

**ORLANDO UTILITIES
COMMISSION
CURTIS H. STANTON
ENERGY CENTER**

UNIT 2

**SUPPLEMENTAL
SITE
CERTIFICATION
APPLICATION**

VOLUME 1A

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VOLUME 1A

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**Orlando Utilities Commission
Curtis H. Stanton Energy Center
Unit 2
Supplemental
Site Certification Application
Volume 1A**

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.

Name and Titles of Chief Executive Officers

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)

Name, Address, and Telephone Number of Official Representative Responsible
for Obtaining Certification

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

Site Location (County)

Orange County

Nearest Incorporated City

Orlando, Florida

Latitude and Longitude

29° 29' North Latitude

81° 10' West Longitude

UTMs (Center of Site)

Northerly 1507528

Easterly 446825

Section, Township, Range

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.

1A.1.0 Overview and Summary

1A.1.1 Overview

Stanton Energy Center Unit 2 (Stanton 2) will be the second unit installed at the previously certified Stanton Energy Center site located approximately 14 miles southeast of Orlando, Florida. The Stanton Energy Center site was certified for an ultimate capacity of approximately 2,000 MW based on four coal fired units. Stanton 2 is being planned as a replication of Stanton 1, with a net generating capacity of approximately 440 MW.

Both Stanton 1 and Stanton 2 will be jointly owned by Orlando Utilities Commission (OUC), the Florida Municipal Power Agency (FMPA), and Kissimmee Utility Authority (KUA). The existing ownership percentages of Stanton 1 and the proposed ownership percentages of Stanton 2 are shown below.

<u>Owner</u>	<u>Stanton 1</u> percent	<u>Stanton 2</u> percent
OUC	68.5542	75.0000
FMPA	26.6265	21.1686
KUA	4.8193	3.8314

Stanton 1 went into commercial operation July 1, 1987. Stanton 2 is scheduled for commercial operation on January 1, 1997.

1A.1.2 Summary

Stanton 2 is planned as a replication of Stanton 1, with an estimated 1997 installed capital cost of \$522,000,000 excluding interest during construction, or \$1,186/kW based on a 440 MW rating. The performance of Stanton 1 has been exceptional. The performance for Stanton 2 as a replicated unit is expected to be similar or better because of improvements incorporated. The replication process not only offers the opportunity to obtain a second unit with the same high level of performance, but also allows for significant capital cost savings. A number of common facilities were installed with Stanton 1 for Stanton 2. The ability to use these existing common facilities further reduces capital costs.

Stanton 1 has an average equivalent availability factor of over 84 percent for the first three years of operation, exceeding the design target of 83 percent. Operation and maintenance costs have been below average compared to similar units in the country, while the unit has achieved an actual full load net heat rate of 9,740 Btu/kWh.

Stanton 1 has also been a superb performer from an environmental perspective. Stanton 2 will incorporate further technological advancements such as low NO_x burners to further reduce emissions. The units will have complementary air quality control equipment which includes wet limestone scrubbers, electrostatic precipitators, and natural draft cooling towers. The units will utilize treated sewage effluent for cooling water. Stanton 1 consumes approximately 4.5 mgd of treated sewage water, helping to solve a critical environmental disposal problem for the area and preserve diminishing supplies of potable water. Stanton Energy Center has no offsite wastewater disposal. All ash and scrubber sludge are permanently disposed of onsite with fly ash being sold as an additive for cement.

The Stanton Energy Center site comprises 3,280 acres, providing an adequate buffer from the public while serving as a sanctuary for the endangered red-cockaded woodpecker. The construction of Stanton 2 will not do any damage to this sanctuary.

Since Stanton 2 is a replication of Stanton 1, the design is well defined and the projected capital costs are well known. Many of the major equipment contracts have been negotiated and signed pending approval of this application. The contracts cover more than 30 percent of the projected capital cost.

Stanton 2 will use the associated facilities constructed with Stanton 1. Stanton 2 will include a 14-mile 230 kV transmission line segment and a 1-mile

alternate access road to the site both of which are to be located in the railroad corridor previously certified for Stanton Energy Center.

Subsection 1A.4.0 addresses the need for additional capacity in Peninsular Florida. The analyses indicate that Peninsular Florida will need over 1,700 MW of additional capacity in 1996 and 1997 above that which was shown to be needed through 1995 by the 1989 Planning Hearing. Furthermore, Stanton 2's low price coal fueled energy will be badly needed by 1997 to reduce consumption of higher priced natural gas and oil.

The following summarizes the Peninsular Florida winter capacity mix as of January 1, 1990, as reported in the Southeastern Electric Reliability Council Coordinated Bulk Power Supply Program IE-411, April 1, 1990.

	<u>MW</u>	<u>Percent</u>
Nuclear	3,920	12.6
Fossil Steam-Oil	7,822	25.1
Fossil Steam-Gas	5,270	16.9
Fossil Steam-Coal	8,467	27.2
Internal Combustion	287	0.9
Combustion Turbine	4,735	15.2
Combined Cycle	559	1.8
Hydro	<u>47</u>	<u>0.2</u>
	31,116	100.0

Nuclear and coal capacity comprise less than 40 percent of Peninsular Florida's capacity.

The remainder of the subsections in this volume provide details of the Stanton 2 project, economic projections including fuel price projections, discussions of the availability of fuel and transportation, alternatives to the construction for Stanton 2, and load flow analysis indicating the need for the additional 14-mile transmission line segment.

1A.2.0 Description of Project

1A.2.1 Description of Facilities

Stanton Energy Center Unit 2 will be a replicate and sister unit to Stanton Energy Center Unit 1, which went into commercial operation on July 1, 1987. Stanton 2 will be a net 440 MW electrical generating station owned by the Orlando Utilities Commission, the Florida Municipal Power Agency, and the Kissimmee Utility Authority. The new unit, like Stanton 1, will be operated by the Orlando Utilities Commission. The Stanton Energy Center is located in Orange County approximately 14 miles east-southeast of the City of Orlando, Florida, on a site which is conceptually designed as a four-unit facility and certified for an ultimate capacity of approximately 2,000 MW. Stanton 2 will be the second unit on this site and will be located north of Stanton 1. Stanton 2 is scheduled for commercial operation on January 1, 1997.

The Stanton Energy Center site encompasses approximately 3,280 acres of Orange County, Florida. Main site access is from the north off State Highway 50 and Alafaya Trail Road. Coal train access is from the south by a spur of the CSX Railroad. Power transmission lines leave the site to the north. The power is transmitted at 230 kV. More details of the site are discussed in Section 2 of the original and Supplemental Site Certification Applications.

Stanton Energy Center Unit 2 will comprise five areas: the powerblock, air quality control, water management, ash and sludge conditioning, and coal handling and storage. The water management area, ash and sludge conditioning area, and the coal handling and storage area are shared with Stanton 1.

1A.2.1.1 Powerblock

The powerblock includes the turbine area, the steam generator area, the Control Center Building, and the Administration and Plant Services Building. The turbine area is a 100-foot wide by 244-foot long building which encloses the turbine generator and related equipment. The turbine area roof is at Elevation 179 feet 6 inches, and the ground elevation at the powerblock is 82 feet. The building and enclosed steam turbine and generator will be positioned east of the steam generator with the turbine generator center line running north to south. In addition to the turbine generator, the turbine area equipment will include the

surface condenser and the steam turbine-driven boiler feed pump and other auxiliary equipment items.

The steam generator area will be located west of and adjacent to the turbine area. The area will be approximately 160 feet wide by 224 feet long. The roof elevation will be 309 feet 0 inch. Major equipment located in the area will be the steam generator, deaerator, and storage tank, feedwater heaters, coal pulverizers, coal feeders and coal silos, air heater, and primary air and forced draft fans.

The Stanton 2 control center area will be an extension of the Stanton 1 Control Center Building located near the southeast corner of the steam generator area and beside the turbine area. The Stanton 2 extension area will be 28 feet wide by 100 feet long and will include four internal levels and a roof at Elevation 163 feet 6 inches. The Control Center Building will be completely enclosed.

The existing Administration and Plant Services Building is a common facility with Stanton 1 and is south of the Stanton 1 turbine area and adjacent to the southeast corner of the Stanton 1 steam generator. The Administration and Plant Services Building is approximately 156 feet wide by 208 feet long and has four internal floors. The ground floor includes maintenance shops, a machine shop, men's and women's locker rooms, and a storage room. The assembly floor provides meeting rooms and maintenance material storage. Office areas, a training room, classroom facilities, conference areas, and storage rooms are located on the top two floors of the building. A small addition to the plant services area is contemplated for the increased shop and maintenance personnel required for Stanton 2.

1A.2.1.2 Air Quality Control Area

The air quality control area will include the precipitator and Air Quality Control Building and equipment. The electrostatic precipitator will be located directly west of the steam generator area. The electrostatic precipitator will be 144 feet long by 176 feet wide and will be partially enclosed. A precipitator penthouse will be located above the precipitator.

The Air Quality Control Building will be located directly west of the electrostatic precipitator. The building will be 210 feet wide by 169 feet long and will be completely enclosed with a roof at Elevation 187 feet 0 inch. The Air Quality Control Building will enclose the induced draft fans and the scrubber equipment. The plant chimney will be located directly west of the Air Quality

Control Building. The chimney will be 550 feet tall; the same height as the chimney for Stanton 1.

1A.2.1.3 Water Management Area

The existing water management area is located south of the Stanton 1 steam generator, the Stanton 1 electrostatic precipitator, and the Stanton 2 Air Quality Control Building. The area includes the Water Management Building, the storage tanks, and neutralization basin.

The Water Management Building is approximately 72 feet wide by 126 feet long. It encloses the plant demineralizer equipment, a solids contact unit and equipment, six service water gravity filter cells and clearwell, and the chlorination equipment. Service water storage and demineralized water storage tanks are located west of the Water Management Building.

1A.2.1.4 Ash and Sludge Conditioning Area

The existing ash and sludge conditioning area is located west of the Stanton 1 air quality control area and east of the coal storage areas. The area includes a Sludge Conditioning Building, thickeners, sludge normal and emergency stockout facilities, ash settling tanks, and ash dewatering tanks. Additional equipment will be added to expand the system capabilities to process the Stanton 2 ash and sludge. The processing of scrubber effluent and fly ash takes place in this area. The Sludge Conditioning Building is approximately 104 feet wide by 186 feet long. The Sludge Conditioning Building includes the lime preparation and storage equipment, the sludge conditioning vacuum filters and equipment, and the ash conveying and mixing equipment.

1A.2.1.5 Coal Handling and Storage Area

The existing coal handling and storage area is designed for expansion for Stanton 2. The area is located along the west side of the plant site. The area includes an existing coal car unloading building, a coal transfer structure, an emergency stockout and reclaim hopper, a coal storage area with a track mounted stacker-reclaimer, a coal crusher building, and the interconnecting conveyors required to transport the coal all installed with Stanton 1.

The coal storage area is an open grade level storage system with storage on both sides of a stacker-reclaimer unit. The stacker-reclaimer operates from rails

in an east to west direction. The coal storage area has the capacity to store a minimum of 24,000 tons in active storage and 400,000 tons in compacted reserve storage. The compacted storage reserve will support approximately 60 days of operation for both units.

The active storage pile consists of a pile on each side of the stacker-reclaimer approximately 440 feet long, 100 feet wide, and 40 feet high. The initial reserve storage pile located on the north and south sides of the active storage pile will extend approximately 390 feet to the north and 210 feet to the south of the active storage piles and approximately 1,100 feet east to west. The pile will be approximately 40 feet high.

1A.2.1.6 Electrical Distribution

Electric power will be transmitted from the generator transformer high voltage terminals to the existing Stanton 230 kV Substation and from this substation to two reserve auxiliary transformers through overhead transmission lines. The Stanton Substation connects directly to OUC's 230 kV transmission network. The steam turbine generator terminals will be rated at a nominal 24 kV and will be connected to the generator transformer low voltage winding terminal and the main auxiliary transformer high voltage winding terminal through isolated phase bus duct. Both the main and reserve auxiliary transformers will supply power to the 6.9 kV switchgear buses. The main auxiliary transformer will provide the normal source of power to the 6.9 kV switchgear buses when the generator is on-line. The two reserve auxiliary transformers will supply the normal source of power to the switchgear buses when the generator is off-line and will serve as the alternate source of power when the generator is on-line. The unit will be capable of starting up with one failed reserve auxiliary transformer.

The auxiliary electric system will consist of four unit associated, and two scrubber 6.9 kV switchgear buses. These switchgear buses will provide power to 33 large motors rated 6.6 kV, and approximately 14 secondary unit substation transformers. Each secondary unit substation (SUS) will contain a 6,900-277Y/480 volt high impedance neutral grounded, cast resin transformer. The transformer secondary will be connected to a 480 volt, three-phase, three-wire switchgear bus through a main breaker. Each SUS 480 volt bus will be connected to a companion 480 volt SUS bus through a tie breaker. The companion 480 volt bus will obtain its power from an alternate power source. The SUS buses will supply

power to approximately 19 motor control centers and to eight precipitator rectifier controllers. The motor control centers will supply power to 460 volt motors, lighting panels, power panels, and other miscellaneous loads. The 120 volt fractional horsepower motors and convenience outlets will be supplied power from the 120 volt power panels.

A 6.9 kV diesel generator common with Unit 1 supplies power at 6.9 kV to provide a safe and orderly shutdown of the steam turbine generator unit.

1A.2.1.7 Water Supply

Water supply to the site was installed with Stanton 1 and is provided by two sources. Two existing wells provide service water, potable water, and demineralized water. Makeup to the cooling water systems is provided through a 30-inch diameter pipeline from the Orange County Easterly Subregional Wastewater Treatment Plant located approximately 4 miles northwest of the plant site and from the site drainage system. A single makeup water supply storage pond containing a minimum of 560 acre-feet of storage receives and holds makeup water for the cooling system. The cooling water makeup piping system and storage pond were installed with Stanton 1. The makeup water storage pond will supply more than two weeks of cooling water for Stanton 1 and 2. Stanton 1 currently consumes an average of approximately 4.5 mgd of treated sewage water from the Orange County Easterly Subregional Wastewater Treatment Plant. Stanton 2 is expected to consume a like amount. OUC currently has a commitment from the Orange County Easterly Subregional Wastewater Treatment Plant to supply up to 10 mgd.

Cooling tower blowdown from Stanton 1 and 2 is directed to the existing recycle basin directly south of the Stanton 2 cooling tower location. Excess blowdown water is processed by brine concentrators and associated equipment. The treatment system is located in the Wastewater Treatment Building located west of the Stanton 1 cooling tower.

Plant floor drains are piped to the recycle basin. Plant roof drains are directed to the makeup water storage pond via swales. The recycle basin also receives excess water from the active combustion waste area runoff pond, the coal storage runoff ponds, and cooling tower blowdown. The recycle basin supplies makeup water for the scrubbers in the air quality control system and for the boiler ash conditioning disposal process.

Water is reserved onsite for fire protection purposes. The service water storage tanks are each provided with an internal standpipe to reserve the lower half of the tanks for fire protection water. A network of yard mains and hydrants provides fire water to the site. Three fire water pumps located in the Water Storage Pump Building provide the pressure and flow required.

The site is designed for zero wastewater discharge. All plant wastewater, including cooling tower blowdown, is reused or treated and no wastewater is discharged off the plant site; therefore, there is no impact to the Econlockhatchee River Basin.

1A.2.1.8 Coal and Oil Supply

The Stanton Energy Center is designed to burn various Appalachian and Illinois Basin coals delivered by unit train. The unloading of coal cars takes place while the train is moving. The system is sized to unload 3,500 tons per hour.

Fuel oil is delivered to the site by truck. No. 6 oil is used for steam generator ignitors during startup and for low load stabilization. No. 2 fuel oil is used for firing the auxiliary boiler and for mobile yard equipment. Fuel oil is stored in aboveground tanks located near the northwest corner of the recycle basin. A special berm containment is provided around the tanks. The containment area has an impermeable liner.

1A.2.1.9 Steam Cycle

The steam cycle will include a natural circulation steam generator which at maximum continuous rating supplies 3,305,000 lb per hour of superheated steam at 2,640 psig and 1,005 F. The steam from the steam generator will be supplied to a condensing type turbine consisting of a high-pressure section, intermediate-pressure section, and a low-pressure section. All three turbine sections will be in line and form a common shaft to drive the electrical generator. Exhaust from the high-pressure turbine will be returned to the reheat section of the steam generator before entering the intermediate-pressure turbine. The reheat steam flow at maximum continuous rating is 2,802,000 lb per hour at 645 psig and 1,005 F. The intermediate-pressure turbine will exhaust directly to the low-pressure turbine. The low-pressure turbine will be a double flow unit of six-stage design. The low-pressure turbine will exhaust to the condenser.

Extraction steam for regenerative feedwater heating will be provided from all three turbine sections. Feedwater Heater 8 will receive steam from an interstage extraction on the high-pressure turbine. Feedwater Heater 7 will receive steam from the high-pressure turbine exhaust (cold reheat). An interstage extraction from the intermediate-pressure turbine will provide steam to the deaerator (Feedwater Heater 5) and the boiler feed pump drive turbine. Extraction steam will be cascaded through the feedwater heater train to the deaerator and the condenser.

The condenser will reject cycle waste heat to the circulating water system, reduce the low-pressure turbine back pressure, and hold cycle water (condensation). The condenser will be of the single shell, two-pass divided water box construction.

Two full capacity condensate pumps will be provided and take suction from the condenser hot well and supply condensate quality water through the low-pressure heater train to the deaerator. A full capacity condensate polisher will be provided.

The deaerator will be the last heater in the low-pressure heater train. It will receive the heated condensate and remove air and other noncondensables. The deaerator will discharge to the deaerator storage tank. The deaerator storage tank will contain approximately 55,000 gallons of condensate available to the boiler feed pump and feedwater system. One full capacity, turbine driven boiler feed pump will take suction from the deaerator storage tank and discharge through the high-pressure heater train to the steam generator economizer inlet connection. The high-pressure feedwater train will include three levels of regenerative heating.

The turbine driven boiler feed pump will include a booster pump, also driven by the turbine, that assures adequate suction pressure to the main boiler feed pump during sudden load changes. The boiler feed pump turbine can use steam from either the main steam source or from the intermediate-pressure turbine exhaust. An electric motor driven startup boiler feed pump is used when steam is not available to the boiler feed pump turbine. The startup boiler feed pump will be sized to allow operation of Stanton 2 at 60 percent capacity if the main turbine driven boiler feed pump is unavailable.

1A.2.1.10 Steam Generator Equipment and Auxiliaries

The steam generator will be a Babcock & Wilcox, indoor drum type, balanced draft, parallel gas flow convection pass radiant boiler designed to burn pulverized bituminous coal from the Southern Appalachian and Illinois basins. It will also be designed to burn high fouling and high slagging coal to maintain fuel flexibility. The steam generator will have a guaranteed efficiency of 89.07 percent at 100 percent load firing the Appalachian design coal.

The maximum continuous rating (MCR) for this unit will be the guarantee load of 3,305,000 lb/h of main superheated steam at 2,640 psig and 1,005 F. This represents the 5 percent overpressure and 11 percent overflow condition for the steam turbine. The reheat steam conditions leaving this boiler at MCR will be 2,802,000 lb/h at 645 psig and 1,005 F.

The steam generator will be equipped with Babcock & Wilcox dual register Type XCL low NO_x burners with a guaranteed NO_x emission rate of 0.32 pound NO_x/MBtu, which represents over a 45 percent decrease below the current Prevention of Significant Deterioration (PSD) permit emission rates for the unit of 0.60 pound NO_x/MBtu.

1A.2.1.10.1 Combustion Air Fans. Two TLT Babcock radial flow fans will supply the primary air for the steam generator. Each fan will be capable of supplying the air requirements up to approximately 70 percent of MCR. Above MCR, both fans must be in service. These fans will take atmospheric suction through inlet silencers. Flow will be controlled by inlet vanes. Each fan will have a test block rating of 291,181 acfm when driven by a single-speed electric motor at 1,180 rpm.

Two forced draft fans of the double width, airfoil-bladed centrifugal type will provide secondary air to the furnace for combustion. The fans will take suction from atmosphere through inlet silencers. Each forced draft fan will be rated for 482,200 acfm at 17.7 inches wg test block. The forced draft fans will be driven by two-speed motors at either 711 rpm or 594 rpm.

Two induced draft fans of the double width, airfoil-bladed centrifugal type with double inlet will provide transport of the flue gas from the furnace through the air quality control equipment and to the chimney. The induced draft fans will be driven by two-speed motors at either 885 rpm or 705 rpm.

The forced draft and induced draft fans will be sized so that two fans operating at low speed are adequate to maintain boiler maximum continuous rated load

point during operation with a clean air heater and the boiler unfouled by slag in the steam generator.

1A.2.1.10.2 Air Preheater. A fin tube type air preheater coil will be located in the ductwork between the forced draft fan discharge and the regenerative air heater inlet. The preheater will be designed to protect the air heater against corrosion by maintaining a minimum cold end average temperature. The coils will use condensing auxiliary steam for supply of heat. Condensate will be returned to the steam cycle at the flash tank.

1A.2.1.10.3 Air Heater. The air heater will be a Ljungstrom trisector regenerative type with vertical shaft. The air heater will normally be driven by either of two full capacity, 100-horsepower electric motors. An air driven adjustable speed motor is provided for maintenance purposes only. The air heater will be equipped with both soot blowing and water wash cleaning devices.

1A.2.1.10.4 Soot Blowing. The steam generator is provided with gas side soot blowers to remove ash and slag buildup, thereby improving heat transfer. The system will include 46 retractable soot blowers, 54 furnace wall soot blowers, and two air heater soot blowers. The soot blowers will use steam from the platen superheater outlet. Steam for the air heater will also be available from the plant auxiliary steam system.

1A.2.1.11 Turbine Equipment and Auxiliaries

The turbine will be a Westinghouse tandem compound (34-inch last-stage blades), two-flow exhaust turbine consisting of two primary sections: a combined single-flow high-pressure (HP) and single-flow intermediate-pressure (IP) section, and double-flow low-pressure (LP) section. The turbine will be designed to operate at 3,600 rpm and will be guaranteed to produce 427,420 kW when operating with a 2,400 psig throttle pressure at 1,000 F, reheating to 1,000 F, 3.0 inches Hg absolute condenser pressure and zero makeup. The 5 percent overpressure rating will be approximately 460 MW. The guaranteed net turbine heat rate at design condition will not exceed 7,834 Btu/kWh. The turbine will also be designed to provide extraction heating steam to four low-pressure feedwater heaters from the LP turbine; to a deaerator, boiler feed pump turbine, and air preheat coils from the IP turbine exhaust; to one high-pressure feedwater heater from the IP turbine; to one high-pressure feedwater heater from an intermediate

stage of the HP turbine; and to one high-pressure feedwater heater from the HP turbine exhaust.

1A.2.1.11.1 Surface Condenser. The LP turbine will exhaust into a bottom mounted surface condenser. The surface condenser will act to maintain a reduced back pressure on the turbine and to remove waste heat from the turbine exhaust. The condenser will be a single shell with divided water box arranged for two passes on the tube side. The condenser tubes will be 1.0 inch in diameter, 22 BWG, ASTM 249, Type 316 stainless steel. The surface condenser will have a total effective surface area of 270,000 square feet. The condenser hot well will have a storage capacity of 25,000 gallons.

1A.2.1.11.2 Low-Pressure Feedwater Heaters. Four stages of LP feedwater heating will be employed. All heating steam will be provided by extraction from the LP turbine. The LP Heater No. 1 and 2 and all extractions from the turbine to the heater shell will be provided with power-assisted nonreturn check valves and motor-operated block valves to protect the turbine from accidental water induction. Heater drains will cascade from No. 4 to No. 3 to No. 2 and then to the flash tank. Steam from the flash tank enters Heater No. 1, and liquid drains will be discharged to the surface condenser through the drains cooler.

1A.2.1.11.3 Deaerator and Storage Tank. The deaerator will be a horizontal mounted cylindrical feedwater heater in which condensate makes direct contact with extraction steam from the intermediate-pressure turbine exhaust. The direct contact of condensate with steam will cause heating of the condensate and separation of the dissolved gasses. The deaerator will be open to atmosphere to permit venting of air and other noncondensables. The deaerator will have an integral vent condenser to reduce loss of steam. The deaerator will be designed for a maximum operating pressure of 270 psig and a maximum design temperature of 650 F. The deaerator will be approximately 8 feet in diameter and 35 feet long.

The deaerator condensate will drain into a bottom-mounted deaerator storage tank. The storage tank will provide condensate to the boiler feed pumps. The storage tank will be approximately 12 feet in diameter, 76 feet long, and have a normal operating storage volume of 55,000 gallons.

1A.2.1.11.4 High-Pressure Feedwater Heaters. Three stages of HP feedwater heating will be employed. Heating steam will be provided from the intermediate- and high-pressure turbine stages. An extraction from the IP turbine will provide steam to Feedwater Heater 6. The HP turbine exhaust (cold reheat) will provide steam to Feedwater Heater 7. An interstage extraction from the HP turbine will provide steam to Feedwater Heater 8. All extractions from the turbines to the high-pressure feedwater heaters will be provided with power-assisted nonreturn check valves and motor-operated block valves to protect the turbine from accidental water induction and turbine overspeed. The shell side drains will cascade from No. 8 to No. 7 to No. 6 and then to the deaerator. A feedwater heater drain pump will be provided to transfer drains to the deaerator below 63 percent load when adequate pressure does not exist. Upon high water level, all heaters will drain directly to the surface condenser.

1A.2.1.11.5 Boiler Feed Pump and Turbine. The boiler feed pump will be a Byron Jackson, four-stage horizontal, double suction, double case barrel, centrifugal, high-speed type designed for continuous operation in boiler feed service. The boiler feed pump will take suction from the booster boiler feed pump discharge and provide the required pressure at the steam generator economizer inlet. The boiler feed pump will be rated at 8,300 gpm and 7,750 foot, total head, at a speed of 5,800 rpm.

The boiler feed pump will be directly connected to a General Electric condensing, nonextraction steam driven boiler feed pump with bottom exhaust, seven impulse stages, tilting pad thrust bearing, elliptical main bearings, and labyrinth shaft seals. The boiler feed pump turbine will be arranged for connection of the exhaust end shaft extension to the boiler feed pump.

The boiler feed pump turbine will be designed for the steam conditions existing at the IP turbine to LP turbine crossover stage extraction of the turbine generator unit. The boiler feed pump turbine will also be designed for startup and low load operation when steam is supplied from the main steam feed to the main turbine.

The booster boiler feed pump will be a horizontal, double suction, single stage, centerline-mounted centrifugal pump with a radial split casing. The booster boiler feed pump will be driven by the boiler feed pump turbine through a speed reducing gear. The pump will be designed for continuous operation in boiler feed service.

The startup boiler feed pump will be a Byron Jackson, five-stage, diffuser type centrifugal pump. It is connected to a 7,000 horsepower, 1,800 rpm induction motor through a Voith adjustable variable-speed drive with integral speed increase gearing.

1A.2.1.12 Generator and Electrical Equipment

The generator will be a Westinghouse 24 kV, 13,000 ampere, 516,200 kVA, 2-pole, 3-phase, 60 hertz, hydrogen cooled, 3,600 rpm synchronous machine. The generator rating will be based on a minimum 0.9 power factor and a 0.58 short-circuit ratio. Maximum hydrogen cooling pressure will be 60 psig. Generator excitation will be provided by a main exciter alternator, permanent magnet pilot exciter, and fuse/diode wheel, all on a common shaft coupled to the generator field. Excitation current will be transmitted from the main exciter armature to a fuse/diode wheel and then to the generator field by means of conductors internal to the shaft. Voltage regulation will be accomplished by controlling the main exciter field current. The voltage regulator will employ static components.

Electrical power will be conducted from the generator terminals by a 3-phase self-cooled isolated phase bus duct to the main generator transformer. One generator phase will be conveyed on each bus duct. Each bus will consist of a 19-inch diameter aluminum conductor inside a 39-inch diameter enclosure. The enclosures will be spaced 54 inches center to center.

The generator transformer will be a three-phase, 60 hertz, two-winding, delta-wye connected unit. The generator transformer will provide step-up of the 24 kV generator voltage output to 230 kV for connection to the electrical transmission and distribution system. The transformer will be rated 537,600 kVA at maximum 65 C rise and 480,000 kVA at maximum 55 C rise.

1A.2.1.13 Air Quality Control Equipment

The Stanton 2 air quality control will be the subject of a Best Available Control Technology (BACT) demonstration during the amendment of the Stanton 2 PSD permit issued by the Environmental Protection Agency (EPA) in 1982. The proposed equipment will include a cold-side electrostatic precipitator, followed by a flue gas scrubber, and then dispersion by a chimney. The electrostatic precipitator will receive flue gas directly from the steam generator and remove particulate prior to forwarding the gas to the flue gas scrubbers. The

scrubbers will function to remove sulfur dioxide by direct contact with an acid neutralizing slurry. The flue gas scrubbers additive system will prepare a slurry of limestone for the scrubbers.

1A.2.1.13.1 Electrostatic Precipitator. One full capacity cold-side electrostatic precipitator will be provided to remove fly ash from the combustion gas and reduce particulate emissions from the unit to comply with a proposed BACT limit of 0.020 lb/MBtu and a plume opacity of less than 10 percent. This emission rate is a 33 percent reduction from the current PSD permit emission rate. Particulate removal will be accomplished by a dc high voltage electrical field between high voltage discharge electrodes and ground collecting electrodes. Particles entering the electrical field will acquire an electrostatic charge which will cause them to migrate across the gas flow path to the collecting electrodes where the charge on the particle normally leaks to ground. The collected particles will be removed by periodic rapping of the electrodes. The particles will fall into hoppers below the combustion gas flow path and will be periodically removed by the fly ash system.

The electrostatic precipitator will be a Wheelabrator size 168/45/6 x 9/12/3 rigid frame type complete with all electrical and control equipment necessary for a complete operating unit. The precipitator will be provided with a weather enclosure completely covering the top of the precipitator and all externally top mounted equipment. The precipitator will be approximately 175 feet wide across the inlet, 116 feet deep, and 55 feet high.

The precipitator hoppers located on the bottom of the precipitator will collect the dust which falls from the collection system. There will be a total of 48 precipitator hoppers, each with a storage volume of 2,831 cubic feet. Each precipitator hopper will be provided with a hopper heating system.

The fly ash system will convey by vacuum transport fly ash collected in the precipitator hoppers, the economizer hoppers, and the air heater hoppers to the existing fly ash silo installed with Stanton 1.

Two parallel crosstied ash collecting systems will each serve 24 precipitator hoppers. Either system can service the entire fly ash unit by conveying continuously.

The mixture of ash and air will be conveyed to the fly ash separators where the heavier ash will be deposited into the silo. The conveying air will be passed through the fly ash exhaust filter to further clean it of the lighter particles. The conveying air will be passed through the exhausters to atmosphere.

The fly ash silo is equipped with fluidizing air blowers. These blowers will fluidize the fly ash and aid in ash removal.

The fly ash will normally be discharged to the scrubber solids system for disposal. The silo is also equipped with a rotary unloader to allow ash unloading into trucks.

The fly ash silo is 40 feet in diameter and 53 feet high. It has a net storage volume of 54,200 cubic feet. The silo has an approximate 72-hour collection capacity at the maximum fly ash collection rate.

1A.2.1.13.2 Flue Gas Scrubber. Sulfur dioxide (SO_2) will be removed from the steam generator flue gas by a direct contact spray type desulfurization system. The system will be designed and furnished by ABB Combustion Engineering Systems. The desulfurization system will comprise three ABB spray tower absorber modules and reaction tanks. The sizing of the modules will be based on two operating and one spare. The system will receive almost particulate-free flue gas from the electrostatic precipitator. As the gas enters the operating absorbers, it will be sprayed counter-currently with the slurry from the associated reaction tanks. Spray nozzles will disperse the slurry into fine droplets covering the entire cross-sectional area of the absorber, thus affording intimate contact between gas and liquid and effective absorption of SO_2 into the liquid phase.

After contacting the sprays, the cleaned gas temperature will be approximately 125 F, will be saturated with water, and will carry some moisture droplets. The removal of most of this entrained moisture will be accomplished in the demister section of the spray tower which will contain the bulk entrainment separator vanes and two series of chevron mist eliminator vanes. Upon exiting the mist eliminator, the treated flue gas will be directed to the chimney.

As the slurry falls to the bottom of the spray tower, it will absorb SO_2 from the flue gas. The slurry will drain from the tower into the reaction tank where the formation of insoluble calcium solids is promoted. Ground limestone additive will be added to the reaction tank under agitation by one top mounted Lightnin mixer.

1A.2.1.13.3 Reaction Tank. Each of the three reaction tanks will have a diameter of 57 feet, a height of 34 feet 6 inches, and an operating capacity of approximately 620,000 gallons, and will serve a single absorber module. The bottom of the absorber shell will hang in the reaction tank and will make a gastight seal with the slurry in the tank.

1A.2.1.13.4 Additive Feed. Raw limestone will be prepared by grinding to a fineness of 70 percent through a 325 mesh to maximize total available surface contact area. The limestone will be mixed with water to a slurry of 35 percent solids by weight which will be stored in three additive storage tanks. The additive feed system will be a common facility shared with Stanton 1.

Additive will be continuously circulated through a supply piping loop by either of three full capacity, rubber-lined centrifugal additive feed pumps. A portion of the slurry will be admitted to the reaction tanks by the pH control system. The remaining slurry will be returned to the additive storage tanks.

1A.2.1.13.5 Makeup Water. Makeup water from the recycle basin will be stored in a recirculation water tank. Water will then be pumped by one of the two full capacity recirculation water pumps to the reaction tanks to compensate for the water lost through the bleed system and from evaporation in the absorber modules. The amount of makeup water supplied to each reaction tank will be regulated through a control valve whose operation will be based on the tank slurry density.

1A.2.1.13.6 Spray System. Four rubber-lined Warman spray pumps, each having a capacity of 15,470 gpm, will take suction from each reaction tank. The slurry will be pumped up to four levels of spray headers and discharged through the spray nozzles. One spray pump will be used for each operating spray level.

1A.2.1.14 Plant Equipment Cooling

Plant equipment cooling will be provided by a closed system which will include a single cooling tower and circulating water system. The circulating water system will remove waste heat from the surface condenser and the auxiliary cooling water heat exchangers. The waste heat will be conveyed to the cooling tower through circulating water system piping by three one-third capacity Ingersoll-Rand vertical, wet-pit centrifugal pumps. Each circulating water pump will be rated 67,000 gpm at 70 feet total head when driven by a 6.6 kV, three-phase, 1,750 hp electric motor.

Heat will be rejected to the atmosphere at the cooling tower. The cooling tower will be a Marley hyperbolic, counterflow, natural draft, reinforced concrete type. The tower will be 430 feet tall, 280 feet in diameter at the tower base, and 153 feet in diameter at the throat. It will be designed to cool 200,000 gpm of water at 113.8 F to 91 F with a 78 F wet-bulb temperature and 91.6 dry-bulb

temperature. A basin below the cooling tower will act to store circulating water and to provide an intake structure for the circulating water pumps.

Circulating water will be conveyed by the circulating water pumps from the cooling tower to the surface condenser and the auxiliary cooling water heat exchangers by underground concrete piping. A continuously operating tube cleaning system will be used to keep fouling and deposition in the condenser and heat exchangers to a minimum. Sponge rubber balls will be sized to check condition and recirculate if acceptable. Worn balls will be replaced to maintain a continuous effective cleaning action.

Waste heat from auxiliary plant equipment will be conveyed through a closed cycle cooling water system piping network to the shell side of the auxiliary cooling water heat exchangers. Waste heat will then be given up to the circulating water on the tube side of the heat exchanger.

The closed cycle cooling water system will continuously circulate high quality water through the equipment coolers to remove waste heat. The use of high quality water will reduce fouling of individual equipment exchangers. Two full capacity, closed cycle cooling water pumps will provide circulation through the equipment located in the main powerblock. Each closed cycle cooling water pump will be rated 10,000 gpm at 120 feet total head. Two full capacity, closed cycle cooling water booster pumps will be provided to circulate cooling water through the scrubber associated equipment and the sludge conditioning equipment. Each closed cycle cooling water booster pump will be rated 200 gpm at 30 feet total head. The closed cycle cooling water supply temperature will be maintained constant at 95 F by mixing of hotter equipment return water with colder water from the auxiliary cooling water heat exchangers.

Makeup to the circulating water system will be from the makeup water supply storage pond by the circulating water makeup pumps located at a pump structure along the west side of the pond. Two full capacity pumps were installed with Stanton 1, and a third full capacity pump will be installed with Stanton 2. The circulating water makeup pumps are of the vertical wet pit type. Each is rated 4,500 gpm at 95 feet total head.

a ty pumps were installed with Stanton 1, and a third full capacity pump will be installed with Stanton 2. The circulating water makeup pumps are of the vertical wet-pit type. Each is rated 4,500 gpm at 95 feet total head.

1A.2.1.15 Scrubber Solids

The Stanton 2 scrubber solids system will be an extension of the Stanton 1 system currently in operation. The function of the system will be to thicken, dewater, stabilize, and chemically fix solids from the Stanton 2 flue gas scrubber which will be suitable for transporting to permanent storage in an onsite landfill disposal area.

1A.2.1.15.1 Thickener and Flocculent Subsystem. The thickener and flocculent subsystem will receive the scrubber blowdown slurry at the chemical conditioning tank and, by physical and chemical means, will increase the underflow discharge solids content while producing a clarified overflow. The thickened slurry will be pumped from the thickeners to the vacuum filters by the thickener underflow pumps. Each pump will be designed for a total head of 100 feet and a capacity of 270 gpm.

One thickener and three thickener underflow pumps will be added and crosstied with Stanton 1.

The flocculent addition will meter polymer to the scrubber blowdown at the chemical conditioning tank. The function of the polymer will be to enhance the settling of the sulfurous compounds, which results in a higher concentration of solids in the underflow slurry.

1A.2.1.15.2 Vacuum Filtration Subsystem. The vacuum filtration subsystem will comprise three vacuum filter units, with each filter having the capacity to handle half the maximum Stanton 2 load. Each of the three units will contain a rotary vacuum filter, filtrate pump, vacuum receiver, vacuum pump, and cake discharge air piping system. Each vacuum filter will have a filtration area of 565 square feet.

Slurry will be pumped from the thickeners to the vacuum filters. A constant vacuum will be maintained in the rotary drum of each filter by a vacuum filter exhauster. Vacuum will then be applied to the slurry as the drum rotates to draw the filtrate out of the slurry, resulting in a 50 to 55 percent cake solids concentration. A scraper blade will remove the cake from the vacuum filter and the dewatered cake will fall onto the discharge conveyor. The filtrate drawn from the slurry will be pumped by the vacuum filter filtrate pumps to the scrubber solids return water tank, and then returned to the scrubber solids chemical conditioning tank by the scrubber solids return water pumps.

1A.2.1.15.3 Fly Ash and Lime Additive Subsystem. The fly ash and lime additive subsystem delivers fly ash and crushed quicklime to the stabilization mixers. Each must be present in the proper proportions and combined with the filter cake to harden the final product into a stabilized material in the landfill.

The system will be made up of three independent trains to handle both Stanton 1 and 2 scrubber solids. Each train consists of the following major components: a lime feeder, a lime crusher, a lime crusher exhaust fan, a fly ash feeder, a fly ash impact weighing element, screw conveyors, and slide gates needed to combine and transfer the fly ash and lime.

1A.2.1.15.4 Conveyor and Stabilization Mixer Subsystem. The conveyor and stabilization mixer subsystem will carry the dewatered filter cake from the vacuum filtration area to the mixer, where fly ash and lime will be mixed with the filter cake.

The subsystem will be made up of new, existing, and expanded equipment, including vacuum filter discharge conveyors, stabilization mixers and their associated dust collectors, stabilization mixer discharge conveyors, sludge transfer conveyors and their associated scales, a fixed stacker, and a radial stacker.

The processed material from the mixers will be discharged onto the mixer discharge conveyors. The mixer discharge conveyors will discharge to the sludge transfer conveyors. The material will then be fed to either the radial stacker or the fixed stacker for stockpiling of the end product. From the stockpiling area, the material will be loaded onto trucks for transport to the landfill area located onsite. The landfill area is approximately 312 acres. About 80 acres will be required for Stanton 2 combustion waste storage. The landfill area will accommodate four units for the total life of each unit.

1A.2.1.16 Associated Facilities

Offsite associated facilities for Stanton 2 include existing facilities constructed for Stanton 1, which will be used in the operation of both units, and a new 230 kV transmission line segment and a new alternate site access road. The existing facilities include the site access road, the cooling water makeup supply line, the railroad spur serving the site, and the transmission facilities which interconnect the site with the OUC transmission system. The new transmission line segment will be used to complete the interconnection of the site with the

OUC Taft Substation. The new site access road will provide alternate access to the plant site from the south by the Bee Line Highway.

1A.2.1.16.1 Existing Associated Facilities. Plant site access is from State Highway 50, south from the intersection of State Highway 50 and the Alafaya Trail Extension, which is maintained by Orange County. This road also provides access to the Orange County Easterly Subregional Wastewater Treatment Plant, located approximately 4 road miles northwest of the plant site. The 30-inch cooling water makeup supply line from the wastewater treatment plant to the Stanton site is located within the site access road right-of-way. The locations of these existing facilities are shown on Figure 1A.2.1-1.

The railroad spur serving the plant site originates at a turnout from the CSX Transportation Railroad (CSXT) mainline approximately 1 mile west of the Orlando International Airport. The rail spur is approximately 18 miles in length from the CSXT turnout to the coal loop at the site. The location of the existing rail spur is shown on Figure 1A.2.1-1.

The four existing 230 kV transmission lines connecting the Stanton Substation to the OUC transmission system exit to the north within a transmission right-of-way corridor and continue to the east-west transmission right-of-way corridor between the Indian River Substation and the Pershing Substation. One line continues west to the Florida Power Corporation Rio Pinar tie. One line continues east to the Indian River Substation. The locations of these facilities and corresponding rights-of-way are shown on Figure 1A.2.1-1.

1A.2.1.16.2 New 230 kV Transmission Line and Alternate Site Access Road.

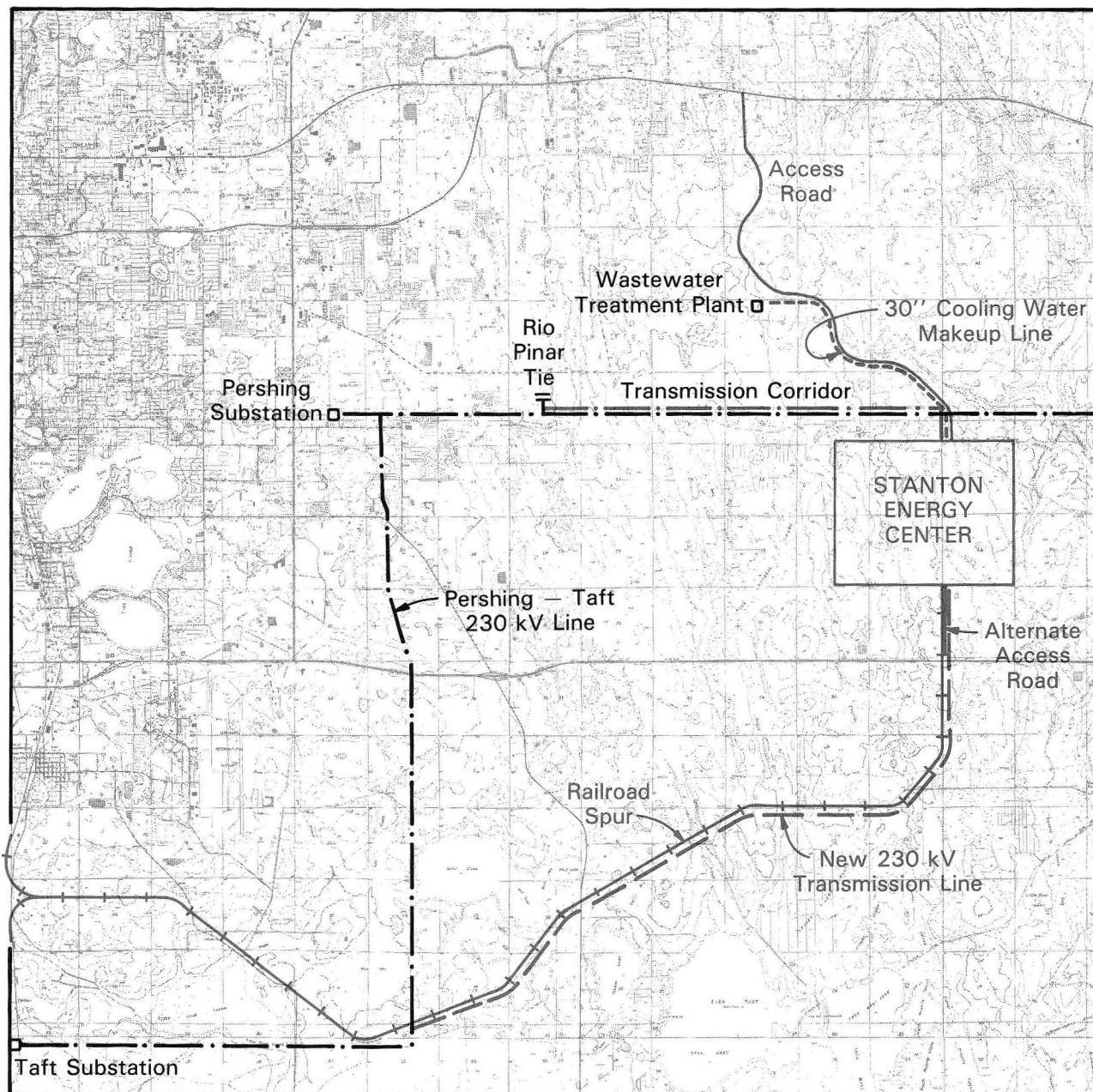
A new 230 kV transmission line segment will exit the site to the south and complete the connection of the Stanton Substation to the Taft Substation. The new line will be located within the existing certified railroad spur right-of-way and will extend from the Stanton site boundary to the intersection of the railroad spur right-of-way with the existing Pershing Substation to Taft Substation 230 kV transmission line right-of-way. The transmission line segment from this point to the Taft Substation will have already been constructed on existing structures within existing transmission right-of-way as part of a transmission line relocation project for Orlando Airport and is not included as part of the Stanton 2 project. The new 230 kV transmission line segment will be approximately 14 miles long and constructed with 954 MCM ACSR conductor supported on single-shaft, tubular steel structures. The new transmission line will not only provide additional

transmission capability, but will increase transmission system reliability by providing another transmission path to the system load centers that is not located within the Indian River-Pershing transmission corridor. The proposed routing of the new transmission line is shown on Figure 1A.2.1-1.

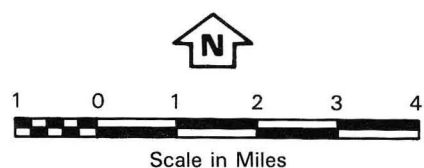
A new alternate site access road will exit the site to the south and connect with the Bee Line Highway. The new access road will be located within the existing certified railroad spur right-of-way between the existing rail spur and the new 230 kV transmission line and will extend from the Stanton site boundary to the existing Bee Line Highway interchange. The new access road will extend for approximately 1 mile into the railroad corridor. The proposed routing of the alternate access road is shown on Figure 1A.2.1-1.

1A.2.1.17 Provisions for Alternate Fuels

Like Stanton 1, Stanton 2 will be designed with space allocated to install burners and piping necessary for the future use of natural gas. The additional cost of actually installing equipment to burn natural gas is not justified at this time. Currently, the price of coal is significantly less than the price of natural gas or oil. Firm pipeline capacity for natural gas is currently not available and the present Florida Gas Transmission rate structure requires payment of a reservation fee for firm capacity even when natural gas is not consumed.



Stanton Energy Center associated facilities shown in red.



STANTON ENERGY CENTER ASSOCIATED FACILITIES

Figure 1A. 2.1-1

1A.2.2 Fuel Supply

The coal for Stanton 1 is currently obtained from Blue Diamond Coal Company and delivered to the Stanton Energy Center by CSX Transportation. The contract with CSX Transportation has provisions to allow for the transportation of coal for Stanton 2. Subsections 1A.3.3 and 1A.3.4 discuss the availability of coal and transportation in detail.

OUC plans to seek bids for coal for Stanton 2 in the 1993 to 1994 time frame depending on market conditions. OUC intends to obtain two firm contracts covering the majority of the coal requirements while also allowing for some spot market purchases. OUC intends to obtain flexibility in the amount of coal to be delivered for each of the firm contracts to enable OUC to optimize purchases as market conditions change. OUC intends to simultaneously sign coal supply and transportation contracts after completion of the negotiations.

OUC desires to contract for a low-sulfur coal for Stanton 2 similar to the low-sulfur coal currently being burned in Stanton 1. However, OUC is designing Stanton 2 to burn the same wide range of coals as can be burned in Stanton 1 and is proposing BACT emission levels which would allow medium sulfur coals to be burned. This flexibility to obtain medium sulfur coals will help OUC to negotiate the purchase of low-sulfur coal at a reasonable price.

1A.2.3 Capital Costs

1A.2.3.1 Plant Cost

The capital cost for Stanton 2 for commercial operation on January 1, 1997, is estimated to be \$522,000,000. Table 1A.2.3-1 presents the projected monthly cash flow requirements. This cost is based on replicating the Stanton 1 major equipment for Stanton 2. The effects on capital costs of replicating Stanton 1 major equipment for Stanton 2 are as follows.

- The number of spare parts required to be maintained in inventory can be reduced through duplicate equipment. While there will be a need to increase the number of some items of spare parts because of a two-unit demand, a complete set of duplicate spare parts is not required. This reduces capital as well as O&M costs.
- The initial training of operating and maintenance personnel will be reduced. While a limited number of new operators and maintenance personnel will require some training because of technical enhancements and upgrades, the existing personnel will already be familiar with these major items of equipment. This reduces the familiarity period and direct training expense in addition to early maintenance costs which are included in the capital cost of Stanton 2.
- Replicating major items of equipment will result in significant savings in both the design cost for the equipment, duplication in procurement of similar components, and the engineering cost of the buildings and associated facilities.

The decision to replicate Stanton 1 was based on a detailed planning study. The Curtis H. Stanton Energy Center Unit 2 Project Planning Study concluded that a total project savings of approximately \$15 million could be realized by replicating the major items of equipment and materials as compared to bidding different designs. In order to confirm this savings, OUC has been receiving proposals and negotiating contracts for the replicated equipment. The contracts contain cancellation clauses resulting in minimum financial risk to OUC if regulatory approval is not obtained and cancellation of Stanton 2 is required. On the basis of proposals received on the equipment being replicated, the savings due to replicated equipment will actually be approximately \$23 million.

There are numerous common facilities that Stanton 2 and Stanton 1 are sharing. Some of these facilities include the site access road; railroad; material handling system; makeup water supply pipeline and storage pond; water treatment; ash, scrubber sludge, and wastewater disposal; Site Security Building; Administration Building; Service Building; turbine room crane; emergency generator; fire protection; and coal cars. These common facilities costs were included in the capital cost of Stanton 1 and are not included in the capital cost of Stanton 2.

The estimated capital cost of Stanton 2 includes direct costs, indirect costs, escalation, and sales tax, and an appropriate amount for contingencies. Standard practices of estimating capital costs of coal fired power plants were used in developing the estimated capital cost of Stanton 2. Because Stanton 2 is a replicate of Stanton 1, the preliminary design has been established and decisions have been made regarding major plant and system parameters. Therefore, the estimate is more definitive than estimates normally developed at this stage of a project.

The estimate is developed on the basis of the firm lump sum contract basis that was used for Stanton 1. The detailed estimate for the 121 individual equipment and construction contracts is presented in Table 1A.2.3-2. Proposals have been received, and negotiations on the contract terms and cost have been initiated on the following equipment that is being replicated for Stanton 2. It is anticipated all pricing regarding these proposals will be established by April 1, 1991.

<u>Specification</u>	<u>Description</u>
61.1001	Concrete Chimney
61.4001	Structural Steel, Grating, and Coal Silos
62.0201	Particulate Removal Equipment
62.0202.1	Flue Gas Scrubber
62.0202.2	Sludge Conditioning Equipment
62.0401	Air Compressors
62.0601	Cooling Tower
62.1001	Turbine Generator
62.1801	Ash Handling System
62.2001	Boiler Feed Pump Turbine

<u>Specification</u>	<u>Description</u>
62.2602	Boiler Feed Pumps
62.2603	Circulating Water Pumps
62.3401	Steam Generator
65.0401	Condensate Polishing

The contracts for the above listed replicated equipment represent 30.7 percent of the Stanton 2 estimated cost.

In addition to the major equipment being replicated, preliminary proposals for the following Stanton 2 equipment have been received.

<u>Specification</u>	<u>Description</u>
61.2006	Duct Dampers
62.2615	General Service Pumps
62.3811	Forged Steel Valves
64.1401	Flue Gas Monitoring Equipment
65.0602	Water Quality Control System

The costs of the remaining contracts were estimated on the basis of the Stanton 1 final contract costs adjusted as required for the difference in quantity and scope. Adjustments have been included for costs due to escalation for the power generation industry including labor rates since Stanton 1 through the date of the Stanton 2 cost estimate. All current costs are based on a March 1, 1991, date. These prices are adjusted for escalation at 4.5 percent per year for the commercial operating date of January 1, 1997.

1A.2.3.2 Coal Pile

The space for the inactive coal pile for Stanton Energy Center is sized to store 400,000 tons, which is equal to approximately a 60-day supply for two units. In order to reduce carrying costs, OUC plans to minimize the use, and therefore the size, of the inactive storage pile except for times when there is potential for strikes or supply disruptions. In addition to reduced carrying charges, savings are also achieved through lowering coal handling costs. OUC plans to maintain a minimum supply of 15 to 20 days for Stanton 2 in active storage. A \$3.5 million cost for the active coal pile is assumed on the basis of 1996 projected coal costs. For

evaluation purposes, the carrying costs for this coal pile are added to the carrying costs for the plant costs.

1A.2.3.3 New 230 kV Transmission Line and Alternate Site Access Road

The capital cost for the new 230 kV transmission line from the Stanton Substation is \$9 million in 1991 dollars, as shown in Table 1A.2.3-3. The new 230 kV transmission line is an associated facility of Stanton 2, and will be fully owned by OUC as part of OUC's transmission system. The cost of the new 230 kV transmission line is therefore not part of the Stanton 2 project cost in Subsection 1A.2.3.1.

The alternate site access road is also an associated facility of Stanton 2. The capital cost for the alternate site access road is included in the Stanton 2 capital cost in Subsection 1A.2.3.1.

Table 1A.2.3-1
Projected Stanton 2 Cash Flow Requirements

Year	Month	Incremental	Cumulative
1990	January	0	0
1990	February	0	0
1990	March	0	0
1990	April	0	0
1990	May	98,550	98,550
1990	June	98,550	197,100
1990	July	98,550	295,650
1990	August	98,550	394,200
1990	September	98,550	492,750
1990	October	98,550	591,300
1990	November	98,550	689,850
1990	December	226,502	916,352
1991	January	249,975	1,166,327
1991	February	249,975	1,416,303
1991	March	249,975	1,666,278
1991	April	305,348	1,971,626
1991	May	389,385	2,361,012
1991	June	2,272,979	4,633,991
1991	July	526,067	5,160,058
1991	August	449,561	5,609,618
1991	September	554,341	6,163,959
1991	October	722,636	6,886,595
1991	November	1,028,992	7,915,587
1991	December	1,287,196	9,202,783
1992	January	10,938,190	20,140,972

Table 1A.2.3-1 (Continued)
Projected Stanton 2 Cash Flow Requirements

Year	Month	Incremental	Cumulative
1992	February	498,219	20,639,192
1992	March	500,050	21,139,242
1992	April	501,888	21,641,130
1992	May	503,732	22,144,862
1992	June	505,583	22,650,445
1992	July	561,525	23,211,970
1992	August	4,639,989	27,851,958
1992	September	511,178	28,363,136
1992	October	567,738	28,930,874
1992	November	5,104,512	34,035,386
1992	December	11,530,912	45,566,298
1993	January	5,376,993	50,943,291
1993	February	567,825	51,511,116
1993	March	1,932,724	53,443,841
1993	April	1,939,827	55,383,667
1993	May	2,659,648	58,043,315
1993	June	3,055,823	61,099,138
1993	July	12,253,583	73,352,720
1993	August	5,731,574	79,084,294
1993	September	5,786,504	84,870,798
1993	October	20,616,264	105,487,061
1993	November	5,250,782	110,737,843
1993	December	10,481,332	121,219,175

Table 1A.2.3-1 (Continued)
Projected Stanton 2 Cash Flow Requirements

Year	Month	Incremental	Cumulative
1994	January	5,169,841	126,389,016
1994	February	9,468,001	135,857,017
1994	March	7,947,687	143,804,704
1994	April	15,796,916	159,601,620
1994	May	10,921,101	170,522,721
1994	June	9,595,734	180,118,455
1994	July	12,252,413	192,370,868
1994	August	22,241,958	214,612,826
1994	September	22,835,493	237,448,319
1994	October	27,882,748	265,331,068
1994	November	21,176,826	286,507,893
1994	December	29,431,113	315,939,007
1995	January	16,890,035	332,829,042
1995	February	15,280,162	348,109,204
1995	March	11,904,483	360,013,687
1995	April	11,147,527	371,161,214
1995	May	9,688,786	380,850,000
1995	June	10,250,317	391,100,316
1995	July	10,183,737	401,284,053
1995	August	9,838,283	411,122,337
1995	September	9,519,631	420,641,968
1995	October	9,372,128	430,014,097
1995	November	9,613,804	439,627,901

Table 1A.2.3-1 (Continued)
Projected Stanton 2 Cash Flow Requirements

Year	Month	Incremental	Cumulative
1995	December	10,368,803	449,996,704
1996	January	8,654,648	458,651,352
1996	February	4,408,748	463,060,100
1996	March	4,166,558	467,226,658
1996	April	4,219,125	471,445,783
1996	May	3,586,738	475,032,521
1996	June	3,578,350	478,610,872
1996	July	3,341,562	481,952,434
1996	August	2,209,909	484,162,343
1996	September	3,823,289	487,985,633
1996	October	1,982,799	489,968,432
1996	November	2,132,877	492,101,309
1996	December	2,397,036	494,498,345
1997	January	27,501,655	522,000,000
1997	February	0	522,000,000

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.

Table 1A.2.3-2
Stanton 2 Detailed Capital Cost Estimate

Spec Number	Description	OUC Code	Replication Pricing Estimate 3/91 \$	1-1-97 Commercial Operation Dollar Total
61.0403	Bulk Materials Handling FUR	61002	867,200	1,026,593
	ERECT	61002	306,700	363,072
61.0405	Dust Collection Equipment	61003	385,000	455,764
61.0408	Coal Cars (297) reduced to (198)		13,086,000	14,988,177
61.0410	Pneumatic Material Handling	61007	29,700	35,159
61.1001	Chimney FUR	61008	2,134,600	2,536,230
	ERECT	61008	2,100,500	2,532,602
61.1201	Cranes & Hoists	61009	350,900	407,847
61.1601	Passenger Elevators FUR	61011	243,428	288,171
	ERECT	61011	121,659	144,020
61.1803	Metal Wall Panel FUR	61012	1,112,751	1,298,091
	ERECT	61012	473,327	552,164
61.2005	Duct Expansion Joints	61013	698,500	826,886
61.2006	Duct Dampers	61014	2,466,000	2,919,256
61.3801	Breeching and Ducts	61019	3,665,200	4,338,872
61.3802	Coal Silos	61020	W 61.4001	N/A
61.4001	Structural Steel-Major Fac.	61021	6,599,160	7,558,412
	FIRM PORTION	61021	12,493,243	14,500,840
61.4002	Str Stl-Coal Hnd,Yd	61022	W 61.4001	N/A
	Subtotal Structural Procurement		47,133,868	54,772,155
62.0201	Particulate Removal Equip FUR	61024	10,564,000	12,414,278
	ESC PORTION-ERECT	61024	5,053,000	6,070,165
	FIRM PORTION-ERECT	61024	2,828,394	3,477,000
62.0202	Flue Gas Scrubber FUR	61025	14,402,000	16,677,993
62.0203	Sludge Conditioner FUR	61026	1,780,316	2,115,287
	ERECT	61026	598,300	724,040
62.0401	Air Compressors	61027	154,000	181,638
62.0405	Carbon Dioxide Supply	61028	88,000	105,327
62.0601	Cooling Tower FUR	61029	6,832,705	7,970,759
	ERECT	61029	4,470,420	5,370,312
62.0801	Fire Protection Equip	61030	200,200	237,868
62.0805	Fire Suppression Systems FUR	61031	380,209	463,496
	ERECT	61031	252,788	302,562

Table 1A.2.3-2 (Continued)
Stanton 2 Detailed Capital Cost Estimate

Spec Number	Description	OUC Code	Replication Pricing Estimate 3/91 \$	1-1-97 Commercial Operation Dollar Total
62.1001	Turbine Generator FUR	61032	29,031,000	33,250,937
62.1201	Air Preheating Coils	61034	110,000	130,697
62.1202	Auxiliary Cooling Heat Exch.	61035	389,400	459,285
62.1203	Condenser and Auxiliary Equip	61036	1,760,000	2,075,863
62.1204	Condenser Tubes	61037	932,800	1,100,208
62.1205	Deaerator	61038	378,400	433,404
62.1206	Feedwater Heaters	61039	2,511,300	2,876,342
62.1211	Fuel Oil Heaters	61041	61,600	73,190
62.1801	Ash Handling System	61043	3,600,300	4,351,094
62.2001	Boiler Feed Pump Turbine	61044	1,605,500	1,859,222
62.2201	High-Pressure Fabricated Pipe	61045	5,017,100	5,895,842
62.2203	Ash Sluice Pipe	61046	133,100	159,308
62.2205	Circulating Water Pipe	61047	1,551,000	1,744,169
62.2403	Expansion Joints-Rubber	61049	34,100	40,814
62.2408	Pipe Supports	61050	588,500	691,575
62.2414	Steam Vent Silencers	61051	16,500	19,749
62.2602	Boiler Feed Pumps (Incl Startup)	61052	1,570,769	1,825,687
	FIRM PORTION	61052	150,261	206,524
62.2603	Circulating Water Pumps	61054	647,000	768,735
62.2604	Condensate Pumps	61055	638,000	749,745
62.2607	Fire Pumps	61056	40,700	46,959
62.2610	Oil Pumps	61057	33,000	39,209
62.2614	Vertical Water Pumps	61058	322,300	382,942
62.2615	General Service Pumps	61059	251,900	299,296
62.2802	Lube Oil Filters	61060	22,000	26,139
62.3001	Auto Flushing Type Water Str.	61061	55,000	65,348
62.3201	Air Conditioning Equipment	61062	51,700	61,427
62.3206	Ventilating Fans	61063	251,900	299,296
62.3401	Steam Generator FUR	61064	39,990,000	46,140,187
62.3402	Forced Draft Fans	61065	695,200	819,966
62.3403	Induced Draft Fans	61066	1,167,100	1,376,557
62.3601	Field Erected Tanks FUR	61068	189,146	220,650
	ERECT	61068	174,906	207,125
62.3602	Shop Fabricated Tanks	61069	212,300	250,401
62.3801	Butterfly Valves-Ext. Steam	61070	27,500	32,555

Table 1A.2.3-2 (Continued)
Stanton 2 Detailed Capital Cost Estimate

Spec Number	Description	OUC Code	Replication Pricing Estimate 3/91 \$	1-1-97 Commercial Operation Dollar Total
62.3802	Large Butterfly Valves	61071	386,100	457,066
62.3803	Butterfly Valves-General Serv.	61072	101,200	119,801
62.3804	Extraction Steam-Non-Return V1	61073	224,400	265,645
62.3805	H.P. Cast Steel & M.O. Valves	61074	1,909,600	2,260,589
62.3807	Cast Steel Gen. Serv. Valves	61075	541,200	640,674
62.3809	Control Valves-Gen Application	61077	304,700	360,705
62.3810	Control Valves-Spec. Application	61078	143,000	169,284
62.3811	Forged Steel Valves-Gen. Serv	61080	431,200	510,455
62.3813	Bronze Valves-General Service	61081	23,100	27,346
62.3815	Safety and Relief Valves	61082	67,100	79,433
62.3817	Knife Gate Valves	61161	82,500	97,664
62.3818	Butterfly Valves-Spec Svce	61166	91,300	108,081
62.3819	Slurry Plug Valves		<u>17,600</u>	<u>20,835</u>
	Subtotal Mechanical Procurement		146,138,683	170,208,747
63.0801	Overhead Conductor		8,800	10,494
63.0802	Control Cable	61086	871,200	1,038,922
63.0804	Instrument Cable	61086	372,900	444,690
63.0806	15 kV Power Cable	61088	724,900	854,996
63.0807	600 Volt Power Cable	61089	974,600	1,149,509
63.0808	Coaxial & Spec. Purpose Cable	61087	106,700	127,242
63.1201	Isolated Phase Bus	61091	376,200	443,716
63.2002	Electrical Panels	61092	292,600	346,381
63.2201	Motors	61093	1,711,600	2,026,196
63.2601	Cable Tray	61095	198,000	232,680
63.2801	Batteries and Battery Chargers	61096	205,700	241,728
63.2803	Continuous AC Power Equipment	61097	193,600	227,509
63.3001	Motor Control Centers	61098	476,300	561,781
63.3201	Trans. & Subst. Struc. & Mat.	61099	584,100	691,459
63.3401	Power Circuit Breakers	61101	550,000	651,091
63.3404	SCADA Equipment	61103	17,600	21,299
63.3407	Substation Control & Relay Pnl	61106	125,400	148,449
63.3409	Fiber Optic Equipment	61215	33,000	39,065

Table 1A.2.3-2 (Continued)
Stanton 2 Detailed Capital Cost Estimate

Spec Number	Description	OUC Code	Replication Pricing Estimate 3/91 \$	1-1-97 Commercial Operation Dollar Total
63.3601	Switchgear & Sec Unit Substations	61108	3,671,800	4,346,685
63.3801	Transformers	61110	<u>3,991,900</u>	<u>4,725,620</u>
	Subtotal Electrical Procurement		15,486,900	18,329,510
64.0202	Coord. Control & Info Computer	61111	2,400,000	2,862,045
64.0204	Programmable Controllers	61112	1,200,000	1,431,022
64.0401	Annunciation Equipment	61113	256,300	305,643
64.0404	Machinery Monitoring	61114	220,000	262,354
64.0602	Primary Flow Elements	61116	120,000	143,102
64.1401	Flue Gas Monitoring System I	61162	535,800	638,951
64.1601	Control Panels	61124	371,800	443,378
64.1602	Instrument Racks	61125	673,200	802,804
64.1603	Control Relay Cabinets	61126	<u>163,900</u>	<u>195,454</u>
	Subtotal Control Procurement		5,941,000	7,084,753
65.0202	Chemical Feed System	61127	133,100	157,564
65.0203	Chlorination Equipment	61128	66,000	78,131
65.0401	Condensate Polishing System	61129	1,457,000	1,724,800
65.0602	Water Quality Control System	61134	300,000	355,141
65.0801	Blowdown Treatment Eqpt FUR	61168	3,387,031	4,009,574
	ERECT	61168	<u>1,541,610</u>	<u>1,851,935</u>
	Subtotal Chemical Procurement		6,884,741	8,177,145
71.0401	Piling FUR	61144	4,076,075	4,500,428
	ERECT	61144	2,156,719	2,407,600
71.0402	General Constr. Substruct. FUR	61145	6,731,815	7,570,228
	ERECT	61145	8,222,027	9,348,345
71.0403	General Const.- Superstruct. FUR	61146	4,515,854	5,365,523
	ERECT	61146	9,402,530	11,336,760
71.0404	Painting FUR	61147	173,382	212,139
	ERECT	61147	1,065,945	1,338,142
71.0407	Concrete Supply	61150	330,299	385,314
71.0408	Construction Testing		1,189,100	1,418,024
71.0409	Ductwork Lining FUR	61167	618,833	743,404
	ERECT	61167	<u>604,867</u>	<u>726,626</u>
	Subtotal Structural Construction		39,087,446	45,352,532

Table 1A.2.3-2 (Continued)
Stanton 2 Detailed Capital Cost Estimate

Spec Number	Description	OUC Code	Replication Pricing Estimate 3/91 \$	1-1-97 Commercial Operation Dollar Total
72.0202	Heating, Vent & Air Cond FUR	61152	1,018,636	1,228,183
	ERECT	61152	666,424	818,389
72.0401	Mechanical Construction FUR	61153	5,677,445	6,845,374
	ERECT	61153	54,510,917	67,187,096
72.0403	Piping and Equip. Insultn FUR	61154	977,340	1,209,041
	ERECT	61154	861,447	1,081,424
72.0601	Flue Gas Cln For Test		<u>107,800</u>	<u>138,339</u>
	Subtotal Mechanical Construction		63,820,009	78,507,847
73.0201	Electrical Construction FUR	61155	4,202,043	5,066,461
	ERECT	61155	6,059,492	7,551,229
73.0204	T-Line & Subst. Construct. FUR	61156	456,092	547,903
	ERECT	61156	629,061	766,860
74.0400	Elec. Test & Calibration	61157	<u>2,015,774</u>	<u>2,521,252</u>
	Subtotal Elect/Cont Construction		13,362,462	16,453,706
75.0100	Boiler and Preblr Clnng	61158	176,604	224,154
75.0200	Special Protective Coatings	61159	63,043	75,180
76.0100	Site Services	61160	<u>2,076,991</u>	<u>2,476,850</u>
	Subtotal Service Construction		2,316,638	2,776,185
90.1001	OUC Indirects			
	Startup Bunker Coal	61163	553,449	694,776
	Startup Diesel Oil	61165	119,999	150,642
	Administrative Costs	61201	2,750,000	3,161,314
	Pre-operations & Maint	61204	7,700,000	9,666,255
	Construction Management	61206	2,750,000	3,267,419
	Insurance-General	61208	3,000,000	3,448,706
	Insurance-Workmen's Comp.	61208	20,000,000	23,763,047
	Special Projects	61210	330,000	390,655
	Field Security and First Aid		2,243,650	2,656,038
	Training		87,975	104,145
	Project Spare Parts		2,200,000	2,604,365
	Net Of Power Sales		<u>(4,400,000)</u>	<u>(5,247,082)</u>
	Subtotal OUC Indirects		37,335,073	44,660,278

Table 1A.2.3-2 (Continued) Stanton 2 Detailed Capital Cost Estimate				
Spec Number	Description	OUC Code	Replication Pricing Estimate 3/91 \$	1-1-97 Commercial Operation Dollar Total
90.1100	B&V Engineering Services	61203	21,725,000	23,898,928
90.1150	B&V Need For Power	61203	450,000	451,654
90.1300	B&V Construction Mgmt. Service	61207	13,557,000	17,692,787
90.2000	Project Contingency		27,500,000	33,214,007
90.4000	Sales Tax		<u>352,000</u>	<u>419,767</u>
			<u>63,584,000</u>	<u>75,677,142</u>
	TOTAL		441,090,820	522,000,000

Table 1A.2.3-3
Estimated Capital Cost 230 kV 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*		1,858,175
Estimated Total Cost		9,000,000
Total Length	14.0 miles	
Estimated Per Mile Cost		642,855
*Orlando Utilities Commission costs for surveying, engineering, legal, and soil investigation.		

1A.2.4 O&M Cost

1A.2.4.1 Fixed O&M Cost

Fixed O&M costs for Stanton 1 and 2 for 1990 are presented in Table 1A.2.4-1. The Stanton 1 fixed O&M costs are based on OUC's actual budget for 1990. The Stanton 2 fixed O&M costs are based on the following assumptions relative to Stanton 1 costs.

- Stanton 2 will require 85 additional personnel which, combined with the existing 162 personnel for Stanton 1, will result in 247 personnel at Stanton Energy Center.
- The above numbers of personnel include 60 mechanics for Stanton 1 and 37 mechanics for Stanton 2.
- Maintenance material costs are highly correlated to maintenance man-hours and represent \$28.44 per maintenance man-hour. A total of 1,878 maintenance man-hours are assumed per mechanic per year.
- Annual burdened labor costs are assumed to be \$43,333 per person.
- Administrative and general costs for Stanton 2 are assumed to be 52 percent of Stanton 1.
- One D-9 bulldozer is assumed to be added for Stanton 2 with a flat rate charge of \$40,800 per year.
- The cost of chemicals for Stanton 2 is assumed to equal the cost of chemicals for Stanton 1.
- General operations costs for Stanton 2 are assumed to be 52 percent of Stanton 1.
- It is assumed that there will be no additional costs for Stanton 2 for outside computer services for maintenance.
- General maintenance costs for Stanton 2 are assumed to be 52 percent of Stanton 1.
- Brine plant costs for Stanton 2 are assumed to be 52 percent of Stanton 1.
- CSI costs for scrubber sludge disposal for Stanton 2 are estimated to be 52 percent of Stanton 1 costs.

In addition to the fixed O&M shown in Table 1A.2.4-1, capital additions to Stanton 1 are estimated to be \$1,200,000 in 1998 and thereafter, in 1998 dollars. Capital additions for Stanton 2 are assumed to be \$800,000 in 1997 and

\$1,200,000 in 1998 and thereafter, in 1998 dollars. The lower capital additions for Stanton 2 in 1997 result from manufacturer's warranties associated with Stanton 2's construction. For evaluation purposes, these capital additions are included as fixed O&M. Fixed O&M costs are assumed to escalate at the O&M escalation rates shown in Table 1A.3.2-1. The projected fixed O&M costs are shown in Table 1A.2.4-2 for the evaluation period.

1A.2.4.2 Variable O&M Cost

Variable O&M costs for Stanton 1 and 2 other than fuel are assumed to consist of lime and limestone costs. The 1990 budget lime and limestone costs for Stanton 1 were \$0.183/MWh. Escalating the 1990 variable O&M costs to 1997 at the O&M escalation rates from Table 1A.3.2-1 for the most likely scenario results in a variable O&M cost for Stanton 1 and 2 of \$0.254/MWh in 1997. Table 1A.2.4-3 presents the projected variable O&M costs for Stanton Energy Center.

Table 1A.2.4-1
Stanton Energy Center Fixed O&M Costs (1990\$)

Item	Stanton 1	Stanton 2	Total
Maintenance Material	3,205,877	1,976,484	5,182,361
Labor Costs	7,344,000	3,853,333	11,197,333
Administrative and General Costs	499,188	259,578	758,766
Operations Costs			
Vehicles	452,836	40,800	493,636
Chemicals	173,040	173,040	346,080
General	36,212	18,830	55,042
Maintenance Costs			
Outside Services-Computer	49,000	0	49,000
General Costs	2,653,550	1,379,846	4,033,396
Brine Plant Costs	85,132	44,269	129,401
CSI Costs	890,000	462,800	1,352,800
Insurance	<u>400,000</u>	<u>500,000</u>	<u>900,000</u>
Total	15,788,835	8,708,980	24,497,815

Table 1A.2.4-2
Stanton Energy Center Fixed O&M Costs Excluding Fuel
Most Likely Scenario (\$/kW/yr)

Year	Stanton 1	Stanton 2	Both Units
1997	52.33	29.26	40.80
1998	54.81	31.47	43.15
1999	57.41	32.96	45.20
2000	60.14	34.53	47.35
2001	63.00	36.17	49.60
2002	65.99	37.89	51.95
2003	69.13	39.69	54.42
2004	72.41	41.57	57.01
2005	75.85	43.55	59.72
2006	79.45	45.62	62.55
2007	83.22	47.78	65.52
2008	87.18	50.05	68.64
2009	91.32	52.43	71.90
2010	95.66	54.92	75.31
2011	100.20	57.53	78.89
2012	104.96	60.26	82.64
2013	109.95	63.13	86.56
2014	115.17	66.12	90.67
2015	120.64	69.26	94.98
2016	126.37	72.56	99.49
2017	132.37	76.00	104.22
2018	138.66	79.61	109.17
2019	145.25	83.39	114.35
2020	152.14	87.35	119.78

Table 1A.2.4-3
Stanton Energy Center Variable O&M Costs Most Likely
Scenario (\$/MWh)

Year	Stanton 1	Stanton 2	Both Units
1997	0.254	0.254	0.254
1998	0.266	0.266	0.266
1999	0.279	0.279	0.279
2000	0.292	0.292	0.292
2001	0.306	0.306	0.306
2002	0.320	0.320	0.320
2003	0.336	0.336	0.336
2004	0.351	0.351	0.351
2005	0.368	0.368	0.368
2006	0.386	0.386	0.386
2007	0.404	0.404	0.404
2008	0.423	0.423	0.423
2009	0.443	0.443	0.443
2010	0.464	0.464	0.464
2011	0.486	0.486	0.486
2012	0.510	0.510	0.510
2013	0.534	0.534	0.534
2014	0.559	0.559	0.559
2015	0.586	0.586	0.586
2016	0.613	0.613	0.613
2017	0.643	0.643	0.643
2018	0.673	0.673	0.673
2019	0.705	0.705	0.705
2020	0.739	0.739	0.739

1A.2.5 Heat Rate

The estimated average net heat rate for Stanton Energy Center Unit 2 is as follows.

<u>Net Load</u>		<u>Net Heat Rate</u>
MW	Percent	Btu/kWh
440	100	9,740
330	75	9,640
220	50	10,310

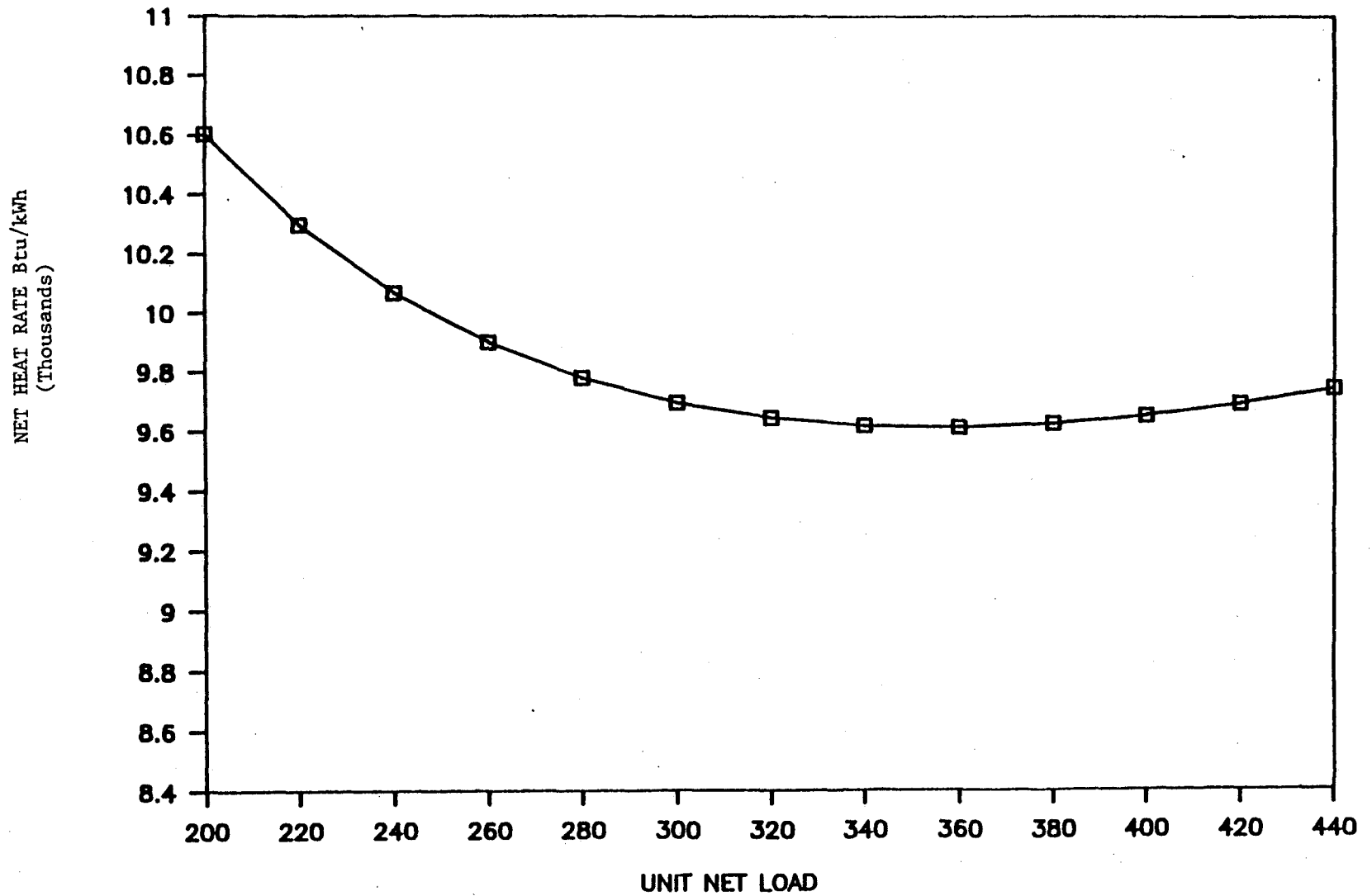
The data presented for the respective loads were derived from actual data recorded during performance tests of Stanton Energy Center Unit 1. The heat rate curve provided in Figure 1A.2.5-1 was also developed from performance tests of Stanton 1. Since the major equipment from Stanton 1 is being replicated for Stanton 2, it is expected that Stanton 2 will meet, if not surpass, the performance of Stanton 1.

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1A.2.5-2

STANTON

NET HEAT RATE vs. NET LOAD



NET HEAT RATE VS NET LOAD

Figure 1A.2.5-1

1A.2.6 Availability

The major equipment of Stanton 1 is being replicated for Stanton 2. One of the major incentives for replicating the Stanton 1 equipment is the reliability demonstrated by Stanton 1. The equivalent availability of Stanton 1 for the first three years of operation was 84.54 percent, and the equivalent forced outage rate was 4.76 percent. Stanton 2 is being designed on the basis that it will achieve an equivalent availability of 83 percent with an equivalent forced outage rate of 4 percent. Maintenance outages are assumed to be three weeks each in the spring and the fall, with every third spring maintenance outage increased to six weeks for a turbine inspection and overhaul.

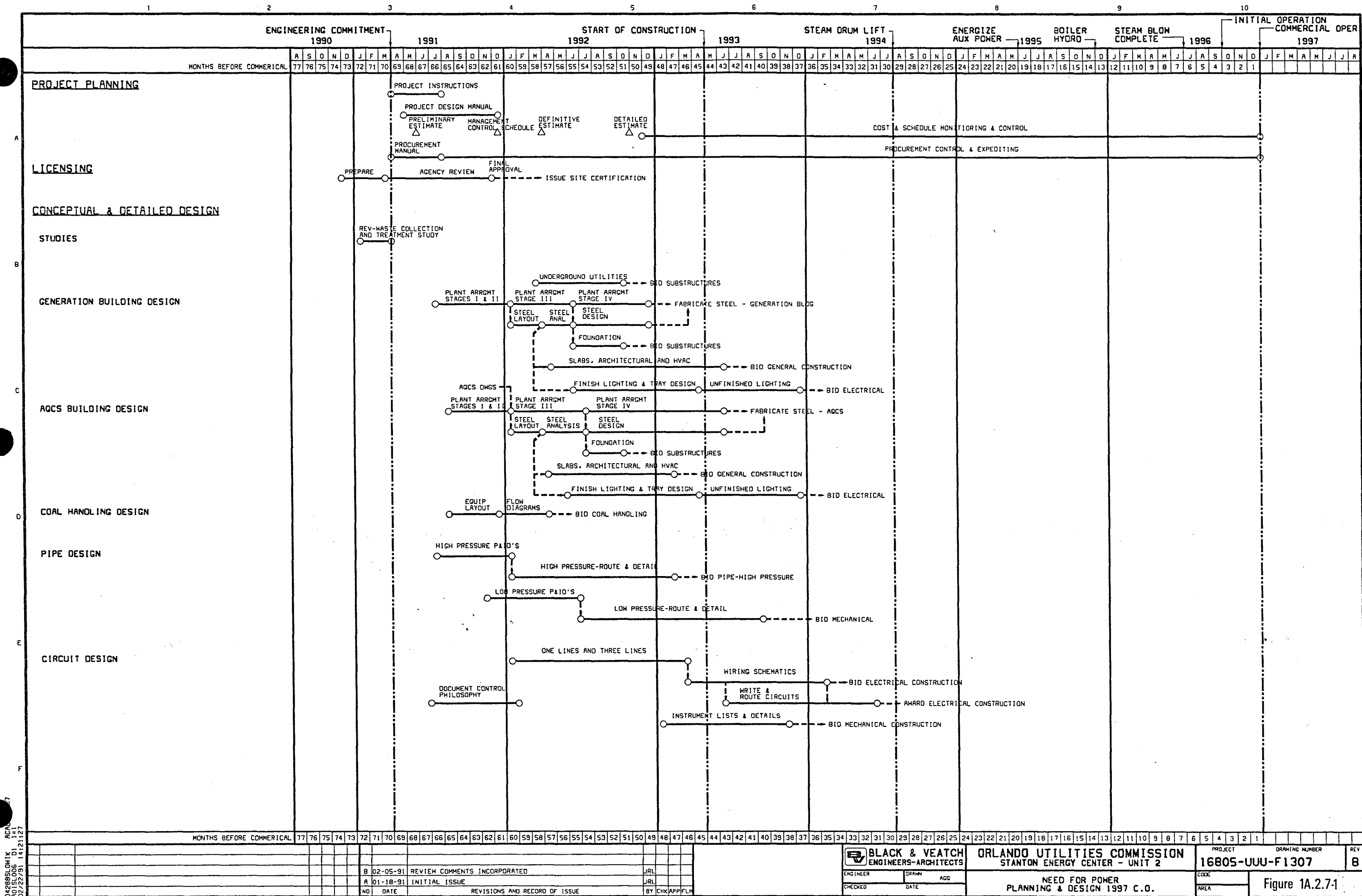
1A.2.7 Schedule

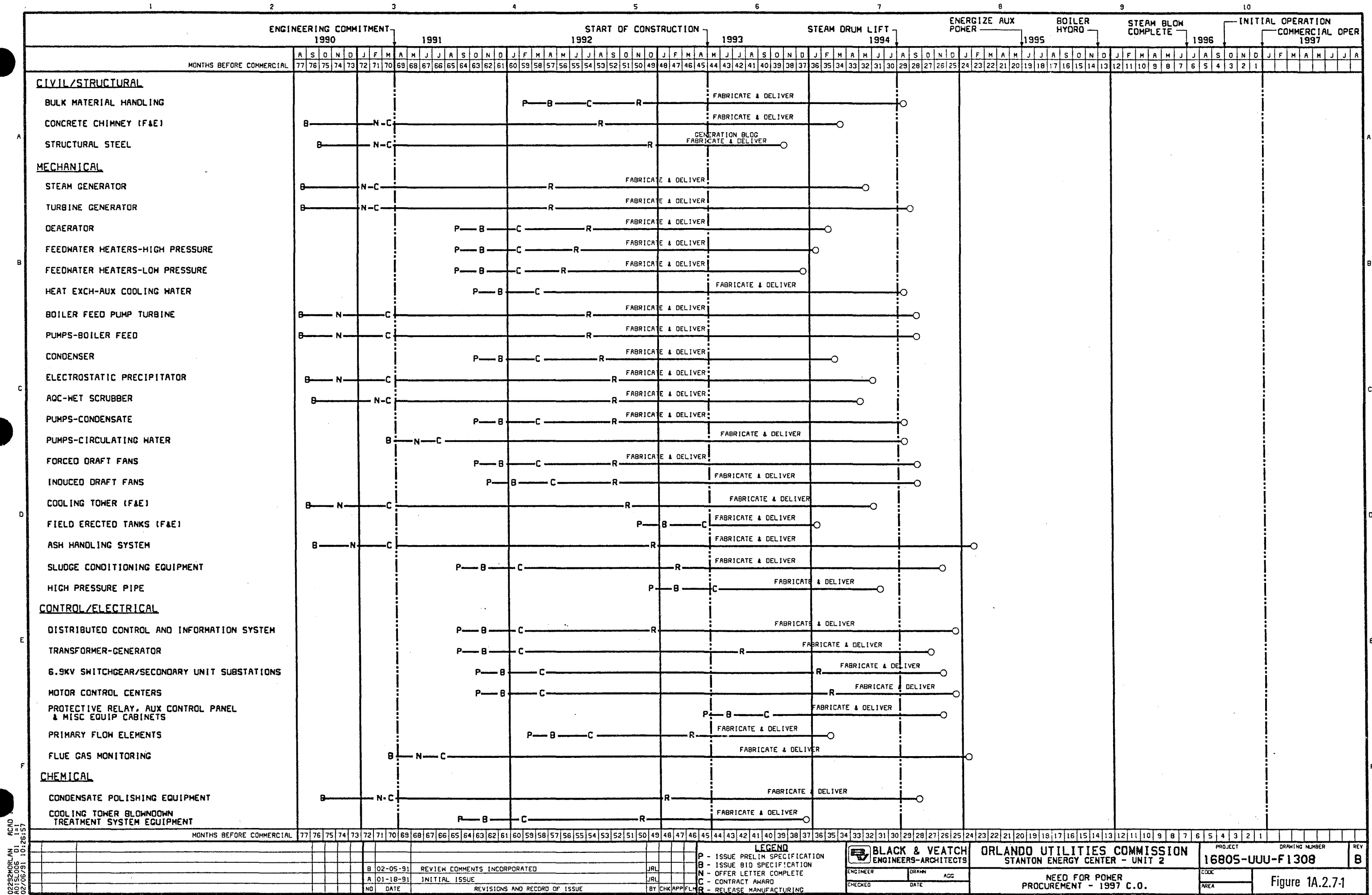
The schedule for Stanton 2 is based on a 44-month construction period. Engineering would start 25 months before the start of construction to complete the design in advance of construction. With engineering well underway, there would be few unknowns during construction and there would be sufficient time to give consideration to a smaller number of construction contractors. To meet a January 1, 1997, commercial operation date, construction would start May 1, 1993, and engineering would start April 1, 1991.

The 44-month period for construction starts with eight months of foundation construction for the generator building complex. Foundation construction is followed by seven months of steel erection for the building, followed by boiler erection. Boiler erection is a major critical path item. Sixteen months after the start of boiler erection, the boiler should be ready to be hydro tested. This 16-month period is also used to erect the other major mechanical equipment, mechanical piping, and electrical equipment. Boiler hydro testing is followed by 10 months of other plant systems testing before initial operation. Commercial operation is expected to follow initial operation by three months.

The 25-month period for engineering before construction starts includes the time required to procure major equipment and to complete the detailed foundation design. Ten months of procurement is followed by 10 months of detailed design. Five months is allowed to bid, evaluate, and award the first construction package so that foundation construction can be initiated.

This project schedule is based on reasonable durations and a logical, efficient approach to the project. This approach will support completing the project on time with minimum total cost. The detailed schedule is presented in Figure 1A.2.7-1.





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LEGEND

- P - ISSUE PRELIM SPECIFICATION
- B - ISSUE BID SPECIFICATION
- N - OFFER LETTER COMPLETE
- C - CONTRACT AWARD
- R - RELEASE MANUFACTURING

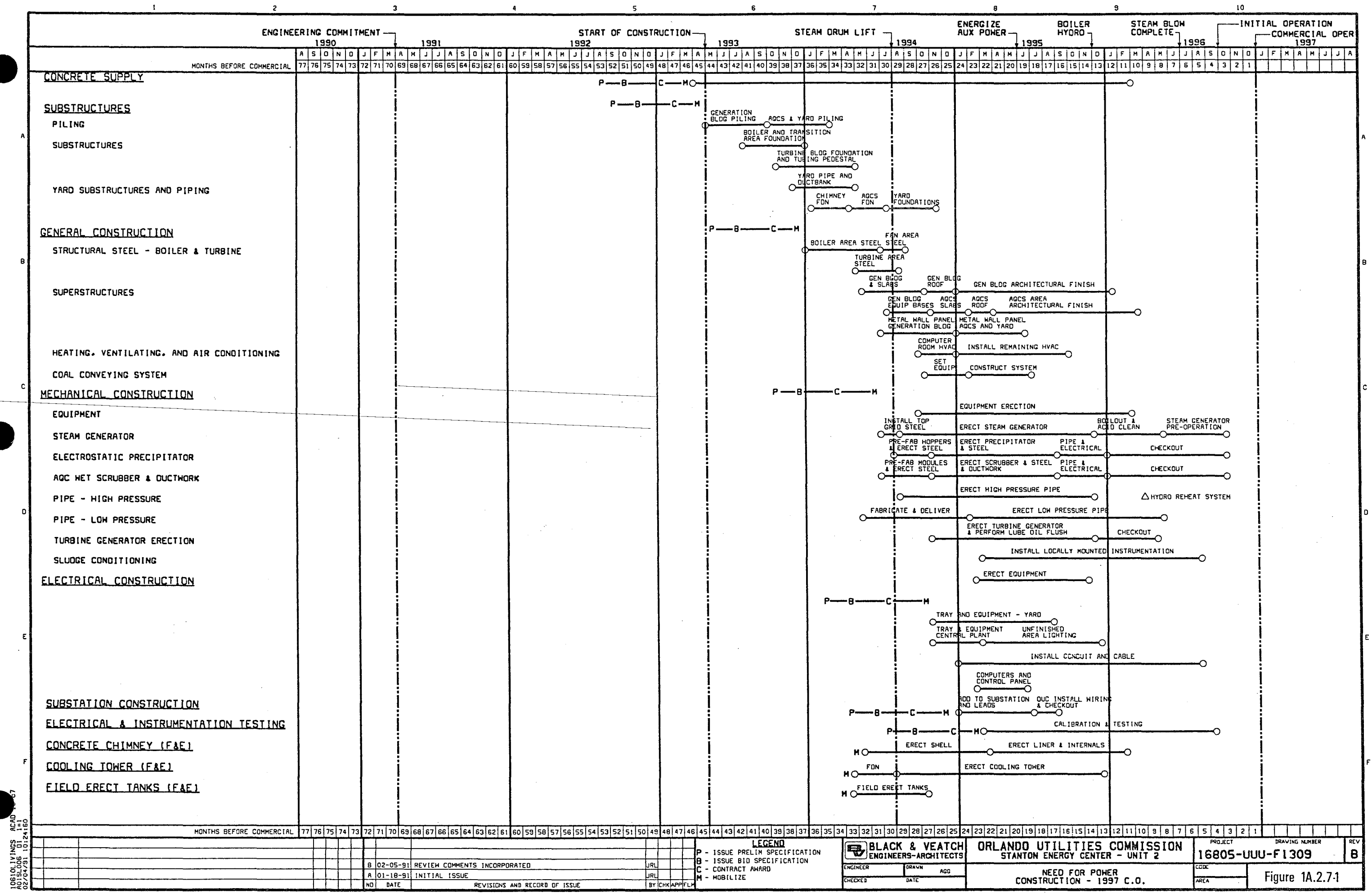
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ENGINEERS-ARCHITECTS

ENGINEER: [] DRAWN: [] AGG: []
CHECKED: [] DATE: []

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 2

PROJECT: 16805-UUU-F1308
DRAWING NUMBER: 1A.2.7-1
REV: B

NEED FOR POWER
PROCUREMENT - 1997 C.O.



1A.2.7-4

1A.2.8 Stanton 1 Performance

Since much of the major equipment used in Stanton 1 will also be used in Stanton 2, the performance of Stanton 1 provides a good indication of how well Stanton 2 will perform. The following subsections contain a description of the Stanton 1 performance.

In order to gain a perspective on how well Stanton 1 has performed in its first three years of operation, comparisons to similar utility plants and industry averages have been made. These comparisons are based on operation and maintenance and reliability performance data. In addition, the ability to complete construction of Stanton 1 within the scheduled time frame and under the projected budget are key issues that are considered in the following description of Stanton 1 performance.

1A.2.8.1 Operation and Maintenance

The operation and maintenance (O&M) performance of Stanton 1 is compared to single coal fired units, with scrubbers installed, and with a capacity of 400 to 499 MW. An average of the total nonfuel O&M costs for the units falling within this category are listed in the table below. The O&M cost on a dollars per MWh basis compare favorably in all three years, demonstrating that the design of Stanton 1 and the management by OUC result in O&M costs less than the average for comparable units.

	<u>Stanton 1</u> \$/MWh	<u>Comparable Plants</u> \$/MWh
1987	4.41	4.54
1988	4.46	4.52
1989	4.92	4.95

1A.2.8.2 Reliability

In its first three years of operation, Stanton 1 has compared very favorably to other utilities with respect to the reliability of the unit. This comparison is based on major industry developed and accepted criteria for assessing operating performance for large electric generating units. These criteria are contained in the North American Electric Reliability Council's (NERC) Generating Availability

Data System. The following table summarizes the comparison of Stanton 1 reliability performance with industry averages based on the Generating Availability Data System information for a 400 to 499 MW coal fired unit.

	<u>Equivalent Forced Outage Rate</u>		<u>Equivalent Availability Rate</u>	
	<u>Stanton 1</u>	<u>Percent Industry Average^a</u>	<u>Stanton 1</u>	<u>Percent Industry Average^a</u>
Fiscal 1988	1.8	8.81	88.49	78.55
Fiscal 1989	3.49	8.80	86.64	79.31
Fiscal 1990	<u>9.65</u>	<u>^b</u>	<u>70.28</u>	<u>^b</u>
Average ^c	4.76	9.47 ^c	84.54	78.35 ^d

For the fiscal 1988 and 1989 periods, Stanton 1 had a 10 percent and 7 percent higher availability rate, respectively, than the industry average. In 1988, the Stanton 1 equivalent forced outage rate of 1.8 percent indicates that, on the average, other utilities operating similar units experience roughly five hours of forced outages or forced load capacity reductions for every one hour of forced outage at Stanton 1.

The rates for the 1989 fiscal period again reflect a significant advantage in performance by Stanton 1. Although the equivalent forced outage rate increased, it is significant to note that a single turbine-related malfunction was responsible for roughly half of the forced outage hours. The malfunction was due to a throttle valve stem binding. The problem was subsequently alleviated by implementing a revised, more frequent, maintenance schedule. Despite the malfunction, the unit performance was still significantly better than the industry average.

Largely as a result of a planned turbine overhaul that was extended an additional five weeks, the 1990 period numbers have dropped off somewhat. Inspections during the overhaul revealed damage to turbine components. The damage included cracks in the HP inlet sleeve, nozzle chamber, and nozzle block. After extensive investigation,

^aIndustry averages are based on calendar year.

^bData not yet available.

^cBecause of NERC availability definitions, averages are not simply numerical averages of individual years.

^dFive-year average from the NERC Generating Availability Report 1985-1989.

Westinghouse has diagnosed the probable cause of these cracks. The primary cause of the cracks was uneven heating across the components. Westinghouse has enhanced the design of these components which will be installed during the next turbine overhaul. Both Stanton 1 and Stanton 2 will be equipped with the improved components. A similar fix has been performed on other Westinghouse units of this type and proved to correct the problem.

In addition, Westinghouse has limited operation at lower loads to the single valve mode of operation. This allows steam to flow to the control stage through all the nozzle chambers (full ARC admission) which allows all of the nozzle chambers to heat and expand evenly.

As a result of the overhaul and subsequent damage repairs, the unit was unavailable for service for 83 days. Similar to 1989, it is important to notice that nearly all of the forced outage hours were a result of the turbine overhaul that was significantly extended by an irregular occurrence. Otherwise, the performance would have been comparable to the previous two fiscal periods.

The aggregate of the first three fiscal periods shows steady performance which, on an annual basis, exceeds that of similar units in North America. The equivalent availability of Unit 1 for the three-year period was 84.54 percent, and the equivalent forced outage rate was 4.76 percent.

As stated above, Stanton 2 will replicate much of the major equipment used for Stanton 1. Therefore, it is expected that the level of reliability achieved by Stanton 1 will also be achieved or exceeded by Stanton 2.

1A.2.8.3 Schedule

The planned construction period for Stanton 1 was 50 months. This period was based on the number of months between the start of construction and the commercial operation of the plant. Construction was completed in 45 months, 5 months under the planned schedule. Based on reasonable durations and a logical efficient approach to the project, the schedule for Stanton 2 is a 44-month construction period. The construction period has been reduced by 1 month as a result of reduced site preparation time. Given the reduced site preparation time and the successful completion of Stanton 1 in 45 months, it is expected that Stanton 2 will also be completed within the scheduled time frame.

1A.2.8.4 Budget

With a projected budget of \$546 million and completed capital costs of approximately \$536 million, Stanton 1 was completed \$10 million under budget. The Stanton 1 capital cost included direct cost of land, sitework, buildings, and equipment. Indirect costs such as project management, engineering, and startup cost were also included. After escalation of the Stanton 1 capital costs to 1997 dollars, a substantial savings is realized in the \$522 million cost of Stanton 2. As mentioned in Subsection 1A.2.3, these savings are largely a result of Stanton 2 being designed as a second unit under the concept that the Stanton 1 major equipment will be replicated for Stanton 2 and common facilities constructed as part of Stanton 1. Consequently, vendor engineering is reduced, quantities are known, many of the special tools used in maintenance and erection are already purchased, and manufacturer administration is reduced.

1A.3.0 Evaluation Criteria

1A.3.1 Scenario Description

The need for power is evaluated on the basis of criteria provided by "Long Term Economic Forecasts 1990 to 2021," prepared by Fishkind & Associates, Inc., November 26, 1990. Three projected scenarios are provided: (1) most likely growth, (2) high growth, and (3) low growth. These three forecasts are designed to bracket the future behavior of the economy and to provide a consistent set of forecasts as a basis for evaluating the need for Stanton 2.

A supply side view of economic growth forms the basis of the long-term US economic forecasts for the 1990 through 2020 planning horizon. During this period, the growth rate of the US economy will be limited by three key supply-side variables: (1) growth in the labor force, (2) changes in the number of hours worked per employee, and (3) productivity. Over the last 20 years, growth in the real gross national product (GNP) of the US was 2.7 percent per year. This level of economic growth was the result of an expansion in productivity of 1.3 percent per year, an increase in the labor force of 2.0 percent per year, and a decline in hours worked per employee of 0.6 percent per year. Forecasts of the US economy for the 1990 to 2020 period are dependent upon projections of the key supply-side variables for each of the three economic scenarios.

The three scenarios which are used as the basis for evaluating the need for power are summarized in the following paragraphs

1A.3.1.1 Most Likely Growth Forecast

The most likely growth forecast for the US economy is characterized by a 1.5 percent per year growth in the labor force and a 1.5 percent per year increase in productivity. The 1.5 percent per year increase in the labor force is less than the average 2.0 percent rate experienced in the last 20 years. This rate of growth reflects a decreasing rate of women entering the labor force as well as an aging population. The 1.5 percent per year increase in productivity is more than the 1.3 percent rate experienced in the last 20 years. This rate of growth will be required to compensate for a declining young population and available labor pool. On the basis of these key variables, the growth of real GNP is forecast at 3 percent per year, general inflation is forecast at 4 percent per year, the real

interest rate on federal funds is forecast at 4 percent per year, and the real interest rate on long-term bonds is forecast at 5 percent per year.

1A.3.1.2 High Growth Forecast

The high growth forecast for the US economy is characterized by a 2.25 percent per year growth in the labor force and a 1.75 percent per year increase in productivity. These growth rates represent a high growth view for the US economy when compared to the average growth rates experienced since 1970. On the basis of these key variables, the growth of real GNP is forecast at 4 percent per year, general inflation is forecast at 2.5 percent per year, the real interest rate on federal funds is forecast at 3 percent per year, and the real interest rate on long-term bonds is forecast at 4 percent per year.

1A.3.1.3 Low Growth Forecast

The low growth forecast for the US economy is characterized by a 1.0 percent per year growth in the labor force and a 1.0 percent per year increase in productivity. These growth rates represent a low growth view for the US economy when compared to the average growth rates experienced since 1970. On the basis of these key variables, the growth of real GNP is forecast at 2 percent per year, general inflation is forecast at 5.5 percent per year, the real interest rate on federal funds is forecast at 5 percent per year, and the real interest rate on long-term bonds is forecast at 6.5 percent per year.

1A.3.2 Economic Parameters

Table 1A.3.2-1 summarizes the pertinent economic projections that are common to all participants. The GNP deflator is generally considered to be the best measure of the decreasing value of the dollar and was selected for use as the inflation rate. The selection of the capital cost escalation rate was based on Black & Veatch's perceptions of the market conditions for power plant construction consistent with Fishkind's projections for the GNP deflator and producer price index. The O&M cost escalation rate is based on Fishkind's projections of changes in the average compensation per man-hour. The bond rate was selected for use as the present worth discount rate.

Table 1A.3.2-1
Economic Parameter Projections

Projection	Year	Most Likely (percent)	High Growth (percent)	Low Growth (percent)
Inflation Rate	1991	4.50	4.50	4.50
	1992-20	4.00	2.50	5.50
Capital Cost Escalation Rate	1991-20	4.50	3.00	6.00
O&M Escalation Rate	1991	5.30	5.30	5.30
	1992	4.39	2.93	5.85
	1993-20	4.75	3.25	6.25
AAA Municipal Bond Rate	1991	6.91	6.91	6.91
	1992	7.28	5.06	9.48
	1993-20	7.03	5.06	9.48

1A.3.3 Fuel Price Projections

Forecasts of nuclear and fossil fuels that are likely to be used for generating electricity were developed for the period 1990 to 2020. The forecasts are in real, or constant, 1989 dollars and in nominal dollars using the general inflation rates specified in Subsection 1A.3.2. The following discusses the basis of the price forecasts for coal, oil, natural gas, and nuclear fuels.

Numerous forecasts could be chosen for price projections. For evaluation purposes, the 1990 Annual Energy Outlook by the Energy Information Administration (EIA) has been chosen because it is a recent forecast and it compares favorably with other forecasts. EIA provides a comparison of their current forecast with other major forecasting firms such as DRI/McGraw-Hill, the WEFA Group, Gas Research Institute, and the American Gas Association. A comparison of fossil fuel forecasts from these other forecasters for the year 2010 and the EIA forecast is shown in Table 1A.3.3-1. The forecasts are similar; therefore, the EIA forecast should be representative of what the major forecasters predict for the future price of fossil fuels.

As in any forecast, uncertainties are present; therefore, the 1990 Annual Energy Outlook provides a base case and four other cases to account for these uncertainties. The four cases are low oil price, high oil price, low growth, and high growth, and are based on upper and lower bounds for world oil prices and the rate of economic growth, the key factors affecting energy use and price trends. To provide fuel price projections for most likely, high, and low growth scenarios, the base, low oil price, and high oil price scenarios developed by the EIA were used. High and low oil price scenarios are used instead of the low and high growth scenarios because they represent the highest and lowest price forecasts for oil. The 1990 Annual Energy Outlook forecasts fuel prices to the year 2010. To project fuel prices to the year 2020, the average annual escalation rate from 2005 to 2010 was assumed to continue until the year 2020.

The most likely fuel cost projections based on the 1990 Annual Energy Outlook base case are shown in Tables 1A.3.3-2 and 1A.3.3-3 in 1989 constant dollars and nominal dollars, respectively. The nominal prices shown in Table 1A.3.3-3 are based on applying the projected most likely GNP deflator escalation rates in Subsection 1A.3.2 to the 1989 constant dollar prices shown in Table 1A.3.3-2. Table 1A.3.3-4 indicates the low, average, and high 1990 actual costs for OUC along with the 1990 forecasted price from Table 1A.3.3-3. The extreme

volatility of gas and oil prices within a single year points out the difficulty of determining an appropriate starting point for fuel price projections. Because of this large volatility and the fact that transportation costs represent a small portion of the delivered cost for gas and oil, the 1990 Annual Energy Outlook forecasts for the delivered cost of gas and oil are used directly without adjustment since they have been developed to be internally consistent. The following sections discuss the development of the forecast for each fuel.

1A.3.3.1 Coal

The coal being burned in Stanton 1 and McIntosh 3 is being purchased under long-term contracts. The contract for Stanton 1 is with the Blue Diamond Coal Company and is a requirements contract until July 1992. After July 1992, OUC can purchase a minimum of 600,000 tons per year and a maximum of 950,000 tons per year. The actual amount purchased in a given year will be based on the amount nominated by OUC. On an annual basis, OUC can increase or decrease the amount nominated by 75,000 tons over that nominated the previous year. The contract extends to 1997 with two additional five-year extensions at OUC's sole discretion. The contract for McIntosh 3 is a requirements contract. The contract expires in December 1991. OUC's coal contract is for a higher quality coal with significantly lower sulfur content than OUC is permitted to burn and as a result is more expensive than the least expensive coal that could be burned. OUC contracted for this coal to improve unit operation and reliability as well as to reduce SO₂ emissions. On an as-burned basis, the higher quality low-sulfur coal results in lower costs for scrubber additive and waste disposal, which offsets at least a portion of the lower cost of the higher sulfur coal. In addition, the higher quality low-sulfur coal results in higher unit availability, which further offsets the lower cost of the higher sulfur coal. The actual cost and quality of all the coal burned at Stanton 1 and McIntosh 3 during 1989 are shown in Table 1A.3.3-5.

The actual prices paid for Stanton 1 and McIntosh 3 coal are significantly above the average US price for 1989 of \$1.46/MBtu from the 1990 Annual Energy Outlook. Part of the difference is accounted for by the higher quality of coal, but other factors contribute to the higher cost of coal for units in Florida. One of the factors is the higher cost of coal transportation to Florida. Another factor is the large amount of low cost western coal in the US average. While the 1990 Annual

Energy Outlook escalation rates are probably appropriate, the starting value must be adjusted to reflect the above factors.

For the low-sulfur coal burned in Stanton 1, the 1989 actual delivered price shown in Table 1A.3.3-5 was used as the starting point with the 1990 Annual Energy Outlook escalation rates applied. For the medium-sulfur coal, the starting point was the 1989 average actual contract delivered price for 1.5 to 2.0 percent sulfur coal to plants in the South Atlantic region as presented in the Cost and Quality of Fuels for Electric Utility Plants 1989. This adjustment essentially accounts for deleting much of the western coal that is included in the national average. A second adjustment is made to the starting point to account for the increase in transportation costs to Florida relative to the South Atlantic region. The adjustment is obtained by taking the ratio of the delivered 1989 cost of coal for Florida compared to the South Atlantic region. The adjustments result in a 1989 medium-sulfur coal cost of \$1.67/MBtu to which the 1990 Annual Energy Outlook escalation rates are applied.

The passage of the 1990 Clean Air Act will place greater demands on the high quality low-sulfur coal that OUC is currently burning. As a result, an increase in the price of the coal is expected. Since the 1990 Annual Energy Outlook did not consider the effect of the 1990 Clean Air Act Amendments, a further adjustment for low-sulfur coal is necessary. While there are various opinions regarding the level of the price increase, several estimates have been used to select a consensus price of \$1.37/MBtu f.o.b. mine in 2000 in 1989 dollars. These estimates are presented in Table 1A.3.3-6. The forecast of the low-sulfur coal was increased to this \$1.37/MBtu f.o.b mine price in 2000, assuming that f.o.b mine costs represent 61 percent of the delivered coal cost based on the actual 1989 OUC f.o.b mine and transportation costs. Though it is likely that there will be a corresponding reduction in the price of medium- and high-sulfur coals due to the Clean Air Act, no reduction has been included in the forecasts.

The flexibility in the design of the Stanton units will allow them to burn the medium-sulfur coal at essentially the same emission levels as being actually achieved with the low-sulfur coal. OUC may, however, continue to burn the lower sulfur coal as long as the premium does not become excessive. With the commercial operation of Stanton 2 in 1997, significantly more coal will be required than is available under the Stanton 1 contract. For evaluation purposes and to be conservative, it will be assumed that OUC will continue to burn the

same low-sulfur coal that it is currently burning. It is assumed that McIntosh 3 will burn the medium-sulfur coal projected in Table 1A.3.3-2. In reality, however, the specific escalation provisions in OUC's contract may allow it to be extended for the two 5-year extensions beginning in 1997 at prices below those for the low-sulfur coal in Table 1A.3.3-2.

1A.3.3.2 No. 6 Oil

The most likely forecast of No. 6 oil prices is based on the base end-use price for heavy oil to electric utilities from the 1990 Annual Energy Outlook.

1A.3.3.3 No. 2 Oil

The most likely forecast of No. 2 oil prices is based on the base price of distillate oil from the 1990 Annual Energy Outlook.

1A.3.3.4 Natural Gas

The most likely forecast of natural gas price is based on the base end-use price for electric utilities from the 1990 Annual Energy Outlook. No upward adjustment has been made to reflect the effect of the 1990 Clean Air Act Amendments.

1A.3.3.5 Nuclear

The 1990 Annual Energy Outlook does not forecast prices for nuclear fuel. The nuclear fuel forecast is taken from the 1989 Planning Hearing Generation Expansion Planning Studies by the Florida Electric Power Coordinating Group, Inc. (FLG) forecast adjusted to reflect the underlying general inflation rates presented in Subsection 1A.3.2.

1A.3.3.6 Low and High Forecasts

Low and high forecasts are developed by applying the low and high oil price scenarios (expressed in 1989 dollars) from the 1990 Annual Energy Outlook and the high growth and low growth inflation projections from Subsection 1A.3.2. The low and high forecasts in 1989 dollars and nominal dollars are shown in Tables 1A.3.3-7 and 1A.3.3-8 and in Tables 1A.3.3-9 and 1A.3.3-10, respectively.

1A.3.3.7 1989 Planning Hearing Forecast

The 1989 Planning Hearing base case fuel forecast is presented in Table 1A.3.3-11 for use in sensitivity analyses. The 1990 Annual Energy Outlook base case forecast was selected for the most likely case for evaluation purposes instead of the 1989 Planning Hearing forecast since the 1989 Planning Hearing forecast was developed in 1988.

Table 1A.3.3-1
Comparison of Fossil Fuel Price Forecasts for Year 2010
(1989 \$)

	EIA Base Case	DRI	WEFA	GRI	AGA
World Oil Price (dollars per barrel)	36.90	32.09	33.59	33.68	46.59
Natural Gas Wellhead (dollars per thousand cubic feet)	5.63	4.48	5.12	5.10	4.47
Coal Minemouth (dollars per short ton)	28.55	29.56	36.12	NA	NA

Source: 1990 Annual Energy Outlook.

Acronyms: Energy Information Administration (EIA)
DRI/McGraw-Hill (DRI)
WEFA Group (WEFA)
Gas Research Institute (GRI)
American Gas Association (AGA)

Table 1A.3.3-2
Most Likely Delivered Fuel Price Projections Using
1990 Annual Energy Outlook Base Scenario
(1989 \$/MBtu)

Year	Low-Sulfur Coal*	Medium-Sulfur Coal**	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
1990	1.90	1.68	2.39	2.75	4.40	0.68
1991	1.93	1.71	2.48	2.88	4.56	0.68
1992	1.96	1.74	2.58	3.02	4.73	0.68
1993	1.99	1.76	2.68	3.17	4.90	0.68
1994	2.03	1.79	2.79	3.32	5.08	0.68
1995	2.06	1.82	2.90	3.48	5.27	0.68
1996	2.08	1.83	3.07	3.70	5.49	0.68
1997	2.09	1.85	3.24	3.92	5.72	0.68
1998	2.11	1.87	3.43	4.17	5.96	0.68
1999	2.13	1.88	3.62	4.43	6.21	0.68
2000	2.21	1.90	3.83	4.70	6.47	0.68
2001	2.23	1.92	4.03	4.86	6.66	0.68
2002	2.26	1.94	4.23	5.02	6.85	0.68
2003	2.29	1.97	4.45	5.19	7.05	0.68
2004	2.31	1.99	4.68	5.36	7.26	0.68
2005	2.34	2.01	4.92	5.54	7.47	0.68
2006	2.37	2.04	5.12	5.67	7.63	0.68
2007	2.39	2.06	5.33	5.80	7.78	0.68
2008	2.42	2.08	5.54	5.93	7.95	0.68
2009	2.45	2.10	5.77	6.07	8.11	0.68
2010	2.48	2.13	6.00	6.21	8.28	0.68
2011	2.50	2.15	6.24	6.35	8.45	0.68
2012	2.53	2.18	6.50	6.50	8.63	0.68
2013	2.56	2.20	6.76	6.65	8.81	0.68
2014	2.59	2.22	7.03	6.80	8.99	0.68
2015	2.62	2.25	7.32	6.96	9.18	0.68
2016	2.64	2.27	7.61	7.12	9.37	0.68
2017	2.67	2.30	7.92	7.29	9.56	0.68
2018	2.70	2.32	8.24	7.45	9.76	0.68
2019	2.73	2.35	8.58	7.63	9.97	0.68
2020	2.76	2.38	8.92	7.80	10.17	0.68

*0.7 to 1.0 percent sulfur.

**1.5 to 2.0 percent sulfur.

Table 1A.3.3-3
Most Likely Delivered Fuel Price Projections Using
1990 Annual Energy Outlook Base Scenario
(\$/MBtu)

Year	Low-Sulfur Coal*	Medium-Sulfur Coal**	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
1990	1.99	1.76	2.50	2.87	4.59	0.71
1991	2.11	1.86	2.71	3.14	4.98	0.74
1992	2.23	1.97	2.93	3.43	5.37	0.77
1993	2.35	2.08	3.17	3.74	5.79	0.81
1994	2.49	2.20	3.42	4.07	6.24	0.85
1995	2.63	2.32	3.70	4.44	6.73	0.90
1996	2.76	2.43	4.07	4.91	7.29	0.95
1997	2.89	2.55	4.47	5.42	7.90	1.00
1998	3.03	2.68	4.92	5.98	8.56	1.05
1999	3.18	2.81	5.41	6.61	9.27	1.10
2000	3.43	2.95	5.95	7.30	10.05	1.16
2001	3.61	3.10	6.50	7.84	10.75	1.22
2002	3.80	3.26	7.11	8.43	11.51	1.28
2003	4.00	3.44	7.77	9.06	12.32	1.35
2004	4.20	3.61	8.50	9.74	13.19	1.42
2005	4.42	3.80	9.29	10.47	14.11	1.49
2006	4.65	4.00	10.06	11.14	14.98	1.56
2007	4.89	4.21	10.88	11.85	15.91	1.64
2008	5.14	4.42	11.78	12.61	16.89	1.73
2009	5.41	4.65	12.74	13.42	17.93	1.82
2010	5.69	4.89	13.79	14.27	19.03	1.91
2011	5.98	5.14	14.92	15.19	20.20	2.01
2012	6.29	5.41	16.15	16.16	21.45	2.11
2013	6.62	5.69	17.47	17.19	22.77	2.22
2014	6.96	5.98	18.91	18.30	24.18	2.33
2015	7.31	6.29	20.46	19.47	25.67	2.45
2016	7.69	6.61	22.14	20.71	27.25	2.57
2017	8.09	6.95	23.96	22.04	28.93	2.70
2018	8.51	7.31	25.93	23.45	30.71	2.84
2019	8.94	7.69	28.06	24.95	32.60	2.99
2020	9.41	8.08	30.36	26.55	34.61	3.14

*0.7 to 1.0 percent sulfur.

**1.5 to 2.0 percent sulfur.

Table 1A.3.3-4
1990 Range of OUC Oil and Gas Prices

	No. 2* (\$/MBtu)	No. 6* (\$/MBtu)	Gas (\$/MBtu)
January	5.23	3.58	3.14
February	4.36	2.85	2.84
March	4.31	2.52	2.28
April	4.19	2.44	2.23
May	4.00	2.36	2.22
June	3.69	2.08	2.28
July	4.07	2.44	2.27
August	5.98	3.69	2.38
September	7.06	4.04	2.36
October	7.41	4.19	2.59
November	6.90	3.89	3.00
December	6.16	3.43	3.01
Minimum	3.69	2.08	2.22
Maximum	7.41	4.19	3.14
Average	5.28	3.12	2.55
AEO**	6.39	2.87	2.50

*Based on Platt's U.S. Gulf Coast prices. To develop a delivered cost to OUC, \$0.20/MBtu was added to No. 6 oil and the No. 2 oil was increased by 12 percent. This is the typical price guideline used by OUC. The No. 2 oil is based on 5.825 MBtu/bbl and the No. 6 oil is based on 6.29 MBtu/bbl.

**Annual Energy Outlook.

1A.3.3-10

Table 1A.3.3-5

Unit	Range	Tons (thousands)	Heating Value (Btu/lb)	Sulfur (percent)	SO ₂ (lb/MBtu*)	Ash (percent)	Ash (lb/MBtu)	Delivered Cost (\$/MBtu)
Stanton	Weighted Average	1,074.26	12,722	0.74	1.16	8.75	6.88	1.89
Stanton	Minimum		12,526	0.57	0.89	6.37	N/A	1.84
Stanton	Maximum		13,033	0.80	1.26	9.87	N/A	1.93
McIntosh	Weighted Average	724.00	12,298	1.29	2.09	11.01	8.95	2.12
McIntosh	Minimum		12,181	1.08	1.74	10.21	N/A	1.97
McIntosh	Maximum		12,395	1.67	2.74	11.39	N/A	2.29

*Before scrubbing.

Source: COALDAT Marketing Report: Utility Format Calendar Year 1989.

Table 1A.3.3-6
Compliance Coal Price Estimates for the Year 2000
(1989 \$)

Source	Range (\$/MBtu)	Average (\$/MBtu)
1	1.35 - 1.46	1.40
2	1.44 - 1.60	1.52
3	--	<u>1.20</u>
Average		1.37

Sources:

- (1) Rafael Villagran, Coal Outlook, June 4, 1990.
- (2) Thomas A. Hewson, Jr., Utility Coal Market Dynamics and Compliance Decisions Under Acid Rain Legislation, June 1990.
- (3) S. C. Suboleski, R. L. Frantz, R. V. Ramani, and R. Rao, Outlook for Coal Productivity, June 1990.

Table 1A.3.3-7
Low Delivered Fuel Price Projections Using
1990 Annual Energy Outlook Low Oil Price Scenario
(1989 \$/MBtu)

Year	Low-Sulfur Coal*	Medium-Sulfur Coal**	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
1990	1.90	1.68	2.17	2.40	3.99	0.68
1991	1.93	1.71	2.26	2.46	4.08	0.68
1992	1.96	1.74	2.35	2.52	4.17	0.68
1993	1.99	1.76	2.45	2.59	4.27	0.68
1994	2.03	1.79	2.55	2.65	4.36	0.68
1995	2.06	1.82	2.66	2.72	4.46	0.68
1996	2.08	1.84	2.81	2.87	4.64	0.68
1997	2.10	1.85	2.98	3.03	4.83	0.68
1998	2.12	1.87	3.15	3.20	5.02	0.68
1999	2.14	1.89	3.34	3.37	5.22	0.68
2000	2.21	1.91	3.53	3.56	5.43	0.68
2001	2.24	1.93	3.67	3.68	5.59	0.68
2002	2.26	1.95	3.82	3.80	5.76	0.68
2003	2.28	1.97	3.97	3.93	5.93	0.68
2004	2.31	1.99	4.13	4.06	6.10	0.68
2005	2.33	2.01	4.30	4.19	6.28	0.68
2006	2.35	2.03	4.44	4.27	6.38	0.68
2007	2.38	2.05	4.59	4.34	6.48	0.68
2008	2.40	2.07	4.74	4.42	6.58	0.68
2009	2.43	2.10	4.90	4.50	6.68	0.68
2010	2.45	2.12	5.06	4.58	6.79	0.68
2011	2.47	2.14	5.23	4.66	6.90	0.68
2012	2.50	2.16	5.40	7.01	7.01	0.68
2013	2.52	2.18	5.58	4.83	7.12	0.68
2014	2.55	2.20	5.76	4.92	7.23	0.68
2015	2.58	2.22	5.95	5.01	7.34	0.68
2016	2.60	2.25	6.15	5.10	7.46	0.68
2017	2.63	2.27	6.35	5.19	7.57	0.68
2018	2.65	2.29	6.57	5.28	7.69	0.68
2019	2.68	2.31	6.78	5.38	7.81	0.68
2020	2.71	2.34	7.01	5.47	7.94	0.68

*0.7 to 1.0 percent sulfur.

**1.5 to 2.0 percent sulfur.

Table 1A.3.3-8
High Delivered Fuel Price Projections Using
1990 Annual Energy Outlook High Oil Price Scenario
(1989 \$/MBtu)

Year	Low-Sulfur Coal*	Medium-Sulfur Coal**	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
1990	1.90	1.68	2.63	3.11	4.79	0.68
1991	1.93	1.71	2.68	3.32	5.00	0.68
1992	1.96	1.74	2.73	3.55	5.22	0.68
1993	1.99	1.76	2.78	3.79	5.46	0.68
1994	2.03	1.79	2.84	4.05	5.70	0.68
1995	2.06	1.82	2.89	4.32	5.95	0.68
1996	2.08	1.83	3.05	4.56	6.19	0.68
1997	2.09	1.85	3.21	4.81	6.44	0.68
1998	2.11	1.87	3.38	5.08	6.70	0.68
1999	2.13	1.88	3.57	5.36	6.98	0.68
2000	2.21	1.90	3.76	5.66	7.26	0.68
2001	2.23	1.92	3.94	5.91	7.51	0.68
2002	2.26	1.94	4.14	6.17	7.77	0.68
2003	2.28	1.96	4.34	6.44	8.04	0.68
2004	2.30	1.98	4.55	6.72	8.32	0.68
2005	2.33	2.00	4.77	7.02	8.61	0.68
2006	2.35	2.02	5.01	7.20	8.80	0.68
2007	2.38	2.05	5.25	7.39	9.00	0.68
2008	2.41	2.07	5.51	7.58	9.21	0.68
2009	2.43	2.09	5.78	7.78	9.42	0.68
2010	2.46	2.12	6.07	7.98	9.63	0.68
2011	2.49	2.14	6.37	8.19	9.85	0.68
2012	2.52	2.16	6.68	8.40	10.07	0.68
2013	2.55	2.19	7.01	8.62	10.30	0.68
2014	2.57	2.21	7.36	8.84	10.53	0.68
2015	2.60	2.24	7.72	9.07	10.77	0.68
2016	2.63	2.26	8.11	9.31	11.01	0.68
2017	2.66	2.29	8.51	9.55	11.26	0.68
2018	2.69	2.31	8.93	9.80	11.52	0.68
2019	2.72	2.34	9.37	10.05	11.78	0.68
2020	2.75	2.36	9.83	10.31	12.05	0.68

*0.7 to 1.0 percent sulfur.

**1.5 to 2.0 percent sulfur.

Table 1A.3.3-9
Low Delivered Fuel Price Projections Using
1990 Annual Energy Outlook Low Oil Price Scenario
(\$/MBtu)

Year	Low-Sulfur Coal*	Medium-Sulfur Coal**	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
1990	1.99	1.76	2.27	2.51	4.17	0.71
1991	2.11	1.86	2.47	2.68	4.45	0.74
1992	2.20	1.94	2.63	2.82	4.67	0.76
1993	2.29	2.02	2.81	2.97	4.89	0.78
1994	2.38	2.10	3.00	3.12	5.12	0.80
1995	2.48	2.19	3.20	3.28	5.37	0.82
1996	2.57	2.27	3.47	3.54	5.73	0.84
1997	2.66	2.35	3.77	3.83	6.10	0.86
1998	2.75	2.43	4.09	4.15	6.51	0.88
1999	2.85	2.51	4.43	4.48	6.94	0.90
2000	3.01	2.60	4.81	4.85	7.40	0.92
2001	3.12	2.70	5.13	5.14	7.81	0.95
2002	3.23	2.79	5.47	5.44	8.24	0.97
2003	3.35	2.89	5.83	5.76	8.69	0.99
2004	3.47	3.00	6.22	6.10	9.17	1.02
2005	3.59	3.10	6.63	6.46	9.68	1.04
2006	3.72	3.21	7.02	6.74	10.08	1.07
2007	3.85	3.33	7.43	7.03	10.49	1.10
2008	3.99	3.44	7.87	7.34	10.93	1.12
2009	4.13	3.56	8.33	7.66	11.37	1.15
2010	4.27	3.69	8.83	7.99	11.84	1.18
2011	4.42	3.82	9.35	8.33	12.33	1.21
2012	4.58	3.96	9.90	8.70	12.84	1.24
2013	4.74	4.10	10.48	9.07	13.36	1.27
2014	4.91	4.24	11.10	9.47	13.91	1.30
2015	5.08	4.39	11.75	9.88	14.49	1.34
2016	5.26	4.54	12.44	10.31	15.08	1.37
2017	5.45	4.70	13.17	10.76	15.70	1.40
2018	5.64	4.87	13.95	11.22	16.35	1.44
2019	5.84	5.04	14.77	11.71	17.02	1.48
2020	6.04	5.22	15.64	12.22	17.72	1.51

*0.7 to 1.0 percent sulfur.

**1.5 to 2.0 percent sulfur.

Table 1A.3.3-10
High Delivered Fuel Price Projections Using
1990 Annual Energy Outlook High Oil Price Scenario
(\$/MBtu)

Year	Low-Sulfur Coal*	Medium-Sulfur Coal**	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
1990	1.99	1.76	2.75	3.25	5.00	0.71
1991	2.11	1.86	2.92	3.62	5.46	0.74
1992	2.26	2.00	3.14	4.08	6.01	0.78
1993	2.42	2.14	3.38	4.60	6.62	0.82
1994	2.60	2.29	3.63	5.18	7.30	0.87
1995	2.78	2.46	3.91	5.84	8.04	0.92
1996	2.96	2.62	4.34	6.50	8.83	0.97
1997	3.15	2.78	4.83	7.24	9.69	1.02
1998	3.35	2.96	5.37	8.06	10.64	1.07
1999	3.57	3.15	5.97	8.98	11.68	1.13
2000	3.90	3.35	6.64	10.00	12.82	1.20
2001	4.16	3.58	7.35	11.01	14.00	1.26
2002	4.44	3.81	8.13	12.13	15.28	1.33
2003	4.73	4.07	9.00	13.36	16.68	1.40
2004	5.04	4.33	9.95	14.71	18.21	1.48
2005	5.38	4.62	11.01	16.21	19.88	1.56
2006	5.74	4.93	12.19	17.54	21.45	1.65
2007	6.12	5.26	13.50	18.99	23.14	1.74
2008	6.53	5.61	14.94	20.55	24.96	1.84
2009	6.96	5.99	16.54	22.24	26.93	1.94
2010	7.43	6.38	18.32	24.08	29.06	2.04
2011	7.92	6.81	20.28	26.06	31.35	2.16
2012	8.45	7.27	22.45	28.21	33.82	2.27
2013	9.02	7.75	24.85	30.53	36.49	2.40
2014	9.62	8.27	27.51	33.05	39.37	2.53
2015	10.26	8.82	30.46	35.77	42.47	2.67
2016	10.95	9.41	33.72	38.72	45.82	2.82
2017	11.68	10.04	37.33	41.91	49.44	2.97
2018	12.46	10.71	41.33	45.36	53.34	3.14
2019	13.29	11.43	45.76	49.10	57.55	3.31
2020	14.18	12.19	50.66	53.15	62.09	3.49

*0.7 to 1.0 percent sulfur.

**1.5 to 2.0 percent sulfur.

Table 3.3-11
1989 Planning Hearing Base Case Forecast
(\$/MBtu)

Year	Low-Sulfur Coal*	Medium-Sulfur Coal**	Natural Gas	No. 6 Oil***	No. 2 Oil	Nuclear
1990	2.14	2.03	2.38	3.10	4.65	0.71
1991	2.25	2.12	2.58	3.35	5.05	0.74
1992	2.38	2.25	2.92	3.68	5.58	0.77
1993	2.52	2.39	3.30	4.09	6.23	0.81
1994	2.68	2.54	3.72	4.54	6.99	0.85
1995	2.86	2.70	4.20	5.02	7.72	0.90
1996	3.05	2.88	4.68	5.54	8.56	0.95
1997	3.25	3.07	5.20	6.11	9.49	1.00
1998	3.46	3.27	5.75	6.72	10.47	1.05
1999	3.68	3.48	6.22	7.23	11.31	1.10
2000	3.91	3.70	6.87	7.77	12.20	1.16
2001	4.15	3.92	7.36	8.30	13.09	1.22
2002	4.40	4.16	7.88	8.87	14.04	1.28
2003	4.68	4.42	8.51	9.45	15.02	1.35
2004	4.96	4.69	9.09	10.06	16.05	1.42
2005	5.27	4.98	9.78	10.69	17.12	1.49
2006	5.60	5.29	10.41	11.34	18.23	1.56
2007	5.94	5.62	11.06	12.01	19.38	1.64
2008	6.31	5.97	11.85	12.70	20.57	1.73
2009	6.70	6.34	12.70	13.43	21.84	1.82
2010	7.12	6.74	13.61	14.21	23.18	1.91
2011	7.56	7.15	14.58	15.02	24.61	2.01
2012	8.03	7.60	15.62	15.89	26.13	2.11
2013	8.53	8.07	16.74	16.80	27.74	2.22
2014	9.06	8.57	17.93	17.77	29.44	2.33
2015	9.63	9.11	19.22	18.80	31.26	2.45
2016	10.23	9.67	20.59	19.88	33.18	2.57
2017	10.86	10.28	22.06	21.02	35.23	2.70
2018	11.54	10.92	23.64	22.23	37.40	2.84
2019	12.25	11.59	25.33	23.51	39.70	2.99
2020	13.02	12.32	27.14	24.87	42.15	3.14

*Less than 1.0 percent sulfur.

**1.0 to 2.0 percent sulfur.

***0.7 to 2.0 percent sulfur.

1A.3.4 Fuel Availability

This section reviews the availability of coal, natural gas, No. 2 oil, and No. 6 oil as potential fuels. For coal, the reserve base, fuel quality, and production capability will be discussed. Factors affecting the future price of these fuels have been discussed in Subsection 1A.3.3, Fuel Price Projections.

1A.3.4.1 Coal

1A.3.4.1.1 Quantity Required. Stanton 2, with a generating capability of 440 MW when operating at an average annual capacity factor of 70 percent, will require about 1.1 million tons of coal per year. This assumes that the coal has a heating value of 12,400 Btu/lb.

1A.3.4.1.2 Quality Required. Stanton 2 is designed to burn coals with a wide range of sulfur content ranging from 0.7 percent to 4.0 percent, which corresponds to uncontrolled sulfur dioxide emission potential rates of 1.1 lb SO₂/MBtu to 6.5 lb SO₂/MBtu, based on a 12,400 Btu/lb higher heating value. A discussion of the proposed BACT fuel for Stanton 2 can be found in Subsection 1A.3.4.3 of this Supplemental Site Certification Application.

1A.3.4.1.2.1 Quality of Potential Coal Sources. Figure 1A.3.4-1 compares western and eastern sources of coal and their uncontrolled sulfur dioxide emission potential. In the East, the primary source of low-sulfur coal is US Bureau of Mines District 8, which includes eastern Kentucky, western Virginia, and southwestern West Virginia. These coal producing areas are shown on Figure 1A.3.4-2, Coal Fields of the Conterminous United States. The average uncontrolled sulfur dioxide emission potential of this coal was 1.6 lb SO₂/MBtu. In the West, the primary source of low-sulfur coal is the Powder River Basin of Wyoming.

The low rank subbituminous coals from the Powder River Basin have a very low uncontrolled sulfur dioxide emission potential (less than 0.9 lb SO₂/MBtu). Because of their favorable geological conditions, the mining economics are also favorable, with current prices being less than \$4.00 per ton. The primary negative characteristic of the Powder River Basin coal is its high moisture content (about 30 percent), which results in an as-received heating value of 8,000 to 9,000 Btu/lb. Considerable research and development are now being conducted on upgrading these coals by reducing their inherent moisture. These processes produce a bituminous rank coal with a heating value of nearly 11,000 Btu/lb. If this can be

done in commercial quantities, the "market reach" of the Powder River Basin coals will be significant in the future.

Figures 1A.3.4-3 and 1A.3.4-4 show the uncontrolled sulfur dioxide emission potential of coals delivered to Florida and Georgia electric utilities in 1989. It is seen that coals from US Bureau of Mines District 8 in central Appalachia had the lowest uncontrolled sulfur dioxide emission potential (1.2 lb SO₂/MBtu - 1.5 lb SO₂/MBtu). It is also seen that foreign coals from Colombia and Venezuela have uncontrolled sulfur dioxide emission potentials of less than 1.2 lb SO₂/MBtu.

The primary alternative source to central Appalachian coals is the Illinois Basin (southern Illinois, southern Indiana, and west Kentucky), where the coals have uncontrolled sulfur dioxide emission potentials which ranged from 4.5 to 6 lb SO₂/MBtu in 1989.

1A.3.4.1.3 Clean Air Act Amendments and Changing Demand. The amendments to the Clean Air Act which were passed into law on November 15, 1990, call for a 10 million-ton reduction in the amount of sulfur dioxide emissions from 1980 levels by the year 2000 (Phase II). Those plants which are not in compliance will have to install flue gas desulfurization systems, switch to low-sulfur coal, or purchase allowances.

It is very difficult to estimate the additional demand for low-sulfur coal which will result from these regulations since "switch versus scrub" decisions have not yet been formalized. The actual amount of fuel switching will be dependent on the cost of retrofitting scrubbers compared to the anticipated premium for low-sulfur coal, the expected value of allowances that can be generated by over compliance, and the expected price of allowances that can be purchased to obviate the need for scrubbing or switching fuels.

The ability of low-sulfur coal reserves and production from central Appalachia to satisfy increased demand by 1995 (Phase I) and the year 2000 (Phase II) will depend upon the following factors.

- The amount of increased demand compared to current excess mine production capability and expansion capability within the central Appalachian coal region.
- The delivered cost of low-sulfur coal from the Powder River Basin of Wyoming.
- The delivered cost of foreign coals from Colombia and Venezuela to tidewater ports.

- Market prices for low-sulfur coals from central Appalachia compared to the cost of developing new mines to exploit undeveloped reserve blocks.
- The amount of increased demand for US origin low-sulfur coals from European utilities due to a reduction in domestic coal mining subsidies and the Europeans' desire to reduce sulfur dioxide emissions.

The interaction between these factors is quite complex. The current period of low prices and excess production capacity is likely to continue for the next few years. During this time, there will be opportunities to arrange long-term supply commitments at favorable prices and with favorable contract provisions.

1A.3.4.1.4 Potential Sources. The following subsections look at potential sources of coal supply from central Appalachia, the Illinois Basin, the Powder River Basin, and foreign sources. For each producing basin, a brief discussion is provided on reserves, coal quality, and production capability.

1A.3.4.1.4.1 Current Sources for Florida and Georgia Utilities. Figures 1A.3.4-5 and 1A.3.4-6 show the sources of coal delivered to Florida and Georgia electric utilities in 1989. The quantity and the predominant modes of transportation from each source are also shown. It is seen that the predominant source has been eastern Kentucky with delivery by rail. The coal from western Kentucky (US Bureau of Mines District 9) was the second largest source for Florida utilities and was predominantly delivered by river and gulf movements to west-coast Florida utilities (Florida Power Corporation and Tampa Electric Company).

There were also significant quantities of coal purchased from Colombia and Venezuela. Georgia utilities have received some coal from the distant Powder River Basin in Wyoming and Montana.

1A.3.4.1.4.2 Central Appalachia. The primary supply source of low-sulfur coal for consumers in the eastern US is the central Appalachian region, which comprises east Kentucky, southwestern West Virginia, and western Virginia. As previously discussed, east Kentucky is a major supply source to electric utilities in Florida and Georgia.

Reserve estimates for this region vary with the assumptions made regarding mineability and the market price level to cover the cost of producing and beneficiating (cleaning or washing) the coal. In 1982, the Kentucky Geological Survey estimated that eastern Kentucky contained 36 billion tons of remaining

coal resources.¹ About 43 percent of these resources have an uncontrolled sulfur dioxide emission potential of less than 1.2 lb SO₂/MBtu.²

In reducing the resource base to economically recoverable resources, or reserve base, the level of mining technology employed and the market price available to cover extraction costs are important. This means that the amount of economically recoverable reserves can vary from time to time with market conditions.

At the present time, no agency of the federal government maintains coal reserve data. The last comprehensive estimate of coal reserves which emphasized low-sulfur reserves was made by the US Bureau of Mines in 1975.² In a recent Electric Power Research Institute sponsored study entitled "Reserves and Potential Supply of Low Sulfur Appalachian Coal," it was found that on the basis of current industry practice, the reserve estimates made by the US Bureau of Mines in a 1974 assessment had significant errors. For example, surface mineable reserves were found to be understated by a factor of 3 to 4. However, underground mineable reserves were overstated by a factor of 2.³ Most of these errors were due to the way in which the feasibility of recovering underground mineable reserves was determined and the methodology used to calculate the cost of mining. However, the net result of these errors seemed to cancel and, therefore, the previously published economically recoverable reserve estimates should be fairly representative and, in fact, may understate the amount of reserves which are economically recoverable.

It has been estimated that at a 1984 price level of \$35 per ton, there would be at least 20 billion tons of recoverable reserves with a sulfur content of less than 1.4 percent.³ This compares with a value of slightly less than 20 billion tons estimated by the US Bureau of Mines.³ For production levels of 264 million tons in 1989, the reserve base should be capable of supporting existing production levels for another 70 years.

The central Appalachian coals are desirable to electric utilities because of their low-sulfur content and relatively low ash content. These characteristics also make them desirable for producing metallurgical grade coking coals. Depending upon demand for metallurgical coking coal, some of these coals move in and out of the low-sulfur steam coal markets.

Of the 144 million tons of coal shipped to electric utilities in 1989, about 40 million tons (28 percent) had uncontrolled sulfur dioxide emission potentials

of less than 1.2 lb SO₂/MBtu, about 90 million tons (63 percent) had uncontrolled sulfur dioxide emission potentials which ranged from 1.2 to 2.5 lb SO₂/MBtu, and only 10 million tons (7 percent) had uncontrolled sulfur dioxide emission potentials greater than 2.5 lb SO₂/MBtu.⁴

Table 1A.3.4-1 shows the quantity and quality of coal shipped from central Appalachia to electric utilities in 1989. As seen from this table, the major production was from east Kentucky. The ash averaged around 10 percent, the sulfur 1.6 lb SO₂/MBtu, and the heating value 12,450 Btu/lb.

A significant amount of coal production from the central Appalachian region is beneficiated. These beneficiation facilities remove the heavy mineral matter such as ash and pyrite (containing a major portion of the sulfur in coal) from the lighter, predominantly carbon particles using gravimetric separation processes. Many of the new mine developments in the mid and late 1990s will be equipped with coal beneficiation plants to produce the low-sulfur coals required by electric utilities who switch to low-sulfur coal to comply with the 1990 Clean Air Act Amendments.

With the increase in coal beneficiation plants, the high-sulfur middlings and refuse from these coal beneficiation plants still contain significant amounts of carbon and will be marketed at very attractive prices. With the proposed BACT emission rate, Stanton 2 will have the ability to burn these high-sulfur middlings and take advantage of this market.

1A.3.4.1.4.3 Illinois Basin. As seen from the map on Figure 1A.3.4-2, the Illinois Basin includes southern Illinois, southwestern Indiana, and western Kentucky. As seen from Figure 1A.3.4-1, the quality of this coal is not as good as that from the central Appalachian region. The uncontrolled sulfur dioxide emission potential ranges from 4.7 to 5.7 lb SO₂/MBtu compared to 1.6 lb SO₂/MBtu from central Appalachia. While the quality of coal from the Illinois Basin is not as desirable, there are very large reserves in this area. The US Bureau of Mines estimates remaining recoverable reserves amount to 110 billion tons which is significantly greater than the approximately 20 billion tons for the central Appalachian region.⁵ Because of their greater thickness and the large area of the two predominant seams (Herrin No. 6 and Harrisburg-Springfield No. 5) making up these reserves, the mining economics are also more favorable than in central Appalachia. An indicator of the low production cost is current spot market prices for this high-sulfur coal, which range from \$14 to \$17 per ton in

Illinois and Indiana as compared to \$21 to \$32 per ton for low-sulfur central Appalachian coal.⁶

While the price of the Illinois Basin coals is attractive and the reserves are plentiful, the high average uncontrolled sulfur dioxide emission potential ranges from 4.7 to 5.7 lb SO₂/MBtu and will require high-sulfur dioxide removal using flue gas desulfurization.

Production from the Illinois Basin peaked at about 145 million annual tons in 1972.⁷ With the advent of the Clean Air Act in 1970 and the New Source Performance Standards promulgated in 1971, and the subsequent preference for low-sulfur coals, many mining operations in the Illinois Basin have been shut down. With increased demand, some of these operations may be reactivated at minimal cost, compared to that required to develop new mines.

1A.3.4.1.4.4 Other Sources. The Powder River Basin, which covers portions of Wyoming and Montana, began to be exploited in the early 1970s because of its low-sulfur coal (average of 0.9 lb SO₂/MBtu) and favorable mining economics. Combined seam thicknesses often total 80 to 100 feet, with minimal interburden and overburden, often less than 50 feet thick. This results in very favorable mining economics with current f.o.b. mine prices less than \$4.00 per ton.

The western railroads have been quite progressive in reducing their cost structure through the use of unit coal trains, changes in work rules, and more favorable terrain compared to the mountainous Appalachian region. This has lead to very low transportation costs compared to eastern railroads. For example, the current cost estimate for moving coal from the Powder River Basin to barge loading terminals on the Mississippi River near St. Louis or on the Ohio River in southern Illinois ranges from \$14 to \$15 per ton. Many of the large power plants along the Ohio River which will have to reduce their sulfur dioxide emissions by the year 2000 may find it economically desirable to switch to low-sulfur Powder River Basin coals. Some of this coal will also be used in blends with higher rank eastern bituminous coals. The Southern Company has conducted successful test burns using Powder River Basin coal at its Scherer Plant in Georgia and Miller Plant in Alabama.

There are several researchers developing processes for reducing the high moisture content of this coal from its typical 30 percent to less than 10 percent. This would effectively increase the heating value from its low value of 8,000 to

8,500 Btu/lb up to about 11,000 Btu/lb. This would have a favorable impact on reducing transportation cost, reducing the derate associated with burning the low rank subbituminous coal in plants designed for bituminous coals, and improve boiler efficiencies with a lower moisture content coal. Several of these concepts have proved to be technologically and economically feasible at the pilot plant stage of development. If successful at the demonstration plant level, the market for Powder River Basin coals will be increased considerably and will have a material impact on the future demand for and price levels of central Appalachian low-sulfur coals.

For those power plants which have access to water delivery, coals from Colombia and Venezuela which have low production costs and low-sulfur dioxide emission potential (Figure 1A.3.4-1) will also constrain demand and price runups for low-sulfur central Appalachian coal. Although the OUC does not currently have water delivery capability for South America or Powder River Basin coals, the fact that other utilities in Florida and the southeast do will act as a constraining influence on future prices at the mine and for rail transportation from central Appalachia to Stanton 2.

1A.3.4.2 Natural Gas

1A.3.4.2.1 Reserves. When the availability of natural gas is evaluated as a fuel for baseload power generation, the quantity of reserves available for commitment and the replacement of production by new reserves must be considered. Historically, there has been a mixed record of the gas industry's ability to replace annual production with newly discovered reserves. According to the Energy Information Administration and the American Gas Association (AGA), the replacement level in the lower 48 states during the decade of 1970-1979 was 46 percent of production. By contrast, the replacement level was nearly 94 percent of production for the period 1980-1989.^{8,9}

A major reason for the dramatic improvement in replacement is the Natural Gas Policy Act of 1978 (NGPA). The NGPA stimulated drilling activity with pricing incentives for new gas. Continued pricing motivation will be required to maintain drilling activity. According to the AGA, continued increases in exploratory drilling will be necessary to maintain an optimum level of reserve replacement.⁸

Florida is served primarily by the Florida Gas Transmission Company (FGT) pipeline system, with the vast majority of natural gas coming from the Texas, Louisiana, and offshore Gulf of Mexico region. According to the DOE, total new discoveries for the lower 48 states accounted for only 63 percent of all 1989 reserve additions.^{8,10} New discoveries are solid additions to reserve figures, including extension of old reservoirs and new reservoir discoveries. By contrast, over one-third of 1989 reserve additions were softer and consisted of producer adjustments and net revisions to the existing reservoir base data. It is significant to note that nearly one-third of the lower 48 states' new discoveries were in the federal offshore Gulf of Mexico region. This reinforces its position as a dominant region for natural gas exploration. In addition, in 1989, gas production reached its highest level since 1984 with lower 48 state production of 16.58 trillion cubic feet. This is indicative of the strong demand for gas during 1989.⁸

The long-term availability of natural gas appears to be good if pricing remains high enough to encourage producers to drill exploratory wells replacing production. The demand for gas is increasing. If this continues, the pricing level will remain strong. In addition, the Clean Air Act Amendments of 1990 may further increase the demand for natural gas.

1A.3.4.2.2 Pipeline Capacity. The ability to deliver natural gas from the location of reserves is dependent on the availability of pipeline capacity. The only natural gas pipeline serving Peninsular Florida is the Florida Gas Transmission (FGT) system. The FGT system has been and continues to be fully allocated to existing demand. The current pipeline cannot accommodate increased firm service demands.

FGT is in the process of expanding its pipeline capability through a construction program known as the Phase II expansion. As part of the Phase II process, all customers were asked to project their increased natural gas requirements. Because consolidated requests for increased service were so large, FGT was unable to satisfy the requests with the Phase II expansion. FGT customer requests for service were decreased on a prorated basis by FGT. For example, OUC's initial request for approximately 7.2 billion cubic feet (bcf) per year was reduced 15 percent by FGT to an allocation of approximately 6.1 bcf per year. Likewise, Kissimmee Utility Authority's initial request of 3.1 bcf per year was reduced by nearly 42 percent to 1.8 bcf per year.

FGT is in the preliminary stage of an additional expansion to be known as Phase III. According to FGT officials, the allocation process for Phase III will be similar to Phase II. Customers will nominate to FGT the increase in firm service desired. If the requests from FGT customers are large enough, it is reasonable to assume FGT will again reduce on a pro rata basis the quantity of service available. This makes planning on increased natural gas availability very difficult and risky.

The cost of the new allocation of service is also unknown. FGT will be unable to make reasonable estimates of service costs until the Phase III expansion is defined in a regulatory application. Even then, the cost and design of service rates will be uncertain until approved by the appropriate regulatory agencies and accepted by FGT.

In summary, the availability of natural gas reserves to fuel baseload electric generation is subject to question. Though the current deliverability is good now, only strong gas prices can ensure exploration activity for reserve replacement. Demand for gas has increased and apparently it will continue to increase, thus reducing excess deliverability and potentially supporting high prices. Pipeline capacity does not exist today for large incremental loads. On the basis of past expansion allocations, sufficient future capacity is uncertain. In addition, should the capacity be installed, its cost is unknown until regulatory approval is obtained.

All of these factors must be considered when evaluating the reliability of natural gas as a fuel for generating unit capacity additions. Currently, when all of these factors are analyzed, natural gas cannot be considered a reliable fuel for alternatives to the addition of Stanton 2.

1A.3.4.3 No. 2 Oil

The following subsections will discuss the current and future sources of No. 2 oil. This fuel could be used as startup fuel for a coal fired power plant, and as a backup or standby fuel for combustion turbines and combined cycle plants fueled with natural gas.

1A.3.4.3.1 Current Sources. During calendar year 1989, OUC purchased 11,000 barrels of No. 2 oil. This compares with purchases of 5,000 barrels in 1987 and 2,000 barrels in 1988.*

*One barrel contains 42 gallons.

OUC currently purchases No. 2 fuel oil from marketers or oil companies on a cost, insurance, and freight (CIF) bid basis, with deliveries in trucks with a capacity of about 7,500 gallons. Most shipments originate at product terminals located at Taft, Port Canaveral, and sometimes Port Manatee. The sulfur content is less than 0.3 percent.

The refineries which produced this No. 2 fuel oil tend to be located along the Gulf Coast, such as Port Arthur/Houston and New Orleans/Baton Rouge. Some No. 2 oil has also come from offshore refineries in the Caribbean. The crude oil sources for these refineries may be domestic or foreign. During 1989, the US imported about 43 percent of its crude oil requirements.¹¹ During 1989, the Organization of Petroleum Exporting Countries (OPEC) controlled about 38 percent of world crude oil production, which averaged 60.3 million barrels per day.¹² OPEC countries controlled about 80 percent of total known world crude oil reserves which totaled 999 billion barrels in 1989.¹²

The Middle Eastern countries control about 65 percent of world crude oil reserves and they accounted for 27 percent of total world production in 1989.¹²

In terms of years of remaining reserves on a world-wide basis, the reserves-to-production ratio (known reserves/annual production) shows about 45 years of remaining reserves. However, this ratio can be misleading because the production history for the typical oil or gas well tends to be one of exponential depletion. That is, most of a well's reserves are produced in the first few years of its operation. Therefore, if production isn't replaced on an annual basis, the deliverability from producing wells can decline significantly and the potential for supply disruption is increased.

Unlike coal, the majority of oil transactions occur in the spot market. Market prices are primarily established on world wide supply and demand considerations over short periods of time. One of the primary uncertainties regarding short-term supply has been OPEC policies regarding production quotas.

1A.3.4.3.2 Future Sources. The future supply of No. 2 fuel oil is likely to come from the same refineries that currently satisfy OUC needs. Crude oil sources for these refineries are likely to change with a shift toward importing more from Latin American and Canadian producers.

1A.3.4.3.2.1 Impact of Clean Air Act Amendments. Clean Air Act Amendments passed by Congress in November 1990 called for a reduction in the sulfur content of highway diesel fuel to 0.05 percent sulfur by weight. This requirement

is to be implemented by October of 1993. At the present time, most refiners produce a single grade of No. 2 fuel oil with a specification that satisfies the ASTM requirements for No. 2 heating oil and No. 2 diesel fuel. By producing a No. 2 fuel oil with properties that satisfy both specifications, they reduce distribution costs by avoiding double tankage and compartmentalization of delivery trucks. With the more stringent sulfur requirement for highway diesel fuel required by October 1993, it is not known whether refiners will produce a single No. 2 fuel oil with a 0.05 percent sulfur level or two fuels. One would be for off-highway diesel and heating oil use which could have a sulfur content up to the maximum ASTM allowed limit of 0.5 percent* and the other with 0.05 percent sulfur would be for highway diesel use.

Numerous considerations affect these decisions which will be made on a refinery specific basis. For example, some product pipelines have specifications on the maximum sulfur content allowed for fungible** fuels transported in their pipelines. The Colonial Pipe Line System currently limits the sulfur content of No. 2 fuel oil to 0.2 percent since it serves the mid-Atlantic markets which have such restrictions.

Should a single No. 2 fuel oil market develop with 0.05 percent maximum sulfur, the cost of No. 2 heating oil is likely to increase significantly. Should a tiered market develop, the higher sulfur fuels would sell at a substantial discount.

At this time, it is not known what air pollution control requirements would be required for power generation facilities using No. 2 fuel oil. It may be that future combustion turbines will have to be fired with a low-sulfur No. 2 highway diesel fuel, albeit at a higher price markup relative to the price of crude than has been suggested by past experience.

1A.3.4.4 No. 6 Oil

No. 6 or residual oil is often referred to as the "bottom of the barrel" after the lighter more profitable fractions have been removed from the crude. The lighter

*As more states and local authorities lower the sulfur content of fuels for off-highway use, this upper limit may have less significance.

**Designates movable goods such as grains or precious metals where any unit or part of which can replace another unit.

fractions usually sell at a premium, and the heavy oil sells at a discount. However, if market conditions lead to a significant No. 6 oil discount relative to crude, refining processes can be modified to extract more light ends from the residual oil with the resulting "waste product" being a solid petroleum coke. The price of residual oil relative to crude oil tends to range from a low level governed by the capital and operating costs associated with coking or other refining processes to "destroy the resid" and the price of crude oil.

1A.3.4.4.1 Current Sources. In 1989, OUC purchased 474,000 barrels of No. 6 oil compared to 1,130,000 barrels in 1986, before commercial operation of Stanton 1.¹³ OUC currently receives shipments of No. 6 oil for the Indian River Plant from refineries located along the Gulf Coast such as Port Arthur/Houston and New Orleans/Baton Rouge and other offshore refineries in the Caribbean. These shipments arrive at Port Canaveral in shipment lots which range from 100,000 to 200,000 barrels. The sulfur content of these shipments ranges from 1.0 to 1.8 percent. No. 6 oil for Stanton Energy Center, which is used during startup, is delivered by truck. The sulfur content is less than 0.7 percent. Since No. 6 oil is a product of the crude oil refining process, the crude sources would be the same as those for the other refined products discussed in Subsection 1A.3.4.3.1.

1A.3.4.4.2 Future Sources. The same refineries and distribution systems are likely to be used in the future for obtaining No. 6 oil. The crude oil sources are likely to shift in the manner discussed in Subsection 1A.3.4.3.2. One problem with shifting to some of the Latin American crudes, such as those from Venezuela, is that the specific gravity of the crude tends to be higher (API gravity is lower) than that of traditionally imported lighter crudes. This could increase the percentage of residual oil produced from a barrel of crude from the current 10 percent level, but it could also increase the economic incentive for installing coking units to recover more light ends which would destroy the excess residual oil.

1A.3.4.5 Coal Transportation

1A.3.4.5.1 Rail Transportation of Coal--Overview. The railroad servicing the Stanton Energy Center plant site is CSX Transportation, a unit of CSX Corporation. CSX Corporation is, in turn, a diversified enterprise operating within four primary lines of business (business units): transportation, energy, technology, and properties.

CSX Transportation (hereafter "CSXT") operates one of the largest coal-haul railroads in the United States and, through a wholly owned subsidiary (American Commercial Barge Lines), operates a major terminaling and large-haul system on the Ohio-Mississippi Rivers (and tributaries) of the eastern half of the nation. This rail and inland waterways transport system is linked to modern deep-water ports on the great lakes, Atlantic, and Gulf Coasts.

The CSXT rail network comprises approximately 18,800 route-miles of rail lines serving several hundred coal mines through the Appalachian coal region extending from north-central Alabama northeastward into southwestern Pennsylvania. CSXT also accesses major mines located in the Illinois Basin coal region of western Kentucky, southern Illinois, and southwestern Indiana. The locations of these coal regions are shown on Figure 1A.3.4-2.

In 1990, the total coal production in the United States was approximately 1.036 billion tons of which approximately 178.4 million tons (17.22 percent) were originated by CSXT railroads. Including traffic originated by other carriers raises the total coal tonnage handled by CSXT railroads to 186.6 million tons (18.01 percent of total US production). CSXT is the largest rail carrier of domestically produced coal in the United States. Additionally, approximately 24.1 million tons were handled by its subsidiary, American Commercial Barge Line Company on the inland waterways.¹⁵

CSXT is the dominant transporter of coal by rail into Florida. The movements use heavy-duty mainline trackage extending from both the Appalachian and Illinois Basin coal regions to access all rail-served utility power plants in Florida. These mainline corridors are shown on Figure 1A.3.4-7.

The CSXT rail system for coal movements to Florida utilities comprises two distinct routes--each having several partial alternative routings as discussed below.

1A.3.4.5.2 CSXT Appalachian Rail Corridor. The CSXT Appalachian Rail Corridor extends south from the major coal producing areas of eastern Kentucky with routing via Corbin, Kentucky; Knoxville, Tennessee; and Atlanta, Cordele, and Waycross, Georgia; to enter Florida at a point northwest of Callahan, Florida. This routing also picks up very limited tonnages of coals originating in Tennessee. Because of the large tonnages originating in eastern Kentucky, this routing is the primary corridor for unit train operations south from the Appalachian coal region to supply coal to Georgia and Florida destinations.

A partial alternative routing originates in the Big Sandy and Tug Fork Rivers area on the Kentucky-West Virginia border with routing south via Elkhorn City, Kentucky, and St. Paul and Speers Ferry, Virginia. This routing continues southward from Speers Ferry, Virginia, over former Clinchfield Railroad mainlines via Kingsport and Johnson City, Tennessee; Marion, North Carolina; to Laurens, South Carolina. At Laurens, South Carolina, the routing branches with one line running east to Savannah, Georgia, via Columbia, South Carolina, and the alternative line running south to Savannah via Greenwood, South Carolina, and Augusta, Georgia. After converging at Savannah, the routing continues southwest to rejoin the principal mainline at either Waycross or Folkston, Georgia. This corridor originates coals from mines located in extreme eastern Kentucky and southwestern Virginia.

The above principal corridors are crosstied in the coal regions by two lines extending between Beaver Junction and Blackey, Kentucky (the Rockhouse Creek-Deane Connection) and between Speers Ferry, Virginia, and Hagans, Kentucky (the Old Cumberland Valley Main-Norfolk Southern Connection). However, because of gradient, curvature, and other operational constraints, these crossties are not extensively used in movement to Florida destinations. A further partial alternative routing (which is also little used) extends from Greenwood, South Carolina, to rejoin the principal mainline corridor at Atlanta, Georgia.

A second partial alternative routing originates in the extreme western areas of West Virginia and runs north via Huntington, West Virginia, then west paralleling the south shore of the Ohio River before turning south at either Cattlettsburg or Newport, Kentucky to link up with the above corridors.

The Cattlettsburg to Newport line also serves as a fourth crosstie between the two north-south lines through the east Kentucky mine regions. Coal shipments occasionally move north to this Ohio River line before turning back to the south to relieve traffic blockages or congestion in the primary corridors. Because of its circuitous routing, this crosstie corridor carries minimal coal traffic destined for Florida. The CSXT Appalachian rail corridor originates major tonnages of coal for utilities located in the southeastern United States (North and South Carolina, Mississippi, Alabama, Georgia, and Florida utilities). These tonnages in 1989 totaled approximately 40.6 million tons. The CSXT Appalachian rail corridor also carries the major volume of rail coal destined for Florida (8.53 million tons in 1989), with the bulk of the coal originating in eastern Kentucky

(6.79 million tons) and Virginia (838 thousand tons). Originations from West Virginia mine areas are limited (608 thousand tons) because of higher transport costs associated with the longer haul distances to Florida utilities. These coal mine areas and 1989 origination tonnages for Florida use points are also shown relative to CSXT trackage on Figure 1A.3.4-8.¹⁶

The rail distance to Stanton Energy Center measured from Corbin, Kentucky, (the center for CSXT rail coal operations in the region) is 808 miles. Distances from Corbin to the various mine origins ranges up to 250 additional miles, depending upon location and routings, with the majority of the movements originating within 105 miles.

1A.3.4.5.3 CSXT Illinois Basin Rail Corridor. The Illinois Basin rail corridor extends from coal source areas in southern Illinois and southwestern Indiana southward--crossing the Ohio River at Evansville, Indiana--to service mines located on lateral branch lines extending west and east in western Kentucky from Madisonville, Kentucky. The corridor continues south via Nashville and Chattanooga, Tennessee, to intercept the Appalachian corridor routing near Cartersville, Georgia. This routing is little used for Florida coal traffic (less than 300 thousand tons in 1989) as the coals from these sources are (1) higher in sulfur content than the Appalachian Region coals and (2) generally move by water (barges on the Ohio, Mississippi, and Tennessee-Tombigbee Rivers) to gulf-port transload points for cross-gulf ocean-barge continuation to west-coast Florida ports.¹⁷ The Illinois Basin coal origination areas are also shown relative to CSXT mainlines on Figure 1A.3.4-8.¹⁷

The rail distance to Stanton Energy Center measured from Madisonville, Kentucky, is about 923 miles. Distances from Madisonville, Kentucky, to the principal mine loadouts in western Kentucky range from 26 to 31 miles (in additional distance) and up to 90 miles for Illinois and Indiana sources.

1A.3.4.5.4 CSXT Coal Mainlines Within Florida. After entering Florida, the CSXT mainline divides at Callahan, Florida. Most of the traffic (approximately 5.35 million tons in 1989) moves southwestward to Starke, Florida, with the remainder (3.18 million tons) continuing south to Jacksonville, Florida. From Starke and Jacksonville, the coal movements branch to various utility power plants as depicted on Figure 1A.3.4-9.

Note that a significant tonnage of coal (3.03 million tons) also enters Florida by intracoastal barges at Port St. Joe, Florida. At Port St. Joe, the coal is

transferred to unit trains and transported via the Apalachicola Northern Railroad (Port St. Joe to Chattahoochee, Florida and CSXT (Chattahoochee to Jacksonville, Florida) to intercept the primary corridor to Orlando, Florida at Jacksonville. This movement adds significant tonnage between Jacksonville and the Seminole Electric Cooperative, Inc., Palatka Plant (about 6 miles north of Palatka, Florida) to the rail corridor serving Stanton Energy Center.

A nominal tonnage of coal (340.6 thousand tons in 1989) is transported by CSXT from mines in western Kentucky to Gulf Power Company's Scholtz Plant west of Chattahoochee, Florida. This rail movement uses the CSXT Illinois Basin Rail Corridor, described in Subsection 1A.3.4.5.3, from the mines to Nashville, Tennessee. From Nashville, the routing continues south via Montgomery, Alabama, to Pensacola, Florida, and then east over the CSXT Panhandle mainline to the plant (Boykin, Florida). As this routing is totally detached from the CSXT coal routes to Florida utilities as outlined above, it has no impact on coal movements to Stanton Energy Center and is not depicted in Figure 1A.3.4-9.

1A.3.4.5.5 CSXT Track Standards and Current Traffic Levels. The CSXT mainlines identified above for the transport of coal to Florida are all heavy-haul corridors with facilities in place for the efficient and expeditious movement of unit coal trains. All rail lines are fully signaled with single- or double-line tracks. Installed trackwork is generally heavy-section rail (131 pounds per yard or higher) with high quality ties and ballast. Continuous welded rail (CWR) is in place in essentially all corridor segments carrying coal traffic to Stanton Energy Center. Exceptions include a short segment between Shelby and Elkhorn City, Kentucky, Big Stone Gap, Virginia, and Hagans, Kentucky, Kearney and Fairfax, South Carolina (via Augusta, Georgia) and south of Jacksonville, Florida (to approximately Orange Park, Florida). These segments are laid with intermediate rail sections (112 pounds per yard or higher weight in both jointed and CWR segments) and are likely to be upgraded to heavy-section CWR in the near future. Trackwork is maintained to high standards of line and grade to facilitate both general merchandise freight as well as unit train coal movements to and from the Georgia-Florida region.¹⁸

Traffic levels carried by the CSXT Appalachia to Florida mainlines are moderate to heavy in density. Levels in the Manchester, Kentucky, to Callahan, Florida, corridor ranged from 27.4 to 72.2 million gross tons in 1989, with the majority of the line segments carrying 45 to 65 million gross tons. Traffic

direction is approximately 2 to 1 southbound versus northbound as could be expected for both coal and merchandise shipments bound to southeastern destinations.¹⁹

Traffic over the secondary CSXT Appalachian rail corridor to Florida (Beaver Jct., Kentucky, to Waycross, Georgia) is considerably lower, ranging between 14.4 and 37.7 million gross tons in 1989, with the bulk in the 25 to 35 million gross tons levels. As in the primary corridor, traffic is predominately southbound at ratios of roughly 2.5:1.

Traffic on the Evansville, Indiana, to Junta, Georgia, mainlines from Illinois Basin mines ranged from 23.8 to 38.0 million gross tons in 1989 and is also in a 2:1 southbound to northbound ratio.

The use of multiple north-south corridors between the coal source regions and southeastern US utility destinations allows the dispersal of movement flows to alleviate any "bottlenecks" in train operations. Present levels of coal traffic (when combined with non-coal traffic) are well within the capacity of the corridor line facilities as currently signaled and maintained. Movements generally encounter minimal delays and "fleeting" of trains to increase operational throughput are not used except in localized areas and for short durations.

1A.3.4.5.6 Projections of Future CSXT Rail Traffic. Projections of future trends in coal traffic on CSXT mainlines serving Florida utilities are dependent upon a number of major factors:

- Development of new coal-fueled generation facilities in the southeastern United States (primarily in Florida) having (or limited to) rail delivery for fuel.
- Extent and nature of fuel-switching (Illinois Basin to Appalachian coal region) employed by rail-dependent southeastern US utilities (principally the Southern Company operating subsidiaries) in response to Phase I compliance with 1990 Clean Air Act Amendments sulfur constraints (Phase I emission limits of 2.5 lb SO₂/MBtu by 1995). A related fuel-switching issue is the extent (tonnages) of market penetration of western United States (Powder River Basin) and foreign origin low-sulfur coals at specific utility plants in the southeastern United States.
- Type and nature of combustion and emissions control systems for coal-fueled facilities to be developed and installed to comply with Phase II limits (1.2 lb SO₂/MBtu by the year 2000) and the degree to which

utilities return to "traditional" (pre-Clean Air Act Amendments of 1990) source areas for coal supply.

These issues are complex, interrelated, and subject to significant uncertainties in forecasting the future. Nevertheless, aspects of the above factors which will influence future CSXT coal traffic levels and operations are summarized below.

1A.3.4.5.6.1 Future Coal Capable Generation Projects in Florida. Coal capable power plants which have either received need for power certification or have had need for power certification hearings held before Florida Public Service Commission include the following.

	<u>Net Capacity</u> MW	<u>Average Coal Use</u> million tpy
FPL Martin Units 3 and 4 (Future GCC)	770	2.3
Indiantown Cogeneration, LP (PC)	330	1.0
AES Cedar Bay Cogeneration (CFB)	250	1.0

The coal sources for the above projects are forecast as being within the traditional coal supply areas (Appalachian and Illinois coal regions) presently used by Florida utilities. Transport of coal is projected as employing the CSXT system except for the FPL Martin Plant which will be served by both CSXT and FEC rail lines.

Stanton 2 is projected to consume an average of about 1.1 million tons of coal per year. Under the most probable scenario, this tonnage will be transported by unit trains along the Corbin-Jacksonville-Orlando CSXT rail corridor employed by Stanton 1 movements.

The impacts of additional coal traffic on the CSXT system generated by the above projects are speculative as they depend upon project in-service schedules, coal sourcing points, and procurement strategies which are not fully definable at this time. However, for purposes of this study, the following factors are assumed.

- All projects are commercial at forecast coal usages by year 2000.
- The FPC Martin and AES Cedar Bay plants are forecast as primarily sourcing higher-sulfur coals from the Illinois Basin coal region owning to advanced sulfur emissions reduction technologies inherent in the coal gasification and fluidized bed combustor technologies to be employed by these projects.

- The Indiantown and Stanton 2 projects are forecast as sourcing lower-sulfur coals from CSXT-served Appalachian coal region mines.

Assuming the development and operation of all of the above power generation projects in accord with the above projections, the resulting rail movements of coal over the Florida rail system by the year 2000 are shown on Figure 1A.3.4-10.

It should be noted that the CSXT Jacksonville-Orlando rail corridor is anticipated as accommodating only increased coal deliveries for Stanton 2. All other increases in Florida coal traffic are forecast as being routed via Callahan, Baldwin, Ocala, and Lakeland, Florida, to the various plants.

Additional coal-fueled generation projects to meet electrical needs in the late 1990s and later are in varying stages of the planning process for other locations within Florida. These projects have not progressed sufficiently to identify unit capacities, combustion technologies, and coal sourcing-transport linkages at this time.

1A.3.4.5.6.2 Future Coal Switching Strategies for Southeastern United States Utilities. The enactment of the Clean Air Act Amendments of 1990 has created a major degree of uncertainty with respect to future sourcing of coals for utilities located in the southeastern US. Virtually all utilities operating plants which lack modern flue gas SO₂ emissions control systems are evaluating the options of switching to lower sulfur sources versus the installation of flue gas desulfurization systems.

Scrub versus switch decisions are complex and dependent upon the interaction of site-specific variables and compliance with implementation regulations which are yet to be issued. The 1990 Clean Air Act Amendments identify 13 power plants located in the southeastern US (Alabama, Mississippi, Tennessee, and Florida) which will require facilities or operational modifications to comply with Phase I standards.²⁰ Four of the power plants are exclusively served by river barges or ocean vessels and are projected as exclusively continuing that delivery mode in future coal supply scenarios. The nine remaining power plants are served by rail either as captive destinations or as an alternative to barge deliveries. Five of the nine plants use Norfolk Southern (NS) as the delivering rail carrier. Four plants have CSXT service either as a captive destination (GPC Plant Bowen), joint service destination with NS (GPC McDonough Plant), or as an alternate to barge service as the primary coal transport mode (TVA Gallatin and

Johnsonville Plants). A forecast overview of the impacts on the coal traffic levels of the CSXT Appalachian to Florida rail corridors resulting from potential compliance strategies is summarized below.

The Alabama Power Company's E. C. Gaston Plant (jointly owned with Georgia Power Company) located near Wilsonville, Alabama, is projected to employ fuel switching for Phase I compliance. The plant is solely served by NS as the delivering carrier for coals originating primarily in Alabama and NS-origin areas of Tennessee and Kentucky. The switching in sourcing is anticipated as de-emphasizing the higher sulfur Alabama source regions in favor of lower-sulfur coals originating in NS-served areas of Tennessee, eastern Kentucky, and western Virginia. Impacts of these coal sourcing initiatives should be minimal with respect to CSXT-served coal areas and CSXT Kentucky to Florida coal traffic patterns.

The Tennessee Valley Authority (TVA) has two power plants (Gallatin and Johnsonville Plants) which are served by CSXT; however, these plants are also served by barge service from the Cumberland and Tennessee Rivers, respectively. The preponderance of coal received at these plants is delivered by barges originated on the Ohio River system in both the Illinois River and Central Appalachian coal regions.

TVA is forecast as employing a strategy to either switch to Powder River Basin coal or to retrofit flue gas desulfurization systems at their larger and more modern steam plants (Paradise and Cumberland) to free up sufficient sulfur dioxide allowances for use at other system plants under "substitution" provisions of the 1990 Clean Air Act Amendments.²¹ This should allow continuation of coal procurements generally from historic source areas for all remaining TVA Phase I plant's with minimal switching to lower-sulfur coals within each area. In any case, any impacts of changes of coal procurements made by TVA should have only minor influence on market competition within the traditional east Kentucky, West Virginia, and southwestern Virginia coal regions and negligible impacts on rail coal traffic patterns for coals moving south to supply Georgia, North and South Carolina, and Florida utilities.

Georgia Power Company (GPC) has five power plants identified as "affected sources" under the 1990 Clean Air Act Amendments. Three of these plants (Hammond, Wansley, and Yates Plants) are served exclusively by the NS, one plant (Plant Bowen) is served solely by CSXT, and one plant (John McDonough Plant) is jointly served by both NS and CSXT. The strategy to be employed by

Georgia Power Company to meet Phase I requirements (while still under development) is forecast as probably incorporating the following elements.

- No installation of flue gas desulfurization at any existing power plant units.
- Integration of fuel switching strategies for sulfur emissions compliance with companion fuel switching strategies to favor system plants having the lowest fuel costs (i.e., "marginal fuel" method for dispatching coal-fueled generation implemented in January 1991).
- Switching of units having high fuel costs (principally Plant Scherer) to low-sulfur Powder River Basin source coals to both reduce costs and create sulfur dioxide allowances for transfer to other units in the GPC system.
- Higher levels of dispatch from other GPC power plants having both lower-sulfur level coal sourcing and delivered coal costs (i.e., Plants Bowen and Branch served by CSXT) at the expense of higher fuel cost plants (Hammond, Wansley, and Yates Plants served solely by NS).

Georgia Power Company initiated the above strategies in the second half of 1990 by switching procurements at certain plants (i.e., McDonough, Wansley, and Yates) from higher-sulfur Illinois Basin sources to lower-sulfur central Appalachian sources to the extent permitted by long-term contractual commitments. GPC also initiated in late 1989 a test firing program to evaluate Powder River Basin (Wyoming origin) low-sulfur coals to reduce high contractual costs of West Virginia origin coals at Plant Scherer and as blend coals with high-sulfur coals at McDonough, Wansley, and Yates Plants. These test firing programs are continuing and may lead to a significant tonnage of Powder River Basin coal (to 12 million tons per year) being procured for GPC plants for the near term.

The Powder River Basin coal is projected as backing down coal consumption from both Appalachian and Illinois Basin sources at GPU's plants having higher fuel costs (i.e., Branch, Hammond, Wansley, and Yates) all served by NS as the delivering rail carrier. These Powder River Basin rail movements will probably employ the NS as the delivering carrier from interchanges with western railroads at either Memphis, Tennessee (Union Pacific System) or Birmingham/Pride, Alabama (Burlington Northern Railroad). Plants served solely by CSXT (Bowen and Mitchell) are forecast to be only minimally impacted by any Powder River Basin coal procurements through 1995. Plants served jointly by CSXT and NS

(Branch and Atkinson-McDonough) are forecast as experiencing modest reductions in deliveries of Appalachian origin coals back-down of generation dispatch by other plants burning lower cost coals. Practically all losses in coal consumption are forecast as being incurred by NS-served mine areas and rail movements.

CSXT-serviced power plants located within North and South Carolina and Florida are either equipped with flue gas desulfurization systems or presently burn low-sulfur coals. These plants are in compliance with the 1990 Clean Air Act Amendments Phase I standards. These plants are forecast as continuing their historic coal sourcing practices, thereby imposing minimal changes in rail coal traffic patterns within the CSXT Appalachian rail corridors to Florida.

1A.3.4.5.6.3 Future Coal Procurement Strategies for Compliance with 1990 Clean Air Act Amendments Phase II Standards. Existing power plants will be required to comply with SO₂ emission limitations of 1.2 lb SO₂/MBtu by the year 2000 under Phase II standards of the Clean Air Act Amendments of 1990. These standards are forecast to result in the following compliance and fuels procurement strategies for southeastern US utilities in the late 1990s:

- Retrofit installation of flue gas desulfurization systems on existing generation units lacking SO₂ removal capability. In the absence of significant breakthroughs in reducing capital and operating costs of the desulfurization technologies, the systems will probably be installed at the larger capacity and newer/most efficient generating units.
- Low-sulfur (less than 1.2 lb SO₂/MBtu) coals will be switched from the above plants and used for older and smaller units operating in standby/peaking service or, alternatively, the units will be retired.
- Powder River Basin coals will maintain market share established in the 1991 to 2000 period because of abundant reserves and mine capacity, favorable production and transport economics, and low-sulfur content (0.75 to 1.1 lb SO₂/MBtu) of this coal.

Most new plants constructed after the late 1970s and furnished with BACT emissions control technologies will be capable of using higher-sulfur content coals. This will help restore the use of some (although not all) of the historical higher-sulfur coal sources within the Illinois Basin and Appalachian coal regions. New coal cleaning and combustion technologies (most notably integrated coal gasification combined cycle) capable of meeting high emissions standards and

environmental-resource usage constraints are forecast as appearing after year 2000. The development and maturation of these technologies will also tend to restore traditional coal sourcing practices.

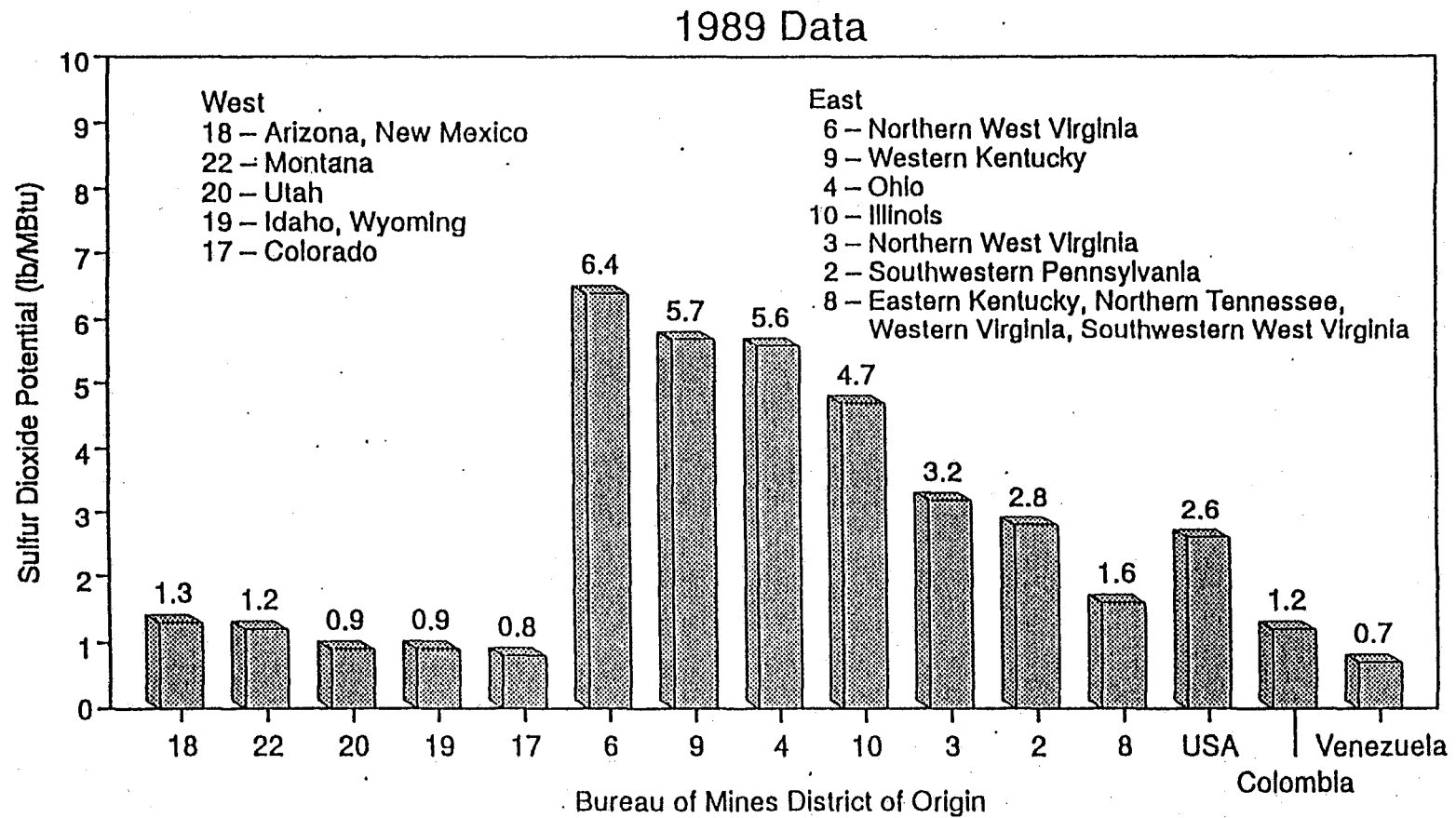
1A.3.4.5.6.4 Summary of CSXT Rail Traffic Projections. The projections of future trends in coal traffic of CSXT mainlines between the anticipated source area (Central Appalachian coal region) and Stanton Energy Center are for modest increases through the year 2000 because of new rail-served projects (including Stanton 2) within Florida and slight growth in Savannah Electric and Georgia Power Company coal use for CSXT destination power plants.

Traffic projections after 2000 are more conjectural, depending upon the location and unit sizes of new coal-capable plants to be built in Georgia, North and South Carolina, and Florida and the market share lost by CSXT to water-borne foreign origin (or Tidewater US origin) coals and Powder River Basin origin coals delivered to Florida plant and port locations.

In view of the track capacities remaining above present-day traffic levels within the CSXT Appalachia to Florida rail corridors, no significant constraints on the efficient and timely movement of unit trains from either Illinois Basin or Central Appalachian coal regions to Stanton Energy Center are envisioned for the foreseeable future.

Table 1A.3.4-1
1989 Central Appalachia Coal Deliveries to US Utilities

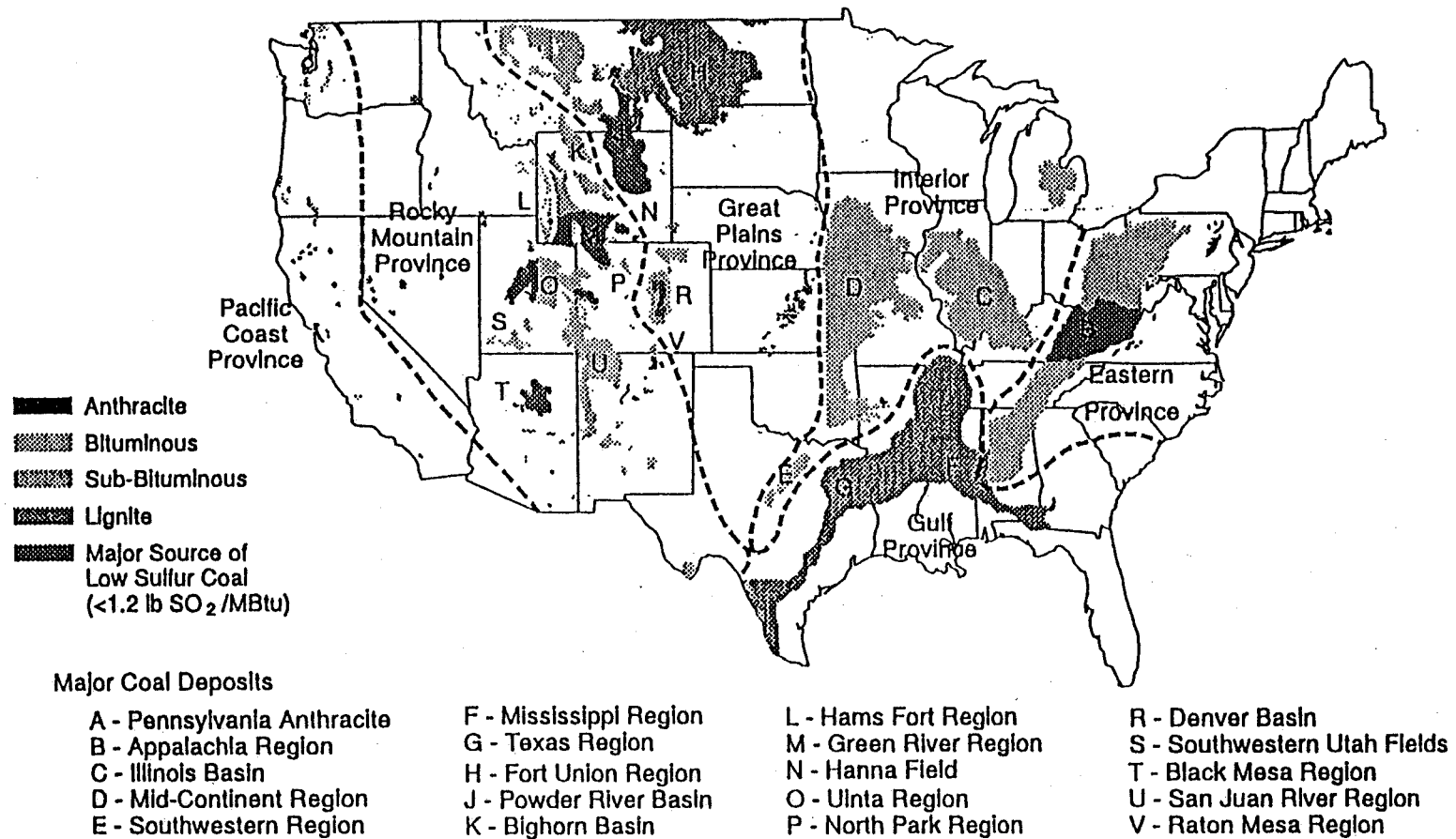
State	Quantity (1,000 tons)	Heating Value (Btu/lb)	Sulfur		Ash (percent)
			(percent)	(lb SO ₂ /MBtu)	
East Kentucky	81,162	12,375	1.1	1.7	9.7
Northern Tennessee	4,019	12,587	1.4	2.3	9.6
West Virginia	17,965	12,894	1.1	1.8	9.4
Southwestern West Virginia	40,562	12,385	0.8	1.3	10.9
Total or Average	143,708	12,449	1.0	1.6	10.0
Source: Resource Data International.					



Source: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants, 1989

WEST VS EAST – SO₂ EMISSION POTENTIAL

Figure 1A.3.4-1



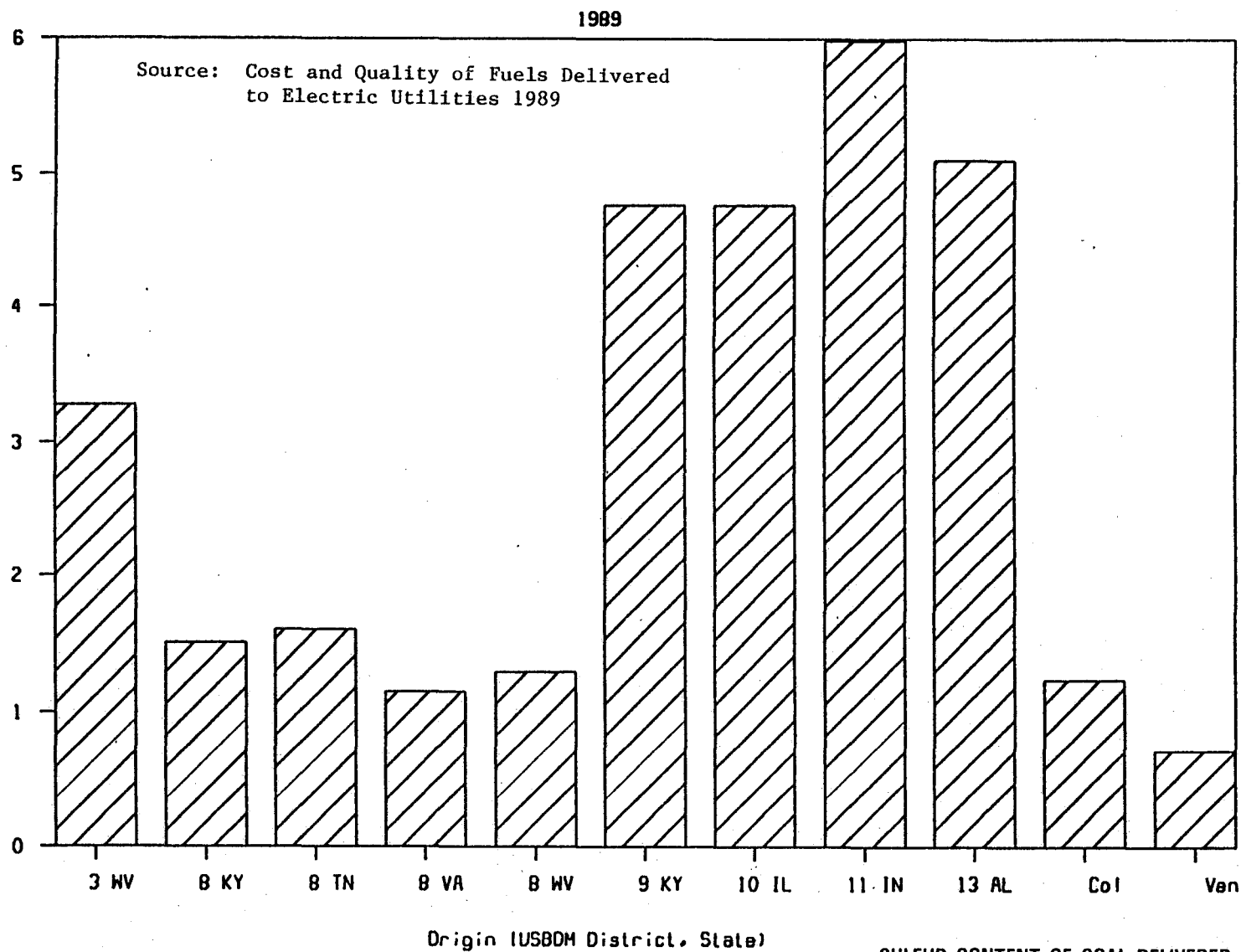
COAL FIELDS OF THE CONTERMINOUS UNITED STATE

Figure 1A.3.4-2

031591

1A.3.4-27

Uncontrolled Sulfur Dioxide Emission Potential (lb/MBtu)



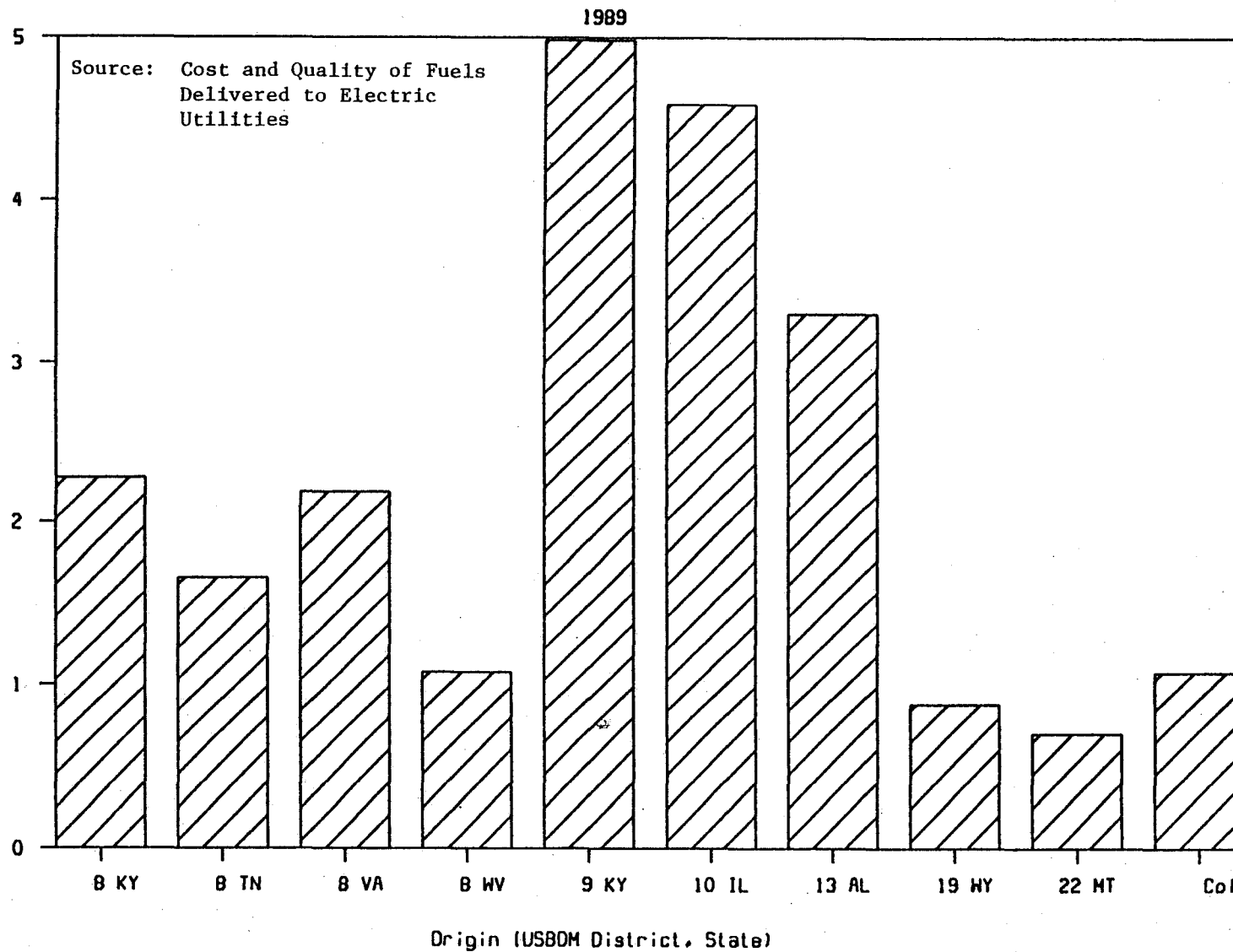
SULFUR CONTENT OF COAL DELIVERED TO FLORIDA ELECTRIC UTILITIES

Figure 1A.3.4-3

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1A.3.4-28

Uncontrolled Sulfur Dioxide Emission Potential (lb/MBtu)



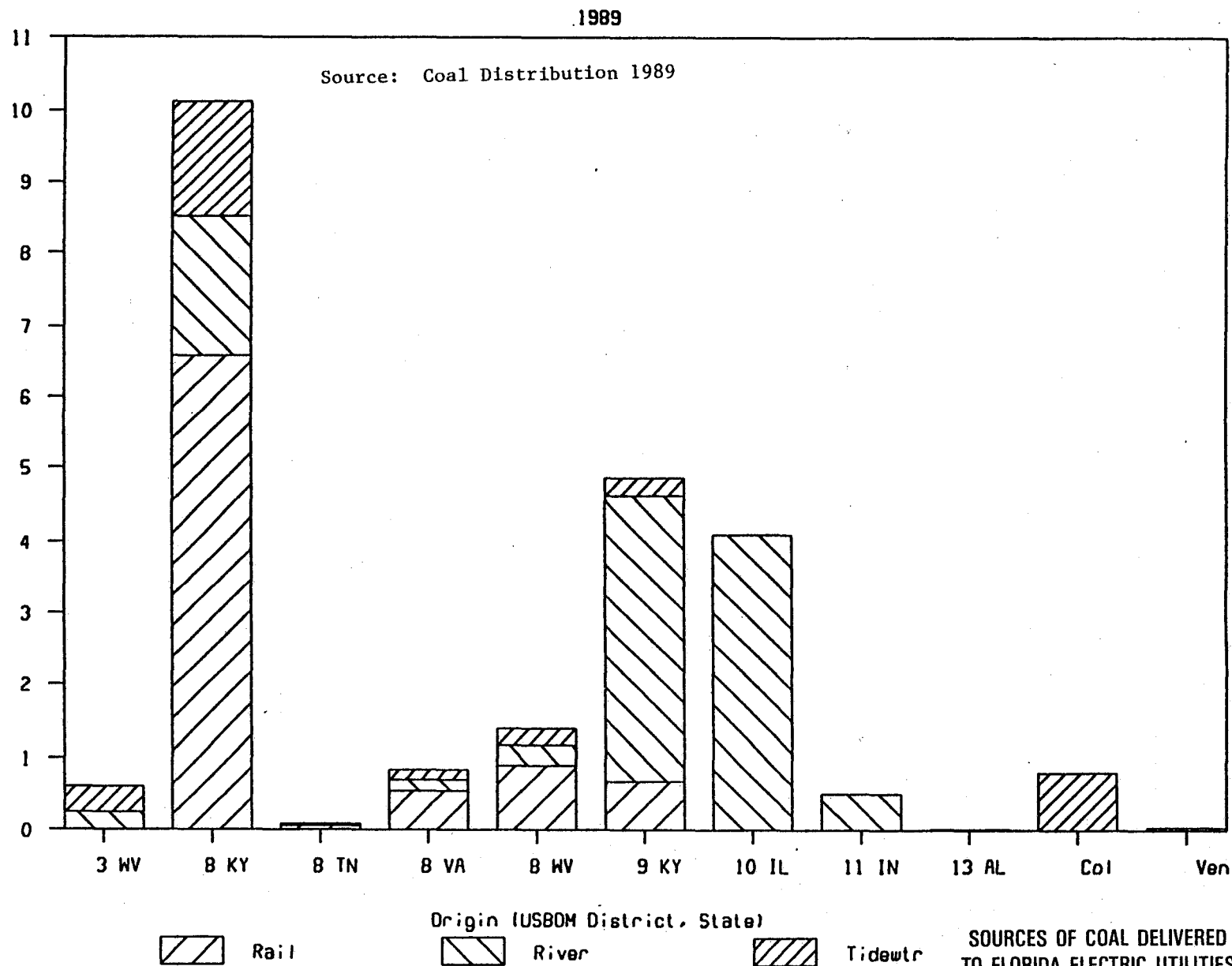
SULFUR CONTENT OF COAL DELIVERED
TO GEORGIA ELECTRIC UTILITIES

Figure 1A.3.4-4

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1A.3.4-29

(Thousands of
Short Tons)



SOURCES OF COAL DELIVERED
TO FLORIDA ELECTRIC UTILITIES

Figure 1A.3.4.5

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1A.3.4-30

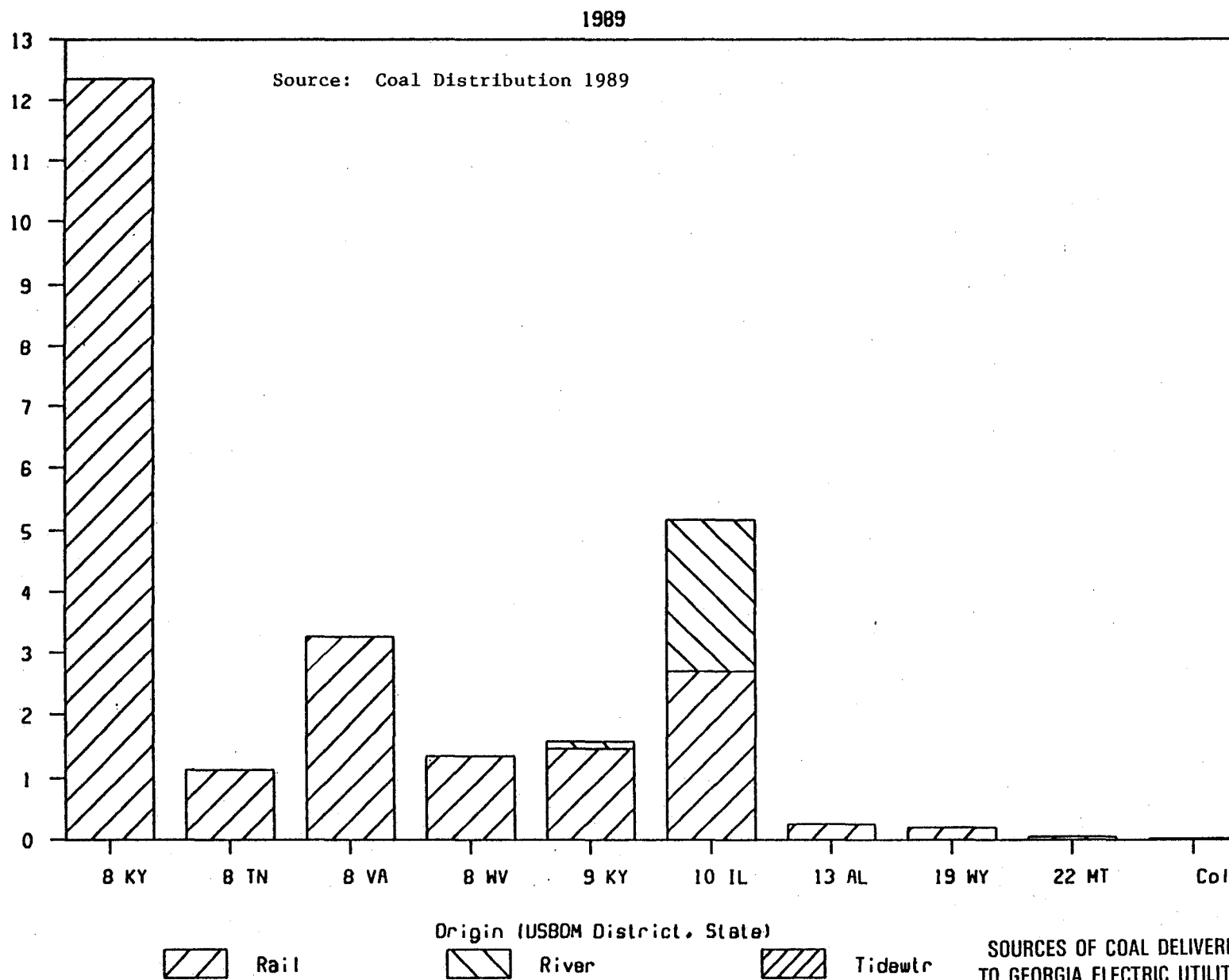
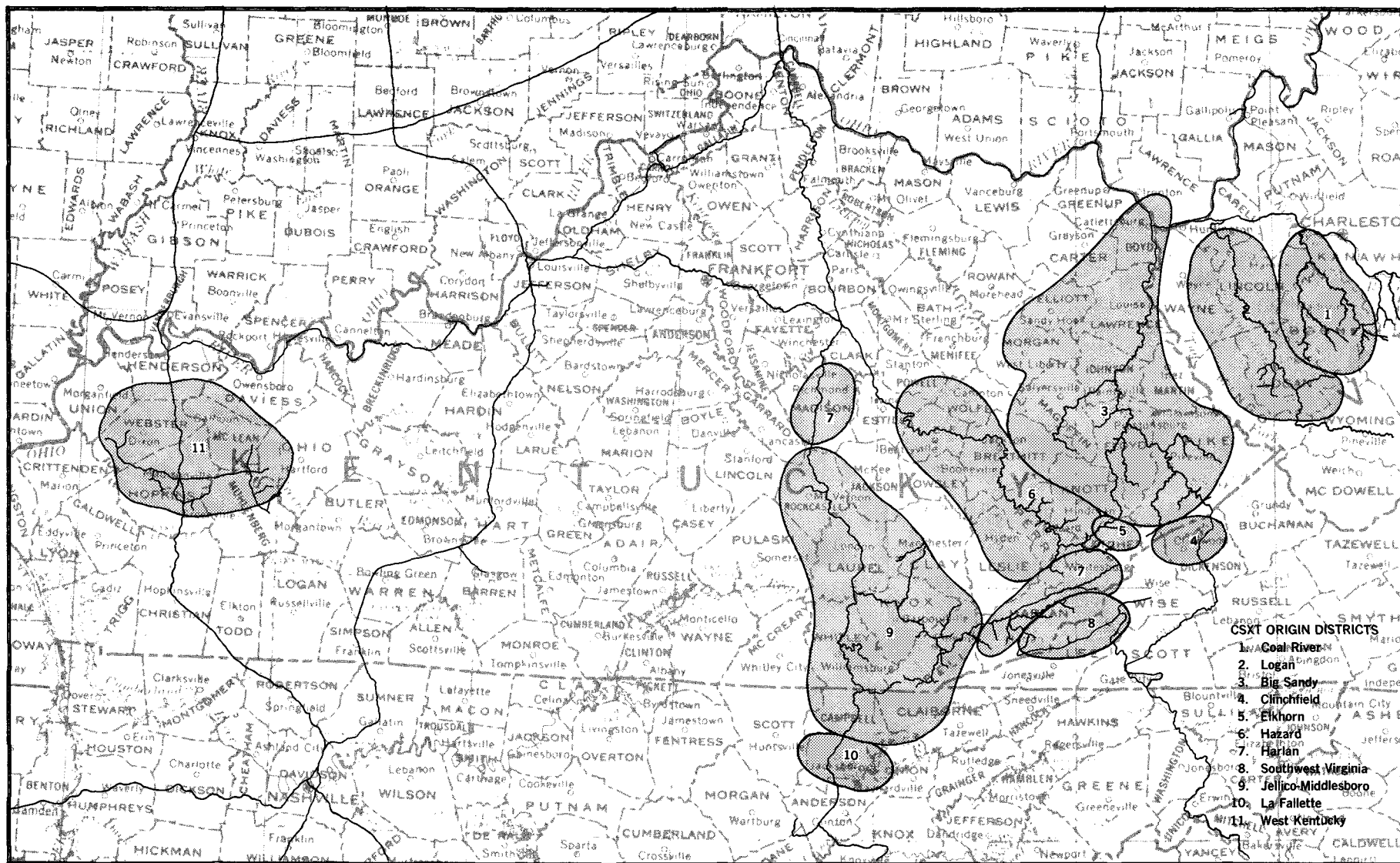
(Thousands)
Short Tons

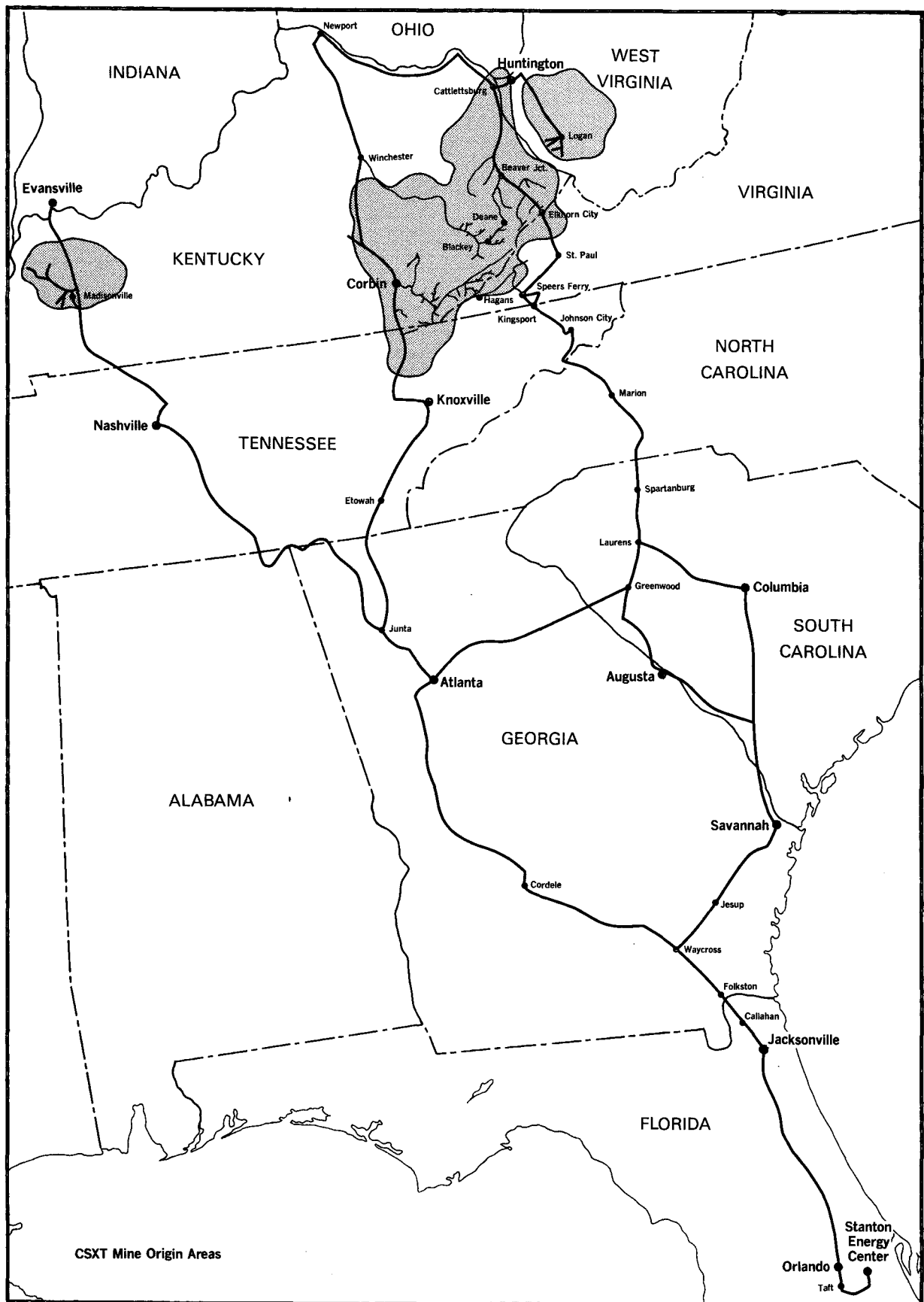
Figure 1A.3.4-6

Image Quality

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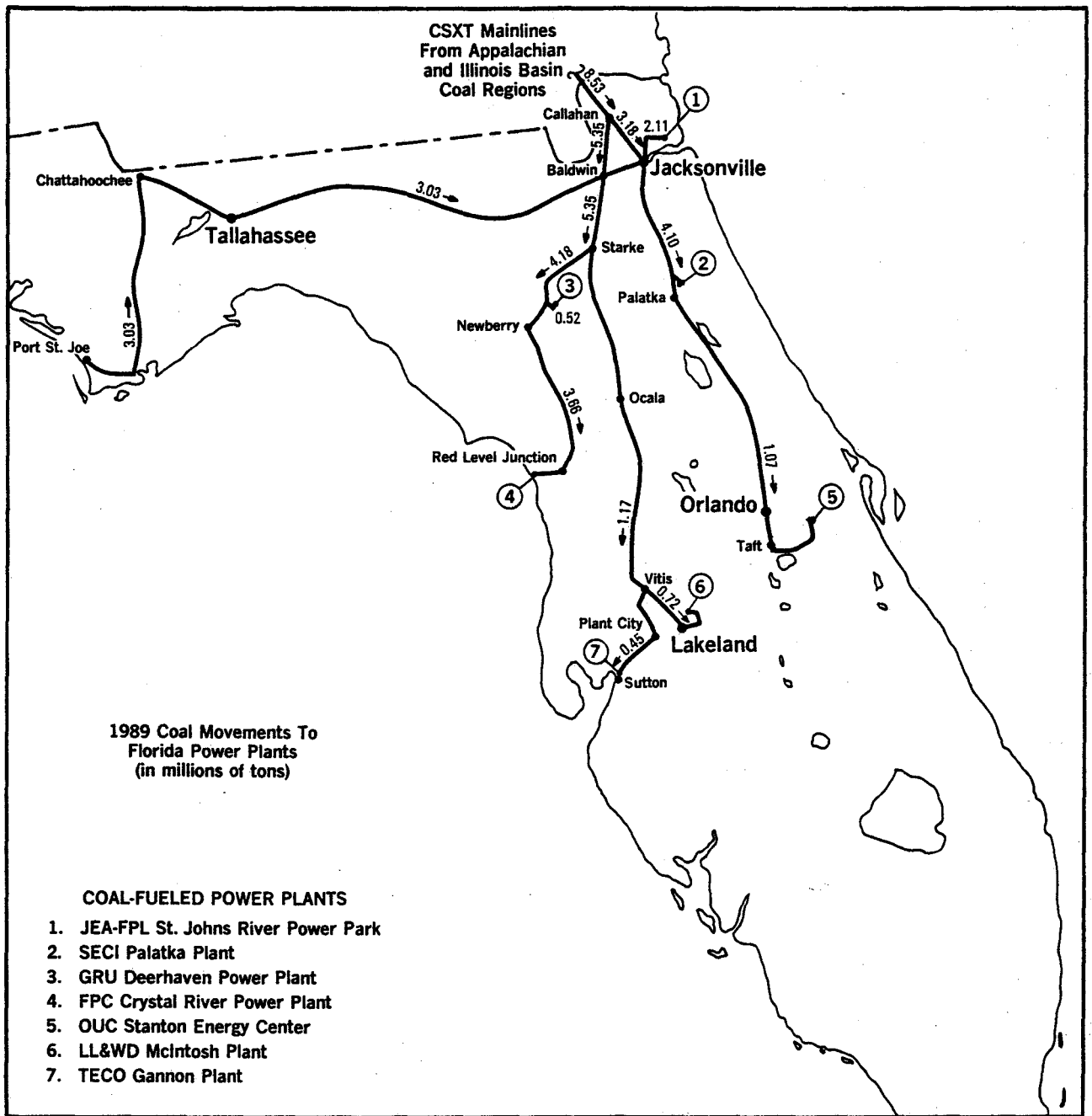


CSXT RAIL LINES AND MINE AREAS SUPPLYING
COAL TO GEORGIA AND FLORIDA UTILITIES



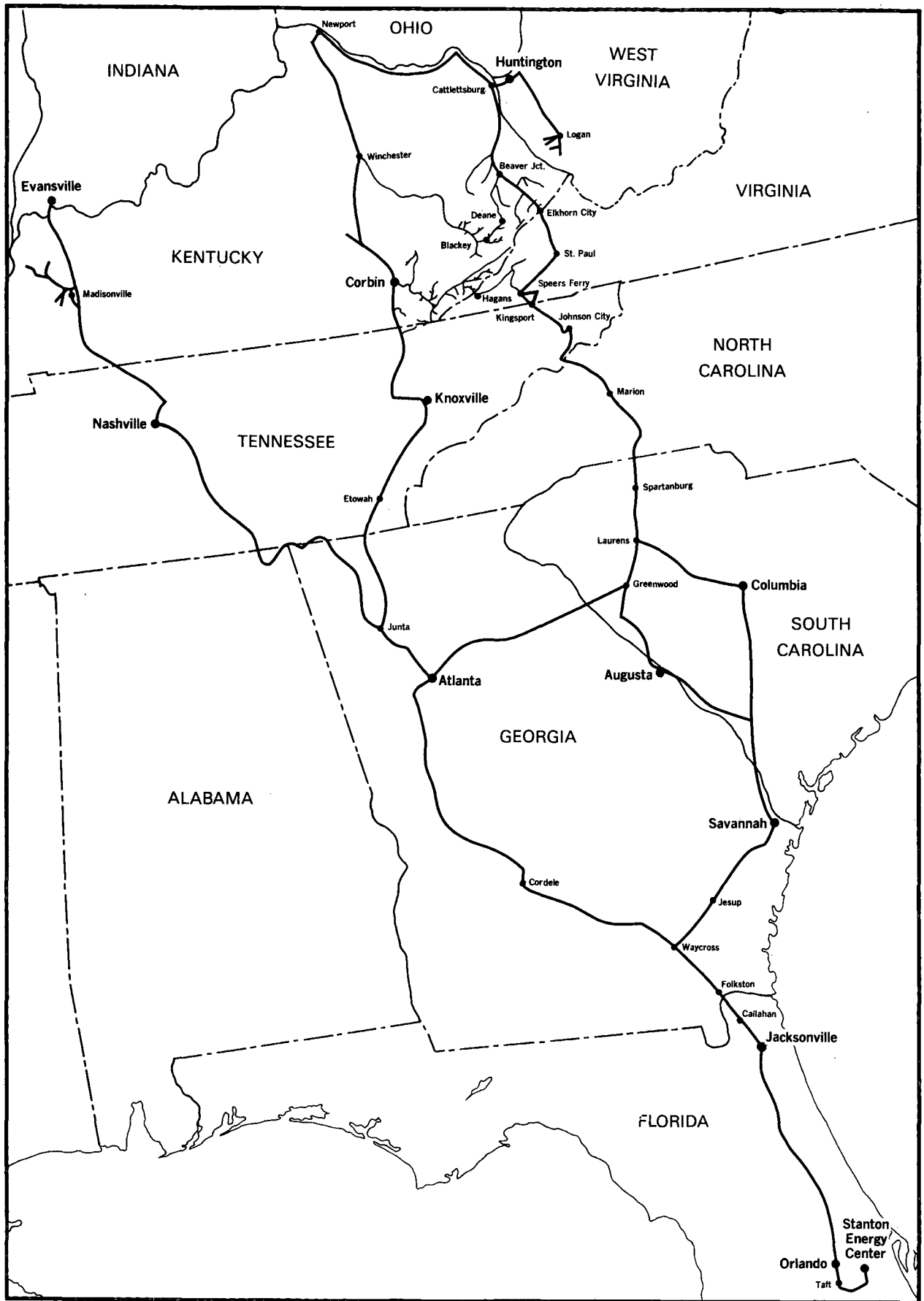
**CSXT RAIL CORRIDORS BETWEEN APPALACHIAN AND
ILLINOIS BASIN COAL REGIONS AND STANTON ENERGY CENTER**

FIGURE 1A.3.4-7



CSXT RAIL CORRIDORS WITHIN FLORIDA

FIGURE 1A.3.4-9



FUTURE COAL TRAFFIC LEVELS IN
CSXT RAIL CORRIDORS BETWEEN APPALACHIAN AND
ILLINOIS BASIN COAL REGIONS AND STANTON ENERGY CENTER

FIGURE 1A.3.4-11

1A.3.5 References

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16. Federal Energy Regulatory Commission (FERC) Form 423 monthly filings by Florida utilities by 1989 as compiled in the "Coalcat" data base published by Resources Data International, Inc.
17. FERC Form 423 filings (1989) for Florida utilities.
18. Personal communications with CSXT coal and facilities engineering personnel.
19. CSXT "Tonnage Chart for Year 1989," July 3, 1990.
20. "Table A - Affected Sources and Units in Phase I and Their Sulfur Dioxide Allowances," Section 404 of Title IV, Acid Deposition Control, Clean Air Act Amendments of 1990, P.L. 101-549 (November 14, 1990). The 13 power plants identified and their mode/rail carrier for coal deliveries are as follows:

Alabama

TVA Colbert 1-5	Tennessee River MP 245.3
	NS (after 1991)
APC E.C. Gaston 1-5	NS

Florida

TECO Big Bend 1-3	Tampa Bay Ship Channel
GPC Crist 6 and 7	Escambia River MP 200.3

Georgia

GPC Bowen 1-4	CSXT
GPC Hammond 1-4	NS
GPC J. McDonough 1 and 2	CSXT/NS
GPC Wansley 1 and 2	NS
GPC Yates 1-7	NS

Tennessee

TVA Allen 1-3

TVA Cumberland 1 and 2

TVA Gallatin 1-4

TVA Johnsonville 1-10

Mississippi River MP 720.3

Cumberland River MP 104.0

CSXT and Cumberland River MP 243.0

CSXT and Tennessee River MP 100.0

No plants located in North and South Carolina are included in the Table A listing.

21. Section 404(b) of Title IV, Acid Deposition Control, Clean Air Act Amendments of 1990, P.L. 101-549 (November 14, 1990).

1A.4.0 Consistency With Peninsular Florida Needs

The Florida Electric Power Coordinating Group, Inc. (FCG), conducts Peninsular Florida planning studies requested by the Florida Public Service Commission (PSC) from time to time to be reviewed at formal Planning Hearings. The most recent Planning Hearing for which a final PSC order has been issued was the 1989 Planning Hearing conducted under PSC Dockets 880004-EU, 890004-EU, and 900004-EU. The results of the 1989 Planning Hearing are contained in PSC Order No. 22341. FCG filed the following three documents as part of the 1989 Planning Hearing.

- Forecast Document.
- Generation Expansion Planning Studies.
- 20-Year Plan.

The Generation Expansion Planning Studies document includes a Long-Range Planning Study and an Avoided Unit Study.

1A.4.1 Peninsular Florida Capacity Needs

Table 1A.4.1-1 compares the Peninsular Florida projected peak demand to the installed capacity, contracted firm interchange, and projected net capacity to grid from qualifying facilities from the 20-Year Plan. In addition, projects which have been certified by the PSC since the 20-Year Plan was prepared have been included. Table 1A.4.1-1 apparently double counts 180 MW of capacity from the AES Cedar Bay Project since this capacity was also included in the projected net capacity to grid from qualifying facilities as a 180 MW unit in the 20-Year Plan. Even with the extra 180 MW of capacity, Table 1A.4.1-1 indicates that Peninsular Florida's reserve margin decreases to 13 percent for the 1997/98 winter period indicating a need for capacity addition based on a 15 percent reserve margin criteria.

The Generation Expansion Planning Studies use a 0.1 day per year loss of load probability (LOLP) reserve criteria. Based on this criteria and the evaluations conducted in the Long-Range Planning Study, reserve margins of between 6,076 and 6,609 MW are required for winter periods 1991/92 through 2000/01. Table 1A.4.1-1 indicates that reserve margins are below these levels beginning with the 1991/92 winter period. By the 1996/97 winter period, over 1,000 MW of additional capacity is required.

Based on either a 15 percent reserve margin criteria or a 0.1 day per year LOLP criteria, the 440 MW capacity of Stanton 2 is needed for reliability purposes for Peninsular Florida on or before the scheduled January 1, 1997, commercial operation date.

Table 1A.4.1-1

Year	Existing and Certified (MW)*	Installed Capacity	Contracted Firm Interchange (MW)*	Projected Net to Grid From QF (MW)*	Total Available Capacity (MW)	Coincident Firm Peak Demand (MW)*	Reserve Margin	
		Subsequent Certified Plus Other Noncertified Additions (MW)**					Amount (MW)	Percent
AT TIME OF SUMMER PEAK								
1991	30,147	20	2,400	389	32,956	25,824	7,132	28
1992	30,400	103	1,700	539	32,742	26,524	6,218	23
1993	30,426	1,723	1,225	770	34,144	27,165	6,979	26
1994	30,425	2,408	1,350	801	34,984	27,851	7,133	26
1995	30,671	2,793	1,500	822	35,786	28,411	7,375	26
1996	30,619	2,793	1,500	863	35,775	28,959	6,816	24
1997	30,618	2,793	1,500	874	35,785	29,580	6,205	21
1998	30,581	2,793	1,500	895	35,769	30,203	5,566	18
1999	30,567	2,793	1,500	926	35,786	30,800	4,986	16
2000	30,224	2,793	1,500	947	35,484	31,538	3,926	12
AT TIME OF WINTER PEAK								
1991/92	31,431	20	2,400	399	34,250	28,374	5,876	21
1992/93	31,530	661	2,000	729	34,920	29,100	5,820	20
1993/94	31,593	2,053	1,775	780	36,201	29,888	6,313	21
1994/95	31,577	2,438	1,600	811	36,426	30,587	5,839	19
1995/96	31,819	2,823	1,500	832	36,974	31,202	5,772	18
1996/97	31,785	2,823	1,500	873	36,981	31,961	5,020	16
1997/98	31,751	2,823	1,500	884	36,958	32,626	4,332	13
1998/99	31,731	2,823	1,500	915	36,969	33,248	3,721	11
1999/00	31,480	2,823	1,500	946	36,749	34,084	2,665	8
2000/01	31,346	2,823	1,500	967	36,636	34,819	1,817	5

*As shown in "1989 Planning Hearing 20-Year Plan."

**1991: KEY, 2 Diesel Units 20 MW.

1992: LAK, Larsen 8, 83 MW; OUC Indian River C&D, 258 MW; FPC DeBary Site, 300 MW.

1993: FPL, Repower Lauderdale 4 and 5, 572 MW; AES-Cedar Bay, 225 MW; and TEC-Seminole, Hardee Power Station, 295 MW; FPC, Northeast substation, 300 MW.

1994: FPL, Martin 3, 385 MW.

1995: FPL, Martin 4, 385 MW.

1A.4.2 Consistency With Avoided Unit

The Avoided Unit Study identifies the best combination of study selected base, intermediate, and peaking generating unit alternatives for 1992 through 1995 to meet the LOLP criteria. Generic unit additions include a 500 MW conventional coal unit, a 220 MW combined cycle unit, and a 75 MW combustion turbine unit. Technical characteristics of these units were based on Electric Power Research Institute's, *Technical Assessment Guide*, Table 2. Selection of best combinations are based on cumulative present worth revenue requirements and strategic considerations.

The Avoided Unit Study selected combinations of combined cycle units for 1992 and 1993, and selected combined cycle units and a combustion turbine for 1994. For 1995, the study found the best combination to be a conventional coal unit, two combined cycle units, and two combustion turbine units. The difference between cumulative present worth revenue requirements of the selected combinations and alternative combinations is small for many of the alternatives studied.

PSC Order No. 22341 designates a 385 MW combined cycle unit as the statewide avoided unit for 1993, 1994, and 1995. On reconsideration, PSC Order No. 23234 finds that the statewide avoided unit should be a 500 MW conventional coal unit with an in-service date of 1996.

Stanton 2 will be the second unit at an existing certified generation site. Stanton 2 will be a replication of the existing unit; consequently, the capital costs associated with Stanton 2 are lower than they would be for a first unit at a new site. Construction cost for Stanton 2 in 1991 dollars is estimated to be \$441,090,820 or \$1,002 per kW. With a construction cost escalation rate of 4.5 percent, the construction cost of Stanton 2 in 1988 dollars is \$878 per kW. The conventional coal unit referenced in the Avoided Unit Study has a construction cost of \$1,023 per kW in 1988 dollars. The lower construction cost of Stanton 2 compared to the Generation Expansion Planning Studies conventional coal unit is estimated to reduce the 1988 cumulative present worth of revenue requirements by at least \$94 million for the Avoided Unit Study alternatives with one conventional coal unit.

Table 1A.4.2-1 summarizes selected results from the Avoided Unit Study.

If Stanton 2 construction costs, on a dollar per kW basis, were substituted for the Generation Expansion Planning Studies referenced conventional coal unit construction costs, the alternative with Stanton 2 construction costs would have

had lower cumulative present worth revenue requirements than the selected alternatives for 1993 and 1994.

Stanton 2 is thus consistent with the statewide avoided units identified in the 1989 Planning Hearing and is consistent with the avoided unit identified in PSC Order No. 23234.

Table 1A.4.2-1
Avoided Unit Study Expansion Alternatives

		1988-2017 Present Worth Revenue <u>Requirements</u> \$million
1992		
Selected Combination	3-CC	55,309
Closest Coal Combination	1-PC, 1-CC	55,468
Selected Combination Advantage		159
1993		
Selected Combination	5-CC	57,998
Closest Coal Combination	1-PC, 3-CC	58,076
Selected Combination Advantage		78
1994		
Selected Combination		60,671
Closest Coal Combination	3-CC, 1-CT	60,684
Selected Combination Advantage	1-PC, 2-CC	13
PC = Pulverized Coal Conventional Unit CC = Combined Cycle Unit CT = Combustion Turbine Unit		

1A.4.3 Peninsular Florida LOLP Evaluation

The 1989 Planning Hearing ordered by the PSC included an evaluation of the capacity needs for Peninsular Florida. The Long-Range Planning Study submitted in Docket 88004-EU showed the new capacity needs and the most economical types of capacity for the period of 1992 through 1995. The study determined the amount of capacity additions needed each year to meet a reliability level of 0.1 day per year LOLP. The type of capacity selected in the study was based on evaluations of the economics of the various combinations of new capacity that could meet the reliability requirements.

Using the load forecast and generation information submitted in the 1989 Planning Hearing, the reliability analysis for Peninsular Florida was extended through 1998 using the FPC TI-line and Generation Reliability (TIGER) program. The capacity additions for 1992 through 1995 that resulted from the Long-Range Planning Study were included in the new study. On this basis, the Peninsular Florida reliability analysis for 1996 through 1998 showed a need for four 220 MW combined cycle units in 1996, two 415 MW coal units in 1997, and two 415 MW coal units in 1998. The new capacity additions were determined as the minimum number of new units needed in each year to meet the required LOLP. The results confirm the continuing need for substantial new capacity in the state using the 1989 Planning Hearing data. Table 1A.4.3-1 presents the results of the evaluation.

The 1989 Planning Hearing load forecast was compared with the aggregation of the individual load forecasts of Peninsular Florida utilities in their 1990 IE-411 filings with the National Electric Reliability Council (NERC). The results of that comparison indicate an increase of approximately 1,400 MW in 1996 Peninsular Florida load over the forecast for summer peak demand from the 1989 Planning Hearing and similar increases in later years.

The total amount of new generation capacity that utilities have to date committed to build or have filed for certification for the 1992-1995 period is about the same as that determined in the 1989 Planning Hearing. With the increased loads that are now expected, the need for new capacity appears to be greater than the committed capacity. The Stanton 2 unit will serve the capacity and energy needs of many of the state's municipal utilities and at the same time help meet the reliability need of the state.

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1A.4.3-2

Table 1A.4.3-1
Peninsular Florida LOLP Evaluation

Year	LOLP			New Capacity Additions				
	Isolated (days/year)	Assistance Area (days/year)	System Net (days/year)	Number	Type	Unit Size (MW)	Total Capacity (MW)	Cumulative Capacity (MW)
1992	0.811694	0.947909	0.094381	1	CC	220	220	220
1993	0.595005	0.601404	0.111174	4	CC	220	880	1,100
				2	CT	75	150	1,250
1994	0.141784	0.909424	0.090828	4	CC	220	880	2,130
1995	0.326988	1.741220	0.092906	3	CC	220	660	2,790
				3	CT	75	225	3,015
1996	0.268602	3.084360	0.089755	4	CC	220	880	3,895
1997	0.267728	2.979843	0.085381	2	Coal	415	830	4,725
1998	0.242246	3.551700	0.077316	2	Coal	415	830	5,555
			Total	25				5,555

1A.5.0 Supply-Side Alternatives

1A.5.1 Advanced Alternatives

This section presents summaries of advanced generation technologies and an evaluation of their applicability. Detailed descriptions of these technologies, along with references for the information sources, are presented in Appendix 1A.A. The assessment includes the following technologies.

- Coal Fueled Alternatives.
 - Gasification Combined Cycle.
 - Pressurized Fluidized Bed Combustion.
 - Advanced Pulverized Coal.
 - Gasification Fuel Cells.
 - Gasification Humid Air Turbine Cycle.
 - Coal Liquefaction.
 - Magnetohydrodynamics.
- Oil or Gas Fired Alternatives.
 - Steam Injected Combustion Turbine.
 - Humid Air Turbine.
 - Fuel Cells.
- Nuclear Alternatives.
 - Advanced Passive Light Water Reactors.
 - Modular Pressurized Heavy Water Reactor.
 - Module High-Temperature Gas-Cooled Reactor.
 - Liquid Metal Reactor.
 - Fusion.
- Renewable Energy Alternatives.
 - Wind Energy.
 - Solar Photovoltaic.
 - Solar Thermal.
 - Ocean Thermal.
 - Ocean Wave.
 - Ocean Tidal.
 - Geothermal.

- Energy Storage.
 - Battery.
 - Compressed Air.
 - Underground Pumped Hydro.

Cost estimates presented in this section were developed by Black & Veatch in January 1990 dollars unless otherwise designated. Capital costs are for overnight construction (not including interest during construction) unless noted.

Screening matrices for the five categories of technologies are presented in Tables 1A.5.1-1 through 1A.5.1-5. Three technologies were retained for screening: coal gasification combined cycle, solar thermal parabolic trough, and lead-acid battery storage.

1A.5.1.1 Coal Fueled Alternatives

The following coal fueled alternative technologies for power generation are discussed in this subsection.

- Gasification combined cycle.
- Pressurized fluidized bed combustion.
- Advanced pulverized coal.
- Gasification fuel cells.
- Gasification humid air turbine cycle.
- Coal liquefaction.
- Magnetohydrodynamics.

1A.5.1.1.1 Gasification Combined Cycle. A gasification combined cycle (GCC) system gasifies a solid fuel, producing a fuel gas for a combined cycle power generation system. Usable solid fuels include bituminous and subbituminous coals, or lignite. Fuel flexibility depends upon the gasifier used. Coal reacts in the gasifier with air or oxygen and water or steam to form raw syngas. A low Btu syngas (less than 200 Btu/scf, HHV basis) is produced by an air blown gasifier. A medium Btu gas (200 to 500 Btu/scf) is produced with an oxygen blown gasifier. The cleansed gas is used to fire a combined cycle power block. In an integrated gasification combined cycle (IGCC) system, steam generated in the heat recovery steam generator (HRSG) is augmented by steam produced in the gasification and gas cleanup system.

Large-scale demonstrations of IGCC plants include the 100 MW Cool Water plant in Daggett, California, which uses a Texaco gasifier, and the 160 MW GCC

unit in Plaquemine, Louisiana, which uses a Dow gasifier. Shell is also developing a coal gasification process. Another large-scale gasifier application within the United States is the 13,000 ton per day Dakota Gasification Plant in North Dakota. The plant uses 16 Lurgi gasifiers with a lignite feed and produces synthetic natural gas. Lurgi gasifiers are also used in the SASOL I, II, and III plants in South Africa, where a total of 80,000 tons per day of coal are gasified to produce a number of products, including transportation fuels.

First commercial operation for GCC plants is projected to be in the mid-1990s. Commercial plants will range in capacity from 250 to 450 MW. Modular building blocks based on the General Electric Frame 7F combustion turbine are about 220 MW. Capital cost estimates for mature commercial scale (400 MW or larger) plants range from about \$1,120/kW to \$1,620/kW. Operation and maintenance (O&M) cost estimates are about \$40/kW (fixed) and \$0.80/MWh to \$4.7/MWh (variable). Heat rates depend upon the degree of integration and the economics driving equipment selection. Heat rates for planned commercial units range from about 8,240 to 9,500 Btu/kWh.

Emission levels of sulfur dioxide (SO_2) and nitrous oxide (NO_x) for a GCC have been reported to be only 10 to 15 percent of the New Source Performance Standards. Sulfur removal efficiency has exceeded 96 percent at prototype plants. These low levels of emission enhance the attractiveness of GCC systems in view of more stringent emission standards accompanying the 1990 Clean Air Act Amendment.

1A.5.1.1.2 Pressurized Fluidized Bed Combustion. Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology in which combustion occurs in a pressure vessel at 10 to 15 atmospheres. The PFBC process involves burning crushed coal under high pressure in a sorbent bed, usually of limestone or dolomite. A compressor provides high-pressure combustion air at the bottom of the combustor to maintain the coal and sorbent in a highly turbulent suspended state. The turbulence promotes good particle mixing and the depth of bed allows long gas residence time, which leads to high combustion efficiency and SO_2 absorption.

Two basic cycle configurations are being considered: a turbocharged cycle and a combined cycle. In the turbocharged cycle, heat is extracted from the combustion gas into steam-cooled convective surfaces before entering the gas turbine, leaving sufficient energy to pressurize the system by driving a compressor,

but not enough energy to generate electricity. Electric power is produced only in the steam cycle. In the combined cycle concept, the high temperature combustion gases are cleaned at the elevated temperature and then expanded to drive both the compressor and a turbine generator. The gas turbine exhaust gas is used to generate steam in a HRSG. The steam drives a steam turbine generator, which also generates electricity. PFBC combined cycle designs have more stringent gas cleanup and material requirements as a result of the elevated temperatures. The hot gas cleanup technology currently being used consists of cyclone separators; however, development of ceramic tubular and candle filters, hot electrostatic precipitators, and other forms of hot gas cleanup is progressing.

The pressurized fluidized bed technology is in the early demonstration stage. The American Electric Power Company recently began startup activities for a 70 MW PFBC combined cycle demonstration plant which repowers its Tidd Station in Ohio. Additional PFBC systems similar in size to the Tidd facility have recently been constructed in Sweden and in Spain. Additional systems to be built in the US are in the planning stage. It is projected that PFBC technology will be available commercially for repowering applications in the mid-to-late 1990s, and for larger-scale new construction applications in the late 1990s to early 2000s.

A capital cost estimate for a mature PFBC system is about \$1,400/kW. O&M costs are about \$30/kW-yr (fixed) and \$6.40/MWh (variable). An estimated heat rate is about 8,700 Btu/kWh.

SO₂ emissions are controlled in the pressurized fluidized bed in a manner similar to that for atmospheric fluidized bed technology. Particulate emission is controlled by using hot gas cleanup consisting of cyclones and ceramic filters.

1A.5.1.1.3 Advanced Pulverized Coal. Advanced pulverized coal power plants make use of recent advances in major power plant components, including the steam generator, turbine generator, flue gas desulfurization (FGD) system, and flue gas reheat system. EPRI is developing a State-of-the-Art Power Plant (SOAPP) incorporating these advancements. SOAPP uses a spiral-wound supercritical steam generator which generates steam at 4,500 psig/1,100 F, with double reheat at 1,100 F. The steam turbine is a three-casing, tandem-compound unit which is designed for hybrid constant/sliding pressure operating with partial arc admission. There are two trains of 50 percent capacity feedwater heaters, with nine heaters in each train, including the deaerator. Turbine bypass facilitates unit startup. The FGD system design depends on the sulfur content of the design coal.

The high-sulfur coal FGD system uses a single 100 percent flow FGD absorber module based on commercial advanced limestone-gypsum FGD technology. A fabric filter is used for particulate removal. The low-sulfur FGD system uses two 50 percent flow lime spray dryer modules and a fabric filter.

Capital cost estimates for a mature technology SOAPP are about \$1,370/kW for a 300 MW facility. The projected heat rate is about 8,800 Btu/kWh.

Various systems within the SOAPP are in different stages of development. A fully integrated SOAPP has not been fully designed or constructed at this time. Should development continue at a steady rate, commercialization might occur in the late 1990s.

1A.5.1.1.4 Gasification Fuel Cells. A gasification fuel cell plant combines the gasifier technologies discussed in Subsection 1A.5.1.1.1 with molten carbonate fuel cell technologies discussed in Subsection 1A.5.1.2.3. A clean medium Btu syngas fuel is supplied to a fuel cell by the gasifier and gas cleanup systems. The molten carbonate fuel cell generates electricity directly from the syngas (Subsection 1A.5.1.2.3). Heat recovered from the fuel cell is used to generate steam, which drives a steam turbine generator.

The gasification fuel cell technology is in the concept stage, with several EPRI studies having been conducted to estimate plant costs and performance. Molten carbonate fuel cell development is in the bench scale stage. Plans are underway for a 2 MW demonstration unit fired by natural gas. Gasification fuel cell systems are not likely to be commercially available until the late 1990s to early 2000s.

A cost estimate for a mature technology gasification fuel cell plant is \$1,800/kW. The estimated heat rate for that plant is 7,400 Btu/kWh.

Emissions from a gasification fuel cell plant will be very low, similar to a GCC plant. NO_x emissions should be lower than for the GCC plant.

1A.5.1.1.5 Integrated Gasification Humid Air Turbine Cycle. An integrated gasification humid air turbine (IGHAT) cycle gasifies coal, producing a fuel gas for a humid air turbine (HAT) cycle. The HAT cycle concept is similar to that described for the gas fueled HAT in Subsection 1A.5.1.2.2. HAT cycles are not commercially available.

The coal gasification plant used in the IGHAT concept is similar to the ones used in IGCC plants described in Subsection 1A.5.1.1.1. In an IGHAT plant, the syngas is water quenched after it leaves the gasifier, and the resulting low level

heat is recovered and used in the HAT cycle. This eliminates the need for expensive syngas coolers.

The net plant heat rate for an IGHAT plant is projected to be about 8,870 Btu/kWh for a 475 MW plant. A preliminary capital cost estimate for a 475 MW IGHAT facility is \$1,160/kW.

Emission controls for sulfur removal described in the IGCC section of this report are applicable to IGHAT cycles. The HAT turbine used in the IGHAT cycle is expected to have NO_x emissions as low as 7 ppmvd (15 percent oxygen) or less without the use of selective catalytic reduction (SCR).

1A.5.1.1.6 Coal Liquefaction. Coal liquefaction processes have been under development for many years. The key objective of a coal liquefaction process is to upgrade the hydrogen content of the feed coal and to remove components of environmental concern. Early liquefaction processes were used in Germany during World War II to provide liquid fuels for military applications. Currently, liquefaction processes are being used in South Africa's SASOL facilities to provide transportation fuels for South Africa as a result of an embargo on oil shipments.

Developmental efforts within the US are aimed at reducing costs for coal derived liquid fuels. In addition to processes which produce synthetic crude oil, efforts are also being made to develop cost-effective coal derived methanol plants. The primary interest for utilities would be to supply fuels to oil fired plants should the price of oil escalate dramatically. In general, use of coal derived liquid fuels would be better suited to peaking applications, where a base load fuel production plant could provide storable fuels. Base load power generation plants would more likely use coal gasification processes rather than coal liquefaction processes to provide fuel.

It is projected that using mature liquefaction processes based on current pilot-scale technology, synthetic oil could be produced at a cost of about \$40/barrel.

1A.5.1.1.7 Magnetohydrodynamics. Magnetohydrodynamics (MHD) is a fossil fuel fired technology in which the electrical generator is static (nonrotating) equipment. The MHD technology is in the early development stage. Coal or another fossil fuel is burned to produce hot gases at temperatures exceeding 4,500 F. Potassium carbonate is injected during the combustion process to increase the electrical conductivity of the combustion products. These hot gases are accelerated in a nozzle and pass through a rectangular channel, which is

surrounded by a superconducting magnet. The electrically conductive gases moving in the magnetic field produce a direct current in the channel's electrodes. This direct current is subsequently converted to alternating current with a solid-state inverter. An MHD device would likely be used for the topping cycle of an MHD combined cycle system.

A heat rate projection for a mature MHD system is about 8,620 Btu/kWh. Capital and O&M costs for MHD systems are highly speculative because of the relatively early stage of development of the technology.

The MHD technology appears to be capable of adequately controlling NO_x and SO₂ emissions.

1A.5.1.2 Oil or Gas Fired Alternatives

Oil or gas fired alternatives considered in this subsection include the steam injected combustion turbine, humid air turbine (HAT) cycle, and fuel cells.

1A.5.1.2.1 Steam Injected Combustion Turbine (Power Augmentation). The steam injection combustion turbine uses steam injected into the combustor and turbine sections of a conventional combustion turbine to increase power output. This is called power augmentation and is also known as the Cheng cycle.

The injection steam has a cooling effect on the combustion turbine internals, allowing greater fuel burn rates. There is no steam turbine or associated equipment as in the combined cycle arrangement. The basic components for this cycle are the combustion turbine and the HRSG. Aero-derivative combustion turbines are typically used in power augmentation applications because of the higher compression ratio associated with the aero-derivative. The aero-derivative also has the ability to pass greater flows. Emissions control is similar to that for oil or gas fired simple cycle and combined cycle systems.

Several power augmentation units began operation in the early to mid-1980s. The cycle is considered a mature technology. However, the long-term impact of massive steam injection on combustion turbine service life is still being evaluated. Furthermore, large combustion turbines designed specifically for steam injection are not commercially available today.

Capital costs for the power augmentation cycle vary with unit size, amount of steam injected, and amount of steam to be produced for cogeneration. Capital cost estimates range from \$800/kW for a 150 MW unit to \$1,050/kW for a nominal 50 MW installation.

Steam injection can increase the power output of a combustion turbine by as much as 50 percent, while reducing the heat rate by as much as 17 percent.

1A.5.1.2.2 Natural Gas Fired Humid Air Turbine Cycle. The humid air turbine (HAT) cycle uses a combustion turbine that employs air intercooling and the substitution of water vapor for a portion of the excess air to the combustor to reduce the power requirement by the compressor. This reduction in air compression load significantly increases the net power output by the turbine. Intercooling and aftercooling provides some of the heat required for generating water vapor. Additional low temperature heat required for generating water vapor is also obtained from the turbine exhaust. A saturator generates water vapor in a multi-stage counter-current operation by directly contacting cooled compressed air with hot water. The humidified air is then further heated by the turbine exhaust prior to entering the combustor.

Natural gas fired HAT cycles are not commercially available. The HAT cycle is still in the early developmental stages, and a commercial prototype combustion turbine designed for the HAT cycle has not yet been built.

NO_x emissions are expected to be very low over the full range of capacity because of the high moisture levels in the air going to the combustor.

A preliminary capital cost estimate for a nominal 200 MW plant size is \$630/kW. The net heat rate is projected to be 7,080 Btu/kWh.

1A.5.1.2.3 Fuel Cells. Fuel cells convert hydrogen rich fuels directly to electricity through electrochemical reactions. The reactants, fuel and oxidant (air or oxygen), are fed to separate anode and cathode electrodes. The electrodes are separated by an electrolyte that transports the ions generated by the anode reaction. This transport of ions creates an electric potential difference that promotes electron flow through an electric load. An inverter converts the direct current into alternating current.

The most common fuel cell concepts for power generation are the phosphoric acid fuel cell and the molten carbonate fuel cell. The solid oxide fuel cell is another advanced option, but it is not as well developed as the other two. Phosphoric acid and molten carbonate fuel cells are fueled with hydrogen, requiring a reforming step for the use of natural gas or methanol as the fuel. Some molten carbonate fuel cells have internal reforming capability, allowing the direct use of natural gas. Molten carbonate fuel cells are also able to operate with syngas from a coal gasification unit, allowing coal to be used as the fuel.

Phosphoric acid fuel cell technology is the most mature of the fuel cell technologies for power plant applications. However, operational problems such as long-term reliability remain to be solved. Phosphoric acid fuel cell power plants are expected to be commercially available and reliable in the 2000 to 2010 time period. Molten carbonate systems offer higher efficiencies than can be achieved with phosphoric acid systems, although the commercial development of these systems lags perhaps 5 to 10 years behind that of phosphoric acid systems. Small area molten carbonate cell stacks have been successfully tested, and scaleup to full area stacks is underway.

A capital cost projection for a mature, central station phosphoric acid fuel cell plant is about \$1,000/kW. The net plant heat rate is projected to be 8,300 Btu/kWh. Combined cycle and molten carbonate fuel cell plants are projected to have significantly lower heat rates.

Because the fuel gas is necessarily very clean and combustion does not occur in a fuel cell, emissions of air pollutants, solid wastes, and contaminated wastewater are extremely low during operation.

1A.5.1.3 Nuclear Alternatives

This assessment consists of five advanced technologies that offer design modularity, reduced construction schedules, and potentially increased safety. The advanced technologies include the advanced passive light water reactor, modular pressurized heavy water reactor, the modular high-temperature gas-cooled reactor, the liquid metal reactor, and fusion.

Licensing procedures for new conventional and advanced generating plants are being revised. The Nuclear Regulatory Commission (NRC) is proposing a one-step licensing process for new nuclear power generation. With the one-step process, electric utilities would obtain a single permit approval for the nuclear power plant from the NRC before construction of the project. The approval would also include a license to operate, assuming the plant is built in accordance with the previously approved construction plans; however, this approval has been overturned in court and is subject to ongoing appeals. Some electric utilities prefer that a law be passed through Congress with similar one-step licensing provisions. The law would minimize potential challenges to the NRC's one-step procedure.

1A.5.1.3.1 Advanced Passive Light Water Reactor. The advanced passive light water reactor (APLWR) has passive emergency core cooling, decay heat removal, and containment cooling systems. In the pressurized water reactor (PWR) version, the core is cooled in an emergency by massive water storage tanks located above the core; water flowing from these tanks by the force of gravity or compressed nitrogen has the capability to cool the core for at least three days after a loss of coolant accident. Excess heat is removed by natural circulation of this water, so electrically driven pumps and other active systems are not needed. The containment is cooled by natural circulation of air and evaporation of water around the steel containment structure. Like all modern US designs, the APLWR's core reactivity naturally decreases as its temperature increases.

The APLWR technology is a scale-down of existing LWR technologies that are commercially available. However, the APLWR designs are still being developed and are not likely to achieve commercial availability until after the year 2000.

Net plant heat rates are similar to those for the conventional LWR power plant--in the 10,000 to 11,000 Btu/kWh range. Fuel usage and load following characteristics are the same as for the conventional LWR power plant. The APLWR plants are best suited to baseload operation. The estimated total capital requirement is probably similar to that of full scale LWRs at \$3,000/kW.

Environmental emissions and discharges are similar to those for a conventional nuclear LWR power plant.

1A.5.1.3.2 Modular Pressurized Heavy Water Reactor. The CANDU 3 is a pressurized heavy water reactor under design and development by Atomic Energy of Canada Limited (AECL). Heavy water (deuterium oxide) is used for neutron energy moderation and fission heat removal. Because heavy water absorbs practically no neutrons, it can be used as a coolant-moderator with natural uranium fuels. The use of natural uranium fuels is a cost advantage over LWRs, which use more costly enriched uranium fuel. However, the production of heavy water is a costly process.

The CANDU 3 design is based on earlier successful CANDU reactor designs (e.g., CANDU 6) which are commercially available. The CANDU 3 is a smaller version of the previous CANDU designs, with an electrical rating of 450 MW.

CANDU 3 is currently going through detailed design with commercial availability expected in the 1994 to 1995 time frame. The first operating unit is

expected after 2000. CANDU design will feature open top construction and modularization to reduce cost and shorten construction schedules. The CANDU 3 construction time in Canada is expected to be about three years. Construction time for CANDU 3 in the US is not known because no CANDU plants have been built in the US. Project duration would likely be similar to LWRs, but may be greater because of the lack of familiarity with the design by federal and state regulatory agencies, leading to longer licensing and permitting times.

The net plant heat rate for CANDU 3 is slightly higher than for LWRs because of the lower turbine inlet steam pressure and temperature. CANDU 3 is best operated as a baseload unit. Plant capacity factor for CANDU 3 is expected to be greater than LWRs because CANDU 3 can be refueled while operating. The average capacity factors for currently operating CANDU reactors in 1986 and 1987 were 66 percent and 67 percent, respectively.

Environmental compliance considerations regarding licensability for pressurized heavy water reactors are not significantly different from those of LWRs. Their disadvantages are similar to those of LWRs.

An accurate capital cost estimate for a CANDU 3 is not available. A longer licensing time in the US could significantly increase this cost. The annual operating cost, including fuel, for operating CANDUs for 1988 is approximately 10.5 mills/kWh.

1A.5.1.3.3 Modular High-Temperature Gas-Cooled Reactor. The modular high-temperature gas-cooled reactor (MHTGR) is an underground modular version of existing high-temperature gas-cooled reactor designs. MHTGRs are conceptualized as 134.5 MWe units that are coupled in pairs to supply each turbine generator, which in turn can be replicated in pairs. The fuel is made of small grains of nuclear fuel, each coated with multiple layers of heat-resistant ceramic material. These fuel grains are put in a low power density core, which makes it slower to overheat during a power surge and limits the possibility of fuel failure. The helium gas coolant, circulated through the system by an electrical blower, is heated to a high temperature, allowing for highly efficient operation. However, even if this forced circulation system should fail, the reactor vessel would be sufficiently cooled by natural air circulation and direct heat loss to the surrounding earth.

Several gas-cooled reactor systems are in commercial operation in Europe. The modular approach to this technology is, however, just entering the demonstration phase. Plants could reach commercial maturity after the year 2000.

Net plant heat rate is approximately 9,000 Btu/kWh for the module power plant. The estimated total capital cost requirement is expected to be in the range of \$2,500 to \$3,000/kW. The MHTGR power plant is best suited for baseload operation.

1A.5.1.3.4 Liquid Metal Reactor. The liquid metal reactor (LMR) uses liquid sodium rather than water for core cooling. The reactor itself is situated in an underground concrete silo and is cooled by natural air circulation when the normal heat removal paths are not available. At about 155 MW, the LMR units are relatively small (about a quarter of the capacity of the APLWR) and are designed as modules that can be shop fabricated and shipped to the site intact. The modules would be installed in groups of three to supply one 465 MW turbine generator.

The development of a modular, passively stable LMR for utility application is being carried out under DOE sponsorship by a design team led by General Electric. Called PRISM (for power reactor inherently safe module), this 465 MW nuclear plant consists of three 155 MW reactor modules connected to a common steam turbine.

The Nuclear Regulatory Commission is expected to require the construction and testing of a single module PRISM demonstration plant before certifying the current design. Experimental reactors at DOE laboratories have already been used to test the passive cooling capability of the LMR concept, and conceptual designs for PRISM are scheduled for completion by 1991.

The LMR is anticipated to be available for commercial orders in the mid-1990s with commercial operation after the turn of the century. This timetable may be adversely affected by current reduced R&D support, which may delay commercial availability in the US well beyond the year 2000.

Net plant heat rates, on an average basis, are anticipated to be in the range of 8,800 to 9,000 Btu/kWh. The estimated total capital cost requirement is expected to be in the range of \$3,000 to \$3,500/kW. The licensing, engineering, and construction schedule information is not available at this time.

Environmental emissions and discharges for the LMR power plant are similar to those for conventional nuclear plants of comparable size.

1A.5.1.3.5 Fusion Reactors. Fusion power results from the release of energy arising from the fusing of light elements into heavier ones (e.g., tritium [T] + deuterium [D] yields helium [He] + neutron with an energy per reaction of 17.6 Mev). Extremely high temperatures are required to fuse light nuclei (e.g., 50 million K for T-D reaction).

Two general concepts are being studied to attain fusion reaction temperatures. The first concept uses magnetic forces to confine and compress the tritium/deuterium plasma. The Tokamak fusion test reactor (TFTR) uses this concept. Superconducting magnets producing intense magnetic fields confine the plasma in a toroidal (doughnut) shaped arrangement. Neutral beam heating is also used to add additional energy to the plasma. The TFTR will use deuterium and tritium for fuel; the proof of the principle for fusion at the TFTR is expected in the mid-1990s.

The second concept (generally referred to as inertial confinement) uses light energy from a laser to impact on a small pellet of T-D. If sufficient energy can be imparted to the pellet, T-D will fuse. In addition to experiments using lasers, particle beam (e.g., lithium ions) impaction on T-D pellets is being studied. Scientific feasibility of using lasers or particle beams for T-D fusion may well be demonstrated in the next 8 to 10 years.

Fusion reactors are currently in the development stage and have a significant number of technical problems to be solved, such as plasma confinement, material qualifications, first wall radiation effects, and blanket and shield materials. Commercial applications of this technology are not expected until well into the next century.

Based on conceptual designs, net plant heat rates for fusion reactor plants are estimated to be in the range of 9,000 to 11,300 Btu/kWh.

Radioactive releases from fusion reactors are expected to be much lower than those from LWRs. Quantities of low-level and high-level waste are expected to be significantly less for fusion reactors than for LWRs. The fusion process produces no fission products, resulting in a significantly cleaner reactor than for fission processes.

1A.5.1.4 Renewable Alternatives

The following renewable alternatives are discussed in this section.

- Wind Energy

- Solar Photovoltaic
- Solar Thermal
- Ocean Thermal
- Ocean Wave
- Ocean Tidal
- Geothermal

1A.5.1.4.1 Wind Energy. Wind energy conversion systems (WECS) convert wind energy into electricity by collecting the wind's kinetic energy with blades that are attached to a rotor that turns a turbine generator.

In 1986, there was a total of 1,327 GWh of electricity generated with wind power worldwide, with 92 percent of that energy generated in California. The 1987 average installed capital cost for WECS in California was \$1,070/kW. However, the costs for individual projects varied widely from the average cost, ranging from \$356/kW to \$1,420/kW. Average installed costs have dropped from \$1,890/kW in 1985 and \$1,600/kW in 1986. Operating and maintenance cost estimates are typically 8 to 12 \$/MWh.

Wind energy is not considered a viable option for large-scale power generation in Florida due to the lack of favorable wind resource.

1A.5.1.4.2 Solar Photovoltaic. Photovoltaic (PV) energy systems convert sunlight (termed insolation) directly into electricity through use of solar cells. Cells are closely packed and electrically interconnected within an environmentally protected unit called a module. Modules are connected in parallel/series combinations to achieve the system operating current and voltage (typically several hundred volts). For utility grid connection, the direct current (dc) from the interconnect modules is converted to alternating current (ac) by a solid-state inverter.

There are two basic configurations of photovoltaic systems: flat plate and concentrating. Flat plate systems use the sun's radiation with no concentration, and are either fixed in orientation or they track the sun by rotating about one or two axes to capture more energy. Concentrating systems use reflectors or lenses to direct sunlight to a line (multiple cells side-by-side) or point (single cell) focus. One- or two-axis tracking is required for concentrator systems.

Large scale photovoltaic power systems in the US include the 2.35 MW one-axis flat plate system owned and operated by the Sacramento Municipal Utility District (SMUD), the 6.5 MW Carrisa Plain two-axis tracking flat plate system

formerly owned and operated by ARCO Solar Power Production, the 860 kW Hesperia two-axis flat plate system, formerly owned and operated by ARCO Solar, and the 300 kW one-axis flat plate system (PV300) owned and operated by the City of Austin Electric Utility. The Carrisa Plain and Hesperia facilities were sold to Carrisa Solar when Siemens acquired ARCO Solar. Those systems are being dismantled, and the solar equipment is being sold.

A national cooperative research and development project, called PVUSA, is installing eight 20 kW emerging module technology (EMT) systems and three utility-scalable systems totaling 800 kW for the purpose of evaluating and comparing performance and reliability of different PV technologies in utility applications. These systems are located near Davis, California, and are connected to the Pacific Gas & Electric system.

Large utility-scale commercialization of PV systems could occur during the 1990s; however, utility market penetration is more likely in the 2000 to 2010 time frame. Favorable market forces and reduced capital costs would speed the commercialization process.

The performance of PV systems is normally indicated by annual energy efficiencies and annual capacity factors. PV power systems operating in 1986 demonstrated annual energy efficiencies from 6.9 to 8.4 percent and annual capacity factors from 23 to 28 percent. With insolation levels reported for Orlando, capacity factors in the 15 to 20 percent range can be anticipated. Annual energy efficiencies from 10 to 14 percent are expected from several PVUSA 20 kW EMT systems installed in 1989 and from the larger 200 to 400 kW utility-scalable systems to be installed in 1990.

Current capital costs for PV installations in the several megawatt range are estimated to be about \$7,000/kW. Operations and maintenance records indicate that PV systems require little operator intervention or equipment servicing. During 1986, the one-axis flat plate SMUD system experienced only minor maintenance problems resulting in a reported annual O&M cost of \$2/MWh.

The land required for a PV system depends on the system size and type, local insolation, and module and inverter efficiencies. Typically, a PV system requires about 6 to 7 acres of land for each MW of rated capacity. This land must be relatively flat and ideally should not be downwind from a source of dust or other substance which would accelerate soiling of module surfaces or decrease insolation.

Other than the preemption of large areas of land, potential ecological and climatic issues are minimal and should be restricted to construction impacts.

1A.5.1.4.3 Solar Thermal. Solar thermal electric generation plants use direct insolation to heat a heat transfer fluid, which in turn heats a working fluid to power the prime mover--typically a Rankine cycle turbine. There are three main categories of solar thermal electric generation concepts, as discussed below.

1A.5.1.4.3.1 Parabolic trough. The commercially available solar thermal technology is the parabolic trough system. A parabolic trough collector consists of a computer controlled, movable parabolic, cylindrical mirror which focuses solar radiation on a fixed receiver tube. The receiver tube, which is located along the focal axis of the mirror, collects the reflected radiation and transforms the radiant energy into thermal energy in the heat transfer fluid, typically a silicone-type oil. Heat is subsequently transferred to a working fluid (water/steam or toluene) to drive a turbine. Parabolic trough systems may employ thermal storage to lengthen or shift the daily power generation period.

The principal commercial application of parabolic troughs for power generation has been the Luz International Solar Electric Generation Systems (SEGS) connected to the Southern California Edison grid. Luz has 354 MW of parabolic trough generating capacity.

The newer SEGS parabolic trough facilities have solar-to-electric efficiencies of about 22 percent. The SEGS VIII facility has an annual solar-only capacity factor of about 27 percent; however, the use of supplemental firing with natural gas improves the annual capacity factor to about 36 percent. The solar-only capacity factor for a parabolic trough system in the Central Florida area is estimated to be about 16 percent.

The installed capital system cost for SEGS VIII is reported to be \$2,600/kW. The annual operating cost for a parabolic trough system is estimated to be \$4.60/kW-yr (fixed), \$0.80/MWh (variable).

1A.5.1.4.3.2 Central receiver. The solar thermal central receiver (STCR) technology is not yet commercially available. In this technology, direct insolation is redirected and concentrated by computer-aimed, movable mirrors called heliostats onto a receiver located atop a tower. In the receiver, a fluid (typically water or molten salt) absorbs the heat. With a water/steam receiver, steam generated in the receiver is used to drive a ground level turbine generator. Because of its thermal storage, an STCR system allows a dispatcher to lengthen

or shift the generating period into nighttime hours to meet peak demand, if required. A water/steam STCR concept has been demonstrated successfully on the pilot scale at the 10 MW Solar One facility near Barstow, California. Solar One began operation in 1982 and continued to operate until 1988. The molten salt STCR technology has been tested only in small scale (5 MW thermal) experiments. Conceptual designs for 100 MW and 200 MW commercial scale STCR plants were developed in 1987 as part of the Utility STCR Studies funded by the Department of Energy (DOE). These studies indicated that plant sizes of at least 100 MW are required for economic operation. Because of the need for a large scale system experiment prior to deployment of a commercial scale plant, it is unlikely that commercial operation of an STCR plant would occur during the 1990s.

Annual performance for a 200 MW STCR plant with six hours of thermal storage is estimated to result in a 15 percent solar-to-electric efficiency and a solar-only capacity factor of about 36 percent for a southern California site. The annual capacity factor for a Central Florida site would be about 22 percent.

The projected cost of a mature technology 200 MW STCR plant with six hours of storage is about \$2,600/kW. Operating costs are projected to be about \$15/MWh in the Orlando area.

1A.5.1.4.3.3 Parabolic dish. Parabolic dish systems consist of a reflective parabolic bowl which tracks the sun, redirecting and concentrating the solar energy on a receiver at the dish's focal point. In the receiver, either an intermediate heat transfer fluid is heated and piped to a central ground level power generation device, or the working fluid is heated to power a prime mover located along with the receiver at the focal point. For the latter concept, toluene Rankine cycle turbines, Brayton cycle turbines, and Stirling cycle engines have been used. A 25 kW Stirling cycle engine system has demonstrated a solar-to-electric efficiency of 29.4 percent, with an engine cycle efficiency of 40 percent. Long-term reliability and availability of the Stirling cycle engine have not been demonstrated.

Two major dish system experiments have operated in the US. The Solar Total Energy Project at Shenandoah, Georgia, produces 400 kW of electrical power plus process heat. The privately financed Warner Springs, California, SOLARPLANT I was designed to produce 4.9 MW of electricity; this facility operated for approximately two years and ceased operation because of operational

and funding difficulties. Depending on market forces, commercialization could occur within the 1990s, but is more likely in the 2000 to 2010 timeframe.

Currently, costs for parabolic dish systems are high because they are in a developmental stage. Mature technology and mature market could make parabolic dish systems competitive in the next decade, first for remote applications and possibly later for utility applications.

1A.5.1.4.4 Ocean Thermal Energy Conversion. An ocean thermal energy conversion (OTEC) plant uses the temperature difference between warm surface water (as high as 81 F) and cold deep water (as low as 39 F) to generate electricity. Because of the relatively small temperature differences, OTEC plants have overall efficiencies of about 2 percent.

There are two basic types of cycles for OTEC plants. A closed-cycle plant uses a working fluid with a low boiling point, such as ammonia. The working fluid is heated and vaporized by the warm surface water, expanded in a turbine generator, and condensed by cold deep water. An open-cycle plant uses seawater as the working fluid. The warm surface water is evaporated in a vacuum in a boiler into low-pressure steam, expanded in a turbine generator, and condensed by the cold deep water.

OTEC plants can also be classified by the location of the plant in relation to the ocean. Shore-based plants are appropriate for islands with steep offshore slopes, and can be tied in with existing electric transmission grids. Offshore plants can be floating platforms or tower-mounted structures, both of which have undersea power cables connecting to an onshore transmission grid.

OTEC plants are not likely to become commercially available until after the year 2000. Capital costs for the first commercial size OTEC plant are expected to range from 6,000 to 8,000 \$/kW (1985 dollars).

Environmental concerns related to OTEC plants include discharge of cool water in tropical surroundings and the possibility of accidental release of ammonia from closed cycle plants.

1A.5.1.4.5 Ocean Wave Energy Conversion. There are three primary wave-energy systems currently under development or in operation. The first of these is the Kvaerner wave-energy plant developed in Norway. This plant uses a water oscillation chamber blasted out of a rock cliff. The rise and fall of waves in this chamber cause air in the chamber to pass up and down through a Wells turbine, thereby generating electricity. The Wells turbine can continue to spin in the same

direction while accepting air from both above and below the turbine. The second of these wave-energy systems is the British Sea Clam, which consists of a hollow, floating chamber and a collapsible bladder, both connected by a hollow duct containing an air turbine. An approaching wave collapses the bladder, forcing air past the turbine and generating electricity. The third system is one designed by the Soviet Union, which has an efficiency of over 80 percent. This system consists of slotted wheels, each with high moments of inertia, that share a common axle with a generator. The motion of ocean waves causes the wheels to rotate, and the wheels can continue to rotate during the intervals between waves due to the fly-wheel effect.

All of the three wave-energy systems should be commercially available by the year 2000. The Norwegian Kvaerner system is currently available in 150 kW, 500 kW, and 1.5 MW sizes. The British Sea Clam system would probably be available in 4.6 MW size, requiring 25 units for a 115 MW plant.

The cost and power generation potential for wave-energy plants depends both on available wave height and length of coastline. Potential environmental impacts include temporary construction impacts, land use for a shoreline power generation facility, aesthetics, and noise.

1A.5.1.4.6 Tidal Energy Conversion. In tidal energy conversion systems energy is extracted from the changes in the level of ocean water during tidal cycles. A tidal energy conversion plant consists of a tidal basin created by a dam, a turbogenerator, and a sluice gate in the dam to allow the tidal flow to enter or leave.

Two tidal energy conversion concepts are the single-basin, single-effect systems, and double-effect systems. Single-basin, single-effect systems impound water when the tide level reaches its peak. After the tidal level falls (ebb tide), water in the basin is released through a turbine generating electrical power. Double-effect systems use reversible turbines to generate power on both the ebb and rising tides.

Tidal energy conversion is a proven technology. However, there are currently no tidal conversion plants in the United States. A 240 MW commercial plant has been operating across La Rance Estuary in northwest France since 1962, and an 18 MW plant operates in Nova Scotia, Canada.

Power output from a tidal energy conversion system depends on tidal amplitude, mean basin surface area, turbine efficiency, and type of scheme (single- or double-effect). The 240 MW plant in France consists of twenty-four 10 MW bulb-type Kaplan turbines and has a mean basin surface area of 8.5 square miles. The mean tidal amplitude at La Rance is 28 feet.

Studies have indicated that for tidal energy systems to be economically feasible a 16 feet minimum tidal amplitude is necessary. This tidal amplitude is not found in Florida.

Potential environmental impacts would be site-specific and would include temporary construction impacts, recreational use, aesthetics, waterway navigation, and marine habitat. Also, large tidal projects could affect tidal levels outside of the basin. The capital cost of a tidal energy conversion system will vary significantly with plant size and site conditions. A study conducted for a potential tidal energy plant located in Half Moon Cove, Maine, projected a cost for a 12 MW plant of \$3,700/kW in 1985 dollars.

1A.5.1.4.7 Geothermal. Geothermal energy is thermal energy associated with the elevated temperature of the interior of the earth. Four principal forms of geothermal energy are dry steam, hot water/wet steam, geopressured zones, and hot dry rock.

The dry steam form is the easiest to use because this steam can be used to power a conventional steam turbine generator. The dry steam form of geothermal energy has been used for the commercial generation of electricity in the United States since 1960, when Pacific Gas and Electric, with others, built an 11 MW power plant at The Geysers in northern California. This geothermal field now supports plants generating over 1,800 MW of electricity. Another such commercial plant is the Sacramento Municipal Utility District (SMUD) Geothermal Plant No. 1, which is rated at 72 MW.

The hot water/wet steam form requires more complicated power conversion equipment because of the presence of liquid water. Currently, there are three ways of using this form of geothermal energy: (1) a rotary separator turbine plant separates the two-phase mixture into steam and liquid water and generates power from a steam turbine and a liquid turbine, respectively, (2) a flashed-steam cycle plant depressurizes the two-phase mixture into steam which is then used to power a conventional steam turbine generator, and (3) in a binary cycle plant, heat from the hot water/wet steam is transferred to another working fluid through a heat

exchanger. This other working fluid, which would have a lower boiling point than water, is used to power a turbine generator. The technologies for using the hot water/wet steam form of geothermal energy are currently in the commercial to demonstration stages of maturity, depending on the particular technology. The flashed-steam cycle technology is now being used for commercial power generation in the United States. An example of this is Southern California Edison's (SCE) Salton Sea 10 MW plant. San Diego Gas & Electric's Heber plant is the first commercial-scale demonstration binary cycle plant; this 70 MW gross (46.6 MW net) plant first went into operation in 1985. The rotary separator turbine technology has been tested in the portable Biphase Wellhead Power Plant at several geothermal fields since 1979. This technology is still in the development phase.

Geopressured zones are reservoirs under extremely high pressure located in formations of impermeable shale. These reservoirs contain mixtures of hot salt water and methane gas. Potentially, energy could be obtained from these zones by burning the methane and using the pressure and heat from the hot water.

To tap the energy contained in the underground hot dry rock, the rock must first be fractured using conventional oil and natural gas drilling techniques. Once a reservoir has been created in the hot dry rock, inlet and outlet water pipes are driven down into the reservoir. Circulating hot water is heated in this reservoir and is used to generate power by one of the three technologies mentioned above for the hot water/wet steam form.

Applications of geopressured zones and hot dry rock technologies are still being developed. Research efforts are aimed at identifying potential sources and developing the necessary energy conversion technologies.

Typically, commercial geothermal plants can be built for an installed cost of \$1,200/kW to \$1,800/kW where a geothermal field exists. The first commercial binary cycle plants similar to the Heber plant are expected to have capital costs near \$1,650/kW.

No geothermal resource has been identified in Florida.

1A.5.1.5 Energy Storage

Energy storage technologies are used to store energy generated by relatively cheap means during off-peak hours to provide power during on-peak periods.

Three energy storage technologies are described in this section.

- Lead-acid batteries.
- Compressed air energy storage.
- Underground pumped hydroelectric.

1A.5.1.5.1 Battery Storage. Lead-acid batteries are economical in load leveling applications when the cost of system construction, operation, and maintenance can be offset by the energy cost differential between peak and off-peak rates. A lead-acid battery storage system consists of the battery, dc switchgear, dc/ac converter/charger, transformer, ac switchgear, and associated building to house these components. During the utility peak periods when energy costs are the highest, the battery system discharges and supplies power to the utility ac power system for a typical period of four to five hours. After the peak period has passed, the battery system is recharged and then remains on "float" until the next peak period, thus completing one cycle of operation.

Two lead-acid battery storage systems for supplying power to a utility ac power system have been operating successfully since 1986: a 17 MW, 14.4 MWh facility in West Germany and a 1 MW, 4 MWh facility in Osaka, Japan. In 1987, five new battery storage sites were announced: three in the US, one in West Berlin, and one in South Africa. Most recently, a 10 MW, 40 MWh battery energy storage system was constructed by Southern California Edison at its Chino substation.

Actual performance parameters from the Chino battery facility are not public information to date; estimated performance based on the EPRI conceptual design project for a 10 MW, 40 MWh plant include an ac-to-ac roundtrip efficiency of about 73 percent. Estimated battery cycle life is about 2,000 cycles. The estimated direct capital cost is \$900/kW, with fixed and variable O&M costs of \$24/kW-yr and \$2.20/MWh, respectively.

The primary environmental concern with lead-acid battery systems is a sustained short circuit, resulting in fire and an acid spill.

1A.5.1.5.2 Compressed Air Energy Storage. Compressed air energy storage (CAES) is a technology for both generating electricity and storing energy from fossil fuels. During off-peak periods, electricity from the grid is used in the motor/generator to run a compressor, which compresses air for storage in a underground cavern. During peak periods, the compressed air is extracted from the cavern and is preheated by turbine exhaust gases in a recuperator. This

preheated air is then mixed with fuel, which is burned in combustion chambers. The resulting hot gases are expanded in a turbine to generate electricity.

Three types of storage are envisioned for CAES units.

- Salt dome
- Hard-rock
- Aquifer

Compressed air is stored at a fixed volume and variable pressure in both the salt dome and the uncompensated hard-rock caverns. In both the compensated hard-rock caverns and the aquifers, compressed air is stored at a variable volume and fixed pressure.

The first CAES unit, rated at 290 MW, went into commercial operation in 1978 for the West German utility Nordwest Deutsche Kraftwerke (NWK). The construction of the first United States CAES unit, rated at 110 MW, has been completed for Alabama Electric Cooperative (AEC). Startup is expected to be complete in mid-1991.

The major resource requirement for a CAES unit is the underground cavern for storage of the compressed air. According to past EPRI-funded studies, possible storage sites exist in about three-fourths of the land area in the United States. Potential hard-rock sites are believed to be the most prevalent of the three.

Storage caverns are created in salt domes (underground salt deposits) by drilling a well into the salt deposit and circulating fresh water to dissolve the salt. The resultant brine solution must then be flushed out to leave the empty storage cavity. These salt deposits are relatively rare in the United States.

An aquifer consists of a layer of porous sand, gravel, or rock which bears water in the spaces between the individual pieces of material. To use an aquifer for a CAES application, it must be shaped like an inverted bowl, leaving an air space at the top. A layer of tight rock, called caprock, covers the aquifer and acts as a seal for the compressed air stored in the aquifer. These aquifers are relatively common in the interior portion of the United States.

The last type of storage site is an underground cavern excavated in hard rock. A hard-rock cavern can be of two types: uncompensated and compensated. The uncompensated cavern is the simpler of the two and is basically an excavated cavern. This cavern provides constant-volume and variable-pressure compressed air storage. The compensated cavern includes an excavated cavern, a surface

water reservoir, and a water column joining the two. The varying water level in the cavern provides constant-pressure and variable-volume storage of compressed air. The compensated approach allows for a smaller underground cavern, but requires a surface reservoir of the same volume as the cavern. Of the three storage schemes, hard-rock caverns are the most expensive to develop. Potential hard-rock sites exist throughout most of the United States.

Because CAES units use combustion turbines, they share many of the environmental impacts with combustion turbines. These impacts include the variety of air pollutants emitted. Although both CAES units and normal combustion turbines emit the same types of pollutants, CAES units will produce about one third of the emissions that a similar-sized combustion turbine produces because power for the compressor is provided by external baseload generation facilities.

The underground storage sites used by CAES units have similar environmental impacts to those created by the underground storage of natural gas except that compressed air is not a pollutant. An impact specific to salt dome storage is the disposal of the brine solution produced during the creation of the salt dome cavern. Several disposal methods are available, each with its own regulatory requirements. These methods include disposal in injection wells, ocean dumping, and shipping to salt producers.

The total capital cost of the 110 MW AEC unit is expected to be approximately \$520/kW in 1989 dollars.

Potential CAES reservoirs in the Central Florida area have not been identified. Further geological investigations would be required to identify and assess potential sites.

1A.5.1.5.3 Underground Pumped Hydroelectric Storage. Underground pumped hydroelectric (UPH) storage is similar to conventional pumped hydroelectric storage. In both cases, energy is stored by pumping water from a lower level to an upper reservoir, and energy is returned to the power system when water is allowed to flow back through the hydraulic turbine powering the generator. For UPH, the lower reservoir is either an existing underground cavern or a newly excavated cavern at a selected depth.

During peak generating hours, water released from the upper reservoir powers the turbine generator, then discharges into the lower reservoir. The energy generated is sold at peak rates. Nightly or weekly, depending on the storage capacity of the reservoirs, the same equipment, powered by off-peak electricity,

is used in reverse to pump the water from the lower reservoir to the upper reservoir during off-peak hours. In situations where a ready supply of excess (hence, lower priced) baseload power is available, the economic tradeoffs can be attractive. Pumped storage is most successful when the length of the piping system is less than 10 times the net head on the plant.

Underground pumped storage uses commercially available equipment, and is therefore not classified as a new technology. However, the concept of using an underground cavern remains unproved, both technically and economically. A consortium is currently studying the feasibility of using an existing mine to house power generation equipment and an underground lower reservoir. The Summit Pumped Storage Project, located near Akron, Ohio, is estimated to cost \$993 million and will have a capacity of 1,500 MW (\$662/kW). A formal license application was recently submitted to the Federal Energy Regulatory Commission (FERC). It is anticipated that the licensing process will take approximately two additional years to complete. Specifications will then be issued for equipment supply and construction services.

A second underground pumped storage project at the Mt. Hope site in New Jersey is being considered for license. This facility is to use an existing mine shaft. Additional excavation may be required to expand the capacity of the lower reservoir. Estimated project costs are similar to the Summit estimate, and size estimates have ranged from 1,000 to 2,000 MW.

UPH performance is best described by an overall cycle efficiency and unit availability. A 76 percent overall cycle efficiency and an 83 percent unit availability have been estimated for a 2,000 MW facility. The unit availability estimate includes both long- and short-term planned outages.

The principal resource requirements for a UPH facility include sufficient water supply for fill water and makeup water for both reservoirs, adequate land area for surface facilities and the upper reservoir, and hard-rock formations at appropriate depth for the lower reservoir. The availability of an existing cavern is desirable because fewer excavation activities are required. No sites have been identified in the Central Florida area; further investigation would be required to identify and assess sites.

The costs to complete a pumped storage project can be as low as \$200/kW for a 2,400 MW plant or as high as \$2,000/kW for a 60 MW plant. A DOE/EPRI study estimated the cost of a 2,000 MW UPH storage facility at \$930/kW. The

lower end of the cost spectrum compares favorably to other technologies because pumped storage plants are projected to have a capacity of 1,000 MW to 3,000 MW. However, the dollar per kW value is not the only economic issue to be considered. The price differential between peaking power and baseload or off-peak power is of critical importance.

Economic considerations are highly site-specific and depend on the fuel and generation mix of a given region. With low gas and oil prices, pumped storage is very difficult to economically justify even under ideal site conditions. The few operating pumped hydro plants in the United States were mostly built during the mid-1970s when experts predicted skyrocketing fuel prices and oil and gas shortages.

Table 1A.5.1-1
Coal Burning Technology Alternative Screening Matrix

Technology	Technical Maturity	Unit Resource	Unit Performance		Environmental Considerations	Project Cost*		Time Frame of OUC Interest	Screening Comments
			Heat Rate (Btu/kWh)	Capacity Factor (percent)		Capital (\$/kW)	O&M**		
Coal Gasification Combined Cycle	Demonstration Scale with Nominal 100 MW and 160 MW in Operation	Abundant Resources of Coal Relatively Certain	8,240 to 9,500	Baseload	Air Emissions Much Lower Than Existing Requirements	1,120 to 1,620	\$37/kW-y; \$0.8/MWh to \$4.70/MWh	Near-Term	Retain for Screening
Pressurized Fluidized Bed	Demonstration Plants at 70 MW, 79 MW, and 135 MW Under Construction	Abundant Resources of Coal and Limestone Relatively Certain	8,700	Baseload	Projected Compliance with Existing Requirements. Requires Hot Gas Cleanup of Particulates, a Developmental Issue.	1,300 to 1,400	\$30/kW-y; \$6.4/MWh	Near to Mid-Term	Drop from Screening; Inadequate Demonstration
Advanced Pulverized Coal	Not All Components Developed for SOAPP Conditions	Abundant Resources of Coal and Limestone Relatively Certain	8,800	Baseload	Projected Compliance with Existing Requirements	1,370	\$30/kW-y; \$3.2/MWh	Mid-Term	Drop from Screening; Inadequate Demonstration
Fuel Cells (Advanced with Coal Gasification)	Bench Scale	Abundant Resources of Coal Relatively Certain	7,500; Lower with Bottom Cycle	Intermediate or Baseload	Projected Compliance. Will Depend On Proven Gas Cleanup Similar to GCC or Hot Gas Cleanup Under Development	Not Available		Mid to Far-Term	Drop from Screening; Inadequate Demonstration
Humid Air Turbine Cycle (With Coal Gasification)	Not Developed	Abundant Resources of Coal Relatively Certain	8,800	Intermediate or Baseload	Projected Compliance. Will Depend On Proven Gas Cleanup Similar to GCC or Hot Gas Cleanup Under Development	1,160	Not Available	Mid-Term to Far-Term	Drop from Screening; Inadequate Demonstration
Coal Liquefaction	Demonstrated in South Africa	Abundant Resources of Coal Relatively Certain	Not Applicable	Not Applicable	Similar to GCC for Fuel Production Plant	Not Applicable		Mid-Term	Drop from Screening; High Cost Liquid Fuel Source Compared with Oil or Gas
Magnetohydrodynamics	Bench Scale	Abundant Resources of Coal Relatively Certain	8,620	Baseload	Projected for Compliance	1,810		Far-Term	Drop from Screening; Not Demonstrated to Date

*Costs in January 1990 dollars. Emerging technology costs typically are mature technology costs rather than present-day costs.

**O&M costs do not include fuel.

Table 1A.5.1-2
Oil or Gas Burning Technology Alternative Screening Matrix

Technology	Technical Maturity	Unit Resource	Unit Performance		Environmental Considerations	Project Cost*		Time Frame of OUC Interest	Screening Comments
			Heat Rate (Btu/kWh)	Capacity Factor (percent)		Capital (\$/kW)	O&M**		
Steam Injected Gas Turbine	Commercial for Smaller Sizes Using Aero-Derivative Turbines	Future of Economic Supply of Oil and/or Gas Not Certain. Also Requires Significant Water.	8,080 at 50 MW	Base or Intermediate Load	Same as Simple Cycle.	800 to 1,050	\$5.4/kW-y; \$0.5/MWh	Near-Term	Drop From Screening; Typically Used in Cogeneration Application Where Process Steam is Generated
Humid Air Cycle	Turbine Not Developed for HAT Cycle	Future of Economic Supply of Oil and/or Gas Not Certain. Also Requires Significant Water.	7,080	Base or Intermediate Load	Same as Simple Cycle.	630	Not Available	Mid-Term	Drop from Screening; Inadequate Demonstration
Fuel Cells	Demonstration	Future of Economic Supply of Natural Gas Not Certain	8,300	Multi Use	Very Low Emissions Because of Clean Fuel (Natural Gas) and Low Temperatures	Current 2,500. Projected 1,000	\$8.4/kW-y; \$5.2/MWh	Mid-Term	Drop from Screening; Inadequate Demonstration

*Costs in January 1990 dollars. Emerging technology costs typically are mature technology costs rather than present-day costs.

**O&M costs do not include fuel.

Table 1A.5.1-3
Nuclear Technology Alternative Screening Matrix

Technology	Technical Maturity	Unit Resource	Unit Performance		Environmental Considerations	Project Cost*		Time Frame of OUC Interest	Screening Comments
			Heat Rate (Btu/kWh)	Capacity Factor (percent)		Capital (\$/kW)	O&M**		
Advanced Passive Light Water Reactor	Under Development	Slightly Enriched Uranium	10,000 to 11,000	65 to 70	Gaseous and Liquid Releases Well Within Requirements. Currently Lack of Permanent Storage for Spent Fuel	Exceeds 3,000. Possible Reduction to 2,000 (See Note***)	Not Available	Mid-Term	Drop from Screening; Licensing Time and Lack of Permanent High Level Waste Storage Make New Construction Unlikely
Modular Pressurized Heavy Water (CANDU)	Under Development	Natural Uranium; Heavy Water	10,000 to 11,000	65 to 70	Similar to Light Water Reactors	Similar to Advanced Passive Light Water Reactors	\$10.5/MWh (includes fuel)	Mid-Term	Drop from Screening; Licensing Time and lack of Permanent High Level Waste Storage Make New Construction Unlikely
Modular High Temperature Gas-Cooled Reactor	Under Development in the US. Several Units in Operation in Europe.	High Enriched Uranium	9,000	Baseload	Projected Gaseous and Liquid Releases Lower than for Light Water Reactors. Also has Passive Safety Features	2,500 to 3,000	Not Available	Far-Term	Drop from Screening; Still Developmental, Plus Licensing and Storage Concerns
Liquid Metal	Under Development in the US	Uranium/Plutonium	9,000	Baseload	Similar to Heavy Water Reactors. Concern Over Production of Weapons Grade Plutonium	3,000 to 3,500	Not Available	Far-Term	Drop from Screening; Still Developmental, Plus Licensing, Storage, and Production of Weapons Grade Plutonium are Concerns
Fusion	Laboratory Scale	Deuterium and Tritium	9,000 to 11,300	Baseload	Projected much Lower Releases than Light Water Reactor.	Not Available	Not Available	Far-Term	Drop from Screening; Very Early in Developmental Stage

*Costs in January 1990 dollars. Emerging technology costs typically are mature technology costs rather than present-day costs.

**O&M costs do not include fuel.

***Projected costs for nuclear plants with reduced licensing times, modularity, and other methods for reducing construction time.

Table 1A.5.1-4
Renewable Energy Source Technology Alternative Screening Matrix

Technology	Technical Maturity	Unit Resource	Unit Performance		Environmental Considerations	Project Cost*		Time Frame of OUC Interest	Screening Comments
			Heat Rate (Btu/kWh)	Capacity Factor (percent)		Capital (\$/kW)	O&M**		
Wind	Commercial with 1,400 MW of Capacity Installed from 1981 to 1987	Inadequate in Florida	Site Specific	Low Capacity Factor in Florida	Generally Acceptable	1,110	\$8.3/kW-y; \$7.4/MWh	Not Applicable	Drop from Screening; Insufficient Resource in Florida
Solar Photovoltaics	Commercial at 1 MW to 6 MW	Moderate Direct and Diffuse Insolation in Central Florida	Solar-to-Electric Efficiency Site Specific	15 to 20	Generally Good. High Land Requirements	7,000	\$6.7/kW-y; \$3.2/MWh	Mid-Term	Drop from Screening; Immature Costs
Solar Thermal Parabolic Trough	Commercial at 30 MW with 80 MW Plant Under Construction	Moderate Direct Insolation in Central Florida	Solar-to-Electric Efficiency About 20 Percent	About 16 Percent in Central Florida	Generally Good. High Land Requirements	2,600	\$4.6/kW-y; \$0.8/MWh	Near-Term	Retain for Screening
Solar Thermal Central Receiver	Pilot Scale (10 MW)	Moderate Direct Insolation in Central Florida	Solar-to-Electric Efficiency about 15 Percent	About 22 Percent in Central Florida	Generally Good. High Land Requirements	2,600	\$15/MWh	Mid-Term to Far-Term	Drop from Screening; Inadequate Demonstration
Solar Parabolic Dish	Bench and Small Scale Demonstration	Moderate Direct Insolation in Central Florida	Solar-to-Electric Efficiency Site Specific	Moderate Capacity Factor in Central Florida	Generally Good. High Land Requirements	Immature (High Cost/kW)		Mid-Term to Far-Term	Drop from Screening; Inadequate Demonstration
Ocean Thermal	Not Demonstrated	Ocean Water with Significant Thermal Gradient	Very High	Baseload	Concern About Cool Water Discharge	Immature (High Cost/kW)		Far-Term	Drop from Screening; Inadequate Demonstration
Ocean Wave	Commercial	High Amplitude Ocean Waves	Not Applicable	Baseload	Shoreline Land Use	Site Dependent		Not Applicable	Drop from Screening; Inadequate Resource
Ocean Tidal	Commercial	High Amplitude Ocean Tides	Not Applicable	Intermediate	Shoreline Land Use	Site Dependent		Not Applicable	Drop from Screening; Inadequate Resource
Geothermal	Commercial	None in Central Florida	Not Applicable	Baseload		Site Dependent		Not Applicable	Drop from Screening; Inadequate Resource

*Costs in January 1989 dollars. Emerging technology costs typically are mature technology costs rather than present-day costs.

**O&M costs do not include fuel.

**Table 1A.5.1-5
Energy Storage Technology Alternative Screening Matrix**

Technology	Technical Maturity	Unit Resource	Unit Performance		Environmental Considerations	Project Cost*		Time Frame of OUC Interest	Screening Comments
			Heat Rate (Btu/kWh)	Capacity Factor (percent)		Capital (\$/kW)	O&M**		
Lead-Acid Batteries	Commercial	Excess Baseload Capacity	72 Percent In/Out Efficiency	Peaking	Requires Containment for Acid Spills	900 (10 MW, 40 MWh)	\$24/kW-y, \$2.2/MWh (10 MW, 40 MWh)	Near- to Mid-Term	Retain for Screening
Compressed Air Energy Systems	Demonstration Level with 290 MW Plant Operational in Europe, 110 MW Plant Under Construction in the US	Existing Caves or Proper Geology for Cavern Construction Unlikely in Central Florida	4,100 to 5,500	Peaking	Emissions Lower than for Combustion Turbine. May Have Constraints Related to Construction and Operation of Cavern.	540 to 680 for 100 MW	Site Dependent	Mid-Term	Drop from Screening; Inadequate Demonstration; and Uncertain Resource
Underground Pumped Hydroelectric	Near-Term	Existing Caves or Proper Geology for Cavern Construction Unlikely in Central Florida	76 Percent In/Out Efficiency	Peaking	Similar to Hydroelectric. May Have Constraints Related to Construction and Operation of Cavern.	930	Site Dependent	Mid-Term	Drop from Screening; Uncertain Resource

*Costs in January 1989 dollars. Emerging technology costs typically are mature technology costs rather than present-day costs.

**O&M costs do not include fuel.

1A.5.2 Cost and Operating Characteristics for Conventional Alternatives

Cost and performance data for pulverized coal, atmospheric circulating fluidized bed, combustion turbine, and combined cycle units are provided in this section. Data were primarily obtained from Black & Veatch Generating Unit Characteristics--July 5, 1990.

1A.5.2.1 Conventional Pulverized Coal

Pulverized coal technology has been the standard of the coal fueled steam electric generating industry for several decades. In a conventional pulverized coal steam generating unit, the dry pulverized coal is entrained in a hot airstream and carried from the pulverizer through coal piping to the furnace, where it is ignited and burned in suspension. Radiant energy from the combustion process is absorbed by the furnace waterwalls. Downstream of the furnace, the flue gas flows through steam-and water-cooled convective heat transfer surfaces and then through a regenerative air heater. From the air heater, the flue gas flows through particulate removal and desulfurization equipment before entering the chimney and being exhausted to the atmosphere. Superheated steam that is generated in the steam-cooled convective heat transfer sections of the boiler is delivered to the steam turbine generator. Steam from the turbine exhaust is condensed, pumped to the steam generator operating pressure, heated by steam from turbine extractions, and fed back to the steam generating unit.

Sulfur dioxide (SO_2) emissions from pulverized coal units can be controlled through any number of flue gas desulfurization (FGD) technologies. The application of an FGD technology is dependent on the type of coal and its sulfur content, site-specific constraints, and other site environmental factors. High-sulfur coal fired units have been typically designed to achieve 90 percent SO_2 removal.

Control of nitrogen oxide (NO_x) emissions from pulverized coal fueled power plants in the US has been traditionally achieved through the use of combustion alternatives rather than installation of a specific nitrogen oxide removal process. However, installation of Thermal De NO_x and Selective Catalytic Reduction (SCR) processes as well as use of low NO_x burners may become more commonplace in the future as proven technology is developed and reliability is demonstrated. Typical NO_x permit values for pulverized coal units have been

0.60 lb/MBtu. The latest low NO_x pulverized coal units have been permitted as low as 0.32 lb/MBtu.

Estimated performance and cost data for 300 MW, 425 MW, and 675 MW pulverized coal units are provided in Table 1A.5.2-1.

1A.5.2.2 Atmospheric Fluidized Bed

Atmospheric fluidized bed combustion (AFBC) systems are in an advanced state of development and are currently being applied in electric utility systems. The largest circulating AFBC in operation is a 96 MW unit in Trona, California. The largest unit scheduled for construction is a 165 MW unit at Point Aconi for Nova Scotia Power Corp.

In a circulating fluidized bed steam generating unit, fuel and sorbent are fed by gravity into a highly turbulent region of the combustion chamber where combustion air, feed fuel, sorbent, and recirculating solids are mixed. The reacting gas and solids flow upward and then enter a particulate separator, usually a cyclone, where the solids are separated and returned to the bottom of the combustion chamber. Flue gas leaves the cyclone and is cooled by a conventional convection bank and an air heater. Additional particulate removal is required before the gas is discharged to the stack.

Flue gas desulfurization is accomplished in fluidized bed combustion units by adding limestone to the bed and promoting high temperature reaction of calcium oxide (CaO) with SO_2 . The level of SO_2 removal is increased by increasing the feed rate of limestone to the bed. On the basis of current operating experience with AFBC units, relatively high levels of excess limestone addition (Ca/S ratio of 2.0 to 3.0) are required to achieve 90 percent SO_2 removal. Higher SO_2 removal rates (95 percent) have not been demonstrated on a continuous basis, and are expected to require much higher limestone consumption rates.

Generation of NO_x in AFBC units is lower than that of pulverized coal units because of the lower combustion temperatures inherent to the process. With staged combustion, NO_x emissions in AFBCs can be controlled to less than 0.30 lb/MBtu.

A current drawback to the implementation of AFBC units over conventional pulverized coal units is the relatively higher limestone and waste disposal costs associated with AFBCs. Although each of the units generates about the same amount of fuel ash, the unreacted limestone in the combustion wastes is

significantly higher for the AFBC. A conventional 150 MW pulverized coal plant will produce about 42,000 tons per year of desulfurization byproducts compared to 62,000 tons per year by a 150 MW AFBC unit. Since fly ash is not separately collected in the APBC, it cannot be marketed as is sometimes done at a pulverized coal unit.

As with most new or rapidly expanding technologies, when new equipment is constructed on the basis of successful design criteria used by significantly smaller equipment installations, operation of the larger equipment normally is accompanied by operating problems due to design shortcomings. The operation of fluidized bed boilers in the US has not been an exception to this rule. It is expected that new fluidized bed installations with capacities in excess of those in operation for several years will be the source of more forced outages than a steam generator of conventional design. After the first few years of operation, it is expected that maintenance requirements will be well defined, and preventive maintenance programs will enable the fluidized bed boilers to operate with availability comparable to that of conventional pulverized coal boilers. Fluidized bed systems lack the high maintenance pulverizers and scrubber equipment of conventional pulverized coal plants, but may experience higher boiler maintenance due to potentially greater heat transfer surface erosion.

Estimated performance and cost data for 300 MW and 425 MW circulating AFBC coal units are provided in Table 1A.5.2-2. Both units are based on two steam generators and one steam turbine.

1A.5.2.3 Combustion Turbines

Combustion turbines burning either natural gas and/or No. 2 oil are available in a wide variety of sizes and configurations. Combustion turbines are generally used for peaking and reserve purposes because of their relatively low capital cost, poorer full load heat rate, and the higher cost of fuel when compared to conventional baseload capacity. Combustion turbines have the added benefit of providing quick-start capability in certain configurations.

Combustion turbine design continues to be improved. Advanced designs such as the General Electric Frame 7FA (MS7001F) offer a lower heat rate than can be achieved with standard machines, mainly because of higher hot gas temperatures. The GE Frame 7FA compared to the Frame 7EA conventional design offers an increased firing temperature of 2,300 F, an increase in the number of

combustion chambers, and a multiple combustor nozzle arrangement instead of a single nozzle, reducing combustion system wear. Estimated performance and cost data for the Frame 7EA and the Frame 7FA are provided in Table 1A.5.2-3.

1A.5.2.4 Combined Cycle

In a combustion turbine combined cycle facility, the hot exhaust gases from the combustion turbine pass through a heat recovery steam generator (HRSG). The steam generated by the HRSG is expanded through a steam turbine which, in turn, drives an additional generator. With a typical gas inlet temperature of 1,000 F, steam conditions of about 1,000 psi and 900 F can be produced by the HRSG. Typically, combined cycle installations can have more than one set of combustion turbines and HRSGs, with steam piped to a common steam turbine. Usually about two-thirds of the power is produced by the combustion turbine generator and about one-third is produced by the steam turbine generator.

Estimated performance and cost data for two Frame 7EA or 7FA combustion turbines, two unfired HRSGs, and one steam turbine are provided in Table 1A.5.2-4.

Table 1A.5.2-1
Pulverized Coal Technology Unit Cost and Performance Data

	Net Plant Output, MW*		
	300	425	675
Direct Capital Cost, 1990 \$/kW**	1,210	1,070	895
Indirect Cost, percent	19.4	18.8	17.7
Fixed O&M Cost, 1990 \$/kW-yr	19	17	15
Variable O&M, 1990 \$/MWh	1.60	1.55	1.55
Net Plant Heat Rate, Btu/kWh			
Full load	9,870	9,820	9,730
75 percent load	10,080	10,010	9,940
50 percent load	10,760	10,690	10,560
25 percent load	12,800	12,730	12,630
Equivalent Availability, percent	83	83	83
Forced Outage Rate, percent	7	7	8
Planned Maintenance Outage, weeks/year	4	4	5
Construction Period, months	41	46	48

*Rated conditions are at valves wide open 5 percent over pressure (VWO-OP).

**Does not include escalation, indirect cost, or interest during construction. Based on first unit at a new site.

Table 1A.5.2-2
Circulating Atmospheric Fluidized Bed Technology Unit Cost
and Performance Data

	<u>Net Plant Output, MW*</u>	
	300	425
Direct Capital Cost, 1990 \$/kW**	1,140	1,000
Indirect Cost, percent	19.4	18.8
Fixed O&M Cost, 1990 \$/kW-yr	17	15
Variable O&M, 1990 \$/MWh	2.15	2.15
Net Plant Heat Rate, Btu/kWh		
Full load	10,260	10,210
75 percent load	10,480	10,410
50 percent load	11,190	11,120
25 percent load	13,310	13,240
Equivalent Availability, percent	83	83
Forced Outage Rate, percent	7	7
Planned Maintenance Outage, weeks/year	4	4
Construction Period, months	38	46
*Based on two boilers serving one steam turbine generator, (VWO-OP). **Does not include escalation, indirect cost, or interest during construction. Based on first unit at a new site.		

Table 1A.5.2-3
Combustion Turbine Technology Unit and Performance Data

	GE Frame 7EA	GE Frame 7FA
Net Plant Output, MW*	87.5	172.3
Direct Capital Cost, 1990 \$/kW**	319	268
Indirect Cost, percent	13.0	12.0
Fixed O&M Cost, 1990 \$/kW-yr	8.50	7.00
Variable O&M, 1990 \$/MWh		
Peaking load, 5 percent capacity factor	3.7	3.7
Intermediate load, 25 percent capacity factor	1.3	1.3
Net Plant Heat Rate, Btu/kWh*		
Full load	12,271	11,221
75 percent load	12,614	11,590
50 percent load	13,905	12,887
25 percent load	18,991	18,008
Equivalent Availability, percent	88	88
Forced Outage Rate, percent	5	5
Planned Maintenance Outage, weeks/year	2.5	2.5
Construction Period, months	12	12

*59 F ambient temperature and 14.9 psi.

**Does not include escalation, indirect cost, or interest during construction.

Table 1A.5.2-4
Combined Cycle Technology Unit and Performance Data

	Combined Cycle with GE 7EA	Combined Cycle with GE 7FA
Net Plant Output, MW*	255	489
Direct Capital Cost, 1990 \$/kW**	505	417
Indirect Cost, percent	13.1	13.1
Fixed O&M Cost, 1990 \$/kW-yr	13.1	10.8
Variable O&M, 1990 \$/MWh	1.80	1.80
Net Plant Heat Rate, Btu/kWh*		
Full load	8,409	7,912
75 percent load	8,514	8,097
50 percent load	9,336	8,896
25 percent load	12,959	12,097
Equivalent Availability, percent	86	86
Forced Outage Rate, percent	6	6
Planned Maintenance Outage, weeks/year	4	4
Construction Period, months	22	27

*Based on two combustion turbines, two unfired HRSGs, and one steam turbine at 59 F and 14.9 psi.

**Does not include escalation, indirect costs, or interest during construction.

1A.5.3 Hydroelectric

Florida has minimal water resources and terrain suitable for the development of significant conventional hydroelectric or pumped storage generation facilities. A study conducted by the Federal Energy Regulatory Commission, "Hydroelectric Power Resources of the United States," shows Florida as having additional potential hydroelectric generation totaling 84 MW. Additionally, the report indicates an average annual generation of 100,932 MWh representing a capacity factor of 14 percent. Hydroelectric is not considered an alternative to Stanton 2 because of the small amount of potential capacity and the low potential capacity factor.

1A.5.4 Joint Request For Power Supply Proposals

As an alternative to the construction of Stanton 2, the Orlando Utilities Commission (OUC), the Florida Municipal Power Agency (FMPA), and the Kissimmee Utility Authority (KUA) underwent an extensive bidding process open to qualifying facilities, independent power producers, and utilities. The following sections discuss the bidding process and the evaluation of the bids that were received.

1A.5.4.1 Request For Proposals

In July 1990, OUC together with FMPA and KUA (collectively the "Utilities") issued a Joint Request for Proposals (RFP). The RFP solicited the interest to supply the Utilities with 440 MW of firm base and intermediate load electric energy and capacity available for commercial operation on January 1, 1997.

The objective of the Utilities in soliciting the RFP is to meet their respective customers' electric needs with dependable and reliable service at the lowest achievable cost through time, with considerations for respect for the environment of Florida; a reduction of reliance on imported oil; and adherence to all laws, rules, ordinances and regulations.

A notice of the availability of the RFP was published in all four regions of the Wall Street Journal on June 14, 1990. In response to the notice there were 64 requests for copies of the RFP.

Proposals to be submitted in accordance with the RFP were required to meet the following minimum requirements.

- Proposed facilities must be a commercially proven technology.
- Proof of the ability to wheel and all associated costs, if applicable, must be included in the proposal.
- The proposed facility must be dispatchable and capable of automatic generation control.
- A specific site must be identified.
- The respondent must submit to the requirements of the Florida Electrical Power Plant Siting Act, if necessary.
- The proposal prices must be submitted in the units specified.
- The term of the agreement for the sale of the capacity and energy to the utilities is 25 years.

- If the facility is located outside Florida, only one intervening utility transmission system is necessary to deliver the power.
- The proposal must include all changes required in addenda.
- The facility must be capable of operating as a base and intermediate load plant, and is not of peaking capacity design.
- The proposal must be firm for twelve months.
- Interconnection and wheeling costs must be included.
- The acceptance date shall be January 1, 1997.
- Evidence must be provided in the proposal to show proof of access, procurement, and transportation plans for primary and secondary fuel sources.
- Finally, if a thermal host is required, evidence showing that an agreement between the respondent and the thermal host is viable for the 25 years specified in the RFP.

1A.5.4.2 Intent to Bid Responses

Of the 64 companies which requested a copy of the RFP, 19 companies submitted a notice of intent/respondent registration form. A list of the companies with intentions to bid is in Table 1A.5.4-1.

1A.5.4.3 Bids Received

Although nineteen notices of intent to bid were received, only three proposals were submitted as of the November 13, 1990, deadline. The three respondents, the Enron Power Corporation, Inc. (Enron), Citrus Energy Partners, L.P. (NRG), and the PG&E-Bechtel Generation Company (PG&E) submitted bids totaling 1,276 MW.

OUC retained R.W. Beck and Associates (R.W. Beck) to independently evaluate the proposals.

1A.5.4.3.1 Enron Power Corporation. Enron proposed as an independent power producer (IPP) (no steam customer) to build, own, and operate, by January 1, 1997, a multiple-unit, 440 MW combined-cycle natural gas fired combustion turbine facility for base, intermediate, or peaking operation. Two sites were proposed: the primary site was a 31.1-acre tract located about 1.5 miles south of the Bee Line Expressway in the International Corporate Park in eastern Orange County, which is about 3.5 miles from OUC's Stanton Energy Center, and the

alternate site was a 38-acre tract of land southeast of the intersection of the Florida Turnpike and Route 527 and relatively close to OUC's Taft Substation. At the primary site, the planned electrical interconnection was proposed through the construction of 3.5 miles of single-pole, double-circuit 230 kV transmission line to OUC's Stanton Energy Center. At the alternate site, the planned electrical interconnection was proposed through the construction of 1.5 miles of wood-pole, double-circuit 230 kV line into OUC's transmission system at the OUC Taft Substation.

Enron proposed that natural gas interconnections would be accomplished using nearby gas transmission lines (west and southwest of the primary site; south of the alternate site). Natural gas fuel was proposed to be acquired from supplies, through Citrus Marketing, located in the Gulf Coast region of Louisiana and Texas. Citrus Marketing, through its existing transportation arrangements, proposed to provide for the delivery of the gas, over other Enron affiliated companies, to Florida Gas Transmission, also an Enron affiliate. Enron proposed that Florida Gas Transmission supply firm gas transportation services for the project's gas requirements, according to a firm reservation of pipeline capability which the project would enter into. Enron proposed to supply three days of onsite distillate fuel inventory for backup fuel.

1A.5.4.3.2 Citrus Energy Partners, L.P. NRG Energy, Inc., of Minneapolis, Minnesota, is the lead owner of Citrus Energy Partners, L.P. and the proposed plant operator. NRG is a nonregulated subsidiary of Northern States Power Company.

As an IPP, NRG proposed a 410 MW eastern bituminous pulverized coal fueled, baseload power station to be on line by January 1, 1997. The project was proposed to be located approximately nine miles to the northwest of the City of Okeechobee in Okeechobee County, Florida. The site comprises 1,050 acres of land area presently used entirely for a cattle grazing operation. The site is bounded on the southwest by the CSX Transportation railroad and on the northeast by US Highway 98/Florida Highway 700.

The project was proposed to be interconnected with Florida Power & Light Company's (FPL) 500 kV transmission system at the Midway or Martin Substation, or at the 230 kV Sherman Substation, whichever is the most advantageous for wheeling purposes. Power from the project was proposed to be

wheeled north through the FPL system to ties with OUC near the Indian River generating facility.

The procurement of fuel for the project, as proposed, consisted of the purchase of bituminous coal from central Appalachian source areas (Kentucky, West Virginia, or Virginia). Present procurement strategy calls for a minimum of 50 percent of the supply being purchased under long-term contracts. The coal was proposed to be transported to the site in unit trains of at least 90 cars each by the CSX Transportation, Inc. rail system under long-term contract.

Onsite coal storage was reported to be capable of supporting 30 days' operation at full load with adequate space to expand to 60 days' supply, if necessary. Limestone for flue gas scrubber additive use was proposed to be purchased under long-term contracts from Florida suppliers and would be a high calcium carbonate product that would either be trucked or railed to the site.

Sufficient onsite land is reported to be available to permit the landfill of all ash and scrubber waste products during the life of the generating unit.

1A.5.4.3.3 PG&E-Bechtel Generating Company. PG&E is the developer/project manager for the Brevard Energy Limited Partnership. PG&E proposed a 426 MW (winter rating) natural gas fueled, combined cycle (two gas turbines, one steam turbine) project, applicable for base and intermediate load operation, to be on line by January 1, 1997.

The proposed site was a 436-acre vacant property located in Brevard County, Florida. The location of the site is reported to be along State Road 528 (Bee Line Expressway) approximately two miles east of its intersection with Interstate I-95.

The project was proposed to be interconnected directly with OUC via the 230 kV OUC transmission line to the Indian River Power Plant. The interconnection point is about five miles north of the proposed project. A new 230 kV transmission line was expected to be built by the respondent from the project to the interconnection point. Three alternative paths have been proposed for the new 230 kV transmission line.

The proposed primary fuel was natural gas. The proposed fuel supply contractor was Chevron, based in Houston, Texas; the proposed fuel transportation contractor was the Florida Gas Transmission Company.

1A.5.4.4 Evaluation of Proposals

The proposals received in response to the RFP were evaluated by R. W. Beck through two stages of a planned three-stage evaluation.

Stage one comprised a detailed inventory of the submission of each respondent to ascertain whether each item requested in the RFP was submitted and that each proposal met or exceeded the minimum requirements established in the RFP. If necessary, requests for additional information or clarification of proposal contents were to be forwarded, through OUC, to the respondents.

In stage two of the planned evaluation process, proposals were to be prioritized by a scoring system used in combination with the information found in the respondents' submittals. Fatal flaws and weaknesses in the submissions were to be determined and documented. A comparison, on a present worth basis, of the pricing of power from Stanton 2 and the proposal was to be performed.

Originally, the stage two evaluation was intended to create a shortlist of prioritized proposals. Stage three of the evaluation process was intended to take the list developed in stage two and compare the proposals in greater detail to the expected characteristics of Stanton 2. However, since only three proposals were received and because of conclusions developed in stage two (Subsection 1A.5.4.4.2), the stage three evaluation was deemed unnecessary.

1A.5.4.4.1 Stage One Evaluation/Results. Initial review of the submittal materials by R. W. Beck found all three proposals responsive but incomplete. Additional clarification of submitted materials was requested and received. Although Enron and PG&E submitted pricing proposals which were inconsistent with the baseline pricing methodology established in the RFP, R. W. Beck concluded that Enron's as well as PG&E's interpretation of OUC's willingness to entertain alternative pricing schemes, as described in the RFP, could be considered defensible. Therefore, all three proposals were advanced to stage two of the evaluation process.

1A.5.4.4.2 Stage Two Evaluation/Results. In stage two of the evaluation process, a weighted scoring system was used to rank the proposals. Each of the proposals was evaluated according to its financial, technical, environmental, and economic merits. Scores from each of these areas were combined to yield an overall ranking of the proposals. The maximum scoring and the weighting used is provided in Table 1A.5.4-2.

The Stanton 2 proposal was not subjected to the Stage Two scoring process in the financial, technical, and environmental areas. However, it was used as the basis of comparison in the economic analysis.

As can be seen from Table 1A.5.4-2, the environmental and economic areas of evaluation have been given equal overall scoring. The technical considerations have been given less weight, and the financial considerations even less weight. Financial markets and technology exist, so that experienced, serious developers can finance, construct, and operate projects of the type contemplated in the development of the RFP. The most important issues are the ability of a project to be licensed in the current environment and the ability of the project to provide economic benefits for the Utilities' customers.

The technical evaluation reflects the desirability of the proposed location of the project (a direct interconnection to OUC's transmission system is preferred); what equivalent availability factor a similar facility to the one proposed by each respondent has achieved; what the status of studies and plans are, such as site surveys, major equipment lists, etc.; the procurement and transportation plans for the type of primary fuel the proposed facility will use; and whether or not the respondent has experience in the procurement and transportation of the fuel supplies.

The financial evaluation involved preliminary review of the financial planning and pro forma information submitted by the respondents for evidence of the amount of capital currently committed to the project; the debt/equity ratio; a satisfactory debt coverage ratio; and the type of security the respondent is willing to provide to guarantee the reliable operation of the proposed facility over the expected term of the agreement.

The environmental evaluation considered the status of the site acquisition; whether or not key permits and licenses had been identified and the level of permitting action to date; the demonstration of an experienced team to meet the identified permitting schedule; the air impacts from the proposed facilities including air emission rates, air emission constituents, physical condition of the emissions streams, the proximity to potentially sensitive receptors, the level of air emissions compared to like facilities and current regulatory standards, the ability of pollution controls to achieve the appropriate levels of emissions, and topographic considerations such as stack height; the water resources impacts including the source and rate of water withdrawal, the rate of wastewater

discharge, the quality of wastewater discharge, the disposition of wastewater relative to existing water resources, the adequacy of available water supply quality and quantity for the project, and a comparison of water impacts for the project with like facilities; the solid waste impacts including the expected volume of solid waste, the disposal method and location, and a waste handling plan; the land use compatibility considered the amount and type of land included in the project site, the use of adjacent land, the consistency of the proposed project with existing land use plans, and potential environmental constraints inherent in the land (wetlands, zoning, etc.); and aesthetic impacts and methods of mitigation of these impacts.

The economic evaluation consisted of a comparison of annual payment streams developed from the pricing proposals provided by the respondents against annual "pricing" projected for Stanton 2. The payment streams were compared on a net present value (\$/kW) basis, and compared to determine if, and the degree to which, the pricing proposals are front loaded (the annual prices of the proposals are greater than the annual expenses for Stanton 2). These values were used in the formulas described below to develop the economic score for each respondent's proposal.

Two components were used in the economic scoring: the price factor score and the front load breakeven score.

- **Price Factor Score:** The price factor score (PFS) is determined by the following formula:

$$PFS = [(PVSC - RPVP)/PSVC] \times 175$$

where

PVSC = the net present value in 1997 dollars per kilowatt over a 25-year term of the capacity and energy pricing related to OUC's Stanton 2; and,

where

RPVP = the net present value per kW in 1997 dollars over a 25-year term of the payments to the respondent based on the respondent's proposed pricing scheme.

- **Front Load Breakeven Score:** This factor was used to determine the degree to which the respondent's pricing proposal was front loaded, as compared to Stanton 2 pricing. The front load breakeven score (FLBS) was determined by the following formula:

$$FLBS = [(25 - \text{Years})/25] \times 25;$$

where

Years = the number of years that the total payment to the respondent in dollars is greater than the total payment based on the pricing proposal of OUC's Stanton 2 facility.

From the above formula for the PFS, it is apparent that it is possible for a proposal to obtain negative points. This would occur if the net present value per kW of the pricing proposed by a respondent over the term of the contract is greater than the net present value per kW of the pricing proposed for the Stanton 2 unit.

With the results of the stage two evaluation, R. W. Beck developed the following conclusions:

- All three proposals meet the minimum requirements set forth in the RFP.
- The "fatal flaw" analysis did not indicate any environmental, financial, or technical problems associated with the three proposals.
- The stage two screening scores result in the following ranking for the three proposals where (i) is the proposal with the highest (best) score.
 - (i) PG&E - 195 points
 - (ii) ENRON - 190 points
 - (iii) NRG - 181 points
- The estimated cumulative twenty-five year power cost for Stanton 2 is projected to be less than such cost for all three proposals for the following reasons:
 - The estimated cumulative twenty-five year nominal power cost for all three proposals under each economic evaluation methodology is projected to be at least 14.9 percent higher when compared to such costs for Stanton 2; and
 - The estimated cumulative twenty-five year present value (1997\$) power cost for all three proposals under each economic evaluation methodology is projected to be at least 19.2 percent higher when compared to such costs for Stanton 2.

A complete description of the evaluation methodology and results developed by R. W. Beck and Associates are presented in their report, "Stage One and Stage Two Evaluation Process Joint Request for Power Supply Proposals," December 11, 1990.

1A.5.4.5 *Rejection of Bids*

The results of the R. W. Beck and Associates evaluation were presented to OUC on December 11, 1990. Upon careful consideration of the evaluation and their alternative, the Commission voted unanimously to reject all bids and to proceed with engineering and licensing activities to support the construction of Stanton 2 for commercial operation by January 1, 1997, with a Supplement Site Certification Application filing in March 1991.

Table 1A.5.4-1
Notice of Intent/Respondent Registration

Company	Generating Technology
Teco Power Service Corporation	To be Determined
Hadson Development Corporation	Combined Cycle
J. Makowski Company, Inc.	Combined Cycle
NRG Energy, Inc.	Coal Fired Steam
Enron Power Corporation	Combined Cycle
General Peat Resources	Steam Turbine
Cogeneration Partners of America	Combined Cycle
PG&E/Bechtel Generating Company	To Be Determined
BXG, Inc.	To Be Determined
Tevco/Transco Energy Company	A - Combustion Turbine B - Steam Turbine
Smith Cogeneration Management, Inc.	Combined Cycle
Entech, Inc.	Photovoltaic
H. B. Zachry Company	Steam Turbine
Stone & Webster Development Corporation	Fluidized Bed
Panda Energy Corporation	Combined Cycle
Enserch Development Corporation	Steam Turbine/Combined Cycle
Fru-Con Construction Corporation	Combined Cycle
Cea, Inc.	Fluidized Bed Boiler
Ark Energy, Inc.	FBB/Combined Cycle

**Table 1A.5.4-2
Stage Two Scoring**

Area of Evaluations/ Exhibit No.*	Description	Maximum Score	Weighting Factor	Weighted Maximum Score
<u>Technical</u>				
B.1.4	Location Respondent	10	2.5	25
E.3.2	Experience	10	2.5	25
E.5.2	Level of Dev. of Tech	10	2.5	25
E.6.2	Status of Plan	10	2.5	25
F.1.4	Fuel Diversity	10	2.5	25
F.1.5	Fuel Supply	10	2.5	25
Subtotal				150
<u>Financial</u>				
D.1.4	Committed Capital	10	1.0	10
D.1.4	Equity Component	10	1.0	10
D.1.4	Debt Coverage Ratio	10	2.0	20
G.3.2	Security	10	2.0	20
Subtotal				60
<u>Environmental</u>				
C.1.3	Site Acquisition	10	2.0	20
C.6.2a	Permitting and Licensing	10	3.0	30
C.6.2b	Permitting Schedule	10	3.0	30
C.6.2c	Air Impacts	10	3.0	30
C.6.2d	Water Resources Impacts	10	3.0	30
C.6.2e	Solid Waste Impacts	10	2.5	25
C.6.2f	Land Use Compatibility	10	2.0	20
C.6.2g	Aesthetics	10	1.5	15
Subtotal				200
<u>Economic</u>				
G.1.1	Price Factor Score	175	--	175
	Front Load Score	25	--	25
Subtotal				200
Total				610
*Exhibit numbers reference RFP.				

1A.5.5 Joint Request for Purchase Power Proposals

In addition to the Joint Request for Power Supply Proposals, detailed in Section 1A.5.4, OUC, together with Florida Municipal Power Agency (FMPA) and the Kissimmee Utility Authority (KUA) (collectively the "Utilities"), in July 1990 issued a Joint Request for Purchase Power Proposals (RFP). The RFP solicited the interest of electric utilities to supply firm power to the Utilities for a minimum of 10 years. Electric generating utilities in Florida, as well as generating utilities outside of Florida with only one intervening transmission system necessary to deliver the power to OUC, were each sent copies of the RFP. A list of utilities that received the RFP is presented in Table 1A.5.5-1.

The RFP requested that the respondents provide a minimum of 50 MW up to a maximum of 440 MW for a minimum of 10 years, beginning on January 1, 1997. Capacity levels of the firm power, to be delivered to OUC's transmission system, were to be constant or increasing on an annual basis. In addition, proposals were required to clearly demonstrate that reliable firm power including firm transmission service from third parties would be available from the resource for the period and at the price described in the proposal.

None of the solicited utilities submitted proposals; consequently, none were evaluated. Therefore, purchase power options will no longer be considered as an alternative to the construction of Stanton 2.

Table 1A.5.5-1
Distribution of Request For Purchase Power Proposals

Utility	Contact
Florida Power & Light Company	Mr. Gus Cepero Director Bulk Power Markets
Florida Power Corporation	Mr. James H. Blanchard Vice President System Operations
Florida Power Corporation	Mr. Wallace L. Barron Director-Energy Management Resources
Ft. Pierce Utilities Authority	Victor Garrison Director-Electric/Gas Systems
Gainesville Regional Utilities	Mr. Mile Kurts Acting General Manager
City of Homestead	Mr. Rex Jerrim General Manager
Jacksonville Electric Authority	Mr. Royce Lyles Managing Director
Key West Utility	Mr. Robert Padron General Manager
Kissimmee Utility Authority	Mr. James C. Welsh General Manager
City of Lake Worth Utility	Mr. Claude L'Engle Utility Director
City of Lakeland	Mr. Robert G. Siegel Managing Director
Utilities Commission of New Smyrna Beach	Mr. R. Ronald Hagen Utility Director
Reedy Creek Improvement District	Mr. Bob Kohl Director Reedy Creek Energy Department
City of St. Cloud	Mr. Sam Faried Utility Director

Table 1A.5.5-1 (Continued)
Distribution of Request For Purchase Power Proposals

Utility	Contact
Sebring Utilities Commission	Mr. James Moothart General Manager
Seminole Electric Cooperative, Inc.	Mr. William Walbridge Executive Vice President & General Manager
City of Starke	Mr. W. M. Weldon City Operation Manager & Director
City of Tallahassee	Mr. B. W. Wait III Director-Electrical Department
Tampa Electric Company	Mr. R. H. Arnold Director System Operations
City of Vero Beach	Mr. John Little Utility Director
Municipal Electric Authority of Georgia	Mr. D. L. Stokley President & General Manager
Alabama Electric Cooperative, Inc.	Mr. J. A. Vann, Jr. Executive Vice President & General Manager
Southern Company Services, Inc.	Mr. W. L. Marshall, Jr. Director Marketing
Oglethorpe Power Corporation	Mr. F. F. Stacy, Jr. President & Chief Executive Officer
Dalton Water & Light	Mr. DeForrest Parrott General Manager

1A.5.6 Nuclear

No new nuclear plants have been ordered in the US since the Three Mile Island accident in 1979. The lead time and cost of the conventional nuclear option in the US is very speculative. Emphasis is focusing on the advanced nuclear technology alternatives that are discussed in Subsection 1A.5.1.3. Recent nuclear units that have entered commercial operation in the US have experienced large cost overruns and long delays in schedule. The schedule for a conventional nuclear unit certainly precludes the nuclear unit from consideration as an alternative to Stanton 2. In addition, the cost overruns experienced by nuclear units recently entering commercial operation would render them uneconomical compared to Stanton 2. For these reasons, the conventional nuclear option is not considered further as an alternative to Stanton 2.

1A.6.0 Need for Associated Transmission Facilities

The proposed addition of Stanton 2 required that studies be conducted to determine the adequacy of the existing transmission facilities to reliably and economically deliver power to the system's load centers. OUC generation resources are integrated into its system grid via two 230 kV and two 115 kV circuits as shown on Figure 1B.2.0-1. These lines are located in a common corridor that extends west from the Indian River plant site to the Stanton plant site and then to the Pershing Substation.

The fiscal year 1990-91 FCG load flow data bank case for 1997 was used to model the state transmission network in the studies. The Power Technologies, Inc., Power System Simulator Program provided the full ac load flow solutions for the base case and single contingency outage cases. An overload criterion of 110 percent for lines and equipment determined the need for the upgrade or addition of facilities. The studies showed that the outage of one of the Stanton to Pershing 230 kV lines resulted in a 130 percent overload of the other. In the base case, each line was carrying 73 percent of its 440 MVA rating. An additional 230 kV circuit is necessary to deliver the total power output of Stanton 1 and 2 under single contingency transmission outage conditions. The load flow results confirmed this with a corresponding reduction in the line loadings to acceptable levels.

The siting for the new line was influenced by the need to better ensure the reliable transfer of power by finding an alternate pathway to the load centers. The route for the 444 MVA rated circuit was chosen to be the existing certified railroad right-of-way starting at the Stanton Energy Center and traveling southwesterly to an interception with existing transmission facilities running between the Pershing and Taft Substations. From that point, a second circuit will have been constructed on the existing double circuit towers to Taft Substation as part of a relocation project associated with the expansion of the Orlando International Airport. In addition to providing increased reliability, the new circuit provides direct support for those load centers located on the south side of the system grid.

Appendix 1A.A.0

Advanced Technology Descriptions

This appendix presents detailed information about the alternative generation technologies summarized in Subsection 1A.5.1. The assessment includes the following technologies.

- **Coal Fired Alternatives.**
 - Gasification Combined Cycle.
 - Pressurized Fluidized Bed Combustion.
 - Advanced Pulverized Coal.
 - Gasification Fuel Cells.
 - Gasification Humid Air Turbine Cycle.
 - Coal Liquefaction.
 - Magnetohydrodynamics.
- **Oil or Gas Fired Alternatives.**
 - Steam Injected Combustion Turbine.
 - Humid Air Turbine.
 - Fuel Cells.
- **Nuclear Alternatives.**
 - Advanced Passive Light Water Reactors.
 - Modular Pressurized Heavy Water Reactor.
 - Module High-Temperature Gas-Cooled Reactor.
 - Liquid Metal Reactor.
 - Fusion.
- **Renewable Energy Alternatives.**
 - Wind Energy.
 - Solar Photovoltaic.
 - Solar Thermal.
 - Ocean Thermal.
 - Ocean Wave.
 - Ocean Tidal.
 - Geothermal.

- Energy Storage
 - Battery
 - Compressed Air.
 - Underground Pumped Hydro.

The assessment of each technology includes a general description of the technology, its technological maturity, typical cost and performance characteristics, required resources, environmental impacts, and references used in producing the assessment. Capital costs are given in January 1990 dollars, and are for overnight construction, unless otherwise noted.

1A.A.1 Coal Fired Alternatives

The following coal fired alternative technologies for power generation are discussed in this report.

- Gasification combined cycle.
- Pressurized fluidized bed combustion.
- Advanced pulverized coal.
- Gasification fuel cells.
- Gasification humid air turbine cycle.
- Coal liquefaction.
- Magnetohydrodynamics.

1A.A.1.1 Gasification Combined Cycle

A gasification combined cycle (GCC) system gasifies a solid fuel, producing a fuel gas for a combined cycle power generation system. Usable solid fuels include bituminous, lignite, or subbituminous coals. Figure 1A.A.1-1 illustrates a GCC plant flow diagram. Coal may be delivered to a pressurized gasifier in a coal/water slurry or as a dry feed depending on the gasifier concept. The coal reacts with air or oxygen and water or steam to form raw syngas. A low Btu syngas (less than 200 Btu per scf, HHV basis) is produced by an air blown gasifier. A medium Btu gas (200 to 500 Btu per scf) is produced with an oxygen blown gasifier. The raw syngas is cooled to about 400 F to allow for particulate removal, and further cooled to 100 F to allow for acid gas removal. The cleansed gas is used in a combustion turbine. The turbine combustion gases are exhausted to a heat recovery steam generator (HRSG), where high-pressure steam is produced; the cooled combustion gases are then exhausted to the atmosphere. The high-pressure steam formed in the HRSG and in the syngas cooler is used to generate power in a bottoming steam cycle. In an integrated gasification combined cycle (IGCC) plant, steam produced in the gasifier portion of the plant is also transported to the HRSG.

1A.A.1.1.1 Technological Maturity. The first large-scale demonstration of an IGCC plant was the 100 MW Cool Water plant in Daggett, California.¹ That unit, which used a Texaco gasifier, operated from 1984 through 1989. Subsequently, Texaco obtained rights to purchase the plant from Southern California Edison. Recommissioning is planned for 1992, with plans for the unit

to gasify a combined coal/municipal sewage sludge feed. It will produce electricity, CO₂, alcohol, and ammonia.² Dow currently operates a 160 MW GCC unit in Plaquemine, Louisiana.³ Shell is also developing a coal gasification process.

The Cool Water unit began operation in mid-1984. In 1988, the maximum permitted feed rate was 1,200 tons per day at a rating of 122 MW (gross).¹ The design coal was Illinois No. 6, although a variety of coals were tested at Cool Water. Carbon conversions exceeded 97 percent for four different coals. The demonstrated heat rate was 10,950 Btu/kWh. The capacity factor for the first eight months of 1988 was 71 percent. During July and August 1988, the capacity factors were 98.0 and 90.6 percent, respectively. The availability of the gasifier was 79.3 percent in 1987.

The Dow Syngas Project uses a coal/water slurry with 52 to 54 percent concentration. The plant uses a gasifier with two stages to improve carbon use and cold gas efficiency. Plant availability for its first full year of operation was 42 percent. Plant availability from May to September 1988 was 52 percent. Production records through September 1988 showed a daily production of 92 percent capacity and a 30-consecutive-day capacity of 65 percent.^{3,4}

The Shell Development Company is developing the Shell Coal Gasification Process (SCGP). Shell's current demonstration unit is SCGP-I, located in Deer Park, Texas. SCGP-I can gasify 250 tons per day of bituminuous coals and 400 tons per day of lignites. Commercial Shell gasifiers are expected to have capacities ranging from 1,000 to 3,000 tons of coal per day.⁵

Another large-scale gasifier application within the United States is the 13,000-ton per day Dakota Gasification Plant in North Dakota. The plant uses 14 Lurgi gasifiers with a lignite feed, and produces synthetic natural gas. Lurgi gasifiers are also used in the SASOL I, II, and III plants in South Africa, where a total of 80,000 tons per day of coal are gasified to produce a number of products, including transportation fuels.

First commercial operation for GCC plants is projected to be in about 1994.⁶

1A.A.1.1.2 Cost and Performance Characteristics. Capital cost estimates for GCC systems vary with system size, design coal, gasifier manufacturer, and degree of integration, as well as plant location. Lowest capital cost estimates are \$1,210/kW for Dow gasifier systems and \$1,120/kW for lignite and subbituminous burning plants with a Texas location.⁷ No data are available in the public domain

for a bituminous coal burning Dow gasifier facility in Florida. A capital cost estimate for a Shell gasifier facility burning bituminous coal at a Florida site is \$1,620/kW.⁷ It is unknown to what extent these estimates reflect real cost differences.

O&M cost estimates vary in a manner similar to capital cost estimates. The low O&M cost estimate (for Dow) is \$37/kW-year (fixed) and \$0.8/MWh.⁸

Estimates of net plant heat rate vary with plant design (e.g., degree of integration and use of quench system versus heat recovery steam generation syngas cooling) and with the design coal. Projected heat rates range from around 8,200 to 9,630 Btu/kWh.

1A.A.1.1.3 Required Resources. The primary resources required for a GCC plant are coal and water. Coal requirements for the 400 GCC MW plant are about 3,800 tons per day at full load. The type of coal which can be burned depends on the gasifier. The Texaco gasifier currently operates on bituminous coal and has not been demonstrated to operate efficiently using subbituminous or lignite coals. The Dow gasifier was designed for, and has been operated with, subbituminous and lignite coals. Small-scale test burns have been made with a high-sulfur bituminous coal, with no operational or equipment problems encountered.⁹ Test burns of several coals at SCGP-1 appear to validate predictions that the Shell gasifier will be flexible with regard to use of bituminous, subbituminous, or lignite coals.¹⁰

1A.A.1.1.4 Environmental Impacts. Emission levels of sulfur dioxide and nitrous oxide have been reported to be only 10 to 15 percent of the New Source Performance Standards.³ Sulfur removal efficiency has exceeded 96 percent at prototype plants. These low levels of emission make GCC systems attractive in view of more stringent emission standards accompanying the 1990 Clean Air Act Amendments.

1A.A.1.1.5 References.

1. D. M. Rib, "Cool Water Environmental Utilizing Four Coal Feedstocks," presented at the Eighth EPRI Coal Gasification Contractors' Conference, Palo Alto, California, October 19-20, 1988.
2. W. H. Cummins, G. N. Richter, and J. S. Stevenson, "The Texaco Gasification Process: Status, New Applications and Proposed Developments," presented at the Ninth Annual EPRI Conference on Gasification Power Plants, Palo Alto, California, October 17-19, 1990.

3. R. D. Hudson and G. C. LeBlanc, "Environmental Monitoring at Dow's Coal Gasification Plant," presented at the Eighth EPRI Coal Gasification Contractors' Conference, Palo Alto, California, October 19-20, 1988.
4. R. M. Webb and K. W. Moser, "The Dow Syngas Project Recent Operating Experience," presented at the Eighth EPRI Coal Gasification Contractors' Conference, Palo Alto, California, October 19-20, 1988.
5. R. P. Jensen, U. Mahagaokar, and A. B. Krewinghaus, "SCGP--Progress in a Proven, Versatile, and Robust Technology," presented at the Ninth Annual EPRI Conference on Coal Gasification Power Plants, Palo Alto, California, October 17-19, 1990.
6. TAG: Technical Assessment Guide, Volume 1: Electricity Supply, EPRI P-587-L, November 1989.
7. Florida Power and Light Company's Study of Shell-Based GCC Power, Plants, EPRI GS-6176, January 1989.
8. Evaluation of a Dow-Based Gasification Combined Cycle Plant Using Low Rank Coals, EPRI GS-6318, April 1989.
9. M. W. Roll, R. J. Payonk, "Operation of the Dow Coal Gasification Process during 1990," presented at the Sixth Annual Pittsburgh Coal Conference, September 25-28, 1989.
10. A. B. Krewinghaus, P. C. Richards, "Coal Flexibility of the Shell Coal Gasification Process," presented at the Sixth Annual Pittsburgh Coal Conference, September 25-29, 1989.

1A.A.1.2 Pressurized Fluidized Bed Combustion

Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology with combustion occurring in a pressure vessel at 10 to 15 atmospheres. The PFBC process shown on Figure 1A.A.1-2 involves burning crushed coal under high-pressure in a sorbent bed, usually of limestone or dolomite. A compressor provides high-pressure combustion air at the bottom of the combustor to maintain the coal and sorbent in a highly turbulent suspended state. The turbulence promotes good particle mixing, and the depth of bed allows long gas residence time, which leads to high combustion efficiency and sulfur dioxide absorption.¹

Two basic cycle configurations are being considered: a turbocharged cycle and a combined cycle. In the turbocharged cycle, heat is extracted from the

combustion gas into steam-cooled convective surfaces before entering the gas turbine, leaving sufficient energy to pressurize the system by driving a compressor, but not enough energy to generate electricity. Electric power is produced only in the steam cycle. In the combined cycle concept, the high temperature combustion gases are cleaned at the elevated temperature and then expanded to drive both the compressor and the turbine generator. The gas turbine exhaust gas is used to generate steam in a heat recovery steam generator (HRSG). PFBC combined cycle designs have more stringent gas cleanup and material requirements as a result of the elevated temperatures. The hot gas cleanup technology currently being used consists of cyclone separators; however, development of ceramic tubular and candle filters, hot electrostatic precipitators, and other forms of hot gas cleanup is progressing.

1A.A.1.2.1 Technological Maturity. The pressurized fluidized bed technology is entering the demonstration stage. Pilot facilities, which are presently not in operation, include the Grimethorpe facility in England and the 15 MWt ASEA Component Test Facility in Sweden. A 40 MWt turbocharged boiler was operated at the University of Aachen in West Germany. A 10 MWe facility is being operated by Ahlstrom (Pyropower) in Finland.

The American Electric Power Company recently completed a 70 MW PFBC combined cycle demonstration plant which repowers its Tidd Station in Ohio. That system began startup activity late in 1990. Additional PFBC systems similar in size to the Tidd facility have recently been constructed in Sweden and in Spain.² Additional systems to be built in the United States are in the planning stage.

A critical developmental issue for PFBC systems is the hot gas cleanup. The Tidd system will use cyclones, which are not adequate for small particle removal. Some gas turbine erosion is anticipated. Tidd will conduct a slip stream test of a ceramic filter. Various high temperature ceramic filters are under development in the United States and abroad.

It is projected that PFBC technology will be available commercially for repowering applications in the mid-to-late 1990s, and for larger-scale new construction applications in the late 1990s to early 2000s.

1A.A.1.2.2 Cost and Performance Characteristics. A cost estimate for a mature technology PFBC plant is about \$1,400/kW.⁷ An estimated heat rate is about 8,700 Btu/kWh. PFBC generating units are anticipated to be baseload units

because their high efficiency (low heat rate) will cause them to be committed and dispatched with a high priority.

1A.A.1.2.3 Required Resources. Principal resource requirements for PFBC facilities are coal, water, and limestone or dolomite. Principal waste products are ash and desulfurization products. Land requirements for PFBC units are less than for conventional pulverized coal plants because the pressurized conditions provide combustion air mass flow requirements in smaller bed areas and volumes. Construction time and costs may be reduced by the modular nature of PFBC systems.¹

1A.A.1.2.4 Environmental Impacts. SO₂ emissions are controlled in the pressurized fluidized bed in a manner similar to that for atmospheric fluidized bed technology. Particulate emission is controlled by using hot gas cleanup consisting of cyclones, ceramic filters, and conventional electrostatic precipitators.

1A.A.1.2.5 References.

1. J. D. McClung, ASEA Babcock PFBC, "Clean, Cost-Effective Kilowatts from Coal," presented to the 1988 Seminar on Fluidized Bed Combustion Technology for Utility Applications, Palo Alto, California, May 3-5, 1988.
2. "ASEA Babcock PFBC Update," A Quarterly Publication of ASEA Babcock, Vol. 1, No. 1, April 1988.
3. P. Almquist and B. Nordmark, "Update on Stockholm Energi's Vartan PFBC Combined Heat and Power Project," presented to the 1988 Seminar on Fluidized Bed Combustion Technology for Utility Applications, Palo Alto, California, May 3-5, 1988.
4. F. L. Kinsinger and D. K. McDonald of Babcock & Wilcox, "Combined Cycle using PFBC," presented to the American Power Conference, Chicago, Illinois, April 18-20, 1988.
5. D. K. McDonald and P. S. Weitzel of Babcock & Wilcox, "This PFBC Boiler for AEP's Tidd Plant Design for Performance and Operation," presented to the 1988 Seminar on Fluidized Bed Combustion Technology for Utility Applications, Palo Alto, California, May 3-5, 1988.
6. "ASEA Babcock PFBC Update," A Quarterly Publication of ASEA Babcock, Vol. 1, No. 2, Summer 1988.
7. TAG--Technical Assessment Guide, Volume 1: Electricity Supply-1986. EPRI, P-4463-SR, December 1986.

1A.A.1.3 Advanced Pulverized Coal

The advanced pulverized coal power plant concept makes use of recent advances in major power plant components, including the steam generator, turbine generator, flue gas desulfurization (FGD) system, and flue gas reheat system.^{1,2} EPRI is developing a State-of-the-Art Power Plant, (SOAPP) incorporating these advancements. SOAPP uses a spiral-wound supercritical steam generator which generates steam at 4,500 psig/1,100 F, with double reheat at 1,100 F. The steam turbine is a three-casing, tandem-compound unit which is designed for hybrid constant/sliding pressure operating with partial arc admission. There are two trains of 50 percent capacity feedwater heaters, with nine heaters in each train, including the deaerator. Turbine bypass facilitates unit startup. The FGD system design depends on the sulfur content of the design coal. The high-sulfur coal FGD system uses a single 100 percent flow FGD absorber module based on commercial advanced limestone-gypsum FGD technology. A fabric filter is used for particulate removal. The low-sulfur FGD system uses two 50 percent flow lime spray dryer modules and a fabric filter.

1A.A.1.3.1 Technological Maturity.

Advanced pulverized coal plants at SOAPP steam conditions are in the conceptual stage. EPRI has undertaken a three-year developmental program which will survey and characterize SOAPP component technologies (1991), develop a plant conceptual design (1992), and perform sensitivity evaluations (1993). Detailed design and construction of an SOAPP facility could follow this program. Commercialization is not anticipated before 1997.³

1A.A.1.3.2 Cost and Performance Characteristics. An estimated cost for a 300 MW SOAPP facility is \$1,370/kW.¹ O&M costs are estimated to be \$30/kW-year (fixed) and \$3.20/MWh (variable). The plant is estimated to have a full load net plant heat rate of 8,820 Btu/kWh.¹

1A.A.1.3.3 Required Resources. The primary resources required for an advanced pulverized coal plant are similar to those for a conventional pulverized coal plant, except that the lower heat rate associated with the advanced design somewhat reduces requirements.

1A.A.1.3.4 Environmental Impacts. It is anticipated that emissions and wastes from SOAPP facilities will be similar to new pulverized coal plants using state-of-the-art emission control and waste management equipment.

1A.A.1.3.5 References.

1. TAG Technical Assessment Guide, Volume 1: Electric Supply--1989 (Revision 6), EPRI P-6587-L, November 1989.
2. G. L. Touchton, J. E. Cichanowicz, A. F. Armor, I. M. Torrens, M. W. McElroy, "State of the Art Pulverized Coal-Fired Power Plant," presented at the EPRI 2nd International Conference on Improved Coal Fired Power Plants, Palo Alto, California, November 2-4, 1988.
3. Charles McGowan, EPRI, in personal communication to L. E. Stoddard, Black & Veatch, January 31, 1991.

1A.A.1.4 Gasification Fuel Cells

A gasification fuel cell plant combines the gasifier technologies discussed in Subsection 1A.A.1.1 with molten carbonate fuel cell technologies discussed in Subsection 1A.A.2.3.^{1,2} A clean medium Btu syngas fuel is supplied to a fuel cell by the gasifier and gas cleanup systems. The molten carbonate fuel cell generates electricity directly from the syngas (Subsection 1A.A.2.3). Heat recovered from the fuel cell is used to generate steam, which drives a steam turbine generator.

1A.A.1.4.1 Technological Maturity. The gasification fuel cell technology is in the concept stage, with several EPRI studies having been conducted to estimate plant costs and performance. Molten carbonate fuel cell development is in the bench-scale stage. Plans are underway for a 2 MW demonstration unit fired by natural gas. Gasification fuel cell systems are not likely to be commercially available until the late 1990s to early 2000s.

1A.A.1.4.2 Cost and Performance. A cost estimate for a mature technology gasification fuel cell plant is \$1,800/kW.¹ The estimated heat rate is 7,400 Btu/kWh.¹

1A.A.1.4.3 Required Resources. Resource requirements for a gasification fuel cell system are likely to be similar to those for a GCC system.

1A.A.1.4.4 Environmental Impacts. Emissions from a gasification fuel cell plant will be very low, similar to a GCC plant. NO_x emissions should be lower than for the GCC plant.

1A.A.1.4.5 References.

1. TAG: Technical Assessment Guide, Volume 1, Electricity Supply, EPRI P-6587-L, November 1989.

2. Steven Myers, "Advanced Molten Carbonate Fuel Cell Systems Using BGL Gasification," presented at the Ninth Annual EPRI Conference on Gasification Power Plants, Palo Alto, California, October 17-19, 1990.

1A.A.1.5 Integrated Gasification Humid Air Turbine Cycle

An integrated gasification humid air turbine (IGHAT) cycle gasifies coal, producing a fuel gas for a humid air turbine (HAT) cycle. The HAT cycle used is similar to the one described in Subsection 1A.A.2.2. HAT cycles are not commercially available.

The coal gasification plant used is similar to the ones used in IGCC plants described in Subsection 1A.A.1.1. However, in an IGHAT plant the syngas is water quenched after it leaves the gasifier, and the resulting low level heat is recovered and used in the HAT cycle. This eliminates the need for expensive syngas coolers.¹ Figure 1A.A.1-3 shows a simplified flow diagram of a HAT cycle used in an IGHAT plant.

1A.A.1.5.1 Technology Maturity. IGHAT systems are not commercially available. A commercial prototype combustion turbine designed for the HAT cycle has not yet been built.

1A.A.1.5.2 Cost and Performance Characteristics. Because the IGHAT system has no steam cycle and expensive syngas coolers, the capital cost of an IGHAT plant is projected to be significantly less than a comparable sized IGCC plant. A preliminary capital cost estimate for a 475 MW IGHAT facility is \$1,160/kW.² The projected heat rate for the IGHAT plant is 8,700 Btu/kW.² Because the HAT cycle is thermodynamically superior to a combined cycle, the heat rate of an IGHAT plant is lower than that of a comparable sized IGCC plant.¹

1A.A.1.5.3 Required Resources. Unit resource requirement for an IGHAT plant are similar to those for a similar sized IGCC plant. The major differences are that the land requirements are reduced because the bottoming steam cycle is eliminated. IGHAT consumes essentially the same amount of water as an IGCC plant.² However, larger water treatment facilities are required because the water vapor absorbed by the compressed air is discharged to the atmosphere and is not recycled.

1A.A.1.5.4 Environmental Impacts. Emission controls for sulfur removal described in Subsection 1A.A.1.1.4 of this appendix are applicable to IGHAT

cycles. The HAT turbine used in the IGHAT cycle is expected to have NO_x emissions as low as 7 ppmvd (15 percent oxygen) or less without the use of SCR.¹

1A.A.1.5.5 References.

1. "AFPS Developments," EPRI, Spring 1990, Issue 4.
2. A. D. Rao and J. R. Joiner, "A Technical and Economic Evaluation of the Humid Turbine Cycle," presented at the Ninth Annual EPRI Conference on Gasification Power Plants, Palo Alto, California, October 17-19, 1990.

1A.A.1.6 Coal Liquefaction

Shortages of oil in the 1970s and the prospect of future oil shortages has resulted in renewed efforts to synthesize liquid fuels from coal. Early liquefaction processes were developed and utilized in Germany during World War II when petroleum supply lines were severed. The technology for the principal process (Bergius) used in Germany has been lost; however, it is known that the thermal efficiency was quite low for that process. A second process developed during that time, the Fischer-Tropsch process, is currently being used in South Africa in the SASOL plants. The Fischer-Tropsch process is one of several indirect processes in which coal is first broken down into a synthesis gas, which is subsequently converted to liquid fuel or other chemicals. Indirect processes have an advantage of an extremely clean liquid product, but possess relatively low (45 to 60 percent) theoretical and demonstrated thermal efficiencies.

The relative low thermal efficiency of the indirect processes has caused the United States Department of Energy (DOE), along with private businesses, to focus attention on direct coal liquefaction processes. In direct processes, a coal slurry is heated under high pressure, and reacts with hydrogen (hydrogenated) to yield liquid hydrocarbons. Several types of direct processes are under development in the United States.

A third generic type of coal liquefaction process is pyrolysis. In this process, coal is heated to a very high temperature, which drives off the volatile matter and results in gaseous, liquid, and solid (char) products. A commercially available method for producing liquids by pyrolysis is the coke oven. A major disadvantage of this method is that it yields low liquid/high coke product ratio.

1A.A.1.6.1 Technology Maturity. Of the three generic methods for liquifying coal, only the indirect approach is currently used on a commercial scale. The SASOL I project near Sasolburg, South Africa, has been operational since 1955.

This state-owned plant, which uses the Fischer-Tropsch process (indirect), produces several thousand barrels of oil and petrochemical products per day. The indirect process used, however, results in a low thermal efficiency of 40 to 45 percent. The SASOL II and III projects are similar in concept to SASOL I. SASOL II and III primarily process coal into motor fuels, with each ton of coal yielding about 49 gallons of gasoline. Additional products include diesel fuel, ethylene, sulfur, coal tar derivatives, and ammonia. The three SASOL plants provide a significant portion of South Africa's liquid fuel requirements.

Because of the low thermal efficiency of the indirect method, and because of low liquid/high char yields of the pyrolysis method, significant development effort in the United States is being focussed on direct liquefaction technologies.

A primary emphasis within the United States using the indirect method has been methanol production. Methanol is generally produced from natural gas using commercially available processes; these processes can be used with the synthesis gas feedstock from a coal gasification process. However, developmental efforts are underway to produce methanol through processes which could be more cost-effective as coproduction applications. Development of these processes is still at the bench scale.

The largest full-time direct liquefaction research project in the United States is the Wilsonville Advanced Coal Liquefaction Research and Development Facility.^{1,2} This facility, which is cosponsored by EPRI and DOE and managed by Southern Company Services, Incorporated, can process up to 6 tons of coal per day.

A 2.5 ton per day direct liquefaction facility is operated by British Coal Corporation at Point of Ayr in Great Britain.³

1A.A.1.6.2 Cost and Performance Characteristics. Costs of coal-derived liquids from existing commercial facilities (SASOL) are significantly higher than current costs of oil, although exact numbers are not available. Fuel costs based on a commercial-scale plant using the Wilsonville technology have been developed from a conceptual design. These fuels appear to be competitive with fuel costs when the price of crude oil is \$35 to \$40 per barrel.¹ The investment cost for the commercial-scale facility is about \$33,000 per barrel per day of capacity.¹

Thermal efficiencies for the SASOL plants are low (45 to 60 percent). Thermal efficiencies for the Wilsonville technology on a commercial scale are estimated to be about 70 percent.¹

1A.A.1.6.3 Required Resources. Coal liquefaction processes can use a variety of coals. The high reactivity and low cost of subbituminous coals make them attractive for the process, although problems have occurred with fouling using low rank coals in the Wilsonville facility.

1A.A.1.6.4 Environmental Impacts. Environmental impacts for coal-derived liquid fuels include the impacts of the facility producing the fuels as well as the combustion of the fuels at the power generation site. Emissions at the plants producing coal-derived liquid fuels are projected to be very low. Combustion tests of coal-derived liquid fuels show that emissions are similar to their petroleum-derived counterparts.

1A.A.1.6.5 References.

1. A. Basu, J. G. Masin, and N. G. Stewart, "Improvements in the Cost of Liquid Fuels from Direct Liquefaction," Proceedings of the Seventh Annual Pittsburgh Coal Conference, September 10-14, 1990.
2. Orlando Utilities Commission Long-Range Power Supply and Demand-Side Planning Study; Appendix B, Supply-Side Technologies, prepared by Southern Company Services, Inc., September 1988.
3. N. Robinson, S. A. Moore, G. M. Kimber, and M. D. Gray, "Transport Fuels from Coal: Modeling British Coal's Liquefaction Process," Proceedings of the Seventh Annual Pittsburgh Coal Conference, September 10-14, 1990.

1A.A.1.7 Magnetohydrodynamics

Magnetohydrodynamics (MHD) is a fossil fuel fired technology in which the electrical generator is static (nonrotating) equipment. Coal or another fossil fuel is burned to produce hot gases at temperatures exceeding 4,500 F.¹ Potassium carbonate is injected during the combustion process to increase the electrical conductivity of the combustion products.² These hot gases are accelerated in a nozzle and pass through a rectangular channel, which is surrounded by a superconducting magnet. The electrically conductive gases moving in the magnetic field produce a direct current in the channel's electrodes. This direct current is subsequently converted to alternating current with a solid-state inverter.¹ A general schematic of the MHD process is shown on Figure 1A.A.1-4.³

One of the more likely configurations for an MHD plant is to use the MHD generator as a topping cycle and a conventional steam power plant as the bottoming cycle. This configuration is attractive since the hot gases leave the MHD channel at a temperature of about 3,000 F. It is expected that an MHD steam, combined cycle plant will produce low emissions and have a thermal efficiency approaching 50 percent.²

The potassium present in the combustion products combines with the sulfur from the coal to form potassium sulfate. The potassium sulfate is precipitated and collected with ash in the steam generator and the electrostatic precipitator. It is then processed to regenerate the potassium carbonate seed.³

1A.A.1.7.1 Technological Maturity. The MHD technology as a whole is in the development stage. Power from an MHD test plant was first produced in 1959 with a 10-second long, 10 kW run. Numerous tests of MHD plants and components have been performed since then. The US Department of Energy currently operates two MHD test facilities: the Component Development and Integration Facility (CDIF) at Butte, Montana, and the Coal Fired Flow Facility (CFFF) at the University of Tennessee Space Institute in Tullahoma, Tennessee. Various private firms, including TRW and Westinghouse, are participating in MHD research, testing, and development.³

1A.A.1.7.2 Cost and Performance Characteristics. Capital and O&M costs for MHD systems are highly speculative because of the relatively early stage of development of the technology. The estimated capital cost for the direct fired MHD concept studied by Westinghouse Advanced Power Train is about \$2,000/kW.³ O&M costs for that plant are estimated to be about \$9/MWh. The clean coal gas fired Westinghouse concept has an estimated capital cost of \$2,900/kW. The O&M cost for that plant is about \$12/MWh.

The unit performance of two commercial-scale MHD configurations has been addressed as part of the Westinghouse Advanced Power Train studies. The first configuration would burn coal directly and would include a 2,400 psig/1,000 F/997 F reheat steam bottoming cycle. Table 1A.A.1-1 presents data illustrating some of the major design performance parameters.³

The second configuration studied by Westinghouse would burn clean coal gas produced from a Texaco gasifier and would have a 1,450 psig/1,000 F/1,000 F reheat steam bottoming cycle. This concept results in a high percentage sulfur removal, but has relatively poor performance and high cost as currently

configured. Some of the major design performance parameters are listed in the Table 1A.A.1-1.³

1A.A.1.7.3 Required Resources. The key resource for MHD is the fossil fuel, in this case coal. The direct burn concept discussed above has a coal feed rate of 4,600 tons/day (as received). The gasified coal concept has a coal feed of 5,700 tons/day of coal (as received) to produce 760,000 lb/h of clean coal gas at 525 psig and 570 F.³

Another resource is either potassium carbonate or potassium sulfate to serve as a seed to increase the electrical conductivity of the combustion products. The direct coal fired design uses 60,000 lb/h of potassium carbonate as the primary seed and 3,000 lb/h of potassium sulfate as makeup seed. In this design, potassium carbonate is regenerated from the potassium sulfate present in the ash that is produced during combustion of the coal. The clean (gasified) coal gas design uses a total of 34,600 lb/h of potassium sulfate, of which 33,000 lb/h is recovered from the ash and 1,700 lb/h is makeup seed.³

1A.A.1.7.4 Environmental Impacts. The MHD technology appears to be capable of adequately controlling NO_x and SO₂ emissions. NO_x is controlled by burning coal (or clean coal gas) in two stages. The first stage of combustion takes place in the primary combustor (before the MHD channel) where the coal is burned with approximately 85 to 90 percent of theoretical air. Although large amounts of NO_x are produced, the reducing conditions in the primary combustor cause the nitrogen oxides to decompose rapidly. The second stage of combustion occurs in the heat recovery steam generator (after the MHD channel) where the combustion products are further burned with approximately 105 percent of theoretical air. Because combustion takes place at lower temperatures with the cooler secondary air, less NO_x is produced.⁴

Sulfur dioxide removal is accomplished through the use of the potassium carbonate seed. The potassium combines with the sulfur in the combustion products, forming potassium sulfate. The sulfur is then removed from this compound during regeneration of the seed. In the direct coal fired design, 95 percent of the sulfur is removed from the combustion products and sulfur emissions are limited to 0.4 lb/MBtu.³

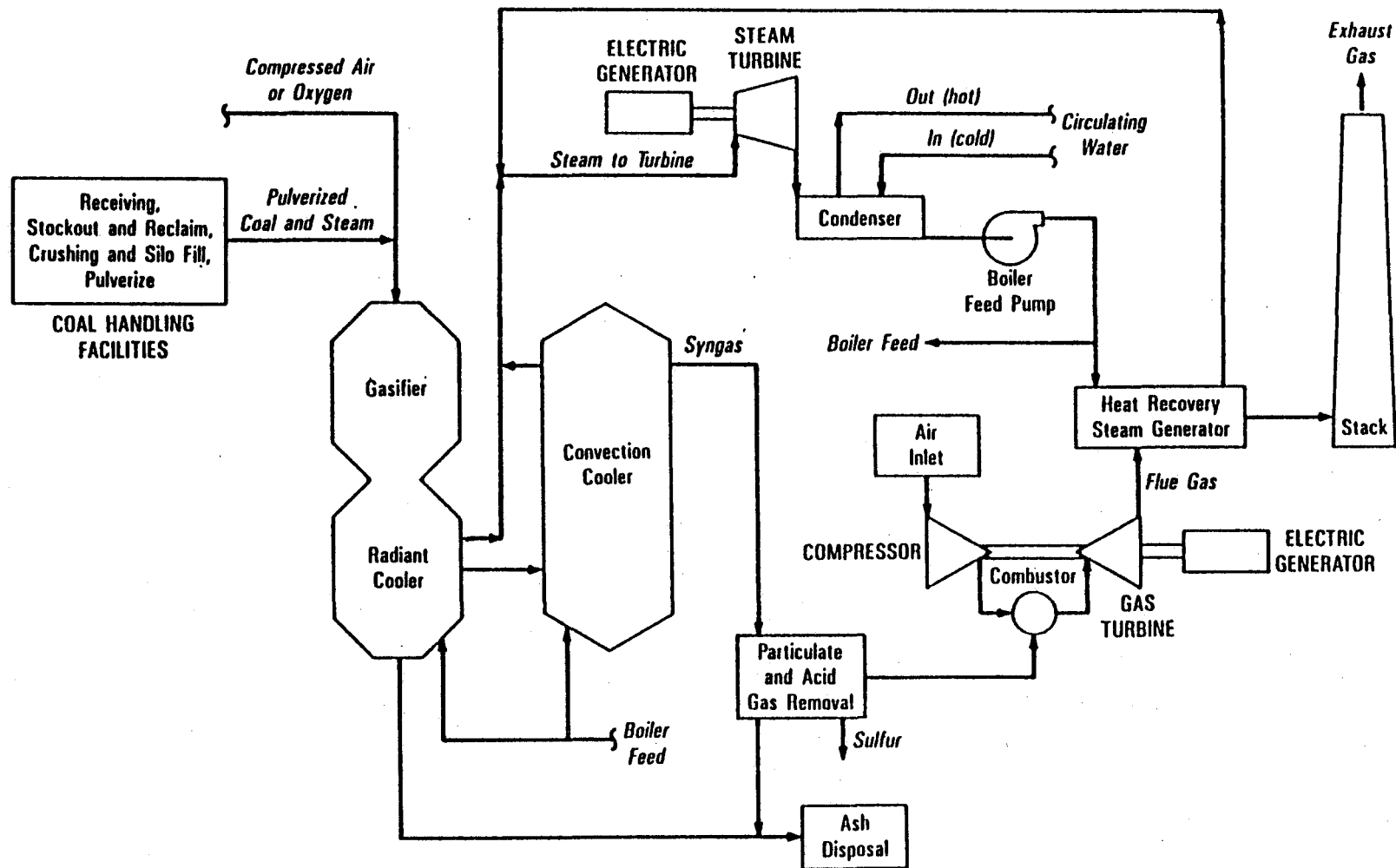
Solid waste disposal includes potassium sulfate, not a conventional waste for coal fueled stations. Specific disposal requirements are unknown at this time.

1A.A.1.7.5 References.

1. Combustion Fossil Power Systems, Combustion Engineering, 1981, pp. 24-34.
2. Energy Technology Status Report, California Energy Commission, October 1988, pp. 4-115 and 4-116.
3. Screening Evaluation of Advanced Power Cycles, EPRI AP-4826 Final Report, RP2477-1, November 1986, pp. 7-1 to 7-52.
4. J. N. Chapman, S. S. Strom, and Y. C. L. Wu, "MHD Steam Power-- Promise, Progress, and Problems," Mechanical Engineering, September 1981, pp. 30-37.

