 50 dB(A) at 400'<br>Stack Wall: 38 dB(A) at 400'<br>Stack Exit: 44 dB(A) at 400' |
| | Noise Control: A stack silencer as well as quiet drum and vent systems. |

## TABLE 4.1-5 (CONTINUED)
## SUMMARY OF NOISE LEVELS AND POTENTIAL CONTROL MEASURES

| Noise Source | Noise Level Specification and Proposed Noise Control Measure |
|---|---|
| Cooling Tower | Near-Field Limit: 85 dB(A) at 3' (grade level & on the fan deck). |
| | Far-Field Limit: 62 dB(A) at 400' |
| | Noise Control: Specification of a special design, including attention to fan tip speed, blade design, drive mechanisms, and splash control. |
| Air Inlet Chiller Modules | Near-Field Limit: 85 dB(A) at 3' (grade level). |
| | Far-Field Limit: 55 dB(A) at 400' |
| | Noise Control: Use of a special design, including attention to fan tip speed, blade design, drive mechanisms, and splash control. |
| Main Transformers | Near-Field Limit: 85 dB(A) at 3' |
| | Far-Field Limit: 55 dB(A) at 400' |
| Aux. Transformers | Near-Field Limit: 72 dB(A) at 3' |
| | Far-Field Limit: 39 dB(A) at 400' |
| Air Compressors | Instrument air compressors should be limited to 80 dB(A) at 3' |
| Pumps | Specification of pump and driver trains such that they will be nominally limited to 85 dB(A) at 3'; per the following:<br>Boiler Feedwater: 90 dB(A) for the combined train<br>Cooling Tower Circ'n: 88 dB(A) for the combined train<br>Vacuum Condensate: 90 dB(A) for the combined train<br>Closed Loop Cooling Water: 88 dB(A) for the combined train<br>All other pumps (>25 hp): 85 dB(A) for the combined train<br>All other pumps (<25 hp): 80 dB(A) for the combined train |
| Control valves | Noise Control: Specification of low-noise valves and/or use of acoustical insulation on valve case and related piping, as appropriate. |
| Atmospheric Vents | Noise Control: Use of low-noise valves (see above) as well as vent discharge silencers, as appropriate, to attain project noise limits and OSHA noise exposure compliance for plant personnel. |
| Piping | Noise Control: Insulation materials and application methods for both acoustical and thermal qualities. |
| Other General Equipment Items (including material handling equipment) | Noise Control: All equipment, stationary and mobile, deemed to be significant noise sources would have noise limits included in the supplier bid conditioning and procurement process. All necessary noise control treatments will be made part of each supplier's scope. |

In addition to the equipment noise control measures listed in Table 4.1-5, modeling results for Phase I and Phase II are predicated on additional noise control features. These additional features are a collection of barriers and walls that were installed as part of Phase I and are detailed in Table 4.1-6.

**TABLE 4.1-6**
**SUMMARY OF ADDITIONAL NOISE CONTROL MEASURES**
**INSTALLED AS PART OF PHASE I**

| Item | Description | Function |
|---|---|---|
| West Sound Wall | The sound wall system is a height of 25' above plant grade. | Shields the majority of plant equipment for both Phases I and II from the sensitive residential receptors to the west. |
| North Cooling Tower Wall (north of Phase I Cooling Tower) | The retaining wall is +20' above plant grade. | Shields cooling tower noise for both Phases I and II. |
| West Cooling Tower Wall (west of Phase I Cooling Tower) | The retaining wall is +20' above plant grade. | Shields cooling tower noise for both Phases I and II. |

## 4.1.2 RISK OF FIRE OR EXPLOSION

The discussion of the risk of a fire or an explosion at the combustion turbine facility is organized in three parts: risk during construction, risk during operation, and mitigation of risk.

### 4.1.2.1 Risk During Construction

The risk of a fire or explosion during construction of the Phase II project is considered to be extremely low. During construction, small quantities of flammable liquids and compressed gases will be stored and used. Liquids will include fuels, paints, and cleaning solvents. Compressed gases will include acetylene, oxygen, helium, hydrogen, and argon for welding. The potential hazards associated with use of these materials will be mitigated by following the state and federal construction safety requirements listed below:

- Washington Administrative Code 296-155
- Federal OSHA Safety Standards are listed in 29 CFR 1910 General Industry and 29 CFR 1926 Construction Industry. The following is a list of applicable standards:
  - OSHA Training programs such as: Hazard Communication 1910.1200, Confined Space Entry 1910.146, Lockout/Tagout 1910.147, and other OSHA mandated programs.
  - OSHA Standards: Fire Prevention 1910.38, Traffic Control, Excavations 1926.650, Scaffolding 1926.451, Ladders 1926.450, Use of Cranes and Crane inspections 1926.550, Storage of flammable and combustible liquids and gasses 1926.152, Fall Protection 1910.128, Welding and Burning 1910.252, 1910.255, Housekeeping 1926.25, Emergency Action Plans 1910.38, First Aid/Bloodborne Pathogens 1910.1030, Electrical Hazards 1910.332, Personal Protective Equipment. (PPE) 1926.28, .100 -.106.

#### 4.1.2.2 Risk During Operation

Operation of the Satsop CT Project will require the use of two materials which can be explosive under certain conditions: natural gas and hydrogen gas. Natural gas will be the primary fuel for the facility. The natural gas will be piped into the site; none will be stored on site. Hydrogen will be used as a coolant for the electrical generator for the combustion turbines and a maximum of approximately 70,000 cubic feet will be stored.

Aqueous ammonia will be used for injection into the selective catalytic reduction (SCR) system for NOx control and will be stored on site. However, aqueous ammonia is not considered a risk in terms of explosion potential or flammability, as it is composed of 70 percent water and will be stored separately from non-compatible materials in compliance with fire safety regulations.

For many years, industry has stored and used natural gas, hydrogen, and fuel oil in large quantities with little history of explosions or fire. When explosions occurred, they resulted from equipment malfunctions or operator errors. During these incidents, flammable gases were released in an unsafe manner, either inside equipment or to the work area. The combination of flammable gases, ignition sources, and oxygen resulted in explosions. As a result of these incidents, codes, regulations, and consensus standards have been upgraded to reduce the likelihood of recurrences. All phases of construction and operation of the proposed project will be conducted in compliance with these codes and regulations, as applicable.

#### 4.1.2.3 Mitigation of Risk

The risk of an explosion in the Phase II facility will be mitigated by designing, constructing, and operating the facility as required in the latest versions of the applicable codes, regulations, and consensus standards.

The Phase II project will be operated by qualified personnel using written procedures. Procedures will provide clear instructions for safely conducting activities involved in the initial startup, normal operations, temporary operations, normal shutdowns, emergency shutdowns, and subsequent startups. The procedures for emergency shutdowns will include the conditions under which emergency shutdowns are required, and the assignment of shutdown responsibilities to qualified operators to ensure that shutdowns are done in a safe and timely manner. Also covered in the procedures will be the consequences of operational deviations and the steps required to correct or avoid the deviations.

Before being involved in operating the Phase II facility, employees will be presented with a facility plan, including a Health and Safety Plan, and will receive training regarding the operating procedures and other requirements of safe operation of the plant. In addition, employees will receive annual refresher training, which will include testing of their understanding of the procedures. Training and testing records will be maintained.

To provide an early warning of a gas release, detectors will be installed for flammable gases and ammonia. Flammable gas detectors will monitor the work areas, and detectors will activate an alarm if the gas concentration reaches 20 percent of the lower explosive limit. If a hazardous concentration of gas is detected, the gas supply will be shut off and the work area evacuated.

A hazardous materials emergency response program will be implemented for Phase II, as will be done for Phase I. Satsop CT Project emergency responders trained and equipped to the technician level will be available at all times when Phase II is in operation. The emergency responders will use a written emergency response plan developed for Phase I and expanded to include Phase II.

### 4.1.3 RELEASES OR POTENTIAL RELEASES TO THE ENVIRONMENT

#### 4.1.3.1 Hazardous Materials Used During Construction

Hazardous materials are used in the initial chemical cleaning of the HRSG and process piping. A vendor has not yet been selected to conduct this task and, therefore, the specific chemicals that will be used are not yet known. However, a list of the typical types of chemicals used during chemical cleaning of the HRSG is expected to include the following:

- Aqueous ammonia
- Surfactant
- Corrosion inhibitors
- Citric or other similar acid
- Sodium nitrate
- Ammonium bicarbonate
- Anti-foam agent

In addition, hazardous materials which could generate solid or hazardous wastes during construction could include diesel fuel and gasoline, lubricants, cleaning solvents, and paint and paint residues. Other solid wastes associated with construction activities could include empty containers, scrap wood and scrap metal, and trash. Solid and hazardous wastes which would likely be generated during operation could include used oil and spent antifreeze, spent cleaning solvents, paint residues, unused adhesives, discarded water treatment chemicals and residuals, spent lead acid batteries, packing materials, scrap metal, trash, and garbage.

#### 4.1.3.2 Hazardous Materials Used During Operation

The types of chemicals and hazardous materials to be used and stored at the power plants are listed in Section 2.9 - Spillage Prevention and Control, WAC 463-42-205. One potentially explosive material, 70,000 cubic feet of hydrogen used as a coolant for the combustion turbine generators, will be stored on site.

### 4.1.3.3 Handling, Storage, and Disposal of Hazardous Materials

Operation of the Phase II project will not produce any spent fuel wastes, ash, or bottoms. A very small amount of sludge will be formed in the cooling tower. However, this sludge is not expected to be designated as a dangerous waste and will be disposed of in a landfill.

Handling, storage, and disposal of toxic and hazardous materials used in construction and operation of the project will be in accordance with applicable state and federal regulations as described below. The handling procedures for wastes produced by the Phase II project will be similar to those currently approved for the Phase I plant and will not result in a threat to public health and safety. However, only minor amounts of hazardous wastes will be generated by the Phase II project, primarily small quantities of materials such as used paints, thinners, and solvents.

**Hazardous Waste Management**

Any dangerous wastes generated by the Phase II Project will be managed by project personnel to ensure compliance with the Washington Dangerous Waste Regulation (WAC 173-303). The dangerous wastes will be limited to solvents and paint wastes generated during maintenance activities. The Satsop Power Plant has been assigned generator identification number WAD 980188510. A comprehensive dangerous waste management program fulfilling all requirements of the regulation is in place for the Satsop Power Plant. This includes waste designation, labeling, storage, handling and disposal procedures; record keeping; inspection; contingency planning; and management oversight elements. This program will be applied to the Satsop CT Project, and will include requirements for training of DEGH and contractor personnel in proper handling, storage, and disposal of hazardous materials.

**Hazardous Substances**

Title III of the Superfund Amendments and Reauthorization Act (SARA Title III) and the Occupational Safety and Health Administration's Hazard Communication Standard mandate communication of information to local agencies to assist in their response to emergency situations. Material Safety Data Sheets (MSDS) which provide specified information on each toxic or hazardous material stored and used on site will be maintained on file. A listing of MSDSs will be provided to local emergency response agencies, including the Elma Fire Department. The MSDS describe the potential health effects of each substance under different types of exposure and appropriate safety and treatment measures. The Certificate Holder will provide an annual inventory of the toxic and hazardous materials used on site (in accordance with Tier 2 reporting requirements).

**Hazardous Substance Release**

If during the operation of the facility any substance listed in 40 CFR 302 is released to the environment, the Certificate Holder will notify EFSEC, the National Response Center, EPA, and

Ecology as required under Section 101(14) of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). Energy Nothwest's response to any accidental release will be guided by its Spill Prevention Control and Countermeasure Plan, which will be expanded as appropriate to include the Phase II project (as described in Section 2.9 - Spillage Prevention and Control, WAC 463-42-205) and any additional measures required by EFSEC or Ecology.

In addition, the state Dangerous Waste Regulations, as codified at WAC 173-303, enforce the federal Resource Conservation and Recovery Act (RCRA) in Washington state. The existing Site Certification Agreement for the Satsop CT Project stipulates waste management procedures in accordance with the state regulations and these will be followed for the Phase II project.

### 4.1.4 SAFETY STANDARDS COMPLIANCE

The contractor and its subcontractors will be required to comply with applicable local, state, and federal safety, health, and environmental regulations. The primary standards to be used in the design, construction and operation of the Phase II project are the same as approved for the Phase I project.

### 4.1.5 RADIATION LEVELS

The proposed project is not expected to use or release any radioactive materials during operation. During construction, there will be a minor, controlled use of radiation. This will consist of X-rays of some plant equipment welds.

Minor controlled use of radiation during construction will be in accordance with state and federal standards and project-specific permit conditions covering these materials.

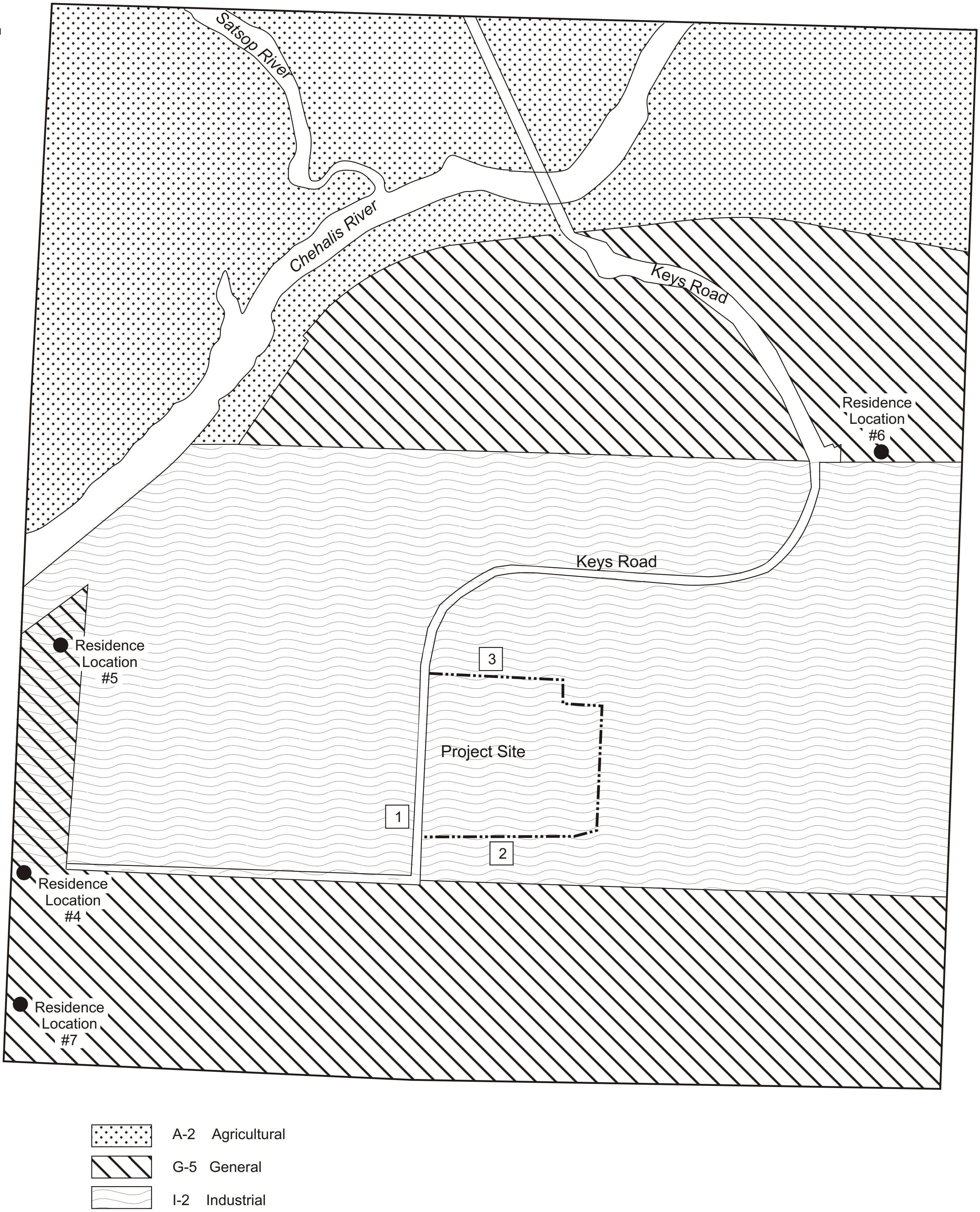
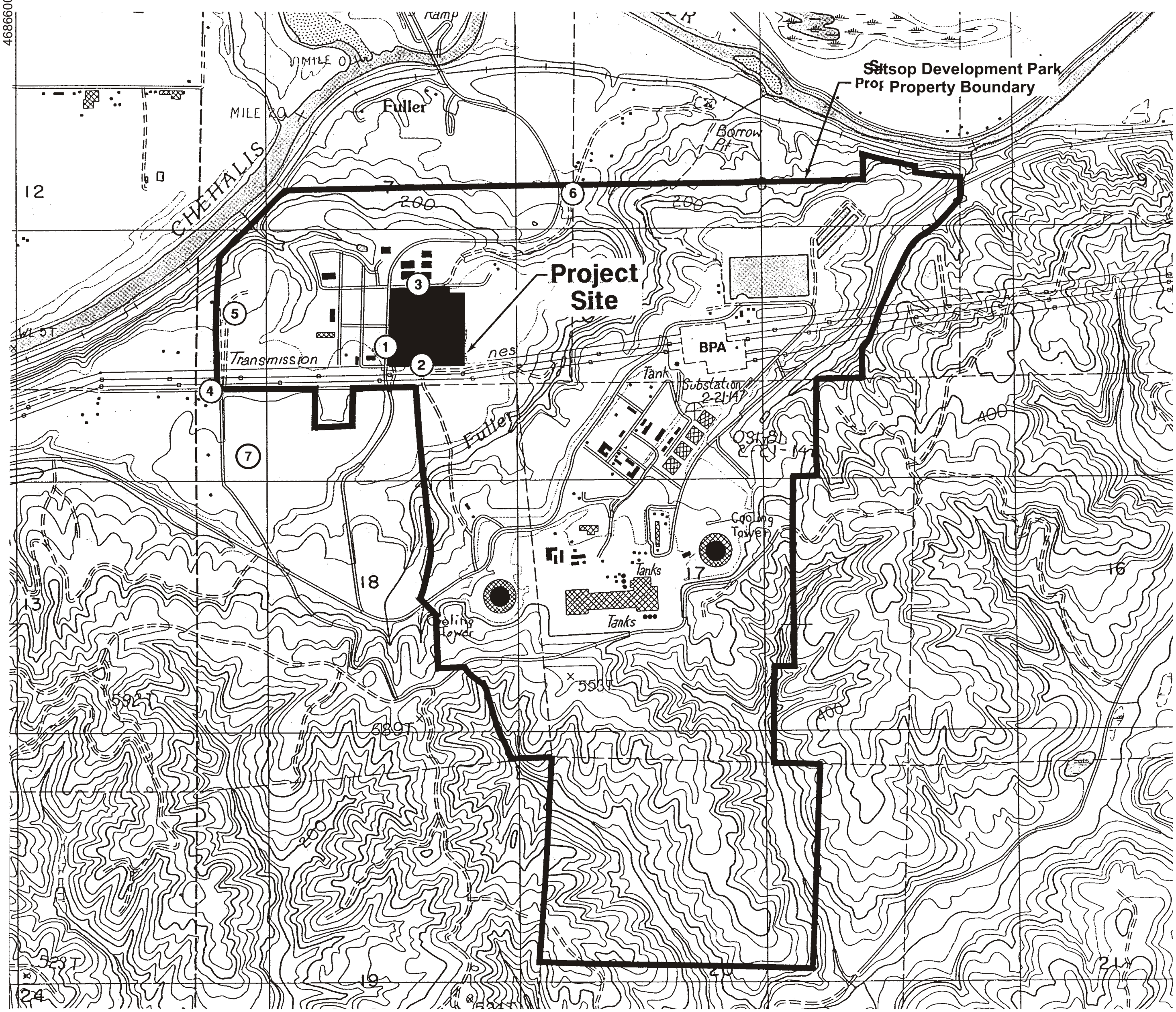



Figure 4.1-1

## Existing Zoning and Noise Monitoring Locations

URS




LEGEND:

(1) Ambient noise monitoring sites

0 0.25 0.50

Scale in Miles

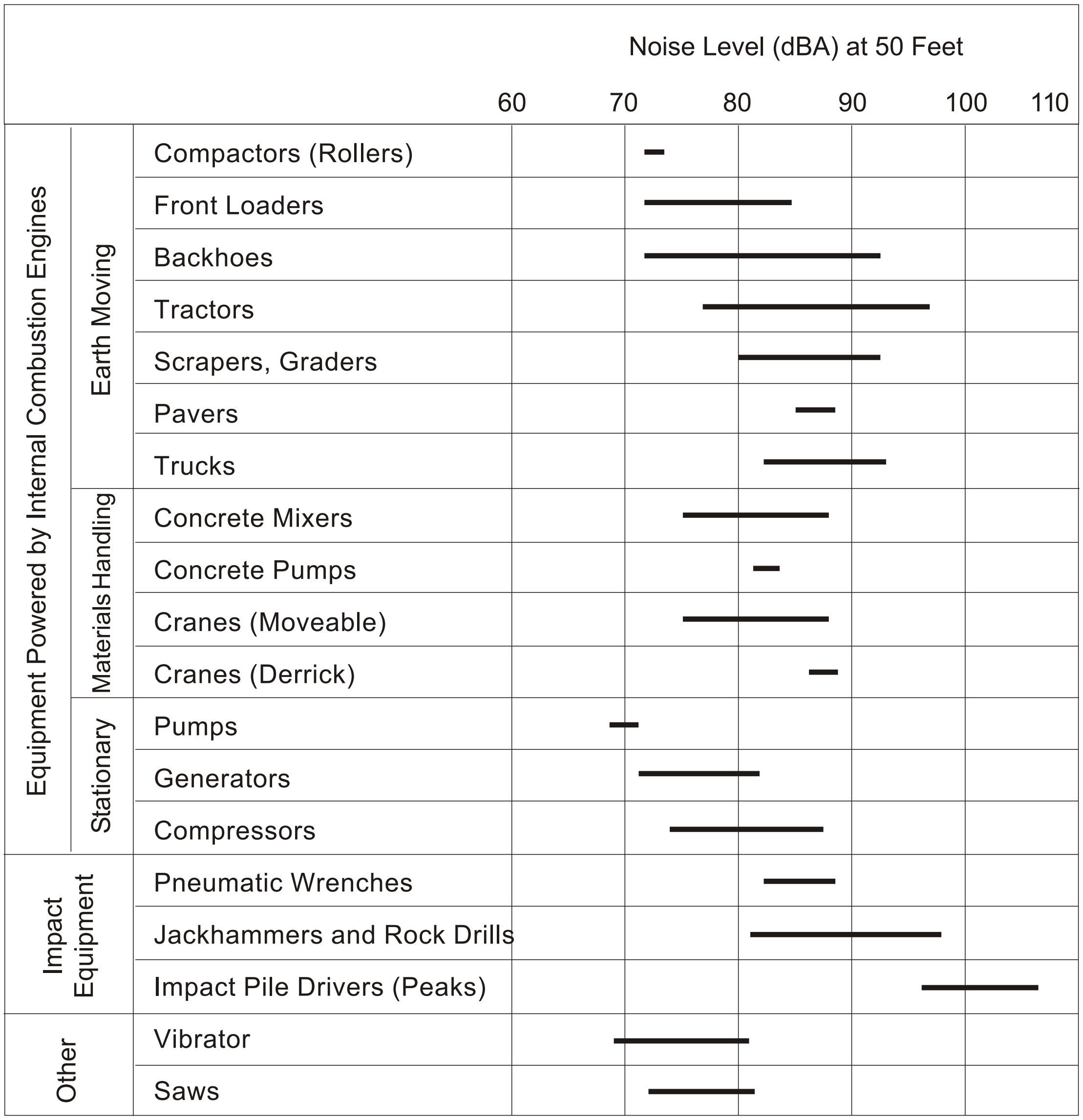
Figure 4.1-2

## Locations of Receptor Analysis Points

URS

Phase II Expansion
Satsop CT Project

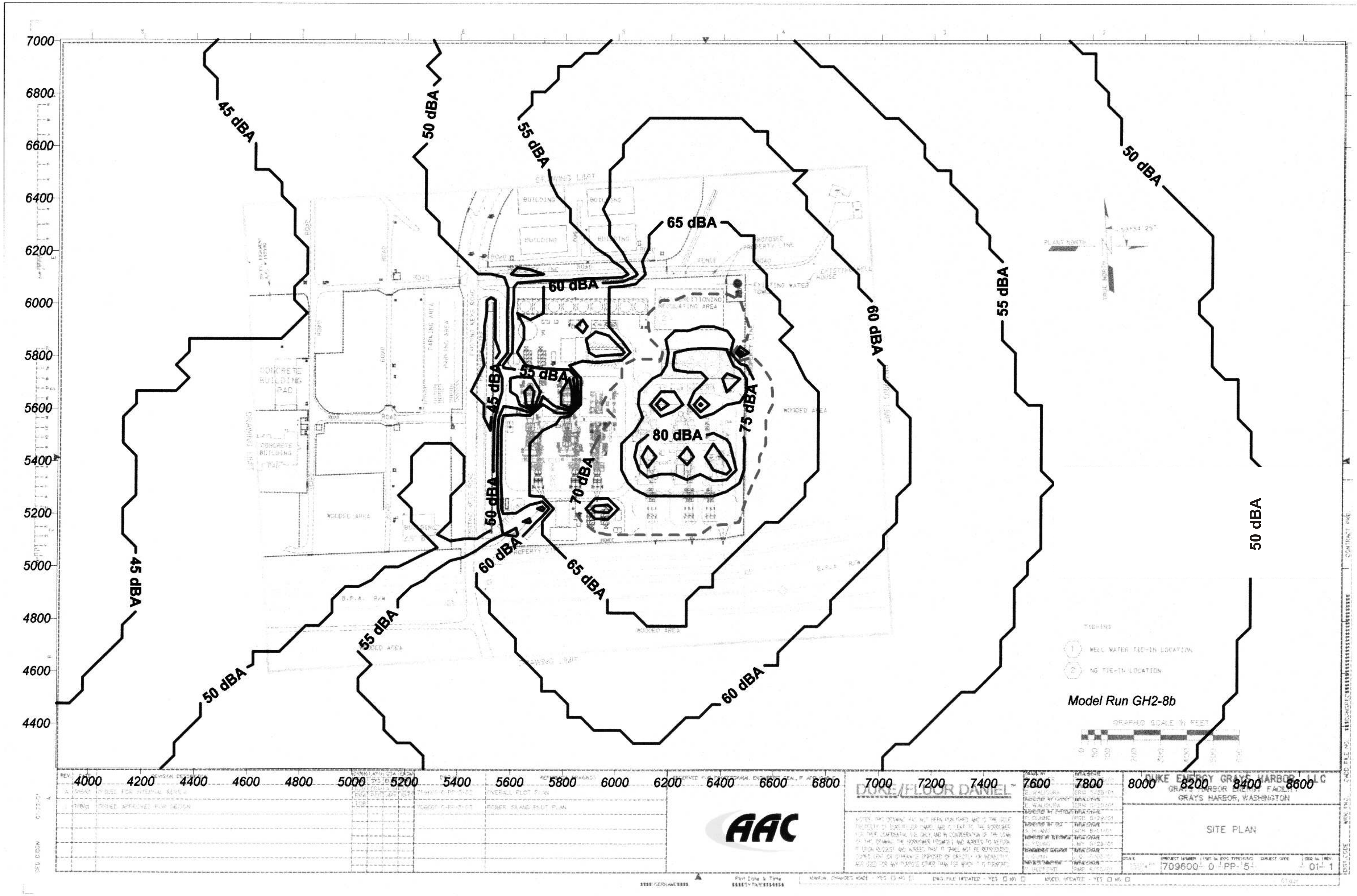
46866002.01_15.cdr




*REFERENCE: "Traffic Noise Analysis and Mitigation Manual," Environmental Section, Oregon State Highway Division, January 1990.*

Figure 4.1-3

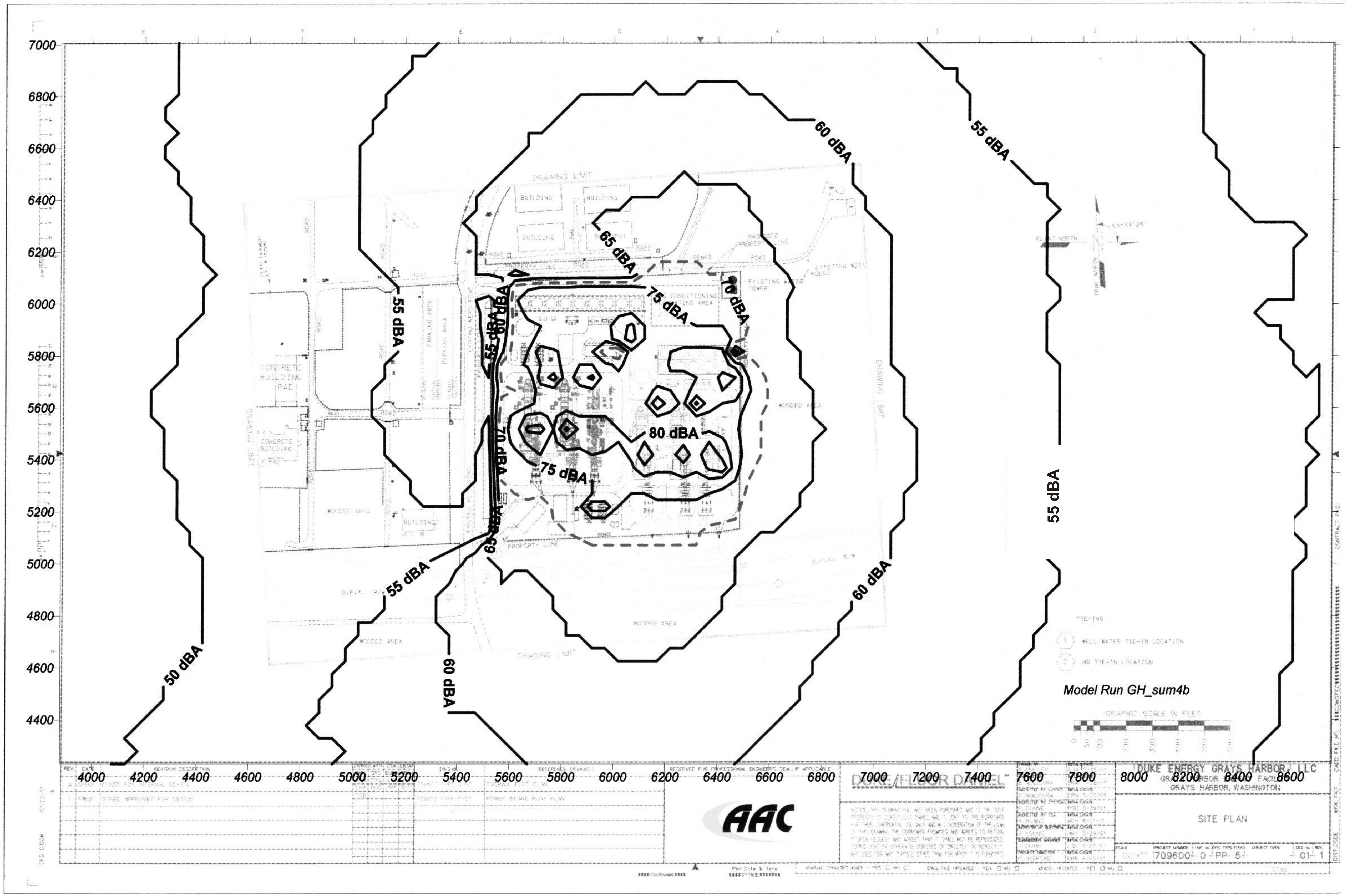
**Typical Range of Sound Levels for Construction Equipment**




SOURCE: Alliance Acoustical Consultants, Inc.

Figure 4.1-4

**Predicted Phase II (Only) Noise Level Contours (With Ambient) at Project Site**




SOURCE: Alliance Acoustical Consultants, Inc.

Figure 4.1-5

**Predicted Phase I plus Phase II Noise Level Contours (With Ambient) at Project Site**

## 5.1

# Land and Shoreline Use (WAC 463-42-362)

**WAC 463-42-362 BUILT ENVIRONMENT — LAND AND SHORELINE USE.**

*(1) The relationship to existing land use plans and to estimated population - As part of the application, the applicant shall furnish copies of adopted land use plans and zoning ordinances, including the latest land use regulation and a survey of present land uses within the following distances of the immediate site area:*

*(a) In the case of thermal power plants, twenty-five miles radius;*

*(b) In the case of petroleum refineries ten miles radius;*

*(c) In the case of petroleum or LNG storage areas or underground natural gas storage, ten miles radius from center of storage area or well heads;*

*(d) In the case of pipe lines and electrical transmission routes, one mile either side of center line.*

*(2) Housing - The applicant shall describe potential impact on housing needs, costs, or availability due to influx of workers for construction and/or operation of the facility.*

*(3) Light and glare - The applicant shall describe the impact of lights and glare from construction and operation and shall describe the measures to be taken in order to eliminate or lessen this impact.*

*(4) Aesthetics - The applicant shall describe the aesthetic impact of the proposed energy facility and associated facilities and any alteration of surrounding terrain. The presentation will show the location and design of the facilities relative to the physical features of the site in a way that will show how the installation will appear relative to its surroundings. The applicant shall describe the procedures to be utilized to restore or enhance the landscape disturbed during construction (to include temporary roads).*

*(5) Recreation - The applicant shall list all recreational sites within the area affected by construction and operation of the facility and shall then describe how each will be impacted by construction and operation.*

*(6) Historic and cultural preservation - The applicant shall list all historical and archaeological sites within the area affected by construction and operation of the facility and shall then describe how each will be impacted by construction and operation.*

*(7) Agricultural crops/animals - The applicant shall identify all agricultural crops and animals which could be affected by construction and/or operation of the facility and any operations, discharges, or wastes which could impact the adjoining agricultural community.*

# 5.1 LAND AND SHORELINE USE (WAC 463-42-362)

This section addresses the land and shoreline use issues applicable to the proposed Phase II Project, including the following subsections:

- Relationship to Existing Land Use Plans and to Estimated Population (Subsection 5.1.1)
- Housing (Subsection 5.1.2)
- Light and Glare (Subsection 5.1.3)
- Aesthetics (Subsection 5.1.4)
- Recreation (Subsection 5.1.5)
- Historic and Cultural Preservation (Subsection 5.1.6)
- Agricultural Crops/Animals (Subsection 5.1.7)

## 5.1.1 RELATIONSHIP TO EXISTING LAND USE, LAND USE PLANS, AND ESTIMATED POPULATION

### 5.1.1.1 Existing Land Uses

The Phase II project will be located within the approved Satsop Combustion Turbine (CT) Project site. Phase I is currently under construction and is expected to be in operation by late 2003. The site is located in Grays Harbor County in western Washington. Adjacent development varies, generally characterized by office, industrial, rural, rural residential, and agricultural land uses. The following sections include descriptions of existing land uses adjacent to the site, descriptions of the plans and policies which guide development on this site, and discussions of the impact of the project on these elements. Detailed discussion of the relationship of the project to estimated population can be found in Section 8.1 - Socioeconomic Impacts, WAC 463-42-535.

**Plant Site**

The site is located near the town of Elma in Grays Harbor County, and is surrounded on all sides by the property boundary of the Satsop Development Park (see Figure 2.1-1). The Satsop Development Park is owned by the Grays Harbor Public Development Authority. The approximately 22-acre site was previously developed for and used as a laydown area during construction of now discontinued nuclear plants WNP-3 and WNP-5 located at the Satsop Development Park. Prior to the start of site work for Phase I, most of the site was covered by a layer of graded gravel several feet deep and surrounded by a chainlike fence topped with barbed wire. The western portions of the site adjacent to Keys Road have been paved with asphalt.

Keys Road provides vehicular access to the site. This is a two-lane county road which runs along the western site perimeter in a generally north-south direction, and connects with SR 12 north of the proposed site. To the south of the site, the Bonneville Power Administration (BPA) maintains a transmission corridor as part of its Olympia-to-Aberdeen grid connection. Most of the other areas surrounding the site are forested. About a quarter mile to the southwest of the site, the

Weyerhaeuser Timber Company manages an experimental forest that is approximately 50 acres in size. On the north side of this forest, about two-thirds of a mile west-southwest of the site, are about a dozen single-family houses (these appear as small black squares on Figure 2.1-1). To the southeast of the site is the Fuller Creek preservation area. The discontinued nuclear power plant facilities (WNP-3 and WNP-5) lie beyond this area, approximately 1 mile south and southeast of the project site. Forested areas are located to the north of the site, beyond which the grade drops rapidly down toward the Chehalis River, which is approximately 0.5 mile from the project site.

Figure 5.1-1 shows general land uses within a 25-mile radius of the Satsop CT Project site. The study area encompassing the 25-mile radius is transected approximately west to east by the Chehalis River, SR 12, and SR 8. Urbanized areas along these highways include the communities of Montesano, Elma, McCleary, and Oakville. Outside of these communities, much of the land along SR 12 and SR 8 supports agricultural and a few industrial and/or commercial uses. Lowland areas along the Chehalis River supports mainly agricultural uses. Outside of incorporated areas, most of the upland regions within the 25-mile radius study area surrounding the site are forested, with a few small pockets of residential development. Near the western edge of the study area, the Chehalis River flows through the urbanized Hoquiam-Aberdeen-Cosmopolis area and ultimately into the Pacific Ocean at Grays Harbor. The highly urbanized Olympia-Tumwater-Lacey area is located on the eastern edge of the 25-mile radius study area, with Interstate 5 intersecting the extreme eastern edge of the study area.

**Impacts to Existing Land Uses**

During construction of the Phase II project, adjacent land uses may be affected by noise, dust, and construction related traffic. Mainly due to the nature of the construction activities, impacts near the project site are expected to be temporary and minor. Further discussion of these impacts and measures that will be taken to mitigate them can be found in the following sections: Dust, Subsection 3.2.4; Noise, Subsection 4.1.1.2; and Traffic, Subsection 5.2.1.2.

In terms of land use, the presence of the Phase II project at the project site will be compatible with the existing Phase I plant and adjacent industrial structures and facilities. Nearby residents may also perceive the plant as an intensified land use. However, this perception would be lessened as views into the project site become increasingly screened by maturing vegetation along Keys Road (see Subsection 5.1.4, below).

### 5.1.1.2 Existing Plans and Policies

The main body of plans and policies which regulate land use activities in the two-county project area are contained in the following Grays Harbor County codes:

- Grays Harbor County Comprehensive Plan
- Grays Harbor County Comprehensive Zoning Ordinance No. 38
- Grays Harbor County Shoreline Management Master Program

In general, Comprehensive Plans contain the official policy guidelines for decisions regarding the future development of an area, such as a county or a city; Zoning Ordinances designate land areas as specific land use zones, and specify uses that are permitted within each zone; and Shoreline Master Programs contain specific policy guidelines governing land use activities in recognized shoreline areas, pursuant to the Washington State Shoreline Management Act of 1971. Figure 5.1-2 illustrates the existing zoning in Grays Harbor County.

The plans and policies that regulate land use activities in the areas of Grays Harbor County where the site is located are summarized below.

**Grays Harbor County Comprehensive Plan**

The proposed Phase II project site is located within the Rural Lands designation contained in the Rural Lands Element of the Comprehensive Plan. The Rural Lands Element provides the policy foundation to guide the county in allocating land for commercial and industrial uses, and also to protect the resources of the county's rural lands.

**Grays Harbor County Comprehensive Zoning Ordinance No. 38 (Title 13)**

As shown on Figure 5.1-2, the project site is located within areas having Grays Harbor County's Industrial (I-2) zoning designation (13.06.080). This designation permits "...industrial uses and activities involving the processing, handling and creating of products and research and technological processes." Industrial development facilities and transportation and utility facilities are permitted uses within the I-2 zoning classification (13.06.090).

The project is consistent with local Grays Harbor County land use plans, with respect to siting of electrical generation plants. In Grays Harbor County, development of electrical power plants in an I-2 zone is permitted outright.

## 5.1.2 HOUSING

The existing housing stock and potential impacts are discussed in Section 8.1 - Socioeconomic Impacts, WAC 463-42-535.

## 5.1.3 LIGHT AND GLARE

### 5.1.3.1 Existing Conditions

The proposed Phase II project is an expansion of the existing Phase I plant which is located on a single site in a rural forest clearing. The Phase I plant will be illuminated at night for facility operations under normal conditions and for means of egress under emergency conditions. Illumination levels were designed in accordance with the Illuminating Engineering Society (IES) standards recommended by the following guidance:

- ANSI/IES RP-7, 1983, Industrial Lighting
- ANSI/EIS RP-8, 1983, Roadway Lighting

- Federal Aviation Administration (FAA)
- Occupational Safety and Health Act (OSHA)

In addition, existing high-mast lights in the adjacent industrial yards provide wide-area illumination. Other lights in the immediate area include entry and yard lights around a small grouping of residences located within about two-thirds of a mile of the project site. Evergreen trees surround the project site on all four sides, as well as a 25-foot-high wall with vegetated berm along Keys Road, screen lights originating from the Phase I plant, the Satsop Development Park and other adjacent land uses.

#### 5.1.3.2 Impacts

The proposed Phase II project would not significantly increase the existing light and glare conditions. The Phase II project would be illuminated at the same times and illumination levels as the existing Phase I plant. Table 5.1-1 summarizes the illumination levels expected at the proposed Phase II project.

**TABLE 5.1-1**
**EXPECTED ILLUMINATION LEVELS FOR EXTERIOR CT FACILITY AREAS**

| Exterior Location | Maintained Foot-Candles |
|---|---|
| Boiler platforms | 10 |
| Emergency lighting | 3 |
| Hydrogen manifold area | 20 |
| Electrical switchyard | 5 |
| Exterior walkways and platforms | 2 |
| Roadway | 1 |
| Security fence | 0.5 |
| Outdoor areas containing equipment that requires periodic inspection | 5 |
| Cooling tower | 5 |

Source: DeRidder 1995

Lighting would be provided for the purposes of general operator access and safety under regular operating conditions. Precise and detailed placement of lighting fixtures has not yet been determined, but light poles will likely be standard street light height, in the range of 20 to 50 feet. Outside lighting around the exterior of buildings and ancillary equipment would likely be attached to walls.

Spot lighting (up to 20 foot-candles) would be provided for purposes of localized area illumination for specific work activities such as the hydrogen manifold area. This lighting would be of higher intensity than wide-area lighting, but will be limited to specific areas and occasional usage. Emergency lighting would be provided for purposes of personnel egress and continuance of critical activities during emergency conditions. These instances are anticipated to be infrequent.

During construction, there would be some lighting associated with construction machinery. During operation of the Phase II project, the most visible points of illumination would be small, high-intensity anti-collision lights on the emission stacks to warn aircraft. These lights are intermittent and would be similar to warning lights present on the nearby WNP-3 and WNP-5 cooling towers.

Light and glare impacts upon nearby residents and travelers along Keys Road are expected to be insignificant. Prior to the start of construction of Phase I, there were existing high-mast lights providing wide-area illumination of the industrial yards. Local residents are already used to this local light source and the separation distance of approximately 3,375 feet provides a buffer zone for light falloff. The 25-foot-high wall with a vegetated berm located along Keys Road will reduce the light from the Phase II project. Vegetation located on the berm and scattered existing vegetation between the project site and residences would screen most of the lights. Additional screening is provided by high trees located along the residential road since the residences are set back an estimated 50 to 75 feet. In specific locations where glare or light spillover would impact Keys Road or be obtrusive to nearby residences, lighting angles could be adjusted to minimize glare impacts, or supplemental light shields/vegetation could be used for extra screening.

### 5.1.4 AESTHETICS

#### 5.1.4.1 Assessment Methodology

This section describes existing visual conditions of the proposed project setting. The visual inventory study consisted of the following:

- Setting criteria for rating levels of visual quality and viewer sensitivity
- Assessing existing visual quality levels
- Identifying viewer types, estimating their view of the facility (general visibility and distance range), and their visual sensitivity
- Selecting key representative viewpoints

Regional topography and site context information were reviewed using U.S. Geological Survey topographic maps. Detailed topography and layout for the project site were analyzed by reviewing project plans provided by the Certificate Holder and its engineering and design contractor. Field work was then conducted by driving and hiking the area to qualitatively determine general visibility of the project site from residences, major roads, and other potentially sensitive viewpoints. Based on visibility, representative viewpoints were photodocumented and two key viewpoints were selected for visual simulation (see Figure 5.1-3).

Assessment methods were based on a combination of visual assessment techniques which characterize visual impact in terms of changes in visual quality, character, and viewer sensitivity. Visual quality levels were estimated for both regional and immediate project area settings. The regional landscape setting is defined as those areas north of the Chehalis River, typically at a distance of 1 mile or greater. Levels of visual quality and viewer sensitivity were qualitatively estimated based upon general criteria that establish ratings of "high," "moderate," or "low" as described below.

Levels of visual quality consist of three primary components: *vividness*, the memorability of the landscape resulting from distinctive landmark features or visual patterns; *intactness*, the visual integrity between natural and modified landscape components and the absence of encroaching disturbances; and *unity*, the visual coherence, composition, and harmony of landscape elements. Visual quality was evaluated using the following general criteria:

- **Low** - Landscape is common to the region and exhibits few, if any, memorable features or patterns which provide visual diversity. A prevalence of encroaching human elements or landscape modifications exist which do not compatibly blend with the natural surroundings (low visual intactness and unity). Human alterations (such as roads and powerlines) exhibit low maintenance or siting sensitivity (such as grading and alignment).

- **Moderate** - Landscape exhibits reasonably attractive natural and human-made features/patterns, although they are not visually distinctive or unusual within the region. The landscape integrity of the area provides some positive visual experiences such as natural open space with some existing disturbance (farm fields, etc.), or well-maintained industrial parks and residential areas.

- **High** - Landscape exhibits distinctive and memorable visual features (such as landforms and rock outcrops) and patterns (vegetation/open space) which are largely undisturbed--usually a rural or open space setting. Development or visual disturbances, if present, are exceptionally well-planned to integrate with the natural landscape materials and character.

Viewer sensitivity is dependent on viewer types and exposure (number of viewers and view frequency), view orientation and duration, and viewer awareness and sensitivity to visual changes. Levels of viewer sensitivity were evaluated using the following criteria:

- **Low** - Viewer types in the project vicinity representing low visual sensitivity include agricultural and power plant workers. Compared with other viewer types, the number of viewers is generally considered small, and the duration of view is short. Viewer activities typically limit awareness and sensitivity to the visual setting immediately outside the workplace, which are often screened by vegetation or adjacent buildings.

- **Moderate** - Viewer types representing moderate visual sensitivity consist of highway and local travelers. The number of viewers varies depending on location; however, in the vicinity of the proposed plant, viewer numbers tend to be moderately large since they include travelers using SR 12 and other roads throughout the Chehalis River Valley. Viewer awareness and sensitivity are also considered moderate because destination travelers often have a focused orientation.

- **High** - Residential and recreational viewers and those congregating in public gathering places (such as churches and schools) are considered to have comparatively high visual sensitivity.

The visual setting may in part contribute to specific building orientation or the enjoyment of the experience. Views may be of long duration and high frequency.

5.1.4.2 Visual Quality

**Regional Setting**

The site for the proposed Phase II project is within the property boundaries of the Satsop Development Park, which includes WNP-3 and WNP-5, two discontinued nuclear power projects. The Satsop Development Park is located in hilly terrain on the south side of the Chehalis River Valley. Two 496-foot-high cooling towers, associated with the nuclear facility, are dominating visual elements within the existing landscape.

The Chehalis River Valley is bounded by tree-covered hills rising approximately 540 feet from the elevation of the valley floor and is dissected by secondary water courses, including the Satsop River, Fuller Creek, Newman Creek, and Vance Creek. Agriculture is the primary activity in the valley, and the landscape is a patchwork of fields whose textures and colors change with the season. Farm buildings, surrounded by groupings of trees, are located throughout the valley. Other elements in the valley which contribute to the visual character of the region include a golf course, trailer park, and gravel pits.

Overall visual quality of the regional landscape setting is classified as "moderate." The regional landscape exhibits moderate vividness because the natural and agricultural features, which are reasonably attractive, are not visually distinctive or unusual within the region. Visual intactness is also moderate because agricultural activities are visually compatible with the colors, textures, and patterns of the river valley, but other elements such as roads, farm buildings, and the cooling towers are not visually integrated with the surrounding landscape. Many farm buildings, for example, are light colored and have reflective metal roofs. Regional visual unity is rated moderate to high. Most scene elements seem to complement a rural/agricultural setting. With the exception of the cooling towers, constructed roads and utility corridors blend with the landform or are not visible.

**Plant Site**

From SR 12, the site is accessed by traveling south on Keys Road which passes agricultural fields and then crosses the Chehalis River. The road then ascends a wooded hillside and emerges into a clearing that was formerly used as an equipment laydown area during construction of WNP-3 and WNP-5. A portion of the laydown area is occupied by the existing Phase I plant, which will share the site with the proposed Phase II project.

Visually, this area can be characterized as industrial. The existing Phase I plant gives the site an industrial appearance with block building forms ranging from 20 to 64 feet in height. Ancillary elements include enclosed combustion turbines and steam turbines, fuel and liquid storage tanks, electrical switchyards, two 41- to 46-foot-high cooling towers, fencing, two heat recovery steam generators, and two 160-foot-high emission stacks with airplane warning lights. Figure 5.1-4 shows an isometric view of the existing Phase I plant without the surrounding existing vegetation or topographic features.

During certain seasons or weather conditions, water vapor and combustion products are visible from the cooling towers and emission stack of the Phase I plant. In addition, existing transmission poles extending along the northern portion of the existing BPA Olympia-to-Aberdeen right-of-way will be replaced as part of the Phase I construction. The existing wooden poles in the right-of-way will be replaced with steel towers similar to the two rows of steel towers currently in the right-of-way. These towers will carry new transmission lines from the plant to the Satsop substation located approximately 4,000 feet east of the project.

A composite visual quality rating of "low" for the immediate project area is a result of low ratings of vividness, intactness, and unity. Although the hilly terrain of the area provides some visual variety, the flat landscape of the project site is fairly monotonous. There are no long-range penetrating views. Surrounded by a uniform stand of trees around the periphery of the cleared laydown area, there is limited color, texture, or pattern variety. Visual intactness is low because elements of the existing storage yard are not visually integrated with the landscape. No screening is provided, and visually contrasting materials consist of asphalt, cinders, and steel. Visual unity is also low because layout configuration of the storage yards is rectilinear (contrasts with native forms), piles of stored materials are scattered across the site, and the transmission line corridor passes through a linear swath of cleared vegetation.

#### 5.1.4.3 Viewer Types and Sensitivity

Primary viewer types in the vicinity of the proposed Phase II project site are residents, travelers along SR 12 and local roads, agricultural workers, and nuclear plant workers.

The nearest communities are Montesano, Satsop, and Elma which are located along SR 12. Residents along the edges of these communities generally have open views across the Chehalis River Valley. These views are bounded by tree-covered hillsides seen in the distance. The WNP-3 and WNP-5 cooling towers, and the upper portion of the discontinued nuclear facility building, are widely visible. Community residents represent the highest concentration viewers in the region, and will be potentially sensitive to visual changes. Typical viewing range to the plant site from the closest community of Satsop will be approximately 2 miles. Similar viewing conditions will exist for scattered farmstead residences throughout the valley between SR 12 and the Chehalis River where the minimum viewing distance will be approximately 1 mile.

The closest and most sensitive residential views are in the vicinity of several houses located on a rural road paralleling the BPA transmission line right-of-way (Figure 5.1-3). These viewers are located approximately 2,300 feet from the project area. Existing views from this location consist of the existing Phase I plant, electrical equipment, including transmission lines and towers, and laydown yards containing concrete forms, steel reinforcing bars, and other remnants of WNP-3 construction. The number of viewers at this location is small, estimated to be 8 to 15. But because the plant site will be relatively close, the residential viewers could be sensitive to visual changes.

SR 12 is the main east-west travel route through the Chehalis River Valley. The attention of travelers is drawn to the open agricultural fields south of the highway. Views are open for approximately 2 miles and are terminated by tree-covered hillsides. Again, the existing cooling towers and the nuclear facilities are dominant visual elements. Visual sensitivity for travelers along SR 12 and local streets within nearby communities is considered “moderate.”

Views from local roads within the immediate plant site area are generally short-range and are typically blocked by vegetation and topography. A few elevated dirt roads located in the hills south of the site have open, overlooking views of the discontinued Satsop nuclear facilities, and the Chehalis River Valley can be seen in the distance. Since these roads are not considered destinations for scenic driving and traffic volumes are estimated to be low, overall visual sensitivity is considered “moderate” to “low.”

Approximately 2 miles south of the intersection of SR 12 and Keys Road, the latter passes immediately adjacent to the plant site. The primary travelers along this section of Keys Road will be power plant employees and a few local residents. In general, local residents who travel this road are expected to be more sensitive to visual impacts than industrial workers, but the overall visual sensitivity of travelers using Keys Road is considered “low” because of the short view duration and the presence of existing industrial yards which has desensitized viewers over time. The higher visual sensitivity of residential travelers, compared to other types of travelers, is reflected in the higher sensitivity rating already given to residential viewers.

Agricultural workers throughout the Chehalis River Valley will have views comparable to those of travelers along SR 12. Workers at the Satsop Development Park have short-range views that are predominately blocked by dense evergreen trees and hilly topography around the facility. The visual sensitivity of agricultural and power plant workers will generally be low because attention is focused on work activities with limited awareness of peripheral visual conditions.

#### 5.1.4.4 Visual Changes Introduced by the Proposed Project

Prior to construction of the Phase I plant, materials stored on the plant site were relocated and the foundations of former buildings were removed. The site was regraded. A 25-foot-high wall with vegetated berm has been constructed to screen views along Keys Road. This berm is be vegetated with native shrubs, grasses, and other appropriate vegetation in a random arrangement to simulate native patterns.

The purpose of this berm is primarily to provide partial visual screening for nearby residents and travelers along Keys Road. Visual screening will be provided during project construction and general operation, both in the day and at night. The relationship of the berm to the existing Phase I plant and proposed Phase II project is shown in Figure 5.1-4 and Figure 5.1-5.

#### 5.1.4.5 Project Visibility

A field visit was conducted to qualitatively note or photograph potential views of the project site from a variety of surrounding land use areas, located both near (less than 1/8-mile) and distant (up to 4 miles). These represent residential, traveler, and industrial/agricultural viewer types. Since topography limits most views from the south and east, field work concentrated to the north and west of the project site. Areas checked included:

- Peripheral edge of the community of Satsop
- SR 12 corridor (east/west)
- Keys Road corridor (north/south)
- Agricultural fields in the Chehalis River Valley
- Elevated dirt roads in the hills south of the project site near WNP-3
- Area immediately surrounding the project site within a 1/2-mile radius

Other surrounding areas were visited, but views were either blocked by topography or vegetation.

Based upon the number of viewers, viewer types/sensitivities, and viewing distance, two viewpoints were selected from the general areas having project visibility. These two viewpoints, located on Figure 5.1-3, were used in the preparation of two photo simulations depicting proposed conditions of the Phase II project. Viewpoint 1 (Figure 5.1-6) is looking south from SR 12 approximately 1/4 mile east of the Keys Road junction. It represents the mid-to-distant viewing range (1 to 2 miles) seen by the largest number of viewers including SR 12 travelers, residents of nearby communities, and agricultural workers.

Figure 5.1-6 shows the existing nuclear facility buildings protruding above the treeline. The cooling towers for WNP-3 and WNP-5 dominate the existing view. The emission stacks of the proposed Phase II project, if visible above the treeline, will be located west of the existing cooling towers. Based upon available project and topographic data, the tops of the stacks will likely be at or just below the treeline elevations from this viewpoint. Since visibility versus no visibility is close to the threshold of model accuracy based on available data, the tops of the stacks protruding above the treeline are shown as a conservative graphic depiction.

The flashing airplane warning lights on the emission stacks may also be visible at night, as are the lights on the existing cooling towers. General visibility of the project buildings and ancillary facilities would not be visible from this viewpoint because the site is screened by topography and vegetation.

The second viewpoint (VP2, Figure 5.1-3) was chosen because the view is sensitive due to close residences that are within about two-thirds of a mile of the proposed Phase II project. As shown in Figure 5.1-7, this view shows the existing power transmission lines as well as portions of the proposed facility, including the emission stacks. The vegetated berms adjacent to and west of the plants partially block the view towards the facility as well as the view of some of the existing buildings on other portions of the laydown area. Figure 5.1-8 presents the existing view of the Phase I plant for comparison.

The vegetated screening berms along Keys Road will block views of the lower portion of the facility, but the tops of the turbine buildings, cooling towers, emission stacks, and electrical switchyards will be visible. The most visible portion of the plant from this location will be the electrical switchyards, which are the closest elements. Visibility will decrease somewhat as screening vegetation reaches maturity. After vegetation is established, views of the project site area may be improved as compared to current conditions. Again, the facility's higher components will protrude above the screen.

In addition to the views selected for visual simulation representing travelers and residents who have higher visual sensitivity views were selected for less sensitive viewer types, including agricultural and industrial workers.

General visibility of the proposed Phase II project by agricultural workers in the Chehalis River Valley will be similar to that of travelers on SR 12 represented by Viewpoint 1. As from most other viewpoints, it is possible that agricultural workers could see a small portion of the emission stacks protruding above the treeline in the distance.

Satsop Development Park workers will have views of the facility when using Keys Road, but once inside the Development Park, views of the facility will be blocked by intervening trees.

#### 5.1.4.6 Visual Impacts

The assessment of impacts of the proposed Phase II project on visual quality included consideration of contrasts between current and proposed conditions for high or moderate levels of visual quality and high or moderate levels of viewer sensitivity as shown in Table 5.1-2. Following these guidelines, high sensitivity and a moderate change in visual quality could be considered potentially significant. Where sensitivity and visual change were both judged to be moderate, impacts are not considered potentially significant.

**TABLE 5.1-2**
**VISUAL IMPACT ASSESSMENT MATRIX**

| Sensitivity Level | Level of Change in Visual Quality[a] | | |
|---|---|---|---|
| | **High** | **Moderate** | **Low** |
| High | PS | PS | A/N |
| Moderate | PS | A/N | N |
| Low | A/N | N | N |

[a] N = Not Significant
A/N = Minor Adverse, Not Significant
PS = Adverse, Potentially Significant (without mitigation)

Visual impacts of construction activities of the Phase II project would be “not significant” regarding the overall landscape setting. Viewers throughout the Chehalis River Valley would not observe construction of the buildings or ancillary facilities, with the possible exception of a small portion of the emission stacks. For nearby residents and travelers on Keys Road passing adjacent to the site, construction of the Phase II project would be seen less and less as the planting on the berm matures and screens views.

Once grading operations and exterior construction are completed, the site would be hydroseeded to enhance visual conditions. The wall and vegetated berm located adjacent to the project site along Keys Road would provide some degree of visual screening of construction activities. Equipment enclosure buildings and exterior tanks would be painted earth-tone beige and gray to reduce contrasts. The emission stacks would be painted to blend with the sky as seen from distant viewpoints.

Visual impacts of the constructed Phase II project upon the existing regional landscape (Figure 5.1-6) are expected to be “minor adverse, not significant.” Even though project buildings and ancillary facilities would not be seen, a small portion of the emission stacks may be visible from some viewpoints in the Chehalis River Valley. The cooling towers, juxtaposed against the horizontal profile of the background hills, are objects of attention for viewers looking across the open plain of the Chehalis River Valley. If visible, the presence of small portions of the emission stacks will be an additional, but minor, element to the west of the existing and taller cooling towers of WNP-3 and WNP-5. Depending on the time of year and weather conditions, attention to the stacks could be more pronounced when a vapor plume is present.

The impact to local residents adjacent to the site (Figure 5.1-7) is expected to be “minor adverse, not significant” due to overall visual compatibility of the project with the existing conditions. Even though the emission stacks and the higher plant structures would be visible, the proposed Phase II project would be screened by the 25-foot-high wall with vegetated berm along Keys Road. The buildings enclosing the turbine equipment would also reduce visual impacts. The screening berm is primarily intended to reduce the visual impacts to nearby residents, and would also reduce the visual impacts for travelers using Keys Road, even though the visual sensitivity for travelers is comparatively lower than other viewer types. Replacement transmission line towers will be constructed within the existing BPA right-of-way with negligible additional visual impact.

### 5.1.5 RECREATION

The proposed Phase II project is an expansion of the existing Phase I project and is located within the same site boundaries; as a result, Phase II would have no additional recreation impacts.

### 5.1.6 HISTORIC AND CULTURAL PRESERVATION

The proposed Phase II project is an expansion of the existing Phase I project and is located within the same site boundaries; as a result, Phase II would have no additional historic and cultural preservation impacts.

### 5.1.7 AGRICULTURAL CROPS/ANIMALS

The proposed Phase II project is an expansion of the existing Phase I project and is located within the same site boundaries; as a result, Phase II would have no additional agricultural impacts.

