May 18, 1981

ORLANDO UTILITIES COMMISSION

CURTIS H. STANTON ENERGY CENTER
UNIT 2

SUPPLEMENTAL
SITE CERTIFICATION APPLICATION

VOLUME 1A

Stanton Energy Center Unit 2
Contents

ATTACHMENT 1

SUPPLEMENTAL SITE CERTIFICATION APPLICATION
SUBMITTED BY ORLANDO UTILITIES COMMISSION

ORLANDO UTILITIES COMMISSION

CURTIS H. STANTON ENERGY CENTER
UNIT 2

SUPPLEMENTAL
SITE CERTIFICATION APPLICATION

VOLUME 2

ORLANDO UTILITIES COMMISSION

CURTIS H. STANTON ENERGY CENTER
UNIT 2

SUPPLEMENTAL
SITE CERTIFICATION APPLICATION

VOLUME 2

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Introduction

The Supplemental Site Certification Application is being submitted by Orlando Utilities Commission (OUC), Florida Municipal Power Agency (FMPA), and Kissimmee Utility Authority (KUA) for the Unit 2 addition to the Curtis H. Stanton Energy Center (Stanton) in accordance with the Florida Electrical Power Plant Siting Act. The site was previously certified for an ultimate site development of approximately 2,000 MW of coal fired capacity at the same time that Unit 1 was certified (order entered December 15, 1982; DOAH Case No. 81-1431). The certified site included corridors for the railroad, transmission lines, makeup water supply pipelines, and the site access road. This supplemental application is filed pursuant to FS 403.517 regarding supplemental site certification applications. No DER instruction guide has been prepared for supplemental site certification applications, so this application has followed the outline of DER Form 17-1-211(1) for certification applications. Information in this supplemental application is supplied only for the purpose of assessing the need, construction, and operation of Stanton 2. This supplemental application is intended to serve the following purposes.

- Supplemental Site Certification for Unit 2 of the Stanton Energy Center including the Need for Power chapter.
- Revision to Best Available Control Technology (BACT) for the existing US Environmental Protection Agency approval of Stanton 2 under a two-unit phased construction Prevention of Significant Deterioration (PSD) permit and request for an amendment of the commence construction date for Unit 2 in the original PSD permit.
- Joint Application (US Army Corps of Engineers and Florida Department of Environmental Regulation) for dredge and fill permit for site development and construction of all associated facilities for Stanton 2 as may be required by the Clean Water Act.
- Permit applications for all other required state, regional, and local approvals.

A PSD permit (PSD-FL-084) was issued to OUC on June 10, 1982, for the phased construction of Units 1 and 2 at the Stanton Energy Center. Within this permit, the construction of Stanton 2 was scheduled to commence on July 1, 1990, with expected startup in January 1994. The authority to construct Stanton 2 under this permit will expire on January 1, 1992, unless construction has commenced by that date. This application includes the revised BACT and request for an extension in the commence construction deadline for a period of 18 months.

The Supplemental Site Certification Application comprises five volumes. The first four volumes contain Chapter 1 of the Supplemental Site Certification Application and are labeled 1A, 1B, 1C, and 1D. Chapter 1 contains the Public Service Commission Need for Power (NFP) Application portion of the Supplemental Site Certification Application. The Joint Need for Power Application is based on the needs of the joint participants in Stanton 2. The joint participants are Orlando Utilities Commission (OUC), Florida Municipal Power Agency (FMPA), and Kissimmee Utility Authority (KUA). Volumes 1A through 1D contain the following information.

- 1A--NFP Information Common to All Participants.
- 1B--NFP Information Specific to OUC.
- 1C--NFP Information Specific to FMPA.
- 1D--NFP Information Specific to KUA.

Appropriate appendices are included at the end of each volume. The last volume (Volume 2) contains Chapters 2.0 through 10.0 relating to all aspects of the Supplemental Site Certification Application other than the need for power.

APPLICANT INFORMATION

Applicants' Official Names and Mailing Addresses

Orlando Utilities Commission
P.O. Box 3193
Orlando, Florida 32802

Florida Municipal Power Agency
7201 Lake Ellenor Drive
Orlando, Florida 32809

Kissimmee Utility Authority
P.O. Box 423219
Kissimmee, Florida 34742-3219

Address of Official Headquarters

Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801

Florida Municipal Power Agency
7201 Lake Ellenor Drive
Orlando, Florida 32809

Kissimmee Utility Authority
8 Broadway
Kissimmee, Florida 34741

Business Entity

Orlando Utilities Commission (OUC) is a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City of Orlando. OUC has the full authority over the management and control of the electric light and water works parts of the City of Orlando. It has the power to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission and distribution systems, and water production, transmission and distribution systems in order to meet the requirements of its customers.

Florida Municipal Power Agency (FMPA) is a joint agency formed pursuant to the Interlocal Cooperation Act and exercises powers under the Joint Power Act. FMPA has authority to undertake and finance electric projects and, among other things, to plan, finance, acquire, construct, reconstruct, own, lease, operate, maintain, repair, improve, extend, or otherwise participate jointly in those projects and to issue bonds or bond anticipation notes for the purpose of financing or refinancing the costs of such projects.

Kissimmee Utility Authority (KUA) is a public body, corporate and politic, duly organized, and legally existing as part of the government of the City of Kissimmee engaged in the generation, transmission, and distribution of electric power to persons within the service area.

<u>Name and Titles of Chief Executive Officers</u>

Orlando Utilities Commission

Jerry Chicone, Jr.	-	President
Royce B. Waldon	-	First Vice President
Susan T. McCaskill Little	-	Second Vice President
James H. Pugh, Jr.	-	Past President
Bill Frederick	-	Mayor
Theodore C. Pope	-	Executive Vice President and General Manager
Thomas B. Tart	-	General Counsel

Florida Municipal Power Agency

Dean G. Shaw	-	Chairman
Joseph M. Tardugno, Jr.	-	Vice Chairman
Harry M. Schindehette	-	Secretary - Treasurer
Vincente R. Ruano	-	Assistant Secretary - Treasurer

Kissimmee Utility Authority

Richard L. Hord	-	Chairman
Bob Bobroff	-	Director
Harry Lowenstein	-	Director
Arnold W. Jones	-	Director
George A. Gant	-	Director
John B. Pollet	-	Mayor (Executive Officio)

<u>Name, Address, and Telephone Number of Official Representative Responsible for Obtaining Certification</u>

Orlando Utilities Commission
Thomas B. Tart, General Counsel
500 South Orange Avenue
Orlando, Florida 32801
407-423-9123

<u>Site Location (County)</u>

Orange County

<u>Nearest Incorporated City</u>

Orlando, Florida

<u>Latitude and Longitude</u>

29° 29' North Latitude
81° 10' West Longitude

<u>UTMs (Center of Site)</u>

Northerly 1507528
Easterly 446825

<u>Section, Township, Range</u>

Sections 13, 14 (E 1/2), 23 (E 1/2), 24; Township T23S; Range R31E
Sections 18, 19; Township T23S; Range R32E

Location of Any Directly Associated Transmission Facilities (Counties)

Orange County

Nameplate Generating Capacity

Stanton 2 will have a nameplate gross generating capacity of 465 megawatts (MW) and is scheduled for commercial operation January 1, 1997.

Capacity of Proposed Additions and Ultimate Site Capacity

Stanton 3 and 4 have not been sized or scheduled at this time. The Stanton site was previously certified for an ultimate site capacity of approximately 2,000 MW.

2.0 Site and Vicinity Characterization

The information presented in this chapter is provided only for purposes of construction and operation of Stanton 2 as discussed and qualified in the Introduction.

2.1 Site and Associated Facilities Delineation

The site location and layout for the Stanton Energy Center including the ultimate development of Units 1, 2, 3, and 4 are shown and documented in Chapter 2 of the original Site Certification Application (SCA) for the facility. This information is still valid and unchanged.

The electric transmission line and alternative restricted or emergency plant access road are located within the railroad/utility corridor, which is part of the previously certified site.

2.2 Sociopolitical Environment

The sociopolitical environment of the Stanton Energy Center project was previously addressed in Sections 2.1, 2.2, and 2.3 of the original SCA.

2.3 Biophysical Environment

2.3.1 Geohydrology

2.3.1.1 Geologic Description of the Site. A general-geologic description of the site was provided in Subsections 2.4.1 and 2.4.2 of the original SCA. Historical seismic activity is detailed in Subsection 2.4.5 of the original SCA.

2.3.1.2 Detailed Site Lithologic Description. A detailed lithologic description of the site was provided in Subsection 2.4.3 of the original SCA. Additional soil borings were performed after the original SCA was produced. Results from that investigation indicate that subsurface conditions are as described in the original SCA.

2.3.1.3 Geologic Maps. Geological details and maps of the site are included in Subsection 2.4.3 and Figures 2.4-3 and 2.4-4 of the original SCA.

2.3.1.4 Bearing Strength. Boring logs and subsurface investigations show that soils are predominantly loose to medium dense sands with intermittent, discontinuous thin clay layers. Standard penetration tests indicate blow counts varying from 5 blows per foot to 120 blows per foot. Density tends to increase with depth but soft clay layers at deeper intervals do exist. Foundations for heavy structures will be friction piles. More lightly loaded structures will be placed on shallow footings, mats, or piles as necessary.

2.3.2 Subsurface Hydrology

2.3.2.1 Subsurface Hydrologic Data for the Site. The subsurface hydrologic data for the site were provided in Subsection 2.5.2 of the original SCA. Results of a pump test conducted on production wells installed in the Floridan Aquifer during construction of Stanton 1 are presented in Subsection 5.3.2.3 of this application. Background water quality data collected from the Floridan Aquifer are presented in Subsection 5.3.5 of this SCA.

2.3.2.2 Karst Hydrogeology. As a part of the original SCA, a sinkhole evaluation potential study was performed for this site by Jammal and Associates. The conclusion from that study was that the potential for sinkholes at this site is very low. No sinkholes have been reported at the site and sinkholes are not expected to be a problem for Stanton 2.

2.3.3 Site Water Budget and Area Uses

Detailed information regarding the site and region water budgets was presented in Sections 2.5 and 2.6 of the original SCA. A discussion of area water uses was included in Subsection 2.2.3 of the original SCA. Water supply wells installed in the region since submittal of the original SCA are shown on Figure 2.3-1. Three water supply wells have been installed within one mile of the site. The well owners and specific well information are summarized in Table 2.3-1.

2.3.4 Surficial Hydrology

Descriptions of regional and local surface waters are included in Subsection 2.5.1 of the original SCA.

2.3.5 Vegetation/Land Use

A discussion of the project area's plant communities is included in Subsection 2.7.2 of the original SCA. The existing land use features are described in Subsection 2.2.2 of the original SCA.

2.3.6 Ecology

Detailed descriptions of the ecological communities in the site area are included in Section 2.7 of the original SCA.

2.3.7 Meteorology and Ambient Air Quality

Discussions of regional climate, site meteorology, and site air quality are included in Sections 2.6 and 2.8 of the original SCA. These discussions include information obtained from the Stanton 1 preconstruction onsite monitoring program, which began operation in May 1980. OUC has continued to operate onsite monitoring with some changes in program configuration. Stanton 1 was put into commercial service in July 1987. Even with the operation of this new source, measurements taken at the site during the entire period of approximately 10 years have been low, well below applicable ambient air quality standards.

Because the initial Prevention of Significant Deterioration (PSD) permit was issued for both Stanton 1 and 2, the Florida Department of Environmental Regulation (FDER) has indicated that preconstruction air monitoring will not be a requirement for the approval of the requested construction schedule extension for Stanton 2.

2.3.8 *Noise*

A detailed discussion of ambient noise levels at the Stanton Energy Center site and in the immediate vicinity was included in Subsection 2.9.1 of the original SCA.

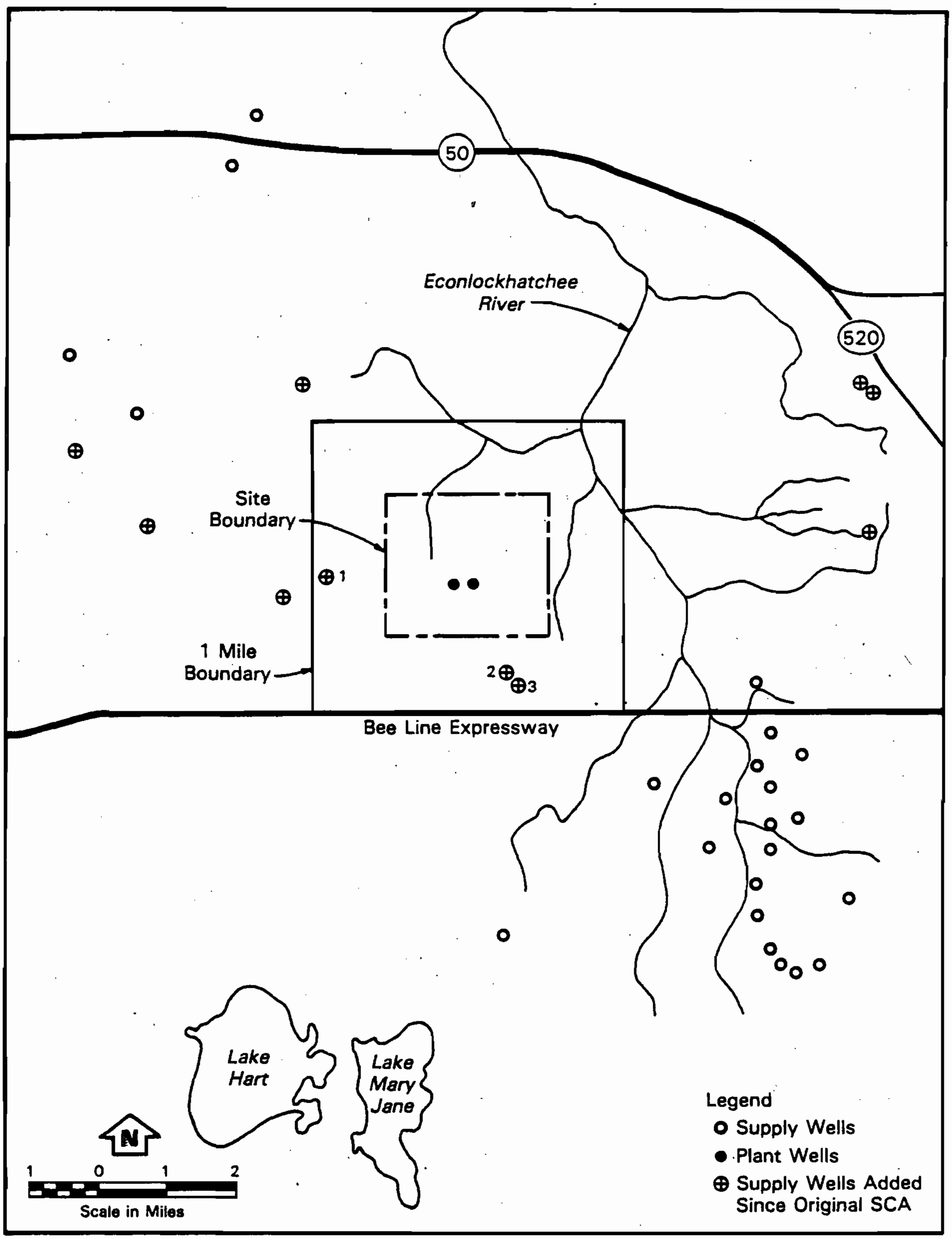
2.3.9 *Other Environmental Features*

No other features pertinent to the environmental evaluation of the proposed Stanton 2 addition have been identified.

Table 2.3-1
Supply Wells Within 1 Mile Boundary of Site

Well No.	Owner	Well Use	Cased Depth (ft)	Total Depth (ft)
1	Waste Management Inc. of Florida	Public Supply	250	400
2	State of Florida, Dept. of Corrections	Public Supply	247	420
3	State of Florida, Dept. of Corrections	Public Supply	252	448

Source: SJRWMD, 1991



Source: SJRWMD, 1991

WATER SUPPLY WELLS
IN THE AREA OF THE SITE

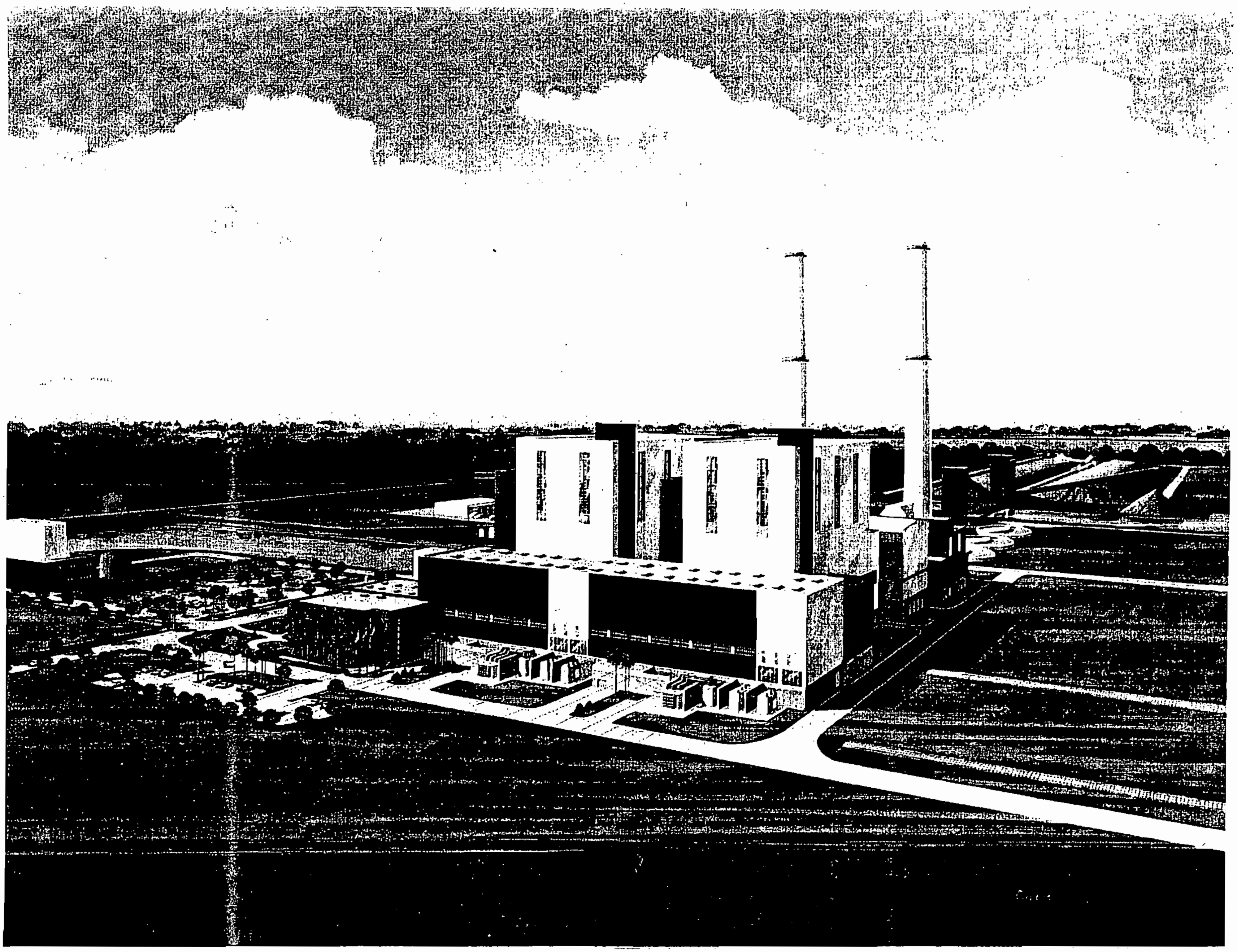
Figure 2.3-1

3.0 The Plant and Directly Associated Facilities

The information presented in this chapter is provided only for the purposes of construction and operation of Stanton 2 as discussed and qualified in the Introduction.

3.1 Background

An artist's rendering of the Stanton Energy Center site with the proposed Stanton 2 added is shown on Figure 3.1-1. Stanton 2 will be a 465 MW gross, 440 MW net, pulverized coal fueled steam/electric power plant. This size is totally consistent with the original ultimate site certification. New Stanton 2 facilities will include sulfur dioxide removal equipment, electrostatic precipitator, chimney, cooling tower, and an expansion of the cooling tower blowdown treatment system. Other facilities previously constructed for Stanton 1 will also be used for Stanton 2. These include the onsite ponds and basins; materials handling and storage systems for coal, oil, limestone, lime, and combustion wastes; administration building; warehousing; and other common support facilities.



ARTIST'S RENDITION OF
CURTIS H. STANTON ENERGY CENTER — 2 UNITS

Figure 3.1-1

3.2 Site Layout

Figure 3.2-1 shows the proposed layout for the Stanton Energy Center with the addition of Stanton 2 and associated facilities. The new onsite facilities will occupy approximately 9 acres of the 3,280-acre site.

A general plant profile of the total two-unit power plant is shown on Figure 3.2-2. This profile is based on the elevations of the various facilities as viewed from the north looking south. The elevations and dimensions shown on Figure 3.2-2 are based on Stanton 1 sizes and considered preliminary. Some changes may occur as detailed engineering design proceeds.

The Stanton Energy Center is designed so that no wastewater discharges to surface waters will be necessary. A detailed description of the water supply, uses, and management is presented in Section 3.5.

Release points for fugitive dust and combustion gas wastes were identified and discussed in the original SCA. The only new source of gaseous wastes will be the 550-foot chimney for Stanton 2. Further, this new air emissions source was previously evaluated with regard to its effect on air quality and is included as an approved source in the Prevention of Significant Deterioration (PSD) permit issued for the project during the initial permitting process. A discussion of the proposed air quality control systems for Stanton 2 is presented in Section 3.4.

3.3 Fuel

3.3.1 Fuel Types and Qualities

The primary fuel for the Stanton Energy Center will continue to be bituminous coal. Although coal supply contracts for Stanton 2 have not been finalized, a design basis coal has been developed for use on the project. Table 3.3-1 presents the typical and ranges of selected properties of the design basis coal. All other properties are expected to fall within the ranges provided for coal quality in Table 3.2-1 of the original SCA. These coal properties provide a "worst case" design basis that will provide OUC with system operating flexibility to burn any coal with properties in the ranges given.

The Stanton 2 steam generator will be started with No. 6 fuel oil. During periods of low load operation, No. 6 fuel oil will also be used for flame stabilization.

3.3.2 Fuel Quantities

With a heating value range of 11,000 to 13,350 Btu/lb, the maximum coal consumption rate will be 150 to 193 tons/h. At a 70 percent capacity factor, the annual coal consumption for Stanton 2 will be 975,000 to 1,190,000 tons per year.

Estimates of No. 6 fuel oil usage for cold and hot startups with Stanton 2 are the same as those discussed for Stanton 1 in Subsection 3.2.2 of the original SCA.

3.3.3 Fuel Transportation

Coal will continue to be transported to the plant site by rail via CSX Transportation, Inc., as described in Subsection 3.2.3 of the original SCA. An additional two to three trains per week will be required to supply coal for Stanton 2. No. 6 fuel oil will continue to be received by trucks as has been the case for Stanton 1.

3.3.4 Coal Handling and Storage

The coal handling system described in Subsection 3.2.4 of the original SCA will serve both Stanton 1 and 2. The existing system as constructed consists of unloading, stocking, reclaiming, and storage facilities. The system will be unchanged except for the addition of new silo fill conveyors and plant silos to serve Stanton 2. Figure 3.2-3 of the original SCA shows a perspective of these facilities.

3.3.5 *Fuel Oil Storage and Handling*

The No. 6 fuel oil required by Stanton 2 will be stored in the previously installed onsite tanks, described in Subsection 3.2.5 of the original SCA.

3.3.6 *Alternate Fuel Types*

As in the case of Unit 1, no special design features have been included in the design of Stanton 2 to allow burning of alternate fuels.

Table 3.3-1
Design Basis Coal Properties

Ultimate Analysis	Typical
Carbon	67.0 percent
Hydrogen	4.50 percent
Sulfur	2.5 percent
Moisture	7.5 percent
Nitrogen	1.29 percent
Chlorine	0.11 percent
Oxygen	5.1 percent
Ash	12.00 percent
Higher Heating Value	12,400 Btu/lb

3.4 Air Emissions and Controls

It is OUC's philosophy for the construction, operation, and maintenance of facilities, to focus on safety, reliability, and redundancy, all accomplished while maintaining an environmentally responsible posture. These goals are achieved by following a course whose bounds are well within the conservative constraints of prudent utility practice.

Following this philosophy, OUC avoids using unproven technologies or technologies applied in an unproven manner. Conservative prudent utility practice requires a diversity of fuels and maximum fuel flexibility within OUC's generation system. Further, OUC will operate its units well below permitted emission levels where this is consistent with energy, environmental, and economic considerations.

Stanton 2 fits into this OUC policy by its duplication of the highly successful and reliable Stanton 1. However, even with this duplication, Stanton 2 will maintain an environmentally responsible posture by the application of advanced but proven control technologies to yield emission rates well below those in the Stanton 1 permit.

Stanton 1 and 2 are both designed as baseload units with load following capabilities. Together they make up 45.1 percent of OUC's generation capacity. Stanton 1 has both design capabilities and permit limitations which allow fuel flexibility. Stanton 2 is being designed with the same design capabilities. Therefore, fuel flexibility in the Stanton 2 permit limitations is important to OUC's successful philosophy.

Another factor demonstrating the unique and special nature of Stanton 2 is the location of the Stanton Energy Center away from all air quality sensitive areas (PSD Class I, nonattainment, and other major increment consumers).

3.4.1 Air Emission Types and Sources

The types and sources of air emissions are the same as previously noted in the Orlando Utilities Commission's Stanton Energy Center Unit 1 Site Certification Application, Subsection 3.7.1.

3.4.2 Air Emission Controls

3.4.2.1 Fugitive Dust. All fugitive dust controls are the same as previously noted in the Orlando Utilities Commission's Stanton Energy Center Unit 1 Site Certification Application, Subsection 3.7.2.1.

3.4.2.2 Nitrogen Oxides. In the combustion process, nitrogen oxides (NO_x) are formed in the high temperature regions of the boiler in and around the flame zone by oxidation of both atmospheric nitrogen and nitrogen in the fuel. Formation of NO_x can be reduced by lowering peak combustion temperatures and by limiting the amount of excess air available to the fuel.

Nitrogen oxides emissions will be controlled by using low NO_x burners and other features designed to limit NO_x formation during combustion. These design features will include the following.

- Compartmented wind box (improved combustion control).
- Large furnace and widely spaced burners (reduced temperatures).
- Overfire air distribution at the burners.
- Staged combustion.
- Modified coal pulverizers for a finer grind.

The large furnace and widely spaced burners increase the burner firing zone absorption area and decrease peak combustion temperatures, thus minimzing NO_x formation.

The steam generator will be designed (and guaranteed by the steam generator manufacturer) to maintain nitrogen oxides emissions to 0.32 lb NO_x per million Btu of heat input (lb/MBtu). This emission compares to a Stanton 1 emission limit of 0.60 lb/MBtu.

3.4.2.3 Particulate. Particulate emissions will be limited through the use of an electrostatic precipitator. The electrostatic precipitator will be located directly downstream of the steam generator air heater. The design of the precipitator is based on meeting a particulate emission limit of 0.02 lb/MBtu when burning the bituminous coal as listed in Table 3.3-1. This emission compares to a Stanton 1 emission limit of 0.03 lb/MBtu. The precipitator design will also include margins to help assure that the emission standards will be met under off-design operating conditions.

The design conditions are essentially the same as previously noted in the Stanton 1 Site Certification Application, Subsection 3.7.2.3.

3.4.2.4 Sulfur Dioxide. The flue gas desulfurization (FGD) system will consist of a multi-module wet limestone spray tower scrubber located downstream of the induced draft fans. The system will have three 50 percent capacity modules with a bypass system. The FGD system will be designed to limit sulfur dioxide emissions to 0.32 lb/MBtu on a 30-day rolling average basis. The proposed 3-hour and 24-hour emission limits are 0.85 lb/MBtu and 0.67 lb/MBtu, respectively. These emissions compare to a Stanton 1 2-hour emission limit of 1.2 lb/MBtu and a 3-hour emission limit of 1.14 lb/MBtu. The scrubber design will also include margins to assure that the emission standards will be met under off-design operating conditions.

The design conditions for the scrubber are essentially the same as previously noted in the Stanton 1 Site Certification Application, Subsection 3.7.2.4.

3.4.3 Best Available Control Technology Analysis

The 1977 Clean Air Act Amendments establish revised conditions for the approval of preconstruction permit applications under the Prevention of Significant Deterioration (PSD) program. One of these requirements is that the best available control technology (BACT) be installed for all pollutants regulated under the Act. Under the revised Act, BACT determinations must be made on a case-by-case basis considering technical, economic, energy, and environmental impacts for various BACT alternatives (rather than automatically applying a specific Federal New Source Performance Standard). To bring consistency to the BACT process, the EPA has authorized development of guidance documents on the use of a "top-down" approach to BACT determinations.* This BACT analysis is based on draft guidance documents issued by the EPA in March 1990.

The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control alternative available for a similar source or source category (lowest achievable emission rate [LAER] technology). If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This

*US EPA memorandum from J. C. Potter (Assistant Administrator for Air and Radiation) to Regional Administrators, December 1, 1987.

process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration.

This analysis supports the selection of BACT for the OUC Stanton 2 project (440 MW net) regarding the control of particulate, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds (VOC), lead, and applicable noncriteria pollutant emissions.

3.4.3.1 Basis of Analysis. The following is a summary of the requirements and assumptions on which this BACT evaluation is based.

- Federal and state ambient air quality standards, emission limitations, significant deterioration increments, solid waste standards, and the requirements of other applicable regulations will be met.
- Federal New Source Performance Standards (NSPS) establish limiting criteria for pollutant emissions from the Stanton 2 project.
- The Stanton Energy Center project is intended to be a baseloaded facility with load following capabilities. With consideration of the large relative portion of Orlando Utilities Commission's generating capacity represented by the Stanton Energy Center, the operating reliability of the air quality control system (AQCS) cannot limit overall unit reliability. Therefore, this reliability consideration may preclude the use of innovative or developmental control technologies.
- The Stanton Energy Center is located in a Class II area which is designated as attainment for all applicable PSD pollutants. In addition, the Stanton Energy Center is not located adjacent to (within its zone of influence) any nonattainment areas.
- The BACT analysis is based on the economic criteria and the coal quality data listed in Tables 3.4-1 and 3.4-2, respectively.
- Costs for OUC Stanton 2 electrostatic precipitator (particulate emissions control) and wet limestone scrubber (flue gas desulfurization) systems reflect virtual duplication of Stanton 1 systems. As such, the costs for these systems presented in the BACT analysis are lower than for a "green field" installation at a new station because of reduced engineering costs. Since air quality control alternatives to these technologies do not have this advantage, their costs will be estimated assuming a "green field" facility.

3.4.3.2 *Particulate Emissions Control.* The objective of this analysis is to determine BACT for particulate removal alternatives for the Stanton 2 project. This analysis evaluates BACT for both total particulate and fine particulate (PM_{10} emissions).

Additional Requirements and Assumptions.

- Federal New Source Performance Standards limit particulate emissions to 0.03 lb/MBtu, and opacity to a maximum of 20 percent.
- The particulate removal system is designed to meet the 24-hour PM_{10} ambient standard of 150 micrograms per cubic meter, not to be exceeded more than once per year, and the PM_{10} annual primary ambient standard of 50 micrograms per cubic meter.
- A review of information contained in the BACT/LAER Clearinghouse (1985 and 1990 editions) indicates that the most stringent particulate emission limit issued to date is a requirement of 0.012 lb/MBtu for a proposed California coal fired project using a fabric filter.

Particulate Removal Methods. Two particulate removal systems have demonstrated removal efficiencies on pulverized coal fired boilers: electrostatic precipitators and fabric filters.

Operating experience obtained with fabric filters during the last decade has indicated that these devices are extremely effective particulate removal devices. Fabric filters have been the technology of choice for a number of recent BACT and lowest achievable emission rate (LAER) determinations. Fabric filters use fabric bags as filters to collect particulate. The particulate laden flue gas enters a fabric filter compartment and passes through collected particulate and filter bags. The collected particulate forms a cake on the bag which greatly enhances the bag's filtering efficiency. Filter bags can be cleaned by any one of three methods: reverse gas, shake-deflate (reduced reverse gas flow with gentle mechanical shaking of the bag), or pulse jet. Dislodged particulate collects in hoppers beneath the bags for subsequent removal by the ash handling system.

In general, pulse jet fabric filters offer cost savings, compared to reverse gas and shake-deflate fabric filters, on units sized to treat less than 300,000 to 500,000 acfm of flue gas. In addition, it is not expected that pulse jet fabric filters will be any more effective than reverse gas and shake-deflate fabric filters since these devices generally operate at higher cloth velocities (air-to-cloth ratio). Therefore, on the basis of relative economics for a facility the size of Stanton 2 (1.6 million acfm) pulse jet fabric filters will not be considered for use.

With proper design, either reverse gas or shake-deflate fabric filters are capable of meeting a particulate emission requirement of 0.02 lb/MBtu. With a number of design considerations (described subsequently) either of these fabric filter alternatives is capable of meeting a LAER emission requirement of 0.012 lb/MBtu. Since costs are very similar for these two alternatives, a reverse gas fabric filter will be evaluated as the base case fabric filter.

Electrostatic precipitators are the most widely used particulate removal devices for coal fired power plants. Electrostatic precipitators remove particulate matter from the flue gas stream by charging fly ash particulates with very high dc voltage and subsequently attracting these particles to oppositely charged collecting plates. A layer of collected particulate forms on the collecting plates (electrodes) and is removed periodically by rapping the electrodes. The collected particulate drops into hoppers below the precipitator and is periodically removed by the fly ash handling system.

Although more difficult to properly design, precipitators can be equally effective as fabric filters at limiting particulate emissions. However, at lower particulate emission limits (i.e., 0.012 lb/MBtu), design considerations become more difficult and the relative economics for a precipitator become prohibitive. For the types of coal under consideration, it is expected that a precipitator could compete effectively with fabric filters down to an emission limit of 0.02 lb/MBtu.

The following are the alternative particulate control technologies evaluated consistent with a top-down approach.

- LAER Alternative–Reverse gas fabric filter designed to achieve an emission rate of 0.012 lb/MBtu.
- BACT Alternative 1–Electrostatic precipitator designed to achieve an emission rate of 0.02 lb/MBtu.
- BACT Alternative 2--Reverse gas fabric filter designed to achieve an emission rate of 0.02 lb/MBtu.

Economic Evaluation of Particulate Removal Alternatives.

Technical Design Criteria. Fabric filter design criteria are presented in Table 3.4-3 and electrostatic precipitator design criteria are presented in Table 3.4-4. Design criteria for the purpose of this analysis are developed for two emission requirements: 0.012, and 0.02 lb/MBtu. These design criteria are presented for the purpose of establishing the capital and operating costs for the economic comparison of the particulate removal alternatives.

The physical size of an electrostatic precipitator is determined by the particulate and flue gas properties, gas flow, and the required collection efficiency. The most significant particulate property affecting precipitator design is fly ash resistivity, which varies with the moisture content, the chemical composition, and the temperature of the fly ash and flue gas.

As emission limits are lowered, the specific collecting area, total collecting area, and the total number of transformer/rectifiers will increase in electrostatic precipitator designs. The maintenance will also increase as emission limits are lowered. The precipitator electrode alignment, efficient rapping of electrodes, and the electrical stability of the transformer/rectifiers must also be maintained on a more regular basis to meet lower emission requirements. Considering the wide range of coal characteristics anticipated for the plant, a precipitator sized to meet an outlet emission limit of 0.02 lb/MBtu would require a relatively high specific collection area of 743 square feet per 1,000 acfm of flue gas.

Fabric filters are sized primarily on the basis of flue gas flow rate and the design cloth velocity (acfm of flue gas per square foot of cloth area or ft/min). A net cloth velocity of 2.3 ft/min (two compartments out of service, one for cleaning, one for maintenance) is typical for reverse gas fabric filters used to meet an emission requirement of 0.02 lb/MBtu. The selection of a filter medium (cloth) is also important in meeting a specified emission requirement. Fabric filters designed to meet emission requirements of 0.02 lb/MBtu typically use filter bags made of woven fiberglass with an acid-resistant finish.

Although fabric filters cannot be specifically designed to meet a particulate emission requirement (as compared to electrostatic precipitators), it is possible to minimize emissions if certain design changes and quality control measures are taken. Therefore, as fabric filter outlet emission requirements are lowered, certain real capital cost additions can be identified.

A significant amount of the particulate that escapes from a fabric filter results from construction deficiencies. Faulty welds attaching the tubesheet to the walls of the compartment, or thimbles to the tubesheet, allow leakage. Flue gas leaks increase emissions significantly. In addition, inproper attachment of the bags to the tubesheet can allow flue gas to slip from beneath the cuff of the bag. Therefore, as emission requirements are tightened, quality control efforts must be increased to ensure gastight construction and tight tolerances between thimble and bag cuffs.

In addition to fabric filter construction quality control, operation and maintenance procedures must be rigorous in order to meet stringent emissions requirements. Fabric filter bag life can become a significant parameter that directly affects a facility's ability to comply with these emission requirements. Typically, for a unit that operates to meet a 0.02 lb/MBtu emission requirement, bag life ranges from three to five years. As a bag ages, fabric fibers may become abraded and brittle. Therefore, as a bag goes through numerous cleaning cycles, the clearance between woven fabric fibers tends to increase, causing increased particulate penetration through the bags. Accordingly, as particulate emission requirements are reduced, bag changes are required more frequently.