Table 1A.A.1-1
Predicted Design Parameters for MHD Facilities

<u>Parameter</u>	<u>Direct Burn MHD</u>	<u>Coal Gasification MHD</u>
Net Plant Output, MW	500	470
MHD Power Output, MW	191	136
Steam Turbine Power Output, MW	401	465
Coal Gas Expander Output, MW	--	30
Internal Power Consumption, MW	92	161
Net Heat Rate, Btu/kWh	8,616	11,289
Overall System Efficiency, percent	39.6	30.2
Sulfur Removal, percent	95	99.3

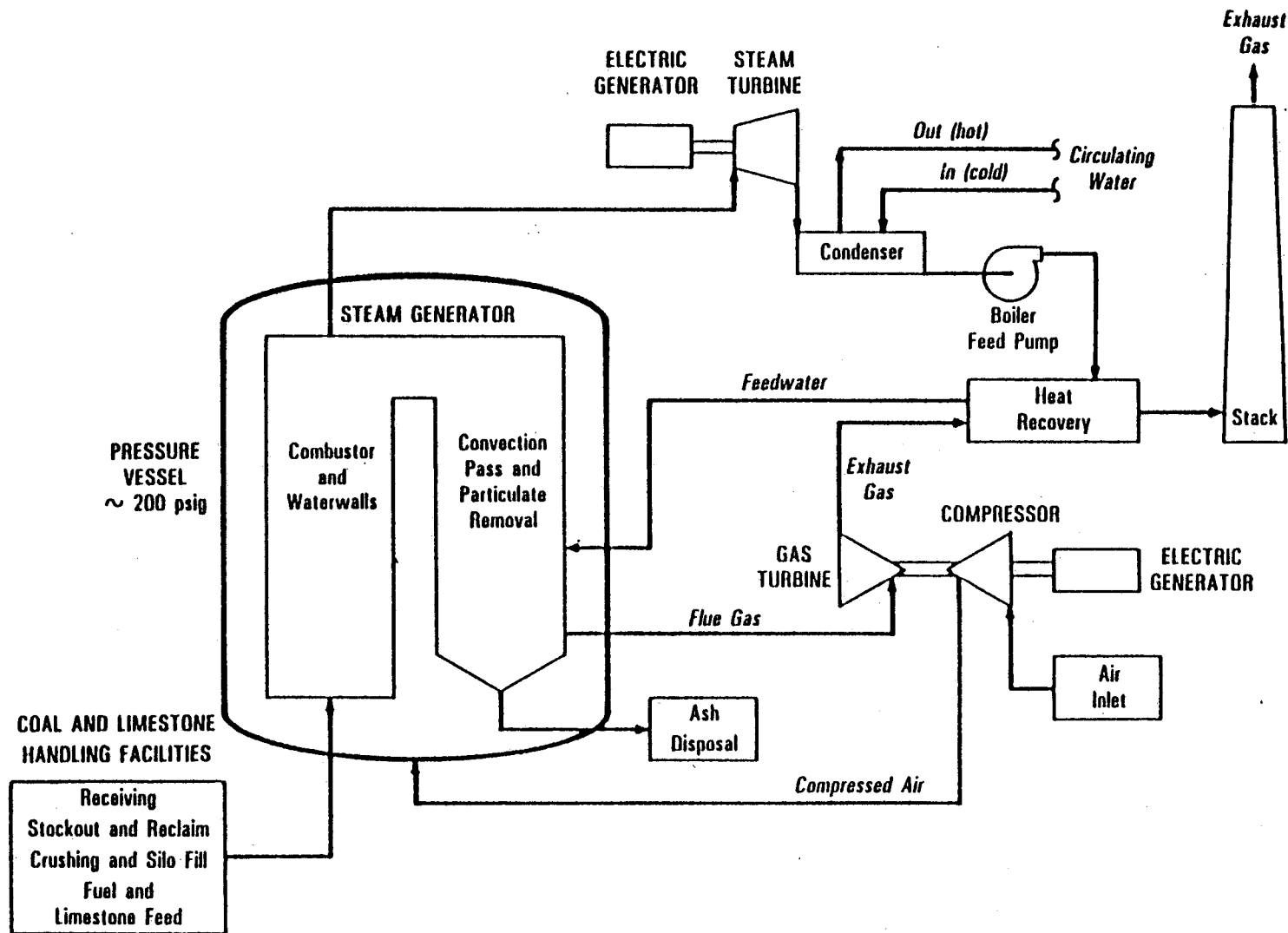


GASIFICATION COMBINED CYCLE PLANT
FLOW DIAGRAM

Figure 1A.A.11

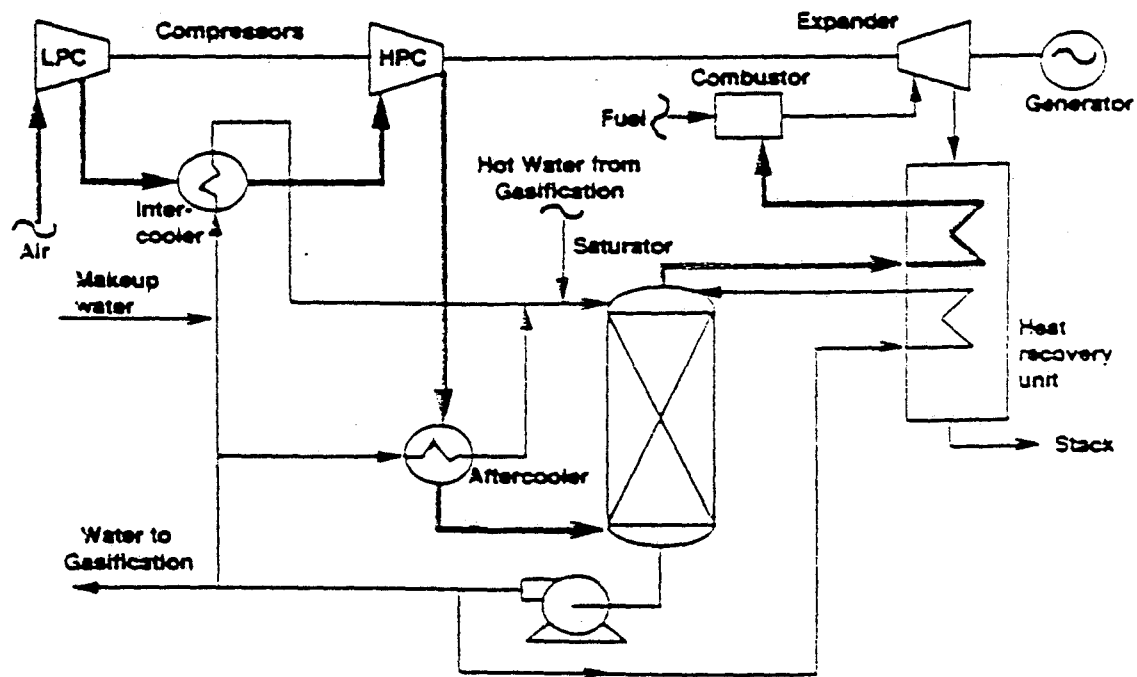
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1A.A.1-18



PRESSURIZED FLUIDIZED BED PLANT
COMBUSTION SYSTEM PLANT FLOW DIAGRAM

Figure 1A.A.1-2

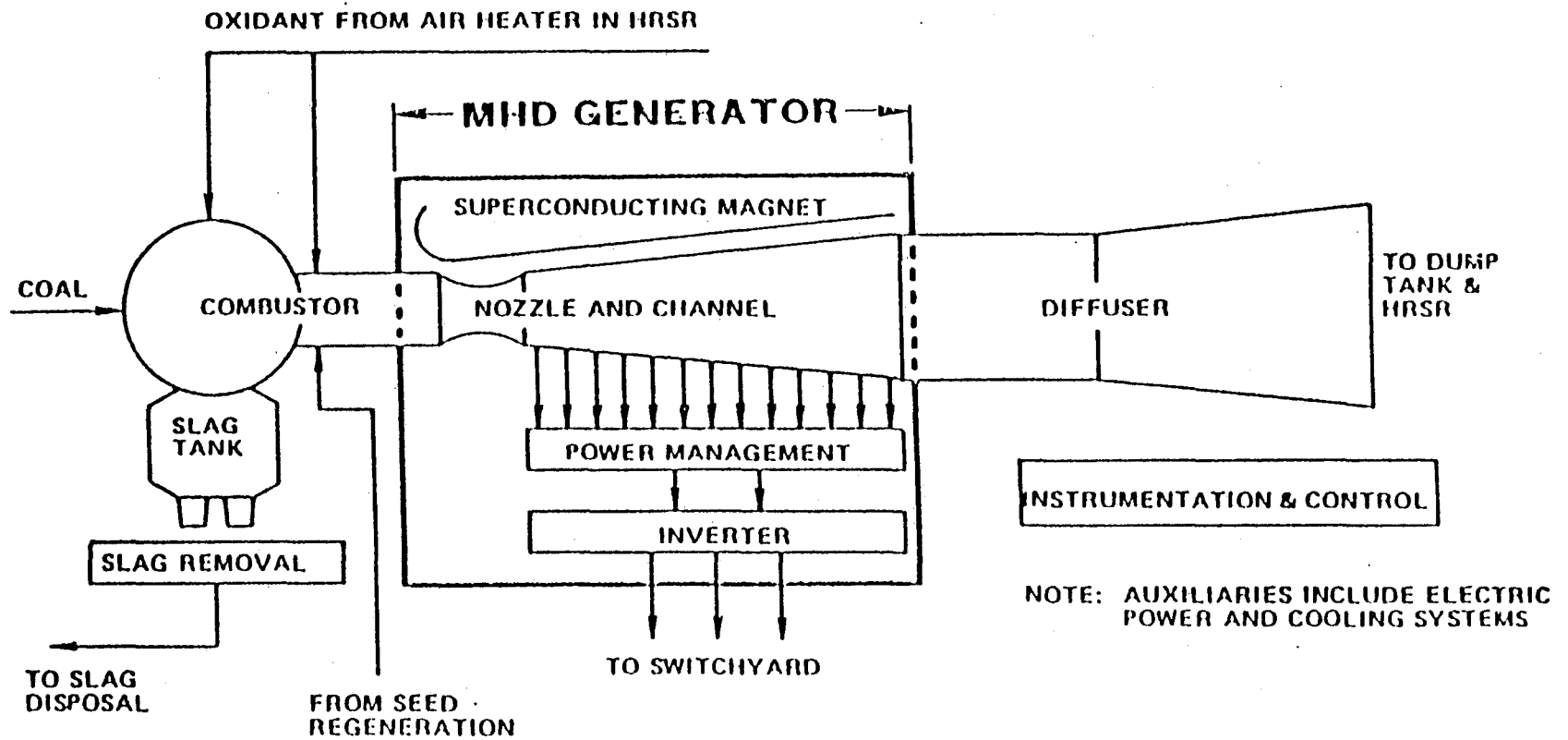


INTEGRATED COAL GASIFICATION
HUMID AIR TURBINE CYCLE FLOW DIAGRAM

Figure 1A.A.1-3

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1A.A.1-20



POWER TRAIN SCHEMATIC SHOWING MHD GENERATOR

Figure 1A.A.14

Source: Reference 3

1A.A.2 Oil or Gas Fired Alternatives

Oil or gas fired alternatives considered in this section include the steam injected combustion turbine, humid air turbine (HAT) cycle, and fuel cells.

1A.A.2.1 Steam Injected Combustion Turbine (Power Augmentation)

The steam injection combustion turbine uses steam injected into the combustor and turbine sections of a conventional combustion turbine to increase power output. This is called power augmentation and is also known as the Cheng cycle.

The injection steam has a cooling effect on the combustion turbine internals, allowing greater fuel burn rates. There is no steam turbine or associated equipment as in the combined cycle arrangement. The basic components for this cycle, shown on Figure 1A.A.2-1, are the combustion turbine and the heat recovery steam generator (HRSG).

Aero-derivative combustion turbines are typically used in power augmentation applications because of the higher compression ratio associated with the aero-derivative. The aero-derivative also has the ability to pass greater flows.

The HRSG is required to produce steam for injection into the combustion turbine and for process use. The typical application of the power augmentation cycle is a cogeneration unit where excess power can be produced during low cogeneration demand and/or peak electrical demand periods.

1A.A.2.1.1 Technological Maturity. Several power augmentation units began operation in the early to mid-1980s. The cycle is considered a mature technology. However, the long-term impact of massive steam injection on combustion service life is still being evaluated. Furthermore, combustion turbines designed specifically for steam injection are not commercially available today.

1A.A.2.1.2 Cost and Performance Characteristics. Capital costs for the power augmentation cycle vary with unit size, amount of steam injected, and amount of steam to be produced for cogeneration. Preliminary capital cost estimates range from \$800/kW for a 150 MW unit to \$1,050/kW for a nominal 50 MW installation.

Based on manufacturers' estimates, the steam injected combustion turbine maintenance costs would increase about 15 to 20 percent over simple cycle combustion turbine maintenance costs because the greater mass flow through the turbine results in increased frequency of maintenance.

The construction schedule for this cycle would be similar to that of the combined cycle unit.

The power augmentation cycle is very flexible with respect to the amount of steam injected relative to output desired. Steam injection can increase combustion turbine power output over 50 percent and decrease heat rate up to 20 percent, depending on the size and design of the unit and amount of steam injection. A General Electric LM5000 system with 133,000 pounds per hour of steam injection is shown in Table 1A.A.2-1 as an example of power augmentation performance.¹ This includes both high- and low-pressure steam injection based on typical unfired HRSG performance.²

1A.A.2.1.3 Required Resources. Unit resource requirements for a steam injected combustion turbine are very similar to those for a combined cycle unit. The major differences are that a significant continuous water source and a larger water treatment facility are required because the steam injected into the combustion turbine is discharged to the atmosphere and is not recycled. Land requirements are reduced because the steam turbine and cooling tower are not required.

1A.A.2.1.4 Environmental Impacts. Emissions control described in the simple cycle and combined cycle sections of this report are directly applicable to combustion turbines using steam injection for power augmentation.

1A.A.2.1.5 References.

1. "Aero-derivative Gas Turbine Performance, Emissions, and STIG," GE Gas Turbine Reference Library, GER-3572, 1988.
2. General Electric Model PG7111(EA) Gas Turbine Estimated Performance, 499HA733, July 8, 1988.

1A.A.2.2 Natural Gas Fired Humid Air Turbine Cycle

The humid air turbine (HAT) cycle uses a combustion turbine that employs air intercooling and the substitution of water vapor for a portion of the excess air to the combustor to reduce the power requirement by the compressor. This reduction in air compression load significantly increases the net power output by the turbine.¹

Figure 1A.A.2-2 shows the basic HAT cycle. Intercooling and aftercooling provides some of the heat required for generating water vapor. Additional low temperature heat required for generating water vapor is also obtained from the

turbine exhaust. A saturator generates water vapor in a multi-stage counter-current operation by directly contacting cooled compressed air with hot water.¹ The humidified air is then further heated by the turbine exhaust prior to entering the combustor.

1A.A.2.2.1 Technological Maturity. Natural gas fired HAT cycles are not commercially available. The HAT cycle is still in the early developmental stages and a commercial prototype combustion turbine designed for the HAT cycle has not yet been built.

1A.A.2.2.2 Cost and Performance Characteristics. A preliminary capital cost estimate for a nominal 200 MW plant size is \$630/kW.¹ Table 1A.A.2-2 shows the expected performance of a natural gas fired HAT cycle.¹ The performance of a combined cycle using a GE 7F combustion turbine is also shown for comparison. The HAT cycle heat rate is lower than that of a combined cycle.

1A.A.2.2.3 Required Resources. Unit resource requirements for a HAT cycle are comparable to those of a similar capacity combined cycle. Land requirements are reduced because the steam turbine and cooling tower are not required. The water requirements are comparable to that of a combined cycle plant with cooling towers.³ Larger water treatment facilities are required by the HAT cycle because the water vapor absorbed by the compressed air is discharged to the atmosphere and is not recycled.

1A.A.2.2.4 Environmental Impacts. NO_x emissions are expected to be very low over the full range of capacity due to the high moisture levels in the air going to the combustor.

1A.A.2.2.5 References.

1. A. D. Rao and J. R. Joiner, "A Technical and Economic Evaluation of Turbine Cycle," presented at the Ninth Annual EPRI Conference on Gasification Power Plants, Palo Alto, CA, October 17-19, 1990.
2. "AFPS Developments," Electric Power Research Institute, Spring 1990, Issue 4.
3. Ashok D. Rao and Thomas R. Morton, "Perspective for Advance High Efficiency Cycles using Gas Turbines," 1989 EPRI Conference on Technologies for Producing Electricity in the 21st Century, San Francisco, CA, October 30-November 2, 1989.

1A.A.2.3 Fuel Cells

Fuel cells convert hydrogen rich fuels directly to electricity through electrochemical reactions. A conceptual design of a fuel cell system is shown on Figure 1A.A.2-3.¹ The reactants, fuel and oxidant (air or oxygen), are fed to separate anode and cathode electrodes. The electrodes are separated by an electrolyte that transports the ions generated by the anode reaction. This transport of ions creates an electric potential difference that promotes electron flow through an electric load. An inverter converts the direct current into alternating current.

The most common fuel cell concepts for power generation are the phosphoric acid fuel cell and the molten carbonate fuel cell. The solid oxide fuel cell is another advanced option, but it is not as well developed as phosphoric acid and molten carbonate fuel cells. Phosphoric acid fuel cells use liquid phosphoric acid as the electrolyte and have operating temperatures of about 400 F. Molten carbonate fuel cells operate at temperatures near 1,000 F. Phosphoric acid and molten carbonate fuel cells operate with hydrogen, requiring a reforming step for the use of natural gas or methanol as the fuel. Some molten carbonate fuel cells have internal reforming capability, allowing the direct use of natural gas. Molten carbonate fuel cells are also able to operate with syngas from a coal gasification unit, allowing coal to be used as the fuel.

Fuel cell power plants are highly modular and can be combined to give almost any power rating desired.

1A.A.2.3.1 Technological Maturity. Phosphoric acid fuel cell technology is the most mature of the fuel cell technologies for power plant applications. Multimegawatt pilot plant tests have been conducted using phosphoric acid fuel cells, and these plants are on the threshold of commercialization. However, operational problems such as long-term reliability remain to be solved.² Phosphoric acid fuel cell power plants are expected to be commercially available and reliable in the 2000 to 2010 time period.

Molten carbonate systems offer higher efficiencies than can be achieved with phosphoric acid systems, although the commercial development of these systems lags perhaps 5 to 10 years behind that of phosphoric acid systems. Small area molten carbonate cell stacks have been successfully tested, and scaleup to full area stacks is underway.

1A.A.2.3.2 Cost and Performance Characteristics. Cost and performance information and resource requirements for phosphoric acid and molten carbonate fuel cells are shown in Table 1A.A.2-3.

1A.A.2.3.3 Required Resources. Fuel cells require clean fuel gas (H_2) that is free of contaminants. Land and water requirements for fuel cells are relatively small compared with those for other power generation technologies. However, the addition of bottoming cycles to improve efficiency will increase land and raw water requirements.

1A.A.2.3.4 Environmental Impacts. A fuel cell requires a very clean fuel to avoid contamination and degradation of performance. Fuel cell tolerance to sulfur, particulate matter, and other contaminants is very low. Since the raw fuel gas is necessarily very clean and combustion does not occur in a fuel cell, emissions of air pollutants, solid wastes, and contaminated wastewater are insignificant during operation.⁶ For a phosphoric acid fuel cell, NO_x emissions are estimated to be 0.1 ppm compared with 10 to 120 ppm from a combustion turbine.⁷ Because a molten carbonate fuel cell operates at higher temperatures than a phosphoric acid fuel cell, NO_x emissions are expected to be greater. Operation of a fuel cell at a given site may shift the source of emissions to the site of the fuel gas preparation facilities.⁸

Because fuel cells are relatively quiet and pollution free, they have excellent potential for application in urban locations where conventional power generation would be difficult or impossible to license.

1A.A.2.3.5 References.

1. V. Minkov, M. Krumpelt, E. Daniels, and J. G. Asbury, "Topping Cycle Fuel Cells Effective Combined with Turbines," Power Engineering, July 1988.
2. "Update on Fuel Cell Demonstration Projects," Technical Brief, RP3061-1, Generation and Storage Division, EPRI, 1989.
3. Fuel Cell Program and Abstracts, 1988 Fuel Cell Seminar, National Fuel Cell Coordinating Group, Long Beach, California, October 23-26, 1988.
4. "Fuel Cells for Electric Utility Applications," Technical Brief, RP1777-1, Advanced Power Systems Division, EPRI, March 1987.
5. "Fuel Cells for the '90s," EPRI Journal, September 1984.

6. "Fuel Cells," Fossil Energy Facts, Office of Fossil Energy, US Department of Energy, April 1987.
7. "Energy for Tomorrow," World Energy Conference, 14th Congress, Montreal, 1989.
8. Energy Technology Status Report, Staff Report, California Energy Commission, October 1988.

Table 1A.A.2-1
Steam Injection Performance Comparison: LM5000

	<u>Without Steam Injection</u>	<u>With Steam Injection</u>	<u>Percent Change</u>
Output, kW	33,060	51,370	+55.4
Gross Heat Rate (HHV), Btu/kWh	10,800	8,969	-17.0

Table 1A.A.2-2
HAT Cycle Performance*

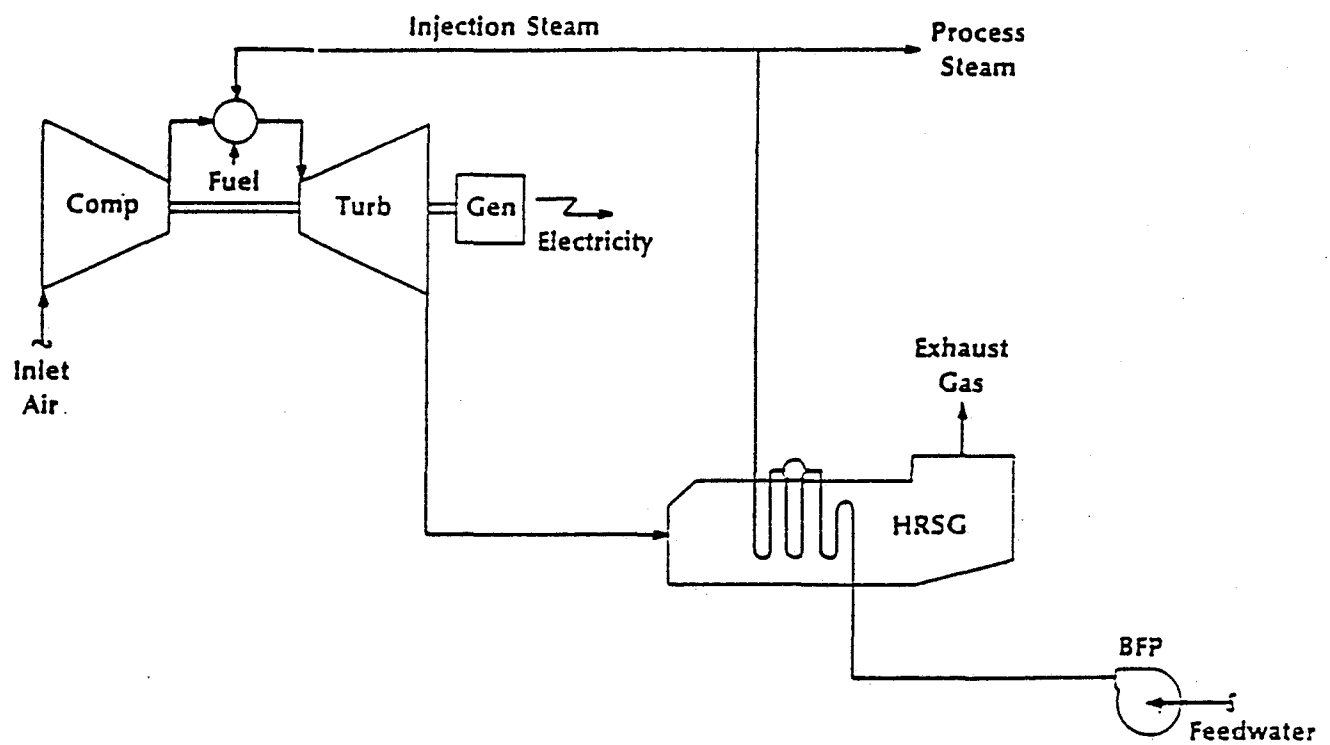
<u>Parameter</u>	<u>HAT</u>	<u>Combined Cycle</u>
Combustion Turbine Output, MW	203	138
Net Plant Output, MW	202	206
Net Plant Heat Rate, Btu/kWh	7,080	7,650

*Based on: 90 F ambient temperature.

Table 1A.A.2-3
Fuel Cell Cost and Performance Characteristics and
Resource Requirements^{3, 4, 5}

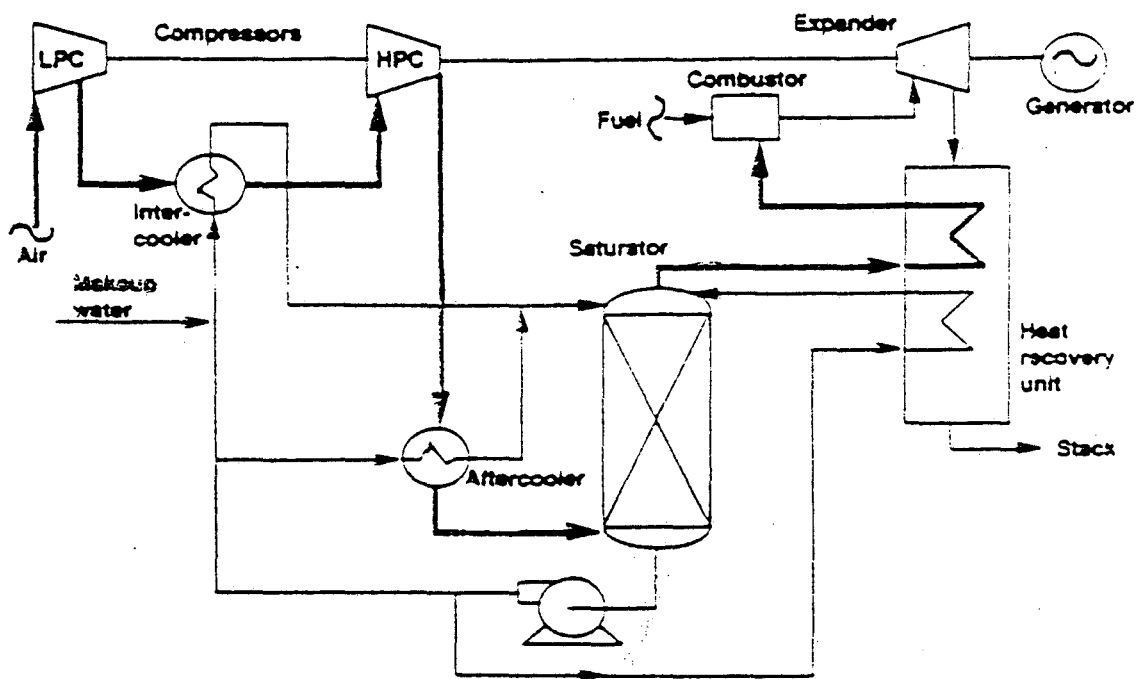
	<u>Phosphoric Acid Fuel Cell</u>	<u>Molten Carbonate Fuel Cell</u>
Module Size, MW	11 +	In Development
Capital Cost, \$/kW (1990\$)	2,500-3,000	Not Available
Nonfuel O&M Cost, mills/kWh (1990\$)	12-19	Not Available
Full Load Net Plant Heat Rate, Btu/kWh (HHV)	8,000-9,600	5,600 [*] -7,500
H ₂ Fuel Consumption, lb/MWh	130-160	90-120
Appropriate Capacity Factor, percent	30-75	75
Land Requirement, acres	0.75-1.0	Expected to be similar to phosphoric acid
Fresh Water Requirement, gpm	Negligible	Negligible
Licensing, Design, and Construction, months	12	--

^{*} Includes a bottoming steam turbine cycle.



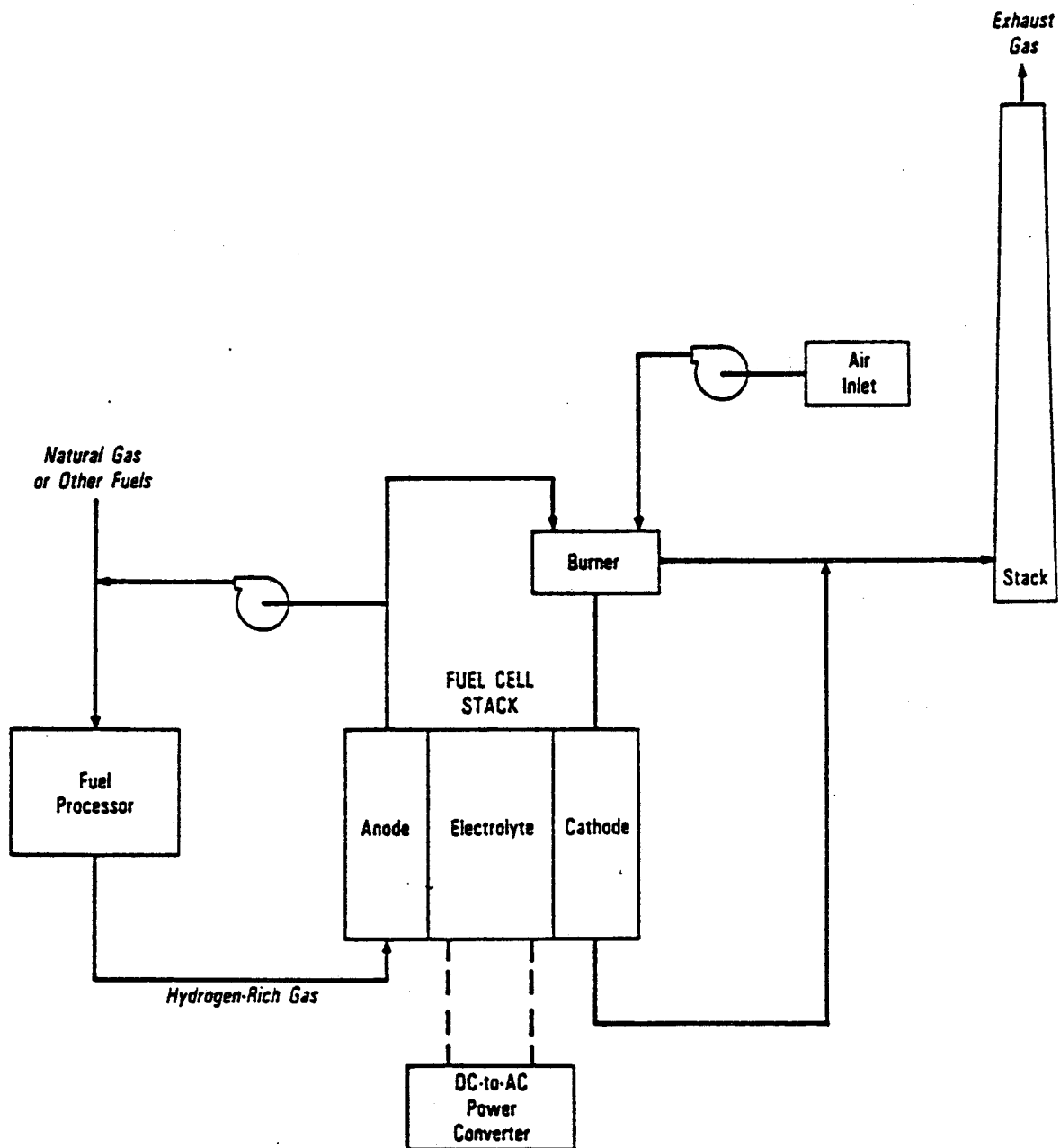
STEAM INJECTED COMBUSTION TURBINE SIMPLIFIED
FLOW DIAGRAM

Figure 1A.A.2-1



HUMID AIR TURBINE CYCLE FLOW DIAGRAM

Figure 1A.A.2-2



FUEL CELL SYSTEM FLOW DIAGRAM

Figure 1A.A.2-3

1A.A.3 Nuclear Alternatives

This assessment consists of five advanced technologies that offer design modularity, reduced construction schedules, and potentially increased safety. The advanced technologies include the advanced passive light water reactor, modular pressurized heavy water reactor, the modular high-temperature gas-cooled reactor, the liquid metal reactor, and fusion.

Licensing procedures for new conventional and advanced generating plants are being revised. The Nuclear Regulatory Commission (NRC) is proposing a one-step licensing process for new nuclear power generation. With the one-step process, electric utilities would obtain a single permit approval for the nuclear power plant from the NRC before construction of the project. The approval would also include a license to operate, assuming the plant is built in accordance with the previously approved construction plans; however, this approval has been overturned in court and is subject to ongoing appeals. Some electric utilities would prefer that a law be passed through Congress with similar one-step licensing provisions. The law would minimize potential challenges to the NRC's one-step procedure.

1A.A.3.1 Advanced Passive Light Water Reactor

The advanced passive light water reactor (APLWR) has passive emergency core cooling, decay heat removal, and containment cooling systems. In the pressurized water reactor (PWR) version, the core is cooled in an emergency by massive water storage tanks located above the core; water flowing from these tanks by the force of gravity or compressed nitrogen has the capability to cool the core for at least three days after a loss of coolant accident. Excess heat is removed by natural circulation of this water, so electrically driven pumps and other active systems are not needed. The containment is cooled by natural circulation of air and evaporation of water around the steel containment structure. Like all modern US designs, the APLWR's core reactivity naturally decreases as its temperature increases.¹

The PWR version is being developed by Westinghouse Electric, Avondale Shipyards, Bechtel, and Burns and Roe. This 600 MWe reactor, called the AP600, features a passive emergency core cooling system in which water is stored in large tanks above the core.

The boiling water reactor (BWR) version of the APLWR, also sized at 600 MW, is being designed by General Electric, Bechtel, and the Massachusetts Institute of Technology. Called the SBWR, this reactor operates at full power with natural circulation of cooling water, which is driven by thermal gradients rather than pumps, valves, and associated controls.

Combustion Engineering, the UK Atomic Energy Agency, and Rolls Royce are sponsoring a 140 MW advanced passive light water reactor called SIR (for safe integral reactor). SIR has a unique design that incorporates both the steam generators and the pressurizer inside the reactor pressure vessel.

1A.A.3.1.1 Technological Maturity. The APLWR technology is a slight scale-down of existing LWR technologies that are commercially available.¹ However, the APLWR designs are still being developed and are not likely to achieve commercial availability until after the year 2000.

1A.A.3.1.2 Cost and Performance Characteristics. Net plant heat rates are similar to those for the conventional LWR power plant in the 10,000 to 11,000 Btu/kWh range. Fuel usage and load following characteristics are the same as for the conventional LWR power plant. The APLWR plants are best suited for baseload operation. The estimated total capital requirement is probably similar to that of full scale LWRs at \$3,000/kW.¹

1A.A.3.1.3 Required Resources. Resource requirements are similar to those for conventional nuclear LWR power plants of the same size. Licensing, engineering, and construction cycle information are not available. Other resource constraints are similar to those for the conventional LWR.

1A.A.3.1.4 Environmental Impacts. Environmental emissions and discharges are similar to those for a conventional nuclear LWR power plant.

1A.A.3.1.5 References.

1. J. Catron, "New Interest in Passive Reactor Designs," EPRI Journal, April/May 1989.

1A.A.3.2 Modular Pressurized Heavy Water Reactor

The CANDU 3 is a pressurized heavy water reactor under design and development by Atomic Energy of Canada Limited (AECL). Heavy water (deuterium oxide) is used for neutron energy moderation and fission heat removal. Because heavy water absorbs practically no neutrons, it can be used as a coolant-moderator with natural uranium fuels.¹ The use of natural uranium

fuels is a cost advantage over LWRs, which use more costly enriched uranium fuel. However, the production of heavy water is a costly process.¹

The CANDU 3 design is based on earlier successful CANDU reactor designs (e.g., CANDU 6) which are commercially available. The CANDU 3 is a smaller version of the previous CANDU designs, with an electrical rating of 450 MW.²

Figure 1A.A.3-1 shows a simplified schematic of the CANDU steam supply system. The CANDU design consists of a calandria reactor vessel, which contains a large number of horizontal pressure tubes (CANDU 3 has 232). Each pressure tube contains fuel element bundles of natural uranium dioxide fuel. Heavy water is pumped through the fuel bundles in the pressure tubes where the fission heat is removed and then sent to two or more steam generators. The steam generators produce steam on the secondary side, using ordinary water at saturated conditions (668 psig, 500 F). The steam is sent to a turbine generator, condensed, and pumped back to the steam generator. The heavy water leaving the primary side of the steam generators is pumped back to the reactor vessel. The heavy water is kept under sufficient pressure to prohibit boiling in the reactor pressure tubes. The calandria vessel is also filled with heavy water, which surrounds the fuel channels containing the pressure tubes and provides for neutron moderation and reflecting processes. The balance-of-plant systems for the CANDU plant are similar to LWR plants using saturated steam cycles.

1A.A.3.2.1 Technological Maturity. CANDU 3 is currently going through detailed design with commercial availability expected in the 1994/1995 time frame.³ The first operating unit is expected after 2000.³ CANDU design will feature open top construction and modularization to reduce cost and shorten construction schedules. Construction time for CANDU 3 in the United States is not known because none have been built in the United States. Project duration would likely be similar to LWRs, but may be greater because of the lack of familiarity of the design by federal and state regulatory agencies, leading to long licensing and permitting times. The CANDU 3 construction time is expected to be about three years.³

1A.A.3.2.2 Cost and Performance. A capital cost estimate for a CANDU 3 is not available. Net plant heat rate for CANDU 3 is slightly higher than for LWRs because of the lower turbine inlet steam pressure and temperature. CANDU 3 is best operated as a baseload unit. The plant capacity factor for CANDU 3 is expected to be greater than for LWRs because CANDU 3 can be refueled while

operating. Average capacity factors for currently operating CANDU reactors in 1986 and 1987 were 66 percent and 67 percent, respectively.

1A.A.3.2.3 Required Resources. Resource requirements for CANDU 3 are similar to LWRs. The CANDU 3 will use approximately 320 metric tons of deuterium oxide, with an annual makeup rate of 3 to 4 metric tons.⁵

1A.A.3.2.4 Environmental Impacts. Environmental compliance considerations regarding licensability for pressurized heavy water reactors are not significantly different from those of LWRs. Their disadvantages are similar to those of LWRs.

1A.A.3.2.5 References.

1. M. M. El-Wakil, Power Plant Technology, McGraw-Hill, Inc., 1984.
2. CANDU 3 Technical Outline, Atomic Energy of Canada Limited, September 1989.
3. D. R. Shiflett, Vice President, AECL Technologies, in personal communication to L. F. Drbal, Black & Veatch, February 1, 1991.
4. "Nucleonics Week," McGraw-Hill, Vol. 29, No. 5, February 4, 1988.
5. D. R. Shiflett, Vice President, AECL Technologies, in personal communication to L. F. Drbal, Black & Veatch, January 31, 1989.

1A.A.3.3 Modular High-Temperature Gas-Cooled Reactor

The modular high-temperature gas-cooled reactor (MHTGR) is an underground modular version of existing high-temperature gas-cooled reactor designs. MHTGRs are conceptualized as 134.5 MW units that are coupled in pairs to supply each turbine generator, which in turn can be replicated in pairs. The fuel is made of small grains of nuclear fuel, each coated with multiple layers of heat-resistant ceramic material. These fuel grains are put in a low power density core, which makes it slower to overheat during a power surge and limits the possibility of fuel failure. The helium gas coolant, circulated through the system by an electrical blower, is heated to a high temperature, allowing for highly efficient operation. However, even if this forced circulation system should fail, the reactor vessel would be sufficiently cooled by natural air circulation and direct heat loss to the surrounding earth.¹

1A.A.3.3.1 Technological Maturity. Several gas-cooled reactor systems are in commercial operation in Europe. The modular approach to this technology is, however, just entering the demonstration phase. Plants could reach commercial maturity after the year 2000.

1A.A.3.3.2 Cost and Performance Characteristics. Net plant heat rate is approximately 9,000 Btu/kWh for the module power plant. The estimated total capital cost requirement is expected to be in the range of \$2,500 to \$3,000 per kW. The MHTGR power plant is best suited for baseload operation for the same reasons discussed for other nuclear technologies. In plants with several modules, operation at reduced load levels over long periods of time could easily be accomplished by removing a module from service.¹

1A.A.3.3.3 Required Resources. Resources required (i.e., fuel, water, land) are projected to be considerably less than those of a similar sized LWR plant because of the number of smaller individual modules which need not all be running at once. Licensing, engineering, and construction schedule information is not available. Modularization and generic licensing approval could result in some schedule savings.

1A.A.3.3.4 Environmental Impacts. Projected gaseous radioactivity releases are expected to be less for HTGRs than LWRs with the exception of tritium (but still well below federal limits). Liquid discharges are expected to also be less for HTGRs over similar sized LWRs. Plant personnel radiation exposures will also be less than for similar sized LWRs.

The HTGR has several advantages over LWRs in the area of passive safety design features. One feature involves the large heat sink afforded by the large amount of graphite in the HTGR core. Another feature involved with the modular design includes the small size of the spherical fuel particles coupled with the smaller core size and power density which will retain fission products under loss of coolant incidents.

1A.A.3.3.5 References.

1. J. Catron, "New Interest in Passive Reactor Designs," EPRI Journal, April/May 1989.

1A.A.3.4 Liquid Metal Reactor

The liquid metal reactor (LMR) uses liquid sodium rather than water for core cooling. The reactor is situated in an underground concrete silo and is cooled by natural air circulation when the normal heat removal paths are not available. At

about 155 MW, the LMR units are relatively small (about a quarter of the capacity of the APLWR) and are designed as modules that can be shop fabricated and shipped to the site intact. The modules would be installed in groups of three to supply one 465 MW turbine generator.¹

1A.A.3.4.1 Technological Maturity. The development of a modular, passively stable LMR for utility application is being carried out under DOE sponsorship by a design team led by General Electric. Called PRISM (for power reactor inherently safe module), this 465 MW nuclear plant consists of three 155 MW reactor modules connected to a common steam turbine.¹

The Nuclear Regulatory Commission is expected to require the construction and testing of a single module PRISM demonstration plant before certifying the current design. Experimental reactors at DOE laboratories have already been used to test the passive cooling capability of the LMR concept, and conceptual designs for PRISM are scheduled for completion by 1991.

The LMR reactor is anticipated to be available for commercial orders in the mid-1990s with commercial operation after the turn of the century. This timetable may be adversely affected by current reduced research and development support, which may delay commercial availability in the US well beyond the year 2000.

1A.A.3.4.2 Cost and Performance Characteristics. Net plant heat rates, on an average basis, are anticipated to be in the range of 8,800 to 9,000 Btu/kWh. The estimated total capital cost requirement is expected to be in the range of \$3,000 to \$3,500/kW.

1A.A.3.4.3 Required Resources. Resource requirements for the LMR power plant are similar to those for conventional nuclear plants of conventional sizes. The licensing, engineering, and construction schedule information is not available at this time. Resource requirements described for the conventional LWR are applicable for this technology as well.

1A.A.3.4.4 Environmental Impacts. Environmental emissions and discharges for the LMR power plant are similar to those for conventional nuclear plants of comparable size.

1A.A.3.4.5 References.

1. J. Catron, "New Interest in Passive Reactor Designs," EPRI Journal, April/May 1989.

1A.A.3.5 Fusion Reactors

Fusion power results from the release of energy arising from the fusing of light elements into heavier ones (e.g., tritium (T) + deuterium (D) yields helium (He) + neutron with an energy per reaction of 17.6 Mev). Extremely high temperatures are required to fuse light nuclei (e.g., 50 million K for T-D reaction).

Two general concepts are being studied to attain fusion reaction temperatures. The first concept uses magnetic forces to confine and compress the tritium/deuterium plasma. The Tokamak fusion test reactor (TFTR) uses this concept. Superconducting magnets producing intense magnetic fields confine the plasma in a toroidal (doughnut shaped) arrangement. Neutral beam heating is also used to add additional energy to the plasma. The TFTR will use deuterium and tritium for fuel; the proof of the principle for fusion at the TFTR is expected in the mid-1990s (1993-94).¹

Designs that use a Tokamak-type device to produce electrical energy are conceptual at this time. Figure 1A.A.3-2 shows a schematic for one such concept called STARFIRE.² With STARFIRE, high-pressure water (approximately 2,200 psia) removes heat from the first wall and blanket material (fertile material for tritium production) and then passes to a steam generator which produces superheated steam (925 psig, 570 F). The balance-of-plant system corresponds to a LWR balance-of-plant system.² The net electrical power for STARFIRE is 1,200 MW.

The second concept (generally referred to as inertial confinement) uses light energy from a laser to impact on a small pellet of T-D. If sufficient energy can be imparted to the pellet, T-D will fuse. In addition to experiments using lasers, particle beam (e.g., lithium ions) impaction on T-D pellets is being studied. Scientific feasibility of using lasers or particle beams for T-D fusion may well be demonstrated in the next 8 to 10 years.³ One conceptual design for using inertial confinement for power production involves using liquid lithium to remove the fusion energy from the laser-pellet fusion vessel.⁴ The lithium transports the energy to a steam generator which produces steam for a conventional steam cycle using superheat and reheat steam conditions. Liquid lithium is returned to the laser-pellet fusion vessel.

1A.A.3.5.1 Technological Maturity. Fusion reactors are currently in the development stage and have a significant number of technical problems to be solved such as plasma confinement, material qualifications, first wall radiation

effects, and blanket and shield materials.⁵ Commercial applications of this technology are not expected until well into the next century.

Demonstration of proof of principle by the TFTR and/or European JET (Joint European Tokamak) is expected in the early 1990s. Following proof of principle, a compact ignition Tokamak (CIT) is planned for the United States to bridge the gap between present plasma machines and future engineering test reactors. A 1997 operating date has been proposed for CIT; however, limited funding has been allocated by Congress.⁶ On the international front, an international thermonuclear engineering test reactor (ITER) is being planned and would be cost-shared by the international community (including the US). ITER operation is planned for the 2000 to 2005 time frame.⁶ Results from the CIT and ITER are expected to lead to a demonstration fusion power plant. Commercial reactors are expected to follow these efforts. In all likelihood, it will be 2020 to 2055 before a fusion unit produces commercial electricity.⁶

1A.A.3.5.2 Cost and Performance. Because of the uncertainty in licensing, design, and construction schedules, a realistic capital cost estimate cannot be provided at this time. Based on conceptual designs, net plant heat rates for fusion reactor plants are estimated to be in the range of 9,000 to 11,300 Btu/kWh.²

1A.A.3.5.3 Required Resources. Land and water resource requirements are expected to be less for a fusion reactor than for a conventional LWR.

Fuel requirements are not expected to significantly impact the environment. Deuterium will be obtained from water; tritium will be produced from neutron reactions with lithium in the fusion device.

1A.A.3.5.4 Environmental Impacts. Radioactive releases from fusion reactors are expected to be much lower than those from LWRs.

Quantities of low-level and high-level waste are expected to be significantly less for fusion reactors than for LWRs. The fusion process produces no fission products, resulting in a significantly cleaner reactor than for fission processes.

Tritium is the major radionuclide to be contained and monitored. Cooling tower blowdown wastes are expected to be similar to or less than those from LWRs of equivalent size.

Fusion energy may represent an almost ideal source of energy. Advantages include the following.

- Fuel source is effectively inexhaustible.
- Fuel source is nonfossil.

- Large accidental releases of energy are not possible because of the small amount of fuel present.⁵
- Radioactive releases to the environment and waste disposal are small and represent minimum problems for the environment.⁵

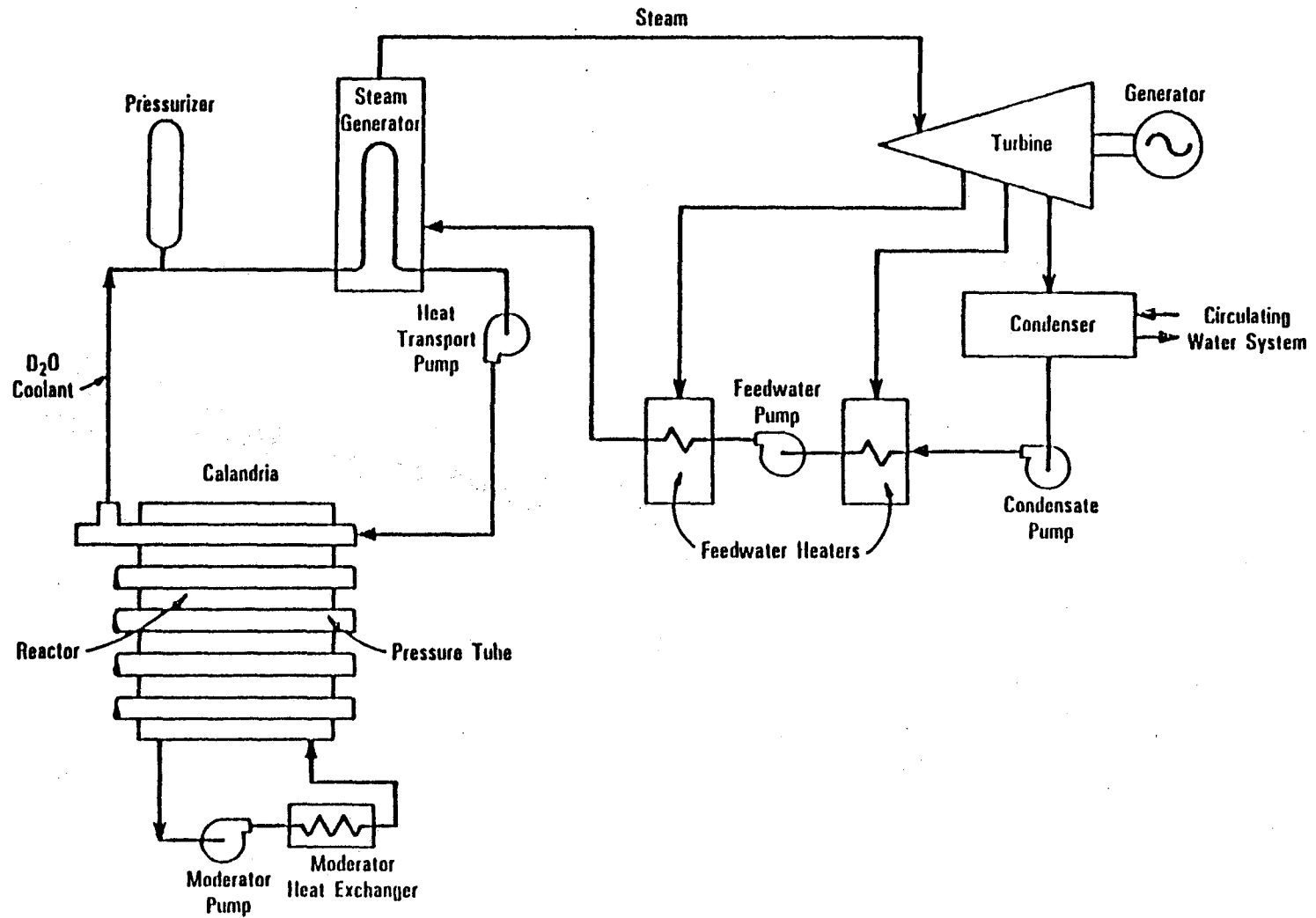
Fusion energy is not commercially available today and is not expected to be available until well into the next century. Many scientific and technological problems require solution before commercialization becomes a reality.

1A.A.3.5.5 References.

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2. "Nuclear Technology/Fusion," American Nuclear Society, La Grange Park, Illinois, Vol. 1, January 1981.
3. R. S. Craxton, R. L. McCrory, and J. M. Soures, "Progress in Laser Fusion," Scientific American, August 1986.
4. A. R. Foster and R. L. Wright, Jr., Basic Nuclear Engineering, Allyn and Bacon, Inc., Boston, Massachusetts, 1973.
5. S. Glasstone, Fusion Energy, US Department of Energy, Technical Information Center, 1980.
6. S. Dean, Fusion Power Associates, in personal communication to L. F. Drbal, Black & Veatch, January 27, 1989.

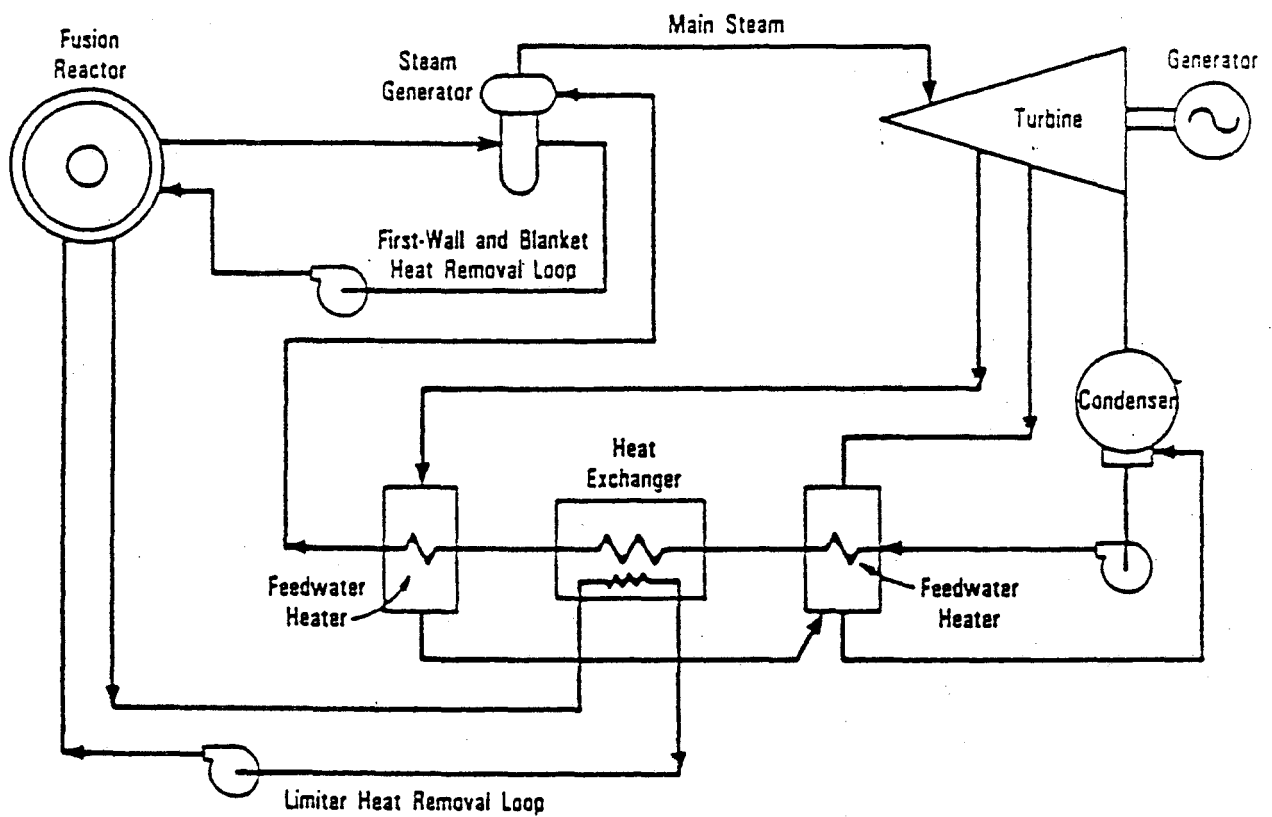
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CANDU STEAM SUPPLY FLOW DIAGRAM

Figure 1A.A.3-1



SCHEMATIC FOR A TOKAMAK FUSION REACTOR

Figure 1A.A.3-2

1A.A.4 Renewable Alternatives

The following renewable alternatives are discussed in this section.

- Wind Energy
- Ocean Wave
- Solar Photovoltaic
- Ocean Tidal
- Solar Thermal
- Geothermal
- Ocean Thermal

1A.A.4.1 Wind Energy

Wind energy conversion systems (WECS) convert wind energy into electricity by collecting the wind's kinetic energy with blades that are connected to a drive shaft (rotor) that turns a turbine generator. All WECS are propelled by either aerodynamic lift or drag forces. Lift type devices use airfoil elements similar to those developed for aircraft. They are characterized by relatively low starting torque, but have high tip-to-wind speed ratios and, therefore, relatively high power outputs. Drag type devices use plates or cups as the drag element. They are characterized by relatively high starting torques (useful for applications such as water pumping), but have relatively low power output in proportion to rotor size and weight.¹ Utility WECS power applications are predominantly lift type devices.

WECS are categorized as either horizontal axis machines or vertical axis machines. These designations refer to the orientation of the axis of rotation of the rotor. Horizontal axis machines are characterized by large blade diameters and large tower structures. Approximately 93 percent of all operating WECS are horizontal axis machines. Almost all large wind turbines (capacity greater than 100 kW) presently under development or commercially available are horizontal axis designs, most commonly having two-blade or three-blade rotors.²

As discussed under "Required Resources," wind energy is not considered a viable option for large-scale power generation in Florida because of inadequate resources.

1A.A.4.1.1 Technological Maturity. Events of the early 1980s, such as rising energy prices, the Public Utilities Regulatory Policies Act (PURPA) and other legislation, and generous tax credits, stimulated the development and installation

of WECS, especially in California. In 1986, California produced 92 percent of the 1,327 GWh total world wind generated electricity.³ The remainder of wind generated electricity was produced in Denmark, Hawaii, and other locations throughout the world.

Most of the California generation capacity is installed in three wind energy producing areas: Altamont Pass, San Geronio Pass, and the Tehachapi Mountains. All three of these areas are narrow mountain passes leading into hot and dry valley or desert regions. Among the three resource areas, 50 percent of all capacity is in Altamont Pass, 30 percent is in Tehachapi Pass, and 20 percent is in San Geronio Pass. Installed wind turbine capacities range from a few kilowatts to several megawatts. However, almost 80 percent of California turbines are from 50 kW to 150 kW, with a 114 kW average capacity for new installations.

The cumulative installed capacity in California from 1981 to 1987 was 1,436 MW. According to the California Energy Commission, a cumulative capacity of 1,304 MW was reported operational during the fourth quarter of 1987,⁴ indicating that WECS totaling 132 MW are not operational.⁵

The occurrence of catastrophic failures, such as thrown blades and collapsed tower, has diminished with the maturing of the industry, but has been reported at about 1 percent per year for the Altamont Pass region for 1985 and 1986.³ Failures such as these pose minimal safety hazards to the general public, but are detrimental to public perception of the industry and reduce the annual unit availability.

1A.A.4.1.2 Cost and Performance Characteristics. The 1987 average installed capital cost for WECS in California was \$1,070/kW. However, individual projects varied widely from the average cost, ranging from \$356/kW to \$1,420/kW. Average installed costs have dropped from \$1,600/kW in 1986 and \$1,890/kW in 1985.⁴

Operating and maintenance cost estimates are typically 8 to 12 mills/kWh. This estimate includes both direct and indirect costs for operations and routine maintenance. Increased maintenance costs of 3 mills/kWh may result from fatigue-related problems which require periodic overhauls of rotor blades and gearboxes.⁶

The 1987 statewide capacity factor of California wind turbines was 15 percent, with 1,304 MW of operating capacity producing 1,727 GWh.⁴ On average, the capacity of each operating WECS was 114 kW, and the annual energy produced was 112 MWh. When only those turbines installed after 1985 are considered, the average capacity factor was 19 percent. The higher capacity factor was primarily the result of nearly 95 percent turbine availability.

1A.A.4.1.3 Required Resources. The performance of WECS is primarily dependent upon an adequate wind resource to drive the system and the ability of the system to convert the wind's kinetic energy into electrical energy. A key measure of wind energy resource is the local annual mean wind speeds. Annual mean wind speeds of 13 to 14 mph are necessary to justify development of a wind resource area.³ The ability of the system to convert this energy to electricity is best estimated by the power curve of the installed turbine. Wind turbines generally require a minimum wind speed (typically 7 to 13 mph) to begin power generation, achieve maximum power generation at rated wind speeds (typically 30 to 35 mph), and are mechanically stopped for safety reasons at high wind speeds (typically above 45 mph).

The amount of power that a WECS produces is highly dependent on the wind resource region in which it is located. The long-term monitoring of wind speed at a potential site is necessary to estimate the site potential. Wind resource maps have been developed for estimating the resource in terms of power classes. Each class represents a range of mean wind power density in watts per square meter (W/m^2) or equivalent mean wind speed at specified heights. The classifications range from Class 1 (0 to 9.8 mph at 33 feet) to Class 7 (15.7 to 21.1 mph at 33 feet). Areas designated Class 3 (11.5 to 12.5 mph at 33 feet) or greater are suitable for most wind turbine applications. Local terrain features can cause the mean wind energy to vary considerably over short distances, especially in areas of coastal, hilly, and mountainous terrains. This local variability is an important factor in assessing the potential of a local region from wind resource atlas data.

The wind resource in Florida is primarily Class 1, with Class 2 regions along the coast.⁷ Therefore, wind energy is not considered a workable option for large-scale power generation in Florida.

1A.A.4.1.4 Environmental Impacts. The environmental impacts caused by existing wind farms are minimal. The modular nature of WECS supports phased construction. Minimal earthwork is required to erect the structures, and flora and

fauna coexist with the system while it is operating. Wind farm royalties allow landowners to remain on their land. There have been few significant environmental objections to WECS.

Surveys have indicated that most people are in favor of wind energy development. The most commonly voiced objections to WECS are visual unattractiveness, turbine noise annoyance, and electromagnetic wave interference. Today's WECSs are relatively quiet and can meet stringent sound level requirements and, because fiberglass or wood and epoxy rotors can be used instead of steel, are less susceptible to television interference.³ The principal continuing environmental problems with wind farm development are the large amounts of land required for substantial generation capacities and the aesthetic impacts of a large wind farm.

1A.A.4.1.5 References.

1. Wind Energy Technical Information Guide, Solar Energy Research Institute, Golden, Colorado, SERI/SP-271-2684, March 1985.
2. "Energy Fact Sheet: Wind," American Wind Energy Association, Arlington, Virginia, 1989.
3. M. A. Ilyin, D. R. Smith Consultants, and W. J. Steely, Pacific Gas and Electric, Altamont Wind Power Plant Evaluation for 1986, Electric Power Research Institute, Palo Alto, California, RP1590-6, EP-5824, May 1988.
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6. R. Lynette, R. Lynette & Associates, Wind Power Stations: 1986 Performance and Reliability, Electric Power Research Institute, Palo Alto, California, RP1590-10, Interim Report, March 1987.
7. D. L. Elliot et al., Pacific Northwest Laboratory, Wind Energy Resource Atlas of the United States, US Department of Energy, DOE/CH 10093-4, October 1986.

1A.A.4.2 Solar Photovoltaic

Photovoltaic (PV) energy systems convert sunlight (termed insolation) into electricity through use of solar cells. The conversion arises from the internal electronic structure of the semiconductor material and the electric fields that can be introduced in the material. Sunlight striking the solar cell frees electrical charge carriers that are separated by the internal potential difference, producing an electric current. Metal contact lines or grids on cell surfaces enable the current to flow through an external circuit to produce electric power.

Cells are closely packed and electrically interconnected within an environmentally protected unit called a module, the smallest assembly of solar cells provided by the photovoltaic manufacturer. Modules are connected in parallel/series combinations to achieve the system operating current and voltage (typically several hundred volts). Groups of modules, called panels, are placed on support structures and interconnected to form arrays. For utility grid connection, the direct current (dc) from the arrays is converted to alternating current (ac) by a solid-state inverter. Figure 1A.A.4-1 illustrates a photovoltaic energy system flow diagram. Because of their modular nature, PV systems in utility applications are generally installed in incremental capacities from tens to thousands of kilowatts.

There are two basic configurations of photovoltaic systems: flat plate and concentrating. Flat plate systems are either fixed in orientation or they track the sun by rotating about one or two axes to capture more energy. Concentrating systems use optical elements such as parabolic reflectors or Fresnel lenses to direct sunlight to a line (multiple cells side-by-side) or point (single cell) focus. One- or two-axis tracking is required for concentrator systems.

1A.A.4.2.1 Technological Maturity. Multi-megawatt photovoltaic power systems are operating at several US locations, notably the one-axis flat plate 2.35 MW system owned and operated by the Sacramento Municipal Utility District (SMUD) and the Carrisa Plain two-axis flat plate 6.5 MW system formerly owned and operated by ARCO Solar Power Production. PV systems under 1 MW in rated capacity, such as the 860 kW Hesperia two-axis flat plate system, formerly owned and operated by ARCO Solar, and the 300 kW one-axis flat plate system (PV300) owned and operated by the City of Austin Electric Utility, are also operating in the US. The Carrisa Plain and Hesperia facilities were sold to Carrisa Solar when

Siemens acquired ARCO Solar. Those systems are being dismantled, and the solar equipment is being sold.

A national cooperative research and development project, called PVUSA, is installing eight 20 kW emerging module technology (EMT) systems and three utility-scalable systems totaling 800 kW for the purpose of evaluating and comparing performance and reliability of different PV technologies in utility applications. These systems are located near Davis, California, and are connected to the Pacific Gas & Electric system.

Large utility-scale commercialization of PV systems could occur during the 1990s; however, utility market penetration is more likely in the 2000 to 2010 time frame. Favorable market forces and reduced capital costs would speed the commercialization process.

1A.A.4.2.2 Cost and Performance Characteristics. The performance of PV systems is normally indicated by annual energy efficiencies and annual capacity factors. PV power systems operating in 1986 demonstrated annual energy efficiencies from 6.9 percent to 8.4 percent and annual capacity factors from 22.8 percent to 27.9 percent.¹ These data were reported for the SMUD and Hesperia systems, although similar values were reported for the Carrisa Plain system² and the 300 kW City of Austin system.³ Annual energy efficiencies from 10 to 14 percent are expected from several PVUSA 20 kW EMT systems installed in 1989 and from the larger 200 to 400 kW utility-scalable systems installed in 1990.

Several factors, such as system availability, module efficiency, and inverter efficiency, influence the annual efficiency of a PV system. In general, PV systems are highly reliable and exhibit availabilities in excess of 90 percent. The City of Austin system demonstrated greater than 99 percent availability during its first year of operation.³ The Carrisa Plain plant, which used mirrors to provide approximately 2X concentration, suffered a phenomenon called "brown cell," which resulted in significant (nominally 50 percent) power degradation. That phenomenon is thought to be related to the 2X operating conditions for which the modules had not been designed.

Capital cost estimates for multi-megawatt PV systems in operation today are generally not available because of proprietary concerns. However, capital cost estimates for systems co-funded by government agencies and utilities are more readily available. The City of Austin reports a total installed plant cost of

\$3 million (1986 dollars) for a 300 kW system, or \$10,000/kW. The annual average cost to generate electricity was approximately 50 cents/kWh for the 1987 fiscal year.³ Total installed plant costs for the SMUD system are not available; however, the first phase module cost was \$5,000/kW (1984 dollars) and the inverter cost was \$400/kW. Another project, the City of Austin/3M system, now under construction in Austin has an estimated total capital cost of \$6,000/kW.⁴ The 300 kW system is being jointly funded by the City of Austin, the 3M Company, and the US Department of Energy.

Operations and maintenance records for several of the larger PV systems indicate that PV systems require little operator intervention or equipment servicing. Documented O&M costs are in the range of 2 to 5 mills/kWh.^{3, 4}

1A.A.4.2.3 Required Resources. Principal resource requirements for a PV plant include solar insolation and a large amount of land. Solar insolation is the rate of solar energy received per unit surface area and is made up of two components: direct and diffuse. Direct insolation is the beam energy that is present on sunny days. Diffuse insolation is the atmospheric-scattered energy that is present on sunny and cloudy days. Concentrating PV systems use only the direct insolation. Flat plate systems (both fixed and tracking) use both direct and diffuse insolation.

An annual average direct insolation of 1,470 kWh/m² is reported in the Orlando, Florida, region.⁵ The annual average total global (direct plus diffuse) insolation for the Orlando region is reported to be 1,710 kWh/m².⁶ These compare with 2,589 kWh/m² and 2,120 kWh/m² for direct and global insolation in Southern California.^{5,6} The instantaneous insolation (kW/m²) determines the instantaneous power output of the system. The annual capacity factor is closely related to the annual average insolation. The capacity factor for a PV in the Orlando area is likely to be in the range of 15 to 20 percent.

The land required for a PV system depends on the system size and type, local insolation, and module and inverter efficiencies. Typically, a PV system requires about six to seven acres of land for each MW of rated capacity. This land must be relatively flat and ideally should not be downwind from a source of dust or other substance which would accelerate soiling of module surfaces or decrease insolation.

1A.A.4.2.4 Environmental Impacts. Operating PV systems do not consume fuel nor produce waste products that require processing or disposal. Photovoltaic power systems are environmentally benign and present few environmental or

health hazards. It is generally thought that the primary health and environmental impacts of operating PV power systems are electrical shock hazard, fire hazard, and disposal of damaged modules. Most of these potential problems can be mitigated or prevented by following normal Occupational Safety and Health Administration practices and existing health and safety codes established for the plastics and chemicals industries.⁷

Other than the use of large land areas, potential ecological and climatic issues are minimal and should be restricted to construction impacts.

1A.A.4.2.5 References.

1. V. V. Risser, New Mexico Solar Energy Institute, Photovoltaic Field Test Performance Assessment: 1986, Electric Power Research Institute, Palo Alto, California, RP1607-6, AP-5762, March 1988.
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5. Direct Normal Solar Radiation Data Manual, SERI/SP-281-1658, October 1982.
6. Insolation Data Manual, SERI/SP-755-789, October 1980.
7. Photovoltaic Technical Information Guide, Solar Energy Research Institute, SERI/SP-320-3328, August 1988.

1A.A.4.3 Solar Thermal

Solar thermal electric generation plants use direct insolation to heat a heat transfer fluid, which in turn heats a working fluid to power the prime mover--typically a Rankine cycle turbine. Figure 1A.A.4-2 shows the solar thermal concept. There are three main categories of solar thermal electric generation concepts.

- Parabolic Trough. The commercially available solar thermal technology is the parabolic trough system. A parabolic trough collector consists of a computer controlled, movable parabolic, cylindrical mirror which

focuses solar radiation on a fixed receiver tube. The collector mirror rotates about a longitudinal axis, thereby tracking the sun throughout the day. The receiver tube, which is located along the focal axis of the mirror, collects the reflected radiation and transforms the radiant energy into thermal energy in the heat transfer fluid, typically a silicone type oil. Parabolic trough collectors are normally installed in rows so that fluid flow through successive collectors contributes to the total temperature rise in the fluid. Heat is subsequently transferred to a working fluid (water or toluene) to drive a turbine. Parabolic trough systems may employ thermal storage to lengthen or shift the daily power generation period.

- Central Receiver. The solar thermal central receiver (STCR) technology is not yet commercially available. In this technology, direct insolation is redirected and concentrated by computer-aimed, movable mirrors called heliostats onto a receiver located atop a tower.¹⁻³ In the receiver, a fluid (typically water or molten salt) absorbs the heat. With a water/steam receiver, steam generated in the receiver is used to drive a ground level turbine generator. With a molten salt system, the salt is heated from about 550 F to about 1,050 F in the receiver, transported to a ground level thermal storage tank, and subsequently used to generate steam to drive a turbine generator. Because of its thermal storage, an STCR system allows a dispatcher to lengthen or shift the generating period into nighttime hours to meet peak demand, if required.
- Parabolic Dish. Parabolic dish systems consist of a reflective parabolic bowl which tracks the sun, redirecting and concentrating the solar energy on a receiver at the dish's focal point.⁴ In the receiver, either an intermediate heat transfer fluid is heated and piped to a central ground level power generation device, or the working fluid is heated to power a prime mover located along with the receiver at the focal point. For the latter concept, toluene Rankine cycle turbines, Brayton cycle turbines, and Stirling cycle engines have been used. A 25 kW Stirling cycle engine system has demonstrated a solar-to-electric efficiency of 29.4 percent, with an engine cycle efficiency of 40 percent. Long-term reliability and availability of the Stirling cycle engine have not been demonstrated.

1A.A.4.3.1 Technological Maturity. Of the three solar thermal system concepts, only parabolic trough systems are commercially available for utility-scale applications.

- **Parabolic Trough.** The principal commercial application of parabolic troughs for power generation has been the Luz International Solar Electric Generation Systems (SEGS) connected to the Southern California Edison grid.⁵⁻⁹ Luz has 354 MW of parabolic trough generating capacity, including the 80 MW SEGS IX plant which began operation in October 1990. SEGS II (1986 operation) through VII (1989 operation) are 30 MW each. SEGS I, which began operation in 1985, is 13.8 MW.
- **Central Receiver.** A water/steam STCR concept has been demonstrated successfully on the pilot scale at the 10 MW Solar One facility near Barstow, California.¹⁰⁻¹⁴ Solar One began operation in 1982 and continued to operate until 1988. The molten salt STCR technology has been tested only in small scale (5 MW thermal) experiments. Conceptual designs for 100 MW and 200 MW commercial scale STCR plants were developed in 1987 as part of the Utility STCR Studies funded by DOE. These studies indicated that plant sizes of at least 100 MW are required for economic operation. Because of the need for a large-scale system experiment prior to deployment of a commercial scale plant, it is unlikely that commercial operation of a STCR plant would occur during the 1990s.
- **Parabolic Dish.** Two major dish system experiments have operated in the US. The Solar Total Energy Project at Shenandoah, Georgia, produces 400 kW of electrical power plus process heat. The privately financed Warner Springs, California, SOLARPLANT I was designed to produce 4.9 MW of electricity; this facility operated for approximately two years and ceased operation because of operational and funding difficulties. A 250 kW facility was planned; however, that facility was not built because of funding and developmental issues.

Depending on market forces, commercialization could occur within the 1990s, but is more likely in the 2000 to 2010 time frame.

1A.A.4.3.2 Cost and Performance Characteristics.

- **Parabolic Trough.** The newer SEGS facilities have solar-to-electric efficiencies of about 22 percent. The SEGS VIII facility has an annual solar-only capacity factor of about 27 percent; however, the use of supplemental firing with natural gas improves the annual capacity factor to about 36 percent. The SEGS facilities are limited contractually to 25 percent of their annual energy production by fossil fuels. The annual capacity factor for a parabolic trough plant in the Orlando area is estimated to be about 16 percent.

The installed capital cost for SEGS VIII is reported to be \$2,600/kW.⁹ The annual operating cost for a parabolic trough system is estimated to be \$4.60/kW-year (fixed) and \$0.80/MWh (variable).

- **Central Receiver.** Annual performance for a 200 MW STCR plant with six hours of thermal storage is estimated to result in a 15 percent solar-to-electric efficiency and a solar-only capacity factor of about 36 percent for a southern California site. The capacity factor for a similar facility in Orlando would be about 22 percent.

The projected cost of a mature technology 200 MW STCR plant is about \$2,600/kW. Operating costs are projected to be about \$5,600,000 per year, or about \$15/MWh for a 22 percent capacity factor.

- **Parabolic Dish.** Currently, costs are high because parabolic dish units are in a developmental stage. Mature technology and mature market could make parabolic dish systems competitive in the next decade, first for remote applications and possibly later for utility applications.

1A.A.4.3.3 Required Resources. Principal resource requirements for a solar thermal plant include direct normal solar insolation and a large amount of land.

The annual average direct insolation for Orlando is reported to be about 1,470 kWh/m².¹⁵ This insolation level is substantially below the 2,580 kWh/m² insolation for southern California and would result in a significantly lower capacity factor than achieved by a facility such as the SEGS plants located in Southern California.

Land requirements for parabolic trough systems are 160 acres for a 30 MW plant and 380 acres for an 80 MW plant. Land requirements for a 200 MW central receiver system with six hours of storage are about four square miles. Land requirements for a parabolic dish system are about four to five acres per MW.

1A.A.4.3.4 Environmental Impacts. There are no significant adverse environmental impacts other than the large land areas required to implement the parabolic trough, central receiver, and parabolic dish technologies.

1A.A.4.3.5 References.

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3. Solar Central Receiver Technology Advancement for Electric Utility Applications, Phase 1 Topical Report, Pacific Gas and Electric Company, August 1988.
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5. D. Kearney and H. Price, "Performance of the SEGS Plants," Proceedings of the Tenth Annual ASME Solar Energy Conference, Denver, Colorado, April 10-14, 1988.
6. C. Jensen, H. Price, and D. Kearney, "The SEGS Power Plants: 1988 Performance," preprinted for presentation at the 1989 ASME International Solar Energy Conference, San Diego, April 1989.
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9. "Luz in Brief: October 1990," information document from Luz International Limited.
10. "Solar One in Perspective," Southern California Edison Company, November 1982.
11. C. W. Lopez, "Solar 1-MWe Pilot Plant," Electric Energy Information Center, Daggett, California, May 1986.
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1A.A.4.4 Ocean Thermal Energy Conversion

An ocean thermal energy conversion (OTEC) plant uses the temperature difference between warm surface water (as much as 81 F) and cold deep water (as low as 39 F) to generate electricity. Because of the relatively small temperature differences, OTEC plants have overall efficiencies of about 2 percent.¹

There are two basic types of cycles for OTEC plants. A closed cycle plant uses a working fluid with a low boiling point, such as ammonia. The working fluid is heated and vaporized by the warm surface water, expanded in a turbine generator, and condensed by deep cold water. An open cycle plant uses seawater as the working fluid. The warm surface water is evaporated in a vacuum in a boiler into low-pressure steam, expanded in a turbine generator, and condensed by the deep cold water.¹

OTEC plants can also be classified by the location of the plant in relation to the ocean. Shore-based plants are appropriate for islands with steep offshore slopes, and can be tied in with existing electric transmission grids. Offshore plants can be floating platforms or tower-mounted structures, both of which have under-sea power cables connecting to an onshore transmission grid. A grazing plantship is another example of an offshore plant. This plant seeks areas of maximum temperature differentials for maximum efficiency and produces an energy-intensive output for transfer back to shore.¹

1A.A.4.4.1 Technological Maturity. The closed cycle OTEC plants are projected to be commercially available by the year 2000.² A closed cycle OTEC plant is being designed for several possible locations, including Indonesia. This 400 MW plant consists of four 100 MW floating offshore units. Indonesia has a power sales contract with the developer of this plant whereby Indonesia will buy power from this plant when the power is available, which will be after 1992.⁴ Open cycle OTEC plants are still under development and will probably be commercially available by 2010.²

1A.A.4.4.2 Cost and Performance Characteristics. Capital costs for the first commercial size OTEC plant are expected to range from 6,000 to 8,000 \$/kW (1985 dollars).² A projected Ocean Thermal Corporation plant, with a capacity of 46 MW and a 68 percent capacity factor, has a predicted total energy cost of \$217/MWh (1985).³ The developer of the proposed 400 MW closed cycle facility for Indonesia estimates that the capital cost for the first 100 MW plant would be \$2,500/kW. A mature 100 MW plant would have a capital cost of \$1,200 to \$1,500/kW. Operating costs are estimated to be \$3/MWh.⁴

1A.A.4.4.3 Required Resources. The best potential OTEC sites are along the equator because of the existence of higher temperature differences between surface and deep water.² The main resource required for OTEC plants is seawater. A typical open cycle OTEC plant would require 50,000 gpm of ocean seawater to generate 1 MW of power. One percent of the warm seawater is flashed into steam and later condensed into fresh water. A 10 MW OTEC plant could produce 5 million gallons of fresh water per day.⁵

1A.A.4.4.4 Environmental Impacts. OTEC plants appear to have more potential environmental benefits than problems. Potential benefits include an environmentally benign technology and the production of a variety of byproducts, such as desalinated water, marine culture products, and refrigeration. Environmental concerns include discharge of cool water in tropical surroundings and the possibility of accidental release of ammonia from closed cycle plants.²

1A.A.4.4.5 References.

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2. Development Plan for the Multiple Product Ocean Thermal Energy Conversion Project, a proposal prepared by the Pacific International Center for High Technology Research, 1989.
3. Jim Anderson, President, Sea Solar Power, Inc., in personal communication to B. P. Spott, Black & Veatch, May 16, 1990.
4. A. Douglas Carmichael and J. Sherman Feher, "Ocean Energy: Can It Compete?" Civil Engineering, November 1987, pp. 70-72.
5. "Federal Laboratories Work on OTEC Power Plants," Alternative Sources of Energy, March 1988, p. 38.

1A.A.4.5 Ocean Wave Energy Conversion

Three primary wave-energy systems are currently under development or in operation. The first of these is the Kvaerner wave-energy plant developed in Norway. This plant uses a water oscillation chamber blasted out of a rock cliff. The rise and fall of waves in this chamber cause air in the chamber to pass up and down through a Wells turbine, thereby generating electricity.¹ The Wells turbine can continue to spin in the same direction while accepting air from both above and below the turbine.² The second of these wave-energy systems is the British Sea Clam, which consists of a hollow, floating chamber and a collapsible bladder, both connected by a hollow duct containing an air turbine. An approaching wave collapses the bladder, forcing air past the turbine and generating electricity.³ The third system is one designed by the Soviet Union, which has an efficiency of over 80 percent. This system consists of slotted wheels, each with high moments of inertia, that share a common axle with a generator. The motion of ocean waves causes the wheels to rotate and, because of the flywheel effect, the wheels can continue to rotate during the intervals between waves (2 to 15 seconds).⁴

1A.A.4.5.1 Technological Maturity. All of the three wave-energy systems should be commercially available by the year 2000. The Norwegian Kvaerner system is currently available in 150 kW, 500 kW, and 1.5 MW sizes.¹ The British Sea Clam system will probably be available in 4.6 MW size, requiring 25 units for a 115 MW plant.³

1A.A.4.5.2 Cost and Performance Characteristics. Predicted energy costs in 1985 dollars are available for two of the wave-energy plants discussed above. A Sea Clam plant, consisting of twenty-five 4.6 MW units for a total production of 115 MW, would have a total energy cost of \$274/MWh, assuming a 17 percent capacity factor.³ The Kvaerner system is projected to have a total energy cost of \$70/MWh.

1A.A.4.5.3 Required Resources. The power generation potential for wave-energy plants depends both on available wave height and length of coastline. With the Soviet system, a wave 6 meters (19 feet 6 inches) high and 15 meters (48 feet 9 inches) wide can produce 220 kW. Likewise, a wave 12 meters (39 feet) high and 15 meters wide can produce 880 kW.⁴

1A.A.4.5.4 Environmental Impacts. Potential environmental impacts include temporary construction impacts, land use for a shoreline power generation facility, aesthetics, and noise.

1A.A.4.5.5 References.

1. "Costs Coming Down?" Civil Engineering, November 1987, pp. 72-73.
2. David Ross, "British U-Turn on Wave Power," Alternative Sources of Energy, January 1988, p. 29.
3. A. Douglas Carmichael and J. Sherman Feher, "Ocean Energy: Can It Compete?" Civil Engineering, November 1987, pp. 70-72.
4. Vadim Pikhnovski, "Soviets to Tap Wave Energy," Alternative Sources of Energy, March 1988, p. 40.

1A.A.4.6 Tidal Energy Conversion

In tidal energy conversion systems, energy is extracted from the changes in the level of ocean water during tidal cycles. A tidal energy conversion plant consists of a tidal basin created by a dam, a turbogenerator, and a sluice gate in the dam to allow the tidal flow to enter or leave. A 16-foot minimum tidal amplitude is required for a tidal energy conversion system to be feasible.¹

Two tidal energy conversion concepts are the single-basin, single-effect systems, and double-effect systems. Single-basin, single-effect systems impound water when the tide level reaches its peak. After the tidal level falls (ebb tide), water in the basin is released through a turbine generating electrical power. Double-effect systems use reversible turbines to generate power on both the ebb and rising tides.²

1A.A.4.6.1 Technological Maturity. Tidal energy conversion is a proven technology. However, there are currently no tidal conversion plants in the United States. A 240 MW commercial plant has been operating across La Rance Estuary in northwest France since 1962, and an 18 MW plant operates in Nova Scotia, Canada.¹

1A.A.4.6.2 Cost and Performance Characteristics. The capital costs of tidal energy conversion systems vary significantly with plant size and site conditions. A study conducted for a potential tidal energy plant located in Half Moon Cove, Maine, projected a cost for a 12 MW plant of \$3,700/kW in 1985 dollars. Power output from a tidal energy conversion system depends on tidal amplitude, mean basin surface area, turbine efficiency, and type of scheme (single- or double-effect). The 240 MW plant in France consists of twenty-four 10 MW bulb-type Kaplan turbines and has a mean basin surface area of 8.5 square miles. The mean tidal amplitude at La Rance is 28 feet.¹

1A.A.4.6.3 Required Resources. Studies have indicated that for tidal energy systems to be economically feasible a 16-foot minimum tidal amplitude is necessary.¹ This tidal amplitude is not found in Florida.³ The only places in the US where these conditions exist are along the northern coast of Maine and in the Cook Inlet and Bristol Bay, Alaska.

1A.A.4.6.4 Environmental Impacts. Potential environmental impacts are site-specific and would include temporary construction impacts, recreational use, aesthetics, waterway navigation, and marine habitat. Also, large tidal projects could affect tidal levels outside of the basin. Studies have shown that large tidal projects (> 1,000 MW) could change tidal amplitudes by several inches along shoreline located several miles from the project. This could have significant impact on shoreline property and ecology.¹

1A.A.4.6.5 References.

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2. Energy Technology Status Report, California Energy Commission, October 1988.
3. Personal Communication between Steve Baig, Oceanographer, National Weather Service, and B. P. Spott, Black & Veatch, on January 25, 1991.

1A.A.4.7 Geothermal

Geothermal energy is thermal energy associated with the elevated temperature of the interior of the earth. There are four principal forms of geothermal energy.

- Dry steam.
- Hot water/wet steam.
- Geopressured zones.
- Hot dry rock.

The dry steam form is the easiest to use because this steam can be used to power a conventional steam turbine generator.¹

Because of the presence of liquid water, the hot water/wet steam form requires more complicated power conversion equipment. Currently, there are three ways of using this form of geothermal energy: (1) a rotary separator turbine plant separates the two-phase mixture into steam and liquid water and generates power from a steam turbine and a liquid turbine, respectively,² (2) a flashed-steam cycle plant depressurizes the two-phase mixture into steam which is then used to power a conventional steam turbine generator,¹ and (3) in a binary cycle plant, heat from the hot water/wet steam is transferred to another working fluid through

a heat exchanger. This other working fluid, which would have a lower boiling point than water, is used to power a turbine generator.³

Geopressured zones are reservoirs under extremely high pressure located in formations of impermeable shale. These reservoirs contain mixtures of hot salt water and methane gas. Potentially, energy could be obtained from these zones by burning the methane and using the pressure and heat from the hot water.¹

To tap the energy contained in the underground hot dry rock, the rock must first be fractured by conventional oil and natural gas drilling techniques. Once a reservoir has been created in the hot dry rock, inlet and outlet water pipes are driven down into the reservoir. Circulating hot water is heated in this reservoir and is used to generate power by one of the three technologies mentioned above for the hot water/wet steam form.¹

1A.A.4.7.1 Technological Maturity. The dry steam form of geothermal energy has been used for the commercial generation of electricity in the United States since 1960, when Pacific Gas and Electric, with others, built an 11 MW power plant at The Geysers in northern California. This geothermal field now supports plants generating over 1,800 MW of electricity.⁴ Another such commercial plant is the Sacramento Municipal Utility District (SMUD) Geothermal Plant No. 1, which is rated at 72 MW.⁵

The technologies for using the hot water/wet steam form of geothermal energy are currently in the commercial to demonstration stages of maturity, depending on the particular technology.¹ The flashed-steam cycle technology is now being used for commercial power generation in the United States. An example of this is Southern California Edison's (SCE) Salton Sea 10 MW plant.⁶ San Diego Gas & Electric's Heber plant is the first commercial-scale demonstration binary cycle plant; this 46.6 MW plant first went into operation in 1985.⁷ The rotary separator turbine technology has been tested in the portable Biphase Wellhead Power Plant at several geothermal fields since 1979. This technology is still in the development phase.²

Applications of geopressured zones and hot dry rock technologies are still being developed. Research efforts are aimed at identifying potential sources and developing the necessary energy conversion technologies.¹

1A.A.4.7.2 Cost and Performance Characteristics. Typically, commercial geothermal plants can be built for an installed cost of \$1,200/kW to \$1,800/kW where a geothermal field exists.⁸ The 72 MW SMUD Geothermal Plant No. 1, which began commercial operation in December 1983, had an installed cost of about \$1,320/kW in 1983. Its annual plant output cost, including steam supply, O&M costs, and capital recovery factor, was \$54/MWh in 1983.⁵

The first commercial binary cycle plants similar to the Heber plant are expected to have capital costs near \$1,650/kW. The busbar electricity costs from such plants are likely to be around \$83/MWh.⁷ Heat rates for geothermal plants depend extensively on the characteristics of the available resource.

1A.A.4.7.3 Required Resources. Power plants using any of the four forms of geothermal energy must be located at a geothermal field because the heat from the field cannot be transported over a long distance. Many of these fields require significant exploration and drilling before they can be located and tapped. Also, geothermal fields are relatively rare. For example, geopressured zones have been found primarily along the Gulf Coast in Texas and Louisiana. Geothermal fields containing dry steam or hot water/wet steam are located almost exclusively in the western states. Dry steam resources are primarily concentrated in California; hot water/wet steam (hydrothermal) resources are about 20 times more plentiful than dry steam resources.¹

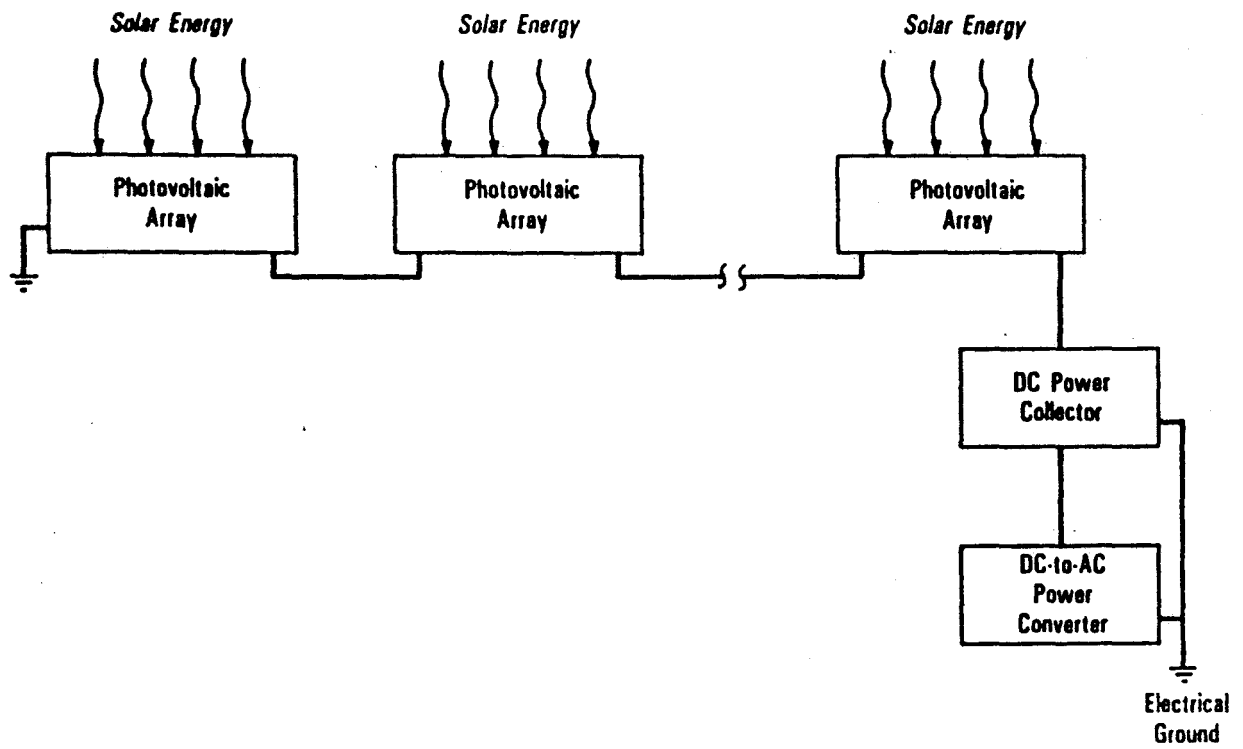
No geothermal resources have been identified in Florida.¹⁰

1A.A.4.7.4 Environmental Impacts. The primary environmental concerns attributed to geothermal energy relate to the drilling during construction.⁹ There may be emissions of noncondensable gases during drilling, particularly with high-temperature resources. There is potential for surface and ground water contamination from the use and disposal of drilling fluids, and high frequency noise can result from drilling. Noise can also be a concern during plant operation. The development of the geothermal resource may also result in surface erosion, ground water siltation, and habitat disturbance.

1A.A.4.7.5 References.

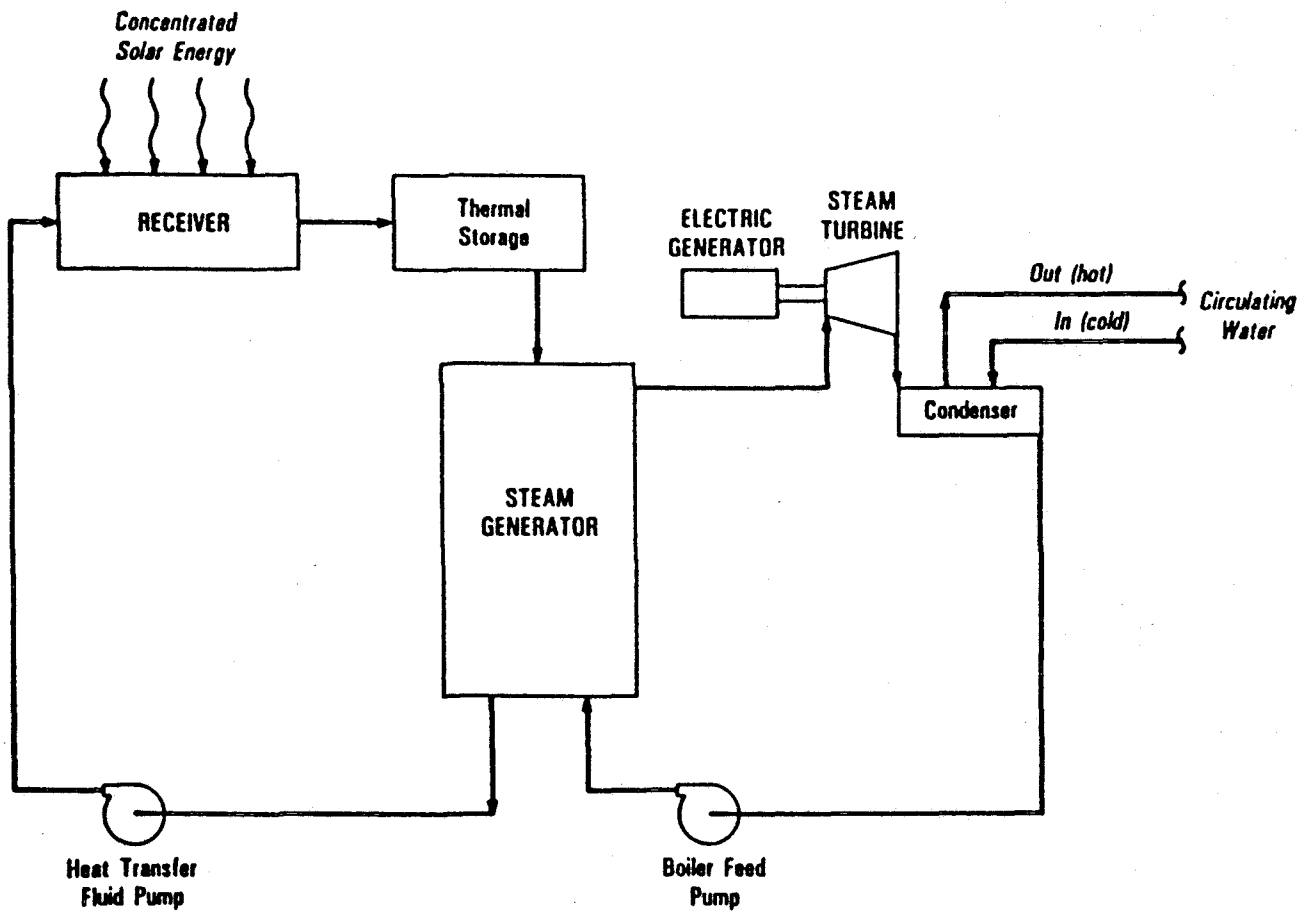
1. Electricity--Today's Technologies, Tomorrow's Alternatives, Electric Power Research Institute, Palo Alto, California, 1987, pp. 37-39, 51-53.
2. Donald J. Cerini and Jeff Record, "Rotary Separator Turbine--Performance and Endurance Test Results," Proceedings: Seventh Annual Geothermal Conference and Workshop, San Diego, California, June 28-30, 1983, pp. 5-75 to 5-86.

3. Nadine Lihach, "Heber: Key to Moderate-Temperature Geothermal Reserves," EPRI Journal, January/February 1985, pp. 24-29.
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6. Elgin Moss, "Initial Operating Results: 10 MW Salton Sea Geothermal Pilot Plant," Proceedings: Seventh Annual Geothermal Conference and Workshop, San Diego, California, June 28-30, 1983, pp. 2-5 to 2-12.
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9. Douglas M. Considine, ed., Energy Technology Handbook, McGraw-Hill Book Company, New York, 1977, pp. 7-37 to 7-41.
10. Evan Hughes, Electric Power Research Institute, in personal communication with B. P. Spott, Black & Veatch, January 29, 1991.



PHOTOVOLTAIC PLANT FLOW DIAGRAM

Figure 1A.A.4-1



SOLAR THERMAL PLANT FLOW DIAGRAM

Figure 1A.A.4-2

1A.A.5 Energy Storage

Three energy storage technologies are described in this section.

- Lead-acid batteries.
- Compressed air energy storage.
- Underground pumped hydroelectric.

1A.A.5.1 Battery Storage

Lead-acid batteries are an energy technology that can store excess energy and release that energy as required as dispatchable power. The major advantages of lead-acid batteries over more conventional peaking systems (such as combustion turbines) are an extremely fast startup and compatibility with the environment. Load leveling can be provided by the lead-acid batteries when charged with off-peak, lower cost power and discharged during peak, higher cost power periods. Lead-acid batteries are economical in this type of application when the cost of system construction, operation, and maintenance can be offset by the energy cost differential between peak and off-peak rates. Basically, two different types of lead-acid battery load leveling systems are currently being considered: a utility-owned (supply-side) energy storage system and a customer-owned energy storage system. This section addresses only the supply-side options.

A lead-acid battery storage system consists of the battery, dc switchgear, dc/ac converter/charger, transformer, ac switchgear, and associated building to house these components. During the utility peak periods when energy costs are the highest, the battery system discharges and supplies power to the utility ac power system for a typical period of four to five hours. After the peak period has passed, the battery system is recharged and then remains on "float" until the next peak period, thus completing one cycle of operation. The following are major advantages of a battery energy storage system.

- Electrical load leveling by supplying power during peak periods and recharging during off-peak periods.
- Load growth matching and capacity deferral because peaking generation equipment is deferred, and peak power can be added in small increments.
- Energy storage because low cost power can be purchased and stored at any time.
- Dynamic source advantages by providing spinning reserve, area frequency and voltage control; and greater system reliability.

- Reduced electrical loss by locating these systems near customer load centers.
- Environmentally compatible in virtually any area.

The system also has disadvantages.

- Initial cost of batteries and replacement cost every 8 to 10 years.
- Maintenance of battery system.
- Removal of neutralized electrolyte because of an accidental spill or fire.

1A.A.5.1.1 Technological Maturity. Two lead-acid battery storage systems for supplying power to a utility ac power system have been operating successfully since 1986: a 17 MW, 14.4 MWh facility in West Germany and a 1 MW, 4 MWh facility in Osaka, Japan. In 1987, five new battery storage sites were announced: three in the US, one in West Berlin, and one in South Africa. Most recently, a 10 MW, 40 MWh battery energy storage system was constructed by Southern California Edison at its Chino substation. The Chino battery facility was originally studied and conceptually designed for EPRI.^{1,2}

1A.A.5.1.2 Cost and Performance Characteristics. Actual performance parameters from the Chino battery facility are not public information to date; therefore, the generic battery plant specifications listed in Table 1A.A.5-1 were based on the EPRI conceptual design project for a 10 MW, 40 MWh plant.^{1,2} Estimated costs for the 40 MWh battery facility are listed in Table 1A.A.5-2.

1A.A.5.1.3 Required Resources. For the utility-owned lead-acid battery energy storage system, the facility should be located close to a substation. This location provides the easiest access to the utility's ac power system and reduces ac power losses. A space-saving single-layer, lengthwise row battery rack arrangement is most desirable for this application.¹ This type of arrangement requires a minimum square foot area of about 30,000 square feet for the battery building of a 50 MWh facility.

1A.A.5.1.4 Environmental Impacts. The primary environmental concern with lead-acid battery systems is a sustained short circuit, resulting in fire and an acid spill. At the Chino facility, the two battery buildings have 18-inch high curbs to provide containment of fire protection water and cell acid content.² In the event of a large spill, a licensed hazardous waste contractor would neutralize and dispose of the acid.

1A.A.5.1.5 References.

1. Design and Costs for a Generic 10-MW Utility Lead-Acid Battery Energy Storage Plant, EPRI AP-5845, June 1988.
2. Douglas Morris, "The Chino Battery Facility," EPRI Journal, March 1988, pp. 46-50.

1A.A.5.2 Compressed Air Energy Storage

Compressed air energy storage (CAES) is a technology for both generating electricity and storing energy from fossil fuels. A typical CAES unit consists of five basic components.

- Compressor train (including compressors and intercoolers).
- Motor generator.
- Turbine expander train (including expanders and combustion chambers).
- Recuperator.
- Underground cavern.

During off-peak periods, electricity from the grid is used in the motor generator to run the compressor, which compresses air for storage in the underground cavern. During peak periods, the compressed air is extracted from the cavern and is preheated by turbine exhaust gases in the recuperator. This preheated air is then mixed with fuel which is burned in the combustion chambers. The resulting hot gases are expanded in the turbine to generate electricity.¹ Figure 1A.A.5-1 shows a schematic of a typical CAES unit.²

CAES units can be identified by two basic size categories: mini-CAES units and maxi-CAES units. Mini-CAES units are generally in the size range of 25 MW to 100 MW; maxi-CAES units are above 100 MW. Brown Boveri & Company (BBC) is offering a 220 MW unit.³

Three types of storage are used for either mini- or maxi-CAES units.

- Salt dome
- Hard-rock
- Aquifer

Compressed air is stored at a fixed volume and variable pressure in both the salt dome and the uncompensated hard-rock caverns. In both the compensated hard-rock caverns and the aquifers, compressed air is stored at a variable volume and fixed pressure.⁴

1A.A.5.2.1 Technological Maturity. The first CAES unit, rated at 290 MW, went into commercial operation in 1978 for the West German utility Northwest Deutsche Kraftwerke (NWK). This unit, designed by BBC, became the basis for commercial 220 MW units currently offered by BBC.³ Construction of the first US CAES unit, rated at 110 MW, has been completed recently for Alabama Electric Cooperative (AEC). Commercial operation is expected in mid-1991. The construction period for this unit was approximately three years. Both the NWK and AEC units use the salt dome form of compressed air storage.¹ A 1,050 MW salt dome unit is under construction in the Soviet Union. A 35 MW CAES unit is also under construction in Japan. This unit is to serve as prototype CAES train to be offered by Mitsubishi.

Although no mini-CAES units are in commercial operation at present, they are considered to have reached the demonstration or commercialization stage for two reasons. First, the necessary plant components are all commercially available from a variety of turbomachinery manufacturers. Second, the technology for both locating and constructing suitable storage caverns has been used for over 30 years in the natural gas industry. Natural gas is often stored in underground caverns. Construction time for these units is expected to be about 2-1/2 years.³

1A.A.5.2.2 Cost and Performance. The first US CAES unit is being constructed for AEC and is expected to begin commercial operation in early 1991. The total capital cost of this 110 MW AEC unit is expected to be approximately \$520/kW in 1989 dollars.¹ EPRI-funded studies have produced capital cost estimates for both mini- and maxi-CAES units. Table 1A.A.5-3 gives capital costs for four different size units.

The annual operating and maintenance (O&M) cost for a CAES unit depends heavily on the costs of both fuel and off-peak electricity. For example, assuming that natural gas costs \$3.5/MBtu and off-peak electricity costs \$20/MWh, the estimated operating cost for a maxi-CAES unit would be \$29.5/MWh.

The West German NWK 290 MW unit, which went into commercial operation in 1978, had the following average reliability parameters from 1980 through 1984.

- Availability--89.1 percent.
- Starting reliability--98.2 percent.
- Forced outage rate--19.3 percent.
- Unscheduled outage rate--1.4 percent.³

Performance data for the AEC 110 MW unit, which is expected to enter commercial operation in early 1991, are presented in Table 1A.A.5-4.

1A.A.5.2.3 Required Resources. Other than the requirements for underground storage, the principal resource requirements for CAES units are fuel and electricity. As is the case for combustion turbine units, CAES units combine fuel, such as natural gas and fuel oil, with the compressed air in the combustion chambers to produce the hot gases necessary to power the turbines. However, for a given MW size, the CAES unit uses only about one third of the fuel required by combustion turbines since about two thirds of the CAES expanders' power will not be needed to run the compressors.³ These compressors are, instead, powered by off-peak electricity from the local grid.

The major resource requirement for a CAES unit is the underground cavern for storage of the compressed air. Figure 1A.A.5-2 illustrates the three types of storage.

According to past EPRI-funded studies, possible storage sites exist in about three fourths of the land area in the United States. Potential hard-rock sites are believed to be the most prevalent of the three.⁶

Storage caverns are created in salt domes (underground salt deposits) by drilling a well into the salt deposit and circulating fresh water to dissolve the salt. The resultant brine solution must then be flushed out to leave the empty storage cavity.⁴ These salt deposits are relatively rare in the United States.

An aquifer consists of a layer of porous sand, gravel, or rock which bears water in the spaces between the individual pieces of material. In order to use an aquifer for a CAES application, it must be shaped like an inverted bowl, leaving an air space at the top. A layer of tight rock, called caprock, covers the aquifer and acts as a seal for the compressed air stored in the aquifer.⁴ These aquifers are relatively common in the interior portion of the United States.

The last type of storage site is an underground cavern excavated in hard rock. A hard-rock cavern can be of two types: uncompensated and compensated. The uncompensated cavern is the simpler of the two and is basically an excavated cavern. This cavern provides constant-volume and variable-pressure compressed air storage. The compensated cavern includes an excavated cavern, a surface water reservoir, and a water column joining the two. The varying water level in the cavern provides constant-pressure and variable-volume storage of compressed air. The compensated approach allows for a smaller underground cavern, but

requires a surface reservoir of the same volume as the cavern. Of the three storage schemes, hard-rock caverns are the most expensive to develop.⁴ Potential hard-rock sites exist throughout most of the United States.⁶

CAES reservoirs have not been identified in the central Florida area; further geological investigation and exploration are required to find and confirm the feasibility of storage sites.

1A.A.5.2.4 Environmental Impacts. Because CAES units use combustion turbines, they share many of the environmental impacts with combustion turbines. These impacts include the variety of air pollutants emitted. Although both CAES units and normal combustion turbines emit the same types of pollutants, CAES units produce about one third of the emissions that a similar-sized combustion turbine produces because power for the compressor is provided by external baseload generation facilities.

The underground storage sites used by CAES units have similar environmental impacts to those created by the underground storage of natural gas, except that compressed air is not a pollutant. An impact specific to salt dome storage is the disposal of the brine solution produced during the creation of the salt dome cavern. Several disposal methods are available, each with its own regulatory requirements. These methods include disposal in injection wells, ocean dumping, and shipping to salt producers.³

1A.A.5.2.5 References.

1. Robert Pollak, "Status of First U.S. CAES Plant," EPRI Journal, December 1988, pp. 49-52.
2. "CAES - It's More Than Hot Air," Mechanical Engineering, January 1982, pp. 20-23.
3. Proceedings: Regional Conferences/Workshops on Small Compressed-Air Energy Storage (Mini-CAES) Plants - A New Option, EPRI EM-4445 Proceedings, Project 1084-11, February 1986.
4. Robert L. Longardner and Anthony Visnesky, "Air Power Boosts Utility Energy Supplies," Civil Engineering, July 1988, pp. 57-59.
5. Energy Technology Status Report, California Energy Commission, October 1988, pp. 4-243, 244.
6. Robert Schainker, "Compressed-Air Energy Storage," EPRI Journal, December 1983, pp. 61-62.

1A.A.5.3 Underground Pumped Hydroelectric Storage

Underground pumped hydroelectric (UPH) storage is similar to conventional pumped hydroelectric storage. In both cases, energy is stored by pumping water from a lower level to an upper reservoir, and energy is returned to the power system when water is allowed to flow back through the hydraulic turbine powering the generator. For UPH, the lower reservoir is either an existing underground cavern or a newly excavated cavern at a selected depth.

During peak generating hours, water released from the upper reservoir powers the turbine generator, then discharges into the lower reservoir. The energy generated is sold at peak rates. Nightly or weekly, depending on the storage capacity of the reservoirs, the same equipment, powered by off-peak electricity, is used in reverse to pump the water from the lower reservoir to the upper reservoir during off-peak hours. In situations where a ready supply of excess (hence, lower priced) baseload power is available, the economic tradeoffs can be attractive.

1A.A.5.3.1 Technological Maturity. Underground pumped storage uses commercially available equipment and is, therefore, not classified as a new technology. However, the concept of using an underground cavern remains unproved, both technically and economically. A consortium is currently studying the feasibility of using an existing mine to house power generation equipment and an underground lower reservoir. The Summit Pumped Storage Project, located near Akron, Ohio, is estimated to cost \$993 million and will have a capacity of 1,500 MW (\$662/kW). A formal license application was recently submitted to the Federal Energy Regulatory Commission. It is anticipated that the licensing process will take approximately two additional years to complete. Specifications will then be issued for equipment supply and construction services.

A second underground pumped storage project at the Mt. Hope site in New Jersey is being considered for license. This facility is to use an existing mine shaft. Additional excavation may be required to expand the capacity of the lower reservoir. Estimated project costs are similar to the Summit estimate, and size estimates have ranged from 1,000 to 2,000 MW.

1A.A.5.3.2 Cost and Performance. The costs to complete a pumped storage project can be as low as \$200/kW for a 2,400 MW plant or as high as \$2,000/kW for a 60 MW plant. A DOE/EPRI study estimated the cost of a 2,000 MW UPH storage facility at \$930/kW. The lower end of the cost spectrum compares

favorably to other technologies because many pumped storage plants are projected to have a capacity of 1,000 MW to 3,000 MW. However, the dollar per kW value is not the only economic issue to be considered. The price differential between peaking power and baseload or off-peak power is of critical importance.

Economic considerations are highly site-specific and depend on the fuel and generation mix of a given region. With low gas and oil prices, pumped storage is very difficult to economically justify even under ideal site conditions. The few operating plants in the United States were mostly built during the mid-1970s when experts predicted skyrocketing fuel prices and fossil fuel shortages. UPH performance is best described by an overall cycle efficiency and unit availability. A 76 percent overall cycle efficiency and an 83 percent unit availability have been estimated for a 2,000 MW facility with a storage capacity of 20,000 MWh. The unit availability estimate includes both long- and short-term planned outages.

Cycle efficiency components for UPH facilities are expected to be similar to those of conventional pumped hydro storage facilities of (66 to 78 percent). Typical plant capacity factors are of the order of 30 percent or less.

1A.A.5.3.3 Required Resources. The principal resource requirements for a UPH facility include sufficient water supply for fill water and makeup water for both reservoirs, adequate land area for surface facilities and the upper reservoir, and hard-rock formations at appropriate depth for the lower reservoir. The availability of an existing cavern is desirable because fewer excavation activities are required.

No resources have been identified in the central Florida area; further geological investigation would be required to identify and assess potential sites.

1A.A.5.3.4 Environmental Impacts. Pumped storage creates changes in the environment which must be studied for each individual project. First, the continuous water level fluctuations in the two reservoirs can cause problems for shore dwelling creatures and plants. Second, the water being pumped back up to the upper reservoir is often at a much different temperature than the water already in the reservoir. Depending on how and where this water is introduced into the reservoir, thermal stratification can occur. The results of such thermal stratification on the indigenous fish population must be studied to satisfy FERC requirements.

As with conventional hydro plants, using intake screens greatly reduces the impact of a pumped storage plant on the local fish population. The environ-

mental impacts of flooding new land and directing flows away from existing river channels must be examined before the Federal Energy Regulatory Commission (FERC) will issue a new license or modify an existing license. The FERC and its predecessors have been licensing hydroelectric plants since the 1930s. The FERC monitors the safety of the dams and tries to ensure that the nation's water resources are used effectively and safely.

1A.A.5.3.5 List of Literature.

1. "Preliminary Inventory of Hydropower Resources," National Hydroelectric Power Resources Study, Volume 5, Southeast Region, US Army Corps of Engineers Institute for Water Resources and Hydrologic Engineering Center, July 1979.
2. "Preliminary Inventory of Hydropower Resources," National Hydroelectric Power Resources Study, Volume 5, Northeast Region, US Army Corps of Engineers Institute for Water Resources and Hydrologic Engineering Center, July 1979.
3. Hydroelectric Power Resources of the United States, Developed and Undeveloped, Federal Energy Regulatory Commission, Washington, DC, January 1, 1984.
4. "Mining New Electricity," Engineering News Record, Volume 217, Number 9, August 28, 1986.
5. Preliminary Design Study of Underground Pumped Hydro and Compressed-Air Energy Storage in Hard Rock, DOE and EPRI, EPRI EM-1589, DOE/ET 5047-1, Final Report, Volume 1, May 1981.
6. David C. Willett, Vice-President, Acres International Corp., in personal communication to G. V. Beard, February 1, 1989.

Table 1A.A.5-1
Generic 40 MWh Lead-Acid Battery Storage Characteristics

	<u>Lead-Acid Battery Storage</u>
Output Power, MW ac	10
Output Voltage, kV ac (three-phase) ^a	13.8
Nominal Discharge Duration (full load), hours	4
Battery Energy Capacity (end of life), MWh dc	42.1
Interface Voltage, volts dc (nominal)	
Baseline	1,052
Alternate ^b	2,104
Roundtrip Efficiencies, percent	
Battery (dc-dc, full load) ^c	78
Power Conditioning System (ac-ac, full load)	94
Overall Plant (250 cycles per year)	
Annual, full load	72
Annual, 25-percent load	76
Battery Cycle Life (warranty), cycles ^d	2,000

^aThe Chino battery facility substation is a nominal 12 kV.

^bThe Chino battery facility is a nominal 2,000 volts.

^cIncludes battery equalization (20 percent overcharge) every 20 cycles.

^dTests on the Chino batteries suggest that 6,000 deep discharge cycles are possible. These performance data are based upon current lead antimony plate construction design.

Sources:

Design and Costs for a Generic 10 MW Utility Lead-Acid Battery Energy Storage Plant, EPRI AP-5845, June 1988.

Douglas Morris, "The Chino Battery Facility," EPRI Journal, March 1988, pp. 46-50.

Table 1A.A.5-2
 Cost Estimates for a Generic 40 MWh Lead-Acid Battery
 Plant (Mature Market) (1990\$)

	<u>Lead-Acid Battery Storage</u>
Net Power Output, MW ac	10
Total Direct Capital Cost, \$/kW (1990\$)	900
Fixed O&M Cost, \$/kW-yr (1990\$)	24
Variable O&M Cost, \$/MWh (1990\$)	2.2

Table 1A.A.5-3
Capital Cost Estimates for CAES Plant* (January 1989\$)

<u>Storage Method</u>	<u>Capital Cost (\$/kW)</u>			
	<u>25 MW</u>	<u>50 MW</u>	<u>100 MW</u>	<u>220 MW</u>
Aquifer	680	530	520	630
Salt Dome	740	550	530	640
Hard Rock	1,300	940	830	690

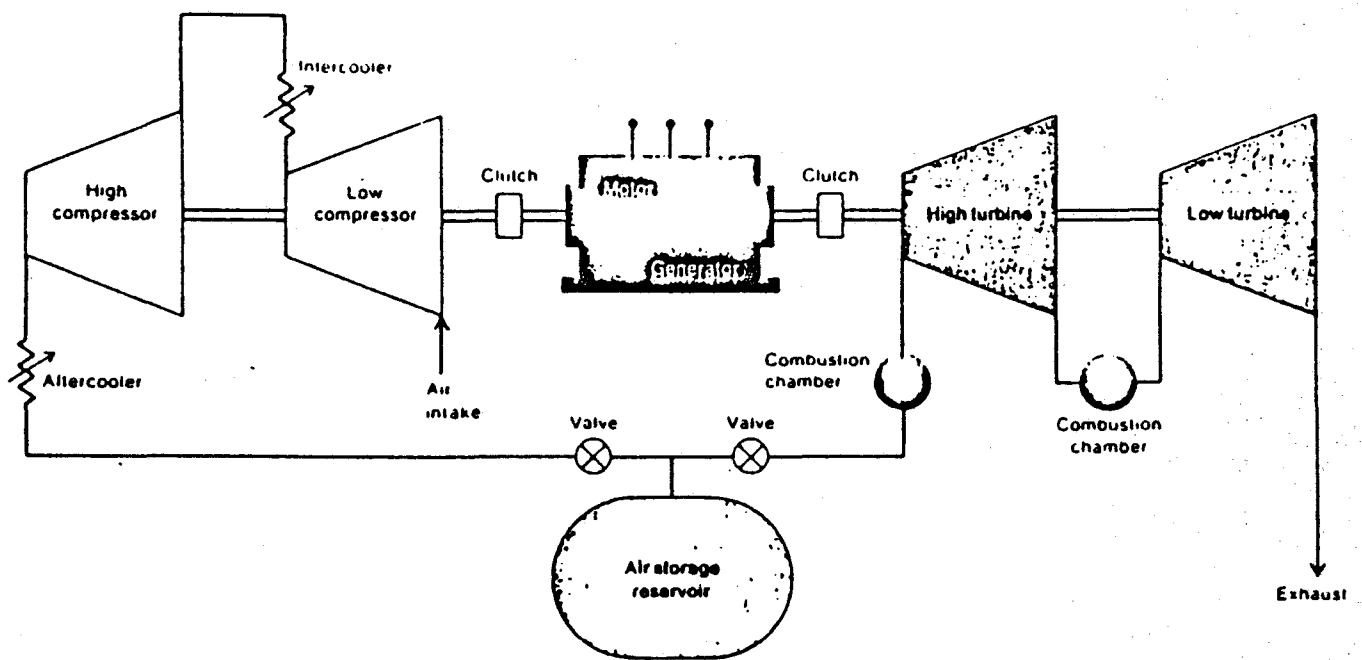
*Estimates are for 10 hours of storage. Escalation and AFUDC are not included.

Table 1A.A.5-4
Performance Data for 110 MW AEC CAES System

<u>Parameter</u>	<u>Value</u>
Generating Capacity, MW	110
Charging Ratio, hours charging/hours generation	1.7:1
Storage, hours	26
Cavern storage volume, ft ³	19 million
Inlet Temperature, HP Turbine, F	1,000
Inlet Temperature, LP Turbine, F	1,600
Heat Rate, natural gas, Btu/kWh	4,122
Heat Rate, fuel oil, Btu/kWh	4,089
Energy Ratio, kW input to compressors/ kW output from turbines	0.818

Source:

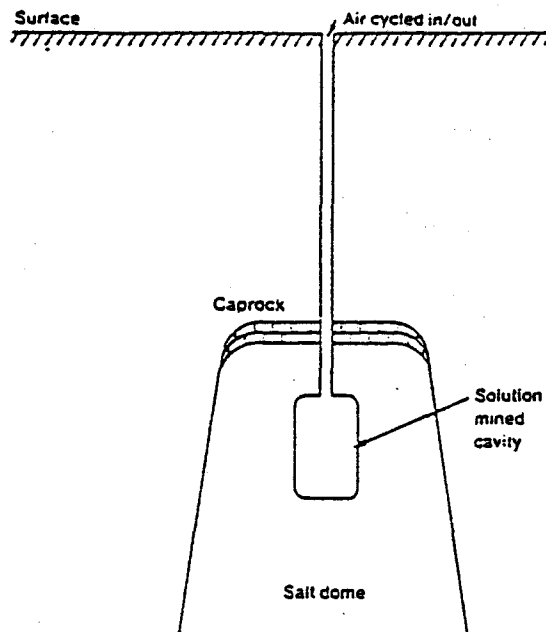
Robert Pollak, "Status of First U.S. CAES Plant," EPRI Journal, December 1988, pp. 49-52.



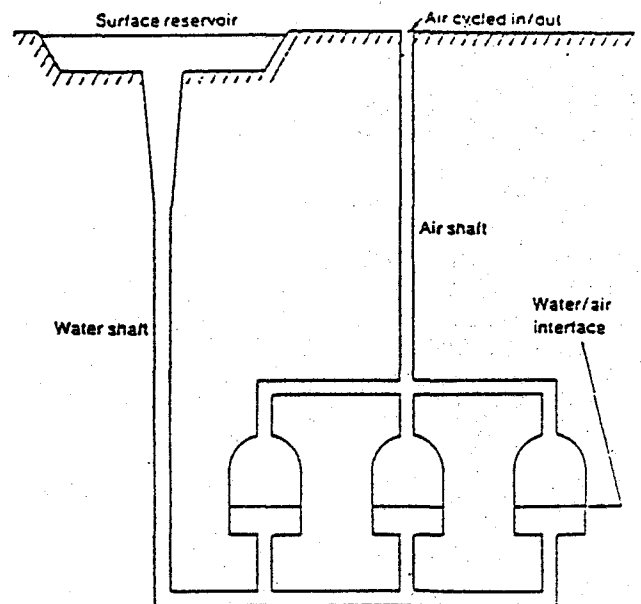
Source: Mechanical Engineering, January 1982

CAES PLANT CONCEPT

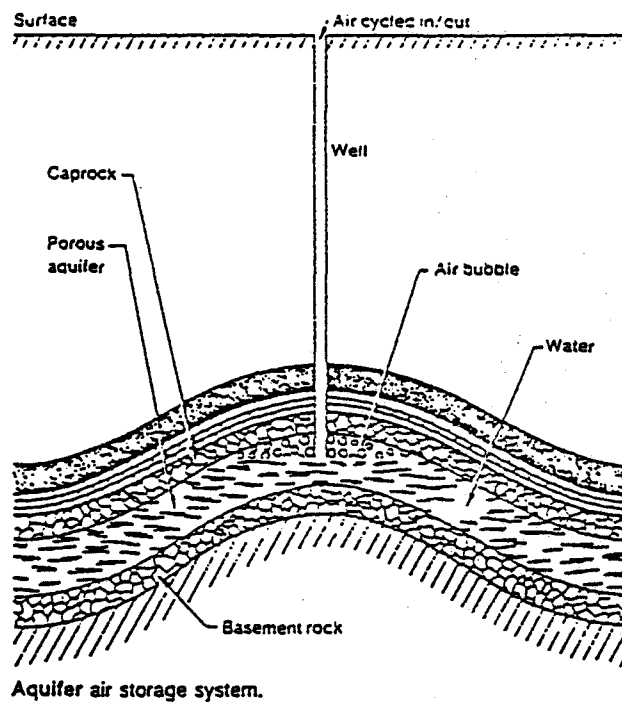
Figure 1A.A.5-1



Conceptual CAES cavern in salt dome.



Water-compensated hard rock cavern CAES system.



Source: Mechanical Engineering, January 1982

CAES CAVERN CONCEPTS

Figure 1A.A.5-2

**ORLANDO UTILITIES
COMMISSION
CURTIS H. STANTON
ENERGY CENTER**

UNIT 2

**SUPPLEMENTAL
SITE
CERTIFICATION
APPLICATION**

VOLUME 1B

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT 2

SUPPLEMENTAL
SITE CERTIFICATION APPLICATION

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UNIT 2

SUPPLEMENTAL
SITE CERTIFICATION APPLICATION

VOLUME 1B

Stanton Energy Center Unit 2
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**Orlando Utilities Commission
Curtis H. Stanton Energy Center
Unit 2
Supplemental
Site Certification Application
Volume 1B**

1B.1.0 Overview and Summary

1B.1.1 Overview

For many years, the Orlando area has been one of the fastest growing areas in the country. Annual growth in net energy for load for the Orlando Utilities Commission (OUC) has averaged 4.6 percent for the last 10 years. OUC has experienced not only a large growth in residential customers during this period, but also a tremendous growth in commercial loads as Orlando has become the tourist capital of the world and developed into a diverse business center.

OUC has strived to meet their responsibility to supply residential and commercial loads in a reliable manner at the lowest achievable cost while maintaining a concern for the environment. One measure of OUC's success is that OUC's rates have consistently remained among the lowest in state, in spite of the rapid growth. Another measure of OUC's success is its AAA bond rating on senior lien debt from Duff and Phelps Inc. OUC is the only municipal utility in the country to have this high rating.

OUC is committed to meeting their customers' needs through a combination of demand- and supply-side resources. OUC, one of the conservation leaders in the state, has been promoting conservation programs since 1973, six years before the passage of the Florida Energy Efficiency and Conservation Act (FEECA). OUC has 10 active conservation programs filed with the Florida Public Service Commission (PSC) and continues to evaluate the cost-effectiveness of additional conservation efforts. In 1987, OUC retained Southern Electric International (SEI) to conduct a comprehensive long-range power supply and demand-side planning study. The study was completed in 1989 after a thorough evaluation of demand-side alternatives. The study recommended that OUC pursue two additional demand-side alternatives in the areas of residential time of use rates and commercial thermal energy storage. OUC has continued to pursue development of these programs as described later in the application. To further address conservation and to further assure that there were no cost-effective conservation measures available which could mitigate the need for Stanton 2, OUC retained Battelle to reevaluate demand-side alternatives. The results of Battelle's evaluations are also contained later in the application. OUC remains committed to the implementation of conservation programs that provide benefits to all customers. However, the success of OUC's supply-side programs makes

cost-effective conservation difficult to achieve for a number of demand-side alternatives not already implemented.

As discussed earlier, in 1987 OUC retained SEI to evaluate both supply- and demand-side alternatives. After incorporating potential demand-side savings, SEI recommended the addition of Stanton 2 as a jointly owned unit with OUC selling a portion of its capacity during the early years of ownership. This recommendation is completely consistent with OUC's past strategies for supply-side alternatives. OUC has a long history of joint ownership projects in which OUC has constructed and managed the project and in which other utilities have constructed and managed the project. This concept allows all participating utilities to enjoy the economies of scale associated with large projects while equitably sharing the responsibility for providing the necessary resources such as cooling water and air quality increments from their respective service areas. OUC is a participant in the Crystal River 3 nuclear unit constructed by Florida Power Corporation, the St. Lucie 2 nuclear unit constructed by Florida Power & Light, and the McIntosh 3 coal unit constructed by the City of Lakeland. OUC has constructed the Stanton 1 coal unit and the Indian River A and B combustion turbine projects in which several cities are participants either individually or through the Florida Municipal Power Agency (FMPA).

OUC also employs a strategy of selling excess system capacity and specific unit power capacity for extended periods of time. This again allows OUC to enjoy the benefits of economies of scale and to share these benefits with the purchasing utility. Further savings through economy interchange and central dispatch are obtained through OUC's participation in the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland, and the FMPA All Requirements Project.

In 1981, OUC petitioned the PSC for a determination of need for Stanton 1 for operation of the unit in 1987. Evaluations indicated that Stanton 1 would not be needed for capacity purposes until 1992, but would provide savings due to a reduction in consumption of oil. The PSC approved the need for Stanton 1 to displace oil. Not only did Stanton 1 reduce consumption of oil, but growth in the Orlando area continued to be greater than expected and resulted in a need for Stanton 1's capacity by 1987 as well. Since its commercial operation in July 1987, Stanton 1 has met every expectation. It has provided OUC with generation using low cost domestically produced coal instead of expensive foreign oil. Stanton 1

was completed five months ahead of schedule and \$10 million under budget. For the first three years of commercial operation, Stanton 1 has operated at an equivalent availability of 84.54 percent. Stanton 1 uses treated sewage water for cooling from the Orange County Eastern Subregional Wastewater Treatment Plant without any offsite wastewater disposal. Stanton 1 and 2 will each consume about 4.5 mgd of treated sewage effluent from the treatment plant, thus helping to solve one of the region's most pressing environmental needs. The use of treated sewage effluent for cooling also helps preserve the potable water resources in the area for future uses. Stanton 1 uses a wet limestone scrubber for SO₂ removal and a precipitator for particulate control.

By replicating Stanton 1, Stanton 2 is expected to achieve the same outstanding level of performance at a significant cost savings. Replicating the major equipment from Stanton 1 is expected to save \$23 million in capital cost. Experience gained in the design, construction, and operation of Stanton 1 will be incorporated into Stanton 2. Advances in technology since Stanton 1 will also be incorporated into Stanton 2.

OUC has strived to maintain a diverse mix of fuels which results in the ability to generate reliably and at low cost even during periods of high fuel cost or supply disruptions. Stanton 2 will further diversify OUC's mix by adding additional coal fueled capacity to the existing mix of coal, oil, gas, and nuclear. OUC's Indian River Units provide OUC with the unique opportunity to generate a large portion of its energy requirements using oil or natural gas if the prices for these fuels become attractive.

OUC has always been committed to preserving the environment. Environmental equipment and construction costs for Stanton 2 amount to \$114 million of the \$522 million capital cost estimate. Included in that cost are a wet limestone flue gas scrubber for SO₂ removal and low NO_x burners which reduce NO_x emissions to a guaranteed level of 0.32 lb NO_x/MBtu or over 45 percent below the New Source Performance Standards of 0.60 lb NO_x/MBtu. In addition, OUC contracted to burn a significantly lower sulfur coal in Stanton 1 than was required by its air quality permit. The design flexibility of Stanton 1 to burn higher sulfur coals contributes to minimizing the additional cost for the lower sulfur coal by increasing the competition among coal suppliers. OUC desires to obtain maximum flexibility for coal combustion in Stanton 2 so that low sulfur coals would continue to compete with other available sources.

As discussed in the remainder of this application, OUC has evaluated appropriate alternatives to Stanton 2 to determine if any are lower in cost. As part of that evaluation process, OUC together with the Florida Municipal Power Agency (FMPA), and Kissimmee Utility Authority (KUA), the joint participants in Stanton 1 and 2, issued a joint request for proposals for power supply as an alternative to Stanton 2. Three bids were received and independently evaluated in detail by R. W. Beck as described in Volume 1A. The least cost bid resulted in cumulative present worth costs that were 19.2 percent higher than costs for Stanton 2. As a result, OUC rejected all the bids and is pursuing the construction of Stanton 2.

OUC believes that Stanton 2 represents a unique opportunity for capacity addition. Stanton 2 represents minimal cost and performance risk due to the replication of Stanton 1. As demonstrated in this application, Stanton 2 represents OUC's least cost alternative that has been demonstrated through continuing extensive evaluations as well as a thorough test of the marketplace.

1B.1.2 Summary

OUC's loads are projected to grow at an annual average rate of 4.0 percent through 2000 and 3.2 percent through 2020. This continued rapid load growth results in a need for capacity addition by 1997 based on a 15 percent reserve margin. With a 0.5 percent expected unserved energy (EUE) criterion, OUC will need to add capacity in 1996. The use of either criterion indicates a need for the Stanton 2 capacity by January 1, 1997.

OUC's corporate model indicates that OUC can install Stanton 2 while maintaining base rate increases below the level of inflation prior to Stanton 2's commercial operation. After Stanton 2's commercial operation, OUC's base rates are projected to decrease.

As a replication of Stanton 1, Stanton 2 is expected to experience a high level of reliable performance. Stanton 2 is projected to maintain an equivalent availability rate of 83 percent with a 4 percent equivalent outage rate. This compares to an average equivalent availability of 84.5 percent and an average equivalent forced outage rate of 4.8 percent for Stanton 1 for the first three years of operation.

Stanton 2 will be designed to burn a wide range of domestically available coals, assuring a reliable fuel supply.

OUC has evaluated all viable alternatives to Stanton 2 including the extensive bidding process for independent power supply. The lowest cost bid was 19.2 percent higher than Stanton 2. Evaluation of OUC owned supply-side alternatives indicates that Stanton 2 is 4.8 percent lower in cost than the next lowest cost alternative which is a combined cycle unit. Stanton 2 is also the least cost alternative for OUC under both the high and low growth sensitivity evaluations.

OUC's 330 MW ownership share will supply OUC's projected capacity needs until 2010.

OUC continually evaluates and implements conservation measures which are beneficial to all customers. OUC retained Battelle to further evaluate conservation to assure that there are no cost-effective conservation measures which could mitigate the need for Stanton 2. While Battelle determined that additional conservation programs to encourage replacement of resistance heating with heat pumps and to encourage efficient commercial lighting appear to be cost-effective to OUC, these programs were not cost-effective for nonparticipating

customers. Nevertheless, even if OUC were to adopt these programs, the 14 MW peak demand reduction projected to be attainable by these programs does not affect the need for Stanton 2 in 1997.

1B.2.0 OUC System Description

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 plants 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.

OUC's electric system provides power to customers within the city and certain contiguous areas encompassing approximately 224 square miles. As of September 30, 1990, the electric system had 117,451 active services. Of these, 101,381 are residential services, 13,596 are general service nondemand services, and the remaining 2,474 are general service demand services.

OUC presently has ownership interests in five electric generating plants or units as follows: (1) Indian River Plant Steam Turbine Units 1, 2, & 3 and Indian River Plant Combustion Turbine Units A & B, (2) Stanton Energy Center Unit 1, (3) Florida Power Corporation Crystal River Unit 3 Nuclear Generating Facility, (4) City of Lakeland McIntosh Unit 3, and (5) Florida Power and Light Company St. Lucie Unit 2 Nuclear Generating Facility. These generating facilities and OUC's ownership share are more specifically described in Table 1B.2.0-1.

OUC has committed to purchase and install two additional combustion turbine generating units at the Indian River Plant in 1992. These units will be jointly owned by OUC (79 percent) and the Florida Municipal Power Agency (FMPA) (21 percent). These units, designated Combustion Turbine Units C & D, along with the original Combustion Turbine Units A & B, will provide peaking, quick start, black start, and emergency capability for OUC and FMPA. Indian River Combustion Turbines C & D are more specifically described in Table 1B.2.0-2.

OUC's generating system has been designed over the years to take advantage of fuel diversity and the resultant system reliability and economic benefits. The two generating plants operated by OUC are an example. The Indian River Plant which began operation in 1960 utilizes natural gas or oil as fuel. The Stanton Energy Center is the other plant operated by OUC. It consists of a coal fired unit

which became commercially available in 1987. OUC's longstanding intent to achieve diversity in its fuel mix is further evidenced by its participation in other generating facilities in the State of Florida. The first such endeavor occurred in 1977 when OUC secured a share of the Crystal River Unit 3 nuclear plant. In 1982, OUC acquired an ownership share of the City of Lakeland's McIntosh Unit 3 coal fired unit. In 1983, OUC acquired a share of the St. Lucie Unit 2 nuclear unit. OUC's future and projected capacity mix is shown below.

	<u>Coal</u> Percent	<u>Nuclear</u> Percent	<u>Gas/Oil</u> Percent
Current	36.8	5.4	57.8
After CT C&D	31.5	4.6	63.9
After Stanton 2	44.5	3.8	51.7

To supplement OUC's commitment to supply electricity to its customers in a reliable and economic manner, two other steps have been taken. OUC currently maintains interchange agreements with the other utilities in the State of Florida for the provision of electrical energy during emergency conditions, short- and long-term capacity shortages, and for economic considerations. In 1988, OUC joined with the City of Lakeland and Florida Municipal Power Agency's All Requirements Project members to form the Florida Municipal Power Pool (FMPP). This is an operating type electric pool. FMPP dispatches all of the generating resources of the pool members in the most economical manner to meet the total load requirements of the pool. The central dispatch is providing savings to all parties because of reduced commitment costs and lower overall fuel costs. OUC serves as the FMPP dispatcher and handles all accounting for the allocation of fuel expense and savings. The term of the pool agreement is one year and automatically renews from year to year until terminated by the consent of all participants.

OUC's existing transmission system consists of approximately 250 miles of 230 kV and 115 kV lines and cables. The system interconnects the generating facilities with 18 substations. OUC is fully integrated into the state transmission grid through its nine 230 kV interconnections with other generating utilities which are members of the Florida Electric Power Coordinating Group including five interconnections with Florida Power Corp., two with Kissimmee Utility Authority, and one each with Florida Power & Light and the City of Lakeland. Figure 1B.2.0-1 shows OUC's service area and transmission system.

List of Abbreviations
Used in Tables 1B.2.0-1 and 1B.2.0-2

<u>Reference</u>	<u>Abbreviation</u>	<u>Definition</u>
Unit Type	N	Nuclear
	ST	Fossil Steam
	CT	Combustion Turbine
	C	Coal Fired

<u>Reference</u>	<u>Abbreviation</u>	<u>Definition</u>
Fuel Type	U	Uranium
	NG	Natural Gas
	F06	#6 Fuel Oil
	F02	#2 Fuel Oil
	C	Coal
	--	None

<u>Reference</u>	<u>Abbreviation</u>	<u>Definition</u>
Fuel Transportation	TK	Truck
	RR	Railroad
	PL	Pipeline
	WA	Waterborne
	--	None

<u>Reference</u>	<u>Abbreviation</u>	<u>Definition</u>
Status	U	Under Construction. Less Than 50 Percent Complete.

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Table 1B.2.0-1
Orlando Utilities Commission
Existing Generating Facilities
as of January 1, 1991

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	
Plant	Unit No.	Location	Unit	Primary	Alternate	Fuel Transportation		Commercial	Expected	Gen Max	Net Capability - MW		
			Type	Fuel	Fuel	Primary	Alternate	In-Service	Retirement	Nameplate	Summer	Winter	
								Date	Date	Capacity			
								(Mo/Yr)	(Mo/Yr)	(kW)			
Indian River		Brevard											
	Unit #1	County	ST	NG (1)	F06	PL	WA	2/60	2/10	86,700	88	90	
	Unit #2		ST	NG (1)	F06	PL	WA	12/64	12/14	207,600	201	205	
	Unit #3		ST	NG (1)	F06	PL	WA	2/74	2/24	344,500	349	353	
	CT A		CT	NG	F02	PL	TK	6/89	6/14	41,400	18 (2)	22 (2)	
	CT B		CT	NG	F02	PL	TK	7/89	7/14	41,400	18 (2)	22 (2)	
Stanton Energy Center		Orange											
	Unit #1	County	C	BIT	-	RR	-	7/87	7/27	464,580	301 (3)	305 (3)	
Crystal River		Citrus											
	Unit #3	County	N	UR	-	TK	-	3/77	3/17	890,460	13 (4)	13 (4)	
McIntosh		Polk											
	Unit #3	County	C	BIT	TK	RR	TK	9/82	9/22	363,870	133 (5)	136 (5)	
St Lucie		St Lucie											
	Unit #2	County	N	UR	-	TK	-	8/83	8/23	850,000	51 (6)	52 (6)	
Total												1,172	1,197

Notes:

- (1) These Units are Permitted to Use and are Capable of Using Natural Gas and/or Oil as Their Primary Fuel.
- (2) OUC's Ownership Share (48.8% of 37/46 MW)
- (3) OUC's Ownership Share (68.5542% of 439/445 MW)
- (4) OUC's Ownership Share (1.6015% of 816/827 MW)
- (5) OUC's Ownership Share (40.0% of 332/340 MW)
- (6) OUC's Ownership Share (6.08951% of 839/853 MW)

See page 1B.2.0-4 for list of abbreviations.

1B.2.0-4

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Table 1B.2.0-2
Orlando Utilities Commission
Proposed Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Plant	Unit No.	Location	Unit Type	Primary Fuel	Alternate Primary	Alternate	Fuel Transportation	Commercial In-Service Date	Gen Max Nameplate kW	Net Capability - MW		Status
Indian River	CT C	Brevard County	CT	NG	F02	PL	TK	9/92	160,000	82 (1)	102 (1)	U
	CT D		CT	NG	F02	PL	TK	10/92	160,000	82 (1)	102 (1)	U

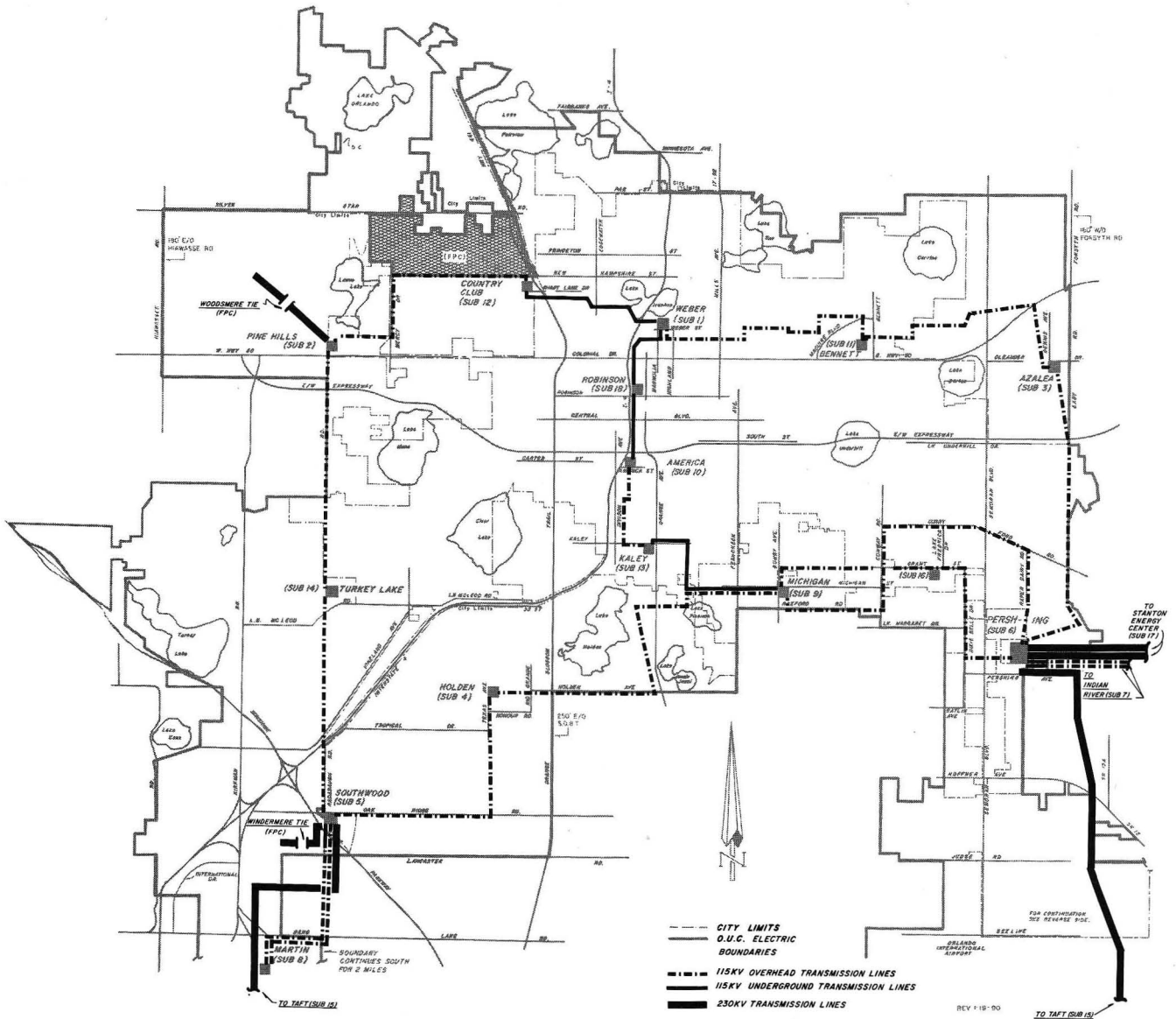
Notes: (1) OUC Ownership Share (79 percent of 104/129 MW)

See page 1B.2.0-4 for list of abbreviations

1B.2.0-5

Image Quality

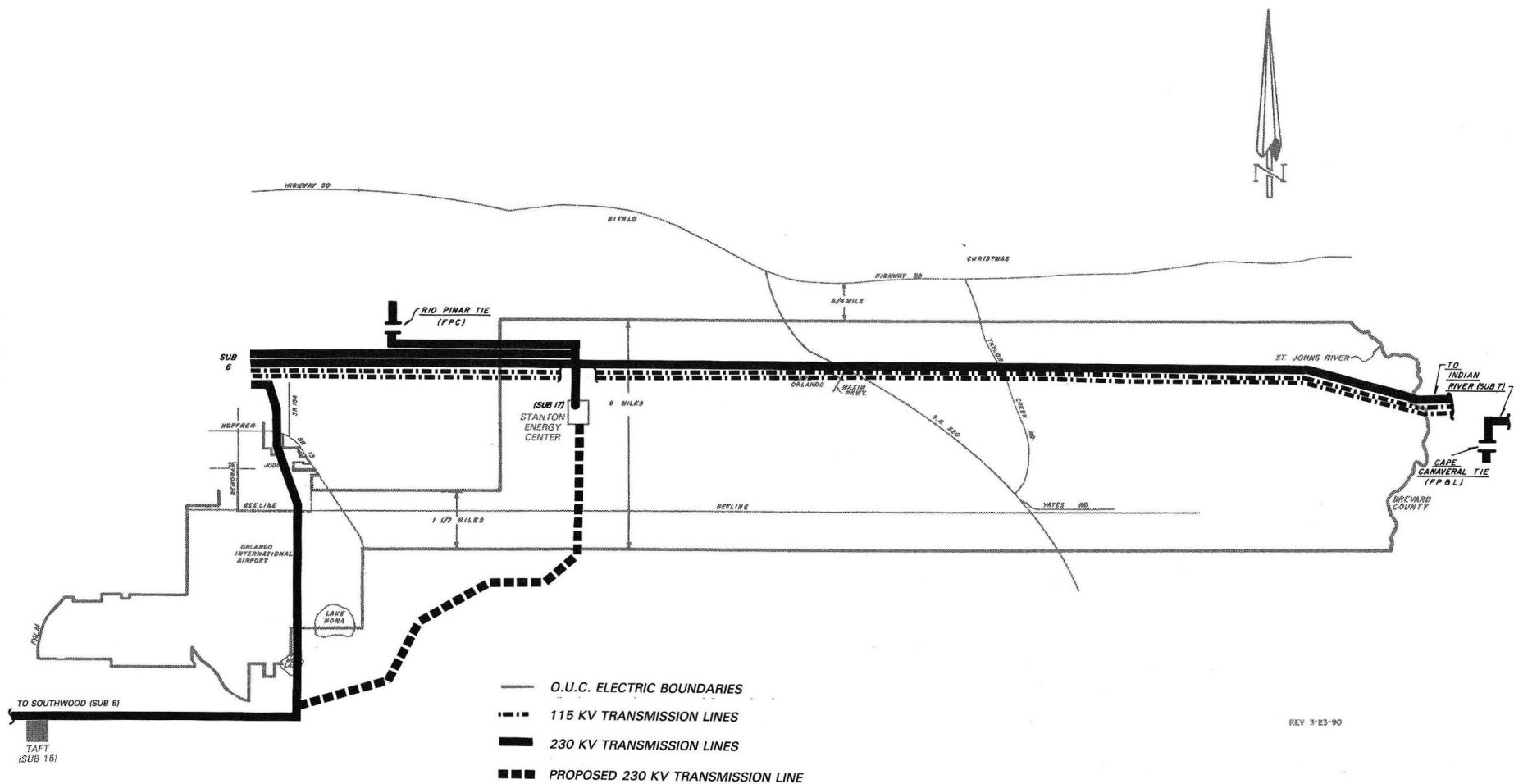
As you review the next group of images, Please note that the original documents were of poor quality.



ORLANDO UTILITIES COMMISSION
ELECTRIC BOUNDARY AND TRANSMISSION MAP

Figure 2.0-1
Sheet 1 of 2

1B.2.0)-7



ORLANDO UTILITIES COMMISSION
ELECTRIC BOUNDARY AND TRANSMISSION MAP

Figure 2.0-1
Sheet 2 of 2

1B.3.0 Methodology

This section describes the methodology used to analyze OUC's power supply and demand-side requirements. The purpose of the power supply planning process is to meet OUC's customers' electricity needs as economically as possible while also giving due consideration to reliability, environmental impact, financial security, regulatory aspects, and other considerations.

1B.3.1 Evaluation Criteria

The first step in the power supply planning process is to establish evaluation criteria. Evaluation criteria include economic and demographic forecasts, financial assumptions, and fuel price projections. Evaluation criteria applicable to all applicants are presented in Volume 1A, Subsection 1A.3.0. Evaluation criteria specific to OUC are presented in Subsection 1B.4.0 of this Volume.

1B.3.2 Load Forecast

The OUC system load forecast is presented in Subsection 1B.5.0. The load forecast was developed using the end-use/econometric methodology for projecting residential, commercial and industrial customers, and energy and demand.

1B.3.3 Demand-Side Management

The potential for economic application of demand-side management programs is discussed in Subsection 1B.6.0. The evaluation consists of a cost-effectiveness screening of potential programs. A subsequent load shape modification analysis is performed on the selected programs. The modified load shapes along with appropriate costs and savings serve as input to the detailed production cost model for evaluation.

1B.3.4 Reliability Criteria

Subsection 1B.7.0 presents the reliability criteria used to identify timing for capacity additions. A 15 percent reserve margin is used to determine capacity addition requirements. The 15 percent reserve margin is supported by the use of a 0.50 percent Expected Unserved Energy (EUE) criterion. The criteria are based on findings in the OUC Long-Range Power Supply and Demand-Side Planning Study developed by Southern Electric International in May 1989, and subsequent updates of these findings by OUC.

1B.3.5 Supply-Side Alternatives

Specific supply-side alternatives that are candidates for meeting OUC's capacity expansion requirements are identified in Subsection 1B.8.0 including municipal solid waste, combined cycle conversion, and qualifying facilities. Conventional alternatives and advanced alternatives are presented in Volume 1A, Subsection 1A.5.0. Typical plant sizes, capital costs, and operating parameters are developed. Options that are not commercially available or that pose an unacceptable economic or technical risk are eliminated.

1B.3.6 Supply-Side Alternative Screening

The economics of the applicable supply-side alternatives are compared using screening curves in Subsection 1B.9.0. These graphs present comparative revenue requirements required for construction and operation of the applicable supply-side generation options versus capacity factor. The generation options are normalized on a \$/kW-yr basis in order to more easily compare different capacities. The capital revenue requirements for each unit are based on the capital investment of the generation option and OUC's levelized fixed charge rate. The operating costs (fuel and operation and maintenance) are levelized over a 25-year period using OUC's present worth rate. The unit's full load heat rate is used to determine fuel costs.

The capital cost plus operating costs are plotted versus capacity factor. At zero capacity factor the y-intercept indicates the fixed revenue requirements associated with the unit, while the slope indicates the variable revenue requirements. Several supply-side options are plotted on the same graph. The lowest curve at a particular capacity factor is the least cost alternative at that capacity factor. When curves do not intercept, it indicates that the upper curve is expected to be higher cost at all capacity factors and potentially may be eliminated from further study.

When curves intercept, it indicates that one alternative is least cost in a range of capacity factors while another option is least cost in a different range. The purpose of the screening curves is to reduce the number of options which are carried forward to the detailed economic analysis. Care must be taken when using this method. The results must be considered preliminary because interaction with other system units and unit availability are not considered.

1B.3.7 Alternative Plan Development

Alternative plans are developed in Subsection 1B.10.0. Plans are developed based on results of the supply-side screening. Plans are developed which incorporate generation, and demand-side management. The plans developed schedule generation as required to meet the reliability criteria developed in Subsection 1B.7.0.

1B.3.8 Economic Analysis

In Subsection 1B.11.0, the economics of the alternative plans developed in Subsection 1B.10.0 are compared. The results are examined to determine which plans best meet the needs of OUC's customers.

The alternative plans are evaluated on a comparative cost basis. Comparative costs include only those costs which are affected by differences in the plans. The economic analyses determine the annual revenue requirements of items which are affected by the alternative plans. Annual comparative revenue requirements include the following components.

- Fuel costs.
- Operation and maintenance (O&M) costs.
- Capital costs for new generation.
- Demand-side management costs and benefits.

Black & Veatch's POWRPRO chronological production cost simulation program is used to model OUC's system for each plan. Annual system fuel and O&M costs are developed for each plan. Production cost simulation is necessary to incorporate the effect upon the operation of the existing units due to the new unit additions.

Other costs, such as demand-side management costs, are added to production costs to provide annual comparative revenue requirements. OUC's levelized fixed charge rate (developed in Subsection 1B.4.0) is applied to the capital investment of various alternatives to produce the levelized fixed costs.

The objective of the economic analysis is to determine the total present worth of the annual comparative revenue requirements. The total present worth of the annual comparative revenue requirements is the sum of the annual nominal comparative revenue requirements discounted using the present worth discount rate. The discount rate is developed in Subsection 1B.4.0. The cumulative present worth of the annual nominal comparative revenue requirements will form the basis for evaluation of the plans.

The economic analyses yield a base plan which is the most economical mix of supply-side and demand-side alternatives.

1B.3.9 Sensitivity Analysis

The base plan, developed in Subsection 1B.11.0, is tested with a number of alternate assumptions. Sensitivity analyses are prepared for the following parameters.

- High Growth Scenario.
- Low Growth Scenario.
- Fuel prices for the 1989 Planning Hearings.
- Increased capital cost for Stanton 2.

These analyses are presented in Subsection 1B.12.0.

1B.3.10 Strategic Considerations

The economic analysis performed in Subsection 1B.11.0 does not address all aspects which must be considered. The lowest cost plan may not necessarily be the "best" plan when other strategic issues are considered. Strategic considerations must be weighed against the economic analysis to meet future needs in the most appropriate manner. Strategic considerations are presented in Subsection 1B.13.0.

1B.3.11 Financial Analysis

Subsection 1B.11.0 evaluates the alternatives available to OUC based on the cumulative present worth of the comparative annual costs discounted to 1991. Comparative costs do not include costs which would be the same for all plans, i.e., current debt service, expenses for existing transmission and distribution systems, and general and administrative expenses. Including these common costs affects the absolute magnitude of the comparative costs but does not affect the differential. The final decision must consider not only the differential costs, but also the absolute magnitude of the cost impact.

Assessment of the magnitude of the impact is essential to ensure that the recommended option is financially feasible. That is, that OUC can secure the needed capital and that the near-term impact of any capacity addition will not result in an unacceptable rate "shock" to the electric customers. This assessment is made using OUC's corporate model. The results of this analysis are provided in Subsection 1B.15.0.

1B.4.0 Evaluation Criteria

1B.4.1 Economic Parameters

The economic parameters presented in Volume 1A, Subsection 1A.3.2 of the information common to all participants are used for the OUC analyses.

1B.4.1.1 Bond Rate

OUC currently has the following ratings for its senior lien debt: AAA from Duff and Phelps Inc., Aa1 rating from Moody's, and AA from Standard & Poor's. Based on these bond ratings, the AAA municipal bond rates from Volume 1A, Subsection 1A.3.2 would apply. OUC is expected to maintain the current bond rating.

1B.4.1.2 Bond Issuance Fee

A bond issuance fee of 1.0 percent has been provided by OUC's financial advisor and is assumed to apply to OUC bond issues.

1B.4.1.3 Interest During Construction Rate

For evaluation purposes, interest during construction is assumed to be equal to the bond rate increased by the bond issuance fee. This represents 6.98 percent for 1991, 7.35 percent for 1992, and 7.10 percent for 1993 through 2020 based on the most likely bond rates.

1B.4.1.4 Fixed Charge Rates

Fixed charge rates were calculated for a 35-year and 30-year bond term. The fixed charge rates include a 1 percent bond issuance fee and a debt service reserve fund earning interest at the bond rate. The debt service reserve fund is equal to a one-year principal and interest payment on the bond. The levelized fixed charge rate was calculated using the 7.03 percent bond rate as the discount rate. OUC specific fixed charge rates are listed in Table 1B.4.1-1.

Table 1B.4.1-1
OUC Levelized Fixed Charge Rates

<u>Bond Term</u>	<u>Levelized Fixed Charge Rate Percent</u>
30-Year	8.26
35-Year	7.90

1B.5 LOAD FORECAST

1B.5.0 Load Forecast

1B.5.1 Introduction

OUC normally prepares 20-year forecasts of customers, sales, net energy for load, and summer and winter net peak demands. For the purpose of evaluating alternatives to OUC's next generation expansion, a 30-year forecast was developed. The forecast period is 1990-2020.

OUC utilizes the System for Hourly and Annual Peak and Energy Simulation (SHAPES-PC) end-use/econometric model from Battelle of Columbus, Ohio as the primary forecasting tool. Other forecasting techniques used include regression analysis and trend analysis.

OUC's "most likely" or base forecast is developed using the most likely assumptions about service area population, employment, income and weather. There is some uncertainty in any forecast associated with economic, demographic, technological, and social changes. Therefore, in addition to the scenario of most likely conditions, alternative scenarios are developed to take into account high and low growth assumptions about the economy and demography. There is also a great deal of uncertainty associated with the weather. Therefore, we chose to use typical weather in the most likely, high growth, and low growth scenarios. These alternative scenarios are used to develop high and low band forecasts of customers, sales, net energy for load, and winter and summer net peak demands. The following is a brief summary of the long-term forecast methodology, input assumptions, and results. Appendix 1B.A contains more detail on OUC's load forecast.

1B.5.2 Forecast Methodology

1B.5.2.1 Residential

The average number of residential customers is forecasted in the SHAPES-PC model as a function of population, age distribution, and headship ratio. Residential energy consumption is the summation of the annual energy consumption of 17 individual appliances and residential miscellaneous use.

1B.5.2.2 Commercial

The SHAPES-PC model defines the commercial sector as all customers dealing with the following activities: (1) forestry, fishing, and construction, (2) transportation and public utilities, (3) wholesale trade, (4) retail trade, (5) finance, insurance, and real estate, and (6) services and government. Annual commercial energy consumption is divided into three components; the baseload, heating load, and cooling load. Each component is computed as energy consumption per employee, times number of employees, times an electric price adjustment factor. The commercial sector energy forecast is then combined with the industrial sector energy forecast to produce the general service nondemand and general service demand energy forecasts which will be discussed later.

1B.5.2.3 Industrial

In the SHAPES-PC model, the industrial sector is defined as those customers dealing in manufacturing and mining activities. The industrial sector is not assumed to be weather sensitive. Annual industrial energy consumption is a function of energy intensity per employee and employment, with adjustments for electric price.

The commercial sector energy forecast is then combined with the industrial sector energy forecast to produce the general service nondemand and general service demand energy forecasts which are discussed later.

1B.5.2.4 General Service Nondemand

Multiple regression analysis was used to develop an econometric model for projecting the average number of general service nondemand (GSND) customers. The average number of GSND customers is projected as a function of the service area employment associated with the number of GSND customers. GSND service area employment is a mix of about 84 percent commercial employment and 21 percent industrial employment. This is based on historical Standard Industrial Classification (SIC) code data for OUC.

The general service nondemand class is a mixture of both commercial and industrial customers as defined by the SHAPES-PC model. Therefore, GSND energy is projected as a percentage based on historical data of the SHAPES-PC model's combined energy forecast for the commercial and industrial sectors.

1B.5.2.5 General Service Demand

The techniques used to forecast the average number of general service demand (GSD) customers and energy consumption were identical to those used to forecast GSND customers and energy consumption. An econometric model of the average number of GSD customers as a function of OUC service area employment associated with the number of GSD customers was developed. GSD service area employment is a mix of about 16 percent commercial employment and 79 percent industrial employment. Again, these ratios are based on historical SIC code data for OUC. Also, GSD energy consumption was developed as a mix of commercial and industrial energy consumption based on historical ratios.

1B.5.2.6 Street, Highway, and Traffic Lights and OUC Use

Total street, highway, and traffic lights use was determined using trend analysis. The effect of OUC's street light conversion program was factored into the forecast. OUC interdepartmental use was also forecasted using trend analysis. OUC interdepartmental use is defined as the energy consumption used by other departments in the company that are associated with OUC being an electric utility. The energy consumption used by OUC as a water utility has been allocated to the proper general service class.

1B.5.2.7 Total Retail Sales and Net Energy for Load

The sum of the consumption of residential, GSND, GSD, street lights, and OUC use equals total OUC retail sales. Retail sales plus distribution and transmission losses of about 5 percent equals Net Energy for Load (NEL). The losses are based on a historical average of the last 10 years.

1B.5.2.8 System Peak Demand

Peak demand on the OUC system is highly weather sensitive with the annual peak demand occurring in both the summer and winter seasons. For the last 6 out of 10 years, the winter peak demand has been the annual peak demand. Therefore, the winter peak demand is forecasted to remain the annual peak demand.

The SHAPES-PC model projects demand on an hour by hour basis. The demand for each of the 8,760 hours in a year is individually projected by using an hourly temperature and the use associated with that temperature, time of day, type of day, and month. This methodology is discussed in more detail in Appendix 1B.A. A typical meteorological year is developed by choosing historical months which most closely resemble "normal" or "typical" weather.

The temperature of each hour of the typical meteorological year is used to determine the weather sensitive portion of hourly demand. Total retail level peak demand is the sum of the hourly demands for all classes. The retail level demands are adjusted for transmission and distribution losses of about 5 percent to arrive at the net system peak demand.

The extreme weather peak demands are determined by substituting a severe weather temperature at the hour of peak demand into the typical meteorological year. The winter extreme temperature is 23 F and the summer extreme temperature is 99 F. These temperatures are based on the extreme temperatures that have occurred during the past 10 years.

1B.5.2.9 Off-System Sales

OUC's future system requirements are not only based on native load, but also on existing off-system sales commitments. In order to determine what these future system requirements are, projections of off-system sales must be combined with projected native load. To this end, OUC has made projections of off-system sales based on capacity commitments that are currently under contract. These

contracts consist of three separate agreements with the Florida Municipal Power Agency (FMPA), two separate agreements with Reedy Creek Improvement District (RDIC), and two separate agreements with Kissimmee Utility Authority (KUA). Appendix 1B.A includes a description of the terms of each of these contracts.

Given these capacity commitments, OUC has developed projections of future off-system requirements based on trends observed in historical off-system sales. Table 1B.5.4-5 contains a summary of projected annual off-system demand and energy sales for the contracts mentioned above. Table 1B.5.4-6 combines the projections of firm off-system sales in Table 1B.5.4-5 with the native net energy for load listed in Table 1B.5.4-2 under the most likely scenario. Table 1B.5.4-6 also combines the OUC forecast of native peak summer and winter demand (Tables 1B.5.4-3 and 1B.5.4-4), under the most likely scenario, with the projections of firm off-system demand given in Table 1B.5.4-5.

1B.5.3 Forecast Assumptions

The Orange County economic and demographic forecast assumptions that drive the customer, energy, and load forecasts were supplied by Fishkind and Associates of Winter Park, Florida in November, 1989. The Orange County population and employment estimates were combined with OUC estimates of OUC's service area share of Orange County to arrive at OUC's service area population and employment estimates. The assumptions used in the creation of OUC's 1990 forecast are shown in Tables 1B.5.3-1 through 1B.5.3-4.

As shown in Table 1B.5.3-1, population in OUC's service area is expected to continue to grow over the next 30 years. The compound average annual growth rate (CAAGR) is expected to be 1.7 percent. This is down from the 2.6 percent CAAGR experienced in the last decade. As indicated in Table 1B.5.3-2, persons per residential meter are expected to be 2.42 by 2000 which is down from 2.59 in 1989. This reduction in household size results from an aging population and other demographic changes.

As shown in Table 1B.5.3-3, employment in OUC's service area is projected to grow at a 2.8 percent CAAGR over the next 30 years which is down from the 6.1 percent CAAGR experienced over the last 10 years.

Table 1B.5.3-4 shows that growth in real personal income is declining to 1.2 percent CAAGR over the next 30 years which is down from the 5.0 percent CAAGR experienced over the last 10 years.

TABLE 1B.5.3-1
ORLANDO UTILITIES COMMISSION
SERVICE AREA POPULATION

YEAR	LOW	MOST LIKELY	HIGH
1980	201,950	201,950	201,950
1981	204,920	204,920	204,920
1982	208,510	208,510	208,510
1983	211,660	211,660	211,660
1984	217,680	217,680	217,680
1985	226,090	226,090	226,090
1986	228,350	228,350	228,350
1987	235,140	235,140	235,140
1988	243,200	243,200	243,200
1989	253,970	253,970	253,970
1990	261,740	261,740	261,740
1991	269,490	269,490	269,490
1992	276,369	276,369	276,369
1993	281,985	282,570	282,960
1994	288,094	289,450	290,226
1995	294,302	296,999	298,155
1996	299,650	305,204	307,119
1997	305,511	312,556	315,222
1998	310,551	319,069	322,476
1999	315,155	324,753	328,894
2000	318,694	328,928	333,767
2001	322,069	333,660	339,547
2002	324,374	338,923	345,834
2003	327,438	344,694	352,603
2004	329,830	349,549	358,432
2005	332,625	353,166	363,349
2006	335,973	355,923	367,373
2007	338,461	358,859	371,885
2008	340,450	362,294	376,856
2009	342,953	366,535	382,925
2010	349,860	375,775	394,166
2011	353,140	380,810	400,780
2012	356,450	385,920	407,500
2013	359,790	391,090	414,340
2014	363,170	396,330	421,290
2015	366,570	401,640	428,350
2016	370,010	407,030	435,540
2017	373,480	412,480	442,840
2018	376,980	418,010	450,270
2019	380,510	423,620	457,820
2020	384,080	429,290	465,500
80-89 CAAGR	2.6%	2.6%	2.6%
90-00 CAAGR	2.0%	2.3%	2.5%
90-20 CAAGR	1.3%	1.7%	1.9%

TABLE 1B.5.3-2
ORLANDO UTILITIES COMMISSION
HOUSEHOLD SIZE

YEAR	PERSONS PER RESIDENTIAL METER
1980	2.72
1981	2.72
1982	2.72
1983	2.71
1984	2.68
1985	2.69
1986	2.63
1987	2.60
1988	2.58
1989	2.59
1990	2.56
1991	2.55
1992	2.51
1993	2.52
1994	2.51
1995	2.50
1996	2.49
1997	2.47
1998	2.45
1999	2.44
2000	2.42
2001	2.42
2002	2.42
2003	2.42
2004	2.42
2005	2.42
2006	2.42
2007	2.42
2008	2.42
2009	2.42
2010	2.42
2011	2.42
2012	2.42
2013	2.42
2014	2.42
2015	2.42
2016	2.42
2017	2.42
2018	2.42
2019	2.42
2020	2.42
80-89 CAAGR	-0.53%
90-00 CAAGR	-0.55%
90-20 CAAGR	-0.18%

Table 1B.5.3-3
Orlando Utilities Commission
Service Area Employment

YEAR	LOW	MOST LIKELY	HIGH
1980	108,350	108,350	108,350
1981	112,660	112,660	112,660
1982	116,230	116,230	116,230
1983	122,140	122,140	122,140
1984	134,500	134,500	134,500
1985	144,020	144,020	144,020
1986	155,710	155,710	155,710
1987	168,850	168,850	168,850
1988	175,670	175,670	175,670
1989	185,376	185,376	185,376
1990	192,545	192,545	192,545
1991	200,336	200,336	200,336
1992	206,307	206,307	206,307
1993	211,281	211,726	212,169
1994	217,566	218,889	220,653
1995	223,378	227,772	230,409
1996	228,264	237,460	241,400
1997	234,821	246,163	250,961
1998	241,300	254,336	259,550
1999	246,397	261,545	267,172
2000	251,595	268,759	275,196
2001	255,390	276,662	283,894
2002	258,767	284,800	292,943
2003	263,488	293,586	302,365
2004	267,754	300,897	310,425
2005	271,058	307,183	317,446
2006	275,861	312,057	323,038
2007	279,335	318,820	330,907
2008	282,299	326,602	339,374
2009	286,717	332,968	348,385
2010	292,344	342,168	360,358
2011	296,770	350,540	370,200
2012	301,260	359,110	380,320
2013	305,820	367,900	390,720
2014	310,440	376,890	401,400
2015	315,140	386,100	412,380
2016	319,920	395,550	423,650
2017	324,760	405,230	435,240
2018	329,670	415,140	447,140
2019	334,670	425,290	459,370
2020	339,730	435,700	471,930
80-89 CAAGR	6.1%	6.1%	6.1%
90-00 CAAGR	2.7%	3.4%	3.6%
90-20 CAAGR	1.9%	2.8%	3.0%

TABLE 18.5.3-4
ORLANDO UTILITIES COMMISSION
REAL PER CAPITA INCOME

YEAR	LOW	MOST LIKELY	HIGH
1980	8,999	8,999	8,999
1981	10,503	10,503	10,503
1982	11,307	11,307	11,307
1983	11,958	11,958	11,958
1984	12,266	12,266	12,266
1985	12,643	12,643	12,643
1986	12,942	12,942	12,942
1987	12,945	12,945	12,945
1988	13,168	13,168	13,168
1989	13,986	13,986	13,986
1990	14,168	14,168	14,168
1991	14,225	14,309	14,709
1992	14,084	14,347	14,883
1993	13,852	14,372	14,648
1994	14,447	14,474	15,369
1995	14,745	14,645	15,864
1996	14,765	14,823	16,098
1997	14,605	14,973	15,986
1998	14,473	15,125	15,842
1999	14,272	15,254	15,670
2000	14,638	15,434	16,155
2001	15,196	15,619	16,931
2002	15,238	15,784	17,097
2003	15,333	15,953	17,266
2004	15,156	16,079	17,085
2005	14,902	16,203	16,883
2006	14,704	16,291	16,640
2007	15,013	16,463	17,104
2008	15,316	16,659	17,576
2009	15,674	16,741	18,024
2010	15,656	16,769	18,100
2011	15,944	17,076	18,518
2012	16,237	17,388	18,946
2013	16,536	17,707	19,384
2014	16,840	18,031	19,831
2015	17,150	18,361	20,289
2016	17,466	18,697	20,758
2017	17,787	19,039	21,238
2018	18,115	19,387	21,728
2019	18,448	19,742	22,230
2020	18,787	20,103	22,744
80-89 CAAGR	5.0%	5.0%	5.0%
90-00 CAAGR	0.3%	0.9%	1.3%
90-20 CAAGR	0.9%	1.2%	1.6%

1B.5.4 Forecast Results

The historical and forecast average annual growth rates in customers, demand, and energy are summarized in Tables 1B.5.4-1 through 1B.5.4-5. Projected off-system energy sales and demand for existing firm commitments are summarized in Table 1B.5.4-6 and combined with OUC native loads in Table 1B.5.4-7.

The population growth and employment growth used in the forecast reflect a consistent decline in the customer growth rate over the forecast period. The compound average annual growth rate in total customers is expected to decline from 3.3 percent during the 1980-1989 period to 1.9 percent over the 1990-2020 period.

This decline in customer growth rate is reflected in the forecasted 30-year most likely growth rates of net energy for load (3.5 percent), summer net peak demand (3.3 percent), and winter net peak demand (3.2 percent), all of which are below the growth rates for the last 10 years.

The forecasts of customers, net energy for load, net winter peak demand and net summer peak demand are shown on Figures 1B.5.4-1 through 1B.5.4-4, respectively. Figure 1B.5.4-5 shows both historical and forecasted annual system load factors for the most likely growth scenario. The projected extreme weather peak demands for the most likely growth scenario are presented in Table 1B.5.4-7. In 1991, the extreme weather winter peak demands are 8.2 percent more than the typical weather peak demands, while the extreme weather summer peak demands are 12.2 percent more than the typical weather peak demands. Additional detail on the forecast results and underlying assumptions is contained in Appendix 1B.A.

The most likely, low, and high growth scenarios reflect only market induced demand-side savings through OUC's existing conservation programs. Utility induced demand savings are discussed in Subsection 1B.6.0.

Table 1B.5.4-1
Orlando Utilities Commission
Average Total Retail Customers

YEAR	LOW	MOST LIKELY	HIGH
1980	84,529	84,529	84,529
1981	86,085	86,085	86,085
1982	87,526	87,526	87,526
1983	89,698	89,698	89,698
1984	93,559	93,559	93,559
1985	97,121	97,121	97,121
1986	100,502	100,502	100,502
1987	105,094	105,094	105,094
1988	109,140	109,140	109,140
1989	113,242	113,242	113,242
1990	117,912	117,912	117,912
1991	121,983	121,983	121,983
1992	125,725	125,725	125,725
1993	128,847	129,077	129,207
1994	132,091	132,662	133,003
1995	135,468	136,636	137,219
1996	138,817	141,350	142,300
1997	142,323	145,802	147,149
1998	145,627	149,870	151,587
1999	148,758	153,579	155,631
2000	151,358	156,615	158,995
2001	153,106	160,295	161,926
2002	154,314	161,766	165,110
2003	155,810	164,702	168,519
2004	157,118	167,304	171,566
2005	158,564	169,294	174,146
2006	160,168	170,860	176,262
2007	161,521	172,495	178,528
2008	162,578	174,281	181,116
2009	163,813	176,561	184,196
2010	166,965	180,808	189,447
2011	168,701	183,511	192,989
2012	170,368	186,190	196,431
2013	172,052	189,176	199,943
2014	173,758	191,667	203,520
2015	175,474	194,471	207,160
2016	177,213	197,322	210,874
2017	178,971	200,214	214,654
2018	180,744	203,156	218,509
2019	182,535	206,145	222,434
2020	184,349	209,175	226,436
80-89 CAAGR	3.3%	3.3%	3.3%
90-00 CAAGR	2.5%	2.9%	3.0%
90-20 CAAGR	1.5%	1.9%	2.2%

Table 1B.5.4-2
Orlando Utilities Commission
Native Net Energy for Load (GWh)

YEAR	LOW	MOST LIKELY	HIGH
1980	2,331	2,331	2,331
1981	2,404	2,404	2,404
1982	2,403	2,403	2,403
1983	2,524	2,524	2,524
1984	2,606	2,606	2,606
1985	2,847	2,847	2,847
1986	2,962	2,962	2,962
1987	3,105	3,105	3,105
1988	3,289	3,289	3,289
1989	3,508	3,508	3,508
1990	3,611	3,611	3,611
1991	3,797	3,797	3,797
1992	3,957	3,957	3,957
1993	4,092	4,102	4,110
1994	4,246	4,271	4,296
1995	4,399	4,473	4,513
1996	4,541	4,690	4,753
1997	4,704	4,891	4,970
1998	4,863	5,083	5,174
1999	5,004	5,263	5,362
2000	5,149	5,444	5,557
2001	5,294	5,672	5,790
2002	5,414	5,865	6,020
2003	5,561	6,092	6,260
2004	5,696	6,288	6,478
2005	5,821	6,469	6,676
2006	5,971	6,628	6,855
2007	6,106	6,821	7,078
2008	6,225	7,030	7,311
2009	6,364	7,219	7,553
2010	6,548	7,481	7,873
2011	6,696	7,714	8,141
2012	6,844	7,948	8,412
2013	6,998	8,191	8,697
2014	7,152	8,440	8,988
2015	7,313	8,699	9,292
2016	7,472	8,962	9,600
2017	7,639	9,239	9,926
2018	7,805	9,519	10,256
2019	7,979	9,810	10,599
2020	8,083	10,107	10,951
80-89 CAAGR	4.6%	4.6%	4.6%
90-00 CAAGR	3.6%	4.2%	4.4%
90-20 CAAGR	2.7%	3.5%	3.8%

Table 1B.5.4-3
Orlando Utilities Commission
Native Summer Net Peak Demand (MW)

YEAR	LOW	MOST LIKELY	HIGH
1980	487	487	487
1981	502	502	502
1982	493	493	493
1983	539	539	539
1984	544	544	544
1985	596	596	596
1986	599	599	599
1987	634	634	634
1988	651	651	651
1989	681	681	681
1990	709	709	709
1991	745	745	745
1992	771	771	771
1993	798	800	801
1994	826	828	833
1995	854	868	875
1996	878	907	920
1997	909	944	958
1998	937	978	995
1999	965	1,012	1,028
2000	990	1,044	1,066
2001	1,015	1,086	1,106
2002	1,036	1,122	1,150
2003	1,063	1,164	1,193
2004	1,089	1,198	1,236
2005	1,112	1,234	1,270
2006	1,138	1,264	1,304
2007	1,163	1,298	1,342
2008	1,184	1,333	1,383
2009	1,207	1,364	1,422
2010	1,241	1,410	1,482
2011	1,263	1,450	1,528
2012	1,288	1,490	1,574
2013	1,313	1,533	1,625
2014	1,341	1,576	1,674
2015	1,368	1,622	1,728
2016	1,393	1,667	1,780
2017	1,420	1,715	1,837
2018	1,450	1,764	1,893
2019	1,480	1,812	1,954
2020	1,494	1,864	2,016
80-89 CAAGR	3.8%	3.8%	3.8%
90-00 CAAGR	3.4%	3.9%	4.2%
90-20 CAAGR	2.5%	3.3%	3.5%

Table IB.5.4-4
Orlando Utilities Commission
Native Winter Net Peak Demand (MW)

YEAR	LOW	MOST LIKELY	HIGH
1980	500	500	500
1981	535	535	535
1982	541	541	541
1983	474	474	474
1984	518	518	518
1985	688	688	688
1986	690	690	690
1987	558	558	558
1988	631	631	631
1989	693	693	693
1990	774	774	774
1991	794	794	794
1992	831	831	831
1993	858	860	863
1994	890	894	901
1995	920	937	943
1996	951	980	992
1997	986	1,023	1,037
1998	1,020	1,061	1,078
1999	1,049	1,097	1,120
2000	1,076	1,134	1,157
2001	1,102	1,175	1,196
2002	1,124	1,206	1,235
2003	1,150	1,245	1,280
2004	1,171	1,282	1,320
2005	1,192	1,311	1,355
2006	1,218	1,336	1,386
2007	1,242	1,367	1,424
2008	1,262	1,405	1,465
2009	1,286	1,440	1,511
2010	1,320	1,490	1,571
2011	1,351	1,535	1,625
2012	1,376	1,574	1,670
2013	1,407	1,622	1,725
2014	1,433	1,664	1,775
2015	1,465	1,712	1,835
2016	1,494	1,755	1,889
2017	1,527	1,806	1,949
2018	1,556	1,855	2,008
2019	1,591	1,912	2,069
2020	1,612	1,958	2,131
80-90 CAAGR	4.5%	4.5%	4.5%
91-00 CAAGR	3.4%	4.0%	4.3%
91-20 CAAGR	2.5%	3.2%	3.5%

Table 1B.5.4-5
Orlando Utilities Commission
Extreme Weather Net Peak Demand
Most Likely Growth Scenario

	<u>Winter (Jan.)</u> MW	<u>Summer</u> MW
1991	859	836
1992	898	867
1993	929	899
1994	967	929
1995	1,013	973
1996	1,058	1,016
1997	1,103	1,057
1998	1,146	1,095
1999	1,185	1,129
2000	1,223	1,164
2001	1,268	1,211
2002	1,300	1,251
2003	1,342	1,296
2004	1,379	1,335
2005	1,412	1,373
2006	1,439	1,405
2007	1,473	1,442
2008	1,511	1,479
2009	1,548	1,513
2010	1,600	1,562
2011	1,651	1,604
2012	1,693	1,646
2013	1,741	1,694
2014	1,785	1,739
2015	1,838	1,788
2016	1,883	1,837
2017	1,936	1,885
2018	1,988	1,938
2019	2,048	1,991
2020	2,098	2,044

Table 1B.5.4-6
Firm Off-System Demand and Energy Sales

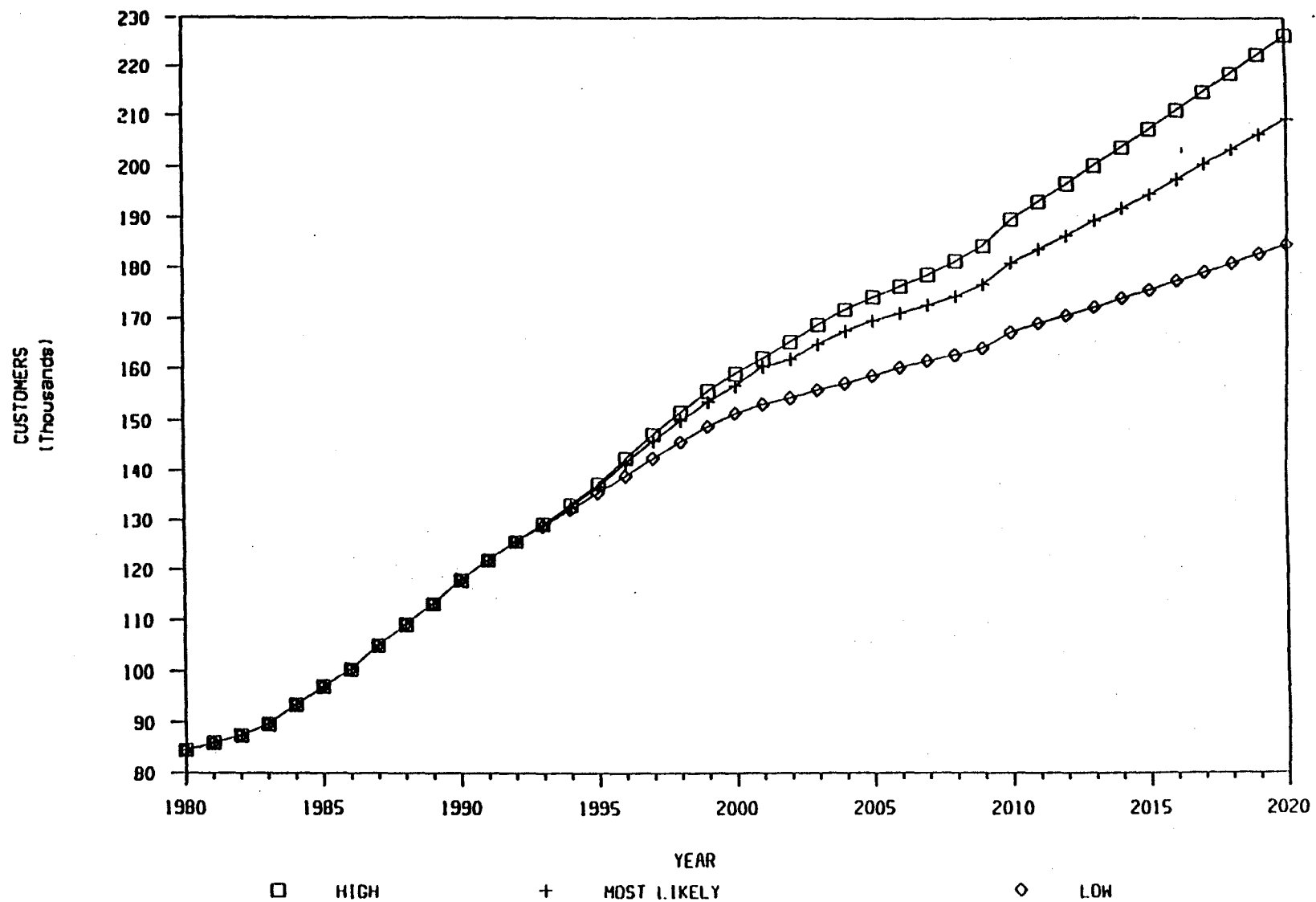
<u>Year</u>	<u>Off-System Sales</u> GWh	<u>Off System Peak Demand</u> MW
1991	365	242
1992	359	237
1993	332	217
1994	336	217
1995	328	207
1996	330	197
1997	334	197
1998	338	197
1999	342	197
2000	361	192
2001	349	187
2002	288	144
2003	247	123
2004	143	61
2005	97	43
2006	59	21

Table 1B.5.4-7
Orlando Utilities Commission
Net Energy for Load and Peak Demand
Most Likely Growth Scenario
(Includes Firm Off-System Sales and Demand)

<u>Year</u>	<u>Net Energy for Load</u> GWh	<u>Summer Peak Demand</u> MW	<u>Winter Peak Demand</u> MW
1991	4,162	987	1,036
1992	4,316	1,008	1,068
1993	4,434	1,017	1,077
1994	4,607	1,045	1,111
1995	4,801	1,075	1,144
1996	5,020	1,104	1,177
1997	5,225	1,141	1,220
1998	5,421	1,175	1,258
1999	5,605	1,209	1,294
2000	5,805	1,236	1,326
2001	6,021	1,273	1,362
2002	6,153	1,266	1,350
2003	6,339	1,287	1,368
2004	6,431	1,259	1,343
2005	6,566	1,277	1,354
2006	6,687	1,285	1,357
2007	6,821	1,298	1,367
2008	7,030	1,333	1,405
2009	7,219	1,364	1,440
2010	7,481	1,410	1,490
2011	7,714	1,450	1,535
2012	7,948	1,490	1,574
2013	8,191	1,533	1,622
2014	8,440	1,576	1,644
2015	8,699	1,622	1,712
2016	8,962	1,667	1,755
2017	9,239	1,715	1,806
2018	9,519	1,764	1,855
2019	9,810	1,812	1,912
2020	10,107	1,864	1,958
91-00 CAAGR	3.8%	2.5%	2.8%
91-20 CAAGR	3.1%	2.2%	2.2%

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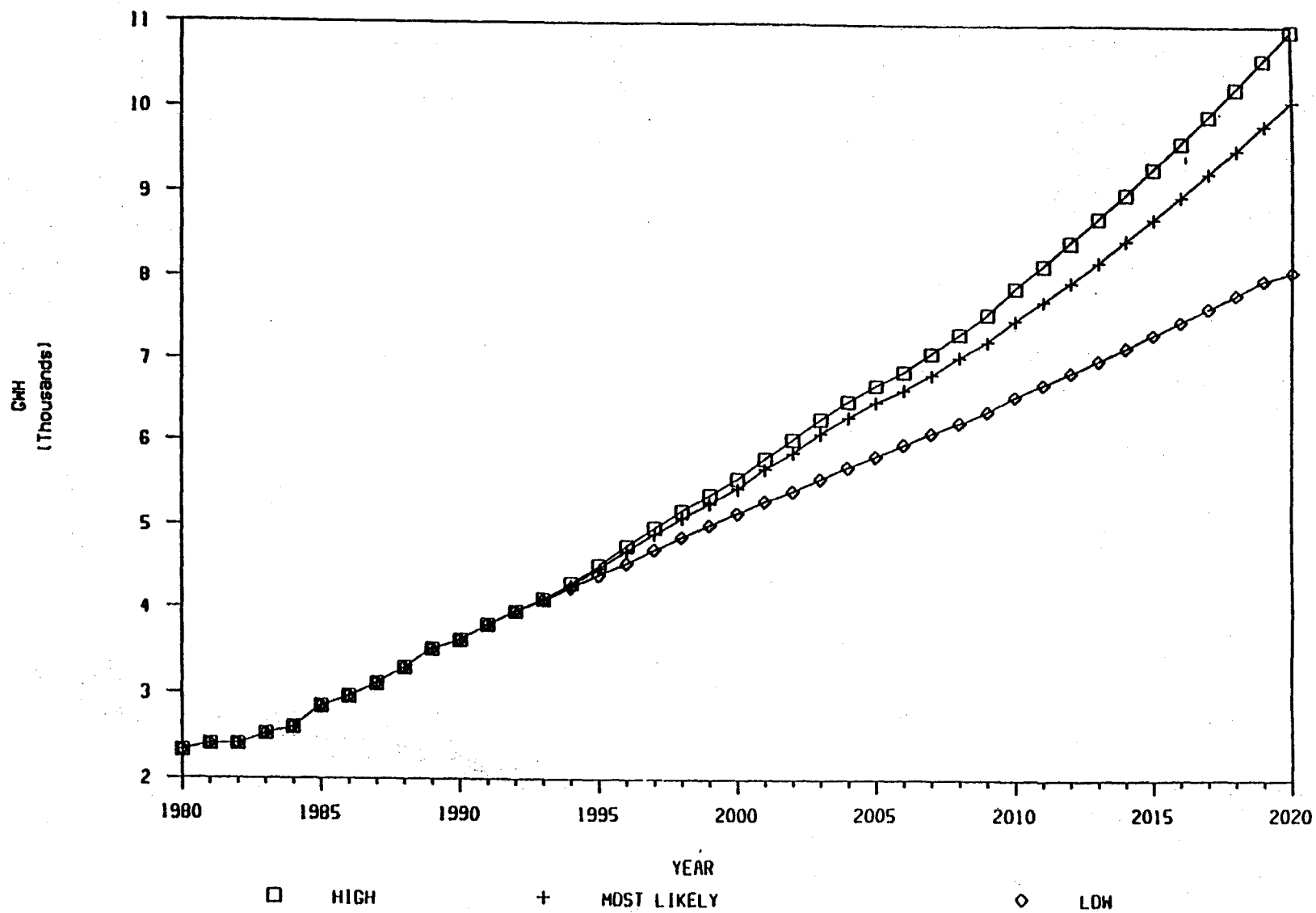
1B.5.4-9



OUC Average Total Retail Customers
Figure 1B.5.4-1

031591

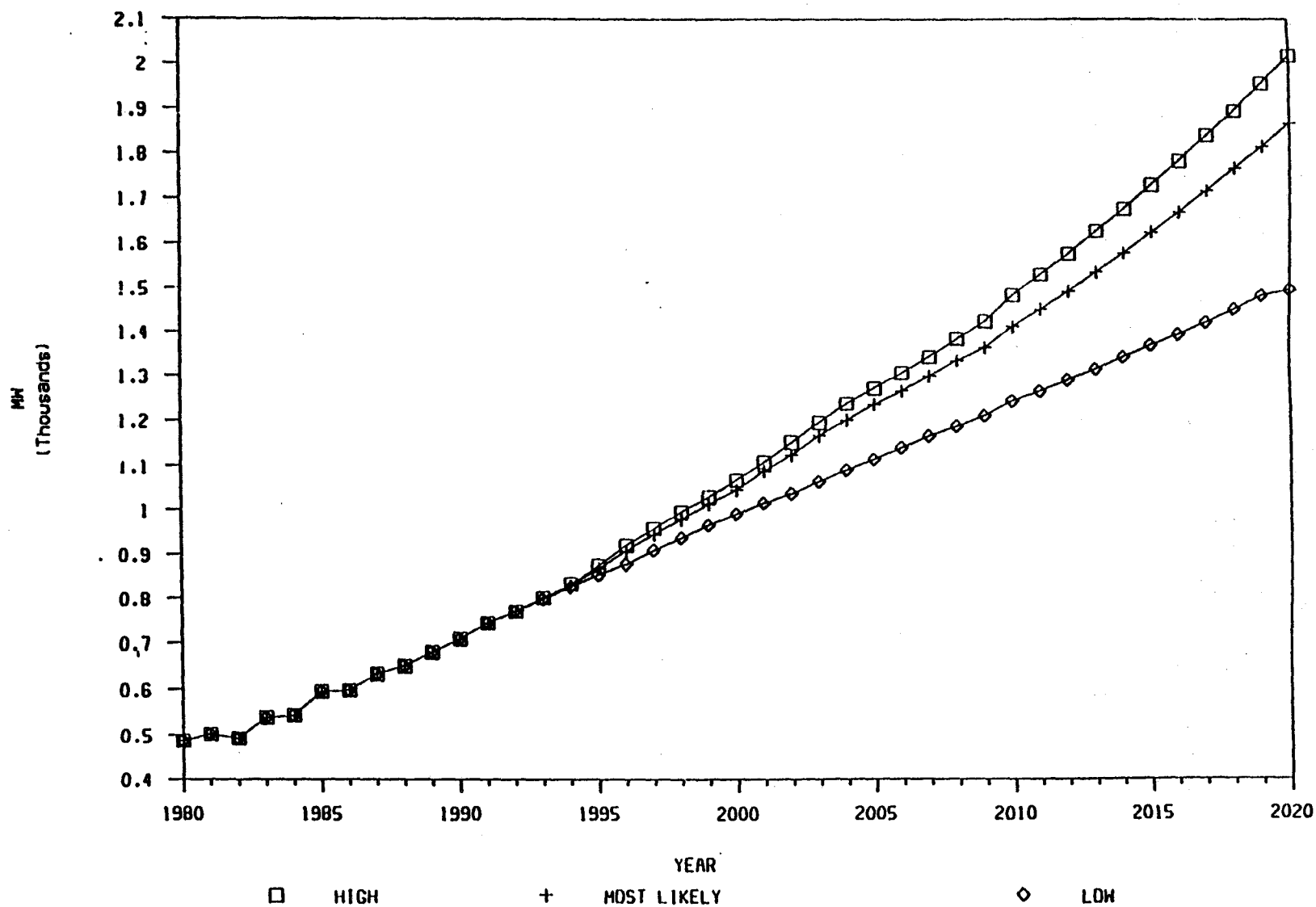
1B.5.4-10



OUC Native Net Energy For Load
Figure 1B.5.4-2

031591

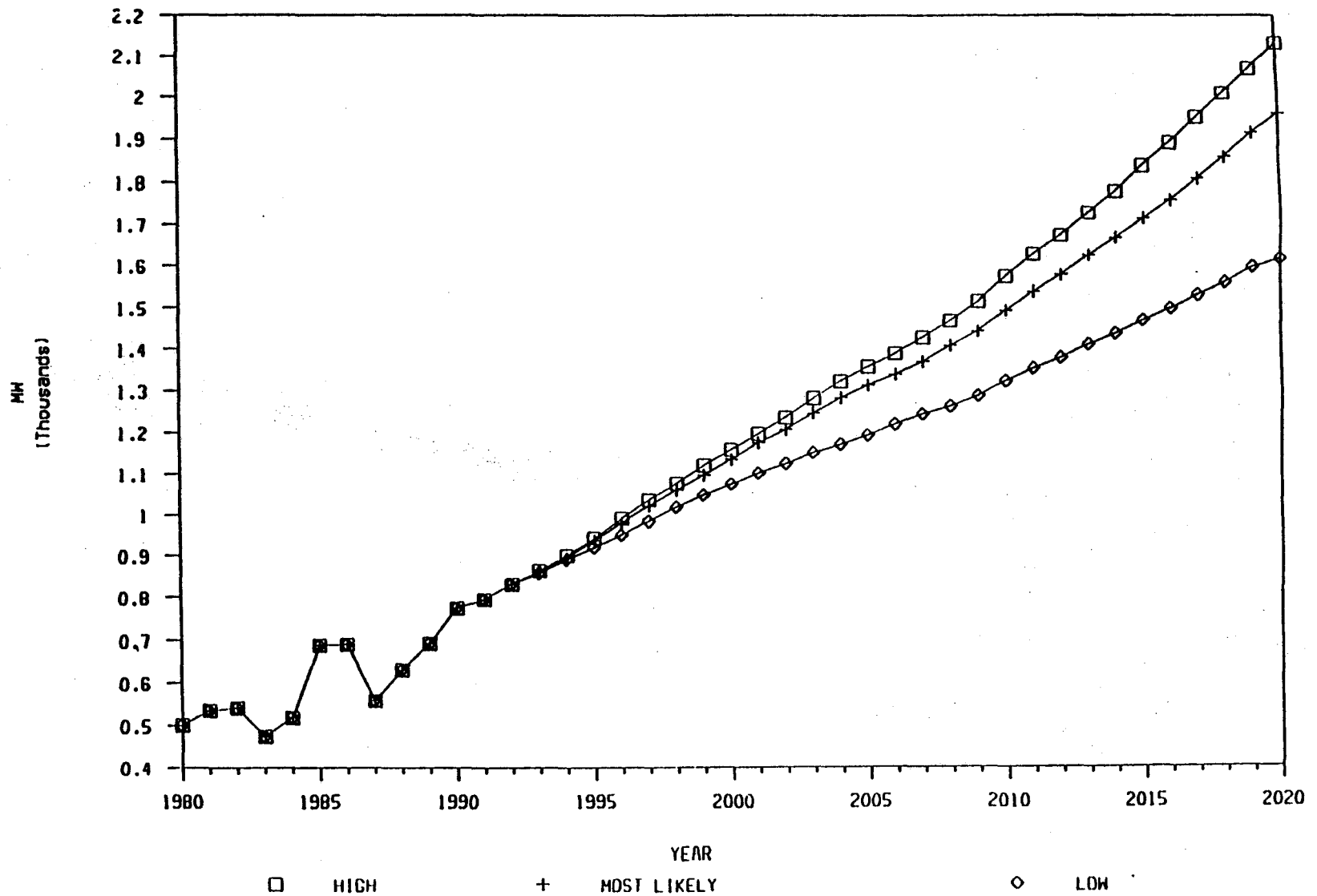
1B.5.4-11



OUC Native Net Summer Peak Demand
Figure 1B.5.4-3

031591

1B.5.4-12

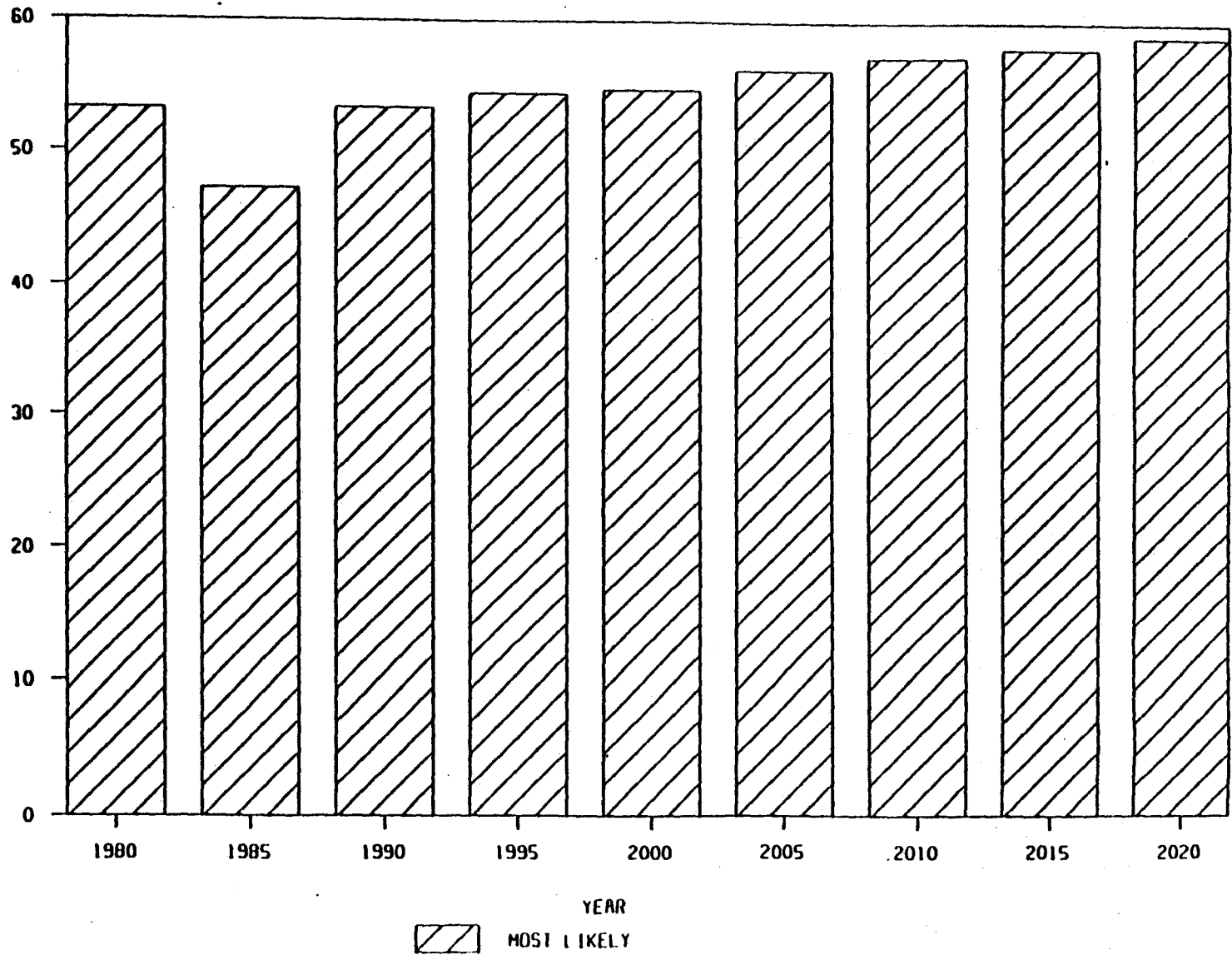


OUC Native Net Winter Peak Demand
Figure 1B.5.4-4

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1B.5.4-13

PERCENT



OUC Annual Load Factor
Figure 1B.5.4-5

1B.6.0 Demand-Side Programs

The Orlando Utilities Commission has been active in demand-side programs since the early 1970s. In 1973, OUC started to formalize its conservation efforts with the introduction of residential and commercial energy surveys. In 1981, OUC filed its first Florida Energy Efficiency and Conservation Act (FEECA) conservation programs. In 1982, OUC established its Strategic Planning Department to integrate demand-side planning with supply-side planning. Through the 1980s, four programs were added to the original FEECA filing. These programs were the following.

- Technical Energy Survey.
- Commercial Energy Survey.
- Abbreviated Basic Commercial (ABC) Survey.
- New Customer Advisory Service.

In 1987, OUC commissioned Southern Electric International (SEI) to conduct a fully integrated resource study. The SEI study was completed in 1989. In 1988, OUC established the full-time staff position of Demand-Side Planner. In 1990, OUC refiled a new set of conservation programs as required by the Florida Public Service Commission under Docket No. 890737-PU. The 1990 filing incorporates information developed in the last 10 years and consolidates programs resulting in more efficient program administration.

In 1990, to further enhance OUC's demand-side analytical capabilities, OUC acquired the Battelle RESHAPE demand-side planning program and retained Battelle to conduct a detailed analysis of cost-effective demand-side alternatives which might mitigate the need for Stanton 2. The RESHAPE program is designed to complement OUC's existing SHAPES-PC program for end-use/econometric forecasting. Battelle's scope of service for the detailed analysis of demand-side alternatives included extensive training of OUC personnel in using the RESHAPE program to analyze demand-side programs.

The following subsections describe in detail OUC's existing conservation programs, OUC's ongoing conservation program development resulting from the SEI study, and Battelle's detailed analysis of demand-side alternatives.

1B.6.1 Existing Conservation Programs

OUC's conservation programs are designed to encourage the efficient production and use of electricity in a cost-effective and environmentally responsible manner. Programs will reduce energy and also shift energy and/or demands from on-peak to off-peak periods.

The current electric demand and energy conservation plan of OUC was filed with the Florida Public Service Commission on February 12, 1990, as required under Docket No. 890737-PU, Order No. 22176, issued November 14, 1989, and the Florida Energy Efficiency Conservation Act (FEECA). This conservation plan includes 10 FEECA Conservation programs. On October 25, 1990, Florida Public Service Commission confirmed final approval of OUC's conservation plan under Docket No. 900111-EG, Order No. 23677.

OUC has been actively promoting customer conservation programs since 1973 when free residential and commercial energy surveys were first offered. Additional conservation programs have been added to OUC's conservation plan whenever they have been found to be beneficial to customers and the system. It is estimated that by the end of 1989, the cumulative impact of conservation programs since 1982 was 11.9 MW avoided system capacity and 54.8 GWh of avoided system energy required for load.

OUC explicitly reflects the effects of demand and energy conservation in planning load forecasts. OUC load forecasts are based on end use projections of customers' demand and energy requirements. The effects of projected conservation plan participation and appliance efficiency improvements are modeled in the end use characteristics used to describe the various classes of customers.

The following sections summarize each of the 10 programs included in OUC's conservation plan.

1B.6.1.1 Residential Energy Survey Program (Free Home Energy Survey)

1B.6.1.1.1 Objectives. The objectives of this program are to help customers make their homes more energy efficient and promote other conservation programs which will reduce annual energy usage and lower weather sensitive peaks.

1B.6.1.1.2 Background. OUC has been offering Free Home Energy Surveys since 1973. Residential Conservation Service computerized audits were begun in 1981. Several thousand of these audits have been performed for residential customers. Free Home Energy Surveys are the cornerstone of OUC's FEECA

conservation programs. The Free Home Energy Survey was expanded in 1988 to include a complete supply air and return air duct inspection for customers with central electric heating and cooling systems. Customers with electric water heaters are given a water heater jacket. Customers received a \$5.00 check from OUC for having a Free Home Energy Survey. Customers also received a "Water Use" audit.

1B.6.1.1.3 Description. OUC will continue to offer Residential Energy Surveys and give a \$10 check to those participating. These surveys will cover conservation measures and practices designed to inspect the home's structural condition, make recommendations, and leave the customer a written checklist of measures and practices. The customer is provided with literature on other OUC conservation programs. A pool pump audit is included as part of the Free Home Energy Survey Program. The Free Home Energy Survey is offered to all single family, multifamily, and mobile home electric customers. Direct mail and use of a program announcement will be continued. Four full-time OUC employees perform Residential Energy Surveys. The use of contracted audit services ceased in March of 1990. The use of full-time OUC personnel underscores the commitment of OUC to the importance of energy conservation.

1B.6.1.1.4 Program Measurement. Six months after the Residential Energy Survey, the customer will be sent a post-audit questionnaire. The post-audit questionnaire will be the prime monitoring tool to determine what actions the customer has taken and the customer's opinions of the Free Home Energy Survey.

The cumulative impact of the Residential Energy Survey Program as estimated for years 1990-1999 is shown in Table 1B.6.1-1.

1B.6.1.2 Commercial Energy Survey Program

1B.6.1.2.1 Objective. The objective of this program is to assist commercial customers in making their facilities and equipment more energy efficient through the implementation of energy conservation measures, practices, and proven energy management techniques. This program will promote the commercial efficient lighting program.

1B.6.1.2.2 Background. OUC has offered Commercial Energy Surveys since 1973. These surveys evaluated point-of-usage electricity waste. As a requirement of FEECA, OUC initiated commercial energy audits in 1981. These consisted of a walk-through audit performed by in-house staff. In response to the Commercial,

Apartment and Conservation Service Act under the National Energy Conservation Policy Act (NECPA), OUC instituted computerized commercial audits performed by a contract audit service. These were offered to all OUC commercial customers whose average monthly consumption was 4,000 kWh or less per month. Several thousand of these type audits were performed. Customers were given a list of recommended energy conservation measures and practices. OUC has also offered two other classes of energy surveys. The Abbreviated Basic Commercial Energy Survey is a walk-through for customers over 50 kW. The Technical Energy Survey is a detailed energy study for customers over 300 kW.

1B.6.1.2.3 Description. The Commercial Energy Survey Program will be the cornerstone of Commercial Energy Services activities. OUC will offer a single class of energy surveys to all commercial electric customers. The energy survey will be a physical walk-through inspection of the facility. The walk-through is structured so that it can be tailored to meet the needs of the individual customers as well as to facilitate different types of structures and operations. The Advanced Commercial Evaluation System (ACES) computer program will be used as a tool to perform economic evaluations. At the end of the energy survey, the customer will receive appropriate conservation literature. Within 30 days of the survey, the customer will receive a written report. The Commercial Energy Survey will be performed by full-time OUC employees. Direct mail will be used to promote the program. Program announcements will be mailed to all eligible commercial customers.

1B.6.1.2.4 Program Measurement. Six months after the Commercial Energy Survey, the customer will receive a post-audit questionnaire. The program will be monitored using the returned questionnaire.

The cumulative impact of the Commercial Energy Survey Program as estimated for years 1990-1999 is shown in Table 1B.6.1-2.

1B.6.1.3 Residential Efficient Heating--Heat Pump Program

1B.6.1.3.1 Objective. The objective of this program is to improve the saturation level of efficient heat pumps and replace electric resistance heating and older air conditioning equipment. This will lower both summer and winter peaks and annual energy usage.

1B.6.1.3.2 Background. Approximately one-third of the single family homes and about half of the multifamily homes have electric strip heating with air

conditioning. The previous efficient heating and air conditioning FEECA program promoted heat pumps with a Coefficient of Performance (COP) of 2.5 and air conditioners with a Seasonal Energy Efficiency Rating (SEER) of 8.5. Customers requiring the installation of heat pumps or central air conditioners that meet these standards received a \$10 bonus check from OUC. This was not intended to be an incentive, but a means for improving the monitoring of appliance purchases. The program was aimed primarily at the existing residential market. The program was promoted by newspaper advertising, direct mail, bill stuffers, auditors, and by air conditioning contractor trade allies. The new federal appliance standards effective January 1, 1992, will require all heat pumps to have an SEER of 10 and a Heating Season Performance Factor (HSPF) of 6.8.

1B.6.1.3.3 Description. The Residential Efficient Heating--Heat Pump Program will be marketed to the owners of existing residential strip heating systems. OUC's role will be to encourage owners to replace electric furnaces with efficient heat pumps. The program will require heat pumps of SEER of 10.5 (or greater) with an HSPF of 7.0 (or greater) in order to qualify for the \$10 bonus check. The program will be an informational endeavor. Market forces will provide the proper incentives to promote heat pump sales. The program will include newspaper advertising, bill stuffers, energy audits, and direct mail to promote the program. New brochures, advertising, and operational cost literature will be developed for customers and air conditioning contractors. An OUC Conservation Specialist will promote the program and strive to assist customers in any way possible when the customer needs to replace their electric heating system.

1B.6.1.3.4 Program Measurement. The customers who convert from electric furnaces to heat pumps will submit application cards to receive \$10 bonus checks from OUC. The participating customers' previous 12-month use history and 12-month post use history (all weather corrected) can be analyzed to determine energy savings.

The cumulative impact of the Residential Efficient Heating--Heat Pump Program as estimated for years 1990-1999 is shown in Table 1B.6.1-3.

1B.6.1.4 Residential Weatherization Program

1B.6.1.4.1 Objectives. The objectives of this program are to promote the weatherization of existing single family homes and multifamily units to make them more energy efficient, educate customers on the benefits of specific conservation

measures and practices, educate customers on how energy efficiency can be achieved, motivate them to take action, and promote the Home Fix Up Program aggressively to qualifying program participants.

1B.6.1.4.2 Background. OUC has been extremely active in the area of residential weatherization. Two FEECA programs, High User Awareness and Weatherization Measures and Practices, have been in use since 1981 to educate OUC customers on the benefits of weatherization. Another FEECA program, the OUC Residential Ceiling Reinsulation Program, was geared toward upgrading ceiling insulation to R-19 insulation (or greater) in existing residences. This program began in 1981. Participants were given a \$10.00 bonus check for reporting this improvement.

1B.6.1.4.3 Description. OUC is combining the Weatherization Measures and Practices, High User Awareness, Window Treatment, and Residential Ceiling Reinsulation Programs into a single Residential Weatherization Program. The program is designed for existing single family and multifamily homes, and will promote the following.

- R-19 ceiling insulation or higher.
- Exterior and interior caulking.
- Weatherstripping.
- Air conditioning/heating supply and return air duct repair.
- Window treatment.
- Water heater insulation.

The program will use newspaper advertising, direct mail, brochures, in-house customer representatives, and in-house residential energy survey personnel to promote the program. Once a customer reports upgrading their ceiling insulation to R-19 or higher and any of the other listed conservation measures, the customer will receive a \$10.00 bonus check.

1B.6.1.4.4 Program Measurement. The program market penetration will be monitored by bonus check disbursements. The annual energy usage change will be monitored by recording 12 months' billings history before and after an installation. The on-peak load change will be monitored by recording load profiles from a sample of participants.

The cumulative impact of the Residential Weatherization Program as estimated for years 1990-1999 is shown in Table 1B.6.1-4.

1B.6.1.5 Low Income Residential Home Fix Up Program

1B.6.1.5.1 Objective. The objective of this program is to provide the opportunity for qualifying participants to have their homes made more energy efficient through weatherized measures. Weatherized homes will lower annual energy usage and reduce weather sensitive peaks.

1B.6.1.5.2 Background. OUC has been extremely active in the area of weatherizing low income homes. OUC started a non-FEECA, Low Income Home Energy Fix Up Program in 1985. The program consisted of a residential energy survey which recommended various weatherization measures. These measures were candidates for implementation. Families with a total family income of \$16,000 per year or less, and owned their own home, qualified for the program. (Renters qualified if the landlord agreed to the program.)

Participants chose which measures to implement and contracted for their completion. They entered into a contract with a qualified (OUC approved) fix up contractor. The participant paid 15 percent of the contract price and OUC paid 85 percent of the price. (OUC paid the contractor directly.) To date, more than 1,200 homes have been weatherized under this successful program.

1B.6.1.5.3 Description. The Fix Up Program will pay for 85 percent of the total contract cost for home weatherization. The qualifying measures are as follows.

- Upgrading ceiling insulation to R-19.
- Exterior and interior caulking.
- Weatherstripping doors and windows.
- Air conditioning/heating supply and return air duct repairs.
- Water heater insulation.

This program is offered to all OUC electric customers who:

- Own their own home.
- Renters who obtain the landlord's permission.
- Total family annual income not to exceed \$20,000.

The program will use newspaper advertising, direct mail, social agency contacts, in-house customer representatives, and in-house residential energy survey personnel to promote the program.

1B.6.1.5.4 Program Measurement. The program will be monitored by in-house records. The annual energy usage change will be monitored by recording 12 months' billing history before and after the installation. The on-peak load change will be monitored by recording load profiles from a sample of participants.

The cumulative impact of the Low Income Residential Home Fix Up Program as estimated for years 1990-1999 is shown in Table 1B.6.1-5.

1B.6.1.6 Residential Efficient Water Heating Program

1B.6.1.6.1 Objective. The objective of this program is to improve energy efficiency in water heating by increasing the saturation level of waste heat recovery systems augmenting electric resistance water heating in the existing and new construction markets, to encourage homeowners to insulate their existing electric water heater with an insulating blanket, and to reduce weather sensitive peak demand and energy usage.

1B.6.1.6.2 Background. A recent OUC appliance survey showed an 70 percent saturation level of electric resistance water heating in the existing residential and multifamily sectors.

Since 1981, residential customers receiving energy audits were given a free water heater jacket kit for their electric water heaters. Post-audit questionnaires received back from customers show more than 80 percent installed their water heater jacket kits. Customers requesting information on alternate water heating systems receive an informative booklet on various water heating systems such as waste heat recovery units, heat pump water heaters, solar water heaters, more efficient electric water heaters, and wrapping electric water heaters with insulation blankets. Subdivisions built in the OUC territory, usually, are not equipped with waste heat recovery units. Many of the subdivisions install central air conditioning/heat pumps, and this presents the opportunity to promote waste heat recovery units. Many builders give home buyers the option to install waste heat recovery units, but the potential buyers are unaware of the energy saving benefits. This situation represents additional opportunity to promote this type of water heating system.

1B.6.1.6.3 Description. The Residential Efficient Water Heating Program will aggressively promote and encourage homeowners of single family homes and owners of multifamily complexes to install waste heat recovery units and to insulate older, less efficient, electric water heaters. The program will use OUC residential energy auditors, direct mail, bill stuffers, and newspaper advertising. Direct mail will be to individual owners in selected subdivisions. OUC has a direct mail location system which can mail to any subdivision or generic area according to vintage of the homes in the area. The existing alternate water

heating booklet will be revised. This booklet will be given to all audited customers and used at the conservation displays. Conservation Specialists will call on builders to encourage the installation of waste heat recovery units in new subdivisions. Owners and maintenance personnel of existing apartment complexes will be encouraged to insulate older water heaters or to replace the units with more efficient electric water heaters which have insulation ratings of R-6 or greater.

1B.6.1.6.4 Program Measurement. Residential customers reporting the installation of waste heat recovery units in existing homes will receive a \$10.00 bonus check from OUC. A 12-month before and after, weather corrected, energy use history will be recorded. This information will determine an energy use change. The load shape of a sample of participants will determine load shape changes.

The cumulative impact of the Residential Efficient Water Heating Program as estimated for years 1990-1999 is shown in Table 1B.6.1-6.

1B.6.1.7 Commercial Efficient Lighting Program

1B.6.1.7.1 Objective. The objective of this program is to improve the market saturation of efficient fluorescent lighting and high intensity discharge exterior lighting (i.e., the replacement of existing mercury vapor fixtures with either high-pressure sodium or metal halide fixtures) in the commercial, office, and retail sectors. This will reduce annual energy consumption and weather sensitive peak load.

1B.6.1.7.2 Background. The vast majority of existing commercial, retail, and office stock is equipped with standard 40 watt and 75 watt fluorescent tubes, standard core and coil ballast, incandescent lamps, and mercury vapor fixtures. Experience has shown that standard fluorescent tubes can be replaced with high efficiency tubes; core and coil ballast can be replaced with electronic ballast (or hybrid ballast); and incandescent lamps with self-ballasted fluorescent lamps--all without an appreciable loss of light or color. Existing exterior mercury vapor fixtures can be replaced with either high-pressure sodium or metal halide fixtures without any loss of light. Another option is to add reflectors to existing four-tube fluorescent fixtures and remove two tubes and one ballast. In all of these cases, the annual customer energy and demand bills are reduced. OUC has historically encouraged these improvements through Commercial Energy Surveys.

1B.6.1.7.3 Description. As stated above, this program is to encourage the following.

- Replace existing 40 watt fluorescent tubes with 34 watt tubes.
- Replace existing 75 watt fluorescent tubes with 60 watt tubes.
- Replace existing standard core and coil ballast with electronic ballast.
- Where appropriate, recommend the conversion to 32 watt fluorescent tubes with electronic ballast.
- The conversion to reflector fluorescent fixture.
- Replace existing incandescent bulbs with self-ballasted, fluorescent bulbs.
- The replacement of existing exterior mercury vapor fixtures to high-pressure sodium or metal halide fixtures.

OUC's Commercial Energy Survey efforts will be the marketing arm for this endeavor. Efficient lighting conversion is an integral part of every energy survey. OUC's in-house staff will perform economic analysis as well as application engineering for each recommendation. OUC will use its trade allies and standard advertising techniques to encourage customers to participate.

1B.6.1.7.4 Program Measurement. By working with the customer, the Commercial Energy Survey personnel will know which customers have installed efficient lighting. In addition, the participant will be reminded twice a year to stock only efficient replacement tubes and bulbs. The energy auditor will visit each participant once a year to visually verify that efficient lighting is being maintained. A 12-month before and after history will be maintained for each participant to verify energy and demand reductions. The recorded histories will be corrected for weather and other changes.

The cumulative impact of the Commercial Efficient Lighting Program as estimated for years 1990-1999 is shown in Table 1B.6.1-7.

1B.6.1.8 Street Light and Outdoor Light Conversion Program

1B.6.1.8.1 Objective. The objective of this program is to utilize more energy efficient street lighting and outdoor lighting while maintaining existing illumination levels by replacing existing mercury vapor fixtures with high-pressure sodium vapor fixtures.

1B.6.1.8.2 Background. This is an existing and ongoing FEECA program since 1981. Energy savings of up to 33 percent can be achieved by converting mercury

vapor lights to high-pressure sodium while still maintaining comparable illumination levels. This program has reduced annual energy usage by 433 MWh.

1B.6.1.8.3 Description. OUC will continue this existing program. Energy efficient high-pressure sodium fixtures are installed in all new subdivisions.

A Department of Transportation program was initiated by the City of Orlando Traffic Department. This program called for the conversion of older mercury vapor fixtures to high-pressure sodium fixtures on state roads within the city limits. OUC has been installing high-pressure sodium street lights on public property for years. OUC will convert the remaining lights to high-pressure sodium as they normally expire due to age. OUC is committed to converting all remaining mercury vapor fixtures to high-pressure sodium by 2000.

1B.6.1.8.4 Program Measurement. Due to quantity and types of light sources on the OUC system, normal attrition is allowing sufficient quantities of high-pressure sodium replacement to satisfy yearly goal commitments. OUC maintains complete mapping and statistical records of its lighting system, thereby eliminating any significant amounts of data acquisition requirements. Monthly installation of high-pressure sodium fixtures are recorded for internal records.

The cumulative impact of the Street Light and Outdoor Light Conversion program, estimated for years 1990-1999, is shown in Table 1B.6.1-8.

1B.6.1.9 Energy Education and School Outreach Program

1B.6.1.9.1 Objectives. The objectives of this program are to increase the awareness of elementary and middle school students on the importance of conservation and minimizing electric and water waste, to encourage students to have their parents sign up for energy audits, and to participate in other OUC conservation programs.

1B.6.1.9.2 Background. This FEECA program has been in existence since 1981. It is highly successful and acclaimed by the Orange County School System and the Additions Program for educating children in energy education. Several thousand children have seen the presentations on energy and water conservation since the inception of the program. OUC intends to continue this program for the benefit of students and the community in an effort to make children more aware of conserving electricity and of their environment.

1B.6.1.9.3 Description. The Energy Education and School Outreach Program consists of an hour long classroom presentation utilizing a display model of a

generating plant, electric meter display, a Florida Electric Power Coordinating Group "blue-box" Watt Counter, energy workbooks, and other attention getting devices. Children are taught how electricity is generated and are encouraged to perform mini-electric and water audits on their own houses. They are asked to encourage their parents to sign up for a Residential Energy Survey. Those who participate are awarded Burger King Whopper certificates. The main thrust of this educational message is the wise use of electricity and water.

1B.6.1.9.4 Program Measurement. There are no measurements applicable for this program.

1B.6.1.10 New Construction Inspection Research Program

1B.6.1.10.1 Objective. Research of this project was conducted for a period of one year (1990). The research determined that blower door testing and air supply and return duct inspections on model subdivision houses identified opportunities for improving energy efficiency. The research provided cost-effective assumptions for future programs.

1B.6.1.10.2 Background. Over a period of time, experiences with energy audits, high bill complaints, and the OUC Home Fix Up Program have proven that many houses need substantial repairs to lessen supply and return air duct leaks. While most of the homes are in the existing home market, many new homes lack proper installation of air conditioning ductwork. The problems are further compounded by the lack of structural integrity of the building envelope of homes. Air leaks are found around windows, doors, plumbing, and electrical penetrations and the improper installation of wall and ceiling insulation. Together, a multiple problem in any given home can result in wasted electrical energy due to air infiltration at many locations. Blower door tests and air supply and return inspections have been offered to builders since July of 1988. To date, eight blower door tests have been performed. Other blower door tests have been offered to builders and are pending their decision to undergo the tests. Builders' acceptance, to date, has been slow.

1B.6.1.10.3 Description. The New Construction Inspection Program will be offered to all builders starting new single family residential subdivisions in the OUC service area. The builders will be offered, at no charge, a blower door test and energy audit with a complete duct and air return inspection. Builders will be offered these inspections of model homes or first homes under construction in

given subdivisions. The purpose will be to discover any serious air infiltration problem in either the building envelope and/or air duct system and to determine the impact on demand and energy consumption. The builder will be offered inspections of other homes under construction before the dry wall is installed.

The builder will be encouraged to have any defects corrected before the sale of the house. Upon completion of necessary repairs, a post-modification blower door test and ductwork inspection will be completed by OUC (again at no charge to the builder) to ensure the repairs have corrected the air infiltration problem. The builder will receive from OUC a letter documenting the air infiltration rate of the house and the completion of any repairs. The builder will be encouraged by OUC to provide all information to the particular building inspection department for oversight review. OUC will provide the builder with assistance at his grand opening or model home preview to assist the potential buyers with operating and maintenance information on the home's appliances, including central air conditioning and heating.

1B.6.1.10.4 Program Measurement. At the end of one year, the program will be reviewed. Data will be gathered from each inspected house to determine potential energy and demand savings attributed. OUC will analyze the data and make appropriate recommendations to management.

1B.6.1.11 Cumulative Impact of Conservation

OUC has been estimating the impact of demand and energy conservation programs since 1982. The estimated cumulative impact of these programs in terms of avoided system capacity and energy is shown in Table 1B.6.1-9 for the period 1982 through 1999. For 1990, it is estimated that the cumulative impact of conservation programs is 13 MW of avoided system capacity and 59 GWh of avoided system energy.

Table 1B.6.1-1
Cumulative Impact of Residential Energy Survey Program
Estimated for Years 1990-1999
Existing FEECA Program

<u>Year</u>	<u>Cumulative Number of Customers</u>	<u>Cumulative Avoided Capacity kW</u>	<u>Cumulative Avoided Energy MWh</u>
1990	2,700	0.0	852.6
1991	5,450	0.0	1,721.1
1992	8,250	0.0	2,605.3
1993	11,100	0.0	3,505.3
1994	14,000	0.0	4,421.1
1995	16,950	0.0	5,352.6
1996	19,950	0.0	6,300.0
1997	22,920	0.0	7,247.4
1998	25,900	0.0	8,179.9
1999	28,800	0.0	9,094.7

Table 1B.6.1-2
Cumulative Impact of Commercial Energy Survey Program
Estimated for Years 1990-1999
Existing FEECA Program

<u>Year</u>	<u>Cumulative Number of Customers</u>	<u>Cumulative Avoided Capacity kW</u>	<u>Cumulative Avoided Energy MWh</u>
1990	800	0.0	842.1
1991	1,600	0.0	1,684.2
1992	2,450	0.0	2,578.9
1993	3,350	0.0	3,526.3
1994	4,300	0.0	4,526.3
1995	5,300	0.0	5,578.9
1996	6,300	0.0	6,631.6
1997	7,300	0.0	7,684.2
1998	8,300	0.0	8,736.8
1999	9,300	0.0	9,789.5

Table 1B.6.1-3
Cumulative Impact of Residential Efficient Heating--
Heat Pump Program Estimated for Years 1990-1999
Existing FEECA Program

<u>Year</u>	<u>Cumulative Number of Customers</u>	<u>Cumulative Avoided Capacity kW</u>	<u>Cumulative Avoided Energy MWh</u>
1990	150	328.5	605.4
1991	300	657.0	1,210.7
1992	500	1,095.0	2,017.9
1993	750	1,642.5	3,026.8
1994	1,050	2,299.5	4,237.6
1995	1,400	3,066.0	5,650.1
1996	1,800	3,942.0	7,264.4
1997	2,200	4,818.0	8,878.7
1998	2,500	5,475.0	10,089.5
1999	2,800	6,132.0	11,300.2

Table 1B.6.1-4
Cumulative Impact of Residential Weatherization Program
Estimated for Years 1990-1999
Existing FEECA Program

<u>Year</u>	<u>Cumulative Number of Customers</u>	<u>Cumulative Avoided Capacity kW</u>	<u>Cumulative Avoided Energy MWh</u>
1990	50	61.9	82.9
1991	100	123.8	165.8
1992	150	185.8	248.7
1993	225	278.6	373.0
1994	300	371.5	497.4
1995	375	464.4	621.7
1996	475	588.2	787.5
1997	575	712.1	953.3
1998	675	835.9	1,119.1
1999	750	928.8	1,243.4

Table 1B.6.1-5
Cumulative Impact of Low Income Residential Home Fix Up
Program Estimated for Years 1990-1999
Existing FEECA Program

<u>Year</u>	<u>Cumulative Number of Customers</u>	<u>Cumulative Avoided Capacity kW</u>	<u>Cumulative Avoided Energy MWh</u>
1990	300	372.0	497.4
1991	600	744.0	994.7
1992	900	1,116.0	1,492.1
1993	1,200	1,488.0	1,989.5
1994	1,500	1,860.0	2,486.8
1995	1,800	2,232.0	2,984.2
1996	2,100	2,604.0	3,481.6
1997	2,400	2,976.0	3,978.9
1998	2,700	3,348.0	4,476.3
1999	3,000	3,720.0	4,973.7

Table 1B.6.1-6
Cumulative Impact of Residential Efficient Water Heating
Program Estimated for Years 1990-1999
Existing FEECA Program

<u>Year</u>	<u>Cumulative Number of Customers</u>	<u>Cumulative Avoided Capacity kW</u>	<u>Cumulative Avoided Energy MWh</u>
1990 ^a	0	0.0	0.0
1991	75	13.9	160.3
1992	175	32.4	373.9
1993	300	55.5	641.1
1994	450	83.3	961.6
1995	625	115.6	1,335.5
1996	800	148.0	1,709.5
1997	950	175.8	2,030.0
1998	1,100	203.5	2,350.5
1999	1,225	226.6	2,617.6

^aIn OUC's submittal under Docket No. 890737-PU, Order No. 22176, there were no customers projected to install waste heat recovery units during 1990. In reality, between 30 and 40 waste heat recovery units were installed in 1990; however, the 1990 projection has been kept at 0 to make it consistent with the filing.

Table 1B.6.1-7
Cumulative Impact of Commercial Efficient Lighting
Program Estimated for Years 1990-1999
Existing FEECA Program

<u>Year</u>	<u>Cumulative Number of Customers</u>	<u>Cumulative Avoided Capacity kW</u>	<u>Cumulative Avoided Energy MWh</u>
1990	0	0.0	0.0
1991	20	371.5	1,477.9
1992	40	743.2	2,955.8
1993	70	1,300.3	5,172.6
1994	100	1,857.6	7,389.5
1995	140	2,600.6	10,345.3
1996	180	3,343.7	13,301.1
1997	230	4,272.4	16,995.8
1998	280	5,201.2	20,690.5
1999	330	6,130.0	24,385.3

Table 1B.6.1-8
Cumulative Impact of Street Lighting and Outdoor Lighting Conversion
Program Estimated for Years 1990-1999
Existing FEECA Program

<u>Year</u>	<u>Cumulative Number of Customers</u>	<u>Cumulative Avoided Capacity kW</u>	<u>Cumulative Avoided Energy MWh</u>
1990	700	0.0	433.3
1991	1,400	0.0	866.5
1992	2,100	0.0	1,299.8
1993	2,800	0.0	1,733.1
1994	3,500	0.0	2,166.3
1995	4,200	0.0	2,599.6
1996	4,900	0.0	3,032.8
1997	5,600	0.0	3,466.1
1998	6,300	0.0	3,899.4
1999	7,000	0.0	4,332.6

Table 1B.6.1-9
Cumulative Impact of All Energy Conservation Programs
Estimated for Years 1982-1999
Existing FEECA Program

<u>Year</u>	<u>Cumulative Avoided Capacity MW</u>	<u>Cumulative Avoided Energy GWh</u>
1982	1.3	5.4
1983	2.2	9.2
1984	3.4	13.6
1985	4.5	17.7
1986	6.0	22.6
1987	8.0	33.5
1988	10.2	45.0
1989	11.9	54.8
1990	13.0	59.2
1991	14.4	65.3
1992	16.0	71.8
1993	18.0	79.5
1994	20.1	86.7
1995	22.5	96.0
1996	25.2	105.6
1997	28.1	115.9
1998	30.7	125.7
1999	33.3	135.4

1B.6.2 Ongoing Conservation Program Development

The results of the Long-Range Power Supply and Demand-Side Planning Study conducted by SEI identified two additional programs other than those that are currently included in OUC's existing conservation programs which deserved further study and possible implementation.

SEI recommended that OUC test a voluntary residential time-of-use rate program to determine if customer response was similar to SEI study projections. SEI recommended that the program be made available to those customers with greater than 10,000 kWh of annual usage. As a first step in the implementation of the program, OUC developed a time-of-use rate structure based on OUC's actual cost of service. The cost of service based time-of-use rate resulted in little differential between on and off peak rates. As a result, OUC decided to have Battelle restudy the projected economics of time-of-use rates.

The second recommendation by SEI involved commercial thermal energy storage (TES). SEI's study indicated that a TES incentive of \$200 to \$300/kW resulted in significant penetration for most utilities; however, SEI's study found that TES for OUC would be cost-effective with a maximum incentive of only \$50/kW. OUC is a winter peaking utility. Reductions in summer peak demand will not in and of themselves reduce capacity addition requirements. Because of these two issues, OUC has elected to evaluate two pilot TES projects and have Battelle reevaluate the economics of TES. The two projects are OUC's Pershing Service Center Office and the new Orlando City Hall.

The Pershing Service Center is a 3,530 square foot office with an 11,270 square foot nonair-conditioned warehouse. The facility opened in 1989. The office is air-conditioned with a 20 ton nominal, DX chiller. During the nighttime hours, the chiller produces low temperature brine which freezes ice on a coil (CALMAC system). During the nonpeak portion of the day, the chiller performs normal duty and provides normal air conditioning. During the peak time of day, the chiller is turned off and ice water is used to air condition the office. The TES system uses a nominal 190 ton-hour tank and it has resulted in 10 kW summer peak reduction.

The new City Hall is a 265,000 square foot governmental office building. The facility is scheduled to open in 1991. It will be air-conditioned with two conventional, 308 ton centrifugal chillers. At night, the chillers produce very cold brine, which freezes ice on tubes (CALMAC system). During the nonpeak

portion of the day, the chillers produce normal chilled water to air condition the building. During the peak portion of the day, the chillers are turned off and ice water is used for air conditioning. The system will have about 5,800 ton-hours of storage and will remove about 635 kW from the summer peak.

In addition to continuing to pursue the SEI identified programs, OUC initiated a curtailable rate program effective July 1, 1990. The curtailable rates apply to General Service Demand Primary and Secondary customers. As of March 1, 1991, no customers have switched to the curtailable rate schedule.

1B.6.3 Analysis of Demand-Side Management Program Alternatives

The following subsections outline the results of the demand-side planning study update done by Battelle.

1B.6.3.1 Description of DSMPRO

The Demand-Side Management Program Design and Impact Assessment Model (DSMPRO) was used to assess the benefits and costs of the DSM-program/technical alternatives. DSMPRO was developed by the Alliance to Save Energy over the years 1981 to 1987 in two major case-study research projects with Arkansas Power & Light Company and General Public Utilities. The model was developed to assess the load impacts, benefits, and costs of utility DSM programs.

DSMPRO was chosen for the following reasons.

- Due to the Alliance work, it was a tested model.
- It requires average and/or peak load shape data.
- It could be easily reprogrammed to account for OUC-specific data and characteristics. Battelle performed the reprogramming of DSMPRO for the present OUC study.

The major steps in the DSMPRO approach are the following.

- Calculation of load curve impacts.
- Calculation of program revenue and expense cash flows.
- Calculation of program benefit/cost tests.

All DSMPRO data input requirements as used for the OUC analysis are listed in Subsection 1B.6.3.2.

1B.6.3.1.1 Calculation of Load Curve Impacts. When estimating the magnitude of annual electricity consumption or peak demand savings for any DSM option, the DSMPRO approach categorizes the option based on one or more of three basic investment assumptions.

Calculation of load curve impacts involve selecting the customer target market in terms of one or more or a combination of these basic investment assumptions, and then conducting a before-and-after DSM program market penetration analysis.

Many DSM options, like high-efficiency appliances, are purchased to meet new needs, such as new housing, or to replace worn out equipment. Other DSM

options, such as low-flow showerheads, are used in new housing, but have their largest conservation opportunity in the retrofit of showerheads in existing housing.

Whether evaluated for new growth, normal replacement, or retrofit, each DSM option is first evaluated on a simple payback basis. The only difference between the treatment of the three basic investment assumptions is how changes in annual energy consumption and peak demand for capacity are allocated over time.

1B.6.3.1.2 New Growth. Certain DSM options can meet electricity service needs for new growth such as higher insulation levels in new home construction and new appliance purchase. The calculation of the number of customers for new growth is illustrated on Figure 1B.6.3-1. In this figure, the number of new customers in the end-use for which a DSM option is applicable is graphed. Taking the growth rate for customers with this end-use, the number of such customers is projected over time (the top line in the graph). Then the percentage of new customers with the end-use for which the DSM option does not technically apply is subtracted. If some portion of the population of customers does not find the option economically attractive, that percentage of customers is also subtracted. The shaded vertical distance for any year is the number of new customers.

1B.6.3.1.3 Normal Replacement. Whenever devices or buildings wear out and need replacement, DSM options compete with standard-efficiency alternatives for traditional uses of electricity just as they do for new growth opportunities. To estimate normal replacement, the useful life for a device is specified and used as a proxy for its rate of turnover. Once the useful life for a DSM option has been established, its stock turnover rate is estimated by assuming that replacement occurs at the end of its useful life and that the ages of all such devices are uniformly distributed. Thus, if an option has a life of five years, it is assumed that one-fifth, or 20 percent, of the devices are replaced each year.

Figure 1B.6.3-2 shows the calculation of the normal replacement or the cumulative number of customers replacing a device. First, the percentage of customers for which the DSM option is applicable and economically attractive is plotted (e.g., 100 percent). Assuming a useful life of five years, 20 percent of the customers will replace the device each year. Therefore, the cumulative percentage of customers replacing the device increases incrementally each year by 20 percent of the initial year's applicable customers until the fifth year when all of the devices currently in the stock have been replaced--the shaded area.

1B.6.3.1.4 Retrofit. DSM options that can be immediately applied to existing devices, buildings, and processes without waiting for normal replacement are called retrofit opportunities. Examples of such opportunities include hot water tank wraps and ceiling or wall insulation. DSMPRO retrofit opportunities are handled as illustrated on Figure 1B.6.3-3.

In Figure 1B.6.3-3, it is assumed that the retrofit DSM option is fitted to a device, building, or process that is subject to a normal replacement pattern. It is also assumed that the decision to retrofit is based on the remaining useful life of the equipment, process, or building upon which the retrofit will be made. For example, customers or society will not consider an expensive weatherization retrofit for a building to be economic if the building is to be torn down in a year or two. In these circumstances, the useful life required to keep a DSM option economic is estimated by determining the shortest useful life that keeps the payback of investment above the customers cutoff criterion.

As an example, assume (for society) that a device with a useful life of five years must have at least two years or more of remaining life for a DSM retrofit option to be economic. Therefore, devices available for retrofit with lives of two years or less are ignored. In Figure 1B.6.3-3 this is indicated by the nonshaded area. The percentage of customers for whom the DSM option is applicable eventually declines as the device or building to which the option applies is replaced in the market.

When each applicable segment of stock for a DSM option has been accounted for separately, the total number of customers entering the market to purchase the device each year is determined by the summation of all individual components: new, normal replacement, or retrofit.

1B.6.3.1.5 Market Penetration. Once the number of customers in the market year-by-year has been estimated, DSMPRO calculates the rate of market penetration for each DSM option and constructs a base case forecast.

Market penetration is the share of a given market that is attained by a DSM option at a given time.

To estimate the incremental impacts of any DSM program, base case market penetration curves of DSM options are first estimated assuming no new DSM programs are offered by a utility or government. Then incremental impacts of the DSM program are analyzed. Thus, the use of market penetration analysis is done

twice: (1) to establish DSM option baseline market shares and (2) to estimate DSM program impacts on DSM option market shares.

For the purpose of analysis, the differences in the market shares between nonprogram and program conditions are expressed as annual energy savings and coincident summer and winter peak demand reductions. The incremental savings in energy and demand are then converted into cost and revenue impacts. These cash flow impacts become the basis for calculating tests of DSM program cost-effectiveness. This section discusses the market penetration approach both for establishing baseline and DSM program market share forecasts.

1B.6.3.1.6 Market Penetration Theory. The theory of market penetration is based on historical evidence that when a product is introduced and accepted in the marketplace, its rate of capture of market share will follow a predictable pattern. The market penetration process can be graphically represented by one of two "S-shaped" curves: (1) the proportion of each year's annual sales the product or process captures, and (2) the proportion of the total market the product or process captures each year. Figure 1B.6.3-4 illustrates these two views. The estimate of market share of current year's sales is graphed as the "current" market penetration curve. This curve shows that after five years, the product has captured 50 percent of annual sales, and by year 10, 100 percent.

The "cumulative" market penetration curve shows the percentage of the total market captured at any point in time. Because only a portion of the stock is replaced each year, even though the product captured 100 percent of annual sales by year 10, it captures only about 30 percent of the total market by that time, and it takes over 10 more years to capture the remainder of the market. The actual shape of such curves depends on the characteristics of the individual DSM options and their markets.

1B.6.3.1.7 Market Penetration Model. Market penetration models using mathematically derived S-shaped curves have been found to accurately approximate historical data on market penetration for many products and processes. Most of these models are deterministic and employ logistic algorithms to estimate the S-shaped market penetration curve. The model used in DSMPRO was originally

developed by Mansfield and later refined by Blackman.* This model was further enhanced in a number of ways that make it even more useful in analyzing DSM market penetration and DSM program impacts on market penetration. The basic Mansfield-Blackman model is described first, followed by a discussion of the enhancements to the model.

1B.6.3.1.8 Mansfield-Blackman Market Penetration Model. The Mansfield-Blackman model calculates market shares for a DSM option over time according to:

$$\ln (m/L-m) = \ln (L/N) - 1 + \phi (t-t_1) \quad (1)$$

where

- m = market share captured at time, t, by the new product or process,
- L = long-run upper market share limit the new product or process can capture,
- N = initial year's market share,
- ϕ = constant, which represents the rate of market substitution, and
- t = time in years.

In equation (1), L, N, and ϕ are provided and the equation is solved year-by-year for m, the market share. The constant, ϕ , is referred to as the rate of market substitution or market response parameter. It is estimated from

$$\phi = Z + 0.53 (\pi) - 0.027 (S) \quad (2)$$

where

- Z = a constant reflecting a given customer classes' propensity to innovate,
- π = required payback/actual payback, and
- S = (original cost of investment x 100)/average customer or firm asset value.

The parameters for this equation were estimated by Mansfield based on the historical substitution of 12 process innovations in the bituminous coal, iron and steel, brewing, and railroad industries. The constant, Z, reflects an industry's relative propensity to undertake an innovative investment. A regression equation

*E. Mansfield, "Technical Change and the Rate of Imitation," Econometrica, No. 4, 29 (1961): 741-65; and A. W. Blackman, Jr., "The Market Dynamics of Technological Substitution," Technology Forecasting and Social Change, 6 (1974): 41-63.

was derived by Blackman to depict the relationship between Z and an innovation index, I.* The relationship is

$$Z = 0.2221(I) - 0.3165 \quad (3)$$

where

I = innovative index.

The innovative index, I, was developed using a factor analysis technique relating market penetration rates to measure innovative activity, such as research and development expenditures and patents.

Once a value for the innovative index is estimated or obtained to calculate Z and the economic characteristics of the DSM option are determined for π and S, Equation (2) can be solved for ϕ . With an estimate of L and N, Equation (1) can be solved for a conservation product's market share as a function of time, t. This results in the construction of an S-shaped curve typified by the S-shaped curves on Figure 1B.6.3-4.

The key variable affecting the rate of investment in a DSM option in the Mansfield-Blackman model is its economic attractiveness. The lower (or shorter) the actual payback, the higher the π value, which in turn raises the value of the market response parameter, ϕ . The higher the ϕ value, the faster the product will enter the market.

The S term is the ratio of the investment (multiplied by 100) to the total assets of an average customer, firm, or plant within a customer class. In industry, Blackman found that the higher the cost of the innovation, the slower it would penetrate the market. This effect, however, is small compared to the effect of the investment's relative profitability.

The other term affecting the rate of investment is I, the innovative index. Blackman provides estimates of this term of 12 SIC categories. Judgment is used to derive estimates for the residential and commercial classes.

Enhancement of the Mansfield-Blackman Model with a Stock Adjustment Model improves the market penetration model. The primary interest in using a

*A. W. Blackman, Jr., E. J. Seligman, and G. C. Soglierd, "An Innovative Index Based on Factor Analysis," Technological Forecasting and Social Change, 4(1973):301-316.

market penetration model is to derive the cumulative market share numbers year-by-year for the total market. DSMPRO does this by using the Mansfield-Blackman model to derive the market penetration curve for a DSM option based on its share of current year's sales. Then a stock adjustment model is applied to track the DSM option's cumulative market share. This two-step process is preferred because it provides better estimates of the rate of investment on a cumulative basis rather than using the Mansfield-Blackman model alone.

The mechanics of the stock adjustment model are first, estimate the share of sales the DSM option captures each year over the planning horizon; second, estimate the number of units purchased each year on the basis of new growth and normal replacement; third, multiply the percentage penetration of sales by the number of units purchased to find the number of purchases of the DSM option for any given year; fourth, calculate the cumulative number of units of the DSM option purchased by adding the current year's purchases to the cumulative total of the previous year; and divide the cumulative total purchases for a DSM option for a given year by that year's total stock to find the cumulative market share.

1B.6.3.1.9 Calibrating Base Case Market Penetration Curves for DSM Options. Once all of the data have been specified, the modified Mansfield-Blackman model is run. The most important results are the market share numbers for the initial year of analysis. The appropriate number (either the current year's sales percentage or the cumulative percentage) is compared to the DSM option's corresponding estimated market penetration percentage for the initial year. These numbers will rarely be equal, even in the industrial sector for which the model estimates were derived, because of the many factors affecting DSM option market penetration. Therefore, the model is adjusted by trial and error until the model's market penetration estimate for the initial year equals the exogenous estimate of the initial year's market penetration percentage of an option.

The model is adjusted by the relative profitability variable (π) parameter because the model assumes that the rate of market penetration is most highly correlated to the relative profitability of an investment. The intent is to more accurately model the real relationship between market penetration for a customer class and the profitability of a DSM option. Equation (4) shows the inclusion of the adjustment factor in Equation (2).

$$\phi = Z + 0.53(AF) (\pi) - 0.027(S) \quad (4)$$

where

AF = adjustment factor.

By applying this approach, the base case cumulative market penetration curve for each DSM option is obtained.

1B.6.3.1.10 Calculating DSM Program Market Penetration Curves for DSM Options. To calculate the impacts on DSM option market penetration, DSM program characteristics and customer response behavior to those characteristics are defined; then the Mansfield-Blackman enhanced model is rerun.

1B.6.3.1.11 Setting DSM Program Characteristics. The DSMPRO model allows specification of two characteristics of a DSM program.

- Incentive values as a percent of option initial cost.
- Changes in the long-run maximum of option market shares.

The user can specify these characteristics differently for each DSM program option or can apply the characteristics to all DSM options.

The first characteristic to be specified is the value of any financial incentive(s) involved in the program. Any financial incentive, such as a cash rebate or subsidized loan, can be modeled by stating the value of the financial incentive in terms of a percentage of a DSM option's initial cost. The incentive can range from zero to any percentage (below 100 percent) of initial cost.

The second characteristic to be specified is the value of any change to the long-run upper market share maximum, L, that will occur due to the DSM program. The final characteristic that must be set is the length of the DSM program, that is, the years in which the program starts and stops.

1B.6.3.1.12 Setting Customer Response Characteristics. The fact that a utility or government offers a financial incentive through a DSM program does not automatically mean that the program will alter the shape of the cumulative market penetration curve. Any change in shape depends on how customers react to the program. Today's government or utility program planner generally knows very little about consumer response to DSM programs. DSMPRO allows users to model customer response--whether they have a lot or very little information--in a highly flexible manner by setting the way the model responds to different levels of incentive.

Customer response to alternative incentive levels can vary widely. But these response characteristics can be categorized into one of four basic patterns.

- Direct (or straight-line).
- S-Shaped.
- Dampened.
- Enhanced.

In Figure 1B.6.3-5, examples of the four patterns are shown. The patterns translate actual incentive percentages into modeled incentive percentages (rebate values are specified in terms of a percentage of option initial cost). For example, suppose consumers react very little to small incentives (incentives below 40 percent of initial cost) but respond to large incentives (about 50 percent). Under these circumstances, one might characterize consumer response as S-shaped. In Figure 1B.6.3-5, the S-shaped curve might portray such a relationship. Thus, an incentive value of 10 percent (read from the horizontal axis) might actually be modeled as an incentive value of perhaps 1 percent. On the other hand, a 70 percent incentive might be treated in the model as an 80 percent incentive. Using these four patterns, virtually any type of consumer response to any incentive level can be modeled.

After all DSM program and customer response characteristics have been set, the Mansfield-Blackman model is rerun to produce a new cumulative market penetration curve. Then load curve impacts are calculated.

1B.6.3.1.13 Program Load Curve Impacts. Once the nonprogram and DSM program cumulative market share curves are estimated for each DSM option, impacts on the utility's load curves can be determined. DSMPRO estimates impacts for annual sales, summer peak demand, and winter peak demand. The impacts on these loads are calculated by performing the following three steps.

- (1) Calculate the market penetration curves for the base case and the DSM program case.
- (2) Convert the market penetration curves into kWh and/or kW loads.
- (3) Calculate the load impacts for each year by subtracting each year's base case kWh and/or kW loads from the DSM program loads.

These calculations produce the year-by-year induced impacts of the DSM program on the utility's load curves:

With the implementation of the DSM program, both the total long-term number of customers and the rate of market penetration may rise. The long-run

total of customers may rise because the financial incentive makes it less expensive for a customer to invest in a DSM option, and increases the net present value (NPV) (or decreases the payback) on the investment. This will increase the number of customers in any given customer class for which the option will be economic. The rate of market penetration of the option will also increase, assuming some customer response to the program, because the relative profitability of the DSM option has been improved by offering the financial incentive which raises the value of the rate of substitution parameter.

1B.6.3.1.14 Calculation of Program Cost-Effectiveness Tests. Five steps are required to calculate the DSM program cost-effectiveness tests. First, DSM option market penetration curves are re-estimated for the incentive impacts. Second, kWh and kW loads are estimated for the DSM program and base cases. Third, the base case forecast (for annual kWh and summer and winter kW) is subtracted from the DSM program forecast. Fourth, load curve impacts are translated into utility, ratepayer, and society cash flow impacts. And finally, the benefit-cost tests are conducted.

1B.6.3.1.15 Cash Flow Impact Estimation. The load forecast differences between the DSM program forecast and the base case forecast are used to estimate the following six cash flow series induced by the DSM program.

- DSM program administrative costs.
- Fuel cost savings.
- Capacity cost savings (generation, transmission, and distribution).
- Societal equipment costs.
- Customer investment incentives (rebates or bill credits).
- Utility revenue losses.

These cash flow series are generated in terms of nominal or escalated dollars based on user-defined escalation rates. The calculation of each of these cash flow series is discussed in turn.

1B.6.3.1.15.1 DSM Program Administrative Costs (called Program Administration). Annual administrative and market (excluding incentives) costs for any DSM program are estimated outside the model and input as data on cost/customer basis. The yearly program operational cost remains fixed. The analyst also specifies the rate at which the yearly administrative costs will escalate. DSMPRO takes these inputs and generates the cash flow series for Program Administrative Costs.

1B.6.3.1.15.2 Fuel Cost Savings (called Energy Savings). Annual fuel cost savings are calculated by aggregating the annual kWh energy savings induced by the DSM program across DSM options, then multiplying by the utility's marginal energy costs per kWh on an escalated basis. The actual calculation, however, is based on seasonal and diurnal marginal energy costs and DSM option kWh program impact data. Marginal energy cost and DSM option kWh savings data are specified for four periods: summer on-peak, summer off-peak, winter on-peak, and winter off-peak. The results of the seasonal on- and off-peak calculations are adjusted upward by estimated line losses, then combined to produce the cash flow series for Fuel Cost Savings.

1B.6.3.1.15.3 Capacity Cost Savings (called Capacity Savings). Appropriate generation capacity credits were assigned to each program/technical option. To calculate Capacity Cost Savings, each DSM option was assigned a credit and multiplied by the respective escalated capacity costs to produce the cash flow series.

1B.6.3.1.15.4 Societal Equipment Costs (called Customer Costs). The calculation of the cash flow series for equipment costs is complex. First, for both the nonprogram and the DSM program cases, the number of units of a DSM option purchased is calculated. Next, the nonprogram (or base case) unit purchased series is subtracted from the DSM program unit purchased series to obtain the incremental units purchased due to the DSM program. Then the incremental number of units purchased each year is multiplied by the option's initial cost on an escalated basis to produce the cash flow series.

1B.6.3.1.15.5 Customer Investment Incentives (called Incentive Payments). Incentive payments in the form of one-time rebates for customer investment are calculated in the following manner. First, for each DSM option, the number of units purchased for the program case is calculated. Then, the same calculation is made for the nonprogram case and yearly values are subtracted from the program numbers to obtain the year-by-year differential. Next, the number of incremental units purchased due to the DSM program is multiplied by the incentive value on an escalated basis to produce the cash flow series for Customer Investment Incentives. Where the incentive consists of a bill credit that is received each year by the customer, DSMPRO tracks the accumulation of such incentives over the full period of the DSM program.

1B.6.3.1.15.6 Utility Revenue Losses (called Revenue Losses). Revenue Losses result from a DSM program's induced customer kWh and peak kW savings. The peak savings are those at the customer's peak, or connected load reductions. Revenue Losses due to induced conservation or load management reduce cash to cover operating expenses and fixed costs. Because induced conservation also reduces operating expenses (measured at the margin), it is only the fixed costs and any nonoffset operating costs that must be made up through additional revenues gained by raising rates. These additional charges fall mainly, but not entirely, on those customers who cannot participate in the DSM program. The amount of the revenue lost is not fully borne by nonparticipating customers because the rate increase required to recover lost revenues also affects customers participating in the DSM program. Therefore, actual revenue losses borne by nonparticipants equal lost revenues induced by the conservation or load management program less the portion borne by participating customers.

DSMPRO calculates Revenue Losses as described above. First, for a given DSM option, it estimates the number of induced units purchased by the DSM program. Next, it calculates the electric bill savings (Revenue Losses) each year on an escalated basis. Third, it calculates the number of participating customers in the DSM program for the DSM option and calculates for each year the percentage of nonparticipating customers.

1B.6.3.1.16 Regulatory Benefit-Cost Test Calculations. This section discusses the three benefit-cost tests considered to assess the cost-effectiveness of DSM programs. These tests, as defined and used in California, are as follows.

- Total Resource Cost (TRC) Test.
- Utility Cost Test (UCT).
- Rate Impact Measure (RIM) Test.

Figure 1B.6.3-6 compares these tests. The benefits associated with all of these tests are the same, namely the present value of the Fuel Savings plus the Capacity Savings, except that the present values are calculated at different discount rates for each test to reflect the tests' different perspectives. Otherwise, the tests differ only in their definition of costs. DSMPRO treats costs to society (TRC Test) as the incremental costs incurred by society to invest in the DSM options (equipment costs) plus program administrative costs. For the calculation of societal costs, externalities are not included because of the lack of data and accepted procedures to measure them.

Costs for the UCT are the administrative costs of the DSM program plus any subsidies paid out to customers as part of the DSM program. Nonparticipants--through higher rates--pay for the DSM program's administrative costs, subsidies, and revenue losses.

The UCT and TRC Tests are categorized as economic efficiency tests, focusing on different perspectives. The TRC Test is identical to a standard investment analysis. To society, the investment required to undertake additional conservation is the cost of the DSM program plus the added cost of making the additional DSM option purchases induced by the program. The benefits are the fuel and capacity cost savings generated by the investments. The calculation is a simple net present value calculation at the estimated discount rate for society. In this formulation, both revenue losses and subsidy payments are ignored because they are transfer payments from one member of society to another, canceling each other. In addition, costs associated with "free-riders" are also not included.

The UCT is also a simple matter of analyzing an investment. In this case, it is an investment in a DSM program rather than a traditional generating supply source. Here, the incremental costs to the utility equal the DSM program administrative costs and subsidy payments required to induce the incremental customer investment. The savings are the incremental fuel and capacity savings resulting from the induced customer investment.

For a utility interested in avoiding overcapacity in the long-term, DSM programs make sense whenever the long-run marginal cost of energy saved is less than energy that would be generated. From a utility perspective, the costs borne by customers in making the additional investments (initial cost less value of any subsidy or incentives) is irrelevant as are any revenue losses (assuming they will be recovered through higher per unit rates). If a commission will not make the utility whole for lost revenues, such lost cash flows should be included in the UCT as a cost of using the program.

The last test (RIM Test) is an equity test. Its sole purpose is to determine if nonparticipating customers of a utility offering a DSM program end up subsidizing participating customers. This occurs when they pay higher bills due to the rate increase required to cover lost revenues. Unless the savings in fuel costs and capacity savings offset program costs plus the lost revenues falling on the nonparticipants, nonparticipants subsidize participants and the test will not be satisfied. This test equals the fuel and capacity savings (benefits) less program

administrative, subsidy, and lost revenue costs. Positive net present values for these tests indicate passage of the tests.

In addition to calculating the TRC, UCT, and RIM tests on a net present value basis (benefits-costs), the results are also presented for the TRC and UCT tests as a benefit/cost ratio. The benefit/cost ratio for each test is formed by dividing the present value of the benefits by the present value of the costs. Benefit/cost ratios greater than one indicate test passage.

1B.6.3.2 Data Requirements for DSMPRO

General Information

Utility requirements

Initial year of analysis

Utility discount rate

Society discount rate

Customer discount rate

Summer period (in months)

Winter period (in months)

Equipment price index (annual growth rate)

Capacity marginal cost growth rates

Utility Marginal Costs

Energy: 30-year values in cents/kWh by summer on- and off-peak and winter on- and off-peak.

Demand: Initial value in \$/kW for summer peak generation capacity (plus start years).

Customer Class Rates

Residential: Energy (summer and winter) in cents/kWh.

Commercial and Industrial:

Energy (on- and off-peak) in cents/kWh.

Demand (summer and winter peak) in \$/kW/mo.

OUC 30-year forecast of nominal rate changes.

Residential End-Use Data

Number of customers

Growth rate in number of customers for the following end-uses:

Other and lighting

Refrigeration

Water heating
Resistance space heating
Heat pump space heating
Cooking
Drying
Freezer
Window air conditioning
Central air conditioning

Commercial End-Use Data

Number of customers

Growth rate in number of customers for the following end uses:

Ventilation
Cooling
Heating
Lighting
Refrigeration
Water heating
Cooking
Other

Technical Option Data

Option description

ID number

Applicable customer class

Investment assumptions (new, normal replacement, retrofit, mandated standard)

End-use category

Units assumed per customer

Initial cost

Cost basis (full or incremental)

Useful life

Number of facilities

Percent of customers in end-use with technical application

Percent of market penetrated

Year of product introduction

Energy Reduction (Increase) in kWh/unit

Winter on-peak
Winter off-peak
Summer off-peak
Summer on-peak
Total

Demand Reduction (Increase) in kW/unit

Winter diversified peak
Summer diversified peak
Winter connected load
Summer connected load

1B.6.3.3 Orlando Utilities Commission Data and Assumptions Used in DSM Program Screening

The DSMPRO model, along with best available data, was used to determine which of the DSM program options were best qualified for detailed load shape analysis.

The DSMPRO computer software program is designed for assessing the load impacts and benefits and costs of utility demand-side programs from the perspective of the utility, society, and nonparticipating customers.

There are four steps in using DSMPRO.

- (1) Collect and input OUC data.
- (2) Collect and input data specific to the DSM program options.
- (3) Estimate baseline technology penetrations.
- (4) Run DSMPRO and analyze the results.

Assumptions specific to OUC used in the DSMPRO analyses include the following.

<u>Commercial and Industrial Customers (1990)</u>	<u>Number</u>	<u>Annual Growth Rate</u> percent
General Service (nondemand)	13,221	2.4
General Service (demand)	2,347	2.4
Primary (demand)	<u>27</u>	2.4
Total	15,712	

Capacity benefits are based on the assumption that the units in the expansion plan could be delayed one year. Thus, for each year that a plant is scheduled to

be placed in service, that plant's deferred cost for one year is the value of the capacity benefit. For any one year, this value is simply the added cost to OUC of the rise in capital cost for the unit, which is assumed to be 4.5 percent per year. For the unit in-service dates in the expansion plan, these values (in nominal dollars) along with the capacity costs are as follows.

<u>Unit Start Year</u>	<u>Unit Cost</u> \$/kW	<u>Deferral Cost</u> \$/kW
1997	1,391	62.59
2010	2,669	120.10
2014	3,182	143.19
2017	3,631	163.40
2019	976	43.92

Lines Losses: 5 percent (applicable to kWh sales)

Reserve Margin: 15 percent (applicable to winter peak capacity reduction)

Escalation Rates: Equipment costs--4.5 percent
OUC administrative costs--4.0 percent

Discount Rates: OUC--7.03 percent
Society--7.00 percent
Customer--12.00 percent

Tables 1B.6.3-1 through 1B.6.3-3 present assumptions and OUC data on residential end-uses, residential and commercial rates, and marginal generation costs.

1B.6.3.4 Demand-Side Program/Technology Alternatives Data

Tables 1B.6.3-4 and 1B.6.3-5 present the data inputs for DSMPRO for each of the program/technology alternatives analyzed. Sources for these inputs are listed in Table 1B.6.3-6.

The following are notes regarding information listed in Tables 1B.6.3-4 and 1B.6.3-5 and the use of the data sources in developing the DSMPRO inputs.

- In Tables 1B.6.3-4 and 1B.6.3-5, the numbers appearing under the End-Use category and Rate Class category mean the following.

<u>Code Number</u>	<u>Residential</u>	<u>Commercial</u>
1	Lighting	Ventilation
2	Refrigerators	Cooling
3	Water Heating	Space Heating
4	Resistance Space Heating	Lighting
5	Heat Pump Space Heating	Refrigeration

<u>Code Number</u>	<u>Residential</u>	<u>Commercial</u>
6	Drying	Water Heating
7	Cooking	Cooling
8	Freezer	Miscellaneous
9	Window A/C	
10	Central A/C	
<u>Rate Class</u>	<u>Rate Schedule</u>	
1	Residential	
2	General Service (nondemand)	
3	General Service (demand)	
4	Primary (demand)	

- Assignment of program/technology alternatives into end-use, market segment, and rate classes are based on judgement.
- kWh and kW impact data are shown as positive values if they reduce energy or demand; negative if they increase energy or demand.
- All kWh impacts involve engineering estimates, or adjustments to secondary source data to reflect OUC's summer and winter peak periods and on- and off-peak categories.
- Diversified kW impacts are at OUC system peak; nondiversified kW impacts are at customer peak usage.
- The values in the column titled "Percent of End-Use" indicate the percentage of technical applications in the end-use category that the technology applies to. For example, it is estimated that only 50 percent of all residential lighting is amenable to compact fluorescent lamp use.
- Because rebate levels are calculated as a percentage of equipment incremental cost, some rebates exceed 100 percent, especially in direct load control and standby generation where the rebate value is actually the value of a billing credit, which is based on the value of kW saved and not equipment cost.
- Cost per program participant values reflect best available information and judgment and reflect average fixed and variable costs exclusive of rebates.

1B.6.3.5 Orlando Utilities Commission DSM Program Screening Results

Tables 1B.6.3-7 and 1B.6.3-8 present the complete results of the screening analyses for the residential and commercial DSM program alternatives. In each

table, the net present values (NPVs) of the benefit-cost tests (TRC, UCT, and RIM) are shown. Positive NPVs for the TRC and UCT indicate benefits exceed costs and the programs are economically cost-effective. Negative values for the RIM test indicate that a DSM program will result in a rise in rates from what they otherwise would have been in order to cover the lost revenues resulting from the program-induced conservation. In addition, the benefit/cost ratios are presented for the TRC and UCT economic cost-effectiveness tests. Values greater than one indicate program benefits cover program costs and the programs are cost-effective.

For residential programs (Table 1B.6.3-7), the programs having a UCT benefits/cost (B/C) ratio greater than one are in rank order.

<u>Residential Programs</u>	1990	1990	1997	1997
	UCT B/C Ratio	NPV (million)	GWh	MW
Replace Resistance Heat with Heat Pumps	6.0	16.8	3.7	2.9
Compact Fluorescent	5.6	5.5	2.5	0.8
Heat Pump Water Heater	1.6	0.8	<u>0.4</u>	<u>0.1</u>
Total			6.6	3.8

Also shown are the programs' GWh and MW savings for 1997, the first year when new capacity is needed.

Of these programs, Replacing Resistance Heat with Heat Pumps and Compact Fluorescent Lighting were chosen for detailed analysis. These programs were cost-effective and had total impacts on OUC energy and capacity requirements in 1997 of 6.2 GWh and 3.7 MW, respectively, according to the screening analysis.

The Heat Pump Water program was not chosen for detailed analysis because it failed the TRC test and OUC has had unfavorable experience promoting heat pump water heaters. OUC has promoted heat pump water heaters with the Residential Energy Surveys and the Low Income Home Fix Up programs since 1986. Only 18 heat pump water heaters have been installed as a result of OUC promotions. In 1990, OUC inspected 11 of the 18 installations. Four of the installations had minor operational problems. By October 3, 1990, four of the 18 installations had been removed due to major failures.

For commercial programs (Table 1B.6.3-8), the programs having a UCT B/C ratio greater than one are the following.

<u>Commercial Programs</u>	<u>1990 B/C Ratio</u>	<u>1990 NPV</u>	<u>1997 GWh</u>	<u>1997 MW</u>
Compact Fluorescent Lighting	16.2	1.7	0.8	0.2
Ellipsoidal Floodlamps	10.0	2.7	6.6	1.6
Ventilation Tune-up	2.4	0.2	0.1	0.0
Window Film	1.7	3.8	<u>21.0</u>	<u>0.0</u>
Total			28.5	1.8

Of these programs, the programs Compact Fluorescent and Ellipsoidal Floodlamps were chosen for detailed analysis. These programs have high benefit/cost ratios and contribute to 1997 demand reduction. The savings from these programs are 7.4 GWh and 1.8 MW.

The Ventilation Tune-Up program was not chosen because it failed the TRC test. The specific Window Film program was not chosen because of its low B/C ratio and lack of capacity savings. The Window Film program does have a high (2.68) benefit/cost ratio for the TRC test indicating the inherent benefits to the customer of installing window film. The installation of window film is encouraged as part of OUC's existing Commercial Energy Survey program and many customers have installed window film to obtain the savings associated with it. For these reasons, the specific Window Film program developed was not chosen for detailed evaluation.

Table 1B.6.3-1
Residential End-Uses: Number of Customers (1990)
and Growth Rates

<u>End-Use</u>	<u>Number of Customers</u>	<u>Growth Rate</u> percent
Lighting and Misc.	102,227	1.8
Refrigerators	107,137	1.9
Water Heat	94,006	1.8
Resistance Space Heat	57,258	0.0
Heat Pump Space Heat	15,227	3.8
Cooking	80,592	1.7
Drying	55,295	3.7
Freezers	21,489	3.0
Window A/C	25,120	(12.0)
Central A/C	60,022	2.4

Table 1B.6.3-2
Residential and Commercial and Industrial Energy and Demand Rates
(1990, Excluding Taxes) and Seasonal/Peak Periods

	<u>Rates</u> ¢/kWh	<u>Demand</u> \$/kW/mo
Rates:		
Residential	7.107	NA
Commercial and Industrial		
General Service (ND)	7.107	NA
General Service (D)	4.147	7.00
Primary (D)	3.865	6.30

Seasonal/Peak Periods:

Summer On-Peak: noon-9 p.m., M-F, April 1-October 31 (1,223 hours)
Summer Off-Peak: all other summer hours (3,913 hours)
Winter On-Peak: 6-10 a.m. and 6-10 p.m., M-F, November 1-March 31 (863 hours)
Winter Off-Peak: all other winter hours (2,761 hours)

Table 1B.6.3-3
Marginal Generation Costs (¢/kWh)

<u>Year</u>	<u>Winter Peak</u>	<u>Winter Off-Peak</u>	<u>Summer Peak</u>	<u>Summer Off-Peak</u>
1991	2.432	2.164	2.652	2.060
1992	2.509	2.298	3.236	2.553
1993	2.642	2.362	3.118	2.539
1994	2.942	2.580	3.396	2.714
1995	3.259	2.866	3.652	2.915
1996	3.267	3.189	4.592	3.424
1997	3.267	2.858	4.419	3.148
1998	3.747	3.149	4.728	3.545
1999	4.114	3.409	5.326	3.919
2000	4.987	4.034	6.022	4.142
2001	5.518	4.494	6.642	4.650
2002	5.751	4.658	7.392	5.340
2003	6.397	5.121	8.436	5.676
2004	7.239	5.706	8.946	6.432
2005	7.687	6.036	9.581	7.254
2006	9.081	7.313	10.982	7.415
2007	9.811	7.554	12.086	8.369
2008	9.374	7.295	12.121	8.586
2009	10.445	8.144	14.259	8.928
2010	7.124	6.103	11.432	7.024
2011	8.523	6.911	13.292	7.941
2012	11.595	8.833	13.400	7.974
2013	11.511	9.026	16.599	9.641
2014	8.420	7.320	12.221	7.382
2015	10.598	8.442	12.837	7.690
2016	13.384	9.896	15.844	8.568
2017	9.575	8.287	10.935	7.996
2018	14.673	11.043	12.811	8.496
2019	11.517	9.775	13.976	9.213
2020	14.091	11.288	16.051	10.021

Table 1B.6.3-4
Orlando Utilities Commission
Residential DSMPRO Input Data

DSM Program	Option Number	Number of Units	End-Use Category	Incremental Cost	Useful Life	Percent of End-Use	1990 Market Penetration	Year of Product Introduction	WOP kWh	WFP kWh	SOP kWh	SFP kWh
Compact Fluorescent	1	3	1	10	4	50	1	1987	37	36	0	102
DLC - Central A/C	2	1	10	175	12	30	0	1980	0	0	10	0
DLC - Water Heater	3	1	3	175	12	30	0	1980	5	3	3	2
DLC - HP/Resistance Heat	4	1	4	175	12	20	0	1980	77	0	0	0
HE Manual Defrost Refrig.	5	1	2	31	16	14	1	1989	6	18	8	25
HE Auto Defrost Refrig.	6	1	2	22	12	86	1	1989	12	38	17	57
HE Electric Water Heater	7	1	3	80	12	100	21	1984	96	97	135	135
WH - Waste Heat Recovery	10	1	3	750	12	100	1	1980	96	97	1005	1006
Heat Pump Water Heater	11	1	3	900	12	100	1	1982	344	344	688	689
Solar Water Heater	12	1	3	2500	20	100	1	1978	210	604	304	874
Replace Resistance w/HP	15	1	4	500	20	69	1	1982	1107	369	1605	535
HE Central Heat Pump	17	1	5	500	12	100	1	1983	86	159	123	232
HE Room Heat Pump	18	1	5	200	9	100	1	1983	28	52	41	79
HE Freezers	19	1	8	15	14	100	1	1989	8	20	9	29
HE Window A/C	20	1	9	150	9	100	1	1982	0	0	24	62

WOP denotes winter on-peak energy usage
WFP denotes winter off-peak energy usage
SOP denotes summer on-peak energy usage
SFP denotes summer off-peak energy usage

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Table 1B.6.3-4 (Continued)
Orlando Utilities Commission
Residential DSMPRO Input Data

DSM Program	Total kWh	Diversified		Non- Diversified		LR Market Penetration	Rate Class Category	Rebate Level (% Original Cost)	Cost per Program Participant
		WP kW	SP kW	WP kW	SP kW				
Compact Fluorescent	175	0.06	0.0	0.00	0.0	100	1	50	5
DLC - Central A/C	10	0.0	0.44	0.0	0.48	100	1	20	175
DLC - Water Heater	13	0.53	0.3	0.62	0.33	100	1	27	175
DLC - HP/Resistance Heat	77	3.4	0.0	3.7	0.0	100	1	20	175
HE Manual Defrost Refrig.	57	0.008	0.013	0.017	0.026	25	1	50	20
HE Auto-Defrost Refrig.	124	0.016	0.026	0.032	0.052	25	1	50	20
HE Electric Water Heater	483	0.018	0.015	0.028	0.023	100	1	50	20
WH-Waste Heat Recovery	2204	0.0	0.37	0.0	0.55	50	1	1	660
Heat Pump Water Heater	2065	0.315	0.218	0.49	0.334	25	1	10	50
Solar Water Heater	2000	0.2	0.26	0.3	0.39	10	1	10	100
Replace Resistance w/HP	3818	2.0	2.0	4.6	2.8	100	1	1.5	242
HE Central Heat Pump	600	1.76	1.78	2.5	2.53	100	1	15	240
HE Room Heat Pump	200	0.50	0.59	0.82	0.84	100	1	15	80
HE Freezers	84	0.008	0.013	0.017	0.026	25	1	50	20
HE Window A/C	86	0.0	0.59	0.0	0.83	100	1	15	80

1B.6.3-24

Table 1B.6.3-5
Orlando Utilities Commission
Commercial DSMPRO Input Data

DSM Program	Option Number	End-Use Category	Incremental Cost	Useful Life	Percent of End-Use	1990 Market Penetration	Year of Product Introduction	WOP kWh	WFP kWh	SOP kWh	SFP kWh
ASD - Ventilation Motor	1	1	21,101	15	20	5	1978	3,510	14,040	1,228	23,342
Ventilation Time-up	2	2	75	1	70	1	1975	0	0	192	600
HE A/C Package System	3	2	2,500	17	100	20	1980	0	0	4,875	1,625
Economizer	4	2	2,667	15	70	10	1972	3,220	3,220	0	1,610
Cool Storage	5	2	100,000	20	10	1	1970	63,505	(20,958)	63,665	(107,005)
Window Film	6	2	1,000	10	100	20	1966	1,000	3,000	3,500	3,500
Indepth Audit	7	3	20,000	5	100	1	1980	8,760	3,720	12,240	5,280
Walk-Thru Audit	8	3	500	5	50	20	1970	292	124	400	176
HE Conventional HP	9	3	2,500	17	100	20	1980	2,250	750	6,100	6,100
HE Lamps & Electronic Bal.	11	4	270	6	100	30	1977	600	600	852	852
T8 Lamps & Electronic Bal.	12	4	2,100	6	100	2	1985	1,977	1,977	2,760	2,760
De-Lamp w/Reflectors	13	4	1,500	30	100	8	1986	2,281	2,281	3,194	3,194
Compact Fluorescents	14	4	60	2	50	0	1987	400	400	560	560
Ellipsoidal Reflector Floods	15	4	30	1	100	15	1978	952	952	1,331	1,331
HP Sodium & Metal Halide	16	4	300	4	7	20	1968	0	593	0	792
HE Water Heater	17	6	50	12	7	21	1984	60	242	92	325
Heat Pump Water Heater	18	6	7,000	20	15	1	1985	5,871	5,872	0	16,139
WH - Heat Recovery System	19	6	1,642	15	30	12	1975	0	0	0	20,433
Demand Mgmt. Co-op	20	8	800,000	20	30	0	1980	0	0	0	0
EMS-Ventilation Control	21	1	32,100	15	10	50	1975	14,590	69,050	21,070	87,290
HE Motors	23	8	1,250	20	20	7	1977	445	1,418	630	2,007
Stand-by Generation	24	8	10,000	20	30	0	1970	(5,200)	0	(7,292)	0

WOP denotes winter on-peak energy usage
WFP denotes winter off-peak energy usage
SOP denotes summer on-peak energy usage
SFP denotes summer off-peak energy usage

Table 1B.6.3-5 (Continued)
Orlando Utilities Commission
Commercial DSMPRO Input Data

DSM Program	Total kWh	Diversified		Non-Diversified		LR Market Penetration	Rate Class Category	Rebate Level (% Original Cost)	Cost per Program Participant
		WP kW	SP kW	WP kW	SP kW				
ASD - Ventilation Motors	49,140	0	0	0	0	40	3	50	1,000
Ventilation Tune-up	800	0	.078	0	.1	60	2	50	75
HE A/C Package System	6,500	0	3.2	0	4.0	70	2	10	150
Economizer	8,050	0	0	0	0	20	3	50	750
Cool Storage	(69,593)	0	186	0	200	100	4	50	1,000
Window Film	11,000	0	3.5	0	3.0	80	2	50	100
Indepth Audit	30,000	6.2	3.2	10	5	15	2	50	1,000
Walk-Thru Audit	1,000	0	0	0	0	50	2	15	110
HE Conventional HP	15,200	4.0	5.6	7.6	8.0	70	2	10	150
HE Lamp & Electronic Bal.	2,920	.72	.72	.89	.89	50	2	25	400
T8 Lamp & Electronic Bal.	9,490	2.34	2.34	2.9	2.9	15	2	50	400
De-Lamping w/Reflectors	10,950	1.4	.77	1.56	1.17	35	2	40	400
Compact Fluorescents	1,940	.48	.48	.48	.48	50	2	75	10
Ellipsoidal Reflector Floods	4,566	1.1	1.1	1.46	1.46	60	2	50	10
HP Sodium & Metal Halide	1,385	0	0	0	0	90	2	50	450
HE Water Heater	725	.05	.04	.26	.26	100	2	50	300
Heat Pump Water Heater	28,128	0	0	0	0	50	2	50	300
WH-Heat Recovery System	20,433	0	0	0	0	30	3	35	1,000
Demand Mgmt. Co-op	0	2,000	2,000	2,000	2,000	5	4	65	20,000
EMS - Ventilation Control	192,000	156	180	240	240	75	4	200	1,000
HE Motors	4,500	.75	.75	1.5	1.5	75	4	50	500
Stand-by Generation	(12,500)	500	500	500	500	60	4	2,000	2,500

Table 1B.6.3-6
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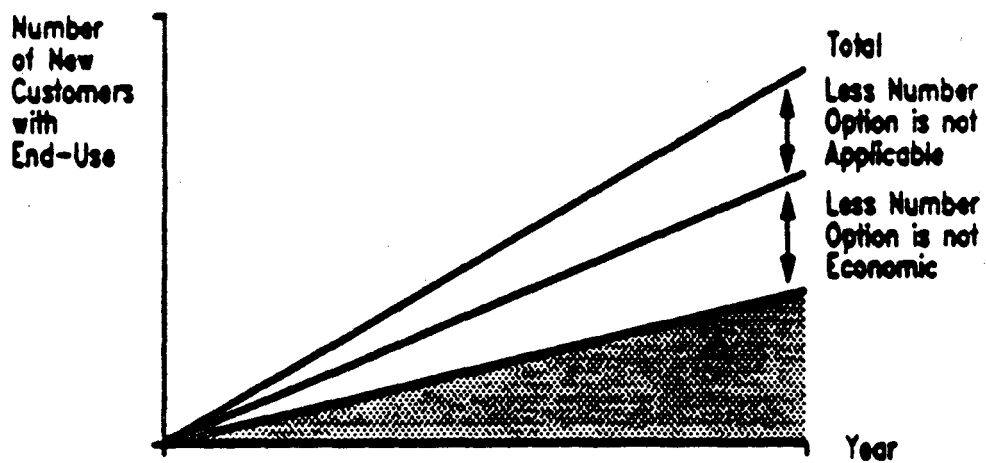
Table 1B.6.3-7
Orlando Utilities Commission
Residential DSM Programs
Primary Benefit/Cost Test Results

Demand-Side Program	Total Resource Cost Test		Utility Cost Test		Ratepayer Impact Measure Net Present Value (\$Million)
	Net Present Value (\$Million)	Benefit/ Cost Ratio	Net Present Value (\$Million)	Benefit/ Cost Ratio	
Compact Fluorescent	3.7	2.25	5.5	5.59	(5.0)
DLC - Central A/C	(4.4)	0.05	(19.8)	0.01	(17.4)
DLC - Water Heater	(3.1)	0.50	(32.4)	0.09	(28.6)
DLC - Heat Pump/Resistance Heat	0.0	3.40	(3.7)	0.69	(4.8)
HE Manual-Defrost Refrigerator	(0.1)	0.06	(0.1)	0.04	(0.1)
HE Auto-Defrost Refrigerator	(0.4)	0.14	(0.6)	0.10	(0.7)
HE Electric Water Heater	(1.5)	0.30	(5.2)	0.15	(6.6)
WH - Water Heat Recovery & Wraps	(9.3)	0.30	(4.2)	0.48	(8.9)
Heat Pump Water Heater	(1.7)	0.55	0.0	1.65	(2.0)
Solar Water Heater	(2.6)	0.23	(0.6)	0.55	(1.6)
Replace Resistance Heat with/ Heat Pump	10.6	2.10	16.8	6.04	(6.0)
HE Central Heat Pump	(2.3)	0.28	(0.9)	0.49	(1.4)
HE Room Heat Pump	(1.1)	0.24	(0.4)	0.48	(0.5)
HE Freezers	(0.1)	0.06	(0.1)	0.05	(0.1)
HE Window A/C	(0.4)	0.07	(0.2)	0.14	(0.2)

1B.6.3-28

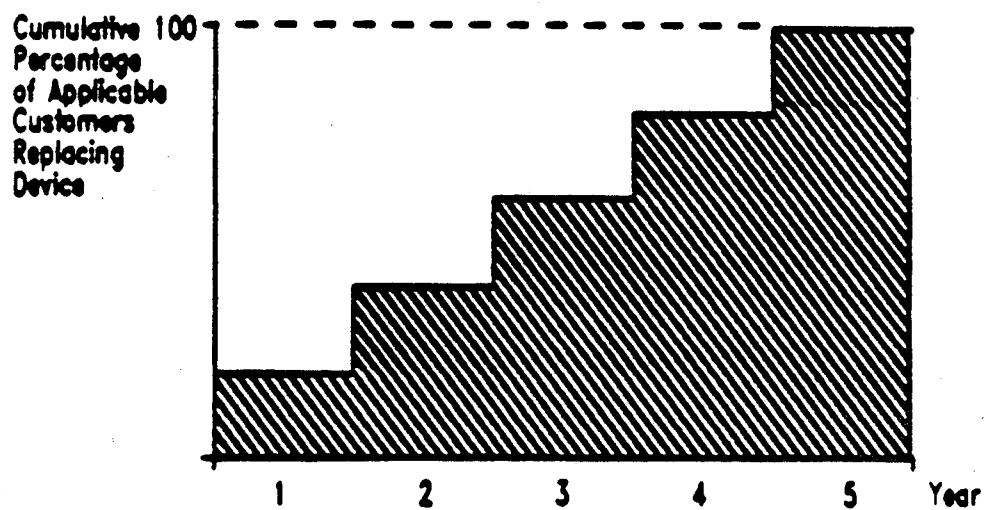
Table 1B.6.3-8
Orlando Utilities Commission
Commercial DSM Programs
Primary Benefit/Cost Test Results

Demand-Side Program	Total Resource Cost Test		Utility Cost Test		Ratepayer Impact Measure
	Net Present Value (\$million)	Benefit/ Cost Ratio	Net Present Value (\$million)	Benefit/ Cost Ratio	Net Present Value (\$million)
ASD - Ventilation Motors	(0.4)	0.19	(3.1)	0.03	(3.2)
Ventilation Tune-up	(0.7)	0.34	0.2	2.38	(0.4)
HE A/C Package System	(0.8)	0.78	(2.1)	0.58	(5.8)
Economizer	(0.3)	0.01	(0.4)	0.00	(0.8)
Cool Storage	0.0	0.0	0.0	0.0	(2.8)
Window Film	5.9	2.68	3.8	1.70	(14.1)
In-depth Audit	(0.1)	0.24	(4.6)	0.29	(6.1)
Walk-thru Audit	(0.9)	0.23	(0.3)	0.45	(0.8)
HE Conventional Heat Pump	(2.5)	0.14	(2.8)	0.13	(3.1)
HE Lamps & Electronic Ballasts	(3.4)	0.17	(3.6)	0.16	(4.9)
T8 Lamps & Electronic Ballasts	(1.2)	0.43	(3.3)	0.21	(4.4)
De-Lamping with Reflectors	0.6	1.21	(3.0)	0.55	(11.0)
Compact Fluorescents	1.1	2.43	1.7	16.19	(1.0)
Ellipsoidal Reflector Floods	2.3	4.38	2.7	9.95	(2.7)
HP Sodium & Metal Halide	(0.1)	0.23	(0.1)	0.34	(0.1)
HE Water Heater	(0.3)	0.05	(0.3)	0.05	(0.3)
Heat Pump Water Heater	(0.0)	0.08	(0.1)	0.53	(0.2)
WH - Heat Recovery System	(0.2)	0.59	(0.4)	0.41	(0.7)
Demand Management Co-ops	(3.1)	0.29	(0.8)	0.61	(8.9)
EMS - Ventilation	0.0	1.04	(17.5)	0.03	(19.1)
HE Motors	(0.1)	0.50	(0.3)	0.29	(0.5)
Stand-by Generation	0.0	0.00	0.0	0.00	4.9



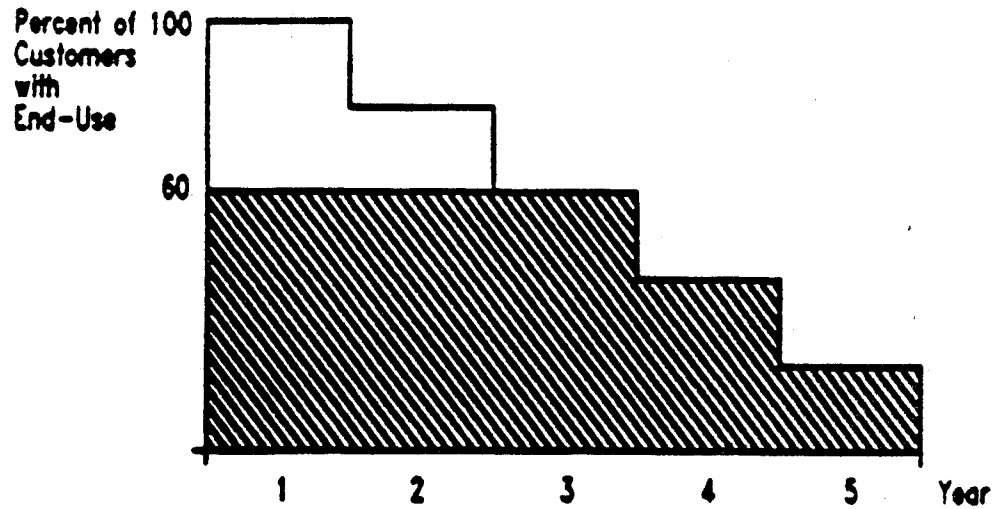
The number of new customers (consumer viewpoint) for which a DSM option is applicable (the shaded area) equals the total number of new customers less new customers for which the option is not applicable and not economic.

Determination of New Customers: Customer Viewpoint
Figure 1B.6.3-1



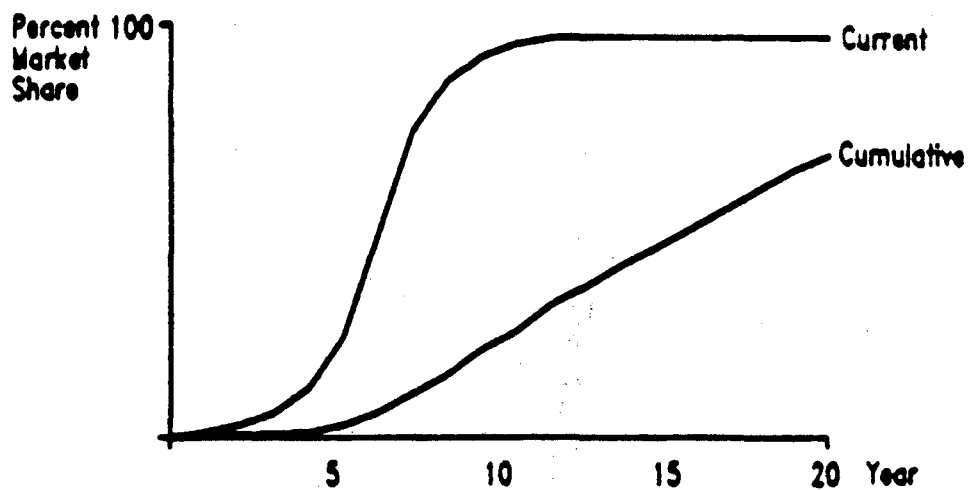
The shaded area shows the cumulative percentage of customers replacing a given electricity-using device for which a DSM option exists.

Determination of the Percentage of
Applicable Customers Replacing a Device
Figure 1B.6.3-2



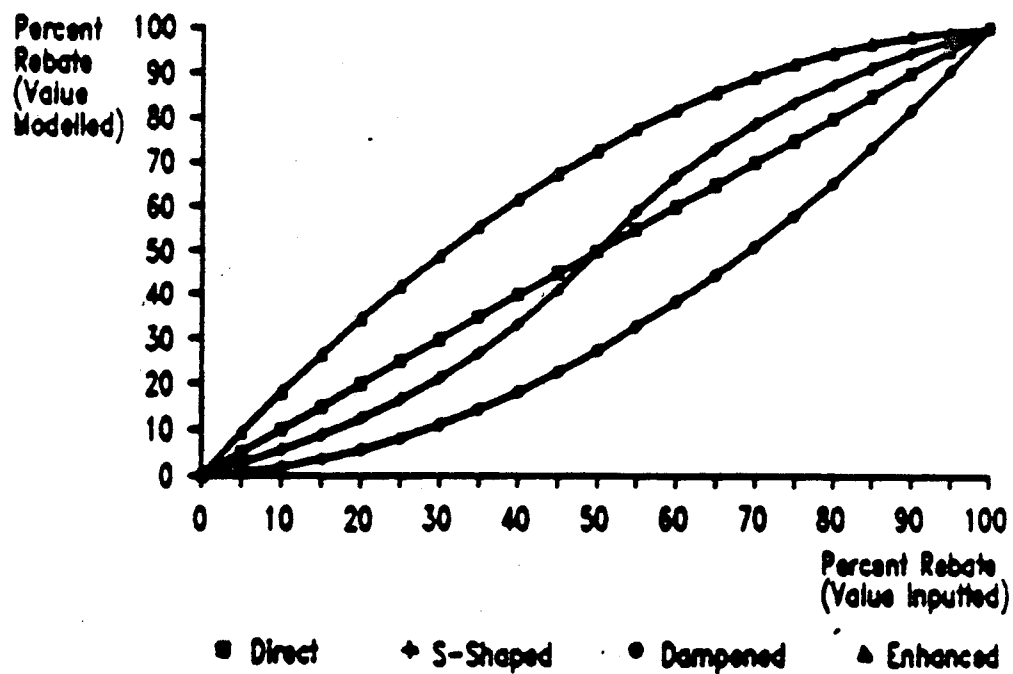
The percentage of customers for which the retrofit opportunity is applicable and economic declines over time as the device or building upon which the retrofit is applied is replaced.

Determination of Percentage of
Customers with Retrofit Opportunity
Figure 1B.6.3-3



The penetration of a DSM option in the total market trails the percentage share of current sales in direct proportion to the length of time it takes for the stock of the device to turn over.

Conservation Opportunity: Customer and Society
Figure 1B.6.3-4



A function translates the percentage value of a financial incentive (input on the x-axis) into a larger or smaller value (modeled on the y-axis) to obtain a DSM program response.

Four Basic Patterns of Customer Response
Figure 1B.6.3-5

Benefit-Cost Test	Benefits* [Less]	Costs*
Total Resource Cost	Fuel Savings Capacity Savings	Customer Costs Program Administration
Utility Cost	Fuel Savings Capacity Savings	Program Administration Rebates or Subsidies
Rate Impact Measures	Fuel Savings Capacity Savings	Program Administration Rebates or Subsidies Revenue Losses
* Present Value at the Test's Applicable Discount Rate.		

Comparison of Society, Utility, and Nonparticipants Benefit-Cost Tests.

Three Regulatory Benefit-Cost Tests
Figure 1B.6.3-6

1B.6.4 Detailed Analysis of DSM Alternatives

The top rated programs from the screening analysis were combined with programs identified previously in the OUC Long-Range Power Supply and Demand-Side Planning Study by SEI and four additional programs of interest to yield a group of potential candidates for detailed analysis. The list of potential candidates included the following.

- Residential
 - Direct load control of electric water heaters.
 - Direct load control of central air conditioners and heat pumps.
 - Direct load control of heat pumps and resistance heating.
 - Conversion of residential resistance space heating to heat pumps.
 - Compact fluorescent lighting.
 - Solar water heaters.
 - Voluntary time-of-use rates.
- Commercial
 - Ellipsoidal reflector flood lamps.
 - Compact fluorescent lighting.
 - Thermal energy storage (air conditioning).

The three residential direct load control programs were included for detailed evaluation because of the interest in direct load control in Florida and because benefits from direct load control are highly dependent upon the assumptions for the value of peak demand reductions associated with direct load control. Solar water heaters were also included for detailed evaluation because of the significant interest regarding them in the state. Voluntary time-of-use rates and thermal energy storage (air conditioning) were included for detailed evaluation because they were recommended by the SEI study.

In addition to the above programs, the demand reduction associated with OUC's curtailable rates based on standby generation was developed. OUC's curtailable rates are not dependent upon standby generation, but the use of standby generation provides a method for estimating the potential demand reductions. The curtailable rates are part of OUC's existing programs and went into effect on July 1, 1990. The effect of these new curtailable rates has not been included in OUC's load forecast necessitating the separate determination of the reductions. Peak only demand reductions were developed since the curtailments would only rarely be implemented, and the energy associated with them would

be minimal. Likewise, costs associated with the program were not developed since the curtailable rate is an existing program and any cost would apply to all expansion plans.

In the commercial class, the two commercial lighting programs were combined into a single program. The remaining nine programs were subsequently subjected for a detailed analyses.

The following sections describe briefly the techniques used in the detailed analysis, the characterization of the programs, and the results of the analysis.

1B.6.4.1 Method of Analysis

In this detailed analysis, the impacts of the selected DSM programs on the system load shape were estimated. The starting point of the analysis was the end-use load shape information contained in the OUC SHAPES-PC data base. Thus, for programs where the load shape modification at a given hour is independent of the corresponding system demand, SHAPES-PC was used directly to estimate the impacts. To illustrate this process, consider the program of converting residential resistance space heating to heat pumps. The current OUC SHAPES-PC data base explicitly recognizes resistance space heating and heat pumps in the residential sector. This implies that the contributions to system demand of these two devices are calculated for all times of day and temperature conditions. Under the assumption that the heating demand of program participants is the same as that in the SHAPES-PC data base, the load shape impact may be estimated by changing the stock of the two devices over time to reflect program participation.

Clearly, the above load shape estimation procedure is based upon the assumption that the load shape modification is independent of other factors, such as system load. For those DSM programs for which the load shape modification is dependent upon the magnitude of the system demand or time of day, another analysis tool, called RESHAPE, was used. RESHAPE is designed to simulate the load shape impacts of time-of-use rates and direct load control.

To illustrate the process of estimating the load shape impacts for programs in this category, consider the example of direct load control of electric water heaters.

1B.6.4.1.1 Step 1--Estimate Controllable Water Heater Load. The controllable water heater load is defined as the total water heater load that is available for control. Thus, it depends upon the number of participants and the customer's water heating contribution to system demand under normal (no control)

conditions. Under the assumption that the total number of electric water heaters is not affected by the program, the number of uncontrolled water heaters must be reduced by the number of program participants.

1B.6.4.1.2 Step 2--Characterization of Controllable Water Heater Load. The characterization of the controllable water heater load defines the operating characteristics of the load. In the case of water heaters, these include specification of the eligibility of the device, maximum hours of control in a 24-hour period, the amount of energy lost due to the curtailment, and the pattern in which the curtailed energy is being paid back after control ceases.

1B.6.4.1.3 Step 3--Estimation of Load Shape Impact. Having defined the operating characteristics of the water heater and estimated the total controllable load, the next step is to simulate the dispatch of the controllable load over time. The controllable load is curtailed whenever the system demand exceeds a user specified trigger point. The degree of curtailment is dependent upon the eligibility of the device and the constraints imposed on the device's operating characteristics.

RESHAPE examines all 8,760 hours of the year to determine if the trigger point has been exceeded. It then exercises control, depending upon the operating characteristics of the controllable load. If there is more than one controllable load, for example, controlled water heaters and controlled central air conditioners, the model dispatches these according to a user specified priority schedule.

Due to the magnitude of this output, hourly demand estimates were estimated for the above DSM options only for a given year. The year 2009 was selected for the hourly demand estimates since it is sufficiently far into the future to allow substantial program penetration into the marketplace.

The most attractive programs identified in the 2009 analyses were subsequently grouped into two categories for the detailed analysis in the integration studies. For both groups, hourly demand values for the entire planning horizon (1993 to 2020) were estimated as well as annual program costs for all three growth scenarios.

1B.6.4.2 Characterization of DSM Programs

In this subsection, the DSM programs listed above are described in terms of their load shape modification potential, the program participation rate, and the cost of the program.

1B.6.4.2.1 Direct Load Control of Electric Water Heaters. The high saturation levels of residential electric water heaters in the OUC service area, as well as their load characteristics, make the water heater an attractive target for direct load control. According to the OUC SHAPES-PC data base, the contribution to the winter peak of the average water heater is 0.53 kW. (This assumes the winter peak to occur in January at 9 a.m.) This estimate is consistent with results obtained by other Florida utilities. In addition to reducing the winter peak, water heater control can also reduce summer peaks. However, the impact of control is less in the summer than in the winter due to the operating characteristics of the water heater.

Based upon the high customer acceptance rate of direct load control of water heaters, particularly in Florida, a target penetration rate of 30 percent was assumed by 2009. This implies that by that date, 30 percent of all residential customers with electric water heaters will be participants in the program. A program start date of 1995 was assumed to allow time for the implementation of a pilot program.

The control limits were set to a maximum of four hours of continuous control, with a two-hour recharging period between controls. No loss in energy was assumed if control was exercised for only one hour. However, if control was exercised for more than one hour, 5 to 10 percent of the curtailed energy was assumed not to be recoverable. The recoverable energy is assumed to be paid back uniformly over a two-hour period. Based upon the experience of Florida utilities, this control schedule should not result in significant customer inconvenience.

Program costs consist of customer incentives to participate in the program, installation of control equipment at the customers' premise, and fixed costs for communications equipment and program administration. These costs, expressed in 1990 dollars, are as follows.

- Customer Incentive--\$48/year/customer.
- Field Equipment--\$175/customer.

- Fixed Program Cost.
 - Annual Program Administration--\$209,000/year.
 - Startup Cost (one time)--\$200,000.

It should be noted that the field costs and the fixed program costs cover all direct load control programs (direct load control of water heaters, space heating, and air conditioning).

1B.6.4.2.2 Direct Load Control of Central Air Conditioners and Heat Pumps (Cooling Mode). Although OUC is a winter peaking utility, direct load control of air conditioners and heat pumps (cooling mode) was included in the list due to the potentially significant operating cost savings and the small incremental cost for the program. In addition, the gap between the winter and summer peaks is projected to narrow on a percentage basis over the forecast horizon. Two types of control are currently used in Florida: air conditioner cycling and total shutoff for up to three hours. The cycling strategy analyzed was based upon a maximum of 30 minutes of interruptions during a 60-minute period.

A target penetration rate of 30 percent by 2009 was assumed. This implies (just as in the case of water heaters) that by that date, 30 percent of customers with central air conditioners and heat pumps will be participants in the program. A program start date of 1995 was assumed to allow time for the implementation of a pilot program.

If control is exercised for one hour, it was assumed that the total curtailed energy would be recovered during subsequent hours. For control periods exceeding one hour, the following recovery factors were assumed.

<u>Hours of Control</u>	<u>Energy Recoverable</u> percent
1	100
2	90
3	80
4	70

It was further assumed that the recoverable energy would be paid back in a 3-hour period with 50 percent of the energy paid back during the first hour and 25 percent in each of the remaining two hours.

Customer incentives for participating in the cycling program were \$36/year in 1990 dollars (\$6/month for the six summer months).

1B.6.4.2.3 Direct Load Control of Resistance Heating and Heat Pumps (Heating Mode). Electric space heating is the major factor influencing OUC's winter peak. Based upon the OUC SHAPES-PC data base, the contribution to the winter peak is 3.9 kW and 3.1 kW for the average resistance heating and heat pump customer, respectively. This estimate is based upon a temperature of 31 F at 9 a.m. These figures are consistent with estimates reported by Tampa Electric Company.

Two types of direct space heating control are currently used in Florida: space heating cycling and total shutoff for up to three hours. The cycling strategy explored here was based upon a maximum of 30 minutes of interruptions during a 60-minute period.

As in the case of air conditioner control, a target penetration rate of 30 percent by 2009 was assumed. Thus, by 2009, 30 percent of electric space heating customers are expected to be on direct load control. Again, a program start date of 1995 was assumed to allow time for the implementation of a pilot program.

Ninety percent of the energy curtailed by control is expected to be recovered. The recoverable energy is assumed to be paid back uniformly over a 2-hour period after control ceases.

Customer incentives for participating in the cycling program were \$36/year in 1990 dollars (\$6/month for the six winter months).

1B.6.4.2.4 Conversion of Residential Resistance Heating Customers to Heat Pumps. This program is designed to encourage residential customers currently using resistance heating to switch to the more energy efficient heat pump. Since resistance heating and heat pumps are already explicitly treated in the OUC SHAPES-PC model, estimating the effects of this program involves estimating the number of participants. By the year 2009, almost 14,000 customers are expected to participate in the program. This number is expected to grow to over 28,000 in the year 2020. These changes are over and above the forecasted changes in the composition of the residential space heating market. A program start date of 1993 was assumed.

Program cost consists of a fixed component of \$153,000 per year and a customer incentive of \$75 per customer in 1990 dollars.

1B.6.4.2.5 Residential Compact Fluorescent Lighting. Residential lighting accounts for roughly 1,000 kWh per year for the average residential customer.

Compact fluorescent lamps with a rating of 18-44 W provide the lighting equivalent of incandescent lamps rated at 60 to 150 W. Thus, the replacement of incandescent with fluorescent lamps results in an energy saving of 67 percent. A 175 kWh per year savings per customer was estimated since compact fluorescent lighting is not appropriate for many residential applications due to its size and shape. Thus, to estimate the impact of the program, the residential lighting load in SHAPES-PC was reduced by 175 kWh per year per program participant. A target program participation rate of 40 percent by 2009 was assumed. The program start date was assumed to be 1993.

1B.6.4.2.6 Commercial Lighting Program. Commercial lighting accounts for approximately 45 percent of the commercial temperature insensitive load. The commercial lighting program is designed to reduce the lighting load through the accelerated introduction of energy efficient fixtures, ballasts, and bulbs. Energy savings for program participants were estimated at 26 percent of the lighting load. A target program maximum participation rate of 20 percent by 2009 was assumed. The program start date was assumed to be 1993, and the program was assumed to culminate in 2009.

To estimate the load shape impact of the program, the commercial temperature insensitive load within SHAPES-PC was reduced to reflect the effect of the program savings and participation rate.

Program costs consist of customer incentives and program administration. These costs in 1990 dollars are as follows.

- Customer Incentives--\$45/kW saved.
- Fixed Program Cost--\$153,000/year.

1B.6.4.2.7 Residential Time-of-Use Rate Program. Time-of-Use rates, which charge different prices for electricity depending upon the time electricity is used, have been proposed as an alternative to the traditional time invariant rate. They reflect more accurately the cost of providing electrical service and thus give a more realistic price signal to the consumer. In addition, they provide an incentive to customers to shift electricity consumption from peak to off-peak periods, thereby flattening the load shape. Estimating the response of customers to Time-of-Use rates has been the subject of numerous experiments and analyses. In 1984, EPRI published a comprehensive study generalizing the results of pricing experiments sponsored by the US Department of Energy in coordination with selected utilities and regulatory agencies (Residential Response to Time-of-Use Rates,

Vol. 1, Development and Demonstration of a Transferability Model, EPRI, EA 3560, June 1984). The results of this study have been used here to estimate the load shape changes resulting from a Time-of-Use rate for the OUC residential sector.

A customer's response to Time-of-Use (TOU) rates may be partitioned into three distinct stages. The first stage shifts energy among periods of the day; i.e. it shifts energy from peak to off-peak periods in a weekday. The second stage shifts energy from weekdays to weekend usage, and the third stage captures the change in overall weekly or monthly electricity usage.

Under the assumption that there is little or no shift in energy from weekday to weekend and that the overall energy remains constant in the winter, but decreases by 6 percent during the summer months, the following load modifications were estimated.

Summer

$$\begin{array}{lcl} \text{Customer Peak Period} & = & 0.775 \times \text{Customer Peak} \\ \text{Demand with TOU} & & \text{Period Demand without TOU} \end{array}$$

$$\begin{array}{lcl} \text{Customer Off-Peak Period} & = & 1.033 \times \text{Customer Off-Peak} \\ \text{Demand with TOU} & & \text{Period Demand without TOU} \end{array}$$

Winter

$$\begin{array}{lcl} \text{Customer Peak Period} & = & 0.866 \times \text{Customer Peak} \\ \text{Demand with TOU} & & \text{Period Demand without TOU} \end{array}$$

$$\begin{array}{lcl} \text{Customer Off-Peak Period} & = & 1.057 \times \text{Customer Off-Peak} \\ \text{Demand with TOU} & & \text{Period Demand without TOU} \end{array}$$

In addition to the above assumptions, the results are predicated upon the following.

$$\text{Peak to Off-Peak Price Ratio} = 5.62$$

Ratio of Peak to Off-Peak
Energy Consumption:

$$\text{Winter} = 0.427$$

$$\text{Summer} = 0.565$$

The energy consumption ratios were computed by summing winter and summer peak and off-peak energy consumption for the residential class. The summer peak period energy was defined as weekday consumption from noon to

9 p.m. for April 1 through October 31. The winter peak period energy was defined as weekday consumption from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. for November 1 through March 31.

Since the program was assumed to be voluntary, a 5 percent participation rate was assumed by 2009. This implies that 5 percent of all residential customers are on the TOU rate by 2009.

1B.6.4.2.8 Commercial Thermal Energy Storage Program. Although OUC is a winter peaking system, thermal energy storage (air conditioning) was included for detailed analysis due to the interest in this technology in the service area. Thermal energy storage holds promise for utilities wishing to reduce cooling loads from system peak. In this analysis, a reduction in peak summer load of 15 MW by 2009 was assumed. Given the rule of thumb for cooling capacity of 3 kW per 1,000 sq ft, this translates into 5 million sq ft of commercial floorspace being cooled using storage air conditioning.

Program costs were estimated at a fixed component of \$126,000/year and a customer incentive of \$240/kW in 1990 dollars.

1B.6.4.2.9 Solar Water Heater Program. Electric water heaters account for a major portion of annual residential electricity consumption. Any change in the energy source for water heating could have a major impact on OUC's energy sales and peak demand.

Based upon data obtained from the Florida Solar Energy Center ("Electrical Use, Efficiency and Peak Demand of Electric Resistance, Heat Pump, DeSuperheater and Solar Hot Water System," Tim Herrigan and Danny Parker, ACEEE 1990 Summer Study on Energy Efficiency in Buildings) 67 percent of a household's water heating requirements may be met by a solar water heater in Florida, the remainder being supplied by the electric backup system. Using an average annual water heater consumption of 2,400 kWh, this translates into an average savings of 1,608 kWh per year. At an average residential rate of 7.1¢/kWh this yields an annual savings of \$114.17.

At an installed cost of \$2,500, the simple payback of the solar water heater to the customer is over 20 years. This is too long to achieve significant market penetration.

It is estimated that the solar water heater will reduce winter peak demand by approximately 0.3 to 0.4 kW per unit. Reducing the payback period to a consumer acceptable range of four to five years requires an incentive of \$1,900

to \$2,000. Given the above capacity impacts, this corresponds to a capacity cost that substantially exceeds the current cost.

Based upon this analysis, the solar water heater was dropped from further consideration.

1B.6.4.2.10 Curtailable Rates. Load reductions for OUC's curtailable rates for General Service Demand Primary and Secondary customers are estimated based on projections of standby generation to achieve curtailments. Costs associated with the curtailable rate program have not been developed since the curtailable rates are an existing program. Energy reductions have not been developed since curtailments are only rarely expected to be implemented and associated energy reductions would be minimal. Load reductions are shown in Table 1B.6.4-1.

1B.6.4.3 Results of Detailed Analyses

The summary results of the detailed analysis are given in Table 1B.6.4-2. Clearly, as shown in Table 1B.6.4-2, direct load control has the greatest impact on the system peak demand. The changes in production costs calculated in the RESHAPE model are small due to the limited amount of control exercised. Substantial reductions in winter and summer peaks are also observed for commercial lighting, conversion of residential resistance heating to heat pumps, and commercial thermal energy storage.

Based upon the above results, TOU rates and the residential lighting program were dropped from further consideration due to the small impact of these programs. The three-hour shutoff of electric space heating load control option was dropped in favor of the cycling strategy since cycling produces less customer inconvenience than the total shutoff. Finally, commercial thermal energy storage was dropped because of its failure to reduce OUC's winter peak. This of course assumes that OUC will remain a winter peaking utility. Thus, as the relative difference in the summer and winter peaks decreases, the thermal energy storage option should be reevaluated periodically.

The remaining DSM options were combined into two groups: (1) commercial lighting and conversion of residential resistance heating to heat pumps and (2) Group 1 plus direct load control of water heaters, space heating, and air conditioning. For both of these groups, load shape estimates were produced for the 1993 to 2020 planning horizon.

A program starting date of 1995 was assumed for direct load control programs. A three- to four-year time frame was felt necessary to conduct more detailed investigations, possibly involving pilot studies and to allow for an effective program initiation. For the commercial lighting program and the conversion of resistance to heat pumps, a shorter lead time seemed to be required. Thus, a starting date of 1993 was assumed.

Statistics of the two DSM cases and the base case are presented in Table 1B.6.4-3. Program costs as well as participation rates are given in Tables 1B.6.4-4 through 1B.6.4-6. All costs are given in nominal dollars. A general cost escalation rate of 4 percent per year was assumed. With the exception of the commercial lighting incentive, which escalates only by 1 percent a year, all other incentives follow the general escalation rate. The 1 percent escalation rate for commercial lighting was based upon the assumption that once the program gains momentum, the importance of incentives will decrease.

The modified load shape data as well as the costs are used with supply options to arrive at the integrated supply- and demand-side expansion plan as described in Subsection 1B.11.0.

Table 1B.6.4-1
Load Reductions for Curtailable Rates

<u>Year</u>	<u>Winter Peak Demand Reduction kW</u>
1991	0
1992	392
1993	1,204
1994	2,054
1995	2,945
1996	3,446
1997	4,411
1998	4,969
1999	6,013
2000	7,105
2001	7,760
2002	8,940
2003	10,172
2004	10,937
2005	12,266
2006	13,652
2007	13,980
2008	14,315
2009	14,659
2010	15,011
2011	15,371
2012	15,740
2013	16,118
2014	16,505
2015	16,901
2016	17,306
2017	17,722
2018	18,147
2019	18,582
2020	19,028

Table 1B.6.4-2
Deviations from Base Case (2009)

Program	OUC Native	Coincident Peak	Annual Energy (Gwhrs)	Production Costs* (Million of 2009\$)
	Summer Peak (MW)	Winter Peak (MW)		
Direct Load Control of Electric Water Heaters	(10)	(22)	--	(0.2)
Direct Load Control of Air Conditioners and Heat Pumps (summer)	(32)	--	--	(0.1)
Direct Load Control of Resistance Heating and Heat Pumps (cycling)	--	(65)	--	--
Direct Load Control of Resistance Heating and Heat Pump (3 hr shut-off)	--	(90)	--	(0.1)
Residential Lighting	--	(2)	(12)	(1.2)
Commercial Lighting	(9)	(24)	(182)	(19.7)
Residential Time of Use	(4)	(5)	(6)	(0.8)
Conversion of Resistance Heating to Heat Pumps	(2)	(19)	(8)	(2.5)
Commercial Thermal Energy Storage	(15)	--	2	(1.3)

Note: Negative differentials indicate reductions in peak energy or cost.

*Approximate cost based on RESHAPE's simplified costing algorithm.

Table 1B.6.4-3
Annual Summary Statistics of Two DSM Cases and the Base Case

Year	Annual Peak--Winter			Annual Net Energy for Load			Annual Load Factor		
	Base Case (MW)	Case 1 (MW)	Case 2 (MW)	Base Case (GWh)	Case 1 (GWh)	Case 2 (GWh)	Base Case	Case 1	Case 2
1993	888	857	854	4182	4098	4098	54.45%	54.56%	54.75%
1994	894	890	888	4271	4257	4257	54.54%	54.68%	54.85%
1995	937	938	928	4473	4452	4452	54.49%	54.65%	54.88%
1996	988	969	968	4698	4662	4662	54.63%	54.92%	55.44%
1997	1023	1009	996	4891	4855	4855	54.58%	54.93%	55.78%
1998	1061	1045	1027	5083	5037	5037	54.69%	55.02%	55.99%
1999	1097	1078	1053	5263	5205	5205	54.77%	55.12%	56.43%
2000	1134	1113	1084	5444	5376	5376	54.88%	55.14%	56.61%
2001	1175	1154	1118	5672	5593	5593	55.11%	55.33%	57.11%
2002	1206	1181	1141	5865	5771	5771	55.52%	55.78%	57.74%
2003	1245	1218	1175	6092	5983	5983	55.86%	56.17%	58.13%
2004	1282	1251	1208	6288	6165	6165	55.99%	56.28%	58.26%
2005	1311	1278	1235	6469	6328	6328	56.33%	56.52%	58.49%
2006	1336	1302	1268	6628	6471	6471	56.63%	56.74%	58.72%
2007	1367	1332	1287	6821	6647	6647	56.96%	56.97%	58.96%
2008	1405	1365	1319	7030	6845	6845	57.12%	57.24%	59.24%
2009	1440	1397	1358	7219	7028	7028	57.23%	57.43%	59.43%
2010	1498	1447	1398	7481	7281	7281	57.32%	57.44%	59.45%
2011	1535	1487	1438	7714	7504	7504	57.37%	57.61%	59.65%
2012	1574	1527	1476	7948	7734	7734	57.84%	57.82%	59.88%
2013	1622	1589	1518	8191	7968	7968	57.85%	57.96%	59.98%
2014	1684	1611	1558	8440	8208	8208	57.98%	58.16%	60.22%
2015	1712	1655	1609	8699	8457	8457	58.99%	58.33%	60.38%
2016	1755	1698	1648	8962	8713	8713	58.29%	58.58%	60.65%
2017	1806	1743	1684	9239	8977	8977	58.48%	58.79%	60.85%
2018	1855	1792	1731	9519	9249	9249	58.58%	58.92%	60.99%
2019	1912	1843	1788	9810	9529	9529	58.57%	59.02%	61.11%
2020	1958	1898	1828	10107	9818	9818	58.93%	59.38%	61.38%

Case 1: Commercial Lighting and Conversion of Resistance Heat to Heat Pumps

Case 2: Direct Load Control (Water Heaters, Heating and Cooling) with Case 1 in place.

Table 1B.6.4-4
Costs and Participation for Commercial Lighting Program

YEAR	CUMULATIVE PROGRAM COST(\$)	CUMULATIVE KW INSTALLED	CUMULATIVE INCENTIVES(\$)	CUMULATIVE TOTAL COSTS(\$)
1993	172,104	1,412	65,454	237,559
1994	351,093	2,824	131,563	482,656
1995	537,240	4,235	198,333	735,574
1996	730,834	5,647	265,771	996,605
1997	932,172	7,059	333,883	1,266,055
1998	1,141,563	8,471	402,677	1,544,239
1999	1,359,330	9,882	472,158	1,831,487
2000	1,585,807	11,294	542,334	2,128,141
2001	1,821,343	12,706	613,211	2,434,555
2002	2,066,301	14,118	684,798	2,751,099
2003	2,321,058	15,529	757,100	3,078,158
2004	2,586,004	16,941	830,126	3,416,130
2005	2,861,548	18,353	903,882	3,765,430
2006	3,148,115	19,765	978,375	4,126,489
2007	3,446,143	21,176	1,053,613	4,499,756
2008	3,756,093	22,588	1,129,603	4,885,697
2009	4,078,441	24,000	1,206,354	5,284,795

Table 1B.6.4-5
Costs and Participation for Heat Pump Conversion Program

YEAR	CUMULATIVE PROGRAM COST(\$)	CUMULATIVE PARTICIPANTS	CUMULATIVE INCENTIVES(\$)	CUMULATIVE TOTAL COSTS(\$)
1993	172,104	692	63,144	235,248
1994	351,093	1,415	131,756	482,849
1995	537,240	2,176	206,863	744,103
1996	730,834	3,015	292,980	1,023,814
1997	932,172	3,889	386,278	1,318,450
1998	1,141,563	4,791	486,417	1,627,980
1999	1,359,330	5,717	593,332	1,952,662
2000	1,585,807	6,643	704,524	2,290,331
2001	1,821,343	7,513	813,170	2,634,513
2002	2,066,301	8,268	911,226	2,977,527
2003	2,321,058	9,111	1,025,090	3,346,148
2004	2,586,004	9,939	1,141,403	3,727,407
2005	2,861,548	10,732	1,257,254	4,118,802
2006	3,148,115	11,495	1,373,181	4,521,296
2007	3,446,143	12,265	1,494,852	4,940,995
2008	3,756,093	13,037	1,621,718	5,377,811
2009	4,078,441	13,840	1,758,957	5,837,398
2010	4,413,683	15,645	2,079,784	6,493,468
2011	4,762,335	15,997	2,144,853	6,907,188
2012	5,124,932	17,948	2,519,928	7,644,861
2013	5,502,034	18,336	2,597,504	8,099,538
2014	5,894,219	20,365	3,019,405	8,913,624
2015	6,302,092	20,789	3,111,096	9,413,188
2016	6,726,280	22,899	3,585,641	10,311,921
2017	7,167,435	23,360	3,693,468	10,860,904
2018	7,626,237	25,555	4,227,412	11,853,650
2019	8,103,391	26,057	4,354,411	12,457,802
2020	8,599,630	28,338	4,954,552	13,554,183

Table 1B.6.4-6
Costs and Participation for Direct Load Control Program

Year	Cumulative Fixed Program Cost (\$1,000)	Water Heating	A/C	Heating	Cumulative Variable Program Costs (\$1,000)	Cumulative Program Incentives (\$1,000)	Cumulative Total Costs (\$1,000)
1994	288						288
1995	454	2373	1883	1777	518	299	1271
1996	719	4918	3949	3712	1898	948	2768
1997	994	7592	6189	5788	1734	1993	4721
1998	1288	18481	8591	8888	2433	3494	7287
1999	1577	13316	11144	18344	3192	5585	18273
2000	1887	16284	13886	12761	3998	8877	13962
2001	2288	19445	18788	15375	4898	11292	18398
2002	2543	22372	19457	17844	5785	15181	23489
2003	2891	25597	22548	28592	6785	19792	29448
2004	3253	28842	25711	23483	7818	25251	38321
2005	3829	32855	28925	28238	8985	31598	44132
2006	4821	35242	32188	29882	18833	38898	52951
2007	4428	38584	35586	32842	11239	47248	62987
2008	4851	41851	39135	35116	12532	58725	74189
2009	5292	45388	42918	38388	13952	67479	88723
2010	5758	48589	44815	39685	14435	78973	99157
2011	8228	47132	44622	48581	14789	91118	112851
2012	8228	47785	45238	41452	15881	183948	125173
2013	8228	48485	45862	42388	15389	117588	139835
2014	8228	49853	46493	43283	15835	131828	153881
2015	8228	49711	47136	44225	15981	148949	189156
2016	8228	58378	47786	45183	18348	182932	185588
2017	8228	51852	48444	46188	18735	179818	282779
2018	8228	51737	49114	47187	17146	197652	221825
2019	8228	52431	49792	48171	17582	218588	248387
2020	8228	53133	58476	49281	18842	236418	268677

1B.7 RELIABILITY CRITERIA

1B.7.0 Reliability Criteria

1B.7.1 Development of Reliability Criteria

OUC and the other utilities in Florida are members of the Florida Electric Power Coordinating Group (FCG). FCG has specific criteria for determining each utility's operating and spinning reserve requirements, but does not have specific criteria for determining planning reserve requirements. The selection of specific planning reserve criteria is the responsibility of the individual utility.

There are several different criteria used for specifying reliability and reserve requirements. The most common is the reserve margin. Reserve margin is a conventional, easily understood method for determining capacity adequacy at a particular time such as summer or winter peak demand.

Typically, minimum reserve margins for utilities range from 15 to 20 percent. The other large municipal utilities in Florida use a 20 percent reserve margin as shown below.

- Gainesville Regional Utilities.
- Jacksonville Electric Authority.
- City of Lakeland Electric Dept.

Florida Power & Light, the largest utility in the state, uses a criterion of 15 percent reserves based on summer peak demand and 0.1 day per year loss of load probability (LOLP). Based on a comparison to the other utilities in the state, a minimum reserve margin criterion of 15 to 20 percent would be reasonable for OUC; however, a 20 percent reserve margin would be more typical for the other large municipal utilities in the state. Table 1B.7.1-1 indicates that OUC's historical reserve margin has averaged 31 percent since 1972, but has dipped below 15 percent four times. Each time the reserve margin has dropped below 15 percent, generation capacity has been added by OUC.

For purposes of evaluating the need for Stanton 2, a 15 percent minimum reserve criterion has been chosen as a conservative criterion for determining the need for capacity additions. Based on the historical data presented in Table 1B.7.1-1 and the criterion used by other municipal utilities, a strong case could be made for a reserve criterion of 20 percent or even higher. The use of a higher reserve margin criterion will advance the need for Stanton 2 to an earlier date. The 15 percent reserve margin criterion is also used for determining the future need for capacity additions after Stanton 2.

As mentioned above, the reserve margin criterion is widely used and relatively simple to understand. It does, however, present only one value per year, ignoring load-shape characteristics which impact reliability. It also does not take into consideration the number, megawatt size, and availability of the generating units. To further substantiate the need for Stanton 2 and supplement the findings disclosed by the reserve margin criterion, additional analysis was done incorporating the Expected Unserved Energy (EUE) criterion.

The EUE methodology is a further extension of the LOLP method. For each hour of the year, the probability of losing increments of load is calculated. The amount of load lost multiplied by the probability of losing that increment of load is obtained for all possible load loss conditions and summed to calculate the hourly expected unserved energy. The annual EUE is the sum of each hour's EUE and is expressed as a percent of total energy required. Because the percent EUE criterion measures the reliability impacts of load shape changes, it is a more encompassing measure of reliability than the percent reserve margin.

The OUC Long-Range Power Supply and Demand-Side Planning Study completed by Southern Electric International (SEI) in May 1989, concluded that the maximum EUE for OUC should be 0.3 percent. Subsequent work by OUC indicates that system costs remain fairly constant between 0.3 and 0.5 percent EUE. In order to be conservative, the higher 0.5 EUE is used as the EUE criterion.

Table 1B.7.1-1
Historical Reliability Levels

<u>Year</u>	<u>Total Capacity MW</u>	<u>Annual Peak* MW</u>	<u>Reserve Margin percent</u>	<u>Unit Addition</u>	<u>Capacity Addition MW</u>
1972	426	381	11.81		
1973	418	406	2.96		
1974	767	629	21.94	Ind. Riv. 3	347
1975	775	641	20.90		
1976	776	660	17.58		
1977	752	718	4.74	Cry. Riv. 3	13
1978	760	437	73.91		
1979	758	496	52.82		
1980	758	547	38.57		
1981	743	582	27.66		
1982	873	571	52.89	McIntosh 3	130
1983	833	584	42.64	St. Lucie 2	49
1984	817	564	44.86		
1985	817	708	15.40		
1986	817	749	9.08		
1987	1,116	764	46.07	Stanton 1	299
1988	1,148	784	46.43		
1989	1,194	950	<u>25.68</u>	Ind. Riv. A & B	46
	Average		30.89		

*Includes firm sales to other utilities.

1B.7.2 Reliability Need for Stanton 2

Table 1B.7.2-1 presents the projected reliability levels for OUC's system without the addition of Stanton 2 and without the implementation of additional demand-side management programs. Peak demands are based on the calendar year peak demand projections from Subsection 1B.5.0 converted to fiscal year. The conversion to fiscal year peak demands is necessary due to the use of the typical meteorological year in developing the load forecast. The typical meteorological year always has the coldest temperature of the year occurring in January. In reality, actual weather variations like those which occurred in December 1989 can cause the peak demand to occur in the previous December, thus capacity additions must be in place to meet the winter peak demand.

Table 1B.7.2-1 includes the addition of 102 MW each of the Indian River C and D combustion turbines in September and October 1992, respectively. During the 1996-97 winter season, OUC's system reserve margin dips below the minimum criterion of 15 percent to 14.8 percent. The EUE increases to 0.55 percent in 1996, exceeding the suggested 0.5 percent. In 1997, it increases to 0.98 percent due to major turbine overhauls scheduled for Indian River Units 2 and 3 and then decreases in 1998 to 0.64 percent.

Table 1B.7.2-2 presents the projected reliability levels for OUC's system without the addition of Stanton 2 and with the implementation of additional demand-side management programs. With demand-side management programs implemented, the reserve margin does not dip below 15 percent until the 1997-98 winter season. The EUE increases to 0.53 percent in 1996 exceeding the 0.5 percent criterion. The EUE further increases to 0.95 percent in 1997.

The reserve margins in Table 1B.7.2-2 do not account for potential extreme weather peak demands. Table 1B.7.2-3 presents reserve margins based on the extreme winter weather peak demand forecast in Subsection 1B.5.0, including peak demand reductions from the implementation of additional demand-side programs. Under the extreme winter weather forecast, OUC's reserve margin dips to 9.3 percent in the 1996-97 winter season and to 6.0 percent in the 1997-98 winter season. With only a 79 MW reserve for the 1997-98 winter season under the extreme weather forecast, OUC would be unable to meet its total obligations with any one of its seven largest units out of service, without Stanton 2.

If OUC were to use a 20 percent minimum reserve criterion, Stanton 2 would be required in 1995 without additional demand-side management and in 1996 with additional demand-side management.

In summary, Stanton 2 is needed in 1997 to meet a 15 percent reserve margin including peak demand reductions for additional demand-side management. Based on a 0.5 percent EUE criterion, Stanton 2 is needed in 1996 with or without the implementation of additional demand-side management programs.

Table 1B.7.2-1
Projected Reliability Levels Without
Additional Demand-Side Management

<u>Winter Season</u>	<u>Total Capacity MW</u>	<u>Peak Demands*</u> MW	<u>Reserve Margin percent</u>	<u>Year</u>	<u>EUE percent</u>
1990-91	1,197	1,036	15.5	1991	0.65
1991-92	1,197	1,068	12.1	1992	1.68
1992-93	1,401**	1,077	30.1	1993	0.14
1993-94	1,401	1,111	26.1	1994	0.12
1994-95	1,401	1,144	22.5	1995	0.16
1995-96	1,401	1,177	19.0	1996	0.55
1996-97	1,401	1,220	14.8	1997	0.98
1997-98	1,401	1,258	11.4	1998	0.64

*Includes firm sales to other utilities.

**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.

Table 1B.7.2-2
Projected Reliability Levels With
Additional Demand-Side Management

<u>Winter Season</u>	<u>Total Capacity MW</u>	<u>Peak Demands*</u> MW	<u>Reserve Margin percent</u>	<u>Year</u>	<u>EUE percent</u>
1990-91	1,197	1,036	15.5	1991	0.65
1991-92	1,197	1,068	12.1	1992	1.68
1992-93	1,401**	1,073	30.6	1993	0.14
1993-94	1,401	1,105	26.8	1994	0.12
1994-95	1,401	1,134	23.5	1995	0.15
1995-96	1,401	1,163	20.5	1996	0.53
1996-97	1,401	1,202	16.6	1997	0.95
1997-98	1,401	1,237	13.3	1998	0.59

*Includes firm sales to other utilities.

**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.

Table 1B.7.2-3
Projected Reserve Margin With
Additional Demand-Side Management
Under Extreme Weather Conditions

<u>Winter Season</u>	<u>Total Capacity MW</u>	<u>Extreme Peak Demands*</u> MW	<u>Reserve Margin percent</u>
1990-91	1,197	1,101	8.7
1991-92	1,197	1,135	5.5
1992-93	1,401**	1,142	22.7
1993-94	1,401	1,178	18.9
1994-95	1,401	1,210	15.8
1995-96	1,401	1,211	15.7
1996-97	1,401	1,282	9.3
1997-98	1,401	1,322	6.0

*Includes firm sales to other utilities.

**Includes 204 MW capacity addition of Indian River Combustion Turbines C and D.

1B.8 SUPPLY-SIDE
ALTERNATIVES

1B.8.0 Supply-Side Alternatives

1B.8.1 Municipal Solid Waste--Co-Firing RDF at Stanton 2

Orange County and OUC cooperatively engaged consultants to conceptualize the systems and estimate costs associated with processing and burning refuse derived fuel (RDF) in the Stanton 2 steam generator.

These studies concluded that the cost of disposal for the county would double and a sizeable increase in the generation cost would occur for OUC. Also, there are capital cost savings to be realized if Stanton 2 can be constructed as a replication of Stanton 1. These savings would be materially eroded if the Stanton 2 steam generator and affected facilities are modified to accommodate co-burning of refuse.

The maximum amount of RDF that could be expected to be burned in Stanton 2 is 400 tons per day. The remainder of the required fuel would be coal. This amount of refuse represents 10 percent of the heat input at full load. At no partial load would the refuse input be allowed to exceed 20 percent of the heat input. Industry experience indicates that any higher percentage would increase the probability of slag formation in the boiler and further jeopardize the operating reliability of the unit.

In addition to the capital costs, there are additional considerations associated with burning refuse, such as reduced efficiency and reduced availability. Two major factors contribute to the loss of efficiency. The RDF transport air would not be preheated and therefore would enter the boiler at ambient temperature. Secondly, the moisture content of the RDF is higher than an equivalent amount of coal. Each of these factors results in the absorption of heat that would otherwise be used to produce steam.

The boiler manufacturer indicates that the boiler efficiency would decrease by 0.9 percent. The cost impact of boiler efficiency loss is reflected in an increase in net plant heat rate. Assuming that the gross electrical generation of the turbine generator remains the same, a reduction in boiler efficiency results in a greater amount of heat input to generate the same amount of power. The plant auxiliary power requirements also increase with the installation of RDF required modifications and additional equipment. The resulting increase in net plant heat rate is 1.7 percent due to the combination of decreased boiler efficiency and increased auxiliary power.

Currently, only four utilities have units co-burning RDF that are considered operationally successful. The additional equipment required and the erosive, corrosive, and slagging potential of RDF lead to the conclusion that unit availability may decrease when co-firing RDF. A review of the units for the four utilities which co-fire RDF and a comparison with similar units without co-firing indicate that it is reasonable to expect a reduction in availability due to co-firing RDF of 5 percent. For Stanton 2, each 1 percent decrease in plant availability is equivalent to approximately \$6 million in levelized cost to OUC over a 30-year period of plant operation.

The county is currently evaluating its recycling and segregated composting programs. The effectiveness of these programs will be studied through 1994 to determine whether a state mandated 30 percent reduction of solid waste can be achieved. The Citizens Coordinating Committee, which was formed to assist in the development and implementation of programs to reduce solid waste, has recommended that, "the County not proceed with permitting or initiating construction of a waste-to-energy facility until 1994 when the effectiveness of the total recycling program can be determined." This recommendation was based, in part, on the high cost of such a program compared to landfilling.

The "Assessment of the Joint Incineration Project between Orange County and the Orlando Utilities Commission" prepared by CSI Resource Systems, Incorporated, November 12, 1990, concludes in part that

Continued reliance of landfill is projected to be less expensive for the County than implementing an arrangement for co-firing RDF at Stanton II [Sic]. The cost of landfill disposal is projected at \$34 per ton in 1996 and \$84 per ton in 2015, with increases resulting mainly from the projected increases in the stringency of the regulatory requirements governing landfill disposal. The average system disposal cost for the base case [cofiring RDF in Stanton 2] RDF cofiring arrangement is projected at \$64 per ton in 1996 and \$87 per ton in 2015. The driving factors behind the comparatively high cost of the RDF cofiring arrangement include the substantial cost to construct and operate the RDF production facility; the need for landfill disposal of 43.2 percent of the waste processed in order to produce RDF of the requisite quality; and the low cost of coal that would be displaced by the RDF.

The "Assessment of the Joint Incineration Project between Orange County and the Orlando Utilities Commission" projects the life-cycle cost of disposal (in 1990 dollars) to be \$417 million for the landfill disposal option and \$536 million for the base case RDF co-firing option.

Based on the findings of various solid waste disposal studies, the county has decided not to pursue refuse co-burning in Stanton 2.

1B.8.2 Combined Cycle Conversion

OUC combustion turbine capacity consists of four combustion turbines, two existing and two planned, at the Indian River Plant. Combustion Turbines A and B are 46 MW winter rating General Electric Frame 6 units. Combustion Turbines C and D are 129 MW winter rating Westinghouse 501D units scheduled for commercial operation on September 1, 1992 and October 1, 1992, respectively. Indian River Units A and B are jointly owned by OUC, Kissimmee Utility Authority (KUA), and the Florida Municipal Power Agency (FMPA). Indian River Units C and D are jointly owned by OUC and FMPA. OUC's ownership share is 48.8 percent of Units A and B and 79 percent of Units C and D.

Technically, these combustion turbines could be converted to combined cycle operation. Conversion of the combustion turbines would change the character of the units from peaking capacity to intermediate capacity. To maintain an optimal generating mix, OUC would be required to add additional peaking capacity. For this reason, conversion of OUC's combustion turbines is not considered further as a generation option. The installation of new combined cycle units is considered as an alternative for providing intermediate capacity.

1B.8.3 Qualifying Facilities

1B.8.3.1 PURPA Requirements and Rules

The Public Utility Regulatory Policies Act (PURPA) was enacted by Congress on November 9, 1978. Section 210 specifically addresses cogeneration and small power production. The purpose of this section was to encourage the development of cogeneration and small power production projects. It required that the Federal Energy Regulatory Commission (FERC) develop a set of rules under which utilities, cogenerators, and small power producers would operate. It also required that each state regulatory authority implement such rules for each regulated utility under its jurisdiction, that each nonregulated utility implement such rules for itself, and that all electric utilities purchase energy from and sell energy to qualifying cogenerators and small power production facilities (QFs). The FERC rules were established on March 20, 1980, which meant that state regulatory authorities and nonregulated utilities were obligated to adopt these rules by March 20, 1981.

1B.8.3.2 OUC Rules

Orlando Utilities Commission (OUC) adopted, after a public hearing, Subparts A and C of the FERC rules, with some changes, on March 10, 1981. OUC's and the QF's obligations are contained in these rules. Since OUC's sales exceeded the 500 million kilowatt-hour per year threshold, it was required to make available to potential QF's, biennially, estimated avoided energy costs, the utility's 10-year generation expansion plans, and estimated capacity costs.

1B.8.3.3 PURPA Reports

Section 133 of PURPA required the filing of cost information beginning in 1980 and continuing every two years thereafter. FERC issued its rules in Order No. 48 on September 28, 1979. OUC filed reports on November 1, 1980; June 30, 1982; and June 30, 1984. On June 9, 1988, OUC was granted an exemption by FERC from filing these reports for the filing due June 30, 1986 and biennially thereafter.

1B.8.3.4 Transmission Service for Qualifying Facilities

In 1985, the PSC adopted Rule 25-17.88 which eventually became 25-17.088. This rule required that all electric utilities provide transmission wheeling service and tariffs for QF generated energy. On March 14, 1986, OUC put into effect its QF Transmission Tariff for firm and nonfirm service after receiving approval from the PSC.

1B.8.3.5 Standard Offer Tariffs and Contracts

The need for Stanton 1 in 1987 was based on the economics of oil back-out rather than meeting increased customer demands. For this reason, there was no avoided unit in OUC's system on which to base avoided capacity costs from 1981 to 1989. The only opportunity for QFs was to contract for as-available energy. Since the need for Stanton 2, in part, will be based on meeting increased customer demands, it is now the avoided unit and, therefore, standard tariffs and contracts have been developed for QFs. Standard offer rates and contracts are available for both firm and nonfirm transactions with QFs. These standard offer rates and contracts were filed for information purposes with the PSC on July 12, 1990.

1B.8.3.6 Inquiries from Potential Qualifying Facilities

OUC has responded to approximately 25 requests for information about avoided costs since 1978. These requests have come from a variety of sources such as government agencies, hospitals, industries, hotels, consultants, colleges, and private citizens. None of these requests have resulted in projects with sales to OUC.

1B.8.3.7 Potential for Cogeneration in OUC's Service Area

This subsection evaluates the potential for cogeneration in OUC's service area.

1B.8.3.7.1 Determination of Potential Cogeneration Candidates. As the first step in determining the potential for cogeneration in OUC's service area, a list of industrial and commercial facilities which would be potential candidates for cogeneration was developed. Industrial and commercial facilities with potential for cogeneration were listed by three-digit Standard Industrial Classification (SIC) code as shown in Table 1B.8.3-1. OUC's commercial and industrial customer

data base was searched for the SIC codes listed in Table 1B.8.3-1. A file was made of all customers having these codes. A total of 460 customers having the specified SIC codes was identified. The list of 460 customers was refined based on information provided by: the "1982 Census of Manufacturers: Fuels and Electric Energy Consumed" issued by the U.S. Department of Commerce; the November 1988 Electric Power Research Institute (EPRI) report "Cogeneration and Utilities: Status and Prospects"; and the June 1987 EPRI "Cogeneration Symposium."

1B.8.3.7.1.1 Industrial Customers. The "1982 Census of Manufacturers: Fuels and Electric Energy Consumed" lists companies which consume natural gas in the Orlando area. Companies currently purchasing natural gas could be potential candidates for cogeneration since they already have a demonstrated heating load and the means to obtain fuel. Table 1B.8.3-2 lists SIC codes for natural gas users in the Orlando area. A list of potential cogenerators by SIC code in EPRI was published by the Department of Energy's "Cogeneration and Utilities: Status and Prospects." The SIC codes that were in the Department of Energy's list and also purchased natural gas in the Orlando area are indicated in Table 1B.8.3-2.

Table 1B.8.3-2 indicates that SIC codes (27) Printing and Publishing; (30) Rubber and Miscellaneous Plastics; (35) Machinery, except electrical; and (36) Electric and Electronic Equipment, are not considered potential cogeneration candidates by the Department of Energy. Therefore, these codes were dropped from the list even though they had purchased natural gas in the Orlando area. The remaining SIC codes which were on both lists are: (20) Food and Kindred Products, (26) Paper and Allied Products, (30) Chemicals and Allied Products, and (34) Fabricated Metal Products. EPRI's "Cogeneration Symposium," Energy Initiative, Inc., shows the capacity range of potential cogenerators to be 500 kW to 60,000 kW. Projects less than 500 kW did not appear to be economically feasible. Therefore, individual companies from OUC's customer data base with an annual peak demand less than 500 kW were eliminated as a potential qualifying facility.

1B.8.3.7.1.2 Commercial Customers. In EPRI's "Cogeneration and Utilities: Status and Prospects," the Gas Research Institute lists potential cogenerators in the commercial sector by building type and capacity range. The only commercial customers in OUC's service areas which are potential cogenerators are hospitals (SIC 806) and hotels and motels (SIC 701), according to the Gas Research

Institute. The Gas Research Institute also showed that the capacity range for cogenerators to be technically feasible is 100 to 2,000 kW for hotels and motels and 200 to 1,000 kW for hospitals. In addition, only hotels and motels with central heat and air conditioning were considered potential qualifying facilities.

A total of 44 industrial and commercial customers in the OUC service area are potential candidates to become cogenerators based on these criteria.

1B.8.3.7.2 Cogeneration Cost. A cogeneration cost was calculated for each of the 44 potential industrial and commercial qualifying facilities. Generation capacity, annual kWh generation, annual capital cost, annual O&M cost, and annual fuel cost were estimated for each potential candidate. The annual kWh generation is a function of the estimated generation capacity and process load factor. The article "Industrial Cogeneration Potential" in Cogeneration World stated that 50 percent of generated capacity is typically sold back to the utility. This implies that a potential qualifying facility would install generation capacity equal to one and one half times its annual peak demand, thus allowing the cogenerator to use as little as one half of its annual peak demand while selling up to 100 percent of the annual peak demand to OUC. Process load factors for hospitals and hotels and motels were assumed to be 50 percent, while the load factors for manufacturers were assumed to be between 50 and 70 percent.

Capital cost and annual O&M cost depend on the type of process installed. A diesel/heat recovery steam generator was used for applications less than 2.5 MW. A combustion turbine/heat recovery steam generator was assumed installed for larger applications. The capital cost and annual O&M cost were estimated for each type of unit for each of the 44 potential cogenerators. A fixed charge rate of 16 percent was used to convert the capital cost into an annual cost.

The annual fuel cost is a function of the annual electric generation, heat rate, and natural gas price. The heat rate was estimated for diesel and combustion turbine processes. The natural gas prices used were the end-use prices to the industrial and commercial sectors as forecasted in the 1990 Annual Energy Outlook.

1B.8.3.7.3 Economic Feasibility. The economic feasibility of each of the potential manufacturing and commercial qualifying facilities was assessed by comparing the estimated cogeneration costs to OUC's commercial/industrial rate and to the standard offer contract price. The standard offer contract has been filed for informational purposes with the Public Service Commission. The

standard offer contract price including fuel, demand (at a 70 percent capacity factor), and nonfuel O&M is \$0.034 per kWh in 1991 dollars. The commercial/industrial rate including municipal utility tax is \$0.065 per kWh. It was considered economically feasible to generate electricity for internal uses instead of purchasing power from OUC if the cogeneration cost was less than the commercial/industrial rate. It was considered economically unfeasible to cogenerate instead of purchasing power from OUC if the cogeneration cost was greater than the commercial/industrial rate. As shown on Figure 1B.8.3-1, there appears to be 29 MW of economically feasible cogeneration available from the potential qualifying facilities.

If the cogeneration cost is less than the standard offer contract price, it is economically feasible to generate electrical energy equivalent to approximately 20 times the energy used in the industrial or commercial process based on the PURPA minimum thermal energy requirements, and sell the excess generation to OUC. If the cogeneration cost is greater than the standard offer contract price, the company would not want to generate substantial excess capacity. As shown on Figure 1B.8.3-1, estimated costs for all the potential cogenerators are greater than the standard offer contract price.

The analysis of cogeneration potential is very site-specific. It appears, however, that there is very little potential for cogeneration in OUC's service area.

Table 1B.8.3-1
Industrial and Commercial Facilities with Potential
for Cogeneration by Three-Digit SIC Code Descriptions

<u>SIC Code</u>	<u>Description</u>
011	Cash Grains
013	Field Crops, Except Cash Grains
016	Vegetables and Melons
017	Fruits and Tree Nuts
018	Horticultural Specialties
019	General Farms, Primarily Crop
021	Livestock, Exc. Dairy, Poultry, Etc.
024	Dairy Farms
025	Poultry and Eggs
027	Animal Specialties
029	General Farmers, Primarily Livestock
201	Meat Products
202	Dairy Products
203	Preserved Fruits and Vegetables
204	Grain Mill Products
205	Bakery Products
206	Sugar and Confectionery Products
207	Fats and Oils
208	Beverages
209	Miscellaneous Foods and Kindred Products
221	Weaving Mills, Cotton
222	Weaving Mills, Synthetics
223	Weaving and Finishing Mills, Wool
224	Narrow Fabric Mills
225	Knitting Mills
226	Textile Finishing, Except Wool
227	Floor Covering Mills
228	Yarn and Thread Mills
229	Miscellaneous Textile Goods
241	Logging Camps & Logging Contractors

Table 1B.8.3-1 (Continued)
Industrial and Commercial Facilities with Potential
for Cogeneration by Three-Digit SIC Code Descriptions

<u>SIC Code</u>	<u>Description</u>
242	Sawmills and Planing Mills
243	Millwork, Plywood & Structural Members
244	Wood Containers
245	Wood Buildings and Mobile Homes
249	Miscellaneous Wood Products
251	Household Furniture
252	Office Furniture
253	Public Building and Related Furniture
254	Partitions and Fixtures
259	Miscellaneous Furniture and Fixtures
261	Pulp Mills
262	Paper Mills
263	Paperboard Mills
265	Paperboard Containers and Boxes
267	Converted Paper and Paperboard Products, Except Containers and Boxes
281	Industrial Inorganic Chemicals
282	Plastics Materials and Synthetics
283	Drugs
284	Soap, Cleaners, and Toilet Goods
285	Paints and Allied Products
286	Industrial Organic Chemicals
287	Agricultural Chemicals
289	Miscellaneous Chemical Products
291	Petroleum Refining
295	Asphalt Paving and Roofing Materials
299	Misc. Petroleum and Coal Products
301	Tires and Inner Tubes
302	Rubber and Plastics Footwear

Table 1B.8.3-1 (Continued)
Industrial and Commercial Facilities with Potential
for Cogeneration by Three-Digit SIC Code Descriptions

<u>SIC Code</u>	<u>Description</u>
305	Gaskets, Packing and Sealing Devices & Rubber and Plastic Hose and Belting
306	Fabricated Rubber Products, Not Elsewhere Classified (NEC)
308	Miscellaneous Plastics Products
321	Flat Glass
322	Glass and Glassware, Pressed or Blown
323	Products of Purchased Glass
324	Cement, Hydraulic
325	Structural Clay Products
326	Pottery and Related Products
327	Concrete, Gypsum, and Plaster Products
328	Cut Stone and Stone Products
329	Misc. Nonmetallic Mineral Products
331	Blast Furnace and Basic Steel Products
332	Iron and Steel Foundries
333	Primary Nonferrous Metals
334	Secondary Nonferrous Metals
335	Nonferrous Rolling and Drawing
336	Nonferrous Foundries
339	Miscellaneous Primary Metal Products
341	Metal Cans and Shipping Containers
342	Cutlery, Hand Tools, and Hardware
343	Plumbing and Heating, Except Electric
344	Fabricated Structural Metal Products
345	Screw Machine Products, Bolts, etc.
346	Metal Forgings and Stampings
347	Metal Services, NEC
348	Ordinance and Accessories, NEC

Table 1B.8.3-1 (Continued)
Industrial and Commercial Facilities with Potential
for Cogeneration by Three-Digit SIC Code Descriptions

<u>SIC Code</u>	<u>Description</u>
349	Miscellaneous Fabricated Metal Products
351	Engines and Turbines
352	Farm and Garden Machinery
353	Construction and Related Machinery
354	Metalworking Machinery
355	Special Industry Machinery
356	General Industrial Machinery
357	Office and Computing Machines
358	Refrigeration and Service Machinery
359	Miscellaneous Machinery, Except Electrical
501	Motor Vehicles and Automotive Equipment
502	Furniture and Home Furnishings
503	Lumber and Construction Materials
504	Professional and Commercial Equipment and Supplies
505	Metals and Minerals, Except Petroleum
506	Electrical Goods
507	Hardware, Plumbing & Heating Equipment
508	Machinery, Equipment, and Supplies
509	Miscellaneous Durable Goods
511	Paper and Paper Products
512	Drugs, Proprietarys, and Sundries
513	Apparel, Piece Goods, and Notions
514	Groceries and Related Products
515	Farm - Product Raw Materials
516	Chemicals and Allied Products
517	Petroleum and Petroleum Products
518	Beer, Wine, and Distilled Alcoholic Beverages
519	Miscellaneous Nondurable Goods
521	Lumber and Other Building Materials

Table 1B.8.3-1 (Continued)
Industrial and Commercial Facilities with Potential
for Cogeneration by Three-Digit SIC Code Descriptions

<u>SIC Code</u>	<u>Description</u>
523	Paint, Glass, and Wallpaper Stores
525	Hardware Stores
526	Retail Nurseries and Garden Stores
527	Mobile Home Dealers
531	Department Stores
533	Variety Stores
539	Miscellaneous General Merchandise Stores
601	Federal Reserve Banks
602	Commercial and Stock Savings Banks
606	Credit Unions
608	Foreign Banking and Branches
609	Functions Related to Depository Banking
631	Life Insurance
632	Medical Service and Health Insurance
633	Fire, Marine, and Casualty Insurance
635	Surety Insurance
636	Title Insurance
637	Pension, Health, and Welfare Funds
639	Insurance Carriers, NEC
701	Hotels and Motels
702	Rooming and Boarding Houses
703	Camps and Trailing Parks
704	Organization Hotels and Lodging Houses, on Membership Basis
791	Dance Halls, Studios, and Schools
792	Producers, Orchestras, Entertainers
794	Commercial Sports
799	Miscellaneous, Amusement, Recreational Services
801	Offices of Physicians

Table 1B.8.3-1 (Continued)
Industrial and Commercial Facilities with Potential
for Cogeneration by Three-Digit SIC Code Descriptions

<u>SIC Code</u>	<u>Description</u>
802	Offices of Dentists
803	Offices of Osteopathic Physicians
804	Offices of Other Health Practitioners
805	Nursing and Personal Care Facilities
806	Hospitals

Table 1B.8.3-2
Potential Cogeneration Candidates in the Orlando Area

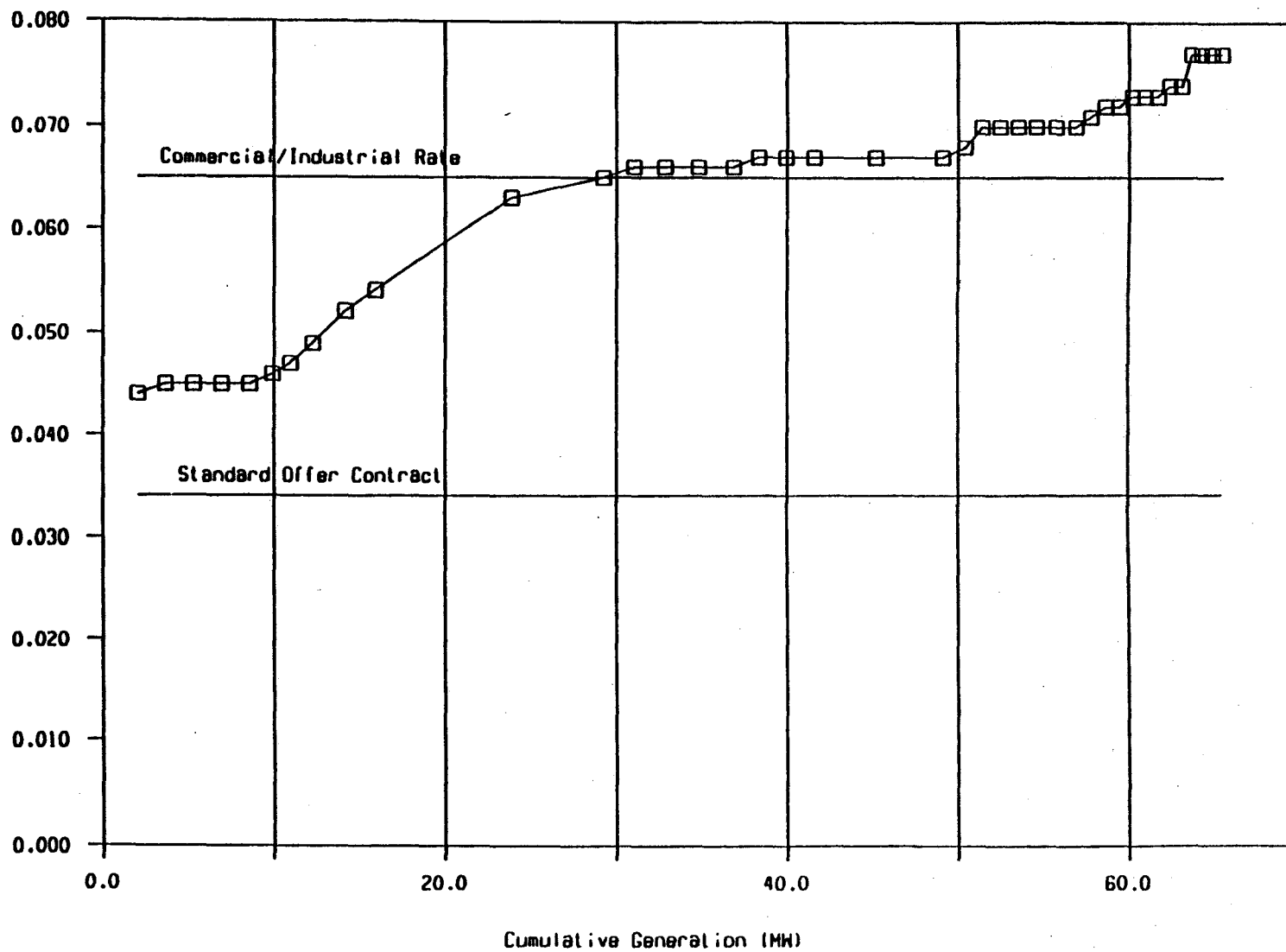
<u>SIC Code</u>	<u>Description</u>	<u>DOE^a</u>
20	Food and Kindred Products	X
26	Paper and Allied Products	X
27	Printing and Publishing	
28	Chemicals and Allied Products	X
30	Rubber and Miscellaneous Plastics	
34	Fabricated Metal Products	X
35	Machinery Except Electrical	
36	Electric and Electronic Equipment	

^aDepartment of Energy's list of potential cogenerators as presented in EPRI's "Cogeneration and Utilities: Status and Prospects."

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Cogeneration Cost (¢/kWh) (1991\$)

1B.8.3-13



Cogeneration Cost Versus Capacity
Figure 1B.8.3-1

1B.9.0 Supply-Side Screening

1B.9.1 General

Conventional and advanced generation alternatives are screened based on 1997 through 2020 levelized total costs developed for each alternative. The purpose of this screening process is to eliminate alternatives with little economic merit from further evaluation. Levelized total costs for conventional and advanced generation alternatives are based on the cost and operating characteristics contained in Subsections 1A.5.1 and 1A.5.2 of Volume 1A, the most likely fuel price projections contained in Subsection 1A.3.3 of Volume 1A, and the economic parameters contained in Subsection 1A.3.2 of Volume 1A and Subsection 1B.4.1 of this Volume 1B. Fuel inventory carrying costs are not included in the screening evaluations. Levelized total costs include capital costs, fixed and variable O&M, and fuel.

1B.9.2 Conventional Generation Alternatives

Screening curves are developed for a combustion turbine, combined cycle, coal alternatives and independent power producer bids. The combustion turbine screening curve, Figure 1B.9.2-1, indicates that a Frame 7FA combustion turbine is slightly more economical than a Frame 7EA on OUC's system. Figure 1B.9.2-2 indicates that a Frame 7FA combined cycle is slightly more economical than a Frame 7EA combined cycle. Based on these screening curves, Frame 7EA simple and combined cycle alternatives will be dropped from further evaluation as capacity options for OUC.

Figure 1B.9.2-3 contains screening curves for a 425 MW fluidized bed unit and a 425 MW pulverized coal unit. The screening curves indicate that the pulverized coal unit is slightly more economical at capacity factors above 50 percent. Since the pulverized coal unit is more economical in the typical operating capacity factor range for these units, fluidized bed capacity is dropped from further evaluation.

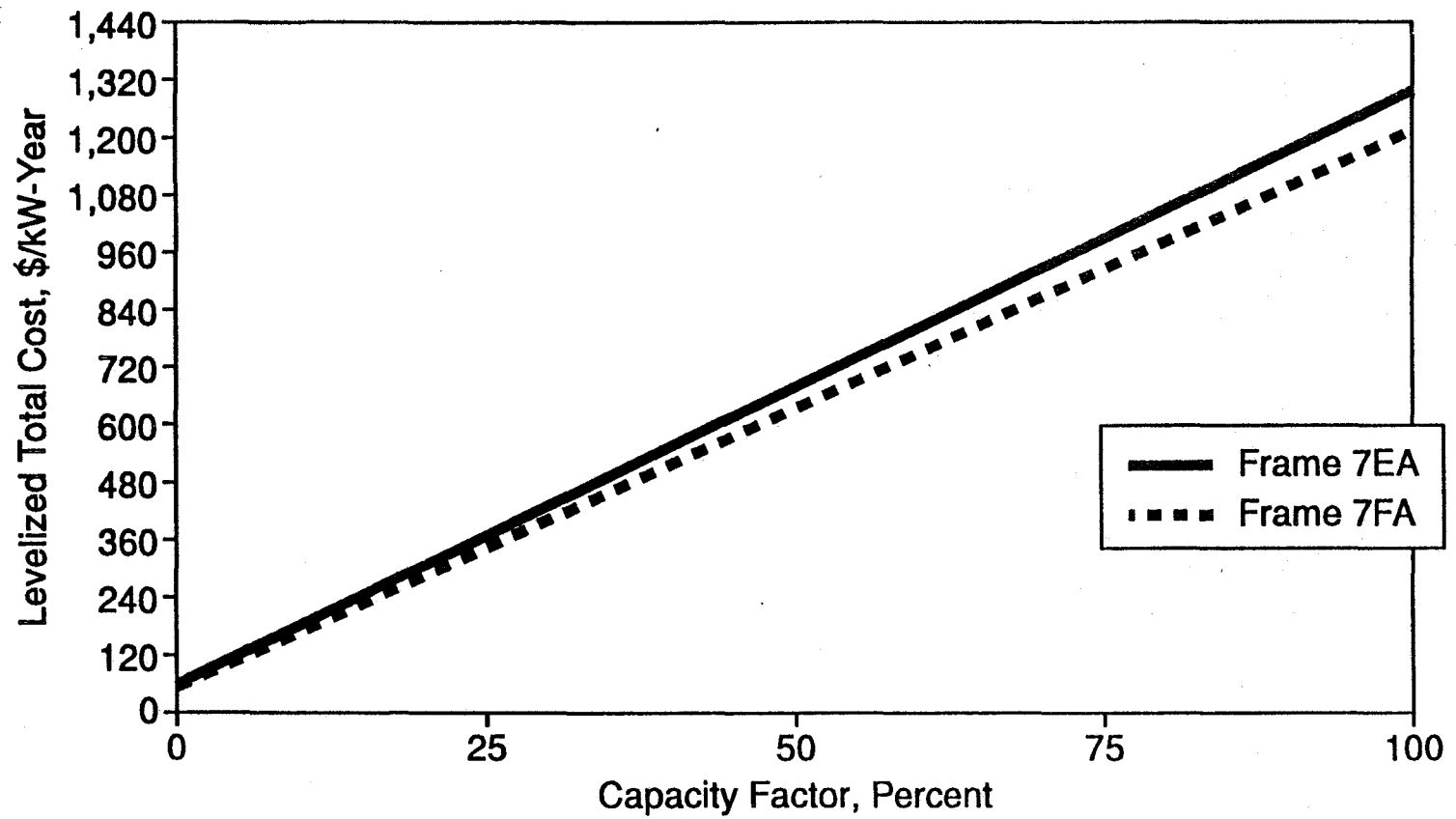
Subsection 1A.5.4 of Volume 1A describes the evaluation of the Independent Power Producer (IPP) Bids received as a result of the Joint Request for Power Supply Proposals. Three bids were received. One bid was for a coal fueled project, while the other bids were for natural gas fueled projects. Figure 1B.9.2-4 compares the bid received from Citrus Energy Partners, L.P. (NRG), PG&E-Bechtel Generation Company (PG&E), and Enron Power Corporation, Inc. (ENRON) with Stanton 2 using the same fuel price projections and economic parameters that were used to screen the other alternatives. As shown on Figure 1B.9.2-4, the IPP offers are uneconomical compared to Stanton 2 further supporting the conclusions of the evaluations of the Joint Request for Power Supply Proposals and the subsequent rejection of the bids by OUC.

Figure 1B.9.2-5 contains screening curves for the best combustion turbine, combined cycle, and coal alternatives as well as for Stanton 2. The curves indicate that Frame 7FA combustion turbine capacity is more economical than Stanton 2 at capacity factors less than 14 percent. Frame 7FA based combined cycle capacity is more economical than Stanton 2 at capacity factors less than 21 percent.

Figure 1B.9.2-5 also indicates the savings for Stanton 2 compared to a generic 425 MW pulverized coal unit. These savings are due to savings in common facilities resulting from Stanton 2 being the second unit at the site and savings due to the replication of Stanton 1.

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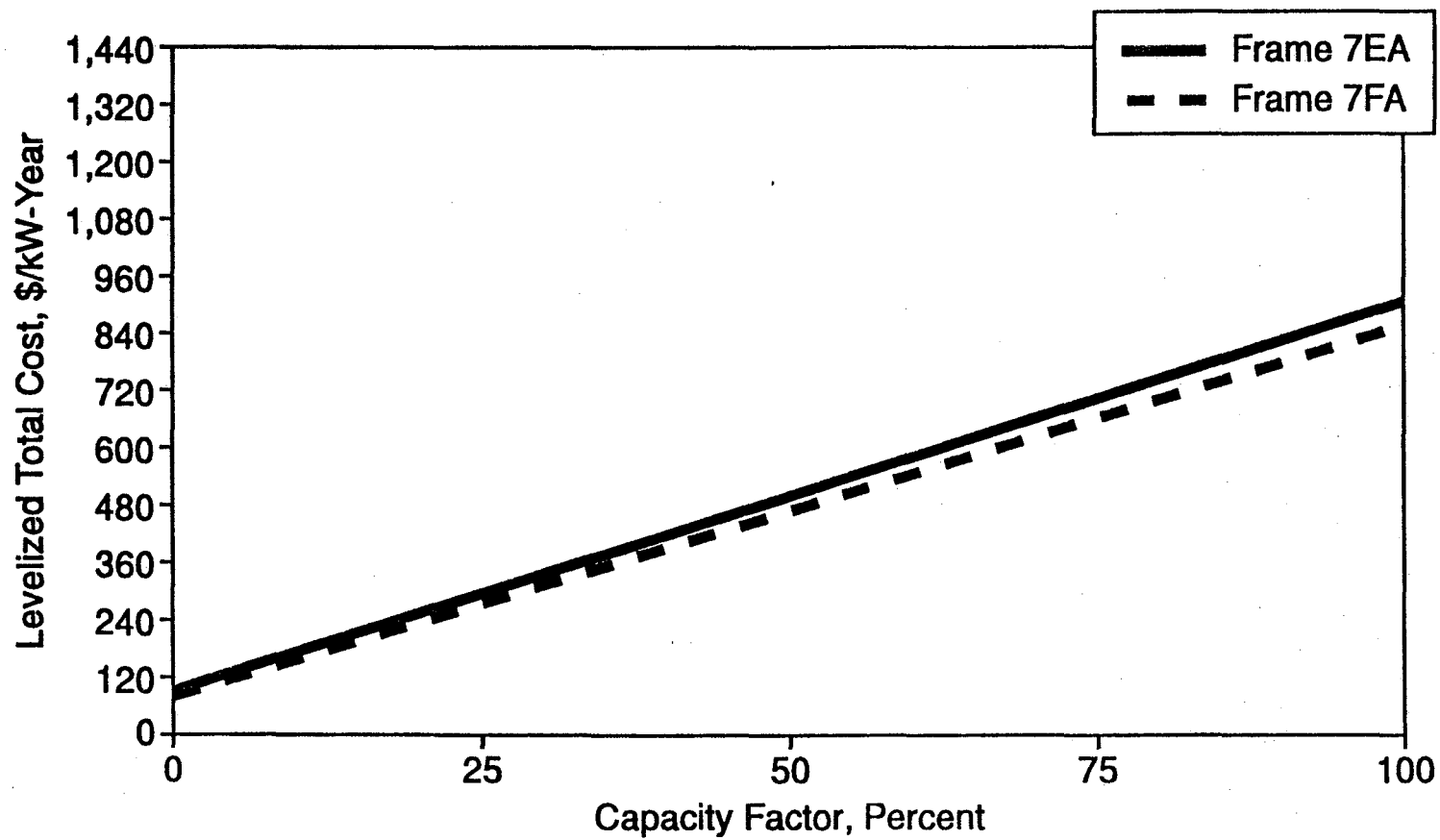
1B.9.2-3



OUC Screening Curves--Combustion Turbine
Figure 1B.9.2-1

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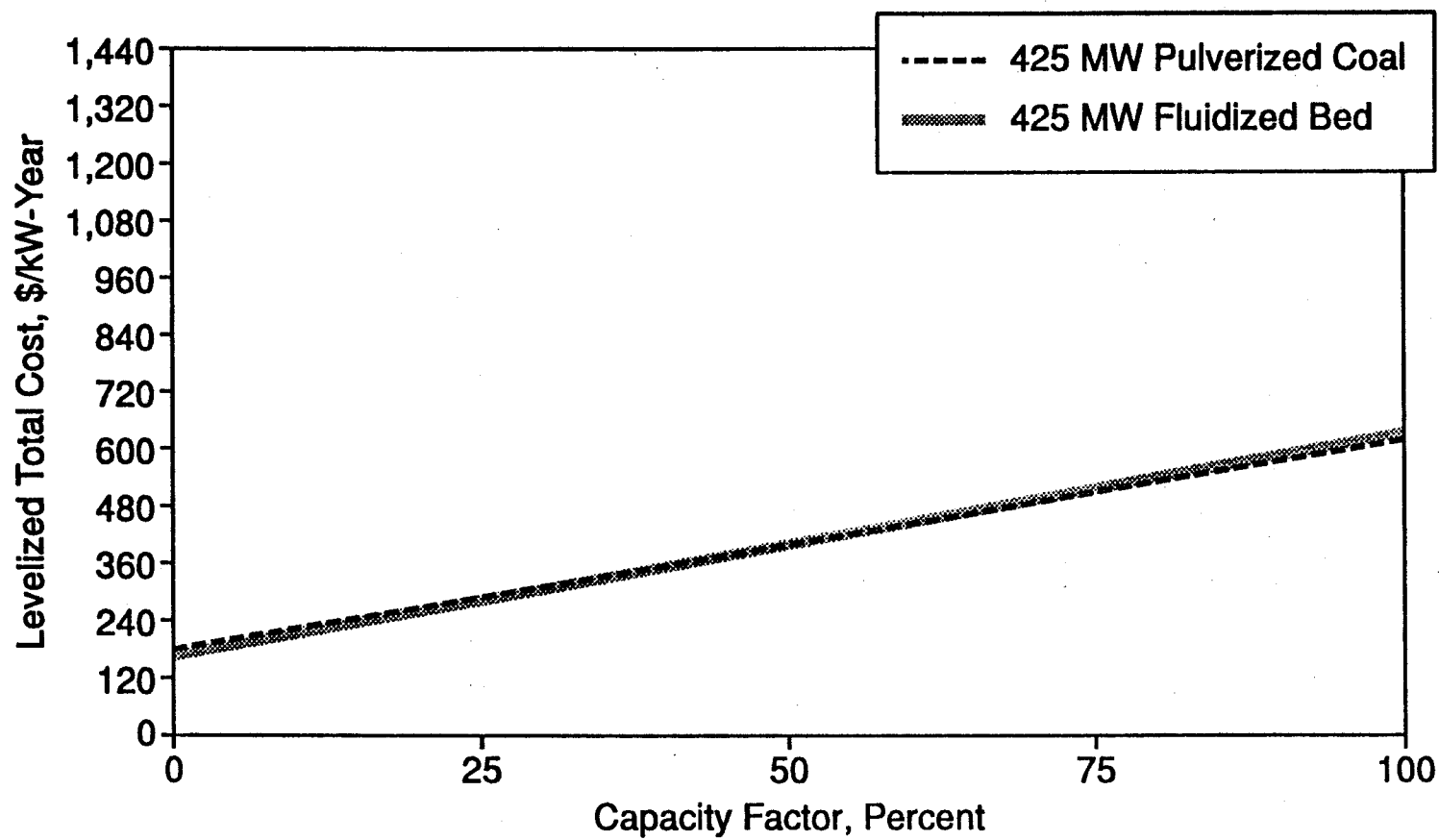
1B.9.2-4



OUC Screening Curves--Combined Cycle
Figure 1B.9.2-2

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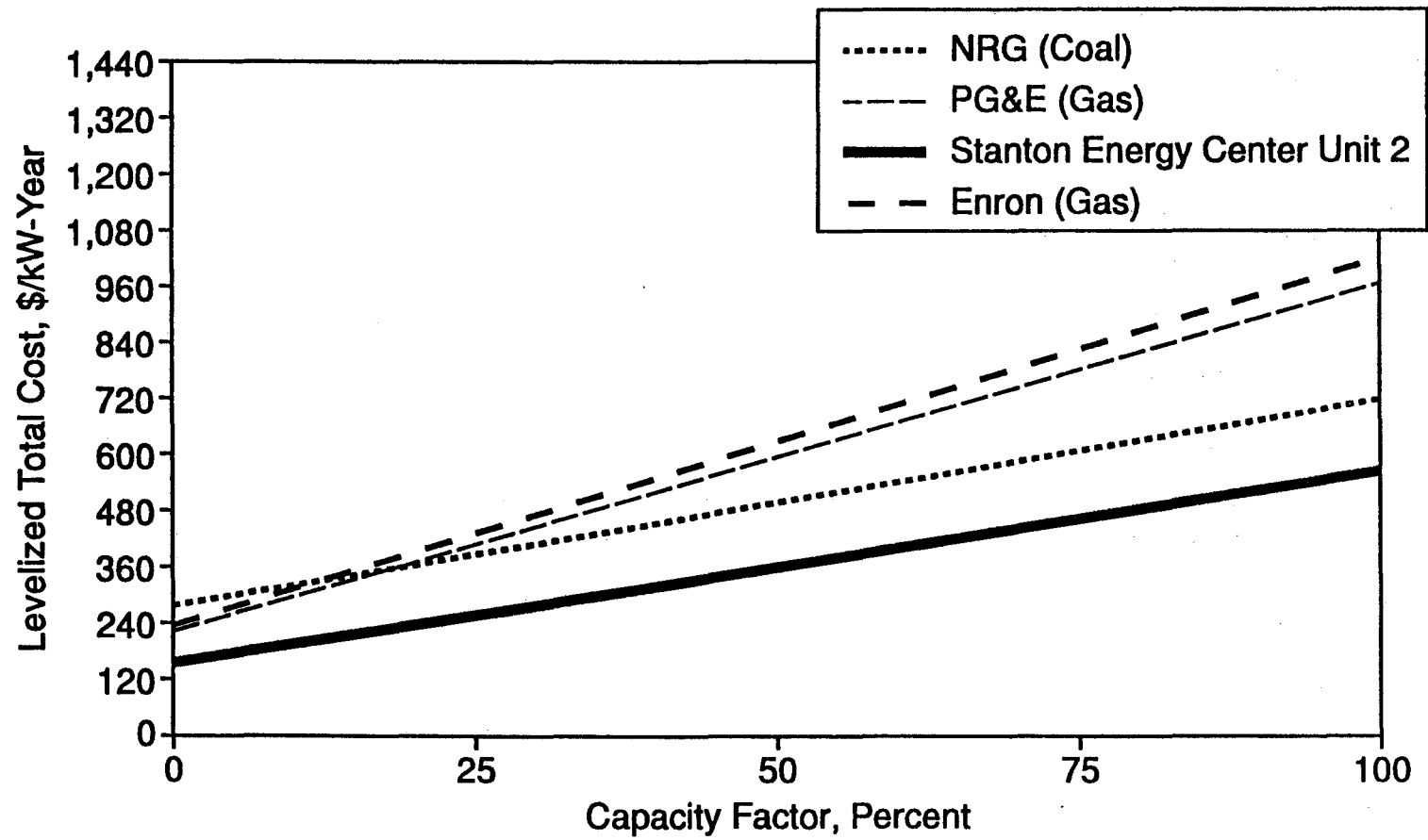
1B.9.2-5



OUC Screening Curves--Coal
Figure 1B.9.2-3

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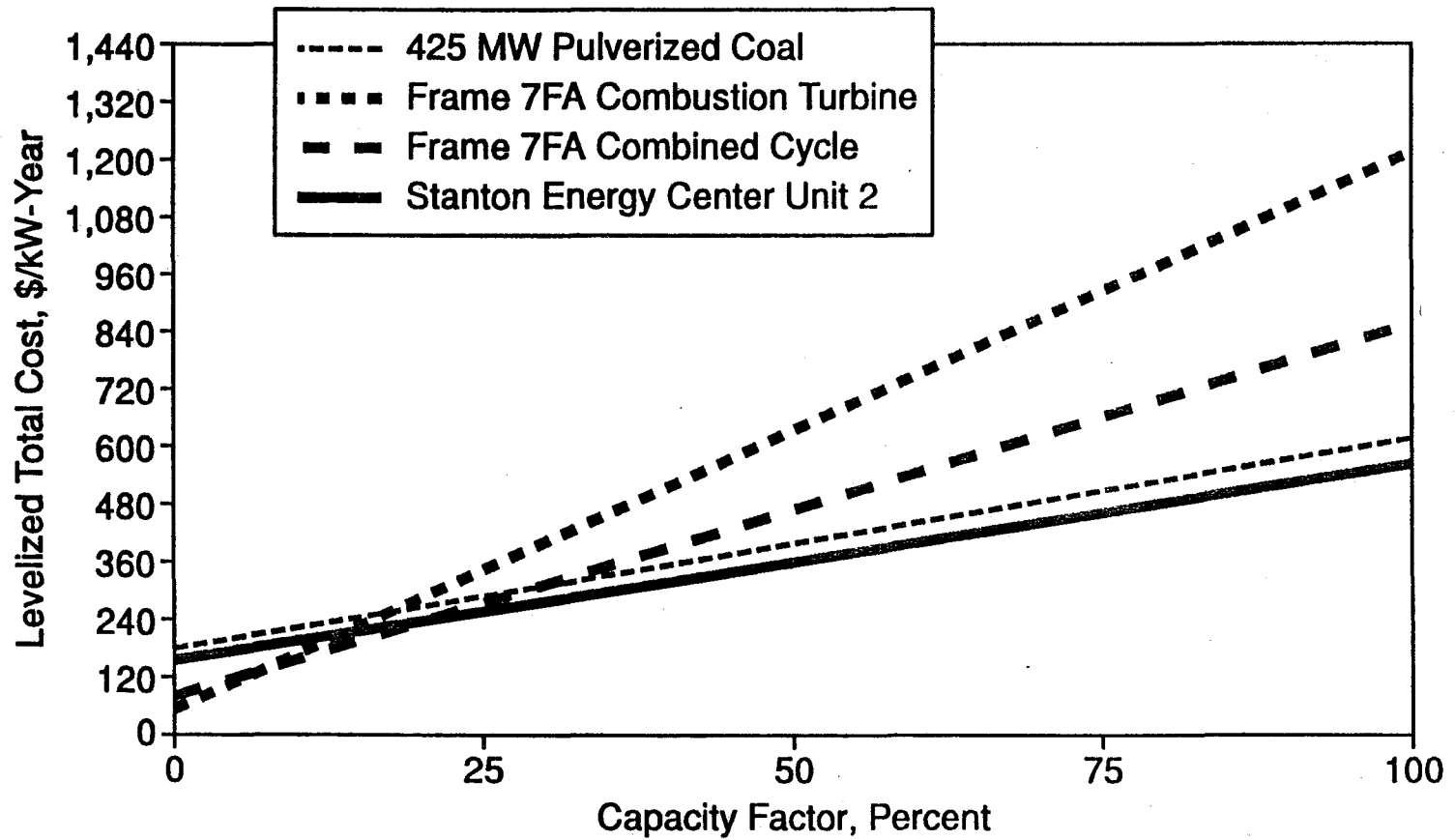
1B.9.2-6



OUC Screening Curves--IPP
Figure 1B.9.2-4

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1B.9.2-7



OUC Screening Curves
Figure 1B.9.2-5

1B.9.3 Advanced Generation Alternatives

Many advanced generation alternatives were identified in Subsection 1A.5.1 of Volume 1A. The majority of these alternatives were eliminated from the screening process based on noncost considerations. Three advanced alternatives were carried forward to the economic screening process.