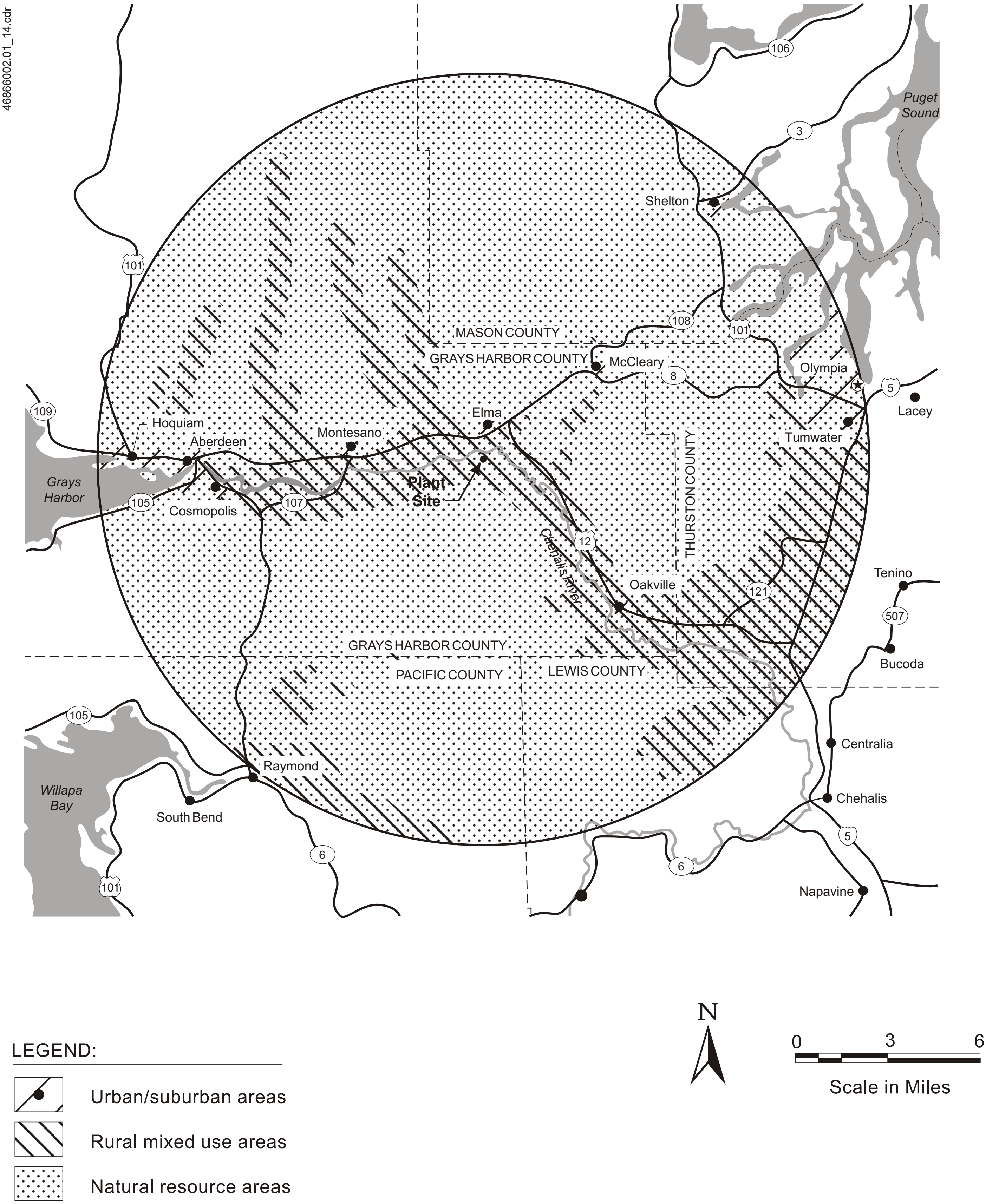



Figure 5.1-1

**Land Use Within 25 Miles of Plant Site**

46866002.01_21.cdr

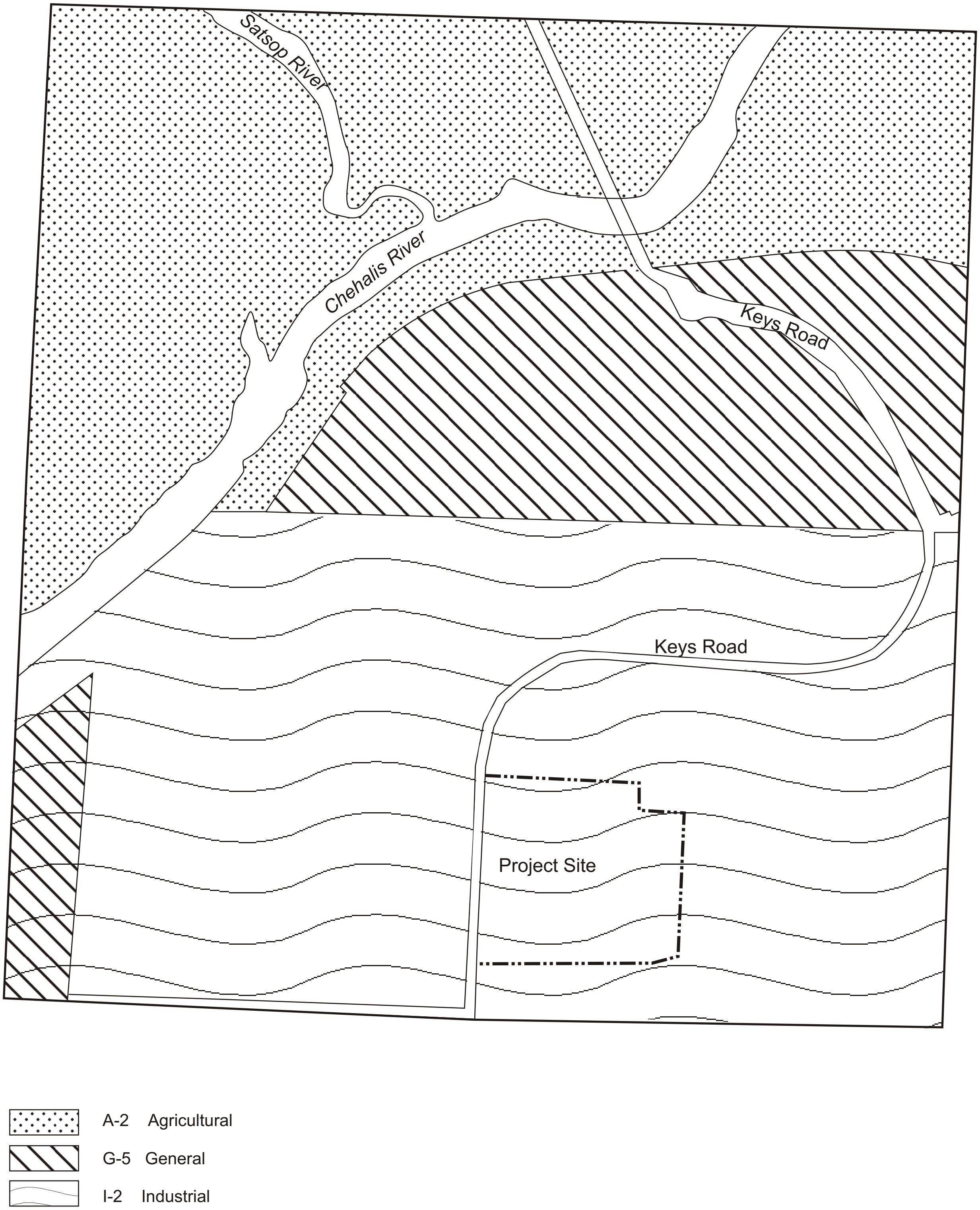



Figure 5.1-2
**Existing Zoning in the Project Area**

46866002.01_34.cdr

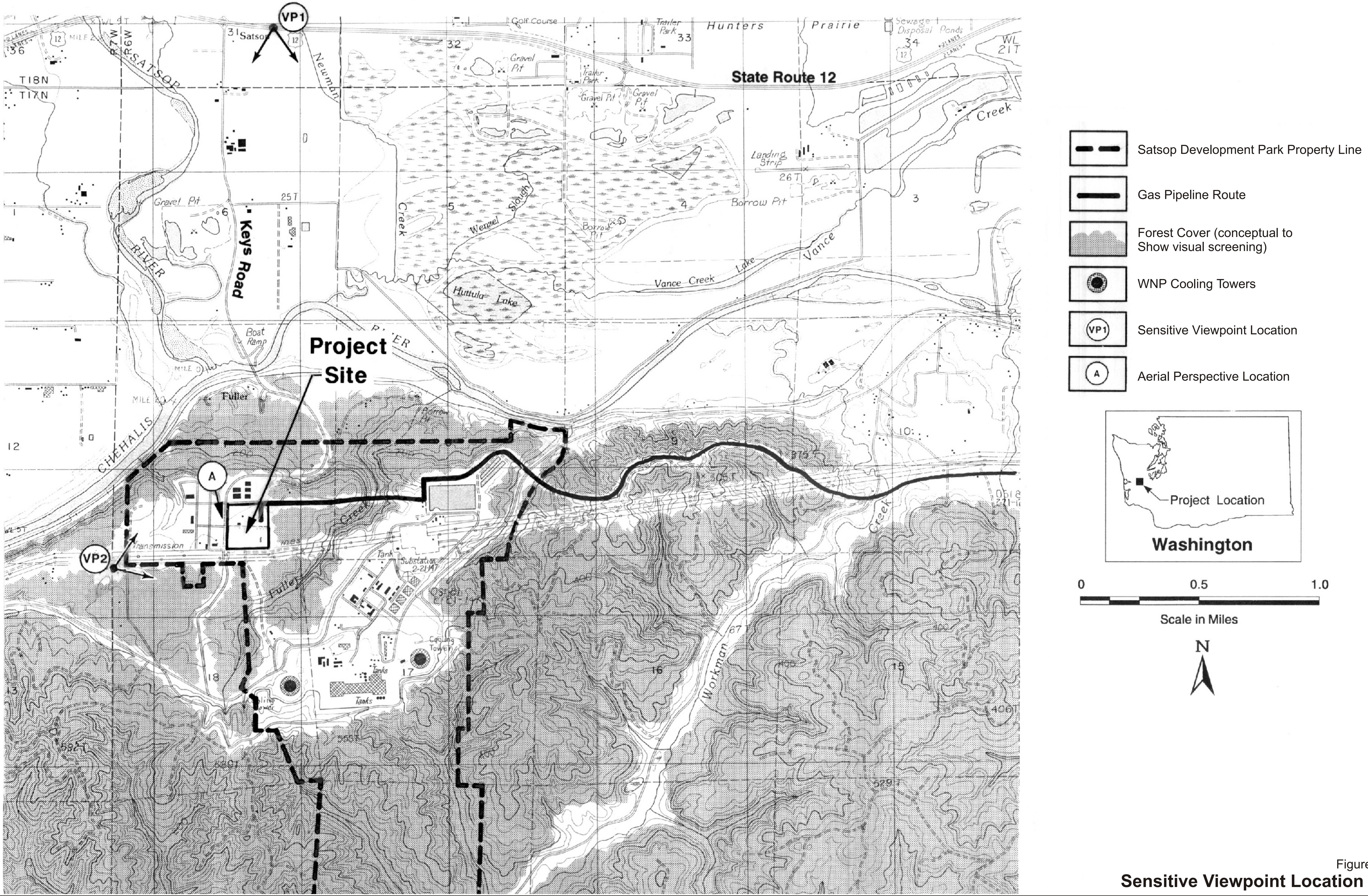



Figure 5.1-3
**Sensitive Viewpoint Location Map**

URS

Phase II Expansion
Satsop CT Project

46866002.01_07

*Source: 3DScape*

Figure 5.1-4

**Existing Phase I Isometric View**

URS

Phase II Expansion
Satsop CT Project

46866002.01_08

*Source: 3DScape*

Figure 5.1-5
**Proposed Phase II Conceptual Isometric View**

URS

Phase II Expansion
Satsop CT Project

46866002.01_36.cdr


Figure 5.1-6
**Simulated View of the Proposed Phase II Project Stacks**

URS

Phase II Expansion
Satsop CT Project

46866002.01_06


*Source: 3DScape*

Figure 5.1-7

**Simulated View of the Proposed Phase II Project (Viewpoint 2)**

*Source: 3DScape*

Figure 5.1-8

**Simulated View of the Existing Phase I Project (Viewpoint 2)**

# 5.2

# Transportation (WAC 463-42-372)

**WAC 463-42-372 BUILT ENVIRONMENT — TRANSPORTATION.**

*(1) Transportation systems - The applicant shall identify all permanent transportation facilities impacted by the construction and operation of the energy facilities, the nature of the impacts and the methods to mitigate impacts. Such impact identification, description, and mitigation shall, at least, take into account:*

*(a) Expected traffic volumes during construction, based on where the work force is expected to reside;*

*(b) Access routes for moving heavy loads, construction materials, or equipment;*

*(c) Expected traffic volumes during normal operation of the facility;*

*(d) For transmission facilities, anticipated maintenance access; and*

*(e) Consistency with local comprehensive transportation plans.*

*(2) Vehicular traffic - The applicant shall describe existing roads, estimate volume, types, and routes of vehicular traffic which will rise from construction and operation of the facility. The applicant shall indicate the applicable standards to be utilized in improving existing roads and in constructing new permanent or temporary roads or access, and shall indicate the final disposition of new roads or access and identify who will maintain them.*

*(3) Waterborne, rail, and air traffic - The applicant shall describe existing railroads and other transportation facilities and indicate what additional access, if any, will be needed during planned construction and operation. The applicant shall indicate the applicable standards to be utilized in improving existing transportation facilities and in constructing new permanent or temporary access facilities, and shall indicate the final disposition of new access facilities and identify who will maintain them.*

*(4) Parking - The applicant shall identify existing and any additional parking areas or facilities which will be needed during construction and operation of the energy facility, and plans for maintenance and runoff control from the parking areas or facilities.*

*(5) Movement/circulation of people or goods - The applicant shall describe any change to the current movement or circulation of people or goods caused by construction or operation of the facility. The applicant shall indicate consideration of multipurpose utilization of rights of way and describe the measures to be employed to utilize, restore, or rehabilitate disturbed areas. The applicant shall describe the means proposed to ensure safe utilization of those areas under applicant's control on or in which public access will be granted during project construction, operation, abandonment, termination, or when operations cease.*

*(6) Traffic hazards - The applicant shall identify all hazards to traffic caused by construction or operation of the facility. Except where security restrictions are imposed by the federal government the applicant shall indicate the manner in which fuels and waste products are to be transported to and from the facility, including a designation of the specific routes to be utilized.*

# 5.2 TRANSPORTATION
# (WAC 463-42-372)

This section presents information on existing traffic conditions and impacts related to transportation, including the following sections:

- Transportation Systems and Vehicular Traffic (Section 5.2.1)
- Waterborne, Rail, and Air Traffic (Section 5.2.2)
- Parking (Section 5.2.3)
- Movement/Circulation of People or Goods (Section 5.2.4)
- Traffic Hazards (Section 5.2.5)
- Conclusions and Recommendations (Section 5.2.6)

## 5.2.1 TRANSPORTATION SYSTEMS AND VEHICULAR TRAFFIC

This section identifies existing transportation facilities and traffic volumes in the vicinity of the proposed project and describes the potential traffic impacts due to construction and operation of the Phase II project.

### 5.2.1.1 Existing Conditions

**Street Highway System**

Figure 5.2-1 shows the major roadways in the area. State Route (SR) 12 is the predominant highway serving the plant site. SR 12 is a four-lane divided highway providing east-west access that extends from Aberdeen on the west to its intersection with SR 8 near Elma, then southeasterly to connect with Interstate 5 (I-5) north of Centralia. SR 8 continues east from Elma until it becomes US Highway 101 and connects to I-5. South of SR 8, SR 12 continues as a two-lane highway with varying width shoulders. The posted speed limit on SR 12 is 60 mph in the Elma to Montesano area.

Keys Road is a two-lane minor collector county arterial providing direct connection to the plant site and proposed project site. Keys Road is 24 feet in width with varying width shoulders (paved or gravel) and is stop sign controlled (one way on Keys Road) at its intersection with SR 12.

Access to the site is provided directly from Keys Road by a new access driveway to be constructed within the site boundaries. The asphalt surface of Keys Road is in good condition, and the posted speed limit is 35 to 40mph. The proposed plant site is located approximately 2.5 miles south of SR 12 along Keys Road.

The Wakefield Road corridor provides access from the east to the project site. Wakefield Road connects SR 12 to Keys Road via Lambert Road and is rated for heavy vehicle (truck) use. Wakefield/Lambert Road is two lanes and the speed limit is 45 mph.

### Existing Traffic Volumes

Traffic volumes for 1999 were obtained from the Washington State Department of Transportation (WSDOT) 1999 Annual Traffic Report and are presented on Figure 5.2-2. In addition, traffic counts were taken (in 1993) at the intersection of SR 12 and Keys Road (see Figure 5.2-3). For all traffic volumes, a growth rate of 3 percent per year was used to bring projected traffic volumes to a year 2001 analysis base.

### Existing Levels of Service

The worst levels of congestion and delay to motorists generally occur during the PM peak period. A measure of the relative congestion levels can be obtained by calculating the Level of Service (LOS) at intersections. Traffic operations at SR 12 and Keys Road were analyzed using the Transportation Research Board *Highway Capacity Manual* (the HCM) (TRB 2000) and 2000 *Highway Capacity Software* (HCS). This program uses the techniques presented in the 2000 HCM and produces a LOS rating based upon a scale ranging from LOS "A" (little or nor delay) to LOS "F" (extreme delays), with LOS "E" being capacity conditions. LOS "C" generally is considered adequate for rural intersections. These classifications account for such factors as truck volumes, roadway geometrics, turning movements, and other traffic-inhibiting factors. The results of these analyses for intersections without traffic signals generally overestimate actual conditions.

The LOS for unsignalized intersections is based on delay of each vehicle. Table 5.2-1 presents the delay used and definitions for levels of service at these types of intersections. Previously reserve capacity was calculated. The HCM has since set the standard for LOS calculations at delay per vehicle (measured in seconds).

**TABLE 5.2-1**
**LEVEL OF SERVICE CRITERIA FOR UNSIGNALIZED INTERSECTIONS**

| Level of Service | Delay per Vehicle (seconds) | Expected Delay to Minor Street Traffic |
|---|---|---|
| A | < 10 | Little or no delay |
| B | >10 and < 15 | Short traffic delay |
| C | >15 and < 25 | Average traffic delay |
| D | >25 and ≤ 35 | Long traffic delay |
| E | >35 and ≤ 50 | Very long traffic delay |
| F | >50 | Even longer traffic delays |

Source: TRB 2000 (HCM)

Using the criteria in Table 5.2-1, a LOS analysis for PM peak-hour traffic (analysis year of 2001, no build) at the intersection of SR 12 and Keys Road was conducted. The eastbound left-turn lane at the intersection of SR 12 and Keys Road currently operates at LOS "B," at a delay of approximately 10 seconds. The northbound and southbound left turns operate at LOS "D" and "E" respectively, with delays of 34 and 39 seconds, respectively. All other movements operate at LOS "C" or better.

The construction estimates of travel for the completion of the Phase I and Phase II projects, consecutively, is anticipated to increase the number of vehicles in the area during the PM peak hour by 325 vehicles all using the northbound approach to the intersection of Keys Road and SR 12. This increase in traffic during the PM peak hour would affect this intersection in the northbound and southbound directions (both controlled by stop signs). During construction the left-turn LOS for northbound and southbound traffic degrades to LOS "F" with more than 600 seconds (10 minutes on average per vehicle) of delay in the northbound direction and 65 seconds delay in the southbound direction. After the construction phase is completed, the overall traffic increase due to the operation of the two plants is minimal and does not affect the individual LOS movements adversely.

**Pedestrian Bicycle Facilities and Transit**

The streets and highways serving the plant site have neither pedestrian nor bicycle facilities. Grays Harbor Transit Bus route 40 currently operates along SR 12 providing service between Olympia and Aberdeen. This route operates six times a day on weekdays and three times a day on weekends.

Accident Experience

Accident reports for the intersection of SR 12 and Keys Road were obtained from WSDOT. From January 1, 1998 to December 31, 2000, 13 accidents were reported, resulting in 14 injuries and no fatalities. These accidents were spread out with 4 of the total 13 happening in the morning hours (midnight to noon) and the remaining 9 occurring in the afternoon/evening hours from 1 PM to midnight. Only the hour of 4 to 5 PM recorded more than one accident during its 60 minutes; two accidents within the 3-year period were recorded in the PM peak hour period. Four accidents were reported in 1998, five in 1999, and four in 2000. Two total accidents were alcohol-related (one in 1999 and one in 2000). Table 5.2-2 lists the accident characteristics during the past 3 years for the intersection of SR 12 and Keys Road.

**Future Plans and Projects**

Discussions with the WSDOT office in Aberdeen have indicated that plans for an additional interchange on SR 8 in the vicinity of McCleary is nearing completion, and construction is expected to begin in 1 to 2 years (Hart 2001). In addition, the Satsop River Bridge retrofitting is expected to occur in the next few years.

**TABLE 5.2-2**
**ACCIDENT ANALYSIS FOR SR 12/KEYS ROAD INTERSECTION**

| Year | Number of Total Accidents | Type of Accidents | Number of injuries | Collision Type |
|---|---|---|---|---|
| 1998 | 4 | Failure to yield (2)<br>Inattention (1)<br>Unknown (1) | 1<br>0<br>0 | 1 rear-end/1 unknown<br>unknown<br>unknown |
| 1999 | 5 | Failure to yield (2)<br>Asleep (1)<br>DWI/failure to yield (1)<br>Other (1) | 9 (6 & 3 respectively)<br>1<br>1<br>0 | 2 enter at angle<br>rear-end<br>enter at angle<br>hit fixed object |
| 2000 | 4 | Failure to yield (1)<br>DWI (1)<br>Unknown (2) | 2<br>1<br>0 | Enter at angle<br>Hit fixed object<br>1 fixed object/1 unknown |

Source: McBee 2001

### 5.2.1.2 Impacts

**Construction**

Traffic impact analyses were based on overlapping construction of Phase I and Phase II. The worst-case peak construction workforce was assumed to be 505 for the two plants. This assumes that the construction startup of Plant II would begin approximately 7 months prior to the completion of Plant I. This will allow maximum use of the first plant's construction workforce. Under those circumstances, the peak construction workforce would decreased. Therefore, the traffic estimates and associated impact evaluations presented below are very conservative. Future trip requirements were distributed to the existing roadway system based on existing travel patterns. A review of existing traffic volumes at the SR 12/Keys Road intersection indicates that approximately 94 percent of the total entering traffic on SR 12 at this intersection remains on SR 12 (as through traffic), four percent exits to northbound Keys Road, and 2 percent exits to the south on Keys Road. The existing minor road traffic entering onto SR 12 distributes evenly to the west and east from either the north or south approach. Using historic traffic counts in the WSDOT *Annual Traffic Report* (WSDOT 1999), a 3 percent annual growth factor was assumed to predict future traffic volumes. Neither construction nor operation will require new roads or improvements to existing roadways.

Figure 5.2-4 presents the estimated traffic increases during project construction. These estimates were calculated based on the following assumptions:

- The construction workforce peak will occur in 2003.
- The auto occupancy rate will be 1.1 individuals per car.

Use of these assumptions resulted in a conservative worst-case analysis of traffic increases. The peak of the workforce at the plant site is expected to occur for approximately 4 months in late

2003 to early 2004, from about Month 13 through Month 16 of construction. However, as shown on Figure 2.12-2, the workforce will range from approximately 500 to 540 during approximately 4 months of construction. As discussed above, these workers will be utilized for work on Phase II as they become available at the completion of work on Phase I of construction (see Table 5.2-3).

**TABLE 5.2-3**
**TRAFFIC PROJECTIONS AND LOS ANALYSIS**

| | Increase in PM Peak Hour Trips | LOS Northbound at Keys Road |
|---|---|---|
| 2001 (Phase I only) | 326 | F |
| 2003 (Phase I and Phase II) | 383 | F |

Source: TRB 2000

Using these worst-case traffic estimates, an LOS analysis for the intersection of SR 12 and Keys Road was performed for the PM peak assuming overlapping construction of the two plants. As described in Section 5.2.1.1, the eastbound left turn of the intersection is currently (based on 2001 estimates) operating at LOS "B," with an average delay of 10 seconds per vehicle, the northbound and southbound left turns operate at LOS "D" and "E," respectively.

During the peak workforce period of construction, the eastbound left turn at the intersection will remain at LOS "B" at the PM peak, with a delay of just over 10 seconds per vehicle. Table 5.2-4 lists the existing and anticipated delays per vehicle of the eastbound, westbound, northbound, and southbound left-turn lanes for this intersection. Calculations based on projections of 1993 traffic counts to 2001 (at a rate of 3 percent per year) were used as the baseline. Since the construction workers for Phase I will be shifted to work on Phase II as they become available, there is only a slight change in LOS based on whether or not Phase II is constructed. This difference is due to the specialization of some sorts of work and their availability in the overall construction process.

Both with and without the construction of Phase II, during the peak hour, the eastbound and westbound movements continue to operate at LOS "B" and "A," respectively. The left turn movements in the northbound and southbound directions deteriorate from LOS "D" and "E" respectively to LOS "E" and "F" with the construction of either one or both of the Phases. These degradations of LOS would be limited to the construction phase of the project. It is anticipated that with the operation of Phase I or Phase I and II, the LOS at this intersection will not be affected significantly.

Short-term transportation impacts from construction of the proposed project will result from the construction work in street rights-of-way and construction vehicle traffic. It is anticipated that 326 additional PM peak hour trips will be attributable to the construction of Phase I and II. Since traffic impacts related to the construction of Phase I have already been accepted, only trips associated with Phase II will be mitigated for.

**TABLE 5.2-4**
**ANTICIPATED LEVELS OF SERVICE AT KEYS ROAD AND SR 12**

| Condition | Eastbound | | Westbound | | Northbound | | | | Southbound | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Left turn | | Left turn | | Left-turn | | Right-turn | | Left-turn | | Right-turn | |
| | LOS[(a)] | Delay[(b)] | LOS | Delay[(b)] | LOS | Delay[(b)] | LOS | Delay[(b)] | LOS | Delay[(b)] | LOS | Delay[(b)] |
| Existing (2001 projections without construction) | B | 10.2 | A | 9.8 | D | 33.6 | B | 11.7 | E | 38.6 | B | 12.2 |
| 2001 with construction of Phase I only | B | 10.3 | A | 9.8 | F | 618.0 | C | 15.0 | F | 60.5 | B | 12.2 |
| 2003 with concurrent construction of Phases I and II | B | 10.3 | A | 9.8 | F | 638 | C | 15.0 | F | 65.5 | B | 12.2 |
| 2003 with operation of Phase I only | B | 10.3 | A | 9.8 | D | 35.6 | B | 12.5 | E | 39.4 | B | 12.4 |
| 2004 with operation of Phases I and II | B | 10.4 | A | 9.8 | D | 36.4 | B | 13.1 | E | 39.5 | B | 12.4 |

(a) See Table 5.2-1 for LOS criteria.
(b) Delay is measured in seconds.

The construction workforce for the plants will result in the addition of approximately 326 PM peak hour vehicular trips per day, attributable to the construction of Phase I and Phase II impacting the roads serving the plant site. However, this situation should last no more than approximately 2 weeks. Because Phase II will utilize workers as they become available from work being completed by Phase I, minimal overall increases in workers will be seen. The length of time that construction workers will be in the area will increase over Phase I but the overall number of workers will remain constant. Therefore, the impacts already shown for Phase I Report will remain and likely impact the area for a longer period of time, but minimal to no additional impacts will be seen.

Construction traffic to and from the plant site for Phase I and II will represent about 17 percent of the total peak-hour traffic on the roads in the area. The LOS on the roadways will decrease due to construction of the project, but these decreases will be temporary.

## Operation

The analysis conducted for the operation of Phase II of the proposed project assumed that operation of the proposed plant would generate traffic by employees and other services associated with the plant only.

During the operation of the two phases, a total of 42 people will be employed, with a maximum of 27 employees on site at the same time. Operation will involve either two 12-hour shifts or three 8-hour shifts.

A LOS analysis for the intersection of SR 12 and Keys Road was conducted using the two-shift operating schedule as a worst-case scenario. Assuming full operation of Phase II in mid-2004, the LOS for both the eastbound and westbound left turns will remain at LOS "B," with delays of 10.3 seconds and 9.8 seconds for the eastbound and westbound lanes, respectively.

Table 5.2-4 lists the existing and anticipated delays of the northbound and southbound left-turn lanes for this intersection, both with and without construction in 2001. With the minimal increase in traffic associated with the operation of the two phases, significant changes to LOS at the SR 12/Keys Road intersection will not change. In contrast, during the construction phase of Phase II, traffic to/from the proposed site will increase, affecting LOS. The northbound left-turn lane will deteriorate from LOS "D" to LOS "F" with the construction of Phase I. Therefore, the impacts of Phase II will not increase the severity of deterioration over Phase I but will increase the length of time the additional traffic (associated with construction) will be present at this intersection. The resulting LOS "F" condition with the construction would result in a net increase in delay of 638 seconds per vehicle during the construction phase. The southbound lane is also expected to deteriorate from LOS "E" to LOS "F" both with and without the project in operation; however, the maximum net increase in delay is 27 seconds per vehicle. All other movements at the intersection will continue to operate within desired limits.

In contrast, once the construction is completed for both phases, the overall LOS at this intersection will not substantially change with operation of the project and will remain at LOS "D." Thus, operation of the proposed project will not result in a significant adverse impact on traffic.

During major maintenance of the plant (assuming similar construction and maintenance timelines as outlined in Phase I), an additional 50 people will be on site for approximately 28 days during the day shift. The maintenance-related traffic will not result in a reduction of the LOS on the roads serving the site. Adequate parking will be provided for both the operations and major maintenance staff.

**Mitigation**

Plant construction could degrade the LOS at the intersection of SR 12 and Keys Road. Prior to construction of Phase I, a traffic management plan was submitted to EFSEC for review and has been approved. The main component of the traffic management plan includes the recommendation to encourage the use of the Wakefield/Lambert corridor for access/egress the site.

The traffic management plan approved for Phase I is also applicable to Phase II construction. If needed, this plan will be amended to address any specific elements required for Phase II.

The Commuter Trip Reduction Act is implemented in the eight largest counties in Washington State. Grays Harbor County is exempt.

### 5.2.2 WATERBORNE, RAIL, AND AIR

5.2.2.1 Transport by Rail

A combination of rail and truck transport will be used to ship some of the project-related equipment and materials from the manufacturers to the site area. The equipment shipped by rail will include the combustion turbine and the combustion turbine generator, the steam turbine and the steam turbine generator, transformers, and the heat recovery steam generator (HRSG). The heaviest single load will be the HRSG modules, which will weigh approximately 221 tons each. The following description of planned rail and truck transport is based on preliminary evaluations of rail and roadway facilities and on estimates of the volume and number of shipments. The Certificate Holder will provide EFSEC with appropriate additional information as final transportation plans are developed.

Items shipped by rail will be delivered to the existing Elma rail siding located approximately 3 miles northeast of the site. The existing facilities are adequate for project-related needs, and there is no need to develop additional rail access or rail facilities for the project. Shipment by rail will require approximately 25 to 30 railcars over a 3- to 6-month period (for materials to construct both phases of the project). From the rail siding at Elma, heavy haulers will be contracted to deliver the items to the laydown area at the plant site using a route that follows SR 12 from Elma to Keys Road to the plant site, or using the Wakefield/Lambert corridor. These roads have the capacity to handle the size and weight of the trucked equipment and materials.

Trucks used for this transport will have the required number of axles to ensure compliance with highway and bridge design loading. The contracted hauling firms will be licensed to operate in the state and will be responsible for obtaining all applicable permits and licenses.

5.2.2.2 Waterborne and Air Transport

Neither phase of the project will use waterborne or air transport during construction or operation, with the possible exception personnel transport on commercial flights and the use of commercial couriers that would use existing private or commercial flights for occasional small deliveries.

### 5.2.3 PARKING

5.2.3.1 Power Plant Construction

No parking will be permitted on the streets and roads serving the plant site. During construction (of both phases), parking will be available on the existing construction laydown located west of Keys Road. This large area has been graveled and graded for use as a construction laydown area for nuclear projects WNP-3 and WNP-5. Approximately half of the area currently contains asphalt overlays. The laydown area has graveled internal roadways and access to and from Keys Road. As described in Section 5.2.2.1, the worst-case construction workforce peak would be 505 workers, although the actual number expected with overlapping of the construction periods for the two plants is slightly less than that. Assuming an occupancy rate of 1.1 workers per car, the expected peak workforce would require approximately 460 parking spaces. Assuming an average of 400 square feet per parking space, including access area, the total size of the parking area would be approximately 184,000 square feet. The planned parking area has sufficient space for use as a laydown area and for accommodating this number of vehicles.

Runoff from the existing construction laydown area is controlled by the Certificate Holder in accordance with the requirements of its existing Environmental Protection Control Plan (see Section 2.10 - Surface Water Runoff, WAC 463-42-215).

5.2.3.2 Operation

Parking will be provided at the plant site and additional parking will be provided at the construction laydown area located on the west side of Keys Road. This amount of parking will be sufficient for the maximum of 26 employees who will be on the site during full operation of both plants (see Table 8.1-11). Runoff from these parking areas will be controlled in accordance with the requirements of the existing Environmental Protection Control Plan (see Section 2.10 - Surface Water Runoff, WAC 463-42-215).

### 5.2.4 MOVEMENT/CIRCULATION OF PEOPLE OR GOODS

Construction of the proposed project will result in temporary and minor delays in traffic during delivery of oversized or heavy loads. During operation, the project will not have an impact on the movement or circulation of people or goods.

During construction and operation, the public will not be permitted in the areas associated with the power plants, including the transmission line right-of-way.

### 5.2.5 TRAFFIC HAZARDS

5.2.5.1 Hazards to Traffic

The contractors will prepare a traffic control and parking plan that will describe procedures to be followed during construction of Phase II and associated facilities. This document will follow standard procedures for safe accomplishment of construction activities such as transporting heavy equipment along roadways, establishing detours, and the use of flaggers. As a result of implementation of the procedures in this plan, construction of Phase II is not expected to cause hazards to the existing traffic. However, the increase in traffic volumes on the adjacent street network would naturally increase the probability of an accident occurring.

As discussed in Subsection 5.2.1.1, 13 accidents, resulting in 14 injuries and no fatalities, occurred at the SR 12/Keys Road intersection during the 3-year analysis period. Typically, an unsignalized intersection with 5 or more accidents per year or a signalized intersection with 10 or more accidents per year is considered a high-accident location (HAL) and warrants analysis for improvements (WSDOT 2001). The intersection of SR 12 and Keys Road was placed on the HAL list in 2000 in response to an average of three accidents per year for a 2-year period along with other criteria (e.g., severity of accidents, etc.). Presence on the list does not mean that improvements are necessary, but is an acknowledgement that conflicts occur. Because of the drop in the number of total accidents at this location, it is possible that this intersection could be removed from the HAL list for 2001-2002 depending on the number of accidents in those 2 years.

5.2.5.2 Fuel and Waste

**Fuel Oil**

The project will use natural gas. Small amounts of fuel oil will be used for the backup generators and fire-water pumps.

**Waste Products**

The Site Certification Agreement for the Satsop CT Project stipulates waste management procedures in accordance with state regulations. A Comprehensive Dangerous Waste Management Program fulfilling all applicable regulatory requirements is in place for the Satsop CT Project site. This includes procedures for waste designation, labeling, storage, handling and disposal procedures; record keeping; inspection; contingency planning; management oversight; and transportation. This program will be applied to Phase II.

Hazardous materials will be transported by a licensed hazardous waste transporter, and when appropriate, hazardous materials will be disposed of at an approved and licensed disposal facility.

## 5.2.6 CONCLUSIONS AND RECOMMENDATIONS

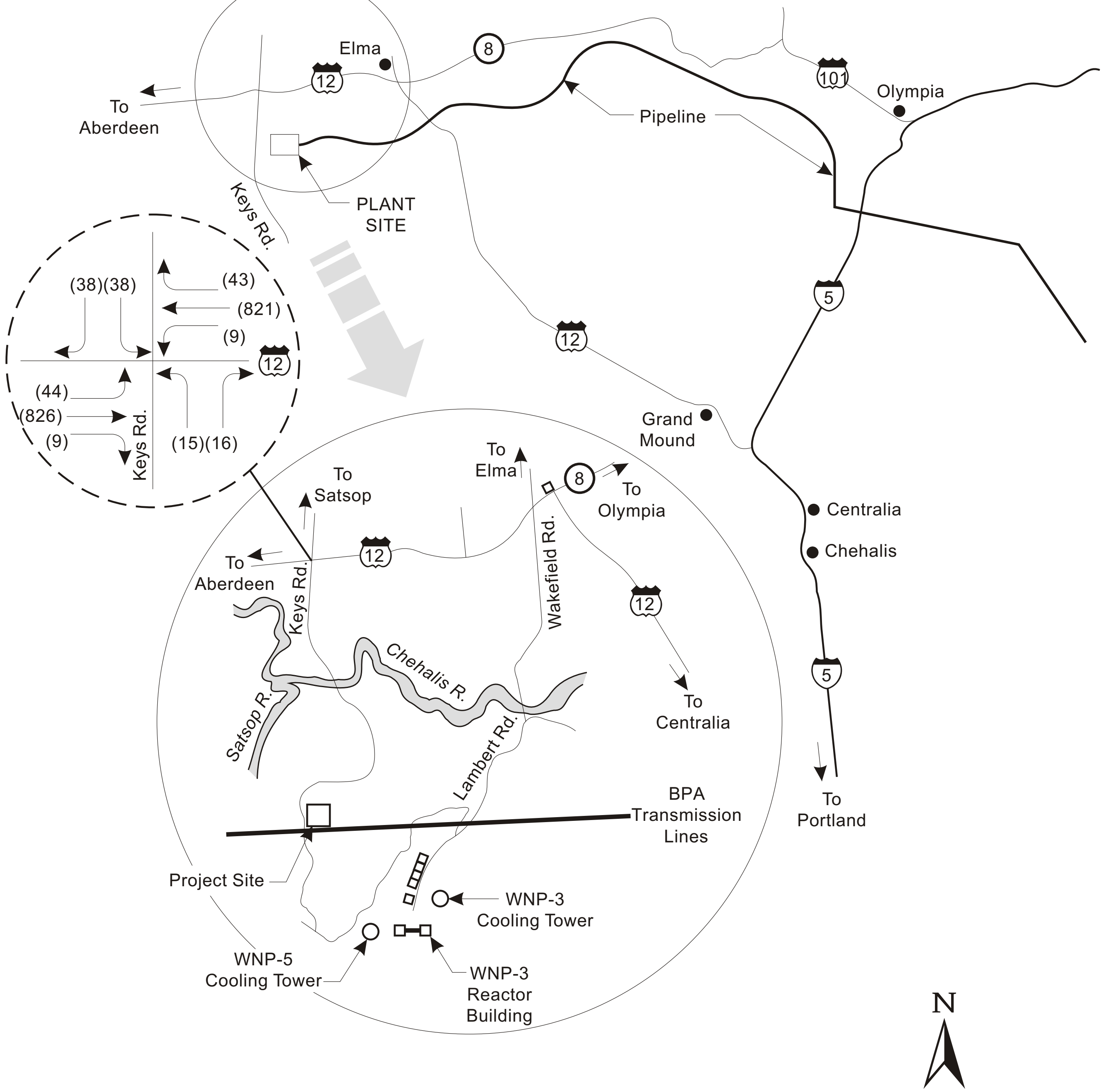
5.2.6.1 Conclusions

With the construction of Phase II occurring in conjunction with the conclusion of Phase I construction, traffic impacts will be minimized but those impacts will occur for a longer period of time. This scheduling of work maximizes the workforce and allows shifting of workers from Phase I to Phase II as the work begins to be completed on Phase I, thereby minimizing the overall traffic impacts. During construction of Phase I, an additional 326 PM peak hour trips were calculated. Considering the worst-case scenario in conjunction with the construction of Phase II, 57 vehicles for 1 month will be added to the existing transportation infrastructure in addition to those calculated for Phase I. These 57 vehicles include the approximately 27 employees needed to operate and maintain Phase I as well as the workforce associated with construction of Phase II.

Calculations of LOS show the intersection of Keys Road and SR 12 to be operating at LOS “D” in 2001 projections (from 1993 traffic counts grown at 3 percent per year). With the construction of Phase I, the LOS at this intersection falls to “F” with a delay of up to 10 minutes for the left-turning northbound vehicles in the PM peak hour. With the additional traffic associated with construction of Phase II, more delays will occur at this intersection. LOS calculations based on operation of one or both of the plants show this intersection to return to a LOS “D.”

### 5.2.6.2 Recommendations

As was recommended for Phase I, both automobiles and heavy trucks traveling to/from the site can utilize the Wakefield/Lambert corridor, avoiding the SR 12/Keys Road intersection.




LEGEND:

(XXX) 2001 traffic projections

Note: Projections calculated based on 3% per year growth from December 1993 count.

Figure 5.2-3

**1993 Traffic Counts at Intersection of SR 12 and Keys Road**

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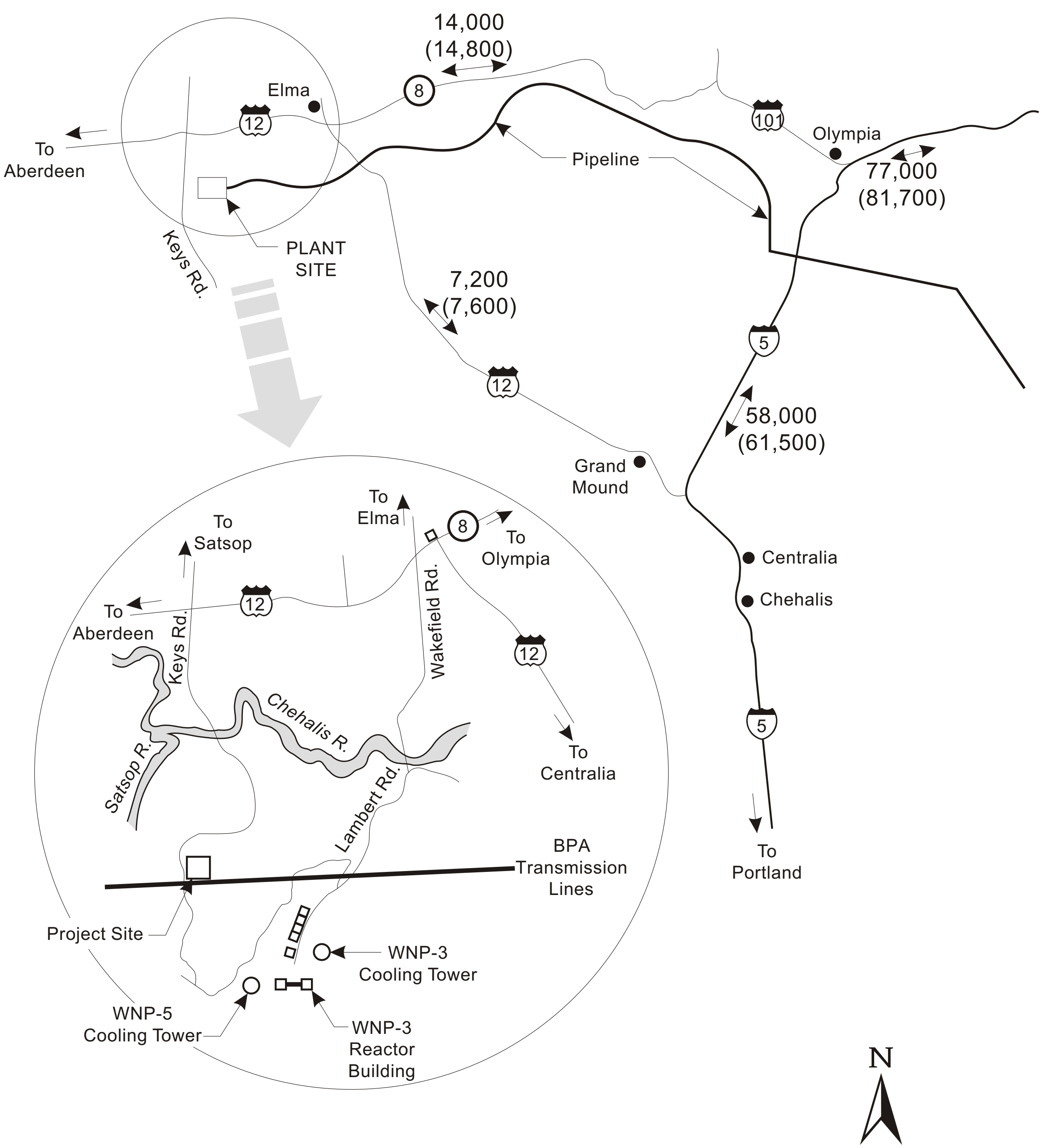
Satsop CT Project




LEGEND:

| | |
|---|---|
| XXX → | Average daily traffic (from Washington State Department of Transportation 1999 Annual Traffic Report) |
| (XXX) → | Average daily traffic (grown to 2001 at 3% per year) |

Figure 5.2-2

## Existing Traffic Volumes

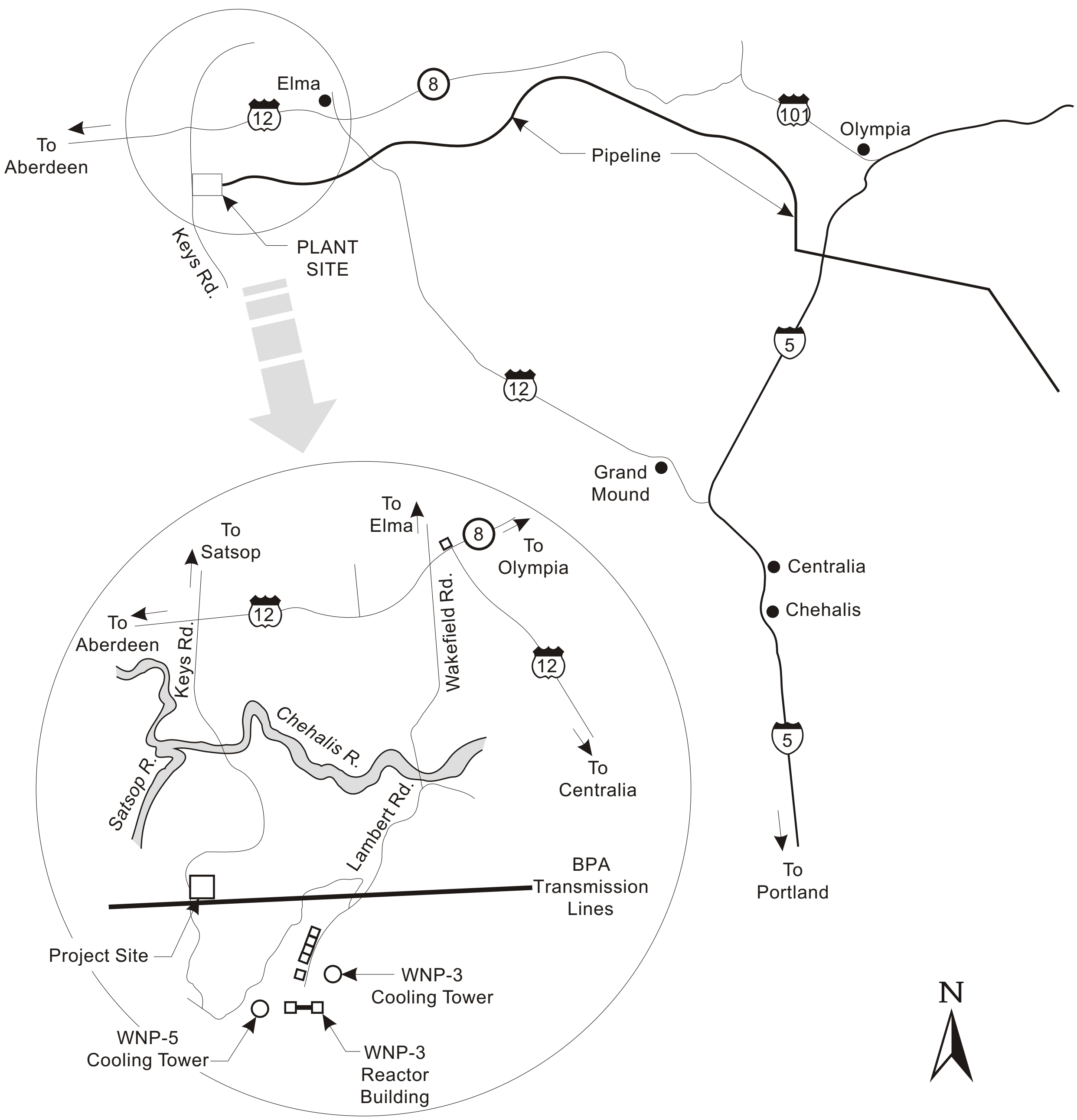



Figure 5.2-1

**Primary Roadways in the Project Area**

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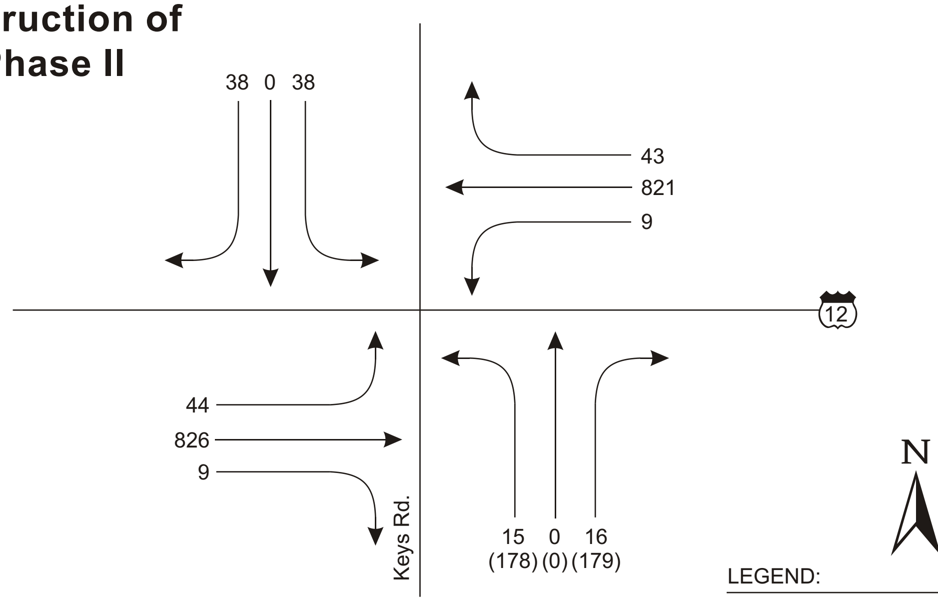
Phase II Expansion
Satsop CT Project

46866002.01_04.cdr

## 2001-2003 Traffic Estimates During Construction of Phase I and Phase II (Overlapped)

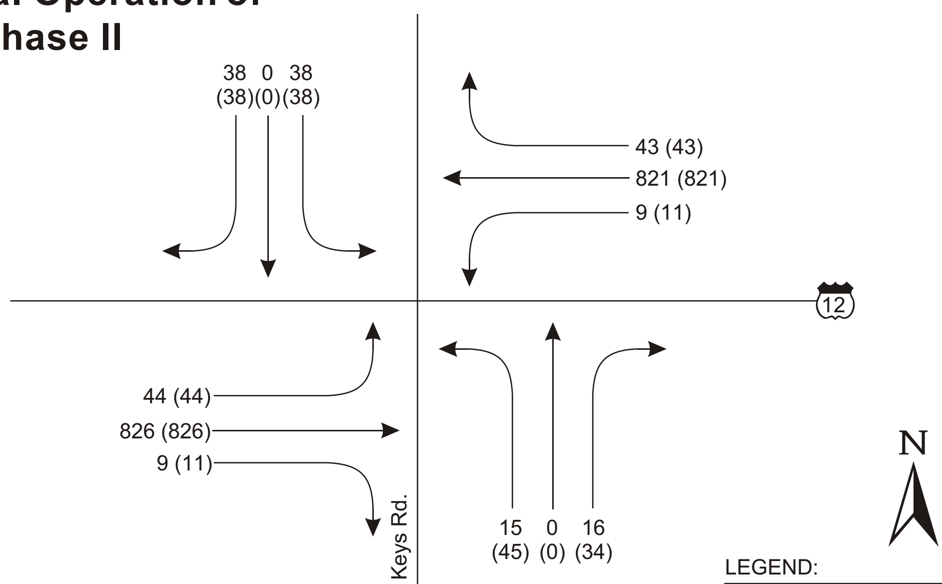



NOTE:
Approach volumes from the north, east, and west would not change during construction.

LEGEND:

| | |
|---|---|
| XXX | Without construction |
| (XXX) | With construction (two plants) |

## 2004 Traffic Estimates During Normal Operation of Phase I and Phase II Plants




(a) Assumes natural gas used as fuel.

LEGEND:

| | |
|---|---|
| XXX | Without project |
| (XXX) | During operation of two plants |

Figure 5.2-4

**Estimated PM Peak Traffic Volumes at Intersection of SR 12 and Keys Road**

# 5.3
# Public Services and Utilities (WAC 463-42-382)

**WAC 463-42-382 BUILT ENVIRONMENT — PUBLIC SERVICES AND UTILITIES.**
*The applicant shall describe the impacts, relationships, and plans for utilizing or mitigating impacts caused by construction or operation of the facility to the following:*

*(1) Fire;*

*(2) Police;*

*(3) Schools;*

*(4) Parks or other recreational facilities;*

*(5) Maintenance;*

*(6) Communications;*

*(7) Water/storm water;*

*(8) Sewer/solid waste; and*

*(9) Other governmental services or utilities.*

# 5.3 PUBLIC SERVICES AND UTILITIES (WAC 463-42-382)

## 5.3.1 EXISTING CONDITIONS

This section describes the existing conditions of public services and utilities including the following subsections:

- Fire (Subsection 5.3.1.1)
- Police (Subsection 5.3.1.2)
- Emergency Medical Services (Subsection 5.3.1.3)
- Schools (Subsection 5.3.1.4)
- Parks and Recreational Facilities (Subsection 5.3.1.5)
- Maintenance (Subsection 5.3.1.6)
- Communications (Subsection 5.3.1.7)
- Water/Storm Water (Subsection 5.3.1.8)
- Sewer/Solid Waste (Subsection 5.3.1.9)

### 5.3.1.1 Fire

The plant site lies within the boundaries of Grays Harbor County Fire Prevention District (FPD) #5 - Porter/Bush Creek/Satsop. These fire stations are relatively small, and are staffed by volunteer fire fighters. Table 5.3-1 presents data on the fire protection districts and departments that exist in the project vicinity. Emergency response plans will be implemented during operation to protect plant employees and structures in emergency situations. (See Section 7 - 2, Emergency Plans, WAC 463-42-525.)

## TABLE 5.3-1
## FIRE DEPARTMENTS IN THE PROJECT VICINITY(A)

| Fire Department | Paid Full-Time Personnel | Volunteer Personnel | Equipment | Protection Class[b] |
|---|---|---|---|---|
| Grays Harbor County FPD #5 - Porter/Bush Creek/Satsop | 0 | 70 | 2 - 1,000 gal. Pumper<br>1 - 750 gal. Pumper<br>1 - 3,000 gal. Tanker<br>1 - 2,000 gal. Tanker<br>1 - 1,500 gal. Tanker<br>1 - Utility Van | 8 |
| Montesano Fire Department | 6<br>(1 of 6 positions was open at the time research was completed) | 31 | 2 - 750 gal. Pumpers<br>1 - 75' Aerial with 500 g tank<br>1 - 2,500 gal. Tanker with 500 g pumps<br>1 - Rescue Vehicle<br>2 - Ambulances<br>1 - Aid Car<br>1 - Staff Vehicle | 5 |
| Elma Fire Department | 0 | 26 | 1 - 750 gal. Pumper<br>1 - 500 gal. Pumper<br>1 - 2,000 gal. Tender<br>1 - Rescue Vehicle<br>1 - Command Vehicle | 6 |
| Grays Harbor County FPD #12 - McCleary/McCleary Fire Department | 0 | 25 | 1 - 850 gal. Pumper<br>1 - 500 gal. Pumper<br>1 - 1,500 gal. Tanker<br>1 - 1,250 gal. Tankers | 8 |
| Grays Harbor County FPD #2 - Wynochee/Central Park/Brady/contract with Montesano F.D. | 1 | 45 | 3 - 1,000 gal. Pumpers<br>1 - 2,850 gal. Tender<br>1 - 2,500 gal. Tender<br>1 - 1,500 gal. Pumper<br>2 - Aid Car<br>1 - Utility Van<br>1 - Command Vehicle<br>1 – Water Rescue Trailer | 8 |

Note: Data from personal communications with individual fire departments (Willis 2001; Crass 2001; Brown 2001; Lewis 2001; Wilder 2001).

As rated by the Washington Surveying and Rating Bureau (2001). Fire district protection class ratings are used to evaluate fire protection availability for insurance purposes and are assessed to all municipal and rural areas by the Washington Surveying and Rating Bureau. Ratings range from 1 to 10, with class 1 representing the highest level of fire protection and class 10 the lowest level. A class 1 rating is rarely achieved. Ratings are based on four elements: the available water supply; the logistical characteristics and makeup of the district fire department; the available communications systems; and finally the fire control/safety measures taken and ordinances in effect in the particular fire district. Adequacy of fire protection indicated by a protection class rating is dependent upon the types of areas being rated. A rating of 8 or 9 is typical for a rural area. This low rating is usually due to the fact that standard fire hydrant service, required in more urban areas, is not available, and rural volunteer fire departments do not have full-time staff or formally equipped fire stations and facilities. The situation is further aggravated by access problems and reliance on volunteers who often must travel long distances to respond to calls. These factors lead to long response times and limited fire fighting ability. A rating of 8 or above, however, does not necessarily mean that fire protection is inadequate. It indicates that according to the standards of fire protection services, set up primarily for municipalities, an area is lacking in some conventional means of fire protection.

### 5.3.1.2 Police

Five separate law enforcement agencies provide police protection to communities in the project vicinity. Unincorporated regions in Grays Harbor County are served by the Grays Harbor County Sheriff's Department. The nearby cities of Montesano, Elma, and McCleary, are each served by separate municipal police departments. The nearby community of Satsop does not have its own police department, and is served by the Grays Harbor County Sheriff's Department. Districts #1 and #8 of the Washington State Patrol provide police services along SR 8, SR 12, and other state highways in the project vicinity. Staffing levels for these police departments are shown in Table 5.3-2. In addition, security will be provided by contract service during construction of the project.

**TABLE 5.3-2**
**POLICE DEPARTMENT STAFFING LEVELS**
**IN THE PROJECT VICINITY**

| County/City | Population 2000[(a)] | Number of Commissioned Officers[(b)] | Ratio of Officers to 1,000 Population[(c)] |
|---|---|---|---|
| Grays Harbor County | 67,194 | 168[(d)] | 2.50 |
| Montesano | 3,312 | 8 | 2.42 |
| Elma | 3,049 | 8 | 2.62 |
| McCleary | 1,454 | 5 | 3.44 |

(a) Source: WSOFM 2001a.
(b) Source: WASPC 2001, except where otherwise noted.
(c) The Washington State average was 1.67 as of October 31, 1999.
(d) Includes county and municipal law enforcement agencies in Grays Harbor County. Number of commissioned officers data for Grays Harbor County Sheriff’s Department from O’Connor (2001). The Washington State Patrol District 8 also provides service to Grays Harbor County; a detached District 8 office is located in Hoquiam. District 8 has 140 employees assigned to law enforcement, commercial vehicle enforcement, vehicle inspections, communications, criminal investigations, and support services

### 5.3.1.3 Emergency Medical Services

Emergency medical services are provided in the project vicinity by primary response ambulance units and area hospitals. In most cases, ambulance units are operated through local fire departments. Ambulance service providers in the vicinity of the project are listed in Table 5.3-3.

Hospitals near the project area are located in Aberdeen, McCleary, and Olympia. Mark Reed Hospital in McCleary and Grays Harbor Community Hospital in Aberdeen are the closest hospitals to the CT facility site. Mark Reed Hospital is approximately 12 miles northeast of the CT facility. Grays Harbor Community Hospital is approximately 17 miles west of the CT facility site. Capitol Medical Center and Saint Peter Hospital, both in Olympia, are approximately 29 miles east of the CT facility site. Further information on these hospitals is presented in Table 5.3-4.

**TABLE 5.3-3**
**AMBULANCE SERVICE PROVIDERS IN THE PROJECT VICINITY**

| Name | Ownership | Level of Care |
|---|---|---|
| Montesano Ambulance Service | Public | ALS and BLS |
| East County Medic One | Public | ALS and BLS |

Source: Jones 2001

Note: ALS = Advanced Life Support; BLS = Basic Life Support

**TABLE 5.3-4**
**HOSPITALS IN THE PROJECT VICINITY**

| County | Name | Location | No. of Beds |
|---|---|---|---|
| Grays Harbor | Grays Harbor Community Hospital | 915 Anderson Dr., Aberdeen | 150 |
| | Mark Reed Hospital | 322 S. Birch St., McCleary | 24 |
| Thurston | Capital Medical Center | 3900 Capital Mall Dr. S.W., Olympia | 119 |
| | Providence Saint Peter Hospital | 413 N. Lilly Road N.E., Olympia | 390 |

Note: Data from personal communications with hospital desk clerks or hospital web sites, October 31, 2001.

### 5.3.1.4 Schools

There are several schools and educational facilities in the project vicinity. Information on public school districts located close to the project is presented in Table 5.3-5. None of the individual school buildings in these districts is located directly adjacent to the proposed project. In addition to these public schools, there are also several private elementary and secondary schools in the project vicinity. Many of these private schools are affiliated with church or religious organizations. Higher education is available in the project corridor vicinity from Grays Harbor Community College in Aberdeen, and South Puget Sound Community College, Evergreen State College, and Saint Martin's College, located in Thurston County. The closest schools to the CT facility site are located in the Montesano, Satsop, Elma, and McCleary School Districts. Existing capacity for these districts is shown in Table 5.3-5.

**TABLE 5.3-5**
**SCHOOL DISTRICTS IN THE PROJECT VICINITY**

| County | School District | Enrollment[a] | Capacity[b] | Excess Capacity |
|---|---|---|---|---|
| Grays Harbor | Montesano #66 | 1,378 | 1,819 | 441 |
| | Satsop #104 | 49 | 104 | 55 |
| | Elma #68 | 2,044 | 1,845 | -199 |
| | McCleary #65 | 322 | 325 | 3 |

Source: WOSPI 2001

Data from personal communications with individual school districts (November 5-7, 2001)

#### 5.3.1.5 Parks and Recreational

Parks and other recreational facilities are described in Section 5.1 - Land and Shoreline Use, WAC 463-42-362.

#### 5.3.1.6 Maintenance

For the purposes of this document, maintenance is defined as the costs, in money and manpower, required for the upkeep of public facilities. This upkeep is often necessary for these facilities to continue providing services to the public into the future. Facilities such as roads, sidewalks, water and sewer mains, bicycle paths, and park benches, all come under the umbrella of public facilities that would require periodic maintenance. Many public agencies, such as counties and cities, have established plans that dictate when, for instance, a road should be resurfaced, or playground facilities should be replaced. These plans often tie into public budgets, thereby allocating funds obtained from taxpayers for the necessary public facility maintenance or improvements. Such plans are sometimes enforced with varying degrees of rigidity, being influenced by a variety of factors, some of which could be the actual need for facility improvement, budget and economic fluctuations, and changing public needs and interests. To facilitate the prudent handling of public funds, several layers of administrative review are often involved in the maintenance planning process. During this planning stage, public agencies generally inspect the facilities over which they have jurisdiction, determine the relative maintenance needs, and then rank these facility maintenance needs with other potential uses for public funds based on an established list of criteria. Maintenance projects determined to have the highest priority would then receive the necessary funding and administrative go-ahead. Other projects, deemed less critical, could then receive consideration after high priority projects are completed.

Maintenance plans and schedules are frequently influenced by outside forces, which may damage, or in some way render inadequate certain public facilities. Such forces could be sudden population growth, new facility construction, and even natural disasters. In order to fairly assign the payment responsibility for maintenance beyond regular periodic upkeep, public agencies use a variety of widely accepted methods. Obviously, as in the case of natural disasters, there can be times when no party can be deemed as being responsible. However, when such a responsible party can be determined, some agencies might choose to assess mitigation fees to that party. Other agencies opt to make an agreement with such a responsible party, to grant a permit for their action only if the facility that would be damaged or rendered inadequate were replaced or reproduced in another location, at the responsible party's expense. Whichever method is used, the justification is usually the same; the responsible party caused the situation requiring the additional cost, and they should therefore be responsible for covering that cost.

In Grays Harbor County there is no established planning document that specifically address maintenance of public facilities. However, the Public Works department has, as part of regular operations, maintenance programs for the public facilities for which they are responsible. These programs provide for regular inspection of public facilities in general, and maintenance and repair on an as-needed basis.

5.3.1.7 Communications

Telephone service to the Satsop CT site, Satsop Development Park, and adjacent residential neighborhoods is provided by CenturyTel.

5.3.1.8 Water/Stormwater

The existing water system and the existing stormwater control systems are discussed in Sections 2.5 - Water Supply System, WAC 463-42-165; 2.10 - Surface-Water Runoff, WAC 463-42-215; and 3.3 - Water, WAC 463-42-322.

5.3.1.9 Sewer/Solid Waste

The plant site is not served by a sewer system. The Satsop CT Project will use septic systems and leach fields for sanitary waste.

A solid waste contractor removes solid waste from the site for disposal at an approved and regulated landfill.

### 5.3.2 POTENTIAL IMPACTS

This section describes the expected impact of the Satsop CT Project on local public services and utilities. The plant construction is estimated to be completed in 22 months (including design). As described in Section 8.1 - Socioeconomics, WAC 463-42-535, the plant construction would require up to 557 workers, of which 10 to 20 percent are expected to come from outside of Washington. Only a small percentage of the 55 to 111 workers would be expected to bring their families with them while working on the plant construction.

The completed Satsop CT Project (Phase I and Phase II) would employ 42 workers. Even if all 42 employees are hired from outside the area (which is not likely) and they all bring families (42 x 2.5 persons per household = 105), the potential impact area is sufficiently large that the project would not have an adverse effect on population or housing in the Grays Harbor and Thurston County areas.

Because no extensive demand on any public service or utility is anticipated, and a traffic control plan will be implemented, the overall impact to the public services and utilities is expected to be minor and short-term. Impacts were determined through a detailed review of the proposed action against existing conditions and a subjective assessment based on professional experience with other similar projects.

5.3.2.1 Construction

A portion of the construction work crew is expected to come from out-of-state areas, and the influx of construction workers into neighboring communities will result in a minor and temporary increase in the demand placed on local public service providers. This demand increase will have a minor and temporary effect on local police departments, providers of emergency medical services, and local fire departments. The impact of project construction on local schools would be at most minor and temporary, as few out-of-state construction workers are expected to be accompanied by families.

Construction is not expected to create any additional maintenance needs for public facilities. During construction, trucks would use county roads to reach the site and pipeline corridor locations. Grays Harbor County does not have a specific schedule for making repairs to local roads. Repairs are done on an as-needed basis determined by local inspections. Construction traffic is not expected to damage the local road system. If such damage occurs, the applicant would either repair the damage or provide funds to the local Public Works Department to repair the damage. All laydown, staging, and parking areas would be restored or revegetated at project expense as necessary upon construction completion.

Section 5.1 - Land and Shoreline Use, WAC 463-42-362 addresses the potential for impacts on parks and other recreational facilities. As described in that section, construction of the project will not result in a significant impact on recreational facilities.