As previously mentioned, reverse gas fabric filters typically use filter bags constructed of woven fiberglass with an acid resistant finish. On applications with low emission requirements (less than 0.02 lb/MBtu), the penetration of particulate from a typical fiberglass bag may become significant. Woven fiberglass bags laminated with a Gore-tex membrane have, in a limited number of applications, minimized particulate bleed-through (penetration) relative to conventional woven fiberglass bags. Therefore, as emission requirements become more strict, the contingency for changeout to Gore-tex filter bags increases.

To ensure compliance with an emission requirement of 0.012 lb/MBtu throughout the life of the plant, it is recommended that design cloth velocities be reduced (increasing the amount of cloth area in the fabric filter). Cloth velocity is a measurement of volumetric gas flow (acfm) per square foot of cloth area. A lower cloth velocity lowers the drag coefficient through the cake built up on the filter bags. A lower coefficient of drag minimizes particulate penetration through filter bags. A net cloth velocity of 2.1 ft/min (two compartments out of service, one for cleaning, one for maintenance) is recommended to comply with an emission requirement of 0.012 lb/MBtu.

A rigorous quality control program must be adhered to during construction to meet an outlet particulate emission requirement of 0.012 lb/MBtu. More frequent inspection visits to the fabrication shop and the construction site will be required to identify potential welding and material defects that may enable flue gas to slip by filter bags untreated. In addition to more frequent inspection of materials and welding, die penetrant or hydro testing of all tubesheet welds will be required.

In addition to increased quality control, the manufacturer is likely to add cost to his contract to account for the increased risk of failing guarantee requirements. This risk money would be held in reserve for the possibility of being required to rebag with Gore-tex bags. Therefore, increased risk money is included in the cost of the 0.012 lb/MBtu alternative to cover rebagging of the fabric filters with Gore-tex filter bags.

Capital and Annual Costs. Comparative costs for a fabric filter particulate removal system designed for a 0.012 lb/MBtu and a 0.02 lb/MBtu particulate emission, and an electrostatic precipitator particulate removal system designed for a 0.02 lb/MBtu particulate emission are presented in Table 3.4-5. The costs presented in Table 3.4-5 are total costs for a complete particulate removal system installed downstream of a pulverized coal fired boiler at Stanton 2.

Capital costs are separated into several categories including electrostatic precipitator, fabric filter, waste handling, ductwork, and differential induced draft (ID) fans. Electrostatic precipitators and fabric filter costs include inlet and outlet plenums, poppet dampers (fabric filter only), electrical and control, and foundations and enclosures. Differential ID fan costs account for the additional fan capacity required to overcome draft losses through the particulate removal systems. Waste handling costs include the solids storage silo, solids blowers, piping, and valves. The capital cost includes contingency, escalation, indirects, and allowance for funds used during construction (see Table 3.4-1 for economic evaluation criteria). Capital costs range from $48 million for a precipitator designed for an outlet emission rate of 0.02 lb/MBtu to $58 million for a fabric filter designed to meet a 0.012 lb/MBtu emission limit.

Levelized annual operating costs include maintenance, operating personnel, and energy. Total levelized annual costs are calculated as the sum of the levelized annual operating costs and the levelized annual fixed charges on capital investment. Levelized annual costs range from $8.7 million to $12 million for a precipitator (0.02 lb/MBtu) and fabric filter (0.012 lb/MBtu), respectively.

Other Considerations. Electrostatic precipitators are more effective than fabric filters at limiting the emission of particulate sized less than 10 microns (PM_{10}). Approximately 92 percent of a total particulate emission rate from a fabric filter is of fine particulate, less than 10 microns in size.. Alternatively, precipitator PM_{10}

emissions constitute only 67 percent of the total emission rate. This fraction is based on information presented in the EPA's "Compilation of Air Pollutant Emission Factors," AP-42, September 1985. However, to estimate maximum ambient impacts, dispersion modeling of PM_{10} emissions from Stanton 2 is performed assuming that 100 percent of the 0.02 lb/MBtu emission rate consists of particulate less than 10 microns in size.

An additional advantage for electrostatic precipitators is that they do not require time to condition their removal efficiency. A precipitator sized to limit outlet emissions to 0.02 lb/MBtu should be capable of meeting that limit immediately. However, as discussed previously, fabric filters rely on both the filter bag and a residual dust cake to attain optimum filtering efficiency. The ultimate filter medium for the fabric filter is this residual dust cake. Until an adequate residual dust cake is established, it is likely that fabric filter emissions will exceed 0.02 lb/MBtu. The development of this residual dust cake can take anywhere from two to six months, depending on dust cake characteristics. This period of noncompliance is likely to reoccur every three to five years whenever a rebagging occurs.

A disadvantage of an electrostatic precipitator is its energy consumption. As indicated in Tables 3.4-3 and 3.4-4, the precipitator consumes 85 percent more energy than a fabric filter sized to meet the same emission requirement. However, this additional energy requirement represents only 0.2 percent of the total unit power output.

Conclusions. A fabric filter designed to meet a particulate emission limit of 0.012 lb/MBtu has the highest evaluated cost. Total levelized annual costs for this LAER alternative are $2.9 million and $2.7 million higher than for an electrostatic precipitator and a fabric filter, respectively, designed to meet a 0.02 lb/MBtu emission limit. These additional costs result in an incremental removal cost in excess of $19,000 per ton of particulate removed (as compared to the electrostatic precipitator case).

In addition, a precipitator will result in lower PM_{10} emissions and more consistent emissions performance than a fabric filter. However, a precipitator would consume more energy than a fabric filter. This increased energy requirement is equivalent to only 0.2 percent of plant power output.

Therefore, based on economics and environmental considerations, an electrostatic precipitator designed to meet an emission requirement of 0.02 lb/MBtu represents BACT for Stanton 2. This level of control is 33 percent less than the Stanton 1 emission limit of 0.03 lb/MBtu.

3.4.3.3 Sulfur Dioxide Emissions Control. The objective of this section is to determine BACT for sulfur dioxide (SO_2) emission control alternatives for the Stanton 2 project.

Additional Requirements and Assumptions.

- Federal New Source Performance Standards (NSPS), applicable to Stanton 2 when firing the design coal presented in Table 3.4-2 requires the facility to meet a 1.2 lb/MBtu SO_2 emission rate. Compliance with this requirement is determined on a 30-day rolling average basis.
- FGD for pulverized coal (PC) fired boilers will be accomplished by either a wet lime or limestone scrubbing system, or a lime spray dryer system.
- A review of information contained in the BACT/LAER Clearinghouse (1985 and 1990 editions) indicates that the most restrictive SO_2 removal permit requirement issued to date is 96.2 percent for a proposed circulating fluidized bed (CFB) boiler project in California. Stanton 2 is proposed to be a pulverized coal (PC) fired project.
- Fluidized bed boilers are not available in the size necessary for Stanton 2, and therefore will not be considered further.
- A review of information contained in the BACT/LAER Clearinghouse indicates that the most restrictive SO_2 removal permit requirement for a pulverized coal installation is 95 percent for a proposed installation in Nevada. Flue gas desulfurization at this facility will be provided by a wet lime scrubber. Therefore, the LAER alternative for a pulverized coal fired source such as Stanton 2 would be a wet lime scrubber.
- Compliance with an SO_2 removal requirement based on a 30-day rolling average requires that the SO_2 removal system routinely maintain a removal efficiency in excess of the permitted removal requirement. If the FGD system were designed to operate exactly at the required 30-day removal efficiency, any upset in system operation that reduced SO_2 removal would cause 30 days of noncompliance. This requires that typical FGD systems located downstream of a PC boiler be operated at a removal rate at least 3 percent higher than the overall removal requirement to account for periods of system upset.

Flue Gas Desulfurization Methods. A number of post-combustion FGD processes have demonstrated SO_2 removal capabilities for use downstream of a pulverized coal fired boiler. However, wet scrubber and spray dryer systems are the most widely used FGD systems. In addition, these FGD systems are favored because of their simplicity of operation and equivalent removal capabilities compared to relatively complex byproduct recovery FGD systems. In addition, byproduct recovery systems require a market for their end product of sulfur or sulfuric acid. These markets do not exist in Orlando. Therefore, byproduct recovery systems are not a suitable alternative for Stanton 2.

Wet lime or limestone scrubbing and lime spray drying FGD systems have the advantage of using widely available calcium based additives compared to remotely located sodium based additives (almost all active sodium mines are located in Wyoming). Therefore, the cost of sodium delivered to the Stanton Energy Center site (approximately $200 to $250 per ton) would be prohibitive compared to the cost of lime or limestone ($80 and $8 per ton, respectively). In addition, the use of sodium based additives increases the complexity and cost of waste disposal due to the high solubility of sodium wastes (increased potential for groundwater contamination due to leachate problems). Considering the location of Stanton 2 in Florida, sodium based FGD alternatives are not a feasible additive for use at Stanton 2.

Currently, 118 utility units with a combined capacity of 53,800 MW are in operation with wet scrubbers using either lime or limestone. In addition, 17 utility units with a combined capacity of 10,500 MW are under construction or under contract to use these wet scrubbing technologies. Lime and limestone wet scrubbers represent about 80 percent (MW basis) of the FGD system capacity in operation, under construction, or under contract in the United States.

During the last decade, the lime spray dryer process has been used on a number of new PC boiler installations. This FGD process absorbs SO_2 through the use of a spray absorber dryer module followed by a fabric filter. A benefit of the spray dryer process compared to wet scrubber FGD systems is the dry waste product resulting in less complicated and less expensive waste disposal.

Both wet scrubbers and spray dryers are capable of very high SO_2 removal efficiencies. Because of the highly alkaline nature of lime, wet lime scrubbers are capable of up to 97 percent SO_2 removal. Considering an adequate control margin of 3 percent (to ensure reliability during process control upsets), a wet lime scrubber should be capable of meeting an outlet emission requirement of 0.24 lb/MBtu (94 percent removal).

The lime spray drying technology is capable of up to 95 percent removal because of the less efficient nature of its SO_2 removal reaction. Accordingly, lime spray dryers should be capable of maintaining compliance with an outlet emission requirement of 0.32 lb/MBtu (92 percent removal). Wet limestone scrubbers are also capable of up to 95 percent SO_2 removal. Considering an adequate 3 percent control margin, wet limestone scrubbers should also be capable of meeting an SO_2 emission requirement of 0.32 lb/MBtu (92 percent removal).

The following are the alternative FGD technologies evaluated consistent with a top-down approach.

- LAER Alternative--Wet lime scrubber designed to achieve an SO_2 emission rate of 0.24 lb/MBtu on a 30-day rolling average basis.
- BACT Alternative 1--Wet limestone scrubber system designed to achieve an SO_2 emission rate of 0.32 lb/MBtu on a 30-day rolling average basis.
- BACT Alternative 2--Lime spray dryer system designed to achieve an SO_2 emission rate of 0.32 lb/MBtu on a 30-day rolling average basis.

Table 3.4-6 lists estimated sulfur dioxide emissions for the various SO_2 removal alternatives when burning the typical coal. Should shorter averaging periods be desired, emission rates should be increased to account for decreased potential for compliance.

Economic Evaluation of FGD Alternatives. To determine relative economics, each FGD alternative is evaluated on a total air quality control system (AQCS) basis. The AQCS includes the following subsystems.

- Additive storage and preparation.
- Flue gas desulfurization.
- Particulate removal.
- Flue gas supply and exhaust.
- Waste storage and conditioning.

Capital costs are based on FGD systems designed to meet SO_2 removal requirements when burning the worst case coal (high sulfur and low heating value). Operating costs are based on FGD systems operated to meet SO_2 removal requirements when burning the typical coal.

Technical Design Criteria.

Wet Lime Scrubber AQCS. Figure 3.4-1 shows the equipment included in a PC boiler/wet lime scrubber AQCS that would be designed for Stanton 2. With this system, flue gas exiting the air heater passes through electrostatic precipitators and is directed by induced draft (ID) fans to the absorber modules (spray towers). The ID fans are located between the electrostatic precipitators and the absorber modules to minimize particulate erosion and water vapor condensation on fan internals.

Wet lime absorber modules serve as the contact zone where the alkaline additive absorbs the SO_2 from the flue gas. Recycle pumps spray the lime slurry counter-current to the direction of the flue gas flow. The resultant reaction products flow downward through the spray tower into the reaction tank while the flue gas flows out of the absorber module and into the stack. Table 3.4-7 lists selected design parameters for wet lime scrubber AQCS.

The scrubber module diameter listed in Table 3.4-7 is based on a flue gas velocity limit through the module of 10 feet per second (fps). At velocities above 10 fps, mist eliminator equipment performance degrades quickly. For consideration of overall plant reliability, system design is based on the use of three 50 percent capacity modules.

The preparation of lime slurry is accomplished by the additive storage and preparation system. With this system, pebble lime is stored in silos to protect it from moisture. Lime from storage silos is hydrated in a slaker/classifier system for feed to the slurry storage tanks (24-hour capacity). Additive from the slurry storage tank is transported to absorber module reaction tanks by additive feed pumps.

To convert the liquid waste to a solid waste product for disposal, blowdown from the absorber module reaction tanks is pumped to a thickener for primary dewatering. The decanted water from the thickener is reused in the reaction tanks and to slurry additional lime, while the underflow from the thickener is pumped to vacuum filters for additional dewatering. Thickened sludge from the vacuum filters is mixed with fly ash to form a product suitable for transport to disposal. Wastes are transported by trucks to an onsite landfill disposal location.

Wet Limestone Scrubber AQCS. Figure 3.4-2 shows the equipment included in a wet limestone scrubber AQCS that would be designed for Stanton 2. With the exception of additive preparation and adipic acid addition, a wet limestone system process flow sheet is very similar to a wet lime scrubber AQCS. Additive preparation differences are due to the low solubility of limestone allowing on-ground bulk storage and requiring ball mills for preparing additive slurry. Adipic acid is required to enhance removal efficiency when higher sulfur coals are burned. The adipic acid tends to buffer slurry pH enhancing liquid phase alkalinity. Table 3.4-8 lists selected design parameters for the wet limestone scrubber AQCS.

Lime Spray Dryer AQCS. Figure 3.4-3 shows the scope of equipment included in a lime spray dryer AQCS. Table 3.4-9 lists the design parameters used to evaluate the lime spray dryer AQCS.

The lime spray dryer AQCS is a two-stage process that removes both sulfur dioxide and particulate from the flue gas through the use of a spray dryer/absorber followed by a fabric filter. The absorber modules serve as the initial contact zone where alkaline additive and SO_2 in the flue gas react to form dry reaction products. The majority of reaction products formed in the spray dryer flow out of the absorber modules and into the fabric filter for removal with the fly ash. The ID fans are located between the fabric filters and the stack to minimize particulate erosion on fan internals.

The absorber modules are sized on the basis of gas flow rate and residence time. Residence times of approximately 10 seconds have proved sufficient to ensure adequate reaction product drying. The atomizers, which disperse the additive slurry, are sized on the basis of additive and tempering water feed necessary to achieve the required SO_2 removal level and outlet gas temperature.

Flue gas temperatures at the fabric filter inlet must be sufficiently high to avoid corrosion in the fabric filter and in other downstream equipment. Low flue gas temperatures can also cause condensation of cementatious fly ash materials on the filter bags, severely affecting bag life and fabric filter operation. Adjustment of the spray dryer module approach temperature (number of degrees that the spray dryer operates above the saturation temperature) determines the spray dryer module outlet gas temperature. The amount of water added to the slurry is adjusted to control the spray dryer module outlet gas temperature. For the same SO_2 removal efficiency, a higher approach temperature results in greater lime consumption. Lime consumption increases as a result of a reduction in the SO_2 removal reaction efficiency at the higher approach temperature. An approach temperature of 40 F results in a fabric filter inlet gas temperature of approximately 165 F. An inlet gas temperature of 165 F is sufficiently high to protect the fabric filter and other downstream equipment.

The preparation of lime for use as additive in a spray dryer AQCS is accomplished by the additive storage and preparation system. With this system, pebble lime is stored in silos to protect it from moisture. Lime from storage silos is hydrated in a slaker/classifier system for feed to the slurry storage tanks (24-hour capacity). Additive from the slurry storage tank is pumped to the additive feed tank.

Since a significant portion of the lime feed does not initially react with the SO_2 in the flue gas stream, a portion of the solids collected in the fabric filter is returned and mixed with fresh lime slurry so that unreacted lime or alkalinity contained in the fly ash can be utilized. The lime and recycled solids are blended in a recycle slurry mix tank and pumped to the additive feed tanks.

The solids collected in the fabric filter, which are not recycled, are collected in the solids storage silo and subsequently transported by trucks to an onsite landfill.

Capital Costs. Table 3.4-10 lists the estimated capital costs for the alternative AQCS when the coal listed in Table 3.4-2 is burned. The table shows the capital costs for a complete SO_2 and particulate removal system. Sulfur dioxide and particulate removal costs are based on the design parameters listed in Tables 3.4-7, 3.4-8, and 3.4-9. Economic criteria used to develop capital costs are listed in Table 3.4-1.

Capital costs for air quality control system alternatives range from $111 million, for the lime spray dryer AQCS (0.32 lb/MBtu emission), to $130 million, for the wet limestone AQCS designed for an emission rate of 0.32 lb/MBtu SO_2. The costs in Table 3.4-10 are separated into five categories. The following paragraphs describe the costs included in each of these categories.

Additive storage and preparation. Additive storage and preparation capital costs include all equipment necessary to store and prepare the additive for use in the SO_2 removal process.

A wet ball mill/classifier system is used to obtain slurry of constant properties for use in the wet limestone scrubber modules. The wet lime and lime spray dryer systems use slakers for additive slurry preparation. Slurry is stored in a storage tank designed to hold 24 hours of additive at peak consumption. For the wet limestone scrubber, wet lime scrubber and lime spray dryer AQCS, fresh additive is pumped from the slurry storage tank to the absorber reaction tanks (wet lime and limestone) or the additive feed tank (lime spray dryer).

A recycle system is included for the lime spray dryer to utilize unreacted additive and residual fly ash alkalinity. Solids from the fabric filters are stored in either of two recycle feed bins, each sized for six hours of average recycle feed requirements. Additive from the slurry storage tanks and the recycle mix tanks are combined in the additive feed tanks. The combined lime/recycle material slurry is then pumped to absorber head tanks.

Costs in this category for the alternative AQCS include a reclaim hopper with vibratory grizzly and mechanical conveyors (wet limestone AQCS), portable pneumatic conveyors (wet lime scrubber and lime spray dryer AQCS), additive storage silos, ball mills (limestone slurry), weigh belt feeders, slakers (lime slurry), slurry storage tanks, additive feed system, recycle system (lime spray dryer AQCS), piping, valves, electrical and control equipment, and foundations and enclosures.

Flue gas desulfurization. Flue gas desulfurization capital costs include all equipment necessary for desulfurization of the flue gas with prepared alkaline additive.

Wet limestone and lime scrubber module costs are estimated assuming rubber-lined carbon steel vessels. Reaction tanks are sized for 10 minutes of slurry retention. FGD capital costs for the wet limestone and lime scrubber AQCS include scrubber modules, reaction tanks, recirculation pumps, miscellaneous tanks and pumps, piping, valves, electrical and control equipment, and foundations and enclosures.

The wet limestone scrubber shows a lower than expected capital cost because it is a virtual duplicate of the Stanton 1 wet limestone scrubber, requiring only replicate engineering and equipment drawings.

Absorber module costs for the lime spray dryer AQCS are estimated assuming carbon steel vessels. Costs for the lime spray dryer AQCS include absorber modules, atomizers, foundations and enclosures, piping, valves, and electrical and control equipment.

Particulate removal. Consistent with the results presented in Subsection 3.4.3.2, particulate removal costs for the wet limestone and the wet lime AQCS include costs for an electrostatic precipitator. The electrostatic precipitator is designed for a SCA of 743 ft^2 per 1,000 acfm of gas flow with a flue gas velocity of 3.5 feet per second.

Particulate removal costs for the lime spray dryer AQCS include costs for two 12-compartment, reverse gas cleaned fabric filters. The fabric filters are designed for a maximum net cloth velocity of 2.3 ft/min (one compartment out of service for cleaning and one out of service for maintenance).

In addition to precipitator and fabric filter costs, particulate removal costs include inlet and outlet ductwork, ash handling equipment, foundations and enclosures, and electrical and control equipment.

Flue gas supply and exhaust. The flue gas supply and exhaust capital cost category includes ductwork needed to route the flue gas to the ID fans, absorber modules (if applicable), the particulate removal system, and the stack. This cost also includes incremental ID fan capacity capable of overcoming additional flow resistance created by the flue gas desulfurization and particulate removal systems.

Waste storage and conditioning. Waste storage and conditioning capital costs include all equipment necessary for transportation, separation, storage, and conditioning of wastes in preparation for transportation to the offsite disposal location.

For the wet limestone and wet lime scrubber AQCS, blowdown from the absorber module reaction tanks is pumped to the thickener for primary dewatering. Thickener overflow is reused in the reaction tanks and to slurry additional limestone or lime, depending on the process. The underflow from the thickener is pumped to a surge tank in preparation for secondary dewatering. Secondary dewatering is accomplished by vacuum filters. Thickened sludge from the vacuum filters is mixed with fly ash to form a product suitable for transport to disposal. Costs in this category include a primary and secondary dewatering system, a sludge/fly ash mixing system, conveyors for transport of conditioned waste products and stockout of the waste mixture, piping, valves, electrical and control equipment, and foundations and enclosures.

For the lime spray dryer AQCS, waste solids from absorber modules and fabric filter hoppers are transported and stored in elevated solids storage silos. It is assumed for this analysis that wastes will be conditioned with water. Conditioning with water fixates the waste as water reacts with unused quantities of lime contained in the waste products, thereby controlling fugitive dust. Waste conditioning capital costs for the lime spray dryer AQCS include solids handling equipment, solids storage silos, waste conditioners, piping, valves, electrical and control equipment, and foundations and enclosures.

Levelized Annual Operating Costs. Table 3.4-11 lists the levelized annual operating costs for the air quality control system alternatives. Levelized annual costs reflect the effects of escalation and present worth discounting on future operating cost expenditures. First year operating costs are multiplied by the levelization factor listed in Table 3.4-1 to obtain a levelized annual operating cost.

Levelized annual operating costs listed in Table 3.4-11 range from $26 million for the 0.32 lb/MBtu SO_2 emission rate wet limestone scrubber AQCS, to $44 million for the lime spray dryer AQCS also designed for an emission rate of 0.32 lb/MBtu SO_2.

Operating personnel costs include personnel required for additive preparation, flue gas desulfurization, particulate removal, and waste conditioning operations. Personnel costs, including salary and benefits, are based on a 1991 labor cost of $43,333 per employee year and a 4.75 percent escalation rate. Maintenance personnel costs are included in the maintenance cost described below.

Maintenance costs are estimates of material and labor required to operate alternative AQCS. Maintenance costs are a major contributor to operating costs and vary proportionally with the amount of equipment installed. It is not likely that the maintenance expense shown in Table 3.4-11 would occur during the first few years of unit operation, but is representative of average annual maintenance costs over the life of the plant.

Additive requirements for the AQCS alternatives are determined on the basis of the SO_2 removal requirements and on actual reaction stoichiometrics obtained from operational and experimental data. Additive costs are based on a 1991 limestone cost of $8 per ton, and on a 1991 pebble lime cost of $80 per ton.

Energy costs are also included to account for alternative AQCS auxiliary power requirements. Energy costs are calculated based on operation of AQCS equipment, and the costs associated with operating ID fans to overcome the differential pressure drop caused by the operation of the AQCS.

Annual waste disposal costs are based on the use of a subcontractor to transport and dispose of wastes. Waste solids will be transported by trucks to an onsite landfill.

Total Levelized Annual Costs. In addition to levelized annual operating costs, Table 3.4-11 presents a levelized annual cost summary. The total levelized annual cost allows comparison of alternative AQCS. The total levelized annual cost is calculated as the sum of fixed charges on capital investments and operating costs. Total levelized annual costs range from \$36 million for the wet limestone scrubber AQCS designed for an emission rate of 0.32 lb/MBtu SO_2, to \$52 million for the lime spray dryer AQCS also designed for an emission rate of 0.32 lb/MBtu SO_2.

Other Considerations. As indicated in the assumptions for this section, it is expected that a 3 percent SO_2 removal control margin between expected and required performance is necessary to ensure compliance during periods of process upset or equipment outages. For contemporary FGD systems, the fundamental element for noncompliance is one of process control. At a target SO_2 removal of 94 to 95 percent for a wet limestone scrubber AQCS (approaching the practical limits of this technology), the distribution of daily efficiencies becomes skewed. Although it would not be unusual for a scrubber targeting 94 percent removal to drift to a 91 percent daily removal rate, it is much less likely that a 97 percent daily removal would occur.

To maintain consistent compliance, the margin between "target" and "30-day average" (compliance) must be large enough to allow for this potential performance shift. Statistical analysis of operating FGD systems correlating performance and reliability have indicated that the appropriate minimum margin is 3 percent to maintain compliance with a 30-day rolling average.

This concern for the Stanton Energy Center is further confirmed by the fact that the plant is designed for zero discharge of plant wastewater. Accordingly, there is a high degree of makeup water quality variability complicating FGD process chemistry (especially with respect to chlorides control). The ability of OUC to achieve or exceed 30-day rolling average removal limitations would be severely compromised by requiring an unduly high compliance level.

Energy Evaluation of Alternatives. The lime spray dryer AQCS has the lowest energy demand of FGD alternatives. At peak demand, this difference represents 1.1 percent and 1.8 percent of total plant power output as compared to the wet lime scrubber AQCS and the wet limestone scrubber AQCS, respectively.

Conclusions. A wet lime scrubber AQCS designed for an emission rate of 0.24 lb/MBtu SO_2 has a total levelized annual cost of \$47 million. Levelized annual costs are \$10 million higher than a wet limestone scrubber AQCS designed for an emission rate of 0.32 lb/MBtu SO_2. The additional costs for a wet lime AQCS result in an incremental removal cost of \$6,900 per ton of SO_2 removed, to go from an emission rate of 0.32 lb/MBtu SO_2 to 0.24 lb/MBtu SO_2. The lime spray dryer AQCS has the highest levelized annual cost of $52 million.

On the basis of economics and environmental considerations, a wet limestone scrubber AQCS designed for an emission rate of 0.32 lb/MBtu SO_2 on a 30-day rolling average is considered to represent BACT for use at Stanton 2. In addition, to accommodate process control and equipment reliability problems as well as provide for some fuel quality flexibility, it is proposed that 3-hour and 24-hour emission requirements of 0.85 lb SO_2/MBtu and 0.67 lb SO_2/MBtu, respectively, be allowed.

3.4.3.4 Nitrogen Oxides, Carbon Monoxide, and VOC Emissions Control. The objective of this analysis is to determine BACT for nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compound (VOC) emissions. Because of the mutually dependent formation characteristics of NO_x, CO, and VOC (expressed as total nonmethane hydrocarbons) emissions, it is necessary to consider BACT concurrently for these emissions.

Additional Requirements and Assumptions.

- Nitrogen oxide emissions are limited by New Source Performance Standards to 0.60 lb/MBtu of heat input to the boiler for bituminous coal. The coal listed in Table 3.4-2 is a bituminous coal.
- There are no coal fired boiler NSPS limiting the emission of CO or VOC.
- A review of information contained in the BACT/LAER Clearinghouse (1985 and 1990 editions) indicates that the most stringent NO_x emission limit issued to date is 0.043 lb/MBtu for a proposed project located in California. The installation will use a circulating fluidized bed boiler with a selective noncatalytic reduction system.
- Fluidized bed boilers are not available in the size necessary for Stanton 2, and, therefore, will not be considered further.
- A review of information contained in the BACT/LAER Clearinghouse indicates that the most restrictive NO_x emission requirement for a pulverized coal installation is 0.44 lb/MBtu for a plant in Arizona. NO_x emissions from this facility are limited through the use of combustion controls.
- The most stringent CO emission limit issued to date is a requirement of 0.014 lb/MBtu for a project operating in Florida. This unit limits CO emissions through the use of combustion controls consistent with meeting a NSPS NO_x emission limit of 0.60 lb/MBtu.

- The most stringent VOC emission limit is a requirement of 0.003 lb/MBtu for a project operating in Virginia. This unit limits VOC emissions through the use of combustion controls consistent with meeting a NSPS NO_x emission of 0.60 lb/MBtu.
- Since NO_x emissions are the dominant pollutant with regard to total impact, this analysis will be based on optimizing combustion controlled emissions to minimize NO_x emissions.

Emission Control Alternatives. Nitrogen oxides and CO/VOC emission controls are divided into two categories: in-furnace formation control and post-combustion emission reduction. In-furnace combustion control processes reduce the quantity of NO_x and CO/VOC formed during the combustion process. Post-combustion NO_x controls reduce a portion of the NO_x exiting the boiler to nitrogen and water. Post-combustion CO/VOC emission controls oxidize a portion of these pollutants to carbon dioxide and water.

In-Furnace Combustion Control. Nitrogen oxides are formed by the oxidation of nitrogen contained in the fuel (fuel NO_x) and in the combustion air (thermal NO_x). Nitrogen oxide emissions are limited by lowering combustion temperatures, minimizing excess combustion air, and staging combustion. Carbon monoxide and volatile organic compounds are formed by incomplete combustion of coal. Increasing combustion temperatures, increasing excess air, and better fuel/air mixing during combustion minimize CO and VOC emissions while increasing NO_x emissions.

The commercial installation of low NO_x burners over the last several years represents an advance in the control of NO_x emissions from pulverized coal fired boilers. Low NO_x burners reduce NO_x formation in the boiler by maintaining a reducing atmosphere at the coal nozzle and diverting additional combustion air (to complete combustion) to secondary air registers. This staged combustion primarily inhibits the formation of fuel NO_x.

The NO_x emission rate of 0.32 lb/MBtu, based on current pulverized coal combustion controls utilizing advanced design burners and associated peripherals, represents over a 45 percent decrease below Stanton 1 emission requirements of 0.60 lb/MBtu. Consistent with the use of these combustion controls minimizing NO_x emissions, carbon monoxide and volatile organic compound emissions are expected to be 0.15 lb/MBtu and 0.015 lb/MBtu, respectively. Further decreases in CO and VOC emissions will result in NO_x emission increases.

Post-Combustion Emissions Reduction Systems. Nitrogen oxide emissions from a coal fired boiler can be reduced by use of either a selective catalytic reduction (SCR) or a selective noncatalytic reduction system (SNCR). These systems are the only potentially viable post-combustion NO_x emission reduction technologies that can be considered for installation on pulverized coal boilers.

SCR Systems. In an SCR system, ammonia is injected into the flue gas stream just upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate reducing a significant portion of the NO_x into nitrogen and water. SCR systems may potentially reduce NO_x emissions by as much as 70 to 90 percent.

The ammonia (either aqueous or anhydrous) is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by either compressed air or steam carrier. Injection of the ammonia must occur at temperatures between 600 and 800 F. Therefore, the system is logically located between the economizer outlet and the air heater inlet. The SCR catalyst is housed in a reactor vessel which is separate from the boiler. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

Ammonia is a hazardous material. Therefore, ammonia must be handled and stored with extreme care. Working on and around ammonia equipment will cause operational personnel to be less productive and functional than under normal working conditions.

SCR systems have been used predominately on Japanese and West German gas, oil, and coal fired boilers. Coal fired boilers that have utilized SCR have all burned low sulfur (less than 1.3 percent) coals with relatively low ash contents. There are no coal fired boilers using SCR systems in the United States.

In addition to fuel quality and safety concerns, SCR systems will experience problems with unreacted ammonia slippage. SCR systems generally have ammonia slip rates of between 5 and 10 ppm. Unreacted ammonia and sulfur trioxide can react to form ammonia bisulfate and ammonia sulfate salts. These sticky substances can severely affect downstream equipment. Air heaters could suffer pluggage problems and fabric filters could experience bag blinding if these substances were present in the flue gas. In addition, fly ash tends to erode the catalyst, leading to premature failures, and a number of trace metals have detrimental effects on catalyst reactivity. In general, United States coals contain higher levels of sulfur, ash, and trace metals than the coals used in Japan and West Germany. The sulfur, ash, and trace metal contents of United States fuels could significantly affect the performance and operating reliability of an SCR system. It has been estimated that SCR systems burning United States coal could experience a catalyst life of one year or shorter. Catalyst costs account for over 60 percent of the initial capital cost of an SCR system.

In summary, based on the eastern United States coals being considered for use at Stanton 2, and based on the complete lack of SCR experience with these coals, this analysis will not consider the use of SCR.

SNCR Systems. Selective noncatalytic NO_x reduction systems rely on the appropriate reagent injection temperature and good reagent/gas mixing rather than a catalyst to achieve NO_x reductions. SNCR systems can use either ammonia (Thermal $DeNO_x$) or urea (NO_xOUT) as reagents.

Ammonia for a Thermal $DeNO_x$ system is stored as a liquid. Subsequently, the ammonia is vaporized and injected into the flue gas using either compressed air or steam as a carrier. The ammonia then reacts with the NO_x to form nitrogen and water. Reagents for SNCR systems are injected in the backpass (convective portion) of the boiler.

Urea for a NO_xOUT system is stored as a 50 percent solution in water. This solution is atomized at the injection point to optimize mixing. In the flue gas, the urea molecule dissociates to form two molecules of NH_3 (ammonia). The NH_3 reacts with NO_x to form nitrogen and water. Urea would be injected at a similar location to an ammonia based SNCR system.

The optimum temperature range for injection of ammonia or urea is 1,550 to 1,900 F. The NO_x reduction efficiency of the SNCR system decreases rapidly at temperatures outside this range. Operation below this temperature window results in excessive ammonia emissions. Operation above this temperature window results in increased NO_x emissions. A pulverized coal boiler operates at a temperature of between 2,500 and 3,000 F. Therefore, the optimum temperature window in a pulverized coal fired boiler occurs somewhere in the backpass of the boiler. To further complicate matters, this temperature location will change as a function of unit load. In addition, residence times in this temperature window are limited, further detracting from optimum performance.

SNCR systems are a less efficient NO_x reduction system than SCR systems. In general, SNCR systems on pulverized coal fired boilers will only be capable of between 40 and 50 percent NO_x reduction. The major site specific considerations that limit the NO_x emission reduction potential of SNCR systems include boiler temperature profile, the coal's sulfur and chlorine contents, and the geometry of the boiler (affecting effective additive distribution).

Both SNCR processes require more than twice the theoretical amount of reagent to achieve these NO_x reductions. Accordingly, SNCR systems produce significant quantities of unreacted ammonia. A portion of this ammonia decomposes into nitrogen and water. However, any ammonia that does not decompose exits the system as ammonia slip. SNCR systems installed on pulverized coal boilers would have ammonia slips of between 10 and 50 ppm.

Ammonia slip will either exit the system through the stack or condense onto the fly ash collected in the electrostatic precipitator. Unless stack emissions are in excess of 50 ppm, it is not likely that a noticeable odor will occur. However, fly ash will absorb some of the ammonia from the flue gas stream and will tend to be odorous. Accordingly, if an SNCR system is used, commercial sale of fly ash will not be possible because of the ammonia contamination. Stanton 1 has historically been capable of selling all ash production for use in the concrete industry. It was expected that Stanton 2 would be similarily capable. However, should an SNCR system be required, the potential for fly ash sales from Stanton 2 would be eliminated due to ammonia contamination. As a result, this contaminated fly ash must be disposed of in an onsite landfill, incurring additional cost.

Close control of SNCR system ammonia or urea injection in a pulverized coal fired boiler is difficult. Tube spacings, temperature profiles, and the physical size of a pulverized coal fired boiler such as Stanton 2 greatly complicate additive injection. These problems are likely to result in additional ammonia slip emissions or diminished performance. In addition, reliable continuous ammonia emission monitors have proved to be highly unreliable. Without ammonia monitors, it is not possible to optimize reagent injection through feedback control by ammonia slip measurements. This also results in higher ammonia slip emissions.

Similar to SCR systems, unreacted ammonia and sulfur trioxide can react to form ammonia bisulfate and ammonia sulfate salts. Based on the SNCR injection location and higher levels of ammonia slip, there is a higher potential to foul equipment more severely in an SNCR system than in an SCR system. In addition, the formation of ammonia salts will increase the fine particulate (less than

10 microns) loading to the fabric filter. Therefore, if an SNCR system is used, it is likely that PM_{10} emissions will increase.

An additional technical concern with the use of an SNCR system is the creation of an ammonia chloride plume (typically brown in color). It has been documented that for fuels with significant chloride content (greater than approximately 0.05 percent), ammonia slips of 5 ppm and higher will result in a continuous ammonia chloride plume. The ammonia chlorides do not increase opacities measured by the continuous emissions monitor, but would nonetheless be visible to the human eye. This would be a significant negative aesthetic impact for use of an SNCR system. It is likely that ammonia slips will exceed 5 ppm unless NO_x reduction efficiencies are maintained at 30 percent or less for Stanton 2.

As previously described for SCR systems, ammonia is a hazardous material. Accordingly, this material for a Thermal $DeNO_x$ type SNCR must be handled and stored with extreme care. Working on and around ammonia equipment will cause operational personnel to be less productive and functional than under normal working conditions.

An additional disadvantage of a NO_xOUT type SNCR system is higher carbon monoxide emissions. Carbon molecules released from the urea molecule during decomposition to ammonia can react to form carbon monoxide. Equipment supplier estimates indicate that CO emissions could increase by as much as 10 to 20 percent.

Despite the potential problems, a review of information contained in the BACT/LAER Clearinghouse (1985 and 1990 editions) provided a number of California projects that were required to use SNCR systems. However, all of these projects are smaller fluidized bed boilers. Fluidized bed boilers provide a more optimum reaction environment for NO_x reduction operations. In addition, because of nonattainment status and California's unique air quality problems, these limitations are more representative of LAER determinations. All of the facilities operating with SNCR burn coal with very low sulfur and chloride contents (approximately 0.5 and 0.03 percent or less, respectively, in fluidized bed boilers). Fluidized bed boilers provide an optimum environment for the use of SNCR systems because of prolonged residence times at the appropriate reaction temperature.