Screening curves were developed for a coal gasification combined cycle, solar thermal parabolic trough, and lead-acid battery storage alternative. The solar thermal parabolic trough screening curve, Figure 1B.9.3-1, indicates that Stanton 2 is more economical at the solar thermal parabolic trough expected central Florida capacity factor of 16.0 percent. Since Stanton 2 is more economical in the typical operating capacity factor range for these units, solar thermal parabolic trough capacity is dropped from further consideration.

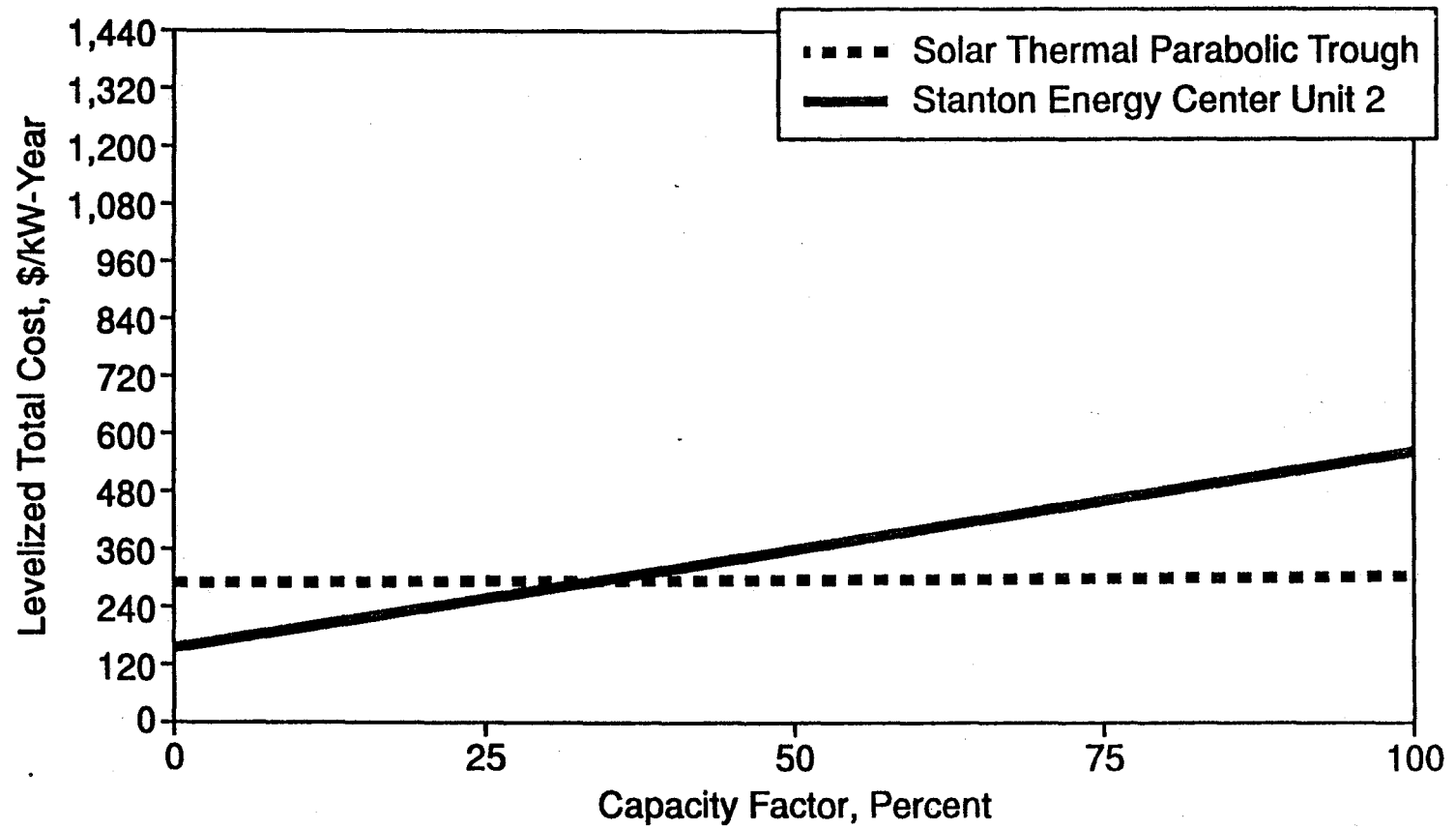
Figure 1B.9.3-2 contains screening curves for a coal gasification combined cycle unit and Stanton 2. The curves indicate that Stanton 2 is more economical at each unit's expected operating capacity factor. The coal gasification combined cycle unit only becomes more economical at a capacity factor exceeding 87.5 percent. Since the expected availability of this type of unit is 85 percent, it is not realistic to expect the unit to operate above an 87.5 percent capacity factor. In addition, the levelized total cost used to develop the coal gasification combined cycle curve is based on the low range of the capital and O&M costs at \$1120/kW and \$0.8/MWh, respectively. Based on these considerations, the coal gasification combined cycle alternative was excluded from further evaluation.

Screening curves for the Frame 7FA combined cycle and lead-acid battery alternatives are contained on Figure 1B.9.3-3. The typical lead-acid battery storage capacity factor is 17 percent. Figure 1B.9.3-3 indicates that at 17 percent capacity factor, the Frame 7FA combined cycle is more economical. Charging energy for the lead-acid battery is based on the fuel cost for Stanton 2. Based on this comparison, the lead-acid battery alternative is dropped from further evaluation.

Based on the screening curve analysis from Subsections 1B.9.2 and 1B.9.3, Stanton 2, the Frame 7FA combustion turbine, and the Frame 7FA combined cycle alternatives are used to develop the alternate plans for the detailed economic evaluation.

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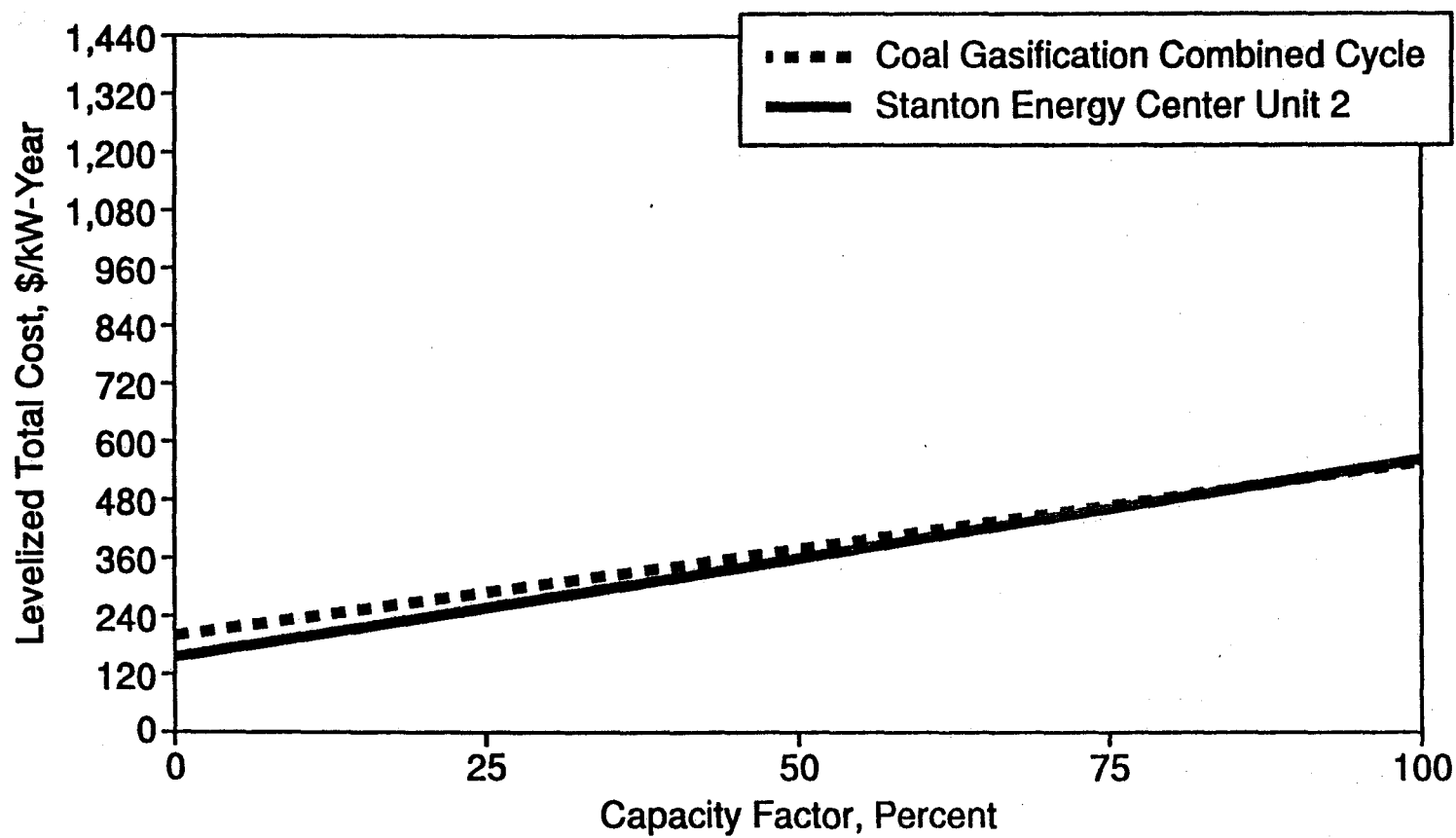
1B.9.3-2



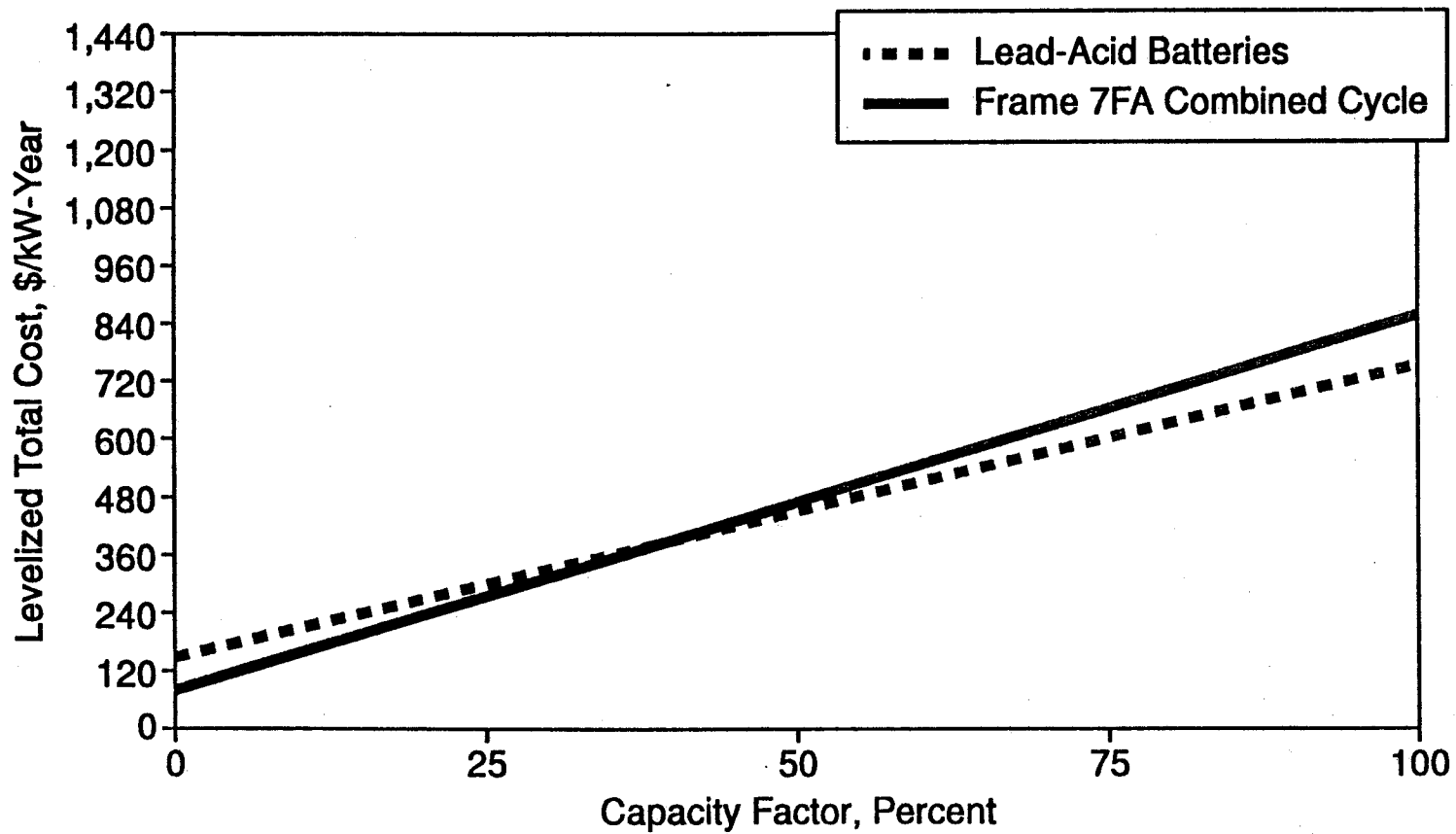
OUC Screening Curves
Figure 1B.9.3-1

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1B.9.3-3



OUC Screening Curves
Figure 1B.9.3-2



OUC Screening Curves
Figure 1B.9.3-3

1B.10.0 Alternative Plan Development

Using the supply side screening curves provided in Subsection 1B.9.0, probable expansion plans and strategies were developed for evaluation in meeting OUC's future energy needs. Evaluation and optimization of the alternatives, detailed in Subsection 1B.11.0, are performed by modeling each of the scenarios in combination with OUC's existing system with POWRPRO, Black & Veatch's chronological production costing program. In each scenario, additional generating capacity required by OUC for the remainder of the study period will be selected based on the screening curves and then optimized using POWRPRO.

1B.10.1 Strategy A--Stanton 2

Plan A represents the base supply-side expansion alternative. It includes the installation of Stanton 2 on January 1, 1997. OUC's ownership share of Stanton 2 will be 75 percent or 330 MW. OUC is planning to sell 110 MW of its ownership share of Stanton 2 as a unit power sale or some other form of firm capacity sale during the first few years of operation. However, for worst case evaluation purposes, OUC system is evaluated with all 330 MW of OUC's share of Stanton 2.

1B.10.2 Strategy B—Additional Demand-Side Management Programs

Strategy B applies the additional demand-side management programs from the detailed analysis of demand-side management alternatives in Subsection 1B.6.4 to Strategy A. Demand-side management programs which are shown to be cost-effective are included in the following strategies.

1B.10.3 Strategy C--Combustion Turbine Addition

Strategy C is based on installing a combustion turbine as the first unit addition on January 1, 1997 instead of Stanton 2 in Strategy B. The generating capacity additions required through the remainder of the planning period are then optimized.

1B.10.4 Strategy D--Combined Cycle Addition

Plan D is based on installing a combined cycle as the first unit addition on January 1, 1997 instead of Stanton 2 in Strategy B. The generating capacity additions required through the remainder of the planning period are then optimized.

1B.11.0 Economic Analysis

1B.11.1 Evaluation Methodology

The power supply strategies developed in Subsection 1B.10.0 are evaluated on a comparative cost basis. Fuel costs, operation and maintenance costs, fixed charges for capacity additions, carrying costs for the coal pile, and demand-side management costs are included in the analysis. Although comparative cost analysis will yield the optimal alternative, it should not be used to project actual total costs. The financial evaluation to determine total system revenue requirements is addressed in Subsection 1B.15.0.

The economic analysis consists of essentially three phases: supply-side, demand-side, and sensitivity analysis. Supply-side and demand-side analyses are discussed in this subsection, whereas, sensitivity analysis will be addressed in Subsection 1B.12.0.

Optimization and production costing for each of the alternatives is performed by simulating OUC's entire system with POWRPRO, Black & Veatch's Chronological Production Costing Program. Each of the alternatives is optimized throughout the study period by adding the appropriate (least cost through time on a cumulative present worth basis) capacity from available generating technologies. Capacity addition units and sizes used in the optimization are provided in Subsection 1B.11.4. In an effort to be conservative in the evaluation of Stanton 2, it is assumed that there are no limitations on the availability of natural gas for use by OUC during the study period.

Realistically, however, there are and will be limitations on the availability of natural gas which will result in the consumption of higher priced oil. Thus, savings from Stanton 2 will be greater than shown in the evaluations. Based on the most likely load growth forecast scenario, Battelle developed three load forecasts for production costing evaluation. The first hourly load forecast, OUC Base, contains the most likely growth scenario without new demand-side programs; the second forecast HPLIGHT includes resistance heating conversion and commercial lighting demand-side programs; and finally the third forecast, HPDLC, includes resistance heating conversion, commercial lighting, and direct load control programs. The costs associated with each of these programs are provided in Section 1B.6.4. Before the hourly load forecasts could be used for production

costing analysis, firm off-system sales were added on an hourly basis to each of the original forecasts. The modified forecasts are as follows.

- Expect 1--(OUCBASE) + firm off-system sales.
- Expect 2--(HPLIGHT) + firm off-system sales.
- Expect 3--(HPDLC) + firm off-system sales.

Optimized expansion plans were developed for each of the above forecasts with Stanton 2 as the first addition followed by an optimal mix of combustion turbines, combined cycles and coal units. The Expect 3 forecast with the addition of direct load control programs did not result in additional system savings over the Expect 2 forecast. The Expect 2 forecast was thus selected for further supply-side evaluations.

1B.11.2 Production Cost Parameters

Operating parameters used to simulate OUC's generating system are based on information provided by OUC for their existing units and by Black & Veatch for Stanton 2 and the generic units. Maximum capacity available for dispatch and the corresponding full load heat rates for each unit are provided in Table 1B.11.2-1.

Table 1B.11.2-1
Production Cost Parameters for Generating Units

	OUC Maximum Capacity Available for Dispatch* (MW)	Full Load Net Heat Rate** (BTU/kWh)
Indian River 1	90	9,991
Indian River 2	205	10,019
Indian River 3	352	9,989
Crystal River 3	13	10,509
MacIntosh 3	136	10,504
St. Lucie 1	26	11,022
St. Lucie 2	26	11,022
Stanton 1	305	9,740
Stanton 2	311	9,740
Indian River CT A and B	44	11,856
Indian River CT C	103	12,296
Indian River CT D	103	12,296
Generic 675 MW PC	338***	9,730
Generic 488 MW CC	269***	7,912
Generic 192 MW CT	172	11,221

*Based on normal high dispatch limit for OUC's portion.

**Heat rate curves are used in production cost simulation.

***Assumes 50 percent joint ownership by OUC.

NOTE: Combined cycle and combustion turbine data at 59 F.

1B.11.3 Capital cost

The capital cost used in the economic analysis for Stanton 2 is shown in Table 1B.11.3-1. The capital cost is based on the capital cost and escalation in Table 1A.2.3-2 with interest during construction applied on a monthly basis to the cash flow presented in Table 1A.2.3-1. Capital costs for the generic units are based on the direct and indirect costs in Subsection 1A.5.2. The capital costs are escalated to the midpoint of construction at the capital cost escalation rate. Interest during construction is applied from the midpoint of construction to the commercial operation date to obtain the total capital cost.

Table 1B.11.3-1
Stanton 2 Capital Cost

	Cost	
	\$1,000	\$kW
Total Capital Cost (3-1-91)	441,091	1,002
Escalation	<u>80,909</u>	<u>184</u>
	522,000	1,186
Interest During Construction	<u>89,864</u>	<u>204</u>
Total Installed Cost	611,864	1,390

*Based on net plant rating of 440 MW.

Note: OUC's ownership share is 75 percent.

1B.11.4 Capacity Addition Criteria

As described in Subsection 1B.11.1, expansion alternatives for OUC are optimized by selecting probable generating unit additions from available technologies to satisfy a 15 percent planning reserve margin. From the screening Subsection 1B.9.0, three probable unit additions were identified to be used in the evaluation. A complete description of each is provided in Subsection 1A.5. Of the three units, 675 MW pulverized coal, 498 MW combined cycle, and 192 MW combustion turbine, it is assumed that OUC's ownership share of the pulverized coal and combined cycle units is 50 percent and OUC's ownership share is 100 percent for the combustion turbine. This is consistent with OUC past and present participation in similar units so that economies of scale inherent to larger units can be realized.

Unit retirement dates for existing units are shown in Table 1B.2.0-1. For modeling purposes, a 25-year operating life is assumed for Combustion Turbines A, B, C, and D at the Indian River site. The Indian River Steam Units 1, 2, and 3 have a planning life of 30 years. However, these units are currently undergoing life management assessments and modifications which indicate that the expected operating life for these units may be 50 years. For purposes of this evaluation, 50 years was assumed as the operating life. A 40-year operating life is assumed for the remainder of the units in the system--Stanton 1, McIntosh 3, St. Lucie 1 & 2, and Crystal River 3. Tables 1B.11.4-1, 1B.11.4-2, and 1B.11.4-3 show capacity requirements under each of the load forecasts: Expect 1, Expect 2 and Expect 3, without any additional capacity additions beyond 1992.

The peak demand is projected to occur in January of each year as discussed in Section 1B.7.0. Since capacity must be available to meet the winter peak which may also occur in December, the system requirements for capacity addition represent the requirements for the winter peak based on the peak demand for the next January.

Table 1B.11.4-1
OUC Capacity Requirements
Expect 1/Base

Year	Peak (MW)	Curtailable Rates (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus/ (Deficit)
1991	1,036	0.0	155.4	1,191.4	1,227.7	1,197.0	204.0		(30.7)
1992	1,068	0.4	160.1	1,227.7	1,237.2	1,197.0			163.8
1993	1,077	1.2	161.4	1,237.2	1,275.3	1,401.0			125.7
1994	1,111	2.1	166.3	1,275.3	1,312.2	1,401.0			88.8
1995	1,144	2.9	171.2	1,312.2	1,349.6	1,401.0			51.4
1996	1,177	3.4	176.0	1,349.6	1,397.9	1,401.0			3.1
1997	1,220	4.4	182.3	1,397.9	1,441.0	1,401.0			(40.0)
1998	1,258	5.0	188.0	1,441.0	1,481.2	1,401.0			(80.2)
1999	1,294	6.0	193.2	1,481.2	1,516.7	1,401.0			(115.7)
2000	1,326	7.1	197.8	1,516.7	1,557.4	1,401.0			(156.4)
2001	1,362	7.8	203.1	1,557.4	1,542.2	1,401.0			(141.2)
2002	1,350	8.9	201.2	1,542.2	1,561.5	1,401.0			(160.5)
2003	1,368	10.2	203.7	1,561.5	1,531.9	1,401.0			(130.9)
2004	1,343	10.9	199.8	1,531.9	1,543.0	1,401.0			(142.0)
2005	1,354	12.3	201.3	1,543.0	1,544.8	1,401.0			(143.8)
2006	1,357	13.7	201.5	1,544.8	1,556.0	1,401.0			(155.0)
2007	1,367	14.0	203.0	1,556.0	1,599.3	1,401.0			(198.3)
2008	1,405	14.3	208.6	1,599.3	1,639.1	1,401.0			(238.1)

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1B.11.4-3

Table 1B.11.4-1 (Continued)
OUC Capacity Requirements
Expect 1/Base

Year	Peak (MW)	Curtable Rates (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus/ (Deficit)
2009	1,440	14.7	213.8	1,639.1	1,696.3	1,401.0			(295.3)
2010	1,490	15.0	221.3	1,696.3	1,747.6	1,401.0		90.0	(436.6)
2011	1,535	15.4	227.9	1,747.6	1,792.0	1,311.0			(481.0)
2012	1,574	15.7	233.7	1,792.0	1,846.8	1,311.0			(535.8)
2013	1,622	16.1	240.9	1,846.8	1,894.6	1,311.0			(583.6)
2014	1,664	16.5	247.1	1,894.6	1,949.4	1,311.0		44.0	(682.4)
2015	1,712	16.9	254.3	1,949.4	1,998.3	1,267.0		205.0	(936.3)
2016	1,755	17.3	260.7	1,998.3	2,056.5	1,062.0			(994.5)
2017	1,806	17.7	268.2	2,056.5	2,112.4	1,062.0		217.0	(1,267.4)
2018	1,855	18.1	275.5	2,112.4	2,177.4	845.0			(1,332.4)
2019	1,912	18.6	284.0	2,177.4	2,229.8	845.0			(1,384.8)
2020	1,958	19.0	290.8	2,229.8	2,283.3	845.0			(1,438.3)

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1B.11.4.4

Table 1B.11.4-2
OUC Capacity Requirements
Expect 2/Commercial Lighting and Heat Pump Conversion

Year	Peak (MW)	DSM Reduction	Curtable Rates (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus/ (Deficit)
1991	1,036	0	0.0	155.4	1,191.4	1,227.7	1,197.0			(30.7)
1992	1,068	0	0.4	160.1	1,227.7	1,233.7	1,197.0	204.0		167.3
1993	1,077	3	1.2	160.9	1,233.7	1,270.7	1,401.0			130.3
1994	1,111	4	2.1	165.7	1,270.7	1,304.2	1,401.0			96.8
1995	1,144	7	2.9	170.1	1,304.2	1,336.9	1,401.0			64.1
1996	1,177	11	3.4	174.4	1,336.9	1,381.8	1,401.0			19.2
1997	1,220	14	4.4	180.2	1,381.8	1,422.6	1,401.0			(21.6)
1998	1,258	16	5.0	185.6	1,422.6	1,459.3	1,401.0			(58.3)
1999	1,294	19	6.0	190.3	1,459.3	1,492.6	1,401.0			(91.6)
2000	1,326	21	7.1	194.7	1,492.6	1,533.2	1,401.0			(132.2)
2001	1,362	21	7.8	200.0	1,533.2	1,513.5	1,401.0			(112.5)
2002	1,350	25	8.9	197.4	1,513.5	1,528.2	1,401.0			(127.2)
2003	1,368	29	10.2	199.3	1,528.2	1,496.2	1,401.0			(95.2)
2004	1,343	31	10.9	195.2	1,496.2	1,505.1	1,401.0			(104.1)
2005	1,354	33	12.3	196.3	1,505.1	1,505.7	1,401.0			(104.7)
2006	1,357	34	13.7	196.4	1,505.7	1,515.7	1,401.0			(114.7)
2007	1,367	35	14.0	197.7	1,515.7	1,553.3	1,401.0			(152.3)
2008	1,405	40	14.3	202.6	1,553.3	1,589.6	1,401.0			(188.6)

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IB.11.4-5

Table 1B.11.4-2 (Continued)
 OUC Capacity Requirements
 Expect 2/Commercial Lighting and Heat Pump Conversion

Year	Peak (MW)	DSM Reduction	Curtailable Rates (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus/ (Deficit)
2009	1,440	43	14.7	207.3	1,589.6	1,646.8	1,401.0			(245.8)
2010	1,490	43	15.0	214.8	1,646.8	1,692.4	1,401.0		90.0	(381.4)
2011	1,535	48	15.4	220.7	1,692.4	1,737.9	1,311.0			(426.9)
2012	1,574	47	15.7	226.7	1,737.9	1,785.8	1,311.0			(474.8)
2013	1,622	53	16.1	232.9	1,785.8	1,833.7	1,311.0			(522.7)
2014	1,664	53	16.5	239.2	1,833.7	1,883.8	1,311.0		44.0	(616.8)
2015	1,712	57	16.9	245.7	1,883.8	1,932.8	1,267.0		205.0	(870.8)
2016	1,755	57	17.3	252.1	1,932.8	1,984.1	1,062.0			(922.1)
2017	1,806	63	17.7	258.8	1,984.1	2,039.9	1,062.0		217.0	(1,194.9)
2018	1,855	63	18.1	266.1	2,039.9	2,098.1	845.0			(1,253.1)
2019	1,912	69	18.6	273.7	2,098.1	2,151.6	845.0			(1,306.6)
2020	1,958	68	19.0	280.6	2,151.6	2,206.3	845.0			(1,361.3)

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1B.11.4-6

Table 1B.11.4-3
OUC Capacity Requirements
Expect 3/Commercial Lighting, Heat Pump Conversion, and Direct Load Control

Year	Peak (MW)	DSM Reduction	Curtailable Rates (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus/ (Deficit)
1991	1,036	3	0.0	155.0	1,188.0	1,224.3	1,197.0			(27.3)
1992	1,068	3	0.4	159.7	1,224.3	1,230.3	1,197.0	204.0		170.7
1993	1,077	6	1.2	160.5	1,230.3	1,266.1	1,401.0			134.9
1994	1,111	8	2.1	165.1	1,266.1	1,299.6	1,401.0			101.4
1995	1,144	11	2.9	169.5	1,299.6	1,326.6	1,401.0			74.4
1996	1,177	20	3.4	173.0	1,326.6	1,365.7	1,401.0			35.3
1997	1,220	28	4.4	178.1	1,365.7	1,401.9	1,401.0			(0.9)
1998	1,258	34	5.0	182.9	1,401.9	1,430.6	1,401.0			(29.6)
1999	1,294	44	6.0	186.6	1,430.6	1,459.2	1,401.0			(58.2)
2000	1,326	50	7.1	190.3	1,459.2	1,491.8	1,401.0			(90.8)
2001	1,362	57	7.8	194.6	1,491.8	1,467.5	1,401.0			(66.5)
2002	1,350	65	8.9	191.4	1,467.5	1,481.0	1,401.0			(80.0)
2003	1,368	70	10.2	193.2	1,481.0	1,446.8	1,401.0			(45.8)
2004	1,343	74	10.9	188.7	1,446.8	1,455.6	1,401.0			(54.6)
2005	1,354	76	12.3	189.9	1,455.6	1,455.1	1,401.0			(54.1)
2006	1,357	78	13.7	189.8	1,455.1	1,464.0	1,401.0			(63.0)
2007	1,367	80	14.0	191.0	1,464.0	1,500.4	1,401.0			(99.4)
2008	1,405	86	14.3	195.7	1,500.4	1,535.6	1,401.0			(134.6)

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1B.11.4-7

Table 1B.11.4-3 (Continued)
 OUC Capacity Requirements
 Expect 3/Commercial Lighting, Heat Pump Conversion, and Direct Load Control

Year	Peak (MW)	DSM Reduction	Curtailable Rates (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus (Deficit)
2009	1,440	90	14.7	200.3	1,535.6	1,590.5	1,401.0			(189.4)
2010	1,490	92	15.0	207.5	1,590.5	1,633.7	1,401.0		90.0	(322.7)
2011	1,535	99	15.4	213.1	1,633.7	1,678.1	1,311.0			(367.1)
2012	1,574	99	15.7	218.9	1,678.1	1,724.9	1,311.0			(413.9)
2013	1,622	106	16.1	225.0	1,724.9	1,770.4	1,311.0			(459.4)
2014	1,664	108	16.5	230.9	1,770.4	1,819.4	1,311.0		44.0	(552.4)
2015	1,712	113	16.9	237.3	1,819.4	1,866.1	1,267.0		205.0	(804.1)
2016	1,755	115	17.3	243.4	1,866.1	1,916.2	1,062.0			(854.2)
2017	1,806	122	17.7	249.9	1,916.2	1,969.8	1,062.0		217.0	(1,124.8)
2018	1,855	124	18.1	256.9	1,969.8	2,025.6	845.0			(1,180.6)
2019	1,912	132	18.6	264.2	2,025.6	2,078.0	845.0			(1,233.0)
2020	1,958	132	19.0	271.0	2,078.0	2,131.5	845.0			(1,286.5)

1B.11.5 Supply-Side Evaluation Results

Optimization of Strategy A with load forecast, Expect 1, which includes OUC's share of Stanton 2 at 330 MW with a commercial operation date of January 1, 1997, yielded a 1991 cumulative present worth of \$4,660 million. The strategy consisted of adding 50 percent OUC ownership shares of 675 MW pulverized coal units in the years 2010, 2014, and 2017, with a 192 MW combustion turbine in the year 2018. Table 1B.11.5-1 shows the capacity additions and reductions while annual comparative costs for the plan are provided in Table 1B.11.5-2.

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1B.11.5-2

Table 1B.11.5-1
OUC Capacity Requirements With Optimal Supply
Side Expansion Strategy A
Expect 1

Year	Peak (MW)	Curtailable Rates (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus/ (Deficit)
1991	1,036	0.0	155.4	1,191.4	1,227.7	1,197.0			(30.7)
1992	1,068	0.4	160.1	1,227.7	1,237.2	1,197.0	204.0		163.8
1993	1,077	1.2	161.4	1,237.2	1,275.3	1,401.0			125.7
1994	1,111	2.1	166.3	1,275.3	1,312.2	1,401.0			88.8
1995	1,144	2.9	171.2	1,312.2	1,349.6	1,401.0			51.4
1996	1,177	3.4	176.0	1,349.6	1,397.9	1,401.0			3.1
1997	1,220	4.4	182.3	1,397.9	1,441.0	1,401.0	330.0		290.0
1998	1,258	5.0	188.0	1,441.0	1,481.2	1,731.0			249.8
1999	1,294	6.0	193.2	1,481.2	1,516.7	1,731.0			214.3
2000	1,326	7.1	197.8	1,516.7	1,557.4	1,731.0			173.6
2001	1,362	7.8	203.1	1,557.4	1,542.2	1,731.0			188.8
2002	1,350	8.9	201.2	1,542.2	1,561.5	1,731.0			169.5
2003	1,368	10.2	203.7	1,561.5	1,531.9	1,731.0			199.1
2004	1,343	10.9	199.8	1,531.9	1,543.0	1,731.0			188.0
2005	1,354	12.3	201.3	1,543.0	1,544.8	1,731.0			186.2
2006	1,357	13.7	201.5	1,544.8	1,556.0	1,731.0			175.0
2007	1,367	14.0	203.0	1,556.0	1,599.3	1,731.0			131.7

Table 1B.11.5-1 (Continued)
OUC Capacity Requirements With Optimal Supply
Side Expansion Strategy A
Expect 1

Year	Peak (MW)	Curtable Rates (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus/ (Deficit)
2008	1,405	14.3	208.6	1,599.3	1,639.1	1,731.0			91.9
2009	1,440	14.7	213.8	1,639.1	1,696.3	1,731.0			34.8
2010	1,490	15.0	221.3	1,696.3	1,747.6	1,731.0	337.5	90.0	230.9
2011	1,535	15.4	227.9	1,747.6	1,792.0	1,978.5			186.5
2012	1,574	15.7	233.7	1,792.0	1,846.8	1,978.5			131.7
2013	1,622	16.1	240.9	1,846.8	1,894.6	1,978.5			83.9
2014	1,664	16.5	247.1	1,894.6	1,949.4	1,978.5	337.5	44.0	322.6
2015	1,712	16.9	254.3	1,949.4	1,998.3	2,272.0		205.0	68.7
2016	1,755	17.3	260.7	1,998.3	2,056.5	2,067.0			10.5
2017	1,806	17.7	268.2	2,056.5	2,112.4	2,067.0	337.5	217.0	75.1
2018	1,855	18.1	275.5	2,112.4	2,177.4	2,187.5	192.3		10.1
2019	1,912	18.6	284.0	2,177.4	2,229.8	2,187.5			150.0
2020	1,958	19.0	290.8	2,229.8	2,283.3	2,379.8			96.5

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18.11.5-4

TABLE 18.11.5-2
OPTIMAL SUPPLY SIDE EXPANSION
CUMULATIVE PRESENT WORTH
EXPECT 1 (EIFINPW.MK)

PROJECT 1 (ELFINPW.WK)																Total Revenue Requirements	
DUC PRODUCTION COSTS					Levelized Capital Costs												
Year	Fuel	O&M	Startup	Total	STANTON 2 1997	675/2 pc 2010	675/2 pc 2014	675/2 pc 2017	192 ct 2019	O COMMER O LIGHT	HEAT PUMP	DIRECT LD CTRL	COAL PILE	Total	Annual	1991 Cumulative Present Worth	
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	
1991	89,682	618	297	90,597							0.00	0.00	0.00	186.375	0	90,597	
1992	103,307	672	388	104,367							0.00	0.00	0.00		0	104,367	
1993	109,535	841	403	110,779							0.00	0.00	0.00		0	110,779	
1994	122,444	982	425	123,850							0.00	0.00	0.00		0	123,850	
1995	136,208	994	446	137,649							0.00	0.00	0.00		0	137,649	
1996	158,890	1,280	492	160,663							0.00	0.00	0.00		0	160,663	
1997	154,408	10,466	746	165,621	36,253						0.00	0.00	0.00	186.375	36,439	202,060	
1998	173,268	11,148	795	185,210	36,253						0.00	0.00	0.00	186.375	36,439	221,650	
1999	189,633	11,726	853	202,212	36,253						0.00	0.00	0.00	186.375	36,439	238,651	
2000	213,544	12,398	979	226,921	36,253						0.00	0.00	0.00	186.375	36,439	263,360	
2001	239,742	13,035	905	253,682	36,253						0.00	0.00	0.00	186.375	36,439	290,121	
2002	264,880	13,694	1,043	279,617	36,253						0.00	0.00	0.00	186.375	36,439	316,056	
2003	289,279	14,460	1,070	304,809	36,253						0.00	0.00	0.00	186.375	36,439	341,248	
2004	321,393	15,199	1,142	337,734	36,253						0.00	0.00	0.00	186.375	36,439	374,173	
2005	349,048	15,950	1,314	366,312	36,253						0.00	0.00	0.00	186.375	36,439	402,752	
2006	382,846	16,898	1,397	401,141	36,253						0.00	0.00	0.00	186.375	36,439	437,581	
2007	421,229	17,595	1,407	440,231	36,253						0.00	0.00	0.00	186.375	36,439	476,670	
2008	475,524	18,660	1,466	495,651	36,253						0.00	0.00	0.00	186.375	36,439	532,090	
2009	516,096	19,783	1,481	537,360	36,253						0.00	0.00	0.00	186.375	36,439	573,799	
2010	477,943	40,176	2,145	520,263	36,253	71,150					0.00	0.00	0.00	186.375	107,589	627,852	
2011	528,718	42,258	1,853	572,829	36,253	71,150					0.00	0.00	0.00	186.375	107,589	680,417	
2012	592,273	44,773	2,217	639,263	36,253	71,150					0.00	0.00	0.00	186.375	107,589	746,852	
2013	666,211	47,284	2,288	715,782	36,253	71,150					0.00	0.00	0.00	186.375	107,589	823,371	
2014	622,055	71,485	3,135	696,675	36,253	71,150	84,847				0.00	0.00	0.00	186.375	192,436	889,112	
2015	683,059	75,310	3,082	761,451	36,253	71,150	84,847				0.00	0.00	0.00	186.375	192,436	953,887	
2016	774,096	79,724	3,248	857,069	36,253	71,150	84,847				0.00	0.00	0.00	186.375	192,436	1,049,505	
2017	767,337	107,935	4,960	880,231	36,253	71,150	84,847	96,825		0	0.00	0.00	0.00	186.375	289,261	1,169,492	
2018	858,204	112,812	4,233	975,249	36,253	71,150	84,847	96,825		0	0.00	0.00	0.00	186.375	289,261	1,264,510	
2019	927,732	124,539	5,190	1,057,461	36,253	71,150	84,847	96,825	15,500	0	0.00	0.00	0.00	186.375	304,761	1,362,222	
2020	1,029,145	131,634	5,841	1,166,621	36,253	71,150	84,847	96,825	15,500	0	0.00	0.00	0.00	186.375	304,761	1,471,382	

1B.11.6 Demand-Side Evaluation Results

To determine the cost-effectiveness of implementing demand-side management programs, Strategy B with the two load forecasts with demand-side management, Expect 2, and Expect 3 was optimized, like Strategy A, based on a 15 percent reserve margin, dictating when unit additions would occur. Both demand-side strategies provide savings on a cumulative present worth basis over the supply-side strategy. However, Strategy B with all three DSM programs resulted in increased costs over the Strategy B without direct load control, as shown below.

	1991 Cumulative Present Worth Comparative Costs \$ million
Strategy A--Supply-Side Only	4,659
Strategy B--Commercial Lighting/Heat Pump	4,557
Strategy B--Commercial Lighting/Heat Pump/ Direct Load Control	4,642

From this it can be concluded that direct load control does not appear to be a cost-effective demand-side management program for OUC at this time. Present worth evaluations for the demand-side strategy are provided in Tables 1B.11.6-1 and 1B.11.6-2. The capacity additions and reductions for Strategy B with the commercial lighting and resistance heating conversion to heat pump demand-side management programs which will be used to evaluate the additional supply-side alternatives are shown in Table 1B.11.6-3.

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TABLE 18.11.6-1
OPTIMAL DEMAND SIDE EXPANSION
CUMULATIVE PRESENT WORTH
EXPECT 2 (E201LP.WK)

Year	OUC PRODUCTION COSTS				Levelized Capital Costs										Total Revenue Requirements		
	Fuel	O&M	Startup	Total	STANTON 2	675/2 pc	675/2 pc	675/2 pc	192 ct	0 COMMER	HEAT	DIRECT	COAL PILE	Total	Annual	Cumulative	1991
	\$1000	\$1000	\$1000	\$1000	1997	2010	2015	2017	2020	0 LIGHT	PUMP	LD CTRL	\$1000	\$1000	\$1000	\$1000	\$1000
1991	89,683	618	297	90,598							0.00	0.00	0.00	186.375	0	90,598	90,598
1992	103,348	673	393	104,414							0.00	0.00	0.00		0	104,414	188,153
1993	109,336	839	403	110,578							237.56	235.25	0.00		473	111,050	285,095
1994	121,970	976	432	123,377							245.10	247.60	0.00		493	123,870	386,124
1995	135,466	991	444	136,902							252.92	261.26	0.00		514	137,417	490,841
1996	157,744	1,265	483	159,492							261.03	279.71	0.00		541	160,033	604,783
1997	153,081	10,457	729	164,268	36,253						269.45	294.64	0.00	186.375	37,003	201,271	738,673
1998	171,385	11,129	774	183,288	36,253						278.18	309.53	0.00	186.375	37,027	220,315	875,605
1999	187,125	11,717	870	199,712	36,253						287.25	324.68	0.00	186.375	37,051	236,763	1,013,095
2000	210,070	12,373	967	223,410	36,253						296.65	337.67	0.00	186.375	37,074	260,484	1,154,424
2001	235,208	13,007	955	249,171	36,253						306.41	344.18	0.00	186.375	37,090	286,260	1,299,537
2002	258,956	13,657	1,079	273,691	36,253						316.54	343.01	0.00	186.375	37,099	310,790	1,446,736
2003	281,654	14,407	1,094	297,155	36,253						327.06	368.62	0.00	186.375	37,135	334,290	1,594,667
2004	311,954	15,126	1,146	328,227	36,253						337.97	381.26	0.00	186.375	37,159	365,385	1,745,737
2005	337,711	15,832	1,267	354,809	36,253						349.30	391.40	0.00	186.375	37,180	391,990	1,897,162
2006	368,469	16,755	1,389	386,614	36,253						361.06	402.49	0.00	186.375	37,203	423,817	2,050,128
2007	404,714	17,525	1,461	423,700	36,253						373.27	419.70	0.00	186.375	37,232	460,933	2,205,563
2008	454,699	18,538	1,511	474,749	36,253						385.94	436.82	0.00	186.375	37,262	512,011	2,366,882
2009	493,329	19,622	1,580	514,531	36,253						399.10	459.59	0.00	186.375	37,298	551,829	2,529,326
2010	459,221	39,884	2,072	501,177	36,253	71,150					0.00	656.07	0.00	186.375	108,245	609,422	2,696,941
2011	506,211	41,990	1,950	550,151	36,253	71,150					0.00	413.72	0.00	186.375	108,003	658,154	2,866,070
2012	564,963	44,455	2,201	611,618	36,253	71,150					0.00	737.67	0.00	186.375	108,327	719,945	3,038,926
2013	633,236	46,917	2,371	682,523	36,253	71,150					0.00	454.68	0.00	186.375	108,044	790,567	3,216,270
2014	714,957	49,437	2,583	766,977	36,253	71,150					0.00	814.09	0.00	186.375	108,403	875,380	3,399,742
2015	652,516	74,889	3,041	730,256	36,253	71,150	88,665				0.00	499.56	0.00	186.375	196,754	927,010	3,581,273
2016	738,957	79,070	3,220	821,246	36,253	71,150	88,665				0.00	898.73	0.00	186.375	197,153	1,018,399	3,767,602
2017	737,425	107,127	4,916	849,468	36,253	71,150	88,665	96,825		0	0.00	548.98	0.00	186.375	293,628	1,143,096	3,963,008
2018	824,983	112,443	4,562	941,988	36,253	71,150	88,665	96,825		0	0.00	992.75	0.00	186.375	294,072	1,236,059	4,160,428
2019	907,452	118,158	4,760	1,030,371	36,253	71,150	88,665	96,825		0	0.00	604.15	0.00	186.375	293,683	1,324,054	4,358,012
2020	980,991	130,719	5,689	1,117,398	36,253	71,150	88,665	96,825	16,197	0	0.00	1096.38	0.00	186.375	310,373	1,427,771	4,557,078

18.11.6-2

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TABLE 18.11.6-2
 EXPECT 3 OPTIMIZED DEMAND SIDE EXPANSION
 CUMULATIVE PRESENT WORTH
 EXPECT 3 (E3FINPW.WK)

Year	OUC PRODUCTION COSTS				Levelized Capital Costs										Total Revenue Requirements		
	Fuel	O&M	Startup	Total	STANTON 2	675/2 pc	675/2 pc	675/2 pc	0	0 COMMER	HEAT	DIRECT	COAL PILE	Total	Annual	1991 Cumulative	
	\$1000	\$1000	\$1000	\$1000	1997	2011	2015	2017	0	0 LIGHT	PUMP	LD CTRL	\$1000			Present	Worth
					\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000
1991	89,682	618	297	90,597							0.00	0.00	0.00	186.375	0	90,597	90,597
1992	103,348	673	393	104,413							0.00	0.00	0.00		0	104,413	188,153
1993	109,333	838	401	110,573							237.56	235.25	0.00		473	111,046	285,090
1994	121,969	976	432	123,376							245.10	247.60	200.00		693	124,069	386,282
1995	135,465	991	444	136,900							252.92	261.26	1070.68		1,585	138,485	491,813
1996	157,744	1,266	484	159,494							261.03	279.71	1489.80		2,031	161,524	606,817
1997	153,080	10,457	729	164,266	36,253						269.45	294.64	1960.60	186.375	38,964	203,230	742,010
1998	171,384	11,129	773	183,286	36,253						278.18	309.53	2486.06	186.375	39,513	222,799	880,486
1999	187,121	11,716	870	199,707	36,253						287.25	324.68	3066.33	186.375	40,118	239,825	1,019,753
2000	210,064	12,373	963	223,400	36,253						296.65	337.67	3688.71	186.375	40,762	264,162	1,163,078
2001	235,203	13,008	956	249,163	36,253						306.41	344.18	4433.94	186.375	41,524	290,687	1,310,435
2002	258,942	13,654	1,073	273,669	36,253						316.54	343.01	5072.49	186.375	42,171	315,841	1,460,027
2003	281,643	14,406	1,092	297,141	36,253						327.06	368.62	5979.43	186.375	43,114	340,255	1,610,597
2004	311,945	15,126	1,145	328,216	36,253						337.97	381.26	6872.74	186.375	44,031	372,247	1,764,504
2005	337,706	15,832	1,266	354,803	36,253						349.30	391.40	7811.48	186.375	44,992	399,795	1,918,944
2006	368,463	16,755	1,389	386,606	36,253						361.06	402.49	8818.88	186.375	46,022	432,628	2,075,091
2007	404,700	17,525	1,461	423,686	36,253						373.27	419.70	9956.00	186.375	47,188	470,874	2,233,878
2008	454,703	18,542	1,509	474,754	36,253						385.94	436.82	11201.59	186.375	48,464	523,217	2,398,728
2009	493,307	19,622	1,580	514,509	36,253						399.10	459.59	12613.78	186.375	49,912	564,421	2,564,879
2010	582,985	21,228	1,684	605,896	36,253						0.00	656.07	12434.17	186.375	49,530	655,425	2,745,147
2011	506,598	41,999	2,039	550,637	36,253	74,351					0.00	413.72	12894.41	186.375	124,099	674,736	2,918,537
2012	564,942	44,453	2,198	611,593	36,253	74,351					0.00	737.67	13121.44	186.375	124,650	736,243	3,095,305
2013	633,213	46,914	2,358	682,485	36,253	74,351					0.00	454.68	13862.78	186.375	125,108	807,593	3,276,469
2014	714,929	49,438	2,576	766,943	36,253	74,351					0.00	814.09	14645.99	186.375	126,251	893,194	3,463,675
2015	652,501	74,700	3,041	730,242	36,253	74,351	88,665				0.00	499.56	15475.03	186.375	215,431	945,673	3,648,861
2016	738,929	79,071	3,225	821,224	36,253	74,351	88,665				0.00	898.73	16349.96	186.375	216,705	1,037,929	3,838,763
2017	737,348	107,128	4,898	849,374	36,253	74,351	88,665	96,825		0	0.00	548.98	17272.81	166.375	314,103	1,163,477	4,037,653
2018	824,893	112,444	4,562	941,899	36,253	74,351	88,665	96,825		0	0.00	992.75	18245.42	186.375	315,519	1,257,418	4,238,484
2019	907,423	118,159	4,760	1,030,343	36,253	74,351	88,665	96,825		0	0.00	604.15	19282.40	186.375	316,167	1,346,510	4,439,419
2020	1,006,033	124,961	5,225	1,136,219	36,253	74,351	88,665	96,825	0	0	0.00	1096.38	20370.54	186.375	317,748	1,453,967	4,642,137

18.11.6-3

Table 1B.11.6-3
OUC Capacity Requirements with Commercial Lighting and
Heat Pump Conversion Expansion Strategy B
Expect 2

Year	Peak (MW)	DSM Reduction	Standby Generator (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus (Deficit)
1991	1,036	0	0.0	155.4	1,191.40	1,227.75	1,197.00			(30.7)
1992	1,068	0	0.4	160.1	1,227.75	1,233.72	1,197.00	204.00		167.3
1993	1,077	3	1.2	160.9	1,233.72	1,270.69	1,401.00			130.3
1994	1,111	4	2.1	165.7	1,270.69	1,304.16	1,401.00			96.8
1995	1,144	7	2.9	170.1	1,304.16	1,336.94	1,401.00			64.1
1996	1,177	11	3.4	174.4	1,336.94	1,381.83	1,401.00			19.2
1997	1,220	14	4.4	180.2	1,381.83	1,422.59	1,401.00	330.00		308.4
1998	1,258	16	5.0	185.6	1,422.59	1,459.34	1,731.00			271.7
1999	1,294	19	6.0	190.3	1,459.34	1,492.58	1,731.00			238.4
2000	1,326	21	7.1	194.7	1,492.58	1,533.23	1,731.00			197.8
2001	1,362	21	7.8	200.0	1,533.23	1,513.47	1,731.00			217.5
2002	1,350	25	8.9	197.4	1,513.47	1,528.15	1,731.00			202.8
2003	1,368	29	10.2	199.3	1,528.15	1,496.22	1,731.00			234.8
2004	1,343	31	10.9	195.2	1,496.22	1,505.05	1,731.00			225.9
2005	1,354	33	12.3	196.3	1,505.05	1,505.70	1,731.00			225.3
2006	1,357	34	13.7	196.4	1,505.70	1,515.72	1,731.00			215.3
2007	1,367	35	14.0	197.7	1,515.72	1,553.31	1,731.00			177.7

Table 1B.11.6-3 (Continued)
OUC Capacity Requirements with Commercial Lighting and
Heat Pump Conversion Expansion Strategy B
Expect 2

Year	Peak (MW)	DSM Reduction	Standby Generator (MW)	Reserve Margin	Total System Requirements	System Requirements for Capacity Addition	Existing Capacity	Capacity Additions	Capacity Reductions	Capacity Surplus/ (Deficit)
2008	1,405	40	14.3	202.6	1,553.31	1,589.65	1,731.00			141.4
2009	1,440	43	14.7	207.3	1,589.65	1,646.80	1,731.00			84.2
2010	1,490	43	15.0	214.8	1,646.80	1,692.37	1,731.00	337.50	90.00	286.1
2011	1,535	48	15.4	220.7	1,692.37	1,737.95	1,978.50			240.6
2012	1,574	47	15.7	226.7	1,737.95	1,785.81	1,978.50			192.7
2013	1,622	53	16.1	232.9	1,785.81	1,833.67	1,978.50			144.8
2014	1,664	53	16.5	239.2	1,833.67	1,883.81	1,978.50		44	50.7
2015	1,712	57	16.9	245.7	1,883.81	1,932.80	1,934.50	337.50	205	134.2
2016	1,755	57	17.3	252.1	1,932.80	1,984.07	2,067.00			82.9
2017	1,806	63	17.7	258.8	1,984.07	2,039.93	2,067.00	337.50	217	147.6
2018	1,855	63	18.1	266.1	2,039.93	2,098.08	2,187.50			89.4
2019	1,912	69	18.6	273.7	2,098.08	2,151.62	2,187.50			35.9
2020	1,958	68	19.0	280.6	2,151.62	2,206.27	2,187.50	192.30		173.5

1B.11.7 Alternatives to Stanton 2

The demand-side strategy which includes resistance heating conversion and commercial lighting DSM programs, was evaluated to determine if the first unit addition in January of 1997 should be Stanton 2. Using the other strategies developed in Section 1B.10.0, 50 percent ownership in a 498 MW combined cycle and complete ownership of a 192 MW combustion turbine were each considered as possible unit additions instead of constructing Stanton 2.

The present worth comparative costs of the optimal strategies implementing combined cycle and combustion turbine technologies in 1997 are shown below.

<u>First Unit Installed</u>	1991		
	Cumulative		
	Present		
	Worth		
	Comparative		
	Costs	<u>Differential</u>	
	\$ million	\$ million	percent
Strategy B--Stanton 2	4,557	Base	Base
Strategy D--Combined Cycle	4,777	220	4.8
Strategy C--Combustion Turbine	4,804	247	5.4

Cumulative present worth values for Strategies D and C are provided in Tables 1B.11.7-1 and 1B.11.7-2, respectively.

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IB.11.7-2

TABLE 1B.11.7-1
EXPECT 2 FIRST UNIT COMBINED CYCLE
CUMULATIVE PRESENT WORTH
EXPECT 2 (E2CCOIL.WK)

															Total Revenue Requirements	
OUC PRODUCTION COSTS					Levelized Capital Costs										1991	
Year	Fuel	O&M	Startup	Total	488/2 cc 1997	675/2 pc 2010	675/2 pc 2014	675/2 pc 2017	192 ct 2019	O COMMER O LIGHT	HEAT PUMP	DIRECT LD CTRL	Total	Annual	Cumulative Present Worth	
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	
1991	89,683	618	297	90,598						0.00	0.00	0.00	0	90,598	90,598	
1992	103,348	673	393	104,414						0.00	0.00	0.00	0	104,414	188,153	
1993	109,336	839	403	110,578						237.56	235.25	0.00	473	111,050	285,095	
1994	121,970	976	432	123,377						245.10	247.60	0.00	493	123,870	386,124	
1995	135,466	991	444	136,902						252.92	261.26	0.00	514	137,417	490,841	
1996	157,744	1,265	483	158,492						261.03	279.71	0.00	541	160,033	604,783	
1997	163,138	7,710	970	171,817	13,317					269.45	294.64	0.00	13,881	185,699	728,314	
1998	185,156	8,139	992	194,287	13,317					278.18	309.53	0.00	13,905	208,192	857,711	
1999	209,642	8,738	1,065	219,445	13,317					287.25	324.68	0.00	13,929	233,374	993,233	
2000	236,890	9,346	1,050	247,287	13,317					296.65	337.67	0.00	13,952	261,238	1,134,971	
2001	264,219	9,816	1,042	275,077	13,317					306.41	344.18	0.00	13,968	289,045	1,281,495	
2002	299,014	10,604	1,076	310,694	13,317					316.54	343.01	0.00	13,977	324,671	1,435,269	
2003	326,952	11,155	1,200	339,308	13,317					327.06	368.62	0.00	14,013	353,320	1,591,621	
2004	360,821	11,798	1,191	373,809	13,317					337.97	381.26	0.00	14,036	387,846	1,751,977	
2005	401,220	12,465	1,203	414,888	13,317					349.30	391.40	0.00	14,058	428,946	1,917,678	
2006	439,333	13,317	1,113	453,763	13,317					361.06	402.49	0.00	14,081	467,844	2,086,535	
2007	479,278	13,862	1,243	494,383	13,317					373.27	419.70	0.00	14,110	508,493	2,258,008	
2008	550,917	15,020	1,329	567,266	13,317					385.94	436.82	0.00	14,140	581,406	2,441,192	
2009	599,113	16,003	1,543	616,659	13,317					399.10	459.59	0.00	14,176	630,835	2,626,894	
2010	530,663	34,971	2,573	568,207	13,317	71,150				0.00	656.07	0.00	85,123	653,330	2,806,585	
2011	597,033	37,205	2,512	636,750	13,317	71,150				0.00	413.72	0.00	84,881	721,630	2,992,026	
2012	668,119	39,676	2,811	710,606	13,317	71,150				0.00	737.67	0.00	85,204	795,810	3,183,096	
2013	749,511	41,762	2,816	794,088	13,317	71,150				0.00	454.68	0.00	84,921	879,010	3,380,280	
2014	671,158	64,441	4,150	739,750	13,317	71,150	84,847			0.00	814.09	0.00	170,128	909,878	3,570,982	
2015	756,635	67,917	3,890	828,442	13,317	71,150	84,847			0.00	499.56	0.00	169,814	998,256	3,766,466	
2016	850,267	72,387	4,533	927,188	13,317	71,150	84,847			0.00	898.73	0.00	170,213	1,097,401	3,967,249	
2017	776,028	97,383	4,304	877,716	13,317	71,150	84,847	96,825		0	0.00	548.98	0.00	266,688	1,144,404	4,162,879
2018	879,722	102,854	4,576	987,152	13,317	71,150	84,847	96,825		0	0.00	992.75	0.00	267,132	1,254,283	4,363,209
2019	965,367	113,856	5,776	1,084,998	13,317	71,150	84,847	96,825	15,500	0	0.00	604.15	0.00	282,243	1,367,241	4,567,237
2020	1,091,901	121,459	6,944	1,220,304	13,317	71,150	84,847	96,825	15,500	0	0.00	1096.38	0.00	282,735	1,503,039	4,776,798

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1B.1.7-3

TABLE 1B.11.7-2
EXPECT 2 FIRST UNIT COMBUSTION TURBINE
CUMULATIVE PRESENT WORTH
EXPECT 2 (E2CT08.WK)

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Levelized Capital Costs															Total Revenue Requirements	
OUC PRODUCTION COSTS					192 ct	675/2 pc	675/2 pc	675/2 pc	488/2 cc	O COMMER	HEAT	DIRECT			1991	
Year	Fuel	O&M	Startup	Total	1997	2009	2014	2015	2018	O LIGHT	PUMP	LD CTRL	Total	Annual	Cumulative Present Worth	
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	
1991	89,683	618	297	90,598						0.00	0.00	0.00	0	90,598	90,598	
1992	103,348	673	393	104,414						0.00	0.00	0.00	0	104,414	188,153	
1993	109,336	839	403	110,578						237.56	235.25	0.00	473	111,050	285,095	
1994	121,970	976	432	123,377						245.10	247.60	0.00	493	123,870	386,124	
1995	135,466	991	444	136,902						252.92	261.26	0.00	514	137,417	490,841	
1996	157,744	1,265	483	159,492						261.03	279.71	0.00	541	160,033	604,783	
1997	173,012	3,391	594	176,997	5,885					269.45	294.64	0.00	6,449	183,446	726,815	
1998	195,969	3,478	688	200,135	5,885					278.18	309.53	0.00	6,473	206,608	855,228	
1999	221,733	3,829	720	226,282	5,885					287.25	324.68	0.00	6,497	232,779	990,404	
2000	251,221	4,476	836	256,533	5,885					296.65	337.67	0.00	6,520	263,052	1,133,127	
2001	279,161	4,553	880	284,595	5,885					306.41	344.18	0.00	6,536	291,131	1,280,708	
2002	316,563	4,948	956	322,467	5,885					316.54	343.01	0.00	6,545	329,012	1,436,538	
2003	346,893	5,510	997	353,401	5,885					327.06	368.62	0.00	6,581	359,982	1,595,838	
2004	383,425	5,632	1,038	390,095	5,885					337.97	381.26	0.00	6,605	396,699	1,759,855	
2005	425,347	6,060	1,148	432,555	5,885					349.30	391.40	0.00	6,626	439,181	1,929,510	
2006	468,762	6,885	1,297	476,943	5,885					361.06	402.49	0.00	6,649	483,592	2,104,051	
2007	508,183	6,862	1,355	516,400	5,885					373.27	419.70	0.00	6,678	523,078	2,280,442	
2008	590,186	8,081	1,602	599,868	5,885					385.94	436.82	0.00	6,708	606,576	2,471,556	
2009	486,252	25,974	1,933	514,158	5,885	68,086				399.10	459.59	0.00	74,830	588,988	2,644,939	
2010	557,475	28,112	1,915	587,501	5,885	68,086				0.00	656.07	0.00	74,627	662,128	2,827,050	
2011	626,489	30,082	2,082	658,653	5,885	68,086				0.00	413.72	0.00	74,385	733,038	3,015,422	
2012	706,300	32,492	2,511	741,304	5,885	68,086				0.00	737.67	0.00	74,709	816,012	3,211,343	
2013	787,829	34,075	2,571	824,475	5,885	68,086				0.00	454.68	0.00	74,426	898,900	3,412,989	
2014	693,681	57,031	2,808	753,520	5,885	68,086	84,847			0.00	814.09	0.00	159,632	913,153	3,604,378	
2015	652,853	81,306	3,096	737,256	5,885	68,086	84,847	88,665		0.00	499.56	0.00	247,983	985,239	3,797,312	
2016	720,447	86,171	3,667	810,285	5,885	68,086	84,847	88,665		0.00	898.73	0.00	248,382	1,058,667	3,991,009	
2017	814,296	91,119	3,618	909,032	5,885	68,086	84,847	88,665		0	0.00	548.98	0.00	248,033	1,157,065	4,188,803
2018	871,445	107,747	5,137	984,329	5,885	68,086	84,847	88,665	33,563	0	0.00	992.75	0.00	282,039	1,266,367	4,391,063
2019	956,595	113,937	5,672	1,076,203	5,885	68,086	84,847	88,665	33,563	0	0.00	604.15	0.00	281,650	1,357,854	4,593,691
2020	1,099,847	121,336	6,749	1,227,932	5,885	68,086	84,847	88,665	33,563	0	0.00	1096.38	0.00	282,143	1,510,074	4,804,232

1B.12.0 Sensitivity Analysis

Sensitivity analyses are performed to determine the impact in changes in key study assumptions on the overall results. Four sensitivity evaluations were performed: high growth, low growth, 1989 Planning Hearing fuel price projections, and break-even capital cost of Stanton 2.

Load forecasts for the high and low growth sensitivity analyses were developed by OUC and modified by Battelle to include the effects of the commercial lighting and resistance heating conversion demand-side management programs. Firm off-system sales were added to the hourly load forecasts to produce the final load forecasts, "HIGH" for the high growth scenario and "LOW" for the low growth scenario. Sensitivity analysis for the change in fuel prices to the 1989 Planning Hearing fuel forecast is developed using the Strategy B hourly load forecast which includes firm off-system sales and the commercial lighting and resistance heating conversion demand-side management programs.

1B.12.1 High Growth Scenario

The first sensitivity analysis is the high growth scenario which includes the low fuel price projections. Economic projections and fuel prices for the high growth scenarios are those provided in Volume 1A, Subsections 1A.3.2 and 1A.3.3, respectively.

The results of the optimizations of the strategies considering Stanton 2, combined cycle, and combustion turbine additions show that the addition of Stanton 2, Strategy B, is still the least cost expansion plan as shown below.

<u>First Unit Installed</u>	<u>1991 Cumulative Present Worth Comparative Cost</u> \$ million	<u>Differential</u>	
		\$ million	percent
Strategy B-- Stanton 2	4,849	Base	Base
Strategy D-- Combined Cycle	4,945	96	2.0
Strategy C-- Combustion Turbine	4,949	100	3.1

Annual cumulative present worth costs for first unit additions of Stanton 2, a combined cycle, and a combustion turbine are provided in Tables 1B.12.1-1, 1B.12.1-2, and 1B.12.1-3, respectively.

The higher load growth associated with the high growth scenario is not sufficient to move the need for capacity addition to an earlier date. Capacity will be required in 1997.

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TABLE IB.12.1-1
HIGH GROWTH SENSITIVITY
FIRST UNIT STANTON 2
CUMULATIVE PRESENT WORTH
OPTIM (OP07PW.WK)

																Total Revenue Requirements	
OUC PRODUCTION COSTS					Levelized Capital Costs												
Year	Fuel	O&M	Startup	Total	STANTON 2 1997	675/2 pc 2009	675/2 pc 2014	192 ct 2015	675/2 pc 2017	192 ct 2020	COMMER LIGHT	HEAT PUMP	DIRECT LD CTRL	COAL PILE	Total	1991 Annual	1991 Cumulative Present Worth
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000
1991	86,924	604	303	87,831							0.00	0.00	0.00	124.903	0	87,831	87,831
1992	98,550	652	382	99,584							0.00	0.00	0.00		0	99,584	182,619
1993	102,587	807	383	103,777							240.57	235.34	0.00		476	104,252	277,071
1994	113,244	940	397	114,581							248.14	247.89	0.00		496	115,077	376,309
1995	124,165	941	407	125,513							255.99	261.65	0.00		518	126,030	479,757
1996	142,500	1,195	443	144,138							264.13	280.84	0.00		545	144,683	592,797
1997	140,533	9,620	672	150,825	28,874						272.58	296.24	0.00	124.903	29,568	180,392	726,948
1998	154,994	10,133	717	165,844	28,874						281.35	311.42	0.00	124.903	29,592	195,435	865,286
1999	166,979	10,501	735	178,216	28,874						290.44	327.22	0.00	124.903	29,616	207,832	1,005,313
2000	184,979	10,947	797	196,723	28,874						299.88	340.67	0.00	124.903	29,639	226,362	1,150,480
2001	202,745	11,342	748	214,836	28,874						309.67	339.94	0.00	124.903	29,648	244,484	1,299,718
2002	220,086	11,758	876	232,719	28,874						319.84	356.52	0.00	124.903	29,675	262,395	1,452,173
2003	235,798	12,233	871	248,902	28,874						330.39	374.16	0.00	124.903	29,703	278,605	1,606,251
2004	256,665	12,680	890	270,235	28,874						341.33	387.44	0.00	124.903	29,728	299,963	1,764,151
2005	272,779	13,115	1,012	286,907	28,874						352.69	399.72	0.00	124.903	29,751	316,658	1,922,811
2006	293,176	13,683	1,019	307,878	28,874						364.49	411.61	0.00	124.903	29,775	337,653	2,083,842
2007	316,765	14,076	1,041	331,882	28,874						376.73	430.92	0.00	124.903	29,806	361,688	2,248,028
2008	350,560	14,700	1,024	366,283	28,874						389.44	450.62	0.00	124.903	29,839	396,122	2,419,184
2009	315,848	29,297	1,529	346,674	28,874	40,849					402.63	475.65	0.00	124.903	70,726	417,401	2,590,848
2010	356,608	30,715	1,382	388,706	28,874	40,849					0.00	682.20	0.00	124.903	70,530	459,236	2,770,622
2011	388,730	31,888	1,318	421,936	28,874	40,849					0.00	427.21	0.00	124.903	70,275	492,211	2,954,023
2012	431,108	33,322	1,456	465,886	28,874	40,849					0.00	769.39	0.00	124.903	70,617	536,503	3,144,301
2013	474,153	34,704	1,518	510,374	28,874	40,849					0.00	471.67	0.00	124.903	70,320	580,694	3,340,331
2014	449,269	51,658	2,157	503,084	28,874	40,849	47,355				0.00	854.43	0.00	124.903	118,058	621,141	3,539,918
2015	481,414	56,711	2,098	540,223	28,874	40,849	47,355	7,357			0.00	520.97	0.00	124.903	125,082	665,304	3,743,398
2016	534,659	59,380	2,324	596,362	28,874	40,849	47,355	7,357			0.00	948.66	0.00	124.903	125,509	721,872	3,953,546
2017	531,662	77,775	3,238	612,674	28,874	40,849	47,355	7,357	51,746		0.00	576.12	0.00	124.903	176,883	789,558	4,172,328
2018	580,232	80,500	2,786	663,517	28,874	40,849	47,355	7,357	51,746		0.00	1054.29	0.00	124.903	177,361	840,879	4,394,109
2019	630,859	83,833	2,807	717,499	28,874	40,849	47,355	7,357	51,746		0.00	637.04	0.00	124.903	176,944	894,443	4,618,655
2020	684,080	91,065	3,451	778,597	28,874	40,849	47,355	7,357	51,746	8,529	0.00	1171.89	0.00	124.903	186,008	964,605	4,849,152

IB.12.1-3

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TABLE 18.12.1-2
HIGH GROWTH SENSITIVITY
FIRST UNIT COMBINED CYCLE
CUMULATIVE PRESENT WORTH
OPTIM (OPCC07PW.MK)

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DUC PRODUCTION COSTS				Levelized Capital Costs											Total Revenue Requirements		
Year	Fuel	O&M	Startup	Total	488/2 cc 1997	675/2 pc 2009	675/2 pc 2013	675/2 pc 2015	192 ct 2017	675/2 pc 2019	COMMER LIGHT	HEAT PUMP	DIRECT LD CTRL	COAL PILE	Total	Annual	1991 Cumulative Present Worth
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000
1991	86,924	604	303	87,831							0.00	0.00	0.00		0	87,831	87,831
1992	98,550	652	382	99,584							0.00	0.00	0.00		0	99,584	182,619
1993	102,587	807	383	103,777							240.57	235.34	0.00		476	104,252	277,071
1994	113,244	940	397	114,581							248.14	247.89	0.00		496	115,077	376,309
1995	124,165	941	407	125,513							255.99	261.65	0.00		518	126,030	479,767
1996	142,500	1,195	443	144,138							264.13	280.84	0.00		545	144,683	592,787
1997	146,347	7,244	839	154,429	9,753						272.58	296.24	0.00	0	10,322	164,751	715,316
1998	163,599	7,507	852	171,959	9,753						281.35	311.42	0.00	0	10,346	182,304	844,359
1999	181,931	7,895	840	190,666	9,753						290.44	327.22	0.00	0	10,371	201,037	979,808
2000	203,528	8,339	838	212,705	9,753						299.88	340.67	0.00	0	10,394	223,099	1,122,882
2001	221,601	8,601	874	231,077	9,753						309.67	339.94	0.00	0	10,403	241,480	1,270,285
2002	246,532	9,147	824	256,503	9,753						319.84	356.52	0.00	0	10,429	266,932	1,425,377
2003	264,954	9,482	845	275,281	9,753						330.39	374.16	0.00	0	10,457	285,738	1,583,400
2004	286,677	9,892	862	297,431	9,753						341.33	387.44	0.00	0	10,482	307,913	1,745,484
2005	311,641	10,303	842	322,786	9,753						352.69	399.72	0.00	0	10,505	333,291	1,912,478
2006	335,310	10,889	858	347,057	9,753						364.49	411.61	0.00	0	10,529	357,586	2,083,016
2007	360,343	11,200	949	372,492	9,753						376.73	430.92	0.00	0	10,561	383,052	2,256,900
2008	405,713	11,973	988	418,674	9,753						389.44	450.62	0.00	0	10,593	429,267	2,442,377
2009	352,594	25,553	2,106	380,254	9,753	40,849					402.63	475.65	0.00	0	51,480	431,734	2,619,937
2010	400,100	27,092	1,749	428,941	9,753	40,849					0.00	682.20	0.00	0	51,284	480,225	2,807,926
2011	442,039	28,432	1,541	472,012	9,753	40,849					0.00	427.21	0.00	0	51,029	523,041	3,002,816
2012	487,124	29,938	1,705	518,767	9,753	40,849					0.00	769.39	0.00	0	51,371	570,139	3,205,022
2013	445,766	44,732	2,331	492,830	9,753	40,849	45,976				0.00	471.67	0.00	0	97,050	589,879	3,404,154
2014	494,280	47,206	2,643	544,129	9,753	40,849	45,976				0.00	854.43	0.00	0	97,433	641,562	3,610,302
2015	476,255	62,701	2,622	541,577	9,753	40,849	45,976	48,776			0.00	520.97	0.00	0	145,875	687,452	3,820,556
2016	519,637	65,627	2,952	588,217	9,753	40,849	45,976	48,776			0.00	948.66	0.00	0	146,303	734,519	4,034,386
2017	558,629	71,630	3,012	633,271	9,753	40,849	45,976	48,776	7,806		0.00	576.12	0.00	0	153,736	787,006	4,252,461
2018	621,910	74,877	3,256	700,043	9,753	40,849	45,976	48,776	7,806		0.00	1054.29	0.00	0	154,214	854,257	4,477,770
2019	618,339	92,994	3,486	714,820	9,753	40,849	45,976	48,776	7,806	54,898	0.00	637.04	0.00	0	208,695	923,514	4,709,614
2020	675,846	97,551	3,686	777,084	9,753	40,849	45,976	48,776	7,806	54,898	0.00	1171.89	0.00	0	209,229	986,313	4,945,299

18.12.1.4

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TABLE 18.12.1-3
HIGH GROWTH SENSITIVITY
FIRST UNIT COMBUSTION TURBINE
CUMULATIVE PRESENT WORTH
OPTIM (OPCT07PW.MK)

OUC PRODUCTION COSTS				Levelized Capital Costs											Total Revenue Requirements		
Year	Fuel	O&M	Startup	Total	192 ct 1997	675/2 pc 2007	675/2 pc 2012	675/2 pc 2015	192 ct 2017	675/2 pc 2018	COMMER LIGHT	HEAT PUMP	DIRECT LD CTRL	COAL PILE	Total	Annual	Cumulative Present Worth 1991
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000
1991	86,924	604	303	87,831								0.00	0.00	0.00	0	87,831	87,831
1992	98,550	652	382	99,584								0.00	0.00	0.00	0	99,584	182,619
1993	102,587	807	383	103,777								240.57	235.34	0.00	476	104,252	277,071
1994	113,244	940	397	114,581								248.14	247.89	0.00	496	115,077	376,309
1995	124,165	941	407	125,513								255.99	261.65	0.00	518	126,030	479,757
1996	142,500	1,195	443	144,138								264.13	280.84	0.00	545	144,683	592,797
1997	155,132	3,162	517	158,811	4,322							272.58	296.24	0.00	0	163,133	714,536
1998	172,833	3,194	600	176,628	4,322							281.35	311.42	0.00	0	181,542	843,040
1999	192,328	3,479	610	196,416	4,322							290.44	327.22	0.00	0	201,356	978,704
2000	215,396	4,019	722	220,136	4,322							299.88	340.67	0.00	0	225,098	1,123,060
2001	234,060	4,040	706	238,806	4,322							309.67	339.94	0.00	0	243,777	1,271,866
2002	260,834	4,374	746	265,954	4,322							319.84	356.52	0.00	0	270,952	1,429,293
2003	280,608	4,830	815	286,253	4,322							330.39	374.16	0.00	0	291,280	1,590,381
2004	304,375	4,905	822	310,102	4,322							341.33	387.44	0.00	0	315,153	1,756,276
2005	330,359	5,239	876	336,474	4,322							352.69	399.72	0.00	0	341,548	1,927,408
2006	358,425	5,867	975	365,268	4,322							364.49	411.61	0.00	0	370,366	2,104,040
2007	388,373	18,426	1,177	327,977	4,322	38,504						376.73	430.92	0.00	0	43,634	371,610
2008	343,828	19,395	1,218	364,543	4,322	38,504						389.44	450.82	0.00	0	43,686	408,209
2009	370,219	20,348	1,225	391,792	4,322	38,504						402.63	475.65	0.00	0	43,704	435,496
2010	420,291	21,909	1,373	443,573	4,322	38,504						0.00	682.20	0.00	0	43,508	487,081
2011	464,080	23,233	1,435	488,758	4,322	38,504						0.00	427.21	0.00	0	43,253	532,012
2012	422,307	38,186	1,626	462,100	4,322	38,504	44,637					0.00	769.39	0.00	0	88,232	550,332
2013	458,677	38,562	1,570	499,810	4,322	38,504	44,637					0.00	471.67	0.00	0	87,935	587,744
2014	509,886	41,750	1,938	553,574	4,322	38,504	44,637					0.00	854.43	0.00	0	88,317	641,891
2015	483,803	58,652	2,061	544,516	4,322	38,504	44,637	48,776				0.00	520.97	0.00	0	136,760	681,276
2016	528,574	61,346	2,388	592,308	4,322	38,504	44,637	48,776				0.00	948.66	0.00	0	137,188	729,495
2017	583,218	67,112	2,331	652,661	4,322	38,504	44,637	48,776	7,806			0.00	576.12	0.00	0	144,621	797,282
2018	577,259	85,489	3,061	665,809	4,322	38,504	44,637	48,776	7,806	53,299		0.00	1054.29	0.00	0	198,398	864,206
2019	622,751	88,794	3,088	714,632	4,322	38,504	44,637	48,776	7,806	53,299		0.00	637.04	0.00	0	197,980	912,613
2020	684,066	93,089	3,424	780,579	4,322	38,504	44,637	48,776	7,806	53,299		0.00	1171.89	0.00	0	198,515	979,095

18.12.1-5

1B.12.2 Low Growth Scenario

The second sensitivity analysis is the low growth scenario which includes high fuel price projections. Economic projections and fuel prices for the low growth scenarios are those provided in Volume 1A, Subsections 1A.3.2 and 1A.3.3, respectively.

The results of the optimization of the strategies considering Stanton 2, combined cycle, and combustion turbine additions show that the addition of Stanton 2, Strategy B, is still the least cost expansion plan as shown below.

<u>First Unit Installed</u>	1991 Cumulative Present Worth Comparative Cost	<u>Differential</u>	
	\$ million	\$ million	percent
Strategy B-- Stanton 2	3,561	Base	Base
Strategy D-- Combined Cycle	3,757	196	5.5
Strategy C-- Combustion Turbine	3,748	187	5.3

Annual cumulative present worth costs for first unit additions of Stanton 2, a combined cycle, and a combustion turbine are provided in Tables 1B.12.2-1, 1B.12.2-2, and 1B.12.2-3, respectively.

The lower load growth would allow the delay of the first unit addition until 1998. Since OUC is making a commitment to Stanton 2 for commercial operation in 1997 at this time, the commercial operation date was kept at 1997. Because of the shorter lead time for combustion turbines and combined cycles, a later commitment could be made and some additional savings for these options are obtained by delaying their commercial operation to 1998.

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TABLE 18.12.2-1
LOW GROWTH SENSITIVITY
FIRST UNIT STANTON 2
CUMULATIVE PRESENT WORTH
PESSIM (PSOILPW.MK)

Year	OUC PRODUCTION COSTS				Levelized Capital Costs										Total Revenue Requirements		
	Fuel	OSM	Startup	Total	STANTON 2	675/2 pc	675/2 pc	0	0	0	HEAT	DIRECT	COAL PILE	Total	Annual	1991	
	\$1000	\$1000	\$1000	\$1000	1997	2014	2017	0	0	0	PUMP	LD CTRL				Cumulative	Present Worth
1991	91,987	620	297	92,904							0.00	0.00	0.00	269.416	0	92,904	92,904
1992	107,036	682	386	108,104							0.00	0.00	0.00		0	108,104	191,647
1993	113,790	858	421	115,070							228.46	235.07	0.00		464	115,533	288,039
1994	127,325	1,004	444	128,774							235.91	247.22	0.00		483	129,257	386,541
1995	140,287	1,027	486	141,801							243.64	259.77	0.00		503	142,304	485,597
1996	162,188	1,280	498	163,966							251.66	276.32	0.00		528	164,494	590,183
1997	158,696	11,257	781	170,734	46,133						259.98	291.01	0.00	269.416	46,953	217,687	716,606
1998	178,476	12,142	880	191,499	46,133						268.62	305.01	0.00	269.416	46,976	238,475	843,109
1999	196,366	12,911	917	210,195	46,133						277.59	319.95	0.00	269.416	47,000	257,195	967,728
2000	220,972	13,852	1,091	235,916	46,133						286.90	333.11	0.00	269.416	47,022	282,938	1,092,949
2001	245,324	14,761	1,215	261,299	46,133						296.56	329.32	0.00	269.416	47,028	308,328	1,217,591
2002	269,611	15,667	1,220	286,499	46,133						306.59	339.25	0.00	269.416	47,048	333,547	1,340,752
2003	290,653	16,706	1,400	308,760	46,133						317.01	354.98	0.00	269.416	47,074	355,834	1,460,766
2004	320,077	17,771	1,489	339,336	46,133						327.82	366.51	0.00	269.416	47,097	386,433	1,579,814
2005	345,893	18,810	1,577	366,280	46,133						339.05	382.19	0.00	269.416	47,124	413,403	1,696,143
2006	382,187	20,080	1,894	404,161	46,133						350.71	399.46	0.00	269.416	47,153	451,314	1,812,142
2007	420,869	21,331	1,946	444,146	46,133						362.81	410.69	0.00	269.416	47,176	491,322	1,927,490
2008	472,847	22,763	1,989	497,599	46,133						375.34	422.85	0.00	269.416	47,201	544,799	2,044,318
2009	515,063	24,302	2,335	541,699	46,133						388.43	441.61	0.00	269.416	47,233	588,932	2,159,673
2010	608,916	26,263	2,007	637,186	46,133						0.00	622.65	0.00	269.416	47,025	684,211	2,282,087
2011	678,749	28,026	2,052	708,827	46,133						0.00	398.38	0.00	269.416	46,801	755,628	2,405,571
2012	768,453	30,532	2,499	801,484	46,133						0.00	697.69	0.00	269.416	47,100	848,584	2,532,238
2013	877,192	32,249	2,502	911,943	46,133						0.00	435.08	0.00	269.416	46,838	958,781	2,662,962
2014	749,889	65,661	3,501	819,051	46,133	154,626					0.00	765.01	0.00	269.416	201,793	1,020,844	2,790,095
2015	833,826	70,287	3,541	907,654	46,133	154,626					0.00	475.34	0.00	269.416	201,503	1,109,158	2,916,266
2016	944,494	75,459	3,948	1,023,901	46,133	154,626					0.00	838.68	0.00	269.416	201,867	1,225,767	3,043,628
2017	882,807	115,163	5,877	1,003,847	46,133	154,626	184,162	0		0	0.00	519.75	0.00	269.416	385,709	1,389,556	3,175,505
2018	997,756	122,199	4,798	1,124,753	46,133	154,626	184,162	0		0	0.00	919.77	0.00	269.416	386,109	1,510,862	3,306,479
2019	1,101,901	130,554	5,557	1,238,012	46,133	154,626	184,162	0		0	0.00	567.72	0.00	269.416	385,757	1,623,769	3,435,053
2020	1,215,128	139,336	6,658	1,361,122	46,133	154,626	184,162	0	0	0	0.00	1008.77	0.00	269.416	386,198	1,747,321	3,561,428

18.12.2-2

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TABLE 18.12.2-2
LOW GROWTH SENSITIVITY
FIRST UNIT COMBINED CYCLE
CUMULATIVE PRESENT WORTH
PESSIM (PSCC08PW.WK)

DUC PRODUCTION COSTS					Levelized Capital Costs										Total Revenue Requirements		
Year	Fuel	O&M	Startup	Total	488/2 cc 1998	675/2 pc 2013	675/2 pc 2016	675/2 pc 2020	0 0	0 COMMER 0 LIGHT	HEAT PUMP	DIRECT LD CTRL	COAL PILE	Total	Annual	Cumulative Present Worth	1991 Cumulative Present Worth
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000
1991	91,987	620	297	92,904							0.00	0.00	0.00	0	92,904	92,904	92,904
1992	107,036	682	386	108,104							0.00	0.00	0.00	0	108,104	191,647	191,647
1993	113,790	850	421	115,070							228.46	235.07	0.00	464	115,533	288,039	288,039
1994	127,325	1,004	444	128,774							235.91	247.22	0.00	483	129,257	386,541	386,541
1995	140,287	1,027	486	141,801							243.64	259.77	0.00	503	142,304	485,597	485,597
1996	162,188	1,280	498	163,966							251.66	276.32	0.00	528	164,494	590,183	590,183
1997	181,228	1,529	559	183,316							259.98	291.01	0.00	551	183,867	696,965	696,965
1998	192,336	8,804	1,199	202,339	19,715						268.62	305.01	0.00	0	20,289	222,628	815,061
1999	218,189	9,530	1,256	228,975	19,715						277.59	319.95	0.00	0	20,313	249,288	935,849
2000	247,254	10,287	1,354	258,894	19,715						286.90	333.11	0.00	0	20,335	279,229	1,059,429
2001	274,916	10,913	1,381	287,210	19,715						296.56	329.32	0.00	0	20,341	307,551	1,183,757
2002	309,277	11,864	1,407	322,548	19,715						306.59	339.25	0.00	0	20,361	342,909	1,310,375
2003	336,189	12,545	1,563	350,297	19,715						317.01	354.98	0.00	0	20,387	370,685	1,435,397
2004	369,938	13,399	1,704	385,042	19,715						327.82	366.51	0.00	0	20,410	405,452	1,560,304
2005	411,749	14,321	1,797	427,867	19,715						339.05	382.19	0.00	0	20,437	448,303	1,686,454
2006	457,988	15,518	1,938	475,445	19,715						350.71	399.46	0.00	0	20,466	495,910	1,813,916
2007	503,977	16,389	2,070	522,436	19,715						362.81	410.69	0.00	0	20,489	542,925	1,941,379
2008	583,207	17,864	2,047	603,117	19,715						375.34	422.85	0.00	0	20,514	623,631	2,075,111
2009	638,330	19,075	2,322	659,727	19,715						388.43	441.61	0.00	0	20,545	680,272	2,208,357
2010	744,019	21,046	1,829	766,893	19,715						0.00	622.65	0.00	0	20,338	787,231	2,349,202
2011	847,386	22,784	2,238	872,408	19,715						0.00	398.38	0.00	0	20,114	892,522	2,495,058
2012	965,066	24,765	2,445	992,276	19,715						0.00	697.69	0.00	0	20,413	1,012,689	2,646,221
2013	789,088	53,215	5,055	847,358	19,715	145,873					0.00	435.08	0.00	0	166,024	1,013,381	2,784,389
2014	908,845	57,610	5,171	971,625	19,715	145,873					0.00	765.01	0.00	0	166,354	1,137,979	2,926,110
2015	1,032,525	61,990	5,079	1,099,595	19,715	145,873					0.00	475.34	0.00	0	166,064	1,265,658	3,070,083
2016	887,138	95,361	6,289	988,788	19,715	145,873	173,737				0.00	838.68	0.00	0	340,165	1,328,952	3,208,166
2017	992,034	102,427	6,458	1,100,920	19,715	145,873	173,737			0	0.00	519.75	0.00	0	339,846	1,440,765	3,344,904
2018	1,122,604	109,234	6,633	1,238,471	19,715	145,873	173,737			0	0.00	919.77	0.00	0	340,246	1,578,717	3,481,760
2019	1,272,369	116,612	7,387	1,396,368	19,715	145,873	173,737			0	0.00	567.72	0.00	0	339,894	1,736,262	3,619,241
2020	1,171,213	162,302	8,146	1,341,661	19,715	145,873	173,737	219,339	0	0	0.00	1008.77	0.00	0	559,674	1,901,335	3,756,756

18.12.2-3

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TABLE 18.12.2-3
LOW GROWTH SENSITIVITY
FIRST UNIT COMBUSTION TURBINE
CUMULATIVE PRESENT WORTH
PESSIM (PSCT12PM.WK)

O&C PRODUCTION COSTS					Levelized Capital Costs										Total Revenue Requirements		
Year	Fuel	O&M	Startup	Total	192 ct 1998	675/2 pc 2011	675/2 pc 2015	488/2 cc 2017	0 0	0 COMMER 0 LIGHT	HEAT PUMP	DIRECT LD CTRL	COAL PILE	Total	Annual	Cumulative Present Worth	1991 Cumulative Present Worth
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000
1991	91,987	620	297	92,904							0.00	0.00	0.00	0	92,904	92,904	92,904
1992	107,036	682	386	108,104							0.00	0.00	0.00	0	108,104	191,647	191,647
1993	113,790	858	421	115,070							228.46	235.07	0.00	464	115,533	288,039	288,039
1994	127,326	1,004	444	128,774							235.91	247.22	0.00	483	129,257	386,541	386,541
1995	140,287	1,027	486	141,801							243.64	259.77	0.00	503	142,304	485,597	485,597
1996	162,188	1,280	498	163,966							251.66	276.32	0.00	528	164,494	590,183	590,183
1997	181,228	1,529	559	183,316							259.98	291.01	0.00	551	183,867	696,965	696,965
1998	203,526	3,637	726	207,889	8,666						268.62	305.01	0.00	0	217,129	812,144	812,144
1999	230,997	4,004	761	235,762	8,666						277.59	319.95	0.00	0	245,026	930,867	930,867
2000	262,748	4,752	925	268,426	8,666						286.90	333.11	0.00	0	277,712	1,053,775	1,053,775
2001	290,365	4,777	1,048	296,189	8,666						296.56	329.32	0.00	0	305,482	1,177,267	1,177,267
2002	327,762	5,163	1,087	334,012	8,666						306.59	339.25	0.00	0	343,325	1,304,039	1,304,039
2003	356,295	5,669	1,117	363,080	8,666						317.01	354.98	0.00	0	372,419	1,429,646	1,429,646
2004	393,613	5,880	1,201	400,695	8,666						327.82	366.51	0.00	0	410,056	1,555,971	1,555,971
2005	435,706	6,135	1,303	443,144	8,666						339.05	382.19	0.00	0	452,532	1,683,310	1,683,310
2006	488,364	7,108	1,432	496,904	8,666						350.71	399.46	0.00	0	506,320	1,813,448	1,813,448
2007	533,275	7,098	1,568	541,941	8,666						362.81	410.69	0.00	0	551,381	1,942,896	1,942,896
2008	620,706	8,117	1,832	630,655	8,666						375.34	422.85	0.00	0	640,120	2,080,164	2,080,164
2009	680,488	9,169	2,004	691,662	8,666						388.43	441.61	0.00	0	701,158	2,217,502	2,217,502
2010	794,049	11,212	2,428	807,689	8,666						0.00	622.65	0.00	0	816,977	2,363,669	2,363,669
2011	662,497	37,115	2,469	702,081	8,666	129,827					0.00	398.38	0.00	0	840,973	2,501,100	2,501,100
2012	744,978	40,296	2,701	787,975	8,666	129,827					0.00	697.69	0.00	0	927,166	2,639,497	2,639,497
2013	831,205	42,654	2,921	876,780	8,666	129,827					0.00	435.08	0.00	0	1,015,708	2,777,983	2,777,983
2014	958,098	45,948	3,318	1,007,364	8,666	129,827					0.00	765.01	0.00	0	1,146,622	2,920,780	2,920,780
2015	824,647	80,448	4,225	909,321	8,666	129,827	163,903				0.00	475.34	0.00	0	1,212,192	3,058,671	3,058,671
2016	912,911	86,188	4,955	1,004,054	8,666	129,827	163,903				0.00	838.68	0.00	0	1,307,288	3,194,503	3,194,503
2017	996,951	108,829	7,051	1,112,832	8,666	129,827	163,903	59,651		0	0.00	519.75	0.00	0	1,475,399	3,334,528	3,334,528
2018	1,105,812	116,420	7,455	1,229,687	8,666	129,827	163,903	59,651		0	0.00	919.77	0.00	0	1,592,654	3,472,592	3,472,592
2019	1,244,157	124,316	8,727	1,377,199	8,666	129,827	163,903	59,651		0	0.00	567.72	0.00	0	1,739,814	3,610,354	3,610,354
2020	1,401,741	134,115	10,198	1,546,054	8,666	129,827	163,903	59,651	0	0	0.00	1008.77	0.00	0	1,909,109	3,748,431	3,748,431

1B.12.2-4

1B.12.3 Alternate Fuel Forecast Sensitivity

To determine the sensitivity of the strategies to an alternate fuel forecast, the 1989 Planning Hearing fuel forecast was input into POWRPRO. The results show that Strategy B, Stanton 2, is still the least cost alternative plan as shown below.

<u>First Unit Installed</u>	1991 Cumulative Present Worth Comparative Cost	<u>Differential</u>	
	\$ million	\$ million	percent
Strategy B-- Stanton 2	5,209	Base	Base
Strategy D-- Combined Cycle	5,359	150	2.9
Strategy C-- Combustion Turbine	5,416	207	4.0

Cumulative present worth values for first unit additions of Stanton 2, a combined cycle, and a combustion turbine are provided in Tables 1B.12.3-1, 1B.12.3-2, and 1B.12.3-3, respectively.

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TABLE 18.12.3-1
FUEL SENSITIVITY
FIRST UNIT STANTON 2
CUMULATIVE PRESENT WORTH
EXPECT 2 (E2011AP.WK)

OUC PRODUCTION COSTS					Levelized Capital Costs										Total Revenue Requirements		
Year	Fuel	O&M	Startup	Total	STANTON 2	675/2 pc	675/2 pc	675/2 pc	192 ct	O COMMER	HEAT	DIRECT	COAL PILE	Total	Annual	Cumulative	1991
	\$1000	\$1000	\$1000	\$1000	1997	2010	2015	2017	2020	O LIGHT	PUMP	LD CTRL		\$1000	\$1000	Present	Worth
																	\$1000
1991	92,787	591	311	93,690						0.00	0.00	0.00	186.375	0	93,690	93,690	
1992	108,261	665	411	109,337						0.00	0.00	0.00		0	109,337	195,845	
1993	116,847	831	391	118,069						237.56	235.25	0.00		473	118,541	299,326	
1994	132,967	964	424	134,355						245.10	247.60	0.00		493	134,848	409,309	
1995	151,161	979	449	152,589						252.92	261.26	0.00		514	153,104	525,981	
1996	178,788	1,254	517	180,560						261.03	279.71	0.00		541	181,101	654,922	
1997	174,200	10,434	864	185,498	36,253					269.45	294.64	0.00	186.375	37,003	222,502	802,935	
1998	197,344	11,111	857	209,312	36,253					278.18	309.53	0.00	186.375	37,027	246,339	956,042	
1999	216,939	11,702	979	229,620	36,253					287.25	324.68	0.00	186.375	37,051	266,671	1,110,899	
2000	242,228	12,363	1,084	255,675	36,253					296.65	337.67	0.00	186.375	37,074	292,749	1,269,734	
2001	270,689	12,984	1,058	284,730	36,253					306.41	344.18	0.00	186.375	37,090	321,820	1,432,873	
2002	297,843	13,650	1,194	312,687	36,253					316.54	343.01	0.00	186.375	37,099	349,786	1,598,542	
2003	323,963	14,382	1,134	339,480	36,253					327.06	368.62	0.00	186.375	37,135	376,615	1,765,202	
2004	357,092	15,115	1,181	373,388	36,253					337.97	381.26	0.00	186.375	37,159	410,546	1,934,944	
2005	386,320	15,818	1,290	403,427	36,253					349.30	391.40	0.00	186.375	37,180	440,607	2,105,150	
2006	420,125	16,723	1,383	438,230	36,253					361.06	402.49	0.00	186.375	37,203	475,433	2,276,746	
2007	458,916	17,504	1,478	477,898	36,253					373.27	419.70	0.00	186.375	37,232	515,131	2,450,457	
2008	514,008	18,532	1,551	534,091	36,253					385.94	436.82	0.00	186.375	37,262	571,353	2,630,473	
2009	558,626	19,612	1,583	579,821	36,253					399.10	459.59	0.00	186.375	37,298	617,119	2,812,137	
2010	548,015	40,201	2,230	590,446	36,253	71,150				0.00	656.07	0.00	186.375	108,245	698,691	3,004,305	
2011	604,365	42,376	2,269	649,009	36,253	71,150				0.00	413.72	0.00	186.375	108,003	757,012	3,198,837	
2012	674,234	44,774	2,429	721,437	36,253	71,150				0.00	737.67	0.00	186.375	108,327	829,764	3,398,060	
2013	750,057	47,240	2,624	799,921	36,253	71,150				0.00	454.68	0.00	186.375	108,044	907,965	3,601,740	
2014	843,389	49,771	2,838	895,997	36,253	71,150				0.00	814.09	0.00	186.375	108,403	1,004,400	3,812,253	
2015	828,227	75,437	3,864	907,529	36,253	71,150	88,665			0.00	499.56	0.00	186.375	196,754	1,104,282	4,028,499	
2016	931,372	79,801	3,884	1,015,157	36,253	71,150	88,665			0.00	898.73	0.00	186.375	197,153	1,212,310	4,250,306	
2017	967,406	108,349	5,422	1,081,176	36,253	71,150	88,665	96,825		0	0.00	548.98	0.00	196,375	293,628	1,374,804	4,485,322
2018	1,085,247	113,565	5,157	1,203,969	36,253	71,150	88,665	96,825		0	0.00	992.75	0.00	186.375	294,072	1,498,041	4,724,584
2019	1,192,063	119,598	5,279	1,316,939	36,253	71,150	88,665	96,825		0	0.00	604.15	0.00	186.375	293,683	1,610,622	4,964,931
2020	1,299,274	131,849	6,006	1,437,129	36,253	71,150	88,665	96,825	16,197	0	0.00	1096.38	0.00	186.375	310,373	1,747,502	5,208,576

18.12.3-2

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TABLE 1B.12.3-2
FUEL SENSITIVITY
FIRST UNIT COMBINED CYCLE
CUMULATIVE PRESENT WORTH
EXPECT 2 (E2CC01AP.MK)

DUC PRODUCTION COSTS					Levelized Capital Costs										Total Revenue Requirements	
Year	Fuel	O&M	Startup	Total	488/2 cc 1997	675/2 pc 2010	675/2 pc 2014	675/2 pc 2017	192 ct 2019	O COMMER O LIGHT	HEAT PUMP	DIRECT LD CTRL	Total	Annual	1991 Cumulative Present Worth	
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	
1991	92,787	591	311	93,690						0.00	0.00	0.00	0	93,690	93,690	
1992	108,261	665	411	109,337						0.00	0.00	0.00	0	109,337	195,845	
1993	116,847	831	391	118,069						237.56	235.25	0.00	473	118,541	299,326	
1994	132,967	964	424	134,355						245.10	247.60	0.00	493	134,848	409,309	
1995	151,161	979	449	152,589						252.92	261.26	0.00	514	153,104	525,981	
1996	178,788	1,254	517	180,560						261.03	279.71	0.00	541	181,101	654,922	
1997	187,364	7,663	1,027	196,054	13,317					269.45	294.64	0.00	13,881	209,935	794,575	
1998	215,150	8,117	1,045	224,312	13,317					278.18	309.53	0.00	13,905	238,217	942,634	
1999	242,419	8,730	1,080	252,228	13,317					287.25	324.68	0.00	13,929	266,157	1,097,193	
2000	274,017	9,326	1,123	284,465	13,317					296.65	337.67	0.00	13,952	298,417	1,259,103	
2001	303,081	9,814	1,089	313,984	13,317					306.41	344.18	0.00	13,968	327,952	1,425,350	
2002	339,230	10,613	1,118	350,960	13,317					316.54	343.01	0.00	13,977	364,937	1,598,195	
2003	369,103	11,143	1,226	381,472	13,317					327.06	368.62	0.00	14,013	395,485	1,773,206	
2004	402,221	11,792	1,208	415,221	13,317					337.97	381.26	0.00	14,036	429,257	1,950,684	
2005	442,530	12,458	1,217	456,205	13,317					349.30	391.40	0.00	14,058	470,263	2,132,346	
2006	480,995	13,323	1,149	495,468	13,317					361.06	402.49	0.00	14,081	509,548	2,316,254	
2007	519,055	13,860	1,283	534,198	13,317					373.27	419.70	0.00	14,110	548,308	2,501,154	
2008	589,912	15,018	1,334	606,264	13,317					385.94	436.82	0.00	14,140	620,404	2,696,624	
2009	640,037	16,001	1,541	657,579	13,317					399.10	459.59	0.00	14,176	671,754	2,894,372	
2010	601,660	35,190	2,636	639,486	13,317	71,150				0.00	656.07	0.00	85,123	724,609	3,093,668	
2011	671,189	37,436	2,533	711,157	13,317	71,150				0.00	413.72	0.00	84,881	796,038	3,298,229	
2012	747,133	39,857	2,775	789,764	13,317	71,150				0.00	737.67	0.00	85,204	874,969	3,508,305	
2013	833,081	41,987	2,811	877,879	13,317	71,150				0.00	454.68	0.00	84,921	962,800	3,724,286	
2014	803,554	65,091	4,490	873,135	13,317	71,150	84,847			0.00	814.09	0.00	170,128	1,043,264	3,942,945	
2015	900,740	68,509	3,893	973,142	13,317	71,150	84,847			0.00	499.56	0.00	169,814	1,142,956	4,166,764	
2016	1,003,783	72,902	4,452	1,081,137	13,317	71,150	84,847			0.00	898.73	0.00	170,213	1,251,350	4,395,714	
2017	995,548	98,539	4,608	1,098,695	13,317	71,150	84,847	96,825		0	0.00	548.98	0.00	266,688	1,365,383	4,629,119
2018	1,119,086	103,971	4,917	1,227,975	13,317	71,150	84,847	96,825		0	0.00	992.75	0.00	267,132	1,495,106	4,867,913
2019	1,224,748	114,982	6,107	1,345,836	13,317	71,150	84,847	96,825	15,500	0	0.00	604.15	0.00	282,243	1,628,079	5,110,865
2020	1,370,930	122,482	7,017	1,500,430	13,317	71,150	84,847	96,825	15,500	0	0.00	1096.38	0.00	282,735	1,783,165	5,359,482

1B.12.3-3

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TABLE 1B.12.3-3
FUEL SENSITIVITY
FIRST UNIT COMBUSTION TURBINE
CUMULATIVE PRESENT WORTH
EXPECT 2 (E2CT08AP.MK)

Levelized Capital Costs															Total Revenue Requirements	
OUC PRODUCTION COSTS					192 ct	675/2 pc	675/2 pc	675/2 pc	488/2 cc	O CONMER	HEAT	DIRECT		1991		
Year	Fuel	O&M	Startup	Total	1997	2009	2014	2015	2018	O LIGHT	PUMP	LD CTRL	Total	Annual	Cumulative Present Worth	
	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	
1991	92,787	591	311	93,690						0.00	0.00	0.00	0	93,690	93,690	
1992	108,261	665	411	109,337						0.00	0.00	0.00	0	109,337	195,845	
1993	116,847	831	391	118,069						237.56	235.25	0.00	473	118,541	299,326	
1994	132,967	964	424	134,355						245.10	247.60	0.00	493	134,848	409,309	
1995	151,161	979	449	152,589						252.92	261.26	0.00	514	153,104	525,981	
1996	178,788	1,254	517	180,560						261.03	279.71	0.00	541	181,101	654,922	
1997	198,838	3,383	623	202,844	5,885					269.45	294.64	0.00	6,449	209,293	794,148	
1998	227,665	3,468	719	231,852	5,885					278.18	309.53	0.00	6,473	238,325	942,274	
1999	256,562	3,824	769	261,156	5,885					287.25	324.68	0.00	6,497	267,653	1,097,702	
2000	290,449	4,463	888	295,800	5,885					296.65	337.67	0.00	6,520	302,320	1,261,729	
2001	320,015	4,544	943	325,502	5,885					306.41	344.18	0.00	6,536	332,038	1,430,048	
2002	358,457	4,943	1,029	364,428	5,885					316.54	343.01	0.00	6,545	370,973	1,605,752	
2003	390,948	5,500	1,047	397,495	5,885					327.06	368.62	0.00	6,581	404,076	1,784,564	
2004	426,424	5,626	1,071	433,120	5,885					337.97	381.26	0.00	6,605	439,725	1,966,371	
2005	468,137	6,054	1,183	475,374	5,885					349.30	391.40	0.00	6,626	482,000	2,152,566	
2006	511,297	6,884	1,326	519,507	5,885					361.06	402.49	0.00	6,649	526,156	2,342,469	
2007	548,738	6,855	1,386	556,979	5,885					373.27	419.70	0.00	6,678	563,657	2,532,545	
2008	629,602	8,080	1,609	639,290	5,885					385.94	436.82	0.00	6,708	645,999	2,736,079	
2009	552,501	26,193	1,965	580,658	5,885	68,086				399.10	459.59	0.00	74,930	655,488	2,929,038	
2010	628,588	28,292	1,896	658,776	5,885	68,086				0.00	656.07	0.00	74,627	733,403	3,130,753	
2011	701,191	30,276	2,100	733,567	5,885	68,086				0.00	413.72	0.00	74,385	807,952	3,338,376	
2012	785,179	32,651	2,472	820,303	5,885	68,086				0.00	737.67	0.00	74,709	895,012	3,553,284	
2013	871,810	34,256	2,553	908,418	5,885	68,086				0.00	454.68	0.00	74,426	982,844	3,773,741	
2014	825,714	57,565	3,079	886,358	5,885	68,086	84,847			0.00	814.09	0.00	159,632	1,045,991	3,992,972	
2015	828,001	82,435	3,995	914,431	5,885	68,086	84,847	88,665		0.00	499.56	0.00	247,983	1,162,414	4,220,601	
2016	915,096	87,374	4,456	1,006,926	5,885	68,086	84,847	88,665		0.00	898.73	0.00	248,382	1,255,308	4,450,275	
2017	1,028,128	92,247	4,183	1,124,558	5,885	68,086	84,847	88,665		0	0.00	548.98	0.00	248,033	1,372,591	4,684,913
2018	1,108,654	108,914	5,488	1,223,055	5,885	68,086	84,847	88,665	33,563	0	0.00	992.75	0.00	282,039	1,505,094	4,925,302
2019	1,215,361	115,054	6,004	1,336,418	5,885	68,086	84,847	88,665	33,563	0	0.00	604.15	0.00	281,650	1,618,068	5,166,760
2020	1,378,412	122,391	6,876	1,507,679	5,885	68,086	84,847	88,665	33,563	0	0.00	1096.38	0.00	282,143	1,789,822	5,416,305

1B.12.3-4

1B.12.4 Break-Even Capital Cost of Stanton 2

In the fourth sensitivity analysis, the capital cost for Stanton 2 was increased until the cumulative present worth was equal to the next least cost alternative to Stanton 2 under the base case which is the addition of a combined cycle in 1997. The capital cost of Stanton 2 can increase 74.4 percent before the base plan, with the installation of Stanton 2, would be equal in cost to the next least cost plan. A 74.4 percent increase in capital costs corresponds to a total installed cost of \$2,426/kW.

1B.13.0 Strategic Considerations

There are a number of strategic considerations which favor the installation of Stanton 2 over other alternatives. By constructing Stanton 2 by January 1, 1997, OUC is able to take advantage of replicating Stanton 1. This results in a significant cost savings over a newly designed unit. In addition, common facilities were installed with Stanton 1 for an identical second unit. The construction of Stanton 2 takes full advantage of this previous investment.

Stanton 2 will use an abundant domestically produced fuel. The source of coal is highly reliable and, in addition, Stanton has the ability to economically store a long-term supply onsite. Oil and gas cannot be considered reliable fuels and the option of long-term storage is not available with gas fueled capacity. Likewise, the price of coal is much more stable than gas or oil. The installation of Stanton 2 will largely insulate OUC's rate payers from potential increases in natural gas and oil prices.

The replication of Stanton 1 will provide a unit with known operating characteristics. The operating performance of Stanton 1 has been exceptional and Stanton 2's performance is expected to be better still. The replicated unit concept will reduce spare parts and inventory charges and will provide additional benefits through standardization by reducing the number of different units for which operating and maintenance personnel must be familiar. The greater familiarization with Stanton 2 will further improve its performance.

The installation of Stanton 2 will largely provide additional sales opportunities that will not be available from other alternatives. Stanton 2's low cost coal fueled energy will serve to reduce energy prices for all rate payers in the state with sales on the Broker. The addition of Stanton 2 will also provide OUC the opportunity to make unit power sales or other firms' sales to further reduce costs to OUC's rate payers.

1B.14 CONSEQUENCES
OF DELAY

1B.14.0 Consequences of Delay

OUC will experience significant adverse consequences if Stanton 2 is not constructed or is delayed. As indicated in Subsection 1B.11.7, Strategy B including ownership of a 330 MW share of Stanton 2 represents the least cost alternative available to OUC. Strategy B with OUC ownership of a 330 MW share of Stanton 2 represents a 1991 cumulative present worth savings of \$183 million or 4.0 percent over Strategy D, next lowest cost expansion plan based on installing a combined cycle. In addition, if OUC is able to sell a portion of the capacity from Stanton 2 during the years when the additional capacity is not required to meet reserve margin requirements, OUC's cost for Stanton 2 will be significantly reduced. Subsection 1B.16.0 indicates that the sale of 110 MW of Stanton 2 capacity from 1997 to 2008 at the Indiantown Cogeneration Project power sales contract price would result in a 1991 cumulative present worth savings to OUC of \$163 million. If Stanton 2 were not constructed, OUC would have to install a more expensive means of meeting their customers' loads and would not have the opportunity to further reduce rates to their customers through power sales.

The installation of Stanton 2 by OUC will provide the benefit of lower cost energy to the Florida Municipal Power Pool. The City of Lakeland and FMPPA will share the savings associated with the lower cost energy associated with Stanton 2. If Stanton 2 is not constructed or is delayed, these benefits will not be available.

The installation of Stanton 2 will also provide the opportunity for additional economy sales on the FCG Energy Broker. The utilities purchasing the economy energy and OUC will share the savings from these Broker sales. If Stanton 2 is not installed or is delayed, the benefits from these Broker sales would not be available to the rate payers of the state.

The installation of Stanton 2 complies with the legislative findings and intent of the Florida Energy Efficiency and Conservation Act. Stanton 2 will serve to reduce natural gas usage and conserve expensive resources, particularly petroleum fuels used in the production of electricity. At a 70 percent capacity factor, Stanton 2 will displace the equivalent of 26,000,000 MCF of gas or 4.2 million barrels of oil annually. If Stanton 2 were not installed, these fuels would be consumed in meeting the electrical energy requirements of the state.

If Stanton 2 were to be delayed, electric system reliability would be reduced for OUC and the state as a whole. If Stanton 2 were delayed, OUC's reserve margin would drop below acceptable levels and reliable service to OUC's customers would be impaired. OUC's reserve margin for the 1998-99 winter period would decrease to 10.4 percent for normal weather and to only 3.2 for extreme weather including peak demand reductions for additional demand-side management programs. If extreme weather occurred, OUC would have only 19 MW of reserves at the time of the 1998-99 peak and would not be able to supply firm load if any of OUC's generating units were unavailable other than OUC's 13 MW share of Crystal River 3. For comparison, the severe power outages in December 1989 occurred when Peninsular Florida had a 23 percent reserve margin based on normal weather and an actual reserve margin based on the extreme weather load of 5.3 percent. Without the addition of Stanton 2, the reserve margin for Peninsular Florida is projected to dip to 11 percent for the 1998-99 peak. A reserve margin of that level would jeopardize the entire grid.

A detailed evaluation was conducted to determine the cost impact of delaying OUC's 330 MW share of Stanton 2 one year to January 1, 1998. The evaluation was based on the assumption that emergency power could be purchased when needed by OUC. The capital cost of Stanton 2 was escalated 4.5 percent. The 1991 cumulative present worth comparative costs for the evaluation period from 1991 through 2020 are shown below.

<u>Commercial Operation</u>	<u>Cumulative Present Worth Comparative Cost</u>	
	<u>\$million</u>	<u>Percent</u>
January 1, 1997	4,557	0.07
January 1, 1998	4,555	Base

The savings for delaying OUC's 330 MW share of Stanton 2 one year are only 0.07 percent. While 0.07 percent is essentially no savings, the actual capital cost for delaying Stanton 2 a year will likely be more than the 4.5 percent escalation rate, thus eliminating any potential savings. A significant portion of the Stanton 2 capital cost savings are due to replicating Stanton 1. Delaying the construction of Stanton 2 would jeopardize the replication process and at some point would render it impractical or even impossible. In any event, the 0.07 percent savings is only 7 cents on a hundred dollar electric bill. This cost will likely be made up

several times over on power sales during the year. In addition, the other benefits described above would be lost for that year.

1B.15.0 Financial Analysis

Orlando Utilities Commission (OUC) has a Corporate Model program which models the financial operations of OUC. The Corporate Model is a personal computer based program written by OUC using Lotus Version 3. The Corporate Model logic was reviewed by Black & Veatch who stated that the model "reasonably reflects the projected financial operations of the Commission." OUC recently issued \$235,820,000 of bonds dated January 1, 1991. The results of the Corporate Model were one of the items that the bond rating agencies used in rating these bonds.

The Corporate Model reflects OUC's operations in their entirety. It projects electric and water rates, issues bonds as necessary, and develops an income statement, a source and use of funds statement, rate level adequacy, and debt service coverage. The rates set for OUC's electric customers reflect only the costs associated with providing electric service. The common facilities and expenses used in providing both electric and water service are allocated to each, based on an analysis of these facilities and expenses on a FERC account basis.

The Corporate Model was run using the results of the base plan developed in the economic studies. Table 1B.15.0-1 summarizes the key results of this model run before and after the construction of Stanton 2.

Examination of Table 1B.15.0-1 reveals that base rates are expected to increase prior to the commercial operation of Stanton 2; however, the increases are all less than the projected rate of inflation and, therefore, rates are projected to decrease in real terms. Senior lien debt service coverage remains above 2.1 in all years which is significantly above OUC's required minimum senior lien debt service coverage of 1.25. Junior lien debt service coverage remains above 3.4 in all years which is significantly above OUC's required minimum junior lien debt service coverage of 1.0. Based on the results of the Corporate Model shown in Table 1B.15.0-1, the Stanton 2 project is financially feasible for OUC and will result in a decrease in the real price of electricity to OUC's customers.

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1B.15.0-2

**Table 1B.15.0-1
Corporate Model Summary**

Year	Change in Average Retail Base Rates Ex- cluding Fuel (percent)	New Long- Term Debt (\$1,000)	Bonds Retired (\$1,000)	Net Bonds Issued (\$1,000)	Senior Lien Debt Service Coverage	Junior Lien Debt Service Coverage	General Rate of Inflation (percent)
1991	0	235,820	0	235,820	2.753	4.598	4.0
1992	+ 4.0	108,500	0	108,500	2.975	5.309	4.0
1993	+ 3.1	90,000	0	90,000	3.252	5.458	4.0
1994	+ 3.7	395,000	268,500	126,500	2.221	4.238	4.0
1995	+ 2.4	137,000	0	137,000	2.135	4.040	4.0
1996	+ 1.0	117,500	165,925	-48,425	2.275	3.496	4.0
1997	-2.1	51,000	0	51,000	2.364	3.912	4.0
1998	-0.3	0	0	0	2.460	4.187	4.0
1999	-0.9	11,500	0	11,500	2.482	4.293	4.0
2000	-0.3	12,000	16,160	-4,160	2.499	4.385	4.0

1B.16.0 Unit Power Sale

The Long-Range Power Supply and Demand-Side Planning Study completed in 1989 by SEI indicated that the strategy including the construction of Stanton 2 was the least cost alternative for OUC. An integral part of that strategy was a unit power sale of 104 MW of Stanton 2 for a period of six years. While many events have taken place and projections have changed since 1987 when the SEI study was begun, the sale of a portion of Stanton 2's capacity (or some type of system power sale) during the early years of operation still represents OUC's least cost strategy. OUC's 330 MW ownership share represents the least cost alternative for OUC as demonstrated in Subsection 1B.11.0. However, sales at a price above OUC's net cost on a portion of the 330 MW until it is needed for reliability purposes will further reduce the cost of the least cost alternative. Currently OUC is planning to sell the equivalent of 110 MW of its 330 MW ownership share at market prices. While prior to having obtained regulatory approval and starting construction of Stanton 2, it is generally premature to have signed contracts for the sale or even letters of commitment. OUC has, however, received a number of inquiries and is continuing the process of negotiation with several utilities. Since firm commitments are not available for determining the benefits of the sale, the benefits will be based on the costs to OUC for making a 110 MW unit power sale from Stanton 2 compared to recent market prices for similar sales in that time period.

For evaluation purposes, the 110 MW sale will be assumed to occur from 1997 to 2009 when the 110 MW would be needed to maintain a 15 percent reserve margin for OUC.

Table 1B.16.0-1 shows the comparison between the net cost to OUC of selling the 110 MW, OUC's carrying cost of the 110 MW, the Scherer 4 Unit Power Sales price, and the Indiantown Cogeneration firm capacity purchase price. The net cost to OUC of selling the 110 MW is based on the difference in annual costs between OUC's base case expansion plan including the cost-effective demand-side management alternatives with OUC's 330 MW ownership share of Stanton 2 and the annual costs with only 220 MW of Stanton 2 available to dispatch. The net costs to OUC shown in Table 1B.16.0-1 are based on dividing the differences in annual costs by the 110 MW of Stanton 2 available for the sale. The negative net price shown in 1997 and 1998 indicates that OUC fuel cost savings associated with

the additional 110 MW of Stanton 2 is not sufficient to offset the fixed O&M of the additional 110 MW. Any price obtained above the net costs shown in Table 1B.16.0-1 for the 110 MW sale would lower the cost of installing Stanton 2 to OUC assuming variable costs associated with the 110 MW sale are fully recovered. The net costs do not include any wheeling costs and would represent the power being available at the Stanton 2 bus. The OUC carrying charge for Stanton 2 is based on the fixed charge rate applied to the projected total capital cost including interest during construction of \$611,864,341 plus the fixed O&M cost for Stanton 2. The costs for Scherer 4 are unit power sales costs based on the costs provided in Florida Power & Light Company's response to Interrogatory No. 16 of the Public Counsel's First Set of Interrogatories for Docket No. 900796-EI and include capacity payments, fixed O&M expenses, and transmission costs based on 646 MW of capacity. The Scherer 4 costs do not include transmission losses. The Indiantown Cogeneration costs are based on the Agreement for the Purchase of Firm Capacity and Energy Between Indiantown Cogeneration, L.P. and Florida Power & Light Company. Indiantown Cogeneration costs include the capacity payment and fixed operation and maintenance credit. The fixed operation and maintenance credit is escalated at the O&M escalation rate of 4.75 percent presented in Volume 1A, Subsection 1A.3.2. The capacity payment is based on an 83 capacity factor which is equal to the Stanton 2 projected equivalent availability.

Analysis of Table 1B.16.0-1 indicates that based on the Scherer 4 and Indiantown Cogeneration costs, there should be a good market for Stanton 2 capacity. The following summarizes the economic benefits of the 110 MW unit power sales based on the assumed sales price.

<u>Sale</u>	1991 Cumulative Present Worth <u>Savings</u> \$1,000	Percent of Base <u>Case</u> Percent
1997-2005 OUC Carrying Cost for Stanton 2	46,226	1.0
1997-2007 Scherer 4 Cost	94,340	2.1
1997-2008 Indiantown Cogeneration Cost	163,442	3.6

Table 1B.16.0-1
Market for 110 MW Unit Power Sale from Stanton 2

<u>Year</u>	<u>Net Cost</u> \$/kW-mo	<u>OUC Carrying Charge for Stanton 2</u> \$/kW-mo	<u>Scherer 4 Costs</u> \$/kW-mo	<u>Indiantown Cogeneration Costs</u> \$/kW-mo
1997	-0.84	11.59	20.83	28.42
1998	-0.40	11.76	20.55	28.67
1999	1.94	11.90	20.28	28.94
2000	3.38	12.03	19.96	29.22
2001	3.49	12.17	19.68	29.52
2002	6.38	12.31	19.40	29.83
2003	7.44	12.46	19.16	30.15
2004	8.57	12.62	19.01	30.49
2005	12.57	12.78	18.98	30.85
2006	14.39	12.96	18.87	31.22
2007	14.52	13.14	18.79	31.61
2008	22.54	13.33	18.79	32.02

1B.17.0 Analysis of 1990 Clean Air Act Amendments

The 1990 Clean Air Act Amendments require OUC to provide sufficient SO₂ allowances for each affected generating unit. In addition, OUC will be required to conform with NO_x emission limits which will be established by the Environmental Protection Agency (EPA) by January 1, 1997. For the purposes of this analysis, only SO₂ allowances will be addressed.

The 1990 Clean Air Act Amendments are complex, and the regulations implementing them have not yet been promulgated by the EPA. The deadline for the EPA to publish the list of basic Phase II allowances is December 31, 1991. The base allowances available to OUC are calculated based on the following assumptions and the data shown in Table 1B.17.0-1. The Indian River Combustion Turbines A and B are simple combustion turbines and as such are not considered existing units under Section 402 (8) if the 1990 Clean Air Act Amendments. The Indian River Combustion Turbines C and D are not considered since they will primarily burn natural gas. The 1985 SO₂ emission rates for the Indian River Units 1-3 and McIntosh 3 are from Table 21 of the 1985 NAPAP Emissions Inventory (Version 2): Development of the National Utility Reference File. The average fuel consumption is the average for 1985 through 1987 and is based on the OUC's System Generation Reports for Indian River 1-3 and the Utility Data Institute Data Base for McIntosh 3. Indian River 1's average fuel consumption from 1980 through 1989 exceeds 90 percent natural gas and as such Indian River 1 appears to fall under Section 405 (h) of the 1990 Clean Air Act Amendments. Under Section 405 (h) Indian River 1 would receive base allowances calculated as $0.99 \text{ lb SO}_2/\text{MBtu} * 1,667,861 \text{ MBtu} * (1 \text{ ton}/2,000 \text{ lb})$ or 826 tons/year reduced by 2.8 percent to 802 tons/year pursuant to Section 416 (b). Indian River 1 would be allocated additional allowances pursuant to Sections 405 (h) (2) and (3) calculated as $0.05 \text{ lb SO}_2/\text{MBtu} * 1,667,861 \text{ MBtu} * (1 \text{ ton}/2,000 \text{ lb})$ or 42 tons/year reduced by 2.8 percent to 41 tons/year pursuant to Section 416 (b). Indian River 1's total allowances would thus be 843 tons/year. Because Indian River 1's 1985 actual emission rate was $0.99 \text{ lb SO}_2/\text{MBtu}$, Indian River would also fall under the jurisdiction of Section 405 (e). Indian River 1's allowances pursuant to 405 (e) would be calculated as $0.99 \text{ lb SO}_2/\text{MBtu} * 1,667,861 \text{ MBtu} * (1 \text{ ton}/2,000 \text{ lb}) * 1.2$ or 991 tons/year reduced by 2.8 percent to 963 tons/year pursuant to Section 416 (b). Since it is unclear which section of the 1990 Clean

Air Act Amendments will govern until the EPA Administrator publishes the list of Phase II allowances, for evaluation purposes Indian River 1 will be assumed to have 963 allowances.

Average fuel consumption for Indian River 2 and 3 for 1980 through 1989 was less than 90 percent natural gas. Allowances for Indian River 2 and 3 are determined by Section 405 (f) (1). Allowances for Indian River 2 are calculated as $0.6 \text{ lb SO}_2/\text{MBtu} * 4,150,286 \text{ MBtu} * (1 \text{ ton}/2000 \text{ lb}) * 1.2$ or 1494 tons/year reduced by 2.8 percent to 1452 tons/year pursuant to Section 416 (b). Allowances for Indian River 3 are calculated as $0.6 \text{ lb SO}_2/\text{MBtu} * 10,996,762 \text{ MBtu} * (1 \text{ ton}/2,000 \text{ lb}) * 1.2$ or 3,959 tons/year reduced by 2.8 percent to 3,848 tons/year pursuant to Section 416 (b).

McIntosh 3's allowances are governed by Section 405 (d) (1) and are calculated as $0.616 \text{ SO}_2/\text{MBtu} * 18,503,964 \text{ MBtu} * (1 \text{ ton}/2000 \text{ lb}) * 1.2$ or 6,661 tons/year reduced by 2.8 percent to 6,475 tons/year pursuant to Section 416 (b).

Indian River Units 2 and 3 will also receive additional allowances pursuant to Section 405 (f) (2). These additional allowances have not been included in the evaluation. OUC units may also receive additional allowances pursuant to Section 405 (i) (1). These additional allowances have not been included in the evaluation.

Allowances for Stanton 1 will be governed by Section 405 (g) (1); however, there are a number of uncertainties with respect to how Section 405 (g) (1) will be administered. It is likely that some annualization factor will be applied to Stanton 1's $1.14 \text{ lb SO}_2/\text{MBtu}$ maximum three-hour emission rate. For evaluation purposes, the annualization factor is assumed to be 90 percent. There is also uncertainty in how the 65 percent capacity factor will be applied. For evaluation purposes, it is assumed to apply to the full load heat rate at 440 MW. Allowances for Stanton 1 are calculated as $1.14 \text{ lb SO}_2/\text{MBtu} * 0.9 * 8,760 \text{ h} * 9.740 \text{ MBtu}/\text{MWh} * 440 \text{ MW} * 0.65 * (1 \text{ ton}/2,000 \text{ lb})$ or 12,518 tons/year reduced 2.8 percent to 12,168 tons/year pursuant to Section 416 (b).

While there is still significant uncertainty with respect to the implementation of the 1990 Clean Air Act Amendments, the OUC allowances shown in Table 1B.17.0-1 represent a reasonable basis for evaluation.

OUC's system was modeled under the base case expansion plan including the additional demand-side management programs described in Subsection 1B.11 to determine the allowances required. While the Indian River units were assumed

to burn 100 percent natural gas in Subsection 1B.11 because it was the least cost fuel, when evaluating SO₂ allowances, the Indian River units were assumed to burn 100 percent oil as the worst possible case. Sulfur content for the Indian River fuel oil is assumed to be equal to the average for that burned in 1989 as reported in Cost and Quality of Fuels for Electric Utility Plants 1989. The sulfur content of coal for Stanton 1 and 2 and McIntosh 3 is assumed to be that burned in 1989 as shown in Table 1A.3.3-5. The assumed sulfur content is summarized below.

<u>Unit</u>	<u>Sulfur</u> percent
Stanton 1 and 2	0.74
McIntosh 3	1.29
Indian River	1.41

An 85 percent removal rate is assumed for Stanton 1 and 2 and 86 percent for McIntosh 3.

Table 1B.17.0-2 presents projected SO₂ emissions for OUC's system compared to the OUC's estimated allowances. As shown in Table 1B.17.0-2, OUC is projected to have sufficient allowances for each year of the planning period.

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IB.17.0-4

Table 1B.17.0-1
Allowance Data

<u>Unit</u>	<u>Maximum Capacity MW</u>	<u>Ownership percent</u>	<u>1985 SO₂ Emission Rate lb/MBtu</u>	<u>Average Fuel Consumption MBtu</u>	<u>Permitted SO₂ Emission Rate lb/MBtu</u>	<u>Basic SO₂ Allowances for Unit tons</u>	<u>OUC Allowances tons</u>
Indian River 1	90	100.0	0.99	1,667,861	2.75	963	963
Indian River 2	205	100.0	0.55	4,150,286	2.75	1,452	1,452
Indian River 3	353	100.0	0.07	10,996,762	2.75	3,848	3,848
McIntosh 3	340	40.0	0.30	18,503,964	1.21	6,475	2,590
Stanton 1	440	68.6	--	--	1.14	12,168	8,656
							17,509

Table 1B.17.0-2
Projected SO₂ Emissions

<u>Year</u>	<u>SO₂ Emissions</u> tons	<u>Cumulative Excess Allowances*</u> tons
2000	11,049	6,460
2001	12,292	11,677
2002	13,129	16,057
2003	12,877	20,689
2004	14,123	24,075
2005	14,408	27,176
2006	14,575	30,110
2007	15,508	30,111
2008	16,695	32,925
2009	16,485	33,949
2010	11,179	40,279
2011	11,699	46,089
2012	12,096	51,502
2013	13,412	55,599
2014	14,574	58,534
2015	9,278	66,765
2016	10,293	73,981
2017	8,888	82,602
2018	9,262	90,849
2019	9,677	98,681
2020	9,988	106,202

*Assuming 17,509 allowances per year.

Appendix 1B.A.0 Documentation of Load Forecast Methodology

1B.A.1 Introduction

Orlando Utilities Commission (OUC) uses the System for Hourly and Annual Peak and Energy Simulation (SHAPES-PC) end-use/econometric forecasting model from Battelle of Columbus, Ohio. This model is also widely used by other major electric utilities in Florida. Other forecasting techniques employed by OUC include regression analysis and trend analysis.

It took OUC's forecasting staff two years to develop the extensive data base that the SHAPES-PC model requires. Battelle's staff assisted OUC in the model's development and calibration. The first official OUC forecast utilizing the SHAPES-PC methodology was published in 1987. Since that time, Battelle has developed many enhancements and improvements to the methodology. OUC has also continued to improve the model's data base. One recent enhancement to the SHAPES-PC model is the addition of a module to produce a chronological (8,760 hours) hourly load shape forecast based on a typical meteorological year. OUC has developed a typical meteorological year, which is used to simulate normal weather when developing chronological hourly demand and energy forecasts (see Table 1B.A-1). OUC's development of the typical meteorological year is discussed later. This enhancement is very important in demand-side planning analysis. OUC also uses Battelle's demand-side planning tool, RESHAPE.

The forecast horizon for this study was 1990 through 2020. OUC's normal forecast period is 20 years, but for the analysis of various alternatives to new generation, a 30-year period was determined to be more appropriate.

1B.A.2 Overview of Shapes-PC Model

The SHAPES-PC model forecasts energy and demand by end-use for the industrial, commercial, and residential sectors. In addition, the model contains a miscellaneous sector to account for such uses as street and highway lighting and OUC interdepartmental use.

Each individual end-use in the SHAPES-PC model is either classified as temperature sensitive or temperature insensitive. A temperature sensitive end-use's consumption varies by time of day, type of day, and temperature. A temperature insensitive end-use's consumption varies by time of day, type of day, and month.

The SHAPES-PC model forecasts demand on an 8,760 chronological hourly basis. A typical meteorological year (8,760 temperatures) is used to determine demand for temperature sensitive end-uses. A typical meteorological year simulates normal weather conditions. The following sections will detail the forecast methodology for the individual sectors and system peak demand.

1B.A.3 Industrial Sector

In the SHAPES-PC model, the industrial sector is defined as those customers dealing in manufacturing and mining activities. The industrial sector is not assumed to be weather sensitive.

The industrial sector model forecasts energy and demand using a top-down approach. A top-down approach is where annual energy is forecasted first, then allocated to the months of the year, and finally allocated on an hourly basis. A flow diagram of the industrial sector forecast methodology is shown on Figure 1B.A.3-1.

The industrial sector model is basically an econometric model. It relies on regressions of energy intensity per employee to forecast annual energy sales.

Annual industrial energy is projected using the following formula.

$$IAE_t = EI_t * IEMP_t * (1 - FSG_t) * IPAF_t$$

where

t = the forecast year,

IAE = the industrial annual energy forecast,

EI = the energy intensity per employee,

IEMP = the industrial sector employment forecast,

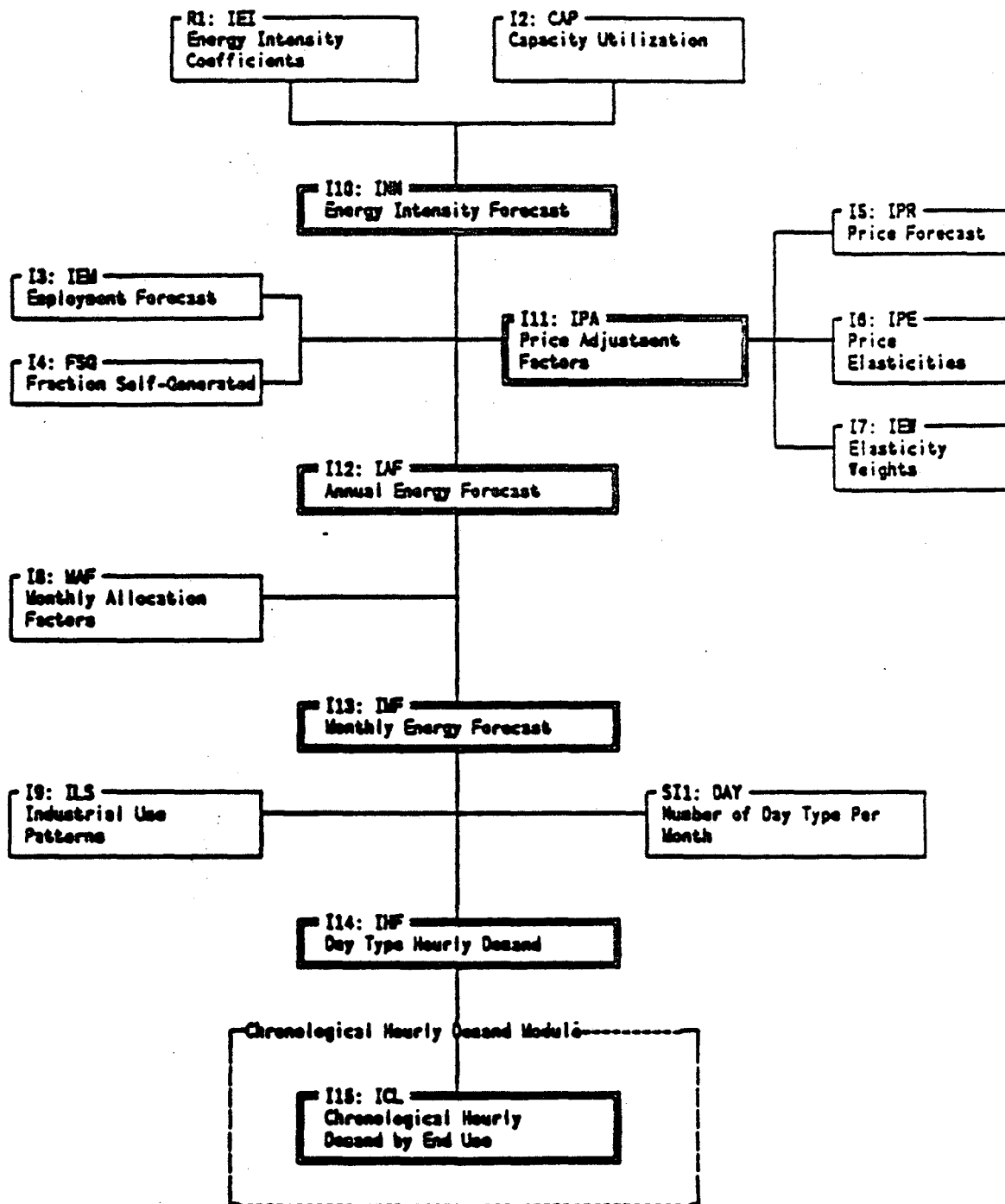
FSG = the fraction of annual energy self-generated, and

IPAF = the industrial price adjustment factor.

Historical data and projections for Orange County industrial employment were obtained from Fishkind and Associates. OUC then determined OUC service area's share of Orange County industrial employment. The OUC share of industrial employment is based on historical data of OUC's share of total nonresidential customers in Orange County. OUC's share of Orange County industrial employment was 46 percent in 1989 and declines to 40 percent by 2010. The price adjustment factor is used to capture the change in electricity consumption as a result of changes in the real price of industrial electricity. The real price of industrial electricity is assumed to remain constant throughout the forecast period. The fraction self-generated refers to that amount of electricity generated by a customer for its own consumption and, therefore, not purchased from a utility. At the time of this forecast, there were no industrial customers known to be self-generators. Therefore, the fraction of self-generation was projected to be zero.

The industrial sector energy consumption forecast that is developed from this formula is combined with the commercial sector energy consumption forecast to

generate the general service nondemand and general service demand energy consumption forecasts.



Industrial Model Flow Chart
Figure 1B.A.3-1

1B.A.4 Commercial Sector

In the SHAPES-PC model, the commercial sector is defined as all customers dealing with the following activities: (1) forestry, fishing, and construction; (2) transportation and public utilities; (3) wholesale trade; (4) retail trade; (5) finance, insurance, and real estate; and (6) services and government. The commercial sector is considered to be weather sensitive.

The commercial sector energy consumption forecast is divided into three components. These components are baseload, heating load, and cooling load. The annual commercial energy consumption is the sum of these three components.

The commercial sector model is basically an econometric model using a top-down approach. Each of the components is forecasted as a function of energy intensity per employee, number of employees, and a price adjustment factor.

A flow diagram of the commercial sector forecast methodology is shown on Figure 1B.A.4-1.

Annual commercial energy consumption is projected using the following formulas.

$$CAEB_t = EIB_t * CEMP_t * CPAF_t$$

$$CAEC_t = EIC_t * CEMP_t * CPAF_t$$

$$CAEH_t = EIH_t * CEMP_t * CPAF_t$$

where

t = the forecast year,

CAEB = the annual baseload energy forecast

CAEC = the annual cooling energy forecast,

CAEH = the annual heating energy forecast,

EIB = the baseload energy intensity per employee,

EIC = the cooling energy intensity per employee,

EIH = the heating energy intensity per employee,

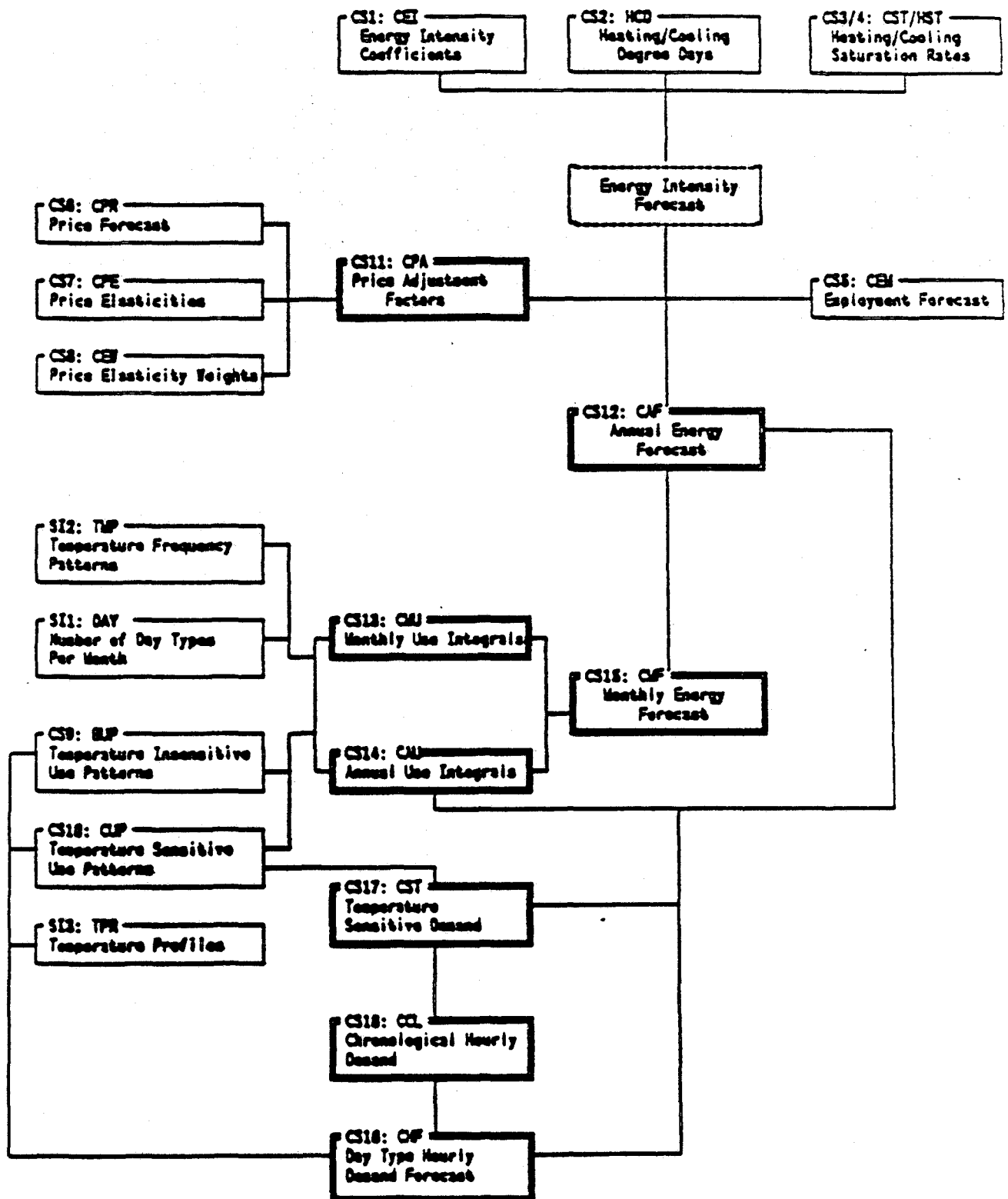
CEMP = the commercial sector employment forecast, and

CPAF = the commercial price adjustment factor.

The OUC commercial service area employment forecast was developed using Orange County commercial employment projections from Fishkind and Associates. Again, OUC's share of Orange County commercial employment was based

on historical data of OUC's share of Orange County nonresidential customers. OUC's share of commercial employment was 46 percent in 1989 and declines to 40 percent by 2010. The price adjustment factor is used to capture the change in electricity consumption as a result of changes in the real price of commercial electricity. The real price of commercial electricity was held constant throughout the forecast period.

The commercial sector energy forecast that is developed from these formulas is combined with the industrial sector energy forecast to generate the general service nondemand and general service demand energy consumption forecasts.



Commercial SIC Model Flow Chart
Figure 1B.A.4-1

1B.A.5 General Service

OUC does not classify its customers by the commercial and industrial categories. Instead, OUC customers are classified by the general service nondemand and general service demand rate categories. Therefore, the commercial and the industrial sector forecasts need to be converted to general service forecasts based on historical ratios from 1989 standard industrial classification (SIC) code data for OUC.

1B.A.5.1 General Service Nondemand

The average number of general service nondemand (GSND) customers for the forecast was projected as a function of the service area employment that is associated with the number of GSND customers. GSND service area employment is a mix of about 84 percent of commercial employment and 21 percent of industrial employment. This is based on information from 1989 SIC code data for OUC. Multiple regression analysis was used to develop an econometric model for projecting the average number of GSND customers. The following model was chosen to be used based on analysis of statistical tests.

$$\text{GSNDCUS} = 2576.566 + 0.0687 (\text{GSNDEMP})$$

$$t = 39.107$$

where

GSNDCUS = average number of general service nondemand customers, and

GSNDEMP = OUC service area general service nondemand employment forecast.

The adjusted coefficient of determination (r^2) for the above model is 0.994.

The GSND class is a mixture of both commercial and industrial customers as defined by the SHAPES-PC model. Therefore, GSND energy consumption is projected as a percentage of the SHAPES-PC model's energy consumption for the commercial and industrial sectors. The GSND percentage of commercial and industrial energy consumption was based on 1989 SIC code historical billing data of 17.6 percent of commercial energy consumption and 4.3 percent of industrial energy consumption.

1B.A.5.2 General Service Demand

Multiple regression analysis was used to develop an econometric model to project the average number of general service demand (GSD) customers. The number of GSD customers were projected as a function of employment that is associated with the number of GSD customers. The following equation was used.

$$\text{GSDCUS} = 490.289 + 0.0622 (\text{GSDEMP})$$
$$t = 24.085$$

where

GSDCUS = average number of general service demand customers, and

GSDEMP = OUC service area general service demand employment forecast.

The adjusted coefficient of determination (r^2) for the above equation is 0.983.

The OUC service area general service demand employment forecast is a mixture of the commercial and industrial employment forecasts. The GSD employment forecast is composed of 16 percent from the commercial employment forecast and 79 percent of the industrial employment forecast.

The GSD class is also a mixture of commercial and industrial customers as defined by SHAPES-PC model. Therefore, GSD sales are projected as a percentage of the SHAPES-PC model's sales forecast for the commercial and industrial sectors. The GSD percentage of commercial and industrial energy consumption was based on 1989 SIC code historical billing data of 82.4 percent of commercial energy consumption and 95.7 percent of industrial energy consumption.

1B.A.6 Residential

The SHAPES-PC model forecasts the residential sector energy and demand using a bottoms-up approach. A bottoms-up approach means that demand is forecasted first, and then energy is computed by summing demand over time.

The first step in the residential forecast is a projection of the average number of residential customers. The average number of residential customers is forecast within the SHAPES-PC model as a function of service area population. The SHAPES-PC methodology uses the following model to estimate the average number of residential customers.

$$\text{RESCUS}_t = (\text{AGE}_t^a * \text{POP}_t * \text{BSHR}^a * \text{HSRT}_t^a) * \text{CHR}_t$$

where

t = the forecast year,

a = the age category,

RESCUS = the average number of residential customers,

AGE = the fraction of population in a given age category,

POP = the OUC service area population forecast,

BSHR = the base year headship ratio,

HSRT = the headship ratio trend, and

CHR = the customer per household ratio.

The population for Orange County was supplied by Fishkind and Associates. OUC's service area share of Orange County was developed from historical information of OUC's share of residential customers. OUC's share of Orange County population was 39 percent in 1989 and declines to 33 percent by 2010. The combination of Orange County population estimates and OUC's share of the county population was used to develop the OUC service area population.

The next step in the forecast process is to forecast the number of appliances for 17 different appliance end-uses. The 17 appliance end-uses are: (1) ranges, (2) frost-free refrigerators, (3) standard refrigerators, (4) frost-free freezers, (5) standard freezers, (6) dishwashers, (7) washers, (8) dryers, (9) water heaters, (10) microwaves, (11) color televisions, (12) black and white televisions, (13) lighting, (14) room air conditioning, (15) central air conditioning, (16) heating, and (17) heat pumps.

Three different techniques are used to compute the number of appliances. These techniques are exogenous saturation rates, exogenous penetration rates, and income related saturation functions. The exogenous saturation rate technique

applies saturation rates projected outside of the SHAPES-PC model for each year of the forecast to estimate the appliance stock. This technique is generally used for those appliances which are considered necessities. The second appliance forecast method, exogenous penetration rates, applies penetration rates to the new housing stock. Appliance types modeled using this methodology are those end-uses which are installed at the time a house is constructed, have a long life, and are regarded as fixed or permanent in nature. The third appliance forecast procedure is the income related saturation function which allows the model to forecast the number of appliances based on saturation rate equations which are related to household income.

OUC uses information from its residential information surveys, which are done about every two years, to develop the exogenous saturation and penetration rates used in the forecast.

After the appliance forecast is complete, the chronological hourly demand is estimated. The general equation used to compute hourly appliance end-use demand is:

$$\text{DEMAND}_h^a = \text{NAP}^a * \text{ADJCL}^a * \text{USE}_h^a$$

where

a = appliance end-use,

h = hour,

DEMAND = demand for appliance a at hour h,

NAP = number of appliances of type a,

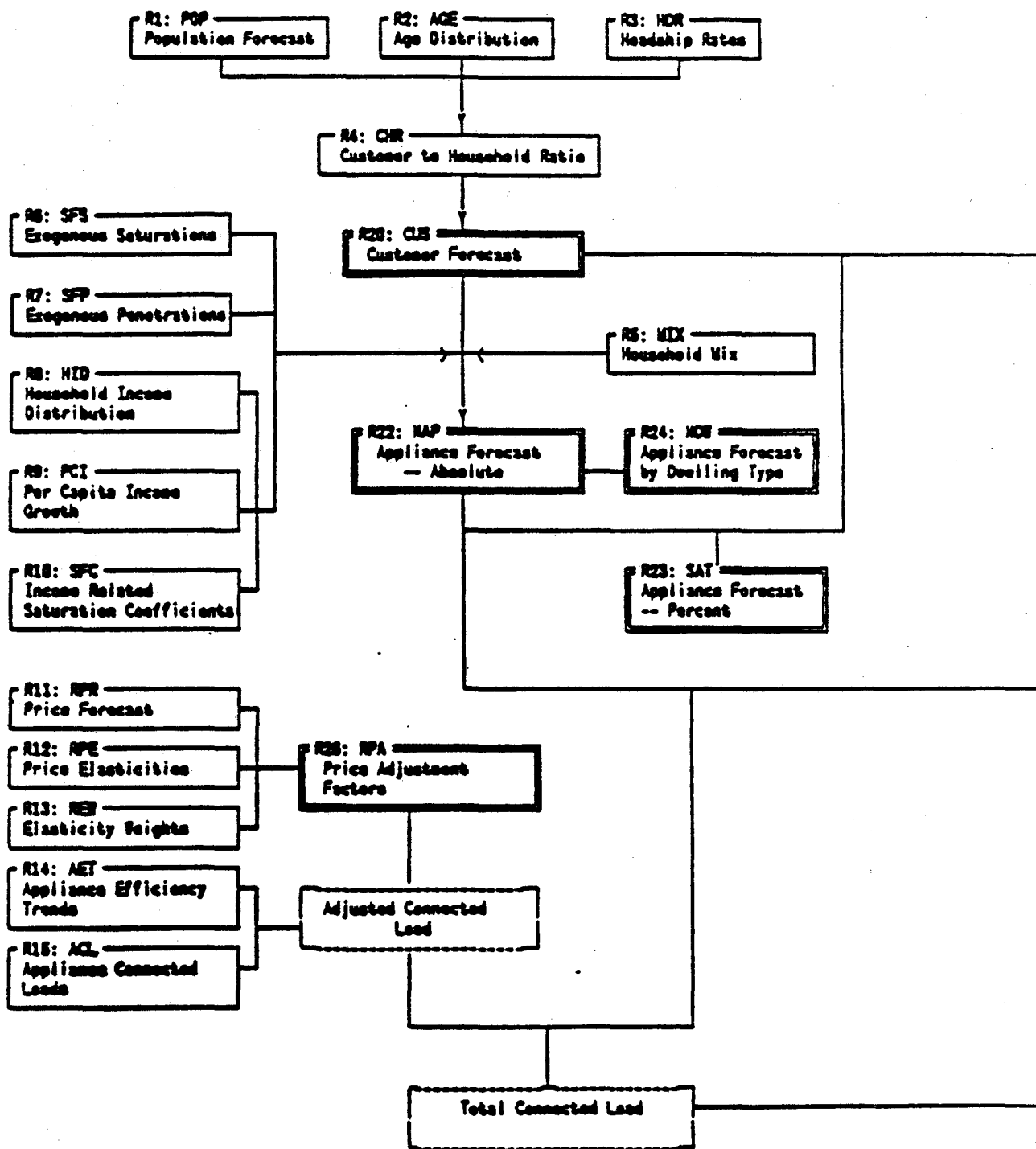
ADJCL = adjusted connected load for appliance type a, and

USE = probability appliance a is in use at a given hour.

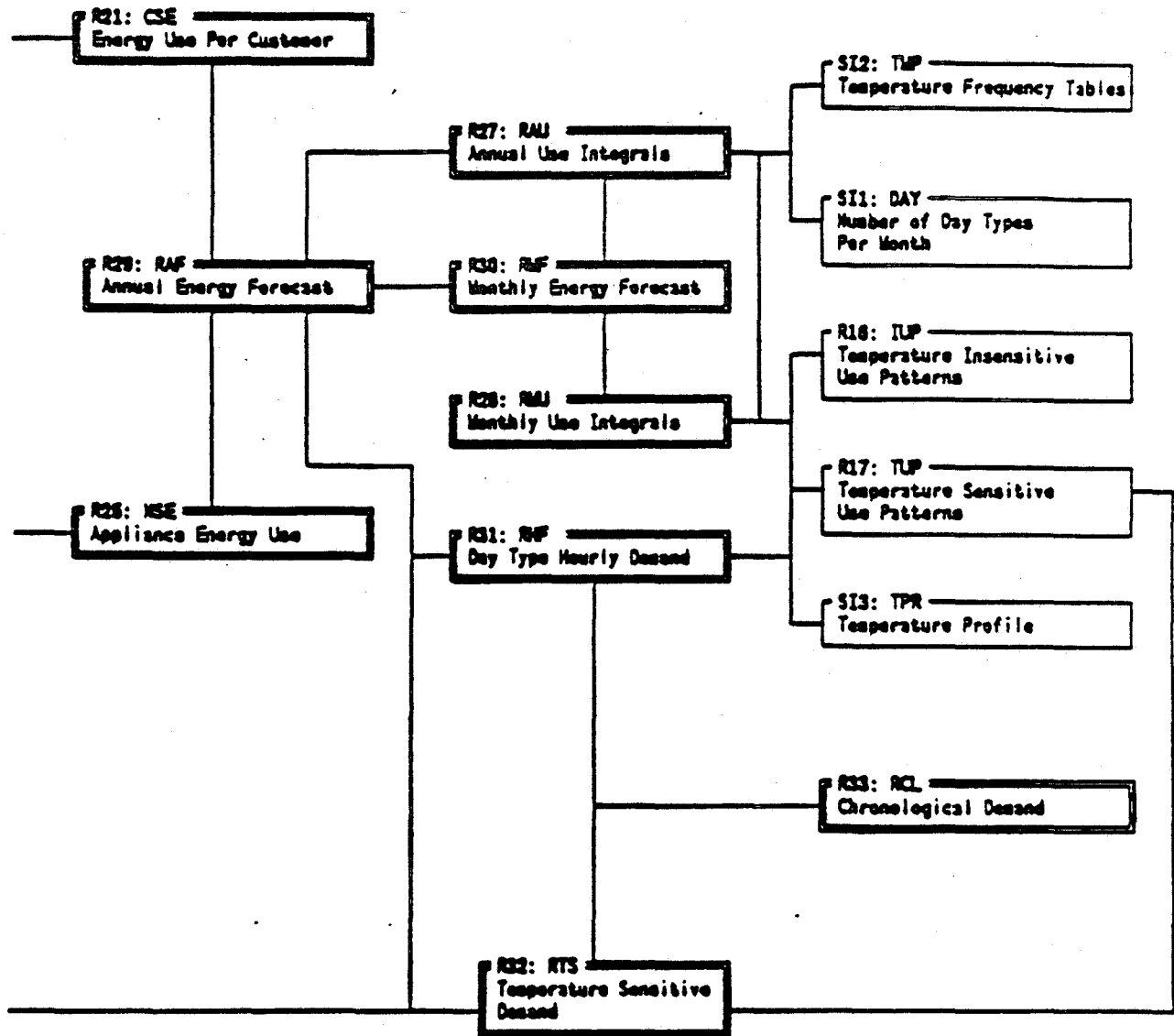
The connected load for each appliance is adjusted for real residential electric price and price elasticities to account for changes in overall usage due to price reactions. Real residential electric price is held constant throughout the forecast. Usage (USE) is determined by use patterns for each appliance. The use patterns in the model were supplied by Battelle and are based on load research for other southern utilities. Some appliances, such as refrigerators, dishwashers, and water heaters, are treated as temperature insensitive. Their use factors vary by time of day, type of day, and month. Other appliances such as air conditioning, resistance heating, and heat pumps are considered temperature sensitive. Their usage varies by time of day, type of day, and temperature.

Residential miscellaneous energy consumption is modeled as a percent of the residential sector. The residential miscellaneous use load shape follows the load shape of the remainder of the residential class.

Annual residential energy consumption is the sum of the 8,760 chronological hourly demands for each end-use. A flow chart of the residential methodology appears on Figure 1B.A.6-1.



Residential Model Flow Chart
Figure 1B.A.6-1



Residential Model Flow Chart
Figure 1B.A.6-1 (Continued)

1B.A.7 Street, Highway, and Traffic Lights and OUC Use

Total street, highway, and traffic light energy consumption was projected using trend analysis. The effect of OUC's street light conversion program was factored into the forecast. OUC interdepartmental energy consumption use (OUC Use) was also forecasted using trend analysis. OUC Use is the energy used by OUC departments associated with being an electric utility. The energy consumption associated with being a water utility is shown in the general service class.

1B.A.8 Total Retail Sales and Net Energy for Load

The sum of the energy consumption of the residential, GSND, GSD, street lighting, and OUC Use equals total OUC retail sales. Retail sales plus distribution and transmission losses of about 5 percent equals Net Energy for Load (NEL). The losses are based on a historical average of the last 10 years.

1B.A.9 System Peak Demand

Peak demand on the OUC system is highly weather sensitive with the annual peak demand occurring in both the summer and winter seasons. For six out of the last 10 years, the winter net peak demand has been the annual peak demand. Therefore, the winter net peak demand is projected to remain the annual peak demand throughout the forecast period.

The SHAPES-PC model projects demand on an hour-by-hour basis. The demand for each of the 8,760 hours in a year is individually projected. The summer peak demand is the highest hourly peak demand occurring between April 1 and October 31. The winter peak demand is the highest hourly demand occurring between November 1 (prior year) and March 31 (current year).

Since each hourly demand of the year is projected, a typical meteorological year is developed to simulate hourly temperatures. A typical meteorological year is developed by choosing historical months which most closely resemble "normal" or "typical" weather. Table 1B.A-1 contains data about the historical months comprising OUC's typical meteorological year. Also, this table shows the historical month's relationship to normal heating degree days (HDD) and cooling degree days (CDD). The normal weather is based on the National Weather Service's 1951-1980 normal period. The temperature of each hour of the typical weather year is used to project the weather sensitive portion of hourly demand.

In the residential sector, the demands of the various appliance types for a given hour are summed together to arrive at the projected residential demand. Certain appliances such as heating and air conditioning are considered to be weather sensitive. A weather sensitive portion of demand for a given temperature is added to the nonweather sensitive portion of demand equalling total demand for weather affected appliances.

In the commercial sector, the hourly demand forecast is a function of the hourly use profile and the annual commercial energy forecast. The hourly use profile is also a function of the hourly temperature of the typical meteorological year. The commercial hourly use profile is the percent of the annual energy consumption forecast that occurs at a given temperature and time. The hourly use profile was supplied by Battelle from load research data from other southern utilities.

In the industrial sector, the hourly demand is a function of the hourly load profile and the annual industrial energy forecast. The industrial hourly use profile

is the percent of the annual energy consumption forecast that occurs at a given time. This data was also supplied by Battelle. The industrial sector is not felt to be weather sensitive.

The hourly demand for street, highway, and traffic lights, and OUC Use is a function of their annual energy forecasts and their load profile relationships to the other sectors. Each miscellaneous use is assigned a percent that relates it to the other sectors' load shape.

The system hourly demand is the sum of the hourly demands of the residential, commercial, industrial, and miscellaneous sectors for each hour of the year.

The extreme weather peak demands are determined by substituting a severe weather temperature at the hour of peak demand into the typical meteorological year (see Table 1B.A-18). The winter extreme temperature is 23 F and the summer extreme temperature is 99 F. These temperatures are based on the extreme temperatures that have occurred during the past 10 years.

1B.A.10 Retail Forecast Conclusion

Orlando Utilities Commission strives to produce a forecast using state-of-the-art technology. This forecast is the third complete forecast developed using the SHAPES-PC end use/econometric forecasting model. OUC is constantly striving to improve and update the extensive data base used by the SHAPES-PC model.

The 8,760 chronological hourly load module is a recent addition to the forecasting model. During this year, a demand side management processor, RESHAPE, was also added to the forecasting methodology. RESHAPE is a Battelle product which is compatible with the SHAPES-PC model.

As part of the continuing effort to improve the model's data base, OUC surveys its customers on a regular basis. During 1987, the first survey of OUC's commercial and industrial customers was developed and mailed out. In 1989, a residential appliance information survey was completed. The results of these recent surveys are included in the most recent forecast. In the past few months, OUC has started to obtain load research data on some of the largest general service customers.

1B.A.11 Off-System Sales

OUC's future system requirements are not only based on native load, but include committed off-system sales as well. In order to determine these system requirements, projections of off-system sales must be combined with projected native load. To this end, OUC has made projections of off-system sales based on capacity commitments that are currently under contract. These contracts consist of three separate agreements with the Florida Municipal Power Agency (FMPA), two separate agreements with Reedy Creek Improvement District (RCID), and two separate agreements with Kissimmee Utility Authority (KUA).

The first of the FMPA contracts consists of a 20 MW capacity commitment for the period January 1, 1991 through December 31, 1994, and a 10 MW commitment for the period January 1, 1995 through December 31, 1995. The second contract is a firm purchase agreement for 20 MW of capacity starting on January 1, 1989 and extending through the next 15 years. The third agreement with FMPA is a 15-year contract beginning in 1986 for capacity supplied by the Indian River Plant. This contract has an additional five-year extension at FMPA's option at reduced capacity levels. The initial part of this third contract is for the firm purchase of 136 MW of capacity through the year 2001. It has been assumed that FMPA will exercise their option for the five-year extension. The contract then decreases to 90 MW in 2002, 67 MW in 2004, 44 MW in 2005, and 21 MW in 2006.

The two contracts with RCID each run from January 1, 1991 through December 31, 2001. One of the contracts is for 6 MW of reserve interchange service. The second contract includes the commitment of 15 MW through December 31, 1999, 10 MW from January 1, 2000 to the end of the year, and 5 MW from January 1, 2001 through the end of the year.

OUC currently has two contracts with KUA. The first contract consists of 25 MW of firm purchase capacity for the period January 1, 1991 through December 31, 1991, and 20 MW of firm purchase capacity for the period January 1, 1992 through December 31, 1992. The second of these agreements is a 15-year contract for 20 MW of capacity beginning on January 1, 1989.

Given these capacity commitments, OUC has developed projections of future off-system requirements based on trends derived from historical off-system sales. Table 1B.A-19 contains a summary of projected annual off system peak demand and energy sales for the contracts mentioned above. Table 1B.A-20 combines the

projections of off-system sales in Table 1B.A-19 with the native net energy for loads listed in Table 1B.A-7 under the most likely scenario. Table 1B.A-20 also combines the OUC forecast of native peak summer and winter demand (Tables 1B.A-8 and 1B.A-9), under the most likely growth scenario, with the projections of off-system demand given in Table 1B.A-19.

1B.A.12 Detailed Tables and Graphs

The tables and graphs that follow give detail about the assumptions and results of the forecast.

Table 1B.A-1
Historical Months Comprising
OUC's Typical Meteorological Year

	<u>Actual</u>		<u>Normal</u>	
	<u>HDD</u>	<u>CDD</u>	<u>HDD</u>	<u>CDD</u>
Jan 79	230	26	212	73
Feb 85	146	74	172	74
Mar 75	57	141	68	124
Apr 75	10	237	0	214
May 76	0	374	0	381
June 75	0	481	0	477
Jul 82	0	550	0	539
Aug 79	0	546	0	543
Sep 79	0	498	0	483
Oct 81	0	359	0	307
Nov 79	47	153	47	122
Dec 77	<u>179</u>	<u>62</u>	<u>157</u>	<u>64</u>
Total	669	3,501	656	3,401

Table 1B.A-2
Orlando Utilities Commission
Service Area Population

YEAR	LOW	MOST LIKELY	HIGH
1980	201,950	201,950	201,950
1981	204,920	204,920	204,920
1982	208,510	208,510	208,510
1983	211,660	211,660	211,660
1984	217,680	217,680	217,680
1985	226,090	226,090	226,090
1986	228,350	228,350	228,350
1987	235,140	235,140	235,140
1988	243,200	243,200	243,200
1989	253,970	253,970	253,970
1990	261,740	261,740	261,740
1991	269,490	269,490	269,490
1992	276,369	276,369	276,369
1993	281,985	282,570	282,960
1994	288,094	289,450	290,226
1995	294,302	296,999	298,155
1996	299,650	305,204	307,119
1997	305,511	312,556	315,222
1998	310,551	319,069	322,476
1999	315,155	324,753	328,894
2000	318,694	328,928	333,767
2001	322,069	333,660	339,547
2002	324,374	338,923	345,834
2003	327,438	344,694	352,603
2004	329,830	349,549	358,432
2005	332,625	353,166	363,349
2006	335,973	355,923	367,373
2007	338,461	358,859	371,885
2008	340,450	362,294	376,856
2009	342,953	366,535	382,925
2010	349,860	375,775	394,166
2011	353,140	380,810	400,780
2012	356,450	385,920	407,500
2013	359,790	391,090	414,340
2014	363,170	396,330	421,290
2015	366,570	401,640	428,350
2016	370,010	407,030	435,540
2017	373,480	412,480	442,840
2018	376,980	418,010	450,270
2019	380,510	423,620	457,820
2020	384,080	429,290	465,500
80-89 CAAGR	2.6%	2.6%	2.6%
90-00 CAAGR	2.0%	2.3%	2.5%
90-20 CAAGR	1.3%	1.7%	1.9%

Table 1B.A-3
Orlando Utilities Commission
Household Size

YEAR	PERSONS PER RESIDENTIAL METER
1980	2.72
1981	2.72
1982	2.72
1983	2.71
1984	2.68
1985	2.69
1986	2.63
1987	2.60
1988	2.58
1989	2.59
1990	2.56
1991	2.55
1992	2.51
1993	2.52
1994	2.51
1995	2.50
1996	2.49
1997	2.47
1998	2.45
1999	2.44
2000	2.42
2001	2.42
2002	2.42
2003	2.42
2004	2.42
2005	2.42
2006	2.42
2007	2.42
2008	2.42
2009	2.42
2010	2.42
2011	2.42
2012	2.42
2013	2.42
2014	2.42
2015	2.42
2016	2.42
2017	2.42
2018	2.42
2019	2.42
2020	2.42
80-89 CAAGR	-0.53%
90-00 CAAGR	-0.55%
90-20 CAAGR	-0.18%

Table 1B.A-4
Orlando Utilities Commission
Service Area Employment

YEAR	LOW	MOST LIKELY	HIGH
1980	108,350	108,350	108,350
1981	112,660	112,660	112,660
1982	116,230	116,230	116,230
1983	122,140	122,140	122,140
1984	134,500	134,500	134,500
1985	144,020	144,020	144,020
1986	155,710	155,710	155,710
1987	168,850	168,850	168,850
1988	175,670	175,670	175,670
1989	185,376	185,376	185,376
1990	192,545	192,545	192,545
1991	200,336	200,336	200,336
1992	206,307	206,307	206,307
1993	211,281	211,726	212,169
1994	217,566	218,889	220,653
1995	223,378	227,772	230,409
1996	228,264	237,460	241,400
1997	234,821	246,163	250,961
1998	241,300	254,336	259,550
1999	246,397	261,543	267,172
2000	251,595	268,759	275,196
2001	255,390	276,662	283,894
2002	258,767	284,900	292,943
2003	263,488	293,586	302,365
2004	267,754	300,897	310,425
2005	271,058	307,183	317,446
2006	275,861	312,057	323,038
2007	279,335	318,820	330,907
2008	282,299	326,602	339,374
2009	286,717	332,968	348,385
2010	292,344	342,168	360,358
2011	296,770	350,540	370,200
2012	301,260	359,110	380,320
2013	305,820	367,900	390,720
2014	310,440	376,890	401,400
2015	315,140	386,100	412,380
2016	319,920	395,550	423,650
2017	324,760	405,230	435,240
2018	329,670	415,140	447,140
2019	334,670	425,290	459,370
2020	339,730	435,700	471,930
80-89 CAAGR	6.1%	6.1%	6.1%
90-00 CAAGR	2.7%	3.4%	3.6%
90-20 CAAGR	1.9%	2.8%	3.0%

Table 1B.A-5
Orlando Utilities Commission
Real Per Capita Income

YEAR	LOW	MOST LIKELY	HIGH
1980	8,999	8,999	8,999
1981	10,503	10,503	10,503
1982	11,307	11,307	11,307
1983	11,958	11,958	11,958
1984	12,266	12,266	12,266
1985	12,643	12,643	12,643
1986	12,942	12,942	12,942
1987	12,945	12,945	12,945
1988	13,168	13,168	13,168
1989	13,986	13,986	13,986
1990	14,168	14,168	14,168
1991	14,225	14,309	14,709
1992	14,084	14,347	14,883
1993	13,852	14,372	14,648
1994	14,447	14,474	15,369
1995	14,745	14,645	15,864
1996	14,765	14,823	16,098
1997	14,605	14,973	15,986
1998	14,473	15,125	15,842
1999	14,272	15,254	15,670
2000	14,638	15,434	16,155
2001	15,196	15,619	16,931
2002	15,238	15,784	17,097
2003	15,333	15,953	17,266
2004	15,156	16,079	17,085
2005	14,902	16,203	16,883
2006	14,704	16,291	16,640
2007	15,013	16,463	17,104
2008	15,316	16,659	17,576
2009	15,674	16,741	18,024
2010	15,656	16,769	18,100
2011	15,944	17,076	18,518
2012	16,237	17,388	18,946
2013	16,536	17,707	19,384
2014	16,840	18,031	19,831
2015	17,150	18,361	20,289
2016	17,466	18,697	20,758
2017	17,787	19,039	21,238
2018	18,115	19,387	21,728
2019	18,448	19,742	22,230
2020	18,787	20,103	22,744
80-89 CAAGR	5.0%	5.0%	5.0%
90-00 CAAGR	0.3%	0.9%	1.3%
90-20 CAAGR	0.9%	1.2%	1.6%

Table IB.A-6
Orlando Utilities Commission
Average Total Retail Customers

YEAR	LOW	MOST LIKELY	HIGH
1980	84,529	84,529	84,529
1981	86,085	86,085	86,085
1982	87,526	87,526	87,526
1983	89,698	89,698	89,698
1984	93,559	93,559	93,559
1985	97,121	97,121	97,121
1986	100,502	100,502	100,502
1987	105,094	105,094	105,094
1988	109,140	109,140	109,140
1989	113,242	113,242	113,242
1990	117,912	117,912	117,912
1991	121,983	121,983	121,983
1992	125,725	125,725	125,725
1993	128,847	129,077	129,207
1994	132,091	132,662	133,003
1995	135,468	136,636	137,219
1996	138,817	141,350	142,300
1997	142,323	145,802	147,149
1998	145,627	149,870	151,587
1999	148,758	153,579	155,631
2000	151,358	156,615	158,995
2001	153,106	160,295	161,926
2002	154,314	161,766	165,110
2003	155,810	164,702	168,519
2004	157,118	167,304	171,566
2005	158,564	169,294	174,146
2006	160,168	170,860	176,262
2007	161,521	172,495	178,528
2008	162,578	174,281	181,116
2009	163,813	176,561	184,196
2010	166,965	180,808	189,447
2011	168,701	183,511	192,989
2012	170,368	186,190	196,431
2013	172,052	189,176	199,943
2014	173,758	191,667	203,520
2015	175,474	194,471	207,160
2016	177,213	197,322	210,874
2017	178,971	200,214	214,654
2018	180,744	203,156	218,509
2019	182,535	206,145	222,434
2020	184,349	209,175	226,436
80-89 CAAGR	3.3%	3.3%	3.3%
90-00 CAAGR	2.5%	2.9%	3.0%
90-20 CAAGR	1.5%	1.9%	2.2%

Table 1B.A-7
Orlando Utilities Commission
Native Net Energy for Load (GWh)

YEAR	LOW	MOST LIKELY	HIGH
1980	2,331	2,331	2,331
1981	2,404	2,404	2,404
1982	2,403	2,403	2,403
1983	2,524	2,524	2,524
1984	2,606	2,606	2,606
1985	2,847	2,847	2,847
1986	2,962	2,962	2,962
1987	3,105	3,105	3,105
1988	3,289	3,289	3,289
1989	3,508	3,508	3,508
1990	3,611	3,611	3,611
1991	3,797	3,797	3,797
1992	3,957	3,957	3,957
1993	4,092	4,102	4,110
1994	4,246	4,271	4,296
1995	4,399	4,473	4,513
1996	4,541	4,690	4,753
1997	4,704	4,891	4,970
1998	4,863	5,083	5,174
1999	5,004	5,263	5,362
2000	5,149	5,444	5,557
2001	5,294	5,672	5,790
2002	5,414	5,865	6,020
2003	5,561	6,092	6,260
2004	5,696	6,288	6,478
2005	5,821	6,469	6,676
2006	5,971	6,628	6,855
2007	6,106	6,821	7,078
2008	6,225	7,030	7,311
2009	6,364	7,219	7,553
2010	6,548	7,481	7,873
2011	6,696	7,714	8,141
2012	6,844	7,948	8,412
2013	6,998	8,191	8,697
2014	7,152	8,440	8,988
2015	7,313	8,699	9,292
2016	7,472	8,962	9,600
2017	7,639	9,239	9,926
2018	7,805	9,519	10,256
2019	7,979	9,810	10,599
2020	8,083	10,107	10,951
80-89 CAAGR	4.6%	4.6%	4.6%
90-00 CAAGR	3.6%	4.2%	4.4%
90-20 CAAGR	2.7%	3.5%	3.8%

Table IB.A-8
Orlando Utilities Commission
Native Summer Net Peak Demand (MW)

YEAR	LOW	MOST LIKELY	HIGH
1980	487	487	487
1981	502	502	502
1982	493	493	493
1983	539	539	539
1984	544	544	544
1985	596	596	596
1986	599	599	599
1987	634	634	634
1988	651	651	651
1989	681	681	681
1990	709	709	709
1991	745	745	745
1992	771	771	771
1993	798	800	801
1994	826	828	833
1995	854	868	875
1996	878	907	920
1997	909	944	958
1998	937	978	995
1999	965	1,012	1,028
2000	990	1,044	1,066
2001	1,015	1,086	1,106
2002	1,036	1,122	1,150
2003	1,063	1,164	1,193
2004	1,089	1,198	1,236
2005	1,112	1,234	1,270
2006	1,138	1,264	1,304
2007	1,163	1,298	1,342
2008	1,184	1,333	1,383
2009	1,207	1,364	1,422
2010	1,241	1,410	1,482
2011	1,263	1,450	1,528
2012	1,288	1,490	1,574
2013	1,313	1,533	1,625
2014	1,341	1,576	1,674
2015	1,368	1,622	1,728
2016	1,393	1,667	1,780
2017	1,420	1,715	1,837
2018	1,450	1,764	1,893
2019	1,480	1,812	1,954
2020	1,494	1,864	2,016
80-89 CAAGR	3.8%	3.8%	3.8%
90-00 CAAGR	3.4%	3.9%	4.2%
90-20 CAAGR	2.5%	3.3%	3.5%

Table 1B.A-9
Orlando Utilities Commission
Native Winter Net Peak Demand (MW)

YEAR	LOW	MOST LIKELY	HIGH
1980	500	500	500
1981	535	535	535
1982	541	541	541
1983	474	474	474
1984	518	518	518
1985	688	688	688
1986	690	690	690
1987	558	558	558
1988	631	631	631
1989	693	693	693
1990	774	774	774
1991	794	794	794
1992	831	831	831
1993	858	860	863
1994	890	894	901
1995	920	937	943
1996	951	980	992
1997	986	1,023	1,037
1998	1,020	1,061	1,078
1999	1,049	1,097	1,120
2000	1,076	1,134	1,157
2001	1,102	1,175	1,196
2002	1,124	1,206	1,235
2003	1,150	1,245	1,280
2004	1,171	1,282	1,320
2005	1,192	1,311	1,355
2006	1,218	1,336	1,386
2007	1,242	1,367	1,424
2008	1,262	1,405	1,465
2009	1,286	1,440	1,511
2010	1,320	1,490	1,571
2011	1,351	1,535	1,625
2012	1,376	1,574	1,670
2013	1,407	1,622	1,725
2014	1,433	1,664	1,775
2015	1,465	1,712	1,835
2016	1,494	1,755	1,889
2017	1,527	1,806	1,949
2018	1,556	1,855	2,008
2019	1,591	1,912	2,069
2020	1,612	1,958	2,131
80-90 CAAGR	4.5%	4.5%	4.5%
91-00 CAAGR	3.4%	4.0%	4.3%
91-20 CAAGR	2.5%	3.2%	3.5%

Table 1B.A-10
Orlando Utilities Commission
Average Residential Customers

YEAR	LOW	MOST LIKELY	HIGH
1980	74,247	74,247	74,247
1981	75,449	75,449	75,449
1982	76,650	76,650	76,650
1983	78,203	78,203	78,203
1984	81,344	81,344	81,344
1985	84,178	84,178	84,178
1986	86,815	86,815	86,815
1987	90,533	90,533	90,533
1988	94,138	94,138	94,138
1989	97,923	97,923	97,923
1990	102,227	102,227	102,227
1991	105,774	105,774	105,774
1992	108,985	108,985	108,985
1993	111,701	111,931	112,061
1994	114,606	115,147	115,457
1995	117,554	118,632	119,096
1996	120,507	122,741	123,511
1997	123,681	126,533	127,612
1998	126,537	130,008	131,398
1999	129,227	133,160	134,857
2000	131,480	135,704	137,701
2001	132,874	138,894	140,086
2002	133,823	139,827	142,677
2003	135,090	142,208	145,470
2004	136,076	144,211	147,875
2005	137,231	145,703	149,905
2006	138,609	146,841	151,563
2007	139,636	148,093	153,428
2008	140,457	149,469	155,479
2009	141,489	151,219	157,983
2010	144,339	155,031	162,620
2011	145,693	157,108	165,347
2012	147,058	159,216	168,119
2013	148,436	161,349	170,941
2014	149,831	163,511	173,809
2015	151,233	165,702	176,721
2016	152,652	167,926	179,688
2017	154,084	170,174	182,699
2018	155,528	172,456	185,765
2019	156,984	174,770	188,880
2020	158,457	177,109	192,048
80-89 CAAGR	3.1%	3.1%	3.1%
90-00 CAAGR	2.5%	2.9%	3.0%
90-20 CAAGR	1.5%	1.8%	2.1%

Table 1B.A-11
Orlando Utilities Commission
Residential Energy (GWh)

YEAR	LOW	MOST LIKELY	HIGH
1980	918	918	918
1981	954	954	954
1982	870	870	870
1983	936	936	936
1984	962	962	962
1985	1,012	1,012	1,012
1986	1,061	1,061	1,061
1987	1,085	1,085	1,085
1988	1,114	1,114	1,114
1989	1,187	1,187	1,187
1990	1,211	1,211	1,211
1991	1,257	1,257	1,257
1992	1,301	1,301	1,301
1993	1,332	1,336	1,338
1994	1,366	1,372	1,376
1995	1,397	1,411	1,418
1996	1,429	1,456	1,465
1997	1,462	1,497	1,511
1998	1,492	1,533	1,551
1999	1,519	1,567	1,588
2000	1,540	1,593	1,617
2001	1,571	1,644	1,658
2002	1,593	1,667	1,703
2003	1,621	1,710	1,749
2004	1,645	1,746	1,793
2005	1,673	1,778	1,830
2006	1,701	1,806	1,866
2007	1,726	1,834	1,903
2008	1,742	1,857	1,935
2009	1,756	1,880	1,968
2010	1,794	1,932	2,031
2011	1,815	1,963	2,069
2012	1,834	1,990	2,104
2013	1,854	2,020	2,145
2014	1,873	2,048	2,183
2015	1,895	2,081	2,224
2016	1,912	2,109	2,262
2017	1,935	2,143	2,305
2018	1,953	2,173	2,344
2019	1,977	2,207	2,388
2020	1,996	2,237	2,430
80-89 CAAGR	2.9%	2.9%	2.9%
90-00 CAAGR	2.4%	2.8%	2.9%
90-20 CAAGR	1.7%	2.1%	2.3%

Table 1B.A-12
Orlando Utilities Commission
Average GSND Customers

YEAR	LOW	MOST LIKELY	HIGH
1980	8,746	8,746	8,746
1981	8,972	8,972	8,972
1982	9,167	9,167	9,167
1983	9,734	9,734	9,734
1984	10,363	10,363	10,363
1985	11,013	11,013	11,013
1986	11,680	11,680	11,680
1987	12,384	12,384	12,384
1988	12,726	12,726	12,726
1989	12,950	12,950	12,950
1990	13,221	13,221	13,221
1991	13,665	13,665	13,665
1992	14,111	14,111	14,111
1993	14,455	14,455	14,455
1994	14,742	14,767	14,793
1995	15,105	15,181	15,282
1996	15,438	15,691	15,843
1997	15,719	16,248	16,475
1998	16,099	16,751	17,028
1999	16,473	17,224	17,524
2000	16,768	17,641	17,965
2001	17,066	18,054	18,425
2002	17,281	18,505	18,922
2003	17,475	18,974	19,443
2004	17,747	19,480	19,985
2005	17,994	19,903	20,452
2006	18,187	20,267	20,838
2007	18,465	20,590	21,183
2008	18,662	20,937	21,634
2009	18,832	21,383	22,119
2010	19,085	21,748	22,635
2011	19,408	22,277	23,324
2012	19,663	22,759	23,890
2013	19,921	23,521	24,472
2014	20,183	23,757	25,071
2015	20,448	24,274	25,685
2016	20,718	24,804	26,316
2017	20,993	25,347	26,965
2018	21,271	25,904	27,631
2019	21,553	26,474	28,315
2020	21,841	27,057	29,019
80-89 CAAGR	4.5%	4.5%	4.5%
90-00 CAAGR	2.4%	2.9%	3.1%
90-20 CAAGR	1.7%	2.4%	2.7%

Table 1B.A-13
Orlando Utilities Commission
GSND Energy (GWh)

YEAR	LOW	MOST LIKELY	HIGH
1980	187	187	187
1981	192	192	192
1982	196	196	196
1983	211	211	211
1984	235	235	235
1985	261	261	261
1986	278	278	278
1987	285	285	285
1988	296	296	296
1989	322	322	322
1990	334	334	334
1991	353	353	353
1992	370	370	370
1993	386	386	387
1994	404	407	410
1995	421	429	434
1996	438	455	462
1997	458	480	489
1998	478	504	515
1999	497	527	539
2000	514	549	563
2001	529	573	588
2002	544	598	615
2003	562	626	644
2004	580	651	672
2005	596	676	698
2006	616	697	721
2007	632	721	748
2008	646	747	777
2009	664	771	807
2010	686	803	846
2011	705	833	880
2012	725	864	915
2013	745	897	952
2014	766	930	990
2015	787	964	1030
2016	808	999	1070
2017	830	1036	1113
2018	853	1074	1156
2019	875	1112	1202
2020	887	1153	1248
80-89 CAAGR	6.2%	6.2%	6.2%
90-00 CAAGR	4.4%	5.1%	5.4%
90-20 CAAGR	3.3%	4.2%	4.5%

Table 1B.A-14
Orlando Utilities Commission
Average GSD Customers

YEAR	LOW	MOST LIKELY	HIGH
1980	1,536	1,536	1,536
1981	1,664	1,664	1,664
1982	1,709	1,709	1,709
1983	1,761	1,761	1,761
1984	1,852	1,852	1,852
1985	1,930	1,930	1,930
1986	2,007	2,007	2,007
1987	2,177	2,177	2,177
1988	2,276	2,276	2,276
1989	2,369	2,369	2,369
1990	2,464	2,464	2,464
1991	2,544	2,544	2,544
1992	2,629	2,629	2,629
1993	2,691	2,691	2,691
1994	2,743	2,748	2,753
1995	2,809	2,823	2,841
1996	2,872	2,918	2,946
1997	2,923	3,021	3,062
1998	2,991	3,111	3,161
1999	3,058	3,195	3,250
2000	3,110	3,270	3,329
2001	3,166	3,347	3,415
2002	3,210	3,434	3,511
2003	3,245	3,520	3,606
2004	3,295	3,613	3,706
2005	3,339	3,688	3,789
2006	3,372	3,752	3,861
2007	3,420	3,812	3,917
2008	3,459	3,875	4,003
2009	3,492	3,959	4,094
2010	3,541	4,029	4,192
2011	3,600	4,126	4,318
2012	3,647	4,215	4,422
2013	3,695	4,306	4,530
2014	3,744	4,399	4,640
2015	3,793	4,495	4,754
2016	3,843	4,592	4,870
2017	3,894	4,693	4,990
2018	3,945	4,796	5,113
2019	3,998	4,901	5,239
2020	4,051	5,009	5,369
80-89 CAAGR	4.9%	4.9%	4.9%
90-00 CAAGR	2.4%	2.9%	3.1%
90-20 CAAGR	1.7%	2.4%	2.6%

Table 1B.A-15
Orlando Utilities Commission
GSD Energy (GWh)

YEAR	LOW	MOST LIKELY	HIGH
1980	1,075	1,075	1,075
1981	1,143	1,143	1,143
1982	1,160	1,160	1,160
1983	1,237	1,237	1,237
1984	1,313	1,313	1,313
1985	1,417	1,417	1,417
1986	1,485	1,485	1,485
1987	1,565	1,565	1,565
1988	1,663	1,663	1,663
1989	1,796	1,789	1,796
1990	1,861	1,862	1,861
1991	1,975	1,975	1,975
1992	2,066	2,066	2,066
1993	2,146	2,151	2,156
1994	2,241	2,255	2,272
1995	2,339	2,386	2,414
1996	2,425	2,522	2,564
1997	2,525	2,646	2,699
1998	2,627	2,769	2,826
1999	2,714	2,882	2,944
2000	2,815	3,006	3,077
2001	2,902	3,144	3,227
2002	2,979	3,279	3,373
2003	3,072	3,425	3,527
2004	3,158	3,548	3,663
2005	3,234	3,664	3,786
2006	3,328	3,766	3,897
2007	3,415	3,897	4,045
2008	3,498	4,047	4,205
2009	3,599	4,179	4,373
2010	3,714	4,346	4,576
2011	3,814	4,504	4,757
2012	3,915	4,668	4,944
2013	4,021	4,837	5,138
2014	4,128	5,013	5,338
2015	4,238	5,193	5,546
2016	4,350	5,379	5,760
2017	4,465	5,571	5,984
2018	4,582	5,769	6,215
2019	4,700	5,973	6,452
2020	4,768	6,184	6,698
80-89 CAAGR	5.9%	5.8%	5.9%
90-00 CAAGR	4.2%	4.9%	5.2%
90-20 CAAGR	3.2%	4.1%	4.4%

Table 1B.A-16
Orlando Utilities Commission
OUC Use and Street Lights Energy

YEAR	PESSIMISTIC	MOST LIKELY	OPTIMISTIC
1980	28	28	28
1981	28	28	28
1982	29	29	29
1983	28	28	28
1984	28	28	28
1985	34	34	34
1986	34	34	34
1987	29	29	29
1988	26	26	26
1989	25	25	25
1990	25	25	25
1991	27	27	27
1992	27	27	27
1993	27	27	27
1994	27	27	27
1995	27	27	27
1996	27	27	27
1997	27	27	27
1998	27	27	27
1999	27	27	27
2000	27	27	27
2001	31	31	31
2002	31	31	31
2003	31	31	31
2004	31	31	31
2005	31	31	31
2006	31	31	31
2007	31	31	31
2008	31	31	31
2009	31	31	31
2010	31	31	31
2011	31	31	31
2012	31	31	31
2013	31	31	31
2014	31	31	31
2015	31	31	31
2016	31	31	31
2017	31	31	31
2018	31	31	31
2019	31	31	31
2020	31	31	31
80-89 CAAGR	-1.3%	-1.3%	-1.3%
90-00 CAAGR	0.8%	0.8%	0.8%
90-20 CAAGR	0.7%	0.7%	0.7%

Table 1B.A-17
Orlando Utilities Commission
Total Retail Energy Sales (GWh)

YEAR	LOW	MOST LIKELY	HIGH
1980	2,203	2,203	2,203
1981	2,312	2,312	2,312
1982	2,250	2,250	2,250
1983	2,407	2,407	2,407
1984	2,533	2,533	2,533
1985	2,712	2,712	2,712
1986	2,847	2,847	2,847
1987	2,959	2,959	2,959
1988	3,098	3,098	3,098
1989	3,330	3,323	3,330
1990	3,434	3,434	3,434
1991	3,612	3,612	3,612
1992	3,764	3,764	3,764
1993	3,891	3,900	3,908
1994	4,038	4,061	4,085
1995	4,184	4,253	4,293
1996	4,319	4,460	4,518
1997	4,472	4,650	4,726
1998	4,624	4,833	4,919
1999	4,757	5,003	5,098
2000	4,896	5,175	5,284
2001	5,033	5,392	5,504
2002	5,147	5,575	5,722
2003	5,286	5,792	5,951
2004	5,414	5,976	6,159
2005	5,534	6,149	6,345
2006	5,676	6,300	6,515
2007	5,804	6,483	6,727
2008	5,917	6,682	6,948
2009	6,050	6,861	7,179
2010	6,225	7,112	7,484
2011	6,365	7,331	7,737
2012	6,505	7,553	7,994
2013	6,651	7,785	8,266
2014	6,798	8,022	8,542
2015	6,951	8,269	8,831
2016	7,101	8,518	9,123
2017	7,261	8,781	9,433
2018	7,419	9,047	9,746
2019	7,583	9,323	10,073
2020	7,682	9,605	10,407
80-89 CAAGR	4.7%	4.7%	4.7%
90-00 CAAGR	3.6%	4.2%	4.4%
90-20 CAAGR	2.7%	3.5%	3.8%

Table 1B.A-18
Orlando Utilities Commission
Extreme Weather Net Peak Demand
Most Likely Growth Scenario

<u>Year</u>	<u>Winter (Jan.)</u> MW	<u>Summer</u> MW
1991	859	836
1992	898	867
1993	929	899
1994	967	929
1995	1,013	973
1996	1,058	1,016
1997	1,103	1,057
1998	1,146	1,095
1999	1,185	1,129
2000	1,223	1,164
2001	1,268	1,211
2002	1,300	1,251
2003	1,342	1,296
2004	1,379	1,335
2005	1,412	1,373
2006	1,439	1,405
2007	1,473	1,442
2008	1,511	1,479
2009	1,548	1,513
2010	1,600	1,562
2011	1,651	1,604
2012	1,693	1,646
2013	1,745	1,694
2014	1,785	1,739
2015	1,838	1,788
2016	1,883	1,837
2017	1,936	1,885
2018	1,988	1,938
2019	2,048	1,991
2020	2,098	2,044

Table 1B.A-19
Off-System Demand and Energy Sales

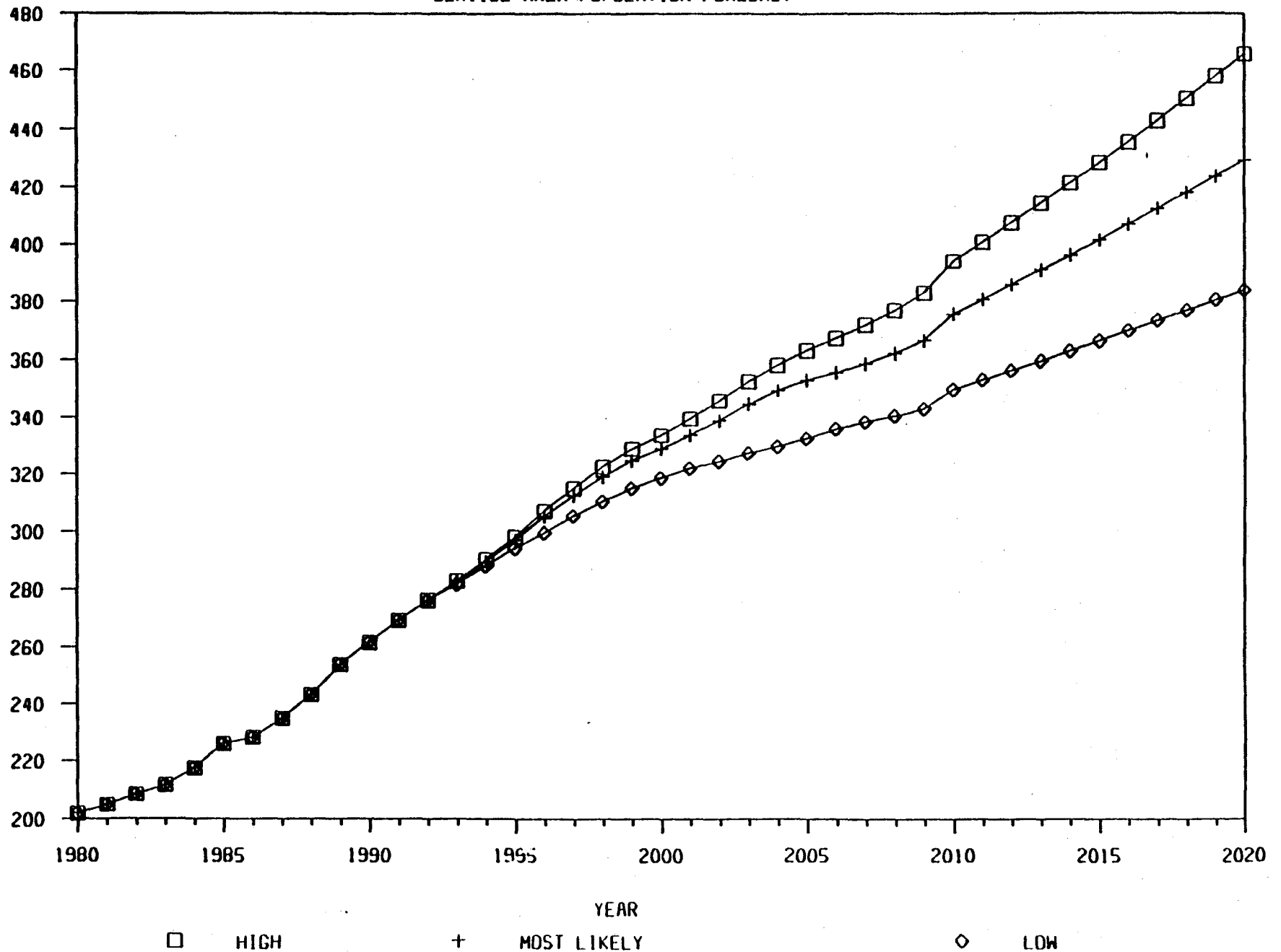
<u>Year</u>	<u>Off-System Sales GWh</u>	<u>Off-System Peak Demand MW</u>
1991	365	242
1992	359	237
1993	332	217
1994	336	217
1995	328	207
1996	330	197
1997	334	197
1998	338	197
1999	342	197
2000	361	192
2001	349	187
2002	288	144
2003	247	123
2004	143	61
2005	97	43
2006	59	21

Table 1B.A-20
Orlando Utilities Commission
Net Energy for Load and Peak Demand
(Includes Off System Sales and Demand)
Most Likely Growth Scenario

<u>Year</u>	<u>Net Energy For Load GWh</u>	<u>Summer Peak Demand MW</u>	<u>Winter Peak Demand MW</u>
1991	4,162	987	1,036
1992	4,316	1,008	1,068
1993	4,434	1,017	1,077
1994	4,607	1,045	1,111
1995	4,801	1,075	1,144
1996	5,020	1,104	1,177
1997	5,225	1,141	1,220
1998	5,421	1,175	1,258
1999	5,605	1,209	1,294
2000	5,805	1,236	1,326
2001	6,021	1,273	1,362
2002	6,153	1,266	1,350
2003	6,339	1,287	1,368
2004	6,431	1,259	1,343
2005	6,566	1,277	1,354
2006	6,687	1,285	1,357
2007	6,821	1,298	1,367
2008	7,030	1,333	1,405
2009	7,219	1,364	1,440
2010	7,481	1,410	1,490
2011	7,714	1,450	1,535
2012	7,948	1,490	1,574
2013	8,191	1,533	1,622
2014	8,440	1,576	1,644
2015	8,699	1,622	1,712
2016	8,962	1,667	1,755
2017	9,239	1,715	1,806
2018	9,519	1,764	1,855
2019	9,810	1,812	1,912
2020	10,107	1,864	1,958
91-00 CAAGR	3.8%	2.5%	2.8%
91-20 CAAGR	3.1%	2.2%	2.2%

ORLANDO UTILITIES COMMISSION

SERVICE AREA POPULATION FORECAST



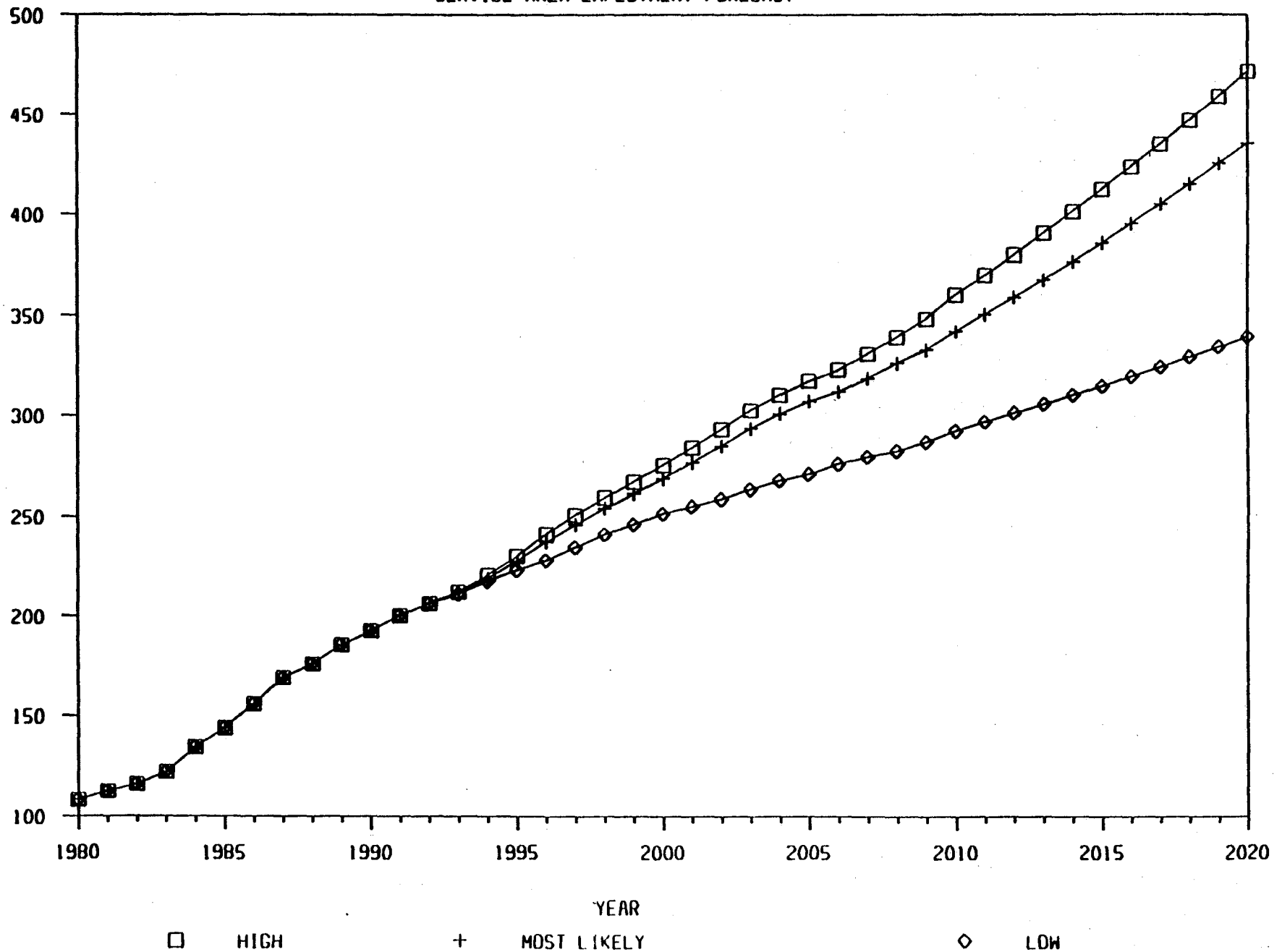
031591

1B.A.12-22

POPULATION
(Thousands)

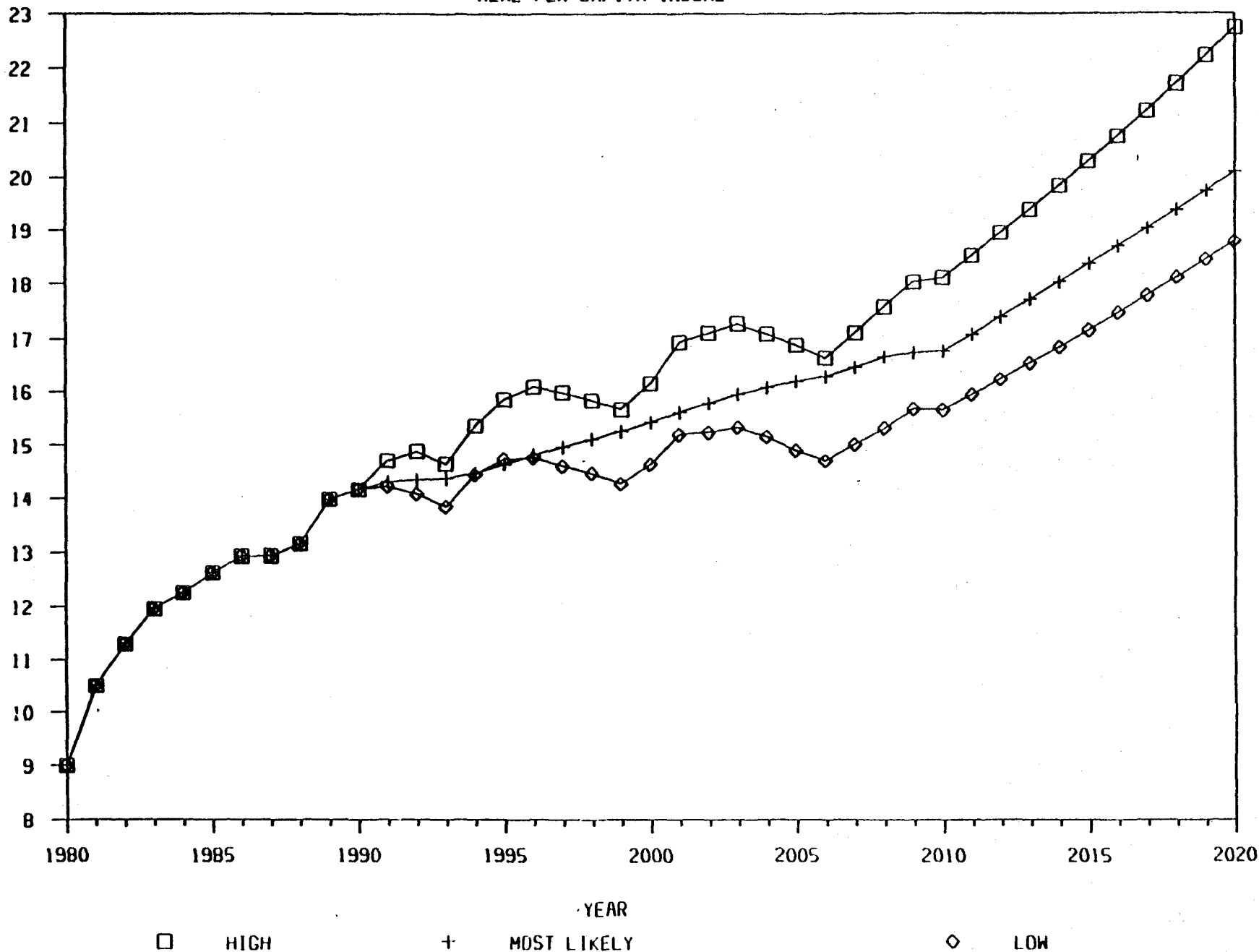
ORLANDO UTILITIES COMMISSION

SERVICE AREA EMPLOYMENT FORECAST



ORLANDO UTILITIES COMMISSION

REAL PER CAPITA INCOME



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1B.A.12-24

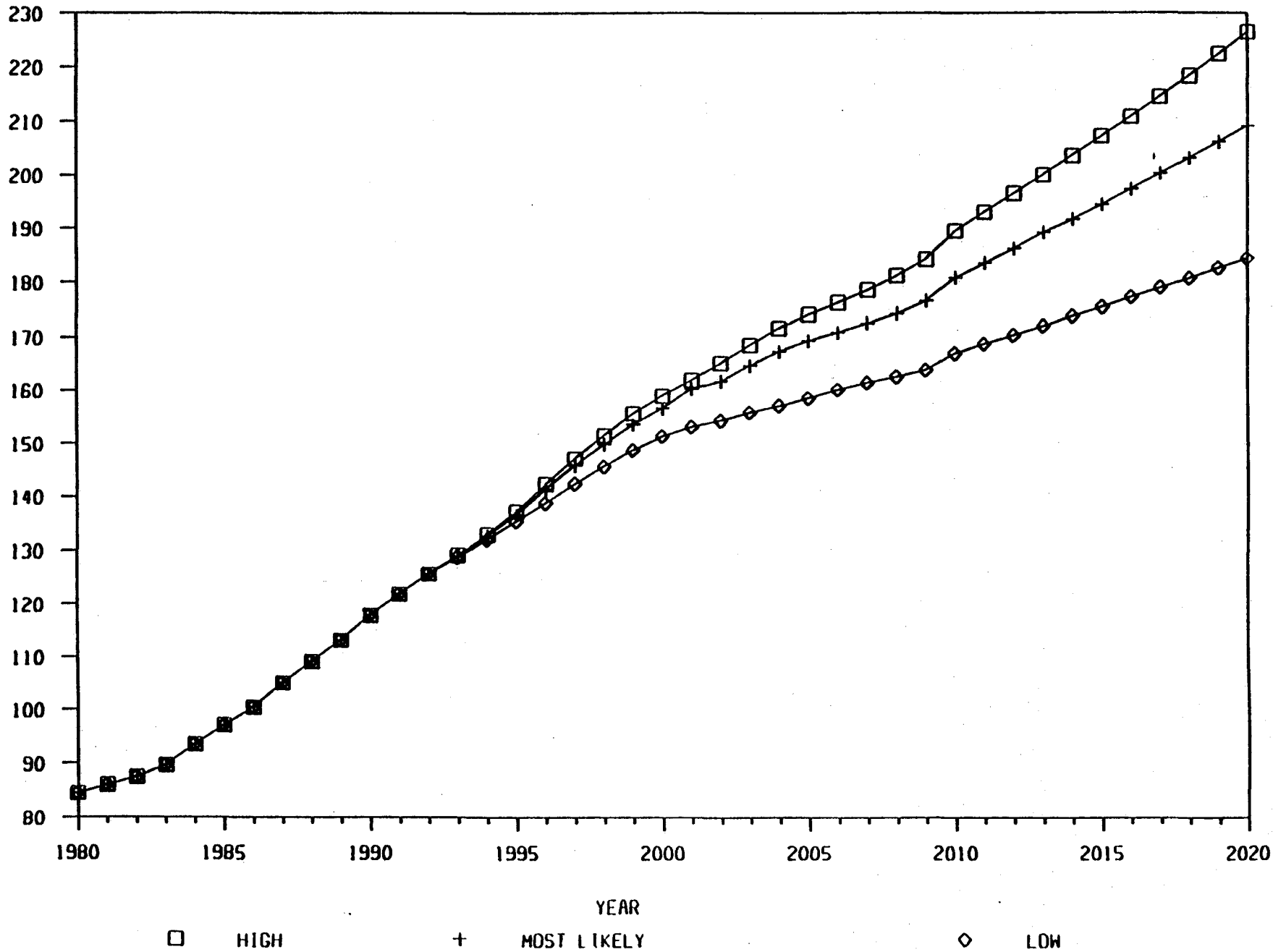
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AVERAGE TOTAL RETAIL CUSTOMERS

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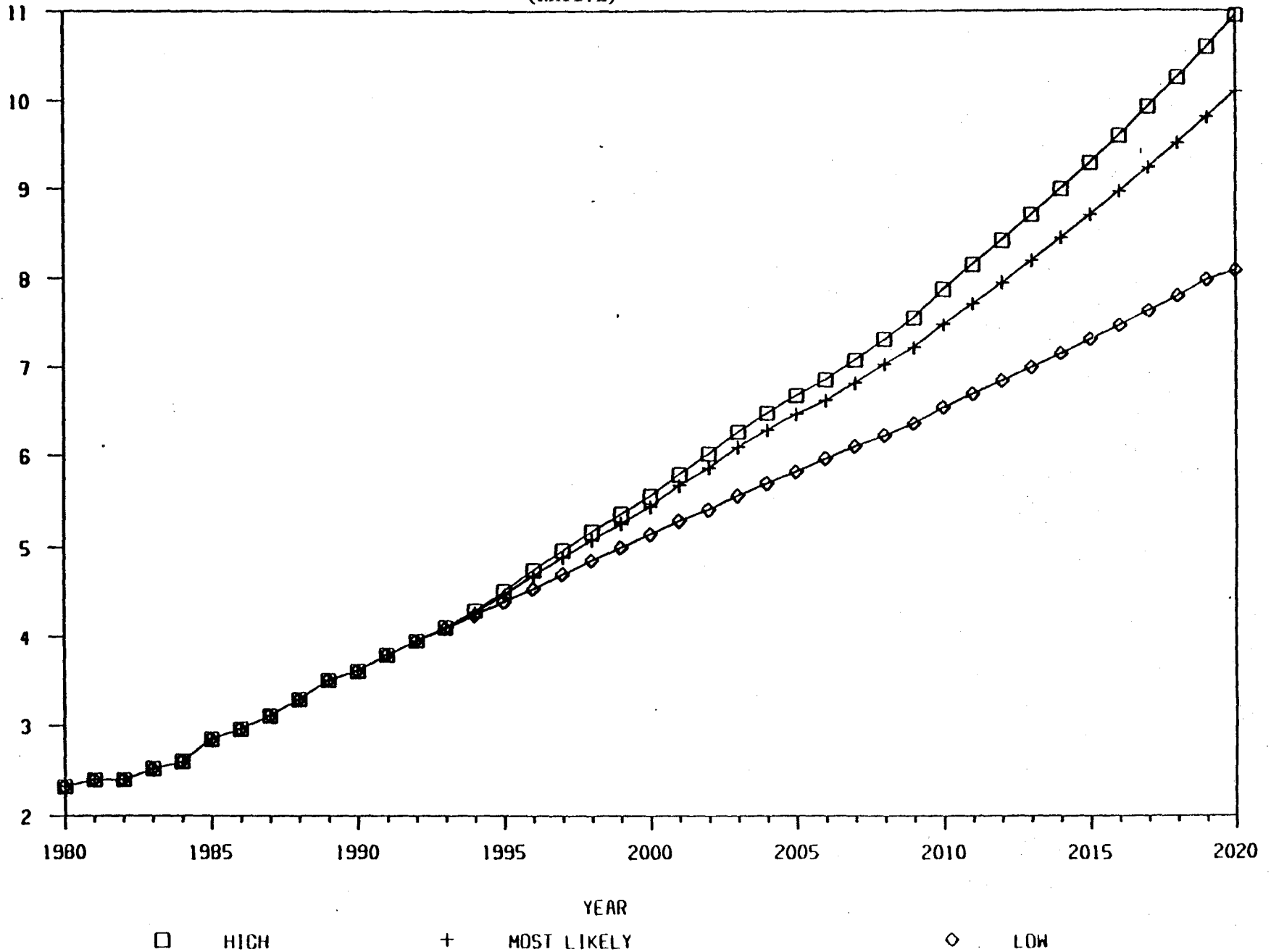
1B.A.12-25

(Thousands)
CUSTOMERS



ORLANDO UTILITIES COMMISSION

NET ENERGY FOR LOAD
(NATIVE)



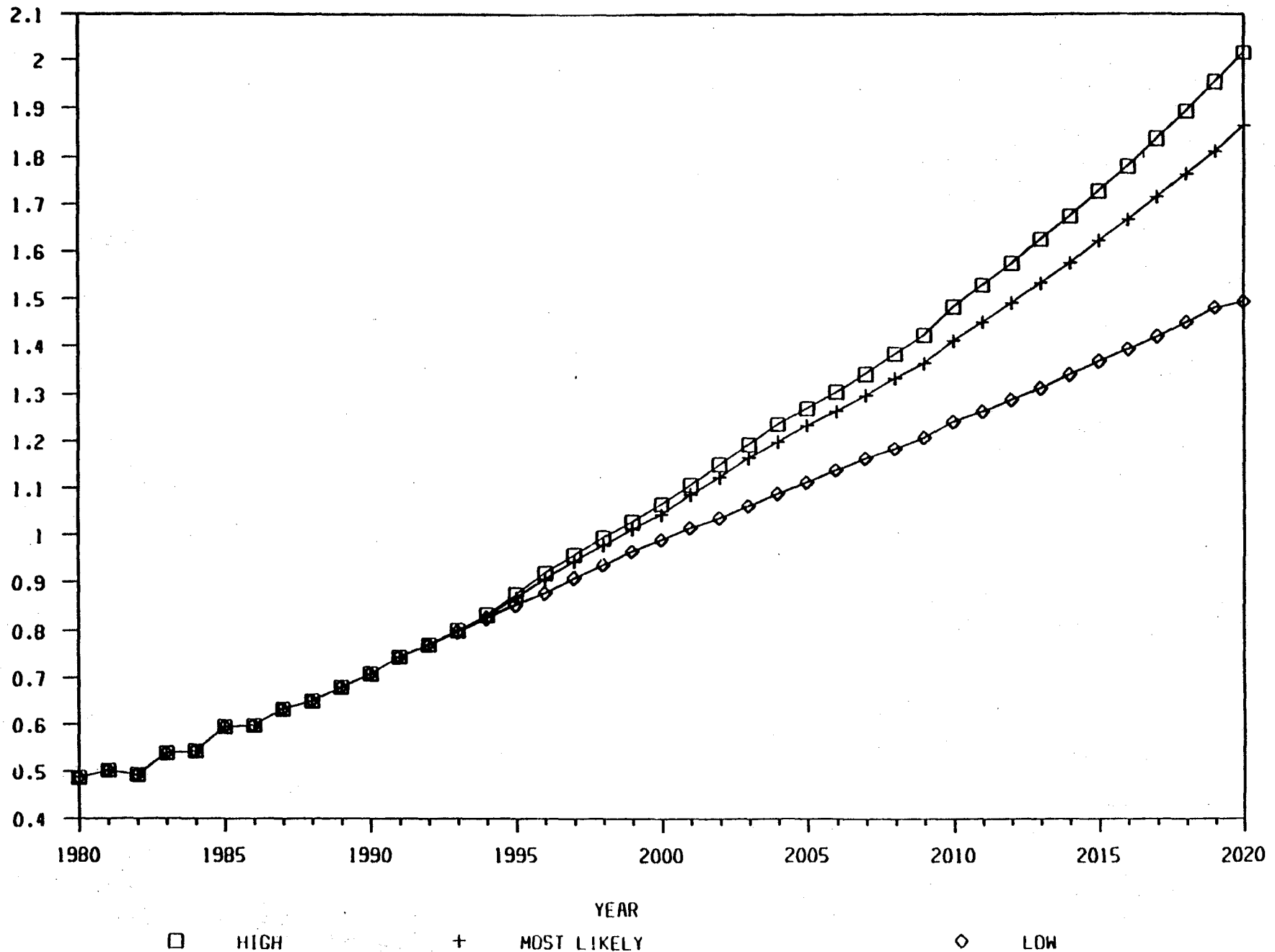
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HMG

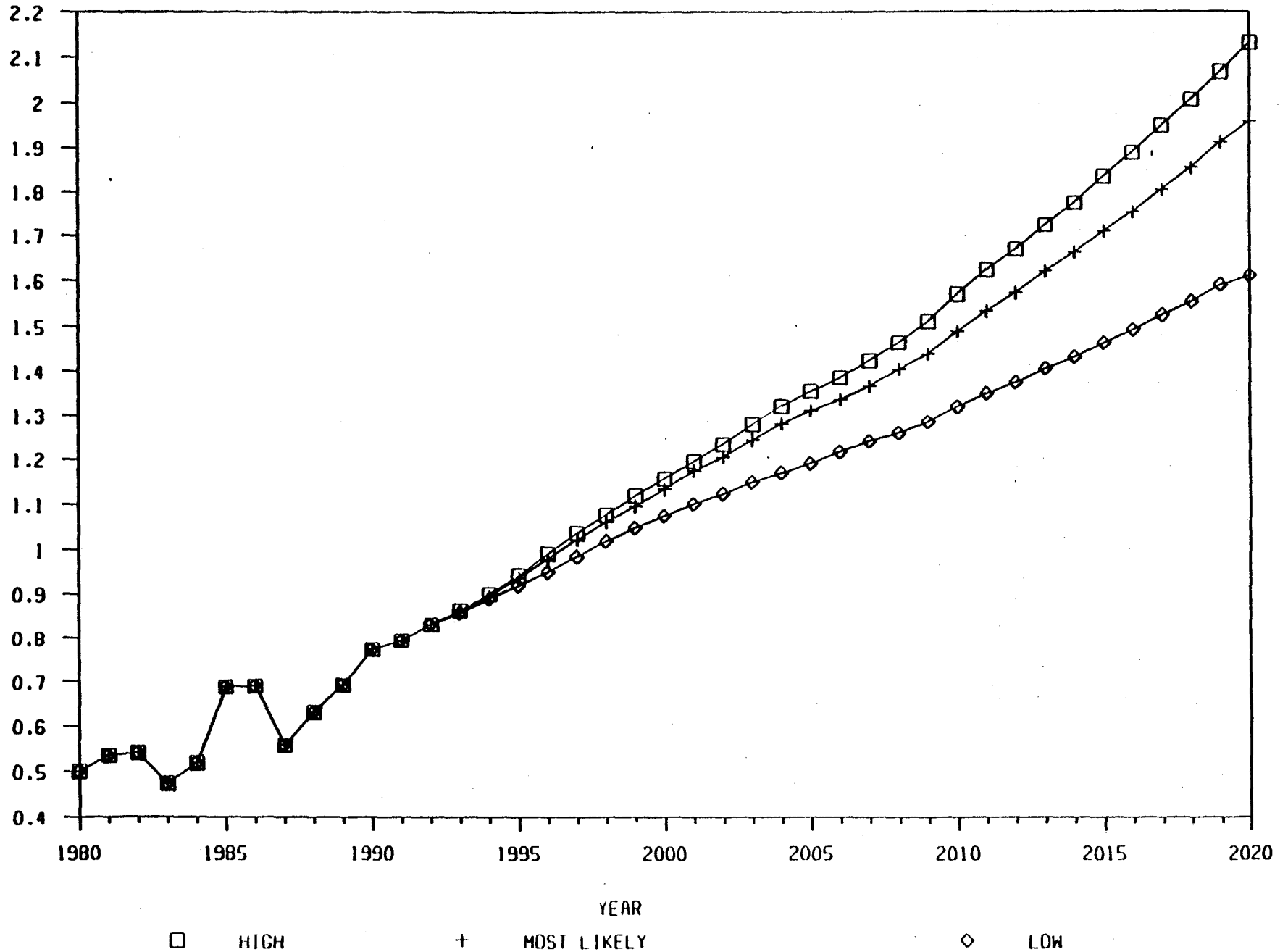
ORLANDO UTILITIES COMMISSION

NET SUMMER PEAK DEMAND
NATIVE



ORLANDO UTILITIES COMMISSION

NET WINTER PEAK DEMAND
NATIVE

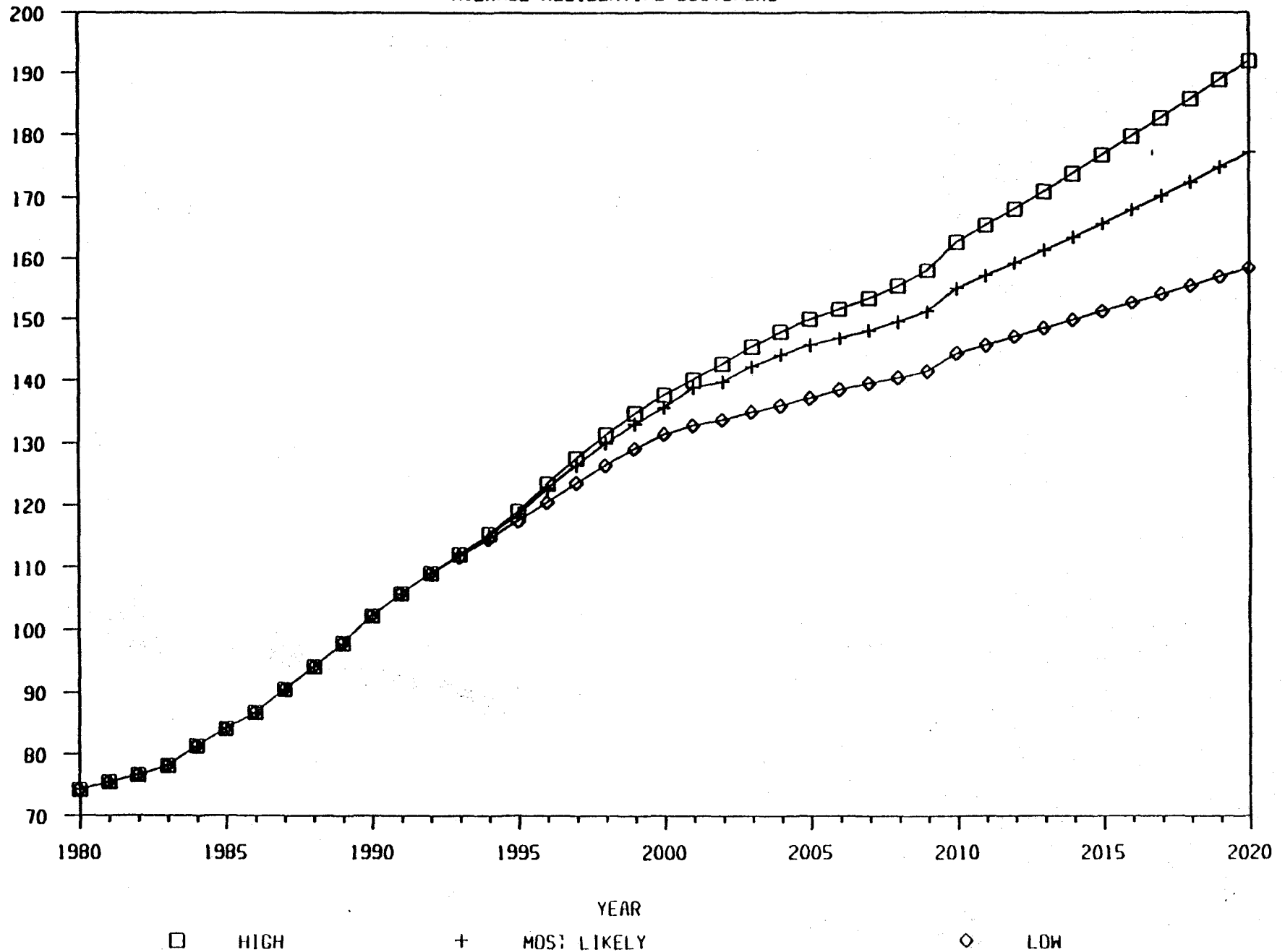


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1B.A.12-28

ORLANDO UTILITIES COMMISSION

AVERAGE RESIDENTIAL CUSTOMERS



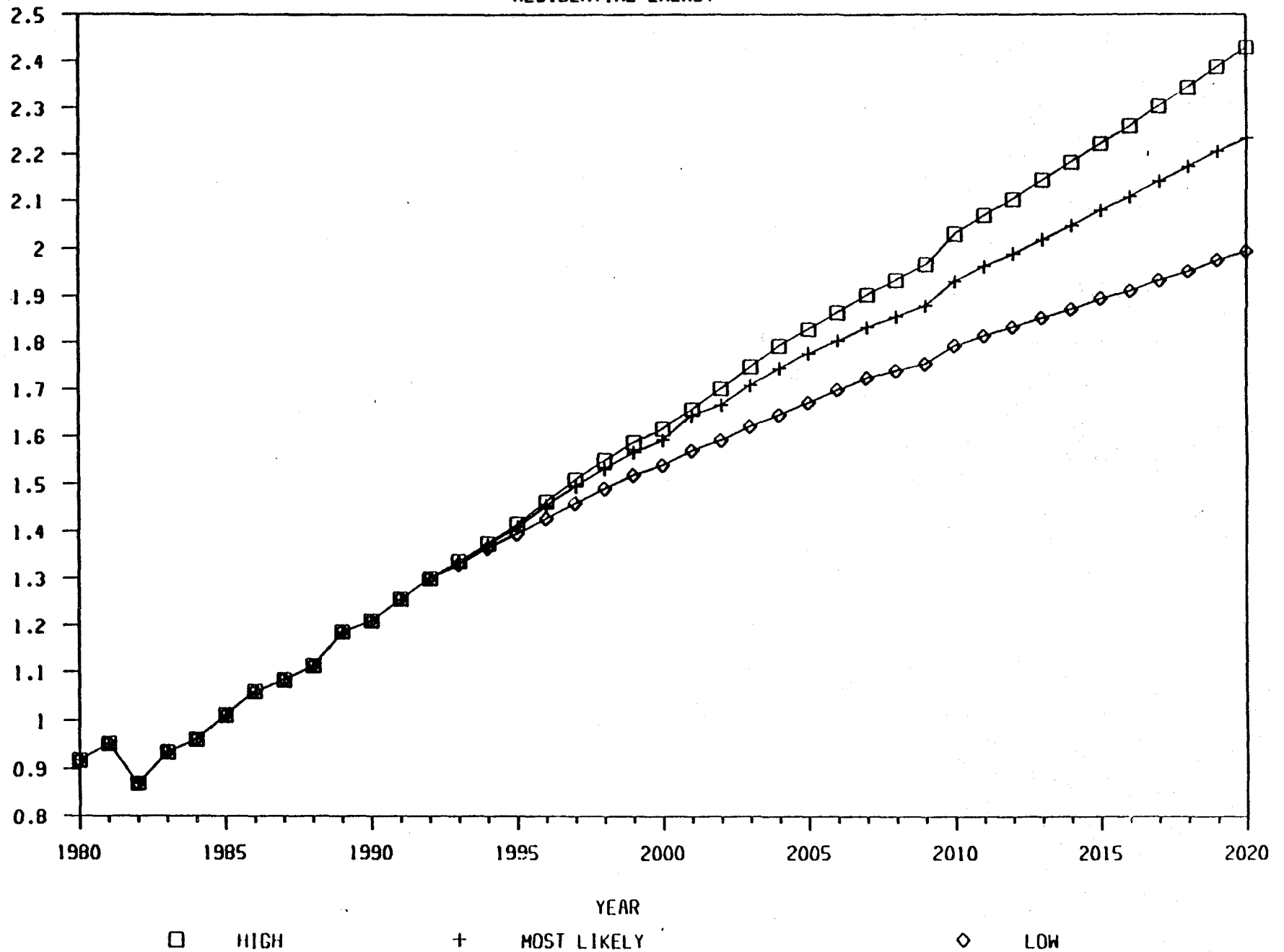
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IB.A.12-29

(spuesnoq)
CUSTOMERS

ORLANDO UTILITIES COMMISSION

RESIDENTIAL ENERGY



031591

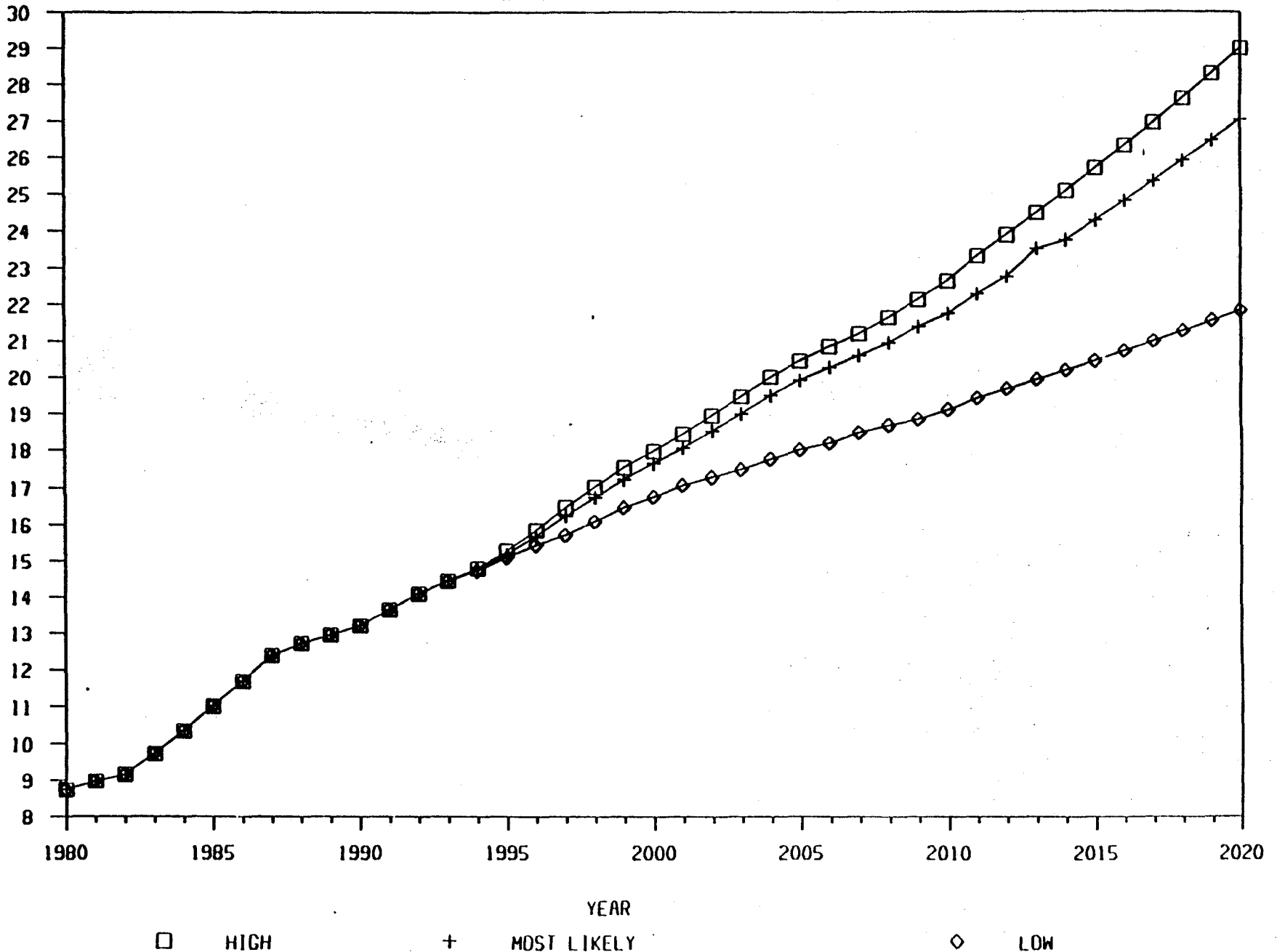
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(Thousands BTUs)

HMC

ORLANDO UTILITIES COMMISSION

AVERAGE GSND CUSTOMERS



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IB.A.12-31
CUSTOMERS
(Thousands)

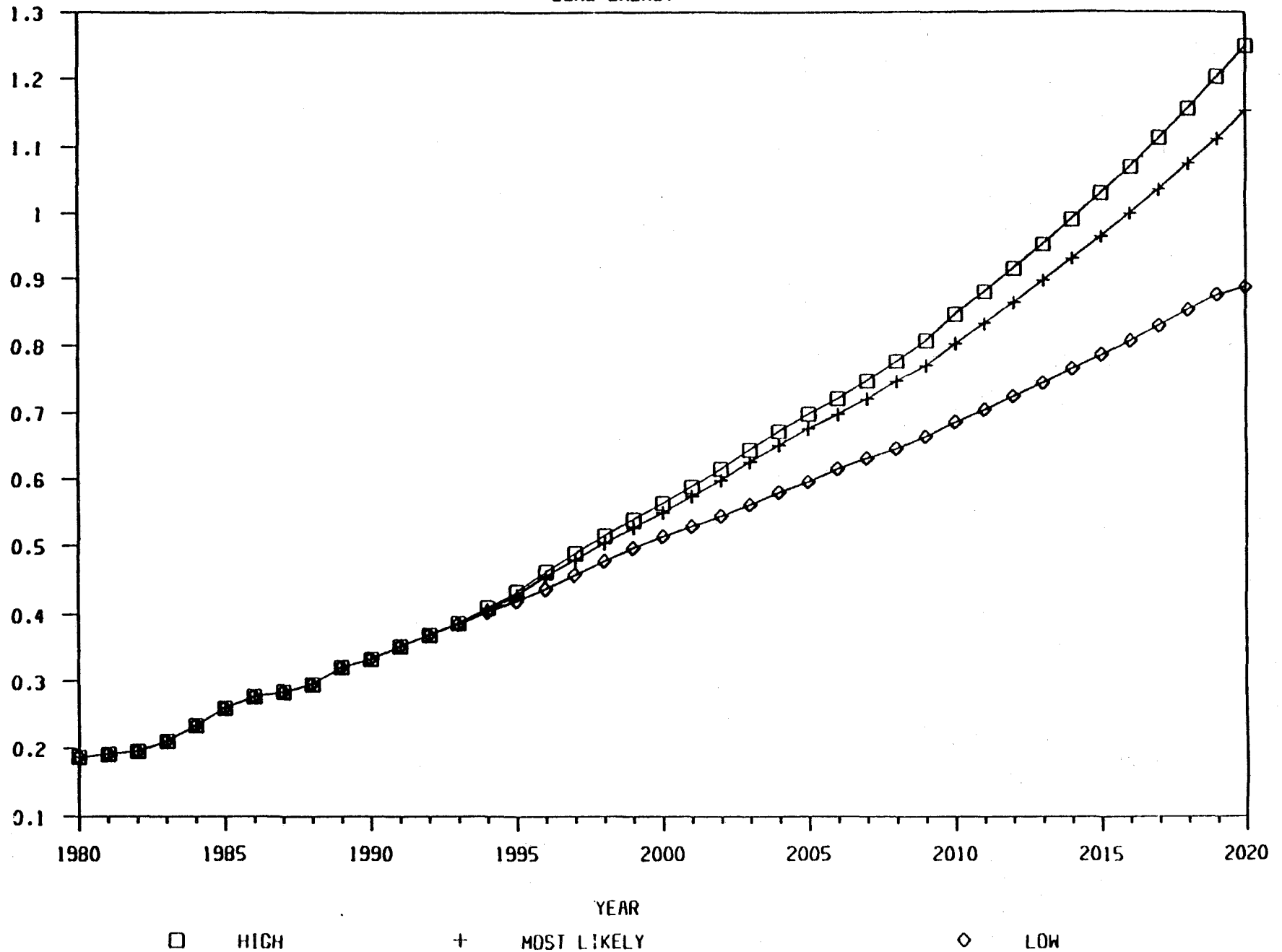
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GSNO ENERGY

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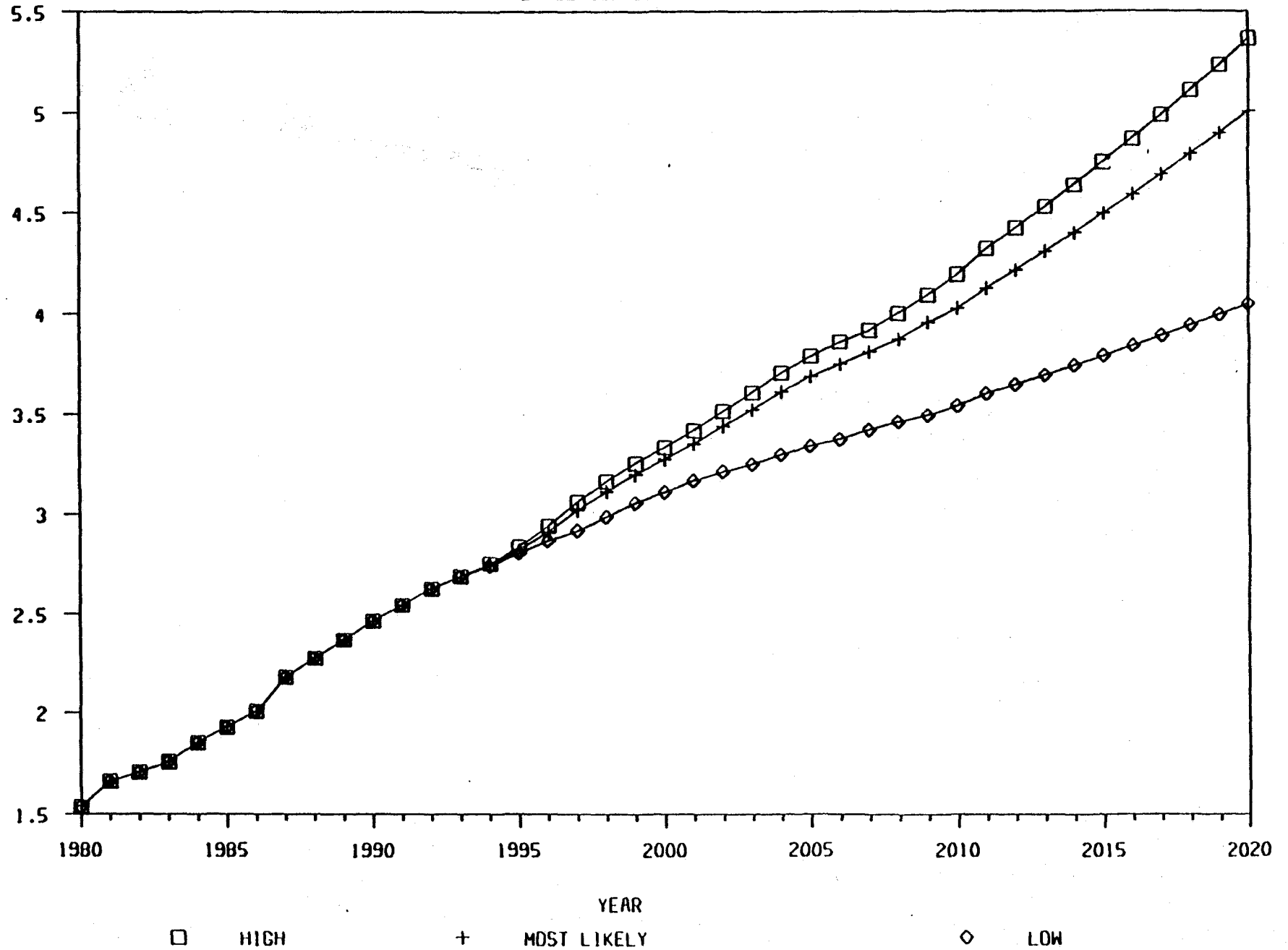
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(Thousands)
MM



ORLANDO UTILITIES COMMISSION

AVERAGE GSD CUSTOMERS



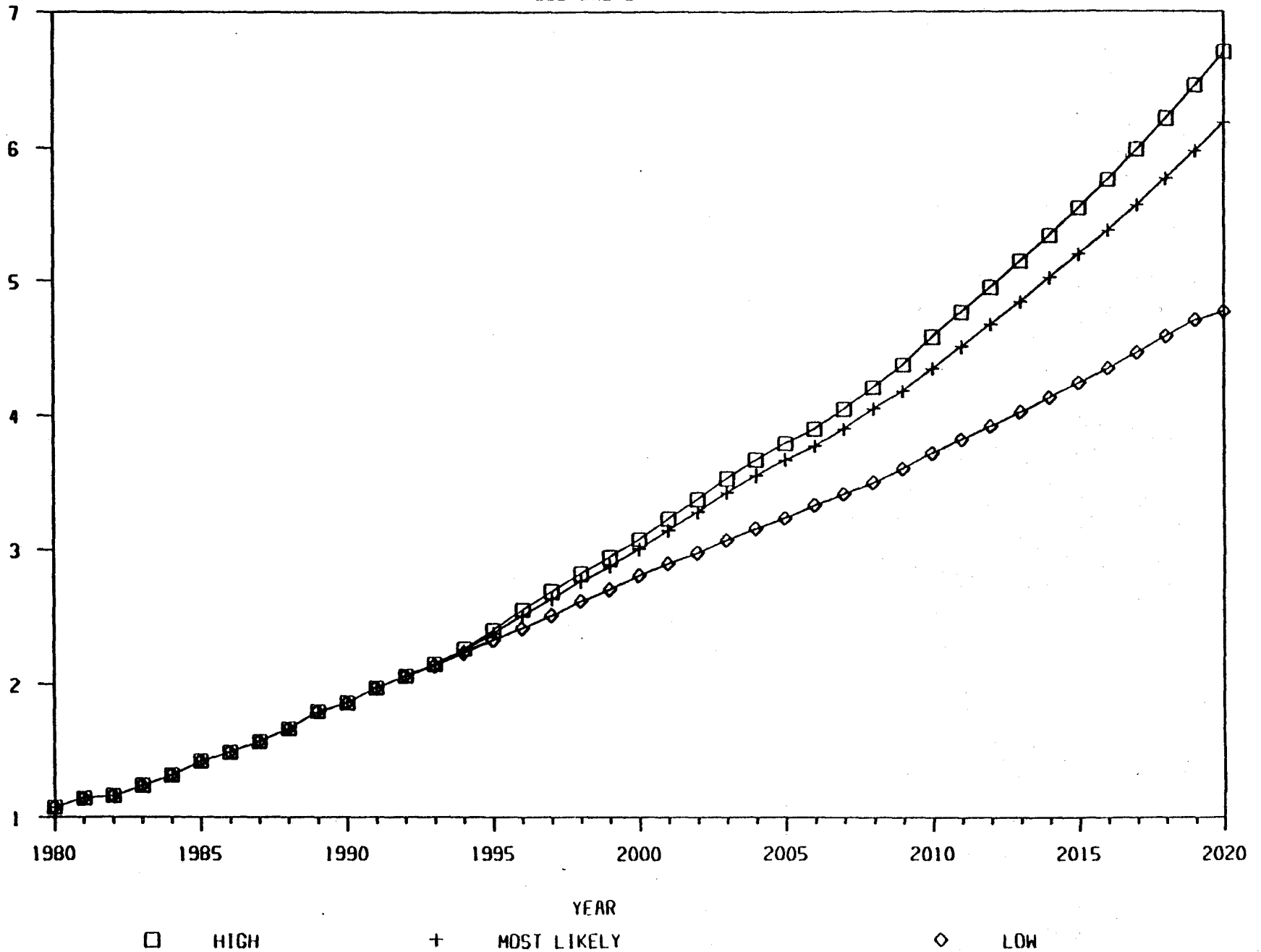
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IB.A.12-33

(Thousands)
CUSTOMERS

ORLANDO UTILITIES COMMISSION

GSD ENERGY



031591

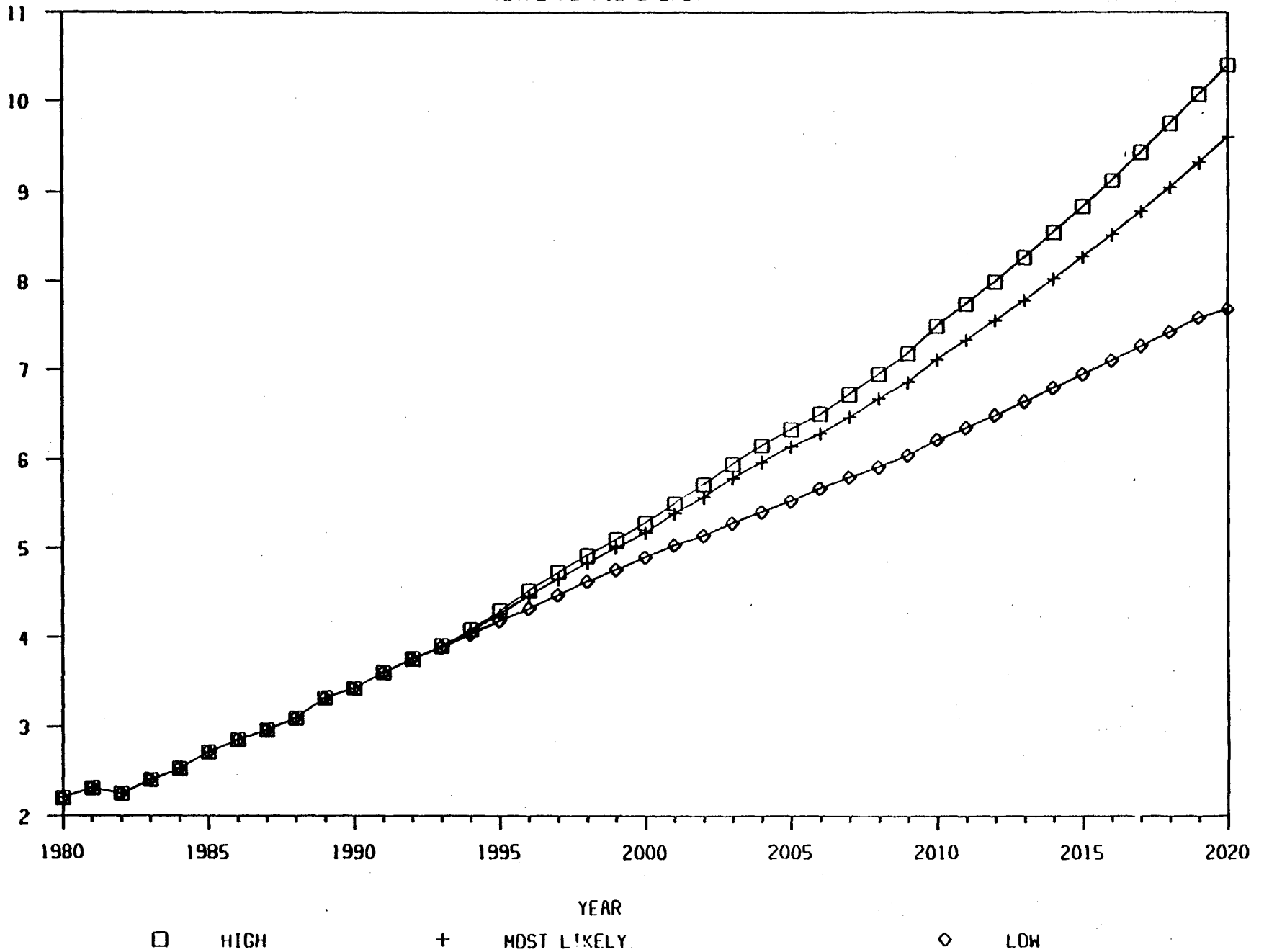
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ORLANDO UTILITIES COMMISSION

TOTAL RETAIL ENERGY



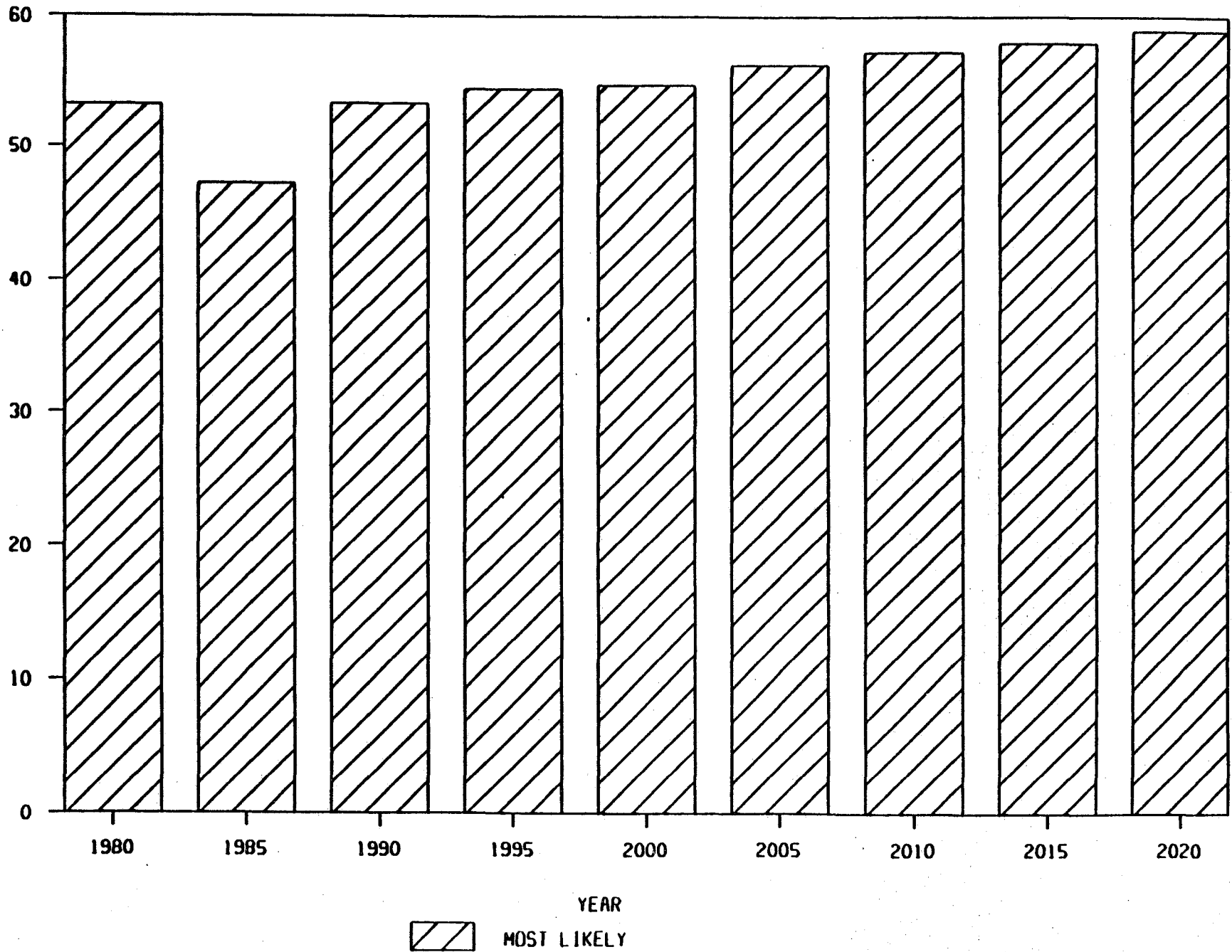
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(spuesnoy)
HMG

ORLANDO UTILITIES COMMISSION

OUR ANNUAL LOAD FACTOR



031591

1B.A.12-36

**ORLANDO UTILITIES
COMMISSION
CURTIS H. STANTON
ENERGY CENTER**

UNIT 2

**SUPPLEMENTAL
SITE
CERTIFICATION
APPLICATION**

VOLUME 1C

ORLANDO UTILITIES COMMISSION

**CURTIS H. STANTON ENERGY CENTER
UNIT 2**

**SUPPLEMENTAL
SITE CERTIFICATION APPLICATION**

VOLUME 1C

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT 2

SUPPLEMENTAL
SITE CERTIFICATION APPLICATION

VOLUME 1C

Stanton Energy Center Unit 2
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**Orlando Utilities Commission
Curtis H. Stanton Energy Center
Unit 2
Supplemental
Site Certification Application
Volume 1C**

1C.1.0 Overview and Summary

1C.1.1 General

The Florida Municipal Power Agency (FMPA or the Agency) was created on February 24, 1978, by the signing of the Interlocal Agreement among its 28 members, which agreement specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution; the Joint Power Act, which constitutes Chapter 361, Part II, as amended; and the Florida Interlocal Cooperation Act of 1969, which begins at Section 163.01 of the Florida Statutes, as amended. The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of joint electric power projects. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

1C.1.2 Organization and Management

Each city commission, utility commission, or authority which is a signatory to the Interlocal Agreement has the right to appoint one member to the Board of Directors of FMPA, the governing body of the Agency. The Board has the responsibility of developing and approving the Agency's budget, hiring a General Manager and establishing bylaws which govern how the Agency operates and policies which implement such bylaws. At its annual meeting, the Board elects a Chairman, a Vice-Chairman, a Secretary-Treasurer, an Assistant Secretary-Treasurer and an Executive Committee. The Executive Committee consists of nine representatives elected by the Board plus the then-current Chairman and Vice-Chairman of the Board. The Executive Committee elects its own chairman and vice-chairman.

The Executive Committee meets regularly to control the Agency's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for assuring that budgeted expenditure levels are not exceeded and that authorized work is completed in a timely manner.

1C.1.3 Agency Projects

FMPA currently has four major power supply projects in operation: (i) the St. Lucie Project; (ii) the Stanton 1 Project; (iii) the Tri-City Project; and (iv) the All-Requirements Project.

On May 12, 1983, the Agency purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the St. Lucie Project), a nuclear generating unit with a summer Seasonal Net Capability of approximately 839 MW and a winter Seasonal Net Capability of approximately 853 MW. St. Lucie Unit No. 2 was declared in commercial operation on August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Sixteen of the Agency's members are participants in the St. Lucie Project.

On August 13, 1984, the Agency purchased from the Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton 1, a coal-fired electric generation unit with a nominally-rated net high dispatch capacity of 415 MW. Stanton 1 went into commercial operation on July 1, 1987.

On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project and the All-Requirements Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton 1 and three of the Agency's members are participants in the Tri-City Project.

Under the All-Requirements Project, the Agency serves all the power requirements (above certain excluded resources) for five of its members through (i) the purchase for an additional 6.5060 percent undivided ownership interest in Stanton 1 from OUC; (ii) capacity and energy from FMPA's 39 percent undivided ownership interest of two 37 MW combustion turbines A and B at the OUC Indian River Plant; (iii) capacity and energy purchases from other utilities including OUC, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), the City of Lake Worth, the City of Gainesville and others; (iv) necessary transmission arrangements; and (v) providing required dispatching services. Service for the five participants in the All-Requirements Project commenced on May 1, 1986. A sixth member of the All-Requirements Project, the City of Clewiston, will be added in 1991.

As described in this volume, FMPA is in the process of forming the Stanton 2 Project, which would include the purchase of a 15.9962 percent ownership share of OUC's Stanton 2 for the FMPA members of Fort Pierce Utilities Authority, the City of Homestead, the Utility Board of the City of Key West, the City of Lake Worth Utilities, the City of Starke, and the City of Vero Beach; and purchasing a 5.1724 percent ownership share of Stanton 2 for the All-Requirements Project.

Shown on Table 1C.1.3-1 is a summary of the participation by the Agency members in the current Agency projects.

Table 1C.1.3-1
Florida Municipal Power Agency

Summary of Project Participation

<u>Agency Member</u>	<u>St. Lucie Project</u>	<u>Stanton 1 Project</u>	<u>Tri-City Project</u>	<u>All Requirements Project</u>
City of Alachua	X			
City of Bartow				
City of Bushnell				X
City of Clewiston*	X			X
City of Fort Meade	X			
Fort Pierce Utilities Authority	X	X	X	
City of Gainesville				
City of Green Cove Springs	X			X
City of Havana				
City of Homestead	X	X	X	
City of Jacksonville Beach	X			X
Utility Board of the City of Key West			X	
Kissimmee Utility Authority	X			
City of Lakeland Electric & Water Utilities				
City of Lake Worth	X	X		
City of Leesburg	X			X
City of Moore Haven	X			
City of Mount Dora				
City of Newberry	X			
Utilities Commission, City of New Smyrna Beach	X			
City of Ocala				X
City of Saint Cloud				
Sebring Utilities Commission	X			
City of Starke	X	X		
City of Tallahassee				
City of Vero Beach	X	X		
City of Wauchula				
City of Williston				

*The City of Clewiston will be added to the All-Requirements Project in 1991.

1C.2.0 System Description

1C.2.1 FMPA Stanton 2 Project System Description

1C.2.1.1 General

The Stanton 2 Project will consist of (i) a 15.9962 percent (66.384 MW) undivided ownership interest in Stanton Unit No. 2, a coal-fired electric generating unit with an estimated net high dispatch limit of 415 MW to be constructed by OUC and purchased by FMPA pursuant to a Participation Agreement, (ii) any Additional Facilities (as defined in a Resolution), and (iii) related contractual arrangements and agreements including arrangements and agreements for the transmission of Electric Capacity and Electric Energy from Stanton 2. For a description of Stanton 2, see Volume 1A. The six FMPA Participants of the Stanton 2 Project are the Fort Pierce Utilities Authority, the City of Homestead, the Utility Board of the City of Key West, the City of Lake Worth, the City of Starke, and the City of Vero Beach. Participation will be through a Power Sales Contract and a Project Support Contract.

1C.2.1.2 Generating System Participants

1C.2.1.2.1 Fort Pierce Utilities Authority. The City of Fort Pierce is located in St. Lucie County on the east coast of Florida approximately 125 miles north of Miami. The Fort Pierce Utilities Authority was established in 1972 for the purpose of governing and operating the City's electric, water, wastewater and natural gas distribution utilities as a separate unit of City government. The City Commission appoints Utility Authority Members to overlapping four-year terms, and each Authority Member is limited to two consecutive terms of office. The Authority employs the Director of Utilities; the current Utilities Director is a registered Professional Engineer with a Master of Business Administration Degree and over 20 years experience in the engineering, operations and management aspects of the electric utility industry. As a matter of operating policy, revenue financing for the Authority combines the resources of all utility operations; thus these utility services are integrated for purposes of the Power Sales Contract and Project Support Contract.

The Fort Pierce Utilities Authority owns and operates electric generating facilities capable of supplying all of its system requirements. The existing on-

system capacity, which amounts to 119 MW (excluding units on extended cold standby), is primarily fueled by natural gas (99.85 percent) pursuant to a contract with Florida Gas Transmission Company (FGT). A new 15-year contract was signed with FGT in the fall of 1989, subject to the right of termination by either party, as provided in such contract. The Authority has the ability to convert on an annual basis 20 percent of their purchases from a direct sales contract, where all gas purchases are made by FGT, to a transportation contract, where the Authority may purchase gas from other companies to be transported by FGT. The operating boilers are capable of burning No. 6 oil as an alternate fuel. Additionally, the Authority has the right to receive up to 11.217 MW from FMPA's St. Lucie Project, consisting of 10.24 MW under the terms of its St. Lucie Project Power Sales Contract and Project Support Contract with the Agency and 0.977 MW under the terms of an agreement with the Sebring Utilities Commission. The Fort Pierce Utilities Authority is a participant in FMPA's Stanton Project and has the right to receive up to approximately 15 MW from Stanton 1 under the terms of the Stanton Project Power Sales Contract and Project Support Contract. The Authority is also a Participant in FMPA's Tri-City Project and has the right to receive approximately 5 MW from Stanton 1 under the terms of the Tri-City Project Power Sales Contract and Project Support Contract. The Authority also acquires a portion of its power supply needs under the terms of a partial requirements contract with FPL. The Authority's 69 kV transmission system includes interconnection with FPL and the City of Vero Beach, and completely loops the service area. Five major substations supply voltage at 13 kV to a predominantly overhead distribution system.

The Authority's electric utility service area encompasses approximately 18 square miles with 80 percent of electric utility customers residing within City limits. Both the Authority and FPL, its only neighboring utility, serve customers outside the City limits on a competitive basis with no territorial agreement. The Authority and FPL are currently involved in a territorial dispute before the Florida Public Service Commission. The primary area in dispute is outside the corporate limits of the City. The thrust of the suit is not to disturb the existing customer base of the City, but to avoid future uneconomic duplication of distribution facilities. The Authority and FPL have tentatively agreed to a resolution of the territorial dispute, subject to final negotiations of an agreement, together with approval by the Florida Public Service Commission.

1C.2.1.2.2 City of Homestead. The City of Homestead is located 30 miles south of Miami in Dade County. The City was incorporated in 1913, and has a Mayor/Councilmen/City Manager form of government. The City operates and maintains electric, water and sewer utility operations. As a matter of operating policy, electric and water revenue financing is accomplished separately from financing related to other utility operations and these two utility services are integrated for purposes of the Power Sales Contract and Project Support Contract.

The City of Homestead owns and operates one of the largest diesel electric generating facilities in the United States and is capable of supplying all its system requirements. Existing on-system capacity amounts to 39.7 MW (excluding Ivey Units 18 and 19), fueled primarily by gas (94 percent) pursuant to a contract with FGT. The City of Homestead, in the fall of 1989, signed contracts with FGT for transportation of gas under Preferred Transportation and Firm Transportation Agreements. The Preferred Transportation Agreement is for a term of 5 years with the option for a second 5-year term. The Firm Transportation Agreement is for a term of 10 years. The Preferred Interruptable Service for Direct Sale agreement dated January 1, 1986 is still in effect until Homestead converts the sales service to transportation, at which time the Sales agreement terminates. In addition to its existing on-system generating capacity, the City has the right to receive up to 6.10 MW from FMPA's St. Lucie Project under the terms of its St. Lucie Project Power Sales Contract and Project Support Contract with the Agency, up to approximately 15 MW from FMPA's Stanton Project under the terms of its Stanton Project Power Sales Contract and Project Support Contract and up to approximately 5 MW from FMPA's Tri-City Project under the terms of its Tri-City Project Power Sales Contract and Project Support Contract. As a matter of economic operating procedure, the City commonly acquires a portion of its power supply needs under the terms of a partial requirements contract with FPL. The City's 138 kV transmission system interconnects with FPL. Two substations supply 13 kV to a predominantly overhead distribution system.

The City's electric utility service area encompasses approximately 13.6 square miles, with 71 percent of customers residing within the City limits. The City is a party to a territorial agreement with FPL, its only neighboring utility, which has been approved by the Florida Public Service Commission.

1C.2.1.2.3 Utility Board of the City of Key West. The City of Key West was first incorporated in 1828 and is the county seat of Monroe County, Florida. It

is located near the southern extreme of the Florida keys, a string of coral islands extending in a southwesterly arc from Biscayne Bay to the Dry Tortugas, and lies further south than any other point in the continental United States. The Utility Board of the City of Key West operates the municipally owned electric generating and distribution system of the City. The Utility Board is composed of a chairman who is elected for a term of two years and four members who are elected for a term of four years by the voters of the City of Key West. The Utility Board employs the Manager of the Electric System; the current manager was employed by the electric system from 1961 until his appointment as manager in 1983.

The Utility Board operates and maintains the on-system electric generating facilities of the electric system which consist of oil-fired steam turbine generating units, diesel generating units and one combustion turbine generating unit, with a total capacity of 81.5 MW (excluding units on extended cold standby). Two new diesel units with a net continuous capacity of 8,800 kW each will be operative in 1991. The Utility Board receives approximately 12 MW from its participation in FMPA's Tri-City Project and purchases short-term power from FPL.

The electric system currently uses No. 2 and No. 6 fuel oil for all of its on-system generation facilities. The generating units of the System are not capable of using alternative fuels. The Utility Board has a contract with Belcher Oil Company of Port Everglades, Florida for the supply of all its fuel oil requirements for its generating plants. The contract permits the Utility Board to purchase fuel oil on the spot market, provided Belcher is given notice of such proposed purchase and an opportunity to meet the price of the spot market fuel oil.

The 69 kV transmission system is the primary transmission network for the system, providing ties between the major 69/13.8 kV substation of the system and the system's Key West and Stock Island power plants. In May 1987, the Utility Board completed the upgrading of its transmission lines and added a new 44-mile long, 138 kV transmission line to allow interconnection between the system at the Stock Island Substation and the Florida Keys Electric Cooperative (FKEC) at its Marathon Substation. Prior to the time of the interconnection in May 1987, the system was isolated from other electric systems in the Keys and in mainland Florida. The 138 kV tie line extends up the Causeway through FKEC's service territory and ties in with FPL on the mainland. The Utility Board's operation of the 138 kV line extends from Marathon Key, in the FKEC service territory, to the Stock Island (U.S.1) Substation.

At the present time there are a total of six 13.8/4.16 kV substations feeding approximately 92 miles of 4.16 kV three-phase lines and approximately 232 miles of 13.8 kV three-phase lines. In an effort to reduce system losses, the Utility Board has an ongoing program to convert all of its 4.16 kV distribution lines to 13.8 kV lines.

The Utility Board's service area consists of approximately 74 square miles of the lower Florida Keys, extending approximately 30 miles in an east-west direction from Pigeon Key, adjacent to the service area of Florida Keys Electric Cooperative Association, Inc., to the City of Key West. Within its area the electric system currently services the area between Ohio Key and the City of Key West. Approximately 50 percent of the Utility Board's customers and approximately 65 percent of the Utility Board's sales are within the City of Key West.

1C.2.1.2.4 City of Lake Worth. The City of Lake Worth is located in Palm Beach County on the east coast of Florida, 7 miles south of West Palm Beach and 61 miles north of Miami. The City was incorporated in 1913 and has been supplying electric power to the area since 1916. The City of Lake Worth assumed the operation of and all obligations for the electric, water and wastewater utilities in 1985 through state of Florida legislative action. As a matter of operating policy, electric and water revenue financing is accomplished separately from financing related to other utility operations and the electric and water utility services are integrated for purposes of the Power Sales Contract and Project Support Contract.

Lake Worth owns on-system electric generating facilities capable of supplying all of its system requirements. The existing on-system capacity amounts to 89.8 MW (excluding units on extended cold standby), primarily fueled by natural gas (98 percent). Lake Worth purchases gas pursuant to a contract for interruptible gas service with Florida Public Utilities Company. Lake Worth receives up to 18.347 MW from FMPA's St. Lucie Project under the terms of its St. Lucie Project Power Sales Contract and Project Support Contract with the Agency and up to approximately 10 MW from FMPA's Stanton Project under the terms of its Stanton 1 Project Power Sales Contract and Project Support Contract. Lake Worth is interconnected with the transmission facilities of FPL and, through them, to the State transmission grid. Five 26 kV transmission lines presently serve nine 26/4 kV distribution substations; however, the distribution system in the western portion of the service area has been upgraded to 26 kV concurrent with the

transmission system improvement program and is served by a 138/26 kV substation. While the distribution system is predominantly overhead, new installations, serving platted developments, are installed underground.

1C.2.1.2.5 City of Starke. The City of Starke, the county seat of Bradford County, is located in northeast Florida, approximately 50 miles southwest of the City of Jacksonville. The City, established in 1875, operates under the Mayor/Commissioner form of government. The City operates and maintains electric, water, sewer and gas distribution utilities. An elected city clerk serves as the City's chief administrative officer, and utility operations are under the supervision of an appointed Electric System Director. The present Electric System Director has been employed in that capacity for approximately four years. As a matter of policy, revenue financing combines the revenues of all utility operations; thus utility services are integrated for purposes of the Power Sales Contract and Project Support Contract.

The City of Starke owns and operates electric generating facilities. The existing on-system capacity amounts to 6.9 MW, primarily fueled by natural gas pursuant to a contract with FGT. A new 15-year contract was signed with FGT in the fall of 1989, subject to the right of termination by either party, as provided in such contract. The City of Starke has the ability to convert on an annual basis 20 percent of their purchases from a direct sales contract, where all gas purchases are made from FGT, to a transportation contract, when the City may purchase gas from other companies to be transported by FGT. Additionally, the City receives up to 1.634 MW from FMPA's St. Lucie Project under the terms of its St. Lucie Project Power Sales Contract and Project Support Contract with the Agency and up to approximately 1.5 MW from FMPA's Stanton 1 Project under the terms of its Stanton Project Power Sales Contract and Project Support Contract. In order to meet its total electric system requirements, in addition to its own electric generating facilities, the City commonly acquires a portion of its power supply needs under the terms of a partial requirements contract with FPL and from wholesale purchases from the City of Gainesville. The City has one 69 kV interconnection with FPL and one substation reduces this voltage to 4 kV for predominantly overhead delivery to electric system customers.

1C.2.1.2.6 City of Vero Beach. The City of Vero Beach, the county seat of Indian River County, is located on the east coast of Florida midway between Miami and Jacksonville. The City was incorporated in 1919 and established a

City Council/City Manager organization in 1951. The City Manager also serves as the Director of Utilities. While the City owns and operates electric, water and sewer utilities, electric revenue financing is, as a matter of operating policy, accomplished separately from financing related to other utility operations. Only electric utility system revenues are available to make payments required under the City's Power Sales Contract and Project Support Contract.

The City of Vero Beach owns and operates on-system electric generating facilities capable of supplying all of its system requirements. The existing on-system capacity amounts to 116 MW (excluding units on extended cold standby) of oil and gas fired units predominantly fueled by natural gas. The City has paid FGT to expand the fuel gas pipeline to allow the City's existing capacity to be totally gas fired. Natural gas is currently supplied pursuant to a contract with FGT. A new 15-year contract was signed with FGT in the fall of 1989, subject to the right of termination by either party, as provided in such contract. The City of Vero Beach has the ability to convert on an annual basis 20 percent of its purchases from a direct sales contract, where all gas purchases are made from FGT, to a transportation contract, where the City may purchase gas from other companies to be transported by FGT. In addition to its existing on-system generating capacity, the City has the right to receive up to 11.214 MW of nuclear power under the terms of its St. Lucie Project Power Sales Contract and Project Support Contract with the Agency. Vero Beach is also a participant in FMPA's Stanton 1 Project and has the right to receive up to approximately 20 MW of coal-fired power from Stanton 1 under the terms of the Stanton 1 Project Power Sales Contract and Project Support Contract. The City acquires a portion of its energy needs under the terms of a partial requirements contract with FPL. The City's 69 kV transmission system includes interconnections with FPL and the Fort Pierce Utilities Authority. The transmission system completely loops the service area, enhancing service reliability. Eight substations supply voltage at 13 kV to a predominantly overhead distribution system.

1C.2.1.3 Transmission Arrangements

Electric capacity and electric energy from the Stanton 2 Project will be transmitted to the Participants utilizing the transmission systems of OUC and FPL. Although specific contracts for transmission services, including provisions for pricing and conditions of service, have not yet been negotiated or executed with

OUC and FPL, respectively, both systems have advised the Agency that they are willing to provide such services subject to reaching agreement with FMPPA as to the terms and conditions of such services.

1C.2.2 FMPA All-Requirements Project System Description

1C.2.2.1 General

FMPA's All-Requirements Project provides (i) each Participant's power supply requirements above Excluded Power Supply Resources and Backup and Support Services (each as defined in the All-Requirements Power Supply Contract), if any, under All-Requirements Services, and (ii) reserves, losses, firming capacity, backup energy, and certain associated transmission and dispatching services required for Excluded Power Supply Resources under Back-up and Support Services. In addition, costs for all these services are developed by FMPA for the combined West (FPC) Cities (the Cities of Bushnell, Leesburg and Ocala) and for the combined East (FPL) Cities (the Cities of Green Cove Springs, Jacksonville Beach, and Clewiston to be added in 1991) separately, based upon the costs associated with providing the services to each group of cities.

1C.2.2.2 Generating Resources

In order to meet its long-term power supply responsibilities to the Participants in the All-Requirements Project, FMPA's All-Requirements Project facilities and arrangements currently include (i) capacity and energy from FMPA's 6.506 percent undivided ownership interest in Stanton 1 (27 MW at the estimated net continuous capability of 415 MW); (ii) capacity and energy from FMPA's 39 percent undivided ownership interest in two 37 MW combustion turbines A and B at the OUC Indian River Plant; (iii) purchased capacity from OUC's Indian River Plant and associated energy from its Indian River Plant or, under certain circumstances, from any of its other generating resources; (iv) purchased capacity and associated energy from the City of Gainesville's Deerhaven 2 coal-fired generating unit, (v) purchased capacity and associated energy from Tampa Electric Company's slow speed diesel generating units located at the James H. Phillips Generating Plant; (vi) wholesale partial requirements capacity and energy purchases from FPC and FPL; (vii) capacity and energy purchases from Lake Worth; (viii) capacity and energy from FMPA's 21 percent undivided ownership of Indian River Combustion Turbines C and D rated 129 MW each, which are scheduled for completion in late 1992; (ix) transmission services from FPC, FPL and OUC; (x) interchange agreements with generating utilities in Florida; (xi)

dispatching services provided by OUC; and (xii) other dispatch-related equipment and services.

The All-Requirements Project will also include capacity and energy from a 5.1724 percent (21.466 MW) undivided ownership interest in Stanton 2.

1C.2.2.3 All-Requirements Project Participants

1C.2.2.3.1 City of Bushnell. Bushnell, "Seat of Sumter County," is located in west central Florida, 55 miles from Orlando and 50 miles north of Tampa. The City operates under a Council-Manager form of government. Bushnell owns and operates its own electric and water system, the revenues from which are combined for financing purposes; thus, these utility services are integrated for purposes of the All-Requirements Power Supply Contract.

The City of Bushnell has entered into an All-Requirements Project Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Energy is delivered through a delivery point in the City at 12 kV. Excluded Power Supply Resources for the City of Bushnell include only its partial ownership in FPC's Crystal River 3 nuclear unit, being 0.0388 percent of that unit (or 306 kW based on current net summer rating).

The City of Bushnell's electric utility service area covers approximately 3 square miles and 92 percent of the customers served reside within the City limits.

1C.2.2.3.2 City of Clewiston. The City of Clewiston is located in Hendry County on the southwest tip of Lake Okeechobee, midway between West Palm Beach on the east and Fort Myers on the west. Clewiston is the headquarters of the United States Sugar Corporation. The City was incorporated in 1925, and has a City Council/City Manager form of government. The City operates and maintains electric, water and sewer utilities. As a matter of operating policy, electric revenue financing is accomplished separately from financing related to other utility operation; thus, only electric utility system revenues are pledged for the purposes of the Power Supply and Project Support Contracts.

The City of Clewiston purchased the electric system in May 1942 from U.S. Sugar Corporation. At the present there are more than 3,500 electric meters in service. Clewiston presently buys power from FPL for resale to its customers on an all-requirements contract. The City of Clewiston will be added to the All-Requirements Project in 1991 and will be purchasing full requirements from the

Agency. Excluded Resources include only its entitlement share in the Agency's St. Lucie Project (approximately 1.6 MW). The City's 138 kV transmission system interconnects with FPL. One substation supplies voltage at 12 kV to a predominantly overhead distribution system.

The City's electric utility service area encompasses approximately 8.5 square miles with 70 percent of the customers served residing within City limits. The City has a territorial agreement with FPL.

1C.2.2.3.3 City of Green Cove Springs. The City of Green Cove Springs is located on the St. John's River in Clay County, 26 miles south of Jacksonville. The City operates and maintains the electric, water and sewer utilities. As a matter of operating policy, revenue financing combines the resources of all utility operations; thus, these utility services are integrated for purposes of the All-Requirements Power Supply Contract. The City operates under the City Council/Manager form of government. The five-member City Council is elected at large and appoints the City Manager, who serves as the City's chief administrative officer and directs the operation of the City's utility service.

The City has entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Green Cove Springs include only its entitlement share in the Agency's St. Lucie Project (approximately 1,296 kW). In March 1982, the City placed into operation its 240 kV substation which interconnects with FPL's transmission grid. Presently, the substation reduces voltage to 23 kV which is delivered to the City limits via two circuits. Either of these lines, on the east and west sides of the City, is capable of supplying all of the 4 kV distribution system requirements.

The City's electric utility service area encompasses approximately 10 square miles with nearly all residential customers residing within the City limits.

1C.2.2.3.4 City of Jacksonville Beach. The City of Jacksonville Beach is located in the northeast corner of Florida, approximately 18 miles east of Jacksonville. The City operates under the City Council/City Manager form of government. The City operates and maintains electric, water and wastewater utility operations. As a matter of policy, revenue financing combines the resources of all utility operations; thus, these utility services are integrated for purposes of the All-Requirements Power Supply Contract. As the Chief Administrative Officer, the City Manager appoints the Directors for Electric and Water

Utilities. The incumbent Director of Electric Utilities has 26 years of utility experience and has served in his present capacity since 1972.

The City of Jacksonville Beach has entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Jacksonville Beach include only its entitlement share in the Agency's St. Lucie Project (approximately 5,406 kW). Jacksonville Beach owns and operates its electric distribution system consisting of 10 substations, which delivers energy at 26, 12 and 4 kV levels. Approximately 25 percent of the distribution circuits are underground installations.

The City of Jacksonville Beach electric utility service area encompasses approximately 30 square miles including the neighboring town of Neptune Beach, and the unincorporated areas of Ponte Vedra and Palm Valley located in St. Johns County. Portions of this territory have been assigned to the City by the Florida PSC. Fifty-four percent of the customers served reside within City limits.

1C.2.2.3.5 City of Leesburg. The City of Leesburg is located in Lake County, 41 miles north of Orlando and 36 miles south of Ocala. The City operates under a Commission/Manager form of government. The five-member City Commission is elected at large and employs the City Manager, who serves as the City's chief administrative officer. The City operates and maintains electric, water, sewer and natural gas distribution utilities. As a matter of operating policy, revenue financing combines the resources for all utility operations. Each of the City's utility operations is supervised by a Director. The Director of the Electric Department has more than 32 years utility experience and has held his present position since 1974.

The City of Leesburg has entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Leesburg include its partial ownership interest in FPC's Crystal River 3 nuclear unit, being 0.8244 percent of that unit (or 6,496 kW based on current net summer rating), and its entitlement in the Agency's St. Lucie Project (approximately 1,716 kW). The City owns four substations which convert the 69 kV voltage delivered by FPC down to the system distribution voltage of 13 kV. These substations and their attendant transmission systems completely loop the service area and assure dependable system operation. The City-owned distribution

system delivers all the system energy at the 13 kV level. Approximately 15 percent of electric service is provided in underground circuits.

The City's electric utility service area includes the incorporated cities of Leesburg and Fruitland Park and encompasses approximately 59 square miles with 40 percent of the customers served residing within the 23.5 square mile City limits of Leesburg. The City has received Florida PSC approval of a territorial agreement with FPC and is currently negotiating a territorial agreement with the local electric cooperative.

1C.2.2.3.6 City of Ocala. The City of Ocala is located in Marion County near the geographic center of the state of Florida, approximately 35 miles south of Gainesville and 75 miles north of Orlando. The City operates under the City Council/City Manager form of government. The City operates and maintains electric, water and wastewater utility operations. As the Chief Administrative Officer, the City Manager appoints the Directors of Electric and Water Utilities. The incumbent Director of Electric Utilities has 33 years utility experience and has served in his present capacity since 1977.

The City of Ocala has entered into an All-Requirements Power Project Supply Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Ocala include only its partial ownership in FPC's Crystal River 3 nuclear unit, being 1.3333 percent of that unit (or 10,504 kW based on current net summer rating). The City owns and operates its bulk power supply system which consists of two 230 to 69 kV substations, a 40 miles of 69 kV transmission loop, and 14 distribution substations delivering power at 12 kV and 4 kV levels. The distribution system consists of approximately 760 miles of overhead lines and 85 miles of underground.

The City's service area encompasses approximately 171 square miles. The service area is generally rectangular in shape, extending approximately 21 miles east and west and 17 miles north and south. The City of Ocala has received Florida PSC approval of a territorial agreement with Clay Electric Cooperative and with Sumter Electric Cooperative. Sixty-one percent of the customers served reside within the City limits.

1C.2.2.4 Transmission Arrangements

Electric capacity and energy from Stanton 2 will be transmitted to the All-Requirements Participants utilizing the transmission systems of OUC, FPC and

FPL. Transmission service is presently supplied by FPL to the All-Requirements Participants pursuant to the Transmission Service Agreement between FPL and FMPA. FPL has stated that transmission service from Stanton 2 for Jacksonville Beach, Green Cove Springs and Clewiston would be provided pursuant to the then-effective rates and provisions of that Agreement.

Transmission service is presently supplied by FPC to the All-Requirements Participants pursuant to the Agreement for Partial Requirements Service, Transmission/Distribution Service and Demand and Energy Losses Service between FMPA and FPC. FMPA has requested from FPC that Stanton 2 be added as a resource covered by this Agreement.

OUC provides transmission service for delivery of power and energy from FMPA's ownership in Stanton 1 for the All-Requirements Project to the FPL and FPC interconnections with OUC for subsequent delivery to the Participants over the life of the Unit. FMPA has requested similar transmission service for Stanton 2.

1C.3.0 Methodology

This section provides a general description of the methodology used to analyze the FMPA Participants' power supply requirements and is arranged according to the sequence of the remaining sections of this volume. The purpose of the power supply planning process is to identify the capacity addition (or additions) which will meet the electricity needs of FMPA Participants as economically as possible while also giving due consideration to reliability, diversity, environmental impact, financial security, regulatory aspects, and other considerations. This requires an analysis of supply and demand side alternatives to identify the plan which is in the collective best interest of all parties involved.

1C.3.1 Evaluation Criteria

The first step in the power supply planning process is to establish evaluation criteria, that is, to identify the assumptions about important parameters used in the analysis. Evaluation criteria presented in Subsection 1C.4.0 include economic forecast assumptions, financial assumptions, an assumption about the availability of natural gas, and fuel price projections.

1C.3.2 Load Forecast

The load forecasts for the FMPA Participants in the Stanton 2 Project and the All-Requirements Project are summarized in Subsection 1C.5.0 and shown in detail in Appendix 1C.B. The Appendix describes the development of the econometric models which forecast system peak demands and energy requirements. The load forecast takes into account FMPA members' existing conservation plans. Demand-side program reductions are forecast separately.

1C.3.3 Conservation and Demand-Side Management

The FMPA Participants' conservation and demand-side management programs are discussed in Subsection 1C.6.0. Estimates of capacity avoided by the various programs are provided.

1C.3.4 Reliability Criteria

Subsection 1C.7.0 presents the reliability criteria used to identify timing of capacity additions. FMPA Participants generally use a 20 percent minimum reserve margin as the reliability criteria.

1C.3.5 Supply-Side Alternatives

Supply-side alternatives that are candidates for meeting the FMPA Participants' capacity expansion requirements are identified in Subsection 1C.8.0. Typical plant sizes, capital costs, and operating parameters of conventional alternatives are developed.

1C.3.6 Supply-Side Screening

The economics of applicable supply-side alternatives are compared using screening curves in Subsection 1C.9.0. These graphs present comparative costs for the construction and operation of potentially viable supply-side generation options at various capacity factors. The costs of generation options are normalized on a \$/kW-month basis in order to more easily compare different capacities. The capital requirements for each alternative are based on the capital investment of the generation option and FMPA's levelized fixed charge rate. The operating costs (fuel and O&M) are levelized over a 25-year period. Each alternative's full load heat rate is used to determine fuel costs.

Graphically, capital cost plus operating costs for each option are plotted against capacity factor. At zero capacity factor (y-intercept), the curve indicates the fixed costs requirements associated with the alternative, while the slope indicates the variable costs. Several supply-side options are plotted on a single graph to allow easy comparison. The lowest curve at a particular capacity factor is the least cost alternative at that capacity factor. If two curves do not intercept, it indicates that the upper curve is expected to be a higher cost alternative at all capacity factors and potentially may be eliminated from further study.

An intersection of two curves indicates that one alternative is lower cost over a range of capacity factors while the other option is least cost over another capacity factor range. The purpose of the screening curves is to show the comparisons of the various alternatives that may be available to the Participants.

1C.3.7 Alternative Plans

Alternative plans for capacity additions are discussed in Subsection 1C.10.0 for the FMPA Participants in the Stanton 2 Project and the All-Requirements Project. Plans incorporate both generation and purchases. The plans developed schedule generation or purchases as required to meet the reliability criteria developed in Subsection 1C.7.0.

1C.3.8 Economic Analyses

In Subsection 1C.11.0, the economics of the alternative plans developed in Subsection 1C.10.0 are compared. The results are examined to determine which plans best meet the needs of the FMPA Participants.

The alternative plans are evaluated on a comparative cost basis. Comparative costs include only those costs which are affected by differences in the plans. The economic analyses determine the annual revenue requirements of items which are affected by the alternative plans. Annual comparative revenue requirements include the following components.

- o Fuel costs.
- o Purchased power costs.
- o Operation and maintenance (O&M) costs.
- o Capital costs for new generation.

A production cost simulation program is used to model each Participant's system for the alternative plans developed in Subsection 1C.10.0. Annual system fuel and O&M costs are developed for each plan. Production cost simulation is necessary to incorporate the effect upon the operation of the existing units due to the new unit additions.

The objective of the economic analysis is to determine the total present worth of the annual comparative revenue requirements. This refers to the sum of the yearly nominal comparative revenue requirements discounted to 1991 using FMPA's present worth discount rate.

The economic analysis indicates the lowest cumulative present worth of the annual nominal comparative revenue requirements of those alternatives compared for the FMPA Participants.

1C.3.9 Sensitivity Analysis

The results of the economic analyses are tested for fuel cost sensitivity in Subsection 1C.12.0.

1C.3.10 Strategic Considerations

Subsection 1C.13.0 consists of a discussion of strategic considerations involved in the alternative power supply plans. Such considerations include fuel mix, fuel supply, and availability of sites.

1C.3.11 Consequences of Delay

Subsection 1C.14.0 addresses the adverse consequences of not building or delaying the proposed generation plant.

1C.3.12 Florida Transmission Grid Considerations

Subsection 1C.15.0 discusses the transmission grid considerations and constraints, if any, for the FMPA Participants and how this affects the Stanton 2 alternative.

1C.4.0 Evaluation Criteria

1C.4.1 Economic Parameters

The economic parameters are based on the "Long Term Economic Forecast 1990 to 2021" prepared by Fishkind & Associates, Inc., November 26, 1990 presented in Subsection 1C.3.0 of Volume 1A. Adjustments to these general economic parameters necessary to make them specific for FMPA Participants are presented below.

Appendix 1C.A summarizes the economic projections for the most likely scenario used in the evaluation of the FMPA Participants' future power supply options.

1C.4.1.1 Inflation and Escalation Rates

The GNP deflator is generally accepted as a good measure of changes in the general price level and was selected for use as the inflation rate. The capital cost escalation rate is selected based on Black & Veatch's perceptions of the market conditions for power plant construction consistent with Dr. Fishkind's projections for the GNP deflator and producer price index. The O&M cost escalation rate is based on the projections of changes in the average compensation per man-hour and was also supplied by Dr. Fishkind.

1C.4.1.2 Bond Interest Rate

The bond interest rate used for FMPA is based on information supplied by FMPA's financial advisor, consistent with assumptions supplied by Dr. Fishkind. The assumed FMPA bond interest rate is 7.25 percent.

1C.4.1.3 Present Worth Rate

The present worth discount rate used in this evaluation is equal to the FMPA bond interest rate.

1C.4.1.4 Bond Issuance Fee

A bond issuance fee of 2 percent is assumed to apply to FMPA bond issues.

1C.4.1.5 Interest During Construction Rate

For evaluation purposes, interest during construction is assumed to be equal to the bond rate.

1C.4.1.6 Debt Service Reserve Fund

The debt service reserve fund is assumed to be the maximum one year's principal and interest. The interest earned on the debt service reserve fund and all other funds is assumed to be the same as the bond rate.

1C.4.2 Fuel Prices

Fuel price projections are based on the projections in Subsection 1A.3.3 of Volume 1A.

1C.4.3 Fuel Availability

It was assumed that sufficient natural gas will be available throughout the study period to fuel the FMPA Participants' existing resources and future resources assumed in each Participant's expansion plan.

1C.4.4 Partial Requirements Capacity and Energy Cost Projections

In making the projections of costs of partial requirements purchases from FPC and FPL, the principal considerations and assumptions include the following.

- (1) Cost of service principles have been based on those currently applicable to FPL's and FPC's (the Companies) wholesale rates filed with FERC, which principles include an allowance for return on rate base, depreciation expense, ad valorem tax, federal income tax, operating and maintenance expense, administrative and general expense, and insurance expense. For purposes of these projections, the construction work in progress (CWIP) assumed added to the Companies' rate base was for 100 percent of pollution control facilities and 50 percent of other major projection facilities.
- (2) Cost allocation and development of demand-related costs have been based on historical and projected relationships involving the 12-month average generation level peak demands of the wholesale customers occurring at the time of the Companies' monthly system peaks, the Companies' 12-month average peak, and the wholesale customers' average billing demands. Billing demand for the FPL demand-related costs are based upon the customers' noncoincident monthly demand at the delivery level and billing demands for the FPC demand-related costs are based upon the coincident monthly peak demand at the generation level.

Cost allocation and development of energy-related costs have been based upon historical relationships involving the Companies' energy requirements at the generation level and the wholesale customers' energy billing determinants. Billing determinants for the energy costs are based on delivery level energy purchases for FPL and are based upon generation level energy purchases for FPC.

- (3) The projected unit cost of partial requirements purchases from FPL assumes that the future characteristics of FPL's partial requirements wholesale power class will be similar to those which have been exhibited recently.

- (4) The projected unit cost of partial requirements purchases from FPC assumes that the current provisions of the FPC Agreement, including the provisions relating to the annual true-up of demand charges, will continue to remain in effect and FMPA will be in a separate cost class for cost allocation purposes.
- (5) Forecasts for the Companies' future power requirements and power supply resources for the period through the year 1999 have been based upon information provided in FPC's 1990 Generation Facility Study and each Company's 1990 Ten-Year Site Plan generation expansion plans. Such generation expansion plans provide for long-term annual reserve levels of approximately 3 percent to 13 percent for FPC and 16 percent to 27 percent for FPL. The FPC reserve levels are lower than the 15 percent to 20 percent levels traditionally used in long-term power supply planning. Generation expansion plans subsequent to the year 1999 were based upon maintaining reserve levels similar to those used by the Companies and through the addition of the same types for generating resources planned by the Companies.

With regard to FPL, the potential ownership interest in Scherer Unit 4, a coal-fired generating unit located on the Georgia Power Company ("GPC") system, was not considered in the projections contained herein due to uncertainty in the finalization of the arrangements necessary for the sale to FPL and a lack of information on the specifics of the sale.

- (6) The generation mix required to meet net energy for load through 1999 was based upon information contained in each Company's 1990 Ten-Year Site Plan generation expansion plan, adjusted for FPC in 1999 for the addition of a new coal unit. Thereafter, the energy mix for each Company was projected based upon the use of the Company's generating resources in a manner similar to that utilized in the previous years. For FPC, it was assumed that new capacity after 1999 would be from 700 MW pulverized coal units and combustion turbine units. For FPL, it was assumed that new capacity after 1999 would be from additional gasified-coal combined cycle units.
- (7) As provided by Dr. Fishkind, projected operations and maintenance expenses, excluding fuel expenses, and administrative and general expenses relating to existing production and transmission plant have been

projected to increase from historical levels at annual growth rates of 5.30 percent for 1991, 4.39 percent for 1992, and 4.75 percent thereafter. Projected operation and maintenance expenses, excluding fuel for new production facilities, are based upon cost estimates developed by FCG for the 1989 APH, to which the above annual growth rates were applied.

- (8) As provided by Dr. Fishkind, the interest cost of new long-term taxable debt of investor-owned utilities is projected to be at an average bond coupon rate of 9.69 percent for 1991, 10.20 percent for 1992, and 9.85 percent thereafter. In addition, we have used a rate of return on equity of 12.29 percent, which rate is the generic allowable return currently calculated by FERC.
- (9) Future fuel costs have been estimated based on projections presented in Subsection 1A.3.3 and average heat rates for existing and planned generation. Approximately one mill/kWh was added to the nuclear fuel cost, and escalated at 5.0 percent per year thereafter, for nuclear fuel disposal costs assumed to be required to be paid to the United States Government under the Nuclear Waste Policy Act of 1982.
- (10) Based on current understanding of the Tax Reform Act of 1986 and publicly-available information, the estimated effects of the major changes resultant from the Act have been included in the analysis of projected costs.

1C.5.0 Load Forecast

1C.5.1 FMPA Stanton 2 Project Systems

The individual load forecasts for each of the FMPA Stanton 2 Participants are discussed in detail in Appendix 1C.B. A summary of the Stanton 2 Participants is shown on Table 1C.5.1-1 and Table 1C.5.1-2. As shown on this table the total combined annual peak demand is projected to increase at an average annual rate of 1.7 percent, and the total combined net energy for load for these participants is projected to increase at an average annual rate of 1.6 percent.

Table 1C.5.1-1

**FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 PROJECT PARTICIPANTS
PROJECTED NET ENERGY REQUIREMENTS**

Net Energy Requirements (Mwh)

Fiscal Year	Fort Pierce Utilities Authority	City of Homestead	City of Key West	City of Lake Worth	City of Starks	City of Vero Beach	Total
1991	517,358	264,938	528,144	350,000	61,300	548,136	2,269,876
1992	526,601	270,933	547,433	356,000	63,300	566,314	2,330,581
1993	536,946	276,601	564,504	364,000	65,300	587,047	2,394,398
1994	546,969	284,648	581,503	372,000	67,300	607,676	2,460,096
1995	553,775	289,939	599,611	381,000	69,300	628,190	2,521,815
1996	558,458	295,507	612,392	388,000	71,300	646,595	2,572,252
1997	563,938	303,422	625,421	395,000	73,300	660,892	2,621,973
1998	569,931	308,816	638,902	403,000	75,300	675,077	2,671,026
1999	576,850	314,096	653,219	411,000	77,300	689,674	2,722,139
2000	584,592	319,280	668,103	419,000	79,300	704,617	2,774,892
2001	591,799	323,183	681,509	422,000	81,300	718,460	2,818,251
2002	598,925	327,088	694,957	426,000	83,300	732,327	2,862,597
2003	606,107	330,995	708,485	429,000	85,300	746,241	2,906,128
2004	613,384	334,903	722,165	433,000	87,300	760,362	2,951,114
2005	620,722	338,814	735,990	437,000	89,300	774,757	2,996,583
2006	628,139	343,828	749,558	439,000	91,400	789,315	3,041,240
2007	635,453	348,855	763,085	441,000	93,400	804,166	3,085,959
2008	642,786	353,896	776,433	443,000	95,400	819,316	3,130,831
2009	650,183	358,951	789,920	445,000	97,400	834,775	3,176,229
2010	657,672	364,020	803,480	448,000	99,400	850,479	3,223,051
2011	665,248	369,089	811,766	451,000	101,400	866,501	3,265,004
2012	672,910	374,158	818,806	454,000	103,400	882,845	3,306,119
2013	680,661	379,227	825,584	457,000	105,400	899,520	3,347,392
2014	688,502	384,296	832,146	460,000	107,400	916,531	3,388,875
2015	696,432	389,365	838,770	463,000	109,400	933,886	3,430,853
2016	704,454	394,434	845,472	466,000	111,400	951,591	3,473,351
2017	712,569	399,503	852,233	469,000	113,400	969,654	3,516,359
2018	720,777	404,572	859,098	472,000	115,400	988,082	3,559,929
2019	729,079	409,641	866,053	475,000	117,400	1,006,882	3,604,055
2020	737,477	414,710	873,071	478,000	119,400	1,026,063	3,648,721
2021	745,972	419,779	880,194	481,000	121,400	1,045,631	3,693,976

Average Annual Compound Rate of Growth for 1991 - 2021							
	1.2%	1.5%	1.7%	1.1%	2.3%	2.2%	1.6%

Table 1C.5.1-2

**FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 PROJECT PARTICIPANTS
PROJECTED ANNUAL NET PEAK DEMAND**

Annual Net Peak Demand (Mw)

Fiscal Year	Fort Pierce Utilities Authority	City of Homestead	City of Key West	City of Lake Worth	City of Starke	City of Vero Beach	Total
1991	107.1	52.0	91.3	74.0	12.8	139.7	476.9
1992	109.8	54.0	94.7	76.0	13.2	144.8	492.5
1993	112.0	55.0	97.6	78.0	13.6	150.3	506.5
1994	113.9	56.0	100.6	79.0	14.1	155.8	519.4
1995	115.2	57.0	103.7	81.0	14.5	161.1	532.5
1996	116.2	59.0	105.9	83.0	14.9	165.9	544.9
1997	117.3	60.0	108.2	84.0	15.3	169.5	554.3
1998	118.6	61.0	110.5	86.0	15.7	173.1	564.9
1999	120.1	62.0	113.0	88.0	16.2	176.9	576.2
2000	121.7	63.0	115.6	89.0	16.6	180.6	586.5
2001	123.2	64.0	117.9	90.0	17.0	184.1	596.2
2002	124.7	65.0	120.2	91.0	17.4	187.6	605.9
2003	126.2	66.0	122.5	91.0	17.8	191.2	614.7
2004	127.7	66.0	124.9	92.0	18.3	194.8	623.7
2005	129.2	67.0	127.3	93.0	18.7	198.5	633.7
2006	130.7	68.0	129.6	94.0	19.1	202.1	643.5
2007	132.3	69.0	132.0	94.0	19.5	205.9	652.7
2008	133.8	70.0	134.3	94.0	19.9	209.8	661.8
2009	135.3	71.0	136.6	95.0	20.4	213.7	672.0
2010	136.9	72.0	139.0	95.0	20.9	217.7	681.5
2011	138.1	73.0	140.4	96.0	21.4	219.8	688.7
2012	139.7	74.0	141.6	97.0	21.9	224.0	698.2
2013	141.3	75.0	142.8	97.0	22.4	228.2	706.7
2014	142.9	76.0	143.9	98.0	22.9	232.5	716.2
2015	144.5	77.0	145.1	99.0	23.4	236.9	725.9
2016	146.2	78.0	146.2	99.0	23.9	241.4	734.7
2017	147.9	79.0	147.4	100.0	24.4	246.0	744.7
2018	149.6	80.0	148.6	101.0	24.9	250.7	754.8
2019	151.3	81.0	149.8	101.0	25.4	255.4	763.9
2020	153.1	82.0	151.0	102.0	25.9	260.3	774.3
2021	154.8	83.0	152.2	103.0	26.4	265.3	784.7

Average Annual Compound Rate of Growth for 1991 - 2021	1.2%	1.6%	1.7%	1.1%	2.4%	2.2%	1.7%
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1C.5.2 FMPA All-Requirements Project Systems

The individual load forecasts for each of the FMPA All-Requirements Project Participants are discussed in detail in Appendix 1C.B. A summary of the All-Requirements Participants is shown on Table 1C.5.2-1 and Table 1C.5.2-2. As shown on this table, the total combined annual peak demand is projected to increase at an average annual rate of 2.5 percent, and the total combined net energy for load for these Participants is projected to increase at an average annual rate of 2.5 percent.

Table 1C.5.2-1

**FLORIDA MUNICIPAL POWER AGENCY
ALL REQUIREMENTS PROJECT PARTICIPANTS
PROJECTED NET ENERGY REQUIREMENTS**

Net Energy Requirements (Mwh)

Calendar Year	City of Bushnell	City of Leesburg	City of Ocala	City of Clewiston	City of Green Cove Springs	City of Jacksonville Beach	Total
1991	17,242	368,677	968,155	92,096	93,373	491,787	2,031,330
1992	17,784	380,354	1,011,310	94,675	96,545	511,442	2,112,110
1993	18,326	392,031	1,054,465	97,254	99,718	531,096	2,192,890
1994	18,868	403,708	1,097,620	99,833	102,890	550,750	2,273,669
1995	19,410	415,385	1,140,774	102,412	106,063	570,405	2,354,449
1996	19,951	427,062	1,174,998	104,991	109,235	590,059	2,426,296
1997	20,493	438,740	1,209,221	107,571	112,408	609,713	2,498,146
1998	21,035	450,417	1,243,444	110,150	115,581	629,367	2,569,994
1999	21,577	462,094	1,277,667	112,729	118,753	649,022	2,641,842
2000	22,119	473,771	1,311,891	115,308	121,926	668,676	2,713,691
2001	22,661	485,448	1,346,114	117,887	125,098	688,330	2,785,538
2002	23,203	497,125	1,380,337	120,467	128,271	707,985	2,857,388
2003	23,745	508,802	1,414,560	123,046	131,444	727,639	2,929,236
2004	24,287	520,479	1,448,784	125,825	134,616	747,293	3,001,084
2005	24,829	532,156	1,483,007	128,204	137,789	766,948	3,072,933
2006	25,371	543,833	1,517,230	130,783	140,961	786,602	3,144,780
2007	25,913	555,510	1,551,453	133,362	144,134	806,256	3,216,628
2008	26,454	567,187	1,585,677	135,942	147,306	825,910	3,288,476
2009	26,996	578,865	1,619,900	138,521	150,479	845,565	3,360,326
2010	27,538	590,542	1,654,123	141,100	153,652	865,219	3,432,174
2011	28,080	602,219	1,688,346	143,679	156,825	884,873	3,504,022
2012	28,622	613,896	1,722,569	146,258	159,998	904,527	3,575,870
2013	29,164	625,573	1,756,792	148,837	163,171	924,181	3,647,718
2014	29,706	637,250	1,791,015	151,416	166,344	943,835	3,719,566
2015	30,248	648,927	1,825,238	153,995	169,517	963,489	3,791,414
2016	30,790	660,604	1,859,461	156,574	172,690	983,143	3,863,262
2017	31,332	672,281	1,893,684	159,153	175,863	1,002,797	3,935,110
2018	31,874	683,958	1,927,907	161,732	179,036	1,022,451	4,006,958
2019	32,416	695,635	1,962,130	164,311	182,209	1,042,105	4,078,808
2020	32,958	707,312	1,996,353	166,890	185,382	1,061,759	4,150,654
2021	33,500	718,989	2,030,576	169,469	188,555	1,081,413	4,222,502

Average Annual Compound Rate of Growth for	1991 - 2021	2.2%	2.3%	2.5%	2.1%	2.4%	2.7%	2.5%
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Table 1C.5.2-2

**FLORIDA MUNICIPAL POWER AGENCY
ALL REQUIREMENTS PROJECT PARTICIPANTS
PROJECTED ANNUAL NET PEAK DEMAND**

Annual Net Peak Demand (Mw)							
Calendar Year	City of Bushnell	City of Leesburg	City of Ocala	City of Clewiston	City of Green Cove Springs	City of Jacksonville Beach	Total
1991	4.7	81.1	213.0	18.7	17.9	126.4	461.8
1992	4.8	83.7	222.5	19.2	18.5	131.4	480.1
1993	5.0	86.2	232.0	19.7	19.1	136.5	498.5
1994	5.1	88.8	241.5	20.3	19.8	141.5	517.0
1995	5.3	91.4	251.0	20.8	20.4	146.6	535.5
1996	5.4	94.0	258.5	21.3	21.0	151.8	551.8
1997	5.6	96.5	266.0	21.8	21.6	156.7	568.2
1998	5.7	99.1	273.6	22.4	22.2	161.7	584.7
1999	5.9	101.7	281.1	22.9	22.8	166.8	601.2
2000	6.0	104.2	288.6	23.4	23.4	171.8	617.4
2001	6.2	106.8	296.1	23.9	24.0	176.9	633.9
2002	6.3	109.4	303.7	24.5	24.6	182.0	650.5
2003	6.5	111.9	311.2	25.0	25.2	187.0	666.8
2004	6.6	114.5	318.7	25.5	25.8	192.1	683.2
2005	6.8	117.1	326.3	26.0	26.5	197.1	699.8
2006	6.9	119.6	333.8	26.5	27.1	202.2	716.1
2007	7.0	122.2	341.3	27.1	27.7	207.2	732.5
2008	7.2	124.8	348.8	27.6	28.3	212.3	749.0
2009	7.3	127.4	356.4	28.1	28.9	217.3	765.4
2010	7.4	129.9	363.9	28.6	29.5	222.3	781.6
2011	7.5	132.4	371.4	29.1	30.1	227.3	797.8
2012	7.6	134.9	378.9	29.6	30.7	232.3	814.0
2013	7.7	137.4	386.4	30.1	31.3	237.3	830.2
2014	7.8	139.9	393.9	30.6	31.9	242.3	846.4
2015	7.9	142.4	401.4	31.1	32.5	247.3	862.6
2016	8.0	144.9	408.9	31.6	33.1	252.3	878.8
2017	8.1	147.4	416.4	32.1	33.7	257.3	895.0
2018	8.2	149.9	423.9	32.6	34.3	262.3	911.2
2019	8.3	152.4	431.4	33.1	34.9	267.3	927.4
2020	8.4	154.9	438.9	33.6	35.5	272.3	943.6
2021	8.5	157.4	446.4	34.1	36.1	277.3	959.8

Average Annual Compound Rate of Growth for 1991 - 2021							
2.0%	2.2%	2.5%	2.0%	2.4%	2.7%	2.5%	

1C.6.0 Conservation Programs

1C.6.1 Fort Pierce Utilities Authority

1C.6.1.1 Introduction

During the 1980s, conservation efforts were mostly directed at the residential sector. Residential kilowatt-hour sales accounted for 43 percent of the Authority's total sales in fiscal year 1990. The 1990s will see continued efforts in the residential sector in the areas of energy audits and home weatherization. Also, significant emphasis will be placed on conservation in the commercial and industrial sectors.

The conservation programs are promoted on cable television in 30-second spots, through newspaper advertisements, and through the Authority's participation in the St. Lucie County Home Show. In addition, a presentation and demonstration of energy efficient lighting technologies was prepared and made available to local civic groups. The demonstration stresses the numerous potential applications and cost-effectiveness of compact lamps and fixtures.

1C.6.1.2 Existing Conservation Programs

The Authority offers the following conservation programs.

- (1) Residential Energy Audits including the 5-Star Award Program,
- (2) High Pressure Sodium Outdoor Lighting Conversion,
- (3) Assistance for Commercial/Industrial Audits, and
- (4) Natural Gas Promotion.

A discussion of each of these programs follows.

(1) Residential Energy Audits

- **Program Description.** Residential energy audits are offered to all residential customers. Audits are conducted in accordance with FPSC rules. Audits consist of a walk-through Home Energy Survey with the following materials available upon customer request.
 - Electric outlet gaskets,
 - Socket protectors,
 - Water flow restrictors, and
 - Low flow shower heads.

Home Energy Surveys also include a water heater temperature reduction and the installation of a water heater insulating blanket upon customer request.

Some residential customers receive new construction and rehabilitation design assistance in accordance with their request. This service consists of a comprehensive heat loss/heat gain calculation using software licensed by the Air Conditioning Contractors of America. The customer is advised regarding equipment sizing and selection, particularly with regard to operating SEER.

The Residential Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing energy consumption by 320,000 kWh per year in 1991 through 2000,
 - Reducing summer peak demand by 200 kW per year in 1991 through 2000, and
 - Reducing winter peak demand by 300 kW per year in 1991 through 2000.
- Program Participation Standards. The Residential Audits Program involves the Authority sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the Authority. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
 - Program Benefits and Costs. The Residential Audits Program has proved beneficial to the Authority's customers in a number of ways. The assumed kilowatt-hour reduction is 400 kWh per audit with assumed reduction in summer and winter peak demands of 0.25 kW and 0.375 kW respectively, per audit.

The Authority anticipates performing a yearly total of 800 residential audits in 1991 through 2000. The total estimated kilowatt-hour reduction for the Authority from the Residential Audits Program is 320,000 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand is 200 kW per year in 1991 through 2000 and the total estimated kilowatt reduction

in winter peak demand is 300 kW in 1991 through 2000. It is estimated that by the year 2000 the Authority will have reduced its kilowatt-hour consumption by 3,200,000 kWh and will have reduced its summer peak demand by 2,000 kW and reduced its winter peak demand by 3,000 kW due to this program.

- Program Monitoring and Evaluation. The Residential Audits Program will be monitored by the FEECA Program for Residential Audits. Comparisons of the customer's previous bills before the audit can be compared to bills after the audit as a way to verify the estimated kilowatt demand and energy reductions.

(2) High Pressure Sodium Streetlight Conversion

- Program Description. This program involves eliminating all mercury vapor street and yard lighting. The fixtures are converted whenever maintenance is required.

The High Pressure Sodium Streetlight Conversion Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 12 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 54,150 kWh per year in 1991 through 2000.
- Program Participation Standards. The High Pressure Sodium Streetlight Conversion Program involves the Authority replacing all mercury vapor street lighting and yard lighting. The program has no rebates paid to the customer from the Authority. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
- Program Benefits and Costs. The High Pressure Sodium Streetlight Conversion Program estimates an annual reduction of kilowatt-hour consumption of 361 kWh per 100 watt mercury vapor lamp, 723 kWh per 250 watt mercury vapor lamp, and 2,689 kWh per 400 watt mercury vapor lamp. The High Pressure Sodium Streetlight Conversion Program estimates an average summer peak demand reduction and a winter peak demand reduction of 0.08 kW demand per lamp replaced.

The Authority anticipates installing a yearly total of 150 outdoor lights in 1991 through 2000. The total estimated kilowatt-hour reduction for the Authority from the High Pressure Sodium Streetlight Conversion Program is 54,150 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 12 kW per year in 1991 through 2000. It is estimated that by the year 2000 the Authority will have reduced its kilowatt-hour consumption by 541,500 kWh and will have reduced its summer peak demand and winter peak demand by 120 kW due to this program.

- Program Monitoring and Evaluation. The High Pressure Sodium Streetlight Conversion Program will be monitored by the FEECA Program for High Pressure Sodium Streetlight Conversion.

(3) Assistance for Commercial/Industrial Audits

- Program Description. Onsite audits are available to all industrial and commercial customers. The purpose of this program is to recommend ways for the customer to improve the efficiency of their energy usage.

The Commercial/Industrial Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 120 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 262,500 kWh per year in 1991 through 2000.
- Program Participation Standards. The Commercial/Industrial Audits Program involves the Authority sending an auditor to all interested commercial/industrial customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the Authority. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.

- Program Benefits and Costs. The Commercial/Industrial Audits Program assumes an annual kilowatt-hour reduction of 1,750 kWh per audit with an assumed reduction in summer and winter peak demands of 0.8 kW per audit.

The Authority anticipates performing a yearly total of 150 commercial/industrial audits in 1991 through 2000. The total estimated kilowatt-hour reduction for the Authority from the Commercial/Industrial Audits Program is 262,500 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 120 kW per year in 1991 through 2000. It is estimated that by the year 2000 the Authority will have reduced its kilowatt-hour consumption by 2,625,000 kWh and will have reduced its summer peak and winter peak demand by 1,200 kW due to this program.

- Program Monitoring and Evaluation. The Commercial/Industrial Audits Program will be monitored by the FEECA Program for Commercial/Industrial Audits. Comparisons of the customer's previous bills before the audit can be compared to bills after the audit as a way to verify the estimated kilowatt demand and energy reductions.

(4) Natural Gas Program

The Energy Services Department coordinates production and purchasing of advertising for natural gas services with the Natural Gas Department. Through radio and cable television, natural gas is promoted as an efficient alternative to electricity for water and space heating, cooking, and appliance uses.

1C.6.2 City of Homestead

1C.6.2.1 Introduction

The City of Homestead offers a wide range of conservation programs including the following.

- (1) Residential Energy Audits,
- (2) High Pressure Sodium Outdoor Lighting Conversion,
- (3) 5-Star Award Program, and
- (4) Public Awareness.

A discussion of each of these programs follows.

1C.6.2.2 Existing Conservation Programs

(1) Residential Energy Audits

Residential energy audits are offered to all customers through the distribution of conservation literature and through program announcements to new customers. The Residential Audits Program involves the City sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. Audits are conducted in accordance with PSC rules. Attics and crawl spaces are inspected throughout for duct leaks and insulation levels, unless it is physically impossible. The program has no rebates paid to the customer from the City of Homestead. The incentive for the customer is in most cases a kWh consumption reduction which reduces the customer's electric bill.

(2) High Pressure Sodium Outdoor Lighting Conversion

This program involves replacing all mercury vapor street lighting and yard lighting. The fixtures are converted whenever maintenance is required. This program has no rebates paid to the customer from the City.

(3) 5-Star Award Program

All residential energy audits are evaluated for the 5-star program.

(4) Public Awareness

Available conservation program announcements are made to new customers. Energy conservation literature is distributed including energy conservation messages in customers' newsletters.

1C.6.3 Utility Board of the City of Key West

1C.6.3.1 Introduction

During the 1980s, conservation efforts were mostly directed at the residential sector. Residential kilowatt-hour sales accounted for 40 percent of the City Electric System's total sales in fiscal year 1990. The 1990s will see continued efforts in the residential sector in the areas of energy audits and home weatherization. Also, significant emphasis will be placed on conservation in the commercial and industrial sectors.

The conservation programs are promoted in program announcements to new customers, through the distribution of energy conservation literature, through energy conservation messages in public service announcements on radio, and through a liaison with the naval base and community housing on energy conservation.

1C.6.3.2 Existing Conservation Programs

The City Electric System offers the following conservation programs.

- (1) Residential Energy Audits including the 5-Star Award Program,
- (2) High Pressure Sodium Outdoor Lighting Conversion,
- (3) Assistance for Commercial/Industrial Audits, and
- (4) Fix-up program for the Elderly and Handicapped.

A discussion of each of these programs follows.

(1) Residential Energy Audits.

- **Program Description.** Residential energy audits are offered to all residential customers. Audits are conducted in accordance with FPSC rules. Audits consist of a walk-through Home Energy Survey with the following materials available upon customer request.
 - Electric water heater jacket,
 - Socket protectors,
 - Water flow restrictors,
 - Low flow shower heads, and
 - Electric outlet gaskets.

The Residential Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing energy consumption by 120,000 kWh per year in 1991 through 2000,
 - Reducing summer peak demand by 75 kW per year in 1991 through 2000, and
 - Reducing winter peak demand by 112.5 kW per year in 1991 through 2000.
- Program Participation Standards. The Residential Audits Program involves the City Electric System sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the City Electric System. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
 - Program Benefits and Costs. The Residential Audits Program has proved beneficial to the City Electric System's customers in a number of ways. The assumed kilowatt-hour reduction is 400 kWh per audit with assumed reduction in summer and winter peak demands of 0.25 kW and 0.375 kW respectively, per audit.

The City Electric System anticipates performing a yearly total of 300 residential audits in 1991 through 2000. The total estimated kilowatt-hour reduction for the City Electric System from the Residential Audits Program is 120,000 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand is 75 kW per year in 1991 through 2000 and the total estimated kilowatt reduction in winter peak demand is 112.5 kW per year in 1991 through 2000. It is estimated that by the year 2000 the City Electric System will have reduced its kilowatt-hour consumption by 1,200,000 kWh, and will have reduced its summer peak demand by 750 kW and reduced its winter peak demand by 1,125 kW due to this program.

- Program Monitoring and Evaluation. The Residential Audits Program will be monitored by the FEECA Program for Residential

Audits. Comparisons of the customer's previous bills before the audit can be compared to bills after the audit as a way to verify the estimated kilowatt demand and energy reductions.

(2) High Pressure Sodium Streetlight Conversion

- Program Description. This program involves eliminating all mercury vapor street and yard lighting. The fixtures are converted whenever maintenance is required.

The High Pressure Sodium Streetlight Conversion Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 8 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 36,100 kWh per year in 1991 through 2000.
- Program Participation Standards. The High Pressure Sodium Streetlight Conversion Program involves the City Electric System replacing all mercury vapor street lighting and yard lighting. The program has no rebates paid to the customer from the City Electric System. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
- Program Benefits and Costs. The High Pressure Sodium Streetlight Conversion Program estimates an annual reduction of kilowatt-hour consumption of 361 kWh per 100 watt mercury vapor lamp, 723 kWh per 250 watt mercury vapor lamp, and 2,689 kWh per 400 watt mercury vapor lamp. The High Pressure Sodium Streetlight Conversion Program estimates an average summer peak demand reduction and a winter peak demand reduction of 0.08 kW demand per lamp replaced.

The City Electric System anticipates replacing a yearly total of 100 street lights in 1991 through 2000. The total estimated kilowatt-hour reduction for the City Electric System from the High Pressure Sodium Streetlight Conversion Program is 36,100 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 8 kW per year in 1991 through 2000. It is estimated that by the year 2000 the City Electric

System will have reduced its kilowatt-hour consumption by 361,000 kWh and will have reduced its summer peak demand and winter peak demand by 80 kW due to this program.

- Program Monitoring and Evaluation. The High Pressure Sodium Streetlight Conversion Program will be monitored by the FEECA Program for High Pressure Sodium Streetlight Conversion.

(3) Assistance for Commercial/Industrial Audits

- Program Description. Onsite audits are available to all industrial and commercial customers. The purpose of this program is to recommend ways for the customer to improve the efficiency of their energy usage.

The Commercial/Industrial Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 0.8 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 1,750 kWh per year in 1991 through 2000.
- Program Participation Standards. The Commercial/Industrial Audits Program involves the City Electric System sending an auditor to all interested commercial/industrial customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the City Electric System. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
- Program Benefits and Costs. The Commercial/Industrial Audits Program assumes an annual kilowatt-hour reduction of 1,750 kWh per audit with an assumed reduction in summer and winter peak demands of 0.8 kW per audit.

The City Electric System anticipates performing a yearly total of one commercial/industrial audit in 1991 through 2000. The total estimated kilowatt-hour reduction for the City Electric System from the Commercial/Industrial Audits Program is 1,750 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 0.8 kW per year in 1991

through 2000. It is estimated that by the year 2000 the City Electric System will have reduced its kilowatt-hour consumption by 17,500 kWh and will have reduced its summer peak demand and winter peak demand by 8 kW due to this program.

- Program Monitoring and Evaluation. The Commercial/Industrial Audits Program will be monitored by the FEECA Program for Commercial/Industrial Audits. Comparisons of the customer's previous bills before the audit can be compared to bills after the audit as a way to verify the estimated kilowatt demand and energy reductions.

(4) Fix-up Program for the Elderly and Handicapped

- Program Description. The City Electric System seeks and receives grants for the Community Block Development Program and Weatherization Program. This is a low-income program with participants as directed by the grants. Energy Auditors submit homes for the weatherization program.

The Fix-up Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 125 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 150,000 kWh in 1991 through 2000.
- Program Participation Standards. Participation in the Fix-up Program is directed by the grants. Energy Auditors submit homes for the weatherization program.
- Program Benefits and Costs. The Fix-up Program assumes an annual reduction of 1,200 kWh consumption per home and an annual reduction of summer peak demand and winter peak demand of one kW per home. The City Electric System estimates having a yearly total of 125 participants in the Fix-up Program. It is estimated that by the year 2000, the City Electric System will have reduced its kWh consumption by 1,500,000 kWh and will have reduced its summer peak demand and its winter peak demand by 1,250 kW due to this program.

- Program Monitoring and Evaluation. Comparisons of the customer's previous bills before the fix-up improvements were performed can be compared to bills after the fix-up improvements were performed as a way to verify the estimated kilowatt demand and energy reductions.

1C.6.4 City of Lake Worth

1C.6.4.1 Introduction

The City of Lake Worth has aggressively marketed energy conservation since the implementation of FEECA in the early 1980s. The initial efforts targeted the residential sector, which accounts for 55 percent of the City's total sales in fiscal year 1990. Last year, the program was expanded to include commercial walk-through surveys. The 1990s will see continued efforts in the residential sector in the areas of energy audits and home weatherization. Also, significant emphasis will be placed on conservation in the commercial and industrial sectors.

One of the City's most effective conservation tools is customer education. This involves a wide variety of activities such as civic and other group presentations, school programs, general weather related education, energy conservation booths at the local fair, judging science fairs with special prizes given for exhibits relating to energy conservation, ads promoting energy conservation in the local news media, monthly bill stuffers, and public service announcements to promote energy awareness to our customers. These efforts began in the early 1980s and are gradually expanding year after year.

1C.6.4.2 Existing Conservation Programs

The City offers the following conservation programs.

- (1) Residential energy audits including the 5-Star Award Program,
- (2) High Pressure Sodium Outdoor Lighting Conversion,
- (3) Assistance for Commercial/Industrial Audits,
- (4) Weatherization and fix-up grant programs,
- (5) Photovoltaic Demonstration Grant Proposal,
- (6) Investigative audit studies, and
- (7) Customer assistance program (Sharing is Caring).

A discussion of each of these programs follows.

(1) Residential Energy Audits

- **Program Description.** Residential energy audits are offered to all residential customers. Audits are conducted in accordance with PSC rules. The Residential Audits Program is quite complete including a "mini fix-up" program whereby the auditor changes out inefficient

lighting and installs hot water heater blankets and shower head water savers.

The Residential Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing energy consumption by 200,000 kWh per year in 1991 through 2000,
 - Reducing summer peak demand by 125 kW per year in 1991 through 2000, and
 - Reducing winter peak demand by 187.5 kW per year in 1991 through 2000.
- Program Participation Standards. The Residential Audits Program involves the City sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the City. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
 - Program Benefits and Costs. The Residential Audits Program has proved beneficial in two ways. First of all, the Program recommends ways the customer can reduce their energy bill while maintaining the same level of service and secondly, the Program reduces both the City's Net Energy for Load and Peak Demands thereby reducing the need to add generation. The assumed kilowatt-hour reduction is 750 kWh per audit with assumed reduction in summer and winter peak demands of 1.0 kW and 1.0 kW respectively, per audit.

The City anticipates performing a yearly total of 500 residential audits in 1991 through 2000. The total estimated kilowatt-hour reduction for the City from the Residential Audits Program is 200,000 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand is 125 kW per year in 1991 through 2000 and the total estimated kilowatt reduction in winter peak demand is 187.5 kW in 1991 through 2000. It is estimated that by the year 2000 the City will have reduced its kilowatt-hour consumption by 2,000,000 kWh and will have reduced

its summer peak demand by 1,250 kW and reduced its winter peak demand by 1,875 kW due to this program.

- Program Monitoring and Evaluation. The City analyzes consumption patterns prior to and after the residential audit to monitor the effectiveness of the audit as well as tracking which customers have had audits.

(2) High Pressure Sodium Streetlight Conversion

- Program Description. This program involves eliminating all mercury vapor street and yard lighting. The City has converted all street lighting to high-pressure sodium lighting and has converted approximately 50 percent of private area lighting to high-pressure sodium lighting. This Program will continue until all private area lighting has been converted to high-pressure sodium lighting.

The High Pressure Sodium Streetlight Conversion Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 13.1 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 50,850 kWh per year in 1991 through 2000.
- Program Participation Standards. The High Pressure Sodium Streetlight Conversion Program involves the City replacing all mercury vapor street lighting and yard lighting. The program has no rebates paid to the customer from the City. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
- Program Benefits and Costs. The High Pressure Sodium Streetlight Conversion Program estimates an annual reduction of kilowatt-hour consumption of 339 kWh per 175 watt mercury vapor lamps, 449 kWh per 250 watt mercury vapor lamps, and 655 kWh per 400 watt mercury vapor lamps. The High Pressure Sodium Streetlight Conversion Program estimates a summer peak demand reduction and a winter peak demand reduction of 0.0875 kW demand per 175 watt lamp, 0.107 kW demand per 250 watt lamp, and 0.156 kW demand per 400 watt lamp.

The City anticipates replacing a yearly total of 150 Private Area Lights in 1991 through 2000. The total estimated kilowatt-hour reduction for the City from the High Pressure Sodium Streetlight Conversion Program is 50,850 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 13.1 kW per year in 1991 through 2000. It is estimated that by the year 2000 the City will have reduced its kilowatt-hour consumption by 508,500 kWh and will have reduced its summer peak demand and winter peak demand by 131 kW due to this program.

- Program Monitoring and Evaluation. The High Pressure Sodium Streetlight Conversion Program will be monitored by the FEECA Program for High Pressure Sodium Streetlight Conversion.

(3) Assistance for Commercial/Industrial Audits

- Program Description. Onsite audits are available to all industrial and commercial customers. The purpose of this program is to recommend ways for the customer to improve the efficiency of their energy usage. The commercial/industrial Audit is basically a simple walk-through. Should the commercial/industrial customer request a more in-depth study, they are referred to a private energy consultant.

The Commercial/Industrial Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 20 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 43,750 kWh per year in 1991 through 2000.
- Program Participation Standards. The Commercial/Industrial Audits Program involves the City sending an auditor to all interested commercial/industrial customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the City. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.

- Program Benefits and Costs. The Commercial/Industrial Audits Program has proved beneficial in two ways. First of all, the Program recommends ways the customer can reduce their energy bill while maintaining the same level of service and secondly, the Program reduces both the City's Net Energy for Load and Peak Demands thereby reducing the need to add generation. The Commercial/Industrial Audits Program assumes an annual kilowatt-hour reduction of 1,750 kWh per audit with an assumed reduction in summer and winter peak demands of 0.8 kW per audit.

The City anticipates performing a yearly total of 25 commercial/industrial audits in 1991 through 2000. The total estimated kilowatt-hour reduction for the City from the Commercial/Industrial Audits Program is 43,750 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 20 kW per year in 1991 through 2000. It is estimated that by the year 2000 the City will have reduced its kilowatt-hour consumption by 437,500 kWh and will have reduced its summer peak demand and winter peak demand by 200 kW due to this program.

- Program Monitoring and Evaluation. The City analyzes consumption patterns prior to and after the commercial/industrial audit to monitor the effectiveness of the audit as well as tracking which customers have had audits.

(4) Weatherization and Fix-up Grant Programs

- Program Description. From 1984 to 1988, the City of Lake Worth participated in a Governor's Energy Office matching fund grant program that provided for up to \$400 for energy related fix-up and home improvement work; i.e., insulation, thermal doors and windows, caulking and weather stripping, replacement of inefficient air conditioning units, and the installation of air-conditioning compressor duty cyclers. During this time, approximately 200 low income customers received assistance.

Another weatherization program that the City assists in and promotes is funded through the Urban League whereby up to \$1,200 is made available, also to low income customers.

The Weatherization and Fix-up Grant Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 400 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 480,000 kWh per year in 1991 through 2000.
- Program Participation Standards. Participation in the Weatherization and Fix-up Program is directed by the particular grant(s). Energy auditors submit homes for these programs.
- Program Benefits and Costs. The Weatherization and Fix-up Program has proved beneficial in two ways. First of all, the Program provides assistance to low income customers so they can reduce their energy bill while maintaining the same level of service and secondly, the Program reduces both the City's Net Energy for Load and Peak Demands thereby reducing the need to add generation. The Weatherization and Fix-up Program assumes an annual kilowatt-hour reduction of 1,200 kWh per home with an assumed reduction in summer and winter peak demands of 1.0 kW per home.

The City anticipates having a yearly total of 400 participants in the Weatherization and Fix-up Program during 1991 through 2000. The total estimated kilowatt-hour reduction for the City from the Weatherization and Fix-up Program is 480,000 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 400 kW per year in 1991 through 2000. It is estimated that by the year 2000 the City will have reduced its kilowatt-hour consumption by 4,800,000 kWh and will have reduced its summer peak demand and winter peak demand by 4,000 kW due to this program.

- Program Monitoring and Evaluation. The City analyzes consumption patterns prior to and after the weatherization improvements to monitor the effectiveness of the audit as well as tracking which customers have had audits.

(5) Photovoltaic Demonstration Grant Program

- Program Description. The City participates in a recent grant request in response to a Request for Proposal from the Florida Solar Energy Center. The City, with engineering provided by the Mechanical Engineering faculty of Florida Atlantic University and with other assistance from Palm Beach Community College and the South Florida Water Management District, proposes to construct the following.
 - A photovoltaic system to produce electric energy for landscape ornamental lighting and a shallow well drip irrigation system for a xeriscape exhibit, and
 - A separate photovoltaic system to provide power to certain City Hall exterior lighting and the City Hall critical communication and computer systems in the event of a loss of power from the public source and the normal emergency generator.

The xeriscape exhibit will demonstrate both the practical uses of drought resistant native plants to create an attractive low water demand landscape and the commercial viability of a photovoltaic system as an energy resource for the associated electric requirements. The second project will demonstrate the applicability of a photovoltaic system as an emergency power source for critical needs.

The projects will be located on the grounds of the Lake Worth City Hall in the virtual center of the downtown area. This site will be highly visible to the public using the adjacent thoroughfares and meeting and conducting business in City Hall.

FSEC has a total of \$30,000 of grant money to be distributed to fund projects demonstrating applications of photovoltaic energy. The grant offer will require at least 20 percent local matching funds with high priority given to local governments. The City is proposing a \$25,000 project with a \$15,000 FSEC grant, \$5,000 local "cash" funding, and \$5,000 in donated goods and services. If the City's proposal is accepted, the project is scheduled for completion by May 31, 1991.

(6) Investigative Audit Studies

- Program Description. In 1990, the Energy Conservation Division of the Utilities began an audit study which investigated energy consumption patterns that appeared to be abnormally low or high. These studies have determined the following.
 - Electric use being calculated without the proper multiplier not only creates a loss of revenue to the City, but also sends the wrong energy consumption signal to the customer, and
 - Cases of meter tampering have been uncovered and quickly resolved.

This program will continue indefinitely.

(7) Customer Assistance Program (Sharing is Caring)

- Program Description. The City Commission recently approved a customer assistance program where customers voluntarily pledge \$1, \$2, etc., per month for those customers that may for some reason need help in paying their electric bills. This program is called "Sharing is Caring" and is administered by the local Salvation Army. This program will assist in the payment of utility bills for customers who are undergoing hardship generally on a one-time basis. This program is not designed for the chronically late or nonpaying customer.

This type of program has proven to be very successful as a voluntary help program locally, statewide, and nationwide. This program is administered by the Salvation Army through the United Way with the City Utility Department promoting and collecting donations through their customers' utility bills. The money collected will then be turned over to the Salvation Army for their determination of customers to be assisted. Utility and City personnel can also refer customers to the Salvation Army for consideration of assistance by this program. The Salvation Army will prepare a monthly report to the City showing monies received, number of customers assisted, and the amount of assistance for the month. At the time the program recipients are known, they will be encouraged to take advantage of the City's Residential Audit Program or any

other programs which may assist them in reducing their energy consumption and thereby reducing their electric bill.

1C.6.5 City of Starke

1C.6.5.1 Introduction

The City of Starke, though having a population of approximately 6,000, offers a wide range of conservation programs including the following.

- (1) Residential Energy Audits,
- (2) High Pressure Sodium Outdoor Lighting Conversion,
- (3) Assistance for Commercial/Industrial Audits,
- (4) 5-Star Award Program, and
- (5) Public Awareness.

A discussion of each of these programs follows.

1C.6.5.2 Existing Conservation Programs

- (1) Residential Energy Audits

Residential energy audits are offered to all customers through the distribution of conservation literature and through program announcements to new customers. The Residential Audits Program involves the City sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. Audits are conducted in accordance with FPSC rules. Attics and crawl spaces are inspected throughout for duct leaks and insulation levels, unless it is physically impossible. The City employs two certified auditors to perform the audits. The program has no rebates paid to the customer from the City of Starke. The incentive for the customer is in most cases a kWh consumption reduction which reduces the customer's electric bill.

- (2) High Pressure Sodium Outdoor Lighting Conversion

This program involves replacing all mercury vapor street lighting and yard lighting. The fixtures are converted whenever maintenance is required. This program has no rebates paid to the customer from the City.

- (3) Assistance for Commercial/Industrial Audits

Onsite audits are offered to all Commercial and Industrial customers. This program involves the City sending an auditor to all interested commercial and industrial customers in an effort to improve the customer's energy efficiency. The program has no rebate paid to the

customer from the City. The incentive for the customer is kW and/or kWh consumption reduction which reduces the customer's electric bill.

(4) 5-Star Award Program

All residential energy audits are evaluated for the 5-star program.

(5) Public Awareness

Available conservation program announcements are made to new customers. Energy conservation literature is distributed including energy conservation messages in customers' newsletters. Available conservation program announcements are made to new customers.

1C.6.6 City of Vero Beach

1C.6.6.1 Introduction

During the 1980s, conservation efforts were mostly directed at the residential sector. Residential kilowatt-hour sales accounted for 53 percent of the City's total sales in fiscal year 1990. The 1990s will see continued efforts in the residential sector in the areas of energy audits and home weatherization. Also, significant emphasis will be placed on conservation in the commercial and industrial sectors.

The conservation programs are promoted on cable television in 30-second spots, through the distribution of energy conservation literature, and program announcements to new customers.

1C.6.6.2 Existing Conservation Programs

The City offers the following conservation programs.

- (1) Residential Energy Audits including the 5-Star Award Program,
- (2) High Pressure Sodium Outdoor Lighting Conversion,
- (3) Assistance for Commercial/Industrial Audits, and
- (4) Fix-up program for the Elderly and Handicapped.

A discussion of each of these programs follows.

(1) Residential Energy Audits

- **Program Description.** Residential energy audits are offered to all residential customers. Audits are conducted in accordance with PSC rules. Audits consist of a walk-through Home Energy Survey with the following materials available upon customer request.
 - Electric outlet gaskets,
 - Socket protectors,
 - Water flow restrictors, and
 - Low flow shower heads.

Home Energy Surveys include a water heater wrap and the installation of showerheads at no cost to the customer.

The Residential Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing energy consumption by 300,000 kWh per year in 1991 through 2000,
 - Reducing summer peak demand by 187.5 kW per year in 1991 through 2000, and
 - Reducing winter peak demand by 281.2 kW per year in 1991 through 2000.
- Program Participation Standards. The Residential Audits Program involves the City sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the City. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
 - Program Benefits and Costs. The Residential Audits Program has proved beneficial to the City's customers in a number of ways. The assumed kilowatt-hour reduction is 400 kWh per audit with assumed reduction in summer and winter peak demands of 0.25 kW and 0.375 kW respectively, per audit.

The City anticipates performing a yearly total of 750 residential audits in 1991 through 2000. The total estimated kilowatt-hour reduction for the City from the Residential Audits Program is 300,000 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand is 187.5 kW per year in 1991 through 2000 and the total estimated kilowatt reduction in winter peak demand is 281.2 kW in 1991 through 2000. It is estimated that by the year 2000 the City will have reduced its kilowatt-hour consumption by 3,000,000 kWh and will have reduced its summer peak demand by 1,875 kW and reduced its winter peak demand by 2,812 kW due to this program.

- Program Monitoring and Evaluation. The Residential Audits Program will be monitored by the FEECA Program for Residential Audits. Comparisons of the customer's previous bills before the audit

can be compared to bills after the audit as a way to verify the estimated kilowatt demand and energy reductions.

(2) High Pressure Sodium Streetlight Conversion

- Program Description. The City has replaced virtually all the mercury vapor lights in its system. This program involves eliminating all mercury vapor street and yard lighting. The fixtures are converted whenever maintenance is required.

The High Pressure Sodium Streetlight Conversion Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by approximately 50 kW during 1981 through 1990, and
- Reducing kilowatt-hour consumption by approximately 450,000 kWh during 1981 through 1990.
- Program Participation Standards. The High Pressure Sodium Streetlight Conversion Program involves the City replacing all mercury vapor street lighting and yard lighting. The program has no rebates paid to the customer from the City. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
- Program Benefits and Costs. The High Pressure Sodium Streetlight Conversion Program estimates an annual reduction of kilowatt-hour consumption of 361 kWh per 100 watt mercury vapor lamp, 723 kWh per 250 watt mercury vapor lamp, and 2,689 kWh per 400 watt mercury vapor lamp. The High Pressure Sodium Streetlight Conversion Program estimates a summer peak demand reduction and a winter peak demand reduction of 0.08 kW demand per 175 lamp replaced.
- Program Monitoring and Evaluation. The High Pressure Sodium Streetlight Conversion Program will be monitored by the FEECA Program for High Pressure Sodium Streetlight Conversion.

(3) Assistance for Commercial/Industrial Audits

- Program Description. Onsite audits are available to all industrial and commercial customers. The purpose of this program is to recommend ways for the customer to improve the efficiency of their energy usage.

The Commercial/Industrial Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 112 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 245,000 kWh per year in 1991 through 2000.
- Program Participation Standards. The Commercial/Industrial Audits Program involves the City sending an auditor to all interested commercial/industrial customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the City. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
- Program Benefits and Costs. The Commercial/Industrial Audits Program assumes an annual kilowatt-hour reduction of 1,750 kWh per audit with an assumed reduction in summer and winter peak demands of 0.8 kW per audit.

The City anticipates performing a yearly total of 140 commercial/industrial audits in 1991 through 2000. The total estimated kilowatt-hour reduction for the City from the Commercial/Industrial Audits Program is 245,000 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 112 kW per year in 1991 through 2000. It is estimated that by the year 2000 the City will have reduced its kilowatt-hour consumption by 2,450,000 kWh and will have reduced its summer peak demand and winter peak demand by 1,120 kW due to this program.

- Program Monitoring and Evaluation. The Commercial/Industrial Audits Program will be monitored by the FEECA Program for Commercial/Industrial Audits. Comparisons of the customer's previous bills before the audit can be compared to bills after the audit as a way to verify the estimated kilowatt demand and energy reductions.

(4) Fix-up Program for the Elderly and Handicapped

- Program Description. The City seeks and receives grants for the Community Block Development Program and Weatherization Program. This is a low-income program with participants as directed by the grants. Energy auditors submit homes for the weatherization program.

The Fix-up Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- Reducing summer peak demand and winter peak demand by 700 kW per year in 1991 through 2000, and
- Reducing kilowatt-hour consumption by 840,000 kWh in 1991 through 2000.
- Program Participation Standards. Participation in the Fix-up Program is directed by the grants. Energy auditors submit homes for the weatherization program.
- Program Benefits and Costs. The Fix-up Program assumes an annual reduction of 1,200 kWh consumption per home and an annual reduction of summer peak demand and winter peak demand of 1 kW per home. The City estimates having a yearly total of 700 participants in the Fix-up Program. It is estimated that by the year 2000 the City will have reduced its kWh consumption by 8,400,000 kWh and will have reduced its summer peak demand and its winter peak demand by 7,000 kW due to this program.
- Program Monitoring and Evaluation. Comparisons of the customer's previous bills before the fix-up improvements were performed can be compared to bills after the fix-up improvements were performed as a way to verify the estimated kilowatt demand and energy reductions.

1C.6.7 City of Bushnell

1C.6.7.1 Introduction

The City of Bushnell, though having a population of approximately 1,500, offers a wide range of conservation programs including the following.

- Residential Energy Audits,
- High Pressure Sodium Outdoor Lighting Conversion,
- Assistance for Commercial/Industrial Audits,
- 5-Star Award Program, and
- Public Awareness.

A discussion of each of these programs follows.

(1) Residential Energy Audits

Residential energy audits are offered to all customers through the distribution of conservation literature and through program announcements to new customers. The Residential Audits Program involves the City sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. Audits are conducted in accordance with PSC rules. Attics and crawl spaces are inspected throughout for duct leaks and insulation levels, unless it is physically impossible. The program has no rebates paid to the customer from the City of Bushnell. The incentive for the customer is in most cases a kWh consumption reduction which reduces the customer's electric bill.

(2) High Pressure Sodium Outdoor Lighting Conversion

This program involves replacing all mercury vapor street lighting and yard lighting. The fixtures are converted whenever maintenance is required. This program has no rebates paid to the customer from the City.

(3) Assistance for Commercial/Industrial Audits

Onsite audits are offered to all commercial and industrial customers. This program involves the City sending an auditor to all interested commercial and industrial customers in an effort to improve the customer's energy efficiency. The program has no rebate paid to the customer from the City. The incentive for the customer is kW and/or kWh consumption reduction which reduces the customer's electric bill.

(4) 5-Star Award Program

All residential energy audits are evaluated for the 5-star program.

(5) Public Awareness

Available conservation program announcements are made to new customers. Energy conservation literature is distributed including energy conservation messages in customers' newsletters.

1C.6.8 City of Leesburg

The City of Leesburg offered conservation programs during 1981 through 1988 including the following.

- Residential Energy Audits,
- High Pressure Sodium Outdoor Lighting Conversion,
- Assistance for Commercial/Industrial Audits,
- 5-Star Award Program, and
- Public Awareness.

These conservation programs were not offered in 1989 or 1990 due to a lack of interest from the City's customers.

In late 1990, the City decided to implement a residential load management program. This program involves the control of participating customers' electric water heaters and central heating or air conditioning units. The projected reductions in summer peak demand, winter peak demand, and net energy for load due to the load management program are summarized in Table B-2 in Appendix 1C-B, Section 2.2, Page 13.

The City is currently training an energy auditor and offers a residential energy audit walk-through to provide suggestions on how the customer may reduce their energy consumption and thereby reduce their energy bill.

1C.6.9 City of Ocala

1C.6.9.1 Introduction

During the 1980s, conservation efforts were mostly directed at the residential sector. Residential kilowatt-hour sales accounted for 42 percent of the City's total sales in fiscal year 1990. The 1990s will see continued efforts in the residential sector with audits, the introduction of load management for electric home heating, air conditioning and water heating, along with further efforts to weatherize homes. Also, significant emphasis will be placed on conservation in the commercial and industrial sectors. The demand-side programs are designed to improve efficiency, implement direct control of residential customer's appliances, encourage time-of-use rates, and achieve additional conservation through commercial and industrial audits.

The City promotes its conservation programs by providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, schools, etc; both on video tape and in person. Bill stuffers are utilized to keep customers aware of the City's conservation programs.

1C.6.9.2 Existing Conservation Programs

The City offers the following conservation programs.

- Residential Energy Audits including the 5-Star Award Program,
- High Pressure Sodium Outdoor Lighting Conversion,
- Assistance for Commercial/Industrial Audits,
- Commercial Time-of-Use Program,
- Natural Gas Promotion,
- Residential Load Management Program, and
- Fix-up Program for the Elderly and Handicapped.

A discussion of each of these programs follows.

(1) Residential Energy Audits.

- Program Description. Residential energy audits are offered to all residential customers on a semi-annual basis by way of bill stuffers. Audits are conducted in accordance with FPSC rules. Attics and crawl spaces are inspected throughout for duct leaks and insulation levels, unless it is physically impossible.

The Residential Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- reducing energy consumption by 200,000 kWh per year in 1991 through 2000,
 - reducing summer peak demand by 125 kW per year in 1991 through 2000, and
 - reducing winter peak demand by 187.5 kW per year in 1991 through 2000.
- Program Participation Standards. The Residential Audits Program involves the City sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the City. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
 - Program Benefits and Costs. The Residential Audits Program has proved beneficial to the City's customers in a number of ways. The assumed kilowatt-hour reduction is 400 kWh per audit with assumed reduction in summer and winter peak demands of 0.25 kW and 0.375 kW, respectively, per audit.

The City of Ocala anticipates performing a yearly total of 500 residential audits in 1991 through 2000. The total estimated kilowatt-hour reduction for the City from the Residential Audits Program is 200,000 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand is 125 kW per year in 1991 through 2000 and the total estimated kilowatt reduction in winter peak demand is 187.5 kW in 1991 through 2000. It is estimated that by the year 2000 the City will have reduced its kilowatt-hour consumption by 2,000,000 kWh and will have reduced its summer peak demand by 1,250 kW and reduced its winter peak demand by 1,875 kW due to this program.

- Program Monitoring and Evaluation. The Residential Audits Program will be monitored by the FEECA Program for Residential Audits. Comparisons of the customer's previous bills before the audit

can be compared to bills after the audit as a way to verify the estimated kilowatt demand and energy reductions.

(2) High Pressure Sodium Streetlight Conversion

- Program Description. The City has 4,129 mercury vapor lights remaining throughout its system. This program involves eliminating all mercury vapor street and yard lighting. The fixtures are converted whenever maintenance is required.

The High Pressure Sodium Streetlight Conversion Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- reducing summer peak demand and winter peak demand by 42.46 kW per year in 1991 through 2000, and
- reducing kilowatt-hour consumption by 178,335 kWh per year in 1991 through 2000.
- Program Participation Standards. The High Pressure Sodium Streetlight Conversion Program involves the City replacing all mercury vapor street lighting and yard lighting. The program has no rebates paid to the customer from the City. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
- Program Benefits and Costs. The High Pressure Sodium Streetlight Conversion Program estimates an annual reduction of kilowatt-hour consumption of 339 kWh per 175 watt mercury vapor lamp, 449 kWh per 250 watt mercury vapor lamp, and 655 kWh per 400 watt mercury vapor lamp. The High Pressure Sodium Streetlight Conversion Program estimates a summer peak demand reduction and a winter peak demand reduction of .0875 kW demand per 175 watt lamps, 0.107 kW demand per 250 watt lamps, and 0.156 kW demand per 400 watt lamps.

The City anticipates replacing a yearly total of 430 street lights in 1991 through 2000. The total estimated kilowatt-hour reduction for the City from the High Pressure Sodium Streetlight Conversion Program is 178,335 kWh per year in 1991 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 42.46 kW per year in 1991 through 2000. It is

estimated that by the year 2000 the City will have reduced its kilowatt-hour consumption by 1,783,350 kWh and will have reduced its summer peak demand and winter peak demand by 424.6 kW.

- Program Monitoring and Evaluation. The High Pressure Sodium Streetlight Conversion Program will be monitored by the FEECA Program for High Pressure Sodium Streetlight Conversion.

(3) Assistance for Commercial/Industrial Audits

- Program Description. Onsite audits are offered to all industrial and commercial customers twice a year via bill notices. The purpose of this program is to recommend ways for the customer to improve the efficiency of their energy usage. To ensure that the City has qualified auditors, two auditors attended Florida Power Corporation's Auditor Training Course that was held in February 1990.

The Commercial/Industrial Audits Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- reducing summer peak demand and winter peak demand by 160 kW per year in 1991 through 2000, and
- reducing kilowatt-hour consumption by 350,000 kWh in 1991 and 175,000 kWh per year in 1992 through 2000.
- Program Participation Standards. The Commercial/Industrial Audits Program involves the City sending an auditor to all interested commercial/industrial customers in an effort to improve the customer's energy efficiency. The program has no rebates paid to the customer from the City. The incentive for the customer is a kilowatt-hour consumption reduction which reduces the customer's electric bill.
- Program Benefits and Costs. The Commercial/Industrial Audits Program assumes an annual kilowatt-hour reduction of 1,750 kWh per audit with an assumed reduction in summer and winter peak demands of 0.8 kW per audit.

The City anticipates performing a yearly total of 200 commercial/industrial audits in 1991 and 100 commercial/industrial audits in 1992 through 2000. These estimates reflect the City's new aggressive

promotion of conservation measures in the commercial and industrial sectors.

The total estimated kilowatt-hour reduction for the City from the Commercial/Industrial Audits Program is 350,000 kWh 1991 and 175,000 kWh per year in 1992 through 2000. The total estimated kilowatt reduction in summer peak demand and winter peak demand is 160 kW in 1991 and 80 kW per year in 1992 through 2000. It is estimated that by the year 2000 the City will have reduced its kilowatt-hour consumption by 1,925,000 kWh and will have reduced its summer peak demand and winter peak demand by 880 kW due to this program.

- Program Monitoring and Evaluation. The Commercial/Industrial Audits Program will be monitored by the FEECA Program for Commercial/Industrial Audits. Comparisons of the customer's previous bills before the audit can be compared to bills after the audit as a way to verify the estimated kilowatt demand and energy reductions.

(4) Commercial Time-of-Use Program

- Program Description. Commercial Time-of-Use Rates are offered to all commercial and industrial customers. This program moves kW demand from peak periods to off-peak periods. Possible participants in this program will be determined by the Commercial/Industrial Audits Program and by the planned City Accounts Load Management Program.

The Commercial Time-of-Use Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by reducing the summer peak demand and winter peak demand by 100 kW per year in 1991 through 2000.

- Program Participation Standards. The Commercial Time-of-Use Program is available to new and existing customers whose business operations can be shifted from on-peak periods to off-peak periods without any detrimental effects to their business. Any commercial or industrial customer is eligible to participate in this program. The incentive for the customer is reduced rates for kW demand and kWh energy. This program has no cost to the participating customer.

- **Program Benefits and Costs.** The Commercial Time-of-Use Program assumes a reduction in summer and winter peak demands of 100 kW per participating customer. The City anticipates having an average of one commercial or industrial customer per year participating in this program.

The total estimated kilowatt reduction in summer peak demand and winter peak demand for the City from the Commercial Time-of-Use Program is 100 kW per year for 1991 through 2000. It is estimated that by the year 2000 the City will have reduced its summer peak demand and winter peak demand by 1,000 kW due to this program.

- **Program Monitoring and Evaluation.** The Commercial Time-of-Use Program will be monitored by viewing the participating customer's current month's billing kW demand usage as an on-peak kW demand reduction.

(5) Natural Gas Program

During residential and commercial audits, the City will, on an individual basis, recommend conversion from electric heat or electric water heating to natural gas when such conversion appears to be cost-effective for the customer. Recommendations will be made in writing on the audit form and the number of recommendations will be included in conservation program reports.

(6) Residential Load Management Program

- **Program Description.** Residential load management will be promoted for residential customers that have electrical water heaters, central air conditioning units, and central heating units. This program, which is being developed with FMPA, allows the City to regulate the usage of the above appliances as a way to reduce weather sensitive peak demand.

The Residential Load Management Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- reducing summer peak demand in 1991 through 2000,
- reducing winter peak demand in 1991 through 2000, and
- reducing kilowatt-hour consumption in 1991 through 2000.

- Program Participation Standards. The Load Management Program involves the City of Ocala installing receivers to control electrical appliances in participating customers' residences. This program reduces the peak electric usage for the City and its power supplier. The program offers the following rebates to participating customers.
 - \$1.50 per month for 12 months paid to customer for control of an electric water heater,
 - \$2.50 per month for 7 months paid to customer for control of an electric central air conditioning unit, and
 - \$2.50 per month for 5 months paid to customer for control of an electric central heating unit.
- Program Benefits and Costs. The Load Management Program assumes an annual average reduction of 246 kWh consumption per installation. The assumed reduction in summer peak demand is 1.12 kW and a winter peak reduction of 2.02 kW per installation.

It is estimated that by the year 2000 the City of Ocala will have reduced its kWh consumption by 1,200,000 kWh and will have reduced its summer peak demand by 4,800 kW and reduced its winter peak demand by 2,800 kW due to this program.

- Program Monitoring and Evaluation. This program will be monitored by tracking the number of active customers participating in the program and by occasional testing to verify the actual kW and kWh reductions.

(7) Fix-up Program for the Elderly and Handicapped

- Program Description. The City seeks and receives grants for the Community Block Development Program and Weatherization Program. This is a low-income program with participants as directed by the grants. Energy auditors submit homes for the weatherization program.

The Fix-up Program meets the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17.001, Florida Administrative Code by the following.

- reducing summer peak demand by 10 kW per year in 1991 through 2000,

- reducing winter peak demand by 10 kW per year in 1991 through 2000, and
- reducing kilowatt-hour consumption by 12,000 kWh in 1991 through 2000.
- Program Participation Standards. Participation in the Fix-up Program is directed by the grants. Energy auditors submit homes for the weatherization program.
- Program Benefits and Costs. The Fix-up Program assumes an annual reduction of 1,200 kWh consumption per home and an annual reduction of summer peak demand and winter peak demand of 1 kW per home. The City estimates having a yearly total of 10 participants in the Fix-up Program. It is estimated that by the year 2000 the City of Ocala will have reduced its kWh consumption by 120,000 kWh and will have reduced its summer peak demand and its winter peak demand by 100 kW due to this program.
- Program Monitoring and Evaluation. Comparisons of the customer's previous bills before the fix-up improvements were performed can be compared to bills after the fix-up improvements were performed as a way to verify the estimated kilowatt demand and energy reductions.

1C.6.10 City of Green Cove Springs

1C.6.10.1 Introduction

The City of Green Cove Springs, though possessing a population of approximately 4,600, offers a wide range of conservation programs including the following:

- Residential Energy Audits,
- High Pressure Sodium Outdoor Lighting Conversion,
- 5-Star Award Program, and
- Public Awareness.

A discussion of each of these programs follows.

(1) Residential Energy Audits

Residential energy audits are offered to all customers through the distribution of conservation literature and through program announcements to new customers. The Residential Audits Program involves the City sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. Audits are conducted in accordance with PSC rules. Attics and crawl spaces are inspected throughout for duct leaks and insulation levels, unless it is physically impossible. The program has no rebates paid to the customer from the City of Green Cove Springs. The incentive for the customer is in most cases a kWh consumption reduction which reduces the customer's electric bill.

(2) High Pressure Sodium Outdoor Lighting Conversion

This program involves replacing all mercury vapor street lighting and yard lighting. The fixtures are converted whenever maintenance is required. This program has no rebates paid to the customer from the City.

(3) 5-Star Award Program

All residential energy audits are evaluated for the 5-star program.

(4) Public Awareness

Available conservation program announcements are made to new customers. Energy conservation literature is distributed including energy conservation messages in customers' newsletters.

1C.6.11 City of Jacksonville Beach

1C.6.11.1 Introduction

The City of Jacksonville Beach offers a wide range of conservation programs including the following.

- Residential Energy Audits,
- High Pressure Sodium Outdoor Lighting Conversion,
- Assistance for Commercial/Industrial Audits,
- 5-Star Award Program, and
- Public Awareness.

A discussion of each of these programs follows.

(1) Residential Energy Audits

Residential energy audits are offered to all customers through the distribution of conservation literature and through program announcements to new customers. The Residential Audits Program involves the City sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. Audits are conducted in accordance with PSC rules. Attics and crawl spaces are inspected throughout for duct leaks and insulation levels, unless it is physically impossible. The program has no rebates paid to the customer from the City of Jacksonville Beach. The incentive for the customer is in most cases a kWh consumption reduction which reduces the customer's electric bill.

(2) High Pressure Sodium Outdoor Lighting Conversion

This program involves replacing all mercury vapor street lighting and yard lighting. The fixtures are converted whenever maintenance is required. This program has no rebates paid to the customer from the City.

(3) Assistance for Commercial/Industrial Audits

Onsite audits are offered to all commercial and industrial customers. This program involves the City sending an auditor to all interested commercial and industrial customers in an effort to improve the customer's energy efficiency. The program has no rebate paid to the customer from the City. The incentive for the customer is kW and/or kWh consumption reduction which reduces the customer's electric bill.

(4) 5-Star Award Program

All residential energy audits are evaluated for the 5-star program.

(5) Public Awareness

Available conservation program announcements are made to new customers. Energy conservation literature is distributed.

1C.6.12 City of Clewiston

1C.6.12.1 Introduction

The City of Clewiston, though having a population of approximately 5,900, offers a wide range of conservation programs including the following.

- Residential Energy Audits,
- High Pressure Sodium Outdoor Lighting Conversion,
- Assistance for Commercial/Industrial Audits,
- 5-Star Award Program, and
- Public Awareness.

A discussion of each of these programs follows.

(1) Residential Energy Audits

Residential energy audits are offered to all customers through the distribution of conservation literature and through program announcements to new customers. The Residential Audits Program involves the City sending an auditor to all interested residential customers in an effort to improve the customer's energy efficiency. Audits are conducted in accordance with PSC rules. Attics and crawl spaces are inspected throughout for duct leaks and insulation levels, unless it is physically impossible. The program has no rebates paid to the customer from the City of Clewiston. The incentive for the customer is in most cases a kWh consumption reduction which reduces the customer's electric bill.

(2) High Pressure Sodium Outdoor Lighting Conversion

This program involves replacing all mercury vapor street lighting and yard lighting. The fixtures are converted whenever maintenance is required. This program has no rebates paid to the customer from the City.

(3) Assistance for Commercial/Industrial Audits

Onsite audits are offered to all commercial and industrial customers. This program involves the City sending an auditor to all interested commercial and industrial customers in an effort to improve the customer's energy efficiency. The program has no rebate paid to the customer from the City. The incentive for the customer is kW and/or kWh consumption reduction which reduces the customer's electric bill.

(4) 5-Star Award Program

All residential energy audits are evaluated for the 5-star program.

(5) Public Awareness

Available conservation program announcements are made to new customers. Energy conservation literature is distributed including energy conservation messages in customers' newsletters.

1C.7.0 Reliability Criteria

Electric utilities customers expect a continuous supply of electricity to help assure their comfort, welfare, and economic well-being. Electric utilities are dedicated to providing continuous and dependable electric supply to their customers in spite of unexpected equipment failures, fuel supply disruptions, load variation and other uncertainties.*

There are two basic approaches used in the utility industry to calculate a system's reliability indices. The two methods are deterministic and probabilistic methods. The most often used deterministic method is reserve margin which is calculated as the system net capacity (excluding firm purchases) less system net peak load (excluding firm purchases), divided by the system peak net load (excluding firm purchases).

The probabilistic method of system planning incorporates the probability of individual unit outages and emergency assistance from other systems and involves calculations that are more mathematically complex, requiring some understanding of different probabilistic reliability indices to interpret the results. The probabilistic index most frequently used is the loss of load probability ("LOLP") which is the expected number of days per year when the utility is projected to have insufficient capacity on-line with tie-line assistance to meet its peak daily load.

There is no "right" level to reliability. Reliability index levels are chosen based on historical system performance and expectation of the future. Utilities usually choose a range of values over which reliability indices are deemed acceptable.

The North American Electric Reliability Council released a report which summarizes the reliability criteria of various regions of the country, indicating that most reliability regions use either a 15 percent reliability criteria or a loss of load probability of one day in 10 years. For state-wide studies in Florida, the FCG utilizes a LOLP criteria of 1 day in 10 years.

Many small electric systems use reserve levels of 15-20 percent, since this index is understandable and easy to calculate. Systems which are isolated often

*North American Reliability Council, 1989 Reliability Assessment.

use the reserve criteria such that capacity is sufficient to meet the annual peak load with the loss of the largest unit.

The following is a summary of individual reliability criteria for the participants.

City of Vero Beach - For purposes of planning for new generation, the City is utilizing a reliability criteria that the installed generating capacity for the combined resources of the City and other resources excluding firm wholesale purchases (FPL partial requirements), but including participation in the Stanton and St. Lucie Unit No. 2, have a combined net capability rating that exceeds the projected weather normalized winter peak demand less firm purchases (FPL partial requirements) by 20 percent. The City normally has a peak annual demand during the winter.

Fort Pierce Utilities Authority - For purposes of planning for new generation, the Authority is utilizing a reliability criteria that the installed generating capacity for the combined resources of the combined resources of the Authority and other resources excluding purchases of partial requirements, but including purchases from Stanton and St. Lucie Unit No. 2, have a combined net capability rating that exceeds the projected weather normalized winter peak demand less firm purchases (FPL partial requirements) by 20 percent. The Authority normally has a peak annual demand during the winter.

City of Homestead - A reserve margin of 20 percent relative to load served from generation or nonfirm purchases is used as the reliability criterion for evaluating new generation for the City of Homestead.

City of Lake Worth - A reserve margin of 20 percent relative to load served from generation or nonfirm purchases is used as the reliability criterion for evaluating new generation for the City of Lake Worth.

Utility Board of the City of Key West - For the Utility Board, a 20 percent reserve margin is used with additional constraints caused by tie-line limitations and the desire to have at least 70 percent of peak load served by the Utility Board's on-island system resources.

City of Starke - A reserve margin of 20 percent relative to load served from generation or nonfirm purchases is used as the reliability criteria for evaluating new generation for the City of Starke.

All-Requirements Project - City of Ocala, City of Leesburg, City of Bushnell, City of Clewiston, City of Jacksonville Beach, City of Green Cove Springs - A 20 percent reserve margin is used by FMPA for load served from generation or nonfirm purchases.

1C.8.0 Supply-Side Alternatives

1C.8.1 General

The FMPA member cities individually have a limited number of supply-side alternatives for capacity additions to their utility system. Through joint action, a number of larger, more economical alternatives can be made available. This section presents the cost and operating characteristics of a number of alternatives available to the FMPA cities.

1C.8.2 Stanton 2

1C.8.2.1 General

FMPA's participation in Stanton 2 is divided into two parts, one for the FMPA Stanton 2 Project serving six generating systems and a second for the FMPA All-Requirements Project serving six nongenerating systems. A complete description of Stanton 2 is presented in Subsection 1A.2.0 Volume 1A. This section presents the cost to the FMPA Stanton 2 Project and the FMPA All-Requirements Project to participate in a 16 percent (66.4 MW) share and a 5.2 percent (21.5 MW) share of Stanton 2, respectively.

1C.8.2.2 Estimated Capital Costs

Estimated capital costs of an ownership share of the Stanton 2 Project and the All-Requirements Project are shown in Table 1C.8.2-1. Dollar amounts shown in the table are for the Stanton 2 Project entitlement share of 66.384 MW and the All-Requirements Project entitlement share of 21.466 MW. Also shown are the unit investment costs expressed in dollars per kilowatt (\$/kW).

Pursuant to the current draft of the Participation Agreement between FMPA and OUC, FMPA will pay to OUC the following purchase and construction costs: (i) its ownership share of the direct construction costs, excluding common facilities, at Stanton Unit No. 2; (ii) its ownership share of interest during construction on direct construction costs, excluding common facilities, through the estimated closing date with OUC; (iii) its ownership share of the initial coal stockpile; (iv) its ownership share of the common facilities for the Stanton Plant; (v) unrecovered carrying costs on its ownership share of the common and external facilities (for the period July 1987 to July 1992); and (vi) projected costs for participation in third unit train.

Estimates of construction costs, common and external facilities costs, and interest during construction for Stanton 2 were based on information provided by OUC and Black & Veatch. For purposes of this analysis, it has been assumed that the commercial operation date for Stanton 2 will be January 1, 1997, as currently estimated by OUC. It was further assumed that FMPA would begin issuing bonds to finance the Stanton 2 Project and the All-Requirements Project's ownership share of Stanton 2 on July 1, 1992 and continue to issue bonds periodically throughout the construction period of Stanton 2. An allowance for initial purchase of the coal stockpile at Stanton 2 and projected costs for participation

in the third unit train has been included in the costs to be capitalized from bonds, as shown on Table 1C.8.2-1. Also included as capitalized costs is an allowance for working capital to provide four months' production operation and maintenance expense (including fuel), administrative and general expense including insurance expense, renewals and replacements expense, common and external facilities use fee and wheeling expenses, and one month's debt service requirement.