No significant adverse impacts to local communication, potable water, sanitary sewer, or solid waste collection systems are anticipated.

In summary, due to the short duration of the project's construction phase and the relatively small size of the proposed construction crew, the overall adverse impact on local public services and utilities caused by construction is not expected to be significant.

#### 5.3.2.2 Operation

Operation of the Satsop CT Project will not have a significant adverse impact on existing public services in the project vicinity. Satsop CT staff will receive appropriate training in handling on-site emergencies, including fire and medical, and will provide the first line of response. As part of Phase I construction, the Certificate Holder has initiated consultation with the local fire departments concerning training, equipment and plant familiarity. This consultation will be expanded to include Phase II.

Because there will be a relatively small staff operating the Satsop facility, no effect on schools in the project vicinity is expected.

The Satsop CT Project will include a septic system and leach field for each plant. These will be constructed and operated in accordance with applicable regulations and will not affect the existing septic systems.

Operation of the proposed project would result in a positive economic impact to Grays Harbor County and the state due to increased tax revenues, employment, and local expenditures. A portion of these funds may be used to upgrade existing public services and utilities. Further discussion on the economic impact of the Satsop CT Project can be found in Subsection 8.1.2.2.

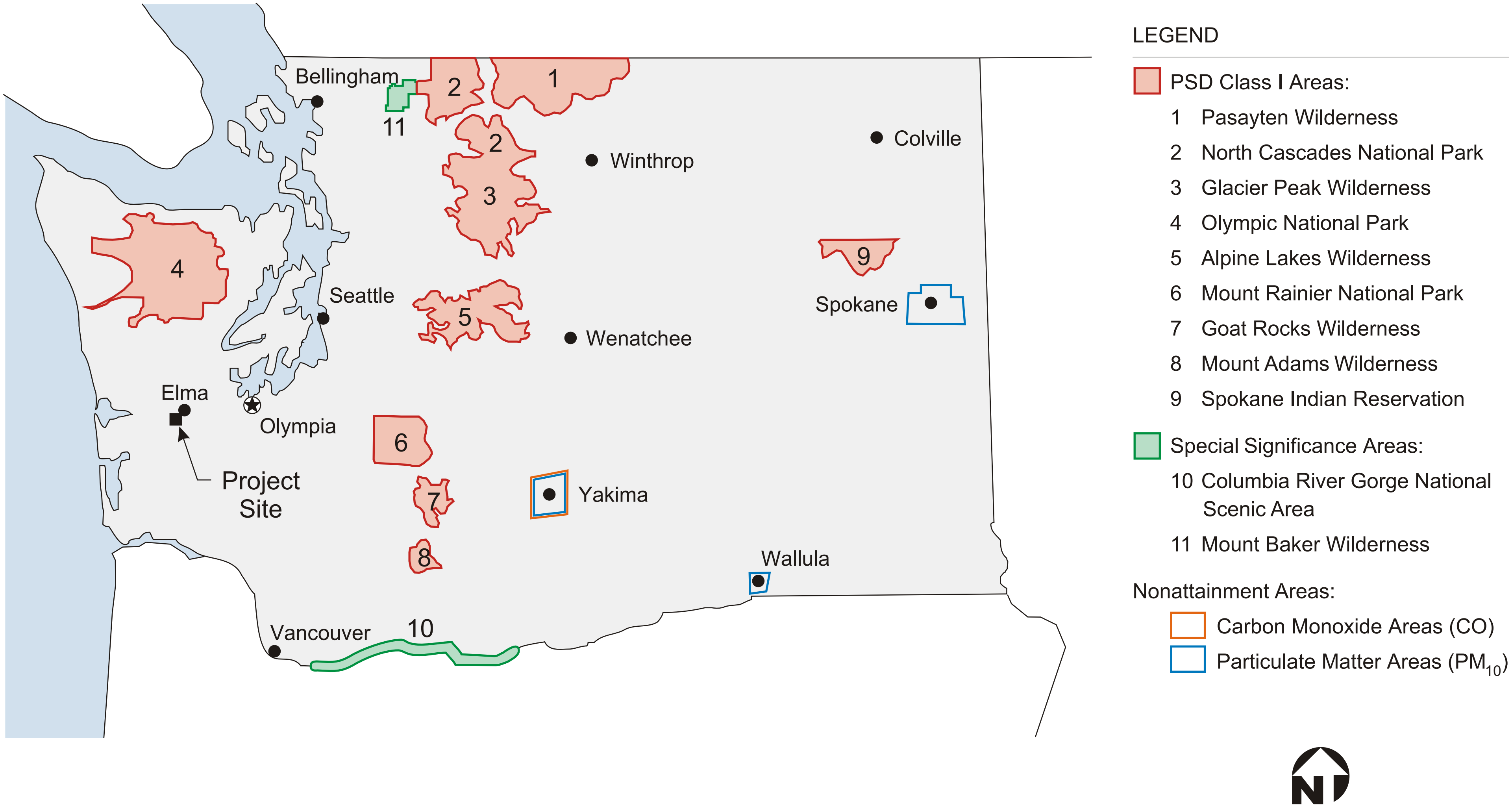



Figure 6.1-1

**Nonattainment, Prevention of Significant Deterioration (PSD) Class I, and Special Significance Areas for Washington State**

URS

Phase II Expansion
Satsop CT Project

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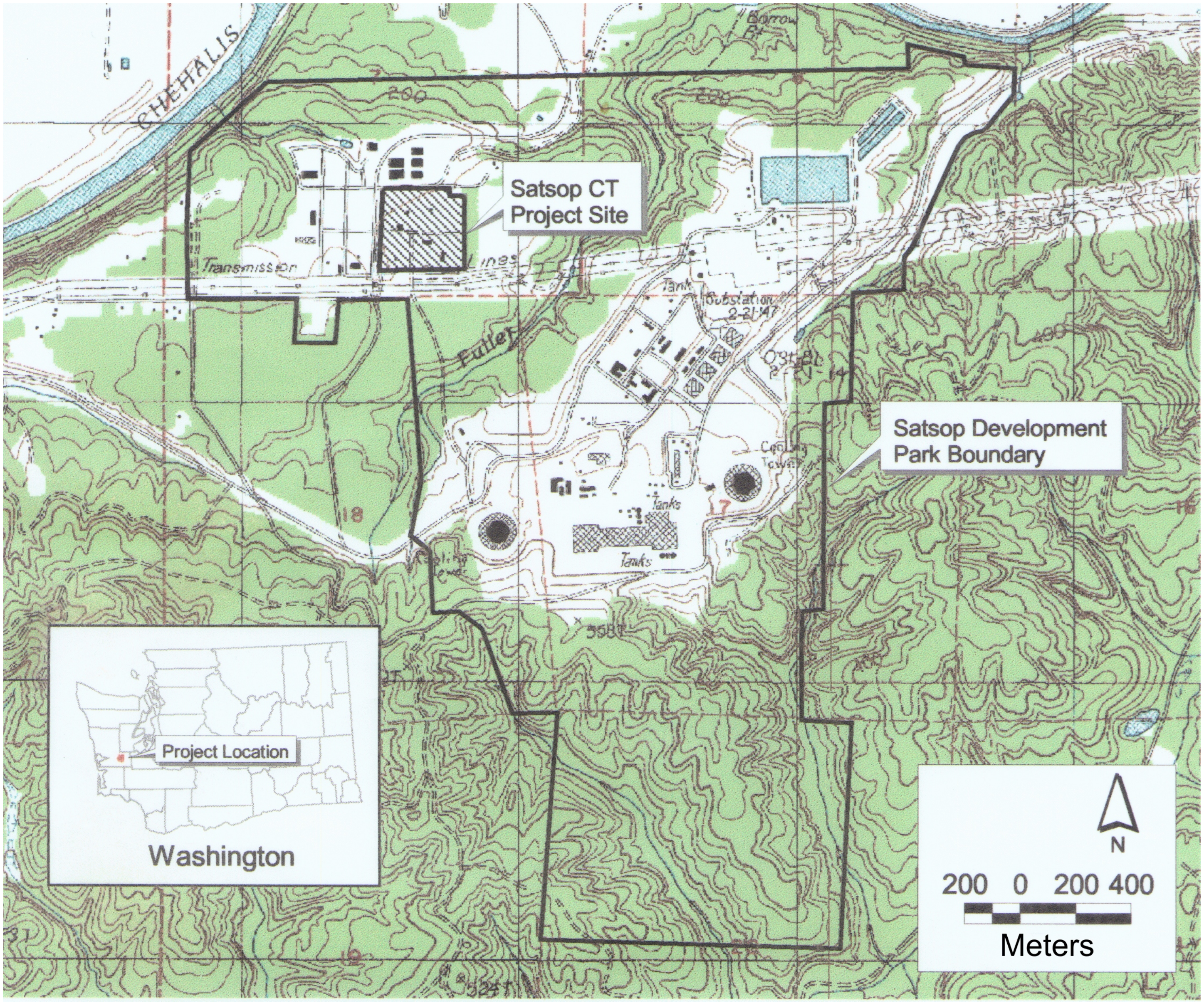


Figure 6.1-2

**Project Location**

URS

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Satsop CT Project

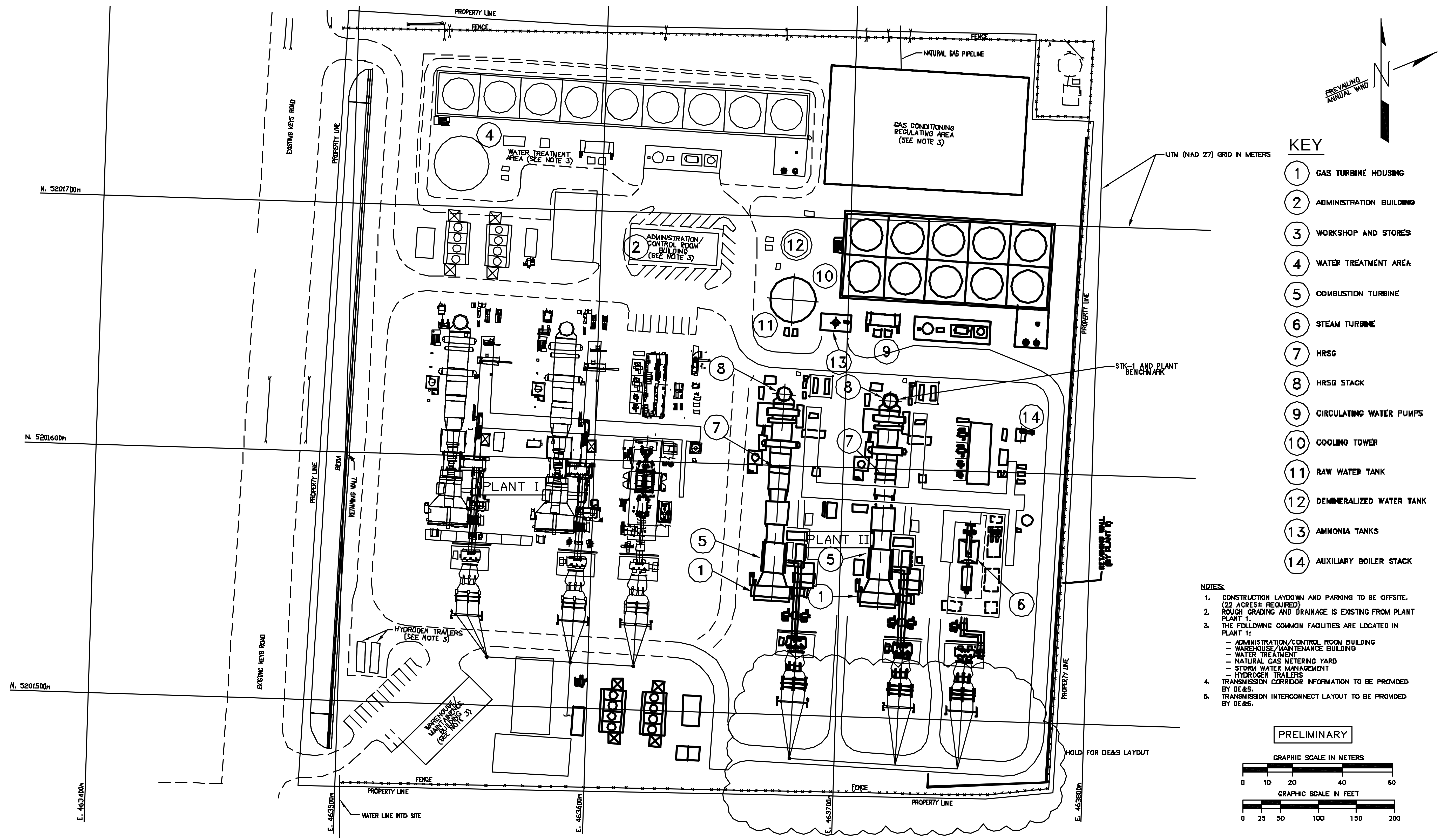
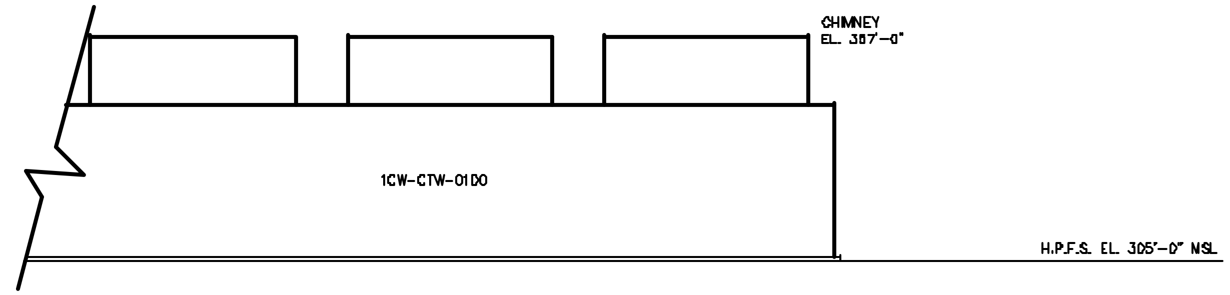
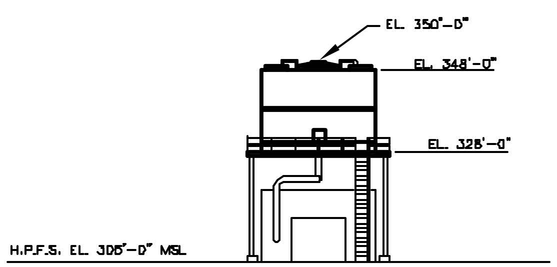


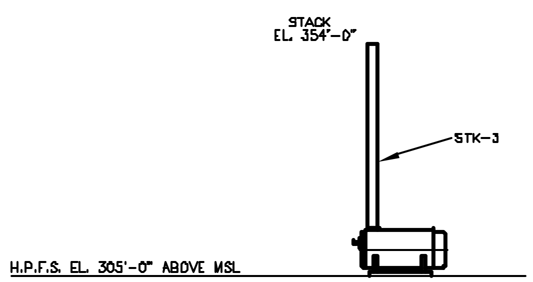

Figure 6.1-3
Site Plan



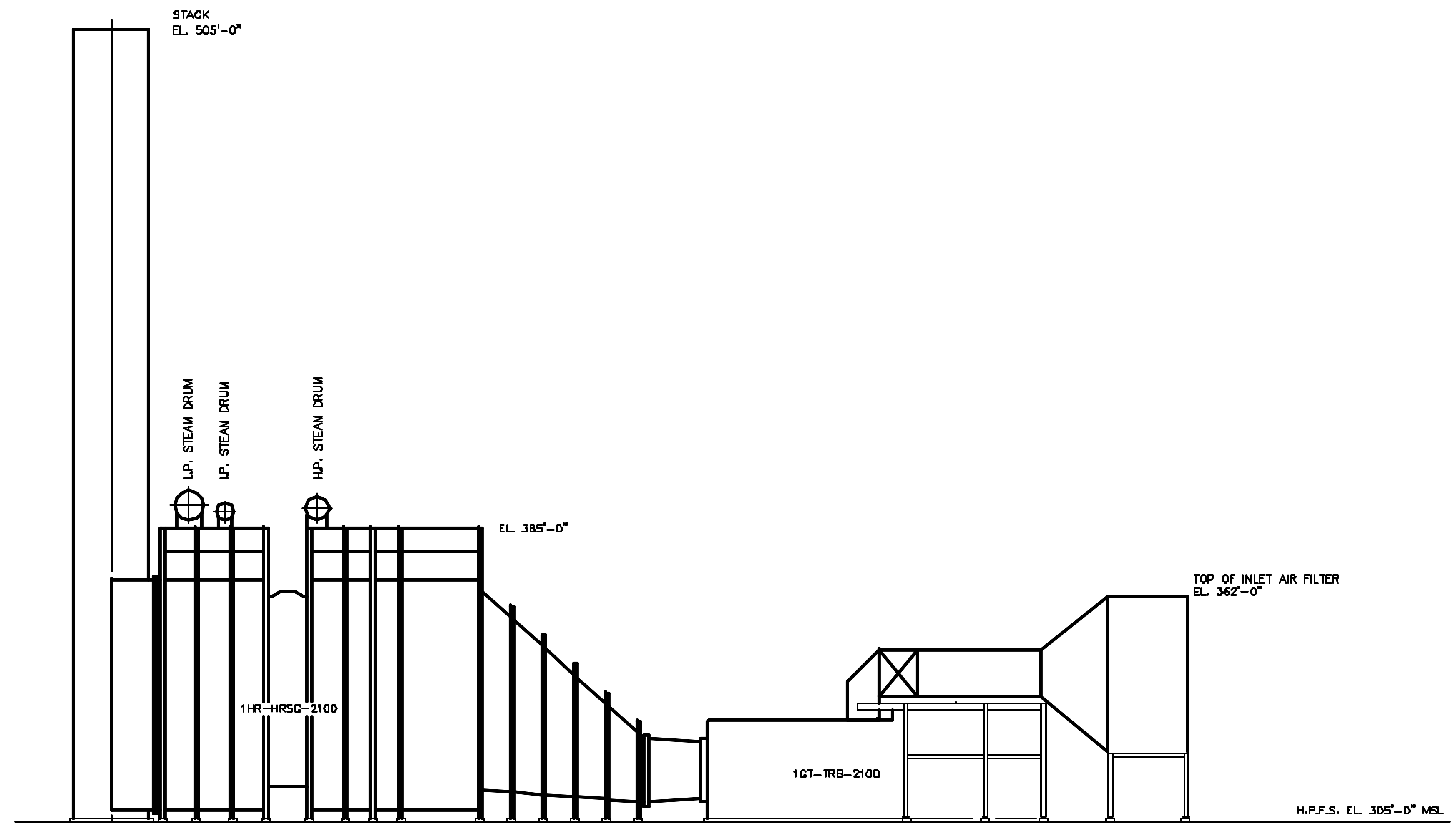

COOLING TOWER ELEVATION
VIEW LOOKING WEST




TURBINE INLET AIR CHILLING UNIT
VIEW LOOKING EAST




AUXILIARY BOILER ELEVATION
VIEW LOOKING NORTH




POWER TRAIN ELEVATION
VIEW LOOKING NORTH

PRELIMINARY


Figure 6.1-4
Plant Elevation

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Phase II Expansion
Satsop CT Project

*Source: 3DScape*

Figure 6.1-5
**Proposed Phase II Conceptual Isometric View**

URS

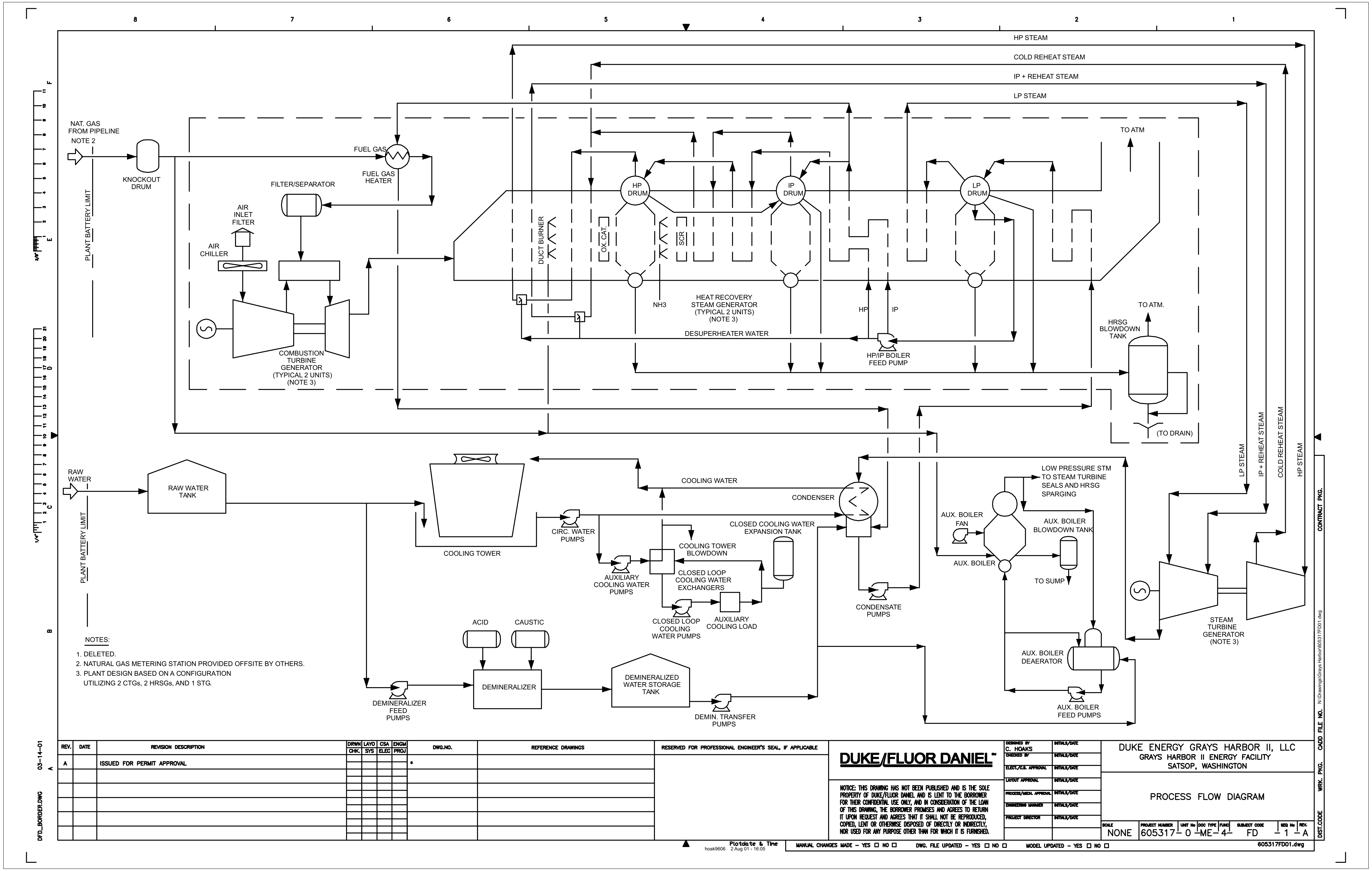


Figure 6.1-6

## Process Flow Diagram

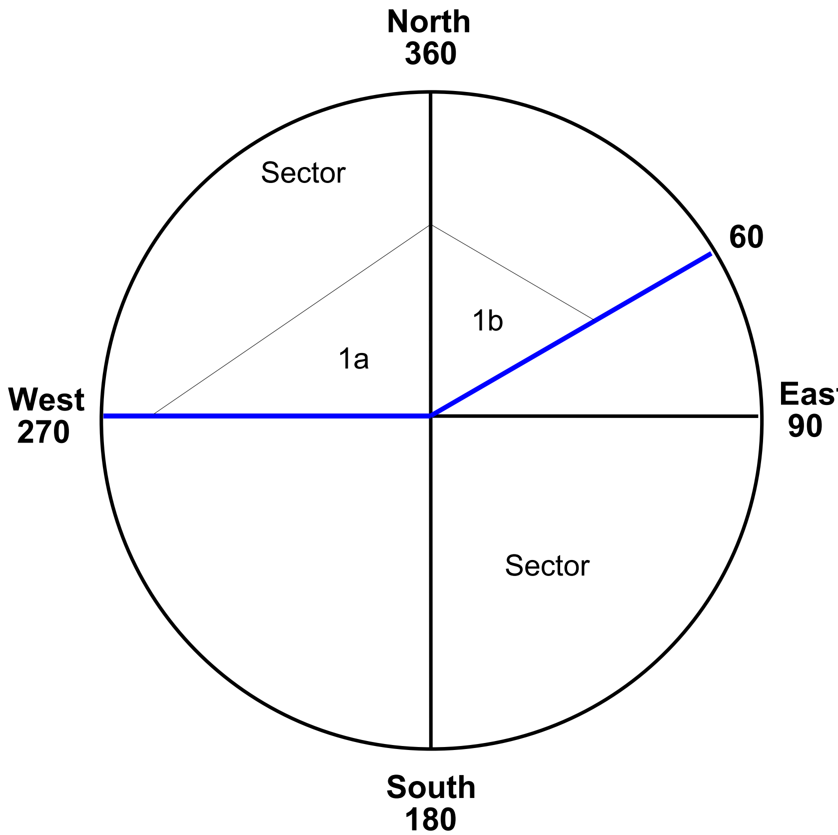


Figure 6.1-7
**Land Use Sectors**

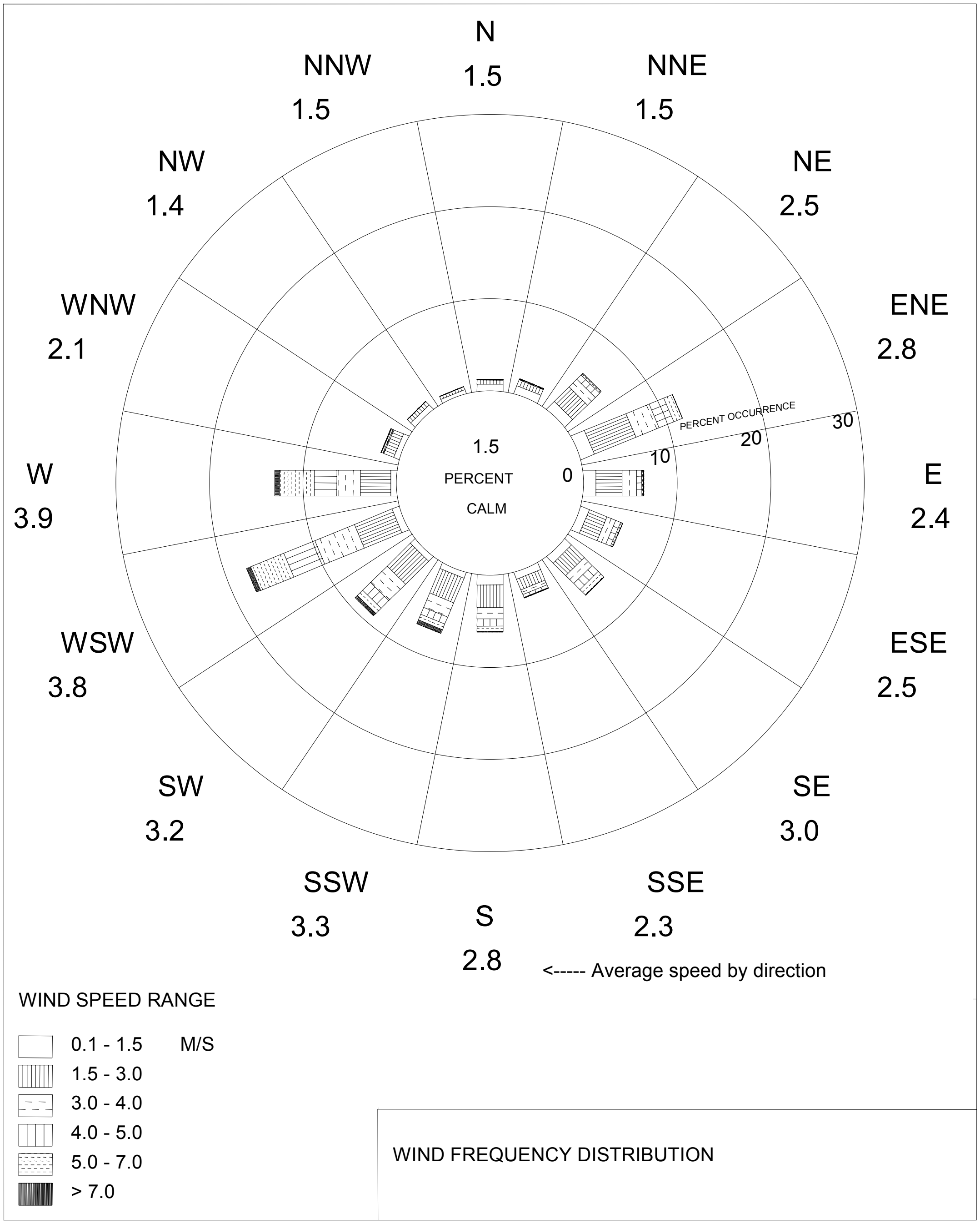


Figure 6.1-8

**Satsop Site Surface Winds**
**10/1/79 to 9/30/80**

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Phase II Expansion
Satsop CT Project

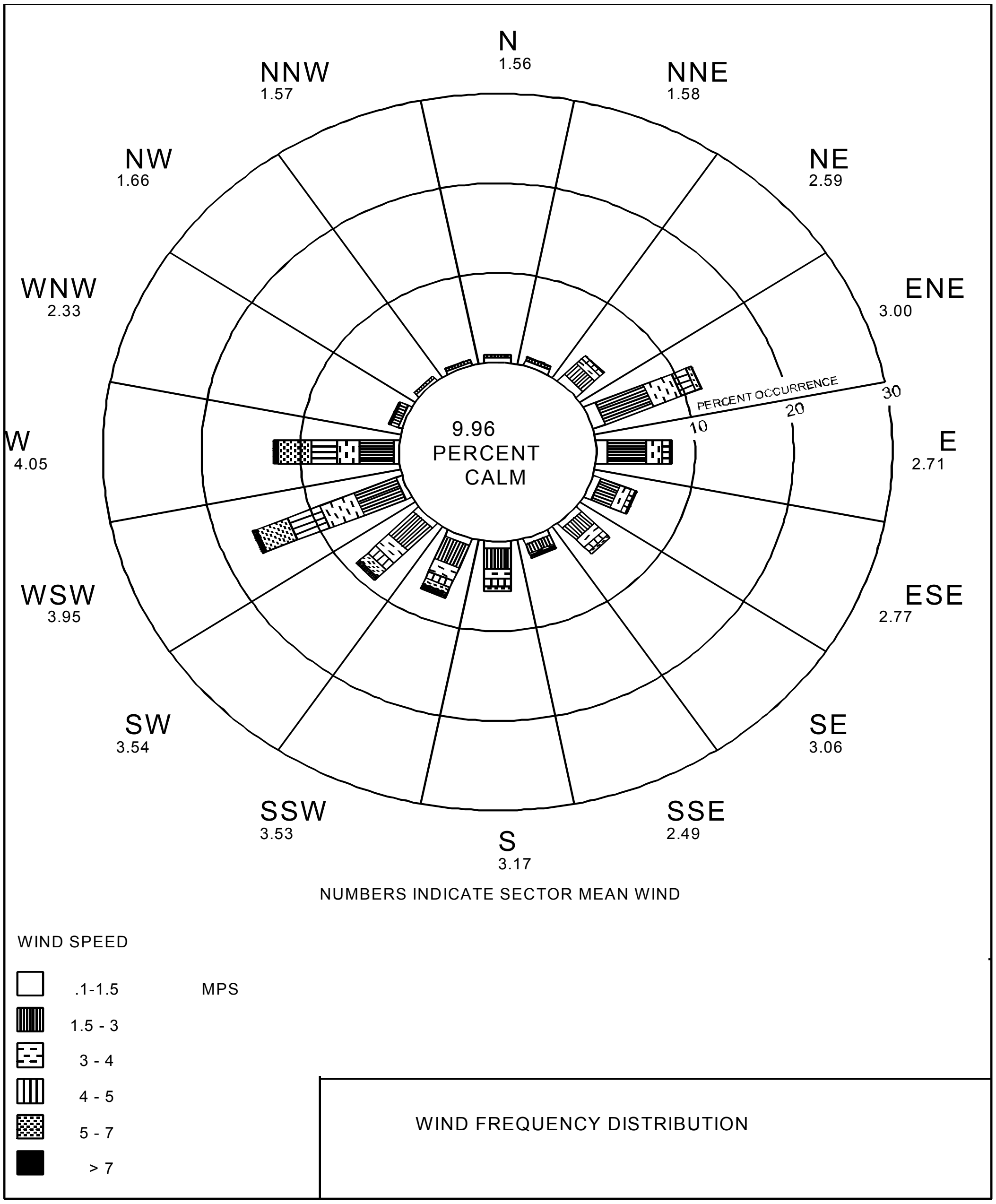


Figure 6.1-9

**Satsop Site Surface Winds**
**2/1/80 to 1/31/81**

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Phase II Expansion
Satsop CT Project

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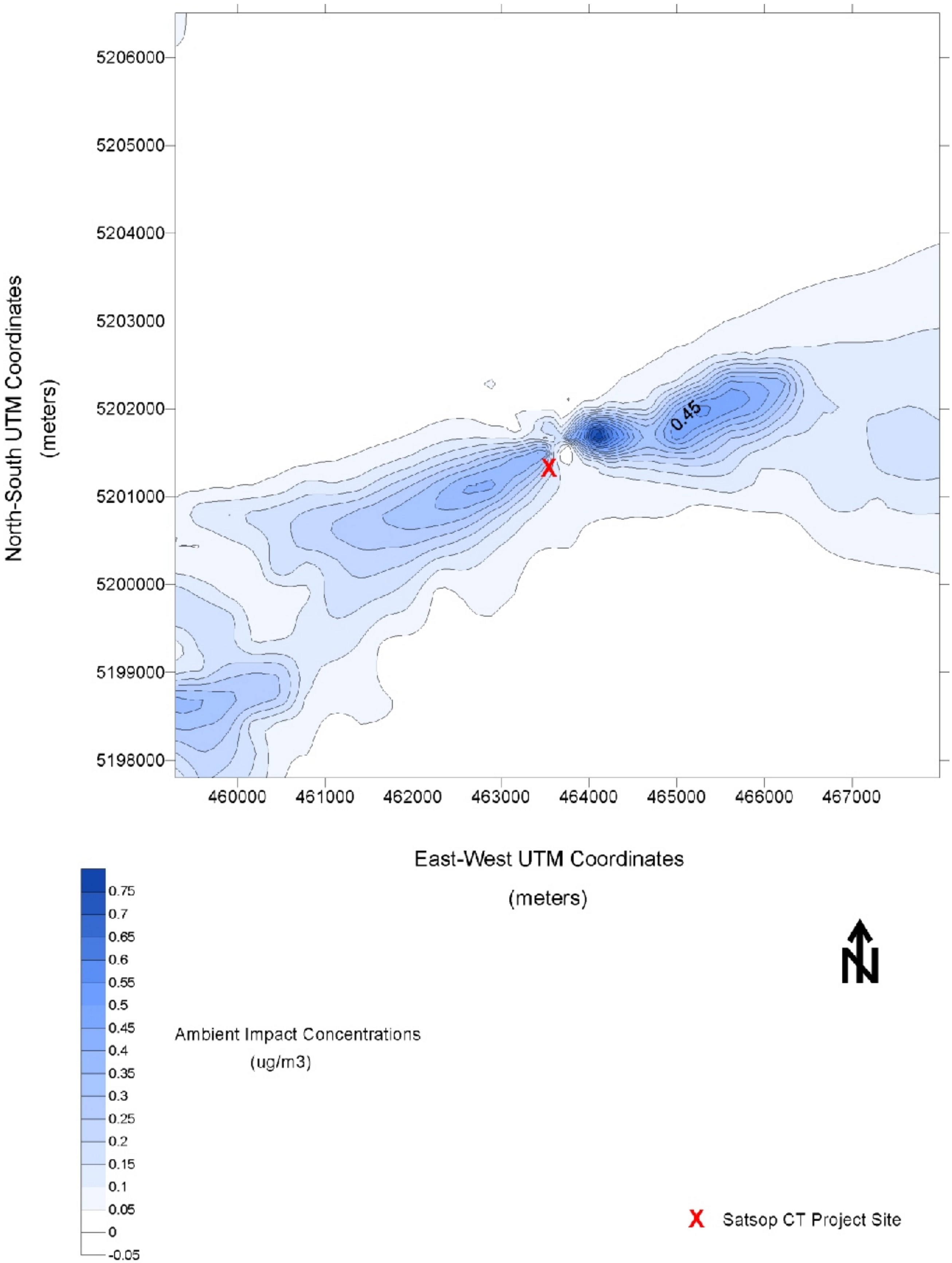


Figure 6.1-10

## Annual PM Impact Concentrations

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Phase II Expansion
Satsop CT Project

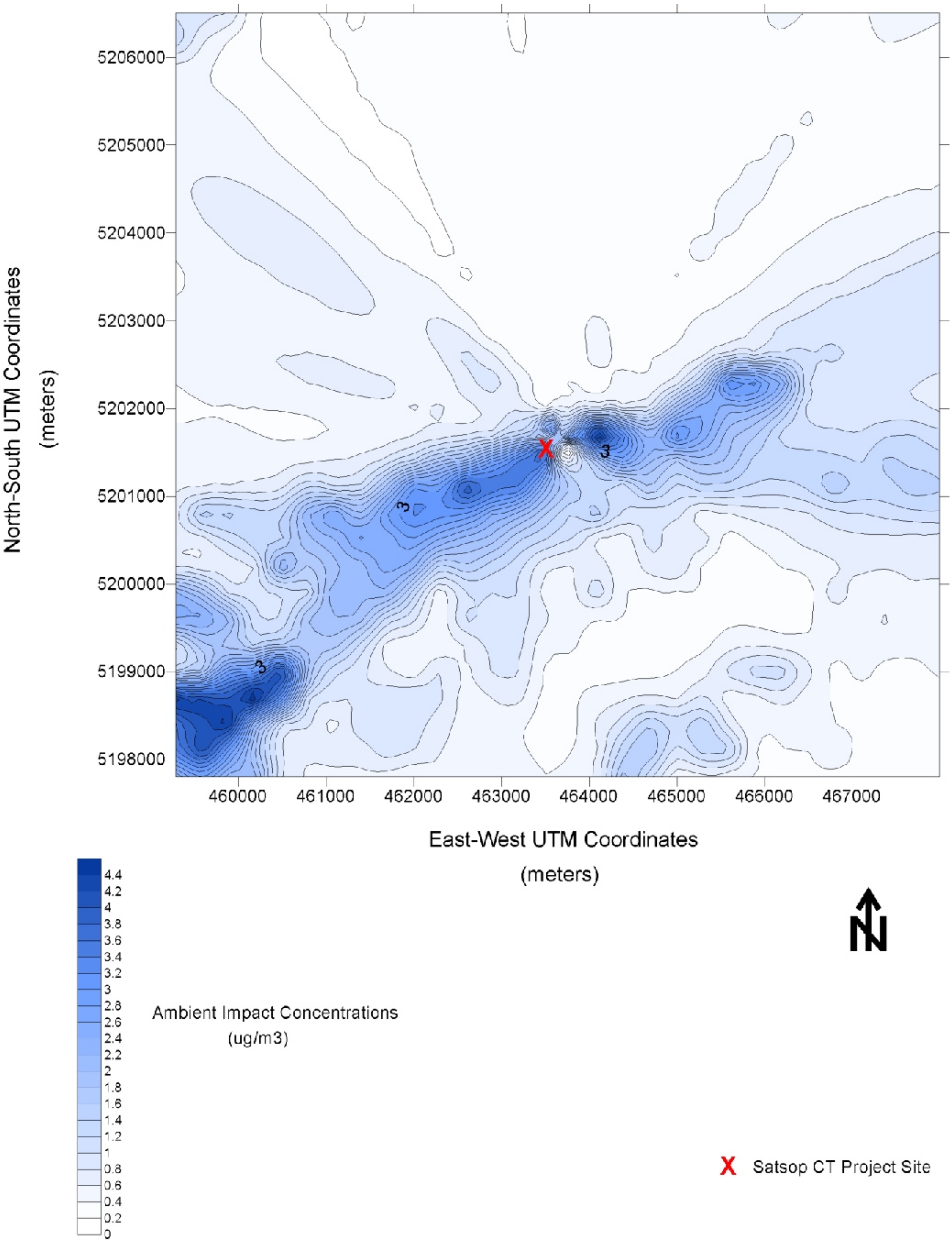


Figure 6.1-11

## Twenty-Four Hour PM Impact Concentrations

URS

Phase II Expansion
Satsop CT Project

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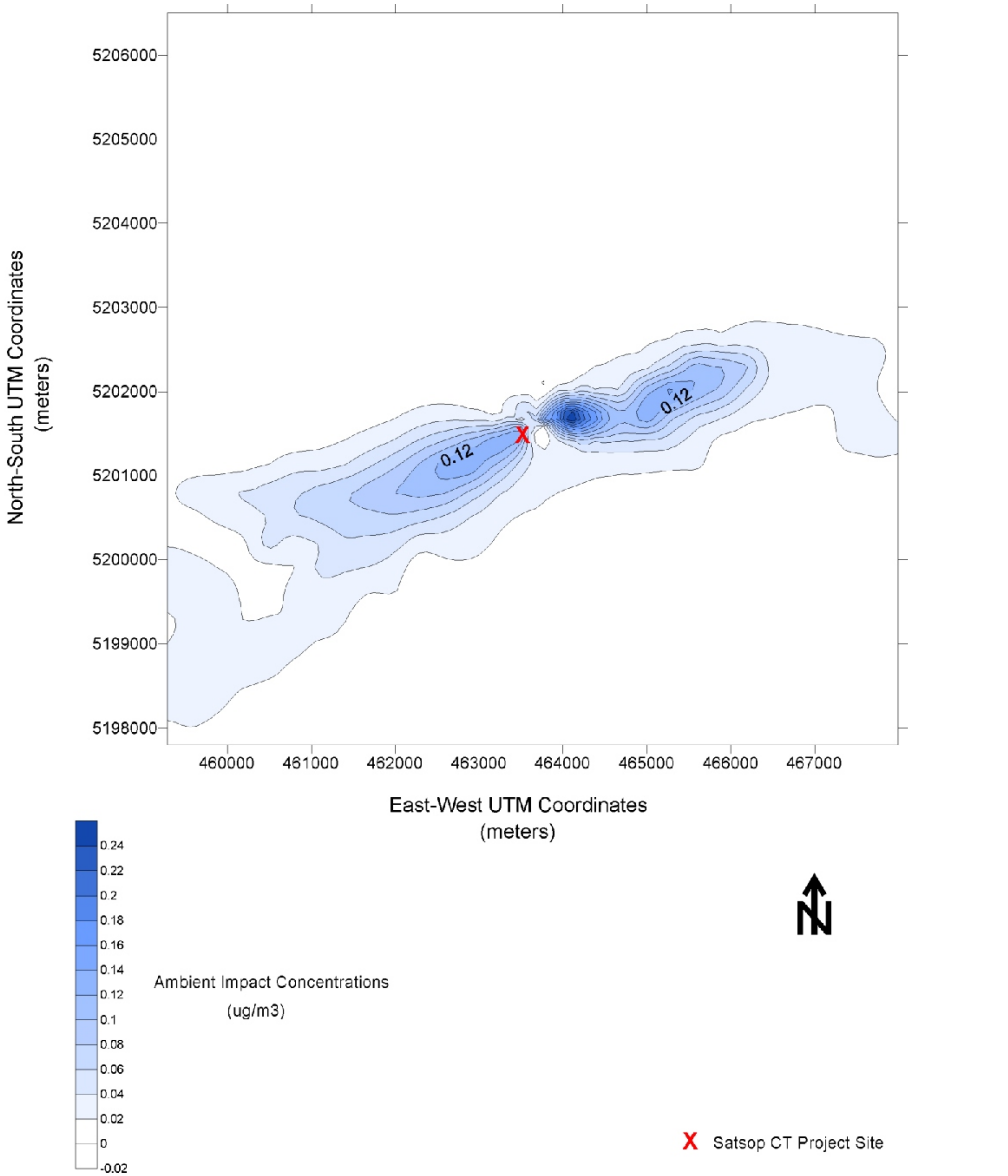


Figure 6.1-12

## Annual $SO_2$ Impact Concentrations

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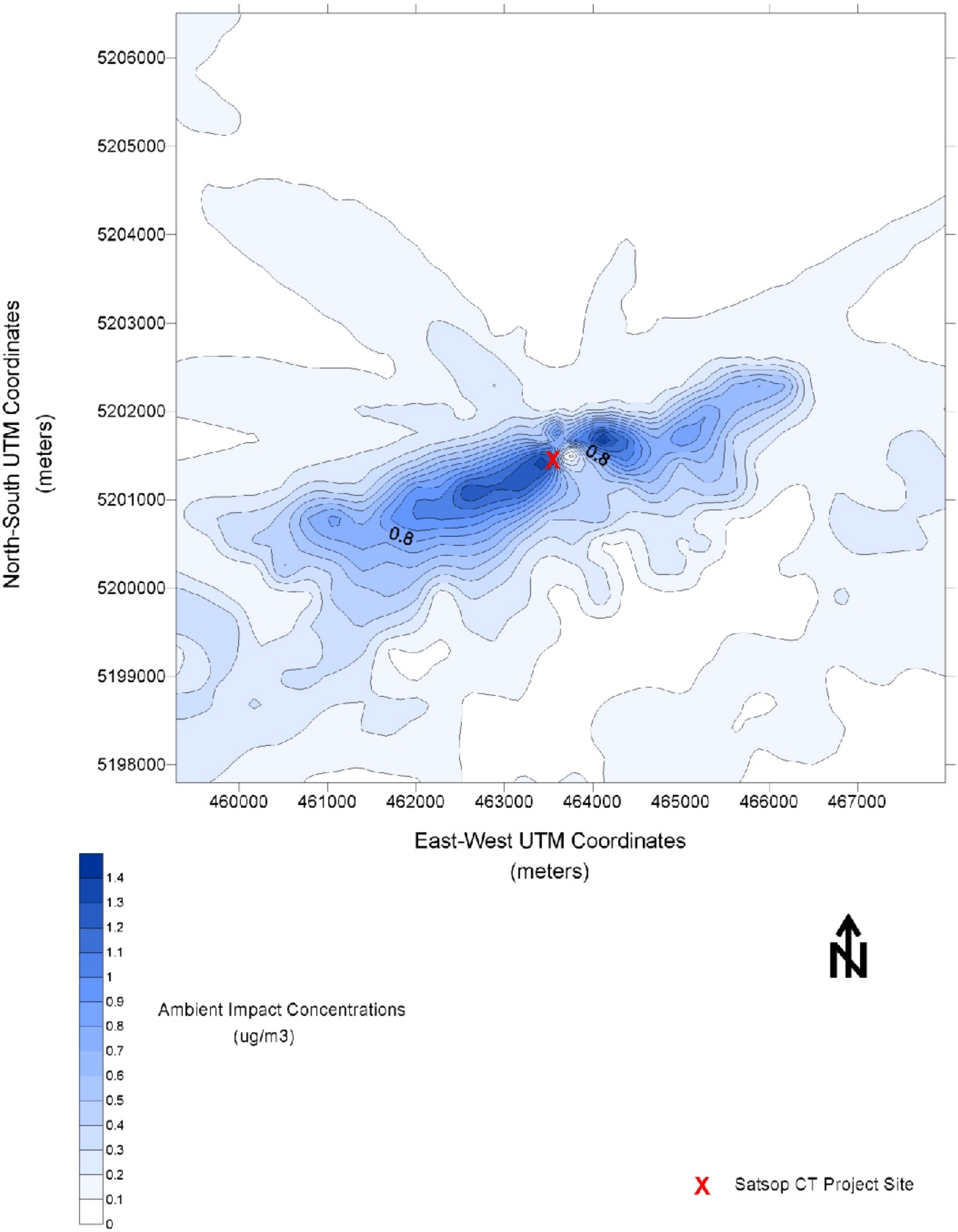


Figure 6.1-13

## $SO_2$ 24-Hour Impact Concentrations

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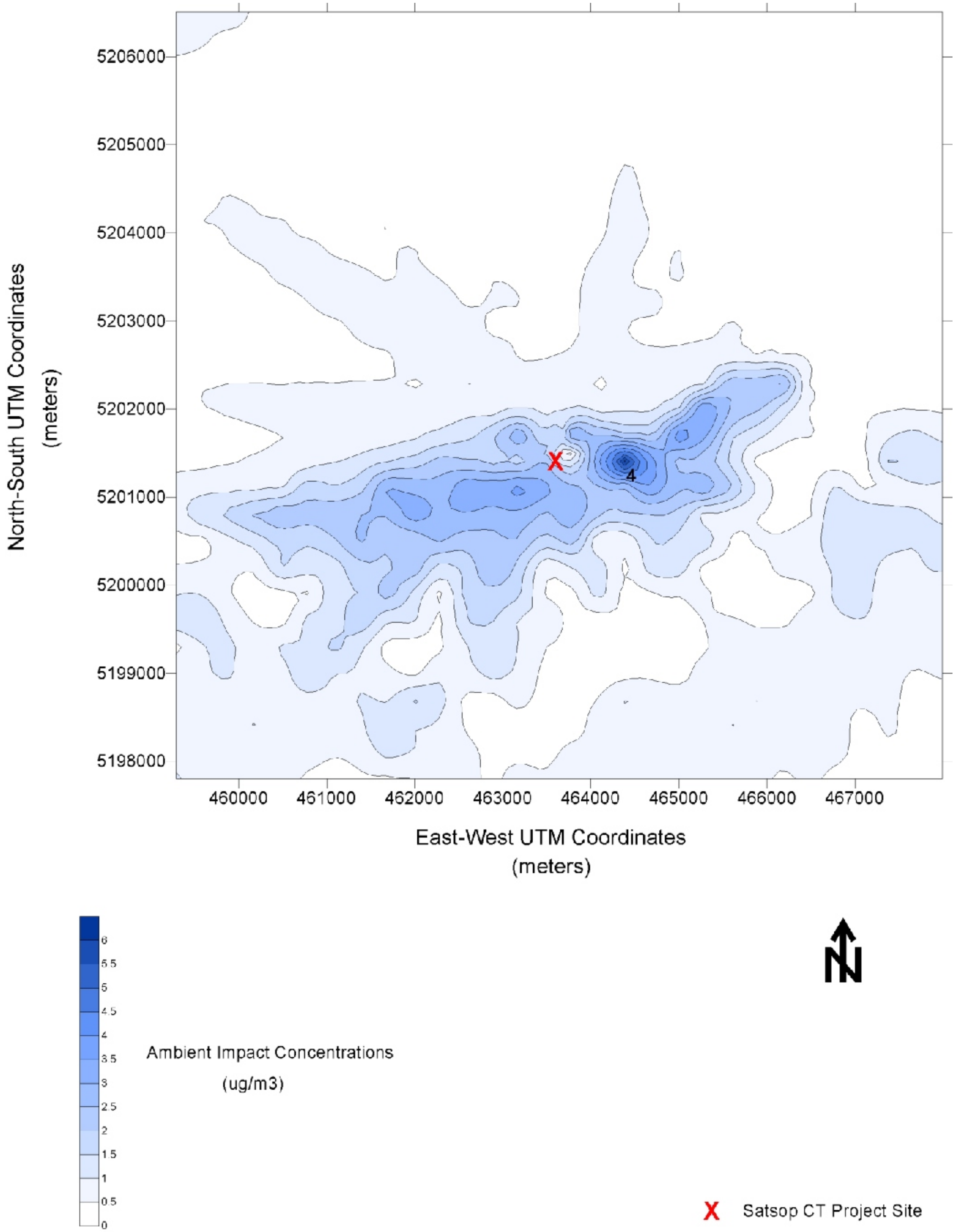


Figure 6.1-14

## $SO_2$ 3-Hour Impact Concentrations

URS

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Satsop CT Project

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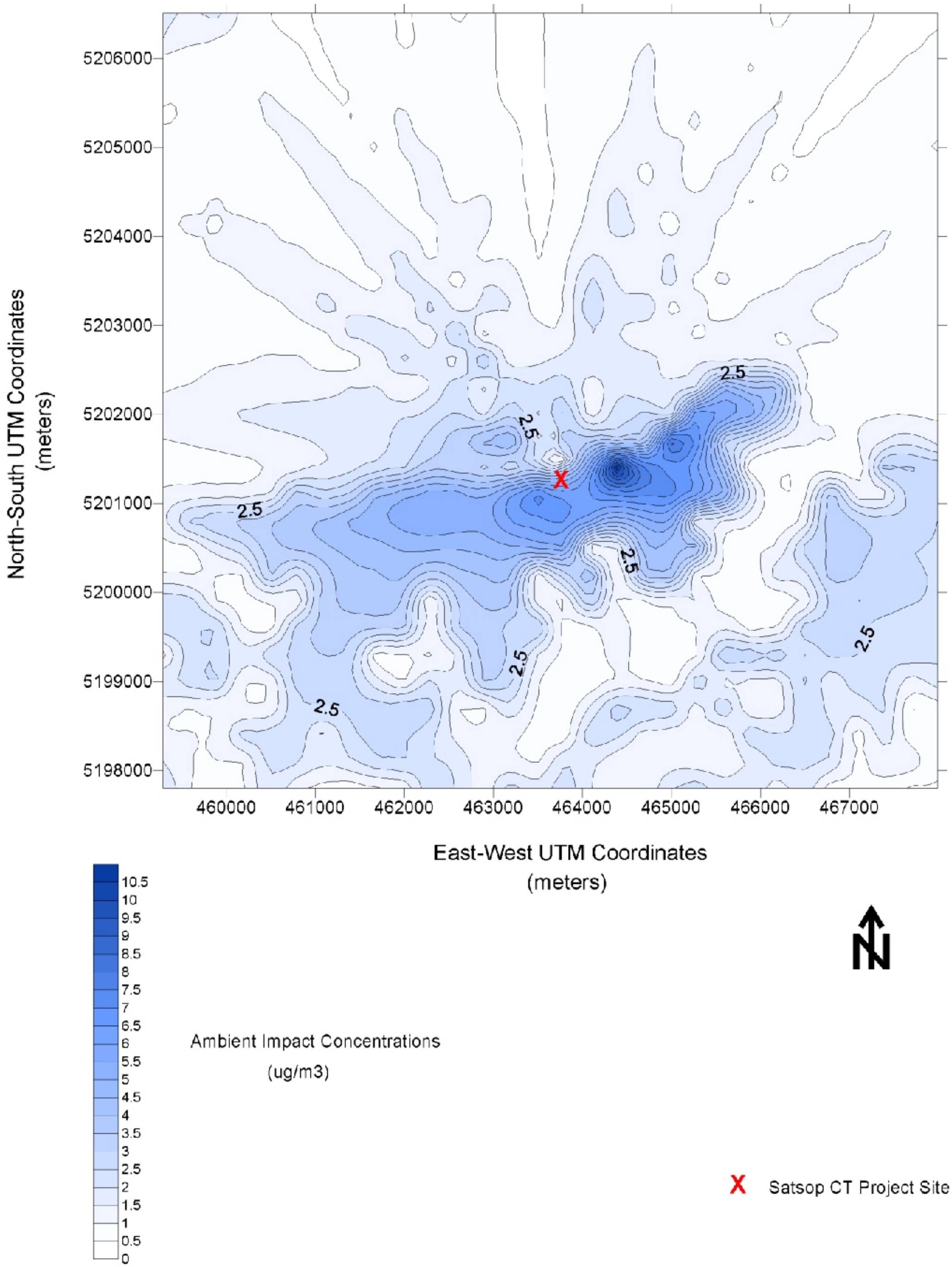


Figure 6.1-15

## $SO_2$ 1-Hour Impact Concentrations

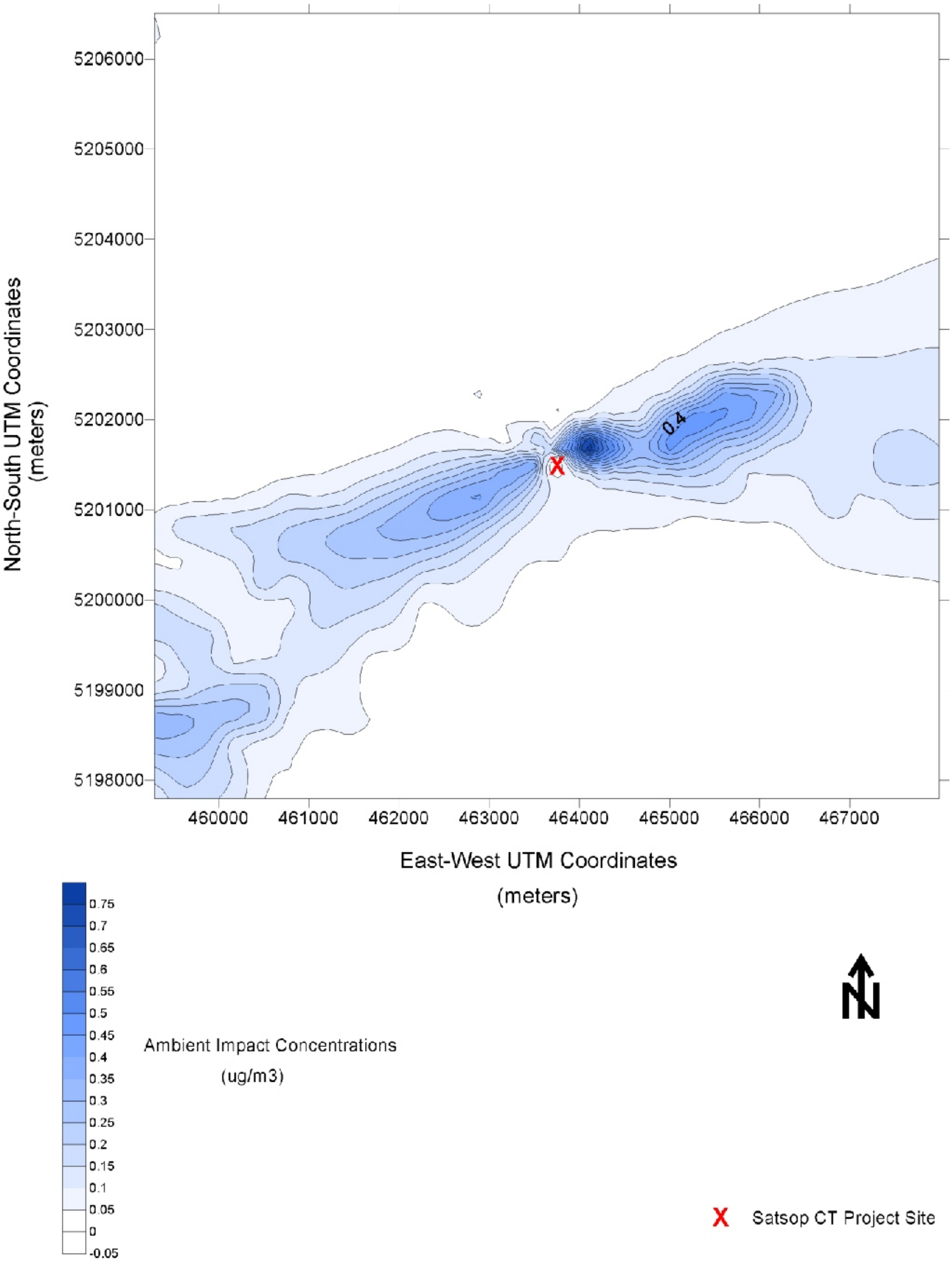


Figure 6.1-16

## Annual $NO_x$ Impact Concentrations

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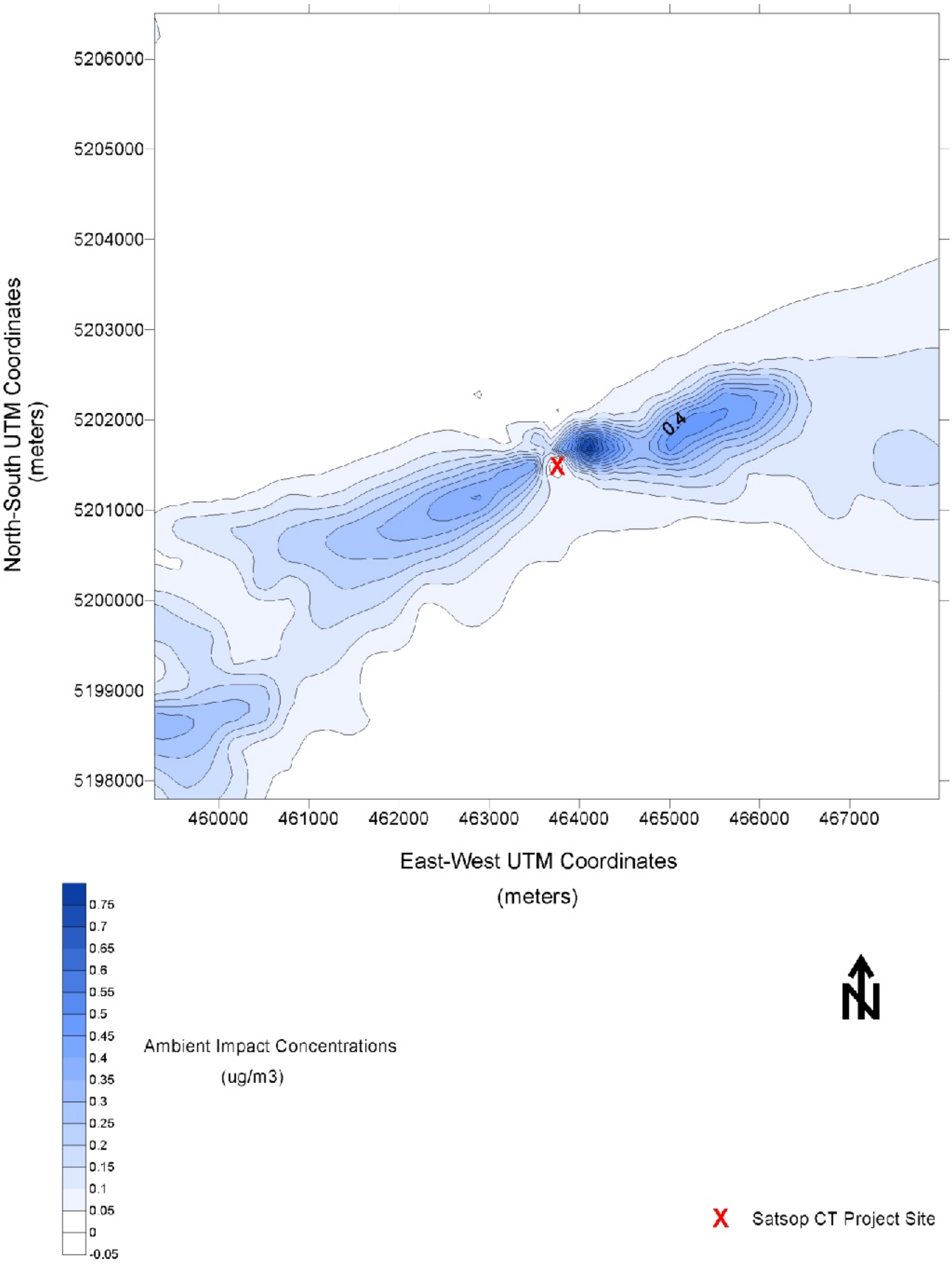