With the relatively high sulfur and chlorine content of the coal available for use at Stanton 2, it is recommended that SNCR systems designed for 40 percent (outlet emission of 0.19 lb/MBtu) and 30 percent (outlet emission of 0.22 lb/MBtu) NO_x reduction be evaluated for use. An SNCR system designed for higher NO_x reductions would have higher ammonia slip emissions and a higher probability of an ammonia chloride plume, and would run a significantly higher risk of lower unit reliability as a result of the possibility of equipment fouling from ammonia salts.

CO and VOC Emissions Reduction Systems. Lower CO and VOC emissions are possible if boiler temperatures are increased. However, NO_x formation would increase. Therefore, consistent with the approach of evaluating BACT for CO and VOC emissions based on BACT for NO_x, increasing combustion temperatures to limit CO and VOC emissions is not an option.

A catalytic CO and VOC emissions reduction method is available for use on the exhaust from combustion turbines and petroleum refining operations. The process oxidizes CO, resulting in the emission of carbon dioxide and water. The process is a straight catalytic oxidation/reduction reaction requiring no additives. However, the platinum coated catalyst is extremely expensive.

This process has never been applied to a coal fired power plant. The catalytic reaction is effective at a temperature of approximately 700 F. In pulverized coal boilers, a temperature of 700 F is available just upstream of the air heater. However, because of the potential for erosion and pluggage of the platinum catalyst by abrasive combustion products, and poisoning of the catalyst by trace metals in the fly ash, this process is unsuited to coal fired applications, and is, therefore, considered not technically feasible for Stanton 2.

Economic Evaluation of Alternatives. Table 3.4-12 lists the estimated emission of NO_x, CO, VOC, and ammonia for the NO_x emission control alternatives. Table 3.4-13 lists the estimated total capital and annual cost for installing an SNCR NO_x emission reduction system on Stanton 2. The table shows all costs for a complete ammonia based SNCR system. It is expected that costs for a urea based system would be approximately equivalent to those for an ammonia based system. The costs listed are incremental costs assuming a base case of combustion controls for NO_x emission control. Economic criteria used to develop these costs are listed in Table 3.4-1.

The capital costs include ammonia receiving, storage, and injection equipment; technology licensing fees; and balance-of-plant costs. Balance-of-plant costs include foundations, dikes, structural steel, piping, wash water system for air heater, and electrical and control equipment. In addition, because of safety considerations regarding the use and storage of ammonia, fire protection and other safety equipment costs were included.

Incremental levelized annual operating costs for an SNCR system are also presented in Table 3.4-13. Operating costs include operating personnel, maintenance, ammonia additive, electric energy, and demand costs, as well as loss of fly ash sales and fly ash landfill costs.

Installing an SNCR system would add approximately $14 million and $11 million to the capital cost of Stanton 2 for 40 percent and 30 percent NO_x reduction systems, respectively. The total levelized annual cost for an SNCR system would be approximately $6.5 million and $5.5 million for 40 percent and 30 percent NO_x reduction systems, respectively. These costs result in an incremental NO_x reduction cost of $2,700 per ton (40 percent reduction--2,403 tons reduced per year) and $3,100 per ton (30 percent reduction--1,802 tons reduced per year) as compared to use of combustion controls to achieve an NO_x emission of 0.32 lb/MBtu.

Energy Evaluation of Alternatives. An SNCR system consumes both electrical and steam energy. An ammonia based SNCR system would require approximately 2,200 kW of electrical energy. This represents approximately 0.5 percent of total plant power output.

Environmental Evaluation of Alternatives. Areas surrounding Stanton 2 are classified as attainment areas for NO_x, CO, and VOC. Modeling analyses based on NO_x and VOC emission rates of 0.32 lb/MBtu and 0.012 lb/MBtu, respectively, indicate that ambient impacts of emissions from Stanton 2 were below impacts predicted in the original Stanton 1 Site Certification Application.

Operation of a selective noncatalytic reduction system to meet an NO_x emission limit of 0.19 lb/MBtu (40 percent reduction) will likely result in excessive ammonia slip emissions of between 20 and 50 ppm. Accordingly, this ammonia slip in conjunction with chloride emissions will result in the formation of a visible ammonia chloride plume. An SNCR system operated to limit NO_x emissions to 0.22 lb/MBtu (30 percent reduction) will likely have ammonia slip emissions below 5 to 10 ppm. Operation of an SNCR system to meet this NO_x emission is less likely to result in any visible ammonia chloride emissions from the plant.

Conclusions. Advances in the control of NO_x from pulverized coal boilers enable the project to lower anticipated NO_x emissions from the Stanton 1 emission limit of 0.6 lb/MBtu to 0.32 lb/MBtu. This level is more than 45 percent lower than the Stanton 1 emission limit of 0.60 lb/MBtu and 27 percent lower than the lowest NO_x emission limit on record (BACT/LAER Clearinghouse) for a pulverized coal boiler. Consistent with this NO_x emission, carbon monoxide and VOC emissions are expected to be 0.15 and 0.015 lb/MBtu, respectively.

Selective catalytic reduction systems are insufficiently developed for use on pulverized coal fired boilers burning United States coal. Selective noncatalytic reduction systems could possibly be used on Stanton 2. However, SNCR systems are not demonstrated on pulverized coal boilers burning coals with sulfur contents greater than 0.5 percent. A higher coal sulfur content results in larger amounts of ammonia bisulfate and ammonia sulfate being produced when an SNCR system is used. It is likely that these relatively sticky compounds will deposit on downstream equipment detrimentally affecting unit reliability. Ammonia salts that do exit the stack will largely consist of particles less than 10 microns.

Reagent injection control for SNCR systems is not precise. Therefore, ammonia slip emissions of between 10 ppm (27 lb/h) and 50 ppm (135 lb/h) can be expected. Fly ash will absorb some of the ammonia from the flue gas stream and will tend to be odorous. Like Stanton 1, it was anticipated that fly ash from Stanton 2 would be sold. Use of an SNCR system on Stanton 2 would eliminate the environmentally sound practic of selling fly ash for reuse in the concrete industry.

In addition, use of an ammonia based system will result in handling and storage of a hazardous material on the Stanton 2 site. Alternatively, use of a urea based system will result in increased CO emissions.

Use of an SNCR system (designed to achieve 40 percent NO_x reduction) at Stanton Unit 2 is estimated to cost $6.5 million annually. This results in an incremental NO_x reduction cost of $2,700 per ton. Ammonia slip emissions from this system of 20 ppm are likely to result in a visible ammonia chloride plume. This is a significant concern considering the location of the Stanton Energy Center in Orlando. NO_x reduction must be lowered to eliminate the potential for an ammonia chloride plume. NO_x reduction must be decreased to 30 percent.

This results in an annual cost of approximately $5.5 million (incremental reduction cost of $3,100 per ton).

In addition to the costs identified in Table 3.4-13, a requirement for an SNCR system on Stanton 2 would limit the operating reliability of the unit. Use of this system would increase the mechanical complexity of the plant as well as impacting downstream equipment operability and reliability. This decreased plant reliability could result in significant additional cost impacts. These cost impacts are not reflected in this analysis.

The preceding discussion strongly supports that on the basis of technical, economic, energy, and environmental considerations, combustion controls designed to meet an NO_x emission requirement of 0.32 lb/MBtu represents BACT for Stanton 2 and SNCR should not be applied to this installation.

3.4.3.5 Lead and Noncriteria Pollutant Emissions Control. An additional requirement of BACT analyses is the evaluation of control technologies for lead, Prevention of Significant Deterioration (PSD) noncriteria pollutants, and other hazardous air pollutants that may occur. Coal contains a number of trace elements which may be volatilized during combustion. In addition, a number of other organic emissions can also occur as a byproduct of combustion. The EPA has identified a list of potential hazardous air pollutants from coal fired combustion ("Control Technologies for Hazardous Air Pollutants," EPA/625/6-86/014, September 1986). This section discusses the control of these emissions from Stanton 2.

Coal does not contain asbestos or vinyl chloride, and none is formed during combustion. Therefore, asbestos and vinyl chloride emissions do not require further consideration since annual emissions will be less than PSD significance levels.

Hydrogen sulfide and reduced sulfur compounds form in a reducing atmosphere. Combustion in a pulverized coal fired boiler occurs in an oxidizing atmosphere. Therefore, emissions of these compounds will be less than PSD significance levels.

An additional benefit of particulate removal and flue gas desulfurization air quality control efforts is the removal of a number of the hazardous air pollutants from the flue gas stream. Removal occurs as a result of either condensation of trace emissions from the flue gas onto fly ash particles, or absorption by the scrubbing liquor. Control of organic emissions occur as a result of complete combustion in the boiler (consistent with the control of carbon monoxide and volatile organic compound emissions). Table 3.4-14 lists estimated emissions for lead, PSD noncriteria pollutants, and other hazardous air pollutants identified by the EPA. Emission estimates listed in Table 3.4-14 are based on coal trace element concentrations, expected removal efficiencies, and other emission factors from available literature.

Coal trace element concentrations vary significantly between coal suppliers. Since a coal supplier has not been selected for Stanton 2, it is necessary to estimate these trace concentrations independently. Where possible, concentrations were estimated on the basis of information contained in the EPA publication "Estimating Air Toxics Emissions from Coal and Oil Combustion Sources" (EPA-450/2-89-001). In the absence of information from that source, concentrations were estimated from values contained in "Trace Elements in Coal" (Vlado Valkovic, CRC Press, 1983).

Expected removal efficiencies were derived from emission test results from similar facilities. The removal efficiencies listed in the table should be representative. However, it should be noted that there is not an abundant amount of information available to predict removal performance.

Formaldehyde, radionuclide, and polycyclic organic matter (POM) emissions are based on emission factors from the EPA publication "Estimating Air Toxics Emissions from Coal and Oil Combustion Sources." Estimates of phenol and pyridine emissions were based on information contained in the EPA publication "Emissions of Reactive Volatile Organic Compounds from Utility Boilers" (EPA-600/7-80-111).

BACT regarding these trace emissions will occur as part of control technologies (BACT) for particulate, sulfur dioxide, carbon monoxide, and volatile organic compound emissions.

3.4.3.6 Summary. The following is a summary of BACT for Stanton 2 and the associated emission rates.

- Sulfur dioxide—A wet limestone scrubber AQCS designed to meet an SO_2 emission limit of 0.32 lb/MBtu.
- Nitrogen oxides, CO, and VOC—Combustion controls designed to meet an NO_x emission requirement of 0.32 lb/MBtu for NO_x, 0.15 lb/MBtu for CO, and 0.015 lb/MBtu for VOCs.

- Particulate--An electrostatic precipitator designed to meet a 0.02 lb/MBtu (0.01 gr/dscf) emission limit.

3.4.4 Design Data for Control Equipment

Control equipment design data are included as part of the detailed BACT analyses contained in Subsection 3.4.3.

3.4.5 Design Philosophy

In general, air quality control system designs are determined based on conservative design parameters. Parameters are developed to ensure adequate performance to equal or better emission requirements. Where necessary, adequate spares (i.e., 50 percent spare capacity in the FGD system) are provided to ensure the operating reliability of the plant. Specific details of the design philosphy can be found in the detailed BACT analyses contained in Subsection 3.4.3.

Table 3.4-1
Economic Evaluation Criteria

Item	Value
Fuel Burn Rate	4,286 MBtu/h
Initial Operation	January 1997
Economic Recovery Period	35 years
Contingency Cost Factor	10 percent
Capital Escalation Rate	4.5 percent
O&M Escalation Rate	4.75 percent
Additive Escalation Rate	4.75 percent
Levelized Fixed Charge Rate[a]	7.90 percent
Present Worth Discount Rate	7.03 percent
Levelization Factor[b]	1.687
Indirects Cost Factor	16 percent
Allowance for Funds Used During Construction	7.10 percent
Capacity Factor	100 percent
1991 Pebble Lime Cost	80 $/ton
1991 Limestone Cost	8 $/ton
1991 Labor Cost	43,333 $/man-year
1991 Energy Cost	47.59 mills/kWh
1991 Waste Disposal Cost	10 $/ton

[a]Calculations are based on the economic recovery period, cost of money, and margins for insurance and taxes.

[b]Calculations are based on the economic recovery period, escalation rate, and present worth discount rate.

Table 3.4-2 Coal Quality Analysis	
Ultimate Analysis	Typical
Carbon	67.0 percent
Hydrogen	4.50 percent
Sulfur	2.5 percent
Moisture	7.5 percent
Nitrogen	1.29 percent
Chlorine	0.11 percent
Oxygen	5.1 percent
Ash	12.00 percent
Higher Heating Value	12,400 Btu/lb

Table 3.4-3
Fabric Filter Design Parameters[a]

Parameter	0.12 lb/MBtu Particulate Emission	0.02 lb/MBtu Particulate Emission
Inlet Gas Flow, acfm	1,636,900	1,636,900
Gas Temperature, F	290	290
Gas Pressure Drop, in. wg	8.0	8.0
Fabric Filter Units	2	2
Compartments Per Unit	12	12
Bags Per Compartment	450	406
Total Number of Bags	10,800	9,744
Filter Area		
Per bag, ft^2	96	96
Per compartment, ft^2	43,200	38,980
Total, ft^2	1,036,800	935,400
Cloth Velocity		
All compartments on-line, ft/min	1.58	1.75
Two compartments out-of-service, ft/min	2.10	2.30
Peak Demand,[b] kW	2,770	2,680

[a]Design parameters are based on one (440 MW net) unit.

[b]Also includes differential ID fan power to overcome fabric filter draft losses.

Table 3.4-4
Electrostatic Precipitator Design Parameters[a]

Parameter	0.02 lb/MBtu Particulate Emission
Inlet Gas Flow, acfm	1,636,900
Gas Temperature, F	290
Gas Velocity, fps	3.5
Aspect Ratio	1.8
Specific Collecting Area, ft^2/1,000 acfm	743
Total Collecting Area, ft^2	1,326,000
Number of Transformer Rectifiers	48
Peak Demand,[b] kW	3,470

[a]Design parameters are based on one (440 MW net) unit.

[b]Also includes differential ID fan power to overcome electrostatic precipitator draft losses.

Table 3.4-5
Capital and Annual Costs of Particulate Removal Systems[a]

	Fabric Filter 0.012 lb/MBtu Particulate Emission ($1,000)	Electrostatic Precipitator 0.02 lb/MBtu Particulate Emission ($1,000)	Fabric Filter 0.02 lb/MBtu Particulate Emission ($1,000)
Capital Costs			
Fabric filter	29,100	NA	25,700
Electrostatic precipitator	NA	22,530	NA
Ductwork and differential ID fans	3,190	4,040	3,190
Waste handling	1,010	1,330	1,000
1991 capital cost	33,300	27,900	29,890
Contingency	3,330	2,790	2,990
1991 direct capital cost	36,630	30,690	32,880
Escalation	7,460	6,250	6,690
Direct capital cost	44,090	36,940	39,570
Indirects	7,050	5,910	6,330
AFUDC	6,680	5,600	6,000
1997 total capital cost	57,820	48,450	51,900
Levelized Annual Costs			
Operating personnel	470	470	470
Maintenance	3,430	790	1,270
Energy	2,860	3,350	2,760
Demand	170	210	170
1997 levelized annual operating cost	6,930	4,820	4,670
Fixed charges on capital	4,570	3,830	4,100
1997 total levelized annual cost	11,500	8,650	8,770
Incremental Removal Cost, $/ton	19,180	Base	NA

[a]Costs are for particulate removal systems installed downstream of a 440 MW net unit.

Table 3.4-6
Sulfur Dioxide Emissions

Alternative	Uncontrolled Emission[a] lb/MBtu	Controlled Emission Rate lb/MBtu	Annual Emission[b] tpy
PC Boiler/Wet Lime AQCS	4.03	0.24	4,506
PC Boiler/Wet Limestone AQCS	4.03	0.32	6,008
PC Boiler/Lime Spray Dryer AQCS	4.03	0.32	6,008

[a]Uncontrolled emissions are based on a typical case fuel sulfur content of 2.5 percent and a higher heating value of 12,400 Btu/lb.

[b]Annual emissions are based on a 100 percent capacity factor.

Table 3.4-7
Selected Wet Lime Scrubber AQCS Design Parameters[a]

Parameter	
Outlet SO_2 Emission, lb/MBtu	0.24
System Inlet Gas Flow, acfm	1,556,000
Inlet Flue Gas Temperature, F	290
Number of Electrostatic Precipitator Units	1
Gas Velocity, ft/sec	3.5
Specific Collection Area, ft^2/1,000 acfm	743
Total Collecting Area, ft^2	1,326,000
Number of Collecting Fields	6
Module Diameter, feet	37
Operating/Spare Modules	2/1
Water Usage, gpm	458
Liquid/Gas Ratio, gal/1,000 acfm	75
Module Outlet Temperature, F	125
Additive Molar Ratio,[b] mol Ca/mol S	1.10
Lime Consumption, tph	8.7
AQCS Peak Demand[c]	13,220

[a]All values are for an AQCS located downstream of one full size (440 MW net) pulverized coal boiler.

[b]Moles of calcium per mole of sulfur in the coal.

[c]Includes all equipment associated with SO_2 and particulate removal system operation including differential ID fan power to overcome AQCS draft losses.

Table 3.4-8
Selected Wet Limestone Scrubber AQCS Design Parameters[a]

Parameter	
Outlet SO_2 Emission, lb/MBtu	0.32
System Inlet Gas Flow, acfm	1,556,000
Inlet Flue Gas Temperature, F	290
Number of Electrostatic Precipitator Units	1
Gas Velocity, ft/sec	3.5
Specific Collection Area, ft^2/1,000 acfm	743
Total Collecting Area, ft^2	1,326,000
Number of Collecting Fields	6
Module Diameter, feet	37
Operating/Spare Modules	2/1
Liquid/Gas Ratio, gal/1,000 acfm	100
Water Usage, gpm	462
System Outlet Temperature, F	125
Additive Molar Ratio[b]	1.12
Limestone Consumption, tph	16.4
AQCS Peak Demand, kW[c]	16,150

[a]All values are for an AQCS located downstream of one full size (440 MW net) pulverized coal boiler.

[b]Moles of calcium per mole of sulfur in the coal.

[c]Includes all equipment associated with SO_2 and particulate removal system operation including differential ID fan power to overcome AQCS draft losses.

Table 3.4-9
Selected Lime Spray Dryer AQCS Design Parameters[a]

Parameter	
Outlet SO_2 Emissions, lb/MBtu	0.32
System Inlet Gas Flow, acfm	1,636,900
Flue Gas Temperature, F	290
Module Diameter, ft	48
Operating/Spare Modules	3/1
Water Usage, gpm	421
Module Outlet Temperature, F	165
Additive Molar Ratio[b], mol Ca/mol S	1.6
Lime Consumption, tph	12.4
Fabric Filter Inlet Gas Flow, acfm	1,425,100
Fabric Filter Compartments	12
Number of Bags per Compartment	338
Total Number of Bags	8,110
Filter Area per Bag, ft^2	96
Cloth Velocity, ft/min	
All Compartments On-Line	1.8
Two Compartments Out-of-Service	2.4
AQCS Peak Demand[c]	8,600

[a]All values are for an AQCS located downstream of one full size (440 MW Net) pulverized coal boiler.

[b]Moles of calcium per mole of sulfur in the coal.

[c]Includes all equipment associated with SO_2 and particulate removal system operation including differential ID fan power to overcome AQCS draft losses.

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Table 3.4-10
Capital Costs of AQCS Alternatives[a]

	Wet Lime AQCS 0.24 lb/MBtu SO_2 Emission Rate $1,000	Wet Limestone AQCS 0.32 lb/MBtu SO_2 Emission Rate $1,000	Lime Spray Dryer AQCS 0.32 lb/MBtu SO_2 Emission Rate $1,000
Additive Storage and Preparation	9,180	10,560	10,210
Flue Gas Desulfurization	27,300	31,680	22,730
Particulate Removal	22,530	22,530	17,950
Flue Gas Supply and Exhaust	7,500	7,500	9,870
Waste Storage and Conditioning	2,630	2,630	2,900
1991 Capital Cost	69,140	74,900	63,660
Contingency	6,910	7,490	6,370
Direct Capital Cost	76,050	82,390	70,030
Escalation	15,480	16,770	14,260
Direct Capital Cost	91,530	99,160	84,290
Indirects	14,640	15,870	13,490
Interest During Construction	13,870	15,030	12,770
1997 Total Capital Cost	120,040	130,060	110,550

[a]Costs are total for one (440 MW net) unit.

Table 3.4-11
Levelized Annual Costs of AQCS Alternatives[a]

	Wet Lime AQCS 0.24 lb/MBtu SO_2 Emission Rate $1,000	PC Boiler/Wet Limestone AQCS 0.32 lb/MBtu SO_2 Emission Rate $1,000	PC Boiler/ Lime Spray Dryer AQCS 0.32 lb/MBtu SO_2 Emission Rate $1,000
Operating Personnel	1,730	1,730	1,570
Maintenance	4,210	4,150	5,680
Additive	15,700	2,960	22,470
Energy	5,530	6,450	3,530
Demand	820	1,000	530
Waste Disposal	9,080	9,710	9,930
1997 Total Levelized Annual Operating Cost	37,070	26,000	43,710
Fixed Charges on Capital	9,480	10,270	8,730
1997 Total Levelized Annual Cost	46,550	36,270	52,440
Incremental Removal Cost, $/ton	6,870	Base	NA

[a]Costs are total for one (440 MW net) unit.

Table 3.4-12 Nitrogen Oxides, Carbon Monoxide, VOC, and Ammonia Emissions				
Alternative	Uncontrolled Emission lb/MBtu	Reduction Rate percent	Emission Rate lb/MBtu	Annual Emission tpy
Post-Combustion NO_x Controls				
NO_x emissions	0.32	40	0.192	3,604
Ammonia emissions (20 ppm)	0.0128	NA	0.0128	240
NO_x emissions[a]	0.32	30	0.224	4,205
Ammonia emissions (10 ppm)	0.0064	NA	0.0064	120
Combustion Controls Only				
NO_x emissions	0.32	NA	0.32	5,943
CO emissions	0.15	NA	0.15	2,816
VOC emissions	0.015	NA	0.015	282
Ammonia emissions	0	NA	0	0

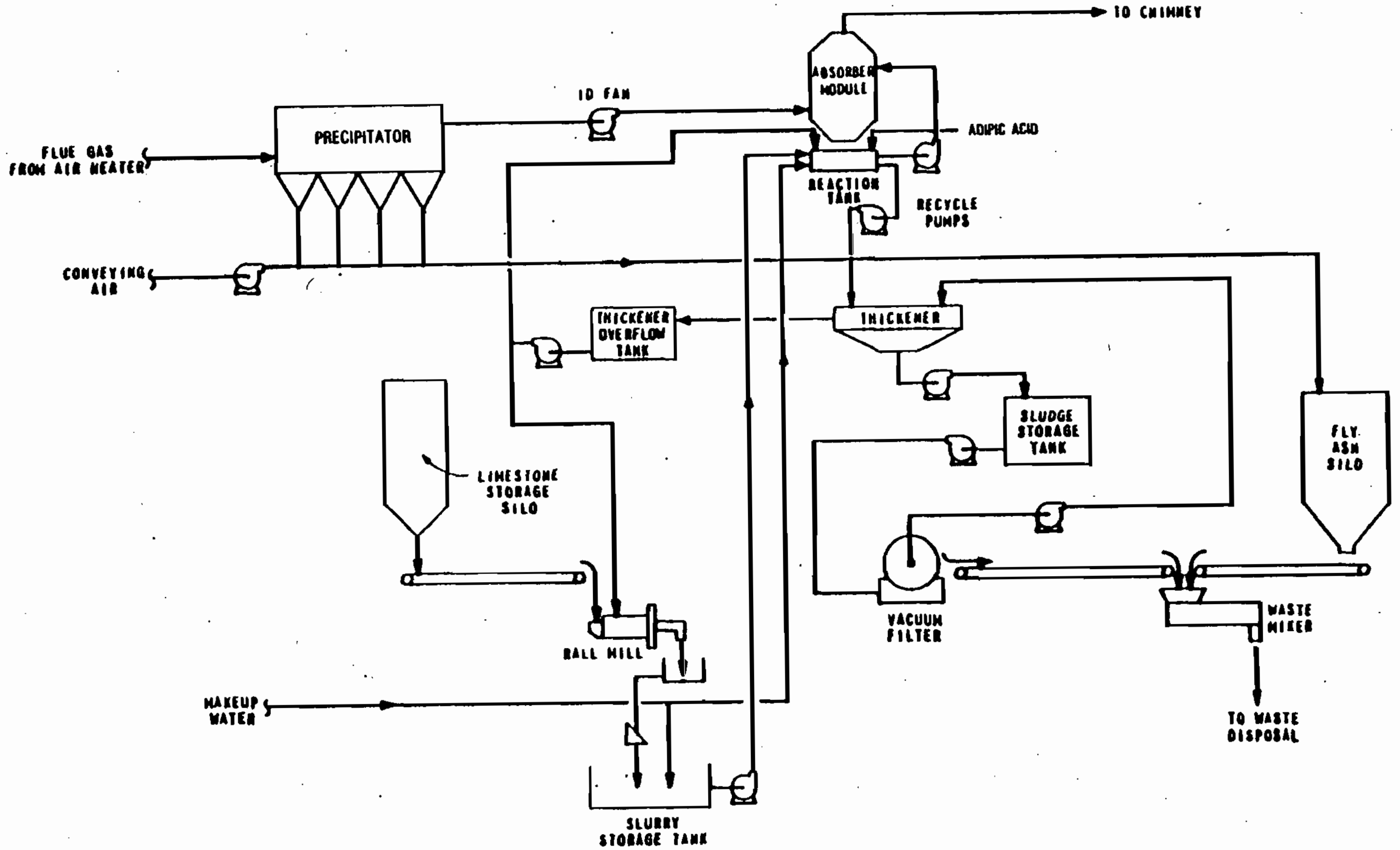
[a]SNCR NO_x reduction limited to 30 percent to minimize ammonia slip and to avoid the potential of an ammonia chloride plume.

Table 3.4-13
SNCR System Capital and Annual Costs

	40 Percent Reduction SNCR System $1,000	30 Percent Reduction SNCR System $1,000
Capital Costs		
SNCR system	5,130	4,320
Balance-of-plant	2,730	2,300
1991 capital cost	7,860	6,620
Contingency	790	660
Direct capital cost	8,650	7,280
Escalation	1,720	1,450
Direct capital cost	10,370	8,730
Indirects	1,660	1,400
Interest during construction	1,570	1,320
1997 total capital cost	13,600	11,450
Levelized Annual Costs		
Operating personnel	260	260
Maintenance	560	470
Additive	2,310	1,730
Loss in fly ash sales	980	980
Landfill costs of fly ash	290	290
Energy	950	800
Demand	110	100
1997 total annual operating cost	5,460	4,630
Fixed charges on capital	1,070	900
1997 total levelized annual cost	6,530	5,530

Table 3.4-14
Estimated Lead and Noncriteria Pollutant Emissions

Pollutant	Uncontrolled Emissions Average Emission (lb/h)	Uncontrolled Emissions Worst Case Emission (lb/h)	Removal Rate (percent)	Controlled Emissions Average Emission (lb/h)	Controlled Emissions Worst Case Emission (lb/h)
Lead	2.9	13	95	0.16	0.64
Beryllium	0.78	2.2	99	0.0088	0.022
Fluorine	32	181	99	0.36	1.8
Mercury	0.083	0.46	90	0.0094	0.046
Sulfuric Acid Mist	0.86	1.2	50	149	179
Antimony	0.59	1.9	99	0.0066	0.019
Arsenic	7.7	44	95	0.43	2.2
Barium	69	164	99	0.78	1.6
Cadmium	1.9	17	90	0.21	1.7
Chromium	9.4	53	90	1.1	5.3
Cobalt	3.4	19	95	0.19	0.95
Copper	6.3	21	90	0.71	2.1
Hydrogen Chloride	0.038	0.078	80	88	160
Manganese	35	273	95	1.9	14
Nickel	9.2	36	90	1.0	3.6
Phosphorus	52	292	90	5.8	29
Zinc	8.6	49	90	0.97	4.9
Formaldehyde	NA	NA		0.56	0.56
Phenol	NA	NA		3.2	3.2
Polycyclic Organic Matter	NA	NA		0.017	0.017
Pyridine	NA	NA		3.2	14
Radionuclides					0.47 μCi/h



WET LIMESTONE SCRUBBER
AIR QUALITY CONTROL SYSTEM

Figure 3.4-1

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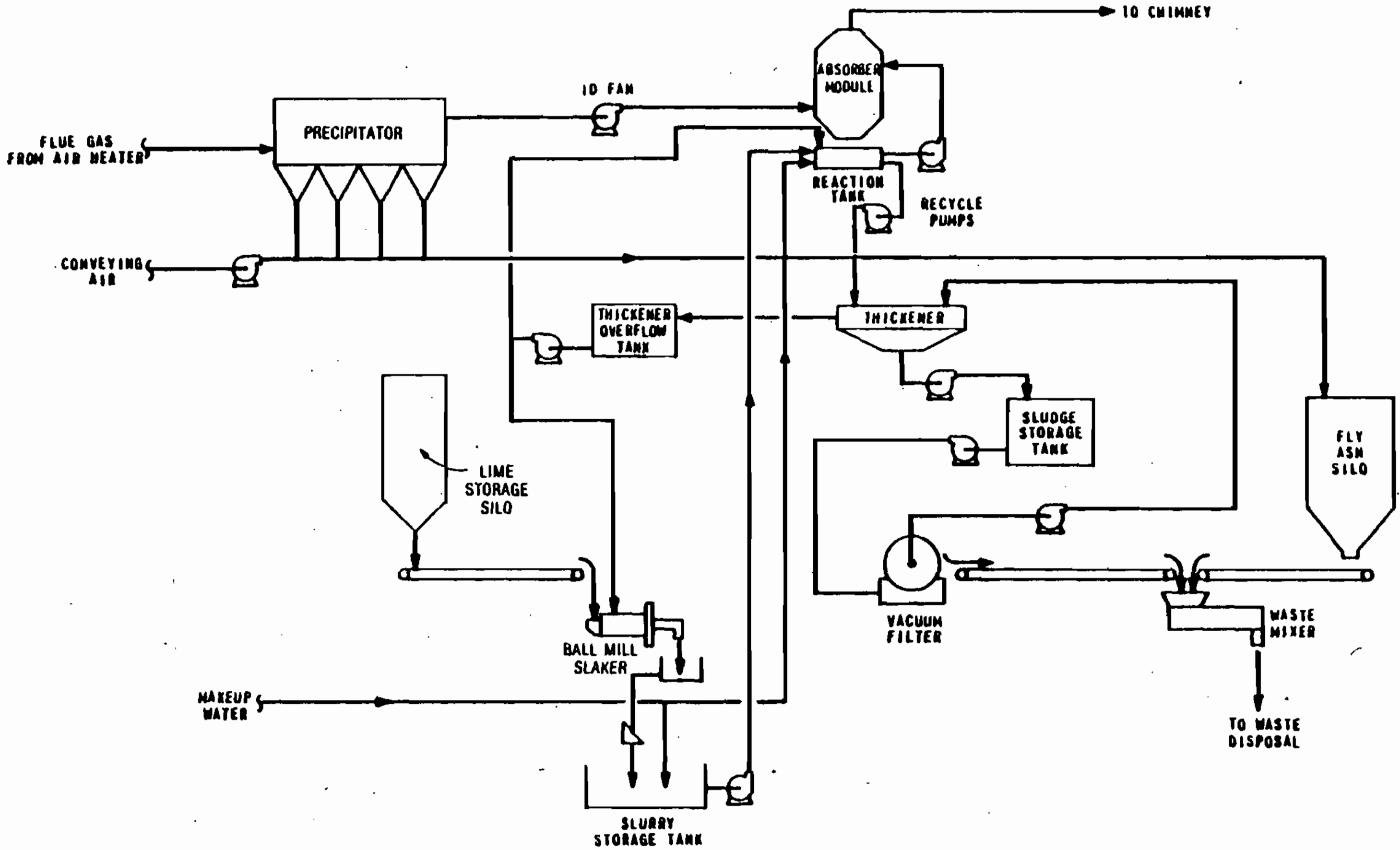
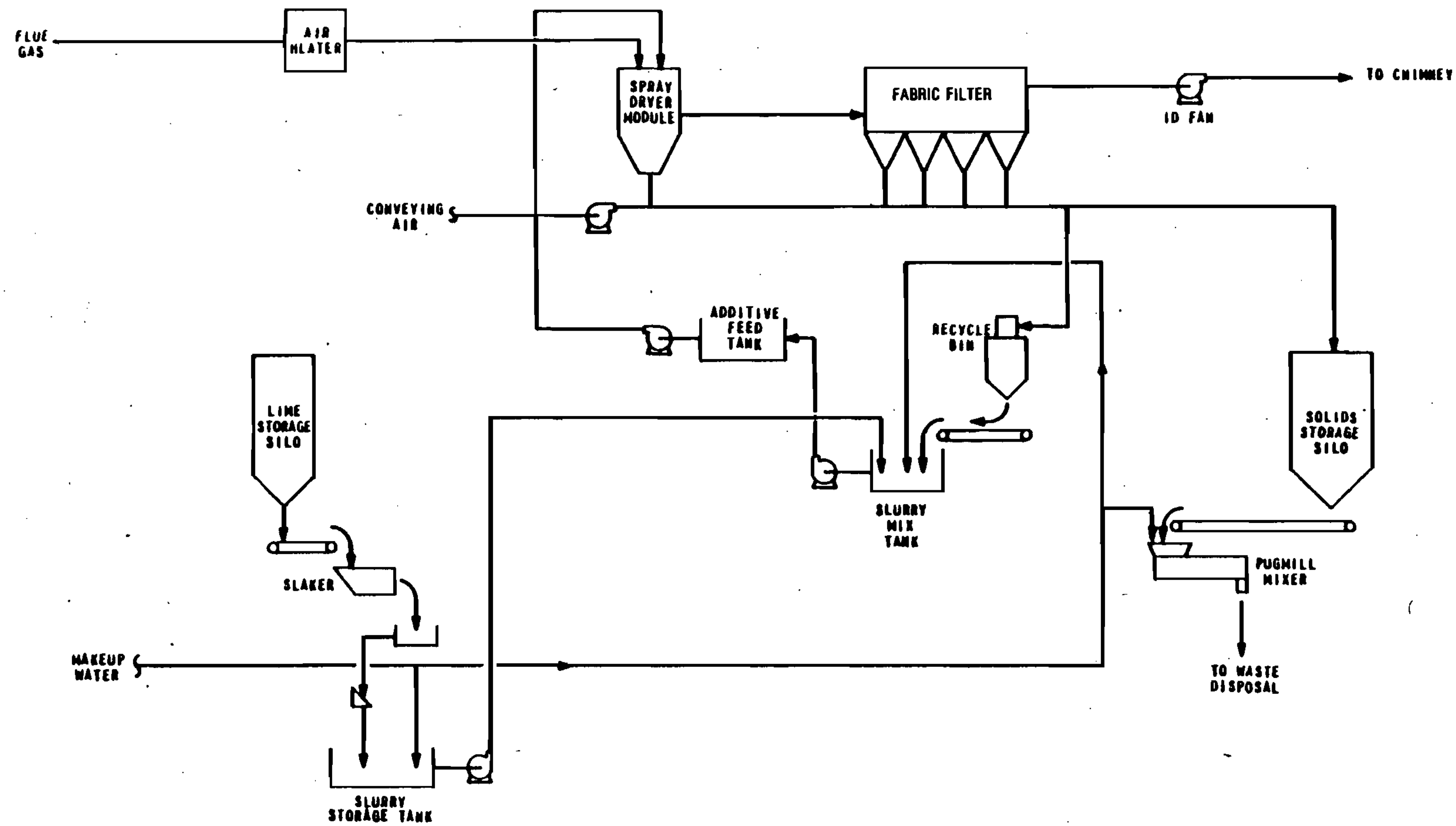


WET LIME SCRUBBER
AIR QUALITY CONTROL SYSTEM

Figure 3.4-2



LIME SPRAY DRYER
AIR QUALITY CONTROL SYSTEM

Figure 3.4-3

3.5 Plant Water Use

The three sources of water identified in the original SCA for use at the Stanton Energy Center will be the same for the Stanton 2 addition. These are effluent from the Orange County Easterly Subregional Wastewater Treatment Plant, onsite wells, and collected site runoff and direct precipitation on the makeup water supply storage pond. Well water withdrawal will be increased with the addition of Stanton 2 because of the need for additional potable water, steam cycle makeup, and general plant service water. A water mass balance with average and peak flows for a two-unit facility is shown on Figure 3.5-1. In addition, Tables 3.5-1 and 3.5-2 present the average annual and full load water balances for flows associated with Stanton 1 and 2. These tables include the estimated additional consumptive use of water by the new Stanton 2 facilities. The water sources and water uses associated with Stanton 1 are described in detail in Subsection 3.3 of the original SCA. Additional information related to Stanton 2 water usage is included in the remainder of this section.

3.5.1 Heat Dissipation System

Stanton 2 waste heat will be rejected to the atmosphere by a closed-cycle circulating water system using a natural draft cooling tower, as in the case of Stanton 1. The design of the system and the source of cooling water are described in Sections 3.3 and 3.4 of the original SCA. The circulating water systems at the Stanton Energy Center will not use a dilution system or injection wells.

The estimated maximum makeup rate for the Stanton 1 and Stanton 2 cooling systems is 7,778 gpm. At a lifetime capacity factor of 70 percent, the average makeup is expected to be 5,445 gpm. The flow rate of the Orange County Plant effluent is predicted to average up to 10 million gallons per day.