Other costs, based on the following assumptions concerning financing, were provided by FMPA's Financial Advisor. It has been assumed that the Agency would issue uninsured bonds with an average interest rate of 7.25 percent, with level debt service over a 30-year period. It has been assumed that interest payments would be funded from bond proceeds until the assumed commercial operation date of Stanton 2. An amount equal to 2 percent of the principal amount of bonds has been assumed to provide for estimated underwriters' discount, engineering costs, legal costs, and all other costs and expenses incurred by FMPA in connection with bond issuance. A Debt Service Reserve Account requirement equal to the estimated maximum annual debt service has been assumed to be funded from bond proceeds. For purposes of this study, it has been assumed that the reinvestment rate on balances in the various funds will be equal to 7.25 percent. Also, it has been assumed that a Reserve and Contingency Fund requirement equal to 10 percent of the Debt Service Reserve Account requirement would be funded from bond proceeds.

Three bond issues are assumed, with the first bond issue assumed to be issued July 1, 1992. Additional bonds are assumed to be issued on January 1, 1994 and January 1, 1996. Interest earnings from all accounts flow to the construction account prior to the on-line date and, except for the Construction Fund, flow to the revenue account after the on-line date.

As shown in Table 1C.8.2-1, the total principal amount of bonds required to fund the estimated capital costs for the Stanton 2 Project under these assumptions is approximately \$164.5 million, or \$2,477.7/kW. Table 1C.8.2-1 also shows the estimated costs for the All-Requirements Project is approximately \$53.2 million, or \$2,477.7/kW. The projected total net debt service for the Stanton 2 Project and the All Requirements Project is projected to be approximately \$12.2 million and \$4.0 million, respectively.

For the purposes of this report, the financing costs for the Stanton 2 Project and the All-Requirements Project were projected assuming interest and principal payments are paid from revenues starting in January 1997, the on-line date of the Unit. FMPA may decide to fund debt service from bond proceeds for the first 1 to 3 years beyond the on-line date of Stanton 2. For example, FMPA could fund 3 years of interest payments such that accruals from revenues to pay principal and interest would begin January 1, 2000. FMPA could then accrue revenues in a rate stabilization fund during the first 3 years after the on-line date of the project and then make withdrawals from this fund in later years to reduce the Participants' revenue requirements. Such a rate stabilization fund could mitigate potential adverse rate impacts on Participants in the initial years of the Project.

1C.8.2.3 Projected Operating Costs

Projected annual operating costs for the Stanton 2 Project and the All-Requirements Project are categorized according to fixed and variable costs and are shown for the period 1997 through 2021 on Tables 1C.8.2-2 and 1C.8.2-3. Fixed costs are shown in dollars per kilowatt per year and variable costs are shown in mills per kWh.

Estimated debt service is assumed funded from bond proceeds at an assumed interest rate of 7.25 percent until January 1, 1997, at which time accruals from revenues to pay interest begin. It was also assumed that interest from the various funds would be deposited into the Construction Fund through the assumed commercial operation date of the Unit, and thereafter earnings from the Debt Service Reserve Account and Contingency Fund, and the Debt Service Account would be deposited into the Revenue Fund to offset Project costs, as reflected in Tables 1C.8.2-2 and 1C.8.2-3.

Pursuant to the current draft of the Participation Agreement between FMPA and OUC, FMPA will pay to OUC a monthly external facilities use fee based on Participants' share of 50 percent of the sum of (i) the external facilities net plant balance times OUC's capital charge rate, plus (ii) OUC's depreciation expense. The estimate of the external facilities use fee was based on information provided by OUC and calculated assuming a 30-year depreciable plant life and a 9.2 percent carrying charge rate. The total external facilities for Stanton 1 and 2 are assumed to be approximately \$31.5 million including \$9.5 million in land and \$22 million in depreciable plant.

Projections of fixed and variable operation and maintenance expenses have been provided by OUC. Administrative and general expenses (including insurance associated with Stanton 2) and capital improvements are included in the projections of fixed operation and maintenance expenses. Renewals and replacements which were included in the operations and maintenance costs provided by OUC were shown separately on Tables 1C.8.2-2 and 1C.8.2-3.

Allowances for OUC system and Agency administrative and general expenses have been estimated based on Agency information, and the escalation rate for these expenses has been assumed to be 4.75 percent per year.

Estimates of wheeling charges for transmission service over the OUC system were based on present charges escalated at 1.5 percent per year. Estimates of wheeling charges for other transmission services are for transmission services over the FPL or FPC system and have been derived based on an analysis of present wheeling charges and the financial model projections of FPL's and FPC's cost of power discussed in detail in Subsection 1C.4.0.

Since the entitlement for cities on the FPL system will be reduced by transmission losses over the FPL system and the OUC system, costs for such capacity and energy losses have been calculated assuming loss factors of 4.1 percent for FPL and 1.63 percent for OUC. Costs for capacity and energy losses for cities on the FPC system have been calculated assuming loss factors of 4.8 percent for FPC and 1.63 percent for OUC.

Fuel costs shown on Tables 1C.8.2-2 and 1C.8.2-3 for Stanton 2 are based on estimates of low sulfur coal costs on a \$/MBtu basis shown in Volume 1A, Table 1A.3.3-3, and on an assumed average heat rate of 10,000 Btu/kWh. An allowance for expenses relating to the acid rain legislation of 1990 has been included, based on \$1,500/ton. This amounts to approximately one mill/kWh in 1997 and is escalated at 4.0 percent per year.

1C.8.3 Advanced Alternatives

The results of OUC's screening analysis indicated that none of the advanced alternatives were cost-effective for OUC. Although the economics for FMPA's members is slightly different than OUC, it is expected that the analysis of advanced alternatives would have similar results for FMPA members. Furthermore, since the amount of capacity being considered under the Stanton 2 Project or All-Requirements Project is rather significant compared to the total load of each of the potential participants, it is believed that this requirement with one of the advanced alternatives versus utilizing conventional commercially proven alternatives represents a certain amount of risk which FMPA's participants are unwilling to take at this time.

1C.8.4 Cost and Operating Characteristics for Selected Alternatives

The relatively small size of the municipal systems represented here is a factor in limiting the available alternatives. The ability to work together in a joint project helps to expand the opportunities.

The primary options available to the Cities are diesels, combustion turbines, combined cycle units and partial requirements purchases. In addition to these, the cost of an atmospheric fluidized bed coal unit will be discussed. The cost data were obtained from several sources including industry data and R. W. Beck and Associates, the Agency's consulting engineer.

1C.8.4.1 Diesel Engines

A common unit among the small generating utilities is the medium speed diesel unit. These units offer good efficiency over a wide range of output and can be configured to operate on a blend of oil (No. 2 oil is used most frequently in utility application) and natural gas when gas is available. The units provide quick start capability and operate well in peaking or intermediate duty. The capital cost for these units is now relatively high compared to most of the other options. Recent permitting experience with the new Key West units confirms the need to consider NO_x reduction equipment. The example included here is estimated with selective catalytic reduction ("SCR") equipment and operating costs.

The estimated performance and cost data for a 9.6 MW diesel is provided on Table 1C.8.4-1.

1C.8.4.2 Combustion Turbine (Simple Cycle)

The combustion turbine (gas turbine) consists of three major components: the air compressor, the combustor, and the expansion turbine. The air compressor is used to charge air into one or more combustion chambers (combustors) where fuel is injected and burned. The products of combustion are then expanded through a turbine until they reach the ambient pressure of the surroundings. The expansion of the combustion products through the turbine results in rotational energy. The rotational energy produced by the turbine is converted to electric energy via an electric generator. Most combustion turbines operate on either No. 2 oil and/or gas fuels.

Combustion turbines are marketed by several manufacturers in various sizes in a compact self-contained power plant package specifically designed for peaking and certain other power applications. There are other more advanced combustion turbine technologies such as the steam injection combustion gas turbine (STIG), in which the combustion gases are passed through a heat recovery steam generator (HRSG) to be injected into the combustion chamber to increase efficiency. Due to the limited commercial experience with STIG type units, this technology was not selected for review.

The major emission from the combustion turbine, operating on natural gas, is nitrogen oxide (NO_x). Control of this emission is achieved by injecting water directly into the combustion zone to lower flame temperature. Selective catalytic reduction (SCR) of nitrogen oxide emissions has not yet been demonstrated in commercial operation of simple cycle machines as the gas turbine exhaust temperature is too high (typically 1000 degrees fahrenheit) for present day catalysts.

Based on the requirements of the Participants, sizes of approximately 38 MW and 75 MW were assumed for this type of unit. These sizes correspond to the currently available General Electric (GE) Frame 6 and Frame 7 combustion turbines at International Standards Organization (ISO) ratings on natural gas at 59 F ambient temperature and sea level. The cost estimate for this unit includes land, structure and improvements, roads, the combustion turbine generator, mechanical equipment, electrical and startup costs. The estimated cost and performance data are included in Table 1C.8.4-1. The smaller unit could be installed for use of one of the generating utilities alone. The larger unit, which reflects economies of scale and higher efficiency associated with larger units, would currently be too large for most of the systems alone. The lower per unit cost of the larger unit allows the unit to be considered for joint ownership including transmission wheeling across other systems.

1C.8.4.3 Combined Cycle Units

The combined cycle unit employs two different thermodynamic cycles: (i) the cycle by which hot combustion gases are expanded through a turbine to do work and (ii) the steam cycle in which water is vaporized and expanded through a turbine to do work, and then pumped back into the boiler. Combined cycle units are capable of achieving relatively high thermal efficiency as compared to simple

cycle combustion turbines and steam electric generating stations. Most combined cycle units operate on No. 2 oil and gas. Several Florida generating utilities have combined cycle units and several are currently planning to construct units.

A combined cycle system utilizes combustion turbines for power generation as previously discussed. The energy in the high temperature exhaust of the combustion turbine is passed through a heat recovery steam generator (HRSG) and the steam generated powers a conventional steam turbine generating unit. High-pressure steam is expanded through the steam turbine which results in rotational energy. This energy is converted to electricity via an electric generator. The primary advantage of combined cycle operation is a sizable increase in plant capacity with no additional fuel input required, which improves the overall plant heat rate or efficiency.

The conventional combined cycle is a mature technology and these units can be constructed in various configurations. The cost estimate for the large unit in this analysis is based upon the installation of two combustion turbines, one HRSG, and one steam turbine. This configuration would have a capability of approximately 220 MW and would provide more reliable capacity than a combined cycle unit utilizing a single combustion turbine.

The combined cycle, with its relatively higher efficiency, is generally utilized for intermediate or base load duty depending on the relative prices and fuel available.

The major emission from the combined cycle unit operating on natural gas is NO_x . Control of this emission is achieved by injecting steam from the HRSG into the combination zone to reduce exhaust temperature and associated NO_x emissions. Steam injection is more efficient than water injection. Further NO_x reduction may be achieved through selective catalytic reduction (SCR). In this process, ammonia is sprayed into the exhaust gas to react with nitrogen oxides in the presence of a catalyst (usually composed of vanadium and/or tungsten). The products of this reaction are nitrogen and water vapor. The SCR catalyst is installed in the HRSG at a point where flue gas temperatures are appropriate for chemical reaction. The cost projections for this analysis are based on the assumption that both steam injection and the SCR are installed.

There is some uncertainty on the emerging environmental requirements for NO_x control. The examples included here are estimated with SCR equipment and operating costs.

The combined cycle estimates are based on a 50 MW and a 220 MW unit. The estimated cost and performance data are included in Table 1C.8.4-1. The smaller unit includes one combustion turbine and could be installed for use of one of the generating utilities alone. The larger unit includes two combustion turbines and would currently be too large for most of the systems alone. The lower per unit cost and improved efficiency of the larger unit allows the unit to be considered for joint ownership including transmission wheeling across other systems.

1C.8.4.4 Atmospheric Fluidized Bed Combustion Unit

Atmospheric Fluidized Bed Combustion (AFBC) units are relatively new to the U.S. but they are being applied in utility systems. FMPA has had discussions with developers proposing to build a modular unit in Florida. This unit was chosen to provide a coal alternative given the limited opportunities to participate or build a coal unit with the more attractive economies of scale.

Fluidized bed technology, a method of burning a broad range of fuels in an environmentally acceptable manner, has been the subject of considerable investigation and study since the 1960s. Fluidized bed combustion is the method of burning solid fuel in a turbulent bed mixed with a fluidizing medium of small inert particles which are kept in a state of agitation and fluidity by a flow of high velocity combustion air and gases of combustion. This technology makes it possible to efficiently burn a broad range of low grade fuels including coals with high sulfur or ash content and petroleum coke. By using limestone as a part of the fluidizing bed medium, it is possible to remove much of the sulfur directly in the combustion process by chemical reaction between the sulfur in the fuel and the calcium carbonate in the limestone, forming gypsum (calcium sulfate).

Fluidized bed technology utilizes two general types of combustors: atmospheric types in which the combustion chamber operates at atmospheric pressure, and the pressurized type in which the combustion chamber operates at a pressure greater than atmospheric. The pressurized fluidized bed would be used generally in a combined gas turbine-steam turbine cycle and, at present, projects of this type would be classed as demonstration projects since performance is being projected only on the basis of laboratory test data. Atmospheric type fluidized bed combustors are divided into three categories: bubbling bed, deep bed, and circulating bed.

The circulating fluidized bed differs from the bubbling bed and deep bed types in that the circulating fluidized beds have no defined bed level, the fluidization extends from the bottom of the combustion chamber to the top, and particles of fuel and the inert material are carried out of the combustion section and into a cyclone-type separator. The cyclone separator permits the hot combustion gas along with particles too fine to be retained by the cyclone-separator to pass into the steam generator section of the assembly. The cyclone-separator is a device with a gas pass arrangement which produces a high velocity spiral flow of the gases and entrained particles and, by means of centrifugal force, causes the particles greater than a certain predetermined size to be recirculated back into the combustion chamber.

A number of advantages are claimed by manufacturers of fluidized bed combustors over conventional firing methods as listed below.

- Ability to more easily burn low grade fuels, low volatile fuels, high ash and high sulfur coals, high vanadium and high sulfur petroleum coke, wood waste and shredded municipal solid waste.
- Simpler operation than pulverized coal boilers equipped with sulfur dioxide removing scrubbers.
- Capital costs competitive with pulverized fuel boilers equipped with scrubbers.
- Because fluidized bed combustors operate at the relatively low firing temperatures of approximately 1650 degrees fahrenheit, slagging problems are virtually eliminated. Slagging occurs when particles of ash leave the combustion chamber at a temperature high enough to cause them to be plastic or fluid and to adhere to boiler tubes as they are cooled in passing through the convection section. The elimination of slagging problems permits the manufacturer to use fewer soot blowers than are generally used with conventional boilers.
- The capture of sulfur contained in the fuel is accomplished directly during the combustion process. This is in contrast to the sulfur removal process in conventional boilers where SO_2 and SO_3 are formed in the combustion chamber and are removed from the flue gas in a reagent type scrubber, generally a spray of limestone and water slurry, after it has passed through the convection section of the boiler. In the fluidized bed combustor, fine grained limestone is fed into the combustor with the fuel

and desulfurization taking place directly in the combustion zone. Sulfur reduction on the order of 90 percent or more can usually be achieved.

- Because of the relatively low combustion temperatures, nitrous oxide formation is low compared to that of conventional boilers.
- The solid waste consisting of bottom ash, fly ash and sorption reaction products forms a dry alkaline solid with advantageous physical and chemical characteristics for disposal in a landfill.

A current disadvantage to implementation of AFBC Units versus conventional pulverized coal units is the relatively high amount of limestone utilized in the desulfurization process and associated waste disposal.

Estimated performance and cost data are provided for a 150 MW AFBC unit in Table 1C.8.4-1. The cost estimate includes the consideration for selecting and developing a new site.

TABLE 1C.8.4-1
Florida Municipal Power Agency
Selected Power Supply Alternatives
Cost and Operating Characteristics

	ALTERNATIVES					
	[1] Diesel	[2] CT	[3] CT	[4] CC	[5] CC	[6] AFBC
<u>Characteristic</u>						
Unit Size (MW)	9.6	38	75	50	220	150
Plant Book Life	30	30	30	30	30	30
Construct. Cost ('90\$/kw)	1,080	477	406	780	643	2,482
Construction Time – yrs.	3	1	2	2	3	3
Fixed O&M ('90\$/kw-yr)	0	1.1	0.7	12.6	3.9	34.0
Variable O&M ('90\$/MWH)	7.5	10.5	8.1	6.0	7.9	7.6
Fuel	No 2	Gas	Gas	Gas	Gas	Coal
Avg. Heat Rate (Btu/kwh)	8,500	12,800	12,500	9,200	8,000	10,100
Equivalent Availability	90	90	90	90	90	81
Forced Outage Rate	5	5	5	5	5	8
Planned Maint. – weeks/yr	2	2	2	2	2	6

Gas* = 95% Nat Gas + 5% No 2 oil

1C.8.5 Combined Cycle Repowering

Conversion of existing steam units to combined cycle units by adding a combustion turbine and a waste heat boiler is an option for a few of the generating cities. The conversion can be economic if space at the existing plant site is available and the existing steam turbine is in reasonable condition. In evaluating the potential benefits of a conversion, each utility must consider, on a case-by-case basis, the requirement for space at the existing site, the impact on existing environmental permitting, the availability of additional gas fuel, the potential cost impacts of adding additional emission control equipment, the costs of removing and/or refurbishing existing equipment to extend the life over the economic life of the new equipment added, and the potential efficiency penalty associated with using existing equipment. When all costs are taken into account, the total cost may not be much different from a new combined cycle plant.

1C.8.6 Independent Power Producers

In July of 1990, the Kissimmee Utility Authority, together with the OUC and the Florida Municipal Power Agency (collectively the Utilities), issued a joint Request For Proposals (RFP). The RFP solicited the interest to supply the Utilities with 440 MW of firm base and intermediate load electric energy and capacity to become commercial on January 1, 1997.

In response to the RFP, 19 companies submitted notices of intent to bid. However, only three proposals were submitted as of the November 13, 1990 deadline. The three respondents, The Enron Power Corporation, Inc. (ENRON); Citrus Energy Partners, L.P. (NRG); and PG&E-Bechtel Generation Company (PG&E), submitted bids totaling 1,276 MW. All three bids were evaluated as described in Subsection 1A.5.4 of Volume 1A, and found to be more expensive than Stanton 2.

1C.8.7 Power Purchases and Wheeling

All of the FMPA participating generating cities have contracts with, commitments from or have made requests to Florida Power & Light to purchase partial requirements through the PR-3 Tariff. The FMPA All-Requirements Project purchases partial requirements from FPL as well as FPC through a specific partial requirements contract (Agreement for Partial Requirements Resale Service, ...). Both FPC and FPL partial requirements costs are based on embedded average system cost for capacity and energy.

The projected costs for FPC and FPL partial requirements power (PR power) as well as the forecast cost for transmission service over their respective transmission systems is given in Table 1C.8.7-1. The costs were projected for FMPA by the firm of R. W. Beck and Associates, the Agency's Consulting Engineers, with the assumptions as previously discussed in Subsection 1C.4.4. The FPL PR power is priced at the delivery point with transmission and losses included in the capacity and energy prices. The FPC PR power is priced at the generation level. For FPC PR power, the cost for transmission and losses must be added to determine the total cost.

The PR power is provided on a basis similar to what FPC and FPL provide for their native load customer. This simply means that FPC and FPL PR power includes reserve for reliability.

Table 1C.8.7-1
Projected Financing Costs for FMPA Stanton 2 Project
and All-Requirements Project \$(000)

	<u>Stanton 2 Project</u>	<u>All-Requirements Project</u>	<u>Total</u> \$(000)	<u>\$/kW</u>
MW	66.384	21.466		
Construction Costs:				
New Facilities ^a	83,500	27,000	110,500	1,257.83
Common Facilities ^b	10,380	3,357	13,737	156.37
Cost of Carry of Common and External Facilities (July 1987 to July 1992) ^c	12,797	4,138	16,935	192.78
Unit Train 3 ^d	266	86	352	4.01
Carrying Costs May 1990 to July 1992 ^e	211	68	279	3.18
SUBTOTAL	107,154	34,649	141,803	1,614.41
Working Capital ^f	10,522	3,403	13,925	158.51
Fuel Stock ^g	3,192	1,032	4,224	48.08
Debt Service Reserve Account ^h	13,589	4,394	17,983	204.71
Contingency Account ⁱ	1,359	440	1,799	20.47
Issuance Expense	3,289	1,064	4,353	49.55
Interest Earnings	(18,623)	(6,022)	(24,645)	(280.54)
Interest During Construction	43,996	14,226	58,222	662.75
TOTAL	164,478	53,186	217,664	2,477.70

^aBased upon total cost of \$522,000,000, Stanton 2 Project share of 15.9962 percent and the All-Requirements Project share of 5.1724 percent, respectively.

^bCommon facilities based upon total common facilities of Stanton 1 and 2 of \$133,748,837 (December 1990), depreciated value of \$129,788,165 (closing date January 1992), Stanton 2 share of common facilities (50 percent) and percentages of Stanton 2 Project and All-Requirements Project in note a above. Costs assumed to be paid at closing on July 1, 1992.

^cEstimated unrecovered carrying costs on common facilities based upon total unrecovered cost of \$20,000,000 for Stanton 2, FMPA's share of the unrecovered cost of 63.984 percent for the Stanton 2 Project and 20.690 percent for the All-Requirements Project. Costs assumed to be paid at closing on July 1, 1992.

^dProjected costs for participation in Unit Train 3 are based upon initial cost of \$5,000,000 as of January 1992, 15-year assumed life, and depreciation of 5 years between January 1992 and January 1997. Cost of Unit Train 3 assumed to be shared between Units 1 and 2. Cost assumed to be paid prior to Unit 2 being placed in service.

^eThis amount includes assumed interest during construction for construction costs prior to closing on July 1, 1992.

Table 1C.8.7-1 (Continued)
Projected Financing Costs for FMPA Stanton 2 Project
and All-Requirements Project \$(000)

^fWorking capital expenses based upon 4 months operating costs including fuel, external facility use fees, operation and maintenance, wheeling, Agency and OUC administrative and general expenses, renewals and replacements, capacity losses, and acid rain allowances.

^gFuel stock based upon the assumed requirement for 3 month fuel supply, and the ownership percentages in note a.

^hThe Debt Service Reserve Account is assumed to be equal to the maximum annual debt service.

ⁱThe contingency account is assumed to be equal to 10 percent of the debt service reserve account.

1C.9 SUPPLY-SIDE SCREENING

1C.9.0 Supply-Side Screening

Normally, a system planning study will evaluate the cost effectiveness of all viable alternatives taking into account the specific needs of the system before making conclusions on the capacity addition. For the FMPA projects, this section will compare the most likely alternatives available to the cities on a somewhat generic basis without specific consideration for the individual system. The comparison of alternatives for each system will not be presented here. It is hoped that this analysis will illustrate the more salient planning considerations common to all the cities.

The supply-side alternatives discussed in Subsection 1C.8.0 represent some of the more cost-effective alternatives available to the cities. This section compares these different technologies using first a screening curve analysis and then a constant capacity factor present worth revenue requirements analysis.

The screening curve analysis graphically compares the total levelized cost of the alternatives at various capacity factors. This technique is useful for comparing a large number of alternatives to determine the most likely alternative to carry forward to more detailed study. The costs compiled for this analysis for generating alternatives include the projected net debt service (debt service less interest earnings), startup and inventory costs, operating and maintenance expenses, and consumables. The capital costs estimates for generation alternatives include costs of emission control equipment necessary to meet more stringent environmental restrictions when there was uncertainty as to what technology may be required to meet the best available control technology ("BACT") criteria. For example, for combined cycle units, SCRs were assumed to control NO_x .

To reflect projected differences in the total fuel costs and in particular the projected differences in future fuel costs between various alternatives, 25-year levelized costs were prepared for each alternative. These levelized cost projections represent a stream of uniform annual costs (\$/kW-yr) which are equivalent to the present worth of the projected annual costs over the first 25 years of each alternative using an annual discount factor of 7.25 percent.

Figure 1C.9-1 at the end of this section shows the levelized cost comparisons for the peak load resources, including the diesel and the two combustion turbines. The area of interest on this graph is usually in the zero to 20 percent capacity factor range. The lowest cost unit for the entire range appears to be the 38 MW

CT; however, all three units are very close. Since it is assumed the 38 MW CT Unit was placed on the utility's system, no wheeling and loss costs over other transmission systems were assumed. It is projected that similar size combustion turbines from other manufacturers would have similar results as indicated on Figure 1C.9-1.

The three alternative base load generating resources are compared on the screening curve shown on Figure 1C.9-2. The area of most interest on base load comparisons is usually between 50 and 85 percent capacity factor. The results of the units compared show that the combined cycles are likely to be the most economical over the range of interest. The small combined cycle is surprisingly competitive with the larger one due again primarily to the lack of transmission and wheeling charges across other transmission systems. The fluidized bed alternative could become much more attractive if the initial capital cost could be lowered. This might be possible if standardized modular designs can be developed and constructed with greater efficiency. The most likely generation alternatives as well as the most likely purchase alternatives are shown on Figure 1C.9-3 comparison of technologies. This screening curve shows how the peaking, intermediate and base load resources compare for all the capacity factors. The combustion turbine for very low capacity factors is projected to be the lowest cost alternative. The combined cycle plant is projected to be the most economical up to about 35 percent capacity factor. The combined cycle plants do not operate well in this low capacity factor range. Based on the screening analyses, Stanton 2 and FPC and FPL partial requirements appear to be the most economical choices for base load operation in the 75 percent range. A lower oil and gas price forecast could make the combined cycle more competitive.

One disadvantage with the screening curves discussed above is that in levelizing the fixed and variable costs over a long period, the relative projected cost differences between the units on a year-to-year basis is not shown. One methodology used to overcome this disadvantage involves calculating the cumulative present worth cost difference between alternatives on a year-by-year basis assuming a certain capacity factor typical for the type of alternatives being compared. Such comparison is shown on Figure 1C.9-4 for a difference in present worth revenue requirements with Stanton 2 costs. This figure shows that the three main competitors to Stanton 2 are less expensive in their early years by up to \$20 million present worth, but they are all more expensive over the 25-year

period analyzed. While the negative cost differences do persist for a number of years, Stanton 2 is projected to have substantial benefits over the life of the plant.

The specific economic comparisons for cities in the Stanton 2 Project and the All-Requirements Project are contained in Appendix 1C.E with a summary of the results in Subsection 1C.11.0. Most of the plans provided by the participants consider partial requirements as their primary alternative to Stanton 2. The screening curves generally confirm that partial requirements purchases are reasonable alternatives to Stanton 2 participation.

1C.10 ALTERNATIVE PLAN
DEVELOPMENT

1C.10.0 Alternative Plans

1C.10.1 General

In order to prepare an economic analysis of the Stanton 2 Project and All-Requirements Project, each participant was requested to supply its current power supply plan to meet its load and reliability criteria utilizing resources other than Stanton 2. These alternative plans are discussed in this section.

1C.10.2 Fort Pierce Utilities Authority and City of Vero Beach

Fort Pierce and Vero Beach currently dispatch their resources jointly to meet the combined system load of both utilities. The last power supply resource added by these two systems was a Frame 5 combustion turbine utilized to repower Fort Pierce's Steam Unit in February 1990. Currently, Vero Beach is undertaking a project to repower its Steam Unit 2 with a Frame 6 combustion turbine which is projected to be placed in service in 1992.

In their response to FMPA, Fort Pierce and Vero Beach have stated that the most likely alternative to the City's participation in the Stanton 2 Unit would be additional purchases of partial requirements from FPL. This alternative is projected to be a long-term alternative that is reasonably attainable and is projected to be available in the quantities required to meet the Authority and City's combined requirements over the period 1991 - 2021. The projected capacity plans with and without Stanton 2 are shown in Table 1C.D.1-1 in Appendix 1C.D. The amount of purchases will be adjusted from year to year in order to obtain the desired reliability margin of 20 percent reserves.

1C.10.3 City of Homestead

Homestead completed a power supply study in 1990 which identified a 30 MW staged combined cycle unit in 1992/1996 followed by a 21 MW combustion turbine unit in 2001 as the most economical nonjoint venture generation alternative. The Stanton 2 Project was still in the preliminary planning stages and was not considered as an alternative at that time. With the Stanton 2 Project now being firmly planned for 1997, the City of Homestead considers Stanton 2 to be a reasonable, obtainable long-term base load generation alternative to its currently planned 30 MW staged combined cycle plant. The projected capacity plans with and without Stanton 2 are shown in Table 1C.D.1-2 in Appendix 1C.D.

1C.10.4 Utility Board of the City of Key West

The Utility Board is currently purchasing short-term power from FPL, through May 1993, and it currently anticipates that when the short-term power purchase is terminated, the Utility Board will replace it with FPL partial requirements purchase which it will utilize as a base load resource. Because the utility is a totally oil dependent utility for generation on-island, it is projected that the Utility Board will continue to import a larger portion of its power for base load requirements. Stanton 2 and FPL partial requirements represent the most reasonably obtainable resources projected to be available in this category of use in the quantities required to meet the Utility Board's requirements over the period 1991 - 2021. The projected capacity plans with and without Stanton 2 are shown in Table 1C.D.1-3 in Appendix 1C.D.

1C.10.5 City of Lake Worth Utilities

The City of Lake Worth Utilities currently serves existing load and reserve requirements with the combined capacity of the City's owned and operated generating facilities and the City's interest in off-system generating projects. Based upon load growth projections and the expected retirement of existing generating facilities at the City's plant, the Utility must add additional capacity by the year 1996. The City has stated that FPL partial requirements and Stanton 2 represent the most reasonably obtainable resources available to the City for increasing the City's capacity over the study period. Stanton 2 provides a long-term alternative for providing a significant portion of the capacity required to meet the City's future power requirements. The projected capacity plans with and without Stanton 2 are shown in Table 1C.D.1-4 in Appendix 1C.D. The amount of purchases will be adjusted from year to year in order to obtain the desired reliability margin of 20 percent reserves.

1C.10.6 City of Starke

The City has stated that the most likely alternative to the City's participation in the Stanton 2 Unit would be additional purchases of partial requirements from FPL. This alternative is projected to be an economical long-term alternative that is reasonably attainable and is projected to be available in the quantities required to meet the City's requirements over the period 1991 - 2021. The annual capacity plans with and without Stanton are shown in Table 1C.D.1-5 in Appendix 1C.D. The amount of purchases will be adjusted from year to year in order to obtain the desired reliability margin of 20 percent reserves.

1C.10.7 All-Requirements Project

The most likely alternative to the All-Requirement Project's participation in the Stanton 2 Unit would be additional purchases of partial requirements from FPL and FPC. This alternative is projected to be an economical long-term alternative that is reasonably attainable and is projected to be available in the quantities required to meet the Project's requirements over the period 1991 - 2021. The annual capacity plans with and without Stanton are shown in Table 1C.D.2-2 in Appendix 1C.D. The amount of purchases will be adjusted from year to year in order to obtain the desired reliability margin of 20 percent reserves.

1C.11.0 Economic Analysis

1C.11.1 General

The alternative plans listed in Subsection 1C.10.0 were evaluated on a comparative cost basis. Comparative costs include only those costs which are affected by differences in the plans. The economic analyses determine the annual revenue requirements of items which are affected by the alternative plans. Annual comparative revenue requirements include the following components.

- Fuel costs.
- Purchased power costs.
- Operation and maintenance (O&M) costs.
- Capital costs for new generation.

A production cost simulation program was used to model each Participant's system for the alternative plans developed in Subsection 1C.10.0. Annual system fuel, purchased power, and O&M costs are developed for each plan. Production cost simulation is necessary to incorporate the effect upon the operation of the existing units due to the new unit additions and future capacity and energy requirements.

The objective of the economic analysis was to determine the total present worth of the annual comparative revenue requirements. This refers to the sum of the yearly nominal comparative revenue requirements discounted to 1991 using FMPA's present worth discount rate.

1C.11.2 FMPA Stanton 2 Project Systems

The individual economic analyses for each of the FMPA Stanton 2 Participants are discussed in Appendix 1C.E. A summary of the Stanton 2 Participants is shown in Table 1C.11.2-1. As shown in this table, the present worth savings for Fort Pierce, Vero Beach, Key West, and Starke are projected to range from 0.6 percent to 2.5 percent with respect to total affected power costs over the period 1997 through 2021. The present worth savings for Homestead and Lake Worth are projected to be 1.6 percent and 1.4 percent, respectively, over the period 1997 through 2010, the period for which such savings were projected.

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1C.11.2-2

Table 1C.11.2-1

Florida Municipal Power Agency Stanton 2 Analysis
Summary of Economic Analysis of Stanton 2 Participants

	Participation Level	1997-2010 Savings \$(000)		1997-2021 Savings \$(000)	
		Cumulative	Present Worth	Cumulative	Present Worth
Fort Pierce Utilities Authority, and City of Vero Beach	31.800	24,393	5,661	174,034	30,420
Homestead	15.900	5,572	3,063 1.6 percent*		
Utility Board, City of Key West	9.540	3,065	206	33,615	5,426
Lake Worth	7.950	10,278	3,522 1.4 percent*		
Starke	1.194	357	(39) -0.1 percent*	5,414	720 0.7 percent*
Total	<u>66.384</u>				

*Cumulative present worth savings as a percent of total cumulative present worth annual comparative revenue requirements.

1C.11.3 FMPA All-Requirements Project System

The individual economic analyses for the FMPA All-Requirements Project Participants are discussed in Appendix 1C.E. A summary of the All-Requirements Participants is shown in Table 1C.11.3-1. As shown in this table, the total present worth savings for these Participants is projected to be \$11.9 million or 0.3 percent over the study period.

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Table 1C.11.3-1
 Florida Municipal Power Agency Stanton 2 Analysis
 Summary of Economic Analysis of All-Requirements Project

<u>Participant</u>	<u>MW Participation Level</u>	<u>1997-2010 Savings \$(000)</u>		<u>1997-2021 Savings \$(000)</u>	
		<u>Cumulative</u>	<u>Present Worth</u>	<u>Cumulative</u>	<u>Present Worth</u>
All-Requirements	21.466	3,240	(943) 0.0 percent*	81,660	11,941 0.3 percent*

*Cumulative present worth savings as a percent of total cumulative present worth annual comparative revenue requirements.

1C.11.3-2

1C.12.0 Sensitivity Analysis

The results of the economic analysis for the Stanton 2 Project Participants and the All-Requirements Project Participants were tested using alternative fuel price projections.

In this sensitivity analysis, a lower cyclical forecast, provided by Black & Veatch, was used for all onsite generation, jointly-owned projects and purchased power. Other than this change in projected fuel price, all other assumptions used in the base case economic analysis were used for the sensitivity case.

The results of the sensitivity analysis are shown in Table 1C.12.0-1 and Table 1C.12.0-2 for the Participants. As shown in the tables, projected savings are lower than for the base case, since this sensitivity case represents a lower cost differential between coal and other fuels (gas, oil), but there are positive cumulative present worth savings for each of the Stanton 2 Project Participants and approximately a break-even on cumulative present worth savings for the All-Requirements Project Participants.

Table 1C.12.0-1
 Florida Municipal Power Agency Stanton 2 Analysis
 Summary of Economic Analysis of Stanton 2 Participants

	Participation Level	1997-2010 Savings \$(000)		1997-2021 Savings \$(000)	
		Cumulative	Present Worth	Cumulative	Present Worth
Fort Pierce Utilities Authority, and City of Vero Beach	31.800	10,994	581 0.1 percent*	100,133	14,809 1.8 percent*
Homestead	15.900	2,562	3,150 1.8 percent*		
Utility Board, City of Key West	9.540	2,821	200 0.1 percent*	32,909	5,101 1.0 percent*
Lake Worth	7.950	7,963	3,160 1.3 percent*		
Starke	1.194	18	(168) -0.3 percent*	3,259	290 0.4 percent*
Total	<u>66.384</u>				

*Cumulative present worth savings as a percent of total cumulative present worth annual comparative revenue requirements.

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Table 1C.12.0-2
 Florida Municipal Power Agency Stanton 2 Analysis
 Summary of Sensitivity Analysis of All-Requirements Project

<u>Participant</u>	MW Participation <u>Level</u>	<u>1997-2010</u> <u>Savings \$(000)</u>		<u>1997-2021</u> <u>Savings \$(000)</u>	
		<u>Cumulative</u>	<u>Present</u> <u>Worth</u>	<u>Cumulative</u>	<u>Present</u> <u>Worth</u>
All-Requirements	21.466	(12,250)	(6,758) (0.5) percent*	27,135	(559) 0.0 percent*

*Cumulative present worth savings as a percent of total cumulative present worth annual comparative revenue requirements.

1C.12-3

1C:13 STRATEGIC
CONSIDERATIONS

1C.13.0 Strategic Considerations

In selecting a power supply alternative, a utility must consider certain strategic factors which reflect the utility's long-term ability to continue to provide economical and reliable electric capacity and energy to its customers. Some of these factors are discussed below.

1C.13.1 Fuel Mix

One of the principal risks in selecting a power supply plan that meets the Utility's objective of reliability and economy is the projection of fuel costs which usually represent a significant portion of total power costs, and are usually the most volatile element of power costs. For this reason one strategic consideration should be to maintain a fuel mix that mitigates the potential impact of price fluctuation due to unforeseen market influences.

The appropriate mix of fuels may be different for each utility, but the general conclusion is that the utility should not be very dependent on one type of fuel.

1C.13.2 Fuel Supply

The supply of fuel is a factor which can determine to some extent the options available to a utility. For example, the Utility Board of the City of Key West has no access to natural gas fuel for electric generation, therefore, its options for on-island generation are limited.

The availability of capacity on the Florida Gas Transmission pipeline is a factor which may limit some of the Participant's options. It is uncertain, at this time, the extent to which the Phase III pipeline expansion, which may occur in the 1994-1995 time frame, will provide sufficient gas fuel for new generation.

1C.13.3 Siting

The availability of space at existing sites and of new sites which comply with more stringent environmental restriction is becoming more limited in the state.

1C.14.0 Consequences of Delay

The initial consequence of delaying the proposed generating plant is primarily the cost impact of construction costs due to price escalation, the potential loss of opportunities with respect to replicating work previously done for Stanton 1, and the need to supply an alternative resource to maintain the same level of system reliability that would be provided to the system by Stanton 2.

If the construction of the Stanton 2 Unit were delayed one year, the net effect of escalating construction costs and discounting future cash flows by one additional year could increase or decrease the cumulative present worth total net financing cost for the Stanton 2 Project and All-Requirements Project over its 30-year life.

This impact would depend on the actual increase in construction costs with the effects of replication and the discount rate. Therefore, it is assumed the delay would not impact the present worth financing costs for the Stanton 2 Project and All-Requirements Project.

The impact on annual costs resulting from delaying the unit one year is projected to be a decrease in costs during the first year of delay by approximately 1.1 million and 3.1 million in 1991 dollars for the All-Requirements and Stanton 2 Project Participants, respectively. This annual cost difference is dependent on the type of resources used to replace the Stanton 2 capacity.

As indicated in Subsection 1C.11.0, the Stanton 2 Project and All-Requirements Project are projected to result in lower comparative power costs to the participants over the period 1997-2021, than the other likely alternatives assumed respectively for each participant. To the extent that Stanton 2 is delayed indefinitely, the benefit of lower cost capacity and energy will be foregone.

The Stanton 2 Project will displace, in part, generation from oil and gas fuel, and to the extent the project is delayed, a burden will be placed on the utilities in the state to obtain additional supplies of gas and oil fuels. If the Stanton 2 is delayed, FMPA will need to supply its capacity and energy from some other resource.

10.15 FL TRANSMISSION
GRID CONSIDERATIONS

1C.15.0 Florida Transmission Grid Considerations

Electrical capacity and energy from the 66.4 MW of the proposed Stanton 2 Project and the 21.5 MW of the All-Requirements Project will be transmitted over the OUC and FPL or FPC transmission systems to the Participants. In the case of the Utility Board of the City of Key West, the Stanton 2 Project electric capacity and energy will also be transmitted over the Florida Keys Electric Cooperative (FKEC) transmission system.

FMPA currently has transmission service agreements with OUC, FPC and FPL for delivery of power from Stanton 1 and the Utility Board of the City of Key West has an agreement for transmission service over FKEC transmission system.

Although specific contracts for transmission, including provisions for pricing and conditions of service, have not yet been negotiated or executed with OUC, FPL or FPC, all three systems have advised the Agency that they are willing to provide such services subject to reaching an agreement with the Agency as to the terms and conditions of such services.

Transmission service is presently supplied by FPL to the All-Requirements Project Participants pursuant to the Transmission Service Agreement between FPL and FMPA. FPL has stated that transmission service from Stanton 2 for Jacksonville Beach, Green Cove Springs and Clewiston would be provided pursuant to the then-effective rates and provisions of that Agreement. With regard to transmission service for the Stanton 2 Project Participants, FPL has said that transmission service would be consistent with FPL's then-effective rates and terms and conditions for similar transmission service on file with the Federal Energy Regulatory Commission. FPL has also stated that it is willing to provide transmission service to FMPA member cities subject to satisfactory arrangements being entered into between FMPA and FPL and their ability to construct any facility additions that may be required.

Transmission service is presently supplied by FPC to the All-Requirements Participants pursuant to the Agreement for Partial Requirements Service, Transmission/Distribution Service and Demand and Energy Losses Service between FMPA and FPC. FMPA has requested from FPC that Stanton 2 be added as a resource covered by this Agreement.

OUC provides transmission service for delivery of power and energy from FMPA's ownership in Stanton 1 for the All-Requirements Project to the FPL and

FPC interconnections with OUC for subsequent delivery to the Participants over the life of the unit. FMPA has requested similar transmission service for Stanton 2.

FMPA reports that it knows of no constraints that would limit the import of the All-Requirements or Stanton 2 Project Participants over each utility's interconnections with the transmission grid.

Fort Pierce currently has two 138 kV interconnections with FPL with a total capacity of 100 MVA for both tie-lines. Vero Beach has two 138 kV interconnections with FP&L with a total capacity of 252 MVA for both interconnections. Fort Pierce and Vero Beach are interconnected by a 69 kV tie-line with a capacity of 62 MVA.

The City of Homestead has one existing 138 kV interconnection with FPL and will soon have a second 138 kV interconnection with FPL, both with a capacity of 100 MVA.

The Utility Board currently has a transmission agreement with FKEC with an initial term through 2005, thereafter automatically renewed for 10-year periods after the end of the initial term unless terminated by either party by giving the other party at least four years' written notice. The Utility Board currently has a 138 kV interconnection with FKEC at its Marathon Substation. The Utility Board's current firm transmission quantity of 50 MW will be more than sufficient to allow the import of both the Stanton 1 and its purchases from the proposed Stanton 2 Project.

The City of Lake Worth currently has one 138 kV interconnection with FPL with a capacity of 213 MVA.

The City of Starke currently has a 69 kV interconnection with FPL with a capacity of 15 MVA and is currently studying a second interconnection.

Appendix 1C.A Economic Forecast

Appendix 1C.A.0 Economic Forecasts

1C.A.1 General

The economic parameters are based on the "Long Term Economic Forecast 1990 to 2021" prepared by Fishkind & Associates, Inc., November 26, 1990 presented in Subsection 1A.3.0 of Volume 1. Adjustments to these general economic parameters necessary to make them specific for FMPA Participants are presented below.

Inflation and Escalation Rates

	<u>Year</u>	<u>Percent</u>
Inflation	1991	4.50
	1992-21	4.00
Capital Cost Escalation	1991-21	4.50
O&M Escalation	1991	5.30
	1992	4.39
	1993-21	4.75
FMPA Bond Interest Rate	7.25 percent	
FMPA Present Worth Rate	7.25 percent	
FMPA Bond Issuance Fee	2.0 percent	
FMPA Interest During Construction Rate	7.25 percent	
FMPA Debt Service Reserve Fund	One year's maximum principal and interest	
FMPA Interest Earnings Rate	7.25 percent	
Fuel Price Projections	See Table 1A.3.3-3, Volume 1A	
Purchased Power Projections	See Table 1C.8.7-1, Volume 1C	

Appendix 1C.B Load Forecast

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GENERATING SYSTEMS

FORT PIERCE UTILITIES AUTHORITY

APPENDIX 1C.B

SECTION 1C.B.1.1

FORT PIERCE UTILITIES AUTHORITY Electric System

Customer, Energy and Demand Forecast 1991-2021

The following is a summary of our analyses and studies pertaining to the design and development of estimates of future energy and demand requirements and residential and other Authority customer forecasts (the "1991 Load Forecast") for the Fort Pierce Utilities Authority (the "Authority").

Projections of the Authority's demand and energy requirements were developed for the period 1991 through 2021. Based on the results of the various analyses, system net energy requirements are projected to increase at a compound annual growth rate of 1.4% and 1.2% for the periods 1991 through 2000 and 1991 through 2021, respectively, while assuming a constant load factor system net peak demand is expected to increase at a compound rate of 1.4% and 1.3% for the same time periods. Selected years of the forecast are summarized on the following page.

Projected Demand and Energy Requirements by Class of Service^[1]
(Fiscal Year)

		<u>1990</u> ^[2]	<u>1991</u>	<u>2000</u>	<u>2021</u>
Residential	- (MWh)	08,598	211,429	230,397	273,992
Commercial/Industrial	- (MWh)	250,620	258,057	300,614	406,376
Street Lighting/ Other City Usage	- (MWh)	<u>22,046</u>	<u>23,235</u>	<u>25,743</u>	<u>30,494</u>
Total Sales	- (MWh)	<u>481,264</u>	<u>492,722</u>	<u>556,755</u>	<u>710,863</u>
System Losses	- (MWh)	27,447	24,636	27,838	35,109
Net Energy Requirements	- (MWh)	508,711	517,358	584,592	745,972
System Net Peak Demand	- (MW)	115.0	107.7	121.7	154.8

[1] Values may not add due to rounding.

[2] Actual 1990 historical data.

These estimates are based on independent energy forecasts for the residential, commercial/industrial, street lighting and other usage sectors. Annual projections of net energy requirements and net peak demand are presented in Table I. Additionally, a detailed forecast by class for the period 1991 to 2021 is presented in Table II.

Assumptions

The forecast is based on a detailed analysis of the electric system's historical growth, usage patterns, state and local economic conditions, and population statistics. An econometric model is used for forecasting energy requirements for all customer classes individually. The following are some of the principal considerations and assumptions employed in the 1991 Load Forecast.

Population

Population growth in St. Lucie County, which is a major component in the commercial energy sales and the residential and other Authority customer forecasts, is assumed to continue to grow throughout the forecast period. St. Lucie County population is assumed to increase by approximately 120,000 persons annually which equates to an average annual compound growth rate of 2.0% between 1991 and the year 2021. The population estimates for the County are published in the Bureau of Economic and Business Research Populations Studies Bulletin #92.

Real Price of Electricity

The real (in 1982 dollars) price of electricity, which is a component of the residential and commercial energy sales models, is assumed to remain constant over the forecast period. This means that the nominal price of electricity is assumed to increase at the general rate of inflation over the forecast period. This rate of increase in prices is based on an analysis of projected power supply costs on the Authority's electric system.

Real Florida Taxable Retail Sales

The level of per capita taxable retail sales (or retail consumer expenditures) in Florida was used as a proxy for economic activity in the econometric model of residential average energy usage. Historical taxable sales data were obtained from the Florida Governor's Office and were adjusted to real terms in 1982 dollars. Per capita real taxable retail sales are projected to increase slightly over the forecast period at a compound average annual growth rate of approximately .6%.

Weather

Quarterly heating and cooling degree days are assumed to remain constant over the forecast period at levels equal to the regional historical 30-year norms compiled and published by the National Oceanic and Atmospheric Administration. While weather will likely deviate from normal and the actual energy consumption and net peak demand can vary from what is shown in this forecast, projections of weather other than normal should only be utilized in conducting sensitivity analyses for load forecasting and system planning purposes.

Incremental Additions

No incremental load additions have been projected for the Authority based on discussions with Authority staff.

System Losses

Based on an historical analysis of system losses, it has been assumed that losses of approximately 5% of total annual retail energy sales will occur over the forecast period.

System Load Factors

The average of historical load factors experienced over the most recent five-year period fiscal year 1985 through fiscal year 1990 served as the basis for the load factors used in the forecast. The estimated winter season load factor of 55% was applied to annual projections of net energy for load to develop projections of annual system peak demand. Likewise, the forecast of the summer season peak demand is based on an estimated load factor of 58% applied to the annual projections of net energy for load.

Conservation

For purposes of the forecast analyses herein, no decremental adjustments have been made with regard to any assumed or estimated energy or demand reductions associated with the Authority's conservation programs.

Residential Sector

The econometric analyses relating to the residential sector are based on quarterly historical observations from the fourth quarter of 1980 through the third quarter of 1990. The forecast of total residential energy sales is the product of the projected number of residential customers and the projected average energy use per customer.

The explanatory variables used to statistically describe average usage per residential customer are the real price of electricity, weather, and an economic variable. Weather conditions are represented by heating and cooling degree days and the selected economic variable is based on real Florida Taxable Retail Sales. The resulting index of determination (R-squared statistic) was 87%.

Residential customers have been forecasted based on a regression analysis of historical quarterly customers and St. Lucie County population, with a resulting index of determination of 99%. The residential sector forecast results are summarized below.

	<u>Fiscal Year</u>	<u>Average Annual Number of Residential Customers</u> (kWh)	<u>Average Energy Use Per Customer</u> (MWh)	<u>Total Residential Energy Sales</u>
Actual	1990	19,702	10,587	208,598
Projected	1991	20,266	10,433	211,429
	2000	21,059	10,941	230,397
	2021	22,481	12,188	273,992
Compound Average Annual Growth Rate	1991-2021	0.3%	0.5%	0.9%

Commercial/Industrial Sector

The econometric analysis of commercial/industrial energy sales is based on quarterly historical observations from the fourth quarter of 1979 through the third quarter of 1990 using Florida Taxable Retail Sales, the real price of electricity and cooling degree days and seasonal indicators as explanatory variables. The resulting index of determination was 96%.

The projected number of commercial (Other City Customers) customers is based on the historical relationship between customers and population in St. Lucie County. The index of determination for the commercial customer model is 96%.

The resulting forecasts of commercial energy sales and of commercial customers are summarized below.

	<u>Fiscal Year</u>	<u>Average Annual Number of Commercial Customers</u>	<u>Average Energy Use Per Customer (kWh)</u>	<u>Total Commercial Energy Sales (MWh)</u>
Actual	1990	3,981	62,954	250,620
Projected	1991	4,031	64,018	258,057
	2000	4,548	66,098	300,614
	2021	5,512	73,726	406,376
Compound Average Annual Growth Rate	1991-2021	1.0%	0.5%	1.5%

Street Lighting/Other City Usage Sectors

Projected energy sales values for street lighting (which includes sale for rental lights, public street and highway lighting, and traffic signals) and other City usage were estimated separately. Street lighting sales were modeled based on statistically derived relationships of street lighting sales to the St. Lucie County population and lagged street lighting energy sales. The resulting index of determination was 88%. Street lighting sales are estimated to increase at an average annual rate of 1.3% for the period 1991 through 2000 and 1.0% for the period

1991 through 2021.

Other City usage was modeled based on a statistically derived relationship of other City usage to the Authority's average number of residential customers and quarterly seasonal indicators. Other City energy sales are projected to increase at an average annual rate of 1.1% and 0.8% for the periods 1991 through 2000 and 1991 through 2021, respectively.

Net Energy for Load and Peak Demand

Projections of residential, commercial, street lighting and other energy sales were aggregated to total system retail energy sales and adjusted for losses to produce forecasted net energy for load. To develop seasonal peak demand projections, the previously described historical seasonal load factors were applied to the forecast of net energy for load. The forecast results are briefly summarized below.

	<u>Fiscal Year</u>	<u>Total Retail Sales</u> (MWh)	<u>Net Energy For Load</u> (MWh)	<u>Winter Peak Demand</u> (MW)	<u>Summer Peak Demand</u> (MW)
Actual	1990	481,264	508,711	115.0	96.0
Projected	1991	492,722	517,358	107.7	102.1
	2000	556,755	584,592	121.7	115.4
	2021	710,863	745,972	154.8	146.8
Compound Average					
Annual Growth Rate	1991-2021	1.2%	1.2%	1.3%	1.3%

The forecast results shown in Tables I and II incorporate "normal" weather conditions as a basic forecast assumption. While it is expected that the long-term trend of the demand forecast is reasonable, it is likely that for any particular year during the forecast period, deviations may occur as a result of weather conditions, which vary from normal.

Summary

The forecasting methodology utilized attempts to identify and reflect key factors that influence the Authority's demand and energy requirements. It should be emphasized that the confidence associated with any projection varies inversely with the length of the forecast. The probability of extraneous factors affecting projected values increases with uncertainty about future developments; this uncertainty, in turn, increases with the length of the forecast period. With this in mind, projections of the Authority's annual net peak demand and net energy requirements should be viewed as reasonable estimates but subject to external disturbances which, at this time, cannot be reasonably foreseen. Therefore, the forecast results and the underlying assumptions should be reviewed periodically and updated when necessary. To the extent that unpredictable economic, demographic, and technological developments affect future expectations, forecasts may require adjustments to reflect such factors.

TABLE I
FORT PIERCE UTILITIES AUTHORITY
Historical and Projected
Net Energy Requirements and Net Peak Demands

(Fiscal Year)

		Net Energy Requirements ----- (Mwh)	Winter Peak Demand ----- (MW)	Summer Peak Demand ----- (MW)
HISTORICAL:	1980	371,148	84.0	72.0
	1981	389,974	89.0	77.5
	1982	383,106	96.0	72.0
	1983	392,792	83.0	82.0
	1984 [1]	403,981	91.0	79.0
	1985	429,568	106.0	86.0
	1986	447,756	98.0	86.0
	1987	471,652	92.0	93.0
	1988	474,747	96.0	95.0
	1989	501,356	106.0	96.0
	1990	508,711	115.0	96.0
Avg. Annual Compound Rate of Growth: -----				
1980-1990		3.2%	3.2%	2.9%
1985-1990		3.4%	1.6%	2.2%
PROJECTED:	1991	517,358	107.7	102.1
	1992	526,601	109.8	104.2
	1993	536,946	112.0	106.2
	1994	546,969	113.9	108.0
	1995	553,775	115.2	109.2
	1996	558,458	116.2	110.2
	1997	563,938	117.3	111.3
	1998	569,931	118.6	112.5
	1999	576,850	120.1	113.9
	2000	584,592	121.7	115.4
	2001	591,799	123.2	116.8
	2002	598,925	124.7	118.2
	2003	606,107	126.2	119.7
	2004	613,384	127.7	121.1
	2005	620,722	129.2	122.5
	2006	628,139	130.7	124.0
	2007	635,453	132.3	125.4
	2008	642,786	133.8	126.9
	2009	650,183	135.3	128.3
	2010	657,672	136.9	129.8
	2011	665,248	138.1	130.9
	2012	672,910	139.7	132.4
	2013	680,661	141.3	134.0
	2014	688,502	142.9	135.5
	2015	696,432	144.5	137.1
	2016	704,454	146.2	138.7
	2017	712,569	147.9	140.2
	2018	720,777	149.6	141.9
	2019	729,079	151.3	143.5
	2020	737,477	153.1	145.1
	2021	745,972	154.8	146.8
Avg. Annual Compound Rate of Growth: -----				
1991-2000		1.4%	1.4%	1.4%
1991-2010		1.3%	1.3%	1.3%
1991-2021		1.2%	1.3%	1.3%

[1] The 1984 winter peak occurred in December 1983.

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TABLE II
 FORT PIERCE UTILITIES AUTHORITY
 Historical and Projected Energy Sales
 and Residential/Other City Customers [1]
 (Fiscal Year)

Year	Residential Energy Sales	Commercial Energy Sales	Other Energy Sales	Street Light Sales	Total Energy Sales	Losses	Net Energy For Load	Residential Customers	Other City Customers	Total Customers
HISTORICAL:										
1980	-	-	-	-	-	-	-	-	3,331	-
1981	-	-	-	-	-	-	-	-	3,291	-
1982	-	-	-	-	-	-	-	-	3,271	-
1983	-	-	-	-	-	-	392,792	-	3,251	-
1984	-	-	-	-	-	-	203,081	-	3,231	-
1985	-	-	-	-	-	-	223,269	-	3,211	-
1986	199,006	213,094	12,273	6,920	431,293	16,463	414,830	18,922	3,191	22,552
1987	198,927	212,431	12,473	7,089	431,920	16,850	415,070	18,289	3,171	21,080
1988	201,137	212,826	13,636	7,261	434,860	16,951	417,909	18,698	3,151	21,401
1989	201,617	250,620	14,121	7,925	474,283	27,447	446,836	19,702	3,981	23,683
1990	208,598	250,620	14,121	7,925	481,264	27,447	508,711	19,702	3,981	23,683
Avg. Annual Compound Rate of Growth:										
1980-1990	1.18%	4.14%	3.57%	3.45%	2.78%	-	3.24%	1.01%	2.33%	1.23%
1986-1990	1.18%	4.14%	3.57%	3.45%	2.78%	-	3.24%	1.01%	2.33%	1.23%
PROJECTED:										
1991	211,429	258,057	15,218	8,017	492,722	24,636	517,358	20,266	4,031	24,297
1992	213,324	258,057	15,218	8,017	494,636	24,636	519,272	20,266	4,031	24,297
1993	215,220	258,057	15,218	8,017	496,540	24,636	521,186	20,266	4,031	24,297
1994	217,116	258,057	15,218	8,017	498,444	24,636	523,100	20,266	4,031	24,297
1995	219,012	258,057	15,218	8,017	500,348	24,636	525,014	20,266	4,031	24,297
1996	220,908	258,057	15,218	8,017	502,252	24,636	526,928	20,266	4,031	24,297
1997	222,804	258,057	15,218	8,017	504,156	24,636	528,842	20,266	4,031	24,297
1998	224,700	258,057	15,218	8,017	506,060	24,636	530,756	20,266	4,031	24,297
1999	226,596	258,057	15,218	8,017	507,964	24,636	532,670	20,266	4,031	24,297
2000	228,492	258,057	15,218	8,017	509,868	24,636	534,584	20,266	4,031	24,297
2001	230,388	258,057	15,218	8,017	511,772	24,636	536,498	20,266	4,031	24,297
2002	232,284	258,057	15,218	8,017	513,676	24,636	538,412	20,266	4,031	24,297
2003	234,180	258,057	15,218	8,017	515,580	24,636	540,326	20,266	4,031	24,297
2004	236,076	258,057	15,218	8,017	517,484	24,636	542,240	20,266	4,031	24,297
2005	237,972	258,057	15,218	8,017	519,388	24,636	544,154	20,266	4,031	24,297
2006	239,868	258,057	15,218	8,017	521,292	24,636	546,068	20,266	4,031	24,297
2007	241,764	258,057	15,218	8,017	523,196	24,636	547,982	20,266	4,031	24,297
2008	243,660	258,057	15,218	8,017	525,100	24,636	549,896	20,266	4,031	24,297
2009	245,556	258,057	15,218	8,017	527,004	24,636	551,810	20,266	4,031	24,297
2010	247,452	258,057	15,218	8,017	528,908	24,636	553,724	20,266	4,031	24,297
2011	249,348	258,057	15,218	8,017	530,812	24,636	555,638	20,266	4,031	24,297
2012	251,244	258,057	15,218	8,017	532,716	24,636	557,552	20,266	4,031	24,297
2013	253,140	258,057	15,218	8,017	534,620	24,636	559,466	20,266	4,031	24,297
2014	255,036	258,057	15,218	8,017	536,524	24,636	561,380	20,266	4,031	24,297
2015	256,932	258,057	15,218	8,017	538,428	24,636	563,294	20,266	4,031	24,297
2016	258,828	258,057	15,218	8,017	540,332	24,636	565,208	20,266	4,031	24,297
2017	260,724	258,057	15,218	8,017	542,236	24,636	567,122	20,266	4,031	24,297
2018	262,620	258,057	15,218	8,017	544,140	24,636	569,036	20,266	4,031	24,297
2019	264,516	258,057	15,218	8,017	546,044	24,636	570,950	20,266	4,031	24,297
2020	266,412	258,057	15,218	8,017	547,948	24,636	572,864	20,266	4,031	24,297
2021	268,308	258,057	15,218	8,017	549,852	24,636	574,778	20,266	4,031	24,297
Avg. Annual Compound Rate of Growth:										
1991-2000	1.0%	1.7%	1.1%	1.3%	1.4%	-	1.4%	0.4%	1.3%	0.6%
1991-2010	0.9%	1.6%	1.0%	1.2%	1.3%	-	1.3%	0.3%	1.2%	0.5%
1991-2021	0.9%	1.5%	0.8%	1.0%	1.2%	-	1.2%	0.3%	1.0%	0.5%

[1] Values may not add due to rounding.

CITY OF HOMESTEAD

APPENDIX 1C.B

SECTION 1C.B.1.2

**ENERGY AND DEMAND FORECAST
UPDATE FOR
THE CITY OF HOMESTEAD, FLORIDA
1991 - 2021**

Prepared by
Resource Mangement International, Inc.
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RESOURCE MANAGEMENT
INTERNATIONAL, INC.

January 4, 1991

Mr. Bob Brush
Assistant Utilities Director
City of Homestead
675 North Flagler Avenue
Homestead, FL 33030-6173

Dear Bob:

Resource Management International, Inc. (RMI) is pleased to submit this final report which provides the City's load forecast of long-range growth. Five copies are being provided for your use.

The results of this study will be utilized in the Needs Certification Hearings before the Florida Public Service Commission when Orlando Utilities Commission applies for certification of its Stanton Energy Center #2. We have coordinated this effort with other potential participants of Stanton Energy Center #2 in order that assumptions associated with individual participant's forecasts will be consistent.

RMI appreciates the opportunity to assist the City of Homestead in planning for its future power supply needs. We look forward to continuing to work with the City in future studies pertaining to its electric utility. Please, contact Larry James or me if you have any questions.

Sincerely,

Gael Penland Paschall, Ph.D.
Executive Consultant

GPP/bjb/677.26

xc: Larry James, RMI

Enclosures

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SECTION I

EXECUTIVE SUMMARY

RMI prepared three load forecasts using the City's econometric forecasting model. The first forecast, reflecting base conditions and assumptions, is referred to throughout this report as the Expected forecast. The remaining two forecasts, the High and Low forecasts, were developed to provide an upper and lower boundary for the Expected forecast. The High and Low forecasts reflect changes in conditions and assumptions resulting in increased and decreased power sales, respectively, based on factors such as population growth and changing economic conditions.

Population growth projections were obtained from the University of Florida Bureau of Economic and Business Research. Employment data were obtained from the Florida Department of Labor and Employment Security, Bureau of Labor Market information. All three forecasts include estimated incremental loads associated with the Homestead Sports Complex and future additions to the Homestead campus of the Miami-Dade Community College. They address a varying range of changes in employment and population. All three peak demand forecasts are shown on Graph E-1.

Summarized on the following page are the updated load forecasts.

ENERGY AND DEMAND FORECAST

	<u>Expected</u>		<u>High</u>		<u>Low</u>	
Fiscal Year						
Ending	Energy Demand		Energy Demand		Energy Demand	
<u>September 30</u>	<u>(MWH)</u>	<u>(MW)</u>	<u>(MWH)</u>	<u>(MW)</u>	<u>(MWH)</u>	<u>(MW)</u>
1990 (actual)	263,409	51	263,409	51	263,409	51
1995	289,939	57	304,698	60	274,843	55
2000	319,280	63	350,849	69	280,696	56
2005	338,814	67	393,979	78	279,725	56
2010	364,020	72	439,850	87	277,203	55
Average Annual Growth (%) (1990-2010)	1.6	1.7	2.6	2.7	0.3	0.4

It is our understanding that the need certification hearings for Stanton Energy Center 2 before the Florida Public Service Commission will require forecasts of demand and energy requirements through the year 2021. These figures are furnished in Appendix A, Attachment 4. Demand and energy forecasts do not include any increases due to additional load in the Villages area that may be acquired from Florida Power & Light (FP&L). The range of forecasts reflect varying rates of growth in population and employment. The forecast can be expected to change if additional customers are added to the City's system as a result of negotiations with FP&L.

SECTION II

ENERGY AND DEMAND FORECAST

A. INTRODUCTION

This section summarizes historic demand and energy requirements and presents the forecast demand and energy requirements for the period Fiscal Year Ending (FYE) September 30, 1991 to FYE 2010. The load forecast was developed excluding the potential effects of additional loads in the Villages area which are discussed below.

In preparing a load forecast, utility planners recognize that assumptions used to develop a load forecast may differ from actual experience. An Expected load forecast is developed assuming expected population growth and economic development. In order to examine the impact of high and low population growth and accompanying economic development on the forecast, RMI also prepared a High and a Low load forecast. The three load forecasts discussed in the balance of this section represent a bounded set of results which reflect various combinations of input assumptions which could result in forecasts that fall between the High and Low forecasts. A bounded set of results assists the decision maker in making the decision several years in advance of the need to commit to future resource additions. However, as part of the assessment of future resources, the load forecasts should be reviewed and updated annually to reflect current conditions and their impact on the assumed resource plan.

B. HISTORIC LOAD DATA

A summary of the period FYE 1980 through FYE 1990 of system peak demand, system energy requirements, customer energy sales, number of customers, and average customer usage is set forth in Exhibit II-1. The average number of residential customers increased by 1,504 during this period, or by approximately 150 customers per fiscal

year. During the same period, average use per residential customer increased by 494 kWh, or by approximately 49 kWh per year. System energy requirements increased over the historical period by approximately 2.9 percent per year, from 197,056 MWH in FYE 1980 to 263,409 MWH in FYE 1990. During the same period, system peak demand showed an overall increase of approximately 2.2 percent per year, from 41 MW in FYE 1980 to 51 MW in FYE 1990. System load factor tended to increase over the ten-year period and varied from a low of 49.6 percent in FYE 1981 to a high of 61.4 percent in FYE 1990.

C. FORECAST METHODOLOGY

RMI utilized econometric modeling techniques to develop the projected energy requirements by customer class for the Expected, High, and Low forecasts. Data for FYE 1980 through FYE 1989 were utilized to develop the forecasting model during FYE 1990. Actual FYE 1990 data were compared to the model's forecast results for that same period. Based on this analysis, it was determined that the model was still appropriate for forecasting purposes and that respecification would not be required at this time. Data were revised to reflect actual FYE 1990 information and the forecasting model was rerun for the period FYE 1991 through FYE 2010.

A brief description of the methodology and a summary of the results are presented herein. A detailed presentation of the methodology and results can be found in Appendix A.

The econometric model considered such factors as population, employment, weather, and the real price of electricity. In particular, the forecast results are based upon the following key assumptions:

1. The City's present service area;
2. Population growth will be as forecast by the University of Florida Bureau of Economic and Business Research (BEER);
3. Employment in retail trade and services in South Florida will tend to follow the forecast provided by the Florida Department of Labor and Employment Security as well as population trends for the area over the same time frame;
4. The real price of electricity will remain constant reflecting an assumption that it will tend to increase at a rate equal to the general rate of inflation;
5. There will be no changes in current City energy and development policies and the City will not provide rebates or financing of energy efficient equipment; and
6. The Homestead Sports Complex and additional facilities for Miami-Dade Community College will become part of the City's system load during the forecast period.

Each factor considered by the model has a range of forecast results which include an expected, high, and low growth scenario. The forecasts of residential, commercial and industrial energy sales were based upon the econometric model, while the forecast of municipal energy sales was not. Municipal use is small compared to other classes. No variables were found which produced a satisfactory correlation. Therefore, this class was forecast based upon empirical determinations.

The energy forecasts of each customer class plus incremental loads associated with the Homestead Sports Complex, and the expansion of Miami-Dade Community College were added together and adjusted for losses to develop the FYE system energy requirements. The system peak demand forecast was determined by applying a load factor projection to the system energy forecast. Contributions to peak demand were calculated separately for both the Homestead Sports Complex and Miami-Dade Community College since it is expected that the load factors associated with these incremental loads will differ significantly from the system as a whole.

Load attributable to the possible future acquisition of customers in the Villages area from FP&L are not reflected in demand and energy forecasts. The area is currently being developed by Homestead Properties where FP&L currently serves approximately 1,542 residential customers of which 640 are condominiums and 902 are single family homes. The customers which are currently under dispute include the 640 condominiums and 751 single family residences.

Discussions with staff at Homestead Properties indicate that the total impact of the Villages area is expected to be approximately 14,000 dwelling units of which 3,830 will be single family residences, 3,457 will be townhomes, and 6,820 will be condominiums. Homestead Properties currently expects that build-out will occur in approximately 25 years with incremental dwelling units being occupied at the rate of approximately 300 per year from 1994 through 2010.

In addition to the residential customers, additional related loads which will be developed in the area include five elementary schools, one junior high school, one senior high school, four community service buildings including fire stations and police stations, four small commercial tracts, one hospital sized clinic, and a large industrial park. Homestead Properties expects that the Park of Commerce will encompass approximately 4.7 million square feet and that the Shops of Homestead will include approximately 6.0 million square feet. Based on the build-out assumptions provided by Homestead Properties, it is currently estimated that the Villages area may contribute approximately 37 MW to the City's load over the next twenty-five years.

In determining the Expected, High and Low demand and energy forecasts, the econometric model equations were selected based on statistical significance and sign patterns of the relevant coefficients, performance of alternative models in a forecasting environment, and overall statistical properties of the equations.

D. ENERGY AND DEMAND FORECASTS

Projections of customer class energy sales, system energy requirements, and system peak demand were developed for the period FYE 1991 through FYE 2010, as described in Appendix A. The forecast system peak demands were derived from the relationship between system energy and load factor. The load factor for existing load was assumed to remain constant throughout the study period. Incremental loads associated with the Homestead Sports Complex and additional load at the Miami-Dade Community College were added to both system energy and peak demand requirements. Due to the nature of these loads the rate of increase for the system peak demand is slightly higher than the rate of increase for projected system energy requirements and overall system load factor fluctuates slightly over the forecast period.

Exhibits II-2, II-3, and II-4 show the system energy and demand requirements (without the effects of additional possible loads in the Villages area) for the Expected, High, and Low forecasts. The detailed forecast by customer class for each of the three forecasts can be found in Appendix A. Graphs II-1 and II-2 display the system energy and demand requirements, respectively, for the Expected, High, and Low forecasts. The Expected forecast system energy requirement projected for FYE 2010 is 364,020 MWH, while the High and Low forecast projections are 439,850 MWH and 277,203 MWH, respectively. Similarly, for the system peak demand requirements, the Expected, High, and Low forecasts for FYE 2010 is 72 MW, 87 MW, and 55 MW, respectively.

E. SUMMARY

The Expected, High, and Low forecasts are based on a range of reasonable assumptions given current economic and political conditions. If the current assumptions continue into the future, the Expected forecast will provide a reasonable estimate of future energy and demand requirements. However, due to the uncertainty of future events

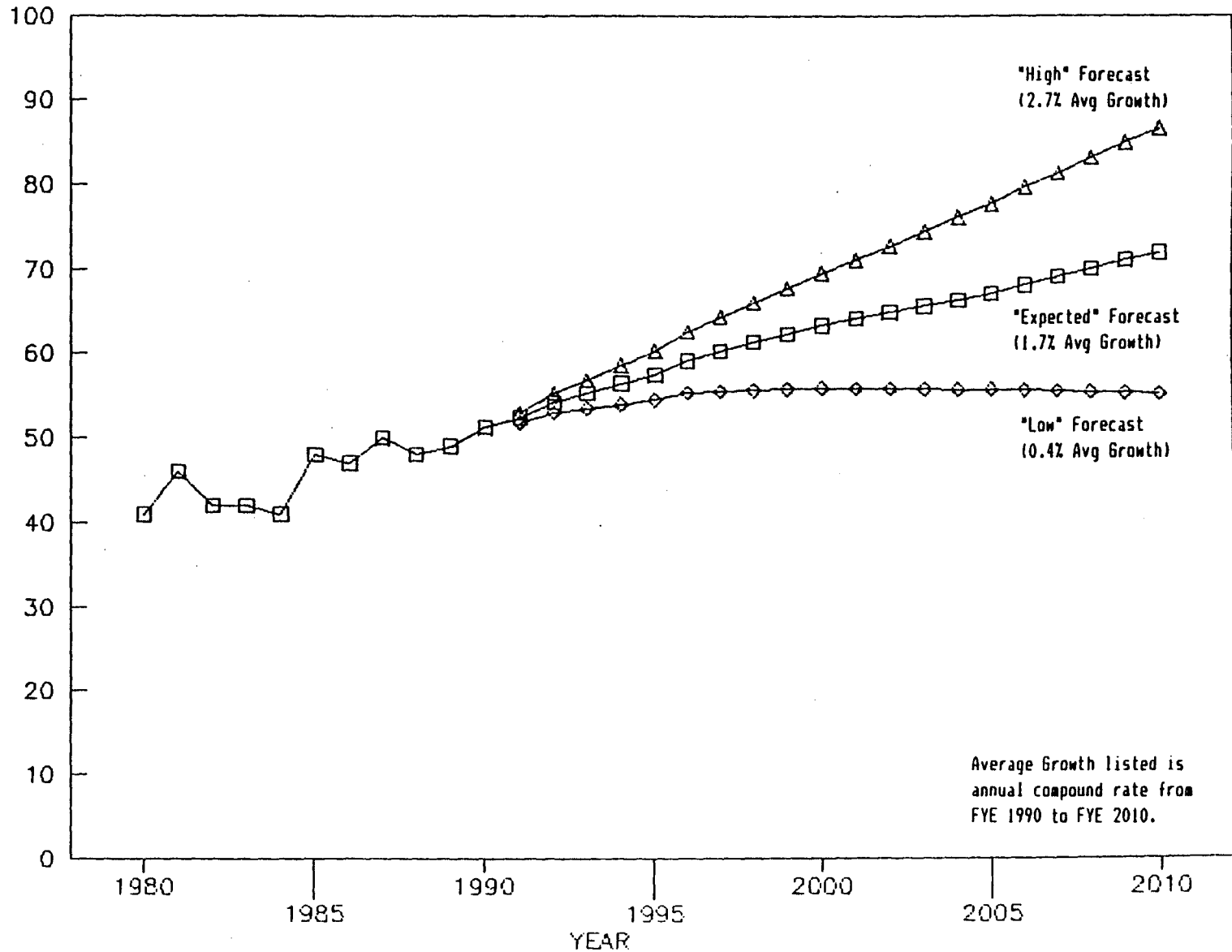
continuing, we recommend that actual energy and peak requirements be compared to the forecast values and the forecast updated annually.

PROJECTED PEAK DEMANDS

ANNUAL PEAK (MEGAWATTS)

9

IC.B.1-24



CITY OF HOMESTEAD
SUMMARY OF ACTUAL ENERGY SALES BY CUSTOMER CLASS
AND SYSTEM PEAK DEMAND AND ENERGY REQUIREMENTS
FISCAL YEARS 1980 - 1990 (1)

ENERGY SALES (MMH)	FYE 1980	FYE 1981	FYE 1982	FYE 1983	FYE 1984	FYE 1985	FYE 1986	FYE 1987	FYE 1988	FYE 1989	FYE 1990
RESIDENTIAL	103,830	109,311	116,401	116,462	109,765	116,750	122,221	125,812	120,575	125,474	124,867
PERCENT CHANGE		5.3%	6.5%	0.1%	-5.8%	6.4%	4.7%	2.9%	-4.2%	4.1%	-0.5%
COMMERCIAL	21,623	21,784	26,461	24,048	25,685	28,805	30,634	28,357	29,277	29,079	28,610
PERCENT CHANGE		0.7%	21.5%	-9.1%	6.8%	12.1%	6.3%	-7.4%	3.2%	-0.7%	-1.6%
INDUSTRIAL	42,678	55,851	63,044	61,285	63,089	70,520	67,483	69,810	70,827	73,653	76,388
PERCENT CHANGE		30.9%	12.9%	-2.8%	2.9%	11.8%	-4.3%	3.4%	1.5%	4.0%	3.7%
CITY USE	9,368	9,915	10,587	10,110	9,868	9,697	8,630	9,963	9,433	10,049	10,645
PERCENT CHANGE		5.8%	6.8%	-4.5%	-2.4%	-1.7%	-11.0%	15.4%	-5.3%	6.5%	5.9%
TOTAL ENERGY SALES	177,499	196,861	216,493	211,905	208,407	225,772	228,968	233,942	230,112	238,255	240,510
PERCENT CHANGE		10.9%	10.0%	-2.1%	-1.7%	8.3%	1.4%	2.2%	-1.6%	3.5%	0.9%

CUSTOMER USAGE

NUMBER OF RESIDENTIAL CUSTOMERS	10,256	10,516	10,795	11,036	10,928	11,113	11,345	11,506	11,497	11,628	11,760
AVERAGE USE (MMH/YR) PER RESIDENTIAL CUSTOMER	10.124	10.395	10.783	10.553	10.044	10.506	10.773	10.934	10.488	10.791	10.618

ENERGY REQUIREMENTS (MMH)

TOTAL ENERGY SALES	177,499	196,861	216,493	211,905	208,407	225,772	228,968	233,942	230,112	238,255	240,510
ENERGY LOSSES (2)	19,557	3,071	(6,160)	(4,818)	7,393	(1,339)	7,856	18,129	19,800	21,119	22,899
SYSTEM ENERGY REQUIREMENT	197,056	199,932	210,333	207,087	215,800	224,433	236,824	252,071	249,912	259,374	263,409
PERCENT CHANGE		1.5%	5.2%	-1.5%	4.2%	4.0%	5.5%	6.4%	-0.9%	3.8%	1.6%

PEAK DEMAND

SYSTEM DEMAND (MW)	41	46	42	42	41	48	47	50	48	49	49
LOAD FACTOR (%)	54.9	49.6	57.2	56.3	60.1	53.4	57.5	57.6	59.4	60.4	61.4

- (1) FISCAL YEAR RUNS FROM OCTOBER 1 TO SEPTEMBER 30 OF DESIGNATED YEAR.
(2) ENERGY LOSSES EQUAL SYSTEM ENERGY REQUIREMENTS MINUS TOTAL ENERGY SALES.
NEGATIVE VALUES MAY INDICATE GENERATION METERING AND RETAIL BILLING CYCLES
WERE ARE NOT SYNCHRONIZED OR MAY RESULT FROM ERRORS IN HISTORIC DATA BASE.

EXHIBIT II-2

CITY OF HOMESTEAD, FLORIDA
ELECTRIC SYSTEM
1990 LOAD FORECASTINPUT FILE FOR TSP
(FISCAL YEAR BASIS)

ROW #	FISCAL YEAR ENDING SEPT 30,	EXPECTED VALUE OF DRIVING VARIABLES			RESIDENTIAL			COMMERCIAL	INDUSTRIAL	CITY USAGE	OTHER	TOTAL			SYSTEM LOAD FACTOR (%)	ANNUAL SYSTEM NET PEAK DEMAND (MW)
		3 COUNTY POPULATION (000'S)	AVERAGE EMPL (000'S)	TOTAL DEGREE DAYS	AVERAGE NUMBER OF ACCOUNTS	CLASS ENERGY SALES (MWH)	USE PER ACCOUNT (KWH)	CLASS ENERGY SALES (MWH)	CLASS ENERGY SALES (MWH)	CLASS ENERGY SALES (MWH)	INCREMENTAL ENERGY SALES (MWH)	TOTAL ENERGY SALES (MWH)	DSTBN LOSSES (MWH)	NET ENERGY FOR LOAD (MWH)	(bh)	(bi)
(ac)	(ad)	(af)	(ag)	(ah)	(aj)	(ak)	(al)	(ap)	(au)	(az)	(bc)	(be)	(bf)	(bg)		
15	1980	2,707	541	4518	10,256	103,830	10,124	21,623	42,678	9,368	0	177,499	19,557	197,056	54.9	41
16	1981	2,830	562	4619	10,516	109,311	10,395	21,784	55,851	9,915	0	196,861	3,071	199,932	49.6	46
17	1982	2,862	567	4759	10,795	116,401	10,783	26,461	63,045	10,587	0	216,494	16,160	210,334	57.2	42
18	1983	2,886	577	4312	11,036	116,462	10,553	24,048	61,285	10,110	0	211,905	14,818	207,087	56.3	42
19	1984	2,914	620	4069	10,928	109,765	10,044	25,685	63,089	9,868	0	208,407	7,393	215,800	60.1	41
20	1985	2,954	643	4320	11,113	116,750	10,506	28,805	70,520	9,697	0	225,772	11,339	224,433	53.4	48
21	1986	2,998	667	4378	11,345	122,221	10,773	30,634	67,483	8,630	0	228,968	7,856	236,824	57.5	47
22	1987	3,058	702	4872	11,506	125,812	10,934	28,357	69,810	9,963	0	233,942	18,129	252,071	57.6	50
23	1988	3,129	726	4515	11,497	120,575	10,488	29,277	70,827	9,433	0	230,112	19,800	249,912	59.4	48
24	1989	3,179	749	4928	11,628	125,474	10,791	29,079	73,653	10,049	0	238,255	21,119	259,374	60.4	49
25	1990	3,226	773	4898	11,760	124,867	10,618	28,610	76,388	10,645	0	240,510	22,899	263,409	58.7	51
26	1991	3,280	797	4529	11,923	124,962	10,480	29,532	78,409	10,043	1,460	244,406	20,533	264,938	57.7	52
27	1992	3,332	821	4529	12,081	127,360	10,542	30,452	80,430	10,043	1,650	249,936	20,997	270,933	57.1	54
28	1993	3,380	845	4529	12,227	129,649	10,604	31,371	82,451	10,043	1,650	255,164	21,437	276,601	57.1	55
29	1994	3,424	869	4529	12,361	131,834	10,665	32,288	84,472	10,043	3,950	262,588	22,060	284,648	57.6	56
30	1995	3,461	893	4529	12,472	133,779	10,726	33,204	86,493	10,043	3,950	267,469	22,470	289,939	57.6	57
31	1996	3,504	916	4529	12,604	135,981	10,788	34,117	88,514	10,043	3,950	272,605	22,902	295,507	57.0	59
32	1997	3,545	940	4529	12,727	138,089	10,850	35,030	90,535	10,043	6,210	279,907	23,515	303,422	57.5	60
33	1998	3,583	964	4529	12,842	140,133	10,912	35,941	92,556	10,043	6,210	284,883	23,933	308,816	57.5	61
34	1999	3,617	988	4529	12,946	142,073	10,974	36,850	94,577	10,043	6,210	289,753	24,342	314,096	57.6	62
35	2000	3,649	1,012	4529	13,041	143,926	11,036	37,758	96,598	10,043	6,210	294,535	24,744	319,280	57.6	63
36	2001	3,646	1,036	4529	13,032	144,599	11,096	38,665	98,619	10,043	6,210	298,136	25,047	323,183	57.6	64
37	2002	3,642	1,060	4529	13,023	145,275	11,156	39,571	100,640	10,043	6,210	301,738	25,349	327,088	57.6	65
38	2003	3,639	1,083	4529	13,013	145,954	11,216	40,475	102,661	10,043	6,210	305,342	25,652	330,995	57.6	66
39	2004	3,636	1,107	4529	13,004	146,636	11,276	41,378	104,682	10,043	6,210	308,948	25,955	334,903	57.6	66
40	2005	3,633	1,131	4529	12,995	147,320	11,337	42,279	106,703	10,043	6,210	312,556	26,258	338,814	57.7	67
41	2006	3,659	1,155	4529	13,072	149,024	11,400	43,180	108,724	10,043	6,210	317,181	26,647	343,828	57.7	68
42	2007	3,684	1,179	4529	13,149	150,742	11,464	44,079	110,745	10,043	6,210	321,819	27,036	348,855	57.7	69
43	2008	3,710	1,203	4529	13,226	152,473	11,528	44,977	112,766	10,043	6,210	326,469	27,427	353,896	57.7	70
44	2009	3,735	1,227	4529	13,303	154,218	11,592	45,874	114,787	10,043	6,210	331,132	27,819	358,951	57.7	71
45	2010	3,761	1,250	4529	13,381	155,978	11,657	46,770	116,808	10,043	6,210	335,808	28,212	364,020	57.8	72
AVG. ANNUAL % GROWTH RATE																
1980 - 1990		1.82	3.62	0.82	1.42	1.92	0.52	2.82	6.02	1.32		3.12	1.62	2.92	0.72	2.22
1990 - 2000		1.22	2.72	-0.82	1.02	1.42	0.42	2.82	2.42	-0.62		2.02	0.82	1.92	-0.22	2.12
1990 - 2100		0.82	2.42	-0.42	0.62	1.12	0.52	2.52	2.12	-0.32		1.72	1.02	1.62	-0.12	1.72

EXHIBIT II-3

CITY OF HOMESTEAD, FLORIDA ELECTRIC SYSTEM 1990 LOAD FORECAST

INPUT FILE FOR TSP
(FISCAL YEAR BASIS)

ROW #	FISCAL YEAR ENDING SEPT 30,	HIGH ESTIMATE FOR DRIVING VARIABLES			RESIDENTIAL			COMMERCIAL	INDUSTRIAL	CITY USAGE	OTHER	TOTAL			SYSTEM LOAD FACTOR (Z)	ANNUAL SYSTEM NET PEAK DEMAND (MW)
		J COUNTY POPULATION (000'S)	AVERAGE EMPL (000'S)	TOTAL DEGREE DAYS	AVERAGE NUMBER OF ACCOUNTS	CLASS ENERGY SALES (MMH)	USE PER ACCOUNT (KWH)	CLASS ENERGY SALES (MMH)	CLASS ENERGY SALES (MMH)	CLASS ENERGY SALES (MMH)	INCREMENTAL ENERGY SALES (MMH)	TOTAL ENERGY SALES (MMH)	DSTBN LOSSES (MMH)	NET ENERGY FOR LOAD (MMH)	(Z)	(MW)
(ac)	(ad)	(af)	(ag)	(ah)	(aj)	(ak)	(al)	(ap)	(au)	(az)	(bc)	(be)	(bf)	(be)		
15	1980	2,707	541	4518	10,256	103,830	10,124	21,623	42,678	9,368	0	177,499	19,557	197,056	54.9	41
16	1981	2,830	562	4619	10,516	109,311	10,395	21,784	55,851	9,915	0	196,861	3,071	199,932	49.6	46
17	1982	2,862	567	4759	10,795	116,401	10,783	26,461	63,045	10,587	0	216,494	16,160	210,334	57.2	42
18	1983	2,886	577	4312	11,036	116,462	10,553	24,048	61,285	10,110	0	211,905	14,818	207,087	56.3	42
19	1984	2,914	620	4069	10,928	109,765	10,044	25,685	63,089	9,868	0	208,407	7,393	215,800	60.1	41
20	1985	2,954	643	4320	11,113	116,750	10,506	28,805	70,520	9,697	0	225,772	11,339	224,433	53.4	48
21	1986	2,998	667	4378	11,345	122,221	10,773	30,634	67,483	8,630	0	228,968	7,856	236,824	57.5	47
22	1987	3,058	702	4872	11,506	125,812	10,934	28,357	69,810	9,963	0	233,942	18,129	252,071	57.6	50
23	1988	3,129	726	4515	11,497	120,575	10,488	29,277	70,827	9,433	0	230,112	19,800	249,912	59.4	48
24	1989	3,179	749	4928	11,628	125,474	10,791	29,079	73,653	10,049	0	238,255	21,119	259,374	60.4	49
25	1990	3,255	788	4898	11,760	124,867	10,618	28,610	76,388	10,645	0	240,510	22,899	263,409	58.7	51
26	1991	3,331	826	4529	11,990	125,680	10,482	30,082	79,620	10,043	1,460	246,885	20,741	267,626	57.7	53
27	1992	3,406	864	4529	12,219	128,868	10,546	31,550	82,851	10,043	1,650	254,963	21,420	276,383	57.1	55
28	1993	3,482	902	4529	12,449	132,086	10,610	33,014	86,083	10,043	1,650	262,877	22,085	284,962	57.2	57
29	1994	3,558	940	4529	12,679	135,335	10,674	34,475	89,315	10,043	3,950	273,117	22,945	296,062	57.7	59
30	1995	3,634	978	4529	12,908	138,613	10,738	35,931	92,547	10,043	3,950	281,084	23,614	304,698	57.7	60
31	1996	3,710	1,017	4529	13,139	141,927	10,802	37,387	95,784	10,043	3,950	289,091	24,287	313,378	57.2	63
32	1997	3,786	1,055	4529	13,369	145,272	10,867	38,839	99,022	10,043	6,210	299,386	25,152	324,538	57.6	64
33	1998	3,862	1,093	4529	13,599	148,649	10,931	40,287	102,260	10,043	6,210	307,449	25,829	333,278	57.6	66
34	1999	3,938	1,131	4529	13,829	152,056	10,996	41,733	105,497	10,043	6,210	315,539	26,509	342,048	57.7	68
35	2000	4,014	1,169	4529	14,059	155,495	11,060	43,175	108,735	10,043	6,210	323,659	27,191	350,849	57.7	69
36	2001	4,087	1,206	4529	14,281	158,877	11,125	44,566	111,863	10,043	6,210	331,559	27,855	359,413	57.7	71
37	2002	4,160	1,243	4529	14,503	162,289	11,190	45,954	114,991	10,043	6,210	339,487	28,521	368,007	57.8	73
38	2003	4,234	1,280	4529	14,726	165,734	11,255	47,339	118,118	10,043	6,210	347,444	29,189	376,633	57.8	74
39	2004	4,307	1,317	4529	14,948	169,209	11,320	48,722	121,246	10,043	6,210	355,430	29,860	385,290	57.8	76
40	2005	4,380	1,354	4529	15,170	172,717	11,385	50,102	124,374	10,043	6,210	363,446	30,533	393,979	57.8	78
41	2006	4,457	1,393	4529	15,404	176,387	11,451	51,549	127,657	10,043	6,210	371,846	31,239	403,085	57.9	80
42	2007	4,534	1,431	4529	15,637	180,090	11,517	52,993	130,941	10,043	6,210	380,277	31,947	412,225	57.9	81
43	2008	4,611	1,470	4529	15,870	183,828	11,583	54,434	134,225	10,043	6,210	388,740	32,658	421,399	57.9	83
44	2009	4,688	1,509	4529	16,104	187,600	11,649	55,874	137,509	10,043	6,210	397,235	33,372	430,607	57.9	85
45	2010	4,765	1,548	4529	16,337	191,406	11,716	57,310	140,792	10,043	6,210	405,762	34,088	439,850	58.0	87

AVG. ANNUAL % GROWTH RATE

1980 - 1990	1.9%	3.8%	0.8%	1.4%	1.9%	0.5%	2.8%	6.0%	1.3%	3.1%	1.6%	2.9%	0.7%	2.2%
1990 - 2000	2.1%	4.0%	-0.8%	1.8%	2.2%	0.4%	4.2%	3.6%	-0.6%	3.0%	1.7%	2.9%	-0.2%	3.1%
1990 - 2010	1.9%	3.4%	-0.4%	1.7%	2.2%	0.5%	3.5%	3.1%	-0.3%	2.6%	2.0%	2.5%	-0.1%	2.7%

EXHIBIT II-4

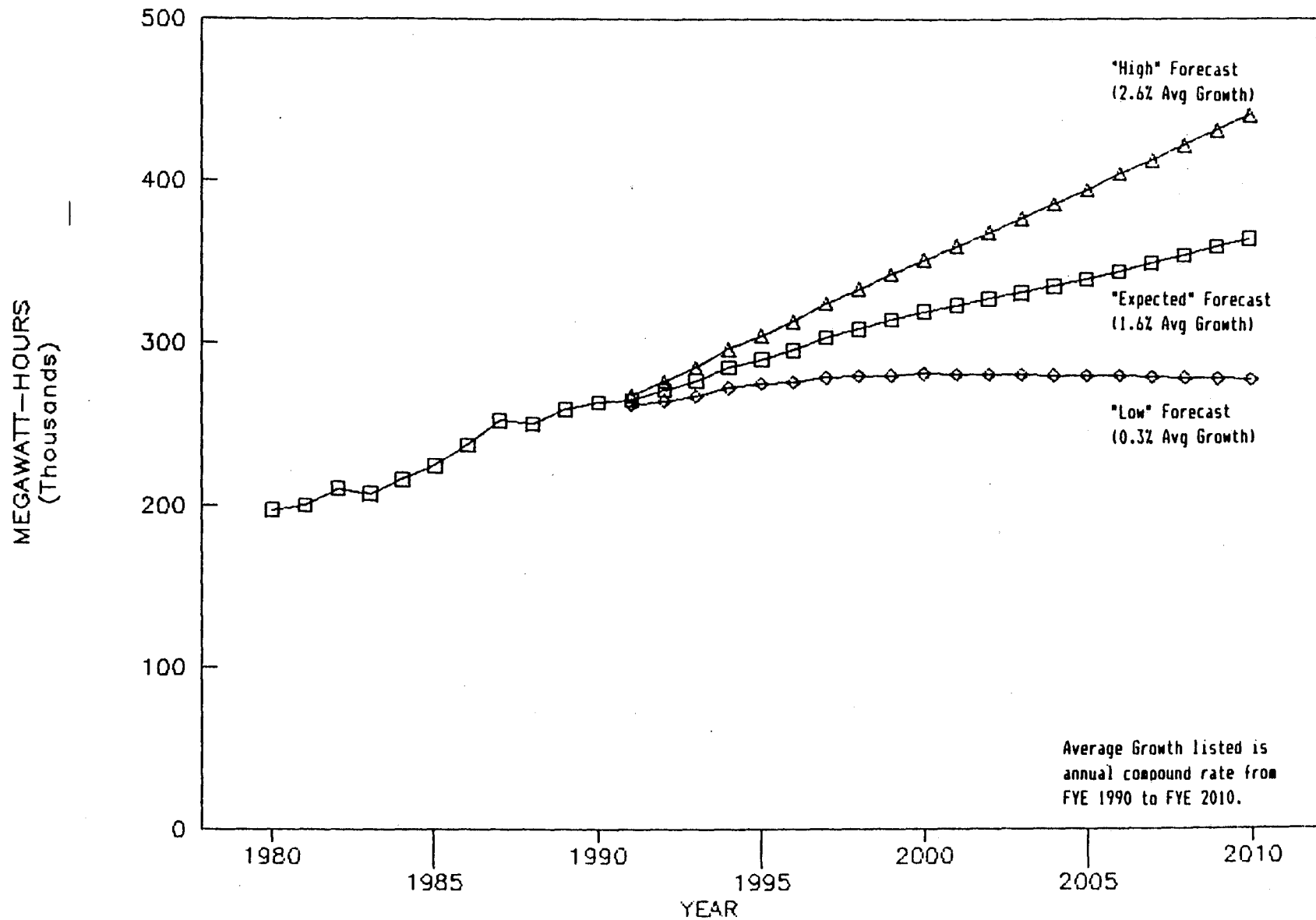
CITY OF HOMESTEAD, FLORIDA
ELECTRIC SYSTEM
1990 LOAD FORECASTINPUT FILE FOR TSP
(FISCAL YEAR BASIS)

ROW #	FISCAL YEAR ENDING SEPT 30,	LOW ESTIMATE FOR DRIVING VARIABLES			RESIDENTIAL			COMMERCIAL	INDUSTRIAL	CITY USAGE	OTHER	TOTAL			SYSTEM LOAD FACTOR (%)	ANNUAL SYSTEM NET PEAK DEMAND (MW)
		3 COUNTY POPULATION (000'S)	AVERAGE ENPL (000'S)	TOTAL DEGREE DAYS	AVERAGE NUMBER OF ACCOUNTS	CLASS ENERGY SALES (MMH)	USE PER ACCOUNT (KWH)	CLASS ENERGY SALES (MMH)	CLASS ENERGY SALES (MMH)	CLASS ENERGY SALES (MMH)	INCREMENTAL ENERGY SALES (MMH)	TOTAL ENERGY SALES (MMH)	DSTBM LOSSES (MMH)	NET ENERGY FOR LOAD (MMH)		
(ac)	(ad)	(af)	(ag)	(ah)	(aj)	(ak)	(al)	(ap)	(au)	(av)	(bc)	(be)	(bf)	(be)	(bf)	(bg)
15	1980	2,707	541	4518	10,256	103,830	10,124	21,623	42,678	9,368	0	177,499	19,557	197,056	54.9	41
16	1981	2,830	562	4619	10,516	109,311	10,395	21,784	55,851	9,915	0	196,861	3,071	199,932	49.6	46
17	1982	2,862	567	4759	10,795	116,401	10,783	26,461	63,045	10,587	0	216,494	(6,160)	210,334	57.2	42
18	1983	2,886	577	4312	11,036	116,462	10,553	24,048	61,285	10,110	0	211,905	(4,818)	207,087	56.3	42
19	1984	2,914	620	4069	10,928	109,765	10,044	25,685	63,089	9,868	0	208,407	7,393	215,800	60.1	41
20	1985	2,954	643	4320	11,113	116,750	10,506	28,805	70,520	9,697	0	225,772	(1,339)	224,433	53.4	48
21	1986	2,998	667	4378	11,345	122,221	10,773	30,634	67,483	8,630	0	228,968	7,856	236,824	57.5	47
22	1987	3,058	702	4872	11,506	125,812	10,934	28,357	69,810	9,963	0	233,942	18,129	252,071	57.6	50
23	1988	3,129	726	4515	11,497	120,575	10,488	29,277	70,827	9,433	0	230,112	19,800	249,912	59.4	48
24	1989	3,179	749	4928	11,628	125,474	10,791	29,079	73,653	10,049	0	238,255	21,119	259,374	60.4	49
25	1990	3,197	758	4898	11,670	124,867	10,700	28,610	76,388	10,645	0	240,510	22,899	263,409	58.7	51
26	1991	3,215	768	4529	11,725	123,797	10,558	28,964	77,161	10,043	1,460	241,424	22,899	261,706	57.7	52
27	1992	3,233	777	4529	11,780	125,064	10,617	29,317	77,933	10,043	1,650	244,007	20,499	264,506	57.0	53
28	1993	3,251	786	4529	11,835	126,341	10,675	29,669	78,705	10,043	1,650	246,409	20,701	267,110	57.0	53
29	1994	3,270	795	4529	11,890	127,628	10,734	30,022	79,478	10,043	3,950	251,121	21,097	272,218	57.6	54
30	1995	3,288	804	4529	11,945	128,926	10,794	30,374	80,250	10,043	3,950	253,542	21,300	274,843	57.6	55
31	1996	3,287	804	4529	11,942	129,595	10,852	30,359	80,217	10,043	3,950	254,163	21,352	275,516	56.9	55
32	1997	3,286	803	4529	11,940	130,268	10,910	30,343	80,184	10,043	6,210	257,048	21,595	278,643	57.4	55
33	1998	3,285	803	4529	11,938	130,944	10,969	30,328	80,150	10,043	6,210	257,676	21,648	279,324	57.4	56
34	1999	3,285	803	4529	11,935	131,624	11,028	30,313	80,117	10,043	6,210	258,307	21,701	280,008	57.4	56
35	2000	3,284	802	4529	11,933	132,308	11,088	30,298	80,084	10,043	6,210	258,942	21,754	280,696	57.4	56
36	2001	3,275	797	4529	11,905	132,701	11,147	30,118	79,690	10,043	6,210	258,762	21,739	280,501	57.4	56
37	2002	3,265	793	4529	11,877	133,095	11,206	29,939	79,296	10,043	6,210	258,583	21,724	280,306	57.4	56
38	2003	3,256	788	4529	11,849	133,490	11,266	29,759	78,902	10,043	6,210	258,403	21,709	280,112	57.4	56
39	2004	3,247	784	4529	11,821	133,885	11,326	29,579	78,508	10,043	6,210	258,225	21,694	279,918	57.4	56
40	2005	3,238	779	4529	11,793	134,280	11,386	29,399	78,114	10,043	6,210	258,046	21,679	279,725	57.4	56
41	2006	3,225	773	4529	11,756	134,571	11,447	29,162	77,596	10,043	6,210	257,582	21,640	279,222	57.4	56
42	2007	3,213	767	4529	11,719	134,862	11,508	28,925	77,077	10,043	6,210	257,118	21,601	278,719	57.4	55
43	2008	3,201	761	4529	11,682	135,153	11,569	28,688	76,559	10,043	6,210	256,653	21,562	278,214	57.4	55
44	2009	3,189	754	4529	11,646	135,442	11,630	28,451	76,040	10,043	6,210	256,187	21,522	277,709	57.4	55
45	2010	3,177	748	4529	11,609	135,731	11,692	28,214	75,522	10,043	6,210	255,720	21,483	277,203	57.4	55

AVG. ANNUAL % GROWTH RATE

1980 - 1990	1.7%	3.4%	0.8%	1.3%	1.9%	0.6%	2.8%	6.0%	1.3%	3.1%	1.6%	2.9%	0.7%	2.2%
1990 - 2000	0.3%	0.6%	-0.8%	0.2%	0.6%	0.4%	0.6%	0.5%	-0.6%	0.7%	-0.5%	0.6%	-0.2%	0.9%
1990 - 2010	-0.0%	-0.1%	-0.4%	-0.0%	0.4%	0.4%	-0.1%	-0.1%	-0.3%	0.3%	-0.3%	0.3%	-0.1%	0.4%

PROJECTED ENERGY REQUIREMENTS

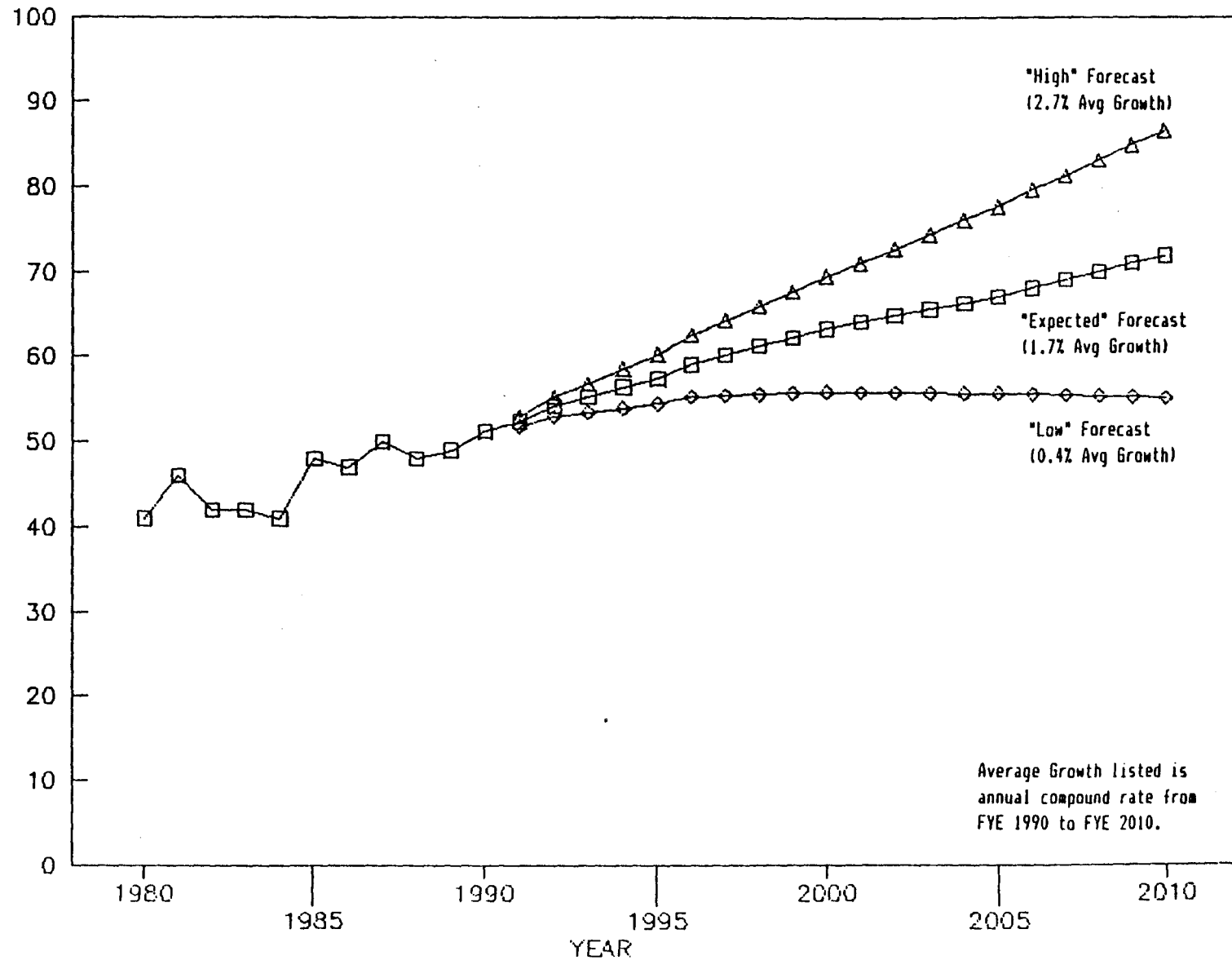


PROJECTED PEAK DEMANDS

ANNUAL PEAK (MEGAWATTS)

15

1C.B.1-30



GRAPH 11-2

APPENDIX A

A. INTRODUCTION

This appendix describes the methodology employed in the development of an econometric forecasting model for The City of Homestead. This model was developed by RMI in the Fall of 1989. A comparison of projected and actual FYE 1990 data was conducted. This analysis indicated that the model was still appropriate for forecasting purposes without further specification. Data were revised to reflect actual FYE 1990 information and the forecasting model was used to project future electrical power and energy usage.

During the development of the forecasting model, an extensive econometric modeling effort was undertaken. The model was specified using actual data from FYE 1980 through FYE 1989. The customer consumption patterns have been analyzed by the model reflecting factors for population, employment, weather, and the real price of electricity.

The forecasted results are based upon certain key assumptions. These are:

1. The City's present service area;
2. Population growth will be as forecast by the University of Florida, Bureau of Economic and Business Research (BEER);
3. Employment in retail trade and services in South Florida will tend to follow the forecast provided by the Florida Department of Labor and Employment Security as well as population trends for the area over the same time frame;
4. The real price of electricity will remain constant reflecting an assumption that it will tend to increase at a rate equal to the general rate of inflation;

5. There will be no changes in current City energy and development policies and the City will not provide rebates or financing of energy efficient equipment; and,
6. The Homestead Sports Complex and additional facilities for Miami-Dade Community College will become part of the City's system load during the forecast period.

The forecasts for population and employment for each category and equations are contained on Attachments 1 and 2 and represent a bounded set of conditions. Each category has a range of forecasted results which includes a low growth, a high growth, and an expected growth scenario. With the exception of municipal energy sales, all forecasts are based upon an econometric formulation. No variables were found which produced a satisfactory correlation for energy sales in the municipal category. Therefore, this category was estimated empirically.

The system net peak demand forecast was determined by applying an annual load factor projection to the forecast of net energy requirements then adding incremental contributions to peak demand as estimated for the Homestead Sports Complex and the expansion of the Miami-Dade Community College.

B. FORECAST DEVELOPMENT METHODOLOGY AND DATA

1. General

An econometric model was utilized to provide projections for each customer category in the service area. In developing the equations, a number of economic, demographic, and climatological variables were tested. The final expressions were selected on the basis of (1) statistical significance and sign patterns of the relevant coefficients, (2) performance of alternative models in a forecasting environment, and (3) overall statistical properties of the equations.

The models were tested for functional form (linear, logarithmic, etc.). It was generally found that logarithmic models produced the most consistent overall performance. This formulation is particularly useful because the slope of the function can be used to approximate the growth rate and estimate price elasticities (the percentage change in sales caused by a percentage change in price). Both can be extremely useful in making policy decisions.

2. Customer Characteristics

Residential customers accounted for 51.9 percent of system energy sales in FYE 1990. Industrial sales accounted for 31.8 percent, commercial sales accounted for 11.9 percent, and City sales accounted for 4.4 percent. No major trend changes in types of enterprises are seen at the present time and there are no major proposed changes in land use controls in effect in the service area.

Commercial developments are expected to continue to be the major non-residential growth segment. Industrial parks offer some potential for new enterprises, however, political and territorial factors generally inhibit many major changes. The potential for the City to attract major new industries may well decline over the forecast horizon due to a broad array of economic and territorial factors.

3. Population

The populations of Homestead and South Florida have shown a continuing increase since 1970. The decennial census data indicates that population growth in Metro-Dade County has begun to mitigate as households have begun to relocate to the suburbs. It is expected that this trend will continue and that Homestead will find itself the recipient of at least a portion of this out-migration from the more heavily populated areas of Dade County.

The population of the South Florida region (including Broward, Dade and Monroe counties) was utilized as a proxy for population trends in Homestead. Projections for population growth for the South Florida area were obtained from the University of Florida, Bureau of Economics and Business Research. Based on this information, RMI projects the addition of approximately 81 residential customers per year in the City's service area between FYE 1990 and FYE 2010. This is down from the average 150 customers per year which the City added between FYE 1980 and FYE 1990.

A correlation between the three-county population estimates and those for the City produced statistically significant results and it was determined that the three-county population figures could be utilized to estimate growth patterns expected in the Homestead area. In fact, regressions relating residential customers to the population in the South Florida area produced coefficients of determination (R^2 's) of 93 percent. This variable is highly desirable as a predictive device, in that detailed population projections are available from well-known and generally accepted sources. The historical and projected population series are presented in Attachment 1.

4. Employment

With respect to the econometric model, it is intuitive that some measure of local economic activity will be relevant. The variable utilized in this regard was average employment in retail trade and services. Estimates of this variable for the three-county region including Broward, Dade and Monroe counties were used to reflect general economic conditions in South Florida. The employment variables were generated from data series provided by the State of Florida Department of Labor and Employment Security.

Approximately 48 percent of employment in the South Florida area is based in retail trade and services. The next most significant category of employment is Government, including military, which accounts for approximately 12 percent of total employment.

Employment in retail trade and services was selected as the appropriate control variable based upon its dominance and the fact that it is subject to the economic variations prompted by fluctuating trends in both local economy and in tourism. The historical and projected employment series utilized in the model are presented in Attachment 2.

5. Weather

Weather factors were introduced into the model through an investigation of the sum of heating degree days and cooling degree days. Given the location of the service area, it seemed likely that cooling degree days would have the more pronounced impact on energy usage. However, due to a presumably high percentage of electric space heaters, this was not found to be the case and combined heating and cooling degree days were utilized.

6. Price Elasticity

One of the considerations in the preparation of a forecast is the future price of electricity and how this may affect future energy requirements. In late 1973, the effects of the oil embargo were realized by electric utility residential customers. With rapidly increasing actual price, average annual energy consumption declined. Since 1973, the price of electricity has been an important determining factor in energy consumption patterns. As the average price of electricity rose, the growth in consumption rates of residential and other customers has slowed considerably. In the City of Homestead, the real price of electricity in the residential, commercial and industrial classes increased rapidly through 1985, and has been somewhat lower rate since.

A number of national studies have shown a residential price elasticity of -0.5. This means that for every one (1) percent increase in the real (deflated) price of electricity, total net usage will decrease by 0.5 percent. Similar price elasticity is indicated by equations in the econometric model. Residential usage shows an elasticity of

approximately -0.4 percent. If the real price of residential electricity is increased one percent and all other factors are held constant, usage is expected to decline -0.4 percent.

7. Alternative Energy Sources

The traditional alternatives to the use of electricity in Homestead, as elsewhere in the United States, include oil, L.P. gas, and natural gas. It is anticipated that existing fuel uses will continue until facilities require replacement. There has been no shortage of petroleum fuels in the past decade and it is assumed that this trend will continue throughout the study period.

There are strong arguments for including the real price of electricity and an alternative fuel price variable in the equations. In practice, however, this information is rarely useful in models of the type specified for municipal forecasts. It is a relatively difficult task for most consumers to shift from, say, electricity to oil in an existing structure. Consequently, most of the decisions regarding a major power source are made at the time of construction. Since new structures and replacements which are brought into use in a given year constitute only a very small fraction of the total stock, it is unlikely that a statistically significant response can be obtained. Thus, investigation of alternative fuel price variables were not included in this study.

8. Empirical Determination

A testing procedure utilizing various formulations and explanatory variables was applied to all customer classifications and usage within the City's service area. It was found that significant relationships could be isolated for all categories of usage except City (municipal government) use. Nevertheless, with the residential, commercial and industrial groups comprising the vast majority of energy usage, a reasonable total usage

forecast was developed. The final equations for the model are summarized in Attachment 3.

In summary, energy sales to the Residential class responded to the area population, price, and weather. Energy sales to the Commercial and Industrial classes were found to be directly related to South Florida Retail Trade and Service employment, but not significantly related to either price of power or weather.

C. ENERGY AND DEMAND FORECAST

The forecast equations for each customer class represent a bounded set of conditions. These equations can be used to provide forecasted results from a range of population and employment projections representing a low growth, a high growth, and an expected growth scenario. With the exception of municipal energy sales, all forecasts are based upon the econometric model prepared for the City. No variables were found which produced a satisfactory correlation for usage in the City use category. City usage can often be affected by events such as changes in local laws and governmental policy. Therefore, the municipal class was forecast based upon empirical determinations. It was assumed that municipal use would remain constant over the forecast period.

The system net peak demand forecast was determined by applying an annual load factor projection to the forecast of net energy and then adding contributions to peak demand as estimated for the Homestead Sports Complex and expansion of the Miami-Dade Community College.

It is our understanding that the need certification hearings for Orlando Utilities Commission's Stanton Energy Center 2 will require forecasts of demand and energy requirements through the year 2021. We have estimated the energy requirements by utilizing the incremental change in net energy for load between FYE 2009 and FYE 2010. The long-term assumes that energy requirements will increase by 5069 MWH per

year for the period FYE 2011 through FYE 2021. Net system peak demand has been estimated for that same period using the system load factor derived in FYE 2010. The results of the forecast for FYE 2011 through 2021 are presented in Attachment 4.

The peak and energy forecasts shown in this study include an Expected, High, and Low forecast which reflects a bounded set of results. The High forecast or upper bound assumes conditions which favor high electrical growth. This includes such factors as strong population growth and employment activity. The Low forecast or lower bound assumes opposite conditions including sluggish employment and lower population growth. The forecast represents the results of our analysis of data and development of an econometric model for energy consumption and consumers for the City. Econometric models are most useful over relatively long forecast periods and should be blended with, not substituted for, local judgment and knowledge.

ATTACHMENT 1

CITY OF HOMESTEAD ECONOMETRIC MODEL

THREE COUNTY POPULATION (1)

FISCAL YEAR ENDING (2)	ACTUAL OR EXPECTED (1,000's)	HIGH GROWTH (1,000's)	LOW GROWTH (1,000's)

HISTORIC			
1980	2,707	2,707	2,707
1981	2,830	2,830	2,830
1982	2,862	2,862	2,862
1983	2,886	2,886	2,886
1984	2,914	2,914	2,914
1985	2,954	2,954	2,954
1986	2,998	2,998	2,998
1987	3,058	3,058	3,058
1988	3,129	3,129	3,129
1989	3,179	3,179	3,179
1990	3,226	3,255	3,197
FORECASTED			
1991	3,280	3,331	3,215
1992	3,332	3,406	3,233
1993	3,380	3,482	3,251
1994	3,424	3,558	3,270
1995	3,461	3,634	3,288
1996	3,504	3,710	3,287
1997	3,545	3,786	3,286
1998	3,583	3,862	3,285
1999	3,617	3,938	3,285
2000	3,649	4,014	3,284
2001	3,646	4,087	3,275
2002	3,642	4,160	3,265
2003	3,639	4,234	3,256
2004	3,636	4,307	3,247
2005	3,633	4,380	3,238
2006	3,659	4,457	3,225
2007	3,684	4,534	3,213
2008	3,710	4,611	3,201
2009	3,735	4,688	3,189
2010	3,761	4,765	3,177
Average Growth			
1990-2010	0.8%	1.9%	-0.0%

(1) SOURCE: UNIVERSITY OF FLORIDA, BUREAU OF ECONOMICS AND BUSINESS RESEARCH

(2) FISCAL YEAR RUNS FROM OCTOBER 1 TO SEPTEMBER 30 OF DESIGNATED YEAR.

ATTACHMENT 2

CITY OF HOMESTEAD ECONOMETRIC MODEL

THREE COUNTY EMPLOYMENT IN RETAIL TRADE AND SERVICES (2)

FISCAL YEAR ENDING (2)	ACTUAL OR EXPECTED (1,000's)	HIGH GROWTH (1,000's)	LOW GROWTH (1,000's)

HISTORIC			
1980	541	541	541
1981	562	562	562
1982	567	567	567
1983	577	577	577
1984	620	620	620
1985	643	643	643
1986	667	667	667
1987	702	702	702
1988	726	726	726
1989	749	749	749
1990	773	788	758
FORECASTED			
1991	797	826	768
1992	821	864	777
1993	845	902	786
1994	869	940	795
1995	893	978	804
1996	916	1,017	804
1997	940	1,055	803
1998	964	1,093	803
1999	988	1,131	803
2000	1,012	1,169	802
2001	1,036	1,206	797
2002	1,060	1,243	793
2003	1,083	1,280	788
2004	1,107	1,317	784
2005	1,131	1,354	779
2006	1,155	1,393	773
2007	1,179	1,431	767
2008	1,203	1,470	761
2009	1,227	1,509	754
2010	1,250	1,548	748
Average Growth			
1990-2010	2.4%	3.4%	-0.1%

(1) SOURCE: FLORIDA DEPARTMENT OF LABOR AND EMPLOYMENT SECURITY FOR EXPECTED.
HIGH AND LOW VALUES REFLECT HIGH AND LOW POPULATION PROJECTIONS FROM
THE UNIVERSITY OF FLORIDA, BUREAU OF ECONOMICS AND BUSINESS RESEARCH.

(2) FISCAL YEAR RUNS FROM OCTOBER 1 TO SEPTEMBER 30 OF DESIGNATED YEAR.

ATTACHMENT 3
FORECAST EQUATIONS AND COEFFICIENTS

Residential Accounts

3.03 * Tri County Population in Thousands + 1985

Residential Energy (MWH)

See Sheet 2 of 2, Attachment 3

Commercial Accounts

1.40 * Tri County Employment in Thousands + 444

Commercial Energy (MWH)

63.0 * Tri County Employment in Thousands raised to the 0.9366 power - 3335

Industrial Accounts

0.272 * Tri County Employment in Thousands + 50

Industrial Energy (MWH)

84.72 * Tri County Employment in Thousands + 10899

Municipal Energy

10043 MWH (for all years)

ATTACHMENT 3

Residential Energy Sales Model

It was postulated that Residential Energy Sales could be expressed by a linear relationship of the following form:

$$(1) \ln(RSALES/RACCTS) = \ln(A) + B*\ln(WEATHER) + YEAR*\ln(c) - d*\ln(COST) + e$$

where a, b, c, and d represent coefficients to be estimated and e represents a random disturbance term. In this form, values for coefficients can be readily estimated from historic data using linear regression procedures. After values for the coefficients are determined, equation (1) can be changed to more simple form by taking the analog of both sides, dropping the random error term e, and rearranging the remaining terms to obtain:

$$(2) RSALES = a * RACCTS * [f(WEATHER) + f(YEAR) / f(COST)]$$

WHERE:

RSALES = Total energy sales to residential accounts.

and

- a = Nominal energy sales per year to each residential account. After correcting for weather, the nominal value in FYE 1990 was 10.426 MWH.
- RACCTS = Number of residential accounts
- f(WEATHER) = Factor representing number of heating and cooling degree days above or below normal. Each additional degree day has historically increased usage by 0.005 percent.
- f(YEAR) = Factor representing increasing average residential sales per customer with time. Average usage has been increasing 0.5 percent per year.

ATTACHMENT 3

f(COST) = Factor representing decrease in usage with increased real cost. From 1980 to 1989, a one percent increase in real cost resulted in a 0.36 percent decrease in residential sales.

ATTACHMENT 4

CITY OF HOMESTEAD ENERGY AND DEMAND FORECAST

FISCAL YEAR ENDING (1)	EXPECTED		HIGH		LOW	
	SYSTEM ENERGY (MMH)	PEAK DEMAND (MW)	SYSTEM ENERGY (MMH)	PEAK DEMAND (MW)	SYSTEM ENERGY (MMH)	PEAK DEMAND (MW)
1991	264,938	52	276,626	53	261,706	52
1992	270,933	54	276,383	55	264,506	53
1993	276,601	55	284,962	57	267,110	53
1994	284,648	56	296,062	59	272,218	54
1995	289,939	57	304,698	60	274,843	55
1996	295,507	59	313,378	63	275,516	55
1997	303,422	60	324,538	64	278,643	55
1998	308,816	61	333,278	66	279,324	56
1999	314,096	62	342,048	68	280,008	56
2000	319,280	63	350,848	69	280,696	56
2001	323,183	64	359,413	71	280,501	56
2002	327,088	65	368,007	73	280,306	56
2003	330,995	66	376,633	74	280,112	56
2004	334,903	66	385,290	76	279,918	56
2005	338,814	67	393,979	78	279,725	56
2006	343,828	68	403,085	80	279,222	56
2007	348,855	69	412,225	81	278,719	55
2008	353,896	70	421,399	83	278,214	55
2009	358,951	71	430,607	85	277,709	55
2010	364,020	72	439,850	87	277,203	55
2011	369,089	73	449,093	88	276,697	55
2012	374,158	74	458,336	90	276,191	55
2013	379,227	75	467,579	92	275,685	55
2014	384,296	76	476,822	94	275,179	55
2015	389,365	77	486,065	96	274,673	55
2016	394,434	78	495,308	97	274,167	55
2017	399,503	79	504,551	99	273,661	54
2018	404,572	80	513,794	101	273,155	54
2019	409,641	81	523,037	103	272,649	54
2020	414,710	82	532,280	105	272,143	54
2021	419,779	83	541,523	107	271,637	54

(1) FISCAL YEAR RUNS FROM OCTOBER 1 TO SEPTEMBER 30 OF DESIGNATED YEAR.

**UTILITY BOARD OF THE
CITY OF KEY WEST**

APPENDIX 1C.B

SECTION 1C.B.1.3

UTILITY BOARD OF THE CITY OF KEY WEST, FLORIDA Electric System

Customer, Energy and Demand Forecast 1991 - 2021

The following is a summary of the analyses and studies pertaining to the design and development of estimates of future energy and demand requirements and customer forecasts for the Utility Board of the City of Key West, Florida (the "City"). The forecast is provided on a fiscal year basis.

Based on our analysis, the system net energy requirements and peak demand are projected to increase at a compound annual growth rate of approximately 2.6% and 1.7% for the period 1991 through 2000, and 1991 through 2021, respectively. The forecast is summarized on a Net Energy for load and Net Peak Demand basis in Table I and on a detailed by-class basis on Table II and Table III. Selected years of the forecast are summarized below.

Projected Demand and Energy Requirements by Rate Class (Fiscal Year)

	<u>1990[1]</u>	<u>1991</u>	<u>2000</u>	<u>2021</u>
Residential (MWh)	188,493	187,321	236,690	346,710
Small Commercial (MWh)	45,000	46,598	59,533	82,466
Church (MWh)	361	361	361	361
Large Power (MWh)	237,949	252,478	320,344	384,592
Private Area Lighting (MWh)	1,380	1,298	1,450	1,618
Street Lighting (MWh)	<u>3,353</u>	<u>3,646</u>	<u>3,627</u>	<u>3,714</u>
Total Sales (MWh)	476,535	491,702	622,005	819,461
System Losses (MWh)	24,571	36,442	46,098	60,733
Net Energy Requirements (MWh)	501,106	528,144	668,103	880,194
Percent Growth (%)	-	5.4%	2.6%	1.3%
Net Peak Demand (MW)	87.5	91.3	115.6	152.2
Percent Growth (%)	-	4.3%	2.7%	1.3%

[1] Actual 1990.

Assumptions

The 1991 Load Forecast is based on econometric modeling techniques which attempt to correlate consumption with economic activity. A description of the explanatory variables utilized in the models for customers and consumption are described on the following pages.

Population

Monroe County population was used as the explanatory variable in the analysis of residential customer growth. Historical and projected values of Monroe County population were taken from the Population Studies Bulletin #92 published by the Bureau of Economic and Business Research ("BEBR") at the University of Florida. Monroe County population is expected to increase by approximately 29,300 people over the period 1991 to 2021; this equates to an average compound growth rate of 1.02% per year.

Real Florida Taxable Retail Sales

Real Florida Taxable Retail Sales was used as an explanatory variable in the consumption models for the Residential and Large Power Class. Real Florida Taxable Retail Sales are projected to grow at an average compound growth rate of 2.0% over the period 1991 to 2021. The historical and projected values of Real Florida Taxable Retail Sales were based on information provided by the Office of the Governor for the State of Florida.

Real Price of Electricity

The Real Price of Electricity (in 1982 dollars) was used as an explanatory variable in the Residential consumption model. Estimates for the real price of electricity were developed using historical sales data provided by the Utility Board's staff. The Real Price of Electricity is assumed to remain flat over the study period 1991 to 2021; therefore, there will be no additional escalation in the price of electricity in excess of inflation.

Weather

Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") were also used as an explanatory variable in the Residential, Small Commercial, and Large Commercial

consumption models. Historical and projected values of HDD and CDD were provided by the National Oceanic and Atmospheric Administration ("NOAA") in its publication entitled "Climatological Data Florida."

System Losses

System losses of 6.9% of energy sales were utilized for the forecast period 1991 to 2021. System losses were developed based on a five year analysis of net energy for load and net sales for the period 1985 to 1990.

System Load Factor

A system load factor of 66% was utilized for the forecast period 1991 to 2021. The system load factor was developed based on a five year (1985 - 1990) analysis of historical net 60 minute peak demands and net energy for load.

Incremental Load Additions

Based on information provided by the City we have included three phases of incremental loads in the forecast. The three phases were divided into projects that would be connected to the system beginning in January 1991, June 1991 and June 1992.

	<u>Project Type</u>	<u>Diversified Load (KW)</u>	<u>Estimated On-Line Date</u>
Phase I	Winn Dixie	516	1/91
	Scotty's Addition	305	1/91
	Eckerd Drugs	<u>85</u>	1/91
		906	
Phase II	J. C. Penney	120	6/91
	Retails A-E	420	6/91
	TGI Fridays	50	6/91
	Shoneys	50	6/91
	Douglas Square	<u>236</u>	6/91
		876	
Phase III	Conch Village	472	6/92
	Kings Haven	80	6/92
	Las Salinas	<u>211</u>	6/92
		763	

The total load of the projects when completed are estimated to be 2.7 MW and roughly 14,716,000 kWh of energy per year from 1992 to 2021. The load factor assumed for these projects was based on the system average of 66%.

Customer Saturation

The City of Key West has experienced approximately 6.8% in energy sales and about 3.5% in customers over the last five years. However, because of the finite amount of land available for residential development in the electric system's service area, it has become evident that this kind of growth cannot be sustained indefinitely. Based on discussions with the City's Planning Department and a review of the Growth Management Ordinance ("GMO") which is an estimate of the build-out rate for the City, by the year 2010 the City of Key West will be saturated from a civilian population standpoint at 30,250 people. Therefore, for purposes of this load forecast, it has been assumed that from the year 2010 to the end of the forecast period -021, the amount of residential customers will remain constant at the 2010 levels.

Residential Class Models

Residential Sales

The econometric analyses relating to the residential class were based on annual historical observations of average kWh usage per residential customer for the period 1980 to 1990. The forecast of total residential energy is a product of the forecasted number of residential customers and the forecasted average use per residential customer. The explanatory variables used to statistically describe the average use per residential customer are weather, price, a constant term, quarterly seasonal indicators, and the Real Florida Taxable Retail Sales. The resulting index of determination (R-squared statistic) was 90%. The index of determination or R-squared statistic is a measure of the adequacy of the equation or the fit of the equation to the historical observations used.

Residential Customers

The forecast of residential customers was based on an econometric model utilizing historical Monroe County Population, a constant term, and quarterly seasonal indicators as explanatory variables. The resulting index of determination was 99%. The residential class forecast results for selected years are summarized below.

<u>Fiscal Year</u>	<u>Average Annual Number of Residential Customers</u>	<u>Average Use Per Residential Customer (kWh)</u>	<u>Total Residential Energy Sales (MWh)</u>
1990*	19,067	9,886	188,493
1991	19,496	9,608	187,321
2000	22,744	10,407	236,690
2021	25,400	13,650	346,710
Average Annual Compound Growth 1991-2021	.9%	1.2%	2.1%

* Actual

Small Commercial Models

Small Commercial Sales

The econometric analyses relating to the small commercial class were based on annual historical observations of energy consumption for the period 1980 to 1990. The explanatory variables used to statistically describe the small commercial class' consumption were Residential Customers, lagged small Commercial class sales, weather, quarterly seasonal indicators, and a constant term. The resulting index of determination was 95%.

Small Commercial Customers

The forecast of small commercial customers was based on an econometric model utilizing a constant term, a time series variable, and quarterly residential customers as explanatory variables. The resulting index of determination was 99%. A summary of the Small Commercial Class forecast for selected years is shown below.

<u>Fiscal Year</u>	<u>Average Annual Number of Small Commercial Customers</u>	<u>Total Small Commercial Energy Sales</u> (MWh)
1990*	2,137	45,000
1991	2,223	46,598
2000	2,668	59,533
2021	3,595	82,466
Average Annual Compound Growth 1991-2021	1.6%	1.9%

* Actual

Church

Based on the apparent volatility of the energy sales in the church rate class, there were no econometric models developed that adequately explained the historical consumption patterns. Therefore, the projected sales for the church class were assumed to remain at the fiscal year 1990 levels of 360,572 kWh/yr for 1991 to 2021.

Large Power Models

Large Power Sales

The econometric analyses relating to the large power class was based on annual historical observations of energy consumption for the period 1980 to 1990. The explanatory variables utilized to statistically describe the large power class consumptions were quarterly seasonal indicators, weather, Real Florida Taxable Retail Sales, residential customers, and a constant term. The resulting index of determination was 98%.

Large Power Customers

The forecast of large power customers was based on an econometric model utilizing a constant term, a time series variable, and quarterly residential customers as explanatory variables. The resulting index of determination was 99%.

Included in the large power class are the projections for the Government Recreational Sales, the Desalination Plant, and the Military Sales. The Government Recreational Sales were assumed to remain at the 1990 levels for 1991 to 2021.

Based on discussions with the City, the Desalination Plant was assumed to be off the system at the end of 1990. Therefore, there were no sales forecasted for 1991 to 2021 for the desalination plant. The Military Sales econometric model was developed utilizing annual historical observations of energy sales for the period 1980 to 1990. The explanatory variables used to statistically describe military consumption were a constant term, quarterly seasonal indicators, a time series variable, lagged military sales and weather. The resulting index of determination was 93%.

The customer projections for both the Government Recreational and Military class were included as part of the large power class. A summary of the large power class forecast for selected years is shown below.

<u>Fiscal Year</u>	<u>Average Annual Number of Large Power Customers[1]</u>	<u>Total Large Power Energy Sales[2]</u> (MWh)
1990*	472	237,949
1991	480	252,478
2000	633	320,344
2021	940	384,592
Average Annual Compound Growth		
1991-2021	2.3%	1.4%

* Actual

- [1] Includes customers for the Government Recreational, Military, and Churches.
[2] Includes sales for the Government Recreational, and Military.

Street Lighting/Private Area Lighting

The projected energy sales for both the street lighting and private area lighting classes were based on the product of the projected number of light fixtures and the projected average kWh usage per fixture. The average number of light fixtures were estimated from data provided by the City. A summary of the Street Lighting and Private Area Lighting Sales forecast for selected years are shown below.

<u>Fiscal Year</u>	<u>Street Lighting Energy Sales</u> (MWh)	<u>Private Area Lighting Energy Sales</u> (MWh)
1990*	3,353	1,380
1991	3,646	1,298
2000	3,627	1,450
2021	3,714	1,618
Average Annual Compound Growth 1991-2021	.1%	0.7%

* Actual

Summary

The forecasting methodology utilized attempts to identify and reflect the key factors which can influence the City's demand and energy requirements. It should be emphasized that the confidence associated with any projection varies inversely with the length of the forecast. The probability of extraneous factors affecting projected values increases with uncertainty about future developments; this uncertainty, in turn, increases with the length of the forecast period. With this in mind, projections of the City's annual net peak demand and net energy requirements should be viewed as reasonable estimates but subject to external disturbances which, at this time, cannot be reasonably foreseen. Therefore, the forecast results and the underlying assumptions should be reviewed periodically and updated when necessary. To the extent that unpredictable economic, demographic, and technological developments affect future expectations, forecasts may require adjustments to reflect such factors.

FN: FRST91B
DN: F3295H
WO: EF5186AA1AA

TABLE 1

UTILITY BOARD OF THE CITY OF KEY WEST, FLORIDA

Historical and Projected
Net Energy Requirements and Net Peak Demands

(Fiscal Year)

	Net Energy Requirements	Winter Peak Demand	Summer Peak Demand
	(MWh)	(MW)	(MW)
HISTORICAL:			
1980	336,542	-	57.5
1981	364,157	-	62.9
1982	362,012	-	59.6
1983	343,098	-	59.9
1984	354,572	-	56.9
1985	363,341	61.2	61.3
1986	392,663	60.0	67.4
1987	444,856	66.5	75.8
1988	449,543	72.5	79.5
1989	486,633	73.3	82.6
1990	501,106	77.3	87.5
Avg. Annual Compound Rate of Growth:			
1980-1990	4.06%	-	4.29%
1985-1990	6.64%	4.78%	7.38%
PROJECTED:			
1991	528,144	82.6	91.3
1992	547,433	85.4	94.7
1993	564,504	88.0	97.6
1994	581,503	90.7	100.6
1995	599,611	93.5	103.7
1996	612,392	95.5	105.9
1997	625,421	97.5	108.2
1998	638,902	99.6	110.5
1999	653,219	101.9	113.0
2000	668,103	104.2	115.6
2001	681,509	106.3	117.9
2002	694,957	108.4	120.2
2003	708,485	110.5	122.5
2004	722,165	112.7	124.9
2005	735,990	114.8	127.3
2006	749,558	117.0	129.6
2007	763,085	119.1	132.0
2008	776,433	121.2	134.3
2009	789,920	123.3	136.6
2010	803,480	125.4	139.0
2011	811,766	126.7	140.4
2012	818,806	127.8	141.6
2013	825,584	128.8	142.8
2014	832,146	129.9	143.9
2015	838,770	130.9	145.1
2016	845,472	132.0	146.2
2017	852,233	133.0	147.4
2018	859,098	134.1	148.6
2019	866,053	135.2	149.8
2020	873,071	136.3	151.0
2021	880,194	137.4	152.2
Avg. Annual Compound Rate of Growth:			
1991-2000	2.6%	2.6%	2.6%
1991-2010	2.2%	2.2%	2.2%
1991-2021	1.7%	1.7%	1.7%

FN: FRST91B
 DN: F3205H
 NO: EF5186AA1AA
 CPI=16, LPI=8
 15-Jan-91
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TABLE II
 UTILITY BOARD OF THE CITY OF KEY WEST
 Historical and Projected Energy Sales and Peak Demands
 (Fiscal Year)

YEAR	Residential Energy Sales (KWH)	Small Commercial Energy Sales (KWH)	Church Engy Sales (KWH)	Total Large Power Energy Sales (KWH) [1]	Private Area Lighting Energy Sales (KWH)	Street Lighting Energy Sales (KWH)	Total System Energy Sales (KWH)	Net Energy For Load (KWH)	Summer Peak Demand [1] (MW)	Incremental Additions (MW)	Net Summer Peak Demand [2] (MW)
HISTORICAL:											
1985	124,105,512	33,275,649	284,528	180,425,570	1,336,184	3,363,621	342,791,064	363,341,316	61.3	---	61.3
1986	134,874,250	35,144,457	307,716	180,107,872	1,310,270	3,284,470	365,027,835	392,062,756	67.4	---	67.4
1987	150,568,088	38,384,223	215,689	211,671,877	1,270,609	3,217,095	412,533,481	444,855,707	75.8	---	75.8
1988	167,879,928	39,553,761	309,921	211,098,568	1,555,671	3,517,606	418,668,855	449,542,652	79.5	---	79.5
1989	167,879,928	22,677,033	246,795	228,601,423	1,558,671	3,507,661	459,547,410	484,635,085	82.6	---	82.6
1990	186,493,346	45,600,137	380,572	237,948,951	1,579,368	3,352,652	478,535,220	501,106,170	87.5	---	87.5
Avg. Annual Compound Rate of Growth											
1985-1990	8.7%	6.2%	4.9%	5.7%	0.6%	-0.1%	6.8%	6.6%	7.4%	-	7.4%
PROJECTED:											
1991	187,321,243	46,598,300	360,572	252,478,440	1,298,148	3,645,816	491,702,519	528,144,688	88.8	2.5	91.3
1992	191,709,570	47,912,520	360,572	264,661,223	1,311,844	3,643,792	509,623,738	547,207,582	92.0	2.6	94.6
1993	196,251,864	49,073,158	360,572	274,368,263	1,331,844	3,641,688	523,323,389	561,502,177	94.0	2.7	96.7
1994	202,523,617	51,169,358	360,572	286,202,392	1,348,692	3,639,624	541,323,236	581,502,810	96.0	2.7	98.7
1995	210,231,933	53,696,965	360,572	289,645,097	1,365,540	3,637,560	558,233,667	599,610,813	97.0	2.7	100.0
1996	219,879,390	54,360,907	360,572	295,719,183	1,382,388	3,635,496	570,136,936	612,391,983	98.0	2.7	100.7
1997	219,506,267	55,632,407	360,572	301,674,914	1,399,236	3,633,432	582,269,918	625,269,918	99.0	2.7	101.7
1998	224,679,662	56,920,984	360,572	301,751,670	1,416,084	3,631,368	594,817,341	638,901,983	100.0	2.7	102.7
1999	230,101,002	58,200,225	360,572	311,004,771	1,432,932	3,629,304	608,146,806	653,218,911	101.0	2.7	103.7
2000	235,689,000	59,532,225	360,572	320,347,278	1,449,780	3,627,240	622,004,327	668,103,467	102.0	2.7	104.7
2001	242,776,776	60,820,225	360,572	329,718,788	1,466,628	3,625,176	637,484,677	683,508,783	103.0	2.7	105.7
2002	248,215,058	61,103,225	360,572	339,118,874	1,483,476	3,623,112	647,905,094	698,957,136	104.0	2.7	106.7
2003	254,518,328	62,400,225	360,572	348,518,924	1,500,324	3,621,048	659,508,656	708,485,136	105.0	2.7	107.7
2004	260,820,193	63,697,225	360,572	357,918,974	1,517,172	3,618,984	672,536,172	723,164,524	106.0	2.7	108.7
2005	268,008,073	65,000,225	360,572	367,319,024	1,534,020	3,616,920	685,733,284	738,083,524	107.0	2.7	109.7
2006	274,169,230	66,303,225	360,572	376,719,074	1,550,868	3,614,856	699,183,384	753,282,768	108.0	2.7	110.7
2007	279,774,230	67,606,225	360,572	386,119,074	1,567,716	3,612,792	712,733,284	768,083,524	109.0	2.7	111.7
2008	285,774,230	68,909,225	360,572	395,519,074	1,584,564	3,610,728	727,183,384	783,282,768	110.0	2.7	112.7
2009	291,774,230	70,212,225	360,572	404,919,074	1,601,412	3,608,664	742,633,384	798,482,016	111.0	2.7	113.7
2010	297,774,230	71,515,225	360,572	414,319,074	1,618,260	3,606,600	758,083,384	813,681,260	112.0	2.7	114.7
2011	303,774,230	72,818,225	360,572	423,719,074	1,635,108	3,604,536	773,533,384	828,880,504	113.0	2.7	115.7
2012	309,774,230	74,121,225	360,572	433,119,074	1,651,956	3,602,472	788,983,384	844,079,748	114.0	2.7	116.7
2013	315,774,230	75,424,225	360,572	442,519,074	1,668,804	3,600,408	804,433,384	859,278,992	115.0	2.7	117.7
2014	321,774,230	76,727,225	360,572	451,919,074	1,685,652	3,598,344	819,883,384	874,478,236	116.0	2.7	118.7
2015	327,774,230	78,030,225	360,572	461,319,074	1,702,500	3,596,280	835,333,384	889,677,480	117.0	2.7	119.7
2016	333,774,230	79,333,225	360,572	470,719,074	1,719,348	3,594,216	850,783,384	904,876,724	118.0	2.7	120.7
2017	339,774,230	80,636,225	360,572	480,119,074	1,736,196	3,592,152	866,233,384	920,075,968	119.0	2.7	121.7
2018	345,774,230	81,939,225	360,572	489,519,074	1,753,044	3,590,088	881,683,384	935,275,212	120.0	2.7	122.7
2019	351,774,230	83,242,225	360,572	498,919,074	1,769,892	3,588,024	897,133,384	950,474,456	121.0	2.7	123.7
2020	357,774,230	84,545,225	360,572	508,319,074	1,786,740	3,585,960	912,583,384	965,673,700	122.0	2.7	124.7
2021	363,774,230	85,848,225	360,572	517,719,074	1,803,588	3,583,896	928,033,384	980,872,944	123.0	2.7	125.7
Avg. Annual Compound Rate of Growth											
1991-2000	2.6%	2.8%	0.0%	2.7%	1.2%	-0.1%	2.6%	2.6%	2.7%	-	2.6%
1991-2010	2.6%	2.8%	0.0%	2.7%	1.2%	-0.1%	2.6%	2.6%	2.7%	-	2.6%
1991-2021	2.1%	1.9%	0.0%	1.4%	0.7%	0.1%	1.7%	1.7%	1.8%	-	1.7%

[1] Summer Peak Demand excluding incremental load additions.
 [2] Summer Peak Demand including incremental load additions.

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TABLE III
 UTILITY BOARD OF THE CITY OF KEY WEST
 Summary of Historical and Projected Number of Customers
 (Fiscal Year)

YEAR	Residential Customers	Small Commercial Customers	Total Large Power Customers	Private Area Lighting Customers	Street Lighting Customers	Total System Customers
HISTORICAL:						
1985	15,909	1,914	366	698	4	18,891
1986	16,536	1,974	383	706	4	19,203
1987	17,360	2,030	413	722	4	20,529
1988	18,071	2,067	425	726	4	21,293
1989	18,520	2,091	420	731	4	21,766
1990	19,067	2,137	472	758	4	22,438
Avg. Annual Compound Rate of Growth						
1985-1990	3.7%	2.2%	5.2%	1.7%	0.0%	3.5%
PROJECTED:						
1991	19,496	2,223	480	790	4	22,993
1992	19,887	2,271	490	809	4	23,470
1993	20,294	2,321	516	828	4	24,063
1994	20,712	2,372	534	848	4	24,669
1995	21,131	2,423	551	867	4	25,295
1996	21,564	2,472	568	886	4	25,934
1997	21,779	2,520	584	905	4	26,592
1998	22,098	2,569	601	925	4	27,197
1999	22,422	2,619	617	944	4	27,805
2000	22,747	2,668	633	963	4	28,412
2001	23,071	2,716	649	982	4	29,025
2002	23,397	2,763	665	1,001	4	29,644
2003	23,724	2,811	681	1,020	4	30,269
2004	24,051	2,859	697	1,039	4	30,900
2005	24,379	2,907	713	1,058	4	31,537
2006	24,707	2,955	729	1,077	4	32,182
2007	25,035	3,003	745	1,096	4	32,833
2008	25,363	3,051	761	1,115	4	33,490
2009	25,691	3,099	777	1,134	4	34,151
2010	26,019	3,147	793	1,153	4	34,808
2011	26,347	3,195	809	1,172	4	35,471
2012	26,675	3,243	825	1,191	4	36,138
2013	27,003	3,291	841	1,210	4	36,809
2014	27,331	3,339	857	1,229	4	37,486
2015	27,659	3,387	873	1,248	4	38,167
2016	27,987	3,435	889	1,267	4	38,852
2017	28,315	3,483	905	1,286	4	39,541
2018	28,643	3,531	921	1,305	4	40,234
2019	28,971	3,579	937	1,324	4	40,931
2020	29,299	3,627	953	1,343	4	41,632
2021	29,627	3,675	969	1,362	4	42,337
Avg. Annual Compound Rate of Growth						
1991-2000	1.7%	2.0%	3.1%	2.2%	0.0%	1.8%
1991-2010	1.7%	2.0%	3.1%	2.2%	0.0%	1.8%
1991-2021	0.9%	1.6%	2.3%	1.3%	0.0%	1.0%

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CITY OF LAKE WORTH

APPENDIX 1C.B
SECTION 1C.B.1.4
ENERGY AND DEMAND FORECAST
FOR
THE CITY OF LAKE WORTH UTILITIES, FLORIDA
1991 - 2021

Prepared by
Resource Mangement International, Inc.
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RESOURCE MANAGEMENT
INTERNATIONAL, INC.

January 22, 1991

Mr. Claude L'Engle
Utilities Director
City of Lake Worth Utilities
1776 Lake Worth Road, Suite 201
Lake Worth, FL 33460

Dear Claude:

Resource Management International, Inc. (RMI) is pleased to submit this final report which provides the City's load forecast of long-range growth. Five copies are being provided for your use.

The results of this study will be utilized in the Needs Certification Hearings before the Florida Public Service Commission when Orlando Utilities Commission applies for certification of its Stanton Energy Center #2. We have coordinated this effort with other potential participants of Stanton Energy Center #2 in order that assumptions associated with individual participant's forecasts will be consistent.

RMI appreciates the opportunity to assist the City of Lake Worth Utilities in planning for its future power supply needs. We look forward to continuing to work with the City in future studies pertaining to its electric utility. Please contact Larry James or me if you have any questions.

Sincerely,

Gael Penland Paschall, Ph.D.
Executive Consultant

GPP/bjb/48012.56

xc: Larry James, RMI

Enclosures

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CITY OF LAKE WORTH UTILITIES

Electric System

SECTION I

EXECUTIVE SUMMARY

Three load forecasts were prepared using econometric forecasting techniques. The first forecast, reflecting base conditions and assumptions, is referred to as the Expected forecast. The remaining two forecasts, the High and Low forecasts, were developed to provide an upper and lower boundary for the Expected forecast. The High and Low forecasts reflect changes in conditions and assumptions resulting in increased and decreased power sales, respectively, based on factors such as population growth and changing economic conditions.

Population growth projections were obtained from the City of Lake Worth Planning Department. Employment data were obtained from the Florida Department of Labor and Employment Security, Bureau of Labor Market information. All three forecasts include estimated incremental loads associated with future development anticipated in the service area west of the City. They address a varying range of changes in population and employment. All three energy and peak demand forecasts are shown on Graphs 1, 2 and 3.

Summarized on the following page are the updated load forecasts.

ENERGY AND DEMAND FORECAST

Fiscal Year Ending September 30	<u>Expected</u>		<u>High</u>		<u>Low</u>	
	Energy Demand[2]		Energy Demand[2]		Energy Demand[2]	
	<u>(MWH)</u>	<u>(MW)</u>	<u>(MWH)</u>	<u>(MW)</u>	<u>(MWH)</u>	<u>(MW)</u>
1990 [1]	350,000	68	350,000	68	350,000	68
1995	381,000	75	396,000	78	365,000	72
2000	419,000	82	451,000	89	387,000	76
2005	437,000	86	492,000	97	392,000	77
2010	448,000	88	536,000	105	396,000	78
Average Annual Growth (%) (1990-2010)	1.2%	1.3%	2.2%	2.2%	0.6%	0.7%

[1] 1990 data is actual.

[2] Demand reflects summer peak which is used for planning purposes.

It is our understanding that the need certification hearings for Stanton Energy Center 2 before the Florida Public Service Commission will require forecasts of demand and energy requirements through the year 2021. These figures are furnished in Table 4. Demand and energy forecasts include increases due to additional load in the service area west of Lake Worth. The range of forecasts reflect varying rates of growth in population and employment. The forecast can be expected to change if additional customers are added to the City's system as a result of increased growth in the western service area.

SECTION II
ENERGY AND DEMAND FORECAST
1991 - 2021

The following is a summary of the analyses and studies pertaining to the design and development of estimates of future energy and demand requirements for the City of Lake Worth Utilities (City). The forecast is provided on a Fiscal Year Ending September 30 (FYE) basis.

Projections of the City's demand and energy requirements were developed for the period 1991 through 2021. Based on the results of the various analyses, system net energy requirements are projected to increase at a compound annual growth rate of 1.8%, 0.7%, and 0.6% for the periods 1990 through 2000, 2000 through 2010, and 2010 through 2021, respectively, on a fiscal year basis. Summer net peak demand is expected to increase at a compound rate of 1.9%, 0.7% and 0.7% over the same periods, respectively. This forecast is summarized below.

CITY OF LAKE WORTH UTILITIES
Projected Demand and Energy Requirements
(Fiscal Year)

		<u>1990[1]</u>	<u>2000</u>	<u>2010</u>	<u>2021</u>
Net Energy Requirements	- (MWH)	350,000	419,000	448,000	481,000
System Net Peak Demand					
Summer	- (MW)	68	82	88	95
Winter	- (MW)	80	89	95	103

[1] Actual

The estimates for FYE 1991 through 2010 are based on an econometric model developed for residential and commercial energy sales and include an adjustment for future incremental loads anticipated by the City. The forecast of residential and commercial energy sales were based upon the econometric model, while the forecast of street lighting sales was not. Street lighting is small compared to other classes and was forecast together with system losses utilizing empirical determinations. Energy requirements for the period 2011 through 2021 were obtained by annually increasing projected energy needs by the incremental change in net energy for load between FYE 2009 and FYE 2010.

Three load forecasts were prepared using the methodology described above. The first forecast, reflecting base conditions and assumptions, is referred to as the Expected forecast. The remaining two forecasts, the High and Low forecasts, were developed to provide an upper and lower boundary for the Expected forecast. The High and Low forecasts reflect changes in conditions and assumptions resulting in increased and decreased power sales, respectively, based on factors such as population growth and changing economic conditions.

Historical and projected energy sales through FYE 2010 are provided in Table 1. Annual projections of net energy requirements and seasonal peak demands are also presented in Table 1. Projected energy and demand requirements through FYE 2021 are provided in Table 4.

A. ASSUMPTIONS

Historical and projected data regarding explanatory variables used in the econometric model of residential and commercial energy sales are described below. Other information regarding considerations and assumptions used in the 1991 load forecast are also discussed.

1. Population

Population in the City of Lake Worth serves as an explanatory variable in the regression analysis of residential and commercial sales. Historical population estimates for the City were obtained from the City of Lake Worth Planning Department and were used to develop projections of residential and commercial sales over the forecast period. Population in the City of Lake Worth is projected to increase by approximately 905 through 2010. This represents a compound average annual increase of approximately 0.2%. The historical and projected population series are presented in Table 1.

2. Employment

With respect to the econometric model, it is intuitive that some measure of local economic activity will be relevant. The variable utilized in this regard was average employment in retail trade and services. Estimates of this variable for Palm Beach County were used to reflect general economic conditions for the area surrounding Lake Worth. The employment variable was generated from data series provided by the State of Florida Department of Labor and Employment Security. The historical and projected employment series utilized in the model are presented in Table 1.

Approximately 50 percent of employment in Palm Beach County is based in retail trade and services. The next most significant category of employment is Government, including military, which accounts for approximately 10 percent of total employment. Employment in retail trade and services was selected as the appropriate control variable based upon its dominance and the fact that it is subject to the economic variations prompted by fluctuating trends in both the local economy and in tourism.

3. Price

One of the considerations in the preparation of a forecast is the future price of electricity and how this may affect future energy requirements. In late 1973, the effects of the oil embargo were realized by electric utility residential customers. With rapidly increasing actual price, average annual energy consumption declined. Since 1973, the price of

electricity has been an important determining factor in energy consumption patterns. As the average price of electricity rose, the growth in consumption rates of residential and other customers slowed considerably. In the City of Lake Worth, the real price of electricity in the residential and commercial classes increased from 1973 through 1982 and has actually declined since.

The historical price of electricity is based on the City's records of energy sales and revenues for the residential and commercial classes. Such information was aggregated and adjusted to real terms in 1982 dollars for use in the residential and the commercial econometric model. For purposes of developing the long-term load forecast, it has been assumed that the real price of electricity will remain constant over the forecast period. Thus, in general, it is expected that changes in the price of electricity will keep pace with inflation.

4. Alternative Energy Sources

The traditional alternatives to the use of electricity in Lake Worth, as elsewhere in the United States, include oil, L.P. gas, and natural gas. It is anticipated that existing fuel uses will continue until facilities require replacement. There are strong arguments for including the real price of electricity and an alternative fuel price variable in the equations. In practice, however, this information is rarely useful in models of the type specified for municipal forecasts. It is a relatively difficult task for most consumers to shift from, say, electricity to oil in an existing structure. Consequently, most of the decisions regarding a major power source are made at the time of construction. Since new structures and replacements which are brought into use in a given year constitute only a very small fraction of the total stock, it is unlikely that a statistically significant response can be obtained. Thus, investigation of alternative fuel price variables were not included in this study.

5. Weather

Historical weather conditions, as represented by heating and cooling degree days at the West Palm Beach weather station, were obtained from publications of the National Oceanic

and Atmospheric Administration (NOAA). For purposes of the long-term load forecast, normal or average weather conditions have been assumed based on the thirty-year norms of heating and cooling degree days reported by the NOAA. For the long-term forecast, normal weather conditions are considered suitable to reasonably depict the long-term trend. It is recognized that in any particular year, weather may deviate from normal and projected energy and demand can be expected to vary accordingly.

6. Incremental Additions

Load attributable to future development in the service area west of Lake Worth has been included as an incremental addition in the load forecast. After discussions with City staff, estimates of additional load attributable to the development of a condominium project in this area were added as a line item and titled "Incremental Additions" in the load forecast. Although there are a number of commercial establishments planned for this area, only the growth associated with the development of a 1,300 unit condominium project has been included as incremental load. It is assumed that additional commercial establishments within the Lake Worth service area are reflected in the econometric model for residential and commercial sales.

The cumulative incremental additions to residential and commercial energy sales are summarized in Table 1.

7. System Load Factors

The average of historical load factors experienced over the three-year period, FYE 1988 through FYE 1990, served as the basis for the assumed load factors used in the forecast. The estimated winter peak demand load factor of 54% was applied to fiscal year projections of net energy for load to develop projections of system winter peak demand. Likewise, the forecast of the summer peak demand is based on an estimated load factor of 58% applied to the fiscal year projections of net energy for load.

8. Conservation

For purposes of the forecast analyses, no adjustments have been made with regard to any assumed or estimated energy or demand reductions associated with the City's conservation programs. The City's conservation plan includes street lighting conversions, a home fix-up program, "Share Program", commercial and residential audits, presentations and various other public awareness and information programs. While it is difficult to estimate savings associated with any conservation program, it is particularly difficult to develop such estimates for awareness and information types of programs. It is also recognized that the City's conservation plan is one of the most aggressive in the state for its size and has been ongoing since 1980. The subsequent historical energy and demand data would inherently reflect changes in consumption associated with conservation usage patterns. For these reasons, it was not considered necessary to make any direct conservation related adjustments to base forecast results. Additionally, the City does not currently have a load management program; however, the City is currently doing a study to possibly implement load management in the future.

B. RESIDENTIAL AND COMMERCIAL ENERGY SALES

The econometric analyses relating to residential and commercial energy sales are based on annual historical observations from FYE 1973 through FYE 1990. The explanatory variables used to statistically describe residential and commercial energy sales are population, employment, the real price of electricity, and weather. Population is as provided by the City of Lake Worth Planning Department. Employment in retail trade and services in Palm Beach County was obtained from the State of Florida Department of Labor and Employment Security. Information on the price of electricity to the residential and commercial classes was obtained from the City's records. Weather conditions are represented by heating and cooling degree days as provided by the NOAA. The resulting index of determination (R-squared statistic) was 98%. Detailed statistical results for the model are presented in Table 5.

C. STREET LIGHTING SALES AND SYSTEM LOSSES

Street lighting sales and system losses were forecast together based upon the ratio of street lighting sales and system losses to residential and commercial sales in FYE 1990. It was assumed that street lighting sales plus losses would remain constant at approximately 6.3% of residential and commercial sales over the forecast period. The forecast of street lighting usage and system losses is provided in Table 1.

D. NET ENERGY FOR LOAD AND PEAK DEMAND

Projections of residential and commercial energy sales, incremental loads, street lighting sales and losses were combined to produce forecasted net energy for load. To develop seasonal peak demand projections, the assumed seasonal load factors were applied to the resulting forecast of net energy for load. The forecast results are summarized below.

	<u>Fiscal Year</u>	<u>Net Energy For Load (MWH)</u>	<u>Winter Peak Demand (MW)</u>	<u>Summer Peak Demand (MW)</u>
Actual	1990	350,000	80	68
Projected	2000	419,000	89	82
	2010	448,000	95	88
	2021	481,000	103	95
Compound Average Annual Growth Rate 1990 - 2021		1.0%	0.8%	1.1%

The forecast results incorporate "normal" weather conditions as a basic forecast assumption. It should be noted that the City's winter peak demand is particularly sensitive to weather conditions. While it is expected that the long-term trend of the demand forecast is

reasonable, it is likely that for any particular year during the forecast period, deviations may occur as a result of unseasonal weather conditions.

E. HIGH AND LOW RANGE FORECAST SCENARIOS

In addition to the Expected forecast, High and Low forecast scenarios were developed based on alternative assumptions with regard to population and employment. The results of the High and Low range forecasts are provided on Tables 2 and 3, respectively. Alternative scenarios of projected net energy for load and system net peak demand are compared below for selected years.

Fiscal Year	Net Energy For Load (MWH)			System Net Peak Demand[2] (MW)		
	<u>Low</u>	<u>Expected</u>	<u>High</u>	<u>Low</u>	<u>Expected</u>	<u>High</u>
1990[1]	350,000	350,000	350,000	68	68	68
2000	387,000	419,000	451,000	76	82	89
2010	396,000	448,000	536,000	78	88	105
2021	407,000	481,000	635,000	80	95	125
Compound Annual Average Growth Rate:						
1990-2021	0.5%	1.0%	1.9%	0.5%	1.1%	2.0%

[1] 1990 data is actual.

[2] Summer peak demand which is utilized for planning purposes.

The alternative assumptions used to develop the High and Low forecast scenarios are as follows:

- 1) City of Lake Worth population served as an explanatory variable in the regression analysis of residential and commercial energy sales. Increased and decreased rates of growth in population, respectively, were used to develop the High and Low projections of residential and commercial sales over the forecast period.
- 2) Employment in retail trade and services in Palm Beach County also served as an explanatory variable in the analysis of residential and commercial energy sales. Based on an analysis of the relationship of total population and persons employed as projected in the expected forecast, high and low range projections of employment in retail trade and services in Palm Beach County have been developed using the high and low range Palm Beach County population forecasts prepared by the University of Florida, Bureau of Economics and Business Research.

It should be noted that the alternative scenarios reflect only variations in assumptions regarding employment and population. The real price of electricity is assumed to remain constant over the forecast period in the Expected, High and Low forecasts. Likewise, normal degree days are assumed in all scenarios. The results of the Expected, High and Low forecasts for net energy for load and summer and winter peak demand are shown on Graphs 1, 2, and 3, respectively.

SUMMARY

The forecasting methodology utilized attempts to identify and reflect the key factors which can influence the City's demand and energy requirements. It should be emphasized that the confidence associated with any projection varies inversely with the length of the forecast. The probability of extraneous factors affecting projected values increases with uncertainty about future developments; this uncertainty, in turn, increases with the length of the forecast period. With this in mind, projections of the City's annual net peak demand and net energy requirements should be viewed as reasonable estimates but subject to external disturbances which, at this time, cannot be reasonably foreseen. Therefore, the

forecast results and the underlying assumptions should be reviewed periodically and updated when necessary. To the extent that unpredictable economic, demographic, and technological developments affect future expectations, forecasts may require adjustments to reflect such factors.

The Expected, High, and Low forecasts are based on a range of reasonable assumptions given current economic and political conditions. If the current assumptions continue into the future, the Expected forecast will provide a reasonable estimate of future energy and demand requirements. However, due to the uncertainty of future events continuing, we recommend that actual energy and peak requirements be compared to the forecast values and the forecast updated annually.

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.

TABLE 1

LAKE WORTH UTILITIES ELECTRIC SYSTEM
1991 LOAD FORECAST

(FISCAL YEAR BASIS)

FISCAL YEAR ENDING SEPT 30,	EXPECTED VALUE OF DRIVING VARIABLES				RESIDENTIAL AND COMMERCIAL SALES (MWH)	INCREMENTAL ENERGY SALES (MWH)	RESID. COMM AND INCREMENT SALES (MWH)	STREET LIGHTING AND LOSSES (MWH)	NET ENERGY FOR LOAD (MWH)	'SUMMER' LOAD FACTOR (%)	'SUMMER' PEAK (MW)	'WINTER' LOAD FACTOR (%)	'WINTER' PEAK (MW)
	LAKE WORTH POPULATION (000'S)	COUNTY EMPLOYMENT (000'S)	TOTAL DEGREE DAYS	REAL COST OF ELECTRICITY									
1973	24,714	79,723	4,580	0.520641	214,159		214,159				45.0		49.5
1974	25,078	83,503	4,469	0.535315	216,218		216,218				52.0		51.5
1975	25,381	87,277	4,070	0.512060	224,773		224,773				51.0		56.0
1976	25,714	91,052	3,985	0.605714	225,189		225,189				52.5		68.5
1977	26,048	94,826	4,150	0.657949	226,766		226,766				51.0		71.0
1978	26,381	98,601	4,194	0.616874	238,387		238,387	22,613	261,000	53.9%	55.3	42.4%	70.2
1979	26,715	106,753	4,081	0.600000	246,501		246,501	24,459	271,000	51.2%	60.4	48.3%	64.0
1980	27,048	114,905	4,230	0.707420	260,630		260,630	21,370	282,000	53.3%	60.4	44.9%	71.7
1981	27,101	123,006	4,344	0.717592	274,080		274,080	18,920	293,000	54.7%	61.1	41.6%	80.4
1982	27,154	131,208	4,366	0.774081	264,904		264,904	22,096	287,000	56.9%	57.6	43.3%	75.7
1983	27,207	139,360	4,295	0.764818	262,920		262,920	15,080	278,000	51.5%	61.6	54.6%	58.1
1984	27,260	146,679	3,852	0.766452	273,282		273,282	22,718	296,000	56.7%	59.6	47.7%	70.8
1985	27,312	153,998	4,255	0.756875	280,591		280,591	26,409	307,000	55.8%	62.8	45.0%	77.9
1986	27,365	161,317	4,335	0.714560	296,970		296,970	24,030	321,000	57.8%	63.4	48.7%	75.3
1987	27,418	168,637	4,504	0.681297	310,676		310,676	27,324	338,000	55.4%	69.6	58.0%	66.5
1988	27,471	175,956	4,181	0.652842	314,702		314,702	21,298	336,000	55.9%	68.6	56.1%	68.4
1989	27,496	183,275	4,630	0.669662	323,974		323,974	28,026	352,000	58.4%	68.8	54.6%	73.6
1990	27,522	190,594	4,686	0.640803	329,249		329,249	20,751	350,000	58.8%	67.9	49.9%	80.1
1991	27,578	197,123	4,290	0.640803	329,000	0	329,000	21,000	350,000	58%	69	54%	74
1992	27,634	203,652	4,290	0.640803	335,000	0	335,000	21,000	356,000	58%	70	54%	76
1993	27,690	210,181	4,290	0.640803	341,000	1,000	342,000	22,000	364,000	58%	72	54%	78
1994	27,746	216,710	4,290	0.640803	346,000	4,000	350,000	22,000	372,000	58%	73	54%	79
1995	27,802	223,239	4,290	0.640803	352,000	6,000	358,000	23,000	381,000	58%	75	54%	81
1996	27,858	229,434	4,290	0.640803	357,000	8,000	365,000	23,000	388,000	58%	76	54%	83
1997	27,895	233,629	4,290	0.640803	361,000	11,000	372,000	23,000	395,000	58%	78	54%	84
1998	27,932	238,825	4,290	0.640803	365,000	14,000	379,000	24,000	403,000	58%	79	54%	86
1999	27,968	244,020	4,290	0.640803	370,000	17,000	387,000	24,000	411,000	58%	81	54%	88
2000	28,005	249,215	4,290	0.640803	374,000	20,000	394,000	25,000	419,000	58%	82	54%	89
2001	28,042	252,776	4,290	0.640803	377,000	20,000	397,000	25,000	422,000	58%	83	54%	90
2002	28,085	256,337	4,290	0.640803	381,000	20,000	401,000	25,000	426,000	58%	84	54%	91
2003	28,128	259,898	4,290	0.640803	384,000	20,000	404,000	25,000	429,000	58%	84	54%	91
2004	28,170	263,459	4,290	0.640803	387,000	20,000	407,000	26,000	433,000	58%	85	54%	92
2005	28,213	267,020	4,290	0.640803	391,000	20,000	411,000	26,000	437,000	58%	86	54%	93
2006	28,256	268,951	4,290	0.640803	393,000	20,000	413,000	26,000	439,000	58%	86	54%	94
2007	28,299	270,882	4,290	0.640803	395,000	20,000	415,000	26,000	441,000	58%	87	54%	94
2008	28,342	272,812	4,290	0.640803	397,000	20,000	417,000	26,000	443,000	58%	87	54%	94
2009	28,384	274,743	4,290	0.640803	399,000	20,000	419,000	26,000	445,000	58%	87	54%	95
2010	28,427	276,674	4,290	0.640803	401,000	20,000	421,000	27,000	448,000	58%	88	54%	95
AVG. ANNUAL % GROWTH RATE													
1980 - 1990	0.2%	5.2%		-1.0%	2.4%		2.4%	-0.3%	2.2%	1.0%	1.2%	1.1%	1.1%
1990 - 2000	0.2%	2.7%		0.0%	1.3%		1.8%	1.9%	1.8%		2.0%		1.1%
1990 - 2010	0.2%	1.9%		0.0%	1.0%		1.2%	1.3%	1.2%		1.3%		0.9%

1C.B.1-74

TABLE 2

LAKE WORTH UTILITIES ELECTRIC SYSTEM
1991 LOAD FORECAST

(FISCAL YEAR BASIS)

FISCAL YEAR ENDING SEPT 30.	HIGH VALUE OF DRIVING VARIABLES				RESIDENTIAL AND COMMERCIAL SALES (MWH)	INCREMENTAL ENERGY SALES (MWH)	RESID. COMM AND INCREMENT SALES (MWH)	STREET LIGHTING AND LOSSES (MWH)	NET ENERGY FOR LOAD (MWH)	'SUMMER' LOAD FACTOR (%)	SUMMER PEAK (MW)	'WINTER' LOAD FACTOR (%)	WINTER PEAK (MW)
	LAKE WORTH POPULATION (000'S)	COUNTY EMPLOYMENT (000'S)	TOTAL DEGREE DAYS	REAL COST OF ELECTRICITY									
1973	24,714	79,723	4,580	0.520641	214,159		214,159				45.0		49.5
1974	25,078	83,503	4,469	0.535315	216,218		216,218				52.0		51.5
1975	25,381	87,277	4,070	0.512060	224,773		224,773				51.0		56.0
1976	25,714	91,052	3,985	0.605714	225,189		225,189				52.5		68.5
1977	26,048	94,826	4,150	0.657949	226,766		226,766				51.0		71.0
1978	26,381	98,601	4,134	0.616874	238,387		238,387	22,613	261,000	53.9%	55.3	42.4%	70.2
1979	26,715	106,753	4,081	0.600000	246,501		246,501	24,499	271,000	51.2%	60.4	48.3%	64.0
1980	27,048	114,905	4,230	0.707420	260,630		260,630	21,370	282,000	53.3%	60.4	44.9%	71.7
1981	27,101	123,006	4,344	0.717592	274,080		274,080	18,920	293,000	54.7%	61.1	41.6%	80.4
1982	27,154	131,208	4,366	0.774081	264,904		264,904	22,096	287,000	56.9%	57.6	43.3%	75.7
1983	27,207	139,360	4,295	0.764818	262,920		262,920	15,080	278,000	51.5%	61.6	54.6%	58.1
1984	27,260	146,679	3,852	0.766452	273,282		273,282	22,718	296,000	56.7%	59.6	47.7%	70.8
1985	27,312	153,998	4,255	0.756875	280,591		280,591	26,409	307,000	55.8%	62.8	45.0%	77.9
1986	27,365	161,317	4,335	0.714560	296,970		296,970	24,030	321,000	57.8%	63.4	48.7%	75.3
1987	27,418	168,637	4,504	0.681297	310,676		310,676	27,324	338,000	55.4%	69.6	58.0%	66.5
1988	27,471	175,956	4,181	0.652842	314,702		314,702	21,298	336,000	55.9%	68.6	56.1%	68.4
1989	27,496	183,275	4,630	0.669662	323,974		323,974	28,026	352,000	58.4%	68.8	54.6%	73.6
1990	27,522	190,594	4,686	0.640803	329,249		329,249	20,751	350,000	58.8%	67.9	49.9%	80.1
1991	27,611	208,500	4,290	0.640803	332,000	0	332,000	21,000	353,000	58%	69	54%	75
1992	27,701	210,400	4,290	0.640803	341,000	0	341,000	21,000	362,000	58%	71	54%	77
1993	27,790	220,200	4,290	0.640803	350,000	1,000	351,000	22,000	373,000	58%	73	54%	80
1994	27,879	230,100	4,290	0.640803	358,000	4,000	362,000	23,000	385,000	58%	76	54%	82
1995	27,969	240,000	4,290	0.640803	367,000	6,000	373,000	23,000	396,000	58%	78	54%	84
1996	28,058	249,300	4,290	0.640803	375,000	8,000	383,000	24,000	407,000	58%	80	54%	87
1997	28,096	258,600	4,290	0.640803	382,000	11,000	393,000	25,000	418,000	58%	82	54%	89
1998	28,134	268,000	4,290	0.640803	390,000	14,000	404,000	25,000	429,000	58%	84	54%	91
1999	28,173	277,300	4,290	0.640803	397,000	17,000	414,000	26,000	440,000	58%	87	54%	94
2000	28,211	286,600	4,290	0.640803	404,000	20,000	424,000	27,000	451,000	58%	89	54%	96
2001	28,249	296,500	4,290	0.640803	412,000	20,000	432,000	27,000	459,000	58%	90	54%	98
2002	28,279	306,400	4,290	0.640803	420,000	20,000	440,000	28,000	468,000	58%	92	54%	100
2003	28,309	316,400	4,290	0.640803	427,000	20,000	447,000	28,000	475,000	58%	93	54%	101
2004	28,338	326,300	4,290	0.640803	435,000	20,000	455,000	29,000	484,000	58%	95	54%	103
2005	28,368	336,200	4,290	0.640803	443,000	20,000	463,000	29,000	492,000	58%	97	54%	105
2006	28,398	347,100	4,290	0.640803	451,000	20,000	471,000	30,000	501,000	58%	99	54%	107
2007	28,428	357,900	4,290	0.640803	459,000	20,000	479,000	30,000	509,000	58%	100	54%	108
2008	28,458	368,800	4,290	0.640803	467,000	20,000	487,000	31,000	518,000	58%	102	54%	110
2009	28,487	379,600	4,290	0.640803	476,000	20,000	496,000	31,000	527,000	58%	104	54%	112
2010	28,517	390,500	4,290	0.640803	484,000	20,000	504,000	32,000	536,000	58%	105	54%	114
AVG. ANNUAL % GROWTH RATE													
1980 - 1990	0.2%	5.2%		-1.0%	2.4%		2.4%	-0.3%	2.2%	1.0%	1.2%	1.1%	1.1%
1990 - 2000	0.2%	4.2%		0.0%	2.1%		2.6%	2.7%	2.6%		2.7%		1.8%
1990 - 2010	0.2%	3.7%		0.0%	1.9%		2.2%	2.2%	2.2%		2.2%		1.6%

TABLE 3

LAKE WORTH UTILITIES ELECTRIC SYSTEM
1991 LOAD FORECAST

(FISCAL YEAR BASIS)

FISCAL YEAR ENDING SEPT 30,	LOW VALUE OF DRIVING VARIABLES				RESIDENTIAL AND COMMERCIAL SALES (MWH)	INCREMENTAL ENERGY SALES (MWH)	RESID. COMM AND INCREMENT SALES (MWH)	STREET LIGHTING AND LOSSES (MWH)	NET ENERGY FOR LOAD (MWH)	'SUMMER' LOAD FACTOR (%)	'SUMMER' PEAK (MW)	'WINTER' LOAD FACTOR (%)	'WINTER' PEAK (MW)
	LAKE WORTH POPULATION (000'S)	COUNTY EMPLOYMENT (000'S)	TOTAL DEGREE DAYS	REAL COST OF ELECTRICITY									
1973	24.714	79.723	4,580	0.520641	214,159		214,159				45.0		49.5
1974	25.078	83.503	4,469	0.535315	216,218		216,218				52.0		51.5
1975	25.381	87.277	4,070	0.512060	224,773		224,773				51.0		56.0
1976	25.714	91.052	3,985	0.605714	225,189		225,189				52.5		68.5
1977	26.048	94.826	4,150	0.657949	226,766		226,766				51.0		71.0
1978	26.381	98.601	4,194	0.616874	238,387		238,387	22,613	261,000	53.9%	55.3	42.4%	70.2
1979	26.715	106.753	4,081	0.600000	246,501		246,501	21,499	271,000	51.2%	60.4	48.3%	64.0
1980	27.048	114.905	4,230	0.707420	260,630		260,630	21,370	282,000	53.3%	60.4	44.9%	71.7
1981	27.101	123.006	4,344	0.717592	274,080		274,080	18,920	293,000	54.7%	61.1	41.6%	80.4
1982	27.154	131.208	4,366	0.774081	264,904		264,904	22,096	287,000	56.9%	57.6	43.3%	75.7
1983	27.207	139.360	4,295	0.764818	262,920		262,920	15,080	278,000	51.5%	61.6	54.6%	58.1
1984	27.260	146.679	3,852	0.766452	273,282		273,282	22,718	296,000	56.7%	59.6	47.7%	70.8
1985	27.312	153.998	4,255	0.756875	280,591		280,591	26,409	307,000	55.8%	62.8	45.0%	77.9
1986	27.365	161.317	4,335	0.714560	296,970		296,970	24,030	321,000	57.8%	63.4	48.7%	75.3
1987	27.418	168.637	4,504	0.681297	310,676		310,676	27,324	338,000	55.4%	69.6	58.0%	66.5
1988	27.471	175.956	4,181	0.652842	314,702		314,702	21,298	336,000	55.9%	68.6	56.1%	68.4
1989	27.496	183.275	4,630	0.669662	323,974		323,974	28,026	352,000	58.4%	68.8	54.6%	73.6
1990	27.522	190.594	4,686	0.640803	329,249		329,249	20,751	350,000	58.8%	67.9	49.9%	80.1
1991	27.554	193.800	4,290	0.640803	327,000	0	327,000	21,000	348,000	58%	68	54%	74
1992	27.567	197.000	4,290	0.640803	329,000	0	329,000	21,000	350,000	58%	69	54%	75
1993	27.590	200.100	4,290	0.640803	332,000	1,000	333,000	21,000	354,000	58%	70	54%	76
1994	27.612	203.300	4,290	0.640803	334,000	4,000	338,000	21,000	359,000	58%	71	54%	77
1995	27.634	206.500	4,290	0.640803	337,000	6,000	343,000	22,000	365,000	58%	72	54%	78
1996	27.657	207.600	4,290	0.640803	338,000	8,000	346,000	22,000	368,000	58%	72	54%	79
1997	27.693	208.600	4,290	0.640803	340,000	11,000	351,000	22,000	373,000	58%	73	54%	80
1998	27.728	209.700	4,290	0.640803	341,000	14,000	355,000	22,000	377,000	58%	74	54%	80
1999	27.764	210.700	4,290	0.640803	342,000	17,000	359,000	23,000	382,000	58%	75	54%	82
2000	27.799	211.800	4,290	0.640803	344,000	20,000	364,000	23,000	387,000	58%	76	54%	83
2001	27.835	212.000	4,290	0.640803	345,000	20,000	365,000	23,000	388,000	58%	76	54%	83
2002	27.891	212.200	4,290	0.640803	346,000	20,000	366,000	23,000	389,000	58%	77	54%	83
2003	27.947	212.300	4,290	0.640803	347,000	20,000	367,000	23,000	390,000	58%	77	54%	83
2004	28.002	212.500	4,290	0.640803	348,000	20,000	368,000	23,000	391,000	58%	77	54%	83
2005	28.058	212.700	4,290	0.640803	349,000	20,000	369,000	23,000	392,000	58%	77	54%	84
2006	28.114	212.200	4,290	0.640803	350,000	20,000	370,000	23,000	393,000	58%	77	54%	84
2007	28.170	211.700	4,290	0.640803	350,000	20,000	370,000	23,000	393,000	58%	77	54%	84
2008	28.226	211.300	4,290	0.640803	351,000	20,000	371,000	23,000	394,000	58%	78	54%	84
2009	28.281	210.800	4,290	0.640803	352,000	20,000	372,000	23,000	395,000	58%	78	54%	84
2010	28.337	210.300	4,290	0.640803	353,000	20,000	373,000	23,000	396,000	58%	78	54%	84
AVG. ANNUAL % GROWTH RATE													
1980 - 1990	0.2%	5.2%		-1.0%	2.4%		2.4%	-0.3%	2.2%	1.0%	1.2%	1.1%	1.1%
1990 - 2000	0.1%	1.1%		0.0%	0.4%		1.0%	1.0%	1.0%		1.2%		0.3%
1990 - 2010	0.1%	0.5%		0.0%	0.3%		0.6%	0.5%	0.6%		0.7%		0.3%

TABLE 4

LAKE WORTH UTILITIES SYSTEM
LOAD FORECAST FOR 1991 - 2021

(FISCAL YEAR BASIS)

FISCAL YEAR ENDING SEPT 30,	EXPECTED			HIGH			LOW		
	NET ENERGY FOR LOAD (MWH)	SUMMER PEAK (MW)	WINTER PEAK (MW)	NET ENERGY FOR LOAD (MWH)	SUMMER PEAK (MW)	WINTER PEAK (MW)	NET ENERGY FOR LOAD (MWH)	SUMMER PEAK (MW)	WINTER PEAK (MW)
1991	350,000	69	74	353,000	69	75	348,000	68	74
1992	356,000	70	76	362,000	71	77	350,000	69	75
1993	364,000	72	78	373,000	73	80	354,000	70	76
1994	372,000	73	79	385,000	76	82	359,000	71	77
1995	381,000	75	81	396,000	78	84	365,000	72	78
1996	388,000	76	83	407,000	80	87	368,000	72	79
1997	395,000	78	84	418,000	82	89	373,000	73	80
1998	403,000	79	86	429,000	84	92	377,000	74	80
1999	411,000	81	88	440,000	87	94	382,000	75	82
2000	419,000	82	89	451,000	89	96	387,000	76	83
2001	422,000	83	90	459,000	90	98	388,000	76	83
2002	426,000	84	91	468,000	92	100	389,000	77	83
2003	429,000	84	91	475,000	93	101	390,000	77	83
2004	433,000	85	92	484,000	95	103	391,000	77	83
2005	437,000	86	93	492,000	97	105	392,000	77	84
2006	439,000	86	94	501,000	99	107	393,000	77	84
2007	441,000	87	94	509,000	100	109	393,000	77	84
2008	443,000	87	94	518,000	102	111	394,000	78	84
2009	445,000	87	95	527,000	104	112	395,000	78	84
2010	448,000	88	95	536,000	105	114	396,000	78	84
2011	451,000	89	96	545,000	107	116	397,000	78	85
2012	454,000	89	97	554,000	109	118	398,000	78	85
2013	457,000	90	97	563,000	111	120	399,000	79	85
2014	460,000	90	98	572,000	113	122	400,000	79	85
2015	463,000	91	99	581,000	114	124	401,000	79	86
2016	466,000	92	99	590,000	116	126	402,000	79	86
2017	469,000	92	100	599,000	118	128	403,000	79	86
2018	472,000	93	101	608,000	120	130	404,000	80	86
2019	475,000	93	101	617,000	121	132	405,000	80	86
2020	478,000	94	102	626,000	123	134	406,000	80	87
2021	481,000	95	103	635,000	125	135	407,000	80	87

TABLE 5

LS // Dependent Variable is SALES

Date: 1-12-1991 / Time: 8:28

SMPL range: 1973 - 1990

Number of observations: 18

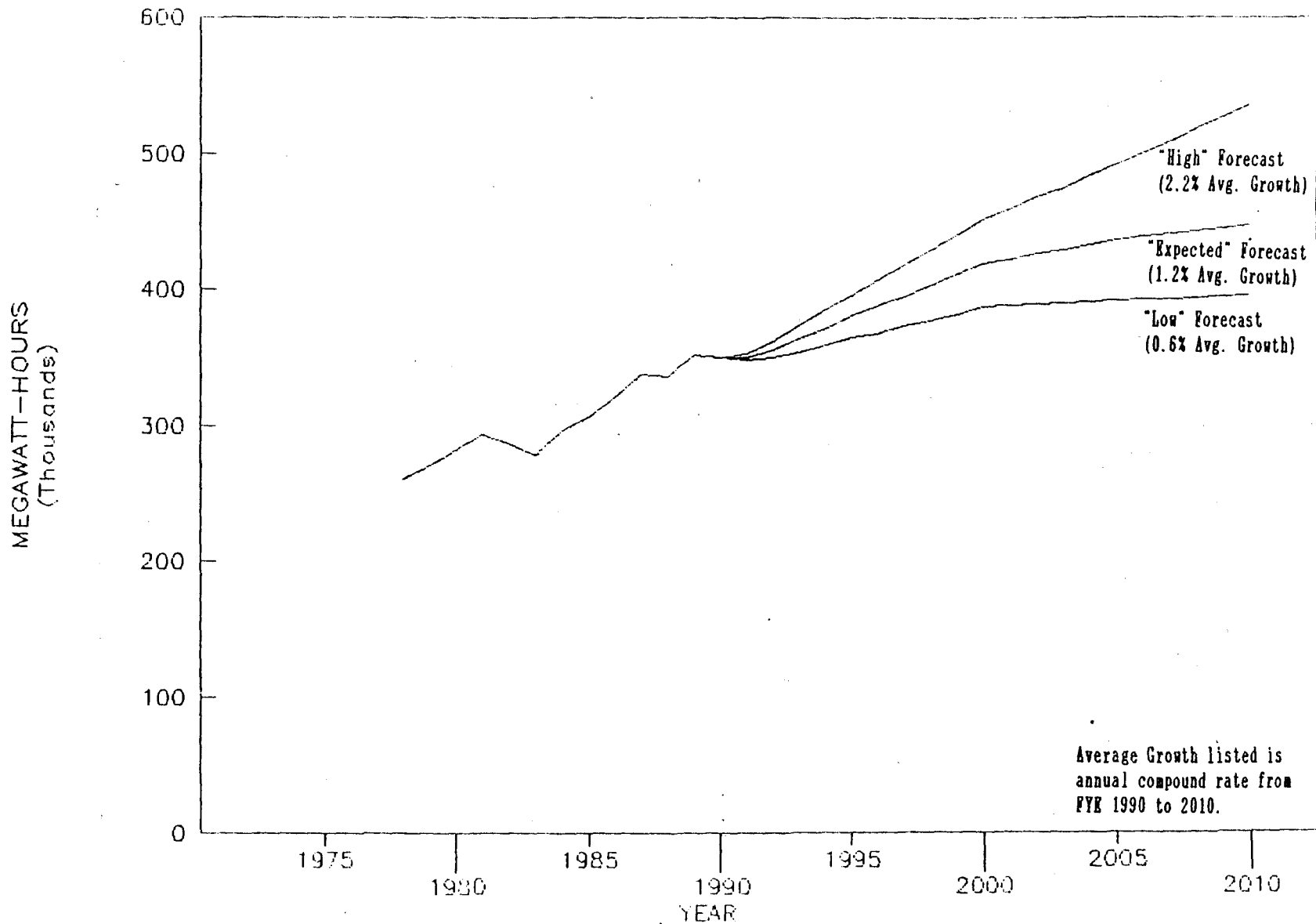
VARIABLE	COEFFICIENT	STD. ERROR	T-STAT.	2-TAIL SIG.
C	-307459.87	112231.05	-2.7395259	0.017
POPLW	18219.274	4581.1338	3.9770229	0.002
EMPPBC	710.85853	90.624175	7.8440276	0.000
TDD	14.145846	6.5786986	2.1502499	0.051
NCOST1	-99453.198	27578.156	-3.6062309	0.003
R-squared	0.986768	Mean of dependent var	265776.2	
Adjusted R-squared	0.982697	S.D. of dependent var	37785.12	
S.E. of regression	4970.336	Sum of squared resid	3.21E+08	
Durbin-Watson stat	1.879772	F-statistic	242.3674	
Log likelihood	-175.8145			

Covariance Matrix			
C,C	1.26E+10	C,POPLW	-4.95E+08
C,EMPPBC	9161949.	C,TDD	-408479.9
C,NCOST1	1.79E+09	POPLW,POPLW	20986787
POPLW,EMPPBC	-357687.4	POPLW,TDD	9747.966
POPLW,NCOST1	-91543126	EMPPBC,EMPPBC	8212.741
EMPPBC,TDD	-311.3290	EMPPBC,NCOST1	992667.2
TDD,TDD	43.27928	TDD,NCOST1	4541.476
NCOST1,NCOST1	7.61E+08		

Residual Plot		obs	RESIDUAL	ACTUAL	FITTED
:	*	1973	1663.86	214159.	212495.
:	*	1974	-2562.86	216218.	218781.
:	*	1975	1120.30	224773.	223653.
:	*	1976	3302.38	225189.	221887.
:	*	1977	-1027.75	226766.	227794.
:	*	1978	-2864.75	238387.	241252.
:	*	1979	-6710.60	246501.	253212.
:	*	1980	4132.00	260630.	256498.
:	*	1981	10221.1	274080.	263859.
:	*	1982	-408.502	264904.	265313.
:	*	1983	-9069.96	262920.	271990.
:	*	1984	1552.71	273282.	271729.
:	*	1985	-3941.68	280591.	284533.
:	*	1986	928.871	296970.	296041.
:	*	1987	2767.02	310676.	307909.
:	*	1988	2363.83	314702.	312338.
:	*	1989	1298.88	323974.	322675.
:	*	1990	-2764.88	329249.	332014.

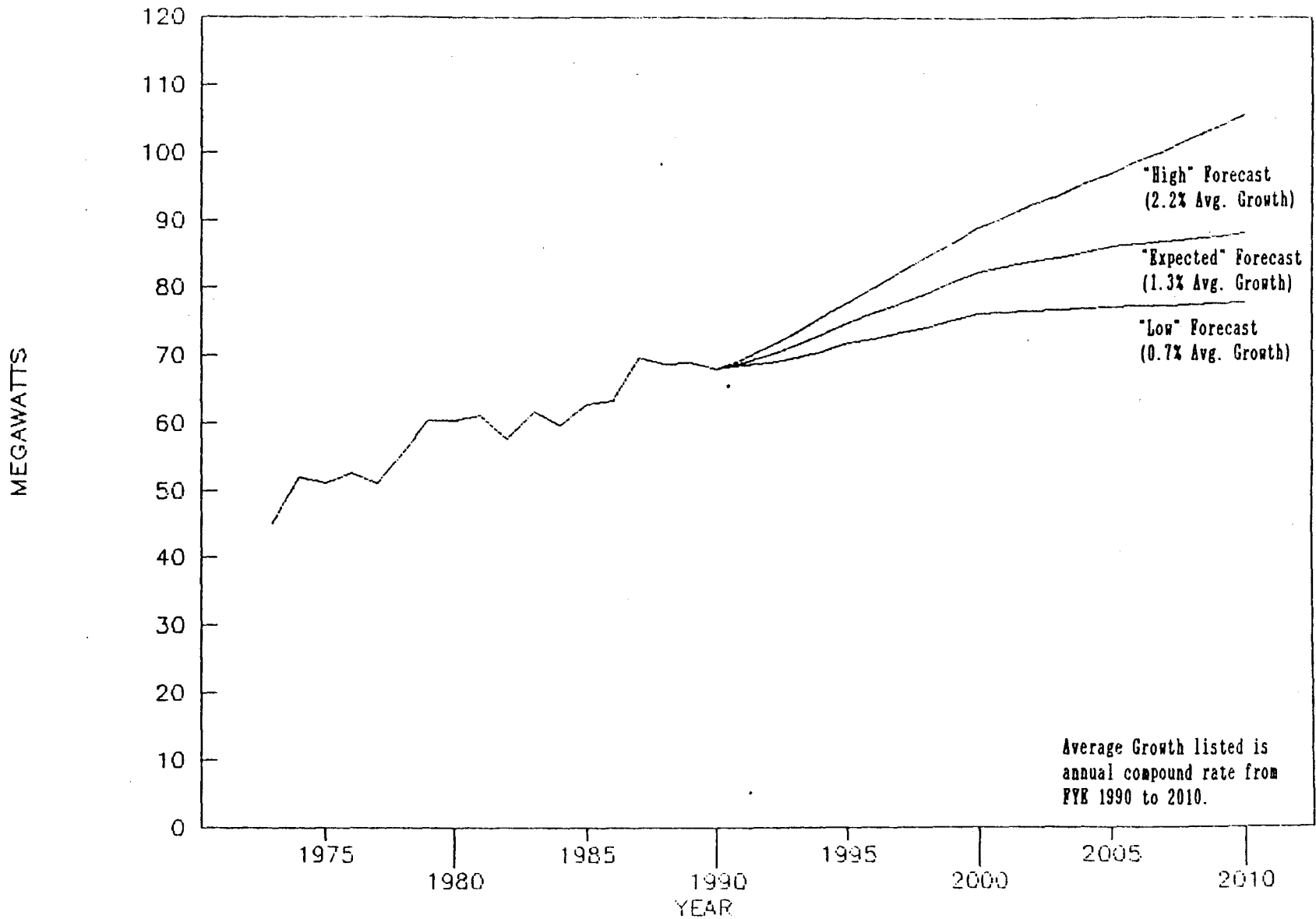
ENERGY

IC.B.1-79



GRAPH 1

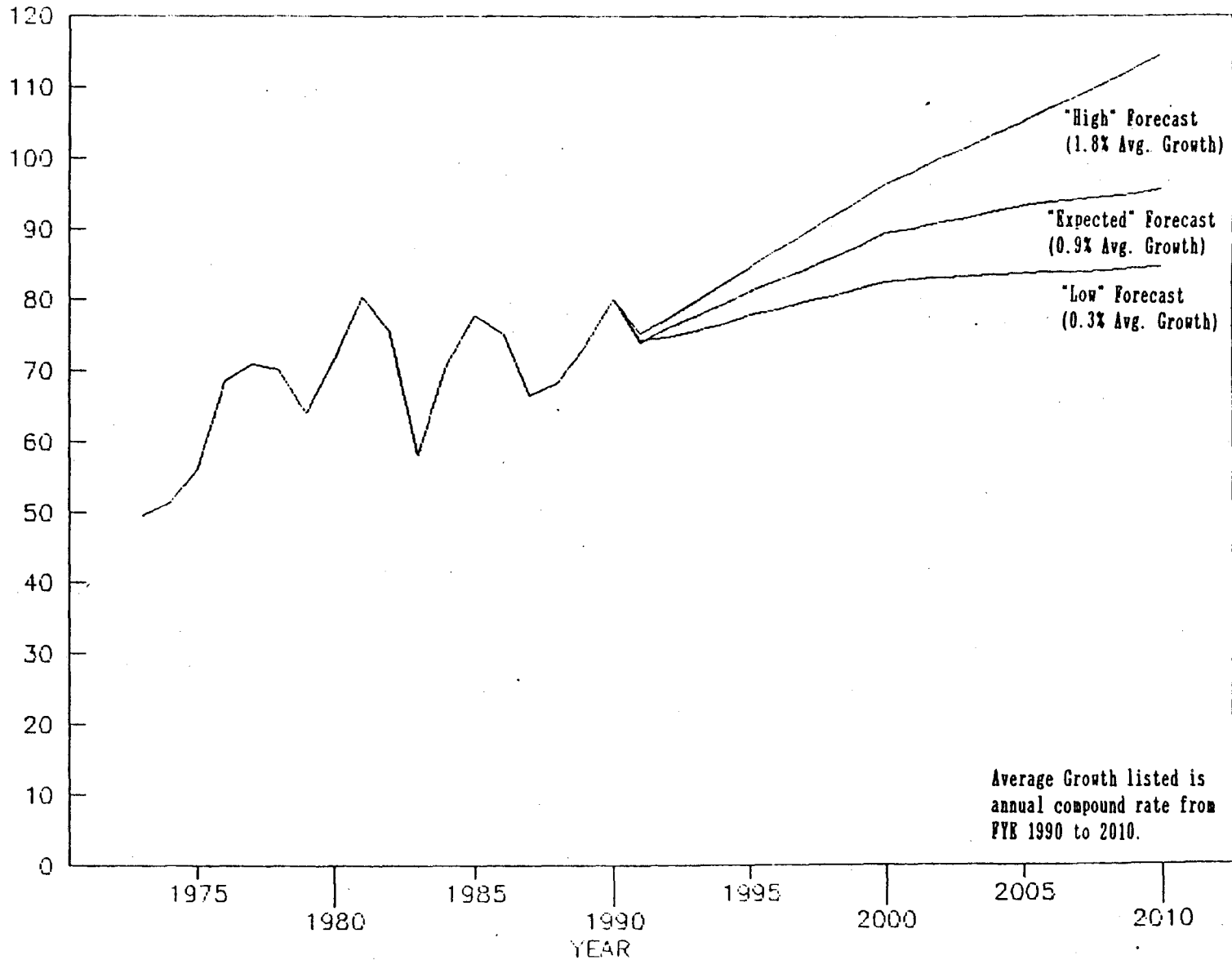
SUMMER PEAK DEMAND



WINTER PEAK DEMAND

MEGAWATTS

1C.B.1-81



GRAPH 3

CITY OF STARKE

APPENDIX 1C.B

SECTION 1C.B.1.5

CITY OF STARKE, FLORIDA

Following is a summary of our analyses and investigations pertaining to the design and development of estimates of future energy and demand requirements for the City of Starke, Florida.

The forecasting technique used to project future energy and demand requirements for the City of Starke is the annual aggregate method. Based on the results of this analysis, system net energy requirements are projected to increase at a compound annual growth rate of 3.0% between 1990 and 1999 and summer peak demand is expected to increase at an annual compound rate of 2.8% over the same period. This forecast is summarized below, presented in detail in Table 1C.B.G-1 and depicted graphically in Exhibits 1C.B.G-1, 1C.B.G-2, and 1C.B.G-3.

CITY OF STARKE, FLORIDA

Projected Demand and Energy Requirements

	1989 [1]	1994	1999
Net Energy Requirements - (MWh)	59,400	67,300	77,300
Summer Net Peak Demand - (MW)	12.2	14.1	16.2

Net Energy Requirements

Aggregate net energy for load is postulated to be a linear function. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project net energy requirements are reported in Equation [G-1].

$$E_t = E_{t-1} + 2.005244 + e_t \quad [G-1]$$

where E_t = net energy for load (Gwh) in calendar year t.

[1] Actual 1989.

The resulting index of determination is greater than .95.

Model inputs consist of annual net energy for load observations over the study period, i.e., 1979 through 1990 on a calendar year basis. This model is used to project energy requirements through the year 2009.

No unusual load additions have been projected for the City of Starke.

Peak Demand

The forecast of summer peak demand is based on the average system summer load factor for 1988 - 1990 and the forecast of winter peak demand is based on the average system winter load factor for 1987 - 1989. Peak demands are obtained by applying an average annual load factor to projected net energy requirements. This assumes that consumer behavior will resemble that encountered during the study period.

Conservation and Load Management

Projected values of net energy requirements and annual peak demand for the City of Starke do not include the effects of any additional conservation and/or load management not observed over the historical study period used to estimate the forecasting models. However, the effects of conservation and/or load management observed over the historical study period are implied in the quantification of the City's forecasting models by including recent historical data which include the effects of existing conservation and load management.

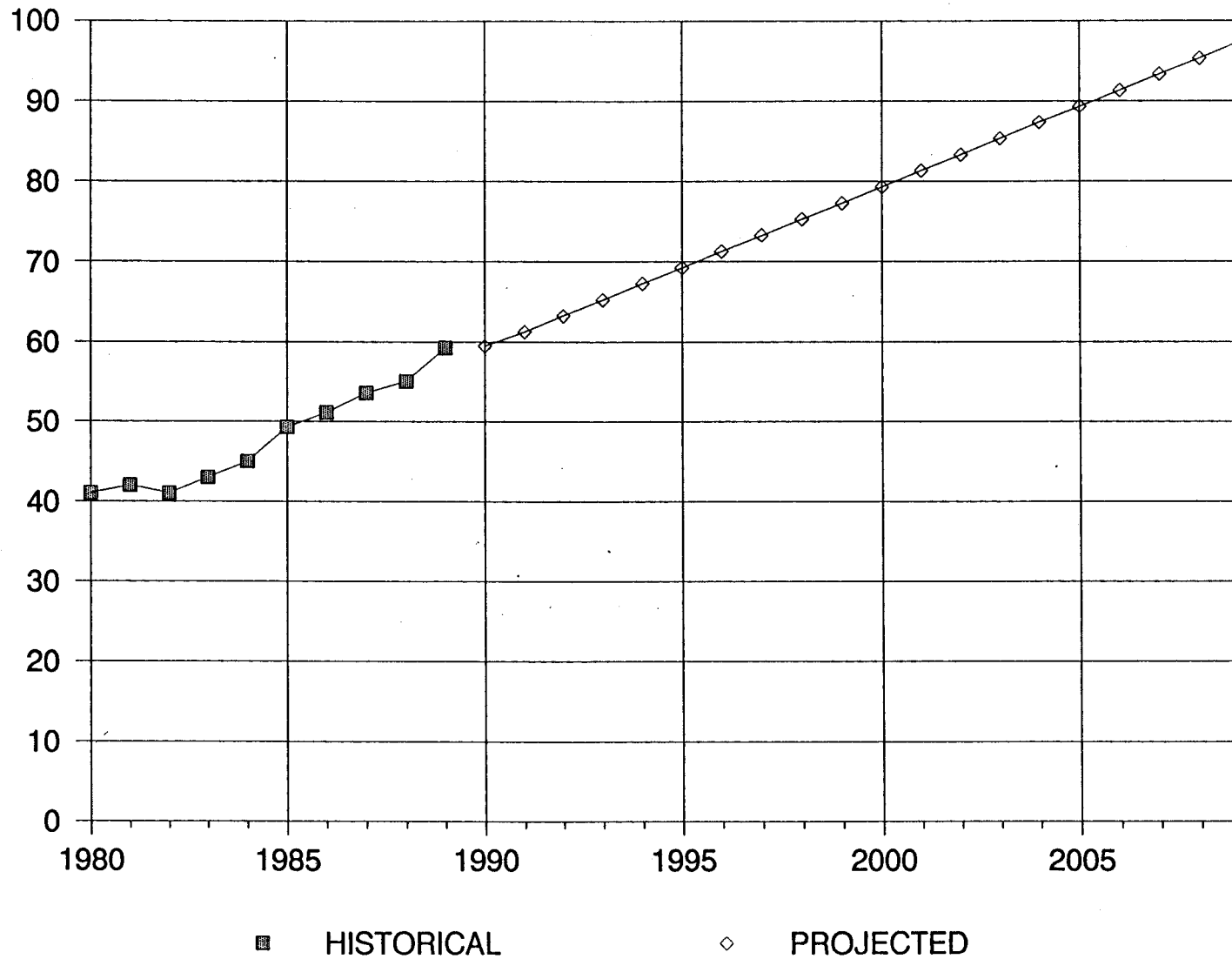
TABLE 1C.B.G-1
CITY OF STARKE
HISTORICAL AND PROJECTED NEL AND PEAK DEMANDS

		CALENDAR YEAR NEL (GWH)	SUMMER NCP (MW)	WINTER NCP (MW)
	1980	41.0	10.0	8.0
	1981	42.0	10.0	9.0
A	1982	41.0	10.0	8.0
C	1983	43.0	11.0	9.0
T	1984	45.0	9.2	9.0
U	1985	49.3	10.5	9.2
A	1986	51.1	10.8	10.0
L	1987	53.6	11.9	8.5
	1988	55.1	11.6	9.4
	1989	59.4	12.2	9.8
	1980 - 1989			
	% A A G R	4.2%	2.2%	2.3%
	1990	59.5 [1]	12.6 [2]	10.9 [2]
	1991	61.3	12.8	11.0
	1992	63.3	13.2	11.3
	1993	65.3	13.6	11.7
	1994	67.3	14.1	12.0
P	1995	69.3	14.5	12.4
	1996	71.3	14.9	12.8
R	1997	73.3	15.3	13.1
	1998	75.3	15.7	13.5
O	1999	77.3	16.2	13.8
J	1990 - 1999			
	% A A G R	3.0%	2.8%	2.7%
E	2000	79.3	16.6	14.2
C	2001	81.3	17.0	14.6
	2002	83.3	17.4	14.9
T	2003	85.3	17.8	15.3
	2004	87.3	18.3	15.6
E	2005	89.3	18.7	16.0
	2006	91.4	19.1	16.4
D	2007	93.4	19.5	16.7
	2008	95.4	19.9	17.1
	2009	97.4	20.4	17.4
	2000 - 2009			
	% A A G R	2.3%	2.3%	2.3%
	1990 - 2009			
	% A A G R	2.6%	2.6%	2.5%

NOTES [1]: INCLUDES ESTIMATED GWH FOR OCT90 - DEC90.
[2]: ACTUAL.

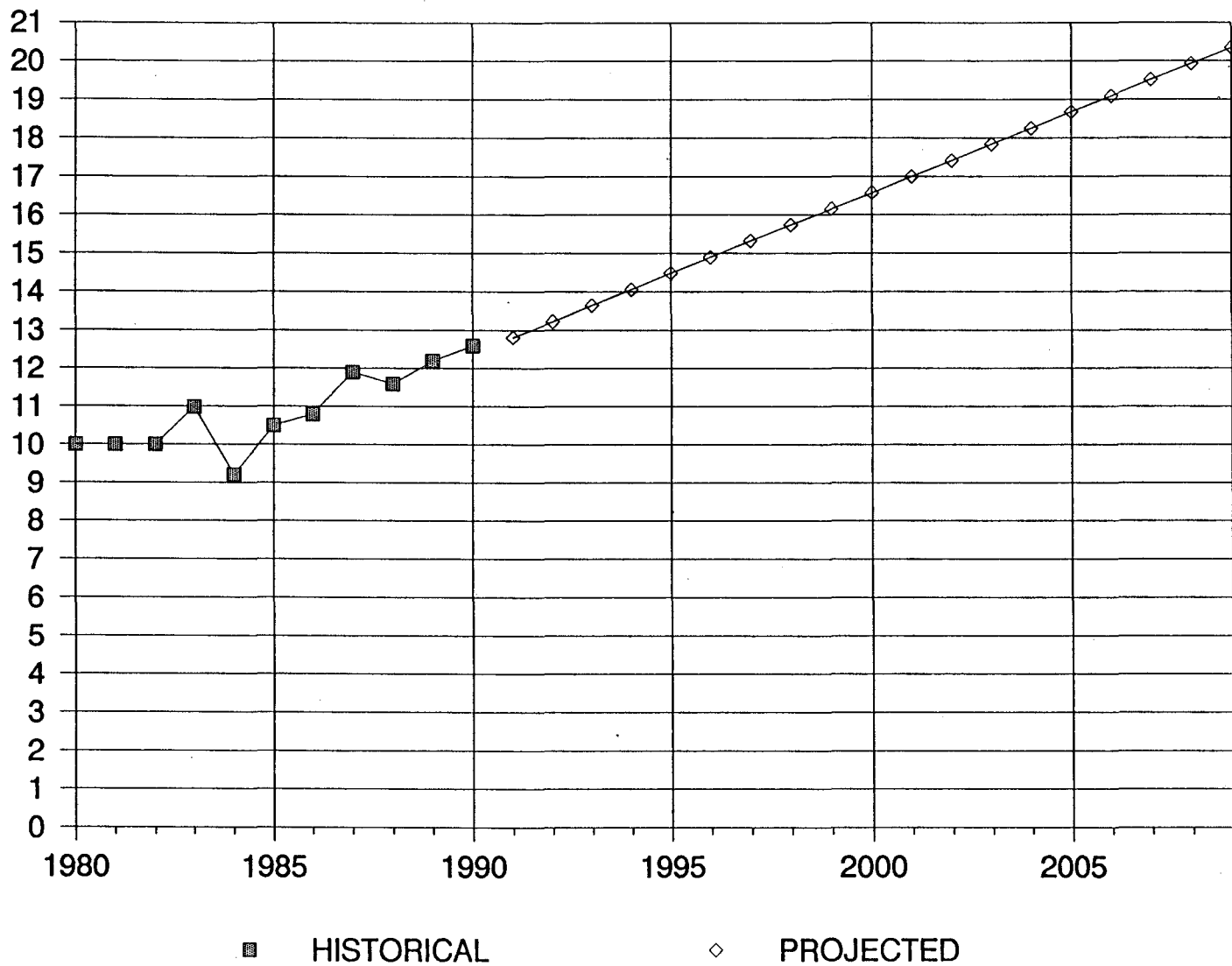
CITY OF STARKE

HISTORICAL AND PROJECTED NEL



CITY OF STARKE

HISTORICAL AND PROJECTED SUMMER NCP

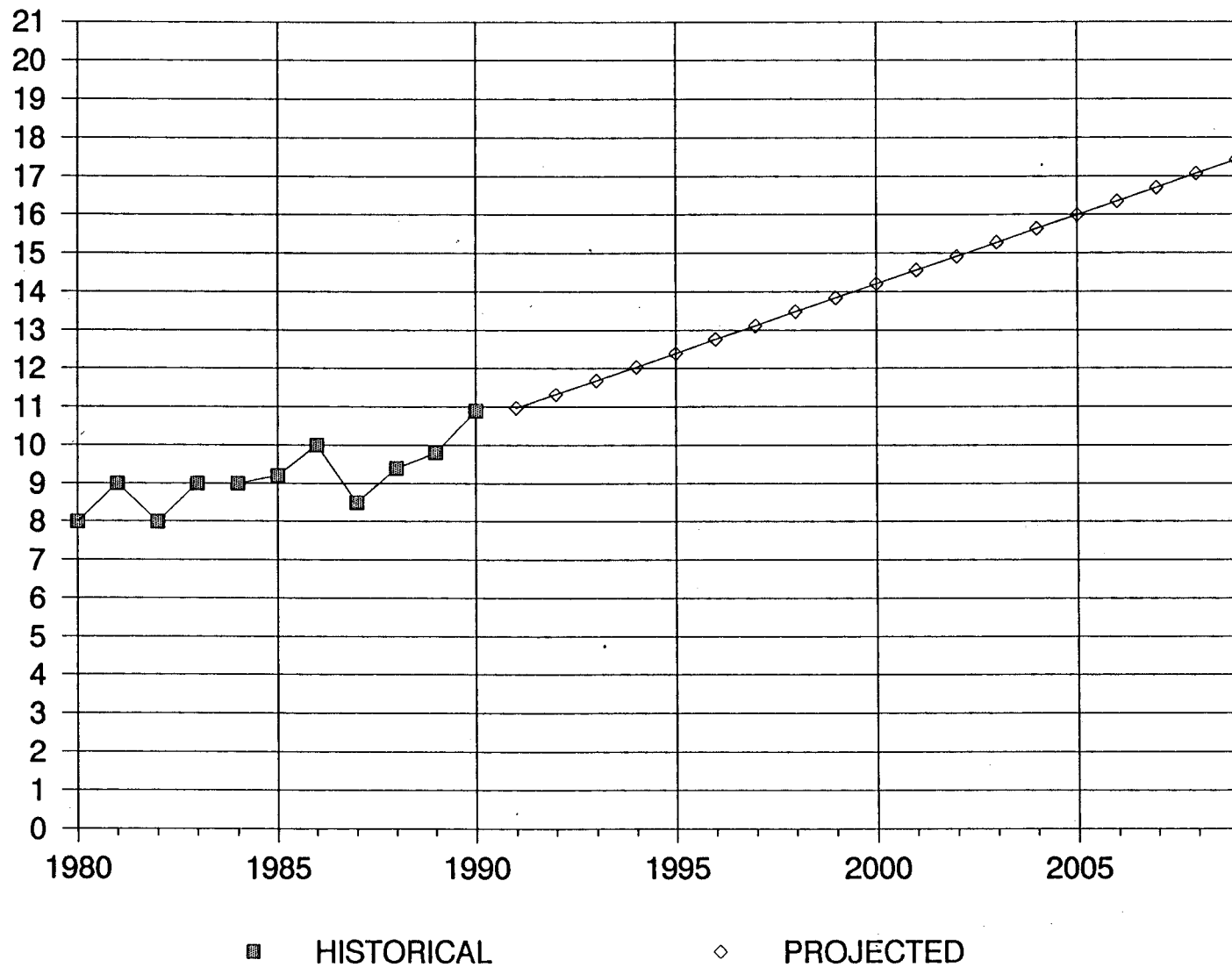


IC.B.1-87

EXHIBIT IC.B.G-2

CITY OF STARKE

HISTORICAL AND PROJECTED WINTER NCP



IC.B.1-88

EXHIBIT IC.B.G-3

CITY OF VERO BEACH

APPENDIX 1C.B

SECTION 1C.B.1.6

CITY OF VERO BEACH, FLORIDA Electric System

Customer, Energy and Demand Forecast 1991-2021

The following is a summary of the analyses and studies pertaining to the design and development of estimates of future energy and demand requirements and customer forecasts for the City of Vero Beach, Florida (the "City"). The forecast is provided on a fiscal year basis.

Projections of the City's demand and energy requirements were developed for the period 1991 through 2021. Based on the results of the various analyses, system net energy requirements are projected to increase at a compound annual growth rate of 2.8% and 2.2% for the periods 1991 through 2000 and 1991 through 2021, respectively, on a fiscal year basis. System net peak demand is expected to increase at a compound rate of 2.9% and 2.2% over the same periods, respectively. This forecast is summarized below.

Projected Demand and Energy Requirements By Class of Service[1] (Fiscal Year)

		<u>1990[2]</u>	<u>1991</u>	<u>2000</u>	<u>2021</u>
Residential	- (MWh)	264,707	276,372	360,062	513,191
Commercial [3]	- (MWh)	212,186	220,121	284,055	452,688
Industrial	- (MWh)	<u>20,616</u>	<u>20,616</u>	<u>20,616</u>	<u>20,616</u>
Total Sales	- (MWh)	497,509	517,109	664,733	986,494
System Losses	- (MWh)	<u>25,323</u>	<u>31,027</u>	<u>39,884</u>	<u>59,137</u>
Net Energy Requirements	- (MWh)	522,832	548,136	704,617	1,045,631
System Net Winter Peak Demand	- (MW)	87.0	139.7	180.6	265.3

[1] Values may not add due to rounding.

[2] Actual.

[3] Includes rental and street lighting.

These estimates are based on independent energy forecasts for the residential, commercial (including rental and street lighting), and industrial sectors, and include an adjustment for future incremental load anticipated by the City. Annual projections of net energy requirements and seasonal net peak demands are presented on Table I. Additionally, a detailed forecast by customer class is presented on Table II.

Assumptions

Historical and projected data regarding explanatory variables used in the econometric models of energy consumption and customer growth are described below. Other information regarding considerations and assumptions used in the 1991 load forecast are also discussed.

Population

Population in Indian River County serves as the explanatory variable in the regression analysis of customer growth. Historical population estimates for the County were obtained from publications of the University of Florida's Bureau of Economic and Business Research (the "BEBR"). Medium-range population projections published by the BEBR in its Population Studies Bulletin No. 92 have been used to develop the base case projections of residential and commercial customers over the forecast period. Population in Indian River County is projected to increase by approximately 70,000 through 2021 which represents a compound average annual increase of approximately 1.86%

Florida Per Capita Income

The level of per capita income in Florida was used as a proxy for economic activity in the econometric model of residential average energy usage. Historical per capita income data were obtained from the Office of the Governor and were adjusted to real terms in 1982 dollars. Per capita real income is projected to increase over the forecast period at a compound average annual growth rate of approximately 2.8%.

State of Florida Employment

Historical data regarding employment in Florida was obtained from the Office of the Governor and served as the economic explanatory variable in the analysis of commercial energy sales. Based on projections provided by the Florida Governor's Office of Planning and Budgeting, employment is expected to increase at a compound average annual rate of approximately 2.7% through 2021.

Price of Electricity

The historical price of electricity is based on the City's records of energy sales and revenues by customer class. Such information was aggregated on a quarterly basis and adjusted to real terms in 1982 dollars for use in the residential and the commercial econometric models. For purposes of developing the long-term load forecast, it has been assumed that the real price of electricity will remain constant over the forecast period. Thus, in general, it is expected that changes in the price of electricity will keep pace with inflation.

Weather

Historical weather conditions, as represented by regional heating and cooling degree days, were obtained from publications of the National Oceanic and Atmospheric Administration (the "NOAA"). For purposes of the long-term load forecast, normal or average weather conditions have been assumed based on the thirty-year norms of heating and cooling degree days reported by the NOAA. For a long-term base case forecast, normal weather conditions are considered suitable to reasonably depict the long-term trend. It is recognized that in any particular year, weather will deviate from normal and projected energy and demand can be expected to vary accordingly.

Incremental Additions

Based on discussions with the City, it is anticipated that the Grand Harbour residential development will affect future load growth incrementally, above and beyond forecast results predicated on historical growth patterns. The total development, which started in 1989, is expected to ultimately consist of 3,000 residential customers with a peak demand impact of 17 megawatts. For purposes of this forecast, it has been assumed that 1,800 of the Grand Harbour customers are inherently reflected in the base forecast results. The remaining 1,200 Grand Harbour customers have been phased in from 1991 through 1996 at 200 incremental customers per year. Average energy use for the Grand Harbour residential customers is expected to be higher than the System average, and has been estimated at 17,000 kWh per year.

The cumulative incremental additions to residential customers, energy sales, losses, net energy for load, and winter and summer peak demands are summarized below.

<u>Fiscal Year</u>	<u>Customers</u> (MWh)	<u>Cumulative Incremental Additions Associated with Grand Harbour</u>				
		<u>Energy Sales</u> (MWh)	<u>Net Energy Losses</u> (MWh)	<u>Winter For Load</u> (MW)	<u>Summer Peak</u> (MW)	<u>Peak</u>
1991	200	8,500	510	9,010	2.9	2.3
1992	400	11,900	714	12,614	4.0	3.2
1993	600	15,300	918	16,218	5.1	4.1
1994	800	18,700	1,122	19,822	6.3	5.0
1995	1,000	22,100	1,326	23,426	7.4	5.9
1996-2021	1,200	25,500	1,530	27,030	8.6	6.9

System Losses

Based on an historical analysis of system losses, it has been assumed that losses of approximately 6% of total annual retail energy sales will occur over the forecast period.

System Load Factors

The average of historical load factors experienced over the most recent fiscal five-year period 1985 through 1990 served as the basis for the assumed load factors used in the forecast. The estimated winter seasonal load factor of 45% was applied to annual projections of net energy for load to develop projections of system annual peak demand. Likewise, the forecast of the summer season peak demand is based on an estimated load factor of 55% applied to the annual projections of net energy for load.

Conservation

For purposes of the forecast analyses herein, no decremental adjustments have been made with regard to any assumed or estimated energy or demand reductions associated with the City's conservation programs. The City's conservation plan includes street light conversions, the home fix-up program, energy audits, and various other public awareness and information programs. While it is difficult to estimate savings associated with any conservation program, it is particularly difficult to develop such estimates for awareness and information types of

programs. It is also recognized that the City's conservation plan has been ongoing for several years, and the subsequent historical energy and demand data would inherently reflect changes in consumption associated with conservation. For these reasons, it was not considered necessary to make any direct conservation-related adjustments to base forecast results. Additionally, the City does not currently have a load management program, nor does it have any specific plans to implement load management in the future.

Residential Sector

The econometric analyses relating to the residential sector are based on quarterly historical observations from the first quarter of 1979 through the third quarter of 1990. The forecast of total residential energy sales is the product of the projected number of residential customers and the projected average energy use per customer.

The explanatory variables used to statistically describe average usage per residential customer are the real price of electricity, weather, and an economic variable. Weather conditions are represented by heating and cooling degree days and the selected economic variable is based on Florida real per capita personal income. The resulting index of determination (R-squared statistic) was 88%.

Residential customers have been forecasted based on a regression analysis of historical quarterly customers and Indian River population, with a resulting index of determination of 98%. The base or unadjusted forecast results for the residential sector were then adjusted incrementally to account for the Grand Harbour development. The adjusted residential sector forecast results are summarized for selected years below.

	Average Annual Number of			
	Fiscal	Residential	Average Energy	Total Residential
	Year	Customers	Use Per Customer	Energy Sales
			(kWh)	(MWh)
Actual	1990	21,541	12,288	264,707
Projected	1991	22,119	12,495	276,372
	2000	27,927	12,893	360,062
	2021	36,690	13,987	513,191
Compound Average				
Annual Growth Rate 1991-2021		1.7%	0.4%	2.1%

Commercial Sector

The econometric analysis of commercial energy sales is based on quarterly historical observations from the first quarter of 1979 through the third quarter of 1990 using Florida employment, the real price of electricity, cooling degree days, and seasonal indicators as explanatory variables. The resulting index of determination was 96%.

The projected number of commercial customers is based on the historical relationship between customers and population in Indian River County. The index of determination for the commercial customer model is 99%.

The resulting forecasts of commercial energy sales, which include rental and street lighting, and of commercial customers are summarized below for selected years.

	Average Annual Number of Fiscal Year	Commercial Customers	Average Energy Use Per Customer (kWh)	Total Commercial Energy Sales (MWh)
Actual	1990	3,963	53,545	212,186
Projected	1991	4,094	53,771	220,121
	2000	5,374	52,858	284,055
	2021	7,755	58,376	452,688
Compound Average Annual Growth Rate 1991-2021		2.2%	0.3%	2.4%

Industrial Sector

Energy sales in the industrial class consist of sales to one industrial customer, Piper Aircraft Corporation. For purposes of the long-term forecast, it has been assumed that no new industrial class customers will be added to the System over the forecast period.

Piper has experienced somewhat erratic energy usage patterns over the historical period. Reduced consumption levels from 1982 through 1985 resulted, in part, from weakness in the small commercial aircraft industry. The increase in energy usage in 1986 occurred when Piper

closed its plant in the City of Lakeland and subsequently utilized more of its production facilities located at the Vero Beach plant. Energy levels during 1987 through 1989 have been relatively stable and represent production levels since the change to new ownership of the company. However in fiscal 1990 sales levels for Piper decreased by approximately 30% from 1989 levels. For purposes of this forecast, it has been assumed that Piper's energy requirements will remain constant at recent 1990 annual levels of approximately 20,616 MWh.

Net Energy for Load and Peak Demand

Projections of residential, commercial, and industrial energy sales were aggregated to total system retail energy sales and adjusted for losses to produce forecasted net energy for load. To develop seasonal peak demand projections, the assumed seasonal load factors were applied to the resulting forecast of net energy for load. The forecast results are summarized below for selected years.

	<u>Fiscal Year</u>	<u>Total Retail Sales</u> (MWh)	<u>Net Energy For Load</u> (MWh)	<u>Winter Peak Demand</u> (MW)	<u>Summer Peak Demand</u> (MW)
Actual	1990	497,509	522,832	87.0	109.0
Projected	1991	517,109	548,136	139.7	114.2
	2000	664,733	704,617	180.6	146.7
	2021	986,494	1,045,631	265.3	217.0
Compound Average					
Annual Growth Rate	1991-2021	2.2%	2.2%	2.2%	2.2%

The forecast results shown on Tables I and II incorporate "normal" weather conditions as a basic forecast assumption. It should be noted that the City's peak demand is particularly sensitive to winter weather conditions. While it is expected that the long-term trend of the demand forecast is reasonable, it is likely that for any particular year during the forecast period, deviations will occur as a result of unseasonal weather conditions.

Summary

The forecasting methodology utilized attempts to identify and reflect key factors which can influence the City's demand and energy requirements. It should be emphasized that the confidence associated with any projections varies inversely with the length of the forecast. The probability of extraneous factors affecting projected values increases with uncertainty about future developments; this uncertainty, in turn, increases with the length of the forecast period. With this in mind, projections of the City's annual net peak demand and net energy requirements should be viewed as reasonable estimates but subject to external disturbances which, at this time, cannot be reasonably foreseen. Therefore, the forecast results and the underlying assumptions should be reviewed periodically and updated when necessary. To the extent that unpredictable economic, demographic, and technological developments affect future expectations, forecasts may require adjustments to reflect such factors.

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TABLE I
 CITY OF VERO BEACH, FLORIDA
 Historical and Projected
 Net Energy Requirements and Peak Demands

 (FISCAL YEAR)

	Net Energy Requirements ----- (MWh)	Winter Peak Demand ----- (MW)	Summer Peak Demand ----- (MW)
HISTORICAL:			
1980	353,812	99.0	83.0
1981	372,060	111.0	82.0
1982	369,995	112.0	80.0
1983	372,660	90.0	81.0
1984	381,775	97.0	79.0
1985	409,426	129.0	90.0
1986	444,628	132.0	91.0
1987	477,427	107.0	102.0
1988	483,348	118.0	101.0
1989	517,152	138.0	108.0
1990	522,832	87.0	109.0
Avg. Annual Compound Rate of Growth:			

1980-1990	4.0%	-1.3%	2.8%
1985-1990	5.0%	-7.6%	3.9%
PROJECTED:			
1991	548,136	139.7	114.2
1992	566,314	144.8	118.4
1993	587,047	150.3	122.9
1994	607,676	155.8	127.3
1995	628,190	161.1	131.7
1996	646,595	165.9	135.6
1997	660,892	169.5	138.6
1998	675,077	173.1	141.5
1999	689,674	176.9	144.6
2000	704,617	180.6	147.6
2001	718,460	184.1	150.5
2002	732,327	187.6	153.4
2003	746,241	191.2	156.3
2004	760,362	194.8	159.2
2005	774,757	198.5	162.2
2006	789,315	202.1	165.2
2007	804,166	205.9	168.3
2008	819,316	209.8	171.5
2009	834,775	213.7	174.7
2010	850,479	217.7	178.0
2011	866,501	219.8	179.8
2012	882,845	224.0	183.2
2013	899,520	228.2	186.7
2014	916,531	232.5	190.2
2015	933,886	236.9	193.8
2016	951,591	241.4	197.5
2017	969,654	246.0	201.3
2018	988,082	250.7	205.1
2019	1,006,882	255.4	209.0
2020	1,026,063	260.3	213.0
2021	1,045,631	265.3	217.0
Avg. Annual Compound Rate of Growth:			

1991-2000	2.8%	2.9%	2.9%
1991-2010	2.3%	2.4%	2.4%
1991-2021	2.2%	2.2%	2.2%

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TABLE II
 CITY OF VERO BEACH, FLORIDA
 Historical and Projected Energy Sales, Number of Customers, and Seasonal Peak Demands [1]
 (Fiscal Year Basis)

Year	Residential			Commercial			Industrial		Total			Net Energy For Load (MWh)	Winter Peak Demand (MW)	Summer Peak Demand (MW)	
	Average Customers	Average Use Per Customer	Energy Sales (MWh)	Average Customers	Average Use Per Customer	[2] Energy Sales (MWh)	Average Customers	Energy Sales (MWh)	Total Retail Customers	Total Retail Energy Sales (MWh)	Losses (MWh)				
		(kWh)			(kWh)										(MWh)
HISTORICAL:															
1980	14,734	12,051	177,562	2,448	53,406	130,732	1	22,509	17,183	330,810	23,002	353,812	99.0	83.0	
1981	15,800	12,148	191,025	2,590	54,550	141,775	1	21,907	18,400	355,627	16,433	372,060	111.0	82.0	
1982	16,663	12,057	199,244	2,690	54,509	147,120	1	20,576	19,363	350,940	10,053	360,995	112.0	80.0	
1983	17,074	10,933	186,678	2,760	51,780	142,557	1	19,812	19,824	328,237	24,723	372,960	90.0	81.0	
1984	17,510	10,757	188,757	2,830	51,323	146,734	1	18,049	20,450	320,650	20,825	381,475	97.0	79.0	
1985	17,822	11,457	202,713	2,924	52,251	154,621	1	18,524	20,865	385,608	23,818	409,426	129.0	90.0	
1986	18,342	11,824	219,288	3,034	52,175	158,621	1	17,887	21,072	410,608	27,006	444,628	135.0	91.0	
1987	18,898	12,283	232,120	3,145	52,102	164,708	1	17,585	22,434	450,203	27,224	477,427	107.0	102.0	
1988	19,475	11,650	236,317	3,205	52,301	167,715	1	16,704	22,780	450,203	26,613	483,328	118.0	101.0	
1989	20,479	11,656	246,055	3,336	52,180	177,884	1	16,630	23,417	483,328	26,583	519,152	138.0	108.0	
1990	21,541	12,288	264,707	3,963	53,545	212,186	1	20,616	23,505	497,509	23,323	522,832	87.0	109.0	
Average Annual Compound Growth Rate:															
1980-1990	3.9%	0.2%	4.1%	4.9%	-0.3%	5.2%	0.0%	-0.2%	4.9%	4.2%	1.0%	4.0%	-1.3%	3.9%	
PROJECTED:															
1991	22,119	12,495	276,372	4,094	53,771	220,121	1	20,616	26,214	517,109	31,027	548,136	139.7	114.2	
1992	22,630	12,538	281,802	4,251	53,164	228,120	1	20,616	26,182	524,818	32,055	556,873	144.8	118.0	
1993	23,226	12,598	288,894	4,400	53,140	234,308	1	20,616	26,137	533,045	33,077	566,122	150.3	122.0	
1994	23,828	12,690	296,774	4,570	52,884	240,417	1	20,616	26,092	542,270	34,077	576,347	156.1	125.7	
1995	24,436	12,757	305,405	4,732	52,752	246,557	1	20,616	26,047	551,558	35,077	586,635	161.8	129.4	
1996	25,050	12,817	314,247	4,882	52,607	252,724	1	20,616	25,957	560,865	36,000	596,865	167.5	133.1	
1997	25,670	12,874	323,317	5,024	52,454	258,924	1	20,616	25,912	570,169	36,958	607,127	173.2	136.8	
1998	26,296	12,933	332,620	5,164	52,302	265,154	1	20,616	25,867	579,465	37,912	617,377	178.9	140.5	
1999	26,928	12,992	342,157	5,302	52,154	271,408	1	20,616	25,822	588,733	38,865	627,598	184.6	144.2	
2000	27,566	13,052	351,930	5,438	52,007	277,688	1	20,616	25,777	598,000	39,818	637,818	190.3	147.9	
2001	28,209	13,112	361,937	5,572	51,858	284,007	1	20,616	25,732	607,270	40,770	648,040	196.0	151.6	
2002	28,858	13,172	372,167	5,704	51,715	290,358	1	20,616	25,687	616,533	41,722	658,255	201.7	155.3	
2003	29,512	13,232	382,620	5,834	51,572	296,732	1	20,616	25,642	625,811	42,674	668,485	207.4	159.0	
2004	30,171	13,292	393,297	5,962	51,430	303,127	1	20,616	25,597	635,365	43,626	678,791	213.1	162.7	
2005	30,835	13,352	404,190	6,088	51,288	309,542	1	20,616	25,552	644,933	44,577	689,110	218.8	166.4	
2006	31,504	13,412	415,397	6,212	51,146	316,000	1	20,616	25,507	654,500	45,528	699,528	224.5	170.1	
2007	32,178	13,472	426,812	6,334	51,004	322,524	1	20,616	25,462	664,065	46,479	710,044	230.2	173.8	
2008	32,857	13,532	438,435	6,454	50,862	329,120	1	20,616	25,417	673,627	47,429	720,556	235.9	177.5	
2009	33,541	13,592	450,266	6,572	50,720	335,788	1	20,616	25,372	683,187	48,379	731,166	241.6	181.2	
2010	34,230	13,652	462,304	6,688	50,578	342,520	1	20,616	25,327	692,733	49,329	741,762	247.3	184.9	
2011	34,924	13,712	474,549	6,802	50,436	349,324	1	20,616	25,282	702,262	50,279	752,341	253.0	188.6	
2012	35,623	13,772	486,990	6,914	50,294	356,192	1	20,616	25,237	711,774	51,229	762,903	258.7	192.3	
2013	36,327	13,832	499,627	7,024	50,152	363,120	1	20,616	25,192	721,270	52,179	773,449	264.4	196.0	
2014	37,036	13,892	512,460	7,132	50,010	370,120	1	20,616	25,147	730,750	53,129	784,079	270.1	200.0	
2015	37,750	13,952	525,489	7,238	49,868	377,192	1	20,616	25,102	740,215	54,079	794,694	275.8	203.7	
2016	38,469	14,012	538,712	7,342	49,726	384,320	1	20,616	25,057	749,665	55,029	805,294	281.5	207.4	
2017	39,193	14,072	552,129	7,444	49,584	391,512	1	20,616	25,012	759,111	55,979	815,891	287.2	211.1	
2018	39,922	14,132	565,739	7,544	49,442	398,768	1	20,616	24,967	768,542	56,929	826,471	292.9	214.8	
2019	40,656	14,192	579,542	7,642	49,300	406,088	1	20,616	24,922	777,957	57,879	837,046	298.6	218.5	
2020	41,395	14,252	593,537	7,738	49,158	413,472	1	20,616	24,877	787,357	58,829	847,616	304.3	222.2	
2021	42,139	14,312	607,724	7,832	49,016	420,920	1	20,616	24,832	796,742	59,779	858,181	310.0	225.9	
Average Annual Compound Growth Rate:															
1991-2000	2.6%	0.3%	3.0%	3.1%	-0.2%	2.9%	0.0%	0.0%	2.7%	2.8%	2.8%	2.8%	2.9%	2.9%	
1991-2010	2.6%	0.3%	3.0%	3.1%	-0.2%	2.9%	0.0%	0.0%	2.7%	2.8%	2.8%	2.8%	2.9%	2.9%	
1991-2021	1.7%	0.4%	2.1%	2.2%	0.3%	2.4%	0.0%	0.0%	1.8%	2.2%	2.2%	2.2%	2.2%	2.2%	

[1] forecast amounts include incremental adjustment to reflect the Grand Harbour development.
 [2] Includes street and rental lighting sales.

ALL-REQUIREMENTS SYSTEMS

CITY OF BUSHNELL

APPENDIX 1C.B

SECTION 1C.B.2.1

CITY OF BUSHNELL, FLORIDA

Following is a summary of our analyses and investigations pertaining to the design and development of estimates of future energy and demand requirements for the City of Bushnell, Florida.

The forecasting technique used to project future energy and demand requirements for the City of Bushnell is the annual aggregate method. Based on the results of this analysis, system net energy requirements are projected to increase at a compound annual growth rate of 2.9% between 1990 and 1999 and summer peak demand is expected to increase at an annual compound rate of 3.2% over the same period. This forecast is summarized below, presented in detail in Table 1C.B.A-1 and depicted graphically in Exhibits 1C.B.A-1, 1C.B.A-2, and 1C.B.A-3.

CITY OF BUSHNELL, FLORIDA

Projected Demand and Energy Requirements

	1989 [1]	1994	1999
Net Energy Requirements - (MWh)	16,320	18,868	21,577
Summer Net Peak Demand - (MW)	3.8	4.3	4.9

Net Energy Requirements

Aggregate net energy for load is postulated to be a linear function. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project net energy requirements are reported in Equation [A-1].

$$E_t = E_{t-1} + .541915 + e_t \quad [A-1]$$

where E_t = net energy for load (Gwh) in calendar year t.

[1] Actual 1989.

The resulting index of determination is greater than .96.

Model inputs consist of annual net energy for load observations over the study period, i.e., 1976 through 1990 on a calendar year basis. This model is used to project energy requirements through the year 2009.

No unusual load additions have been projected for the City of Bushnell.

Peak Demand

The forecast of summer peak demand is based on the average system summer load factor for 1988 - 1990 and the forecast of winter peak demand is based on the average system winter load factor for 1987 - 1989. Peak demands are obtained by applying an average annual load factor to projected net energy requirements. This assumes that consumer behavior will resemble that encountered during the study period.

Conservation and Load Management

Projected values of net energy requirements and annual peak demand for the City of Bushnell do not include the effects of any additional conservation and/or load management not observed over the historical study period used to estimate the forecasting models. However, the effects of conservation and/or load management observed over the historical study period are implied in the quantification of the City's forecasting models by including recent historical data which include the effects of existing conservation and load management.

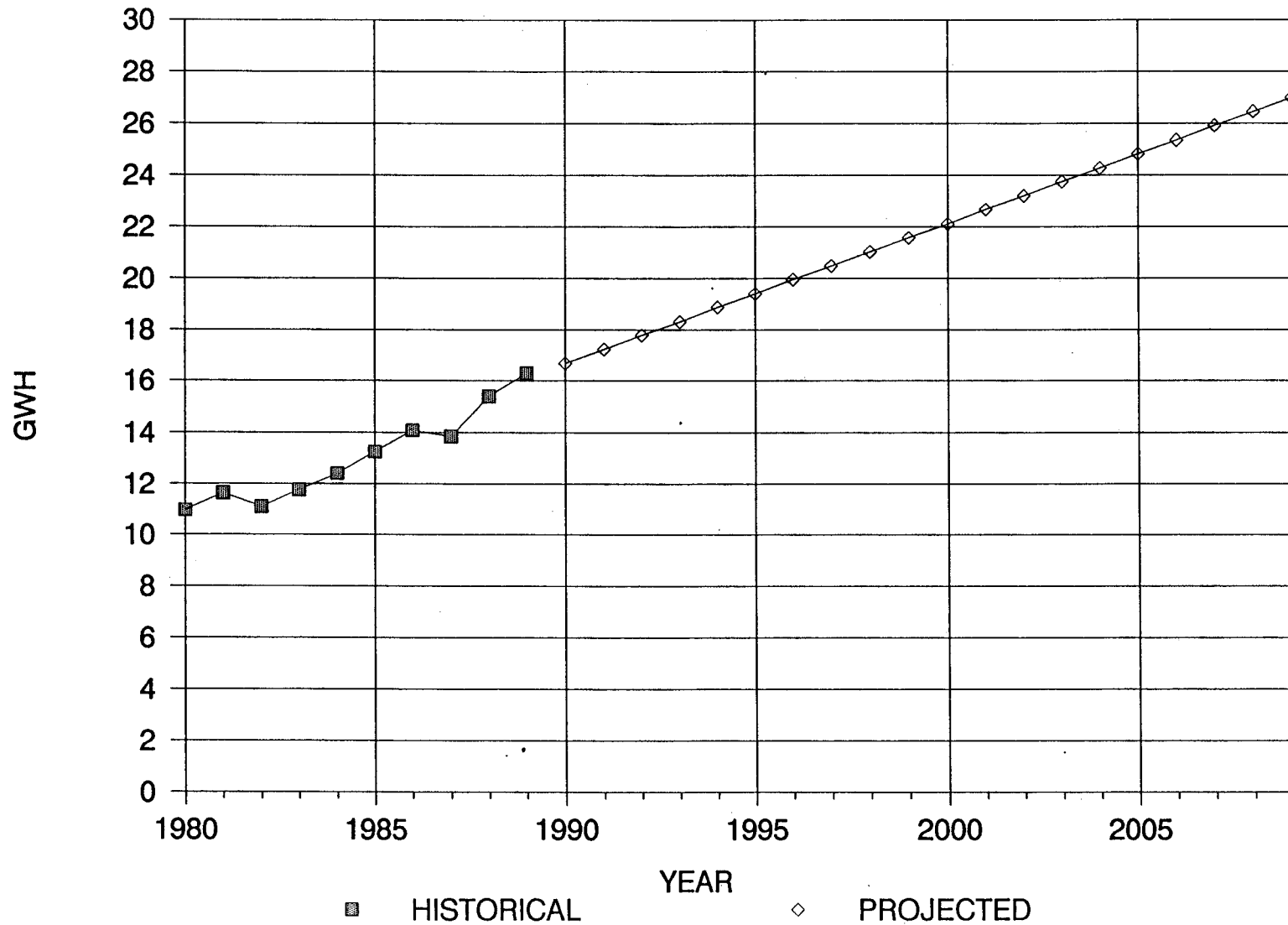
TABLE 1C.B.A-1
CITY OF BUSHNELL
HISTORICAL AND PROJECTED NEL AND PEAK DEMANDS

		CALENDAR YEAR NEL (GWH)	SUMMER NCP (MW)	WINTER NCP (MW)	SUMMER CP (MW)	WINTER CP (MW)
A C T U A L	1980	10.979	2.800	2.900	NA	NA
	1981	11.634	2.800	3.600	NA	NA
	1982	11.108	2.800	3.400	NA	NA
	1983	11.757	2.900	3.100	NA	NA
	1984	12.400	2.900	3.400	NA	NA
	1985	13.249	3.000	4.400	NA	NA
	1986	14.085	3.100	4.200	2.700	NA
	1987	13.847	3.300	3.600	3.000	3.500
	1988	15.402	3.500	4.300	3.500	3.700
	1989	16.320	3.800	4.500	3.300	4.000
1980 - 1989						
	% A A G R	4.5%	3.5%	5.0%	NA	NA
P R O J E C T E D	1990	16.700 [1]	3.700 [2]	4.300 [2]	3.500 [2]	4.200 [2]
	1991	17.242	3.900	4.700	3.600	4.400
	1992	17.784	4.000	4.800	3.700	4.500
	1993	18.326	4.200	5.000	3.900	4.600
	1994	18.868	4.300	5.100	4.000	4.700
	1995	19.410	4.400	5.300	4.000	4.900
	1996	19.951	4.500	5.400	4.100	5.000
	1997	20.493	4.700	5.600	4.300	5.200
	1998	21.035	4.800	5.700	4.400	5.300
	1999	21.577	4.900	5.900	4.500	5.500
1990 - 1999						
	% A A G R	2.9%	3.2%	3.6%	2.8%	3.0%
D I S T R I B U T E D	2000	22.119	5.000	6.000	4.600	5.600
	2001	22.661	5.100	6.200	4.700	5.800
	2002	23.203	5.300	6.300	4.900	5.900
	2003	23.745	5.400	6.500	5.000	6.000
	2004	24.287	5.500	6.600	5.100	6.100
	2005	24.829	5.600	6.800	5.100	6.300
	2006	25.371	5.800	6.900	5.300	6.400
	2007	25.913	5.900	7.000	5.400	6.500
	2008	26.454	6.000	7.200	5.500	6.700
	2009	26.996	6.100	7.300	5.600	6.800
2000 - 2009						
	% A A G R	2.2%	2.2%	2.2%	2.2%	2.2%
1990 - 2009						
	% A A G R	2.6%	2.7%	2.8%	2.5%	2.6%

NOTES [1]: INCLUDES ESTIMATED GWH FOR NOV90 - DEC90.
[2]: ACTUAL.

CITY OF BUSHNELL

HISTORICAL AND PROJECTED NEL

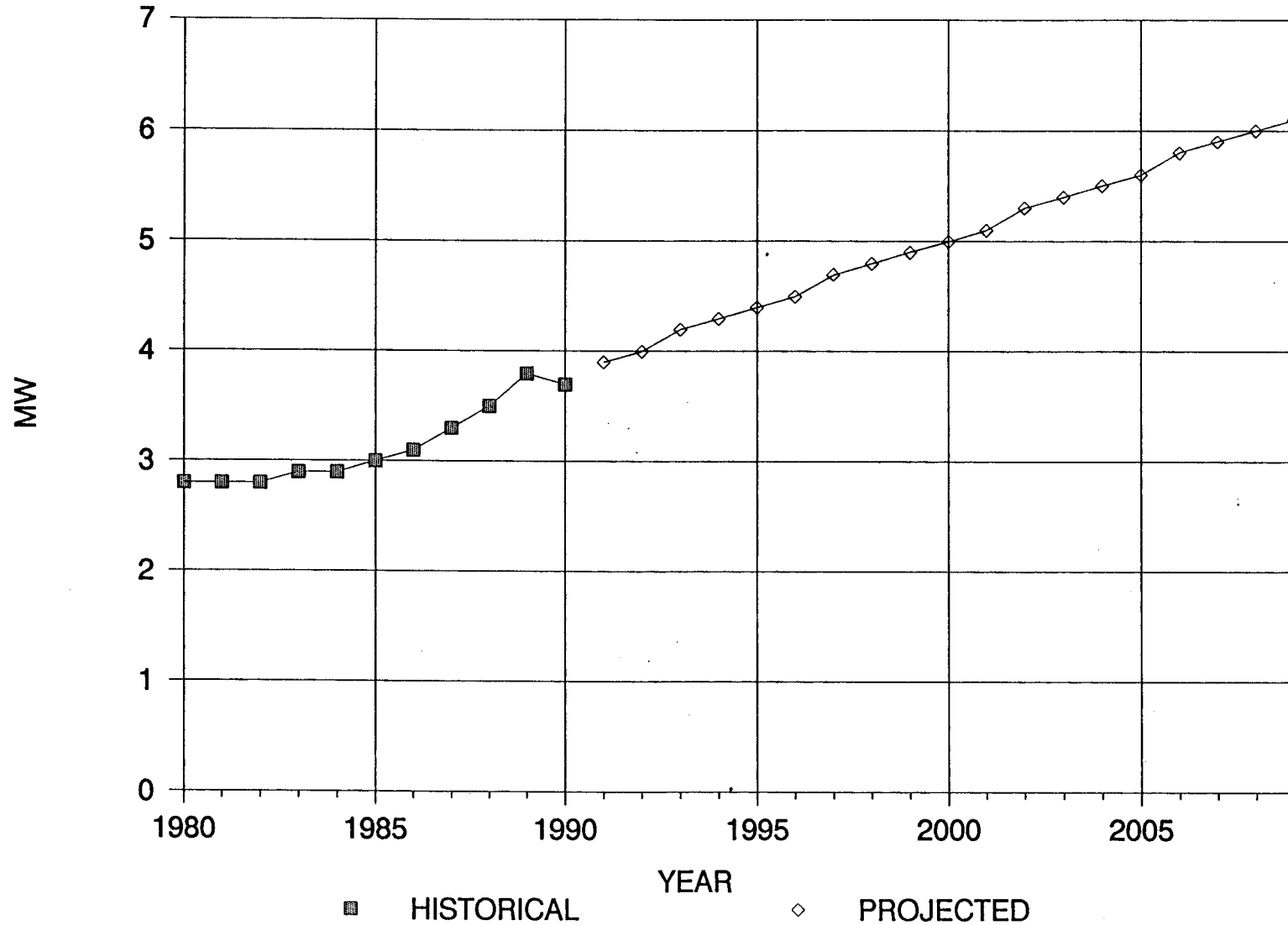


1C.B.2-6

EXHIBIT 1C.B.A-1

CITY OF BUSHNELL

HISTORICAL AND PROJECTED SUMMER NCP

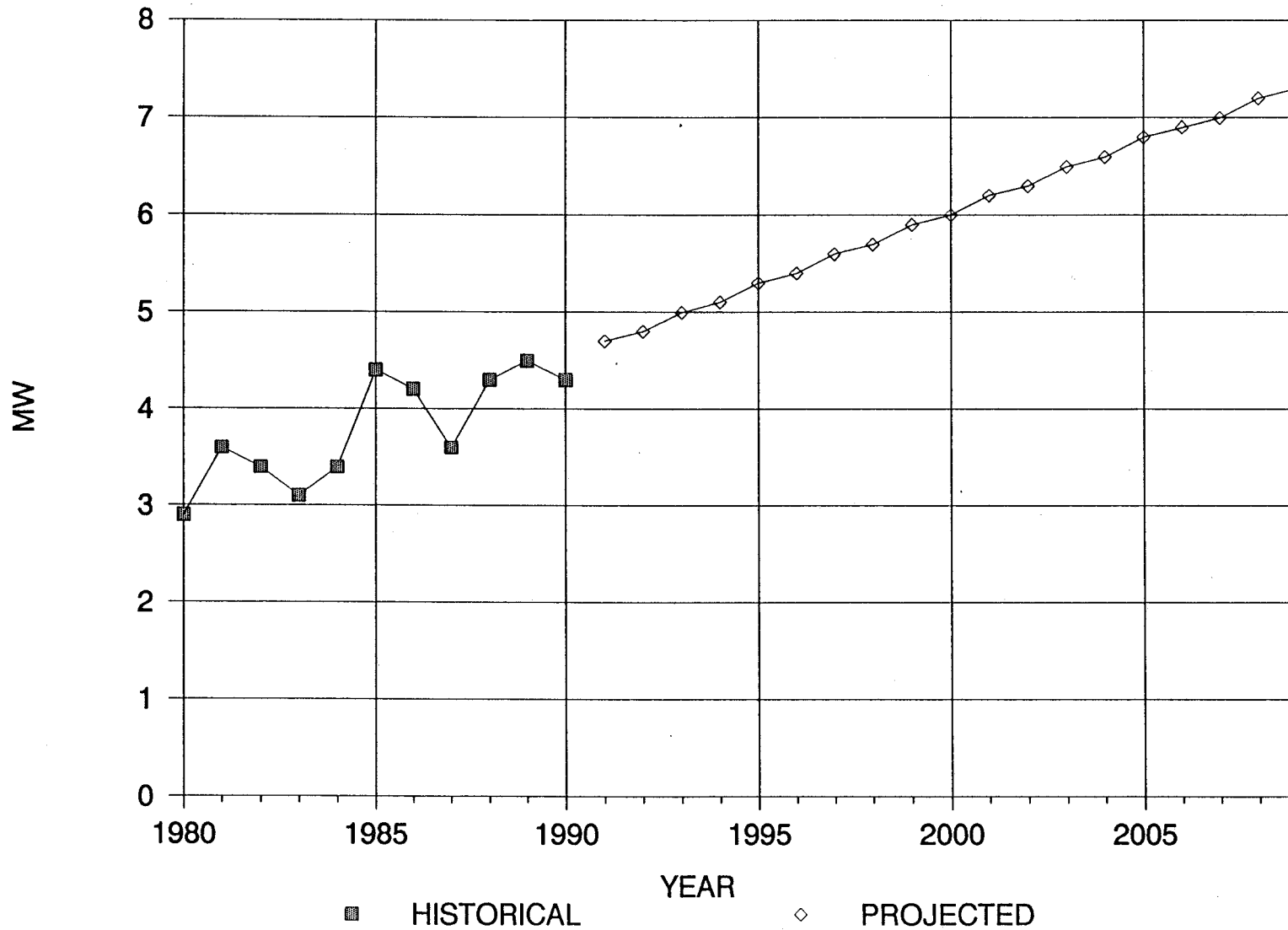


IC.B.2-7

EXHIBIT IC.B.A-2

CITY OF BUSHNELL

HISTORICAL AND PROJECTED WINTER NCP



1C.B.2-8

EXHIBIT 1C.B.A-3

CITY OF LEESBURG

APPENDIX 1C.B

SECTION 1C.B.2.2

CITY OF LEESBURG, FLORIDA

Following is a summary of our analyses and investigations pertaining to the design and development of estimates of future energy and demand requirements for the City of Leesburg, Florida.

The forecasting technique used to project future energy and demand requirements for the City of Leesburg is the annual aggregate method. Based on the results of this analysis, system net energy requirements are projected to increase at a compound annual growth rate of 2.9% between 1990 and 1999 and summer peak demand is expected to increase at an annual compound rate of 2.8% over the same period. This forecast is summarized below, presented in detail in Tables 1C.B.B-1 and 1C.B.B-2 and depicted graphically in Exhibits 1C.B.B-1, 1C.B.B-2 and 1C.B.B-3.

CITY OF LEESBURG, FLORIDA

Projected Demand and Energy Requirements

	1989 [1]	1994	1999
Net Energy Requirements - (MWh)	349,397	403,708	462,094
Summer Net Peak Demand - (MW)	76.7	88.8	101.7

Net Energy Requirements

Aggregate net energy for load is postulated to be a linear function. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project net energy requirements are reported in Equation [B-1].

$$E_t = E_{t-1} + 11.67707 + e_t \quad [B-1]$$

where E_t = net energy for load (Gwh) in calendar year t.

[1] Actual 1989.

The resulting index of determination is greater than .97.

Model inputs consist of annual net energy for load observations over the study period, i.e., 1976 through 1990 on a calendar year basis. This model is used to project energy requirements through the year 2009.

No unusual load additions have been projected for the City of Leesburg.

Peak Demand

The forecast of summer peak demand is based on the average system summer load factor for 1988 - 1990 and the forecast of winter peak demand is based on the average system winter load factor for 1987 - 1989. Peak demands are obtained by applying an average annual load factor to projected net energy requirements. This assumes that consumer behavior will resemble that encountered during the study period.

Conservation and Load Management

Projected values of net energy requirements and annual peak demand for the City of Leesburg do not include the effects of any additional conservation and/or load management not observed over the historical study period used to estimate the forecasting models. However, the effects of conservation and/or load management observed over the historical study period are implied in the quantification of the City's forecasting models by including recent historical data which include the effects of existing conservation and load management.

The City of Leesburg will be implementing a load management program for residential customers beginning in the first quarter of 1991. The projected reduction in net energy for load, summer peak demand, and winter peak demand is given in Table B-2.

TABLE 1C.B.B-1
CITY OF LEESBURG
HISTORICAL AND PROJECTED NEL AND PEAK DEMANDS

		CALENDAR YEAR NEL (GWH)	SUMMER NCP (MW)	WINTER NCP (MW)	SUMMER CP (MW)	WINTER CP (MW)
A C T U A L	1980	237.100	49.400	46.000	NA	NA
	1981	251.200	59.600	52.700	NA	NA
	1982	247.900	56.900	55.500	NA	NA
	1983	255.100	57.200	50.000	NA	NA
	1984	263.700	56.800	54.400	NA	NA
	1985	279.700	60.900	67.600	NA	NA
	1986	305.300	63.900	66.000	63.800	NA
	1987	316.400	71.000	60.200	70.100	60.200
	1988	325.400	70.900	66.000	70.300	66.000
	1989	349.397	76.700	72.400	74.400	72.400
1980 - 1989						
	% A A G R	4.4%	5.0%	5.2%	NA	NA
P R O J E C T E D	1990	357.000 [1]	79.200 [2]	87.000 [2]	79.000 [2]	85.700 [2]
	1991	368.677	81.100	73.700	80.200	73.600
	1992	380.354	83.700	76.100	82.800	76.000
	1993	392.031	86.200	78.400	85.300	78.300
	1994	403.708	88.800	80.700	87.800	80.600
	1995	415.385	91.400	83.100	90.400	83.000
	1996	427.062	94.000	85.400	93.000	85.300
	1997	438.740	96.500	87.700	95.500	87.600
	1998	450.417	99.100	90.100	98.000	90.000
	1999	462.094	101.700	92.400	100.600	92.300
1990 - 1999						
	% A A G R	2.9%	2.8%	0.7%	2.7%	0.8%
D I S T R I B U T E D	2000	473.771	104.200	94.800	103.100	94.700
	2001	485.448	106.800	97.100	105.600	97.000
	2002	497.125	109.400	99.400	108.200	99.300
	2003	508.802	111.900	101.800	110.700	101.700
	2004	520.479	114.500	104.100	113.300	104.000
	2005	532.156	117.100	106.400	115.800	106.300
	2006	543.833	119.600	108.800	118.300	108.700
	2007	555.510	122.200	111.100	120.900	111.000
	2008	567.187	124.800	113.400	123.500	113.300
	2009	578.865	127.400	115.800	126.000	115.700
2000 - 2009						
	% A A G R	2.3%	2.3%	2.2%	2.3%	2.3%
1990 - 2009						
	% A A G R	2.6%	2.5%	1.5%	2.5%	1.6%

NOTES [1]: INCLUDES ESTIMATED GWH FOR NOV90 - DEC90.

[2]: ACTUAL.

[3]: DOES NOT INCLUDE RESIDENTIAL LOAD MANAGEMENT.

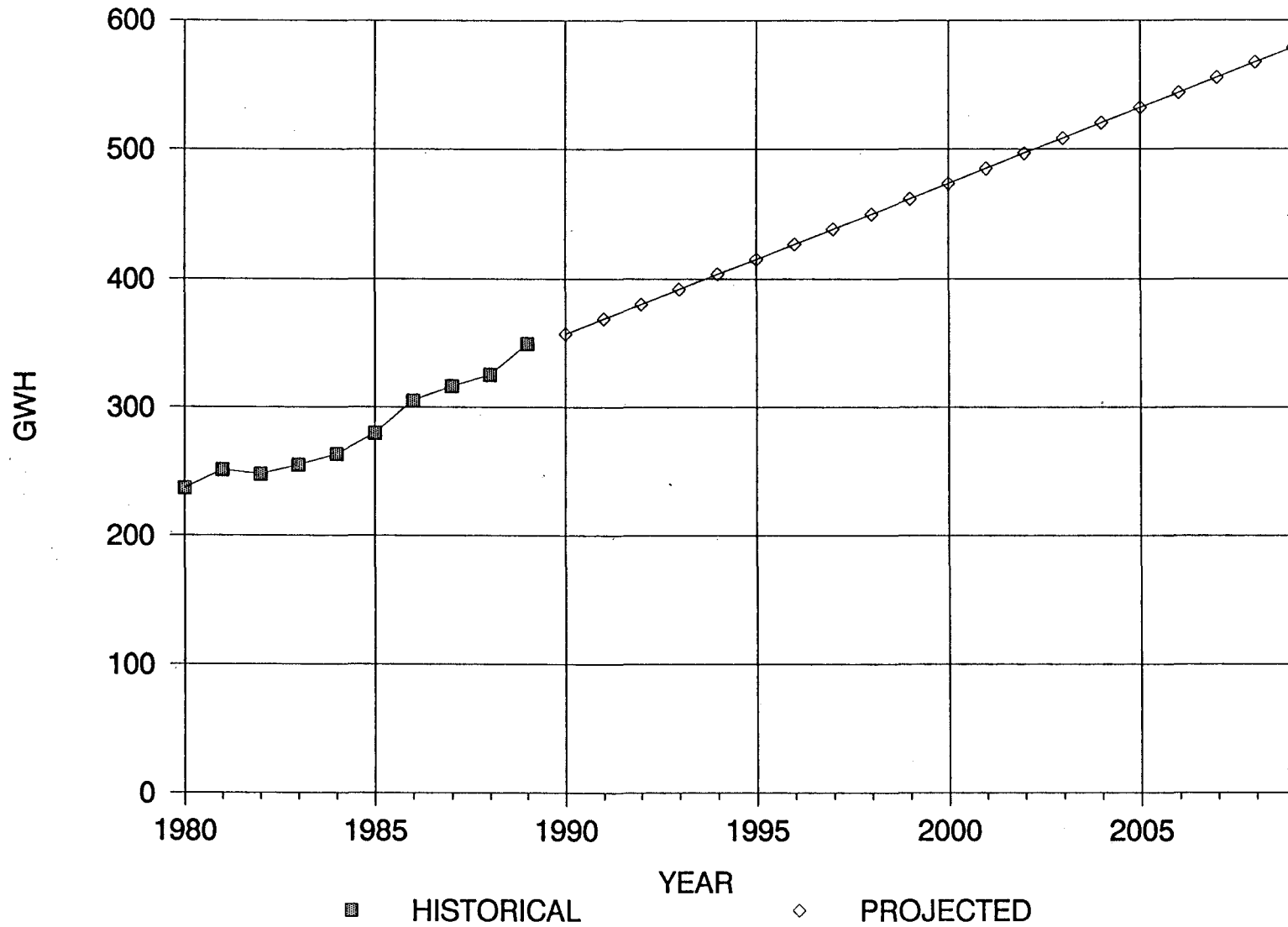
TABLE 1C.B.B-2
CITY OF LEESBURG
PROJECTED DEMAND AND ENERGY REDUCTIONS
FROM THE RESIDENTIAL LOAD MANAGEMENT PROGRAM

	Residential Customers	New Load Management Participants	Cumulative Load Management Participants	Summer NCP Reduction (Kw)	Winter NCP Reduction (Kw)	NEL Reduction (Kwh)
1991	13,930	250	250	163	0	30,750
1992	14,255	450	700	574	215	116,850
1993	14,580	450	1,150	1,078	404	227,550
1994	14,905	450	1,600	1,582	593	338,250
1995	15,230	450	2,050	2,086	782	448,950
1996	15,555	225	2,275	2,443	916	531,975
1997	15,880	113	2,388	2,622	983	573,549
1998	16,205	56	2,444	2,711	1,017	594,336
1999	16,530	56	2,500	2,774	1,040	608,112
2000	16,855	56	2,556	2,837	1,064	621,888
2001	17,180	56	2,612	2,899	1,087	635,664
2002	17,505	56	2,668	2,962	1,111	649,440
2003	17,830	56	2,724	3,025	1,134	663,216
2004	18,155	56	2,780	3,087	1,158	676,992
2005	18,480	56	2,836	3,150	1,181	690,768
2006	18,805	56	2,892	3,213	1,205	704,544
2007	19,130	56	2,948	3,276	1,228	718,320
2008	19,455	56	3,004	3,338	1,252	732,096
2009	19,780	56	3,060	3,401	1,275	745,872

1C.B.2-13

CITY OF LEESBURG

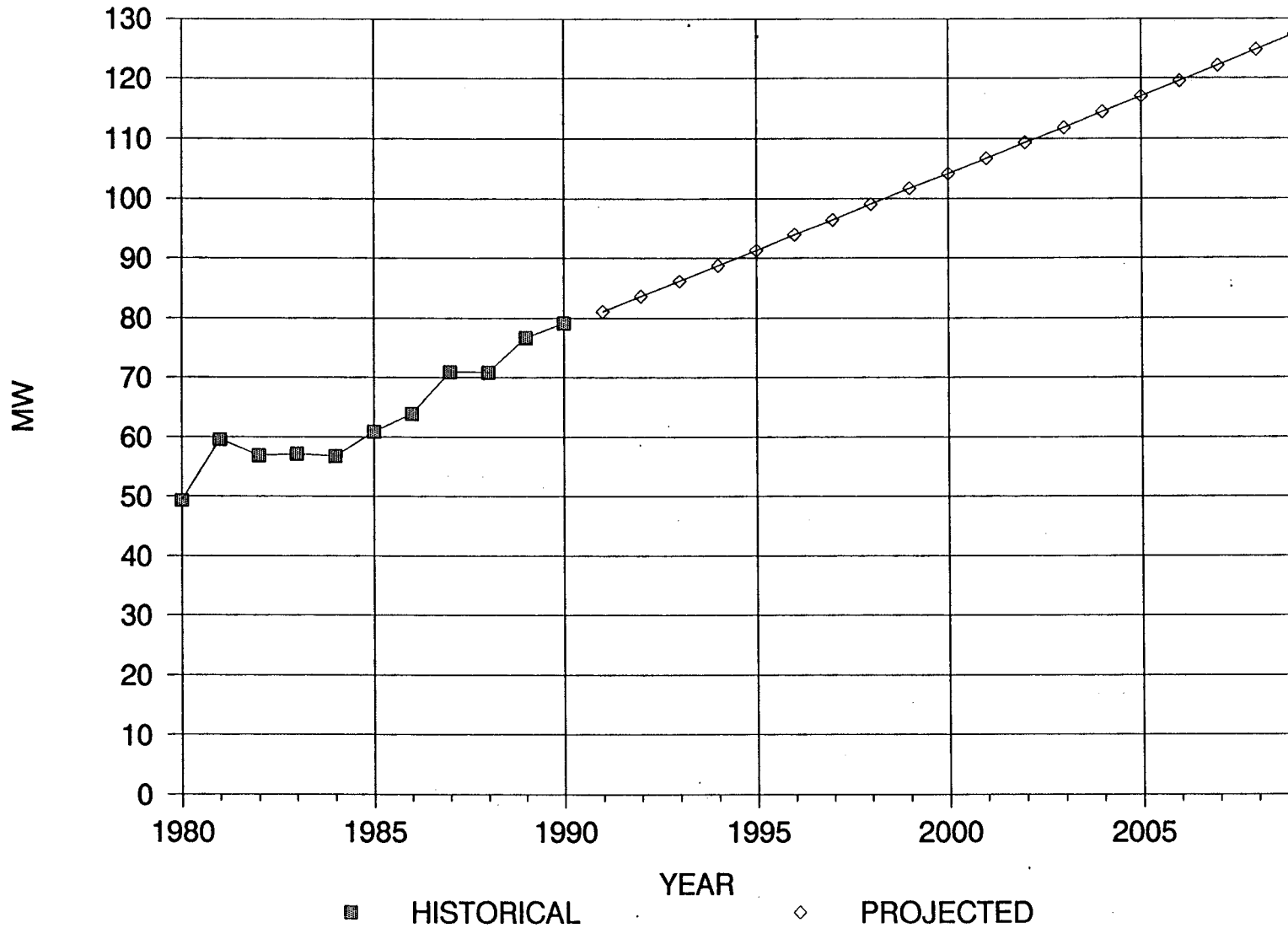
HISTORICAL AND PROJECTED NEL



1C.B.2-14

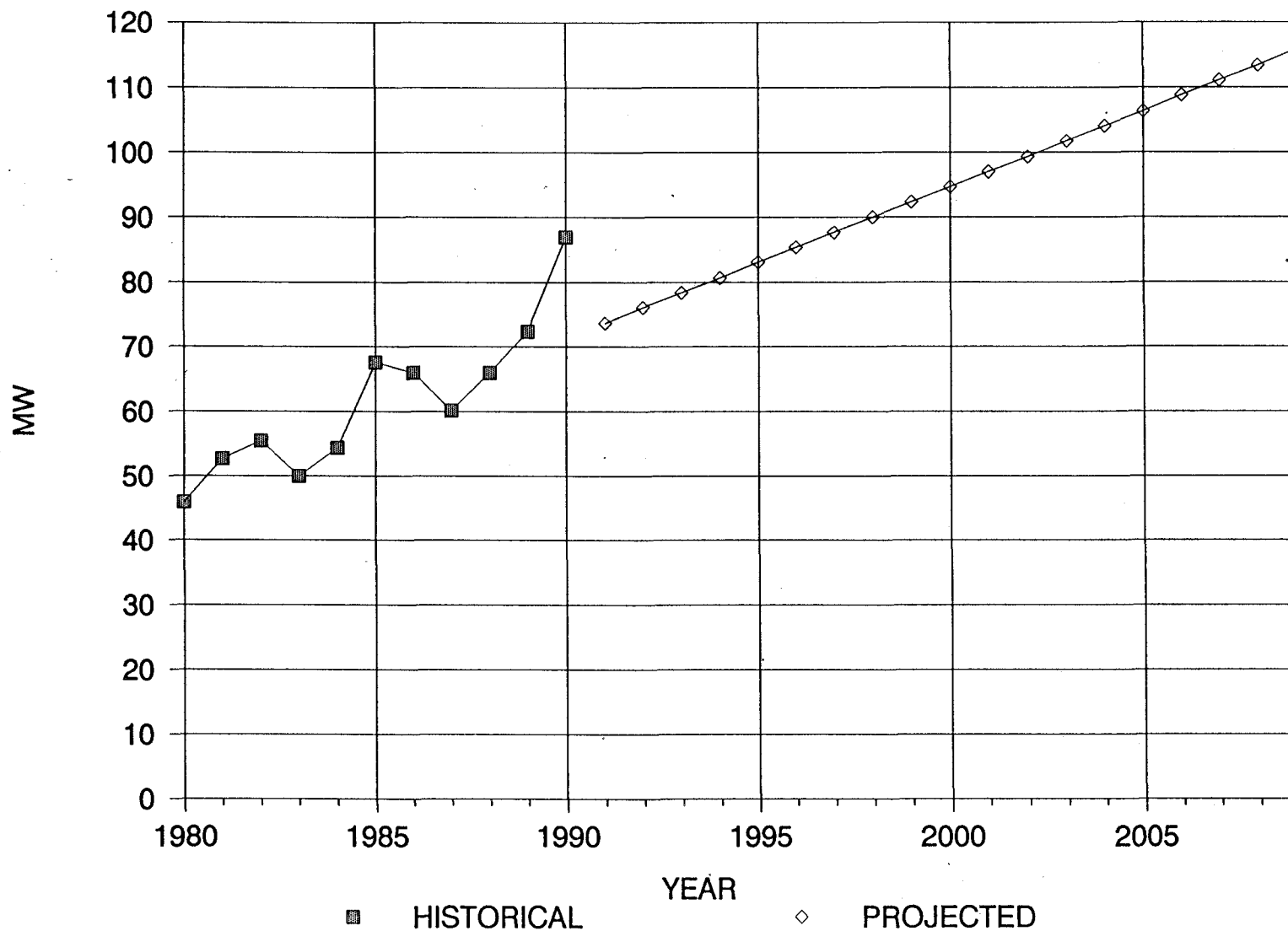
CITY OF LEESBURG

HISTORICAL AND PROJECTED SUMMER NCP



CITY OF LEESBURG

HISTORICAL AND PROJECTED WINTER NCP



CITY OF OCALA

APPENDIX 1C.B

SECTION 1C.B.2.3

CITY OF OCALA, FLORIDA

Following is a summary of our analyses and investigations pertaining to the design and development of estimates of future energy and demand requirements for the City of Ocala, Florida.

The forecasting technique used to project future demand and energy requirements for the City of Ocala is the by-class econometric method. This method separates the total energy requirements for the City of Ocala into various rate classifications and then forecasts each rate class individually. The forecasts of each of the individual rate classifications are then summed together to give the forecast of mwh sales. Losses are then added to the forecast of mwh sales which gives the forecast of net energy for load for the City of Ocala. High and low forecasts for the City of Ocala are also included. Based on the results of this analysis, system net energy requirements are projected to increase at a compound annual growth rate of 3.7% between 1990 and 1999 and summer peak demand is expected to increase at an annual compound rate of 3.5% over the same period. This forecast is summarized below, presented in detail in Tables 1C.B.C-1, 1C.B.C-2, 1C.B.C-3, 1C.B.C-4, and depicted graphically in Exhibits 1C.B.C-1, 1C.B.C-2, and 1C.B.C-3.

CITY OF OCALA, FLORIDA

Projected Demand and Energy Requirements

	1989 [1]	1994	1999
Net Energy Requirements - (MWh)	905,928	1,097,620	1,277,667
Summer Net Peak Demand - (MW)	196.9	241.5	281.1

[1] Actual 1989.

Residential Sales - Quarterly Aggregate

The forecasting technique used to project residential sales for the City of Ocala is the quarterly aggregate method. Residential sales are postulated to be a function of State of Florida employment in services, weather conditions, and seasonality. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project residential sales are reported in Equation [R-1].

$$R_t = -483.9 + 25.3 WH_t + 10.2 WC_t + 52.5 F_t + 22401.6 M_t + e_t \quad [R-1]$$

$$T\text{-ratios} > > > (4.2) \quad (3.0) \quad (13.4) \quad (6.9)$$

where R_t = residential mwh sales in quarter t,

WH_t = a weather factor measured as heating degree days in quarter t,

WC_t = a weather factor measured as cooling degree days in quarter t,

F_t = State of Florida employment in services in quarter t,

M_t = a migration factor in quarter t, and

e_t = a random error term in quarter t.

The resulting index of determination (R^2) is greater than .93. All variables in the model are significant at or above the .01 level as measured by the t-ratio and possess the expected sign. The Durbin Watson statistic is 2.0.

The model was developed using quarterly observations from the first quarter of 1982 through the third quarter of 1990. This model is used to project residential sales through the year 2020. No unusual load additions have been projected for the City of Ocala.

The results of this model were reviewed and the forecast was deemed to be too aggressive. This can be explained due to the fact that the City of Ocala experienced tremendous growth in residential sales from 1982 through 1986. The average annual growth rate of this period was 7.6%. This contrasts with the 3.8% average annual growth rate of the period of 1986 through 1990.

The table below shows residential sales for the City of Ocala for 1982 through 1990.

<u>Calendar</u> <u>Years:</u>	<u>Residential Kwh Sales</u>	<u>% Growth</u>
1982	235,318,695	
1983	256,049,374	8.1%
1984	270,414,460	5.6%
1985	293,354,999	8.5%
1986	315,532,918	7.6%
1987	328,283,187	4.1%
1988	340,389,577	3.7%
1989	351,505,251	3.3%
1990 [1]	366,000,000	4.1%

Note [1]: 1990 residential kwh sales includes an estimate for October 1990 through December 1990.

Using the model as stated in equation R-1, the forecasted residential kwh sales for calendar year 1991 would be 390,943,000 or an increase of 6.8% over calendar year 1990. Another factor which led FMPA to adjust the forecast downward was the realization that the State of Florida employment in services forecast used from the BEBR did not indicate that the United States was in a recession. Couple this with the possibility of war in the Persian Gulf and it is easy to see that the forecast of residential kwh sales from equation R-1 is almost certainly too high. Therefore, a decision was made to use a 3.5% growth for 1991 or an increase of 12,810,000 kwh of residential sales over 1990 and to increase residential kwh sales by this same amount (12,810,000 kwh) for 1992 through 1996. The forecast for years 1997 through 2020 are given by equation R-1.

High and low forecasts for residential sales were developed by using high and low population projections for Marion county as found in the 1989 Florida Statistical Abstract. These projections were used to determine the projected number of residential customers for Ocala. The projected number of residential customers in both the high and low forecast were then multiplied by the average kwh usage per residential customer as forecast in the base case. The results of this yielded the high and low forecast of residential sales.

Commercial Sales - Quarterly Aggregate

The forecasting technique used to project commercial sales for the City of Ocala is the quarterly aggregate method. Commercial sales are postulated to be a function of residential customers and migration. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project commercial sales are reported in Equation [C-1].

$$C_t = -30753.2 + 1.8 RC_{t-1} + 5085.1 M_t + e_t \text{ [C-1]}$$

T-ratios > > > (21.5) (10.6)

where C_t = commercial mwh sales in quarter t,

RC_{t-1} = average number of residential customers in quarter t-1,

M_t = a migration factor in quarter t, and

e_t = a random error term in quarter t.

The resulting index of determination (R^2) is greater than .94. All variables in the model are significant at or above the .001 level as measured by the t-ratio and possess the expected sign. The Durbin Watson statistic is 2.1.

The model was developed using quarterly observations from the first quarter of 1982 through the third quarter of 1990. This model is used to project commercial sales through the year 2020. No unusual load additions have been projected for the City of Ocala.

The results of this model were reviewed and the forecast was deemed to be too aggressive. This can be explained due to the fact that the City of Ocala experienced tremendous growth in commercial sales from 1982 through 1987. The average annual growth rate of this period was 12.4%. This contrasts with the 5.0% average annual growth rate of the period of 1987 through

1990. The table below shows commercial sales for the City of Ocala for 1982 through 1990.

<u>Calendar Years:</u>	<u>Commercial Kwh Sales</u>	<u>% Growth</u>
1982	48,422,136	
1983	53,204,902	9.9%
1984	59,650,419	12.1%
1985	67,233,413	12.7%
1986	73,194,469	8.9%
1987	86,738,486	18.5%
1988	90,588,889	4.4%
1989	96,822,160	6.9%
1990 [1]	100,484,114	3.8%

Note [1]: 1990 commercial kwh sales includes an estimate for October 1990 through December 1990.

Using the model as stated in equation C-1, the forecasted commercial kwh sales for calendar year 1991 would be 107,177,000 or an increase of 6.7% over calendar year 1990. Another factor which led FMPA to adjust the forecast downward was the realization that the United States was in a recession. Couple this with the possibility of war in the Persian Gulf and it is easy to see that the forecast of commercial kwh sales from equation C-1 is almost certainly too high. Therefore, a decision was made to use a 3.5% growth for 1991 or an increase of 3,517,000 kwh of commercial sales over 1990 and to increase commercial kwh sales by this same amount (3,517,000 kwh) for 1992 through 2020.

High and low forecasts for commercial sales were developed by using high and low population projections for Marion county as found in the 1989 Florida Statistical Abstract. These projections were used to determine the projected number of commercial customers for Ocala. The projected number of commercial customers in both the high and low forecast were then multiplied by the average kwh usage per commercial customer as forecast in the base case. The results of this yielded the high and low forecast of commercial sales.

Industrial Sales - Annual Aggregate

The forecasting technique used to project industrial sales for the City of Ocala is the annual aggregate method. Industrial sales are postulated to be a linear function. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project industrial sales are reported in Equation [I-1].

$$I_t = I_{t-1} + 19,739.3 + e_t \quad \text{for } t = 1991, 1992, \dots, 2020 \quad [I-1]$$

where I_t = industrial sales (Mwh) in calendar year t.

The resulting index of determination (R^2) is greater than .98.

Model inputs consist of annual industrial kwh sales for 1982 through 1990. This model is used to project industrial sales through the year 2020. The table below shows industrial sales for the City of Ocala for 1982 through 1990.

<u>Calendar Years:</u>	<u>Industrial Kwh Sales</u>	<u>% Growth</u>
1982	230,392,988	
1983	235,263,274	2.1%
1984	257,732,641	9.6%
1985	286,625,352	11.2%
1986	307,946,114	7.4%
1987	320,214,095	4.0%
1988	334,514,073	4.5%
1989	364,319,114	8.9%
1990 [1]	382,902,832	5.1%

Note [1]: 1990 industrial kwh sales includes an estimate for October 1990 through December 1990.

High and low forecasts for industrial sales were developed based on the high and low forecasts for commercial sales. Industrial sales are assumed to grow at a similar compound rate of growth as do commercial sales.

City Department Sales - Annual Aggregate

The forecasting technique used to project city department sales for the City of Ocala is the annual aggregate method. City department sales are postulated to be a linear function. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project city department sales are reported in Equation [CD-1].

$$CD_t = CD_{t-1} + 747.788 + e_t \quad \text{for } t = 1991, 1992, \dots, 2020 \quad [CD-1]$$

where CD_t = industrial sales (Mwh) in calendar year t .

The resulting index of determination (R^2) is greater than .94.

Model inputs consist of annual city department kwh sales for 1982 through 1989. This model is used to project city department sales through the year 2020. The table below shows city department sales for the City of Ocala for 1982 through 1990.

<u>Calendar Years:</u>	<u>City Department Kwh Sales</u>	<u>% Growth</u>
1982	9,708,231	
1983	11,199,396	15.4%
1984	11,220,722	0.2%
1985	11,272,544	0.5%
1986	12,627,821	12.0%
1987	13,378,665	5.9%
1988	14,877,175	11.2%
1989	14,936,264	0.4%
1990 [1]	15,684,052	5.0%

Note [1]: 1990 city department kwh sales includes an estimate for October 1990 through December 1990.

Yard Lighting Sales

Yard lighting kwh sales were assumed to grow at a 1.0% compound rate of growth over the period 1991 through 2020. The average annual growth rate of yard lighting sales from 1982 through 1990 was 1.5%. The forecast considers that more energy efficient yard lighting systems will be utilized

during 1991 through 2020. The table below shows yard lighting sales for the City of Ocala for 1982 through 1990.

<u>Calendar Years:</u>	<u>Yard Lighting Kwh Sales</u>	<u>% Growth</u>
1982	3,941,426	
1983	4,051,966	2.8%
1984	3,852,860	(4.9)%
1985	4,079,394	5.9%
1986	4,226,676	3.6%
1987	4,033,584	(4.6)%
1988	3,890,930	(3.5)%
1989	4,219,327	8.4%
1990 [1]	4,444,559	5.3%

Note [1]: 1990 yard lighting kwh sales includes an estimate for October 1990 through December 1990.

Street Lighting Sales

Street lighting kwh sales were assumed to grow at a 1.0% compound rate of growth over the period 1991 through 2020. The average annual growth rate of street lighting sales from 1982 through 1990 was 0.2%. This low growth in street lighting sales is due to the replacement of energy inefficient street

lights with more energy efficient street lights. The table below shows street lighting sales for the City of Ocala for 1982 through 1990.

<u>Calendar Years:</u>	<u>Street Lighting Kwh Sales</u>	<u>% Growth</u>
1982	3,607,993	
1983	3,251,207	(9.9)%
1984	3,236,269	(0.5)%
1985	3,295,736	1.8%
1986	3,286,073	(0.3)%
1987	3,366,466	2.4%
1988	3,552,348	5.5%
1989	3,613,704	1.7%
1990 [1]	3,675,785	1.7%

Note [1]: 1990 street lighting kwh sales includes an estimate for October 1990 through December 1990.

Constant Load Sales - Annual Aggregate

The forecasting technique used to project constant load sales for the City of Ocala is the annual aggregate method. Constant load sales are postulated to be a linear function. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project constant load sales are reported in Equation [CL-1].

$$CL_t = CL_{t-1} + 44.506 + e_t \quad \text{for } t = 1991, 1992, \dots, 2020 \text{ [CL-1]}$$

where C_t = constant load sales (Mwh) in calendar year t.

The resulting index of determination (R^2) is greater than .95.

Model inputs consist of annual constant load kwh sales for 1982 through 1989. This model is used to project constant load sales through the year

2020. The table below shows constant load sales for the City of Ocala for 1982 through 1990.

<u>Calendar Years:</u>	<u>Constant Load Kwh Sales</u>	<u>% Growth</u>
1982	749,858	
1983	794,430	5.9%
1984	843,983	6.2%
1985	878,832	4.1%
1986	905,280	3.0%
1987	914,298	1.0%
1988	1,028,213	12.5%
1989	1,083,036	5.3%
1990 [1]	1,127,542	4.1%

Note [1]: 1990 constant load kwh sales includes an estimate for October 1990 through December 1990.

Residential Customers - Annual Aggregate

The forecasting technique used to project residential customers for the City of Ocala is the annual aggregate discounted least squares method. Residential customers are postulated to be a function of the number of permanent resident households of the Ocala Metropolitan Statistical Area (MSA). The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project residential sales are reported in Equation [RC-1].

$$RC_t = 10045.83 + 0.27 HH_t + e_t \quad [RC-1]$$

T-ratios > > > (25.1)

where RC_t = average number of residential customers in calendar year t,

HH_t = number of permanent resident households on July 1 of calendar year t, and

e_t = a random error term in calendar year t.

The resulting index of determination (R^2) is greater than .99. All variables in the model are significant at or above the .01 level as measured by the t-ratio and posses the expected sign. The discount factor is 0.70.

The model was developed using annual observations from 1982 through 1990. This model is used to project residential customers through the year 2020. The table below shows residential customers for the City of Ocala for 1982 through 1990.

<u>Calendar Years:</u>	<u>Residential Customers</u>	<u>% Growth</u>
1982	23,137	
1983	24,193	4.6%
1984	25,283	4.5%
1985	26,423	4.5%
1986	27,538	4.2%
1987	28,465	3.4%
1988	29,287	2.9%
1989	30,205	3.1%
1990 [1]	30,800	2.0%

Note [1]: 1990 residential customers includes an estimate for October 1990 through December 1990.

High and low forecasts of population of Marion county are used to give high and low forecasts of the number of permanent resident households as of July 1 for each year in the forecast period. These high and low forecasts of permanent resident households are the used in Equation [RC-1] to give high and low forecasts of residential customers.

Commercial Customers - Annual Aggregate

The forecasting technique used to project commercial customers for the City of Ocala is the annual aggregate discounted least squares method. Commercial customers are postulated to be a function of the number of residential customers. The mathematical form, estimated coefficients, and revelant statistical properties of the estimating equation used to project

residential sales are reported in Equation [CC-1].

$$CC_t = 10045.83 + 0.27 RC_t + e_t \quad [CC-1]$$

T-ratios > > > (28.2)

where CC_t = average number of commercial customers in calendar year t ,

RC_t = average number of residential customers in calendar year t ,

e_t = a random error term in calendar year t .

The resulting index of determination (R^2) is greater than .99. All variables in the model are significant at or above the .01 level as measured by the t -ratio and posses the expected sign. The discount factor is 0.70.

The model was developed using annual observations from 1982 through 1990. This model is used to project commercial customers through the year 2020. The table below shows commercial customers for the City of Ocala for 1982 through 1990.

<u>Calendar Years:</u>	<u>Commercial Customers</u>	<u>% Growth</u>
1982	3,423	
1983	3,710	8.4%
1984	4,066	9.6%
1985	4,298	5.7%
1986	4,476	4.1%
1987	4,741	5.9%
1988	4,925	3.9%
1989	5,072	3.0%
1990 [1]	5,174	2.0%

Note [1]: 1990 commercial customers includes an estimate for October 1990 through December 1990.

High and low forecasts of commercial customers are given by using the high and low forecasts of residential customers in Equation [CC-1].

Industrial Customers

The industrial customers rate class of the City of Ocala has undergone several changes during 1982 through 1990 that changed certain customers rate classification from an industrial classification to a commercial classification. These changes in customer rate classification as reflected in the table below made developing a model to project the number of industrial customers impossible since in 1987 the number of industrial customers decreased markedly.

<u>Calendar Years:</u>	<u>Industrial Customers</u>	<u>% Growth</u>
1982	688	
1983	705	2.5%
1984	749	6.2%
1985	803	7.2%
1986	817	1.7%
1987 [1]	682	(16.5%)
1988	705	3.4%
1989	723	2.6%
1990 [2]	764	5.7%

Notes [1]: Decrease in industrial customers is due to a transfer of customers into the commercial rate classification

[2]: 1990 industrial customers includes an estimate for October 1990 through December 1990.

Therefore, a decision was made to have industrial customers increase by 39 customers per year for 1991 through 2020.

The high and low forecasts of industrial customers assumes that the number of industrial customers will increase at the same compound rate of growth as does commercial sales.

Peak Demand

The forecast of summer peak demand is based on the average system summer load factor for 1988 - 1990 and the forecast of winter peak demand is based on the average system winter load factor for 1987 and 1989. Peak demands are obtained by applying an average annual load factor to projected

net energy requirements. This assumes that consumer behavior will resemble that encountered during the study period.

Conservation and Load Management

Projected values of net energy requirements and annual peak demand for the City of Ocala do not include the effects of any additional conservation and/or load management not observed over the historical study period used to estimate the forecasting models. However, the effects of conservation and/or load management observed over the historical study period are implied in the quantification of the City's forecasting models by including recent historical data which include the effects of existing conservation and load management.

The City of Ocala will be implementing a load management program for residential customers beginning in the first quarter of 1991. The projected reduction in net energy for load, summer peak demand, and winter peak demand is given in Table C-4.

The City of Ocala will also be implementing a load management program for city accounts in early 1993. Early indications are that the City can reduce its summer peak demand and winter peak demand by 3 MW. The assumed reduction in both summer and winter peak demand is 3 MW for 1993 - 2009. Net energy for load is assumed to be reduced by more than 1.7 Gwh in 2009.

TABLE 1C.B.C-1
CITY OF OCALA - BASE CASE
HISTORICAL AND PROJECTED NEL AND PEAK DEMANDS

		CALENDAR YEAR NEL (GWH)	SUMMER NCP (MW)	WINTER NCP (MW)	SUMMER CP (MW)	WINTER CP (MW)
A C T U A L	1980	517.700	120.200	104.900	NA	NA
	1981	558.200	130.300	120.100	NA	NA
	1982	555.600	136.300	126.100	NA	NA
	1983	586.500	140.000	118.200	NA	NA
	1984	645.000	141.500	129.900	NA	NA
	1985	707.900	158.000	168.400	NA	NA
	1986	774.800	168.000	166.300	168.000	NA
	1987	804.800	184.900	155.100	182.800	155.100
	1988	846.500	185.800	178.500	185.800	178.500
	1989	905.928	196.900	179.700	196.900	179.700
1980 - 1989						
	% A A G R	6.4%	5.6%	6.2%	NA	NA
P R O J E C T E D	1990	925.000 [1]	205.400 [2]	199.400 [2]	205.400 [2]	199.400 [2]
	1991	968.155	213.000	189.800	213.000	189.800
	1992	1011.310	222.500	198.200	222.500	198.200
	1993	1054.465	232.000	206.700	232.000	206.700
	1994	1097.620	241.500	215.100	241.500	215.100
	1995	1140.774	251.000	223.600	250.900	223.600
	1996	1174.998	258.500	230.300	258.400	230.300
	1997	1209.221	266.000	237.000	265.900	237.000
	1998	1243.444	273.600	243.700	273.500	243.700
	1999	1277.667	281.100	250.400	281.000	250.400
1990 - 1999						
	% A A G R	3.7%	3.5%	2.6%	3.5%	2.6%
D E S I G N E D	2000	1311.891	288.600	257.100	288.500	257.100
	2001	1346.114	296.100	263.800	296.000	263.800
	2002	1380.337	303.700	270.500	303.600	270.500
	2003	1414.560	311.200	277.300	311.100	277.300
	2004	1448.784	318.700	284.000	318.600	284.000
	2005	1483.007	326.300	290.700	326.200	290.700
	2006	1517.230	333.800	297.400	333.700	297.400
	2007	1551.453	341.300	304.100	341.200	304.100
	2008	1585.677	348.800	310.800	348.700	310.800
	2009	1619.900	356.400	317.500	356.300	317.500
2000 - 2009						
	% A A G R	2.4%	2.4%	2.4%	2.4%	2.4%
1990 - 2009						
	% A A G R	3.0%	2.9%	2.5%	2.9%	2.5%

NOTES [1]: INCLUDES ESTIMATED GWH FOR NOV90 - DEC90.

[2]: ACTUAL.

[3]: DOES NOT INCLUDE RESIDENTIAL OR CITY ACCOUNT'S
LOAD MANAGEMENT PROGRAMS.

TABLE 1C.B.C-2
CITY OF OCALA - LOW CASE
HISTORICAL AND PROJECTED NEL AND PEAK DEMANDS

		CALENDAR YEAR NEL (GWH)	SUMMER NCP (MW)	WINTER NCP (MW)	SUMMER CP (MW)	WINTER CP (MW)
A C T U A L	1980	517.700	120.200	104.900	NA	NA
	1981	558.200	130.300	120.100	NA	NA
	1982	555.600	136.300	126.100	NA	NA
	1983	586.500	140.000	118.200	NA	NA
	1984	645.000	141.500	129.900	NA	NA
	1985	707.900	158.000	168.400	NA	NA
	1986	774.800	168.000	166.300	168.000	NA
	1987	804.800	184.900	155.100	182.800	155.100
	1988	846.500	185.800	178.500	185.800	178.500
	1989	905.928	196.900	179.700	196.900	179.700
1980 - 1989						
	% A A G R	6.4%	5.6%	6.2%	NA	NA
P R O J E C T E D	1990	925.000 [1]	205.400 [2]	199.400 [2]	205.400 [2]	199.400 [2]
	1991	951.378	206.400	183.600	206.400	183.600
	1992	977.841	212.200	188.700	212.200	188.700
	1993	1003.198	217.700	193.600	217.700	193.600
	1994	1029.607	223.400	198.700	223.400	198.700
	1995	1058.005	229.600	204.200	229.600	204.200
	1996	1063.640	230.800	205.300	230.800	205.300
	1997	1070.517	232.300	206.600	232.300	206.600
	1998	1079.935	234.300	208.400	234.300	208.400
	1999	1088.227	236.100	210.000	236.100	210.000
1990 - 1999						
	% A A G R	1.8%	1.6%	0.6%	1.6%	0.6%
D E M A N D	2000	1096.249	237.900	211.600	237.900	211.600
	2001	1100.865	238.900	212.500	296.000	263.800
	2002	1105.418	239.900	213.300	303.600	270.500
	2003	1109.912	240.900	214.200	311.100	277.300
	2004	1114.349	241.800	215.100	318.600	284.000
	2005	1118.732	242.800	215.900	326.200	290.700
	2006	1120.450	243.100	216.200	333.700	297.400
	2007	1122.109	243.500	216.600	341.200	304.100
	2008	1123.712	243.800	216.900	348.700	310.800
	2009	1125.262	244.200	217.200	356.300	317.500
2000 - 2009						
	% A A G R	0.3%	0.3%	0.3%	4.6%	4.6%
1990 - 2009						
	% A A G R	1.0%	0.9%	0.5%	2.9%	2.5%

NOTES [1]: INCLUDES ESTIMATED GWH FOR NOV90 - DEC90.

[2]: ACTUAL.

[3]: DOES NOT INCLUDE RESIDENTIAL OR CITY ACCOUNT'S
LOAD MANAGEMENT PROGRAMS.

TABLE 1C.B.C-3
CITY OF OCALA - HIGH CASE
HISTORICAL AND PROJECTED NEL AND PEAK DEMANDS

		CALENDAR YEAR NEL (GWH)	SUMMER NCP (MW)	WINTER NCP (MW)	SUMMER CP (MW)	WINTER CP (MW)
A C T U A L	1980	517.700	120.200	104.900	NA	NA
	1981	558.200	130.300	120.100	NA	NA
	1982	555.600	136.300	126.100	NA	NA
	1983	586.500	140.000	118.200	NA	NA
	1984	645.000	141.500	129.900	NA	NA
	1985	707.900	158.000	168.400	NA	NA
	1986	774.800	168.000	166.300	168.000	NA
	1987	804.800	184.900	155.100	182.800	155.100
	1988	846.500	185.800	178.500	185.800	178.500
	1989	905.928	196.900	179.700	196.900	179.700
1980 - 1989						
	% A A G R	6.4%	5.6%	6.2%	NA	NA
P R O J E C T E D	1990	925.000 [1]	205.400 [2]	199.400 [2]	205.400 [2]	199.400 [2]
	1991	969.477	213.300	190.000	213.300	190.000
	1992	1013.711	223.000	198.700	223.000	198.700
	1993	1057.840	232.700	207.300	232.700	207.300
	1994	1103.007	242.700	216.200	242.700	216.200
	1995	1149.753	252.900	225.400	252.900	225.400
	1996	1187.218	261.200	232.700	261.200	232.700
	1997	1225.974	269.700	240.300	269.700	240.300
	1998	1266.923	278.700	248.300	278.700	248.300
	1999	1307.928	287.700	256.400	287.700	256.400
1990 - 1999						
	% A A G R	3.9%	3.8%	2.8%	3.8%	2.8%
D I S T R I B U T E D	2000	1349.508	296.900	264.500	296.900	264.500
	2001	1389.660	305.700	272.400	296.000	263.800
	2002	1430.417	314.700	280.400	303.600	270.500
	2003	1471.801	323.800	288.500	311.100	277.300
	2004	1513.832	333.000	296.700	318.600	284.000
	2005	1556.534	342.400	305.100	326.200	290.700
	2006	1599.283	351.800	313.500	333.700	297.400
	2007	1642.707	361.400	322.000	341.200	304.100
	2008	1686.826	371.100	330.600	348.700	310.800
	2009	1731.665	381.000	339.400	356.300	317.500
2000 - 2009						
	% A A G R	2.8%	2.8%	2.8%	2.0%	2.1%
1990 - 2009						
	% A A G R	3.4%	3.3%	2.8%	2.9%	2.5%

NOTES [1]: INCLUDES ESTIMATED GWH FOR NOV90 - DEC90.

[2]: ACTUAL.

[3]: DOES NOT INCLUDE RESIDENTIAL OR CITY ACCOUNT'S
LOAD MANAGEMENT PROGRAMS.

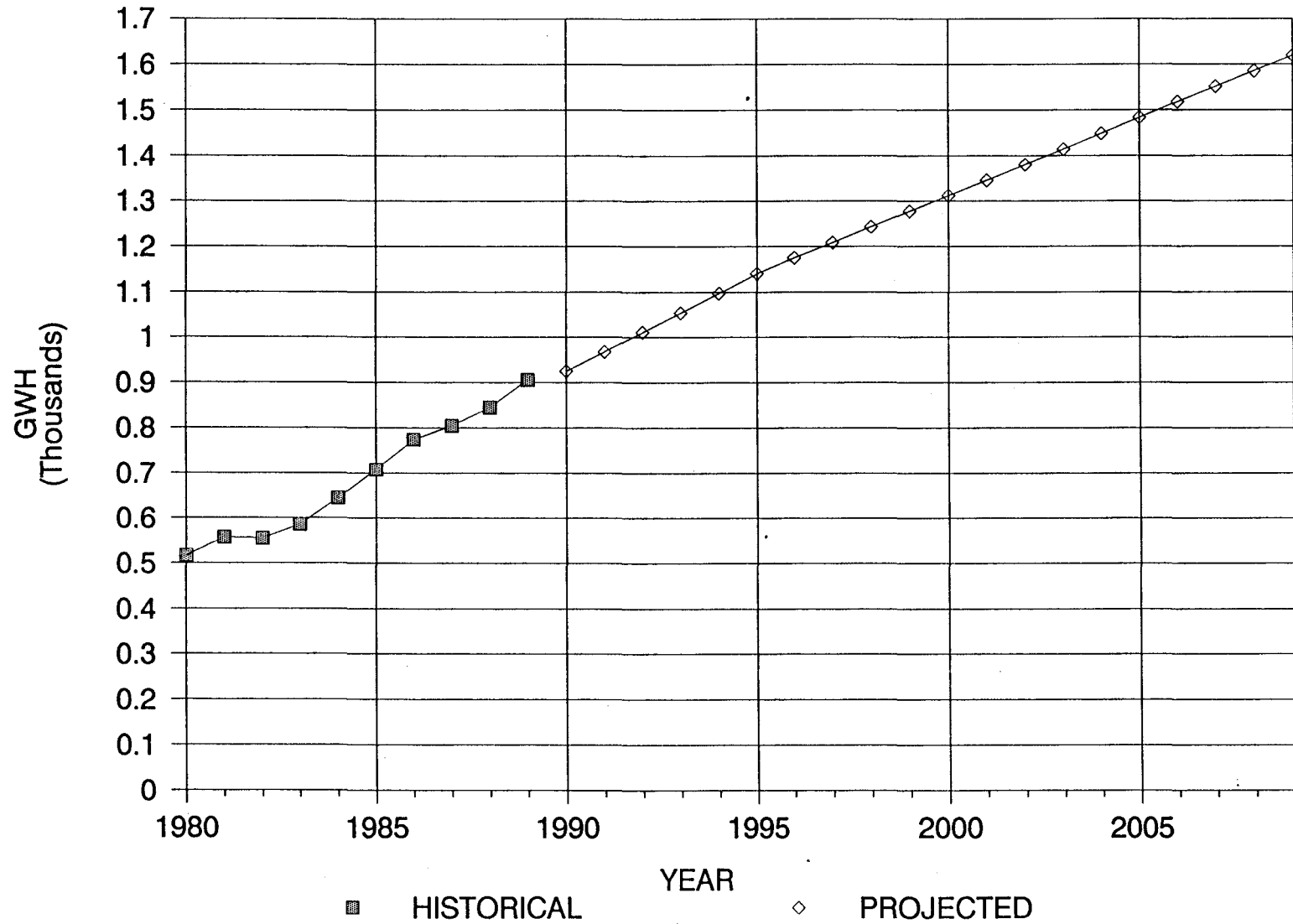
TABLE 1C.B.C-4
CITY OF OCALA
PROJECTED DEMAND AND ENERGY REDUCTIONS
FROM THE RESIDENTIAL AND CITY ACCOUNT'S
LOAD MANAGEMENT PROGRAMS

	Residential Customers	New Load Management Participants	Cumulative Load Management Participants	Summer NCP Reduction (Kw)	Winter NCP Reduction (Kw)	NEL Reduction (Kwh)
1991	32,097	912	912	766	0	224,352
1992	33,132	970	1,882	1,581	951	462,972
1993	34,166	1029	2,911	5,445 [1]	4,471 [1]	716,106
1994	35,201	1558	4,469	6,779	5,273	1,106,754
1995	36,237	647	5,116	7,322	5,600	1,265,916
1996	37,270	146	5,262	7,445	5,674	1,301,832
1997	38,306	138	5,400	7,561	5,744	1,335,780
1998	39,339	138	5,538	7,677	5,814	1,369,728
1999	40,375	138	5,676	7,793	5,884	1,403,676
2000	41,410	138	5,814	7,909	5,954	1,437,624
2001	42,445	138	5,952	8,025	6,024	1,471,572
2002	43,480	138	6,090	8,141	6,094	1,505,520
2003	44,515	138	6,228	8,257	6,164	1,539,468
2004	45,551	138	6,366	8,373	6,234	1,573,416
2005	46,586	138	6,504	8,489	6,304	1,607,364
2006	47,621	138	6,642	8,605	6,374	1,641,312
2007	48,656	138	6,780	8,721	6,444	1,675,260
2008	49,692	138	6,918	8,837	6,514	1,709,208
2009	50,727	138	7,056	8,953	6,584	1,743,156

NOTES [1]: ASSUMES 3 MW PER YEAR REDUCTION IN SUMMER AND WINTER NCP'S DUE TO CITY ACCOUNT'S LOAD MANAGEMENT PROGRAM FROM 1993-2009.

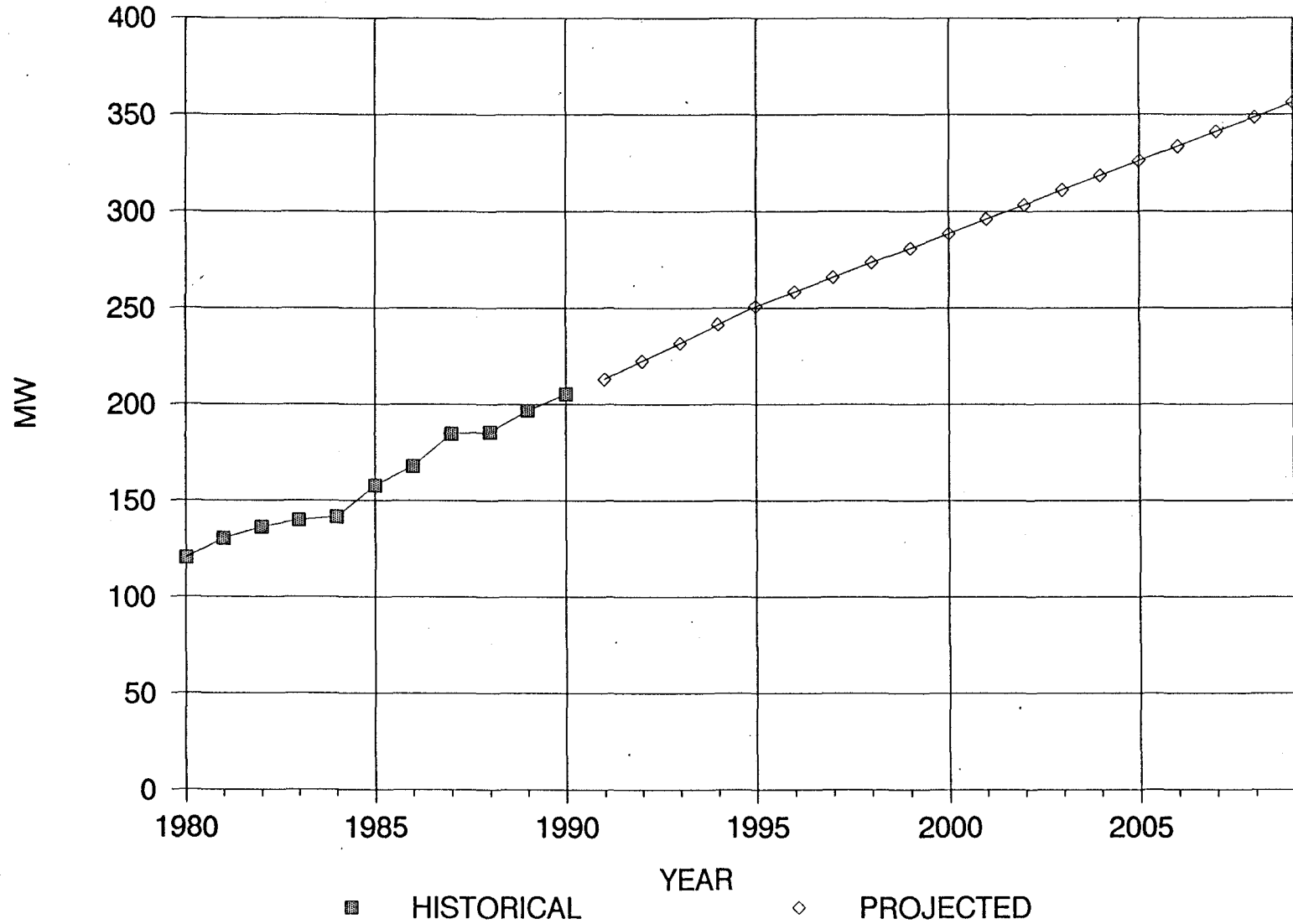
CITY OF OCALA

HISTORICAL AND PROJECTED NEL



CITY OF OCALA

HISTORICAL AND PROJECTED SUMMER NCP

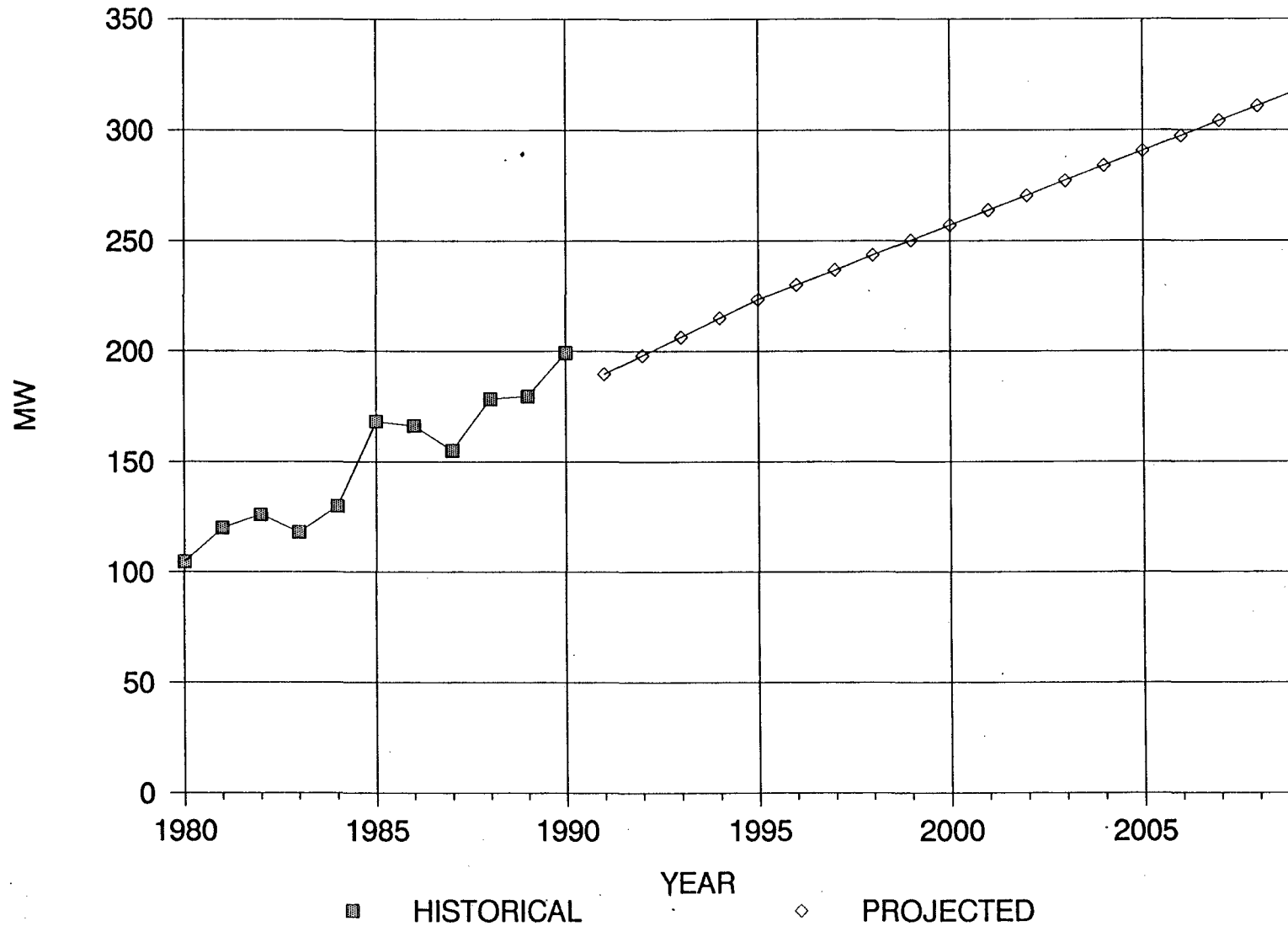


1C.B.2-37

EXHIBIT 1C.B.C-2

CITY OF OCALA

HISTORICAL AND PROJECTED WINTER NCP



1C.B.2-38

EXHIBIT 1C.B.C-3

CITY OF GREEN COVES SPRINGS

APPENDIX 1C.B

SECTION 1C.B.2.4

CITY OF GREEN COVE SPRINGS, FLORIDA

Following is a summary of our analyses and investigations pertaining to the design and development of estimates of future energy and demand requirements for the City of Green Cove Springs, Florida.

The forecasting technique used to project future energy and demand requirements for the City of Green Cove Springs is the annual aggregate method. Based on the results of this analysis, system net energy requirements are projected to increase at a compound annual growth rate of 3.1% between 1990 and 1999 and summer peak demand is expected to increase at an annual compound rate of 3.0% over the same period. This forecast is summarized below, presented in detail in Table 1C.B.D-1 and depicted graphically in Exhibits 1C.B.D-1, 1C.B.D-2, and, 1C.B.D-3.

CITY OF GREEN COVE SPRINGS, FLORIDA

Projected Demand and Energy Requirements

	1989 [1]	1994	1999
Net Energy Requirements - (MWh)	86,938	102,890	118,753
Summer Net Peak Demand - (MW)	16.6	19.8	22.8

Net Energy Requirements

Aggregate net energy for load is postulated to be a linear function. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project net energy requirements are reported in Equation [A-1].

$$E_t = E_{t-1} + 3.17258 + e_t \quad [A-1]$$

where E_t = net energy for load (Gwh) in calendar year t.

[1] Actual 1989.

The resulting index of determination is greater than .91.

Model inputs consist of annual net energy for load observations over the study period, i.e., 1976 through 1990 on a calendar year basis. This model is used to project energy requirements through the year 2009.

No unusual load additions have been projected for the City of Green Cove Springs.

Peak Demand

The forecast of summer peak demand is based on the average system summer load factor for 1988 - 1990 and the forecast of winter peak demand is based on the average system winter load factor for 1988 - 1990. Peak demands are obtained by applying an average annual load factor to projected net energy requirements. This assumes that consumer behavior will resemble that encountered during the study period.

Conservation and Load Management

Projected values of net energy requirements and annual peak demand for the City of Green Cove Springs do not include the effects of any additional conservation and/or load management not observed over the historical study period used to estimate the forecasting models. However, the effects of conservation and/or load management observed over the historical study period are implied in the quantification of the City's forecasting models by including recent historical data which include the effects of existing conservation and load management.

TABLE 1C.B.D-1
CITY OF GREEN COVE SPRINGS
HISTORICAL AND PROJECTED NEL AND PEAK DEMANDS

		CALENDAR YEAR NEL (GWH)	SUMMER NCP (MW)	WINTER NCP (MW)
	1980	51.766	10.100	11.900
	1981	51.838	10.900	12.100
A	1982	53.382	11.800	11.700
C	1983	60.690	12.600	11.700
T	1984	65.860	12.300	12.200
U	1985	71.266	13.700	15.400
A	1986	73.630	14.200	13.800
L	1987	79.333	15.410	14.458
	1988	84.145	15.932	16.004
	1989	86.938	16.658	16.510
	1980 - 1989			
	% A A G R	5.9%	5.7%	3.7%
	1990	90.200 [1]	17.482 [2]	16.322 [2]
	1991	93.373	17.900	16.900
	1992	96.545	18.500	17.500
	1993	99.718	19.100	18.000
	1994	102.890	19.800	18.600
P	1995	106.063	20.400	19.200
	1996	109.235	21.000	19.800
R	1997	112.408	21.600	20.300
	1998	115.581	22.200	20.900
O	1999	118.753	22.800	21.500
J	1990 - 1999			
	% A A G R	3.1%	3.0%	3.1%
E	2000	121.926	23.400	22.100
	2001	125.098	24.000	22.600
C	2002	128.271	24.600	23.200
	2003	131.444	25.200	23.800
T	2004	134.616	25.800	24.400
	2005	137.789	26.500	24.900
E	2006	140.961	27.100	25.500
	2007	144.134	27.700	26.100
D	2008	147.306	28.300	26.700
	2009	150.479	28.900	27.200
	2000 - 2009			
	% A A G R	2.4%	2.4%	2.3%
	1990 - 2009			
	% A A G R	2.7%	2.7%	2.7%

NOTES [1]: INCLUDES ESTIMATED GWH FOR NOV90 - DEC90.
[2]: ACTUAL.

CITY OF GREEN COVE SPRINGS

HISTORICAL AND PROJECTED NEL

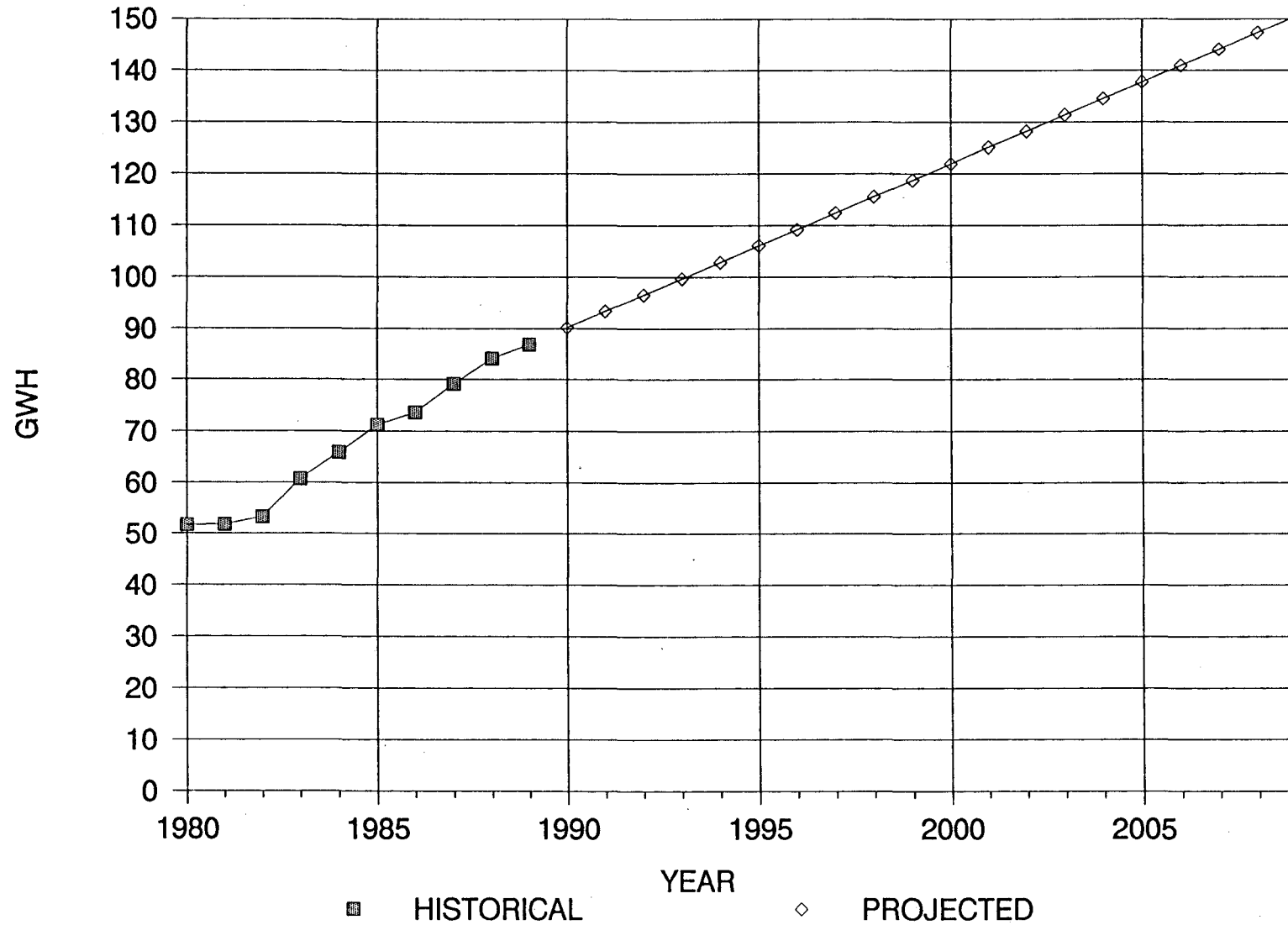
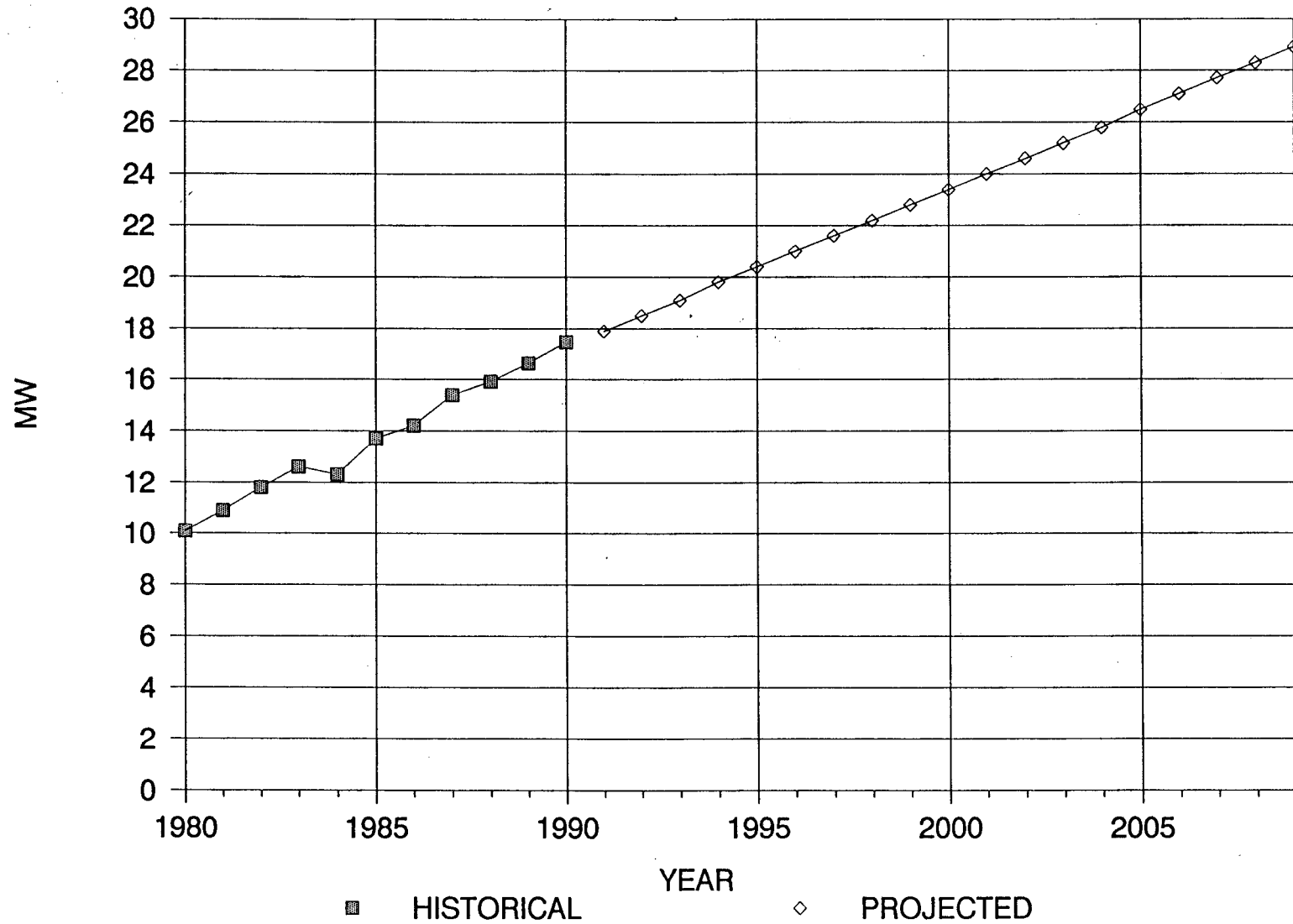


EXHIBIT 1C.B.D-1

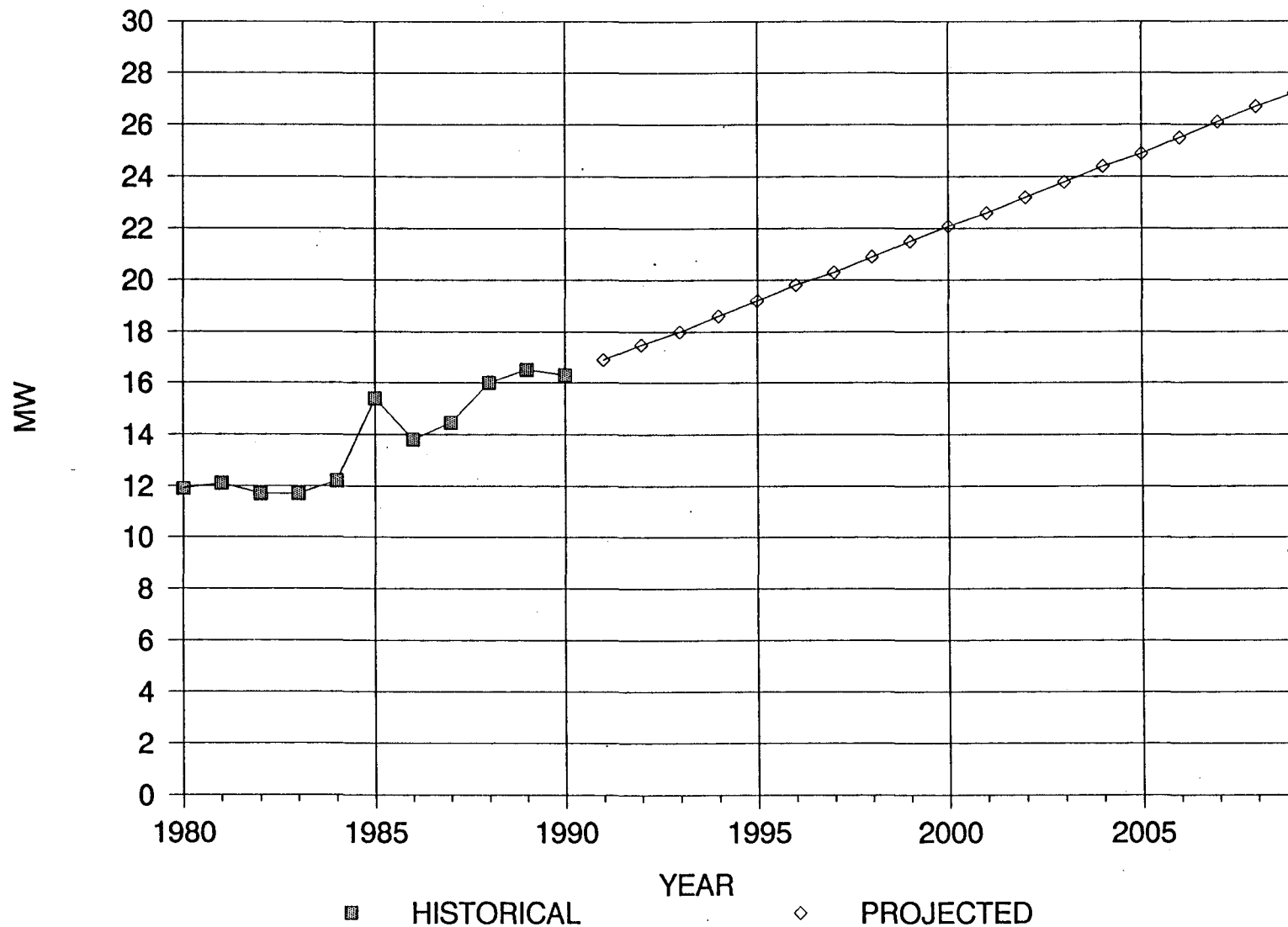
CITY OF GREEN COVE SPRINGS

HISTORICAL AND PROJECTED SUMMER NCP



CITY OF GREEN COVE SPRINGS

HISTORICAL AND PROJECTED WINTER NCP



CITY OF JACKSONVILLE BEACH

APPENDIX 1C.B

SECTION 1C.B.2.5

CITY OF JACKSONVILLE BEACH, FLORIDA

Following is a summary of our analyses and investigations pertaining to the design and development of estimates of future energy and demand requirements for the City of Jacksonville Beach, Florida.

The forecasting technique used to project future energy and demand requirements for the City of Jacksonville Beach is the annual aggregate method. Based on the results of this analysis, system net energy requirements are projected to increase at a compound annual growth rate of 3.6% between 1990 and 1999 and summer peak demand is expected to increase at an annual compound rate of 3.5% over the same period. This forecast is summarized below, presented in detail in Table 1C.B.E-1 and depicted graphically in Exhibits 1C.B.E-1, 1C.B.E-2, and 1C.B.E-3.

CITY OF JACKSONVILLE BEACH, FLORIDA

Projected Demand and Energy Requirements

	1989 [1]	1994	1999
Net Energy Requirements - (MWh)	456,583	550,750	649,022
Summer Net Peak Demand - (MW)	102.4	125.6	148.0

Net Energy Requirements

Aggregate net energy for load is postulated to be a linear function. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project net energy requirements are reported in Equation [A-1].

$$E_t = E_{t-1} + 19.654303 + e_t \quad [A-1]$$

where E_t = net energy for load (Gwh) in calendar year t .

[1] Actual 1989.

The resulting index of determination is greater than .92.

Model inputs consist of annual net energy for load observations over the study period, i.e., 1976 through 1990 on a calendar year basis. This model is used to project energy requirements through the year 2009.

No unusual load additions have been projected for the City of Jacksonville Beach.

Peak Demand

The forecast of summer peak demand is based on the average system summer load factor for 1987 - 1990 and the forecast of winter peak demand is based on the average system winter load factor for 1987 - 1990. Peak demands are obtained by applying an average annual load factor to projected net energy requirements. This assumes that consumer behavior will resemble that encountered during the study period.

Conservation and Load Management

Projected values of net energy requirements and annual peak demand for the City of Jacksonville Beach do not include the effects of any additional conservation and/or load management not observed over the historical study period used to estimate the forecasting models. However, the effects of conservation and/or load management observed over the historical study period are implied in the quantification of the City's forecasting models by including recent historical data which include the effects of existing conservation and load management.

TABLE 1C.B.E-1
CITY OF JACKSONVILLE BEACH
HISTORICAL AND PROJECTED NEL AND PEAK DEMANDS

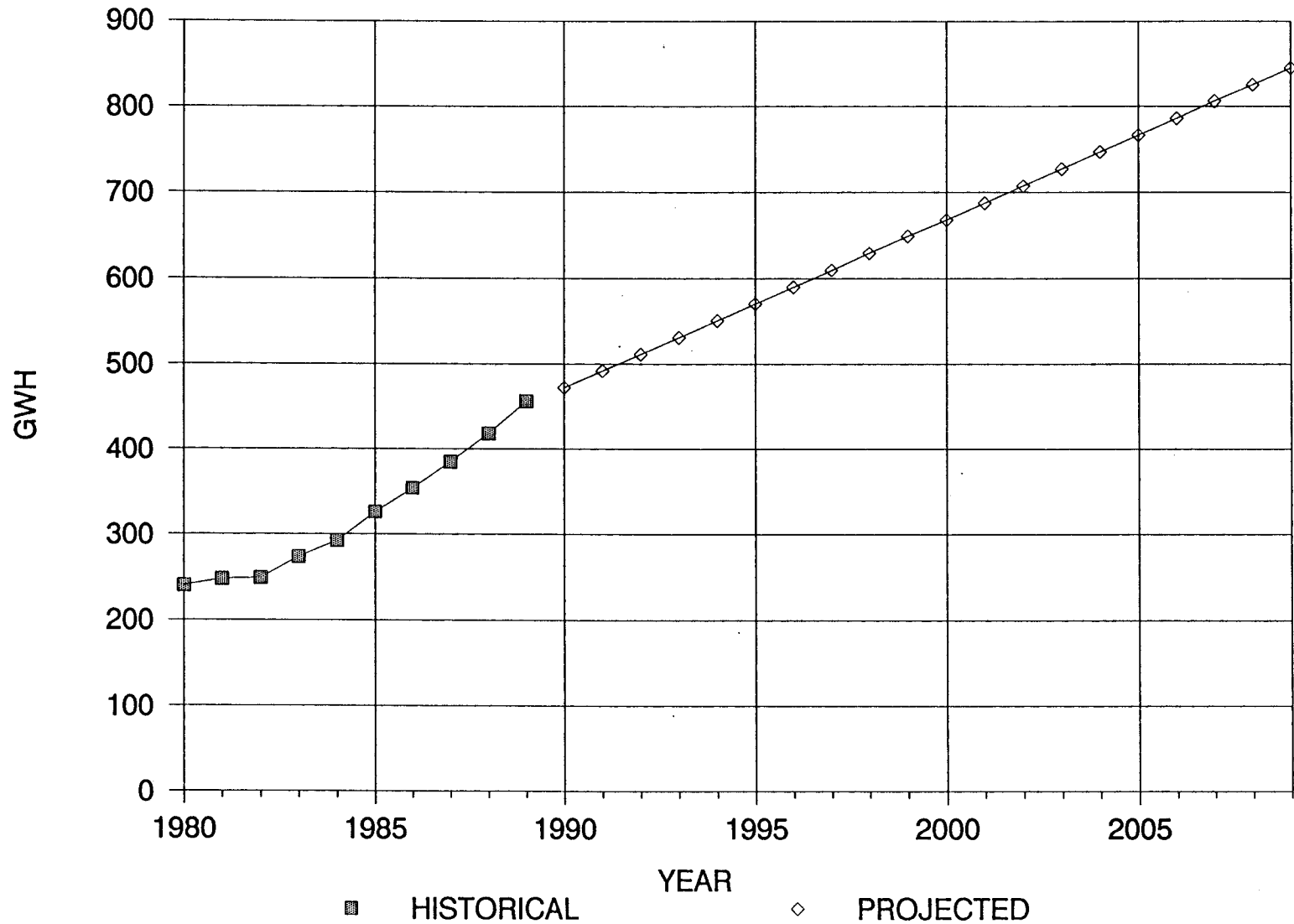
		CALENDAR YEAR NEL (GWH)	SUMMER NCP (MW)	WINTER NCP (MW)	SEVERE WEATHER WINTER NCP (MW)	BASE CASE WINTER NCP (MW)
A C T U A L	1980	240.395	59.200	63.200		
	1981	247.871	58.300	68.200		
	1982	249.262	59.200	60.300		
	1983	274.262	66.900	80.300		
	1984	292.500	68.800	80.300		
	1985	326.736	74.000	97.700		
	1986	354.235	89.080	103.500		
	1987	385.442	90.640	85.940		
	1988	418.660	93.560	101.360		
	1989	456.583	102.440	114.400		
1980 - 1989						
	% A A G R	7.4%	6.3%	6.8%		
P R O J E C T E D	1990	472.000 [1]	108.700 [2]		147.210 [2]	147.210 [2]
	1991	491.787	112.100		126.400	109.700
	1992	511.442	116.600		131.400	114.100
	1993	531.096	121.100		136.500	118.400
	1994	550.750	125.600		141.500	122.800
	1995	570.405	130.100		146.600	127.200
	1996	590.059	134.500		151.600	131.600
	1997	609.713	139.000		156.700	136.000
	1998	629.367	143.500		161.700	140.300
	1999	649.022	148.000		166.800	144.700
1990 - 1999						
	% A A G R	3.6%	3.5%		1.4%	-0.2%
C O N F I D E N T I A L	2000	668.676	152.500		171.800	149.100
	2001	688.330	156.900		176.900	153.500
	2002	707.985	161.400		182.000	157.900
	2003	727.639	165.900		187.000	162.300
	2004	747.293	170.400		192.100	166.600
	2005	766.948	174.900		197.100	171.000
	2006	786.602	179.300		202.200	175.400
	2007	806.256	183.800		207.200	179.800
	2008	825.910	188.300		212.300	184.200
	2009	845.565	192.800		217.300	188.600
2000 - 2009						
	% A A G R	2.6%	2.6%		2.6%	2.6%
1990 - 2009						
	% A A G R	3.1%	3.1%		2.1%	1.3%

NOTES [1]: INCLUDES ESTIMATED GWH FOR NOV90 - DEC90.

[2]: ACTUAL.

CITY OF JACKSONVILLE BEACH

HISTORICAL AND PROJECTED NEL

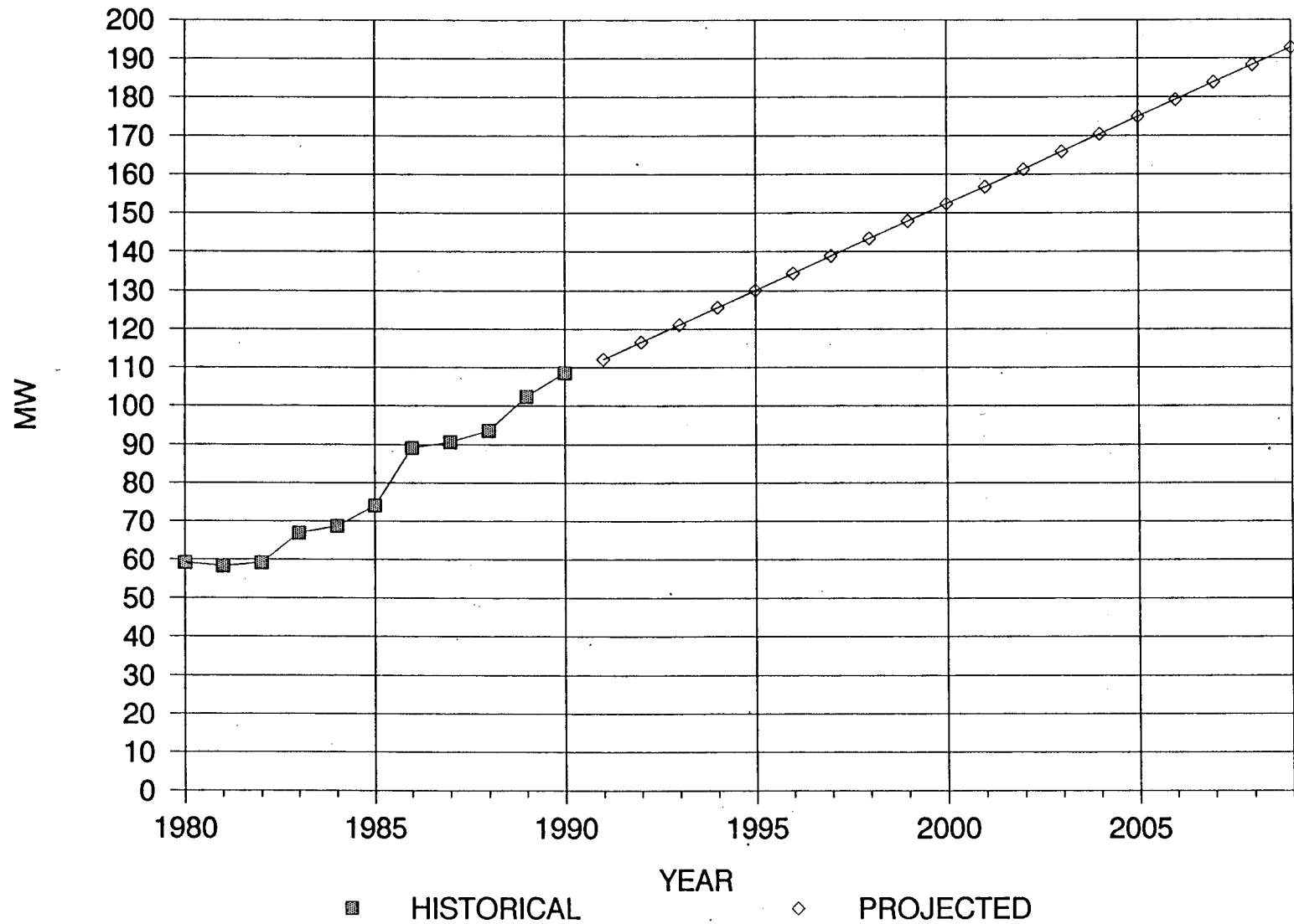


IC.B.2-50

EXHIBIT IC.B.E-1

CITY OF JACKSONVILLE BEACH

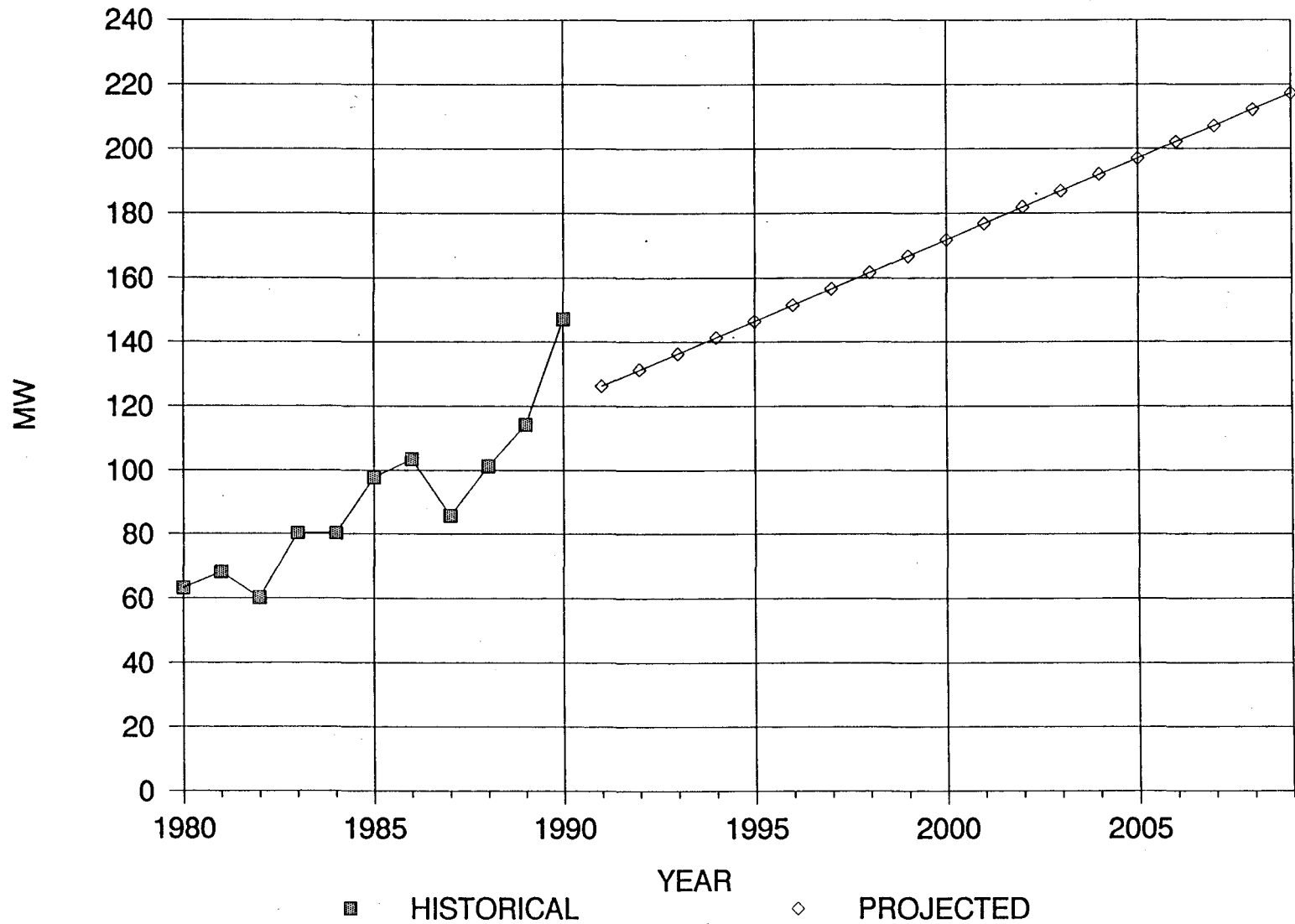
HISTORICAL AND PROJECTED SUMMER NCP



1C.B.2-51

CITY OF JACKSONVILLE BEACH

HISTORICAL AND PROJECTED WINTER NCP



IC.B.2-52

EXHIBIT IC.B.E-3

CITY OF CLEWISTON

APPENDIX 1C.B

SECTION 1C.B.2.6

CITY OF CLEWISTON, FLORIDA

Following is a summary of our analyses and investigations pertaining to the design and development of estimates of future energy and demand requirements for the City of Clewiston, Florida.

The forecasting technique used to project future energy and demand requirements for the City of Clewiston is the annual aggregate method. Based on the results of this analysis, system net energy requirements are projected to increase at a compound annual growth rate of 2.5% between 1990 and 1999 and summer peak demand is expected to increase at an annual compound rate of 2.6% over the same period. This forecast is summarized below, presented in detail in Table 1C.B.F-1 and depicted graphically in Exhibits 1C.B.F-1, 1C.B.F-2, and 1C.B.F-3.

CITY OF CLEWISTON, FLORIDA

Projected Demand and Energy Requirements

	1989 [1]	1994	1999
Net Energy Requirements - (MWh)	89,225	99,833	112,729
Summer Net Peak Demand - (MW)	18.1	20.3	22.9

Net Energy Requirements

Aggregate net energy for load is postulated to be a linear function. The mathematical form, estimated coefficients, and relevant statistical properties of the estimating equation used to project net energy requirements are reported in Equation [A-1].

$$E_t = -5043.043 + 2.579176 t + e_t \quad [A-1]$$

where E_t = net energy for load (Gwh) in calendar year t

[1] Actual 1989.

The resulting index of determination is greater than .96.

Model inputs consist of annual net energy for load observations over the study period, i.e., 1981 through 1990 on a calendar year basis. This model is used to project energy requirements through the year 2009.

No unusual load additions have been projected for the City of Clewiston.

Peak Demand

The forecast of summer peak demand is based on the average system summer load factor for 1988 - 1990 and the forecast of winter peak demand is based on the average ratio of winter non-coincident peak demand divided by the summer non-coincident peak demand for calendar years 1987 - 1990. Peak demands are obtained by applying an average annual load factor to projected net energy requirements. This assumes that consumer behavior will resemble that encountered during the study period.

Conservation and Load Management

Projected values of net energy requirements and annual peak demand for the City of Clewiston do not include the effects of any additional conservation and/or load management not observed over the historical study period used to estimate the forecasting models. However, the effects of conservation and/or load management observed over the historical study period are implied in the quantification of the City's forecasting models by including recent historical data which include the effects of existing conservation and load management.

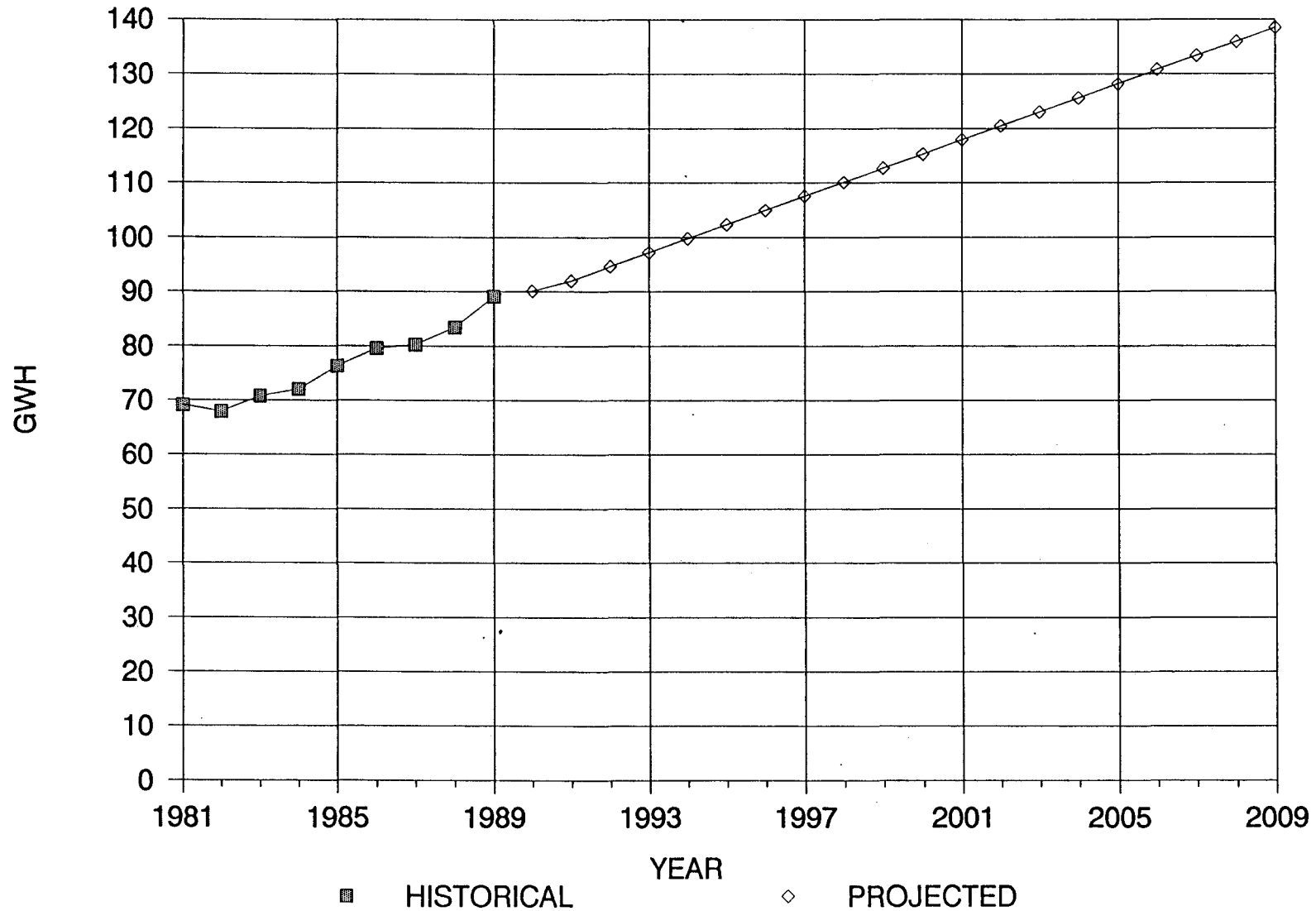
TABLE 1C.B.F-1
CITY OF CLEWISTON
HISTORICAL AND PROJECTED NEL AND PEAK DEMANDS

		CY		
		NEL	SUMMER	WINTER
		(GWH)	NCP (MW)	NCP (MW)
Historical:				
	1981	69.154	14.326	17.305
	1982	67.929	14.453	17.448
	1983	70.886	15.639	13.566
	1984	72.097	15.132	16.860
	1985	76.484	16.584	20.578
	1986	79.701	16.267	18.663
	1987	80.377	17.252	16.492
	1988	83.498	17.091	17.062
	1989	89.225	18.139	17.655
1981 - 1989	% AAGR	3.2%	3.0%	0.3%
Forecast:				
	1990	90.200	18.248	21.434
	1991	92.096	18.700	17.600
	1992	94.675	19.200	18.100
	1993	97.254	19.700	18.600
	1994	99.833	20.300	19.100
	1995	102.412	20.800	19.600
	1996	104.991	21.300	20.100
	1997	107.571	21.800	20.600
	1998	110.150	22.400	21.100
	1999	112.729	22.900	21.600
1990 - 1999	% AAGR	2.5%	2.6%	0.1%
	2000	115.308	23.400	22.100
	2001	117.887	23.900	22.500
	2002	120.467	24.500	23.100
	2003	123.046	25.000	23.600
	2004	125.625	25.500	24.000
	2005	128.204	26.000	24.500
	2006	130.783	26.500	25.000
	2007	133.362	27.100	25.600
	2008	135.942	27.600	26.000
	2009	138.521	28.100	26.500
2000 - 2009	% AAGR	2.1%	2.1%	2.0%
1990 - 2009	% AAGR	2.3%	2.3%	1.1%

NOTES: 1990 NEL INCLUDES ESTIMATED GWH
FOR NOV90 - DEC90.

CITY OF CLEWISTON

HISTORICAL AND PROJECTED NEL

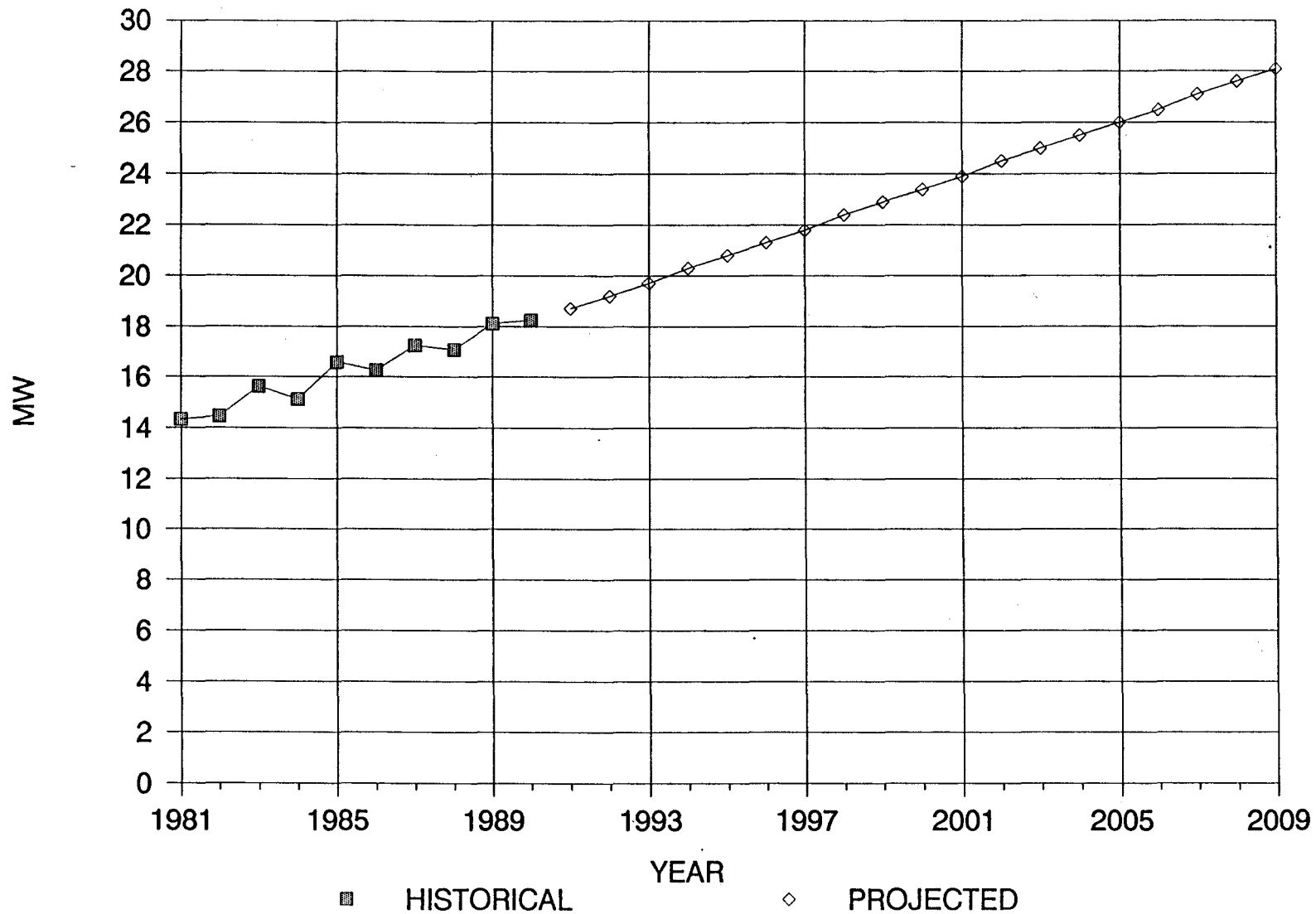


IC.B.2-57

EXHIBIT IC.B.F-1

CITY OF CLEWISTON

HISTORICAL AND PROJECTED SUMMER NCP



1C.B.2-58

CITY OF CLEWISTON

HISTORICAL AND PROJECTED WINTER NCP

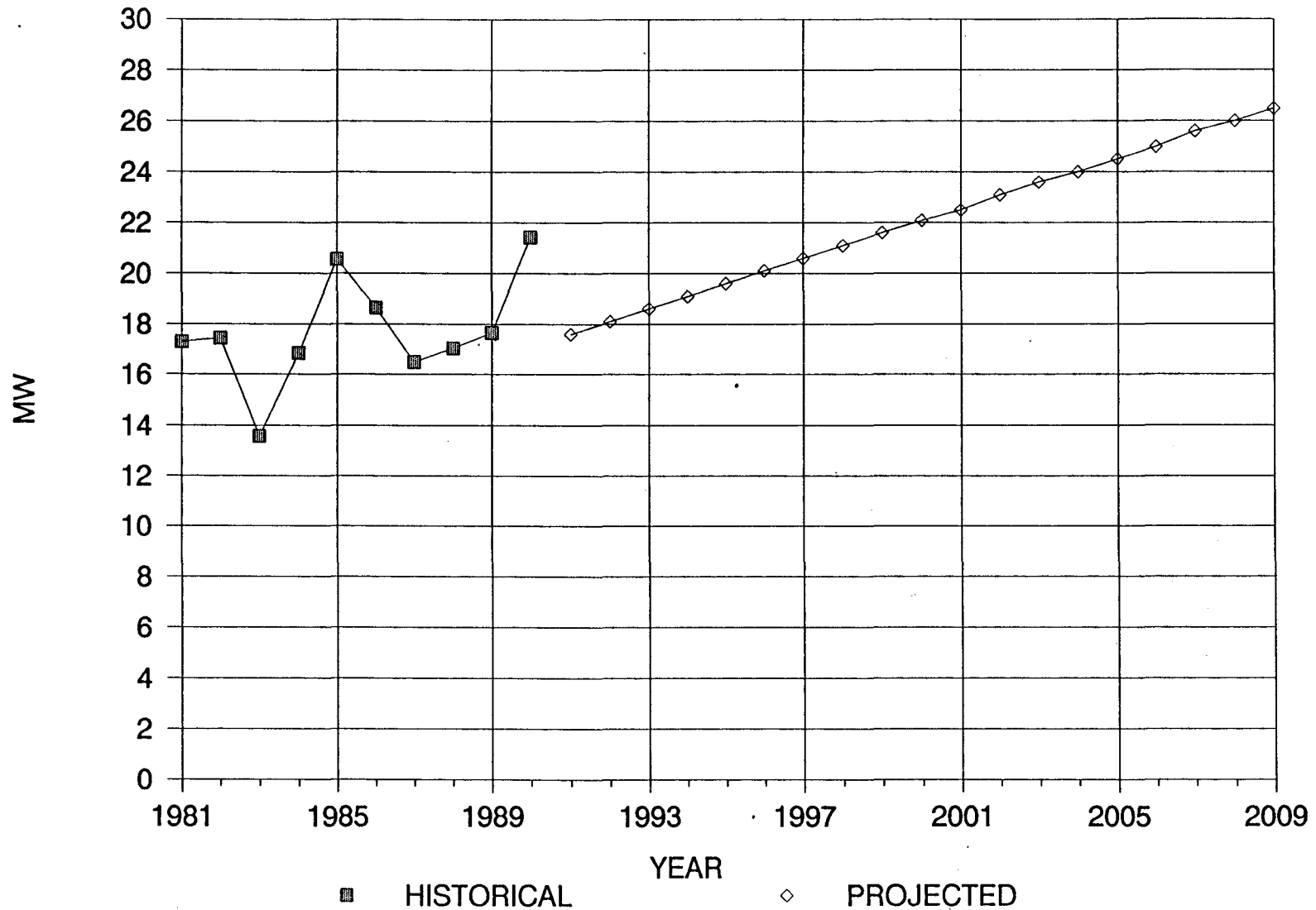


EXHIBIT IC.B.F-3

Appendix 1C.C Existing Facilities

**TABLE 1C.C-1
STANTON 2 PARTICIPANTS
EXISTING GENERATING FACILITIES**

UNIT	NET CAPABILITY		TYPE	CLASS	FUEL		1989	COM'L OPER'N Mo/Yr
	SUMMER Mw	WINTER Mw			AVERAGE HEAT RATE (Btu/Kwh)	PRI	ALT	
FORT PIERCE UTILITIES AUTHORITY								
King-1	2.7	2.7	D	PK	LO	--	10,600	04/70
King-2	2.7	2.7	D	PK	LO	--	10,600	04/70
King-6 [1]	16.5	16.5	FS	PK	HO	--	13,750	01/58
King-7	32.0	32.0	FS	PK	NG	HO	12,640	01/64
King-8	50.5	50.5	FS	IM	NG	HO	11,940	05/76
King-9	31.4	31.4	CC	BL	NG	--	9,980	01/89
CITY OF HOMESTEAD								
Ivey-2	2.1	2.1	D	IM	NG	LO	11,175	03/70
Ivey-3	2.1	2.1	D	IM	NG	LO	10,652	03/70
Ivey-8	2.0	2.0	D	IM	NG	LO	11,942	01/54
Ivey-9	2.0	2.0	D	IM	NG	LO	11,481	01/58
Ivey-10	2.0	2.0	D	IM	NG	LO	11,847	01/58
Ivey-11	3.0	3.0	D	IM	NG	LO	11,942	01/65
Ivey-12	3.0	3.0	D	IM	NG	LO	12,793	01/65
Ivey-13	2.1	2.1	D	IM	NG	LO	11,395	11/72
Ivey-14	2.1	2.1	D	IM	NG	LO	11,771	11/72
Ivey-15	2.1	2.1	D	IM	NG	LO	11,799	11/72
Ivey-16	2.1	2.1	D	IM	NG	LO	11,976	11/72
Ivey-17	2.1	2.1	D	IM	NG	LO	11,565	11/72
Ivey-18 [2]	0.0	0.0	D	BL	NG	LO	10,244	04/75
Ivey-19 [2]	0.0	0.0	D	BL	NG	LO	9,021	04/75
Ivey-20	6.4	6.4	D	BL	NG	LO	10,382	05/81
Ivey-21	6.4	6.4	D	BL	NG	LO	10,166	05/81

Notes [1]: Unit on extended cold standby.

[2]: Unit physically available, but not included as firm capacity.

**TABLE IC.C-1
STANTON 2 PARTICIPANTS
EXISTING GENERATING FACILITIES**

UNIT	NET CAPABILITY		TYPE	CLASS	FUEL		1989	COM'L OPER'N Mo/Yr
	SUMMER Mw	WINTER Mw			PRI	ALT	AVERAGE HEAT RATE (Btu/Kwh)	

UTILITY BOARD OF THE CITY OF KEY WEST

Big Pine Key-1	2.8	2.8	D	PK	L0	--	13,500	03/69
Cudjoe Key-2	2.8	2.8	D	PK	L0	--	13,500	09/66
Cudjoe Key-3	2.2	2.2	D	PK	L0	--	13,500	03/69
Key West-P1	20.0	20.0	CT	PK	L0	--	14,000	12/78
Key West-3 [1]	15.1	15.1	FS	PK	H0	--	15,300	12/57
Key West-4 [2]	15.2	15.2	FS	PK	H0	--	14,400	01/63
Key West-5 [1]	15.5	15.5	FS	PK	H0	--	13,500	08/66
Stock Island-S1	32.5	32.5	FS	BL	H0	--	12,800	12/72
Stock Island-D1	2.0	2.0	D	PK	L0	--	13,500	02/65
Stock Island-D2	2.0	2.0	D	PK	L0	--	13,500	02/65
Stock Island-D3	2.0	2.0	D	PK	L0	--	13,500	02/65

CITY OF LAKE WORTH UTILITIES

Smith S1	5.2	5.2	FS	IM	NG	HO	19,600	01/61
Smith S3	20.8	20.8	FS	IM	NG	HO	14,400	11/67
Smith S4 [1]	28.3	28.3	FS	IM	NG	HO	14,400	08/71
Smith CGT-1	25.8	25.8	CT	PK	L0	--	17,800	12/76
Smith CGT-2/S-5	28.0	28.0	CCT	BL	NG	L0	10,100	03/78
Smith MU-1	2.0	2.0	D	PK	L0	--	12,600	12/65
Smith MU-2	2.0	2.0	D	PK	L0	--	12,600	12/65
Smith MU-3	2.0	2.0	D	PK	L0	--	12,600	12/65
Smith MU-4	2.0	2.0	D	PK	L0	--	12,600	12/65
Smith MU-5	2.0	2.0	D	PK	L0	--	12,600	12/65

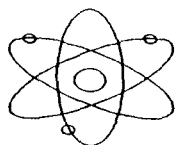
Notes [1]: Unit on extended cold standby.

[2]: Unit currently limited to 13 MW.

**TABLE 1C.C-1
STANTON 2 PARTICIPANTS
EXISTING GENERATING FACILITIES**

UNIT	NET CAPABILITY		TYPE	CLASS	FUEL		1989	COM'L OPER'N Mo/Yr
	SUMMER Mw	WINTER Mw			AVERAGE HEAT RATE (Btu/Kwh)			
CITY OF STARKE								
Starke-1	1.3	1.3	D	PK	NG	LO	14,600	03/83
Starke-2	0.8	0.8	D	PK	NG	LO	14,600	04/57
Starke-3	0.8	0.8	D	PK	NG	LO	14,600	10/56
Starke-4	0.8	0.8	D	PK	NG	LO	14,600	07/56
Starke-5	0.8	0.8	D	PK	NG	LO	14,600	06/56
Starke-6	1.4	1.4	D	PK	NG	LO	12,300	06/68
Starke-7	1.0	1.0	D	PK	LO	--	14,175	06/82
CITY OF VERO BEACH								
Vero Beach-1	11.8	11.8	FS	PK	NG	HO	14,900	11/61
Vero Beach-2	16.9	16.9	FS	PK	NG	HO	13,950	08/64
Vero Beach-3	32.9	32.9	FS	IM	NG	HO	13,000	09/71
Vero Beach-4	54.0	54.0	FS	IM	NG	HO	11,440	10/76
Vero Beach-D1 [1]	0.9	0.9	D	PK	LO	--	15,000	01/47
Vero Beach-D2 [1]	0.6	0.6	D	PK	LO	--	15,000	01/37
Vero Beach-D4 [1]	2.7	2.7	D	PK	LO	--	15,000	01/52
Vero Beach-D5 [1]	2.5	2.5	D	PK	LO	--	15,000	01/53
Vero Beach-D6 [1]	5.5	5.5	D	PK	LO	--	15,000	01/57

Note [1]: Unit on extended cold standby.



**TABLE 1C.C-2
FLORIDA MUNICIPAL POWER AGENCY
EXISTING GENERATING FACILITIES**



UNIT	NET CAPABILITY		TYPE	CLASS	FUEL		1989 AVERAGE HEAT RATE (Btu/Kwh)	COM'L OPER'N Mo/Yr
	SUMMER Mw	WINTER Mw			PRI	ALT		

ALL REQUIREMENTS POWER SUPPLY PROJECT

Stanton 1 [1]		27.0	27.0	FS	BL	C	--	9,762	07/87
Indian River CT A [2]		14.4	18.7	CT	PK	NG	LO	12,560	06/89
Indian River CT B [3]		14.4	18.7	CT	PK	NG	LO	12,560	06/89

ST. LUCIE PROJECT

St. Lucie 2 [4]		73.5	75.1	N	BL	N	--	9,900	08/83
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STANTON PROJECT

Stanton 1 [5]		61.5	61.5	FS	BL	C	--	9,762	07/87
---------------	--	------	------	----	----	---	----	-------	-------

TRI-CITY PROJECT

Stanton 1 [6]		22.0	22.0	FS	BL	C	--	9,762	07/87
---------------	--	------	------	----	----	---	----	-------	-------

Notes [1]: Based on 6.5% ownership share of Stanton 1 with a 415 MW seasonal net capability.

[2]: Based on 39% ownership share of Indian River CT A with a 37 MW summer and a 48 MW winter seasonal net capability.

[3]: Based on 39% ownership share of Indian River CT B with a 37 MW summer and a 48 MW winter seasonal net capability.

[4]: Based on 8.8% ownership share of St. Lucie 2 with a 837.7 MW summer and a 855.2 MW winter seasonal net capability.

[5]: Based on 14.8% ownership share of Stanton 1 with a 415 MW seasonal net capability.

[6]: Based on 5.3% ownership share of Stanton 1 with a 415 MW seasonal net capability.

Appendix 1C.D Capacity Plans

TABLE 1C.D.1-1

CITY OF VERO BEACH AND FORT PIERCE UTILITIES AUTHORITY

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS
WITHOUT STANTON 2 CAPACITY

NO.	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021				
CAPACITY REQUIREMENTS																																			
1 PROJECTED PEAK DEMAND FT PIERCE	108	110	112	114	116	118	117	119	120	122	123	126	128	128	129	131	132	134	136	137	138	140	141	143	145	146	148	150	151	153	155				
2 PROJECTED PEAK DEMAND VERO BEACH	120	125	130	135	141	148	152	157	163	170	173	177	181	184	188	191	195	199	202	208	210	214	218	220	224	228	233	237	241	246	251	255	259	265	
3 TOTAL COMBINED PEAK DEMAND	247	256	262	270	278	282	287	292	297	302	307	312	317	323	328	333	338	344	349	356	364	370	375	381	388	394	400	407	413	420	426	432	438	444	
4 GENERATING CAPACITY RESERVES @ 20%	49	51	52	54	56	56	57	58	59	60	61	62	63	65	66	67	68	69	70	71	72	73	74	75	76	78	79	80	81	83	84	85	86	87	
5 TOTAL CAPACITY REQUIREMENTS	297	306	316	324	332	339	344	350	356	363	368	375	381	387	393	399	406	412	419	428	436	443	450	458	465	473	480	488	496	504	512	520	528	536	
6 REQUIREMENTS RATIO FT PIERCE	44%	43%	43%	42%	42%	41%	41%	41%	40%	40%	40%	40%	40%	40%	39%	39%	39%	39%	39%	39%	39%	38%	38%	38%	38%	38%	37%	37%	37%	37%	37%	37%	37%		
7 REQUIREMENTS RATIO VERO BEACH	56%	57%	57%	58%	58%	59%	59%	59%	60%	60%	60%	60%	60%	60%	61%	61%	61%	61%	61%	61%	61%	62%	62%	62%	62%	62%	63%	63%	63%	63%	63%	63%	63%	63%	
GENERATING RESOURCES																																			
8 TOTAL COMBINED EXISTING CAPACITY	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	
9 VERO NEW CC UNIT #2 ADDITION	0	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	
10 STANTON PROJECT (Unit #1)	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	
11 STANTON PROJECT (Unit #2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
12 TRI-CITY PROJECT	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	
13 ST LUCE PROJECT	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	
14 CUMULATIVE RETIREMENTS	0	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	
15 TOTAL GENERATING RESOURCES	294	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328
16 NET RESERVE (DEFICIENCY)	[2]	(2)	23	14	5	(3)	(10)	(10)	(22)	(28)	(34)	(40)	(46)	(52)	(59)	(65)	(71)	(77)	(84)	(90)	(97)	(101)	(108)	(115)	(122)	(129)	(137)	(144)	(152)	(160)	(168)	(176)	(183)	(190)	
17 NET FIRM RESERVE (DEFICIENCY)	[3]	(2)	19	11	4	(3)	(9)	(13)	(18)	(23)	(29)	(34)	(39)	(44)	(49)	(54)	(59)	(65)	(70)	(76)	(81)	(84)	(90)	(94)	(102)	(108)	(114)	(120)	(127)	(133)	(140)	(146)	(152)	(158)	
PARTIAL REQUIREMENTS PURCHASES																																			
18 FORT PIERCE MAXIMUM PR (115%)	7	7	7	7	7	8	10	12	15	18	21	23	26	28	27	28	26	27	29	31	32	35	36	38	41	43	46	47	50	52	54	56	58	60	
19 VERO BEACH MAXIMUM PR (115%)	4	3	3	3	4	5	6	7	8	10	12	15	18	22	27	33	39	43	48	50	52	55	59	63	66	71	75	79	83	87	92	97	102	107	
20 TOTAL COMBINED MAXIMUM DEMAND	11	10	10	10	11	13	16	19	23	28	33	38	43	48	54	59	64	70	76	81	84	90	95	101	107	114	120	126	133	139	146	153	160	167	

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS
WITH STANTON 2 CAPACITY

LINE NO.	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		
CAPACITY REQUIREMENTS																																	
1 PROJECTED PEAK DEMAND FT PIERCE	108	110	112	114	116	118	117	119	120	122	123	126	128	128	129	131	132	134	136	137	138	140	141	143	145	146	148	150	151	153	155		
2 PROJECTED PEAK DEMAND VERO BEACH	120	125	130	135	141	148	152	157	163	170	173	177	181	184	188	191	195	199	202	206	210	214	218	222	226	231	236	241	246	251	255	260	265
3 TOTAL COMBINED PEAK DEMAND	247	255	282	270	278	282	287	292	297	302	307	312	317	323	328	333	338	344	349	356	364	370	375	381	388	394	400	407	413	420	426	433	
4 GENERATING CAPACITY RESERVES @ 20%	49	51	52	54	56	56	57	58	59	60	61	62	63	65	66	67	68	69	70	71	72	73	74	75	76	78	79	80	81	83	84		
5 TOTAL CAPACITY REQUIREMENTS	297	306	316	324	332	339	344	350	356	363	368	375	381	387	393	399	406	412	419	426	436	443	450	458	465	473	480	488	496	504	504		
6 REQUIREMENTS RATIO FT PIERCE	44%	43%	43%	42%	42%	41%	41%	41%	40%	40%	40%	40%	40%	40%	39%	39%	39%	39%	39%	39%	39%	38%	38%	38%	38%	38%	37%	37%	37%	37%	37%		
7 REQUIREMENTS RATIO VERO BEACH	56%	57%	57%	58%	58%	59%	59%	59%	60%	60%	60%	60%	60%	60%	61%	61%	61%	61%	61%	61%	61%	61%	62%	62%	62%	62%	62%	63%	63%	63%	63%	63%	
GENERATING RESOURCES																																	
8 TOTAL COMBINED EXISTING CAPACITY	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	236	
9 VERO NEW CC UNIT #2 ADDITION	0	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	
10 STANTON PROJECT (Unit #1)	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	
11 STANTON PROJECT (Unit #2)	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
12 TRI-CITY PROJECT	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	
13 ST LUCE PROJECT	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	
14 CUMULATIVE RETIREMENTS	0	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	
15 TOTAL GENERATING RESOURCES	294	328	328	328	328	328	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	
16 NET RESERVE (DEFICIENCY)	[2]	(2)	23	14	5	(3)	(10)	14	8	2	(4)	(10)	(18)	(23)	(29)	(35)	(41)	(48)	(54)	(61)	(67)	(71)	(78)	(85)	(92)	(99)	(107)	(114)	(122)	(130)	(138)	(148)	
17 NET FIRM RESERVE (DEFICIENCY)	[3]	(2)	19	11	4	(3)	(9)	12	7	2	(4)	(9)	(14)	(19)	(24)	(29)	(34)	(40)	(46)	(50)	(56)	(59)	(65)	(71)	(77)	(83)	(89)	(95)	(102)	(108)	(115)	(122)	
PARTIAL REQUIREMENTS PURCHASES																																	
18 FORT PIERCE MAXIMUM PR (115%)	7	7	7	7	7	7	7	7	7	8	9	11	13	16	19	22	24	27	28	29	29	29	29	29	31	34	36	38	40	42	45		
19 VERO BEACH MAXIMUM PR (115%)	4	3	3	3	3	3	3	3	3	3	4	5	6	7	8	10	12	15	18	22	27	33	40	43	47	51	55	59	63	68	72	78	
20 TOTAL COMBINED MAXIMUM DEMAND	11	10	10	10	10	10	10	10	10	12	14	17	20	24	29	34	39	45	50	56	59	65	70	78	82	89	95	101	108	114	121	121	

NOTES [1]. CAPACITY OF OFF-SYSTEM RESOURCES SHOWN WITH WHEELING LOSSES REMOVED.
 [2]. NET RESERVE IS CAPACITY AVAILABLE (NEEDED) ABOVE REQUIRED LEVEL.