Figure 6.1-16

**Annual $NO_x$ Impact Concentrations**

URS

Phase II Expansion
Satsop CT Project

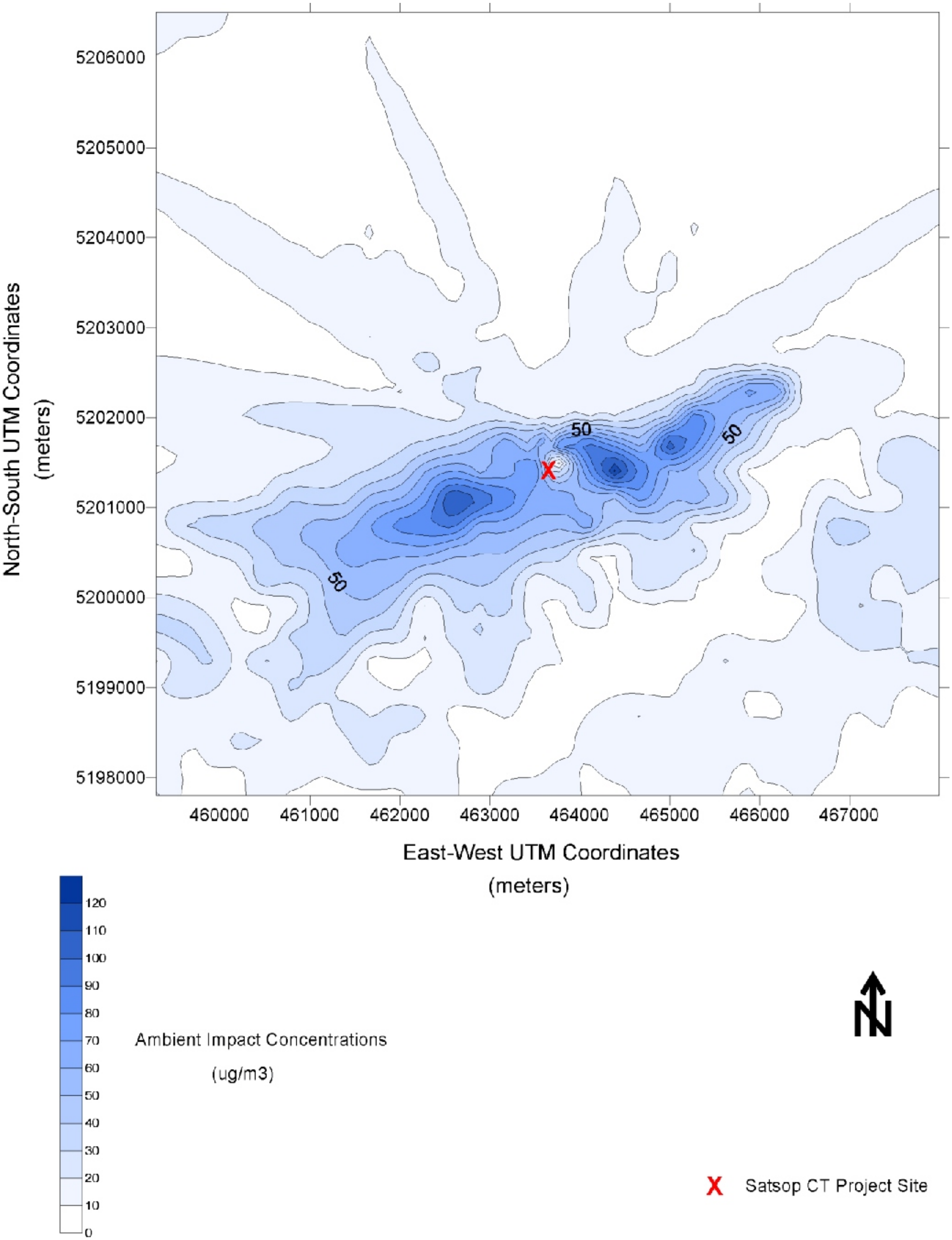


Figure 6.1-17

## CO 8-Hour Impact Concentrations

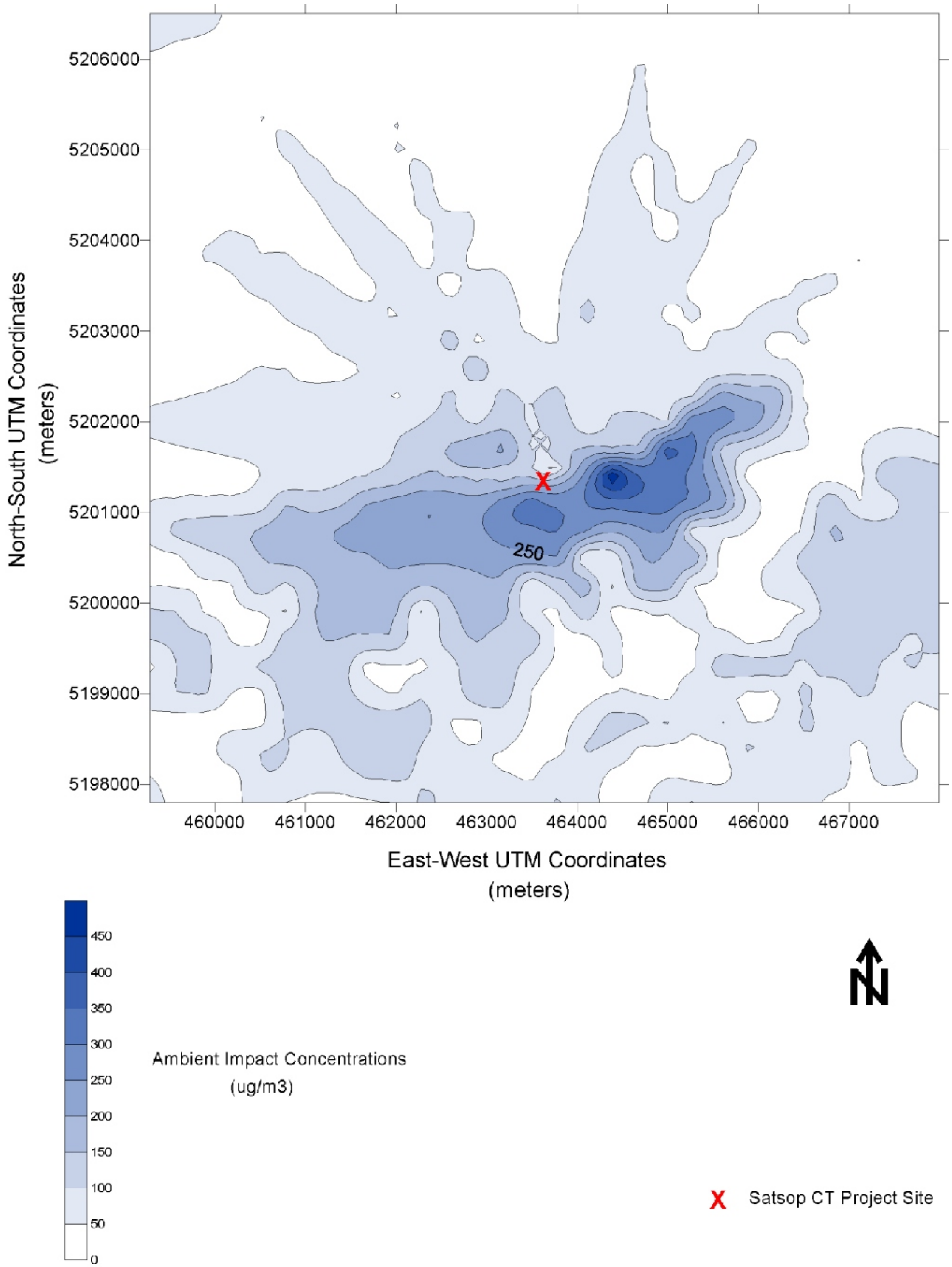


Figure 6.1-18

## CO 1-Hour Impact Concentrations

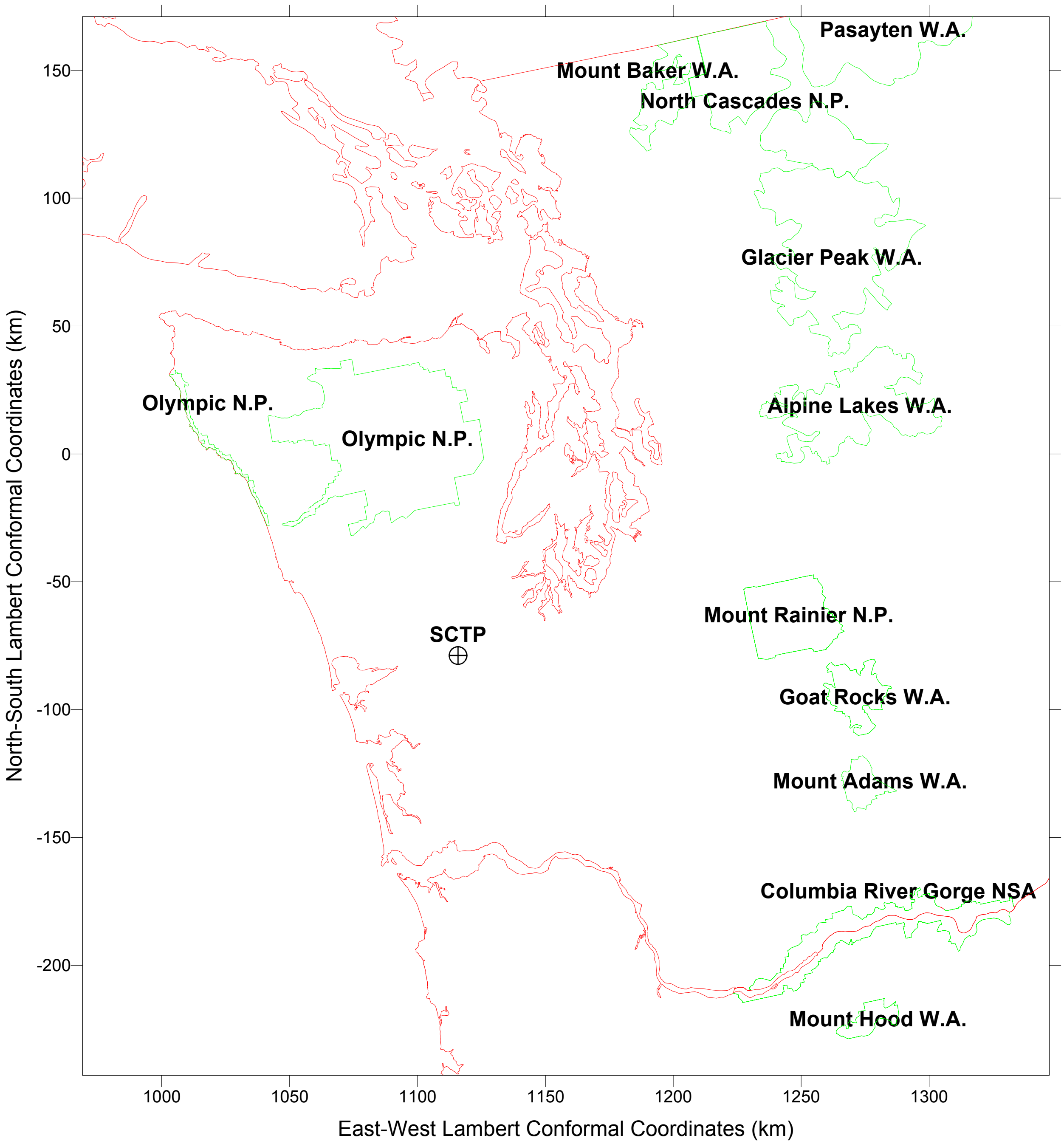


Figure 6.1-19
**Study Domain with Location of Class I Areas**

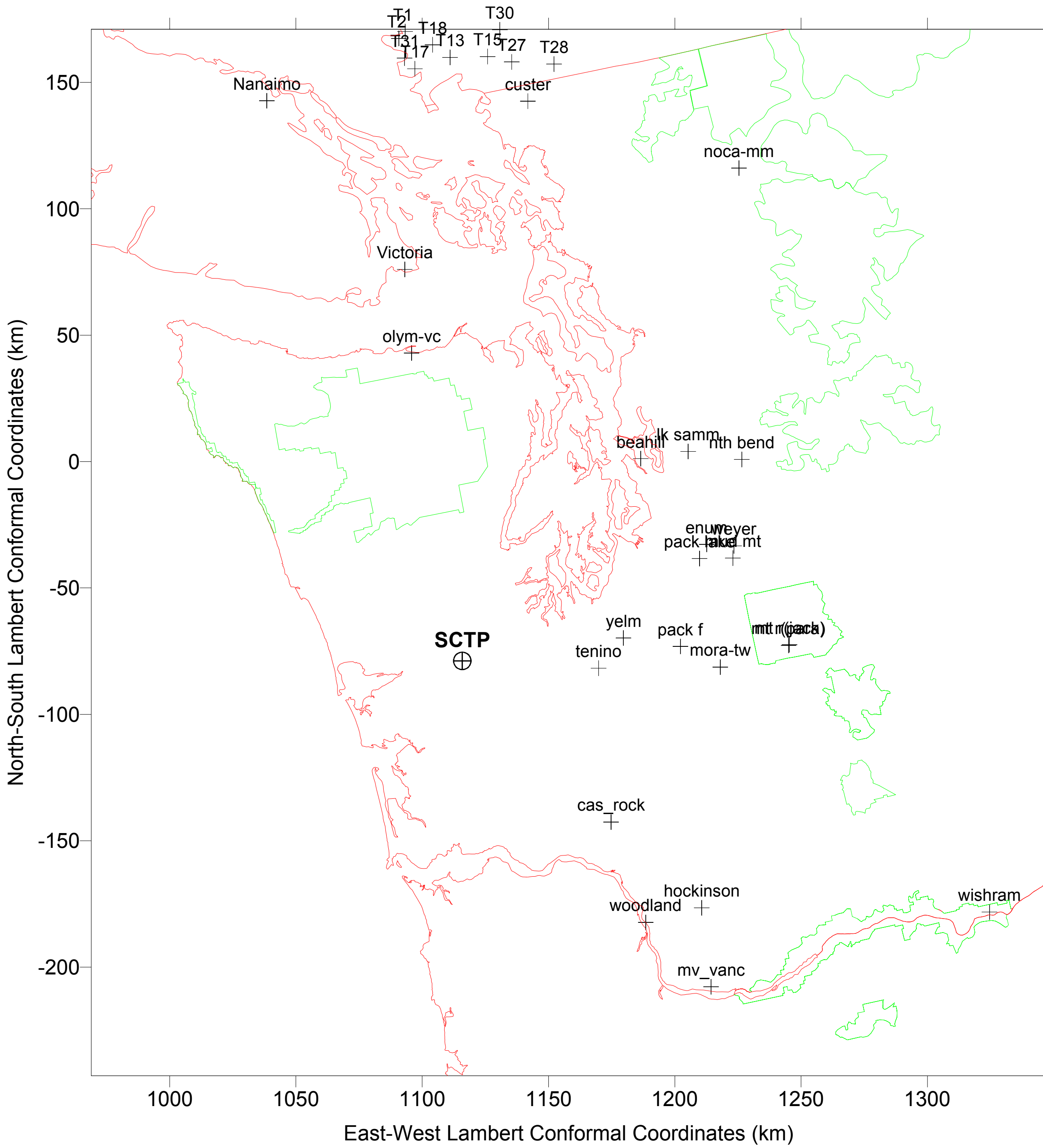


Figure 6.1-20

## Location of Ozone Stations

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Satsop CT Project

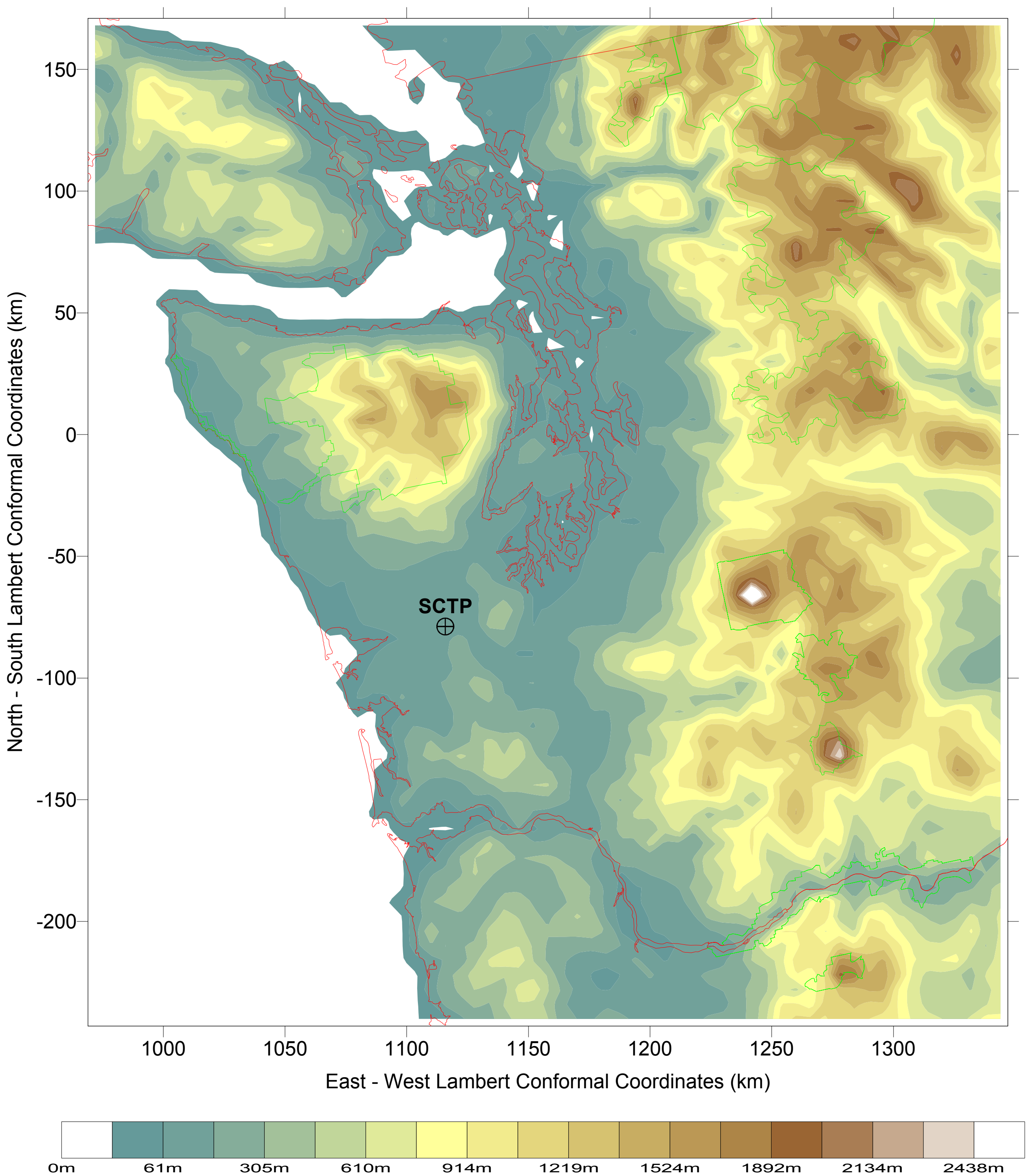


Figure 6.1-21

## Study Terrain, Grid Mesh Size of 6 km

URS

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Satsop CT Project

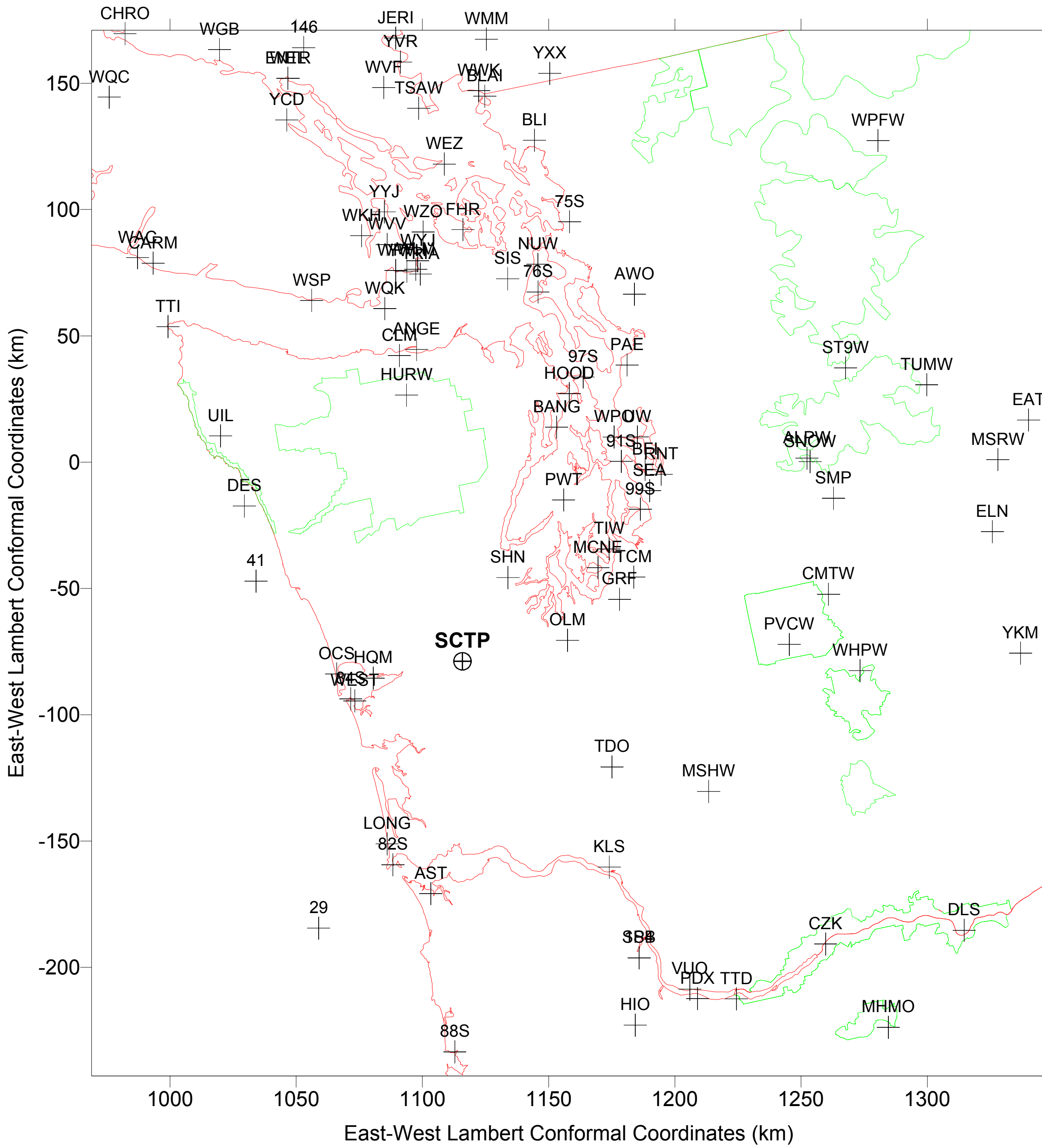


Figure 6.1-22

## Surface Station Locations

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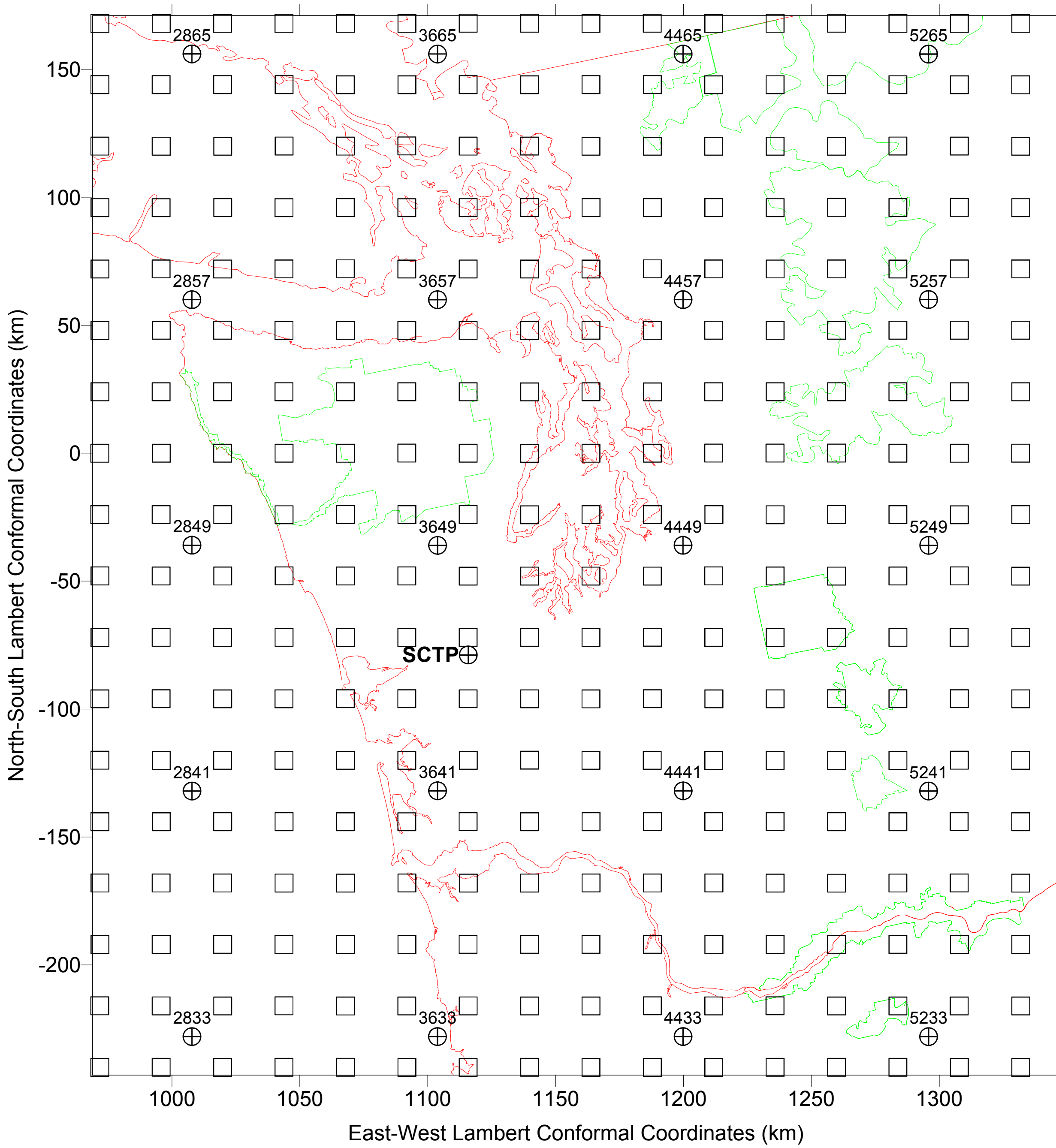


Figure 6.1-23
**Location of MM5 Pseudo Stations, Squares – Precipitation and Circles – Upper Air**

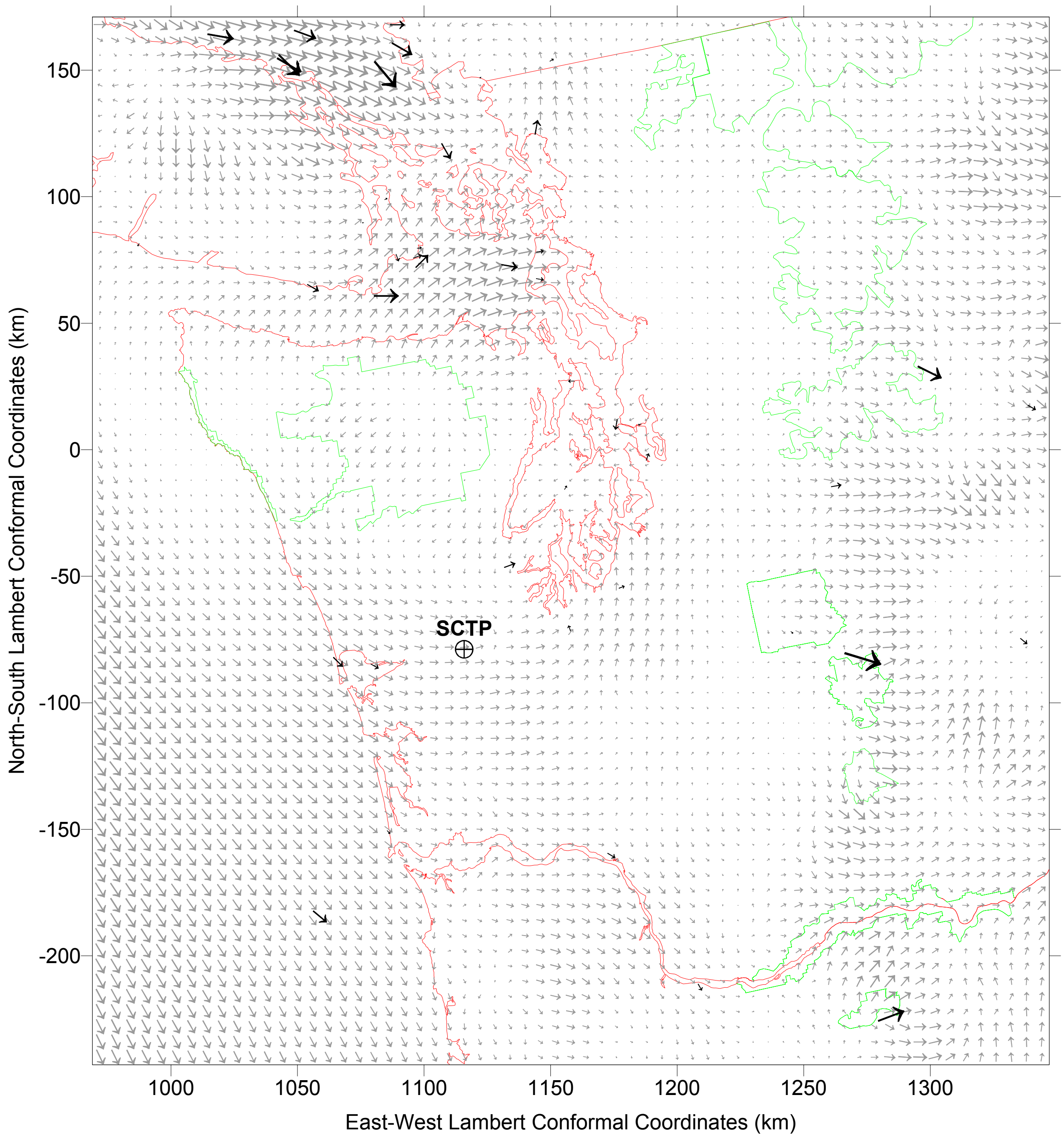


Figure 6.1-24

**CALMET Surface Winds of 6/1/98 hour 0400-0500 PST, Surface Observations Also Shown**

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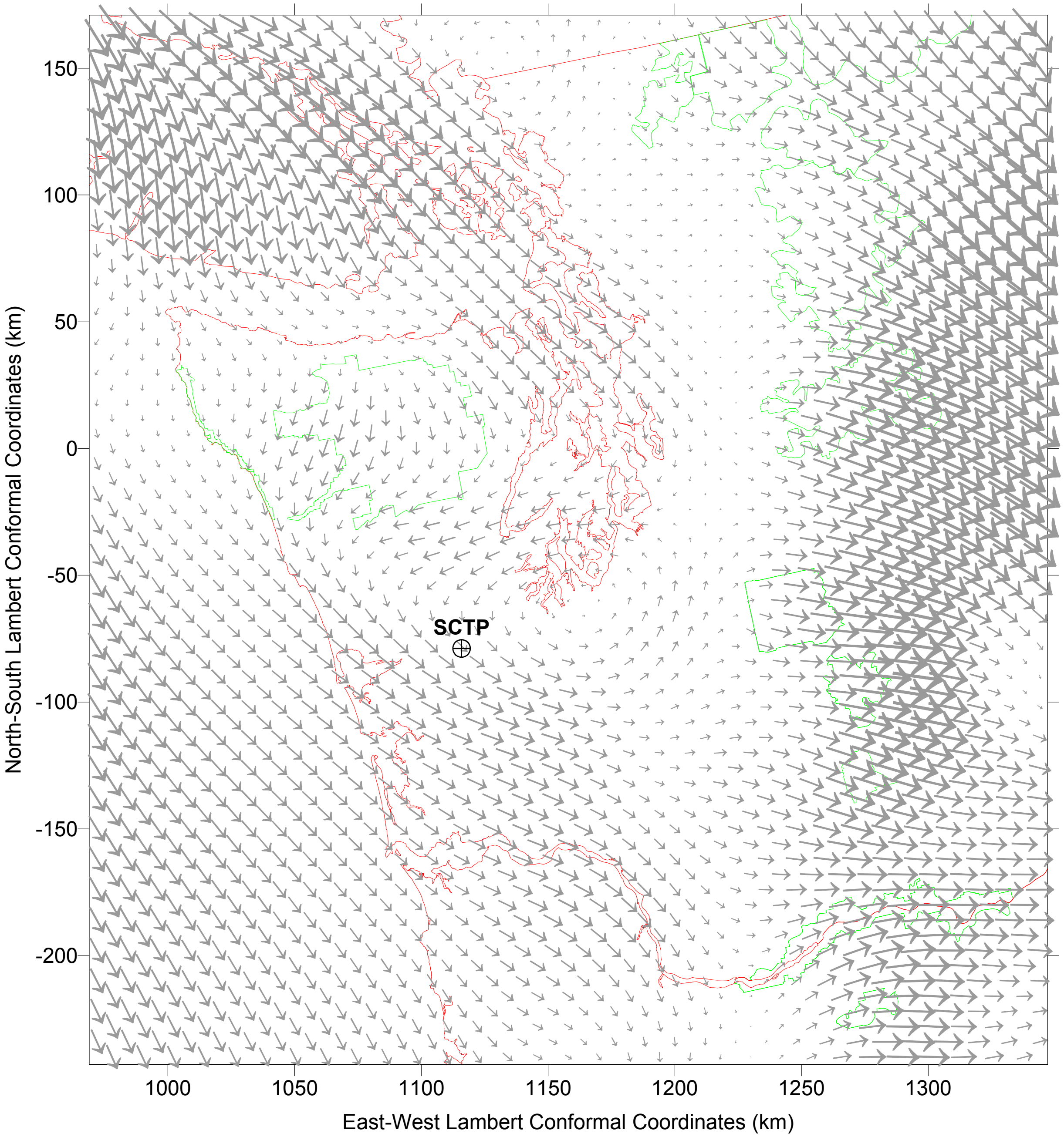


Figure 6.1-25

**CALMET Level 6 (300 m) Winds 6/1/98 hour 0400-0500 PST**

URS

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Satsop CT Project

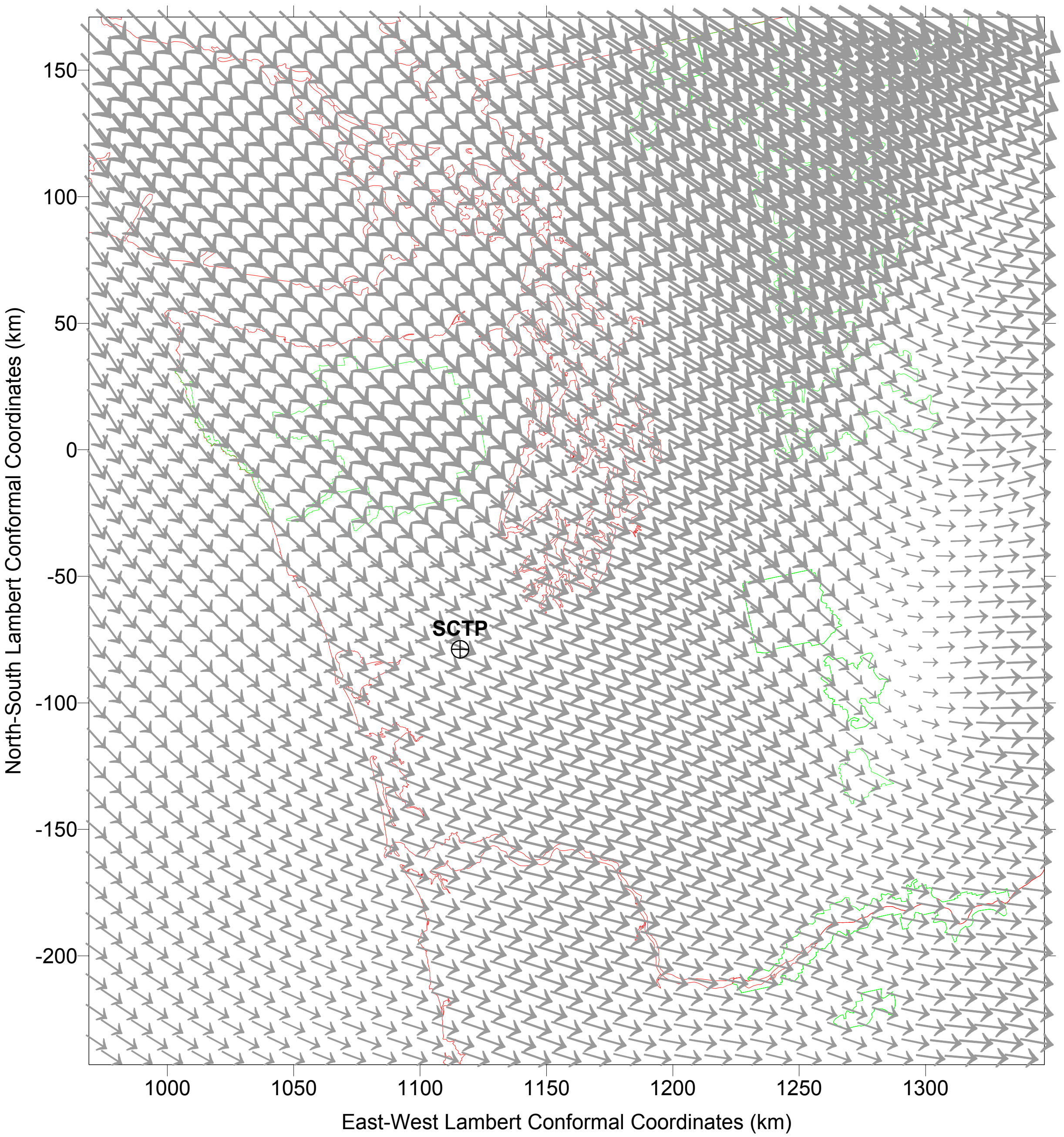


Figure 6.1-26

**CALMET Level 10 (3000 m) Winds 6/1/98 hour 0400-0500 PST**

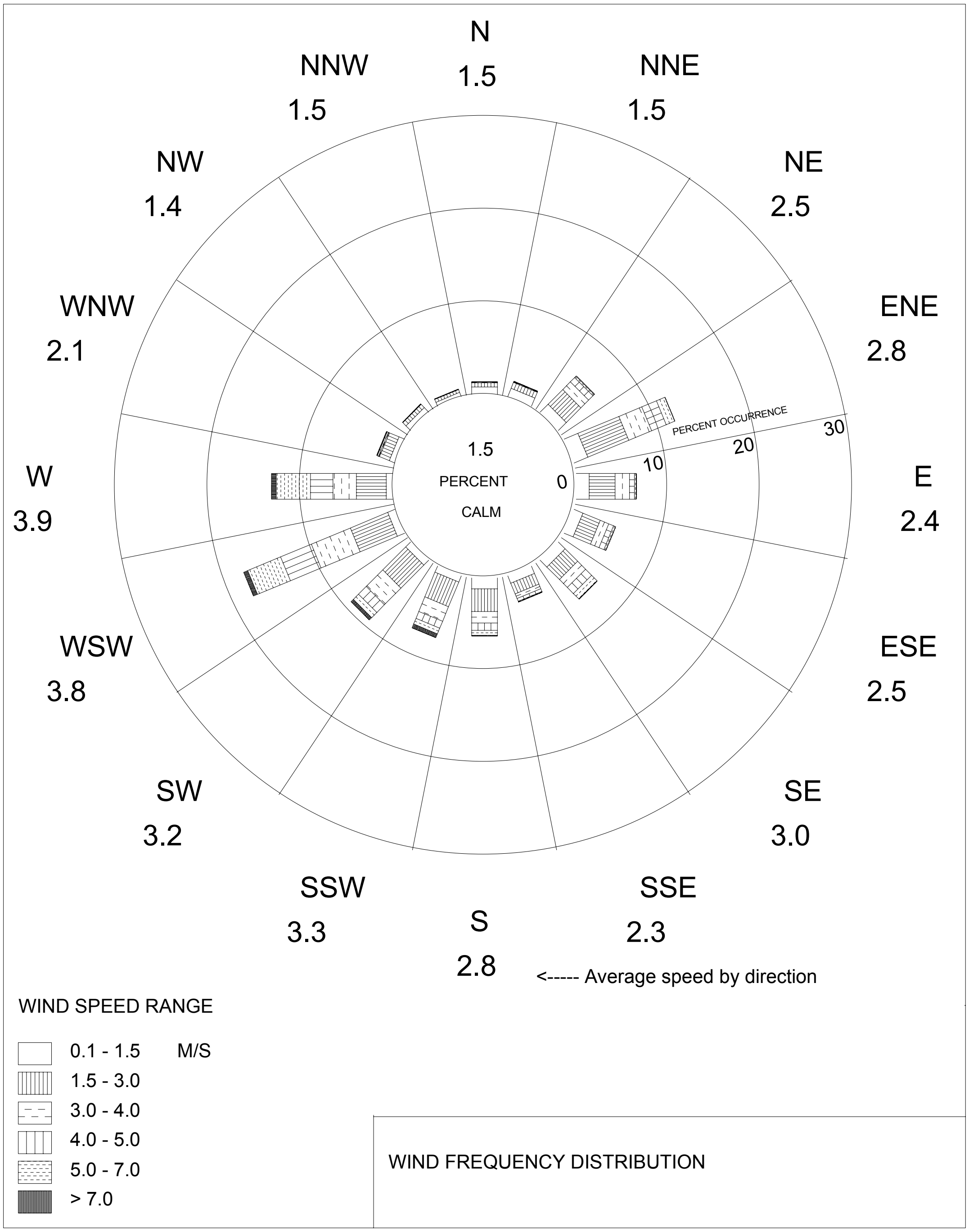


Figure 6.1-27

**Satsop Site Surface Winds**

URS

Phase II Expansion
Satsop CT Project

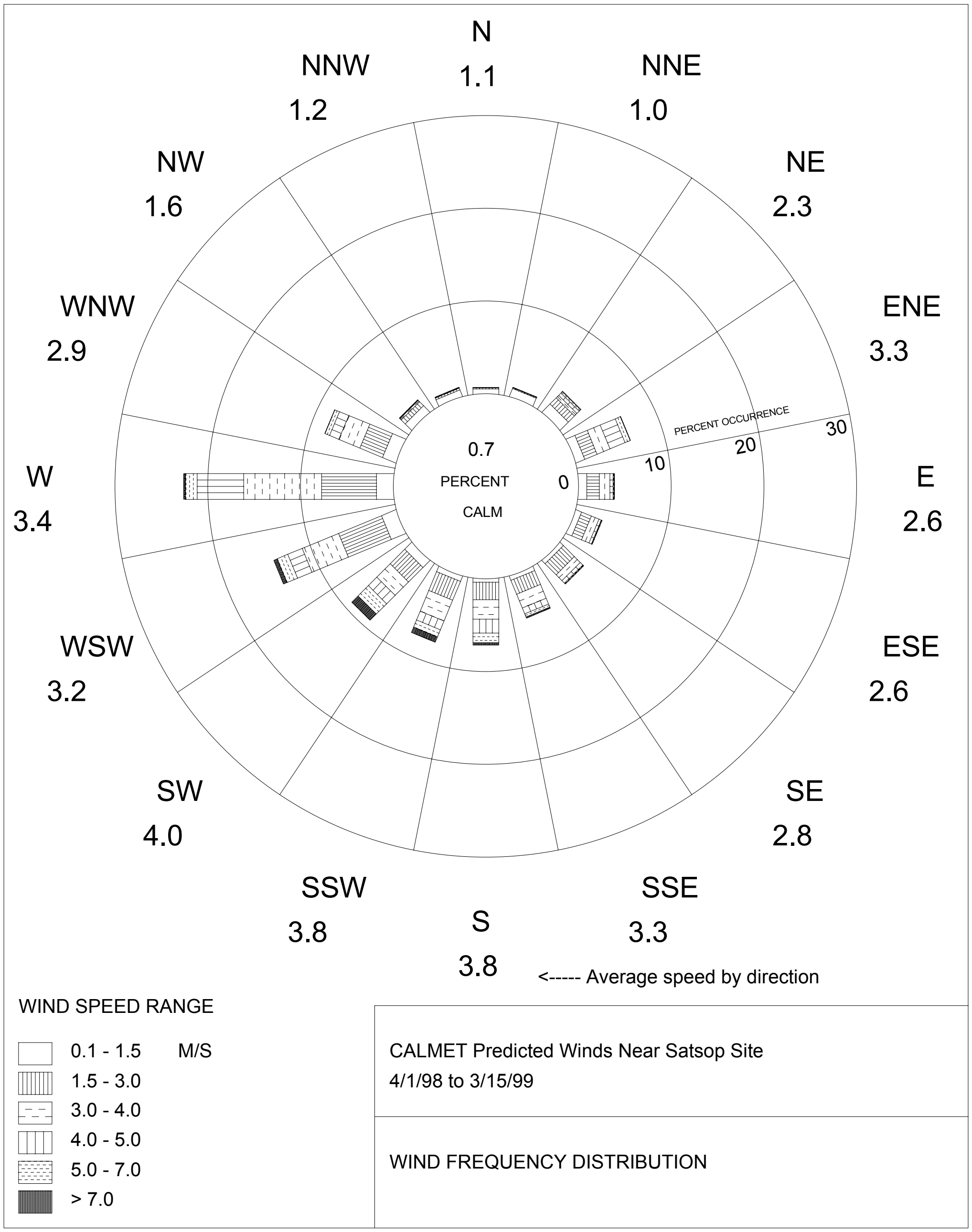


Figure 6.1-28

## CALMET Surface Winds

URS

Phase II Expansion
Satsop CT Project

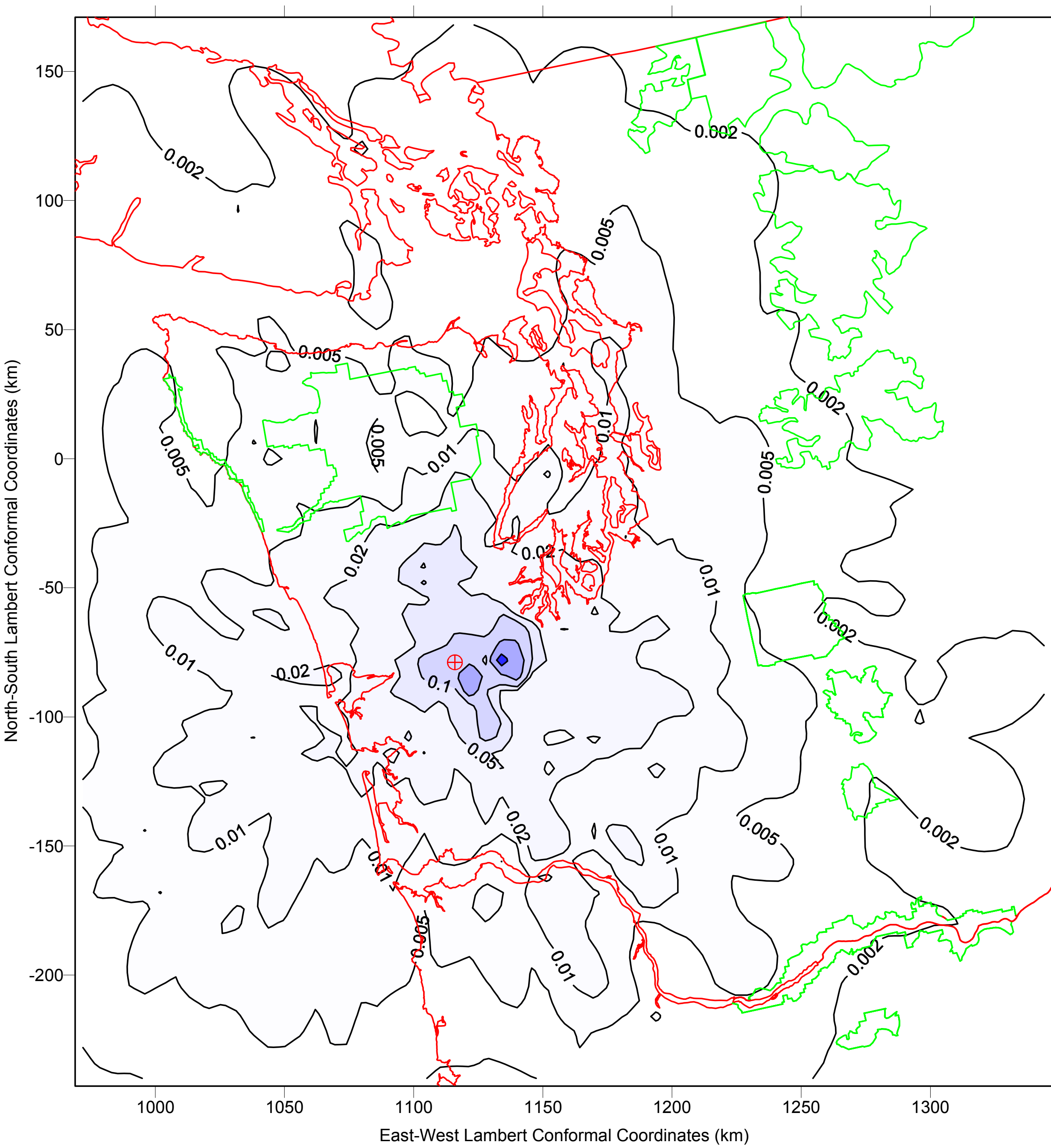


Figure 6.1-29

**Three-Hour Maximum $SO_2$ ($\mu g/m^3$), April 1, 1998, through March 15, 1999**

URS

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Satsop CT Project

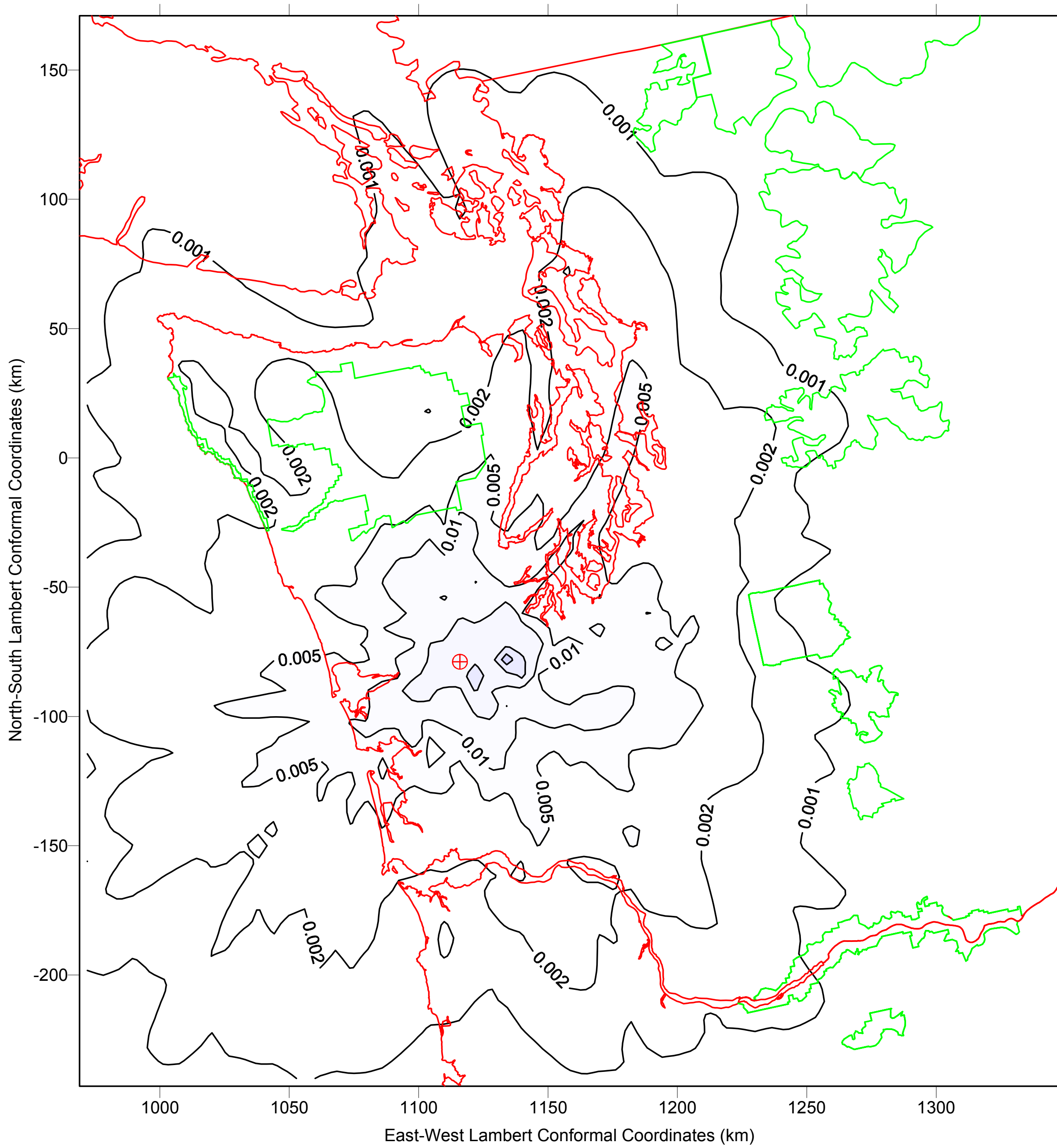


Figure 6.1-30

**Twenty-Four Hour Maximum $SO_2$ ($\mu g/m^3$), April 1, 1998, through March 15, 1999**

URS

Phase II Expansion
Satsop CT Project

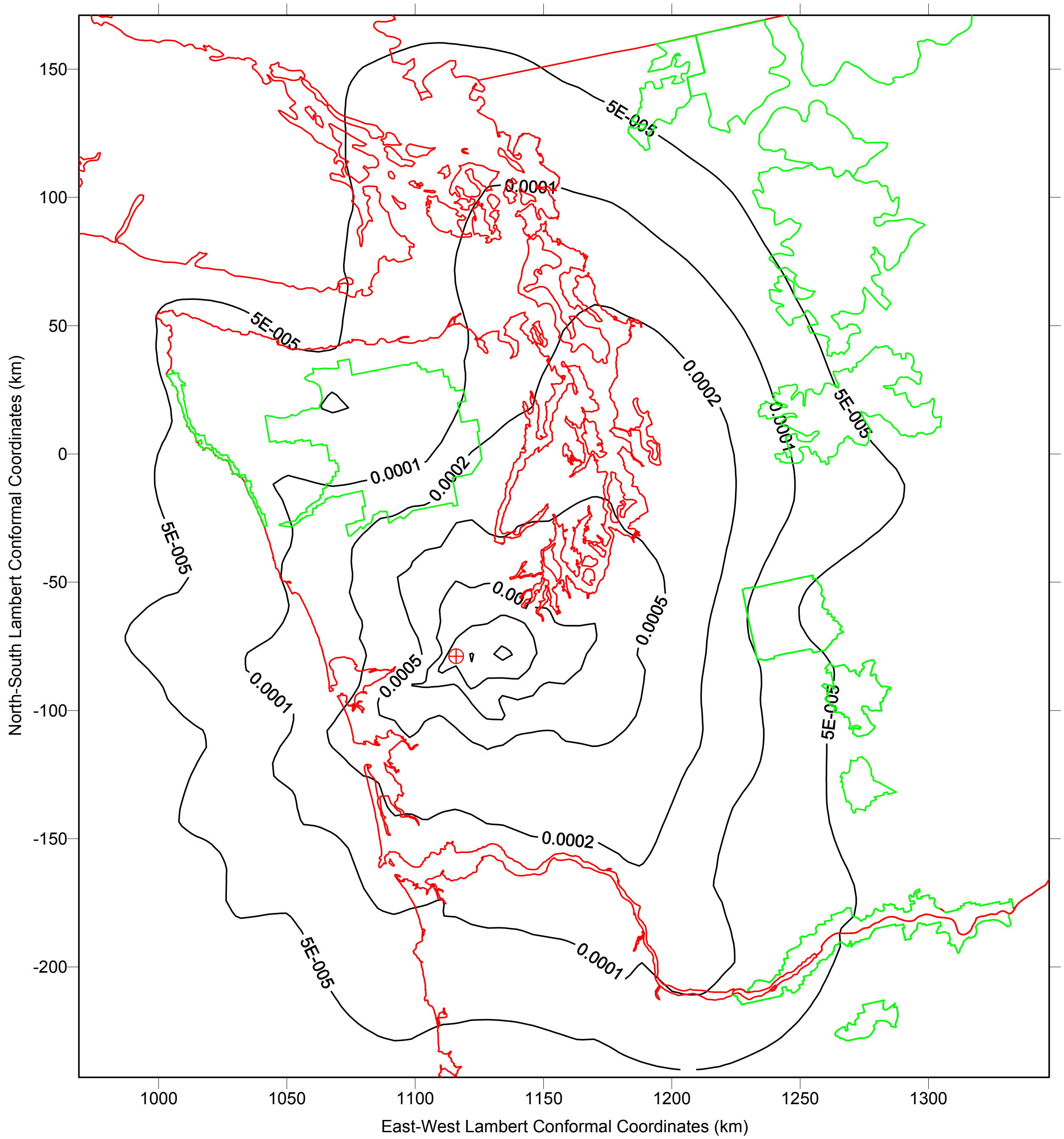


Figure 6.1-31

**Annual $SO_2$ ($\mu g/m^3$), April 1, 1998, through March 15, 1999**

URS

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Satsop CT Project

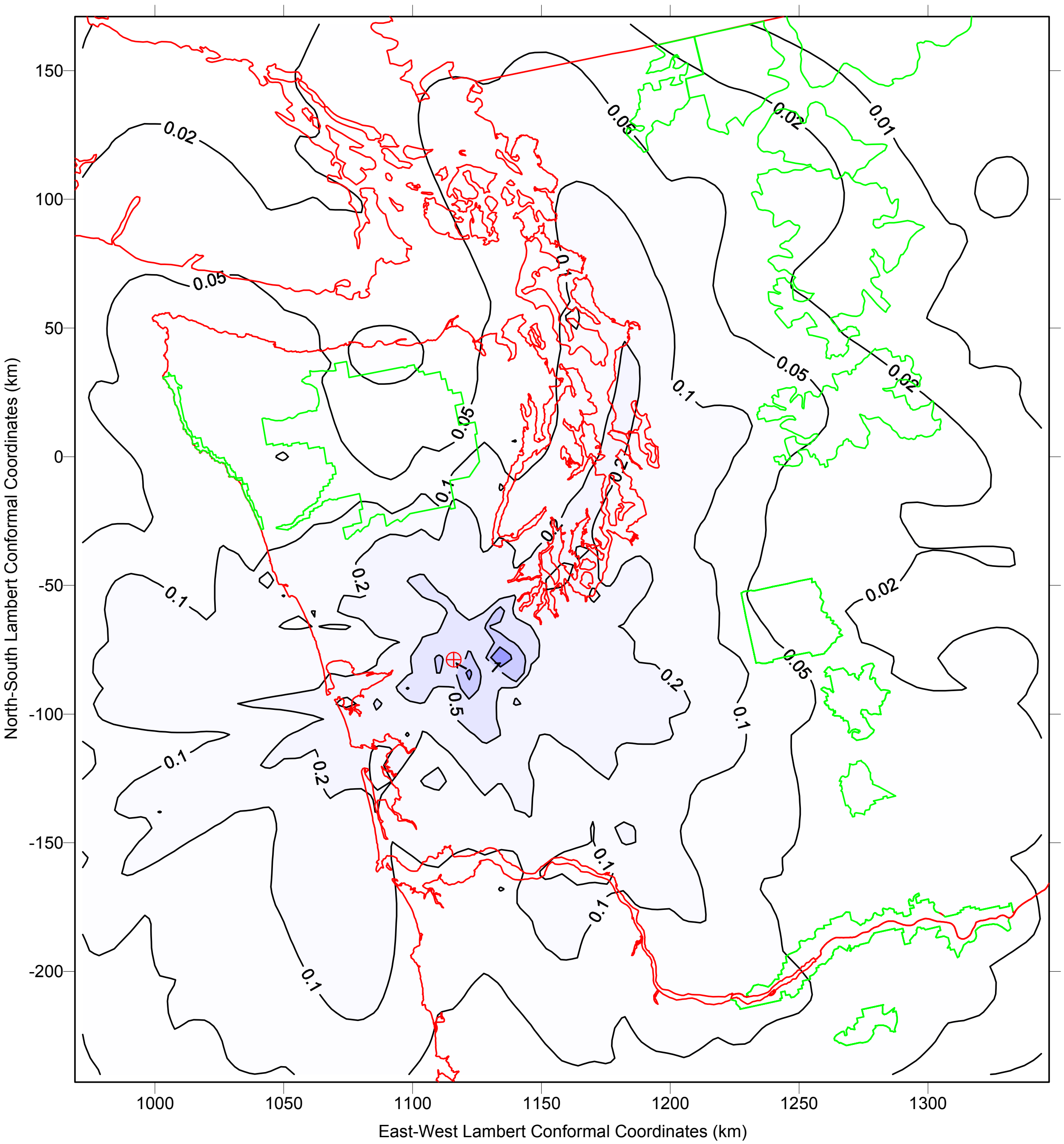


Figure 6.1-32
**Twenty-Four Hour Maximum $PM_{10}$ ($\mu g/m^3$), Including Sulfates and Nitrates April 1, 1998, through March 15, 1999**