The cooling tower blowdown treatment system will be expanded with the addition of Stanton 2. The expansion will include additional treatment equipment, as described in Subsection 3.3.2.1 of the original SCA. A schematic of the system is shown on Figure 3.5-2.

3.5.2 Domestic/Sanitary Wastewater

Sanitary wastes will be disposed of by two methods, the existing plant sanitary waste treatment facility and the use of portable toilet facilities. During construction, both of these methods will be employed in the same manner as for

Stanton 1. During Stanton 2 operation, sanitary wastes from each of the permanent buildings that have sanitary facilities will be routed to the plant sanitary waste treatment facility.

Prior to operation of Stanton 2, the estimated additional hydraulic loadings for the existing onsite sewage treatment plant will be as follows.

126 construction supervisory and secretarial personnel at 25 gpd	3,150 gpd
50 visitors and temporary personnel at 25 gpd	1,250 gpd
Total	4,400 gpd

Biological loading will be approximately 0.045 pound of BOD_5 per day for each construction person, visitor, and temporary, or a total of approximately 8 pounds of BOD_5 per day.

Sanitary wastes from the additional 857 (maximum) construction personnel will be handled by portable toilet facilities, with waste disposed of offsite by an approved contractor.

After construction is complete and Stanton 2 is operating, the total estimated hydraulic loading figures for both Stanton 1 and 2 are as follows.

185 permanent personnel at 35 gpd	6,500 gpd
30 maintenance personel at 150 gpm	4,500 gpd
20 visitors and temporary personnel at 25 gpd	500 gpd
Total	11,500 gpd

Biological loading will be approximately 0.075 pound per day of BOD_5 for permanent personnel and 0.045 pound per day of BOD_5 for visitors and temporary personnel, or a total of approximately 16 pounds per day of BOD_5.

The existing plant sanitary waste treatment facility has adequate capacity (30,000 gpd) to accept this total loading.

3.5.3 Potable Water Systems

The potable water system for the Stanton Energy Center is described in Subsection 3.3.2.7 of the original SCA. The annual average increase in expected potable water usage, because of Stanton 2, is 4,475 gpd (3.1 gpm), based on an average plant staff increase of 85 people and an average potable water requirement of 52 gallons per capita per day. The existing system is adequate to provide this required increase in potable water.

3.5.4 Process Water Systems

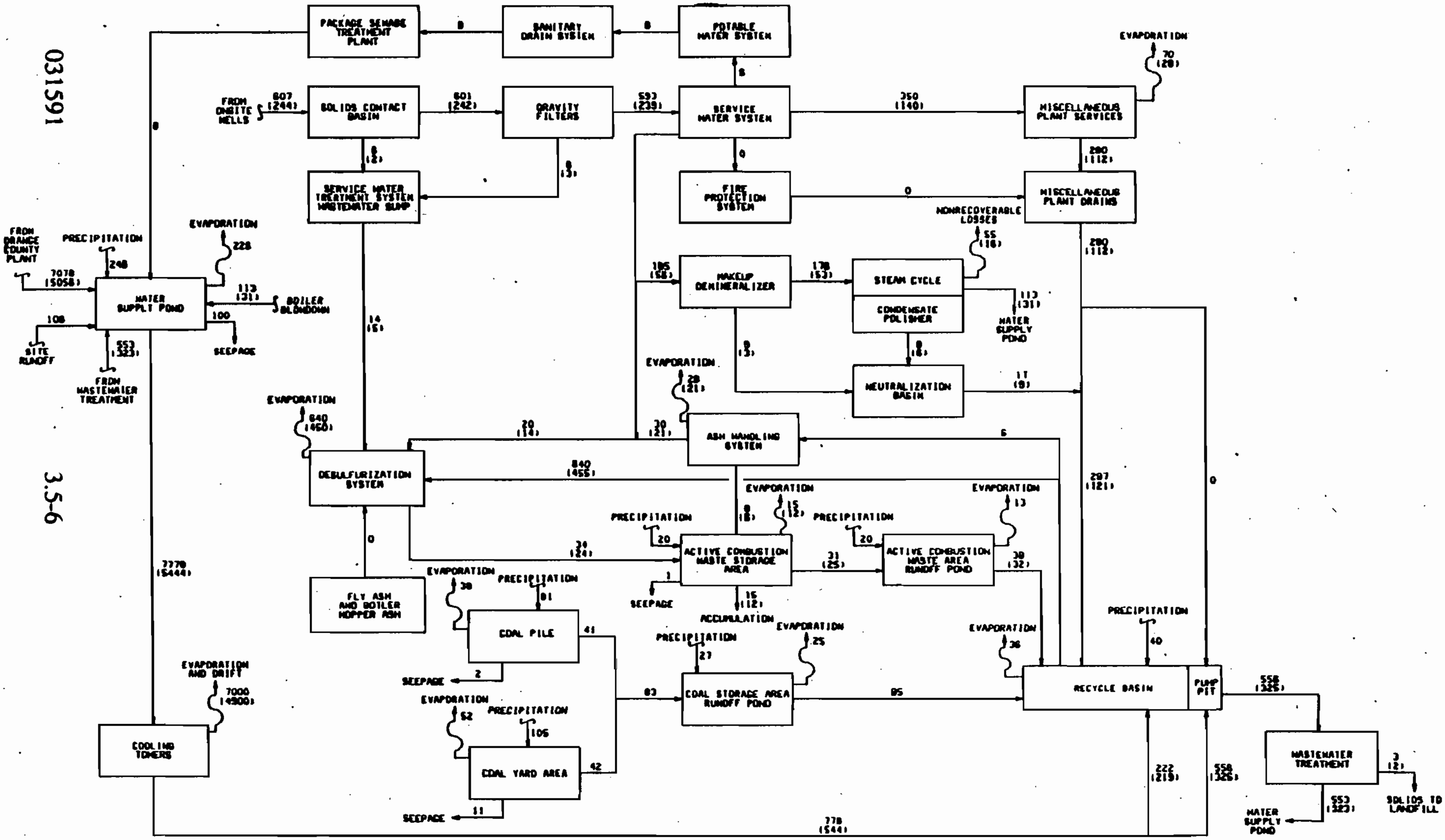
The various process water systems to be incorporated as part of Stanton 2 other than the heat rejection/cooling systems are described in Subsection 3.3.1 and Section 3.5 of the original SCA. These describe the water uses and chemicals and biocides, respectively, associated with the power plant. The treatments used for the various waste streams are discussed. Details of the heat rejection/cooling systems are described in Subsection 3.3.2.1 and Section 3.4 of the original SCA.

Table 3.5-1
Annual Average Water Balance

	Balance for Unit 1 (gpm)	Balance for Units 1 and 2 (gpm)	Additional for Unit 2 (gpm)
Water Inflows			
Precipitation	1,019	1,019	0
Orange County Plant Effluent	2,472	5,056	2,584
Well Water	124	244	120
Total	3,615	6,319	2,704
Water Losses			
Evaporation and Transpiration	3,326	6,025	2,699
Seepage	280	280	0
Wastewater Disposal Retention	9	14	5
Total	3,615	6,319	2,704

Table 3.5-2
Full Load Water Balance

	Balance for Unit 1 (gpm)	Balance for Units 1 and 2 (gpm)	Additional for Unit 2 (gpm)
Water Inflows			
Precipitation	1,019	1,019	0
Orange County Plant Effluent	3,492	7,078	3,586
Well Water	305	607	302
Total	4,816	8,704	3,888
Water Losses			
Evaporation and Transpiration	4,525	8,406	3,881
Seepage	280	280	0
Wastewater Disposal Retention	11	18	7
Total	4,816	8,704	3,888



NOTES:

1. ALL FLOWS ARE EXPRESSED IN GALLONS PER MINUTE.
2. FLOWS REPRESENT TYPICAL REQUIREMENTS FOR TWO UNITS OPERATING AT 100 PERCENT LOAD ASSUMING PEAK SERVICE WATER DEMANDS.
3. FLOWS IN PARENTHESIS REPRESENT REQUIREMENTS FOR TWO UNITS OPERATING AT AVERAGE LOAD OF 70 PERCENT WHILE OPERATING WHEN DIFFERENT FROM THE REQUIREMENTS AT 100 PERCENT LOAD.
4. MASS BALANCE IS BASED ON BURNING LOW SULFUR APPALACHIAN COAL.

WATER MASS BALANCE FOR UNITS 1 AND 2

Figure 3.5-1

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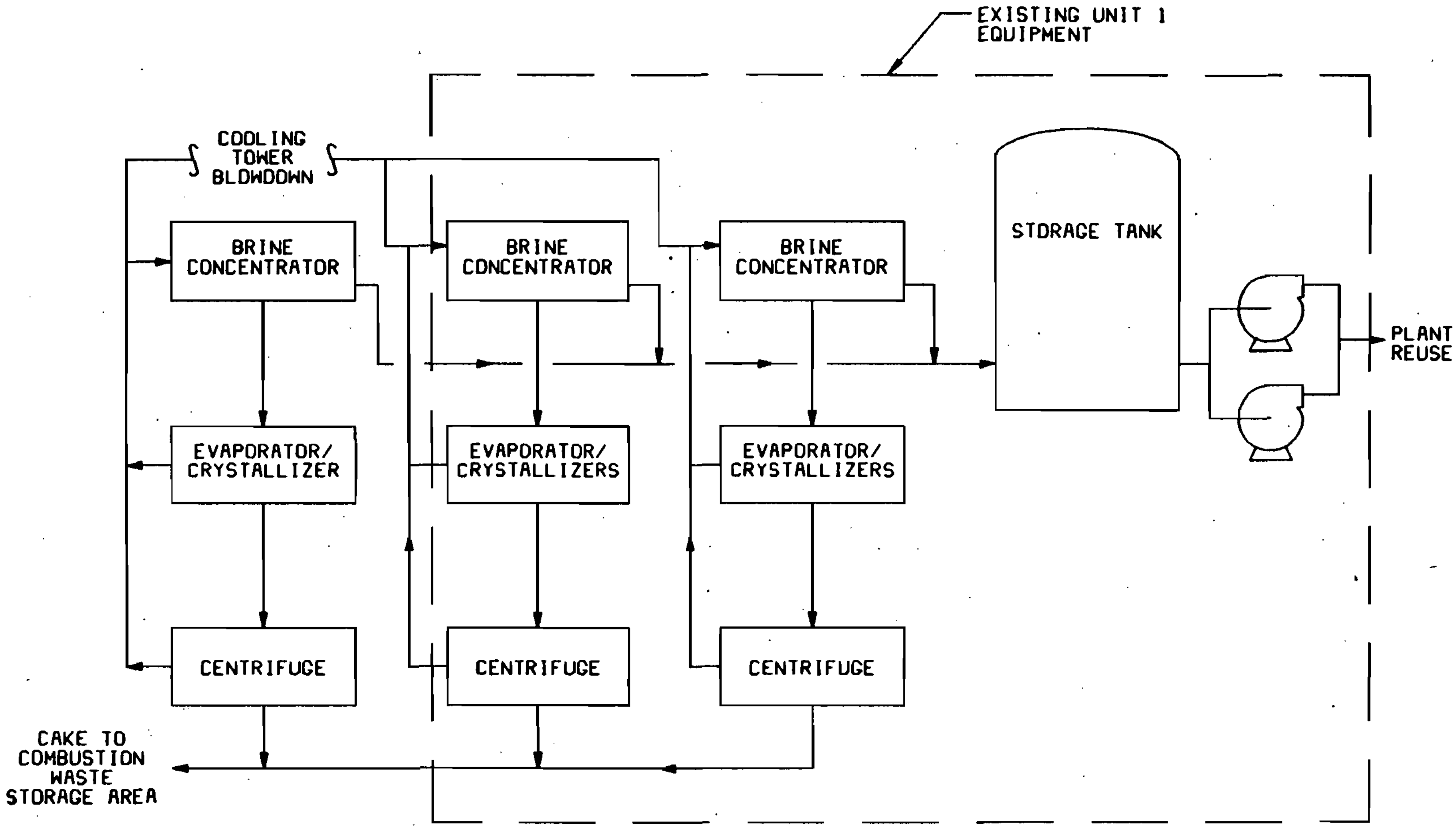


COOLING TOWER BLOWDOWN TREATMENT SYSTEM

Figure 3.5-2

3.6 Chemical and Biocide Waste

The uses of chemicals and biocides at the Stanton Energy Center were discussed in Section 3.5 of the original SCA. The treatment of cooling tower circulating water, steam cycle water, service water, sanitary wastewater, and demineralizer regeneration and condensate polishing wastes will be handled in the same manner for Stanton 2 as was described for Stanton 1. An exception will be the use of a polyacrylate as a scale inhibitor for cooling tower circulating water treatment instead of the organic phosphate indicated in the original SCA.

The steam generator and preboiler cycle piping will be chemically cleaned initially during commissioning and also periodically during the life of the plant. The chemical boiler cleaning wastes resulting from this process will be handled in one of the following two ways.

These wastes may be immediately neutralized onsite, thereby avoiding the classification as hazardous wastes. The treated wastes would then be either disposed of offsite by a contractor in an approved facility or onsite by OUC using the cooling tower blowdown treatment system.

The second alternative for dealing with chemical boiler cleaning wastes would include obtaining a hazardous waste permit for the Stanton Energy Center facility. These wastes would then be disposed of offsite by OUC or a contractor at a licensed hazardous waste treatment facility. Application for the appropriate permits as a hazardous waste generator and transporter (as appropriate) will be made at the time a decision is made to select that alternative.

3.7 Solid and Hazardous Waste

3.7.1 Solid Waste

The generation, handling, and disposal of solid wastes at Stanton Energy Center were described in Subsection 3.6.2 of the original SCA. The operation of Stanton 2 will be the same as that described for Stanton 1, with essentially equivalent quantities of the various solid wastes.

3.7.2 Hazardous Waste

No hazardous waste will be generated by the operation of Stanton 2. Demineralizer wastes, condensate polisher wastes, and chemical boiler cleaning wastes, which can have pHs that are less than or equal to 2 or greater than or equal to 12.5, will be routed to the neutralization basin for pH adjustment. The neutralization basin serves as an "elementary neutralization unit," allowing the plant an exemption from permitting as a hazardous waste facility. Furthermore, because the demineralizer wastes are not stored prior to pH adjustment, they are not counted as generated hazardous waste, and the plant is therefore not subject to regulation as a hazardous waste generator.

3.8 Onsite Drainage System

A detailed analysis and discussion of Stanton Energy Center site runoff was included in Section 3.10 of the original SCA. The construction of Stanton 2 will not appreciably change this drainage system, with the possible exception of the size of the recycle basin. Expansion of the recycle basin may be required for Stanton 2. If the recycle basin requires expansion as a result of detailed design, the additional expanded surface area of approximately 5 acres is shown on Figure 3.2-1.

3.9 Materials Handling

The original SCA contains detailed discussions of the handling, storage, and/or disposal of various materials associated with the operation of Stanton Energy Center. These materials include fuel (coal and oil), limestone, lime, combustion wastes (ash and scrubber sludge), and cooling tower blowdown solids. The facilities for handling and storage of these materials that were installed for Stanton 1 are also capable of serving Stanton 2. Although an addition to the Cooling Tower Blowdown Treatment System will be required for Stanton 2, the handling, storage, and disposal of cooling tower blowdown solids from Stanton 2 will be the same as for Stanton 1.

The addition of the alternate access road, which connects to the Bee Line Expressway south of the site, will provide an alternate site access for plant operating personnel and delivery of operating materials.

4.0 Effects of Site Preparation and Plant and Associated Facilities Construction

The information presented in this chapter is provided only for the purposes of construction and operation of Stanton 2 as discussed and qualified in the Introduction.

4.1 Land Impact

4.1.1 General Construction Impacts

General construction impacts for Stanton 2 were included in Chapter 4 of the original SCA for the Stanton Energy Center.

As described in Chapter 6 of this application, a new electric transmission line will extend from the Stanton Energy Center to the junction of the planned airport relocation transmission line (OUC Line 7-0615) and the existing railroad corridor near Mud Lake. A total distance of approximately 14 miles of new line will be constructed. The new line will follow the existing railroad corridor south and west of the site. Construction impacts associated with the 14-mile segment of new line with several access roads needed for maintenance purposes and the alternate site access road are discussed in Chapter 6.

4.1:2 Roads

The alternate site access road which will be built with the new Stanton 2 facilities will extend from the Bee Line Expressway offramp north along the existing railroad to the plant site perimeter road system. Although the Bee Line Expressway is a part of the state road system, the proposed alternate access road will not tie directly into it and, therefore, information requested in the Florida Department of Transportation "Utility Accommodation Guide" is not required.

4.1.3 Flood Zones

As discussed in Subsection 2.5.1 and Section 3.10 of the original SCA, the 100-year flood elevations on the Stanton Energy Center site vary from approximately 60 feet msl at the northeast corner of the site to approximately 90 feet msl at the southwest. All existing major plant facilities and Stanton 2 facilities will be located above the 100-year flood elevation.

4.1.4 Topography and Soils

No significant additional change in topography of the plant site is planned during Stanton 2 construction. Minimal grading modifications including backfill and contour adjustments will be made in the area of the Stanton 2 structures. The construction of the planned electric transmission line or alternate access road will not significantly alter the topography or soils along the corridor. Most of the line will be constructed along the existing railroad right-of-way or installed on vacant circuits of existing towers.

4.2 Impact on Surface Water Bodies and Uses

The only impacts on surface water bodies potentially will occur as the result of the construction of the proposed electric transmission line and associated maintenance roads. These impacts are addressed in Chapter 6.

4.3 Ground Water Impacts

4.3.1 Impact Assessment

4.3.1.1 Water Table Zone. Ground water quality impacts due to construction activities will be negligible. Runoff from the construction activities will be contained in a collection basin. The basin will be unlined and there will be some exfiltration of the collected runoff water, providing recharge of the water table zone.

Dewatering for the Stanton 2 circulating water pipeline and other necessary underground utilities will be required. These dewatering activities will be confined to localized temporary construction zones and will have minimal effect on the water table zone. Ground water removed during these activities will be routed away from the construction work zone and discharged to ground surface and allowed to recharge the water table zone. By releasing the water, no net impact to the water table zone will occur.

4.3.1.2 Intermediate Artesian Aquifer. The intermediate artesian aquifer should not be affected by construction activities.

4.3.1.3 Floridan Aquifer. The two existing wells onsite will be used to supply water from the Floridan Aquifer to be used for construction activities. Construction activity water requirements are estimated to be 300 gpm. This quantity is about half of the water required for Stanton 2 for normal operations once the new unit is completed. The effects of the increased pumping rates are discussed in Subsection 5.3.2.3 of this application. Water quality of the Floridan Aquifer will not be affected during construction activities.

4.3.2 Measuring and Monitoring Program

Background water quality data for the site were described in Subsection 2.3.2, Subsurface Hydrogeology. Ground water monitoring and description of existing monitoring facilities are described in Subsection 5.3.5, Measurement Programs.

4.4 Ecological Impacts

The ecological impacts related to the construction of Stanton 2 were included in the original SCA for the Stanton Energy Center. Ecological impacts potentially resulting from the construction of the planned electric transmission line are discussed in Chapter 6 of this application.

4.5 Air Impacts

There will be temporary and minor air quality impacts during the construction phase for Stanton 2. These impacts will include the generation of fugitive dust and equipment exhaust emissions. The local air quality impact will be minimized by the application of appropriate dust suppression control methods, such as water spraying. The impacts will end when the construction activities are completed and the facilities are ready for operation.

Fugitive dust emissions will be associated with the construction of buildings and roads onsite. These construction activities will include land clearing, ground excavation, cut and fill operations, and actual construction of facilities. There can be considerable variation in daily fugitive dust emissions depending upon the level of activity, the nature of the operations, and prevailing weather conditions. Vehicular traffic at the construction site will produce a large portion of the emissions.

Stanton 2 will be constructed on the existing Stanton Energy Center site which is fairly isolated and has a reasonable buffer area due to the large size of the site. Fugitive dust impacts should be localized and of short duration.

The operation of construction equipment will cause a minor, temporary impact on the local air quality. The use of construction equipment will be short-term, and air quality impacts will cease at the completion of construction.

Air quality impacts related to the construction of the transmission line and alternate access road are discussed in Chapter 6.

4.6 Impact on Human Populations

Construction impacts on human populations are anticipated to be minimal. There will be a temporary increase in noise levels as the result of operating various types of construction equipment, however, there are no nearby residences or other facilities that will be impacted by the noise. The Stanton Energy Center site is rather isolated and there is a reasonable buffer area around the proposed construction due to the large size of the site.

The construction workforce will be onsite about May 1993 to initiate construction activities, and construction work will be completed by approximately December 1996. The peak construction force will total 983 workers during late 1995. Table 4.6-1 shows the number of construction personnel expected to be onsite during each month of the construction period.

Nearly all of the construction workers are expected to come from the Orlando metropolitan area and commute to the Stanton Energy Center site. No impacts are likely to occur on housing, educational, or other services. There will be some increase in traffic in the vicinity of the site during the construction period, but because of the location of the worksite, there should be only minor impacts on the general public.

Table 4.6-1
Construction Work Force (Personnel per Month)

Month	1993	1994	1995	1996
January	0	363	825	811
February	0	408	863	730
March	0	452	893	666
April	0	497	924	585
May	45	541	962	518
June	87	588	978	451
July	132	632	980	362
August	169	656	981	276
September	202	692	983	226
October	249	729	983	139
November	292	747	946	52
December	325	783	873	0

4.7 Impact on Landmarks and Sensitive Areas

As addressed in the original SCA for the Stanton Energy Center, there will be no impacts on area landmarks or sensitive areas as the result of the construction of Stanton 2. See Chapter 6 for a discussion of transmission line and alternate access road construction impacts.

4.8 Impacts on Archaeological and Historic Sites

The SCA for the Stanton Energy Center documented that there will be no impacts on archaeological and historic sites from the construction of Stanton 2 since all new construction is within the previously certified site or associated corridors. Transmission line and alternate access road impacts are addressed in Chapter 6.

4.9 Special Features

Trash and garbage will be collected in appropriate containers and removed from the site by a contractor for disposal at an approved facility. There will be no unusual products or raw materials used during construction which may affect the environment.

4.10 Benefits from Construction

The construction of Stanton 2 will have a beneficial impact on the local and regional economy. Construction materials will be purchased locally, within the state, and regionally. There will be increased employment opportunities, additional income, and more tax revenue. The result will be an overall increase in economic activity. The beneficial impacts will be significant, but small in context of the entire Orlando economy. Projections of the beneficial construction impacts are discussed in Subsection 7.2.1.2 of the original SCA for the Stanton Energy Center.

4.11 Variances

No variances from applicable standards due to construction activities have been identified at this time as being required for Stanton 2.

5.0 Effects of Plant Operation

The information presented in this chapter is provided only for the purposes of construction and operation of Stanton 2 as discussed and qualified in the Introduction.

5.1 Effects of the Operation of the Heat Dissipation System

The effects of the operation of the cooling towers for the ultimate (4-unit) development of the Stanton Energy Center were presented in Section 5.1 of the original SCA. The potential effects of additional fogging and drift due to these units were assessed to be insignificant.

5.2 Effects of Chemical and Biocide Discharges

There will be no chemical or biocide discharges from the Stanton Energy Center; therefore, this section does not apply.

5.3 Impacts on Water Supplies

5.3.1 *Surface Water*

Impacts on surface water were addressed in Subsection 5.3.2 of the original SCA. There will be no surface water impacts associated with the operation of Stanton 2. The water required for plant operations is received as effluent from the Orange County Easterly Subregional Wastewater Treatment Plant and withdrawn from the Floridan Aquifer, as discussed in Section 3.5. In addition, no discharge of wastewater to surface waters will occur as a result of routine plant operation, as discussed in Sections 3.3, 3.4, and 3.5 of the original SCA.

5.3.2 *Ground Water Impacts*

The following describes the effects of the plant operations on the aquifers underlying the plant site.

5.3.2.1 Water Table Zone. Plant operation will have negligible effect on the water table quality. No additional facilities that would affect the water table zone will be constructed for Stanton 2 operation. No water for plant use will be withdrawn from the water table zone. Existing facilities and effects on water table zone are described in Subsection 5.3.3 of the original SCA.

5.3.2.2 Intermediate Artesian Aquifer. Plant operation will have negligible effect on the intermediate artesian aquifer water quality. No new facilities will be constructed that would affect the intermediate artesian aquifer for Stanton 2 operation. No water for plant use will be withdrawn from the intermediate artesian aquifer.

5.3.2.3 Floridan Aquifer. Stanton 1 plant operations require withdrawal of water from two existing wells installed in the Floridan Aquifer. These wells pump at an average discharge of 305 gpm. Monitoring records indicate 0.3 foot drawdown at the wells. The radius of influence, based on these withdrawal rates, is 100 feet. Major water supply wells near the site are described in Subsection 2.3.3. Withdrawal from these two onsite wells, with the operation of Stanton 1, have had minimal effects on the surrounding water supply wells.

A pump test was conducted on the existing wells after initial construction. A constant rate discharge of 850 gpm for a test duration of 48 hours resulted in 1.5 and 2.0 feet drawdown at the wells and 0.1 foot of drawdown in a monitoring well located 400 feet from the production well. Monitoring wells installed in the water table zone and intermediate artisan aquifer registered no piezometric water level movement in these aquifers. This indicates that there is no direct connection from the screened zones in these wells to the Floridan Aquifer.

The proposed Stanton 2 addition will not require construction of any new wells. The existing wells will be pumped at an average discharge of 611 gpm. The USGS flow model MODFLOW was used to simulate the effects of the increased withdrawals from the Floridan Aquifer for Stanton 2. The MODFLOW model was calibrated to the actual results of the pump tests performed on the existing wells during the construction of Stanton 1. The following parameters were developed based on the site geology and model calibration.

<u>Layer</u>	
1	Surficial Aquifer (Unconfined) Storage Coefficient, S = 0.01 Horizontal Permeability, KH = 15.7 ft/day Vertical Permeability, KV = 0.4 ft/day Thickness = 50 feet
2	Upper Confining Unit (Confined) Storage Coefficient, S = 1×10^{-5} Horizontal Permeability, KH = 1×10^{-3} ft/day Vertical Permeability, KV = 1×10^{-7} ft/day Transmissivity, T = 0.4 ft^2/day Thickness = 140 feet
3	Floridan Aquifer (Confined) Storage Coefficient, S = 0.0005 Transmissivity, T = 50,000 ft^2/day Thickness = 2,000 feet

Computer modeling indicates that the increased withdrawal rates will increase drawdown in each well to a total of 0.6 foot. The radius of influence for each well will extend to 250 feet. Figure 5.3-1 shows the location of the onsite supply wells and the radius of influence for two-unit operation. The increased withdrawal rates will continue to have minimal effect on the surrounding water supply wells.

5.3.3 Drinking Water

Subsection 5.3.1 of the original SCA considered potential impacts on drinking water supplies. There should continue to be no impacts associated with the operation of Stanton 2.

5.3.4 Leachate and Runoff

The impacts of leachate and runoff were addressed in Subsection 5.2.2 of the original SCA. With the use of liners on the coal pile, the coal storage area runoff pond, and the combustion waste runoff pond, no significant impacts due to leachate and runoff were expected during the operation of Stanton 1. Results of the onsite ground water monitoring program have demonstrated compliance with ground water quality standards.

There will be essentially no changes in materials handling and storage with the operation of Stanton 2. Active and reserve coal storage and pond areas will not change appreciably by the addition of Stanton 2.

5.3.5 Measurement Program

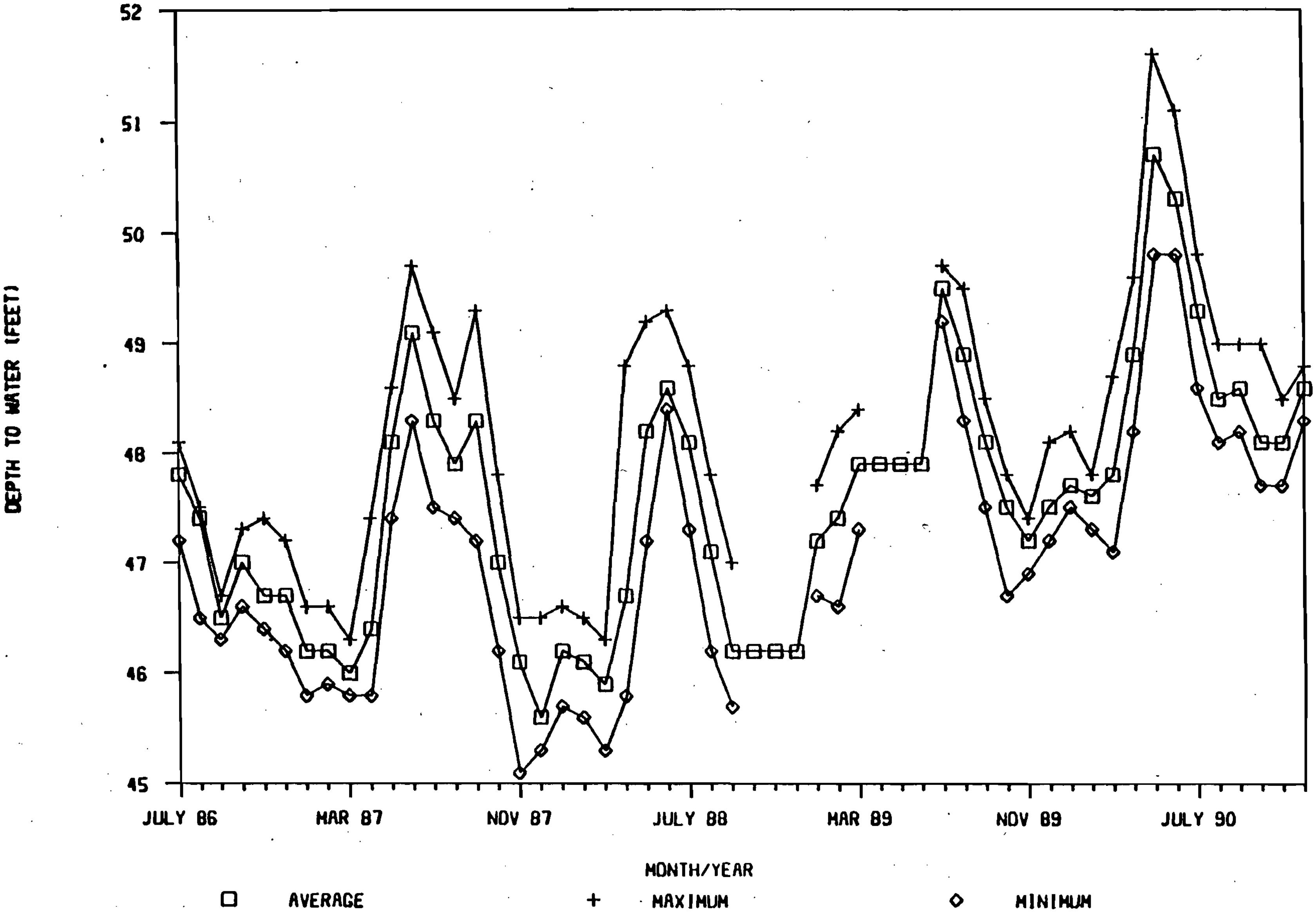
Monitoring programs as described in Subsection 6.3.6 of the original SCA have been implemented and will continue to be used for monitoring effects of plant operation on water supplies during and after construction of Stanton 2. Historical ground water quality data collected from the implemented monitoring program are presented in Table 5.3-1. Water level values of the potentiometric surface for the site aquifers collected to date are presented on Figure 5.3-2.

Table 5.3-1
Historical Onsite Well Water Quality

Parameter	Units	Minimum	Maximum	Average
Alkalinity (to pH 4.5)	mg/l	160	170	165
Alpha, Gross	pCi/l	<0.8	14	<3.5
Aluminum	mg/l	<0.05	0.90	<0.13
Arsenic	mg/l	<0.002	0.05	<0.005
Barium	mg/l	<0.02	0.18	<0.07
Beryllium	mg/l	<0.001	<0.01	<0.009
Bicarbonate (as $CaCO_3$)	mg/l	150	180	163
Cadmium	mg/l	<0.0005	<0.01	<0.0015
Calcium	mg/l	5.1	60	47.4
Chloride	mg/l	<1	53	<17
Chromium	mg/l	<0.001	<0.05	<0.005
Cobalt	mg/l	<0.005	<0.1	<0.21
Color	PCU	<2	20	<7
Conductance, Specific	umhos/cm	230	450	321
Copper	mg/l	<0.01	<0.05	<0.04
Hardness (as $CaCO_3$)	mg/l	55	510	180
Iron	mg/l	<0.03	0.84	<0.19
Lead	mg/l	<0.001	0.04	<0.005
Magnesium	mg/l	9	90	14
Manganese	mg/l	<0.01	<0.05	<0.02
Mercury	mg/l	<0.0002	<0.0005	<0.0002
Molybdenum	mg/l	<0.008	<0.1	<0.020
Nickel	mg/l	<0.001	<0.03	<0.003
Nitrate-N	mg/l	<0.03	0.28	<0.07
Phosphate-P, Ortho	mg/l	<0.05	0.07	<0.05

Table 5.3-1 (Continued)
Historical Onsite Well Water Quality

Parameter	Units	Minimum	Maximum	Average
Phosphate-P	mg/l	<0.05	<0.05	<0.05
Phosphorus, Total	mg/l	<0.028	0.12	<0.066
Potassium	mg/l	<1	11	<2
Selenium	mg/l	<0.002	<0.02	<0.003
Silver	mg/l	<0.00007	<0.01	<0.00209
Sodium	mg/l	10	89	16
Solids, Total Dissolved	mg/l	150	250	211
Sulfate (as SO_4)	mg/l	<3	35	<23
Sulfite (as SO_3)	mg/l	<2	<2	<2
Vanadium	mg/l	<0.008	<0.1	<0.015
Zinc	mg/l	<0.01	0.08	<0.05



ORLANDO UTILITIES STANTON 2
WELL WATER LEVELS

Figure 5.3-2

5.4 Solid/Hazardous Waste Disposal Impacts

The solid waste disposal for the ultimate site development was presented in the original SCA; therefore, no further discussion is provided.

5.5 Sanitary and Other Waste Discharges

There will be no sanitary or other waste discharges from the site as discussed in the original SCA.

5.6 Air Quality Impacts

Air quality impacts for the operation of Stanton 1 and 2 were included in Section 5.5 of the original SCA. However, because combustion parameters and emissions rates for Stanton 2 have been revised, additional dispersion modeling was performed to verify that air quality impacts remain below all applicable PSD increments and ambient air quality standards.

5.6.1 Description of Pollutant Emissions

5.6.1.1 Steam Generator Emissions. Pollutant emissions for Stanton 1 and 2 were summarized in Table 5.5-1 of the original SCA. The sulfur dioxide (SO_2) emission rate was 1.14 lb SO_2/MBtu heat input. Particulate matter and nitrogen oxides (NO_x) emissions were equal to the New Source Performance Standards (NSPS) levels of 0.03 and 0.60 lb/MBtu heat input, respectively. Carbon monoxide (CO) emissions were based on an emission factor recommended by EPA of 1.0 lb CO/ton of coal fired.

The revised emission rates for Stanton 2 reflect new pollutant control technology as determined by the revised Best Available Control Technology (BACT) assessment, included in Section 3.4 of this application. The Stanton 2 SO_2 emission rate is 0.32 lb SO_2/MBtu heat input on a 30-day rolling average basis. This rate will also be appropriate on an annual basis. The maximum 3-hour and 24-hour SO_2 emission rates are proposed to be 0.85 and 0.67 lb SO_2/MBtu heat input, respectively. The Stanton 2 particulate matter and NO_x emission rates also reflect improved pollutant removal rates resulting from advances in technology. The particulate matter emission rate is 0.02 lb particulate matter/MBtu heat input. The NO_x emission rate is 0.32 lb NO_2/MBtu heat input. Carbon monoxide emissions for Stanton 2 will reflect more current methods of estimating emission rates than previous EPA recommended estimates. The Stanton 2 CO emission rate is 0.15 lb CO/MBtu heat input.

Table 5.6-1 presents emission rate data for Stanton 1 and the proposed Stanton 2 steam generators. These rates were used in the revised dispersion modeling analysis.

5.6.1.2 Emissions from Other Station Sources. Emissions from other station sources were included in Subsection 5.5.1.2 of the original SCA. These emissions and associated impacts are not expected to change significantly.

5.6.2 Revised Impacts of Stack Emissions

The revised impacts of stack emissions on ambient air quality concentrations of SO_2, NO_2, TSP, and CO were evaluated using currently accepted EPA computer dispersion modeling methods. The primary objective of this analysis was to verify that the reduced emissions from Stanton 2, coupled with minor changes in exhaust gas parameters, would result in equal or lower ambient air quality impact levels.

5.6.2.1 Dispersion Modeling Methodology. The dispersion modeling methodology for the revised impact analysis differs somewhat from the original analysis. This was necessary because of changes in EPA's modeling guidelines since the original SCA was issued.

5.6.2.1.1 Screening Modeling. Previous screening-level modeling, using the EPA approved PTMAX model, had shown that the boiler operating at maximum capacity would result in the highest ground level concentrations. This result was assumed to continue. Therefore, no additional screening modeling was performed.

5.6.2.1.2 Refined Modeling. Refined dispersion modeling was originally performed using EPA's CRSTER model. The revised dispersion modeling uses an updated version of the CRSTER model known as the Industrial Source Complex Short Term (ISCST) model. Like the CRSTER model, the ISCST model uses site-specific meteorological data to predict ground level concentrations at various user defined receptor locations.

5.6.2.1.3 Meteorological Data. The original dispersion modeling used surface meteorological data from Orlando, Florida, and upper air mixing height data from nearby Tampa, Florida, for the years 1974-1978. The revised dispersion modeling uses more current data for the years 1981-1985 from the same surface and upper air stations.