1C.D-2

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS WITHOUT STANTON 2 CAPACITY

[illegible]

NOTES (1): CAPACITY OF OFF-SYSTEM RESOURCES SHOWN WITH WHEELING LOSSES REMOVED.
(2): NET RESERVE IS CAPACITY AVAILABLE (NEEDED) ABOVE REQUIRED LEVEL.
(3): NET FIRM RESERVE IS CAPACITY AVAILABLE (NEEDED) ABOVE REQUIRED LEVEL.

UTILITY BOARD OF THE CITY OF KEY WEST

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS WITHOUT STANTON 2 CAPACITY

[illegible]

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS WITH STANTON 2 CAPACITY

[illegible]

TABLE I.C.D.1-4

CITY OF LAKE WORTH

SUMMARY OF PROJECTED SUMMER PEAK LOAD AND CAPACITY REQUIREMENTS
WITHOUT STANTON 2 CAPACITY

LINE NO.	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
CAPACITY REQUIREMENTS																																
1 PROJECTED PEAK DEMAND.....	69	70	72	73	75	76	78	79	81	82	83	84	84	85	86	86	87	87	87	88	89	89	90	90	91	92	92	93	93	94	95	
2 FIRM SALES.....	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
3 TOTAL COMBINED PEAK DEMAND.....	84	85	87	88	90	91	93	94	96	97	98	99	99	100	101	86	87	87	87	88	89	89	90	90	91	92	92	93	93	94	95	
4 GENERATING CAPACITY RESERVES @ 20%.....	17	17	17	18	18	18	19	19	19	19	20	20	20	20	20	17	17	17	17	17	18	18	18	18	18	18	18	19	19	19	19	
5 TOTAL CAPACITY REQUIREMENTS.....	101	102	104	106	108	109	112	113	115	116	118	119	119	120	121	103	104	104	104	106	107	107	108	108	109	110	110	112	112	113	114	
GENERATING RESOURCES																																
6 TOTAL COMBINED EXISTING CAPACITY.....	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	
7 ST LUCE PROJECT.....	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	
8 STANTON PROJECT (Unit #1).....	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
9 STANTON PROJECT (Unit #2).....	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 GAINESVILLE ST LUCE RECALL.....	0	0	0	0	0	0	0	0	0	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	
11 REPLACE CC.....	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26	26	26	26	26	26	26	26	26	26	26	26	
12 CUMULATIVE RETIREMENTS/REDUCTIONS.....	(33)	(33)	(38)	(38)	(40)	(42)	(44)	(46)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	
13 TOTAL GENERATING RESOURCES.....	117	117	112	112	110	108	106	104	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	
14 NET RESERVE (DEFICIENCY)..... [2].....	18	15	8	8	2	(1)	(6)	(9)	(37)	(38)	(40)	(41)	(41)	(42)	(43)	(25)	(26)	(26)	(26)	(28)	(29)	(29)	(30)	(30)	(31)	(32)	(32)	(34)	(34)	(35)	(36)	
15 NET FIRM RESERVE (DEFICIENCY)..... [3].....	14	13	6	6	2	(1)	(5)	(7)	(31)	(32)	(33)	(34)	(34)	(35)	(36)	(21)	(22)	(22)	(22)	(23)	(24)	(24)	(25)	(25)	(26)	(27)	(27)	(28)	(28)	(29)	(30)	
PARTIAL REQUIREMENTS PURCHASER																																
16 MAXIMUM DEMAND (115% CONTRACT).....	0	8	10	12	15	18	22	27	31	32	33	34	34	35	36	27	22	22	22	23	24	24	25	25	26	27	27	28	28	29	30	

CITY OF LAKE WORTH

SUMMARY OF PROJECTED SUMMER PEAK LOAD AND CAPACITY REQUIREMENTS
WITH STANTON 2 CAPACITY

LINE NO.	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
CAPACITY REQUIREMENTS																																
1 PROJECTED PEAK DEMAND.....	69	70	72	73	75	76	78	79	81	82	83	84	84	85	86	86	87	87	87	88	89	89	90	90	91	92	92	93	93	94	95	
2 FIRM SALES.....	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
3 TOTAL COMBINED PEAK DEMAND.....	84	85	87	88	90	91	93	94	96	97	98	99	99	100	101	86	87	87	87	88	89	89	90	90	91	92	92	93	93	94	95	
4 GENERATING CAPACITY RESERVES @ 20%.....	17	17	17	18	18	18	19	19	19	19	20	20	20	20	20	17	17	17	17	18	18	18	18	18	18	18	18	19	19	19	19	
5 TOTAL CAPACITY REQUIREMENTS.....	101	102	104	106	108	109	112	113	115	116	118	119	119	120	121	103	104	104	104	106	107	107	108	108	109	110	110	112	112	113	114	
GENERATING RESOURCES																																
6 TOTAL COMBINED EXISTING CAPACITY.....	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	122	
7 ST LUCE PROJECT.....	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	
8 STANTON PROJECT (Unit #1).....	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
9 STANTON PROJECT (Unit #2).....	0	0	0	0	0	0	0	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	
10 GAINESVILLE ST LUCE RECALL.....	0	0	0	0	0	0	0	0	0	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	
11 REPLACE CC.....	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28	28	28	28	28	28	28	28	28	28	28	28	28	
12 CUMULATIVE RETIREMENTS/REDUCTIONS.....	(33)	(33)	(38)	(38)	(40)	(42)	(44)	(46)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	
13 TOTAL GENERATING RESOURCES.....	117	117	112	112	110	108	113	111	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	
14 NET RESERVE (DEFICIENCY)..... [2].....	18	15	8	8	2	(1)	1	(2)	(30)	(31)	(33)	(34)	(34)	(35)	(36)	(18)	(19)	(19)	(19)	(19)	(21)	(22)	(22)	(23)	(23)	(24)	(25)	(25)	(27)	(27)	(28)	
15 NET FIRM RESERVE (DEFICIENCY)..... [3].....	14	13	6	6	2	(1)	1	(2)	(25)	(26)	(27)	(28)	(28)	(29)	(30)	(15)	(16)	(16)	(16)	(17)	(18)	(18)	(19)	(19)	(20)	(21)	(21)	(22)	(22)	(23)	(24)	
PARTIAL REQUIREMENTS PURCHASER																																
16 MAXIMUM DEMAND (115% CONTRACT).....	0	7	8	10	12	14	17	21	25	26	27	28	28	29	30	22	17	16	16	17	18	18	19	19	20	21	21	22	22	23	24	

NOTES [1]: CAPACITY OF OFF-SYSTEM RESOURCES SHOWN WITH WHEELING LOSSES REMOVED.
 [2]: NET RESERVE IS CAPACITY AVAILABLE (NEEDED) ABOVE REQUIRED LEVEL.
 [3]: NET FIRM RESERVE IS PR CAPACITY AVAILABLE (NEEDED) ABOVE REQUIRED LEVEL.

CITY OF STARKE

TABLE 1C.D.1-5

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS
WITHOUT STANTON 2 CAPACITY

LINE NO.	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
CAPACITY REQUIREMENTS																																
1 PROJECTED PEAK DEMAND.....	13	13	14	14	15	15	16	16	16	17	17	17	18	18	19	19	20	20	20	21	21	22	23	23	24	24	25	25	26	27	27	
2 GENERATING CAPACITY RESERVES @ 20%.....	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	
3 TOTAL CAPACITY REQUIREMENTS.....	16	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24	24	25	26	26	27	28	28	29	30	30	31	32	33	
GENERATING RESOURCES																																
4 TOTAL EXISTING CAPACITY.....	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7		
5 GAINESVILLE PURCHASE.....	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
6 ST LUCIE PROJECT.....	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
7 STANTON PROJECT (Unit #1).....	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
8 STANTON PROJECT (Unit #2).....	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 TOTAL GENERATING RESOURCES.....	13	13	13	13	13	13	13	13	13	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	9	9	9	9	9	9	
10 NET RESERVE (DEFICIENCY).....[2].....	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(7)	(10)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)	(15)	(15)	(16)	(17)	(17)	(18)	(19)	(20)	(21)	(21)	(22)	(23)	(24)	
11 NET FIRM RESERVE (DEFICIENCY).....[3].....	(2)	(3)	(3)	(3)	(4)	(4)	(5)	(5)	(6)	(6)	(9)	(9)	(10)	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)	(15)	(15)	(17)	(17)	(18)	(18)	(19)	(20)	
PARTIAL REQUIREMENTS PURCHASES																																
12 FPL PLANNED PR PURCHASE (115%).....	2	3	3	4	4	5	5	6	7	9	9	10	10	11	11	11	12	12	13	13	14	14	15	15	16	17	18	18	19	20	20	

CITY OF STARKE

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS
WITH STANTON 2 CAPACITY

NO	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
CAPACITY REQUIREMENTS																																
1 PROJECTED PEAK DEMAND.....	13	13	14	14	15	15	15	16	16	17	17	17	18	18	19	19	20	20	20	21	21	22	23	23	24	24	25	25	26	27	27	
2 GENERATING CAPACITY RESERVES @ 20%.....	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	
3 TOTAL CAPACITY REQUIREMENTS.....	16	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24	24	24	25	25	26	27	28	28	29	30	30	31	32	33
GENERATING RESOURCES																																
4 TOTAL EXISTING CAPACITY.....	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	
5 GAINESVILLE PURCHASE.....	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
6 ST LUCIE PROJECT.....	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	1.428	0.714	0.714	0.714	0.714	0.714	
7 STANTON PROJECT (UHR #1).....	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	1.403	
8 STANTON PROJECT (UHR #2).....	0	0	0	0	0	0	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	1.115	
9 TOTAL GENERATING RESOURCES.....	13	13	13	13	13	13	14	14	14	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	10	10	10	10	10	
10 NET RESERVE (DEFICIENCY).....[2].....	(3)	(3)	(4)	(4)	(5)	(5)	(5)	(5)	(6)	(9)	(10)	(10)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)	(15)	(15)	(16)	(17)	(17)	(18)	(20)	(20)	(21)	(22)	(23)	
11 NET FIRM RESERVE (DEFICIENCY).....[3].....	(2)	(3)	(3)	(3)	(4)	(4)	(4)	(4)	(5)	(8)	(9)	(9)	(9)	(9)	(10)	(10)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(15)	(16)	(18)	(18)	(19)	(19)	(19)	(19)	
PARTIAL REQUIREMENTS PURCHASES																																
12 FPL PLANNED PR PURCHASE (115%).....	2	3	3	4	4	5	4	5	6	6	6	9	9	10	10	11	11	11	12	12	13	13	14	14	15	16	17	17	18	19	19	

NOTES [1]: CAPACITY OF OFF-SYSTEM RESOURCES SHOWN WITH WHEELING LOSSES REMOVED.

[2]: NET RESERVE IS CAPACITY AVAILABLE (NEEDED) ABOVE REQUIRED LEVEL.

[3]: NET FIRM RESERVE IS PR CAPACITY AVAILABLE (NEEDED) ABOVE REQUIRED LEVEL.

FLORIDA MUNICIPAL POWER AGENCY
ALL-REQUIREMENTS PROJECT

TABLE 1C.D.2-1

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS
WITHOUT STANTON 2 CAPACITY

LINE NO.	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
CAPACITY REQUIREMENTS																																
1 PROJECTED COINCIDENT PEAK DEMAND	439	457	474	492	509	525	540	556	571	587	602	618	634	649	665	680	696	711	727	742	758	774	789	805	820	836	851	867	883	898	914	
2 GENERATING CAPACITY RESERVES @20%	88	91	95	98	102	106	108	111	114	117	120	124	127	130	133	136	139	142	145	148	152	155	158	161	164	167	170	173	177	180	183	
3 TOTAL CAPACITY REQUIREMENTS	527	548	569	590	611	629	648	667	686	704	723	742	760	779	798	818	835	854	872	891	909	928	947	966	984	1003	1022	1041	1060	1078	1097	
GENERATING RESOURCES																																
4 TOTAL COMBINED EXISTING CAPACITY	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	
5 ST. LUCIE PROJECT	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	5	5	5	5	5	
6 CRYSTAL RIVER 3	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	0	0	0	0	
7 MUNICIPAL PURCHASES	227	211	198	196	181	171	171	171	171	171	171	148	128	83	80	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 INDIAN RIVER CT UNITS C&D	0	0	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	
9 STANTON UNIT 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10 TOTAL GENERATING REBOURCES	311	295	324	324	308	298	299	299	299	299	299	278	263	211	188	150	128	128	128	128	128	128	128	128	128	122	105	105	105	105	105	
11 NET RESERVE (DEFICIENCY) [2]	(216)	(253)	(245)	(266)	(302)	(331)	(360)	(369)	(387)	(406)	(424)	(466)	(507)	(568)	(610)	(668)	(707)	(726)	(744)	(763)	(782)	(801)	(819)	(838)	(857)	(881)	(917)	(935)	(964)	(973)	(991)	
12 NET FIRM RESERVE (DEFICIENCY) ... [3]	(180)	(211)	(204)	(222)	(252)	(276)	(291)	(307)	(322)	(338)	(353)	(388)	(422)	(474)	(508)	(555)	(589)	(605)	(620)	(636)	(652)	(667)	(683)	(699)	(714)	(734)	(764)	(779)	(795)	(811)	(826)	
PARTIAL REQUIREMENTS PURCHASES																																
13 PLANNED FPL PR PURCHASES	58	64	58	71	83	89	95	101	107	115	124	137	155	168	193	206	213	220	225	232	238	245	251	257	267	275	281	287	293	300	306	
14 PLANNED FPC PR PURCHASES	142	170	159	165	185	203	213	224	234	243	250	273	292	331	344	378	407	418	427	437	447	457	467	477	484	497	522	532	543	552	563	
15 TOTAL PR PURCHASES	200	234	217	236	268	292	308	325	341	358	374	410	447	499	537	584	620	638	652	669	685	702	718	734	751	772	803	819	836	852	869	

FLORIDA MUNICIPAL POWER AGENCY
ALL-REQUIREMENTS PROJECT

SUMMARY OF PROJECTED PEAK LOAD AND CAPACITY REQUIREMENTS
WITH STANTON 2 CAPACITY

LINE NO.	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
CAPACITY REQUIREMENTS																																
1 PROJECTED COINCIDENT PEAK DEMAND	439	457	474	492	508	525	540	556	571	587	602	618	634	649	665	680	696	711	727	742	758	774	789	805	820	836	851	867	883	898	914	
2 GENERATING CAPACITY RESERVES @20%	88	91	95	98	102	106	108	111	114	117	120	124	127	130	133	136	139	142	145	148	152	155	158	161	164	167	170	173	177	180	183	
3 TOTAL CAPACITY REQUIREMENTS	527	548	569	590	611	629	648	667	686	704	723	742	760	779	798	816	835	854	872	891	909	928	947	966	984	1003	1022	1041	1060	1078	1097	
GENERATING RESOURCES																																
4 TOTAL COMBINED EXISTING CAPACITY	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	
5 ST. LUCIE PROJECT	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	5	5	5	5	5	5	
6 CRYSTAL RIVER 3	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	
7 MUNICIPAL PURCHASES	227	211	196	196	181	171	171	171	171	171	171	148	126	83	80	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 INDIAN RIVER CT UNITS C&D	0	0	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	
9 STANTON UNIT 2	0	0	0	0	0	0	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	
10 TOTAL GENERATING RESOURCES	311	296	324	324	308	299	321	321	321	321	321	298	275	233	210	172	150	150	150	150	150	150	150	150	150	150	144	127	127	127	127	
11 NET REBERVE (DEFICIENCY) [2]	(216)	(263)	(245)	(266)	(302)	(331)	(328)	(347)	(366)	(384)	(402)	(444)	(486)	(548)	(588)	(644)	(686)	(704)	(722)	(741)	(760)	(779)	(797)	(816)	(836)	(859)	(895)	(913)	(932)	(951)	(969)	
12 NET FIRM RESERVE (DEFICIENCY) [3]	(180)	(211)	(204)	(222)	(252)	(278)	(273)	(289)	(304)	(320)	(336)	(370)	(404)	(456)	(490)	(537)	(571)	(587)	(602)	(618)	(633)	(649)	(664)	(680)	(696)	(716)	(745)	(761)	(777)	(792)	(808)	
PARTIAL REQUIREMENTS PURCHASES																																
13 PLANNED FPL PR PURCHASES	58	64	58	71	83	86	87	93	99	105	116	128	145	159	183	197	205	211	218	223	230	236	242	248	258	265	271	278	283	291	296	
14 PLANNED FPC PR PURCHASES	142	170	159	165	185	206	202	213	223	233	239	263	283	321	334	368	398	408	415	427	436	447	457	467	474	488	512	522	533	542	553	
15 TOTAL PR PURCHASES	200	234	217	236	268	292	289	308	322	338	355	391	428	480	517	565	601	617	633	650	666	682	699	715	732	753	783	800	816	833	849	

NOTES [1]: CAPACITY OF OFF-SYSTEM RESOURCES SHOWN WITH WHEELING LOSSES REMOVED.
[2]: NET RESERVE IS CAPACITY AVAILABLE (NEEDED) ABOVE REQUIRED LEVEL.
[3]: NET FIRM RESERVE IS PR CAPACITY AVAILABLE (NEEDED) ABOVE REQUIRED LEVEL.



Appendix 1C.E Economic Comparisons

Appendix 1C.E.0 Economic Analyses

1C.E.1 Fort Pierce Utilities Authority and City of Vero Beach

The resources of the Fort Pierce Utilities Authority ("Fort Pierce") and City of Vero Beach ("Vero Beach") electric systems are dispatched jointly to meet the combined system load of the two utilities. For this reason the economics of participating in the Stanton 2 Project was evaluated for these two utilities on a combined basis.

Based on the load projections for Fort Pierce and Vero Beach, presented in Subsection 1C.5.0, the reliability criteria discussed in Subsection 1C.7.0 and the existing resources for each utility discussed in Subsection 1C.2.0, joint power supply plans were developed by Fort Pierce and Vero Beach to meet their respective power supply requirements assuming, alternatively, with and without Stanton 2 participation. For purposes of preparing these plans, it was assumed that the alternative resource to participation in the Stanton 2 Project would be additional purchases of partial requirements from FPL. Fort Pierce and Vero Beach have determined that purchases of partial requirements from FPL are the most likely alternative to participation in the Stanton 2 Project since partial requirements purchases are projected to be an economical long-term alternative that is reasonably attainable and is projected to be available in the quantities required to meet the Authority and City's combined requirements over the study period.

Alternative plans for the combined system of Fort Pierce and Vero Beach, with and without Stanton 2 are shown in Table 1C.D.1-1. Annual capacity requirements for Fort Pierce and Vero Beach are calculated based on the projected peak demand plus generating capacity reserves based on a 20 percent reserve margin. Annual capacities available from generating resources are calculated based on existing capacity, retirements, additions, and participation in off-system generation projects. From the projected capacity requirements and generating resources, the projected annual capacity excess or deficiency is calculated. From these deficiencies the amount of capacity purchased from partial requirements is calculated. It was assumed that the annual contract demand for partial requirements purchases could not be changed by more than 25 percent in any year. As shown in Table 1C.D.1-1, the projected partial requirements

purchases for Fort Pierce and Vero Beach start at 16 MW in 1997, increasing to 139 MW in 2020 for the plan without Stanton 2, and start at 10 MW in 1997, increasing to 114 MW in 2020 for the plan including Stanton 2.

The economic analysis of Stanton 2 for Fort Pierce and Vero Beach is shown in Table 1C.E.1-1. Comparative annual costs are shown for the plans with and without Stanton 2, along with annual differences in costs. The average monthly partial requirements demands were calculated based on the results of the monthly production costing model. The demand costs were calculated based on the projected partial requirements rates as described in Section 1C.4.0.

Annual fuel costs were estimated based on the production costing model, in which a monthly simulation of the dispatching of system resources was made based on the projected monthly demand and energy requirements. The fuel costs shown include fuel costs for onsite generation, fuel costs for participation in off-system generation and all purchased energy costs. Variable operation and maintenance expense for onsite generation has also been calculated in each case. For the case including Stanton 2, fixed costs of Stanton 2 were calculated based on the Fort Pierce and Vero Beach entitlement share times the fixed cost \$/kW calculated in Section 1C.8.0.

The differences between the comparative costs with and without Stanton 2 are shown for Fort Pierce and Vero Beach in Table 1C.E.1-1 on an annual basis, percent, cumulative, present worth, cumulative present worth dollars, and percent basis. As shown on this table, the costs for the case including Stanton 2 are projected to be higher than the case without Stanton 2 for the first five years, and lower thereafter. The projected cumulative present worth savings for Fort Pierce and Vero Beach are projected to be approximately \$30.4 million, or 2.5 percent overall savings for the period 1997 - 2021.

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TABLE ICE.1-1
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FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

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FORT PIERCE AND VERO BEACH

Description	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Without Stanton 2															
1 PR Average Demand MW	9.7	5.8	5.8	9.2	9.9	11.8	14.7	17.3	20.9	26.0	30.0	33.8	39.6	43.2	47.5
2 PR Demand Rate ... \$/kW/No	13.53	14.42	15.16	15.51	16.13	17.91	18.09	20.00	20.38	21.04	23.17	25.41	25.98	28.39	30.63
3 PR Demand Costs \$000	1,572	1,004	1,055	1,712	1,916	2,543	3,195	4,150	5,119	6,575	8,350	10,312	12,333	14,717	17,466
4 Fuel Costs \$000	27,860	29,669	32,954	36,763	40,203	44,715	49,639	54,307	60,161	66,983	72,630	79,950	87,472	94,927	103,757
5 On-Site Generation ... MWh	588	637	675	682	688	700	702	686	681	665	637	629	611	586	575
6 Variable O&M \$/MWh	2.00	2.10	2.19	2.30	2.41	2.52	2.64	2.77	2.90	3.04	3.18	3.33	3.49	3.66	3.83
7 Variable O&M \$000	1,176	1,335	1,481	1,568	1,657	1,766	1,855	1,899	1,974	2,019	2,026	2,096	2,133	2,143	2,202
8 Total Costs \$000	30,608	32,007	35,490	40,043	43,776	49,023	54,689	60,355	67,254	75,577	83,006	92,358	101,938	111,787	123,426
With Stanton 2															
9 PR Average Demand MW	9.7	5.8	5.8	9.2	9.2	9.3	8.2	8.1	8.0	10.0	11.6	13.9	17.2	20.2	23.8
10 PR Demand Rate ... \$/kW/No	13.53	14.42	15.16	15.51	16.13	17.91	18.09	20.00	20.38	21.04	23.17	25.41	25.98	28.39	30.63
11 PR Demand Costs \$000	1,572	1,004	1,055	1,712	1,781	1,999	1,780	1,944	1,956	2,515	3,231	4,251	5,362	6,868	8,741
12 Fuel Costs \$000	27,860	29,669	32,954	36,763	40,234	44,905	46,935	50,304	56,031	62,819	68,215	75,424	83,034	89,898	98,550
13 On-Site Generation ... MWh	588	637	675	682	696	724	597	563	589	601	596	600	603	585	577
14 Variable O&M \$/MWh	2.00	2.10	2.19	2.30	2.41	2.52	2.64	2.77	2.90	3.04	3.18	3.33	3.49	3.66	3.83
15 Variable O&M \$000	1,176	1,335	1,481	1,568	1,676	1,826	1,577	1,558	1,708	1,825	1,896	1,999	2,105	2,139	2,210
16 Stanton 2 Non-Fuel . \$000	0	0	0	0	0	0	6,887	9,292	9,413	9,799	9,942	10,092	10,251	10,415	10,587
17 Total Costs \$000	30,608	32,007	35,490	40,043	43,691	48,730	57,179	63,098	69,109	76,958	83,284	91,766	100,752	109,320	120,088
Difference															
18 Annual \$000	0	0	0	0	85	293	(2,490)	(2,743)	(1,855)	(1,381)	(278)	593	1,186	2,466	3,338
19 Percent %	0.0%	0.0%	0.0%	0.0%	0.2%	0.6%	-4.6%	-4.5%	-2.8%	-1.8%	-0.3%	0.6%	1.2%	2.2%	2.7%
20 Cumulative \$000	0	0	0	0	85	378	(2,112)	(4,855)	(6,709)	(8,090)	(8,369)	(7,776)	(6,590)	(4,124)	(786)
21 Annual Present Worth \$000	0	0	0	0	64	207	(1,636)	(1,681)	(1,059)	(736)	(138)	274	512	993	1,253
22 Cum Present Worth ... \$000	0	0	0	0	64	271	(1,365)	(3,046)	(4,105)	(4,841)	(4,979)	(4,704)	(4,192)	(3,200)	(1,947)
23 Cum Present Worth %	-	-	-	-	-	-	-3.8%	-4.2%	-3.7%	-3.2%	-2.6%	-2.0%	-1.5%	-1.0%	-0.5%

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TABLE 1C.E.1-1
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FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

Date: 3/6/91
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FORT PIERCE AND VERO BEACH

Description	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Without Stanton 2																
1 PR Average Demand MW	52.5	57.0	60.2	66.8	68.0	73.9	79.2	78.9	88.9	94.2	100.3	105.6	110.9	117.0	122.3	128.5
2 PR Demand Rate ... \$/kW/Mo	33.10	33.37	35.67	37.66	37.92	40.22	42.66	45.25	48.00	50.91	54.00	57.27	60.75	64.43	68.34	72.49
3 PR Demand Costs \$000	20,857	22,809	25,768	30,166	30,961	35,677	40,544	42,816	51,195	57,524	65,007	72,573	80,832	90,491	100,312	111,762
4 Fuel Costs \$000	113,107	120,591	131,165	141,787	151,822	165,325	179,445	192,657	208,629	226,090	245,012	265,518	287,741	311,823	337,921	366,203
5 On-Site Generation ... MWh	558	536	528	513	496	495	484	471	458	446	434	423	412	401	391	380
6 Variable O&M \$/MWh	4.01	4.20	4.40	4.61	4.83	5.06	5.30	5.55	5.82	6.09	6.38	6.68	7.00	7.33	7.68	8.05
7 Variable O&M \$000	2,239	2,252	2,324	2,365	2,396	2,504	2,565	2,615	2,663	2,717	2,771	2,827	2,884	2,941	3,000	3,061
8 Total Costs \$000	136,203	145,653	159,257	174,318	185,179	203,506	222,554	238,087	262,487	286,331	312,791	340,918	371,456	405,255	441,233	481,025
With Stanton 2																
9 PR Average Demand MW	28.9	33.2	36.0	43.0	47.0	50.7	55.3	58.8	65.4	69.7	75.7	80.8	85.9	91.8	96.9	102.9
10 PR Demand Rate ... \$/kW/Mo	33.1	33.37	35.67	37.66	37.92	40.22	42.66	45.25	48	50.91	54	57.27	60.75	64.43	68.34	72.49
11 PR Demand Costs \$000	11,479	13,275	15,409	19,433	21,405	24,489	28,284	31,928	37,647	42,581	49,021	55,495	62,585	70,976	79,466	89,467
12 Fuel Costs \$000	107,674	114,749	124,744	135,377	144,370	157,589	171,136	183,321	198,711	215,700	234,141	254,160	275,889	299,477	325,081	352,874
13 On-Site Generation ... MWh	566	543	532	522	498	500	490	473	462	454	446	438	431	423	416	409
14 Variable O&M \$/MWh	4.01	4.20	4.40	4.61	4.83	5.06	5.30	5.55	5.82	6.09	6.38	6.68	7.00	7.33	7.68	8.05
15 Variable O&M \$000	2,271	2,282	2,342	2,407	2,405	2,530	2,597	2,626	2,687	2,766	2,847	2,930	3,016	3,105	3,196	3,290
16 Stanton 2 Non-Fuel .. \$000	10,767	10,956	11,153	11,359	11,573	11,796	12,027	12,273	12,524	12,789	13,066	13,355	13,655	13,967	14,298	14,644
17 Total Costs \$000	132,191	141,262	153,649	168,576	179,754	196,404	214,044	230,149	251,569	273,836	299,075	325,939	355,146	387,525	422,041	460,275
Difference																
18 Annual \$000	4,012	4,391	5,608	5,742	5,425	7,103	8,510	7,939	10,918	12,495	13,716	14,979	16,310	17,730	19,192	20,750
19 Percent %	2.9%	3.0%	3.5%	3.3%	2.9%	3.5%	3.8%	3.3%	4.2%	4.4%	4.4%	4.4%	4.4%	4.4%	4.3%	4.3%
20 Cumulative \$000	3,226	7,617	13,226	18,968	24,393	31,496	40,006	47,945	58,863	71,358	85,074	100,052	116,362	134,092	153,284	174,034
21 Annual Present Worth \$000	1,404	1,433	1,706	1,629	1,435	1,752	1,957	1,702	2,183	2,329	2,384	2,427	2,465	2,498	2,521	2,542
22 Cum Present Worth ... \$000	(543)	890	2,597	4,226	5,661	7,413	9,370	11,072	13,255	15,584	17,968	20,395	22,860	25,358	27,879	30,420
23 Cum Present Worth %	-0.1%	0.2%	0.5%	0.7%	0.9%	1.1%	1.3%	1.4%	1.6%	1.8%	1.9%	2.1%	2.2%	2.3%	2.4%	2.5%

1C.E.2 City of Homestead

Based on the load projections of the City of Homestead, presented in Subsection 1C.5.0, the reliability criteria discussed in Subsection 1C.7.0 and the existing resources for Homestead discussed in Subsection 1C.2.0, power supply plans were developed by Homestead to meet their power supply requirements assuming, alternatively, with and without Stanton 2 participation. For purposes of preparing these plans, it was assumed that the alternative resource to participation in the Stanton 2 Project would be Homestead's current base case expansion plan which calls for a 30 MW staged combined cycle unit in 1992/1996 followed by a 21 MW combustion turbine unit in 2001. Homestead's recent 1990 power supply study identified the need for baseload generation in the early to mid 1990s followed by peaking generation in the early 2000s. As a follow-up to Homestead's 1990 power supply study, a Stanton 2 Project Ownership Review Study was performed which examined alternative ownerships of Stanton 2 of up to 16 MW in comparison to building Homestead's planned 30 MW staged combined cycle unit.

Alternative plans for the City of Homestead, with and without Stanton 2 are shown in Table 1C.D.1-2. Annual capacity requirements for the City of Homestead are calculated based on the projected peak demand plus generating capacity reserves based on a 20 percent reserve margin. Annual capacities available from generating resources are calculated based on existing capacity, retirements, additions and participation in off-system generation projects. From the projected capacity requirements and generating resources, the projected annual capacity excess or deficiency is calculated. To meet reserve requirements, each Stanton 2 expansion plan alternative will require a 21 MW combustion turbine in the early 1990s.

The economic analysis of Stanton 2 for the City of Homestead is shown in Table 1C.E.2-1. Comparative annual costs are shown for the plans with and without Stanton 2, along with annual differences in cost. The annual fuel costs were estimated based on the production costing model, in which a monthly simulation of the dispatching of system resources was made based on the projected monthly demand and energy requirements. The fuel costs shown include fuel cost for onsite generation, and fuel cost for participation in off-system generation has also been calculated in each case. For the cases including Stanton 2, fixed costs of Stanton 2 were calculated based on the City of Homestead's

entitlement share times the fixed cost (in \$/kW) as calculated in Subsection 1C.8.0.

The differences between the comparative cost with and without Stanton 2 are shown for the city of Homestead in Table 1C.E.2-1 on an annual basis, percent, cumulative, present worth and cumulative present worth dollars, and percent basis. As shown in this table, the cost for the case including Stanton 2 are projected to be higher than the case without Stanton 2 for the first few years and lower thereafter. The projected cumulative present worth savings are approximately \$3.063 million, or 1.6 percent for the period 1997 through 2010. Homestead's study recognized that ownership for Stanton 2 provided a savings of 300,000 present worth dollars in the year 2010, and that Stanton 2 is expected to have a service life of 30-40 years.

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TABLE 1C.E.2-1
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STANTON 2 ANALYSIS

CITY OF HOMESTEAD

Description	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Without Stanton 2															
FIXED COSTS.....\$000	\$0	\$2,345	\$2,345	\$2,345	\$2,345	\$3,433	\$3,433	\$3,433	\$3,433	\$3,433	\$5,837	\$5,837	\$5,837	\$5,837	\$5,837
O&M COSTS.....\$000	\$1,816	\$1,171	\$1,232	\$1,316	\$1,403	\$2,057	\$3,213	\$3,386	\$3,560	\$3,615	\$3,951	\$4,156	\$3,986	\$4,194	\$4,408
FUEL COSTS.....\$000	\$5,487	\$6,132	\$6,657	\$7,423	\$8,187	\$8,238	\$8,951	\$9,885	\$10,872	\$11,988	\$13,162	\$14,393	\$15,744	\$17,255	\$18,859
Total Costs.....\$000	\$7,303	\$9,648	\$10,234	\$11,084	\$11,935	\$13,728	\$15,597	\$16,704	\$17,665	\$19,036	\$22,950	\$24,386	\$25,567	\$27,286	\$29,104
Cumulative.....\$000	\$7,303	\$16,951	\$27,185	\$38,269	\$50,204	\$63,932	\$79,529	\$96,233	\$114,098	\$133,134	\$156,084	\$180,470	\$206,037	\$233,323	\$262,427
Cum Present Worth..\$000	\$6,809	\$15,197	\$23,493	\$31,870	\$40,281	\$49,301	\$58,857	\$68,399	\$77,914	\$87,368	\$97,995	\$108,524	\$118,816	\$129,058	\$139,244
With Stanton 2															
FIXED COSTS.....\$000	\$0	\$1,618	\$1,618	\$1,618	\$1,618	\$1,618	\$1,618	\$1,618	\$1,618	\$1,618	\$1,618	\$4,167	\$4,167	\$4,167	\$4,167
O&M COSTS.....\$000	\$1,816	\$1,169	\$1,230	\$1,314	\$1,401	\$1,284	\$8,081	\$10,069	\$10,429	\$10,897	\$11,338	\$11,912	\$12,000	\$12,447	\$12,922
FUEL COSTS.....\$000	\$5,487	\$6,132	\$6,657	\$7,423	\$8,187	\$9,097	\$6,113	\$5,980	\$6,558	\$7,346	\$8,126	\$9,048	\$9,933	\$10,997	\$12,052
Total Costs.....\$000	\$7,303	\$8,919	\$9,505	\$10,355	\$11,206	\$11,999	\$15,812	\$17,667	\$18,605	\$19,861	\$21,082	\$25,127	\$26,100	\$27,611	\$29,141
Cumulative.....\$000	\$7,303	\$16,222	\$25,727	\$36,082	\$47,288	\$59,287	\$75,099	\$92,766	\$111,371	\$131,232	\$152,314	\$177,441	\$203,541	\$231,152	\$260,293
Cum Present Worth..\$000	\$6,809	\$14,563	\$22,268	\$30,094	\$37,991	\$45,876	\$55,563	\$65,655	\$75,565	\$85,428	\$95,190	\$106,039	\$116,546	\$126,910	\$137,108
Difference															
Annual.....\$000	\$0	\$729	\$729	\$729	\$729	\$1,729	(\$215)	(\$963)	(\$740)	(\$825)	\$1,868	(\$741)	(\$533)	(\$325)	(\$37)
Percent.....%	0.0%	7.6%	7.1%	6.6%	6.1%	12.6%	-1.4%	-5.8%	-4.1%	-4.3%	8.1%	-3.0%	-2.1%	-1.2%	-0.1%
Cumulative.....\$000	\$0	\$729	\$1,458	\$2,187	\$2,916	\$4,645	\$4,430	\$3,467	\$2,727	\$1,902	\$3,770	\$3,029	\$2,496	\$2,171	\$2,134
Ann. Pres. Worth..\$000	\$0	\$634	\$591	\$551	\$514	\$1,136	(\$132)	(\$550)	(\$394)	(\$410)	\$865	(\$320)	(\$215)	(\$122)	(\$13)
Cum Present Worth..\$000	\$0	\$634	\$1,225	\$1,776	\$2,289	\$3,426	\$3,294	\$2,744	\$2,350	\$1,940	\$2,805	\$2,485	\$2,270	\$2,148	\$2,135
Cum Present Worth...%	0.0%	4.2%	5.2%	5.6%	5.7%	6.9%	5.6%	4.0%	3.0%	2.2%	2.9%	2.3%	1.9%	1.7%	1.5%

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TABLE IC.E.2-1
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FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

CITY OF HOMESTEAD

Description	2006	2007	2008	2009	2010
Without Stanton 2					
FIXED COSTS.....\$000	\$5,837	\$5,837	\$5,837	\$5,837	\$5,837
O&M COSTS.....\$000	\$4,646	\$4,888	\$5,158	\$5,431	\$5,726
FUEL COSTS.....\$000	\$20,495	\$22,446	\$24,739	\$26,945	\$29,547
Total Costs.....\$000	\$30,978	\$33,171	\$35,734	\$38,213	\$41,110
Cummulative.....\$000	\$293,405	\$326,576	\$362,310	\$400,523	\$441,633
Cum Present Worth.\$000	\$149,352	\$159,445	\$169,583	\$179,690	\$189,830
With Stanton 2					
FIXED COSTS.....\$000	\$4,167	\$4,167	\$4,167	\$4,167	\$4,167
O&M COSTS.....\$000	\$13,437	\$13,975	\$14,537	\$15,132	\$15,760
FUEL COSTS.....\$000	\$13,189	\$14,647	\$16,298	\$18,027	\$19,931
Total Costs.....\$000	\$30,793	\$32,789	\$35,002	\$37,326	\$39,858
Cummulative.....\$000	\$291,086	\$323,875	\$358,877	\$396,203	\$436,061
Cum Present Worth.\$000	\$147,157	\$157,133	\$167,063	\$176,936	\$186,767
Difference					
Annual.....\$000	\$185	\$382	\$732	\$887	\$1,252
Percent.....%	0.6%	1.2%	2.0%	2.3%	3.0%
Cummulative.....\$000	\$2,319	\$2,701	\$3,433	\$4,320	\$5,572
Ann. Pres. Worth..\$000	\$60	\$116	\$208	\$235	\$309
Cum Present Worth.\$000	\$2,196	\$2,312	\$2,520	\$2,754	\$3,063
Cum Present Worth... %	1.5%	1.5%	1.5%	1.5%	1.6%

1C.E.3 Utility Board of the City of Key West

Based on the load projections for the Utility Board of the City of Key West (Key West), presented in Subsection 1C.5.0, the reliability criteria discussed in Subsection 1C.7.0 and the existing resources discussed in Subsection 1C.2.0, power supply plans were developed by Key West to meet its power supply requirements assuming, alternatively, with and without Stanton 2 participation. For purposes of preparing these plans, it was assumed that the alternative resource to participation in the Stanton 2 Project would be additional purchases of partial requirements from FPL. Key West determined that purchases of partial requirements from FPL are the most likely alternative to participation in the Stanton 2 Project since partial requirements purchases are projected to be an economical long-term alternative that is reasonably attainable and is projected to be available in the quantities required to meet the demand and energy requirements over the study period.

Alternative plans for Key West, with and without Stanton 2 are shown in Table 1C.D.1-3. Annual capacity requirements for Key West are calculated based on the projected peak demand plus generating capacity reserves based on a 20 percent reserve margin. In addition, it was assumed that Key West would maintain generation on island totaling at least 70 percent of its annual peak load. To meet this requirement, it was assumed that two 8,800 KW diesel units would be added in 2002 and 2014. Annual capacities available from generating resources are calculated based on existing capacity, retirements, additions, and participation in off-system generation projects. From the projected capacity requirements and generating resources, the projected annual capacity excess or deficiency is calculated. From these deficiencies the amount of capacity purchased from partial requirements is calculated. It was assumed that the annual contract demand for partial requirements purchases could not be changed by more than 25 percent in any year. As shown in Table 1C.D.1-3, the projected partial requirements purchases for Key West start at 29 MW in 1997, increasing to 43 MW in 2020 for the plan without Stanton 2, and start at 22 MW in 1997, increasing to 35 MW in 2020 for the plan including Stanton 2.

The economic analysis of Stanton 2 for Key West is shown in Table 1C.E.3-1. Comparative annual costs are shown for the plans with and without Stanton 2, along with annual differences in costs. The average monthly partial requirements demands were calculated based on the results of the monthly production costing

model. The demand costs were calculated based on the projected partial requirements rates as described in Subsection 1C.4.0.

Annual fuel costs were estimated based on the production costing model, in which a monthly simulation of the dispatching of system resources was made based on the projected monthly demand and energy requirements. The fuel costs shown include fuel costs for onsite generation, fuel costs for participation in off-system generation and all purchased energy costs. Variable operation and maintenance expense for onsite generation has also been calculated in each case. For the case including Stanton 2, fixed costs of Stanton 2 were calculated based on the Key West entitlement share times the fixed cost \$/Kw calculated in Subsection 1C.8.0.

The differences between the comparative costs with and without Stanton 2 are shown for Key West in Table 1C.E.3-1 on an annual basis, percent, cumulative, present worth, cumulative present worth dollars, and percent basis. As shown on this table, the costs for the case including Stanton 2 are projected to be higher than the case without Stanton 2 for six of the first seven years, and lower thereafter. The projected cumulative present worth savings for Key West are projected to be approximately \$5.4 million, or 0.6 percent overall savings for the period 1997 - 2021.

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TABLE 1C.E.3-1
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FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

Date: 3/6/91
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UTILITY BOARD OF KEY WEST

Description	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Without Stanton 2															
1 PR Average Demand MW	0.0	0.0	18.4	21.3	24.3	26.2	28.1	30.1	33.0	35.9	37.8	29.1	28.1	30.1	33.0
2 PR Demand Rate ... \$/kW/Mo	13.53	14.42	15.16	15.51	16.13	17.91	18.09	20.00	20.38	21.04	23.17	25.41	25.98	28.39	30.63
3 PR Demand Costs \$000	0	0	3,353	3,972	4,694	5,629	6,106	7,217	8,066	9,062	10,518	8,873	8,770	10,244	12,122
4 Fuel Costs \$000	17,246	19,603	22,971	26,121	28,466	30,907	33,883	37,136	40,339	44,121	47,983	57,356	64,010	69,758	74,869
5 On-Site Generation ... MWh	205	213	282	302	295	291	288	284	275	266	263	342	362	359	349
6 Variable O&M \$/MWh	2.00	2.10	2.19	2.30	2.41	2.52	2.64	2.77	2.90	3.04	3.18	3.33	3.49	3.66	3.83
7 Variable O&M \$000	410	446	619	694	710	734	761	786	797	808	837	1,140	1,264	1,313	1,337
8 Total Costs \$000	17,656	20,049	26,943	30,787	33,870	37,270	40,750	45,139	49,202	53,990	59,338	67,369	74,043	81,315	88,328
With Stanton 2															
9 PR Average Demand MW	0.0	0.0	18.4	21.3	24.3	26.2	21.3	23.3	25.2	28.1	30.1	23.3	20.4	23.3	25.2
10 PR Demand Rate ... \$/kW/Mo	13.53	14.42	15.16	15.51	16.13	17.91	18.09	20.00	20.38	21.04	23.17	25.41	25.98	28.39	30.63
11 PR Demand Costs \$000	0	0	3,353	3,972	4,694	5,629	4,632	5,587	6,168	7,102	8,361	7,099	6,351	7,931	9,270
12 Fuel Costs \$000	17,246	19,603	22,971	26,121	28,466	30,907	33,973	36,478	40,039	43,790	47,605	55,690	63,536	68,407	74,196
13 On-Site Generation ... MWh	205	213	282	302	295	291	306	286	277	275	265	330	370	360	357
14 Variable O&M \$/MWh	2.00	2.10	2.19	2.30	2.41	2.52	2.64	2.77	2.90	3.04	3.18	3.33	3.49	3.66	3.83
15 Variable O&M \$000	410	446	619	694	710	734	808	792	803	835	843	1,100	1,291	1,316	1,367
16 Stanton 2 Non-Fuel . \$000	0	0	0	0	0	0	2,058	2,786	2,822	2,936	2,979	3,024	3,072	3,121	3,172
17 Total Costs \$000	17,656	20,049	26,943	30,787	33,870	37,270	41,472	45,642	49,832	54,664	59,788	66,912	74,250	80,775	88,005
Difference															
18 Annual \$000	0	0	0	0	0	0	(721)	(504)	(630)	(674)	(450)	457	(206)	540	323
19 Percent %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-1.8%	-1.1%	-1.3%	-1.2%	-0.8%	0.7%	-0.3%	0.7%	0.4%
20 Cumulative \$000	0	0	0	0	0	0	(721)	(1,225)	(1,855)	(2,529)	(2,979)	(2,522)	(2,728)	(2,188)	(1,866)
21 Annual Present Worth \$000	0	0	0	0	0	0	(474)	(309)	(360)	(359)	(224)	211	(89)	217	121
22 Cum Present Worth ... \$000	0	0	0	0	0	0	(474)	(783)	(1,143)	(1,501)	(1,725)	(1,513)	(1,602)	(1,385)	(1,264)
23 Cum Present Worth %	-	-	-	-	-	-	-1.8%	-1.4%	-1.4%	-1.3%	-1.2%	-0.9%	-0.8%	-0.6%	-0.5%

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FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

Date: 3/6/91
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UTILITY BOARD OF KEY WEST

Description	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Without Stanton 2																
1 PR Average Demand MW	34.9	36.9	39.8	41.7	43.7	45.6	46.6	47.5	35.9	35.9	36.9	37.8	38.8	39.8	41.7	42.7
2 PR Demand Rate ... \$/kW/Mo	33.10	33.37	35.67	37.66	37.92	40.22	42.66	45.25	48.00	50.91	54.00	57.27	60.75	64.43	68.34	72.49
3 PR Demand Costs \$000	13,870	14,760	17,023	18,850	19,862	22,004	23,835	25,809	20,673	21,926	23,885	25,998	28,285	30,749	34,206	37,126
4 Fuel Costs \$000	80,890	86,625	92,539	99,362	106,824	113,847	122,257	131,192	156,439	168,631	184,753	202,416	221,768	242,970	266,199	291,648
5 On-Site Generation ... MWh	345	342	332	329	326	318	317	316	406	413	420	427	435	442	450	458
6 Variable O&M \$/MWh	4.01	4.20	4.40	4.61	4.83	5.06	5.30	5.55	5.82	6.09	6.38	6.68	7.00	7.33	7.68	8.05
7 Variable O&M \$000	1,384	1,437	1,461	1,517	1,575	1,609	1,680	1,754	2,361	2,516	2,681	2,856	3,044	3,243	3,456	3,683
8 Total Costs \$000	96,144	102,822	111,024	119,729	128,261	137,459	147,772	158,755	179,473	193,073	211,319	231,271	253,097	276,962	303,860	332,457
With Stanton 2																
9 PR Average Demand MW	27.2	30.1	32.0	34.0	36.9	37.8	38.8	40.7	31.0	28.1	29.1	31.0	32.0	33.0	34.0	34.9
10 PR Demand Rate ... \$/kW/Mo	33.1	33.37	35.67	37.66	37.92	40.22	42.66	45.25	48	50.91	54	57.27	60.75	64.43	68.34	72.49
11 PR Demand Costs \$000	10,788	12,041	13,702	15,343	16,773	18,258	19,862	22,122	17,879	17,185	18,857	21,332	23,335	25,499	27,842	30,376
12 Fuel Costs \$000	80,101	85,030	91,718	98,533	104,867	112,825	121,129	128,766	150,301	167,002	182,968	200,461	219,626	240,623	263,627	288,831
13 On-Site Generation ... MWh	347	344	340	330	327	327	319	318	395	421	449	478	510	543	579	617
14 Variable O&M \$/MWh	4.01	4.20	4.40	4.61	4.83	5.06	5.30	5.55	5.82	6.09	6.38	6.68	7.00	7.33	7.68	8.05
15 Variable O&M \$000	1,392	1,446	1,497	1,522	1,579	1,654	1,691	1,765	2,297	2,565	2,863	3,197	3,569	3,984	4,448	4,966
16 Stanton 2 Non-Fuel .. \$000	3,226	3,282	3,341	3,403	3,467	3,533	3,602	3,676	3,751	3,830	3,913	3,999	4,089	4,182	4,281	4,385
17 Total Costs \$000	95,507	101,799	110,258	118,800	126,686	136,271	146,285	156,329	174,228	190,582	208,601	228,988	250,619	274,288	300,199	328,558
Difference																
18 Annual \$000	638	1,023	766	928	1,575	1,189	1,487	2,426	5,245	2,491	2,718	2,282	2,478	2,674	3,662	3,899
19 Percent %	0.7%	1.0%	0.7%	0.8%	1.2%	0.9%	1.0%	1.5%	2.9%	1.3%	1.3%	1.0%	1.0%	1.0%	1.2%	1.2%
20 Cumulative \$000	(1,228)	(205)	561	1,490	3,065	4,253	5,741	8,166	13,411	15,902	18,620	20,902	23,380	26,054	29,716	33,615
21 Annual Present Worth \$000	223	334	233	263	417	293	342	520	1,049	464	472	370	374	377	481	478
22 Cum Present Worth ... \$000	(1,041)	(707)	(474)	(210)	206	499	841	1,362	2,410	2,874	3,347	3,717	4,091	4,468	4,949	5,426
23 Cum Present Worth %	-0.3%	-0.2%	-0.1%	-0.1%	0.0%	0.1%	0.2%	0.3%	0.4%	0.5%	0.5%	0.5%	0.6%	0.6%	0.6%	0.6%

1C.E.3-4

1C.E.4 City of Lake Worth Utilities

Based upon the load projections for the City of Lake Worth Utilities, presented in Subsection 1C.5.0, the reliability criteria discussed in Subsection 1C.7.0, and the existing resources discussed in Subsection 1C.2.0, a supply plan was developed to meet the projected power supply requirements assuming, alternatively, with and without Stanton 2 participation. For purposes of preparing these plans, it was assumed that the alternative resource to participating in the Stanton 2 Project would be additional purchases of partial requirements from FPL. The City's utility staff has determined that purchases of partial requirements from FPL are the most likely alternative to participating in the Stanton 2 Project since partial requirements purchases are projected to be reasonably attainable and available in the quantities required to meet the City's requirements over the study period.

Alternative plans for the City of Lake Worth Utilities, with and without Stanton 2, are shown in Table 1C.D.4-1. Annual capacity requirements are calculated based on the projected peak demand plus generating capacity reserves on a 20 percent margin. Annual capacities available from generating resources are calculated based on existing capacity, retirements, and participation in off-system generating projects. From the projected capacity requirements and generating resources, the projected annual capacity excess or deficiency is calculated. From these, the amount of capacity purchased from partial requirements is calculated. It was assumed that the annual contract demand for partial requirements purchases could not be changed by more than 25 percent in any year, and thus, purchases in excess of minimum needs may be required before or after certain critical years. As shown in Table 1C.D.1-4, the projected partial requirements purchases for the plan without Stanton 2 start at 8 MW in 1992, increase to 22 MW in 1997, and to a high of 36 MW in 2005. For the plan which includes Stanton 2, purchases start at 7 MW in 1992, increase to 17 MW in 1997, and to a high of 30 MW in 2005.

Results of the economic analysis of Stanton 2 for the City of Lake Worth Utilities is shown in Table 1C.E.4-1. Comparative annual costs are shown for plans with and without Stanton 2, along with annual differences in costs. The average monthly partial requirements demands were calculated based on the results of an annual production costing model. The demand costs were calculated

based on the projected partial requirements rates as described in Subsection 1C.4.0.

Annual fuel costs developed by the production cost model include fuel used by City owned and operated generation, fuel costs for participating in off-system generation projects, and the energy charge for purchased power. Variable operation and maintenance expense for both cases includes costs for both City owned generation and for Stanton 1. For the case including Stanton 2, fixed costs of Stanton 2 were calculated based on the City's entitlement share times the fixed cost (in \$/kW) calculated in Subsection 1C.8.0.

The differences between the comparative costs with and without Stanton 2 are shown in Table 1C.E.4-1. Costs for the case including Stanton are projected to be lower than the case without Stanton 2 for all years except for the initial three years that Stanton is available (1997-1999). The cumulative present worth savings are projected to be approximately \$3.5 million, or 1.4 percent for the period 1992-2010. During the final three years of this period (2008-2010), cumulative present worth savings increase by over \$200,000 each year. This rate of savings is expected to continue for the remaining service life of the Stanton 2 unit.

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TABLE IC.E.4-1
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FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

CITY OF LAKE WORTH

Description	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005

Without Stanton 2															

Total Costs \$000	\$9,623	\$11,367	\$12,277	\$13,600	\$14,991	\$16,667	\$18,505	\$21,139	\$24,442	\$26,649	\$29,065	\$31,959	\$33,612	\$36,893	\$41,114
Cummulative \$000	\$9,623	\$20,990	\$33,267	\$46,867	\$61,858	\$78,525	\$97,030	\$118,169	\$142,611	\$169,260	\$198,325	\$230,284	\$263,896	\$300,789	\$341,903
Cum Present Worth ... \$000	\$8,972	\$18,855	\$28,806	\$39,085	\$49,650	\$60,601	\$71,939	\$84,014	\$97,033	\$110,267	\$123,726	\$137,524	\$151,055	\$164,903	\$179,292

With Stanton 2															

Total Costs \$000	\$9,623	\$11,257	\$12,119	\$13,394	\$14,761	\$16,334	\$18,559	\$21,476	\$24,468	\$26,640	\$28,851	\$31,476	\$33,072	\$36,048	\$40,125
Cummulative \$000	\$9,623	\$20,880	\$32,999	\$46,393	\$61,154	\$77,488	\$96,047	\$117,523	\$141,991	\$168,631	\$197,482	\$228,958	\$262,030	\$298,078	\$338,203
Cum Present Worth ... \$000	\$8,972	\$18,759	\$28,583	\$38,706	\$49,108	\$59,841	\$71,211	\$83,479	\$96,512	\$109,742	\$123,101	\$136,691	\$150,005	\$163,535	\$177,578

Difference															

Annual \$000	\$0	\$110	\$158	\$206	\$230	\$333	(\$54)	(\$337)	(\$26)	\$9	\$214	\$483	\$540	\$845	\$989
Percent %	0.0%	1.0%	1.3%	1.5%	1.5%	2.0%	-0.3%	-1.6%	-0.1%	0.0%	0.7%	1.5%	1.6%	2.3%	2.4%
Cummulative \$000	\$0	\$110	\$268	\$474	\$704	\$1,037	\$983	\$646	\$620	\$629	\$843	\$1,326	\$1,866	\$2,711	\$3,700
Annual Present Worth \$000	\$0	\$96	\$128	\$156	\$162	\$219	(\$33)	(\$193)	(\$14)	\$4	\$99	\$209	\$217	\$317	\$346
Cum Present Worth ... \$000	\$0	\$96	\$224	\$379	\$541	\$760	\$727	\$535	\$521	\$525	\$624	\$833	\$1,050	\$1,368	\$1,714
Cum Present Worth %	0.0%	0.5%	0.8%	1.0%	1.1%	1.3%	1.0%	0.6%	0.5%	0.5%	0.5%	0.6%	0.7%	0.8%	1.0%

IC.E.4-3

031591

TABLE IC.E.4-1
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FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

CITY OF LAKE WORTH

Description		2006	2007	2008	2009	2010

Without Stanton 2						

Total Costs	\$000	\$44,704	\$49,923	\$58,140	\$61,457	\$64,094
Cumulative	\$000	\$386,607	\$436,530	\$494,670	\$556,127	\$620,221
Cum Present Worth ...	\$000	\$193,880	\$209,069	\$225,563	\$241,819	\$257,627
With Stanton 2						

Total Costs	\$000	\$44,096	\$49,077	\$56,581	\$59,713	\$62,273
Cumulative	\$000	\$382,299	\$431,376	\$487,957	\$547,670	\$609,943
Cum Present Worth ...	\$000	\$191,968	\$206,900	\$222,951	\$238,746	\$254,105
Difference						

Annual	\$000	\$608	\$846	\$1,559	\$1,744	\$1,821
Percent	%	1.4%	1.7%	2.7%	2.8%	2.8%
Cumulative	\$000	\$4,308	\$5,154	\$6,713	\$8,457	\$10,278
Annual Present Worth	\$000	\$198	\$257	\$442	\$461	\$449
Cum Present Worth ...	\$000	\$1,912	\$2,169	\$2,612	\$3,073	\$3,522
Cum Present Worth	%	1.0%	1.0%	1.2%	1.3%	1.4%

IC.E.4-4

1C.E.5 City of Starke

Based on the load projections for Starke in Subsection 1C.5.0, the reliability criteria discussed in Subsection 1C.7.0 and the existing resources discussed in Subsection 1C.2.0, a power supply plan was developed to meet power supply requirements assuming, alternatively, with and without Stanton 2 participation. For purposes of preparing these plans, it was assumed that the alternative resource to participation in the Stanton 2 Project would be additional purchases of partial requirements from FPL. Increased purchases are the most likely alternative to participation in the Stanton 2 Project, since partial requirements purchases are projected to be an economical long-term alternative that is reasonably attainable and is projected to be available in the quantities required to meet the City's requirements over the study period.

Alternative plans for Starke, with and without Stanton 2, are shown in Table 1C.D.1-5. Annual capacity requirements for Starke are calculated based on the projected peak demand plus generating capacity reserves based on a 20 percent reserve margin. Annual capacities available from generating resources are calculated based on existing capacity, nonfirm purchases, and participation in off-system generation projects. From the projected capacity requirements and generating resources, the projected annual capacity excess or deficiency is calculated. From these deficiencies the amount of capacity purchased from partial requirements is calculated. It was assumed that the annual contract demand for partial requirements could not be changed by more than 25 percent in any year. As shown in Table 1C.D.1-5, the current 1991 purchase of 2 MW is projected to increase to 5 MW in 1997 and 20 MW in 2020 for the plan without Stanton 2, and for the plan with Stanton 2 to 4 MW in 1997 and 19 MW in 2020.

The economic analysis of Stanton 2 for Starke is shown in Table 1C.E.5-1. Comparative annual costs are shown for the plans with and without Stanton 2, along with annual differences in costs. The average monthly partial requirements demands were calculated based on the results of the monthly production costing model. The demand costs were calculated based on the projected partial requirements rates as described in Subsection 1C.4.0.

Annual fuel and variable operation and maintenance costs were estimated based on the production costing model, in which a monthly simulation of the dispatching of system resources was made based on projected monthly demand and energy requirements. For the case including Stanton 2, fixed costs of

Stanton 2 were calculated based on the Starke entitlement share times the fixed cost \$/kW calculated in Subsection 1C.8.0.

The differences between the comparative costs with and without Stanton 2 are shown in Table 1C.E.5-1 on an annual percent, cumulative, present worth, cumulative present worth, and cumulative present worth percent basis. As shown on this table, the annual costs for the case including Stanton 2 are lower the first year, higher the next six years, and lower thereafter. The primary reason for the negative results in some years can be attributed to the large impact that a 1.0 MW change has on Starke's costs. PR must be purchased in whole MW quantities. The projected cumulative present worth savings for Starke are projected to be approximately \$720,000 for the period 1997-2021.

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TABLE IC.E.5-1
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STANTON 2 ANALYSIS

CITY OF STARKE

Description	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Without Stanton 2															
PR Avg Demand MW	1.00	2.00	2.00	3.00	3.00	4.00	4.00	4.00	5.00	6.17	7.08	7.08	7.25	8.08	8.17
PR Demand Rate \$/kw-mo	\$13.53	\$14.42	\$15.16	\$15.51	\$16.13	\$17.91	\$18.09	\$20.00	\$20.38	\$21.04	\$23.17	\$25.41	\$25.98	\$28.39	\$30.63
PR Demand Costs .. \$000	\$162	\$346	\$364	\$558	\$581	\$860	\$868	\$960	\$1,223	\$1,557	\$1,969	\$2,160	\$2,260	\$2,754	\$3,002
Fuel,Var O&M Costs \$000	\$1,815	\$1,876	\$2,047	\$2,217	\$2,400	\$2,533	\$2,734	\$2,979	\$3,186	\$4,004	\$4,234	\$4,753	\$5,244	\$5,626	\$6,188
Total Costs \$000	\$1,977	\$2,222	\$2,410	\$2,775	\$2,980	\$3,392	\$3,602	\$3,939	\$4,409	\$5,561	\$6,204	\$6,913	\$7,504	\$8,380	\$9,190
Cummulative \$000	\$1,977	\$4,199	\$6,609	\$9,384	\$12,365	\$15,757	\$19,359	\$23,298	\$27,708	\$33,269	\$39,472	\$46,385	\$53,889	\$62,269	\$71,459
Cum Present Worth \$000	\$1,843	\$3,775	\$5,729	\$7,826	\$9,926	\$12,155	\$14,362	\$16,613	\$18,961	\$21,723	\$24,596	\$27,580	\$30,601	\$33,746	\$36,963
With Stanton 2															
PR Avg Demand MW	1.00	2.00	2.00	3.00	3.00	4.00	3.00	4.00	5.00	6.00	6.08	7.00	7.00	7.08	7.17
PR Demand Rate \$/kw-mo	\$13.53	\$14.42	\$15.16	\$15.51	\$16.13	\$17.91	\$18.09	\$20.00	\$20.38	\$21.04	\$23.17	\$25.41	\$25.98	\$28.39	\$30.63
PR Demand Costs .. \$000	\$162	\$346	\$364	\$558	\$581	\$860	\$651	\$960	\$1,223	\$1,515	\$1,691	\$2,134	\$2,182	\$2,413	\$2,634
Fuel,Var O&M Costs \$000	\$1,815	\$1,876	\$2,047	\$2,217	\$2,400	\$2,533	\$2,678	\$2,821	\$3,026	\$3,805	\$4,154	\$4,499	\$5,005	\$5,508	\$6,060
Stanton2 Fix Costs \$000							\$261	\$352	\$356	\$360	\$365	\$369	\$374	\$379	\$384
Total Costs \$000	\$1,977	\$2,222	\$2,410	\$2,775	\$2,980	\$3,392	\$3,591	\$4,133	\$4,605	\$5,680	\$6,210	\$7,002	\$7,561	\$8,300	\$9,078
Cummulative \$000	\$1,977	\$4,199	\$6,609	\$9,384	\$12,365	\$15,757	\$19,347	\$23,481	\$28,085	\$33,765	\$39,975	\$46,977	\$54,538	\$62,838	\$71,916
Cum Present Worth \$000	\$1,843	\$3,775	\$5,729	\$7,826	\$9,926	\$12,155	\$14,355	\$16,716	\$19,169	\$21,990	\$24,865	\$27,888	\$30,932	\$34,048	\$37,225
Difference															
Annual \$000	\$0	\$0	\$0	\$0	\$0	\$0	\$12	(\$194)	(\$195)	(\$119)	(\$6)	(\$90)	(\$57)	\$80	\$112
Percent %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	-4.9%	-4.4%	-2.1%	-0.1%	-1.3%	-0.8%	1.0%	1.2%
Cummulative \$000	\$0	\$0	\$0	\$0	\$0	\$0	\$12	(\$182)	(\$378)	(\$497)	(\$503)	(\$592)	(\$649)	(\$569)	(\$458)
Ann Present Worth \$000	\$0	\$0	\$0	\$0	\$0	\$0	\$7	(\$111)	(\$104)	(\$59)	(\$3)	(\$39)	(\$23)	\$30	\$39
Cum Present Worth \$000	\$0	\$0	\$0	\$0	\$0	\$0	\$7	(\$104)	(\$208)	(\$267)	(\$270)	(\$308)	(\$331)	(\$301)	(\$262)
Cum Present Worth ... %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	-0.6%	-1.1%	-1.2%	-1.1%	-1.1%	-1.1%	-0.9%	-0.7%

IC.E.5-3

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TABLE 1C.E.5-1
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STANTON 2 ANALYSIS
-----CITY OF STARKE

Description	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021

Without Stanton 2																

PR Avg Demand MW	8.33	9.17	9.25	10.08	10.25	10.33	10.58	11.33	11.58	12.33	13.58	13.67	14.00	14.67	15.58	15.83
PR Demand Rate \$/kw-mo	\$33.10	\$33.37	\$35.67	\$37.66	\$37.92	\$40.22	\$42.66	\$45.25	\$48.00	\$50.91	\$54.00	\$57.27	\$60.75	\$64.43	\$68.34	\$72.49
PR Demand Costs .. \$000	\$3,310	\$3,671	\$3,959	\$4,557	\$4,664	\$4,987	\$5,418	\$6,154	\$6,672	\$7,535	\$8,802	\$9,392	\$10,206	\$11,340	\$12,780	\$13,773
Fuel,Var O&M Costs \$000	\$6,892	\$7,179	\$7,898	\$8,501	\$9,123	\$10,001	\$11,043	\$11,745	\$12,791	\$13,967	\$15,372	\$16,728	\$18,348	\$19,852	\$21,218	\$23,293

Total Costs \$000	\$10,202	\$10,850	\$11,857	\$13,058	\$13,787	\$14,989	\$16,461	\$17,899	\$19,463	\$21,502	\$24,174	\$26,120	\$28,554	\$31,191	\$33,997	\$37,065

Cummulative \$000	\$81,661	\$92,511	\$104,368	\$117,426	\$131,213	\$146,202	\$162,662	\$180,561	\$200,024	\$221,526	\$245,700	\$271,820	\$300,374	\$331,565	\$365,563	\$402,628
Cum Present Worth \$000	\$40,292	\$43,593	\$46,957	\$50,411	\$53,811	\$57,258	\$60,787	\$64,366	\$67,994	\$71,731	\$75,649	\$79,595	\$83,618	\$87,716	\$91,880	\$96,113

With Stanton 2																

PR Avg Demand MW	8.08	8.08	8.25	9.08	9.25	10.08	10.25	10.33	10.58	11.33	12.50	13.25	13.58	13.67	14.58	14.83
PR Demand Rate \$/kw-mo	\$33.10	\$33.37	\$35.67	\$37.66	\$37.92	\$40.22	\$42.66	\$45.25	\$48.00	\$50.91	\$54.00	\$57.27	\$60.75	\$64.43	\$68.34	\$72.49
PR Demand Costs .. \$000	\$3,211	\$3,237	\$3,531	\$4,105	\$4,209	\$4,867	\$5,247	\$5,611	\$6,096	\$6,924	\$8,100	\$9,106	\$9,902	\$10,567	\$11,960	\$12,903
Fuel,Var O&M Costs \$000	\$6,579	\$7,066	\$7,734	\$8,322	\$8,941	\$9,578	\$10,615	\$11,509	\$12,534	\$13,677	\$15,117	\$16,223	\$17,741	\$19,454	\$20,759	\$22,816
Stanton2 Fix Costs \$000	\$389	\$395	\$401	\$407	\$413	\$420	\$427	\$434	\$442	\$450	\$458	\$466	\$475	\$484	\$494	\$504

Total Costs \$000	\$10,179	\$10,698	\$11,667	\$12,834	\$13,563	\$14,865	\$16,289	\$17,554	\$19,072	\$21,050	\$23,675	\$25,795	\$28,118	\$30,505	\$33,212	\$36,223

Cummulative \$000	\$82,095	\$92,792	\$104,459	\$117,293	\$130,856	\$145,721	\$162,010	\$179,564	\$198,636	\$219,686	\$243,361	\$269,156	\$297,274	\$327,779	\$360,991	\$397,214
Cum Present Worth \$000	\$40,546	\$43,801	\$47,111	\$50,505	\$53,851	\$57,269	\$60,762	\$64,271	\$67,826	\$71,485	\$75,322	\$79,219	\$83,181	\$87,188	\$91,256	\$95,393

Difference																

Annual \$000	\$23	\$152	\$191	\$224	\$224	\$124	\$172	\$345	\$391	\$451	\$499	\$325	\$436	\$687	\$785	\$842
Percent %	0.2%	1.4%	1.6%	1.7%	1.6%	0.8%	1.0%	1.9%	2.0%	2.1%	2.1%	1.2%	1.5%	2.2%	2.3%	2.3%
Cummulative \$000	(\$434)	(\$282)	(\$91)	\$134	\$357	\$481	\$653	\$998	\$1,389	\$1,840	\$2,339	\$2,664	\$3,100	\$3,787	\$4,572	\$5,414
Ann Present Worth \$000	\$8	\$46	\$54	\$59	\$55	\$28	\$37	\$69	\$73	\$78	\$81	\$49	\$61	\$90	\$96	\$96
Cum Present Worth \$000	(\$254)	(\$208)	(\$154)	(\$95)	(\$39)	(\$11)	\$26	\$95	\$168	\$246	\$327	\$376	\$438	\$528	\$624	\$720
Cum Present Worth ... %	-0.6%	-0.5%	-0.3%	-0.2%	-0.1%	-0.0%	0.0%	0.1%	0.2%	0.3%	0.4%	0.5%	0.5%	0.6%	0.7%	0.7%

1C.E.5-4

1C.E.6 All-Requirements Project

Based on the load projections for the All-Requirements Project presented in Subsection 1C.5.0, the reliability criteria discussed in Subsection 1C.7.0 and the existing resources discussed in Subsection 1C.2.0, a power supply plan was developed to meet power supply requirements assuming, alternatively, with and without Stanton 2 participation. For the purpose of preparing these plans, it was assumed that the alternative resource to participation in the Stanton 2 Project would be additional purchases of partial requirements from FPL and FPC. Increased purchases are the most likely alternative to participation in the Stanton 2 Project, since partial requirements purchases are projected to be an economical long-term alternative that is reasonably attainable and is projected to be available in the quantities required to meet the Project's requirements over the study period.

Alternative plans for the Project, with and without Stanton 2 are shown on Table 1C.D.2-1. Annual capacity requirements for the Project are calculated based on the projected co-incident peak demand plus generating capacity reserves based on a 20 percent reserve margin. Annual capacities available from generating resources are calculated based on existing capacity, nonfirm purchases and participation in off-system generation projects. From the projected capacity requirements and generating resources, the projected annual capacity excess or deficiency is calculated. From these deficiencies the amount of capacity purchased from partial requirements is calculated. It was assumed that the annual contract demand for partial requirements could not be changed by more than 25 percent in any year. As shown in Table 1C.D.2-1, the current 1991 purchase of 200 MW is projected to increase to 308 MW in 1997 and 852 MW in 2020 for the plan without Stanton 2, and for the plan with Stanton 2 to 289 MW in 1997 and 833 MW in 2020.

The economic analysis of Stanton 2 for the Project is shown in Table 1C.E.6-1. Comparative annual costs are shown for the plans with and without Stanton 2, along with annual differences in costs. The average monthly partial requirements demands were calculated based on the results of the monthly production costing model. The demand costs were calculated based on the projected partial requirements rates as described in Subsection 1C.4.0.

Annual fuel and variable operation and maintenance costs were estimated based on the production costing model, in which a monthly simulation of the

dispatching of system resources was made based on projected monthly demand and energy requirements. For the case including Stanton 2, fixed costs of Stanton 2 were calculated based on the Project's entitlement share times the fixed cost \$/kW calculated in Subsection 1C.8.0.

The differences between the comparative costs with and without Stanton 2 are shown in Table 1C.E.6-1 on an annual percent, cumulative, present worth, cumulative present worth, and cumulative present worth percent basis. As shown on this table, the annual costs for the case including Stanton 2 are higher for the first full seven years, and lower thereafter. The projected cumulative present worth savings for the Project are projected to be approximately \$11.9 million for the period 1997-2021.

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TABLE 1C.E.6-1
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STANTON 2 ANALYSIS

ALL REQUIREMENTS PROJECT

Description	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021

Without Stanton 2																

FPC PR Demand Costs \$000	54,120	67,564	69,860	72,099	83,671	89,796	96,363	103,320	110,668	118,535	126,961	141,518	151,230	161,622	172,670	183,940
FPL PR Demand Costs \$000	55,608	59,265	65,490	70,951	73,716	80,118	87,538	95,568	104,256	113,631	125,712	136,761	147,987	160,044	173,857	188,139
Fuel Costs \$000	237,051	246,476	268,765	284,680	311,996	333,367	362,683	388,615	421,587	450,757	493,085	539,767	580,181	625,023	672,313	719,847

Total Costs \$000	346,779	373,305	404,114	427,730	469,384	503,281	546,584	587,502	636,511	682,922	745,758	818,046	879,398	946,689	1,018,840	1,091,926

With Stanton 2																

FPC PR Demand Costs \$000	51,980	65,095	67,371	69,595	80,838	86,827	93,251	100,060	107,252	114,956	123,211	137,589	147,113	157,309	168,150	179,212
FPL PR Demand Costs \$000	52,828	56,462	62,494	67,788	70,531	76,740	83,955	91,224	99,648	108,744	120,528	131,263	142,155	154,632	167,296	181,203
Fuel Costs \$000	233,758	242,948	265,065	280,785	307,888	328,834	357,894	383,478	416,148	444,866	486,874	532,897	572,801	617,173	663,869	710,949
Stanton 2 Fixed Costs \$000	7,005	7,107	7,214	7,324	7,439	7,558	7,682	7,813	7,947	8,089	8,236	8,389	8,548	8,714	8,889	9,071

Total Costs \$000	345,571	371,611	402,144	425,492	466,696	499,959	542,783	582,575	630,995	676,655	738,849	810,139	870,617	937,828	1,008,204	1,080,435

Difference																

Annual \$000	1,208	1,694	1,970	2,238	2,689	3,322	3,802	4,927	5,516	6,267	6,909	7,907	8,781	8,861	10,636	11,491
Percent %	0.3%	0.5%	0.5%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%	0.9%	0.9%	1.0%	1.0%	0.9%	1.0%	1.1%
Cumulative \$000	(5,350)	(3,657)	(1,686)	552	3,240	6,562	10,364	15,291	20,807	27,075	33,984	41,891	50,673	59,533	70,170	81,660
Annual Present Worth \$000	423	553	599	635	711	819	874	1,056	1,103	1,168	1,201	1,281	1,327	1,248	1,397	1,407
Cum Present Worth \$000	(3,441)	(2,888)	(2,289)	(1,654)	(943)	(123)	751	1,807	2,910	4,079	5,279	6,561	7,888	9,136	10,533	11,941
Cum Present Worth %	-0.2%	-0.2%	-0.1%	-0.1%	-0.0%	-0.0%	0.0%	0.1%	0.1%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%

1C.E.6-3

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TABLE IC.E.6-1
Page 1 of 2FLORIDA MUNICIPAL POWER AGENCY
STANTON 2 ANALYSIS

ALL REQUIREMENTS PROJECT

Description	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005

Without Stanton 2															
FPC PR Demand Costs \$000	6,579	8,744	8,158	9,654	11,581	13,822	15,478	17,603	22,539	24,226	28,926	32,836	37,468	44,354	48,761
FPL PR Demand Costs \$000	5,520	6,749	6,731	7,631	9,872	12,250	13,242	15,600	16,875	18,936	22,243	27,138	30,864	37,815	45,577
Fuel Costs \$000	56,585	65,326	72,296	82,328	89,125	101,590	110,032	125,929	134,861	151,780	163,750	178,867	188,234	205,089	217,402
Total Costs \$000	68,685	80,819	87,185	99,613	110,577	127,662	138,751	159,132	174,275	194,942	214,919	238,841	256,566	287,259	311,741

With Stanton 2															
FPC PR Demand Costs \$000	6,579	8,744	8,158	9,654	11,581	13,822	14,130	16,160	20,795	22,449	26,911	30,836	35,439	42,301	46,679
FPL PR Demand Costs \$000	5,520	6,749	6,731	7,631	9,872	12,036	12,374	14,160	15,407	17,169	20,575	25,003	28,994	35,431	43,005
Fuel Costs \$000	56,585	65,326	72,296	82,328	89,125	101,695	108,635	124,386	133,245	150,098	161,859	176,724	185,914	202,443	214,398
Stanton 2 Fixed Costs \$000	0	0	0	0	0	0	4,696	6,337	6,408	6,483	6,560	6,641	6,727	6,816	6,909
Total Costs \$000	68,685	80,819	87,185	99,613	110,577	127,552	139,834	161,043	175,856	196,199	215,906	239,204	257,074	286,991	310,991

Difference															
Annual \$000	0	0	0	0	0	111	(1,082)	(1,911)	(1,581)	(1,256)	(987)	(363)	(507)	268	750
Percent %	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	-0.8%	-1.2%	-0.9%	-0.6%	-0.5%	-0.2%	-0.2%	0.1%	0.2%
Cumulative \$000	0	0	0	0	0	111	(972)	(2,882)	(4,463)	(5,720)	(6,707)	(7,069)	(7,577)	(7,309)	(6,558)
Annual Present Worth \$000	0	0	0	0	0	78	(711)	(1,170)	(903)	(669)	(490)	(168)	(219)	108	282
Cum Present Worth \$000	0	0	0	0	0	78	(633)	(1,804)	(2,707)	(3,376)	(3,866)	(4,034)	(4,253)	(4,145)	(3,864)
Cum Present Worth %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.1%	-0.3%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.3%	-0.3%

IC.E.6-4

**ORLANDO UTILITIES
COMMISSION
CURTIS H. STANTON
ENERGY CENTER**

UNIT 2

**SUPPLEMENTAL
SITE
CERTIFICATION
APPLICATION**

VOLUME 1D

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT 2

SUPPLEMENTAL
SITE CERTIFICATION APPLICATION

VOLUME 1D



BLACK & VEATCH

8400 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114, (913) 339-2000

Orlando Utilities Commission
Stanton Energy Center Unit 2

B&V Project 16805
B&V File 33.0600
September 12, 1991

Ms. Diane K. Kiesling
Division of Administrative Hearings
1209 Apalachee Parkway
DeSoto Building
Tallahassee, FL 32399-1550

Subject: DOAH Case No: 91-1813EPP

Dear Ms. Kiesling:

Pursuant to your order of July 18, 1991, please find one copy of the prepared direct testimonies which will be presented at the September 23, 1991 hearing for the Orlando Utilities Commission Stanton Energy Center Unit 2 Supplemental Site Certification Application.

Enclosed is a Certificate of Service, certifying those parties which have also been provided with a copy of the prepared direct testimonies.

Please contact Mr. C. Laurence Keesey with Young, Van Assenderp, Varnadoe, & Benton, P.A. at (904) 222-7206 if you have any questions.

Very truly yours,

BLACK & VEATCH

Hal E. Smith

bjr
Enclosure

ORLANDO UTILITIES COMMISSION

**CURTIS H. STANTON ENERGY CENTER
UNIT 2**

**SUPPLEMENTAL
SITE CERTIFICATION APPLICATION**

VOLUME 1D

Stanton Energy Center Unit 2
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**Orlando Utilities Commission
Curtis H. Stanton Energy Center
Unit 2
Supplemental
Site Certification Application
Volume 1D**



1D.1.0 Overview and Summary

1D.1.1 Overview of the KUA System

The City of Kissimmee is located approximately 15 miles south of Orlando, Florida, and approximately 18 miles southeast of Walt Disney World. The Kissimmee Utility Authority (KUA) service area encompasses 85 square miles including the City of Kissimmee and adjoining areas.

For many years the Orlando area has been one of the fastest growing areas in the country. KUA's annual net energy for load growth has averaged 10.41 percent for the last 14 years from 1976 to 1989. Net energy for load includes all categories of sales and uses plus system losses. Annual growth in the number of residential and general service customers has averaged 8.6 and 7.6 percent, respectively.

Projections of load growth, as outlined in Subsection 1D.5.0, present a picture of continued energy and demand growth in the future. Table 1D.5.1-1 projects a 4.3 percent average annual growth rate in net energy for load from 1990 through 2020. Peak MW demand is also expected to continue in growth. Table 1D.6.2-3 (which includes the effect of KUA's proposed load management program) indicates an annual growth rate in summer peak demand of 4.5 percent, with demand reaching a level of 634 MW in 2020. These sustained growth rates of energy and demand for the KUA system will give rise to a need for significant capacity resource additions in the future.

KUA currently has a total net summer generation capability of 114.65 MW and a net winter capability of 123.05 MW. These capacity resources, as described in detail in Subsection 1D.2.5, are made up of a combination of wholly owned and jointly owned generation units. Table 1D.2.5-1 lists these resources. In addition to the generation resources mentioned, KUA has firm purchase agreements with Orlando Utilities Commission, Florida Power Corporation, and Tampa Electric Company.

1D.1.2 Summary

In 1989, KUA retained Black & Veatch to provide a system operation and expansion evaluation. The evaluation concluded that ownership participation in OUC's Stanton 2 of up to 50 MW offered the least cost alternative for KUA. Based on KUA's ownership share in Stanton 1, KUA has been allocated a 16.9 MW or 3.83 percent ownership share of Stanton 2. As evidenced in Subsection 1D.2.5, KUA has developed an effective strategy of joint ownership in other plants. This type of joint ownership provides KUA with long-term ownership of a low-cost, baseload unit; provides energy from a low-cost and reliable fuel source (coal); and enables KUA to enjoy the economics of scale of a larger unit while only purchasing a quantity of capacity optimal for KUA's system needs.

Stanton 2 will be a replicate of Stanton 1, an existing coal fired unit owned primarily by the Orlando Utilities Commission (KUA's ownership share is 4.8193 percent in Stanton 1). Stanton 2 should realize significant cost savings by using many of the same design and construction procedures that were used in Stanton 1. This will also provide KUA with the opportunity for obtaining reliable generation capacity. A detailed description of the Stanton 2 project is presented in Volume 1A.

1D.2 DESCRIPTION OF
EXISTING SYSTEM

1D.2.0 Description of Existing System

1D.2.1 General

Kissimmee Utility Authority (KUA) is a municipal electric utility engaged in the activity of producing and distributing electricity to its customers. The KUA service territory includes the area in and around the City of Kissimmee, Florida, including the township of Campbell City, Florida. The electric system was established under laws of the State of Florida and the City Charter in 1901. In 1985, KUA was established as an independent utility authority. KUA is headed by a General Manager and a five-member Board of Directors.

1D.2.2 Description of Service Area

The KUA's headquarters are located in the City of Kissimmee approximately 15 miles south of Orlando and approximately 18 miles southeast of Walt Disney World. The KUA service area encompasses 85 square miles including the City of Kissimmee and the adjoining areas as shown on Figure 1D.2.2-1. The service area is bordered on the north by the Orange-Osceola county line and by the City of St. Cloud's service area on the east. The remainder of KUA's service area is surrounded by the service area of Florida Power Corporation.

KUA serves approximately an equal number of customers within the Kissimmee city limits as outside the city boundaries. The majority of the KUA's load and load growth is in the northern portion of its service territory.

1D.2.3 Historical Customer Growth

Electrical demand on the KUA system has increased dramatically in recent years at a time when many of the nation's utilities experienced peak and energy growth rates below 3 percent annually. This growth has been the direct result of the large increase in the number of customers on the KUA system. As seen in Table 1D.2.3-1, from 1976 to 1990, the total number of residential customers increased from 8,666 to 27,363, an 8.6 percent annual average rate of growth. The number of general service customers grew from 1,735 to 4,814 during this period, a 7.6 percent annual average growth rate. The total number of residential plus general service customers increased from 10,401 in 1976 to 32,117 in 1990. This is an 8.4 percent average annual rate of growth.

Table 1D.2.3-1
Historical Number of Residential, General Service,
and Total Customers, 1976-1990

Fiscal Year	Residential Customers	General Service Customers	Total Residential Plus General Service Customers
1976	8,666	1,735	10,401
1977	8,860	1,732	10,592
1978	9,518	1,775	11,293
1979	10,178	1,887	12,065
1980	11,146	1,959	13,105
1981	12,611	1,896	14,507
1982	13,770	1,986	15,756
1983	14,909	2,076	16,985
1984	16,363	3,263	19,626
1985	18,091	2,649	20,740
1986	19,427	2,824	22,251
1987	20,996	3,099	24,095
1988	22,235	3,515	25,750
1989	24,464	4,814	28,765
1990	27,363	4,814	32,117
1976-90 Average Annual Percent Growth	8.6	7.6	8.4

1D.2.4 Historical Energy Requirements and Peak Demand

As seen in Table 1D.2.4-1, 1976 total residential sales were approximately 81 GWh. By 1990, total residential sales had increased to 316.9 GWh, an annual average growth rate of 10.2 percent. Sales to the general services sector also increased dramatically from 76.3 GWh in 1976 to 326.3 GWh in 1990. This equates to a 10.9 percent annual average growth rate. KUA's net energy for load, which includes all categories of sales and uses plus system losses, increased from 171.3 GWh in 1976 to 697.7 GWh in 1990. This is an annual average growth rate of 10.6 percent.

The KUA system winter and summer peaks also experienced substantial growth from 1976 to 1990. The winter peak has been consistently higher than the summer peak. The winter peak of 1990 was 200 MW which is unusually high due to the extreme cold weather. KUA's winter peak has grown at approximately 11.6 percent since 1976. The summer peak has grown at a rate of 10.0 percent during this period. The 1990 summer peak was 149 MW compared to 39 MW in 1976.

As detailed in Subsection 1D.5.0 Load Forecast, the KUA system is projected to experience significant growth in energy requirements and peak demand although at a lower rate than experienced from 1976 through 1990.

Table 1D.2.4-1
Historical Energy Sales by Sector, Net Energy
for Load, and Peak Demand

Fiscal Year	Residential Sales (GWh)	General Services Sales (GWh)	Total Sales (GWh)	KUA Use Lighting and Losses (GWh)	Net Energy for Load (GWh)	Peak MW Demand	
						Summer	Winter
1976	81.0	76.3	157.3	14.0	171.3	39	43
1977	91.0	80.6	171.6	19.3	190.9	38	46
1978	103.7	86.9	190.6	22.2	212.8	42	47
1979	110.4	93.8	204.2	24.5	228.7	44	52
1980	117.3	105.6	222.9	24.4	247.3	57	64
1981	135.0	118.5	253.5	21.6	275.1	67	80
1982	138.7	128.6	267.3	24.1	291.4	67	87
1983	149.5	141.4	290.9	26.7	317.6	77	78
1984	165.1	155.1	320.2	32.0	325.2	82	97
1985	186.5	178.7	365.2	32.9	398.1	93	121
1986	206.1	202.7	408.8	39.1	447.9	101	128
1987	234.7	236.1	470.8	39.3	510.1	115	115
1988	245.3	262.7	507.7	32.3	540.0	121	131
1989	276.9	295.3	572.2	48.8	621.0	141	148
1990	316.9	326.3	643.2	54.5	697.7	151	200
1976-90 Average Annual Percent Growth	10.2	10.9	10.6	10.2	10.6	10.0	11.6

1D.2.5 Existing Generating Units

KUA has total net summer generation capability of 114.65 MW and net winter capability of 123.05 MW. These capacity resources are made up of a combination of wholly owned and jointly owned generation units which are quite diverse in size, fuel type, and operating characteristics. Table 1D.2.5-1 lists these generating resources.

KUA owns and operates the Roy G. Hansel Generating Station which is located adjacent to the downtown Kissimmee area near Lake Tohopekaliga. The station consists of nine operating diesel generators having a combined capability of 20.8 MW. The diesel generators were installed at various times beginning in 1960 and, other than the two units which were rebuilt in 1983, all are capable of operation on either natural gas or No. 2 fuel oil. When operating on natural gas, approximately 6 percent by Btu content No. 2 fuel oil is required for pilot fuel.

KUA's other wholly owned generation facility is a combined cycle plant (Hansel Units 21, 22, and 23) adjacent to the Roy G. Hansel Diesel Station. The combined cycle plant went into commercial operation in December 1983 and consists of a Westinghouse 251 combustion turbine generator, a Foster Wheeler heat recovery boiler with supplementary duct firing, and two Turbodyne steam turbine generators. The plant has dual fuel capability for natural gas and No. 2 fuel oil. The net summer capacity is 54.3 MW and net winter capacity is rated at 58.7 MW (manufacturer's rating).

KUA owns a 0.6754 percent interest in Florida Power Corporation's Crystal River 3 nuclear unit in Citrus County. The unit provides approximately 5.2 MW to KUA's system. Through the Florida Municipal Power Agency (FMPA), KUA also is a participant in Florida Power & Light's St. Lucie 2 nuclear unit. KUA's participation share is 0.828 percent. A reliability exchange splits KUA's capacity and energy entitlement between St. Lucie 1 and 2. KUA receives approximately 3.2 MW from each unit.

KUA owns a 4.8193 percent interest (20 MW) in the Orlando Utilities Commission Stanton Energy Center Unit 1.

KUA also has an ownership interest in the Orlando Utilities Commission Indian River Combustion Turbine A & B Project. KUA's ownership interest is 12.2 percent (approximately 11 MW) of the project's two General Electric Frame 6 simple cycle combustion turbines.

Table 1D.2.5-1
Existing Unit Characteristics

Net Winter Capacity Unit MW		Net Summer Capacity (MW)	Fuel Type	Availability (Percent)	Date On-Line/ Planned Retirement	Average Heat Rate (Btu/kWh) ^a
Hansel 8	2.70	2.70	Gas/No. 2	77	1960/1998	11,200
Hansel 9	2.70	2.70	Gas/No. 2	77	1963/1998	11,200
Hansel 14	2.07	2.07	Gas/No. 2	77	1972/2002	11,900
Hansel 15	2.07	2.07	Gas/No. 2	77	1972/2002	11,700
Hansel 16	2.07	2.07	Gas/No. 2	77	1972/2002	11,800
Hansel 17	2.07	2.07	Gas/No. 2	77	1972/2002	11,300
Hansel 18	2.07	2.07	Gas/No. 2	77	1972/2002	11,500
Hansel 19	2.50	2.50	No. 2	77	1983/2013	10,600
Hansel 20	2.50	2.50	No. 2	77	1983/2013	10,600
Hansel Combined Cycle ^b	58.70	54.30	Gas/No. 2	78	1983	13,450/ 9,630
Crystal River 3	5.20	5.20	Uranium	69	1977	10,900
St. Lucie 2 ^c	6.40	6.40	Uranium	74/85 ^d	1983	11,400
Stanton 1	20.00	20.00	Coal	82	1987	10,200
Indian River A	6.00	4.00	Gas/No. 2	21	1989	12,560
Indian River B	6.00	4.00	Gas/No. 2	21	1989	12,560
Total	123.05	114.65				

^aHeat rate is based on capacity delivered to the KUA system.

^bCombined cycle plant includes combustion turbine, steam turbines, and supplementary firing. Heat rates are for simple cycle/combined cycle, respectively. Availability is for total plant including steam turbines.

^cKUA is a participant in the FMPA St. Lucie 2 Project which includes a reliability exchange such that half the capacity comes from Unit 1 and half from Unit 2.

^dUnit 1/Unit 2.

1D.2.6 Existing Firm Purchases and Sales

In addition to the generating resources listed above, KUA has additional capacity entitlements through its firm purchase agreements. Purchase agreements are in effect with Orlando Utilities Commission (OUC), Florida Power Corporation (FPC), and Tampa Electric Company. The purchase with OUC is for 45 MW in 1991, 40 MW in 1992, and 20 MW from 1993 through 2003. The agreement with OUC also provides for an additional 50 MW of optional capacity on an as-available basis.

KUA has a stratified demand partial requirements purchase power contract with FPC which extends through 2005. Either party may terminate the agreement after 2005; otherwise, it will continue. The currently specified annual contract demand levels for base, intermediate, and peaking capacity for 1991 through 1995 are shown in Table 1D.2.6-1. Annual contract demands may be updated according to contract limits.

KUA also has a 10 MW Schedule J purchase power contract with Tampa Electric Company in 1991 and a 26 MW Schedule D contract in 1992.

KUA currently has no firm contracts for the sale of capacity and energy.

Table 1D.2.6-1
Stratified Demand Contract Specification Updates (MW)

Calendar Year	Base	Intermediate	Peaking	Total
1991	0	0	43	43
1992	0	0	47	47
1993	10	10	52	72
1994	15	5	57	77
1995	10	10	63	83

1D.2.7 Existing Transmission System

The existing transmission system is shown on Figure 1D.2.2-1. The KUA transmission system is interconnected with the Roy G. Hansel Diesel Station, the Hansel combined cycle plant, and is tied to other utilities via four interconnections. These interconnections include a 69 kV interconnection at Florida Power Corporation's Lake Bryan Substation, a 230 kV interconnection at the Orlando Utilities Commission's Taft Substation, another interconnection at the Taft Substation through a 230/69 kV transformer, and a 69 kV interconnection at the City of St. Cloud's power plant. The St. Cloud interconnection is currently used primarily to supply power to St. Cloud although St. Cloud has recently completed an interconnection with Florida Power Corporation which will allow KUA to import power through that tie line.

1D.3.0 Methodology

This section provides a general description of the methodology used to analyze KUA's power supply requirements and is arranged according to the sequence of the remaining subsections. The purpose of the power supply planning process is to identify the capacity addition (or additions) which will meet the electricity needs of KUA customers as economically as possible while also giving due consideration to reliability, environmental impact, financial security, regulatory aspects, and other considerations. This requires an analysis of numerous supply and demand side alternatives to identify the plan which is in the collective best interest of all parties involved.

1D.3.1 Evaluation Criteria

The first step in the power supply planning process is to establish evaluation criteria, that is, to identify the assumptions about important parameters used in the analysis. Evaluation criteria presented in Subsection 1D.4.0 include economic forecast assumptions, financial assumptions, and fuel price projections.

1D.3.2 Load Forecast

The KUA system load forecast is presented in Subsection 1D.5.0. The subsection describes the development of the econometric model which forecasts system peak demand and energy requirements. In addition, the results of the forecast over the planning horizon are presented. The individual equations of the model are presented in Appendix 1D.A. The load forecast takes into account KUA's existing conservation programs.

1D.3.3 Conservation and Demand-Side Management

KUA's existing conservation and demand-side management programs are discussed in Subsection 1D.6.0. Estimates of capacity avoided by the various programs are provided.

1D.3.4 Reliability Criteria

Subsection 1D.7.0 presents the reliability criteria used to identify timing of capacity additions. KUA uses a 15 percent reserve margin as its reliability criteria.

1D.3.5 Supply-Side Alternatives

Supply-side alternatives that are candidates for meeting KUA's capacity expansion requirements are identified in Subsection 1D.8.0. Typical plant sizes, capital costs, and operating parameters of conventional and advanced alternatives are developed. Options that are not commercially available or that pose an unacceptable economic or technical risk are eliminated from further analysis.

1D.3.6 Supply-Side Screening

The economics of applicable supply-side alternatives are compared using screening curves in Subsection 1D.9.0. These graphs present comparative costs for the construction and operation of potentially viable supply-side generation options at various capacity factors. The cost of generation options are normalized on \$/kW-month basis in order to more easily compare different capacities. The capital requirements for each alternative are based on the capital investment of the generation option and KUA's levelized fixed charge rate. The operating costs (fuel and O&M) are levelized over a 24-year period. Each alternative's full load heat rate is used to determine fuel costs.

Graphically, capital cost plus operating costs for each option are plotted against capacity factor. At zero capacity factor (y-intercept) the curve indicates the fixed costs requirements associated with the alternative, while the slope indicates the variable costs. Several supply-side options are plotted on a single graph to allow easy comparison. The lowest curve at a particular capacity factor is the least cost alternative at that capacity factor. If two curves do not intercept, it indicates that the upper curve is expected to be a higher cost alternative at all capacity factors and potentially may be eliminated from further study.

An intersection of two curves indicates that one alternative is lower cost over a range of capacity factors while the other option is least cost over another capacity factor range. The purpose of the screening curves is to reduce the number of options which are carried forward to the detailed economic analysis. Care must be taken when using this method. The results must be considered preliminary because interaction with other system units and unit availability are not considered.

1D.3.7 Alternative Plan Development

Alternative plans for capacity additions are developed in Subsection 1D.10.0. Plans are developed based on results of the supply-side screening in Subsection 1D.9.0. Plans are developed which incorporate both generation and purchases. The plans developed schedule generation or purchases as required to meet the reliability criteria developed in Subsection 1D.7.0.

1D.3.8 Economic Analyses

In Subsection 1D.11.0, the economics of the alternative plans developed in Subsection 1D.10.0 are compared. The results are examined to determine which plans best meet the needs of KUA's customers.

The alternative plans are evaluated on a comparative cost basis. Comparative costs include only those costs which are affected by differences in the plans. The economic analyses determine the annual revenue requirements of items which are affected by the alternative plans. Annual comparative revenue requirements include the following components.

- Fuel costs.
- Operation and maintenance (O&M) costs.
- Capital costs for new generation.

Black & Veatch's POWRPRO chronological production cost simulation program is used to model KUA's system for each of the alternative plans developed in Subsection 1D.10.0. Annual system fuel and O&M costs are developed for each plan. Production cost simulation is necessary to incorporate the effect upon the operation of the existing units due to the new unit additions. KUA's levelized fixed charge rate is applied to the capital investment of various alternatives to produce the levelized fixed costs.

The objective of the economic analysis is to determine the total present worth of the annual comparative revenue requirements. This refers to the sum of the yearly nominal comparative revenue requirements discounted to 1997 using KUA's present worth discount rate. The cumulative present worth of the annual nominal comparative revenue requirements will form the basis for selection of the optimal capacity addition plan.

The economic analyses yield a base plan which is the most economical mix of supply-side alternatives. This section will enable a conclusion as to which capacity addition plan is the least cost alternative for KUA.

1D.3.9 Consequences of Delay

Subsection 1D.12.0 addresses the adverse consequences of not building or delaying the proposed generation plant. System reliability and KUA's ability to serve load will be evaluated based on the reliability criteria developed in Subsection 1D.7.0.

1D.3.10 Financial Analysis

Subsection 1D.11.0 of the report identifies the optimal capacity plan based on the comparative costs of alternative plans, discounted to 1997. This analysis does not include costs which would be the same for all plans, i.e., current debt service, expenses for existing transmission and distribution systems, and general and administrative expenses. While this is appropriate for the identification of the least cost plan (since these common costs do not affect the differential between alternatives), the financial impact on the total system costs (which include all common costs) that will be incurred by KUA must also be considered. Subsection 1D.13.0 considers the impact of the absolute magnitude of the preferred plan's cost on KUA.

Assessment of the magnitude of the impact is essential to ensure that the recommended option is financially feasible, that is, that KUA can secure the needed capital and that the near-term impact of any capacity addition will not result in an unacceptable rate "shock" to KUA's customers.

1D.3.11 Transmission System Considerations

Subsection 1D.14.0 will discuss the transmission system considerations and constraints for the KUA system and how this affects the alternative selected. In particular, this section analyzes whether KUA's transmission system is capable of supporting the plan recommended by the economical and financial analyses.

1D.4 EVALUATION CRITERIA

1D.4.0 Evaluation Criteria

1D.4.1 Economic Parameters

The economic parameters are based on the "Long Term Economic Forecasts 1990 to 2021" prepared by Fishkind & Associates, Inc., November 26, 1990, presented in Subsection 1A.3.0. Adjustments to these general economic parameters necessary to make them specific for KUA's system are presented below.

Table 1D.4.1-1 summarizes the economic projections for the most likely scenario used in the evaluation of KUA's future power supply options.

1D.4.1.1 Inflation and Escalation Rates

The GNP deflator is generally accepted as a good measure of changes in the general price level and was selected for use as the inflation rate. The capital cost escalation rate is selected based on Black & Veatch's perceptions of the market conditions for power plant construction consistent with Dr. Fishkind's projections for the GNP deflator and producer price index. The O&M cost escalation rate is based on the projections of changes in the average compensation per man-hour and was also supplied by Dr. Fishkind.

1D.4.1.2 Bond Interest Rate

The AAA bond interest rate is used for KUA based on the purchase of bond insurance. A 0.4 percent bond insurance rate is used.

1D.4.1.3 Present Worth Rate

The present worth discount rate used in this evaluation is equal to the insured AAA bond interest rate.

1D.4.1.4 Bond Issuance Fee

A bond issuance fee of 2.9 percent including 0.4 percent for bond insurance is assumed to apply to KUA bond issues.

1D.4.1.5 Interest During Construction Rate

For evaluation purposes, interest during construction is assumed to be equal to the bond rate increased by the bond issuance fee. This represents 7.11 percent

for 1991, 7.49 percent for 1992, and 7.23 percent for 1993 through 2020 based on the most likely bond rates.

1D.4.1.6 Debt Service Reserve Fund

The debt service reserve fund is assumed to be one year's principal and interest. The interest earned on the debt service reserve fund is assumed to be the same as the bond rate.

1D.4.1.7 Fixed Charge Rate

A fixed charge rate is developed for a 30-year bond term based on the economic parameters for 1997 through 2020. The fixed charge rate includes principal and interest payments, a debt service reserve fund equal to one year's principal and interest with interest earnings credit, a 2.9 percent bond fee (which includes 0.4 percent for bond insurance), and 1.0 percent for property insurance. The fixed charge rate is 0.09442.

**Table 1D.4.1-1
Most Likely Scenario
Economic Projections**

Projection	Year	Percent
Inflation	1991	4.50
	1992-2020	4.00
Capital Cost Escalation	1991-2020	4.50
O&M Escalation	1991	5.30
	1992	4.39
	1993-2020	4.75
AAA Bond Rate	1991	6.91
	1992	7.28
	1993-2020	7.03
Interest During Construction	1991	7.11
	1992	7.49
	1993-2020	7.23

1D.4.2 Fuel Prices

Fuel price projections are based on the projections in Subsection 1A.3.3. Fuel price projections for the dual fuel diesels are based on 94 percent natural gas and 6 percent No. 2 oil. The fuel price projections for the most likely scenario are shown in Table 1D.4.2-1.

Table 1D.4.2-1
Delivered Fuel Price Projections (\$/MBtu)

Year	Low Sulfur Coal	Medium Sulfur Coal	Natural Gas	No. 2 Oil	Dual Fuel*	No. 6 Oil	Nuclear
1997	2.89	2.55	4.47	7.90	4.68	5.42	1.00
1998	3.03	2.68	4.92	8.56	5.14	5.98	1.05
1999	3.18	2.81	5.41	9.27	5.64	6.61	1.10
2000	3.43	2.95	5.95	10.05	6.19	7.30	1.16
2001	3.61	3.10	6.50	10.75	6.76	7.84	1.22
2002	3.80	3.26	7.11	11.51	7.37	8.43	1.28
2003	4.00	3.44	7.77	12.32	8.05	9.06	1.35
2004	4.20	3.61	8.50	13.19	8.78	9.74	1.42
2005	4.42	3.80	9.29	14.11	9.58	10.47	1.49
2006	4.65	4.00	10.06	14.98	10.35	11.14	1.56
2007	4.89	4.21	10.88	15.91	11.19	11.85	1.64
2008	5.14	4.42	11.78	16.89	12.08	12.61	1.73
2009	5.41	4.65	12.74	17.93	13.06	13.42	1.82
2010	5.69	4.89	13.79	19.03	14.11	14.27	1.91
2011	5.98	5.14	14.92	20.20	15.24	15.19	2.01
2012	6.29	5.41	16.15	21.45	16.47	16.16	2.11
2013	6.62	5.69	17.47	22.77	17.79	17.19	2.22
2014	6.96	5.98	18.91	24.18	19.23	18.30	2.33
2015	7.31	6.29	20.46	25.67	20.77	19.47	2.45
2016	7.69	6.61	22.14	27.25	22.45	20.71	2.57
2017	8.09	6.95	23.96	28.93	24.26	22.04	2.70
2018	8.51	7.31	25.93	30.71	26.21	23.45	2.84
2019	8.94	7.69	28.06	32.60	28.33	24.95	2.99
2020	9.41	8.08	30.36	34.61	30.62	26.55	3.14

*Based on 94 percent natural gas and 6 percent No. 2 oil.

1D.5 LOAD FORECAST

1D.5.0 Load Forecast

1D.5.1 Overview

One of the basic requirements of a system planning study is a forecast of peak demand and energy requirements. Forecast capacity requirements are compared to available capacity resources to determine the amount and timing of future resource additions needed to ensure continued system reliability. KUA's peak demand and net energy for load requirements were forecast using an econometric model developed for the KUA system. Net energy for load was calculated as the sum of total sales (residential use and general service use), street lighting, use by KUA and system losses. These customer classes were projected individually, given their historical variation in growth. The results of the forecast and most recent historical peak and energy requirements are presented in Table 1D.5.1-1. Appendix 1D.A contains a more detailed discussion of the econometric methodology utilized.

Table 1D.5.1-1
Projected KUA Energy Use by Customer Class,
Net Energy for Load and Peak Demand

Fiscal Year	Residential Sales (GWh)	General Services Sales (GWh)	Total Sales (GWh)	KUA Use Lighting and Losses (GWh)	Net Energy for Load (GWh)	Peak MW Demand	
						Summer	Winter
1984*	165	155	320	32	352	82	97
1985*	187	179	365	33	398	93	121
1986*	206	203	409	39	448	101	119
1987*	235	236	471	39	510	115	115
1988*	245	263	508	32	540	121	131
1989*	277	295	572	49	621	141	148
1990*	317	326	643	53	698	151	200
1991	330	343	673	64	737	171	191
1992	353	368	721	69	789	183	204
1993	372	391	763	73	836	195	216
1994	393	415	808	77	884	207	228
1995	415	440	855	81	936	220	241
1996	432	465	897	85	982	232	253
1997	450	491	941	90	1,030	244	265
1998	468	517	985	94	1,079	256	277
1999	487	545	1,032	98	1,130	270	290
2000	508	573	1,081	103	1,184	283	304
2001	526	602	1,129	107	1,236	297	317
2002	546	633	1,179	112	1,291	312	331
2003	566	662	1,228	117	1,345	326	344
2004	586	691	1,278	122	1,399	340	357
2005	608	721	1,329	127	1,456	355	371
2006	624	752	1,376	131	1,508	369	384
2007	642	784	1,426	136	1,562	384	398
2008	660	816	1,476	140	1,617	399	411
2009	678	849	1,527	145	1,673	415	425
2010	697	883	1,581	150	1,731	431	439
2011	717	920	1,637	156	1,793	448	454

Table 1D.5.1-1 (Continued)
Projected KUA Energy Use by Customer Class,
Net Energy for Load and Peak Demand

Fiscal Year	Residential Sales (GWh)	General Services Sales (GWh)	Total Sales (GWh)	KUA Use Lighting and Losses (GWh)	Net Energy for Load (GWh)	Peak MW Demand	
						Summer	Winter
2012	738	958	1,696	161	1,857	466	470
2013	760	998	1,757	167	1,924	485	487
2014	782	1,039	1,821	173	1,994	505	504
2015	805	1,082	1,887	180	2,067	525	522
2016	829	1,128	1,956	186	2,143	547	540
2017	854	1,175	2,028	193	2,221	569	559
2018	879	1,224	2,103	200	2,303	592	579
2019	906	1,275	2,181	208	2,388	617	600
2020	934	1,328	2,262	215	2,477	642	622
Actual Percent Growth 1984-90	11.5	13.2	12.3	9.4	12.1	10.5	12.8
Percent Growth 1990-2020	3.7	4.8	4.3	4.6	4.3	5.0	3.9
*Historical.							

1D.5.2 Energy Requirements Forecast

Annual heating and cooling degree-days, price of electricity, and per capita income were all found to be significant variables in explaining variation in historical levels of net energy for load. Therefore, these variables were used to forecast the net energy for load requirements for the KUA system. Forecast results predict that net energy for load will experience substantial growth over the forecast horizon although considerably less than the 12 percent average annual growth experienced from 1984 through 1990. Net energy for load, which increased from 352 GWh in 1984 to 698 GWh in 1990, is expected to increase to 1,184 GWh by the year 2000 and to 2,477 GWh by 2020. The annual average growth rate during the 1990 through 2020 horizon is projected to be 4.3 percent.

Sales to the general service sector represented the largest component of sales for the KUA system in 1990. This trend is expected to continue as total sales are projected to increase from the 1990 level of 326 GWh to 1,328 GWh by 2020. The expected average annual growth rate from 1990 through 2020 of 4.8 percent is also the highest rate of all sectors.

Historically, energy sales to the residential sector have been roughly equal to general services sales. In 1990, GWh sales to the residential sector were 317 GWh. This figure is expected to increase to 934 by 2020 and equates to an expected annual average growth rate of 3.7 percent from 1990 through 2020.

System losses plus KUA use and lighting have averaged 9.5 percent of total sales historically. This percentage was held constant throughout the forecast horizon.

1D.5.3 Winter and Summer Peak Demand Forecast

The KUA system is dual peaking, meaning that the magnitude of the winter peak demand and summer peak demand are generally close together for most years. In the last seven historical years (1984-1990), the winter peak was slightly greater than the summer peak in six years while the two were equal in 1987. From 1984 through 1990, the summer peak demand increased at an annual average growth rate of 10.5 percent. The corresponding winter growth rate during this time frame was 12.8 percent.

Results of the econometric evaluation indicate that maximum and minimum temperatures and net energy for load explain nearly all variation in peak demand historically. These variables were used to forecast KUA's annual peak through 2020. According to the forecast, KUA is expected to incur significant growth in both summer and winter peak demand; each is forecasted to increase more than fourfold. The summer peak is forecasted to increase from the 151 MW experienced in 1990 to 642 MW by 2020. This represents a 5.0 percent average annual growth rate. The winter peak is expected to encounter a 3.9 percent average annual growth rate, increasing from the 1990 peak of 200 MW (which was an unusually high figure) to 622 MW in 2020. Thus, as is consistent with recent historical trends, the summer peak is predicted to experience a greater percentage growth than the winter peak and is projected to surpass the winter peak during the final years of the forecast.

The summer and winter peak demands shown in Table 1D.5.1-1 do not include the effects of load management. Table 1D.6.2-3 in Subsection 1D.6.0 contains the peak demands as adjusted for load management capacity savings.

1D.6.0 Conservation and Demand-Side Management

1D.6.1 Existing Conservation Plan

KUA has employed conservation programs since 1982. The current electric demand and energy conservation plan of KUA was filed with the Florida Public Service Commission on February 1, 1990 as required under Docket No. 89073-PU, Order No. 22176, issued November 14, 1989 and the Florida Energy Efficiency Conservation Act (FEECA). This conservation plan includes 10 FEECA Conservation programs. On October 25, 1990, the Florida Public Service Commission confirmed final approval of KUA's conservation plan under Docket No. 900086, Order No. 23681.

1D.6.1.1 Residential Energy Audits (Analysis) Program

1D.6.1.1.1 Objective. The objective of this program is to reduce energy consumption and demand in existing residential dwellings by encouraging adoption of energy conservation practices and measures.

1D.6.1.1.2 Description. KUA has a trained energy auditor who has successfully passed the qualifications as set forth in FAC 25-17.0052, and works full time on energy audits. The "Class A Audit" is provided to customers upon request; however, since providing energy audits beginning in the early 80s, the response from customers for this service has been limited. A Residential Energy Analysis which places more emphasis on personal consultations with the customer has been more successful. All residential analyses are evaluated under guidelines of the "Five-Star Rating System."

Program announcements offer the Residential Energy Analysis to all KUA residential customers within the service territory. There are no minimum usage and/or equipment standards to exclude any consumer from this free service. KUA will continue to aggressively market this analysis program.

1D.6.1.1.3 Program Measurement. The monitoring and evaluation of this program will be an ongoing process. A review to determine actual savings will be conducted after a 12 month before and after history of energy consumption for participating customers has been compiled. Consumption history will be normalized for such variables as weather, rates, and anticipated changes in end-use equipment.

The cumulative impact of the Residential Energy Audits (Analysis) Program as estimated for years 1990-1999 is shown in Table 1D.6.1-1.

1D.6.1.2 Commercial/Industrial Energy Analysis Program

1D.6.1.2.1 Objective. The objective of this program is to reduce coincident kW system peak demand and kWh usage through implementation of energy conservation practices and measures by this class of customer.

1D.6.1.2.2 Description. This program is similar to the Residential Energy Analysis Program which provides personal consultation on energy conservation matters as requested by the customer. This service is free through a trained energy auditor and is available to all commercial and industrial customers. Various studies have indicated that commercial and industrial customers represent a significant opportunity to reduce system peak demands and conserve energy.

KUA will aggressively market this program through program announcements. There are no restrictions to exclude any consumer in the service territory from this service.

1D.6.1.2.3 Program Measurement. Follow-up visits will be made by KUA to determine how many of the recommended practices or measures have been implemented. It is expected that customers in general will be receptive to the recommendations since they can benefit from a reduction in their cost of doing business.

The cumulative impact of the Commercial/Industrial Energy Analysis Program as estimated for years 1990-1999 is shown in Table 1D.6.1-2.

1D.6.1.3 Fix-Up Program (Residential)

1D.6.1.3.1 Objective. The objective of this program is to reduce energy consumption and demand in existing residential dwellings by assisting the consumer with installation or arranging to have others install energy conservation measures.

1D.6.1.3.2 Description. KUA will advise customers of the benefits and estimated costs of installing energy saving devices such as electric outlet gaskets, water heater jackets, solar screen/reflective film, water flow restrictors, weather stripping, caulking, duct tape, energy conserving lamps, clock thermostats, pool timers, hot water pipe insulation, and water heater timers or switches. At the customer's direction, KUA will assist the consumer with the installation of these devices or arrange for installation by others.

KUA also offers a \$10.00 Appreciation Dollar\$ billing credit as an incentive to install or upgrade ceiling insulation levels to R-19 or greater. This incentive applies to owners who reside at single family, condominium, and multi-family structures or to the account of record in the case of rental property. To be eligible for the credit, insulation must have been installed after April 1, 1988 and the residence must be equipped with some type of whole house or central air conditioning and/or electric heating system. Mobile homes are not eligible for the credit. Customers must file an application verifying installation to receive the billing credit.

1D.6.1.3.3 Program Measurement. A 12 month before and after energy use history will indicate any savings that are realized. A follow-up contact 30-60 days after the customer is advised of program benefits will report program implementations.

The cumulative impact of the Fix-Up Program (Residential) as estimated for years 1990-1999 is shown in Table 1D.6.1-3.

1D.6.1.4 High Pressure Sodium Street Lighting/Private Area Lighting Conversion Program

1D.6.1.4.1 Objectives. The objectives of this program are to increase the efficiency of street lighting applications and to encourage customers to utilize high efficiency lamps for private area lighting applications.

1D.6.1.4.2 Description. KUA is currently converting approximately 175 mercury vapor lighting units annually to lower wattage, comparable illumination high pressure sodium vapor lighting units. The conversion replaces 175 and 400 watt mercury vapor lights with 100 and 250 watt sodium vapor lights, respectively. Customers utilizing private area lighting will be advised of the economies of replacing mercury vapor units with lower wattage sodium vapor units. Minimum reduction in system peak demand will be realized with this program because lighting load occurs at off-peak times. There are, however, significant annual energy savings related to this program.

1D.6.1.4.3 Program Measurement. Energy savings related to this program will be based on the number of units replaced and energy savings for various sizes of units based on research data from large, neighboring utilities.

The cumulative impact of the High Pressure Sodium Street Lighting/Private Area Lighting Conversion Program as estimated for years 1990-1999 is shown in Table 1D.6.1-4.

1D.6.1.5 Water Heater Conversion Program

1D.6.1.5.1 Objective. The objective of this program is to reduce system coincident kW demand and kWh energy usage by encouraging customers to install efficient water heating systems.

1D.6.1.5.2 Description. The Water Heater Conversion Program will be offered to all residential and commercial customers. Program participation will be voluntary. KUA is not currently offering any rebates or billing credits for program participation. Customers will be advised of the economies of replacing existing electric resistance water heaters with more efficient waste heat recovery systems, dedicated heat pump water heaters, natural gas water heaters, or solar water heating systems. The State of Florida Model Energy Code will encourage efficient water heating alternatives for new construction.

1D.6.1.5.3 Program Measurement. Demand and energy savings related to this program are estimated based on the results of similar programs offered by large neighboring utilities.

The cumulative impact of the Water Heater Conversion Program as estimated for years 1990-1999 is shown in Table 1D.6.1-5.

1D.6.1.6 Elimination of Electric Resistance Space Heating Program

1D.6.1.6.1 Objective. The objective of this program is to promote the installation of high efficiency heat pumps for heating and air conditioning or other space heating alternatives at both new and existing residences to eliminate the use of electric strip heaters.

1D.6.1.6.2 Description. KUA encourages customers using electric strip heating to convert their space heating requirements to alternative energy sources. Maximum customer savings can be realized by replacing existing inefficient air conditioners and electric strip heaters with high efficiency heat pumps. KUA offers an Appreciation Dollar\$ incentive program to existing customers who install qualifying cooling and heating equipment. To qualify for Appreciation Dollar\$, heat pumps and air conditioning equipment must meet specified minimum standards and receive the approval of the City or County Mechanical

Inspection Department. Heat pumps must have a minimum 2.5 C.O.P. for heating and a minimum 8.0 S.E.E.R. for cooling. Central air conditioning must have a minimum 8.5 S.E.E.R. if matched with the inside unit and a minimum 9.0 S.E.E.R. if not matched.

1D.6.1.6.3 Program Measurement. Demand and energy savings related to this program will be estimated based on results data from other sources, 12 months before and after consumption histories, and City and County building departments' records.

The cumulative impact of the Elimination of Electric Resistance Space Heating Program as estimated for years 1990-1999 is shown in Table 1D.6.1-6.

1D.6.1.7 Public Awareness Program

1D.6.1.7.1 Objective. The objective of this program is to provide energy conservation information to the public to promote reducing peak kW demands and kWh energy use of electric customers.

1D.6.1.7.2 Description. KUA aggressively pursues the dissemination of information to the public through the following means.

- Use of bill stuffers promoting energy conservation and reduction of demand.
- Distribution of energy conservation literature.
- Radio public service announcements.
- Newspaper public service announcements.
- Provide guest speakers for public meetings, social events, and special groups.
- Present "Safety City" demonstration in schools.

1D.6.1.7.3 Program Measurement. The effectiveness of this program is difficult to quantify. Public response to the various means of information dissemination indicates that many people are interested in energy conservation. Demand for guest speakers is another indication of the value that the public places on this program.

1D.6.1.8 Cumulative Impact of Conservation

KUA has not previously estimated the impacts of conservation programs prior to 1990. The estimated cumulative impact of all programs included in the existing conservation plan, in terms of avoided system capacity and energy, is shown in

Table 1D.6.1-7. Table 1D.6.1-7 includes the effect of ongoing programs since 1982. For 1990, it is estimated that the cumulative impact of conservation programs is 2.7 MW of avoided system capacity and 10.7 GWh of avoided system energy.

1D.6.1.9 Natural Gas Program

1D.6.1.9.1 Objective. The objective of this program is to encourage the use of natural gas wherever possible to limit the growth of electric demand.

1D.6.1.9.2 Description. KUA will continue to encourage the use of natural, propane, and bottle gas for cooking, space conditioning, and water heating wherever these energy alternatives are available.

1D.6.1.9.3 Program Measurement. Due to the limited availability of natural gas in the KUA service area, the impact of this program on system demand and energy is estimated to be less than 0.02 percent. No other effects are estimated.

Table 1D.6.1-1
Impact of Residential Energy Audits
(Analysis) Program Estimated for Years 1990-1999

Year	Number of Customers	Summer Avoided Capacity* (kW)	Avoided Energy** (kWh)
1990	400	115	173,920
1991	800	230	347,840
1992	1,200	345	521,760
1993	1,600	460	695,680
1994	2,000	575	869,600
1995	2,400	690	1,043,520
1996	2,800	805	1,217,440
1997	3,200	920	1,391,360
1998	3,600	1,035	1,565,280
1999	4,000	1,150	1,739,200

*Based on 15 percent reserved margin.

**Based on net energy for load.

Table 1D.6.1-2
Impact of Commercial/Industrial
Energy Analysis Program Estimated
for Years 1990-1999

Year	Number of Customers	Summer Avoided Capacity* (kW)	Avoided Energy** (kWh)
1990	20	18	38,045
1991	40	37	76,090
1992	60	55	114,135
1993	80	74	152,180
1994	100	92	190,225
1995	120	110	228,270
1996	140	129	266,315
1997	160	147	304,360
1998	180	166	342,405
1999	200	184	380,450

*Based on 15 percent reserve margin.

**Based on net energy for load.

Table 1D.6.1-3
Impact of Fix-Up Program
(Residential) Estimated for Years 1990-1999

Year	Number of Customers	Summer Avoided Capacity* (kW)	Avoided Energy** (kWh)
1990	200	230	260,880
1991	400	460	521,760
1992	600	690	782,640
1993	800	920	1,043,520
1994	1,000	1,150	1,304,400
1995	1,200	1,380	1,565,280
1996	1,400	1,610	1,826,160
1997	1,600	1,840	2,087,040
1998	1,800	2,070	2,347,920
1999	2,000	2,300	2,608,800

*Based on 15 percent reserve margin.

**Based on net energy for load.

Table 1D.6.1-4
Impact of High Pressure Sodium Street
Lighting/Private Area Lighting Conversion
Program Estimated for Years 1990-1999

Year	Number of Fixtures	Summer Avoided Capacity (kW)	Avoided Energy* (kWh)
1990	175	0	103,102
1991	350	0	206,204
1992	525	0	309,306
1993	700	0	412,408
1994	875	0	515,510
1995	1,050	0	618,612
1996	1,225	0	721,714
1997	1,400	0	824,816
1998	1,575	0	927,918
1999	1,750	0	1,031,020

*Based on net energy for load.

Table 1D.6.1-5
Impact of Water Heater Conversion
Program Estimated for Years 1990-1999

Year	Number of Customers	Summer Avoided Capacity* (kW)	Avoided Energy** (kWh)
1990	500	121	1,222,875
1991	1,000	241	2,445,750
1992	1,500	362	3,668,625
1993	2,000	483	4,891,500
1994	2,500	604	6,114,375
1995	3,000	725	7,337,250
1996	3,500	845	8,560,125
1997	4,000	966	9,783,000
1998	4,500	1,087	11,005,875
1999	5,000	1,208	12,228,750

*Based on 15 percent reserve margin.

**Based on net energy for load.

Table 1D.6.1-6
Impact of Elimination of Electric
Resistance Space Heating Program
Estimated for Years 1990-1999

Year	Number of Customers	Summer Avoided Capacity (kW)	Avoided Energy* (kWh)
1990	500	0	489,150
1991	1,000	0	978,300
1992	1,500	0	1,467,450
1993	2,000	0	1,956,600
1994	2,500	0	2,445,750
1995	3,000	0	2,934,900
1996	3,500	0	3,424,050
1997	4,000	0	3,913,200
1998	4,500	0	4,402,350
1999	5,000	0	4,891,500

*Based on net energy for load.

Table 1D.6.1-7*
**Cumulative Impact of All Energy Conservation
 Programs Estimated for Years 1990-1999**

Year	Summer Cumulative Avoided Capacity (MW)	Cumulative Avoided Energy (GWh)
1990	2.7	10.7
1991	3.2	12.8
1992	3.7	14.9
1993	4.1	16.9
1994	4.6	19.1
1995	5.1	21.2
1996	5.6	23.3
1997	6.1	25.4
1998	6.6	27.5
1999	7.0	29.6

*Includes savings accumulated since programs were implemented in 1982.

1D.6.2 Load Management Program

1D.6.2.1 Objective

The objective of this program is to defer specific customer loads from the hour of KUA's system peak to off-peak hours using utility activated radio control devices.

1D.6.2.2 Description

Kissimmee Utility Authority (KUA) is planning a Direct Load Control type of Load Management Program. KUA will install a radio signal system to control customer's space heating, air conditioning, water heating, and swimming pool pump loads. KUA's direct load control program will be offered on a voluntary basis to all residential customers regardless of their usage level. KUA plans to implement the program without offering any credit incentives to participating customers.

1D.6.2.3 Program Measurement

Because of the prohibitive cost of customer load research, KUA will rely on load research data of large, neighboring utilities to estimate the effects of this program.

The program assumes a 12.6 percent saturation level among eligible participants. The cumulative impact of the Load Management Program as estimated for years 1992-2020, is shown in Table 1D.6.2-1. The winter avoided capacity due to both the Energy Conservation and Load Management Programs, as estimated for years 1990-1999, is shown in Table 1D.6.2-2. The summer and winter peak demands in Table 1D.5.1-1 reflect the effect of the existing conservation programs, but not load management. The peak demands adjusted to include load management are shown in Table 1D.6.2-3.

1D.6.2.4 Program Cost Savings

On the basis of estimated program costs and demand charge savings, the program realizes a positive net savings beginning in 1998. Table 1D.6.2-4 lists the cumulative present worth savings of the Load Management Program. Table 1D.6.2-5 lists the estimated expenses associated with implementing the Load Management Program.

Table 1D.6.2-1
Impact of Load Management
Program Estimated for Years 1992-2020

Year	Number of Customers	Winter Avoided Capacity (kW)	Avoided Energy (kWh)
1992	374	561	0
1993	1,070	1,605	0
1994	1,706	2,559	0
1995	2,444	3,666	0
1996	3,069	4,604	0
1997	3,611	5,417	0
1998	4,424	6,637	0
1999	5,125	7,687	0
2000	5,310	7,964	0
2001	5,472	8,208	0
2002	5,639	8,459	0
2003	5,812	8,718	0
2004	5,990	8,985	0
2005	6,174	9,261	0
2006	6,307	9,460	0
2007	6,443	9,665	0
2008	6,582	9,873	0
2009	6,724	10,086	0
2010	6,870	10,304	0
2011	7,018	10,527	0
2012	7,170	10,756	0
2013	7,326	10,989	0

Table 1D.6.2-1 (Continued)
Impact of Load Management
Program Estimated for Years 1992-2020

Year	Number of Customers	Winter Avoided Capacity (kW)	Avoided Energy (kWh)
2014	7,485	11,227	0
2015	7,647	11,471	0
2016	7,814	11,720	0
2017	7,983	11,975	0
2018	8,157	12,236	0
2019	8,335	12,502	0
2020	8,517	12,775	0

Table 1D.6.2-2*
Impact of Energy Conservation and
Load Management Programs Estimated
for Years 1992-1999

Year	Winter Avoided Capacity (MW)
1992	9.4
1993	11.7
1994	14.0
1995	16.4
1996	18.7
1997	20.8
1998	23.3
1999	25.7

*Includes savings from the Energy
Conservation programs that have been
implemented since 1982.

**Table 1D.6.2-3
Peak Demand Adjusted for Load
Management Capacity Savings**

Fiscal Year	Peak MW Demand	
	Summer	Winter
1992	183	203
1993	194	214
1994	205	225
1995	218	237
1996	229	248
1997	241	260
1998	252	270
1999	265	282
2000	278	296
2001	292	309
2002	307	323
2003	321	335
2004	335	348
2005	349	362
2006	363	375
2007	378	388
2008	393	401
2009	409	415
2010	425	429
2011	442	443
2012	460	459
2013	478	476

**Table 1D.6.2-3 (Continued)
Peak Demand Adjusted for Load
Management Capacity Savings**

Fiscal Year	Peak MW Demand	
	Summer	Winter
2014	498	493
2015	518	511
2016	540	528
2017	562	547
2018	585	567
2019	610	588
2020	634	609

Table 1D.6.2-4
Load Management Cost Savings

Year	Residential Customers	Load Management Customers	Avoided Winter Capacity (kW)*	Avoided Summer Capacity (kW)*	Demand Charge (\$/kW/mo)	Savings (Nom. \$)	Total Cost (Nom.\$)**	Cumulative Present Worth of Savings***
1992	30,389	374	561	336	4.52	30,411	231,134	(200,723)
1993	31,945	1,070	1,605	963	4.89	94,195	190,998	(291,167)
1994	33,587	1,706	2,559	1,536	5.35	164,309	193,694	(316,819)
1995	35,319	2,444	3,666	2,200	5.40	237,564	228,389	(309,336)
1996	36,584	3,069	4,604	2,762	5.45	301,108	221,657	(248,791)
1997	37,896	3,611	5,417	3,250	5.70	370,539	219,186	(141,030)
1998	39,258	4,424	6,637	3,982	7.78	619,590	295,546	74,531
1999	40,672	5,125	7,687	4,612	7.02	647,554	290,391	296,518
2000	42,140	5,310	7,964	4,779	7.16	684,306	184,132	586,972
2001	43,427	5,472	8,208	4,925	7.20	709,146	188,037	869,707
2002	44,754	5,639	8,459	5,075	7.21	731,830	199,048	1,139,788
2003	46,125	5,812	8,718	5,231	8.17	854,676	210,848	1,444,724
2004	47,539	5,990	8,985	5,391	8.29	893,815	223,318	1,741,433
2005	48,999	6,174	9,261	5,556	9.32	1,035,729	236,641	2,071,820
2006	50,055	6,307	9,460	5,676	9.44	1,071,674	233,156	2,395,738
2007	51,135	6,443	9,665	5,799	9.67	1,121,470	245,607	2,711,859
2008	52,239	6,582	9,873	5,924	9.79	1,159,900	258,732	3,015,750
2009	53,367	6,724	10,086	6,052	9.91	1,199,470	272,567	3,307,788

Table 1D.6.2-4 (Continued)
Load Management Cost Savings

Year	Residential Customers	Load Management Customers	Avoided Winter Capacity (kW)*	Avoided Summer Capacity (kW)*	Demand Charge (\$/kW/mo)	Savings (Nom. \$)	Total Cost (Nom.\$)**	Cumulative Present Worth of Savings***
2010	54,521	6,870	10,304	6,183	10.21	1,262,504	287,241	3,594,881
2011	55,701	7,018	10,527	6,316	10.58	1,336,570	302,715	3,879,232
2012	56,908	7,170	10,756	6,453	10.96	1,283,058	319,082	4,126,949
2013	58,142	7,326	10,989	6,593	11.36	1,170,830	336,342	4,327,306
2014	59,403	7,485	11,227	6,736	11.77	951,435	354,546	4,461,203
2015	60,693	7,647	11,471	6,883	12.21	1,008,437	337,853	4,594,206
2016	62,012	7,814	11,720	7,032	12.66	1,068,326	394,223	4,726,212
2017	63,361	7,983	11,975	7,185	13.12	1,131,228	415,771	4,857,114
2018	64,740	8,157	12,236	7,342	13.60	1,198,135	438,506	4,986,969
2019	66,150	8,335	12,502	7,501	14.10	1,269,239	462,558	5,115,809
2020	67,592	8,517	12,775	7,665	14.62	1,344,736	488,005	5,243,656

*Includes 9 percent average losses.

**Assumes a 4.0 percent rate of inflation.

***Discounted at KUA's 7.03 percent discount rate.

Table 1D.6.2-5
Load Management Program Costs (\$1992)

Initial Costs	
Cost of FM Radio Equipment	\$97,812
Advertising Cost	\$10,868
Total Initial Cost	\$108,680
Annual Expenses	
Radio Station Lease	\$19,562
Phone Line Lease	\$6,521
Advertising	\$2,174
Maintenance	\$27,170
Renewal and Replacement	5 percent per year
Total Annual Expenses	\$55,427 plus Renewal and Replacement
Installation and Equipment	
Radio Receiver Switches	\$103.25 each
Installation	\$76.08 each
Total Installation and Equipment Cost	\$179.32 each

1D.6.3 Cogeneration Program

1D.6.3.1 Objective

The objective of this program is to encourage the development of all cogeneration potential within the service area.

1D.6.3.2 Description

There are currently no cogeneration installations operating in the service area. KUA is not aware of any plans to develop cogeneration projects in the near future. In response to Florida legislation, KUA encourages development of all potential cogeneration projects in its service area and is currently planning to adopt specific policies and procedures for integrating them into the electric system. Following the directives from PSC, KUA is currently preparing standard offer contract documents for any potential QFs in KUA's service territory.

1D.6.3.3 Program Measurement

Until a specific cogeneration project is identified, KUA will not estimate any system demand or energy effects for this program.

1D.7 RELIABILITY CRITERIA

1D.7.0 Reliability Criteria

1D.7.1 Capacity Reserve Requirements

An electric utility needs sufficient capacity to enable it to provide customers with adequate electricity in a reliable manner. To meet this reliability standard, electric utilities maintain capacity resources that are greater than their system peak. Reserve margin is used to express the amount of capacity in excess of predicted system peak demand divided by the peak demand. Excess capacity is required since the total of all installed capacity is not always available and since system peak demand may be higher than expected. The factors listed below contribute to the need for reserve capacity.

- **Scheduled maintenance.** Although utilities attempt to schedule maintenance during off-peak months, reserve capacity is still needed to provide reliability in case of unexpected demand during these maintenance periods.
- **Forced outages.** In addition to scheduled maintenance, units commonly require unscheduled maintenance and must be taken off-line. When this occurs, a utility must have replacement capacity available.
- **Unit deratings.** Generating units can experience mechanical malfunctions which cause a decrease in output without requiring a complete outage.
- **Higher than expected peak demand.** Since the reserve margin is a function of the peak demand, a higher than forecasted peak demand will reduce the reserves of a system. Therefore, to allow for deviations between actual and forecasted peak demand, reserve capacity is required. These deviations could be caused by extreme weather conditions, inaccurate forecasts, and less than expected conservation and demand-side program capacity savings.

There is no single reserve margin appropriate for all utilities. Reserve margins of 15 to 25 percent are used by most utilities for planning purposes. Other things, being equal, the fewer the number of generation units and the fewer the interconnections with outside utilities, the higher the reserve margin that is required to achieve the same level of reliability.

KUA uses a 15 percent reserve margin as its reliability criteria. From a system planning standpoint, the need for additional resource capacity is determined by calculating the reserve margin for each year in the planning horizon. A

capacity addition is required when, in the absence of new capacity, the reserve margin would fall below 15 percent. Historically, KUA's peak demand has been as high as 11.9 percent above that expected during normal weather. A 15 percent reserve margin appears to be the minimum that can be considered acceptable given the variability of peak demand to changes in weather conditions. The 15 percent reserve margin applies to generation capacity and purchased capacity that does not inherently include reserves.

Table 1D.7.1-1 lists the projected system peak demand for KUA adjusted for load management as presented in Subsection 1D.6.0. Also listed is the total capacity required to maintain a 15 percent reserve margin throughout the forecast period. System peak is expected to increase from 200 MW in 1990 to 634 MW in 2020. To maintain the 15 percent reserve margin, total capacity requirements are expected to increase from 230 MW to 729 MW. Thus, about 500 MW in additional capacity needs are projected to ensure adequate reliability for the KUA system through 2020.

Table 1D.7.1-1 also shows KUA's existing generating unit capacity as presented in Table 1D.2.5-1. The difference between the required capacity and the existing generating unit capacity must be made up through purchase power or additional generating units.

Table 1D.7.1-1
Projected KUA Capacity Needs to Meet a
15 Percent Reserve Requirement

Fiscal Year	Peak MW Demand	Reserve Capacity	Capacity Required to Maintain Reserve Margin	Existing Generating Unit Capacity
1990	200.0 (actual)	30.0	230.0	123.0
1991	191.0	28.7	219.7	123.0
1992	203.0	30.5	233.5	123.0
1993	214.0	32.1	246.1	123.0
1994	225.0	33.8	258.8	123.0
1995	237.0	35.6	272.6	123.0
1996	248.0	37.2	285.2	123.0
1997	260.0	39.0	299.0	123.0
1998	270.0	40.5	310.5	117.7
1999	282.0	42.3	324.3	117.7
2000	296.0	44.4	340.4	117.7
2001	309.0	46.4	355.4	117.7
2002	323.0	48.5	371.5	107.3
2003	335.0	50.3	385.3	107.3
2004	348.0	52.2	400.2	107.3
2005	362.0	54.3	416.3	107.3
2006	375.0	56.3	431.3	107.3
2007	388.0	58.2	446.2	107.3
2008	401.0	60.2	461.2	107.3
2009	415.0	62.3	477.3	107.3
2010	429.0	64.4	593.4	107.3

Table 1D.7.1-1 (Continued)
Projected KUA Capacity Needs to Meet a
15 Percent Reserve Requirement

Fiscal Year	Peak MW Demand	Reserve Capacity	Capacity Required to Maintain Reserve Margin	Existing Generating Unit Capacity
2011	443.0	66.5	509.5	107.3
2012	460.0	69.0	529.0	107.3
2013	478.0	71.7	549.7	102.3
2014	498.0	74.7	572.7	102.3
2015	518.0	77.7	595.7	102.3
2016	540.0	81.0	621.0	102.3
2017	562.0	84.3	646.3	102.3
2018	585.0	87.8	672.8	102.3
2019	610.0	91.5	701.5	102.3
2020	634.0	95.1	729.1	102.3

1D.8 SUPPLY-SIDE
ALTERNATIVES

1D.8.0 Supply-Side Alternatives

1D.8.1 Stanton 2

1D.8.1.1 General

KUA's participation in Stanton 2 is described in Subsection 1D.1.0. A description of the Stanton 2 project is presented in Subsection 1A.2.0. This section presents the cost to KUA to participate in 3.8 percent or 16.9 MW of Stanton 2.

1D.8.1.2 Project Costs

1D.8.1.2.1 Participation Fee. OUC is proposing to charge a participation fee to cover the unrecovered carrying costs on common facilities based on a July 1, 1992, closing date. OUC and FMPA and KUA are negotiating the amount of this participation fee. OUC proposes that the participation fee be \$20 million. FMPA and KUA propose that the fee be \$16 million. For evaluation purposes, the higher \$20 million fee is used. Table 1D.8.1-1 shows the \$20 million cost for the participation fee. KUA's portion is \$3 million in July 1, 1992, dollars. Interest is added to the cost until the January 1997 commercial operation date of Stanton 2 at KUA's interest during construction rate. KUA's portion of the participation fee in January 1997 is \$4.2 million including interest.

1D.8.1.2.2 Cost of Common Facilities. With participation in Stanton 2, KUA will purchase the common facilities except for certain external facilities at their book value. The total common facility costs are \$133.7 million in December 1990 and will depreciate to \$128 million in July 1992 as shown in Table 1D.8.1-2. One half of the common facilities (\$64 million) is allocated to Stanton 2. KUA's share of the common facilities allocated to Stanton 2 in January 1997 is \$3.4 million. When KUA purchases the common facilities for Stanton 2, the users fee for Stanton 1 common facilities will effectively decrease from the present 60 percent to 50 percent. This is a benefit to Stanton 1 participation and has not been included as a reduction in Stanton 2 participation cost.

1D.8.1.2.3 Stanton 2 Capital Cost. The capital cost for 3.8 percent of Stanton 2 is shown in Table 1D.8.1-3. The capital cost includes directs, indirects, escalation, and interest during construction at KUA's interest during construction rate. Table 1D.8.1-3 shows KUA's participation fee and cost to purchase the common facilities associated with Stanton 2. KUA's total capital cost is \$31.1 million.

System transmission losses reduce the capacity delivered to KUA. The delivered cost of capacity from Stanton 2 is \$1,871/kW.

1D.8.1.2.4 External Facilities. A user's charge is assessed to all external facilities associated with Stanton 2. The user charge is based on a total external facilities value of \$31 million on September 30, 1989. The facilities' value is depreciated at 2.5 percent per year. The monthly user's charge is calculated as the monthly depreciation and the capital charge for the undepreciated balance. OUC's current capital charge rate is 9.2 percent per year. KUA's share of the external facilities user charge is projected to be \$52,654 in 1997.

1D.8.1.2.5 Administration and General. Administration and general expenses for Stanton 2 are projected on the basis of Stanton 1 expenses. Stanton 1 expenses are determined by ratioing Stanton 1 employees with total utility employees. That ratio is applied to total administration and general expenses.

Stanton 2 will have fewer employees than Stanton 1. The ratio of Stanton 2 employees to total employees will be less. Thus, the administration and general expense for Stanton 2 will be less than for Stanton 1. KUA's share of administration and general expense is expected to be \$45,273 in 1997.

1D.8.1.2.6 Coal Pile. KUA is responsible for their share of the stockpile of coal for Stanton 2. It is assumed that KUA will finance their share of the coal pile. The annual interest on KUA's share of the \$3.5 million coal pile, is expected to be \$9,725.

Table 1D.8.1-1 Participation Fee (\$)	
KUA and FMPA Participation Fee (January 1, 1992)	20,000,000
KUA's Share of Participation Fee (15.33 percent)*	3,066,000
KUA Interest**	1,135,784
KUA's Equivalent Participation Fee at January 1, 1997	4,201,784
*KUA's and FMPA's share of Stanton 2 is 25 percent. KUA's share of the 25 percent is 15.33 percent. **At KUA's interest during construction rate.	

Table 1D.8.1-2
Stanton 2 Estimated Common Facilities Cost (\$)

Total Common Facilities Stanton 1 and 2 (December 1990)	133,748,837
Total Common Facilities Stanton 1 and 2 at Closing Date (January 1992)	127,960,163
Stanton 2 Share of Common Facilities (50 percent)	63,980,082
KUA's Share of Stanton 2 Common Facilities (3.8325 percent)*	2,452,037
KUA Interest**	908,345
KUA's Equivalent Common Facility Cost at January 1, 1997	3,360,382
*KUA's and FMPA's share is 25 percent. KUA's share of the 25 percent is 15.33 percent. $(0.25 \times 0.1533 = 0.038325)$ **At KUA's interest during construction rate.	

Table 1D.8.1-3
Estimated Capital Cost (\$)

Capital Cost* (January 1, 1997)	23,568,777
KUA's Share of Participation Fee (January 1, 1997)	4,201,784
KUA's Share of Common Facilities Cost (January 1, 1997)	3,360,382
Total	31,130,943
\$/kW at Stanton 2	1,842
\$/kW Delivered**	1,871
Levelized Annual Capital Cost***	2,939,383
Levelized \$/kW-mo Delivered	14.72

*Capital cost for 3.8 percent includes direct construction cost, indirect costs, escalation and interest during construction.

**Delivered cost includes transmission losses of 1.66 percent on OUC's system, but does not include transmission wheeling charges.

***KUA's fixed charge rate of 0.09442 applied.

1D.8.2 Advanced Alternatives

A detailed discussion of advanced alternatives is presented in Subsection 1A.5.0. A total of 27 potentially viable advanced alternative technologies are discussed to determine their applicability as an alternative to Stanton 2. Most were eliminated because of the lack of adequate demonstration of the technology, their comparatively high cost versus conventional alternatives or because Florida is not well suited to the technology's requirements. Of the 27 advanced alternatives reviewed, only three were carried forward to the screening curve analysis by OUC. These three were a coal gasification combined cycle unit, a solar thermal parabolic trough, and lead-acid batteries.

The results of OUC's screening curve analysis indicated that none of these advanced alternatives were cost-effective for OUC. Furthermore, a utility as small as KUA cannot afford the risk associated with advanced alternatives. Since KUA has similar economics to OUC and since KUA cannot afford the risk associated with advanced alternatives, the advanced alternatives will not be considered further as an alternative to Stanton 2.

1D.8.3 Cost and Operating Characteristics for Conventional Alternatives

A system planning study must evaluate the viability of other generation alternatives before making conclusions as to the cost-effectiveness of a proposed capacity addition. Among the more important alternatives are those generation alternatives fitting a utility's requirements that are commonly used in the industry and that have a proven record regarding cost, reliability, and fuel availability. These are termed conventional alternatives.

Given KUA's capacity requirements and fuel price and availability considerations, the conventional alternatives evaluated for the KUA system are a coal fired atmospheric fluidized bed unit, a combustion turbine, and a combined cycle unit. Cost and performance data for each of these units are provided in this section. The cost estimates provided in this section include the offsite and onsite facilities required for operation of these units at the Cane Island site.

1D.8.3.1 Atmospheric Fluidized Bed Combustion Unit

Atmospheric fluidized bed combustion (AFBC) systems are in an advanced state of development and are currently being applied in electric utility systems. The largest single circulating AFBC unit in operation is a 96 MW unit in Trona, California, which was designed by Black & Veatch. The largest single unit scheduled for construction is a 165 MW unit at Point Aconi for Nova Scotia Power Corporation.

In a circulating fluidized bed steam generating unit, fuel and sorbent are fed by gravity into a highly turbulent region of the combustion chamber where combustion air, feed fuel, sorbent, and recirculating solids are mixed. The reacting gas and solids flow upward and then enter a particulate separator, usually a cyclone, where the solids are separated and returned to the bottom of the combustion chamber. Flue gas leaves the cyclone and is cooled by a conventional convection bank and an air heater. Additional particulate removal is required before the gas is discharged to the stack.

Flue gas desulfurization is accomplished in fluidized bed combustion units by adding limestone to the bed and promoting high temperature reaction of calcium oxide with sulfur dioxide (SO_2). Removal of SO_2 is increased by increasing the feed rate of limestone to the bed. Current operating experience with AFBC units indicates that relatively high levels of excess limestone addition (Ca/S ratio of 2.0

to 3.0) are required to achieve 90 percent SO₂ removal. Higher SO₂ removal rates (95 percent) have not been demonstrated on a continuous basis, and are expected to require much higher limestone consumption rates.

A current drawback to implementation of AFBC units over conventional pulverized coal units is the relatively high waste disposal costs associated with AFBCs. Although each of the units generates about the same amount of fly ash, the desulfurization byproducts generated are about 50 percent higher for AFBC units as compared with those of the pulverized coal unit. Since fly ash is not separately collected in the AFBC, it cannot be marketed as is sometimes done at a pulverized coal unit.

Generation of nitrogen oxides (NO_x) in AFBC units is lower than that of pulverized coal units because of the lower combustion temperatures inherent to the process.

AFBC units have accumulated several years of operating experience in the 50 MW size range appropriate for consideration by KUA. It is expected that maintenance requirements will be well defined and preventive maintenance programs will enable fluidized bed boilers to operate with availability comparable to that of conventional pulverized coal units. However, AFBC units may experience higher boiler maintenance due to the potential for greater heat transfer surface erosion.

Estimated performance and cost data for a 50 MW circulating AFBC coal unit are provided in Table 1D.8.3-1. The cost estimate includes estimates for offsite rail facilities and onsite water treatment facilities. The water treatment facilities are sized for treatment of sewage treatment effluent for makeup to the demineralizer (cycle water), plant service, and circulating water systems. The AFBC unit would utilize the common facilities at the Cane Island site as presented in the KUA Combustion Turbine Site Feasibility Study. The costs associated with these common facilities, such as the demineralizer system and water storage tanks, are considered a capital cost burden on the first combustion turbine unit installed at the site and are not included in the AFBC capital cost estimate.

1D.8.3.2 Combustion Turbine Unit

Combustion turbines typically burn natural gas and/or No. 2 oil and are available in a wide variety of sizes and configurations. This section provides cost and performance estimates for the addition of a single combustion turbine unit at

the Cane Island site. The estimates are based on a General Electric PG6541(B) combustion turbine (Frame 6) with an International Standards Organization (ISO) rating of 38.3 MW on natural gas at 59 F ambient temperature and sea level. The rating would be 43.3 MW at normal winter peak conditions of 25 F. Performance estimates are based on burning natural gas fuel in a standard combustor using water injection for NO_x control to 42 ppm.

Combustion turbines are generally used for peaking and reserve purposes because of their relatively low capital cost, poorer full load heat rate, and the higher cost of fuel when compared to conventional baseload capacity. Combustion turbines have the added benefit of providing quick-start capability in certain configurations.

Estimated performance and cost data for the Frame 6 combustion turbine system are provided in Table 1D.8.3-2. The cost estimates are based on the installation of a second combustion turbine at the Cane Island site as described in the KUA Combustion Turbine Site Feasibility Study. Only those costs associated with the installation of the second combustion turbine power block are included in the direct capital cost estimate. The cost of the common facilities at the Cane Island site as shown in the above-mentioned study, although sized to support two Frame 6 combustion turbines, are considered a capital cost burden for the first combustion turbine which will already be installed at the site.

1D.8.3.3 Combined Cycle Unit

In a combustion turbine combined cycle facility, the hot exhaust gases from the combustion turbine pass through a heat recovery steam generator (HRSG). The steam generated by the HRSG is expanded through a steam turbine which, in turn, drives an additional generator. With a typical gas inlet temperature of 1,000 F into the HRSG, steam conditions of about 1,000 psi and 900 F can be produced by the HRSG.

Combustion turbine combined cycle systems typically burn natural gas and/or No. 2 oil and are available in a wide variety of sizes and configurations. This section provides cost and performance estimates for the addition of a combustion turbine combined cycle unit at the Cane Island site. The estimates are based on a Frame 6 combustion turbine in combined cycle operation with a single HRSG and steam turbine. This unit configuration can produce a net plant output of approximately 60 MW. Performance estimates are based on burning natural gas

fuel in a standard combustor using water injection for NO_x control to 42 ppm, with no supplemental firing in the HRSG.

Estimated performance and cost data for the 60 MW combined cycle system are provided in Table 1D.8.3-3. The cost estimates are based on the installation of a second Frame 6 combustion turbine with a single HRSG and steam turbine at the Cane Island site. Only those costs associated with the installation of the combined cycle power block and the water treatment and storage facilities of sewage treatment effluent are included in the direct capital cost estimate. The water treatment facilities are sized for treatment of 1,008,000 gpd of sewage treatment effluent as makeup water for the demineralizer (injection and cycle water), plant service, and circulating water. The common facilities at the Cane Island site, although sized to support two Frame 6 combustion turbines, are considered a capital cost burden for the first combustion turbine installed at the site.

Table 1D.8.3-1
Circulating Atmospheric Fluidized Bed Technology
Unit Cost and Performance Data

Net Plant Output, MW*	50
Direct Capital Cost, 1990\$/kW**	2,410
Indirect Cost, percent	18.0
Fixed O&M Cost, 1990\$/kW-yr	47
Variable O&M, 1990\$/MWh	3.00
Net Plant Heat Rate, Btu/kWh	
Full load	10,360
75 percent load	10,570
50 percent load	11,240
25 percent load	13,330
Equivalent Availability, percent	85
Forced Outage Rate, percent	6
Planned Maintenance Outage, weeks/year	4
Construction Period, months	24

*Based on one boiler serving one steam turbine generator, VWO-OP.

**Does not include escalation, indirect cost, or interest used during construction.

Table 1D.8.3-2
Combustion Turbine Unit and Performance Data

	GE Frame 6
Net Plant Output, MW*	38.3
Direct Capital Cost, 1990\$/kW**	280
Indirect Cost, percent	12.0
Fixed O&M Cost, 1990\$/kW-yr	9.50
Variable O&M, 1990\$/MWh	
Peaking load, 5 percent capacity factor	3.7
Intermediate load, 25 percent capacity factor	1.3
Net Plant Heat Rate, Btu/kWh HHV*	
Full load	12,760
75 percent load	13,530
50 percent load	15,250
25 percent load	21,060
Equivalent Availability, percent	89
Forced Outage Rate, percent	5
Planned Maintenance Outage, weeks/year	2
Construction Period, months	10
*59 F ambient temperature and 14.9 psi. **Does not include escalation, indirect cost, or interest during construction.	

Table 1D.8.3-3
Combined Cycle Unit and Performance Data

	CC With GE 6
Net Plant Output, MW*	60
Direct Capital Cost, 1990\$/kW**	670
Indirect Cost, percent	13.0
Fixed O&M Cost, 1990\$/kW-yr	12.0
Variable O&M, 1990\$/MWh	1.80
Net Plant Heat Rate, Btu/kWh HHV*	
Full load	8,620
75 percent load	8,870
50 percent load	9,860
25 percent load	10,300
Equivalent Availability, percent	86
Forced Outage Rate, percent	6
Planned Maintenance Outage, weeks/year	4
Construction Period, months	16
*Based on one combustion turbine, one unfired HRSG, and one steam turbine at 59 F and 14.9 psi. **Does not include escalation, indirect costs, or interest during construction.	

1D.8.4 Combined Cycle Conversion

Conversion of the proposed Cane Island combustion turbine to combined cycle operation could provide additional baseload capacity for the KUA system. However, the conversion of the Cane Island combustion turbine to combined cycle would effectively eliminate the peaking capacity of the combustion turbine requiring it to be replaced with other peaking capacity. For that reason, it is more reasonable to evaluate the addition of a new combined cycle unit as described in Subsection 1D.8.3 rather than convert the proposed Cane Island combustion turbine to combined cycle.

1D.8.5 Independent Power Producers

In July of 1990, the Kissimmee Utilities Authority, together with the Orlando Utilities Commission (OUC) and the Florida Municipal Power Agency (collectively the "Utilities"), issued a joint Request For Proposals (RFP). The RFP solicited the interest to supply the Utilities with 440 MW of firm base and intermediate load electric energy and capacity to become commercial on January 1, 1997.

In response to the RFP, 19 companies submitted notices of intent to bid. However, only three proposals were submitted as of the November 13, 1990, deadline. The three respondents: the Enron Power Corporation, Inc. (ENRON); Citrus Energy Partners, L. P. (NRG); and the PG&E-Bechtel Generation Company (PG&E), submitted bids totaling 1,276 MW. All three bids were evaluated as described in Subsection 1A.5.4, and found to be more expensive than Stanton 2.

1D.8.6 Power Purchases

In addition to the power purchase options from IPP projects discussed in Subsection 1D.8.5, KUA could purchase additional power from Florida Power Corporation under the existing Stratified Partial Requirements Contract. The stratified rate structure of the contract includes three classes of generation: base, intermediate, and peaking. Energy for each of the classes is supplied from specified Florida Power Corporation units. The capacity demand charge for each class is different, based on the units which supply the energy. The units designated to supply the base energy are Anclote Units 1 and 2 and Crystal River Units 1 through 5. The units designated to supply the intermediate energy are the Bartow Units 1 through 3, Higgins Units 1 through 3, Suwannee Units 1 through 3, and Turner Units 2 through 4. All the remaining Florida Power Corporation units are considered peaking units.

Charges for the Florida Power Corporation stratified purchase would include a capacity demand charge, a nonfuel energy charge, a fuel charge, and a wheeling charge. Table 1D.8.6-1 shows the demand charge appropriate for base, intermediate, and peaking capacity. The projected demand charges were developed by R. W. Beck and Associates based on the evaluation criteria presented in Subsection 1A.3.0.

Table 1D.8.6-1 presents projected energy charges for base, intermediate, and peaking capacity. The energy charge is made up of a nonfuel charge and a fuel charge. Also shown is the projected transmission charge appropriate for all generation classes. The nonfuel charge, fuel charge, and wheeling rate were also developed by R. W. Beck and Associates based on the evaluation criteria presented in Subsection 1A.3.0.

Table 1D.8.6-1
Projected Florida Power Commission Stratified Purchase Power Costs

Year	Base		Intermediate		Peaking		Transmission Charge (\$/kW-mo)
	Demand Charge (\$/kW-mo)	Total Energy Charge (\$/MWh)	Demand Charge (\$/kW-mo)	Total Energy Charge (\$/MWh)	Demand Charge (\$/kW-mo)	Total Energy Charge (\$/MWh)	
1992	12.21	26.77	4.49	46.57	3.12	95.67	1.40
1993	12.18	27.49	4.53	50.94	3.43	97.20	1.46
1994	12.81	30.22	4.97	53.61	3.83	98.59	1.52
1995	12.85	31.41	5.57	59.10	3.81	104.92	1.59
1996	12.81	34.26	6.74	65.55	3.79	113.00	1.66
1997	13.54	35.66	7.17	71.42	3.96	119.65	1.74
1998	14.36	39.63	7.65	76.55	5.95	128.77	1.83
1999	16.47	40.77	10.34	88.33	5.11	143.15	1.91
2000	16.79	44.24	10.55	96.53	5.15	154.70	2.01
2001	20.17	46.84	10.94	103.59	5.10	165.40	2.10
2002	20.02	49.65	10.89	110.68	5.01	176.37	2.20
2003	20.23	51.54	11.05	118.52	5.86	188.34	2.31
2004	20.45	54.71	11.22	126.96	5.86	201.16	2.43
2005	20.85	56.85	11.48	136.08	6.77	214.81	2.55
2006	21.22	60.26	11.74	144.63	6.81	227.79	2.63
2007	25.95	63.80	12.23	153.99	6.97	241.95	2.70
2008	26.09	67.43	12.40	163.50	6.94	256.36	2.85
2009	26.19	69.87	12.54	173.58	6.90	271.60	3.01
2010	30.93	74.91	13.05	184.73	7.04	288.24	3.17
2011	32.87	78.95	13.33	197.18	7.26	306.79	3.32
2012	34.94	83.23	13.61	210.49	7.49	326.55	3.47
2013	37.14	87.72	13.91	224.71	7.73	347.59	3.63
2014	39.48	92.47	14.21	239.91	7.97	370.00	3.80
2015	41.97	97.47	14.51	256.14	8.23	393.86	3.98

Table 1D.8.6-1 (Continued)
Projected Florida Power Commission Stratified Purchase Power Costs

Year	Base		Intermediate		Peaking		Transmission Charge (\$/kW-mo)
	Demand Charge (\$/kW-mo)	Total Energy Charge (\$/MWh)	Demand Charge (\$/kW-mo)	Total Energy Charge (\$/MWh)	Demand Charge (\$/kW-mo)	Total Energy Charge (\$/MWh)	
2016	44.61	102.74	14.82	273.49	8.49	419.28	4.17
2017	47.42	108.30	15.14	292.03	8.76	446.33	4.36
2018	50.40	114.16	15.47	311.85	9.04	475.16	4.56
2019	53.57	120.33	15.80	333.02	9.32	505.85	4.78
2020	56.95	126.84	16.14	355.66	9.62	538.55	5.00

1D.9.0 Supply-Side Screening

Subsection 1D.8.0 identified several potentially viable alternatives to the proposed participation in Stanton 2, including conventional alternatives, advanced technologies, and power purchases. The total levelized costs, or revenue requirements, of these alternatives are compared in this subsection by the use of screening curves. Screening curves are a graphical presentation of the expected levelized revenue requirements of each alternative at various capacity factors. When several alternatives are graphed together, the relative costs of each option are easily interpreted and clearly uneconomic alternatives may be screened out from detailed economic analysis. Caution must be used, however, before eliminating an alternative based on screening curves since they do not consider unit availability or interaction with other system units.

The screening curves show graphically the total levelized revenue requirements consisting of the fixed plus operating revenue requirements for all capacity factors. Where a screening curve intersects the y-axis (zero capacity factor) the total revenue requirement will equal the fixed revenue requirements. At zero percent capacity factor, no variable revenue requirements would be incurred. The slope of a screening curve reflects the variable revenue requirements.

If several curves are plotted on a single graph, the curve lying closest to the x-axis above a particular capacity factor is the least cost option for that capacity factor. If two curves do not intersect, then the upper curve is expected to be a higher cost alternative at all capacity factors and potentially, may be eliminated from further study. The screening curves for viable alternatives are presented and discussed below. The revenue requirements of these alternatives are normalized on \$/kW-month basis to allow for direct comparison.

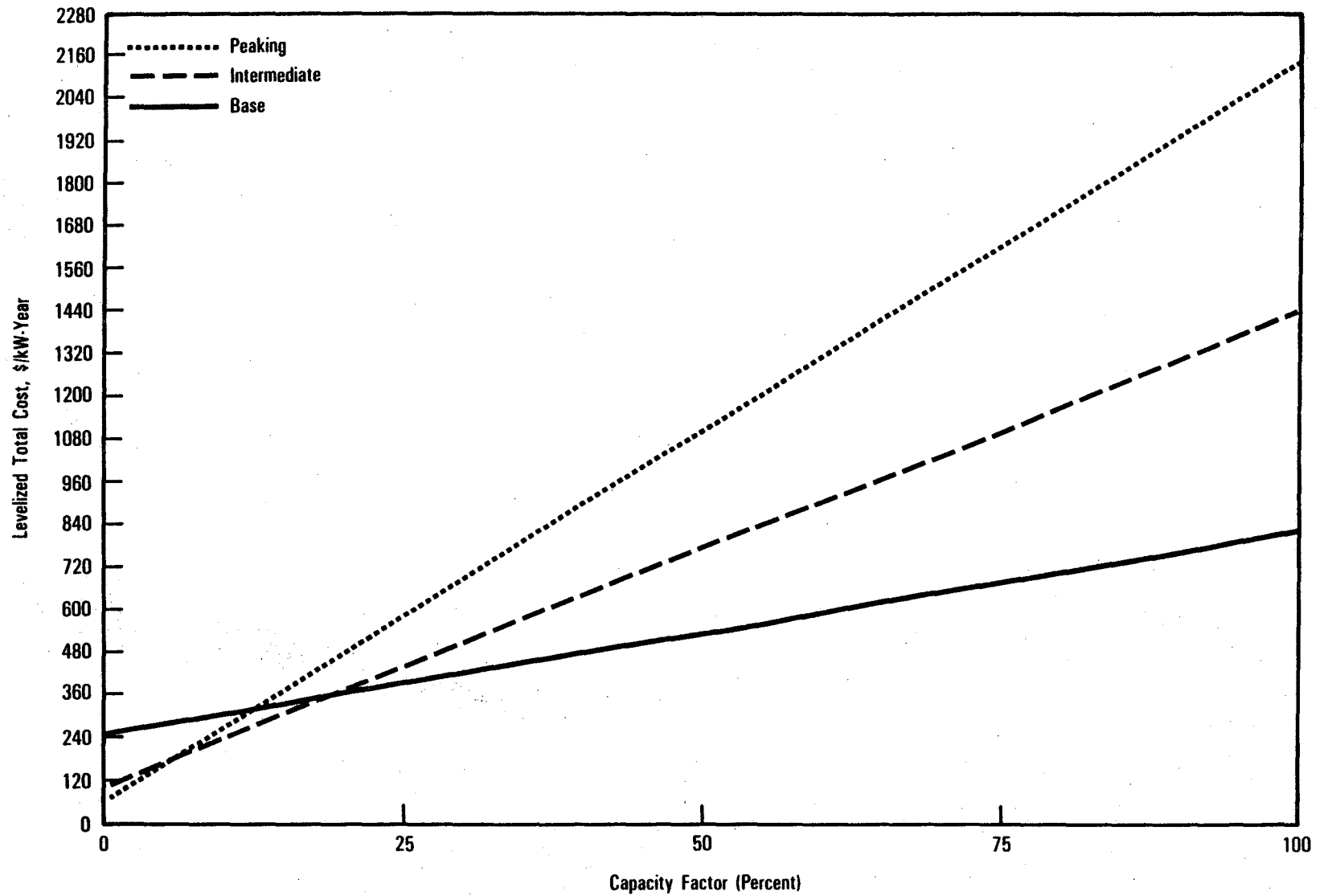
1D.9.1 Florida Power Corporation Purchase

As discussed in Subsection 1D.8.6, the existing stratified purchase contract with FPC allows for base, intermediate, and peaking purchases. In this subsection, the corresponding demand, energy, and wheeling charges for these purchases are graphed as screening curves. By plotting each type of purchase at various capacity factors, the optimal combination of base, intermediate, and peaking purchases from FPC can be identified. This combination can then be compared to the screening curves of other alternatives.

The levelized revenue requirements for the stratified purchases are plotted in Figure 1D.9.1-1. Since the stratified purchases from FPC contain reserves, the levelized fixed revenue requirements have been reduced by 15 percent for comparison to generating unit alternatives. Since purchases under the stratified contract with FPC can be a combination of base, intermediate, and peaking purchases, the least cost screening curve involves segments of all three curves. The peaking purchase is the least cost option for a capacity factor up to 8 percent; therefore, this segment becomes a part of the least cost screening curve. Likewise, an intermediate purchase would be optimal in a capacity factor range from 8 percent to 22 percent. For a capacity factor over 22 percent, a base purchase would be least cost and this segment is a part of the least cost screening curve for the FPC purchase option. This segmented least cost curve is carried forward and compared to conventional alternatives.

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ID.9.1-3



KUA SCREENING CURVES FOR THE FPC STRATIFIED CONTRACT

Figure 1D.9.1-1

1D.9.2 Conventional Alternatives

In Subsection 1D.8.3, costs were derived for conventional alternatives including a fluidized bed unit, a combustion turbine, and a combined cycle unit. This subsection compares the screening curves for these alternatives to the optimal FPC purchase.

The levelized fixed revenue requirements for each alternative are based on the capital investment of the generation option and KUA's levelized fixed charge rate. Each alternative's full load heat rate is used to determine fuel costs. The operating costs (fuel and operation and maintenance) are levelized over a 24-year period from 1997 to 2020.

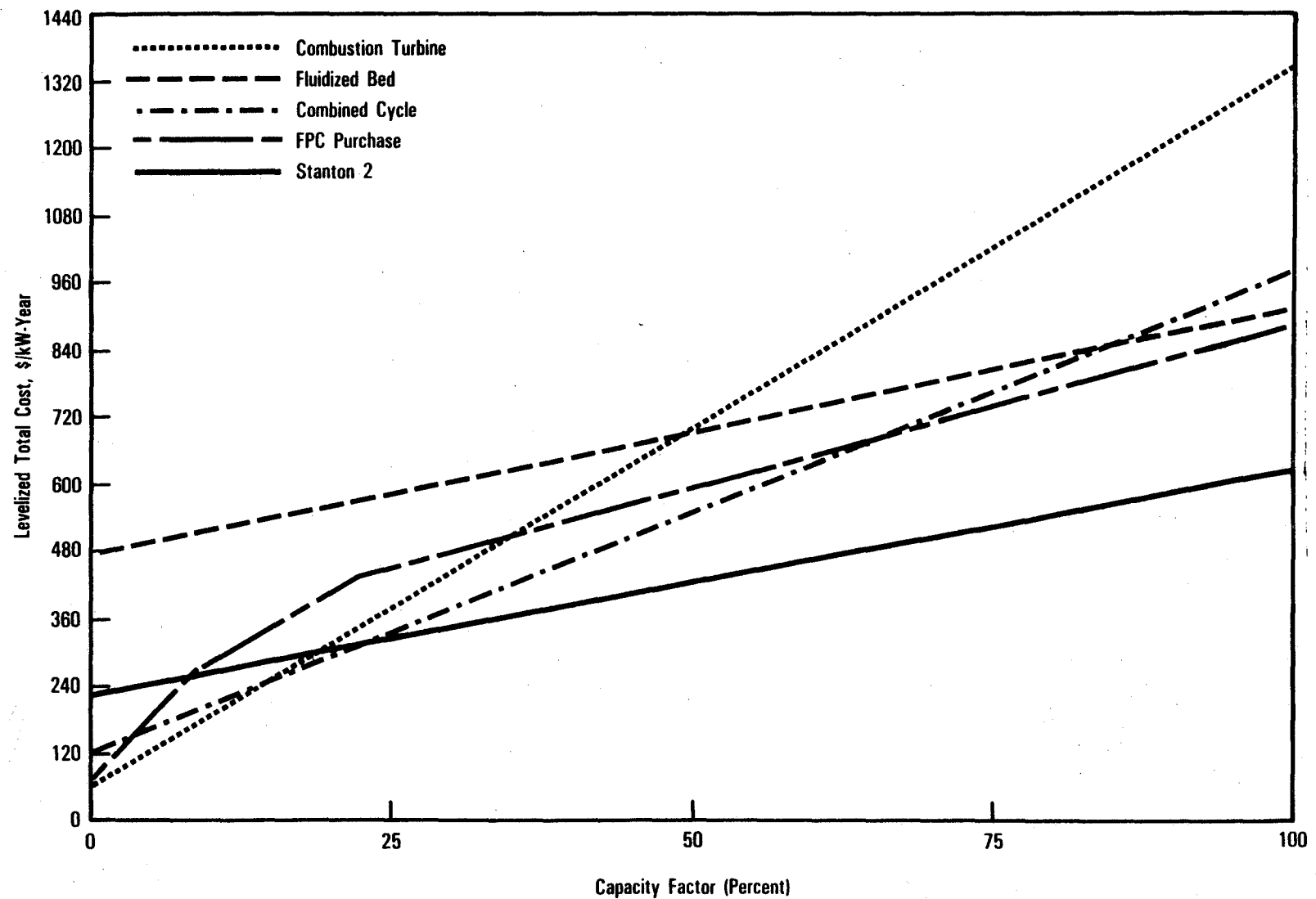
Figure 1D.9.2-1 presents the screening curves for the three conventional alternatives and for the FPC purchase. The screening curves indicate that at a zero percent capacity factor, the fluidized bed unit has a \$48.52/kW-mo levelized revenue requirement, the highest of any conventional alternative. The combined cycle's revenue requirement of \$10.38/kW-mo is the next highest conventional alternative at a zero percent capacity factor. The FPC purchase option's revenue requirement of \$6.33/kW-mo at zero percent capacity factor is just above the \$5.09/kW-mo revenue requirements for the combustion turbine.

The variable costs for each option are reflected in the slope of their screening curve. The combustion turbine has the highest variable cost of the conventional alternatives followed by the combined cycle and fluidized bed option.

The fluidized bed option, because of its high fixed costs, is not least cost at any capacity factor. Because the fluidized bed alternative has significantly higher revenue requirements than the least cost alternative at all capacity factors, it is dropped from further analysis. The remaining options will be carried forward to the detailed economic analysis.

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1D.9.2-2



KUA SCREENING CURVES: CONVENTIONAL ALTERNATIVES,
STANTON 2, AND THE FPC PURCHASE

Figure 1D.9.2-1

1D.9.3 Stanton 2

For comparison purposes, the screening curve for Stanton 2 is also plotted on Figure 1D.9.2-1. At a zero percent capacity factor, the Stanton 2 option has a levelized cost of \$19.06/kW-mo. The variable cost associated with Stanton 2 is low, which results in it having the lowest levelized cost between a capacity factor from about 25 percent to 100 percent. At a 100 percent capacity factor, the projected levelized cost is \$53.11/kW-mo, well below the cost of any other alternative.

1D.10.0 Alternative Expansion Plans

1D.10.1 General

This section uses the alternatives developed in Subsections 1D.7.0 and 1D.8.0 to formulate expansion plans to supply KUA's future power requirements. The economic evaluations, developed with a production cost program, are presented in Subsection 1D.11.0. The program calculates the total fuel, operation and maintenance, startup, and purchase energy costs associated with supplying KUA's power requirements for the 24-year evaluation period. Each alternative expansion plan is considered separately.

1D.10.2 Strategy A—Purchase Power

Strategy A is based on supplying all KUA's future expansion requirements through long-term firm purchase power agreements. It is assumed that all future requirements will be met with Florida Power Corporation Stratified PR purchases. Varying MW amounts of capacity (peak, intermediate and base) will be examined to determine the optimum mix. This process will be repeated on an annual basis to determine the best mix for the entire study period.

1D.10.3 Strategy B--Stanton 2 Ownership

Strategy B is based on KUA owning 16.9 MW of Stanton 2. Capacity from Stanton 2 will displace Florida Power Corporation Stratified PR purchases. The mix of FPC base, intermediate, and peaking capacity purchase will be reoptimized to reflect the effect of Stanton 2 on total system operation.

1D.10.4 Strategy C--Combustion Turbine Addition

The optimum mix of Florida Power Corporation purchase power is evaluated with a new combustion turbine unit. The 38.3 MW combustion turbine will displace Florida Power Corporation peaking capacity purchases.

1D.10.5 Strategy D—Combined-Cycle Addition

The optimum mix of Florida Power Corporation purchase power is evaluated with a new combined cycle unit. The 60 MW combined cycle unit will displace Florida Power Corporation Stratified purchases. The mix of peaking, intermediate, and base purchases will be reoptimized to reflect the effect of the combined cycle unit on total system operation.

1D.11.0 Economic Analysis

1D.11.1 Evaluation Method and Bases

Subsection 1D.9.0 identified viable capacity resources which potentially could be a part of KUA's least cost resource plan. Specific supply strategies or capacity expansion plans utilizing these resources were developed in Subsection 1D.10.0. This subsection summarizes the economic evaluation of the specific capacity expansion plans. Evaluation involves the development and comparison of the cumulative present worth revenue requirements for each expansion plan over the 24-year planning horizon (1997-2020). In line with the methodology utilized by the Florida Public Service Commission in past need determinations, the expansion plan having the lowest present worth of total incremental revenue requirements is considered the least cost plan to the ratepayer. For each expansion plan, yearly revenue requirements are derived and discounted to 1997 using the discount rate developed in Subsection 1D.4.0. Revenue requirements are made up of the following components.

- Generation costs (fuel, startup, O&M).
- Purchase power costs (demand and energy).
- Fixed charges for new generation.
- Transmission costs associated with each plan.

The production costs are based on production cost simulation for the entire KUA system. Production cost simulation is necessary to incorporate the effect of the operating characteristics of new capacity resources with the operation of the existing units. Production costs include fuel, variable and fixed O&M, startup, and purchased energy costs for all KUA-owned units and purchases.

Purchased power costs in each expansion plan consist of purchased demand charges, energy costs, O&M adders, wheeling charges, and losses.

The fixed charge components of each expansion plan are derived by applying the fixed charge rate developed in Subsection 1D.4.0 to the capital cost of various alternatives. The capital costs include direct, indirect, escalation, and interest during construction. Costs for the existing KUA system and expansion projects common to all plans are not included since these costs would have no impact on the relative economics of alternative plans. The results of four expansion plans are presented below. In each case, the capacity addition is modeled to begin in

1997 and additional capacity needs are met through the Florida Power Corporation stratified demand partial requirements purchase.

1D.11.2 Expansion Plan Revenue Requirements

1D.11.2.1 *Florida Power Corporation Stratified Demand Partial Requirements Purchase--Base Case*

KUA could meet its capacity requirements through the existing stratified demand partial requirements purchase agreement with Florida Power Corporation. Since this expansion plan would not require additional contracts or the construction of additional generation capacity, it is identified as the base case.

As explained in Subsection 1D.8.6, the stratified rate structure is based on three classes of generation: base, intermediate, and peaking. Each class of generation has a different demand charge and energy cost. This contract is essentially three contracts in one. The optimal mix of base, intermediate, and peaking capacity was determined for each year of the planning horizon. Contract terms limit peaking capacity to 24 percent of annual peak demand; intermediate and base capacity are limited to 40 and 36 percent of annual demand, respectively.

Table 1D.B-1 (in Appendix 1D.B) provides a yearly breakdown of the resulting capacity of stratified purchases for the base case. Total Florida Power Corporation purchases would equal 105 MW in 1997 and increase to a total of 510 MW in 2020. The 1997 cumulative present worth of total incremental revenue requirements for the base plan would be \$2,222 million. It is against this figure that alternative capacity expansion plans are measured.

1D.11.2.2 *Stanton 2 Purchase*

An alternative capacity expansion plan identified in Subsection 1D.10.0 involves ownership of 16.9 MW of Stanton 2 in 1997. The annual and cumulative present worth cost including the 16.9 MW of Stanton 2 is shown in Table 1D.B-2. A 16.9 MW ownership in Stanton 2 would reduce the amount of purchased capacity from Florida Power Corporation by 14.7 MW. Capacity purchased from Florida Power Corporation includes reserves, whereas KUA must provide reserve margin when participating in Stanton 2. Thus, purchased capacity from Florida Power Corporation would be reduced only by 14.7 MW. The capacity expansion plan involving 16.9 MW of Stanton 2 ownership still requires substantial purchases from Florida Power Corporation. First year purchases from Florida Power Corporation under the Stanton 2 capacity plan would be 90 MW, increasing to 495 MW by 2020.

As seen in Table 1D.B-2, the 16.9 MW Stanton 2 ownership plan would produce cumulative present worth revenue requirements of \$2,160 million. Stanton 2 ownership would be \$62 million less costly in present worth revenue requirements than the base case. The savings arise because the Stanton 2 purchase displaces power and energy otherwise purchased through the Florida Power Corporation stratified contract.

1D.11.2.3 Combustion Turbine

The third expansion plan involves the installation of a second 38.3 MW combustion turbine unit at KUA's Cane Island site. The combustion turbine unit would reduce purchased capacity from Florida Power Corporation by 33.3 MW after accounting for the 15 percent reserve margin.

Results of the analysis presented in Table 1D.B-3 indicate that the cumulative present worth of total revenue requirements under the combustion turbine expansion plan would be \$2,201 million. This expansion plan is a lower cost alternative than the base case (\$2,222 million) but would be approximately \$41 million more costly than the Stanton 2 ownership option. The higher cost relative to the Stanton 2 purchase option is attributable primarily to higher fuel costs over the planning horizon.

1D.11.2.4 Combined Cycle

KUA could meet future expansion requirements by building a 60 MW combined cycle unit at the Cane Island site. The combined cycle unit would reduce Florida Power Corporation purchases by 52.2 MW.

Results of the analysis presented in Table 1D.B-4 indicate that the cumulative present worth of total revenue requirements for the combined cycle expansion plan would total \$2,140 million. This is approximately \$82 million less costly than the base case and is \$20 million less costly than the Stanton 2 purchase option.

1D.11.2.5 Stanton 2 Versus the Combined Cycle

The additional savings of the combined cycle option arise because it would displace more Florida Power Corporation capacity than the Stanton 2 option, not because it would involve lower revenue requirements on a per MW basis. To demonstrate this concept, a hypothetical scenario was run in which 60 MW

participation in Stanton 2 (an amount equal to the combined cycle capacity) was assumed. As seen in Table 1D.B-5, this hypothetical scenario would result in revenue requirements of \$2,033 million. This is \$107 million less costly than the combined cycle option and \$189 million less than the base case.

This hypothetical scenario indicates that KUA could save approximately \$3.2 million per MW of Stanton 2 participation while only \$1.4 million per MW is saved with a combined cycle addition. While KUA's ownership option in Stanton 2 is limited to 16.9 MW, this scenario demonstrates that on a per MW basis, the Stanton 2 ownership option is the most cost-effective alternative for KUA and should be the next increment of capacity added to KUA's system. It also demonstrates that further reductions in revenue requirements are possible if additional capacity resources can further displace FPC purchases in a cost-effective manner. KUA is currently investigating capacity expansion options beyond the Stanton 2 purchase to determine the resource option(s) that can integrate with the KUA system, including Stanton 2, to serve customers in the most cost-effective manner throughout the planning horizon. Thus, the Stanton 2 ownership is but the first step in securing a reliable power supply at the lowest reasonable cost for KUA ratepayers.

1D.11.2.6 Conclusions

The purpose of this subsection was to present the results of the capacity expansion plans for the KUA system and identify the plan which represented the least cost alternative for KUA. Capacity expansion plans were evaluated for four options: the FPC purchase (the base case), the Stanton 2 ownership option, a combustion turbine option, and a combined cycle option. While the combined cycle option had lower cumulative revenue requirements than the Stanton 2 option, this was attributable to the fact that it displaced more FPC capacity, not because it was a lower cost alternative on a per MW basis. In other words, if an equal amount of Stanton 2 capacity is compared with the combined cycle option, Stanton 2 is a lower cost option. Thus, the Stanton 2 ownership represents the most cost-effective alternative for KUA. While additional capacity resources will further reduce costs to customers, the Stanton 2 purchase should be the first addition in KUA's expansion plan.

1D.12 CONSEQUENCES
OF DELAY

1D.12.0 Consequences of Delay

If the proposed 16.9 MW purchase from Stanton 2 in 1997 is delayed or if a do nothing approach were taken, the adverse consequences could include decreased reliability and added costs to the KUA ratepayer.

KUA's need for capacity is based on the 15 percent reserve margin developed in Subsection 1D.7.0. To maintain this reliability criteria throughout the planning horizon, over 500 MW of additional capacity will be required on the KUA system. The capacity requirements in 1997, the on-line date of Stanton 2, are expected to be 300 MW. This represents an increase of 70 MW over the 1990 requirements. If the proposal is significantly delayed, the opportunity to secure a cost-effective resource could be lost. If the proposal is not approved, alternative resources would have to be built or purchased to ensure adequate reliability of the KUA system.

As evaluated in Subsection 1D.11.0, there are several alternatives to the proposal but none are as cost-effective. The cumulative present worth system cost of the capacity plan including Stanton 2 participation is \$62 million lower than the base case. A one year delay in the commercial operation date of Stanton 2 would cause an increase of \$1.6 million in KUA's cumulative present worth system cost over the study period. Thus, for KUA to purchase all capacity shortfall from Florida Power Corporation, or a delay in approval of the proposed purchase, could not only negatively impact the reliability of the KUA system, but could also increase cost of electricity for KUA ratepayers. Given these potentially adverse affects, a decision to do nothing or to delay approval of the purchase is inconsistent with the goals of KUA to maintain a reliable electric system at the lowest reasonable cost.

ID13 FINANCIAL ANALYSIS

1D.13.0 Financial Analysis

1D.13.1 General

In the economic analysis outlined in Subsection 1D.11.0, five alternatives were evaluated based on cumulative present worth revenue requirements. Cumulative present worth revenue requirements allow evaluation of alternatives on a comparative cost basis, but do not indicate the absolute cost impact with respect to changes in the cost of power. Two of the four alternatives outlined in Subsection 1D.11.0 were selected for additional cost of power analysis. These two alternatives include the base plan (Florida Power Corporation purchase power only) and the Stanton 2 participation option. The other alternatives were not considered for additional financial analysis because either they had greater cumulative present worth revenue requirements than the Stanton 2 option or because they were not as cost-effective on a cost per MW basis as the Stanton 2 option.

The remaining paragraphs of this subsection discuss the financial evaluation of the purchase power only option and the Stanton 2 participation option. This discussion includes the following.

- General method for evaluation.
- Development of a financing criterion and its use to define a general strategy.
- Identification of optimum alternative.

1D.13.2 General Method for Evaluation

The financial feasibility is based on the calculation of the average cost of power. The average cost of power is determined by dividing the annual required revenue from system sales by total power sales. Total power sales are based on the forecast in Subsection 1D.5.0. The cost of power was calculated using a pro forma income and expense statement computer program developed for KUA. The income and expense statement is intended to include all expenses and revenues incurred by KUA.

The computer program calculates the required revenue from system sales as the greater of the following.

- The revenue required to meet operating expenses and maintain a debt service coverage ratio of 2 which is considerably above the minimum requirement of 1.29.
- The revenue required to meet operating expenses, plus bond service requirement, transfers to the City, Crystal River 3 decommissioning fund increase, self insurance fund increase, and present unbonded capital additions.

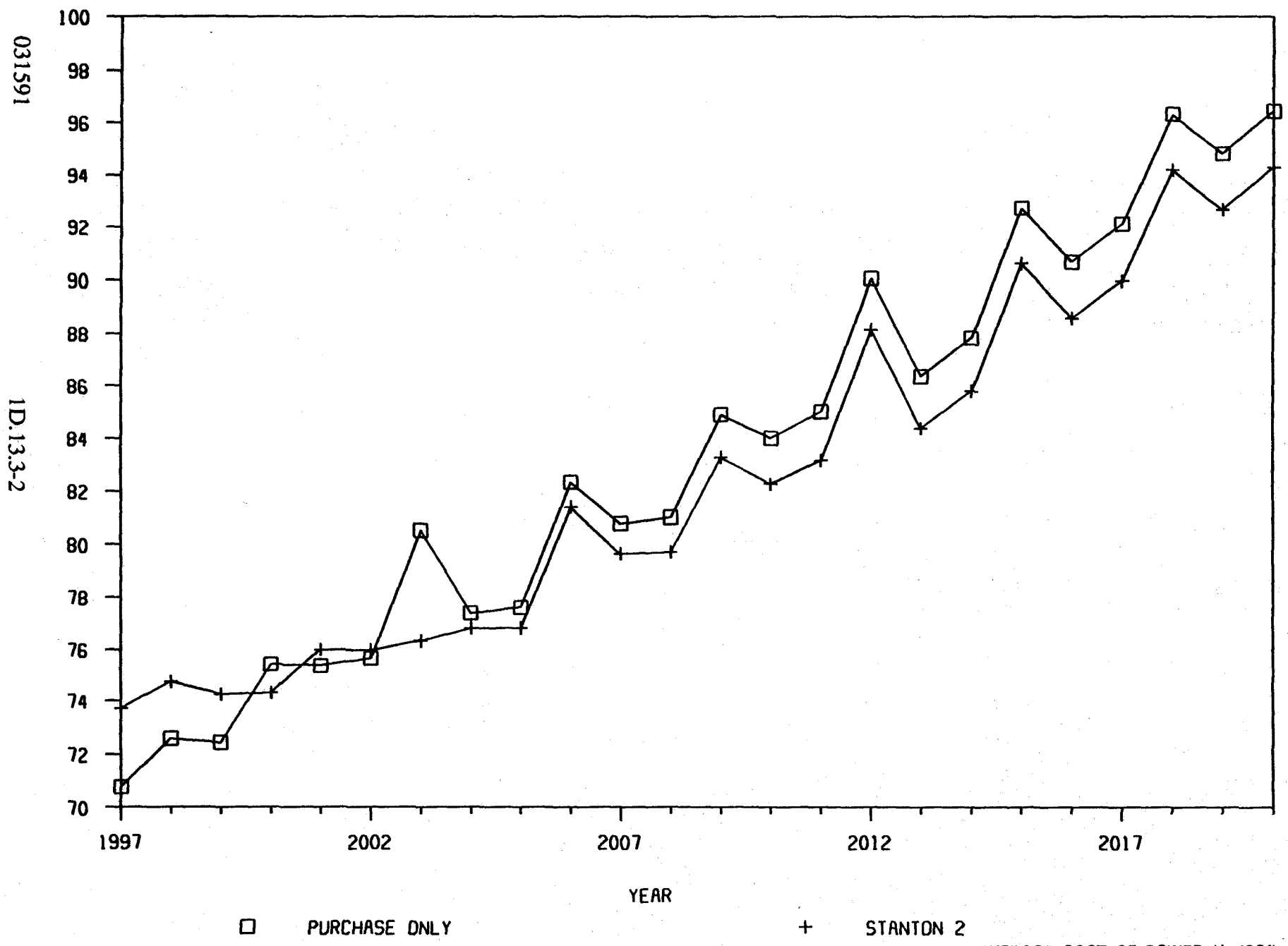
1D.13.3 Criteria and General Financing Strategy

As mentioned above, the following two cases were analyzed for financial feasibility.

- Case 1--Purchase all additional power requirements from Florida Power Corporation under the partial requirement rate tariff.
- Case 2--Participate in 3.8 percent of Stanton 2 and purchase remaining capacity requirements from Florida Power Corporation.

Case 1 requires that all of KUA's additional power requirements be met through purchase power from Florida Power Corporation under the partial requirements rate. This case assumes that all of the funds accumulated in the capital additions account are allowed to be depleted. The revenue requirements are as defined above. Figure 1D.13.3-1 illustrates the effect of the purchase power option on the average cost of power.

In Case 2 KUA's requirements would be met by a combination of participation in Stanton 2 and purchase power. In this case, the funds in the capital additions account are used to reduce the bond requirements created by KUA's participation in Stanton 2. Figure 1D.13.3-1 illustrates the effect of the Stanton 2 participation option on the average cost of power.



AVERAGE COST OF POWER (\$ 1991)

Figure 1.D.13.3-1

1D.13.4 Optimum Alternative

Initially, the cost of power under the Stanton 2 option is slightly higher as a result of the increased revenue requirements created by the additional debt service and coverage ratio. However, the relatively low operation expense of Stanton 2 quickly offsets the additional debt service. Figure 1D.13.3-1 indicates that by the year 1999, the average cost of power for Case 2 is less than Case 1 and from the year 2003 and thereafter, the average cost of power for Case 2 is less than for Case 1.

Figure 1D.13.3-1 shows six years with significant cost of power increases beginning in 2003. These result from capital additions other than Stanton 2 (mainly substations) which are assumed to be funded from revenues not bonded.

Figure 1D.13.3-1 also indicates that the average cost of power for Case 2 is much less than for Case 1 in 2003. This happens because excess revenue is required in prior years to satisfy the 2.0 bond coverage rates. The excess revenue is applied to the capital addition fund. That fund reduces the impact of the substation addition assumed in 2003.

The financial evaluation indicates that KUA's participation in Stanton 2 will not have any adverse financial impact on customer rates and after 2002 rates will continue to be less under the Stanton 2 option.

1D.14.0 Transmission System Considerations

Power from the proposed participation in 16.9 MW of Stanton 2 would be imported over the existing transmission line interconnections with OUC. Therefore, it is important that the total contracted capacity between OUC and KUA is within the import capability of the KUA transmission system.

Figure 1D.2.2-1 illustrated KUA's four interconnections with outside utilities. Two of these interconnections are with OUC. The KUA/OUC interconnections include the Taft 230 kV interconnection, which connects Taft Substation to KUA's Marydia Substation, and the Taft 69 kV interconnection, which links the Taft Substation with the Buenaventura Lakes Substation. The Taft/Marydia interconnection has a capacity of 120 MVA while the Taft/Buenaventura Lakes interconnection has a capacity of 150 MVA. The combined import capability of these two interconnections with OUC is 270 MVA or 270 MW assuming a unity power factor. Import requirements from OUC are listed below.

Stanton 1	20 MW
OUC Purchase	20 MW
St. Lucie 2	5 MW
Indian River A & B	12 MW
Stanton 2	<u>17 MW</u>
Total	74 MW

The total 1997 firm imports are 74 MW including Stanton which is significantly below the 270 MW import capability.

1D.A KUA ECONOMETRIC
MODEL FORECAST

Appendix 1D.A
KUA Econometric Model Forecasting Methodology

Appendix 1D.A

KUA Econometric Model Forecasting Methodology

An econometric model statistically estimates the dependence of one variable, the dependent variable, on one or more other variables, the explanatory or independent variables. A forecast of the dependent variable, as a function of the value of the independent variables, can also be made provided there is an estimate of the future independent variable(s). Due to the forecasting ability of econometric models, they are widely used to project utility system peak and energy requirements. Generally, the relationship between dependent and independent variables is estimated through an equation in the form:

$$y = a + bx + e,$$

where

- y = dependent variable,
- a and b = coefficient terms,
- x = independent variable, and
- e = error term.

An important consideration in an econometric equation (or regression analysis) is the selection of variables. Sufficient historical data for dependent and independent variables must be available to produce a regression equation. Also, there must be confidence in the reasonableness of the forecasted values of the independent variables if a forecast of the dependent variable is to be credible.

The KUA econometric model was designed to forecast peak demand and net energy for load. Net energy for load was calculated as the sum of total sales (residential use plus general service use), street lighting, use by KUA and system losses. The customer classes were projected individually due to the variation in growth historically and because a sector by sector analysis allows a more detailed evaluation. Historical data from 1976 through 1989 was collected for several variables and the significance of each variable was tested. In accordance with standard econometric techniques, statistical evaluation criteria included an analysis of the adjusted R-Square, the F statistic, and the t statistic; only those variables with significant regression coefficients were retained in the final equation.

The adjusted R-Square is the coefficient of determination corrected for reduced degrees of freedom due to the inclusion of additional independent

variables in the regression equation. The coefficient of determination is the proportion of variability in the dependent variables that is explained by the independent variables.

The F statistic is a test to determine whether there is a significant linear relationship between the dependent variable and the entire set of independent variables. The Student t test (t statistic) is used to estimate the relationship between the independent variable and the dependent variable. The major equations used in the model are summarized below.

1D.A.1 Historical Data

Uses of electricity are categorized by sector for the purpose of this study, as follows:

- Residential
- General Service
- KUA use, Lighting, and Losses

Table 1D.A.1-1 shows the historical sales, number of customers and use per customer for the residential and general service sectors. All general service customers have been combined into one sector due to the changes in customer billing practices since 1976. KUA use, lighting, and losses are also shown along with net energy for load and peak demand.

Table 1D.A.1-1
Historical Energy Sales by Sector, Net Energy for Load, and Peak Demand

Fiscal Year	Residential			General Service			Total Sales (GWh)	KUA Use Lighting and Losses (GWh)	Net Energy For Load (GWh)	Peak Demand (MW)
	Customers	Sales (GWh)	Use Per Customer (kWh)	Customers	Sales (GWh)	Use Per Customer (kWh)				
1976	8,666	81.0	9,347	1,735	76.3	43,977	157.3	14.0	171.3	43
1977	8,860	91.0	10,271	1,732	80.6	46,536	171.6	19.3	190.9	46
1978	9,518	103.7	10,895	1,775	86.9	48,958	190.6	22.2	212.8	47
1979	10,178	110.4	10,847	1,887	93.8	49,709	204.2	24.5	228.7	52
1980	11,146	117.3	10,524	1,959	105.6	53,905	222.9	24.4	247.3	64
1981	12,611	135.0	10,705	1,896	118.5	62,500	253.5	21.6	275.1	80
1982	13,770	138.7	10,073	1,986	128.6	64,753	267.3	24.1	291.4	87
1983	14,909	149.5	10,028	2,076	141.4	68,112	290.9	26.7	317.6	78
1984	16,363	165.1	10,090	3,263	155.1	47,533	320.2	32.0	325.2	97
1985	18,091	186.5	10,309	2,649	178.7	67,459	365.2	32.9	398.1	121
1986	19,427	206.1	10,609	2,824	202.7	71,778	408.8	39.1	447.9	128
1987	20,996	234.7	11,178	3,099	236.1	76,186	470.8	39.3	510.1	115
1988	22,235	245.3	11,019	3,515	262.7	74,737	507.7	32.3	540.0	131
1989	24,464	276.9	11,319	4,301	295.3	68,658	572.2	48.8	621.0	148
1990	27,363	316.9	11,580	4,814	326.3	67,778	643.2	54.5	697.7	200

Note: Rows may not add due to rounding.

1D.A.2 Residential Customers

An equation was developed to measure residential use per customer and several independent variables were tested for their ability to explain residential use per customer. These variables included:

- Total Osceola County personal income (adjusted to 1989 dollars).
- Osceola County per capita income (adjusted to 1989 dollars).
- Osceola County household income (adjusted to 1989 dollars).
- Number of households.
- Typical electric bill (adjusted to 1989 dollars).
- Heating degree-days.
- Cooling degree-days.
- Total degree-days.

The final adopted equation used to predict residential electrical use per customer is shown below.

	t statistic
RGWH = 0.18843 (PCINC)	9.381
- 54.78265 (BILL)	-8.362
+ 0.79168 (HDD)	2.450
+ 12357.39696 (CONSTANT)	19.446

$$\text{Adjusted R-Square} = 0.80 \quad F = 41.09$$

where

RGWH = annual average residential use per customer,

PCINC = Osceola County per capita income,

BILL = typical electric bill, and

HDD = annual heating degree-days.

Table 1D.A.2-1 presents historical and projected values of Osceola County per capita income, electric bill, and annual heating degree days. The values for Osceola County per capita income were obtained from the National Planning Association through 2010. From 2011 through 2020 per capita income was assumed to increase at the same rate as from 2005 through 2010. The electric bill for 1,000 kWh/month for residential customers was calculated as the average monthly electric bill adjusted to 1989 dollars. The projected values for the

electric bill are based on a 1 percent annual real increase. The projection of annual heating degree-days is the average of the years from 1976 through 1989. While the number of cooling degree-days was expected to provide insight into residential energy usage, no statistical correlation was shown.

To arrive at the total sales for the residential sector, the use per customer was multiplied by the projected number of residential customers. The population within the KUA service area was estimated from population projections made by the East Central Florida Regional Planning Council. Historically, the number of people per residential customer was determined from residential customers and population. The number of people per residential customer was projected to decline at the same rate as the East Central Florida Regional Planning Council's projection of people per household by traffic zone. The number of customers was then projected based on the population and the number of people per household. The number of residential customers has increased 8.4 percent on average since 1984. East Central Florida Regional Planning Council's population projection does not reflect this large increase. In order to resolve this, the annual increase in the expected number of residential customers was increased to 8.5 percent in 1990, 7.5 percent in 1991, and 6.5 percent in 1992. East Central Florida Regional Planning Council's projection was used after 1992.

Table 1D.A.2-1
KUA Historical and Projected Independent Variables

Year	Osceola County Per Capita Income* (\$)	Osceola County Personal Income* (1,000)	Heating Degree Days	Average Monthly Electric Bill* (\$)
1976	10,790	435,915	660	98.39
1977	11,250	469,105	836	90.32
1978	12,240	527,533	834	80.05
1979	12,517	580,795	476	78.86
1980	12,642	639,686	626	82.71
1981	12,369	688,939	824	90.24
1982	12,138	725,843	410	88.73
1983	14,128	911,252	594	98.74
1984	14,745	1,038,053	578	99.31
1985	15,628	1,198,637	505	100.94
1986	16,711	1,330,205	684	99.91
1987	16,863	1,424,933	592	90.84
1988	17,524	1,571,922	810	92.09
1989	18,108	1,712,074	461	87.99
1990	18,637	1,859,280	635	88.87
1991	19,163	2,007,219	635	89.76
1992	19,726	2,160,041	635	90.66
1993	20,205	2,303,676	635	91.56
1994	20,696	2,449,957	635	92.48
1995	21,243	2,603,422	635	93.40
1996	21,814	2,760,908	635	94.34
1997	22,403	2,921,838	635	95.28
1998	22,976	3,081,484	635	96.23
1999	23,611	3,250,432	635	97.20
2000	24,250	3,426,011	635	98.17
2001	24,907	3,605,419	635	99.15
2002	25,619	3,793,745	635	100.14
2003	26,253	3,971,958	635	101.14

Table 1D.A.2-1 (Continued)
KUA Historical and Projected Independent Variables

Year	Osceola County Per Capita Income* (\$)	Osceola County Personal Income* (1,000)	Heating Degree Days	Average Monthly Electric Bill* (\$)
2004	26,894	4,152,676	635	102.15
2005	27,555	4,337,918	635	103.18
2006	28,239	4,527,234	635	104.21
2007	28,967	4,724,066	635	105.25
2008	29,687	4,921,219	635	106.30
2009	30,418	5,123,140	635	107.36
2010	31,170	5,331,666	635	108.44
2011	31,948	5,556,218	635	109.52
2012	32,745	5,790,226	635	110.62
2013	33,562	6,034,091	635	111.72
2014	34,400	6,288,226	635	112.84
2015	35,259	6,553,065	635	113.97
2016	36,138	6,829,058	635	115.11
2017	37,040	7,116,675	635	116.26
2018	37,965	7,416,405	635	117.42
2019	38,912	7,728,758	635	118.60
2020	39,884	8,054,267	635	119.78
*1989 Dollars				

1D.A.3 General Service Customers

For model estimation purposes, all classes of general service customers (general service, general service demand, and large light and power) had to be lumped together since extensive reclassification had occurred since 1976, making the data for each individual class inconsistent.

The final form of the equation used to predict general service sales utilized historical data from 1976 through 1989 and was based on total Osceola County personal income and the average monthly electric bill. Other econometric variables (KUA system population, per capita income, heating degree-days, cooling degree-days, and total degree-days) were also considered, but no statistical significance was shown.

The equation developed to predict general service customer sales is shown below.

	t statistic
GSGWH = 1.668302E-04 (CHANC)	28.112
- 0.78799 (BILL)	-2.272
+ 68.49362 (CONSTANT)	2.252
Adjusted R-Square = 0.98	
F = 421.50	

where

GSGWH = general service total annual GWh used,
CHANC = Osceola County total personal income, and
BILL = electric bill.

Table 1D.A.2-1 presents the historical and projected values of Osceola County total personal income as estimated by the National Planning Association. Values for 2011 through 2020 were projected assuming the same growth rate as the previous five years.

1D.A.4 Losses, Use by KUA, and Street Lighting

Historically, losses, electricity use by KUA, and street lighting have averaged 9.5 percent of total sales. This category was projected at 9.5 percent of total sales throughout the forecast period.

1D.A.5 Net Energy for Load

Net energy for load is projected as the sum of residential sales, general service sales, losses, use by KUA, and street lighting.

1D.A.6 Winter Peak Demand Forecast

Winter peak demand on the KUA system was projected using regression analysis to evaluate the ability of several independent variables to explain variation in the winter peak historically. The independent variables adopted in the winter peak equation were net energy for load and minimum temperature, as these explained 96 percent of the historical variation in winter peak demand. The equation is shown below.

$$\begin{aligned}\text{WPEAK} &= 0.3670428 (\text{NEL}) \\ &- 0.00431 (\text{MINTEMP} \times \text{NEL}) \\ &+ 0.9695194 \\ R &= 0.96\end{aligned}$$

where

WPEAK = the winter peak demand,
NEL = annual net energy for load, and
MINTEMP = annual minimum temperature.

1D.A.7 Summer Peak Demand Forecast

The summer peak demand forecast was developed similarly to the winter peak demand forecast. A multilinear regression model was developed with summer peak demand as the dependent variable. The independent variables in the equation are net energy for load and maximum temperature. The equation developed is as follows.

$$\begin{aligned}\text{SPEAK} &= 0.2212728 (\text{NEL}) \\ &+ 0.000116 (\text{MAXTEMP} \times \text{NEL}) \\ &- 2.459262 \\ R &= 0.99\end{aligned}$$

where

SPEAK = the summer peak demand,
NEL = annual net energy for load, and
MAXTEMP = annual maximum temperature.

As with the winter peak equation, nearly all variation in summer peak is explained by the independent variables. This provides confidence as to the equation's ability to forecast the expected value of future peaks accurately.

1D.A.8 Results

Table 1D.A.8-1 provides the results of the load forecast.

Table 1D.A.8-1
Projected KUA Energy Use by Customer Class, Net Energy for Load and Peak Demand

Fiscal Year	Residential			General Service			Total Sales (GWh)	KUA Use, Lighting, and Losses (GWh)	Net Energy For Load (GWh)	Summer Peak Demand (MW)	Winter Peak Demand (MW)
	Customers	Sales (GWh)	Use Per Customer (kWh)	Customers	Sales (GWh)	Use Per Customer (kWh)					
1991	28,534	330	11,554	4,649	343	73,816	673	64	737	171	191
1992	30,389	353	11,611	4,822	368	76,296	721	69	789	183	204
1993	31,945	372	11,651	4,996	391	78,295	763	73	836	195	216
1994	33,587	393	11,694	5,170	415	80,243	808	77	884	207	228
1995	35,319	415	11,746	5,344	440	82,288	855	81	936	220	241
1996	36,584	432	11,802	5,518	465	84,324	897	85	982	232	253
1997	37,896	450	11,862	5,692	491	86,335	941	90	1,030	244	265
1998	39,258	468	11,918	5,865	517	88,190	985	94	1,079	256	277
1999	40,672	487	11,984	6,039	545	90,193	1,032	98	1,130	270	290
2000	42,140	508	12,052	6,213	573	92,261	1,081	103	1,184	283	304
2001	43,427	526	12,122	6,387	602	94,315	1,129	107	1,236	297	317
2002	44,754	546	12,201	6,561	633	96,486	1,179	112	1,291	312	331
2003	46,125	566	12,266	6,734	662	98,294	1,228	117	1,345	326	344
2004	47,539	586	12,331	6,908	691	100,069	1,278	122	1,399	340	357
2005	48,999	608	12,400	7,082	721	101,863	1,329	127	1,456	355	371
2006	50,055	624	12,473	7,256	752	103,664	1,376	131	1,508	369	384
2007	51,135	642	12,553	7,430	784	105,548	1,426	136	1,562	384	398

Table 1D.A.8-1 (Continued)
Projected KUA Energy Use by Customer Class, Net Energy for Load and Peak Demand

Fiscal Year	Residential			General Service			Total Sales (GWh)	KUA Use, Lighting, and Losses (GWh)	Net Energy For Load (GWh)	Summer Peak Demand (MW)	Winter Peak Demand (MW)
	Customers	Sales (GWh)	Use Per Customer (kWh)	Customers	Sales (GWh)	Use Per Customer (kWh)					
2008	52,239	660	12,630	7,604	816	107,352	1,476	140	1,617	399	411
2009	53,367	678	12,710	7,777	849	109,176	1,527	145	1,673	415	425
2010	54,521	697	12,793	7,951	883	111,058	1,581	150	1,731	431	439
2011	55,701	717	12,880	8,125	920	113,188	1,637	156	1,793	448	454
2012	56,908	738	12,970	8,299	958	115,418	1,696	161	1,857	466	470
2013	58,142	760	13,064	8,473	998	117,749	1,757	167	1,924	485	487
2014	59,403	782	13,160	8,646	1,039	120,183	1,821	173	1,994	505	504
2015	60,693	805	13,260	8,820	1,082	122,723	1,887	180	2,067	525	522
2016	62,012	829	13,364	8,994	1,128	125,371	1,956	186	2,143	547	540
2017	63,361	854	13,471	9,168	1,175	128,129	2,028	193	2,221	569	559
2018	64,740	879	13,581	9,342	1,224	131,000	2,103	200	2,303	592	579
2019	66,150	906	13,695	9,516	1,275	133,986	2,181	208	2,388	617	600
2020	67,592	934	13,813	9,689	1,328	137,090	2,262	215	2,477	642	622

Appendix 1D.B
Economic Evaluation

TABLE 1.D.B-1 BASE CASE OPTIMIZED
NFP020

03/07/91

Florida Power Corp Stratified													
Production Costs				Base		Intern.		Peak		Transm.		Total Annual Cost	Cumulative 1997 Present Worth System Cost
Year	Fuel	Start Up	O&M	Total	Demand		Demand		Demand		Total		
	\$1000	\$1000	\$1000	\$1000	MW	\$/kW-mo	MW	\$/kW-mo	MW	\$/kW-mo	\$1000	\$1000	\$1000
1997	37,554	298	957	38,809	65	13.54	0	7.17	40	3.96	14,324	53,133	53,133
1998	41,898	283	711	42,892	87	14.36	0	7.65	33	5.95	19,642	62,534	111,560
1999	46,298	303	737	47,339	92	16.47	0	10.34	40	5.11	23,253	70,592	173,183
2000	52,488	328	721	53,537	102	16.79	0	10.55	44	5.15	26,261	79,798	238,267
2001	59,255	389	854	60,497	103	20.17	0	10.94	56	5.10	31,749	92,247	308,563
2002	65,599	407	783	66,789	116	20.02	0	10.89	65	5.01	35,763	102,552	381,579
2003	72,297	452	832	73,581	121	20.23	0	11.05	73	5.86	38,989	112,570	456,463
2004	82,843	539	1,025	84,407	125	20.45	15	11.22	84	5.86	44,134	128,542	536,355
2005	91,138	556	1,075	92,768	130	20.85	21	11.48	87	6.77	48,603	141,371	618,450
2006	100,653	583	1,131	102,367	135	21.22	26	11.74	90	6.81	51,935	154,302	702,169
2007	111,213	623	1,206	113,042	140	25.95	32	12.23	93	6.97	63,068	176,109	791,443
2008	123,207	656	1,314	125,177	144	26.09	37	12.40	96	6.94	66,562	191,739	882,256
2009	134,769	698	1,358	136,824	149	26.19	42	12.54	100	6.90	70,410	207,235	973,962
2010	150,077	764	1,463	152,303	154	30.93	48	13.05	103	7.04	83,161	235,464	1,071,316
2011	165,415	834	1,560	167,808	160	32.87	53	13.33	106	7.26	91,434	259,242	1,171,461
2012	182,923	918	1,684	185,525	165	34.94	60	13.61	110	7.49	100,598	286,123	1,274,730
2013	201,904	1,000	1,784	204,688	171	37.14	71	13.91	114	7.73	111,644	316,332	1,381,403
2014	222,597	1,068	1,882	225,547	178	39.48	78	14.21	119	7.97	122,896	348,443	1,491,186
2015	245,572	1,061	1,874	248,507	185	41.97	86	14.51	123	8.23	135,651	384,158	1,604,273
2016	270,354	1,111	1,920	273,385	193	44.61	95	14.82	128	8.49	149,973	423,358	1,720,713
2017	297,811	1,135	1,919	300,865	201	47.42	103	15.14	134	8.76	165,505	466,369	1,840,558
2018	328,508	1,160	1,931	331,599	209	50.40	112	15.47	139	9.04	182,529	514,128	1,963,998
2019	361,557	1,239	1,982	364,778	218	53.57	122	15.80	145	9.32	201,797	566,575	2,091,095
2020	398,652	1,322	2,076	402,050	227	56.95	132	16.14	151	9.62	222,465	624,515	2,221,988

1D.B-2

TABLE 1.D.B-2 16.9 MW STANTON 2 OPTIMIZED
NFP018

03/07/91

Florida Power Corp Stratified																				Cumulative	
Production Costs					Orlando Utilities Commission			Base		Intern.		Peak			Stanton 2				Total	1997	
Year	Fuel	Start Up	D&M	Total		Transm.	Total	Demand		Demand		Demand		Transm.	Total	Capital Costs	Users	Fees	Annual	Present Worth	
=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	
	\$1000	\$1000	\$1000	\$1000	MW	\$/kW-mo	\$1000	MW	\$/kW-mo	MW	\$/kW-mo	MW	\$/kW-mo	\$/kW-mo	\$1000	\$1000	\$1000	\$1000	\$1000	\$1000	
1997	36,971	302	996	38,269	16.9	0.77	156	50	13.54	0	7.17	40	3.96	1.74	11,640	2,939	108	53,113	53,113		
1998	41,022	284	743	42,049	16.9	0.77	156	72	14.36	0	7.65	33	5.95	1.83	16,770	2,939	108	62,022	111,061		
1999	45,572	316	783	46,671	16.9	0.77	156	77	16.47	0	10.34	40	5.11	1.91	20,038	2,939	109	69,914	172,092		
2000	51,042	304	667	52,013	16.9	0.77	156	92	16.79	0	10.55	39	5.15	2.01	23,679	2,939	109	78,896	236,441		
2001	59,108	420	993	60,520	16.9	0.77	156	83	20.17	0	10.94	61	5.10	2.10	26,930	2,939	110	90,656	305,524		
2002	64,673	415	822	65,909	16.9	0.77	156	101	20.02	0	10.89	65	5.01	2.20	31,906	2,939	111	101,022	377,451		
2003	68,837	379	622	69,838	16.9	0.77	156	121	20.23	0	11.05	58	5.86	2.31	37,621	2,939	112	110,667	451,069		
2004	79,203	554	840	80,597	16.9	0.77	156	125	20.45	0	11.22	84	5.86	2.43	41,859	2,939	113	125,664	529,173		
2005	86,953	575	883	88,410	16.9	0.77	156	130	20.85	6	11.48	87	6.77	2.55	46,297	2,939	114	137,917	609,262		
2006	95,892	602	926	97,420	16.9	0.77	156	135	21.22	11	11.74	90	6.81	2.63	49,571	2,939	115	150,202	690,756		
2007	105,772	617	973	107,362	16.9	0.77	156	140	25.95	17	12.23	93	6.97	2.70	60,589	2,939	116	171,162	777,522		
2008	117,001	643	1,061	118,704	16.9	0.77	156	144	26.09	22	12.40	96	6.94	2.85	63,986	2,939	118	185,904	865,572		
2009	127,370	702	1,124	129,197	16.9	0.77	156	149	26.19	27	12.54	100	6.90	3.01	67,560	2,939	119	199,971	954,063		
2010	141,937	745	1,221	143,904	16.9	0.77	156	154	30.93	33	13.05	103	7.04	3.17	80,220	2,939	121	227,341	1,048,059		
2011	156,367	786	1,297	158,450	16.9	0.77	156	160	32.87	39	13.33	106	7.26	3.32	88,420	2,939	123	250,089	1,144,668		
2012	173,045	862	1,412	175,319	16.9	0.77	156	165	34.94	45	13.61	110	7.49	3.47	97,506	2,939	124	276,045	1,244,299		
2013	191,148	935	1,507	193,590	16.9	0.77	156	171	37.14	56	13.91	114	7.73	3.63	108,477	2,939	126	305,289	1,347,248		
2014	210,823	1,011	1,603	213,437	16.9	0.77	156	178	39.48	63	14.21	119	7.97	3.80	119,658	2,939	128	336,318	1,453,212		
2015	232,660	1,039	1,625	235,323	16.9	0.77	156	185	41.97	71	14.51	123	8.23	3.98	132,332	2,939	131	370,881	1,562,390		
2016	256,427	1,101	1,694	259,222	16.9	0.77	156	193	44.61	80	14.82	128	8.49	4.17	146,645	2,939	133	409,095	1,674,907		
2017	282,634	1,083	1,673	285,390	16.9	0.77	156	201	47.42	89	15.14	134	8.76	4.36	162,129	2,939	136	450,750	1,790,738		
2018	312,162	1,146	1,745	315,053	16.9	0.77	156	209	50.40	98	15.47	139	9.04	4.56	179,109	2,939	138	497,396	1,910,161		
2019	343,981	1,208	1,803	346,992	16.9	0.77	156	218	53.57	108	15.80	145	9.32	4.78	198,252	2,939	141	548,480	2,033,199		
2020	379,655	1,307	1,904	382,867	16.9	0.77	156	227	56.95	117	16.14	151	9.62	5.00	218,805	2,939	144	604,911	2,159,982		

ID:B-4

ID: B-4

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TABLE 1.D.B-4 COMBINED CYCLE ADDITION OPTIMIZED
NFPO30

03/07/91

Florida Power Corp Stratified														
Year	Production Costs				Base			Interm.		Peak		Capital Costs		Cumulative 1997 Present Worth System Cost
	Fuel	Start Up	O&M	Total	Demand		Demand		Demand		Transm.	Total	Combustion Cycle	
	\$1000	\$1000	\$1000	\$1000	MW	\$/kW-mo	MW	\$/kW-mo	MW	\$/kW-mo	\$/kW-mo	\$1000	\$1000	\$1000
1997	38,016	276	2,884	41,177	18	13.54	0	7.17	35	3.96	1.74	5,499	5,938	52,614
1998	42,275	290	2,715	45,280	40	14.36	0	7.65	28	5.95	1.83	10,249	5,938	61,467
1999	47,349	325	2,585	50,259	45	16.47	0	10.34	35	5.11	1.91	12,599	5,938	68,796
2000	53,151	363	2,501	56,015	60	16.79	0	10.55	34	5.15	2.01	16,117	5,938	78,070
2001	61,034	421	2,893	64,348	56	20.17	0	10.94	51	5.10	2.10	18,924	5,938	89,211
2002	66,930	450	2,732	70,111	74	20.02	0	10.89	55	5.01	2.20	23,954	5,938	100,004
2003	71,822	421	2,528	74,771	94	20.23	0	11.05	48	5.86	2.31	29,602	5,938	110,311
2004	78,755	468	2,411	81,634	118	20.45	0	11.22	54	5.86	2.43	37,170	5,938	124,742
2005	85,596	504	2,432	88,532	130	20.85	0	11.48	56	6.77	2.55	42,063	5,938	136,533
2006	94,688	532	2,589	97,810	135	21.22	0	11.74	63	6.81	2.63	44,954	5,938	148,702
2007	104,777	599	2,761	108,137	140	25.95	0	12.23	72	6.97	2.70	55,518	5,938	169,593
2008	116,053	670	2,967	119,690	144	26.09	0	12.40	81	6.94	2.85	58,382	5,938	184,010
2009	126,631	771	3,168	130,570	149	26.19	0	12.54	90	6.90	3.01	61,535	5,938	198,043
2010	141,370	850	3,389	145,609	154	30.93	0	13.05	99	7.04	3.17	73,551	5,938	225,098
2011	155,907	913	3,604	160,424	160	32.87	1	13.33	106	7.26	3.32	81,296	5,938	247,658
2012	172,063	979	3,845	176,887	165	34.94	8	13.61	110	7.49	3.47	90,230	5,938	273,056
2013	189,508	1,015	4,066	194,590	171	37.14	19	13.91	114	7.73	3.63	101,064	5,938	301,591
2014	209,261	1,034	4,286	214,580	178	39.48	26	14.21	119	7.97	3.80	112,331	5,938	332,849
2015	231,021	1,075	4,535	236,631	185	41.97	34	14.51	123	8.23	3.98	124,824	5,938	367,392
2016	254,842	1,127	4,775	260,745	193	44.61	42	14.82	128	8.49	4.17	138,896	5,938	405,579
2017	281,096	1,169	5,002	287,267	201	47.42	51	15.14	134	8.76	4.36	154,108	5,938	447,313
2018	310,648	1,255	5,277	317,180	209	50.40	60	15.47	139	9.04	4.56	170,823	5,938	493,941
2019	342,614	1,360	5,538	349,513	218	53.57	70	15.80	145	9.32	4.78	189,741	5,938	545,192
2020	378,506	1,455	5,834	385,795	227	56.95	80	16.14	151	9.62	5.00	210,114	5,938	601,847

1D.B-5

TABLE 1.D.B-5 60 MW STANTON 2 OPTIMIZED
NFP032

03/07/91

Florida Power Corp Stratified																				Cumulative 1997 Present Worth System Cost
Production Costs				Orlando Utilities Commission			Base		Interna.		Peak		Stanton 2			Total Annual Cost				
Year	Fuel	Start Up	O&M	Total		Transa.	Total		Demand		Demand		Demand	Transa.	Total		Capital Costs	Users Fees		
-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	
	\$1000	\$1000	\$1000	\$1000	MW	\$/kW-mo	\$1000	MW	\$/kW-mo	MW	\$/kW-mo	MW	\$/kW-mo	\$/kW-mo	\$1000	\$1000	\$1000	\$1000	\$1000	
1997	35,438	289	1,012	36,739	60	0.77	554	13	13.54	0	7.17	40	3.96	1.74	5,000	10,436	383	53,112	53,112	
1998	38,546	269	778	39,592	60	0.77	554	35	14.36	0	7.65	33	5.95	1.83	9,703	10,436	383	60,669	109,796	
1999	43,219	308	824	44,350	60	0.77	554	40	16.47	0	10.34	40	5.11	1.91	11,944	10,436	387	67,672	168,870	
2000	48,408	307	714	49,429	60	0.77	554	55	16.79	0	10.55	39	5.15	2.01	15,479	10,436	387	76,286	231,090	
2001	56,433	413	1,037	57,883	60	0.77	554	46	20.17	0	10.94	61	5.10	2.10	17,165	10,436	391	86,429	296,952	
2002	61,565	421	853	62,839	60	0.77	554	64	20.02	0	10.89	65	5.01	2.20	22,153	10,436	394	96,376	365,570	
2003	65,705	386	654	66,745	60	0.77	554	84	20.23	0	11.05	58	5.86	2.31	27,813	10,436	398	105,946	436,048	
2004	75,962	564	870	77,397	60	0.77	554	88	20.45	0	11.22	84	5.86	2.43	31,783	10,436	401	120,571	510,986	
2005	82,711	606	823	84,140	60	0.77	554	99	20.85	0	11.48	87	6.77	2.55	36,693	10,436	405	132,227	587,771	
2006	90,460	634	810	91,903	60	0.77	554	108	21.22	0	11.74	90	6.81	2.63	40,178	10,436	408	143,480	665,618	
2007	98,429	641	767	99,836	60	0.77	554	119	25.95	0	12.23	93	6.97	2.70	50,667	10,436	412	161,905	747,692	
2008	107,411	662	751	108,823	60	0.77	554	129	26.09	0	12.40	96	6.94	2.85	54,907	10,436	419	175,140	830,643	
2009	116,050	680	734	117,464	60	0.77	554	139	26.19	0	12.54	100	6.90	3.01	59,270	10,436	422	188,147	913,902	
2010	127,523	693	725	128,941	60	0.77	554	150	30.93	0	13.05	103	7.04	3.17	72,337	10,436	430	212,698	1,001,843	
2011	139,182	698	723	140,602	60	0.77	554	160	32.87	2	13.33	106	7.26	3.32	81,508	10,436	437	233,537	1,092,058	
2012	153,422	751	802	154,974	60	0.77	554	165	34.94	8	13.61	110	7.49	3.47	90,320	10,436	440	256,724	1,184,716	
2013	169,059	781	853	170,692	60	0.77	554	171	37.14	19	13.91	114	7.73	3.63	101,117	10,436	447	283,247	1,280,232	
2014	186,310	800	920	188,030	60	0.77	554	178	39.48	26	14.21	119	7.97	3.80	112,127	10,436	454	311,602	1,378,409	
2015	205,553	816	988	207,356	60	0.77	554	185	41.97	34	14.51	123	8.23	3.98	124,617	10,436	465	343,429	1,479,505	
2016	226,712	834	1,044	228,590	60	0.77	554	193	44.61	43	14.82	128	8.49	4.17	138,806	10,436	472	378,858	1,583,706	
2017	250,130	827	1,067	252,023	60	0.77	554	201	47.42	52	15.14	134	8.76	4.36	154,110	10,436	483	417,607	1,691,020	
2018	276,501	895	1,144	278,540	60	0.77	554	209	50.40	61	15.47	139	9.04	4.56	170,797	10,436	490	460,817	1,801,660	
2019	305,170	959	1,210	307,338	60	0.77	554	218	53.57	71	15.80	145	9.32	4.78	189,697	10,436	501	508,526	1,915,736	
2020	337,482	1,036	1,300	339,818	60	0.77	554	227	56.95	80	16.14	151	9.62	5.00	209,938	10,436	511	561,257	2,033,370	

1D.B-6

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

original

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT 2

SUPPLEMENTAL
SITE CERTIFICATION APPLICATION

VOLUME 2

Directions for inserting Revision 1, February 17, 1992

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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.

Name and Titles of Chief Executive Officers

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)

Name, Address, and Telephone Number of Official Representative Responsible
for Obtaining Certification

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

Site Location (County)

Orange County

Nearest Incorporated City

Orlando, Florida

Latitude and Longitude

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

UTMs (Center of Site)

Northerly 1507528
Easterly 446825

Section, Township, Range

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, and for the purposes of the construction and operation of the Alafaya Trail extension.

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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.

The Alafaya Trail extension is located within an already improved right-of-way that was cleared for the construction and operation of water and sewer pipelines that service the Department of Corrections Correctional Institution and an industrial development south of the Stanton Energy Center. The clearing of the right-of-way and construction of the water and sewer pipelines were previously approved by the U.S. Army Corps of Engineers (ACOE), Florida Department of Environmental Regulation, the St. Johns River Water Management District, and Orange County. Florida Department of Environmental Regulation Secretary Dale Twatchmann determined that regional water and sewer pipelines were not inconsistent with the Florida Electrical Power Plant Siting Act. The location of this road on the site is depicted on Figure 3.2-1. A detailed discussion of the roadway is presented in Section 6.2 of this Supplemental Site Certification Application (SSCA).

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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

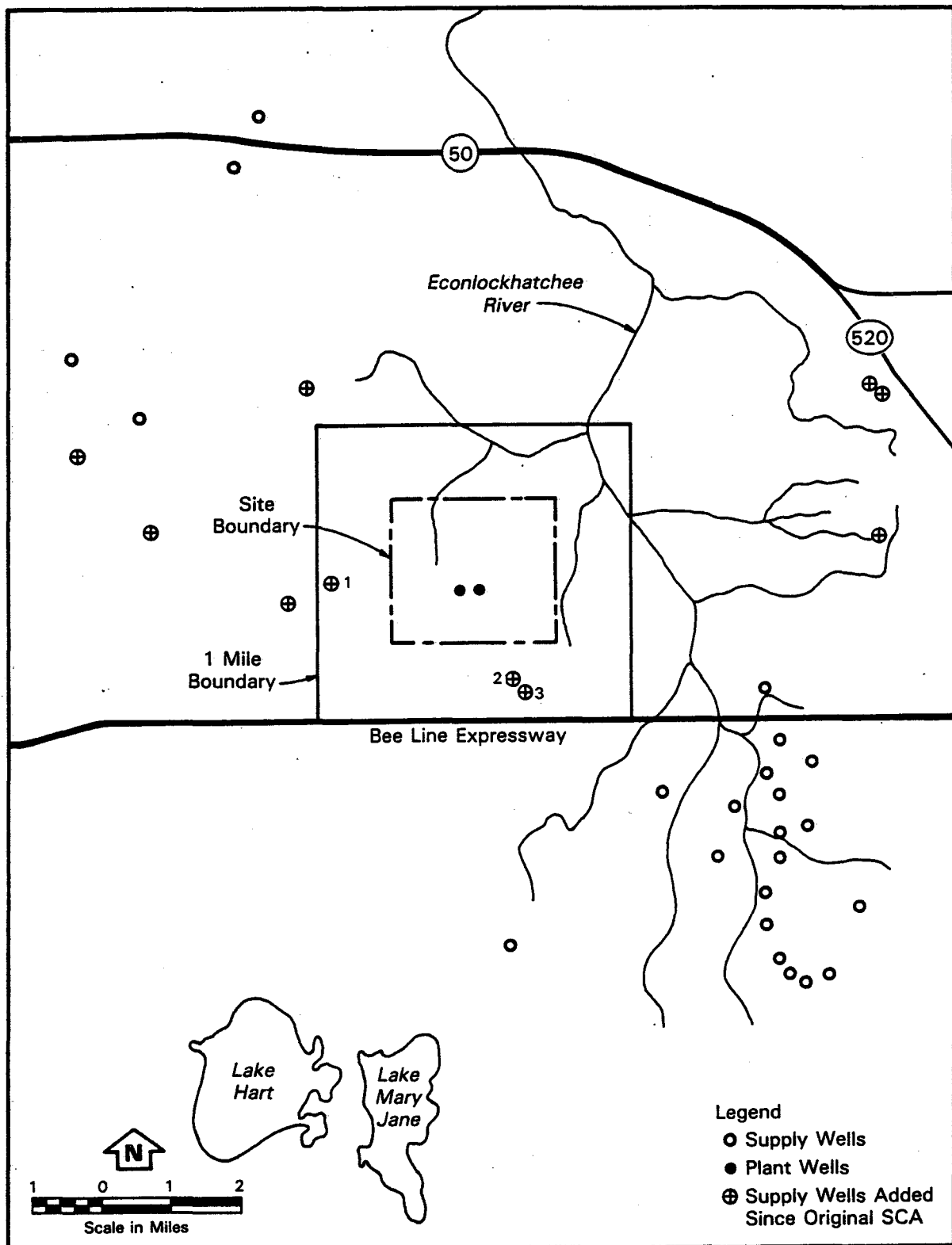
A detailed discussion of ambient noise levels at the Stanton Energy Center site and in the immediate vicinity was included in Subsection 2.9.1 of the original SCA.

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

031591

2.3-5

WATER SUPPLY WELLS
IN THE AREA OF THE SITE

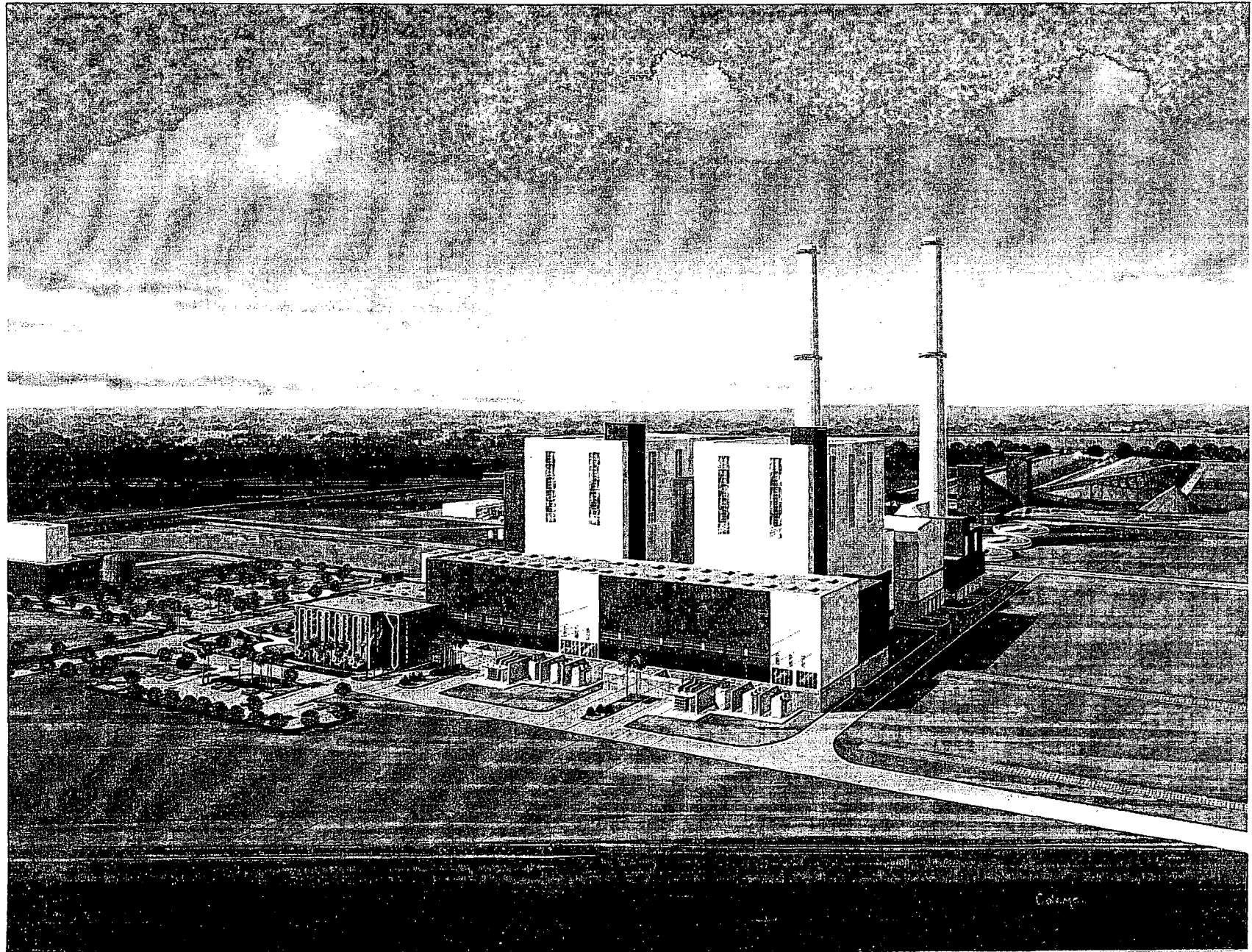
Figure 2.3-1

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, including the Alafaya Trail extension. The new onsite facilities will occupy approximately 58 acres of the 3,280-acre site.

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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.

3.2 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.

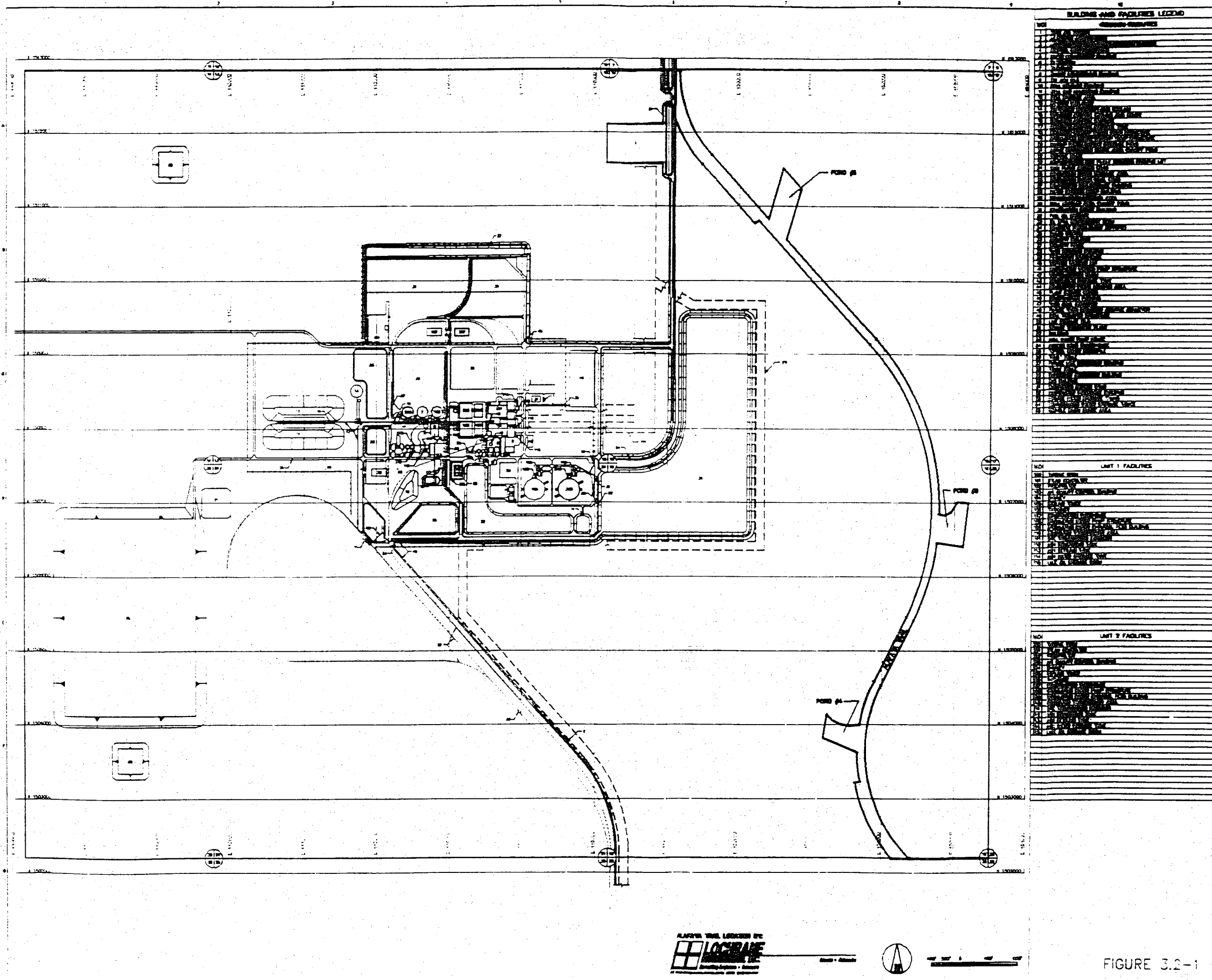
A general plant profile of the total two-unit power plant is shown on Figure 3.2-2. This profile is based on the elevations of the various facilities as viewed from the north looking south. The elevations and dimensions shown on Figure 3.2-2 are based on Stanton 1 sizes and considered preliminary. Some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

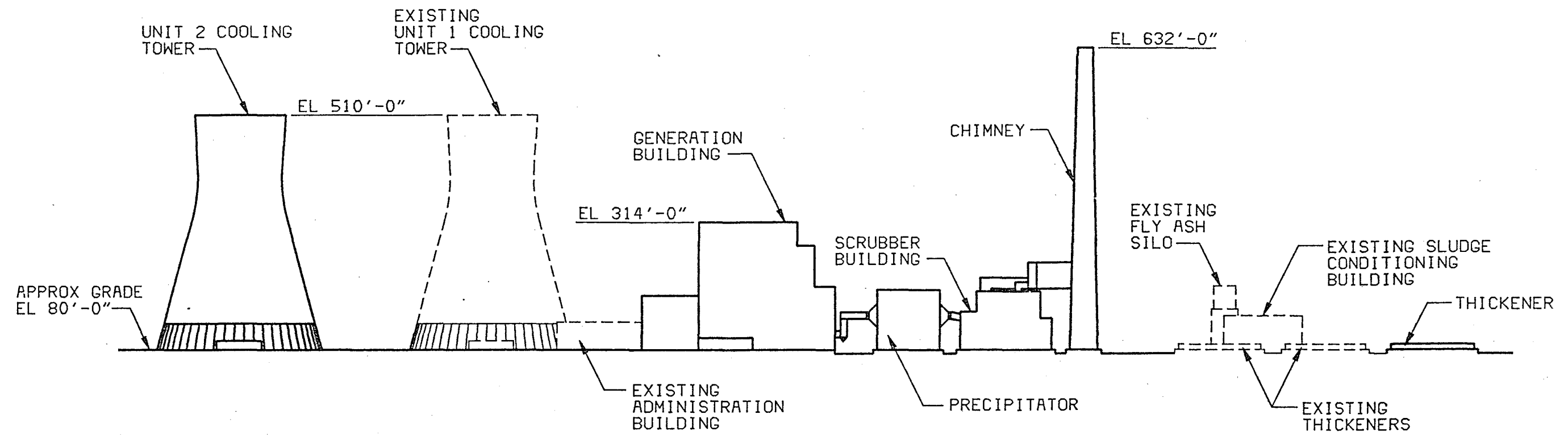
The Stanton Energy Center is designed so that no wastewater discharges to surface waters will be necessary. A detailed description of the water supply, uses, and management is presented in Section 3.5.

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.

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.





PLANT VIEW LOOKING SOUTH

GENERATION FACILITIES PROFILE

Figure 3.2-2

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 minimizing 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 (PM₁₀ 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 PM₁₀ ambient standard of 150 micrograms per cubic meter, not to be exceeded more than once per year, and the PM₁₀ 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, improper 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 (SO₂) 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ removal requirement based on a 30-day rolling average requires that the SO₂ 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 SO₂ 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.

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 SO₂ 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 SO₂ removal. Considering an adequate 3 percent control margin, wet limestone scrubbers should also be capable of meeting an SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ removal requirements when burning the worst case coal (high sulfur and low heating value). Operating costs are based on FGD systems operated to meet SO₂ removal requirements when burning the typical coal.

Flue Gas Desulfurization Methods. A number of post-combustion FGD processes have demonstrated SO₂ 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 SO₂ 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 SO₂ removal efficiencies. Because of the highly alkaline nature of lime, wet lime scrubbers are capable of up to 97 percent SO₂ removal. Considering an adequate control margin of 3 percent (to ensure reliability during process control upsets), a wet

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 cementitious 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 ft² 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 SO₂ 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 SO₂.

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 SO₂ 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 SO₂, to \$52 million for the lime spray dryer AQCS also designed for an emission rate of 0.32 lb/MBtu SO₂.

Other Considerations. As indicated in the assumptions for this section, it is expected that a 3 percent SO₂ 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 SO₂ 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 SO₂ 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 SO₂. The additional costs for a wet lime AQCS result in an incremental removal cost of \$6,900 per ton of SO₂ removed, to go

from an emission rate of 0.32 lb/MBtu SO₂ to 0.24 lb/MBtu SO₂. 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 SO₂ 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 SO₂/MBtu and 0.67 lb SO₂/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 De NO_x) or urea (NO_xOUT) as reagents.

Ammonia for a Thermal De NO_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 similarly 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 De NO_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_x OUT 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 practice 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 SO₂ 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 philosophy 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

^aCalculations are based on the economic recovery period, cost of money, and margins for insurance and taxes.

^bCalculations 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

^aDesign parameters are based on one (440 MW net) unit.

^bAlso 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
^aDesign parameters are based on one (440 MW net) unit. ^bAlso 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	<u>1,010</u>	<u>1,330</u>	<u>1,000</u>
1991 capital cost	33,300	27,900	29,890
Contingency	<u>3,330</u>	<u>2,790</u>	<u>2,990</u>
1991 direct capital cost	36,630	30,690	32,880
Escalation	<u>7,460</u>	<u>6,250</u>	<u>6,690</u>
Direct capital cost	44,090	36,940	39,570
Indirects	7,050	5,910	6,330
AFUDC	<u>6,680</u>	<u>5,600</u>	<u>6,000</u>
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	<u>170</u>	<u>210</u>	<u>170</u>
1997 levelized annual operating cost	6,930	4,820	4,670
Fixed charges on capital	<u>4,570</u>	<u>3,830</u>	<u>4,100</u>
1997 total levelized annual cost	11,500	8,650	8,770
Incremental Removal Cost, \$/ton	19,180	Base	NA

^aCosts are for particulate removal systems installed downstream of a 440 MW net unit.

**Table 3.4-6
Sulfur Dioxide Emissions**

Alternative	Uncontrolled <u>Emission</u>^a lb/MBtu	Controlled <u>Emission</u> Rate lb/MBtu	Annual <u>Emission</u>^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

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

^bAnnual 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
^aAll values are for an AQCS located downstream of one full size (440 MW net) pulverized coal boiler. ^bMoles of calcium per mole of sulfur in the coal. ^cIncludes all equipment associated with SO₂ 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

^aAll values are for an AQCS located downstream of one full size (440 MW net) pulverized coal boiler.

^bMoles of calcium per mole of sulfur in the coal.

^cIncludes all equipment associated with SO₂ 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

^aAll values are for an AQCS located downstream of one full size (440 MW Net) pulverized coal boiler.

^bMoles of calcium per mole of sulfur in the coal.

^cIncludes all equipment associated with SO₂ and particulate removal system operation including differential ID fan power to overcome AQCS draft losses.

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	<u>2,630</u>	<u>2,630</u>	<u>2,900</u>
1991 Capital Cost	69,140	74,900	63,660
Contingency	<u>6,910</u>	<u>7,490</u>	<u>6,370</u>
Direct Capital Cost	76,050	82,390	70,030
Escalation	<u>15,480</u>	<u>16,770</u>	<u>14,260</u>
Direct Capital Cost	91,530	99,160	84,290
Indirects	14,640	15,870	13,490
Interest During Construction	<u>13,870</u>	<u>15,030</u>	<u>12,770</u>
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	<u>9,080</u>	<u>9,710</u>	<u>9,930</u>
1997 Total Levelized Annual Operating Cost	37,070	26,000	43,710
Fixed Charges on Capital	<u>9,480</u>	<u>10,270</u>	<u>8,730</u>
1997 Total Levelized Annual Cost	46,550	36,270	52,440
Incremental Removal Cost, \$/ton	6,870	Base	NA

^aCosts are total for one (440 MW net) unit.

Table 3.4-12
Nitrogen Oxides, Carbon Monoxide, VOC, and Ammonia Emissions

Alternative	<u>Uncontrolled Emission</u> lb/MBtu	<u>Reduction Rate</u> percent	<u>Emission Rate</u> lb/MBtu	<u>Annual Emission</u> 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

^aSNCR 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

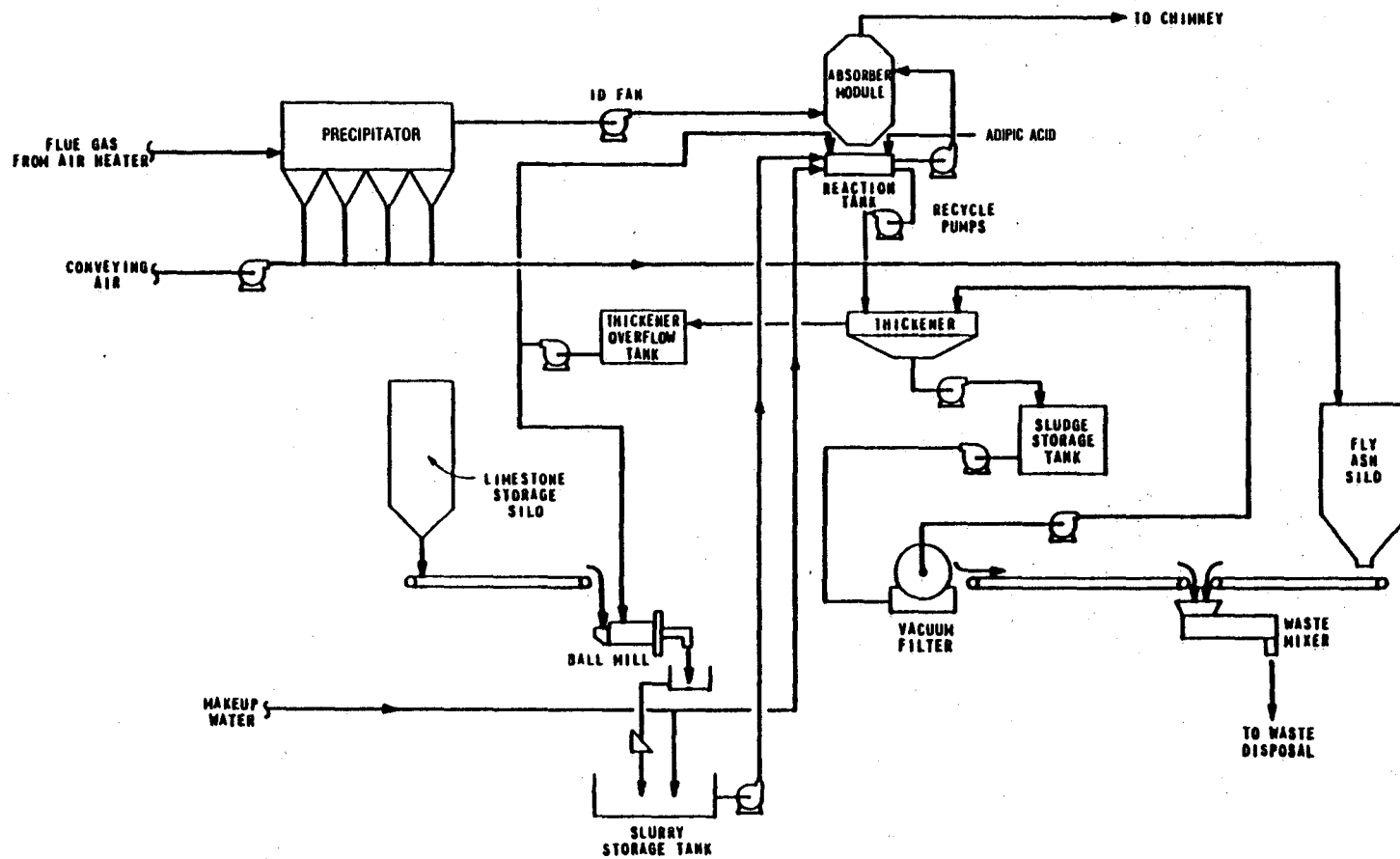
	40 Percent Reduction <u>SNCR System</u> \$1,000	30 Percent Reduction <u>SNCR System</u> \$1,000
Capital Costs		
SNCR system	5,130	4,320
Balance-of-plant	<u>2,730</u>	<u>2,300</u>
1991 capital cost	7,860	6,620
Contingency	<u>790</u>	<u>660</u>
Direct capital cost	8,650	7,280
Escalation	<u>1,720</u>	<u>1,450</u>
Direct capital cost	10,370	8,730
Indirects	1,660	1,400
Interest during construction	<u>1,570</u>	<u>1,320</u>
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	<u>110</u>	<u>100</u>
1997 total annual operating cost	5,460	4,630
Fixed charges on capital	<u>1,070</u>	<u>900</u>
1997 total levelized annual cost	6,530	5,530

Table 3.4-14
Estimated Lead and Noncriteria Pollutant Emissions

Pollutant	<u>Uncontrolled Emissions</u>		Removal Rate (percent)	<u>Controlled Emissions</u>	
	Average Emission (lb/h)	Worst Case Emission (lb/h)		Average Emission (lb/h)	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	0.86 232	4.2 280	50	149 116	179 140
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	0.038 440	0.078 800	80	88	160
Manganese	35	273	95	1.9	14
Nickel	9.2	36	90	1.0	3.6
Phosphorus	52 19	202 106	90	5.8 1.9	29 10.6
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 μ Ci/h

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3.4-47

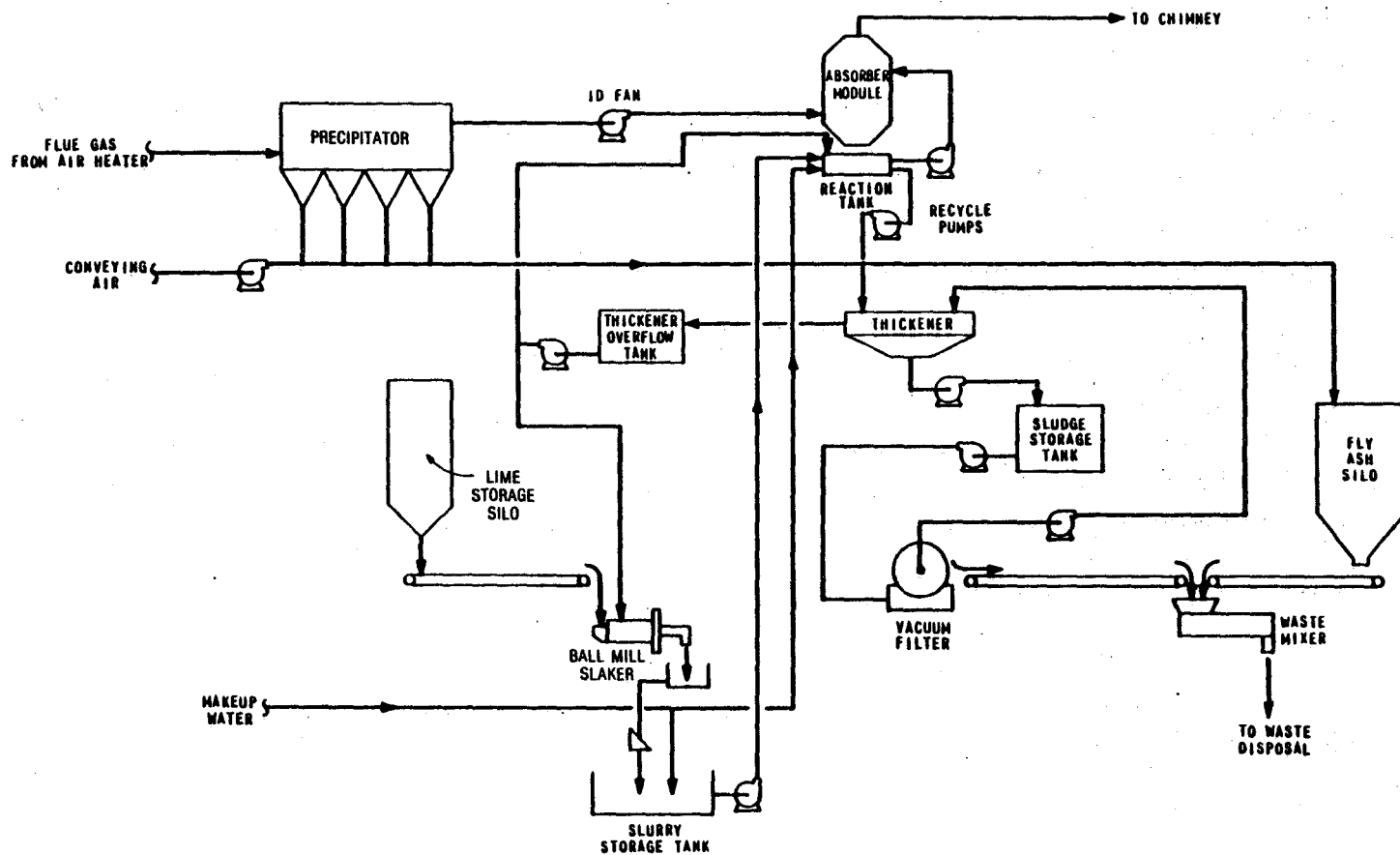


WET LIMESTONE SCRUBBER
AIR QUALITY CONTROL SYSTEM

Figure 3.4-1

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3.4-48

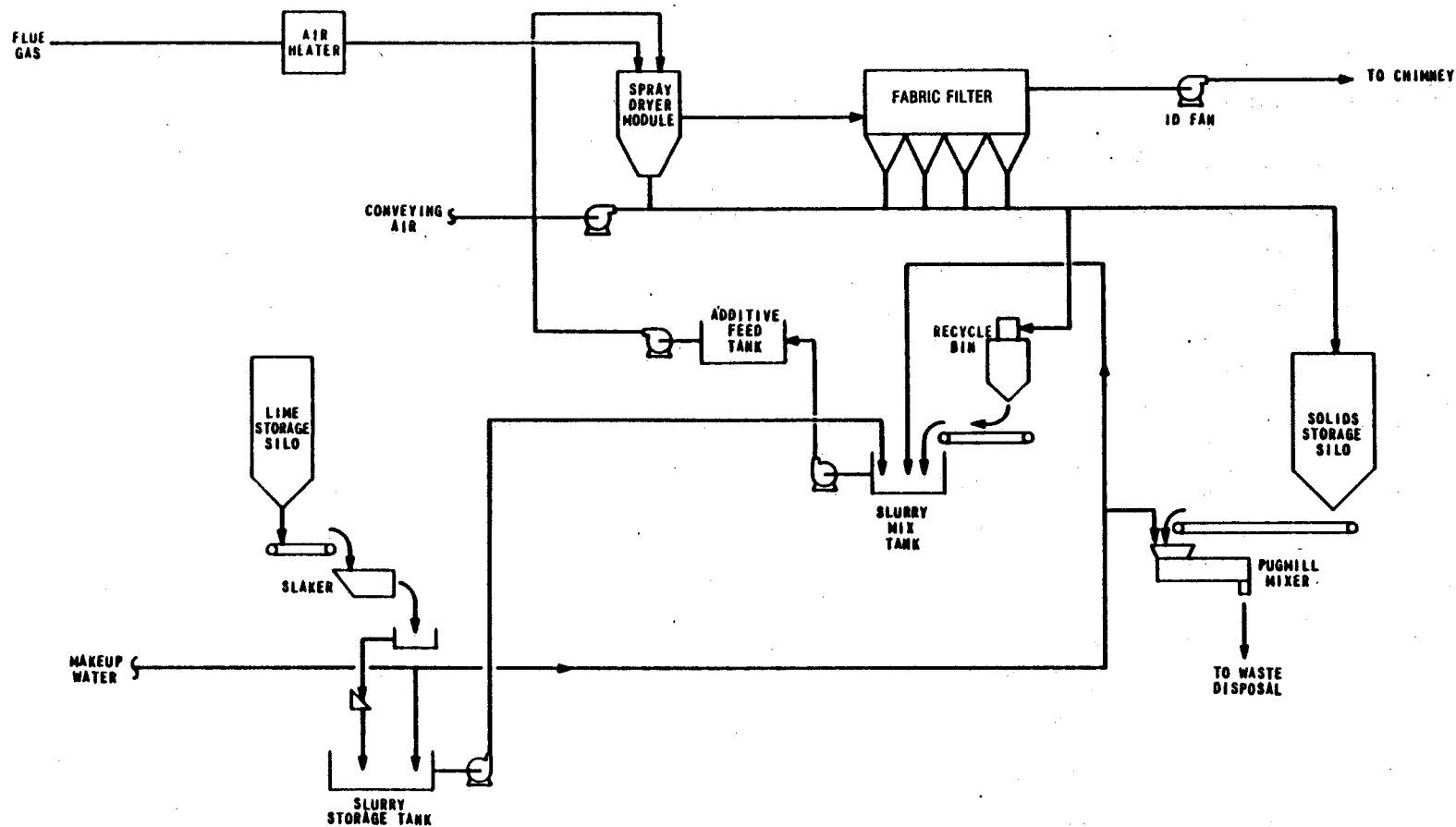


**WET LIME SCRUBBER
AIR QUALITY CONTROL SYSTEM**

Figure 3.4-2

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3.4-49



**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.

11/2 MGD
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	<u>1,250 gpd</u>
Total	4,400 gpd

Biological loading will be approximately 0.045 pound of BOD₅ per day for each construction person, visitor, and temporary, or a total of approximately 8 pounds of BOD₅ 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 personnel at 150 gpm	4,500 gpd
20 visitors and temporary personnel at 25 gpd	<u>500 gpd</u>
Total	11,500 gpd

Biological loading will be approximately 0.075 pound per day of BOD₅ for permanent personnel and 0.045 pound per day of BOD₅ for visitors and temporary personnel, or a total of approximately 16 pounds per day of BOD₅.

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

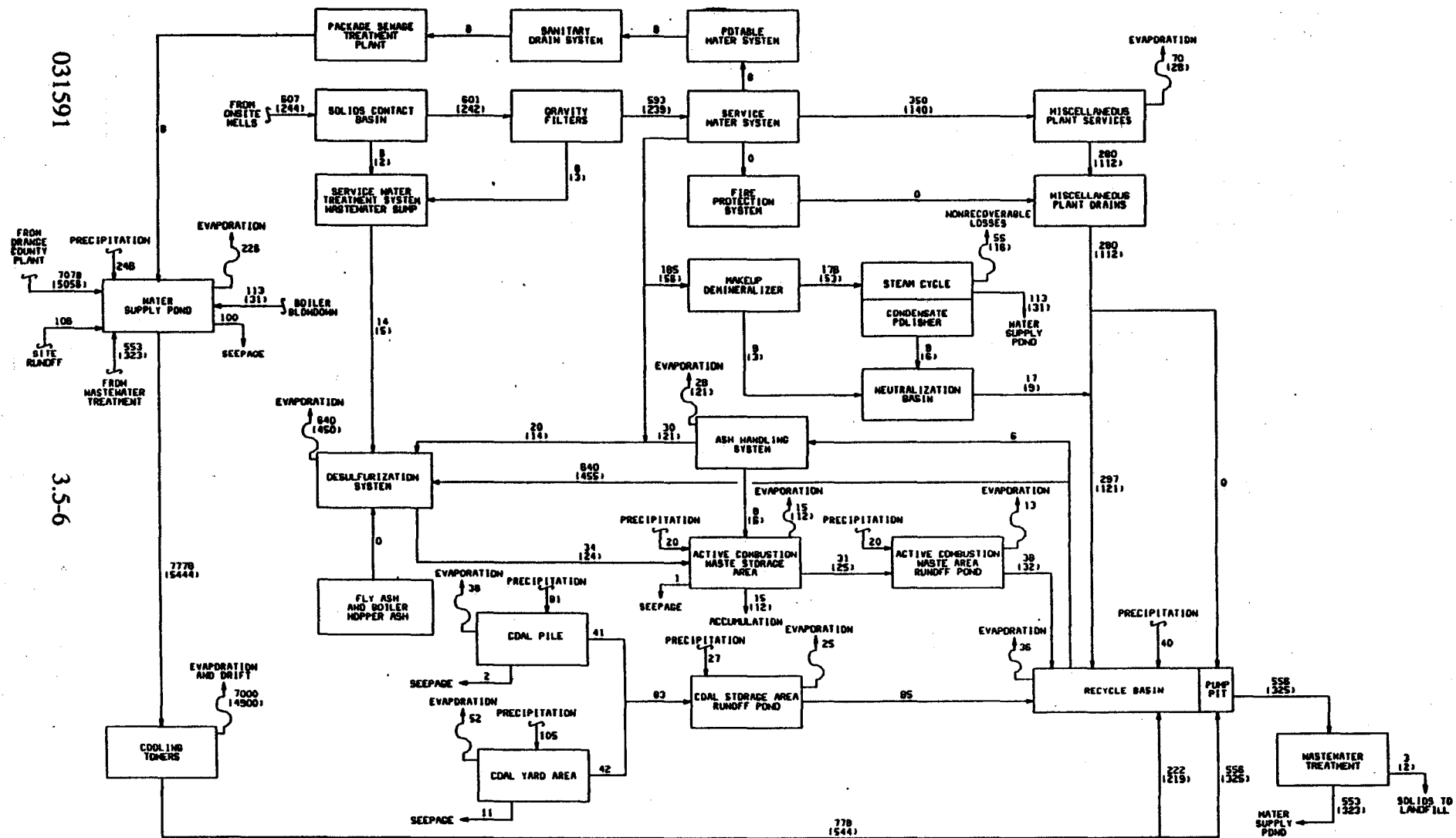
The various process water systems to be incorporated as part of Stanton 2 other than the heat rejection/cooling systems are described in Subsection 3.3.1 and Section 3.5 of the original SCA. These describe the water uses and chemicals and biocides, respectively, associated with the power plant. The treatments 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	<u>124</u>	<u>244</u>	<u>120</u>
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	<u>9</u>	<u>14</u>	<u>5</u>
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	<u>305</u>	<u>607</u>	<u>302</u>
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	<u>11</u>	<u>18</u>	<u>7</u>
Total	4,816	8,704	3,888



NOTES:

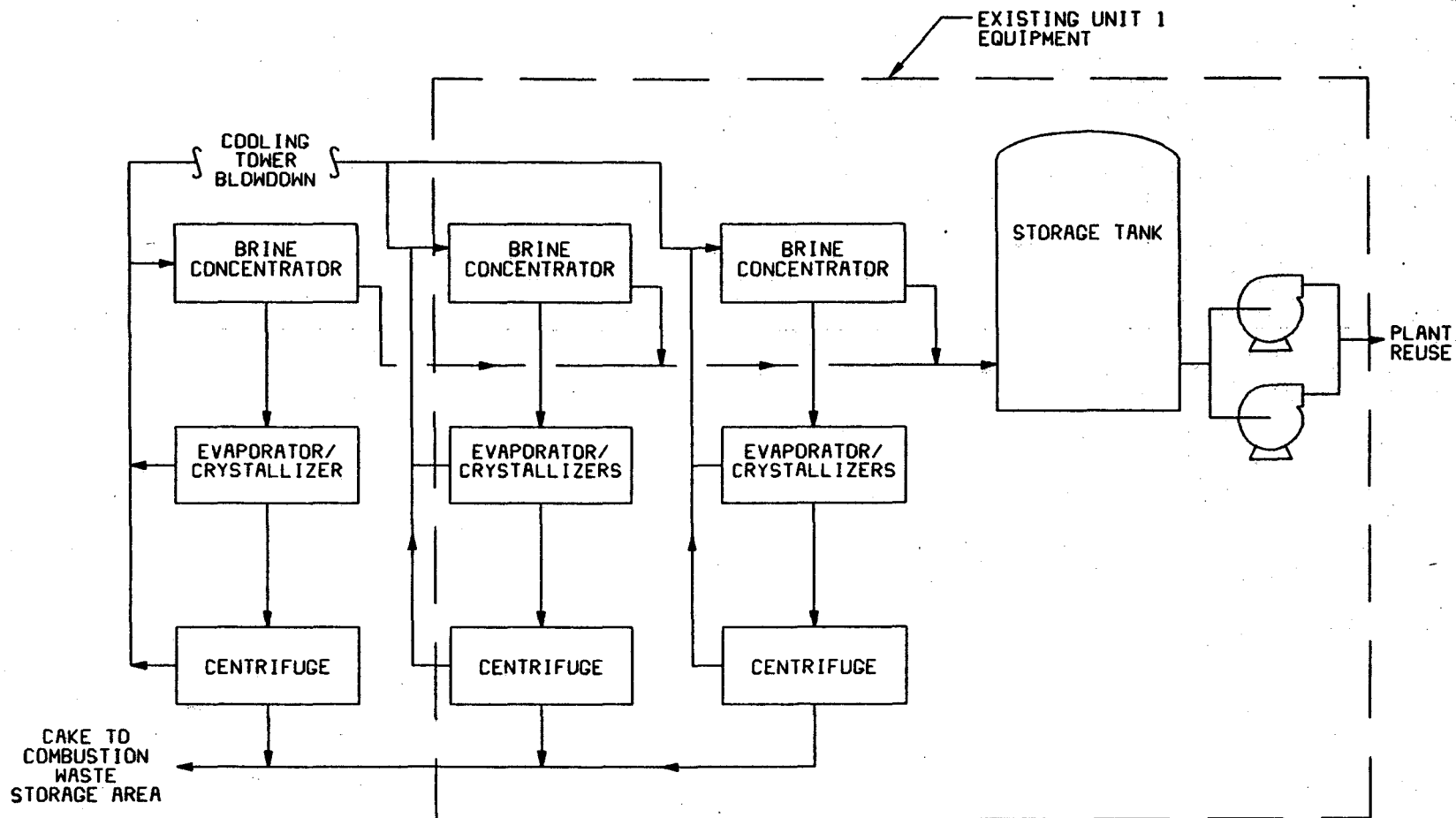
1. ALL FLOWS ARE EXPRESSED IN GALLONS PER MINUTE.
2. FLOWS REPRESENT TYPICAL REQUIREMENTS FOR TWO UNITS OPERATING AT 100 PERCENT LOAD ASSUMING PEAK SERVICE WATER DEMANDS.
3. FLOWS IN PARENTHESES REPRESENT REQUIREMENTS FOR TWO UNITS OPERATING AT AVERAGE LOAD OF 70 PERCENT WHILE OPERATING WHEN DIFFERENT 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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3.5-7



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.

A drainage system has been designed specifically for the Alafaya Trail extension. This system is independent of the remainder of the onsite drainage system for Units 1 and 2. Within the 180-foot right-of-way, the road typically provides for construction of two lanes with 10-foot shoulders. Drainage is collected within roadside swales and ditches and transmitted longitudinally within the limits of the right-of-way to surface stormwater management facilities. Two lanes of urban roadway are contained within the 100-foot right-of-way limits. Runoff is collected through a system of curb inlets and transmitted longitudinally within the road right-of-way utilizing underground pipes to surface stormwater management facilities. At locations where the road interrupts natural drainage patterns, culverts or bridge drainage structures are provided. The location of the stormwater management facilities are depicted on Figure 3.2-1.

RFM-1

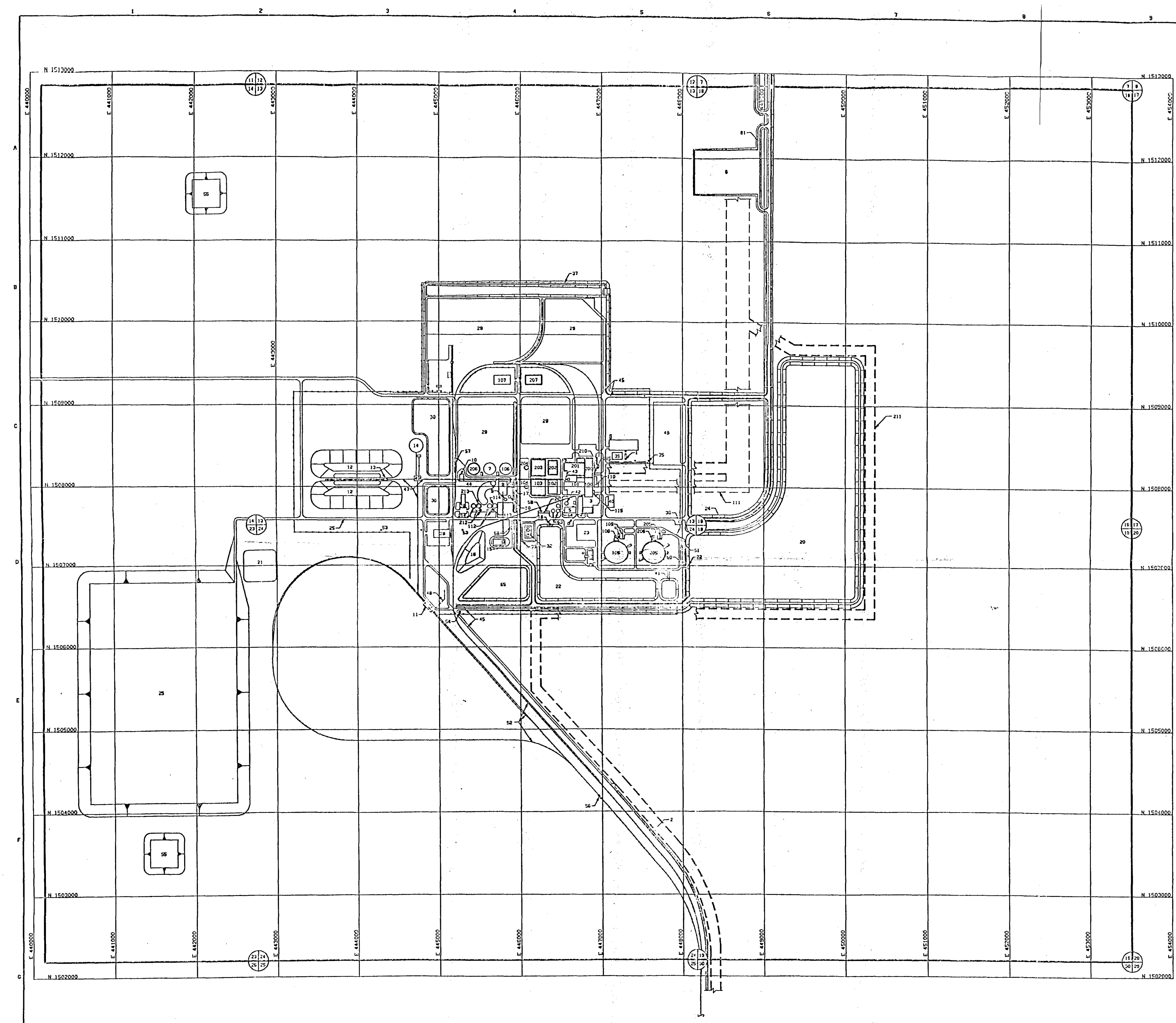
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3.9 Materials Handling

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.



BUILDING AND FACILITIES LEGEND	
COMMON FACILITIES	
NO	DESCRIPTION
1	FIRST AID TRAILER
2	ALTERNATE ACCESS ROAD
3	ADMINISTRATION AND PLANT SERVICES BUILDING
4	CONTROL CENTER BUILDING
5	WATER MANAGEMENT BUILDING
6	SUBSTATION
7	SLUDGE CONDITIONING BUILDING
8	FLY ASH SILO
9	COAL CRUSHER BUILDING
10	COAL CAR UNLOADING BUILDING
11	COAL STORAGE AREA
12	STACKER RECLAIMER
13	EMERGENCY STOCKOUT AND RECLAIM
14	SCRUBBER ADDITIVE RECLAIM AND COVER
15	SCRUBBER ADDITIVE STORAGE
16	SCRUBBER ADDITIVE STORAGE TANK
17	SCRUBBER MAKEUP WATER PUMP STRUCTURE
18	CIRCULATING WATER MAKEUP PUMP STRUCTURE
19	MAKEUP WATER SUPPLY STORAGE POND
20	ACTIVE COMBUSTION WASTE AREA RUNOFF POND
21	RECYCLE BASIN
22	ADMINISTRATION AND PLANT SERVICES PARKING LOT
23	MAIN PLANT ACCESS ROAD
24	COMBUSTION WASTE STORAGE AREA
25	COMBUSTION WASTE Haul ROAD
26	COMPRESSED GAS STORAGE BUILDING
27	WATER STORAGE PUMP BUILDING
28	CONSTRUCTION LAYDOWN AREA
29	COAL STORAGE AREA RUNOFF POND
30	CONSTRUCTION OFFICE BUILDING
31	FUEL OIL STORAGE
32	OIL SPILL CONTAINMENT BERM
33	CONCRETE BATCH PLANT (OFFSITE)
34	GUARD STATION
35	SECURITY BUILDING
36	SECURITY FENCE
37	YARD SERVICES BUILDING
38	PERMANENT WAREHOUSE
39	VISITORS PARKING LOT
40	WASTEWATER RETURN PUMP STRUCTURE
41	NEUTRALIZATION BASIN
42	CONDENSATE STORAGE TANK
43	COMBUSTION WASTE LOADING AREA
44	PLANT SERVICE ROADS
45	CONSTRUCTION PARKING
46	YARD COAL CONVEYOR
47	FUTURE YARD SCRUBBER ADDITIVE CONVEYOR
48	COAL TRANSFER STRUCTURE
49	LIME STORAGE SILO
50	SEWAGE TREATMENT PLANT
51	RAILROAD
52	WELL WATER PUMP HOUSE
53	ACCESS ROAD GUARDHOUSE
54	TOPSOIL COVER STOCKPILE
55	TRUCK SCALE
56	FUTURE LIVE UNLOADING BUILDING
57	TRUCK SCALE
58	EMERGENCY GENERATOR BUILDING
59	SUS BUILDING
60	SUBSTATION ACCESS ROAD
61	WASTEWATER TREATMENT BUILDING
62	SERVICE WATER STORAGE TANKS
63	DEMINERALIZED WATER STORAGE TANKS
64	RECYCLE BASIN SURGE AREA
UNIT 1 FACILITIES	
100	TURBINE ROOM
101	STEAM GENERATOR
102	PRECIPITATOR
103	AIR QUALITY CONTROL BUILDING
104	CHIMNEY
105	COOLING TOWER
106	THICKENER
107	CONSTRUCTION WAREHOUSE
108	CIRCULATING WATER PUMP STRUCTURE
109	CIRCULATING WATER CHEMICAL FEED BUILDING
110	GENERATOR TRANSFORMER AREA
111	SITE TRANSMISSION CORRIDOR
112	ASH DEWATERING TANK
113	ASH SETTLING TANK
114	ASH WATER STORAGE TANK
115	LUBE OIL STORAGE ROOM
UNIT 2 FACILITIES	
200	TURBINE ROOM
201	STEAM GENERATOR
202	PRECIPITATOR
203	AIR QUALITY CONTROL BUILDING
204	CHIMNEY
205	COOLING TOWER
206	THICKENER
207	CONSTRUCTION WAREHOUSE
208	CIRCULATING WATER PUMP STRUCTURE
209	CIRCULATING WATER CHEMICAL FEED BUILDING
210	GENERATOR TRANSFORMER AREA
211	SITE TRANSMISSION CORRIDOR
212	ASH DEWATERING TANK
213	ASH SETTLING TANK
214	ASH WATER STORAGE TANK
215	LUBE OIL STORAGE ROOM

NOT TO BE USED
FOR CONSTRUCTION
DATE OF ISSUE

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 and for the purpose of construction and operation of the extension of Alafaya Trail.

RFM-1

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.

As described in Chapter 6 of this application, a new roadway will traverse the Stanton Energy Center. This roadway will extend Alafaya Trail from its terminus at the northern boundary of the Stanton Energy Center to approximately 3,000 feet south of the Bee Line Expressway. The roadway will be approximately 4.2 miles long; only approximately 2.3 miles are on the Stanton Energy Center property and, therefore, subject to this application. Construction impacts associated with the 2.3 mile segment of this roadway are discussed in Chapter 6.

RFM-1

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. The Alafaya Trail extension will be wholly owned by Orange County and is not a part of the state road system. Therefore, information requested in the Florida Department of Transportation "Utility Accommodation Guide" is not required.

RFM-1

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.

4.0 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

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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.

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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 and the Alafaya Trail extension. These impacts are addressed in Chapter 6.

RFM-1

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 and the extension of Alafaya Trail are discussed in Chapter 6 of this application.

RFM-1

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 and the extension of Alafaya Trail are discussed in Chapter 6.

|RFM-1

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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

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 artesian 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.

Layer

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

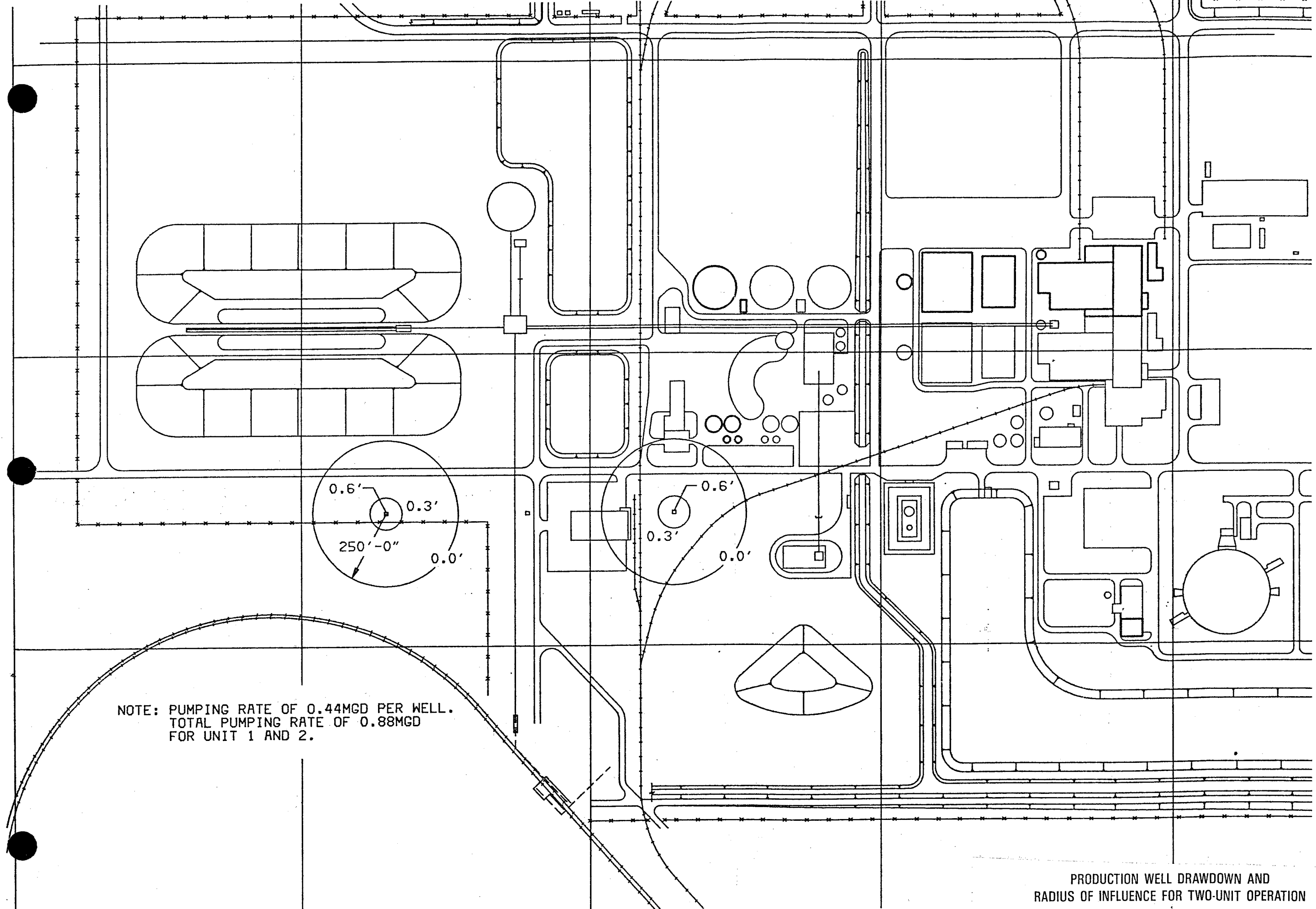
Monitoring programs as described in Subsection 6.3.6 of the original SCA have been implemented and will continue to be used for monitoring effects of plant operation on water supplies during and after construction of Stanton 2. Historical ground water quality data collected from the implemented monitoring 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

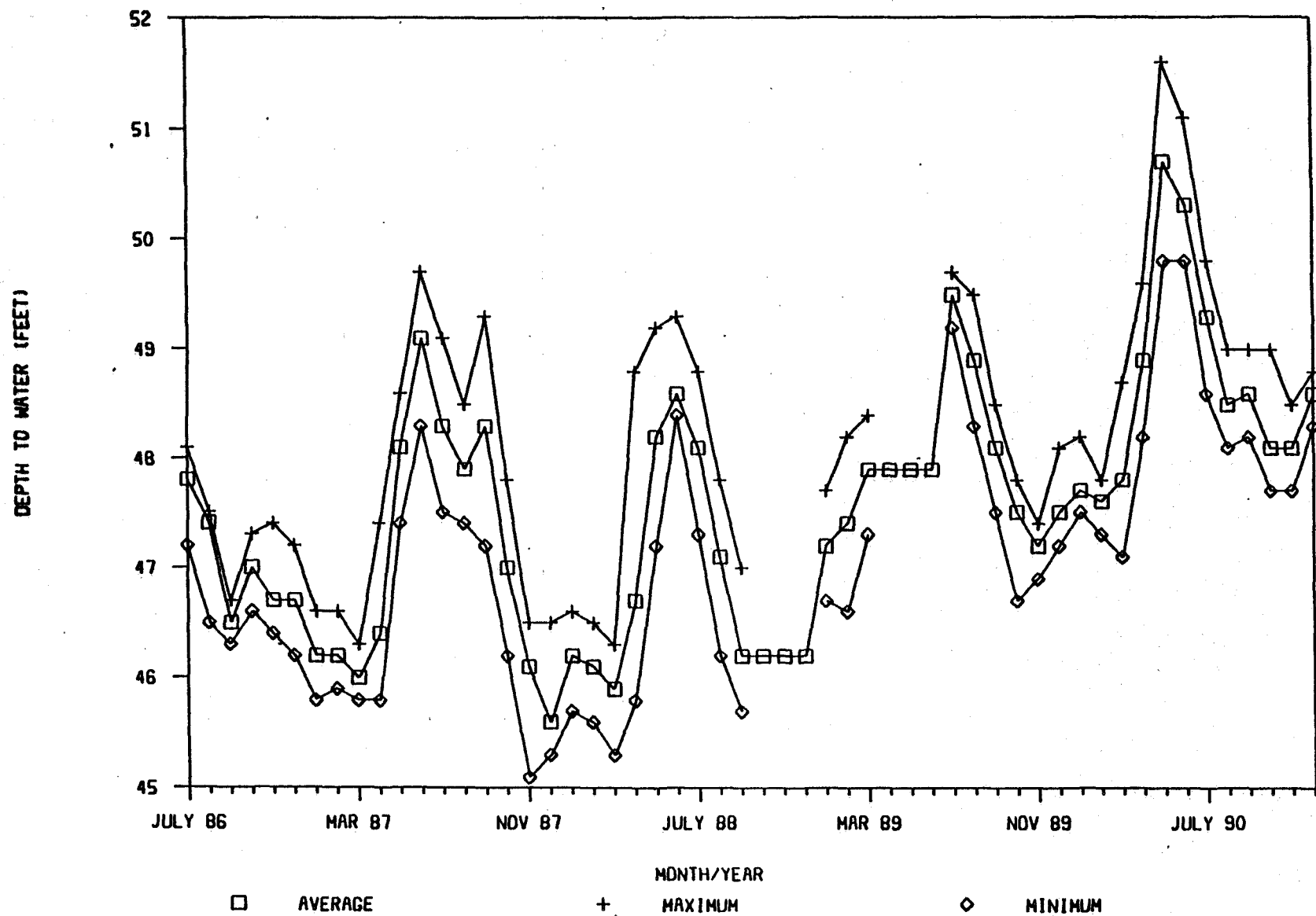


NOTE: PUMPING RATE OF 0.44MGD PER WELL.
TOTAL PUMPING RATE OF 0.88MGD
FOR UNIT 1 AND 2.

PRODUCTION WELL DRAWDOWN AND
RADIUS OF INFLUENCE FOR TWO-UNIT OPERATION

031591

5.3-7



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 (SO₂) emission rate was 1.14 lb SO₂/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 SO₂ emission rate is 0.32 lb SO₂/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 SO₂ emission rates are proposed to be 0.85 and 0.67 lb SO₂/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 NO₂/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 SO₂, NO₂, 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	—
^aEmission 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 ($\mu\text{g}/\text{m}^3$)	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

^aImpacts 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 ($\mu\text{g}/\text{m}^3$)	Predicted Impacts ($\mu\text{g}/\text{m}^3$)	Percent of Increment Consumed
SO₂			
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 ($\mu\text{g}/\text{m}^3$)	Revised Pollutant Concentrations ^b ($\mu\text{g}/\text{m}^3$)
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

^aModeled with 1974-1979 meteorological data.

^bModeled with 1981-1985 meteorological data.

^cCO impacts from the original SCA were listed as only < <1 mg/m³. The values listed are given in $\mu\text{g}/\text{m}^3$ 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.

The noise impacts from the extension of Alafaya Trail are discussed in Chapter 6.

RFM-1

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 LINEAR FACILITIES

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 and for the construction and operation of the extension of Alafaya Trail.

RFM-1

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.

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 makeup 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 necessary 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
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)	IN WETLAND (CU YD)
101	102	930	0	0.0	0.00	120	0	465	465	0.98	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	1.85	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	1.88	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)	WETLAND (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
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)	EXCAVATION IN WETLAND (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	0.48	0	0.00	0.0
170	171	865	0	0.0	0.00	100	0	665	0	0.00	0	0.00	0.0
171	172	865	0	0.0	0.00	100	0	665	0	0.00	0	0.00	0.0
172	173	860	0	0.0	0.00	100	0	640	20	0.002	0	0.00	0.0
173	174	860	0	0.0	0.00	100	0	640	20	0.002	0	0.00	0.0
174	175	860	50	70.4	0.03	100	0	660	0	0.00	0	0.00	0.0
175	176	860	450	633.3	0.24	100	0	310	50	0.01	300	0.03	0.0
176	177	860	300	422.2	0.18	100	0	460	50	0.01	150	0.02	31.4
177	178	860	300	422.2	0.18	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.

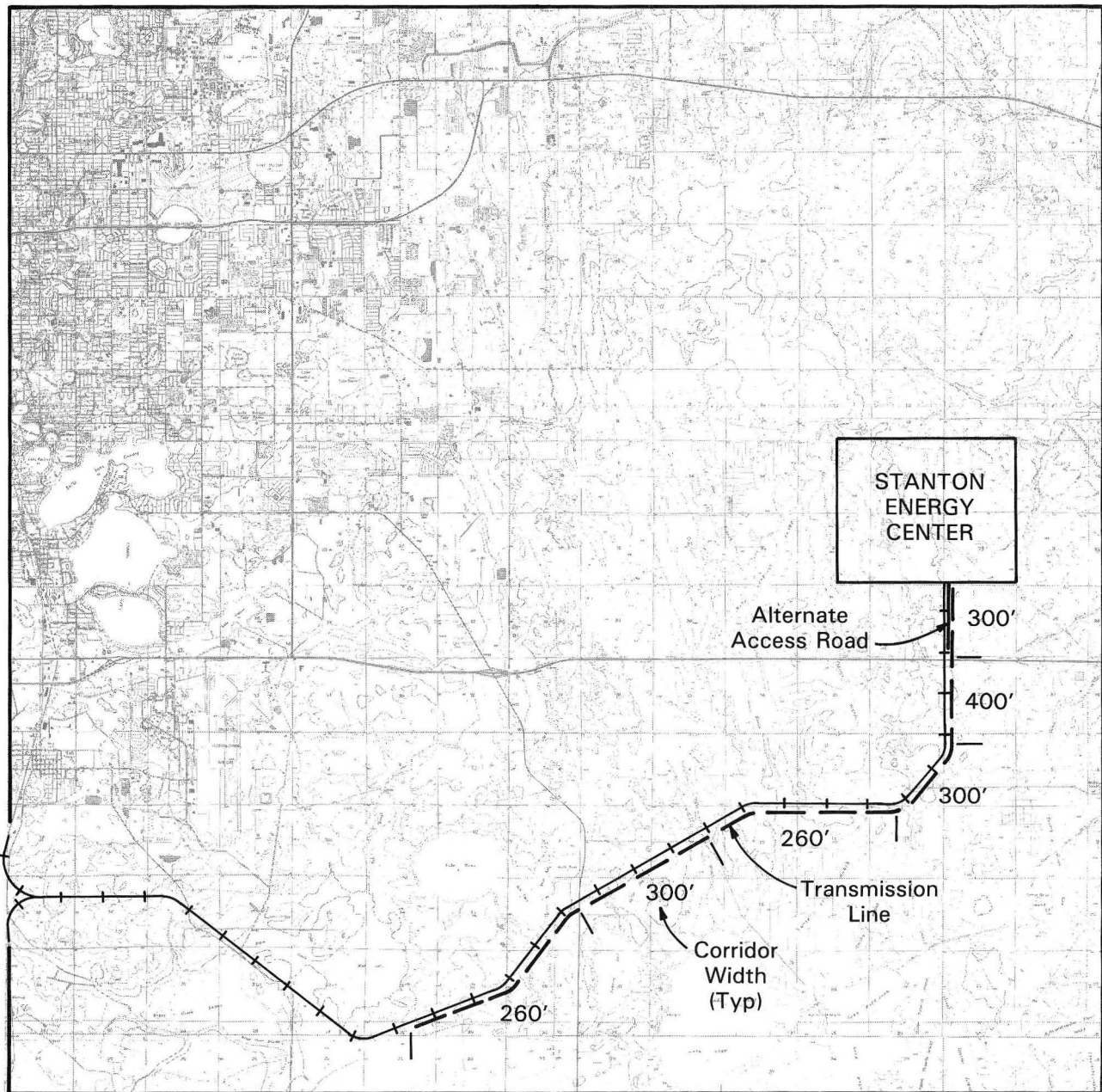
Table 6.1-2
Estimated Total Cost of Transmission Line

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		<u>1,858,175</u>
Estimated Total Cost		9,000,000
Total Length	14.0 miles	
Estimated Per Mile Cost		642,855

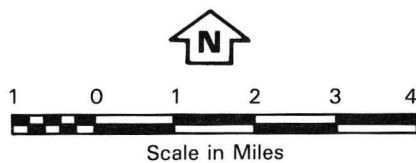
^aOrlando Utilities Commission costs, surveying, engineering, legal, soil investigation costs.

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.

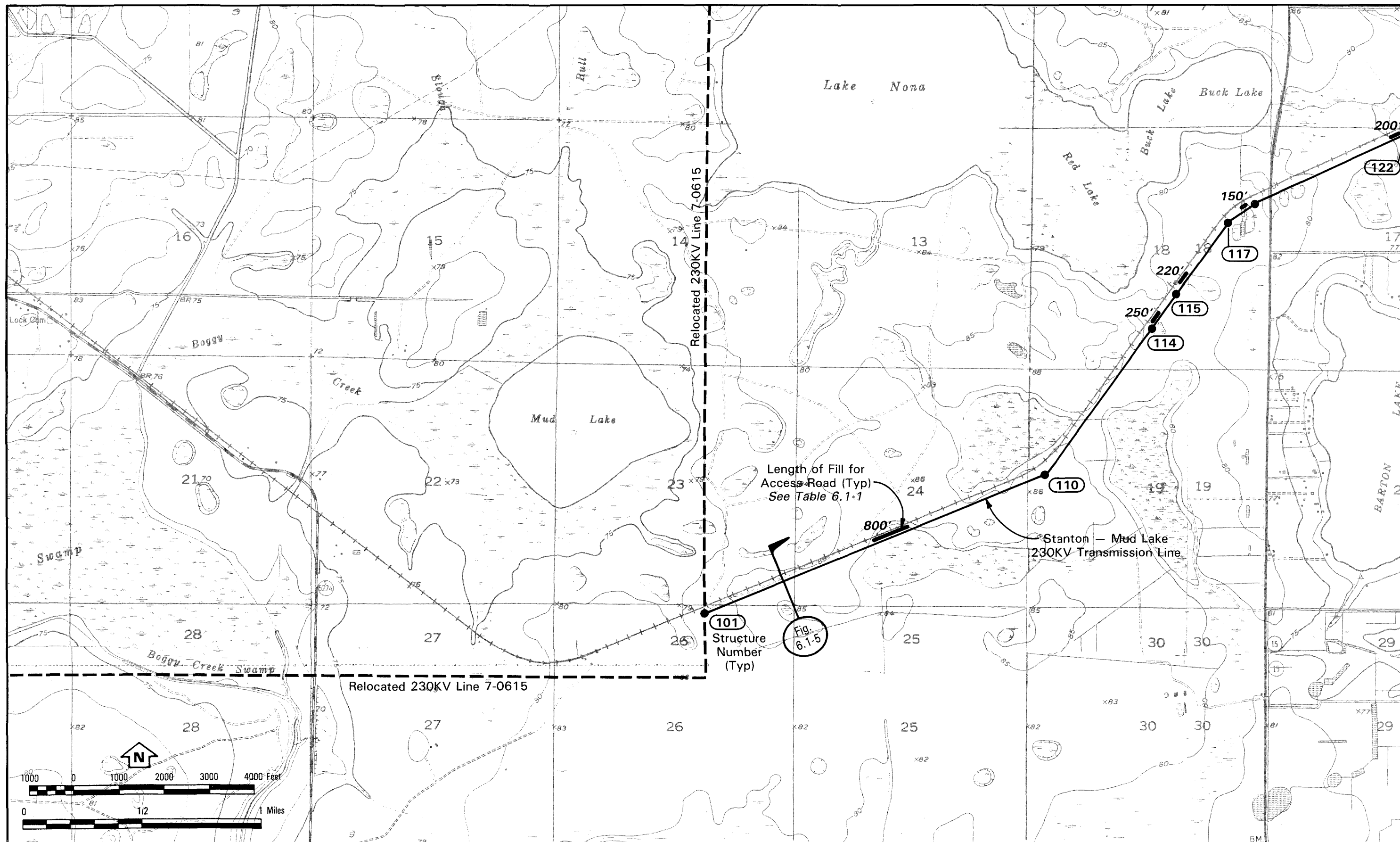


Base Map Source: USGS, Orland East, Oviedo SW, Pine Castle, Narcoossee NW, St. Cloud North, Narcoossee, FL Quadrangles



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

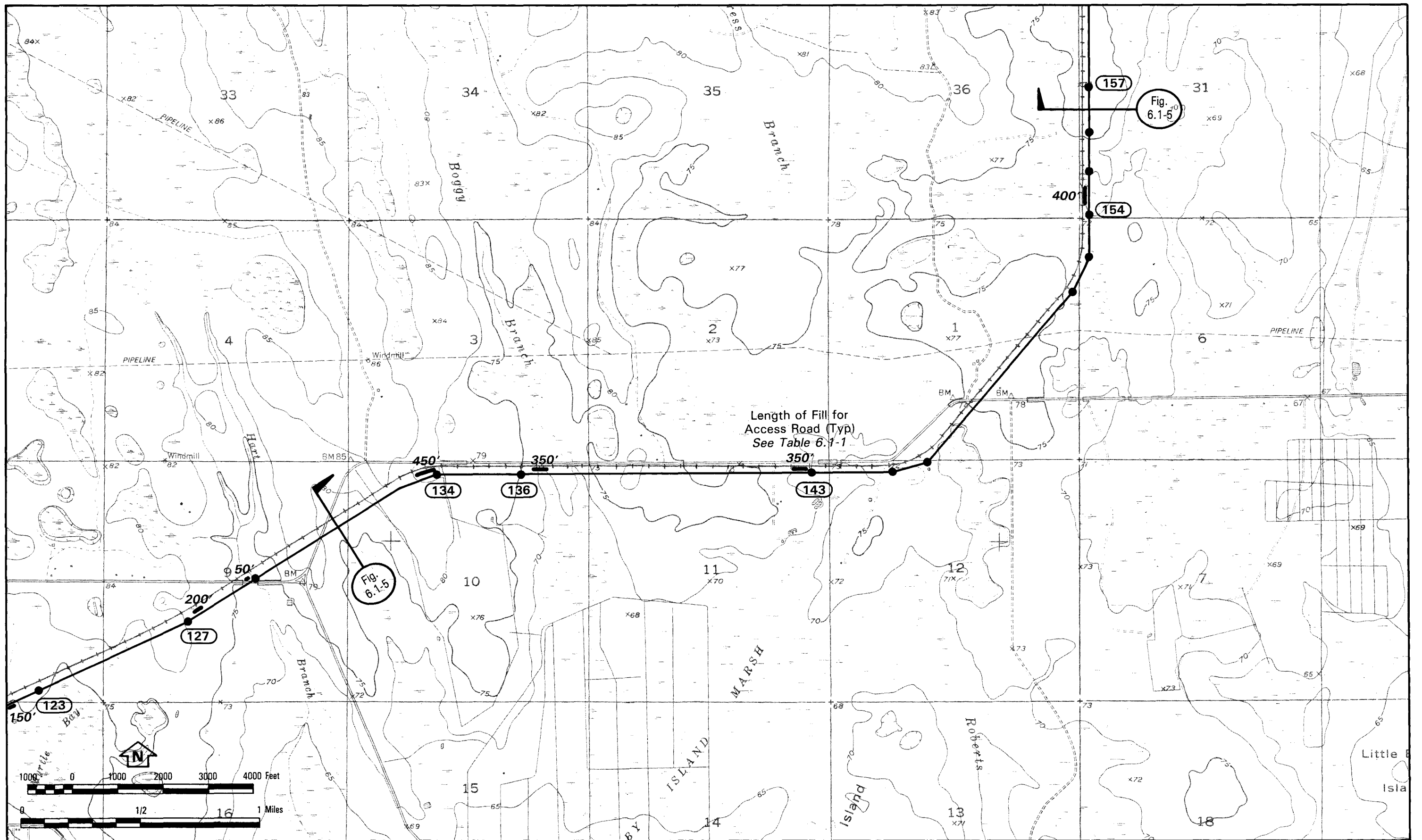
Figure 6.1-1



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

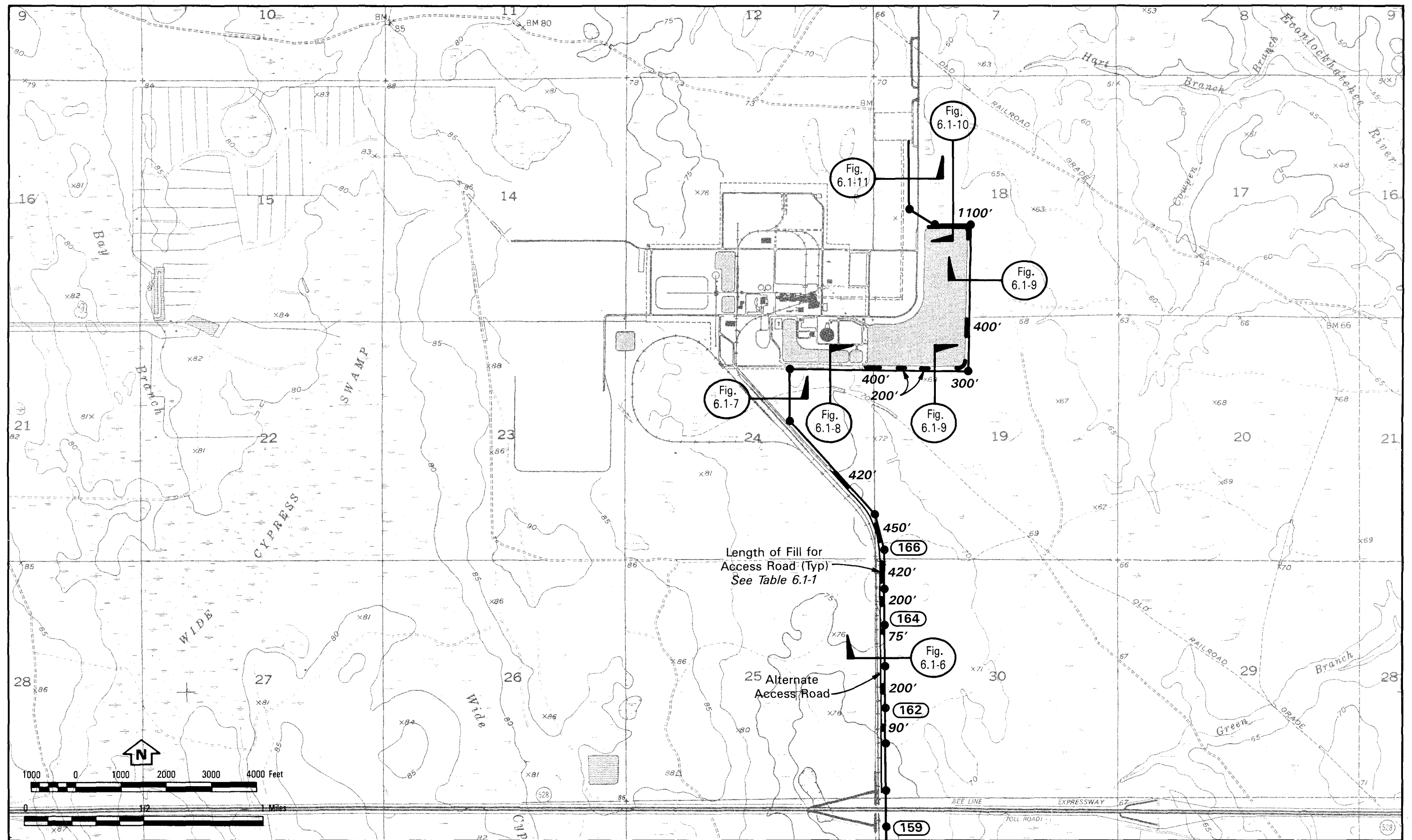
TRANSMISSION LINE CORRIDOR LOCATION — WEST

Figure 6.1-2



TRANSMISSION LINE CORRIDOR LOCATION — CENTRAL

Figure 6.1-3

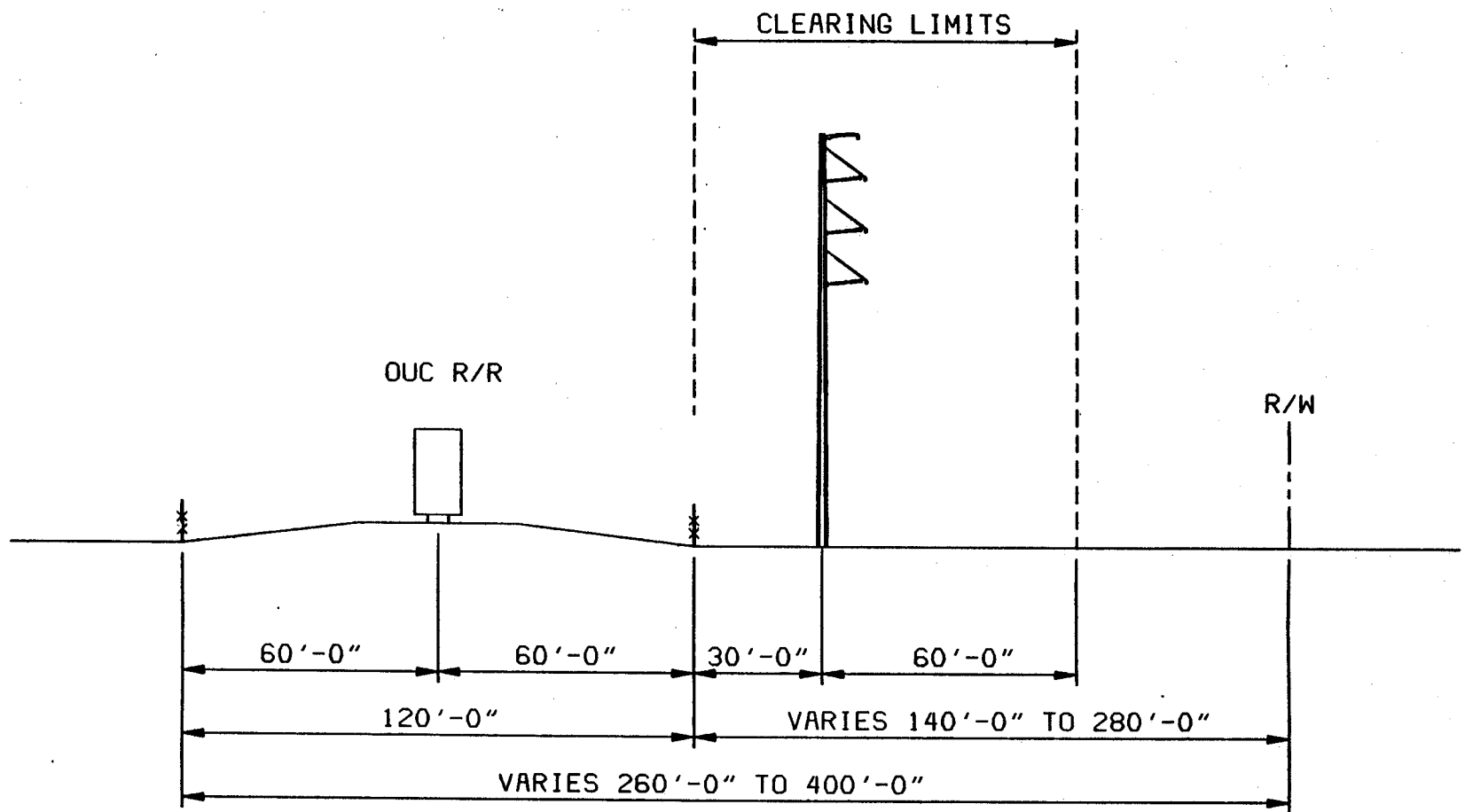


Base Map Source: USGS,
Narcoossee NW, FL Quadrangle

TRANSMISSION LINE CORRIDOR LOCATION — EAST
AND ALTERNATE ACCESS ROAD

031591

6.1-22

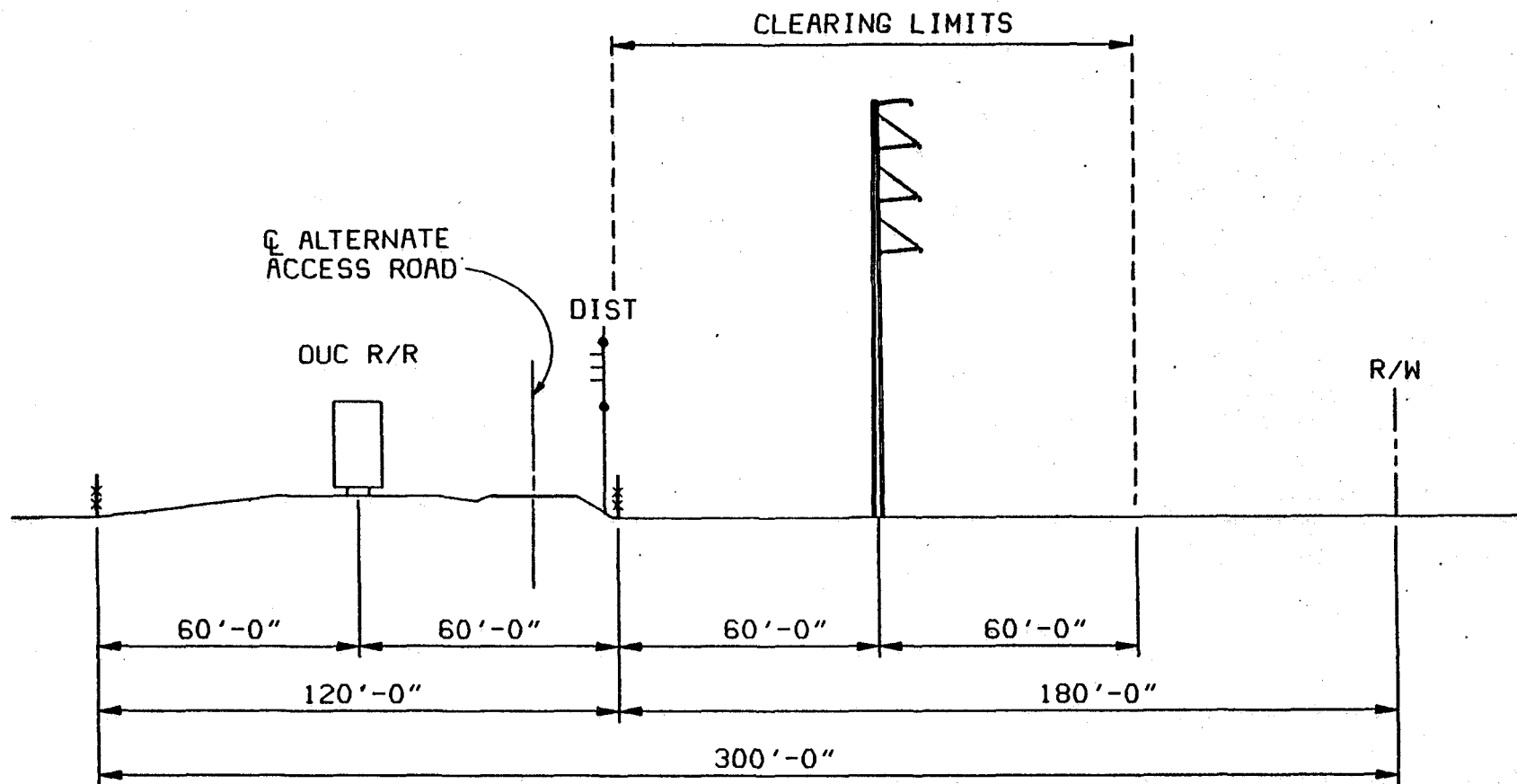


STANTON-MUD LAKE 230 KV TRANSMISSION LINE ALONG RAILROAD —
RELOCATED LINE 7-0615 TO BEE LINE EXPRESSWAY (Looking North)

Figure 6.1-5

031591

6.1-23

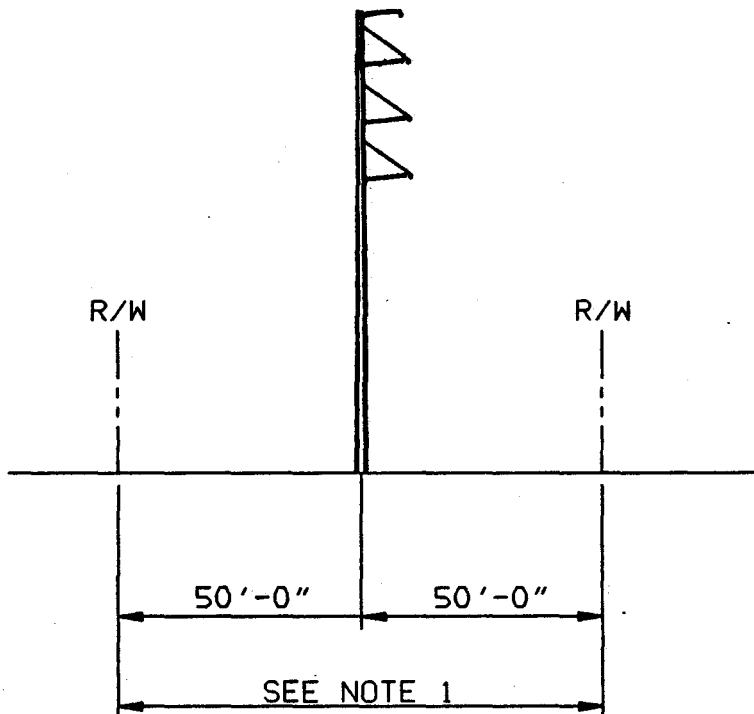


STANTON-MUD LAKE 230 KV TRANSMISSION LINE ALONG RAILROAD —
BEE LINE EXPRESSWAY TO STANTON SITE (Looking North)

Figure 6.1-6

NOTES:

1. PREVIOUSLY CLEARED, NO ADDITIONAL CLEARING ANTICIPATED.

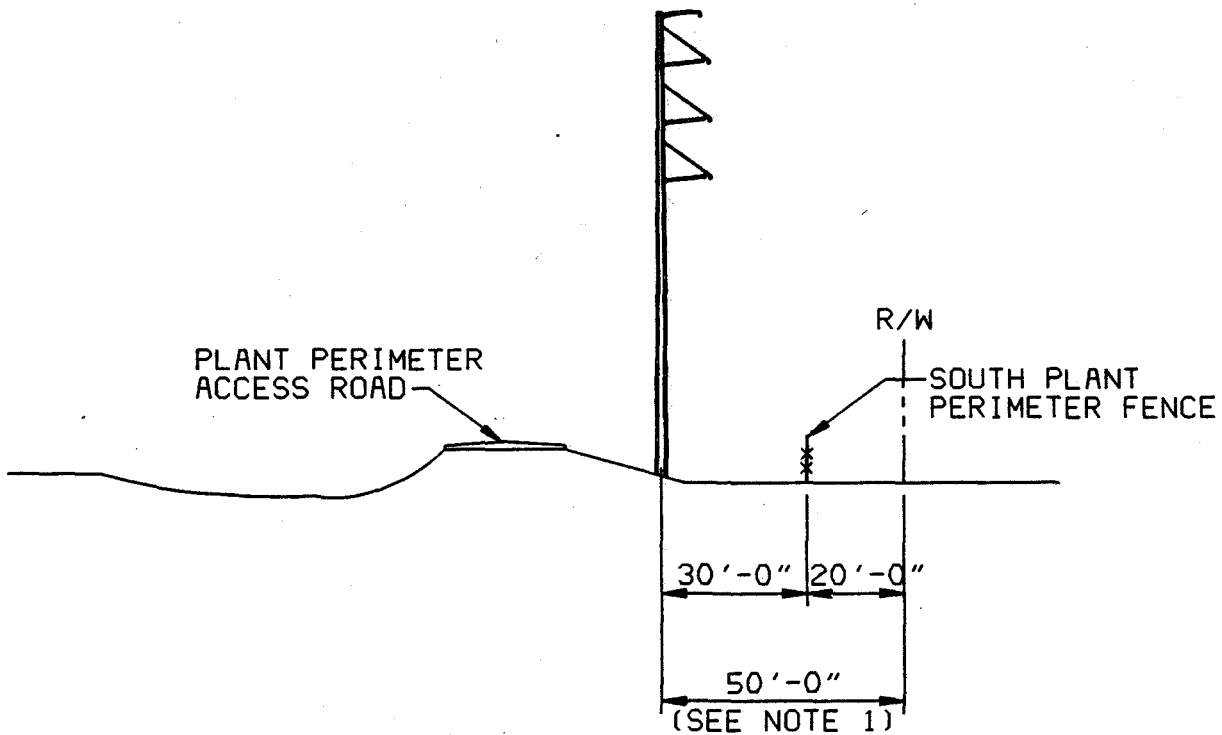


**STANTON-MUD LAKE 230 KV TRANSMISSION LINE ALONG
EXISTING CONSTRUCTION ROAD (Looking North)**

Figure 6.1-7

NOTES:

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

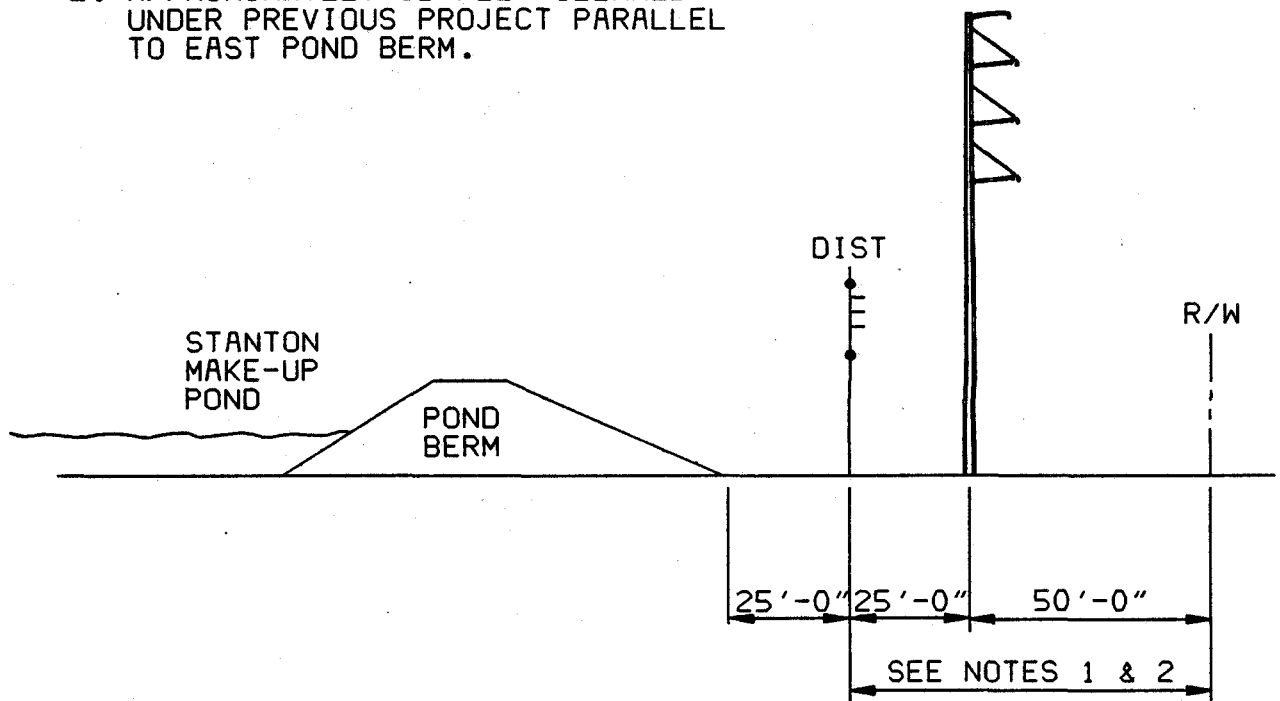


**STANTON-MUD LAKE 230 KV TRANSMISSION LINE
PARALLEL TO SOUTH PLANT PERIMETER FENCE
(Looking East)**

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.

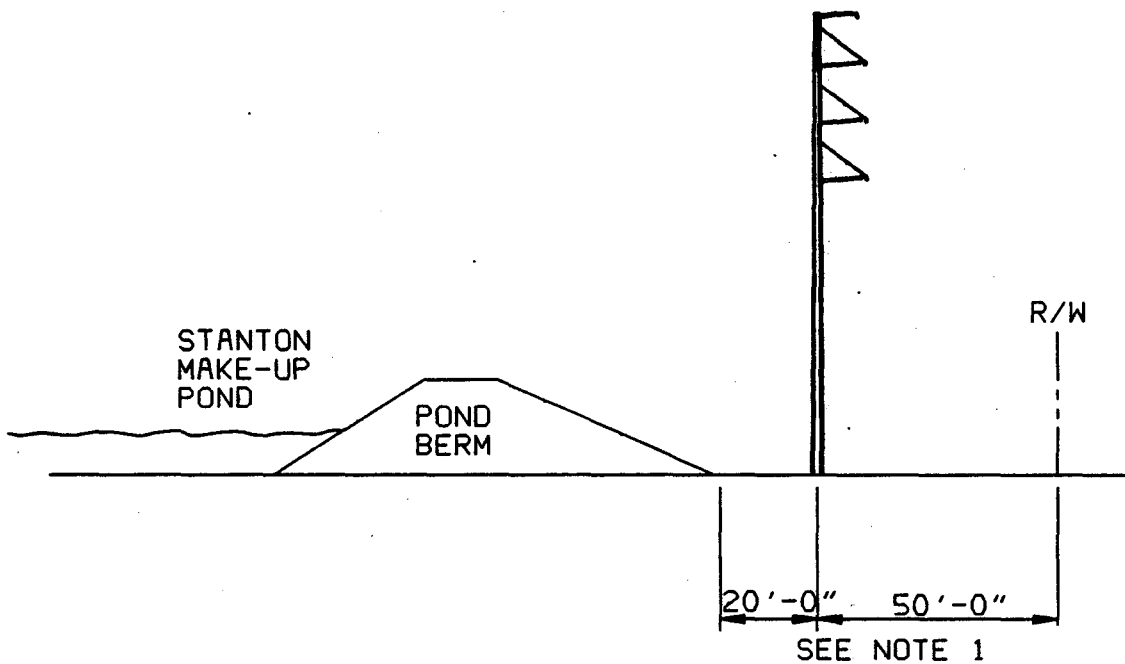


STANTON-MUD LAKE 230 KV TRANSMISSION LINE ALONG
PLANT MAKEUP POND (Looking East or North)

Figure 6.1-9

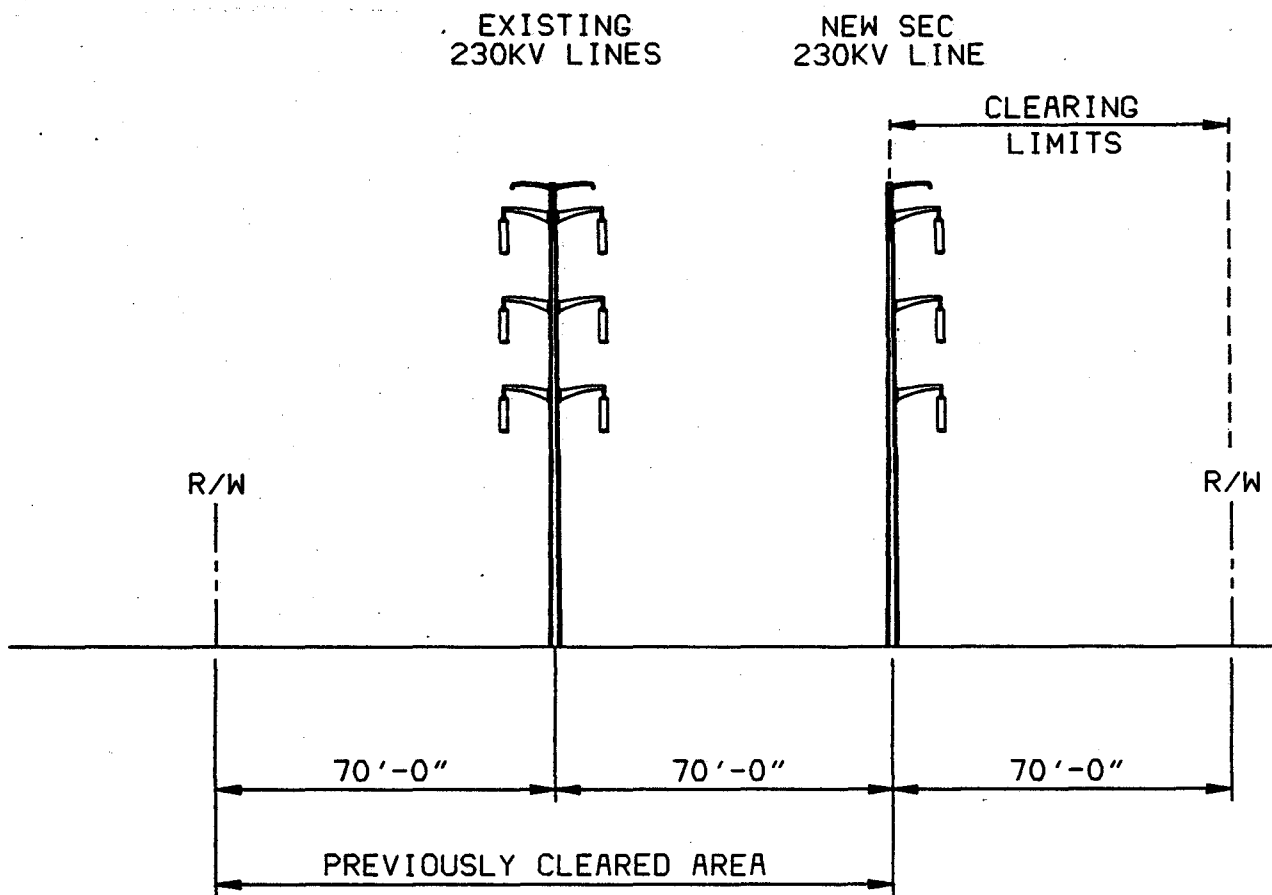
NOTES:

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



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

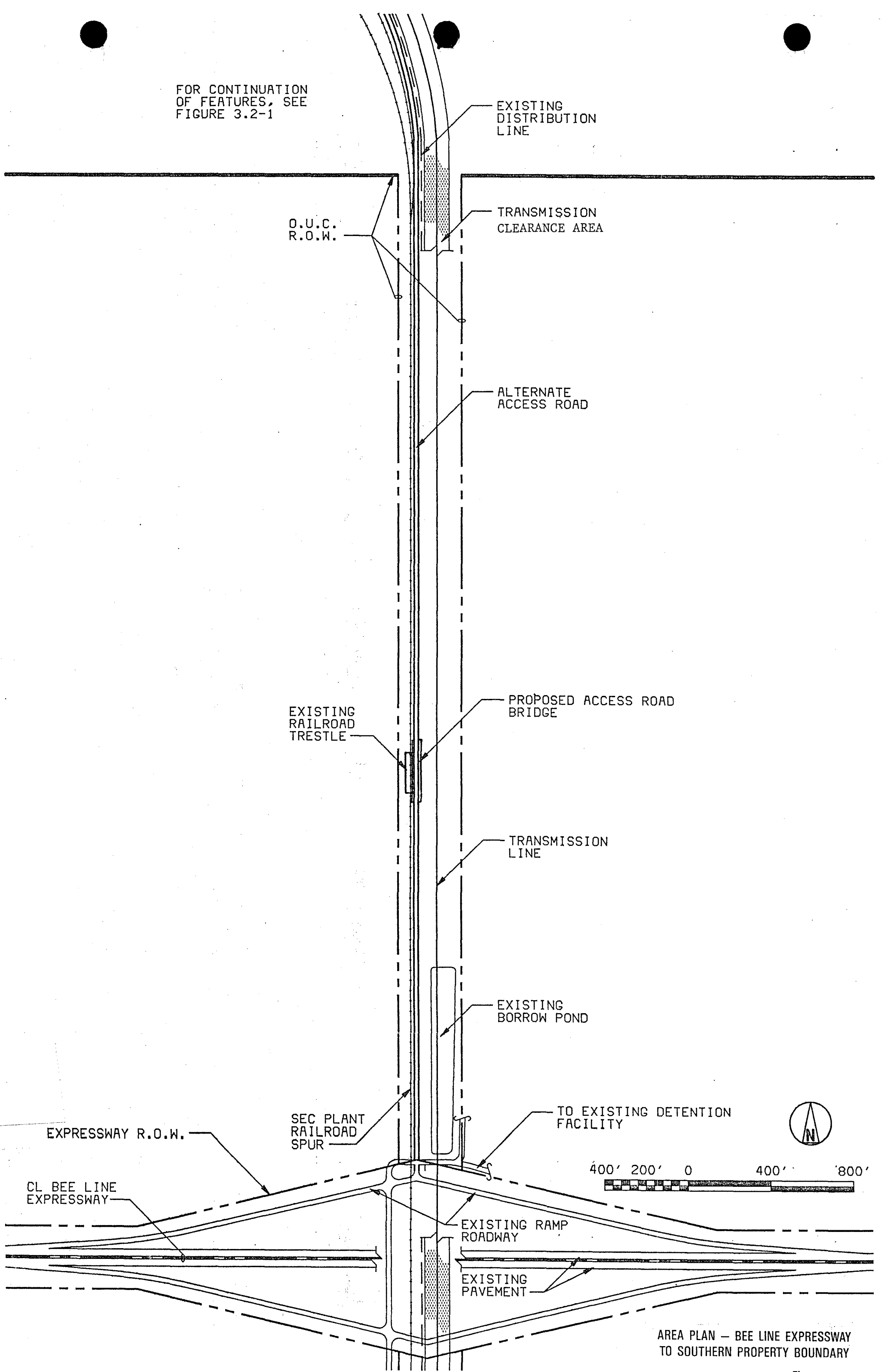
Figure 6.1-10



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

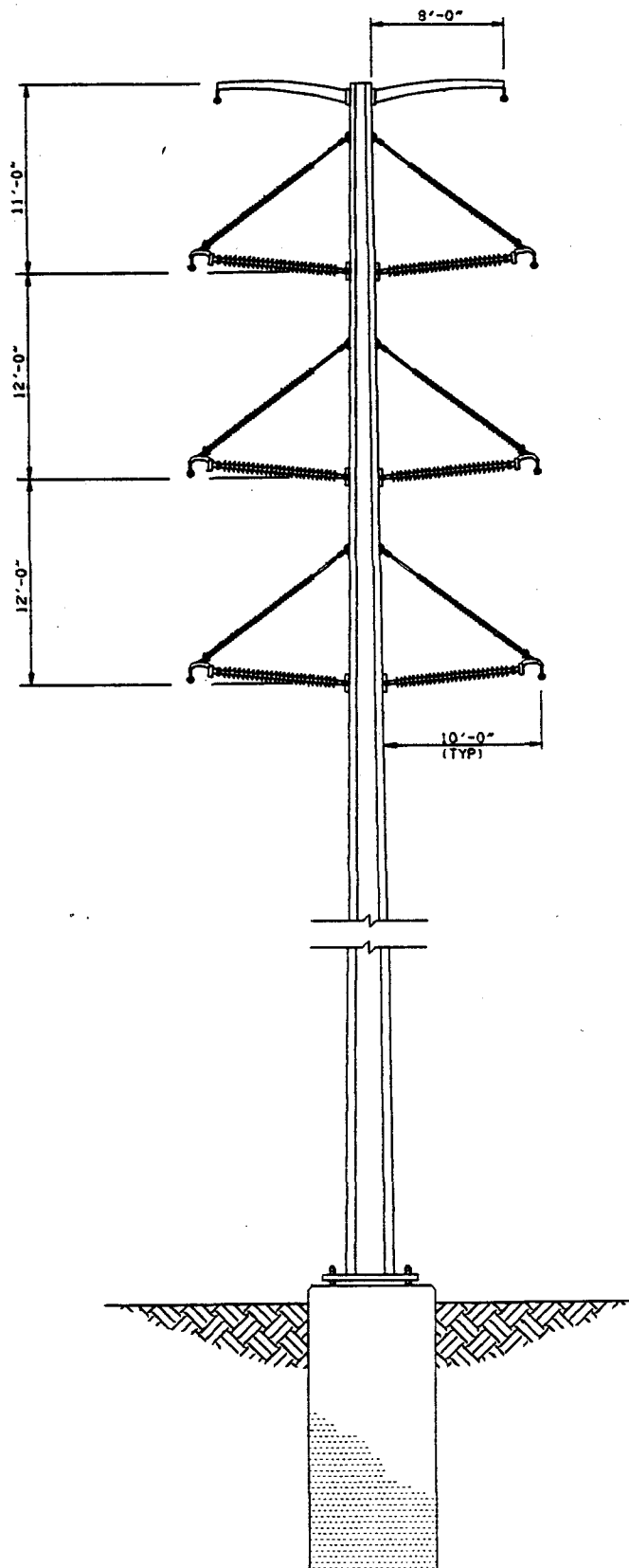
Figure 6.1-11

FOR CONTINUATION
OF FEATURES, SEE
FIGURE 3.2-1



AREA PLAN — BEE LINE EXPRESSWAY
TO SOUTHERN PROPERTY BOUNDARY

Figure 6.12

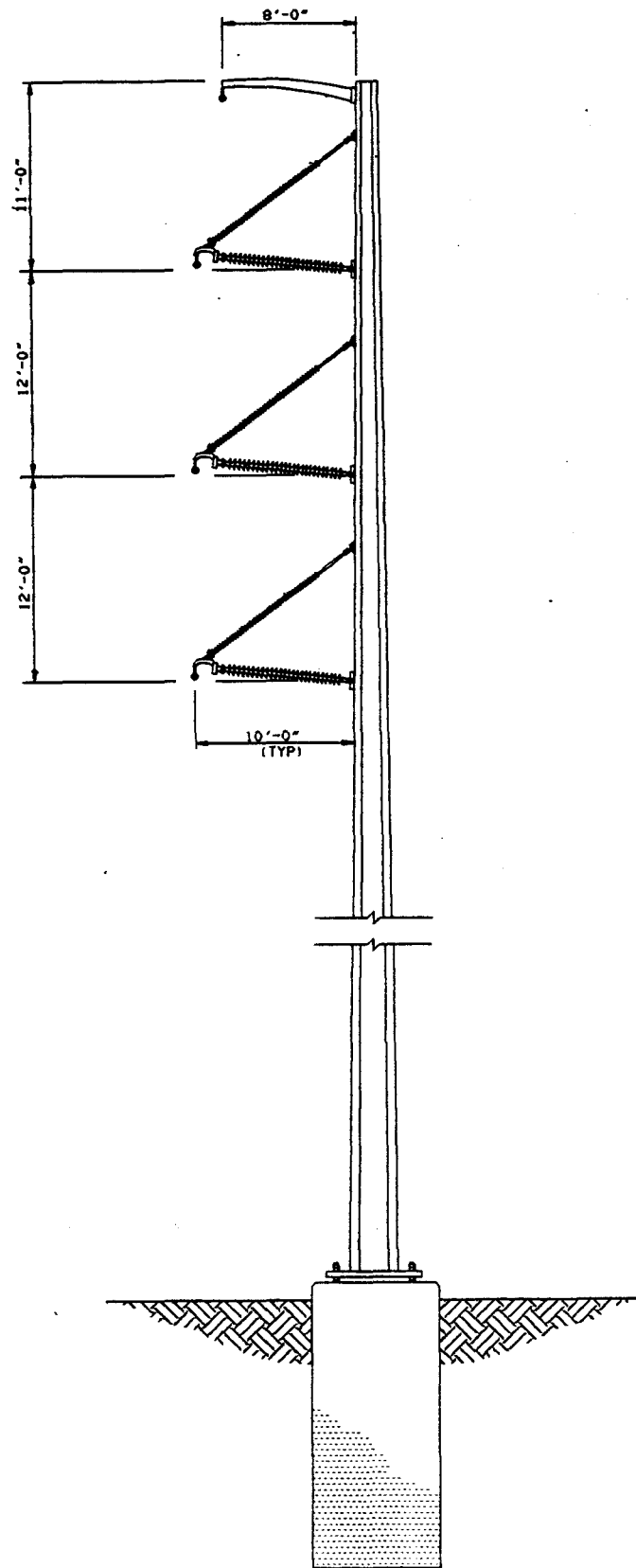


DOUBLE CIRCUIT TRANSMISSION LINE STRUCTURE

031591

6.1-30

Figure 6.1-13

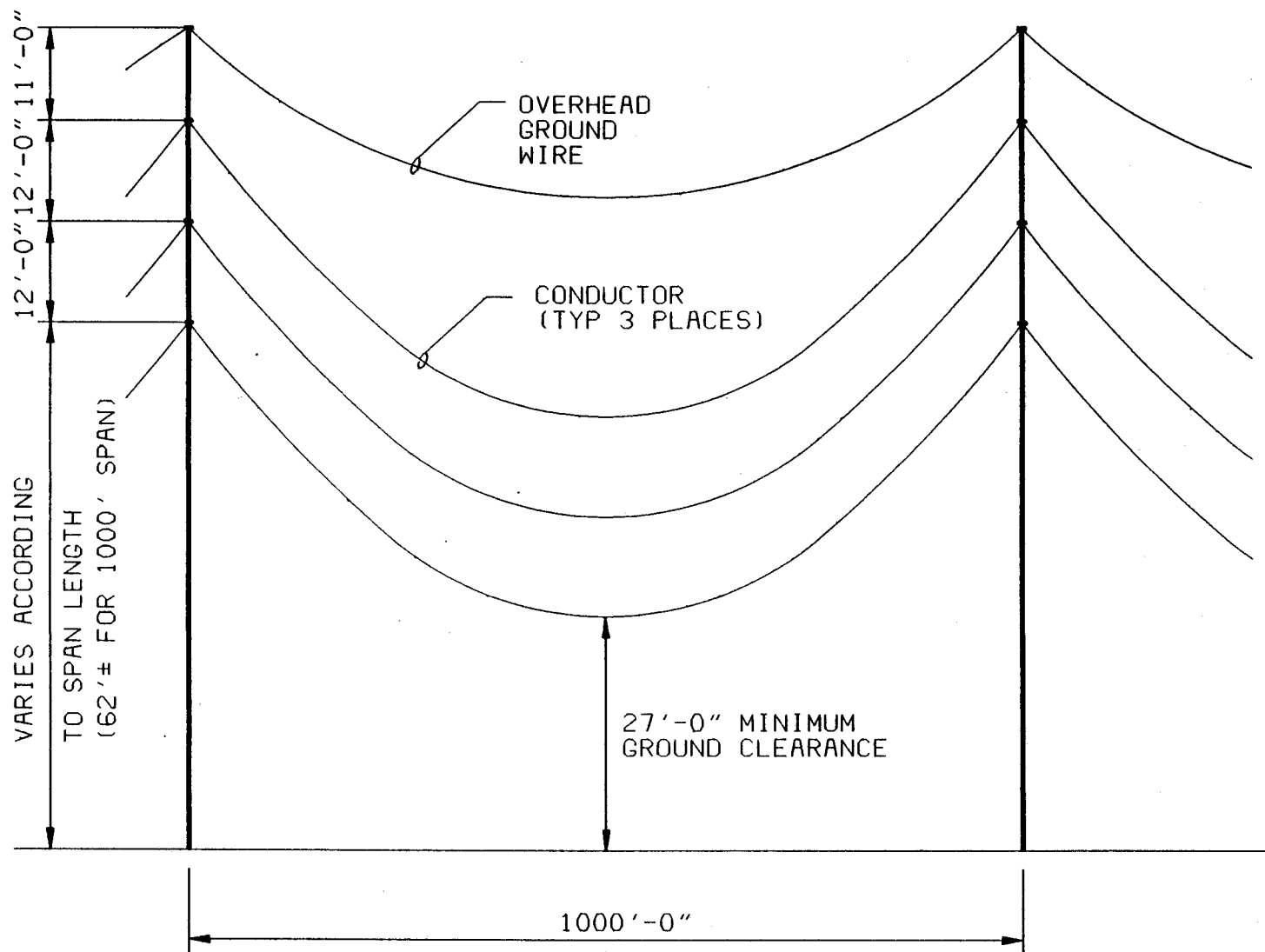


SINGLE CIRCUIT TRANSMISSION LINE STRUCTURE

Figure 6.14

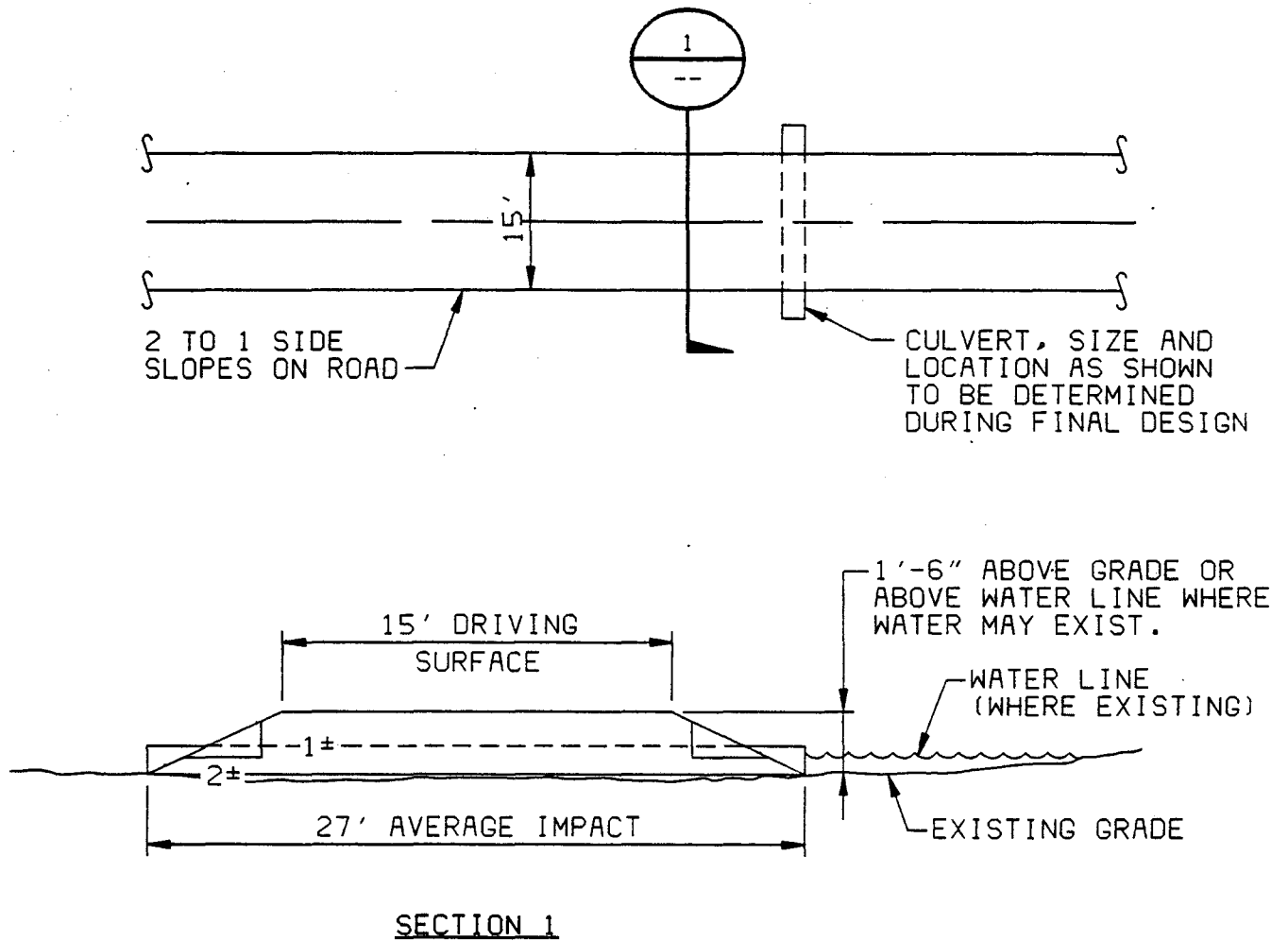
031591

6.1-32



PROFILE OF 1000-FOOT SPAN

Figure 6.115

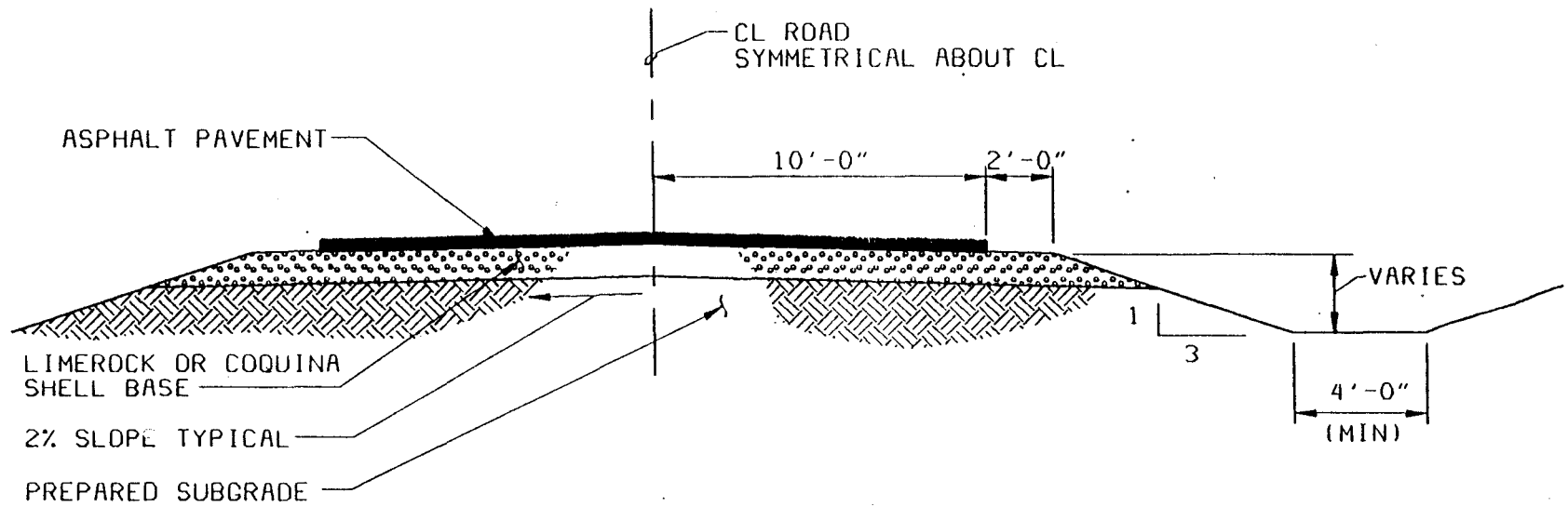


STANTON-MUD LAKE 230 KV TRANSMISSION LINE CROSS SERCTION
OF TYPICAL TRANSMISSION LINE ACCESS ROAD

Figure 6.1-16

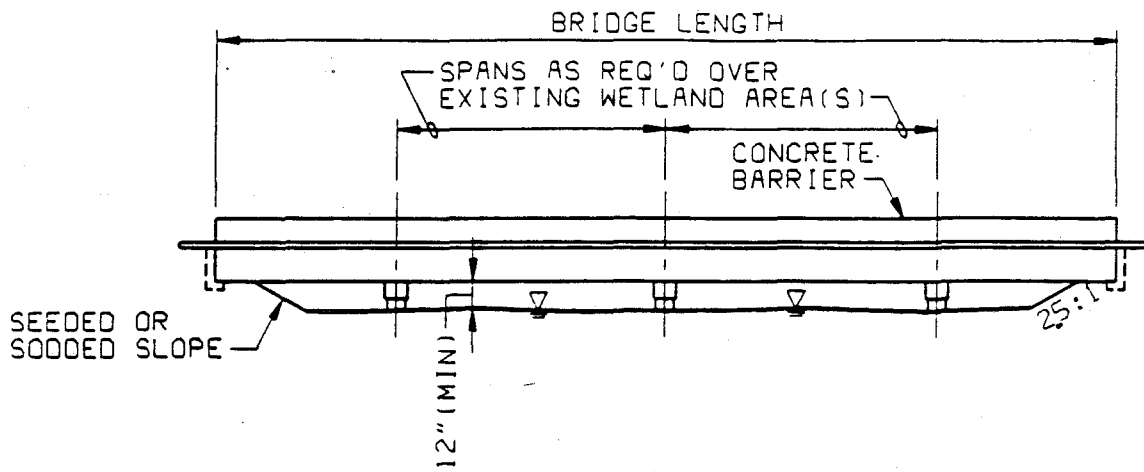
031591

6.1-34

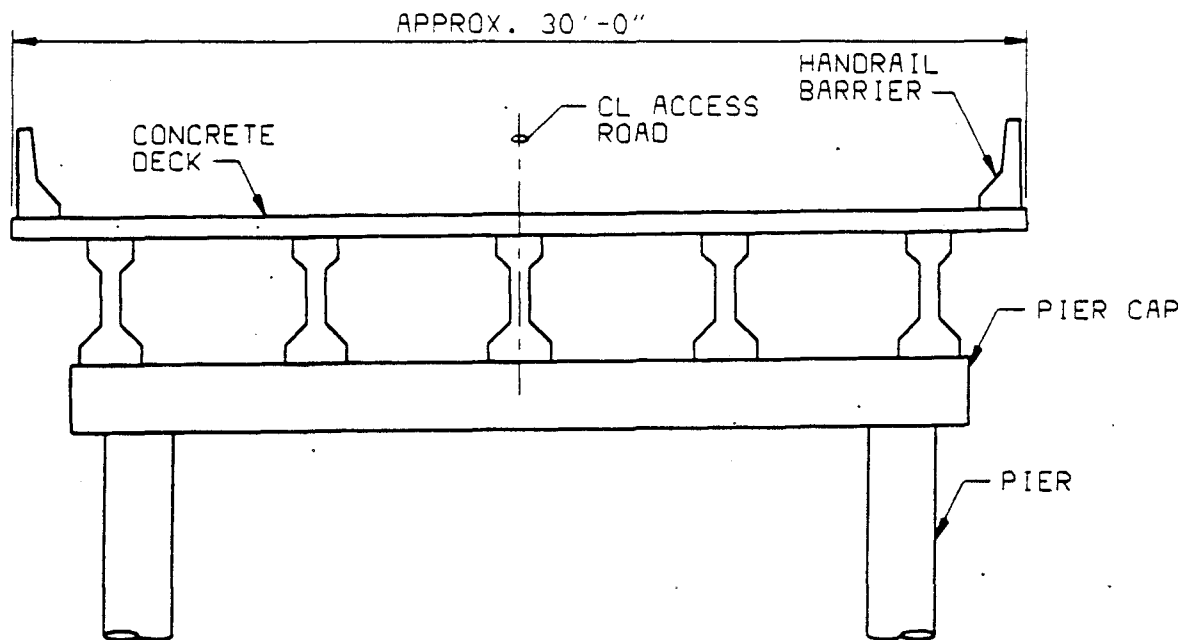


ALTERNATE ACCESS ROAD

Figure 6.117



ELEVATION



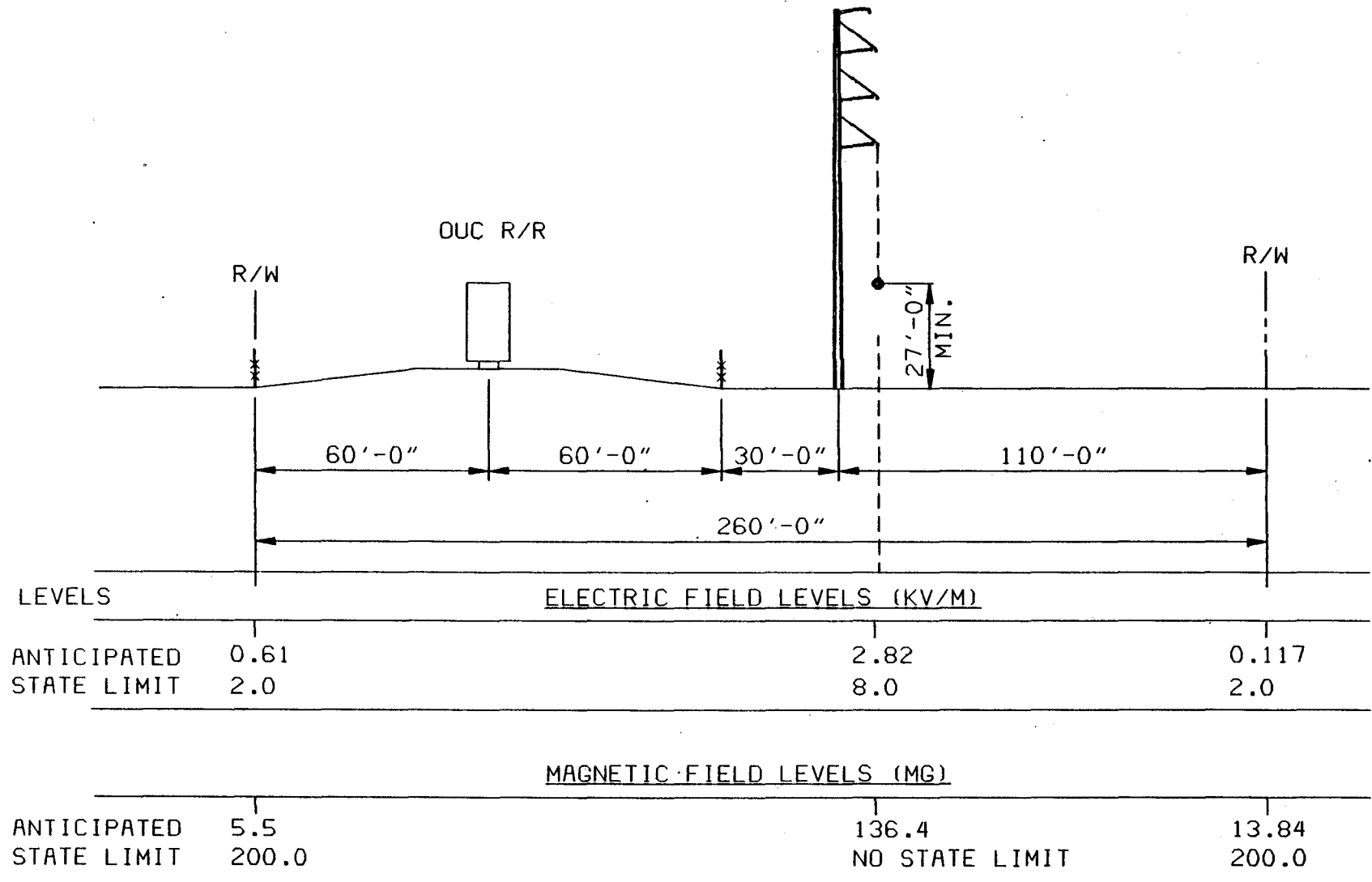
SECTION

TYPICAL ACCESS ROAD BRIDGE DETAIL

Figure 6.118

031591

6.1-36



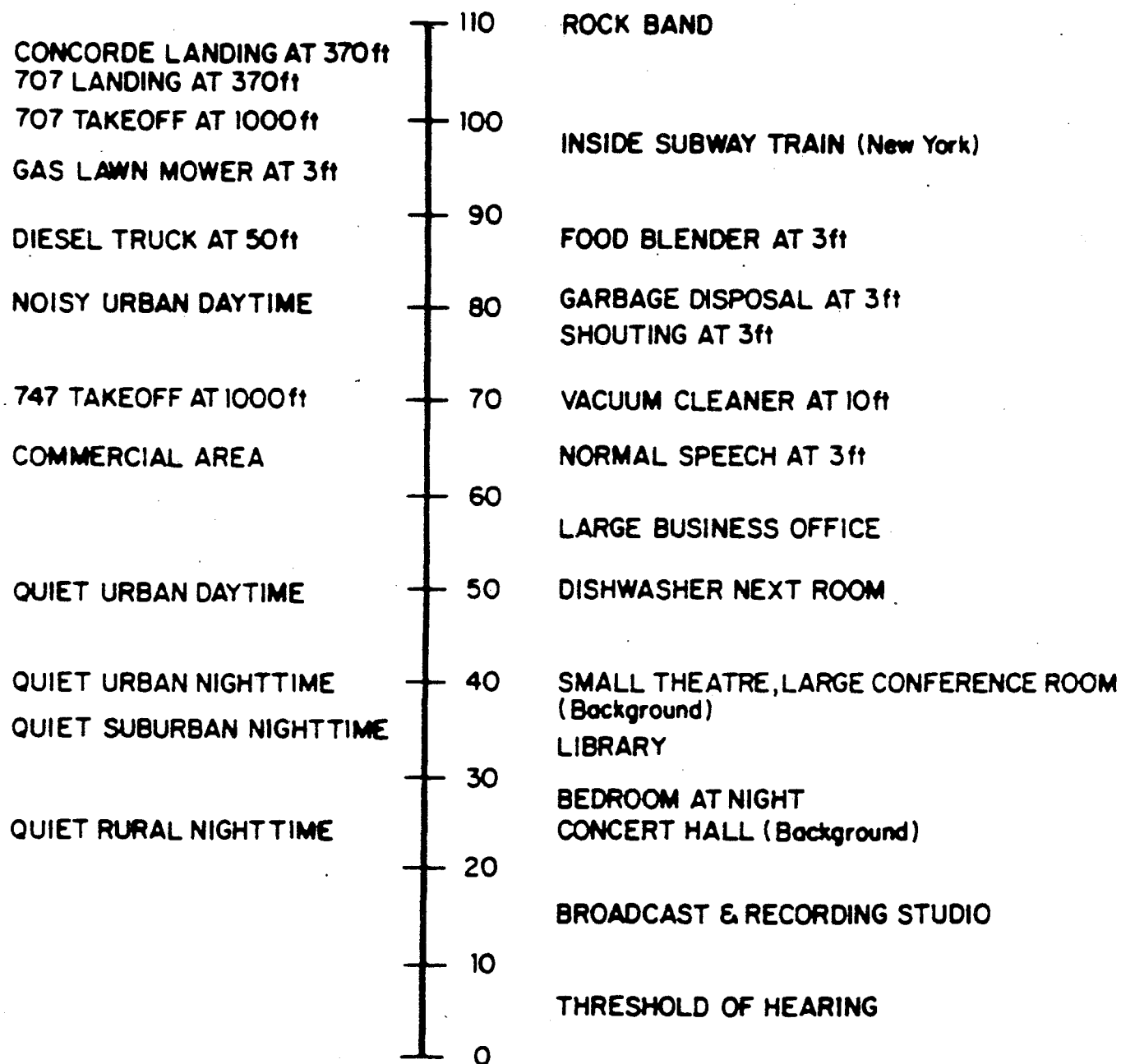
STANTON-MUD LAKE 230 KV TRANSMISSION LINE
ELECTRIC AND MAGNETIC FIELD LEVELS

Figure 6.1-19

**COMMON OUTDOOR
SOUND LEVELS**

**NOISE LEVEL
dB(A)**

**COMMON INDOOR
SOUND LEVELS**



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.

6.2 Alafaya Trail Extension

6.2.1 Project Introduction

According to DER, in order to construct the extension of Alafaya Trail across the Stanton Energy Center, the Siting Board, pursuant to Supplemental Certification Condition VII/II, must approve the project. This road is an important component of Orange County's transportation plan. It will provide north-south access from south of the Bee Line to Seminole County. Additionally, it will provide an alternate transportation route to the Department of Corrections prison complex and to International Corporate Park.

The new Alafaya Trail extension will be approximately 4.2 miles long. Approximately 2.3 miles of the roadway traverses the eastern part of the Stanton Energy Center. The portion of the Alafaya Trail extension located off the Stanton Energy Center property has received all necessary local, state, and federal permits or approvals for construction of the roadway. However, by virtue of DER's interpretation of the Electrical Power Plant Siting Act, all construction will be delayed until the portion traversing the Stanton Energy Center is authorized by the Siting Board.

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6.2.2 Road Extension, Corridor Location, and Layout

The Alafaya Trail extension corridor varies in width from 110 feet to 180 feet along its route beginning at a point approximately 3,000 feet south of the Bee Line Expressway intersecting with the easterly extension of Aerospace Parkway. North of the Bee Line Expressway the road meanders through open, rural terrain traversing through the OUC properties and connecting to the southerly end of the existing Alafaya Trail. In an effort to minimize impacts upon threatened and endangered species located within the Orlando Utilities Commission properties, the right-of-way was reduced in width from 180 feet to 110 feet beginning approximately 1,000 feet north of the south line of Section 19 Township 23 South Range 32 East and continues approximately 1.63 miles to the north. From this point to the northerly terminus at the existing Alafaya Trail, the right-of-way is once again expanded to 180 feet.

6.2.3 Road Design Characteristics

The roadway right-of-way provides sufficient width for a four-lane, divided roadway section. Within the 180-foot right-of-way the road typically provides for construction of two lanes of the future four lanes with 10-foot shoulders. Drainage is collected within roadside swales and ditches and transmitted longitudinally within the limits of the right-of-way to surface stormwater management facilities. Two lanes of the future four lanes of urban roadway are contained within the 110 foot right-of-way limits. Runoff is collected through a system of curb inlets and transmitted longitudinally within the road right-of-way utilizing underground pipes to surface stormwater management facilities.

The two lanes consist of 12-foot asphalt paved lanes with 4 feet of the 10-foot shoulders paved within the rural sections and 2-foot standard curb and gutters on each side within the urban section. The road is elevated above the 100-year flood elevation on embankment fill. At locations where the access road interrupts natural drainage patterns, culverts or bridge drainage structures are provided. Additional openings are provided as required for wildlife crossings.

6.2.4 Cost Projections

As required by Condition 4.5, et seq., of a Development of Regional Impact Development Order issued by Orange County on June 30, 1986, ICP Associates is required to construct the road at its cost. Orange County will own and maintain the road after construction is completed. Therefore, OUC is not responsible for any costs of building or maintaining the road.

6.2.5 Corridor Selection

The extension of Alafaya Trail from its current terminus at the north boundary of the Stanton Energy Center south past the Bee Line Expressway to ICP properties was required by Orange County, and included as Condition No. 4.5, et seq., in the ICP Development of Regional Impact (DRI) Development Order (DO) that was issued on June 30, 1986. In anticipation of the DO condition, the alignment was first studied in the fall of 1985, after meetings with OUC regarding the placement of Alafaya Trail within the Stanton Energy Center property. OUC supported the construction of Alafaya Trail within its boundaries, and agreed to provide the right-of-way.

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In order to develop the three initial alternatives, all of which traversed the Stanton Energy Center property, ICP's engineering consultants utilized existing aerial photography and USGS maps, together with plans for the Stanton Energy Center in the vicinity of the proposed roadway. The alternative alignments were designed to minimize impacts to existing wetlands and to utilize, as much as possible, crossing points which had already been established and disturbed. For each alternative, three waterways required crossing--Hart, Cowpen, and Green Branches. Each of these branches had certain disturbed areas already present in their stream bed. The initial alignments were set to occur as near as possible or coincide with existing crossings whenever possible.

Subsequent to the establishment of the initial three alternatives (Alternates A, B, and C), a survey of the Red-Cockaded Woodpeckers (RCW) was conducted on the OUC property in late 1985. Each of the alignments was found to impact a RCW colony site. At this time, a fourth alignment (Alternate D) was developed to avoid all known RCW colony sites on the property by means of a serpentine design, while still minimizing impacts to wetland areas as they had been determined at that time. This alignment was informally presented to Orange County, and in May 1986 it was inspected by representatives of OUC and Alafaya Trail extension project engineers and consultants. The alignment was modified slightly as a result of the field inspection to provide additional avoidance to RCW sites. OUC and Alafaya Trail extension project consultants supported the resultant alignment, Alternate E, and formally established it as the Alafaya Trail Extension Alignment. Furthermore, in a joint meeting with the US Army Corps of Engineers (ACOE) and EPA, EPA indicated that ICP had met the test of corridor selection. EPA was concerned about additional wetland impacts and secondary impacts of the other proposed corridors. With this in mind, EPA approved the final selection.

In June of 1986, the Orange County Board of County Commissioners approved, and ICP executed, the ICP DRI Development Order.

In the summer of 1987, two additional alignments were studied. One was an alignment east of the OUC property and known as the Altman Ranch Alternative (Alternate F). The second additional alignment (Alternate X) was wholly contained within the OUC property boundary, but located as far east as possible. These alignments were examined in part to determine if the wetland impacts could be reduced by moving the alignments further east. The Altman alignment

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was found to increase the wetland impact by approximately 50 percent, and because of its additional length, the Altman alignment would also impact upland habitat to a greater extent. The Alternate X alignment on the OUC property was found to have no appreciable change on the wetland impacts. This alignment, however, necessitated crossing a fourth (unnamed) stream that had previously not been impacted by the alignments. Both these alignments, though studied, were ultimately not selected for implementation.

In the fall of 1987, the ACOE issued a permit for the construction of water supply and sewage pipelines on the selected alignment for use by the Florida Department of Corrections, ICP, and Orange County's master system. ICP met with the ACOE to discuss the pipelines and the development of International Corporate Park, Phase I. ICP and the project consultants presented the alignment, and the ACOE acknowledged that the pipeline alignment would eventually become the alignment for the proposed Alafaya Trail extension.

The pipeline project engineers submitted an application for permitting to the St. Johns Water Management District (SJRWMD), but ultimately withdrew when SJRWMD determined that no permit was required for the pipeline installation work. An informal jurisdiction determination was sought and received from the Florida Department of Environmental Regulation (FDER) regarding the impact areas for the pipelines. FDER determined that no dredge and fill permits were required due to construction techniques that avoided impacts to "waters of the state" (Exhibit 6.2-1).

After obtaining all necessary permits to construct the pipelines, the right-of-way was cleared along the selected alignment, and the pipeline project was completed in early 1988. ICP submitted the same alignment to Orange County for the Alafaya Trail extension, and on May 1, 1989, the Orange County Board of County Commissioners approved the alignment (Exhibit 6.2-2). On November 20, 1989, Orange County formally accepted the maintenance of sewer and water force mains along the Alafaya Trail extension alignment (Exhibit 6.2-3).

On October 9, 1990, SJRWMD issued permits for the southern half of the Alafaya Trail extension. In addition, on November 4, 1990, Orange County approved the project along the entire corridor from the Stanton Energy Center to south of the Bee Line Expressway. However, due to concerns from the U.S. Fish and Wildlife Service (USFWS) and the Florida Game & Fresh Water Fish Commission (FGFWFC), the right-of-way width within OUC properties was

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reduced and the location of the mitigation site was relocated south of the Bee Line Expressway. Permits for these modifications were obtained from the SJRWMD on July 9, 1991 (Exhibits 6.2-4 and 6.2-5).