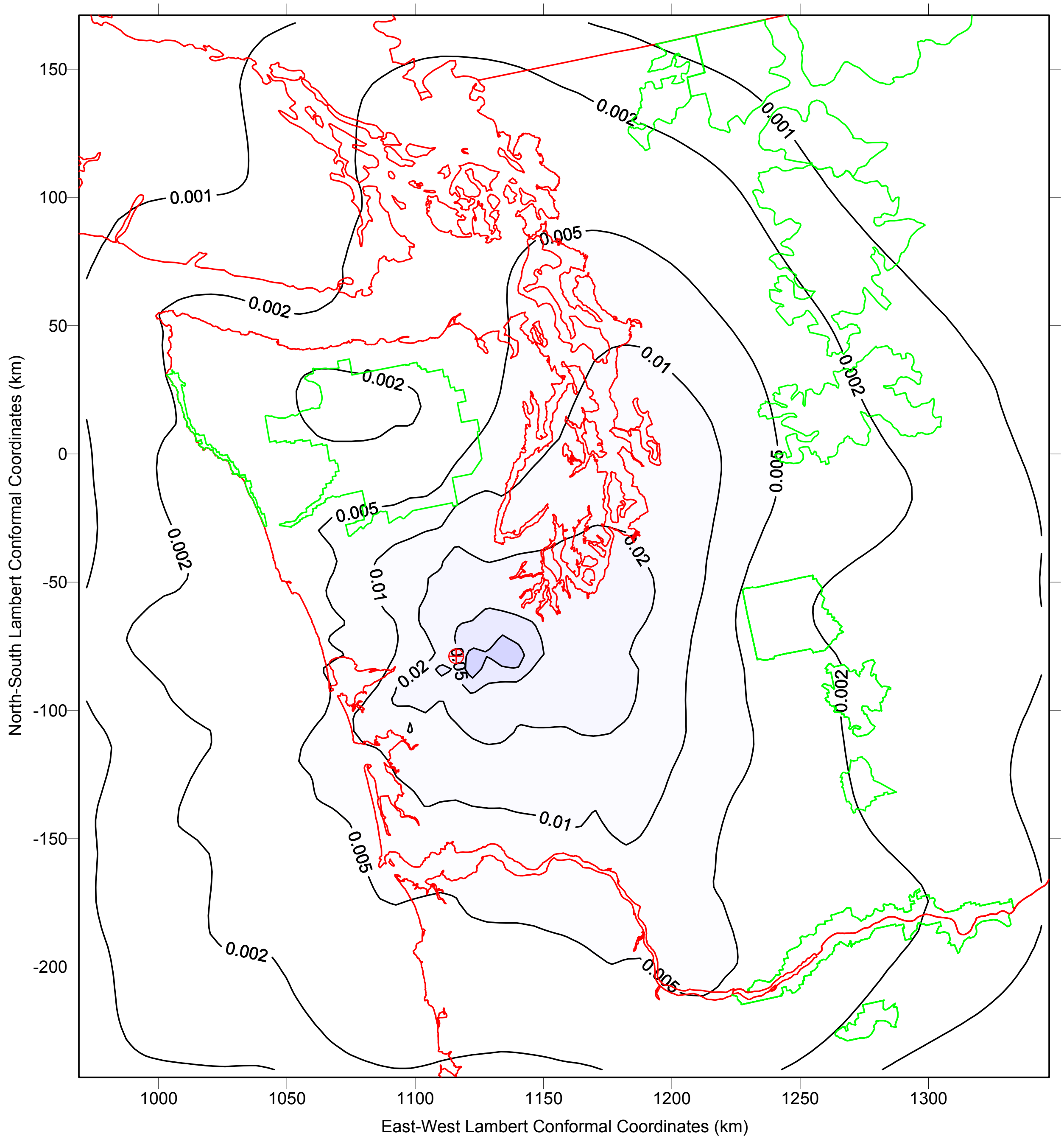


Figure 6.1-33

**Annual Average $PM_{10}$ ($\mu g/m^3$), Including Sulfates and Nitrates April 1, 1998, through March 15, 1999**

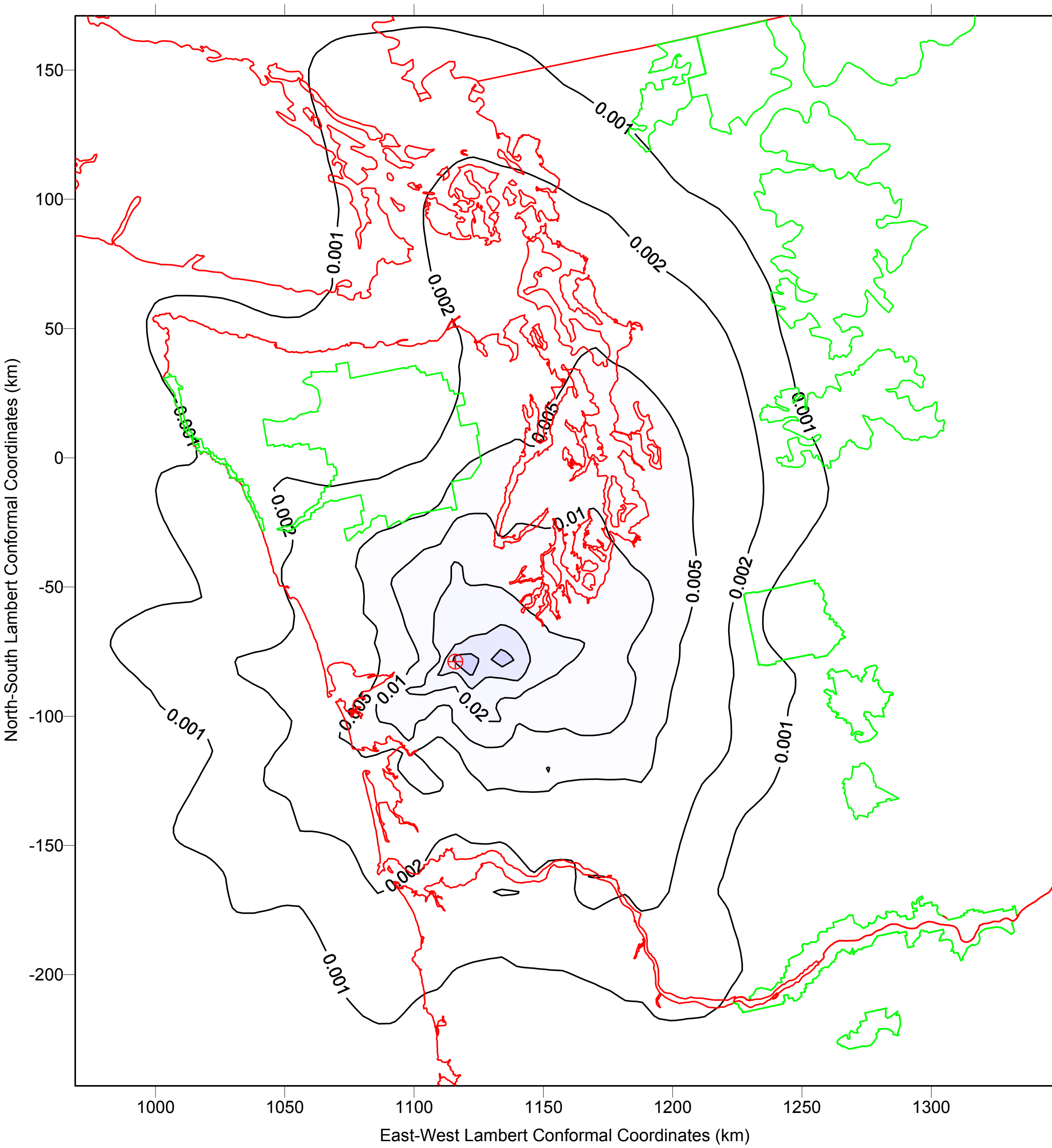


Figure 6.1-34

## Annual Average $NO_X$ ($\mu g/m^3$), April 1, 1998, through March 15, 1999

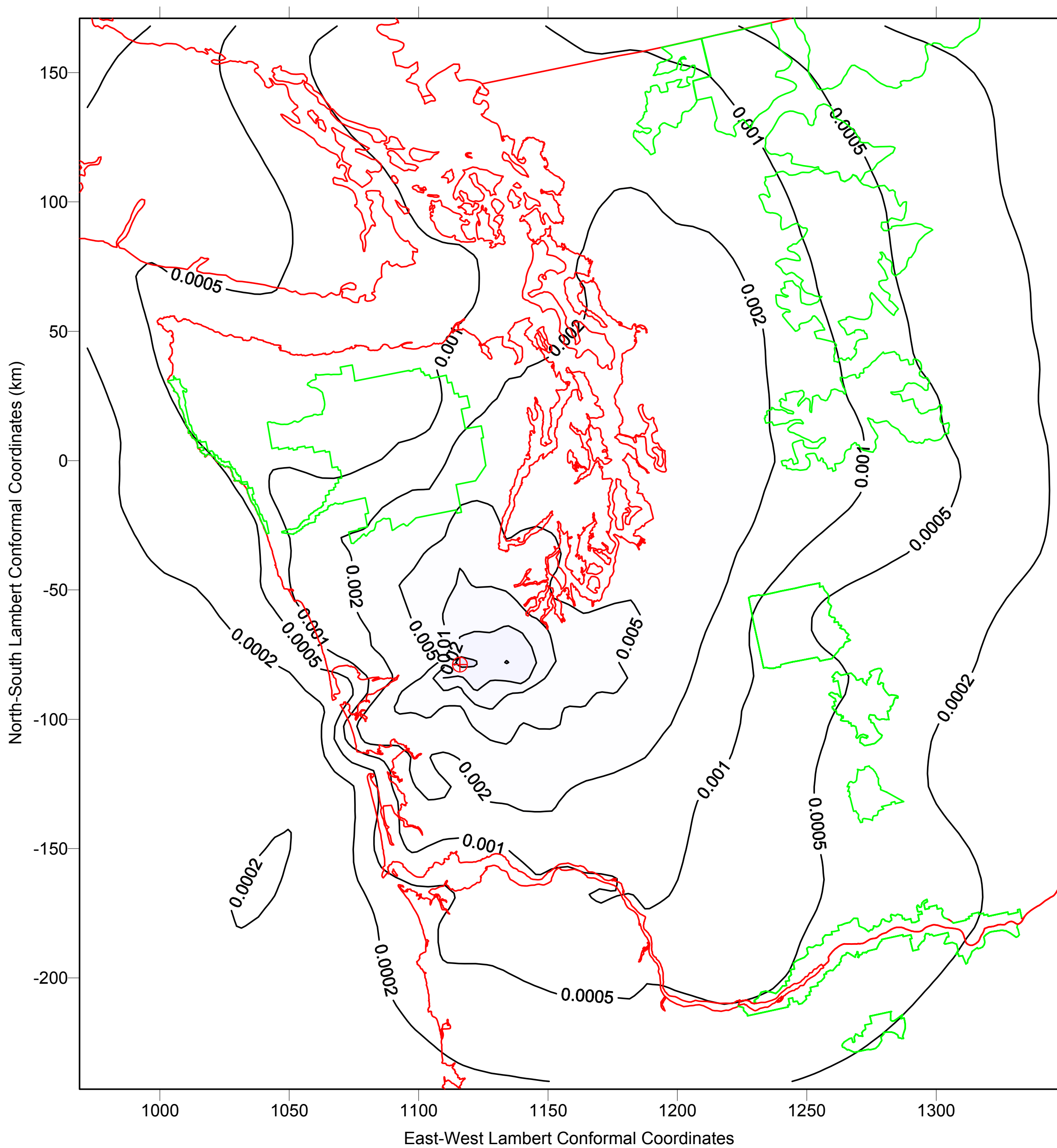


Figure 6.1-35

**Total Annual Nitrogen Deposition (kg/ha/yr), Includes Wet & Dry Deposit and Ammonium Ion**

URS

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Satsop CT Project

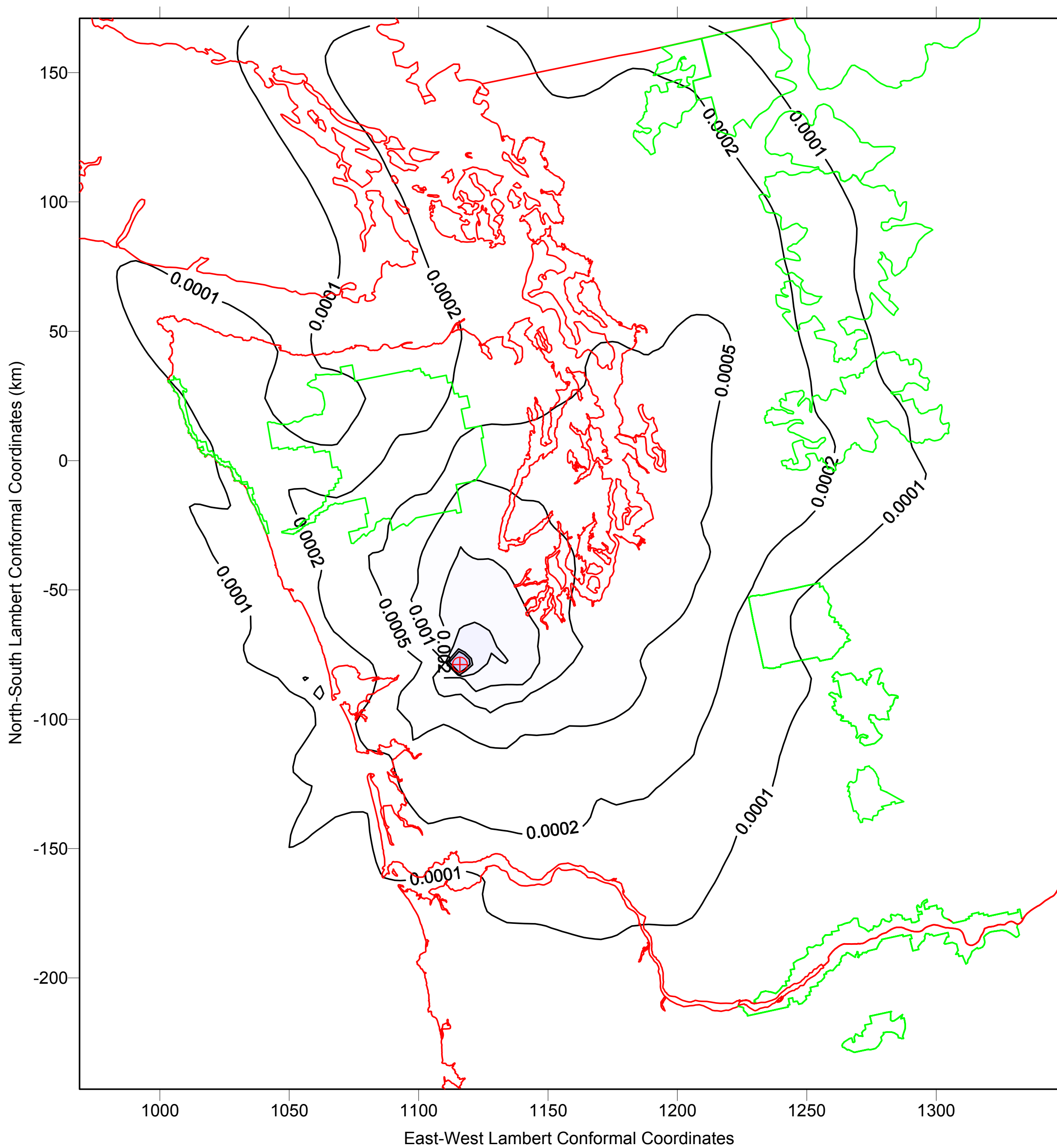


Figure 6.1-36

**Total Annual Sulfur Deposition (kg/ha/yr), Includes Wet & Dry Deposition**

URS

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Satsop CT Project

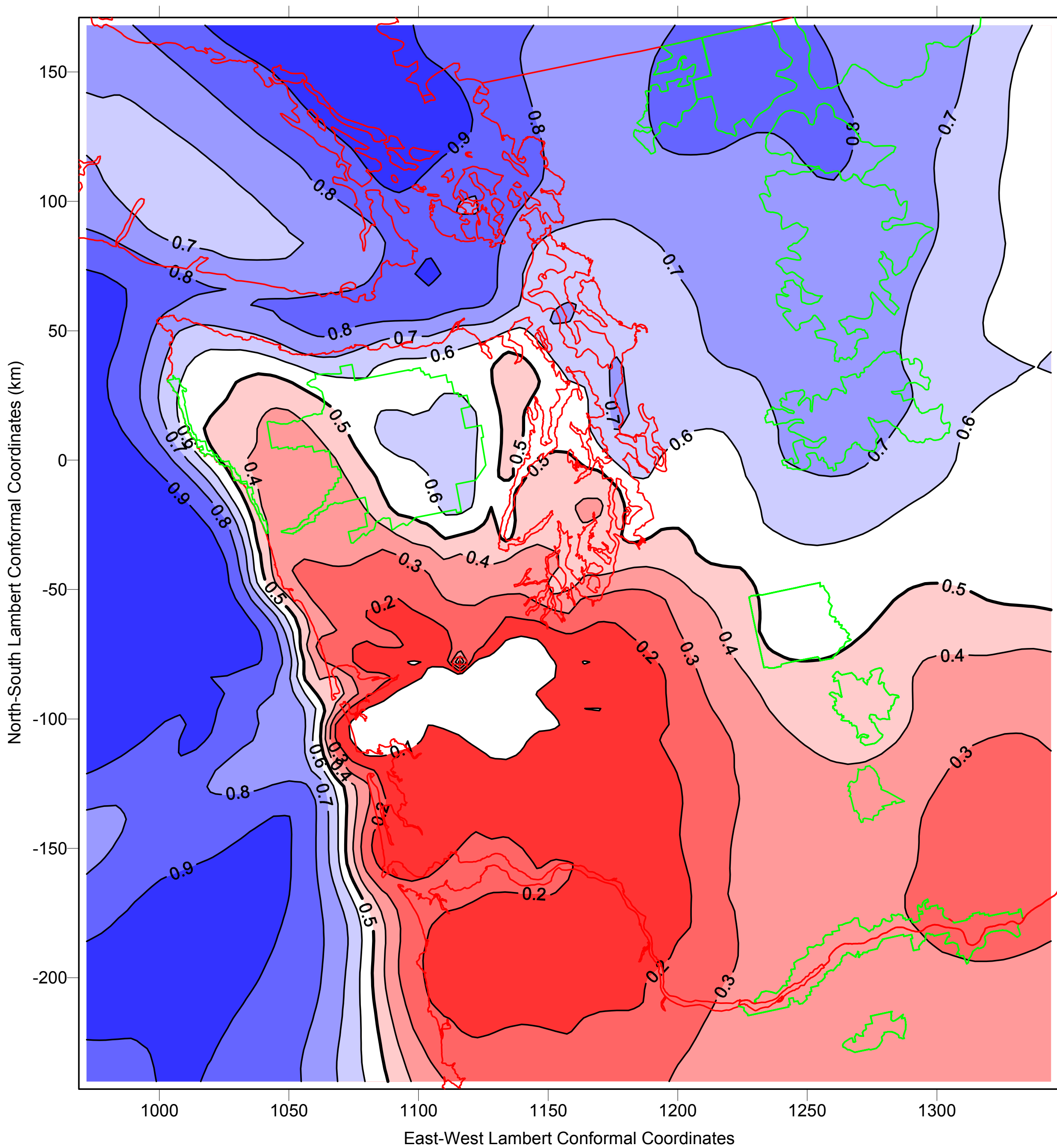


Figure 6.1-37

## Ratio of Wet Over Total Annual Nitrogen Deposition

URS

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Satsop CT Project

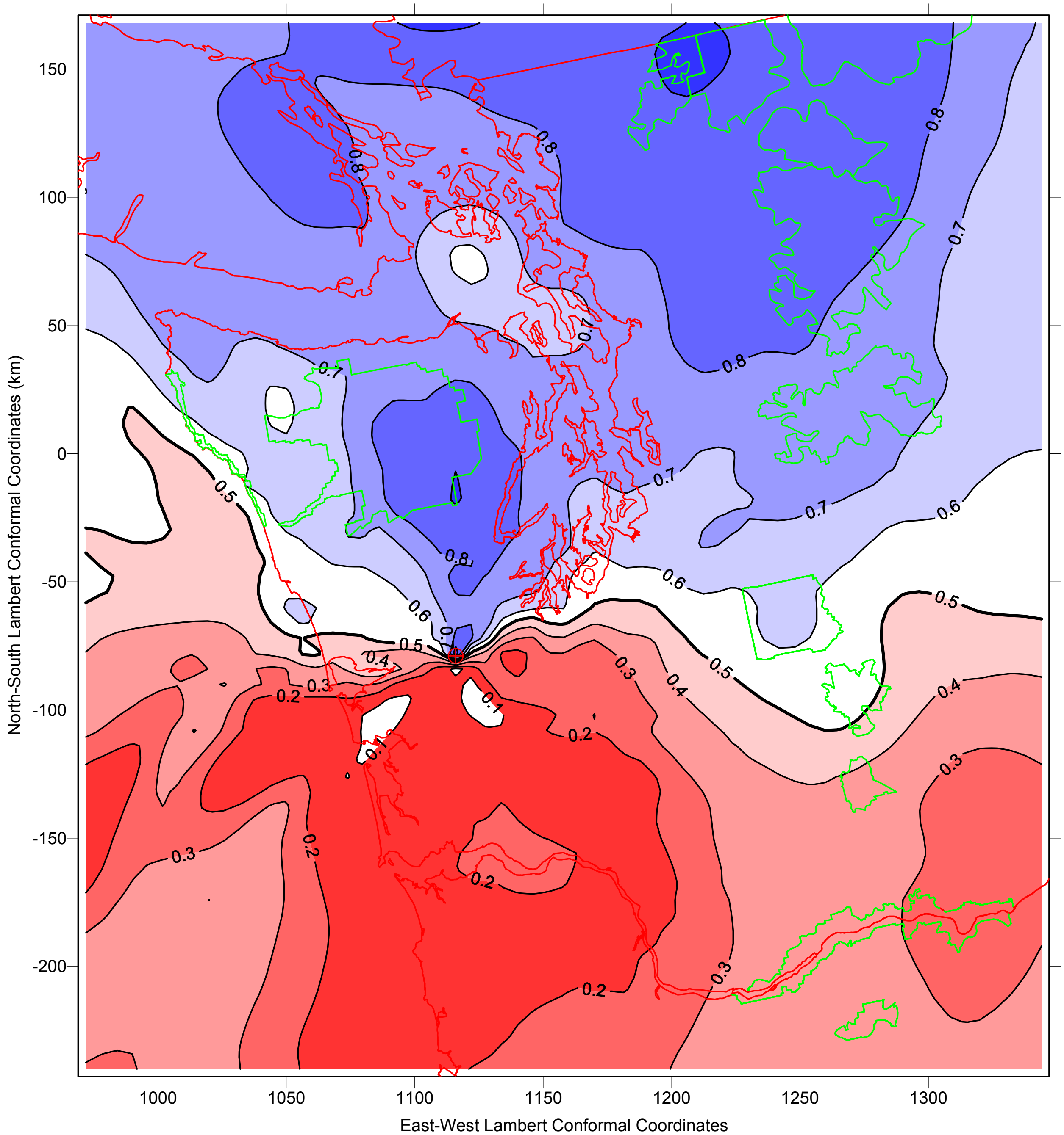



Figure 6.1-38

# Ratio of Wet Over Total Annual Sulfur Deposition

URS

Phase II Expansion
Satsop CT Project

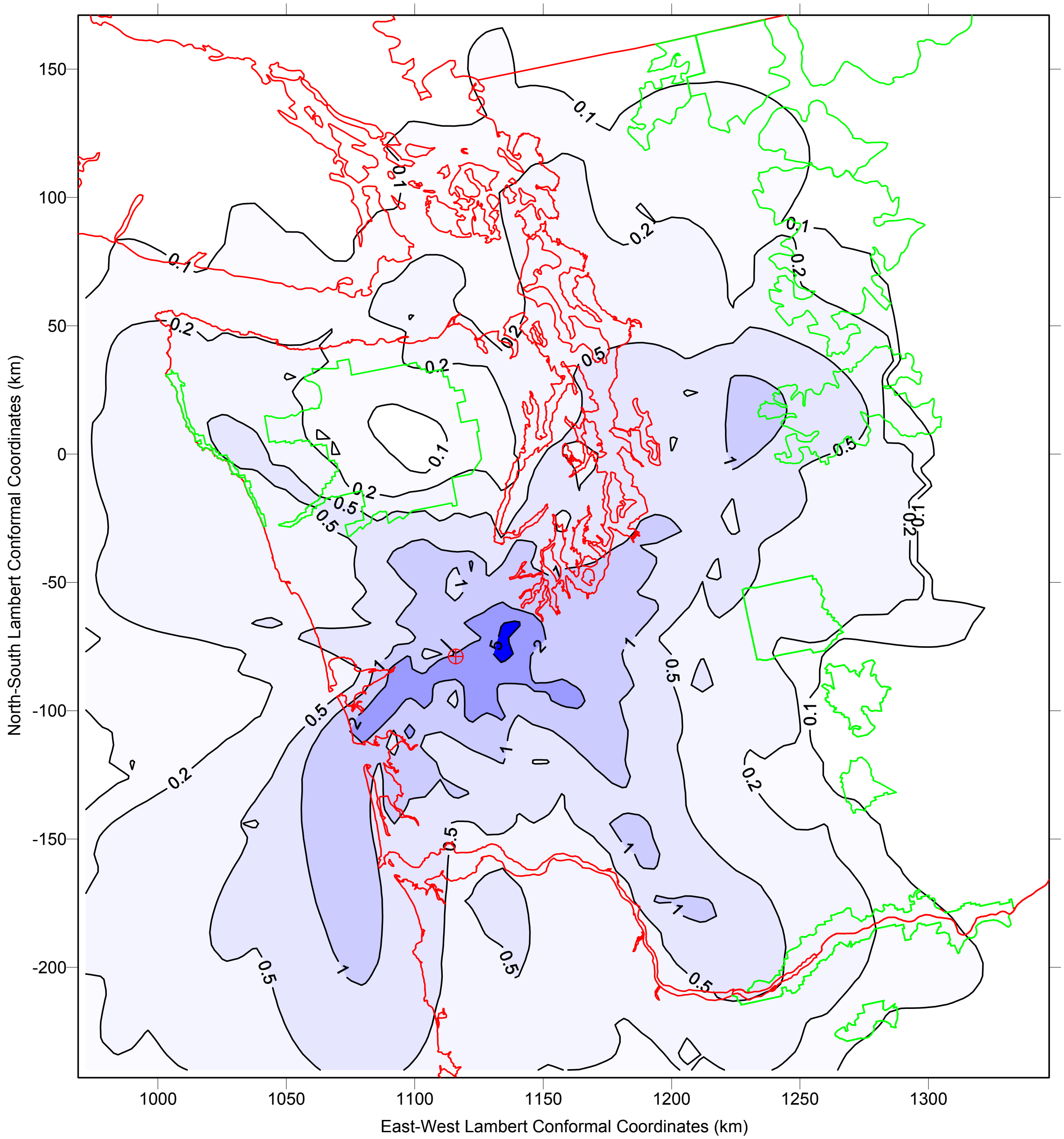



Figure 6.1-39

**Twenty-Four Hour Maximum Extinction Coefficients (1/MM) from SCTP, April 1 to May 31, 1998**

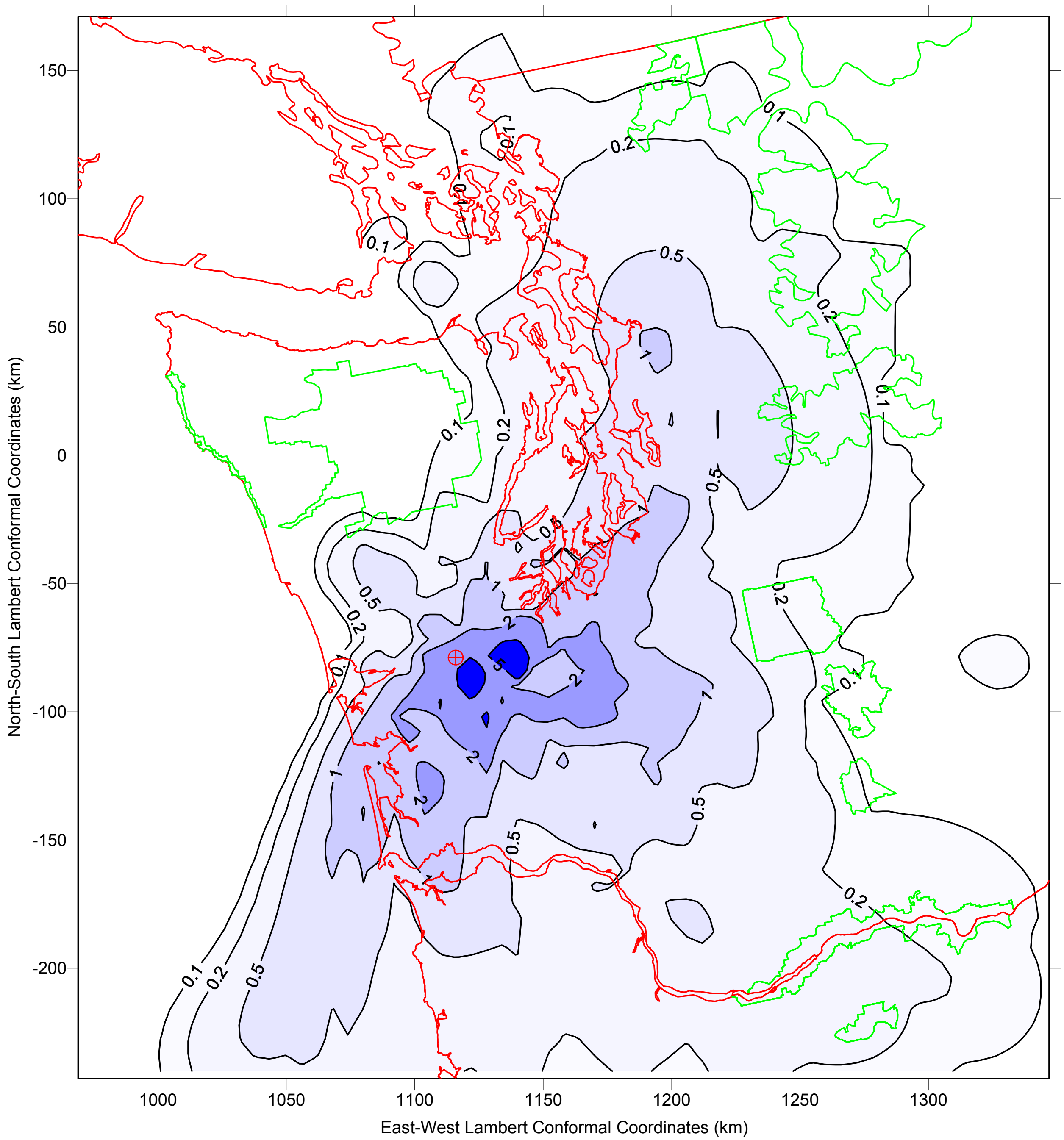



Figure 6.1-40

**Twenty-Four Hour Maximum Extinction Coefficients (1/MM) from SCTP, June 1 to August 31, 1998**

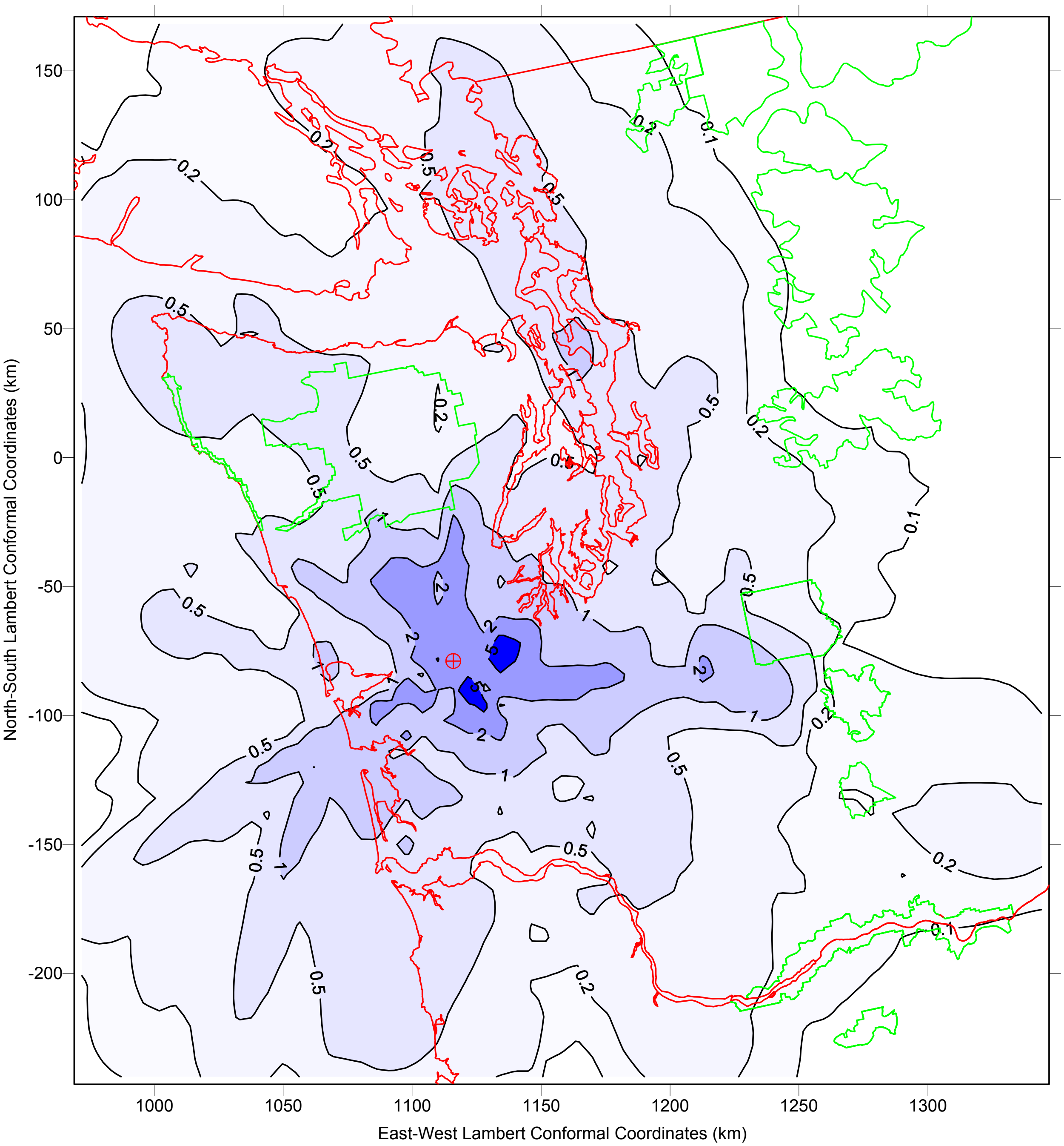



Figure 6.1-41

**Twenty-Four Hour Maximum Extinction Coefficients (1/MM) from SCTP, September 1 to November 30, 1998**

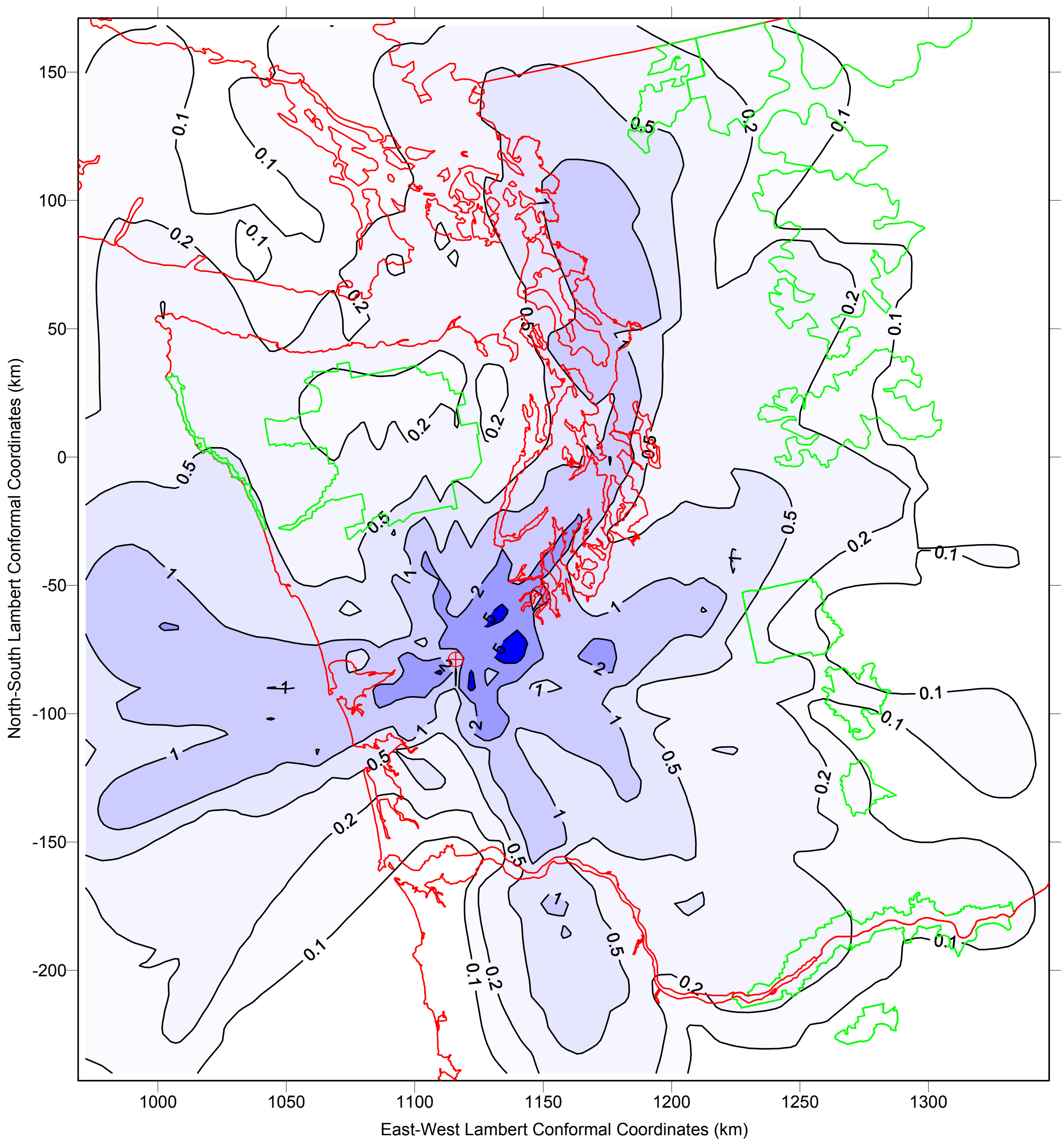



Figure 6.1-42

**Twenty-Four Hour Maximum Extinction Coefficients (1/MM) from SCTP, December 1, 1998, to March 31, 1999**

URS

Phase II Expansion
Satsop CT Project

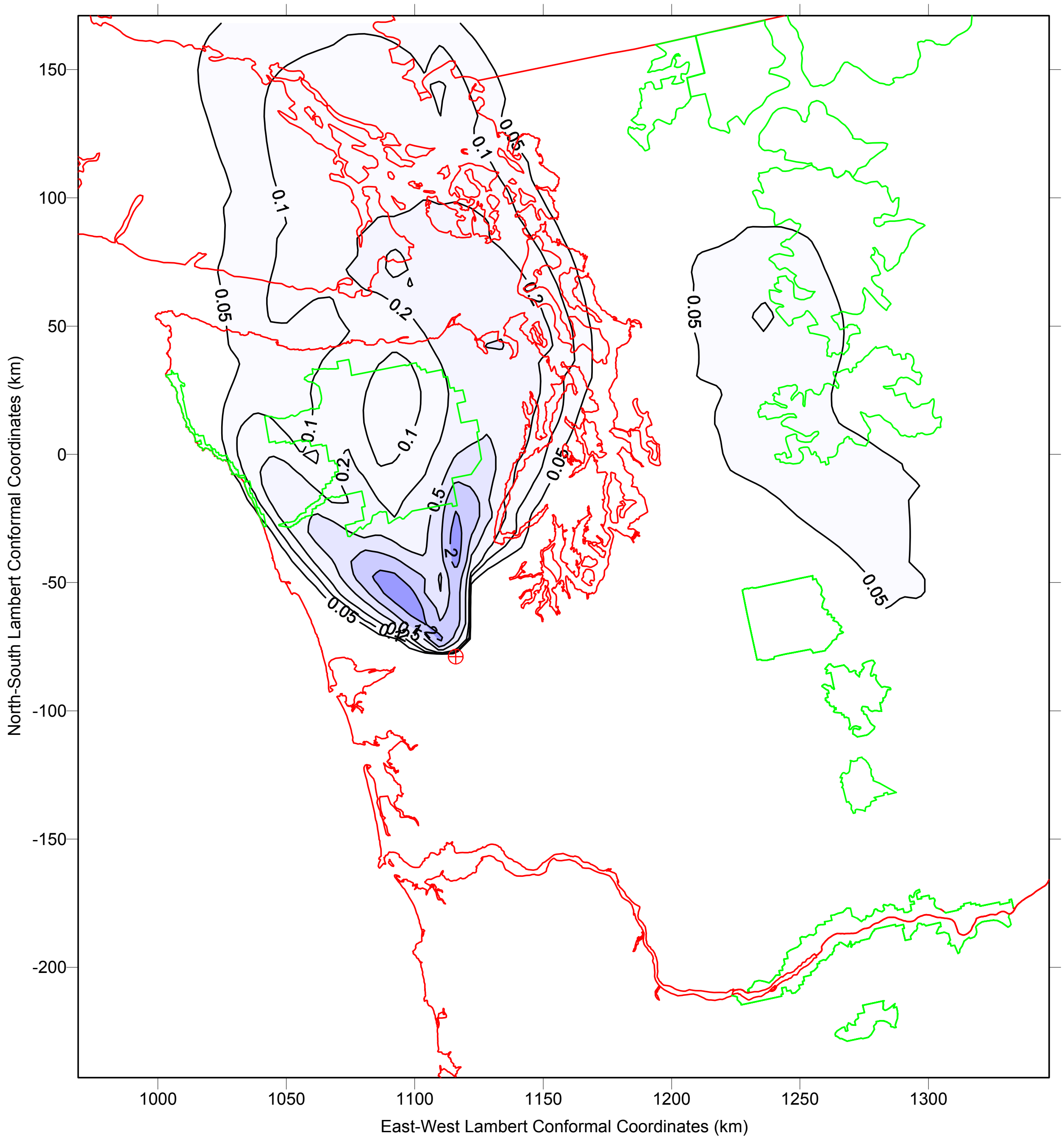



Figure 6.1-43

**Twenty-Four Hour Maximum Extinction Coefficients (1/MM) from SCTP, October 29, 1998**

URS

Phase II Expansion
Satsop CT Project

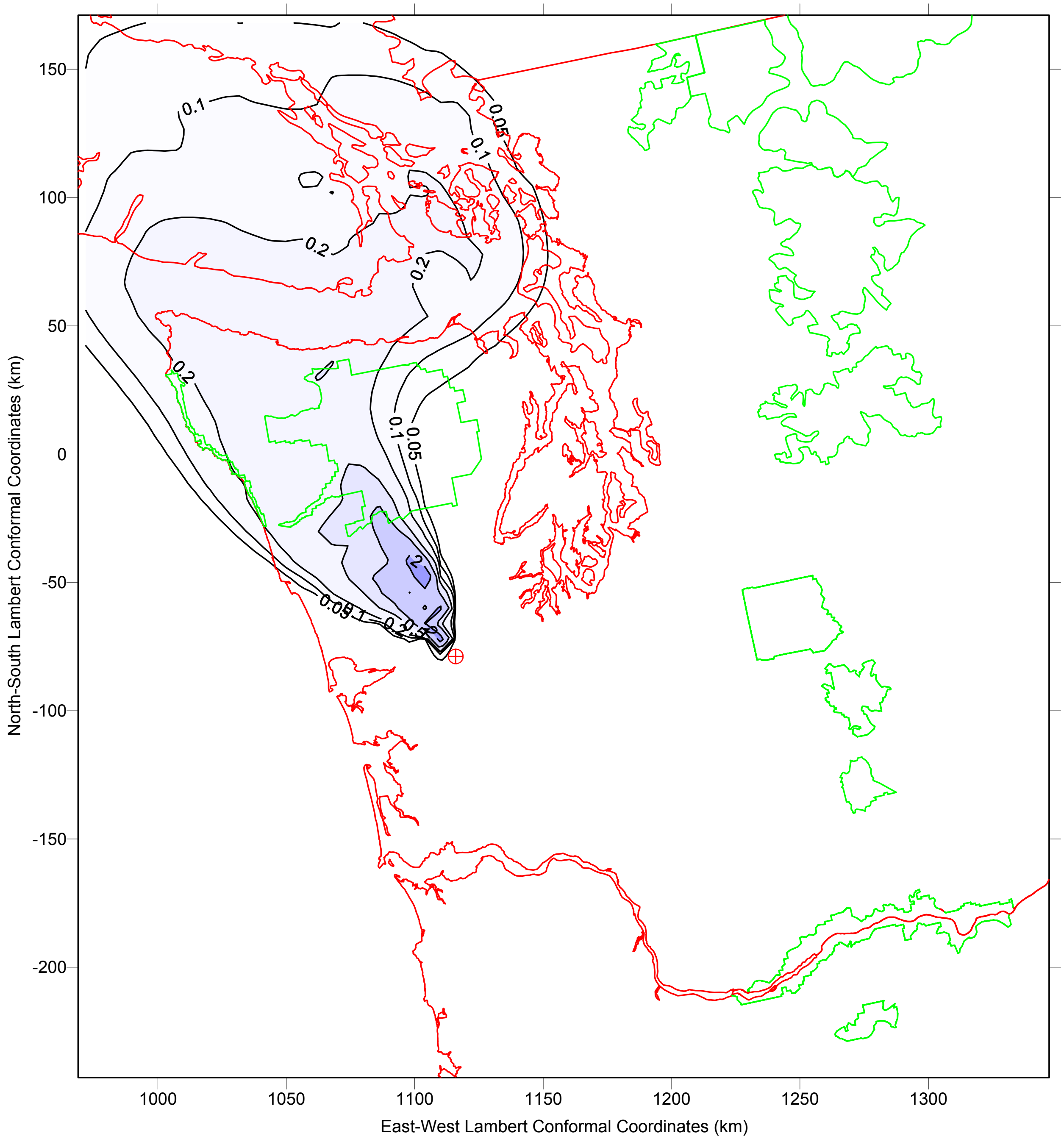



Figure 6.1-44

**Twenty-Four Hour Extinction Coefficients (1/MM) from SCTP, October 30, 1998**

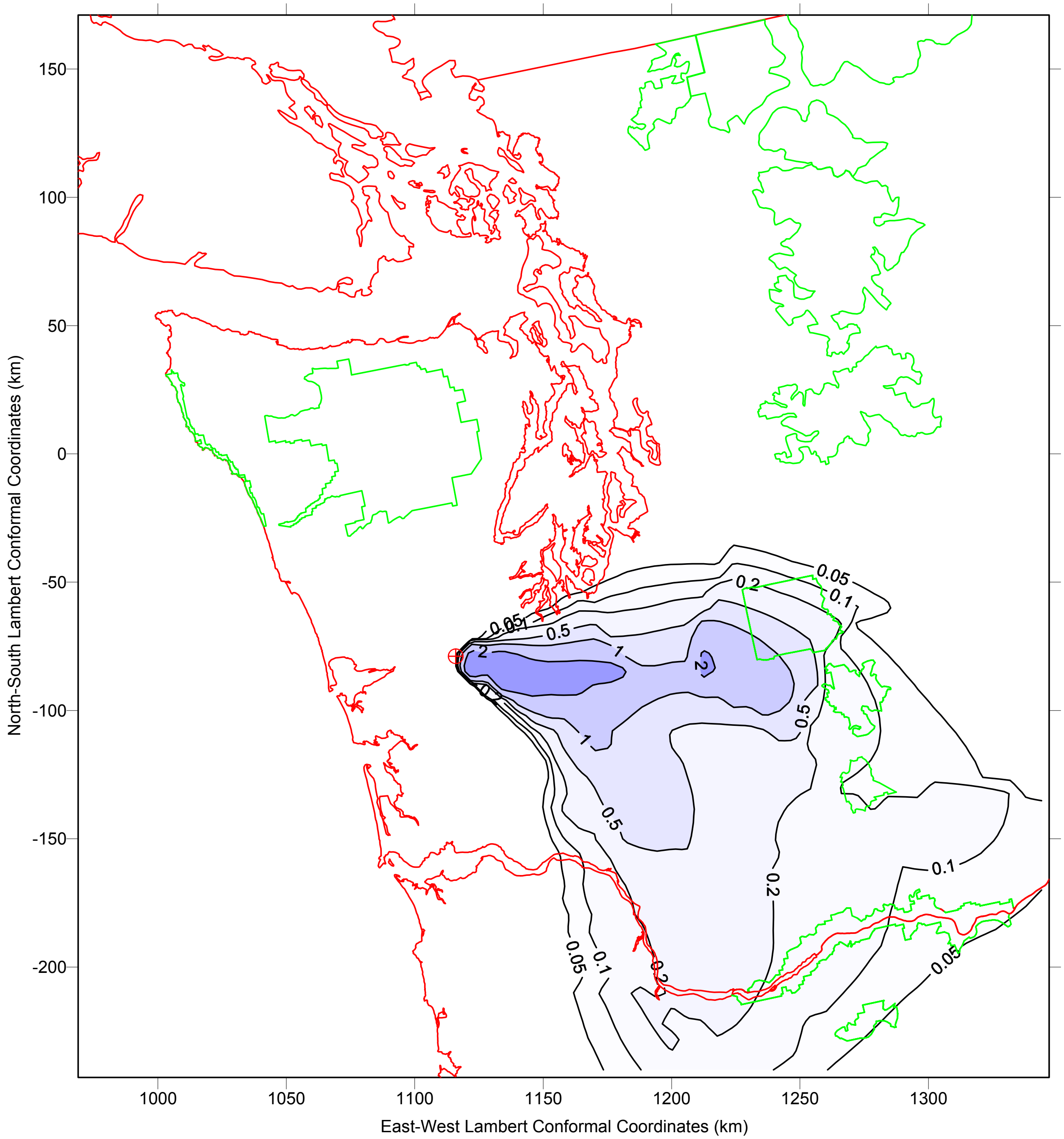



Figure 6.1-45

**Twenty-Four Hour Extinction Coefficients (1/MM) from SCTP, September 24, 1998**

URS

Phase II Expansion
Satsop CT Project

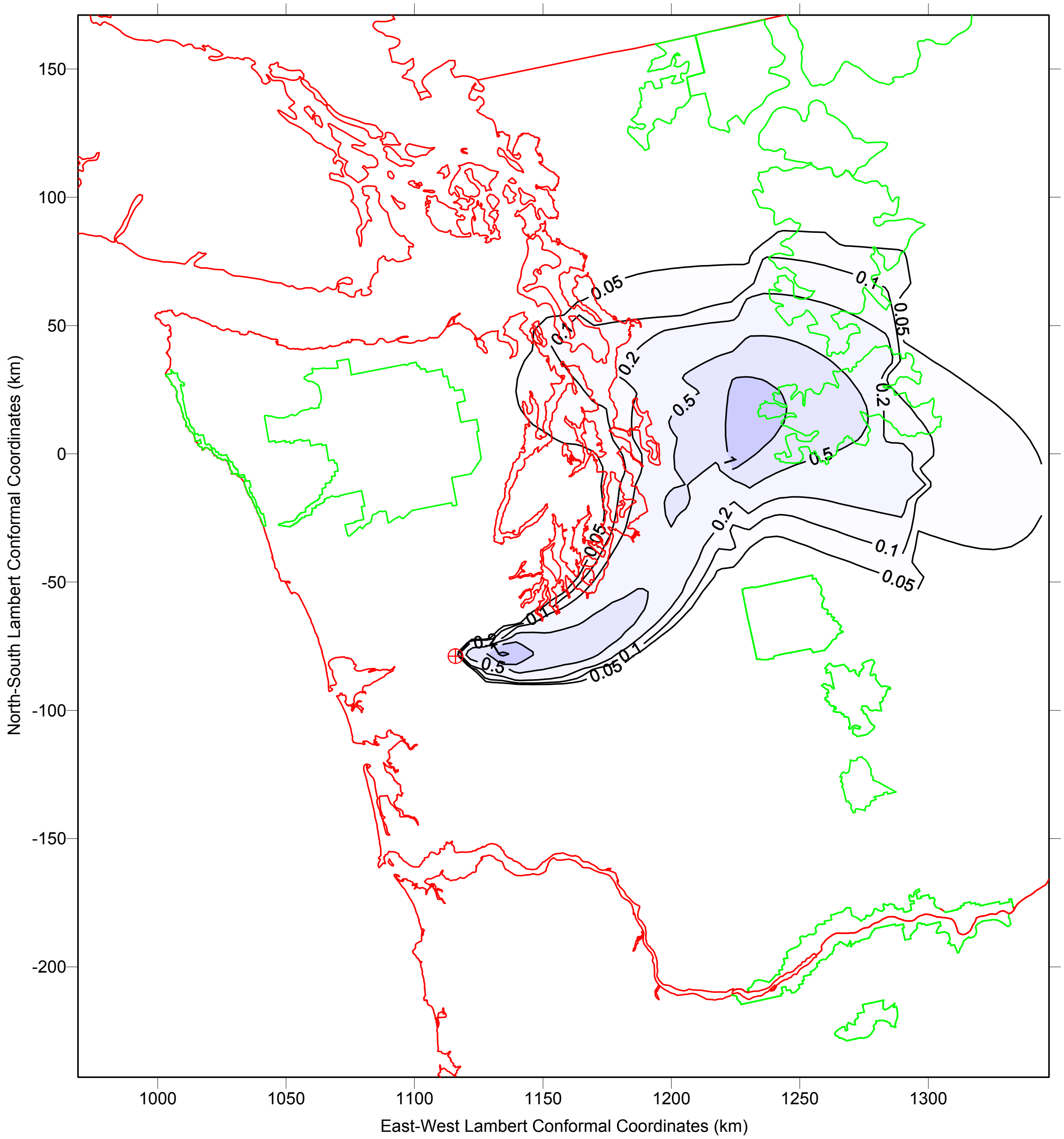



Figure 6.1-46

**Twenty-Four Hour Extinction Coefficients (1/MM) from SCTP, May 8, 1998**

# 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 ($PM_{10}$), and 23 tons per year of sulfur dioxide ($SO_2$). 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 ($\mu g/m^3$) | | PSD Increments ($\mu g/m^3$) | | Washington Ambient Air Quality Standards ($\mu g/m^3$) | Significant Impact Levels ($\mu g/m^3$) | Monitoring *DeMinimus* Concentrations ($\mu g/m^3$) |
|---|---|---|---|---|---|---|---|---|
| | | 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 ($PM_{2.5}$) | Annual | 15(j) | (a) | -- | -- | -- | -- | -- |
| | 24-Hour | 65(j) | (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)(j) | (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 $4^{th}$ 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 then 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 $\mu g/m^3$. 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<br>Satsop, Washington 99583 |
| Phone: | (360) 482-7700 |
| Contact: | Mr. Michael J. Sotak, Duke Energy<br>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 $PM_{10}$ are a portion of the TSP emission rate. However, to be conservative, emissions of $PM_{10}$ and $PM_{2.5}$ were assumed to equal the TSP emission rate. Similarly, emissions of $NO_2$ 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, $PM_{10}$, 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 $SO_2$ 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, $PM_{10}$,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 $SO_2$ 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 $SO_2$ 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 $SO_2$ 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 $SO_2$ and $NO_x$. The proposed emission rates for each duct burner are 5.5 lb/hr for PM, 0.31 lb/hr for $SO_2$, 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:

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

where

STD = allowable $NO_x$ emissions, percent by volume at 15 percent $O_2$ 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 $O_2$. Consequently, the Satsop CT Project will comply with the $NO_x$ emission standard.

Subpart GG of 40 CFR Part 60.333(a) limits $SO_2$ emissions to 0.015 percent by volume at 15 percent $O_2$. This equates to 150 ppmvd and the Satsop CT Project is proposing 0.11 ppm. Consequently, the Satsop CT Project will comply with the $SO_2$ 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 $O_2$ 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 $NO_x$, $SO_2$, $O_2$, 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 $NO_2$, $SO_2$, 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% $O_2$<br>9 ppm @ 15% $O_2$ (24-hour average) | LAER for PSD-avoidance<br>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% $O_2$<br>8 ppm @ 15% $O_2$ | LAER for PSD-avoidance<br>duct burner and SCR | 2000 | Under Construction |
| Florida Power & Light, Everett | 235 MW | Natural Gas, No. 2 Oil | 3.5 ppm @ 15% $O_2$<br>3.5 ppm @ 15% $O_2$ (8-hour average) | LAER for PSD-avoidance<br>SCR | 1997 | Not Built |
| Florida Power & Light - Delta II, Everett | 247.4 MW | Natural Gas, No. 2 Oil | 3.5 ppm @ 15% $O_2$<br>42 ppm @ 15% $O_2$ (8-hour average) | PSD-avoidance<br>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-$NO_x$ Combusters | 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$_x$™ 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.

- **XONON™:** Catalytica Combustion Systems' XONON™ 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 XONON™ 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 XONON™ combustion system is a proprietary catalytic component, called the XONON™ Module, which is integral to the gas turbine combustor. XONON™ 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 ($O_2$) 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 ($N_2$) and water ($H_2O$). 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 $O_2$ 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 hydroscopic 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 hydroscopic, 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 $N_2$ prior to exit from the stack. CO is oxidized to $CO_2$ and exits the stack, and VOC is reduced as well.

SCONO$_x$™ 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, $NO_2$ 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 $O_2$) for turbine load conditions greater than 73 percent (10 ppmvd at 15 percent $O_2$ for low load conditions). Current emissions data show that the Federal Plant is controlling $NO_x$ emissions to 2 ppmvd (at 15 percent $O_2$) 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$_x$™ commercially available for an F-Class ABB turbine at a guaranteed emissions level of 2.5 ppmvd $NO_x$ (at 15 percent $O_2$). To date, due to company restructuring and other issues, SCONO$_x$™ has not been placed on an F-Class turbine.

The La Paloma Generating Project in California initially proposed to demonstrate the viability of SCONO$_x$™ 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$_x$™ or DLN/SCR was approved under LAER criteria. Commercial, warranty, and operational issues of concern for SCONO$_x$™ 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$_x$™ 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$_x$™ 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.

- **SCONOx™:** 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 $SCONO_x$™ as a control for three of four turbines. The fourth turbine can be controlled using either $SCONO_x$™ or SCR; however, the project was built using SCR due to problems obtaining the $SCONO_x$™ system. This facility will be in an ozone nonattainment area. Therefore, $SCONO_x$™ is considered technically feasible but unproven for large power plants such as the Satsop CT Project.

<u>Control Technology Hierarchy</u>

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 $SCONO_x$™ 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 $SCONO_x$™ 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. $SCONO_x$™
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 $SCONO_x$™.

## TABLE 6.1-11
## $NO_x$ EMISSION CONTROL EFFICIENCIES FOR EACH PGU

| Emission Control Mechanism | CT Load | $NO_x$ Emission Concentration (ppmvd @15% $O_2$ 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$_x$™ | 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$_x$™ 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 $SO_3$ from some of the $SO_2$ entering the system in the exhaust stream. $SO_3$ 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$_x$™:*

- **Environmental Impacts:** Unlike the SCR system, there are no ammonia emissions associated with the SCONO$_x$™ system.

- **Energy Impacts:** As with SCR, the greater the catalyst volume, the higher the pressure drop. The presence of the SCONO$_x$™ 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$_x$™ system is greater than that associated with the proposed SCR and oxidation catalyst systems.

- **Economic Impacts:** The annualized cost of a $SCONO_x$™ system is $4,757,834 resulting in a cost per ton of $NO_x$ removed of $12,521. The costs for $SCONO_x$™ 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 $SCONO_x$™.

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 $O_2$. 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% $O_2$ | 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

$SO_2$ emissions from gas turbines are a function of the sulfur content of the fuel, with virtually all fuel sulfur converted to $SO_2$. 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 $SO_2$ 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 $SO_2$ - 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 $SO_2$ 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 $SO_2$ by mixing the flue gas with an atomized slurry in a spray dry scrubber. The water in the slurry evaporates, and the $SO_2$ 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.

<u>Evaluation of Technical Feasibility</u>

*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 $SO_2$ 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 $SO_2$ emissions. The proposed $SO_2$ emissions for the Satsop CT Project are representative of RACT/BACT/LAER determinations. The proposed $SO_2$ emission limits are shown in Table 6.1-14.

**TABLE 6.1-14**
**PROPOSED BACT $SO_2$ EMISSION LIMITS FOR EACH PGU[(a), (b)]**

| Pollutant | Emissions (ppmvd) at 15% $O_2$ | Emissions (lb/hr) |
|---|---|---|
| $SO_2$ | 0.11 | 1.3 |

[(a)]These emission limits apply to CT loads ≥ 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 $CO_2$ and $H_2O$. 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 $CO_2$ 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 $CO_2$ 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 $CO_2$ 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 $SCONO_x$™ 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 $SCONO_x$™ system contains an oxidation catalyst which theoretically achieves a 90% reduction in CO and VOC emissions. The $SCONO_x$™ 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 $SCONO_x$™ system. The total of pollutants (CO, VOC, and $NO_x$) that can theoretically be controlled by a single $SCONO_x$™ 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 $SCONO_x$™ system. This is 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% $O_2$ | 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% $0_2$. 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.

<u>Control Technology Hierarchy</u>

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.

<u>BACT Determination</u>

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

<u>Selected BACT</u>

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 $PM_{10}$ 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 ≥ 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 $PM_{10}$ 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 $PM_{10}$ 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 $PM_{10}$ 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, $PM_{10}$, $SO_2$, 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 MMBt/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 NOx 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<br>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 Svcs 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 dilutent 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.

<u>Evaluation of Technical Feasibility</u>

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% $O_2$ | 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, $PM_{10}$, $SO_2$, 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

$SO_2$ emissions from diesel IC generators are a function of the sulfur content of the fuel. Virtually all fuel sulfur is converted to $SO_2$. The RBLC listed no $SO_2$ 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 $SO_2$ 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**

$PM_{10}$ emissions arise primarily from non-combustible metals present in trace quantities in liquid fuels. Other sources of $PM_{10}$ 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 | $4.00 \times 10^{-5}$ lb/MMcf | $2.13 \times 10^{-5}$ lb/MMcf | 47% | Afterburner |
| | Acetaldehyde | $4.00 \times 10^{-5}$ lb/MMcf | $4.29 \times 10^{-6}$ lb/MMcf | 89% | SCR |
| | Benzene | $1.20 \times 10^{-5}$ lb/MMBtu | $9.10 \times 10^{-7}$ lb/MMBtu | 92% | Catalytic reduction |
| | Formaldehyde | $7.10 \times 10^{-4}$ lb/MMBtu | $2.00 \times 10^{-5}$ lb/MMBtu | 97% | Catalytic reduction |
| | Naphthalene | $1.30 \times 10^{-6}$ lb/MMBtu | $1.03 \times 10^{-5}$ lb/MMBtu | (691%) | SCR |
| Natural Gas Fired Boiler 10 - 100 MMBtu/hr | Ammonia | $4.90 \times 10^{-1}$ lb/MMcf | $9.10 \times 10^{0}$ lb/MMcf | (1757%) | SNCR |
| Natural Gas Fired Boiler >100 MMBtu/hr (Duct Burner) | Ammonia | $3.20 \times 10^{0}$ lb/MMcf | $1.80 \times 10^{1}$ lb/MMcf | (463%) | SNCR |
| | | $3.20 \times 10^{0}$ lb/MMcf | $9.10 \times 10^{0}$ lb/MMcf | (184%) | SCR |
| | Formaldehyde | $7.50 \times 10^{-2}$ lb/MMcf | $3.95 \times 10^{-5}$ lb/MMBtu | 46% | Flue Gas Recirculation |
| | Mercury | $2.60 \times 10^{-4}$ lb/MMcf | $2.27 \times 10^{-6}$ 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:

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

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:

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

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 then 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 meterological 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 (60º – 270º)**

| | 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 (270º – 60º)**

| | 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, $PM_{10}$,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 ($\mu g/m^3$) | Significant Impact Levels ($\mu g/m^3$) |
|---|---|---|
| $PM_{10}$ 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 ($\mu g/m^3$) | PSD Class II Increment ($\mu g/m^3$) | Monitoring *De Minimus* Concentrations ($\mu g/m^3$) |
|---|---|---|---|
| $PM_{10}$ 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 ($\mu g/m^3$) | National Ambient Air Quality Standards ($\mu g/m^3$) | | Washington Ambient Air Quality Standards ($\mu g/m^3$) |
|---|---|---|---|---|---|
| | | | 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[j] | 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 |
| Polyaromatic 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 $\mu g/m^3$ or TAP ASIL is not established.
(b) Dispersion modeling required if TAP emissions exceed SQER, TAP ASIL is < 0.001 $\mu g/m$
(c) Polyaromatic 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 ($\mu g/m^3$) | ASIL ($\mu g/m^3$) | 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 $PM_{10}$ emitted are needed for the regional haze assessment. The $PM_{10}$ 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 $PM_{10}$ averaged 23 percent for gas-fired turbines. In the stack tests summarized by Corio and Sherwell, the condensable (non-filterable) fraction of the $PM_{10}$ 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 $PM_{10}$ 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 $SO_2$ in the HRSG. Note, $SO_2$ and $PM_{10}$ 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 $PM_{10}$ emission was assumed to be 23 percent.
(d) The organic portion of the non-filterable $PM_{10}$ was assumed to be OC.
(e) Sixty-seven percent of the non-filterable $PM_{10}$ 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 $PM_{10}$ 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 turbines 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:

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

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:

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

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:

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

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 μg/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 $SO_2$, $NO_x$, and $PM_{10}$ 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 $SO_2$, $NO_x$, and $PM_{10}$ 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 $SO_2$, $NO_x$, and $PM_{10}$ concentration for each Class I increment averaging period. $PM_{10}$ concentrations include primary $PM_{10}$ 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 ($\mu g/m^3$) | | | | | |
|---|---|---|---|---|---|---|
| | $NO_2$ | $SO_2$ | | | $PM_{10}$ | |
| | Annual | 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 $NO_2$. $PM_{10}$ 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 $SO_2$ concentrations not exceed 40 to 50 ppb (105 to 130 $\mu g/m^3$), and annual $SO_2$ concentrations should not exceed 8 to 12 ppb (21 to 31 $\mu g/m^3$) (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 $SO_2$ concentrations in the range of 5 to 15 ppb (13 to 39 $\mu g/m^3$). The USFS also indicates that no significant amount of injury to plants species in the Pacific Northwest are expected for annual $NO_2$ concentrations less than 15 ppb (28 $\mu g/m^3$).

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 mountains 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 $SO_2$ 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 $PM_{10}$ 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, $PM_{10}$, 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 $PM_{10}$, $SO_2$ and $NO_2$ 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.

## 7.1

# NPDES Application (WAC 463-42-435)

**WAC 463-42-435 PHYSICAL ENVIRONMENT — NPDES APPLICATION.**
*The applicant shall include a completed National Pollutant Discharge Elimination System permit application.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-435, filed 10/8/81. Formerly WAC 463-42-480.]*

## 7.1 NPDES APPLICATION (WAC 463-42-435)

The waste stream from each phase of the Satsop CT Project (see Section 2.8 - Wastewater Treatment, WAC 463-42-195) will be routed to a common pipe, and discharged to the existing blowdown line that was originally constructed for the nuclear plants. From the blowdown pipe, discharge to the Chehalis River will be through an existing diffuser, recorded as Outfall 001 in the existing National Pollutant Discharge Elimination System (NPDES) permit. The Phase II project's discharge will meet the criteria of the existing NPDES permit. However, an amendment to the existing NPDES permit will be needed to specifically permit discharge from Phase II. An application for amendment of the NPDES will be sent to EFSEC on December 1, 2001.