5.6.2.1.4 Stack Parameters. Exhaust gas parameters for Stanton 2 changed slightly as a result of revised coal characteristics and pollution control technologies. Table 5.6-2 presents the exhaust gas parameters for both units.

5.6.2.1.5 Receptor Locations. The original dispersion modeling used a polar receptor array with one receptor on each of 36 radials (one every 10 degrees by azimuth) at downwind distances that were required to give a representative spacial coverage. The revised modeling analysis uses the same approach. The downwind spacing of the polar rings starts at 450 meters (the nearest property fence line) and locates additional rings at 100-meter intervals out to 2,000 meters. Between 2,000 and 4,000 meters, the ring spacing was increased to 200 meters.

5.6.2.2 Modeling Results. Tables 5.6-3 through 5.6-5 present the results of the revised dispersion modeling analysis. Table 5.6-3 shows the maximum predicted ground level pollutant concentrations for the existing Stanton 1 and revised Stanton 2 emissions. The table also lists the location, year, and period when the concentrations were expected to occur.

Table 5.6-4 presents a similar comparison of predicted ground level concentrations and PSD Class II increments. Again, each pollutant's impact is below the applicable level.

Table 5.6-5 presents a comparison of the predicted ground level concentrations determined in the original and revised dispersion modeling studies. The modeling results show a net air quality improvement for every pollutant except carbon monoxide.

The apparent increase in CO impacts is due solely to the lower emission factor recommended by EPA at the time of the original SCA submittal. The previously used emission factor of 1.0 lb CO/ton of coal fired results in an emission rate lower than rates currently used based on manufacturer's experience.

Table 5.6-1
Steam Generator Emission Rates for Units 1 and 2

Pollutant	Unit 1	Unit 2
Sulfur Dioxide, lb/MBtu		
Long-term emission rate	1.14	0.32
24-hour emission rate	1.14	0.67
3-hour emission rate	1.14	0.85
Nitrogen Oxides, lb/MBtu	0.60	0.32
Particulate Matter, lb/MBtu		
TSP	0.03	0.02
PM_{10}	–	0.02
Carbon Monoxide		
lb/MBtu	–	0.15
lb/ton coal[a]	1.00	–

[a]Emission estimate was based on recommended emission factor from EPA's document AP-42, applicable at the time of the original SCA submittal.

Table 5.6-2
Exhaust Gas Parameters for Units 1 and 2

Parameter	Unit 1	Unit 2
Stack Height, ft	550	550
Stack Exit Temperature, F	126.5	123.9
Stack Exit Flow, acfm	1,202,867	1,310,120
Stack Exit Diameter, ft	19	19
Stack Exit Velocity, fpm	4,242.5	4,620.8
Heat Input, MBtu/h	4,183	4,286

Table 5.6-3
Maximum Predicted Ground Level Pollutant Concentrations from the Two-Unit Operation

Pollutant	Averaging Period	Impact ($\mu g/m^3$)	Distance (meters)	Direction (degrees)	Year	Period (day/h)
SO_2	Annual	3	2,800	130	1985	--
	24-hour[a]	84	900	20	1984	243/1
	3-hour[a]	508	900	260	1981	176/5
NO_2	Annual	2	2,800	130	1985	--
PM	Annual	2	(See Note Below)			
	24-hour[a]	27	(See Note Below)			
CO	8-hour[a]	26	900	20	1984	183/2
	1-hour[a]	94	900	240	1983	232/13

[a]Impacts represent the highest, second-highest pollutant concentrations for the five-year period 1981-1985.

Note: Maximum annual and highest, second-highest 24-hour ground level particulate impacts result from fugitive dust and material handling particulate matter emissions. Because these emissions are not expected to change, impacts from the original SCA have been used.

Table 5.6-4 Comparison of PSD Class II Increments with Predicted Ground Level Pollutant Concentrations from the Two-Unit Operation			
Pollutant	PSD Class II Increment ($\mu g/m^3$)	Predicted Impacts ($\mu g/m^3$)	Percent of Increment Consumed
SO_2			
Annual	20	3	15
24-hour	91	84	92
3-hour	512	508	99
PM			
Annual	19	2	11
24-hour	37	27	73

Table 5.6-5
Comparison of Ground Level Pollutant Impacts
from the Original SCA and the Current SCA

Pollutant	Original SCA Pollutant Concentrations[a] ($\mu g/m^3$)	Revised Pollutant Concentrations[b] ($\mu g/m^3$)
SO_2		
Annual	6	3
24-hour	85	84
3-hour	509	508
NO_2		
Annual	3	2
PM		
Annual	2	2
24-hour	27	27
CO		
8-hour	12[c]	26
1-hour	44[c]	94

[a]Modeled with 1974-1979 meteorological data.

[b]Modeled with 1981-1985 meteorological data.

[c]CO impacts from the original SCA were listed as only $<<1$ mg/m^3. The values listed are given in $\mu g/m^3$ and are two times the impact from Stanton 1 based on the revised modeling.

5.7 Noise

The noise impacts of the ultimate (4-unit) development of the Stanton Energy Center were included in Subsection 5.7.2.1 of the original SCA, and they will not be discussed further.

5.8 Changes in Nonaquatic Species Population

There will be no changes in nonaquatic species populations as the result of the operation of Stanton 2.

5.9 Other Plant Operation Effects

The operation of Stanton 2 will require an additional two to three unit train coal deliveries per week. Traffic will be impacted by the passage of these trains at various grade crossings. The severity of the traffic impact will depend on the day of the week and time of day of the coal deliveries.

5.10 Archaeological Sites

An archaeological survey was made of the Stanton Energy Center site and the results reported as part of the original SCA. No archaeological sites will be impacted by Stanton 2.

5.11 Resources Committed

Approximately nine acres of the existing Stanton Energy Center site will be committed to Stanton 2. The area currently is vacant land reserved for the planned facility.

The materials used to construct Stanton 2 will be committed resources. It is possible that some of the materials may be reclaimed in the future after closure of the plant.

The coal and oil burned as fuel will be a permanent commitment of resources. It is estimated that 975,000 to 1,190,000 tons of coal and about 80,000 gallons of No. 6 fuel oil will be consumed annually.

5.12 Variances

No variances from applicable standards have been identified at this time as being required as a result of Stanton 2 operation.

6.0 Transmission Lines and Other Linear Facilities

The information presented in this chapter is provided only for the purposes of construction and operation of Stanton 2 as discussed and qualified in the Introduction.

6.1 Transmission Lines and Alternate Access Road

6.1.1 Project Introduction

In order to integrate the power from the Stanton 2 into the Orlando Utilities Commission transmission system, a new 230 kV transmission line will be required. The Stanton-Mud Lake 230 kV transmission line will originate at the existing Stanton Energy Center 230 kV Substation and will interconnect into the existing OUC Transmission Line 7-0615 relocation near Mud Lake. The need for new transmission facilities for Stanton 2 is discussed in Section 1A.6.

The new Stanton-Mud Lake Transmission Line will be approximately 14.0 miles in length and will be constructed totally within the existing and previously certified Orlando Utilities Commission Coal Haul Railroad/Utility Corridor from the Stanton Energy Center to its interconnection with existing Transmission Line 7-0615. Figure 6.1-1 shows the routing of the existing Orlando Utilities Commission Coal Haul Railroad/Utility Corridor. The existing corridor varies in width along its route, from 260 feet to 400 feet. The location of the transmission line within the existing corridor is described in Subsection 6.1.2.

The alternate access road, to be built with the new Stanton 2 facilities, will extend north approximately 1 mile from the Bee Line Expressway offramp along the existing railroad to the site boundary. From there, the alternate access road will follow the onsite rail line and join the onsite road system, as described in Subsection 6.1.2.

6.1.2 Corridor Location and Layout

Figure 6.1-1 shows the full length of the proposed transmission line corridor. Figures 6.1-2, 6.1-3, and 6.1-4 show additional details of the proposed Stanton-Mud Lake 230 kV transmission line route. Also shown on Figure 6.1-2 are existing 115 kV or larger transmission lines in the area.

Figures 6.1-5 through 6.1-11 provide sections of the transmission line location within the Stanton Energy Center site, as well as the existing OUC Railroad/ Utility corridor.

As shown on Figure 6.1-5, the existing railroad/utility corridor varies in width from 260 feet to 400 feet along its route from the existing Line 7-0615 to the Bee Line Expressway. The existing railroad right-of-way uses 120 feet of the corridor. In the area south of the Bee Line Expressway, the transmission line will be located approximately 30 feet outside the 120-foot railroad right-of-way. Approximately 90 feet of the existing corridor will be cleared for the new transmission line.

As shown on Figure 6.1-6, the existing corridor is 300 feet in width, extending north of the Bee Line Expressway. In this area, the transmission line will be located approximately 60 feet outside the 120-foot railroad right-of-way in order to avoid an existing distribution line which serves the Orange County Correctional Facility and to avoid lighting structures at the Bee Line Expressway. In this area, approximately 120 feet of corridor will be cleared for the new transmission line. In the vicinity of the existing rail loop, the new transmission line will depart from the railroad and proceed due north to the south plant perimeter fence. In order to minimize the impacts to the woodpecker habitat, the new line will be constructed within a previously cleared plant construction road area as shown on Figure 6.1-7. No additional clearing is anticipated in this area.

After reaching the south plant perimeter fence, the transmission line will turn east and parallel the perimeter fence and the south and east sides of the make up pond. Figures 6.1-8 and 6.1-9 show the approximate location of the line in this area. As shown on Figure 6.1-8, approximately 45 feet of the 50-foot right-of-way required on the south side of the line has been previously cleared through the area parallel to the plant perimeter access road.

As shown on Figure 6.1-9, approximately 70 feet of the 75 feet required on the south side of the existing distribution line has been previously cleared along the south pond berm. Also, approximately 15 feet of the 75 feet required on the east side of the existing distribution line has been previously cleared along the east pond berm.

At the northeast corner of the makeup pond, the line will turn west and proceed to the existing plant-substation transmission corridor. Figure 6.1-10 shows the proposed location of the new line in this area. It is anticipated that tree clearing will be required only in the portion of this segment extending from the northwest corner of the makeup pond to the existing plant-substation transmission corridor.

After reaching the existing plant-substation transmission corridor, the new line will turn north and parallel the existing corridor to its termination at the Substation, as shown on Figure 6.1-11.

The alternate access road will extend north approximately one mile from the Bee Line Expressway offramp to the Stanton Energy Center site and will be located within the existing 300-foot wide corridor as shown on Figures 6.1-4, 6.1-6, and 6.1-12. From the southern site boundary, the access road will continue parallel to the existing railroad and tie into the existing plant road system as shown on Figure 3.2-1.

6.1.3 Transmission Line and Road Design Characteristics

The Stanton-Mud Lake 230 kV Transmission Line will be constructed using single-pole tubular steel structures as shown on Figure 6.1-13. The structures will be designed to support two 230 kV circuits; however, as shown on Figure 6.1-14, only one circuit will be installed. The structures will be spaced approximately 800 to 1,100 feet apart along the right-of-way. The transmission line conductors will be 954 kcmil 54/7 ACSR/AW conductors designed for a maximum loading of 444 MVA. One fiber-optic shield wire will be installed on the structures for shielding, relaying, and communications.

The transmission line will be designed to meet the clearance requirements of the National Electrical Safety Code. A minimum ground clearance of 27 feet will be maintained to ground under the maximum design loading condition of the line. Figure 6.1-15 shows the profile of a typical 1,000-foot span. The structures will vary in height along the route, depending on the span lengths and obstacles that must be crossed.

Access to the transmission line right-of-way will be from existing roads where practical. Construction of access roads will be necssary along the segments of the right-of-way which are not accessible. The access roads are necessary, not only for the initial construction, but also for maintenance of the line and right-of-way. Figure 6.1-16 shows a cross section of a typical access road segment. The 15-foot wide driving surface of the road will be composed of crushed aggregate or shell surfacing. Where access roads are necessary through wetlands, corrugated metal pipe culverts will be installed at regular intervals to maintain equal water level between the sides of the roads.

Figures 6.1-2 through 6.1-4 show where the construction of new transmission line access roads is anticipated along the route. Table 6.1-1 shows the location, number, length and width of each access road segment and the anticipated volume of fill required.

The route of the alternate access road is shown on Figures 3.2-1 and 6.1-12. The alternate access road will be 24 feet in width with two 10-foot asphalt paved lanes and 2-foot shoulders as shown on Figure 6.1-17. The road will be elevated above the 100-year flood elevation by an embankment. Characteristics of the access road route will be similar to the existing railroad route which is discussed in Subsection 3.9.1 of the original SCA. At locations where the access road interrupts natural drainage patterns, culverts or bridge drainage structures will be provided. Wetland and swamp crossings will use precast concrete pile bridge structures in addition to embankment construction. Additional openings will be provided as required for wildlife crossings. A typical alternate access road bridge is shown on Figure 6.1-18. The final location of embankments, drainage, and crossing structures (if required) along with other detailed information will be determined during the final detailed design stage of the project.

6.1.4 Cost Projections

The estimated total cost of the Stanton-Mud Lake 230 kV transmission line is $9 million. This total cost is itemized in Table 6.1-2.

The estimated total cost of the alternate site access road is $1.5 million (1991 dollars).

6.1.5 Corridor Selection

Studies of OUC's electric transmission and distribution system showed that a connection from the Stanton Energy Center to the Taft Substation integrated very well with the existing system and was preferable to other possible connections for the addition of Stanton 2. In addition, the construction of the new line will be totally onsite or within the existing certified railroad/utility corridor from the plant site to the point of system connection near Mud Lake. Construction of the alternate access road will also be within the existing certified railroad corridor. Therefore, there will be minimal environmental impacts associated with the line installation or alternate access road construction. Other available route options would result in greater impacts because of vegetation clearing and construction within wetland areas that would be necessary. Finally, all of the preferred corridor is owned by OUC and no additional acquisition of land will be required.

6.1.6 Sociopolitical Environment of the Corridor Area

The sociopolitical environment for the Stanton Energy Center project, including the railroad/utility corridor, was described in the original SCA. The entire new transmission line and alternate access road will be located either onsite or within the associated railroad/utility corridor. This corridor received certification with regard to land use compatibility (as part of the initial SCA process) on October 20, 1981.

6.1.7 Biophysical Environment of the Corridor Area

6.1.7.1 Land Use/Vegetation.

6.1.7.1.1 Land Use. The planned transmission line and alternate access road will be located onsite or within the existing railroad/utility corridor. The land use associated with the corridor was described in the original SCA. Final certification of the site and associated facility linear corridors for land use compatibility was made on October 20, 1981 and no further certifications for land use will be necessary.

6.1.7.1.2 Vegetation. Most of the railroad/utility corridor in which the transmission line and alternate access road will be constructed has been previously cleared and is regularly maintained. Grasses and weeds dominate within the right-of-way. Minor additional clearing will be necessary along the transmission line within the railroad/utility corridor and on the site itself.

Prior to the construction of the railroad, a thorough vegetation survey was made of the corridor and the results of the survey were included in Subsection 2.7.7 of the original SCA. Vegetative communities that occurred within the corridor before the railroad was constructed were shown on Figure 2.7-7 of the original SCA. No threatened, endangered, or rare plant species were found during the survey.

6.1.7.2 Affected Water and Wetlands. No surface water will be significantly impacted by the construction of the planned transmission line and alternate access road.

As shown in Table 6.1-1, approximately 20.3 acres of wetlands will be impacted by clearing for the transmission line. The areas that will be affected range from 0.1 to 1.9 acres. These wetlands are in the segment of the corridor between the site boundary and the interconnection with the existing transmission line near Mud Lake. Wetlands in the area are classified as "621, Cypress" by the Florida Land Use, Cover, and Forms Classification System dated September 1985. Surface waters associated with these wetlands are classified as Class III in accordance with FAC 17-302.600.

Approximately 3.7 acres of wetlands will be filled during the construction of transmission line access roads as shown in Table 6.1-1. Approximately 2.5 acres of wetlands will also be impacted by the construction of the alternate site access road from the Bee Line Expressway offramp to the connection point with the onsite road system. The total estimated fill for the alternate site access road and transmission line access road construction in the preliminarily identified wetland areas (Figure 6.1-4) is 30,000 and 13,400 cubic yards, respectively. The quantity of fill material to be placed below the ordinary high water level in these areas will be determined later, as design proceeds. In addition, some dredging will be necessary in wetlands for the placement of foundation structures for transmission line towers. Table 6.1-1 shows that 220 cubic yards of dredged material must be removed in wetlands in order to construct tower foundations.

Drainage patterns should not be significantly affected by the construction and operation of the transmission line and alternate access road. The line and road will be constructed within the existing railroad corridor right-of-way. In affected wetland areas, culverts and bridge structures will be installed where appropriate to maintain flow between segments of wetlands. Surface water hydrology is described in Subsection 2.5.1 and the onsite drainage system in Section 3.10 of the original SCA. Modifications to accommodate existing drainage patterns along the alternate access road are described in Subsection 6.1.3 of this application.

6.1.7.3 Ecology. The ecology of the Stanton Energy Center project area and the railroad corridor were addressed in Section 2.7 of the original SCA.

6.1.7.4 Other Environmental Features. There are no other environmental features applicable to the proposed transmission line and alternate access road.

6.1.8 Effect of Right-of-Way Preparation and Transmisssion Line Construction

6.1.8.1 Construction Techniques. Several distinct tasks will be required for construction of the proposed transmission line and alternate access road. These will include surveying, clearing, road construction, foundation construction, structure assembly and erection, conductor and shield wire installation, and cleanup. The tasks will occur in the following sequence and will be separated, in time, by several days to several months.

The right-of-way center line and edges and structure sites are established prior to construction. This task is usually performed by three- to five-person survey teams and requires minimum clearing for a "line of sight." Clearing and road construction usually run concurrently because the requirements for heavy equipment are the same. Road construction is necessary where the structure site would otherwise be under water or the terrain will not support the heavy equipment to be used in subsequent phases of work.

In wetlands connected to waters-of-the-state, chain saws and/or light, tracked shear machines will be used for clearing, and fill material will be hauled in for the construction of roads. Stumps and root mat will be left in place except for the area where the structure foundation is to be installed. There will be no need to demuck.

In areas outside of wetlands, the right-of-way will be cleared by heavy tracked machines, usually bulldozers, and dressed to facilitate future maintenance using wheeled tractors with "bush-hog" mowers. Stumps and cuttings will be piled and burned. The method will depend on OUC preferences at the time, requirements of the Division of Forestry, and other conditions at the time.

Fill material for access roads is hauled in by truck and spread with bulldozers to obtain suitable compaction. Culverts are installed as the road construction progresses to maintain drainage and water flow.

Construction of concrete foundations makes up the second phase of construction. Equipment required for foundation construction consists of an augering machine mounted on a tracked or all-wheel drive vehicle, "ready-mix" concrete trucks, water trucks, pile driving equipment, and medium-sized (25- to 75-ton) tracked cranes. Each work group will have a bulldozer available to assist in the installation. Tractors, trailers, and light vehicles are used to transport material and personnel.

The next series of tasks consist of hauling material, assembly of structures, erection of structures, and installation of the conductors. The structures and conductor hardware will probably be hauled to the site by tractors and trailers, then offloaded with medium-sized truck cranes or all-wheeled cranes. Medium-sized (1-1/2 to 2-ton) all-wheel-drive trucks are used to transport personnel and tools. Medium-sized trucks or all-wheel-drive cranes are required to move structure components and place the structure for erection. The most common method of erecting the structure is with heavy tracked cranes. A work group will normally place the entire structure in one "pick." The boom "reach" will be sufficient to work the tallest structures. Insulators and roller blocks are installed during or immediately following this task. The location of the worksite for installation of conductors and shield wires is determined by the length of conductor on a reel or the line configuration. The basic equipment used for conductor installation is a matched set of machines (puller and tensioner) to pull the conductor and static wires through the rollers to the receiving end and, at the same time, to retard the conductor or maintain light tension at the sending end. The conductors and shield wires are hauled to the sending end on tractors and trailers. A variety of other equipment (radio-equipped pickups to medium-sized cranes and bulldozers) is required at both ends to complete the pull. The puller and tensioner then "leap-frog" as consecutive sections are completed. A bulldozer with a three- or four-drum winch is ordinarily used at the receiving ends to bring the conductors to final tension. The rollers are then removed and the conductors are permanently affixed ("clipped") to each structure. The time required to complete a "pull" averages less than a week.

Finally, at each "heavy-angle" or "dead-end" structure (where the wire has been stopped and/or started), it is necessary to install short pieces of conductor between the ends in order to electrically connect the conductors. Structures, fences, and gates are grounded during this phase of construction and before the line is energized.

Soil erosion is not a problem with proper design and maintenance. Consequently, each contractor will be required to have sufficient equipment and personnel to maintain roads and to keep the right-of-way clear of debris and waste materials. Roads will be constructed with slight crowns and slopes. In addition, culverts will be placed at necessary locations to allow for proper sheet flow and prevent road washouts. Turbidity screens will be used as required to maintain water quality. Roads, pastures, lawns, and open areas will be maintained throughout the construction period. If necessary, restoration, including grading the soil and replanting or reseeding disturbed areas of the construction site(s), will be accomplished prior to the end of the construction phase of the project.

6.1.8.2 Impacts on Waterbodies and Uses. The proposed transmission line, associated construction and maintenance road, and alternate site access road are located more than a mile from the Econlockhatchee and Little Econlockhatchee Rivers and will have no impacts on them. These proposed linear facilities will have some impact on isolated wetland areas in the existing railroad corridor. Minor wetland dredge and fill will be necessary in a few locations in order to construct transmission pole foundations. The placement of fill will also be necessary in a number of locations associated with the construction of access and maintenance roads. The expected locations of fill placement are shown on Figures 6.1-2, 6.1-3, and 6.1-4. In addition, estimates of dredging, fill, and clearing necessary for the transmission line and roads are included in Table 6.1-1. Cross sections showing transmission line and road locations within the existing corridor are shown on Figures 6.1-5 through 6.1-11. Road and typical bridge sections are shown on Figures 6.1-16 through 6.1-18. The Joint Application form (DER Form 17-1.203[1]) is included in Subsection 10.6.2.

This application includes all currently available preliminary design information regarding the wetland impacts of the proposed transmission line and access roads. Paragraphs B and C of Section 6.1.8.2 of DER Form 17-1.211(1) allow submittal of detailed wetland impact information either during the certification process or post-certification for later review. The additional information is being developed and is expected to be available by approximately mid-June 1991 during the certification process.

6.1.8.3 Solid Wastes. Solid wastes generated during construction of the proposed transmission line and alternate access road will consist of construction material debris and cleared vegetation. Cleared vegetation and other combustible materials will be burned on the right-of-way, following applicable regulations regarding open burning. Merchantable timber may be removed by the landowner or tenant. Noncombustible materials will be collected and disposed of at local landfills or other approved disposal sites.

6.1.8.4 Changes to Vegetation, Wildlife, and Aquatic Life. Approximately 30 acres of upland habitat will be cleared for the construction of the proposed transmission line and associated access roads. All of these areas are within the existing railroad corridor and have been previously disturbed. Construction within the railroad corridor is expected to have very minimal impact on wildlife.

In the vicinity of the existing rail loop, located in the southwest portion of the Stanton Energy Center site, the new transmission line will be constructed within a previously cleared plant construction road to minimize any impacts to the red-cockaded woodpecker foraging habitat (Figure 6.1-7). At the south perimeter of the developed plant site, the transmission line will proceed east and parallel the perimeter fence in the vicinity of the makeup water holding pond (Figures 6.1-8 and 6.1-9). No tree clearing is planned in this area of red-cockaded woodpecker habitat. No significant impacts on the woodpeckers are anticipated.

As shown in Table 6.1-1, an estimated 19.7 acres of wetland vegetation will be cleared, and 4.2 acres of wetland filled. Although these areas have been previously disturbed by construction activities associated with the rail line installation, there will be some loss of wildlife habitat. These areas are used by a variety of birds, small mammals, amphibians, and reptiles. The proposed transmission line has been routed to minimize impacts on wetlands as much as possible by confining construction to areas previously disturbed.

6.1.8.5 Impact on Human Population. The Stanton Energy Center, including the previously certified railroad/utility corridor, is located in a sparsely populated area and impacts on humans during Stanton 2 construction will be minimal. There will be some increase in noise levels during construction, but most of the noise impacts will be confined to the Stanton Energy Center plant site.

Because of the relatively remote location of the construction site, there should be little, if any, noticeable effect on traffic as the result of the movement of materials and workers.

6.1.8.6 Impact on Regional Scenic, Cultural, and Natural Landmarks. There are no regional scenic, cultural, or natural landmarks that will be affected by the proposed transmission line or alternate access road.

6.1.8.7 Impact on Archaeological and Historic Sites. There are no archaeological or historic sites within the planned transmission line corridor or alternate access road. During an archaeological survey of the railroad corridor in 1981, an Indian campsite was identified within the proposed corridor (Site Number 80 or 391) near Wewahootee Road. The railroad was realigned to the south to miss the archaeological site. The State Historic Preservation Officer cleared the project for construction following the realignment. Details of the archaeological survey are contained in the original SCA.

6.1.9 Post-Construction Impacts and Effects of Maintenance

6.1.9.1 Maintenance Techniques. Orlando Utilities Commission will inspect and maintain its transmission line and line right-of-way by the following activities.

- o Monthly inspection on foot or by vehicle.
- o Emergency patrol by vehicle and/or aerial in the event of damage to the line by severe weather, etc.
- o Use of farm type tractors with mowing and brush-cutting attachment to maintain the initial clearing of vegetation at intervals of one, two, or more years, as necessary.
- o Application of herbicides, as required, in areas where the soil remains too wet for vegetation to be maintained by mechanical means.

Herbicides may be used throughout the right-of-way. Applications will include only those registered by the US Environmental Protection Agency and which have the required state approval. Application rates and concentrations will be in accordance with the label directions. In most cases, the frequency of application will be one treatment every three to five years. Only in a very unusual situation would treatment be required more frequently.

Burning is not normally required for maintenance of the transmission line right-of-way. When extensive reclearing of the right-of-way is necessary, as during construction, limited burning of cleared vegetation may occur. Since the cleared right-of-way itself acts as a fire lane, no fire lanes are anticipated to be necessary, and Orlando Utilities Commission has no plans to create them within the right-of-way.

The alternate access road to the Stanton Energy Center site will require periodic inspection, maintenance, cleaning, and occasional repair work. These activities will help to maintain the serviceability and safety and to prolong the service life of the access road. Inspection of the pavement structure (asphalt, base, and drainage system) will be done on a seasonal basis and also after any severe weather. Early detection and prompt repair of any of the damaged portions of the structure will be a part of the regular inspection and maintenance program.

6.1.9.2 Multiple Uses. There are no multiple uses planned for the existing railroad/transmission line corridor. The alternate access road will provide restricted or emergency site access for plant operating personnel and delivery of operating materials.

6.1.9.3 Changes in Species Populations. No significant long-term changes in the populations of threatened, endangered, or species of special concern within the transmission line or alternate access road rights-of-way are expected as the result of maintenance practices. Only about 14 miles of new transmission line and 1 mile of alternate access road will be constructed within the existing railroad/utility corridor.

6.1.9.4 Effects of Public Access. Any new transmission line access roads will have controlled entry (locked gates) and there should be no impacts on any existing wildlife from increased public exposure. Traffic on the alternate access road will be controlled by gates at the fenced site boundary.

6.1.10 Other Post-Construction Effects

6.1.10.1 Electric and Magnetic Fields. Figure 6.1-19 shows the electric and magnetic field levels anticipated for the line for the 260-foot corridor under maximum loading conditions (444 MVA). Also shown are the state limits for both electric and magnetic fields. As previously discussed, the existing railroad/utility corridor varies in width from 260 feet to 400 feet. The 260-foot corridor is shown, as this would represent the worst case. The electric and magnetic field levels would be lower at the edge of the 400-foot right-of-way. As shown, the expected levels anticipated for the line are significantly lower than the state limits.

6.1.10.2 Audible Noise. The energy that produces sound is usually expressed in units of decibels (dB). The perception of sound varies with the frequency of sound. In order to refine the measurement of sound to approximate human perception, weighting networks have been developed. Among these networks is the A-weighted decibel system (dBA), which simulates human hearing response at low sound pressure levels and discriminates among frequencies below 500 Hz. A-weighting has been found to effectively evaluate subjective hearing response as well as those frequencies responsible for harmful hearing effects (Goldstein, 1979). Figure 6.1-20 shows the relative sound levels in dBA of several common sources.

The audible noise associated with a transmission line is generated by either corona created around the conductors or gap type discharges between energized parts of the line. The proposed transmission line will use hardware which will minimize gap noise. Foul or wet weather produces the higher noise levels; however, the background noise from foul weather usually masks the transmission line noise.

The proposed 230 kV transmission line will have an audible noise level at the edge of the 260-foot right-of-way of approximately 45 dBA with a wet conductor condition.

The fair weather audible noise from the proposed transmission line will be approximately 20 dBA at the edge of the 260-foot right-of-way. While the human ear can perceive a noise of 10 dBA above ambient, the ambient noise level in rural, semirural, or urban areas (typically 30 to 50 dBA) will essentially mask the audible noise from the transmission lines.

6.1.10.3 Radio and Television Interference (RI and TVI). Like audible noise, RI and TVI can be produced by either gap type discharges or corona discharges. However, calculations and measurements that describe RI and TVI are not converted to A-weighted values (dBA). RI affects AM reception; however, FM reception is not affected. The predicted RI level at the edge of the right-of-way during fair weather conditions will be approximately 36.2 dB. Foul weather RI is generally 17 to 24 dB higher than fair weather values. The predicted TVI at the edge of the right-of-way during fair weather conditions will be less than the ambient level. During foul weather, the predicted TVI will be approximately 18.57 dB.

Design and operating experiences to date with other similar lines in the Orlando Utilities Commission system indicate that no impact to radio and television reception is anticipated. There are no residences in close proximity to the existing railroad/utility corridor.

6.1.10.4 Ozone. During periods of very heavy rain, ozone will be produced by the line. The estimated ozone concentration is 0.584 parts per billion at ground level during a 1-inch per hour rainfall. This is well below the national ambient air quality standard for ozone of 0.12 parts per million.

Table 6.1-1

ORLANDO UTILITIES COMMISSION
STANTON – MUD LAKE 230 KV TRANSMISSION LINE
SUMMARY OF DESIGN DATA AND LAND USE

LOCATION			ACCESS ROAD SUMMARY				CLEARING SUMMARY						FOUNDATION EXCAVATION IN WETLAND
FROM STRUCTURE NUMBER	TO STRUCTURE NUMBER	SPAN (FT)	LENGTH (FT)	FILL (CU YD)	IMPACT (AC)	R/W WIDTH (FT) (1)	CITRUS (FT)	UNFORESTED UPLAND (FT)	FORESTED UPLAND (FT)	FORESTED UPLAND CLEARING (AC)	WETLAND (FT)	WETLAND CLEARING (AC) (2)	(CU YD)
101	102	930	0	0.0	0.00	120	0	465	465	0.96	0	0.00	0.0
102	103	950	0	0.0	0.00	120	0	475	475	0.98	0	0.00	0.0
103	104	950	0	0.0	0.00	120	0	475	475	0.98	0	0.00	0.0
104	105	950	0	0.0	0.00	120	0	475	475	0.98	0	0.00	0.0
105	106	960	800	1866.7	0.50	120	0	0	160	0.33	800	1.65	0.0
106	107	900	0	0.0	0.00	120	0	675	225	0.46	0	0.00	0.0
107	108	850	0	0.0	0.00	120	0	650	200	0.41	0	0.00	0.0
108	109	830	0	0.0	0.00	120	0	630	200	0.41	0	0.00	0.0
109	110	800	0	0.0	0.00	120	500	150	150	0.31	0	0.00	0.0
110	111	940	0	0.0	0.00	120	940	0	0	0.00	0	0.00	0.0
111	112	940	0	0.0	0.00	120	200	740	0	0.00	0	0.00	0.0
112	113	940	0	0.0	0.00	120	0	940	0	0.00	0	0.00	0.0
113	114	940	0	0.0	0.00	120	0	940	0	0.00	0	0.00	0.0
114	115	940	250	583.3	0.15	120	0	690	0	0.00	250	0.52	0.0
115	116	940	220	513.3	0.14	120	0	720	0	0.00	220	0.45	0.0
116	117	940	0	0.0	0.00	120	0	940	0	0.00	0	0.00	0.0
117	118	940	150	350.0	0.09	120	0	940	0	0.00	0	0.00	0.0
118	119	900	0	0.0	0.00	120	0	900	0	0.00	0	0.00	0.0
119	120	900	0	0.0	0.00	120	0	900	0	0.00	0	0.00	0.0
120	121	900	0	0.0	0.00	120	0	900	0	0.00	0	0.00	0.0
121	122	900	200	466.7	0.12	120	0	700	0	0.00	200	0.41	0.0
122	123	900	150	350.0	0.09	120	0	750	0	0.00	150	0.31	0.0
123	124	900	0	0.0	0.00	120	0	900	0	0.00	0	0.00	0.0
124	125	900	0	0.0	0.00	120	0	900	0	0.00	0	0.00	0.0
125	126	900	0	0.0	0.00	120	0	900	0	0.00	100	0.21	0.0
126	127	900	0	0.0	0.00	120	0	800	0	0.00	0	0.00	0.0
127	128	800	200	466.7	0.12	120	0	600	0	0.00	200	0.41	0.0
128	129	800	0	0.0	0.00	120	0	750	0	0.00	50	0.10	31.4
129	130	1000	50	116.7	0.03	120	0	100	0	0.00	900	1.86	0.0
130	131	1000	0	0.0	0.00	120	0	950	50	0.10	0	0.00	0.0
131	132	1000	0	0.0	0.00	120	0	200	600	1.24	200	0.41	0.0
132	133	1000	0	0.0	0.00	120	0	1000	0	0.00	0	0.00	0.0
133	134	1000	400	933.3	0.25	120	0	450	0	0.00	550	1.14	31.4

(1) TOTAL WIDTH INCLUDING PORTIONS THAT MAY EXTEND OVER OTHER RIGHTS-OF-WAY.
(2) WETLAND CLEARING ACREAGE INCLUDES ACCESS ROAD IMPACT AREA.

Table 6.1-1 (continued)

ORLANDO UTILITIES COMMISSION

STANTON – MUD LAKE 230 KV TRANSMISSION LINE

SUMMARY OF DESIGN DATA AND LAND USE

LOCATION			ACCESS ROAD SUMMARY				CLEARING SUMMARY						FOUNDATION EXCAVATION IN WETLAND
FROM STRUCTURE NUMBER	TO STRUCTURE NUMBER	SPAN (FT)	LENGTH (FT)	FILL (CU YD)	IMPACT (AC)	R/W WIDTH (FT) (1)	CITRUS (FT)	UNFORESTED UPLAND (FT)	FORESTED UPLAND (FT)	FORESTED UPLAND CLEARING (AC)	WETLAND (FT)	WETLAND CLEARING (AC) (2)	(CU YD)
134	135	920	50	116.7	0.03	120	0	770	0	0.00	100	0.21	0.0
135	136	920	0	0.0	0.00	120	0	920	0	0.00	0	0.00	0.0
136	137	910	350	816.7	0.22	120	0	610	0	0.00	300	0.62	31.4
137	138	910	0	0.0	0.00	120	0	560	0	0.00	350	0.72	0.0
138	139	910	0	0.0	0.00	120	0	910	0	0.00	0	0.00	0.0
139	140	910	0	0.0	0.00	120	0	910	0	0.00	0	0.00	0.0
140	141	910	0	0.0	0.00	120	0	910	0	0.00	0	0.00	0.0
141	142	910	0	0.0	0.00	120	0	910	0	0.00	0	0.00	0.0
142	143	910	350	816.7	0.22	120	0	0	560	1.16	350	0.72	31.4
143	144	910	0	0.0	0.00	120	0	0	160	0.33	750	1.55	31.4
144	145	910	0	0.0	0.00	120	0	0	910	1.88	0	0.00	0.0
145	146	750	0	0.0	0.00	120	0	100	300	0.62	350	0.72	0.0
146	147	910	0	0.0	0.00	120	0	810	100	0.21	0	0.00	0.0
147	148	910	0	0.0	0.00	120	0	455	455	0.94	0	0.00	0.0
148	149	840	0	0.0	0.00	120	0	500	340	0.70	0	0.00	0.0
149	150	840	0	0.0	0.00	120	0	600	240	0.50	0	0.00	0.0
150	151	840	0	0.0	0.00	120	0	500	340	0.70	0	0.00	0.0
151	152	830	0	0.0	0.00	120	0	200	630	1.30	0	0.00	0.0
152	153	800	0	0.0	0.00	120	0	300	500	1.03	0	0.00	0.0
153	154	950	0	0.0	0.00	120	0	0	950	1.96	0	0.00	0.0
154	155	960	400	933.3	0.25	120	0	0	560	1.16	400	0.83	0.0
155	156	960	0	0.0	0.00	120	0	0	710	1.47	250	0.52	0.0
156	157	960	0	0.0	0.00	120	0	0	610	1.26	350	0.72	0.0
157	158	960	0	0.0	0.00	120	0	760	200	0.41	0	0.00	0.0
158	159	1000	0	0.0	0.00	120	0	1000	0	0.00	0	0.00	0.0
159	160	870	0	0.0	0.00	120	0	870	0	0.00	0	0.00	0.0
160	161	1050	0	0.0	0.00	120	0	1050	0	0.00	0	0.00	0.0
161	162	750	0	0.0	0.00	120	0	325	325	0.90	100	0.28	0.0
162	163	900	0	0.0	0.00	120	0	100	450	1.24	350	0.96	0.0
163	164	900	0	0.0	0.00	120	0	400	425	1.17	75	0.21	0.0
164	165	850	0	0.0	0.00	120	0	300	350	0.96	200	0.55	0.0
165	166	850	0	0.0	0.00	120	0	200	250	0.69	450	1.24	0.0

(1) TOTAL WIDTH INCLUDING PORTIONS THAT MAY EXTEND OVER OTHER RIGHTS-OF-WAY.