On September 20, 1991, the ACOE issued its letter of intent to permit when the state issues its Section 404 Water Quality Certification for the entire Alafaya Trail extension project (Exhibit 6.2-6).

In summary, the alignment selection process occurred during the period 1985 to 1987, prior to the Memorandum of Agreement between the EPA and the ACOE (February 17, 1990) concerning the determination of mitigation under the Clean Water Act Section Guidelines 404(b)(1), specifically addressing the alternative analysis. ICP has acted in reliance on the review, and/or approval, of the ACOE, FDER, SJRWMD, and Orange County regarding the determination of the selected alignment for the pipelines and the Alafaya Trail extension. Finally, the County, which required ICP to construct the Alafaya Trail extension, approved the roadway alignment during a public hearing nearly two years ago. Adequate opportunity was provided for comment during the selection and approval process in effect at that time. The alternatives associated with Alafaya Trail were identified on a map which is attached as Figure 6.2-1. The following description establishes the alignment corridor selection by station.

Station 505+00 to 435+00: The connection point for the Alafaya Trail extension was placed at Station 505+00 to avoid RCW Colony "X." The alignment is on the west side of Colony "X" extending outside the colony limits. The crossing of Hart Branch was set by the serpentine geometry required to miss Colonies "E" and "X." Colony "X" is located to the east of the alignment between Section 465+00 to 445+00.

Station 435+00 to 410+00: The road geometry was located to the east to avoid RCW Colony "E." The alignment is located between Station 435+00 to 410+00 west of Colony "E." Start hole No. 8 at Station 417+50 was not in existence at the time of alignment selection and has since been abandoned.

Station 410+00 to 380+00: The alignment passes between RCW Colony Site "H" to the west and colony site "I" to the east. The alignment was curved to the west to avoid Colony Site "I." The curve back to the southeast was dictated by wetlands 1, 2, 45, and 46. The crossing of Cowpen Branch at Station 405+00 was

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at an existing disturbed tram road. The vicinity of wetlands along the proposed roadway is depicted on Figure 6.2-2.

6.2.6 Socio-Political Environment of the Corridor Area

6.2.6.1 Governmental Jurisdictions. The Alafaya Trail extension lies entirely within Orange County, Florida; the entire length of the roadway extension does not cross the boundaries of any municipality.

6.2.6.2 Zoning and Land Use Plans. The zoning and land use for the Alafaya Trail extension alignment on the Stanton Energy Center property was discussed generally in the original SCA. The zoning for the plant site, including the segment of the Alafaya Trail extension traversing the site, is "A-2," which is defined as Ranch and Farmland Rural District. Approximately 49.37 acres of the site will be modified by roadway construction. The proposed roadway alignment is shown on Figure 3.2-1. The road alignment was designed to minimize impacts to wetlands and wildlife (Figures 6.2-1 and 6.2-2). Only 1.53 acres of the proposed wetland impacts are "waters of the state" wetlands of which only 0.54 acre would require a permit to impact since the other two wetlands qualify for ditch block exemptions pursuant to Section 403.913(4), F.S. Due to the roadway's design and location, the roadway will have a minimal impact on the environment and wildlife in eastern Orange County.

The roadway extension will provide toll-free access to the DOC prison facilities, which currently are accessible only from the Bee Line Expressway, and access to International Corporate Park. Furthermore, the extension of Alafaya Trail from its present terminus at the Stanton Energy Center to a location on the International Corporate Park site will complete a much needed transportation corridor in eastern Orange County. Accordingly, the proposed roadway is consistent with Orange County's Comprehensive Plan.

6.2.6.3 Easements, Title, Agency Works. On December 28, 1987, a Temporary Construction Easement was obtained by ICP in order for it to construct the road on the Stanton Energy Center property. This easement was recorded on December 30, 1987, in Orange County at Official Records 3946, Pages 3186 to 3199.

6.2.6.4 Vicinity of Scenic, Cultural, and Natural Landmarks. There are no recorded historic, scenic, cultural, or natural landmarks located on the plant site. The nearest recognized sites are located in or near Orlando. The National Register of Historic Places currently lists the following sites located in Orange County, Florida.

- (1) Orlando--Old Orlando Railroad Depot.
- (2) Orlando--First Church of Christ Scientist.
- (3) Orlando--The Tinker Building.
- (4) Winter Park--The Parsonage.

The National Registry of Natural Landmarks does not include any sites for Orange County, Florida.

6.2.6.5 Archaeological and Historical Sites. An archaeological and historic survey of the Stanton Energy Center site was conducted in two stages. Sections 13 and 24, and the eastern halves of Sections 14 and 23 of Township 23 South, Range 31 East, initially were surveyed. When access later became available, the remainder of the site also was examined for the presence of archaeological and cultural resources. The site survey was conducted by personnel from the Florida Secretary of State, Division of Archives, History, and Records Management.

Four sites were found during the surveys. Three were prehistoric archaeological sites, and one was a historic hunting lodge from about the early 20th century. This lodge is located just off the site near the southwest corner of the proposed property line. The Division of Archives, History and Records Management concluded that the sites did not represent significant archaeological or historical resources. A copy of a letter from Mr. L. Ross Morrell, Director, Division of Archives, History and Records Management concerning the initial survey is presented as Exhibit 2.3-1 in the original SCA.

6.2.7 Bio-Physical Environment of the Corridor Area

6.2.7.1 Land Use/Vegetation. The existing land uses within a one-half mile of the proposed Alafaya Trail extension alignment are primarily undeveloped pine flatwoods and wetland areas (Figure 6.2-3). Approximately 90 feet of the actual corridor has been previously cleared for the construction of the utility pipelines which service the DOC and ICP properties and is part of the Orange County's master system. Grasses and shrubs indicative to disturbed sites which are mowed

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regularly dominate the area. Only Hart Branch has predominantly tree vegetation. This area is considered a mixed hardwood wetland (631). In addition, Cowpen Branch has a few isolated cypress trees (621). Occasional isolated pockets of wetlands exist within this corridor even though they have been disturbed by the existing pipeline corridor which was permitted and constructed in 1987 and 1988.

6.2.7.2 Affected Waters and Wetlands. The corridor crosses only two water bodies, Hart Branch and Cowpen Branch, which are designated as Class III waters as defined in the Florida Administrative Code. Clearing and culverting have occurred within these systems which have altered the natural integrity of the habitats. The proposed Alafaya Trail extension will cross Cowpen Branch at an existing crossing where most of the wetlands have already been cleared and a large culvert and a dirt road exist to date. The crossing at Hart Branch will occur at a narrow section of the wetland. Several existing dirt road crossings occur downstream of the proposed Alafaya Trail extension crossing.

These two crossings are considered wetlands, therefore, "waters of the state," which require a state dredge and fill permit for filling in these systems. Since Cowpen Branch, in the area of the Alafaya Trail crossing, has been determined to qualify for the ditch exemption, pursuant to Section 403.913(4) F.S., only the crossing of Hart Branch will require a dredge and fill permit. A total of 0.54 acre of wetland impact would be required for roadway construction within the Hart Branch's system.

6.2.7.3 Ecology. The Stanton Energy Center is located within the Floridian section of the Atlantic Coastal Plain in eastern Orange County. The natural vegetative communities of the site and along the Alafaya Trail extension are typical of the region and the Big Econolockhatchee River drainage. Nearly level flatwoods predominate, with scattered wetlands and low ridges on the western portion and in the center of the Stanton site. The wetlands, which consist primarily of cypress strands and cypress domes, are aligned in a north-south direction and are often seasonally isolated. Most surface drainage flows in an easterly direction toward the Big Econolockhatchee River. Several low ridges that occur onsite are aligned in a north-south direction. These ridges are west of the Alafaya Trail corridor. Intermediate between these low ridges and the cypress wetlands are longleaf pine flatwoods.

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Longleaf pine (*Pinus palustris*) is the characteristic tree species of the flatwoods. The extremely open canopy of the flatwoods permits development of a rich understory of shrubs and herbaceous species. Saw palmetto (*Serenoa repens*) is the most abundant shrub in the flatwoods; staggerbush (*Lyonia fruticosa*) and shiny lyonia (*Lyonia lucida*) are also common. Wiregrass (*Aristida stricta*) dominates the herbaceous layer, but is accompanied by a diverse array of forbs.

The extreme dryness of the flatwoods in winter and spring, and the highly flammable litter, create a condition conducive to frequent fires. Fire and cattle grazing have maintained the species composition and open structure of the flatwoods onsite prior to construction of Stanton 1. Observations reveal that the site has been subjected to numerous fires in the past, both planned (to improve the quality for livestock grazing) and accidental.

Pine densities and age class of the onsite flatwoods varied depending on a number of factors, including soil and moisture conditions, frequency of fire, and primarily logging history. The entire central Florida area was logged intensively for pine 70 to 80 years ago. Since that time, pulp wood has been periodically harvested from portions of the site. Major recruitment classes of longleaf pine have occurred at about 9.75-year intervals since 1910. Ten recruitment classes from 1910 to 1990 averaged covering about 8 percent of the site. Recruitment pine stands (N = 35) for 1960 (best available data), covered about 10 percent of the site, with most patches (60 percent) 2 acres or less in size. One very large recruitment class of 1936 covered about 22 percent of the site, with patches averaging about 70 acres in size. The southern half of the property is dominated by much older trees, apparently from six age classes. The northern half of the site is dominated by pine trees less than 70 years of age, which includes the 1936 age class.

The distribution of animal communities onsite also reflects the range of conditions described above. Species found on the site, such as the red-cockaded woodpecker, are restricted primarily to the pine flatwood habitats. Other species, such as the rufous-sided towhee, while not confined to one habitat type, are more abundant in the dryer situations (xeric oak scrub). No unique species were found in the cypress strands; however, a greater number and variety of wildlife species were observed in these wetlands than in the pine flatwoods and oak scrub.

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During the 1980-81 field surveys, 16 species of mammals, 68 species of birds, 15 species of reptiles, and 9 species of amphibians were observed in the area of concern (Section 2.7 of the original SCA). The preferred habitat and relative abundance of mammals, reptiles, and amphibians observed onsite are listed in Appendix 2.7A and Tables 2.7A-7 and 2.7A-8 of the 1982 SCA.

Prior to Stanton 1, construction logging activity had occurred in most onsite flatwoods. However, this disturbance has not drastically affected the diversity of wildlife present. Some sections, particularly those on the southern portion of the site, are dominated by relatively old (80 years or more) pines. The presence of these older stands has provided habitat for the red-cockaded woodpecker and other species. Other typical flatwoods species included Bachman's sparrow, pine warbler, brown-headed nuthatch, and Sherman's fox squirrel. The central and northern portions of the site have been logged more recently although recruitment of pines has occurred and stands are dominated by younger pine trees.

Endangered and threatened wildlife species occurring along the corridor for the Alafaya Trail include four colonies (clusters of cavity trees used for roosting and nesting) of red-cockaded woodpeckers. The territory associated with these four colonies averages about 278 acres and includes about 9,812 pine trees each (Habitat Management Plan for Red-Cockaded Woodpecker included herein as Exhibit 6.2-12).

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6.2.7.4 Other Environmental Features. There are no other environmental features applicable to the proposed extension of Alafaya Trail.

6.2.8 Effect of Right-of-Way Preparation and Roadway Construction

6.2.8.1 Roadway Construction. The portion of the right-of-way within the 110 feet through the Orlando Utilities Commission property has previously been cleared for installation of a forcemain and watermain. This right-of-way is to be maintained as cleared right-of-way. Within the 180-foot right-of-way, sideslopes will be maintained to the toe of slope. Prior to any clearing and grubbing and construction of the proposed roadway, erosion protection methods will be implemented. This includes the installation of silt fence barriers in areas designed on the plans and approved by permitting agencies.

Several distinct tasks will be required for construction of the proposed roadway. These will include surveying, clearing, road construction, foundation and structure assembly, and cleanup. The tasks will occur in the following sequence and will be separated by several days to several months.

The right-of-way center line and edges and structure sites will be 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 be under water or where 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 track shear machines will be used for clearing, and fill material will be hauled in for the construction of roads.

In areas outside of wetlands, the right-of-way will be cleared by heavy track machines using 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 the requirements of the Division of Forestry and other conditions at that time.

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

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

The next series of tasks consist of hauling material, assembly of structures, and direction of structures. The structure hardware will probably be hauled to the site by tractors and trailers, then off-loaded with medium-sized truck cranes or all wheeled cranes. Medium-sized all wheel drive trucks will be used to transport personnel and tools. Medium-sized trucks or all wheel drive cranes will be required to move structure components and place the structure for erection. The most common method of erecting the structure is with heavy track cranes. A

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work group will normally place the entire structure in one "Pick." The boom reach will be sufficient to work the tallest structures.

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 materials. Roads will be constructed with slight crowns and slopes. In addition, culverts will be placed at necessary locations to allow for proper sheetflow and prevent road washouts. Turbidity screens will be used as required to maintain water quality. Roads, pastures, lawns, and other open areas will be maintained throughout the construction. 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.

6.2.8.2 Impacts on Waterbodies and Uses. The original dredge and fill permit application for the entire Alafaya Trail alignment was submitted to the SJRWMD on January 8, 1990 (Exhibit 6.2-7); however, on August 8, 1990, this permit application was modified to divide the alignment into two parts--the northern extent (OUC properties) and the southern extent (Exhibit 6.2-8). At that time, SJRWMD gave verbal approval of the whole alignment. However, communications from FDER indicated that the alignment through OUC properties (the northern extent) would require modification of the existing permit. Therefore, SJRWMD proceeded with the permitting process for only the southern extent of the alignment. The dredge and fill (wetland resource) and MSSW permit for the southern alignment (outside of OUC boundaries) was issued by the SJRWMD (Exhibits 6.2-4 and 6.2-5). As shown on Table 1A, page 5, of the permit application modification letter to SJRWMD on August 8, 1990, only 1.53 acres of proposed wetland impacts are "waters of the state" wetlands of which only 0.54 acre (Hart Branch) would require a permit to impact since the other two wetlands qualify for a ditch block exemption pursuant to Section 403.913(4) F.S.

The specifications showing the location of the proposed Alafaya Trail alignment are included in the construction plans which are attached as Exhibit 6.2-9.

The plan and profile sheets are found on Sheets 18 through 26 of the construction plans.

Specifications of the structures at Hart Branch are shown on Sheet 133 of the construction plans.

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The design capacities of the structures and the drainage calculations are attached as Exhibit 6.2-10.

The Joint Application form (DER Form 17-1.203[1]) is included in Subsection 10.6.2. This application includes all currently available design information regarding the wetland impacts of the proposed extension of Alafaya Trail from the north boundary of the Stanton Energy Center to a location approximately 3,000 feet south of the Bee Line Expressway.

6.2.8.3 Solid Wastes. Wastes generated during construction of the proposed roadway 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. Noncombustible materials will be collected and disposed of at local landfills or other approved disposal sites. No other form of solid waste will be produced during the construction of the roadway.

6.2.8.4 Changes to Vegetation, Wildlife, and Aquatic Life. Approximately 1.53 acres of "waters of the state" wetlands will be impacted by the proposed Alafaya Trail extension project. However, 0.99 acre of this acreage has been qualified for the ditch block exemption pursuant to Section 403.913(4), F.S. Therefore, only 0.54 acre (Hart Branch) of "waters of the state" wetlands is proposed to be impacted by Alafaya Trail extension on the OUC properties and permitted through this permit modification process.

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To compensate for this loss of wetlands and for all impacts to wetlands for the entire length of the proposed Alafaya Trail extension project, a mitigation plan has been developed through extensive designing and coordination with local, state, and federal permitting agencies. This plan is attached as Exhibit 6.2-11 and has been approved by the SJRWMD, Orange County, ACOE, EPA, USFWS, and FGFWFC.

The total wetland impacts for the entire length of the roadway will be 20.08 acres of SJRWMD wetlands, 17.26 acres of ACOE wetlands, and 6.54 acres of Orange County wetlands. The maximum extent of impact to wetlands is 20.08 acres.

The approved mitigation plan provides for the creation of six different wetland types on Parcel 9 of the International Corporate Park site for a total of 37.31 acres: wetland shrub island (1.12 acres); freshwater marsh (8.28 acres); deep

water aquatic (1.87 acres); shallow water aquatic (3.26 acres); cypress-dominated wetland (20.31 acres); and mixed hardwood wetland (2.47 acres). The wetland impacts from the proposed Alafaya Trail extension include only four wetland types, one of which is manmade: cypress, mixed forested wetland, wet prairie, and upland cut drainage ditch. The proposed wetland shrub islands which are surrounded by deep water aquatic habitats and buffered from development by expansive wetland areas will provide habitat that should serve as rookery sites for wading birds. The numerous lakes with littoral zones and wetland mitigation sites proposed at ICP buildout will supply forage habitat for wading birds, many species of which are onsite now, but breed elsewhere.

Approximately 12.7 acres of upland pine forest will be converted to surface runoff ponds during construction of the Alafaya Trail extension through the Stanton Energy Center. All of these pond areas are adjacent to the road and were located to avoid impacting any substantial amounts of foraging resources for red-cockaded woodpeckers. Neither the construction of the ponds nor any aspect of the roadway will be in proximity to the colony sites. The Alafaya Trail extension will use the existing corridor of the newly constructed pipelines on the eastern portion of the Stanton Energy Center property. Further discussions on the potential changes to the woodpecker population are provided in Exhibits 6.2-12, 6.2-13, and 6.2-14.

Mitigation measures were developed for red-cockaded woodpeckers:

- (1) A demonstration colony creation project.
- (2) Habitat enhancement procedure.
- (3) A routine monitoring program.

These actions will result in population increase and improvements in overall foraging habitat quality. Exhibit 6.2-15 provides a description of the various mitigation procedures and their overall importance to red-cockaded woodpeckers in this area.

6.2.8.5 Impact on Human Population. The Stanton Energy Center is located in a sparsely populated area, and impacts on humans during the road 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 site.

RFM-1

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.

Impacts to air quality, if any, will be negligible from the construction of the roadway.

6.2.8.6 Impact on Regional Scenic, Cultural, and Natural Landmarks. There are no regional scenic, cultural, or natural landmarks that will be affected by the proposed extension of Alafaya Trail.

6.2.8.7 Impact on Archaeological and Historic Sites. There are no archaeological or historic sites within the right-of-way of the proposed extension of Alafaya Trail.

6.2.9 Post-Construction Impacts and Effects of Maintenance

6.2.9.1 Maintenance Techniques. The road will require periodic inspection, maintenance, cleaning, and occasional repair work. These activities will help to maintain serviceability and safety and to prolong the service life of the 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. Orange County will own the roads. Accordingly, Orange County will be responsible for periodic inspection, maintenance, cleaning, and occasional repair work for the life of the road.

6.2.9.2 Multiple Uses. The road will serve the public as a north-south public road in east Orange County. Access to the property, however, will remain restricted. The property bordering the right-of-way will be posted, and a fence may be erected to prevent access to the Stanton Energy Center from the road right-of-way. Additionally, the road will provide important non-toll access to the DOC prison complex and to International Corporate Park.

6.2.9.3 Changes in Species Populations. No significant long-term changes will occur in the populations of threatened or endangered species or species of special concern within the road alignment as a result of construction and maintenance of the road. However, with the implementation of ICP's Red-Cockaded Woodpecker Management Plan, the population of RCWs on the Stanton Energy Center property is expected, at a minimum, to stabilize and not to decrease as is the

RFM-1

current situation without the road. Long-term expectations under ICP's management plan are that the RCW population should increase.

6.2.9.4 Effects of Public Access. A low probability exists that some RCWs, while flying over the road, will collide with vehicles (Exhibit 6.2-14).

6.2.10 Other Post-Construction Effects

Currently, OUC is not required under its certification (including its supplemental certification) to actively manage the RCW population and habitat in order to increase the viability of the RCW population. Other than a prescribed burning program, OUC must merely manage the Red-Cockaded Management Area in its natural state. Over the last ten years while the RCW Management Area was managed in its natural state, the population of RCWs on the Stanton Energy Center property has declined from nine active colonies in 1981 to six such colonies in 1991.

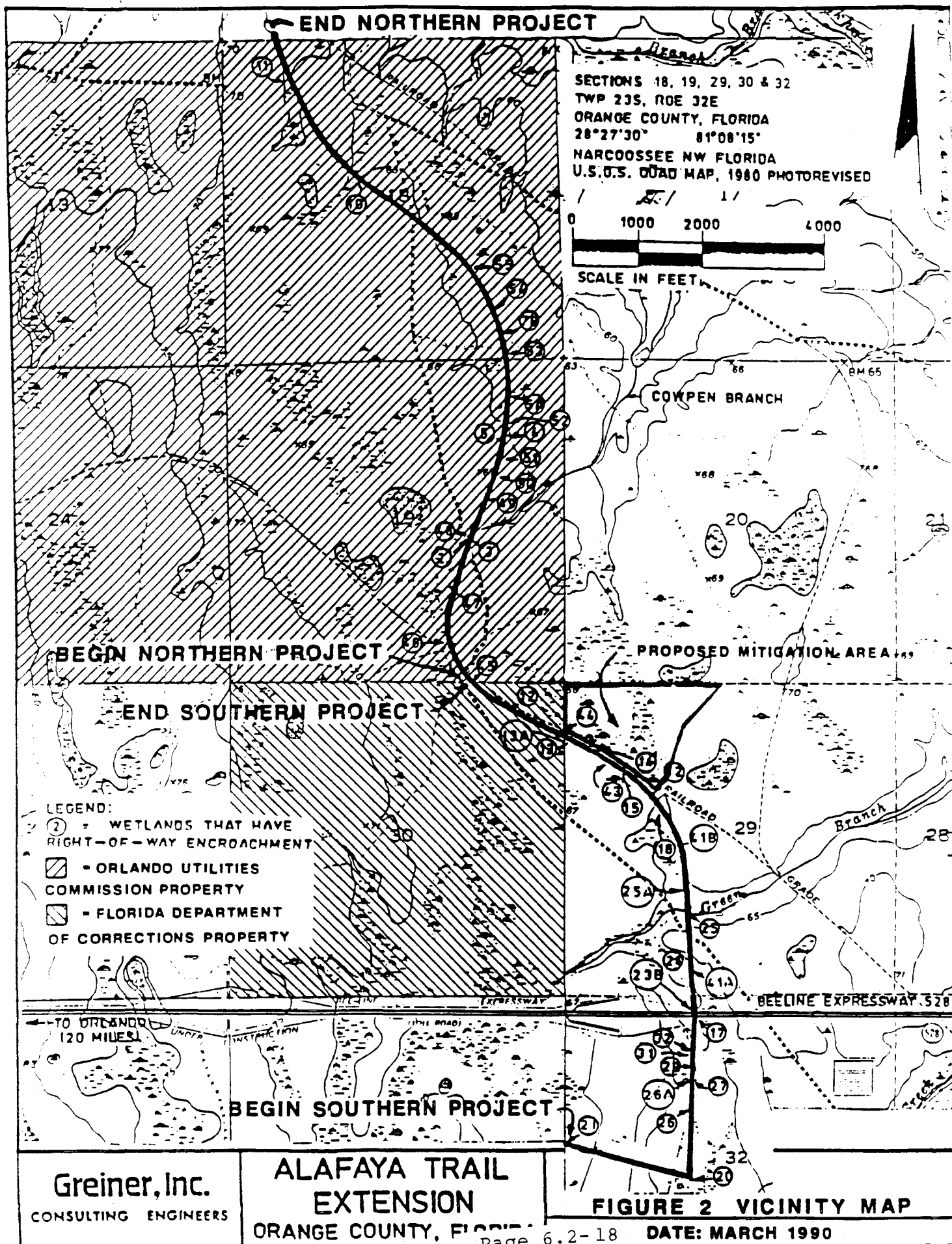
The road will not significantly affect the RCW population on the Stanton Energy Center property. The road will impact the RCW habitat by causing a slight loss of foraging habitat. However, if the road is constructed, the RCW impacts will be mitigated pursuant to "The Curtis H. Stanton Energy Center, Habitat Management Plan for Red-Cockaded Woodpeckers." It is expected that the requirements of the RCW Habitat Management Plan will substantially increase the chance of the long-term survival of the RCWs on the Stanton Energy Center property. The RCW Habitat Management Plan requires the road builder to plant pine trees to improve the RCW foraging habitat, to create artificial cavities in pine trees to facilitate population expansion, and to actively monitor the RCW population on the property.

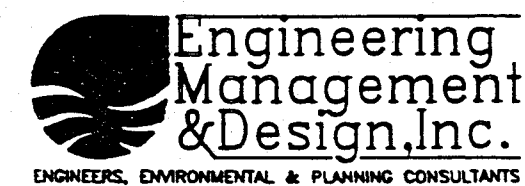
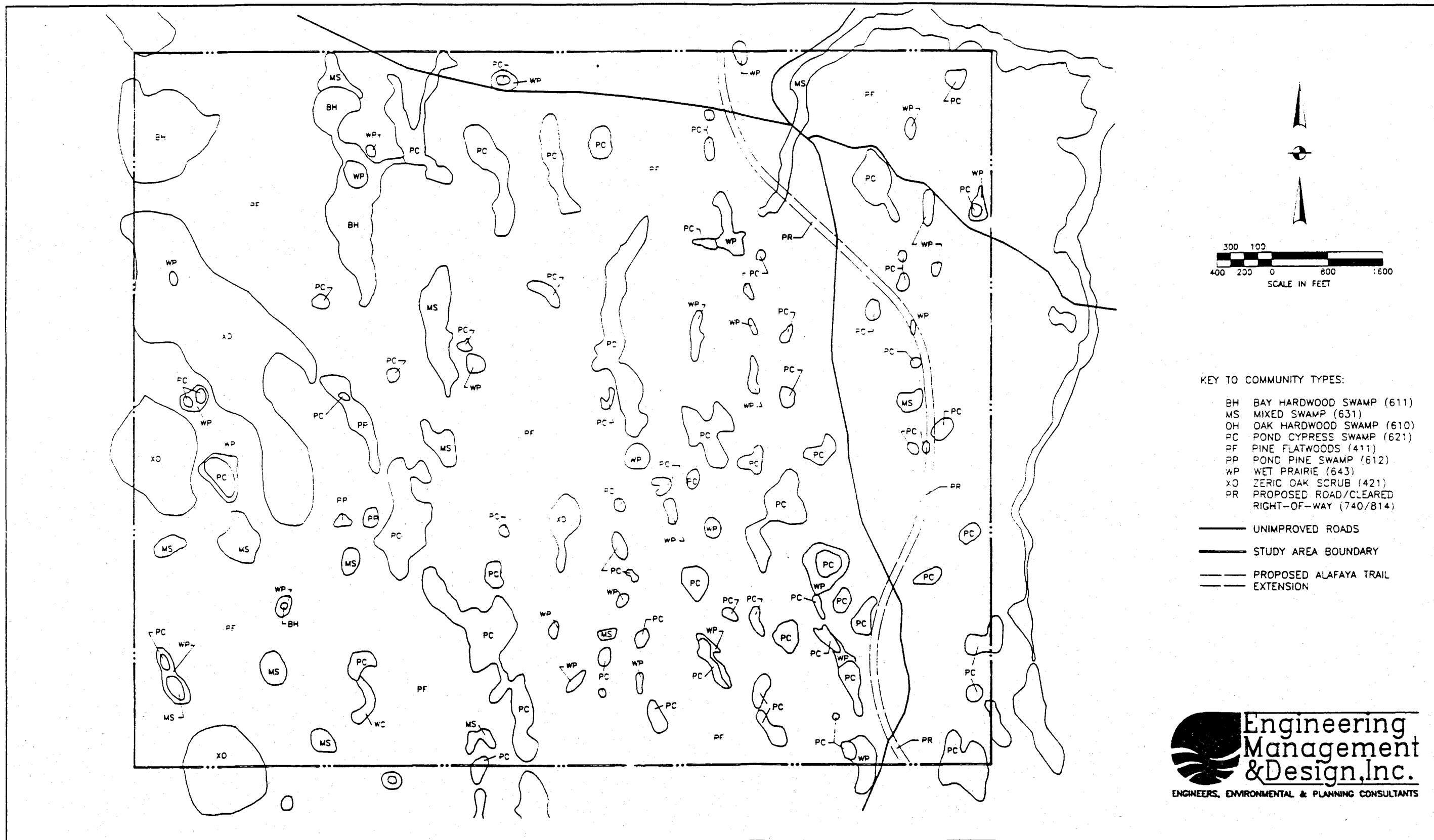
RFM-1

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.







CENTRAL FLORIDA DISTRICT

3319 MAGUIRE BOULEVARD
SUITE 232
ORLANDO, FLORIDA 32803-3767



OCT 19 1987

FILE NO. 3450-1

CC: FSE FDER
10/19/87

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ALEX ALEXANDER
DISTRICT MANAGER

October 15, 1987

OCF-DF-87-0213

Mr. Thomas A. Cloud
Gray, Harris & Robinson
Suite 1200
Southeast Bank Building
201 East Pine Street
Post Office Box 3068
Orlando, Florida 32802

Orange County - D/F
International Corporate Park (ICP)

Dear Mr. Cloud:

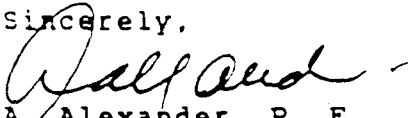
Thank you for promptly supplying the minutes of the October 8, 1987 meeting in regard to the International Corporate Park (ICP) project. One purpose of this meeting was to clarify the necessity of dredge and fill permits for activities conducted due to the proposed pipeline installation.

Although it was not apparent at the meeting, department personnel and Bill Grey of Breedlove, Dennis and Associates conducted an informal jurisdictional determination on May 1, 1987 of a large portion of the Florida Department of Corrections' property. This inspection clearly describes areas in addition to Hart Branch as being within the landward extent of waters of the state pursuant to Rule 17-4.022, Florida Administrative Code. It is a valid assumption that if ICP bores and jacks below jurisdictional wetlands, such as Hart Branch, to install the pipelines and the construction proceeds from upland to upland, a dredge and fill permit would not be required for the activity. However, your letter also reflects your belief that no dredge and fill permit would be required to extend the pipeline through the remainder of the Florida Department of Corrections' property. Department personnel inspected two potential pipeline crossings of wetlands with representatives of Breedlove, Dennis and Associates on October 9, 1987 to determine the necessity of a dredge and fill permit. Based upon the on-site meeting and the drawings which depict the proposed crossings, it appears that one of the crossings will require a dredge and fill

permit. It seems that one crossing, which will require a permit, involves removal and replacement of an 18-inch diameter steel culvert. If the bore and jack technique is utilized at this crossing so that manipulation of the existing culvert is not involved and all construction activities occur on the existing upland roadbed, a dredge and fill permit will not be required. The other crossing which involves vertical extension of a headwall, road elevation and installation of the two pipelines above the existing concrete pipes in the roadbed will not require a dredge and fill permit.

Please advise if any additional information is required.

Sincerely,


A. Alexander, P. E.
District Manager

MSA
AA:mah

May 1, 1989

Page 419

Upon a motion by Commissioner Dorman, seconded by Commissioner Donegan, and carried with all present commissioners voting AYE by voice vote; Commissioner Chapin being absent; the Board overturned the decision of the Planning and Zoning Commission and denied the request for a change in zoning classification from R-2 to R-3 by RTI of Orlando, Inc. on the above described property.

PUBLIC HEARING - CONSIDER THE ALIGNMENT AND CROSS SECTION FOR THE PROPOSED EXTENSION OF ALAFAYA TRAIL - DISTRICT 13

Notice was given that the Board of County Commissioners would hold a public hearing to consider:

Alignment and typical cross section for the proposed Alafaya Trail Extension from the end of the existing road in a southerly direction to a point approximately 0.3 miles South of the Deeline.

County Engineer George Cole presented a cross section of the proposal which is to construct an initial two-lane rural roadway. He recommended approval, as presented, subject to completion of final engineering to resolve any engineering or environmental questions that may arise.

Tom Cloud, Esq., of Gray, Harris and Robinson, P.A., stated that they have received all of the required permits to date, with the exception of those for the recertification of the Curtis Stanton Energy Center and the necessary permit crossings over wetlands.

A representative of Breedlove, Dennis & Associates explained that his organization conducted some of the environmental analysis and determined that this alignment allowed for the least impact on environmentally sensitive lands, such as wetlands, and woodpecker habitats.

Upon a motion by Commissioner Marston, seconded by Commissioner Donegan, and carried with all commissioners present and voting AYE by voice vote; Commissioner Chapin was absent; the Board approved staff recommendation concerning the alignment and cross section for the proposed extension of Alafaya Trail.

PUBLIC HEARING - LUCY E. BARAGNESI - BOARD OF ZONING ADJUSTMENT 123 (CONTINUED FROM 4/10/89) - DISTRICT 13

It was the consensus of the Board to continue with the public hearing under the name of Lucy E. Baragnesi, continued from April 10, 1989 Board meeting.

Assistant Zoning Director Joanne McMurray stated that the public hearing was continued, pending the outcome of the meeting this date regarding service-oriented uses in P-O districts.

An unidentified citizen spoke in favor of this request and no one appeared in opposition.

Upon a motion by Commissioner Marston, seconded by Commissioner Donegan, and carried with Commissioners Marston, Donegan, and Dorman voting AYE by voice vote; Commissioner Carter voting NO by voice vote; Commissioner Chapin being absent; the Board approved the request by Lucy E. Baragnesi for a special exception in P-O zone for a beauty shop integrated within a primary use structure and oriented

OFFICE OF COMPTROLLER



ORANGE
COUNTY
FLORIDA

Martha O. Haynie
Clerk to the Board of County Commissioners
201 S. Rosalind Avenue
Post Office Box 38
Orlando, Florida 32802-0038
Telephone (407) 236-7300

November 22, 1989

RECEIVED
AUG 23 1990

International Corporate Park, Inc.
933 Lee Road, Suite 400
Orlando, Florida 32810

HUEY, GUILDAY,
KUERSTEINER & TUCKER, P.A.

Gentlemen:

On November 20, 1989, at a meeting of the Board of County Commissioners a motion was made by Commissioner Marston, seconded by Commissioner Donegan, and carried with all Commissioners present and voting AYE by voice vote; to approve water main and force main for maintenance at I.C.P. off-site water main and wastewater main, NOT PLATTED.

Sincerely,

MARTHA O. HAYNIE, Clerk
Board of County Commissioners of
Orange County, Florida

By: Maury Jo Harrison
Deputy Clerk

MOH:MJG:rhs
Enclosure

c: George Cole, Engineering Department

APPROVED BY THE BOARD OF COUNTY
COMMISSIONERS AT THEIR MEETING

NOV 20 1989

DISTRICT 5

APPROVAL FOR MAINTENANCE

This is to certify that the following facilities: Water main
and force main

Constructed By: International Corporate Park, Inc.

(address): 933 Lee Road, Suite 400, Orlando, Florida 32810

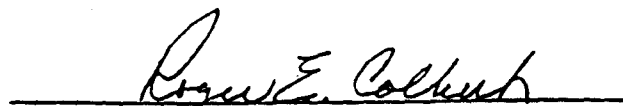
In the development of: I.C.P. Off-Site Water Main and Wastewater
Force Main

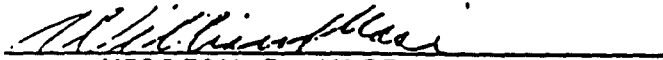
as recorded in Plat Book NOT, Page(s) PLATTED, Orange
County Records, have been completed in form and manner acceptable for
maintenance by ORANGE COUNTY, FLORIDA.

CONTRACTOR: Southeastern Utilities

THIS CONSTITUTES FINAL ACCEPTANCE FOR MAINTENANCE BY ORANGE COUNTY AND
RELEASED THE DEVELOPER FROM RESPONSIBILITY FOR MAINTENANCE OF THE
LISTED FACILITIES.


SENIOR INSPECTOR


STAFF ENGINEER


WILLIAM J. MASI, P.E.
MANAGER

EXECUTED BY ORDER OF THE BOARD OF COUNTY COMMISSIONERS, ORANGE COUNTY,
FLORIDA, THIS 20th DAY OF October, 1989.


CHAIRMAN


DEPUTY CLERK

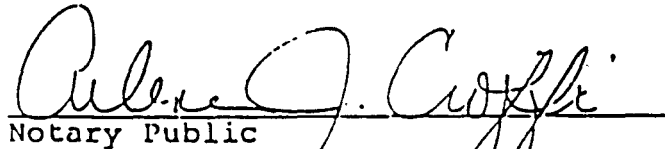
(SEAL)

STATE OF FLORIDA

COUNTY OF ORANGE

On this 27th day of October, 1988 before me personally came James L. Clark, to me personally known, who, being by me duly sworn, did depose and say that he is the Senior Vice President of International Corporate Park, Inc., a Florida Corporation, which corporation is a general partner of ICP Investors Limited, a Florida limited partnership, which limited partnership is a general partner of ICP Associates, a Florida general partnership, the general partnership described in and which executed the above instrument; and that he signed his name thereto by authority of the board of directors of such corporation as general partner of such limited partnership.

(NOTARIAL SEAL)


Notary Public

My commission expires: 

NOTARY PUBLIC, STATE OF FLORIDA AT LARGE
MY COMMISSION EXPIRES SEPT. 01, 1992
BONDED THRU HUCKLEBERRY & ASSOCIATES

BILL OF SALE
SEWER AND WATER SYSTEMS

RECEIVED

AUG 23 1990

International Corporate Park, Incorporated, a Florida corporation,
and ICP Investors, Ltd. and ICP Associates
located at 933 Lee Road, Ste. 400, Orlando, FL 32810

HUEY, GUILDAY,
KUEFSTEINER & GUY, P.A.

Orange, State of Florida, Seller, for and in consideration of the sum of One (\$1.00) Dollar and other valuable consideration paid to Seller by County of Orange, a political subdivision of the State of Florida, Buyer, receipt of which is hereby acknowledged does grant, sell, transfer, convey and deliver to Buyer all pipes, lines, gate valves, valve boxes, fittings, thrust blocks, hydrants, equipment, lift stations and other goods which comprise the water and sewer system installed by Seller and located on the following County easements or rights-of-way as shown on the record drawings, more specifically described as follows:

PROJECT: International Corporate Offsite Water Transmission Main
and Wastewater Force Main

Buyer shall have all rights and title to the goods in itself and its assigns.

Seller warrants that it is lawful owner of the goods and the goods are free from all liens and encumbrances. Seller has good right to sell the goods and will warrant and defend the right against the lawful claims and demands of all persons.

IN WITNESS WHEREOF, Seller has executed this Agreement at

Orlando

, Florida on October 27, 1981

SIGNED, SEALED AND DELIVERED

James L. Clark

IN THE PRESENCE OF:

By: James L. Clark

S.R.U. Pres., S.R.U. Inc.

*Managing General Partner
for ICP Investors, LTD
Managing General Partner*

Lin J. Murray

(Witness)

Page 6.2-26

ATTEST:



**WATER
MANAGEMENT
DISTRICT**

Henry Dean, Executive Director

John R. Wehle, Assistant Executive Director

POST OFFICE BOX 1429
TELEPHONE 904/329-4500

PALATKA, FLORIDA 32178-142
SUNCOM 904/860-4500

FAX (EXECUTIVE/LEGAL) 329-4125

(PERMITTING) 329-4315

(ADMINISTRATION/FINANCE) 329-4125

FIELD STATIONS

618 E. South Street
Orlando, Florida 32801
407/894-5423

7775 Baymeadows Way
Suite 102
Jacksonville, Florida 32256
904/730-6270

PERMITTING
305 East Drive
Melbourne, Florida 32904
407/984-4940

OPERATIONS
2133 N. Wickham Road
Melbourne, Florida 32935-61
407/254-1762

JULY 9, 1991

INTERNATIONAL CORPORATE PARK
8243 ICP BOULEVARD
ORLANDO FL 32552

RECEIVED

SEP 23 1991

EMD

SUBJECT: WELAND RESOURCE PROJECT
PERMIT NUMBER 12-095-0040M2

ENCLOSED IS YOUR PERMIT AS AUTHORIZED BY THE GOVERNING BOARD
OF THE ST. JOHNS RIVER WATER MANAGEMENT DISTRICT ON JULY 9,
1991. THIS PERMIT WILL EXPIRE ON JULY 9, 1995.

THIS PERMIT IS A LEGAL DOCUMENT AND SHOULD BE KEPT
WITH YOUR OTHER IMPORTANT DOCUMENTS. THE ATTACHED COMPLETION
REPORT SHOULD BE FILLED IN AND RETURNED TO THE PALATKA OFFICE
WITHIN THIRTY DAYS AFTER THE WORK IS COMPLETED. BY SO DOING,
YOU WILL ENABLE US TO SCHEDULE A PROMPT INSPECTION OF THE
PERMITTED ACTIVITY.

PERMIT ISSUANCE DOES NOT RELIEVE YOU FROM THE RESPONSIBILITY
OF OBTAINING PERMITS FROM ANY FEDERAL, STATE, AND/OR LOCAL
AGENCIES ASSERTING CONCURRENT JURISDICTION FOR THIS WORK.

IN THE EVENT YOU SELL YOUR PROPERTY, THE PERMIT WILL BE
TRANSFERRED TO THE NEW OWNER, IF WE ARE NOTIFIED BY YOU WITHIN
NINETY DAYS OF THE SALE. PLEASE ASSIST US IN THIS MATTER SO AS
TO MAINTAIN A VALID PERMIT FOR THE NEW PROPERTY OWNER.

THANK YOU FOR YOUR COOPERATION AND IF THIS OFFICE CAN BE OF
ANY FURTHER ASSISTANCE TO YOU, PLEASE DO NOT HESITATE TO CONTACT
US.

SINCERELY,

Lacy Livingston

LACY LIVINGSTON, DATA CONTROL TECHNICIAN
DIVISION OF RECORDS

ENCLOSURES: PERMIT WITH COMPLETION REPORT

CC: DISTRICT PERMIT FILE
VICKI CURTIS
MARGARET LANGWORTHY, CORPS OF ENGINEERS
DER
DER FIELD OFFICE

Saundra H. Gray, CHAIRMAN
DE BARY

Joe E. Hill, VICE CHAIRMAN
LEESBURG

Joseph D. Collins, TREASURER
JACKSONVILLE

Morris C. Fore, SECRETARY
OCALA

Jesse J. Pamsh, III
TITUSVILLE

Ralph E. Simmons
FERNANDINA BEACH

Patricia T. Harden
SAFORD

Lenore N. McCullagh
ORANGE PARK

James H. Wilkier
OCALA

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

Post Office Box 1429
Palatka, Florida 32178-1429

PERMIT NO. 12-093-006042

DATE ISSUED JULY 9, 1991

WETLAND RESOURCE PROJECT

A PERMIT AUTHORIZING:

**THE EXCAVATION OF 7625244.0 CUBIC YARDS OF MATERIAL AND PLACEMENT
OF 0.00 CUBIC YARDS OF FILL MATERIAL IN WATERS OF THE STATE FOR
CONSTRUCTION OF A MITIGATION AREA.**

LOCATION:

**SECTION 29, 30, 31, 32, TOWNSHIP 23 SOUTH, RANGE 32 EAST
ORANGE COUNTY**

ISSUED TO:
(owner)

**INTERNATIONAL CORPORATE PARK
8248 ICP BOULEVARD
ORLANDO FL 32832**

Permittee agrees to hold and save the St. Johns River Water Management District and its successors harmless from any and all damages, claims, or liabilities which may arise from permit issuance. Said application, including all plans and specifications attached thereto, is by reference made a part hereof.

This permit does not convey to permittee any property rights nor any rights or privileges other than those specified herein, nor relieve the permittee from complying with any law, regulation or requirement affecting the rights of other bodies or agencies. All structures and works installed by permittee hereunder shall remain the property of the permittee.

This Permit may be revoked, modified or transferred at any time pursuant to the appropriate provisions of Chapter 373, Florida Statutes.

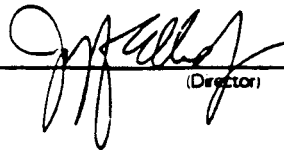
PERMIT IS CONDITIONED UPON:

SEE CONDITIONS ON ATTACHED "EXHIBIT A", DATED JULY 9, 1991

AUTHORIZED BY: St. Johns River Water Management District

Department of Resource Management Governing Board

By: _____


(Director)

JEFF ELLEDGE

By: _____


(Assistant Secretary)

HENRY DEAN

"EXHIBIT A"

CONDITIONS FOR ISSUANCE OF PERMIT NUMBER 12-U95-U060M2

INTERNATIONAL CORPORATE PARK

DATED JULY 9, 1991

1. THE TERMS, CONDITIONS, REQUIREMENTS, LIMITATIONS, AND RESTRICTIONS SET FORTH IN THIS PERMIT, ARE "PERMIT CONDITIONS" AND ARE BINDING AND ENFORCEABLE PURSUANT TO SECTIONS 403.747, 403.727, OR 403.839 THROUGH 403.861, FLORIDA STATUTES. THE PERMITTEE IS PLACED ON NOTICE THAT THE DISTRICT WILL REVIEW THIS PERMIT PERIODICALLY AND MAY INITIATE ENFORCEMENT ACTION FOR ANY VIOLATION OF THESE PERMIT CONDITIONS.
2. THIS PERMIT IS VALID ONLY FOR THE SPECIFIC PROCESSES AND OPERATIONS APPLIED FOR AND INDICATED IN THE APPROVED DRAWINGS OR EXHIBITS. ANY UNAUTHORIZED DEVIATION FROM THE APPROVED DRAWINGS, EXHIBITS, SPECIFICATIONS, OR CONDITIONS OF THIS PERMIT MAY CONSTITUTE GROUNDS FOR REVOCATION AND ENFORCEMENT ACTION BY THE DISTRICT.
3. AS PROVIDED IN SUBSECTIONS 403.087(6), AND 403.722(5), FLORIDA STATUTES, THE ISSUANCE OF THIS PERMIT DOES NOT CONVEY ANY VESTED RIGHTS OR ANY EXCLUSIVE PRIVILEGES. NEITHER DOES IT AUTHORIZE ANY INJURY TO PUBLIC OR PRIVATE PROPERTY OR ANY INVASION OF PERSONAL RIGHTS, NOR ANY INFRINGEMENT OF FEDERAL, STATE, OR LOCAL LAWS OR REGULATIONS. THIS PERMIT IS NOT A WAIVER OF OR APPROVAL OF ANY OTHER DER OR DISTRICT PERMIT THAT MAY BE REQUIRED FOR OTHER ASPECTS OF THE TOTAL PROJECT WHICH ARE NOT ADDRESSED IN THIS PERMIT.
4. THIS PERMIT CONVEYS NO TITLE TO LAND OR WATER, DOES NOT CONSTITUTE STATE RECOGNITION OR ACKNOWLEDGEMENT OF TITLE, AND DOES NOT CONSTITUTE AUTHORITY FOR THE USE OF SUBMERGED LANDS UNLESS HEREIN PROVIDED AND THE NECESSARY TITLE OR LEASEHOLD INTERESTS HAVE BEEN OBTAINED FROM THE STATE. ONLY THE TRUSTEES OF THE INTERNAL IMPROVEMENT TRUST FUND MAY EXPRESS STATE OPINION AS TO TITLE.
5. THIS PERMIT DOES NOT RELIEVE THE PERMITTEE FROM LIABILITY FOR HARM OR INJURY TO HUMAN HEALTH OR WELFARE, ANIMAL, OR PLANT LIFE, OR PROPERTY CAUSED BY THE CONSTRUCTION OR OPERATION OF THIS PERMITTED SOURCE, OR FROM PENALTIES THEREFOR; NOR DOES IT ALLOW THE PERMITTEE TO CAUSE POLLUTION IN CONTRAVENTION OF FLORIDA STATUTES AND DEPARTMENT OF ENVIRONMENTAL REGULATION (DER) RULES, UNLESS SPECIFICALLY AUTHORIZED BY AN ORDER FROM THE DER OR DISTRICT.
6. THE PERMITTEE SHALL PROPERLY OPERATE AND MAINTAIN THE FACILITY AND SYSTEMS OF TREATMENT AND CONTROL (AND RELATED APPURTENANCES) THAT ARE INSTALLED AND USED BY THE PERMITTEE TO ACHIEVE COMPLIANCE WITH THE CONDITIONS OF THIS PERMIT, AS REQUIRED BY DEPARTMENT RULES. THIS PROVISION INCLUDES THE OPERATION OF BACKUP OR AUXILIARY FACILITIES OR SIMILAR SYSTEMS WHEN NECESSARY TO ACHIEVE COMPLIANCE WITH THE CONDITIONS OF THE PERMIT AND WHEN REQUIRED BY DEPARTMENT RULES.
7. THE PERMITTEE, BY ACCEPTING THIS PERMIT, SPECIFICALLY AGREES TO ALLOW AUTHORIZED DISTRICT PERSONNEL, UPON PRESENTATION OF CREDENTIALS OR OTHER DOCUMENTS AS MAY BE REQUIRED BY LAW AND AT REASONABLE TIMES, ACCESS TO THE PREMISES WHERE THE PERMITTED ACTIVITY IS LOCATED OR CONDUCTED TO:
 - (A) HAVE ACCESS TO AND COPY ANY RECORDS THAT MUST BE KEPT UNDER CONDITIONS OF THE PERMIT;

(B) INSPECT THE FACILITY, EQUIPMENT, PRACTICES, OR OPERATIONS REGULATED OR REQUIRED UNDER THIS PERMIT; AND

(C) SAMPLE OR MONITOR ANY SUBSTANCES OR PARAMETERS AT ANY LOCATION REASONABLE NECESSARY TO ASSURE COMPLIANCE WITH THIS PERMIT OR DEPARTMENT RULES.

REASONABLE TIME MAY DEPEND ON THE NATURE OF THE CONCERN BEING INVESTIGATED.

5. IF, FOR ANY REASON, THE PERMITTEE DOES NOT COMPLY WITH OR WILL BE UNABLE TO COMPLY WITH ANY CONDITION OR LIMITATION SPECIFIED IN THIS PERMIT, THE PERMITTEE SHALL IMMEDIATELY PROVIDE THE DISTRICT WITH THE FOLLOWING INFORMATION:

(A) A DESCRIPTION OF AND CAUSE OF NON-COMPLIANCE; AND

(B) THE PERIOD OF NONCOMPLIANCE, INCLUDING DATES AND TIMES; OR, IF NOT CORRECTED, THE ANTICIPATED TIME THE NON-COMPLIANCE IS EXPECTED TO CONTINUE, AND STEPS BEING TAKEN TO REDUCE, ELIMINATE, AND PREVENT RECURRENCE OF THE NON-COMPLIANCE.

THE PERMITTEE SHALL BE RESPONSIBLE FOR ANY AND ALL DAMAGES WHICH MAY RESULT AND MAY BE SUBJECT TO ENFORCEMENT ACTION BY THE DISTRICT FOR PENALTIES OR REVOCATION OF THIS PERMIT.

7. IN ACCEPTING THIS PERMIT, THE PERMITTEE UNDERSTANDS AND AGREES THAT ALL RECORDS, NOTES, MONITORING DATA AND OTHER INFORMATION RELATED TO THE CONSTRUCTION OR OPERATION OF THIS PERMITTED SOURCE, WHICH ARE SUBMITTED TO THE DISTRICT MAY BE USED BY THE DISTRICT AS EVIDENCE IN ANY ENFORCEMENT CASE INVOLVING THE PERMITTED SOURCE ARISING UNDER THE FLORIDA STATUTES OR DEPARTMENT RULES, EXCEPT WHERE SUCH USE IS PRESCRIBED BY SECTIONS 403.111 AND 403.73, FLORIDA STATUTES. SUCH EVIDENCE SHALL ONLY BE USED TO THE EXTENT IT IS CONSISTENT WITH THE FLORIDA RULES OF CIVIL PROCEDURE AND APPROPRIATE EVIDENTIARY RULES.

10. THE PERMITTEE AGREES TO COMPLY WITH CHANGES IN DEK RULES AND FLORIDA STATUTES AFTER A REASONABLE TIME FOR COMPLIANCE, PROVIDED, HOWEVER, THE PERMITTEE DOES NOT WAIVE ANY OTHER RIGHTS GRANTED BY FLORIDA STATUTES OR DEK RULES.

11. THIS PERMIT IS TRANSFERABLE ONLY UPON DISTRICT APPROVAL IN ACCORDANCE WITH RULES 17-4.720 AND 17-30.300, FLORIDA ADMINISTRATIVE CODE, AS APPLICABLE. THE PERMITTEE SHALL BE LIABLE FOR ANY NON-COMPLIANCE OF THE PERMITTED ACTIVITY UNTIL THE TRANSFER IS APPROVED BY THE DISTRICT.

12. THIS PERMIT OR A COPY THEREOF SHALL BE KEPT AT THE WORK SITE OF THE PERMITTED ACTIVITY.

13. THIS PERMIT ALSO CONSTITUTES:

(A) DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT),

(B) DETERMINATION OF PREVENTION OF SIGNIFICANT DETERIORATION (PSD),

(C) CERTIFICATION OF COMPLIANCE WITH STATE WATER QUALITY STANDARDS (SECTION 401, PL 92-500), AND

(D) COMPLIANCE WITH NEW SOURCE PERFORMANCE STANDARDS.

14. THE PERMITTEE SHALL COMPLY WITH THE FOLLOWING:

- (A) UPON REQUEST, THE PERMITTEE SHALL FURNISH ALL RECORDS AND PLANS REQUIRED UNDER DER RULES. DURING ENFORCEMENT ACTIONS, THE RETENTION PERIOD FOR ALL RECORDS WILL BE EXTENDED AUTOMATICALLY UNLESS OTHERWISE STIPULATED BY THE DISTRICT.
- (B) THE PERMITTEE SHALL HOLD AT THE FACILITY OR OTHER LOCATION DESIGNATED BY THIS PERMIT RECORDS OF ALL MONITORING INFORMATION (INCLUDING ALL CALIBRATION AND MAINTENANCE RECORDS AND ALL ORIGINAL STRIP CHART RECORDINGS FOR CONTINUOUS MONITORING INSTRUMENTATION) REQUIRED BY THE PERMIT, COPIES OF ALL REPORTS REQUIRED BY THIS PERMIT, AND RECORDS OF ALL DATA USED TO COMPLETE THE APPLICATION FOR THIS PERMIT. THESE MATERIALS SHALL BE RETAINED AT LEAST THREE YEARS FROM THE DATE OF THE SAMPLE, MEASUREMENT, REPORT OR APPLICATION UNLESS OTHERWISE SPECIFIED BY DEPARTMENT RULE.

(C) RECORDS OF MONITORING INFORMATION SHALL INCLUDE:

- 1. THE DATE, EXACT PLACE, AND TIME OF SAMPLING OR MEASUREMENTS;
- 2. THE PERSON RESPONSIBLE FOR PERFORMING THE SAMPLING OR MEASUREMENTS;
- 3. THE DATES ANALYSES WERE PERFORMED;
- 4. THE PERSON RESPONSIBLE FOR PERFORMING THE ANALYSES;
- 5. THE ANALYTICAL TECHNIQUES OR METHODS USED; AND
- 6. THE RESULT OF SUCH ANALYSES.

- 15. WHEN REQUESTED BY THE DISTRICT, THE PERMITTEE SHALL WITHIN A REASONABLE TIME FURNISH ANY INFORMATION REQUIRED BY LAW WHICH IS NEEDED TO DETERMINE COMPLIANCE WITH THE PERMIT. IF THE PERMITTEE BECOMES AWARE THAT RELEVANT FACTS WERE NOT SUBMITTED OR WERE INCORRECT IN THE PERMIT APPLICATION OR IN ANY REPORT TO THE DISTRICT, SUCH FACTS OR INFORMATION SHALL BE CORRECTED PROMPTLY.
- 16. THIS PERMIT SUPERSEDES ALL OF THE CONDITIONS RELATIVE TO ABILGATION APPROVED PERMIT #12-095-0040, ISSUED IN OCTOBER 1990.
- 17. ALL CORRESPONDENCE, SUBMITTALS, AND NOTIFICATIONS REQUIRED BY THE FOLLOWING PERMIT CONDITIONS MUST BE SUBMITTED TO THE ORLANDO FIELD DISTRICT OFFICE AT 618 EAST SOUTH STREET, ORLANDO, FLORIDA 32801.
- 18. THE ABILGATION AREA MUST BE CONSTRUCTED IN ACCORDANCE WITH THE PLANS RECEIVED ON APRIL 26, 1991.
- 19. THIS PERMIT FOR CONSTRUCTION WILL EXPIRE FIVE YEARS FROM THE DATE OF ISSUANCE.
- 20. THE PERMITTEE SHALL TAKE ALL MEASURES NECESSARY TO CONTROL TURBIDITY, INCLUDED BUT NOT LIMITED TO, THE INSTALLATION OF TURBIDITY BARRIERS AT ALL LOCATIONS WHERE THE POSSIBILITY OF TRANSPORTING SUSPENDED SOLIDS INTO THE RECEIVING WATERBODY EXISTS DUE TO THE PROPOSED WORK. TURBIDITY BARRIERS MUST REMAIN IN EFFECTIVE CONDITION AT ALL LOCATIONS UNTIL CONSTRUCTION IS COMPLETED, AND DISTURBED SOILS ARE STABILIZED. THEREAFTER, THE PERMITTEE MUST REMOVE THE BARRIERS. AT NO TIME SHALL THERE BE ANY OFF-SITE DISCHARGE WHICH VIOLATES THE WATER QUALITY STANDARDS IN CHAPTER 17-302, FLORIDA

21. ALL WETLAND AREAS OR WATER BODIES WHICH ARE OUTSIDE OF THE SPECIFIC LIMITS OF CONSTRUCTION AUTHORIZED BY THIS PERMIT MUST BE PROTECTED FROM EROSION, SILTATION, SCOURING, OR EXCESS TURBIDITY OF DEWATERING.
22. THE PERMITTEE IS HEREBY ADVISED THAT PURSUANT TO SECTION 403.922, FLORIDA STATUTES NO PERSON SHALL COMMENCE ANY EXCAVATION, CONSTRUCTION, OR OTHER ACTIVITY INVOLVING THE USE OF SOVEREIGN OR OTHER LANDS OF THE STATE, TITLE TO WHICH IS VESTED IN THE BOARD OF TRUSTEES OF THE INTERNAL IMPROVEMENT TRUST FUND (BOARD TRUSTEES) OR THE DEPARTMENT OF NATURAL RESOURCES UNDER CHAPTER 253, F.S. UNTIL SUCH PERSON HAS RECEIVED FROM THE BOARD OF TRUSTEES OF THE INTERNAL IMPROVEMENT TRUST FUND, THE REQUIRED LEASE, LICENSE, EASEMENT, OR OTHER FORM OF CONSENT AUTHORIZING THE PROPOSED USE. PURSUANT TO CHAPTER 18-14, FLORIDA ADMINISTRATIVE CODE, IF DONE WITHOUT CONSENT, OR IF A PERSON OTHERWISE WILLFULLY DAMAGES STATE LAND OR WILLFULLY DAMAGES OR REMOVES PRODUCTS OF STATE LAND IN VIOLATION OF STATE OR FEDERAL LAW, THE BOARD OF TRUSTEES MAY LEVY ADMINISTRATIVE FINES UP TO \$10,000 PER OFFENSE.
23. IF HISTORICAL OR ARCHEOLOGICAL ARTIFACTS ARE DISCOVERED AT ANY TIME WITHIN THE PROJECT SITE, THE PERMITTEE SHALL IMMEDIATELY HALT CONSTRUCTION AND NOTIFY THE DISTRICT'S ORLANDO OFFICE AND THE DIVISION OF HISTORICAL RESOURCES, K.A. GRAY BUILDING, TALLAHASSEE, FLORIDA, 32399-0250.
24. THE PROJECT SHALL COMPLY WITH APPLICABLE STATE WATER QUALITY STANDARDS, NAMELY:
 - A. 17-302.300 - MINIMUM CRITERIA FOR ALL SURFACE WATERS AT ALL PLACES AND AT ALL TIMES;
 - B. 17-302.310 - SURFACE WATERS: GENERAL CRITERIA, AND,
 - C. 17-302.350 - CLASS III WATERS: RECREATION, PROPAGATION, AND MAINTENANCE OF A HEALTHY, WELL-BALANCED POPULATION OF FISH AND WILDLIFE.
25. GRASS AND MULCH OR SOD MUST BE INSTALLED AND MAINTAINED ON EXPOSED SLOPES MUST BE SEEDED AND MULCHED WITHIN 48 HOURS OF COMPLETING FINAL GRADE, AND AT ANY OTHER TIME TO PREVENT EROSION, SEDIMENTATION OR TURBID DISCHARGES INTO WATERS OF THE STATE.
26. AT LEAST 48 HOURS PRIOR TO THE COMMENCEMENT OF WORK AUTHORIZED BY THIS PERMIT, THE PERMITTEE MUST PROVIDE TWO WRITTEN COPIES OF WRITTEN NOTIFICATION OF THE SCHEDULED DATE OF COMMENCEMENT TO THE DISTRICT'S ORLANDO FIELD OFFICE.
27. ALL CONTRACTORS MUST BE PROVIDED A COPY OF THE PERMIT CONDITIONS BEFORE BEGINNING CONSTRUCTION.
28. PRIOR TO CONSTRUCTION, THE PERMITTEE MUST CLEARLY DELINEATE THE LIMITS OF CONSTRUCTION IN WATERS OF THE STATE. THE PERMITTEE MUST ADVISE THE CONTRACTOR THAT ANY WORK WITHIN WATERS OF THE STATE, OUTSIDE THE LIMITS OF CONSTRUCTION, INCLUDING CLEANING, IS A VIOLATION OF THIS PERMIT.
29. THE WATERS OF THE STATE LINES SHOWN ON THE ATTACHED PLANS ARE ONLY BINDING UPON THE DISTRICT AND THE DER IN THOSE SPECIFIC LOCATIONS WHERE DREDGING AND FILLING IS AUTHORIZED BY THIS PERMIT. THE PORTIONS OF THE WETLAND LINE SHOWN WHICH EXTEND BEYOND THE SCOPE OF WORK AUTHORIZED BY THIS PERMIT ARE FOR REFERENCE ONLY AND SHALL NOT BE RELIED UPON FOR FUTURE COMPLIANCE OF SECTION 403.913, F.S. NOR ANY OTHER PROVISION OF LAW OR RULE.

30. PRIOR TO INITIATING ANY CONSTRUCTION, THE PERMITTEE MUST RECORD A CONSERVATION EASEMENT ON THE REAL PROPERTY PURSUANT TO SECTION 704.06, F.S., PROHIBITING ALL CONSTRUCTION INCLUDING GRADING, DREDGING OR FILLING, EXCEPT THAT WHICH IS SPECIFICALLY AUTHORIZED BY THIS PERMIT OR WHICH MAY BE AUTHORIZED BY FUTURE DISTRICT PERMIT, WATERWARD OF THE WETLAND LIMITS LINES AS DELINEATED ON PLANS DATED AS RECEIVED ON APRIL 29, 1997. SAID EASEMENT MUST CONTAIN PROVISIONS AS SET FORTH IN SUBSECTION 1 (A) - (1) OF SECTION 704.06, F.S., AS WELL AS PROVISIONS INDICATING THAT THEY MAY BE ENFORCED BY THE DISTRICT AND MAY NOT BE AMENDED WITHOUT DISTRICT APPROVAL. WITHIN 30 DAYS OF THE DATE OF ISSUANCE OF THIS PERMIT AND PRIOR TO RECORDING, 2 COPIES OF SAID EASEMENT WITH SURVEY MUST BE SUBMITTED TO THE DISTRICT'S ORLANDO OFFICE FOR REVIEW AND APPROVAL. THE SURVEY MUST BE PERFORMED BY A REGISTERED PROFESSIONAL LAND SURVEYOR.

WITHIN 30 DAYS OF RECEIPT OF DISTRICT APPROVAL THE PERMITTEE MUST PROVIDE THE DISTRICT'S ORLANDO OFFICE 2 CERTIFIED COPIES OF THE RECORDED EASEMENT SHOWING THE DATE IT WAS RECORDED AND THE OFFICIAL RECORDS PLAT BOOK AND PAGE NUMBER.

31. THE WETLAND CREATION AREAS MUST BE PLANTED PRIOR TO ANY OF THE FOLLOWING EVENTS (WHICHEVER OCCURS FIRST): ISSUANCE OF THE FIRST CERTIFICATE OF OCCUPANCY; USE OF THE INFRASTRUCTURE FOR ITS INTENDED USE; OR TRANSFER OF RESPONSIBILITY FOR OPERATION AND MAINTENANCE OF THE SYSTEM TO A LOCAL GOVERNMENT OR OTHER RESPONSIBLE ENTITY.

32. WITHIN 30 DAYS OF COMPLETION OF INITIAL PLANTING, THE PERMITTEE MUST SUBMIT TO THE DISTRICT'S ORLANDO FIELD OFFICE, TWO (2) COPIES OF A PLAN DETAILING THE SITE-SPECIFIC METHODS TO BE USED FOR MONITORING THE WETLAND CREATION AREAS SO THAT ACHIEVEMENT OF SUCCESS CRITERIA CAN BE QUANTITATIVELY DEMONSTRATED. THE PLAN MUST INCLUDE SUCH INFORMATION AS THE SIZE, LOCATION AND NUMBER OF MONITORING QUADRANTS, THE LOCATION AND NUMBER OF PHOTOGRAPHIC STATIONS, THE LOCATION OF THE REFERENCE WETLAND(IF APPLICABLE), THE LOCATION OF STAFF GAUGE(S) AND PIEZOMETER(S) AND OTHER PERTINENT FACTORS TO DEMONSTRATE ACHIEVEMENT OF SUCCESS CRITERIA.

33. WITHIN THE WETLAND CREATION AREAS, NON-NATIVE VEGETATION, CATTAILS (TYPHA SPP.), AND PRIMROSE WILLOW (LUDWIGIA PERUVIANA), MUST BE HAND CONTROLLED BY HAND CLEARING OR OTHER MEANS RECEIVING WRITTEN APPROVAL BY THE DISTRICT SO THAT THEY CONSTITUTE NO MORE THAN 10% OF THE AREAL COVER IN EACH STRATUM AT ANY TIME.

34. THE PERMITTEE MUST FURNISH THE DISTRICT WITH TWO (2) MONITORING REPORTS FOR THE WETLAND CREATION AREA(S) DESCRIBING:

A. PERCENT SURVIVAL AND RECORDED GROWTH VIA ESTABLISHED PARAMETERS FOR PLANTED TREES AND SHRUBS;

B. PERCENT COVER FOR ALL SPECIES WITHIN EACH STRATUM;

C. TOTAL PERCENT COVER OF HERBACEOUS SPECIES;

D. GROUND AND SURFACE WATER MONITORING DATA INCLUDING:

1) SURFACE WATER ELEVATION REFERENCED TO N.G.V.D., OR IF SURFACE WATER IS NOT PRESENT, GROUND WATER REFERENCED TO N.G.V.D.; AND,

2) LOCATION OF STAFF GAUGE(S) OR PIEZOMETER (S), AND

3) DATE AND TIME OF MEASUREMENTS;

E. OBSERVATIONS OF WILDLIFE UTILIZATION;

F. PANORAMIC PHOTOGRAPHS OF THE MITIGATION SITE TAKEN FROM APPROVED PERMANENT STATIONS.

G. A DESCRIPTION OF ANY PROBLEMS ENCOUNTERED, INCLUDING REMOVAL OF ANY NON-TARGETED SPECIES, REPLACEMENT AND MAINTENANCE DATES, AND SOLUTIONS; AND,

H. ANY ANTICIPATED WORK FOR THE SUCCESSIVE SIX MONTH PERIOD FOLLOWING EACH ASSESSMENT.

THE DATA MUST BE COLLECTED AND SUBMITTED SEMI-ANNUALLY, ONCE DURING THE WET SEASON (AUGUST-SEPTEMBER) AND ONCE DURING THE DRY SEASON (MARCH-APRIL) UNTIL THE CREATED AREAS ACHIEVE THE SUCCESS CRITERIA.

33. SUCCESSFUL ESTABLISHMENT OF THE WETLAND CREATION AREA(S) WILL HAVE OCCURRED WHEN:

A. AT LEAST 80 PERCENT OF THE PLANTED INDIVIDUALS IN EACH STRATUM HAVE SURVIVED AND ARE SHOWING SIGNS OF NORMAL ANNUAL GROWTH, BASED UPON STANDARD GROWTH PARAMETERS SUCH AS HEIGHT AND BASE DIAMETER, OR CANOPY CIRCUMFERENCE;

B. AT LEAST 50 PERCENT COVER BY APPROPRIATE WETLAND HERBACEOUS SPECIES HAS BEEN OBTAINED; AND,

C. THE ABOVE CRITERIA HAS BEEN ACHIEVED BY THE END OF A FIVE (5) YEAR PERIOD FOLLOWING INITIAL PLANTING.

IF SUCCESSFUL ESTABLISHMENT HAS NOT OCCURRED AS STATED ABOVE, OR IS UNLIKELY BASED UPON THE MONITORING REPORTS OR TRENDS, THE PERMITTEE MUST WITHIN 30 DAYS, PROVIDE THE DISTRICT WITH A NARRATIVE DESCRIBING THE TYPE AND CAUSES OF FAILURE AND CONTAIN A COMPLETE SET OF PLANS FOR THE REDESIGN AND/OR REPLACEMENT PLANTING OF THE WETLAND CREATION SO THAT SUCCESS CRITERIA WILL BE ACHIEVED. WITHIN 30 DAYS OF DISTRICT APPROVAL AND ISSUANCE OF THE PERMIT MODIFICATION, THE PERMITTEE MUST IMPLEMENT THE REDESIGN AND/OR REPLACEMENT PLANTING. FOLLOWING COMPLETION OF SUCH WORK, SUCCESS CRITERIA AS STATED ABOVE OR MODIFIED BY SUBSEQUENT PERMIT MUST BE ACHIEVED. IN ADDITION, THE MONITORING REQUIRED BY THESE CONDITIONS MUST BE CONDUCTED.

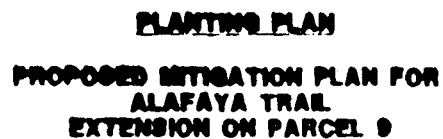
34. WITHIN 30 DAYS OF ANY MONITORING EVENT THAT INDICATES 50% OR GREATER MORTALITY OF PLANTED WETLAND SPECIES IN ANY STRATUM WITHIN THE MITIGATION AREA, THE APPLICANT MUST SUBMIT A REMEDIATION PROGRAM (TWO COPIES) FOR DISTRICT STAFF REVIEW AND APPROVAL.

35. THE PERMITTEE MUST SUBMIT TWO COPIES OF AN AS-BUILT SURVEY OF THE WETLAND CREATION AREA CERTIFIED BY A REGISTERED SURVEYOR OR PROFESSIONAL ENGINEER SHOWING DIMENSIONS, GRADE, GROUND ELEVATIONS, AND WATER SURFACE ELEVATIONS AND AN INVENTORY OF THE PLANTED SPECIES IN THE WETLAND CREATION AREA(S). THE INVENTORY MUST INCLUDE THE TYPE, NUMBER, DISTRIBUTION, AND SIZE (IF APPLICABLE) OF THE PLANTED VEGETATION, AND MUST BE REFERENCED TO THE AS-BUILT SURVEY. THE AS-BUILT SURVEY AND THE INVENTORY MUST BE SUBMITTED WITHIN THIRTY (30) DAYS OF COMPLETION OF INITIAL PLANTING.

36. THE PERMITTEE MUST PLANT HERBACEOUS WETLAND SPECIES, APPROVED BY DISTRICT STAFF, TO SUPPLEMENT GROUND COVER, IF NATURAL RECRUITMENT OF DESIRABLE SPECIES DOES NOT OCCUR IN THE COVER STRATUM. IF PLANTED, SUCH SPECIES MUST ACHIEVE 80% COVER AFTER A THREE YEAR PERIOD.

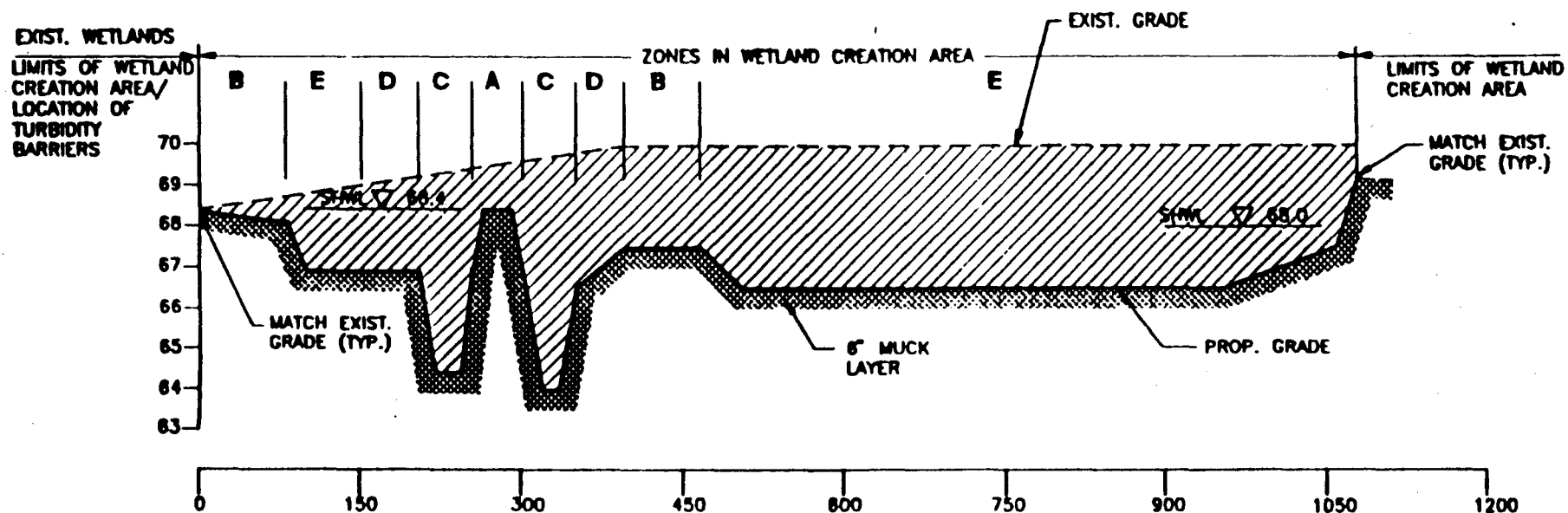
39. IRRIGATION AND FERTILIZATION OF THE WETLAND CREATION AREA MAY OCCUR IN THE FIRST YEAR AFTER INITIAL PLANTING IN ACCORDANCE WITH RULE 40C-27, F.A.C.
40. THE USE OF NON-NATIVE GRASSES, OR THE PLACEMENT OF SOO, IN THE WETLAND CREATION AREAS IS SPECIFICALLY PROHIBITED.
41. WITHIN SIX (6) MONTHS FROM THE DATE OF ISSUANCE OF THIS PERMIT AND PRIOR TO COMMENCEMENT OF ANY CONSTRUCTION, THE PERMITTEE SHALL FURNISH TO THE ST. JOHNS RIVER WATER MANAGEMENT DISTRICT A FINANCIAL STATEMENT IN ACCORDANCE WITH F.A.C. RULE 17-312.390 AS IT PRESENTLY EXISTS.
42. WITHIN SIX (6) MONTHS FROM THE DATE OF ISSUANCE OF THIS PERMIT AND PRIOR TO COMMENCEMENT OF ANY CONSTRUCTION, THE PERMITTEE SHALL FURNISH THE ST. JOHNS RIVER WATER MANAGEMENT DISTRICT WITH A FULLY EXECUTED AGREEMENT (REASONABLY SATISFACTORY TO THE ST. JOHNS RIVER WATER MANAGEMENT DISTRICT) BETWEEN THE PERMITTEE, ORANGE COUNTY AND/OR OTHER WHICH AGREEMENT SHALL:
(1) ALLOCATE ACCEPTANCE OF AND RESPONSIBILITY FOR THE OPERATION, MAINTENANCE AND MONITORING OF THE SURFACE WATER MANAGEMENT SYSTEM AND THE WETLAND CREATION AREAS; (2) SHALL SPECIFY THE TIME FRAMES IN WHICH THE PERMITTEE OR ORANGE COUNTY OR OTHER RESPONSIBLE PARTIES WILL PERFORM THE OPERATION, MAINTENANCE AND MONITORING OF THE SURFACE WATER MANAGEMENT SYSTEM AND THE WETLAND CREATION AREAS; (3) SHALL SPECIFY WHEN TRANSFER OF THIS PERMIT AND THE PERMIT CONDITIONS. OTHERWISE, THE PERMITTEE SHALL REMAIN FULLY RESPONSIBLE FOR THE OPERATION, MAINTENANCE AND MONITORING OF THE SURFACE WATER MANAGEMENT SYSTEM AND THE WETLAND CREATION AREAS.
43. PRIOR TO COMMENCEMENT OF ANY CONSTRUCTION, THE PERMITTEE SHALL ALSO FURNISH TO THE ST. JOHNS RIVER MANAGEMENT DISTRICT AN EXECUTED COPY OF THE CONSTRUCTION CONTRACT BETWEEN PERMITTEE AND ITS CONSTRUCTION CONTRACTOR (TO BE CHOSEN SOLELY BY PERMITTEE AT PERMITTEE'S SOLE DISCRETION) AND A COPY OF THE PAYMENT AND PERFORMANCE BOND REQUIRED TO BE PROVIDED BY THE CONTRACTOR TO THE PERMITTEE UNDER THE CONSTRUCTION CONTRACT. THE PAYMENT AND PERFORMANCE BOND SHALL BE IN THE AMOUNT OF THE ALAFAYA TRAIL EXTENSION IMPROVEMENTS INCLUDING THE CONSTRUCTION THE CONTRACTION OF THE WETLAND CREATION (MITIGATION) AREAS. THE PERMITTEE'S CONTRACT WITH ITS CONSTRUCTION CONTRACTOR IS NOT SUBJECT TO REVIEW BY THE ST. JOHNS RIVER WATER MANAGEMENT DISTRICT.
44. THE MITIGATION PLAN APPROVED BY THIS PERMIT IS TO COMPENSATE FOR WATERS OF THE STATE ENCKOACHMENTS FOR THE 1.9 MILE SEGMENT OF THE ALAFAYA TRAIL EXTENSION SOUTH TO THE ORLANDO UTILITIES COMMISSION (OUC) PROPERTY. IN ADDITION, THE MITIGATION PLAN PROVIDES COMPENSATION FOR ALL, OR PART, OF WATERS OF THE STATE ENCKOACHMENTS FOR THE REMAINING 2.3 MILES OF ALAFAYA TRAIL EXTENSION. THIS OFF-SITE COMPENSATION MAY BE USED BY THE APPLICANT TO MITIGATE FOR ALL, OR PART, OF FUTURE IMPACTS THAT MAY OCCUR AS A RESULT OF FUTURE IMPACTS THAT MAY OCCUR AS A RESULT OF FUTURE CONSTRUCTION WITHIN THE ALAFAYA TRAIL EXTENSION CORRIDOR. PROPOSED IMPACTS TO WATERS OF THE STATE, FOR THAT PORTION OF THE ALAFAYA TRAIL EXTENSION ON THE OUC PROPERTY, MUST BE EVALUATED AND APPROVED BY THE FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION IN ACCORDANCE WITH THE POWER PLANT SITING ACT CERTIFICATION (PA-87-14).

45. SINCE POTENTIALLY SIGNIFICANT ARCHAEOLOGICAL AND HISTORICAL SITES MAY BE PRESENT, PRIOR TO INITIATING ANY PROJECT RELATED LAND CLEARING OR GROUND DISTURBING ACTIVITIES WITHIN THE PROJECT AREA, THE SITE MUST BE SUBJECTED TO A SYSTEMATIC, PROFESSIONAL ARCHAEOLOGICAL AND HISTORICAL SURVEY. THE PURPOSE OF THIS SURVEY WILL BE TO LOCATE AND ASSESS THE SIGNIFICANCE OF CULTURAL RESOURCES PRESENT. THE RESULTANT SURVEY REPORT MUST BE FORWARDED TO THE FLORIDA DEPARTMENT OF STATE, DIVISION OF HISTORICAL RESOURCES (WITH 2 COPIES FORWARDED TO THE DISTRICT'S ORLANDO OFFICE) IN ORDER TO COMPLETE THE PROCESS OF REVIEWING THE IMPACTS OF THIS PROJECT ON ARCHAEOLOGICAL AND HISTORICAL RESOURCES.
46. DURING THE CONSTRUCTION OF THE 1.9 MILE PORTION OF THE TWO LANE EXTENSION OF ALAFAYA TRAIL AS PERMITTED HEREUNDER, THE PERMITTEE SHALL NOT UTILIZE HEAVY EARTH MOVING EQUIPMENT WITHIN 400 FEET OF ACTIVE RED CUCKADED WOODPECKER NEST TRENCH DURING THE BREEDING SEASON FROM APRIL 15 TO JULY 10.
47. PRIOR TO BEGINNING ANY CONSTRUCTION, THE NORTHERN PORTION OF THE ALAFAYA TRAIL EXPANSION PROPOSED TO CROSS THE ORLANDO UTILITY COMMISSION (OUC) STANTON POWER PLANT PROPERTY MUST BE APPROVED PURSUANT TO A MODIFICATION OF THE OUC'S CERTIFICATION UNDER THE FLORIDA ELECTRICAL POWER PLANT SITING ACT, CHAPTER 403 FLORIDA STATUTES.



DATE: APRIL 19, 1991

FIGURE 2



NOTE:
EXISTING GROUND ELEVATIONS ARE BASED ON
THE TOPOGRAPHIC SURVEY BY AERIAL
CARTOGRAPHICS OF AMERICA, MAY 29, 1986.
SEASONAL HIGH WATER ELEVATION IS BASED
ON THE WETLANDS HYDROLOGICAL DATA FROM
BREEDLOVE, DENNIS, AND ASSOCIATES, INC.

ZONES

- A WETLAND SHRUB ISLAND
- B FRESHWATER MARSH/WET PRAIRIE
- C DEEP WATER AQUATIC
- D SHALLOW WATER AQUATIC (LITTORAL ZONE)
- E CYPRESS DOMINATED WETLAND
- F MIXED HARDWOOD WETLAND

SHWL - SEASONAL HIGH WATER LEVEL



UPLAND EXCAVATION FOR
WETLAND CREATION

SECTION 1-1
PROPOSED MITIGATION PLAN FOR
ALAFAYA TRAIL
EXTENSION ON PARCEL 9

DATE: APRIL 19, 1991

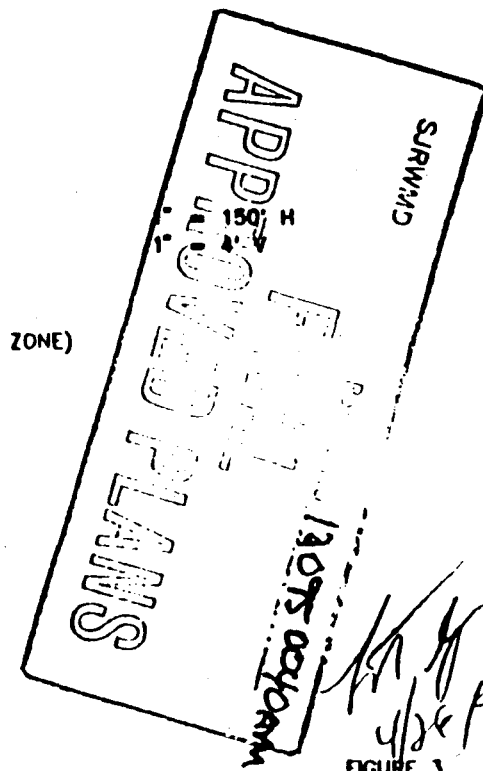
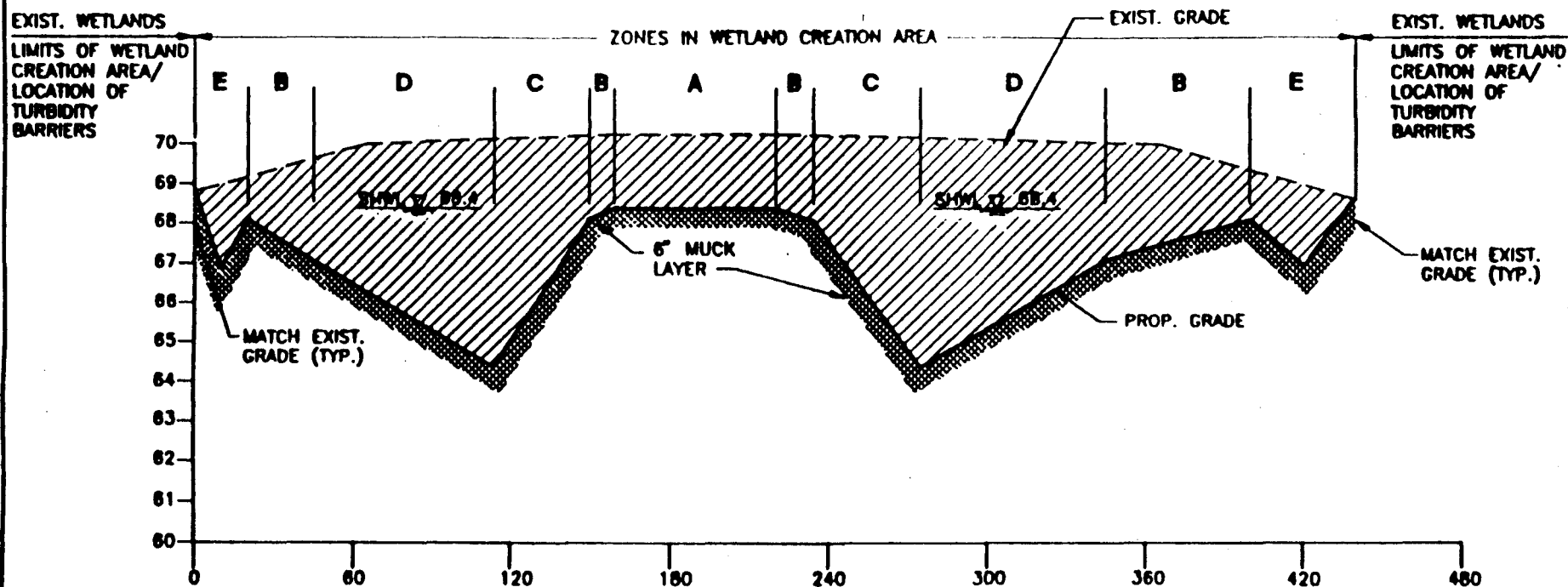


FIGURE 3

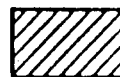


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- F MIXED HARDWOOD WETLAND

SHWL - SEASONAL HIGH WATER LEVEL

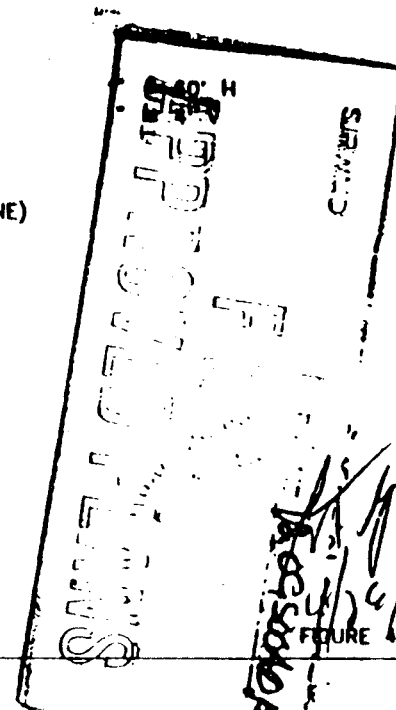


UPLAND EXCAVATION FOR
WETLAND CREATION

SECTION 2 - 2

PROPOSED MITIGATION PLAN FOR
ALAFAYA TRAIL
EXTENSION ON PARCEL 9

DATE: APRIL 19, 1991



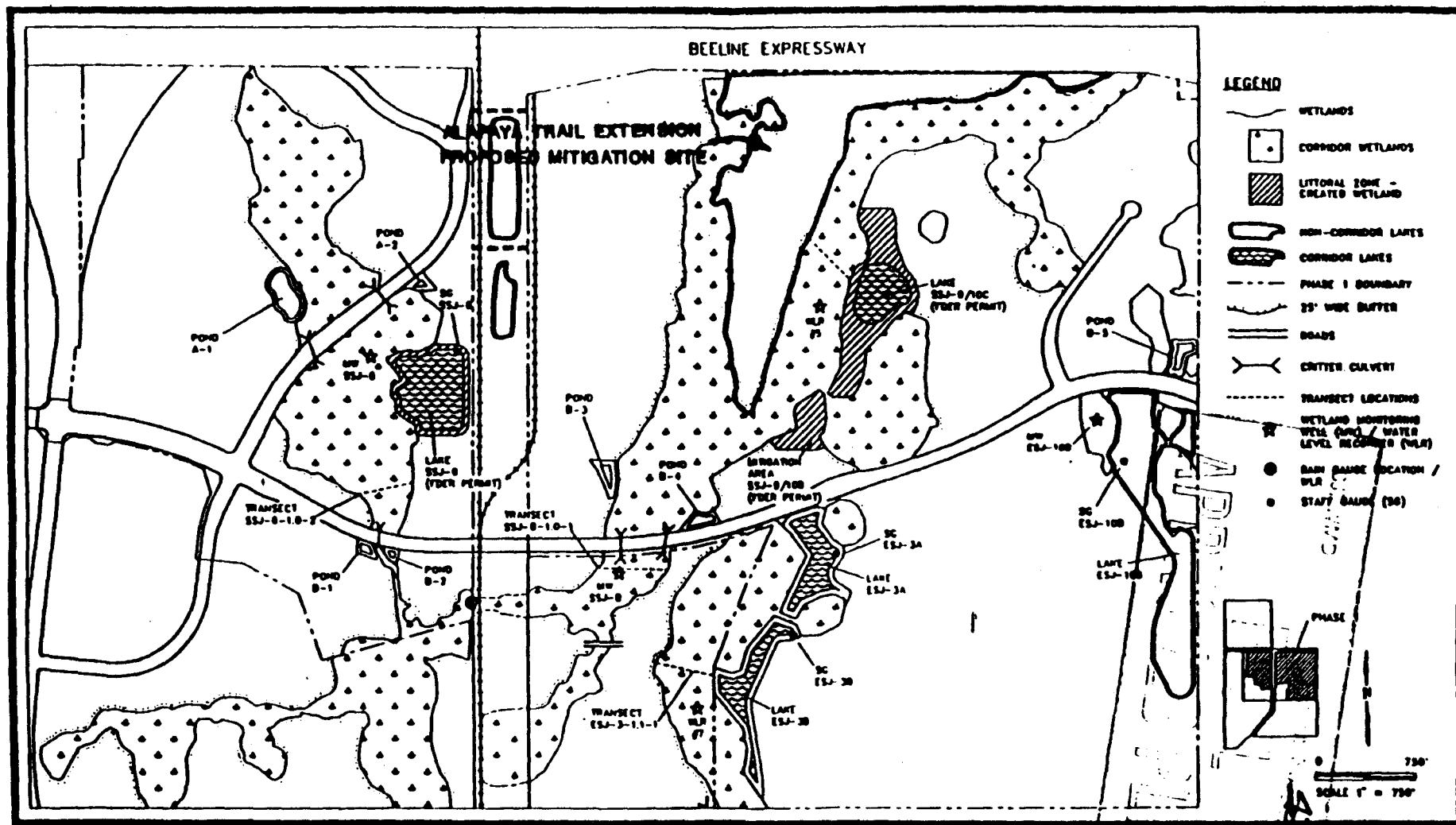


FIGURE 8 LOCATION OF THE WETLAND MONITORING TRANSECTS, WETLAND MONITORING WELLS, WATER LEVEL RECORDERS, RAIN GAUGE AND LAKE STAFF GAUGES IN PHASE I OF THE INTERNATIONAL CORPORATE PARK PROJECT SITE, ORANGE COUNTY, FLORIDA.

NOTE: ALL INFORMATION ON THIS FIGURE, EXCEPT THE ALAFAYA TRAIL EXTENSION PROPOSED MITIGATION SITE LOCATION, WAS DESIGNED AND PRODUCED BY BREEDLOVE, DENNIS AND ASSOCIATES, INC.

ATTACHMENT T

LOCATION OF PARCEL 1 SITE PARCEL 27

SURVIVED

Page 12

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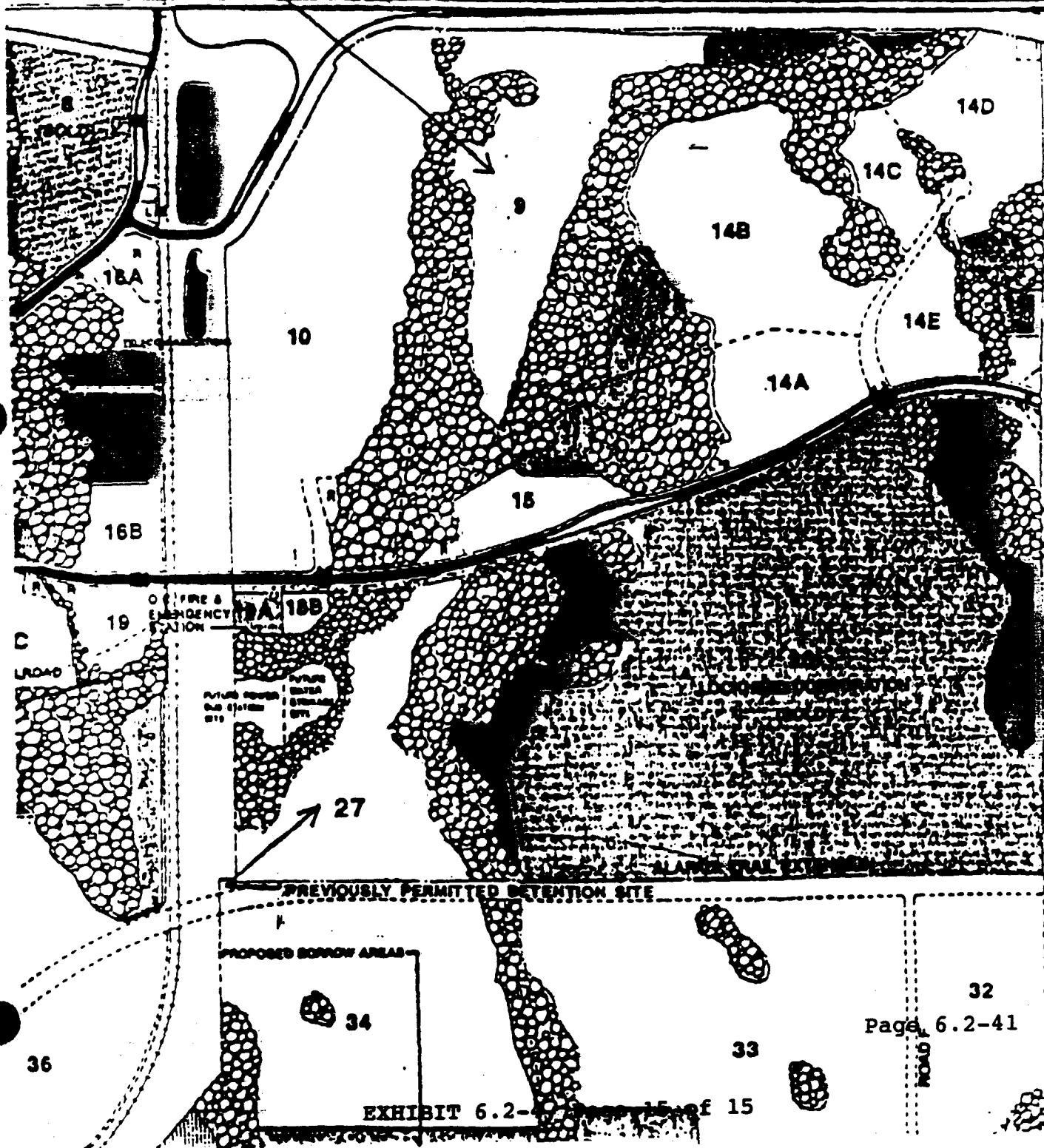
APPROVED
PROPOSED
ROAD

ENVIRONMENTAL

STATE OF CALIFORNIA

BEELINE EXPRESSWAY

PROPOSED DETENTION AND MITIGATION SITE





**WATER
MANAGEMENT
DISTRICT**

John R. Wehle, Assistant Executive Director

POST OFFICE BOX 1429 PALATKA, FLORIDA 32178-1429
TELEPHONE 904/329-4500 SUNCOM 904/850-4500
FAX (EXECUTIVE/BOAL) 329-4135 (PERMITTING) 329-4316 (ADMINISTRATION/FINANCE) 329-4504

FIELD STATIONS

618 E. South Street Orlando, Florida 32801 407/894-6423	7775 Baymeadows Way Suite 102 Jacksonville, Florida 32256 904/730-6270	PERMITTING: 306 East Drive Melbourne, Florida 32904 407/894-4940	OPERATIONS: 2133 N. Western Road Melbourne, Florida 32935-8105 407/254-1782
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JULY 9, 1991

INTERNATIONAL CORPORATE PARK
 ATTN: JAMES CLARK
 8246 ICP BOULEVARD
 ORLANDO, FL 32832

RECEIVED

SEP 23 1991

EMD

**SUBJECT: MANAGEMENT AND STORAGE OF SURFACE WATERS
 INDIVIDUAL PERMIT NUMBER 4-UYS-0035M2**

DEAR SIR/MADAM:

ENCLOSED IS YOUR PERMIT AS AUTHORIZED BY THE GOVERNING BOARD OF THE ST. JOHNS RIVER WATER MANAGEMENT DISTRICT ON JULY 9, 1991. THIS PERMIT WILL EXPIRE ON JULY 9, 1996.

THIS PERMIT IS A LEGAL DOCUMENT AND SHOULD BE KEPT WITH YOUR OTHER IMPORTANT DOCUMENTS. THE ATTACHED COMPLETION REPORT SHOULD BE FILLED IN AND RETURNED TO THE PALATKA OFFICE WITHIN THIRTY DAYS AFTER THE WORK IS COMPLETED. BY SO DOING, YOU WILL ENABLE US TO SCHEDULE A PROMPT INSPECTION OF THE PERMITTED ACTIVITY.

IN ADDITION TO THE COMPLETION REPORT, YOUR PERMIT ALSO CONTAINS CONDITIONS WHICH REQUIRE SUBMITTAL OF ADDITIONAL INFORMATION. ALL INFORMATION SUBMITTED AS COMPLIANCE TO PERMIT CONDITIONS MUST BE SUBMITTED TO THE PALATKA OFFICE ADDRESS.

PERMIT ISSUANCE DOES NOT RELIEVE YOU FROM THE RESPONSIBILITY OF OBTAINING PERMITS FROM ANY FEDERAL, STATE AND/OR LOCAL AGENCIES ASSERTING CONCURRENT JURISDICTION FOR THIS WORK.

IN THE EVENT YOU SELL YOUR PROPERTY, THE PERMIT WILL BE TRANSFERRED TO THE NEW OWNER, IF WE ARE NOTIFIED BY YOU WITHIN NINETY DAYS OF THE SALE. PLEASE ASSIST US IN THIS MATTER SO AS TO MAINTAIN A VALID PERMIT FOR THE NEW PROPERTY OWNER.

THANK YOU FOR YOUR COOPERATION AND IF THIS OFFICE CAN BE OF ANY FURTHER ASSISTANCE TO YOU, PLEASE DO NOT HESITATE TO CONTACT US.

SINCERELY,

Lacy Livingston

LACY LIVINGSTON, DATA CONTROL TECHNICIAN
 DIVISION OF RECORDS

ENCLOSURES: PERMIT WITH COMPLETION REPORT

CC: DISTRICT PERMIT FILE

Joe E. Hill, VICE CHAIRMAN	Joseph D. Collins, TREASURER	Merritt C. Fore, SECRETARY
EXHIBIT 642-5	Page 1 of 6	
Jesse J. Patton, III, AGENT OF BAY	Patricia L. Harden, SANFORD	Lenore N. McCullagh, ORANGE PARK
Titusville JUNEY	Ralph E. Simmons, FERNANDINA BEACH	James H. Wills, OCALA

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
POST OFFICE BOX 1429
PALATEKA, FLORIDA 32178-1429

PERMIT NO. 4-UY3-003382

DATE ISSUED JULI 2, 1991

A PERMIT AUTHORIZING:

THE MODIFICATION OF PERMIT #4-UY3-003382, ISSUED OCTOBER 9, 1990. THE MODIFICATION CONSISTS OF THE RELOCATION OF THE ALAPATA TRAIL AND AEROSPACE PARKWAY EXTENSION MITIGATION AREA, TO BE WITHIN THE ICP DEVELOPMENT.

LOCATION:

SECTION 7, TOWNSHIP SOUTH, RANGE EAST
ORANGE COUNTY

ISSUED TO:
(OWNER)

INTERNATIONAL CORPORATE PARK
8248 ICP BOULEVARD
ORLANDO, FL 32832

PERMITTEE AGREES TO HOLD AND SAVE THE ST. JOHNS RIVER WATER MANAGEMENT DISTRICT AND ITS SUCCESSORS HARMLESS FROM ANY AND ALL DAMAGES, CLAIMS, OR LIABILITIES WHICH MAY ARISE FROM PERMIT ISSUANCE. SAID APPLICATION, INCLUDING ALL PLANS AND SPECIFICATIONS ATTACHED THERETO, IS BY REFERENCE MADE A PART HEREOF.

THIS PERMIT DOES NOT CONVEY TO PERMITTEE ANY PROPERTY RIGHTS NOR ANY RIGHTS OR PRIVILEGES OTHER THAN THOSE SPECIFIED HEREIN, NOR RELIEVE THE PERMITTEE FROM COMPLYING WITH ANY LAW, REGULATION OR REQUIREMENT AFFECTING THE RIGHTS OF OTHER BODIES OR AGENCIES. ALL STRUCTURES AND WORKS INSTALLED BY PERMITTEE HEREUNDER SHALL REMAIN THE PROPERTY OF THE PERMITTEE.

THIS PERMIT MAY BE REVOKED, MODIFIED OR TRANSFERRED AT ANY TIME PURSUANT TO THE APPROPRIATE PROVISIONS OF CHAPTER 375, FLORIDA STATUTES:

PERMIT IS CONDITIONED UPON:

SEE CONDITIONS ON ATTACHED "EXHIBIT A", DATED JULY 9, 1991

AUTHORIZED BY: ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
DEPARTMENT OF RESOURCE MANAGEMENT

GOVERNING BOARD

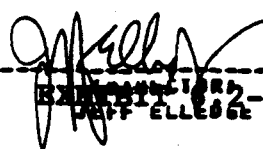
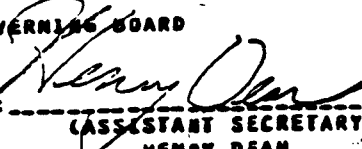
BY: 

EXHIBIT 2-5
JEFF ELLEDGE

BY: 

(ASSISTANT SECRETARY)
HENRY DEAN

Page 2 of 6

"EXHIBIT A"

CONDITIONS FOR ISSUANCE OF PERMIT NUMBER 4-U95-U035M2

INTERNATIONAL CORPORATE PARK

DATED JULY 9, 1991

1. PRIOR TO LOT OR UNIT SALES, OR UPON COMPLETION OF CONSTRUCTION OF THE SYSTEM, WHICHEVER OCCURS FIRST, THE DISTRICT MUST RECEIVE THE FINAL OPERATION AND MAINTENANCE DOCUMENT(S) APPROVED BY THE DISTRICT AND RECORDED, IF THE LATTER IS APPROPRIATE. FOR THOSE SYSTEMS WHICH ARE PROPOSED TO BE MAINTAINED BY COUNTY OR MUNICIPAL ENTITIES, FINAL OPERATION AND MAINTENANCE DOCUMENTS MUST BE RECEIVED BY THE DISTRICT WHEN MAINTENANCE AND OPERATION OF THE SYSTEM IS ACCEPTED BY THE LOCAL GOVERNMENT ENTITY. FAILURE TO SUBMIT THE APPROPRIATE FINAL DOCUMENT WILL RESULT IN THE PERMITTEE REMAINING PERSONALLY LIABLE FOR CARRYING OUT MAINTENANCE AND OPERATION OF THE PERMITTED SYSTEM.
2. ALL CONSTRUCTION, OPERATION AND MAINTENANCE SHALL BE AS SET FORTH IN THE PLANS, SPECIFICATIONS AND PERFORMANCE CRITERIA AS APPROVED BY THIS PERMIT.
3. DISTRICT AUTHORIZED STAFF, UPON PROPER IDENTIFICATION, WILL HAVE PERMISSION TO ENTER, INSPECT AND OBSERVE THE SYSTEM TO INSURE CONFORMITY WITH THE PLANS AND SPECIFICATIONS APPROVED BY THE PERMIT.
4. TURBIDITY BARRIERS MUST BE INSTALLED AT ALL LOCATIONS WHERE THE POSSIBILITY OF TRANSFERRING SUSPENDED SOLIDS INTO THE RECEIVING WATERBODY EXISTS DUE TO THE PROPOSED WORK. TURBIDITY BARRIERS MUST REMAIN IN PLACE AT ALL LOCATIONS UNTIL CONSTRUCTION IS COMPLETED AND SOILS ARE STABILIZED AND VEGETATION HAS BEEN ESTABLISHED. THEREAFTER THE PERMITTEE WILL BE RESPONSIBLE FOR THE REMOVAL OF THE BARRIERS.
5. THE OPERATION PHASE OF THE PERMIT SHALL NOT BECOME EFFECTIVE UNTIL A FLORIDA REGISTERED PROFESSIONAL ENGINEER CERTIFIES THAT ALL FACILITIES HAVE BEEN CONSTRUCTED IN ACCORDANCE WITH THE DESIGN APPROVED BY THE DISTRICT. WITHIN 30 DAYS AFTER COMPLETION OF CONSTRUCTION OF THE SURFACE WATER MANAGEMENT SYSTEM, THE PERMITTEE SHALL SUBMIT THE FOLLOWING: COMPLETION CERTIFICATION REPORT SIGNED AND SEALED BY THE P.E.; AND WHEN THE COMPLETED SYSTEM SUBSTANTIALLY DIFFERS FROM PERMITTED PLANS, TWO SETS OF RECORD (AS BUILT) PLANS WHICH REFLECT THE SURFACE WATER MANAGEMENT SYSTEM AS ACTUALLY CONSTRUCTED. THIS SUBMITTAL WILL SERVE TO NOTIFY THE DISTRICT STAFF THAT THE FACILITIES ARE READY FOR INSPECTION AND APPROVAL. THE PERMIT CANNOT BE TRANSFERRED TO THE RESPONSIBLE OPERATION AND MAINTENANCE ENTITY APPROVED BY THE DISTRICT UNTIL CONSTRUCTION OF THE COMPLETED SURFACE WATER MANAGEMENT SYSTEM IS APPROVED BY THE DISTRICT.
6. IF ANY OTHER REGULATORY AGENCY SHOULD REQUIRE REVISIONS OR MODIFICATION TO THE PERMITTED PROJECT, THE DISTRICT IS TO BE NOTIFIED OF THE REVISIONS SO THAT A DETERMINATION CAN BE MADE WHETHER A PERMIT MODIFICATION IS REQUIRED.
7. THE DISTRICT MUST BE NOTIFIED, IN WRITING, WITHIN 30 DAYS OF ANY SALE, CONVEYANCE, OR OTHER TRANSFER OF A PERMITTED SYSTEM OR FACILITY OR WITHIN 30 DAYS OF ANY TRANSFER OF OWNERSHIP OR CONTROL OF THE REAL PROPERTY AT WHICH THE PERMITTED SYSTEM OR FACILITY IS LOCATED. ALL TRANSFERS OF OWNERSHIP OR TRANSFERS OF A PERMIT ARE SUBJECT TO THE REQUIREMENTS OF CHAPTER 49C-1.
8. THE PERMITTEE MUST REQUIRE THE CONTRACTOR TO REVIEW AND MAINTAIN A COPY OF THIS PERMIT, COMPLETE WITH ALL CONDITIONS, ATTACHMENTS, EXHIBITS, AND PERMIT MODIFICATIONS IN GOOD CONDITION AND POSTED AT THE SAME LOCATION AS OTHER AGENCY PERMITS ON THE CONSTRUCTION SITE. **EXHIBIT 6-2-5** **Page 3 of 6** **Page 3 of 6** BE AVAILABLE FOR REVIEW UPON REQUEST BY DISTRICT REPRESENTATIVES.

9. THIS PERMIT FOR CONSTRUCTION WILL EXPIRE FIVE YEARS FROM THE DATE OF ISSUANCE.
10. CONSTRUCTION OR ALTERATION OF THE SURFACE WATER MANAGEMENT SYSTEM MUST BE COMPLETED AND ALL DISTURBED AREAS MUST BE STABILIZED IN ACCORDANCE WITH PERMITTED PLANS AND PERMIT CONDITIONS PRIOR TO ANY OF THE FOLLOWING EVENTS (WHICHEVER OCCURS FIRST): ISSUANCE OF A CERTIFICATE OF OCCUPANCY; USE OF THE INFRASTRUCTURE FOR ITS INTENDED USE; OR TRANSFER OF RESPONSIBILITY FOR OPERATION AND MAINTENANCE TO A LOCAL GOVERNMENT OR OTHER RESPONSIBLE ENTITY.
11. PERMITTEE MUST OBTAIN A GENERAL OR INDIVIDUAL PERMIT FROM THE DISTRICT PRIOR TO BEGINNING CONSTRUCTION OF SUBSEQUENT PHASES OR ANY OTHER WORK NOT SPECIFICALLY AUTHORIZED BY THIS PERMIT.
12. ALL WETLAND AREAS OR WATER BODIES THAT ARE OUTSIDE OF THE SPECIFIC LIMITS OF CONSTRUCTION AUTHORIZED BY THIS PERMIT MUST BE PROTECTED FROM EROSION, SILTATION, SCOURING OR EXCESS TURBIDITY, AND DOWATERING.
13. WITHIN THE WETLAND CREATION AREAS, NON-NATIVE VEGETATION, CATTAILS (ITPMA SPP.) AND PRIMROSE WILLOW (LUDWIGA PERUVIANNA), MUST BE CONTROLLED BY HAND CLEARING OR OTHER METHODS APPROVED BY THE DISTRICT SO THAT THEY CONSTITUTE NO MORE THAN 10% OF THE AREAL COVER IN EACH STRATUM.
14. ALL CORRESPONDENCE, SUBMITTALS, AND NOTIFICATIONS REQUIRED BY THE FOLLOWING PERMIT CONDITIONS MUST BE SUBMITTED TO THE ORLANDO FIELD DISTRICT OFFICE AT 618 EAST SOUTH STREET, ORLANDO FLORIDA 32807.
15. THE MITIGATION AREA MUST BE CONSTRUCTED IN ACCORDANCE WITH THE PLANS RECEIVED ON APRIL 26, 1991.
16. THE PERMITTEE SHALL TAKE ALL MEASURES NECESSARY TO CONTROL TURBIDITY, INCLUDING BUT NOT LIMITED TO, THE INSTALLATION OF TURBIDITY BARRIERS AT ALL LOCATIONS WHERE THE POSSIBILITY OF TRANSPORTING SUSPENDED SOLIDS INTO THE RECEIVING WATERBODY EXISTS DUE TO THE PROPOSED WORK. TURBIDITY BARRIERS MUST REMAIN IN EFFECTIVE CONDITION AT ALL LOCATIONS UNTIL CONSTRUCTION IS COMPLETED, AND DISTURBED SOILS ARE STABILIZED. THEREAFTER, THE PERMITTEE MUST REMOVE THE BARRIERS. AT NO TIME SHALL THERE BE ANY OFF-SITE DISCHARGE WHICH VIOLATES THE WATER QUALITY STANDARDS IN CHAPTER 17-322, FLORIDA ADMINISTRATIVE CODE.
17. GRASS AND MULCH OR SOG MUST BE INSTALLED AND MAINTAINED AND EXPOSED SLOPES MUST BE SEEDED AND MULCHED WITHIN 48 HOURS OF COMPLETING FINAL GRADE, AND AT ANY OTHER TIME TO PREVENT EROSION, SEDIMENTATION OR TURBID DISCHARGES INTO WATERS OF THE STATE.
18. AT LEAST 48 HOURS PRIOR TO THE COMMENCEMENT OF WORK AUTHORIZED BY THIS PERMIT, THE PERMITTEE MUST PROVIDE TWO WRITTEN COPIES OF WRITTEN NOTIFICATION OF THE SCHEDULED DATE OF COMMENCEMENT TO THE DISTRICT'S ORLANDO FIELD OFFICE.
19. ALL CONTRACTORS MUST BE PROVIDED A COPY OF THE PERMIT CONDITIONS BEFORE BEGINNING CONSTRUCTION.
20. PRIOR TO CONSTRUCTION, THE PERMITTEE MUST CLEARLY DELINEATE THE LIMITS OF CONSTRUCTION IN WATERS OF THE STATE. THE PERMITTEE MUST ADVISE THE CONTRACTOR THAT ANY WORK WITHIN WATERS OF THE STATE, OUTSIDE THE LIMITS OF CONSTRUCTION, INCLUDING LEAKING, IS A VIOLATION OF THIS PERMIT.

EXHIBIT 6.2-5 Page 4 of 6

21. PRIOR TO INITIATING ANY CONSTRUCTION, THE PERMITTEE MUST RECORD A CONSERVATION EASEMENT ON THE REAL PROPERTY PURSUANT TO SECTION 704.06, F.S., PROHIBITING ALL CONSTRUCTION INCLUDING GRADING, DREDGING OR FILLING, EXCEPT THAT WHICH IS SPECIFICALLY AUTHORIZED BY THIS PERMIT OR WHICH MAY BE AUTHORIZED BY FUTURE DISTRICT PERMIT, WATERWARD OF THE WETLAND LIMITS LINES AS DELINEATED ON PLANS DATED AS RECEIVED ON APRIL 20, 1991. SAID EASEMENT MUST CONTAIN PROVISIONS AS SET FORTH IN SUBSECTION 1 (A) - (1) OF SECTION 704.06, F.S., AS WELL AS PROVISIONS INDICATING THAT THEY MAY BE ENFORCED BY THE DISTRICT AND MAY NOT BE AMENDED WITHOUT DISTRICT APPROVAL. WITHIN 30 DAYS OF THE DATE OF ISSUANCE OF THIS PERMIT AND PRIOR TO RECORDING, EASEMENT WITH SURVEY MUST BE SUBMITTED TO THE DISTRICT'S ORLANDO OFFICE FOR REVIEW AND APPROVAL. THE SURVEY MUST BE PERFORMED BY A REGISTERED PROFESSIONAL LAND SURVEYOR.

WITHIN 30 DAYS OF RECEIPT OF DISTRICT APPROVAL, THE PERMITTEE MUST PROVIDE THE DISTRICT'S ORLANDO OFFICE 2 CERTIFIED COPIES OF THE RECORDED EASEMENT SHOWING THE DATE IT WAS RECORDED AND THE OFFICIAL RECORDS PLAT BOOK AND PAGE NUMBER.

22. WITHIN 30 DAYS OF COMPLETION OF INITIAL PLANTING, THE PERMITTEE MUST SUBMIT TO THE DISTRICT'S ORLANDO FIELD OFFICE, TWO (2) COPIES OF A PLAN DETAILING THE SITE-SPECIFIC METHODS TO BE USED FOR MONITORING THE WETLAND CREATION AREAS SO THAT ACHIEVEMENT OF SUCCESS CRITERIA CAN BE QUANTITATIVELY DEMONSTRATED. THE PLAN MUST INCLUDE SUCH INFORMATION AS THE SIZE, LOCATION AND NUMBER OF MONITORING QUADRANTS, THE LOCATION AND NUMBER OF PHOTOGRAPHIC STATIONS, THE LOCATION OF THE REFERENCE WETLAND(IF APPLICABLE), THE LOCATION OF STAFF GAUGE(S) AND PIEZOMETER(S) AND OTHER PERTINENT FACTORS TO DEMONSTRATE ACHIEVEMENT OF SUCCESS CRITERIA.

23. THE PERMITTEE MUST FURNISH THE DISTRICT WITH TWO (2) MONITORING REPORTS FOR THE WETLAND CREATION AREA(S) DESCRIBING:

- A. PERCENT SURVIVAL AND RECORDED GROWTH VIA ESTABLISHED PARAMETERS FOR PLANTED TREES AND SHRUBS;
- B. PERCENT COVER FOR ALL SPECIES WITHIN EACH STRATUM;
- C. TOTAL PERCENT COVER OF HERBACEOUS SPECIES;
- D. GROUND AND SURFACE WATER MONITORING DATA INCLUDING:
 - 1) SURFACE WATER ELEVATION REFERENCED TO M.G.V.D., OR IF SURFACE WATER IS NOT PRESENT, GROUND WATER REFERENCED TO M.G.V.D.;
 - 2) LOCATION OF STAFF GAUGE(S) OR PIEZOMETER(S); AND,
 - 3) DATE AND TIME OF MEASUREMENTS.
- E. OBSERVATIONS OF WILDLIFE UTILIZATION;
- F. PANORAMIC PHOTOGRAPHS OF THE MITIGATION SITE TAKEN FROM APPROVED PERMANENT STATIONS;
- G. A DESCRIPTION OF ANY PROBLEMS ENCOUNTERED, INCLUDING REMOVAL OF ANY NON-TARGETED SPECIES, REPLACEMENT AND MAINTENANCE DATES, AND SOLUTIONS; AND,
- H. AN EVALUATION OF THE SUCCESS OF THE SUCCESSIVE SIX MONTH PERIOD FOLLOWING EACH ASSESSMENT.

Exhibit 6.2-5 Page 5 of 6

THE DATA MUST BE COLLECTED AND SUBMITTED SEMI-ANNUALLY, ONCE DURING THE WET SEASON (AUGUST-SEPTEMBER) AND ONCE DURING THE DRY SEASON (MARCH-APRIL) UNTIL THE CREATED AREAS ACHIEVE THE SUCCESS CRITERIA.

24. SUCCESSFUL ESTABLISHMENT OF THE WETLAND CREATION AREA(S) WILL HAVE OCCURRED WHEN:

A. AT LEAST 80 PERCENT OF THE PLANTED INDIVIDUALS IN EACH SITUATION HAVE SURVIVED AND ARE SHOWING SIGNS OF NORMAL ANNUAL GROWTH FOR THREE CONSECUTIVE YEARS, BASED UPON STANDARD GROWTH PARAMETERS SUCH AS HEIGHT AND BASE DIAMETER, OR CANOPY CIRCUMFERENCE;

B. AT LEAST 80 PERCENT COVER BY APPROPRIATE WETLAND HERBACEOUS SPECIES HAS BEEN OBTAINED; AND,

C. THE ABOVE CRITERIA HAS BEEN ACHIEVED BY THE END OF A FIVE (5) YEAR PERIOD FOLLOWING INITIAL PLANTING.

IF SUCCESSFUL ESTABLISHMENT HAS NOT OCCURRED AS STATED ABOVE, OR IS UNLIKELY BASED UPON THE MONITORING REPORTS OR TRENDS, THE PERMITTEE MUST WITHIN 30 DAYS, PROVIDE THE DISTRICT WITH A NARRATIVE DESCRIBING THE TYPE AND CAUSES OF FAILURE AND CONTAIN A COMPLETE SET OF PLANS FOR THE REDESIGN AND/OR REPLACEMENT PLANTING OF THE WETLAND CREATION SO THAT SUCCESS CRITERIA WILL BE ACHIEVED. WITHIN 30 DAYS OF DISTRICT APPROVAL AND ISSUANCE OF THE PERMIT MODIFICATION, THE PERMITTEE MUST IMPLEMENT THE REDESIGN AND/OR REPLACEMENT PLANTING. FOLLOWING COMPLETION OF SUCH WORK, SUCCESS CRITERIA AS STATED ABOVE OR MODIFIED BY SUBSEQUENT PERMIT MUST BE ACHIEVED. IN ADDITION, THE MONITORING REQUIRED BY THESE CONDITIONS MUST BE CONDUCTED.

25. WITHIN 30 DAYS OF ANY MONITORING EVENT THAT INDICATES 50% OR GREATER MORTALITY OF PLANTED WETLAND SPECIES IN ANY SITUATION WITHIN THE MITIGATION AREA, THE APPLICANT MUST SUBMIT A REMEDIATION PROGRAM (TWO COPIES) FOR DISTRICT STAFF REVIEW AND APPROVAL.

26. THE PERMITTEE MUST SUBMIT TWO COPIES OF AN AS-BUILT SURVEY OF THE WETLAND CREATION AREA(S) CERTIFIED BY A REGISTERED SURVEYOR OR PROFESSIONAL ENGINEER SHOWING DIMENSIONS, GRADE, GROUND ELEVATIONS, AND WATER SURFACE ELEVATIONS AND AN INVENTORY OF THE PLANTED SPECIES IN THE WETLAND CREATION AREA(S). THE INVENTORY MUST INCLUDE THE TYPE, NUMBER, DISTRIBUTION, AND SIZE (IF APPLICABLE) OF VEGETATION, AND MUST BE REFERENCED TO THE AS-BUILT SURVEY. THE AS-BUILT SURVEY AND THE INVENTORY MUST BE SUBMITTED WITHIN THIRTY (30) DAYS OF COMPLETION OF INITIAL PLANTING.

27. THE PERMITTEE MUST PLANT HERBACEOUS WETLAND SPECIES, APPROVED BY DISTRICT STAFF, TO SUPPLEMENT GROUND COVER, IF NATURAL RECRUITMENT OF DESIRABLE SPECIES DOES NOT OCCUR IN THE COVER SITUATION OF THE WETLAND CREATION AREA. IF PLANTED, SUCH SPECIES MUST ACHIEVE 80% COVER AFTER A THREE YEAR PERIOD.

28. IRRIGATION AND FERTILIZATION OF THE WETLAND CREATION AREA MAY OCCUR IN THE FIRST YEAR AFTER INITIAL PLANTING IN ACCORDANCE WITH RULE 40C-27, F.A.C.

29. THE USE OF NON-NATIVE GRASSES, OR THE PLACEMENT OF SOB, IN THE WETLAND CREATION AREAS IS SPECIFICALLY PROHIBITED.

30. THIS PERMIT SUPERSEDES ANY CONDITIONS REGARDING MITIGATION THAT WERE APPROVED IN PERMIT 4-093-0033M.



DEPARTMENT OF THE ARMY
JACKSONVILLE DISTRICT CORPS OF ENGINEERS
P. O. BOX 4970
JACKSONVILLE, FLORIDA 32232-0019

REPLY TO
ATTENTION OF

SEP 20 1991

Regulatory Division
Central Permits Branch
199000060(IP-BL)

Mr. James L. Clark
ICP Associates
8248 International Corporate Park Boulevard
Orlando, Florida 32832

Dear Mr. Clark:

This letter refers to Department of the Army permit application number 199000060(IP-BL). The application is for 17.76 acres of wetland fill for the construction of Alafaya Trail from the present terminus to a point one-half mile south of the Bee Line Expressway in Orange County, Florida.

The Corps has completed the evaluation of your proposal and is in a position to issue your Department of the Army permit but by law cannot do so until the State of Florida has issued Section 401 Water Quality Certification for the project.

You must notify us in writing when you receive a State permit/certification and enclose a copy of the State permit/certification as well as any revised drawings illustrating project modifications. Upon receipt of State approval the Department of the Army permit will be issued, providing the State approval is furnished within two years of the date of this letter and there have been no significant changes in the Corps evaluation policies during that period nor any significant project modifications.

You are cautioned that commencement of the proposed work prior to Department of the Army authorization would constitute a violation of Federal laws and subject you to possible enforcement action. Receipt of a permit from the Florida Department of Environmental Regulation does not obviate the requirement for obtaining a Department of the Army permit prior to commencing the proposed work.

If you have any questions, please contact Ms. Beverlee Lawrence at the letterhead address or by telephone at (904) 791-2517.

Sincerely,

John R. Hall
Chief, Regulatory Division

RECEIVED

SEP 23 1991

EMD

January 8, 1990

Mr. Pat Frost
ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
618 E. South Street, Suite 200
Orlando, Florida 32801

Reference: **Alafaya Trail Extension
Dredge and Fill Permit Application**

Dear Mr. Frost:

International Corporate Park (ICP) plans to build an extension to Alafaya Trail in east Orange County which will consist of 4.2 miles of two-lane roadway improvements and a new bridge structure over the Bee Line Expressway. At the conclusion of construction, this roadway will be turned over to Orange County to comply with ICP's Development Order and to form an integral part of the County's future road system. The new alignment will adjoin the southern terminus of existing Alafaya Trail at the Orlando Utilities Commission Curtis H. Stanton Energy Center and will terminate 3,000 feet south of the Bee Line Expressway.

Enclosed are two (2) permit application packages for this project. Each package contains the following items:

1. A completed joint permit application with three (3) attachments.
2. Four (4) sets of permit drawings (one set has the original P.E. Certification).
3. Two (2) sets of blue-line aerials (1" = 300') of the project area.
4. One (1) set of aerials with the location of the red-cockaded woodpecker cavity trees in the project area.

Greiner

Mr. Pat Frost
January 8, 1990
Page Two

If you require additional information or have any questions, please do not hesitate to contact us.

Sincerely,

GREINER, INC.



Kathleen S. Hale, E.P.
Manager, Environmental Services

KSH:d
Enclosures

CC: Mr. Jim Clark, ICP, w/encl.
Mr. Ralph Smith, ICP, w/encl.
Mr. George Cole, Orange County, w/encl.
Mr. Joe Montalto, LEI, w/encl.
Mr. Greg Smith, Greiner, w/encl.

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

I N T E R N A T I O N A L C O R P O R A T E P A R K &
NAME

9 3 3 L E E R D S U I T E 4 0 0
STREET

O R L A N D O F L 3 2 8 1 0
CITY STATE ZIP

TELEPHONE NUMBER (Day) (407) 629-6660 (ICP) (Night) ()

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

Ms. Kathleen S. Hale
GREINER, INC.
225 E. Robinson St., Suite 255
Orlando, FL 32801-1913

Telephone Number (407) 422-0353

3. NAME OF WATERWAY AT LOCATION OF THE ACTIVITY.

Hart Branch, Cowpen Branch & Green Branch

DER Code _____
W/X Code _____

4. LOCATION WHERE PROPOSED ACTIVITY EXISTS OR WILL OCCUR

Bee Line Expwy-10.5 miles E. of SR 436
Street, road or other descriptive location

N/A
Incorporated city or town

Orange
County

18,19,29
30,32
Section Township Range
28°27'30" 81°08'15"
Latitude Longitude

Tax Assessors Descriptions (if known)

Map No. Subdiv. No. Lot No.

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

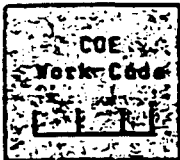
See Attachment "A" - Adjoining Property Owners

6. PROPOSED USE

Private Single Dwelling [] Private Multi-dwelling [] Public [X]
Commercial [] Other [] (Explain in remarks)

7. DESCRIPTION OF PROJECT (Use additional sheets, if necessary)

A. Structures: 1. New work ☒ Maintenance of existing structure ☐



2. Piers, docks and uses: 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 6'x24' arch culvert in Green Br., 2-1/2" RCP in Cowpen Br., 6'x20' arch culvert in Part Br.

4. Other type of structure _____

B. Excavation or Dredging: New Work ☒ Maintenance work ☐ Total acreage involved 1.37
2.67

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 Alafaya Trail Extension Length varies ft. Width varies ft. Depth varies ft.

4. Cubic yards: Total for project 13,893 ACOE
5,781 FDER
 a. 5,781 ACOE cyd. waterward/ 8,112 ACOE cyd. landward of ordinary/mean high water
 b. 1,795 (demucking) 9,417 (demucking) sand with silt and clayey sand

C. Fill:

1. Amount of material
3,712 FDER
18,997 ACOE
 a. Cubic yards placed waterward of ordinary/mean high water 1,795 (Backfilling)
8,711 FDER
 b. Cubic yards placed landward of ordinary/mean high water 106,957 ACOE
9,417 (Backfilling)
 c. Total acreage to be filled 2.43 FDER Total acreage of wetlands involved 2.43 FDER
16.16 ACOE 17.26 ACOE

2. Containment for fill

a. Dikes ☐ b. Seawall, etc. ☐ c. Other (please explain) On site

Uplands with vegetated slopes

3. Type of fill material to be used clean sand

4. Source of fill material to be used offsite uplands

8. Date activity is proposed to commence March 1990 ; to be completed July 1991.

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

A. Denied (date) _____

B. Issued (date) _____

C. Other (please explain) SJRWMD MSSW Permit Application to be submitted 1/9/90

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 Attachment "B" - Environmental Report

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)

☒ 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)

See Attachment "C"

James G. Clark
Signature

Sworn and subscribed before me at STATE OF FLORIDA, ORANGE County,
this 9th day of JANUARY, 1990.

Patricia A. Boden
Notary Public, State of Florida at Large
My Commission Expires September 17, 1990
Bounded thru Huckleberry & Associates

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 all of the required state, federal or local permits before 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.


Signature of Applicant

1-9-90
Date

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 NOT a Joint Permit!

You Must Obtain All Required Local, State, and Federal

Authorizations or Permits Before Commencing Work!!

For your information: 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.

ATTACHMENT "A"

ADJOINING PROPERTY OWNERS

D.O.C.

State of Florida
Dept. of Corrections
1311 Winewood Blvd.
Tallahassee, FL 32399-2500

Mr. Ned Terry 904/487-1330
Mr. Ralph Kenyon

O.U.C.

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

Mr. Wendell Dixon 407/423-9100

Deseret Ranches of Florida

Star Route
Box 1250
Melbourne, FL 32904

Mr. John King 407/892-5646

ATTACHMENT "B"
ENVIRONMENTAL REPORT

1. BACKGROUND

International Corporate Park (ICP) plans to extend Alafaya Trail from its present terminus near S.R. 50 to a point one-half mile south of the Bee Line Expressway. This work will consist of constructing 4.2 miles of two-lane rural roadway improvements for Alafaya Trail and a new bridge structure over the Bee Line Expressway.

Construction start date is based on the Development Order approved by Orange County. At the conclusion of this construction, these improvements will be turned over to Orange County in compliance with ICP's Development Order. Entities which will be served by this roadway extension include the Orlando Utilities Commission Curtis H. Stanton Power Plant, the Florida Department of Corrections prison facility and International Corporate Park, a 3,000-acre proposed business/industrial park.

2. PROJECT STATUS

Alafaya Trail is currently under final design with construction anticipated to begin in early 1990. Initially, only two lanes of Alafaya Trail will be built at first although at a later date, additional lanes will be added to form a divided four-lane roadway. The future Alafaya Trail/Bee Line Expressway interchange is expected to be constructed in the mid-1990s.

The proposed Alafaya Trail alignment was set after an exhaustive study to minimize environmental impacts to wetlands and protected wildlife such as the red-cockaded woodpecker. On May 1, 1989, a Public Hearing concerning this project was held before the Orange County Board of County Commissioners to brief interested parties on the project and to

gain the County's initial concurrence of the alignment and typical section before proceeding with the design work. The Commissioners voted to approve this alignment.

3. Previous permit activities within this project limit involved installation of two 24-inch diameter pipelines consisting of a water main and a force main. Permitting included State of Florida Department of Environmental Regulation Permit Number CS48-138524 covering the construction of the sewage collection/transmission system and a Nationwide Permit from the U.S. Army Corps of Engineers (87NW780363) for construction of the water main and wastewater force main. St. Johns River Water Management District did not require a permit for construction of these pipelines. A 90-foot right-of-way has been previously cleared for approximately two miles starting at the north end of the project.
4. As part of this project, approximately 2.43 acres of FDER jurisdictional wetlands, 20.29 acres of St. Johns River Water Management District jurisdictional wetlands and 17.26 acres of U.S. Army Corps of Engineers jurisdictional wetlands will be affected.
5. This project will require the following quantities of dredge and fill:

	<u>ACOE</u>	<u>FDER</u>	
Landward dredge	8,112 CY	0	CY
Waterward dredge	5,781 CY	5,781	CY
Landward fill	106,957 CY	8,711	CY
Waterward fill	18,997 CY	8,712	CY

5. Fill source(s) will be clean, compactible soil material from an upland source.

6. All necessary turbidity and erosion control measures will be implemented during construction to minimize water quality degradation on adjacent wetlands. Visual monitoring for potential turbidity problems will be conducted throughout the construction activities.
7. During construction, all bare ground will be seeded, sodded and/or otherwise appropriately treated to prevent runoff of suspended solids into adjacent water bodies.
8. Attached is Table 1 listing each wetland by agency jurisdiction with the amount of wetland encroachment (by acreage) and the wetland vegetation community affected by the Alafaya Trail Extension.

Table 1
ALAFAYA TRAIL JURISDICTIONAL WETLANDS

Wetland Number ^a	FLUCFCS Category ^b	Project Impact Acreage	Agency Jurisdiction ^c
3	621	0.23	ACOE, SJRWMD
4	621	0.07	ACOE, SJRWMD
5	643	0.05	ACOE, SJRWMD
5A	621	0.32	SJRWMD
7B	621	0.06	ACOE, SJRWMD
10	630	0.41	ACOE, SJRWMD FDER
10	630	0.13	SJRWMD, FDER
11	621	0.09	ACOE, SJRWMD
11	621	0.71	SJRWMD
12	621	0.55	ACOE, SJRWMD
12	643	0.41	SJRWMD
13	621	0.56	ACOE, SJRWMD FDER
13	621	0.32	SJRWMD
14	621	0.50	ACOE, SJRWMD FDER
15	621	0.58	ACOE, SJRWMD
15	643	0.20	ACOE, SJRWMD
16	621	0.87	ACOE, SJRWMD
17	643	0.35	ACOE, SJRWMD
20	621	0.21	ACOE, SJRWMD
21	621	0.03	ACOE, SJRWMD
23B	643	0.16	ACOE, SJRWMD
24	621	1.14	ACOE, SJRWMD
25	621	0.83	ACOE, SJRWMD FDER
26	510	0.17	ACOE
26A	643	0.06	ACOE
27	510	0.03	ACOE
29	643	0.25	ACOE
31	510	0.04	ACOE
32	510	0.09	ACOE
41A	643	0.13	ACOE
41B	643	0.26	SJRWMD
42	643	0.08	ACOE, SJRWMD
43	643	1.38	ACOE, SJRWMD
43		0.67	SJRWMD, FDER
44	643	0.97	ACOE, SJRWMD
45	643	0.27	ACOE, SJRWMD
46	643	0.15	ACOE, SJRWMD
47	643	2.58	ACOE, SJRWMD

Wetland Number ^a	FLUCFCS Category ^b	Project Impact Acreage	Agency Jurisdiction ^c
48	643	0.60	ACOE, SJRWMD
48	643	0.16	SJRWMD
49	643	0.41	ACOE, SJRWMD
50	643	0.40	ACOE, SJRWMD
51	643	0.35	ACOE, SJRWMD
52	643	1.34	ACOE, SJRWMD
52	643	0.23	SJRWMD
53	643	0.97	ACOE, SJRWMD
54	643	0.37	SJRWMD
55	643	0.11	SJRWMD

TOTAL IMPACT (AC):

	510	621	630	643	TOTAL
ACOE	0.38	5.72	0.41	10.75	17.26
SJRWMD	--	7.07	0.54	12.68	20.29
FDER	--	1.89	0.54	--	2.43

^aSee Permit Drawings (Sheet 2 of 15) for location of Wetlands

^b510 - Drainage Ditch
621 - Cypress
630 - Mixed wetland forest
643 - Wet prairie

^cACOE - Army Corps of Engineers
SJRWMD - St. Johns River Water Management District
FDER - Florida Department of Environmental Regulation

ATTACHMENT "C"

LEGAL DESCRIPTIONS

Legal Description: Interchange North of Bee Line

Commence at the Southwest corner of Section 29, Township 23 South, Range 32 East, Orange County, Florida; thence run N.00°04'38"W. along the West line of the Southwest 1/4 of said Section 29 a distance of 64.19 feet to a point on the North right of way line of the Bee Line Expressway (S.R. 528); thence leaving said West line run N.78°29'51"E. along aforementioned North right of way line a distance of 333.58 feet for a POINT OF BEGINNING; said point also being on a curve concave Northwesterly having a radius of 864.93 feet and a central angle of 13°31'01"; thence leaving said Northerly right of way from a tangent bearing of N.58°57'30"E. run Northeasterly along the arc of said curve a distance of 204.05 feet to the point of tangency; thence run N.45°26'30"E. 564.35 feet to the point of curvature of a curve concave Southeasterly having a radius of 640.00 feet and a central angle of 26°02'37"; thence run Easterly along the arc of said curve 290.91 feet to the point of tangency; thence run N.71°29'07"E. 395.54 feet to the point of curvature of a curve concave Northwesterly having a radius of 460.00 feet and a central angle of 67°13'46"; thence run Northerly along the arc of said curve a distance of 539.75 feet to the point of tangency; thence run N.04°15'21"E. 460.03 feet; thence run N.00°26'30"E. 100.00 feet; thence run S.89°33'30"E. 47.20 feet; thence run N.00°26'30"E. 49.94 feet to the point of curvature of a curve concave Southwesterly having a radius of 2,201.83 feet and a central angle of 26°55'05"; thence run Northwesterly along the arc of said curve a distance of 1,034.44 feet; thence leaving said curve run S.61°10'52"W. 1,454.96 feet to the point of curvature of a curve concave Southeasterly having a radius of 910.00 feet and a central angle of 20°36'38"; thence run Southwesterly along the arc of said curve a distance of 327.35 feet to the point of tangency; thence run S.40°34'14"W. 230.78 feet to a point on the aforementioned West line of the Southwest 1/4 of Section 29; thence run N.00°04'38"W. along said West line of the Southwest 1/4 of Section 29 a distance of 276.32 feet; thence leaving said West line run N.40°34'14"E. 21.12 feet to the point of curvature of a curve concave Southeasterly having a radius of 1,090.00 feet and a central angle of 20°36'38"; thence run Northeasterly along the arc of said curve a distance of 392.09 feet to the point of tangency; thence run N.61°10'52"E. 1,454.96 feet to a point on a curve concave Southwesterly having a radius of 2,201.83 feet and a central angle of 26°55'05"; thence from a chord bearing of N.44°37'14"W. run Northwesterly along the arc of said curve a distance of 1,034.44 feet to the point of tangency; thence run N.58°04'47"W. 1,017.85 feet to a point on the West line of the Northwest 1/4 of the aforementioned Section 29; thence run N.00°15'55"E. along said West line of the Northwest 1/4 of Section 29 a distance of 211.46 feet; thence leaving said West line run S.58°04'47"E. 1,128.83 feet to the point of curvature of a curve concave Southwesterly having a radius of 2,381.83 feet and a central angle of 58°31'17"; thence run Southeasterly along the arc of said curve a distance of 2,432.78 feet to the point of tangency; thence run S.89°33'30"E. 50.49 feet; thence run S.01°50'56"E. 541.33 feet to the point of curvature of a curve concave Northeasterly having a radius of 460.00 feet and a central angle of 42°42'34"; thence run Southeasterly along the arc of said curve a distance of 342.89 feet to the point of tangency; thence run S.44°53'34"E. 1,216.48 feet to the point of curvature of a curve concave Northeasterly having a radius of 626.20 feet and a central angle of 45°00'00"; thence run Southeasterly along the arc of said curve a distance of 491.81 feet to the point of tangency; thence run S.89°33'30"E. 909.80 feet to a point on the South line of the aforementioned Section 29; thence run S.89°35'34"W. along the South line of said Section 29 a distance of 2,436.71 feet to a point on the North right of way line of the Bee Line Expressway (S.R. 528); thence leaving said South line of Section 29 run the following courses and distances along said North right of way line: N.78°00'30"W. 1,151.69 feet; thence run S.78°29'51"W. 617.85 feet to the POINT OF BEGINNING.

Containing 71.189 acres, more or less.

LEGAL DESCRIPTION SECTION 32

Begin at the Southwest corner of Section 32, Township 23 South, Range 32 East, Orange County, Florida; thence run N.00°00'48"W. along the West line of the Southwest 1/4 of said Section 32 a distance of 30.00 feet to a point on a curve concave Northwesterly having a radius of 1,875.81 feet and a central angle of 89°21'32"; thence leaving said West line from a tangent bearing of N.89°48'02"E. run Northeasterly along the arc of said curve a distance of 2,925.53 feet to the point of tangency; thence run N.00°26'30"E. 382.18 feet to a point of curvature of a curve concave Southwesterly having a radius of 25.00 feet and a central angle of 90°00'00"; thence run Northwesterly along the arc of said curve a distance of 39.27 feet to the point of tangency; thence run N.89°33'30"W. 116.12 feet to the point of curvature of a curve concave Northeasterly having a radius of 2,339.83 feet and a central angle of 24°42'48"; thence run Northwesterly along the arc of said curve a distance of 1,009.23 feet to the point of tangency; thence run N.64°50'42"W. 815.73 feet to the point of curvature of a curve concave Southwesterly having a radius of 1,225.24 feet and a central angle of 00°52'29"; thence run Northwesterly along the arc of said curve a distance of 18.71 feet to a point on said curve said point also being on the West line of the Southwest 1/4 of said Section 32; thence leaving said curve run N.00°00'48"W. along the West line of the Southwest 1/4 of said Section 32 a distance of 53.07 feet to the West 1/4 corner of said Section 32; thence run N.00°09'42"E. along the West line of the Northwest 1/4 of said Section 32 a distance of 79.47 feet to a point on a curve concave Southwesterly having a radius of 1,347.24 feet and a central angle of 09°27'16"; thence leaving said West line from a tangent bearing of S.68°01'48"E. run Southeasterly along the arc of said curve 222.31 feet to the point of reverse curvature of a curve concave Northeasterly having a radius of 3,000.00 feet and a central angle of 06°16'10"; thence run Southeasterly along the arc of said curve 328.27 feet to the point of tangency; thence run S.64°50'42"E. 230.96 feet to the point of curvature of a curve concave Northeasterly having a radius of 2,243.83 feet and a central angle of 24°42'48"; thence run Southeasterly along the arc of said curve a distance of 967.82 feet to the point of tangency; thence run S.89°33'30"E. 216.07 feet to the point of curvature of a curve concave Northwesterly having a radius of 25.00 feet and a central angle of 90°00'00"; thence run Northeasterly along the arc of said curve a distance of 39.27 feet to the point of tangency; thence run N.00°26'30"E. 689.99 feet; thence run N.89°33'30"W. 47.07 feet; thence run N.00°26'30"E. 100.00 feet; thence run N.01°50'56"W. 626.90 feet to the point of curvature of a curve concave Southwesterly having a radius of 460.00 feet and a central angle of 68°45'11"; thence run

Northwesterly along the arc of said curve a distance of 551.9 feet to the point of tangency; thence run N.70°36'07"W. 400.84 feet to the point of curvature of a curve concave Northeasterly having a radius of 640.00 feet and a central angle of 26°02'37"; thence run Northwesterly along the arc of said curve a distance of 290.91 feet to the point of tangency; thence run N.44°33'30"W. 353.36 feet to the point of curvature of a curve concave Southwesterly having a radius of 1,342.40 feet and a central angle of 25°23'15"; thence run Northwesterly along the arc of said curve a distance of 594.81 feet to a point on said curve and on the South right of way line of the Bee Line Expressway (S.R. 528); thence leaving said curve run the following courses and distance along said South right of way line; thence run S.77°36'51"E. 811.60 feet; thence run N.78°29'51"E. 1,328.77 feet; thence run S.89°33'30"E. 5,430.32 feet; thence leaving said right of way line run S.89°17'45"W. 1,718.43 feet to the point of curvature of a curve concave Southeasterly having a radius of 5,639.58 feet and a central angle of 03°06'15"; thence run Southwesterly along the arc of said curve a distance of 305.55 feet to the point of reverse curvature of a curve concave Northwesterly having a radius of 11,549.16 feet and a central angle of 04°15'00"; thence run Southwesterly along the arc of said curve a distance of 856.68 feet to the point of tangency; thence run N.89°33'30"W. 1,265.00 feet to the point of curvature of a curve concave Southeasterly having a radius of 460.00 feet and a central angle of 45°00'00"; thence run Southwesterly along the arc of said curve a distance of 361.28 feet to the point of tangency; thence run S.45°26'30"W. 1,285.30 feet to the point of curvature of a curve concave Southeasterly having a radius of 460.00 feet and a central angle of 41°11'09"; thence run Southwesterly along the arc of said curve a distance of 330.66 feet to the point of tangency; thence run S.04°15'21"W. 460.03 feet; thence run S.00°26'30"W. 100.00 feet; thence run N.89°33'30"W. 47.20 feet; thence run S.00°26'30"W. 1,384.63 feet to the point of curvature of a curve concave Northwesterly having a radius of 2,055.81 feet and a central angle of 89°20'10"; thence run Southwesterly along the arc of said curve a distance of 3,205.44 feet to a point on said curve, said point also being on the West line of the Northwest 1/4 of Section 5, Township 24 South, Range 32 East Orange County, Florida; thence run N.00°32'51"W. along said West line a distance of 150.00 feet to the POINT OF BEGINNING;

Together with

Begin at the Northwest corner of Section 33, Township 23 South, Range 32 East, Orange County, Florida; thence run S.89°03'58"E. along the North line of the Northwest 1/4 of said Section 33 a distance of 1,405.12 feet; thence leaving said North line run S.00°26'30"W. 80.35 feet to the North right of way line of the Bee Line Expressway (S.R. 528); thence run the following courses and distances along said North right of way line; thence run N.89°33'30"W. 4,480.51 feet; thence run N.00°26'30"E. 9.33 feet; thence run N.78°00'30"W. 175.03 feet to a point on the North line of Section 32, Township 23 South, Range 32 East, Orange County, Florida; thence run N.89°35'38"E. along said North line a distance of 3,247.19 feet to the POINT OF BEGINNING.

Containing 87.405 acres, more or less.

LEGAL DESCRIPTION SECTION 30

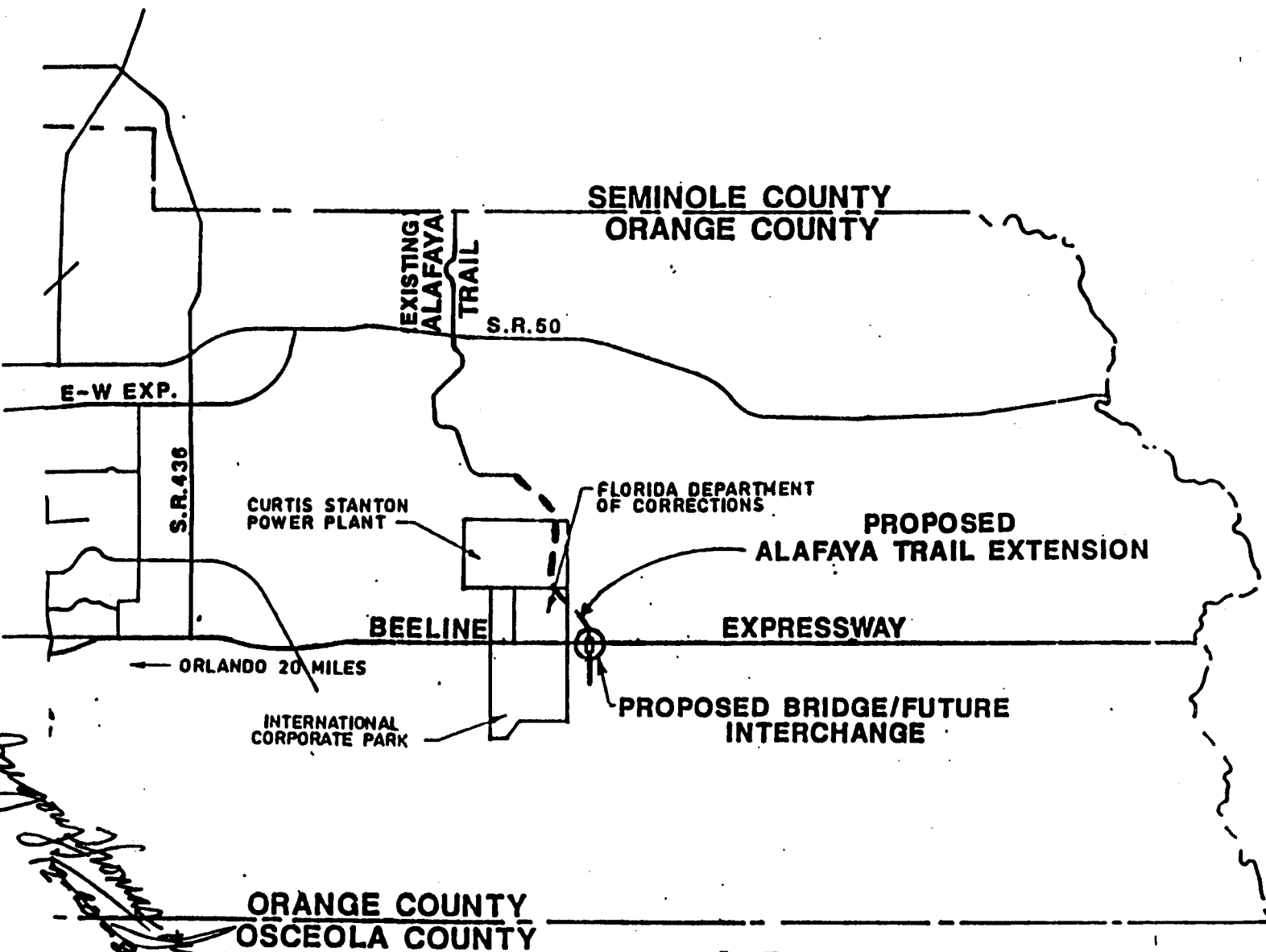
Right of Way description (180 foot wide) Alafaya Trail Extension situate in the Northeast 1/4 of Section 30, Township 23 South, Range 32 East, Orange County, Florida; being more particularly bounded and described as follows:

Commence at the Northeast corner of Section 30, Township 23 South, Range 32 East, Orange County, Florida; thence run S.00 15'55"W. along the East line of the Northeast 1/4 of said Section 30 a distance of 742.18 feet for a POINT OF BEGINNING; thence continue S.00 15'55"W. along said East line a distance of 211.46 feet; thence leaving said line run N.58 04'47"W. 1,027.60 feet to the point of curvature of a curve concave Northeasterly having a radius of 2,173.48 feet and a central angle of 16 39'34"; thence run Northwesterly along the arc of said curve 631.97 feet to a point on the North line of the Northeast 1/4 of said Section 30; thence leaving said curve run N.89 51'23"E. along said North line of Section 30 a distance of 248.49 feet to a point on a curve concave Northeasterly having a radius of 1,993.48 feet and a central angle of 11 56'34"; thence from a tangent bearing of S.46 08'13"E. run Southeasterly along the arc of said curve 415.52 feet to the point of tangency; thence run S.58 04'47"E. 916.63 feet to the POINT OF BEGINNING.

LEGAL DESCRIPTION SECTIONS 18 & 19

Centerline description of a portion of Alafuya Trail extension situate in Section 18 and 19, Township 23 South, Range 32 East, Orange County, Florida; the right of way of said road lying 90 feet right and 90 feet left of the following described centerline said centerline being more particularly described as follows:

Commence at the Northwest corner of Section 18, Township 23 South, Range 32 East, Orange County, Florida; thence run N.89°51'54"E. along the North line of the Northwest 1/4 of Section 18, Township 23 South, Range 32 East, Orange County, Florida, a distance of 924.99 feet to the POINT OF BEGINNING of the centerline of this description; thence along said centerline run S.00°02'52"W. a distance of 10.31 feet to the point of curvature of a curve concave Northeasterly having a radius of 1,762.95 feet and a central angle of 42°43'57"; thence run Southeasterly along the arc of said curve 1,314.85 feet to the point of tangency; thence run S.42°41'05"E. 3,365.36 feet to the point of curvature of a curve concave Southwesterly having a radius of 3,274.05 feet and a central angle of 32°12'44"; thence run Southeasterly along the arc of said curve 1,840.71 feet to a point on the South line of the Southeast 1/4 of Section 18, Township 23 South, Range 32 East, said point also being S.89°48'48"W. a distance of 849.02 feet from the Southeast corner of said Section 18; thence continue along the arc of said curve through a central angle of 37°09'56"; a distance of 2,123.74 feet to the point of tangency; thence run S.26°41'35"W. 979.10 feet to the point of curvature of a curve concave Easterly having a central angle of 70°19'25"; thence run Southerly along the arc of said curve having a radius of 2,083.48 feet, a distance of 2,557.23 feet to the South line of the Southeast 1/4 of said Section 19 and the POINT OF TERMINATION of said centerline; said point being S.89°51'23"W. a distance of 1,235.45 feet from the Southeast corner of Section 19, Township 23 South, Range 32 East; the side lines of said right of way to terminate on the North line of said Section 18 and on the South line of Section 19.



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SHEET: 1 OF: 15

Greiner, Inc.

CONSULTING ENGINEERS

ALAFAYA TRAIL

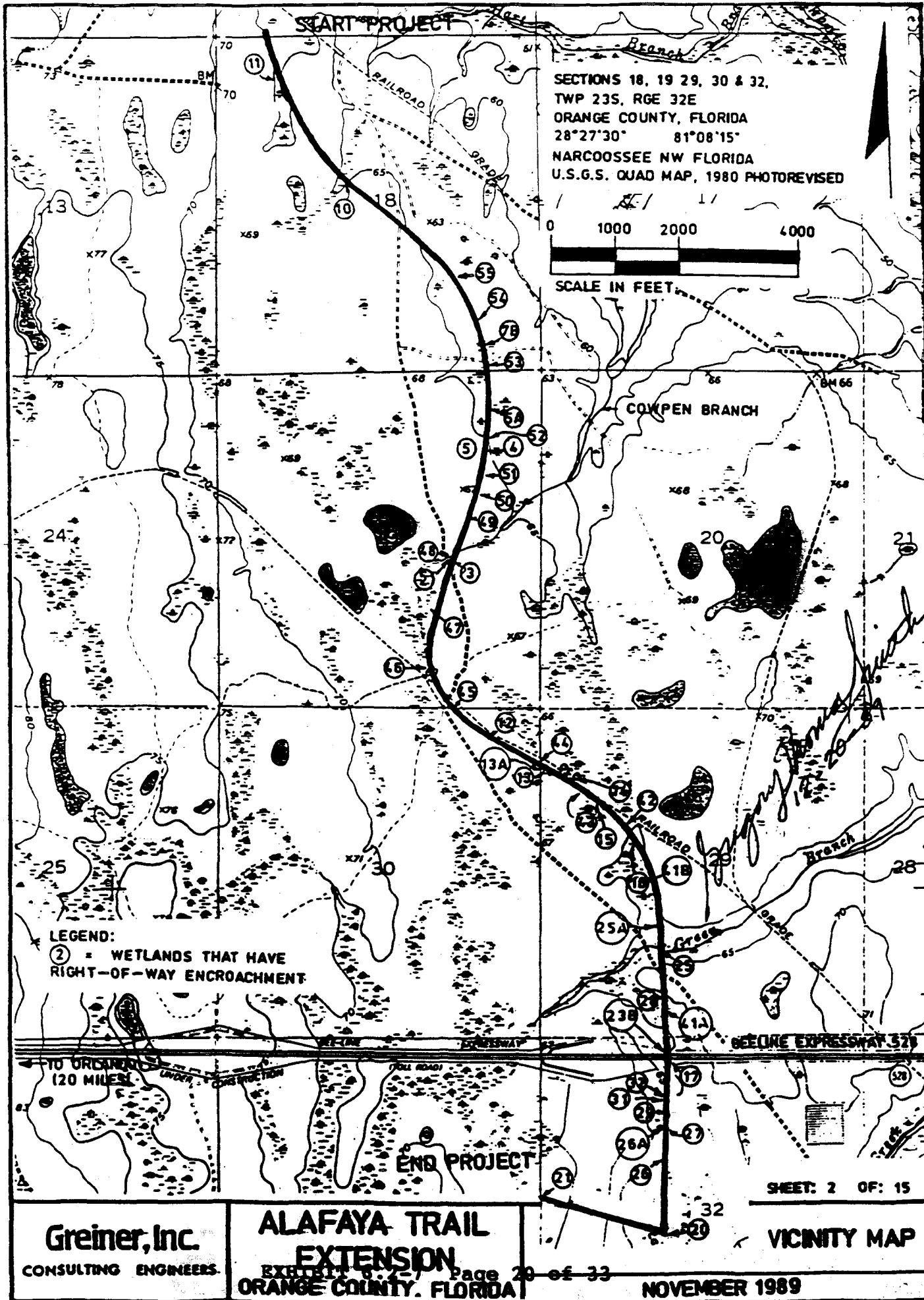
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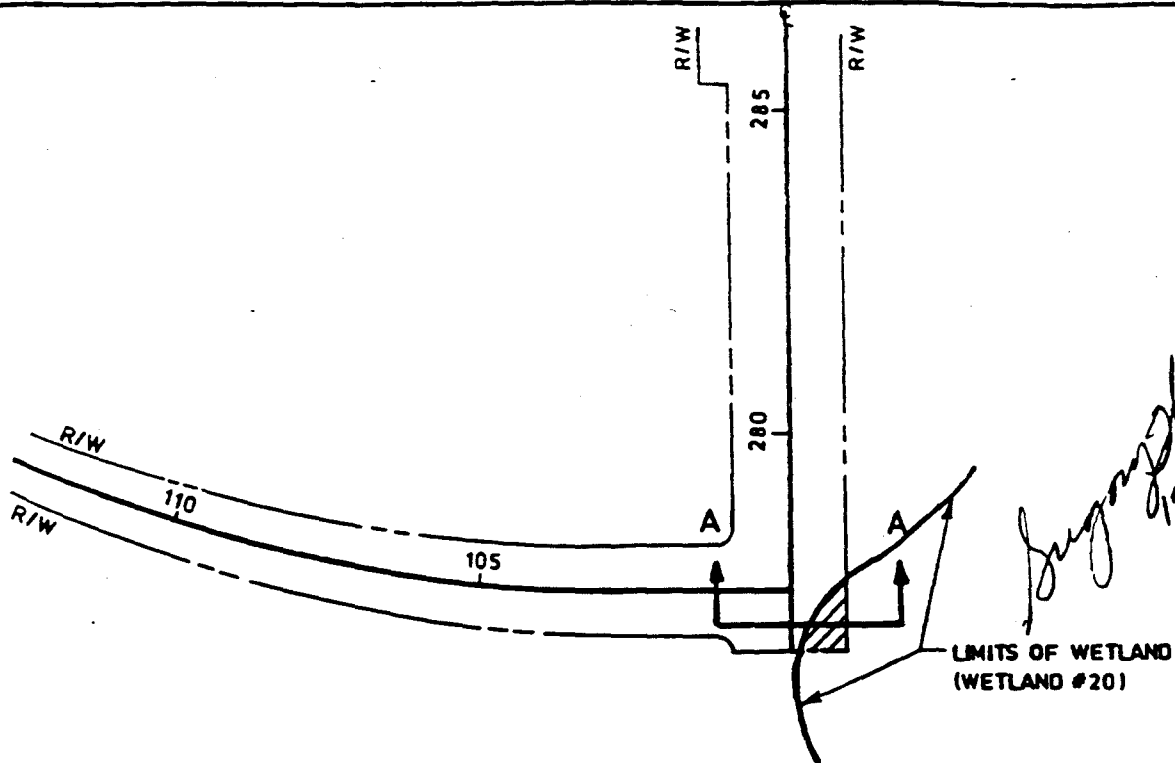
ORANGE COUNTY, FLORIDA

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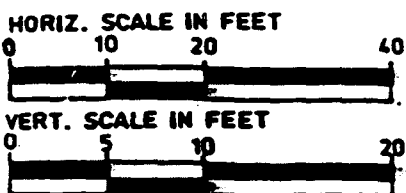
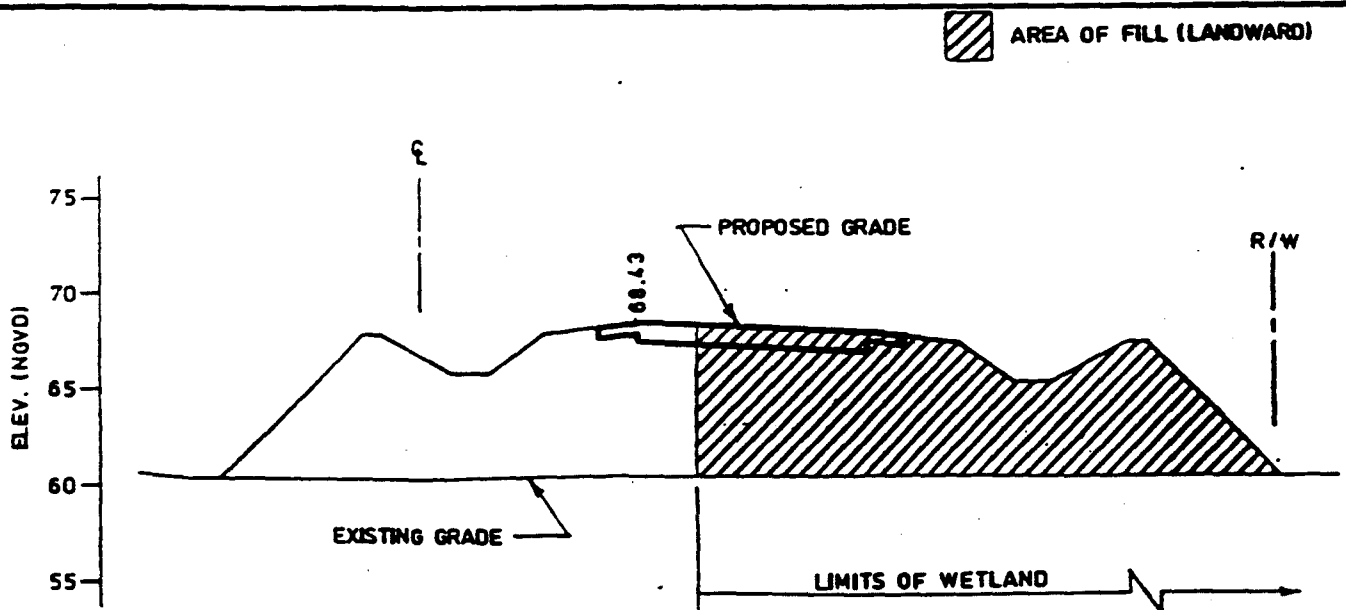
VICINITY MAP

NOVEMBER 1989



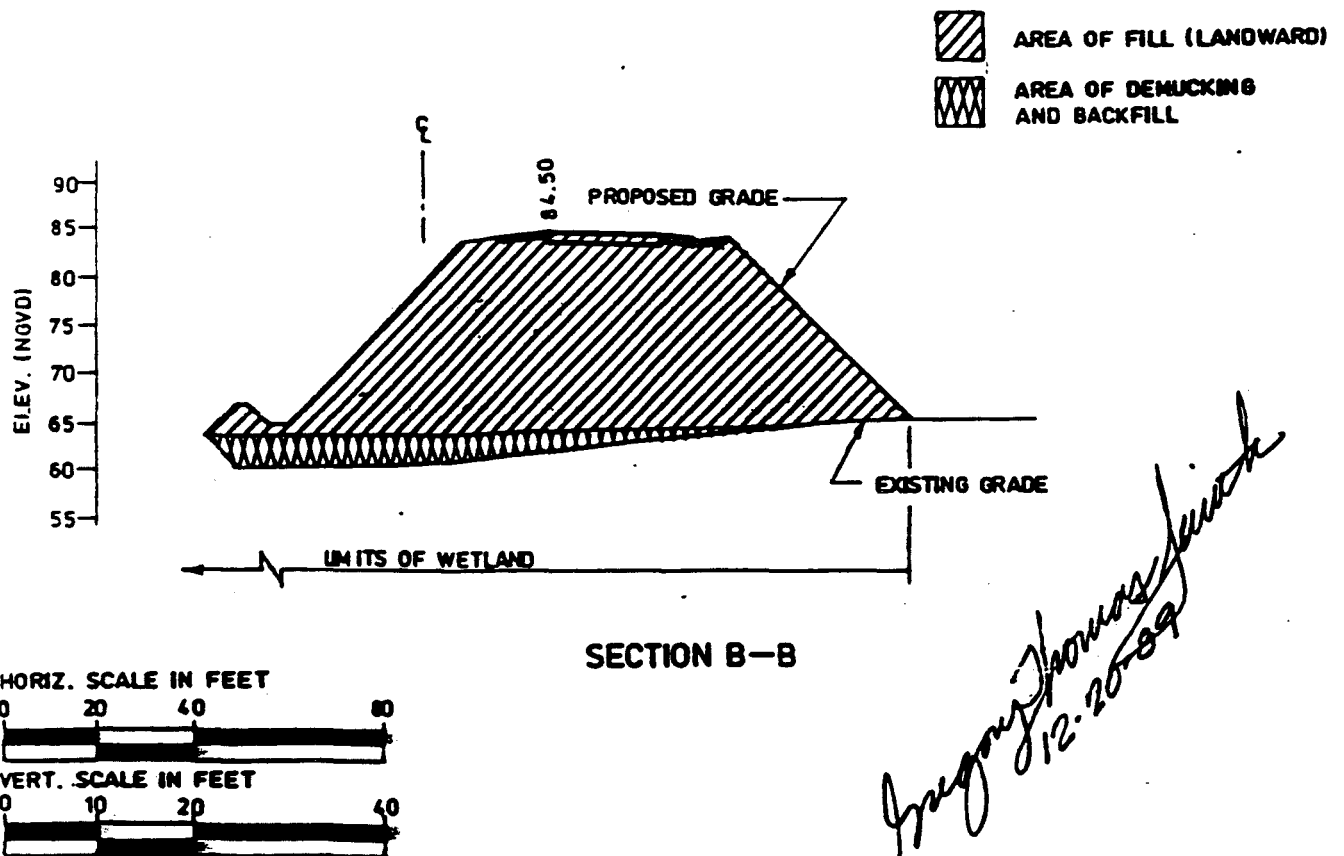
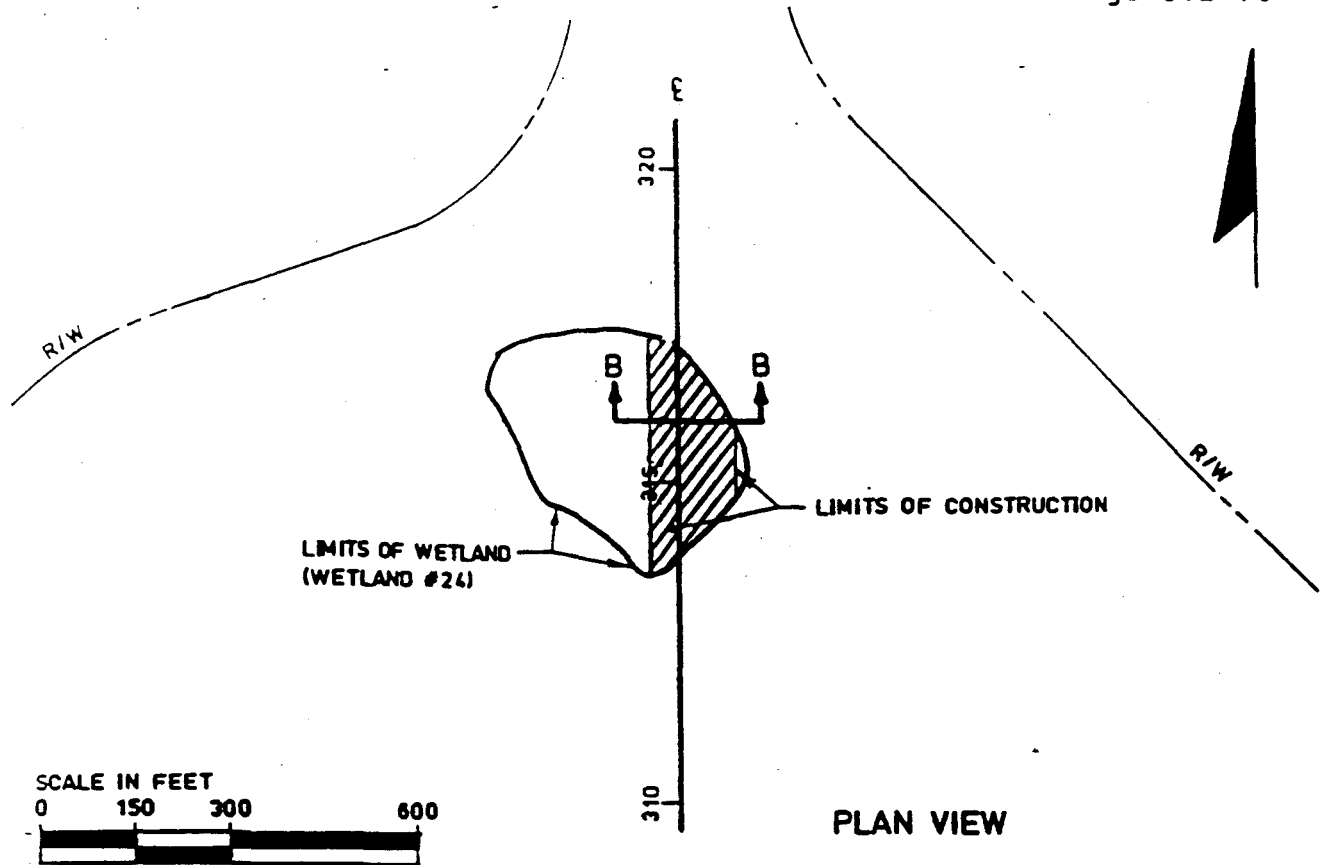


PLAN VIEW



SECTION A-A

SHEET: 3 OF: 15



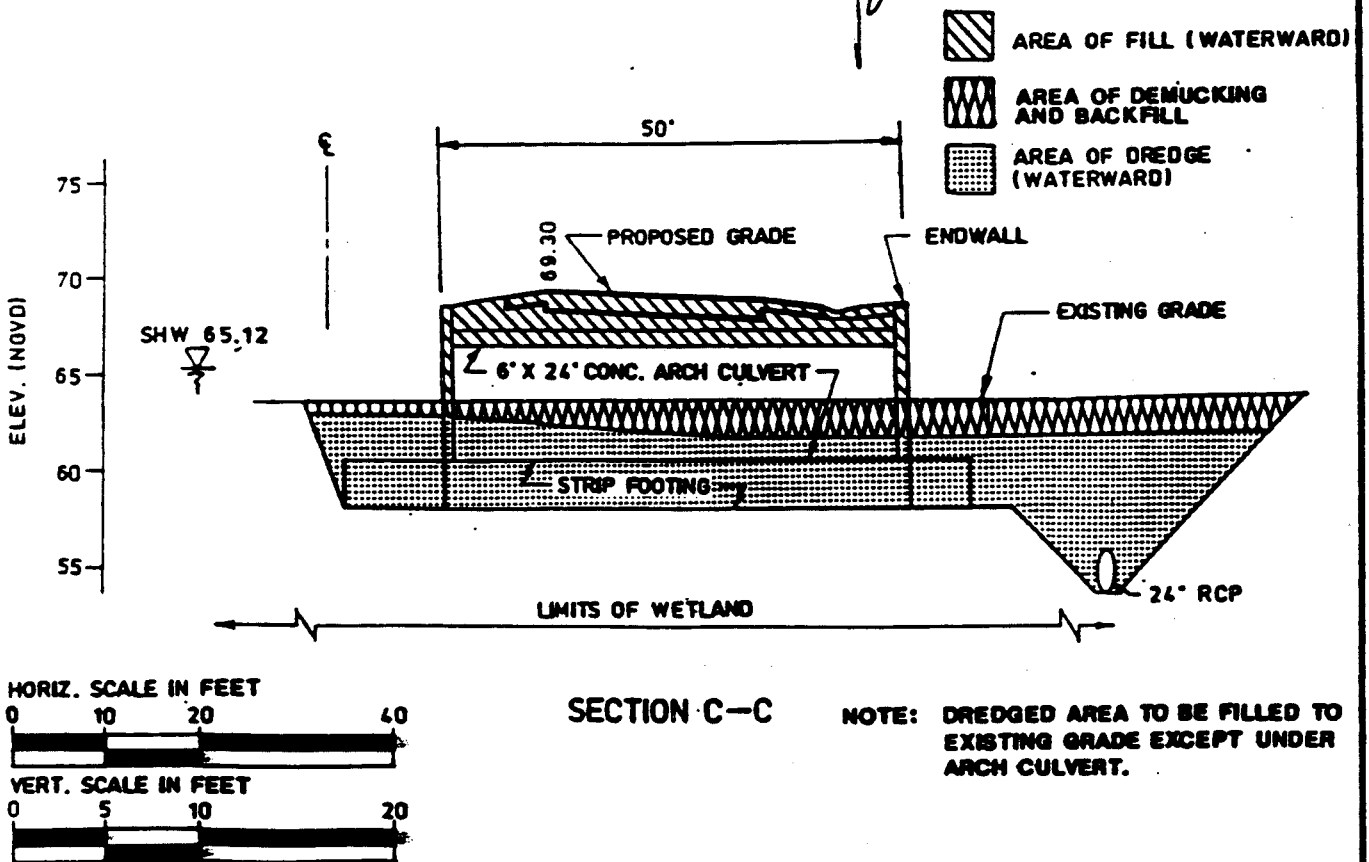
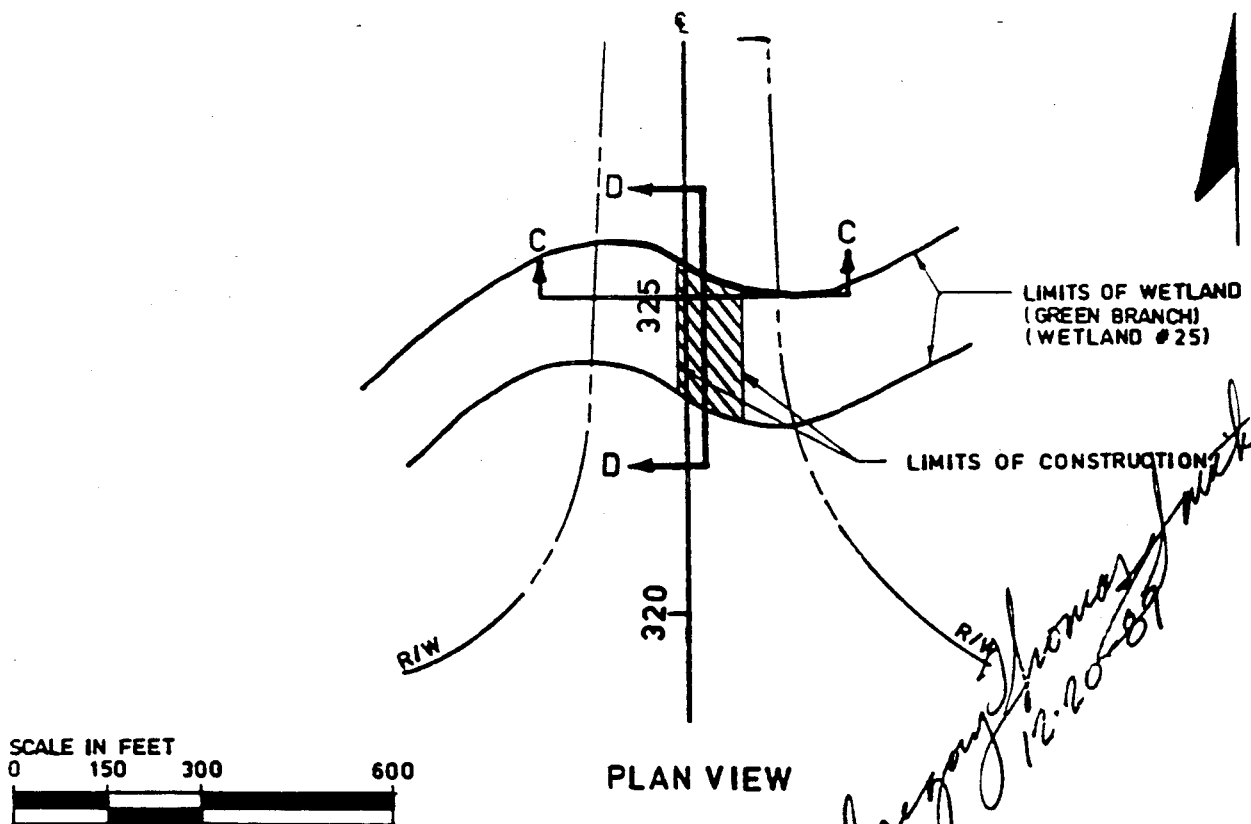
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Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 316 + 00

22 of 33 NOVEMBER 1989



SHEET: 5 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 325 + 00

23 of 33 NOVEMBER 1989

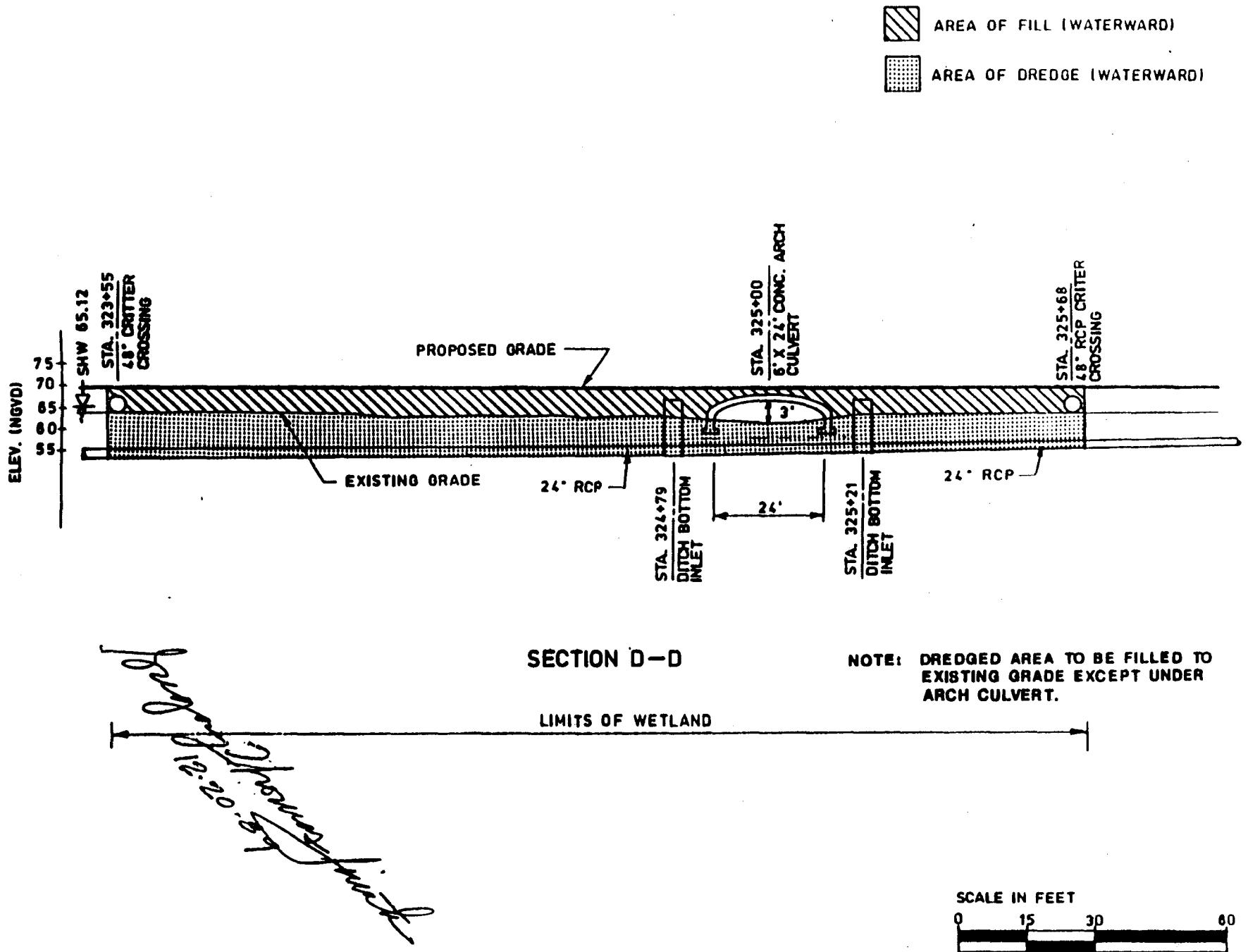
Greiner, Inc.
CONSULTING ENGINEERS

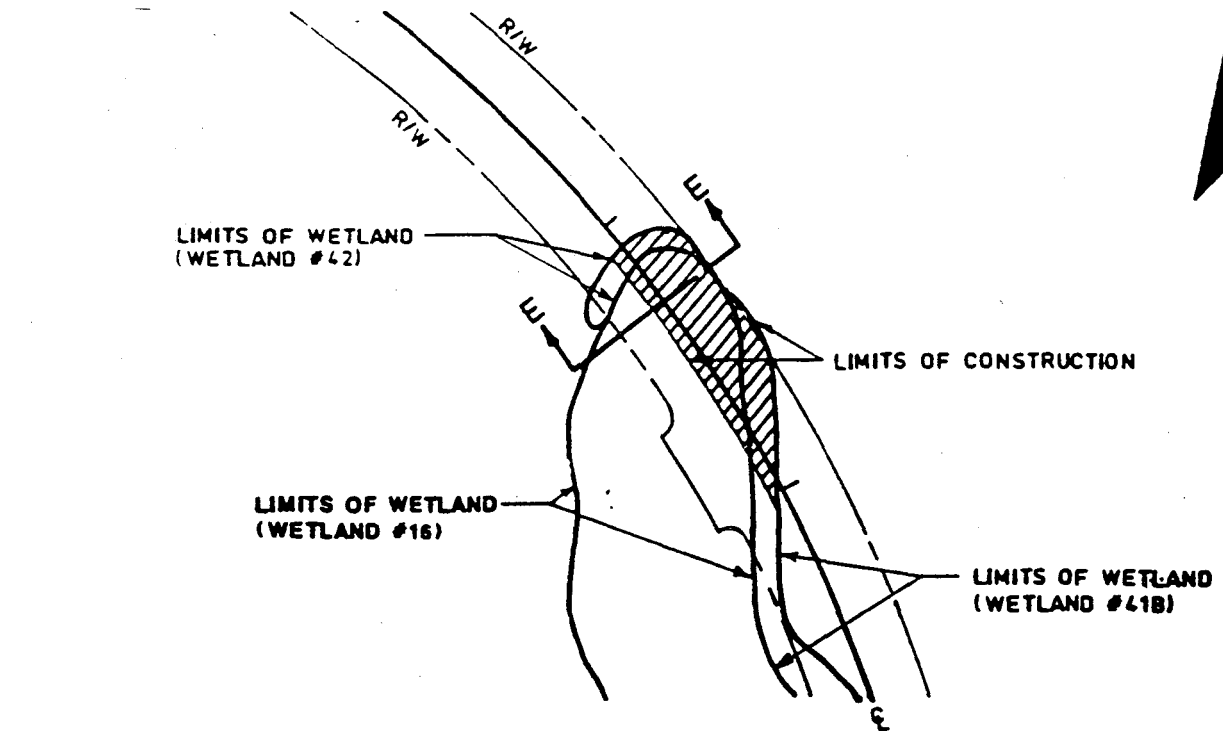
ALAFAYA TRAIL
EXTENSION
ORANGE COUNTY, FLORIDA

24 OF 33 NOVEMBER 1989

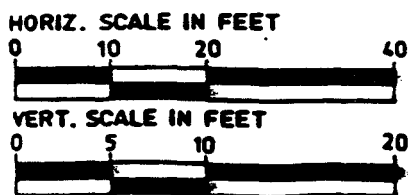
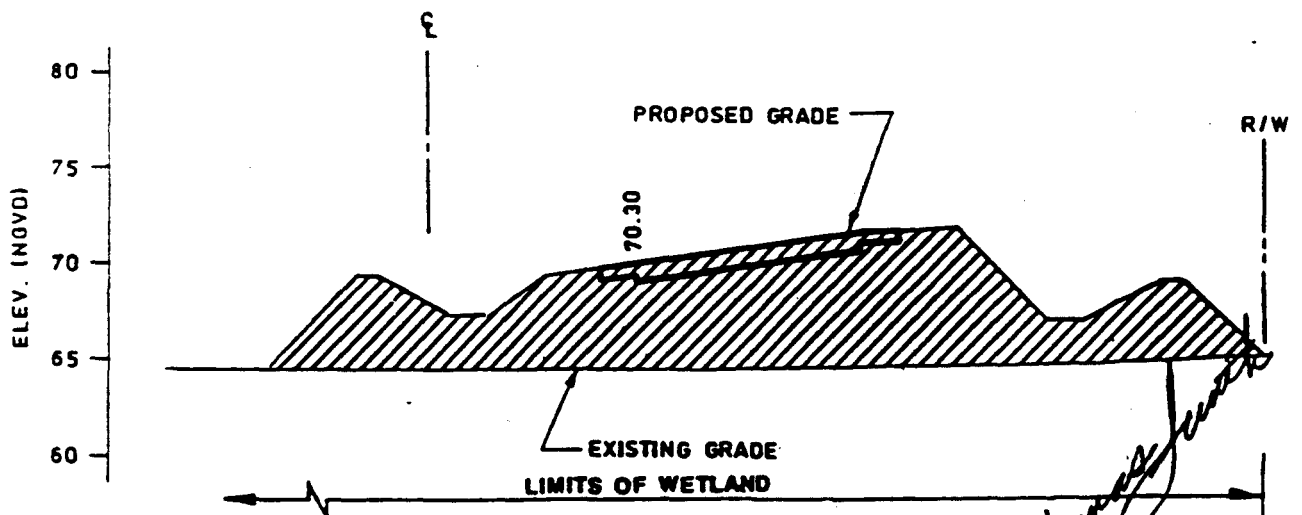
SECTION D-D

SHEET: 6 OF 15





AREA OF FILL (LANDWARD)



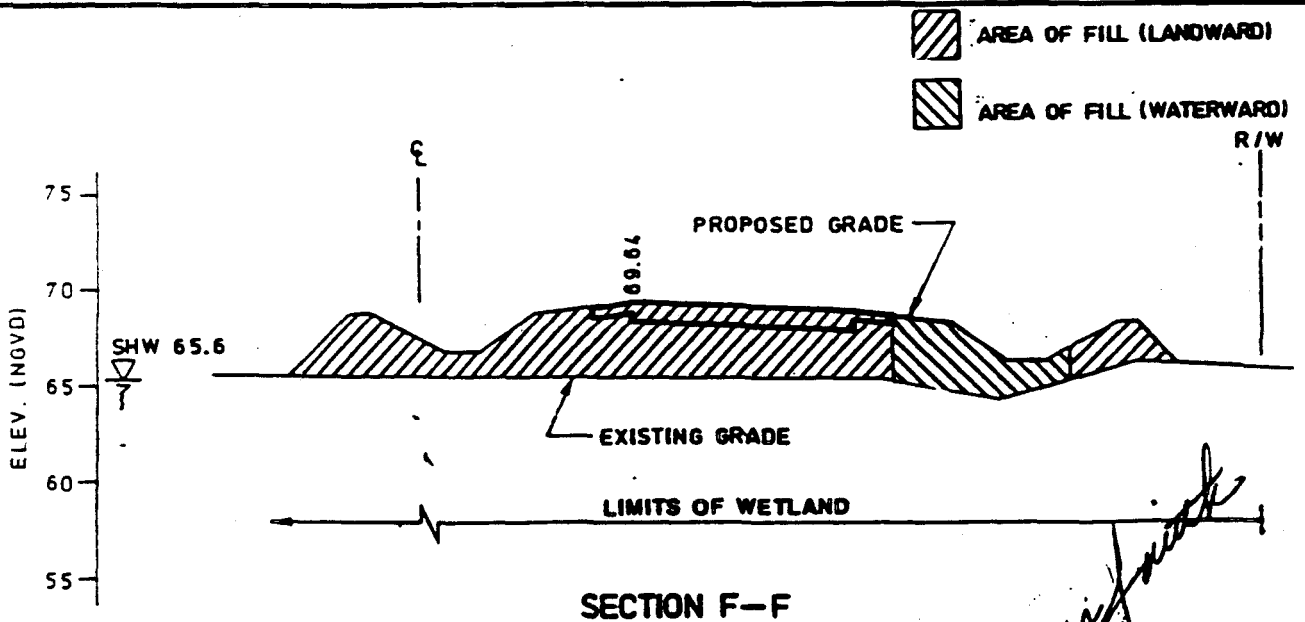
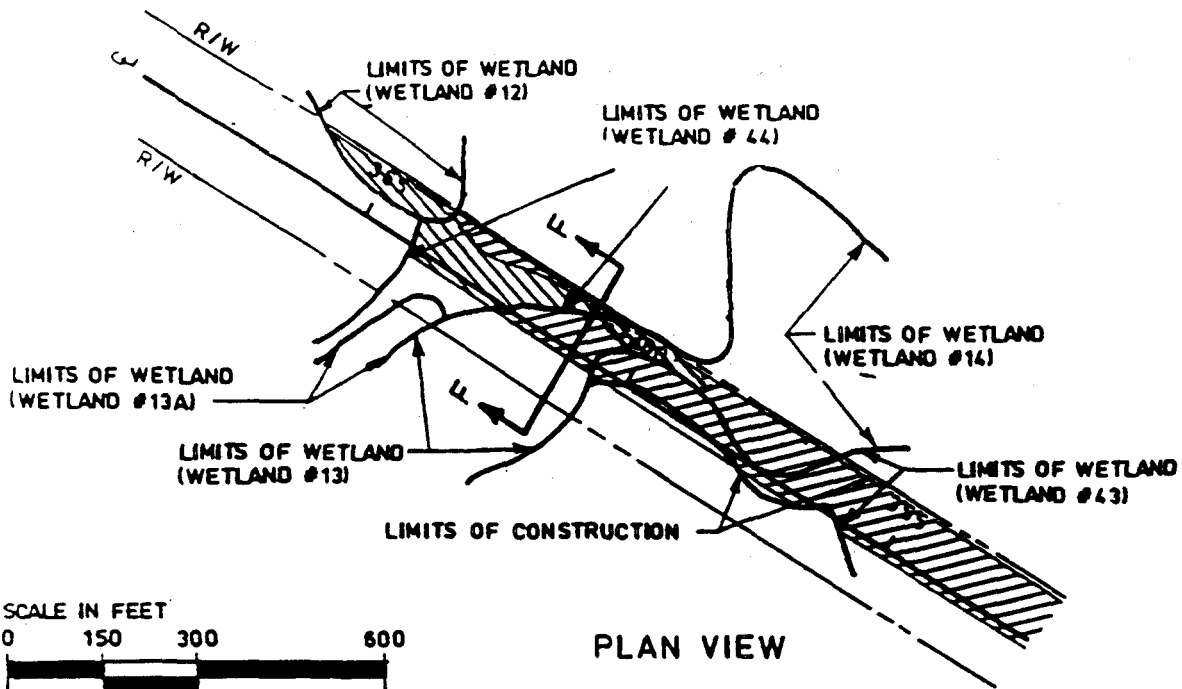
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SHEET: 7 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 343 + 00
NOVEMBER 1989



Gregory Thomas
12.20.89

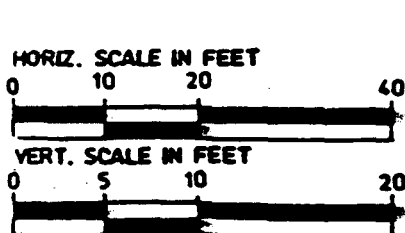
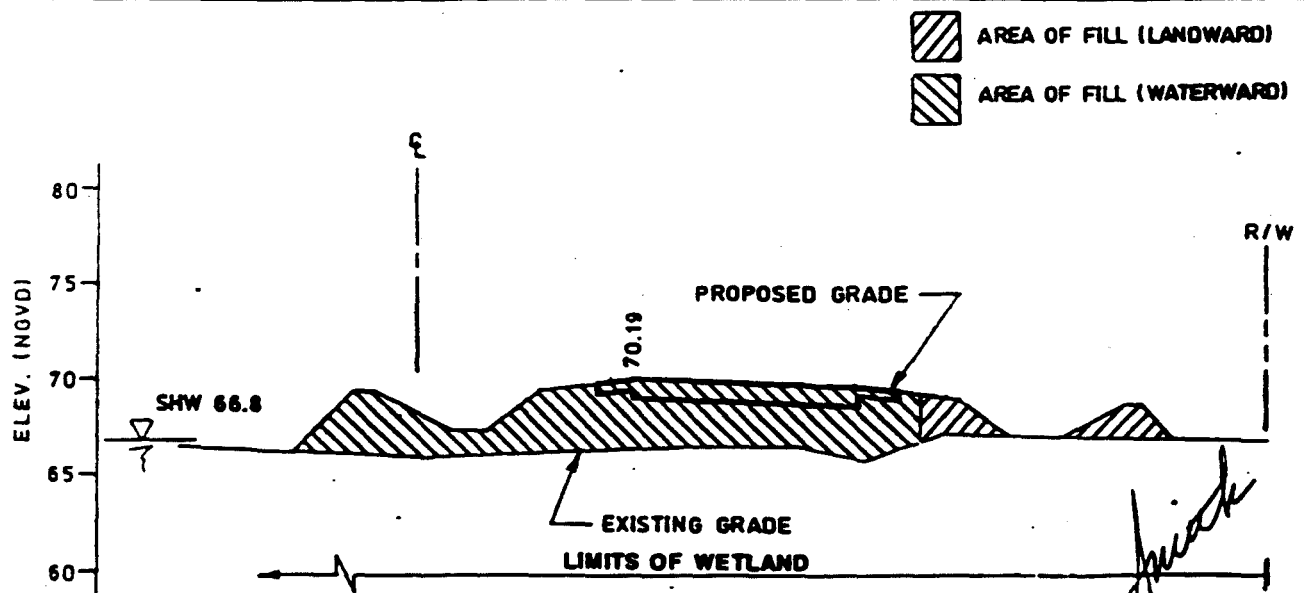
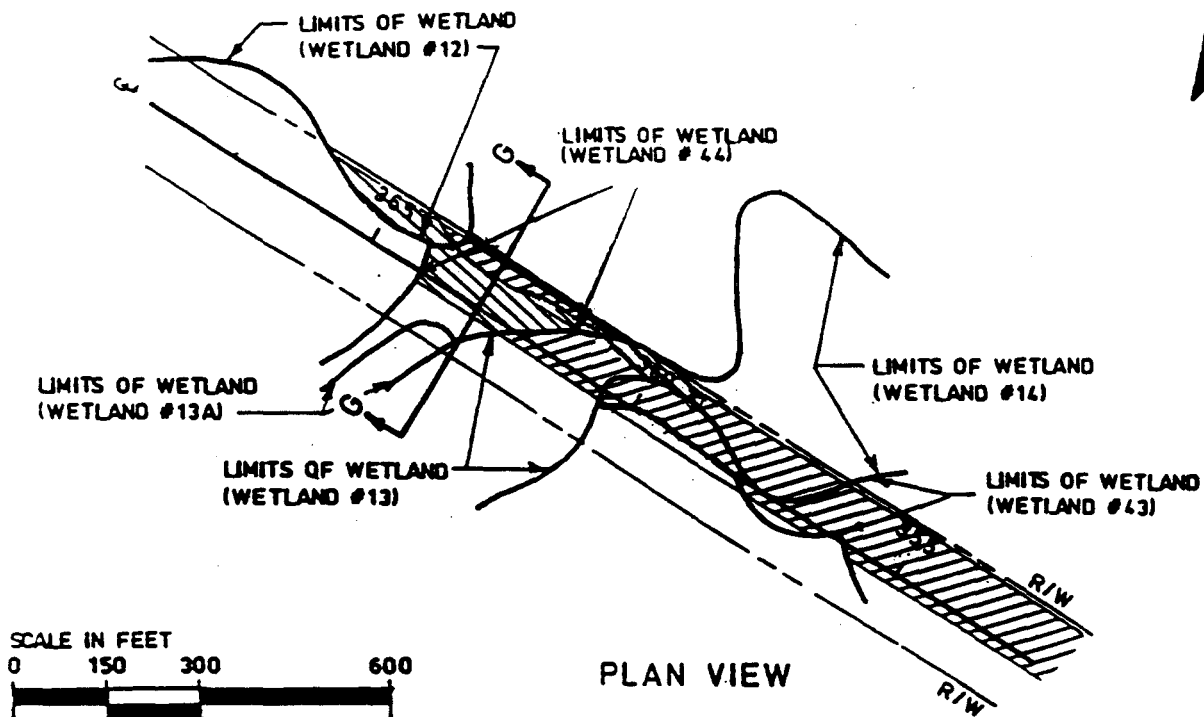
SHEET: 8 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 361 + 00

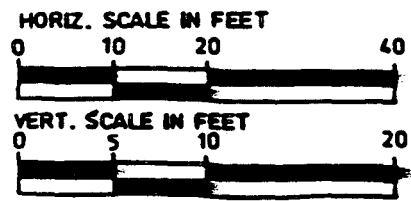
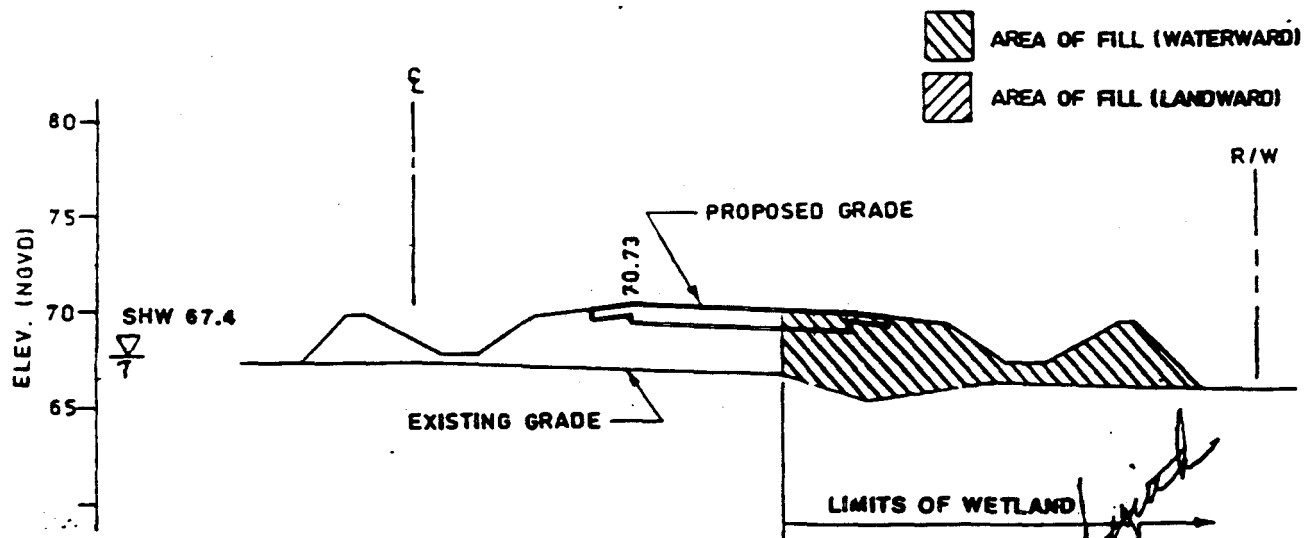
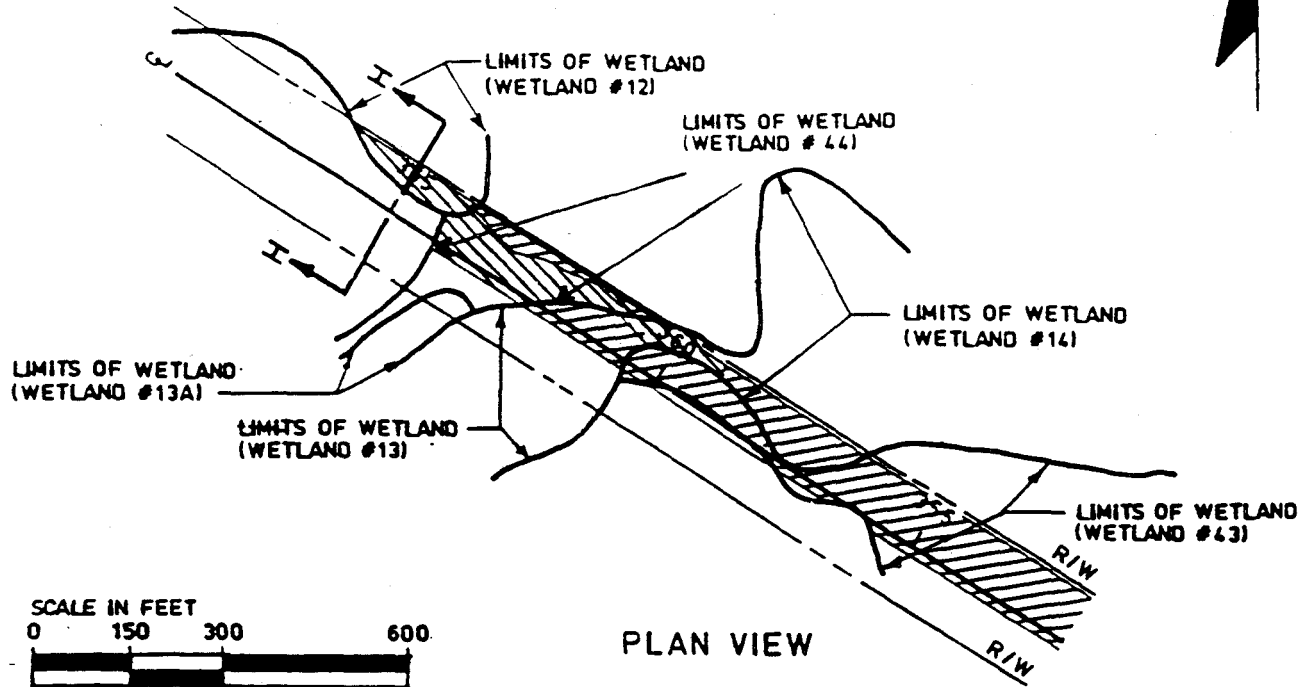
26 of 33: NOVEMBER 1989



SECTION G-G

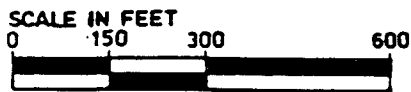
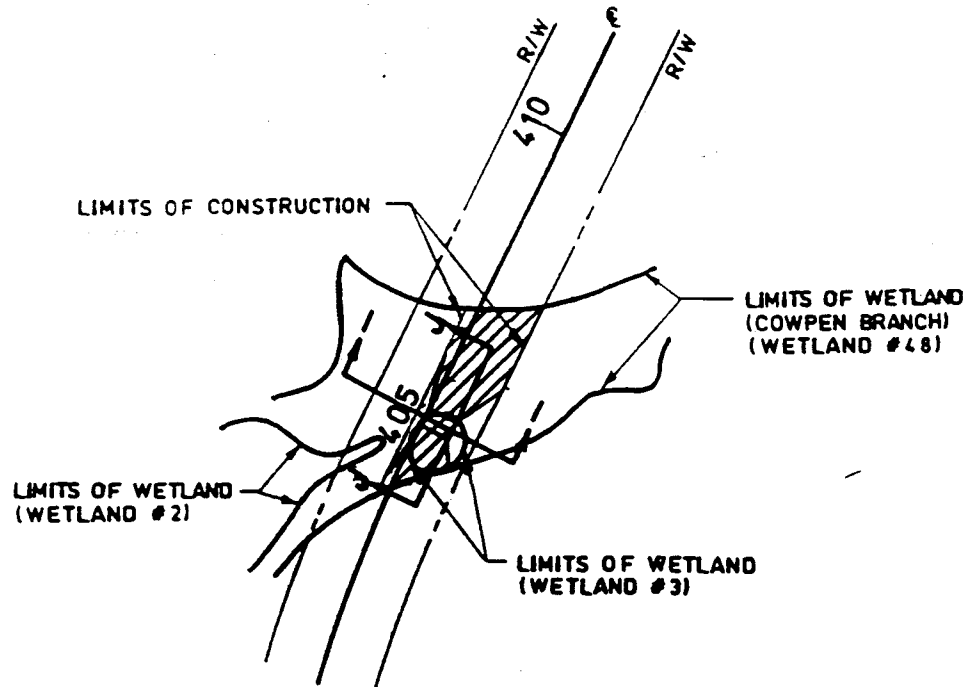
Gregory Thomas
12-20-89

SHEET: 9 OF: 15

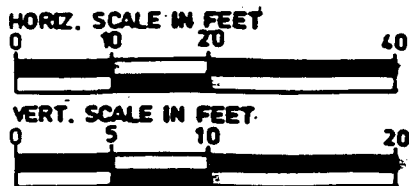
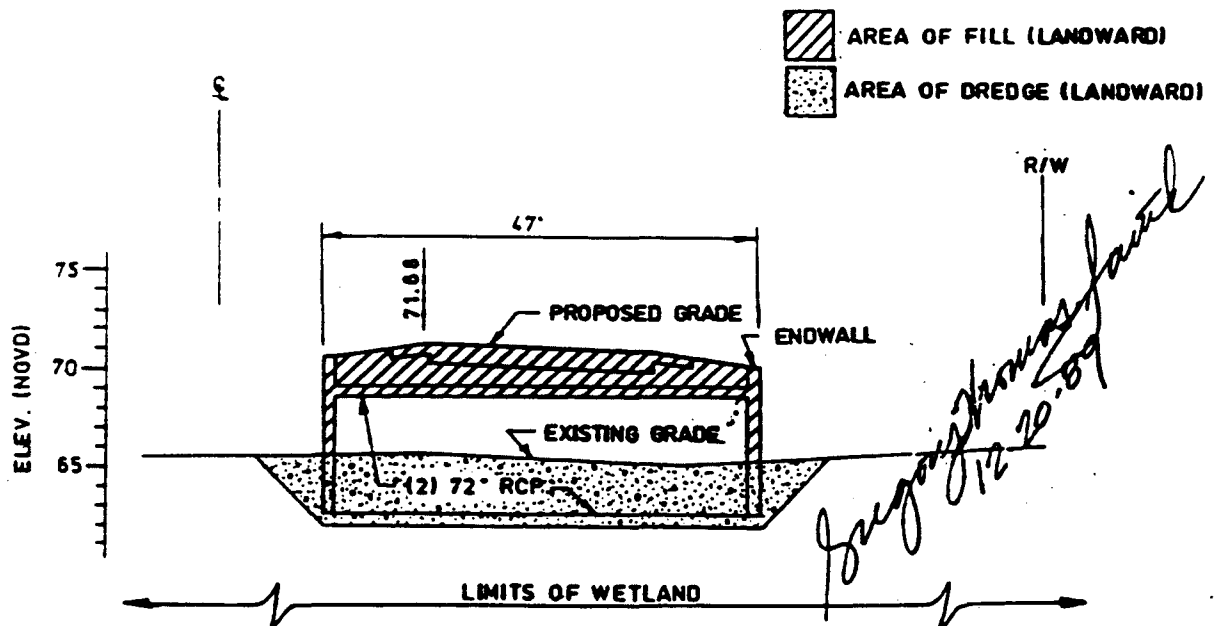


Barry Thomas
12.20.89

SHEET: 10 OF: 15



PLAN VIEW



SECTION I-I

NOTE: DREDGED AREA TO BE FILLED TO EXISTING GRADE EXCEPT IN CULVERTS.

SHEET: 11 OF: 15

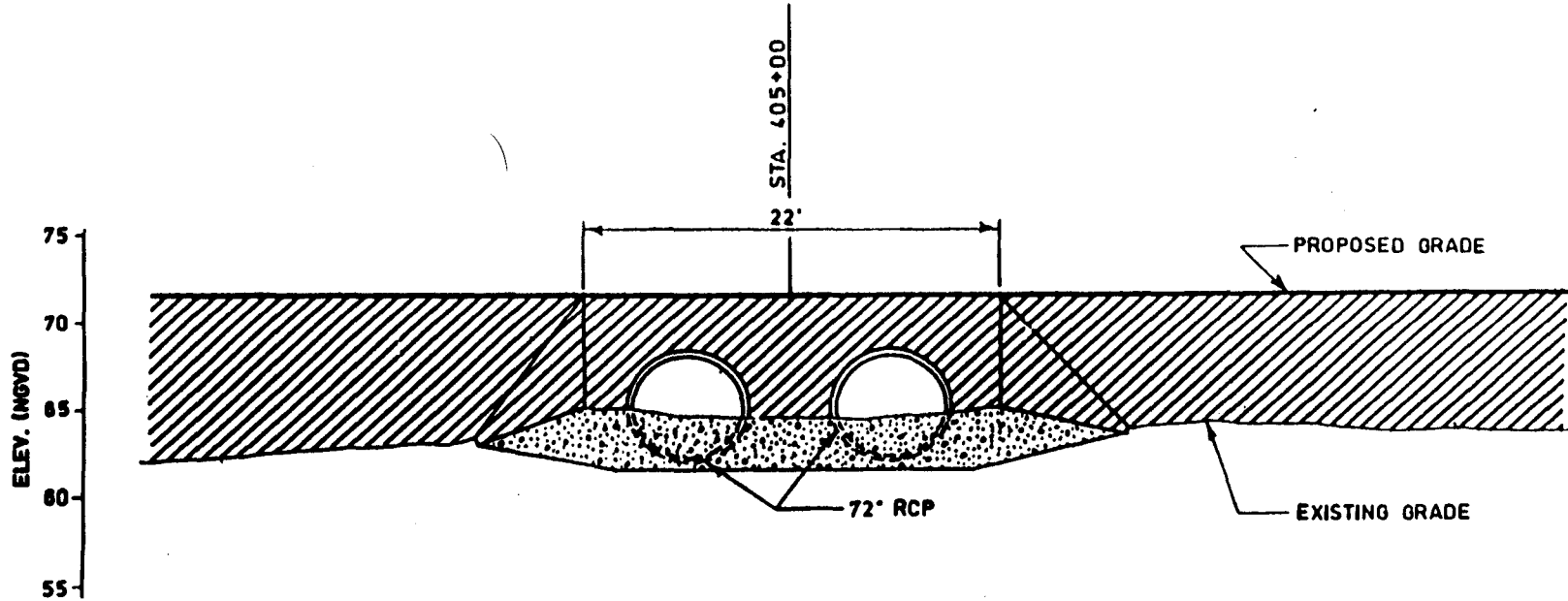
Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 405 + 00

29 of 33 NOVEMBER 1989

-  AREA OF FILL (LANDWARD)
-  AREA OF DREDGE (LANDWARD)

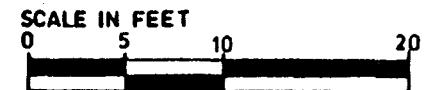


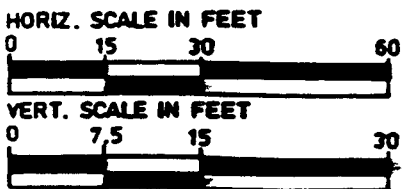
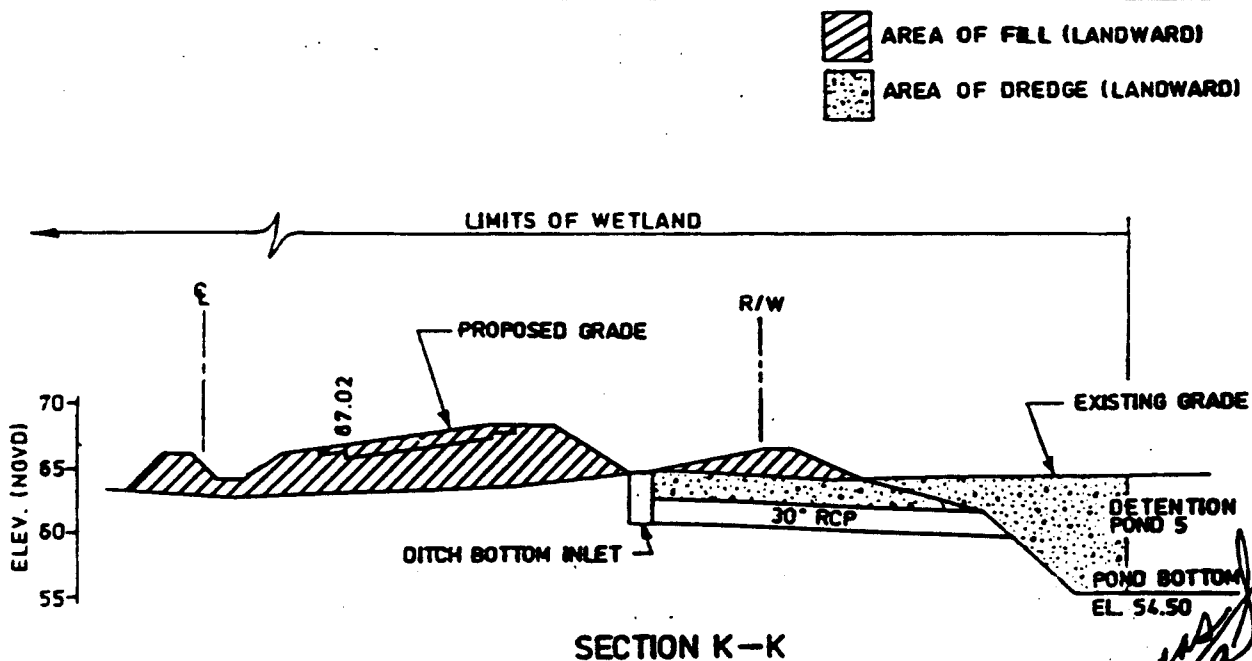
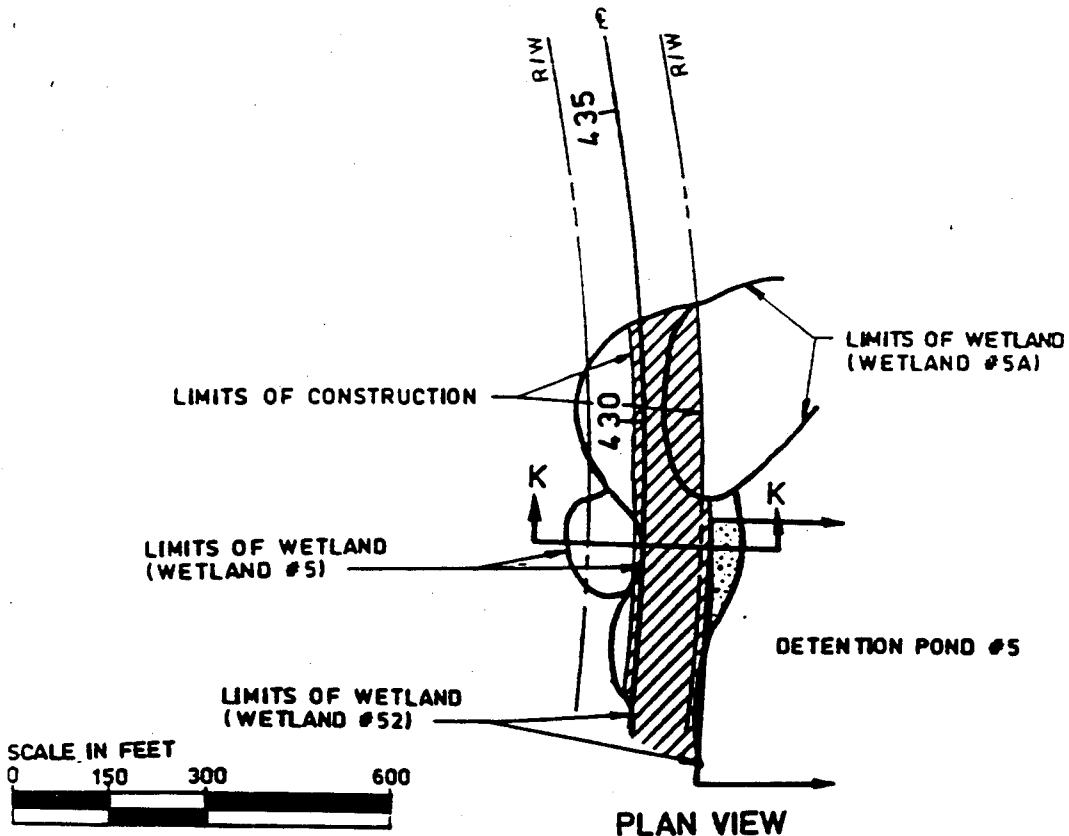
SECTION J-J

NOTE: DREDGED AREA TO BE FILLED TO EXISTING GRADE EXCEPT IN CULVERTS.

LIMITS OF WETLAND

Proposed Wetland Limits





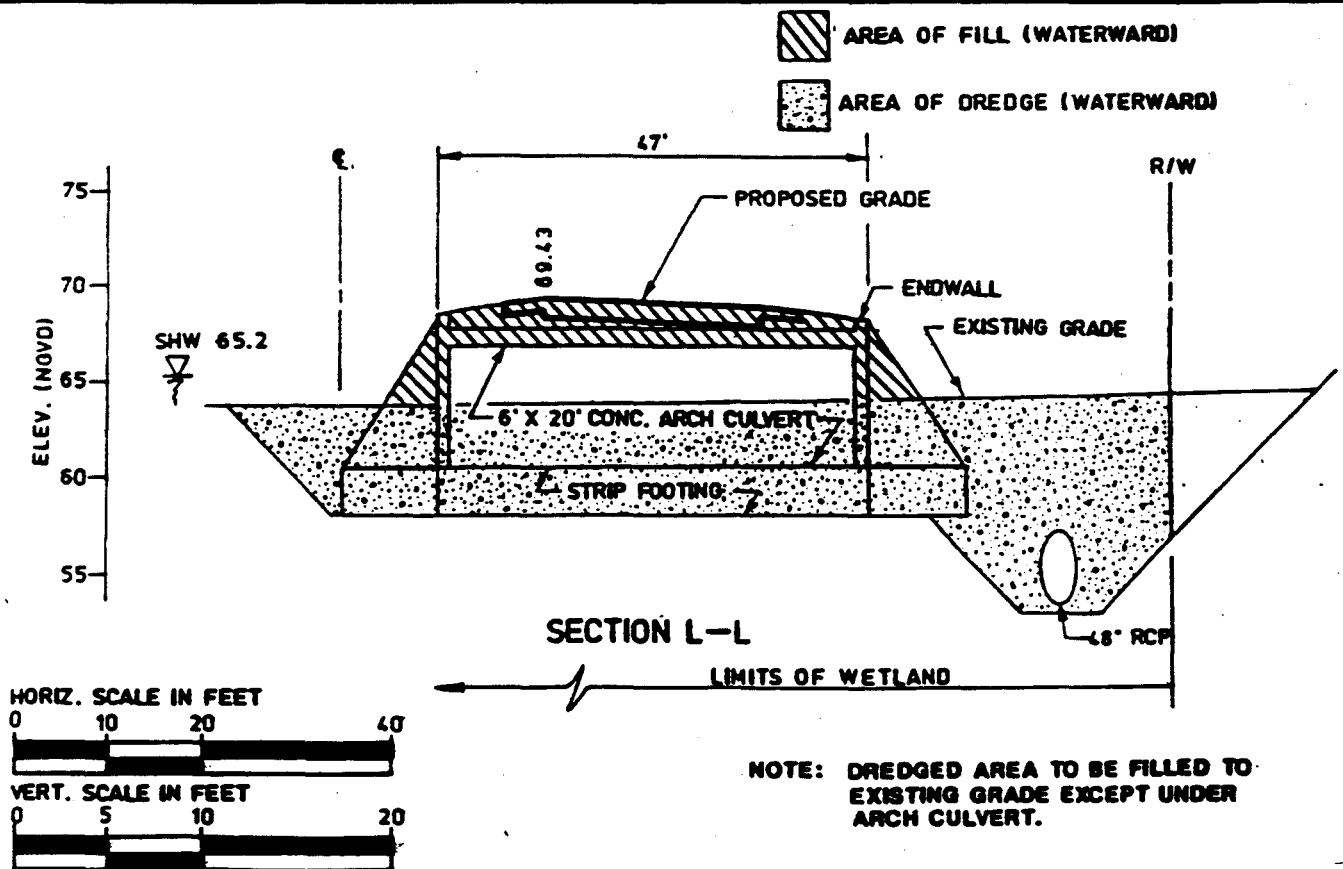
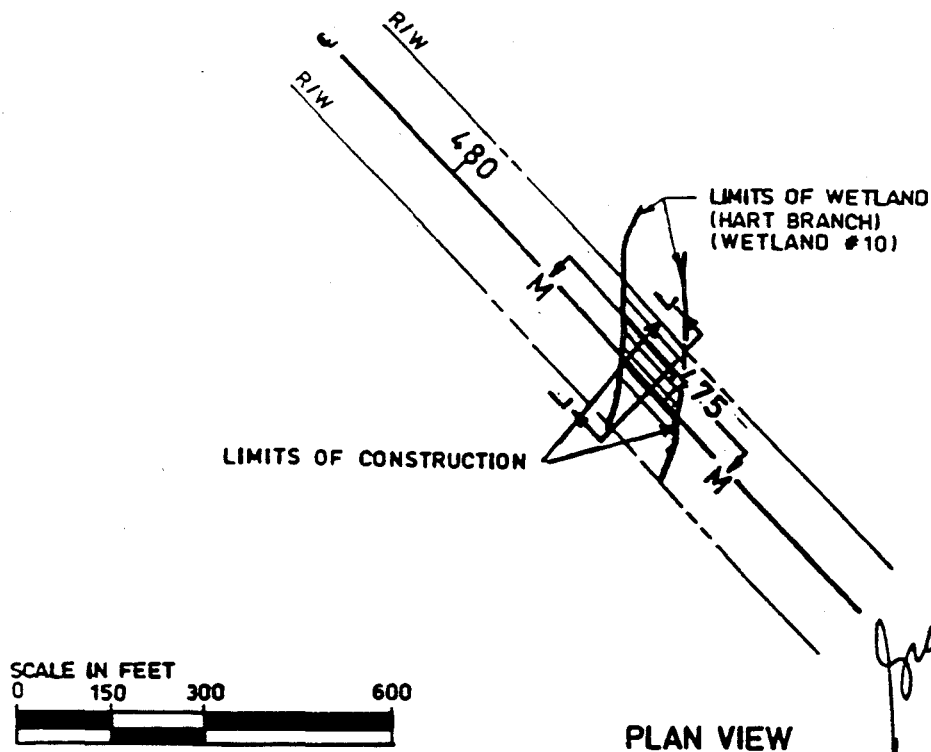
Gregory Thomas Smith
12-20-89

SHEET: 13 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA 428 + 00
NOVEMBER 1989



SHEET: 14 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 475 + 52

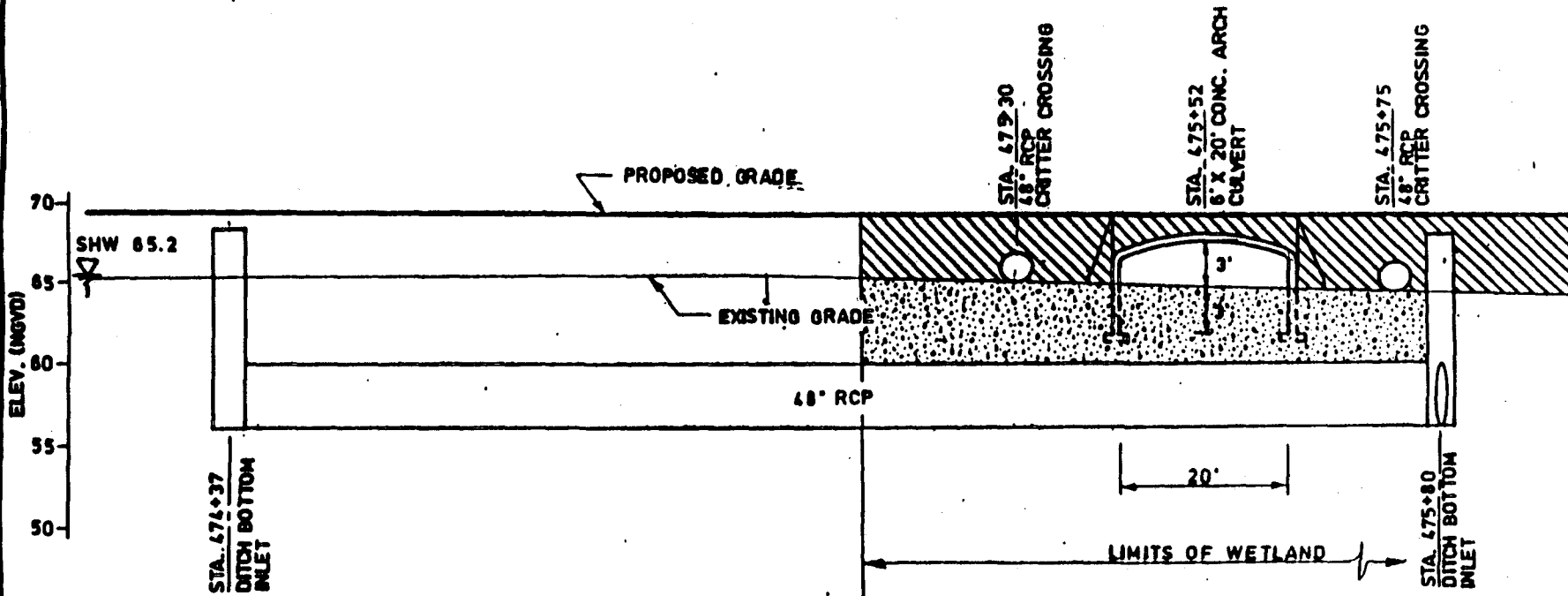
NOVEMBER 1989

Greiner, Inc

ALAFAYA TRAIL EXTENSION

SECTION M-M

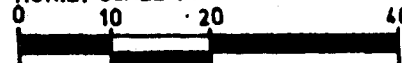
SHEET: 15 OF: 15



SECTION M-M

NOTE: DREDGED AREA TO BE FILLED TO EXISTING GRADE EXCEPT UNDER ARCH CULVERT.

HORIZ. SCALE IN FEET



VERT. SCALE IN FEET



Page 6.2-81

Greiner

Greiner, Inc.
225 East Robinson St., Suite 255
Orlando, Florida 32801-1913
(407) 422-0353

August 8, 1990

C2177.21

Mr. Pat Frost
ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
618 E. South Street, Suite 200
Orlando, Florida 32801

Reference: Alafaya Trail Extension
Dredge and Fill Permit Application No. 12-095-0040A

Dear Mr. Frost:

As a condition of its 1987 Development of Regional Impact approval, International Corporate Park (ICP) is required to construct an extension of existing Alafaya Trail south from its current termination at the Orlando Utilities Commission Curtis Stanton Plant (OUC) to 3,000 feet south of the Bee Line Expressway or a distance of 4.2 miles. ICP previously submitted an application for a Dredge & Fill permit (Permit Application No. 12-095-0040A) but was advised by the Florida Department of Environmental Regulations (FDER) that the portion of roadway lying within the geographic boundaries of the OUC Plant site must be permitted under the State of Florida Power Plant Siting Act.

As such, we are submitting a modified permit application which will omit the northern 2.3 miles of the Alafaya Trail project lying within the OUC site. ICP and OUC will address this omitted section at a later date under the modification request to the existing OUC Power Plant siting approval.

This modified application addresses the south 1.9 miles of Alafaya Trail improvements plus mitigation for wetlands impact for the entire 4.2-mile project. Enclosed are two (2) permit application packages for this project. Each package contains the following items:

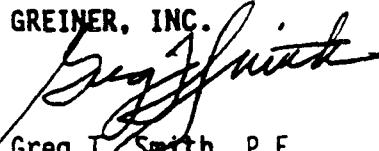
1. A complete joint permit application with seven (7) attachments.
2. Four (4) sets of permit drawings (one set has the original P.E. Certification).
3. Two (2) sets of blue-line aerials (1" = 300') of the entire 4.2-mile project area.

Mr. Pat Frost
August 8, 1990
Page 2

If you should require any additional information or have any questions,
please do not hesitate to contact us.

Sincerely,

GREINER, INC.



Greg T. Smith, P.E.
Project Manager

GTS/tg

Enclosures

cc: Jim Clark, ICP, w/encl.
Ralph Smith, ICP, w/encl.
George Cole, Orange County, w/encl.
Joe Montalto, LEI, w/encl.
Jim Lee Greiner, Inc.
Kathy Hale EMD, w/encl.

/FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION For Activities in the Waters of the State of Florida	
 DER APPLICATION NUMBER (official use only) 1 2 0 9 5 0 0 4 0 A	
1. APPLICANT'S NAME AND ADDRESS I N T E R N A T I O N A L C O R P O R A T E P A R K NAME 9 3 3 L E E R D S U I T E 2 0 0 STREET O R L A N D O F L 3 2 8 1 0 CITY STATE ZIP TELEPHONE NUMBER (Day) (407) 647-4200 (ICP) (Night) ()	
2. Name, address, zip code and title of applicant's authorized agent for permit application coordination Greg T. Smith, P.E. GREINER, INC. 225 E. Robinson St., Suite 255 Orlando, FL 32801-1913 Telephone Number (407) 422-0353	
3. NAME OF WATERWAY AT LOCATION OF THE ACTIVITY. Green Branch	DER Code: _____ W/W Code: _____
4. LOCATION WHERE PROPOSED ACTIVITY EXISTS OR WILL OCCUR. <u>Bee Line Expwy-10.5 miles E. of S.R. 436</u> Street, road or other descriptive location <u>N/A</u> Incorporated city or town <u>Orange</u> County ²⁹ <u>30.32</u> Section <u>23S</u> Township <u>32E</u> Range <u>28°27'30"</u> Latitude <u>81°08'15"</u> Longitude Tax Assessors Description: (if known) <u> </u> Map No. <u> </u> Subdiv. No. <u> </u> Lot No.	
5. NAME AND ADDRESS INCLUDING ZIP CODE OF ADJOINING PROPERTY OWNERS WHOSE PROPERTY ALSO ADJOINS THE WATERWAY. See Attachment "A" - Adjoining Property Owners	
6. PROPOSED USE Private Single Dwelling [] Private Multi-dwelling [] Public [XX] Commercial [] Other [] (Explain in remarks)	

7. DESCRIPTION OF PROJECT (Use additional sheets, if necessary)

A. Structures: 1. New work ☒ Maintenance of existing structure ☐2. Piers, docks and uses: 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 6' x 24' arch culvert in Green BranchB. Excavation or Dredging: New Work ☒ Maintenance work ☐ Total acreage involved 0.83 FDER1. Access Channel ☐ or Canal ☐ Length _____ ft. Width _____ ft. Depth _____ ft.2. Boat Basin ☐ or Boat Slip ☐ Length _____ ft. Width _____ ft. Depth _____ ft.3. Other Alafaya Trail Extension Length varies ft. Width varies ft. Depth varies ft.4. Cubic yards: Total for project 4,889 FDERa. 4,889 FDER cyd. waterward/ 0 FDER cyd. landward of ordinary/mean high water
1489 (demucking) 3926 (demucking)b. Type of material to be excavated/dredged sand with silt & clayey sand

C. Fill:

1. Amount of material

a. Cubic yards placed waterward of ordinary/mean high water 4,982 FDER
1489 (Backfilling)b. Cubic yards placed landward of ordinary/mean high water 45,495 FDER
3926 (Backfilling)c. Total acreage to be filled 3.7 FDER Total acreage of wetlands involved 3.99 FDER*

2. Containment for fill *Includes 0.29 AC which qualify for a ditch exemption.

a. Dikes ☐ b. Seawall, etc. ☐ c. Other (please explain) On siteUpland with vegetated slopes3. Type of fill material to be used clean sand4. Source of fill material to be used Offsite uplandsCOE
Work CodeDER
Code253
403

8. Date activity is proposed to commence March 1991 ; to be completed March 1992.

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

A. Denied (date) _____

B. Issued (date) _____

C. Other (please explain) SJRWD MSSW Permit Application No. 4-095-0033AM has been revised and resubmitted on 7/25/90.

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 attachment "B" - Environmental Report

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)

☒ 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)

See Attachment "C"

Sworn and subscribed before me at Orange County,

Florida, this 30th day of August, 1990.

Signature Pres.

NOTARY PUBLIC

My commission expires: _____
Notary Public, State of Florida
My Commission Expires: _____
General Use Notary Public Seal

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 all of the required state, federal or local permits before 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.

EXHIBIT 6.2-8 Page 6 of 66

Signature of Applicant *[Signature]*

Date 8.5.90

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 NOT a Joint Permit!

You Must Obtain All Required Local, State, and Federal

Authorizations or Permits Before Commencing Work!!

For your information: 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.**

Page 6 2-87

LIST OF ATTACHMENTS

1. Attachment A - Adjoining Property Owners
2. Attachment B - Environmental Report
3. Attachment C - Legal Description
4. Attachment E - Mitigation Plan
5. Attachment F - Calculated Flow Rates
6. Attachment G - Water Budget
7. Attachment H - ICP letter of intent to provide evidence of financial resources

ATTACHMENT "A"

ADJOINING PROPERTY OWNERS

D.O.C.

State of Florida
Dept. of Corrections
1311 Winewood Blvd.
Tallahassee, FL 32399-2500

Mr. Ned Terry 904/487/1330
Mr. Ralph Kenyon

O.U.C.

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

Mr. Wendell Dixon 407/423/9100

Deseret Ranches of Florida

Star Route
Box 1250
Melbourne, FL 32904

Mr. John King 407/892/5646

ATTACHMENT "B"
ENVIRONMENTAL REPORT

1. BACKGROUND

On January 8, 1990, a Dredge and Fill Permit Application package was submitted to the St. Johns River Management District (SJRWD) and the U.S. Corps of Engineers (ACOE) for approval to construct the Alafaya Trail Extension. Due to the Power Plant Certification Act, the Alafaya Trail Extension has been divided into two separate projects, -- the northern extent on Orlando Utilities Commission property (2.3 miles) and the southern extent on Florida Department of Corrections, Deseret Ranch, and International Corporate Park properties (1.9 miles). It is the southern extent for which the dredge and fill permit application (Application No. 12-095-0040A) is being modified. The total mitigation plan, however, is proposed for the whole Alafaya Trail Extension alignment.

International Corporate Park (ICP) plans to build an extension to Alafaya Trail in east Orange County which will consist of 4.2 miles of two-lane roadway improvements and a new bridge structure over the Bee Line Expressway. This modification to the permit application consists of the southern terminus, which is approximately 1.9 miles and crosses over the Bee Line Expressway, and will terminate 3,000 feet south of the Bee Line Expressway.

Construction start date is based on the Development Order approved by Orange County. At the conclusion of this construction, these improvements will be turned over to Orange County in compliance with ICP's Development Order. Entities which will be served by this roadway extension include the Orlando Utilities Commission Curtis H. Stanton Power Plant, the Florida Department of Corrections prison facility and International Corporate Park, a 3,000-acre business/industrial park.

2. PROJECT STATUS

Alafaya Trail Extension is currently under final design with construction anticipated to begin in 1991. Initially, only two lanes of Alafaya Trail will be built at first although at a later date, additional lanes will be added to form a divided four-lane roadway. The future Alafaya Trail/Bee Line Expressway interchange is expected to be constructed in the mid-1990's.

1. The proposed Alafaya Trail Extension alignment was set after an exhaustive study to minimize environmental impacts to wetlands and protected wildlife such as the red-cockaded woodpecker. On May 1, 1989, a Public Hearing concerning this project was held before the Orange County Board of County Commissioners to brief interested parties on the project and to gain the County's initial concurrence of the alignment and typical section before proceeding with the design work. The Commissioners voted unanimously to approve this alignment.

2. It was decided by FDER that the permit package would be divided into northern and southern projects so that permitting on the southern portion could proceed through the normal permitting procedure. As of July 8, 1990, that portion on the OUC site will require a modification to the Power Plant application and will be permitted by FDER.
3. As part of this project, approximately 3.70 acres of FDER jurisdictional wetlands and 10.07 acres of St. Johns River Water Management District jurisdictional wetlands will be affected.
4. This project will require the following quantities of dredge and fill:

	<u>FDER</u>
Waterward dredge	4,889 CY
Landward fill	45,495 CY*
Waterward fill	4,982 CY

- * Quantity includes 36,784 CY of fill material for overpass approach ramp at the Bee Line Expressway.

5. Fill source(s) will be clean, compactible soil material from an upland source.

6. All necessary turbidity and erosion control measures will be implemented during construction to minimize water quality degradation on adjacent wetlands. Visual monitoring for potential turbidity problems will be conducted throughout the construction activities.
7. During construction, all bare ground will be seeded, sodded and/or otherwise appropriately treated to prevent runoff of suspended solids into adjacent water bodies.
8. Attached is Table 1 listing each wetland by agency jurisdiction with the amount of wetland encroachment (by acreage) and the wetland vegetation community affected by the Alafaya Trail Extension located on ICP/DOC and Deseret Ranch properties (southern portion 1.9 miles).
9. Attached is Table 1A which lists each wetland by agency jurisdiction, amount of wetland encroachment (by acreage), and the wetland vegetation community affected by the Alafaya Trail Extension (northern extent on OUC property). This portion of the alignment is not considered part of this permit application. However, the impact to wetlands within the northern extent (OUC property) and the southern extent (ICP/DOC property) will be compensated as part of this application. The application for the northern extent on OUC property will be submitted under the State of Florida Power Plant Siting Act.

TABLE 1

ALAFAYA TRAIL JURISDICTIONAL WETLANDS
(Southern Extent)
ICP/DOC and Deseret Ranch Properties

Wetland Number ^a	FLUCFCS Category ^b	Project Impact Acreage	Agency Jurisdiction ^c	Cubic Yards of Material ^d
12	621	0.55	SJRWMD	
12	643	0.41	SJRWMD	
13	621	0.56	SJRWMD, FDER	2,820 L.F. 500 W.F.
13	621	0.32	SJRWMD	
14	621	0.50	SJRWMD, FDER	2,518 L.F.
15	621	0.58	SJRWMD	
15	643	0.20	SJRWMD	
16	621	0.87	SJRWMD	
17	643	0.35	SJRWMD	
20*	621	0.21*	SJRWMD, FDER*	
21	621	0.03	SJRWMD	
23B	643	0.16	SJRWMD	
24	621	1.14	SJRWMD, FDER	36,784 L.F.
25 (Green Branch)	621	0.83	SJRWMD, FDER	4,482 W.F. 4,889 W.D.
27*	510	0.03*	FDER*	
28*	510	0.05*	FDER*	
41B	643	0.26	SJRWMD	
42	643	0.08	SJRWMD	
43	643	1.38	SJRWMD	
43	643	0.67	SJRWMD, FDER	3,373 L.F.
44	643	0.97	SJRWMD	

TOTAL IMPACT (AC):

	510	621	643	TOTAL
SJRWMD	--	5.59	4.48	10.07
FDER	--	3.03	0.67	3.70

TABLE 1

ALAFAYA TRAIL JURISDICTIONAL WETLANDS
(Southern Extent)
ICP/DOC and Deseret Ranch Properties
(Continued)

^aSee Permit Drawings (Sheet 2 of 13) for location of Wetlands

- ^b510 - Drainage ditch (dominant vegetation includes pickerelweed, cattails, primrose willow, pennywort, and beakrush)
621 - Cypress (dominant canopy includes cypress)
643 - Wet prairie (dominant vegetation includes St. Johns wort, maidencane, cattails, spike rush, bloodroot, and bacopa)

^cSJRWMD= St. Johns River Water Management District
FDER = Florida Department of Environmental Regulation

^dFDER = Cubic Yards (C.Y.) of Material
W.F. = Waterward Fill (4,982 C.Y.)
W.D. = Waterward Dredge (4,889 C.Y.)
L.F. = Landward Fill (45,495 C.Y.)**

* Wetlands which are "waters of the state" but qualify for a ditch block exemption pursuant to Section 403.913(4), F.S.

**Quantity includes 36,784 C.Y. of fill material for overpass approach ramps at Bee Line Expressway.

TABLE 1A

ALAFAYA TRAIL JURISDICTIONAL WETLANDS
(Northern Extent)
OUC Property

(For information purposes only - This portion
of wetland impacts will be addressed in the Power Plant
Siting Act Permit Application)

Wetland Number	FLUCFCS Category ^a	Project Impact Acreage	Agency Jurisdiction ^b	Cubic Yards of Material ^c
3 (Cowpen Branch)*	621	0.23*	SJRWMD, FDER*	
4	621	0.07	SJRWMD	
5	643	0.05	SJRWMD	
5A	621	0.32	SJRWMD	
7B	621	0.06	SJRWMD	
10 (Hart Branch)	630	0.54	SJRWMD, FDER	3,730 W.F. 892 W.D.
11	621	0.80	SJRWMD	
45	643	0.27	SJRWMD	
46	643	0.15	SJRWMD	
47	643	0.48	SJRWMD	
47	643	2.10	SJRWMD, (Pond 4 Dredge)	
48*	643	0.76*	SJRWMD, FDER*	
49	643	0.41	SJRWMD	
50	643	0.40	SJRWMD	
51	643	0.35	SJRWMD	
52	643	1.47	SJRWMD	
52	643	0.10	SJRWMD, (Pond 5 Dredge)	
53	643	0.97	SJRWMD	
54	643	0.37	SJRWMD	
55	643	0.11	SJRWMD	

TOTAL IMPACT (AC):

	621	630	643	TOTAL
SJRWMD	1.48	0.54	7.99	10.01
FDER	--	0.54	--	0.54

TABLE 1A

ALAFAYA TRAIL JURISDICTIONAL WETLANDS
(Northern Extent)
OUC Property

(For information purposes only - This portion
of wetland impacts will be addressed in the Power Plant
Siting Act Permit Application)
(CONTINUED)

- ^a510 - Drainage ditch (dominant vegetation includes pickerelweed, cattails, primrose willow, pennywort, and beakrush)
- 621 - Cypress (dominant canopy includes cypress)
- 630 - Mixed hardwood wetland (dominant canopy vegetation includes red maple, black gum, cypress, sweet bay, and red bay)
- 643 - Wet prairie (dominant vegetation includes St. Johns wort, maidencane, cattails, spike rush, bloodroot, and bacopa)

^bSJRWMD= St. Johns River Water Management District
FDER = Florida Department of Environmental Regulation

^cFDER = Cubic Yards (C.Y.) of Material
W.F. = Waterward Fill (3,730 C.Y.)
W.D. = Waterward Dredge (892 C.Y.)

* Wetlands which are "waters of the state" but qualify for a ditch block exemption pursuant to Section 403.913(4), F.S.

ATTACHMENT "C"

LEGAL DESCRIPTIONS

Legal Description: Interchange North of Bee Line

Commence at the Southwest corner of Section 29, Township 23 South, Range 32 East, Orange County, Florida; thence run N.00°04'38"W. along the West line of the Southwest 1/4 of said Section 29 a distance of 64.19 feet to a point on the North right of way line of the Bee Line Expressway (S.R. 528); thence leaving said West line run N.78°29'51"E. along aforementioned North right of way line a distance of 333.58 feet for a POINT OF BEGINNING; said point also being on a curve concave Northwesterly having a radius of 864.93 feet and a central angle of 13°31'01"; thence leaving said Northerly right of way from a tangent bearing of N.58°57'30"E. run Northensterly along the arc of said curve a distance of 204.05 feet to the point of tangency; thence run N.45°26'30"E. 564.35 feet to the point of curvature of a curve concave Southeasterly having a radius of 640.00 feet and a central angle of 26°02'37"; thence run Easterly along the arc of said curve 290.91 feet to the point of tangency; thence run N.71°29'07"E. 395.54 feet to the point of curvature of a curve concave Northwesterly having a radius of 460.00 feet and a central angle of 67°13'46"; thence run Northerly along the arc of said curve a distance of 539.75 feet to the point of tangency; thence run N.04°15'21"E. 460.03 feet; thence run N.00°26'30"E. 100.00 feet; thence run S.89°33'30"E. 47.20 feet; thence run N.00°26'30"E. 49.94 feet to the point of curvature of a curve concave Southwesterly having a radius of 2,201.83 feet and a central angle of 26°55'05"; thence run Northwesterly along the arc of said curve a distance of 1,034.44 feet; thence leaving said curve run S.61°10'52"W. 1,454.96 feet to the point of curvature of a curve concave Southeasterly having a radius of 910.00 feet and a central angle of 20°36'38"; thence run Southwesterly along the arc of said curve a distance of 327.35 feet to the point of tangency; thence run S.40°34'14"W. 230.78 feet to a point on the aforementioned West line of the Southwest 1/4 of Section 29; thence run N.00°04'38"W. along said West line of the Southwest 1/4 of Section 29 a distance of 276.32 feet; thence leaving said West line run N.40°34'14"E. 21.12 feet to the point of curvature of a curve concave Southeasterly having a radius of 1,090.00 feet and a central angle of 20°36'38"; thence run Northensterly along the arc of said curve a distance of 392.09 feet to the point of tangency; thence run N.61°10'52"E. 1,454.96 feet to a point on a curve concave Southwesterly having a radius of 2,201.83 feet and a central angle of 26°55'05"; thence from a chord bearing of N.44°37'14"W. run Northwesterly along the arc of said curve a distance of 1,034.44 feet to the point of tangency; thence run N.58°04'47"W. 1,017.85 feet to a point on the West line of the Northwest 1/4 of the aforementioned Section 29; thence run N.00°15'55"E. along said West line of the Northwest 1/4 of Section 29 a distance of 211.46 feet; thence leaving said West line run S.58°04'47"E. 1,128.83 feet to the point of curvature of a curve concave Southwesterly having a radius of 2,381.83 feet and a central angle of 58°31'17"; thence run Southeasterly along the arc of said curve a distance of 2,432.78 feet to the point of tangency; thence run S.89°33'30"E. 50.49 feet; thence run S.01°50'56"E. 541.33 feet to the point of curvature of a curve concave Northeasterly having a radius of 460.00 feet and a central angle of 42°42'34"; thence run Southeasterly along the arc of said curve a distance of 342.89 feet to the point of tangency; thence run S.44°53'34"E. 1,216.48 feet to the point of curvature of a curve concave Northeasterly having a radius of 626.20 feet and a central angle of 45°00'00"; thence run Southeasterly along the arc of said curve a distance of 491.81 feet to the point of tangency; thence run S.89°33'30"E. 909.80 feet to a point on the South line of the aforementioned Section 29; thence run S.89°35'34"W. along the South line of said Section 29 a distance of 2,436.71 feet to a point on the North right of way line of the Bee Line Expressway (S.R. 528); thence leaving said South line of Section 29 run the following courses and distances along said North right of way line: N.78°00'30"W. 1,151.69 feet; thence run S.78°29'51"W. 617.85 feet to the POINT OF BEGINNING.

Containing 71.189 acres, more or less.

LEGAL DESCRIPTION SECTION 32

Begin at the Southwest corner of Section 32, Township 23 South, Range 32 East, Orange County, Florida; thence run N.00°00'48"W. along the West line of the Southwest 1/4 of said Section 32 a distance of 30.00 feet to a point on a curve concave Northwesterly having a radius of 1,875.81 feet and a central angle of 89°21'32"; thence leaving said West line from a tangent bearing of N.89°48'02"E. run Northeasterly along the arc of said curve a distance of 2,925.53 feet to the point of tangency; thence run N.00°26'30"E. 382.18 feet to a point of curvature of a curve concave Southwesterly having a radius of 25.00 feet and a central angle of 90°00'00"; thence run Northwesterly along the arc of said curve a distance of 39.27 feet to the point of tangency; thence run N.89°33'30"W. 116.12 feet to the point of curvature of a curve concave Northeasterly having a radius of 2,339.83 feet and a central angle of 24°42'48"; thence run Northwesterly along the arc of said curve a distance of 1,009.23 feet to the point of tangency; thence run N.64°50'42"W. 815.73 feet to the point of curvature of a curve concave Southwesterly having a radius of 1,225.24 feet and a central angle of 00°52'29"; thence run Northwesterly along the arc of said curve a distance of 18.71 feet to a point on said curve said point also being on the West line of the Southwest 1/4 of said Section 32; thence leaving said curve run N.00°00'48"W. along the West line of the Southwest 1/4 of said Section 32 a distance of 53.07 feet to the West 1/4 corner of said Section 32; thence run N.00°09'42"E. along the West line of the Northwest 1/4 of said Section 32 a distance of 79.47 feet to a point on a curve concave Southwesterly having a radius of 1,347.24 feet and a central angle of 09°27'16"; thence leaving said West line from a tangent bearing of S.68°01'48"E. run Southeasterly along the arc of said curve 222.31 feet to the point of reverse curvature of a curve concave Northeasterly having a radius of 3,000.00 feet and a central angle of 06°16'10"; thence run Southeasterly along the arc of said curve 328.27 feet to the point of tangency; thence run S.64°50'42"E. 230.96 feet to the point of curvature of a curve concave Northeasterly having a radius of 2,243.83 feet and a central angle of 24°42'48"; thence run Southeasterly along the arc of said curve a distance of 967.82 feet to the point of tangency; thence run S.89°33'30"E. 216.07 feet to the point of curvature of a curve concave Northwesterly having a radius of 25.00 feet and a central angle of 90°00'00"; thence run Northeasterly along the arc of said curve a distance of 39.27 feet to the point of tangency; thence run N.00°26'30"E. 689.99 feet; thence run N.89°33'30"W. 47.07 feet; thence run N.00°26'30"E. 100.00 feet; thence run N.01°50'56"W. 626.90 feet to the point of curvature of a curve concave Southwesterly having a radius of 460.00 feet and a central angle of 68°45'11"; thence run

Northwesterly along the arc of said curve a distance of 551.9 feet to the point of tangency; thence run N.70°36'07"W. 400.84 feet to the point of curvature of a curve concave Northeasterly having a radius of 640.00 feet and a central angle of 26°02'37"; thence run Northwesterly along the arc of said curve a distance of 290.91 feet to the point of tangency; thence run N.44°33'30"W. 353.36 feet to the point of curvature of a curve concave Southwesterly having a radius of 1,342.40 feet and a central angle of 25°23'15"; thence run Northwesterly along the arc of said curve a distance of 594.81 feet to a point on said curve and on the South right of way line of the Bee Line Expressway (S.R. 528); thence leaving said curve run the following courses and distance along said South right of way line; thence run S.77°36'51"E. 811.60 feet; thence run N.78°29'51"E. 1,328.77 feet; thence run S.89°33'30"E. 5,430.32 feet; thence leaving said right of way line run S.89°17'45"W. 1,718.43 feet to the point of curvature of a curve concave Southeasterly having a radius of 5,639.58 feet and a central angle of 03°06'15"; thence run Southwesterly along the arc of said curve a distance of 305.55 feet to the point of reverse curvature of a curve concave Northwesterly having a radius of 11,549.16 feet and a central angle of 04°15'00"; thence run Southwesterly along the arc of said curve a distance of 856.68 feet to the point of tangency; thence run N.89°33'30"W. 1,265.00 feet to the point of curvature of a curve concave Southeasterly having a radius of 460.00 feet and a central angle of 45°00'00"; thence run Southwesterly along the arc of said curve a distance of 361.28 feet to the point of tangency; thence run S.45°26'30"W. 1,285.30 feet to the point of curvature of a curve concave Southeasterly having a radius of 460.00 feet and a central angle of 41°11'09"; thence run Southwesterly along the arc of said curve a distance of 330.66 feet to the point of tangency; thence run S.04°15'21"W. 460.03 feet; thence run S.00°26'30"W. 100.00 feet; thence run N.89°33'30"W. 47.20 feet; thence run S.00°26'30"W. 1,384.63 feet to the point of curvature of a curve concave Northwesterly having a radius of 2,055.81 feet and a central angle of 89°20'10"; thence run Southwesterly along the arc of said curve a distance of 3,205.44 feet to a point on said curve, said point also being on the West line of the Northwest 1/4 of Section 5, Township 24 South, Range 32 East Orange County, Florida; thence run N.00°32'51"W. along said West line a distance of 150.00 feet to the POINT OF BEGINNING;

Together with

Begin at the Northwest corner of Section 33, Township 23 South, Range 32 East, Orange County, Florida; thence run S.89°03'58"E. along the North line of the Northwest 1/4 of said Section 33 a distance of 1,405.12 feet; thence leaving said North line run S.00°26'30"W. 80.35 feet to the North right of way line of the Bee Line Expressway (S.R. 528); thence run the following courses and distances along said North right of way line; thence run N.89°33'30"W. 4,480.51 feet; thence run N.00°26'30"E. 9.33 feet; thence run N.78°00'30"W. 175.03 feet to a point on the North line of Section 32, Township 23 South, Range 32 East, Orange County, Florida; thence run N.89°35'38"E. along said North line a distance of 3,247.19 feet to the POINT OF BEGINNING.

Containing 87.405 acres, more or less.

LEGAL DESCRIPTION SECTION 30

Right of Way description (180 foot wide) Alafaya Trail Extension situate in the Northeast 1/4 of Section 30, Township 23 South, Range 32 East, Orange County, Florida; being more particularly bounded and described as follows:

Commence at the Northeast corner of Section 30, Township 23 South, Range 32 East, Orange County, Florida; thence run S.00 15'55"W. along the East line of the Northeast 1/4 of said Section 30 a distance of 742.18 feet for a POINT OF BEGINNING; thence continue S.00 15'55"W. along said East line a distance of 211.46 feet; thence leaving said line run N.58 04'47"W. 1,027.60 feet to the point of curvature of a curve concave Northeasterly having a radius of 2,173.48 feet and a central angle of 16 39'34"; thence run Northwesterly along the arc of said curve 631.97 feet to a point on the North line of the Northeast 1/4 of said Section 30; thence leaving said curve run N.89 51'23"E. along said North line of Section 30 a distance of 248.49 feet to a point on a curve concave Northeasterly having a radius of 1,993.48 feet and a central angle of 11 56'34"; thence from a tangent bearing of S.46 08'13"E. run Southeasterly along the arc of said curve 415.52 feet to the point of tangency; thence run S.58 04'47"E. 916.63 feet to the POINT OF BEGINNING.

ATTACHMENT "E"

MITIGATION PLAN
FOR THE
ALAFAYA TRAIL EXTENSION

SUBMITTED TO:
ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

SUBMITTED THROUGH:
MR. JAMES L. CLARK
INTERNATIONAL CORPORATE PARK (ICP)
933 LEE ROAD
SUITE 200
ORLANDO, FLORIDA 32810

SUBMITTED BY:
GREINER, INC.

REVISED AUGUST 6, 1990

MITIGATION PLAN

ALAFAYA TRAIL EXTENSION

1.0 INTRODUCTION

1.1 Background

On January 8, 1990, a Dredge and Fill Permit Application package was submitted to the St. Johns River Management District (SJRWMD) and the U.S. Corps of Engineers (ACOE) for approval to construct the Alafaya Trail Extension. Due to the Power Plant Certification Act, the application has been divided into two separate projects, -- the northern extent on Orlando Utilities Commission property (2.3 miles) and the southern extent on Florida Department of Corrections, International Corporate Park, and Deseret Ranch properties (1.9 miles). It is the southern extent for which the dredge and fill permit application (Application No. 12-095-0040A) is being modified. The total mitigation plan, however, is proposed for the whole Alafaya Trail Extension alignment.

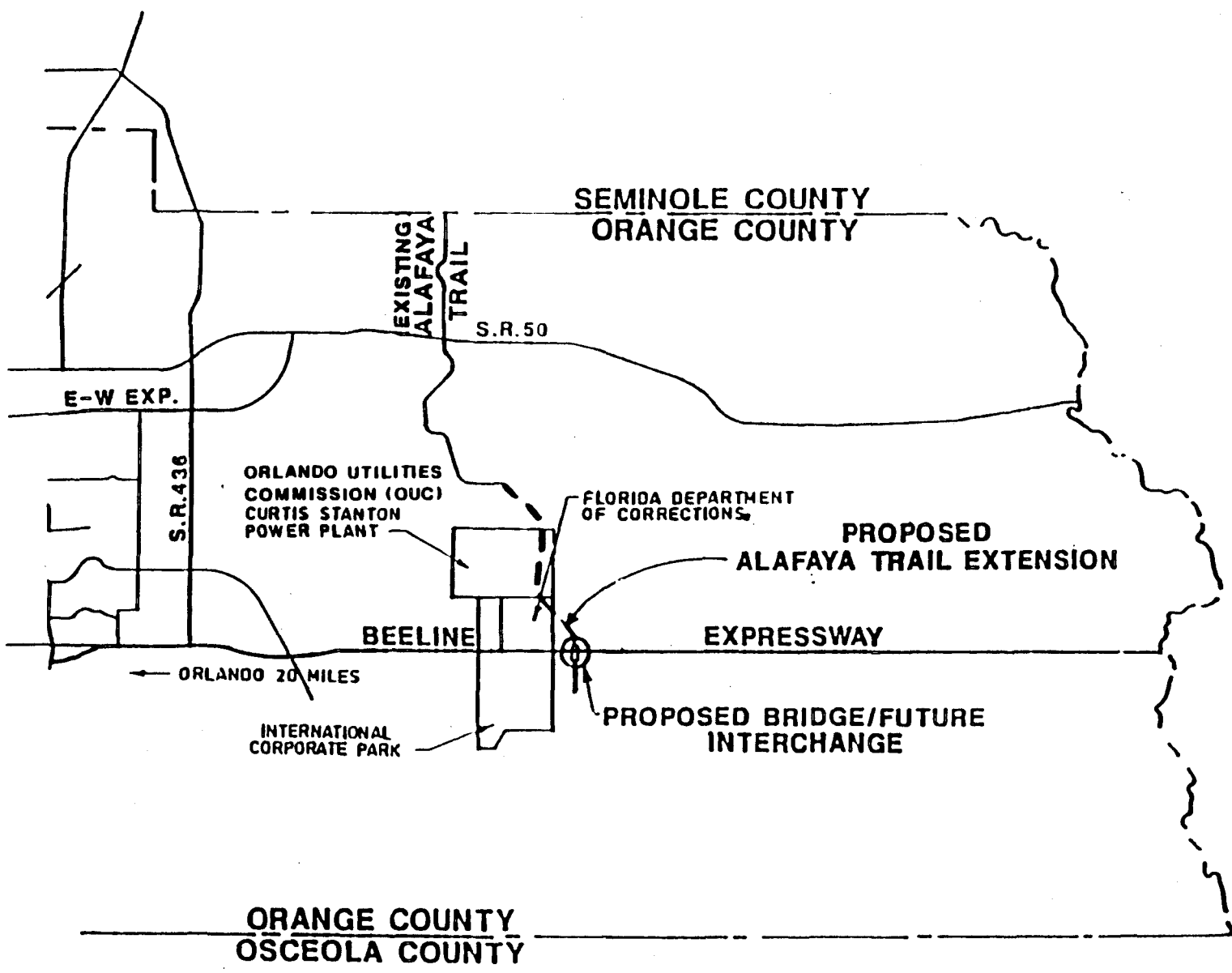
International Corporate Park (ICP) plans to build an extension to Alafaya Trail in east Orange County which will consist of 4.2 miles of two-lane roadway improvements and a new bridge structure over the Bee Line Expressway. This modification to the permit application consists of the southern terminus, which is approximately 1.9 miles and crosses over the Bee Line Expressway, and will terminate 3,000 feet south of the Bee Line Expressway.

1.2 Scope of Work

The planning phase of the Alafaya Trail Extension project provided every effort to avoid and minimize adverse impacts to wetlands and their functions. For this application it has been determined that there are 10.07 acres of SJRWMD's jurisdictional wetlands and 3.70 acres of Florida Department of Environmental Regulation's (FDER) jurisdictional wetlands which will be impacted by this project (southern terminus). To compensate for the unavoidable environmental impact to these wetlands and wetlands impacted by the northern portion which will be permitted under the Power Plant Certification Act, these projects (including the northern extent and the southern terminus) propose to create 1.23 acres of a hardwood wetland community, 9.29 acres of cypress wetlands, 12.76 acres of freshwater marsh, 17.96 acres of restoration/enhancement to existing wetland communities, retain a 2.18-acre 50-foot upland buffer, and the permanent preservation of these systems.

2.0 GENERAL SITE DESCRIPTION OF THE PROJECT AREA

The project areas begin 3,000 feet south of the Bee Line Expressway and extend north 4.2 miles to adjoin the southern terminus of the existing Alafaya Trail in Sections 18, 19, 29, 30, and 32, Township 23S, Range 32E, Orange County, Florida (see Figures 1 and 2).

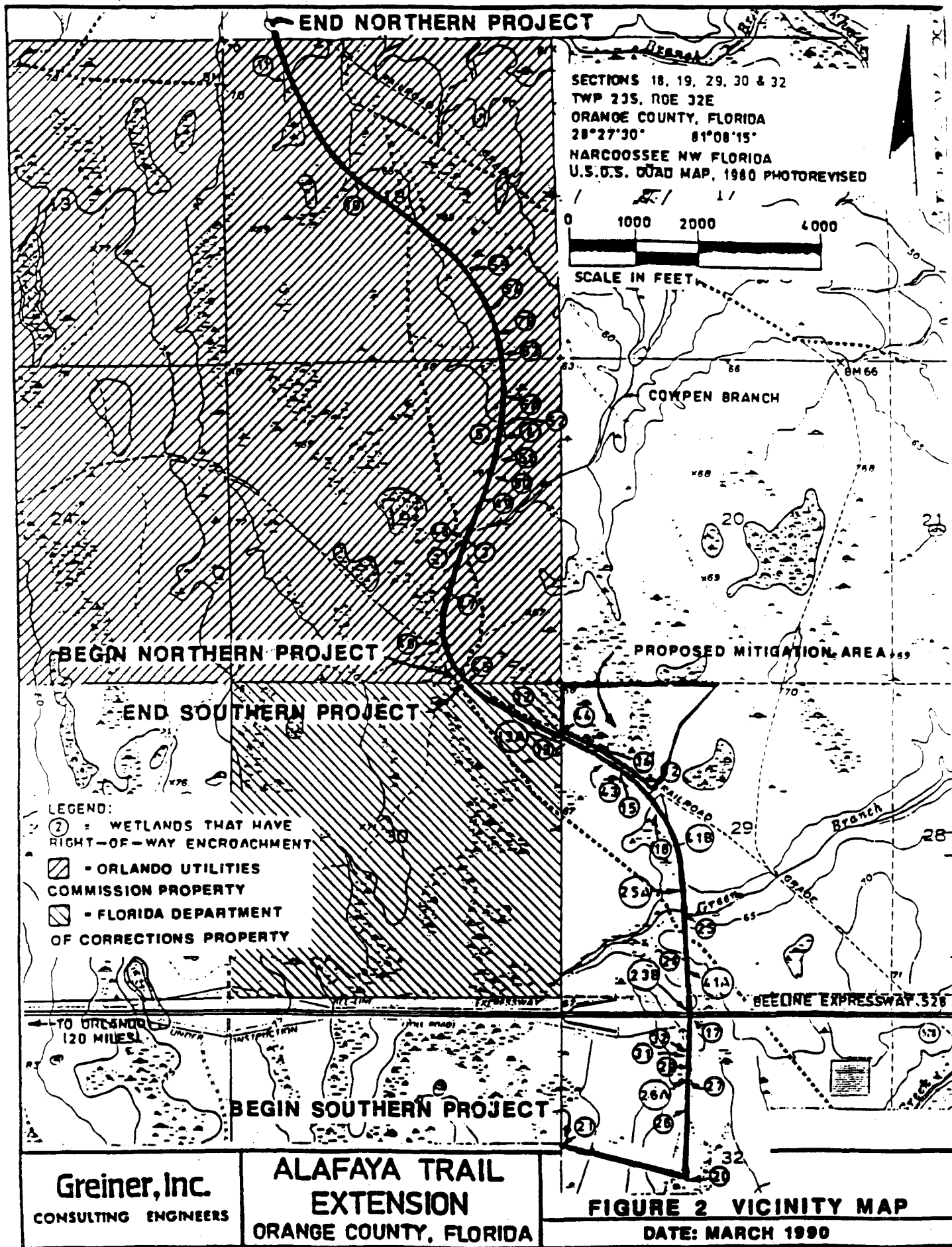


Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

FIGURE 1 VICINITY MAP

DATE: MARCH 1990
REVISED: JULY 1990



2.1 Wetland Communities

Table 1 identifies each wetland by agency jurisdiction (southern extent) along with the amount of wetland encroachment of the project (by acreage) and the wetland vegetation community (using the Florida Land Use, Cover and Forms Classification System - FLUCFCS). Green Branch (Wetland No. 25) will be crossed by the project. This system collects surrounding surface waters and drains them northeast to the Econlockhatchee River.

Attached is Table 1A which lists each wetland by agency jurisdiction, amount of wetland encroachment (by acreage), and the wetland vegetation community affected by the Alafaya Trail Extension (northern extent on OUC property). The northern portion of the alignment located on OUC property is not considered part of this permit application. However, the impacts to wetlands within the northern extent (OUC property) and the southern extent (ICP/DOC and Deseret Ranch properties) will be compensated in this mitigation plan. The permit application for the northern extent on OUC property will be submitted under the State of Florida Power Plant Siting Act.

The wetlands that exist in the project site are small isolated wetlands as well as larger wetland systems within the surrounding area. Wetland categories include drainage ditches (510), cypress (621), mixed hardwood forests (630), and wet prairies (643).

Plant species found in the man-made upland ditches (510) include pickerelweed (Pontederia cordata), cattails (Typha sp.), primrose willow (Ludwigia sp.), beakrush (Rhynchospora corniculata), softrush (Juncus effusus), and pennywort (Hydrocotyle sp.).

Vegetation associated with cypress wetlands (621) include primarily pond cypress (Taxodium ascendens) with some black gum (Nyssa sylvatica var. biflora) and red maple (Acer rubrum). Isolated pockets of submerged herbaceous vegetation, including pickerelweed and swamp fern (Blechnum serrulatum) are present within the cypress areas.

Vegetation within the mixed hardwood wetlands (630) include red maple, black gum, cypress, sweet gum, (Liquidambar styraciflua), red bay (Persea borbonia), and wax myrtle (Myrica cerifera). Yellow eyed grass (Xyris sp.), swamp fern, cinnamon fern (Osmunda cinnamomea), and maidencane are present as ground cover.

Vegetation associated with the wet prairies (643) include cattails, maidencane (Panicum hemitomon), spike rush (Eleocharis sp.), St. Johns wort (Hypericum sp.), bloodroot (Lachnanthes caroliniana), and bacopa (Bacopa caroliniana).

2.2 Soils

There are three soil types found within the project site. They are mapped as Rutledge fine sand (Ra), Plummer fine sand (Pb), and Leon fine sand (Lf). The site is characterized by broad strips of better drained Leon

TABLE 1

ALAFAYA TRAIL JURISDICTIONAL WETLANDS
(Southern Extent)
ICP/DOC and Deseret Ranch Properties

Wetland Number ^a	FLUCFCS Category ^b	Project Impact Acreage	Agency Jurisdiction ^c	Cubic Yards of Material ^d
12	621	0.55	SJRWMD	
12	643	0.41	SJRWMD	
13	621	0.56	SJRWMD, FDER	2,820 L.F. 500 W.F.
13	621	0.32	SJRWMD	
14	621	0.50	SJRWMD, FDER	2,518 L.F.
15	621	0.58	SJRWMD	
15	643	0.20	SJRWMD	
16	621	0.87	SJRWMD	
17	643	0.35	SJRWMD	
20*	621	0.21*	SJRWMD, FDER*	
21	621	0.03	SJRWMD	
23B	643	0.16	SJRWMD	
24	621	1.14	SJRWMD, FDER	36,784 L.F.
25 (Green Branch)	621	0.83	SJRWMD, FDER	4,482 W.F. 4,889 W.D.
27*	510	0.03*	FDER*	
28*	510	0.05*	FDER*	
41B	643	0.26	SJRWMD	
42	643	0.08	SJRWMD	
43	643	1.38	SJRWMD	
43	643	0.67	SJRWMD, FDER	3,373 L.F.
44	643	0.97	SJRWMD	

TOTAL IMPACT (AC):

	510	621	643	TOTAL
SJRWMD	--	5.59	4.48	10.07
FDER	--	3.03	0.67	3.70

TABLE 1

ALAFAYA TRAIL JURISDICTIONAL WETLANDS
(Southern Extent)
ICP/DOC and Deseret Ranch Properties
(CONTINUED)

^aSee Figure 2 for location of Wetlands

- ^b510 - Drainage ditch (dominant vegetation includes pickerelweed, cattails, primrose willow, pennywort, and beakrush)
621 - Cypress (dominant canopy includes cypress)
643 - Wet prairie (dominant vegetation includes St. Johns wort, maidencane, cattails, spike rush, bloodroot, and bacopa)

^cSJRWMD= St. Johns River Water Management District
FDER = Florida Department of Environmental Regulation

^dFDER = Cubic Yards (C.Y.) of Material
W.F. = Waterward Fill (4,982 C.Y.)
W.D. = Waterward Dredge (4,889 C.Y.)
L.F. = Landward Fill (45,495 C.Y.)**

* Wetlands which are "waters of the state" but qualify for a ditch block exemption pursuant to Section 403.913(4), F.S.

**Quantity includes 36,784 C.Y. of fill material for overpass approach ramp at Bee Line Expressway.

TABLE 1A

ALAFAYA TRAIL JURISDICTIONAL WETLANDS
(Northern Extent)
OUC Property

(For information purposes only - This portion
of wetland impacts will be addressed in the Power Plant
Siting Act Permit Application)

Wetland Number ^a	FLUCFCS Category ^b	Project Impact Acreage	Agency Jurisdiction ^c	Cubic Yards of Material ^d
3 (Cowpen Branch)*	621	0.23*	SJRWMD, FDER*	
4	621	0.07	SJRWMD	
5	643	0.05	SJRWMD	
5A	621	0.32	SJRWMD	
7B	621	0.06	SJRWMD	
10 (Hart Branch)	630	0.54	SJRWMD, FDER	3,730 W.F. 892 W.D.
11	621	0.80	SJRWMD	
45	643	0.27	SJRWMD	
46	643	0.15	SJRWMD	
47	643	0.48	SJRWMD	
47	643	2.10	SJRWMD, (Pond 4 Dredge)	
48*	643	0.76*	SJRWMD, FDER*	
49	643	0.41	SJRWMD	
50	643	0.40	SJRWMD	
51	643	0.35	SJRWMD	
52	643	1.47	SJRWMD	
52	643	0.10	SJRWMD, (Pond 5 Dredge)	
53	643	0.97	SJRWMD	
54	643	0.37	SJRWMD	
55	643	0.11	SJRWMD	

TOTAL IMPACT (AC):

	621	630	643	TOTAL
SJRWMD	1.48	0.54	7.99	10.01
FDER	--	0.54	--	0.54

7001 10.54

TABLE 1A

ALAFAYA TRAIL JURISDICTIONAL WETLANDS
(Northern Extent)
OUC Property

(For information purposes only - This portion
of wetland impacts will be addressed in the Power Plant
Siting Act Permit Application)
(CONTINUED)

^aSee Figure 2 for location of Wetlands

- ^b510 - Drainage ditch (dominant vegetatin includes pickerelweed, cattails, primrose willow, pennywort, and beakrush)
- 621 - Cypress (dominant canopy includes cypress)
- 630 - Mixed hardwood wetland (dominant canopy vegetation includes red maple, black gum, cypress, sweet bay, and red bay)
- 643 - Wet prairie (dominant vegetation includes St. Johns wort, maidencane, cattails, spike rush, bloodroot, and bacopa)

^cSJRWMD= St. Johns River Water Management District
FDER = Florida Department of Environmental Regulation

^dFDER = Cubic Yards (C.Y.) of Material
W.F. = Waterward Fill (3,730 C.Y.)
W.D. = Waterward Dredge (892 C.Y.)

* Wetlands which are "waters of the state" but qualify for a ditch block exemption pursuant to Section 403.913(4), F.S.

fine sand paralleled by narrow convoluted strips of poorly drained Plummer fine sand and Rutledge fine sand soils. Of these, Plummer fine sand and Rutledge fine sand have characteristics of being inundated or saturated on an average of 30 consecutive days or more per year, according to the USDA Soil Conservation Service. These soils indicate that the area is flat with little slope for runoff. Hydric soils typically support wetland vegetation that corresponds to the St. Johns River Water Management District and Florida Department of Environmental Regulation's Index List (Chapter 17-3.022, F.A.C., and Rule 40C-4, Florida Statutes). Plummer fine sand and Rutledge fine sand are considered hydric soils unless altered by drainage or drought conditions.

2.3 Topography

Elevations on the site vary from 60 feet above sea level in the southern portion, south of the Bee Line Expressway, to 68 feet along the western half of the site. The three branches provide drainage of surface water from the project site, consisting of pine flatwoods and wet prairies, northeast toward the Econlockhatchee River. There are numerous shallow depressions or isolated cypress wetlands that are scattered throughout the area. Several of these shallow depressions temporarily retain surface water and spill over into the next depression forming an intermittent chain of wetlands during storm events. Many of these systems have been ditched around their perimeters to permanently eliminate saturated ground conditions.

3.0 WETLANDS MITIGATION PLAN

3.1 Proposed Impact To Wetlands

The mitigation plan compensates for the loss of approximately 20.08 acres of SJRWMD jurisdictional wetlands and 4.24 acres of FDER jurisdictional wetlands that will be affected by the entire alignment of both the northern section and southern sections of Alafaya Trail Extension (4.2 miles). Approximately 10.07 acres of SJRWMD jurisdictional wetlands and 3.07 acres of FDER jurisdictional wetlands (Table 1) will be affected by the southern alignment (1.9 miles).

The three branches will be culverted by either appropriately sized pipes or concrete arched culvert which are adequately sized to meet flow conditions for storm events. The arch concrete culverts at Green and Hart Branches have been oversized in order to span the main channel of each branch. This will not change the hydroperiod or drainage practices of Green Branch and Hart Branch.

3.2 Mitigation Site

The mitigation site is located within and adjacent to a portion of the proposed Alafaya Trail Extension right-of-way in the northwest corner of Section 29, Township 23S, Range 32E, Orange County, Florida (see Figure 2).

Existing topographic elevations of the proposed mitigation site average between 62 and 65 feet mean sea level. The mitigation site encompasses approximately 50 acres of uplands and wetlands of which 17.96 acres of altered wetlands exist as isolated cypress systems or wetlands connected off-site. Several drainage ditches have been historically constructed to drain existing wetlands and along on old railroad bed. Upland areas consist as palmetto prairies with a few scattered pines.

3.3 Wetlands Mitigation Plan

The wetlands mitigation plan includes the construction conversion of upland areas into a mixed hardwood wetland (1.23 acres), cypress (9.29 acres), and marshes (12.76 acres); restoration/enhancement of existing wetland communities (17.96 acres); and the preservation of an upland buffer (2.18 acres) as shown on Figures 3 and 4. In the center of the mitigation area will be a 3.00-acre bermed stormwater detention pond which will have a 0.91-acre littoral shelf. A 4.0-acre borrow site will also be located adjacent to the detention pond.

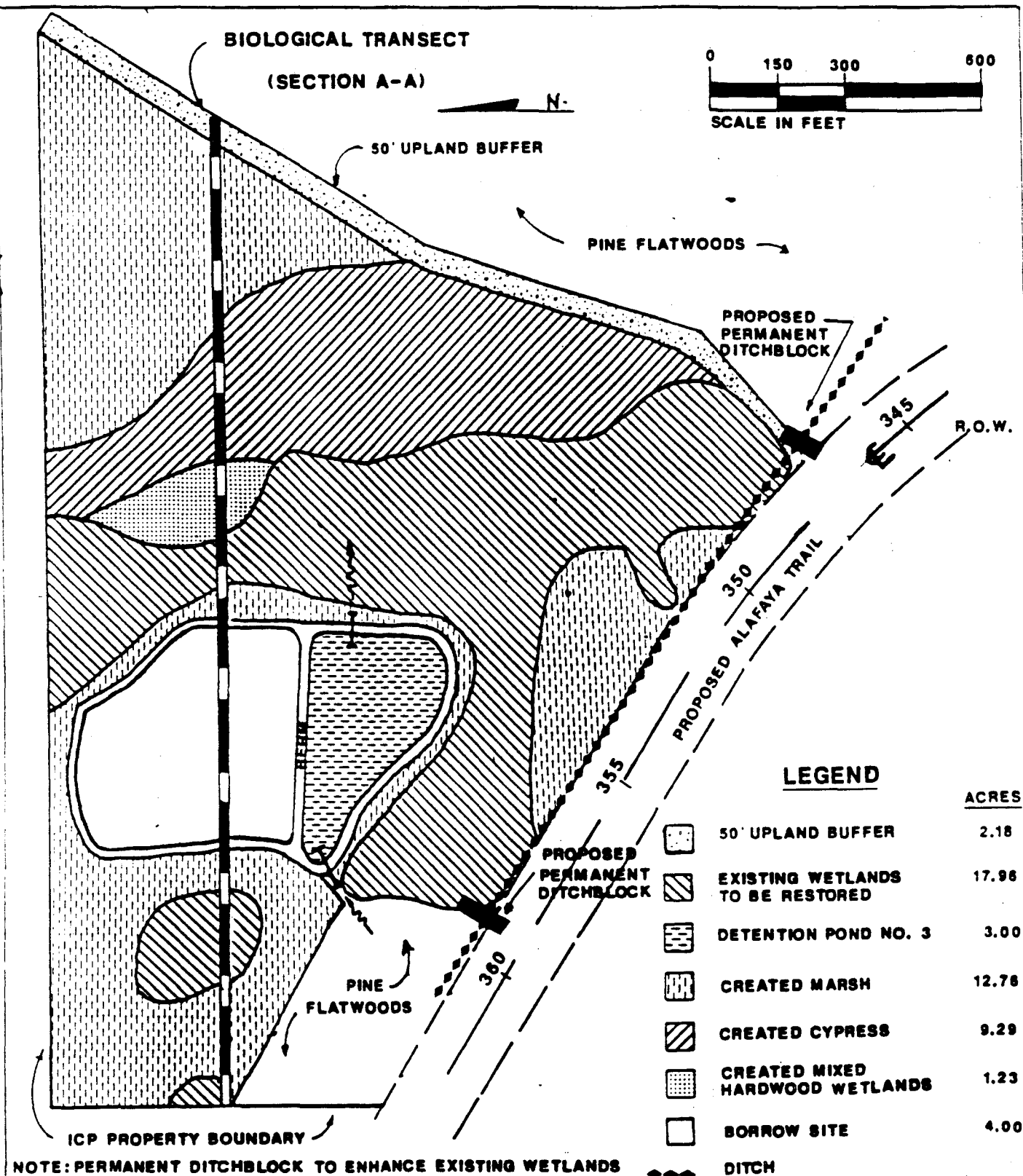
The detention pond and the borrow site will not be considered as part of the mitigation compensation for SJRWMD or FDER. However, the littoral zone within the detention pond will be used as mitigation credit with the U.S. Army Corps of Engineers (COE). Wildlife will utilize the wet detention pond for foraging and possible nesting as if the system was a natural wetlands. The littoral zone will be planted with herbaceous species (i.e., maidencane, pickerelweed, etc.).

The following plan should compensate for the wetland impacts on-site.

1. The wetland mitigation plan will consist of the components listed on Table 2.

Vegetation species will be selected from the preceding list and in accordance with established planting schedules. Species selection will be approved by the appropriate agency(ies). Lines of planting shall be meandered to simulate natural occurrence.

2. A six-inch (6") muck blanket will be placed in the created marsh areas. If herbaceous plants colonize successfully within a year, no herbaceous planting will be initiated. As part of the contingency plan the plants listed in Tables 2 and 3 and Figure 5 will be used.
3. Tree species will be installed with spacing and density as depicted on Table 3 and Figures 6 and 7.
4. Planting of tree species will be supervised to ensure shock is minimal and that their survivability is increased. Planting of herbaceous species, if required, will be conducted in early spring or summer to avoid chance of frost and allow establishment of root systems prior to the rainy seasons.



PROPOSED MITIGATION PLAN

GREINER, INC
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE CO., FLORIDA

FIGURE 3 PLAN VIEW

DATE: MARCH 1990 REV. MAY 1990

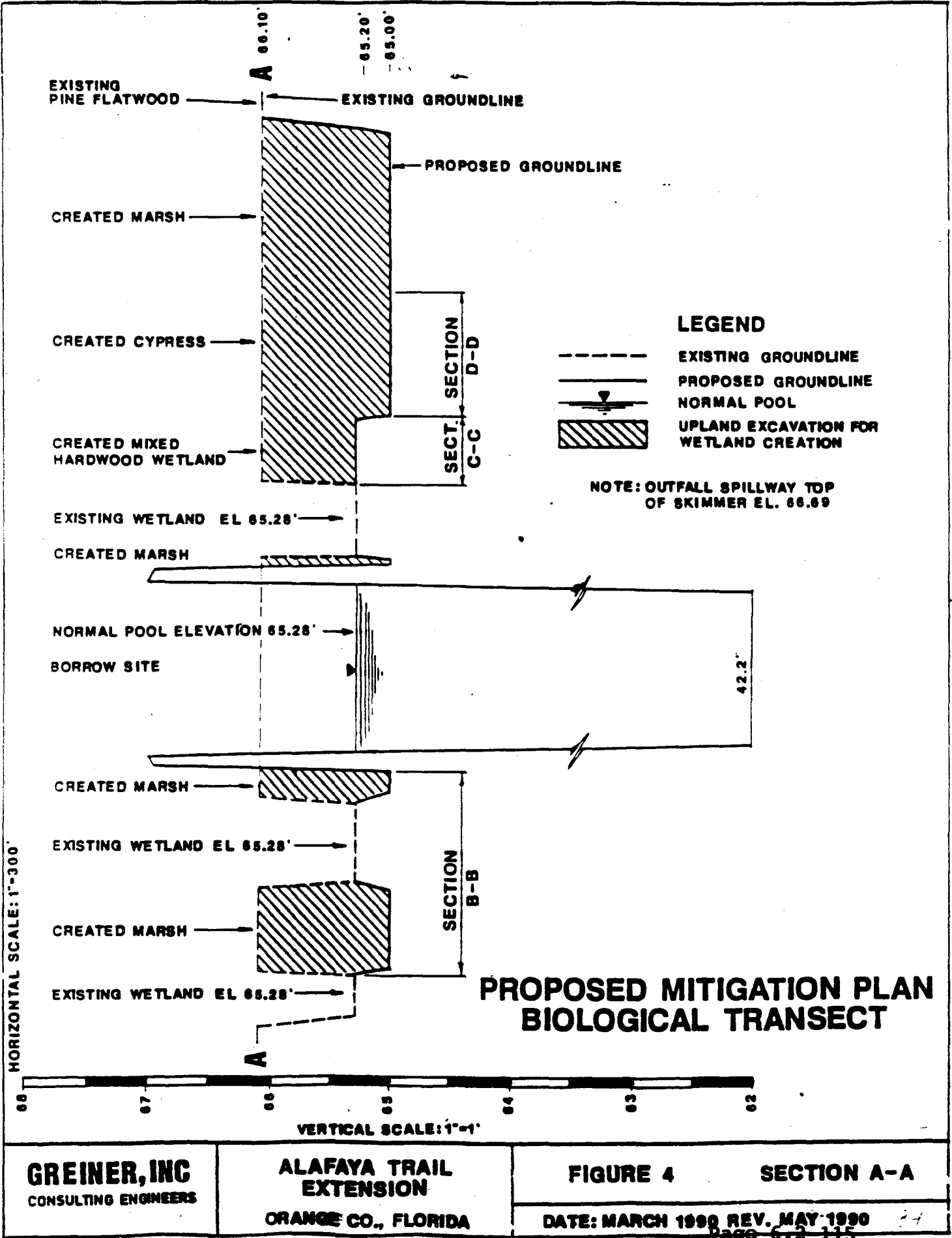


TABLE 2

WETLAND MITIGATION PLANTING AREAS

AREA	ELEVATION	ACREAGE	RECOMMENDED PLANT SPECIES
Created Marsh*	12" below existing grade	12.76	*Pickerelweed (<u>Pontederia cordata</u>) *Arrowhead (<u>Sagittaria</u> spp.) *Soft Rush (<u>Juncus effusus</u>) *Cordgrass (<u>Spartina bakerii</u>)
Created Cypress	12" below existing grade	9.29	Cypress (<u>Taxodium</u> spp.) Tupelo (<u>Nyssa</u> spp.)
Created Mixed Hardwood Wetland	9" below existing grade	1.23	Red Maple (<u>Acer rubrum</u>) Dahoon Holly (<u>Ilex cassine</u>) Water Oak (<u>Quercus nigra</u>) Laurel Oak (<u>Quercus laurifolia</u>)
Littoral Zone of Detention Ponds	Normal Pool to 2' below normal pool elevation	3.73	Pickerelweed (<u>Pontederia cordata</u>) Arrowhead (<u>Sagittaria</u> spp.) Soft Rush (<u>Juncus effusus</u>) Cordgrass (<u>Spartina bakerii</u>)
Wetland Restoration/ Enhancement	Existing Elevation	17.96	None
Upland Buffer	Existing Elevation	2.18	None
TOTAL MITIGATION CREDIT		43.42	
PLUS LITTORAL SHELF		<u>3.73</u>	
		47.15	

NOTE: Mitigation Ratios for the Alafaya Trail Extension Mitigation Site:
(Including the northern and southern extent)

	<u>Creation</u>	<u>Restoration</u>	<u>Total</u>
FDER	5.5:1	4.2:1	9.7:1
SJRWMD	1.2:1	0.9:1	2.1:1

* A 6" thick muck blanket will be placed in the created marsh areas. If herbaceous plants colonize successfully within a year, the above listed herbaceous planting will not be initiated.

TABLE 3

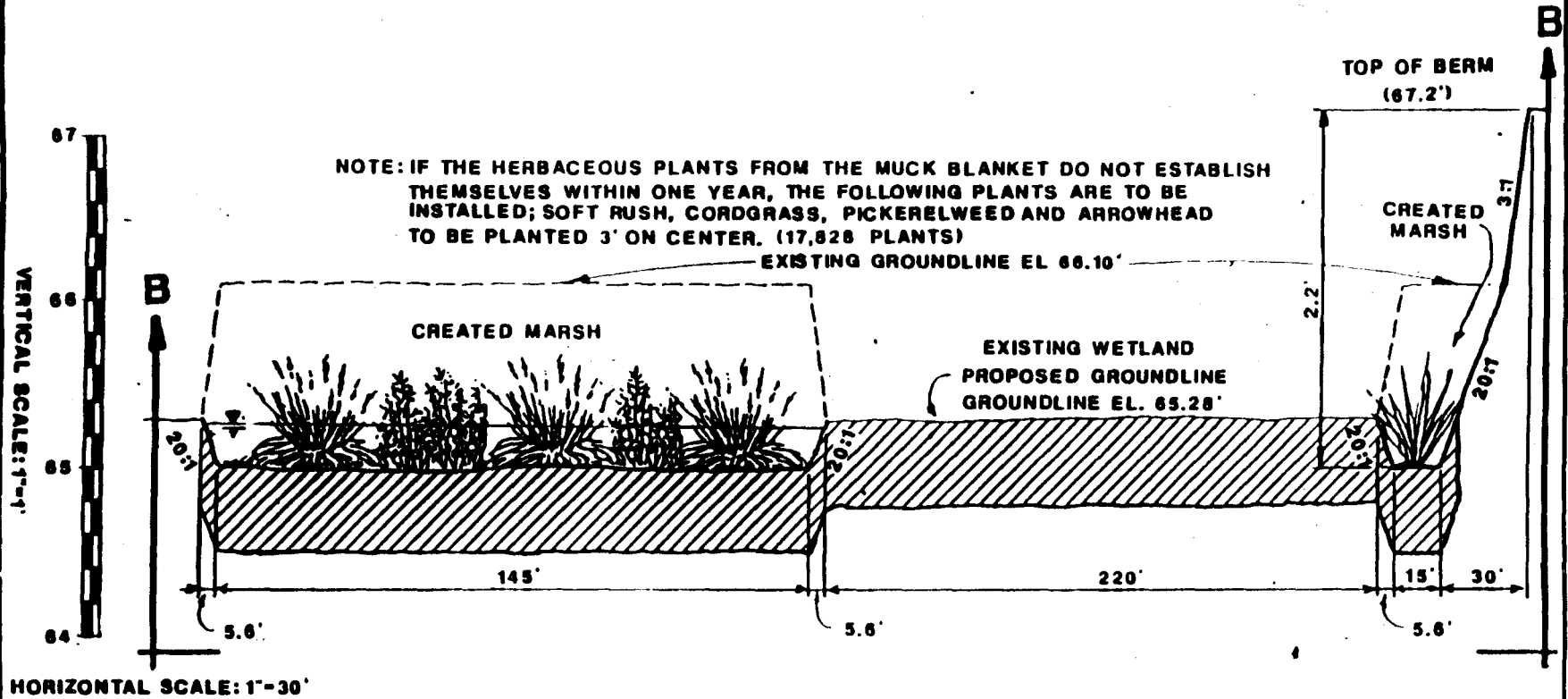
WETLAND MITIGATION PLAN
PLANT SPACING AND DENSITY

SPECIES	AREA	SLOPE	ON-CENTER SPACING	SIZE SPECIFICATION	REMARKS
Red Maple Dahoon Water Oak Laurel Oak	Created Mixed Hardwood Wetland	20:1	10 feet	three gallon	
Cypress* Typhelo	Created Cypress	20:1	10 feet	three gallon	
Pickersweed Arrowhead Soft Rush Cordgrass	Created Marsh** & Littoral Zone	6:1 to 12:1	3 feet	1.5 to 2 feet 5 to 7 petioles or stems	Species staggered. Plants in cluster spaced 3 feet on center.

* Primarily Cypress will be planted in this area.

** A 6" thick muck blanket will be placed in the created marsh area. If herbaceous plants colonize successfully within a year, the above listed herbaceous planting will not be initiated.

NOTE: Mulching from good wetland sources will occur in the created forested wetlands to allow for herbaceous plant species to revegetate naturally.



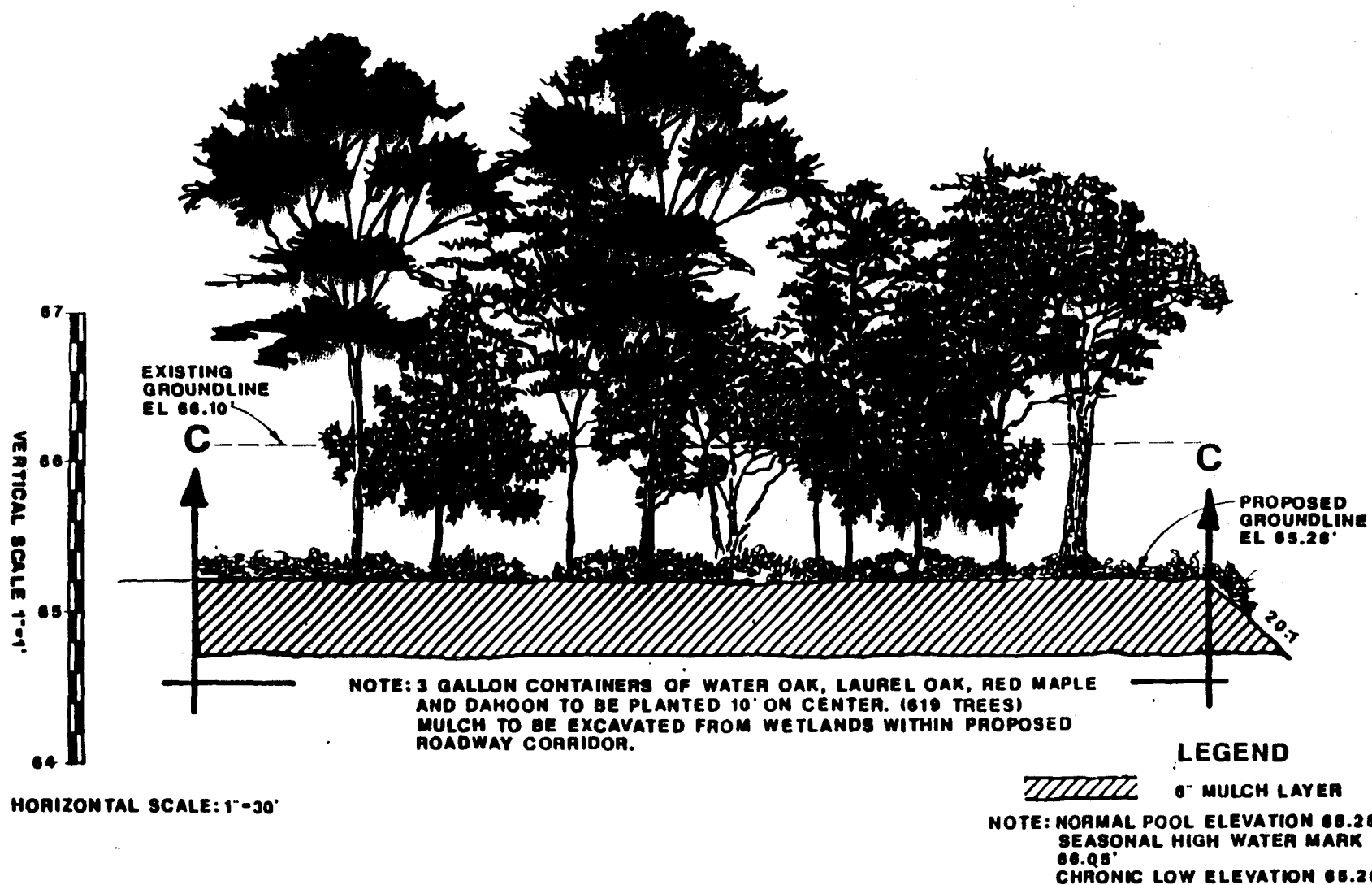
HORIZONTAL SCALE: 1"=30'

LEGEND

6 INCH MUCK BLANKET

NOTE: NORMAL POOL ELEVATION 65.28'
SEASONAL HIGH WATER MARK 66.05'
CHRONIC LOW ELEVATION 65.20'

**CREATED MARSH
CROSS SECTION**



CREATED MIXED HARDWOOD WETLAND CROSS SECTION

GREINER, INC
CONSULTING ENGINEERS

ALAFAYA TRAIL
EXTENSION
ORANGE CO., FLORIDA

FIGURE 6 SECTION C-C

DATE: MAY 1990

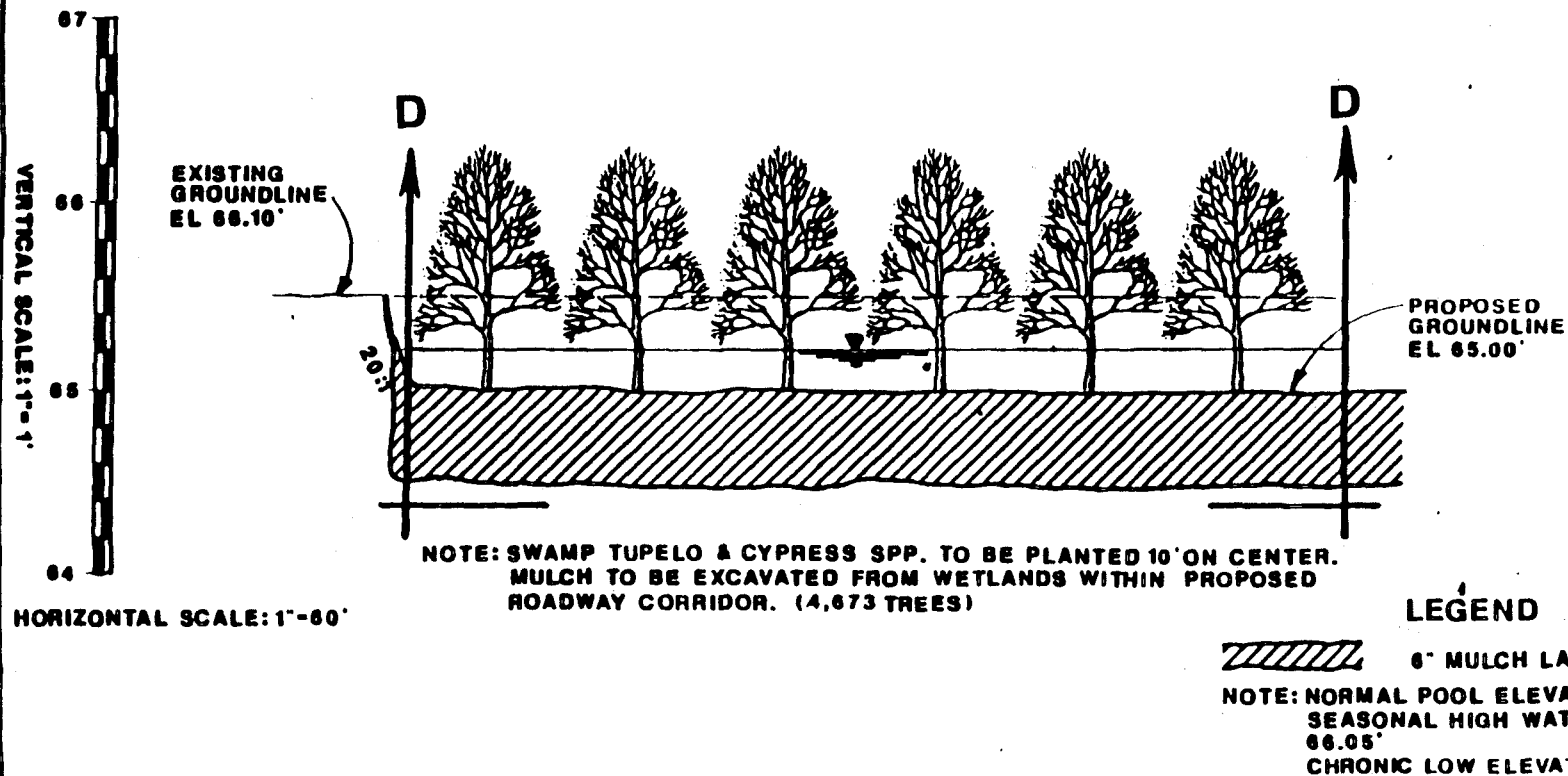
REVISED: JUNE 1990

GREINER, INC
CONSULTING ENGINEERS

ALAPAYA TRAIL
EXTENSION
ORANGE CO., FLORIDA

FIGURE 7 SECTION D-D

DATE: MAY 1990



CREATED CYPRESS
CROSS SECTION

5. All created wetlands will be inspected by a biologist/ecologist and engineer for optimum hydrological conditions, water table elevations, design slope, and design contours prior to planting. No planting will begin until all of the above conditions and special conditions of the permit are met. The Contractor will maintain a saturated soil condition during plant installation within the created wetlands.
6. After construction of the wetlands mitigation area is complete, engineer's as-built certification will be submitted to the appropriate regulatory agency(ies) for final inspection and approval for sign-off.
7. Construction of the wetland creation areas will occur at the time of land clearing of the road alignment. The creation areas will be mulched and planted as soon as existing wetlands are impacted.
8. The mitigation area will be recorded as a permanent conservation easement and no wetland destruction/alteration can take place within this easement.
9. The creation of littoral shelves around all six project detention ponds located adjacent to the Alafaya Trail Extension will consist of 3.73 acres.
10. The placement of two "critter crossings" at Green Branch and Hart Branch will consist of 48-inch concrete pipes.
11. The existing wetlands within the mitigation area will be enhanced. Ditches that drain these wetlands will be blocked to allow the distressed hydroperiod to return to pre-existing conditions.

Existing Wetland Conditions

The adjacent cypress system to the proposed mitigation site is dominated by cypress (Taxodium spp), with understory of dahoon (Ilex cassine) and wax myrtle (Myrica cerifera). Ground cover consists of swamp fern (Blechnum serrulatum), grasses, sedges and vines.

This system is inundated periodically and fluctuates in accordance with natural wet and dry seasonal cycles.

There is a swale that is cut from this wetland to the next cypress system, which drains this system. These restored wetlands are to receive enhancement credit.

Assurance of Success

The monitoring plan and maintenance program provide a check and balance to ensure continued performance of the created wetlands. Any non-compliance deviation will be corrected and noted in the annual report.

Tree and Herbaceous Species Density

The freshwater marsh, if required to be planted, will have approximately 1,397 plants installed per acre for a total of 17,828 plants.

The mixed hardwood wetland will have approximately 503 trees (three-gallon size) installed per acre for a total of 619 trees.

The created cypress wetlands will have approximately 503 trees per acre (three-gallon size) installed per acre for a total of 4,673 trees (9.29 acres).

3.4 WETLANDS MONITORING AND MAINTENANCE PROGRAM

The following monitoring and maintenance program will be implemented for the wetlands mitigation plan after installation of the plant species. Figure 4 is a plan view showing typical location of a transect through the created and existing wetlands to be monitored.

Annual reports are to evaluate the success of the wetlands and provide corrective measures that will make the wetland successful, if needed.

1. The Contractor is required to monitor the planted areas bi-annually for the first year and then annually the last two years to document the success of the mitigation plan. Each monitoring episode will include photo documentation, percent survival, percent cover and percent undesirables. An annual report of findings and recommendations for the mitigation plan will be submitted to the appropriate governmental agency(ies).
2. All plants installed in the created wetlands will be guaranteed for at least 80% survival rate for three years in the mitigation area.
3. The Contractor is expected to replant those plant materials which do not achieve the 80% survival rate for three years in the mitigation area.
4. A maintenance program is vital for any created wetlands to be successful. Undesirable species, such as cattails, primrose willow, and exotics are to be removed/eliminated from the created wetlands annually after the plants are installed. The exotics/nuisance species should not exceed above 10 percent in ground cover.
5. ICP will issue a maintenance bond to Orange County and be responsible for three years' monitoring, maintenance, and success. After three years, the County will be responsible for monitoring, maintenance and success of the mitigation area.

6. As recorded in the Orange County Plat Book (OR BK. 3802, Pages 4466 through 4496) and as a condition of ICP's Development Order (DO), ICP is required to design and construct Alafaya Trail Extension. This DO was adopted and signed by the Orange County Board of County Commissioners June 30, 1986.

Vegetation Sampling and Data Analysis Methods

Field sampling to determine the success of the created wetlands is described below:

Two permanent elongated quadrants (transect quadrants measuring 30 feet by 60 feet) will be established in each created wetland (cypress, mixed hardwood wetland and freshwater marsh). A PVC pipe 10 feet in length will be placed in the ground at 30-foot intervals and at the end of the elongated (60-foot) portion of each quadrant. All vegetation strata will be monitored by sampling of 10 square foot plots for percent coverage of herbaceous species and stem counts of woody vegetation. The vegetation sampling frequency schedule will commence at the end of the planting phase of each wetland created.

All systems will be sampled in June each year for a total of three years. Each wetland created will have a survival rate of 80%.

Shrubs will be sampled by noting points along the transect line where canopies of shrubs intercept the line. Species of shrub, beginning and ending intercept points of shrub canopy, and number of shrubs will be recorded. Shrub data will be used to determine density and relative cover of shrubs in each wetland plot.

Cover data for each species will be generated on number of species, approximate percent cover (by cover) and frequency of occurrence of each species.

Photographic documentation of the mitigation/monitoring (fixed) sites will be provided in the annual report.

Water level will be monitored by placing a permanent staff gage in each wetland created. The water levels will be monitored monthly during construction and for three years following buildout. A rain gage will also be installed to provide information on monthly precipitation.

Data Analysis Methods

The following information on community structure will be collected for canopy and sub-canopy species:

Density = the average number of individuals per acre sampled (also number of stems of each species per acre).

Dominance = dominance of a single species divided by total number of all species expressed as 100%.

Relative Cover = Cover of individuals of single species divided by cover of individuals of all species (expressed as a percent).

Frequency = an expression of the percentage of sample plots in which a species occurs over time.

Annual Report

An annual report will be provided to the appropriate agency within 60 days of the completion of the last sampling, which will include construction/plant installation phase of the created wetlands and one year sampling results. Areas not achieving a minimum of 80% coverage will be replanted with the appropriate species. Any additional mitigative measures, if needed, will be addressed in the annual report.

ATTACHMENT "F"

CALCULATED FLOW RATES

03.07.90 10:29AM

LOCHRANE ENGINEERING, INC.

201 S. Bumby Avenue
ORLANDO, FL 32803
(407) 896-3317

SHEET NO

OF

CALCULATED BY

Cal

DATE

CHECKED BY

DATE

SCALE

Green Branch Crossing

$$Q = C i A$$

$$C = 0.15 \text{ (Flat Woodlands)}$$

$$t_c = 14.41 \text{ hrs}$$

EDYR

$$Q = 0.15 (.035 \text{ in/hr}) 1944 \text{ AC}$$

$$= 169.13 \text{ cfs}$$

$$\# 90" \phi @ S=0\%$$

100YR

$$Q = 0.15 (.064 \text{ in/hr}) 1944 \text{ AC}$$

$$= 186.62 \text{ cfs}$$

$$\# 96" \phi @ S=0\%$$

D. B. O'LEARY & ASSOCIATES, INC.

201 S. Bumby Avenue
ORLANDO, FL 32803
(407) 896-3317

SHEET NO. _____ OF _____

CALCULATED BY Col DATE _____

CHECKED BY _____ DATE _____

SCALE _____

CulvertsGreen Branch Crossing

$$Q = C \cdot A \quad C = 0.15 \text{ (FIRM Woodlands)}$$

$$T_c = 10.41 \text{ hrs}$$

$$100 \text{ yr} \quad Q = 0.15 (0.64 \text{ in/hr}) 844 \text{ ac}$$

$$= 126.62 \text{ cfs}$$

$$\# 16" \phi @ s = 0.007\% \quad \text{Area} = 50.26 \text{ sf}$$

Use (1) 3' x 24' (on span arch)
 #1 bury footing to 3' clearance between
 existing ground & top of arch

reduced to (1) 3' x 24' 49.0 sf Waterway Area
 critter crossings (2) 30" x 60" (2) 12.9 sf

61.9 sf Waterway Area provided

$$50 \text{ yr} \quad Q = 0.15 (0.58 \text{ in/hr}) 1944 \text{ ac}$$

$$= 169.13 \text{ cfs}$$

$$\# 90" \phi @ s = 0.007\% \quad \text{Area} = 44.17 \text{ sf}$$

61.9 sf Waterway Area provided

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.

WATER BUDGET

PROJECT: OLNEYA TRAIL

ENGINEER: EUSTWICK

RESID: 1

RAINAGE AREA 4.6 AC

POND AREA 1.7 AC

WEIGHTED 'C'
 35 % PRE
 52 % POST

MONTH	MEAN RAINFALL (in)	PRE-DEV RUNOFF (ac-ft)	POST DEV RUNOFF (ac-ft)	PRE-DEV E.T. VOL (ac-ft)	POST DEV EVAP (ac-ft)	NET RUNOFF VOL (ac-ft)
JANUARY	2.19	0.21	0.44	0.40	0.55	0.07
FEBRUARY	2.79	0.27	0.56	0.40	0.55	0.13
MARCH	3.48	0.33	0.69	0.40	0.55	0.21
APRIL	2.41	0.23	0.48	0.40	0.55	0.09
MAY	3.42	0.33	0.68	0.40	0.55	0.20
JUNE	7.04	0.67	1.40	0.40	0.55	0.57
JULY	8.01	0.77	1.60	0.40	0.55	0.67
AUGUST	6.72	0.64	1.34	0.40	0.55	0.54
SEPTEMBER	6.82	0.65	1.36	0.40	0.55	0.55
OCTOBER	3.33	0.32	0.66	0.40	0.55	0.19
NOVEMBER	1.96	0.19	0.39	0.40	0.55	0.05
DECEMBER	1.96	0.19	0.39	0.40	0.55	0.05
TOTAL	50.13	4.80	9.99	4.80	6.66	3.33

COLUMN 1- Mean rainfall for Orlando, Florida recorded by NOAA

COLUMN 2- (Pre-Dev weighted 'C'* Rainfall* Drainage Area)/12

COLUMN 3- (Post Dev. weighted 'C'* Rainfall* Drainage Area)/12

COLUMN 4- Pre-Dev Evapotrans. Vol. = 33.9 in/yr* Pond area* 1ft-yr/144in-mo
 "EVAPOTRANSPIRATION PATTERNS IN FLORIDA", R. DOHRENWEND

COLUMN 5- Post Dev Pond Evap. Vol. = 47in/yr* Pond Area* 1ft-yr/144in-mo
 "AVG LAKE EVAPORATION RATE FOR THE ORLANDO AREA", FL. BUREAU OF GEOLOGY.

COLUMN 6- POST RUNOFF- PRE RUNOFF- (POND EVAP.- PRE E.T.)

WATER BUDGET

PROJECT: ALNFAYA TRAIL

ENGINEER: BOSTWICK

DESIGN: 2

DRAINAGE AREA 4.2 AC

POND AREA 3.9 AC

WEIGHTED 'C' 25 % PRE
67 % POST

MONTH	MEAN RAINFALL (in)	PRE-DEV RUNOFF (ac-ft)	POST DEV RUNOFF (ac-ft)	PRE-DEV E.T. VOL (ac-ft)	POST DEV EVAP (ac-ft)	NET RUNOFF VOL (ac-ft)
JANUARY	3.19	0.19	0.51	0.92	1.27	-0.03
FEBRUARY	3.79	0.24	0.65	0.92	1.27	0.06
MARCH	3.48	0.30	0.92	0.92	1.27	0.16
APRIL	3.41	0.21	0.57	0.92	1.27	-0.00
MAY	3.42	0.30	0.80	0.92	1.27	0.15
JUNE	7.04	0.62	1.65	0.92	1.27	0.69
JULY	8.01	0.70	1.89	0.92	1.27	0.82
AUGUST	6.72	0.59	1.58	0.92	1.27	0.63
SEPTEMBER	5.82	0.60	1.60	0.92	1.27	0.63
OCTOBER	3.33	0.23	0.78	0.92	1.27	0.13
NOVEMBER	1.96	0.17	0.46	0.92	1.27	-0.07
DECEMBER	1.96	0.17	0.46	0.92	1.27	-0.07
TOTAL	50.13	4.39	11.76	11.02	15.28	3.11

COLUMN 1- Mean rainfall for Orlando, Florida recorded by NOAA

COLUMN 2- (Pre-Dev weighted 'C' * Rainfall * Drainage Area) / 12

COLUMN 3- (Post Dev. weighted 'C' * Rainfall * Drainage Area) / 12

COLUMN 4- Pre-Dev Evapotrans. Vol. = 33.9 in/yr * Pond Area * 1ft-yr/144in-mo
"EVAPOTRANSPIRATION PATTERNS IN FLORIDA", R. DOHREMWEND

COLUMN 5- Post Dev Pond Evap. Vol. = 47in/yr * Pond Area * 1ft-yr/144in-mo
"AVG LAKE EVAPORATION RATE FOR THE ORLANDO AREA", FL. BUREAU OF GEOLOGY

COLUMN 6- POST RUNOFF- PRE RUNOFF- (POND EVAP. - PRE E.T.)

WATER BUDGET

PROJECT: ALAFAYA TRAIL

ENGINEER: BOSTWICK

BASIN: 3

DRAINAGE AREA 8.1 AC

POND AREA 2.9 AC

WEIGHTED 'C' 25 % PRE
53 % POST

MONTH	MEAN RAINFALL (in)	PRE-DEV RUNOFF (ac-ft)	POST DEV RUNOFF (ac-ft)	PRE-DEV E.T. VOL (ac-ft)	POST DEV EVAP (ac-ft)	NET RUNOFF VOL (ac-ft)
JANUARY	2.19	0.37	0.78	0.68	0.95	0.15
FEBRUARY	2.79	0.47	1.00	0.68	0.95	0.26
MARCH	3.48	0.59	1.24	0.68	0.95	0.39
APRIL	2.41	0.41	0.86	0.68	0.95	0.19
MAY	3.42	0.58	1.22	0.68	0.95	0.38
JUNE	7.04	1.19	2.52	0.68	0.95	1.07
JULY	8.01	1.35	2.87	0.68	0.95	1.25
AUGUST	6.72	1.13	2.40	0.68	0.95	1.01
SEPTEMBER	6.62	1.15	2.44	0.68	0.95	1.03
OCTOBER	2.33	0.56	1.19	0.68	0.95	0.37
NOVEMBER	1.55	0.33	0.70	0.68	0.95	0.11
DECEMBER	1.96	0.33	0.70	0.68	0.95	0.11
T O T A L	50.13	8.46	17.93	8.19	11.36	6.21

COLUMN 1- Mean rainfall for Orlando, Florida recorded by NOAA

COLUMN 2- (Pre-Dev weighted 'C' * Rainfall * Drainage Area)/12

COLUMN 3- (Post Dev. weighted 'C' * Rainfall * Drainage Area)/12

COLUMN 4- Pre-Dev Evapotrans. Vol. = 33.9 in/yr * Pond area * 1ft-yr/144in-mo
"EVAPOTRANSPIRATION PATTERNS IN FLORIDA", R. DOHRENWENDCOLUMN 5- Post Dev Pond Evap. Vol. = 47in/yr * Pond Area * 1ft-yr/144in-mo
"AVG LAKE EVAPORATION RATE FOR THE ORLANDO AREA", FL. BUREAU OF GEOLOGY

COLUMN 6- POST RUNOFF- PRE RUNOFF- (POND EVAP.- PRE E.T.)

TABLE 1

<u>POND SURVEY 4/22/90</u>		<u>NORMAL POOL ELEVATION</u>	<u>GEOTECHNICAL REPORT NO. 9796</u>
<u>POND 1</u>			
WET GROUND	64.08	65.0	64.5
LICHEN LINE	65.16		
<u>POND 2</u>			
WET GROUND	63.71	63.5	63.0
LICHEN LINE	64.14		
<u>POND 3</u>			
WET GROUND	65.28	65.2	65.3
LICHEN LINE	65.96		

ELEV. POINT (BAT HEADS)
I.C.P.

90/23

STATION 33 H1 FS FLEV

POND #1

17.52 3.22 10.82 17.597

60 R. NAIL 10 10" PINE STA 305 120 1.6 LT

6.21

GRD. SHOT
WBT

5.65

TUR. NAIL
HICKORY LINE

5.66

LICKING LINE

APR 22 1980

17.52 3.22 67.60

EXHIBIT 6.2.3 Page 51 of 66

ATTACHMENT "G"

STATION (S/I HEADS)
I.C.F.

211.27

STN	135	HI	FS	ELVD
4.24		<u>11.52</u>		65.28

STATION 355.40, 75.27 FS 22

5.61	END SHOT	(4.24)
5.25	RIGHT LINE	
5.38	" "	
4.24		65.28

240.3

3.11	<u>79.92</u>	57.71
------	--------------	-------

5.54	END SHOT
4.78	RIGHT LINE
4.25	" "

STATION 355.40, 75.27 FS 22

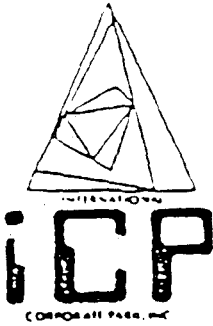
(4.24)

APR 25 1960

3.11	67.71
------	-------

ATTACHMENT "G"

ATTACHMENT "II"



INTERNATIONAL CORPORATE PARK, INC.

May 4, 1990

Mr. Pat Frost
St. Johns River Water Management District
618 E. South Street
Orlando, FL 32801

RE: Application Number 12-095-0040A

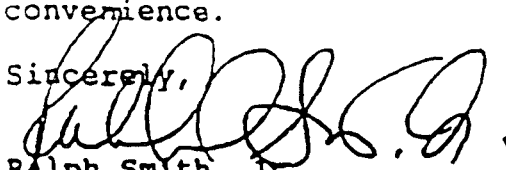
Dear Pat,

Please note the following per the above reference.

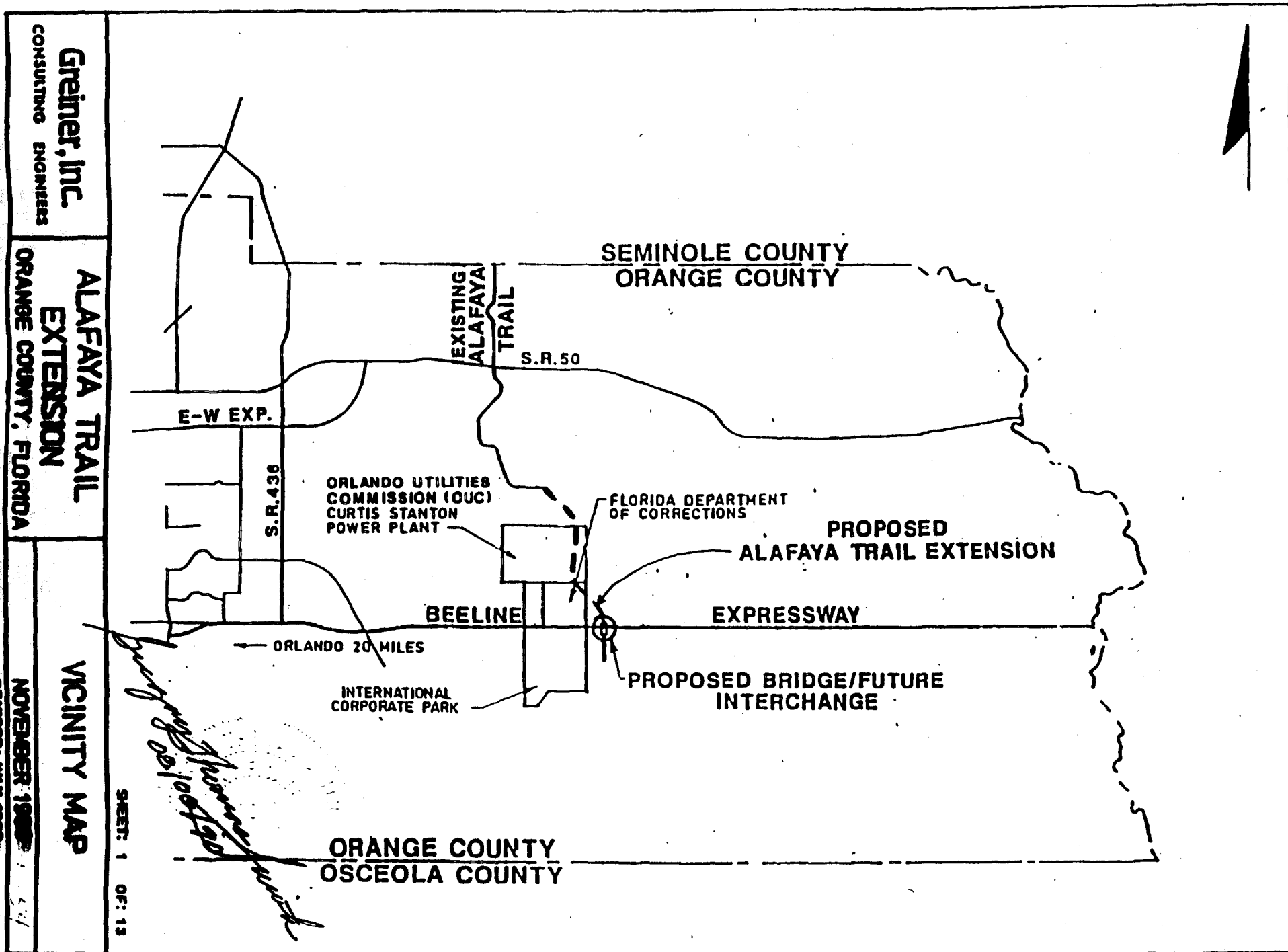
Under D.E.R. rules 17-312.390 International Corporate Park will provide evidence of financial resources necessary to conduct mitigation, before the start of any construction on Alafaya Trail.

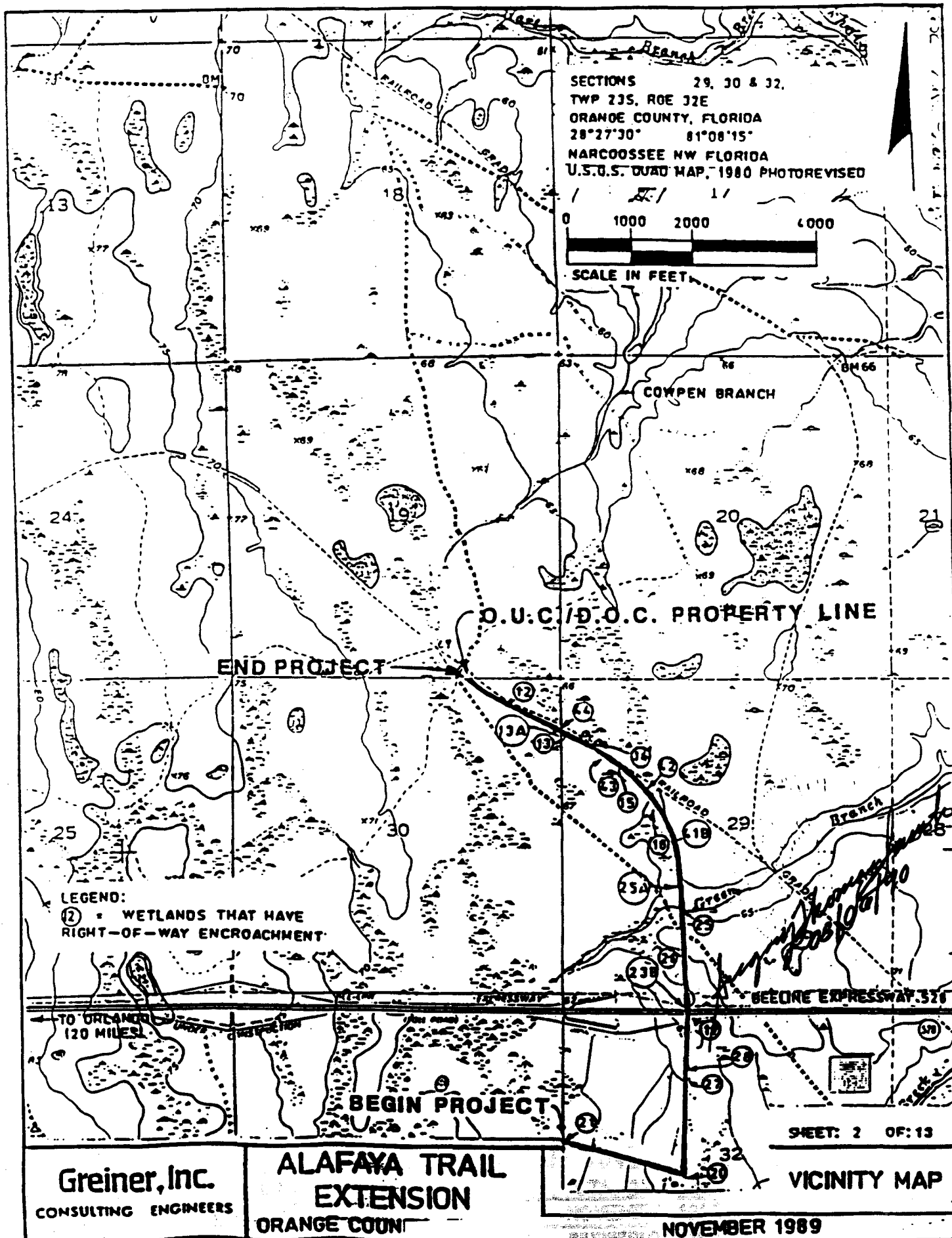
Should you have any questions or comments call me at your convenience.

Sincerely,

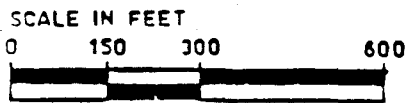
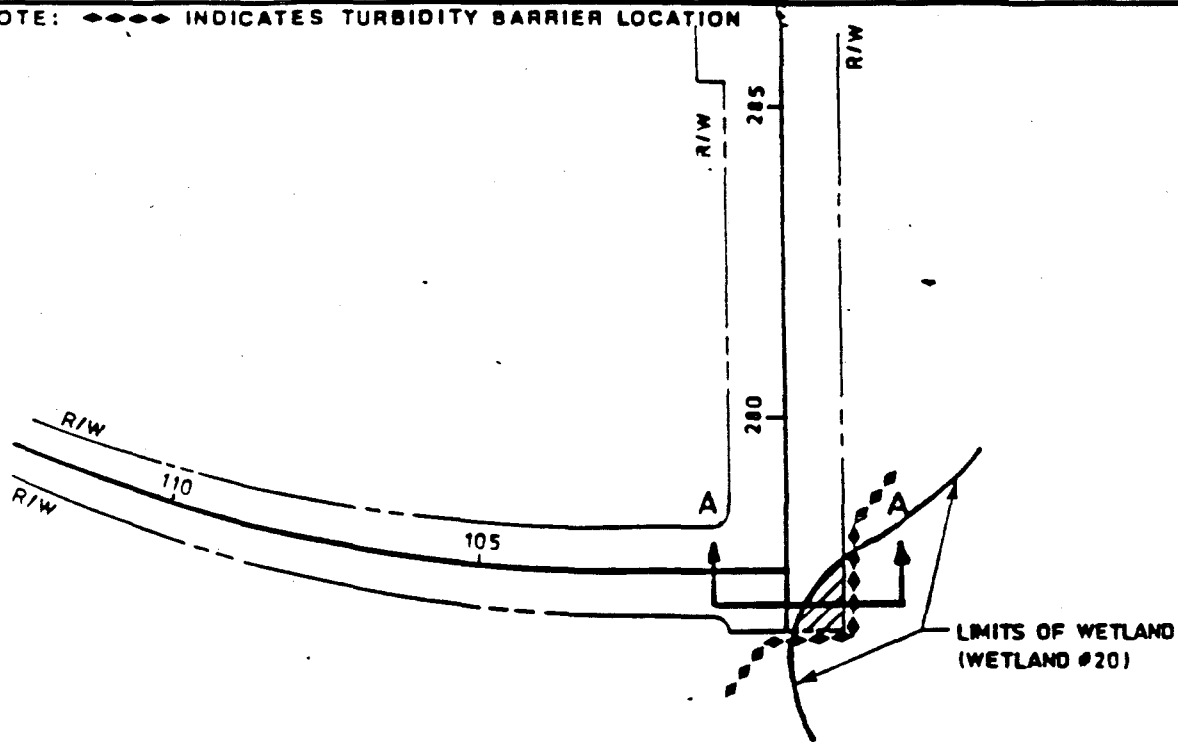

Ralph Smith, Jr.
Project Engineer

RS/jc



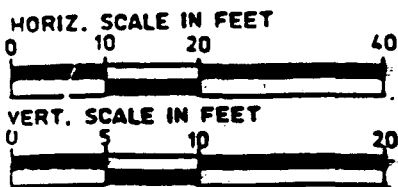
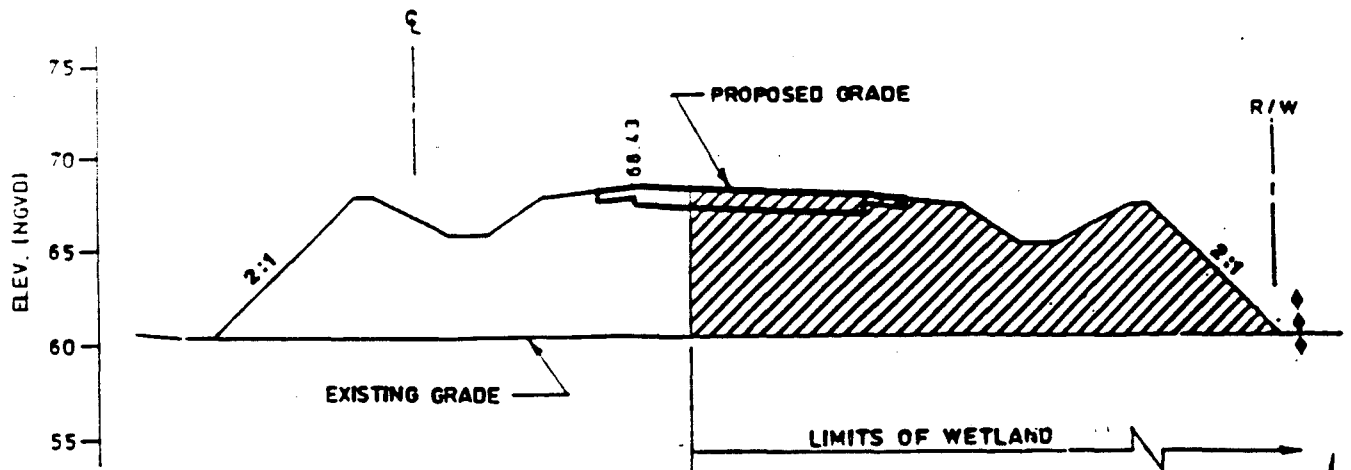


NOTE: ◆◆◆◆ INDICATES TURBIDITY BARRIER LOCATION



PLAN VIEW

AREA OF FILL (LANDWARD)



SECTION A-A

SHEET: 3 OF 13

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY

PLAN AND PROFILE
STA. 277 + 00
NOVEMBER 1989

REVISED: JULY 1988

NOTE: ◆◆◆ INDICATES TURBIDITY BARRIER LOCATION

LIMITS OF WETLAND
(WETLAND #23)

R/W

LIMITS OF WETLAND
(WETLAND #24)

320
310

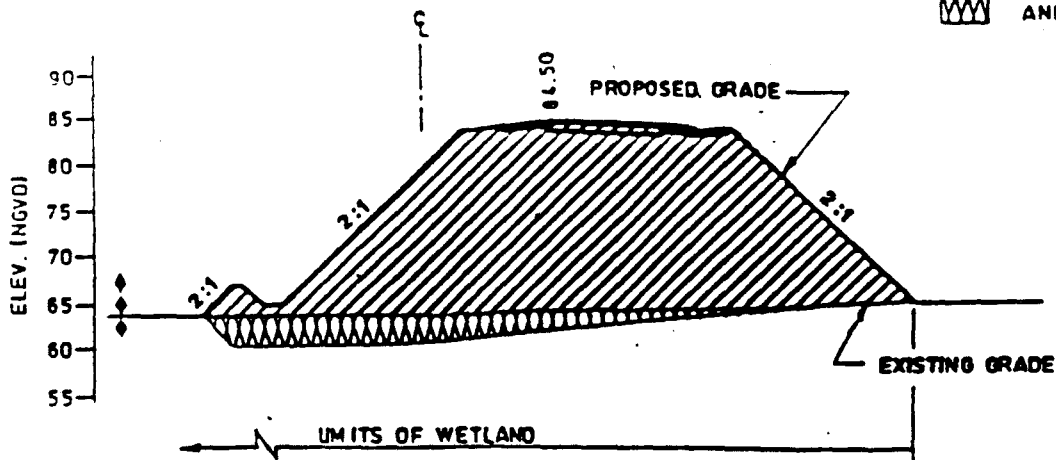
LIMITS OF CONSTRUCTION

R/W

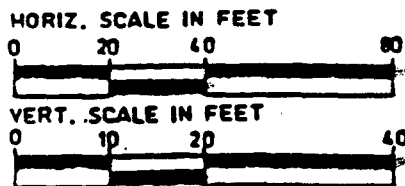


PLAN VIEW

- AREA OF FILL (LANDWARD)
- AREA OF DEMUCKING AND BACKFILL



SECTION B-B



SHEET: 4 OF 13

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

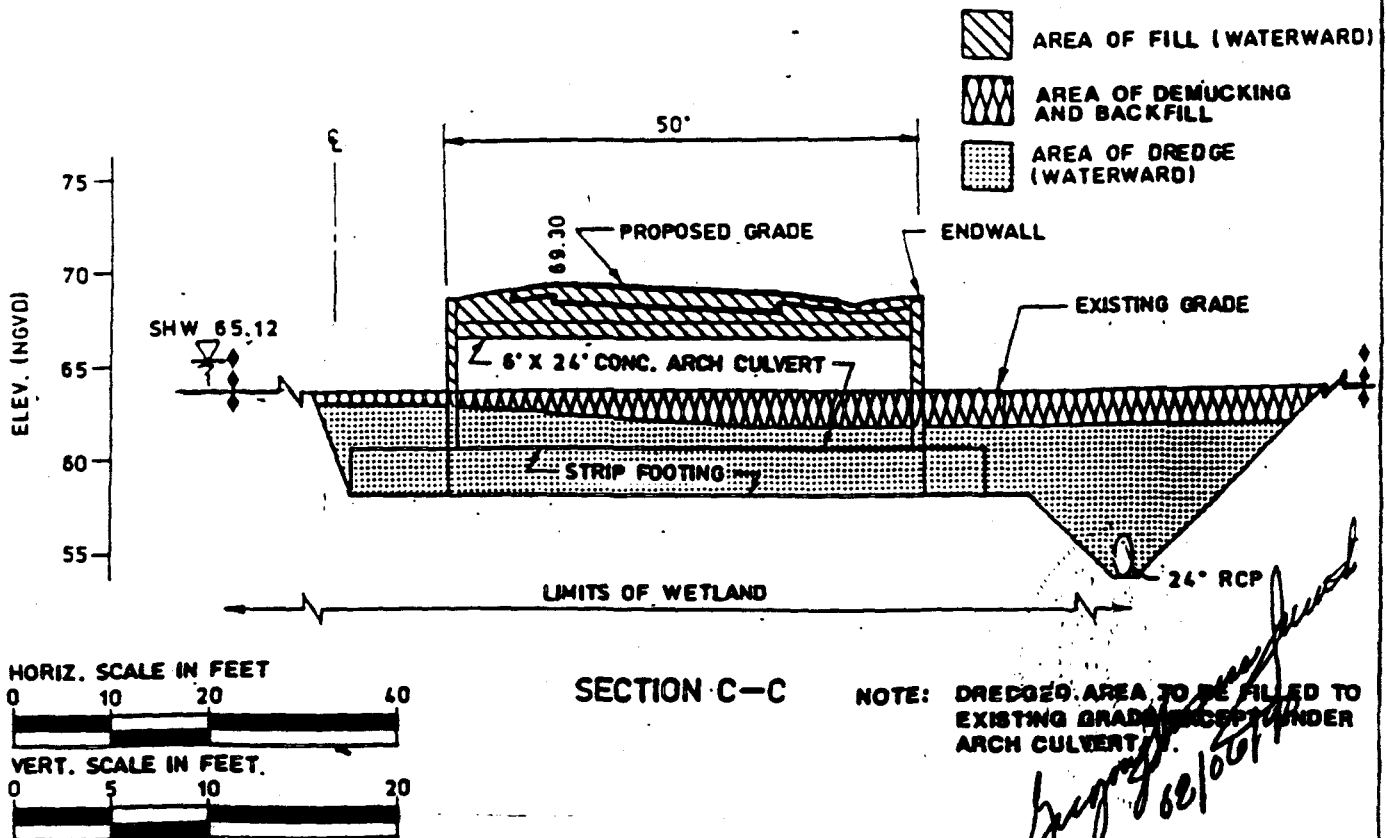
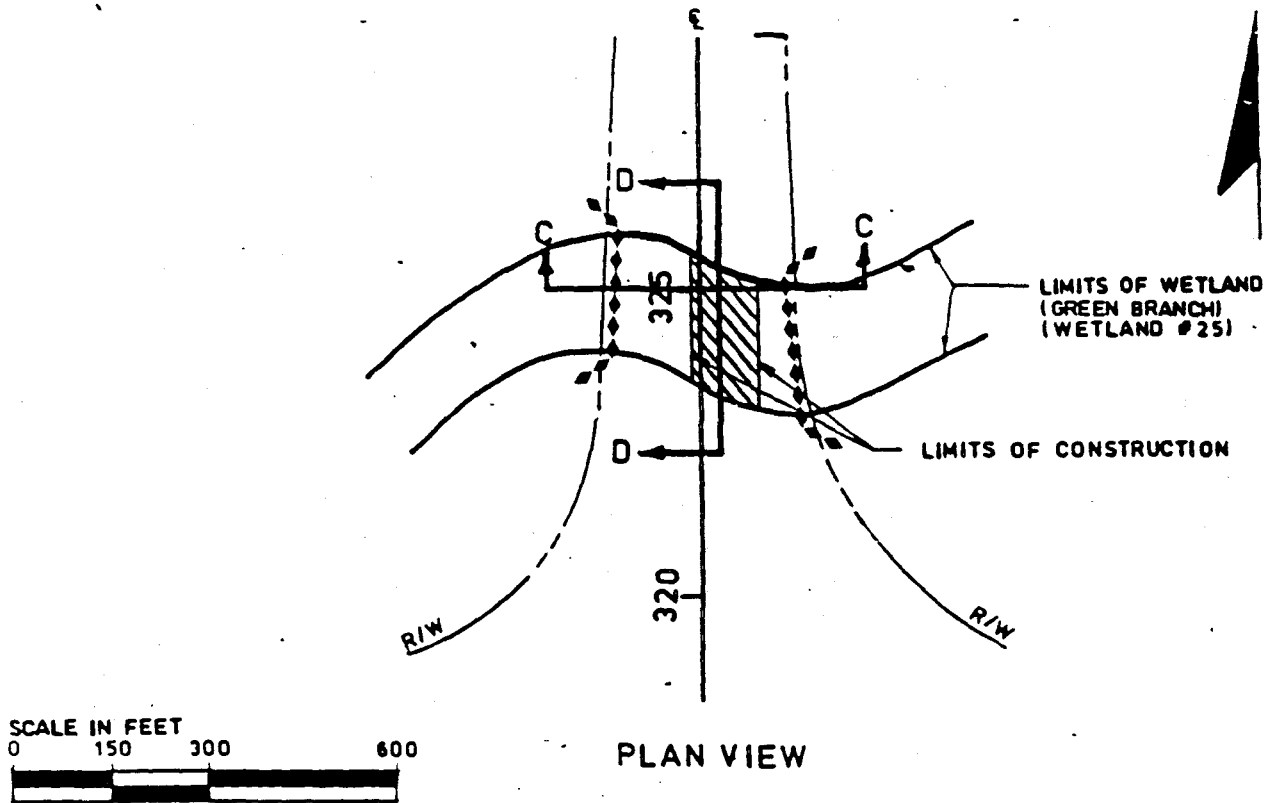
PLAN AND PROFILE

STA. 316 + 00

NOVEMBER 1989

REVISED: JULY 1990

NOTE: ◆◆◆◆ INDICATES TURBIDITY BARRIER LOCATION



SHEET: 5 OF: 13

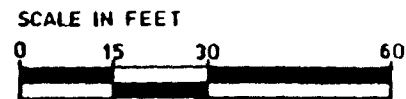
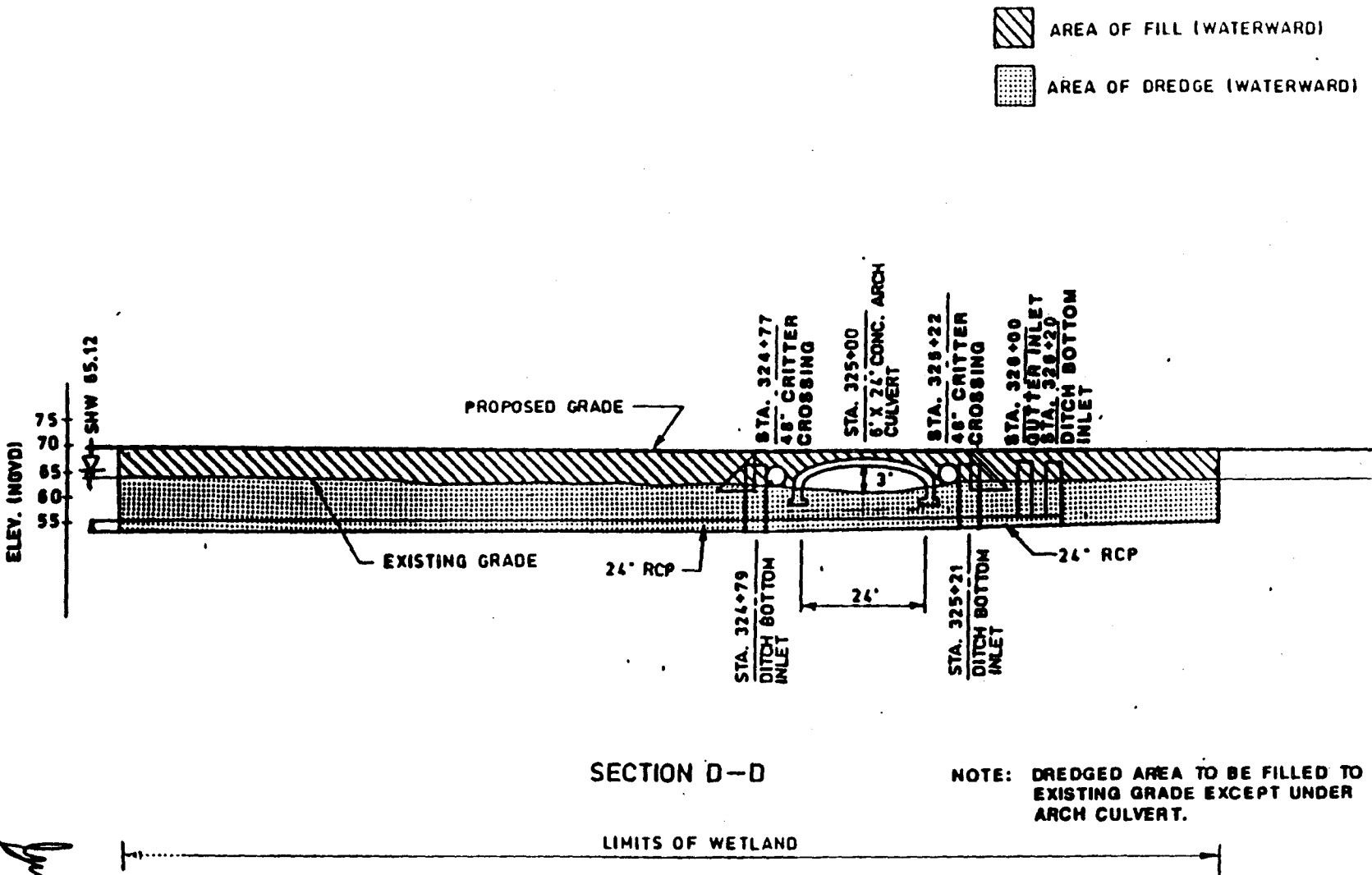
Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 325 + 00

NOVEMBER 1989

REVISED: JULY 1990



SHEET: 6 OF 13

John J. Greiner, Inc.
 November 1989

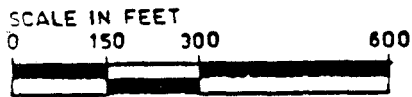
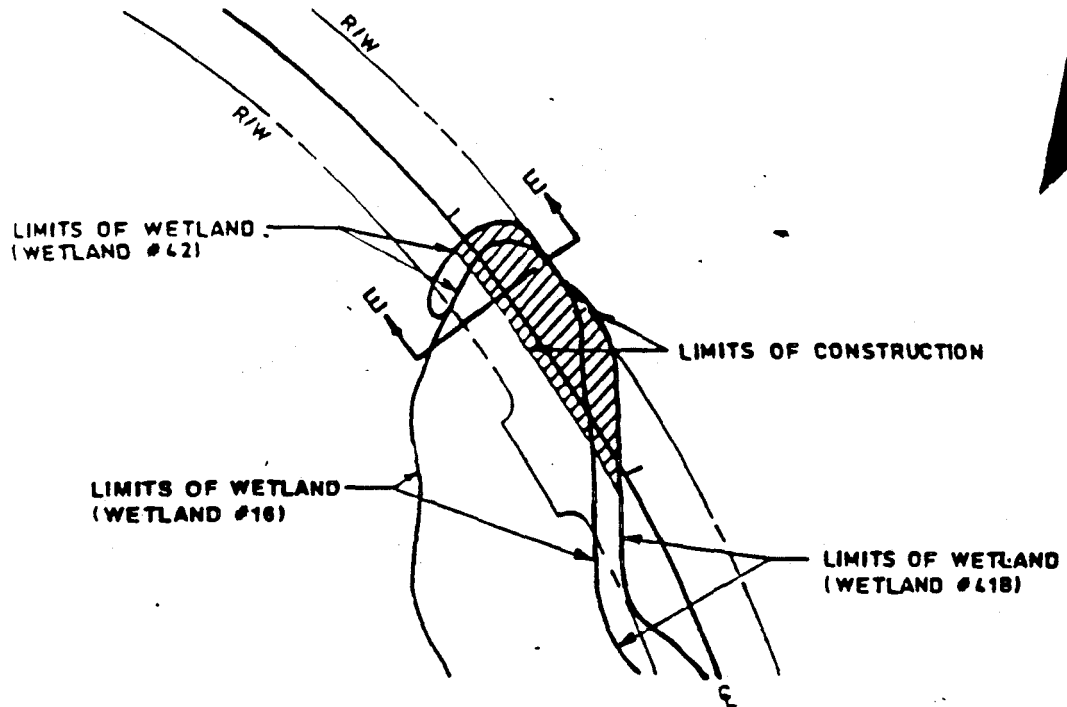
Greiner, Inc.
 CONSULTING ENGINEERS

**ALAFAYA TRAIL
 EXTENSION
 ORANGE COUNTY, FLORIDA**

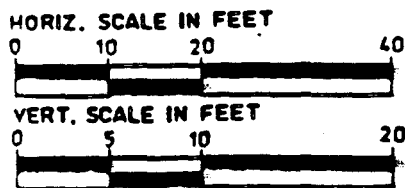
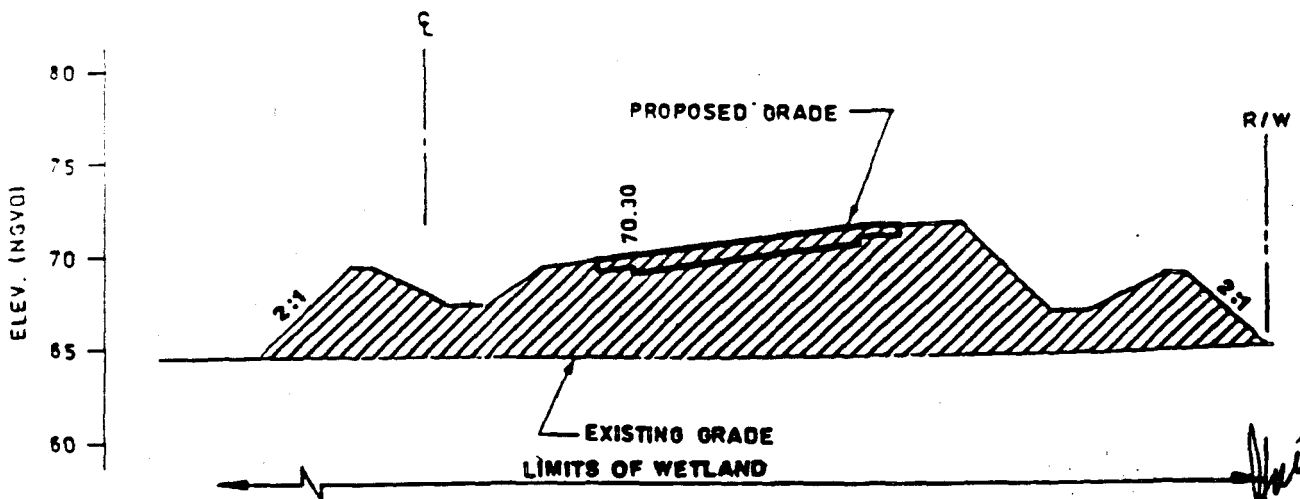
SECTION D-D

NOVEMBER 1989

REVISED: JULY 1990



AREA OF FILL (LANDWARD)



Frederick Thomas Smith
08/06/90

SHEET: 7 OF: 13

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

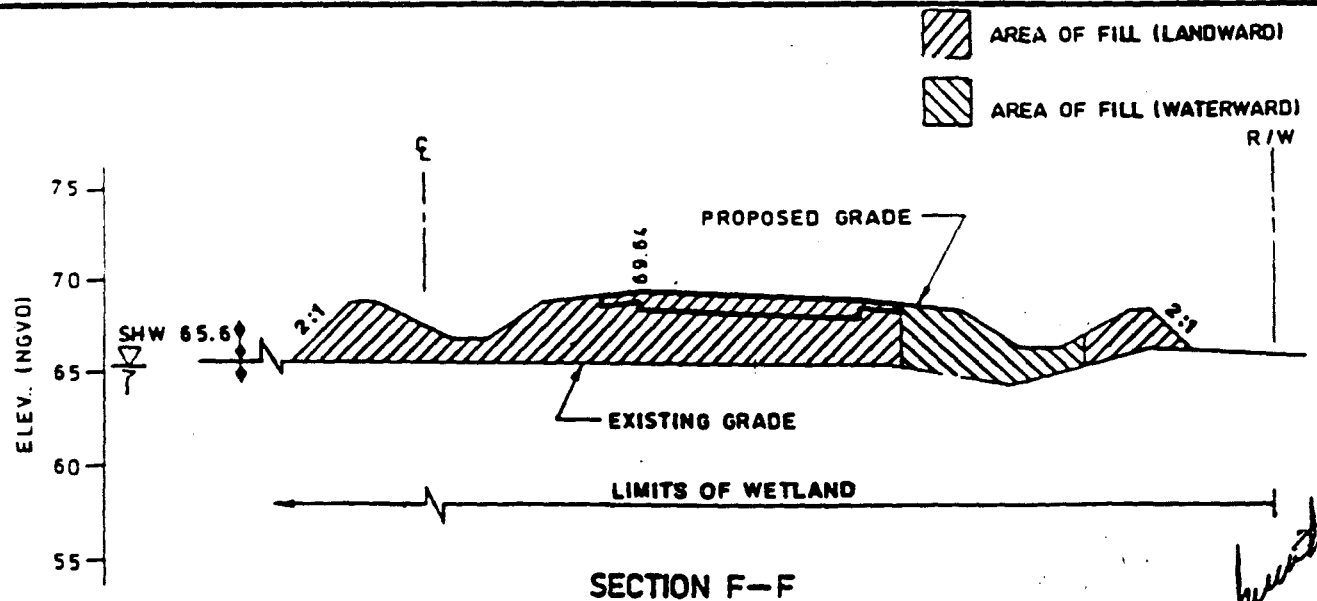
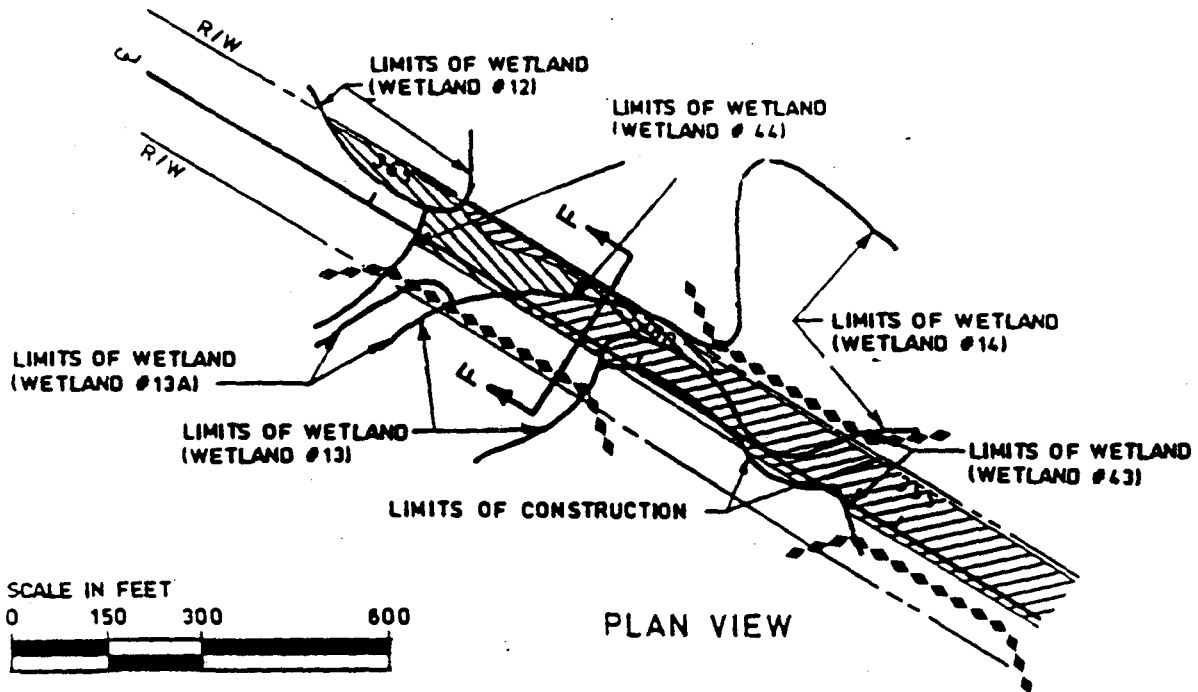
PLAN AND PROFILE

STA. 343 + 00

NOVEMBER 1989

REVISED: JULY 1990

NOTE: ◆◆◆ INDICATES TURBIDITY BARRIER LOCATION



SHEET: 8 OF: 13

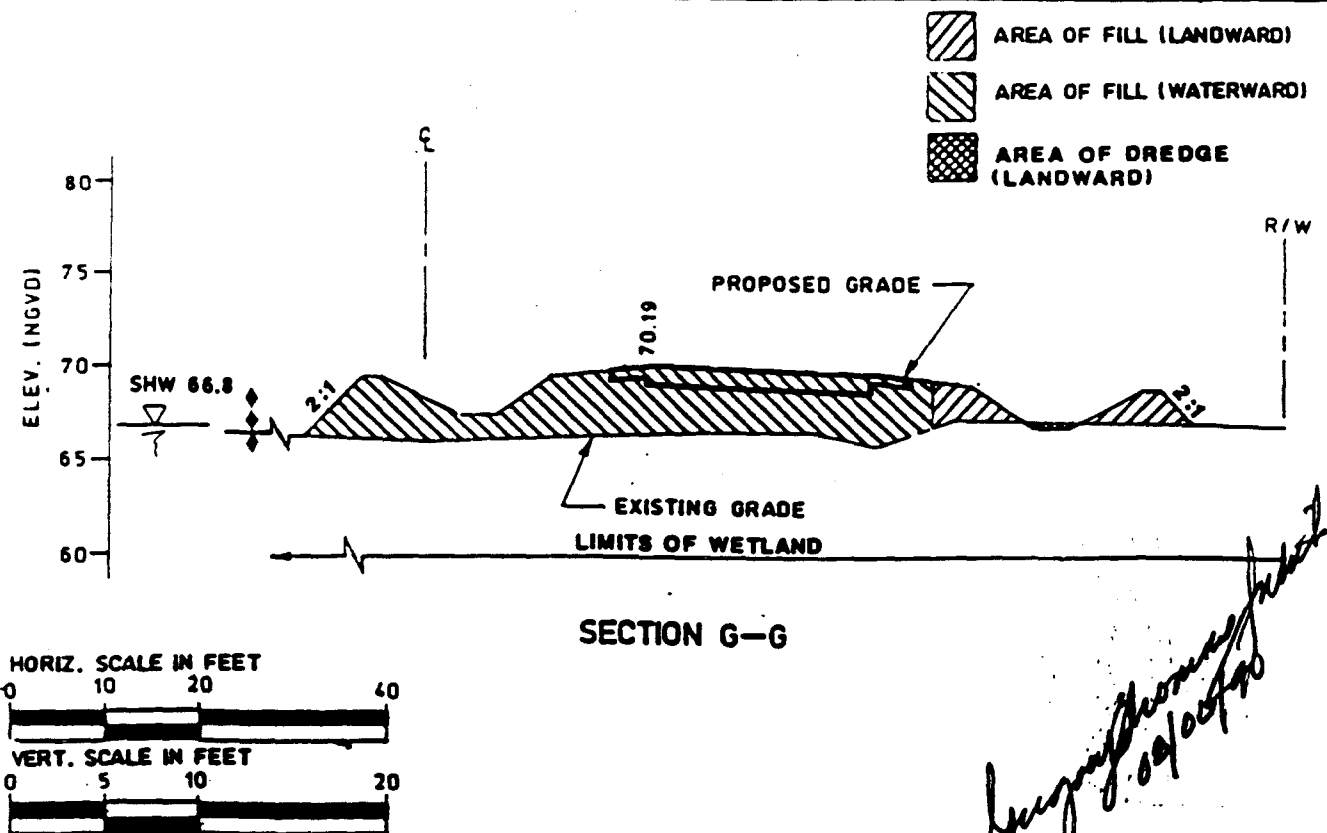
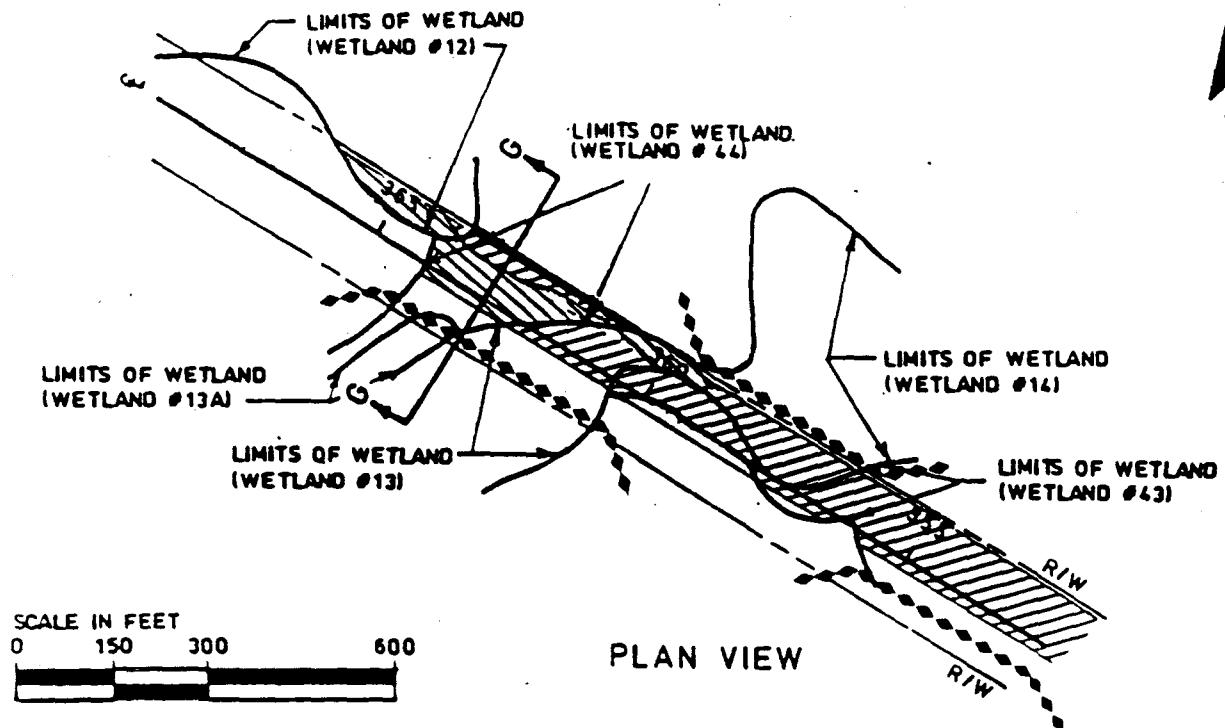
Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 361 + 00
NOVEMBER 1989
REVISED: JULY 1990

Gregory Thomas Hunt
08/01/90

NOTE: ◆◆◆ INDICATES TURBIDITY BARRIER LOCATION



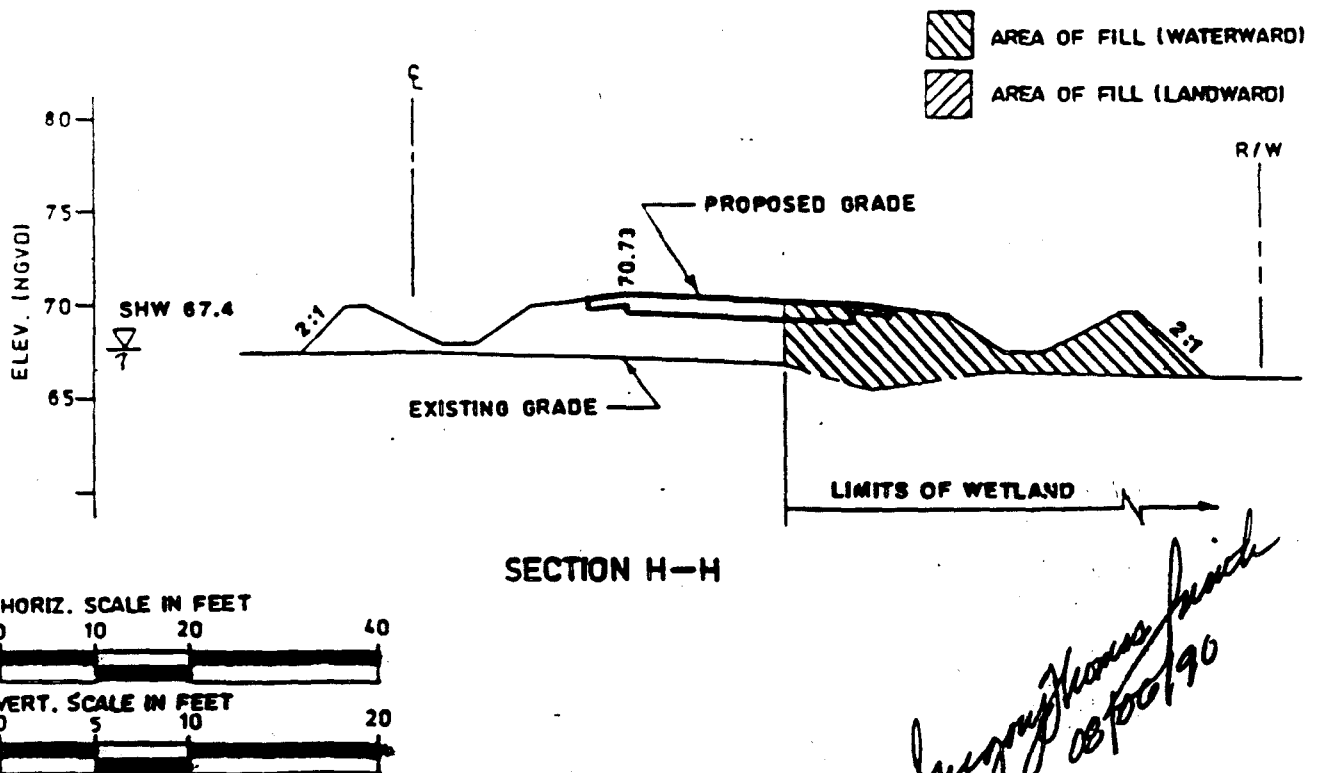
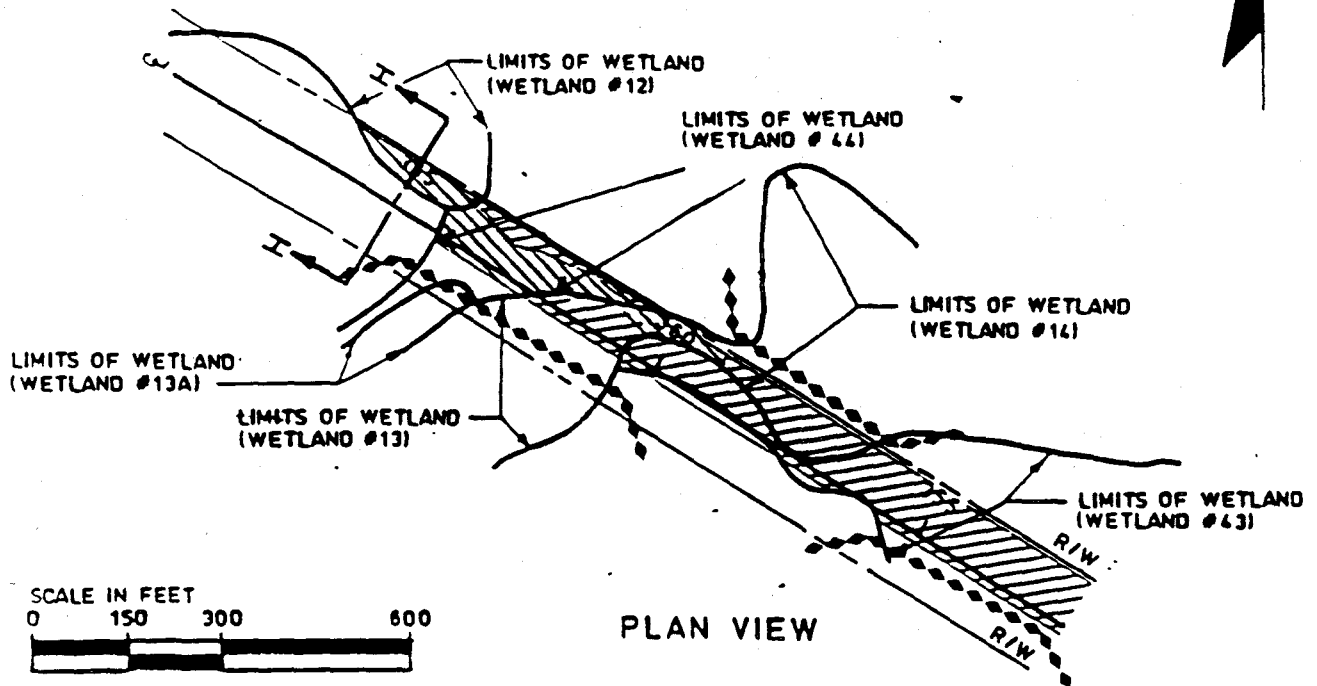
SHEET: 9 OF 13

Greiner, Inc.
CONSULTING ENGINEERS

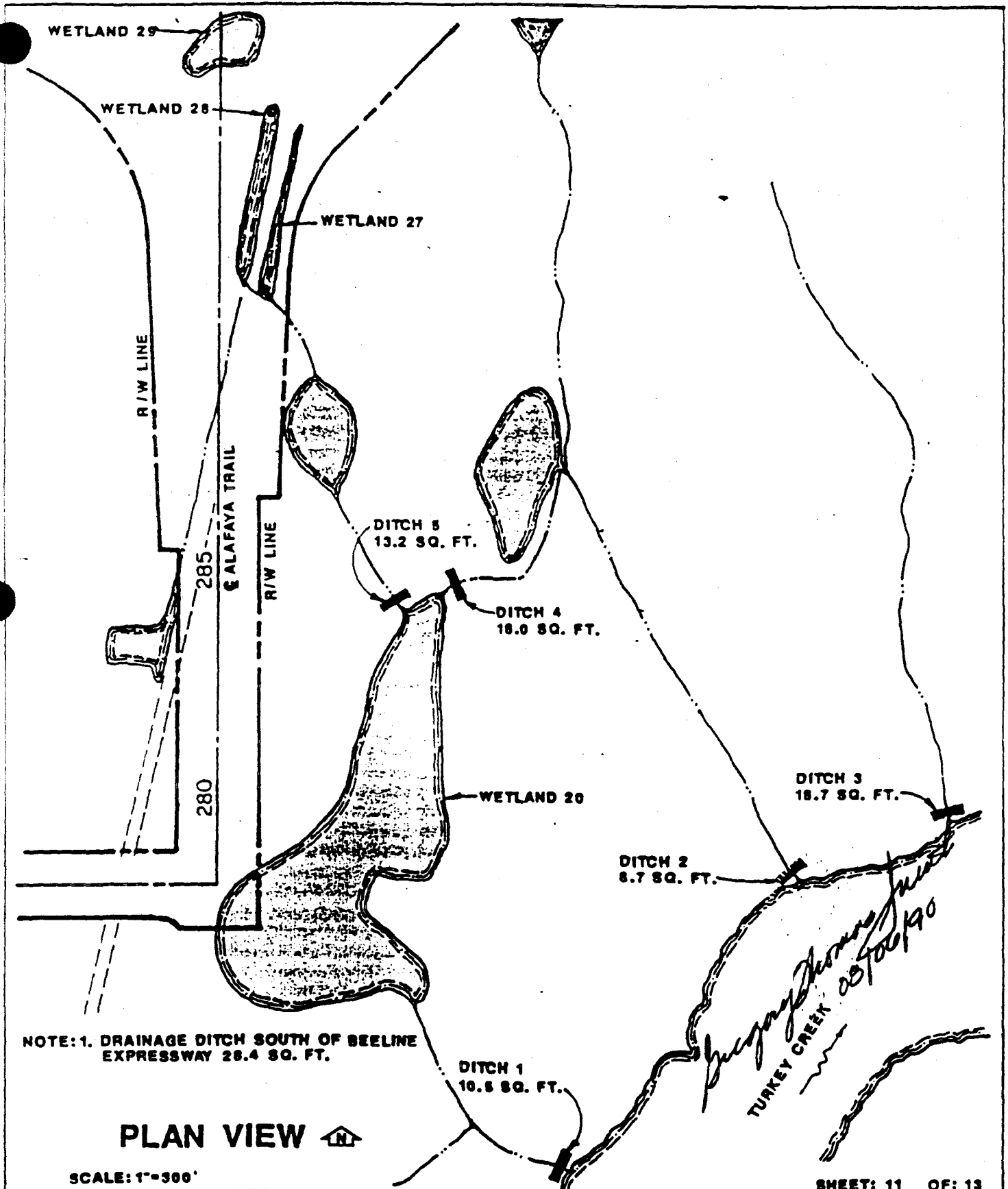
**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 363 + 00
NOVEMBER 1999
REVISED: JULY 1999

NOTE: ◆◆◆ INDICATES TURBIDITY BARRIER LOCATION



SHEET: 10 OF 13



GREINER, INC.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE CO., FLORIDA

DITCH CROSS SECTIONAL AREAS

DATE: MAY 1990
REVISED: JULY 1990

DITCH NO. 1



DITCH NO. 2



DITCH NO. 3



DITCH NO. 5



Gregory Thomas Smith
02/05/90

HORIZONTAL AND VERTICAL SCALE, 1"=5'

SHEET: 12 OF: 13

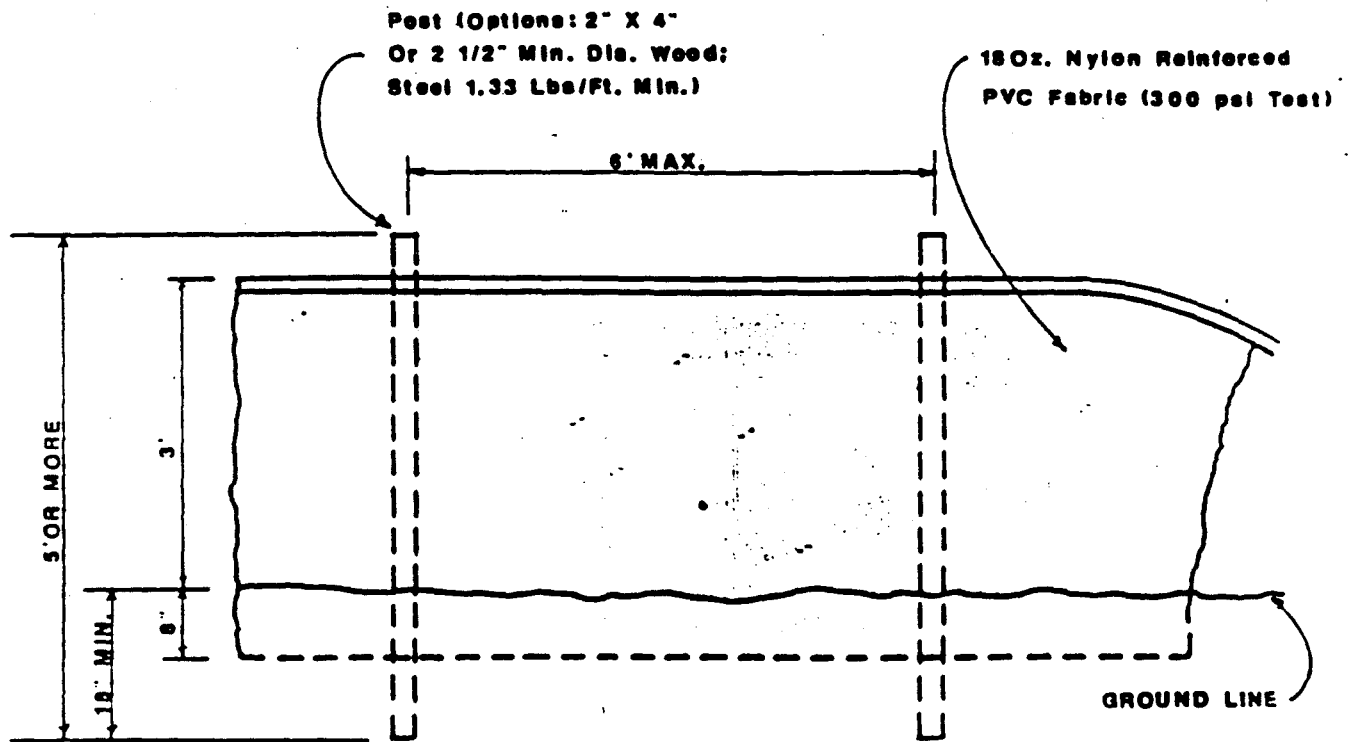
GREINER, INC
CONSULTING ENGINEERS

**ALABAMA TRAIL
EXTENSION**
ORANGE CO., FLORIDA

DITCH CROSS-SECTIONAL AREAS

DATE: MAY 1990

REVISED: JULY 1990



SOURCE: FLORIDA DEPARTMENT OF TRANSPORTATION -
ROADWAY AND TRAFFIC DESIGN STANDARDS; INDEX # 103

TYPICAL STAKED TURBIDITY BARRIER

SHEET: 13 OF: 13

Greiner, Inc
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN VIEW

May 1990
REVISED: JULY 1990

Signature
02/05/90

7.0 ECONOMIC AND
SOCIAL EFFECTS

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

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

10.0 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 ADDRESSO R L A N D O U T I L I T I E S C O M M I S S I O N
NAME5 0 0 S o u t h O r a n g e A v e n u e
STREETO r l a n d o F L 3 2 8 0 1
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 coordinationOrlando 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.**

Stanton Energy Center

(see attached Figures)

Street, road or other descriptive location

Southeast Orlando (Rural)

Incorporated city or town

Orange

County

13, 14, 23, 24

18, 19

Section

28° 29'

Latitude

23S

23S

Township

81° 10'

Longitude

31E

32E

Range

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 ☒ Maintenance of existing structure ☐

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 ☒ 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 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:

1. Amount of material

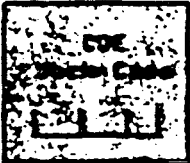
- a. Cubic yards placed waterward of ordinary/mean high water Later _____
b. Cubic yards placed landward of ordinary/mean high water Later _____
c. Total acreage to be filled 6.2 Total acreage of wetlands involved Later _____

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.