# 7.2
# Emergency Plans (WAC 463-42-525)

**WAC 463-42-525 PHYSICAL ENVIRONMENT — EMERGENCY PLANS.**
*The applicant shall describe emergency plans which will be required to assure the public safety and environmental protection on and off the site in the event of a natural disaster or other major incident relating to or affecting the project and further, will identify the specific responsibilities which will be assumed by the applicant.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-525, filed 10/8/81. Formerly WAC 463-42-310.]*

# 7.2 EMERGENCY PLANS
# (WAC 463-42-525)

## 7.2.1 INTRODUCTION

Duke Energy Grays Harbor, LLC, and Energy Northwest, collectively the Certificate Holder, has prepared and implemented a series of emergency plans for the Satsop CT Project site, and the plans are applicable to the construction and operation of Phase II. These plans, which are briefly described below, have been prepared to ensure public safety and environmental protection on and off the Satsop CT property in the event of a natural disaster or other major incident relating to or affecting the Satsop CT Project. The plans describe the emergency response procedures that are to be implemented during emergency situations, and have been found by EFSEC to be in compliance with WAC 296-62-3112. The plans were approved by EFSEC on September 19, 2001.

## 7.2.2 SAFETY

The Safety Procedure (CSP-4-02) applies to all personnel and defines the responsibilities for compliance of specific personnel. Included are the following:

- General safety
- Unsafe conditions or actions
- Safety audits
- Safety meetings
- Accidents
- Hazardous materials (non-radioactive)
- Non-routine work activities

## 7.2.3 FIRST AID AND EMERGENCY MEDICAL RESPONSE

The First Aid and Emergency Medical Response Procedure (CSP-4-03), which applies to all personnel, has established the requirements for the emergency medical responses and associated documentation. The responsibilities of all personnel are outlined in the plan. Specific procedures include the following:

- Medical emergency procedures
- Routine first aid procedures

### 7.2.4 SITE EMERGENCY PLAN

The Site Emergency Plan (CSP-4-01) applies to all personnel and visitors and provides the guidelines necessary to ensure timely notification and rapid response in the event of emergencies occurring on the Satsop CT property. Specific procedures include the following:

- Emergency notification
- Fire emergency
- Medical emergency
- Bomb threat emergency
- Demonstration emergency
- Hazardous materials accidents

# 7.3
# Initial Site Restoration Plan (WAC 463-42-655)

**WAC 463-42-655 PHYSICAL ENVIRONMENT — INITIAL SITE RESTORATION PLAN.**

*The applicant or certificate holder shall in the application, or within twelve months after the effective date of this section, whichever occurs later, provide an initial plan for site restoration at the conclusion of the plant's operating life. The plan shall parallel a decommissioning plan, if such a plan is prepared for the project. The initial site restoration plan shall be prepared in sufficient detail to identify, evaluate, and resolve all major environmental, and public health and safety issues presently anticipated. It shall describe the process used to evaluate the options and select the measures that will be taken to restore or preserve the site or otherwise protect all segments of the public against risks or danger resulting from the site. The plan shall include a discussion of economic factors regarding the costs and benefits of various restoration options versus the relative public risk and shall address provisions for funding or bonding arrangements to meet the site restoration or management costs. The plan shall be prepared in detail commensurate with the time until site restoration is to begin. The scope of proposed monitoring shall be addressed in the plan.*

*[Statutory Authority: RCW 80.50.040(1). 87-05-017 (Order 87-1), §463-42-655, filed 2/11/87.]*

## 7.3 INITIAL SITE RESTORATION PLAN (WAC 463-42-655)

The Initial Site Restoration Plan for the Satsop CT site was submitted to EFSEC on April 9, 2001 and approved by EFSEC on June 18, 2001. This plan covers the entire 22-acre site, including the area on which the Phase II project will be constructed, and is applicable to Phase II. No revisions to this approved plan are required for Phase II.

# 8.1
# Socioeconomic Impact (WAC 463-42-535)

**WAC 463-42-535 HUMAN ENVIRONMENT — SOCIOECONOMIC IMPACT.**
*The applicant shall submit a detailed socioeconomic impact study which identifies primary and secondary and positive as well as negative impacts on the socioeconomic environment with particular attention and analysis of impact on population, work forces, property values, housing, traffic, health and safety facilities and services, education facilities and services, and local economy.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-535, filed 10/8/81. Formerly WAC 463-42-620.]*

# 8.1 SOCIOECONOMIC IMPACT (WAC 463-42-535)

## 8.1.1 EXISTING CONDITIONS

Phase II of the Satsop Combustion Turbine (CT) Project would affect the local socioeconomic environment due to impacts to population, work forces, property values, housing, and the economy. An analysis of traffic impacts attributable to the project is presented in Section 5.2 - Transportation, WAC 463-42-372. Analyses of potential impacts to health and safety, and educational facilities and services, attributable to the project are contained in Section 5.3 - Public Services and Utilities, WAC 463-42-382.

8.1.1.1 Population

**Demographic Characteristics**

The proposed project site is located in Grays Harbor and Thurston counties in western Washington. In April 2000, the combined population of the two counties was approximately 274,500 individuals, or 4.7 percent of the statewide population of approximately 5.9 million. Table 8.1-1 shows the population distribution in Grays Harbor and Thurston counties' communities, including both incorporated cities and unincorporated area, and in Washington state.

Approximately 62 percent of the Grays Harbor County population lives in incorporated cities, while 45 percent of Thurston County's population lives in incorporated cities. Thurston County's population is more than three times the population of Grays Harbor County. Approximately 40 percent of the population of each of the two counties resides in the counties' respective central population areas, Olympia/Lacy/Tumwater in Thurston County, and Aberdeen/Hoquiam/Cosmopolis in Grays Harbor County (Table 8.1-1; WSOFM 2001a).

The ratios of working-age persons (age 15 to 64) to younger and older residents in Grays Harbor and Thurston counties affect both the supply of labor and the level and distribution of income. Sixty-one percent of the population in Grays Harbor County is of working age, while Thurston County's population is 63 percent working age (Table 8.1-2; WSOFM 2001a). The Washington state population, in comparison, is 67 percent working age. Thurston County has a higher percentage of residents over 65 when compared to the state and Grays Harbor County, and Grays Harbor County has more residents under the age of 14 when compared to the two other areas. Rural counties such as Grays Harbor County tend to have a lower percentage of working age residents compared to residents over 65 due to (1) less in-migration of younger working-age residents (new entrants to the labor force), and (2) the increasing life-span of the general population. Rural communities also often experience an influx of retired persons seeking lower cost housing in a more rural setting.

## TABLE 8.1-1
## POPULATION DISTRIBUTION IN THE PROJECT VICINITY

| Jurisdiction | Population, April 2000 |
|---|---|
| Grays Harbor County | 67,194 |
| Unincorporated | 25,578 |
| Incorporated | 41,616 |
| Aberdeen | 16,461 |
| Cosmopolis | 1,595 |
| Elma | 3,049 |
| Hoquiam | 9,097 |
| McCleary | 1,454 |
| Montesano | 3,312 |
| Oakville | 675 |
| Ocean Shores | 3,836 |
| Westport | 2,137 |
| Thurston County | 207,355 |
| Unincorporated | 114,061 |
| Incorporated | 93,294 |
| Bucoda | 628 |
| Lacey | 31,226 |
| Olympia | 42,514 |
| Rainier | 1,492 |
| Tenino | 1,447 |
| Tumwater | 12,698 |
| Yelm | 3,289 |
| Washington State | 5,894,121 |
| Unincorporated | 2,379,012 |
| Incorporated | 3,515,109 |

Source: WSOFM 2001a

## TABLE 8.1-2
## POPULATION AGE DISTRIBUTION IN THE PROJECT VICINITY, 2000

| | Age 14 and Under | | Age 15 to 64 | | Age 65 and Over | |
|---|---|---|---|---|---|---|
| Jurisdiction | Number | Percent | Number | Percent | Number | Percent |
| Grays Harbor County | 4,657 | 28 | 10,064 | 61 | 1,707 | 10 |
| Thurston County | 4,278 | 21 | 12,918 | 63 | 3,355 | 16 |
| Washington State | 1,255,051 | 21 | 3,976,922 | 67 | 662,148 | 11 |

Source: WSOFM 2001a

In 2000, Grays Harbor County had slightly more males than females, while the opposite was true for Thurston County and for Washington state as a whole (Table 8.1-3; WSOFM 2001a). Both counties' populations were predominantly white, with 88 and 86 percent white residents, respectively. Compared to state percentages, the two-county area has more white residents and slightly fewer Hispanic/Latino residents. The second-most common races are American Indian/Alaska Native in Grays Harbor County (5 percent of population) and Asian in Thurston County (4 percent of population)[1] (Table 8.1-3; WSOFM 2001a).

**TABLE 8.1-3**
**RACE AND SEX COMPOSITION OF AREAS IN THE PROJECT VICINITY**

| Category | Grays Harbor County | | Thurston County | | Washington State | |
|---|---|---|---|---|---|---|
| | **Number** | **Percent** | **Number** | **Percent** | **Number** | **Percent** |
| Male | 33,390 | 51.1 | 101,543 | 47.7 | 2,934,300 | 49.8 |
| Female | 33,804 | 48.9 | 105,812 | 52.3 | 2,959,821 | 50.2 |
| One Race Only: | | | | | | |
| White | 59,335 | 88.3 | 177,617 | 85.7 | 4,821,823 | 81.8 |
| Black or African American | 226 | 0.3 | 4,881 | 2.4 | 190,267 | 3.2 |
| American Indian and Alaska Native | 3,132 | 4.7 | 3,143 | 1.5 | 93,301 | 1.6 |
| Asian | 818 | 1.2 | 9,145 | 4.4 | 322,335 | 5.5 |
| Native Hawaiian, Other Pacific Islander | 73 | 0.1 | 1,078 | 0.5 | 23,953 | 0.4 |
| Some other race | 1,527 | 2.3 | 3,506 | 1.7 | 228,923 | 3.9 |
| Two or more races | 2,083 | 3.1 | 7,985 | 3.9 | 213,519 | 3.6 |
| Hispanic or Latino (of any race) | 3,258 | 4.8 | 9,392 | 4.5 | 441,509 | 7.5 |
| **Total Population** | **67,194** | **100** | **207,355** | **100** | **5,894,121** | **100** |

Source: WSOFM 2001a

## Growth Trends

On average, Washington state's population growth rate was 1.8 percent per year between 1960 and 2000, slightly higher in the 1970s and 1990s than in the 1960s and 1980s. On average, Grays Harbor County grew slower (0.7 percent annually) and Thurston County grew faster (3.5 percent annually) than the state during the same 40-year period (Table 8.1-4; WSOFM 2001b).

[1] The Hispanic/Latino category is not included in this count because Hispanic/Latino is an ethnicity and can include all races.

**TABLE 8.1-4**
**POPULATION GROWTH TRENDS AND PROJECTIONS**
**FOR THE PROJECT AREA VICINITY**

| Year | Grays Harbor County | Thurston County | Washington State |
|---|---|---|---|
| 1960 | 54,465 | 55,049 | 2,853,214 |
| 1970 | 59,553 | 76,894 | 3,413,250 |
| 1980 | 66,314 | 124,264 | 4,132,353 |
| 1990 | 64,175 | 161,238 | 4,866,692 |
| 2000 | 71,848 | 214,767 | 5,849,891 |
| 1960 – 2000 Number Change | 17,383 | 159,718 | 2,996,677 |
| 1960 – 2000 AARG | 0.7% | 3.5% | 1.8% |
| 1990 – 2000 Number Change | 7,673 | 53,529 | 983,199 |
| 1990 – 2000 AARG | 1.1% | 2.9% | 1.9% |
| 2010 Forecast | 76,821 | 267,988 | 6,693,329 |
| 2000 – 2010 Number Change | 4,973 | 53,221 | 843,438 |
| 2000 – 2010 AARG | 0.7% | 2.2% | 1.4% |
| 2020 Forecast | 86,309 | 324,911 | 7,610,090 |
| 2010 – 2020 Number Change | 9,488 | 56,923 | 916,761 |
| 2010 – 2020 AARG | 1.2% | 1.9% | 1.3% |

AARG = Annual Average Rate of Growth

Source: WSOFM 2001b

The Thurston County population has grown consistently since 1960, with average annual growth rates over 2.5 percent during each decade between 1960 and 2000, and a current (2000) population that has doubled since 1960. In particular, average annual growth rates in the 1960s and 1970s were 3.4 percent and 4.9 percent, respectively. Between 1990 and 2000, Thurston County's average annual population growth rate was more than double that of Grays Harbor County, and was 1 percentage point higher than the state's rate. Historically, Thurston County's population has consistently grown faster than Grays Harbor County, due to the location of the capital city of Olympia in Thurston County and the accompanying high government employment and supporting economic activity. In contrast, Grays Harbor County has experienced relatively slow growth in general, and in fact experienced a population decline in the 1980s, due in part to a timber industry downturn and related economic slowing.

Washington state is expected to grow by approximately 14 percent (843,450 individuals), or 1.4 percent annually between 2000 and 2010. During the same period, Grays Harbor County and Thurston County are expected to grow at annual rates of 0.7 percent and 2.2 percent respectively, which is generally consistent with prior years.

During the decade 2010 to 2020, the state is again expected to grow by an additional 14 percent (916,800 individuals), or 1.3 percent per year. The Thurston County population growth rate is expected to have slowed from the prior decade, while the Grays Harbor County rate is expected to have risen (Table 8.1-4; WSOFM 2001b). The two counties' growth rates are expected to approach one another after decades of substantial difference.

8.1.1.2 Housing

In 2000, Grays Harbor County had over 32,000 housing units (1.3 percent of the state of Washington's housing units) and Thurston County had over 86,000 housing units (3.5 percent of Washington's housing units). Housing availability in the incorporated cities could be lower than the stated percentages, since higher housing demand generally exists within incorporated areas when compared to the counties overall. The vacancy rate in Grays Harbor County (17 percent) was 10 percentage points higher than the state's rate (7 percent), indicating more availability, while the vacancy rate in Thurston County (6 percent) was slightly lower than the rate for Washington state (Table 8.1-5; WSOFM 2001b). However, vacancy rates of over 5 percent are considered to generally indicate a relatively relaxed real estate market. An analysis of existing housing stock based on age and value was not performed because the project is not expected to have a significant impact on housing in the project area (see Subsection 8.1.2 for further discussion). Housing unit trends will likely follow future population trends in the two counties.

**TABLE 8.1-5**
**HOUSING CHARACTERISTICS IN THE PROJECT VICINITY, 2000**

| Jurisdiction | Total Housing Units | Total Occupied Units | Vacancy Rates | Owner Occupied | Renter Occupied | Average Household Size |
|---|---|---|---|---|---|---|
| Grays Harbor County | 32,489 | 26,808 | 17% | 18,495 | 8,313 | 2.48 |
| Thurston County | 86,652 | 81,625 | 6% | 54,371 | 27,254 | 2.50 |
| Washington State | 2,451,075 | 2,271,398 | 7% | 1,467,009 | 804,389 | 2.53 |

8.1.1.3 Source: WSOFM 2001a Employment and Income

Employment and income in Grays Harbor and Thurston counties indicate the health, character, and direction of the local economy, and to an extent, are a determining factor in the welfare and quality of life of area residents.

In 1999, the median household income in Grays Harbor County ($29,259) was approximately 61 percent of Washington state's median household income ($48,289). The same measure for Thurston County ($43,475) was 90 percent of that of Washington state. Similarly, the per capita income in 1999 in Grays Harbor County ($21,004) and in Thurston County ($25,760) were 69 percent and 85 percent of Washington state's per capita income ($30,380), respectively (Table 8.1-6; WSOFM 2001c; WSESD 2001a). Lower incomes in Grays Harbor County are consistent with the County's percentage of persons below poverty level in 1989 (16.4 percent) that was over 4 percentage points higher than the state's percentage (10.9 percent). Thurston County's percentage of persons below poverty level in 1999 (10.1 percent ) was slightly below that of the state.

## TABLE 8.1-6
## PROJECT AREA INCOME AND LABOR FORCE INDICATORS

| Economic Indicator | Grays Harbor County | Thurston County | Washington State |
|---|---|---|---|
| Median Household Income, 1999[1] | $29,259 | $43,475 | $48,289 |
| Per Capita Income, 1999[2] | $21,004 | $25,760 | $30,380 |
| Persons Below Poverty Level, 1989[3] | 10,306 | 15,907 | 517,933 |
| Percent Below Poverty Level, 1989[3] | 16.4% | 10.1% | 10.9% |
| Total Civilian Labor Force, 2000[2] | 25,580 | 99,200 | 3,045,000 |
| Male Percentage of Civilian Labor Force, 1990[3] | 58.5% | 52.3% | 55.0% |
| Female Percentage of Civilian Labor Force, 1990[3] | 41.5% | 47.7% | 45.0% |
| Overall Unemployment Rate (Age 16 and over), 2000[2] | 9.9% | 5.0% | 5.2% |
| Unemployment Rate, Males Age 16 and Over, 1990[3] | 9.8% | 7.4% | 5.7% |
| Unemployment Rate, Females Age 16 and Over, 1990[3] | 8.7% | 6.3% | 5.8% |

[1.] Source: WSOFM 2001c
[2] Source: WSESD 2001a
[3] Source: United States Census Bureau 2001. Note that 2000 census data for persons below poverty level were not available in September 2001.

Females comprised a lower percentage of the civilian labor force in 1990 in Grays Harbor County (41.5 percent) when compared to Thurston County (47.4 percent) and Washington state (45.0 percent). In 2000, the total civilian labor forces in Grays Harbor County (25,580) and in Thurston County (99,200) were less than 1 percent and 3 percent of the Washington state civilian labor force, respectively. The unemployment rates in 2000 for Grays Harbor County, Thurston County, and Washington state were 9.9 percent, 5.0 percent, and 5.2 percent, respectively; Thurston County and Washington state's rates are similar while Grays Harbor County's rate is slightly higher, consistent with other economic conditions discussed in this section (Table 8.1-6; WSESD 2001a).

In 2000, non-agricultural employment was 23,840 in Grays Harbor County and 84,700 in Thurston County (WSESD 2001a). In 1998, Grays Harbor County's employment was highest in government (21.3 percent of total employment), services (21.2 percent of total employment), retail trade (20.4 percent of total employment), and manufacturing (19.8 percent of total employment). Wages were relatively higher in the manufacturing and government sectors, representing 29.3 percent and 23.6 percent of total wages paid, respectively (Table 8.1-7; WSOFM 2001d).

**TABLE 8.1-7**
**1998 AVERAGE MONTHLY EMPLOYMENT AND TOTAL WAGES**
**GRAYS HARBOR COUNTY**

| Industry | Average Number of Employees | Percent of Total | Wages Paid ($1,000s) | Percent of Total |
|---|---|---|---|---|
| Agriculture, Forestry, Fishing | (a) | (a) | (a) | (a) |
| Mining | (a) | (a) | (a) | (a) |
| Construction | 1,042 | 4.5 | 30,083 | 5.34 |
| Manufacturing | 4,567 | 19.8 | 164,834 | 29.26 |
| Transportation, Communication, Utilities | 857 | 3.7 | 26,500 | 4.7 |
| Wholesale Trade | 561 | 2.4 | 15,682 | 2.78 |
| Retail Trade | 4,717 | 20.4 | 65,565 | 11.64 |
| Finance, Insurance, Real Estate | 951 | 4.1 | 20,784 | 3.69 |
| Services | 4,909 | 21.2 | 94,256 | 16.73 |
| Government (Federal, State, Local) | 4,912 | 21.3 | 132,932 | 23.59 |
| Other Industries | 598 | 2.6 | 12,771 | 2.27 |
| **Total** | **23,114** | **100** | **563,405** | **100** |

(a) = data suppressed for confidentiality. The sum of the (a) entries equals the entry for "Other."
Source: WSOFM 2001d

In 1998, most employment in Thurston County was in government (39.7 percent), due to the state capital's location in the city of Olympia; services (22.3 percent); and retail trade (17.4 percent). Government employees earned almost one-half (49.4 percent) of the total wages earned in the County (Table 8.1-8; WSOFM 2001d).

**TABLE 8.1-8**
**1998 AVERAGE MONTHLY EMPLOYMENT**
**AND TOTAL WAGES THURSTON COUNTY**

| Industry | Average Number of Employees | Percent of Total Employees | Wages Paid ($1,000s) | Percent of Total Wages Paid |
|---|---|---|---|---|
| Agriculture, Forestry, Fishing | 1,938 | 2.5 | 34,320 | 1.59 |
| Mining | 76 | 0.1 | 2,180 | 0.1 |
| Construction | 3,184 | 4.0 | 81,103 | 3.77 |
| Manufacturing | 4,250 | 5.4 | 133,951 | 6.22 |
| Transportation, Communication, Public Utilities | 1,908 | 2.4 | 60,783 | 2.82 |
| Wholesale Trade | 2,092 | 2.7 | 65,555 | 3.04 |
| Retail Trade | 13,744 | 17.4 | 210,738 | 9.79 |
| Finance, Insurance, Real Estate | 2,817 | 3.6 | 79,527 | 3.69 |
| Services | 17,560 | 22.3 | 421,996 | 19.6 |
| Government (Federal, State, Local) | 31,280 | 39.7 | 1,062,859 | 49.37 |
| Other Industries (a) | 0 | 0 | 0 | 0 |
| **Total** | **78,849** | **100** | **2,153,013** | **100** |

(a) = No data are suppressed, therefore all entries in the "Other Industries" category are zero.

Source: WSOFM 2001d

Although the Grays Harbor County economy has historically been dependent on manufacturing (including timber), services and trade, local economic growth has slowed in recent years, likely due to environmental pressure to reduce logging operations in the Olympic National Forest. Between 1990 and 1995, four of nine industries for which employment was reported experienced a decline in employment (Table 8.1-9; WSESD 2001b).[2] Between 1995 and 1999, manufacturing, transportation/public utilities, retail trade, and other industries declined by 5.3 percent, 8.0 percent, 3.9 percent and 13.2 percent, respectively. Services experienced an increase during that period. Employment growth overall has not been strong during the 1990s; total Grays Harbor County employment declined from 1990 to 1995 and grew by just 0.4 percent over the period 1995 to 1999 (an average annual rate of growth of 0.1 percent).

Similar to Grays Harbor County during the period 1990 to 1995, employment in Thurston County's manufacturing and transportation/public utilities sectors decreased; however, total employment increased during this period by 15.5 percent (1.5 percent per year, on average). Between 1995 and 1999, overall employment increased by 11.3 percent, but was accompanied by decreases in agriculture, forestry and fishing; and mining. comparatively, Washington state manufacturing employment also decreased during the period 1990 to 1995, but total employment still grew by 10.6 percent. Between 1990 and 1995, Washington state employment grew by 13.0 percent with decreases in the mining sector. Thurston County grew slightly slower than the state as a whole between 1995 and 1999, while Grays Harbor County grew much slower (Table 8.1-10; WSESD 2001b).

Projections for the larger area that includes Grays Harbor, Lewis, Mason, Pacific and Thurston counties indicate future growth of 1.3 percent per year in employment by occupation between 2000 and 2008, with increases expected in 49 of 542 occupations.

### 8.1.2 IMPACTS

Impacts to the local socioeconomic environment attributable to the proposed project would include increased local employment and associated income, spending for local services and materials, and tax revenues. Due to the relatively short construction period of 22 months and the small size of the construction crew and operation staff, computerized economic modeling or other similar quantitative methodologies are not warranted. Instead, impacts were estimated by reviewing the components of the proposed action and comparing the impacts to existing conditions. Specific quantitative data are presented in support of the conclusions.

[2] Manufacturing declined by 19.1 percent; transportation/public utilities declined by 12.2 percent; services declined by 7.8 percent, and other industries declined by 6.1 percent.

## TABLE 8.1-9
## GRAYS HARBOR COUNTY AVERAGE MONTHLY EMPLOYMENT GROWTH

| Industry | 1990 | 1995 | 1990-1995 | | 1999 | 1995-1999 | |
|---|---|---|---|---|---|---|---|
| | Average Number of Employees | Average Number of Employees | Change in Number of Employees (Numerical) | Change in Number of Employees (Percentage) | Average Number of Employees | Change in Number of Employees (Numerical) | Change in Number of Employees (Percentage) |
| Agriculture, Forestry, Fishing | 573 | 626 | 53 | 9.2 | (a) | (b) | (b) |
| Mining | (a) | (a) | (b) | (b) | (a) | (b) | (b) |
| Construction | 948 | 988 | 40 | 4.2 | 1075 | 87 | 8.8 |
| Manufacturing | 5,594 | 4,528 | -1066 | -19.1 | 4286 | -242 | -5.3 |
| Transportation, Public Utilities | 951 | 835 | -116 | -12.2 | 768 | -67 | -8.0 |
| Wholesale Trade | (a) | (a) | (b) | (b) | 674 | (b) | (b) |
| Retail Trade | 4,356 | 5,036 | 680 | 15.6 | 4,839 | -197 | -3.9 |
| Finance, Insurance, Real Estate | 763 | 916 | 153 | 20.1 | 1,029 | 113 | 12. |
| Services | 5,036 | 4,643 | -393 | -7.8 | 5,023 | 380 | 8.2 |
| Government (Federal, State, Local) | 4,154 | 4,660 | 506 | 12.2 | 4,718 | 58 | 1.2 |
| Other Industries | 693 | 651 | -42 | -6.1 | 565 | -86 | -13.2 |
| Total | 23,068 | 22,883 | -185 | -0.8 | 22,977 | 94 | 0.4 |

Note: Totals do not include "not reported" items.
(a) Indicates "not reported."
(b) Not available due to unreported data.
Source: WSESD 2001b

## TABLE 8.1-10
## THURSTON COUNTY AVERAGE MONTHLY EMPLOYMENT GROWTH

| Industry | 1990 | 1995 | 1990-1995 | | 1999 | 1995-1999 | |
|---|---|---|---|---|---|---|---|
| | Average Number of Employees | Average Number of Employees | Change in Number of Employees (Numerical) | Change in Number of Employees (Percentage) | Average Number of Employees | Change in Number of Employees (Numerical) | Change in Number of Employees (Percentage) |
| Agriculture, Forestry, Fishing | 1,632 | 1,858 | 226 | 13.8% | 1,831 | -27 | -1.5% |
| Mining | 36 | 68 | 32 | 88.9% | 61 | -7 | -10.3% |
| Construction | 2,982 | 2,982 | 0 | 0.0% | 3,738 | 756 | 25.4% |
| Manufacturing | 4,241 | 4,131 | -110 | -2.6% | 4,257 | 126 | 3.1% |
| Transportation, Public Utilities | 1,720 | 1,705 | -15 | -0.9% | 2,152 | 447 | 26.2% |
| Wholesale Trade | 1,871 | 2,058 | 187 | 10.0% | 2,155 | 97 | 4.7% |
| Retail Trade | 11,330 | 13,316 | 1,986 | 17.5% | 14,520 | 1,204 | 9.0% |
| Finance, Insurance, Real Estate | 2,125 | 2,635 | 510 | 24.0% | 3,071 | 436 | 16.5% |
| Services | 11,699 | 15,884 | 4,185 | 35.8% | 18,732 | 2,848 | 17.9% |
| Government (Federal, State, Local) | 26,813 | 29,807 | 2,994 | 11.2% | 32,373 | 2,566 | 8.6% |
| Other Industries | 0 | 0 | 0 | 0.0% | 0 | 0 | 0.0% |
| Total | 64,449 | 74,444 | 9,995 | 15.5% | 82,890 | 8,446 | 11.3% |

Source: WSESD 2001d

Subsections, 8.1.2.1 and 8.1.2.2 discuss potential socioeconomic impacts on population, housing, and property values that would be attributable to the proposed project. A traffic impact discussion is presented in Section 5.2 – Transportation, WAC 463-42-372 and discussions of health and safety impacts and education impacts are presented in Section 5.3 – Public Services and Utilities, WAC 463-42-382.

8.1.2.1 Construction

**Local Economy**

Phase II construction would have beneficial impacts on the local socioeconomic environment of Grays Harbor and Thurston counties, including additional employment and associated income and spending at local merchants' establishments.

The Phase II construction period would begin in October 2002 and would last approximately 22 months (through July 2004). Peak employment for Phase II would occur during the months October 2002 through February 2004. The construction workforce would consist of boilermakers, carpenters, cement masons, electricians, insulators, ironworkers, laborers, millwrights, operating engineers, painters, and pipefitters, in addition to non-craft staff. Table 8.1-11 shows the breakdown between the craft and non-craft workforce. The construction workforce for Phase II would be identical to the workforce for Phase I, construction of which would be 7 months away from completion when Phase II construction begins. Table 8.1-12 shows the total construction workforce on site by month. As shown in Figure 8.8-1, the peak construction period for Phase I would have just ended when the construction period for Phase II would begin.

It is intended that the Phase I workforce already mobilized for construction would be used for Phase II. To ensure that the Phase II construction workforce originates from the local labor pool to the extent possible, the Certificate Holder would require construction contractors to advertise positions locally and to hire local workers where practicable and possible. Although some construction skills are specialized and might not be available within the local or state labor pools, top hiring priority for construction would be given to qualified local and in-state construction workers. Therefore, most of the work force for construction of the plants would probably come from inside the state of Washington.

The influx of the out-of-area construction workers into communities near the proposed project would generate additional spending and business activity for temporary housing establishments such as hotels and motels, recreational vehicle parks, and campgrounds. Other service providers and retailers such as gas stations and food stores/restaurants would experience an increase in revenues during the construction phase due to construction workers' spending during the day. Many of the purchases and rental of required construction materials and equipment would also be made locally, thus generating additional revenue for local suppliers.

## TABLE 8.1-11
## POWER PLANT CONSTRUCTION WORKFORCE, PHASE II CRAFT AND NON-CRAFT

| Month | | Craft | Non-Craft (Project Management) | Total Workforce |
|---|---|---|---|---|
| December 2002 | 1 | 19 | 11 | 30 |
| January 2003 | 2 | 28 | 17 | 45 |
| February 2003 | 3 | 52 | 20 | 72 |
| March 2003 | 4 | 78 | 22 | 100 |
| April 2003 | 5 | 98 | 28 | 126 |
| May 2003 | 6 | 130 | 30 | 160 |
| June 2003 | 7 | 162 | 36 | 198 |
| July 2003 | 8 | 196 | 37 | 233 |
| August 2003 | 9 | 225 | 42 | 267 |
| September 2003 | 10 | 288 | 42 | 330 |
| October 2003 | 11 | 376 | 42 | 418 |
| November 2003 | 12 | 438 | 43 | 481 |
| December 2003 | 13 | 480 | 50 | 530 |
| January 2004 | 14 | 487 | 52 | 539 |
| February 2004 | 15 | 505 | 52 | 557 |
| March 2004 | 16 | 487 | 48 | 535 |
| April 2004 | 17 | 433 | 48 | 481 |
| May 2004 | 18 | 306 | 45 | 351 |
| June 2004 | 19 | 203 | 42 | 245 |
| July 2004 | 20 | 105 | 34 | 139 |
| August 2004 | 21 | 16 | 27 | 43 |
| September 2004 | 22 | 0 | 12 | 12 |

Note: The peak construction period is shaded.

Total construction employment would account for approximately $22 million in pre-tax wages and salaries (labor income). With much of the construction labor on the project expected to come from local sources, it is expected that a large portion of the wages and salaries earned during construction would be spent locally, or in other parts of the state.

Local non-salary expenditures associated with construction are expected to total about $28 million, with about $20 million for materials and supplies and about $8 million for subcontracted services. These expenditures would likely occur within a radius of approximately 50 miles from the site. The remainder of the construction cost would likely be spent outside the state on high capital cost items such as turbine generators, heat recovery steam generators, and civil and mechanical structures. Total project-related expenditures are expected to generate approximately $30 million in total sales taxes during construction, based on a sales tax rate of 8 percent and a total construction cost of $400 million, with a portion of this amount to be paid as Washington state and local sales taxes. These positive impacts to Thurston and Grays Harbor counties would be temporary, lasting until construction is complete.

## TABLE 8.1-12
## PHASE I AND PHASE II
## ESTIMATED CONSTRUCTION WORKFORCE
## CRAFT AND NON-CRAFT

| Month | Phase II Workforce | | | Phase I and Phase II Combined Workforce | | |
|---|---|---|---|---|---|---|
| | Craft | Non-Craft | Total | Phase I | Phase II | Total |
| February 2002 | | | | 233 | 0 | 233 |
| March 2002 | | | | 267 | 0 | 267 |
| April 2002 | | | | 330 | 0 | 330 |
| May 2002 | | | | 418 | 0 | 418 |
| June 2002 | | | | 481 | 0 | 481 |
| July 2002 | | | | 530 | 0 | 530 |
| August 2002 | | | | 539 | 0 | 539 |
| September 2002 | | | | 557 | 0 | 557 |
| October 2002 **(Phase II begins)** | | | | 535 | 0 | 535 |
| November 2002 | | | | 481 | 0 | 481 |
| October 2002 | 19 | 11 | 30 | 351 | 30 | 381 |
| November 2003 | 28 | 17 | 45 | 245 | 45 | 290 |
| December 2003 | 52 | 20 | 72 | 139 | 72 | 211 |
| January 2003 | 78 | 22 | 100 | 43 | 100 | 143 |
| February 2003 | 98 | 28 | 126 | 12 | 126 | 138 |
| March 2003 | 130 | 30 | 160 | 0 | 160 | 160 |
| April 2003 | 162 | 36 | 198 | 0 | 198 | 198 |
| May 2003 | 196 | 37 | 233 | 0 | 233 | 233 |
| June 2003 | 225 | 42 | 267 | 0 | 267 | 267 |
| July 2003 | 288 | 42 | 330 | 0 | 330 | 330 |
| August 2003 | 376 | 42 | 418 | 0 | 418 | 418 |
| September 2003 | 438 | 43 | 481 | 0 | 481 | 481 |
| October 2003 | 480 | 50 | 530 | 0 | 530 | 530 |
| November 2004 | 487 | 52 | 539 | 0 | 539 | 539 |
| December 2004 | 505 | 52 | 557 | 0 | 557 | 557 |
| January 2004 | 487 | 48 | 535 | 0 | 535 | 535 |
| February 2004 | 433 | 48 | 481 | 0 | 481 | 481 |
| March 2004 | 306 | 45 | 351 | 0 | 351 | 351 |
| April 2004 | 203 | 42 | 245 | 0 | 245 | 245 |
| May 2004 | 105 | 34 | 139 | 0 | 139 | 139 |
| June 2004 | 16 | 27 | 43 | 0 | 43 | 43 |
| July 2004 | 0 | 12 | 12 | 0 | 12 | 12 |

Note: "Phase I and Phase II Combined Workforce" assumes that Phase II would begin construction in December, 2002.

**Population and Housing**

Up to 20 percent of the construction workforce for the plant (approximately 100 workers, measured during the peak month) would be from outside of the local area. The presence of 100 workers is a "worst-case" scenario because the number 100 is based on the peak number of workers, and some percentage of the 100 non-local workers would likely continue to reside in their permanent residence and commute daily throughout the construction period. A small percentage of these 100 workers could bring their families with them while working on the project, and would commute daily from their new, temporary residence. However, most of these workers are expected to live in western Washington and would likely commute on a weekly basis[3]. A temporary increase in population would occur in the local area during the week due to the construction workforce.

As described in the recreation portion of Section 5.1 – Land Use, WAC 463-42-362, the use of recreation facilities by construction workers would be temporary and is not expected to result in a significant impact. Housing vacancy rates in Thurston and Grays Harbor counties are 6 percent and 17 percent, respectively, indicating that sufficient housing is available in the general area for the portion of the non-local construction workforce that could choose to live in permanent housing. Workers could find temporary housing in Montesano, Satsop, Elma, and McCleary, as well as in the Aberdeen-Hoquiam area and the Olympia-Tumwater area. Due to (1) the large number of recreational facilities and the availability of sufficient housing in the general area, (2) the relatively low number of construction workers from outside the local area that would seek temporary housing, and (3) the relatively short 7-month period of peak construction, construction of the proposed project is not expected to result in a significant impact on housing. Furthermore, the plant would be constructed on an existing plant site and would not displace or directly affect surrounding residences.

**Property Values**

The potential for long-term impacts of the project on property values is addressed below in Subsection 8.1.2.2, Operation. Construction activities may result in a temporary and minor impact on property values for property owners attempting to sell property located in the vicinity of the plant site during the peak periods of construction. However, the impact on property values in the area would be temporary and is expected to be minor.

8.1.2.2 Operation

**Local Economy**

Operation of the proposed project would result in a positive economic impact to Grays Harbor and Thurston counties and the state due to increased tax revenues, employment, and local expenditures. After completion of construction, the value of the Phase II project would be

[3] Weekly commuters would drive to the job site on Monday morning, stay in nearby temporary housing during the week, and return home on Friday evening.

approximately $400 million. Operation of the project would involve approximately 22 employees working either two 12-hour shifts or three 8-hour shifts, with a maximum of 26 employees working on site at any time (see Table 8.1-13). The operational labor force would include the following positions: plant manager, operations supervisor/engineer, control operators, auxiliary operators, maintenance supervisor, mechanical and electrical technicians, and clerks. Efforts would be made to hire local individuals to staff the project as much as practicable.

**TABLE 8.1-13**
**POSSIBLE PLANT SHIFT SCHEDULES**

| Schedule | Shifts | Personnel and Hours |
|---|---|---|
| Option 1 | Two 12-hour shifts | 26 people working from 6:00 a.m. to 6:00 p.m. |
| | | 4 people working from 6:00 p.m. to 6:00 a.m. |
| Option 2 | Three 8-hour shifts | 26 people working from 8:00 a.m. to 4:00 p.m. |
| | | 4 people working from 4:00 p.m. to 12:00 a.m. |
| | | 4 people working from 12:00 a.m. to 8:00 a.m. |

The plant would be operated "base loaded," which would require a scheduled major maintenance outage during the sixth year of operation. During maintenance outage, 50 additional workers would be on site for 28 days during the day shift. Thus, the presence of additional on-site daytime employment (maintenance crews) would increase local spending during this period.

Total operating and maintenance costs for the two-plant configuration would be approximately $14 million per year. Of this, about $2.2 million per year would be in salaries and wages. Generating and Business and Occupation taxes are expected to total approximately $2 million per year.

### Population and Housing

Operation of Phase II would require a maximum of approximately 22 employees. Efforts would be made to hire local individuals to staff the project as much as practicable. Operation employees would likely choose to reside in various areas from Aberdeen to Olympia, based on an approximately 40-minute drive to work. Even if all 22 employees come from outside of the local area, and they all bring families (22 × 2.5 persons per household = 55), the potential impact area is sufficiently large (with a population of over 286,000 and over 10,500 estimated available housing units as shown in Tables 8.1-4 and 8.1-5) that the project would not have an adverse impact on population or housing in the area (WSOFM 2001e). The number of vacant housing units was estimated by applying the vacancy rate ( 1 – occupancy rate = vacancy rate) to the number of housing units.

### Property Values

The values of homes near the Satsop Development Park property have been affected by the nearby nuclear power plants and related facilities. The values of homes nearest the proposed plant site have been affected by three major conditions: (1) the presence of the BPA transmission line right-of-way, which is adjacent to many of the residences and includes two rows of steel transmission towers and a row of wooden power poles; (2) the presence of the construction laydown area for the nuclear plants, an area that includes steel buildings, graveled storage areas, chain link fencing, and stockpiled materials; and (3) the presence of the nuclear plants, cooling towers, and associated facilities about 1 mile to the southeast. In addition, property values have been influenced by Grays Harbor County's growth plans that include use of the Satsop Development Park property for commercial and industrial development.

As a result of the existing influences on the value of homes and property in the vicinity of the proposed plant site, it is not likely that the expansion of the Satsop CT Project would result in a significant impact on property values.

# 8.2

# Criteria, Standards and Factors Utilized to Develop Transmission Route (WAC 463-42-625)

**WAC 463-42-625 HUMAN ENVIRONMENT — CRITERIA, STANDARDS, AND FACTORS UTILIZED TO DEVELOP TRANSMISSION ROUTE.**

*The applicant shall indicate the federal, state, and industry criteria used in the energy transmission route selection and construction factors considered in developing the proposed design and shall indicate how such criteria are satisfied.*
*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-625, filed 10/8/81. Formerly WAC 463-42-250.]*

## 8.2 CRITERIA, STANDARDS, AND FACTORS UTILIZED TO DEVELOP TRANSMISSION ROUTE (WAC 463-42-625)

The Phase II project will utilize the natural gas pipeline and electrical transmission lines constructed as part of Phase I. No new transmission routes are required for Phase II.

# 9.1

# Analysis of Alternatives (WAC 463-42-645)

**WAC 463-42-645 ANALYSIS OF ALTERNATIVES.**

*The applicant shall provide an analysis of alternatives for site, route, and other major elements of the proposal.*

*[Statutory Authority: RCW 80.50.040(1) and chapter 80.50 RCW. 81-21-006 (Order 81-5), §463-42-645, filed 10/8/81. Formerly WAC 463-42-150.]*

# 9.1 ANALYSIS OF ALTERNATIVES (WAC 463-42-645)

## 9.1.1 INTRODUCTION

As a part of developing the proposed Phase II Satsop CT Project, Duke Energy Grays Harbor, LLC, and Energy Northwest (the Certificate Holder) considered alternatives for cooling technologies and water discharge. The discussion on discharge alternatives is located in Subsection 2.8.5. The discussion on alternative cooling technologies is included below in Subsection 9.1.2.

No alternative sites were considered for Phase II for the following reasons:

- The existing Satsop CT site is being developed for gas-fired power production and is appropriately zoned.
- The Certificate Holder owns the site, and therefore is able to maintain site control.
- There is adequate space within the existing approved site for the construction of Phase II.
- Locating within the existing site will maximize the use of an already disturbed site, and eliminate the need to use more land.
- The natural gas pipeline line and electrical transmission lines installed for Phase I are adequately sized for Phase II, eliminating the need to establish new utility line corridors as would be the case for an alternative site.
- The electrical transmission lines provide the ability to wheel power to BPA or other utilities using the BPA transmission system.
- The plant site is located near regional load growth centers, minimizing the need to wheel power over long distances and contributing to the stability of the BPA transmission system.
- There is an existing infrastructure on the property, including access roads, water wells developed for the nuclear program, and a discharge line and approved NPDES outfall.

## 9.1.2 ALTERNATIVE COOLING TECHNOLOGIES

Four cooling system alternatives were considered: once-through cooling, mechanical draft (wet) cooling, parallel condensing (wet/dry), and dry (air) cooling. The Certificate Holder has determined that a mechanical draft (wet) cooling tower system, identical to that being installed for Phase I, is the most appropriate for the site.

### 9.1.2.1 Consideration of Alternatives

The consideration of alternatives focused on several factors: (1) whether the cooling system would fit within the space available at the site; (2) whether sufficient water was available; (3) whether the cooling system would increase noise levels associated with the project; (4) how the system would affect capital and operational costs; (5) the effect of the system on the project's electrical output and efficiency (i.e., its parasitic load); and (6) the visual effects of the system.

**Space Available**

The Satsop CT site has approximately 10 acres available for construction of Phase II. The site is bounded on the west side by Keys Road, and on the east side by a wildlife mitigation area. The wildlife mitigation area was established for the Satsop nuclear power plants and is maintained by the Grays Harbor Public Development Authority (PDA). The PDA owns the land surrounding the site.

**Available Water Supply**

The nuclear projects were authorized to withdraw 80 cfs of water, of which approximately 88 percent was to come from the Chehalis River, and approximately 12 percent from groundwater. Ranney wells were installed to provide the water supply. With the amendment to the Site Certification Agreement (SCA) for the Satsop Combustion Turbine (CT) Project (Phase I), the Washington Public Power Supply System (Supply System) agreed to relinquish all but 9.5 cfs if the two nuclear plants did not go forward. The 9.5 cfs was allocated in the SCA to the Phase I project. Subsequently, the Satsop power plant site, with the exception of the CT site, was transferred by Energy Northwest (formerly the Supply System) to the PDA, and the Washington State Legislature agreed to allocate 20 cfs of water to the PDA for industrial uses at the Satsop Development Park.

With the wet cooling system proposed in this Amendment Application, Phase II will require the same amount of water as Phase I (a maximum instantaneous flow of 9.5 cfs). The PDA has agreed to sell the Certificate Holder 9.5 cfs of water from its authorization of 20 cfs. No new water rights or authorization would be required, and there is sufficient water available for the proposed wet cooling system.

**Additional Noise Impacts**

Noise levels were another consideration. There are no residences directly adjacent to the site, but there are homes located to the west and north. As part of the Phase I development, a 25-foot-high noise wall, with a 12-foot-high landscaped berm on the street side of the wall, are being installed. The projected-related noise levels are discussed in Section 4.1 - Environmental Health, WAC 463-42-352, and assume that the proposed wet cooling system is used. Air cooling or parallel (wet/dry) systems that use more fans would result in higher noise levels.

**Capital and Operating Costs**

Relative capital and operating are an important consideration in determining whether a project is financed and built. Although a once-through cooling system might be less expensive, the Certificate Holders have proposed mechanical draft (wet) cooling to reduce water use. Air-cooled and parallel cooling systems are considerably more expensive to construct and operate.

**Parasitic Load**

The Certificate Holder also considered the relative effect of different cooling systems on the electrical output and efficiency of the facility. All mechanical cooling systems require some form of power to operate, and this "parasitic load" reduces the amount of net power generated by the facility. The more fans that are required for cooling, the higher the energy demand. Parallel cooling systems use approximately 7 MW of power, while an all-dry cooling system would require 10 or more MW of power. This is power that could otherwise be added to the area's energy supply. The corresponding reduction in the facility's efficiency would also result in an increase in regulated and greenhouse gas emissions per unit of electricity produced.

**Visual**

Although these power plants are somewhat large in scale and are industrial in nature, much as been done with the Satsop site to reduce the visual appearance. Visual impact reduction started with the construction of the 12-foot-high landscaped berm along Keys Road. This visual barrier is supplemented with the 25-foot-high noise wall directly behind the berm. Equipment will be painted in earth tones to reduce visual contrast with the surrounding wooded areas. Cooling fans for either a parallel system or an air cooling system need to be approximately 100 feet in height to provide adequate clearance for air movement.

For the reasons described in more detail below, wet cooling was selected as most appropriate for the site, and the other three alternatives were rejected.

9.1.2.2 Once-through Cooling

This alternative was rejected because it would require more water than is currently available. Once-through cooling systems use a large water body, such as the Chehalis River, as a heat sink. Water from the Chehalis River (or the Ranney wells if they could provide a sufficient volume of water) would be continuously circulated through a heat exchanger to transfer waste heat to the cooling water, which would be discharged to the river. This system would require the use of a large volume of water from the Chehalis River or the Ranney wells, likely requiring water rights in addition to those held by the Grays Harbor PDA or the 9.5 cfs allowed for Phase I by the Site Certification Agreement.

In addition, without the use of a cooling tower, it is unlikely that the temperature of the water returned to the river could comply with the temperature limitations in the existing NPDES permit. The discharge temperature could also be sufficiently high to result in impacts to the aquatic resources of the river. If the Ranney wells could not provide the required volume of water, this alternative would also require construction of large intake and discharge structures, the operation of large pumps to maintain the correct water flow rates, additional water rights, and a major revision to the NPDES permit.

Another method of accomplishing once-through cooling would be to construct a large cooling pond in the vicinity of the project site. However, the volume of water required for cooling would be enormous, and it is unlikely that the Certificate Holder could obtain sufficient water rights to fill the cooling pond and maintain the appropriate water level during operation. In addition, the project site does not have enough space to construct a large cooling pond, and the potential environmental impacts associated with such a pond would be much greater than those associated with the proposed system.

Once-through cooling was rejected due to potentially higher environmental impacts as compared to the proposed method of heat dissipation, the anticipated difficulties in meeting permit requirements, and the anticipated difficulty of acquiring additional water rights.

9.1.2.3 Parallel Condensing (Wet/Dry) Cooling

The parallel condensing (wet/dry) cooling system is a method of condensing steam from the steam turbine using both a standard steam surface condenser (SSC) and an air-cooled direct condenser (ACC). This system, known as the PAC System ™, a registered trademark of GEA Power Cooling Systems, Inc., is also sometimes called a hybrid cooling system. The PAC System can become a viable alternative to the standard all-wet cooling system in areas where water is in scarce supply.

The Certificate Holder selected the mechanical draft (wet) cooling system instead of the parallel (wet/dry) cooling system because the wet/dry cooling system would have required additional property, increased noise levels, reduced the facility's output and efficiency, and substantially increased costs.

**Land Requirements**

There is not sufficient space available on the project site to construct the PAC System. Construction of the air-cooled portion of the PAC System would require encroachment into the wildlife mitigation land to the east of the Satsop project site as shown in Figure 9.1-1**.** It is estimated that approximately 2.25 acres of mitigation land would be needed. It is also likely that additional mitigation land would be necessary for construction, startup, and testing of the ACC. Further, to allow proper airflow into the ACC, the mitigation area immediately surrounding the structure would need to be cleared of trees and shrubby vegetation.

**Noise Impacts**

Noise impacts due to the ACC portion of the PAC System are of concern for several reasons. First, a significant number of fans are necessary to meet cooling requirements and, secondly, the fan modules operate at an elevation up to 100 feet above grade. This latter concern means that barrier walls are not effective in controlling the noise because the necessary barrier benefit could only be achieved with an unreasonably high wall structure.

Noise data estimates provided by the vendor indicate that typical noise emissions from a 35 to 40 fan system are in excess of 68 dB(A) at 400 feet from the perimeter of the ACC, and in excess of 62 dB(A) at 800 feet. Noise inside each fan module can be as high as 109 dB(A). The noise attributed to the ACC would require that additional noise mitigation be installed. Since external noise controls (such as boundary barrier walls) are not practical or effective, noise control for

ACCs is essentially limited to inherent design changes for reducing noise emissions. These potential design changes may include lowering each fan's rotational tip speed and/or using special-design blades. In both cases, each fan would need to be enlarged or the array would need to have more cells, so as to provide the necessary total cooling capacity. Therefore, the array size would have to increase and additional plot space would be required (over and above the nominal array size which would already necessitate incursion into the adjoining wooded area to the east). Also, additional or larger drive motors would be needed that could increase the noise from this part of the overall ACC system, as well as add to the cost and auxiliary loads (decreased net power output and efficiency).

To quantify the increased noise impacts from an ACC-based cooling system for Phase II, an analysis similar to the process described in Section 4.1 was performed. The results of that ACC analysis are summarized in Table 9.1-1 below.

**TABLE 9.1-1**
**SUMMARY OF MODELING RESULTS FOR THE CUMULATIVE PHASE I AND PHASE II PLANTS WITH ACC COOLING OPTION**

| Location | 2001 Nighttime Ambient Noise Level, $L_{eq}$ dB(A) | Maximum Allowable Contribution from Combined Project Site, dB(A) | Predicted Cumulative Contribution from Combined Projects (Ph. I + Ph. II) with water cooling, dB(A) | Predicted Cumulative Contribution from Combined Projects (Ph. I + Ph. II with ACC cooling), dB(A) | Total Predicted Future Noise Environment (Measured Ambient plus Proposed Combined Projects, Ph. I + Ph. II with ACC cooling), dB(A) |
|---|---|---|---|---|---|
| Plant_W (#1) | 42.8 | 70 | 52 | 52 | 52 |
| Plant_S (#2) | 35.8 | 70 | 70 | 71 | 71 |
| Plant_N (#3) | 34.7 | 70 | 53 | 53 | 53 |
| Plant_E[a] | No data | 70 | 75 | 78 | 78 |
| #4 | 42.4 | 50 | 40 | 43 | 46 |
| #5 | 32.4 | 50 | 41 | 43 | 43 |
| #6 | 41.2 | 50 | 37 | 40 | 44 |
| #7 | 35.0 | 50 | 40 | 44 | 45 |

[a] Note that with the PAC System, the east property line would be moved farther to the east to accommodate the additional space required for the PAC System. Therefore, while both measurements are predicted for the "east property line" the east property line for the PAC System would be farther to the east than the east property line for the wet system. A noise measurement taken for the PAC System at the original east property line would find noise levels approximately 10 decibels higher than predicted for the wet system. Compare Figure 9.1-2 with the figures found in Section 4.1.

Figure 9.1-2 shows combined project contributions in the mid-50 dB(A) range along the west and north property lines. With ACC, the south property line noise levels would increase to slightly over 71 dB(A); compared to the wet cooling tower system at 70 dB(A). The new, expanded site along the east would be expected to generally have noise levels in the upper-70s to low-80s range of A-weighted levels with the ACC system. The area in the adjacent wooded parcel receiving noise levels about the 70-dB(A) limit would extend approximately 500 feet east of the original Satsop CT Project site boundary. The distant residential receptors are predicted to experience total site contributions in the mid-40s dB(A).

The table shows that compliance with the WAC noise level limits would not be achieved with the nominal ACC noise emissions along the south and east boundaries. Further, when compared to the predicted modeling results for the cumulative Phase I and Phase II plants, the change from a wet tower cooling system to an ACC cooling system for Phase II results in a 2- to 4-dB(A) increase at the distant residential receptors and a 1- to 3-dB(A) increase at the south and east ends of the plant site (for the latter, the increase would also be on top of the additional land area that would be taken by the ACC footprint). Thus, the potential site expansion to the east would have to be significantly increased to accommodate both the additional physical incursion and the higher noise levels of the ACC-based cooling alternative.

The projected ACC-based noise environment is shown graphically in Figure 9.1-1, which gives a noise map, in terms of the constant, A-weighted sound level contours in 5-dB increments on the currently planned project site from the combined Satsop CT Project, Phase I plus Phase II with the ACC configuration (including the contributions from the measured ambient noise levels).

**Visual Impacts**

Typical design estimates for the ACC portion of the PAC System include a structure approximately 100 feet high by 270 feet long and 200 feet wide containing between 35 and 40 fan modules or cells. The ACC structure must be elevated above grade to allow air to flow under, up, and through the condenser. Each fan module is 30 feet in diameter and contains a 200-horsepower electric motor.

**Reduced Electric Generation and Efficiency**

Due to the operational nature of the air-cooled portion of the cooling system, the turbine back pressure would be elevated above normal conditions and thereby reduce steam turbine output by approximately 4.9 MW with chiller on and full duct firing. In addition to the reduction in steam turbine output, the parasitic load requirement for the 35 to 40 fan modules is estimated by the vendor to be an additional 5.3 MW. In total, the net plant output would be reduced by 7.3 MW, with chiller on and full duct firing, if the PAC System were chosen as the method for cooling. The resulting loss of 7.3 MW would have to be replaced by the addition of more power plants in the region. The reduced efficiency would also result in more emissions of regulated pollutants and greenhouse gases being emitted per unit of electricity being produced.

**Increased Project Costs and Construction Schedule**

Estimated capital costs for constructing the PAC System are $45 to 50 million dollars more than the capital investment for an all-wet cooling system. Currently it is believed that the timeline from time of purchase of the PAC System to commercial operation is at least 24 months. The resulting increased capital costs and carrying costs associated with a 24-month construction schedule for the PAC System would translate directly into higher production costs for energy from the facility. Yearly operating and maintenance costs are estimated to be $30,000 higher for the PAC System than for the proposed mechanical draft (wet) cooling system.

#### 9.1.2.4 Dry (Air) Cooling

This alternative was eliminated because insufficient space was available at the site, it would substantial increase noise associated with the facility, it would significantly decrease the facility's power output and efficiency, and it was substantially more expensive than the proposed mechanical draft (wet) cooling system.

Construction of an entirely air-cooled system would have required an additional 4 acres of space. This would have required expanding the project site into an area currently set aside for wildlife mitigation.

As explained in regard to the parallel cooling system discussed above, the fans associated with an air cooling system generate significant amounts of noise. Although a detailed analysis was not conducted regarding the noise associated with an air cooling system, it would involve at least the 3- to 4-dB(A) increase associated with the parallel cooling system.

An air cooling system utilizes large quantities of fin tubes for the heat transfer surface. Large fans are used to transfer the heat from the finned tubes (cooling water inside the tubes) to the atmosphere. This type of cooling system can be impacted by temperature extremes that can lower power production and it has higher auxiliary power consumption. The result is a reduction in the output of the facility of approximately 10 MW. The reduced efficiency would also result in more emissions of regulated pollutants and greenhouse gases being emitted per unit of electricity being produced.

Finally, it is expected that an air cooling system would require capital expenses approximately $45-$50 million capital cost greater than those associated with the proposed mechanical draft system.

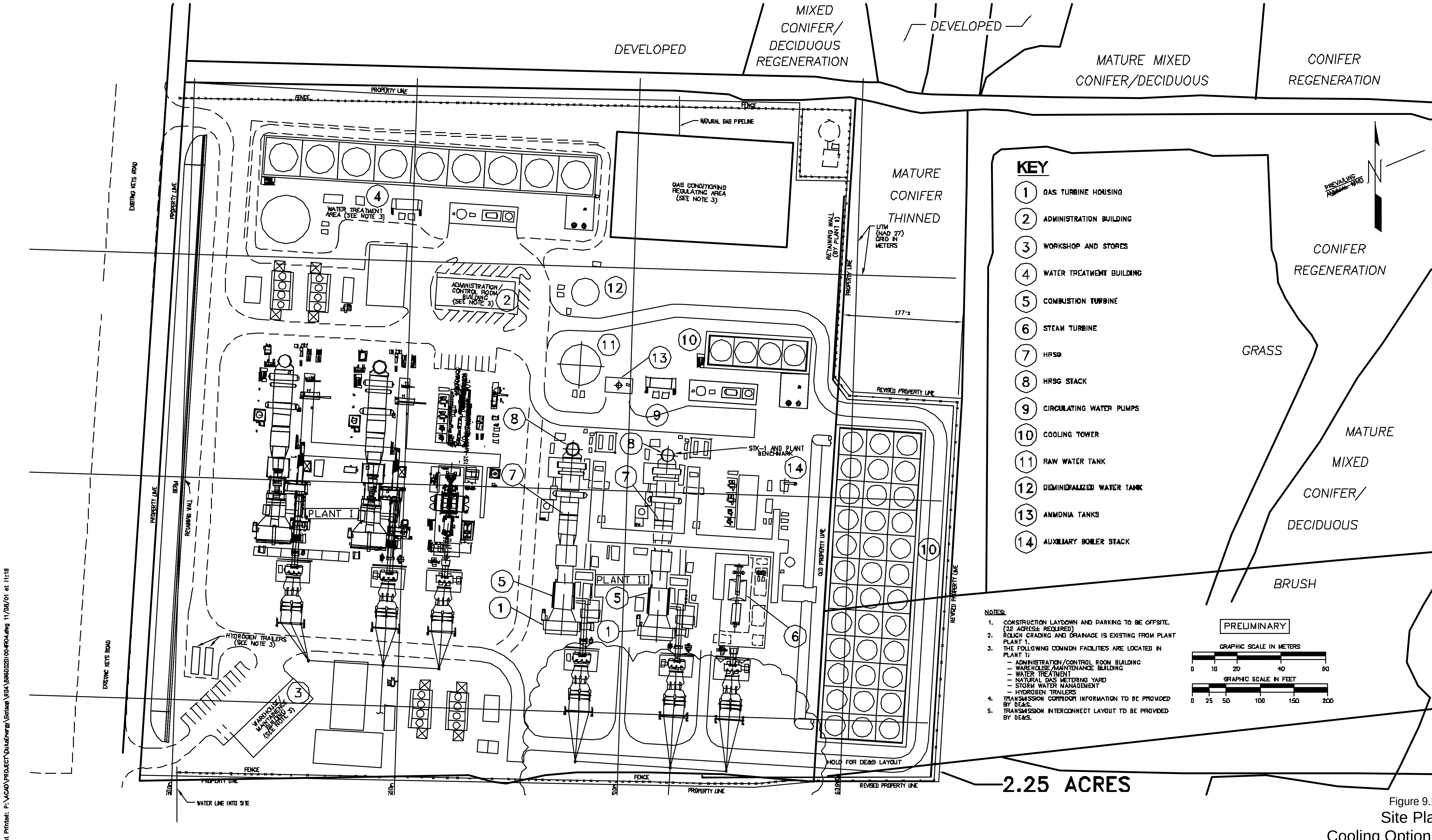
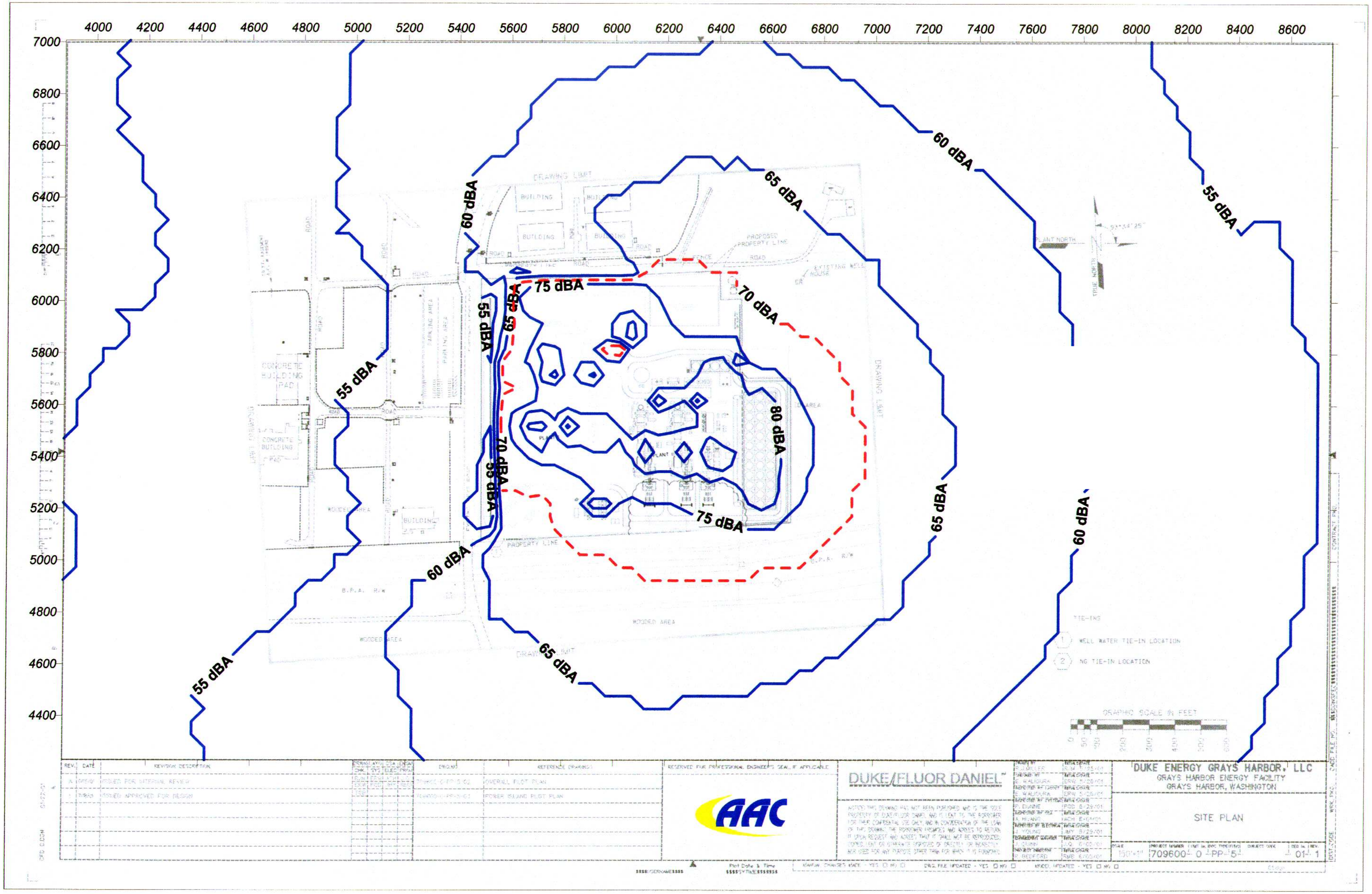



Figure 9.1-1
Site Plan
Cooling Option 1




SOURCE: *Alliance Acoustical Consultants, Inc.*

Figure 9.1-2

**Predicted Phase I plus Phase II Combined Noise Level Contours (With Ambient) at Project Site**

## ABBREVIATIONS AND ACRONYMS

| | |
|---|---|
| ACC | air-cooled direct condenser |
| ADTV | average daily traffic volumes |
| AQIA | air quality impact assessment |
| AQRV | air-quality-related value |
| ASCE | American Society of Civil Engineers |
| ASIL | acceptable source impact level |
| BACT | best available control technology |
| BMP | best management practices |
| BPA | Bonneville Power Administration |
| CARB | California Air Resources Board |
| CEC | California Energy Commission |
| CEM | continuous emission monitoring |
| CERCLA | Comprehensive Environmental Response, Compensation and Liability Act |
| CFR | Code of Federal Regulations |
| cfs | cubic feet per second |
| CO | carbon monoxide |
| CRGNSA | Columbia River Gorge National Scenic Area |
| CSZ | Cascadia Subduction Zone |
| CT | combustion turbine |
| CTG | combustion turbine generator |
| D/FD | Duke/Fluor-Daniel |
| DLN | dry low-$NO_x$ |
| dB(A) | A-weighted decibel |
| DEHG | Duke Energy Grays Harbor LLC |
| DNR | Washington State Department of Natural Resources |
| DWI | driving while impaired |
| Ecology | Washington State Department of Ecology |
| EDNA | environmental designation for noise abatement |
| EFSEC | Energy Facility Site Evaluation Council |
| EIS | environmental impact statement |
| EPA | U.S. Environmental Protection Agency |
| EPC | engineering, procurement, and construction |
| ESA | Endangered Species Act |
| F | Fahrenheit |
| FAA | Federal Aviation Administration |
| FEMA | Federal Emergency Management Agency |
| FGR | flue gas recirculation |
| FIRE | Factor Information Retrieval |
| FITR | fuel injection timing retard |
| FLM | federal land manager |
| FPD | Fire Prevention District |
| FSAR | Final Safety Analysis Report |

**ABBREVIATIONS AND ACRONYMS (Continued)**

| | |
|---|---|
| g | gravity |
| GE | General Electric |
| GEP | good engineering practice |
| gpm | gallons per minute |
| HAL | high-accident location |
| HCM | Highway Capacity Manual |
| HCS | highway capacity software |
| HRSG | heat recovery steam generator |
| IES | Illuminating Engineering Society |
| IWQAM | Interagency Workgroup on Air Quality Modeling |
| K | erodibility factor |
| kJ | kilojoule |
| kW-hr | kilowatt-hour |
| km | kilometer |
| kV | kilovolt |
| LAER | lowest achievable emission rate |
| LCCD | Lewis County Conservation District |
| $L_{eq}$ | equivalent sound measure |
| LOS | level of service |
| M | magnitude |
| MCE | maximum credible earthquake |
| MHHW | mean higher high water |
| MM5 | Mesoscale Model |
| MMBtu | million British thermal units |
| MSDS | Material Safety Data Sheet |
| MSL | mean sea level |
| MV | megavolt |
| MVA | megavolt (average) |
| MW | megawatt |
| NAAQS | National Ambient Air Quality Standards |
| NDE | non-destructive examination |
| NEPA | National Environmental Policy Act |
| NFPA | National Fire Protection Association |
| NMFS | National Marine Fisheries Service |
| NOC | Notice of Construction |
| NOx | oxides of nitrogen |
| NPDES | National Pollutant Discharge Elimination System |
| NPS | National Park Service |
| NPSH | net positive suction head |
| NSPS | New Source Performance Standard |
| NSR | New Source Review |
| NWPC | Northwest Pipeline Company |

| | |
|---|---|
| NWS | Northwest Weather Service |
| OAPCA | Olympic Air Pollution Control Agency |
| OSHA | Occupational Safety and Health Administration |
| PAC | parallel condensing (wet/dry) cooling |
| PDA | Public Development Authority |
| PGA | peak ground acceleration |
| PGU | power generation unit |
| PHS | Priority Habitat and Species |
| PM | particulate matter |
| PMF | probable maximum flood |
| ppb | parts per billion |
| ppm | parts per million |
| ppmvd | parts per million by volume, dry |
| PSD | Prevention of Significant Deterioration |
| psig | pounds per square inch gauge |
| PUD | Public Utility District |
| PWHT | post-weld heat treatment |
| QA/QC | quality assurance/quality control |
| RACT | reasonably achievable control technology |
| RBLC | RACT/BACT/LAER Clearinghouse |
| RCP | resource contingency program |
| RCRA | Resource Conservation and Recovery Act |
| RCW | Revised Code of Washington |
| RH | relative humidity |
| ROW | right-of-way |
| SCA | Site Certification Agreement |
| SCR | selective catalytic reduction |
| SIC | Standard Industrial Classification |
| SIL | significant impact level |
| SNCR | selective non-catalytic reduction |
| SOC | Species of Concern |
| SPCC | Spill Prevention Control and Countermeasures |
| SQER | small quantity emission rate |
| SR 12 | State Route 12 |
| SSC | steam surface condenser |
| STG | steam turbine generator |
| SWPPP | Stormwater Pollution Prevention Plan |
| TAP | toxic air pollutant |
| T-BACT | best available control technology for toxics |
| TDML | total maximum daily load |
| TEFC | totally enclosed fan-cooled |
| UBC | Uniform Building Code |

## ABBREVIATIONS AND ACRONYMS (Continued)

| | |
|---|---|
| USFS | U.S. Forest Service |
| USFWS | U.S. Fish and Wildlife Service |
| USGS | U.S. Geological Survey |
| UW | University of Washington |
| V | volt |
| VFITR | variable fuel injection timing retard |
| WAAQS | Washington Ambient Air Quality Standards |
| WAC | Washington Administrative Code |
| WARIS | Washington Rivers Information System |
| WNP-3 | Washington Nuclear Project Unit 3 |
| WNP-5 | Washington Nuclear Project Unit 5 |
| WPPSS | Washington Public Power Supply System |
| WRIA | Water Resources Inventory Area |
| WSDOT | Washington State Department of Transportation |

# Appendix A

# Power Plant Design Information

# APPENDIX A1

## Power Plant Design Information

# PLANT DESCRIPTION

## INTRODUCTION

The Combined Cycle Power Plant (CCPP) is designed to provide a highly reliable, efficient, and low cost means of generating electricity. Design features of the plant have been carefully considered, resulting in an optimum balance between capital cost and Operations and Maintenance benefits. The plant is also designed to minimize environmental impacts to the fullest extent possible by employment of the best available technologies and utilization of clean burning fuels.