(2) WETLAND CLEARING ACREAGE INCLUDES ACCESS ROAD IMPACT AREA.

Table 6.1-1 (continued)

ORLANDO UTILITIES COMMISSION
STANTON – MUD LAKE 230 KV TRANSMISSION LINE
SUMMARY OF DESIGN DATA AND LAND USE

LOCATION			ACCESS ROAD SUMMARY				CLEARING SUMMARY						FOUNDATION EXCAVATION IN WETLAND
FROM STRUCTURE NUMBER	TO STRUCTURE NUMBER	SPAN (FT)	LENGTH (FT)	FILL (CU YD)	IMPACT (AC)	R/W WIDTH (FT) (1)	CITRUS (FT)	UNFORESTED UPLAND (FT)	FORESTED UPLAND (FT)	FORESTED UPLAND CLEARING (AC)	WETLAND (FT)	WETLAND CLEARING (AC) (2)	(CU YD)
166	167	850	0	0.0	0.00	120	0	200	200	0.55	450	1.24	0.0
167	168	800	0	0.0	0.00	120	0	500	300	0.83	0	0.00	0.0
168	169	850	0	0.0	0.00	120	0	300	150	0.41	400	1.10	0.0
169	170	900	0	0.0	0.00	100	0	700	200	0.46	0	0.00	0.0
170	171	665	0	0.0	0.00	100	0	665	0	0.00	0	0.00	0.0
171	172	665	0	0.0	0.00	100	0	665	0	0.00	0	0.00	0.0
172	173	660	0	0.0	0.00	100	0	640	20	0.002	0	0.00	0.0
173	174	660	0	0.0	0.00	100	0	640	20	0.002	0	0.00	0.0
174	175	660	50	70.4	0.03	100	0	660	0	0.00	0	0.00	0.0
175	176	660	450	633.3	0.24	100	0	310	50	0.01	300	0.03	0.0
176	177	660	300	422.2	0.16	100	0	460	50	0.01	150	0.02	31.4
177	178	660	300	422.2	0.16	100	0	610	50	0.01	0	0.00	0.0
178	179	620	0	0.0	0.00	100	0	590	30	0.04	0	0.00	0.0
179	180	620	400	933.3	0.25	100	0	190	30	0.04	400	0.55	31.4
180	181	620	0	0.0	0.00	100	0	590	30	0.04	0	0.00	0.0
181	182	620	0	0.0	0.00	100	0	570	50	0.07	0	0.00	0.0
182	183	610	100	233.3	0.06	100	0	560	50	0.07	0	0.00	0.0
183	184	780	780	1820.0	0.48	100	0	780	0	0.00	0	0.00	0.0
184	185	730	220	513.3	0.14	100	0	530	200	0.23	0	0.00	0.0
185	186	650	0	0.0	0.00	140	0	325	325	0.52	0	0.00	0.0
186	187	690	0	0.0	0.00	140	0	345	345	0.55	0	0.00	0.0
187	188	500	0	0.0	0.00	140	0	300	100	0.16	0	0.00	0.0
TOTALS		74180 14.0	6170	13378.1	3.7		1640	47705	15040	31.77	9695	20.27	219.8

(1) TOTAL WIDTH INCLUDING PORTIONS THAT MAY EXTEND OVER OTHER RIGHTS–OF–WAY.
(2) WETLAND CLEARING ACREAGE INCLUDES ACCESS ROAD IMPACT AREA.

Table 6.1-2
Estimated Total Cost of Transmission Line

Item	Quantity	Estimated Total Cost ($1991)
Land Requisition	14.0 miles	0
Right-of-Way Preparation	14.0 miles	950,000
Access Road Construction	14,163 cu yd	262,440
Structures (Including Foundations)		
Tangent (0-1 degree)	64	2,759,340
Angle (1-10 degree)	6	350,975
Angle (10-30 degree)	10	853,495
Dead-ends (30-90 degree)	7	627,085
Conductors	14.0 miles	1,338,490
Other[a]		1,858,175
Estimated Total Cost		9,000,000
Total Length	14.0 miles	
Estimated Per Mile Cost		642,855

[a]Orlando Utilities Commission costs, surveying, engineering, legal, soil investigation costs.

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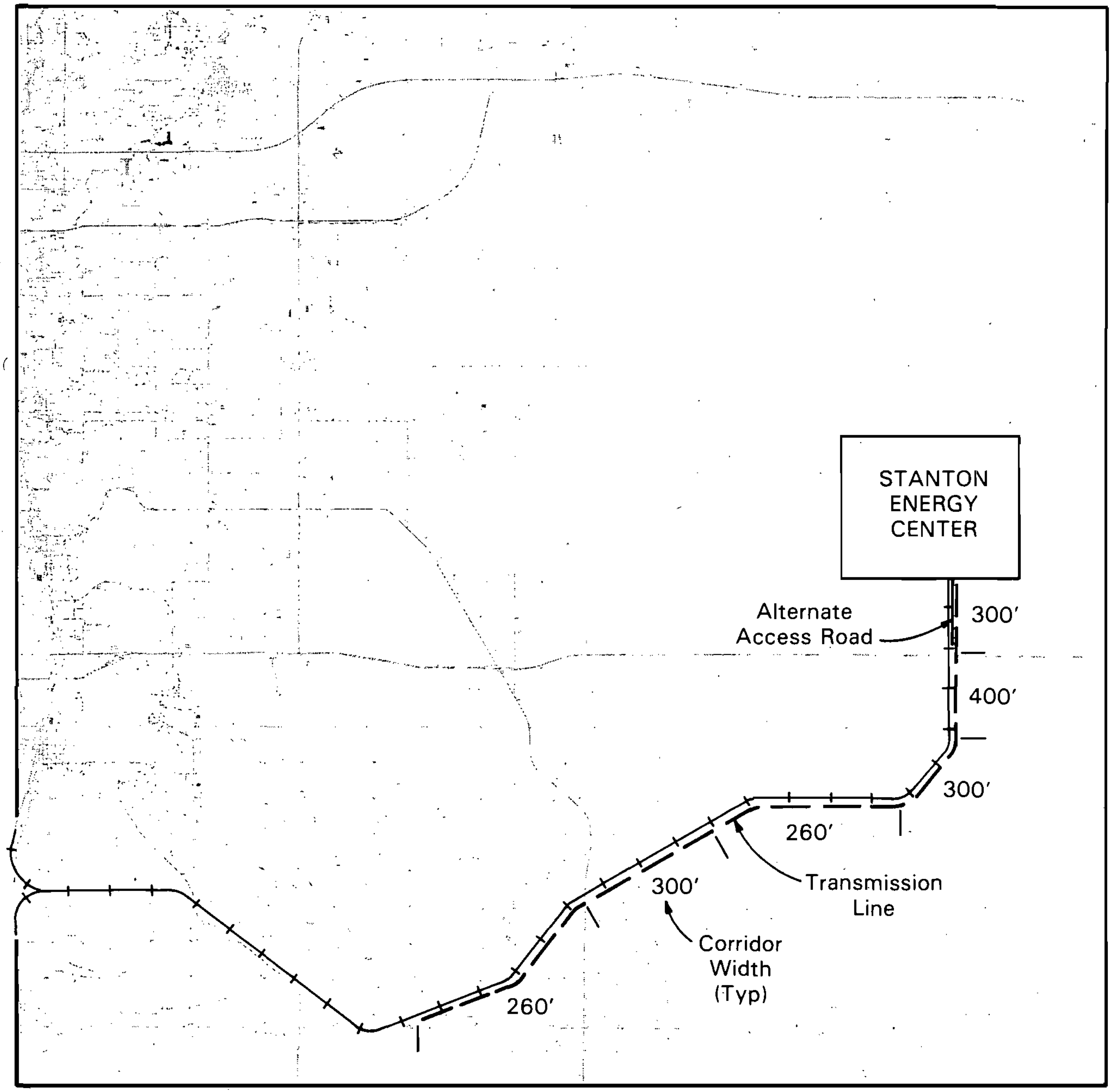
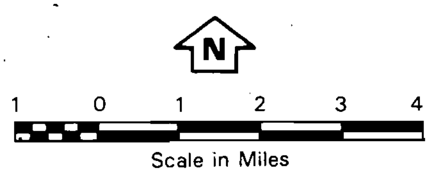
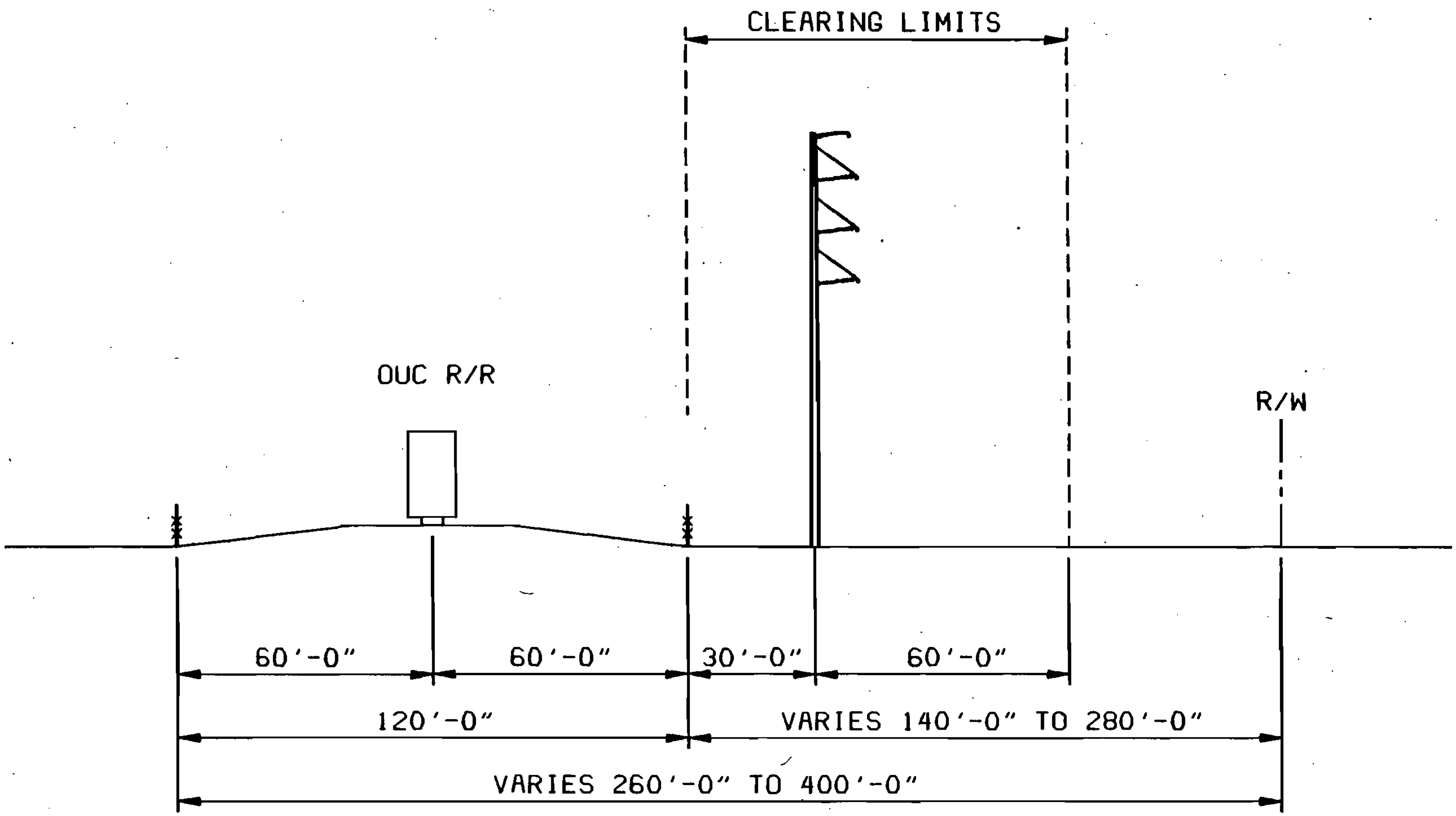


Base Map Source: USGS, Orland East, Oviedo SW, Pine Castle, Narcoossee NW, St. Cloud North, Narcoossee, FL Quadrangles



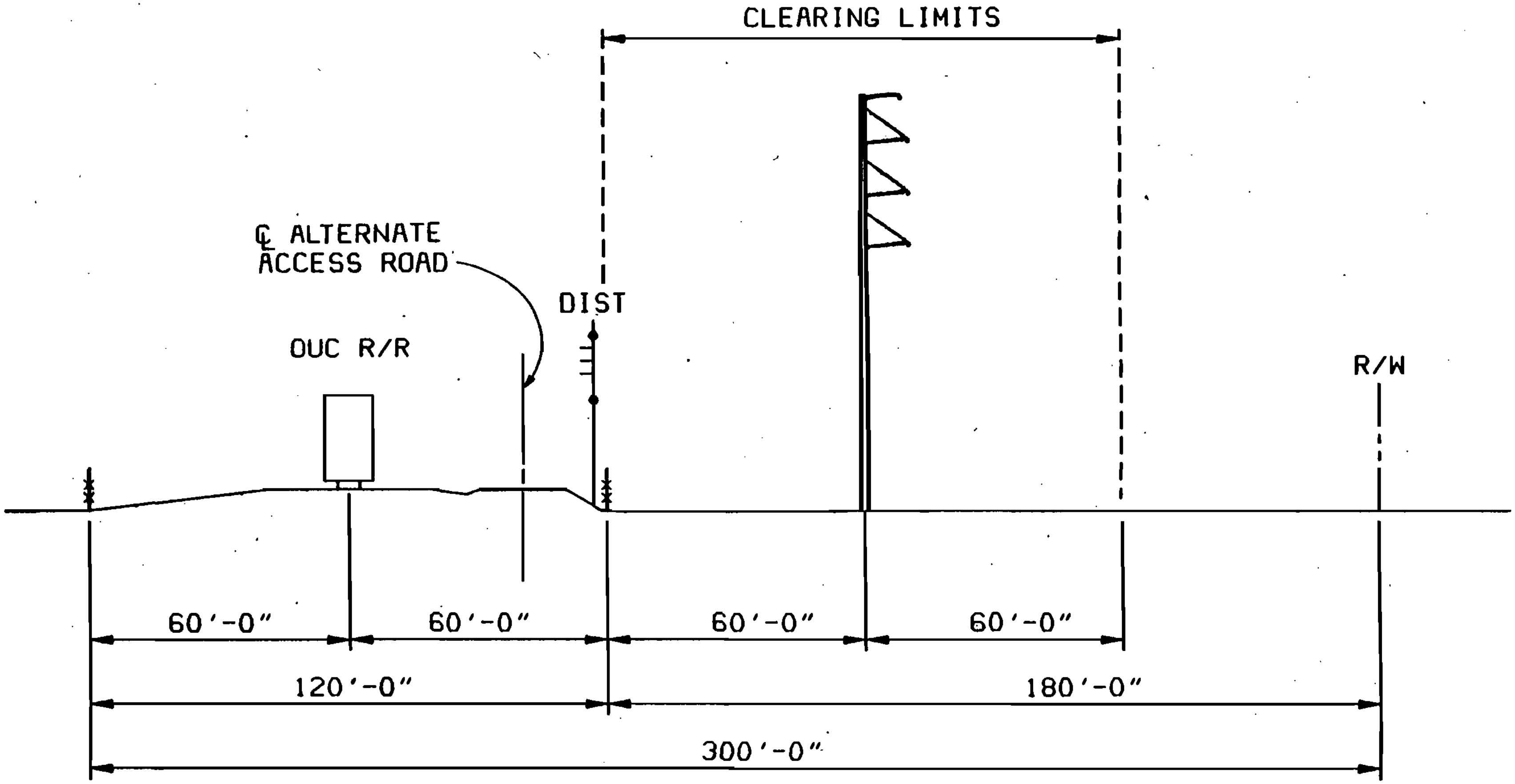
LOCATION OF THE STANTON ENERGY CENTER
TO MUD LAKE TRANSMISSION LINE
AND ALTERNATE ACCESS ROAD

Figure 6.1-1



STANTON-MUD LAKE 230 KV TRANSMISSION LINE ALONG RAILROAD – RELOCATED LINE 7-0615 TO BEE LINE EXPRESSWAY (Looking North)

Figure 6.1-5

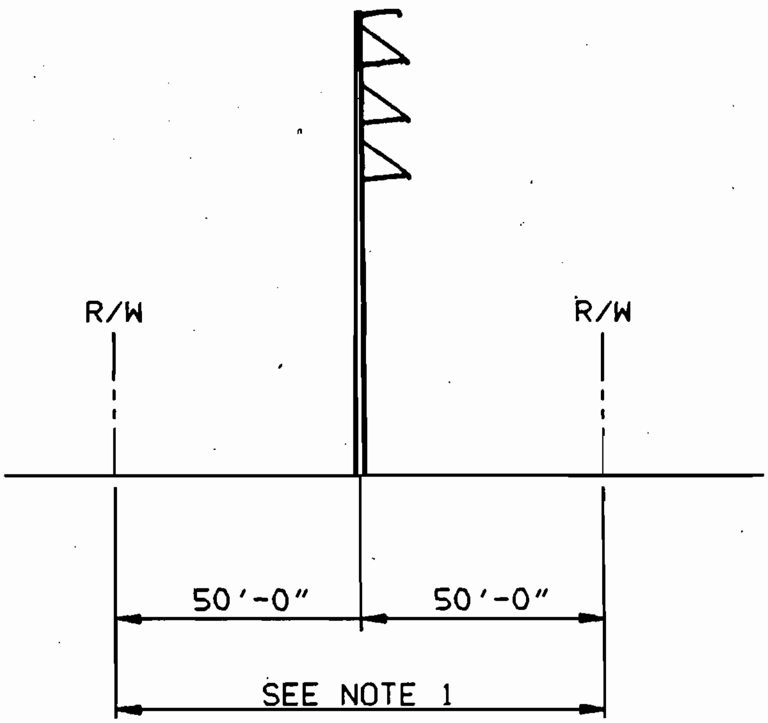


STANTON-MUD LAKE 230 KV TRANSMISSION LINE ALONG RAILROAD — BEE LINE EXPRESSWAY TO STANTON SITE (Looking North)

Figure 6.1-6

NOTES:

1. PREVIOUSLY CLEARED, NO ADDITIONAL CLEARING ANTICIPATED.

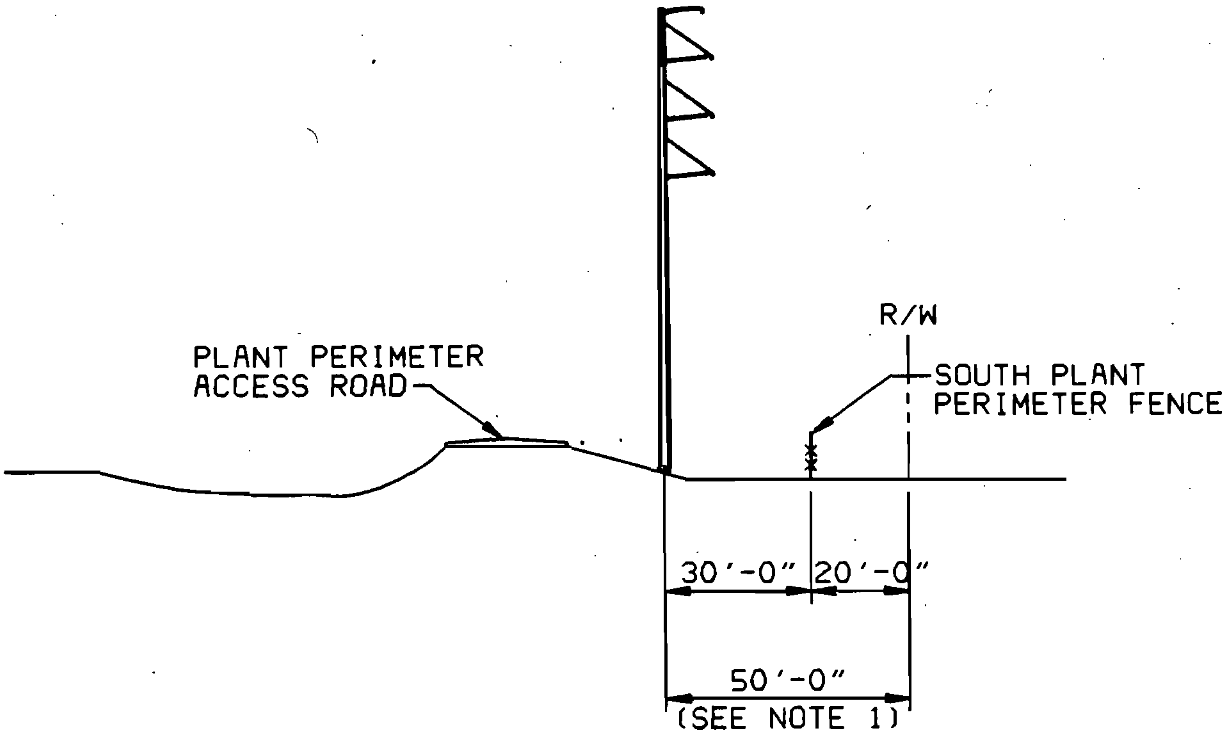


STANTON-MUD LAKE 230 KV TRANSMISSION LINE ALONG EXISTING CONSTRUCTION ROAD (Looking North)

Figure 6.1-7

NOTES:

1. APPROXIMATELY 45 FEET CLEARED UNDER PREVIOUS PROJECT, MINIMUM ADDITIONAL CLEARING ANTICIPATED.



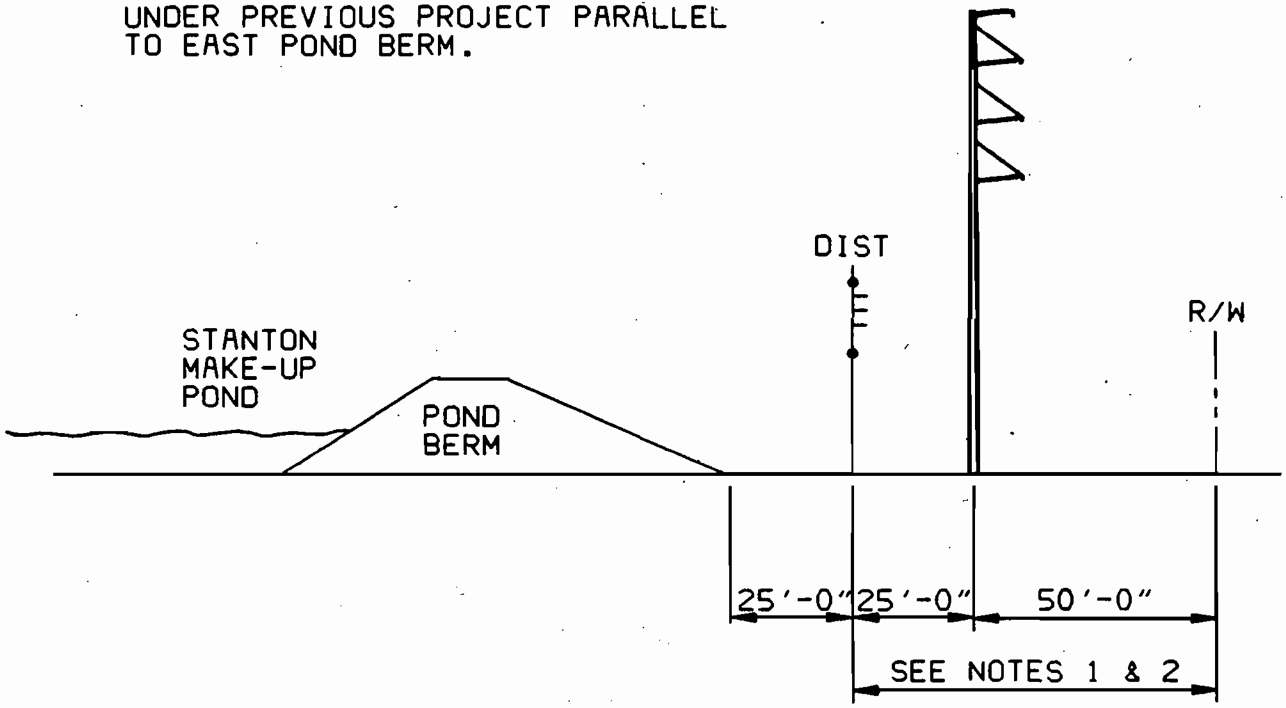
STANTON-MUD LAKE 230 KV TRANSMISSION LINE PARALLEL TO SOUTH PLANT PERIMETER FENCE (Looking East)

Figure 6.1-8

NOTES:

1. APPROXIMATELY 70 FEET CLEARED UNDER PREVIOUS PROJECT PARALLEL TO SOUTH POND BERM.

2. APPROXIMATELY 15 FEET CLEARED UNDER PREVIOUS PROJECT PARALLEL TO EAST POND BERM.

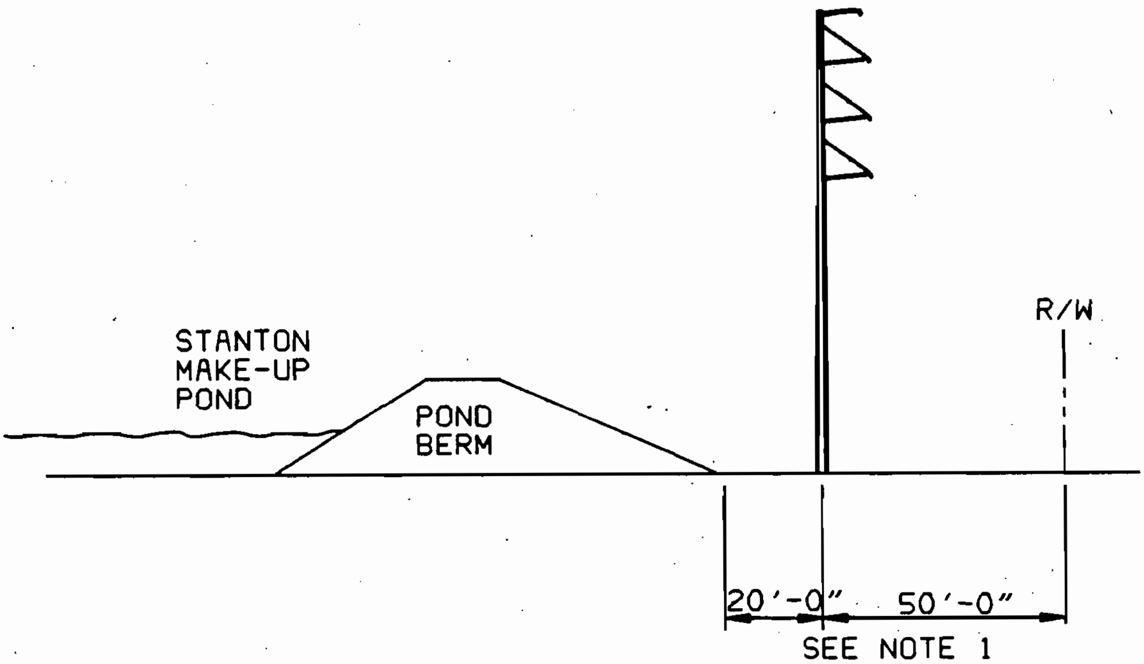


STANTON-MUD LAKE 230 KV TRANSMISSION LINE ALONG PLANT MAKEUP POND (Looking East or North)

Figure 6.1-9

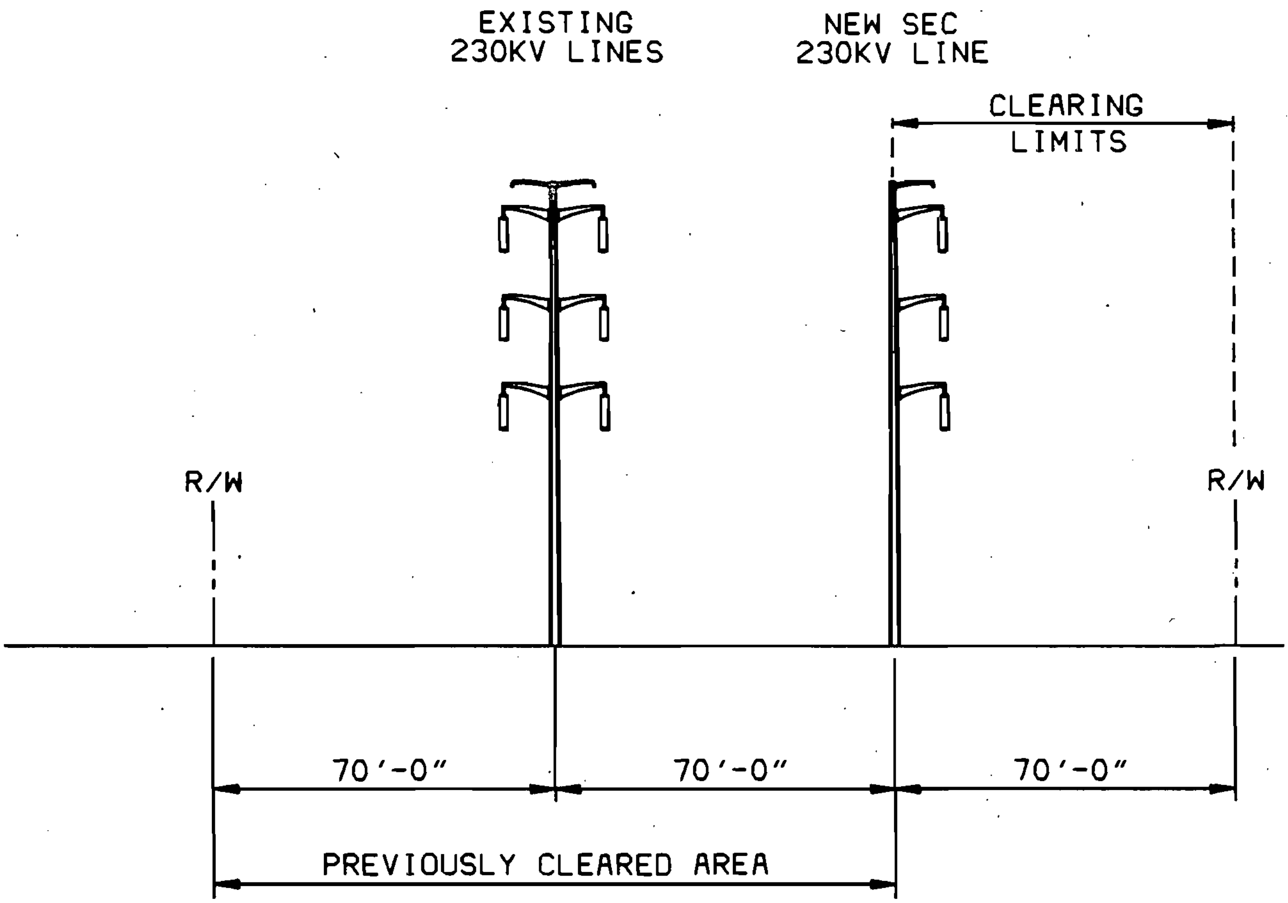
NOTES:

1. PREVIOUSLY CLEARED, NO ADDITIONAL CLEARING ANTICIPATED EXCEPT FROM NORTHWEST CORNER OF MAKE-UP POND TO EXISTING PLANT SUBSTATION TRANSMISSION CORIDOR.



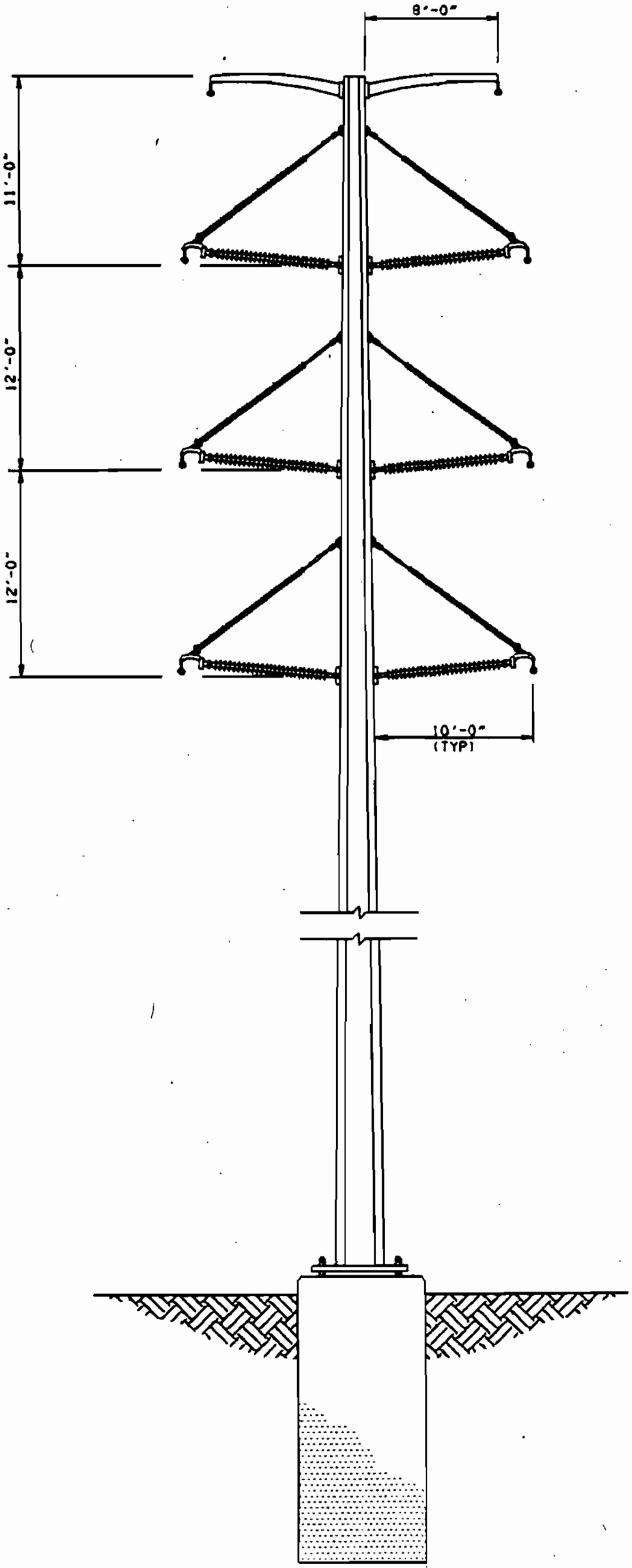
STANTON-MUD LAKE 230 KV TRANSMISSION LINE ALONG PLANT MAKEUP POND (Looking West)

Figure 6.1-10



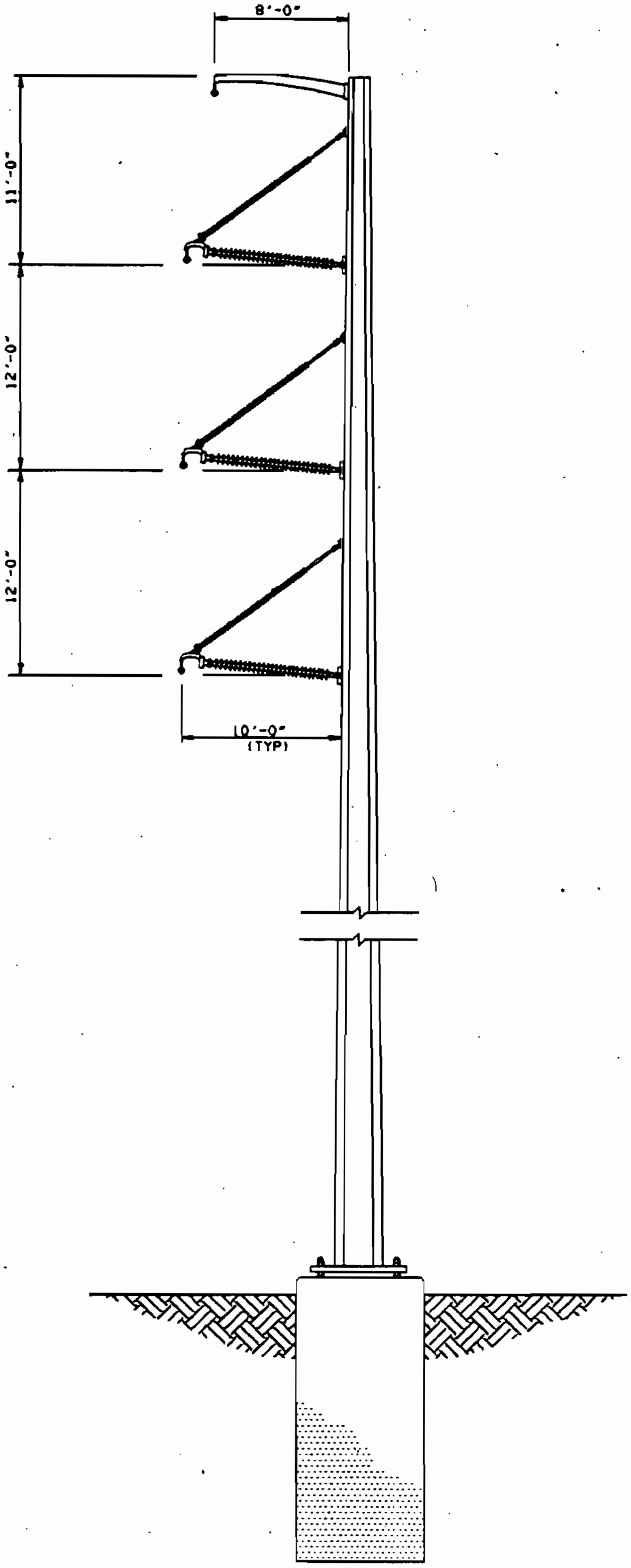
STANTON-MUD LAKE 230 KV TRANSMISSION LINE ENTERING STANTON SUBSTATION (Looking North)