DER
Code
253
403

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 Brogden Lant

Signature
General Counsel, OUC

Sworn and subscribed before me at Orange County,

Florida, this 12th day of March

Patricia A. Gillespie

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

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 all of the required state, federal or local permits before 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 Jant

Signature of Applicant
General Counsel, OUC

3/12/91

Date

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 NOT a Joint Permit!

You Must Obtain All Required Local, State, and Federal

Authorizations or Permits Before Commencing Work!!

For your information: 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.

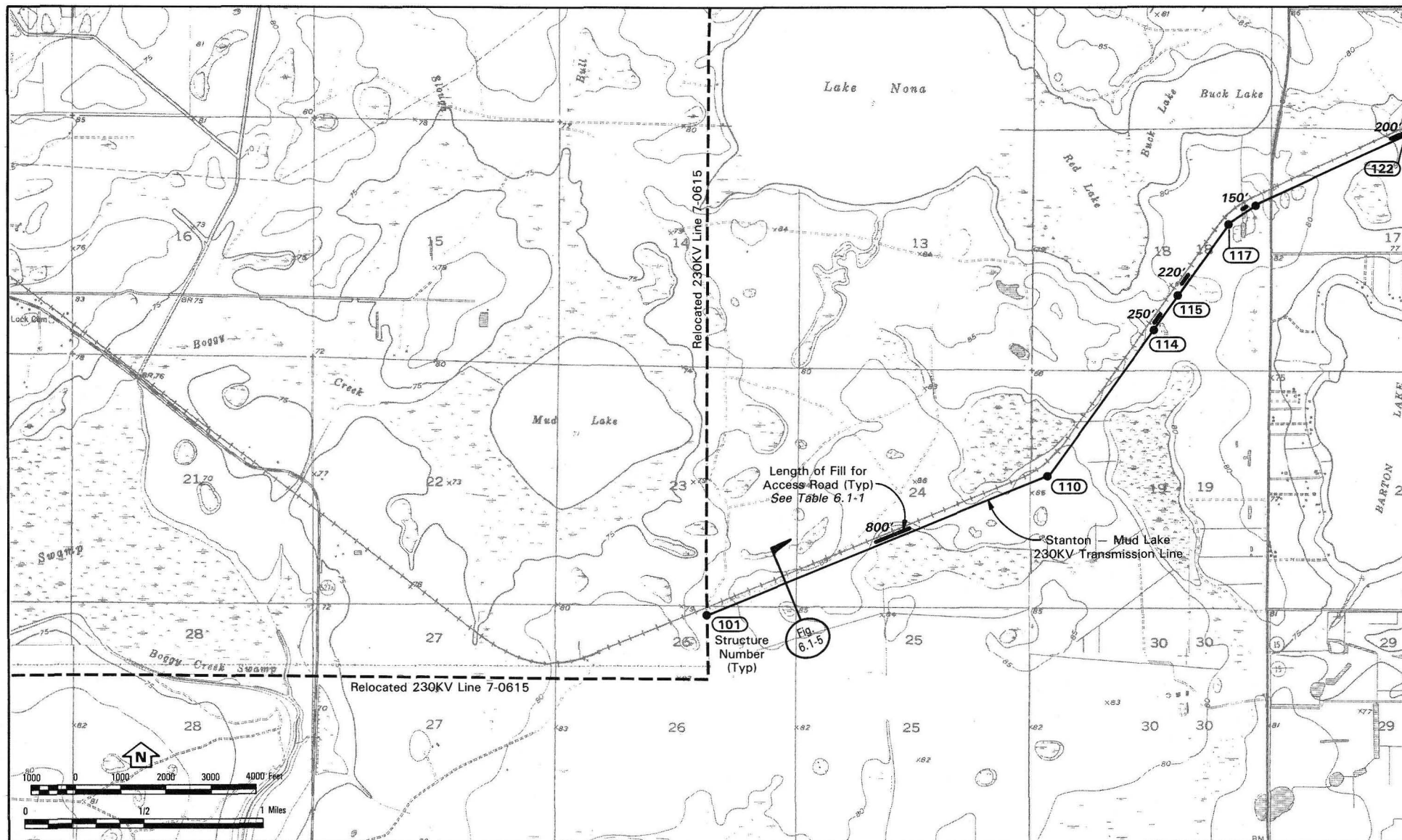
Protection of State Water. Culverts will be placed as necessary to ensure that sheet flow and runoff is not compromised by the project. Turbidity screens will be placed and maintained prior to and during construction to protect water quality against erosion. Access roads and working surfaces will be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

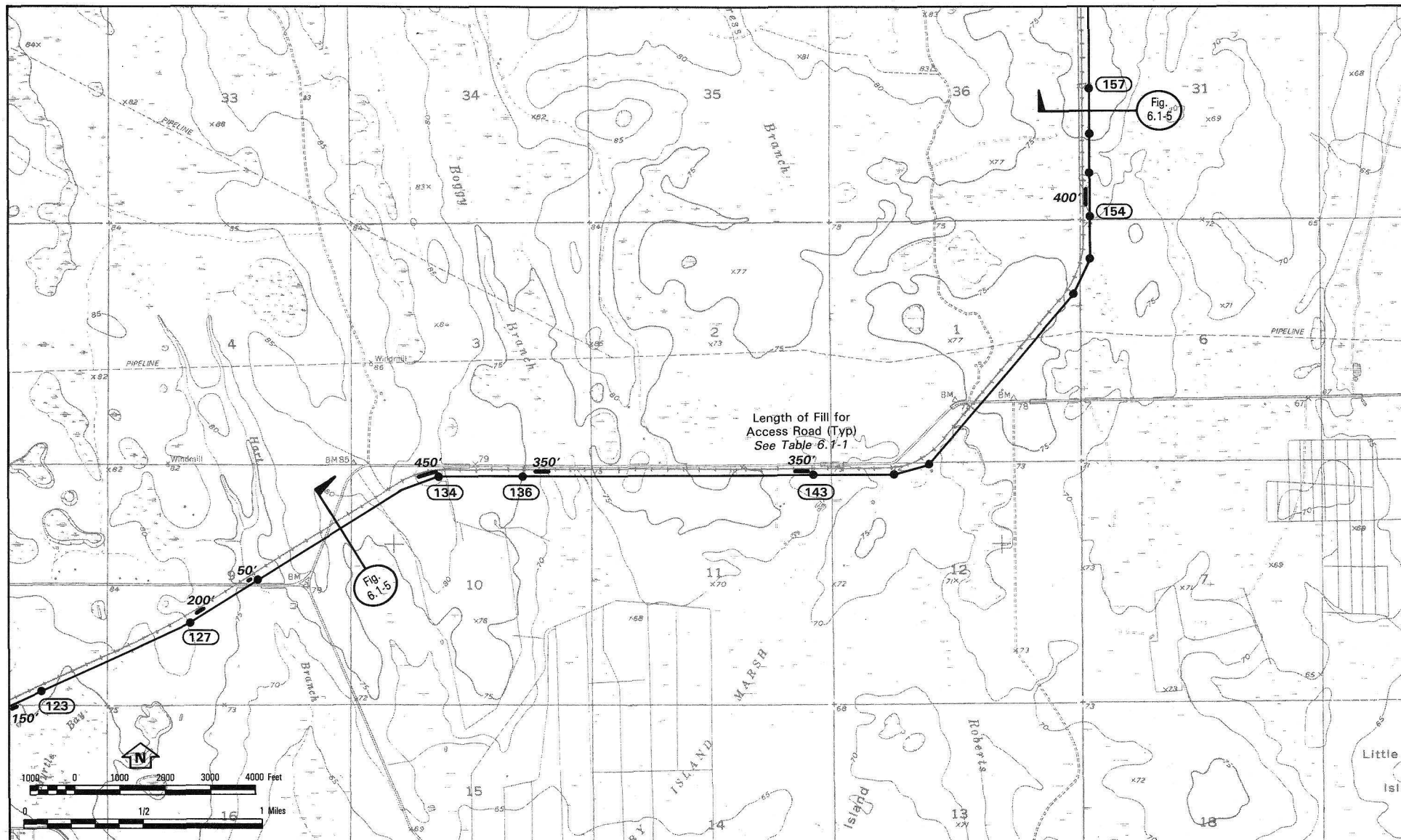
Hazardous Materials. Not applicable.



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

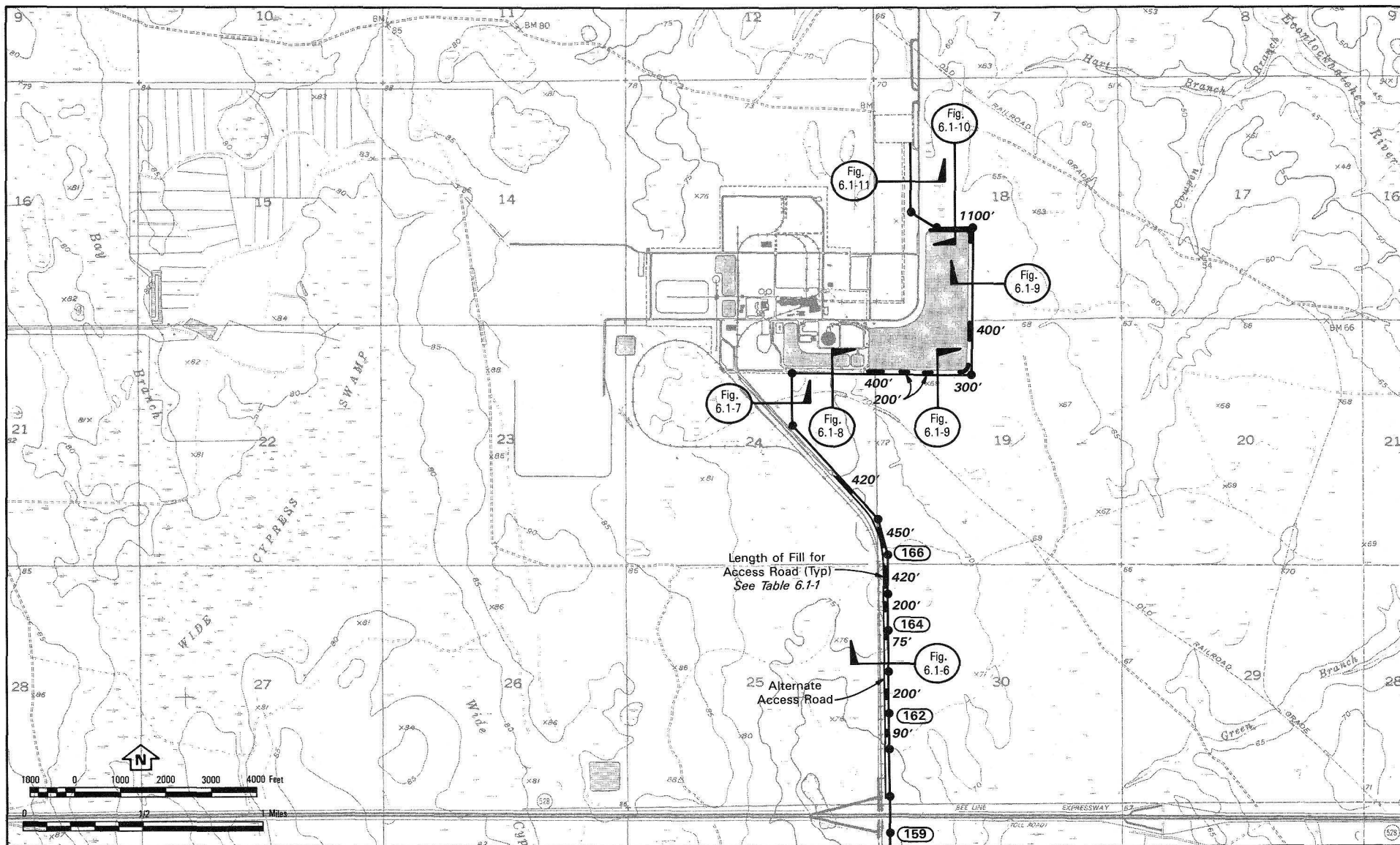
TRANSMISSION LINE CORRIDOR LOCATION — WEST

Figure 6.1-2



TRANSMISSION LINE CORRIDOR LOCATION — CENTRAL

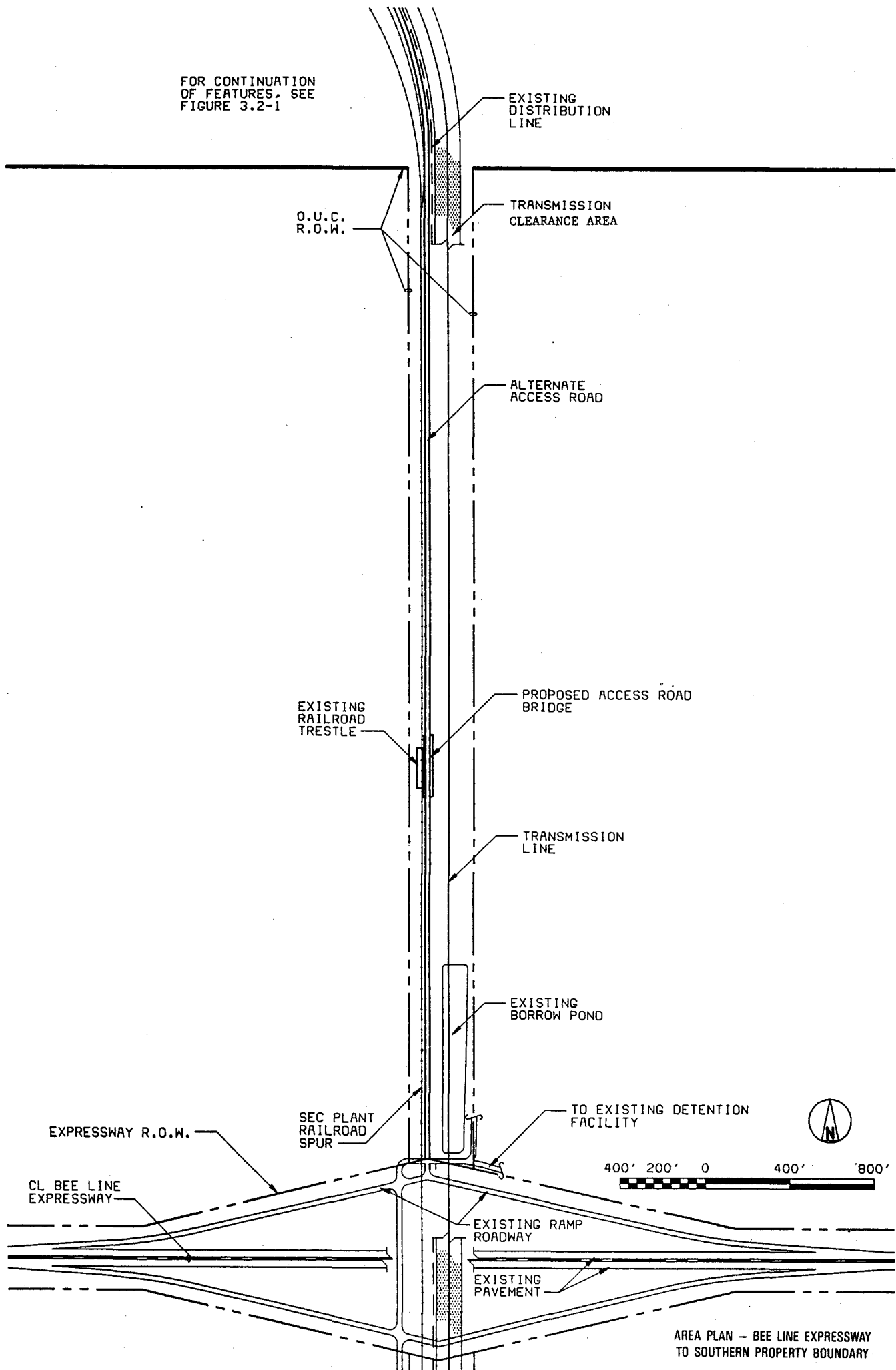
Figure 6.1-3



TRANSMISSION LINE CORRIDOR LOCATION — EAST
AND ALTERNATE ACCESS ROAD

Figure 6.1-4

FOR CONTINUATION
OF FEATURES, SEE
FIGURE 3.2-1



AREA PLAN - BEE LINE EXPRESSWAY
TO SOUTHERN PROPERTY BOUNDARY

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.



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.

Orlando Utilities Commission
500 South Orange Avenue
P.O. Box 3193
Orlando, Florida 32801

1.b. STREET ADDRESS(ES) AT WHICH RADIOACTIVE
MATERIAL WILL BE USED, IF DIFFERENT FROM
1.a. INCLUDE ZIP CODE.

Curtis H. Stanton Energy Center
Orange County, Florida

TELEPHONE NO: Area Code (407) 423-9100

2.a. LICENSE FEE CATAGORY:

3L(1)

b. LICENSE FEE ENCLOSED: \$ N/A

3. THIS IS AN APPLICATION FOR (Check and complete
appropriate items):

☒ 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 POS-
SESSED AT ANY ONE TIME (If seal-
ed 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			
APPLICANT	CITY	Orlando	COUNTY	Orange	
	STATE	FL	ZIP CODE	32801	
AGENT (IF APPLICABLE)	TELEPHONE NO.	407 / 423 - 91100			
	NAME OF AGENT	LAST FIRST			
CONSULTANT OR ENGINEER (IF APPLICABLE)	ADDRESS				
	CITY		COUNTY		
SITE LOCATION	STATE		ZIP CODE		
	TELEPHONE NO.				
USE	NAME OF FIRM	Black & Veatch			
	NAME OF FIRM CONTACT	LAST FIRST		Day Steven M	
MODIFICATION OR RENEWAL	ADDRESS	8400 Ward Parkway			
	CITY	Kansas City	COUNTY	Jackson	
AMOUNT	STATE	MO	ZIP CODE	64114	
	TELEPHONE NO.	913 / 339 - 2000			
U.S.G.S. TOPO QUAD MAP	NAME OF FIRM CONTACT	LAST FIRST		Day Steven M	
	ADDRESS	8400 Ward Parkway			
TOTAL ACREAGE	CITY	Kansas City	COUNTY	Jackson	
	STATE	MO	ZIP CODE	64114	
RANGE	TELEPHONE NO.	913 / 339 - 2000			
	NAME OF FIRM CONTACT	LAST FIRST		Day Steven M	
RECREATION AREA	ADDRESS	8400 Ward Parkway			
	CITY	Kansas City	COUNTY	Jackson	
NURSERY	STATE	MO	ZIP CODE	64114	
	TELEPHONE NO.	913 / 339 - 2000			
WATER BASED RECREATION	NAME OF FIRM CONTACT	LAST FIRST		Day Steven M	
	ADDRESS	8400 Ward Parkway			
WATER UTILITY	CITY	Kansas City	COUNTY	Jackson	
	STATE	MO	ZIP CODE	64114	
MILLION GALLONS PER DAY (AVERAGE)	TELEPHONE NO.	913 / 339 - 2000			
	NAME OF FIRM CONTACT	LAST FIRST		Day Steven M	
MILLION GALLONS PER DAY (MAXIMUM)	ADDRESS	8400 Ward Parkway			
	CITY	Kansas City	COUNTY	Jackson	
PLEASE PROVIDE INFORMATION IF APPLICATION IS FOR MODIFICATION OR RENEWAL OF AN EXISTING PERMIT:	STATE	MO	ZIP CODE	64114	
	TELEPHONE NO.	913 / 339 - 2000			
PERMIT NO.	NAME OF FIRM CONTACT	LAST FIRST		Day Steven M	
	ADDRESS	8400 Ward Parkway			
OWNER'S NAME	CITY	Kansas City	COUNTY	Jackson	
	STATE	MO	ZIP CODE	64114	
DESCRIBE MODIFICATION	TELEPHONE NO.	913 / 339 - 2000			
	NAME OF FIRM CONTACT	LAST FIRST		Day Steven M	
INCREASE PUMPING RATE FROM EXISTING TWO WELLS FROM 0.44 mgd TO 0.88 mgd FOR ADDITIONAL POWER GENERATION UNIT AT STANTON ENERGY CENTER.	ADDRESS	8400 Ward Parkway			
	CITY	Kansas City	COUNTY	Jackson	
MILLION GALLONS PER DAY (MAXIMUM)	STATE	MO	ZIP CODE	64114	
	TELEPHONE NO.	913 / 339 - 2000			
PLEASE PROVIDE INFORMATION IF APPLICATION IS FOR MODIFICATION OR RENEWAL OF AN EXISTING PERMIT:	NAME OF FIRM CONTACT	LAST FIRST		Day Steven M	
	ADDRESS	8400 Ward Parkway			
PERMIT NO.	CITY	Kansas City	COUNTY	Jackson	
	STATE	MO	ZIP CODE	64114	
OWNER'S NAME	TELEPHONE NO.	913 / 339 - 2000			
	NAME OF FIRM CONTACT	LAST FIRST		Day Steven M	
DESCRIBE MODIFICATION	ADDRESS	8400 Ward Parkway			
	CITY	Kansas City	COUNTY	Jackson	
INCREASE PUMPING RATE FROM EXISTING TWO WELLS FROM 0.44 mgd TO 0.88 mgd FOR ADDITIONAL POWER GENERATION UNIT AT STANTON ENERGY CENTER.	STATE	MO	ZIP CODE	64114	
	TELEPHONE NO.	913 / 339 - 2000			

In compliance with the provisions of Chapter 373, Florida Statutes, 1977 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)

General Counsel, OUC

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
Section 18, 19

Township T23S
Township T23S

Range R31E
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

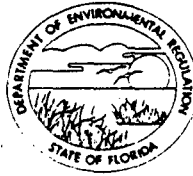
Attach any available water quality data on supply water and wastewater. Attached

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 County: Orange
System Address: Potable Water Distribution System
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
(Subdivision, trailer park, school, etc.) Stanton
Latitude 28 ° 29 ' ____ "N Longitude 81 ° 10 ' ____ "W Provide latitude/longitude and section-
2 addi-
tion
Section: ____ Township: ____ Range: ____
13, 14, 23, 24 23S 31E
18, 19 23S 32E
attach additional sheet, if necessary

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
are true, correct and complete to the best of my knowledge and belief. Further, the undersigned agrees to maintain System
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) For 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 water:
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-in. Max. size pipe 6-in. Min. system pressure 210 ft. @ Max. system pressure 240 ft.
3. Is fire control provided in design? Existing storage tank also supplies water for separate five pump discharge 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

**ORLANDO UTILITIES
COMMISSION
CURTIS H. STANTON
ENERGY CENTER**

UNIT 2

**SUPPLEMENTAL
SITE
CERTIFICATION
APPLICATION**

VOLUME 3

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT 2

SUPPLEMENTAL
SITE CERTIFICATION APPLICATION
Alafaya Trail Extension

VOLUME 3

ORLANDO UTILITIES COMMISSION

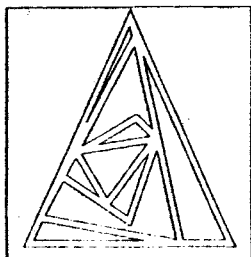
**CURTIS H. STANTON ENERGY CENTER
UNIT 2**

**SUPPLEMENTAL
SITE CERTIFICATION APPLICATION**

VOLUME 3

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.

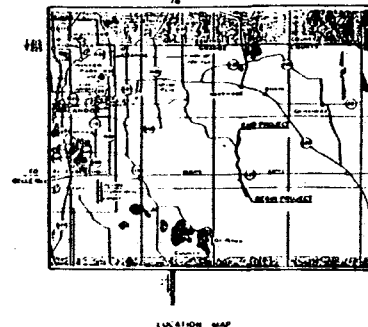


INTERNATIONAL
CORPORATE
PARK

CONSTRUCTION PLANS FOR

ALAFAYA TRAIL

ORANGE COUNTY, FLORIDA



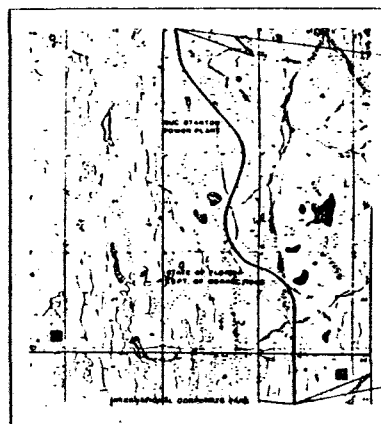
STATE OF FLORIDA DEPARTMENT OF TRANSPORTATION
"MANUAL OF STANDARD SPECIFICATIONS FOR HIGHWAY AND TRAFFIC DESIGN STANDARDS"
BUREAU 1, DATED JANUARY 1988
WHICH ARE CONSIDERED PART OF THESE PLANS

BSHA #1	STANDARD DESCRIPTION
001	STANDARD SYMBOLS
002	STANDARD SYMBOLS
102	BALED HAY OR STRAW BARRIERS AND SALT FENCES
103	EMERGENCY BARRIERS
104	EROSION CONTROL FOR PERMANENT CONSTRUCTION
200	STRUCTURE BOTTOMS TYPE J AND P
201	SUPPLEMENTARY DETAILS FOR MANHOLES AND INLETS
205	COVER HEIGHT
210	CURB INLET TOPS TYPE 1, 2, 3, AND 4
220	GUTTER INLET TYPE 5
232	INLET BOTTOM INLETS TYPE C, D, E, AND H
253	STRAIGHT CONCRETE ENDWALLS DOUBLE 72" CONCRETE PIPE
272	CROSS DRAIN INTERIOR END SECTION
273	SIDE DRAIN INTERIOR END SECTION
280	MISCELLANEOUS DRAINAGE DETAILS
281	MEDIAN OPENING FLUME
300	CURB, CURB AND GUTTER
302	TRAFFIC SEPARATORS
303	CURB RETURN PROFILES
305	CONCRETE PAVEMENT JOINTS
308	BRIDGE APPROACH EXPANSION JOINT - CONCRETE PAVEMENT
309	GUARDRAIL
400	GUARDRAIL ANCHORAGE AND CONTINUOUS BARRIER FOR EXISTING
401	BRICKS
410	CONCRETE BARRIER WALL
415	PRECAST CONCRETE TEMPORARY BARRIER WALL
500	EXCAVATION, EMBANKMENT AND GRADING
505	EMBANKMENT UTILIZATION
510	SUPERELEVATION
513	FLEXIBLE PAVEMENT - LAYER THICKNESS FOR STRUCTURAL
514	COURSES
515	OPTIMAL BASE GROUPS AND STRUCTURAL NUMBERS
600	TURNAROUNDS
601	GENERAL INFORMATION FOR TRAFFIC CONTROL THROUGH WORK
602	ZONES
700	TWO LANE TWO WAY BUREAU DAY OR NIGHT OPERATIONS
701	DESIGN CRITERIA RELATED TO HIGHWAY SAFETY

UTILITIES ENCOUNTERED

TYPE	UTILITY	TELEPHONE
WATER	ORANGE COUNTY PUBLIC UTILITIES DIVISION	244 7200
SEWER	ORANGE COUNTY PUBLIC UTILITIES DIVISION	244 7200
TELEPHONE	SAFARI FIBER OPTIC	351 8014

ALL UTILITIES ENCOUNTERED SHALL BE MAINTAINED PRIOR TO CONSTRUCTION.



END PROJECT
STA. 505+00.00

N

SCALE:
1"=0.631 MILES

BEGIN PROJECT
STA. 274+81.41

LENGTH OF PROJECT
24,762 LF OR 4.7 MI

BENCH MARK DATUM SOURCE
U.S. GEOLOGICAL SURVEY 333 1950 EL. 73.00

PREPARED FOR:

INTERNATIONAL CORPORATE PARK
933 LEE ROAD, SUITE 400
ORLANDO, FLORIDA 32810

PREPARED BY:



LOCHRANE ENGINEERING, INC.

CONSULTING CIVIL, ENVIRONMENTAL ENGINEERS
AND SURVEYORS

201 South Broadway Avenue, Orlando, Florida 32803 (407) 895-3317

INDEX OF ROADWAY PLANS

SHEET NO.	SHEET DESCRIPTION
1	KEY SHEET
2-3	DRAINAGE MAPS
4-6	TYPICAL SECTIONS
7	SUMMARY OF QUANTITIES
7-10	SUMMARY OF DRAINAGE STRUCTURES
11-20	PLAN AND PROFILES SHEET
20-31	INTERSECTION LAYOUT/DETAILS
32-40	DRAINAGE STRUCTURES
40-55	POWD DETAIL SHEETS
56-122	ROADWAY CROSS SECTIONS
123	SIGNING/PAVEMENT GENERAL NOTES
124	SUMMARY OF QUANTITIES (TRAFFIC)
125-132	SIGNING AND PAVEMENT MARKING SHEETS
133-135	CONSPAN DETAIL SHEETS
136	SPECIAL DETAILS - EROSION CONTROL

PRINTED

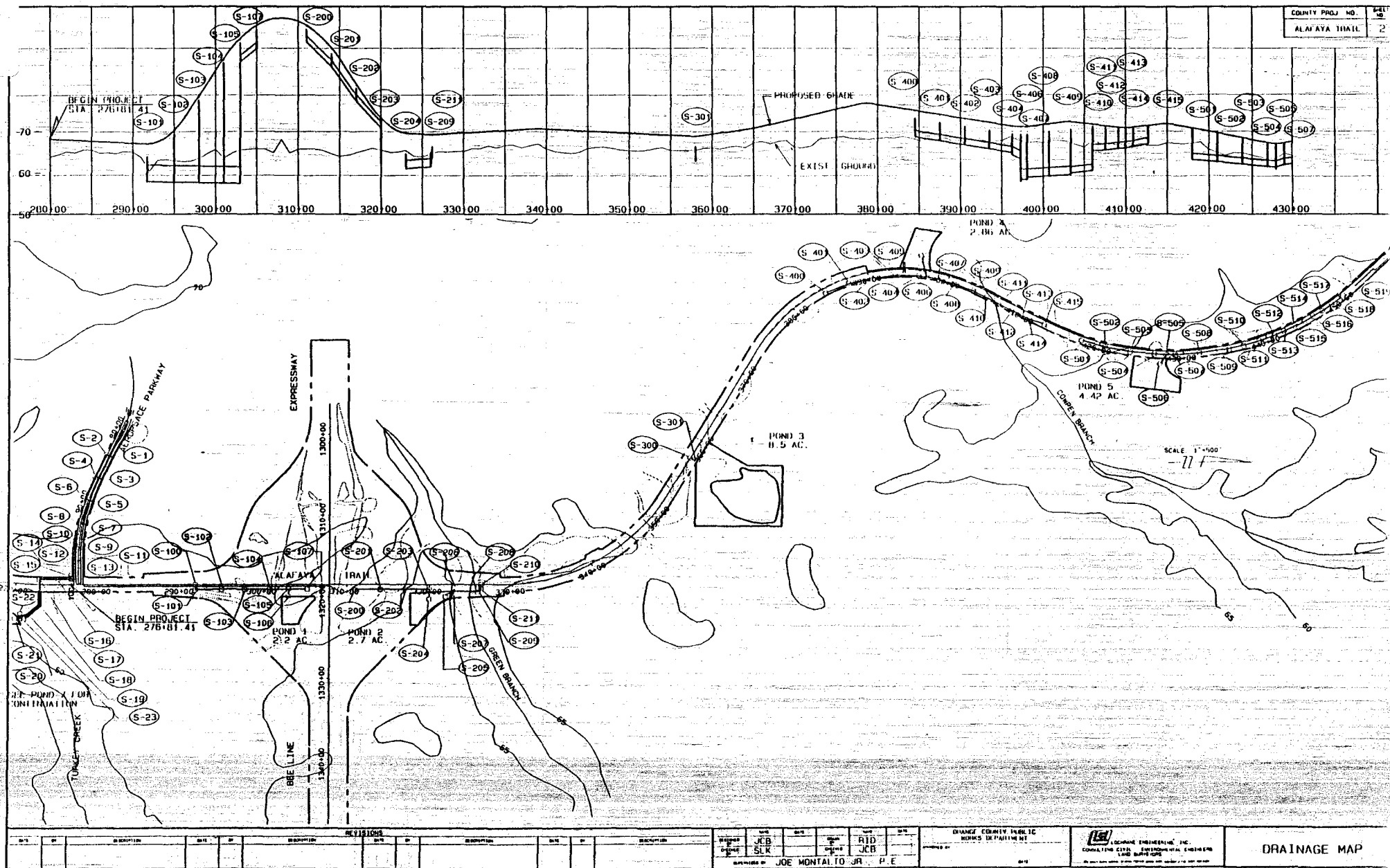
JAN 27 1992

LOCHRANE
ENGINEERING
INCORPORATED

CERTIFICATION OF PLANS

THIS IS TO CERTIFY THAT THE ROADWAY CONSTRUCTION PLANS AND SPECIFICATIONS AS CONTAINED HEREIN WERE DESIGNED TO APPLICABLE STANDARDS AS SET FORTH IN THE "MANUAL OF UNIFORM MINIMUM STANDARDS FOR DESIGN, CONSTRUCTION AND MAINTENANCE FOR STREETS AND HIGHWAYS", STATE OF FLORIDA, AS PREPARED BY THE FLORIDA DEPARTMENT OF TRANSPORTATION, TALLAHASSEE, FLORIDA DATED JULY, 1988.

DATE ENGINEER REG. NO.







ALAFAYA TRAIL - TYPICAL SECTION

DESIGN SPEED: 60 M.P.H.

EXIST. GROUND

EXISTING 24" FM

EXISTING 24" WM

ADD 1 1/4" TYPE "S" ASPH. CONC.

EXIST. GROUND

180' R/W

90' (FUTURE)

STANDARD CLEARING & GRUBBING

90'

SEED & MULCH

VARIES 2'

14'

4'

6'

10'

12'

12'

10'

13'

13'

10'

12'

12'

10'

6'

4'

14'

2' VARIES

2' SOD

SEED & MULCH

2' SOD

2' SOD

PAVED SHOULDER

P.G.L.

0.06

0.02

0.06

0.06

0.02

0.06

3:1

4:1

2:1

3:1

4:1

2:1

1

2

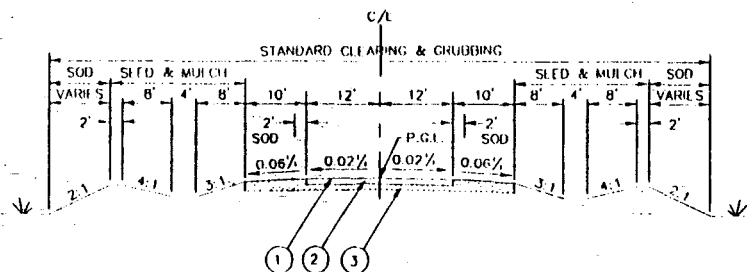
3

4

- 1 ASPHALTIC CONCRETE FRICTION COURSE (5/8" THICK)(FC-2)
- 2 TYPE 5-1 ASPHALTIC CONCRETE (2 1/2" MIN. THICKNESS)
- 3 SOIL CEMENT BASE (8" MIN. THICKNESS), COMPACTED TO 95% DENSITY, T-134
- 4 TYPE "B" STABILIZATION (12" MIN. THICKNESS), LBR-40

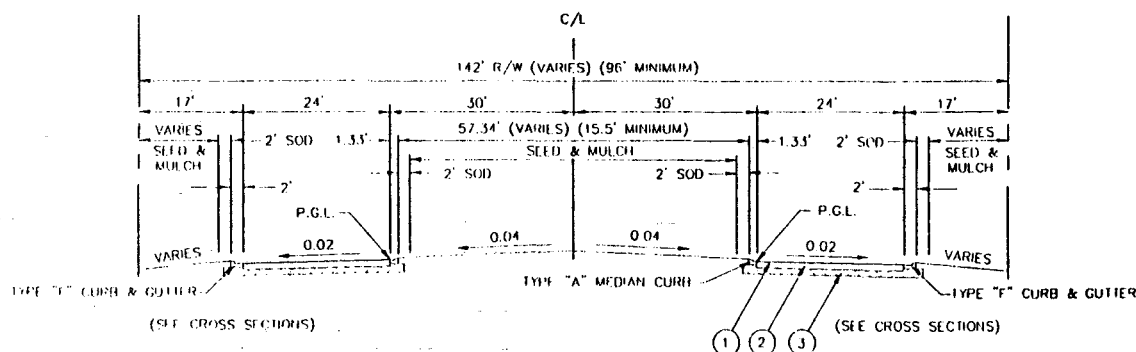
[illegible]

COMPLETION DATE	DATE
ALAFAYA TRAIL	5



OUC SERVICE ROAD CONNECTOR
TYPICAL SECTION

- ① TYPE S-1 ASPHALTIC CONCRETE (1 1/2" MIN. THICKNESS)
- ② SOIL CEMENT BASE (8" MIN. THICKNESS), COMPACTED TO 95% DENSITY, T-134
- ③ TYPE "B" STABILIZATION (12" MIN. THICKNESS), LBR-40



AEROSPACE PARKWAY - TYPICAL SECTION

DESIGN SPEED: 40 M.P.H.

- ① TYPE S-1 ASPHALTIC CONCRETE (1 1/2" MIN. THICKNESS)
- ② SOIL CEMENT BASE (8" MIN. THICKNESS), COMPACTED TO 95% DENSITY, T-134
- ③ TYPE "B" STABILIZATION (12" MIN. THICKNESS), LBR-40

GENERAL NOTES

1. ALL CONSTRUCTION AND MATERIALS TO BE IN ACCORDANCE WITH ORANGE COUNTY STANDARDS AND SPECIFICATIONS AND "THE FLORIDA DEPARTMENT OF TRANSPORTATION STANDARD SPECIFICATIONS FOR ROAD AND BRIDGE CONSTRUCTION - LATEST EDITION" UNLESS OTHERWISE SPECIFIED IN THE TECHNICAL PROVISIONS.
2. ALL DISTURBED AREAS TO BE FERTILIZED, SEEDED AND MULCHED UNLESS OTHERWISE NOTED.
3. GRADES SHOWN ARE FINISHED GRADES.
4. ANY NGVD '29 MONUMENT WITHIN THE LIMITS OF CONSTRUCTION IS TO BE PROTECTED. IF IN ANY DANGER, THE PROJECT ENGINEER SHOULD NOTIFY:
 GEODETIC INFORMATION CENTER
 ATTN: MARK MAINTENANCE SECTION
 N/CG-162
 6001 EXECUTIVE BOULEVARD
 ROCKVILLE, MARYLAND 20852
 TELEPHONE NO. (301) 443-8319
5. EXISTING DRAINAGE STRUCTURES WITHIN CONSTRUCTION LIMITS SHALL BE REMOVED UNLESS OTHERWISE NOTED.
6. ALL EXISTING UTILITIES TO BE LOCATED AND VERIFIED BY THE CONTRACTOR PRIOR TO THE START OF CONSTRUCTION. ANY RELOCATION OF THESE UTILITIES SHALL BE COORDINATED BY THE CONTRACTOR WITH THE ENGINEER & ORANGE COUNTY PUBLIC UTILITIES. ANY RELOCATION OF EXISTING UTILITIES WILL BE PAID FOR BY THE DEVELOPER.
7. ANY U.S.C. & G.S. MONUMENTS OR PUBLIC LAND CORNER (SECT. CORNER) WITHIN THE LIMITS OF CONSTRUCTION SHALL BE PROTECTED. IF IN DANGER OF DAMAGE THE CONTRACTOR SHALL NOTIFY THE ORANGE COUNTY SURVEYOR.
8. SOD ALL SLOPES GREATER THAN 3:1.
9. FINAL LOCATION OF PROPOSED DRIVES TO BE DETERMINED IN THE FIELD BY THE ENGINEER.
10. ALL PERSONAL PROPERTY, EXCEPT MAILBOXES, WITHIN THE R/W SHALL BE RELOCATED BY THE OWNER OR IT SHALL BE REMOVED BY THE CONTRACTOR AS NECESSARY TO CONSTRUCT THE PROJECT IN ACCORDANCE WITH THE PLANS.
11. THE DISPOSAL OF EXCESS EARTHWORK MATERIAL SHALL BE THE RESPONSIBILITY OF THE CONTRACTOR. APPROVALS OF DISPOSAL SITE SHALL BE OBTAINED FROM THE OWNER PRIOR TO DISPOSAL. ALL EXCESS MATERIAL IS THE PROPERTY OF THE OWNER.
12. CONTRACTOR SHALL EXERCISE CAUTION AROUND EXISTING TREES TO BE "SAVED". CONTRACTOR SHALL REFER TO SPECIFICATIONS FOR PROCEDURES.
13. CONTRACTOR SHALL COORDINATE CONSTRUCTION WITH ORANGE COUNTY.
14. ALL DIMENSIONS ARE TO EDGE OF PAVEMENT UNLESS OTHERWISE NOTED.
15. NOTE SPECIAL ATTENTION AND EFFORTS MUST BE INCORPORATED FOR EROSION CONTROL MEASURES ESPECIALLY AT EACH CROSSING AND ANY DISCHARGE POINTS FOR DEWATERING (REF. FDOT INDEX 102 & 103) AN EROSION CONTROL PLAN NEEDS TO BE SUBMITTED & APPROVED BY THE COUNTY ENGINEER PRIOR TO THE PRECONSTRUCTION MEETING.
16. CONTRACTOR SHALL MAINTAIN ACCESS TO FIRE HYDRANTS AT ALL TIMES. CONTRACTOR SHALL COORDINATE ANY ADJUSTMENTS TO THE FIRE HYDRANTS WITH THE ENGINEER OF RECORD AND ORANGE COUNTY PUBLIC UTILITIES.

TYPICAL SECTION
AND
GENERAL NOTES

LOCHANE ENGINEERING, INC.
CONSULTING ENGINEERS
LAND SURVEYORS

NAME	DATE	NAME	DATE
DESIGNED BY JCB		DRAWN BY JFY	
CHECKED BY SLK		ENGINEER BY JCB	
APPROVED BY JCB			

SUMMARY OF PAY ITEMS			
ITEM NO.	ITEM DESCRIPTION	UNIT	ESTIMATED QUANTITY
101-1	MOBILIZATION	LS	1
102-1	MAINTENANCE OF TRAFFIC	LS	1
104-10	EROSION CONTROL & TURBIDITY BARRIERS	LS	1
110-2	CLEARING AND GRADING	AC	66
120-1	EXCAVATION, EMBANKMENT & GRADING	LS	1
180-70	12" STABILIZED SUBBASE	SY	131.279
270-1-1	4' SHOULDER BASE	SY	21,720
270-1-2	8" SOIL CEMENT BASE	SY	77,801
208-1	TURNOUT CONSTRUCTION	SY	708
300-1-1	BITUMINOUS MATERIAL (PRIME COAT)	GAL	11,677
300-1-3	BITUMINOUS MATERIAL (TACK COAT)	GAL	3,114
400-2-2	CLASS II CONCRETE	CY	43.62
415-1-1	REINFORCED STEEL	LBS	39.74
425-1-321	CURB INLET (TYPE P-2) (<10')	EA	1
425-1-331	CURB INLET (TYPE P-3) (<10')	EA	11
425-1-351	CURB INLET (TYPE P-5) (<10')	EA	57
425-1-361	CURB INLET (TYPE P-6) (<10')	EA	2
425-1-362	CURB INLET (TYPE P-6) (10')	EA	1
425-1-421	CURB INLET (TYPE J-2) (<10')	EA	1
435-1-431	CURB INLET (TYPE J-3) (<10')	EA	1
425-1-461	CURB INLET (TYPE J-6) (<10')	EA	1
425-1-521	DITCH BOTTOM INLET (TYPE C) (<10')	EA	1
425-1-541	DITCH BOTTOM INLET (TYPE D) (<10')	EA	0
425-1-701	INLET (TYPE S) (<10')	EA	8
425-1-702	INLET (TYPE S) (>10')	EA	5
425-2-41	MANHOLE (TYPE P-71) (<10')	EA	2
425-2-71	MANHOLE (TYPE J-77) (<10')	EA	3
425-2-101	CONFLICT STRUCTURES	EA	6
430-11-325	CONC. PIPE CULVERT (CLASS III) (18" SS)	LF	9,567
430-11-329	CONC. PIPE CULVERT (CLASS III) (24" SS)	LF	3,645
430-11-333	CONC. PIPE CULVERT (CLASS III) (30" SS)	LF	441
430-11-338	CONC. PIPE CULVERT (CLASS III) (36" SS)	LF	1,244
430-11-340	CONC. PIPE CULVERT (CLASS III) (42" SS)	LF	357
430-11-341	CONC. PIPE CULVERT (CLASS III) (48" SS)	LF	1,167
430-11-345	CONC. PIPE CULVERT (CLASS III) (72" SS)	LF	192
430-982-225	MITERED END SECTION (18" RCP)	EA	13
430-982-229	MITERED END SECTION (24" RCP)	EA	1
430-982-233	MITERED END SECTION (30" RCP)	EA	2
430-982-230	MITERED END SECTION (36" RCP)	EA	1
430-982-241	MITERED END SECTION (48" RCP)	EA	3
520-1-7	CURB & GUTTER (TYPE E)	LF	4,393
520-1-10	CURB & GUTTER (TYPE F)	LF	4,259
536-1-2	BRIDGE GUARDRAIL	LF	9,502
536-9	END ANCHORAGE ASSEMBLY (TYPE IV)	EA	18
545-70	BRIDGE RETAINING WALLS	SF	3,600
550-73	SPECIAL FENCING (U.C.)	LF	12,100
570-2	SEED & MULCH	SY	221,809
570-9	WATER FOR GRASS	MG	258
575-1	SODDING	SY	61,237
5331-72-12	TYPE S ASPHALT CONC. (INC. BIT.) (1 1/4")	SY	20,454
5331-72-24	TYPE S ASPHALT CONC. (INC. BIT.) (2 1/2")	SY	77,649
5337-1-2	ASPHALT CONC. FRICTION COURSE (FC-2) (5/8")	SY	77,649
N	6" x 20" CONC. ARCH CULVERTS	EA	1
N	6" x 24" CONC. ARCH CULVERTS	EA	1
**	ROAD CRESTED WEIR	EA	6

SUMMARY OF SIDEDRAIN							
LOCATION		SIDE	SIZE	PIPE		MES	
STA.	TO STA.			D I.F.	E I.F.	D A.	E I.A.
OUC CONNECTION							
12+18	- 12+25		18	65		2	
293+92	- 294+28		18	36		2	
359+52	- 359+88		18	36		2	
394+88	- 395+40		18	52		2	
424+30	- 424+68		18	36		2	
471+87	- 472+28		18	41		2	
TOTALS							
Description				Quantity			
18" MCP				266 LF			
18" MES				32 EA			

SUMMARY OF SODDING		
LOCATION	P	F
	SY	SY
ALAFAYA TRAIL	29, 155	
AEROSPACE PKWY.	943	
OUC CONNECTOR	413	
POND 1	2, 862	
POND 2	3, 535	
POND 3	13, 698	
POND 4	2, 990	
POND 5	3, 641	
POND 6	3, 980	
TOTAL	61, 237	

STANDARD PAY ITEM FOOTNOTES

xx The cost of the PVC pipe and fiberglass skimmer and steel posts to be included in the bid price of the control structure

SUMMARY OF EARTHWORK		
DESCRIPTION	EXC.	FILL
	CY	CY
ALAFAYA TRAIL	169.809 *	393.444
AEROSPACE PKWY.	11.750 *	26.649
DUC CONNECTOR		7.874
PONDS	300.443 *	
TOTAL	483.140	427.967

* Includes excavation of unsuitable material, stripping, and 30% shrinkage. All unsuitable material to be stockpiled in areas designated by ICP for the use in muck blanket operations.

SUMMARY OF GUARDRAIL					
LOCATION	SIDE	GUARDRAIL		END ANCHORAGE TYPE IV	
		P LF	F LF	P EA	F EA
SIA. TO SIA.					
295+00 - 306+93	LT	1, 193		1	
295+00 - 306+93	RT	1, 193		1	
308+88 - 326+50	LT	1, 762		1	
308+88 - 326+50	RT	1, 762		1	
328+50 - 348+50	RT	2, 000		2	
403+76 - 404+00	LT	24		1	
404+60 - 404+84	LT	24		1	
404+70 - 404+94	RT	24		1	
405+60 - 405+84	RT	24		1	
412+50 - 420+50	RT	800		2	
444+50 - 450+50	RT	600		2	
475+06 - 475+30	LT	24		1	
475+06 - 475+30	RT	24		1	
475+75 - 475+99	LT	24		1	
475+75 - 475+99	RT	24		1	

NOTE: Guardrail limits and location along the project may be varied based on actual project conditions at the time of construction.

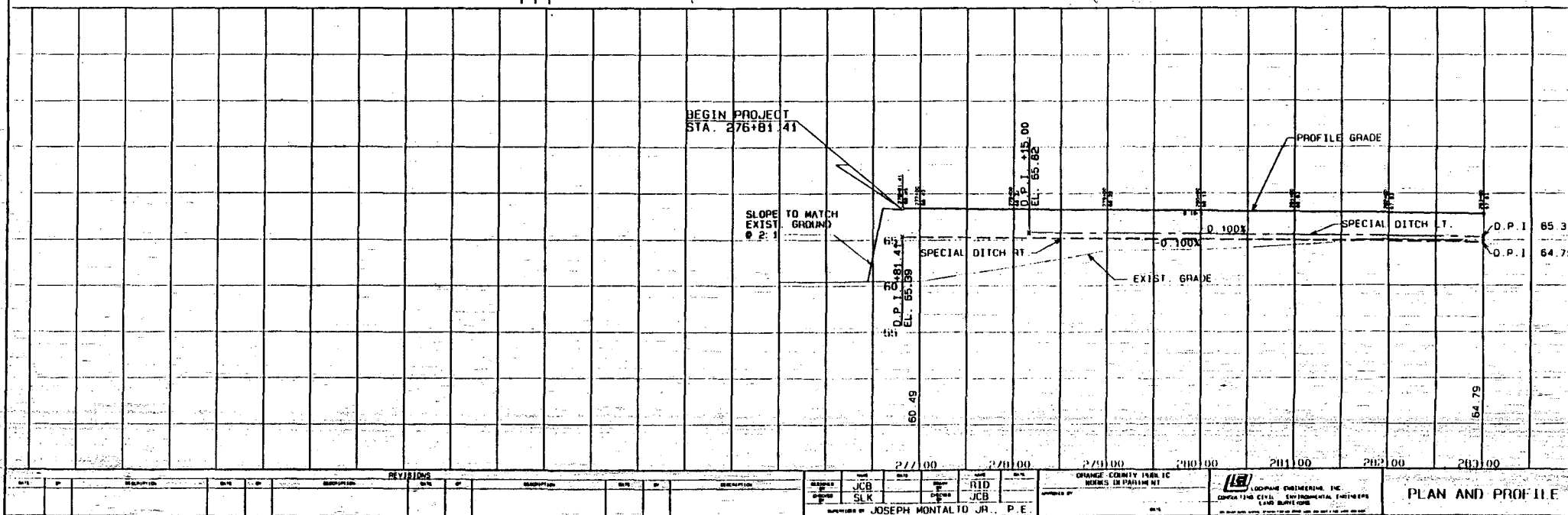
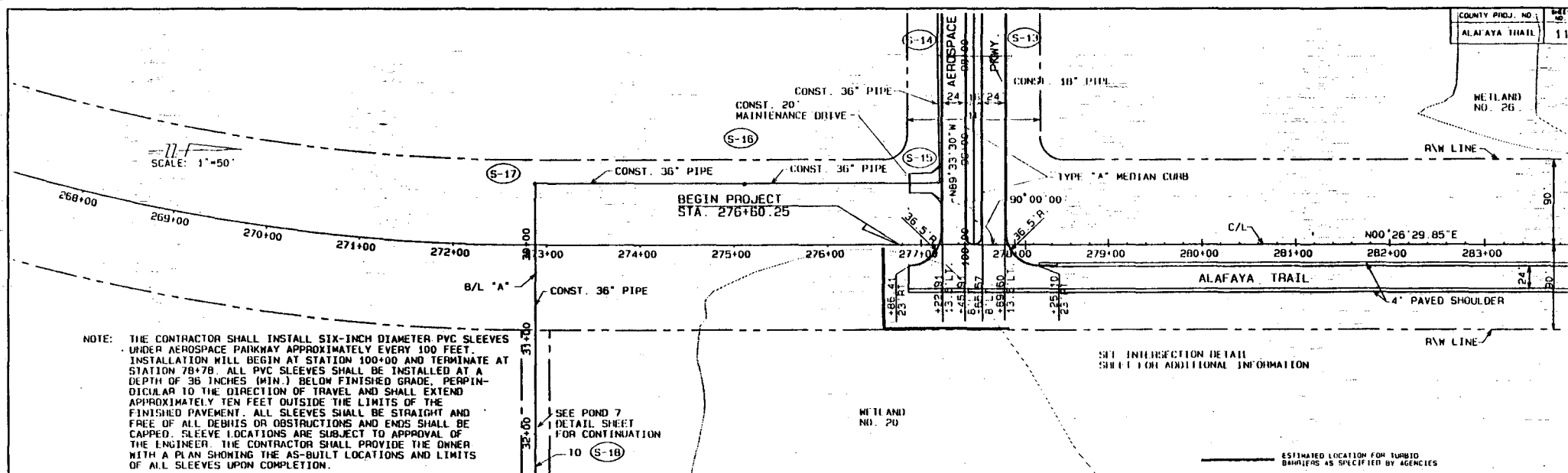
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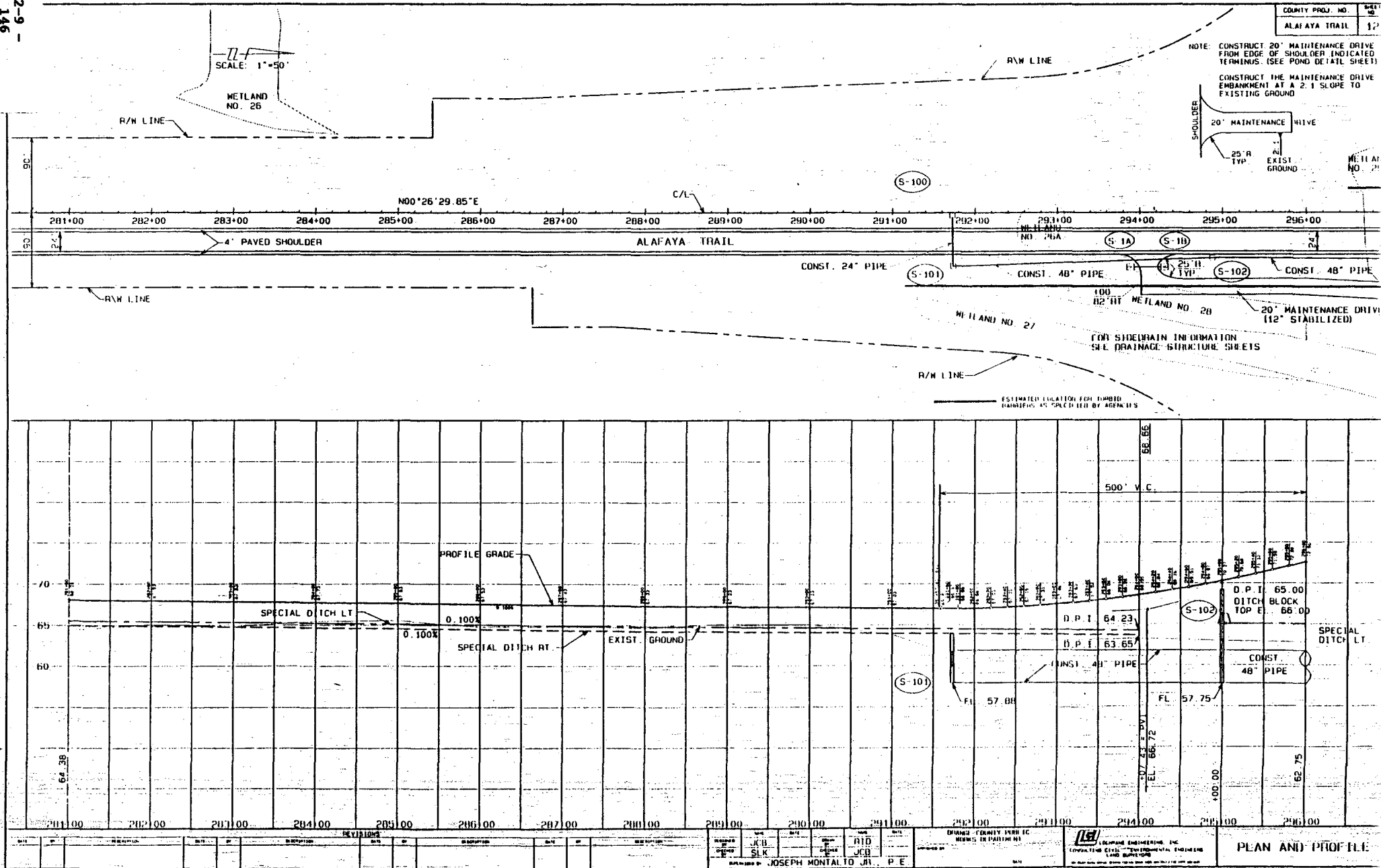
 LOCHRAN ENGINEERING ESTABLISHED 1974 • 1000 10TH AVENUE SUITE 100 • DENVER, COLORADO 80202 • 303.733.1100	SUMMARY OF DRAINAGE STRUCTURES
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[illegible]

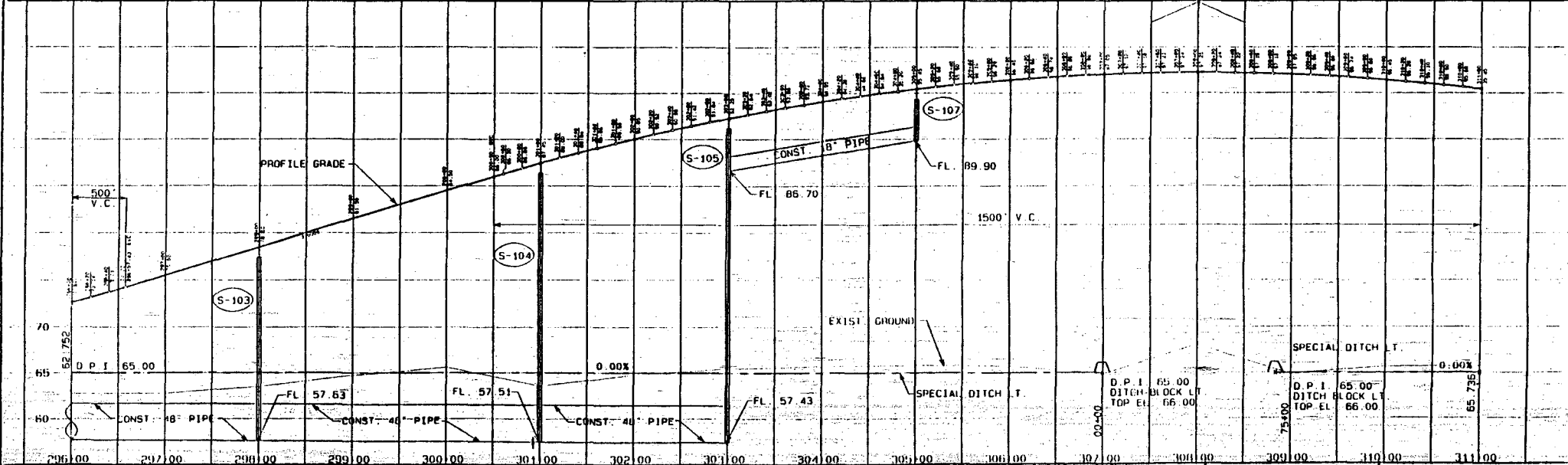
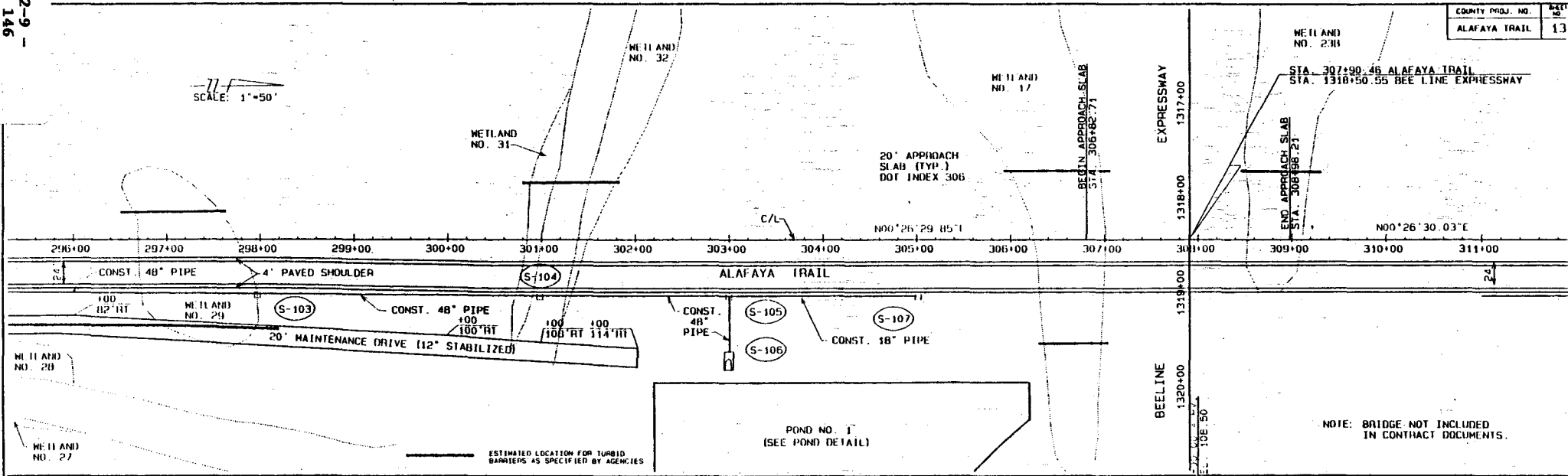
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SCALE: 1"=50'

COUNTY PROJ. NO.	SHEET NO.
ALAFAYA TRAIL	13



NO.	DATE	DESCRIPTION	BY	CHKD.	APP'D.
1					
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CHANCE COUNTY PUBLIC WORKS DEPARTMENT

DESIGNED BY: JOSEPH MONTALTO JR., P.E.

CHECKED BY: JCB

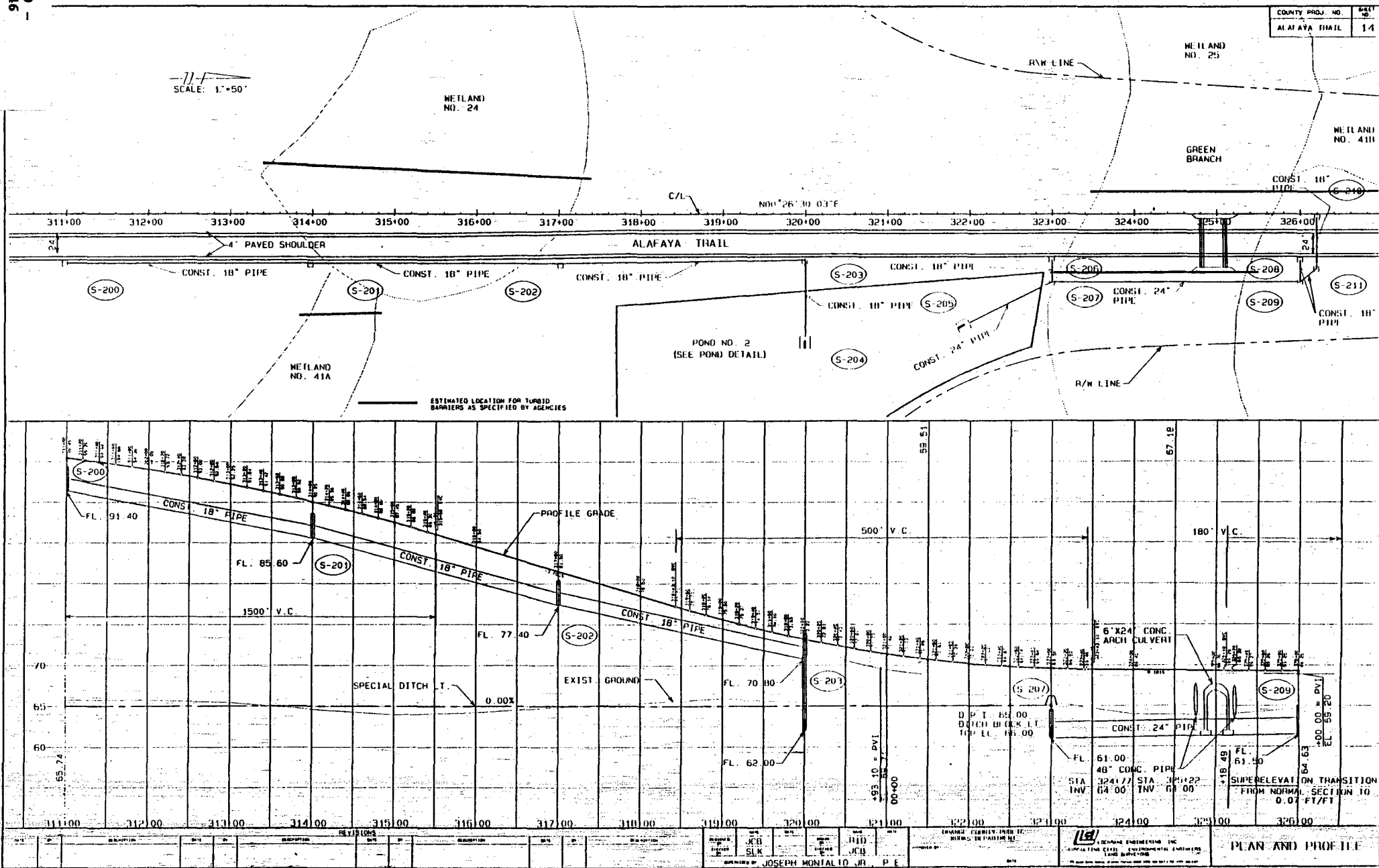
APPROVED BY: JCB

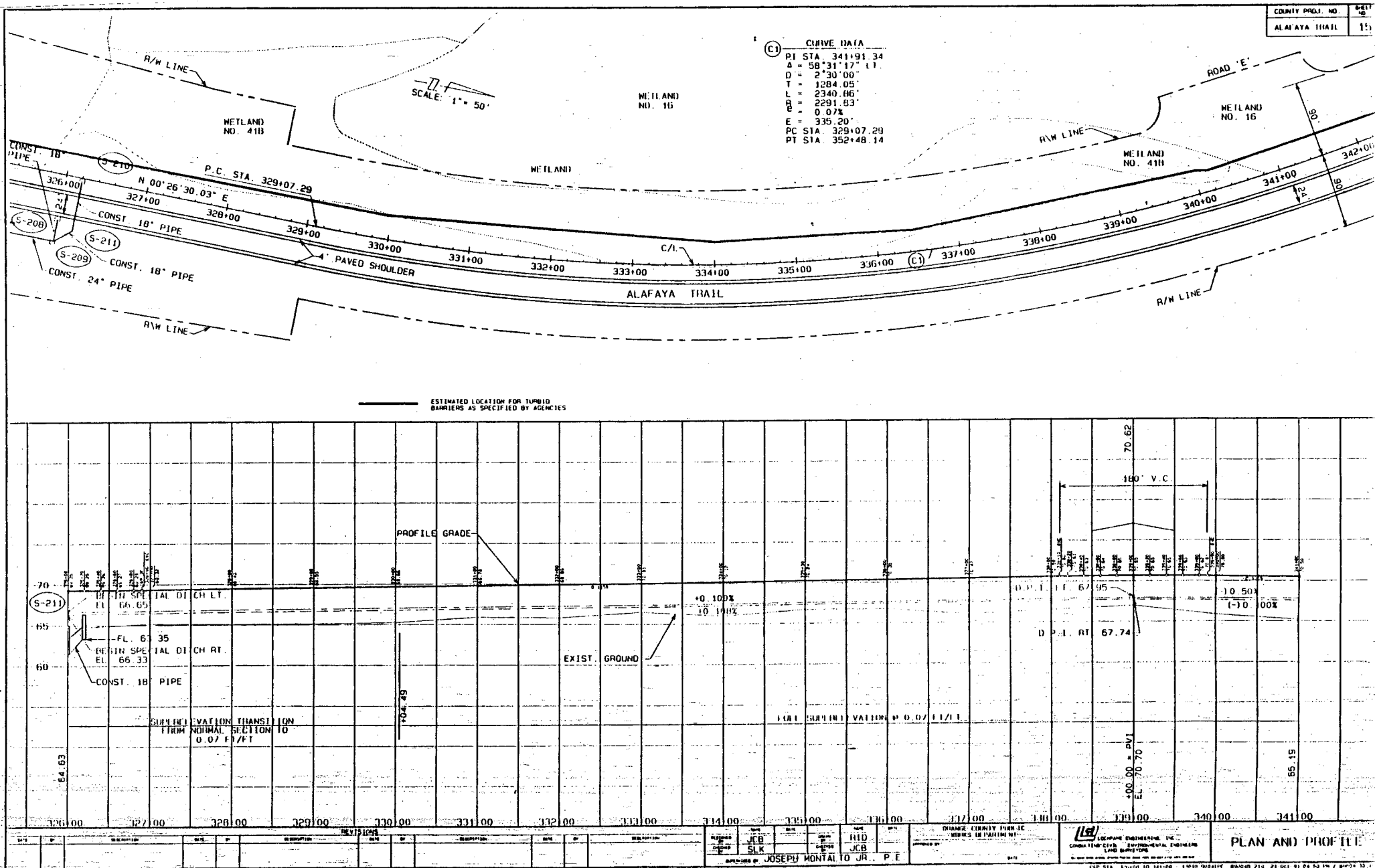
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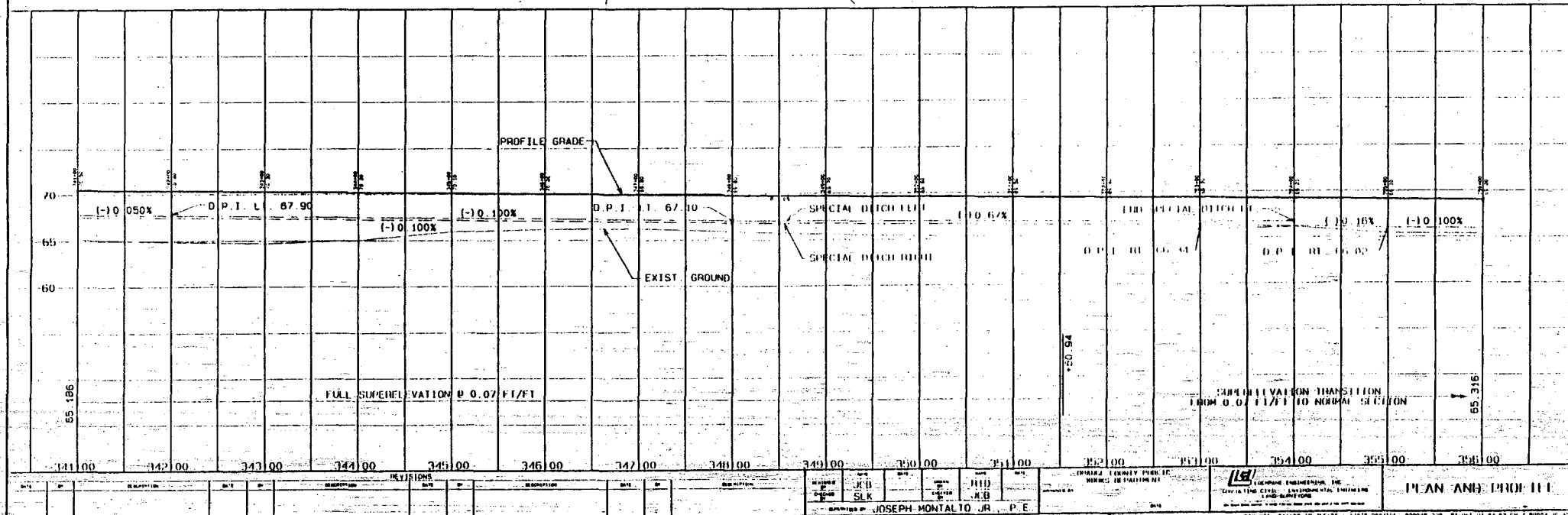
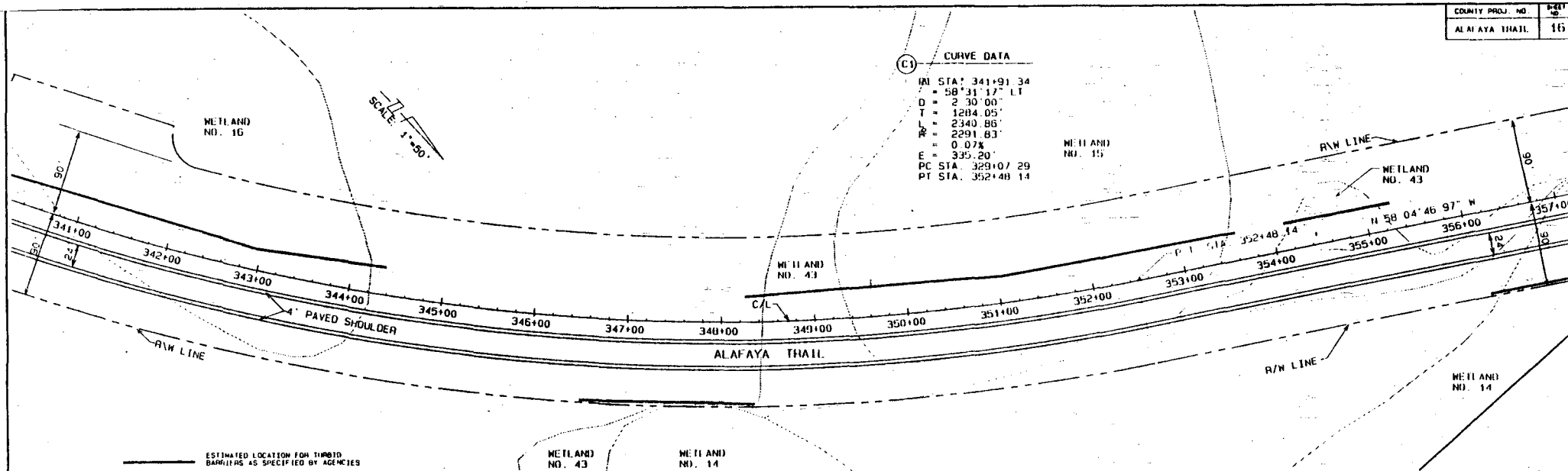
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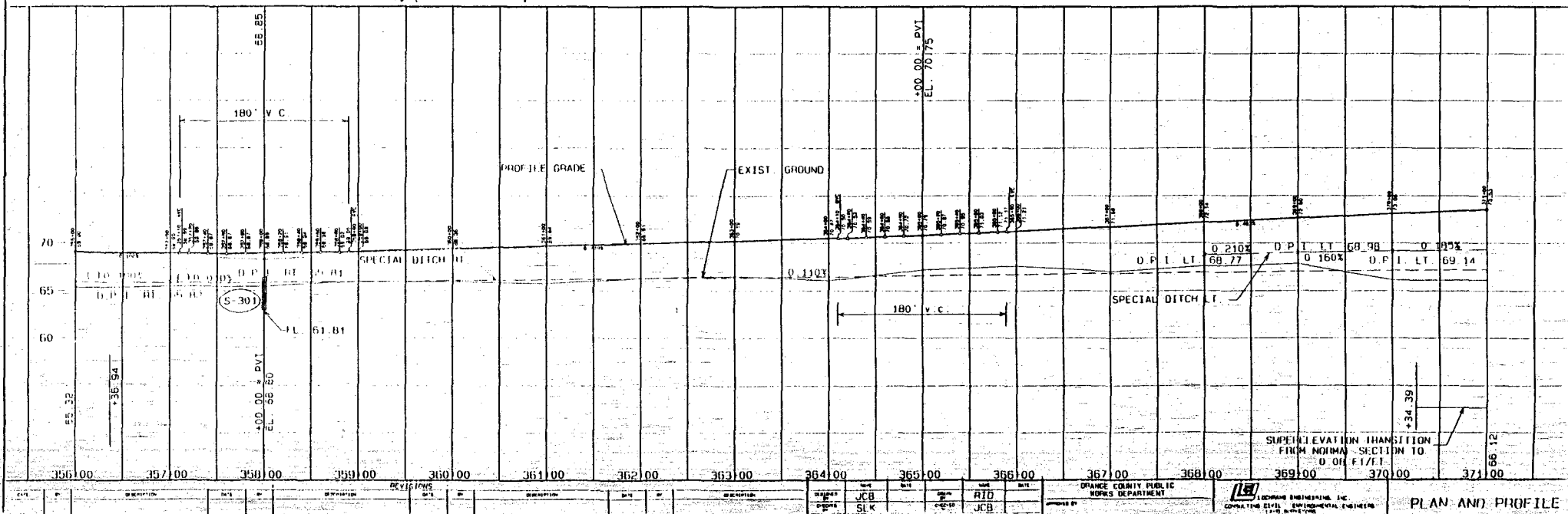
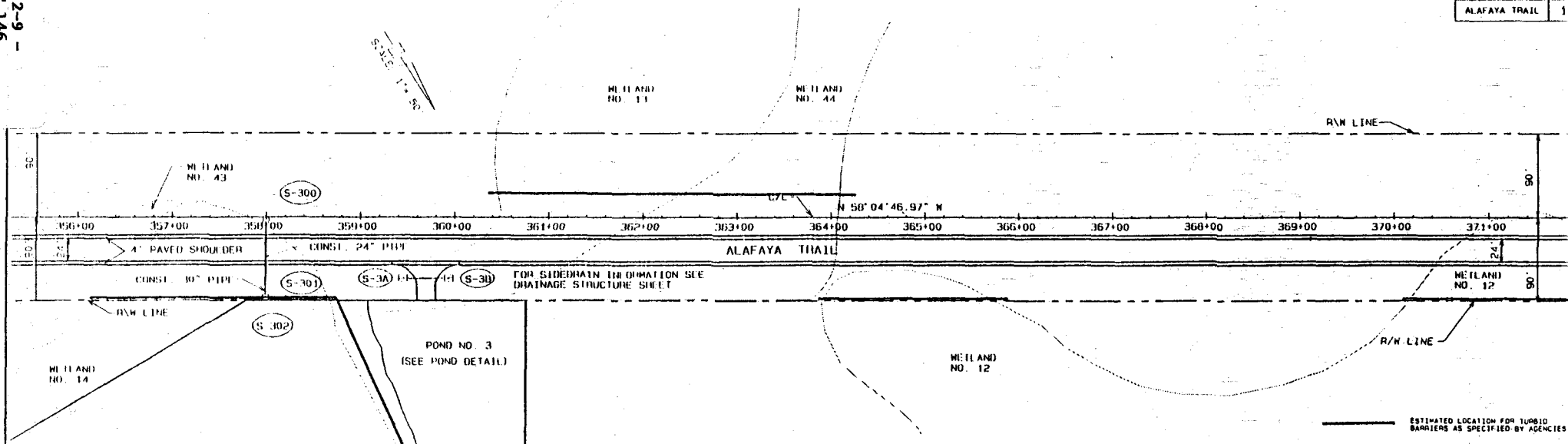
SCALE: 1"=50'

PLAN AND PROFILE





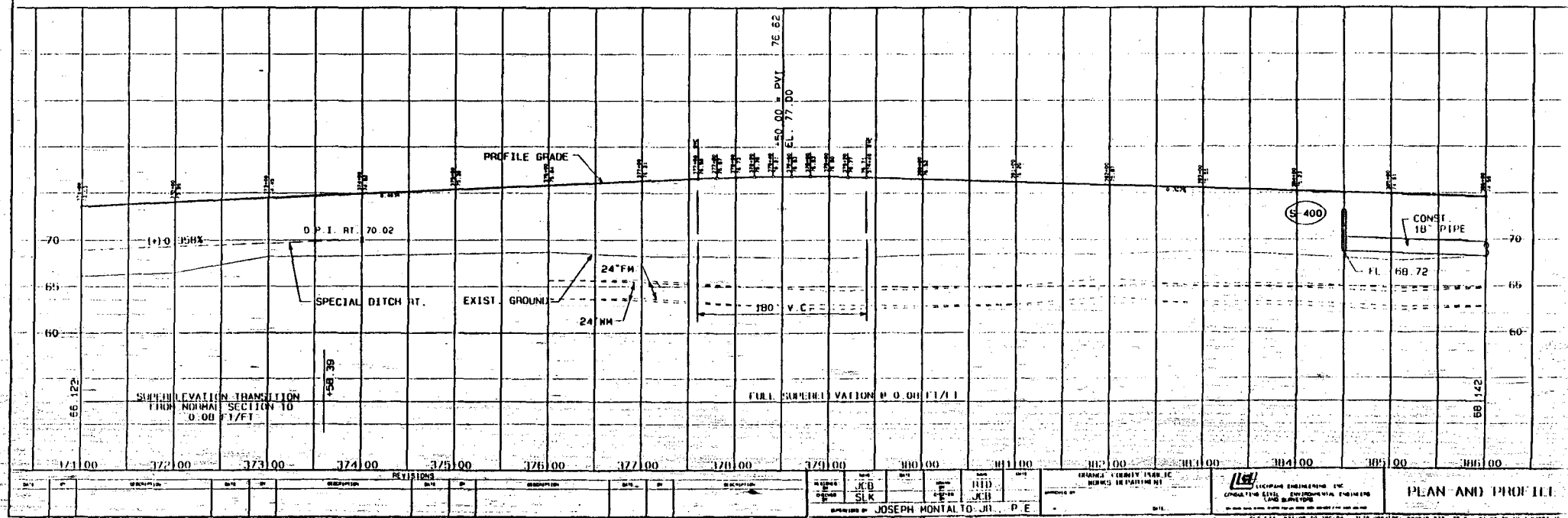


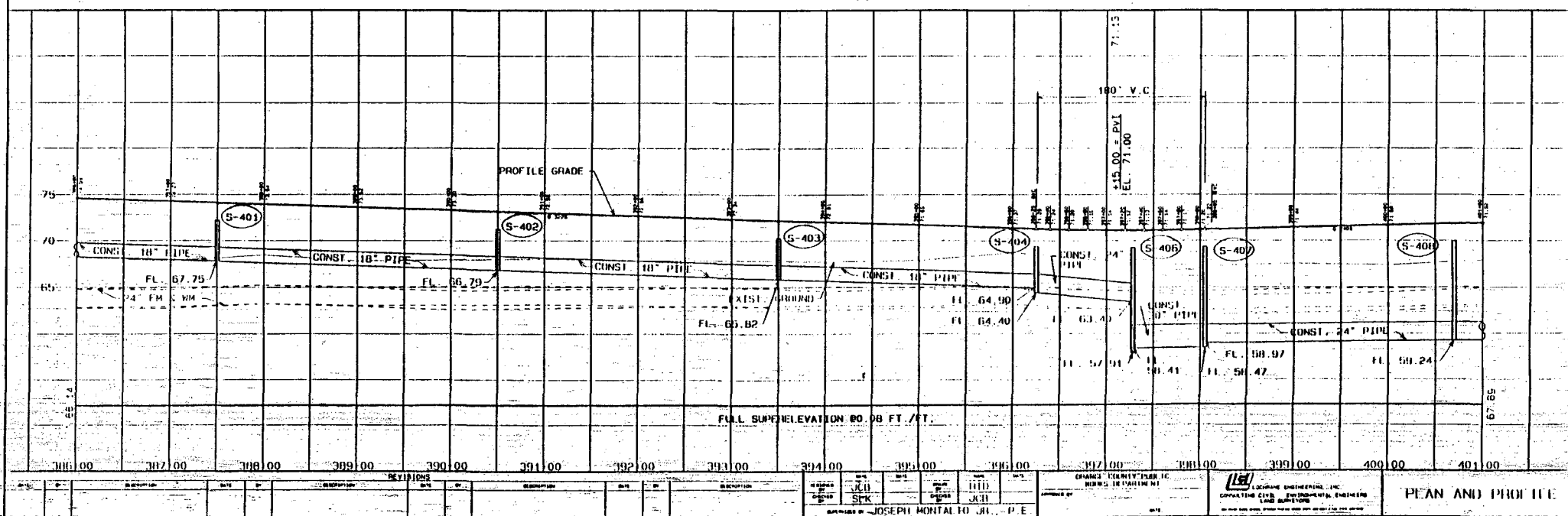
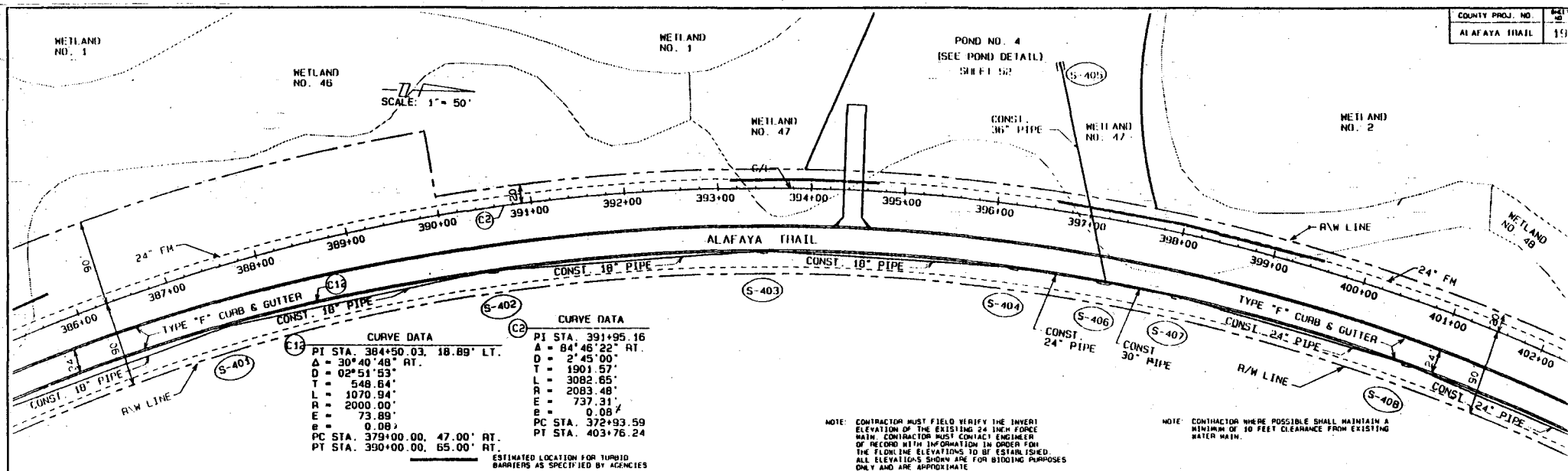


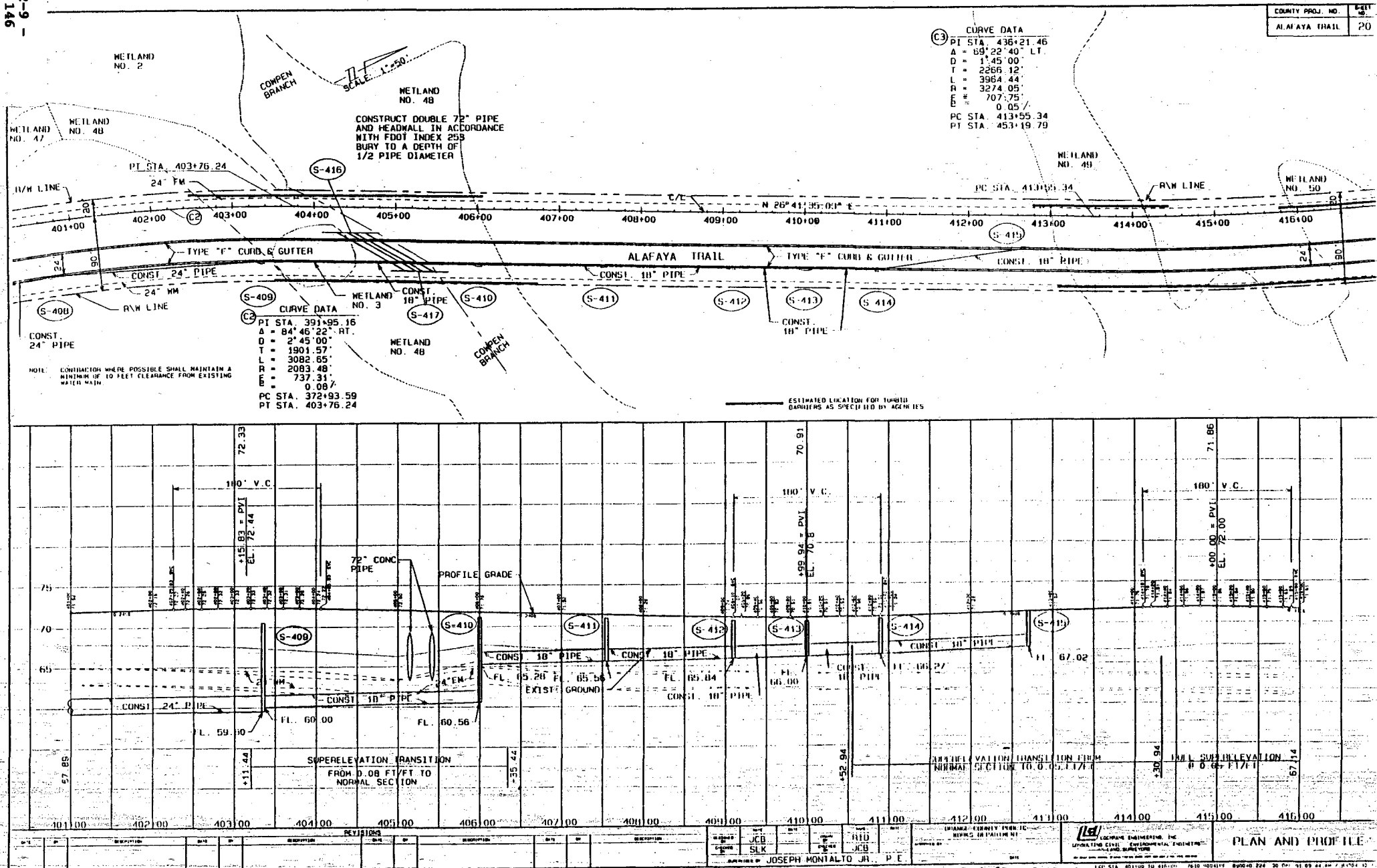
DESIGNED BY JCB SLK	CHECKED BY ATD JCB	DATE 10-10-10	PROJECT NO. 6.2-9	ORANGE COUNTY PUBLIC WORKS DEPARTMENT	DESIGNED BY JCB SLK	CHECKED BY ATD JCB	DATE 10-10-10	PROJECT NO. 6.2-9	ORANGE COUNTY PUBLIC WORKS DEPARTMENT
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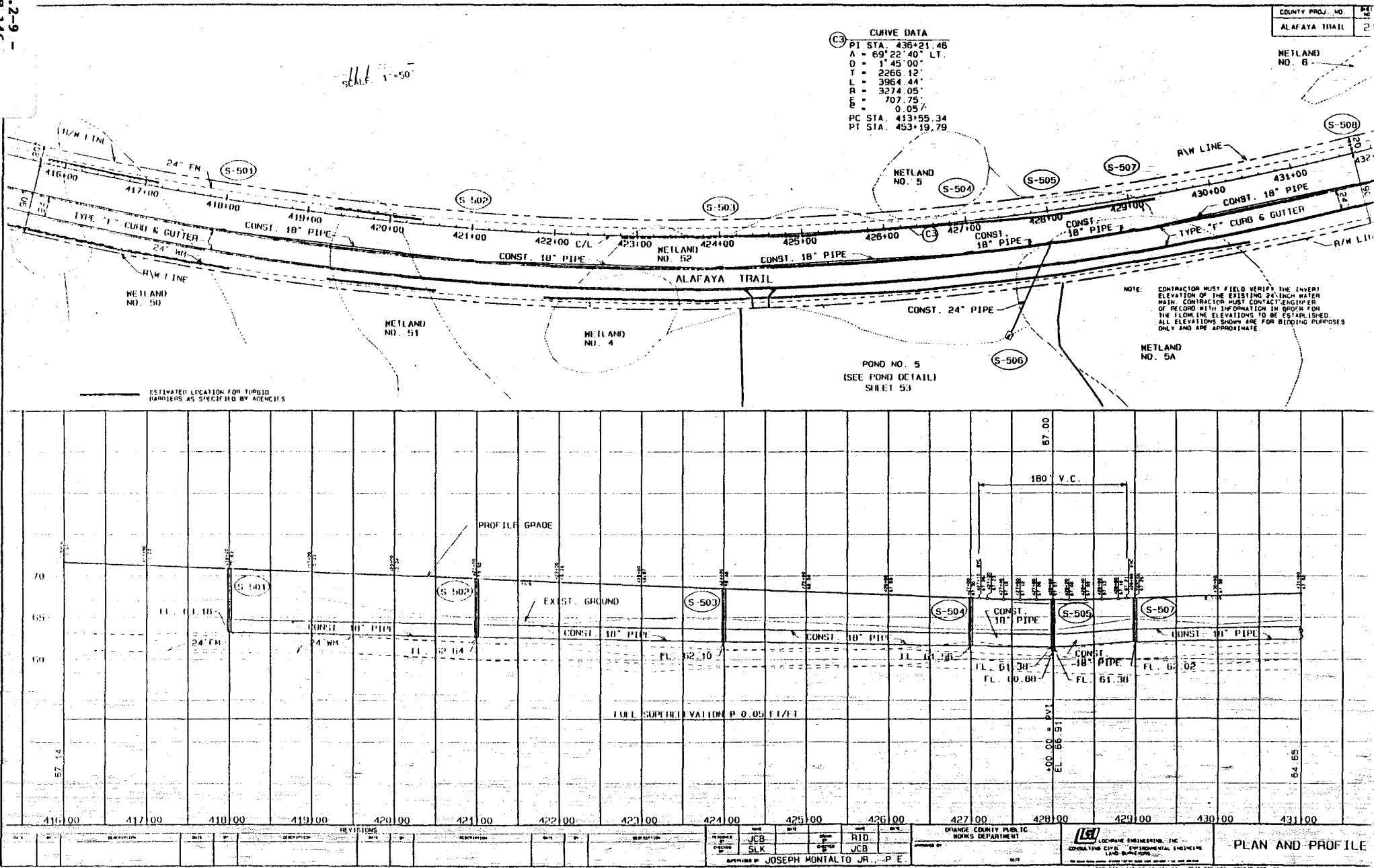

L&B ENGINEERING, INC.
 1210 S. GATEWAY
 ORANGE, CA 92667
 (714) 961-1111

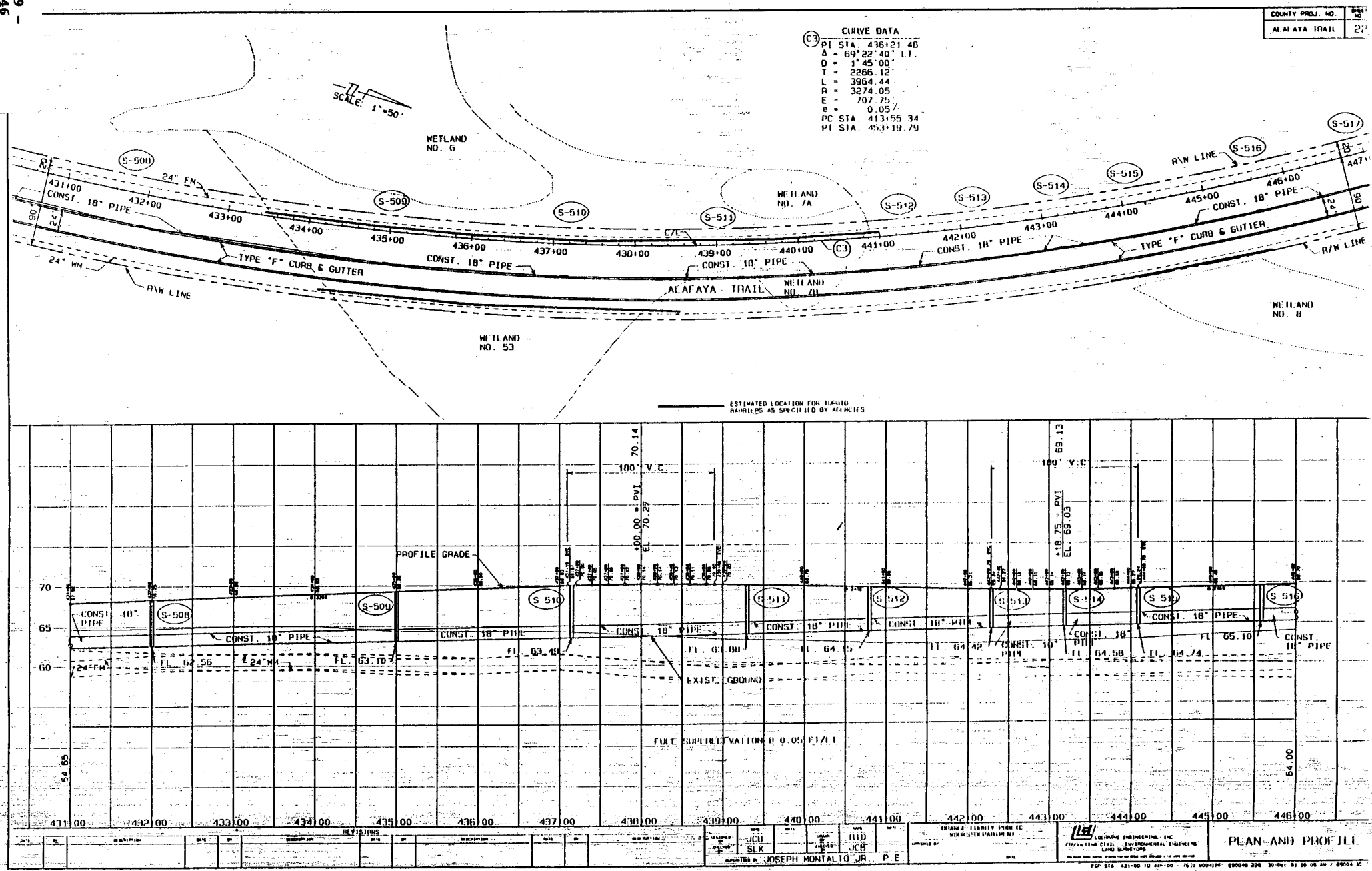
PLAN AND PROFILE

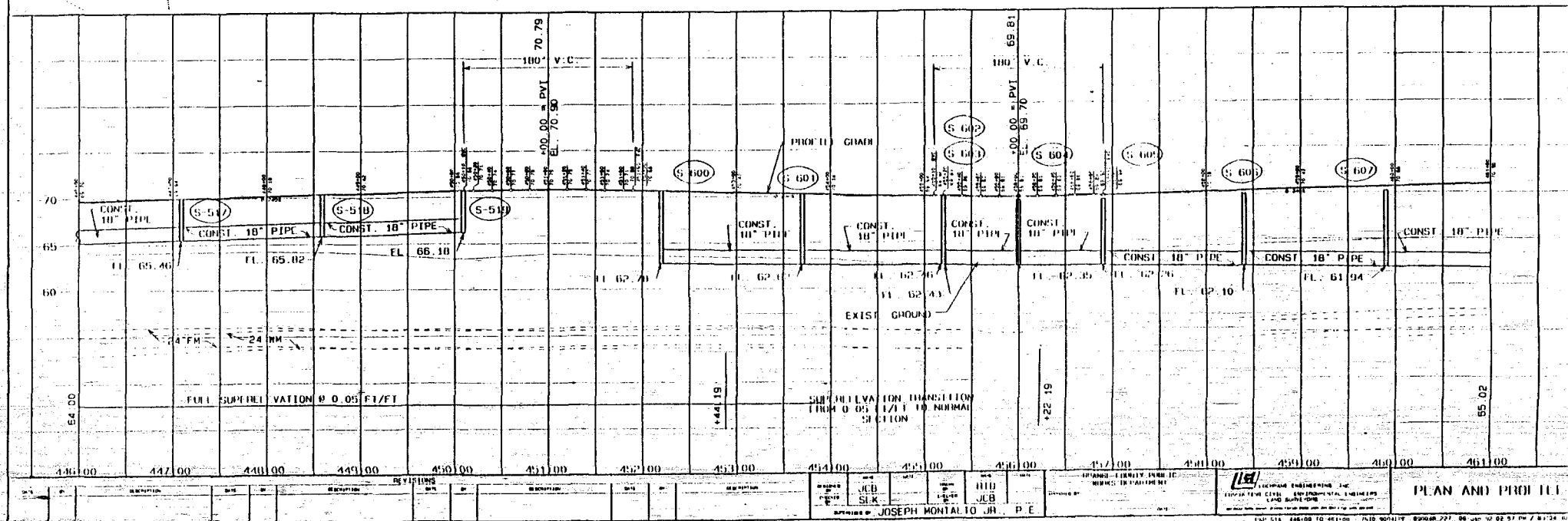
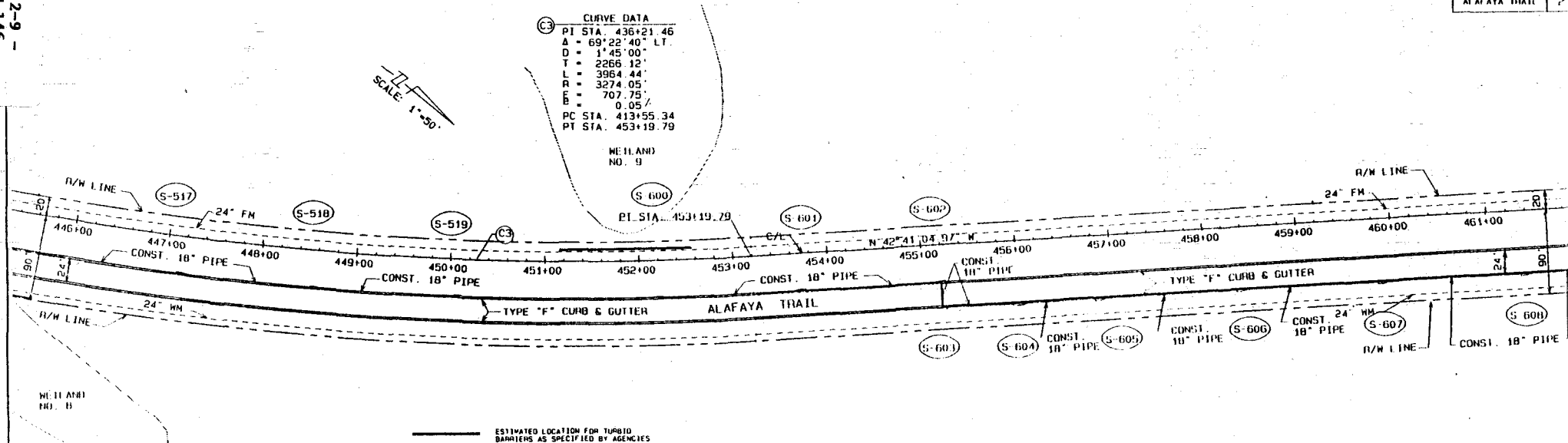


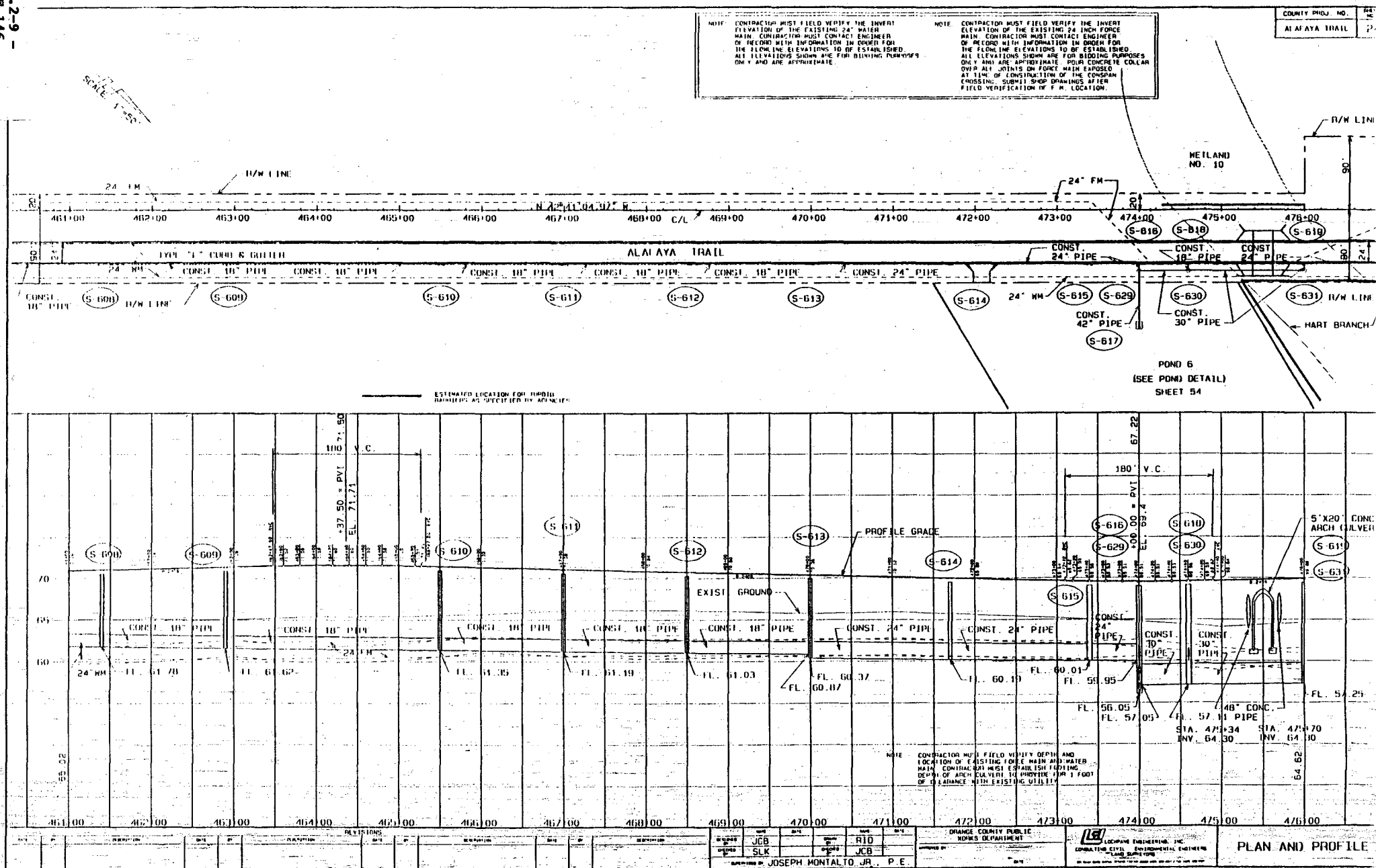


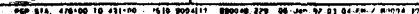


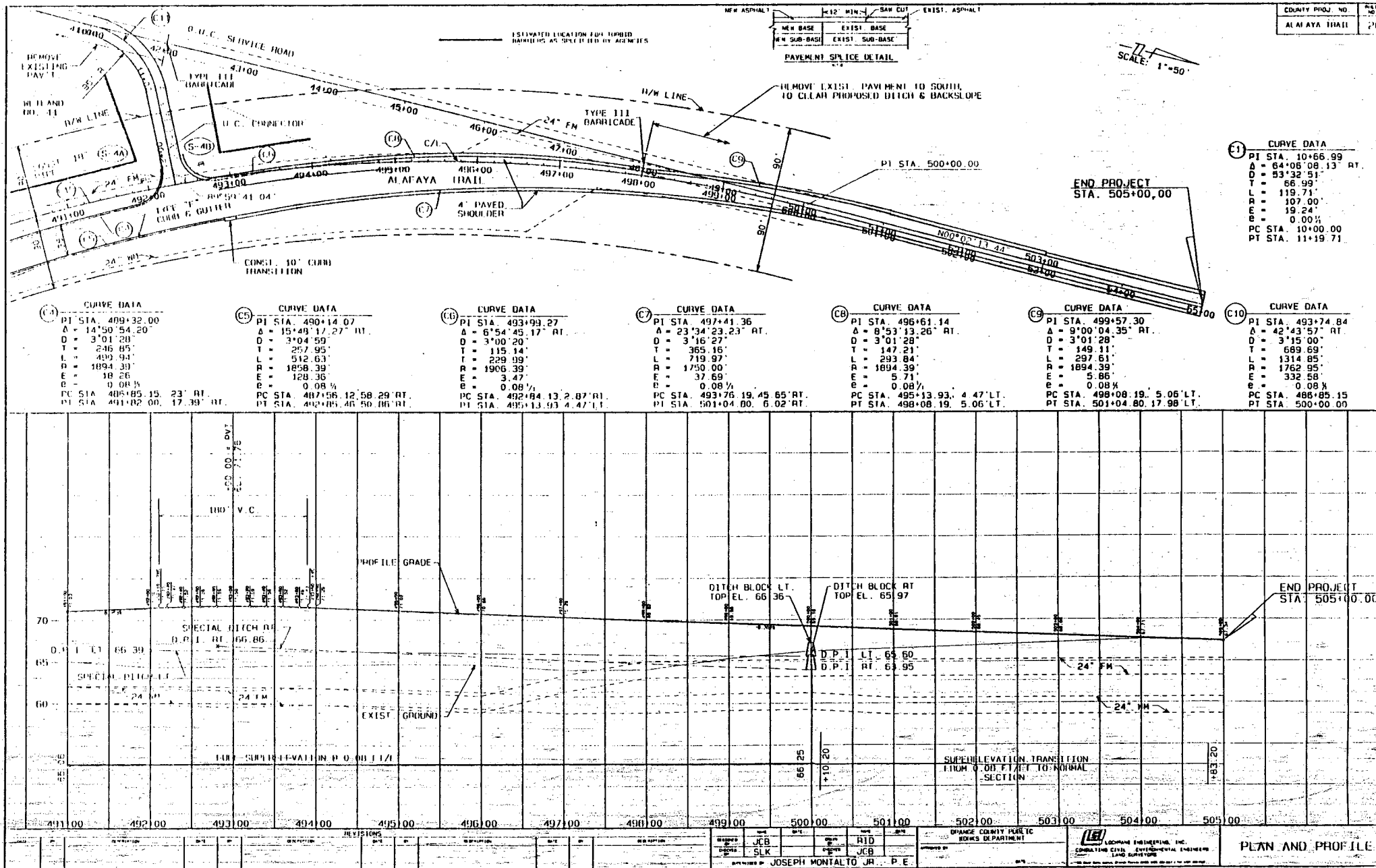


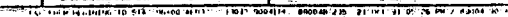










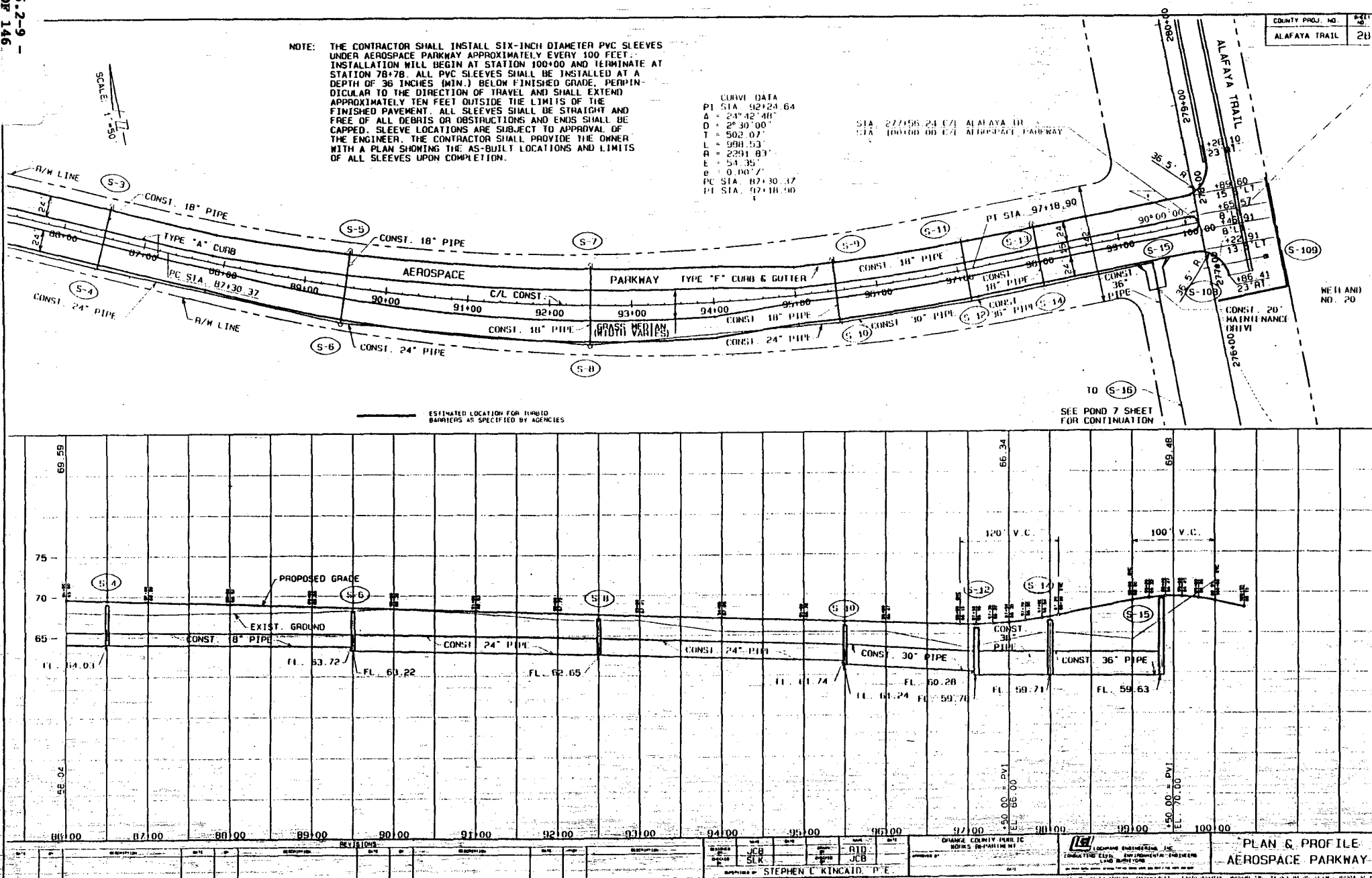


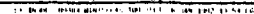
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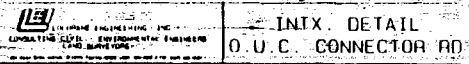
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D = 2°30'00"
T = 502.07'
L = 998.53'
R = 2291.83'
E = 54.35'
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PC STA. 87+30.37
PI STA. 97+18.90

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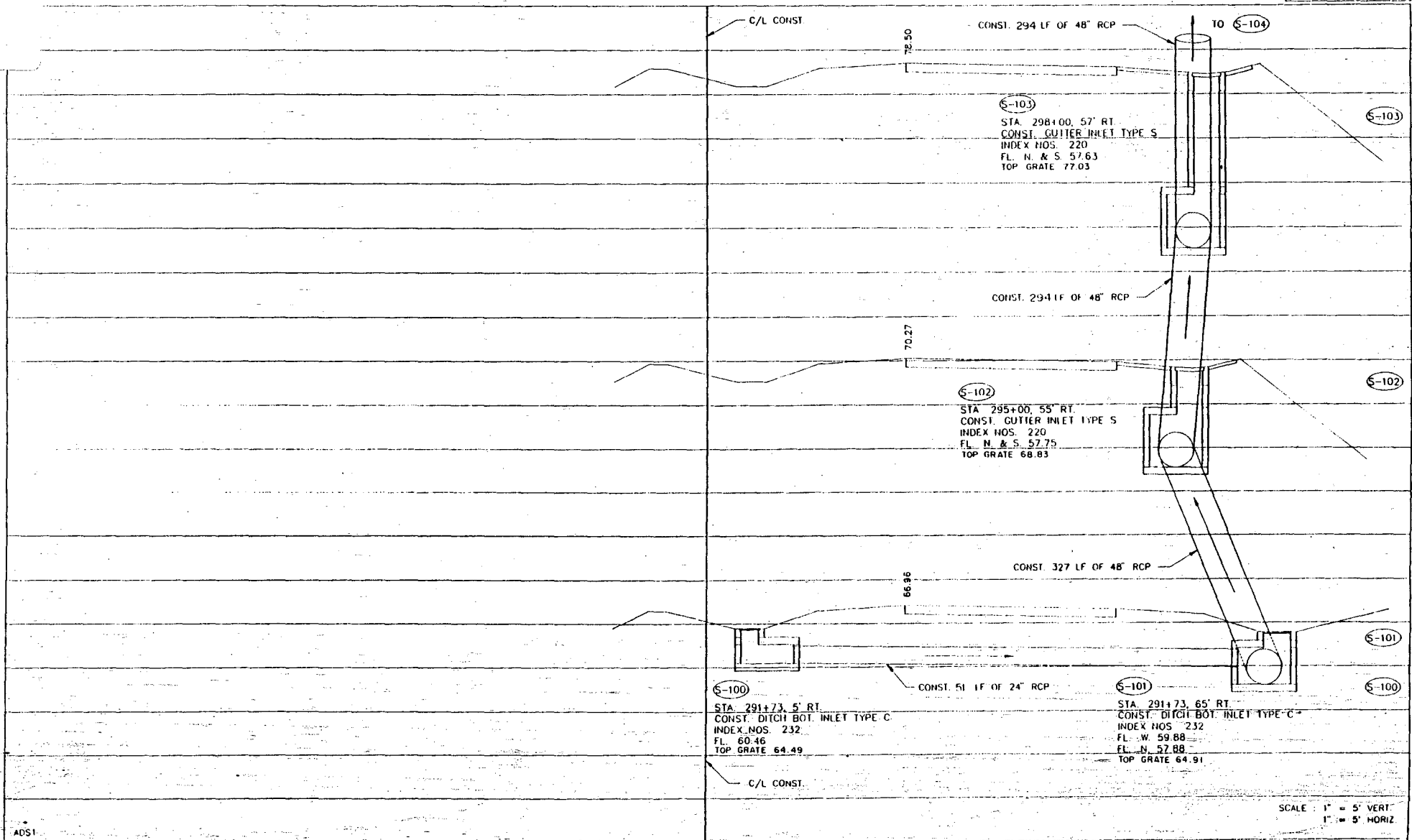
STA. 277+95.24 C/I ALIAYA TR
STA. 100+00.00 C/I AIRPORT PARKWAY







STATE PROJ. NO. ALAFAYA TRAIL
SHEET NO. 32



ADSI

REVISIONS											
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION

DESIGNED BY	CHECKED BY	DATE	DESIGNED BY	CHECKED BY	DATE
BLK	JCB		BLK	JCB	

APPROVED BY	DATE

LOCKHART ENGINEERING, INC.
CIVIL & ENVIRONMENTAL ENGINEERS
LAND SURVEYORS

DRAINAGE
STRUCTURES

STATE PROJ. NO.	SHEET NO.
ALAFAYA TRAIL	33

C/L CONST.

95.45

S-107

STA. 305+00, 59' RT.
CONST. GUTTER INLET TYPE S
INDEX NOS. 220
FL. 89.80

CONST. 200 LF OF 18" RCP

S-107

92.35

S-105

STA. 303+00, 59' RT.
CONST. GUTTER INLET TYPE S
INDEX NOS. 220
FL. N. 86.70
FL. E. & S. 57.43

CONST. 58 LF OF 48" RCP

S-106

STA. 303+00, 117' RT.
CONST. M.E.S.
INDEX NOS. 272
FL. 57.0

S-106

S-105

87.45

CONST. 200 LF OF 48" RCP

C/L CONST.

S-104

STA. 301+00, 59' RT.
CONST. GUTTER INLET TYPE S
INDEX NOS. 220
FL. N. & S. 57.51

S-104

CONST. 48" RCP

FROM S-103

SCALE: 1" = 5' VERT.
1" = 5' HORIZ.

AJ/S2

REVISIONS									
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE

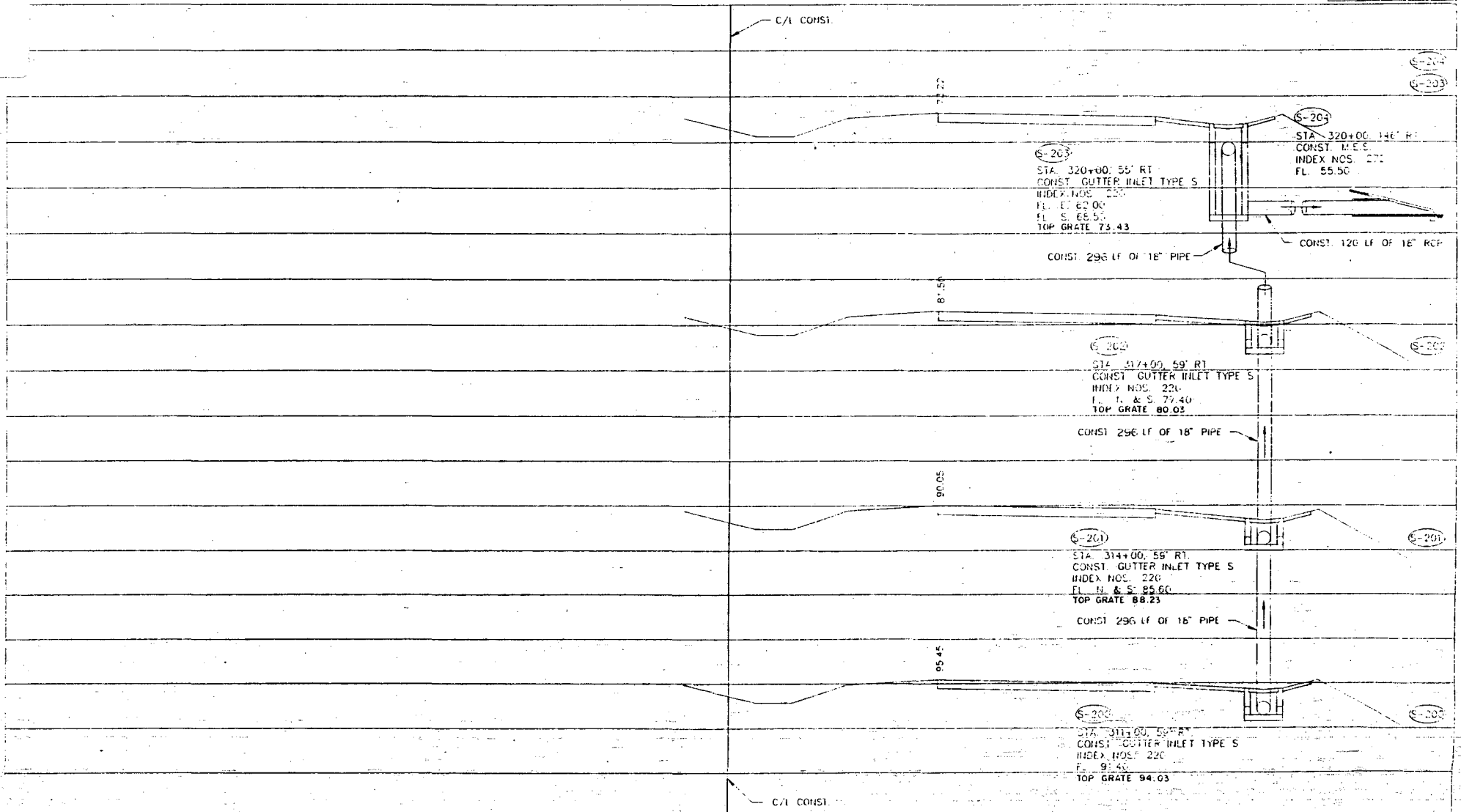
DESIGNED BY	JCB	CHECKED BY	JCB	DATE	
DRAWN BY	BLK	CHECKED BY	JCB	DATE	
SUPERVISED BY	STEPHEN L. KINCAID, P.E.				

FLORIDA DEPARTMENT OF TRANSPORTATION	DATE
APPROVED BY	

LE LOGGINS ENGINEERING, INC.
CONSULTING CIVIL ENGINEERS
LAND SURVEYORS
3000 South Orange Avenue, Suite 200, Orlando, FL 32809

DRAINAGE
STRUCTURES

STATE PROJ. NO. 1
ALAFAYA TRAIL 34



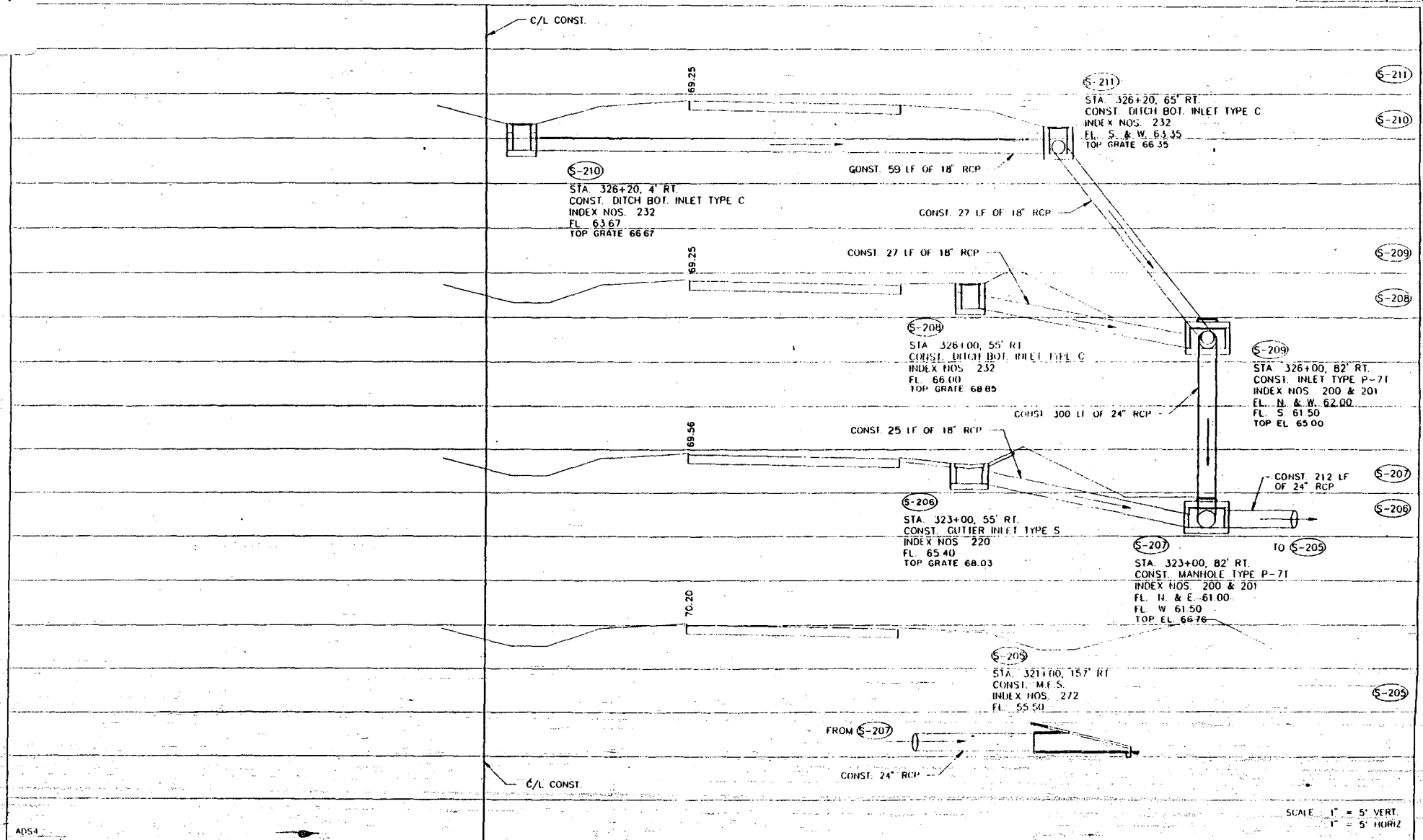
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1" = 4' VERT.

REVISIONS									
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE

DESIGNED BY: JCP
CHECKED BY: JCP
SUPERVISED BY: STEPHEN A. ADAMS, P.E.

LEIGH ENGINEERING
CONSULTING CIVIL ENGINEERS
10000 N. W. 11th Ave., Suite 100
Miami, FL 33150

DRAWING
STRUCTURES



ADS4

SCALE 1" = 5' VERT.
1" = 5' HORIZ.

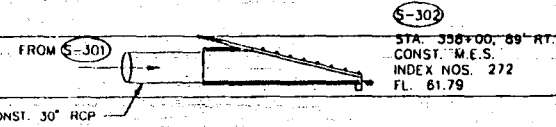
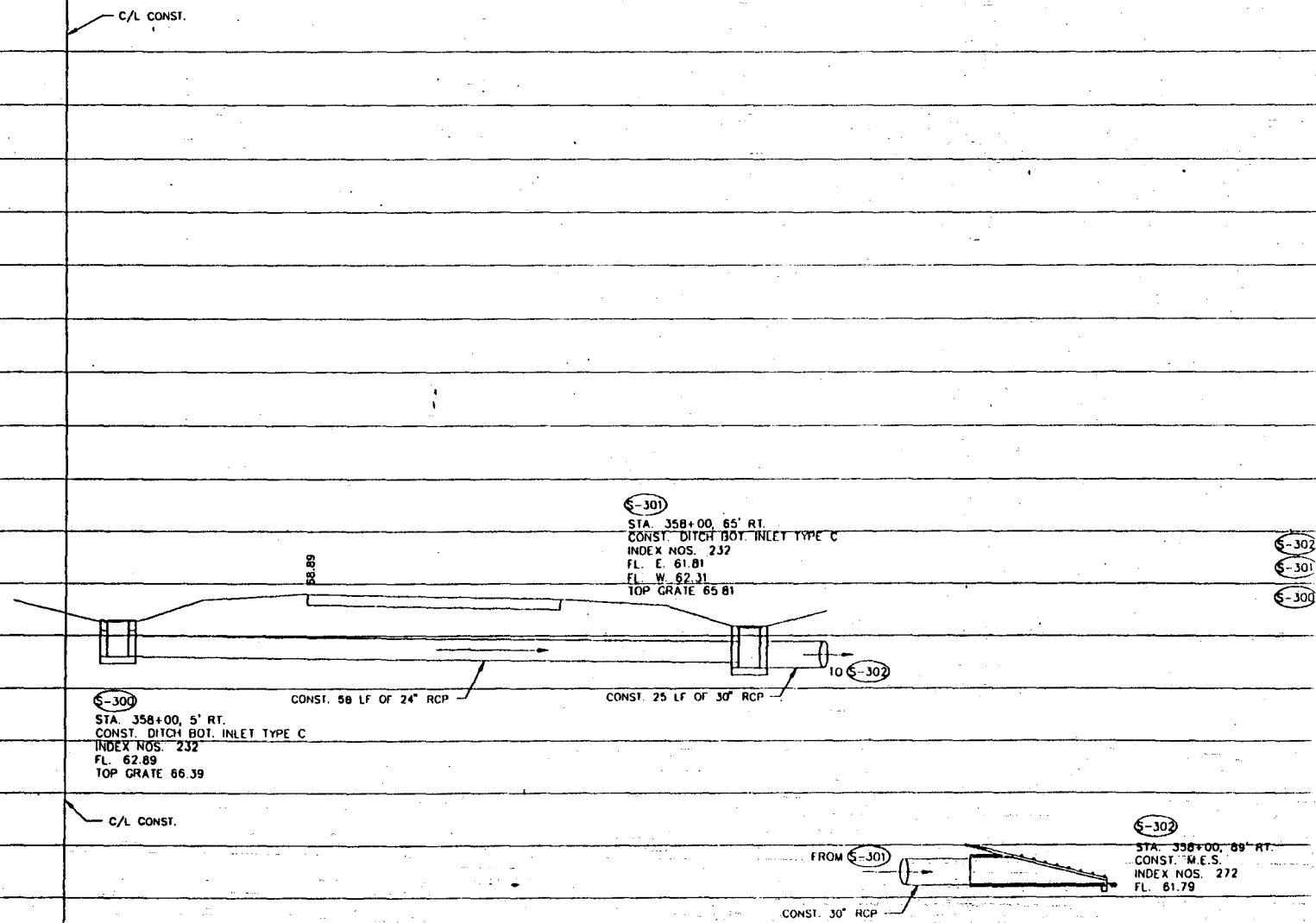
REVISIONS				REVISIONS			
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY

DESIGNED BY	NAME	DATE	CHECKED BY	NAME	DATE
JCB					
SLK					

FLORIDA DEPARTMENT OF TRANSPORTATION	DATE

LE LINCHANE ENGINEERING, INC.
CONSULTING CIVIL, ENVIRONMENTAL ENGINEERS
1401 S. GULF BLVD., SUITE 200
FORT MYERS, FL 33901

DRAINAGE STRUCTURES



SCALE : 1" = 5' VERT.
1" = 5' HORIZ.

A055

REVISIONS				REVISIONS				REVISIONS			
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION

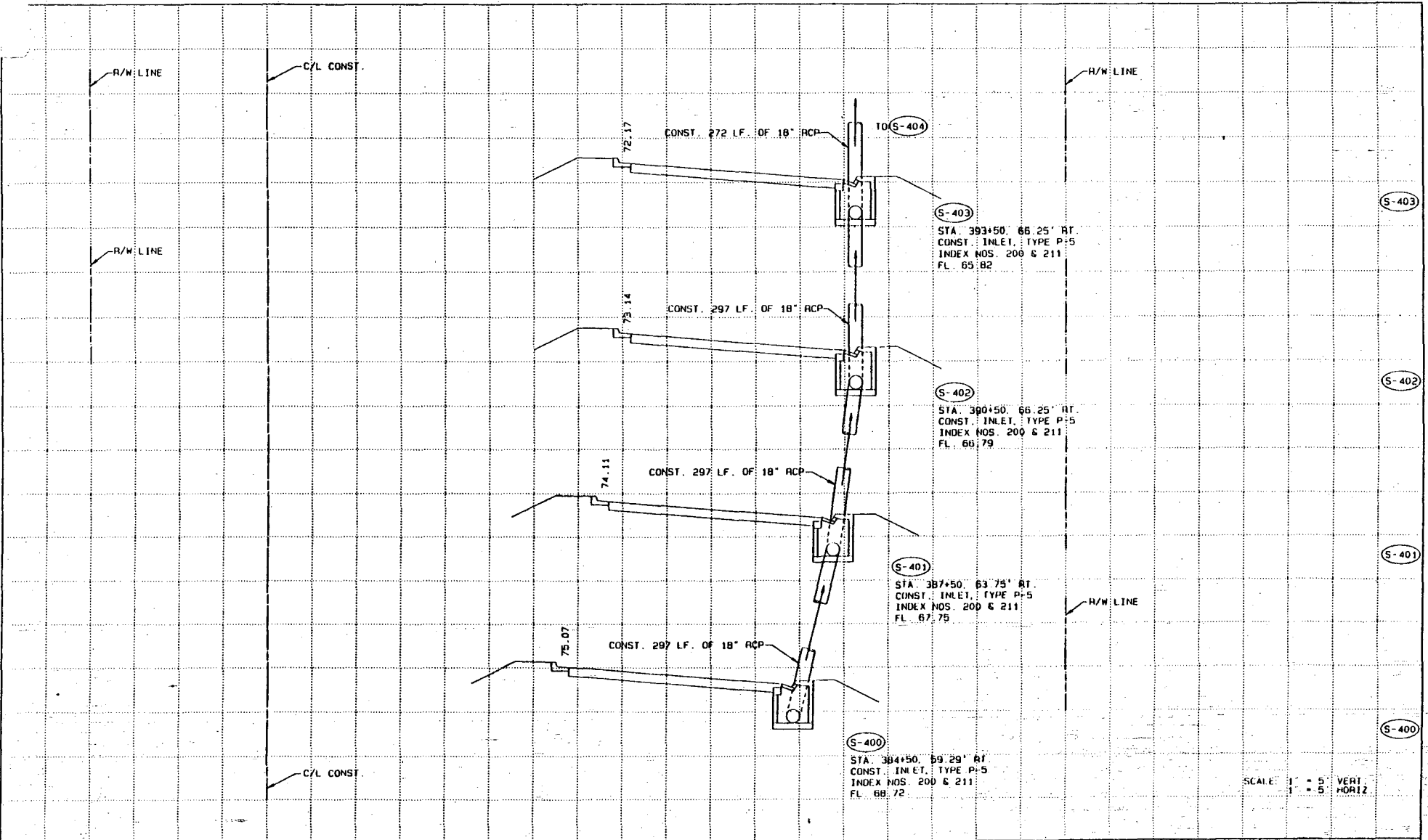
DESIGNED BY	JCB	NAME	DATE	DRAWN BY	JFY	NAME	DATE
CHECKED BY	BLK	DATE		CHECKED BY	JCB	DATE	
SUPERVISOR BY	STEPHEN I. KINCAD, P.E.	DATE		SUPERVISOR BY		DATE	

FLORIDA DEPARTMENT OF TRANSPORTATION	DATE
APPROVED BY	

LOCHANE ENGINEERING, INC.	DATE
CONSULTING CIVIL ENGINEERS	

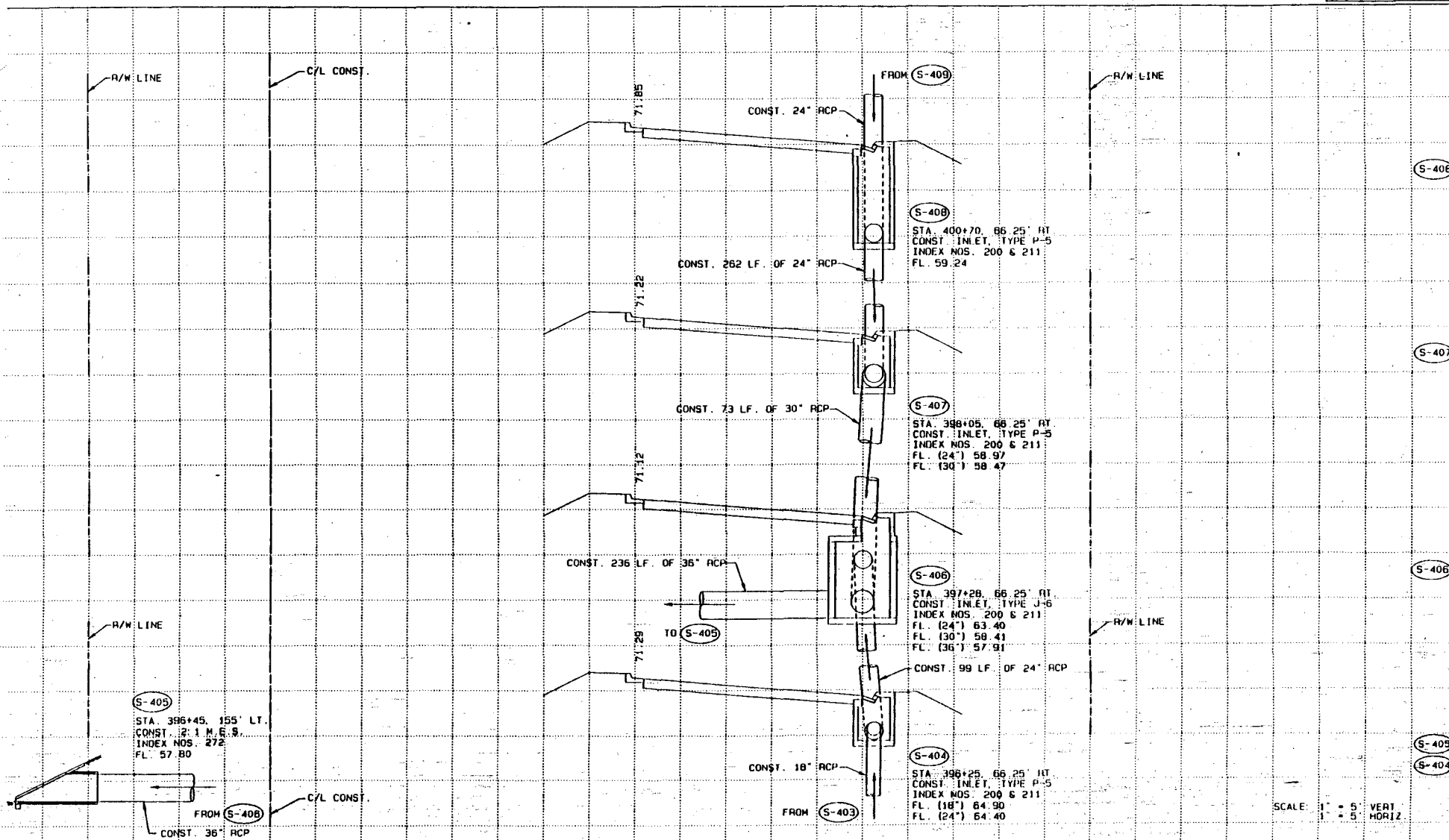
DRAINAGE
STRUCTURES

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	37

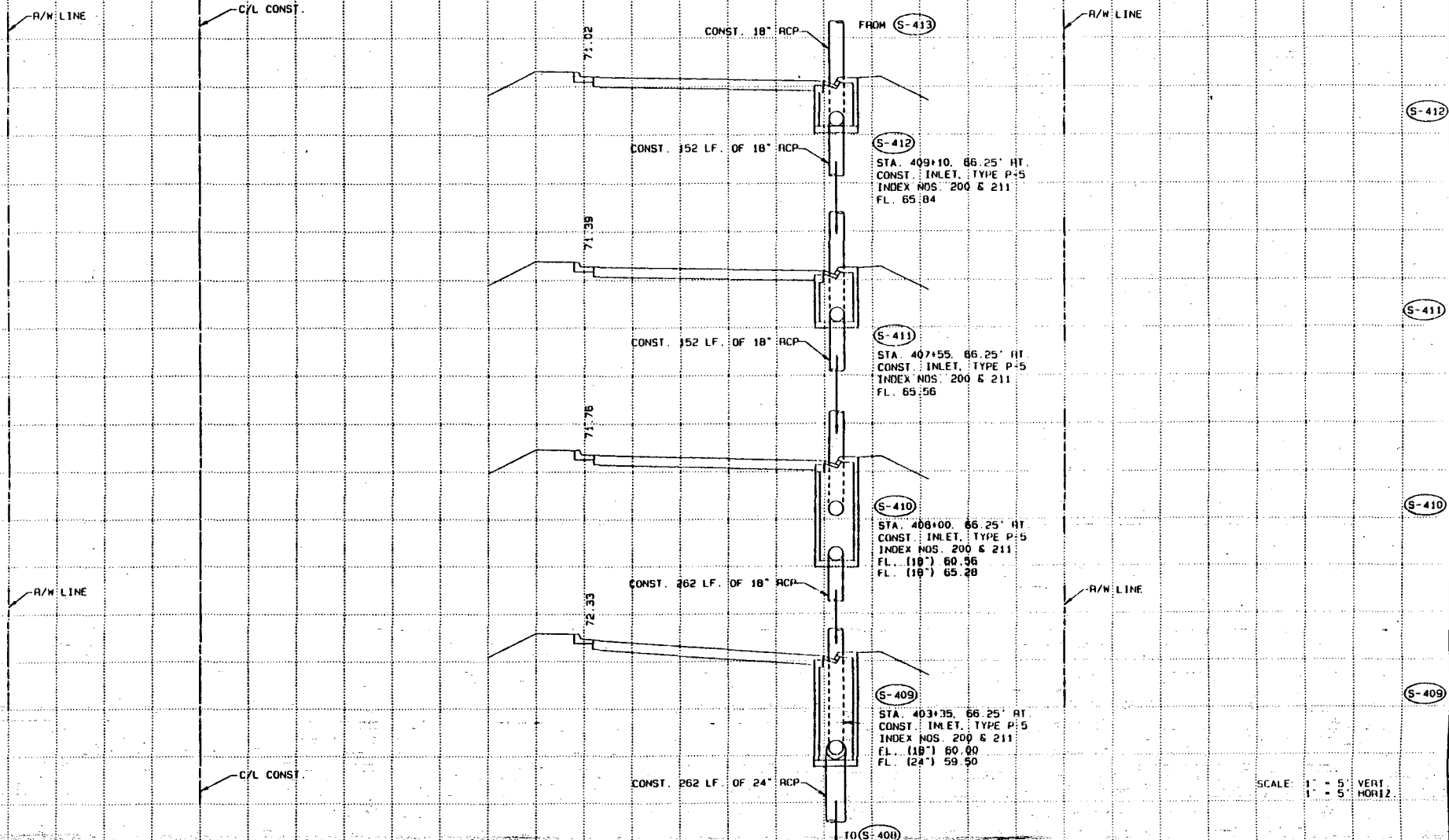


REVISIONS									
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	38

[illegible]

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	39

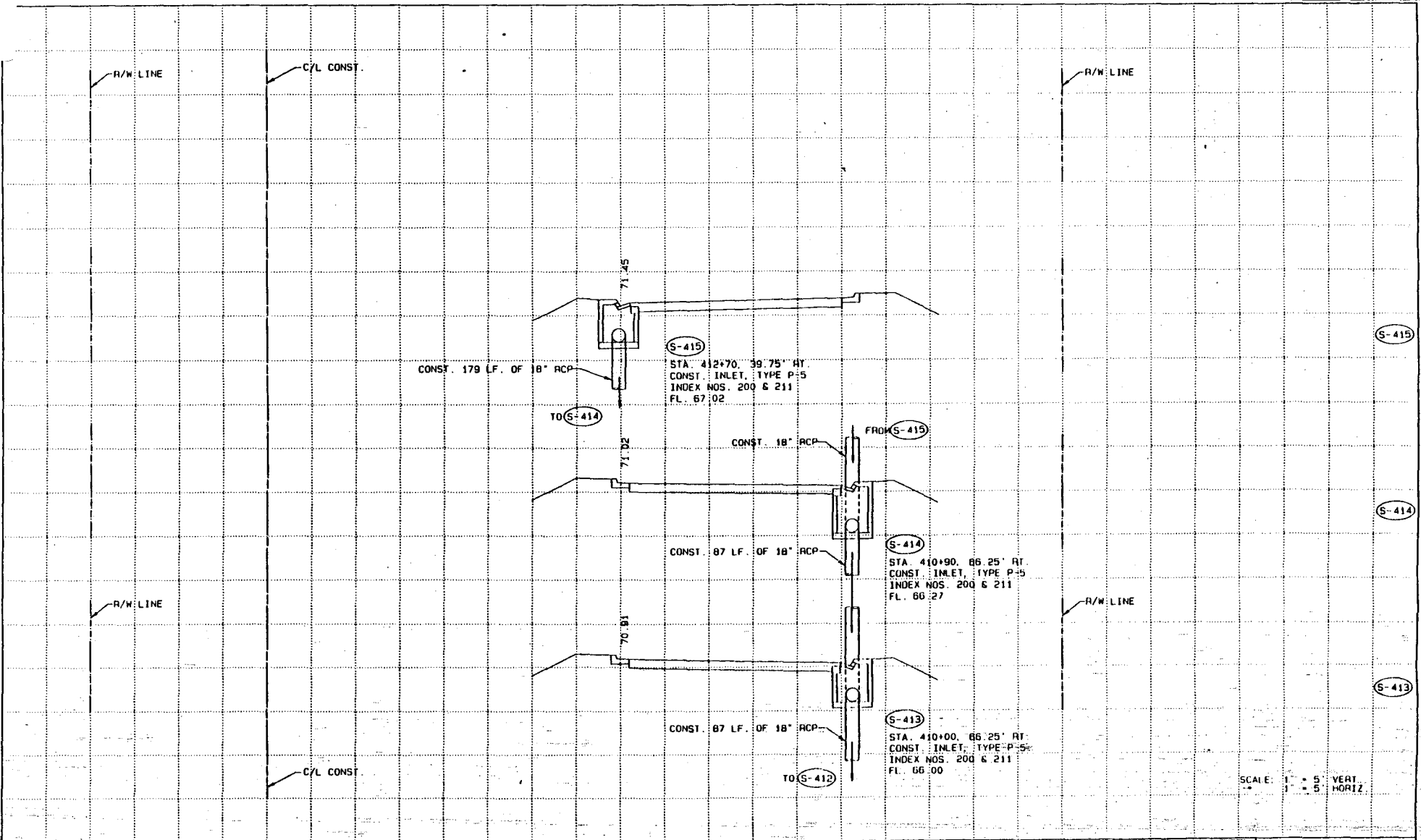


REVISIONS				REVISIONS				REVISIONS			
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION

LOCKHART ENGINEERING
Drainage Structures Division
1000 West 10th Street, Suite 100, Fort Worth, TX 76102

DRAINAGE STRUCTURES

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	40



SCALE: 1" = 5' VERT.
1" = 5' HORIZ.

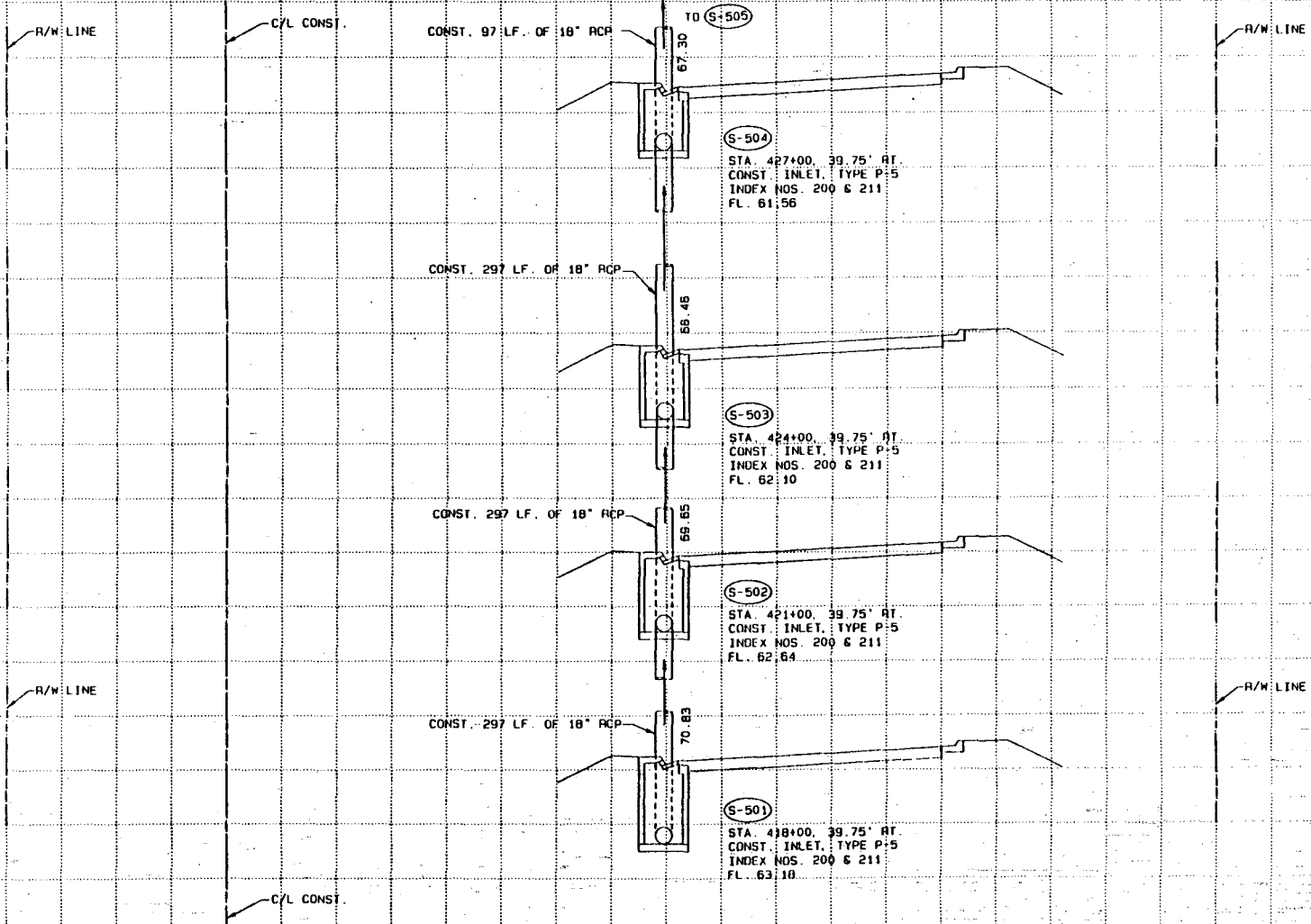
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DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE

DESIGNED BY	SLK	DATE	12/91	DRAWN BY	CSG	DATE	12/91
CHECKED BY	JRB	DATE	12/91	CHECKED BY	SLK	DATE	12/91
APPROVED BY STEPHEN KIRKPAID, P.E.				APPROVED BY			



DRAINAGE
STRUCTURES

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	41



SCALE: 1" = 5' VERT.
1" = 5' HORIZ.

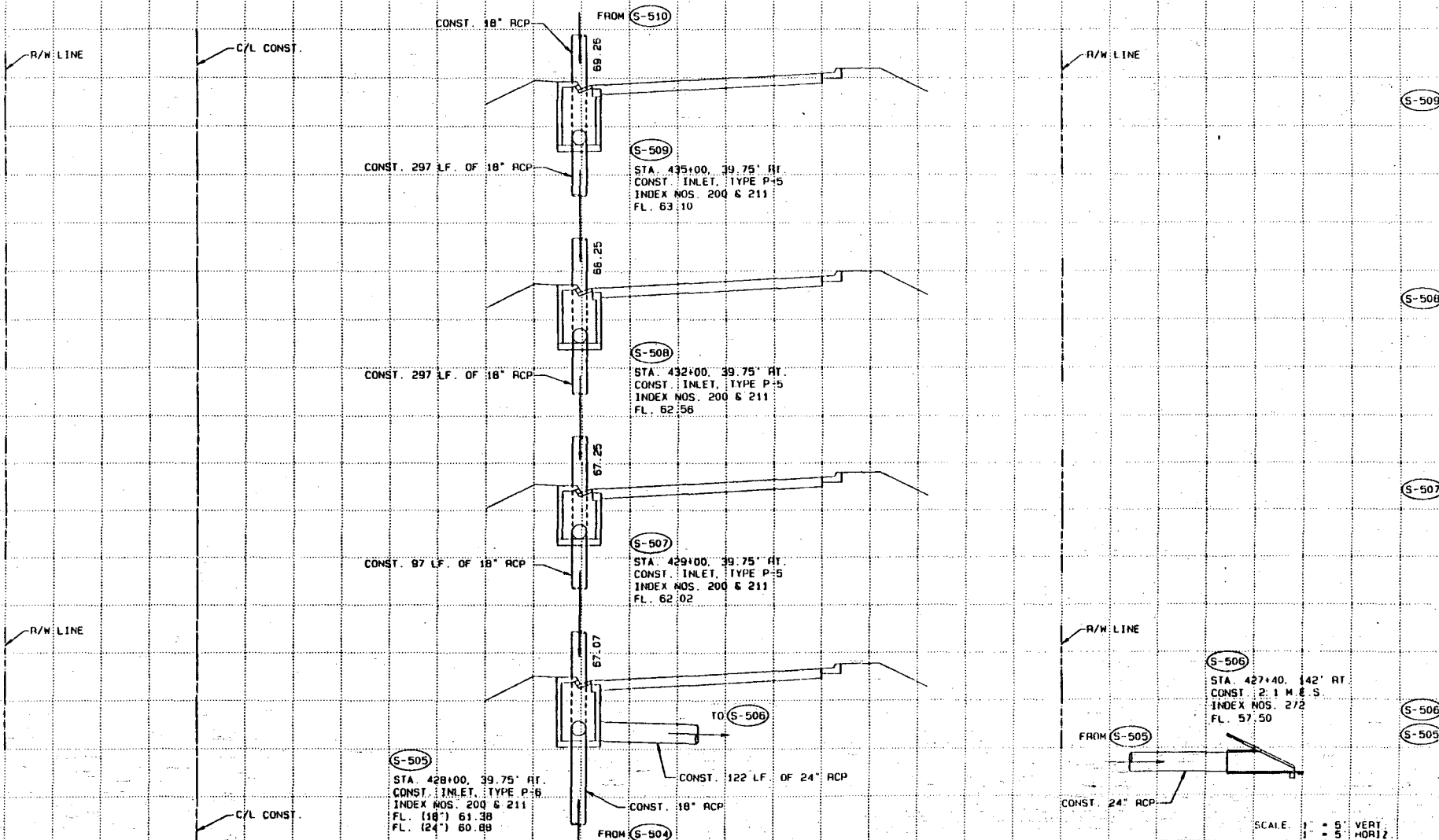
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DESIGNED BY	NAME	DATE	CHECKED BY	NAME	DATE
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JOE	JOE	12/91	SLK	SLK	12/91
SUPERVISOR BY	NAME	DATE	APPROVED BY	NAME	DATE
STEPHEN	STEPHEN	12/91	ALAN	ALAN	12/91

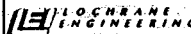


DRAINAGE
STRUCTURES

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	42



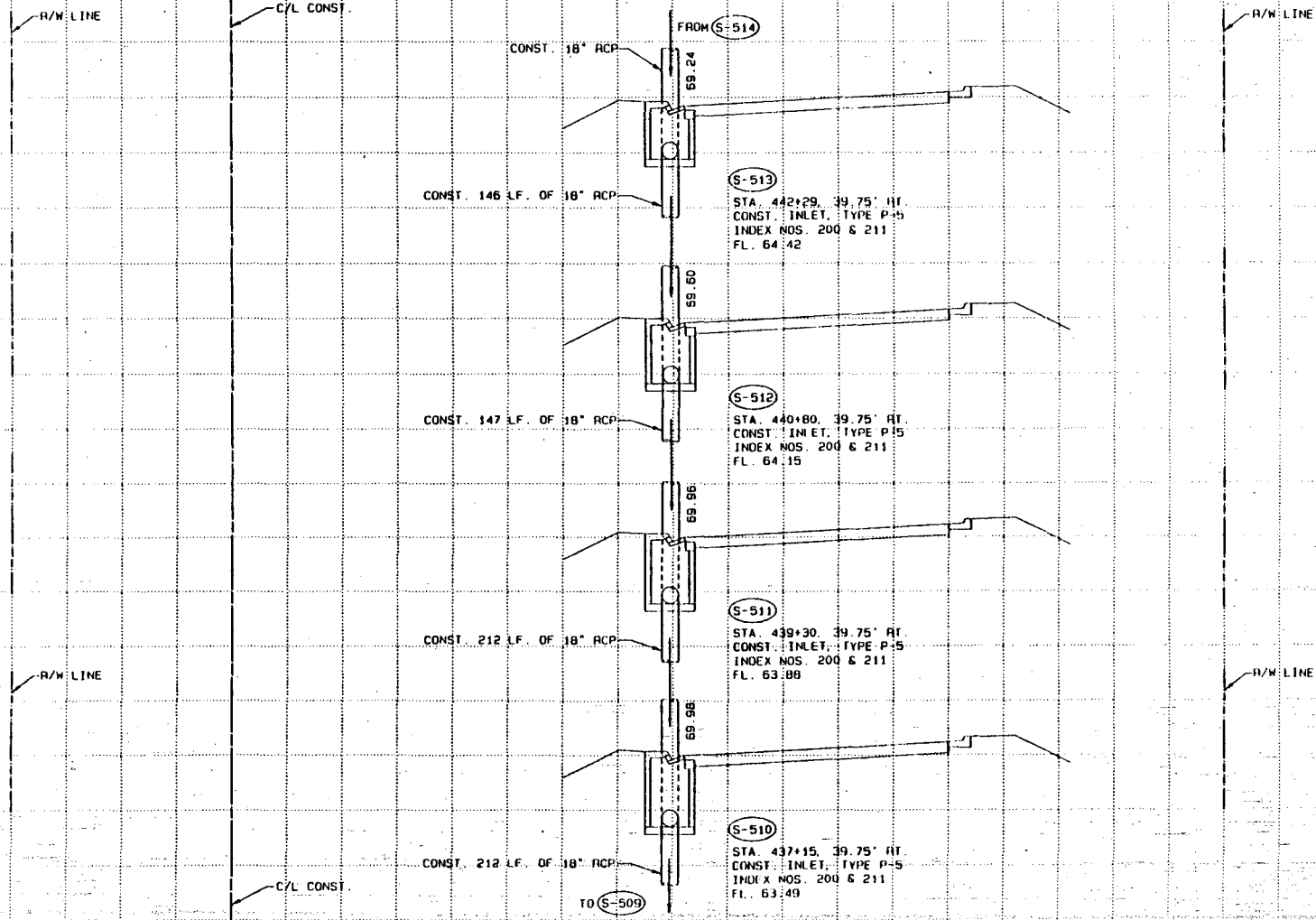
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												URB	12/91	SLK	12/91		
												STEPHEN		KINCAID, P.E.			


LOCHRANE ENGINEERING, INC.
 CONSULTING ENGINEERS AND ARCHITECTS
 1000 N. W. 10th Ave., Suite 100, Ft. Lauderdale, FL 33304
 (954) 561-1111

DRAINAGE STRUCTURES

[illegible]

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	42A



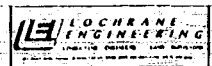
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SCALE 1" = 5' VERT.
1" = 5' HORIZ.

REVISIONS			
DATE	BY	DESCRIPTION	DATE

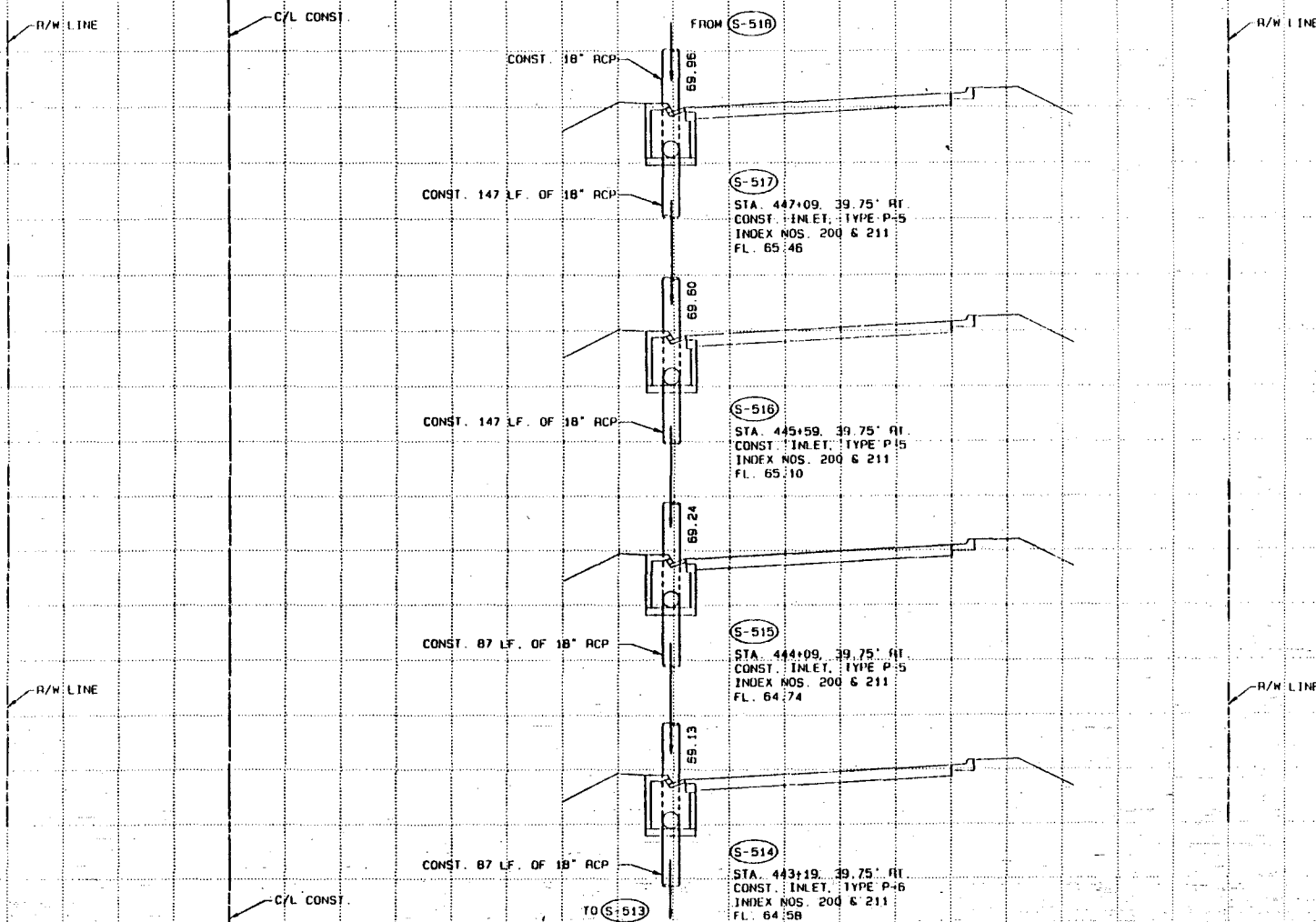
DESIGNED BY	DATE	CHECKED BY	DATE
SLK	12/91	CSG	12/91
JRB	12/91	SLK	12/91

DRAINAGE COUNTY
PUBLIC WORKS DEPARTMENT
APPROVED BY



DRAINAGE
STRUCTURES

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	42B



SCALE: 1" = 5' VERT.
1" = 5' HORIZ.

REVISIONS									
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE

DESIGNED BY	CHECKED BY	DATE	DATE	DATE
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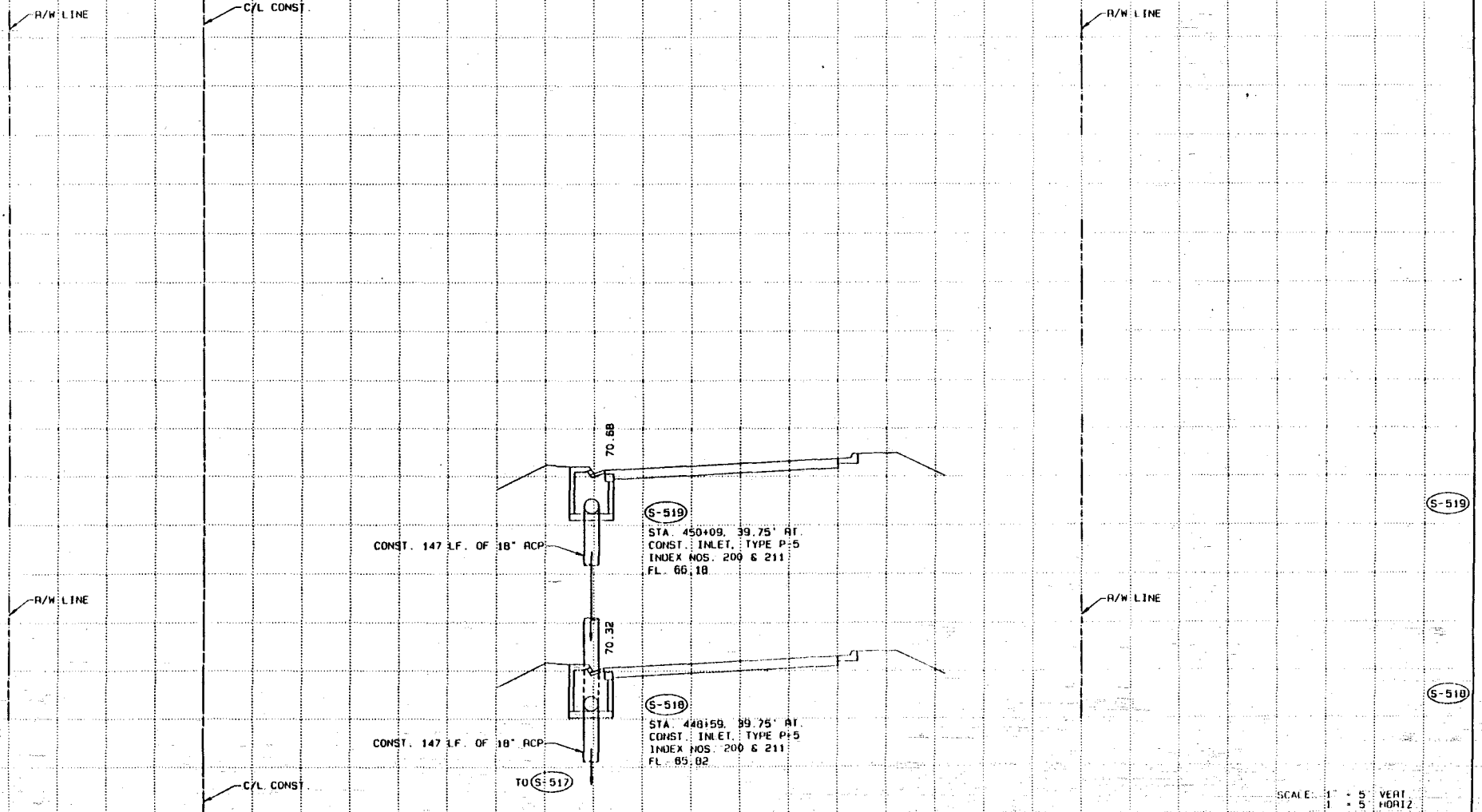
NAME	DATE	DATE	DATE
CSG	12/91	12/91	12/91
SLK			

PROJECT NO.	PROJECT NAME	PROJECT LOCATION
ALAFAYA TRAIL		

ENGINEER	DATE	DATE
LOCRANE ENGINEERING	12/91	12/91

DRAINAGE
STRUCTURES

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	42C

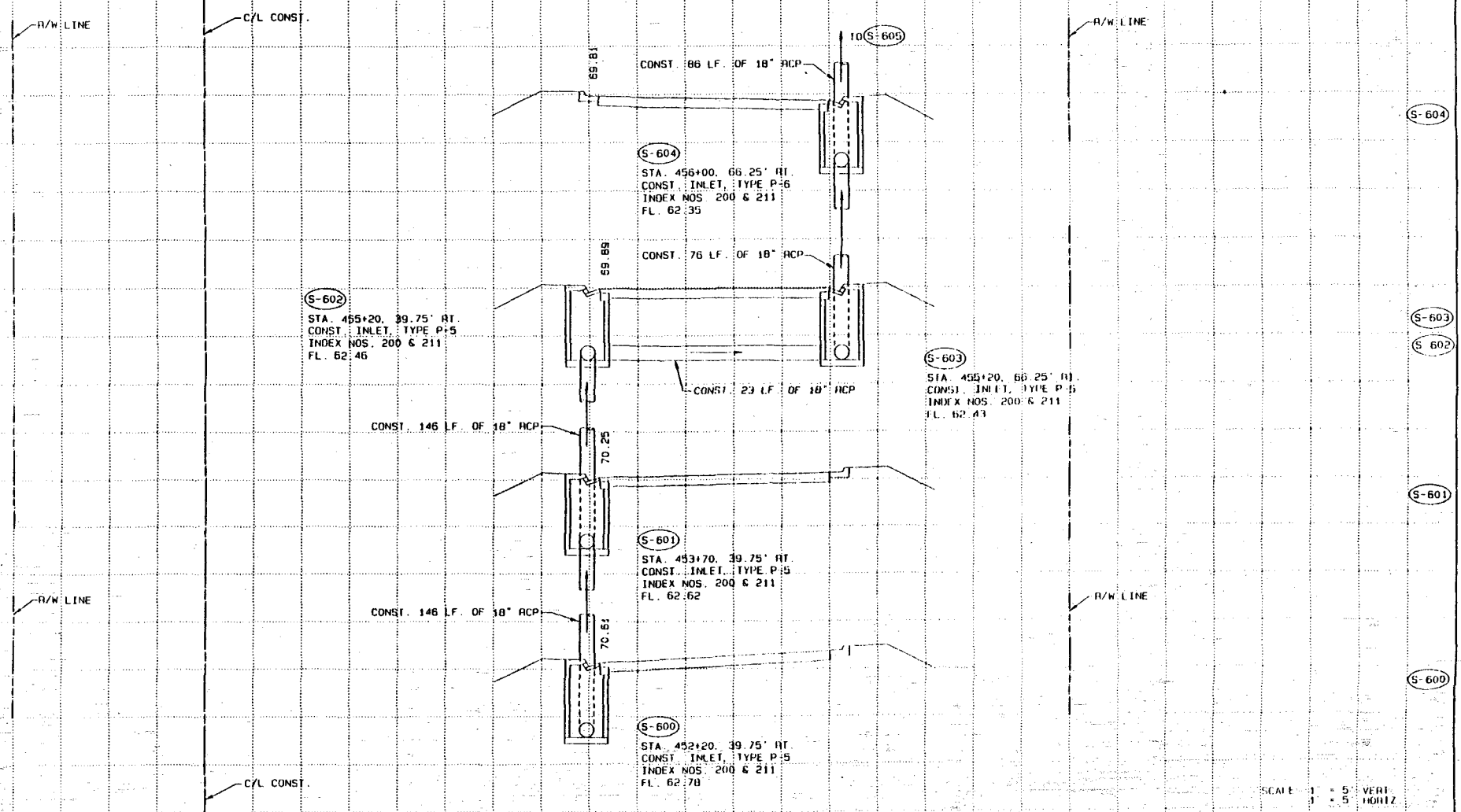


REVISIONS				DESIGN				CHECKS				APPROVALS				PROJECT INFORMATION	
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2	12/91	JRB	DESIGNED	2	12/91	CSG	CHECKED	2	12/91	SLK	APPROVED	2	12/91	SLK	APPROVED	ALAFAYA TRAIL	42C
3	12/91	JRB	DESIGNED	3	12/91	CSG	CHECKED	3	12/91	SLK	APPROVED	3	12/91	SLK	APPROVED	ALAFAYA TRAIL	42C



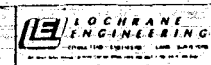
DRAINAGE
STRUCTURES

PROJECT NO	SHEET NO
ALAFAYA TRAIL	43



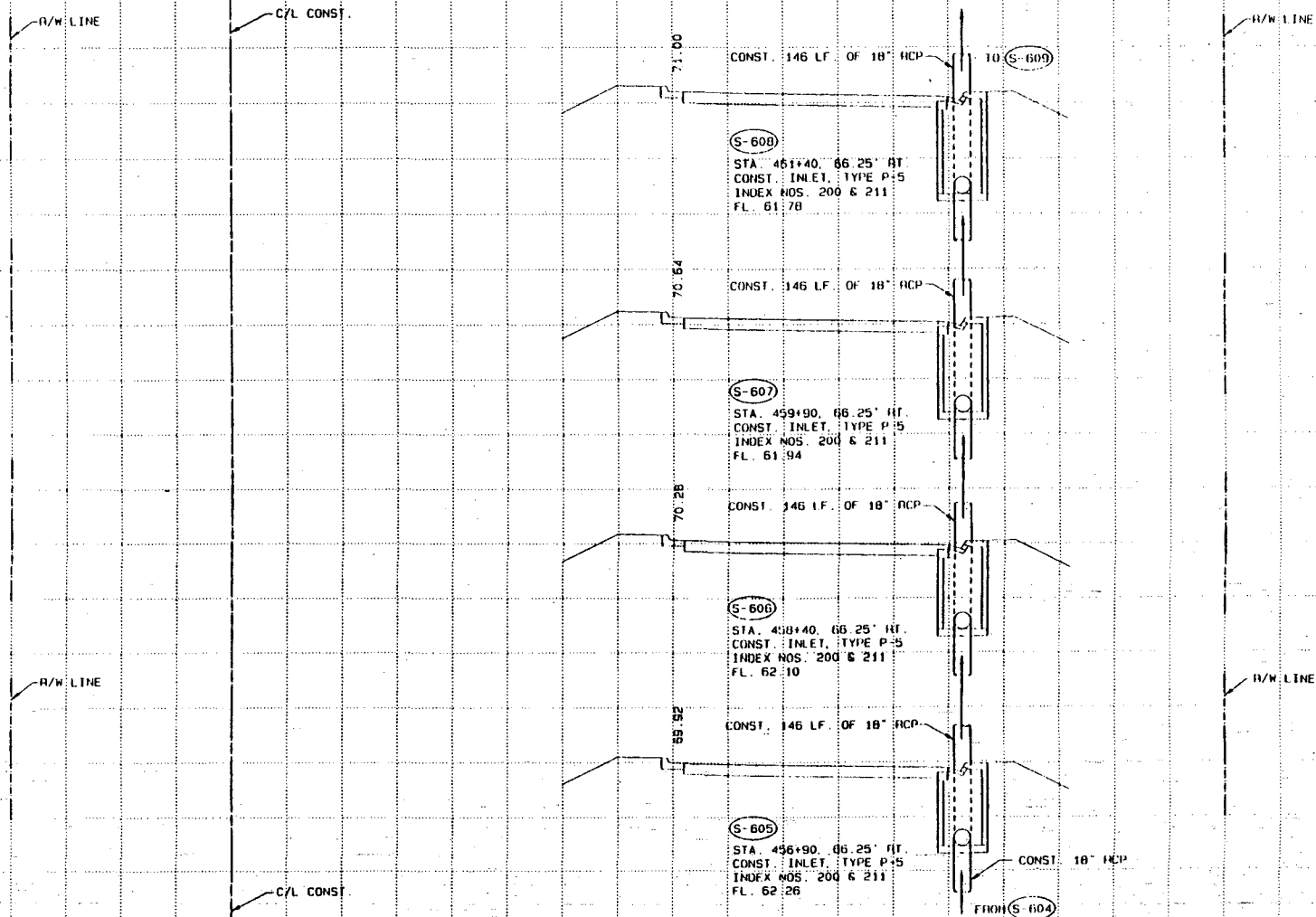
SCALE: 1" = 5' VERT.
1" = 5' HORIZ.

REVISIONS																NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE				NAME				DATE			
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DRAINAGE
STRUCTURES

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	44



SCALE: 1" = 5' VERT
1" = 5' HORIZ

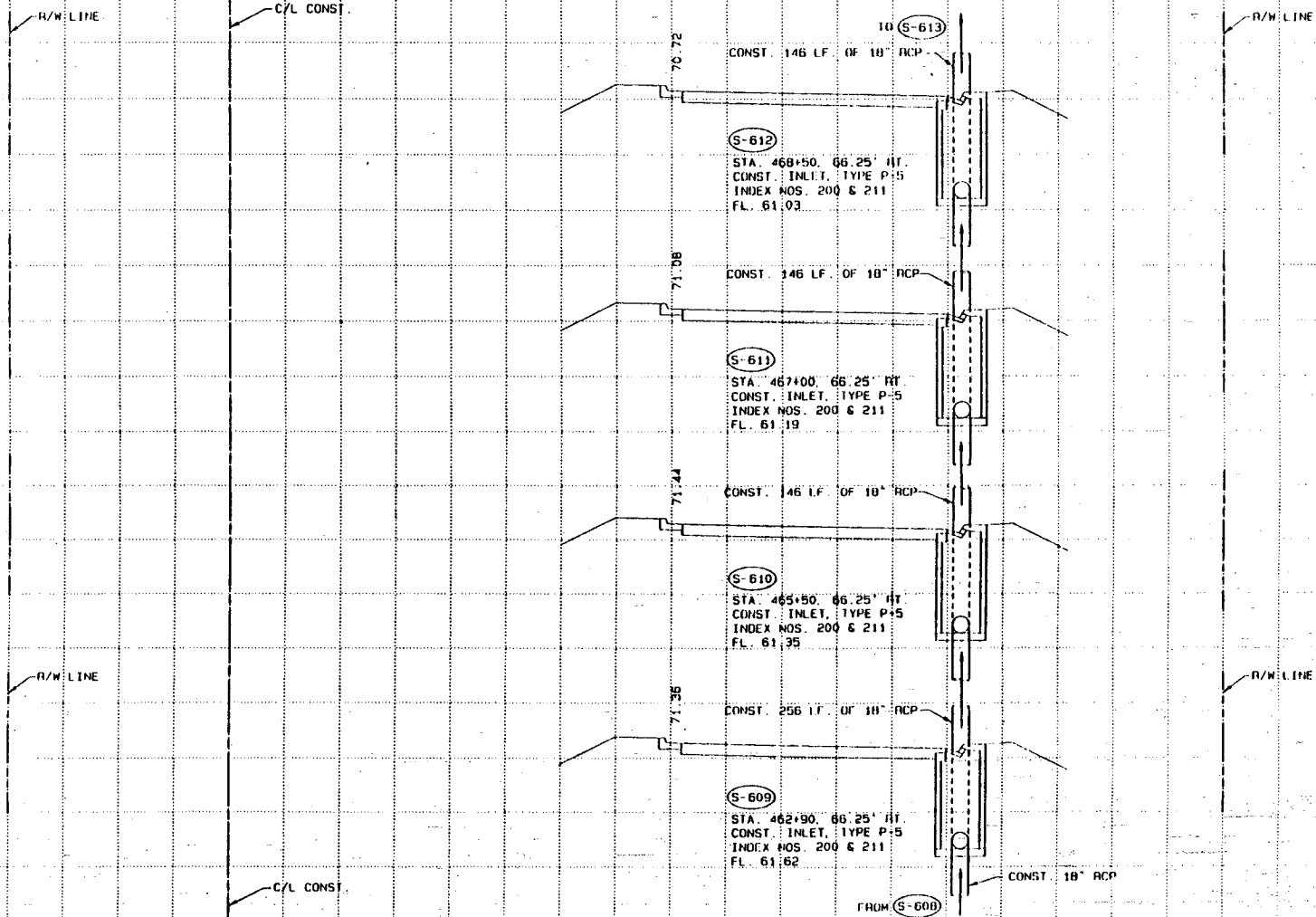
REVISIONS									
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE

NAME	DATE	NAME	DATE
DESIGNED BY	12/91	CHECKED BY	12/91
DRAWN BY	12/91	APPROVED BY	12/91
SLK		CSG	
SLK		SLK	
STEPHEN		KINCAID, P.E.	



DRAINAGE
STRUCTURES

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	44A



SCALE: 1" = 5' VERT
1" = 5' HORIZ

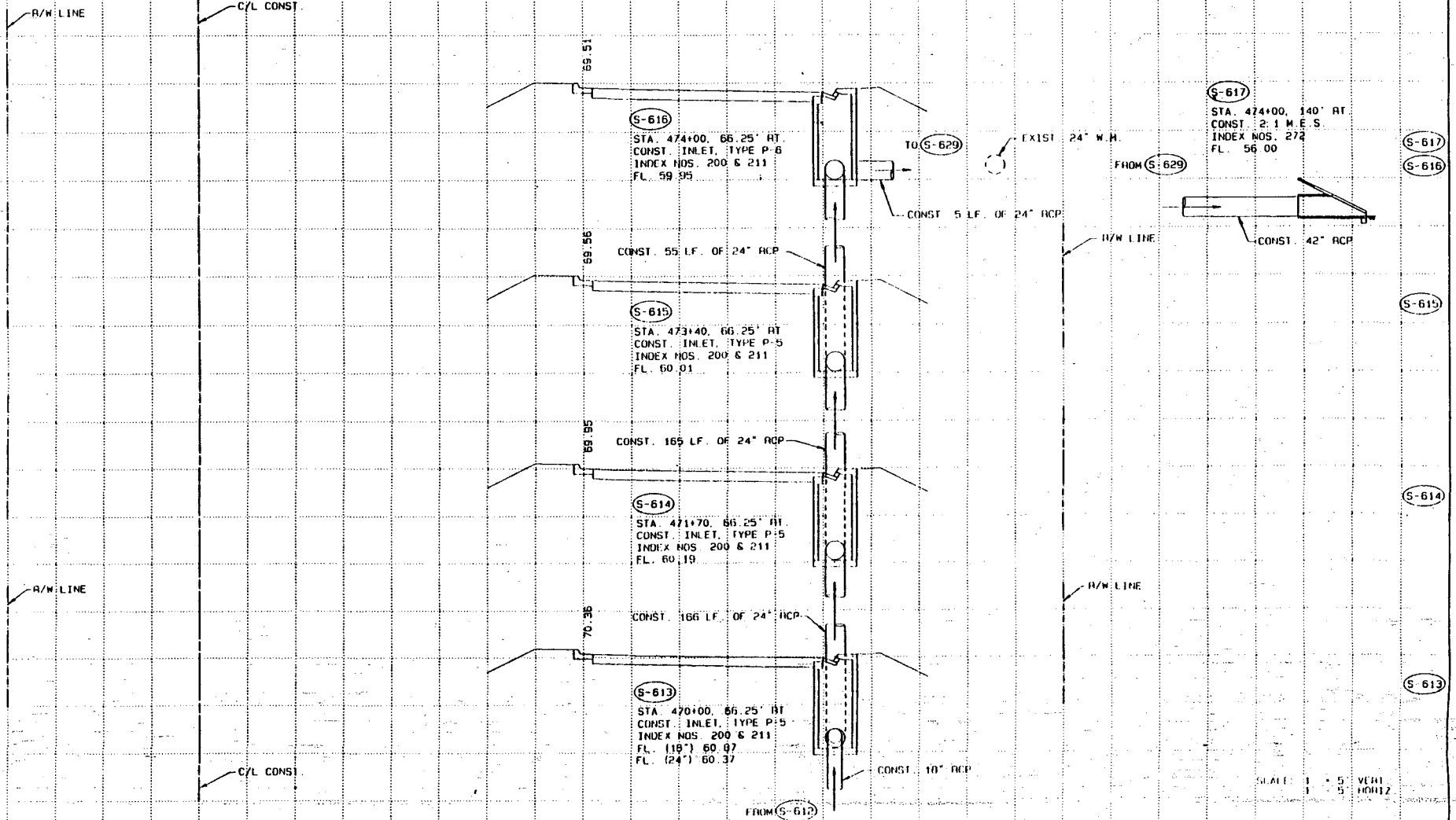
REVISIONS									
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NAME	DATE	NAME	DATE
SLK	12/91	SLK	12/91
SLK	12/91	SLK	12/91
SLK	12/91	SLK	12/91



DRAINAGE
STRUCTURES

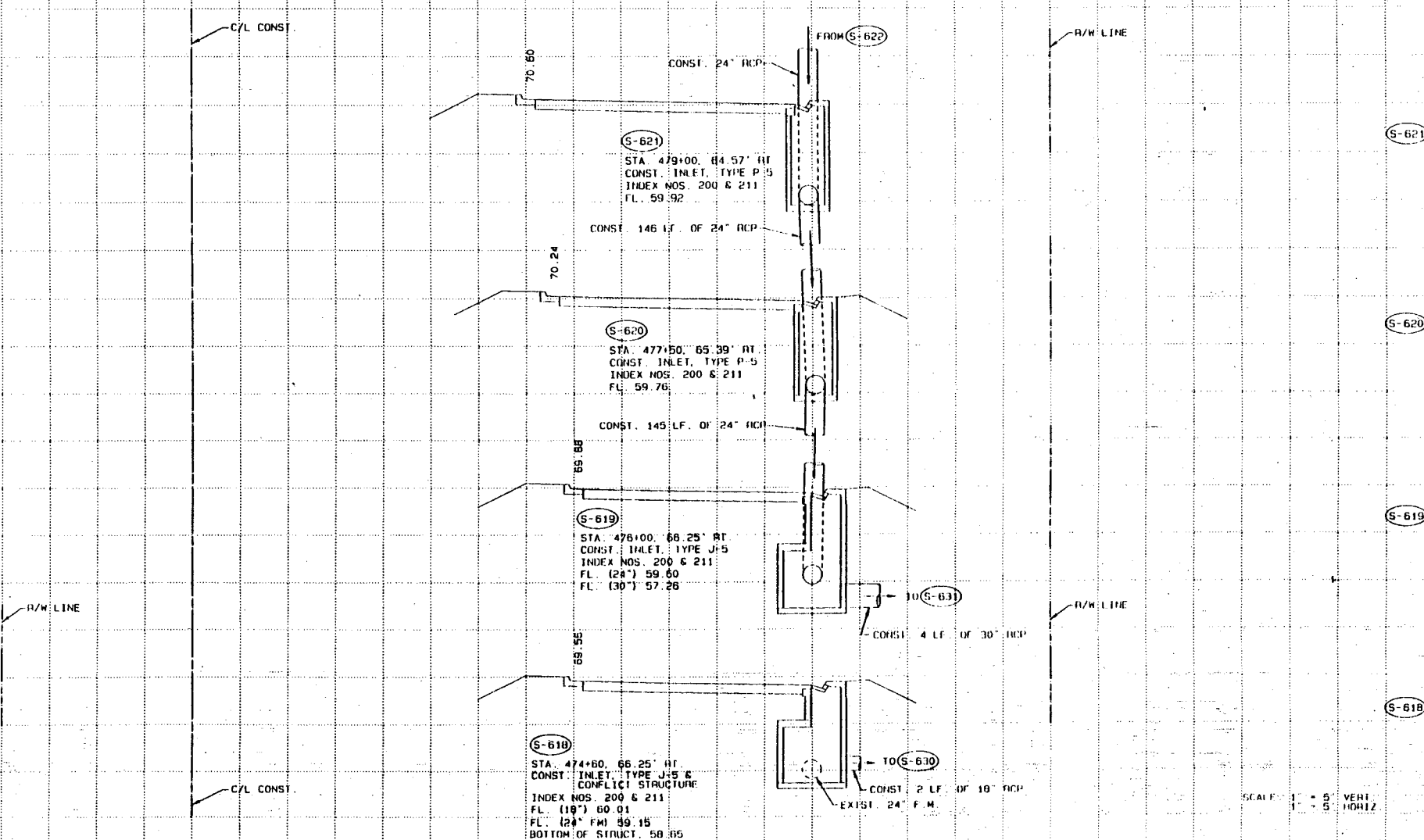
PROJECT NO	SHEET NO
ALAFAYA TRAIL	44B



LEITCH ENGINEERING
CONSULTING ENGINEERS

DRAINAGE STRUCTURES

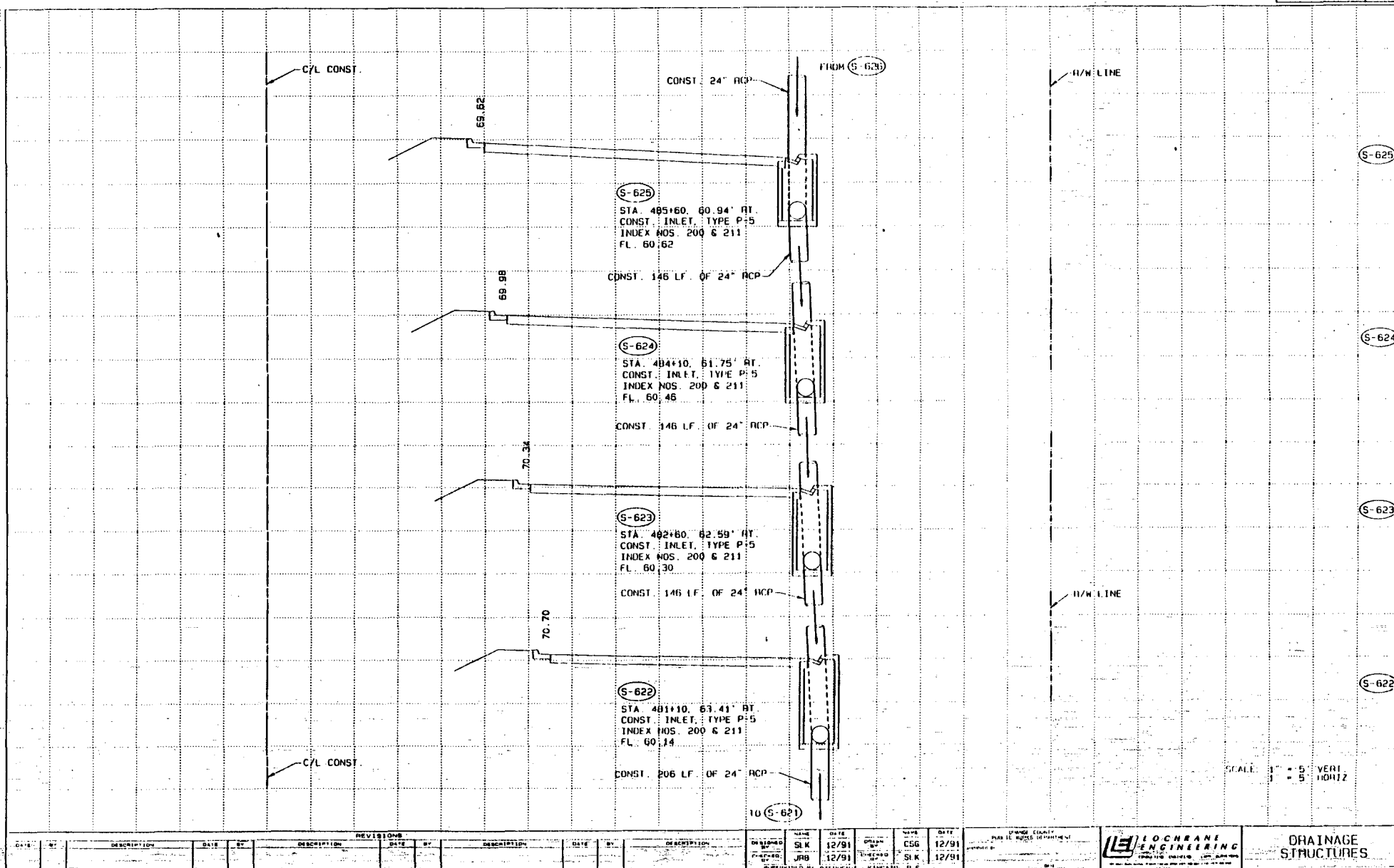
PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	44C



SCALE: 1" = 5' VERT.
1" = 5' HORIZ.

REVISIONS									
NO.	DATE	BY	DESCRIPTION	NO.	DATE	BY	DESCRIPTION	NO.	DATE
1	12/91	SLK	12/91	2	12/91	SLK	12/91	3	12/91
4	12/91	SLK	12/91	5	12/91	SLK	12/91	6	12/91
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PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	440



PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	44E

C/L CONST.

R/W LINE

70.82

(S-628)

STA. 490+40, 60.25' RT.
CONST. INLET, TYPE P-5
INDEX NOS. 200 & 211
FL. 61.75

CONST. 206 LF. OF 18" RCP

69.73

(S-627)

STA. 487+40, 60.25' RT.
CONST. INLET, TYPE P-5
INDEX NOS. 200 & 211
FL. (18") 61.30
FL. (24") 60.80

CONST. 86 LF. OF 24" RCP

69.54

(S-626)

STA. 486+50, 60.44' RT.
CONST. INLET, TYPE P-6
INDEX NOS. 200 & 211
FL. 60.71

CONST. 86 LF. OF 24" RCP

C/L CONST.

R/W LINE

(S-628)

(S-627)

(S-626)

SCALE: 1" = 5' VERT.
1" = 5' HORIZ.

10(S-629)

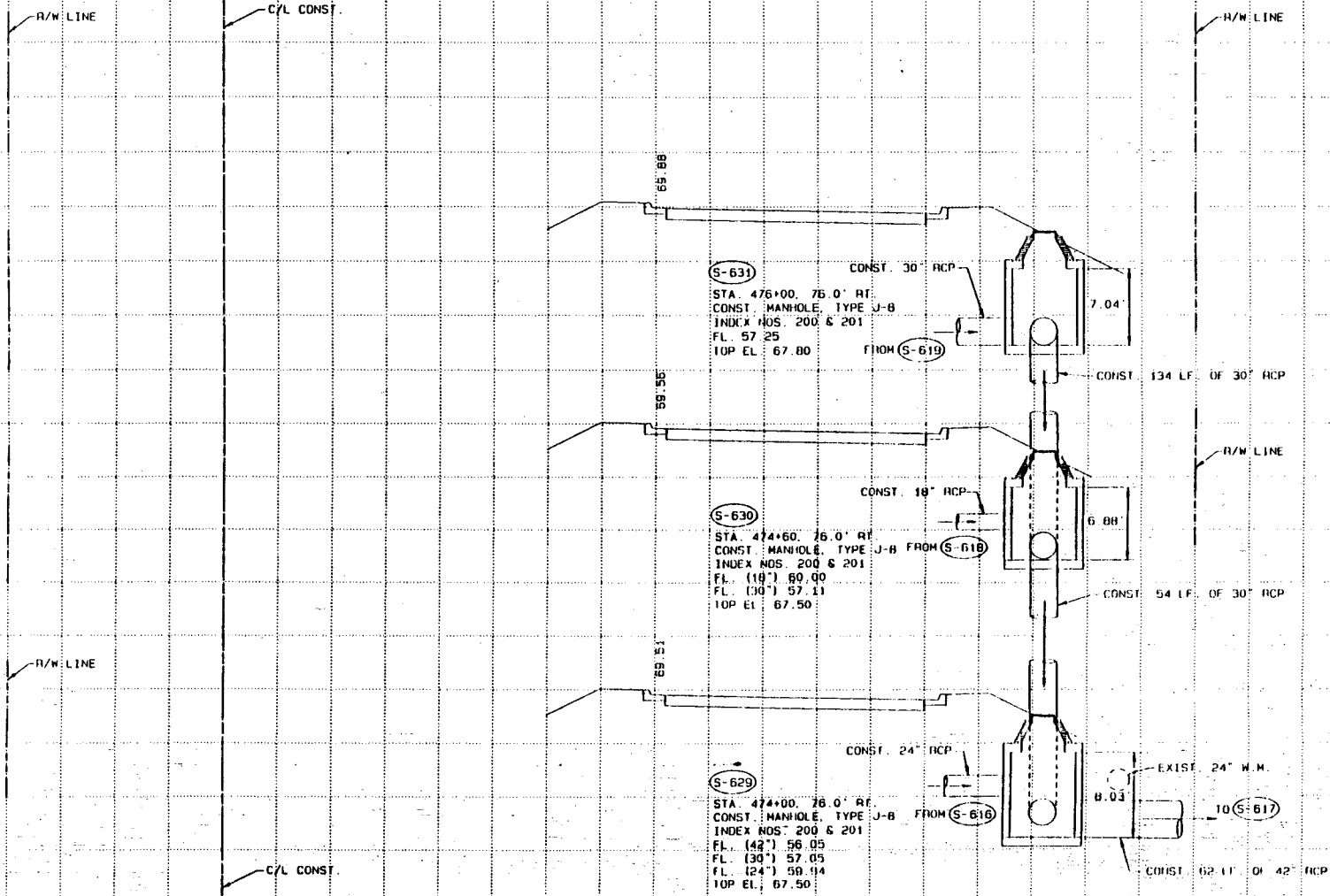
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DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION

DESIGNED BY	NAME	DATE	CHECKED BY	NAME	DATE
JFB	SLK	12/91	JFB	SLK	12/91
APPROVED BY		DATE	APPROVED BY		DATE
SITPHEN		12/91	KINCAID, P.E.		12/91

LOCHRANE ENGINEERING
1001 11th Street, Suite 100
Tallahassee, FL 32301
(904) 224-1111

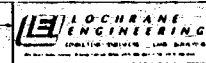
DRAINAGE STRUCTURES

PROJECT NO. 44F
ALAFAYA TRAIL

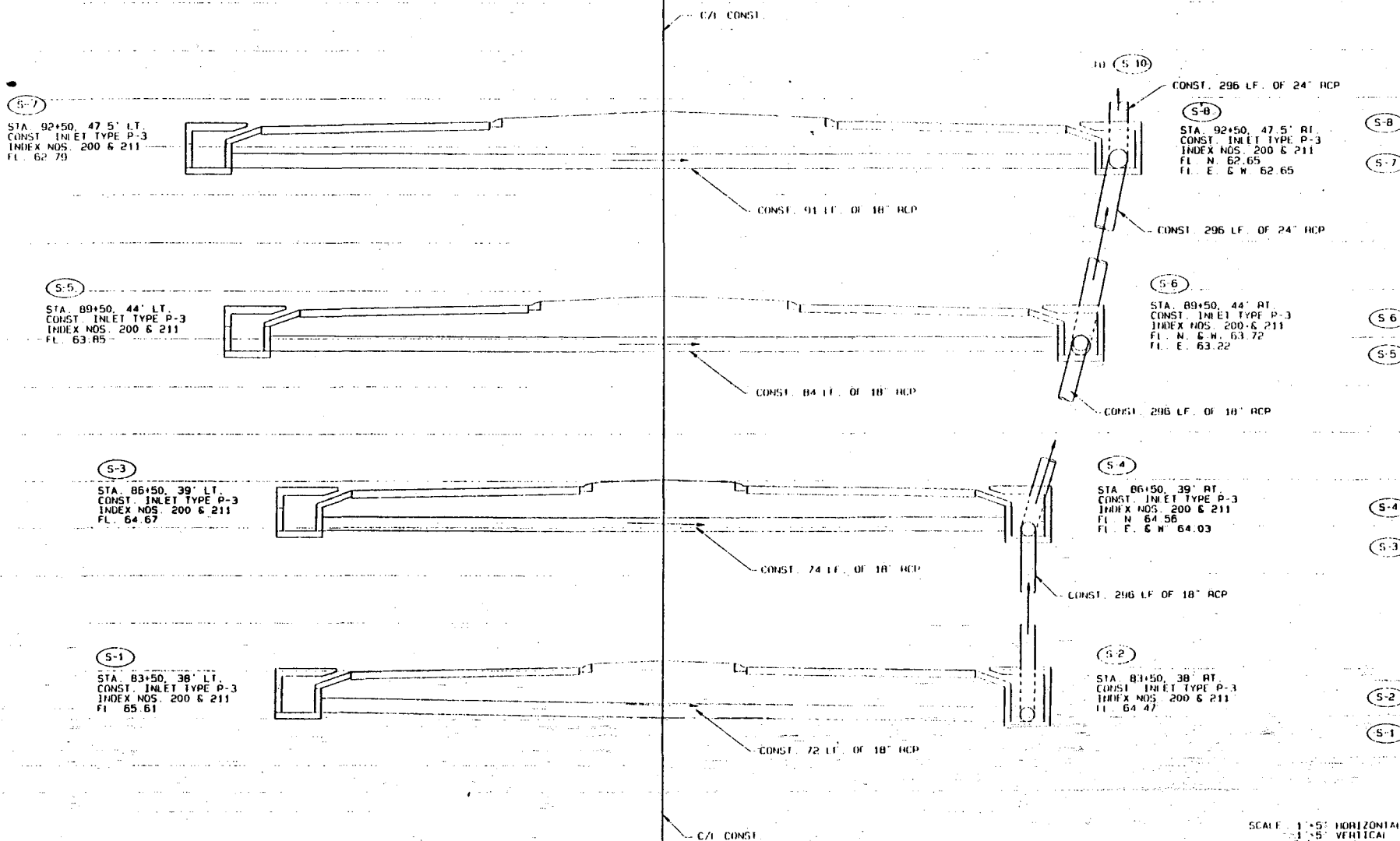


REVISIONS							
DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY

DESIGNED	DATE	CHECKED	DATE	APPROVED	DATE
SLK	12/91	CSG	12/91	SLK	12/91
JRB	12/91	CSG	12/91	SLK	12/91



DRAINAGE
STRUCTURES

[illegible]

PROJECT NO.	SHEET NO.
ALAFAYA TRAIL	46

(S-13)

STA. 98+00, 38.5' LT.
CONST. INLET TYPE P-3
INDEX NOS. 200 & 211
FL. 62.24

(S-11)

STA. 97+10, 38.5' LT.
CONST. INLET TYPE P-2
INDEX NOS. 200 & 211
FL. 61.39

(S-9)

STA. 95+50, 38.5' LT.
CONST. INLET TYPE P-3
INDEX NOS. 200 & 211
FL. 61.85

C/A CONST.

(S-15)

STA. 98+35, 38.5' RT.
CONST. MANHOLE TYPE J 71
INDEX NOS. 200 & 201
FL. 59.63

(S-15)

TO (S-16)

CONST. 206 LF. OF 36" RCP
CONST. 129 LF. OF 36" RCP

(S-14)

STA. 98+00, 38.5' RT.
CONST. INLET TYPE J-3
INDEX NOS. 200 & 211
FL. B. 62.13
FL. F. & W. 59.71

(S-14)

(S-13)

CONST. 84 LF. OF 36" RCP

(S-12)

STA. 97+10, 38.5' RT.
CONST. INLET TYPE J-2
INDEX NOS. 200 & 211
FL. B. 61.28
FL. W. 60.28
FL. F. 59.78

(S-12)

(S-11)

CONST. 155 LF. OF 30" RCP

(S-10)

STA. 95+50, 38.5' RT.
CONST. INLET TYPE P-3
INDEX NOS. 200 & 211
FL. B. & W. 61.74
FL. F. 61.24

(S-10)

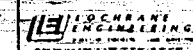
(S-9)

CONST. 73 LF. OF 18" RCP

FROM (S-11)

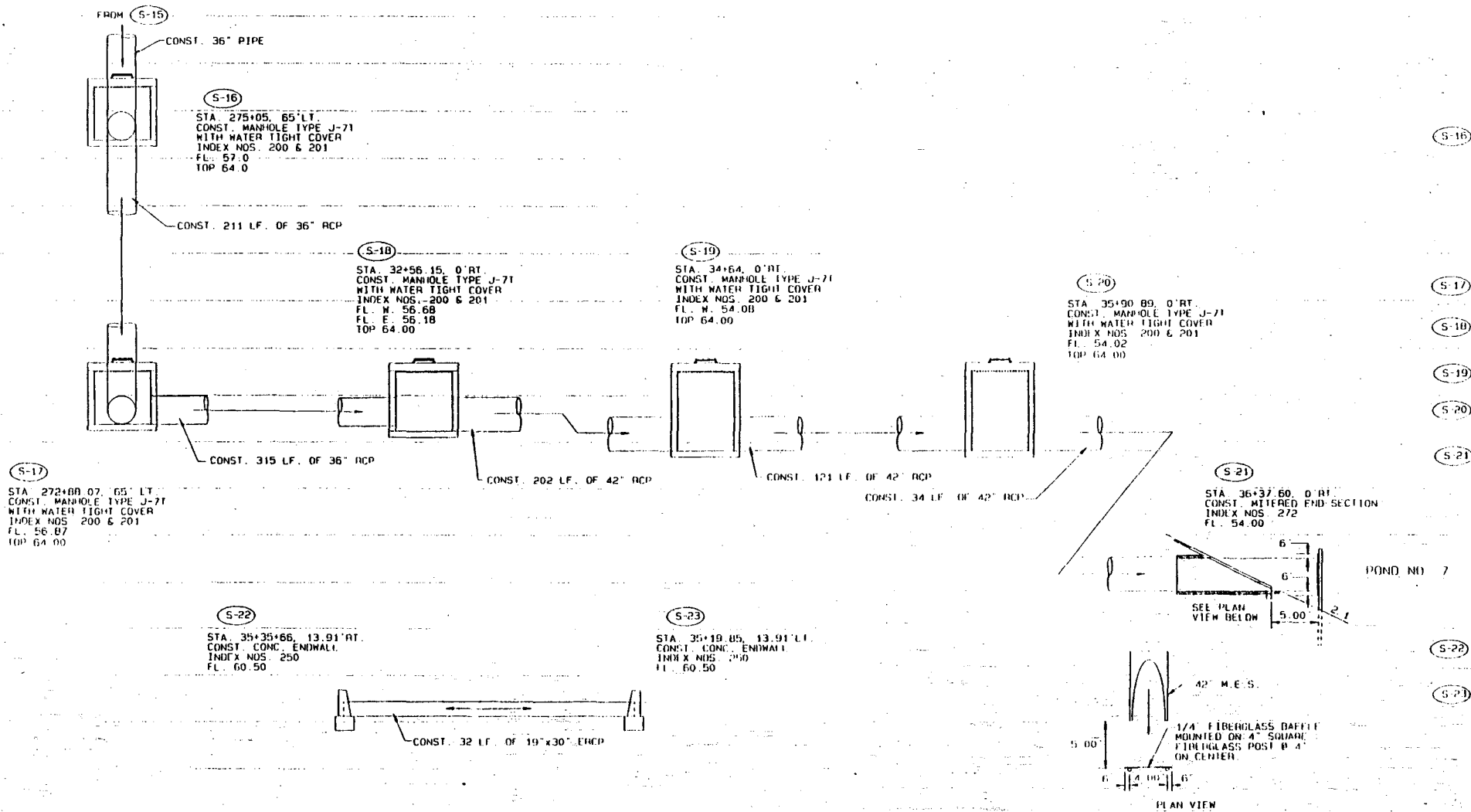
C/A CONST.

SCALE: 1"=5' HORIZONTAL
1"=5' VERTICAL



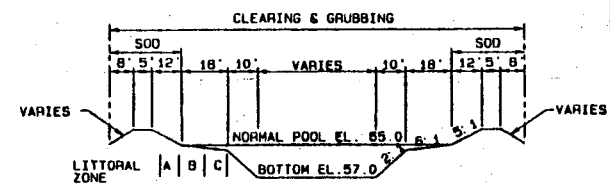
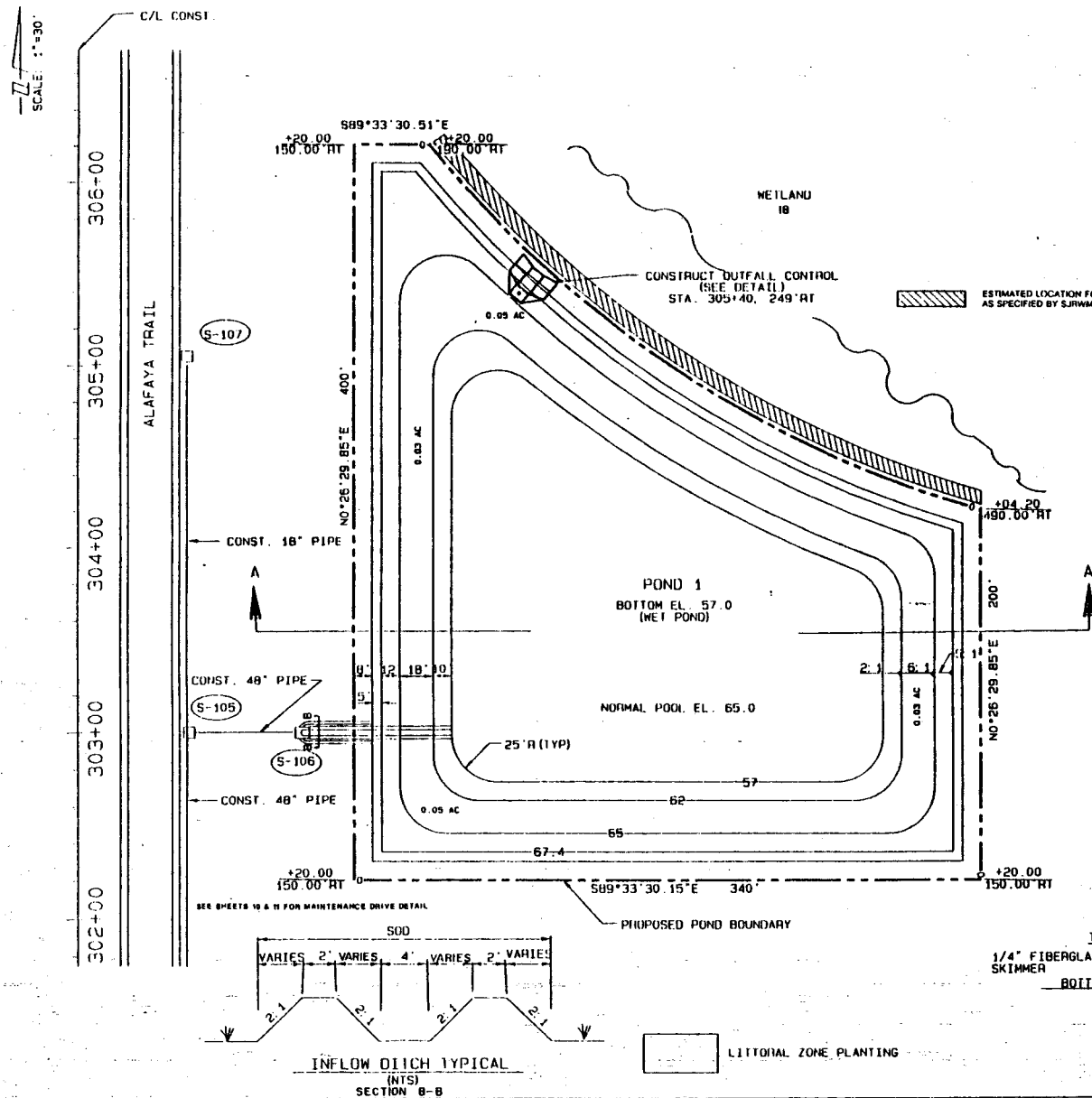
DRAINAGE
STRUCTURES

PROJECT NO.	SHEET
ALAFAYA TRAIL	47



[illegible]

COUNTY PROJ. NO.	SEI NO
ALAFAYA TRAIL	49



TYPICAL POND SECTION

(N.T.S)

SECTION A-A

CONTROL STRUCTURE:

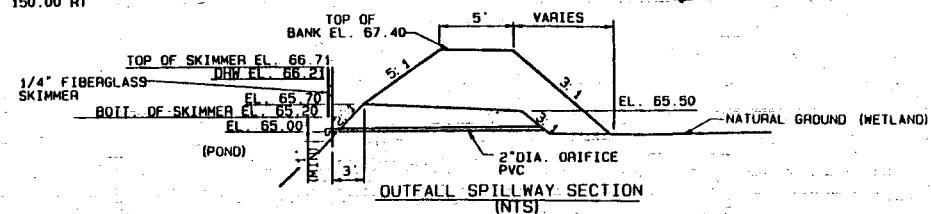
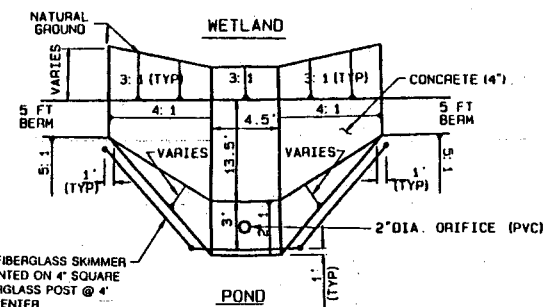
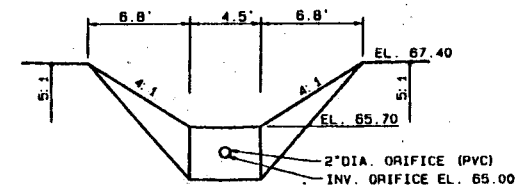
CONTINUED STRUCTURE	
T08	67.40 FT
WELL	66.70 FT

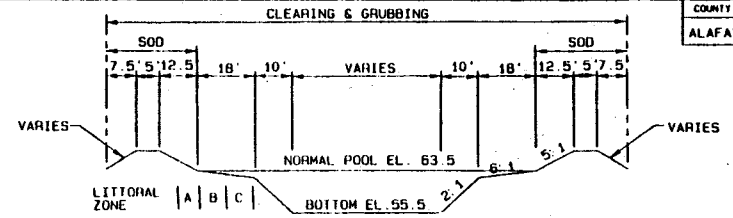
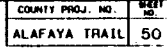
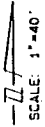
WEIR EL.	65.70 FT
WEIR LENGTH	4.5 FT

WEIR LENGTH 15.00
2" DIA. ORIFICE
3.44 25 ORIFICE 65.00 53

C/L OF ORIFICE 65.08 FT
INV. OF ORIFICE 65.00 FT

INV. OF OFFICE 85.00 FT

[illegible]



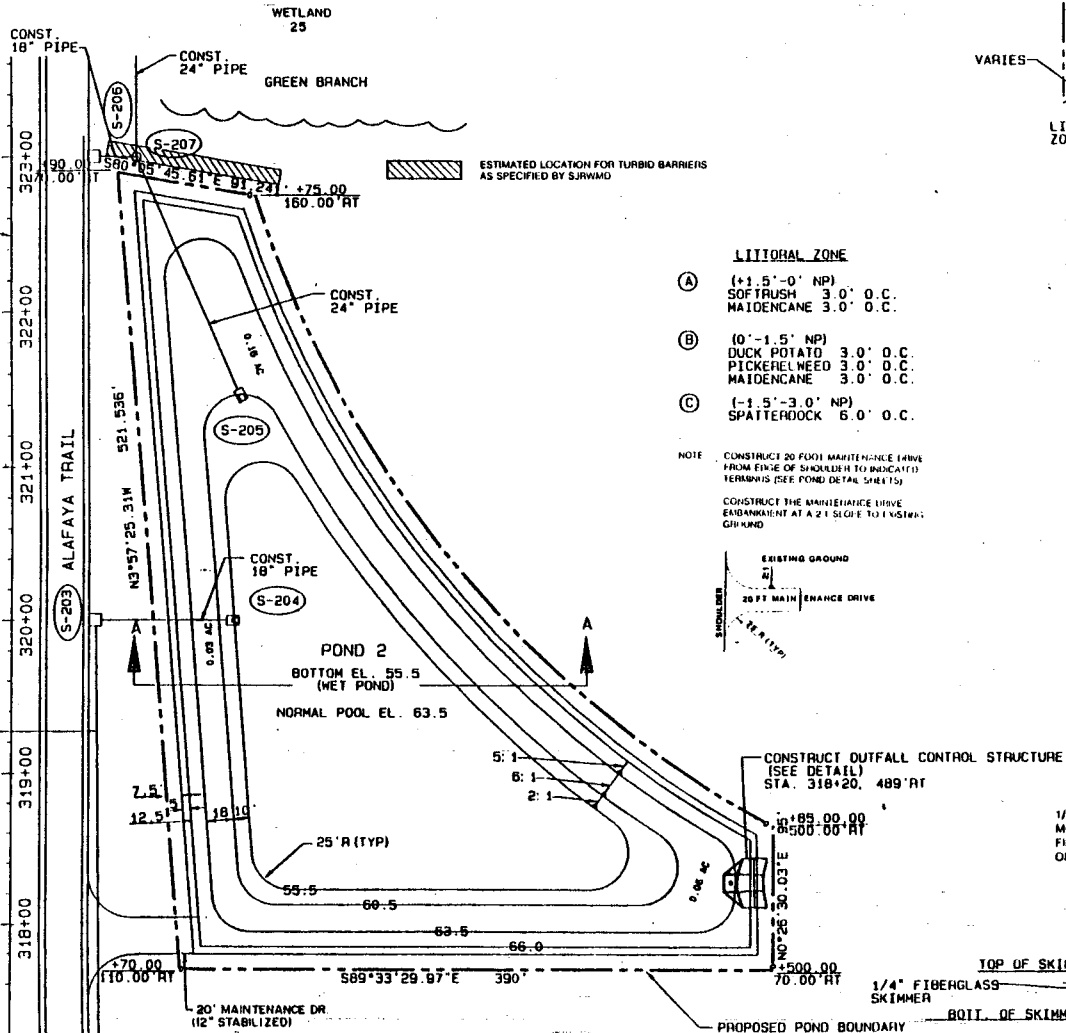
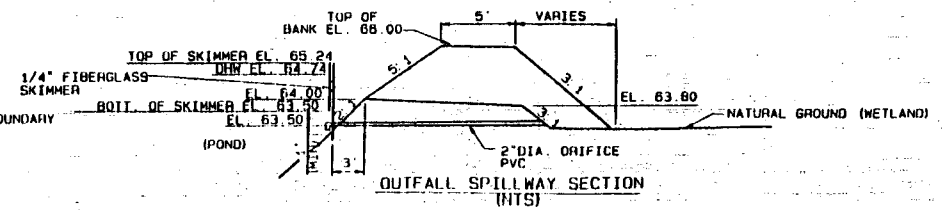
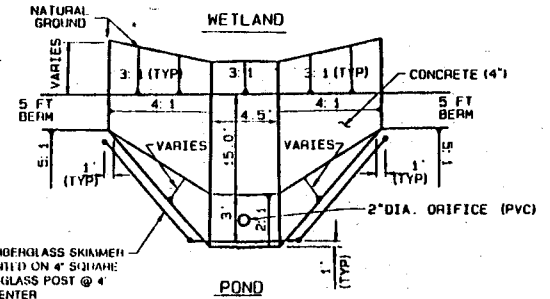
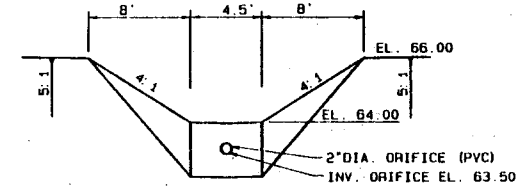
TYPICAL POND SECTION

{N . T . S}

SECTION A-A

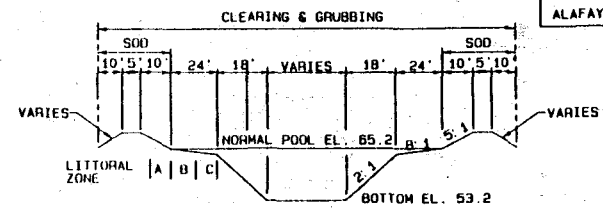
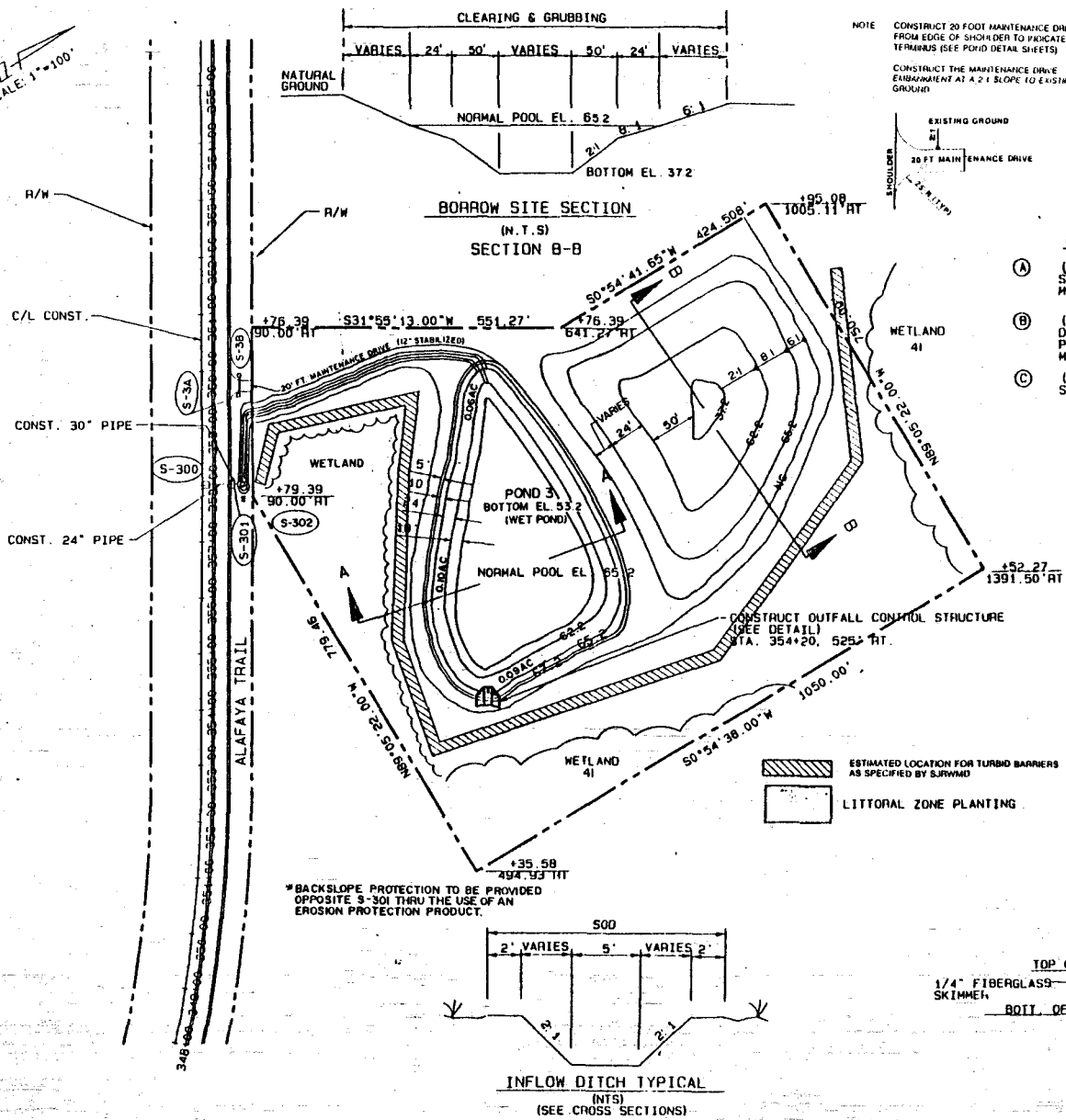
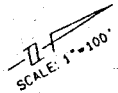
CONTROL STRUCTURE

TOB	66.00 FT
WEIR EL.	64.00 FT
WEIR LENGTH	4.5 FT
2" DIA. ORIFICE	
C/L OF ORIFICE	63.58 FT
INV. OF ORIFICE	63.50 FT



LITTORAL ZONE PLANTING

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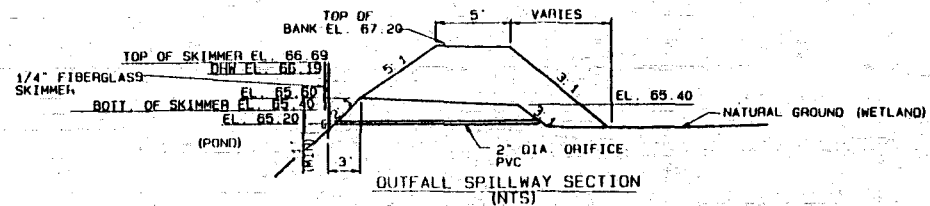
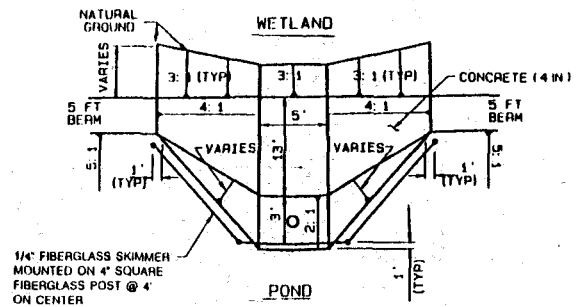
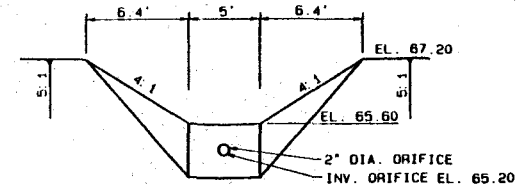
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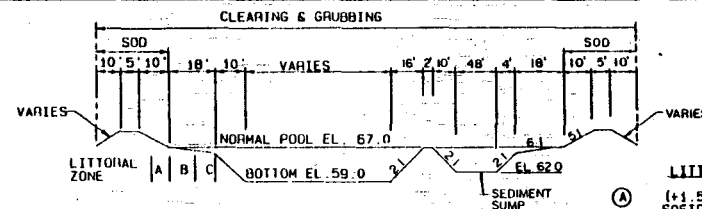
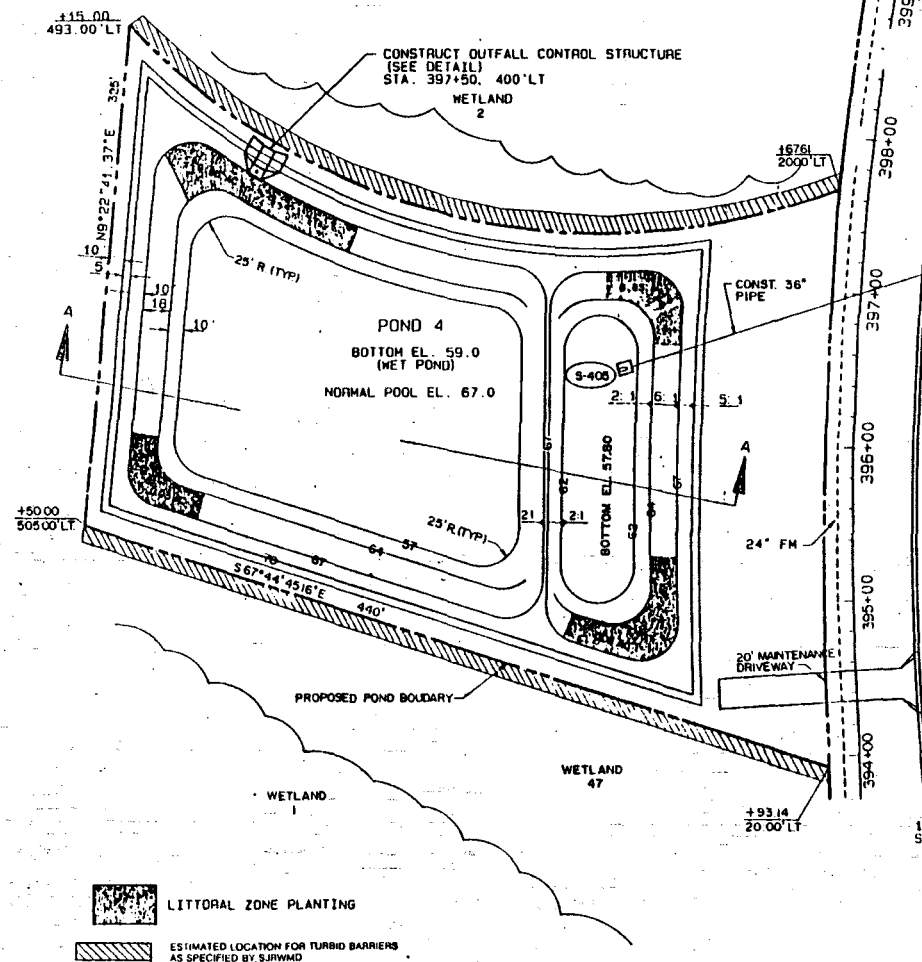
SECTION A-A

CONTROL STRUCTURE

TOB	67.20 FT
WEIR EL.	65.60 FT
WEIR LENGTH	5 FT
2" DIA. ORIFICE	
C/L OF ORIFICE	65.53 FT
INV. OF ORIFICE	65.20 FT



REVISIONS <table><tr><th>DATE</th><th>BY</th><th>DESCRIPTION</th><th>DATE</th><th>BY</th><th>DESCRIPTION</th><th>DATE</th><th>BY</th><th>DESCRIPTION</th></tr><tr><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td></tr><tr><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td></tr><tr><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td></tr></table>												DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION																												GRAND COUNTY PUBLIC WORKS DEPARTMENT <table><tr><th>DATE</th><th>BY</th><th>DESCRIPTION</th><th>DATE</th><th>BY</th><th>DESCRIPTION</th></tr><tr><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td></tr><tr><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td></tr><tr><td> </td><td> </td><td> </td><td> </td><td> </td><td> </td></tr></table>				DATE	BY	DESCRIPTION	DATE	BY	DESCRIPTION																			LOCKHART ENGINEERING, INC. 1700 17th Street, Suite 100, Grand Forks, ND 58201 (701) 775-1111				POND 3 DETAIL											
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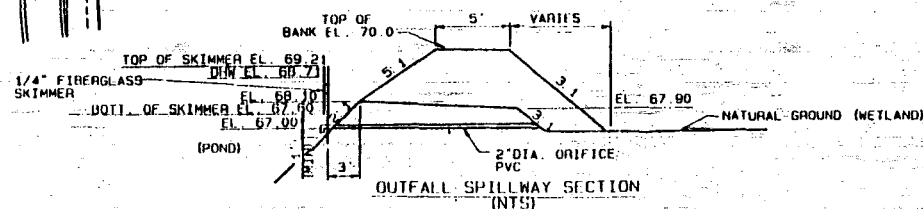
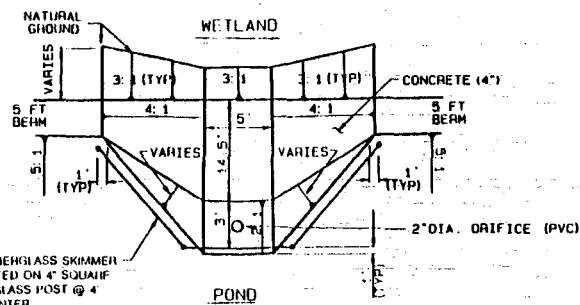
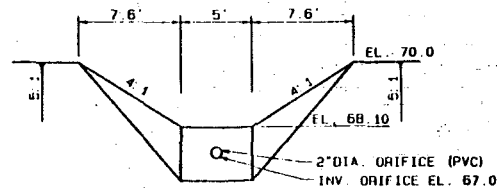


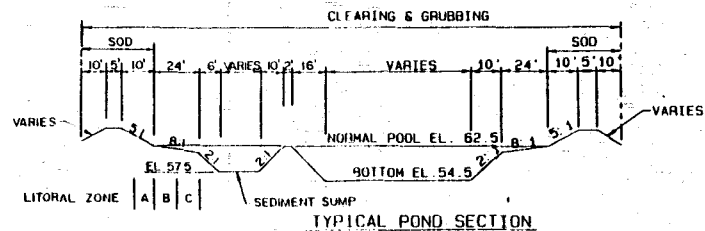
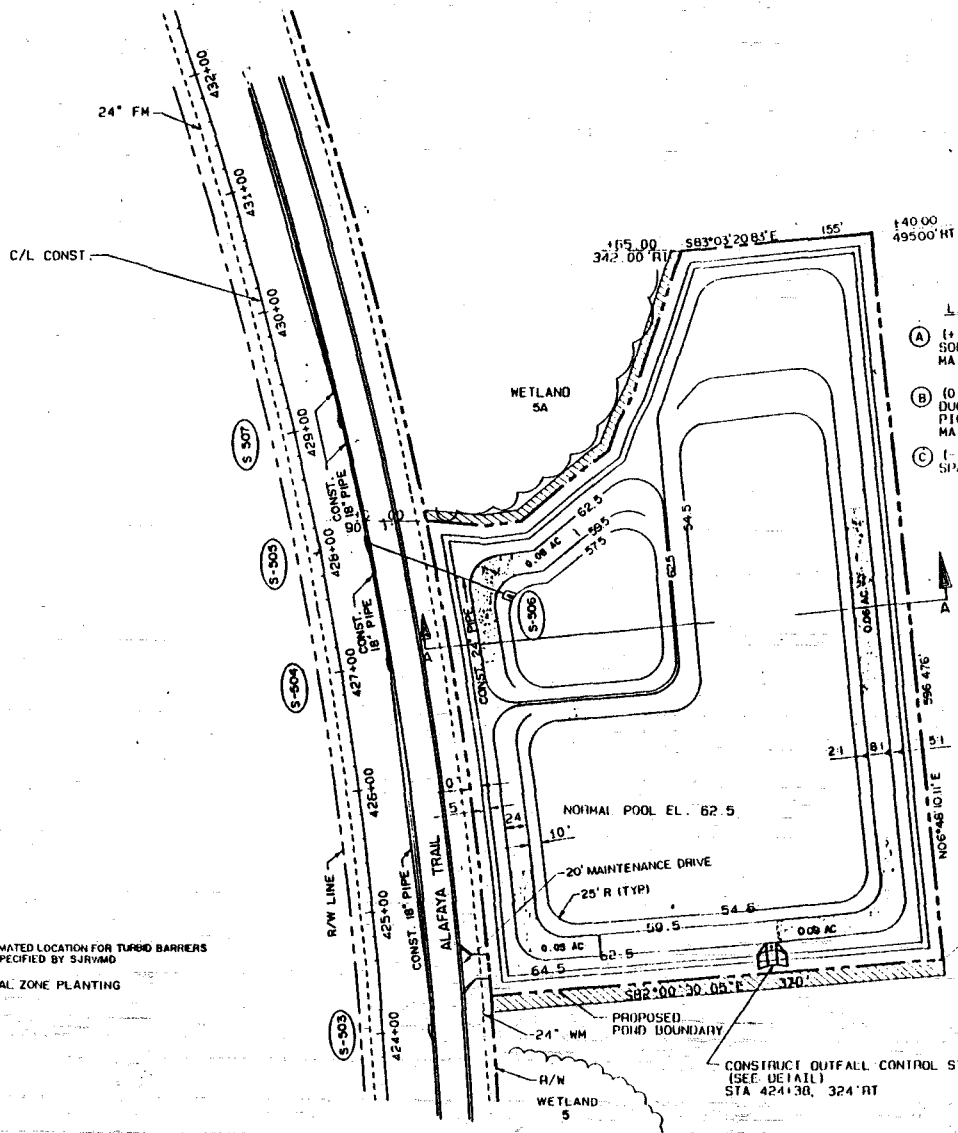
LITTORAL ZONE

(A) (+1.5'-0' NP)
SOFTGRASS 3.0' 0 C
MAIDENCANE 3.0' 0 C

(B) (0'-1.5' NP)
DUCK POTATO 3.0' 0 C
PICKERELWEED 3.0' 0 C
MAIDENCANE 3.0' 0 C

(C) (-1.5' -3.0' NP)
SPATTERDOCK 6.0' 0 C

[illegible]



TROPICAL POND SECTION

(N . T . S)

SECTION A-A

CONTROL STRUCTURE

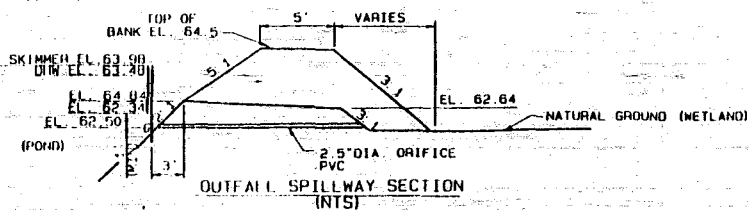
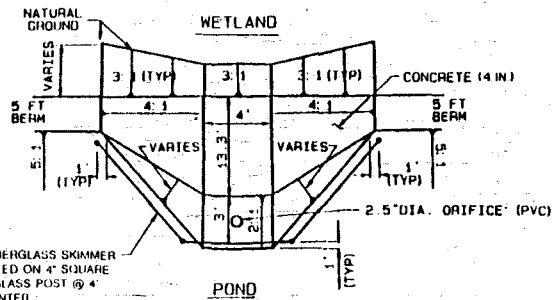
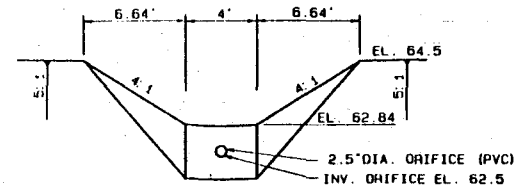
T08	64.50 FT
T09	62.84 FT

WEIR EL.	62.84 FT
WEIR LENGTH	4 FT

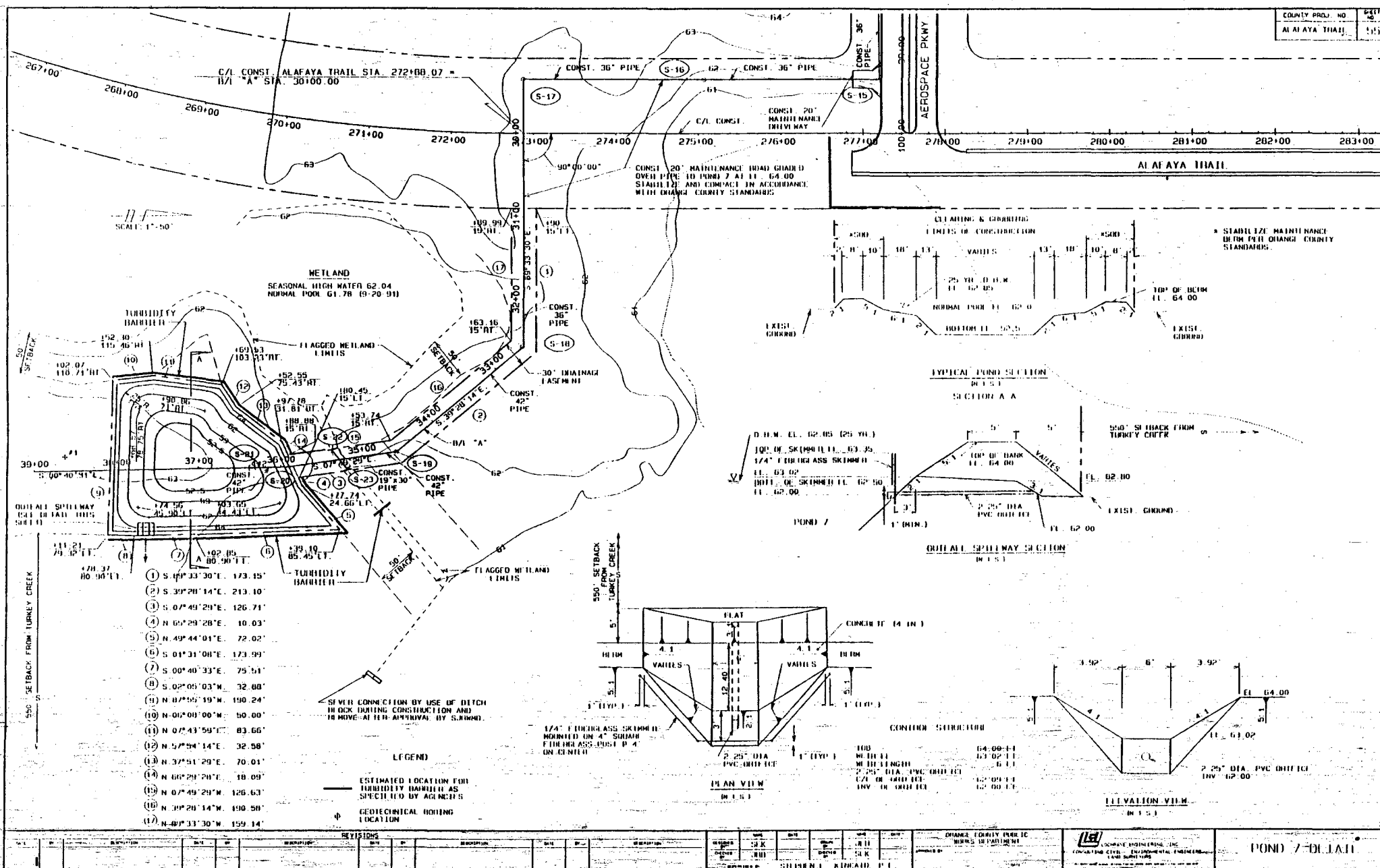
2.5" DIA. ORIFICE

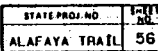
C/L OF ORIFICE	62.60 FT
INV. OF ORIFICE	62.50 FT

INV. OF OFFICE 62.50 FT

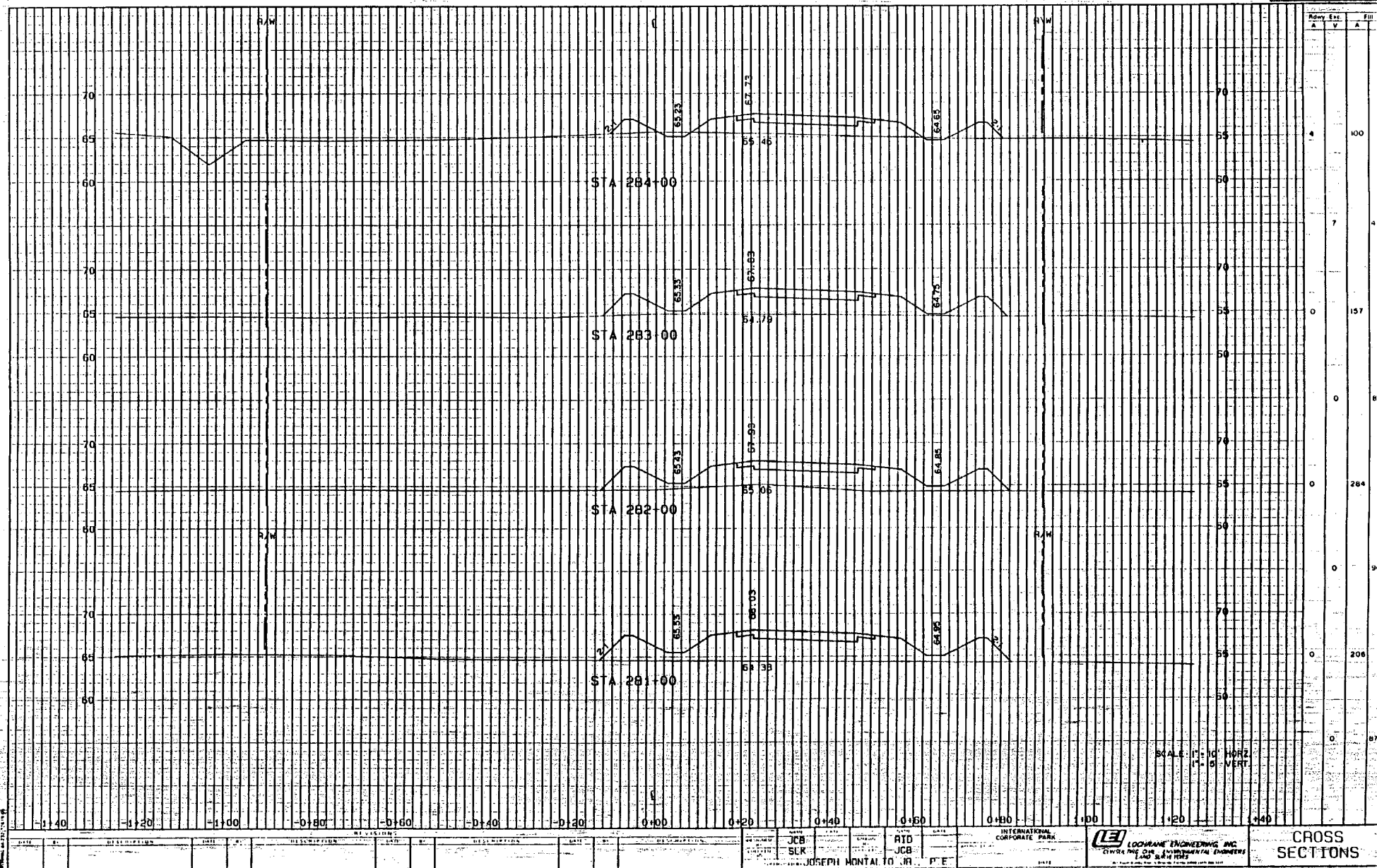
[illegible]







STATE PROJ NO 57-1
ALAFAYA TRAIL 57



SCALE: 1" = 10' HORIZ
1" = 5' VERT

LOUISIANA ENGINEERING, INC.
CIVIL AND MECHANICAL ENGINEERS
1000 PINE STREET, SUITE 200
NEW ORLEANS, LOUISIANA 70112
PHONE: (504) 581-1111
FAX: (504) 581-1112
WWW.LEINC.COM

CROSS
SECTIONS

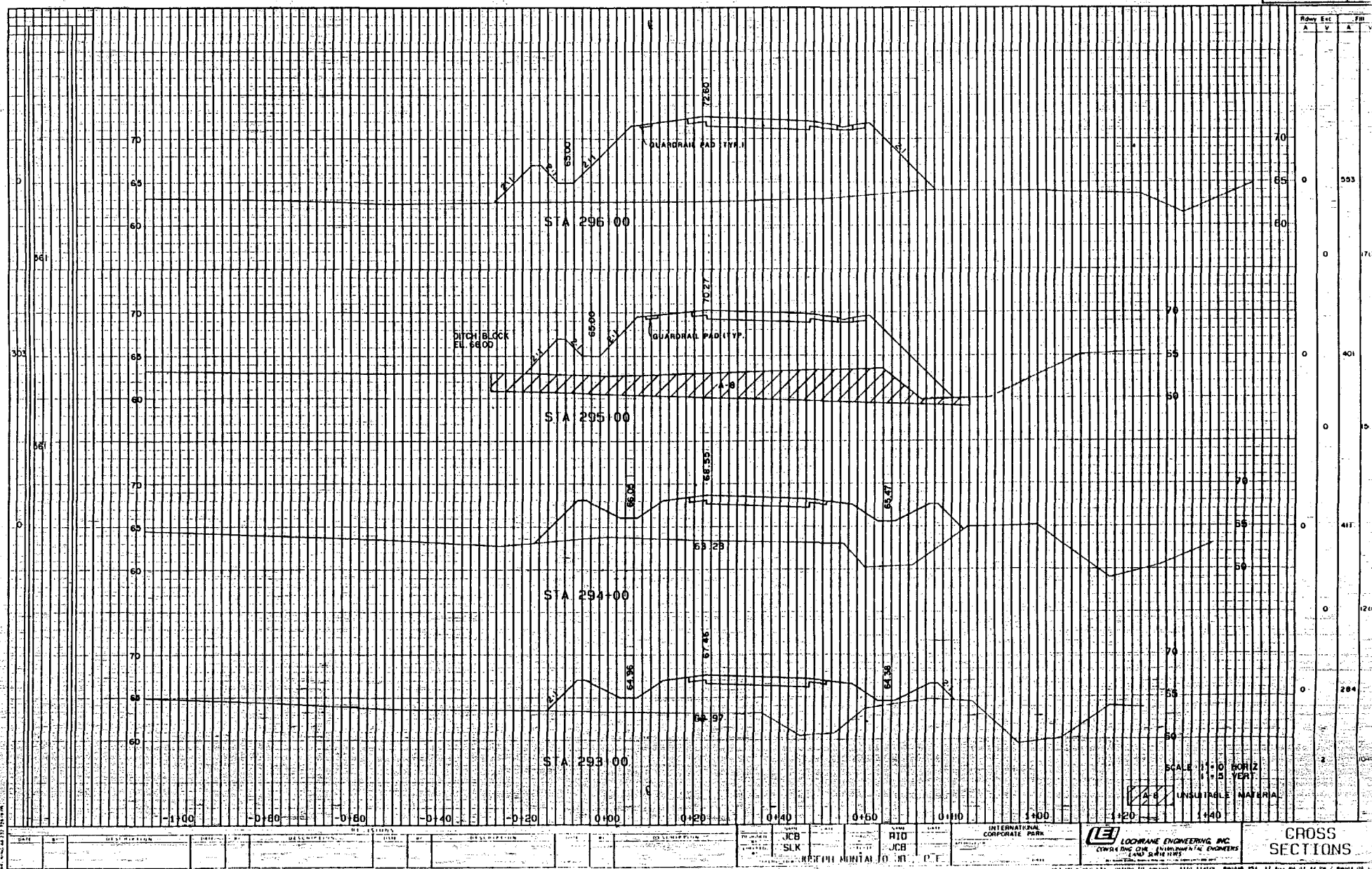
STATE PROJ. NO. SHEET
ALAFAYA TRAIL 58



STATE PROJ. NO. 5
ALAFAYA TRAIL 5

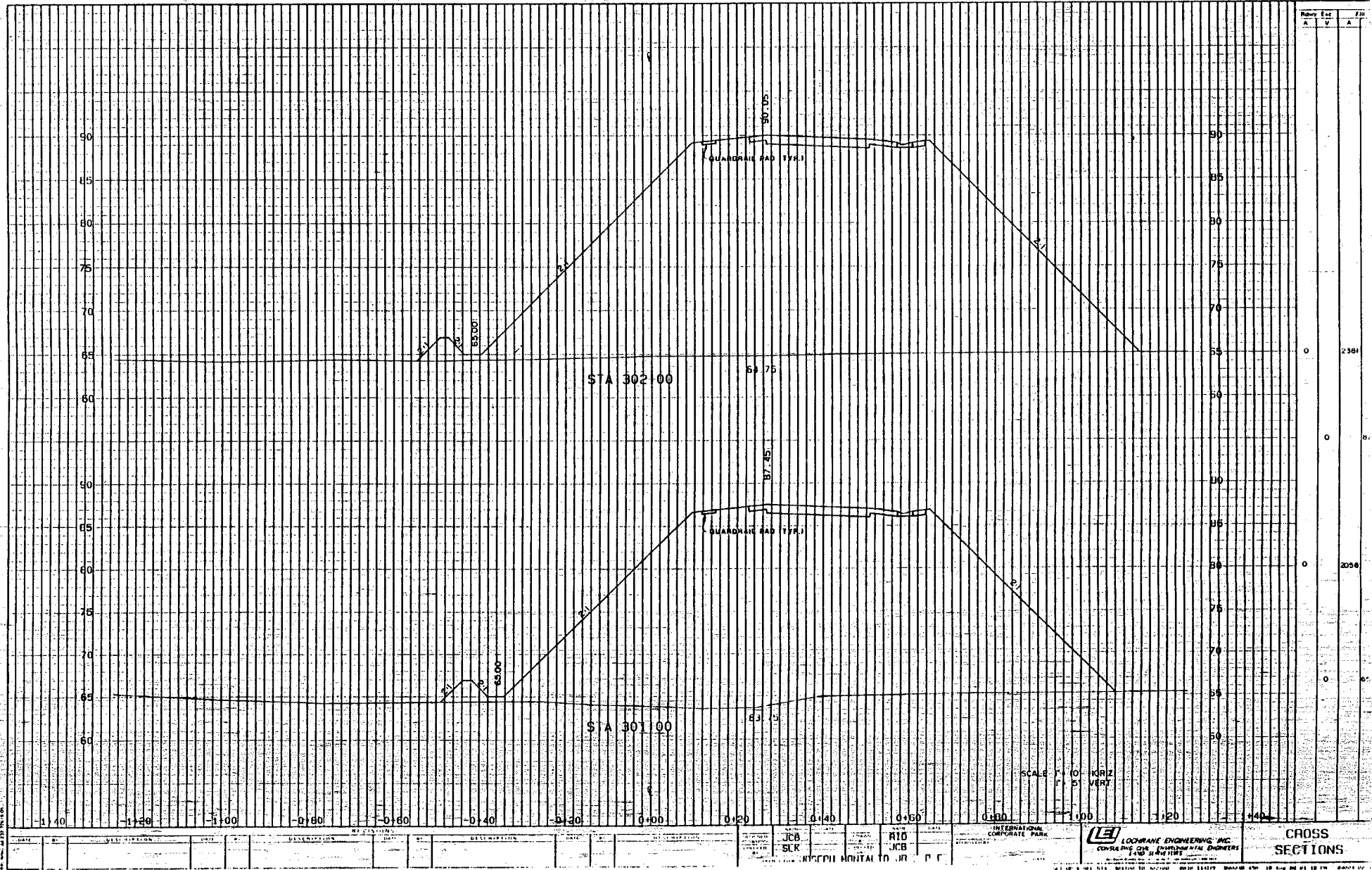


STATE PROJ NO 5-111
ALAFAYA TRAIL 60

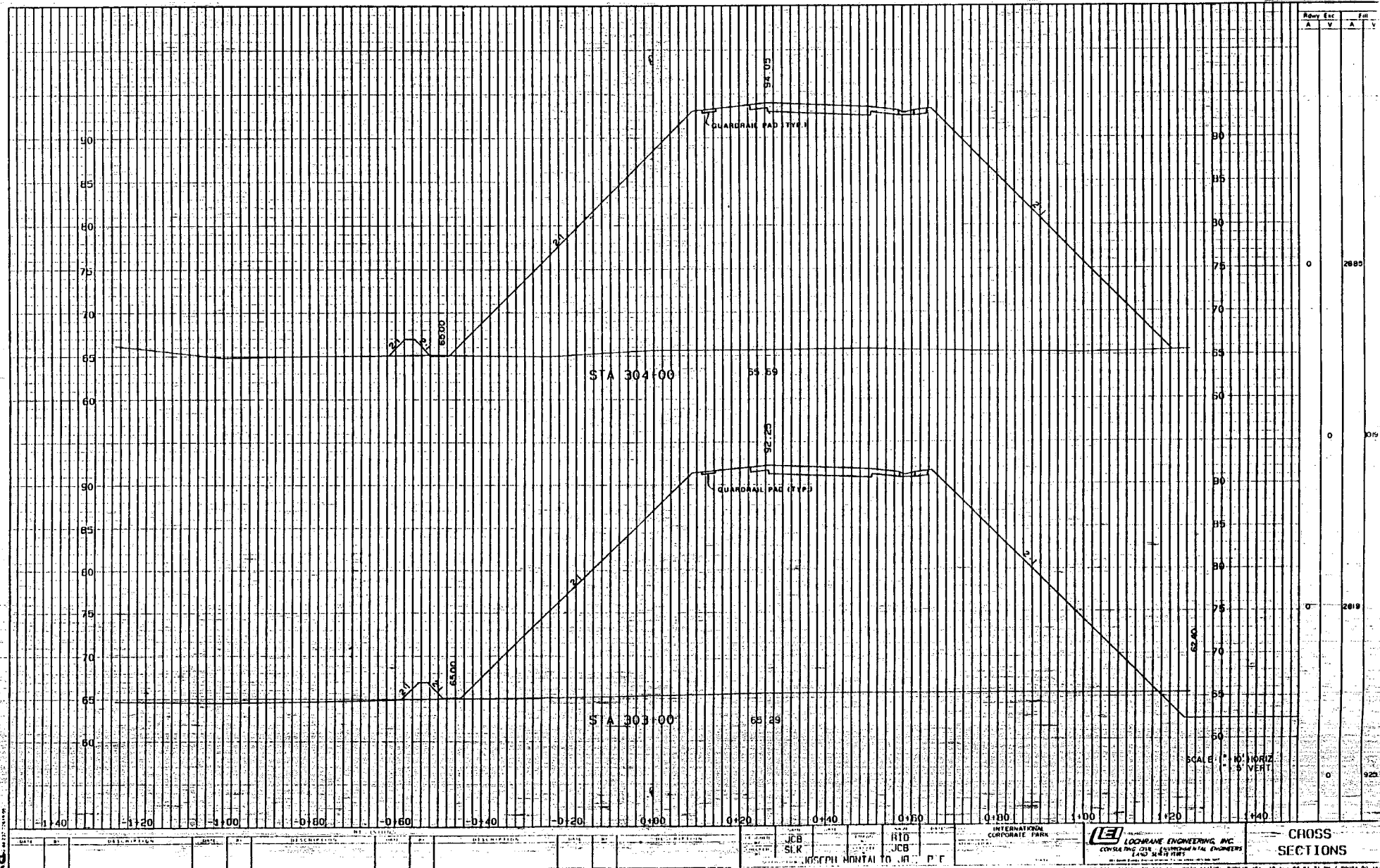


STATE PROJ NO 1-117
ALAFAYA TRAIL 61





STATE PROJ NO
ALAFAYA TRAIL
SHEET NO
63



CROSS
SECTIONS

LOCHRANE ENGINEERING, INC.
CONSULTING ENGINEERS
1403 N. 10TH STREET
TAMPA, FL 33606

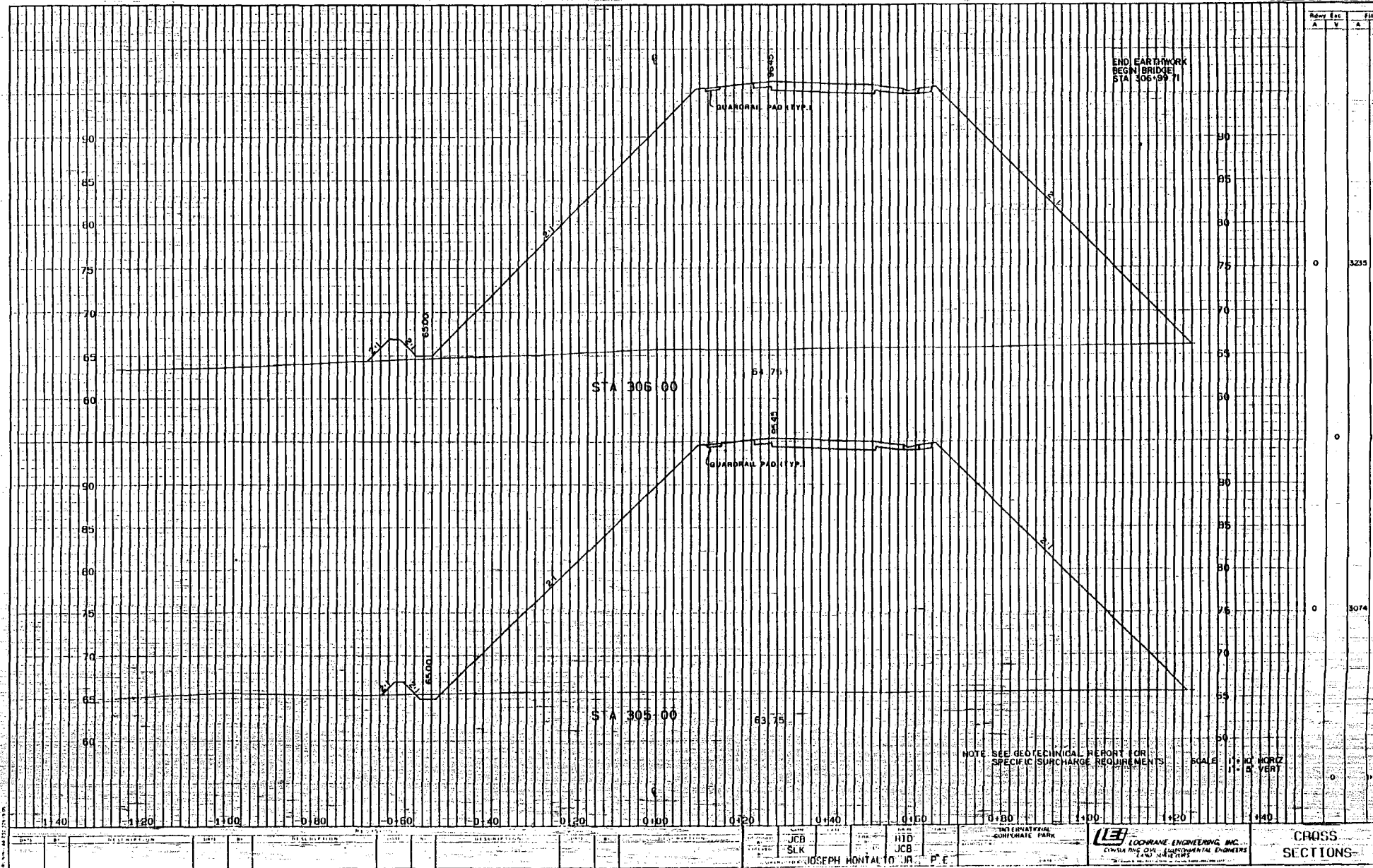
INTERNATIONAL
CORPORATE PARK

JOSEPH MONTALTO, JR. P.E.

JCB
SLR

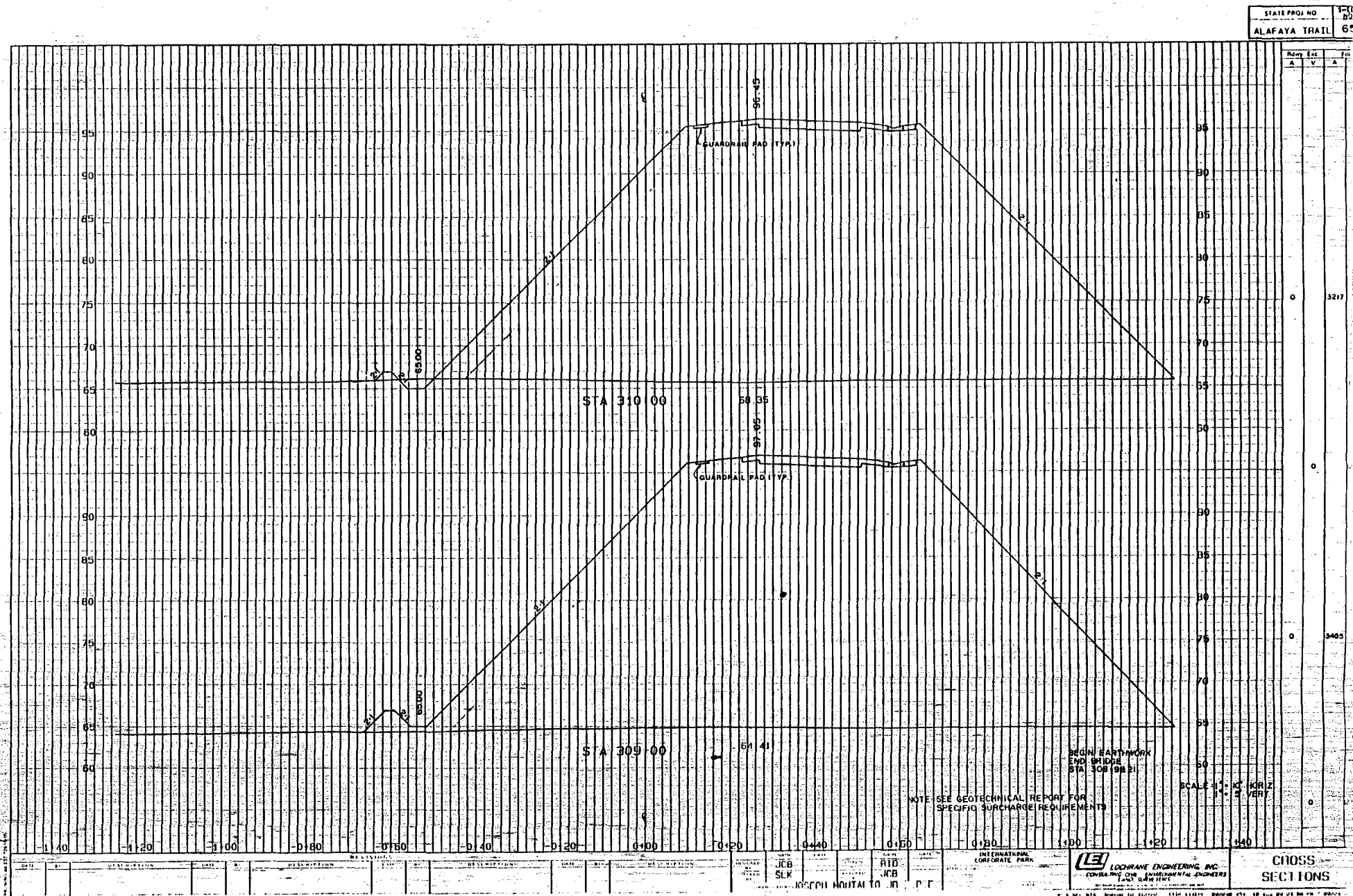
RJB
JCB

STATE PROJ. NO. 1-77
ALAFAYA TRAIL 64



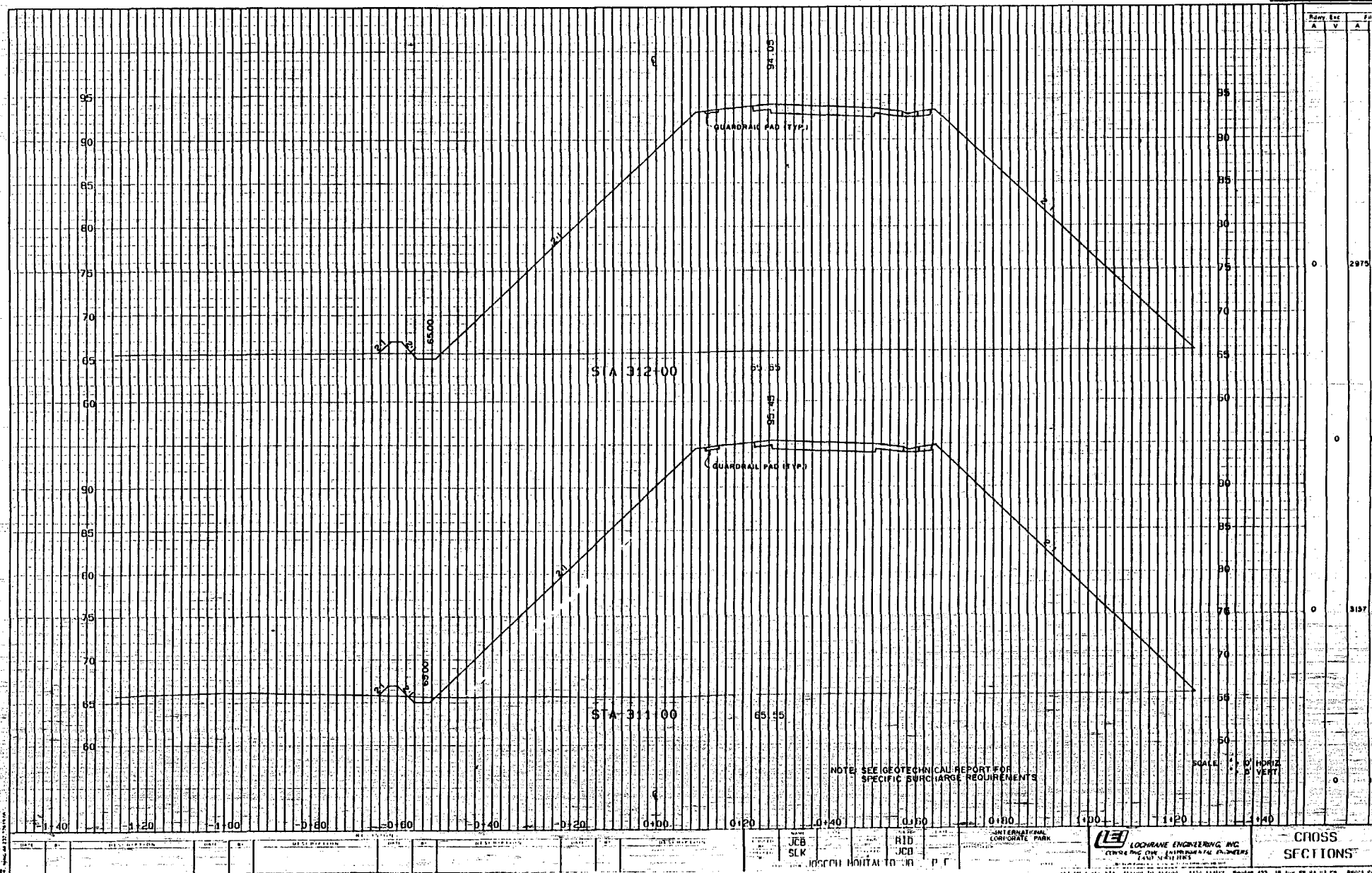
LOOHRAN ENGINEERING, INC.
CIVIL AND ENVIRONMENTAL ENGINEERS
LAND SURVEYING

CROSS
SECTIONS



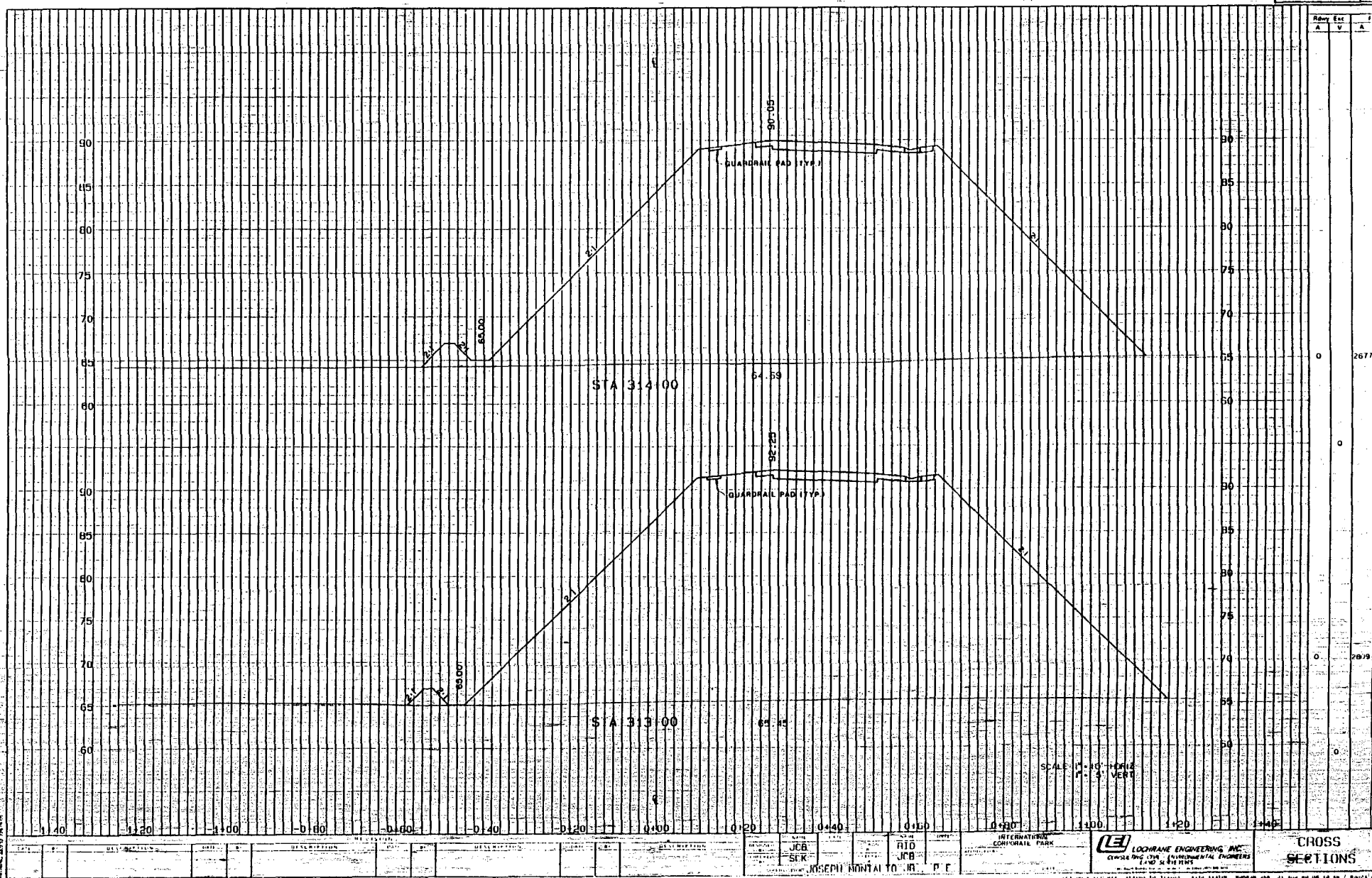
STATE PROJ NO
ALAFAYA TRAIL 66

Sheet No
66



STATE PROJ NO
ALAFAYA TRAIL

Rdwy Est
A V A



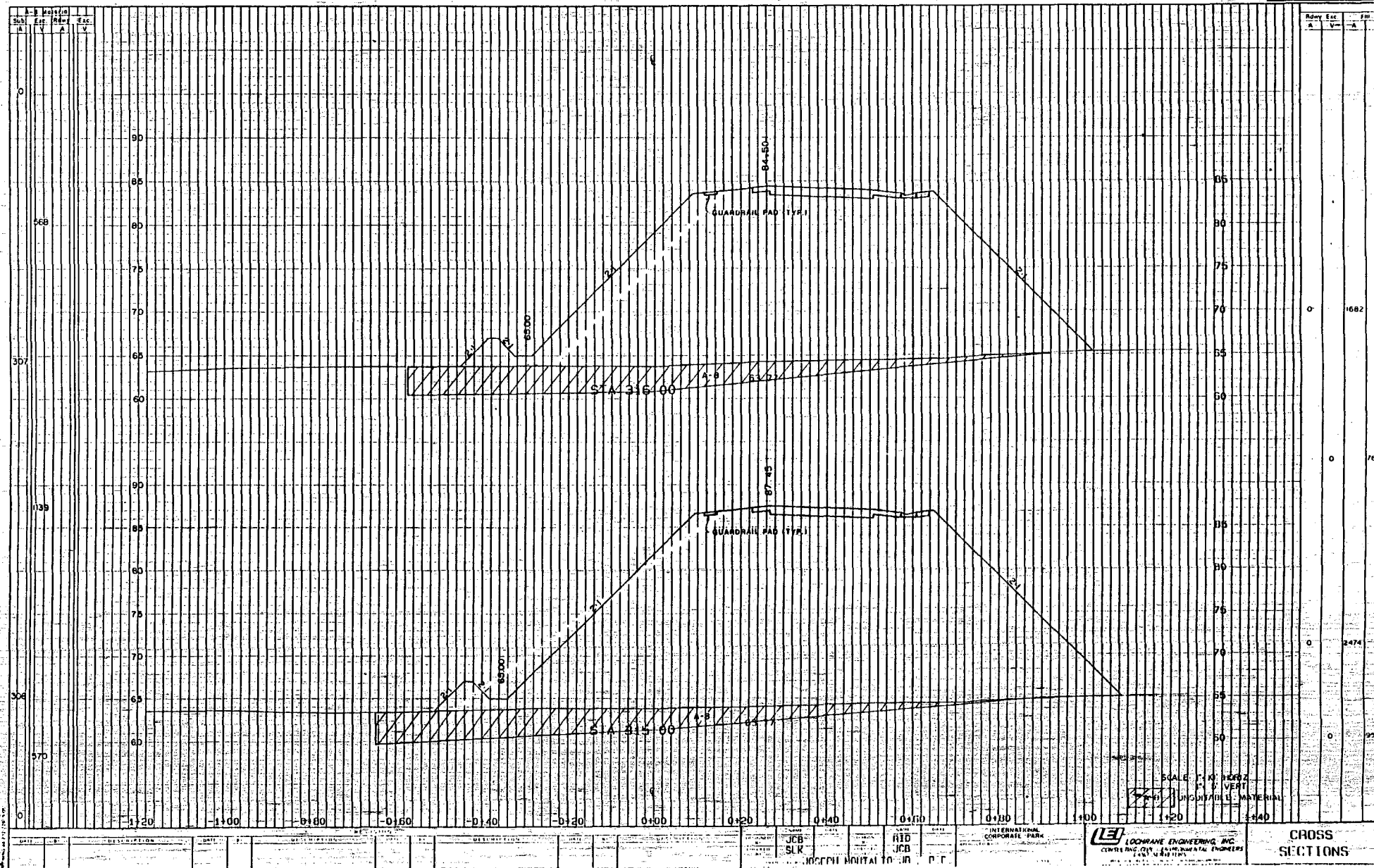
SCALE 1" = 10' HORIZ
1" = 5' VERT

LOCHANE ENGINEERING, INC.
CIVIL ENGINEERING, SURVEYING, AND LAND SURVEYING

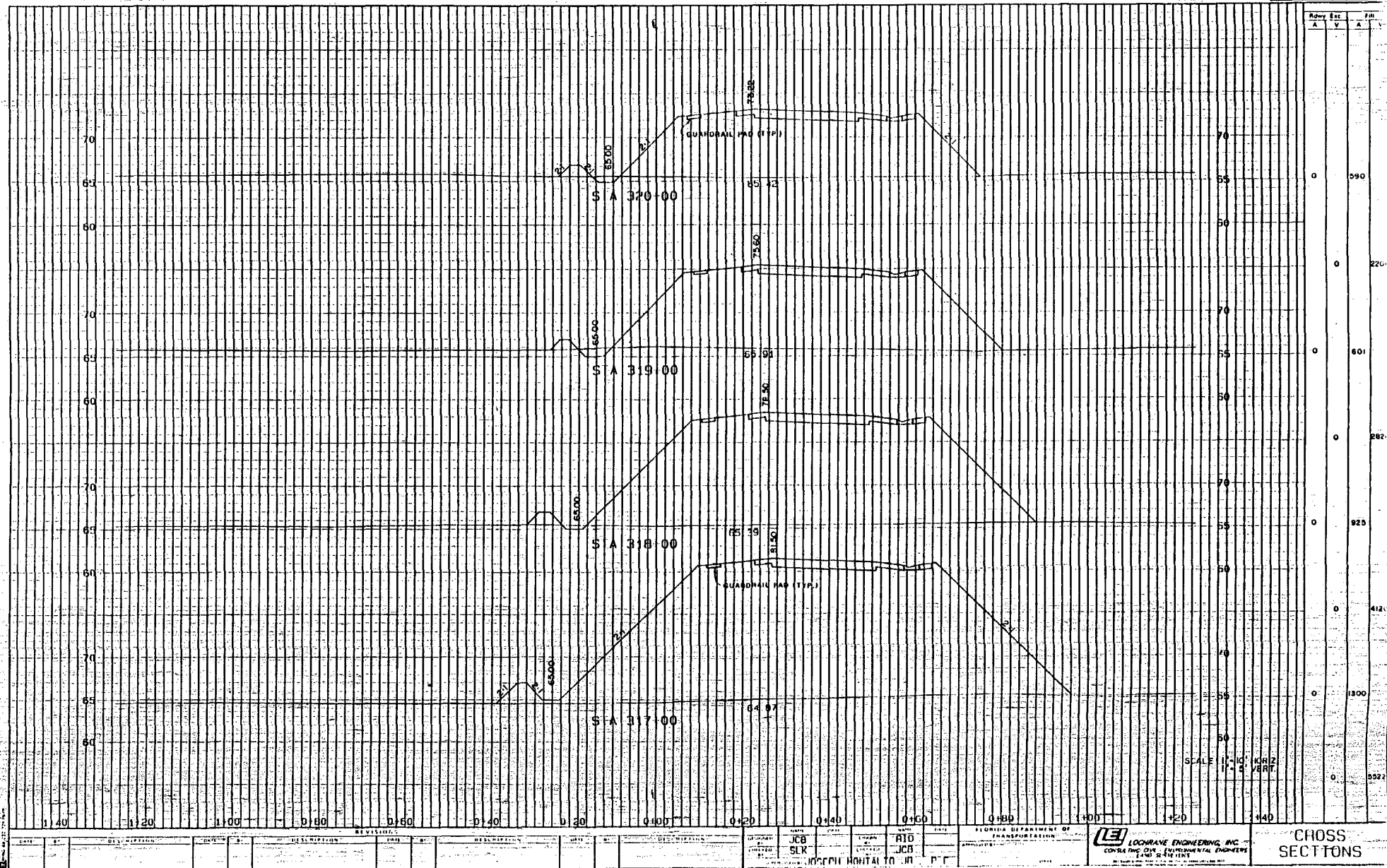
CROSS
SECTIONS

21 Aug 2008 10:50 AM

STATE PROJ. NO. 68
ALAFAYA TRAIL



STATE PROJ. NO. 69
ALAFAYA TRAIL



Station	Elevation	File
0+00	69.0	590
0+20	69.0	220
0+40	69.0	601
0+60	69.0	282
0+80	69.0	925
1+00	69.0	410
1+20	69.0	1300
1+40	69.0	552

CROSS
SECTIONS

LOCKHART ENGINEERING, INC.
CONSULTING CIVIL ENGINEERS
2401 S. 10th Street
Tampa, FL 33610
TEL: 813-288-1111 FAX: 813-288-1112

FLORIDA DEPARTMENT OF
TRANSPORTATION

DATE: 08/20/01
BY: JCB
CHECKED: JCB
APPROVED: JCB

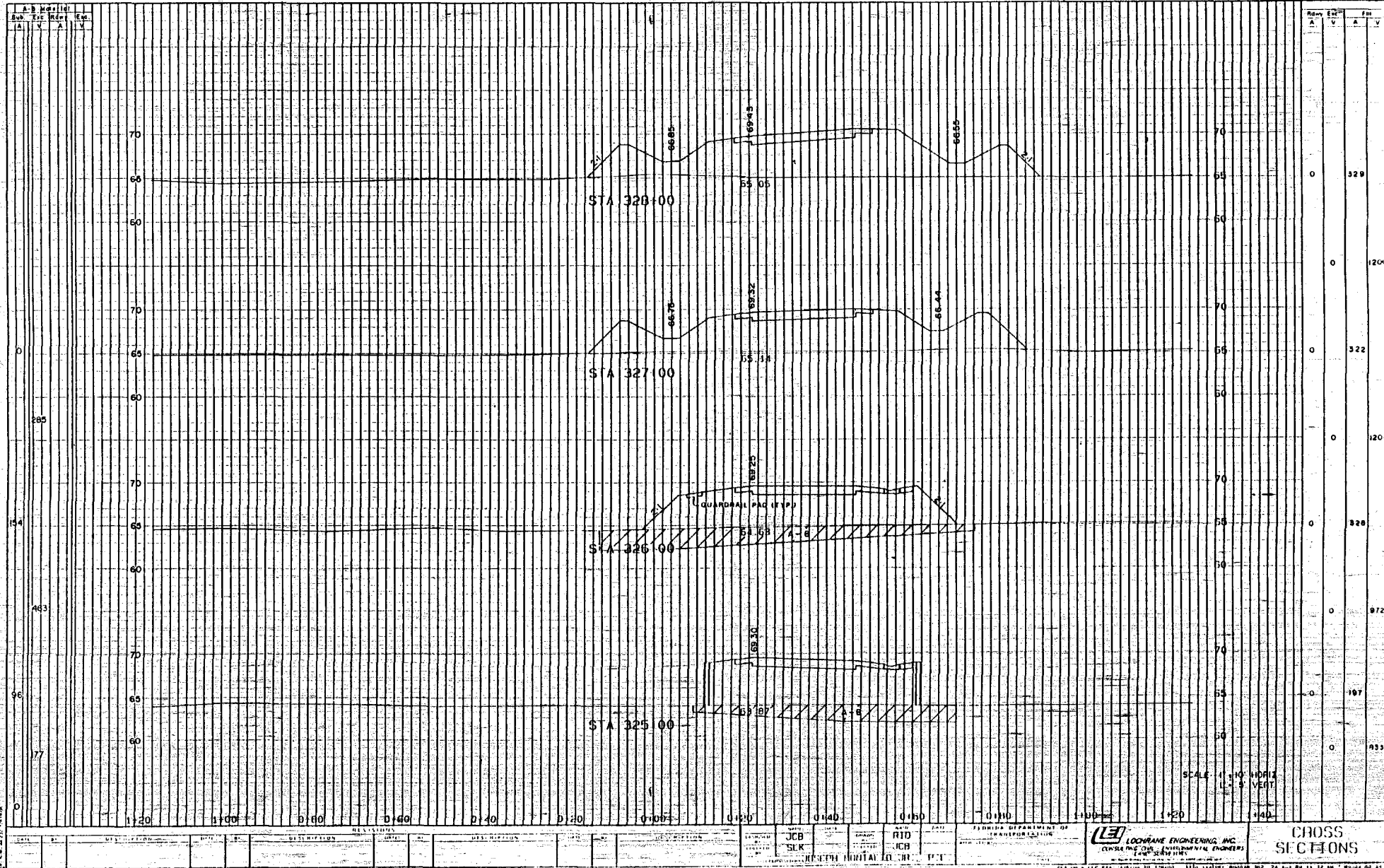
REVISIONS:

NO.	DATE	DESCRIPTION
1	08/20/01	ISSUED FOR BIDDING

STATE PROJ NO
ALAFAYA TRAIL 7



STATE PROJ. NO. 71
ALAFAYA TRAIL 71



CROSS
SECTIONS

LOCHRANE ENGINEERING, INC.
CONSULTING CIVIL ENGINEERS
LONG BEACH, CA

FLORIDA DEPARTMENT OF
TRANSPORTATION
DESIGN DIVISION

JCB
SLK

DATE
10/10/00

BY
JCB

FOR
ALAFAYA TRAIL

PROJECT NO.
100000000

DATE
10/10/00

BY
JCB

FOR
ALAFAYA TRAIL

PROJECT NO.
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DATE
10/10/00

BY
JCB

FOR
ALAFAYA TRAIL

PROJECT NO.
100000000

DATE
10/10/00

BY
JCB

FOR
ALAFAYA TRAIL

PROJECT NO.
100000000

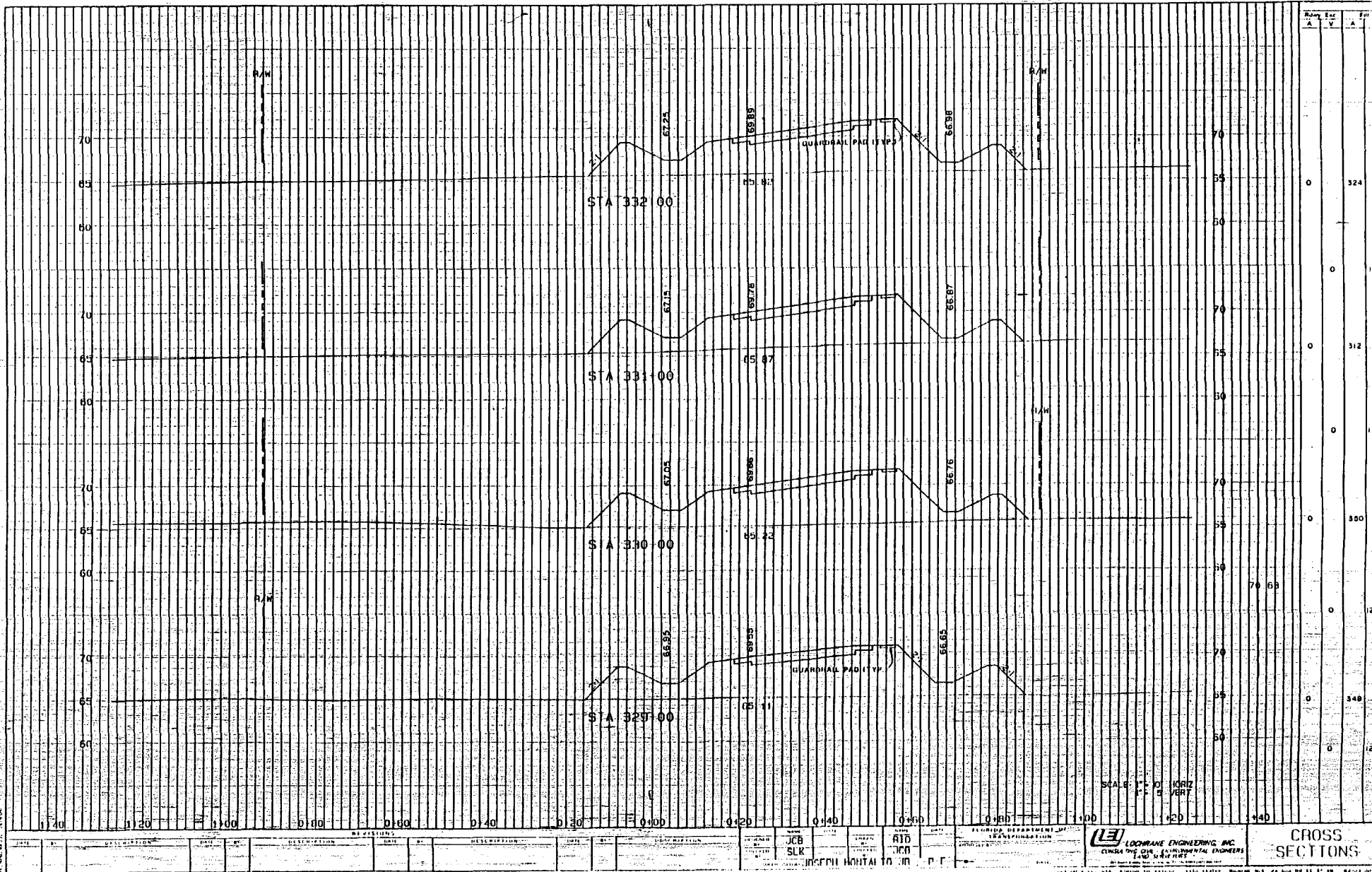
DATE
10/10/00

BY
JCB

FOR
ALAFAYA TRAIL

PROJECT NO.
100000000

STATE PROJ NO 1-11
ALAFAYA TRAIL 72



STATE PROJ. NO. 5-21
ALAFAYA TRAIL 7



SCALE 1"=10' VERT
1"=40' HORIZ

LEI LOOPRANE ENGINEERING, INC.
CIVIL AND ENVIRONMENTAL ENGINEERS
1000 N. 10TH AVE., SUITE 100
TAMPA, FL 33604

CROSS
SECTIONS

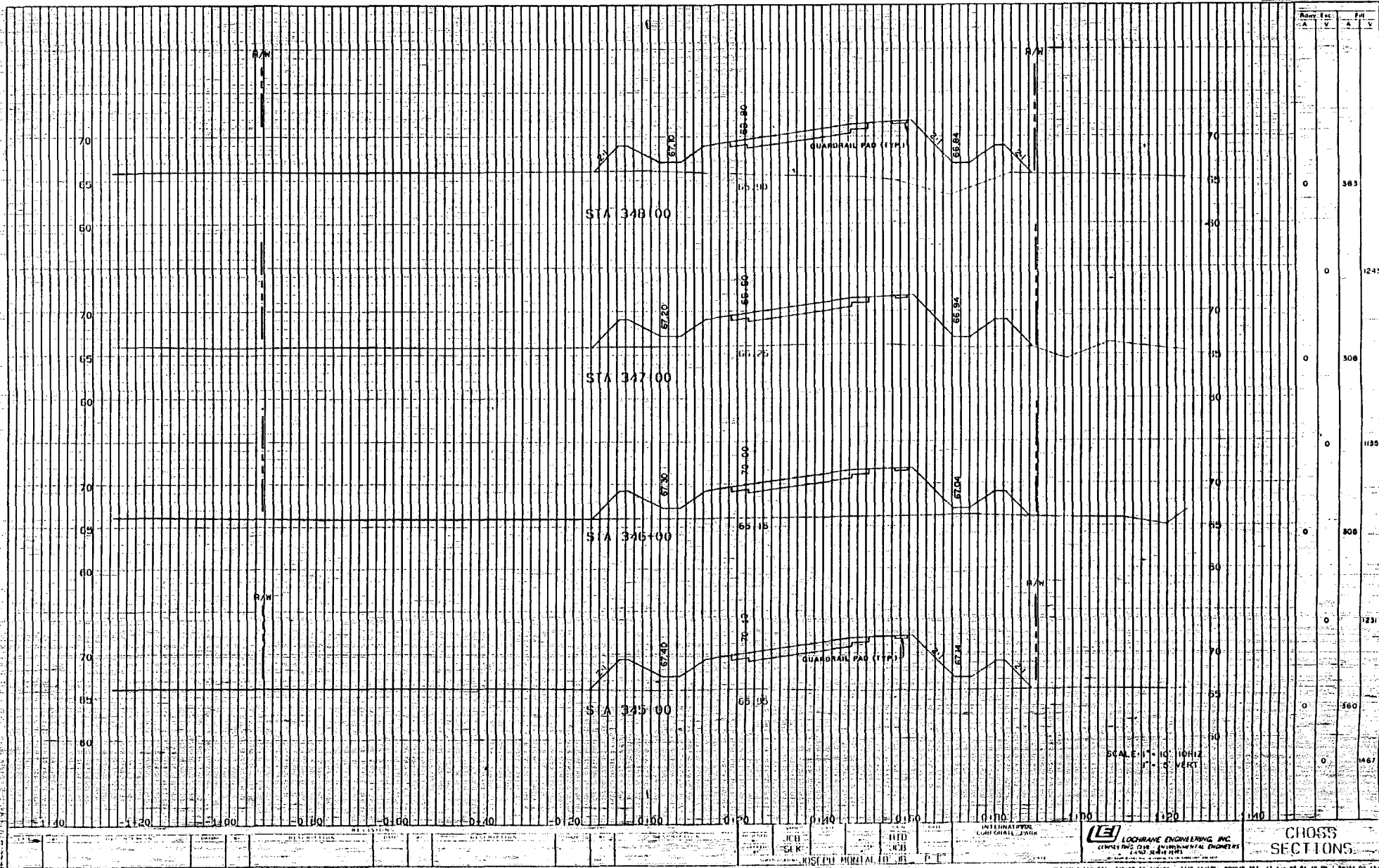
STATE PROJ NO 1-111
94
ALAFAYA TRAIL 74



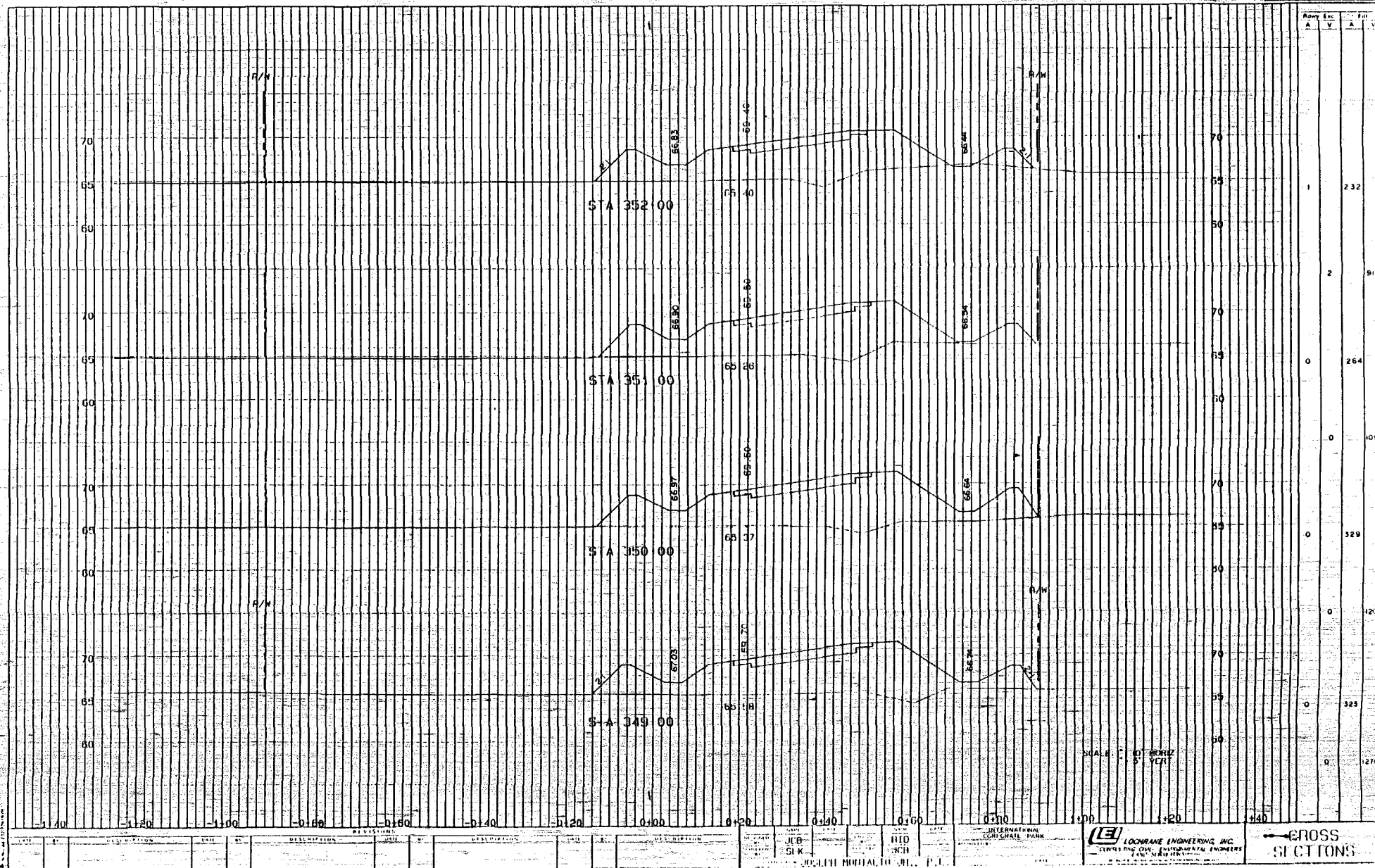
STATE PROJ NO
ALAFAYA TRAIL
SHEET NO
75



STATE PROJ NO
ALAFAYA TRAIL
S-471
76



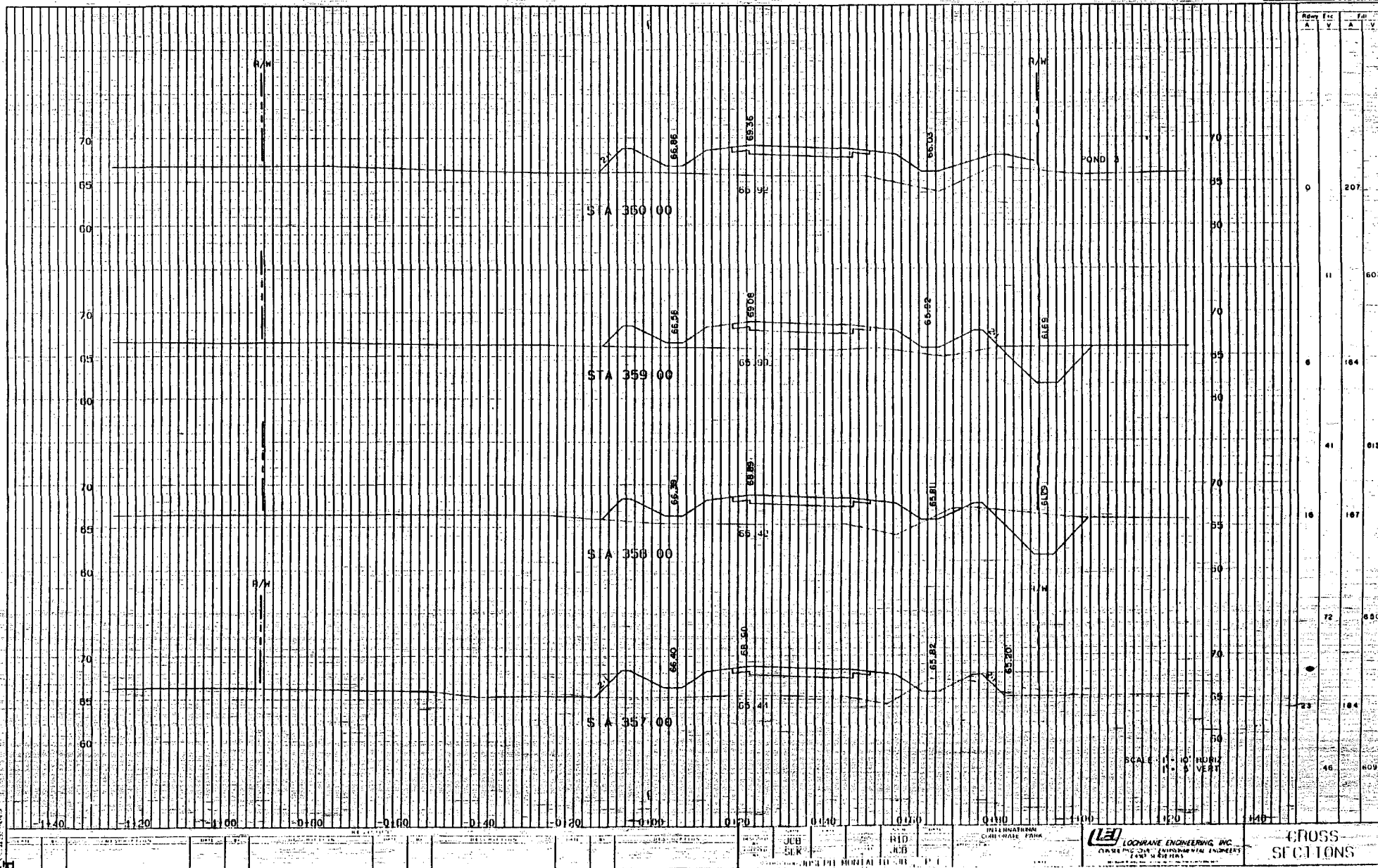
STATE PROJ NO 152
ALAFAYA TRAIL 77

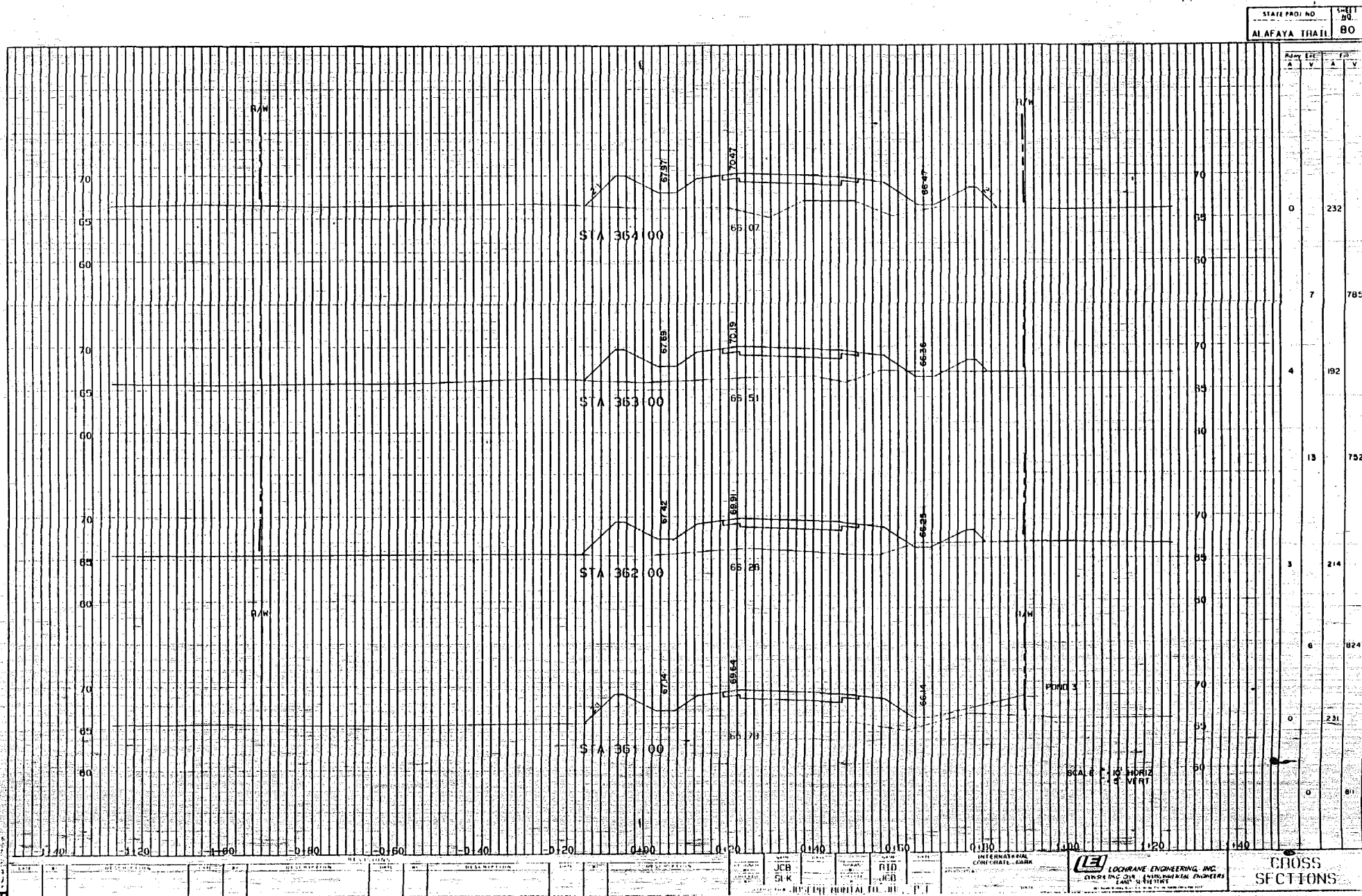


SCALE: 1" = 40' HORIZ
1" = 5' VERT

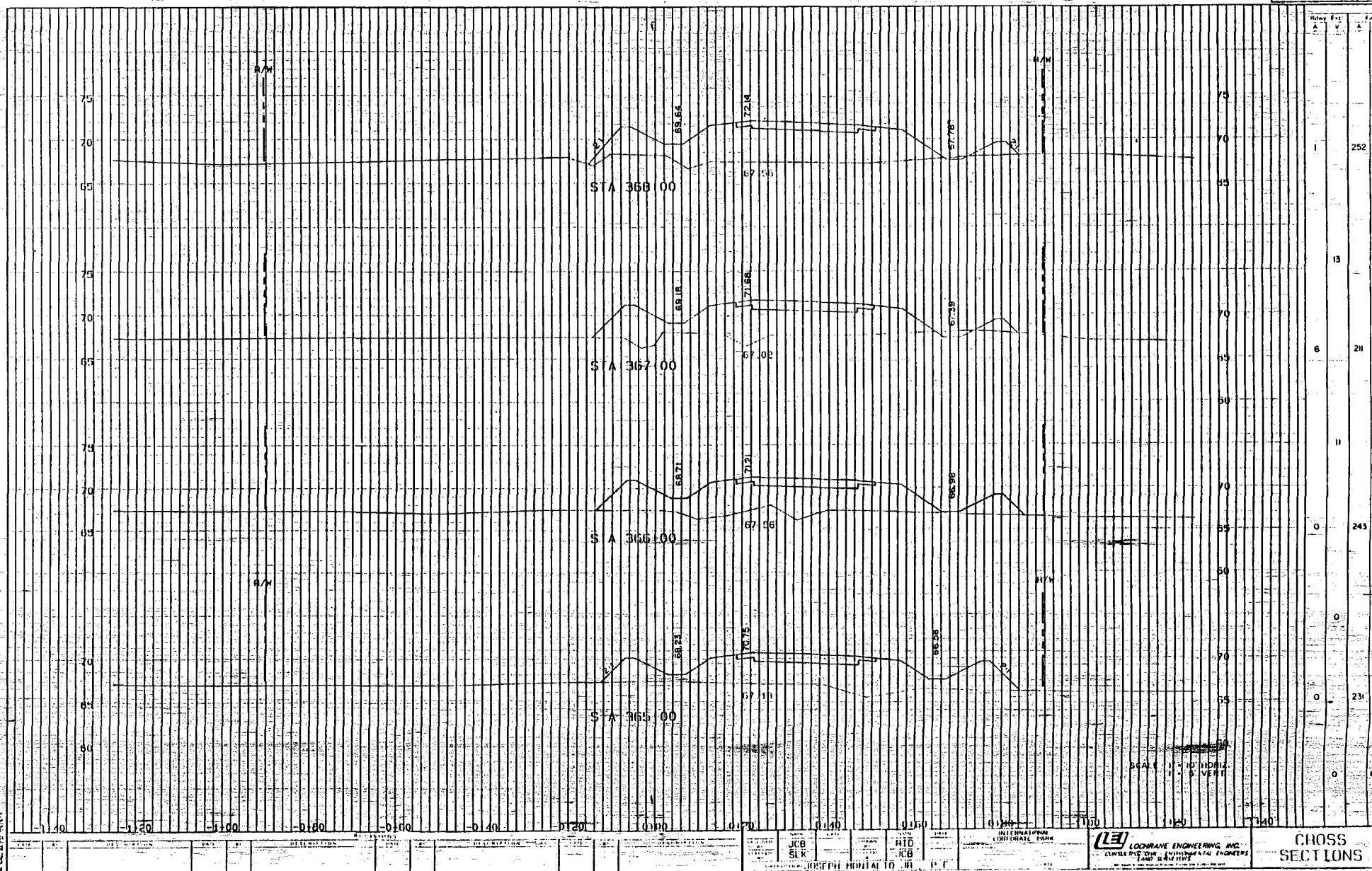
JOSEPH MORTALTO JR., P.E.
LOOMBAE ENGINEERING, INC.
CIVIL AND ELECTRICAL ENGINEERS
1401 SOUTH 11TH AVENUE
SUITE 100
TAMPA, FL 33610
CROSS SECTIONS







STATE PROJ. NO. 81
AL AFAYA TRAIL



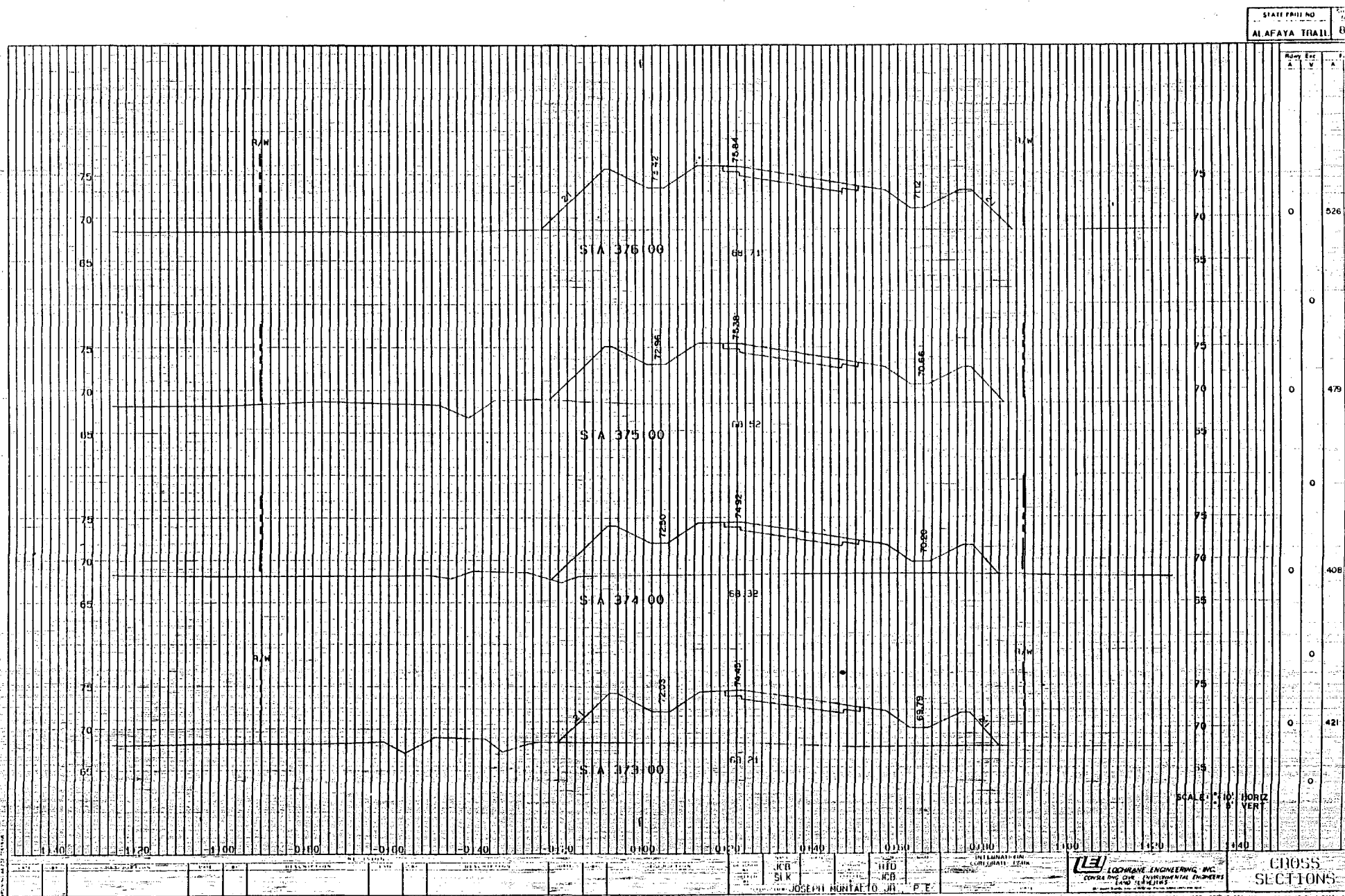
STATE PROJ NO
ALAFAYA TRAIL
SHEET NO
82



SCALE 1" = 10' HORIZ
1" = 5' VERT

LOOMANE ENGINEERING INC
CORPORATE OFFICE
2000 N. W. 10th Ave
Fort Lauderdale, FL 33309

CROSS
SECTIONS



STATE PROJ NO
ALAFAYA TRAIL 8



CROSS
SECTIONS

STATE PROJ NO 1-111
BU
ALAFAYA TRAIL 85

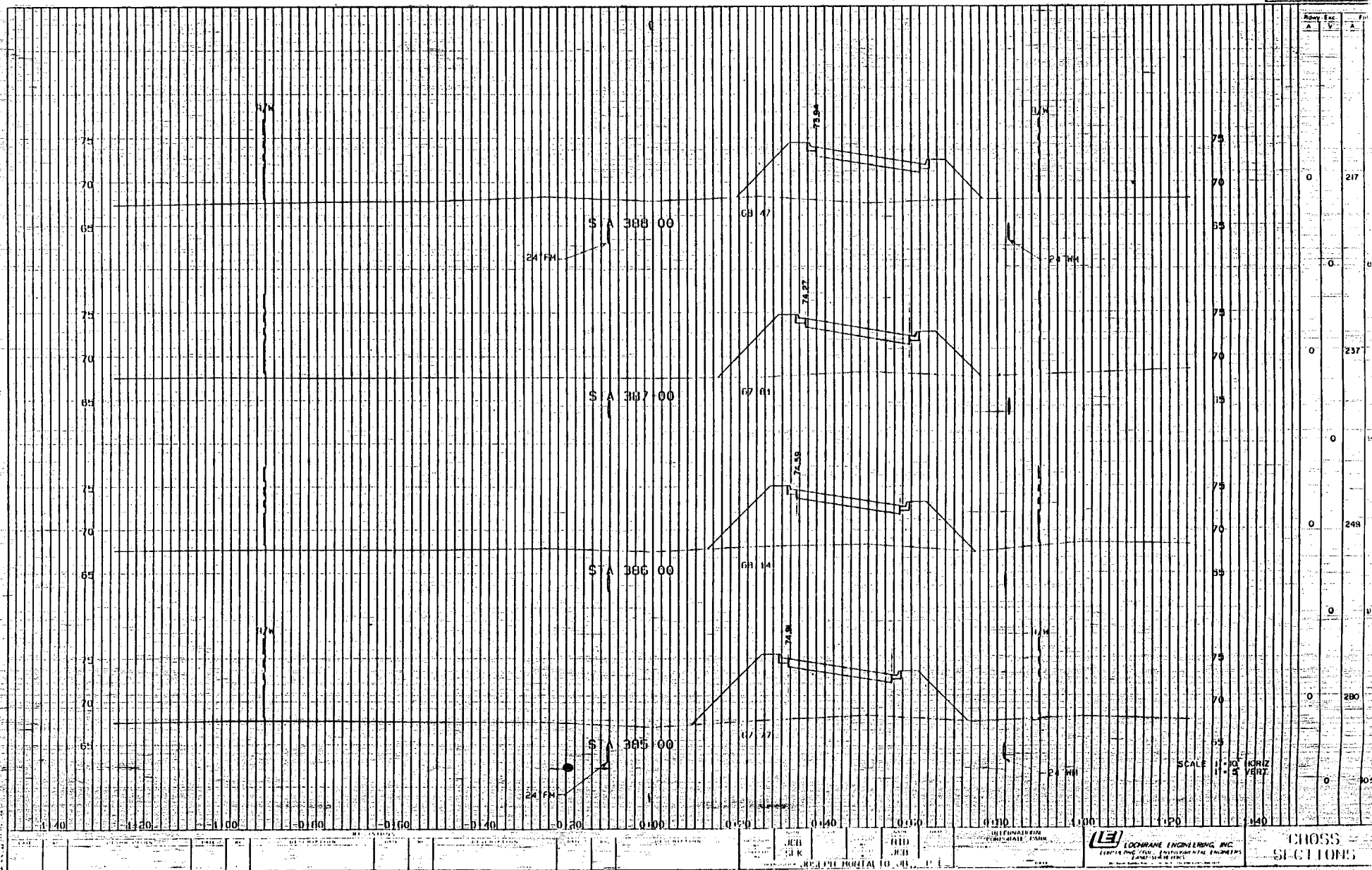


CH055
SECTIONS

LOCKHART ENGINEERING, INC.
ENGINEERS AND ARCHITECTS
1000 N. GULF BLVD., SUITE 100
FORT WORTH, TEXAS 76102
TEL: 817.339.1111
FAX: 817.339.1112
WWW.LOCKHART-ENGINEERING.COM

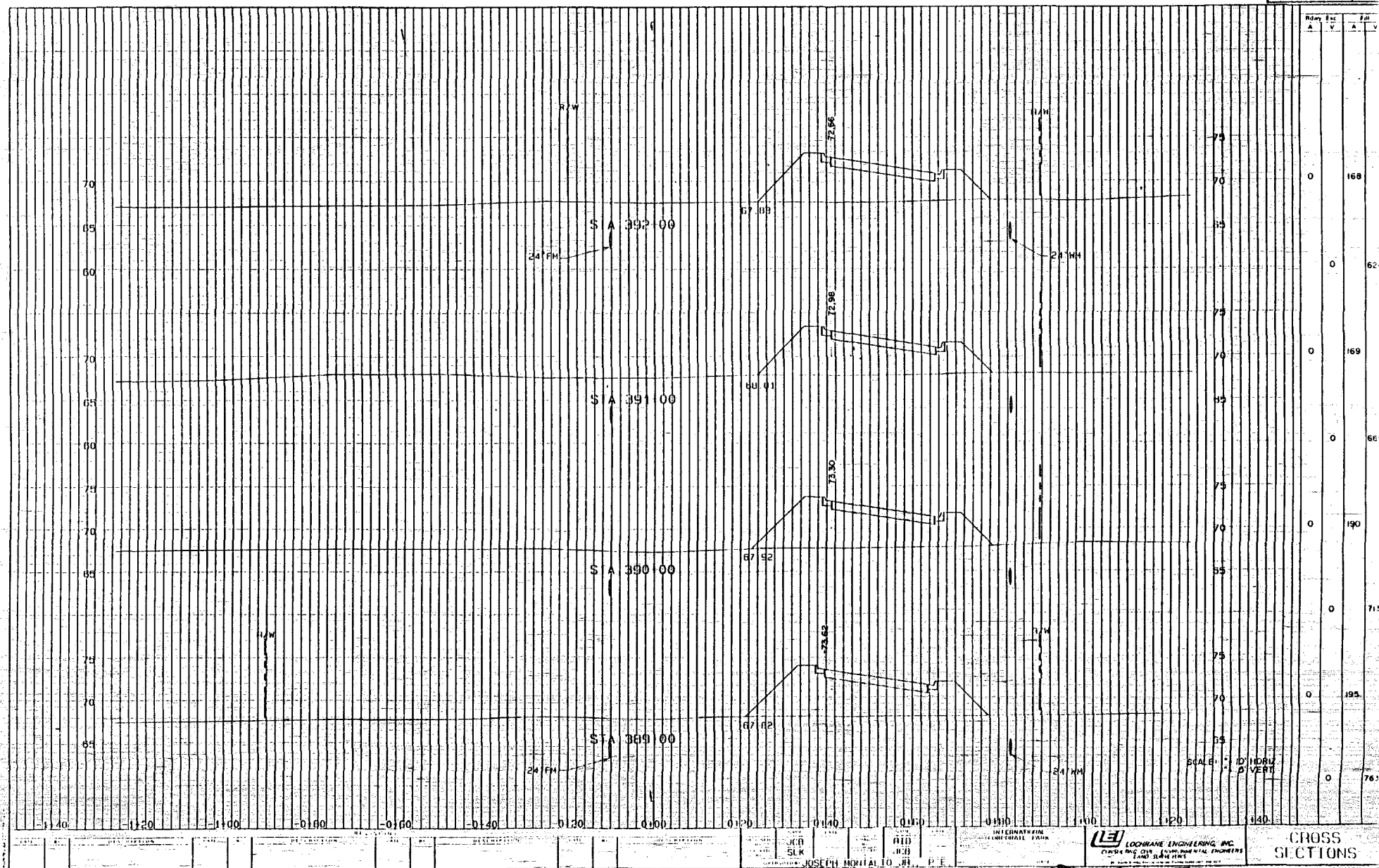
543 UP & SEC STA 301+00 TO 304+00 - 1110, 1111, 1112, 1113, 1114, 1115, 1116, 1117, 1118, 1119, 1120, 1121, 1122, 1123, 1124, 1125, 1126, 1127, 1128, 1129, 1130, 1131, 1132, 1133, 1134, 1135, 1136, 1137, 1138, 1139, 1140, 1141, 1142, 1143, 1144, 1145, 1146, 1147, 1148, 1149, 1150, 1151, 1152, 1153, 1154, 1155, 1156, 1157, 1158, 1159, 1160, 1161, 1162, 1163, 1164, 1165, 1166, 1167, 1168, 1169, 1170, 1171, 1172, 1173, 1174, 1175, 1176, 1177, 1178, 1179, 1180, 1181, 1182, 1183, 1184, 1185, 1186, 1187, 1188, 1189, 1190, 1191, 1192, 1193, 1194, 1195, 1196, 1197, 1198, 1199, 1200, 1201, 1202, 1203, 1204, 1205, 1206, 1207, 1208, 1209, 1210, 1211, 1212, 1213, 1214, 1215, 1216, 1217, 1218, 1219, 1220, 1221, 1222, 1223, 1224, 1225, 1226, 1227, 1228, 1229, 1230, 1231, 1232, 1233, 1234, 1235, 1236, 1237, 1238, 1239, 1240, 1241, 1242, 1243, 1244, 1245, 1246, 1247, 1248, 1249, 1250, 1251, 1252, 1253, 1254, 1255, 1256, 1257, 1258, 1259, 1260, 1261, 1262, 1263, 1264, 1265, 1266, 1267, 1268, 1269, 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STATE PROJ NO 3071
ALAFAYA TRAIL B1



SET-UP + SEC STA 385+00 TO 389+00 - 310 1142PM - 090648 377 17-Aug-89 02:31 PM / 090648 07

STATE PROJECT NO. 6-11
ALAFAYA TRAIL 87

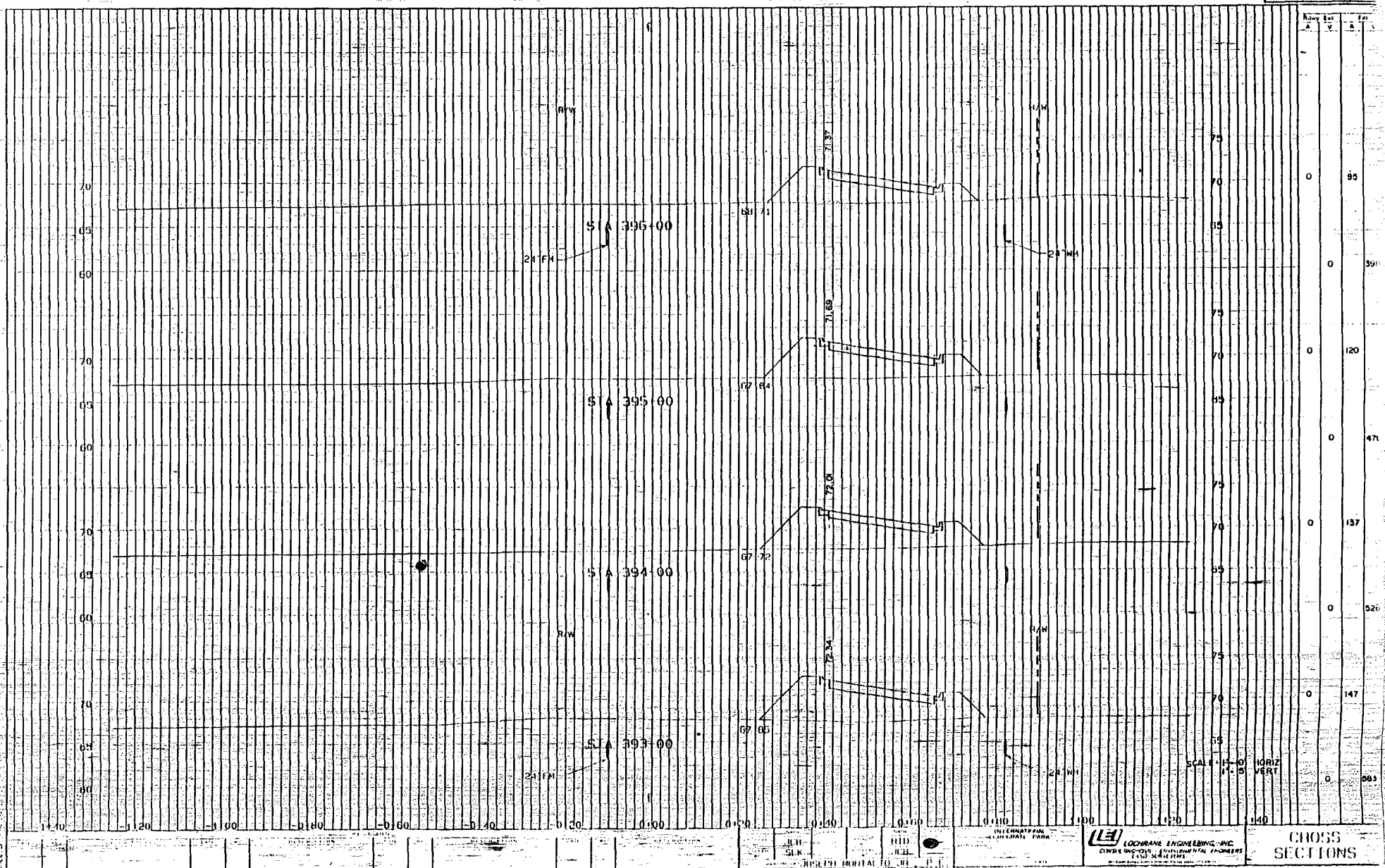


LOOMIS ENGINEERING, INC.
CIVIL ENGINEERS
1000 N. 10th St., Suite 100
Tampa, FL 33604

CROSS
SECTIONS

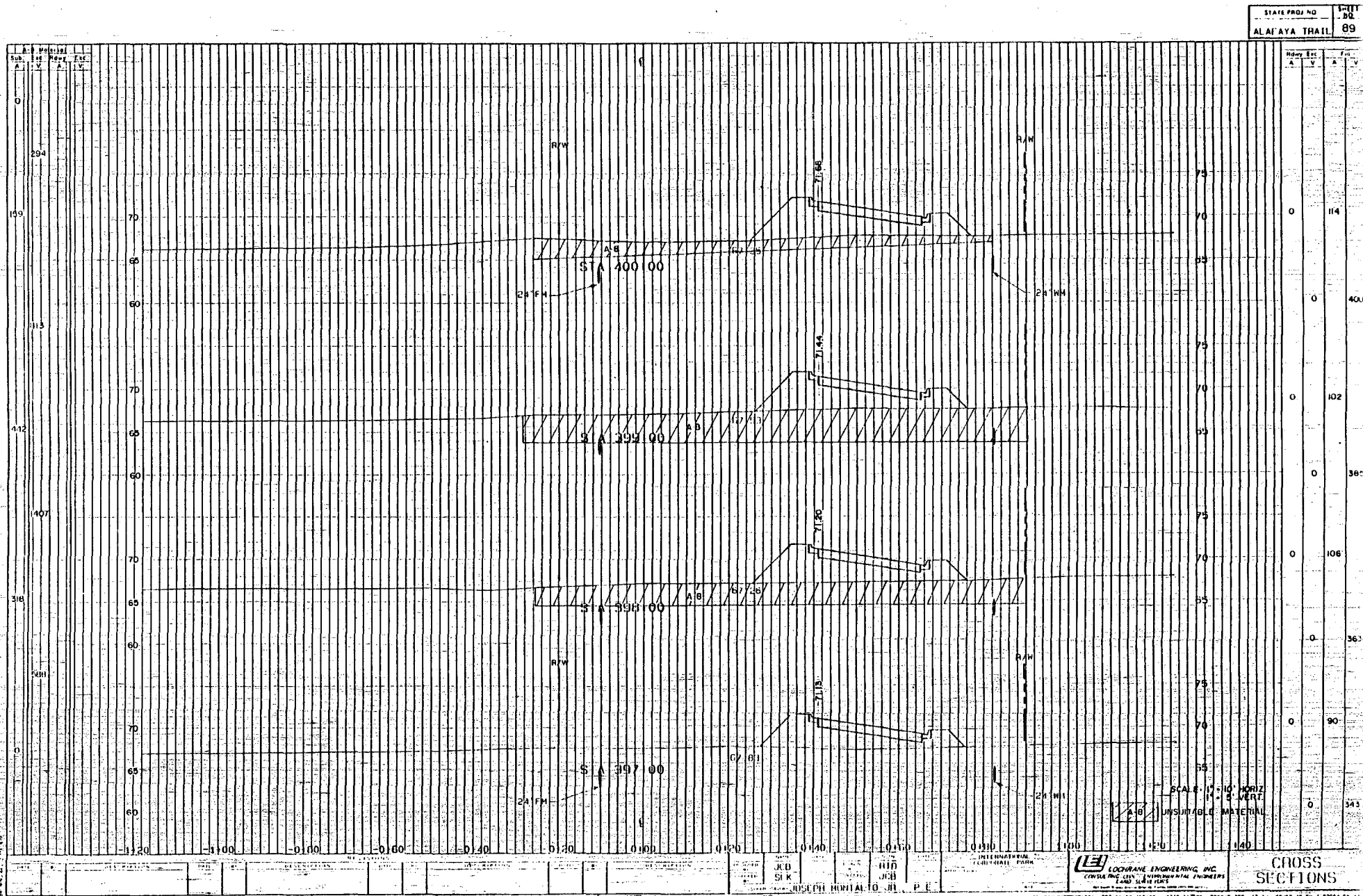
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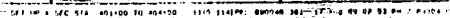
STATE PROJ NO
ALAFAYA TRAIL
88

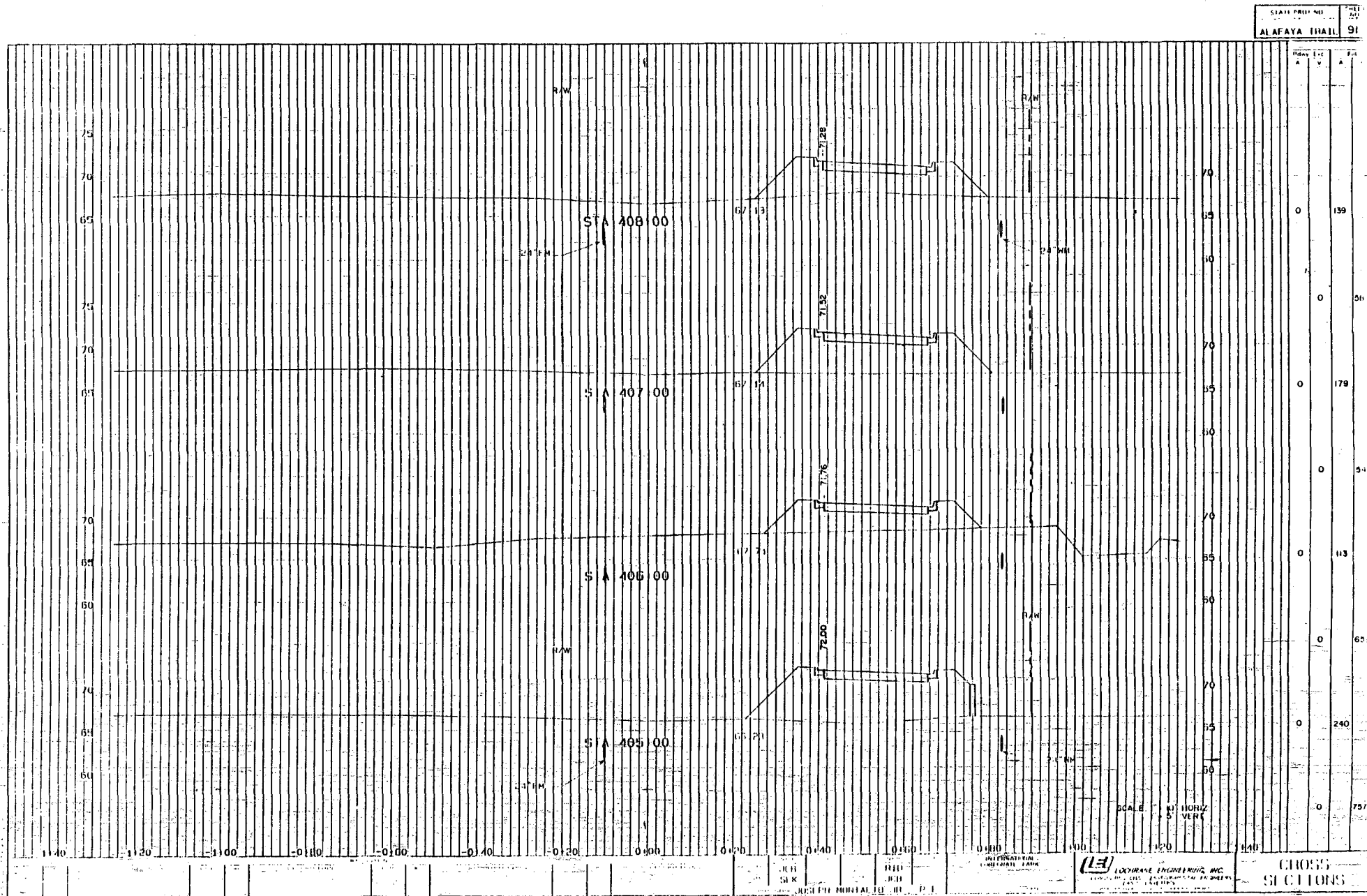


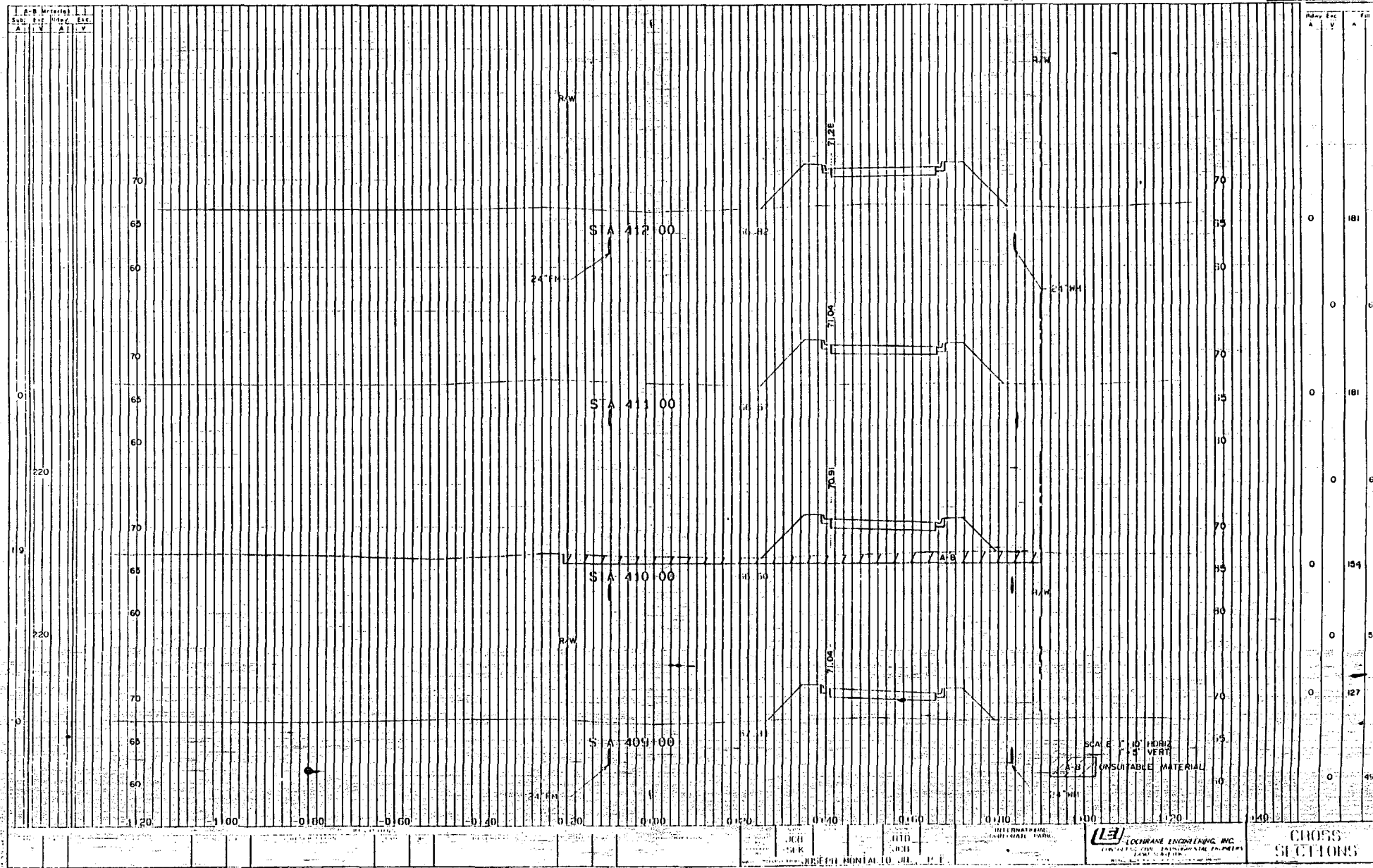
CROSS
SECTIONS

LOCHANE ENGINEERING, INC.
CIVIL ENGINEERS
1115 N. 11TH ST.
TAMPA, FL 33604



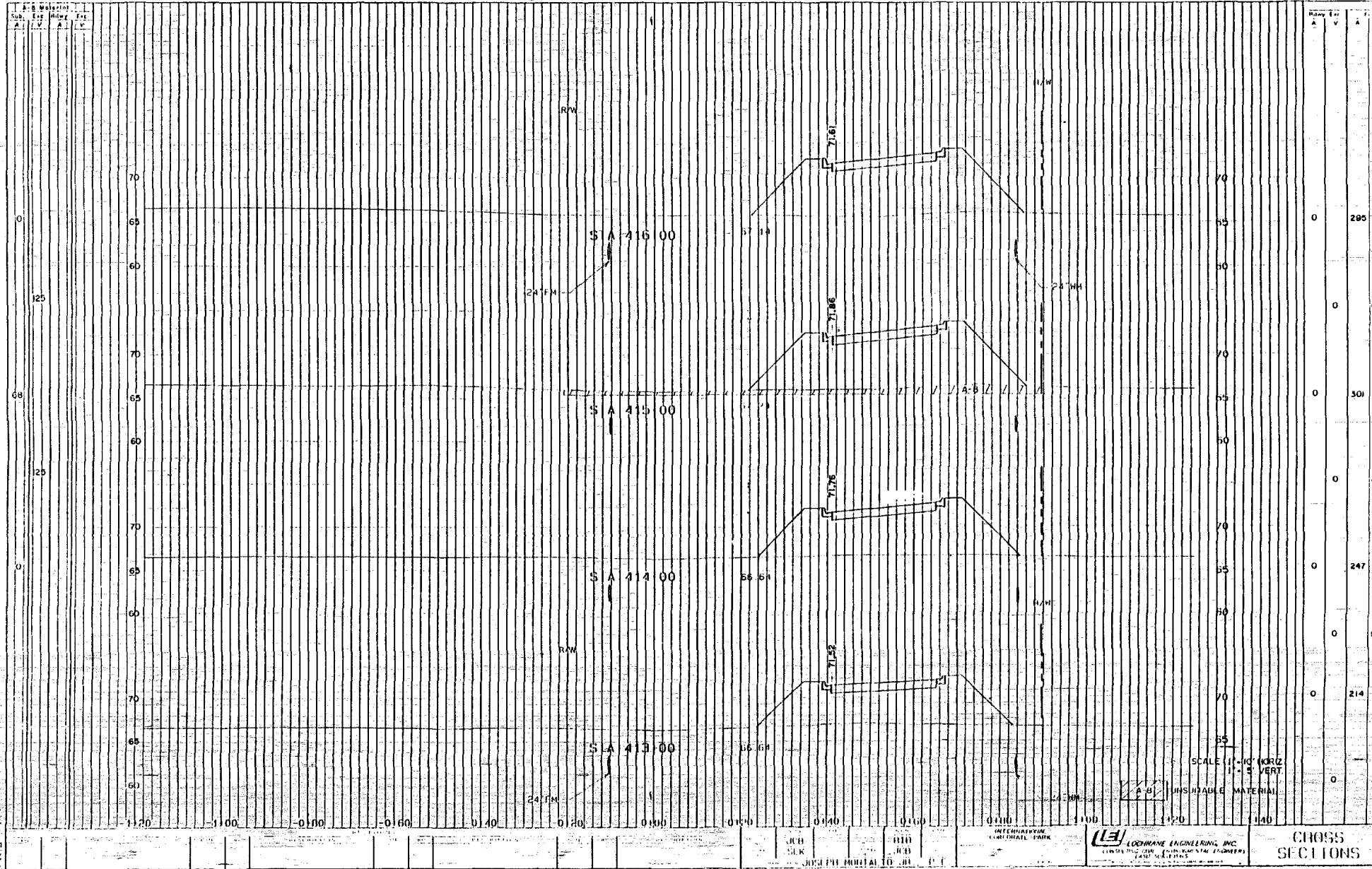


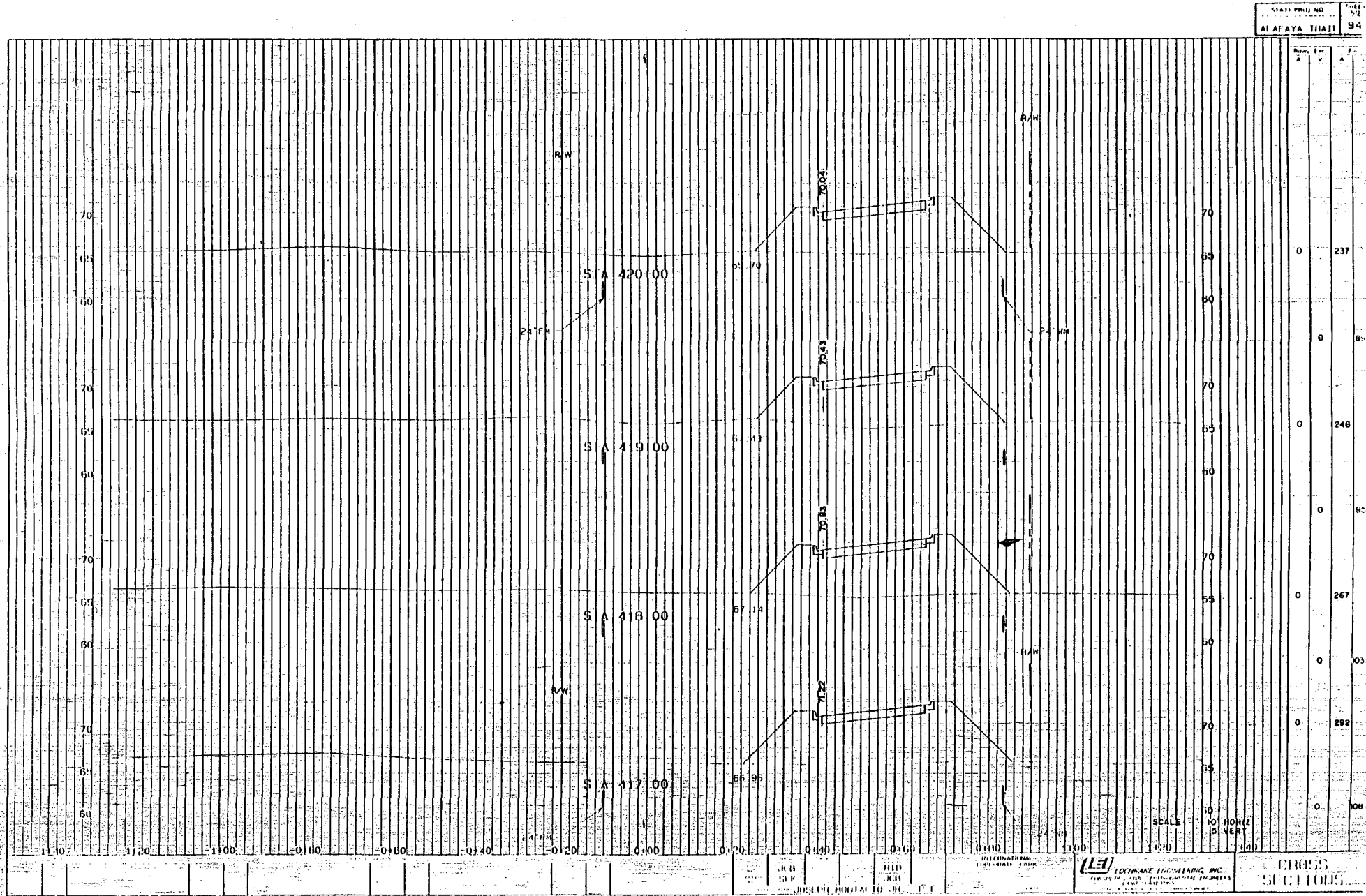




CROSS
SECTIONS

STATE PROJ. NO.
ALAFAYA TRAIL S





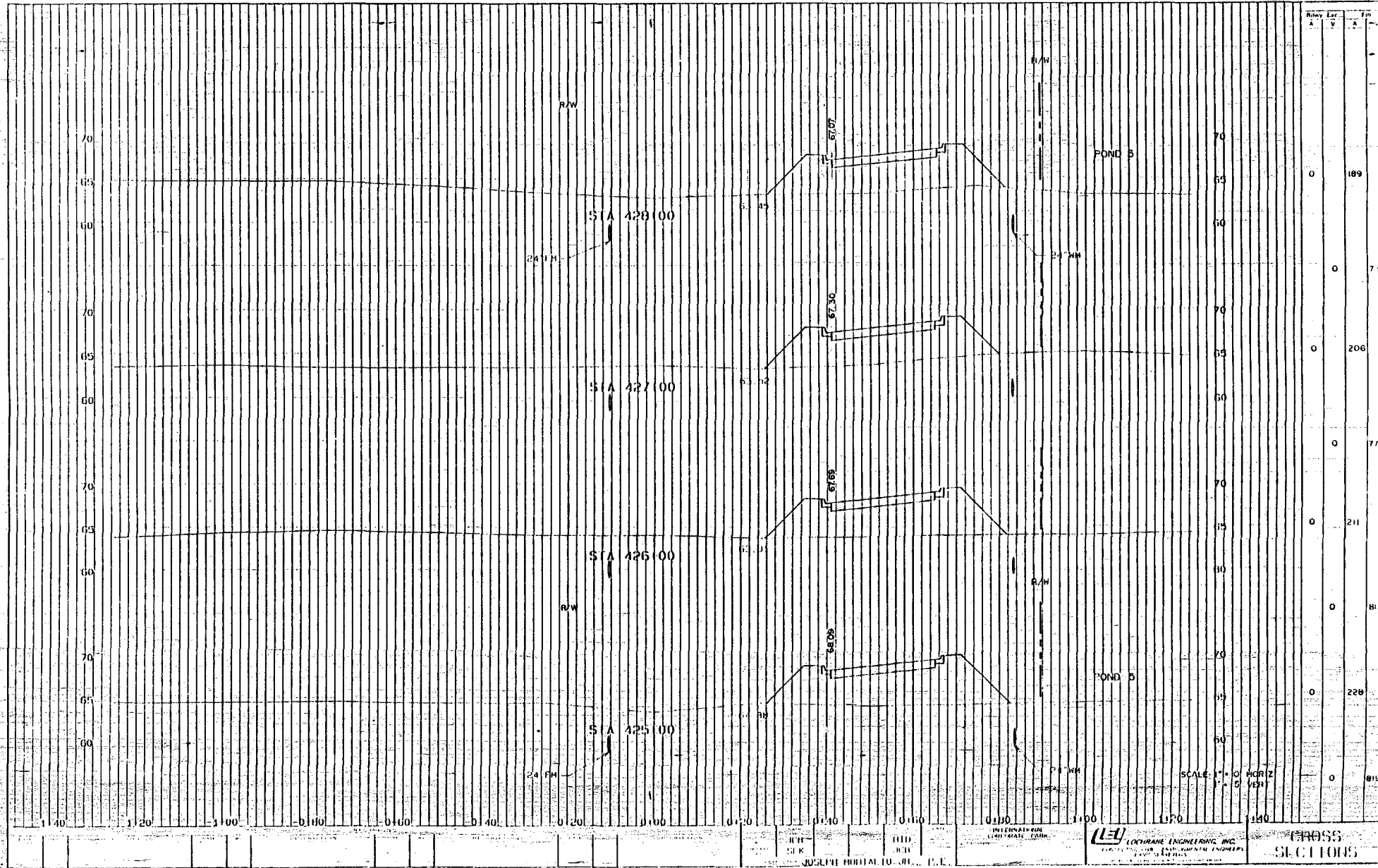
STATE PROJ NO
ALAFAYA TRAIL

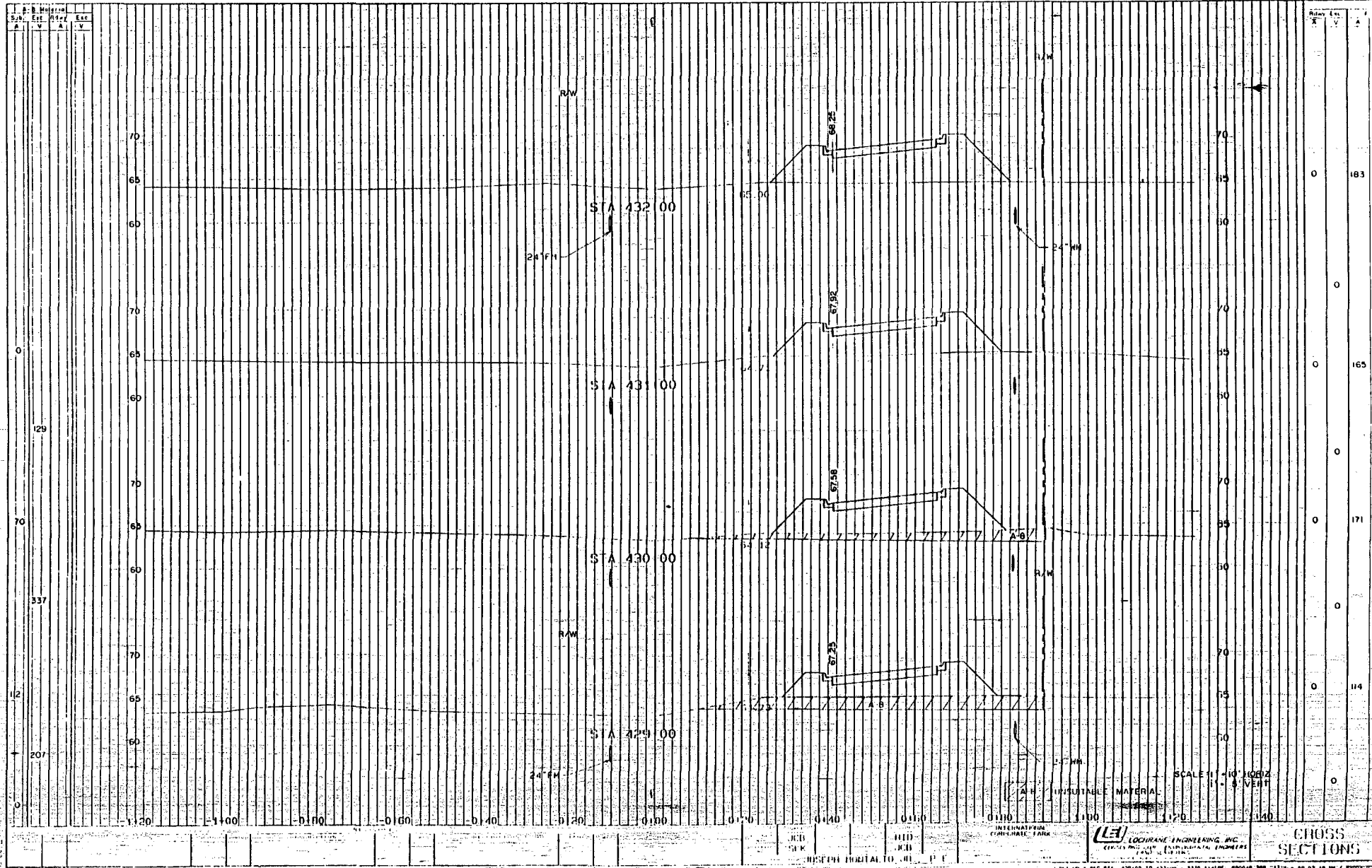


SCALE 1" = 10' HORIZ
1" = 5' VERT

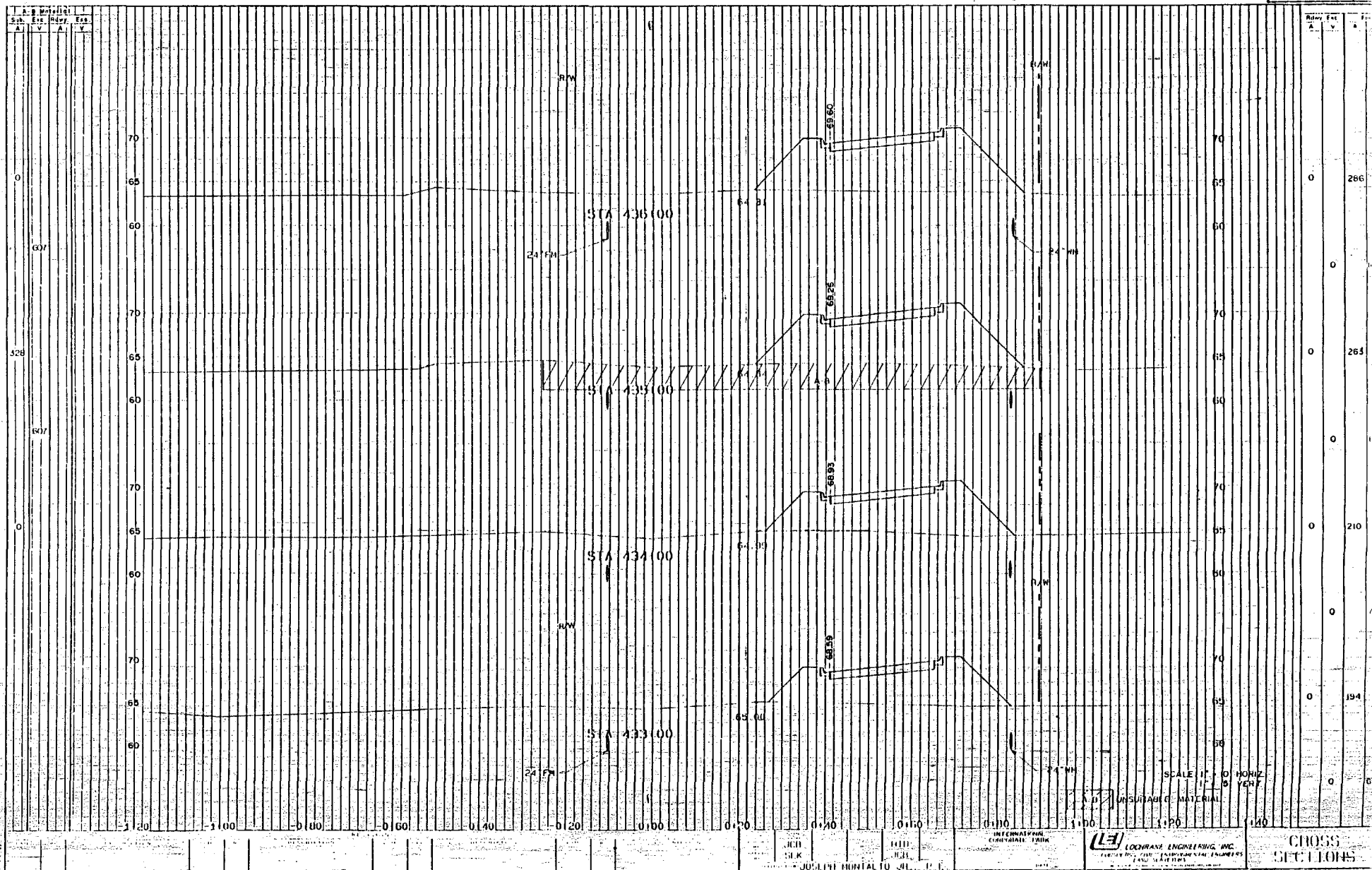
LOHMEYER ENGINEERING, INC.
CONSULTING ENGINEERS
1000 N. 10TH AVE., SUITE 100
DENVER, CO 80202

CROSS
SECTIONS



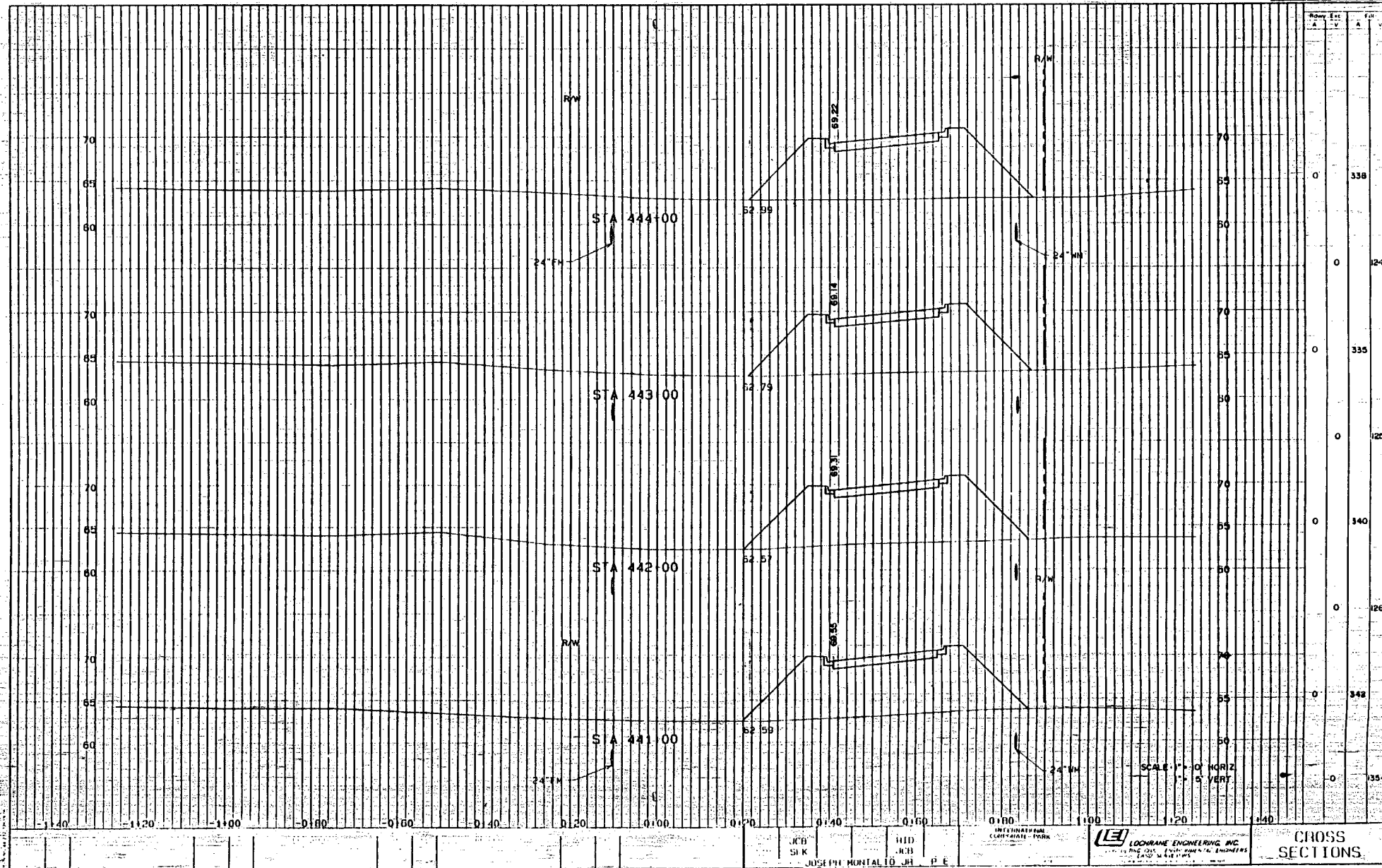


STATE PROJ NO
ALAFAYA TRAIL 91





STATE PROJ. NO. ALAFAYA TRAIL
SHEET NO. 100



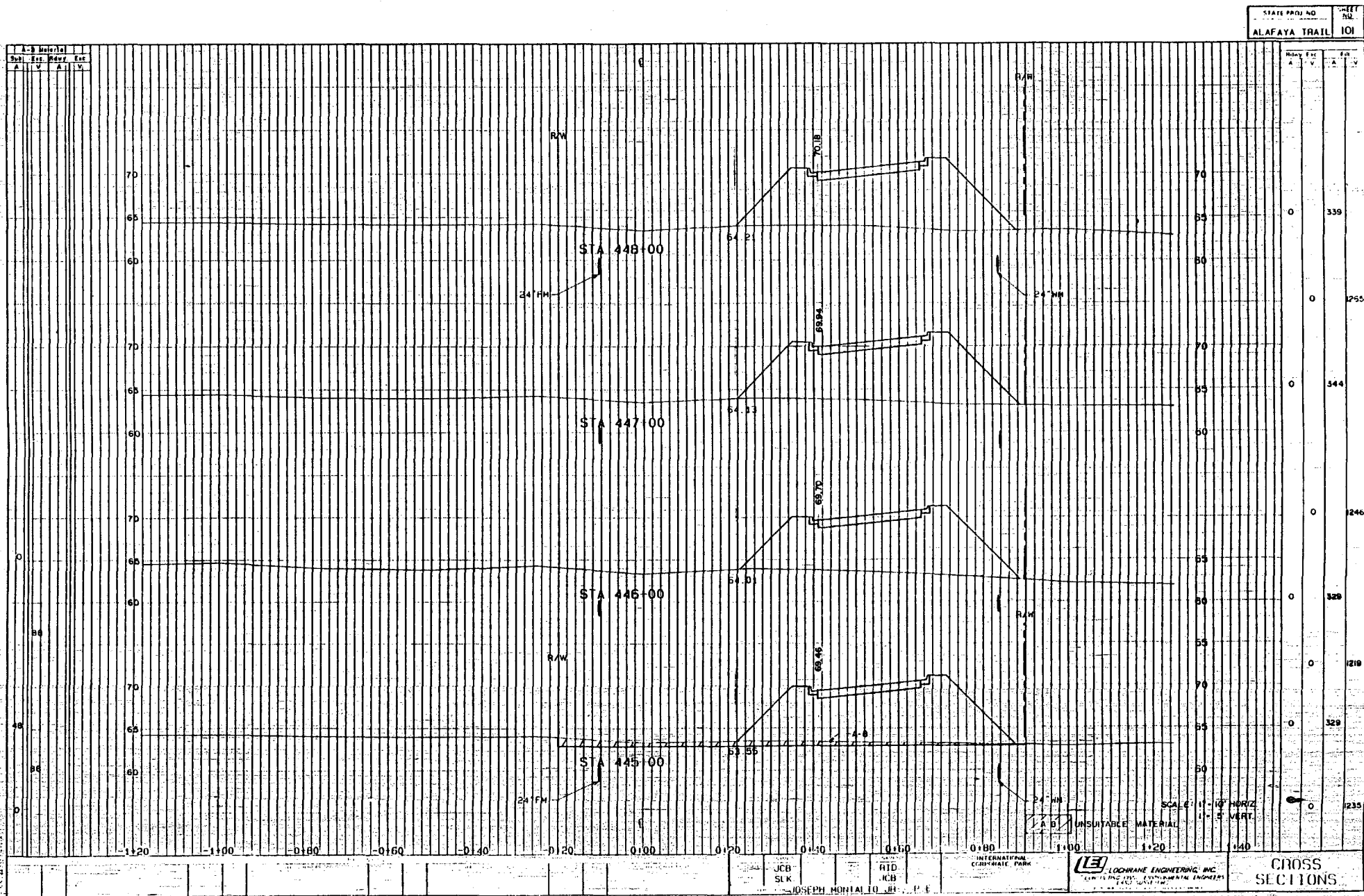
JCB
SJK
HID
JCB
JOSEPH MONTALTO JR. P.E.