The plant consists of the following major equipment:

- Two (2) General Electric 7FA Combustion Turbine and Hydrogen Cooled Generator
- Two (2) Fired Three Pressure Heat Recovery Steam Generator (HRSG) with Stack
- Two (2) Selective Catalytic Reductions (SCR) for NOx Control
- Two (2) CO Catalyst
- One (1) GE D-11 Steam Turbine and Hydrogen- Cooled Generator
- One (1) Water Cooled Condenser
- One (1) Induced Draft Cooling Tower
- Balance of Plant Equipment Consisting of Pumps, Heat Exchangers, Transformers, Switchgear, etc.
- One (1) Integrated Plant Distributed Control System (DCS)
- 230 kV Switchyard

The plant is designed for base load operation, but is capable of working under cyclic load conditions.

## PLANT CYCLE ARRANGEMENT

Ambient air is drawn into the compressor element of the combustion turbine through the inlet air filtration and silencing system where it is compressed to approximately 16 atmospheres. Inlet air filtration is accomplished with a pad type filter.

Fuel is fired in the combustion section, and hot gases then expand through the turbine element. The combustion turbine has two functions: to produce electrical power through its directly connected Hydrogen Cooled Generator and to supply hot gases to the Heat Recovery Steam Generator (HRSG).

The combustion turbine is designed to be fired with natural gas. The combustion turbine will be designed for Dry Low NOx Combustor operation.

Exhaust gases from the combustion turbine pass through the HRSG using its heat to generate steam. The gases will then exhaust to the stack. Further NOx control will be accomplished by the supply of the SCR system, that is designed to be integral to the HRSG. Also, a Continuous Emission Monitoring System (CEMS) is provided to monitor stack emissions.

The HRSG forms the link between the combustion turbine and the steam cycle. It is a horizontal gas flow type waste heat recovery boiler which incorporates extended fin tube construction. The combined cycle plant utilizes a three pressure level, reheat HRSG design. The high pressure (HP), intermediate pressure (IP), and low pressure (LP) sections contain an economizer tube bundle, a natural circulation type evaporator tube bundle with steam drum, and a superheater tube bundle.

The steam generated in the HRSG is distributed to the steam turbine. HP steam is supplied directly to the steam turbine inlet as main steam. Cold reheat steam is directed to the HRSG, mixed with IP steam, and reheated to 1035°F before being directed back to the steam turbine. LP steam enters the steam turbine through an induction port. The steam expands through the steam turbine sections and discharges to the condenser. The steam turbine produces electrical power through its directly connected Hydrogen- cooled generator.

The steam exits the steam turbine through the downward exhaust configuration and is directed to the condenser. The condenser is designed to allow 100% steam bypass to the steam turbine.

Condensate is removed from the condenser hotwell by one of two 100% capacity condensate pumps. The condensate passes through a feedwater heater in the HRSG after which it enters the low pressure steam drum.

Two 100% capacity HRSG feedwater pumps are supplied. Each pump is of the interstage takeoff design and supplies feedwater to the HP and IP boiler sections. The pumps are electric motor driven and are located near the HRSG. The pump takes suction from the LP steam drum which is located above the pump at an elevation adequate to provide sufficient NPSH during all normal and transient operating conditions.

By virtue of this cycle design, maximum power is generated at an economical energy cost, while maintaining the simplicity of the total plant arrangement. An off line combustion turbine compressor water wash system is provided to help maintain plant performance between maintenance outages.

## ELECTRICAL

A conventional, open air, 230 kV radial switchyard arrangement is provided. The switchyard includes three 242 kV power circuit breakers: two on the high side of the combustion turbine's step-up transformer, and one on the high side of the steam turbine's step-up transformer. Disconnect switches, instrument transformers, metering and protective relaying, as well as the steel structures and bus work, are provided.

A two-winding, oil-filled stepup transformer is provided to increase the voltage from 13.8 kV at each generator terminal to 230 kV at the high side terminals. The combustion turbine generator is connected to its stepup transformer via isolated phase bus duct, and the steam turbine generator is connected to its stepup transformer via nonsegregated phase bus duct.

A 4.16 kV switchgear bus will supply 4.16 kV loads and 4.16 – 0.48 kV transformers which feed various 480 V motor control centers.

Critical services, such as DCS power, field instruments, etc., will be served from the vital power's uninterruptable power supply system.

## INSTRUMENTATION AND CONTROL

The Distributed Control System (DCS) is the principal operation and control system for the plant. The DCS is an on-line real time system that provides automatic operation, control, monitoring, and data trending and logging of all plant processes from the central control room by means of a control system which will provide for programmed sequence and analog control.

The DCS continuously monitors the parameters of the plant process systems. The monitored data is used by the DCS to determine whether the various processes are operating correctly, to identify any alarm conditions to the DCS operator, and to generate operating and management reports.

The DCS automatically controls the operation of all process component systems to provide smooth control over design operating ranges. The DCS also provides to the control room operator interactive control stations. The operator utilizes the control stations for process system operations including start-ups and shutdowns and modification of operating parameter set points.

The DCS provides for control of the combustion turbine, steam turbine, heat recovery steam generator, and other systems, including steam and combustion turbine generator load selection, fuel controls, active and reactive load and voltage control, synchronizing controls, HRSG steam temperature and pressure control and monitoring, main steam pressure control and biasing.

## PLANT ARRANGEMENT

The overall site and building arrangement has been developed to minimize space requirements while maintaining ample access for operation and maintenance activities.

The orientation of the plant has been selected in such a way to reduce environmental impact and optimize runs of interconnecting lines with the gas pipeline and the power grid.

The electrical switchgear, control room, and associated auxiliary equipment are all located within pre-engineered metal sided buildings. All other equipment will be outdoors.

Sufficient operations, administrative and support facilities are provided. A central control room provides a controlled atmosphere from which to monitor and control plant functions. Plant computers and a programming office are located in the control room. Offices for plant management and administrative staff are also provided. Locker facilities are provided for operations and maintenance staff. A maintenance shop is also provided.

Sufficient laydown area has been provided around the steam turbine. Mobile crane access has been provided to facilitate maintenance of equipment located outdoors including the heat recovery steam generator, the combustion and steam turbine generators.

A demineralized water storage tank is provided to store water from the plant water treatment system.

An induced draft cooling tower system will provide the heat sink for the plant. Make up water will be provided by the use of off-site wells.

Site access roads are provided as required to permit normal operations and maintenance (including major equipment overhauls). A storm drainage system of swales and ditches is provided. Appropriate site lighting is provided. A chain link fence is provided around the perimeter of the plant site.

Potable water will be piped from the site boundary.

Plant waste water will be treated and discharged. Sanitary wastes will be piped to an onsite septic system and leach field.

## APPENDIX A2

## Auxiliary Systems

## AUXILIARY SYSTEMS

### Lubricating and Hydraulic Systems

The lubricating provisions for the turbine and generator are incorporated into common lubrication system. Oil is taken from this system, pumped to a higher pressure, and used in the hydraulic system for all hydraulic oil control system components. The lubrication system includes oil pumps, coolers, filters, instrumentation and control devices, a mist elimination device and an oil reservoir.

### Pumps

The lubrication system relies on several pumps to distribute oil from the reservoir to the systems which need lubrication. Similarly, redundant pumps are used to distribute high pressure oil to all hydraulic oil control systems components. These and other oil pumps are listed below.

- Lubrication oil pumps
  - Dual redundant ac motor-driven main lubrication oil pumps are provided.
  - A partial flow, dc motor-driven, emergency lubrication oil centrifugal pump is included as a back up to the main and auxiliary pumps.

- Hydraulic pumps
  - Dual redundant ac motor-driven variable displacement hydraulic oil pumps are provided.

- Seal oil pump
  - An auxiliary generator seal oil pump driven by piggyback ac/dc motors is provided as backup to distribute seal oil to the generator.

- Oil Pump for pressure lift journal bearings
  - Oil for the pressure lift bearings is provided by the hydraulic oil pump.

### Coolers

The oil is cooled by dual stainless steel plate/frame oil-to-coolant heat exchangers with transfer valve. The coolers have an ASME code stamp.

### Filters

Dual, full flow filters clean the oil used for lubrication. Each filter includes differential pressure transmitter to signal an alarm through the gas turbine control system when cleaning is required. A replaceable cartridge is utilized for easy maintenance. Filters have an ASME code stamp.

Dual filters clean the oil for the hydraulic system. Each filter includes a differential pressure transmitter to signal an alarm through the gas turbine control system when cleaning is required. A replaceable cartridge is utilized for easy maintenance. Filters have an ASME code stamp.

**Mist Elimination**

Lubrication oil mist particles are entrained in the system vent lines by seal air returns of the gas turbine lubricating system. In order to remove the particles, a lube vent demister is used as an air-exhaust filtration unit. The demister filters the mist particles and vents the air to the atmosphere while draining any collected oil back to the oil reservoir.

The lube vent demister assembly consists of a holding tank with filter elements, motor-driven blowers, and relief valve. One assembly is provided for the vent line from the lubrication oil reservoir.

**Oil Reservoir**

The oil reservoir has a nominal capacity of 6200 gallons (23,470 liters) and mounted within the accessory module. It is equipped with lubrication oil level switches to indicate full, empty, high level alarm, low level alarm, and low level trip. In addition the following are mounted on the reservoir:

- Oil tank thermocouples
- Oil filling filter
- Oil reservoir drains

**Inlet System**
**General**

Gas turbine performance and reliability are a function of the quality and cleanliness of the inlet air entering the turbine. Therefore, for most efficient operation, it is necessary to treat the ambient air entering the turbine and filter out contaminants. It is the function of the air inlet system with its special], designed equipment and ducting to modify the quality of the air under various: temperature, humidity, and contamination situations and make it more suitable for use. The inlet system consists of the equipment and materials defined in the Scope of Supply. The following paragraphs provide a brief description of the major components of the inlet system.

**Inlet Filtration**
**Inlet Filter Compartment**

Dust-laden ambient air flows at a very low velocity into filter modules which are grouped around a clean-air plenum. The filter elements are pleated provide an extended surface. The air, after being filtered, passes through venturis to the clean air plenum and into the inlet ductwork.

The filter elements are contained within a fabricated steel enclosure which has been specially designed for proper air flow management and weather protection.

**Inlet System Instrumentation**
**Inlet System Differential Pressure Indicator**

Standard pressure drop indicator (gauge) displays the pressure differential across the inlet filters in inches of water.

**Inlet System Differential Pressure Alarm**

When the pressure differential across the inlet filters reaches a preset value, an alarm is initiated. This alarm may signify a need to change the filter elements.

**Exhaust System**

The exhaust system arrangement includes the exhaust diffuser section in which a portion of the dynamic pressure is recovered as the gas expands. The gas then flows axially into the exhaust system.

**Gas Turbine Packaging**
**Enclosures**

Gas turbine enclosures consist of several connected sections forming an all weather protective housing which may be structurally attached to each compartment base or mounted on an off-base foundation. Enclosures provide thermal insulation, acoustical attenuation, and fire extinguishing media containment. For optimum performance of installed equipment, compartments include the following as needed:

- Ventilation
- Heating
- Cooling

In addition, enclosures are designed to allow access to equipment for routine inspections and maintenance.

**Acoustics**

Lagging consisting of glass wool protected with perforated metal is used the interior of the side and roof panels of the turbine and accessory compartments for acoustical attenuation.

**Painting**

The exteriors of all compartments and other equipment are painted with two coats of alkyd primer prior to shipment. The exterior surfaces of the inlet compartment and inlet and exhaust duct are painted with one coat of inorganic zinc primer.

Interiors of all compartments are painted as well with the turbine compartment interior receiving high-temperature paint. The interior and exterior of the inlet system is painted with zinc rich paint.

**Lighting**

AC lighting on automatic circuit is provided in the accessory compartment. When ac power is not available, a dc battery-operated circuit supplies a lower level of light

**Fire Protection System**

Fixed temperature sensing fire detectors are provided in the gas turbine accessory and liquid fuel/atomizing air compartments, and #2 bearing tunnel. The detectors provide signals to actuate the low pressure carbon dioxide (CO2) automatic multi-zone fire protection system. Nozzles in these compartments direct the CO2 to the compartments at a concentration sufficient for extinguishing flame. This concentration is maintained by gradual addition of CO2 for an extended period.

The fire protection system is capable of achieving a non-combustible atmosphere in less than one minute, which meets the requirements of the United States National Fire Protection Association (NFPA) # 12.

The supply system is composed of a low pressure CO2 tank with refrigeration system mounted off base, a manifold and a release mechanism. Initiation of the system will trip the unit, provide an alarm on the annunciator, turn of ventilation fans and close ventilation openings.

**Cleaning Systems**

Compressor water wash is used to remove fouling deposits which accumulate on compressor blades and to restore unit performance. Deposits such as dirt, oil mist, industrial or other atmospheric contaminants from the surrounding site environment, reduce air flow, lower compressor efficiency, and lower compressor pressure ratio, which reduce thermal efficiency and output of the unit. Compressor cleaning removes these deposits to restore performance and slows the progress of corrosion in the process, thereby increasing blade wheel life.

**Starting System**
**Cooldown System**

The cooldown system provides uniform cooling of the rotor after shutdown. A low speed turning gear with motor is used for the cooldown system.

**Static Start System**
**Operation**

The static start system uses a Load Commutating Inverter (LCI) adjustable frequency drive as the starting means for the gas turbine. By providing variable frequency power directly to the generator terminals, the generator used as a synchronous motor to start the gas turbine. The generator will be turning at approximately 6 rpm, via a low speed turning gear, prior to starting. With signals from the turbine control, the LCI will accelerate or decelerate the generator to a self-sustaining speed required for purge, light-off, waterwash etc. Deceleration is a coast down function.

The system can accelerate the gas turbine-generator without imposing high inrush currents, thereby avoiding traditional voltage disturbances on the ac station service line.

Conventional three phase, 12-pulse bridge circuits are used for the rectifier and inverter and are connected through a dc link inductor. A transformer provides three phase power, impedance for fault protection, and electrical isolation from system disturbances to ground.

Starting excitation is provided by the generator excitation system.

**System Protection**

The drive system protective strategy is to provide a high level of fault protection for the major equipment. The protective relaying includes phase overcurrent ground fault and motor protection. The rectifier inverter includes voltage surge protection and full fault suppression capability for internal faults or malfunctions. A drive system monitor and diagnostic fault' indications continuously monitor the condition and operation of the LCI.

**Equipment**
**Low Speed Turning Gear**

The turning gear assembly is located on the collector end of the generator and is used for slow speed operation (approximately 6 rpm), cooldown and standby turning, and rotor breakaway during startup.

**LCI Power Conversion Equipment**

The LCI power conversion equipment is mounted in a NEMA I ventilate enclosure and consists of the following:

- 12-pulse converter with series redundant thyristor cells to rectify ac line power to controlled voltage dc power.
- Inverter with series redundant cells to convert dc link power to controlled frequency ac power.
- Cooling system using a liquid coolant to transfer heat from heat producing devices such as SCRs and high wattage resistors to a remote liquid-liquid heat exchanger. The system is closed-loop with a covered reservoir for makeup coolant. Coolant circulates from the pump discharge to the heat exchanger to the power conversion bridges and returns to the pump. A portion of the coolant bypasses to a deionizer system to maintain coolant resistivity. Redundant pumps are provided.
- Control panel containing microprocessor system control logic for firing, drive sequencing, diagnostics and protective functions, acceleration (ramping function), excitation system interface, and input/output signal interfacing.

Note: The control panel is located in the enclosure and includes door mounted panel meters and operator devices.

**DC Link Reactor**

The dc link reactor helps smooth the dc current to eliminate coupling between the frequencies of the converter and inverter and provides protection during system faults by limiting the current.

The dc link is a dry-type, air core reactor which is convection cooled. It is located in an outdoor protective enclosure and electrically connected between the converter and the inverter.

**Fused Contactor**

A 4160 Volt fused contactor provides circuit isolation under normal conditions. The fuse is rated to interrupt the current if a fault occurs in the inverter section during startup.

**Isolation Transformer**

The isolation transformer provides electrical isolation and impedance system protection against notching and harmonic distortion. The transformer is designed for service with a three phase, six pulse power converter connected to the secondary winding. One transformer is provided for each LCI and located in an outdoor weather-protected enclosure.

**Motorized Disconnect Switch**

A motorized disconnect switch is provided to disconnect the static start system during normal generator operation. The disconnect switch is electrical connected between the LCI and the feed for the generator stator.

# APPENDIX A3

## Heat Recovery Steam Generator (HRSG)

## HEAT RECOVERY STEAM GENERATOR (HRSG)

### INTRODUCTION

In order to fully realize the potential benefit of combustion turbines, it is necessary to capture and use the exhaust energy of the turbine. In the combined cycle application, this energy is converted into steam for expansion in a steam turbine. The conversion of this otherwise wasted heat energy is accomplished in a heat recovery steam generator which is an adaptation of conventional water tube boiler design.

The design of the heat recovery unit is closely integrated with the steam turbine in order to obtain optimum cycle efficiency. High pressure, reheat, intermediate, and low pressure superheated steam are produced within the heat recovery unit to drive a reheat induction type steam turbine.

### SYSTEM DESCRIPTION

The heat recovery steam generator (HRSG) is designed to be located outdoors. It is a natural circulation, three pressure level (reheat) design which supplies high pressure (HP), reheat (RH), intermediate pressure (IP), and low pressure (LP) superheated steam to the steam turbine.

The HRSG receives hot exhaust gas from the combustion turbine through horizontal ductwork connected to the turbine exhaust transition piece. The gas is distributed in a horizontal transition duct before entering the heat transfer section of the steam generator through vertically oriented heat transfer modules until it reaches the stack transition. There the flow is turned and directed upward out of the exhaust stack.

The gas passes over each module performing the following functions in sequence:

a. High pressure superheater - heating of dry and saturated steam from the high pressure steam drum. (Main supply of steam to steam turbine).

b. Reheater - heating of steam which has been partly expanded in the steam turbine and is mixed with the IP steam.

c. High pressure evaporator - generation of high pressure steam.

d. Selective catalytic reactor/CO catalyst - reduces combustion turbine NOx and CO emissions.

e. IP superheater-heating of dry and saturated steam from the IP steam drum.

f. High pressure economizer - heating of feedwater to near saturation temperature of the high pressure steam drum.

g. Intermediate pressure evaporator - generation of IP steam.

h. Low pressure superheater - heating of dry and saturated steam from the low pressure steam drum (induction steam to steam turbine).

i. HP/IP intermediate temperature economizers. Preheat HP/IP feedwater entering next element of HRSG.

j. Low pressure evaporator - generation of low pressure steam.

k. Feedwater heater - heats feedwater to near LP saturation temperature of LP drum.

The HRSG is equipped with economizer sections between the HP, IP, and LP evaporator sections and after the LP evaporator.

The cycle utilizes a deaerating type condenser. Feedwater is supplied to the HRSG from the condensate pumps where it passes through the low pressure feedwater heater and enters the low pressure steam drum. The IP/HP feedwater supply is taken from the LP steam drum where it is pumped using an interstage take off type feed pump.

**DESIGN FEATURES**

The HRSG being supplied is designed to meet the startup requirements for the plant. The unit is designed and built in accordance with the ASME Boiler and Pressure Vessel Code, Section 1. Special design features include:

**Shop Assembly**

The various components are all designed to be built in shop assembled modules. This permits quality and schedule control beyond that possible with total field fabrication.

**Thermal Expansion**

Pressure Parts: The tube bundles are designed to allow unrestrained expansion during thermal transients.

Outer Casing: The HRSG is designed to place the critical gas tight casing on the outside. Internal insulation assures that the outer casing remains cool. The structural steel framework is also located outside. By keeping the outer casing and structure cool, thermal expansion is minimized. Vertical expansion of the casing is allowed to occur unimpeded. Axial thermal expansion will be accommodated by the use of expansion joints.

Inner Casing: The inner casing is a liner of material suitable for the temperatures encountered. The inner casing is a "floating" design which means that the inner panels are designed with lagged joints so the liner is free to expand in all directions without distortion.

Insulation: Internal insulation is positioned between the outer and inner HRSG casings.

**Vibration Control**

Provisions are made to prevent flow induced vibration. Potential vibration problems are carefully analyzed for each tube bundle. A network of tube supports is installed to prevent whirling instability. A system of baffles is used to prevent any vortex induced vibration.

**Circulation**

The entire system has been designed to ensure circulation at all loads. In the evaporators, a high circulation ratio, vertical tubes and feeder system ensure that steam blanketing does not occur.

The economizers are designed so that any steam formation which occurs does not develop into a vapor lock of any flow circuit.

**Accessibility**

The heat recovery system has been designed to make heat transfer surfaces accessible for maintenance and repair. Access doors are located in the various ducts and between each heat exchanger module.

**Ductwork**

All ductwork between the turbine and the heat recovery steam generator as well as ductwork between the heat recovery components uses the double cased construction described above. All pieces are shipped in panels to be field erected.

**Superheaters/Reheaters**

The steam pressure drop is kept low while maintaining uniform flow among the circuits. Uniformity of flow is essential for achieving a predictable steam outlet temperature. Headers are provided at the bottom to provide drainability.

**Evaporators**

The evaporators furnished in this system are conventional, conservatively designed natural circulation evaporators requiring no circulating pump (with the related power source and power consumption). In the evaporators, steam is discharged from the upper collecting header through risers to the steam drum. The natural circulation circuit is closed through downcomers, feeding water from the steam drum to the evaporator's lower header.

**Economizers**

Waterside velocities are selected to minimize the pressure drop while maintaining a high fluid flow to avoid excessive fouling. Headers are provided at the bottom to provide drainability.

**Steam Drums**

The steam drums are fusion welded. The thickness of the drum material includes a 1/16" corrosion allowance. The drum includes 12" X 16" manways (minimum).

Drum internals include distribution pipes and a steam separator. A feedwater distribution pipe distributes the feedwater adjacent to the downcomers. Continuous blowdown and chemical feed distribution pipes are also provided.

**Walkways and Ladders**

Walkways and ladders are provided to obtain access to portions of the steam drums. For convenience, stairs are provided on one side with ladder access on the other side. All structural supports for the walkway and ladder system are included.

**BILL OF MATERIAL**

One heat recovery steam generator consisting of:

- High pressure superheater, evaporator, and economizer.
- Reheater.
- Intermediate pressure, superheater, evaporator, and economizer.
- Low pressure superheater, evaporator, and economizer.
- High pressure steam drum with internal steam purification system.
- Intermediate pressure steam drum with internal purification system.
- Low pressure steam drum with internal steam purification system.
- HRSG casing with internal insulation.
- HRSG inlet duct with internal insulation and stainless steel liner.
- Expansion joint at the inlet duct (in CTG scope).
- HRSG trim piping, valves, and fittings plus required supports and hangers.

- Interconnecting piping between heat transfer sections.
- Platforms, ladders, and stairs including support steel.
- Selective catalytic reduction for NOx control.
- CO catalyst
- Structural steel for support of all modules and ductwork.
- Instrumentation as required to monitor and operate the HRSG as an integral part of the overall combined cycle control system.
- Duct burner system.

# APPENDIX A4

## Reheat Steam Turbine

## REHEAT STEAM TURBINE

## MECHANICAL SYSTEMS DESCRIPTION

### Turbine
### Casing

Horizontally split, cast-alloy steel symmetrical casing design incorporates free expansion of both rotating and stationary parts in all directions. The internal parts of the turbine, diaphragms, packing boxes, etc., are supported at the horizontal centerline of the unit. This allows expansion to be evenly distributed around the center of the unit where clearances are critical with respect to the rotor. During startups or rapid load swings, the casings are free to expand radially and axially, while diaphragms remain concentric with the shaft at all times. The casing design incorporates minimum wall thickness with liberally designed fillets to reduce stress concentrations.

### Diaphragms

The diaphragm assembly is fabricated of semicircular flat plates with nozzIe airfoils inserted between the inner and outer rings. The diaphragm rings are constructed of low-alloy steel suitable for the operating temperature, and the aerodynamically shaped nozzles are made of 12-chrome steels.

### Rotor

Forged alloy-steel rotor features rows of separate wheels that are an integral part of the shaft and are designed to carry the centrifugal load of the mechanically attached impulse type buckets. This design results in smaller shaft diameters and therefore decreases the sealing area of the inter-stage packing, which reduces leakage from the steam path and increase efficiency.

Integral wheel construction allows for thinner wheel thickness, which minimizes thermal stresses across the wheel and external dovetail. Fillet radii, where the wheel meets the shaft, are kept generous to reduce stress concentrations to the required low levels. By controlling the integral wheel thickness and shape, centrifugal stresses are kept at low levels.

Consistent with good rotor dynamic practices, rotor geometry is optimized to ensure that critical speeds are located sufficiently away from troublesome areas, creating a smooth running machine. Diameter changes in the shaft are kept small and gradual so that bending stresses are extremely low.

### Buckets

The buckets are made of a steel alloy which is resistant to corrosion and erosion by steam. They are machined from bar stock or forgings and are dovetailed to the wheel rims by a precision machine fit.

Metal shroud bands are used to tie together the outer ends of the buckets. This improves efficiency and rotor dynamics.

**Labyrinth Shaft Packing**

Spring-backed metallic labyrinth packings are used on both ends of the shaft and between the stages. High-low tooth construction assures maximum protection against steam leakage and resultant energy waste.

**Thrust Bearing**

Self-aligning, cast babbit-on-copper, pivoted shoe thrust bearings are used to position the rotor axially in the casing and to absorb thrust loads generated during operation. Copper is used as the backing material to create a more uniform temperature distribution between lands, alleviating thermal distortions which contribute to thrust failure.

**Journal Bearings**

Both tilting pad and elliptical journal bearings are employed. The journal bearings contain ports through which oil is supplied to the bearing. Oil flowing through the bearing absorbs heat from the journal as the shaft carries oil over the upper half of the bearing. A portion of the oil is carried between the lower half of the lining and the journal by rotation of the shaft. This forms a hydrodynamic oil film which supports the weight of the rotor and prevents any metal-to-metal contact. Instrumentation is provided to present vibration data to the operator.

The turbine rotor journal bearings are made in halves, which allows the bearings to be removed without removing the rotor from the casing.

**Combined Inlet Stop and Control Valve**

Off-chest valves are made specifically for sliding pressure combined cycle applications. They contain in a common casing two (2) poppet type valves with independent actuators.

The control valve portion is normally fully open to provide minimum flow restriction. It can be used to control flow if the steam turbine is operated in a pressure control mode of operation during start-up/shut-down transients. The valve is spring closed, and opened with a hydraulic actuator for throttling or full open positions. LVDTs and servo valves are used for feedback and control. Closing of this valve is used as back-up protection to the stop valve. The stop valve portion of the combined stop valve/control valve (SV/CV) assembly is actuated independently of the control valve portion. It contains it's own hydraulic actuator with a spring for closure. The stop valve is used to isolate the main steam inlet during emergency conditions.

Provisions are made for on-line periodic testing of both valve actuators and steam freedom. A steam strainer is provided to prevent material from entering the valve/turbine. The strainer has a coarse mesh wrapper for normal running and a fine mesh (start-up) screen.

**Combined Reheat Valves**

There are two combined reheat valves, one located on each side of the reheat turbine. Their primary purpose is to protect the unit from overspeed due to the energy stored in the reheater and reheat piping. Each combined reheat valve consists of a reheat stop valve, and intercept valve. The reheat stop and intercept valves have separate actuators and operate completely independently. As with the SV/CV, strainers are provided.

**Lubrication System**

A lubrication system is supplied to provide lubrication for turbine and generator bearings and to provide seal oil to the generator shaft seals.

The turbine lubrication system is primarily comprised of a main oil reservoir which contains various pumps, cooler(s), regulators and other items required for a completely integrated lubrication system.

**Oil Reservoir**

A welded steel oil storage tank of sufficient capacity is provided to store all of the oil required by the pumping system. The tank is located at an elevation below the turbine operating floor so the oil drainage from the main bearings is by gravity. The oil level in the tank provides adequate submergence of all pumps, which extend vertically down into the oil. This also results in a low recirculation rate. Oil returning to the tank is discharged at approximately the operating oil level to minimize turbulence. The low recirculation rate and minimum turbulence permit the returned oil to detrain air before being picked up by pump suction.

An ac motor-driven vapor extractor is provided to create negative pressure in the oil tank. This will cause an inward flow of air through the oil deflectors in the bearing housing, which will eliminate leakage of oil out through the oil deflectors.

**Oil Pumps**

Two (2) ac motor-driven, centrifugal-type oil pumps are arranged in parallel. If the operating pump fails, a drop in oil pressure will be sensed by pressure switch which will provide a signal to start the alternate pump. A DC motor-driven emergency oil pump is provided should both of the ac motor-driven pumps fail. Such a double failure would cause the oil pressure to drop to a lower level and the pressure switch would then signal the DC pump to start.

All pumps are serviceable without draining the oil reservoir.

**Oil Coolers**

Two (2) full-capacity oil-to-water coolers are mounted vertically at the end of the main oil tank to cool the oil before it is supplied to the turbine bearings. The cooler is plate and frame type.

One (1) cooler at a time is in use, with the second in reserve. This permits the removal of one (1) cooler from service for repair or replacement without having to shut down the unit.

**Oil Filters**

Two (2) full capacity oil filters are mounted on top of the tank. The filters are replaceable cartridge type.

**Hydraulic Power Unit**

The hydraulic power unit supplies fire resistant fluid under pressure both directly to the servo-valves on the power actuators of the valve gear to open and close the steam valves and indirectly to the stop valve through a series of trip devices.

**Hydraulic Fluid Reservoir**

The fluid reservoir is constructed entirely of stainless steel. Front and rear cover plates provide access to the reservoir for cleaning.

A desiccant-type air dryer on top of the reservoir removes moisture from both the air inside the reservoir and air breathed by the reservoir as the fluid level changes. Air is drawn through a filter and circulates around and through bags of desiccant in a perforated canister.

A heating/cooling circulating pump is used to add heat, when required to maintain fluid temperature. An air/fluid heat exchanger is employed to cool the fluid. Its design insures that cooling water cannot contaminate the hydraulic fluid. The system operates automatically by a preset temperature controller which senses reservoir temperatures.

Accumulators under the reservoir provide an immediate source of hydraulic fluid to satisfy large transient demands of valve actuators. The accumulators are normally pre-charged with nitrogen.

**Pumping System**

Two (2) AC motor-driven, variable displacement pumps with pressure compensator are used to operate the hydraulic power unit. The pressure compensator maintains a preset pressure throughout the delivery flow range. A relief valve on the pump discharge protects the system bypassing pump output back to the reservoir.

A filter is provided downstream of each pump discharge to assure system cleanliness.

**Fluid Conditioning Unit**

A fluid conditioning unit is provided to clean and condition the fluid by recirculating fluid from the reservoir, in a bypass loop through a Selexsorb filter and cartridge type polishing filter. This system utilizes an AC motordriven fixed displacement pump, and incorporates connections for filling and draining the unit.

**Steam Seal and Exhauster System**
**Automatic Steam Seal Regulator**

A shaft sealing system is required to seal the turbine casing so that a vacuum may be established in the exhaust for startup. After startup, sealing must be maintained so that air will not leak into the sub-atmospheric section of the turbine and so that excess steam in the high-pressure section of the turbine will not blow out into the turbine room or into bearing housings an contaminate the lubricating oil.

**Exhauster System**

The gland exhauster system maintains a slight vacuum between the two (2) outer rings of packing. This prevents sealing steam from escaping past the outer shaft packing at each end of the turbine rotor to the atmosphere. The system continuously removes a mixture of sealing steam and air (which tends to enter the turbine along the rotor shaft) and discharges the condensate to a suitable drain.

The basic system consists of a skid-mounted gland condenser to condense the steam and a motor-driven air blower to evacuate the air. A blower throttle valve is used to regulate system vacuum.

**Turning Gear**

A turning gear is provided to rotate the turbine-generator shaft slowly (approximately 3-5 rpm) during shutdown and startup. When a turbine is shut down, its internal elements continue to cool for many hours. To eliminate distortion that would occur if the rotor remained stationary during the cool down period, the turning gear keeps the turbine and generator rotor: revolving continuously until temperature change has stopped and the casing has become cool. Additionally, the turning gear can be used as a jacking device to turn the rotor small amounts for inspection.

The turning gear is driven by an ac motor, and power is transmitted to the turbine shaft through a reducing gear train. Lubrication for the turning gear is provided from the main lube oil system directly from the main bearing header. Valves are provided to admit oil to the turning gear. A pressure switch senses oil pressure within the turning gear and interlocks the turning gear motor starter circuit to prevent operation without adequate lube oil supply. A remote jog push button with extension cable is also provided.

# APPENDIX A5

## Combustion Turbine
## and Static Excitation System

## COMBUSTION TURBINE
## AND STATIC EXCITATION SYSTEM

### ELECTRICAL RATING

The generator is designed to operate within Class "B" temperature rise limit per ANSI standards, throughout the allowable operating range. The insulation systems utilized throughout the machine are proven Class "F" materials. The generator is designed to exceed the gas turbine capability at all ambient conditions between -8 and 104°F.

### PACKAGING

The 7FH2 generator is designed for compactness and ease of service and maintenance. Location permitting, the unit ships with the rotor, gas shields and end shields factory assembled. The high voltage bushings, bearings, oil deflectors, hydrogen seals, and coolers are also factory assembled. The collector cab ships separately for assembly to the generator at the customer site. Clearances of the bearings, rub rings, fans, hydrogen seals and deflectors are factory fitted and only require a minimum amount of field inspection these components.

Prior to full assembly, the generator stator receives a pressure test at 150% of operating pressure followed by a leakage test at 100% of operating speed.

Feed piping between the bearings are stainless steel and mounted on the unit in the factory to a common header. All connections to the end shields are assembled. All assembled piping is welded without backing rings and a first pass TIG weld. A full oil flush is performed prior to shipping.

### FRAME FABRICATION

The frame is a stiff structure, constructed to be a hydrogen vessel and to able to withstand in excess of 14 kg/cm2 (200 psi). It is a hard frame design with its four-nodal frequency significantly above 120Hz. The ventilation system completely self contained, including the gas coolers within the structure. The gastight structure is constructed of welded steel plate, reinforced internally by radial web plates and axially by heavy wall pipes, bars and axial braces.

### CORE

The core is laminated from grain oriented silicon steel to provide maximum flux density with minimum losses, thereby providing a compact electrical design. The laminations are coated on both sides to ensure electrical insulation and reduce the possibility of localized heating resulting from circulation currents.

The overall core is designed to have a natural frequency in excess of 170 hertz, well above the critical two-per-rev electromagnetic stimulus from the rotor. The axial length of the core is made up of many individual segments separated by radial ventilation ducts. The ducts at the core ends are made of stainless steel to reduce heating from end fringing flux. The flanges are made of cast iron to minimize losses. To ensure compactness, the unit receives periodic pressing during stacking and a final press in excess of 700 tons of stacking.

**ROTOR**

The rotor is machined from a single high alloy steel forging. The two pole design has 24 axial slots machined radially in the main body of the shaft. The axial vent slots machined directly into the main coil slot are narrower than the main slots and provide the direct radial cooling of the field copper.

**FIELD ASSEMBLY**

The field consists of six coils per pole with turns made from high conductivity copper. Each turn has slots punched in the slot portion of the winding to provide direct cooling of the field.

The collector assembly incorporates all the features of GE proven generator packages with slip on insulation over the shaft and under the rings. The collector rings use a radial stud design to provide electrical contact between the rings and the field leads. The rings are designed to handle the excitation requirements of the design (approximately 2200 amps on cold day operation and 1900 amps at rated conditions).

The entire rotor assembly, weighing 74,000 pounds is balanced up to 20% over operating speed.

**END SHIELD/BEARING**

The unit is equipped with end shields on each end designed to support the rotor bearings, to prevent gas from escaping, and to be able to withstand, a hydrogen explosion in the unlikely event of such a mishap. In order to provide the required strength and stiffness, the end shield is constructed from steel plate and is reinforced. The split at the horizontal joint allows for ease assembly and removal.

The horizontal joints, as well as the vertical face which bolts to the structure, are machined to provide a gas tight joint. Sealing grooves are machined into these joints. These steps are taken to prevent gas leakage between all the structural components for pressures up to 45 psig.

The center section of the end shields contain the bearings, oil deflectors and hydrogen seals.

The hydrogen seal casing and seals, which prevent hydrogen gas from escaping along the shaft, utilize steel babbitted rings. Pressurized oil for the seals is supplied from the main oil system header to the seal oil control unit where it is regulated. The seal oil control unit is factory assembled packaged system and is located in the collector end compartment.

The collector end bearing and hydrogen seals are insulated from the rotor to prevent direct electrical contact between the rotor and the end shield. Both end shields have proximity type vibration probes. These are located axially at the bearing. Mounting for velocity type vibration sensors is also provided on the surface of the bearing caps.

## WINDING

The armature winding is a three phase, two circuit design consisting of "Class F" insulated bars. The stator bar stator ground insulation is protected with semi-conducting armor in the slot and GE's well proven voltage grading system on the end arms.

The ends of the bars are pre-cut and solidified prior to insulation to allow strap brazing connections on each end after the bars are assembled. An epoxy resin filled insulation cap is used to insulate the end turn connections.

The bars are secured in the slot with side ripple springs (SRS) to provide circumferential force and with a top ripple spring (TRS) for additional mechanical restraint in the radial direction. The end winding support structure consists of glass binding bands, radial rings, and the conformable resin-impregnated felt pads and glass roving to provide the rigid structure require for system electrical transients.

## LEAD CONNECTIONS

All the lead connection rings terminate at the top of the excitation end of the unit and the six high voltage bushings (HVBs) exit at the top of the frame.

Each of the circuits are connected to the high voltage bushings (HVBS.) The bushings, which provide a compact design for factory assembly and shipment, are positioned in the top of the frame and are offset to allow proper clearances to be maintained. This configuration also allows connections to the leads to be staggered and provides ease of bolting and insulation.

The bushings are made up of a porcelain insulators containing silver plated copper conductors which form a hydrogen tight seal. The bushings are assembled to non-magnetic terminal plates to minimize losses. Copper bus is assembled to the bushings within an enclosure. Customer connections are made beyond the terminal enclosure and the specific mating arrangements are provided within the enclosure, not inside the generator.

## LUBRICATION SYSTEM

Lubrication for the generator bearings is supplied from the turbine lubrication system. Generator bearing oil feed and drain interconnecting lines are provided, and have a flanged connection at the turbine end of the general package for connection to the turbine package.

## HYDROGEN COOLING SYSTEM

The generator is cooled by a recirculating hydrogen gas stream cooled by gas-to-water heat exchangers. Cold gas is forced by the generator fans into the gas gap, and also around the stator core. The stator is divided axially into sections by the web plates and outer wrapper so that in the center section cold gas forced from the outside of the core toward the gap through the radial gas ducts, and in the end section it passes from the gas gap toward the outside the core through the radial ducts. This arrangement results in substantial uniform cooling of the windings and core.

The rotor is cooled externally by the gas flowing along the gap over the rotor surface, and internally by the gas which passes over the rotor and winding through the rotor ventilating slots, and radially outward to the gap through holes in the ventilating slot wedges.

After the gas has passed through the generator, it is directed to five horizontally mounted gas-to-water heat exchangers. After the heat is remove, cold gas is returned to the rotor fans and recirculated.

## HYDROGEN CONTROL PANEL

To maintain hydrogen purity in the generator casing at approximately 9 percent, a small quantity of hydrogen is continuously scavenged from the seal drain enlargements and discharged to atmosphere. The function of the hydrogen control panel is to control the rate of scavenging and to analyze the purity of the hydrogen gas. The panel is divided into two compartments, the gas compartment and the electrical compartment, which are separated by a gas-tight partition.

## GENERATOR COLLECTOR COMPARTMENT

An exciter-end, enclosure is provided with the generator. It will contain the following assemblies:

- Hydrogen control panel
- Seal oil control unit, regulator and flowmeter
- Seal oil drain system, float trap and liquid level detector
- H2 and CO2 feed and purge system, valves and gauges
- Switch and gauge, block and porting system
- Collector housing and brush rigging assembly
- Collector filters and silencers
- Level-separated electrical junction boxes
- Turning gear

The above items are packaged in the enclosure. The completed enclosure is assembled to the generator at the customer site. The enclosure has been designed to simplify interconnecting wiring and piping between the enclosure and the generator.

The enclosure is designed with a removable end wall section and roof to allow ease of rotor removal without moving the housing. Position of all the above hardware is spaced to allow easy access for maintenance and to prevent an, unnecessary disassembly during rotor removal. Two doors are provided on the end wall to allow access from either side. Safety latches are provided on the inside of the doors to provide easy exit from the enclosure. AC lighting is standard.

**GENERATOR TERMINAL ENCLOSURE**

The Generator Terminal Enclosure (GTE) is a reach-in weather-protected enclosure made of steel and/or aluminum and is located on the generator. The GTE is convection cooled through ventilation louvers to the outside of the enclosure. The louvers are designed to inhibit debris from entering into the compartment.

The GTE houses the following major electric components:

- Neutral current transformers (CTs)
- Line CTs
- Lightning arresters
- Neutral grounding transformer with secondary resistor
- Fixed voltage transformers (VT)
- 89SS LCI disconnect switch
- Motor operated neutral disconnect switch

# APPENDIX A6

## Steam Turbine Generator
## and Brushless Excitation

## STEAM TURBINE GENERATOR AND BRUSHLESS EXCITATION

### GENERATOR ELECTRICAL RATING

The generator is designed for outdoor installation and to operate within Class "B" temperature rise limits, per ANSI standards, throughout the allowable operating range. The insulation systems utilized throughout the machine are proven Class "I" materials.

The generator is designed to exceed the steam turbine capability at the operating conditions.

### PACKAGING

The generator is designed for ease of service and maintenance. Location permitting, the unit can ship with the rotor, gas shields and end shields all factory assembled. The bearings, oil deflectors, hydrogen seals and coolers can also be factory assembled. The clearances of the bearings, rub rings, fans, hydrogen seals and deflectors will be factory fitted and will require only a minimum amount of field inspection.

### FRAME FABRICATION

The frame is a stiff structure, constructed to be a hydrogen vessel and to withstand in excess of 14 kg/cm2 (200 psi). The ventilation system is completely self contained, including the gas coolers within the structure. The gastight frame is constructed of welded steel plate, reinforced internally by radial web plates and axially by heavy wall pipes, bars and axial braces.

### CORE

The core is laminated from grain oriented silicon steel to provide maximum flux density with minimum losses, thereby providing a compact electrical design. The laminations are coated on both sides to ensure electrical insulation and reduce the possibility of localized heating resulting from circulating currents.

The overall core is designed to have a natural frequency well above the critical two-per-rev electromagnetic stimulus from the rotor. The axial length of the core is made up of many individual segments separated by radial ventilation ducts. The ducts at the core ends are made of stainless steel to reduce heating from end fringing flux. The flanges are made of cast iron to minimize losses. The unit will receive periodic pressing during stacking to ensure compactness and after stacking the core will receive a final press in excess of 635 metric tons (700 tons).

### ROTOR

The rotor is machined from a single high alloy steel forging. The two (2) pole design has twenty-four (24) axial slots machined radially in the main body of the shaft. The axial vent slots machined directly into the main coil slot are narrower than the main slots and provide the direct radial cooling of the field copper.

## FIELD ASSEMBLY

The field turns are made from high conductivity copper. Each turn will have vent slots punched in the slot portion of the winding to provide direct cooling of the field.

The collector assembly incorporates all the features of GE proven generator packages with slip on insulation over the shaft and under the rings. The collector rings use a radial stud design to provide electrical contact between the rings and the field leads.

The entire rotor assembly is balanced at speeds up to 20% over rate operating speed.

## END SHIELD/BEARING

The unit is equipped with end shields designed to support the rotor bearings prevent gas from escaping, and to withstand an internal hydrogen explosion in the unlikely event of such a mishap. The end shields are constructed from steel plate and are reinforced to provide the required strength and stiffness. The split at the horizontal joint allows for ease of assembly and removal. The horizontal joints as well as the vertical face which bolts to the end structure are machined to provide a gas tight joint. Grooves are machined into all these areas to accommodate sealing compounds which are injected into place during assembly. These steps are taken to prevent gas leakage between all the structural components for pressures up to 3 kg/cm2 g (45 psig).

The center section of the end shields contains the bearings, oil deflectors and hydrogen seals.

The hydrogen seal oil casings and seals, which prevents hydrogen from escaping along the shaft, utilize steel babbitted rings. Pressurized oil for the seals is supplied from the main oil system header to the seal oil control unit where it is filtered and regulated. The seal oil control unit is a factory assembled packaged system, is located in the collector end compartment.

The collector end bearing and hydrogen seals are insulated from the rotor to prevent direct electrical contact between the rotor and the end shield Where specified, both end shields will have proximity type vibration probes These are located axially outboard of the bearing. Mounting for velocity type vibration sensors is also provided on the surface of the bearing caps.

## WINDING

The armature winding consists of Class "F" insulated bars. The winding is three (3) phase, two (2) circuit design. The bar ground insulation is protected with a semi-conducting armor in the slot and GE's well proven grading system on the end arms.

The ends of the bars are pre-cut and solidified prior to insulation to allow strap brazing connections on each end after the bars are assembled. A resin impregnated insulation cap is used to insulate the end turn connections.

The bars are secured in the slot with both side ripple springs (SRS) to provide circumferential force and with a top ripple spring (TRS) for additional mechanical restraint in the radial direction. The SRSs, TRSs and the wedging system are well-proven reliable designs. The end winding support structure consists of glass binding bands, radial rings and the conformable resin-impregnated felt pads and glass roving to provide the rigid structure required for system electrical transients.

**LEAD CONNECTIONS**

The main armature leads are brought out at the bottom of the generator casing through the generator terminal plates via six (6) high voltage bushing at which point connection is made to the Purchaser's system. The bushing are made up of porcelain insulators containing silver plated, copper conductors which form a hydrogen tight seal. The bushings are assembled to non-magnetic terminal plates to minimize losses.

**LUBRICATION**

Lubrication for the generator is supplied by the turbine lubrication system. Lubricant feed and drain lines are provided as an integral part of the generator package.

**COOLING SYSTEM**

The generator is cooled by a recirculating gas stream cooled by gas-to-water heat exchangers. Cold gas is forced by the generator fans into the gas gap and also around the stator core. The stator is divided axially into sections by the web plates and outer wrapper. In the center section cold gas is force from the outside of the core toward the gap through the radial gas ducts. In the end section gas passes from the gas gap towards the outside of the core through the radial ducts. This arrangement results in substantially uniform cooling of the windings and core.

The rotor is cooled externally by the gas flowing along the gap over the rotor surface, and internally by the gas which passes over the rotor and winding through the rotor ventilating slots and radially outward to the gap and the through holes in the ventilating slot wedges.

After the gas has passed through the generator, it is directed to four vertically mounted gas-to-water heat exchangers. After the heat is remove cold gas is returned to the rotor fans and recirculated.

## COLLECTOR COMPARTMENT

An exciter-end enclosure will be provided separately. It will contain the following assemblies:

- Collector housing and brush rigging assembly
- Collector filters and silencers

All interconnecting piping and wiring will be completed and terminated convenient locations in the housing.

The enclosure is designed to be removable. Position of all the above hardware will be spaced to allow easy access for maintenance. Lighting with a switch is provided as standard.

## VOLTAGE REGULATOR

The generator field current and terminal voltage is controlled by a combined AC/DC (manual) regulator. The DC (manual) inter control loop controls generator field current with setpoint normally provided by the AC regulator output. The AC regulator controls generator terminal voltage with reactive current compensation.

# APPENDIX A7

## Combined Cycle Control System

## COMBINED CYCLE CONTROL SYSTEM

### INTRODUCTION

The control system for the combined cycle generation plant has been designed to provide the following features:

- Flexible Operation: The plant provides independent plant operating configurations at levels of automation which provide the user with complete flexibility in the starting and loading of the individual subsystems: combustion turbine (CT), Heat Recovery Steam Generator (HRSG), steam turbine (ST), and balance of plant (BOP).

- Safe Operation: Start-up and loading of the entire plant can be accomplished without risk to equipment from the central control room.

- Flexibility to accommodate the future addition of hardware and software.

- Color graphic operator stations.

- Installed spare I/0 and layout space for additional I/0.

### CONTROL SYSTEM DESCRIPTION

The control system for the gas turbine, HRSG, steam turbine and major balance of plant equipment (not packaged) utilizes a 32-bit microprocessor based Distributed Control System (DCS) on a data highway which permits automatic operation of the complete plant. The operator is provided with interface equipment, information and display devices, and protection devices to ensure confident, safe and efficient operation.

The control system, along with associated safety systems, is partitioned according to major plant subsystems, thereby increasing the plant availability and operating flexibility to meet the needs of the operator.

Using field proven hardware, the control system generates command signals to devices such as fuel, feedwater, condensate and steam flow control valves, combustion turbine inlet guide vanes, and display devices as a function of inputs from the plant sensors and operator inputs.

#### Control Levels

The control system allows the operation of major subsystems at two operating control levels, namely Operator Automatic Control Level and Manual Control Level.

1. Operator Automatic Control Level

   At this level, the system will automatically implement all the monitoring, controlling, operator's interface and primary information and display functions for each major subsystem. The system requires that the initial sequencing of the various major subsystems and loading are the responsibility of the operator.

2. Manual System Control

   The control system, through interactive operator stations, may be utilized to control selected equipment as long as it does not interfere with plant protection. Functions required to make the transition from the cold shutdown condition to the ready-to-start conditions are at the manual control level and include operating equipment such as: water and fuel supply block valves, drain valves and process pump controls.

**Operator Console(s) - Central Control Room**

The interactive operator console includes CRT's with color graphic displays and operator keyboards required to control the turbines and water and steam cycle. In addition, a single screen engineer's station is provided for the control system modifications, configurations, and maintenance.

The expected use of these CRT's is as follows:

- Overall plant summary
- Combustion turbine and HRSG
- Steam turbine
- Condenser
- Balance of plant
- Plant alarms

The consoles have preprogrammed color graphics pages with dynamic data update and various video enhancements such as reverse video, blinking, scrolling, etc. Pages will include:

1. Alarm Review - A list of all active alarms and their times of occurrence. Alarms will be highlighted until acknowledged. For the sequence of events alarms, the first out alarms are highlighted.

2. Maintenance Display for DCS equipment status

3. Selected Group Review

4. Data Trend

5. Quality of Points Review

6. Plant Graphics for each area of the plant

7. Annunciator Panel Graphic

The DCS graphics displays negate the need for a hard-wired alarm annunciator panel. The alarm annunciator graphic contains alarm "windows" to provide visual backup to critical alarms being printed on the alarm summary. It is expected that one CRT display will be dedicated to the alarm graphic.

The DCS graphics also negate the need for a mimic panel. Both high level and detailed P&ID type displays provide the operator a clear understanding of the process. Process schematics and the one line schematics are overlaid with real-time data to maximize operator's knowledge of system performance.

DCS graphics are arranged in a hierarchical or tree structure starting with the unit overall performance summary with branching into each major component; CT, HRSG, ST, condenser, and B.O.P.

In addition to the operator consoles, the central control room contains a hardware type critical operator panel with pushbuttons for tripping the combustion turbine, steam turbine.

**Plant Control Equipment**

Local control equipment is provided to control CT and ST functions as well as the continuous emissions monitoring system (CEMS). These local controls communicate with the control room DCS to provide a single point for plant control, operation and system status. GE will also provide PC’s for monitoring and control of the CT and ST as well as vibration monitoring.

Additionally, local instrument panels are located throughout the plant consisting of gages, transmitters, converters and transducers related to control and monitoring of the various processes.

DCS equipment located in the main control room include:

1. One (1) multiple CRT Operator console.
2. One (1) Engineer's console.
3. Plant logger.
4. Historical Storage and Retrieval.

DCS located remote from the control room include those that interface with:

1. Combustion turbine functions
2. Steam turbine functions
3. B.O.P. functions
4. HRSG and feedwater functions

## CONTROL PHILOSOPHY

The following control philosophy is used on individual major components and systems. This control philosophy permits efficient plant operation with a minimum of control room operators and roving plant operators.

- Sufficient and accurate information is provided at the central control room operator consoles to permit safe start-up/operation and rapid operator response to plant anomalies.

- It shall be necessary for the roving operators to place auxiliary equipment into operation manually at the equipment location or at a motor control center in order to establish ready-to-start status.

- The control system provides sufficient protective features to ensure safe operation. The system has built-in logic and circuitry to alarm, annunciate and trip as a result of any abnormal operating condition. Logic is employed to provide interlocks wherever it will improve plant availability and will prevent the operator from exceeding design limits.

- Major safety protection systems are inherent to the basic control system, such as overspeed trips, reverse current trip of the generator, etc. The use of such protection systems is in accord with accepted power plant practices. Manual trips are provided for all energy input components; e.g., fuel and steam valves.

### Combustion Turbine Control

The combustion turbine control system provides the operator with one-button automatic start-up from a cold condition to base load. When desired, the operator may elect to synchronize and load the generator manually from the electrical/control package, otherwise synchronization is automatic.

Start-up and operation of the combustion turbine requires status information which is generated by position switches, temperature measurements, pressure switches and other instrumentation. This information is sent to the control through transducers, amplifiers, isolation transformers, and other signal conditioning equipment.

### HRSG Control

For the High, Intermediate, and Low Pressure Drums, level control will be provided by feedwater control valves. Single element control is provided for start-up and at low loads, and three-element control for normal operation.

High Pressure Steam Temperature control will utilize the desuperheater spray control valve. A power operated vent valve is provided in the LP steam header.

Steam header vent valves as required by ASME code will be provided. Operator controls (open/close) for feedwater block valve operation will be provided from the control room console.

**Steam Turbine Bypass Valve(s) Control**

The steam bypass is provided with 100% capacity.

**Steam Turbine Control**

The steam turbine is controlled from the central control room. The steam turbine start-up is performed after the proper auxiliaries have been started manually and proper steam conditions are established in the HRSG.

The DCS provides full control and protection. The controller receives the process inputs from transducers, panel pushbuttons, and process relay contacts.

**LP Drum Level**

Condensate valves - Block and control valves will be provided. The control valve will have three-element low pressure (LP) drum level controls. The block valve will be operated by the operator and automatically closed by protective logic.

Central control room remote start-stop is provided for condensate and feedwater pumps.

# APPENDIX A8

## Plant Electrical Systems

## PLANT ELECTRICAL SYSTEMS

### INTRODUCTION

A major objective of this plant design is to promote safety, flexibility, reliability, economy and consistency in the electrical design effort, which also encompasses engineered mechanical "packages" that include electrical apparatus, materials and systems as an integral part.

The primary consideration in the design of the electrical system is that the plant must have external power from the utility system or other source to start. In addition, depending on length of shutdown and ambient conditions, some supplemental power for heating and/or cooling may be required before a start can be initiated.

The plant will have a 230 kV switchyard that will connect to a new transmission line within the BPA transmission line corridor just south of the facility. The new transmission line will terminate at BPA's Satsop Substation located 4000 feet to the east.

Revenue meters will be installed at the facility that will conform to BPA requirements. Communication link will be established with BPA to provide any information required by BPA.

The electrical system provides the necessary protection, control and utility interface requirements for the combustion turbine-generator, the steam turbine-generator, and the plant auxiliary power equipment.

The major components are:

1. 230 kV radial switchyard
2. 18kV - 230 kV generator stepup transformers
3. 18kV - 4.16 kV unit Auxiliary Transformer
4. 18kV generator Circuit Breakers
5. kV switchgear and motor controllers
6. 4.16-0.48 kV auxiliary power transformers
7. 480 V auxiliary AC system
8. 125 V auxiliary DC system

The single line diagram depicts the major electrical system and devices. Synchronization of the CTG and STG will be accomplished across their respective 230 kV circuit breakers.

### 230 KV SWITCHYARD

The switchyard is a conventional, open air, radial bus design that transforms the generator outputs from 18 kV to 230 kV for delivery via one outgoing 230 kV transmission line circuit.

The switchyard consists of three generator stepup transformers, three 230 kV power circuit breakers, disconnect switches, instrument transformers, surge arresters, substation steel structures, a separate control room and protective relaying equipment.

The combustion turbine generator and steam turbine generator are each connected to their own two-winding; outdoor, oil filled stepup transformer rated 18-230 kV.

The power circuit breakers are a three-phase, dead tank, SF-6 puffer design rated 242 kV, 1200 A. The disconnect switches are three-pole, air insulated, gang operated devices rated 242 kV, 1200 A continuous.

**18 - 230 kV Generator Stepup Transformers**

The generators are connected to the 230 kV transmission system through their respective outdoor, two-winding, three-phase, oil filled stepup transformer via 18 kV isolated phase bus duct.

**18 - 4.16 kV Station Auxiliary Transformer**

The outdoor, three phase, oil filled station auxiliary transformers are rated for full capacity for plant auxiliary loads. The power supply to this transformer is from an 18 kV tap point in the isolated phase.

**4.16 kV Switchgear and Motor Controllers**

Vacuum type metal-clad switchgear assemblies rated 4.16 kV, 3000 A are provided to serve the medium voltage motor controllers. Protective relays, current and voltage transformers and indicating meters are provided as required.

The 4.16-0.48 kV auxiliary transformers are served from metal-clad switchgear breakers.

Medium voltage motor controllers are provided to serve motor loads larger than 200 HP. These starters include an isolation switch and fuses in series with 400 A or 800 A vacuum contactors to provide coordinated overload and fault protection for the motor circuits.

**4.16-0.48 kV Auxiliary Power Transformers**

Outdoor, oil filled transformers rated at 4160V delta - 480V Wye are provided to feed 480 V switchgear and motor control centers.

**480 V Auxiliary AC System**

AC Motor Control Centers are used for power distribution and control of the various low voltage auxiliary loads of the combustion turbine, steam turbine, and cooling tower.

The 480V Motor Control Centers contain the majority of starter assemblies for the auxiliary load of the plant. Combination starters incorporating type HMCP motor circuit protectors are supplied for motors. The HMCP is designed specifically for motor circuits and provides optimum protection with maximum convenience. Operating on the magnetic principle, the breaker incorporates three sensors with a single trip point adjustment. In this way, protection is customized for each individual motor.