Figure 6.1-11



DOUBLE CIRCUIT TRANSMISSION LINE STRUCTURE

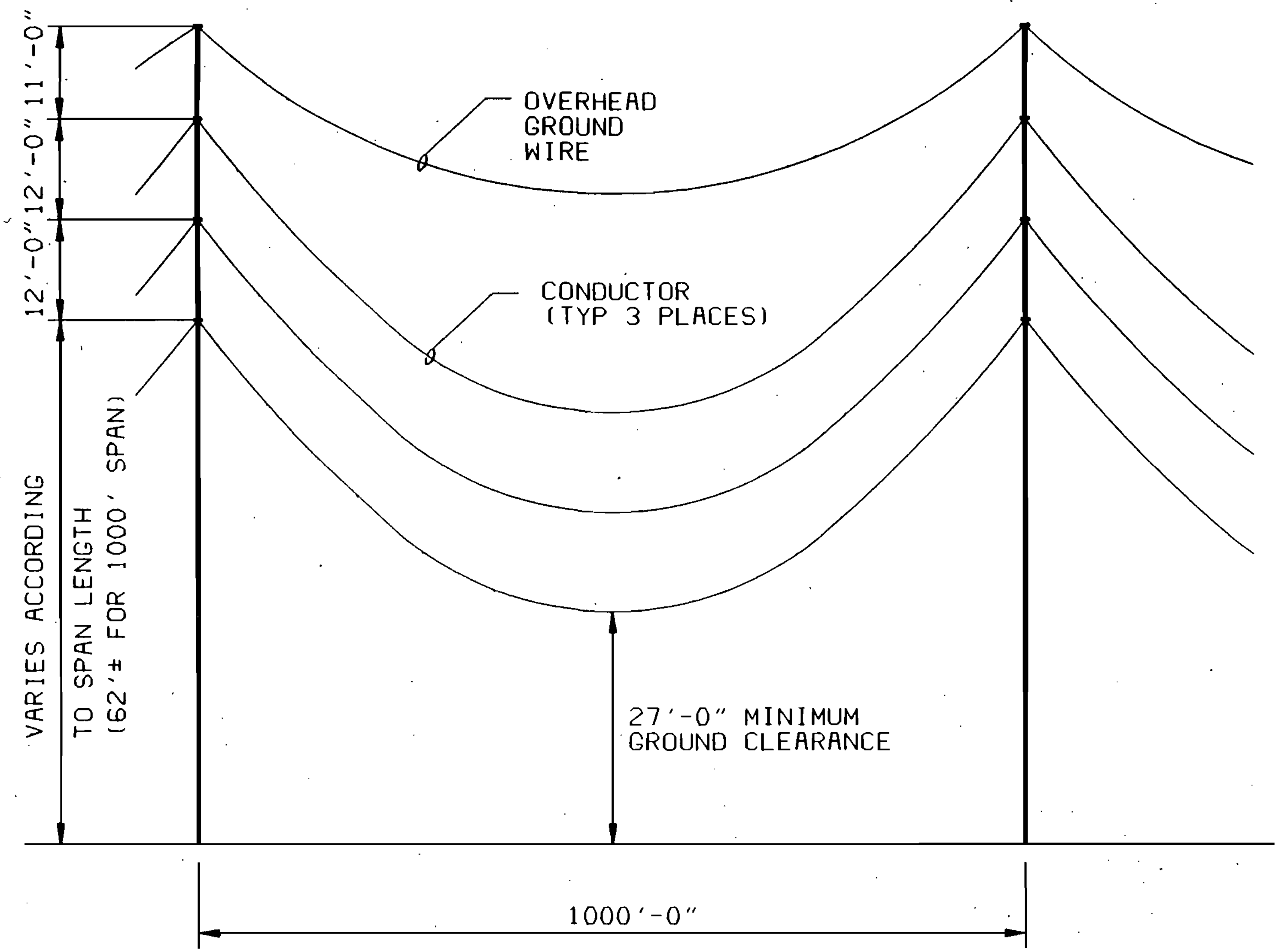
Figure 6.1-13



SINGLE CIRCUIT TRANSMISSION LINE STRUCTURE

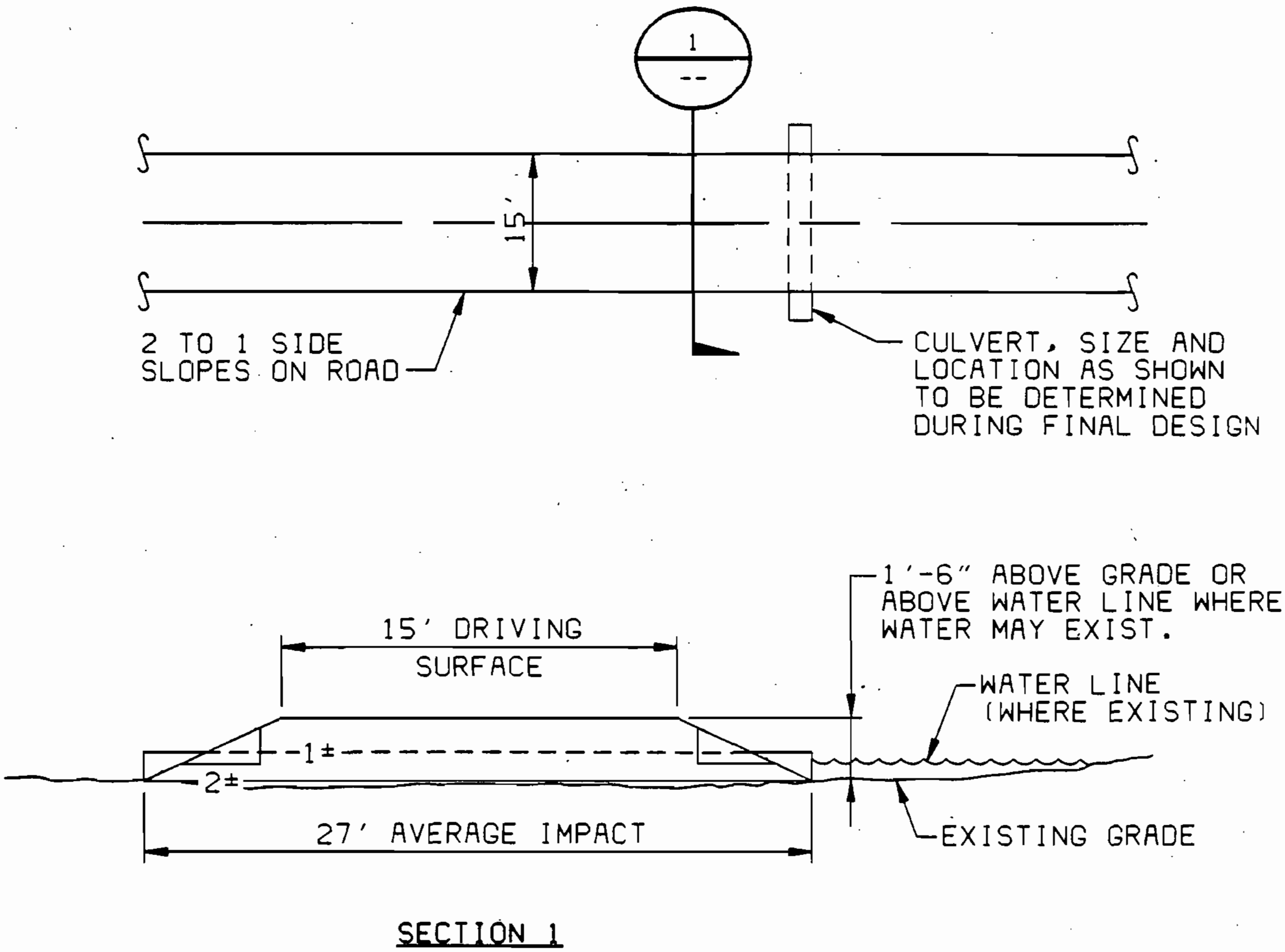
Figure 6.1-14

031591



PROFILE OF 1000-FOOT SPAN

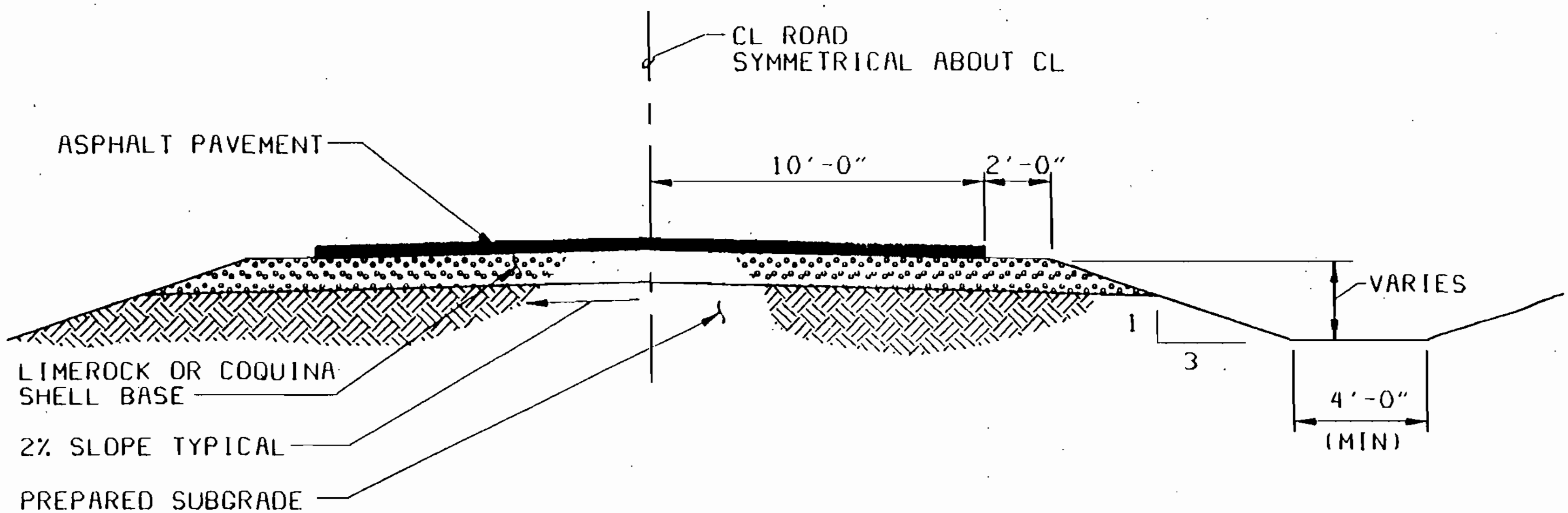
Figure 6.1-15



STANTON-MUD LAKE 230 KV TRANSMISSION LINE CROSS SERCTION
OF TYPICAL TRANSMISSION LINE ACCESS ROAD
Figure 6.1-16

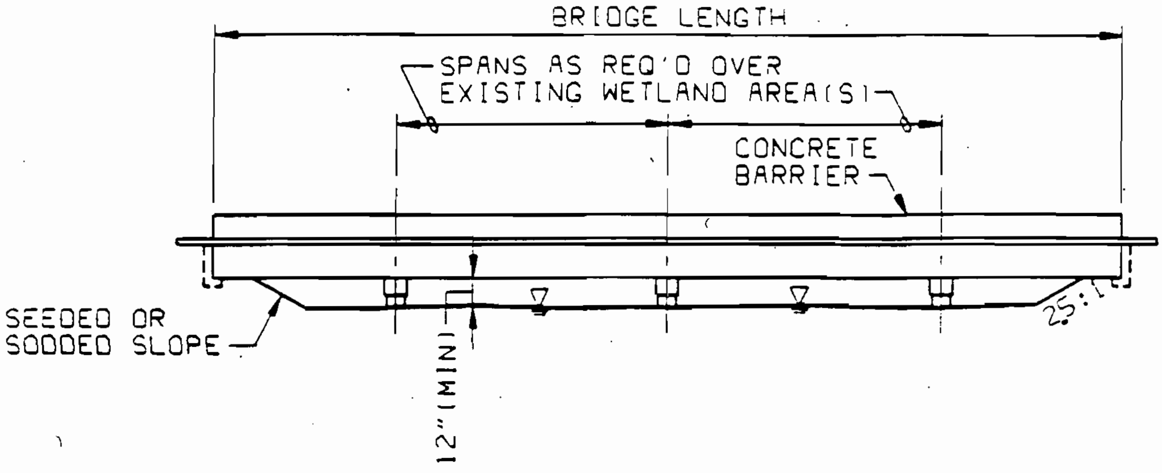
031591

6.1-34

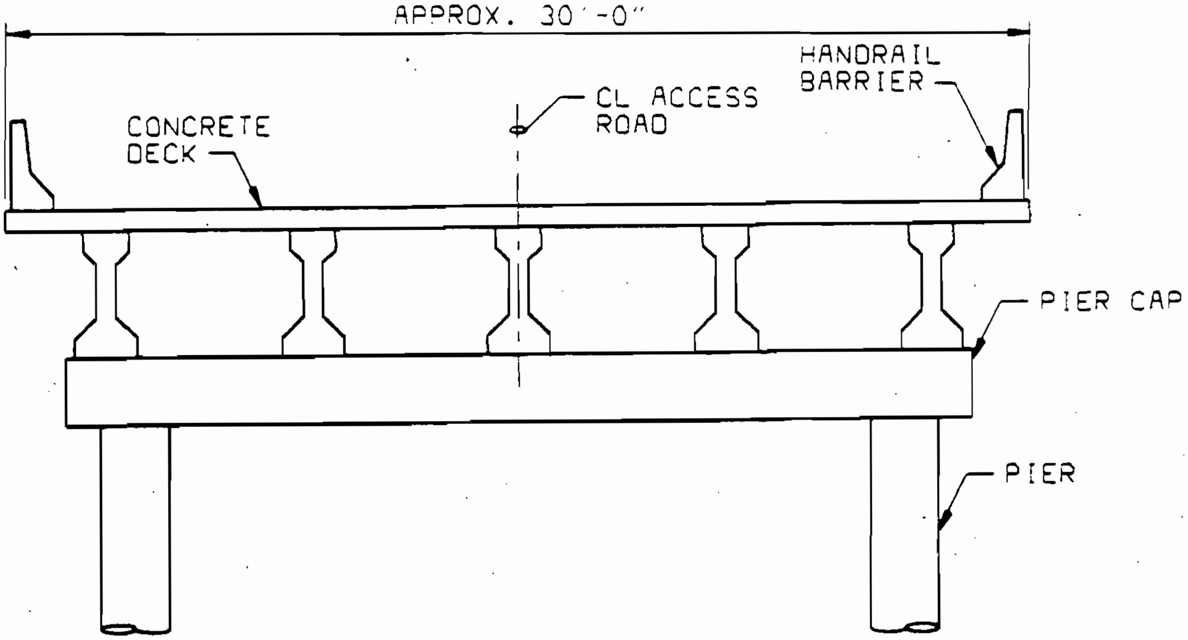


ALTERNATE ACCESS ROAD

Figure 6.1-17



ELEVATION

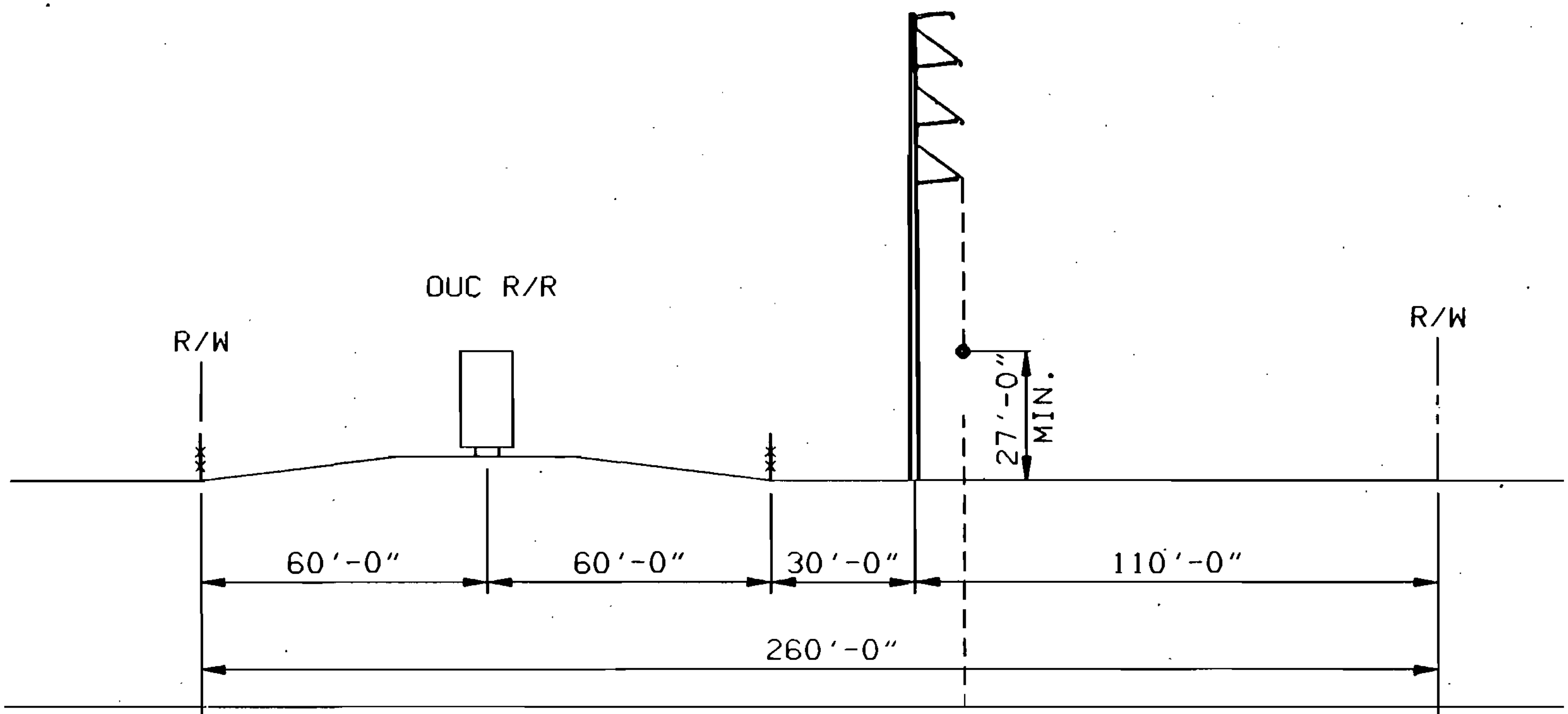


SECTION

TYPICAL ACCESS ROAD BRIDGE DETAIL

Figure 6.1-18

031591

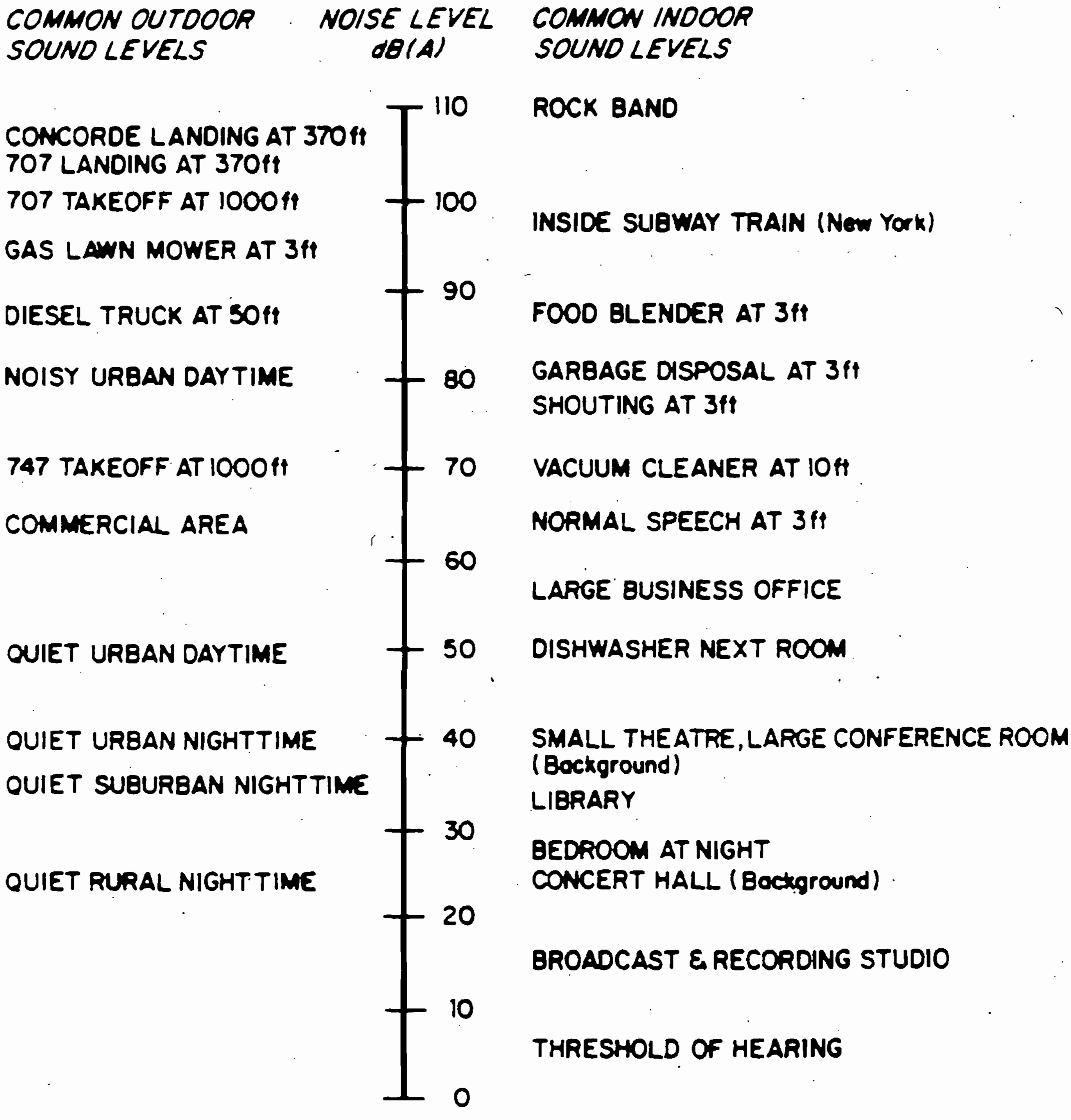


LEVELS		ELECTRIC FIELD LEVELS (KV/M)	
ANTICIPATED	0.61	2.82	0.117
STATE LIMIT	2.0	8.0	2.0

		MAGNETIC FIELD LEVELS (MG)	
ANTICIPATED	5.5	136.4	13.84
STATE LIMIT	200.0	NO STATE LIMIT	200.0

STANTON-MUD LAKE 230 KV TRANSMISSION LINE
ELECTRIC AND MAGNETIC FIELD LEVELS

Figure 6.1-19



COMMON SOUND LEVELS

Figure 6.1-20

6.2 Associated Linear Facilities

There will be no other new linear facilities associated with the Stanton Energy Center Unit 2 project.

7.0 Economic and Social Effects of Plant Construction and Operation

The economic and social effects of plant construction and operation were addressed in the original SCA for the project. For details, refer to Chapter 7 of the original SCA.

8.0 Site and Design Alternatives

This chapter is not applicable because a federal Environmental Impact Statement is not required for the proposed project. See Chapter 8 of DER Form 17-1.211(1) "Instruction Guide for Certification Application: Electrical Power Plant Site, Associated Facilities, and Associated Transmission Lines."

9.0 Coordination

Orlando Utilities Commission Government Contacts

FEDERAL

Environmental Protection Agency, Region IV

Atlanta Office - (404) 347-2904

Brian Beals	Chief of the Source Evaluation Unit
Gregg M. Worley	Chemical/Environmental Engineer
Lewis Nagler	Regional Meteorologist

STATE

Public Service Commission - (904) 488-1234

Joe Jenkins	Director of Electric and Gas
Bob Trapp	Assistant Director of Electric and Gas
Jim Dean	Chief of Conservation and System Planning (No longer with PSC)

Department of Community Affairs - (904) 488-2356

Jenny Underwood--Dietzel	Planning Manager
Paul Darst	Planner IV

Department of Environmental Regulation - (904) 488-4805

Bureau of Air Quality Management - (904) 488-1344

Max A. Linn	Meteorologist
Barry Andrews	PE Administrator
Tom Rogers	Meteorologist Environmental Administrator
Pradeep Raval	Engineer

Bureau of Water Resources Management - (904) 488-0130

Trudie D. Bell	Environmental Supervisor
Guy Rodriquez	Environmental Specialist - Wetlands Resource Management

Power Plant Siting - (904) 488-1344

Hamilton (Buck) S. Oven	Administrator of Siting Coordination

Office of General Counsel - (904) 488-1344

Richard Donelan	Assistant General Counsel

Game and Fresh Water Fish Commission - (904) 488-1960

Doug Baily	Assistant Director - Office of Environmental Services
Perry Oldenburg	Deceased

St. Johns River Water Management District - Orlando Office - (407) 894-5423

Dwight Jenkins	Hydrologist III

10.0 Appendices

10.1 Federal Permit Applications or Approvals

10.1.1 316 Demonstrations

None required for Stanton 2.

10.1.2 NPDES Applications/Permits

The Stanton Energy Center plant is designed as a zero discharge facility and, therefore, Stanton 1 and the proposed Stanton 2 have no requirement for a federal wastewater discharge permit.

10.1.3 Hazardous Waste Disposal Applications/Permits

Not applicable to this project.

10.1.4 Section 10 or 404 Applications/Permits

The Joint Application for Construction Activities in Waters of the State is included in Subsection 10.6.2.

10.1.5 PSD Applications/Permits

A PSD permit for phased construction of both Stanton 1 and 2 was issued by EPA Region IV during the initial permitting process. An updated BACT analysis is required for Stanton 2 and is included as part of Section 3.4 of this application. In addition, air quality dispersion modeling has been conducted for Stanton 1 and 2. Stanton 2 was modeled at both the emission rate provided in the original application and at the rate proposed as BACT in this application in order to demonstrate a reduced level of air quality impact and compliance with ambient air quality standards and PSD increments. A description of the modeling analysis and results is presented in Section 5.6.

10.1.6 Coastal Zone Management Certification

Not applicable to this project because proposed facilities will not be located in a coastal county.

10.2 Zoning Descriptions

A discussion of the plant site and surrounding area zoning designations is presented in Subsection 2.2.2.2 of the original SCA. The Stanton 2 addition will use only property originally certified for Stanton 1 and ultimate capacity. Zoning in these areas has not changed since the initial land use certification was final on October 20, 1981.

10.3 Land Use Plan Descriptions

Detailed land use descriptions of the plant site, associated corridors, and surrounding areas are presented in Subsection 2.2.2 of the original SCA. The site and associated railroad corridor were certified with regard to land use compatibility by the Governor and Cabinet, with their final order issued on October 20, 1981.

10.4 Existing State Permits

This section is not applicable for the Stanton Unit 2 application because this is a supplemental SCA for a power plant site previously certified for ultimate capacity.

10.5 Monitoring Programs

Several environmental monitoring programs and surveys were conducted during the permitting process for Stanton 1. Measurement/survey programs were conducted for noise, terrestrial ecology, lithology, ground water quality, and air quality. These programs were described in detail in the original SCA. No additional onsite surveys have been conducted for the Stanton 2 permitting process.

10.6 State Permit Applications or Approvals

10.6.1 Joint Application for Permit: Dredge, Fill, Structures

JOINT APPLICATION
DEPARTMENT OF THE ARMY/FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
For Activities in the Waters of the State of Florida

CORPS APPLICATION NUMBER (official use only) | DER APPLICATION NUMBER (official use only)

1. APPLICANT'S NAME AND ADDRESS

ORLANDO UTILITIES COMMISSION
NAME

500 South Orange Avenue
STREET

Orlando FL 32801
CITY STATE ZIP

TELEPHONE NUMBER (Day) (407) 423-9100 (Night) ( )

2. Name, address, zip code and title of applicant's authorized agent for permit application coordination

Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801
Telephone Number (407) 423-9123

Thomas B. Tart, General Counsel

3. NAME OF WATERWAY AT LOCATION OF THE ACTIVITY.

Unnamed wetland areas

DER Code ________
W/W Code ________

4. LOCATION WHERE PROPOSED ACTIVITY EXISTS OR WILL OCCUR.

Street, road or other descriptive location	Section	Township	Range
Stanton Energy Center	13,14,23,24	23S	31E
(see attached Figures)	18, 19	23S	32E

Southeast Orlando (Rural)
Incorporated city or town

28° 29' Latitude 81° 10' Longitude

Orange
County

Tax Assessors Description: (if known)

N/A Map No. N/A Subdiv. No. N/A Lot No.

5. NAME AND ADDRESS INCLUDING ZIP CODE OF ADJOINING PROPERTY OWNERS WHOSE PROPERTY ALSO ADJOINS THE WATERWAY.

Not required; see section 6.1.8.2 of FDER Form 17-1.211(1).

6. PROPOSED USE

Private Single Dwelling [ ] Private Multi-dwelling [ ] Public [ ]
Commercial [ ] Other [X] (Explain in remarks) Electric transmission line and access roads. Attached Project Description.

7. DESCRIPTION OF PROJECT (Use additional sheets, if necessary) See attached sheet for description.

A. Structures: 1. New work [X] Maintenance of existing structure [ ]

COE Permit Code

2. Piers, docks and use: Commercial [ ] Private [ ] Public [ ]

a. Single pier [ ] length ______ width ______

b. Number of piers [ ] length ______ width ______

c. Number of boat slips [ ] length ______ width ______

d. Number of finger piers [ ] length ______ width ______

e. Other (please describe) ______

3. Seawalls, revetments, bulkheads: length ______

a. Type: Vertical [ ] Riprap [ ] Slope: ______ Horizontal: ______ Vertical

b. Material to be used ______

4. Other type of structure Construction and maintenance of transmission line, associated access road, and alternate access road.

B. Excavation or Dredging: New Work [X] Maintenance work [ ] Total acreage involved 4.0

1. Access Channel [ ] or Canal [ ] Length ______ ft. Width ______ ft. Depth ______ ft.

2. Boat Basin [ ] or Boat Slip [ ] Length ______ ft. Width ______ ft. Depth ______ ft.

3. Other Foundation excavation in wetlands Length ______ ft. Width ______ ft. Depth ______ ft.

4. Cubic yards: Total for project 220

a. Later cyd. waterward/ Later cyd. landward of ordinary/mean high water

b. Type of material to be excavated/dredged Existing muck and soil

C. Fill:

DER Code
253
403

1. Amount of material

a. Cubic yards placed waterward of ordinary/mean high water Later

b. Cubic yards placed landward of ordinary/mean high water Later

c. Total acreage to be filled 6.2 Total acreage of wetlands involved Later

2. Containment for fill

a. Dikes [ ] b. Seawall, etc. [ ] c. Other (please explain) Geo-grid will be layered in fill to provide stabilization. Roadway will revegetate to prevent erosion.

3. Type of fill material to be used Clean sand for roadway, select backfill for wetland areas.

4. Source of fill material to be used Commercial sources.

8. Date activity is proposed to commence Later ; to be completed Later

9. Previous permits for this project have been DER # Corps #

A. Denied (date) None

B. Issued (date)

C. Other (please explain)

Differentiate between existing work and proposed work on the drawings.

10. Remarks (See Instruction Pamphlet for additional information required for all applications and certain activities. Use additional sheets if necessary.)

See attached sheets.

11. AFFIDAVIT OF OWNERSHIP OR CONTROL of the property on which the proposed project is to be undertaken

I CERTIFY THAT: (please check appropriate space)

[X] I am the record owner, lessee, or record easement holder of the property described below.

[ ] I am not the record owner, lessee, or record easement holder of the property described below, but I will have before undertaking the proposed work the requisite property interest. (Please explain what the interest will be and how it will be acquired.)

LEGAL DESCRIPTION OF PROPERTY SITUATED IN Orange COUNTY, FLORIDA
(Use additional sheets if necessary)

Later

Thomas Bragdon Fant
Signature
General Counsel, OUC

Sworn and subscribed before me at Orange County, Florida, this 12th day of March, 19 91

Patricia A. Gillespie
NOTARY PUBLIC

NOTARY PUBLIC STATE OF FLORIDA
MY COMMISSION EXP. AUG.25,1994
BONDED THRU GENERAL INS. UND.

My commission expires:

12. Application is made for a permit(s) to authorize the activities described herein.

A. I authorize the agent listed in Item #2 to negotiate modifications or revisions, when necessary, and accept or assent to any stipulations on my behalf.

B. I understand I may have to provide any additional information/data that may be necessary to provide reasonable assurance or evidence to show that the proposed project will comply with the applicable State Water Quality Standards or other environmental standards both before construction and after the project is completed.

C. In addition, I agree to provide entry to the project site for inspectors with proper identification or documents as required by law from the environmental agencies for the purpose of making preliminary analyses of the site. Further, I agree to provide entry to the project site for such inspectors to monitor permitted work if a permit is granted.

D. Further, I hereby acknowledge the obligation and responsibility for obtaining <u>all</u> of the required state, federal or local permits <u>before</u> commencement of construction activities I also understand that before commencement of this proposed project I must be granted separate permits or authorizations from the U.S. Corps of Engineers, the U.S. Coast Guard, the Department of Environmental Regulation, and the Department of Natural Resources, as necessary.

I CERTIFY that I am familiar with the information contained in this application, and that to the best of my knowledge and belief such information is true, complete and accurate. I further certify that I possess the authority to undertake the proposed activities.

Thomas Brogden Fout 3/12/71

Signature of Applicant Date
General Counsel, OUC

NOTE: THIS APPLICATION MUST BE SIGNED by the person who desires to undertake the proposed activity or by an authorized agent. If an agent is applying on behalf of the applicant, attach proof of authority for the agent to sign and bind the applicant.

18 U.S.C. Section 1001 provides that: Whoever in any manner within the jurisdiction of any department or agency of the United States knowingly and willfully falsifies, conceals, or covers up by any trick, scheme, or device a material fact or makes any false, fictitious or fraudulent statements or representations or makes or uses any false writing or document knowing same to contain any false, fictitious or fraudulent statement or entry, shall be fined not more than $10,000 or imprisoned not more than five years, or both.

NOTICE TO PERMIT APPLICANTS

This is a Joint Application; it is <u>NOT</u> a Joint Permit!

You Must Obtain <u>All</u> Required Local, State, and Federal

Authorizations or Permits <u>Before</u> Commencing Work!!

<u>For your information:</u> Section 370.034, Florida Statutes, requires that all dredge and fill equipment owned, used, leased, rented or operated in the state shall be registered with the Department of Natural Resources. Before selecting your contractor or equipment you may wish to determine if this requirement has been met. For further information, contact the Chief of the Bureau of Licenses and Motorboat Registration, Department of Natural Resources, 3900 Commonwealth Boulevard, Tallahassee, Florida 32303. Telephone Number 904/488-1195. THIS IS NOT A REQUIREMENT FOR A PERMIT FROM THE DEPARTMENT OF ENVIRONMENTAL REGULATION.

Item 7 -- Description of Project

A new 230 kV transmission line will be required to integrate the power from Stanton 2 into the Orlando Utilities Commission (OUC) Transmission System. The proposed Stanton-Mud Lake 230 kV transmission line will originate at the existing Stanton Energy Center substation and will interconnect into the existing (after relocation) OUC Transmission Line 7-0615 near Mud Lake, following the existing OUC rail line corridor. There will also be an associated unpaved access road installed in portions of the corridor for transmission line construction and maintenance. Finally, an alternate site access road will be constructed in the rail line corridor south from the plant site to the Bee Line Expressway.

The new Stanton-Mud Lake Transmission Line will be approximately 14 miles long and will be constructed totally within the existing OUC railroad/utility corridor from the Stanton Energy Center plant to its interconnection with existing Transmission Line 7-0615. Figure 6.1-1 of the SCA shows the transmission line and alternate access road routing within the existing corridor. The corridor varies in width along its route from 260 feet to 400 feet. The location of the proposed transmission line and access road routes is shown in further detail on Figures 6.1-2, 6.1-3, and 6.1-4 of the SCA. Existing 115 kV or longer transmission lines in the area are also shown on Figure 6.1-2.

Additional details with regard to the location, layout, and design of the proposed transmission line and access roads are included in Subsections 6.1.2 and 6.1.3 of the SCA.

US Army Corps of Engineers approval for this project is requested under the Nationwide Permit Provision Number 26.

Item 10 -- Additional Information

The following additional information is provided as requested under Item 10 of the Joint Application Form.

Need. The proposed transmission line is necessary to connect the energy produced by Stanton 2 with OUC's power system. Access roads are needed to install and maintain the transmission line facilities. The new alternate site access road is necessary to provide adequate emergency access to the site.

Alternatives. A study was made of the OUC electric transmission system, and it was concluded that an interconnection of Stanton 2 with the Taft Substation would function very well. Other possible interconnections would not be as functional or desirable. The selected route also is currently owned by OUC, and no additional land acquisition will be required.

Waterway Width. The impacts of the proposed transmission line with regard to wetland clearing, dredging, and filling are summarized in Table 6.1-1 of the SCA. The lengths and acreage of affected wetlands are provided.

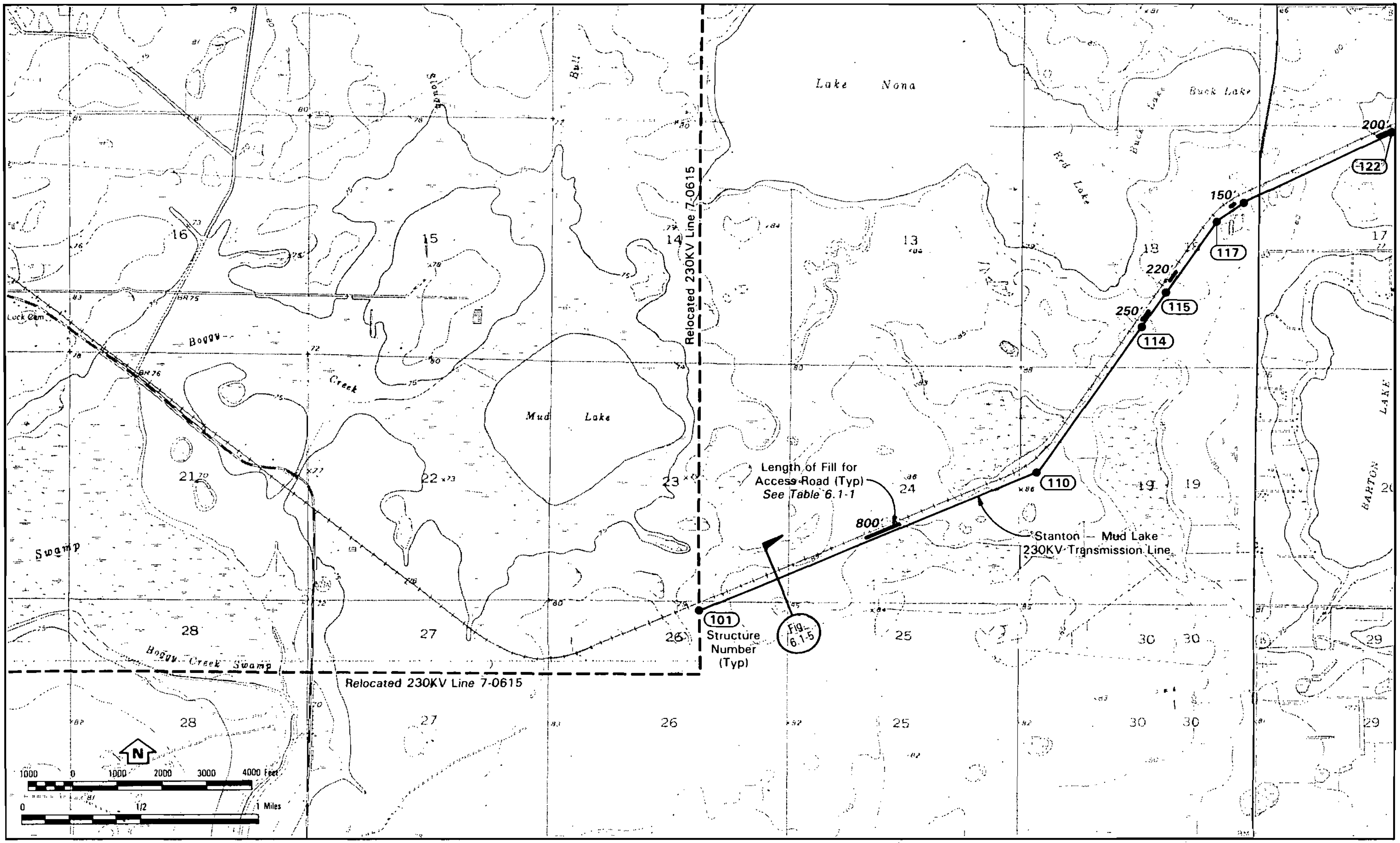
Protection of State Water. Culverts will be placed as necessary to ensure that sheet flow and runoff is not compromised by the project. Turbidity screens will be placed and maintained prior to and during construction to protect water quality against erosion. Access roads and working surfaces will be allowed to revegetate to prevent erosion after construction is complete.

Dredging. Wetlands dredging will be limited to areas identified for the placement of foundations for tower structures. Material removed will be spread and compacted on access roads or on adjacent upland areas.

Filling. Fill to be used for access roads and working surface construction will consist of clean sand purchased from a commercial source. Disruption of the aquatic ecosystem will be prevented by means stated in Protection of State Waters.

Construction. Transmission line and access roads will be as detailed on drawings included in Section 6.1 of this application.

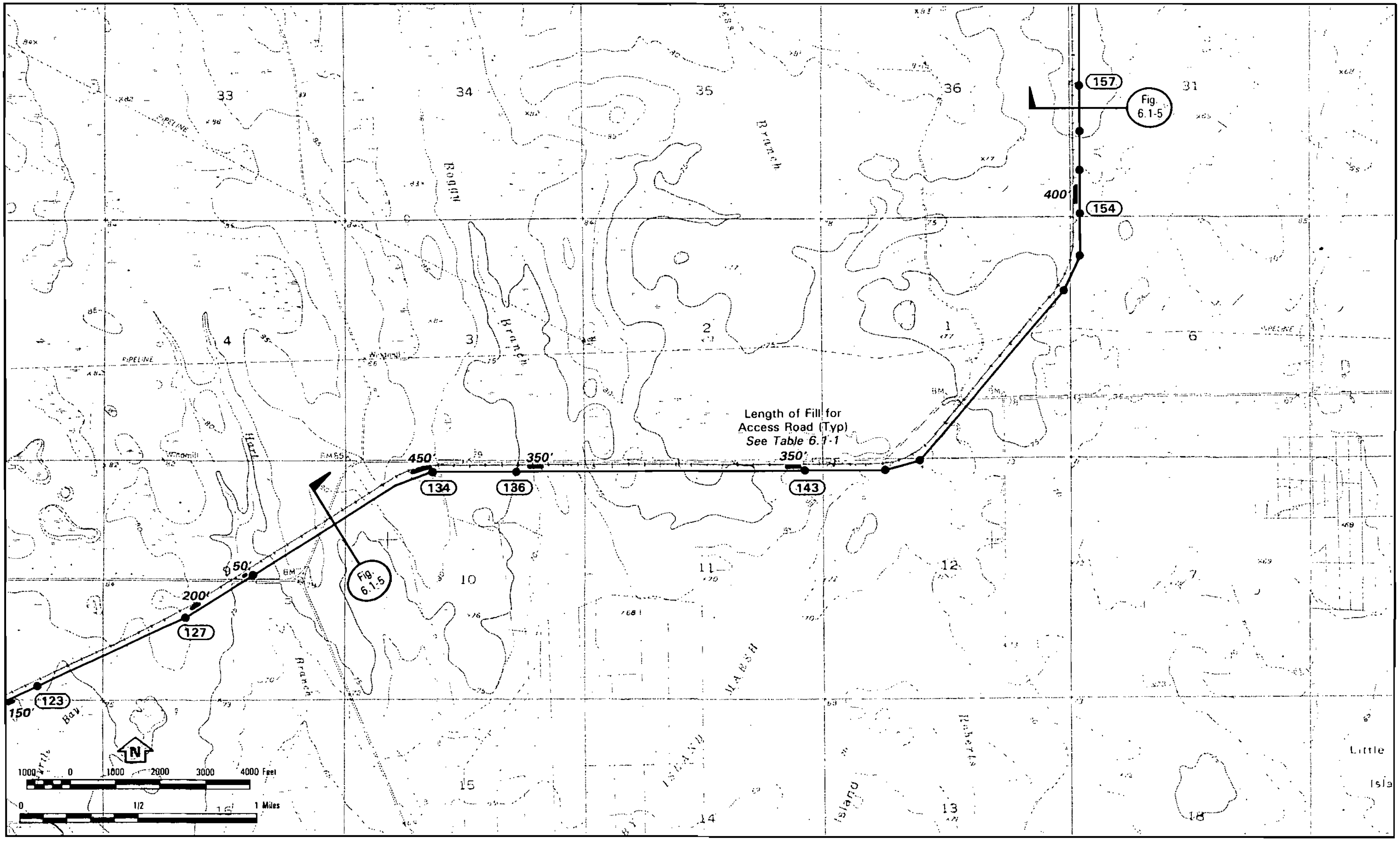
Hazardous Materials. Not applicable.



Base Map Source: USGS, Pine Castle, Narcoosee NW, St. Cloud North, and Narcoosee, FL Quadrangles

TRANSMISSION LINE CORRIDOR LOCATION – WEST

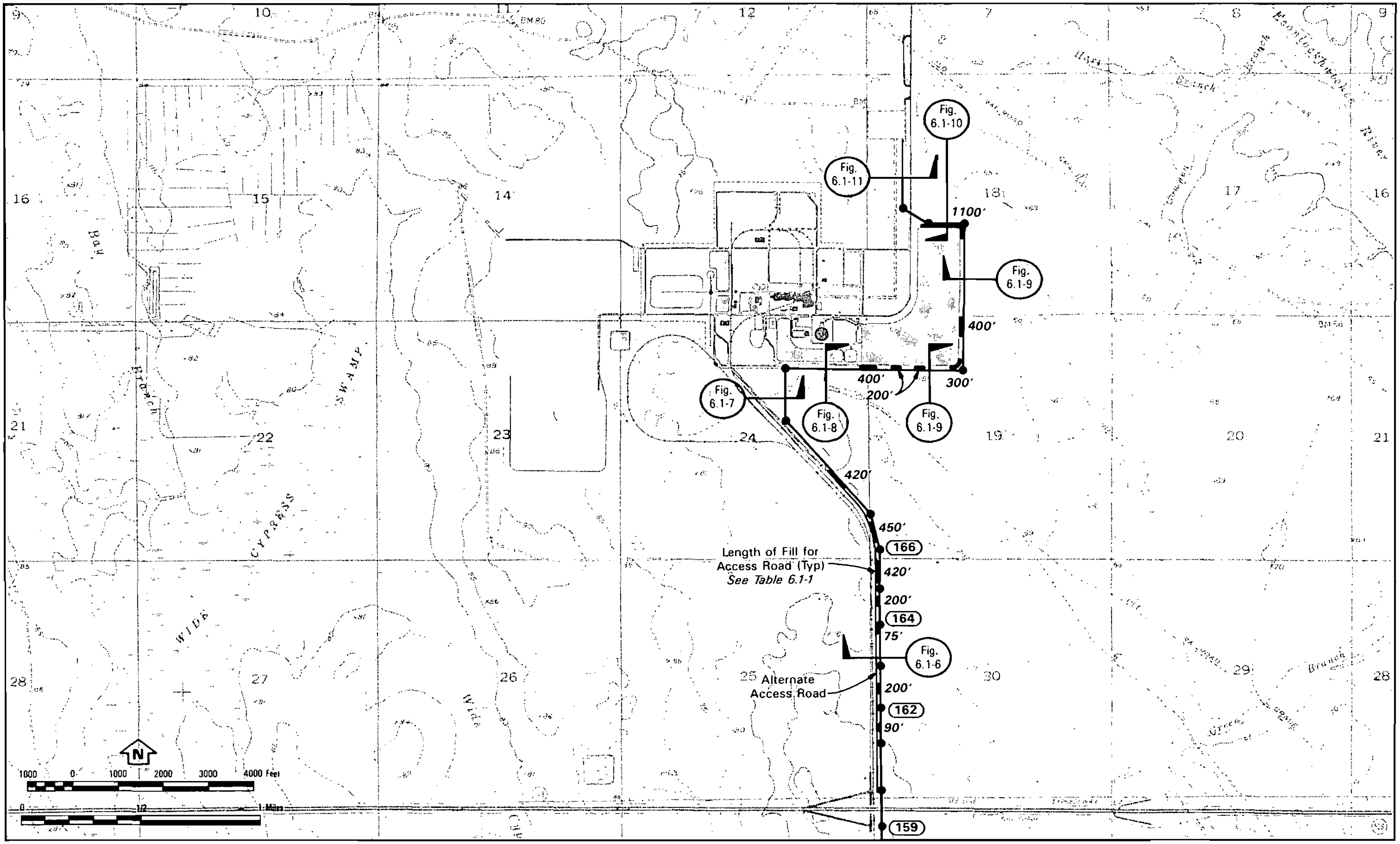
Figure 6.1-2



Base Map Source: USGS,
Narcoossee NW, FL Quadrangle

TRANSMISSION LINE CORRIDOR LOCATION – CENTRAL

Figure 6.1-3

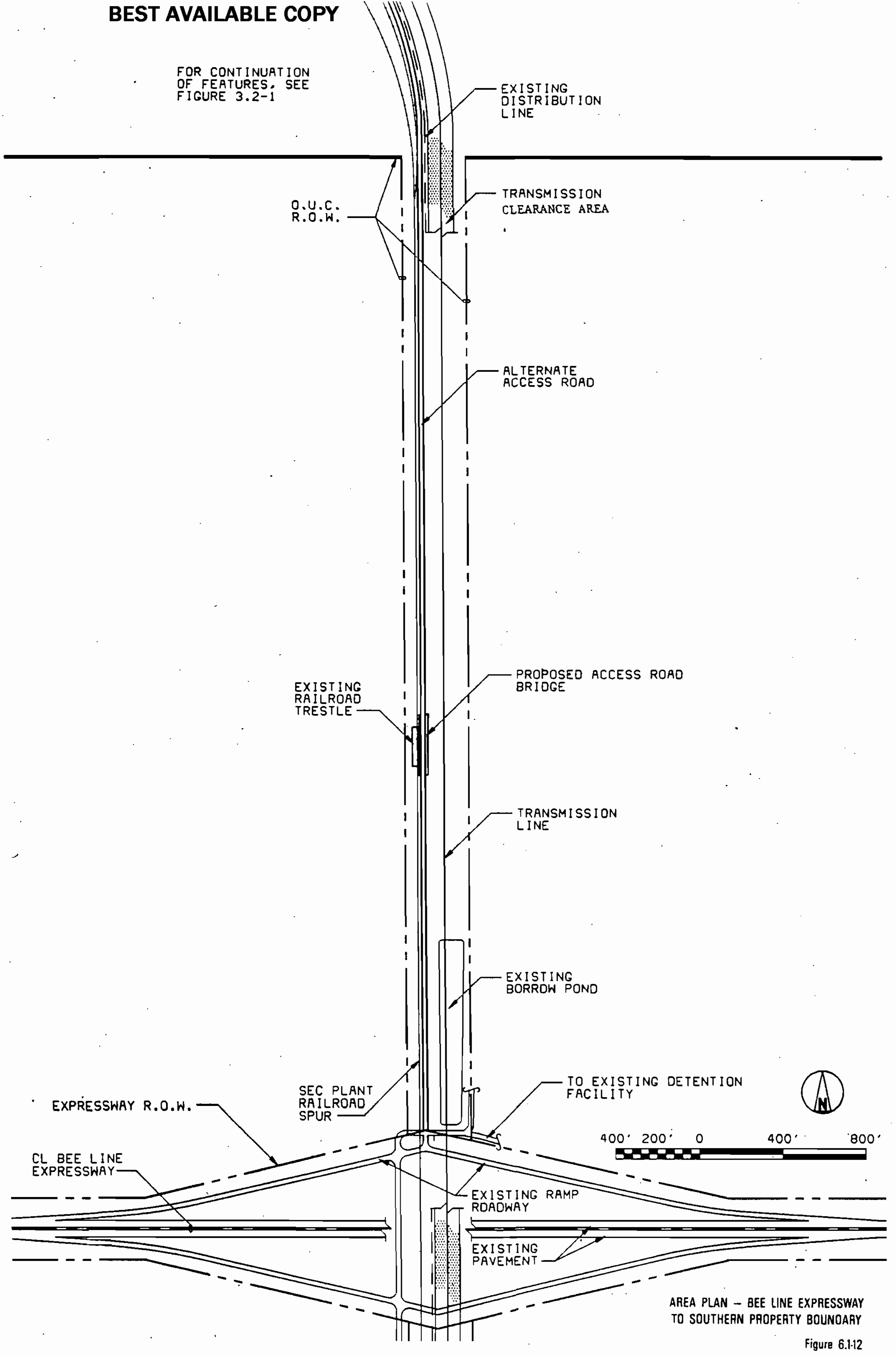


Base Map Source: USGS, Narcoossee NW, FL Quadrangle

TRANSMISSION LINE CORRIDOR LOCATION – EAST AND ALTERNATE ACCESS ROAD

Figure 6.1-4

BEST AVAILABLE COPY



AREA PLAN – BEE LINE EXPRESSWAY TO SOUTHERN PROPERTY BOUNDARY

Figure 6.1-12

10.6.2 Florida Ground Water Monitoring Plan Approval

The Stanton Energy Center has an approved Florida Ground Water Monitoring Plan. This plan was developed to comply with conditions of the Unit 1 site certification process.

Monitoring wells are located upgradient and downgradient of the Recycle Basin, the Coal Storage Area, and the Combustion Waste Storage Area. Because of the high quality of the makeup water supply, water in the Makeup Water Supply Pond is monitored directly to ensure compliance with applicable ground water standards.

Ground water monitoring in accordance with the existing approved Florida Ground Water Monitoring Plan will continue during the construction and operation of Stanton Unit 2.

10.6.3 Application for Radioactive Materials License

Radioactive devices will be used to monitor levels of bulk materials, liquids, and combustion wastes. Coal silos, main steam line moisture collection pots, and fly ash hoppers under the electrostatic precipitators are the principal system applications of these devices. The radioactive materials used in these devices are regulated by the Florida Department of Health and Rehabilitative Services. The application form for licenses for radioactive materials follows.

BEST AVAILABLE COPY

STATE OF FLORIDA
DEPARTMENT OF HEALTH AND REHABILITATIVE SERVICES
OFFICE OF RADIATION CONTROL
RADIOACTIVE MATERIALS PROGRAM
APPLICATION FOR RADIOACTIVE MATERIALS LICENSE

NON-HUMAN USE

INSTRUCTIONS - Complete items 1 through 15 as applicable. **Use supplemental sheets where necessary.** Item 15 must be completed on all applications. **Mail three copies to:** Department of HRS, Office of Radiation Control, Radioactive Materials Program, 1317 Winewood Boulevard, Tallahassee, FL 32399-0700.

1.a. NAME AND MAILING ADDRESS OF APPLICANT (institution, firm, company, person, etc.) INCLUDE ZIP CODE.	1.b. STREET ADDRESS(ES) AT WHICH RADIOACTIVE MATERIAL WILL BE USED, IF DIFFERENT FROM 1.a. INCLUDE ZIP CODE.
Orlando Utilities Commission 500 South Orange Avenue P.O. Box 3193 Orlando, Florida 32801 TELEPHONE NO: Area Code (407) 423-9100	Curtis H. Stanton Energy Center Orange County, Florida
2.a. LICENSE FEE CATAGORY: 3L(1) b. LICENSE FEE ENCLOSED: $ N/A	3. THIS IS AN APPLICATION FOR (Check and complete appropriate items): _X_ a. NEW LICENSE ___ b. AMENDMENT TO LICENSE NO. ______ ___ c. RENEWAL OF LICENSE NO. ______
4. INDIVIDUAL USERS: Name individuals who will use or directly supervise use of radioactive material. To be named later	5. RADIATION SAFETY OFFICER (RSO): Name of person designated. To be named later

6. TRAINING AND EXPERIENCE IN RADIATION SAFETY. Later

A. FORMAL TRAINING IN RADIATION SAFETY: Attach a resumé for each individual named in Items 4 and 5. Describe individual's formal training in principles and practices of radiation protection; radioactivity measurement standardization and monitoring techniques and the use of instruments; mathematics and calculations basic to the use and measurement of radioactivity; and biological effects of radiation. Include the name of the person or institution providing the training, duration of training and when training was received, or attach a copy of a training certificate from an approved training course where applicable.

B. EXPERIENCE: Attach a resumé for each individual named in Items 4 and 5. Describe individual's work experience with radiation, including where experience was obtained. Include a list of radioisotopes and the maximum activity of each use. Work experience or on-the-job training should be commensurate with the proposed use.

7. RADIOACTIVE MATERIAL.

(a) ELEMENT AND MASS NUMBER	(b) CHEMICAL AND/OR PHYSICAL FORM (If sealed sources, include manufacturer's name and model number).	(c) MAXIMUM AMOUNT TO BE POSSESSED AT ANY ONE TIME (If sealed source(s) also state number of sources and maximum activity per source).
Later		

8. DESCRIBE PURPOSE FOR WHICH RADIOACTIVE MATERIALS LISTED IN ITEM 7, ABOVE, WILL BE USED. (If radioactive material is in the form of a sealed source, include the manufacturer and model number of the storage container and/or device in which the source will be stored and/or used.)

Later

9. RADIATION DETECTION INSTRUMENTS.

TYPE OF INSTRUMENTS (Include manufacturer and model number of each)	NUMBER AVAILABLE	RADIATION DETECTED	SENSITIVITY RANGE (mr/hr)	USE (Monitoring, surveying, measuring)
Later				

10. CALIBRATION OF INSTRUMENTS LISTED ABOVE.

☐ a. CALIBRATED BY SERVICE COMPANY
State the name, address and license number of the service company and the frequency of calibration of the device.

Later

☐ b. CALIBRATED BY APPLICANT
Attach a separate sheet describing procedures, frequency and standards used for calibrating instruments.

11. PERSONNEL MONITORING DEVICES. Complete Items a, b, c and d.

Later

a. ☐ Film ☐ TLD b. ☐ Whole Body ☐ Extremity

c. Radiation Detected: ☐ Beta ☐ Gamma ☐ Neutron

d. SUPPLIER ________________ FREQUENCY OF EXCHANGE ________________

2. FACILITIES AND EQUIPMENT. Describe facilities where radioactive material, including waste, will be used and/or stored. **Attach an annotated diagram of the areas of use and/or storage, including adjacent areas.** Describe equipment such as, remote handling devices, storage containers, shielding, fume hoods, etc.

Later

3. RADIATION PROTECTION PROGRAM. Describe the radiation protection program as appropriate for the material to be used, including general radiation safety procedures, emergency procedures and bioassay procedures. If the application includes a request for sealed sources, submit leak testing procedures; or if leak testing will be performed using a leak test kit, specify the manufacturer and model number of the kit and the name and radioactive materials license number of the individuals who will perform the analysis.

Later

4. WASTE DISPOSAL. Describe the procedures for handling, storing and disposing of radioactive wastes (solid, liquid and/or gas). Name the commercial waste disposal service employed, if applicable. If sealed sources and/or devices will be returned to the manufacturer, so state.

Later

5. CERTIFICATE.

The applicant and any official executing this certificate on behalf of the applicant named in Item 1, certify that this application has been prepared in accordance with Chapter 10D-91, Florida Administrative Code, and that all information contained herein, including any supplements attached hereto, is true and correct to the best of our knowledge and belief.

Certifying Official (Signature)

Name (Typed or Printed)

Title

Date

WARNING: KNOWINGLY MAKING FALSE STATEMENTS TO A PUBLIC SERVANT IS A VIOLATION OF SECTION 837.06, FLORIDA STATUTES, AND IS PUNISHABLE BY FINE OR IMPRISONMENT.

10.7 Local Permit Applications or Approvals

10.7.1 St. Johns River Water Management District Water Use Permit Application

CONSUMPTIVE USE PERMIT APPLICATION

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
RESOURCE MANAGEMENT DEPARTMENT
RECORDS DIVISION
P.O. BOX 1429
PALATKA, FLORIDA 32078-1429

APPLICATION NO. ______
DATE RECEIVED ______
COUNTY ______
ASSIGNED REVIEWER ______
REVIEW COMPLETION DATE ______
PROJECTED BOARD DATE ______

Please type or print with BLACK ball point pen. Read ALL instructions on the back of this sheet before completing application. Complete necessary data sheets attached. PRESS HARD!

APPLICATION IS FOR: NEW USE ☐ EXISTING USE ☐ MODIFICATION OF EXISTING PERMIT ☒ RENEWAL ☐

OWNER

NAME OF OWNER (LAST / FIRST): ORLANDO UTILITIES COMMISSION
ADDRESS: Box 3193 500 South Orange Avenue
CITY: Orlando COUNTY: Orange
STATE: FL ZIP CODE: 32801 -
TELEPHONE NO. 407 / 423 - 9100

APPLICANT

NAME OF APPLICANT (LAST / FIRST): Tart Thomas B
ADDRESS: 500 South Orange Avenue
CITY: Orlando COUNTY: Orange
STATE: FL ZIP CODE: 32801 -
TELEPHONE NO. 407 / 423 - 9123

AGENT (IF APPLICABLE)

NAME OF AGENT (LAST / FIRST):
ADDRESS:
CITY: COUNTY:
STATE: ZIP CODE: /
TELEPHONE NO. / -

CONSULTANT, OR ENGINEER (IF APPLICABLE)

NAME OF FIRM: Black & Veatch
NAME OF FIRM CONTACT (LAST / FIRST): Day Steven M
ADDRESS: 8400 Ward Parkway
CITY: Kansas City COUNTY: Jackson
STATE: MO ZIP CODE: 64114 /
TELEPHONE NO. 913 / 339 - 2000

SITE LOCATION

U.S.G.S. TOPO QUAD MAP: Narcoossee NW Quadrangle
COUNTY: Orange TOTAL ACREAGE: 3280
SECTION: TOWNSHIP: RANGE: See attached

USE

AESTHETIC ____ % AGRICULTURAL ____ % COOLING AND AIR CONDITIONING ____ %
DEWATERING ____ % DIVERSION AND IMPOUNDMENT INTO NON-DISTRICT FACILITIES ____ %
~~ESSENTIAL~~ ____ % FREEZE PROTECTION ____ % GOLF COURSE ____ % RECREATION AREA ____ %
HOUSEHOLD TYPE ____ % LIVESTOCK ____ % NAVIGATIONAL ____ % NURSERY ____ %
POWER ~~PRODUCTION~~ X % COMMERCIAL AND INDUSTRIAL ____ % WATER BASED RECREATION ____ %
SOIL FLOODING ____ % URBAN LANDSCAPE IRRIGATION ____ % WATER UTILITY ____ %

AMOUNT

~~INCHES PER YEAR~~ N/A MILLION GALLONS PER YEAR 321 (2 Units)
MILLION GALLONS PER DAY (AVERAGE) 0.88 (2 Units) MILLION GALLONS PER DAY (MAXIMUM) 1.25 (2 Units)

MODIFICATION OR RENEWAL

PLEASE PROVIDE INFORMATION IF APPLICATION IS FOR MODIFICATION OR RENEWAL OF AN EXISTING PERMIT:
PERMIT NO. ______ OWNER'S NAME Orlando Utilities Commission
DESCRIBE MODIFICATION Increase pumping rate from existing two wells from 0.44 mgd to 0.88 mgd for additional power generation unit at Stanton Energy Center.

In compliance with the provisions of Chapter 373, Florida Statutes, 197_ and applicable rules and regulations of St. Johns River Water Management District, application is hereby made for a permit as identified above, and in accordance with support data and incidental information filed with this application and made a part thereof.

Thomas B. Tart — APPLICANT'S NAME (Please Print)
Thomas B. Tart — APPLICANT'S SIGNATURE
General Counsel, OUC
3/12/91 — DATE

If person other than applicant has completed this form, that person certifies by his signature below that he is acting as an authorized agent of the applicant and his signature will be certification that he is in fact the authorized agent.

______ AGENT'S NAME (Please Print) ______ AGENT'S SIGNATURE ______ DATE

Site Location

Section 13, 14, 24, 28	Township T23S	Range R31E
Section 18, 19	Township T23S	Range R32E

SUMMARY DATA SHEET

Complete applicable sections only. Type or print legibly.
Attach additional sheets if space provided below is not sufficient.

EXISTING SOURCE(S) OF WATER INFORMATION

GROUND WATER

Well number	Open Hole Diameter	Casing Diameter	Total Depth	Casing Depth	Average Withdrawal	Flowing* or Pumped	Pump Capacity or Flow Rate	Source Aquifer (if known)	Use
PW-1	11 in	12 in	530 ft	240 ft	140 gpm	Pumped	2000 gpm	Floridan	Industrial
PW-2	11 in	12 in	505 ft	243 ft	140 gpm	Pumped	2000 gpm	Floridan	Industrial
	in	in	ft	ft	gpm		gpm		

*Flowing wells must be equipped with a working valve, per Chapter 373.206, Florida Statutes.

SURFACE WATER

Source number	Pump capacity	Average withdrawal	Contingent property	Impounded area	Name of water source	Use
Not	gpm	gpm	acres	acres		
Applicable	gpm	gpm	acres	acres		
	gpm	gpm	acres	acres		

PROPOSED SOURCE(S) OF WATER INFORMATION

GROUND WATER

Well number	Open Hole Diameter	Casing Diameter	Total Depth	Casing Depth	Average Withdrawal	Flowing or Pumped	Pump Capacity or flow rate	Source Aquifer	Use
PW-1	11 in	12 in	530 ft	240 ft	305 gpm	Pumped	2000 gpm	Floridan	Industrial
PW-2	11 in	12 in	505 ft	243 ft	305 gpm	Pumped	2000 gpm	Floridan	Industrial
	in	in	ft	ft	gpm		gpm		

SURFACE WATER

Source Number	Pump capacity	Average withdrawal	Contingent property	Impounded area	Name of water source	Use
Not	gpm	gpm	acres	acres		
Applicable	gpm	gpm	acres	acres		
	gpm	gpm	acres	acres		

If application is for an initial permit, state the date upon which the use commenced or is planned to commence
No additional wells are required.

If modification or renewal, state amount of additional water applied for N/A inches per year

161 million gallons per year., additional for Unit 2.

Describe in detail reason(s) for request for additional water and/or sources:

Orlando Utilities Commission Stanton Energy Center is currently producing 440 MW (net) of electricity from Unit 1. This application is a request for additional groundwater for the proposed 440 MW (net) Unit 2 addition. For a more detailed description of water use see Section 3.5, Plant Water Use.

Attach a list of adjacent property owners as prescribed by S.4.4 of the "Applicant's Handbook, Chapter 40C-2, F.A.C.".

COMMERCIAL/INDUSTRIAL TYPE USES
SUPPLEMENTARY DATA SHEET

Complete the appropriate sections only. Type or print legibly.
Attach additional sheets if space provided below is not sufficient.

Area owned at withdrawal site 3280 acres.

Type of business Power Generation. The Stanton Energy Center has one 440 MW (net) unit and is proposing building a second 440 MW (net) unit.

Specific use(s) of water Well water will be used for potable water, general plant services, flue gas scrubber and boiler makeup. For a more detailed description see SCA Section 3.5, Plant Water Use.

Average daily use last service year 0.40 MGD

Maximum daily use last service year 0.72 MGD

Number of days per week when used 7 days

Months of year used January through December

Proposed average daily use 0.88 MGD in 1996 (year)

Proposed maximum daily use 1.25 MGD in 1996 (year)

Reason for any increase in use Currently permitted 0.44 mgd will increase to 0.88 mgd with the addition of Stanton Unit 2.

Average amount of wastewater disposed per day None MGD

Maximum amount of wastewater disposed per day None MGD

Method of treatment

Disposal On site Off site

If treatment or disposal occurs off site, name treatment facility

If disposal takes place on site, describe in detail Well water treatment process wastewater is reused as scrubber additive and scrubber makeup water. None is discharged.

Is wastewater quality monitored? yes no

Attach any available water quality data on supply water and wastewater. Attached

Explain water conservation measures currently implemented or planned for implementation in the near future Plant is zero discharge and all wastewaters from plant processes are reused and therefore consumptive use of well water is minimized.

Sheets 4 and 5 of 6 are not applicable to this application. Sheet 6 of 6 requests location information. Refer to Figure 2.1-1 of the original SCA for the plant site location, Figure 3.2-1 of this SCA for the location of the existing onsite wells, and Figure 2.3-1 of this SCA for the location of other wells in the plant vicinity.

10.7.2 Application to Construct a Public Drinking Water System

Additional distribution systems will be necessary for all Stanton 2 facilities provided with potable water. A generic application form for construction of such distribution facilities follows this subsection. Completed forms for all applicable distribution systems will be provided as detailed design of the Stanton 2 project proceeds.

State of Florida
Department of Environmental Regulation

Application to Construct a Public Drinking Water System

INSTRUCTIONS: All of the application forms, including engineering plans and specifications, must be completed and submitted. For construction of facilities consisting solely of pumping and disinfection, Parts A, B, C, D, and E 1 and 2, (d) through (f), as well as engineering plans and specifications, must be completed and submitted. When using this form for distribution systems alone, only Part B and applicable sections of Part A need to be completed. Submission of any false statement of representation in this application is a violation of the law. Attach additional sheets as necessary.

Project Name: Stanton Energy Center Unit 2 Potable Water Distribution System County: Orange

System Address: Street Orange County (Rural) City: N/A

Applicant's Name and Title: Orlando Utilities Commission

Applicant's Address: 500 South Orange Avenue, Orlando, FL 32801

Utility Supplying Water: Name Orlando Utilities Commission

Utility Address: same as above

Owner/Operator After Construction, if different: same as above

Owner/Operator Address: same as above

Type of Proposed Facility: Potable Water Distribution System To Serve: Facilities associated with Stanton 2 addition
(Subdivision, trailer park, school, etc.)

Latitude 28 ° 29 ' ____ "N Longitude 81 ° 10 ' ____ "W

Provide latitude/longitude and section-township-range of all plants and sources – attach additional sheet, if necessary

Section:	Township:	Range:
13,14,23,24	23S	31E
18,19	23S	32E

A. Applicant:

I, the owner/authorized representative* of Orlando Utilities Commission am fully aware that the statements made in this application for a permit to construct a Potable Water Distribution System are true, correct and complete to the best of my knowledge and belief. Further, the undersigned agrees to maintain the facility in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules of the department, will be non-transferable and will promptly notify the department upon sale or legal transfer of the permitted facility. The undersigned also accepts responsibility for retaining the project engineer as indicated on this application to observe that construction of the project is in accordance with engineering plans as submitted.

*Attach letter of authorization

Signed: ______________________
Owner/Authorized Representative

____
Name and Title (Please type)

Date: ______ Telephone No. ______________

B. Owner/Authorized Representative of Utility Supplying Water (if applicable):

The undersigned, owner/authorized representative* of ______________________________
hereby certifies that the above referenced utility has adequate reserve capacity to supply water to this project and will provide the necessary treatment as required by Chapter 403, Florida Statutes, and all rules of the department. Further, the undersigned verifies that his treatment plant was constructed under a valid permit, Number ____________ dated ______________ issued by the department, and the connection of the proposed project will not be in violation of any condition of said permit.

*Attach letter of authorization

Signed: ______________________________

____
Name and Title (Please type)

Date: ________ Telephone No. ____________________

C. Owner/Operator* After Construction (if different from applicant):

I, the undersigned, do certify that I will become the owner/operator of the proposed facility after construction. Further, I certify that I am fully aware that the statements made in this application are true, correct and complete to the best of my knowledge. Also, I agree to operate and maintain the facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all rules of the department. I understand the permit is non-transferable and will promptly notify the department upon sale or legal transfers of the permitted establishment.

*Attach letter of authorization

Signed: ______________________________

____
Name and Title (Please Type)

Date: ________ Telephone No.: ____________________

D. Professional Engineer Registered in Florida:

This is to certify that the engineering features of this public drinking water system have been designed/examined by me and found to be in conformity with modern engineering principles, applicable to the treatment and distribution of drinking water characterized in this application. There is reasonable assurance in my professional judgment that the facility, when constructed as planned and properly maintained and operated, will comply with all applicable statutes of the State of Florida and the rules of the department.

Signed: ______________________________

____
Name (Please Type)

(Affix Seal)

____
Company Name (Please Type)

____
Mailing Address (Please Type)

Florida Registration No. ______________ Date: __________ Telephone No. ______________

PART A - GENERAL

1. Estimated total cost of project Later Describe all water treatment Aeration and Chlorination (existing)
2. Existing plant capacity (MGD) 1.0 Plant capacity increase (MGD) 0
3. Previous DER permit number(s), if any Permitted under the Power Plant Siting Act (OGC File No. 81-0145)
4. Present population of area served about 150 (plant staff) Per capita consumption 50 gpd
5. Design population (additional served by this project) approximately 1000 daytime transient during construction and about 100 additional plant staff
6. Total connections served Later Total connections approved Later Additional connections Later
7. Give any industrial users of abnormal commands N/A
8. Current system water demand, in MGD (from plant operation report) combined potable and plant service wat
   Average day 0.44 Maximum day 1.0 Maximum hour (GPM) 850
   Additional water demand, MGD: Avg. day 0.44 Max. day 0.5 Max. Hr. GPM) 305
9. Is plant designed for 24-hour operation of what portion? 24-hour operation
10. Give characteristics of raw water (attach primary and secondary chemical analysis pursuant to Chapter 17-550, F.A.C.
    see water quality data attached to Consumptive Use Permit Application, Subsection 10.7.1
11. Give source proposed water (deep well, shallow well, spring, surface) deep wells (existing)
12. Sewage disposal Existing onsite sewage facility - OUC
    (Name and Address of sewerage utility)
13. Finished water storage: Elevated (gals) N/A Ground (gals) 500,000 (existing)
    Hydropneumatic (gals) 0 Existing Capacity (gals) 500,000 Capacity Increase (gals) 0
14. Existing service pump capacity (MGD) 2.45 Additional service pump capacity (MGD) 0
15. Static head in relation to pumping plant 20 to 40 feet
16. Well permit from water management district? Yes ☐ Permit No.
    No ☒ Explain Permitted under the Power Plant Siting Act (OGC File No. 81-0145)

PART B - DISTRIBUTION SYSTEM

1. Interconnection with other system No
2. Min. size pipe 2-inch Max. size pipe 6-in. Min. system pressure 210 ft. @ pump discharge Max. system pressure 240 ft.
3. Is fire control provided in design? Existing storage tank also supplies water for separate five water system.
4. Describe dead-end conditions and necessity for flushing including number of such conditions and flushing schedule
   All piping will be flushed and disinfected per AWWA C601.
5. Describe cross-connection control program Reduced pressure back flow preventers installed on the process connections.
6. Describe corrosion control program as necessary Not Necessary.
7. Water demand for additional connections (MGD) N/A
8. Number of each type of additional connections (residential, commercial, agricultural, industrial) to be served
   None