**125 V Auxiliary DC System**

Emergency power at the main plant is afforded through station batteries and an uninterruptible power supply to provide power for critical processes and instrumentation/ control system loads to effect a safe and orderly shutdown of facility operation.

Components included in this system are located in the turbine building and are:

- Battery System
- Battery Chargers
- DC Motor Control Centers
- Uninterruptible Power Supply

**BATTERY SYSTEM**

The battery system comprises sixty (60) lead-acid type cells and provides 125 Vdc.

The batteries are rack mounted in a separate ventilated room in the turbine building.

**BATTERY CHARGER**

The battery charger fulfills the dual function of providing power to the DC bus during normal operation as well as maintaining a float charge on the unit battery.

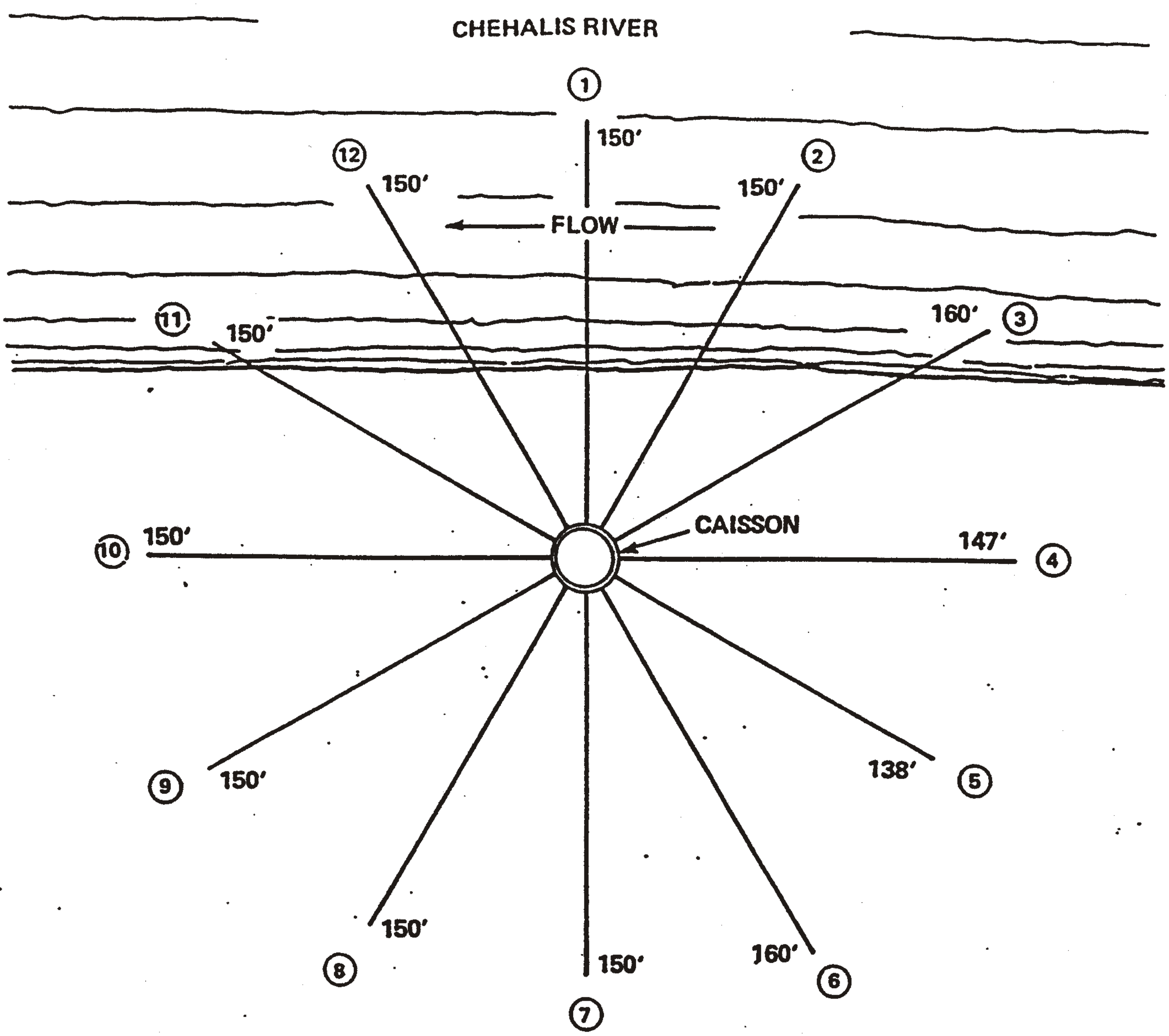
The charger contains a solid-state rectifier and front mounted output voltmeter and ammeter. Three phase power is supplied to the charger from a 480V Motor Control Center. Output 125 volt DC voltage is automatically regulated to ± 1 % with load variations of 0 to 100%. A low voltage relay provides an alarm if the DC bus voltage drops to a dangerously low level.

**UNINTERRUPTIBLE POWER SUPPLY**

The uninterruptible power supply provides 120V AC single-phase power for critical loads in the central control room and in the combustion turbine Electrical/Control Package. The UPS system consists of an inverter, a static switch, a manual bypass switch, a regulated alternate power source, and an AC panelboard. DC power is provided from the battery system.

# Appendix B

# Ranney Well Water Quality Information

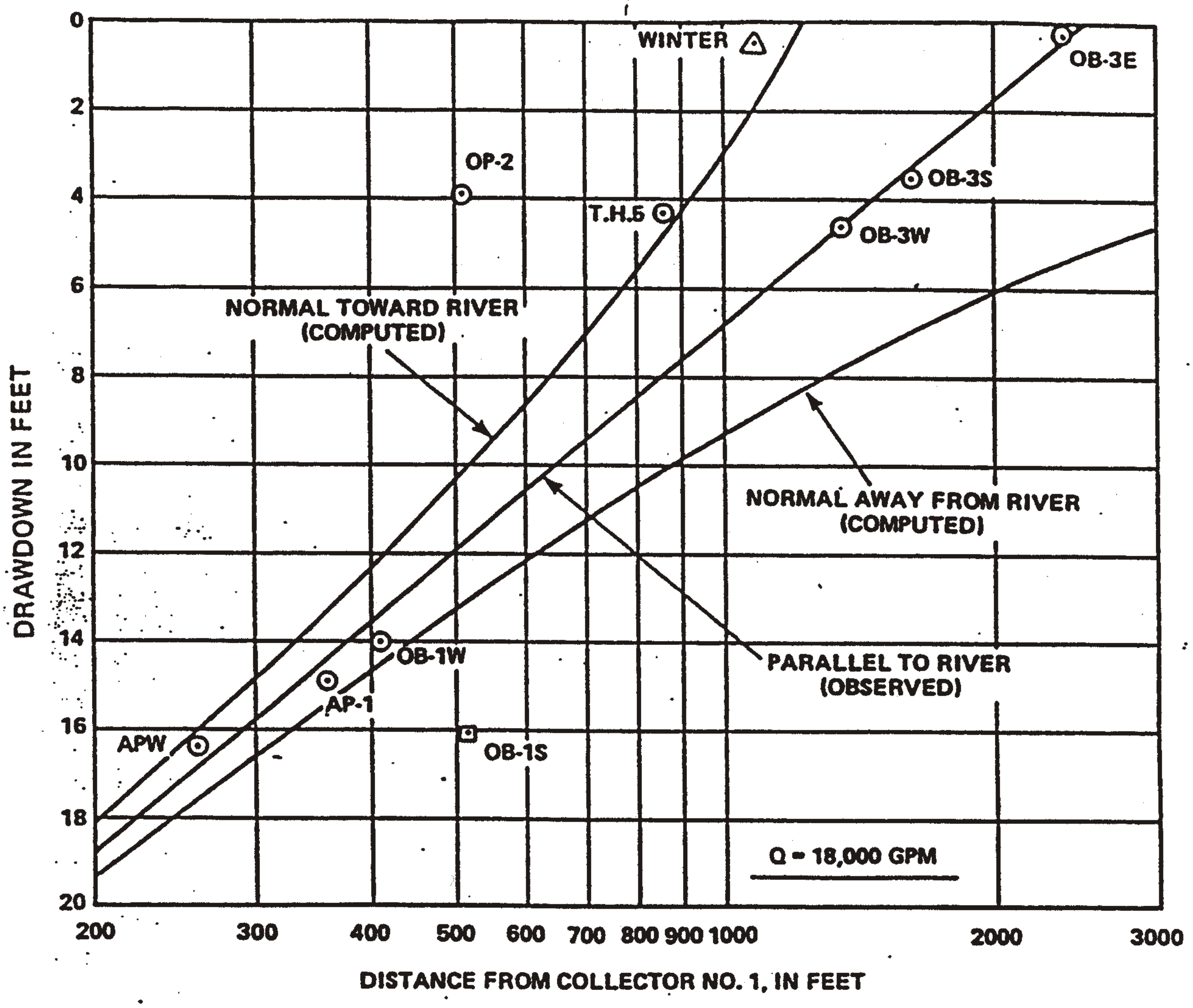



LATERAL PROJECTION DIAGRAM

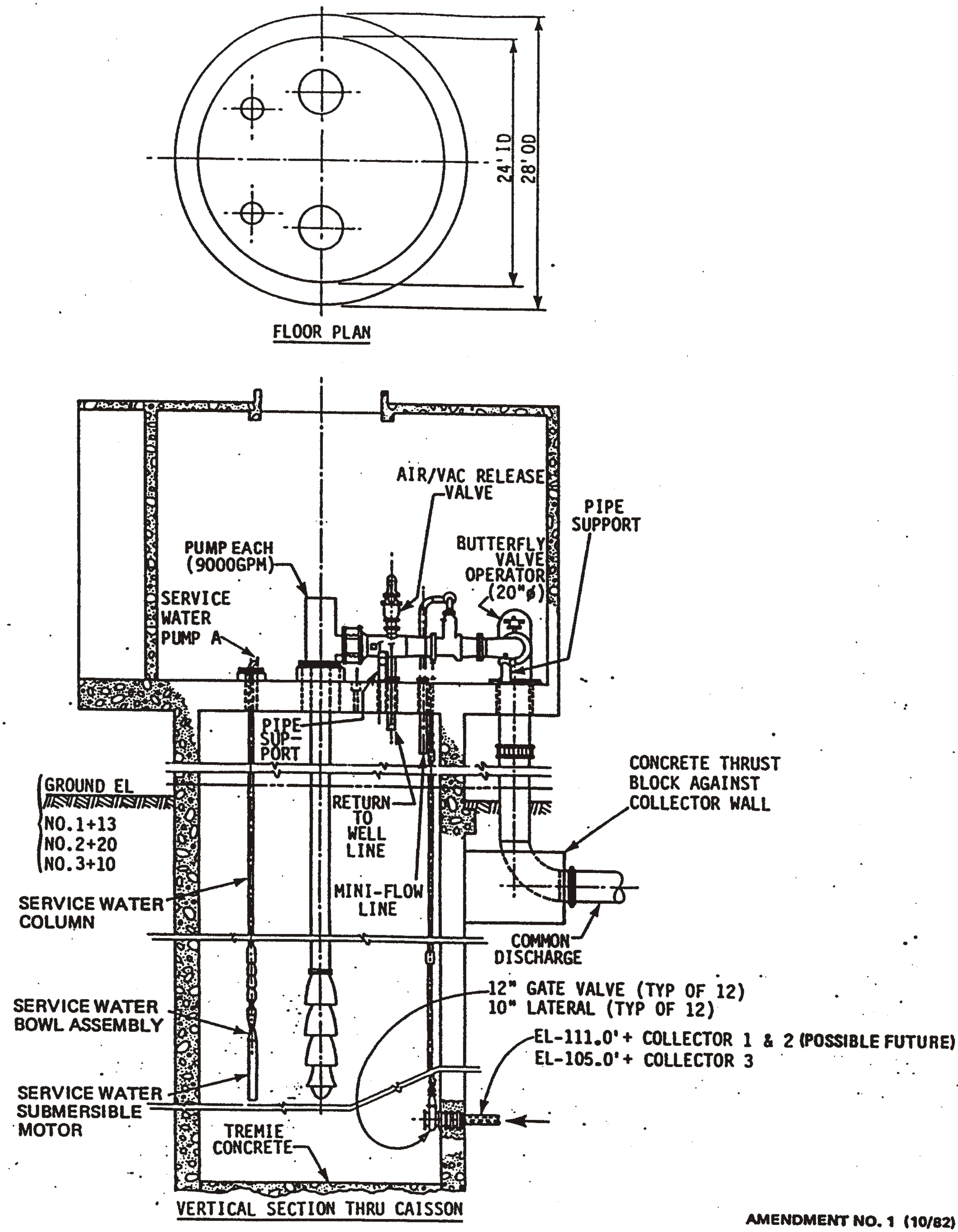
(1" = 60')

| | ELEV. IN FEET (MSL) |
|---|---|
| TOP OF CAISSON | + 20.0 |
| GROUND | + 13.0 |
| LATERALS | −111.0 |
| TOP OF PLUG | −116.0 |
| CUTTING SHOE | −125.5 |

| WASHINGTON PUBLIC POWER SUPPLY SYSTEM<br>Nuclear Projects 3 & 5<br>FINAL SAFETY ANALYSIS REPORT | LATERAL PROJECTION DIAGRAM<br>RANNEY COLLECTOR NO. 1 | FIGURE<br>2.4-40 |
|---|---|---|




| WASHINGTON PUBLIC POWER SUPPLY SYSTEM<br>Nuclear Projects 3 & 5<br>FINAL SAFETY ANALYSIS REPORT | DISTANCE – DRAWDOWN GRAPH<br>RANNEY COLLECTOR NO. 1 | FIGURE<br>2.4-41 |
|---|---|---|




AMENDMENT NO. 1 (10/82)

| WASHINGTON PUBLIC POWER SUPPLY SYSTEM<br>Nuclear Projects 3 & 5<br>FINAL SAFETY ANALYSIS REPORT | HORIZONTAL GROUNDWATER COLLECTOR (RANNEY SYSTEM) | FIGURE<br>2.4-35 |
|---|---|---|

RANNEY WELL WATER QUALITY

| Parameter | Well # Sample Date #1 Jan-31-89 |
|---|---|
| Arsenic | <0.005 |
| Barium | <0.02 |
| Cadmium | <0.002 |
| Chloride | ND |
| Chromium | <0.005 |
| Color (Units) | ND |
| Copper | 0.003 |
| Fluoride | <0.2 |
| Hardness | ND |
| Iron | 0.10 |
| Lead | <0.01 |
| Manganese | 0.004 |
| Mercury | <0.001 |
| Nickel | <0.01 |
| Nitrate + Nitrite - N | 0.73 |
| pH | 7.0 |
| Selenium | <0.005 |
| Silver | <0.002 |
| Sodium | 7 |
| Specific Conductance (mho/cm) | 140 |
| Sulfate | 5 |
| Total Dissolved Solids | 110 |
| Turbidity (NTU) | ND |
| Zinc | 0.027 |

ND = No Data

Reference: Supply System, 1989

# RAW WELL WATER QUALITY

(WELL LOCATED AT THE CONFLUENCE OF THE SATSOP AND CHEHALIS RIVERS)

| Parameter | Sample Date<br>Sep-27-78 | Jun-29-82 | Jan-6-83 | Jul-29-83 | Apr-24-91 | Jul-21-92 |
|---|---|---|---|---|---|---|
| Arsenic | <0.010 | <0.01 | <0.01 | <0.01 | <0.010 | <0.010 |
| Barium | <0.25 | <0.25 | <0.25 | <0.25 | <0.25 | <0.25 |
| Cadmium | <0.002 | <0.002 | <0.002 | <0.002 | <0.002 | <0.002 |
| Chloride | ND | 17 | <10 | ND | <10 | <10 |
| Chromium | <0.010 | <0.01 | <0.01 | <0.010 | <0.010 | <0.010 |
| Color (Units) | <5 | 5 | <5 | ND | <5 | <5 |
| Copper | ND | ND | ND | ND | <0.3 | 0.020 |
| Fluoride | <0.2 | <0.2 | <0.2 | <0.2 | <0.2 | <0.2 |
| Hardness | 50 | 32 | 39 | 34 | 0 | 30 |
| Iron | <0.05 | 0.06 | <0.05 | <0.05 | <0.05 | 3.80 |
| Lead | 0.017 | <0.01 | <0.01 | <0.01 | <0.005 | <0.002 |
| Manganese | <0.010 | <0.01 | <0.01 | <0.010 | 0.028 | 0.045 |
| Mercury | <0.001 | <0.001 | <0.001 | <0.001 | <0.001 | <0.001 |
| Nitrate + Nitrite - N | ND | ND | ND | ND | ND | ND |
| Nitrate - N | 0.5 | 0.68 | 0.4 | 0.3 | 1.7 | <0.2 |
| Selenium | <0.003 | <0.005 | <0.005 | <0.005 | <100.000 | <0.005 |
| Silver | <0.010 | <0.01 | <0.01 | <0.010 | <0.010 | <0.010 |
| Sodium | ND | <10 | <10 | <10 | <10 | <10 |
| Specific Conductance (mho/cm) | 90 | 130 | 90 | ND | 140 | 78 |
| Sulfate | ND | ND | ND | ND | <10 | <10 |
| Turbidity (NTU) | 0.3 | <0.5 | 0.8 | ND | <0.5 | 6.0 |
| Zinc | ND | ND | ND | ND | <0.3 | <0.2 |

ND = No Data

Reference: Supply System, 1978 to 1992

## DOMESTIC WELL WATER QUALITY IN THE VICINITY OF THE SATSOP POWER PLANT

| Parameter | Well # / Sample Date: Saginaw Laydown Sep-12-79 | Saginaw Laydown Oct-10-79 | Saginaw Laydown Jun-18-80 | Witner* Nov-80 | Brumfield* Nov-80 | Coker* Nov-80 |
|---|---|---|---|---|---|---|
| Arsenic | <0.001 | <0.004 | <0.001 | 0.03 | 0.03 | 0.012 |
| Barium | <0.10 | <0.10 | <0.10 | 0.03 | 0.02 | 0.04 |
| Cadmium | <0.0001 | 0.0001 | <0.0001 | <0.01 | <0.01 | <0.01 |
| Chloride | 3.3 | 2.1 | 3.9 | 4.0 | 3.8 | 4.5 |
| Chromium | <0.0005 | <0.0005 | <0.0005 | <0.01 | <0.01 | <0.01 |
| Color (Units) | 10 | 10 | 25 | 2.3 | <1 | <1 |
| Fluoride | 0.122 | 0.109 | 0.18 | 0.1 | 0.1 | 0.1 |
| Hardness | 51 | 84 | 68 | 79 | 52 | 25 |
| Iron | 0.89 | 7.0 | 3.1 | 1.18 | 0.28 | 0.08 |
| Lead | <0.001 | 0.007 | 0.003 | 0.003 | 0.007 | 0.005 |
| Manganese | 0.26 | 0.57 | 0.38 | <0.01 | <0.01 | <0.01 |
| Mercury | <0.0002 | <0.0002 | <0.0002 | <0.0001 | <0.0001 | 0.0001 |
| Nitrate + Nitrite - N | <0.010 | <0.010 | <0.010 | ND | ND | ND |
| Nitrate - N | ND | ND | ND | 0.7 | 0.1 | 1.8 |
| Selenium | <0.002 | <0.002 | <0.002 | 0.003 | 0.002 | 0.004 |
| Silver | <0.0003 | <0.0003 | <0.0003 | <0.01 | <0.01 | <0.01 |
| Sodium | 11.1 | 14.8 | 11.9 | ND | ND | ND |
| Specific Conductance (mho/cm) | 150 | 225 | 181 | 191 | 149 | 112 |
| Sulfate | 3.3 | <1.0 | <1.0 | ND | ND | ND |
| Turbidity (NTU) | 10 | 46 | 14 | 1.2 | 3.1 | 0.4 |

*Wells located in the vicinity of the Ranney well field.

ND = No Data

Reference: Supply System, 1979 to 1980

## MAKEUP WELL WATER QUALITY[a]

| Parameter | Concentration[b] |
|---|---|
| Biochemical Oxygen Demand | <1 |
| Chemical Oxygen Demand | <5 |
| Ammonia (as N) | <0.0005 |
| Total Organic Carbon | <2 |
| Bromide | 0.30 |
| Color (Color Units) | 0 |
| Fecal Coliform (MF) (colonies/100ml | <2 |
| Fluoride | 0.122 |
| Nitrate + Nitrate (as N) | 0.54 |
| Total Organic Nitrogen (as N) | <0.50 |
| Oil and Grease | <1 |
| Total Phosphorus (as P) | 0.240 |
| Sulfate | 2.7 |
| Sulfide | <0.10 |
| Surfactants (LAS-mg/l | <0.01 |
| Gross Alpha (picocuries/l) | <0.60 |
| Gross Beta (picocuries/l) | <10 |
| Aluminum | <0.10 |
| Boron | <0.01 |
| Cobalt | <0.001 |
| Molybdenum | <0.001 |
| Tin | <0.03 |
| Titanium | 0.018 |
| Antimony | <0.15 |
| Arsenic | <0.001 |
| Beryllium | <0.003 |
| Silver | <0.0003 |
| Thallium | 0.008 |
| Total Cyanide | <0.003 |
| Phenol | <0.004 |
| Iron | 0.017 |
| Maganese | <0.001 |
| Barium | <0.10 |
| Cadmium | <0.0001 |
| Chromium | 0.0006 |
| Copper | <0.001 |
| Lead | <0.001 |
| Mercury | <0.0002 |
| Nickel | 0.002 |
| Selenium | <0.002 |
| Zinc | 0.005 |
| Magnesium | 4.0 |

(a) Ranney Collector No. 1 test of November 25, 1980.
(b) Units of mg/l or as indicated.

ER-OL, 1982

## CHEMICAL ANALYSES OF GROUNDWATER IN THE CHEHALIS RIVER BASIN[a]

| Well Number | Owner or Tenant | Parts Per Million: Hardness ($CaCO_3$) | Iron (Fe) | Sulfate ($SO_4$) | Chloride (Cl) | Nitrate ($NO_3$) | Dissolved Solids | Well Depth |
|---|---|---|---|---|---|---|---|---|
| 17/6-1C1 | Chris Wheeler | 22 | 0.04 | 4.4 | 3.0 | 3.5 | 67 | 76 |
| 17/6-4D1 | City of Elma | 24 | 0.00 | 2.1 | 4.0 | 1.9 | 58 | 40 |
| 17/7-7P1 | Weyerhaeuser Timber Company | 92 | 1.20 | - | 37.0 | - | - | 201 |
| 17/7-8Q1 | " | 60 | 0.50 | - | 11.0 | - | - | 141 |
| 17/7-9H1 | " | 51 | 0.30 | - | 20.2 | - | - | 160 |
| 17/7-9H2 | " | 50-54 | 0.03-0.11 | - | 9.5-12 | - | - | 102 |
| 17/7-9P1 | " | 50 | 0.20 | - | 11.0 | - | - | 153 |
| 17/7-11B1 | Earl Richard | 62 | 2.40 | 0.6 | 2.8 | 0.7 | 106 | 50 |
| 17/7-11E1 | Robert Smith | 76 | 0.73 | 0.6 | 3.2 | 0.2 | 119 | 36 |
| 17/7-11H1 | Milton Larson | 52 | 0.19 | 4.2 | 3.5 | 3.5 | 93 | 10 |
| 17/7-11K1 | G. W. Streiter | 58 | 0.29 | 4.0 | 4.0 | 0.6 | 108 | 51 |
| 17/7-11P1 | Weyerhaeuser Timber Company | 54 | 0.6-1.7 | - | 1.2 | - | - | 188 |
| 17/8-14K1 | " | 50 | 0.30 | - | 12-16 | - | - | 180 |
| 18/6-31H1 | Erling Olson | 52 | 0.33 | 2.6 | 3.5 | 0.1 | 100 | 98 |
| 18/12-27F1 | Frank Minard | 26 | 0.33 | 2.9 | 11.0 | 0.1 | 127 | 358 |

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(a) ER-OL, 1982

Laucks 85
Testing Laboratories, Inc.
940 South Harney St., Seattle, WA 98108 (206) 767-5060 FAX 767-5063
Chemistry, Microbiology, and Technical Services

REPORT ON SAMPLE: 9309633-02
Client Sample ID: Well #3

Date Received : 09/17/93 Collection Date : 09/13/93

| Test | MCL | | Results | Units |
|---|---|---|---|---|
| Antimony | 0.006 | < | 0.0020 | mg/L |
| Arsenic | 0.05 | < | 0.010 | mg/L |
| Barium | 2.0 | < | 0.20 | mg/L |
| Beryllium | 0.004 | < | 0.0010 | mg/L |
| Cadmium | 0.005 | < | 0.0020 | mg/L |
| Chromium | 0.1 | < | 0.010 | mg/L |
| Copper | 1.0* | < | 0.1 | mg/L |
| Iron | 0.8 | < | 0.10 | mg/L |
| Lead | 0.05* | < | 0.002 | mg/L |
| Manganese | 0.05 | < | 0.010 | mg/L |
| Mercury | 0.002 | < | 0.0010 | mg/L |
| Nickel | 0.1 | < | 0.005 | mg/L |
| Selenium | 0.05 | < | 0.005 | mg/L |
| Silver | 0.1 | < | 0.001 | mg/L |
| Thallium | 0.002 | < | 0.0010 | mg/L |
| Zinc | 5.0 | | 0.1 | mg/L |
| Hardness | | | 77 | mg/L, as CaCO3 |
| Conductivity | 700 | | 160 | Micromhos/cm, 25°C |
| Turbidity | 1.0 | < | 0.5 | NTU |
| Color | 15.0 | < | 5.0 | Color Units |
| Chloride | 250 | < | 10 | mg/L |
| Cyanide | 0.2 | < | 0.01 | mg/L |
| Fluoride | 2.0 | < | 0.2 | mg/L |
| Nitrate | 10.0 | | 0.9 | mg/L |
| Nitrite | 1.0 | < | 0.1 | mg/L |
| Sulfate | 250 | < | 10 | mg/L |

MCL = Maximum Contamination Level established for drinking water under current EPA and State of Washington regulations. No MCL has been established for hardness or sodium, although 20 mg/L is a recommended MCL for sodium.

* = This is the Washington State MCL. Federal action levels are 0.015 mg/L for lead and 1.3 mg/L for copper.

Reference: Supply System, 1993

Laucks 85
Testing Laboratories, Inc.
940 South Harney St., Seattle, WA 98108 (206) 767-5060 FAX 767-5063
Chemistry, Microbiology, and Technical Services

REPORT ON SAMPLE: 9309633-01
Client Sample ID: Well #1

Date Received : 09/17/93 Collection Date : 09/13/93

| Test | MCL | | Results | Units |
|---|---|---|---|---|
| Antimony | 0.006 | < | 0.0020 | mg/L |
| Arsenic | 0.05 | < | 0.010 | mg/L |
| Barium | 2.0 | < | 0.20 | mg/L |
| Beryllium | 0.004 | < | 0.0010 | mg/L |
| Cadmium | 0.005 | < | 0.0020 | mg/L |
| Chromium | 0.1 | < | 0.010 | mg/L |
| Copper | 1.0* | < | 0.1 | mg/L |
| Iron | 0.3 | | 0.16 | mg/L |
| Lead | 0.05* | < | 0.002 | mg/L |
| Manganese | 0.05 | < | 0.010 | mg/L |
| Mercury | 0.002 | < | 0.0010 | mg/L |
| Nickel | 0.1 | < | 0.005 | mg/L |
| Selenium | 0.05 | < | 0.005 | mg/L |
| Silver | 0.1 | < | 0.001 | mg/L |
| Sodium | | < | 10 | mg/L |
| Thallium | 0.002 | < | 0.0010 | mg/L |
| Zinc | 5.0 | | 0.1 | mg/L |
| Hardness | | | 32 | mg/L, as CaCO3 |
| Conductivity | 700 | | 110 | Micromhos/cm, 25°C |
| Turbidity | 1.0 | | 1.0 | NTU |
| Color | 15.0 | < | 5.0 | Color Units |
| Chloride | 250 | < | 10 | mg/L |
| Cyanide | 0.2 | < | 0.01 | mg/L |
| Fluoride | 2.0 | < | 0.2 | mg/L |
| Nitrate | 10.0 | | 0.9 | mg/L |
| Nitrite | 1.0 | < | 0.1 | mg/L |
| Sulfate | 250 | < | 10 | mg/L |

MCL = Maximum Contamination Level established for drinking water under current EPA and State of Washington regulations. No MCL has been established for hardness or sodium, although 20 mg/L is a recommended MCL for sodium.

* = This is the Washington State MCL. Federal action levels are 0.01 mg/L for lead and 1.3 mg/L for copper.

Reference: Supply System, 1993

7

MEANS AND RANGES OF PARAMETERS FOR METALS MONITORING PROGRAM AT WELL APW, 5 NOVEMBER 1980 - 28 OCTOBER 1981



| | | First Quarter, 5 November 1980 - 4 February 1981 | | | Second Quarter, 11 February 1981 - 29 April 1981 | | | Third Quarter, 6 May 1981 - 29 July 1981 | | | Fourth Quarter, 5 August 1981 - 28 October 1981 | | | Entire Year, 5 November 1980 - 28 October 1981 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | EPA (1980) Criteria |
| Chromium (µg/l) | T | 0.6 | <0.5-1.0 | 12 | 0.8 | <0.5-1.2 | 11 | 0.5 | <0.5-0.9 | 13 | <0.5 | <0.5-1.0 | 13 | 0.6 | <0.5-1.2 | 49 | |
| | D | 0.6 | <0.5-0.8 | 12 | 0.7 | <0.5-1.2 | 11 | <0.5 | <0.5-0.6 | 13 | <0.5 | <0.5-1.0 | 13 | 0.5 | <0.5-1.2 | 49 | |
| Nickel (µg/l) | T | <1 | <1-5 | 12 | <1 | <1-2 | 11 | 1 | <1-10 | 13 | <1 | <1-1 | 13 | <1 | <1-10 | 49 | 60/1155 |
| | D | <1 | <1-5 | 12 | <1 | <1-1 | 11 | <1 | all <1 | 13 | <1 | all <1 | 13 | <1 | <1-5 | 49 | |
| Iron (µg/l) | T | 11 | <1-60 | 12 | 23 | 2-90 | 11 | 17 | 1-80 | 13 | 14 | <1-50 | 13 | 16 | <1-90 | 49 | 1000 |
| | D | 4 | <1-14 | 12 | 8 | <1-26 | 11 | 13 | <1-80 | 13 | 7 | <1-40 | 13 | 8 | <1-80 | 49 | |
| Zinc (µg/l) | T | <5 | all <5 | 12 | <5 | all <5 | 11 | <5 | all <5 | 13 | <5 | <5-7 | 13 | <5 | <5-7 | 49 | 47/193 |
| | D | <5 | all <5 | 12 | <5 | all <5 | 11 | <5 | all <5 | 13 | <5 | all <5 | 13 | <5 | all <5 | 49 | |
| Copper (µg/l) | T | <1 | <1-1 | 12 | 1 | <1-7 | 11 | <1 | <1-2 | 13 | <1 | <1-3 | 13 | <1 | <1-7 | 49 | 5.6/12 |
| | D | <1 | all <1. | 12 | <1 | <1-4 | 11 | <1 | <1-1 | 13 | <1 | <1-1 | 13 | <1 | <1-4 | 49 | |
| Cadmium (µg/l) | T | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 3 | 0.1 | <0.1-0.2 | 3 | <0.1 | all <0.1 | 3 | <0.1 | <0.1-0.2 | 12 | 0.013/1.6 |
| | D | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 12 | |
| Lead (µg/l) | T | <1 | all <1 | 3 | <1 | all <1 | 3 | <1 | <1-1 | 3 | <1 | all <1 | 3 | <1 | <1-1 | 12 | 0.90/81 |
| | D | <1 | all <1 | 3 | <1 | all <1 | 3 | <1 | all <1 | 3 | <1 | all <1 | 3 | <1 | all <1 | 12 | |
| Barium (µg/l) | T | 2a/ | | 1 | 6 | 2-12 | 3 | 2 | 2-3 | 3 | 6 | 3-11 | 3 | 4 | 2-12 | 10 | |
| | D | 2a/ | | 1 | 3 | 2-4 | 3 | 2 | all 2 | 3 | 5 | 3-10 | 3 | 3 | 2-10 | 10 | |
| Manganese (µg/l) | T | 2 | <1-4 | 3 | 1 | <1-2 | 3 | <1 | <1-1 | 3 | <1 | <1-1 | 3 | 1 | <1-4 | 12 | |
| | D | 1 | <1-3 | 3 | 1 | <1-2 | 3 | <1 | all <1 | 3 | <1 | all <1 | 3 | <1 | <1-3 | 12 | |
| Mercury (µg/l) | T | <0.2 | all <0.2 | 3 | 0.2 | <0.2-0.4 | 3 | <0.2 | all <0.2 | 3 | 0.3 | <0.2-0.7 | 3 | <0.2 | <0.2-0.7 | 12 | 0.20/4.1 |
| Selenium (µg/l) | T | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 12 | 35/260 |
| | D | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 12 | |
| Calcium (mg/l) | D | 12.0 | | 1 | 11.0 | | 1 | 13.1 | | 1 | 12.2 | | 1 | 12.1 | 11.0-13.1 | 4 | |
| Magnesium (mg/l) | D | 3.9 | | 1 | 4.4 | | 1 | 4.1 | | 1 | 4.8 | | 1 | 4.3 | 3.9-4.8 | 4 | |
| Potassium (mg/l) | D | 0.71 | | 1 | 0.67 | | 1 | 0.65 | | 1 | 0.77 | | 1 | 0.70 | 0.65-0.77 | 4 | |

MEANS AND RANGES OF PARAMETERS FOR METALS MONITORING PROGRAM AT WELL APW, 5 NOVEMBER 1980 - 28 OCTOBER 1981

| | First Quarter, 5 November 1980 - 4 February 1981 | | | Second Quarter, 11 February 1981 - 29 April 1981 | | | Third Quarter, 6 May 1981 - 29 July 1981 | | | Fourth Quarter, 5 August 1981 - 28 October 1981 | | | Entire Year, 5 November 1980 - 28 October 1981 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | EPA (1980) Criteria |
| Sodium (mg/l) D | 6.5 | | 1 | 5.6 | | 1 | 6.2 | | 1 | 5.7 | | 1 | 6.0 | 5.6-6.5 | 4 | |
| Hardness (mg/l as $CaCO_3$) | 55 | | 1 | 54 | 49-60 | 11 | 54 | 52-58 | 13 | 53 | 51-56 | 13 | 54 | 49-60 | 38 | |
| Alkalinity (mg/l as $CaCO_3$) | 64 | | 1 | 56 | 56-57 | 11 | 55 | 53-58 | 13 | 56 | 51-58 | 13 | 56 | 51-64 | 38 | 20 (min) |
| Temperature (°C) | 10.6 | 10.5-10.6 | 12 | 10.5 | 10.4-10.6 | 11 | 10.6 | 10.4-10.7 | 13 | 10.6 | 10.6-10.8 | 13 | 10.6 | 10.4-10.8 | 49 | |
| pH | 6.9[b,d] | 6.6-7.1 | 11 | 6.9[b,d] | 6.6-6.9 | 11 | 7.4[b,c]<br>6.9[b,d] | 7.4-7.5<br>all 6.9 | 8<br>5 | 7.3[b,c] | 7.2-7.4 | 13 | 7.4[b,c]<br>6.9[b,c] | 7.2-7.5<br>6.6-7.1 | 21<br>27 | 6.5-9.0 |
| Conductivity (µmhos/cm at 25°C) | 110 | | 1 | 117 | 112-121 | 11 | 119 | 115-121 | 13 | 117 | 114-119 | 13 | 117 | 110-121 | 38 | |

a/ Two other barium samples were taken during this quarter but were analyzed using flame AA instead of graphite furnace AA due to an equipment malfunction. Both samples analyzed by flame AA were reported as <100 µg/l and are not included in this table due to the high detection limit.

b/ Median.

c/ A new pH electrode was used beginning on 10 June. The mean and range given are for the samples analyzed with the new electrode.

d/ Values for samples analyzed with old pH electrode (samples prior to 10 June).

Envirosphere, 1982

MEANS AND RANGES OF PARAMETERS FOR METALS MONITORING
PROGRAM AT INTAKE AREA, 5 NOVEMBER 1980 - 28 OCTOBER 1981

| | | First Quarter, 5 November 1980 - 4 February 1981 | | | Second Quarter, 11 February 1981 - 29 April 1981 | | | Third Quarter, 6 May 1981 - 29 July 1981 | | | Fourth Quarter, 5 August 1981 - 28 October 1981 | | | Entire Year, 5 November 1980 - 28 October 1981 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | EPA (1980) Criteria |
| Chromium (µg/l) | T | 1.3 | 0.6-3.3 | 12 | 1.8 | 0.8-3.8 | 11 | 0.5 | <0.5-0.8 | 13 | 1.4 | <0.5-10.8 | 13 | 1.2 | <0.5-10.8 | 49 | |
| | D | 0.7 | <0.5-1.0 | 12 | 1.1 | <0.5-3.3 | 12 | <0.5 | <0.5-0.6 | 13 | <0.5 | <0.5-0.6 | 13 | 0.6 | <0.5-3.3 | 50 | |
| Nickel (µg/l) | T | 2 | <1-4 | 12 | 2 | <1-14 | 12 | 1 | <1-3 | 13 | 1 | <1-6 | 13 | 1 | <1-14 | 50 | 37/720 |
| | D | <1 | <1-2 | 12 | <1 | <1-1 | 12 | <1 | all <1 | 13 | <1 | <1-3 | 13 | <1 | <1-3 | 50 | |
| Iron (µg/l) | T | 1063 | 200-2870 | 12 | 1397 | 300-7400 | 12 | 421 | 270-830 | 13 | 622 | 80-3905 | 13 | 861 | 80-7400 | 50 | 1000 |
| | D | 70 | 40-130 | 12 | 109 | 30-820 | 12 | 122 | 26-280 | 13 | 88 | 13-160 | 13 | 98 | 13-820 | 50 | |
| Zinc (µg/l) | T | 5 | <5-21 | 12 | <5 | <5-24 | 12 | <5 | all <5 | 13 | 6 | <5-37 | 13 | <5 | <5-37 | 50 | 47/115 |
| | D | <5 | <5-9 | 12 | <5 | all <5 | 12 | <5 | all <5 | 13 | <5 | <5-7 | 13 | <5 | <5-9 | 50 | |
| Copper (µg/l) | T | 2 | <1-6 | 12 | 2 | 1-7 | 12 | 2 | 1-5 | 13 | 3 | <1-8 | 13 | 2 | <1-8 | 50 | 5.6/6.9 |
| | D | <1 | <1-2 | 12 | 1 | <1-2 | 12 | 1 | 1-2 | 13 | 1 | <1-3 | 13 | 1 | <1-3 | 50 | |
| Cadmium (µg/l) | T | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 3 | <0.1 | <0.1-0.1 | 3 | 0.2 | <0.1-0.5 | 3 | <0.1 | <0.1-0.5 | 12 | 0.007/0.82 |
| | D | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 3 | <0.1 | all <0.1 | 12 | |
| Lead (µg/l) | T | <1 | <1-1 | 3 | <1 | all <1 | 3 | <1 | <1-1 | 3 | 12 | <1-36 | 3 | 4 | <1-36 | 12 | 0.21/38 |
| | D | <1 | all <1 | 3 | <1 | all <1 | 3 | <1 | all <1 | 3 | <1 | all <1 | 3 | <1 | all <1 | 12 | |
| Barium (µg/l) | T | 8a/ | | 1 | 12 | 10-15 | 3 | 6 | 6-7 | 3 | 11 | 6-22 | 3 | 10 | 6-22 | 10 | |
| | D | 6a/ | | 1 | 8 | 6-9 | 3 | 5 | 4-5 | 3 | 8 | 6-12 | 3 | 7 | 4-12 | 10 | |
| Manganese (µg/l) | T | 26 | 18-30 | 3 | 33 | 20-39 | 3 | 23 | 21-25 | 3 | 35 | 11-80 | 3 | 29 | 11-80 | 12 | |
| | D | 8 | 6-9 | 3 | 12 | 6-19 | 3 | 8 | 7-9 | 3 | 9 | 7-10 | 3 | 9 | 6-19 | 12 | |
| Mercury (µg/l) | T | <0.2 | all <0.2 | 3 | 0.4 | <0.2-0.9 | 3 | 0.7 | <0.2-1.3 | 3 | 0.3 | <0.2-0.7 | 3 | 0.4 | <0.2-1.3 | 12 | 0.20/4.1 |
| Selenium (µg/l) | T | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 12 | 35/260 |
| | D | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 3 | <2 | all <2 | 12 | |
| Calcium (mg/l) | D | 6.0 | | 1 | 4.5 | | 1 | 8.4 | | 1 | 7.6 | | 1 | 6.6 | 4.5-8.4 | 4 | |
| Magnesium (mg/l) | D | 1.6 | | 1 | 1.5 | | 1 | 2.2 | | 1 | 2.4 | | 1 | 1.9 | 1.5-2.4 | 4 | |
| Potassium (mg/l) | D | 0.47 | | 1 | 0.45 | | 1 | 0.50 | | 1 | 0.76 | | 1 | 0.55 | 0.45-0.76 | 4 | |

MEANS AND RANGES OF PARAMETERS FOR METALS MONITORING PROGRAM AT DISCHARGE AREA, 5 NOVEMBER 1980 – 28 OCTOBER 1981



| | First Quarter, 5 November 1980 - 4 February 1981 | | | Second Quarter, 11 February 1981 - 29 April 1981 | | | Third Quarter, 6 May 1981 - 29 July 1981 | | | Fourth Quarter, 5 August 1981 - 28 October 1981 | | | Entire Year, 5 November 1980 - 28 October 1981 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | EPA (1980) Criteria |
| Sodium D (mg/l) | 4.5 | | 1 | 3.0 | | 1 | 5.4 | | 1 | | | | 4.3 | 3.0-5.4 | 3 | |
| Hardness (mg/l as $CaCO_3$) | 27 | | 1 | 21 | | 1 | 36 | | 1 | 33 | | 1 | 29 | 21-36 | 4 | |
| Alkalinity (mg/l as $CaCO_3$) | 27 | | 1 | 20 | | 1 | 34 | | 1 | 31 | | 1 | 28 | 20-34 | 4 | 20 (min) |
| Temperature (°C) | 5.1 | | 1 | 10.7 | | 1 | 17.8 | | 1 | 13.4 | | 1 | 11.8 | 5.1-17.8 | 4 | |
| pH | 6.7b/ | | 1 | 6.5b/ | | 1 | 7.4a/ | | 1 | 7.3a/ | | 1 | 7.4a/<br>6.6b/ | 7.3-7.4<br>6.5-6.7 | 2<br>2 | 6.5-9.0 |
| Conductivity (µmhos/cm at 25°C) | 72 | | 1 | 60 | | 1 | 88 | | 1 | 82 | | 1 | 76 | 60-88 | 4 | |

a/ A new pH electrode was used beginning on 10 June. The mean and range given are for the samples analyzed with the new electrode.

b/ Values for samples analyzed with old pH electrode (samples prior to 10 June).

Note: Refer to Rurther Explanatory Notes on page 16.

Envirosphere, 1982

MEANS AND RANGES OF PARAMETERS FOR METALS MONITORING PROGRAM AT SOUTH ELMA BRIDGE, 5 NOVEMBER 1980 - 28 OCTOBER 1981

| | First Quarter, 5 November 1980 - 4 February 1981 | | | Second Quarter, 11 February 1981 - 29 April 1981 | | | Third Quarter, 6 May 1981 - 29 July 1981 | | | Fourth Quarter, 5 August 1981 - 28 October 1981 | | | Entire Year, 5 November 1980 - 28 October 1981 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | EPA (1980) Criteria |
| Sodium D (mg/l) | 5.2 | | 1 | 3.6 | | 1 | 6.4 | | 1 | 5.2 | | 1 | 5.1 | 3.6-6.4 | 4 | |
| Hardness (mg/l as $CaCO_3$) | 32 | | 1 | 25 | | 1 | 38 | | 1 | 36 | | 1 | 33 | 25-38 | 4 | |
| Alkalinity (mg/l as $CaCO_3$) | 29 | | 1 | 21 | | 1 | 38 | | 1 | 34 | | 1 | 30 | 21-38 | 4 | 20 (min) |
| Temperature (°C) | 5.0 | | 1 | 10.7 | | 1 | 18.9 | | 1 | 14.0 | | 1 | 12.2 | 5.0-18.9 | 4 | |
| pH | 6.6 b/ | | 1 | 6.7 b/ | | 1 | 7.7 a/ | | 1 | 7.6 a/ | | 1 | 7.6 a/<br>6.6 b/ | 7.6-7.7<br>6.6-6.7 | 2<br>2 | 6.5-9.0 |
| Conductivity (µmhos/cm at 25°C) | 80 | | 1 | 64 | | 1 | 97 | | 1 | 89 | | 1 | 82 | 64-97 | 4 | |

a/ A new pH electrode was used beginning on 10 June. The mean and range given are for the samples analyzed with the new electrode.

b/ Values for samples analyzed with old pH electrode (samples prior to 10 June).

Envirosphere, 1982

MEANS AND RANGES OF PARAMETERS FOR METALS MONITORING
PROGRAM AT SOUTH ELMA BRIDGE, 5 NOVEMBER 1980 - 28 OCTOBER 1981



| | | First Quarter, 5 November 1980 - 4 February 1981 | | | Second Quarter, 11 February 1981 - 29 April 1981 | | | Third Quarter, 6 May 1981 - 29 July 1981 | | | Fourth Quarter, 5 August 1981 - 28 October 1981 | | | Entire Year, 5 November 1980 - 28 October 1981 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | EPA (1980) Criteria |
| Chromium (µg/l) | T | 1.0 | | 1 | 2.0 | | 1 | <0.5 | | 1 | 1.0 | | 1 | 1.1 | <0.5-2.0 | 4 | |
| | D | 0.5 | | 1 | 2.0 | | 1 | <0.5 | | 1 | 0.6 | | 1 | 0.8 | <0.5-2.0 | 4 | |
| Nickel (µg/l) | T | <1 | | 1 | <1 | | 1 | 2 | | 1 | <1 | | 1 | <1 | <1-2 | 4 | 41/794 |
| | D | <1 | | 1 | <1 | | 1 | 1 | | 1 | <1 | | 1 | <1 | <1-1 | 4 | |
| Iron (µg/l) | T | 450 | | 1 | 595 | | 1 | 330 | | 1 | 360 | | 1 | 434 | 330-595 | 4 | 1000 |
| | D | 60 | | 1 | 130 | | 1 | 330 | | 1 | 140 | | 1 | 165 | 60-330 | 4 | |
| Zinc (µg/l) | T | <5 | | 1 | <5 | | 1 | <5 | | 1 | <5 | | 1 | <5 | all <5 | 4 | 47/128 |
| | D | <5 | | 1 | <5 | | 1 | <5 | | 1 | <5 | | 1 | <5 | all <5 | 4 | |
| Copper (µg/l) | T | 1 | | 1 | 3 | | 1 | 6 | | 1 | <1 | | 1 | 3 | <1-6 | 4 | 5.6/7.8 |
| | D | <1 | | 1 | 1 | | 1 | 1 | | 1 | <1 | | 1 | <1 | <1-1 | 4 | |
| Calcium (mg/l) | D | 6.8 | | 1 | 4.5 | | 1 | 8.4 | | 1 | 7.6 | | 1 | 6.8 | 4.5-8.4 | 4 | |
| Magnesium (mg/l) | D | 2.0 | | 1 | 1.8 | | 1 | 2.3 | | 1 | 2.6 | | 1 | 2.2 | 1.8-2.6 | 4 | |
| Potassium (mg/l) | D | 0.55 | | 1 | 0.45 | | 1 | 0.55 | | 1 | 0.77 | | 1 | 0.58 | 0.45-0.77 | 4 | |

## MEANS AND RANGES OF PARAMETERS FOR METALS MONITORING PROGRAM AT INTAKE AREA, 5 NOVEMBER 1980 - 28 OCTOBER 1981



| | First Quarter, 5 November 1980 - 4 February 1981 | | | Second Quarter, 11 February 1981 - 29 April 1981 | | | Third Quarter, 6 May 1981 - 29 July 1981 | | | Fourth Quarter, 5 August 1981 - 28 October 1981 | | | Entire Year, 5 November 1980 - 28 October 1981 | | | EPA (1980) Criteria |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | |
| Sodium D (mg/l) | 4.3 | | 1 | 3.2 | | 1 | 5.4 | | 1 | 4.6 | | 1 | 4.4 | 3.2-5.4 | 4 | |
| Hardness (mg/l as $CaCO_3$) | 27 | | 1 | 28 | 22-36 | 12 | 28 | 22-34 | 13 | 31 | 24-38 | 13 | 29 | 22-38 | 39 | |
| Alkalinity (mg/l as $CaCO_3$) | 24 | | 1 | 22 | 14-28 | 12 | 29 | 23-35 | 13 | 33 | 26-38 | 13 | 28 | 14-38 | 39 | 20 (min) |
| Temperature (°C) | 7.6 | 4.7-11.0 | 12 | 8.6 | 4.1-10.7 | 12 | 14.0 | 9.8-17.8 | 13 | 14.4 | 9.0-20.4 | 13 | 11.3 | 4.1-20.4 | 50 | |
| pH | 6.7[b,d] | 6.4-7.0 | 11 | 6.6[b,d] | 6.3-6.9 | 12 | 7.4[b,c]<br>6.8[b,d] | 7.3-7.5<br>6.7-6.8 | 8<br>5 | 7.2[b,c] | 6.9-7.5 | 13 | 7.3[b,c]<br>6.7[b,d] | 6.9-7.5<br>6.3-7.0 | 21<br>28 | 6.5-9.0 |
| Conductivity (µmhos/cm at 25°C) | 71 | | 1 | 66 | 52-76 | 12 | 75 | 65-88 | 13 | 81 | 65-89 | 13 | 74 | 52-89 | 39 | |

a/ Two other barium samples were taken during this quarter but were analyzed using flame AA instead of graphite furnace AA due to an equipment malfunction. Both samples analyzed by flame AA were reported as <100 µg/l and are not included in this table due to the high detection limit.

b/ Median.

c/ A new pH electrode was used beginning on 10 June. The mean and range given are for the samples analyzed with the new electrode.

d/ Values for samples analyzed with old pH electrode (samples prior to 10 June).

Envirosphere Company, March 1982

MEANS AND RANGES OF PARAMETERS FOR METALS MONITORING
PROGRAM AT DISCHARGE AREA, 5 NOVEMBER 1980 - 28 OCTOBER 1981

| | | First Quarter, 5 November 1980 - 4 February 1981 | | | Second Quarter, 11 February 1981 - 29 April 1981 | | | Third Quarter, 6 May 1981 - 29 July 1981 | | | Fourth Quarter, 5 August 1981 - 28 October 1981 | | | Entire Year, 5 November 1980 - 28 October 1981 | | | EPA (1980) Criteria |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | Mean | Range | No. of Samples | |
| Chromium (μg/l) | T | 1.2 | | 1 | 2.1 | | 1 | <0.5 | | 1 | 0.5 | | 1 | 1.0 | <0.5-2.1 | 4 | |
| | D | 1.2 | | 1 | 1.3 | | 1 | <0.5 | | 1 | | | | 0.9 | <0.5-1.3 | 3 | |
| Nickel (μg/l) | T | <1 | | 1 | <1 | | 1 | <1 | | 1 | <1 | | 1 | <1 | all <1 | 4 | 37/720 |
| | D | <1 | | 1 | <1 | | 1 | <1 | | 1 | | | | <1 | all <1 | 3 | |
| Iron (μg/l) | T | 350 | | 1 | 1260 | | 1 | 240 | | 1 | 200 | | 1 | 512 | 200-1260 | 4 | 1000 |
| | D | 70 | | 1 | 50 | | 1 | 200 | | 1 | | | | 107 | 50-200 | 3 | |
| Zinc (μg/l) | T | <5 | | 1 | <5 | | 1 | <5 | | 1 | <5 | | 1 | <5 | all <5 | 4 | 47/115 |
| | D | <5 | | 1 | <5 | | 1 | <5 | | 1 | | | | <5 | all <5 | 3 | |
| Copper (μg/l) | T | 1 | | 1 | 2 | | 1 | 1 | | 1 | 1 | | 1 | 1 | 1-2 | 4 | 5.6/6.9 |
| | D | 1 | | 1 | <1 | | 1 | 1 | | 1 | | | | <1 | <1-1 | 3 | |
| Calcium (mg/l) | D | 6.1 | | 1 | 4.2 | | 1 | 8.2 | | 1 | | | | 6.2 | 4.2-8.2 | 3 | |
| Magnesium (mg/l) | D | 1.9 | | 1 | 1.5 | | 1 | 2.2 | | 1 | | | | 1.9 | 1.5-2.2 | 3 | |
| Potassium (mg/l) | D | 0.50 | | 1 | 0.45 | | 1 | 0.50 | | 1 | | | | 0.48 | 0.45-0.50 | 3 | |

# Appendix C

# Air Quality

**Potential to Emit**

**Phase I and Phase II**

| **Pollutant** | **Emission Rate per Power Generation Unit stack** | | **Emission Rate per Auxiliary Boiler stack** | **Emission Rate per Diesel Generator stack** | **Annual PTE (TPY) Four PGUs including 130 Startup/Shutdown Cycles per Year per PGU** | **Annual PTE (TPY) Two Auxiliary Boilers** | **Annual PTE (TPY) Two Diesel Generators** | **Annual PTE TPY (Four PGUs including 130 Startup/Shutdown Cycles per Year per PGU, two Cooling Towers, two Auxiliary Boilers, and two Diesel Generators)** |
|---|---|---|---|---|---|---|---|---|
| | **With Duct Firing Natural Gas ppm (gr/dscf for PM)** | **With Duct Firing Natural Gas lb/hr (lb/day for PM)** | **lb/hr (lb/day for PM)** | **lb/hr (lb/day for PM)** | | | | |
| NOx | 2.5 | 21.7 | 1.03 | 10.19 | 580.2 | 2.6 | 5.1 | 588 |
| NH3 | 5 | 16.1 | 0 | 0 | 282.1 | 0.0 | 0.0 | 282 |
| CO | 2 | 10.6 | 1.07 | 12.55 | 873.7 | 2.7 | 6.3 | 883 |
| SO2 | 0.11 | 1.3 | 0.03 | 0.27 | 22.8 | 0.1 | 0.1 | 23 |
| VOCs | 2.78 | 8.4 | 0.47 | 1.48 | 193.2 | 1.2 | 0.7 | 195 |
| PM ("front and back half") | 0.0037 | 583.2 | 7.03 | 14.16 | 425.7 | 0.7 | 0.3 | 436 |

**Notes:**

1. Cooling Tower PM Emissions (TPY each):
   4.51
2. Hours for Each PGU:
   8760
   Hours with Duct Firing:
   8760
3. Hours for Each Auxiliary Boiler:
   2500
4. Hours for Each Diesel Generator
   500
5. Startup/Shutdown Emissions for each pair of PGUs based on 130 cycles per year for each PGU:
   NOx 100
   CO 344
   VOCs 23
6. Number of PGUs with Duct Firing: 4
7. Number of Pairs of PGUs: 2
8. Number of Auxiliary Boilers: 2
9. Number of Cooling Towers: 2
10. Number of Diesel Generators: 2
11. Emission rates based on 0.2 gr S/100 scf natural gas and 30% sulfate conversion.

## SCR Costs (per gas turbine/HRSG)

| Description of Cost | Cost Factor | Cost ($) | Notes |
|---|---|---|---|
| **Direct Capital Costs (DC):** | | | |
| Purchased Equip. Cost (PE): | | | |
| Basic Equipment: | | | |
| Auxiliary Equipment: HRSG tube/fin modification | | | |
| Instrumentation: SCR controls | | | |
| Ammonia storage system | | | |
| Taxes and freight | | | |
| PE Total: | | $1,581,200 | 1 |
| Direct Install. Costs (DI): | | | |
| Foundation & supports | | | 9 |
| Handling and erection | | | 9 |
| Electrical: | | | 9 |
| Piping: | | | 9 |
| Insulation: | | | 9 |
| Painting: | | | 9 |
| DI Total: | | $395,300 | 1 |
| Site preparation for ammonia tanks (included in PE cost) | | $0 | 1 |
| DC Total (PE+DI): | | $1,976,500 | |
| Indirect Costs (IC): | | | |
| Engineering: | 0.10 PE | $158,120 | 2 |
| Construction and field expenses | 0.05 PE | $79,060 | 2 |
| Contractor fees: | 0.10 PE | $158,120 | 2 |
| Start-up: | 0.02 PE | $31,624 | 2 |
| Performance testing | 0.01 PE | $15,812 | 2 |
| Contingencies: | 0.05 PE | $79,060 | 1 |
| IC Total: | | $521,796 | |
| Less: Capital cost of initial catalyst charge | | -$752,000 | |
| Total Capital Investment (TCI = DC + IC): | | $1,746,296 | |
| **Direct Annual Costs (DAC):** 0.5 hr/SCR per shift | hr/yr: 4,380 | | |
| Operating Costs (O): sched. (hr/day) 24 | day/week: 7; wk/yr: 52 | | |
| Operator: hr/shift: 2.0 | operator pay ($/hr) 39.20 | $85,613 | 2 |
| Supervisor: 15% of operator | | $12,842 | 2 |
| Maintenance Costs (M): 0.5 hr/SCR per shift | | | |
| Labor: hr/shift: 2.0 | labor pay ($/hr): 39.2 | $85,613 | 2 |
| Material: % of labor cost 100% | | $85,613 | 2 |
| Utility Costs: | | | |
| Perf. loss: (kwh/unit): 0.0 | SCONOx losses are shown as incremental to SCR losses | | 1 |
| Electricity cost ($/kwh): | | | 9 |
| Ammonia based on 120.7 lbs/hr of 28% wt aqueous ammonia, $440/ton | | $232,613 | 4 |
| Catalyst replace: based on 3 year catalyst life | | $250,667 | 1 |
| Catalyst dispose: based on 2,750 $ft^3$ catalyst, $15/$ft^3$, 3 yr. Life | | $13,750 | 1 |
| Total DAC: | | $766,710 | |
| **Indirect Annual Costs (IAC):** | | | |
| Overhead: 60% of O&M | | $161,808 | 2 |
| Administrative: | 0.02 TCI | $34,926 | 2 |
| Insurance: | 0.01 TCI | $17,463 | 2 |
| Property tax: | 0.01 TCI | $17,463 | 2 |
| Total IAC: | | $231,660 | |
| Total Annual Cost (DAC + IAC): | | $998,370 | |
| **Capital Recovery (CR):** | | | |
| Capital recovery: interest rate (%): 10 | | | |
| period (years): 15 | 0.1315 | $229,592 | 2 |
| **Total Annualized Costs** | | **$1,227,962** | |
| **Total TPY of NOx Removed with SCR System per Turbine/HRSG:** | **361** | | |
| **Cost per Ton of NOx Removed:** | | **$3,402** | |

| Oxidation Catalyst and Summary of Proposed Control Technology | |
|---|---|
| **TOTAL ANNUALIZED COSTS FOR EACH OXIDATION CATALYST SYSTEM:** | **$500,000** |
| Total TPY of CO Removed with Oxidation Catalyst System per Turbine/HRSG: | 279 |
| **Cost per Ton of CO Removed:** | **$1,792** |
| Total TPY of VOC Removed with Oxidation Catalyst System per Turbine/HRSG: | 23 |
| **Cost per Ton of VOC Removed:** | **$21,739** |
| **TOTAL ANNUALIZED COSTS FOR SCR SYSTEM:** | **$1,227,962** |
| Total TPY of NOx Removed with SCR System per Turbine/HRSG: | 361 |
| **Cost per Ton of NOx Removed:** | **$3,402** |
| **Total TPY of Pollutants Removed with Proposed System per Turbine/HRSG:** | **640** |
| **Cost per Ton of Pollutant Removed:** | **$2,700** |

The proposed system is SCR and CO catalytic oxidation.
The cost for VOC control is too excessive and is therefore eliminated from the final analysis.

| Multi-Pollutant SCONOx Cost and Adjusted Cost (per gas turbine/HRSG) | | | | Notes |
|---|---|---|---|---|
| Direct Capital Costs | | | | |
| | Capital (less cost of initial catalyst charge) | (PE) | $10,750,000 | 8 |
| | Installation | | | 9 |
| Indirect Capital Costs | | | | |
| | Engineering: | 0.10 PE | $1,075,000 | 2 |
| | Construction and field expenses: | 0.05 PE | $537,500 | 2 |
| | Contractor fees: | 0.10 PE | $1,075,000 | 2 |
| | Start-up: | 0.02 PE | $215,000 | 2 |
| | Performance testing: | 0.01 PE | $107,500 | 2 |
| | Contingencies: | 0.05 PE | $537,500 | 1 |
| | Other: | | | 9 |
| **Total Capital Investment** | | | $14,297,500 | |
| Direct Annual Costs | | | | |
| | Maintenance | | $250,000 | 3 |
| | Ammonia | | $0 | |
| | Natural Gas: 2.2 MMbtu/hr @ $4.00/MMbtu | | $77,088 | 7 |
| | Pressure Drop | | $226,000 | 3 |
| | Catalyst Replacement (based on 3-yr catalyst life) | | $2,100,000 | 5,6 |
| | Catalyst Disposal | | | 9 |
| **Total Direct Annual Costs** | | | $2,653,088 | |
| Indirect Annual Costs | | | | |
| | Overhead | | | 9 |
| | Administrative, Tax & Insurance | | $225,000 | 3 |
| **Total Indirect Annual Costs** | | | $225,000 | |
| **TOTAL ANNUAL COST** | | | $2,878,088 | |
| Capital Recovery Factor | | | 0.1315 | 2 |
| Capital Recovery | | | $1,879,746 | |
| **TOTAL ANNUALIZED COSTS** | | | **$4,757,834** | |
| Total TPY of NOx Removed with SCONOx System per Turbine/HRSG: | | | 380 | |
| **Cost per Ton of NOx Removed:** | | | **$12,521** | |
| Total TPY of CO Removed with SCONOx System per Turbine/HRSG: | | | 302 | |
| **Cost per Ton of CO Removed:** | | | **$15,754** | |
| **Cost per Ton of CO Removed (adjusted):** | | | **$11,688** | |
| Total TPY of VOC Removed with SCONOx System per Turbine/HRSG: | | | 33 | |
| **Cost per Ton of VOC Removed:** | | | **$144,177** | |
| **Cost per Ton of VOC Removed (adjusted):** | | | **$91,814** | |
| Tons of Ammonia not Emitted: | | | 70 | |
| **Cost per Ton of Ammonia not Emitted:** | | | **$67,969** | |
| **Cost per Ton of Ammonia not Emitted (adjusted):** | | | **$43,284** | |
| Total TPY of Pollutants Removed with SCONOx System per Turbine/HRSG: | | | 785 | |
| **Cost per Ton of Pollutant Removed:** | | | **$6,061** | |

Note: "Adjusted" cost accounts for reduction in SCONOx annualized cost based on proposed SCR/oxidation catalyst system cost, per Ecology request.

| Notes: SCONOx Cost Effectiveness Analysis | |
|---|---|
| Note No. | Source |
| 1 | Based on information from Duke/Fluor-Daniel. |
| 2 | From EPA/OAQPS Control Cost Manual. EPA-450/3-90-006. January 1990. |
| 3 | Based on 6/15/2000 telefax from Aalborg Industries to Duke/Fluor-Daniel, SCONOx capital cost is $36MM for four HRSGs. |
| 4 | Based on aqueous ammonia cost of $440/ton. |
| 5 | Based on information from May 8, 2000 "Testimony of J. Phyllis Fox, Ph.D. on Behalf of the California Unions for Reliable Energy on Air Quality Impacts of the Elk Hills Power Project", cost of replacement catalyst for SCONOx is 70% of initial capital investment. |
| 6 | Based on information from May 5, 2000 letter from ABB Alstom Power to Bibb and Associates indicating that SCONOx catalyst life is guaranteed for a 3-year period. |
| 7 | Personal communication, ABB Environmental, 1/18/00 |
| 8 | Based on e-mail from EmeraChem to Cascade Environmental Management stating capital cost is between $21,000,000 and $22,000,000 for two SCONOx systems for two GE Frame 7FA turbines. |
| 9 | Undetermined at this time. |