INTERNATIONAL
CORPORATE - FORM

LOCHANE ENGINEERING, INC.
1000 RING RD. S.W.
ALBUQUERQUE, NM 87102
(505) 263-1111

CROSS
SECTIONS.

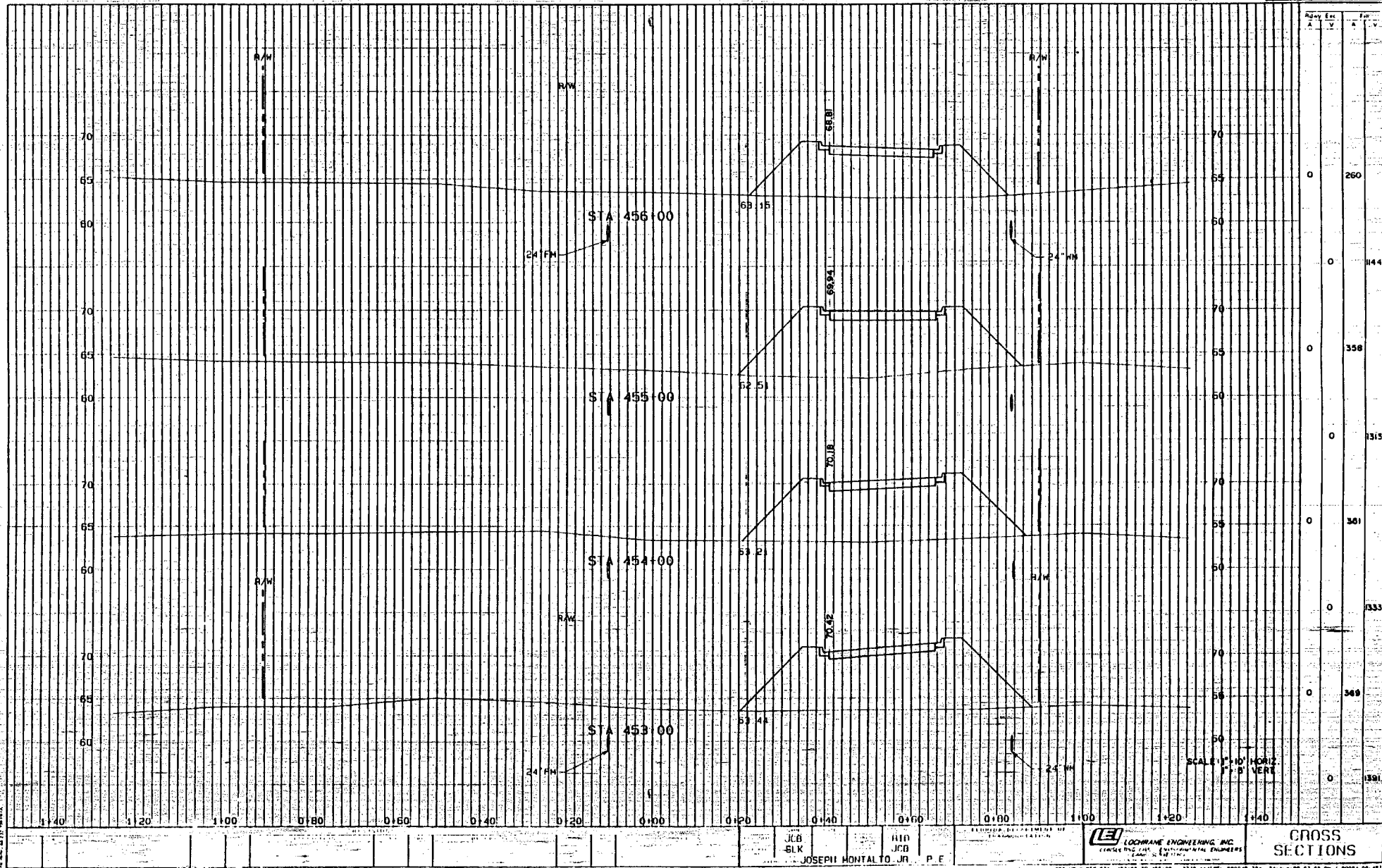
SET-UP: SEC STA: 441+00 TO 444+00 - 3710 11/15/97 890048 291: 17.4: 09 03 20 PM / 890048 00-41



STATE PROJ NO. 102
ALAFAYA TRAIL



STATE PROJ. NO. 1-111
ALAFAYA TRAIL 103



STATE PROJ NO. 104
ALAFAYA TRAIL

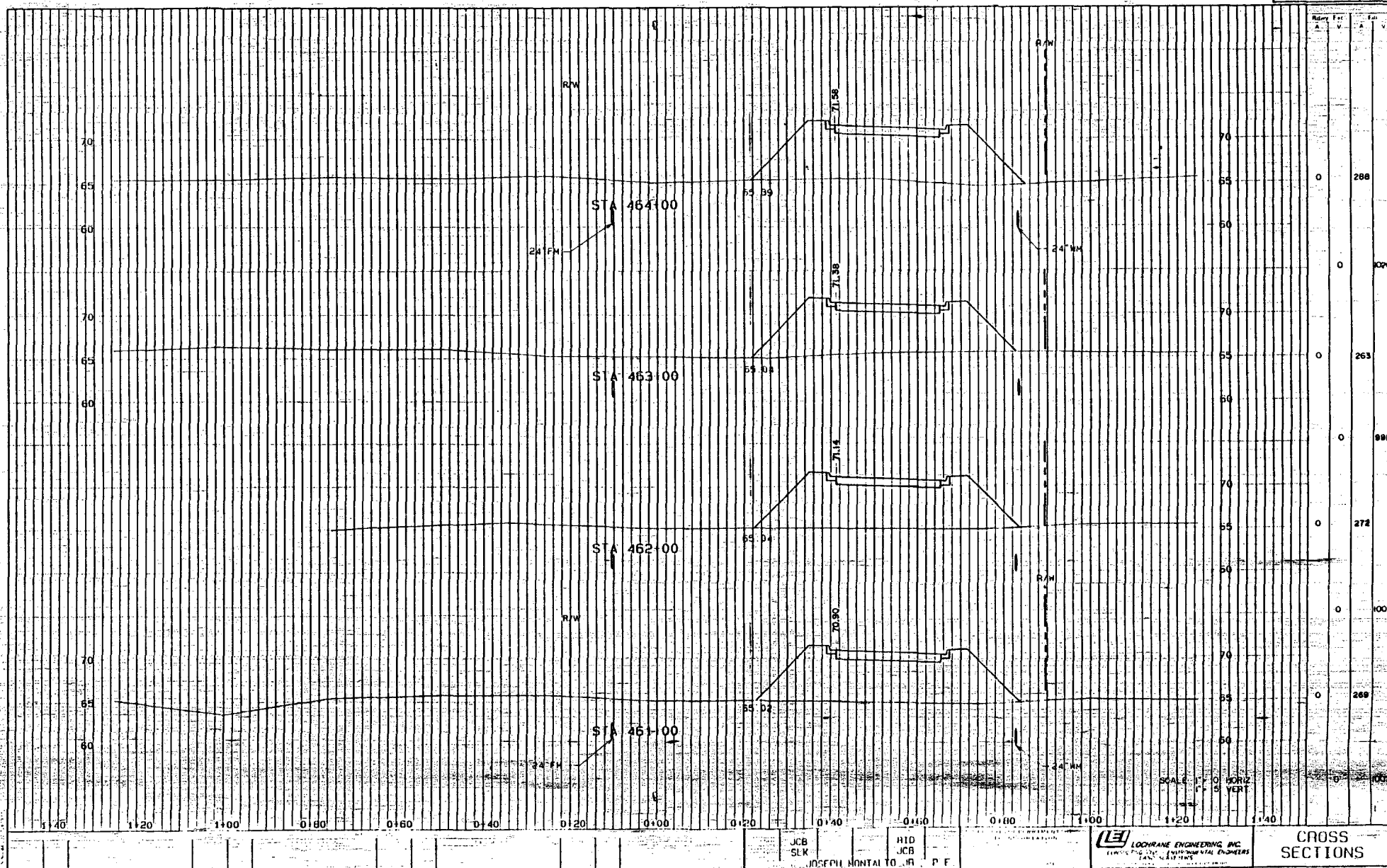


CROSS SECTIONS

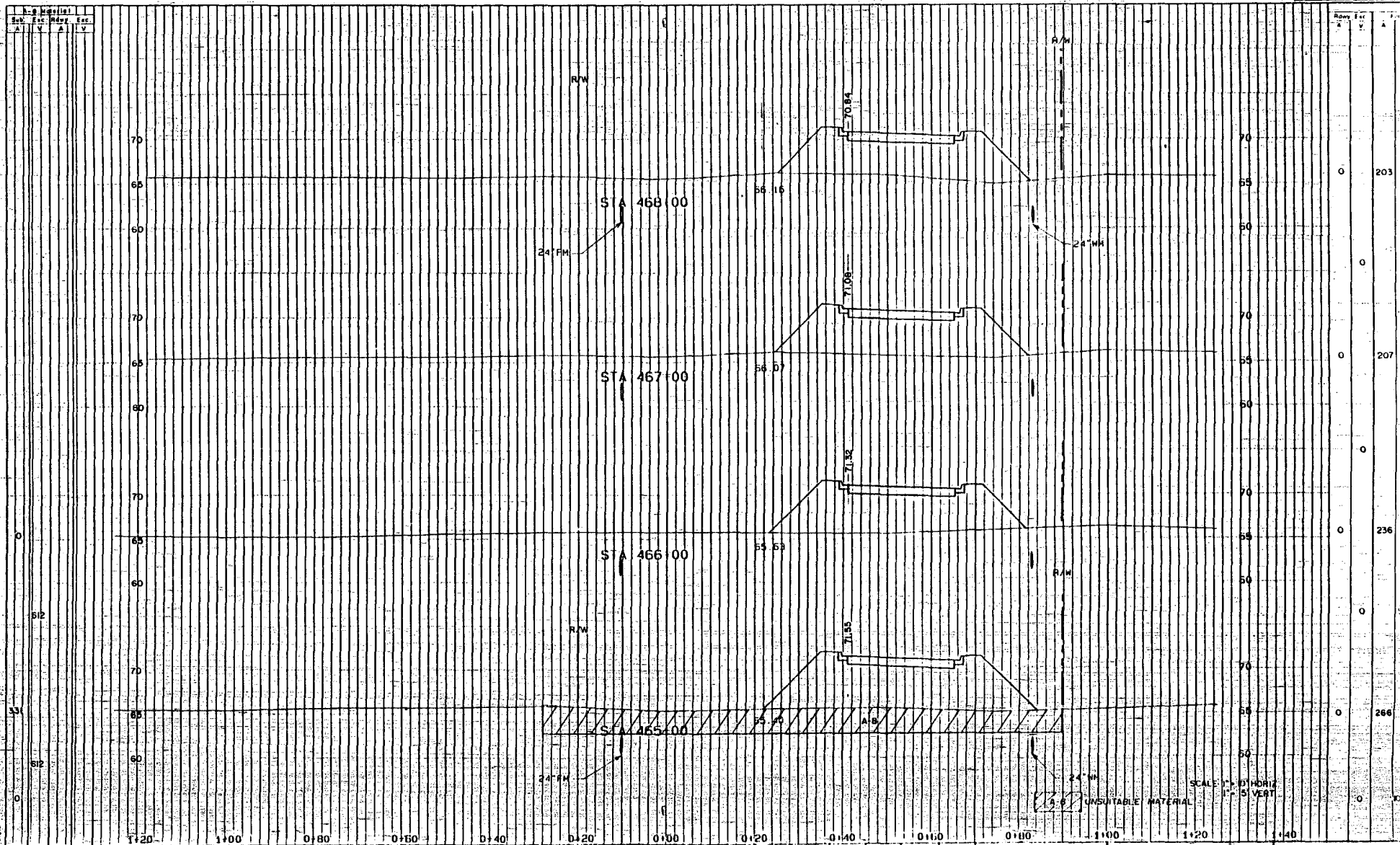
LOCHRANE ENGINEERING, INC.
PROJECT: ALAFAYA TRAIL
11/10/00

JOSEPH MORTAL TO JR. P. E.

STATE PROJECT NO. ALAFAYA TRAIL 105
SHEET NO. 105



CLASSIFIED BY
ALAFAYA TRAIL 10



SCALE 1" = 10' HORIZ
1" = 5' VERT

UNSATURABLE MATERIAL

CROSS
SECTIONS

JCB
SLK

R10
ICR

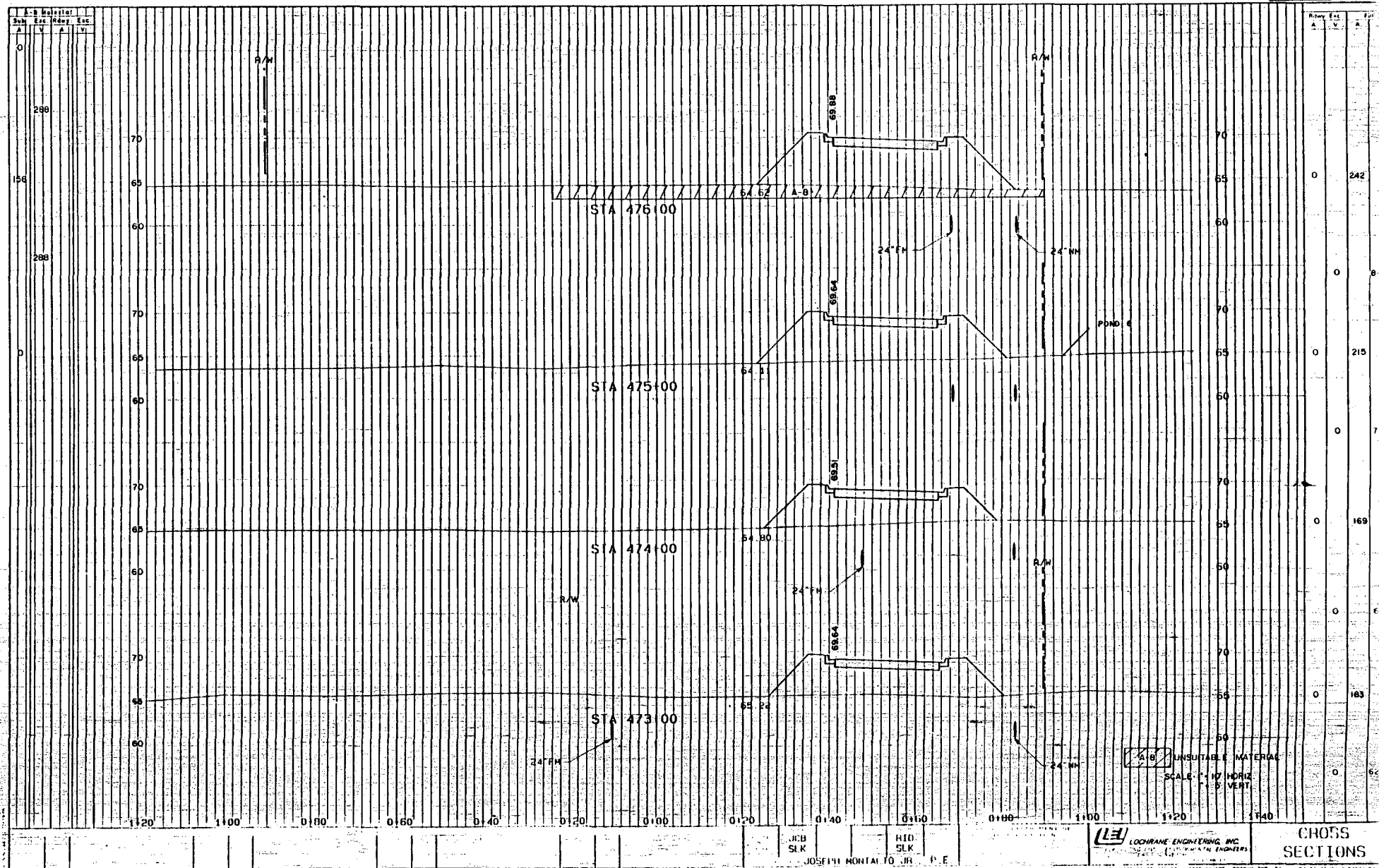
JOSEPH MONTA TO JH P E

LOCHANE ENGINEERING, INC.
1000 S. 10TH AVE., SUITE 100
TAMPA, FL 33606

24 AUG 2007 10:00 AM

STATE PROJ NO: 107
ALAFAYA TRAIL





STATE PROJ. NO. 109
ALAFAYA TRAIL



STATE PROJECT NO. 110
ALAFAYA TRAIL



JCB
SLK
HID
JCB
JOSEPH MONTALTO JR. P.E.

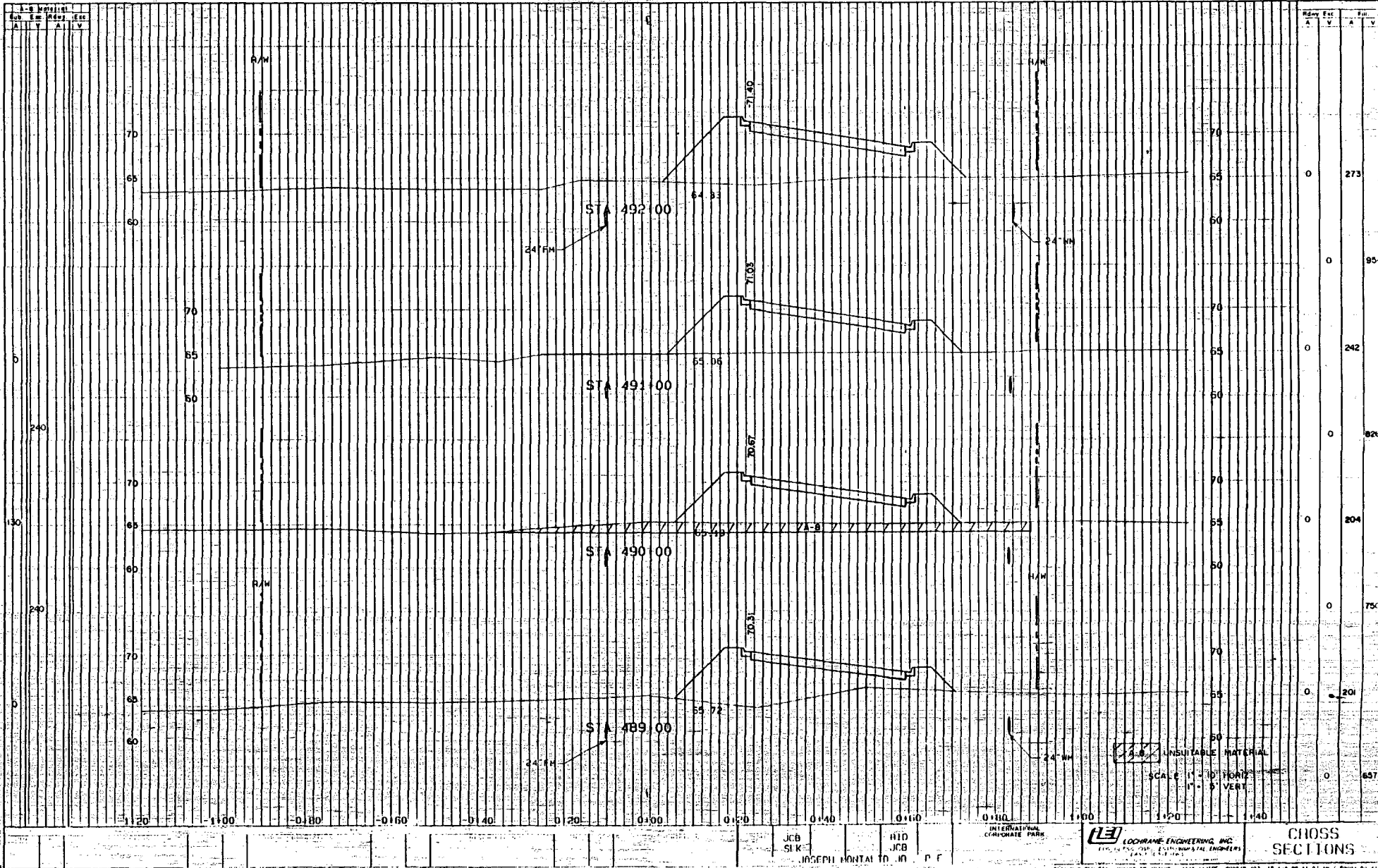
LOOMANE ENGINEERING, INC.
A DIVISION OF ENVIRONMENTAL PARTNERS
INCORPORATED

GROSS
SECTIONS

421 10' x 1/2" DIA. 481100 TO 484100 - 3310 114100 890000 401 24'-6" H3 02 05 PM 11/07/04 04 11

STATE PROJ. NO. 30
ALAFAYA TRAIL III





CHROSS
SECTIONS

LOCHANE ENGINEERING, INC.
10000 100th Ave. N. #100
Plymouth, MN 55442

INTERNATIONAL
CORPORATE PARK

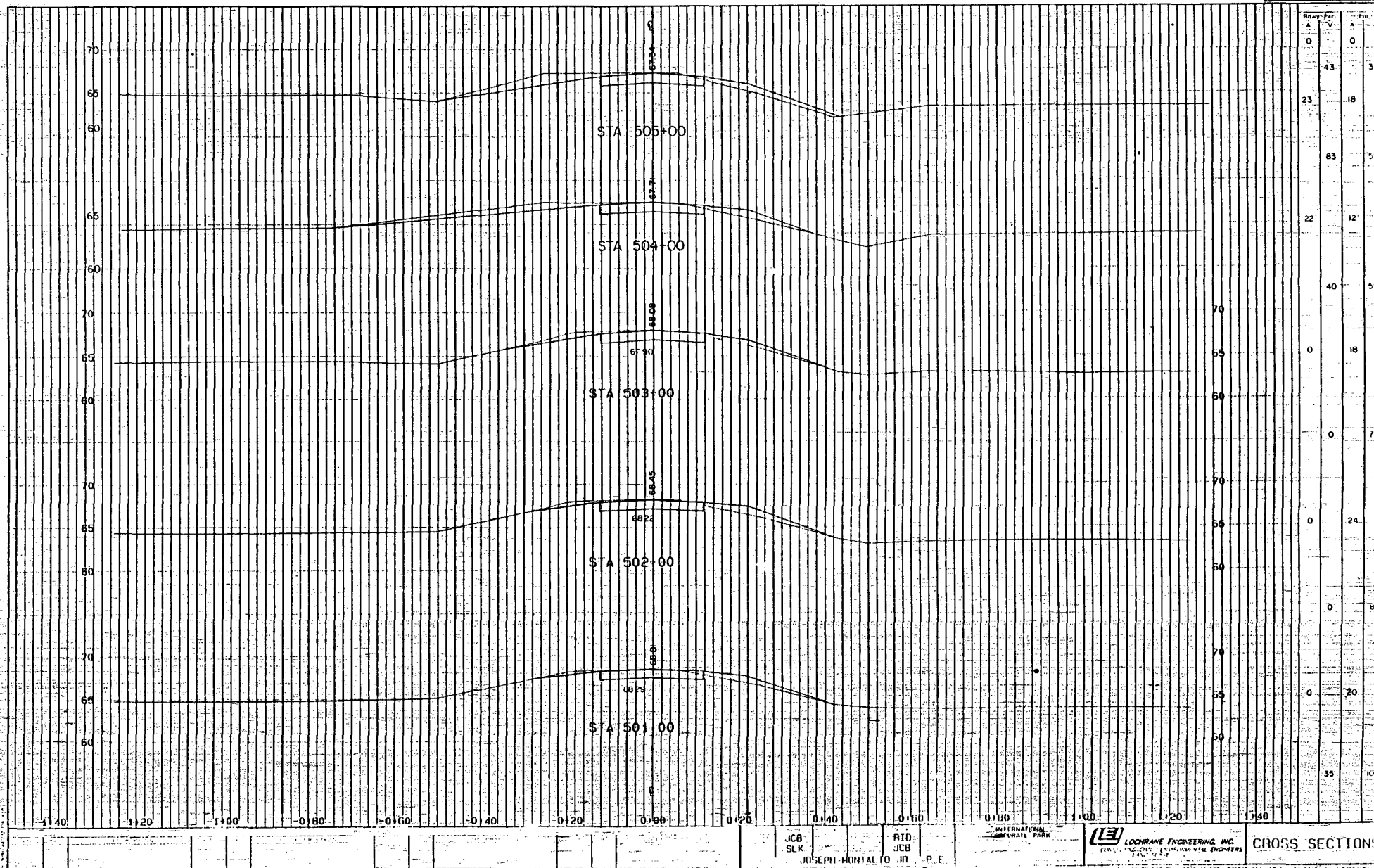
JCB
SLK
JCB
JCB
JOSEPH MONTA TO IN P F



STATE PROJ. NO. 114
ALAFAYA TRAIL



STATE PROJECT NO. 115
ALAFAYA TRAIL



JCB

SLK

RTD

JCB

P. E.

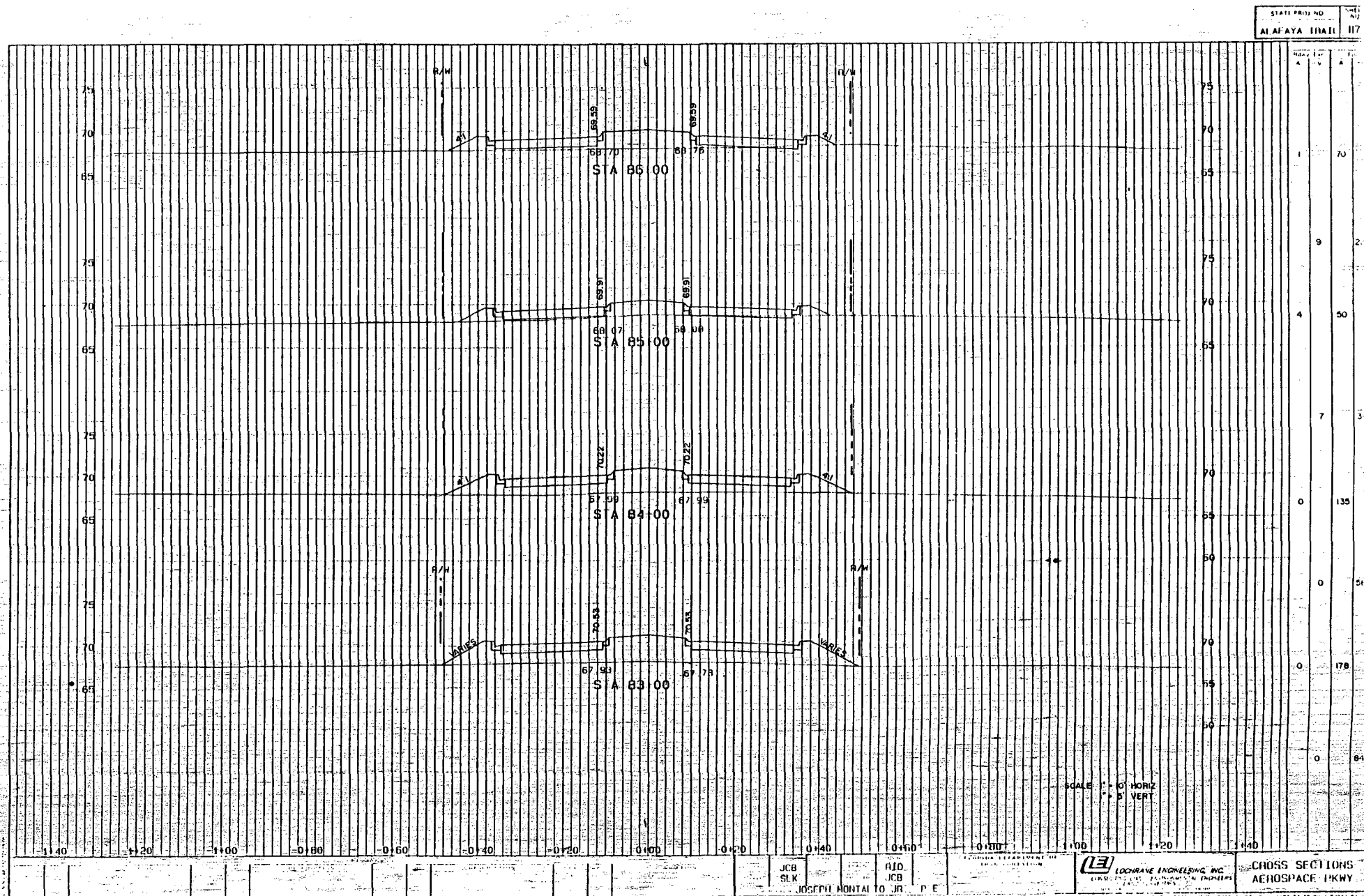
INTERNATIONAL
CONCRETE PARK



LOCHRANE ENGINEERING, INC.
CONSULTING ENGINEERS
1405 N. 17th St., Suite 100
Tampa, FL 33606

CROSS SECTION

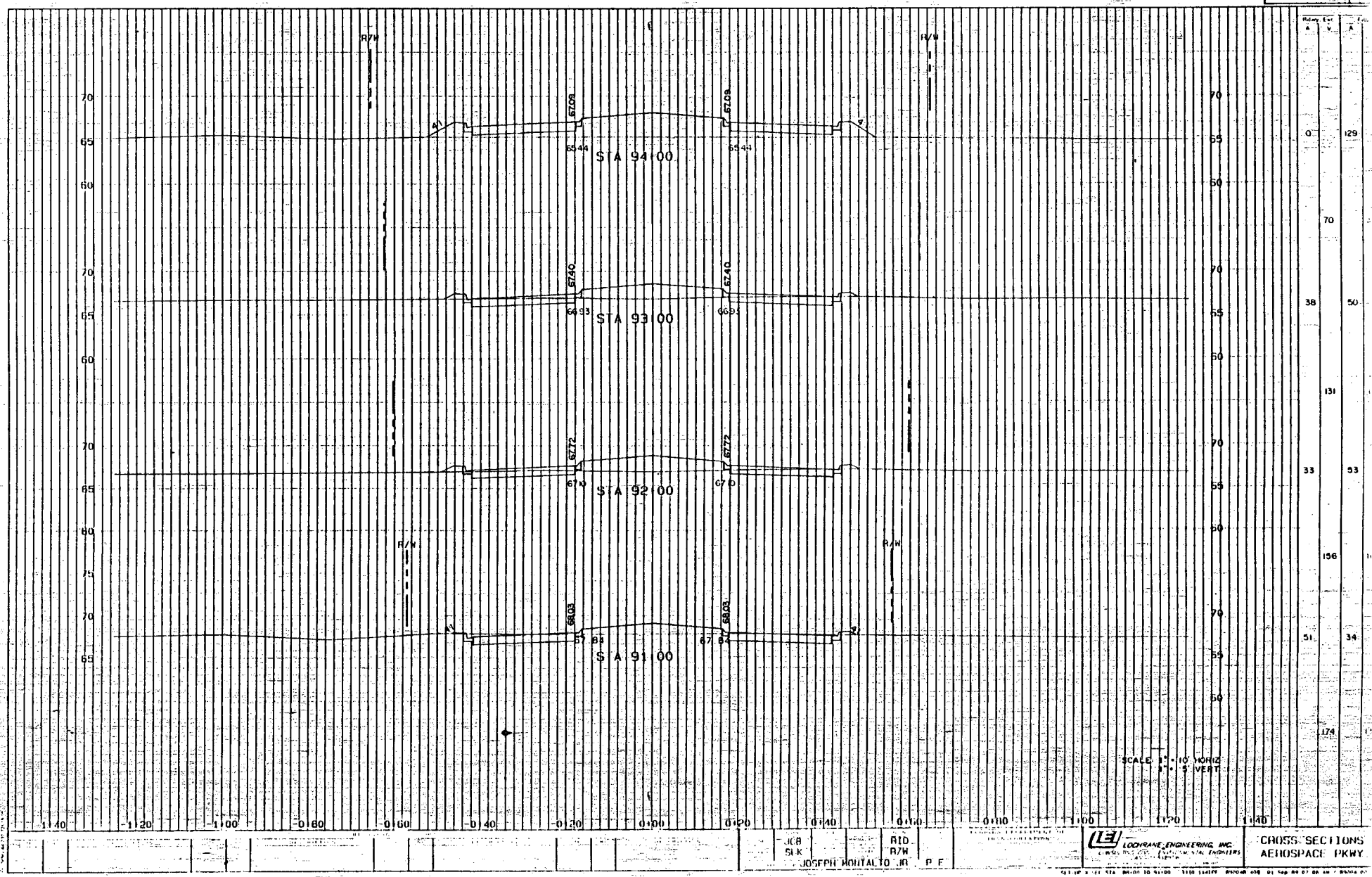




STATE PROJ NO
ALAFAYA TRAIL



STATE PROJECT NO. 11111
ALACAYA IIIA II



CROSS SECTIONS
AEROSPACE PKWY

LOOMIS ENGINEERING, INC.
CIVIL ENGINEERS

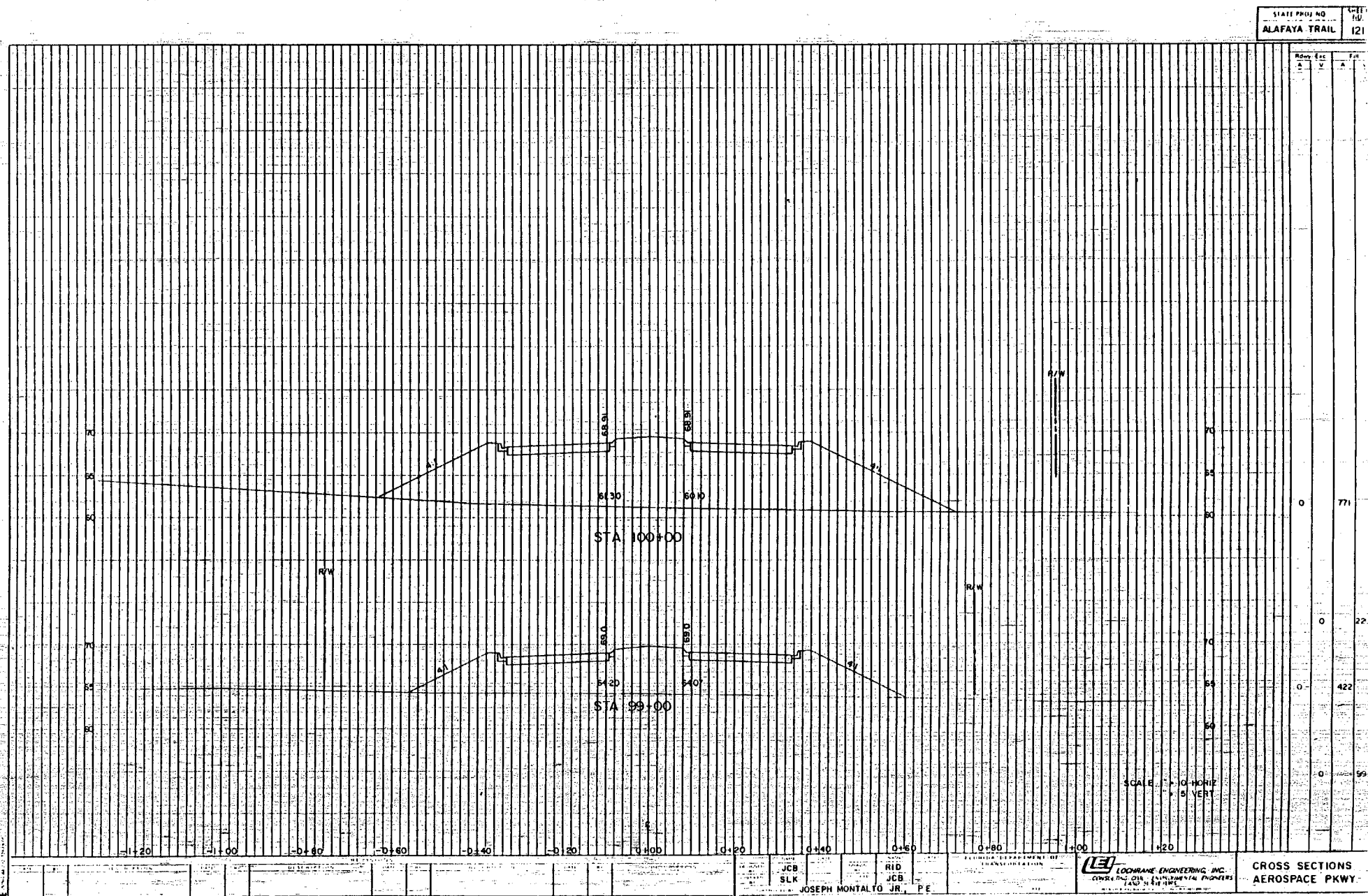
JCB
SJK
RJD
R/W
JOSEPH MONTALTO, JR.
P.E.

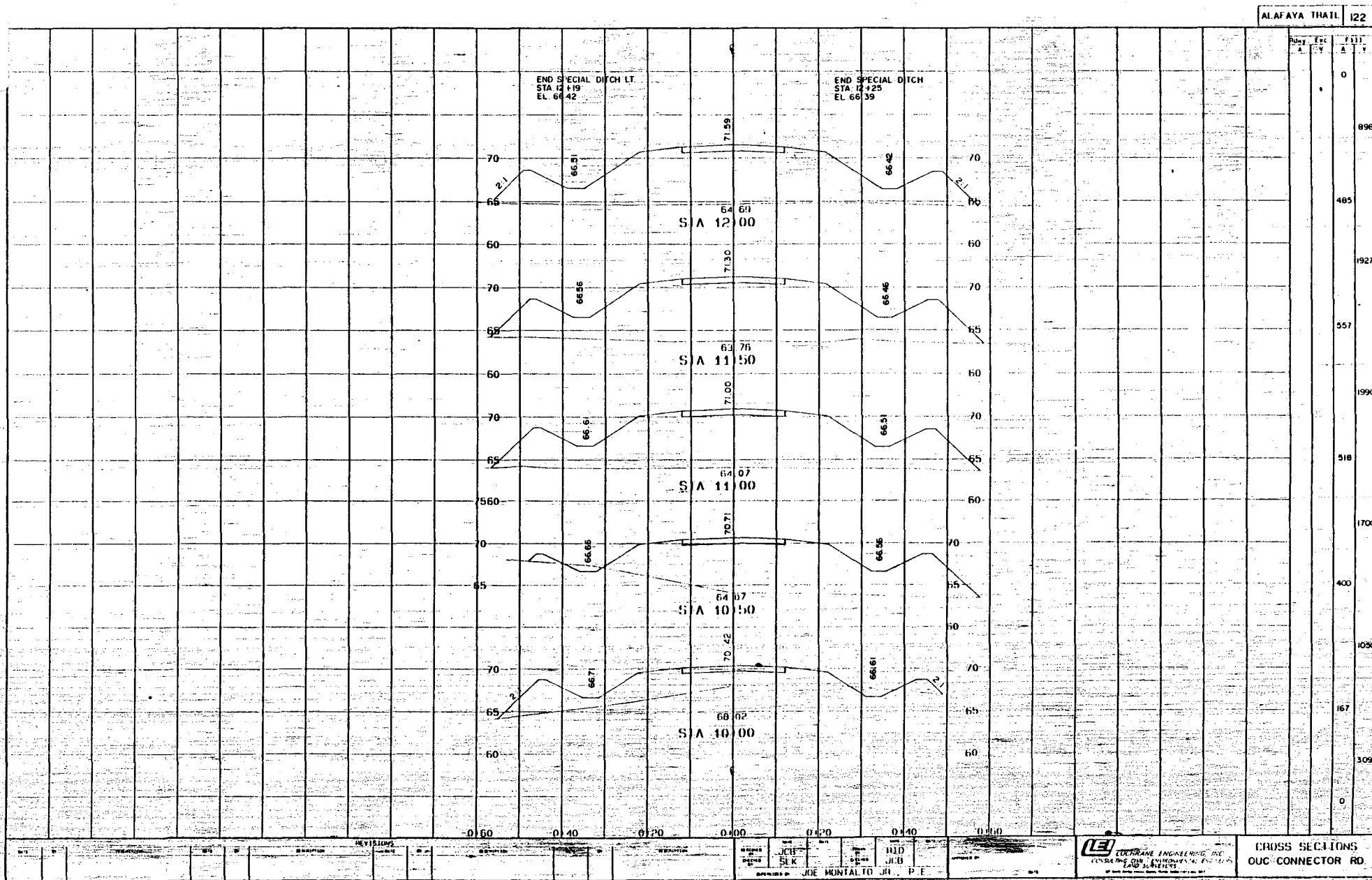
STATE PROJ. NO. 120
ALAFAYA TRAIL



LOONRAN ENGINEERING, INC.
(ENGINEERING AND ARCHITECTURAL ENGINEERS)
1400 S. 10TH AVE., SUITE 100
TAMPA, FL 33606
TEL: 813-281-1111 FAX: 813-281-1112

CROSS SECTIONS
AEROSPACE PKWY





SIGNING & PAVEMENT MARKING GENERAL NOTES

NOTE: ONLY THE CIRCLED NOTES PERTAIN TO THIS JOB.

1. Mileposts are Department of Transportation straightline mileposts.
2. 100' of double yellow centerline is to be placed on sidestreets or as shown on sidestreet tab sheet.
3. Reflective pavement markers are not to be placed on sidestreet centerlines.
4. Some brooming may be required for installation of sidestreet stopbars. Brooming shall be incidental to the Item 711-6-241.
5. All ground mounted STOP, YIELD, WRONG WAY, DO NOT ENTER, sign faces shall be fabricated entirely with Type "B" reflective sheeting.
6. All signs to be removed are to be stockpiled on the job site in a workman like manner for removal by Department of Transportation forces.
7. Stopbars shall be replaced in the same location for proper signal operation unless otherwise noted on the signal plans.
8. The contractor shall establish No Passing Zones in accordance with Section 5-7.4 of the Standard Specifications and Section 3B-3 and 3B-5 of the 1978 MUTCD. The contractor's proposed method of establishing no passing zones shall be approved by the engineer.
9. RPM's shall be placed on all turn lane lines as shown below.
10. All pavement markings are to be thermoplastic, unless otherwise noted on the plans.
11. All pavement markings are to be paint, unless otherwise noted on the plans.
12. For signing and striping details, refer to the Manual on Uniform Traffic Control Devices, published by U.S. Department of Transportation, Federal Highway Administration.
13. Item no. 711-2, Skip Traffic Stripe, Thermoplastic (LF) refers to LF of 10'-30' skip and LF of 6'-10' skip stripe.
14. Item no. 711-2, is for 6'-10' skip traffic stripe.
15. "Parking Lane Lines shall be broken at driveways."
16. On-street parking is to be placed according to Index No. 17346 of the latest design standards.
17. Existing pavement markings and messages to be noted and replaced by the contractor unless otherwise specified in the plans or latest design standards. The cost of this work is to be paid for under the appropriate pavement marking pay item.
18. Pavement marking shall be included on all bridges within the specified job limits.
19. Existing reflective pavement markers on concrete bridges within the project limits are to be removed and replaced.
20. School crosswalk is to be marked in accordance with Special Emphasis Crosswalk, Standard Index No. 17346, drawing 7 of 7.
21. Beginning station equals beginning milepost.
22. All ground mounted guide signs shall have Type "A" background material with legend of either Type "B" material or reflective button copy.
23. All overhead guide signs shall have either Type "A" background material or porcelain enamel background material. Legends shall be either Type "B" material or reflective button copy.
24. Independently mounted interstate shields or route shields shall be of Type "A" material.
25. The back of all finished panels shall be stenciled with the date of fabrication, fabricator's initials and the name of the sheeting at the bottom edge in 3 inch letters.
26. Caution should be exercised while relocating existing signs to prevent unnecessary damage to signs. If the signs are damaged beyond use, as determined by the engineer, signs shall be replaced by the contractor at his expense.

TYPICAL RPM PLACEMENT FOR LANE LINES
AT SIGNALIZED INTERSECTIONS



TYPICAL RPM PLACEMENT FOR LANE LINES
AT NON-SIGNALIZED INTERSECTIONS



DATE	BY	REVISION	DATE	BY	REVISION	DATE	BY	REVISION	DATE	BY	REVISION

DESIGNED BY	NAME	DATE	DRAWN BY	NAME	DATE
CHECKED BY			APPROVED BY		

APPROVED BY	NAME	DATE

 LOCHRANE ENGINEERING, INC. CONSULTING CIVIL ENGINEERS 2000 STATE ST.
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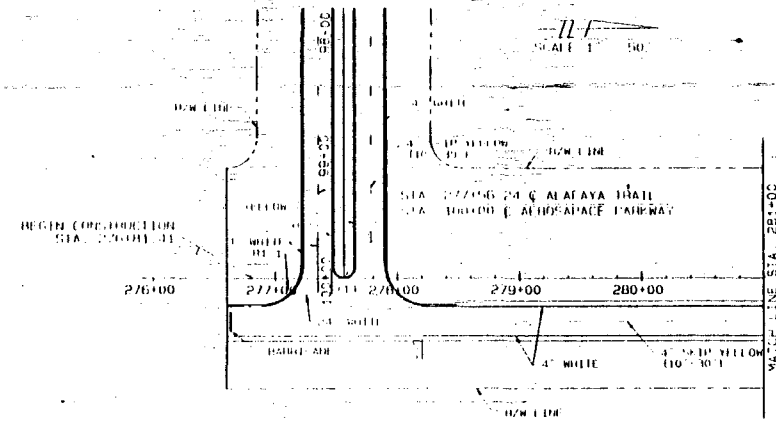
SIGNING AND PAVEMENT MARKING
GENERAL NOTES

TABULATION OF QUANTITIES

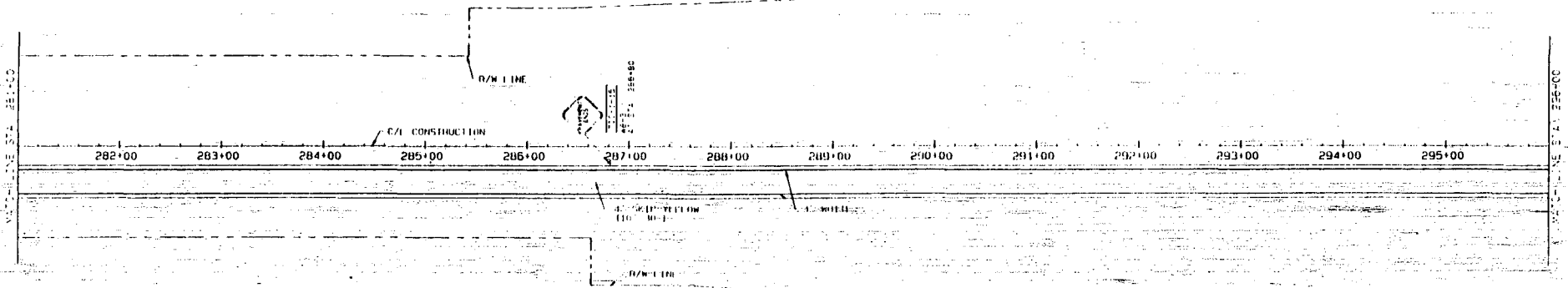
[illegible]

Image Quality

As you review the next group of images, Please note that the original documents were of poor quality.



SCALE 1" = 50'



REVISIONS									
NO.	DATE	DESCRIPTION	BY	CHKD.	DATE	DESCRIPTION	BY	CHKD.	DATE

CHANCE COUNTY PUBLIC WORKS DEPARTMENT

DATE: 11/11/11

BY: [Signature]

CHCKD: [Signature]

DATE: 11/11/11

BY: [Signature]

CHCKD: [Signature]

LE LECHE ENGINEERING, INC.

1000 LINDSEY DRIVE, SUITE 100

ALBUQUERQUE, NM 87102

TEL: 505.263.1111

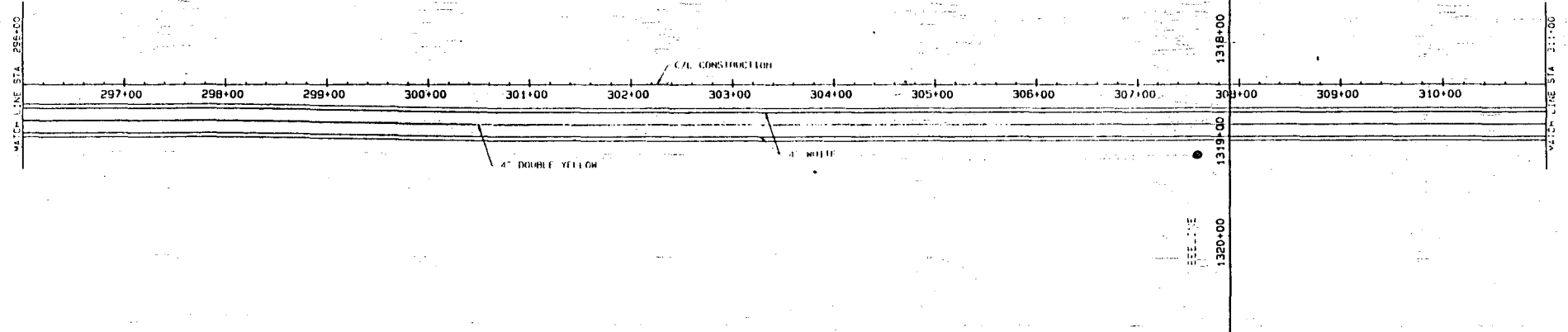
FAX: 505.263.1112

WWW.LECHEENGINEERING.COM

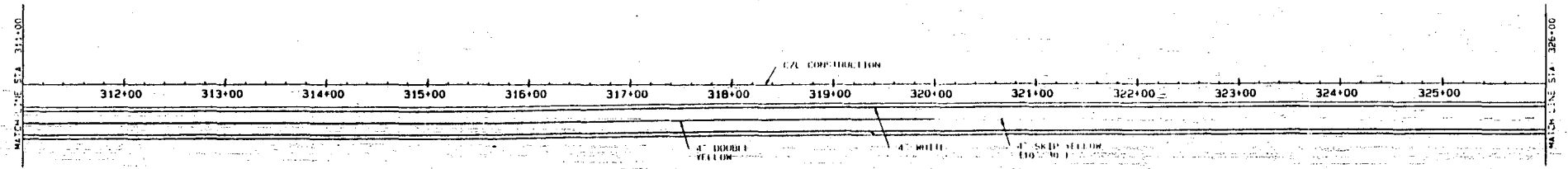
SIGNING & PAVEMENT MARKING

ALAFAYA TRAIL

SCALE 1" = 50'



SCALE 1" = 50'

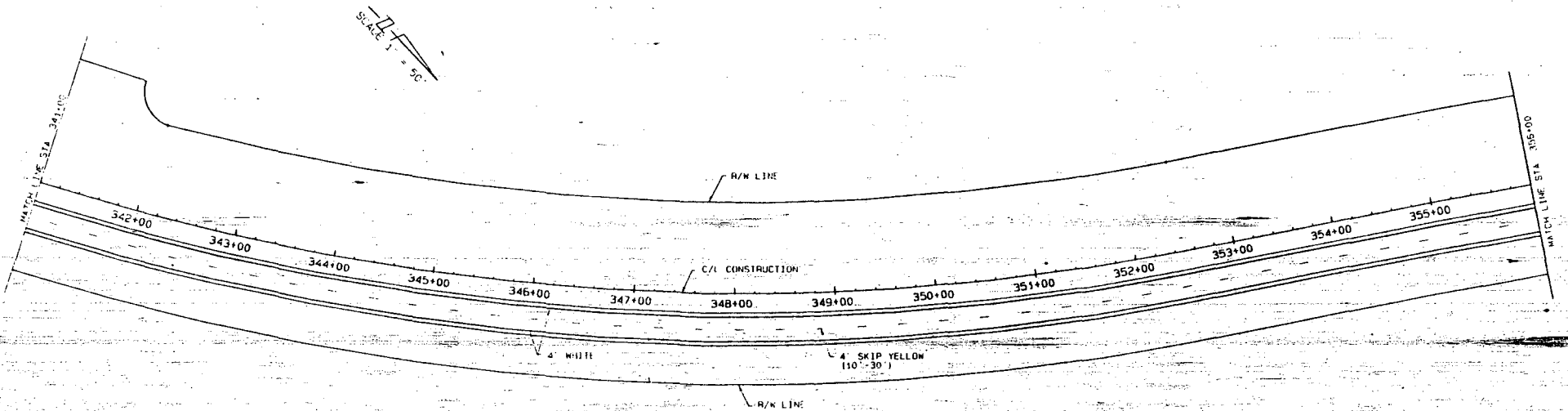
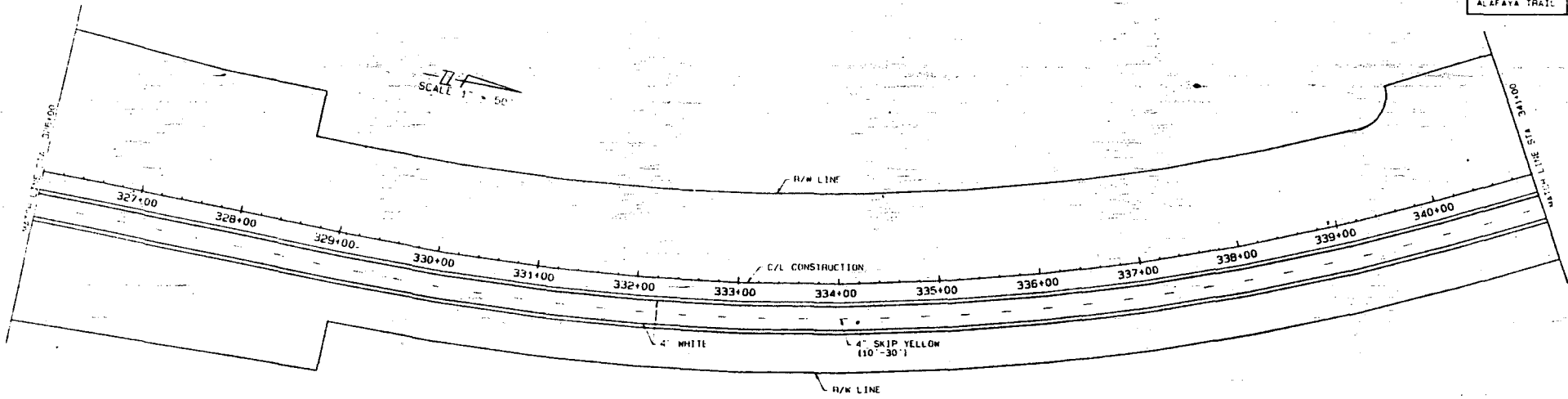


REVISIONS										DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE		DATE			
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LOOHR ENGINEERING, INC.
REGISTERED CIVIL ENGINEERS
1400 STATE ST.
SUITE 200
ALBUQUERQUE, NM 87102
505.263.1111

**SIGNING & PAVEMENT MARKING
ALAFAYA TRAIL**

COUNTY PROJ. NO.	MC
ALAFAYA TRAIL	127



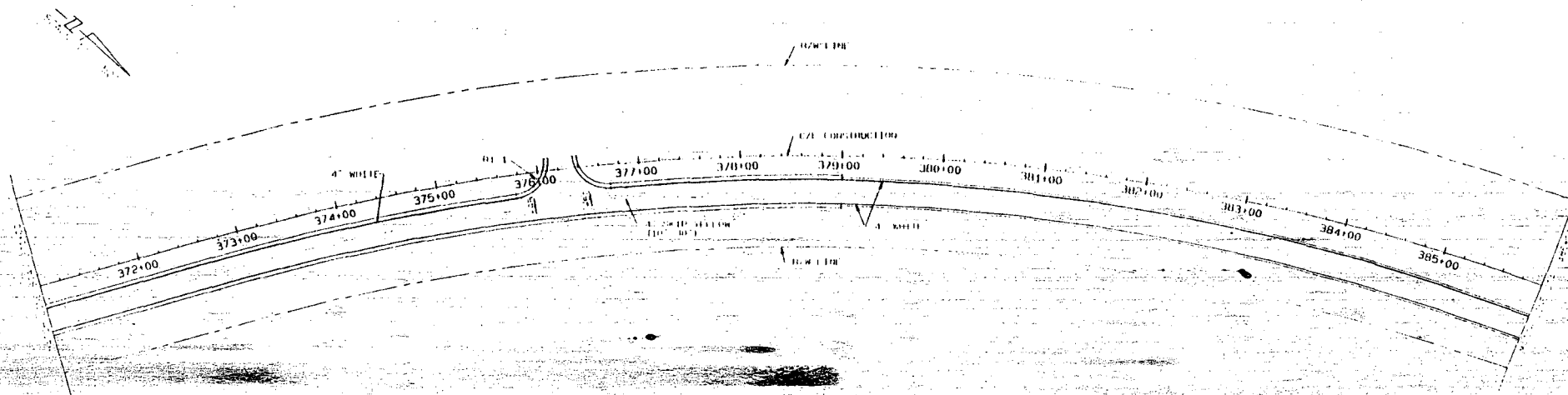
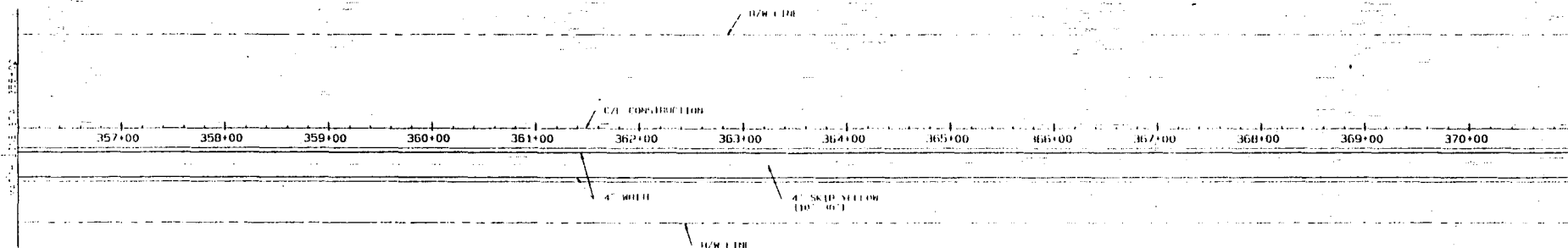
REVISION									
NO.	DATE	DESCRIPTION	BY	CHKD	DATE	DESCRIPTION	BY	CHKD	DATE

ORANGE COUNTY PUBLIC
WORKS DEPARTMENT

LE LOONAN ENGINEERING, INC.
CONSULTING CIVIL ENGINEERS
LAND SURVEYORS
1000 N. GARDEN AVENUE, SUITE 200
ORANGE, CA 92668

SIGNING & PAVEMENT MARKING
ALAFAYA TRAIL

COUNTY PROJ. NO.	SHEET NO.
AL ALA-A-THAI	128



REVISIONS

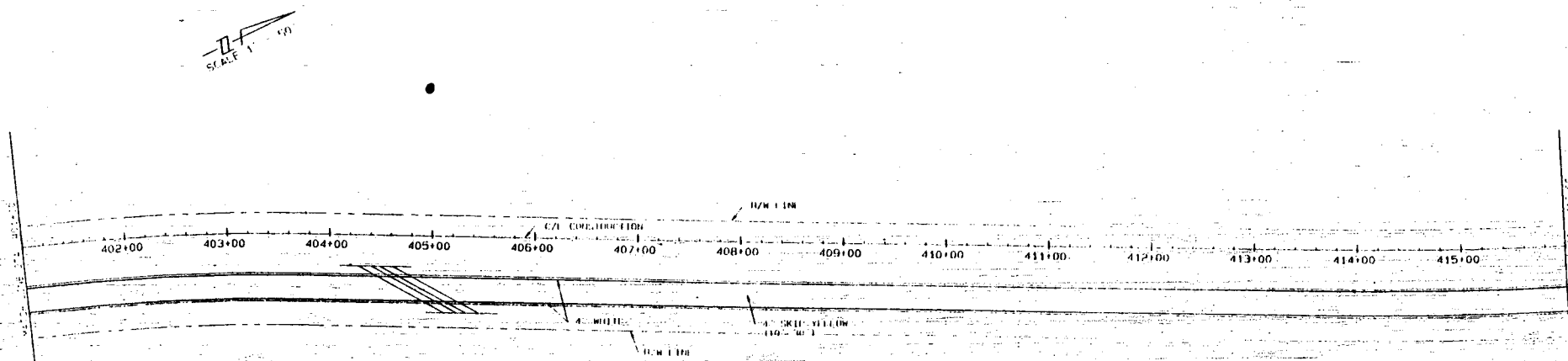
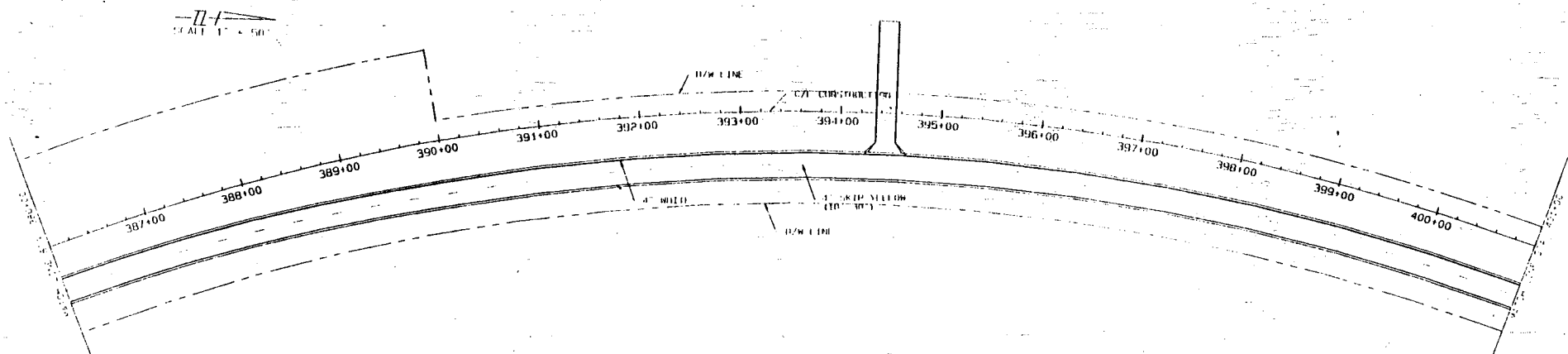
NO.	DATE	BY	DESCRIPTION

CHARGE CURRENT PUBLIC
WORKS DEPARTMENT



LUCIANE ENGINEERING, INC.
CONSULTING CIVIL, LANDSCAPE ARCHITECTS
1000 N. 10th St., Suite 100, Tallahassee, FL 32301
(904) 833-1111

SIGNING & PAVEMENT MARKING
AL ALA-A-THAI



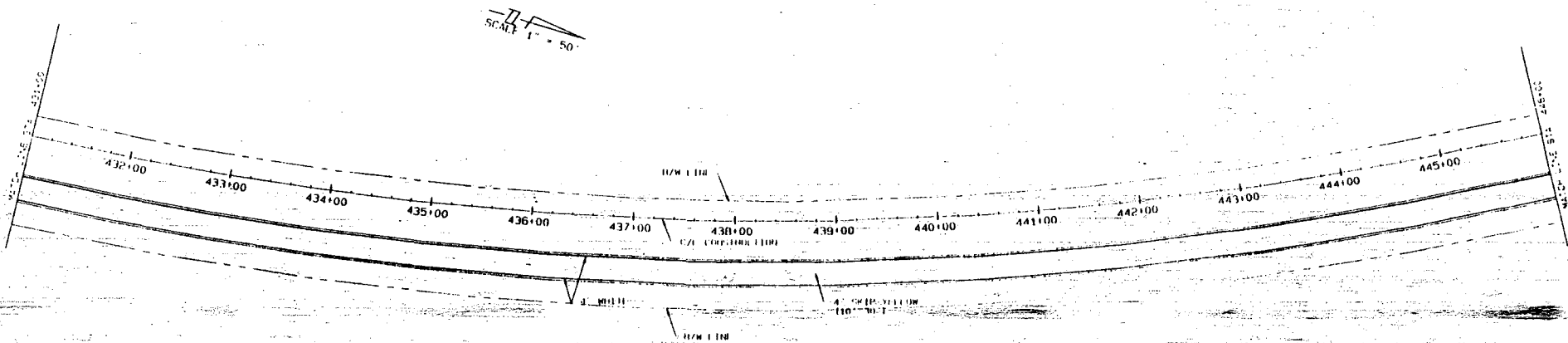
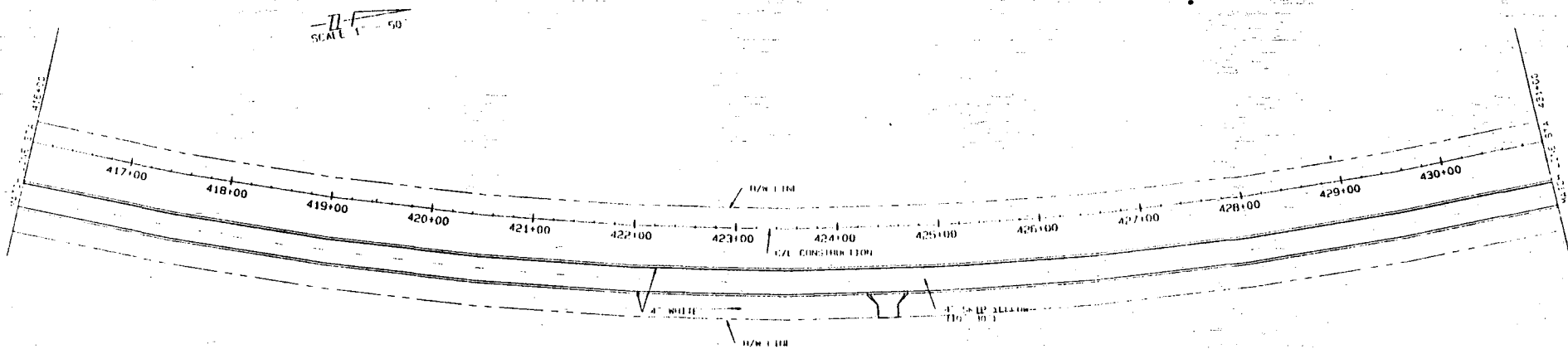
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AND SURVEYORS

SIGNING & PAVEMENT MARKING
ALAFAYA TRAIL

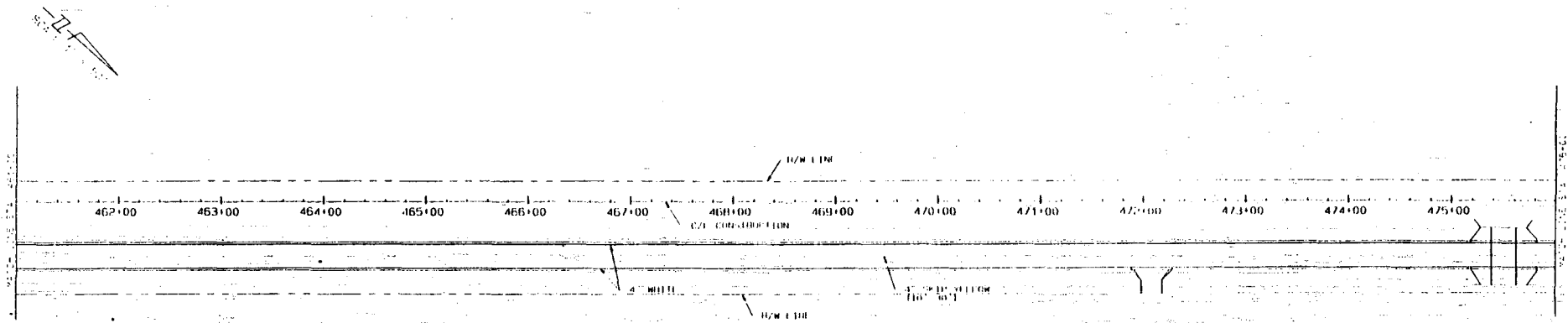
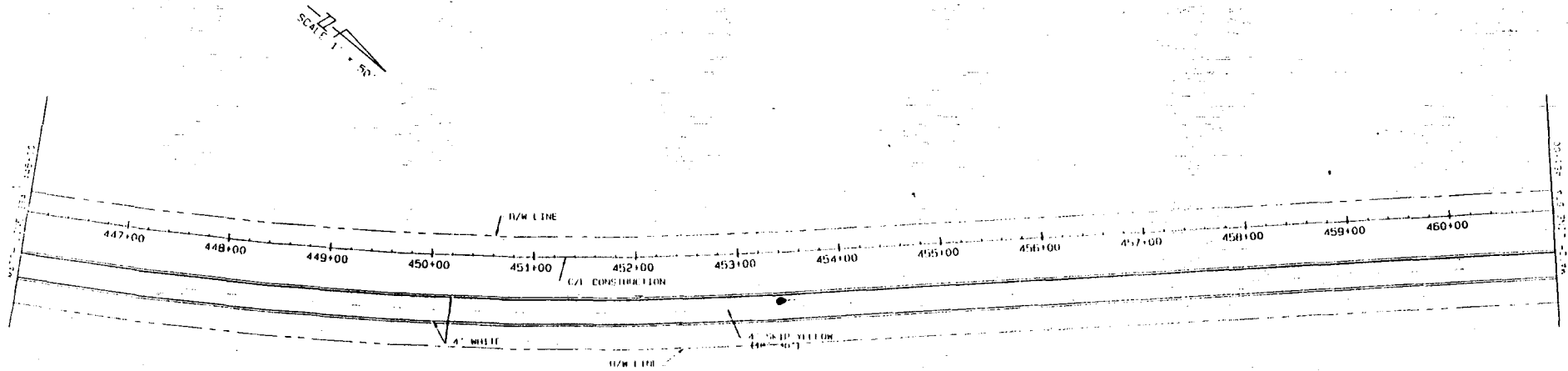


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LOCKHART ENGINEERING, INC.
TULSA, OKLAHOMA
CIVIL ENGINEERING
LAND SURVEYING

SIGNING & PAVEMENT MARKING
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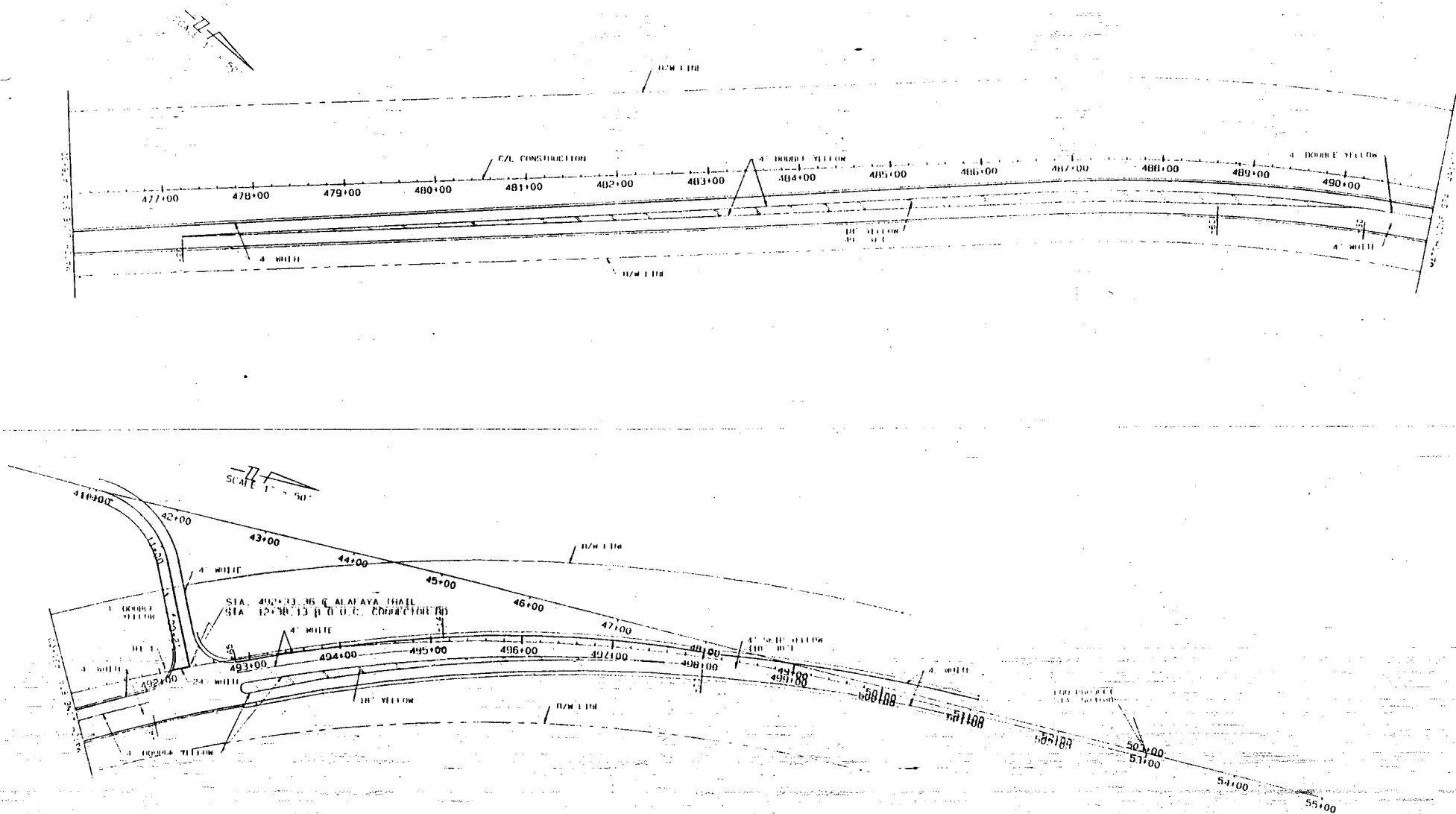
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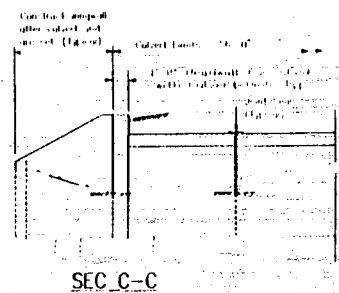
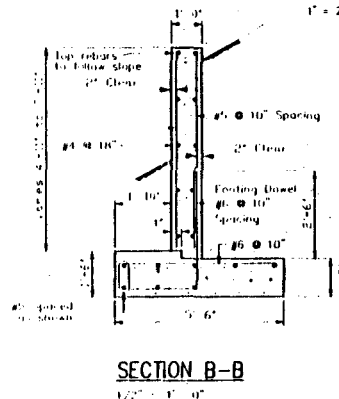
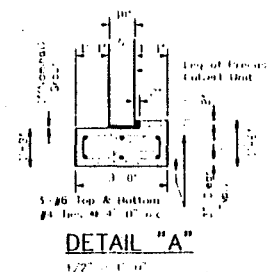
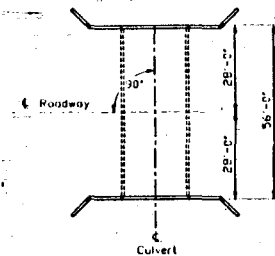
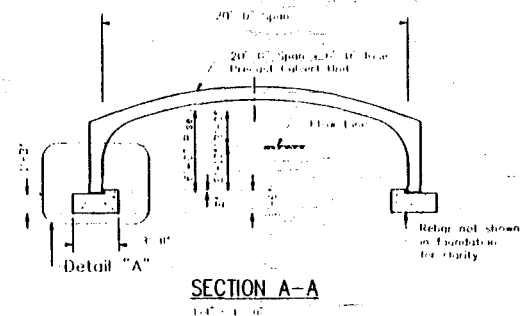
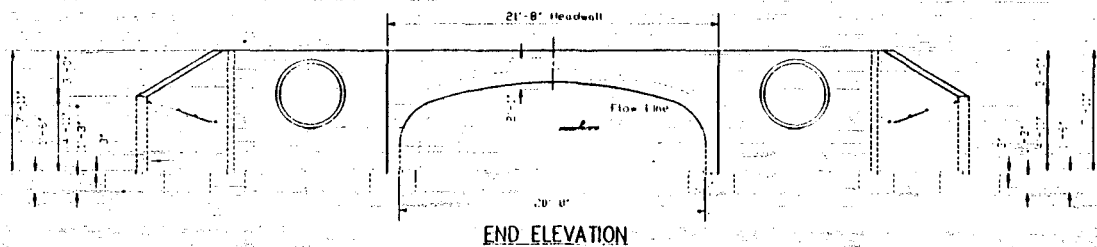
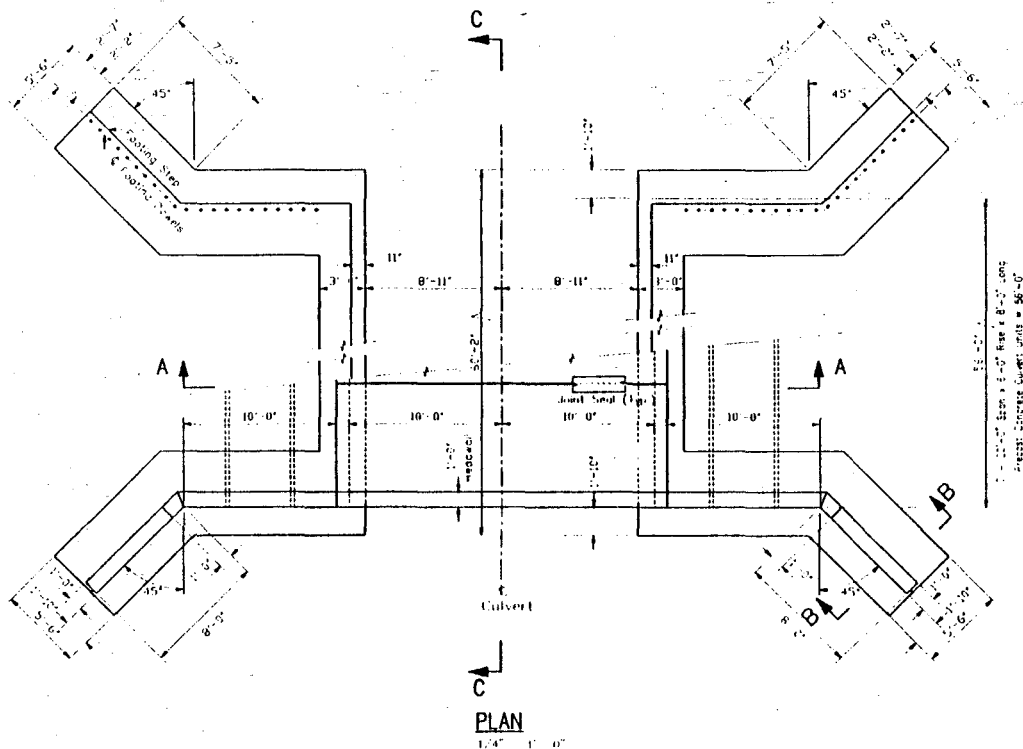
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NOTES

DESIGN DATA

Design Loading: HS-20-44
Design Method: Load factor per AASHTO Specification
Assumed Allowable Soil Bearing: PSI (Verify)

MATERIALS

Precast units shall be constructed and installed in accordance with *Cul/Spn* Specifications.
Concrete for Footings and Wingwalls shall be Class C with minimum compressive strength of 4000 psi.
Reinforcing steel for Footings and Wingwalls shall conform to ASTM A615, A616 or A617 Grade 60.

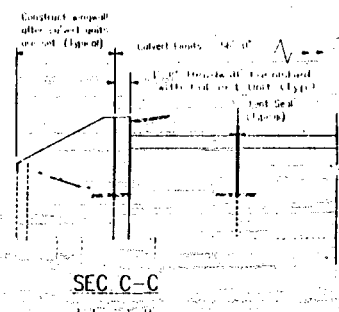
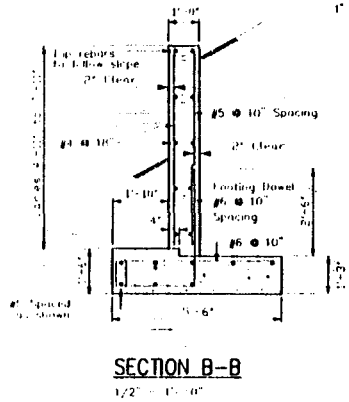
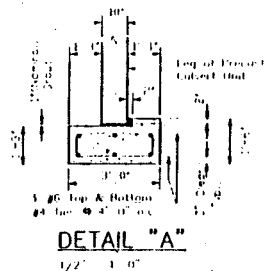
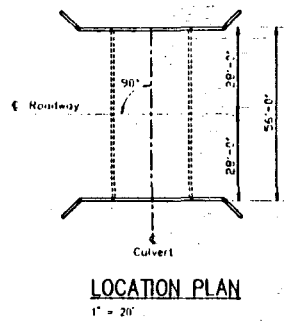
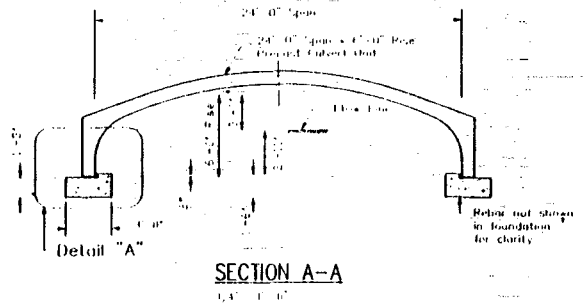
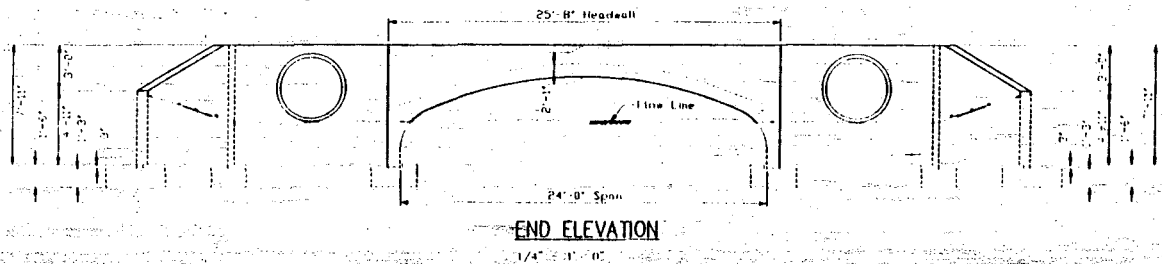
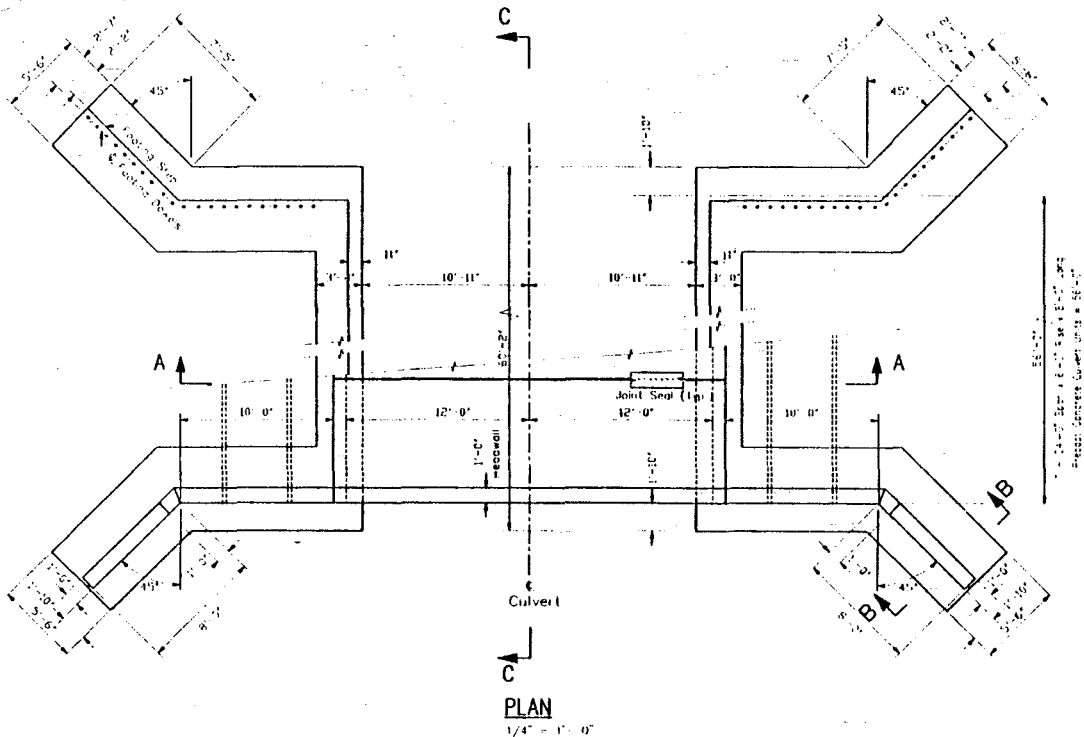
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HART BRANCH CROSSING

Con/Spn Culvert Systems

Span	Length	Notes
20'-0"	21'-8"	1



NOTES

DESIGN DATA
Design Loading: HS20-44
Design Method: Load Factor per AASHTO Specification
Assumed Allowable Soil Bearing: 1000 (Verify)

MATERIALS
Precast units shall be constructed and installed in accordance with Con/Span Specifications.
Concrete for footings and wingwalls shall be Class C with minimum compressive strength of 4000 psi.
Reinforcing steel for footings and wingwalls shall conform to ASTM A615, A616, or A617 Grade 60.

FLORIDA			
GREEN BRANCH CROSSING			
Con/Span Culvert Systems			
Span No.	1	Span No.	1
Span No.	1	Span No.	1

SPECIFICATIONS FOR MANUFACTURE AND INSTALLATION OF CON/SPAN CULVERTS

1. DESCRIPTION

This work shall consist of constructing a Con/Span culvert in accordance with the specifications and in reasonably close conformity with the plans, grades, design and dimensions shown on the plans or as established by the Engineer.

2. TYPES

Precast reinforced concrete Con/Span culverts manufactured in accordance with this specification shall be designated by span and rise.

3. MATERIALS - CONCRETE

The concrete for the culverts shall be air-entrained when installed in areas subject to freeze/thaw conditions, composed of portland cement, fine and coarse aggregates, admixtures and water. Concrete shall contain 6 ± 2 percent air. The air-entraining admixture shall conform to ASTM C 150.

- 3.1 Cement - Portland cement shall conform to the requirements of ASTM Specifications C150 Type I, Type II, or Type III cement.
- 3.2 Coarse Aggregate - Shall consist of stone having a maximum size of 1 inch. Aggregate shall meet requirements for ASTM C 33.
- 3.3 Water Reducing Admixture - The manufacturer may submit for approval by the Engineer, water-reducing admixture for the purpose of increasing workability and reducing the water requirement for the concrete.
- 3.4 Calcium Chloride - The addition to the mix of calcium chloride or admixtures containing calcium chloride will not be permitted.

4. MATERIALS - STEEL REINFORCEMENT AND HARDWARE

All reinforcing steel for the culverts shall be fabricated and placed in accordance with the detailed shop drawings submitted by the manufacturer.

- 4.1 Steel Reinforcement - Reinforcement shall consist of welded wire fabric covering to ASTM Specification A 185 or A 401, or deformed billet steel bars conforming to ASTM Specification A 615, Grade 60. Longitudinal distribution reinforcement may consist of welded wire fabric or deformed billet steel bars.

5. MANUFACTURE

- 5.1 Mixture - The aggregates, cement and water shall be proportioned and mixed in a batch mixer to produce a homogeneous concrete meeting the strength requirements of this specification. The proportion of portland cement in the mixture shall not be less than 564 pounds (6 sacks) per cubic yard of concrete.
- 5.2 Curing - The precast concrete culvert units shall be cured for a sufficient length of time so that the concrete will develop the specified compressive strength in 28 days or less. Any one of the following methods of curing or combinations thereof shall be used:
 - 5.2.1 Steam Curing - The culverts may be low pressure, steam cured by a system that will maintain a moist atmosphere.
 - 5.2.2 Water Curing - The culverts may be water cured by any method that will keep the surfaces moist.
 - 5.2.3 Membrane Curing - A sealing membrane conforming to the requirements ASTM Specification C 309 may be applied and shall be left intact until the required concrete compressive strength is obtained. The curing temperature of the time of application shall be within ± 10 degrees F. of the atmospheric temperature. All surfaces shall be kept moist prior to the application of the compounds and shall be damp when the compound is applied.
- 5.3 Forms - The forms used in manufacture shall be sufficiently rigid and accurate to maintain the culvert dimensions within the permissible variations given in Section 7. All casting surfaces shall be of smooth material.
- 5.4 Handling - Handling devices or hoists shall be permitted in each culvert for the purpose of handling and setting.
- 5.5 Storage - The culverts shall be stored in such a manner to prevent cracking or damage. The units shall be stored in an upright position until the compressive strength is a minimum of 4,000 psi.

6. DESIGN

- 6.1 The culvert dimension and reinforcement details shall be as prescribed in the plan and the shop drawings provided by the manufacturer, subject to the provisions of Section 7. The minimum concrete compressive strength shall be 4,000 psi. The minimum steel yield strength shall be 60,000 psi.

The culverts are designed in accordance with the "Standard Specifications for Highway Bridges" adopted by the American Association of State Highway and Transportation Officials, 1983 including the 1984 Interim Specifications, and the Alternate Military Loading. A minimum of one foot of cover above the crown of the culvert is required in the installed condition, (unless noted otherwise and designed accordingly.)

- 6.2 Placement of Reinforcement - The cover of concrete over the outside circumferential reinforcement shall be 2 inches minimum. The cover of concrete over the inside circumferential reinforcement shall be 1 1/2 inches minimum. The clear distance of the inside circumferential wires shall not be less than one inch nor more than two inches from the ends of the culvert. Reinforcement shall be assembled utilizing single or multiple layers of welded wire fabric, or utilizing a single layer of deformed billet steel bars. The welded wire fabric shall be composed of circumferential and longitudinal wires meeting the spacing requirements of 6.4 and shall maintain the shape and position of reinforcement. Longitudinal distribution reinforcement may be welded wire fabric or deformed billet steel bars and shall meet the spacing requirements of 6.4. The ends of the longitudinal distribution reinforcement shall be not more than 3 inches from the ends of the culvert.

- 6.3 Bending of Reinforcement - The outside and inside circumferential reinforcing steel or longitudinal reinforcement shall be bent to such an angle that it is approximately equal to the configuration of the culvert's outside corner.

- 6.4 Laps, Welds, and Spacing - Tension splices in the circumferential reinforcement shall be made by lapping. Laps may be lapped welded together for assembly purposes. For smooth welded wire fabric, the overlap shall meet the requirements of A112.9 and 12.20. For deformed welded wire fabric, the overlap shall meet the requirements of A112.8 and 12.19. For deformed billet steel bars, the overlap shall meet the requirements of A112.8. For splices other than tension splices, the overlap shall be a minimum of 12 inches for welded wire fabric or deformed billet steel bars. The spacing center to center of the circumferential wires in a wire fabric steel shall be not less than 2 inches nor more than 4 inches. For the wire fabric, the spacing center to center of the longitudinal wires shall not be more than 8 inches. The spacing center to center of the longitudinal distribution steel for either type of reinforcing in the top slab shall be not more than 16 inches.

7. PERMISSIBLE VARIATIONS

- 7.1 Internal Dimensions - The internal dimension shall vary not more than 1% from the design dimension nor more than 1 1/2 inches whichever is less. The height dimensions shall vary not more than 3/4 inch from the design dimension.
- 7.2 Slab and Wall Thickness - The slab and wall thickness shall not be less than that shown in the design by more than 1/4 inch. A thickness more than that required in the design shall not be cause for rejection.
- 7.3 Length of Opposite Surfaces - Variations in laying length of two opposite surfaces of the culvert shall not be more than 5/8 inch in any culvert section, except where beveled ends for laying of curves are specified by the purchaser.
- 7.4 Length of Section - The underlain length of a section shall not be more than 1/2 inch in any culvert.
- 7.5 Position of Reinforcement - The maximum variation in position of the reinforcement shall be 1/2 inch. In no case shall the cover over the reinforcement be less than 1 1/2 inch for the outside circumferential steel or less than 1 inch for the inside circumferential steel as measured to the exterior or interior surface of the culvert. These tolerances or cover requirements do not apply to mating surfaces of the joints.
- 7.6 Area of Reinforcement - The area of steel reinforcement shall be the design steel area as shown in the manufacturer's shop drawings. Steel areas greater than those shown shall be cause for rejection. The permissible variation in volume of any reinforcement shall conform to the tolerances prescribed in the ASTM Specification for that type of reinforcement.

8. TESTING AND INSPECTION

- 8.1 Type of Test Specimens - Concrete compressive strength shall be determined from compression tests made on cylinders or cores. For cylinder testing a minimum of 4 cylinders shall be taken during each production run. For core testing, one core shall be cut from a culvert section selected at random from each group of 15 culverts or less of a particular size and production run. For each continuous production run, each group of 15 culverts of a single size or fraction thereof shall be considered separately for the purpose of testing and acceptance. A production run shall be considered continuous if not interrupted for more than 5 consecutive days.

- 8.2 Compression Testing - Cylinders shall be made and tested as prescribed by the ASTM C 39 Specification. Cores shall be obtained and tested for compressive strength in accordance with the provisions of the ASTM C 490 Specification.

- 8.3 Acceptability of Cylinder Tests - Failure of any of the 28 day test cylinders to more than 90 percent of the minimum compressive strength requirement can be cause for rejection.

- 8.4 Acceptability of Core Tests - The compressive strength of the concrete in each group of culverts as defined in 8.1 is acceptable when the core test strength are equal to or greater than the design concrete strength. When the compressive strength of the core is equal to or greater than the design concrete strength, the culvert from which the core was taken may be rejected. When the compressive strength of the core is equal to or greater than the design concrete strength, the compressive strength of the concrete in that group of culverts is acceptable.

- 8.4.1 When the compressive strength of any core is less than the design concrete strength, the culvert from which the core was taken shall be rejected. Two culverts from the remainder of the group shall be selected for testing and one core shall be taken from each. If the compressive strength of both cores is equal to or greater than the design concrete strength, the compressive strength of the remainder of that group of culverts is acceptable. If the compressive strength of either of the two cores tested is less than the design concrete strength, the remainder of the group of culverts shall be rejected or, at the option of the manufacturer, such culvert of the remainder of the group shall be core and accepted individually, and any of these culverts that have cores with less than the design concrete strength shall be rejected.

- 8.4.2 Mugging Core Notes - The core holes shall be plugged and sealed by the manufacturer in a manner such that the culvert will meet all of the test requirements of this specification. Culverts so sealed shall be considered satisfactory for use.

- 8.4.3 Test Equipment - Every manufacturer furnishing culverts under this specification shall furnish all facilities and personnel necessary to carry out the test required.

9. JOINTS

The culverts shall be produced with flat butt ends. The ends of the culvert shall be such that when the sections are laid together they will make a continuous line of culverts with a smooth interior free of appreciable irregularities, all compatible with the permissible variations in Section 7. The joint width shall not exceed 1/4 inch.

10. WORKMANSHIP AND FINISH

The culverts shall be substantially free of fractures. The ends of the culverts shall be smooth to the walls and corners. In the interior of the culvert section, within the limits of the surface finish, the results are sound, even, and the required section dimensions in the requirements of this specification.

11. REPAIRS

Culverts may be repaired, if necessary, because of imperfections in manufacture or handling damage and will be installed in the position of the culvert. The repairs are sound, even, finished and cured, and the required section dimensions in the requirements of this specification.

12. INSPECTION

The quality of materials, the process of manufacture, and the finished culverts shall be subject to inspection by the purchaser.

13. REJECTION

Culverts shall be subject to rejection on account of any of the specification requirements. Individual culverts may be rejected because of any of the following:

- 13.1 Fractures or cracks passing through the wall, except for a single and crack that does not exceed one half the thickness of the wall.
- 13.2 Defects that indicate poor workmanship, mixing, and mending not in compliance with Section 5.
- 13.3 Homogeneity or open texture and
- 13.4 Damaged ends, where such damage would prevent making a satisfactory joint.

14. MARKING

Each culvert shall be clearly marked by waterproof paint. The following shall be shown on the inside of the vertical leg of the culvert section:

Culvert Section Span x Culvert Rise
(Date of Manufacture)
Name or trademark of the manufacturer

15. CONSTRUCTION REQUIREMENTS

- 15.1 Footings - The culverts shall be installed on either precast or cast-in-place concrete footings with a design size and elevations of the footings shall be as determined by the Engineer. A two to three inch step up shall be formed in the top surface of the footing two inches clear of the interior face of the culvert. The footings shall be given a smooth top finish and shall reach a compressive strength of 2,000 psi before placement of the culvert sections. The completed footing surface shall be constructed in accordance with grades shown on the plans. When finished with a 10 foot straight edge, the surface shall not vary more than 1/4 inch in 10 feet. If a precast concrete footing is used, the contractor shall provide a 4 inch thick layer of compacted granular material to the full width of the footing prior to placing the precast form.

- 15.2 Placement of the Culverts - The culverts shall be placed as shown on the Engineer's plan drawings. Special care shall be taken in setting the culverts to the true line and grade. The culverts shall be set on 5" x 5" masonry or steel struts. A minimum of 1/2 inch gap shall be provided between the footing and the bottom of the culvert's vertical legs. The gap shall be filled with cement grout (cement and water or cement mortar composed of one part portland cement and three parts of sand, by volume, and water.)

- 15.3 External Protection of Joints - The butt joint made by two adjoining culverts shall be covered with a minimum of a 9 inch wide felt wrap. The surface shall be free of dirt before applying the joint material. The exterior wrapping shall conform to ASTM C 671 Specification for External Sealing Devices, or approved equal. The joint shall be covered continuously from the bottom of one culvert section leg, across the top of the arch, and to the opposite culvert section leg. During the butt fitting operation, care shall be taken to keep the felt wrap in its proper location over the joint.

- 15.4 Backfill - Backfill shall be considered as all required excavation and new embankment adjacent to the Con/Span culvert and wingwalls. The project construction and material specifications which include the specifications for excavation for structures and roadway excavation and embankment construction shall apply, except as modified in this section.

Backfill material within four feet of each side of the culvert shall be granular material or satisfactory granular having a minimum laboratory dry weight of not less than 90 pounds per cubic foot, except that soils having a maximum dry weight of less than 100 pounds per cubic foot shall not be used in the top 12 inches of embankment substrate. Maximum dry density shall be determined by ASTM D 1557 or other approved methods. Backfill shall be placed and compacted in layers until the specified and the following requirements: Granular material shall be compacted to not less than 95 percent of maximum dry density. Soil with a maximum laboratory dry weight of 90-104.9 pounds per cubic foot shall be compacted to not less than 100 percent of maximum dry density. Soil with a maximum dry weight of 105 to 119.9 pounds per cubic foot shall be compacted to not less than 100 percent of maximum dry density. Elsewhere the required compaction of soil shall be 95 percent of the maximum laboratory dry weight.

No backfill shall be placed against any structural elements until they have been approved by the Engineer.

Backfill against a water-proofed surface shall be placed carefully to avoid damage to the water-proofing material.

Mechanical tampers or approved compacting equipment shall be used to compact all backfill and embankment immediately adjacent to each side of the culvert and over the top of the culvert until it is covered to a minimum depth of one foot. The backfill within four feet of each side of the culvert shall be placed in lifts of eight inches or less loose depth. Heavy compaction equipment shall not be operated in this area or over the culvert until it is covered to a depth of one foot.

Lightweight dozers and graders may be used to compact culverts having one foot of compacted cover, but heavy earth moving equipment larger than a D-4 Caterpillar wheel loader or 12 tons and having track pressures of eight psi or greater shall require two feet of cover.

Any additional fill and subsequent excavation required to provide the minimum cover shall be made at no additional cost to the project.

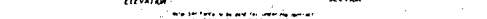
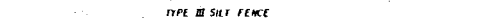
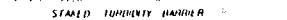
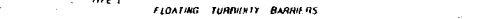
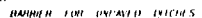
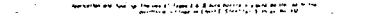
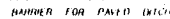
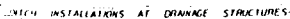
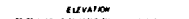
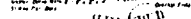
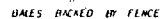
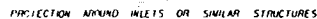
As a precaution against introducing unbalanced stresses in the culvert and wingwalls, the backfill shall be placed and compacted to the same elevation on both sides of the culvert and wingwalls before proceeding to the next layer.

Backfill in front of wingwalls shall be carried to ground lines shown in the plans.

SPECIFICATIONS FOR MANUFACTURE AND INSTALLATION OF CON/SPAN CULVERTS

Con/Span Culvert Systems

Span	Rise	Material	Finish
12	4	Concrete	Smooth
12	4	Concrete	Textured
12	4	Concrete	Painted



BUDCHRAM ENGINEERING CORPORATION

POND 4

POND 4

Pond 4 is a wet detention facility located between Station 394 + 80 and Station 397 + 40 adjacent to the westerly right-of-way line. The pond is encompassed by a 5 foot wide maintenance berm with the top bank elevation set at 70.0 Ft. NGVD. From the top of bank, the pond sideslopes are 5:1 to elevation 67.0 Ft. NGVD, then 6:1 to elevation 64.0 Ft. NGVD, then 2:1 to the bottom elevation 59.0 Ft. NGVD. The 6:1 slopes are to be covered with muck from area excavation and allowed to naturally vegetate.

Inflow to the pond is via a combination open (swale) drainage, inlet and pipe system along Alafaya Trail. The runoff will enter the northwest most access point to the pond to prevent direct movement to the outfall structure.

Discharge from the pond is over a large broad crested weir located on the north side of the facility. A 5 Ft. weir, set at 68.1 Ft. NGVD, contains a 2.5 inch diameter bleeder with an invert at 67.01 Ft. NGVD. The discharge flow over the weir outfalls into the adjacent wetland strand.

EXISTING CONDITIONS

The portion of Alafaya Trail from Station 378 + 50 to Station 413 + 50 was considered as Drainage Basin 4. Drainage Basin 4 currently outfalls through a series of wetland strands to Cowpen Crossing Branch. While these positive outfalls exist, the runoff from the existing area is conveyed by surface sheetflow. Considering the area's flat topography, there are no well defined drainage pathways. The peak rate of discharge from the project area was estimated using Santa Barbara Unit Hydrograph. The peak rate of discharge from this portion of Alafaya Trail is approximately 8.5 CFS during the 25 year/24 hours storm event.

PROPOSED CONDITIONS

The design of Pond 4 proposes to collect the roadway right-of-way from Station 378+50 to 413+50. The pond inflows were calculated using Santa Barbara Unit Hydrograph and routed using Inter-Connected Pond Routing.

The project runoff is collected and conveyed by swales on each side of the roadway. The runoff is then collected in a ditch bottom inlet and piped to the proposed pond facility location.

This pond is designed using the 25 year/24 hour storm event. The crest of the outfall weir is set to provide wet detention for 1 inch of runoff from the project area. The bleeder orifice, in the weir structure, is sized to recover an 0.5 inch of the detained volume within 60 hours.

The post development peak rate of discharge for this portion of Alafaya Trail is 8.32 CFS, with the peak stage in the pond being 68.71 Ft. NGVD, thus insuring ample freeboard for the pond facility.

PRIMARY SYSTEM

ALAFAYA TR. PRE POND4

How many basins? --> 3
Simulation Duration (hrs) --> 24.5
Time Increment (mins) --> 1
Print Interval --> 15
Save Results? (Y/N) --> Y

Specify FILENAME containing INPUT DATA
Specify FILENAME to be used for COMPOSITES

--> D:SP4.PRE
--> D:SP4.HYD

SANTA BARBARA URBAN HYDROGRAPH SE88118 VER 1.2
ALAFAYA TR. FRE POND4

BASIN NODE ID	#	AREA (acres)	% LAKE	% DCIA	INI AB INI AB			
					DN N-DCIA	TC (min)	DCIA (ins)	N-DCIA (dec)
400	54	7.2	0.0	0.0	73.0	171.0	0.10	0.20
401	54	1.5	0.0	0.0	73.0	171.0	0.10	0.20
904	54	0.1	0.0	0.0	1.0	100.0	0.10	0.20

***** RAINFALL INPUT SECTION *****

Pass Curve or Actual Rainfall? (M/A) --> M

- 1 SCS TYPE II
- 2 ORANGE COUNTY 6-HOUR
- 3 24-HOUR
- 4 SCS TYPE II-M
- 5 FDOT 1 HOUR
- 6 FDOT 2 HOUR
- 7 FDOT 4 HOUR
- 8 FDOT 8 HOUR
- 9 FDOT 1 DAY
- 10 FDOT 3 DAY
- 11 FDOT 7 DAY
- 12 FDOT 10 DAY
- 13 SCS TYPE 2M 96HR

Specify CURVE TYPE = 4

Storm Duration (hrs) --> 24
Total Rainfall (inches) --> 8.6

BLAFAYA TR. PRE POND4

TIME (hrs)	RAIN (ins)	BASIN 400	BASIN 401	BASIN 904
0.000	0.000	0.0	0.0	0.0
0.250	0.026	0.0	0.0	0.0
0.500	0.051	0.0	0.0	0.0
0.750	0.077	0.0	0.0	0.0
1.000	0.102	0.0	0.0	0.0
1.250	0.123	0.0	0.0	0.0
1.500	0.134	0.0	0.0	0.0
1.750	0.145	0.0	0.0	0.0
2.000	0.216	0.0	0.0	0.0
2.250	0.246	0.0	0.0	0.0
2.500	0.275	0.0	0.0	0.0
2.750	0.306	0.0	0.0	0.0
3.000	0.335	0.0	0.0	0.0
3.250	0.365	0.0	0.0	0.0
3.500	0.395	0.0	0.0	0.0
3.750	0.429	0.0	0.0	0.0
4.000	0.463	0.0	0.0	0.0
4.250	0.497	0.0	0.0	0.0
4.500	0.532	0.0	0.0	0.0
4.750	0.572	0.0	0.0	0.0
5.000	0.612	0.0	0.0	0.0
5.250	0.650	0.0	0.0	0.0
5.500	0.689	0.0	0.0	0.0
5.750	0.727	0.0	0.0	0.0
6.000	0.765	0.0	0.0	0.0
6.250	0.808	0.1	0.0	0.0
6.500	0.851	0.1	0.0	0.0
6.750	0.898	0.1	0.0	0.0
7.000	0.945	0.1	0.0	0.0
7.250	0.996	0.1	0.0	0.0
7.500	1.047	0.2	0.0	0.0
7.750	1.105	0.2	0.0	0.0
8.000	1.163	0.2	0.0	0.0
8.250	1.223	0.3	0.1	0.0
8.500	1.282	0.3	0.1	0.0
8.750	1.346	0.3	0.1	0.0
9.000	1.410	0.4	0.1	0.0
9.250	1.483	0.4	0.1	0.0
9.500	1.555	0.5	0.1	0.0
9.750	1.641	0.5	0.1	0.0
10.000	1.726	0.6	0.1	0.0
10.250	1.832	0.7	0.1	0.0
10.500	1.958	0.8	0.2	0.0
10.750	2.060	0.9	0.2	0.0
11.000	2.225	1.0	0.2	0.0
11.250	2.435	1.3	0.3	0.0
11.500	2.661	1.5	0.3	0.0
11.750	2.935	3.7	0.8	0.0
12.000	3.212	5.0	1.2	0.0

SLAFAYA TR. PRE FOND4

TIME (hrs)	RAIN (in/s)	BSIN 400	BSIN 401	BSIN 304
12.250	5.589	5.5	1.3	0.0
12.500	5.157	7.1	1.4	0.0
12.750	5.338	5.3	1.4	0.0
13.000	5.505	5.7	1.3	0.0
13.250	5.438	5.4	1.3	0.0
13.500	5.745	5.1	1.2	0.0
13.750	5.545	5.3	1.2	0.0
14.000	5.543	5.3	1.1	0.0
14.250	7.034	5.3	1.1	0.0
14.500	7.113	5.0	1.0	0.0
14.750	7.173	4.7	1.0	0.0
15.000	7.341	4.5	0.9	0.0
15.250	7.305	4.3	0.9	0.0
15.500	7.333	4.1	0.8	0.0
15.750	7.435	3.8	0.8	0.0
16.000	7.430	3.6	0.7	0.0
16.250	7.532	3.5	0.7	0.0
16.500	7.533	3.3	0.7	0.0
16.750	7.632	3.1	0.6	0.0
17.000	7.631	3.0	0.6	0.0
17.250	7.724	2.8	0.6	0.0
17.500	7.756	2.7	0.5	0.0
17.750	7.809	2.5	0.5	0.0
18.000	7.852	2.4	0.5	0.0
18.250	7.930	2.3	0.5	0.0
18.500	7.939	2.2	0.4	0.0
18.750	7.957	2.1	0.4	0.0
19.000	8.005	2.0	0.4	0.0
19.250	8.040	1.9	0.4	0.0
19.500	8.074	1.8	0.4	0.0
19.750	8.109	1.8	0.4	0.0
20.000	8.145	1.7	0.3	0.0
20.250	8.179	1.6	0.3	0.0
20.500	8.213	1.6	0.3	0.0
20.750	8.243	1.5	0.3	0.0
21.000	8.273	1.5	0.3	0.0
21.250	8.303	1.4	0.3	0.0
21.500	8.333	1.4	0.3	0.0
21.750	8.363	1.3	0.3	0.0
22.000	8.393	1.3	0.3	0.0
22.250	8.422	1.2	0.2	0.0
22.500	8.452	1.2	0.2	0.0
22.750	8.479	1.2	0.2	0.0
23.000	8.506	1.1	0.2	0.0
23.250	8.532	1.1	0.2	0.0
23.500	8.557	1.1	0.2	0.0
23.750	8.579	1.0	0.2	0.0
24.000	8.600	1.0	0.2	0.0
24.250	8.600	0.9	0.2	0.0

SANTA BARBARA URBAN HYDROGRAPH SB88118 VER 1.2
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ALAFAYA TR. PRE POND4

TIME	RAIN	BASIN	BASIN	BASIN
(hrs)	(ins)	400	401	904
----	----	----	----	----
24.500	2.600	0.3	0.2	0.0

ALAFAYA TR. PRE POND4

*** RUNOFF SUMMARY ***

BASIN ID# --)	400	401	304
RD VOL (cfs-hrs)	42	3	0
RD VOL (ac-ft)	3.5	0.7	0.0
RD VOL (inches)	5.75	5.75	0.00
PEAK FLOW (cfs)	7.1	1.4	0.0
PEAK TIME (hrs)	12.517	12.517	0.000

--> COMPOSITE HYDROGRAPHS (--- (EBUHIX1)
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TIME (hrs)	NODE 54
0.000	0.0
0.250	0.0
0.500	0.0
0.750	0.0
1.000	0.0
1.250	0.0
1.500	0.0
1.750	0.0
2.000	0.0
2.250	0.0
2.500	0.0
2.750	0.0
3.000	0.0
3.250	0.0
3.500	0.0
3.750	0.0
4.000	0.0
4.250	0.0
4.500	0.0
4.750	0.0
5.000	0.0
5.250	0.0
5.500	0.0
5.750	0.0
6.000	0.0
6.250	0.1
6.500	0.1
6.750	0.1
7.000	0.1
7.250	0.2
7.500	0.2
7.750	0.2
8.000	0.3
8.250	0.3
8.500	0.3
8.750	0.4
9.000	0.4
9.250	0.5
9.500	0.6
9.750	0.6
10.000	0.7
10.250	0.8
10.500	0.9
10.750	1.1
11.000	1.3
11.250	1.5
11.500	1.8
11.750	4.5
12.000	7.2

-- COMPOSITE HYDROGRAPHS (--- (SEBUHIX1)
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TIME (hrs)	WIDE SA
12.250	7.9
12.500	8.5
12.750	8.3
13.000	8.0
13.250	7.7
13.500	7.4
13.750	7.0
14.000	6.7
14.250	6.3
14.500	6.0
14.750	5.7
15.000	5.4
15.250	5.1
15.500	4.8
15.750	4.5
16.000	4.4
16.250	4.2
16.500	3.9
16.750	3.7
17.000	3.5
17.250	3.4
17.500	3.2
17.750	3.1
18.000	2.9
18.250	2.8
18.500	2.7
18.750	2.5
19.000	2.4
19.250	2.3
19.500	2.2
19.750	2.1
20.000	2.0
20.250	2.0
20.500	1.9
20.750	1.8
21.000	1.8
21.250	1.7
21.500	1.6
21.750	1.6
22.000	1.5
22.250	1.5
22.500	1.4
22.750	1.4
23.000	1.3
23.250	1.3
23.500	1.3
23.750	1.2
24.000	1.2
24.250	1.1

-- COMPOSITE HYDROGRAPHS -- (SBUH1X1)
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TIME	MODE
(hrs)	
24.500	1.0

ALAFAYA TR. POST PONDA

How many basins? --> 3
Simulation Duration (hrs)--> 24.5
Time Increment (mins) --> 1
Print Interval --> 15
Save Results? (Y/N) --> Y

Specify FILENAME containing INPUT DATA --> D:SP4.POS
Specify FILENAME to be used for COMPOSITES --> D:SP4.HYD1

ALAFAYA TR. POST PONDA

BASIN ID	NODE #	AREA (acres)	% LAKE	% DCIA	DN N-DCIA	TC (min)	INI AB DCIA (ins)	INI AB N-DCIA (dec)
400	41	7.2	0.0	36.0	79.0	75.0	0.10	0.20
401	41	1.5	0.0	100.0	98.0	75.0	0.10	0.20
904	94	0.1	0.0	0.0	1.0	100.0	0.10	0.20

***** RAINFALL INPUT SECTION *****

Mass Curve or Actual Rainfall? (M/A) --> M

- 1 SCS TYPE II
- 2 ORANGE COUNTY 6-HOUR
- 3 24-HOUR
- 4 SCS TYPE II-M
- 5 FDOT 1 HOUR
- 6 FDOT 2 HOUR
- 7 FDOT 4 HOUR
- 8 FDOT 8 HOUR
- 9 FDOT 1 DAY
- 10 FDOT 3 DAY
- 11 FDOT 7 DAY
- 12 FDOT 10 DAY
- 13 SCS TYPE 2M 55HR

Specify CURVE TYPE = 4

Storm Duration (hrs) --> 24
Total Rainfall (inches) --> 3.6

SLAFAYA TR. POST POND4

TIME (hrs)	RAIN (ins)	BASIN 400	BASIN 401	BASIN 904
0.000	0.000	0.0	0.0	0.0
0.250	0.025	0.0	0.0	0.0
0.500	0.051	0.0	0.0	0.0
0.750	0.077	0.0	0.0	0.0
1.000	0.102	0.0	0.0	0.0
1.250	0.113	0.1	0.0	0.0
1.500	0.154	0.1	0.1	0.0
1.750	0.185	0.1	0.1	0.0
2.000	0.215	0.2	0.1	0.0
2.250	0.246	0.2	0.1	0.0
2.500	0.275	0.2	0.1	0.0
2.750	0.306	0.2	0.1	0.0
3.000	0.335	0.2	0.1	0.0
3.250	0.365	0.3	0.1	0.0
3.500	0.395	0.3	0.2	0.0
3.750	0.429	0.3	0.2	0.0
4.000	0.463	0.3	0.2	0.0
4.250	0.497	0.3	0.2	0.0
4.500	0.532	0.3	0.2	0.0
4.750	0.572	0.3	0.2	0.0
5.000	0.612	0.4	0.2	0.0
5.250	0.650	0.4	0.2	0.0
5.500	0.689	0.4	0.2	0.0
5.750	0.727	0.4	0.2	0.0
6.000	0.765	0.4	0.2	0.0
6.250	0.808	0.5	0.2	0.0
6.500	0.851	0.5	0.2	0.0
6.750	0.893	0.5	0.2	0.0
7.000	0.945	0.5	0.2	0.0
7.250	0.996	0.6	0.3	0.0
7.500	1.047	0.6	0.3	0.0
7.750	1.105	0.7	0.3	0.0
8.000	1.163	0.7	0.3	0.0
8.250	1.223	0.8	0.3	0.0
8.500	1.282	0.8	0.3	0.0
8.750	1.346	0.9	0.3	0.0
9.000	1.410	0.9	0.3	0.0
9.250	1.483	1.0	0.3	0.0
9.500	1.555	1.1	0.4	0.0
9.750	1.641	1.2	0.4	0.0
10.000	1.726	1.3	0.4	0.0
10.250	1.832	1.4	0.4	0.0
10.500	1.938	1.6	0.5	0.0
10.750	2.080	1.8	0.5	0.0
11.000	2.225	2.1	0.6	0.0
11.250	2.435	2.5	0.7	0.0
11.500	2.661	3.0	0.8	0.0
11.750	3.936	8.0	2.0	0.0
12.000	5.212	12.5	3.0	0.0

ALAFAYA TR. POST POND4

TIME (hrs)	RAIN (ins)	BASIN 400	BASIN 401	BASIN 504
12.250	5.689	12.7	3.0	0.0
12.500	5.167	12.7	2.9	0.0
12.750	6.333	11.3	2.5	0.0
13.000	6.505	10.1	2.3	0.0
13.250	6.636	8.9	2.0	0.0
13.500	6.745	7.9	1.9	0.0
13.750	6.845	7.0	1.6	0.0
14.000	6.943	6.2	1.4	0.0
14.250	7.024	5.5	1.2	0.0
14.500	7.105	4.9	1.1	0.0
14.750	7.173	4.4	1.0	0.0
15.000	7.241	3.9	0.9	0.0
15.250	7.305	3.5	0.8	0.0
15.500	7.369	3.2	0.7	0.0
15.750	7.425	2.9	0.6	0.0
16.000	7.480	2.7	0.6	0.0
16.250	7.532	2.5	0.5	0.0
16.500	7.593	2.3	0.5	0.0
16.750	7.632	2.1	0.5	0.0
17.000	7.681	2.0	0.4	0.0
17.250	7.724	1.8	0.4	0.0
17.500	7.766	1.7	0.4	0.0
17.750	7.809	1.6	0.3	0.0
18.000	7.852	1.5	0.3	0.0
18.250	7.890	1.5	0.3	0.0
18.500	7.929	1.4	0.3	0.0
18.750	7.967	1.3	0.3	0.0
19.000	8.005	1.3	0.3	0.0
19.250	8.040	1.2	0.3	0.0
19.500	8.074	1.2	0.3	0.0
19.750	8.109	1.1	0.2	0.0
20.000	8.145	1.1	0.2	0.0
20.250	8.179	1.1	0.2	0.0
20.500	8.213	1.1	0.2	0.0
20.750	8.243	1.0	0.2	0.0
21.000	8.273	1.0	0.2	0.0
21.250	8.303	1.0	0.2	0.0
21.500	8.333	0.9	0.2	0.0
21.750	8.363	0.9	0.2	0.0
22.000	8.393	0.9	0.2	0.0
22.250	8.422	0.9	0.2	0.0
22.500	8.452	0.9	0.2	0.0
22.750	8.479	0.9	0.2	0.0
23.000	8.506	0.8	0.2	0.0
23.250	8.532	0.8	0.2	0.0
23.500	8.557	0.8	0.2	0.0
23.750	8.579	0.8	0.2	0.0
24.000	8.600	0.7	0.2	0.0
24.250	8.600	0.6	0.1	0.0

SANTA BARBARA URBAN HYDROGRAPH SB68118 VER 1.2
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ALAFAYA TR. POST POND4

TIME	RAIN	BASIN	BASIN	BASIN
(hrs)	(ins)	400	401	504
24.500	8.600	0.5	0.1	0.0

SANTA BARBARA URBAN HYDROGRAPH 3388118 VER 1.2
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ALAFAYA TR. POST POND4

*** RUNOFF SUMMARY ***

BASIN ID# -->	400	401	304
RD VOL (cfs-hrs)	50	12	0
RD VOL (ac-ft)	4.1	1.0	0.0
RD VOL (inches)	6.86	8.41	0.00
PEAK FLOW (cfs)	12.7	3.0	0.0
PEAK TIME (hrs)	12.500	12.017	0.000

-- COMPOSITE HYDROGRAPHS (--- (SEUMIX1)
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TIME (hrs)	NODE -1	NODE 94
0.000	0.0	0.0
0.250	0.0	0.0
0.500	0.0	0.0
0.750	0.0	0.0
1.000	0.0	0.0
1.250	0.1	0.0
1.500	0.1	0.0
1.750	0.2	0.0
2.000	0.3	0.0
2.250	0.3	0.0
2.500	0.3	0.0
2.750	0.4	0.0
3.000	0.4	0.0
3.250	0.4	0.0
3.500	0.4	0.0
3.750	0.4	0.0
4.000	0.5	0.0
4.250	0.5	0.0
4.500	0.5	0.0
4.750	0.5	0.0
5.000	0.6	0.0
5.250	0.6	0.0
5.500	0.6	0.0
5.750	0.6	0.0
6.000	0.6	0.0
6.250	0.7	0.0
6.500	0.7	0.0
6.750	0.8	0.0
7.000	0.8	0.0
7.250	0.8	0.0
7.500	0.9	0.0
7.750	1.0	0.0
8.000	1.0	0.0
8.250	1.1	0.0
8.500	1.1	0.0
8.750	1.2	0.0
9.000	1.3	0.0
9.250	1.4	0.0
9.500	1.4	0.0
9.750	1.6	0.0
10.000	1.7	0.0
10.250	1.9	0.0
10.500	2.1	0.0
10.750	2.4	0.0
11.000	2.7	0.0
11.250	3.3	0.0
11.500	3.8	0.0
11.750	10.0	0.0
12.000	15.5	0.0

-- COMPOSITE HYDROGRAPHS (--- (SBUH1X1)
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TIME (hrs)	NODE 41	NODE 34
12.250	15.7	0.0
12.500	15.7	0.0
12.750	13.9	0.0
13.000	12.4	0.0
13.250	10.9	0.0
13.500	8.7	0.0
13.750	6.5	0.0
14.000	4.3	0.0
14.250	3.7	0.0
14.500	3.0	0.0
14.750	2.3	0.0
15.000	1.6	0.0
15.250	1.3	0.0
15.500	1.3	0.0
15.750	1.6	0.0
16.000	2.3	0.0
16.250	3.0	0.0
16.500	3.8	0.0
16.750	4.6	0.0
17.000	5.4	0.0
17.250	6.2	0.0
17.500	7.1	0.0
17.750	8.0	0.0
18.000	8.9	0.0
18.250	9.8	0.0
18.500	10.7	0.0
18.750	11.6	0.0
19.000	12.5	0.0
19.250	13.4	0.0
19.500	14.3	0.0
19.750	15.2	0.0
20.000	16.1	0.0
20.250	17.0	0.0
20.500	17.9	0.0
20.750	18.8	0.0
21.000	19.7	0.0
21.250	20.6	0.0
21.500	21.5	0.0
21.750	22.4	0.0
22.000	23.3	0.0
22.250	24.2	0.0
22.500	25.1	0.0
22.750	26.0	0.0
23.000	26.9	0.0
23.250	27.8	0.0
23.500	28.7	0.0
23.750	29.6	0.0
24.000	30.5	0.0
24.250	31.4	0.0

-- COMPOSITE HYDROGRAPHS -- (SSUH1X1)
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TIME	NODE	NODE
(hrs)	-1	34
24.500	0.6	0.0

ELEVATION - STORAGE VALUES

Prgram : DTBSIN6R.VOL

DETENTION BASIN DESIGN

01-04-1980

Name of Storage Basin : ALAFAYA POND 4

ELEVATION TOP STORAGE BASIN-FT ==> 70

ELEVATION BOT STORAGE BASIN - FT ==> 67

INCREMENTAL STAGE DEPTH - FT ==> .1

STORAGE BASIN AREA - ACRES AT TOP OF BASIN ==> 1.7

STORAGE BASIN PERIMETER @ TOP OF BASIN ==> 1247

AVERAGE SIDE SLOPE RATIO ==> 5

STAGE EL.	AREA-ACRES	STORAGE-AC FT
67.00	1.270	0.00
67.10	1.280	0.13
67.20	1.300	0.26
67.30	1.310	0.39
67.40	1.330	0.52
67.50	1.340	0.65
67.60	1.360	0.79
67.70	1.370	0.92
67.80	1.390	1.06
67.90	1.400	1.20
68.00	1.410	1.34
68.10	1.430	1.48
68.20	1.440	1.63
68.30	1.460	1.77
68.40	1.470	1.92
68.50	1.490	2.07
68.60	1.500	2.22
68.70	1.510	2.37
68.80	1.530	2.52
68.90	1.540	2.67
69.00	1.560	2.83
69.10	1.570	2.98
69.20	1.590	3.14
69.30	1.600	3.30
69.40	1.610	3.46
69.50	1.630	3.62
69.60	1.640	3.79
69.70	1.660	3.95
69.80	1.670	4.12
69.90	1.690	4.29
70.00	1.700	4.46

EXHIBIT 6.2-10 Page 13 of 147
 *** End of This Calculation ***

LOCHRANE ENGINEERING, INC.

201 S. Bumby Avenue
ORLANDO, FL 32803
(407) 896-3317

JOB _____
SHEET NO. _____ OF _____
CALCULATED BY Cal DATE _____
CHECKED BY _____ DATE _____
SCALE _____

Net Detention

POND 4

1" runoff (water quality)

$$3.59 \text{ ac (1")}/2 = 0.55 \text{ ac ft} \Rightarrow 67.42 \text{ ft.}$$

Hein El.

67.00 Normal Pool El.

Using 2.5" orifice invert @ N.P. el.
 $67.0' + 0.200/2 = 67.10'$ $\frac{1}{2}$ of orifice

Area Ratio

Basin Area = 7.2 ac
Normal Pool = 1.27 ac

$$\frac{7.2}{1.27} = 5.67 < 13 \quad \checkmark$$

Littoral Shelf

Normal Pool = 1.27 ac
Open Water = 0.80

$$\frac{0.80}{1.27} = 63\% < 75\% \quad \checkmark$$

Pre Development Flow 8.5 cfs

Post Development Peak stage 68.71 Ft (T.O.B. 70.0 Ft)
Peak Flow 8.32 cfs

EXHIBIT 6.2-10 Page 24 of 147

$$\text{T.W. El.} \quad \left(\frac{68.71 + 67.0}{2} \right) = 67.86 \text{ Ft}$$

LOCHRANE ENGINEERING, INC.

201 S. Bumby Avenue
ORLANDO, FL 32803
(407) 896-3317

JOB 23000-73
SHEET NO. _____ OF _____
CALCULATED BY cal DATE _____
CHECKED BY _____ DATE _____
SCALE _____

POND 4

Orifice (Recovery)

Purpose: to recover 2.5" runoff in 60 hrs

$$2.5"/12 (8.90 \text{ ac}) = 0.37 \text{ ac ft}$$

$$\begin{aligned} 0.37 \text{ ac ft} &\rightarrow 16117 \text{ CF} \\ 60 \text{ hrs} &\rightarrow 216000 \text{ sec} \end{aligned}$$

$$\underline{0.07 \text{ CFS}}$$

$$1" \text{ runoff } 1"/12 (8.90 \text{ ac}) = 0.74 \text{ ac ft} \rightarrow 67.50 \text{ Ft NGVD}$$

$$0.74 \text{ ac ft} - 0.37 \text{ ac ft} = 0.37 \text{ ac ft} \rightarrow 67.28 \text{ Ft NGVD @ 60 hrs}$$

$$A = \frac{Q}{C(2gH)^{1/2}}$$

$$H = \left(\frac{67.50 + 67.28}{2} \right) - 67.0 = 0.42 \text{ Ft}$$

$$C = 0.6$$

$$A = \frac{0.07 \text{ CFS}}{0.6 (64.4 (0.42))^{1/2}}$$

$$A = 0.02 \text{ sf} \sim 3.2 \text{ in}^2$$

$$D = (4A/\pi)^{1/2}$$

$$D = 2.03 \text{ in}$$

Use ~~2"~~ 2" orifice

2"

ELEVATION - STORAGE VALUES

Prgr : STBSINER.VOL

DETENTION BASIN DESIGN

01-04-1980

Name of Storage Basin : P4

ELEVATION TOP STORAGE BASIN-FT ==> 69

ELEVATION BOT STORAGE BASIN - FT ==> 59

INCREMENTAL STAGE DEPTH - FT ==> .5

STORAGE BASIN AREA - ACRES AT TOP OF BASIN ==> 1.7

STORAGE BASIN PERIMETER @ TOP OF BASIN ==> 1247

AVERAGE SIDE SLOPE RATIO ==> 5

CHANGE IN SLOPE TO ==> 6 AT ELEVATION ==> 67

CHANGE IN SLOPE TO ==> 2 AT ELEVATION ==> 64

STAGE EL.	AREA-ACRES	STORAGE-AC FT
59.00	0.700	0.00
59.50	0.720	0.35
60.00	0.740	0.72
60.50	0.770	1.10
61.00	0.790	1.49
61.50	0.810	1.89
62.00	0.840	2.30
62.50	0.860	2.73
63.00	0.880	3.16
63.50	0.910	3.61
64.00	0.930	4.07
64.50	1.010	4.56
65.00	1.090	5.08
65.50	1.170	5.65
66.00	1.250	6.25
66.50	1.330	6.90
67.00	1.410	7.59
67.50	1.490	8.31
68.00	1.560	9.07
68.50	1.630	9.87
69.00	1.700	10.70

*** End of This Calculation ***

Incident Vol. = $\frac{(1247)(.5)(.70)}{12} = 29.16 \text{ ac-ft}$

Resident Vol. (provided) = 7.59 ac-ft

7.59 ac-ft > 29.16 ac-ft ✓

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IC88136 VER 2.83

SLAFAYA TRAIL POND 4 (POST)
30NOV89

*** CONTROL DATA ***

Simulation time increment (mins)	-->	1
Simulation duration (hrs)	-->	24
Starting time (hrs)	-->	0
Print interval	-->	13

*** NODE AND INITIALIZATION DATA ***

NODE #	NODE TYPE	INITIAL STAGE
41	1	67.000
54	2	67.000

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LAFAYA TRAIL POND 4 (POST)
 30NOV89

 *** STAGE/STORAGE/TIME DATA ***

NODE # 41

STAGE	67.000	67.500	68.000	68.500	69.000
STAGE	0.000	0.850	1.340	2.070	2.930
STAGE	69.500	70.000	0.000	0.000	0.000
STAGE	3.920	4.460	0.000	0.000	0.000
STAGE	0.000	0.000	0.000	0.000	0.000
STAGE	0.000	0.000	0.000	0.000	0.000

NODE # 94

STAGE	67.000	67.000	0.000	0.000	0.000
TIME	0.000	24.000	0.000	0.000	0.000
STAGE	0.000	0.000	0.000	0.000	0.000
TIME	0.000	0.000	0.000	0.000	0.000
STAGE	0.000	0.000	0.000	0.000	0.000
TIME	0.000	0.000	0.000	0.000	0.000

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ALAFAYA TRAIL POND 4 (POST)
 30NOV89

 *** REACH DATA ***

NOTE: Type 1 for sharp crested weir/gate and orifice
 Type 2 for broad crested weir/gate and orifice
 + Type 3 for culvert
 + Type 4 for trapezoidal channel
 + Type 5 for parabolic channel
 Type 6 for rating curve

(Negative type indicates riser)

REACH	FROM	TO	REACH
#	NODE	NODE	TYPE
1	41	94	2

REACH # 1 from node # 41 -- to node # 94

Broad Crested Weir/Gate and Orifice (-

crest elevation (feet)	-->	68.1
crest length (feet)	-->	5
weir discharge coefficient	-->	3.367
weir exponent	-->	1.5
+ to effective submergence	-->	67
gate opening (feet)	-->	99
+ or end contractions	-->	0
Discharge coef for gate under ori flw ->		1
orifice centerline (feet)	-->	67.1
orifice diameter (feet)	-->	.208
orifice discharge coefficient	-->	.6
+ identical orifices	-->	1

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ALAFAYA TRAIL POND 4 (POST)
30NOV89

-- INFLOW HYDROGRAPHS --

INFLOW HYDROGRAPHS TO BE READ FROM DISK FILE

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ALAFAYA TRAIL POND 4 (POST)
 30NOV89

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW (cfs) # 1	TOTAL
41	0.00	67.00	0.00	0.00	0.00	0.00
94	0.00	67.00	0.00	0.00	-----	0.00
41	0.25	67.00	0.00	0.00	0.00	0.00
94	0.25	67.00	0.00	0.00	-----	0.00
41	0.50	67.00	0.00	0.00	0.00	0.00
94	0.50	67.00	0.00	0.00	-----	0.00
41	0.75	67.00	0.00	0.00	0.00	0.00
94	0.75	67.00	0.00	0.00	-----	0.00
41	1.00	67.00	0.00	0.00	0.00	0.00
94	1.00	67.00	0.00	0.00	-----	0.00
41	1.25	67.00	0.00	0.08	0.00	0.00
94	1.25	67.00	0.00	0.00	-----	0.00
41	1.50	67.00	0.00	0.14	0.00	0.00
94	1.50	67.00	0.00	0.00	-----	0.00
41	1.75	67.01	0.01	0.21	0.00	0.00
94	1.75	67.00	0.00	0.00	-----	0.00
41	2.00	67.01	0.01	0.26	0.00	0.00
94	2.00	67.00	0.00	0.00	-----	0.00
41	2.25	67.01	0.02	0.30	0.00	0.00
94	2.25	67.00	0.00	0.00	-----	0.00
41	2.50	67.02	0.02	0.34	0.00	0.00
94	2.50	67.00	0.00	0.00	-----	0.00
41	2.75	67.02	0.03	0.36	0.00	0.00
94	2.75	67.00	0.00	0.00	-----	0.00
41	3.00	67.03	0.04	0.39	0.00	0.00
94	3.00	67.00	0.00	0.00	-----	0.00
41	3.25	67.04	0.05	0.40	0.00	0.00
94	3.25	67.00	0.00	0.00	-----	0.00

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LAFAYA TRAIL POND 4 (POST)
 30NOV89

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW (cfs) # 1	TOTAL
41	3.50	67.04	0.06	0.42	0.00	0.00
94	3.50	67.00	0.00	0.00	-----	0.00
41	3.75	67.05	0.06	0.44	0.00	0.00
94	3.75	67.00	0.00	0.00	-----	0.00
41	4.00	67.06	0.07	0.46	0.00	0.00
94	4.00	67.00	0.00	0.00	-----	0.00
41	4.25	67.06	0.08	0.48	0.00	0.00
94	4.25	67.00	0.00	0.00	-----	0.00
41	4.50	67.07	0.09	0.50	0.00	0.00
94	4.50	67.00	0.00	0.00	-----	0.00
41	4.75	67.08	0.10	0.53	0.00	0.00
94	4.75	67.00	0.00	0.00	-----	0.00
41	5.00	67.09	0.12	0.56	0.00	0.00
94	5.00	67.00	0.00	0.00	-----	0.00
41	5.25	67.10	0.13	0.58	0.00	0.00
94	5.25	67.00	0.00	0.00	-----	0.00
41	5.50	67.11	0.14	0.60	0.01	0.01
94	5.50	67.00	0.00	0.01	-----	0.00
41	5.75	67.12	0.15	0.62	0.02	0.02
94	5.75	67.00	0.00	0.02	-----	0.00
41	6.00	67.13	0.16	0.64	0.03	0.03
94	6.00	67.00	0.00	0.03	-----	0.00
41	6.25	67.14	0.18	0.67	0.03	0.03
94	6.25	67.00	0.00	0.03	-----	0.00
41	6.50	67.15	0.19	0.71	0.04	0.04
94	6.50	67.00	0.00	0.04	-----	0.00
41	6.75	67.16	0.20	0.73	0.04	0.04
94	6.75	67.00	0.00	0.04	-----	0.00

ALAPAYA TRAIL POND 4 (POST)
 30NOV89

CODE	TIME	STAGE	STORAGE	INFLOW	OUTFLOW (cfs)	
#	(hrs)	(feet)	(acft)	(cfs)	# 1	TOTAL
41	7.00	67.17	0.22	0.73	0.04	0.04
94	7.00	67.00	0.00	0.04	-----	0.00
41	7.25	67.18	0.24	0.84	0.05	0.05
94	7.25	67.00	0.00	0.05	-----	0.00
41	7.50	67.19	0.25	0.93	0.05	0.05
94	7.50	67.00	0.01	0.05	-----	0.00
41	7.75	67.31	0.27	0.98	0.05	0.05
94	7.75	67.00	0.01	0.05	-----	0.00
41	8.00	67.22	0.23	1.02	0.06	0.06
94	8.00	67.00	0.01	0.06	-----	0.00
41	8.25	67.24	0.31	1.09	0.06	0.06
94	8.25	67.00	0.01	0.06	-----	0.00
41	8.50	67.36	0.33	1.14	0.06	0.06
94	8.50	67.00	0.01	0.06	-----	0.00
41	8.75	67.27	0.36	1.21	0.07	0.07
94	8.75	67.00	0.01	0.07	-----	0.00
41	9.00	67.39	0.38	1.27	0.07	0.07
94	9.00	67.00	0.01	0.07	-----	0.00
41	9.25	67.31	0.41	1.37	0.08	0.08
94	9.25	67.00	0.01	0.08	-----	0.00
41	9.50	67.33	0.43	1.43	0.08	0.08
94	9.50	67.00	0.02	0.08	-----	0.00
41	9.75	67.36	0.46	1.58	0.08	0.08
94	9.75	67.00	0.02	0.08	-----	0.00
41	10.00	67.38	0.49	1.69	0.09	0.09
94	10.00	67.00	0.02	0.09	-----	0.00
41	10.25	67.41	0.53	1.89	0.09	0.09
94	10.25	67.00	0.02	0.09	-----	0.00

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ALAFAYA TRAIL POND 4 (POST)
 30NOV89

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW # 1	OUTFLOW (cfs) TOTAL
41	10.50	67.44	0.57	2.06	0.09	0.09
94	10.50	67.00	0.02	0.09	-----	0.00
41	10.75	67.47	0.61	2.38	0.10	0.10
94	10.75	67.00	0.03	0.10	-----	0.00
41	11.00	67.51	0.66	2.67	0.10	0.10
94	11.00	67.00	0.03	0.10	-----	0.00
41	11.25	67.55	0.72	3.25	0.11	0.11
94	11.25	67.00	0.03	0.11	-----	0.00
41	11.50	67.60	0.79	3.60	0.12	0.12
94	11.50	67.00	0.03	0.12	-----	0.00
41	11.75	67.70	0.93	3.95	0.13	0.13
94	11.75	67.00	0.03	0.13	-----	0.00
41	12.00	67.89	1.19	15.50	0.15	0.15
94	12.00	67.00	0.04	0.15	-----	0.00
41	12.25	68.12	1.51	15.67	0.20	0.20
94	12.25	67.00	0.04	0.20	-----	0.00
41	12.50	68.33	1.82	15.68	1.39	1.39
94	12.50	67.00	0.06	1.39	-----	0.00
41	12.75	68.49	2.06	13.95	4.32	4.32
94	12.75	67.00	0.12	4.32	-----	0.00
41	13.00	68.60	2.22	12.44	6.16	6.16
94	13.00	67.00	0.23	6.16	-----	0.00
41	13.25	68.67	2.32	10.94	7.39	7.39
94	13.25	67.00	0.37	7.39	-----	0.00
41	13.50	68.70	2.38	9.69	8.07	8.07
94	13.50	67.00	0.53	8.07	-----	0.00
41	13.75	68.71	2.40	8.56	8.31	8.31
94	13.75	67.00	0.70	8.31	-----	0.00

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IC88136 VER 2.93

ALAPAYA TRAIL POND 4 (POST)
 10NOV89

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW (cfs) # 1	TOTAL
41	14.00	68.71	2.33	7.61	8.23	8.23
94	14.00	67.00	0.87	8.23	-----	0.00
41	14.25	68.70	2.37	6.74	7.99	7.99
94	14.25	67.00	1.04	7.99	-----	0.00
41	14.50	68.68	2.34	6.02	7.61	7.61
94	14.50	67.00	1.20	7.61	-----	0.00
41	14.75	68.65	2.31	5.35	7.16	7.16
94	14.75	67.00	1.36	7.16	-----	0.00
41	15.00	68.63	2.27	4.60	6.69	6.69
94	15.00	67.00	1.50	6.69	-----	0.00
41	15.25	68.60	2.23	4.33	6.22	6.22
94	15.25	67.00	1.63	6.22	-----	0.00
41	15.50	68.58	2.19	3.94	5.77	5.77
94	15.50	67.00	1.76	5.77	-----	0.00
41	15.75	68.55	2.15	3.57	5.34	5.34
94	15.75	67.00	1.87	5.34	-----	0.00
41	16.00	68.53	2.12	3.26	4.94	4.94
94	16.00	67.00	1.98	4.94	-----	0.00
41	16.25	68.51	2.08	2.99	4.58	4.58
94	16.25	67.00	2.08	4.58	-----	0.00
41	16.50	68.49	2.05	2.76	4.23	4.23
94	16.50	67.00	2.17	4.23	-----	0.00
41	16.75	68.47	2.02	2.56	3.92	3.92
94	16.75	67.00	2.25	3.92	-----	0.00
41	17.00	68.45	1.99	2.40	3.64	3.64
94	17.00	67.00	2.33	3.64	-----	0.00
41	17.25	68.43	1.97	2.23	3.39	3.39
94	17.25	67.00	2.40	3.39	-----	0.00

*** INTER-CONNECTED POND ROUTING PROGRAM ***
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1028136 VER 2.83

ALAFAYA TRAIL POND 4 (POST)
 30NOV89

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW (cfs) # 1	TOTAL
41	17.50	63.41	1.95	2.09	3.16	3.16
94	17.50	67.00	2.47	3.16	-----	0.00
41	17.75	68.40	1.92	1.97	2.95	2.95
94	17.75	67.00	2.53	2.95	-----	0.00
41	18.00	68.39	1.90	1.88	2.77	2.77
94	18.00	67.00	2.59	2.77	-----	0.00
41	18.25	68.37	1.89	1.77	2.61	2.61
94	18.25	67.00	2.65	2.61	-----	0.00
41	18.50	68.36	1.87	1.69	2.46	2.46
94	18.50	67.00	2.70	2.46	-----	0.00
41	18.75	68.35	1.85	1.62	2.32	2.32
94	18.75	67.00	2.75	2.32	-----	0.00
41	19.00	68.34	1.84	1.56	2.20	2.20
94	19.00	67.00	2.80	2.20	-----	0.00
41	19.25	68.33	1.83	1.49	2.09	2.09
94	19.25	67.00	2.84	2.09	-----	0.00
41	19.50	68.33	1.82	1.43	1.99	1.99
94	19.50	67.00	2.88	1.99	-----	0.00
41	19.75	68.32	1.80	1.39	1.90	1.90
94	19.75	67.00	2.92	1.90	-----	0.00
41	20.00	68.31	1.79	1.36	1.82	1.82
94	20.00	67.00	2.96	1.82	-----	0.00
41	20.25	68.31	1.79	1.32	1.74	1.74
94	20.25	67.00	3.00	1.74	-----	0.00
41	20.50	68.30	1.78	1.29	1.68	1.68
94	20.50	67.00	3.04	1.68	-----	0.00
41	20.75	68.29	1.77	1.24	1.62	1.62
94	20.75	67.00	3.07	1.62	-----	0.00

*** INTER-CONNECTED POND ROUTING PROGRAM ***
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IC98135 VER 2.83

ALAPAYA TRAIL POND 4 (POST)
 30NOV89

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW # 1	(cfs) TOTAL
41	21.00	68.29	1.76	1.20	1.56	1.56
94	21.00	67.00	3.10	1.56	-----	0.00
41	21.25	68.29	1.75	1.17	1.50	1.50
94	21.25	67.00	3.13	1.50	-----	0.00
41	21.50	68.28	1.75	1.14	1.45	1.45
94	21.50	67.00	3.16	1.45	-----	0.00
41	21.75	68.27	1.74	1.11	1.41	1.41
94	21.75	67.00	3.19	1.41	-----	0.00
41	22.00	68.27	1.74	1.10	1.37	1.37
94	22.00	67.00	3.22	1.37	-----	0.00
41	22.25	68.27	1.73	1.08	1.33	1.33
94	22.25	67.00	3.25	1.33	-----	0.00
41	22.50	68.26	1.73	1.07	1.29	1.29
94	22.50	67.00	3.28	1.29	-----	0.00
41	22.75	68.26	1.72	1.04	1.26	1.26
94	22.75	67.00	3.30	1.26	-----	0.00
41	23.00	68.26	1.72	1.02	1.23	1.23
94	23.00	67.00	3.33	1.23	-----	0.00
41	23.25	68.25	1.71	0.99	1.20	1.20
94	23.25	67.00	3.36	1.20	-----	0.00
41	23.50	68.25	1.71	0.97	1.17	1.17
94	23.50	67.00	3.38	1.17	-----	0.00
41	23.75	68.25	1.70	0.93	1.14	1.14
94	23.75	67.00	3.40	1.14	-----	0.00
41	24.00	68.25	1.70	0.89	1.11	1.11
94	24.00	67.00	3.43	1.11	-----	0.00

*** INTER-CONNECTED POND ROUTING PROGRAM *** IC98136 VER 2.83

ALAPAYA TRAIL POND 4 (POST)
30NOV89

*** PEAK CONDITIONS SUMMARY ***

NODE	PEAK STAGE (feet)	PEAK STORAGE (acft)	TIME TO PEAK (hrs)	PEAK OUTFLOW (cfs)	TIME TO PEAK (hrs)
41	58.71	2.40	13.82	3.32	13.82
94	57.00	0.00	0.02	0.00	0.02

FROM NODE	TO NODE	PEAK OUTFLOW (cfs)	TIME TO PEAK (hrs)
41	94	3.32	13.82

SECONDARY SYSTEM

TIME PROCESSED
ENGINEER: ROSTWICK

DESIGN STANDARDS

PIPE COST DATA: SIZE(IN): COST(\$):

Page 6.2-333

DATE PROCESSED
PROJECT

0- 0

FINAL SYSTEM DESIGN
ZONE 7 FREQ10

TIME PROCESSED
PAGE

3

ALAFAYA TRAIL POND 4

PIPE IDENT FROM TO (STA)	TYPE	LENGTH (FEET)	DRAINAGE AREA (ACRES) C1=0.90 C2=0.20 C3=0.00			TIME OF CONC (MIN)	TIME OF FLOW IN PIPE (MIN)	INTENSITY (IN/HR)	TOTAL CA	2 (CFS)	GUTTER OR INLET INCLUDES ELEV ADDED FLOW OF ()	ELEV. OF H.W. FALL PIPE CROWN ELEV P.L. ELEV UPPER END LOWER END			PIPE DIA (IN)	SLOPE (%)	VEL. (FPS)	HYD GRADIENT PHYSICAL
			INCREMENT	TOTAL	SUB TOTAL CA													
403-402	H	51	2.57	2.57	2.31	58.00	0.51	3.00	2.83	8.48	69.40	68.37	68.28	0.09	30	0.146	1.73	.024
399-400	S-R		2.57	2.57	0.51													
			0.00	0.00	0.00													
402-401	H	100	2.57	5.14	4.63	58.51	1.25	2.98	5.30	18.60	71.54	68.28	67.98	0.31	35	0.153	2.65	.018
399-400	SR		5.73	8.35	1.67													
			0.00	0.00	0.00													
401-400	H	32	0.00	5.14	4.63	59.76	0.77	2.95	5.30	18.60	69.00	67.98	67.66	0.32	42	0.129	1.95	.025
397-23	34L		0.00	8.35	1.67													
			0.00	0.00	0.00													

DATE PROCESSED
PROJECT

0- 0

COST SUMMARY

TIME PROCESSED
PAGE

3

ALAFAYA TRAIL FOND 4

PIPE IDENT	COST (\$)	PIPE IDENT	COST (\$)	PIPE IDENT	COST (\$)
FROM TO		FROM TO		FROM TO	
403 402	1359.32	402 401	7500.00	401 400	4788.80

TOTAL SYSTEM COST = 14647.92

DATE PROCESSED
PROJECT

SYSTEM ANALYSIS

TIME PROCESSED
PAGE

ALAFAYA TRAIL POND 4

MESSAGE		PIPE LINE
MAXIMUM DEPTH OF CUT (TO CROWN)	0.00 FT	403 TO 402
MAXIMUM VELOCITY (GRADIENT FLOW)	2.66 FPS	402 TO 401
MAXIMUM PIPE SLOPE	0.00 PERCENT	403 TO 402
MINIMUM VELOCITY IN MAIN (H.G. FLOW)	1.73 FPS	403 TO 402
MINIMUM VELOCITY (GRAVITY FLOW)	0.00 FPS	403 TO 402
MINIMUM HYDRAULIC GRADIENT CLEARANCE TO GUTTER	1.02 FT	401 TO 400
MINIMUM HYDRAULIC GRADIENT CLEARANCE TO CONTROL	0.02 FT	401 TO 400
TOTAL DRAINAGE AREA	13.50 ACRES	
WEIGHTED COEFFICIENT	0.47	

MAXIMUM DEPTH OF CUT CONTROL USED FOR RESTRAINT AT -

NO PIPES

DESIGN FLOW GREATER THAN 10 FPS IN THE FOLLOWING PIPE LENGTHS -

NO PIPES

COMMENTS

POND 5

POND 5

Pond 5 is a wet detention facility located between Station 424+00 and Station 428+00 adjacent to the easterly right-of-way line. The pond is encompassed by a 5 foot wide maintenance berm with the top bank elevation set at 64.5 Ft. NGVD. From the top of bank, the pond sideslopes are 5:1 to elevation 62.5 Ft. NGVD, then 6:1 to elevation 59.5 Ft. NGVD, then 2:1 to the bottom elevation 54.5 Ft. NGVD. The 6:1 slopes are to be covered with muck from area excavation and allowed to naturally vegetate.

Inflow to the pond is via a combination open (swale) drainage, inlet and pipe system along Alafaya Trail. The runoff will enter the northwest most access point to the pond to limit direct movement to the outfall wetland.

Discharge from the pond is over a large broad-crested weir located at the north end of the facility. A 4 Ft. weir, set at 62.84 Ft. NGVD, contains a 3 inch diameter bleeder with an invert of 62.5 Ft. NGVD. The discharge flow over the weir outfalls into the adjacent wetland strand.

EXISTING CONDITIONS

The portion of Alafaya Trail from Station 413+50 to Station 451+50 was considered as Drainage Basin 5. Drainage Basin 5 currently outfalls through a series of wetland strands to Cowpen Branch Crossing. While these positive outfalls exist, the runoff from the existing area is conveyed by surface sheetflow. Considering the area's flat topography, there are no well defined drainage pathways. The peak rate of discharge from the project area was estimated using Santa

Barbara Unit Hydrograph. The peak rate of discharge from this portion of Alafaya Trail is approximately 8.1 CFS during the 25 year/24 hours storm event.

PROPOSED CONDITIONS

The design of Pond 5 proposes to collect the roadway right-of-way from Station 413+50 to 451+50. The pond inflows were calculated using Santa Barbara Unit Hydrograph and routed using Inter-Connected Pond Routing.

The project runoff is collected and conveyed by swales on each side of the roadway. The runoff is then collected in a ditch bottom inlet and piped to the proposed pond facility location.

This pond is designed using the 25 year/24 hour storm event. The crest of the outfall weir is set to provide wet detention for 1 inch of runoff from the project area. The bleeder orifice, in the weir structure, is sized to recover an 0.5 inch of the detained volume within 60 hours.

The post development peak rate of discharge for this portion of Alafaya Trail is 7.0 CFS, with the peak stage in the pond being 63.48 Ft. NGVD, thus insuring ample freeboard for the pond facility.

PRIMARY SYSTEM

ALAFAYA TR. FRE PONDS

How many basins? --> 3
Simulation Duration (hrs) --> 24.5
Time Increment (mins) --> 1
Print Interval --> 15
Save Results? (Y/N) --> Y

Specify FILENAME containing INPUT DATA --> D:SP5.PRE
Specify FILENAME to be used for COMPOSITES --> D:SP5.HYD

ALAFAYA TR. PRE PONDS

BASIN ID	NODE #	AREA (acres)	% LAKE	% DCIA	CN N-DCIA	TC (min)	INI AB	INI AB
							DCIA	N-DCIA
							(ins)	(dec)
500	95	7.8	0.0	0.0	79.0	206.0	0.10	0.20
501	95	1.6	0.0	0.0	79.0	206.0	0.10	0.20
505	95	0.1	0.0	0.0	1.0	100.0	0.10	0.20

***** RAINFALL INPUT SECTION *****

Less Curve or Actual Rainfall? (M/A) --) M

- 1 SCS TYPE II
- 2 ORANGE COUNTY 6-HOUR
- 3 24-HOUR
- 4 SCS TYPE II-M
- 5 FDOT 1 HOUR
- 6 FDOT 2 HOUR
- 7 FDOT 4 HOUR
- 8 FDOT 8 HOUR
- 9 FDOT 1 DAY
- 10 FDOT 3 DAY
- 11 FDOT 7 DAY
- 12 FDOT 10 DAY
- 13 SCS TYPE 2M 96HR

Specify CURVE TYPE = 4

Storm Duration (hrs) --) 24
Total Rainfall (inches) --) 8.6

ALAFAYA TR. FFE PONDS

TIME (hrs)	RAIN (in/hr)	BASIN 500	BASIN 501	BASIN 505
0.000	0.000	0.0	0.0	0.0
0.250	0.000	0.0	0.0	0.0
0.500	0.001	0.0	0.0	0.0
0.750	0.007	0.0	0.0	0.0
1.000	0.011	0.0	0.0	0.0
1.250	0.013	0.0	0.0	0.0
1.500	0.014	0.0	0.0	0.0
1.750	0.015	0.0	0.0	0.0
2.000	0.016	0.0	0.0	0.0
2.250	0.016	0.0	0.0	0.0
2.500	0.016	0.0	0.0	0.0
2.750	0.016	0.0	0.0	0.0
3.000	0.016	0.0	0.0	0.0
3.250	0.016	0.0	0.0	0.0
3.500	0.016	0.0	0.0	0.0
3.750	0.016	0.0	0.0	0.0
4.000	0.016	0.0	0.0	0.0
4.250	0.017	0.0	0.0	0.0
4.500	0.032	0.0	0.0	0.0
4.750	0.072	0.0	0.0	0.0
5.000	0.012	0.0	0.0	0.0
5.250	0.050	0.0	0.0	0.0
5.500	0.069	0.0	0.0	0.0
5.750	0.727	0.0	0.0	0.0
6.000	0.735	0.0	0.0	0.0
6.250	0.808	0.1	0.0	0.0
6.500	0.851	0.1	0.0	0.0
6.750	0.858	0.1	0.0	0.0
7.000	0.845	0.1	0.0	0.0
7.250	0.935	0.1	0.0	0.0
7.500	1.047	0.1	0.0	0.0
7.750	1.105	0.2	0.0	0.0
8.000	1.163	0.2	0.0	0.0
8.250	1.223	0.2	0.0	0.0
8.500	1.252	0.3	0.1	0.0
8.750	1.345	0.3	0.1	0.0
9.000	1.410	0.4	0.1	0.0
9.250	1.483	0.4	0.1	0.0
9.500	1.555	0.4	0.1	0.0
9.750	1.641	0.5	0.1	0.0
10.000	1.726	0.6	0.1	0.0
10.250	1.832	0.7	0.1	0.0
10.500	1.938	0.7	0.2	0.0
10.750	2.080	0.9	0.2	0.0
11.000	2.225	1.0	0.2	0.0
11.250	2.435	1.2	0.3	0.0
11.500	2.561	1.5	0.3	0.0
11.750	3.936	3.5	0.7	0.0
12.000	5.212	5.6	1.1	0.0

LOAFAYA TR. ARE PONDS

TIME (hrs)	RAIN (ins)	BASIN 500	BASIN 501	BASIN 505
12.250	5.883	5.1	1.3	0.0
12.500	5.187	5.7	1.4	0.0
12.750	5.333	5.5	1.3	0.0
13.000	5.505	5.5	1.3	0.0
13.250	5.622	5.3	1.3	0.0
13.500	5.745	5.1	1.2	0.0
13.750	5.845	5.3	1.2	0.0
14.000	5.943	5.5	1.1	0.0
14.250	7.024	5.4	1.1	0.0
14.500	7.115	5.2	1.1	0.0
14.750	7.173	5.0	1.0	0.0
15.000	7.241	4.8	1.0	0.0
15.250	7.305	4.5	0.9	0.0
15.500	7.369	4.4	0.9	0.0
15.750	7.423	4.2	0.8	0.0
16.000	7.480	4.0	0.8	0.0
16.250	7.532	3.8	0.8	0.0
16.500	7.583	3.7	0.7	0.0
16.750	7.632	3.5	0.7	0.0
17.000	7.681	3.4	0.7	0.0
17.250	7.724	3.2	0.7	0.0
17.500	7.766	3.1	0.6	0.0
17.750	7.809	2.9	0.6	0.0
18.000	7.852	2.8	0.6	0.0
18.250	7.890	2.7	0.6	0.0
18.500	7.929	2.5	0.5	0.0
18.750	7.967	2.5	0.5	0.0
19.000	8.005	2.4	0.5	0.0
19.250	8.040	2.3	0.5	0.0
19.500	8.074	2.2	0.4	0.0
19.750	8.109	2.1	0.4	0.0
20.000	8.145	2.1	0.4	0.0
20.250	8.179	2.0	0.4	0.0
20.500	8.213	1.9	0.4	0.0
20.750	8.243	1.8	0.4	0.0
21.000	8.273	1.8	0.4	0.0
21.250	8.303	1.7	0.3	0.0
21.500	8.333	1.7	0.3	0.0
21.750	8.363	1.6	0.3	0.0
22.000	8.393	1.5	0.3	0.0
22.250	8.422	1.5	0.3	0.0
22.500	8.452	1.5	0.3	0.0
22.750	8.479	1.4	0.3	0.0
23.000	8.506	1.4	0.3	0.0
23.250	8.532	1.3	0.3	0.0
23.500	8.557	1.3	0.3	0.0
23.750	8.579	1.2	0.3	0.0
24.000	8.600	1.2	0.2	0.0
24.250	8.600	1.1	0.2	0.0

SANTA BARBARA URBAN HYDROGRAPH 3338118 VER 1.2
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ALAFAYA TR. FFE PONDS

TIME	RAIN	BASIN	BASIN	BASIN
(hrs)	(ins)	500	501	505
----	----	----	----	----
14.500	8.500	1.0	0.2	0.0

SANTA BARBARA URBAN HYDROGRAPH 8888118 VER 1.2
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BLAFAYA TR. PRE PONDS

*** RUNOFF SUMMARY ***

Basin ID# —)	500	501	505
FD VOL (cfs-hrs)	44	3	0
FD VOL (ac-ft)	3.7	0.7	0.0
FD VOL (inches)	5.92	5.92	0.00
PEAK FLOW (cfs)	3.7	1.4	0.0
PEAK TIME (hrs)	12.517	12.517	0.000

-- COMPOSITE HYDROGRAPHS (— (SBUH1X1)
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TIME (hrs)	WIDE SE
1.000	0.0
1.250	0.0
1.500	0.0
1.750	0.0
2.000	0.0
2.250	0.0
2.500	0.0
2.750	0.0
3.000	0.0
3.250	0.0
3.500	0.0
3.750	0.0
4.000	0.0
4.250	0.0
4.500	0.0
4.750	0.0
5.000	0.0
5.250	0.0
5.500	0.0
5.750	0.0
6.000	0.0
6.250	0.1
6.500	0.1
6.750	0.1
7.000	0.1
7.250	0.1
7.500	0.2
7.750	0.2
8.000	0.3
8.250	0.3
8.500	0.3
8.750	0.4
9.000	0.4
9.250	0.5
9.500	0.5
9.750	0.6
10.000	0.7
10.250	0.8
10.500	0.9
10.750	1.0
11.000	1.2
11.250	1.5
11.500	1.8
11.750	4.2
12.000	6.7

-- COMPOSITE HYDROGRAPHS -- (SBUH1X1)
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TIME (hrs)	WDE SS
13.350	7.5
13.500	6.1
13.750	7.9
13.000	7.3
13.350	7.5
13.500	7.3
13.750	7.0
14.000	6.8
14.350	6.5
14.500	6.2
14.750	6.0
15.000	5.7
15.350	5.5
15.500	5.2
15.750	5.0
16.000	4.8
16.350	4.6
16.500	4.4
16.750	4.2
17.000	4.0
17.250	3.9
17.500	3.7
17.750	3.5
18.000	3.4
18.350	3.3
18.500	3.1
18.750	3.0
19.000	2.9
19.250	2.8
19.500	2.7
19.750	2.6
20.000	2.5
20.250	2.4
20.500	2.3
20.750	2.2
21.000	2.1
21.250	2.1
21.500	2.0
21.750	1.9
22.000	1.9
22.250	1.8
22.500	1.8
22.750	1.7
23.000	1.6
23.250	1.6
23.500	1.5
23.750	1.5
24.000	1.4
24.250	1.3

-- COMPOSITE HYDROGRAPHS -- (SBUH1X1)
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TIME	NODE
(hrs)	95
24.500	1.2

ALAFAYA TR. POST PONDS

How many basins? --> 3
Simulation Duration (hrs) --> 24.5
Time Increment (mins) --> 1
Print Interval --> 15
Save Results? (Y/N) --> Y

Specify FILENAME containing INPUT DATA --> D:SP5.POS
Specify FILENAME to be used for COMPOSITES --> D:SP5.HYD1

PLAFAYA TR. POST PONDS

BASIN ID	NODE #	AREA (acres)	% LAKE	% DCIA	CN N-DCIA	TC (min)	INI AB	INI AB
							DCIA	N-DCIA (dec)
500	51	7.8	0.0	35.0	79.0	37.0	0.10	0.20
501	51	1.5	0.0	100.0	99.0	37.0	0.10	0.20
505	55	0.1	0.0	0.0	1.0	100.0	0.10	0.20

***** RAINFALL INPUT SECTION *****

Use Curve or Actual Rainfall? (M/A) --) M

- 1 SCS TYPE II
- 2 ORANGE COUNTY 6-HOUR
- 3 24-HOUR
- 4 SCS TYPE II-M
- 5 FDOT 1 HOUR
- 6 FDOT 2 HOUR
- 7 FDOT 4 HOUR
- 8 FDOT 8 HOUR
- 9 FDOT 1 DAY
- 10 FDOT 3 DAY
- 11 FDOT 7 DAY
- 12 FDOT 10 DAY
- 13 SCS TYPE 2M 96HR

Specify CURVE TYPE = 4

Storm Duration (hrs) --> 24
Total Rainfall (inches) --> 3.6

BLAFAYA TR. POST PONDS

TIME (hrs)	RAIN (ins)	BASIN 500	BASIN 501	BASIN 505
0.000	0.000	0.0	0.0	0.0
0.250	0.026	0.0	0.0	0.0
0.500	0.051	0.0	0.0	0.0
0.750	0.077	0.0	0.0	0.0
1.000	0.102	0.0	0.0	0.0
1.250	0.128	0.0	0.0	0.0
1.500	0.154	0.1	0.0	0.0
1.750	0.185	0.1	0.1	0.0
2.000	0.216	0.2	0.1	0.0
2.250	0.246	0.2	0.1	0.0
2.500	0.275	0.2	0.1	0.0
2.750	0.306	0.2	0.1	0.0
3.000	0.335	0.3	0.1	0.0
3.250	0.365	0.3	0.2	0.0
3.500	0.395	0.3	0.2	0.0
3.750	0.429	0.3	0.2	0.0
4.000	0.463	0.3	0.2	0.0
4.250	0.497	0.3	0.2	0.0
4.500	0.532	0.3	0.2	0.0
4.750	0.572	0.4	0.2	0.0
5.000	0.612	0.4	0.2	0.0
5.250	0.650	0.4	0.2	0.0
5.500	0.689	0.4	0.2	0.0
5.750	0.727	0.4	0.2	0.0
6.000	0.765	0.5	0.2	0.0
6.250	0.808	0.5	0.2	0.0
6.500	0.851	0.5	0.2	0.0
6.750	0.893	0.5	0.3	0.0
7.000	0.945	0.6	0.3	0.0
7.250	0.996	0.6	0.3	0.0
7.500	1.047	0.7	0.3	0.0
7.750	1.105	0.7	0.3	0.0
8.000	1.163	0.8	0.3	0.0
8.250	1.223	0.8	0.3	0.0
8.500	1.282	0.9	0.3	0.0
8.750	1.346	0.9	0.3	0.0
9.000	1.410	1.0	0.4	0.0
9.250	1.483	1.1	0.4	0.0
9.500	1.555	1.1	0.4	0.0
9.750	1.641	1.2	0.4	0.0
10.000	1.725	1.3	0.4	0.0
10.250	1.822	1.5	0.5	0.0
10.500	1.928	1.6	0.5	0.0
10.750	2.030	1.9	0.6	0.0
11.000	2.225	2.1	0.6	0.0
11.250	2.435	2.6	0.7	0.0
11.500	2.661	3.1	0.8	0.0
11.750	3.036	7.3	2.0	0.0
12.000	5.212	12.4	3.0	0.0

SLAFAYA TR. POST PONDS

TIME (hrs)	RAIN (ins)	BASIN 500	BASIN 501	BASIN 905
12.250	5.669	12.7	3.0	0.0
12.500	6.167	12.9	3.0	0.0
12.750	6.338	11.7	2.7	0.0
13.000	6.505	10.7	2.5	0.0
13.250	6.622	9.5	2.2	0.0
13.500	6.745	8.6	2.0	0.0
13.750	6.845	7.7	1.8	0.0
14.000	6.943	7.0	1.6	0.0
14.250	7.024	6.2	1.4	0.0
14.500	7.105	5.6	1.3	0.0
14.750	7.173	5.1	1.1	0.0
15.000	7.241	4.6	1.0	0.0
15.250	7.315	4.2	0.9	0.0
15.500	7.389	3.8	0.9	0.0
15.750	7.465	3.5	0.8	0.0
16.000	7.490	3.2	0.7	0.0
16.250	7.522	2.9	0.6	0.0
16.500	7.553	2.7	0.6	0.0
16.750	7.622	2.5	0.6	0.0
17.000	7.681	2.4	0.5	0.0
17.250	7.724	2.2	0.5	0.0
17.500	7.766	2.0	0.4	0.0
17.750	7.809	1.9	0.4	0.0
18.000	7.852	1.8	0.4	0.0
18.250	7.890	1.7	0.4	0.0
18.500	7.929	1.6	0.4	0.0
18.750	7.967	1.6	0.3	0.0
19.000	8.005	1.5	0.3	0.0
19.250	8.040	1.4	0.3	0.0
19.500	8.074	1.4	0.3	0.0
19.750	8.109	1.3	0.3	0.0
20.000	8.145	1.3	0.3	0.0
20.250	8.173	1.2	0.3	0.0
20.500	8.213	1.2	0.3	0.0
20.750	8.243	1.2	0.2	0.0
21.000	8.273	1.1	0.2	0.0
21.250	8.303	1.1	0.2	0.0
21.500	8.333	1.1	0.2	0.0
21.750	8.363	1.0	0.2	0.0
22.000	8.393	1.0	0.2	0.0
22.250	8.422	1.0	0.2	0.0
22.500	8.452	1.0	0.2	0.0
22.750	8.479	1.0	0.2	0.0
23.000	8.506	0.9	0.2	0.0
23.250	8.532	0.9	0.2	0.0
23.500	8.557	0.9	0.2	0.0
23.750	8.579	0.9	0.2	0.0
24.000	8.600	0.8	0.2	0.0
24.250	8.600	0.7	0.1	0.0

SANTA BARBARA URBAN HYDROGRAPH S566118 VER 1.2
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BLAFAYA TR. POST PONDS

TIME	RAIN	BASIN	BASIN	BASIN
(hrs)	(ins)	500	501	505
24.500	3.500	0.5	0.1	0.0

SANTA BARBARA URBAN HYDROGRAPH SB68118 VER 1.2
(C) Copyright 1983, Peter J. Singhofen, P.E.

ALAFAYA TR. POST PONDS

*** RUNOFF SUMMARY ***

Basin ID# --)	500	501	505
PD VOL (cfs-hrs)	54	14	0
PD VOL (ac-ft)	4.5	1.1	0.0
PD VOL (inches)	5.84	8.39	0.00
PEAK FLOW (cfs)	12.9	3.0	0.0
PEAK TIME (hrs)	12.500	12.500	0.000

-- COMPOSITE HYDROGRAPHS (--- (SBUHIX1)
 (C) Copyright 1983, Peter J. Singhofen, P.E.

TIME (hrs)	NODE E1	NODE E5
0.000	0.0	0.0
0.250	0.0	0.0
0.500	0.0	0.0
0.750	0.0	0.0
1.000	0.0	0.0
1.250	0.1	0.0
1.500	0.1	0.0
1.750	0.2	0.0
2.000	0.3	0.0
2.250	0.3	0.0
2.500	0.3	0.0
2.750	0.4	0.0
3.000	0.4	0.0
3.250	0.4	0.0
3.500	0.4	0.0
3.750	0.5	0.0
4.000	0.5	0.0
4.250	0.5	0.0
4.500	0.5	0.0
4.750	0.6	0.0
5.000	0.6	0.0
5.250	0.6	0.0
5.500	0.6	0.0
5.750	0.7	0.0
6.000	0.7	0.0
6.250	0.7	0.0
6.500	0.7	0.0
6.750	0.8	0.0
7.000	0.8	0.0
7.250	0.9	0.0
7.500	0.9	0.0
7.750	1.0	0.0
8.000	1.1	0.0
8.250	1.1	0.0
8.500	1.2	0.0
8.750	1.3	0.0
9.000	1.3	0.0
9.250	1.4	0.0
9.500	1.5	0.0
9.750	1.7	0.0
10.000	1.8	0.0
10.250	2.0	0.0
10.500	2.2	0.0
10.750	2.5	0.0
11.000	2.8	0.0
11.250	3.4	0.0
11.500	3.9	0.0
11.750	9.9	0.0
12.000	15.3	0.0

-- COMPOSITE HYDROGRAPHS (--- (SBUH1X1)
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TIME (hrs)	NODE 51	NODE 55
12.250	15.7	0.0
12.500	16.0	0.0
12.750	14.5	0.0
13.000	13.1	0.0
13.250	11.8	0.0
13.500	10.6	0.0
13.750	9.5	0.0
14.000	8.3	0.0
14.250	7.7	0.0
14.500	6.9	0.0
14.750	6.1	0.0
15.000	5.3	0.0
15.250	5.1	0.0
15.500	4.7	0.0
15.750	4.2	0.0
16.000	3.9	0.0
16.250	3.6	0.0
16.500	3.3	0.0
16.750	3.1	0.0
17.000	2.9	0.0
17.250	2.7	0.0
17.500	2.5	0.0
17.750	2.3	0.0
18.000	2.2	0.0
18.250	2.1	0.0
18.500	2.0	0.0
18.750	1.9	0.0
19.000	1.8	0.0
19.250	1.7	0.0
19.500	1.7	0.0
19.750	1.6	0.0
20.000	1.6	0.0
20.250	1.5	0.0
20.500	1.5	0.0
20.750	1.4	0.0
21.000	1.4	0.0
21.250	1.3	0.0
21.500	1.3	0.0
21.750	1.3	0.0
22.000	1.2	0.0
22.250	1.2	0.0
22.500	1.2	0.0
22.750	1.2	0.0
23.000	1.1	0.0
23.250	1.1	0.0
23.500	1.1	0.0
23.750	1.0	0.0
24.000	1.0	0.0
24.250	0.8	0.0

→ COMPOSITE HYDROGRAPHS (--- (SBUH1X1)
C) Copyright 1983, Peter J. Singhofen, P.E.

TIME	NODE	NODE
(hrs)	E1	E5
14.500	0.7	0.0

ELEVATION - STORAGE VALUES

Prgrm : DTBSIN6R.VOL

DETENTION BASIN DESIGN

01-04-1980

Name of Storage Basin : ALAFAYA TRAIL POND 5

ELEVATION TOP STORAGE BASIN-FT ==> 64.5

ELEVATION BOT STORAGE BASIN - FT ==> 62.5

INCREMENTAL STAGE DEPTH - FT ==> .1

STORAGE BASIN AREA - ACRES AT TOP OF BASIN ==> 3.13

STORAGE BASIN PERIMETER @ TOP OF BASIN ==> 1562

AVERAGE SIDE SLOPE RATIO ==> 5

STAGE EL.	AREA-ACRES	STORAGE-AC FT
62.50	2.770	0.00
62.60	2.790	0.28
62.70	2.810	0.56
62.80	2.830	0.84
62.90	2.840	1.12
63.00	2.860	1.41
63.10	2.880	1.70
63.20	2.900	1.98
63.30	2.910	2.27
63.40	2.930	2.57
63.50	2.950	2.86
63.60	2.970	3.16
63.70	2.990	3.45
63.80	3.000	3.75
63.90	3.020	4.06
64.00	3.040	4.36
64.10	3.060	4.66
64.20	3.080	4.97
64.30	3.090	5.28
64.40	3.110	5.59
64.50	3.130	5.90

*** End of This Calculation ***

LOCHRANE ENGINEERING, INC.

201 S. Bumby Avenue
ORLANDO, FL 32803
(407) 896-3317

JOB 413-242-73
SHEET NO. _____ OF _____
CALCULATED BY Cal DATE _____
CHECKED BY _____ DATE _____
SCALE _____

Net Detention

Pond 5

1" Runoff (Water Quality)

$$7.15 \text{ ac } (1")/2 = 0.60 \text{ acft} \rightarrow 62.72 \text{ Ft NGVD}$$

min. weir el.

62.5 Ft Normal Pool El.

Using 3" orifice invert at N.P. el.

$$62.5 \text{ Ft} + 0.25'/2 = 62.62 \text{ Ft } \phi \text{ of orifice}$$

Area Ratio	Basin Area	7.15 ac
	Normal Pool	2.77 ac

$$\frac{7.15}{2.77} = 2.58 \leq 10 \quad \checkmark$$

Littoral shelf	Normal Pool	2.77 ac
	Open Water	2.08 ac

$$\frac{2.08}{2.77} = 75\% \leq 75\% \quad \checkmark$$

Pre Development Flow 8.1 cfs

Post Development	Peak stage	63.48 Ft (T.O.B. 64.50 Ft)
	Peak Flow	7.00 cfs

$$T.L. El. = \frac{63.48 + 62.72}{2} = 63.10 \text{ Ft NGVD}$$

POND 5

Orifice (Recovery)

Purpose: to recover 0.5" runoff in 60 hrs.

$$0.5" / 12 (10.28 \text{ ac}) = 0.43 \text{ ac ft}$$

$$0.43 \text{ ac ft} \rightarrow 18731 \text{ CF}$$

$$60 \text{ hrs} \rightarrow 216000 \text{ sec}$$

$$0.09 \text{ CFS}$$

$$1" \text{ runoff } 1" / (12) [10.28 \text{ ac}] = 0.86 \text{ ac ft} \rightarrow 62.91 \text{ FT NGVD}$$

$$0.86 \text{ ac ft} - 0.43 \text{ ac ft} = 0.43 \text{ ac ft} \rightarrow 62.65 \text{ FT NGVD @ 60 hrs}$$

$$A = \frac{Q}{C(2gH)^{1/2}}$$

$$H = \left(\frac{62.91 + 62.65}{2} \right) - 62.5 \text{ FT} = 0.23 \text{ FT}$$

$$C = 0.6$$

$$A = \frac{0.09 \text{ CFS}}{0.6 (64.4 (0.23))^{1/2}}$$

$$A = 0.04 \text{ SF} \sim 5.6 \text{ in}^2$$

$$D = (4A / \pi)^{1/2}$$

$$D = 2.7 \text{ in.}$$

Use ~~3/4"~~ ^{2.5"} orifice

ELEVATION - STORAGE VALUES

Prgr : DTBSINGR.VOL

DETENTION BASIN DESIGN

01-04-1980

Name of Storage Basin : P5

ELEVATION TOP STORAGE BASIN-FT ==> 63.5

ELEVATION BOT STORAGE BASIN - FT ==> 54.5

INCREMENTAL STAGE DEPTH - FT ==> .5

STORAGE BASIN AREA - ACRES AT TOP OF BASIN ==> 3.13

STORAGE BASIN PERIMETER @ TOP OF BASIN ==> 1562

AVERAGE SIDE SLOPE RATIO ==> 5

CHANGE IN SLOPE TO ==> 6 AT ELEVATION ==> 62.5

CHANGE IN SLOPE TO ==> 2 AT ELEVATION ==> 59.5

<u>STAGE EL.</u>	<u>AREA-ACRES</u>	<u>STORAGE-AC FT</u>
54.50	2.010	0.00
55.00	2.040	1.01
55.50	2.070	2.04
56.00	2.100	3.08
56.50	2.130	4.14
57.00	2.160	5.21
57.50	2.200	6.30
58.00	2.230	7.41
58.50	2.260	8.53
59.00	2.290	9.67
59.50	2.320	10.82
60.00	2.430	12.01
60.50	2.530	13.24
61.00	2.640	14.54
61.50	2.740	15.88
62.00	2.850	17.28
62.50	2.950	18.73
63.00	3.040	20.22
63.50	3.130	21.77

*** End of This Calculation ***

14 day resident reqmt

$$\text{Resident Vol. (reqd)} = \frac{23.6 (0.46) (18.22)}{12} = 2.33$$

$$\text{Resident Vol. (provided)} = 18.73 \text{ ac.ft}$$

$$18.73 \text{ ac.ft} > 2.33 \text{ ac.ft} \checkmark$$

ACKNOWLEDGMENTS

Variable	Mean	Standard Deviation	Minimum	Maximum
Age	35.2	12.5	21	65
Gender	0.45	0.50	0	1
Education	12.8	1.5	9	16
Income	45000	15000	20000	80000

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082	2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094	2095	2096	2097	2098	2099
1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082	2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094	2095	2096	2097	2098	2099	

*** INTER-CONNECTED FUND ADJUSTING PROGRAM *** 1058108 JAN 1, 83
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11-4-74, FUND 2 FIRST YEAR
 8-17-83

 - STAGE ESTIMATED DATA -

 STAGE

STAGE	83.000	83.000	83.000	84.000	84.000
TIME	1.000	1.000	1.000	1.000	1.000

STAGE	1.000	1.000	1.000	1.000	1.000
TIME	1.000	1.000	1.000	1.000	1.000

STAGE	1.000	1.000	1.000	1.000	1.000
TIME	1.000	1.000	1.000	1.000	1.000

STAGE

STAGE	83.000	84.000	1.000	1.000	1.000
TIME	1.000	1.000	1.000	1.000	1.000

STAGE	1.000	1.000	1.000	1.000	1.000
TIME	1.000	1.000	1.000	1.000	1.000

STAGE	1.000	1.000	1.000	1.000	1.000
TIME	1.000	1.000	1.000	1.000	1.000

1979: 100-101.

14. Does the patent protect all rights and interests
 15. Does the patent protect all rights and interests
 16. Does the patent protect all rights and interests
 17. Does the patent protect all rights and interests
 18. Does the patent protect all rights and interests
 19. Does the patent protect all rights and interests
 20. Does the patent protect all rights and interests

1. *Journal of the American Medical Association*, 1997; 277: 1033-1036.

Year	1990	1991	1992	1993
1990	1991	1992	1993	1994
1995	1996	1997	1998	1999
2000	2001	2002	2003	2004
2005	2006	2007	2008	2009
2010	2011	2012	2013	2014
2015	2016	2017	2018	2019
2020	2021	2022	2023	2024
2025	2026	2027	2028	2029
2030	2031	2032	2033	2034
2035	2036	2037	2038	2039
2040	2041	2042	2043	2044
2045	2046	2047	2048	2049
2050	2051	2052	2053	2054
2055	2056	2057	2058	2059
2060	2061	2062	2063	2064
2065	2066	2067	2068	2069
2070	2071	2072	2073	2074
2075	2076	2077	2078	2079
2080	2081	2082	2083	2084
2085	2086	2087	2088	2089
2090	2091	2092	2093	2094
2095	2096	2097	2098	2099
2100	2101	2102	2103	2104
2105	2106	2107	2108	2109
2110	2111	2112	2113	2114
2115	2116	2117	2118	2119
2120	2121	2122	2123	2124
2125	2126	2127	2128	2129
2130	2131	2132	2133	2134
2135	2136	2137	2138	2139
2140	2141	2142	2143	2144
2145	2146	2147	2148	2149
2150	2151	2152	2153	2154
2155	2156	2157	2158	2159
2160	2161	2162	2163	2164
2165	2166	2167	2168	2169
2170	2171	2172	2173	2174
2175	2176	2177	2178	2179
2180	2181	2182	2183	2184
2185	2186	2187	2188	2189
2190	2191	2192	2193	2194
2195	2196	2197	2198	2199
2200	2201	2202	2203	2204
2205	2206	2207	2208	2209
2210	2211	2212	2213	2214
2215	2216	2217	2218	2219
2220	2221	2222	2223	2224
2225	2226	2227	2228	2229
2230	2231	2232	2233	2234
2235	2236	2237	2238	2239
2240	2241	2242	2243	2244
2245	2246	2247	2248	2249
2250	2251	2252	2253	2254
2255	2256	2257	2258	2259
2260	2261	2262	2263	2264
2265	2266	2267	2268	2269
2270	2271	2272	2273	2274
2275	2276	2277	2278	2279
2280	2281	2282	2283	2284
2285	2286	2287	2288	2289
2290	2291	2292	2293	2294
2295	2296	2297	2298	2299
2300	2301	2302	2303	2304
2305	2306	2307	2308	2309
2310	2311	2312	2313	2314
2315	2316	2317	2318	2319
2320	2321	2322	2323	2324
2325	2326	2327	2328	2329
2330	2331	2332	2333	2334
2335	2336	2337	2338	2339
2340	2341	2342	2	

1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015, 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023, 2024, 2025, 2026, 2027, 2028, 2029, 2030, 2031, 2032, 2033, 2034, 2035, 2036, 2037, 2038, 2039, 2040, 2041, 2042, 2043, 2044, 2045, 2046, 2047, 2048, 2049, 2050, 2051, 2052, 2053, 2054, 2055, 2056, 2057, 2058, 2059, 2060, 2061, 2062, 2063, 2064, 2065, 2066, 2067, 2068, 2069, 2070, 2071, 2072, 2073, 2074, 2075, 2076, 2077, 2078, 2079, 2080, 2081, 2082, 2083, 2084, 2085, 2086, 2087, 2088, 2089, 2090, 2091, 2092, 2093, 2094, 2095, 2096, 2097, 2098, 2099, 2100, 2101, 2102, 2103, 2104, 2105, 2106, 2107, 2108, 2109, 2110, 2111, 2112, 2113, 2114, 2115, 2116, 2117, 2118, 2119, 2120, 2121, 2122, 2123, 2124, 2125, 2126, 2127, 2128, 2129, 2130, 2131, 2132, 2133, 2134, 2135, 2136, 2137, 2138, 2139, 2140, 2141, 2142, 2143, 2144, 2145, 2146, 2147, 2148, 2149, 2150, 2151, 2152, 2153, 2154, 2155, 2156, 2157, 2158, 2159, 2160, 2161, 2162, 2163, 2164, 2165, 2166, 2167, 2168, 2169, 2170, 2171, 2172, 2173, 2174, 2175, 2176, 2177, 2178, 2179, 2180, 2181, 2182, 2183, 2184, 2185, 2186, 2187, 2188, 2189, 2190, 2191, 2192, 2193, 2194, 2195, 2196, 2197, 2198, 2199, 2200, 2201, 2202, 2203, 2204, 2205, 2206, 2207, 2208, 2209, 2210, 2211, 2212, 2213, 2214, 2215, 2216, 2217, 2218, 2219, 2220, 2221, 2222, 2223, 2224, 2225, 2226, 2227, 2228, 2229, 2230, 2231, 2232, 2233, 2234, 2235, 2236, 2237, 2238, 2239, 2240, 2241, 2242, 2243, 2244, 2245, 2246, 2247, 2248, 2249, 2250, 2251, 2252, 2253, 2254, 2255, 2256, 2257, 2258, 2259, 2260, 2261, 2262, 2263, 2264, 2265, 2266, 2267, 2268, 2269, 2270, 2271, 2272, 2273, 2274, 2275, 2276, 2277, 2278, 2279, 2280, 2281, 2282, 2283, 2284, 2285, 2286, 2287, 2288, 2289, 2290, 2291, 2292, 2293, 2294, 2295, 2296, 2297, 2298, 2299, 2300, 2301, 2302, 2303, 2304, 2305, 2306, 2307, 2308, 2309, 2310, 2311, 2312, 2313, 2314, 2315, 2316, 2317, 2318, 2319, 2320, 2321, 2322, 2323, 2324, 2325, 2326, 2327, 2328, 2329, 2330, 2331, 2332, 2333, 2334, 2335, 2336, 2337, 2338, 2339, 2340, 2341, 2342, 2343, 2344, 2345, 2346, 2347, 2348, 2349, 2350, 2351, 2352, 2353, 2354, 2355, 2356, 2357, 2358, 2359, 2360, 2361, 2362, 2363, 2364, 2365, 2366, 2367, 2368, 2369, 2370, 2371, 2372, 2373, 2374, 2375, 2376, 2377, 2378, 2379, 2380, 2381, 2382, 2383, 2384, 2385, 2386, 2387, 2388, 2389, 2390, 2391, 2392, 2393, 2394, 2395, 2396, 2397, 2398, 2399, 2400, 2401, 2402, 2403, 2404, 2405, 2406, 2407, 2408, 2409, 2410, 2411, 2412, 2413, 2414, 2415, 2416, 2417, 2418, 2419, 2420, 2421, 2422, 2423, 2424, 2425, 2426, 2427, 2428, 2429, 2430, 2431, 2432, 2433, 2434, 2435, 2436, 2437, 2438, 2439, 2440, 2441, 2442, 2443, 2444, 2445, 2446, 2447, 2448, 2449, 2450, 2451, 2452, 2453, 2454, 2455, 2456, 2457, 2458, 2459, 2460, 2461, 2462, 2463, 2464, 2465, 2466, 2467, 2468, 2469, 2470, 2471, 2472, 2473, 2474, 2475, 2476, 2477, 2478, 2479, 2480, 2481, 2482, 2483, 2484, 2485, 2486, 2487, 2488, 2489, 2490, 2491, 2492, 2493, 2494, 2495, 2496, 2497, 2498, 2499, 2500, 2501, 2502, 2503, 2504, 2505, 2506, 2507, 2508, 2509, 2510, 2511, 2512, 2513, 2514, 2515, 2516, 2517, 2518, 2519, 2520, 2521, 2522, 2523, 2524, 2525, 2526, 2527, 2528, 2529, 2530, 2531, 2532, 2533, 2534, 2535, 2536, 2537, 2538, 2539, 2540, 2541, 2542, 2543, 2544, 2545, 2546, 2547, 2548, 2549, 2550, 2551, 2552, 2553, 2554, 2555, 2556, 2557, 2558, 2559, 2560, 2561, 2562, 2563, 2564, 2565, 2566, 2567, 2568, 2569, 2570, 2571, 2572, 2573, 2574, 2575, 2576, 2577, 2578, 2579, 2580, 2581, 2582, 2583, 2584, 2585, 2586, 2587, 2588, 2589, 2590, 2591, 2592, 2593, 2594, 2595, 2596, 2597, 2598, 2599, 2600, 2601, 2602, 2603, 2604, 2605, 2606, 2607, 2608, 2609, 2610, 2611, 2612, 2613, 2614, 2615, 2616, 2617, 2618, 2619, 2620, 2621, 2622, 2623, 2624, 2625, 2626, 2627, 2628, 2629, 2630, 2631, 2632, 2633, 2634, 2635, 2636, 2637, 2638, 2639, 2640, 2641, 2642, 2643, 2644, 2645, 2646, 2647, 2648, 2649, 2650, 2651, 2652, 2653, 2654, 2655, 2656, 2657, 2658, 2659, 2660, 2661, 2662, 2663, 2664, 2665, 2666, 2667, 2668, 2669, 2670, 2671, 2672, 2673, 2674, 2675, 2676, 2677, 2678, 26

ALL INFORMATION CONTAINED HEREIN IS UNCLASSIFIED

```

Water elevation (feet)          ---  82.24
Gate length (feet)              ---  1
Discharge coefficient            ---  3.037
Gate thickness (feet)           ---  1.5
Structural coefficient           ---  50
Gate opening (feet)             ---  15
Gate orifices                   ---  1
Discharge coef for gate under full ---  1
Gate opening coefficient (feet) ---  82.24
Gate diameter (feet)            ---  1.5
Discharge coefficient            ---  3
Vertical position                ---  1

```

INTERCONNECTED ROAD ROUTING PROGRAM *** 000000 VER 2.00
Copyright 1982, Peter J. Singhofen, A.E.

1.00, MONO 8 BIT 256K
10/7/82

1.0000000000000000

1.0000000000000000 1.0000000000000000

— *Journal of the American Medical Association*, 1997

100

LINE	TIME	SPACE	STORAGE	INFLOW	OUTFLOW	DIFER
NO.	HH:MM	SEC	MBT	MBT	MBT	TOTAL
01	00:00	00:00	0.00	0.00	0.00	0.00
02	00:01	00:01	0.00	0.00	0.00	0.00
03	00:02	00:02	0.00	0.00	0.00	0.00
04	00:03	00:03	0.00	0.00	0.00	0.00
05	00:04	00:04	0.00	0.00	0.00	0.00
06	00:05	00:05	0.00	0.00	0.00	0.00
07	00:06	00:06	0.00	0.00	0.00	0.00
08	00:07	00:07	0.00	0.00	0.00	0.00
09	00:08	00:08	0.00	0.00	0.00	0.00
10	00:09	00:09	0.00	0.00	0.00	0.00
11	00:10	00:10	0.00	0.00	0.00	0.00
12	00:11	00:11	0.00	0.00	0.00	0.00
13	00:12	00:12	0.00	0.00	0.00	0.00
14	00:13	00:13	0.00	0.00	0.00	0.00
15	00:14	00:14	0.00	0.00	0.00	0.00
16	00:15	00:15	0.00	0.00	0.00	0.00
17	00:16	00:16	0.00	0.00	0.00	0.00
18	00:17	00:17	0.00	0.00	0.00	0.00
19	00:18	00:18	0.00	0.00	0.00	0.00
20	00:19	00:19	0.00	0.00	0.00	0.00
21	00:20	00:20	0.00	0.00	0.00	0.00
22	00:21	00:21	0.00	0.00	0.00	0.00
23	00:22	00:22	0.00	0.00	0.00	0.00
24	00:23	00:23	0.00	0.00	0.00	0.00
25	00:24	00:24	0.00	0.00	0.00	0.00
26	00:25	00:25	0.00	0.00	0.00	0.00
27	00:26	00:26	0.00	0.00	0.00	0.00
28	00:27	00:27	0.00	0.00	0.00	0.00
29	00:28	00:28	0.00	0.00	0.00	0.00
30	00:29	00:29	0.00	0.00	0.00	0.00
31	00:30	00:30	0.00	0.00	0.00	0.00
32	00:31	00:31	0.00	0.00	0.00	0.00
33	00:32	00:32	0.00	0.00	0.00	0.00
34	00:33	00:33	0.00	0.00	0.00	0.00
35	00:34	00:34	0.00	0.00	0.00	0.00
36	00:35	00:35	0.00	0.00	0.00	0.00
37	00:36	00:36	0.00	0.00	0.00	0.00
38	00:37	00:37	0.00	0.00	0.00	0.00
39	00:38	00:38	0.00	0.00	0.00	0.00
40	00:39	00:39	0.00	0.00	0.00	0.00
41	00:40	00:40	0.00	0.00	0.00	0.00
42	00:41	00:41	0.00	0.00	0.00	0.00
43	00:42	00:42	0.00	0.00	0.00	0.00
44	00:43	00:43	0.00	0.00	0.00	0.00
45	00:44	00:44	0.00	0.00	0.00	0.00
46	00:45	00:45	0.00	0.00	0.00	0.00
47	00:46	00:46	0.00	0.00	0.00	0.00
48	00:47	00:47	0.00	0.00	0.00	0.00
49	00:48	00:48	0.00	0.00	0.00	0.00
50	00:49	00:49	0.00	0.00	0.00	0.00
51	00:50	00:50	0.00	0.00	0.00	0.00
52	00:51	00:51	0.00	0.00	0.00	0.00
53	00:52	00:52	0.00	0.00	0.00	0.00
54	00:53	00:53	0.00	0.00	0.00	0.00
55	00:54	00:54	0.00	0.00	0.00	0.00
56	00:55	00:55	0.00	0.00	0.00	0.00
57	00:56	00:56	0.00	0.00	0.00	0.00
58	00:57	00:57	0.00	0.00	0.00	0.00
59	00:58	00:58	0.00	0.00	0.00	0.00
60	00:59	00:59	0.00	0.00	0.00	0.00
61	01:00	01:00	0.00	0.00	0.00	0.00
62	01:01	01:01	0.00	0.00	0.00	0.00
63	01:02	01:02	0.00	0.00	0.00	0.00
64	01:03	01:03	0.00	0.00	0.00	0.00
65	01:04	01:04	0.00	0.00	0.00	0.00
66	01:05	01:05	0.00	0.00	0.00	0.00
67	01:06	01:06	0.00	0.00	0.00	0.00
68	01:07	01:07	0.00	0.00	0.00	0.00
69	01:08	01:08	0.00	0.00	0.00	0.00
70	01:09	01:09	0.00	0.00	0.00	0.00
71	01:10	01:10	0.00	0.00	0.00	0.00
72	01:11	01:11	0.00	0.00	0.00	0.00
73	01:12	01:12	0.00	0.00	0.00	0.00
74	01:13	01:13	0.00	0.00	0.00	0.00
75	01:14	01:14	0.00	0.00	0.00	0.00
76	01:15	01:15	0.00	0.00	0.00	0.00
77	01:16	01:16	0.00	0.00	0.00	0.00
78	01:17	01:17	0.00	0.00	0.00	0.00
79	01:18	01:18	0.00	0.00	0.00	0.00
80	01:19	01:19	0.00	0.00	0.00	0.00
81	01:20	01:20	0.00	0.00	0.00	0.00
82	01:21	01:21	0.00	0.00	0.00	0.00
83	01:22	01:22	0.00	0.00	0.00	0.00
84	01:23	01:23	0.00	0.00	0.00	0.00
85	01:24	01:24	0.00	0.00	0.00	0.00
86	01:25	01:25	0.00	0.00	0.00	0.00
87	01:26	01:26	0.00	0.00	0.00	0.00
88	01:27	01:27	0.00	0.00	0.00	0.00
89	01:28	01:28	0.00	0.00	0.00	0.00
90	01:29	01:29	0.00	0.00	0.00	0.00
91	01:30	01:30	0.00	0.00	0.00	0.00
92	01:31	01:31	0.00	0.00	0.00	0.00
93	01:32	01:32	0.00	0.00	0.00	0.00
94	01:33	01:33	0.00	0.00	0.00	0.00
95	01:34	01:34	0.00	0.00	0.00	0.00
96	01:35	01:35	0.00	0.00	0.00	0.00
97	01:36	01:36	0.00	0.00	0.00	0.00
98	01:37	01:37	0.00	0.00	0.00	0.00
99	01:38	01:38	0.00	0.00	0.00	0.00
100	01:39	01:39	0.00	0.00	0.00	0.00
101	01:40	01:40	0.00	0.00	0.00	0.00
102	01:41	01:41	0.00	0.00	0.00	0.00
103	01:42	01:42	0.00	0.00	0.00	0.00
104	01:43	01:43	0.00	0.00	0.00	0.00
105	01:44	01:44	0.00	0.00	0.00	0.00
106	01:45	01:45	0.00	0.00	0.00	0.00
107	01:46	01:46	0.00	0.00	0.00	0.00
108	01:47	01:47	0.00	0.00	0.00	0.00
109	01:48	01:48	0.00	0.00	0.00	0.00
110	01:49	01:49	0.00	0.00	0.00	0.00
111	01:50	01:50	0.00	0.00	0.00	0.00
112	01:51	01:51	0.00	0.00	0.00	0.00
113	01:52	01:52	0.00	0.00	0.00	0.00
114	01:53	01:53	0.00	0.00	0.00	0.00
115	01:54	01:54	0.00	0.00	0.00	0.00
116	01:55	01:55	0.00	0.00	0.00	0.00
117	01:56	01:56	0.00	0.00	0.00	0.00
118	01:57	01:57	0.00	0.00	0.00	0.00
119	01:58	01:58	0.00	0.00	0.00	0.00
120	01:59	01:59	0.00	0.00	0.00	0.00
121	02:00	02:00	0.00	0.00	0.00	0.00
122	02:01	02:01	0.00	0.00	0.00	0.00
123	02:02	02:02	0.00	0.00	0.00	0.00
124	02:03	02:03	0.00	0.00	0.00	0.00
125	02:04	02:04	0.00	0.00	0.00	0.00
126	02:05	02:05	0.00	0.00	0.00	0.00
127	02:06	02:06	0.00	0.00	0.00	0.00
128	02:07	02:07	0.00	0.00	0.00	0.00
129	02:08	02:08	0.00	0.00	0.00	0.00
130	02:09	02:09	0.00	0.00	0.00	0.00
131	02:10	02:10	0.00	0.00	0.00	0.00
132	02:11	02:11	0.00	0.00	0.00	0.00
133	02:12	02:12	0.00	0.00	0.00	0.00
134	02:13	02:13	0.00	0.00	0.00	0.00
135	02:14	02:14	0.00	0.00	0.00	0.00
136	02:15	02:15	0.00	0.00	0.00	0.00
137	02:16	02:16	0.00	0.00	0.00	0.00
138	02:17	02:17	0.00	0.00	0.00	0.00
139	02:18	02:18	0.00	0.00	0.00	0.00
140	02:19	02:19	0.00	0.00	0.00	0.00
141	02:20	02:20	0.00	0.00	0.00	0.00
142	02:21	02:21	0.00	0.00	0.00	0.00
143	02:22	02:22	0.00	0.00	0.00	0.00
144	02:23	02:23	0.00	0.00	0.00	0.00
145	02:24	02:24	0.00	0.00	0.00	0.00
146	02:25	02:25	0.00	0.00	0.00	0.00
147	02:26	02:26	0.00	0.00	0.00	0.00
148	02:27	02:27	0.00	0.00	0.00	0.00
149	02:28	02:28	0.00	0.00	0.00	0.00
150	02:29	02:29	0.00	0.00	0.00	0.00
151	02:30	02:30	0.00	0.00	0.00	0.00
152	02:31	02:31	0.00	0.00	0.00	0.00
153	02:32	02:32	0.00	0.00	0.00	0.00
154	02:33	02:33	0.00	0.00	0.00	0.00
155	02:34	02:34	0.00	0.00	0.00	0.00
156	02:35	02:35	0.00	0.00	0.00	0.00
157	02:36	02:36	0.00	0.00	0.00	0.00
158	02:37	02:37	0.00	0.00	0.00	0.00
159	02:38	02:38	0.00	0.00	0.00	0.00
160	02:39	02:39	0.00	0.00	0.00	0.00
161	02:40	02:40	0.00	0.00	0.00	0.00
162	02:41	02:41	0.00	0.00	0.00	0.00
163	02:42	02:42	0.00	0.00	0.00	0.00
164	02:43	02:43	0.00	0.00	0.00	0.00
165	02:44	02:44	0.00	0.00	0.00	0.00
166	02:45	02:45	0.00	0.00	0.00	0.00
167	02:46	02:46	0.00	0.00	0.00	0.00
168	02:47	02:47	0.00	0.00	0.00	0.00
169	02:48	02:48	0.00	0.00	0.00	0.00
170	02:49	02:49	0.00	0.00	0.00	0.00
171	02:50	02:50	0.00	0.00	0.00	0.00
172	02:51	02:51	0.00	0.00	0.00	0.00
173	02:52	02:52	0.00	0.00	0.00	0.00
174	02:53	02:53	0.00	0.00	0.00	0.00
175	02:54	02:54	0.00	0.00	0.00	0.00
176	02:55	02:55	0.00	0.00	0.00	0.00
177	02:56	02:56	0.00	0.00	0.00	0.00
178	02:57	02:57	0.00	0.00	0.00	0.00
179	02:58	02:58	0.00	0.00	0.00	0.00
180	02:59	02:59	0.00	0.00	0.00	0.00
181	03:00	03:00	0.00	0.00	0.00	0.00
182	03:01	03:01	0.00	0.00	0.00	0.00

*** INTER-CONNECTED POND ROUTING PROGRAM *** 1089138 VER 3.83
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***** POND 1 *****
 1-17-88

ISE	TIME	STAGE	STORAGE	INFLOW	OUTFLOW	Net/
	Hr.	(feet)	(acft)	(cfs)	"	TOTAL
11	0.00	82.62	0.00	0.42	-0.00	-0.00
12	0.50	82.63	-0.00	-0.00	-----	0.00
11	0.75	82.63	0.07	0.46	-0.00	-0.00
12	1.00	82.64	-0.00	-0.00	-----	0.00
11	1.25	82.63	0.05	0.45	-0.00	-0.00
12	1.50	82.65	-0.00	-0.04	-----	0.00
11	1.75	82.65	0.03	0.51	-0.05	-0.05
12	2.00	82.66	-0.00	-0.05	-----	0.00
11	2.25	82.64	0.10	0.52	-0.02	-0.05
12	2.50	82.67	-0.00	-0.05	-----	0.00
11	2.75	82.64	0.11	0.55	-0.06	-0.05
12	3.00	82.68	-0.00	-0.06	-----	0.00
11	3.25	82.64	0.13	0.59	-0.06	-0.05
12	3.50	82.69	-0.01	-0.06	-----	0.00
11	3.75	82.65	0.14	0.61	-0.07	-0.07
12	4.00	82.70	-0.01	-0.07	-----	0.00
11	4.25	82.65	0.15	0.63	-0.07	-0.07
12	4.50	82.71	-0.01	-0.07	-----	0.00
11	4.75	82.65	0.17	0.65	-0.07	-0.07
12	5.00	82.72	-0.01	-0.07	-----	0.00
11	5.25	82.65	0.16	0.63	-0.08	-0.06
12	5.50	82.72	-0.01	-0.08	-----	0.00
11	5.75	82.67	0.20	0.71	-0.08	-0.08
12	6.00	82.73	-0.01	-0.08	-----	0.00
11	6.25	82.68	0.22	0.75	-0.08	-0.08
12	6.50	82.74	-0.02	-0.08	-----	0.00
11	6.75	82.68	0.23	0.73	-0.09	-0.09
12	7.00	82.75	-0.02	-0.09	-----	0.00

*** INTER-CONNECTED POND RAISING PROGRAM *** 1033103 VER 2.03
 Copyright 1981, Peter A. Sengsteden, P.E.

JARANA TRAIL POND 2 FIRST DIVE
 6-17-86

TIME	DATE	STAGE	STORAGE	INFLOW	OUTFLOW	Net/
h	m	Feet	Feet	cfs	cfs	TOTAL
11	7:00	11.71	0.00	1.54	-0.13	-0.13
12	7:00	11.71	-0.01	-0.03	-----	0.00
11	7:30	11.67	0.07	1.35	-0.03	-0.03
12	7:30	11.67	-0.01	-0.03	-----	-0.01
11	7:50	11.61	0.06	1.34	-0.13	-0.13
12	7:50	11.58	-0.03	-0.03	-----	0.00
11	7:55	11.61	0.01	1.31	-0.10	-0.10
12	7:55	11.59	-0.02	-0.10	-----	0.00
11	8:00	11.61	0.01	1.28	-0.10	-0.10
12	8:00	11.59	-0.02	-0.10	-----	0.00
11	8:25	11.55	0.06	1.25	-0.10	-0.10
12	8:25	11.51	-0.04	-0.10	-----	0.00
11	8:50	11.54	0.01	1.21	-0.10	-0.10
12	8:50	11.51	-0.03	-0.10	-----	0.00
11	8:55	11.55	0.02	1.23	-0.10	-0.10
12	8:55	11.51	-0.04	-0.10	-----	0.00
11	9:00	11.51	0.04	1.24	-0.10	-0.10
12	9:00	11.54	-0.03	-0.10	-----	0.00
11	9:25	11.57	0.03	1.44	-0.11	-0.11
12	9:25	11.53	-0.04	-0.11	-----	0.00
11	9:50	11.55	0.01	1.53	-0.13	-0.13
12	9:50	11.55	-0.04	-0.13	-----	0.00
11	9:55	11.59	0.55	1.65	-0.15	-0.15
12	9:55	11.57	-0.04	-0.15	-----	0.00
11	10:00	11.71	0.53	1.78	-0.19	-0.19
12	10:00	11.68	-0.05	-0.18	-----	0.00
11	10:25	11.72	0.53	1.97	-0.22	-0.22
12	10:25	11.69	-0.05	-0.22	-----	0.00

INTER-CONNECTED POND ROUTING PROGRAM *** 1038136 VER 2.83
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POND NO. 1000 1 FIRST 18YR
 8-17-83

TIME	STAGE	STORAGE	INFLOW	OUTFLOW (cfs)		
(hrs)	(feet)	(acft)	(cfs)	# 1	TOTAL	
11	11.60	11.74	1.13	-0.13	-0.13	
12	11.50	11.69	-0.13	-----	0.00	
13	11.75	11.76	1.48	-0.30	-0.30	
14	11.75	11.80	-0.13	-0.30	-----	0.00
15	11.61	11.71	1.73	-0.35	-0.35	
16	11.60	11.61	-0.07	-0.35	-----	0.00
17	11.85	11.81	1.35	-0.40	-0.40	
18	11.85	11.82	-0.07	-0.40	-----	0.00
19	11.80	11.84	1.31	-0.44	-0.44	
20	11.80	11.83	-0.08	-0.44	-----	0.00
21	11.75	11.83	1.10	-0.48	-0.48	
22	11.75	11.84	-0.03	-0.48	-----	0.00
23	12.00	11.88	1.33	13.34	0.75	0.75
24	12.00	11.95	-0.10	0.75	-----	0.00
25	12.25	11.89	1.65	15.75	1.72	1.72
26	12.25	11.96	-0.07	1.72	-----	0.00
27	12.50	11.98	1.94	13.97	1.81	1.81
28	12.50	11.97	-0.03	1.81	-----	0.00
29	12.75	11.87	2.18	14.47	3.89	3.89
30	12.75	11.98	1.14	3.89	-----	0.00
31	13.00	11.93	2.38	13.13	4.62	4.62
32	13.00	11.99	0.13	4.62	-----	0.00
33	13.25	11.93	2.53	11.75	5.58	5.58
34	13.25	11.90	0.24	5.58	-----	0.00
35	13.50	11.42	2.64	10.53	5.16	5.16
36	13.50	11.91	0.36	5.16	-----	0.00
37	13.75	11.45	2.72	9.48	6.57	6.57
38	13.75	11.92	0.49	6.57	-----	0.00

*** INTER-CONNECTED POND ROUTING PROGRAM *** 1088138 - VER 3.83
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DATA ON POND 3 FROM 2513
 1-17-88

LINE	TIME	STAGE	STORAGE	INFLOW	OUTFLOW (CFS)	
	HR:MM	Feet	(ac-ft)	(cfs)	#	TOTAL
01	14.00	63.47	1.75	6.84	6.84	6.84
02	14.00	63.43	0.83	6.84	-----	0.00
01	14.15	63.47	1.75	7.66	6.97	6.97
02	14.15	63.43	1.77	6.97	-----	0.00
01	14.30	63.47	1.74	8.31	7.00	7.00
02	14.30	63.44	0.81	7.00	-----	0.00
01	14.45	63.47	1.73	8.21	6.95	6.95
02	14.45	63.41	1.16	6.95	-----	0.00
01	15.00	63.47	1.73	8.63	6.84	6.84
02	15.00	63.43	1.21	6.84	-----	0.00
01	15.15	63.48	1.74	9.10	6.67	6.67
02	15.15	63.47	1.35	6.67	-----	0.00
01	15.30	63.44	1.70	4.67	5.46	5.46
02	15.30	63.48	1.48	5.46	-----	0.00
01	15.45	63.43	1.66	4.25	5.25	5.25
02	15.45	63.43	1.51	5.25	-----	0.00
01	16.00	63.42	1.62	3.90	5.03	5.03
02	16.00	63.40	1.74	5.03	-----	0.00
01	16.15	63.40	1.57	3.58	5.79	5.79
02	16.15	63.41	1.55	5.79	-----	0.00
01	16.30	63.39	1.53	3.31	5.54	5.54
02	16.30	63.42	1.53	5.54	-----	0.00
01	16.45	63.37	1.48	3.07	5.30	5.30
02	16.45	63.43	1.09	5.30	-----	0.00
01	17.00	63.35	1.43	2.67	5.05	5.05
02	17.00	63.44	1.20	5.06	-----	0.00
01	17.15	63.34	1.39	2.66	4.83	4.83
02	17.15	63.45	1.30	4.83	-----	0.00

*** INTER-CONNECTED POND ROUTING PROGRAM ***
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1038103 VER 2.65

JARVIS IS. POND 2 POST 25YR
 6-17-89

DATE	TIME	STAGE	STORAGE	INFLOW	OUTFLOW	(cfs)
#	(hrs)	(feet)	(acft)	(cfs)	# 1	TOTAL
11	17.50	63.32	3.34	3.43	4.81	4.81
55	17.50	63.15	3.40	4.61	-----	0.00
11	17.75	63.31	3.31	3.34	4.35	4.35
55	17.75	63.17	3.45	4.15	-----	0.00
11	18.00	63.33	3.33	3.33	4.15	4.15
55	18.00	63.17	3.53	4.15	-----	0.00
11	18.25	63.32	3.22	2.93	3.85	3.85
55	18.25	63.19	3.61	3.85	-----	0.00
11	18.50	63.27	3.13	1.93	3.44	3.44
55	18.50	63.19	2.74	3.44	-----	0.00
11	18.75	63.25	3.15	1.83	2.94	2.94
55	18.75	63.20	2.91	2.94	-----	0.00
11	19.00	63.25	3.14	1.82	2.39	2.39
55	19.00	63.21	2.85	2.39	-----	0.00
11	19.25	63.25	3.14	1.73	1.85	1.85
55	19.25	63.22	2.91	1.85	-----	0.00
11	19.50	63.25	3.14	1.65	1.33	1.33
55	19.50	63.23	2.94	1.33	-----	0.00
11	19.75	63.23	3.15	1.50	1.00	1.00
55	19.75	63.24	3.55	1.00	-----	0.00
11	20.00	63.25	3.16	1.55	0.72	0.72
55	20.00	63.25	2.96	0.72	-----	0.00
11	20.25	63.27	3.18	1.51	0.52	0.52
55	20.25	63.26	2.99	0.52	-----	0.00
11	20.50	63.27	3.20	1.47	0.37	0.37
55	20.50	63.27	3.00	0.37	-----	0.00
11	20.75	63.28	3.23	1.41	0.26	0.26
55	20.75	63.28	3.01	0.26	-----	0.00

10-7-68

LINE	DATE	STAGE (feet)	STORAGE (ac-ft)	INFLOW (cfs)	OUTFLOW (cfs)	(cfs) TOTAL
10	11.10	11.10	1.10	1.10	0.00	0.00
15	11.15	11.15	1.15	1.15	0.00	0.00
20	11.20	11.20	1.20	1.20	0.00	0.00
25	11.25	11.25	1.25	1.25	0.00	0.00
30	11.30	11.30	1.30	1.30	0.00	0.00
35	11.35	11.35	1.35	1.35	0.00	0.00
40	11.40	11.40	1.40	1.40	0.00	0.00
45	11.45	11.45	1.45	1.45	0.00	0.00
50	11.50	11.50	1.50	1.50	0.00	0.00
55	11.55	11.55	1.55	1.55	0.00	0.00
60	11.60	11.60	1.60	1.60	0.00	0.00
65	11.65	11.65	1.65	1.65	0.00	0.00
70	11.70	11.70	1.70	1.70	0.00	0.00
75	11.75	11.75	1.75	1.75	0.00	0.00
80	11.80	11.80	1.80	1.80	0.00	0.00
85	11.85	11.85	1.85	1.85	0.00	0.00
90	11.90	11.90	1.90	1.90	0.00	0.00
95	11.95	11.95	1.95	1.95	0.00	0.00
100	12.00	12.00	2.00	2.00	0.00	0.00
105	12.05	12.05	2.05	2.05	0.00	0.00
110	12.10	12.10	2.10	2.10	0.00	0.00
115	12.15	12.15	2.15	2.15	0.00	0.00
120	12.20	12.20	2.20	2.20	0.00	0.00
125	12.25	12.25	2.25	2.25	0.00	0.00
130	12.30	12.30	2.30	2.30	0.00	0.00
135	12.35	12.35	2.35	2.35	0.00	0.00
140	12.40	12.40	2.40	2.40	0.00	0.00
145	12.45	12.45	2.45	2.45	0.00	0.00
150	12.50	12.50	2.50	2.50	0.00	0.00
155	12.55	12.55	2.55	2.55	0.00	0.00
160	12.60	12.60	2.60	2.60	0.00	0.00
165	12.65	12.65	2.65	2.65	0.00	0.00
170	12.70	12.70	2.70	2.70	0.00	0.00
175	12.75	12.75	2.75	2.75	0.00	0.00
180	12.80	12.80	2.80	2.80	0.00	0.00
185	12.85	12.85	2.85	2.85	0.00	0.00
190	12.90	12.90	2.90	2.90	0.00	0.00
195	12.95	12.95	2.95	2.95	0.00	0.00
200	13.00	13.00	3.00	3.00	0.00	0.00
205	13.05	13.05	3.05	3.05	0.00	0.00
210	13.10	13.10	3.10	3.10	0.00	0.00
215	13.15	13.15	3.15	3.15	0.00	0.00
220	13.20	13.20	3.20	3.20	0.00	0.00
225	13.25	13.25	3.25	3.25	0.00	0.00
230	13.30	13.30	3.30	3.30	0.00	0.00
235	13.35	13.35	3.35	3.35	0.00	0.00
240	13.40	13.40	3.40	3.40	0.00	0.00
245	13.45	13.45	3.45	3.45	0.00	0.00
250	13.50	13.50	3.50	3.50	0.00	0.00
255	13.55	13.55	3.55	3.55	0.00	0.00
260	13.60	13.60	3.60	3.60	0.00	0.00
265	13.65	13.65	3.65	3.65	0.00	0.00
270	13.70	13.70	3.70	3.70	0.00	0.00
275	13.75	13.75	3.75	3.75	0.00	0.00
280	13.80	13.80	3.80	3.80	0.00	0.00
285	13.85	13.85	3.85	3.85	0.00	0.00
290	13.90	13.90	3.90	3.90	0.00	0.00
295	13.95	13.95	3.95	3.95	0.00	0.00
300	14.00	14.00	4.00	4.00	0.00	0.00
305	14.05	14.05	4.05	4.05	0.00	0.00
310	14.10	14.10	4.10	4.10	0.00	0.00
315	14.15	14.15	4.15	4.15	0.00	0.00
320	14.20	14.20	4.20	4.20	0.00	0.00
325	14.25	14.25	4.25	4.25	0.00	0.00
330	14.30	14.30	4.30	4.30	0.00	0.00
335	14.35	14.35	4.35	4.35	0.00	0.00
340	14.40	14.40	4.40	4.40	0.00	0.00
345	14.45	14.45	4.45	4.45	0.00	0.00
350	14.50	14.50	4.50	4.50	0.00	0.00
355	14.55	14.55	4.55	4.55	0.00	0.00
360	14.60	14.60	4.60	4.60	0.00	0.00
365	14.65	14.65	4.65	4.65	0.00	0.00
370	14.70	14.70	4.70	4.70	0.00	0.00
375	14.75	14.75	4.75	4.75	0.00	0.00
380	14.80	14.80	4.80	4.80	0.00	0.00
385	14.85	14.85	4.85	4.85	0.00	0.00
390	14.90	14.90	4.90	4.90	0.00	0.00
395	14.95	14.95	4.95	4.95	0.00	0.00
400	15.00	15.00	5.00	5.00	0.00	0.00
405	15.05	15.05	5.05	5.05	0.00	0.00
410	15.10	15.10	5.10	5.10	0.00	0.00
415	15.15	15.15	5.15	5.15	0.00	0.00
420	15.20	15.20	5.20	5.20	0.00	0.00
425	15.25	15.25	5.25	5.25	0.00	0.00
430	15.30	15.30	5.30	5.30	0.00	0.00
435	15.35	15.35	5.35	5.35	0.00	0.00
440	15.40	15.40	5.40	5.40	0.00	0.00
445	15.45	15.45	5.45	5.45	0.00	0.00
450	15.50	15.50	5.50	5.50	0.00	0.00
455	15.55	15.55	5.55	5.55	0.00	0.00
460	15.60	15.60	5.60	5.60	0.00	0.00
465	15.65	15.65	5.65	5.65	0.00	0.00
470	15.70	15.70	5.70	5.70	0.00	0.00
475	15.75	15.75	5.75	5.75	0.00	0.00
480	15.80	15.80	5.80	5.80	0.00	0.00
485	15.85	15.85	5.85	5.85	0.00	0.00
490	15.90	15.90	5.90	5.90	0.00	0.00
495	15.95	15.95	5.95	5.95	0.00	0.00
500	16.00	16.00	6.00	6.00	0.00	0.00
505	16.05	16.05	6.05	6.05	0.00	0.00
510	16.10	16.10	6.10	6.10	0.00	0.00
515	16.15	16.15	6.15	6.15	0.00	0.00
520	16.20	16.20	6.20	6.20	0.00	0.00
525	16.25	16.25	6.25	6.25	0.00	0.00
530	16.30	16.30	6.30	6.30	0.00	0.00
535	16.35	16.35	6.35	6.35	0.00	0.00
540	16.40	16.40	6.40	6.40	0.00	0.00
545	16.45	16.45	6.45	6.45	0.00	0.00
550	16.50	16.50	6.50	6.50	0.00	0.00
555	16.55	16.55	6.55	6.55	0.00	0.00
560	16.60	16.60	6.60	6.60	0.00	0.00
565	16.65	16.65	6.65	6.65	0.00	0.00
570	16.70	16.70	6.70	6.70	0.00	0.00
575	16.75	16.75	6.75	6.75	0.00	0.00
580	16.80	16.80	6.80	6.80	0.00	0.00
585	16.85	16.85	6.85	6.85	0.00	0.00
590	16.90	16.90	6.90	6.90	0.00	0.00
595	16.95	16.95	6.95	6.95	0.00	0.00
600	17.00	17.00	7.00	7.00	0.00	0.00
605	17.05	17.05	7.05	7.05	0.00	0.00
610	17.10	17.10	7.10	7.10	0.00	0.00
615	17.15	17.15	7.15	7.15	0.00	0.00
620	17.20	17.20	7.20	7.20	0.00	0.00
625	17.25	17.25	7.25	7.25	0.00	0.00
630	17.30	17.30	7.30	7.30	0.00	0.00
635	17.35	17.35	7.35	7.35	0.00	0.00
640	17.40	17.40	7.40	7.40	0.00	0.00
645	17.45	17.45	7.45	7.45	0.00	0.00
650	17.50	17.50	7.50	7.50	0.00	0.00
655	17.55	17.55	7.55	7.55	0.00	0.00
660	17.60	17.60	7.60	7.60	0.00	0.00
665	17.65	17.65	7.65	7.65	0.00	0.00
670	17.70	17.70	7.70	7.70	0.00	0.00
675	17.75	17.75	7.75	7.75	0.00	0.00
680	17.80	17.80	7.80	7.80	0.00	0.00
685	17.85	17.85	7.85	7.85	0.00	0.00
690	17.90	17.90	7.90	7.90	0.00	0.00
695	17.95	17.95	7.95	7.95	0.00	0.00
700	18.00	18.00	8.00	8.00	0.00	0.00
705	18.05	18.05	8.05	8.05	0.00	0.00
710	18.10	18.10	8.10	8.10	0.00	0.00
715	18.15	18.15	8.15	8.15	0.00	0.00
720	18.20	18.20	8.20	8.20	0.00	0.00
725	18.25	18.25	8.25	8.25	0.00	0.00
730	18.30	18.30	8.30	8.30	0.00	0.00
735	18.35	18.35	8.35	8.35	0.00	0.00
740	18.40	18.40	8.40	8.40	0.00	0.00
745	18.45	18.45	8.45	8.45	0.00	0.00
750	18.50	18.50	8.50	8.50	0.00	0.00
755	18.55	18.55	8.55	8.55	0.00	0.00
760	18.60	18.60	8.60	8.60	0.00	0.00
765	18.65	18.65	8.65	8.65	0.00	0.00
770	18.70	18.70	8.70	8.70	0.00	0.00
775	18.75	18.75	8.75	8.75	0.00	0.00
780	18.80	18.80	8.80	8.80	0.00	0.00
785	18.85	18.85	8.85	8.85	0.00	0.00
790	18.90	18.90	8.90	8.90	0.00	0.00
795	18.95	18.95	8.95	8.95	0.00	0.00
800	19.00	19.00	9.00	9.00	0.00	0.00
805	19.05	19.05	9.05	9.05	0.00	0.00
810	19.10	19.10	9.10	9.10	0.00	0.00
815	19.15	19.15	9.15	9.15	0.00	0.00
820	19.20	19.20	9.20	9.20	0.00	0.00
825	19.25	19.25	9.25	9.25	0.00	0.00
830	19.30	19.30	9.30	9.30	0.00	0.00
835	19.35	19.35	9.35	9.35	0.00	0.00
840	19.40	19.40	9.40	9.40	0.00	0.00
845	19.45	19.45	9.45	9.45	0.00	0.00
850	19.50	19.50	9.50	9.50	0.00	0.00
855	19.55	19.55	9.55	9.55	0.00	0.00
860	19.60	19.60	9.60	9.60	0.00	0.00
865	19.65	19.65	9.65	9.65	0.00	0.00
870	19.70	19.70	9.70	9.70	0.00	0.00
875	19.75	19.75	9.75	9.75	0.00	0.00
880	19.80	19.80	9.80	9.80	0.00	0.00
885	19.85	19.85	9.85	9.85	0.00	0.00
890	19.90	19.90	9.90	9.90	0.00	0.00
895	19.95	19.95	9.95	9.95	0.00	0.00
900	20.00	20.00	10.00	10.00	0.00	0.00
905	20.05	20.05	10.05	10.05	0.00	0.00
910	20.10	20.10	10.10	10.10	0.00	0.00
915						

*** INTER-CONNECTED FOND ROUTING PROGRAM *** 1109.05 VER. 2.00

REPORT TO FOND'S PEET EYS
3-17-88

*** PEAK CONDITIONS SUMMARY ***

NOE	PEAK STAGE (feet)	PEAK STORAGE (cfs)	TIME TO PEAK (hrs)	PEAK OUTFLOW (cfs)	TIME TO PEAK (hrs)
1	11.48	1.75	14.47	7.00	14.47
2	11.41	1.75	14.41	7.00	14.41

NOE	PEAK OUTFLOW (cfs)	TIME TO PEAK (hrs)
1	7.00	14.47

SECONDARY SYSTEM

REG0032 L(2) 07/31/85
DATE PROCESSED
DATE SUBMITTED 15/OCT/85

FLORIDA DEPARTMENT OF TRANSPORTATION
STORM SEWER DESIGN
PROJECT 04-10

TIME PROCESSED
ENGINEER: POSTWICK

ALAFAYA POND 3

OP III ALTERNATE
RUN

DESIGN STANDARDS

10 YR 7.5 STORM FREQUENCY 10 YEARS OUTLET CONTROL ELEVATION: 81.39 FT.
MINIMUM CLEARANCE H.G. BELOW GUTTER: 1.00 FT. MINIMUM PIPE COVER BELOW GUTTER: 8.00 FT.

PIPE COST DATA: SIZING: COST(\$):

12	14	16	18	20	22	24	26	28	30	32	34	36	38	40	42	44	46	48
174.5	19.33	21.94	25.17	28.12	31.50	35.05	38.55	42.01	44.93	47.81	50.52	53.15	55.82	58.00	60.46	63.00	654.25	654.25

SYSTEM INPUT

PIPE	LINE	LENGTH	AREA	MIN	GUTTER	PIPE	EXTRA	MAX	H.G.	MAX	CROWN	ELEV	IN	C
INCH	NO	(FEET)	(SQ FT)	TO	OR	DIA	FLOW	DEPTH	MAX	CROWN	UPPER	LOWER	VALUE	D
FROM	TO	ELEV		MIN	GRATE	(IN)	(CFS)	OUT	CONTROL	ELEV	END	END		D
STA	STA				ELEV									E
INCREMENT														
500	501	8	65	5.83	78.00	55.30	20	0.00	0.0	0.00	0.00	0.00	0.00	.024
499+00	500	BR		5.81										
				5.79										
501	502	8	73	6.35	78.00	56.14	0	0.00	0.0	0.00	0.00	0.00	0.00	.023
499+00	501	TR		6.70										
				6.00										

DATE PROCESSED
PROJECT

04-0

FINAL SYSTEM DESIGN
ZONE 7 FREQ10

TIME PROCESSED
PAGE

3

ALAFAYA POND 2

PIPE	TYPE	LENGTH	DRAINAGE AREA (ACRES)	TIME OF	TIME OF	INTENSITY	TOTAL	2	OUTLET	ELEV. OF H.B.	FALL PIPE	SLOPE	VEL.	
LINE		FEET		OF	OF	(IN/HR)	CA	(CFS)	OR	CROWN ELEV	DIA	(X)	(FPS)	
			01=0.50	CONC	FLOW				INLET	F.L. ELEV	LINE		HYD GRADIENT	
			02=0.50						INCLUDES ELEV					
			03=0.00						ADDED	UPPER	LOWER		PHYSICAL	
									FLOW OF (I)	END	END			
11-101	A	65	5.83	15.00	0.32	2.74	15.07	15.62	55.30	53.84	53.46	0.38	30*	0.581 3.33 1.024
11-102	B		5.81											
			5.80											
11-103	C	10	5.83	15.02	0.31	2.73	15.33	15.91	55.14	53.46	53.39	0.46	30	0.567 3.35 1.023
11-104	D		5.70											
			0.00											

DATE PROCESSED
PROJECT

0- 0

COST SUMMARY

TIME PROCESSED
PAGE

3

ALAFAYA POND 5

PIPE IDENT	COST (\$)
FROM TO	
500 501	3087.60

PIPE IDENT	COST (\$)
FROM TO	
501 502	3344.78

PIPE IDENT	COST (\$)
FROM TO	

TOTAL SYSTEM COST = 4432.38

DATE PROCESSED
PROJECT

SYSTEM ANALYSIS

TIME PROCESSED
PAGE

SLAPPA POND E

MESSAGE		PIPE LINE
MAXIMUM DEPTH OF CUT (TO CROWN)	0.00 FT	000 TO 001
MAXIMUM VELOCITY (GRAVITY FLOW)	0.95 FPS	001 TO 002
MAXIMUM PIPE SLOPE	0.00 PERCENT	000 TO 001
MINIMUM VELOCITY (ON MAIN (H.S. FLOW)	0.95 FPS	000 TO 001
MINIMUM VELOCITY (GRAVITY FLOW)	0.95 FPS	000 TO 001
MINIMUM HYDRAULIC GRADIENT CLEARANCE TO GUTTER	0.46 FT	000 TO 001
MINIMUM HYDRAULIC GRADIENT CLEARANCE TO CONTROL	0.46 FT	000 TO 001
TOTAL DRAINAGE AREA	15.05 ACRES	
WEIGHTED COEFFICIENT	0.46	

MAXIMUM DEPTH OF CUT CONTROL USED FOR RESTRAINT AT -

NO PIPES

DESIGN FLOW GREATER THAN 10 FPS IN THE FOLLOWING PIPE LENGTHS -

NO PIPES

COMMENTS

POND 6

POND 6

Pond 6 is a wet detention facility located just south of Hart Branch Crossing adjacent to the easterly right-of-way line. The pond is encompassed by a 5 foot wide maintenance berm with the top bank elevation set at 65.9 Ft. NGVD. From the top of bank, the pond sideslopes are 5:1 to elevation 63.9 Ft. NGVD, then 6:1 to elevation 60.9 Ft. NGVD, then 2:1 to the bottom elevation 55.9 Ft. NGVD. The 6:1 slopes are to be covered with muck from area excavation and allowed to naturally vegetate.

Inflow to the pond is via a combination open (swale) drainage, inlet and pipe system along Alafaya Trail. The runoff will enter from the west to prevent direct movement to the outfall adjacent to Hart Branch Crossing .

Discharge from the pond is over a large broad-crested weir located at the north end of the facility. A 5 Ft. weir, set at 64.23 Ft. NGVD, contains a 3 inch diameter bleeder with an invert of 63.9 Ft. NGVD. The discharge flow over the weir outfalls into the adjacent wetland vegetation bordering Hart Branch Crossing.

EXISTING CONDITIONS

The portion of Alafaya Trail from Station 451 + 50 to Station 493 + 00 was considered as Drainage Basin 6. Drainage Basin 6 currently outfalls to Hart Branch Crossing either directly or indirectly through a series of wetland strands. While these positive outfalls exist, the runoff from the

existing area is conveyed by surface sheetflow. Considering the area's flat topography, there are no well defined **drainage** pathways. The peak rate of discharge from the project area was estimated using **Santa Barbara** Unit Hydrograph. The peak rate of discharge from this portion of Alafaya Trail is approximately 14.0 CFS during the 25 year/24 hours storm event.

The remainder of the area from Station 493+00 to Station 503+00 currently drains, by surface sheetflow, in a northeasterly direction to arrive at the upper reaches of Hart Branch Crossing.

PROPOSED CONDITIONS

The design of Pond 6 proposes to collect the roadway right-of-way from Station 451+50 to 493+00. The pond inflows were calculated using Santa Barbara Unit Hydrograph and routed using Inter-Connected Pond Routing.

The project runoff is collected and conveyed by swales on each side of the roadway. The runoff is then collected in a ditch bottom inlet and piped to the proposed pond facility location.

This pond is designed using the 25 year/24 hour storm event. The crest of the outfall weir is set to provide wet detention for 1 inch of runoff from the project area. The bleeder orifice, in the weir structure, is sized to recover an 0.5 inch of the detained volume within 60 hours.

The post development peak rate of discharge for this portion of Alafaya Trail is 9.12 CFS, with the peak stage in the pond being 64.89 Ft. NGVD, thus insuring ample freeboard for the pond facility.

The runoff from the remainder of the project from Station 493+00 to Station 503+00 will be allowed to continue to drain in the northeasterly direction as in the predeveloped conditions. This runoff will be treated in the proposed swale system, with ditch blocks set to provide detention for 1 inch of runoff from the appropriate project area.

PRIMARY SYSTEM

ALAFAYA TR. PRE POND6

How many basins? --> 3
Simulation Duration (hrs) --> 24.5
Time Increment (mins) --> 1
Print Interval --> 15
Save Results? (Y/N) --> Y

Specify FILENAME containing INPUT DATA --> D:SP6.PRE
Specify FILENAME to be used for COMPOSITES --> D:SP6.HYD

ALAFAYA TR. ARE POND6

BASIN	NODE	AREA	% LAKE	% DCIA	CN	TC	INI AB	INI AB
ID	#	(acres)			N-DCIA	(min)	DCIA	N-DCIA
							(ins)	(dec)
800	85	10.2	0.0	0.0	79.0	139.0	0.10	0.20
801	85	2.2	0.0	0.0	79.0	139.0	0.10	0.20
806	85	0.1	0.0	0.0	1.0	100.0	0.10	0.20

***** RAINFALL INPUT SECTION *****

Mass Curve or Actual Rainfall? (M/A) --> M

- 1 SCS TYPE II
- 2 ORANGE COUNTY 6-HOUR
- 3 24-HOUR
- 4 SCS TYPE II-M
- 5 FDOT 1 HOUR
- 6 FDOT 2 HOUR
- 7 FDOT 4 HOUR
- 8 FDOT 8 HOUR
- 9 FDOT 1 DAY
- 10 FDOT 3 DAY
- 11 FDOT 7 DAY
- 12 FDOT 10 DAY
- 13 SCS TYPE 2M 96HR

Specify CURVE TYPE = 4

Storm Duration (hrs) --> 24
 Total Rainfall (inches) --> 8.6

LAJAVIA TR. PRE POND6

TIME (hrs)	RAIN (ins)	BASIN 500	BASIN 501	BASIN 506
0.000	0.000	0.0	0.0	0.0
0.250	0.026	0.0	0.0	0.0
0.500	0.051	0.0	0.0	0.0
0.750	0.077	0.0	0.0	0.0
1.000	0.102	0.0	0.0	0.0
1.250	0.128	0.0	0.0	0.0
1.500	0.154	0.0	0.0	0.0
1.750	0.185	0.0	0.0	0.0
2.000	0.216	0.0	0.0	0.0
2.250	0.246	0.0	0.0	0.0
2.500	0.276	0.0	0.0	0.0
2.750	0.306	0.0	0.0	0.0
3.000	0.335	0.0	0.0	0.0
3.250	0.365	0.0	0.0	0.0
3.500	0.395	0.0	0.0	0.0
3.750	0.429	0.0	0.0	0.0
4.000	0.463	0.0	0.0	0.0
4.250	0.497	0.0	0.0	0.0
4.500	0.532	0.0	0.0	0.0
4.750	0.572	0.0	0.0	0.0
5.000	0.612	0.0	0.0	0.0
5.250	0.650	0.0	0.0	0.0
5.500	0.689	0.0	0.0	0.0
5.750	0.727	0.0	0.0	0.0
6.000	0.765	0.1	0.0	0.0
6.250	0.808	0.1	0.0	0.0
6.500	0.851	0.1	0.0	0.0
6.750	0.898	0.1	0.0	0.0
7.000	0.945	0.2	0.0	0.0
7.250	0.996	0.2	0.0	0.0
7.500	1.047	0.3	0.1	0.0
7.750	1.105	0.3	0.1	0.0
8.000	1.163	0.4	0.1	0.0
8.250	1.223	0.4	0.1	0.0
8.500	1.282	0.5	0.1	0.0
8.750	1.346	0.5	0.1	0.0
9.000	1.410	0.6	0.1	0.0
9.250	1.483	0.7	0.1	0.0
9.500	1.555	0.7	0.2	0.0
9.750	1.641	0.8	0.2	0.0
10.000	1.726	0.9	0.2	0.0
10.250	1.832	1.1	0.2	0.0
10.500	1.938	1.2	0.3	0.0
10.750	2.080	1.4	0.3	0.0
11.000	2.225	1.7	0.4	0.0
11.250	2.435	2.0	0.4	0.0
11.500	2.661	2.5	0.5	0.0
11.750	3.936	6.2	1.3	0.0
12.000	5.212	10.0	2.2	0.0

SLAFAYA TR. PRE POND6

TIME (hrs)	RAIN (ins)	BASIN 500	BASIN 501	BASIN 906
12.250	5.589	10.8	2.4	0.0
12.500	6.167	11.5	2.5	0.0
12.750	6.338	11.0	2.4	0.0
13.000	6.505	10.5	2.3	0.0
13.250	6.626	9.9	2.2	0.0
13.500	6.745	9.4	2.0	0.0
13.750	6.845	8.8	1.9	0.0
14.000	6.943	8.3	1.8	0.0
14.250	7.024	7.7	1.7	0.0
14.500	7.105	7.2	1.6	0.0
14.750	7.173	6.6	1.5	0.0
15.000	7.241	6.3	1.4	0.0
15.250	7.305	5.9	1.3	0.0
15.500	7.369	5.6	1.2	0.0
15.750	7.425	5.2	1.1	0.0
16.000	7.480	4.9	1.1	0.0
16.250	7.532	4.6	1.0	0.0
16.500	7.583	4.3	0.9	0.0
16.750	7.632	4.1	0.9	0.0
17.000	7.681	3.9	0.8	0.0
17.250	7.724	3.6	0.8	0.0
17.500	7.766	3.4	0.7	0.0
17.750	7.809	3.2	0.7	0.0
18.000	7.852	3.1	0.7	0.0
18.250	7.890	2.9	0.6	0.0
18.500	7.929	2.8	0.6	0.0
18.750	7.967	2.6	0.6	0.0
19.000	8.005	2.5	0.5	0.0
19.250	8.040	2.4	0.5	0.0
19.500	8.074	2.3	0.5	0.0
19.750	8.109	2.2	0.5	0.0
20.000	8.145	2.1	0.5	0.0
20.250	8.179	2.0	0.4	0.0
20.500	8.213	1.9	0.4	0.0
20.750	8.243	1.9	0.4	0.0
21.000	8.273	1.8	0.4	0.0
21.250	8.303	1.7	0.4	0.0
21.500	8.333	1.7	0.4	0.0
21.750	8.363	1.6	0.4	0.0
22.000	8.393	1.6	0.3	0.0
22.250	8.422	1.5	0.3	0.0
22.500	8.452	1.5	0.3	0.0
22.750	8.479	1.4	0.3	0.0
23.000	8.506	1.4	0.3	0.0
23.250	8.532	1.4	0.3	0.0
23.500	8.557	1.3	0.3	0.0
23.750	8.579	1.3	0.3	0.0
24.000	8.600	1.2	0.3	0.0
24.250	8.600	1.1	0.2	0.0

SANTA BARBARA URBAN HYDROGRAPH 3368118 VER. 1.2
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ALAFAYA TR. PRE POND6

TIME (hrs)	RAIN (ins)	BASIN 500	BASIN 501	BASIN 506
24.500	3.500	1.0	0.2	0.0

ALAFAYA TR. PRE POND6

*** RUNOFF SUMMARY ***

Basin ID#	---	500	501	506
RD VOL (cfs-hrs)		50	13	0
RD VOL (ac-ft)		5.0	1.1	0.0
RD VOL (inches)		5.95	5.95	0.00
PEAK FLOW (cfs)		11.5	2.5	0.0
PEAK TIME (hrs)		12.517	12.517	0.000

--> COMPOSITE HYDROGRAPHS (— (SBUH11)
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TIME hrs)	NODE 35
0.000	0.0
0.250	0.0
0.500	0.0
0.750	0.0
1.000	0.0
1.250	0.0
1.500	0.0
1.750	0.0
2.000	0.0
2.250	0.0
2.500	0.0
2.750	0.0
3.000	0.0
3.250	0.0
3.500	0.0
3.750	0.0
4.000	0.0
4.250	0.0
4.500	0.0
4.750	0.0
5.000	0.0
5.250	0.0
5.500	0.0
5.750	0.1
6.000	0.1
6.250	0.1
6.500	0.1
6.750	0.2
7.000	0.2
7.250	0.3
7.500	0.3
7.750	0.4
8.000	0.4
8.250	0.5
8.500	0.5
8.750	0.6
9.000	0.7
9.250	0.8
9.500	0.9
9.750	1.0
10.000	1.1
10.250	1.3
10.500	1.5
10.750	1.7
11.000	2.0
11.250	2.5
11.500	3.0
11.750	7.5
12.000	12.2

-- COMPOSITE HYDROGRAPHS (--- (SBUH1X1)
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TIME (hrs)	NODE 35
12.250	13.2
12.500	14.0
12.750	13.4
13.000	12.8
13.250	12.1
13.500	11.4
13.750	10.7
14.000	10.1
14.250	9.4
14.500	8.8
14.750	8.2
15.000	7.7
15.250	7.2
15.500	6.8
15.750	6.4
16.000	6.0
16.250	5.6
16.500	5.3
16.750	5.0
17.000	4.7
17.250	4.4
17.500	4.2
17.750	3.9
18.000	3.7
18.250	3.5
18.500	3.4
18.750	3.2
19.000	3.1
19.250	2.9
19.500	2.8
19.750	2.7
20.000	2.6
20.250	2.5
20.500	2.4
20.750	2.3
21.000	2.2
21.250	2.1
21.500	2.0
21.750	2.0
22.000	1.9
22.250	1.9
22.500	1.8
22.750	1.8
23.000	1.7
23.250	1.6
23.500	1.6
23.750	1.5
24.000	1.5
24.250	1.3

-- COMPOSITE HYDROGRAPHS -- (S3UH11)
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TIME	MODE
(hrs)	
-----	-----
24.500	1.3

ALAFAYA TR. POST POND6

How many basins? --> 3
Simulation Duration (hrs) --> 24.5
Time Increment (mins) --> 1
Print Interval --> 15
Save Results? (Y/N) --> Y

Specify FILENAME containing INPUT DATA --> D:SP6.POS
Specify FILENAME to be used for COMPOSITES --> D:SP6.HYD1

ALAFAYA TR. POST POND6

BASIN ID	NODE #	AREA (acres)	% LAKE	% DCIA	CN N-DCIA	TC (min)	INI AB	INI AB
							DCIA	N-DCIA
							(ins)	(dec)
800	81	10.4	0.0	40.0	79.0	145.0	0.10	0.20
801	81	2.2	0.0	100.0	88.0	145.0	0.10	0.20
806	85	0.1	0.0	0.0	1.0	100.0	0.10	0.20

***** RAINFALL INPUT SECTION *****

Mass Curve or Actual Rainfall? (M/A) --> M

- 1 SCS TYPE II
- 2 ORANGE COUNTY 6-HOUR
- 3 24-HOUR
- 4 SCS TYPE II-M
- 5 FDOT 1 HOUR
- 6 FDOT 2 HOUR
- 7 FDOT 4 HOUR
- 8 FDOT 8 HOUR
- 9 FDOT 1 DAY
- 10 FDOT 3 DAY
- 11 FDOT 7 DAY
- 12 FDOT 10 DAY
- 13 SCS TYPE 2M 96HR

Specify CURVE TYPE = 4

Storm Duration (hrs) --> 24
Total Rainfall (inches) --> 3.6

BLAFRA TR. POST POND6

TIME (hrs)	RAIN (ins)	BASIN 500	BASIN 501	BASIN 506
0.000	0.000	0.0	0.0	0.0
0.250	0.026	0.0	0.0	0.0
0.500	0.051	0.0	0.0	0.0
0.750	0.077	0.0	0.0	0.0
1.000	0.102	0.0	0.0	0.0
1.250	0.128	0.0	0.0	0.0
1.500	0.154	0.1	0.0	0.0
1.750	0.185	0.1	0.1	0.0
2.000	0.215	0.2	0.1	0.0
2.250	0.246	0.2	0.1	0.0
2.500	0.276	0.2	0.1	0.0
2.750	0.306	0.3	0.1	0.0
3.000	0.335	0.3	0.1	0.0
3.250	0.365	0.3	0.2	0.0
3.500	0.395	0.3	0.2	0.0
3.750	0.429	0.3	0.2	0.0
4.000	0.463	0.4	0.2	0.0
4.250	0.497	0.4	0.2	0.0
4.500	0.532	0.4	0.2	0.0
4.750	0.572	0.4	0.2	0.0
5.000	0.612	0.5	0.2	0.0
5.250	0.650	0.5	0.3	0.0
5.500	0.689	0.5	0.3	0.0
5.750	0.727	0.5	0.3	0.0
6.000	0.765	0.5	0.3	0.0
6.250	0.808	0.6	0.3	0.0
6.500	0.851	0.6	0.3	0.0
6.750	0.898	0.7	0.3	0.0
7.000	0.945	0.7	0.3	0.0
7.250	0.996	0.8	0.3	0.0
7.500	1.047	0.8	0.3	0.0
7.750	1.105	0.9	0.4	0.0
8.000	1.163	0.9	0.4	0.0
8.250	1.223	1.0	0.4	0.0
8.500	1.282	1.0	0.4	0.0
8.750	1.346	1.1	0.4	0.0
9.000	1.410	1.2	0.4	0.0
9.250	1.483	1.3	0.5	0.0
9.500	1.555	1.3	0.5	0.0
9.750	1.641	1.4	0.5	0.0
10.000	1.726	1.5	0.5	0.0
10.250	1.832	1.7	0.6	0.0
10.500	1.938	1.9	0.6	0.0
10.750	2.080	2.1	0.7	0.0
11.000	2.225	2.4	0.7	0.0
11.250	2.435	2.8	0.8	0.0
11.500	2.661	3.3	1.0	0.0
11.750	3.936	7.3	2.0	0.0
12.000	5.212	11.3	2.9	0.0

BLAFAYA TR. POST POND6

TIME (hrs)	RAIN (ins)	BASIN 500	BASIN 501	BASIN 506
12.250	5.669	12.1	3.0	0.0
12.500	6.167	12.8	3.2	0.0
12.750	6.338	12.2	3.0	0.0
13.000	6.505	11.7	2.9	0.0
13.250	6.626	11.0	2.7	0.0
13.500	6.745	10.4	2.5	0.0
13.750	6.845	9.8	2.4	0.0
14.000	6.943	9.2	2.2	0.0
14.250	7.024	8.6	2.1	0.0
14.500	7.105	8.1	1.9	0.0
14.750	7.173	7.5	1.8	0.0
15.000	7.241	7.1	1.7	0.0
15.250	7.305	6.6	1.5	0.0
15.500	7.369	6.2	1.5	0.0
15.750	7.425	5.8	1.4	0.0
16.000	7.480	5.5	1.3	0.0
16.250	7.532	5.1	1.2	0.0
16.500	7.583	4.8	1.1	0.0
16.750	7.632	4.6	1.1	0.0
17.000	7.681	4.3	1.0	0.0
17.250	7.724	4.0	1.0	0.0
17.500	7.766	3.8	0.9	0.0
17.750	7.809	3.6	0.8	0.0
18.000	7.852	3.4	0.8	0.0
18.250	7.890	3.2	0.8	0.0
18.500	7.929	3.1	0.7	0.0
18.750	7.967	3.0	0.7	0.0
19.000	8.005	2.8	0.6	0.0
19.250	8.040	2.6	0.6	0.0
19.500	8.074	2.5	0.6	0.0
19.750	8.109	2.4	0.6	0.0
20.000	8.145	2.3	0.5	0.0
20.250	8.179	2.2	0.5	0.0
20.500	8.213	2.1	0.5	0.0
20.750	8.243	2.0	0.5	0.0
21.000	8.273	2.0	0.4	0.0
21.250	8.303	1.9	0.4	0.0
21.500	8.333	1.8	0.4	0.0
21.750	8.363	1.8	0.4	0.0
22.000	8.393	1.7	0.4	0.0
22.250	8.422	1.7	0.4	0.0
22.500	8.452	1.6	0.4	0.0
22.750	8.479	1.6	0.4	0.0
23.000	8.506	1.5	0.3	0.0
23.250	8.532	1.5	0.3	0.0
23.500	8.557	1.4	0.3	0.0
23.750	8.579	1.4	0.3	0.0
24.000	8.600	1.3	0.3	0.0
24.250	8.600	1.2	0.3	0.0

ALAFAYA TR. POST POND6

TIME	RAIN	BASIN	BASIN	BASIN
(hrs)	(ins)	500	501	506
24.500	9.600	1.1	0.2	0.0

ALAFAYA TR. POST POND6

*** RUNOFF SUMMARY ***

BSIN ID# →	500	501	506
RD VOL (cfs-hrs)	71	18	0
RD VOL (ac-ft)	5.9	1.5	0.0
RD VOL (inches)	5.79	8.24	0.00
PEAK FLOW (cfs)	12.3	3.2	0.0
PEAK TIME (hrs)	12.517	12.517	0.000

→ COMPOSITE HYDROGRAPHS (← (SBLHIXI)
 (C) Copyright 1983, Peter J. Singhofen, P.E.

TIME (hrs)	NODE 51	NODE 55
0.000	0.0	0.0
0.250	0.0	0.0
0.500	0.0	0.0
0.750	0.0	0.0
1.000	0.0	0.0
1.250	0.1	0.0
1.500	0.1	0.0
1.750	0.2	0.0
2.000	0.3	0.0
2.250	0.3	0.0
2.500	0.3	0.0
2.750	0.4	0.0
3.000	0.4	0.0
3.250	0.5	0.0
3.500	0.5	0.0
3.750	0.5	0.0
4.000	0.6	0.0
4.250	0.6	0.0
4.500	0.6	0.0
4.750	0.7	0.0
5.000	0.7	0.0
5.250	0.7	0.0
5.500	0.8	0.0
5.750	0.8	0.0
6.000	0.8	0.0
6.250	0.9	0.0
6.500	0.9	0.0
6.750	1.0	0.0
7.000	1.0	0.0
7.250	1.1	0.0
7.500	1.1	0.0
7.750	1.2	0.0
8.000	1.3	0.0
8.250	1.4	0.0
8.500	1.4	0.0
8.750	1.5	0.0
9.000	1.6	0.0
9.250	1.7	0.0
9.500	1.8	0.0
9.750	1.9	0.0
10.000	2.1	0.0
10.250	2.3	0.0
10.500	2.5	0.0
10.750	2.8	0.0
11.000	3.1	0.0
11.250	3.6	0.0
11.500	4.2	0.0
11.750	9.3	0.0
12.000	14.2	0.0

— COMPOSITE HYDROGRAPHS (— (SBUHIXI)
 (C) Copyright 1983, Peter J. Singhofen, P.E.

TIME (hrs)	NODE 51	NODE 55
12.250	15.2	0.0
12.500	15.0	0.0
12.750	15.2	0.0
13.000	14.5	0.0
13.250	13.7	0.0
13.500	12.9	0.0
13.750	12.1	0.0
14.000	11.4	0.0
14.250	10.7	0.0
14.500	10.0	0.0
14.750	9.4	0.0
15.000	8.8	0.0
15.250	8.2	0.0
15.500	7.7	0.0
15.750	7.2	0.0
16.000	6.8	0.0
16.250	6.4	0.0
16.500	6.0	0.0
16.750	5.6	0.0
17.000	5.3	0.0
17.250	5.0	0.0
17.500	4.7	0.0
17.750	4.5	0.0
18.000	4.2	0.0
18.250	4.0	0.0
18.500	3.8	0.0
18.750	3.6	0.0
19.000	3.4	0.0
19.250	3.3	0.0
19.500	3.1	0.0
19.750	3.0	0.0
20.000	2.9	0.0
20.250	2.7	0.0
20.500	2.6	0.0
20.750	2.5	0.0
21.000	2.4	0.0
21.250	2.3	0.0
21.500	2.2	0.0
21.750	2.2	0.0
22.000	2.1	0.0
22.250	2.0	0.0
22.500	2.0	0.0
22.750	1.9	0.0
23.000	1.9	0.0
23.250	1.8	0.0
23.500	1.7	0.0
23.750	1.7	0.0
24.000	1.6	0.0
24.250	1.5	0.0

→ COMPOSITE HYDROGRAPHS (— (SBUH1X1)
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TIME	MODE	MODE
(hrs)	51	35
24.500	1.3	0.0

ELEVATION - STORAGE VALUES

Prgm : DTBSIN6R.VOL

DETENTION BASIN DESIGN

01-04-1980

Name of Storage Basin : ALAFAYA POND 6

ELEVATION TOP STORAGE BASIN-FT ==> 65.9

ELEVATION BOT STORAGE BASIN - FT ==> 63.9

INCREMENTAL STAGE DEPTH - FT ==> .1

STORAGE BASIN AREA - ACRES AT TOP OF BASIN ==> 3.35

STORAGE BASIN PERIMETER @ TOP OF BASIN ==> 1711

AVERAGE SIDE SLOPE RATIO ==> 5

STAGE EL. -----	AREA-ACRES -----	STORAGE-AC FT -----
63.90	2.960	0.00
64.00	2.980	0.30
64.10	3.000	0.60
64.20	3.020	0.90
64.30	3.040	1.20
64.40	3.060	1.50
64.50	3.080	1.81
64.60	3.090	2.12
64.70	3.110	2.43
64.80	3.130	2.74
64.90	3.150	3.06
65.00	3.170	3.37
65.10	3.190	3.69
65.20	3.210	4.01
65.30	3.230	4.33
65.40	3.250	4.66
65.50	3.270	4.98
65.60	3.290	5.31
65.70	3.310	5.64
65.80	3.330	5.97
65.90	3.350	6.31

*** End of This Calculation ***

LOCHRANE ENGINEERING, INC.

201 S. Bumby Avenue
ORLANDO, FL 32803
(407) 896-3317

JOB 102942-131
SHEET NO. _____ OF _____
CALCULATED BY Cal DATE _____
CHECKED BY _____ DATE _____
SCALE _____

Let Detention

Pond 6

1" runoff (Water Quality)

$$3.96 \text{ ac } (1")/12 = 0.71 \text{ acft} \rightarrow 64.14 \text{ FT NGVD}$$

min weir el.

63.9 FT Normal Pool El.

Using 3" orifice invert @ N.P. el.

$$63.9 + 0.25'/12 = 64.02 \text{ FT } \frac{1}{2} \text{ of orifice}$$

Area Ratio

$$\text{Basin Area} = 8.46 \text{ ac}$$

$$\text{Normal Pool} = 2.96 \text{ ac}$$

$$\frac{8.46}{2.96} = 2.86 < 19 \quad \checkmark$$

Littoral shelf

$$\text{Normal Pool} = 2.96 \text{ ac}$$

$$\text{Open Water} = 2.23 \text{ ac}$$

$$\frac{2.23}{2.96} = 75\% \leq 75\% \quad \checkmark$$

Pre Development Flow 14 cfs

Post Development Peak Stage 64.89 FT (TOB 65.9 FT)

Peak Flow 912 cfs

T.W. El.

EXHIBIT 6.2-10 Page 111 of 147

$$\frac{64.89 + 63.9}{2} = 64.40 \text{ FT NGVD}$$

LOCHRANE ENGINEERING, INC.

201 S. Bumby Avenue
ORLANDO, FL 32803
(407) 896-3317

JOB Alafaya Trail
SHEET NO. _____ OF _____
CALCULATED BY Cal DATE _____
CHECKED BY _____ DATE _____
SCALE _____

PND 6

Orifice (Recovery)

Purpose: to recover 0.5" runoff in 60 hrs

$$0.5" / 12 (11.42 \text{ ac}) = 0.48 \text{ acft}$$

$$0.48 \text{ acft} \rightarrow 20909 \text{ CF}$$

$$60 \text{ hrs} \rightarrow 216000 \text{ sec}$$

$$0.10 \text{ CFS}$$

$$1" \text{ runoff } 1" / 12 (11.42 \text{ ac}) = 0.95 \text{ acft} \rightarrow 64.22 \text{ Ft NBVD}$$

$$0.95 \text{ acft} - 0.48 \text{ acft} = 0.47 \text{ acft} \rightarrow 64.06 \text{ Ft NBVD @ 60 hrs}$$

$$A = \frac{Q}{C(2gH)^{1/2}}$$

$$H = \left(\frac{64.22 + 64.06}{2} \right) - 63.9 = 0.24 \text{ FT}$$

$$C = 0.6$$

$$A = \frac{0.10 \text{ CFS}}{0.6 (64.4 (0.24))^{1/2}}$$

$$A = 0.04 \text{ SF} \sim 5.8 \text{ in}^2$$

$$D = (4A/\pi)^{1/2}$$

$$D = 2.7 \text{ in}$$

Use ~~3/4"~~ orifice

2.5"

ELEVATION - STORAGE VALUES

Prgm : DTESINGR.VOL

DETENTION BASIN DESIGN

01-04-1980

Name of Storage Basin : P6

ELEVATION TOP STORAGE BASIN-FT ==> 64.9

ELEVATION BOT STORAGE BASIN - FT ==> 55.9

INCREMENTAL STAGE DEPTH - FT ==> .5

STORAGE BASIN AREA - ACRES AT TOP OF BASIN ==> 3.35

STORAGE BASIN PERIMETER @ TOP OF BASIN ==> 1711

AVERAGE SIDE SLOPE RATIO ==> 5

CHANGE IN SLOPE TO ==> 6 AT ELEVATION ==> 63.9

CHANGE IN SLOPE TO ==> 2 AT ELEVATION ==> 60.9

STAGE EL.	AREA-ACRES	STORAGE-AC FT
55.90	2.110	0.00
56.40	2.150	1.07
56.90	2.180	2.15
57.40	2.220	3.25
57.90	2.250	4.37
58.40	2.290	5.50
58.90	2.320	6.65
59.40	2.360	7.82
59.90	2.390	9.01
60.40	2.430	10.22
60.90	2.460	11.44
61.40	2.580	12.70
61.90	2.690	14.02
62.40	2.810	15.39
62.90	2.920	16.83
63.40	3.040	18.32
63.90	3.150	19.86
64.40	3.250	21.47
64.90	3.350	23.12

*** End of This Calculation ***

4 day resident reqmt.

$$\text{Resident Vol. (reqd)} = \frac{28.6(0.44)(15.11)}{12} = 2.47 \text{ ac-ft}$$

$$\text{Resident Vol. (provided)} = 19.86 \text{ ac-ft}$$

$$19.86 \text{ ac-ft} > 2.47 \text{ ac-ft} \checkmark$$

*** INTER-CONNECTED POND ROUTING PROGRAM *** 1088185 VER 2.83
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ALAPATA TR. POND 151R
 3-17-83

 *** CONTROL DATA ***

Simulation time increment (mins) --- 1
 Simulation duration (mins) --- 24
 Starting time (mins) --- 1
 Print interval --- 11

 *** NODE AND INITIALIZATION DATA ***

NODE	NODE	INITIAL
"	NAME	STAGE
----	----	----
01	1	13.000
02	2	13.300

*** INTER-CONNECTED POND ROUTING PROGRAM *** 1008118 VER 2.00
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ALAFAYA TR. POND# 35A
 8-17-83

 *** STAGE/STORAGE/TIME DATA ***

NODE # 31

STAGE	61.500	64.000	64.500	65.000	65.500
STORAGE	1.000	0.300	1.310	2.370	4.691
STAGE	65.500	66.000	66.500	67.000	67.500
STORAGE	5.310	6.000	6.600	7.431	7.700
STAGE	67.500	68.000	68.500	69.000	69.500
STORAGE	7.700	8.000	8.600	9.100	9.600

NODE # 35

STAGE	63.500	65.400	0.000	0.000	0.000
TIME	1.000	40.000	0.000	0.000	0.000
STAGE	0.000	0.000	0.000	0.000	0.000
TIME	0.000	0.000	0.000	0.000	0.000
STAGE	0.000	0.000	0.000	0.000	0.000
TIME	0.000	0.000	0.000	0.000	0.000

*** INTER-CONNECTED FOND ROUTING PROGRAM *** 1085135 VER 2.83
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LAKEVIEW TR. FOND 25XR
 3-17-83

 *** FINDER DATA ***

NOTE: Type 1 for sharp crested weir/gate and orifice
 Type 2 for broad crested weir/gate and orifice
 - Type 3 for culvert
 - Type 4 for trapezoidal channel
 - Type 5 for parabolic channel
 Type 6 for rating curve

- Negative type indicates riser/

REACH	FROM	TO	REACH
=	NODE	NODE	TYPE
-----	-----	-----	-----
1	61	66	1

REACH # 1 from node # 61 -- to node # 66

Broad Crested Weir/Gate and Orifice :-

Crest elevation (feet) --> 54.01
 Crest length (feet) --> 5
 Weir discharge coefficient --> 3.057
 Weir exponent --> 1.5
 % to effective submergence --> 67
 Gate opening (feet) --> 69
 # of end contractions --> 0
 Discharge coef for gate under ori flow --> 1
 Circular orifice centerline (feet) --> 54.01
 Orifice diameter (feet) --> .135
 Orifice discharge coefficient --> .6
 # identical orifices --> 1

*** INTER-CONNECTED POND ROUTING PROGRAM *** 1088108 VER 2.02
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ALAPPA TR. POND 2118
8-17-99

*** INFLOW HYDROGRAPHS ***

INFLOW HYDROGRAPHS TO BE READ FROM DISK FILE

ALABAMA TR. PONDS 83YR
 8-17-85

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW (cfs)	TOTAL
81	0.00	63.90	0.00	0.00	0.00	0.00
85	0.00	63.90	0.00	0.00	-----	0.00
81	0.25	63.90	0.00	0.00	0.00	0.00
85	0.25	63.91	0.00	0.00	-----	0.00
81	0.50	63.91	0.00	0.00	0.00	0.00
85	0.50	63.92	0.00	0.00	-----	0.00
81	0.75	63.90	0.00	0.00	0.00	0.00
85	0.75	63.93	0.00	0.00	-----	0.00
81	1.00	63.90	0.00	0.00	0.00	0.00
85	1.00	63.94	0.00	0.00	-----	0.00
81	1.25	63.90	0.00	0.07	0.00	0.00
85	1.25	63.95	0.00	0.00	-----	0.00
81	1.50	63.90	0.00	0.12	0.00	0.00
85	1.50	63.95	0.00	0.00	-----	0.00
81	1.75	63.90	0.01	0.13	0.00	0.00
85	1.75	63.97	0.00	0.00	-----	0.00
81	2.00	63.90	0.01	0.25	0.00	0.00
85	2.00	63.97	0.00	0.00	-----	0.00
81	2.25	63.91	0.02	0.30	0.00	0.00
85	2.25	63.98	0.00	0.00	-----	0.00
81	2.50	63.91	0.02	0.35	0.00	0.00
85	2.50	63.99	0.00	0.00	-----	0.00
81	2.75	63.91	0.03	0.39	0.00	0.00
85	2.75	64.00	0.00	0.00	-----	0.00
81	3.00	63.91	0.04	0.43	0.00	0.00
85	3.00	64.01	0.00	0.00	-----	0.00
81	3.25	63.92	0.05	0.45	-0.01	-0.01
85	3.25	64.02	-0.00	-0.01	-----	0.00

ALAFAYA TR. PONDS 25YR
 8-17-89

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW (cfs) # 1	TOTAL
91	3.50	63.81	0.05	0.48	-0.03	-0.03
95	3.50	64.03	-0.00	-0.03	-----	0.00
91	3.75	63.82	0.07	0.53	-0.03	-0.03
95	3.75	64.04	-0.00	-0.03	-----	0.00
91	4.00	63.82	0.11	0.55	-0.04	-0.04
95	4.00	64.05	-0.00	-0.04	-----	0.00
91	4.25	63.83	0.13	0.58	-0.05	-0.05
95	4.25	64.06	-0.00	-0.05	-----	0.00
91	4.50	63.84	0.15	0.62	-0.05	-0.05
95	4.50	64.07	-0.00	-0.05	-----	0.00
91	4.75	63.84	0.12	0.66	-0.06	-0.06
95	4.75	64.08	-0.00	-0.06	-----	0.00
91	5.00	63.85	0.14	0.70	-0.06	-0.06
95	5.00	64.09	-0.01	-0.06	-----	0.00
91	5.25	63.85	0.15	0.74	-0.07	-0.07
95	5.25	64.10	-0.01	-0.07	-----	0.00
91	5.50	63.85	0.17	0.77	-0.07	-0.07
95	5.50	64.11	-0.01	-0.07	-----	0.00
91	5.75	63.86	0.19	0.80	-0.07	-0.07
95	5.75	64.12	-0.01	-0.07	-----	0.00
91	6.00	63.87	0.21	0.84	-0.08	-0.08
95	6.00	64.13	-0.01	-0.08	-----	0.00
91	6.25	63.88	0.23	0.88	-0.08	-0.08
95	6.25	64.13	-0.01	-0.08	-----	0.00
91	6.50	63.88	0.25	0.92	-0.08	-0.08
95	6.50	64.14	-0.02	-0.08	-----	0.00
91	6.75	63.89	0.27	0.97	-0.09	-0.09
95	6.75	64.15	-0.02	-0.09	-----	0.00

*** INTER-CONNECTED POND ROUTING PROGRAM ***
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1038108 VER 2.83

ALABAMA TR. POND 15YSR
 3-17-83

TIME	STAGE	STORAGE	INFLOW	OUTFLOW	NOTES
#	(Feet)	(acft)	(cfs)	# 1	TOTAL
----	-----	-----	-----	-----	-----
81	10.50	84.18	0.75	2.47	-0.38
85	10.50	84.29	-0.08	-0.38	0.00
81	10.75	84.18	0.85	2.73	-0.41
85	10.75	84.30	-0.17	-0.41	0.00
81	11.00	84.21	1.18	3.11	-0.43
85	11.00	84.31	-0.03	-0.43	0.00
81	11.25	84.23	1.31	3.55	-0.54
85	11.25	84.31	-0.09	-0.54	0.00
81	11.50	84.28	1.50	4.20	-0.60
85	11.50	84.33	-0.10	-0.60	0.00
81	11.75	84.31	1.85	5.33	-0.64
85	11.75	84.34	-0.11	-0.64	0.00
81	12.00	84.35	2.45	6.33	1.16
85	12.00	84.35	-0.11	1.16	0.00
81	12.25	84.48	3.75	15.13	2.23
85	12.25	84.35	-0.03	2.23	0.00
81	12.50	84.57	5.22	15.55	3.42
85	12.50	84.37	-0.02	3.42	0.00
81	12.75	84.63	6.35	15.35	4.63
85	12.75	84.35	0.05	4.63	0.00
81	13.00	84.71	8.45	14.54	5.73
85	13.00	84.35	0.17	5.73	0.00
81	13.25	84.76	9.53	13.65	6.63
85	13.25	84.40	0.30	6.63	0.00
81	13.50	84.80	9.76	12.92	7.46
85	13.50	84.41	0.44	7.46	0.00
81	13.75	84.84	9.86	12.13	8.03
85	13.75	84.42	0.51	8.03	0.00

ALAPPA TR. PONDS LBR
 3-17-89

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW (cfs) # 1	TOTAL
51	17.50	84.78	3.87	4.71	3.83	3.83
55	17.50	84.55	3.21	3.83	-----	0.00
51	17.75	84.78	3.88	4.45	3.81	3.81
55	17.75	84.57	3.35	3.81	-----	0.00
51	18.00	84.78	3.88	4.31	3.85	3.85
55	18.00	84.57	3.42	3.85	-----	0.00
51	18.25	84.73	3.84	3.99	3.03	3.03
55	18.25	84.59	3.81	3.03	-----	0.00
51	18.50	84.73	3.43	3.79	3.77	3.77
55	18.50	84.59	3.73	3.77	-----	0.00
51	18.75	84.71	3.45	3.60	3.33	3.33
55	18.75	84.60	3.85	3.33	-----	0.00
51	19.00	84.70	3.41	3.43	4.63	4.63
55	19.00	84.61	3.95	4.63	-----	0.00
51	19.25	84.69	3.39	3.25	4.30	4.30
55	19.25	84.61	4.05	4.30	-----	0.00
51	19.50	84.68	3.38	3.11	3.67	3.67
55	19.50	84.63	4.13	3.67	-----	0.00
51	19.75	84.68	3.37	2.97	3.05	3.05
55	19.75	84.64	4.10	3.05	-----	0.00
51	20.00	84.63	3.37	2.85	2.53	2.53
55	20.00	84.65	4.25	2.53	-----	0.00
51	20.25	84.68	3.38	2.74	2.10	2.10
55	20.25	84.66	4.31	2.10	-----	0.00
51	20.50	84.69	3.40	2.63	1.77	1.77
55	20.50	84.67	4.35	1.77	-----	0.00
51	20.75	84.69	3.42	2.52	1.52	1.52
55	20.75	84.68	4.38	1.52	-----	0.00

ALAFAYA TR. POND6 25YR

8-17-89

NODE #	TIME (hrs)	STAGE (feet)	STORAGE (acft)	INFLOW (cfs)	OUTFLOW (cfs)	
					# 1	TOTAL
61	21.00	64.70	2.44	2.41	1.32	1.32
95	21.00	64.69	4.41	1.32	-----	0.00
61	21.25	64.71	2.46	2.32	1.16	1.16
95	21.25	64.70	4.44	1.16	-----	0.00
61	21.50	64.72	2.48	2.24	1.03	1.03
95	21.50	64.71	4.46	1.03	-----	0.00
61	21.75	64.72	2.51	2.16	0.92	0.92
95	21.75	64.72	4.48	0.92	-----	0.00
61	22.00	64.73	2.54	2.09	0.82	0.82
95	22.00	64.72	4.50	0.82	-----	0.00
61	22.25	64.74	2.56	2.03	0.74	0.74
95	22.25	64.73	4.51	0.74	-----	0.00
61	22.50	64.75	2.59	1.98	0.67	0.67
95	22.50	64.74	4.53	0.67	-----	0.00
61	22.75	64.76	2.62	1.91	0.60	0.60
95	22.75	64.75	4.54	0.60	-----	0.00
61	23.00	64.77	2.64	1.86	0.53	0.53
95	23.00	64.75	4.55	0.53	-----	0.00
61	23.25	64.78	2.67	1.80	0.47	0.47
95	23.25	64.77	4.56	0.47	-----	0.00
61	23.50	64.78	2.70	1.74	0.41	0.41
95	23.50	64.78	4.57	0.41	-----	0.00
61	23.75	64.79	2.73	1.68	0.35	0.35
95	23.75	64.79	4.58	0.35	-----	0.00
61	24.00	64.80	2.75	1.62	0.28	0.28
95	24.00	64.80	4.59	0.28	-----	0.00

*** INTER-CONNECTED POND ROUTING PROGRAM *** ICS8135 VER 2.83

ALAFAYA TR. PONDS ESYR
8-17-89

*** PEAK CONDITIONS SUMMARY ***

NODE #	PEAK STAGE (feet)	PEAK STORAGE (acft)	TIME TO PEAK (hrs)	PEAK OUTFLOW (cfs)	TIME TO PEAK (hrs)
51	54.89	3.02	14.85	3.12	14.85
55	54.80	4.59	14.02	0.00	0.02

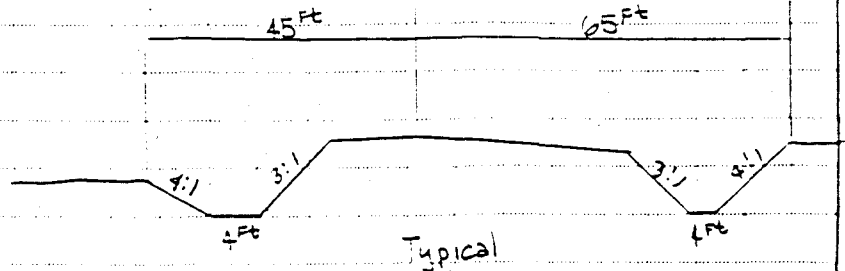
FROM NODE	TO NODE	PEAK OUTFLOW (cfs)	TIME TO PEAK (hrs)
51	55	3.12	14.85

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(407) 896-3317

JOB Alafaya Trail
SHEET NO. _____ OF _____
CALCULATED BY cal DATE _____
CHECKED BY _____ DATE _____
SCALE _____

Special Ditch

Sta 443+00 1000 LF
Sta 503+00



West side

$\frac{1}{2}$ " Runoff 45 ft section

$$1.03 \text{ ac } (\frac{1}{2}) / 12 = 0.04 \text{ ac-ft}$$

<u>stage</u>	<u>storage</u>	
66.52 ft	0.04 ac-ft	Ditch Block El. 66.52 ft

East side

Runoff 65 ft section

$$1.49 \text{ ac } (\frac{1}{2}) / 12 = 0.06 \text{ ac-ft}$$

<u>stage</u>	<u>storage</u>	
66.17	0.058	
X	0.06	Ditch Block El. 66.19 ft
66.27	0.068	

* Note runoff presently drains to these roadside swales providing $\frac{1}{2}$ " treatment in swales (water quality)

****DITCH STAGE STORAGE ****
/EAST/

Bottom width = 4
 z1+z2 (side slope sum) = 7
 ditch bottom elev. (ngvd) = 84.67
 ditch grade % = .41
 length = 1000

elev.	cu. ft.	ac. ft.	elev.	cu. ft.	ac. ft.
84.67	0	0	84.77	5	0
84.67	32	0	84.97	35	9.999999E-04
84.67	113	.002	85.17	175	.004
84.67	237	.006	85.37	385	.008
84.67	330	.012	85.37	706	.016
84.67	414	.02	85.77	1158	.026
84.67	440	.033	85.97	1762	.04
84.67	5127	.048	86.17	2538	.058
84.67	5997	9.8000001E-02	86.37	3506	.08
84.67	4069	.093	86.37	4688	.107
84.67	3365	.123	86.77	6104	.14
84.67	5905	.158	86.97	7773	.178

SECONDARY SYSTEM

100

1. The first group of variables includes the demographic characteristics of the respondents, such as age, gender, and education level. These variables are used to control for potential confounding factors that may influence the relationship between the independent and dependent variables.

THE UNIVERSITY OF CHICAGO

TABLE 1

1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, 2013, 2014, 2015, 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023, 2024, 2025, 2026, 2027, 2028, 2029, 2030, 2031, 2032, 2033, 2034, 2035, 2036, 2037, 2038, 2039, 2040, 2041, 2042, 2043, 2044, 2045, 2046, 2047, 2048, 2049, 2050, 2051, 2052, 2053, 2054, 2055, 2056, 2057, 2058, 2059, 2060, 2061, 2062, 2063, 2064, 2065, 2066, 2067, 2068, 2069, 2070, 2071, 2072, 2073, 2074, 2075, 2076, 2077, 2078, 2079, 2080, 2081, 2082, 2083, 2084, 2085, 2086, 2087, 2088, 2089, 2090, 2091, 2092, 2093, 2094, 2095, 2096, 2097, 2098, 2099, 2100, 2101, 2102, 2103, 2104, 2105, 2106, 2107, 2108, 2109, 2110, 2111, 2112, 2113, 2114, 2115, 2116, 2117, 2118, 2119, 2120, 2121, 2122, 2123, 2124, 2125, 2126, 2127, 2128, 2129, 2130, 2131, 2132, 2133, 2134, 2135, 2136, 2137, 2138, 2139, 2140, 2141, 2142, 2143, 2144, 2145, 2146, 2147, 2148, 2149, 2150, 2151, 2152, 2153, 2154, 2155, 2156, 2157, 2158, 2159, 2160, 2161, 2162, 2163, 2164, 2165, 2166, 2167, 2168, 2169, 2170, 2171, 2172, 2173, 2174, 2175, 2176, 2177, 2178, 2179, 2180, 2181, 2182, 2183, 2184, 2185, 2186, 2187, 2188, 2189, 2190, 2191, 2192, 2193, 2194, 2195, 2196, 2197, 2198, 2199, 2200, 2201, 2202, 2203, 2204, 2205, 2206, 2207, 2208, 2209, 2210, 2211, 2212, 2213, 2214, 2215, 2216, 2217, 2218, 2219, 2220, 2221, 2222, 2223, 2224, 2225, 2226, 2227, 2228, 2229, 2230, 2231, 2232, 2233, 2234, 2235, 2236, 2237, 2238, 2239, 2240, 2241, 2242, 2243, 2244, 2245, 2246, 2247, 2248, 2249, 2250, 2251, 2252, 2253, 2254, 2255, 2256, 2257, 2258, 2259, 2260, 2261, 2262, 2263, 2264, 2265, 2266, 2267, 2268, 2269, 2270, 2271, 2272, 2273, 2274, 2275, 2276, 2277, 2278, 2279, 2280, 2281, 2282, 2283, 2284, 2285, 2286, 2287, 2288, 2289, 2290, 2291, 2292, 2293, 2294, 2295, 2296, 2297, 2298, 2299, 2300, 2301, 2302, 2303, 2304, 2305, 2306, 2307, 2308, 2309, 2310, 2311, 2312, 2313, 2314, 2315, 2316, 2317, 2318, 2319, 2320, 2321, 2322, 2323, 2324, 2325, 2326, 2327, 2328, 2329, 2330, 2331, 2332, 2333, 2334, 2335, 2336, 2337, 2338, 2339, 2340, 2341, 2342, 2343, 2344, 2345, 2346, 2347, 2348, 2349, 2350, 2351, 2352, 2353, 2354, 2355, 2356, 2357, 2358, 2359, 2360, 2361, 2362, 2363, 2364, 2365, 2366, 2367, 2368, 2369, 2370, 2371, 2372, 2373, 2374, 2375, 2376, 2377, 2378, 2379, 2380, 2381, 2382, 2383, 2384, 2385, 2386, 2387, 2388, 2389, 2390, 2391, 2392, 2393, 2394, 2395, 2396, 2397, 2398, 2399, 2400, 2401, 2402, 2403, 2404, 2405, 2406, 2407, 2408, 2409, 2410, 2411, 2412, 2413, 2414, 2415, 2416, 2417, 2418, 2419, 2420, 2421, 2422, 2423, 2424, 2425, 2426, 2427, 2428, 2429, 2430, 2431, 2432, 2433, 2434, 2435, 2436, 2437, 2438, 2439, 2440, 2441, 2442, 2443, 2444, 2445, 2446, 2447, 2448, 2449, 2450, 2451, 2452, 2453, 2454, 2455, 2456, 2457, 2458, 2459, 2460, 2461, 2462, 2463, 2464, 2465, 2466, 2467, 2468, 2469, 2470, 2471, 2472, 2473, 2474, 2475, 2476, 2477, 2478, 2479, 2480, 2481, 2482, 2483, 2484, 2485, 2486, 2487, 2488, 2489, 2490, 2491, 2492, 2493, 2494, 2495, 2496, 2497, 2498, 2499, 2500, 2501, 2502, 2503, 2504, 2505, 2506, 2507, 2508, 2509, 2510, 2511, 2512, 2513, 2514, 2515, 2516, 2517, 2518, 2519, 2520, 2521, 2522, 2523, 2524, 2525, 2526, 2527, 2528, 2529, 2530, 2531, 2532, 2533, 2534, 2535, 2536, 2537, 2538, 2539, 2540, 2541, 2542, 2543, 2544, 2545, 2546, 2547, 2548, 2549, 2550, 2551, 2552, 2553, 2554, 2555, 2556, 2557, 2558, 2559, 2560, 2561, 2562, 2563, 2564, 2565, 2566, 2567, 2568, 2569, 2570, 2571, 2572, 2573, 2574, 2575, 2576, 2577, 2578, 2579, 2580, 2581, 2582, 2583, 2584, 2585, 2586, 2587, 2588, 2589, 2590, 2591, 2592, 2593, 2594, 2595, 2596, 2597, 2598, 2599, 2600, 2601, 2602, 2603, 2604, 2605, 2606, 2607, 2608, 2609, 2610, 2611, 2612, 2613, 2614, 2615, 2616, 2617, 2618, 2619, 2620, 2621, 2622, 2623, 2624, 2625, 2626, 2627, 2628, 2629, 2630, 2631, 2632, 2633, 2634, 2635, 2636, 2637, 2638, 2639, 2640, 2641, 2642, 2643, 2644, 2645, 2646, 2647, 2648, 2649, 2650, 2651, 2652, 2653, 2654, 2655, 2656, 2657, 2658, 2659, 2660, 2661, 2662, 2663, 2664, 2665, 2666, 2667, 2668, 2669, 2670, 2671, 2672, 2673, 2674, 2675, 2676, 2677, 2678, 26

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100

552-91-100-0000

[illegible]

ALARMING - 1001-1000

PIPE IDENT	COST \$	PIPE IDENT	COST \$	PIPE IDENT	COST \$
FROM TO		FROM TO		FROM TO	
800 801	1078.00	801 802	1078.00	802 803	1078.00
804 805	1078.00				

TOTAL SYSTEM COST = 1078.00

ALPHA TAIL BOARD

FEET-PS		PIPE LINE
MAXIMUM DEPTH OF CUT INTO CROWN	0.10 FT	80 TO 800
MAXIMUM VELOCITY (GRAVITY FLOW)	1.84 FPS	80 TO 800
MAXIMUM PIPE SLOPE	1.00 PERCENT	80 TO 800
MINIMUM VELOCITY (GRAVITY FLOW)	1.00 FPS	80 TO 800
MINIMUM VELOCITY (GRAVITY FLOW)	1.00 FPS	80 TO 800
MINIMUM HYDRAULIC GRADIENT CLEARANCE TO GUTTER	1.00 FT	80 TO 800
MINIMUM HYDRAULIC GRADIENT CLEARANCE TO GUTTER	1.00 FT	80 TO 800
MINIMUM HYDRAULIC GRADIENT	1.00 PERCENT	80 TO 800
MINIMUM HYDRAULIC GRADIENT	1.00 PERCENT	80 TO 800

MAXIMUM DEPTH OF CUT CONTROL USED FOR FOOTPRINT AT -

NO PIPES

DESIGN ALL OTHER THAN 10 FT IN THE FOLLOWING PIPE LENGTHS -

NO PIPES

COMMENT:

THE CROSSINGS

THE CROSSINGS

Each of the crossings were analyzed using the rational method for both the 50 year and 100 year storm event. Addressing the concerns and requests of the involved environmental agencies, the following approved culvert system will be installed at Green Branch and Hart Branch Crossings. The culvert system will include a single concrete arch culvert with one (1) 48 inch concrete pipe placed on each side of the arch to serve as critter crossings. Considering previous disturbances of Cowpen Branch Crossing, the agencies agreed that properly sized pipe culverts would be appropriate at this crossing.

GREEN BRANCH CROSSING

The drainage area contributing to the Alafaya Trail extension crossing is approximately 1944 acres. A 6 foot x 24 foot concrete arch culvert will be placed at the crossing of Alafaya Trail and this tributary branch. The arch culvert structure will be buried to allow a 3 foot opening to reduce proposed profile grade concerns. Along with the arch culvert one 48 inch concrete pipe will be placed on each side of the arch to serve as critter crossings. Using the rational method and the 100 year storm event, the required waterway area was found to be approximately 50 SF. The proposed culvert system to be installed at Green Branch Crossing will provide approximately 62 SF of available waterway area. This will insure adequate area for the post development conditions.

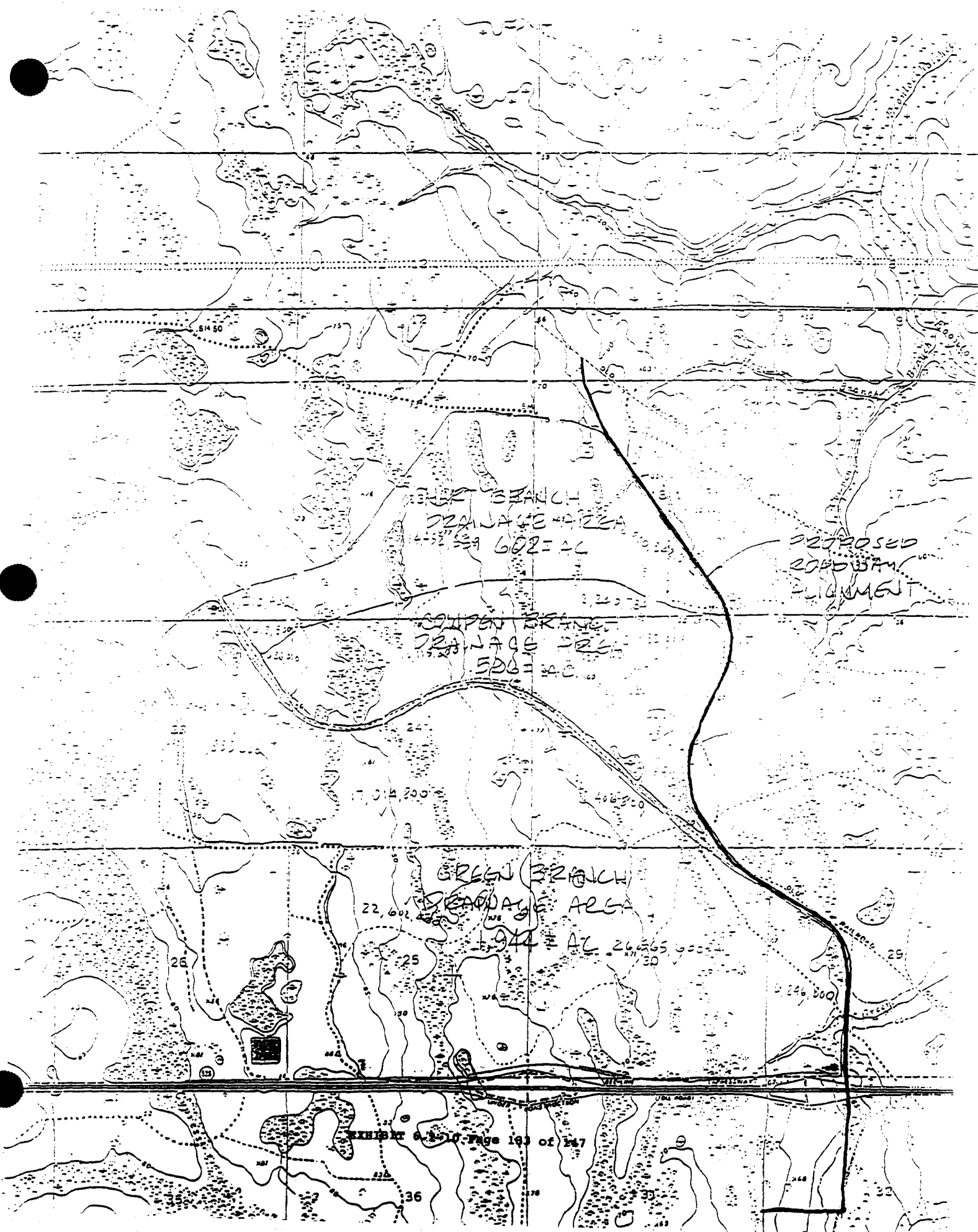
COWPEN BRANCH CROSSING

The drainage area contributing to the Alafaya Trail extension crossing is approximately 596 acres. A pair of 72 inch concrete pipe culverts will be placed at the crossing of Alafaya Trail and

this tributary branch. The invert of the pipes will be buried to one half the diameter of the pipe to reduce proposed profile grade concerns. Using the rational method and the 100 year storm event, the required waterway area was found to be approximately 28 SF. The proposed culvert system to be installed at Hart Branch Crossing will provide approximately 28 SF. This will insure adequate area for the post development conditions.

HART BRANCH CROSSING

The drainage area contributing to the Alafaya Trail extension crossing is approximately 602 acres. A 6 foot x 20 foot concrete arch culvert will be placed at the crossing of Alafaya Trail and this tributary branch. The arch culvert structure will be buried to allow a 3 foot opening to reduce proposed profile grade concerns. Along with the arch culvert, one 48 inch concrete pipe will be placed on each side of the arch to serve as critter crossings. Using the rational method and the 100 year storm event, the required waterway area was found to be approximately 28 SF. The proposed culvert system to be installed at Hart Branch Crossing will provide approximately 71 SF of available waterway area. This will insure adequate area for the post development conditions.



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CB HLAFAYA TRAIL 89-004.0
SHEET NO 1 OF
CALCULATED BY KKP DATE 6-1-89
CHECKED BY DATE
SCALE

PRELIMINARY DRAINAGE CALCULATIONS FOR CULVERT CROSSINGS

• USE 25-YR. DESIGN STORM FOR CULVERT
SIZING (ORANGE CO. DESIGN REG.) (10.4.2)

• USE KINEMATIC WAVE FORMULATION FOR
DETERMINING TIME OF CONCENTRATION (T_c)

$$T_c = 0.83 \frac{L^{0.77} S^{-0.38}}{Q^{0.38}}$$

T_c = REPRESENTATIVE TIME OF CONCENTRATION (MIN.)

S = REPRESENTATIVE OVERLAND FLOW PATH SLOPE (FT./FT.)

n = SURFACE ROUGHNESS COEFFICIENT

L = REPRESENTATIVE LENGTH OF OVERLAND FLOW PATH (FT.)

Q = ESTIMATED RAINFALL INTENSITY OF DESIGN
FREQUENCY (IN./HR.)

• FROM APPENDIX 10.1.C n -VALUE = 0.8

• 25 YR / 24 HR RAINFALL = 8.60 IN.

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ALAFAYA TRAIL 89-004
SHEET NO. 2 OF
CALCULATED BY DKP DATE
CHECKED BY DATE
SCALE

2. HART BRANCH CROSSING

- AREA = 602 = AC.
- DISTANCE (REMOTE POINT TO POINT OF CULVERT) =
9600' = 1.8 MI.
- ELEV. CHG. = 90.0 - 64.0 = 26.0'
- AVG. SLOPE = 0.27% = 0.0027%

3. LOUPEL BRANCH CROSSING

- AREA = 596 = AC.
- DISTANCE (REMOTE POINT TO POINT OF CULVERT) =
10,000' = 1.9 MI.
- ELEV. CHG. = 88.0 - 67.0 = 21.0'
- AVG. SLOPE = 0.21% = 0.0021%

C. GREEN BRANCH CROSSING

- AREA = 1,944 = AC.
- DISTANCE (REMOTE POINT TO POINT OF CULVERT) =
18,000' = 3.4 MI.
- ELEV. CHG. = 90.0 - 63.0 = 27.0'
- AVG. SLOPE = 0.15% = 0.0015%

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JOB ALAFMA TRAIL 89-004.00
SHEET NO 3 OF
CALCULATED BY DKP DATE
CHECKED BY DATE
SCALE

TIME OF CONCENTRATION (T_C)

A. HART BRANCH CROSSING

$$\begin{aligned} T_C &= 0.93 \frac{L^{0.6} S^{0.6}}{C^{0.4}} \\ &= 0.93 \frac{9600^{0.6} 0.8^{0.6}}{8.6^{0.4} 0.0027^{0.3}} \\ &= 0.93 \frac{(245.11 \times 0.8747)}{(2.3648 \times 0.1696)} \\ &= \underline{497 \text{ MIN.}} = \underline{8.28 \text{ HRS.}} \end{aligned}$$

B. LOWPEN BRANCH CROSSING

$$\begin{aligned} T_C &= 0.93 \frac{L^{0.6} S^{0.6}}{C^{0.4}} \\ &= 0.93 \frac{10,000^{0.6} 0.8^{0.6}}{8.6^{0.4} 0.0021^{0.3}} \\ &= 0.93 \frac{(251.19 \times 0.8747)}{(2.3648 \times 0.1573)} \\ &= \underline{549 \text{ MIN.}} = \underline{9.15 \text{ HRS.}} \end{aligned}$$

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JOB ALAFAMA TRAIL 89-004.00
SHEET NO 4 OF
CALCULATED BY BKP DATE
CHECKED BY DATE
SCALE

2. GREEN BRANCH CROSSING

$$T_c = 0.93 \frac{L^{0.6} S^{0.6}}{C^{0.4} S^{0.3}}$$

$$= 0.93 \frac{13,000^{0.6} 0.8^{0.6}}{3.6^{0.4} 0.0015^{0.3}}$$

$$= 0.93 \frac{(357.41 \times 0.8747)}{(2.3648 \times 0.1422)}$$

$$= \underline{364 \text{ MIN}} = \underline{14.4 \text{ HRS.}}$$

146-2-10-138-147

0.80"

625-040-205-a
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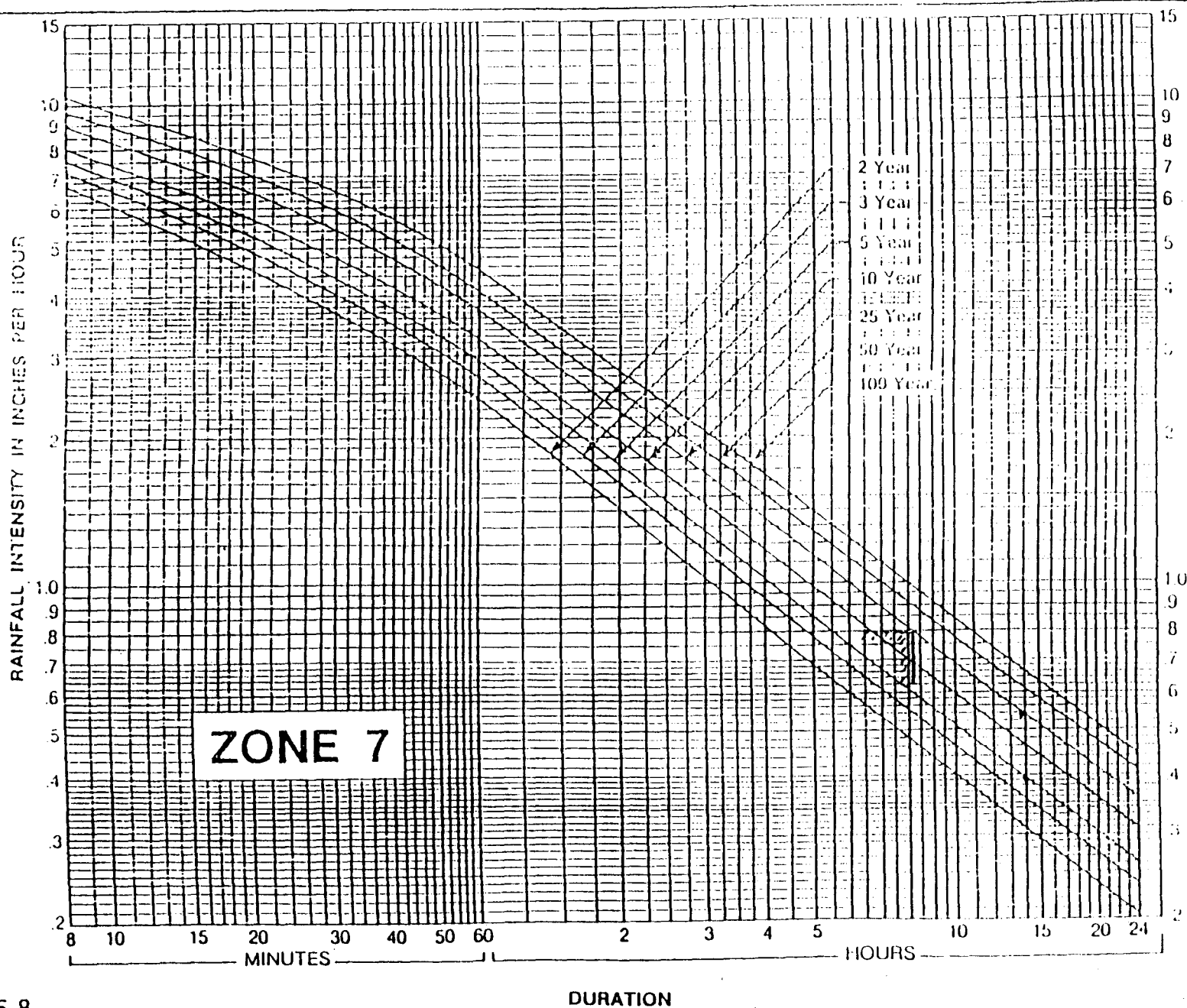


EXHIBIT 6.2-10 Page 138 of 147

FIGURE 5-8
Rainfall Intensity-Duration-Frequency Curves for Zone 7

Column REACHED (205516)

0125

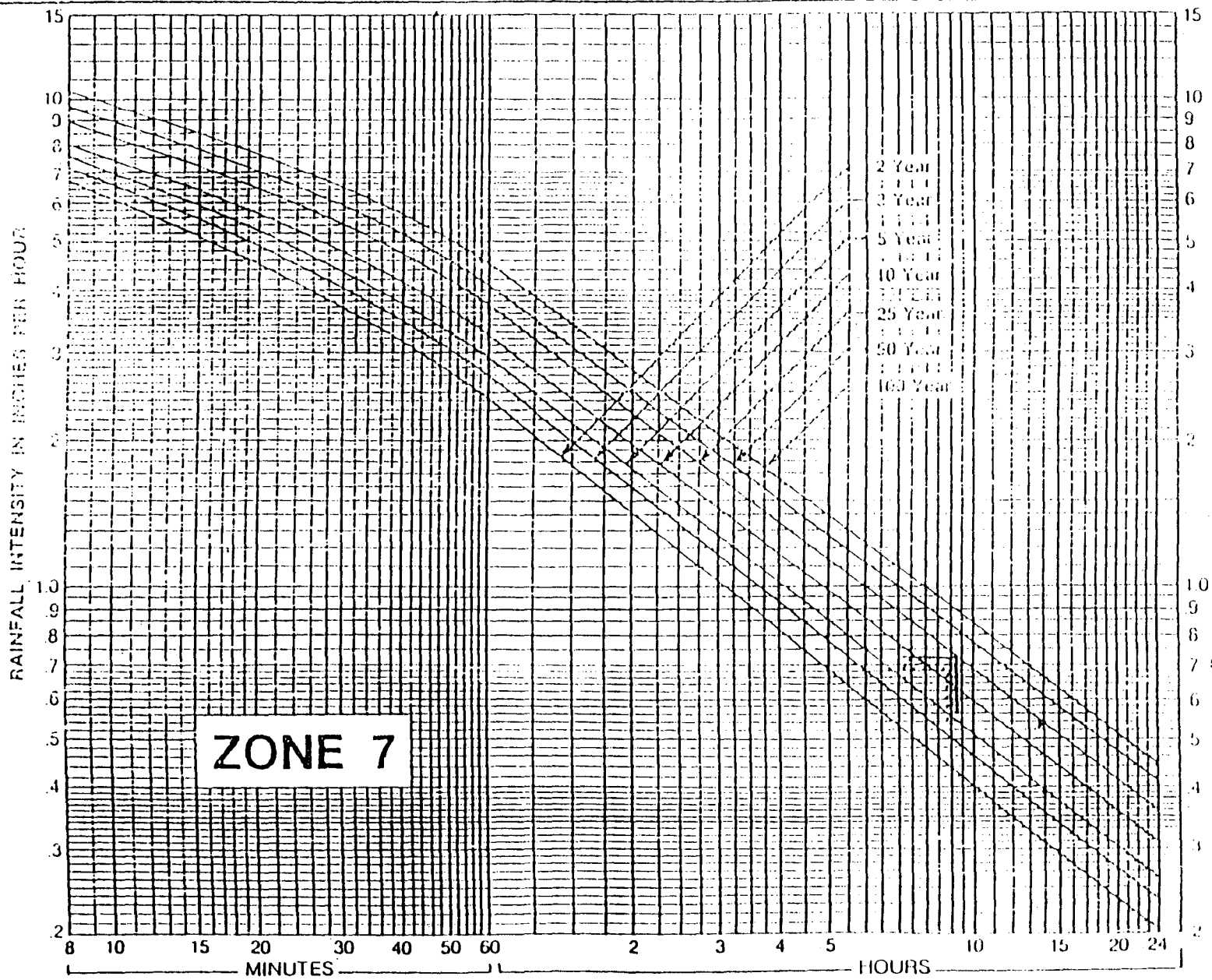


FIGURE 5-8
Rainfall Intensity-Duration-Frequency Curves for Zone 7

GREEN 21310 1205 116

625-040-205-a
Page 79 of 98

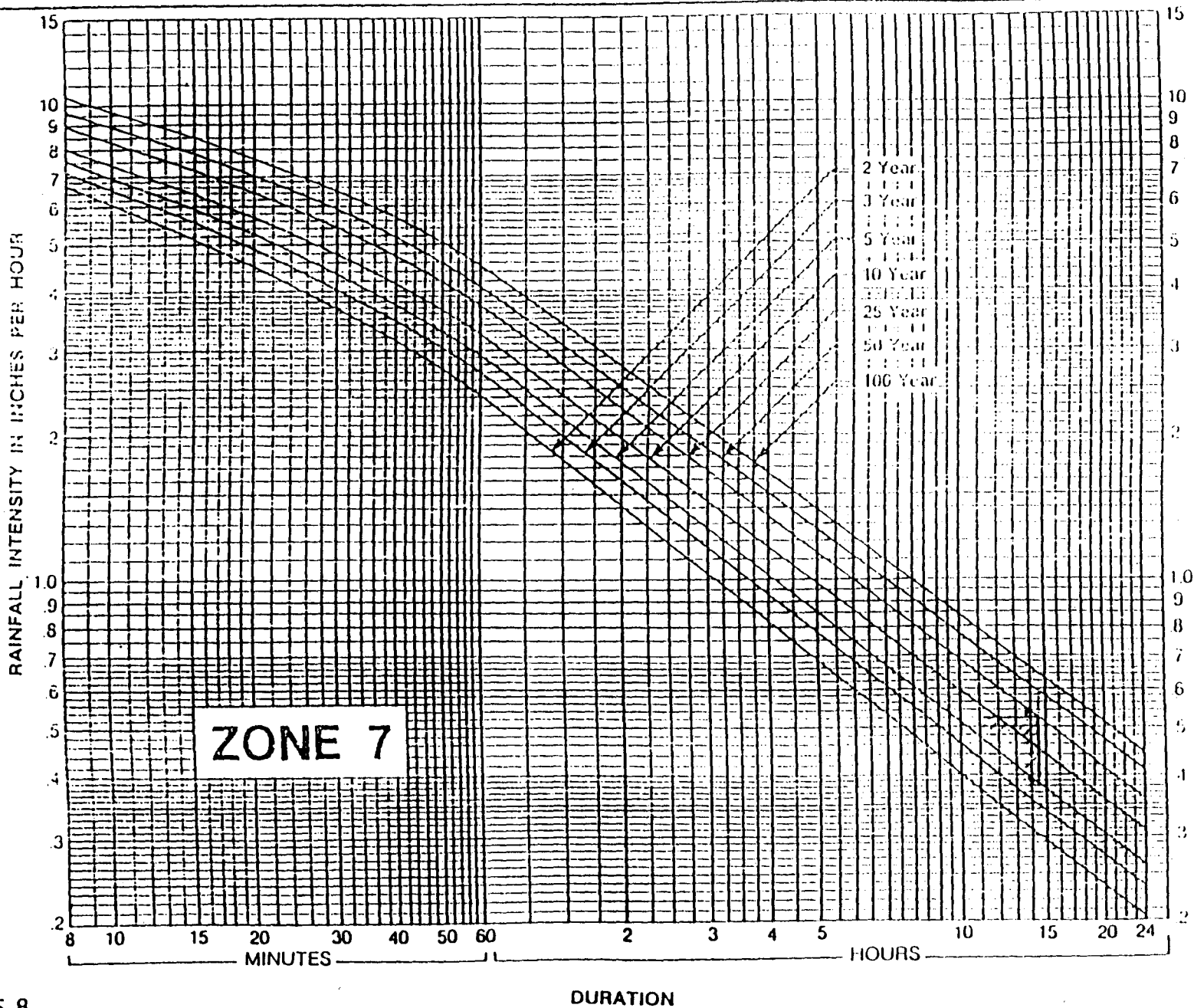


EXHIBIT 6.2-10 Page 140 of 147

FIGURE 5-8
Rainfall Intensity-Duration-Frequency Curves for Zone 7

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(407) 896-3317

JOB ALAFAMA TRAIL 89-004.00

SHEET NO. 8 OF

CALCULATED BY DATE

CHECKED BY DATE

SCALE

2. PRELIMINARY PIPE SIZING USING
RATIONAL FORMULA: $Q = CIA$

Q = PEAK DISCHARGE (CFS)

C = RUNOFF COEFFICIENT

I = INTENSITY OF RAINFALL (FDOT CHART -
ZONE 7)

A = AREA CONTRIBUTING (ACRES)

A. HART BRANCH CROSSING

1. C (RUNOFF COEFFICIENT) = FLAT WOODLANDS 0.15

$$Q = CIA$$

$$= 0.15 \times 0.80 \times 602 \text{ AC.}$$

$$= 72.24 \text{ CFS.}$$

2. PIPE SIZING (USING FIELDS HYD. CALC.)

• 54" RCP

• RATE OF FLOW = 72 ± CFS

• USE RCP @ $n = 0.012$

• 54" ϕ PIPE @ $S = 0.11\%$

• VELOCITY = 4.5 fps

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ORLANDO, FL 32803
(407) 896-3317

JOB ALAFAMA TRAIL 89-004
SHEET NO. 9 OF
CALCULATED BY DATE
CHECKED BY DATE
SCALE

B. COWPEN BRANCH CROSSING

1. C (RUNOFF COEFFICIENT) = FLAT WOODLANDS 0.15

$$Q = C \cdot A$$

$$= 0.15 \times 0.725' \times 596 \text{ AC.}$$

$$= 64.82 \text{ C.F.S.}$$

2. PIPE SIZING (USING FIELDS HYD. CALC.)

- 48" ϕ RCP
- RATE OF FLOW = 65 $\pm$ CFS
- USE RCP @ $n = 0.012$
- 48" ϕ PIPE @ $S = 0.17$
- VELOCITY = 5.1 f/s
- * 66" ϕ @ $S = 0.002$

C. GREEN BRANCH CROSSING

1. C (RUNOFF COEFFICIENT) = FLAT WOODLANDS 0.15

$$Q = C \cdot A$$

$$= 0.15 \times 0.52' \times 1,944 \pm \text{AC.}$$

$$= 151.63 \text{ C.F.S.}$$

LOCHRANE ENGINEERING, INC.

201 S. Bumby Avenue
ORLANDO, FL 32803
(407) 896-3317

JOB ALAFAYA TRAIL 89-004.0
SHEET NO 10 OF
CALCULATED BY DATE
CHECKED BY DATE
SCALE

2. PIPE SIZING (USING FIELDS HYD. CALC.)

- 72" ϕ RCP
- RATE OF FLOW = 152 $\pm$ CFS
- USE RCP @ $n = 0.012$
- 72" ϕ PIPE @ $s = 0.10\%$
- VELOCITY = 5.2 fps

* 90" ϕ @ $s = 0.00\%$

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JOB ICP - Alafaya Trail
SHEET NO _____ OF _____
CALCULATED BY Cal DATE _____
CHECKED BY _____ DATE _____
SCALE _____

Green Branch Crossing

$$Q = C i A$$

$$C = 0.15 \text{ (Flat Woodlands)}$$

$$t_c = 14.41 \text{ hrs}$$

EDYR

$$Q = 0.15 (0.53 \text{ in/hr}) 1944 \text{ AC}$$

$$= 169.13 \text{ CFS}$$

$$\# 90" \phi @ S=0\%$$

100YR

$$Q = 0.15 (0.64 \text{ in/hr}) 1944 \text{ AC}$$

$$= 186.62 \text{ CFS}$$

$$\# 96" \phi @ S=0\%$$

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ORLANDO, FL 32803
(407) 896-3317

JOB ICP - Alafaya Trail

SHEET NO. _____

OF _____

CALCULATED BY _____

Cal

DATE _____

CHECKED BY _____

DATE _____

SCALE _____

Hart Branch Crossing

$$Q = CIA$$

$$C = 0.15 \text{ (Flat Woodlands)}$$

$$t_c = 3.25 \text{ hrs}$$

50YR

$$Q = 0.15 (0.37 \text{ in/hr}) 602 \text{ AC}$$

$$= 73.56 \text{ CFS}$$

$$\approx 72" \phi @ S = 0\%$$

100YR

$$Q = 0.15 (0.97 \text{ in/hr}) 602 \text{ AC}$$

$$= 97.59 \text{ CFS}$$

$$\approx 72" \phi @ S = 0\%$$

Cowden Crossing

$$Q = CIA$$

$$C = 0.15 \text{ (Flat Woodlands)}$$

$$t_c = 9.15 \text{ hrs}$$

50YR

$$Q = 0.15 (0.35 \text{ in/hr}) 596 \text{ AC}$$

$$= 75.99 \text{ CFS}$$

$$\approx 72" \phi @ S = 0\%$$

100YR

$$Q = 0.15 (0.90 \text{ in/hr}) 596 \text{ AC}$$

$$= 90.46 \text{ CFS}$$

$$\approx 72" \phi @ S = 0\%$$

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ORLANDO, FL 32803
(407) 896-3317

JOB Alafaya Trail
SHEET NO. _____ OF _____
CALCULATED BY Col DATE _____
CHECKED BY _____ DATE _____
SCALE _____

Culverts

Green Branch Crossing

$$Q = C \cdot A \quad C = 0.15 \text{ (Flat Woodlands)} \\ T_p = 14.41 \text{ hrs}$$

$$100 \text{ yr} \quad Q = 0.15 (0.64 \text{ in/hr}) 844 \text{ ac} \\ = 186.62 \text{ CFS} \\ \pm 16" \phi @ S = 0.00\% \quad \text{Area} = 50.266 \text{ SF}$$

Use (1) 6' x 24' con span arch
± bury footing to 3' clearance between
existing ground & top of arch

reduced to (1) 3' x 24' 49.0 SF waterway Area
critter crossings (2) 38" x 60" (2) 12.9 SF

61.9 SF waterway Area provided

$$50 \text{ yr} \quad Q = 0.15 (0.59 \text{ in/hr}) 1944 \text{ ac} \\ = 169.13 \text{ CFS} \\ \pm 90" \phi @ S = 0.00\% \quad \text{Area} = 44.17 \text{ SF}$$

61.9 SF waterway area provided

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ORLANDO, FL 32803
(407) 896-3317

JOB Alafaya Trail

SHEET NO. _____ OF _____

CALCULATED BY Cal DATE _____

CHECKED BY _____ DATE _____

SCALE _____

Culverts

Hart Branch Crossing

$$Q = C I A \quad C = 0.15 \text{ (Flat Woodlands)}$$

$$\frac{1}{2} \text{ in } 8.28 \text{ hrs}$$

100 yr

$$Q = 0.15 (0.97 \text{ in/hr}) 602 \text{ AC}$$

$$= 87.59 \text{ CFS}$$

$$\star 72" \phi @ S=0.00\% \quad \text{Area} = 28.274$$

use (1) 6' X 20' Con span Arch

* bury footing to 3' clearance between
existing ground & top of arch.

reduced to (1) 3' X 20' 45.0 SF

(2) 38" X 60" (2) 12.9 SF

70.8 SF Waterway Area Provided

50 yr

$$Q = 0.15 (0.87 \text{ in/hr}) 602 \text{ AC}$$

$$= 73.56 \text{ CFS}$$

$$\star 72" \phi @ S=0.00\% \quad \text{Area} = 28.274$$

70.8 SF Waterway Area Provided

ATTACHMENT "E"

REVISED MITIGATION PLAN
FOR THE
ALAFAYA TRAIL EXTENSION

SUBMITTED TO:
ST. JOHNS RIVER WATER MANAGEMENT DISTRICT

SUBMITTED FOR:
INTERNATIONAL CORPORATE PARK

SUBMITTED BY:
ENGINEERING MANAGEMENT & DESIGN, INC.

EMD NO. 02312.38

MARCH 27, 1991

REVISED APRIL 22, 1991

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1.0 INTRODUCTION

International Corporate Park (ICP), requests St. Johns River Water Management District (SJRWMD) to modify the two existing permits [Permit Nos. 4-095-0033M (MSSW) and 12-095-0040 (Dredge & Fill)] for Alafaya Trail Extension to reflect a proposed revision to the Mitigation Plan which was approved and permitted by the SJRWMD. The reason for modifying these permits is that the U.S. Fish and Wildlife Service and Florida Game and Fresh Water Fish Commission objected to the location of the Mitigation Plan (wetland creation) for the Alafaya Trail Extension project which is located north of the Bee Line Expressway. Their objection is that the creation of wetlands would occur in potential red-cockaded woodpecker (RCW) habitat.

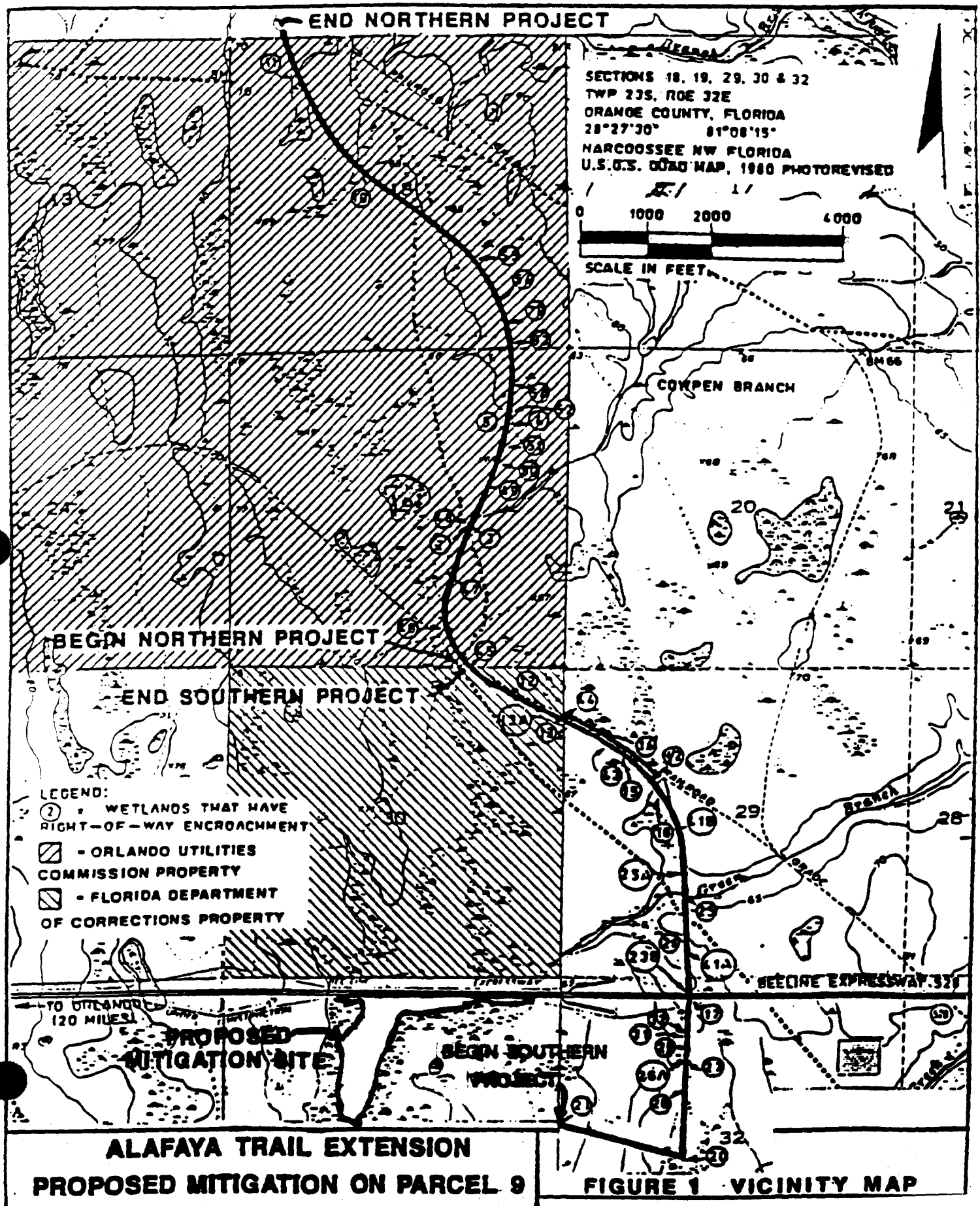
ICP is proposing to relocate the Alafaya Trail Extension wetlands mitigation to the 2,921-acre ICP DRI site on Parcel 9 located south of the Bee Line Expressway (see Figure 1). The new mitigation site will enhance the ongoing habitat management implemented for the ICP DRI site.

2.0 SITE DESCRIPTION OF THE PROPOSED MITIGATION ON PARCEL 9

The proposed ICP mitigation site is dominated by pine flatwoods with some shrub and brush adjacent to the wetland strands. This area has been reviewed for the occurrence of RCW's and none were found. The nearest RCW colony site is approximately 2,500 feet to the north on the Florida Department of Corrections' (DOC) site, north of the Bee Line Expressway. Current monitoring of the DOC RCW clan, which has been ongoing for one year, indicates that these birds do not utilize habitat on ICP property to the south of the Bee Line Expressway.

ICP has an established Conservation Mitigation/Wildlife Management Plan (Habitat Plan) that was approved by the Florida Game & Fresh Water Fish Commission, SJRWMD, South Florida Water Management District, and the Orange County Planning Department. Key components of the Habitat Plan are as follows:

- o Preservation of primary wetland strands.
- o Preservation of larger isolated wetlands.
- o Creation of wetlands for impacted areas.
- o Creation of permanent water bodies adjacent to seasonally and shallowly flooded wetland strands.
- o Increasing the size and contiguity of a wetland strand system to create a wildlife corridor.
- o Placement of wetland edge culverts solely to assist animals in moving past roadways to gain access to wetlands.



- o Juxtapositioning of vegetation cover types and land use features to generate habitat value.
- o Retention of upland areas as a wetland adjunct.
- o Addition of buffer areas to wetlands.
- o Provision of a boundary area landscape buffer.
- o Creation of a Red-Cockaded Woodpecker Management Area.

3.0 PROPOSED MITIGATION PLAN

The proposed Mitigation Plan for the Alafaya Trail Extension wetlands mitigation is depicted on Figure 2. Typical cross sections through the mitigation site are shown on Figures 3 and 4. This plan will augment the value of a wildlife corridor already established by providing a diversity of wetland habitats between two wetland strands and increasing the effective width of the corridor (see Figure 5).

The proposed plan encompasses a modification to ICP's Permit No. 4-095-0159CM which would transfer the storage of surface waters from Parcel 27 (Lake SSJ-8) back to Parcel 9 (Lake SSJ-9/10A) as it was originally permitted as Permit No. 4-095-0246 (Attachment 1). This area will function not only as mitigation for wetland impacts from Alafaya Trail Extension and Aerospace Parkway Extension, but also as attenuation of surface waters from ICP's DRI site. Also, this area is a larger surface area; therefore, the attenuation capabilities are increased over what was previously permitted.

In the course of constructing the proposed mitigation area in Parcel 9, 37.31 acres of developable land will be utilized for wetland mitigation. In return, 24.7 acres in Parcel 27 will now be available for development.

The proposed Mitigation Plan provides for the creation of six different wetland types on Parcel 9 of the ICP site (as shown on the attached Table 1): wetland shrub island (1.12 acres); freshwater marsh (8.28 acres); deep water aquatic (1.87 acres); shallow water aquatic (3.26 acres); cypress-dominated wetland (20.31 acres); and mixed hardwood wetland (2.47 acres). The wetland impacts from the proposed Alafaya Trail Extension include only 4 wetland types, one of which is manmade: cypress, mixed forested wetland, wet prairie, and ditch. The proposed wetland shrub islands shown on Figure 2 which are surrounded by deep water aquatic habitats and buffered from development by expansive wetland areas will provide habitat that could serve as rookery sites for wading birds. The numerous lakes with littoral zones and wetland mitigation sites proposed at ICP buildout will supply forage habitat for wading birds, many species of which are present on-site now, but breed elsewhere.

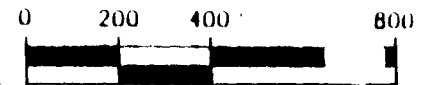
LIMITS OF WETLAND
CREATION AREA/
LOCATION OF TURBIDITY
BARRIERS

EXIST.
WETLANDS

LIMITS OF WETLAND
CREATION AREA/
LOCATION OF TURBIDITY
BARRIERS

EXIST.
WETLANDS

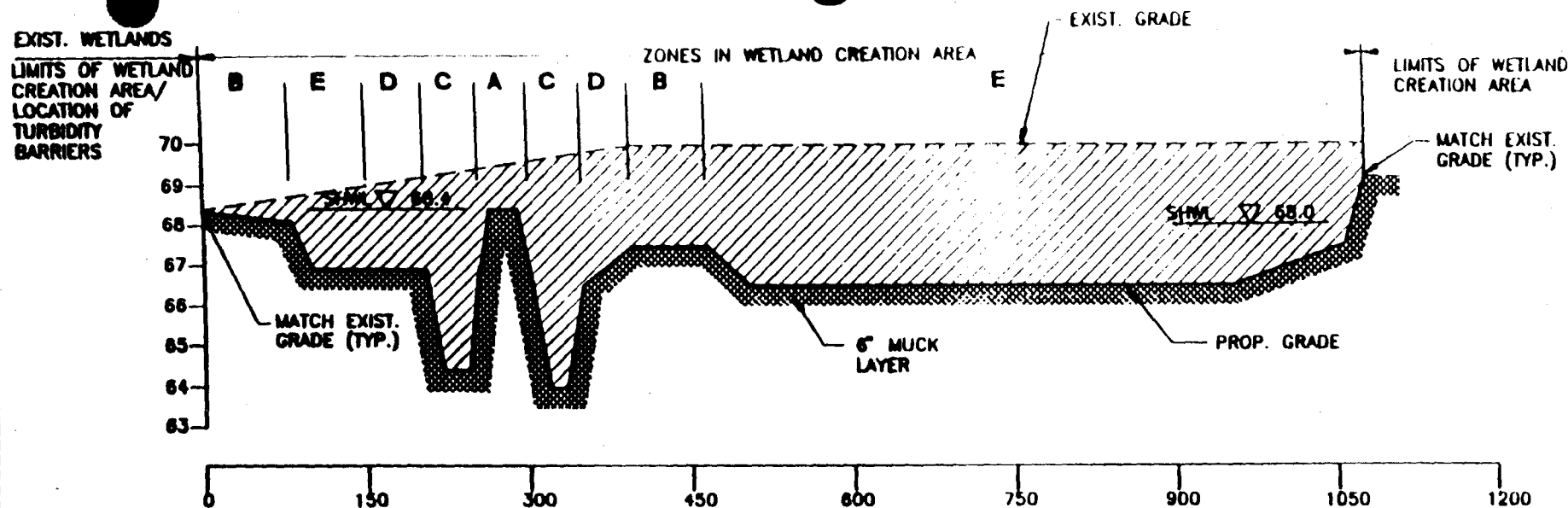
EXIST.
WETLANDS



ZONES IN WETLAND CREATION AREAS		ACREAGE
	A - Wetland Shrub Island	1.12
	B - Freshwater Marsh/Wet Prairie	8.28
	C - Deep Water Aquatic	1
	D - Shallow Water Aquatic	3.26
	E - Cypress Dominated Wetland	20.31
	F - Mixed Hardwood Wetland	2.47
TOTAL ACREAGE		37.31

PLANTING PLAN

PROPOSED MITIGATION PLAN FOR ALAFAYA TRAIL EXTENSION ON PARCEL 9



NOTE:
 EXISTING GROUND ELEVATIONS ARE BASED ON
 THE TOPOGRAPHIC SURVEY BY AERIAL
 CARTOGRAPHICS OF AMERICA, MAY 29, 1986.
 SEASONAL HIGH WATER ELEVATION IS BASED
 ON THE WETLANDS HYDROLOGICAL DATA FROM
 BREEDLOVE, DENNIS, AND ASSOCIATES, INC.

ZONES

- A WETLAND SHRUB ISLAND
- B FRESHWATER MARSH/WET PRAIRIE
- C DEEP WATER AQUATIC
- D SHALLOW WATER AQUATIC (LITTORAL ZONE)
- E CYPRESS DOMINATED WETLAND
- F MIXED HARDWOOD WETLAND

SHWL - SEASONAL HIGH WATER LEVEL



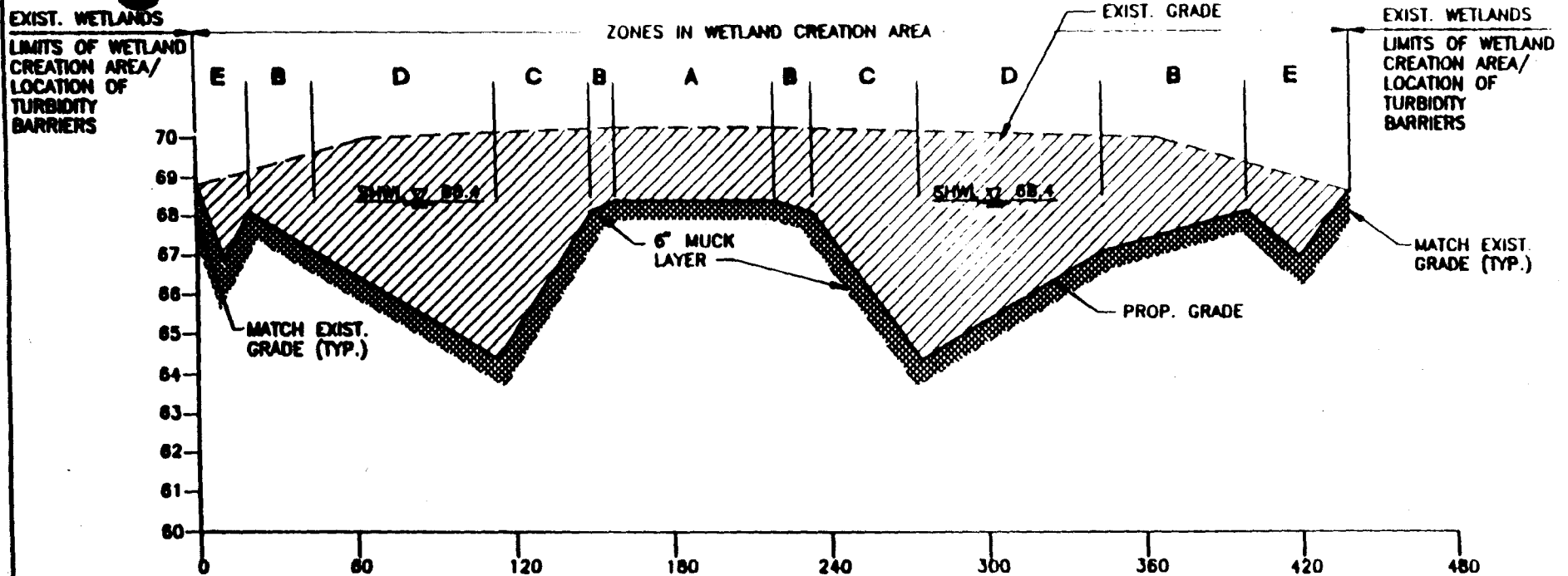
UPLAND EXCAVATION FOR
 WETLAND CREATION

1" = 150' H
 1" = 4' V

SECTION 1 - 1
 PROPOSED MITIGATION PLAN FOR
 ALAFAYA TRAIL
 EXTENSION ON PARCEL 9

DATE: APRIL 19, 1991

FIGURE 3

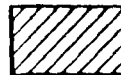


NOTE:
 EXISTING GROUND ELEVATIONS ARE BASED ON
 THE TOPOGRAPHIC SURVEY BY AERIAL
 CARTOGRAPHICS OF AMERICA, MAY 29, 1988.
 SEASONAL HIGH WATER ELEVATION IS BASED
 ON THE WETLANDS HYDROLOGICAL DATA FROM
 BREEDLOVE, DENNIS, AND ASSOCIATES, INC.

ZONES

- A WETLAND SHRUB ISLAND
- B FRESHWATER MARSH/WET PRAIRIE
- C DEEP WATER AQUATIC
- D SHALLOW WATER AQUATIC (LITTORAL ZONE)
- E CYPRESS DOMINATED WETLAND
- F MIXED HARDWOOD WETLAND

SHWL - SEASONAL HIGH WATER LEVEL



UPLAND EXCAVATION FOR
 WETLAND CREATION

1" = 60' H
 1" = 4' V

SECTION 2 - 2
 PROPOSED MITIGATION PLAN FOR
 ALAFAYA TRAIL
 EXTENSION ON PARCEL 9

DATE: APRIL 19, 1991

FIGURE 4

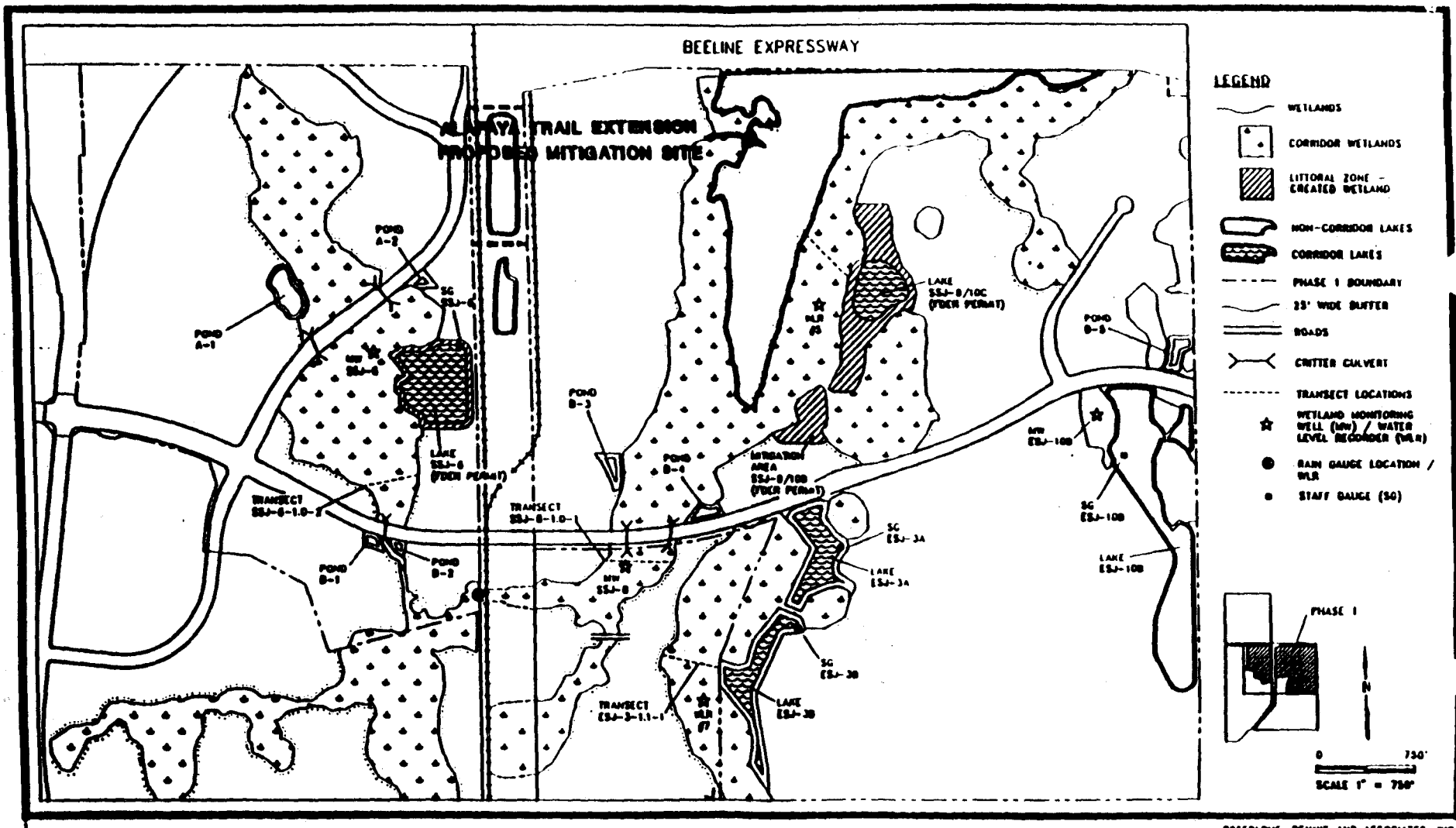


FIGURE 6

LOCATION OF THE WETLAND MONITORING TRANSECTS, WETLAND MONITORING WELLS, WATER LEVEL RECORDERS, RAIN GAUGE AND LAKE STAFF GAUGES IN PHASE I OF THE INTERNATIONAL CORPORATE PARK PROJECT SITE, ORANGE COUNTY, FLORIDA.

DATE: MARCH 1991

NOTE: ALL INFORMATION ON THIS FIGURE, EXCEPT THE ALAFAYA TRAIL EXTENSION PROPOSED MITIGATION SITE LOCATION, WAS DESIGNED AND PRODUCED BY BREEDLOVE, DENNIS AND ASSOCIATES, INC.

ATTACHMENT 1
LOCATION OF PARCEL 8 and PARCEL 27

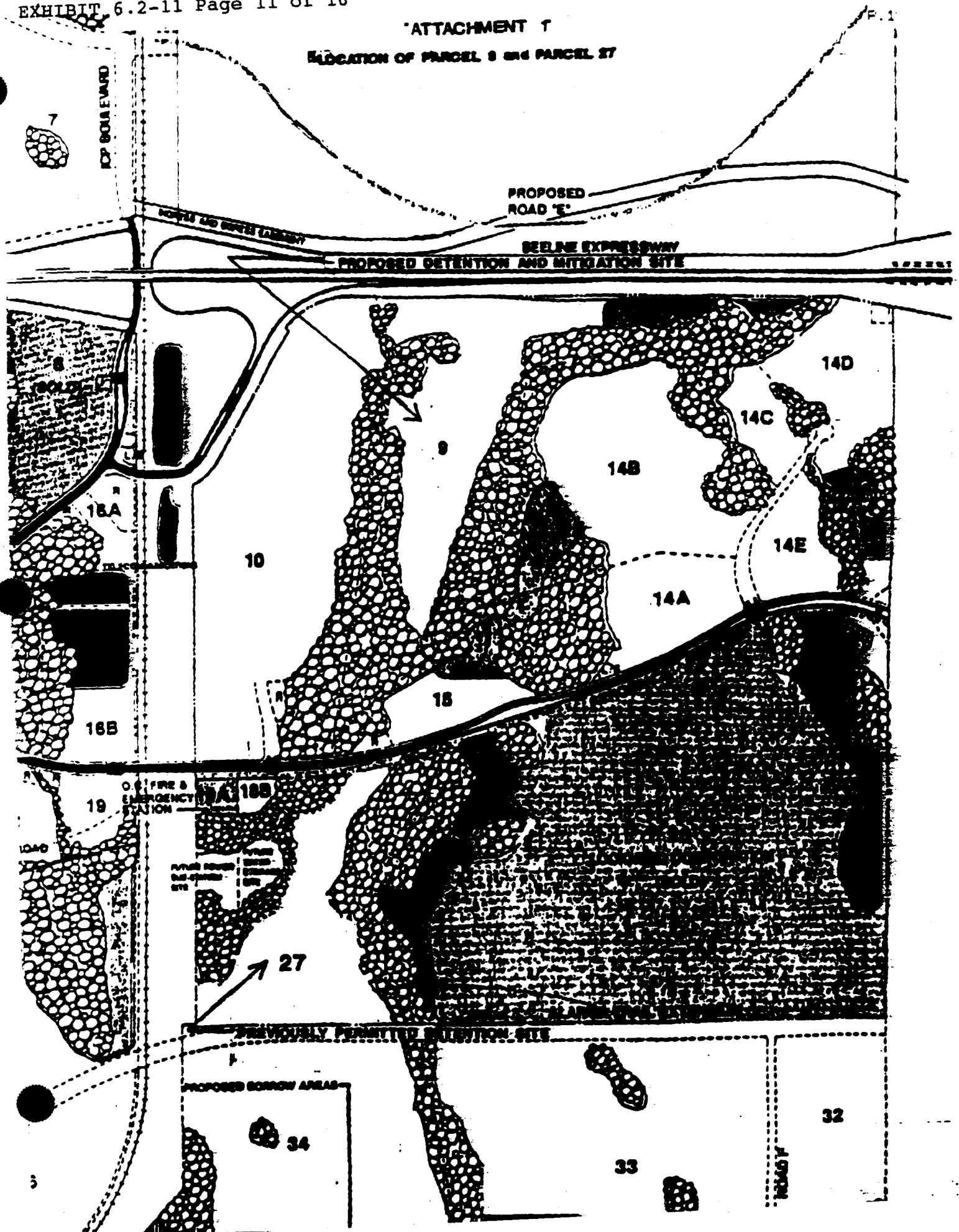


TABLE 1
ALAFAYA TRAIL EXTENSION
PROPOSED MITIGATION PLANTING SPECIFICATIONS

<u>Area</u>	<u>Acres</u>	<u>Density/ Acre</u>	<u>Species</u>	<u>Size</u>	<u>Spacing</u>	<u>Remarks</u>
A - Wetland Shrub Island	1.12	890	Willow (40%) Buttonbush (40%) Wax Myrtle (10%) Fetterbush (10%)	1 gal	7 feet	---
B - Freshwater Marsh/Wet Prairie	8.28		A 6" thick muck blanket will be placed in the created Freshwater Marsh/Wet Prairie. If herbaceous plants do not colonize successfully within a year, Marsh/Wet Prairie species will be planted.			
C - Deep Water Aquatic	1.87	4840	Water Lilies Emergent Species	1 gal	3 feet	---
D - Shallow Water Aquatic (Littoral Zone)	3.26	4840	Pickereelweed Arrowhead Soft Rush Cordgrass	1.5 to 2 feet (5 to 7 petioles or stems)	3 feet	Species staggered. Plants in clusters.
E - Cypress Dominated Wetland	20.31	440	Cypress (80%) Tupelo (20%)	3 gal	10 feet	Species will be 3 to 5 feet in height.
F - Mixed Hardwood Wetland	2.47	440	Cypress Tupelo Red Maple Dahoon Water Oak	3 gal	10 feet	Species will be 3 to 5 feet in height and evenly mixed.
Total	37.31					

Other details of the proposed Mitigation Plan include the following components from the permitted Mitigation Plan:

1. The proposed wetland Mitigation Plan will consist of the components listed on Table 1. Vegetation species will be selected from the preceding list and in accordance with established planting schedules. Species selection will be approved by the appropriate agency(ies). Lines of planting shall be meandered to simulate natural occurrence.
2. A six-inch (6") muck blanket will be placed in the created marsh/wet prairie areas. If herbaceous plants colonize successfully within a year, no herbaceous planting will be initiated.
3. Tree species will be installed with spacing and density as depicted on Table 1.
4. Planting of tree species will be supervised to ensure shock is minimal and that their survivability is increased. Planting of herbaceous species, if required, will be conducted in early spring or summer to avoid chance of frost and allow establishment of root systems prior to the rainy seasons.
5. All created wetlands will be inspected by a biologist/ecologist and engineer for optimum hydrological conditions, water table elevations, design slope, and design contours prior to planting. No planting will begin until all of the above conditions and special conditions of the permit are met. The Contractor will maintain a saturated soil condition during plant installation within the created wetlands.
6. Silt fence barriers will be staked adjacent to the existing wetlands prior to construction of the created wetlands to prevent turbidity from entering existing wetlands. These barriers will remain in-place until construction is complete.
7. A maintenance trail will be established adjacent to existing wetlands on the edge of the wetland creation area to allow the construction, planting, and maintenance of the site. The elevation of this trail will be established no greater than the seasonal high water elevation.
8. After construction of the wetlands mitigation area is complete, engineer's as-built certification will be submitted to the appropriate regulatory agency(ies) for final inspection and approval for sign-off.
9. Construction of the wetland creation area will occur at the time of land clearing of the road alignment. The creation area will be mulched and planted as soon as existing wetlands are impacted.
10. The mitigation area will be recorded as a permanent conservation easement and no wetland destruction/alteration can take place within this easement.

11. The creation of littoral shelves around all six project detention ponds located adjacent to the Alafaya Trail Extension will consist of 3.73 acres.
12. The placement of two "critter crossings" at Green Branch and Hart Branch will consist of 48-inch concrete pipes.
13. The monitoring plan and maintenance program outlined in Section 4.0 provide a check and balance to ensure continued performance of the created wetlands. Any non-compliance deviation will be corrected and noted in the annual report.
14. As recorded in the Orange County Plat Book (OR BK. 3802, Pages 4466 through 4496) and as a condition of ICP's Development Order (DO), ICP is required to design and construct Alafaya Trail Extension. This DO was adopted and signed by the Orange County Board of County Commissioners June 30, 1986.

4.0 MONITORING AND MAINTENANCE PROGRAM

1. The Contractor is required to monitor the planted areas bi-annually for the first year and then annually the last two years to document the success of the mitigation plan. Each monitoring episode will include photo documentation, percent survival, percent cover and percent undesirables. An annual report of findings and recommendations for the mitigation plan will be submitted to the appropriate governmental agency(ies).
2. All plants installed in the created wetlands will be guaranteed for at least 80% survival rate for three years in the mitigation area.
3. The Contractor is expected to replant those plant materials which do not achieve the 80% survival rate for three years in the mitigation area.
4. A maintenance program is vital for any created wetlands to be successful. Undesirable species, such as cattails, primrose willow, and exotics are to be removed/eliminated from the created wetlands annually after the plants are installed. The exotics/nuisance species should not exceed above 10 percent in ground cover.
5. ICP will be responsible for monitoring, maintenance and success of the mitigation area for five years following initial planting.

5.0 VEGETATION SAMPLING AND DATA ANALYSIS METHODS

Field sampling to determine the success of the created wetlands is described below:

Two permanent elongated quadrants (transect quadrants measuring 30 feet by 60 feet) will be established in each created wetland. A PVC pipe 10 feet in length will be placed in the ground at 30-foot intervals and at the end of the elongated (60-foot) portion of each quadrant. All vegetation strata will be monitored by sampling 10-

square foot plots for percent coverage of herbaceous species and stem counts of woody vegetation. The vegetation sampling frequency schedule will commence at the end of the planting phase of each wetland created.

All areas will be sampled in the summer of each year for a total of three years. Each wetland created will have a survival rate of 80%.

Shrubs will be sampled by noting points along the transect line where canopies of shrubs intercept the line. Species of shrub, beginning and ending intercept points of shrub canopy, and number of shrubs will be recorded. Shrub data will be used to determine density and relative cover of shrubs in each wetland plot.

Cover data for each species will be generated on number of species, approximate percent cover (by cover) and frequency of occurrence of each species.

Photographic documentation of the mitigation/monitoring (fixed) sites will be provided in the annual report.

Water levels will be monitored by placing a permanent staff gauge in each wetland created. The water levels will be monitored monthly during construction and for three years following buildout. A rain gauge will also be installed to provide information on monthly precipitation.

6.0 DATA ANALYSIS METHODS

The following information on community structure will be collected for canopy and sub-canopy species:

Density = The average number of individuals per acre sampled (also number of stems of each species per acre).

Dominance = Dominance of a single species divided by total number of all species expressed as 100%

Relative Cover = Cover of individuals of single species divided by cover of individuals of all species (expressed as a percent).

Frequency = An expression of the percentage of sample plots in which a species occurs over time.

7.0 ANNUAL REPORT

An annual report will be provided to the appropriate agency within 60 days of the completion of the last sampling, which will include construction/plant installation phase of the created wetlands and one year sampling results. Areas not achieving a minimum of 80% coverage will be replanted with the appropriate species. Any additional mitigative measures, if needed, will be addressed in the annual report.

8.0 SUMMARY

The proposed wetlands Mitigation Plan for Alafaya Trail Extension includes a 35 percent increase (35.7 acres) in created wetlands compared with the permitted mitigation plan (23.3 acres). The mitigation ratio for impacts to SJRWMD's jurisdictional wetlands increases from 1.3:1 to 1.8:1, and the ratio for impacts to the Florida Department of Environmental Regulation's wetlands increases from 5.5:1 to 8.4:1 for the creation of wetlands.

THE CURTIS H. STANTON ENERGY
CENTER,
HABITAT MANAGEMENT PLAN FOR
RED-COCKADED WOODPECKERS

Submitted To:

FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION,
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Provided By:

ICP ASSOCIATES
8248 ICP Boulevard,
Orlando, Florida 32832

Presented By:

Roy S. DeLotelle,
ALVAREZ, LEHMAN & ASSOCIATES, INC.,
2444 Northeast 1st Boulevard, Suite 500
Gainesville, Florida 32609

November 18, 1991
(Revised March 13, 1992)

ADDENDUM

The enclosed report has been revised to reflect certain editions and changes to the original Plan as described in the November 18, 1991 edition. A number of small editorial changes have been made consisting of additions to clarify certain portions of the November edition. These changes have not changed the basic presentation. The discussion on the extinction probabilities model (Figure 6) has been expanded to assist the reader in interpreting the figure (see pages 20-23). The locations of the longleaf pine tree plantings and colony creation sites have been revised as discussed on page 27 and in Figure 7 of the report. All tree planting activities and colony creation or enhancement activities have been relocated to the vicinity of the proposed Alafaya Trail Extension. The changes on the planting program and colony creation have been informally agreed to by the United States Fish and Wildlife Service and United States Army Corps of Engineers in Jacksonville, Florida.

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EXECUTIVE SUMMARY

The Red-cockaded woodpecker (*Picoides borealis*) a threatened species, was first observed in the area southeast of Orlando, Florida in 1980. At that time nine occupied colonies (the pine trees used as roosting habitat) were located on the proposed Curtis H. Stanton Energy Center and 16 occupied colonies occurred in other habitats north of the Bee Line Expressway. These colonies plus those located on the Martin-Marrietta property represent 32 percent (%) of the central Florida red-cockaded woodpecker population extending from the Ocala National Forest to Lake Okeechobee.

Because of the protected status of the red-cockaded woodpecker, a management plan and monitoring program were initiated on the Stanton Energy Center in 1983 by Orlando Utilities Commission. The plan included both a regular winter prescribed burning program and monitoring activities consisting of studying habitat use, demographics, and other factors concerning the woodpecker.

Since 1980 the core population north of Bee Line which includes groups on the Stanton site, has declined by 50%. Based on the ratio of active to inactive colonies, however, the Bee Line population has outperformed any National Forest population of similar size over a comparable time period. Thus, the central Florida woodpecker population would appear to exist in favorable conditions assuming long term management of habitat is adequate and fragmentation problems within the population can be overcome. In order to compensate for these population losses, to reduce the probability of extinction because of population size and fragmentation, and to compensate for construction of the

Alafaya Trail through the Stanton site, a population enhancement plan consisting of a demonstration colony creation project and foraging habitat improvements is proposed.

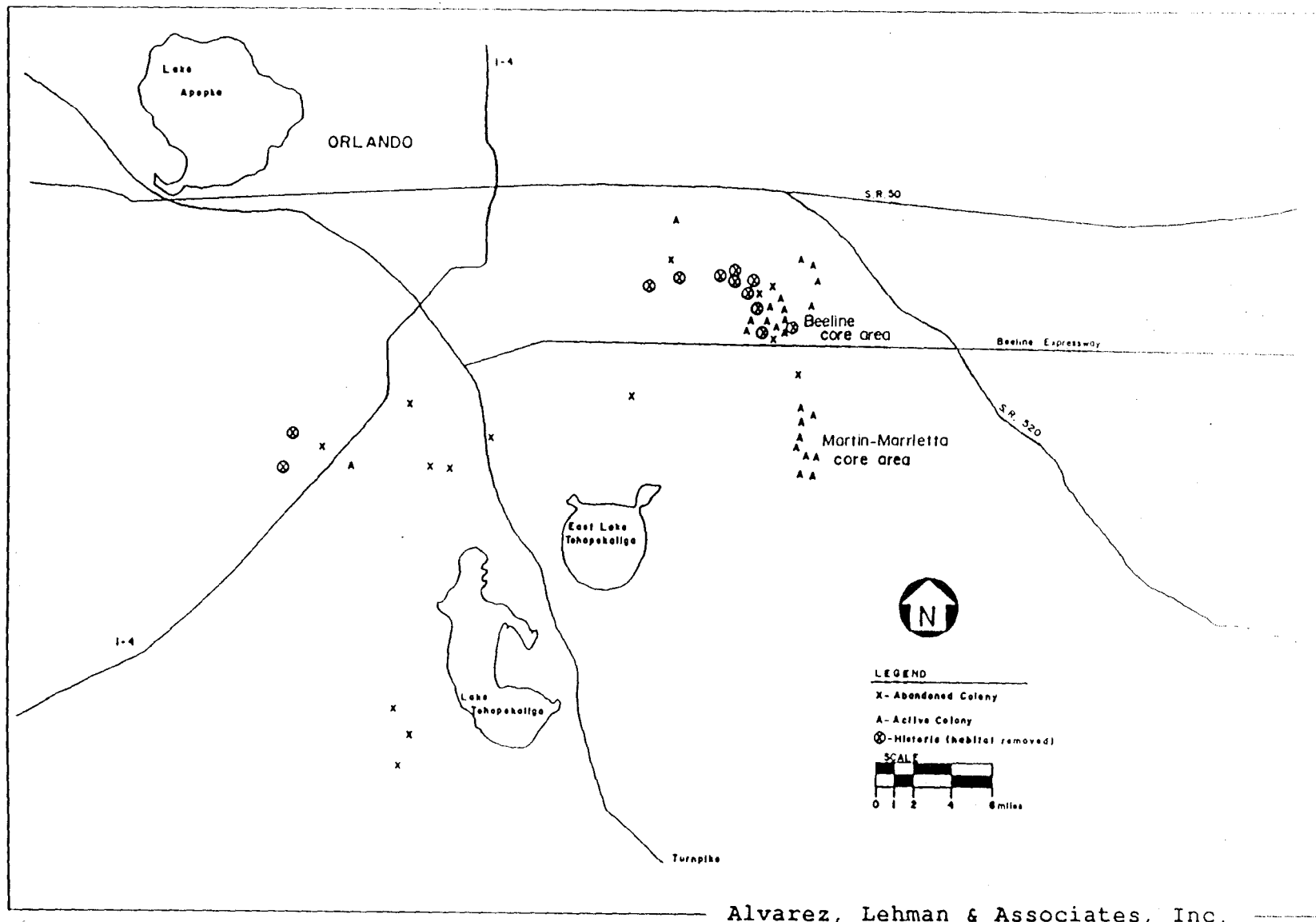
The proposed colony creation technique is based on proven methodology of constructing cavities in living pine trees. The methodology was developed by North Carolina Woodpecker biologists and has been applied successfully in seven different woodpecker populations. Adjacent to the proposed Alafaya Trail Extension, one new colony site will be created while one abandoned site will be provisioned with new cavities. A pine tree planting program will be established on about 100 acres on the Stanton site. Although the construction of the Alafaya Trail may appear inconsistent with certain recommendations in the woodpecker management plan specified in Condition 31 of the Stanton 1 and Stanton 2 Site Certification, the potential benefits of the proposed enhancement plan outweigh any perceived negative impacts on the habitat from the road construction. Certainly, the mitigation activities, which were agreed to by the United States Fish and Wildlife Services, will greatly enhance the survival probability of this core population.

1.0 INTRODUCTION

1.1 Scope of the Project

The occurrence of the red-cockaded woodpecker (*Picoides borealis*), an endangered [U.S. Fish and Wildlife Service (FWS)] and threatened species [Florida Game and Fresh Water Fish Commission (FGFWFC)] on the Orlando Utilities Commission's (OUC) Curtis H. Stanton Energy Center was first observed in August 1980 by Environmental Science and Engineering, Inc. (ESE). These studies were part of the Stanton (1) Energy Center Site Certification Application (SCA) for the Florida Department of Environmental Regulation (FDER). During the initial field surveys for the Stanton 1 SCA, nine occupied colonies (the area where roosting and nesting cavity trees are clustered) of red-cockaded woodpeckers were discovered onsite. An additional 16 occupied colonies occurred in surrounding habitats north of the Bee Line Expressway and 11 or more occupied colonies occurred south of the Bee Line Expressway, approximately 8.5 miles away (Figure 1). Nine of the colonies south of the Bee Line Expressway were not observed until 1986 (Exum, Personal Communication, 1991). These eastern Orange County woodpeckers presently account for 32% (24 occupied colonies) of the entire central Florida population extending from the Ocala National Forest to Lake Okeechobee (Wood and Wenner, 1983).

A Management Plan for the woodpecker, which included a long-term Monitoring and Fire Management Program, was developed as part of the SCA to FDER (DeLotelle and Newman, 1981). In developing the plan, only the FGFWFC, FWS, ESE,



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FIGURE 1. Location of Red-cockaded Woodpecker Colonies in Orange County, Florida, Curtis H. Stanton Energy Center, Orlando, Florida, 1992

B&V, and OUC, played any role in evaluating the various approaches to the plan and in recommending it to FDER. The objectives of the management plan, which was submitted under Condition 31 of the Stanton 1 SCA, were to:

1. Identify the distribution and abundance of red-cockaded woodpeckers in the area;
2. Map existing colonies and cavity trees and their status onsite as well as in the surrounding areas;
3. Map potential colony sites and foraging habitats onsite;
4. Develop a fire management schedule for the longleaf pine flatwoods ecosystem in the undeveloped portions of the site; and
5. Propose a long-term Monitoring Plan for the onsite red-cockaded woodpeckers.

The clearing of a corridor for the water and sewer service pipelines for both Florida Department of Corrections and International Corporate Park (ICP), have removed about 2.3% of the foraging habitat used by the red-cockaded woodpecker along the corridor (see Epperson and Dennis, 1990 and Alvarez, Lehman & Associates, Inc., 1990). The cleared area for the pipeline is intended to serve as the alignment for the extension of the Alafaya Trail. Because of this recent event, portions of red-cockaded woodpecker management plan are being revised to include mitigation activities associated with the Alafaya Trail extension and to take a broader view of the red-cockaded woodpecker population in Orange County and, in particular, the portion north of the Bee Line Expressway.

Since it can be anticipated that each new unit on the Stanton site will operate from 40 to 50 years, the life of the plant will be well into the 21st century. As indicated in Condition 31 for Stanton 1 and as modified for Stanton 2, the red-cockaded woodpecker management plan was to be implemented for the life of the power plant on almost 2000 acres of the longleaf pine flatwoods ecosystem. This essentially left about 1/3 of the site for power plant related activities and about 2/3 of the site for the red-cockaded woodpeckers, and other wildlife and vegetation of the flatwoods ecosystem.

The Stanton Energy Center is a unique situation in terms of industrial land development and management which includes large areas of habitat for an endangered species, such as the red-cockaded woodpecker (Bryntt, Personal Communication, 1991), for Florida as well as for the rest of the southeastern United States. Interestingly, a similar siting and mitigation problem occurred south of the Bee Line Expressway on the Martin-Marrietta Britt Ranch site. Since these may well be the only two large industrial facilities with a relatively large number of red-cockaded woodpeckers, success of the two management plans are difficult to evaluate from that perspective. In comparison, other somewhat larger state wildlife management areas such as Cecil Webb Game Preserve in Charlotte County, also include similar populations of red-cockaded woodpeckers. These sites also have impacts on pine tree resources from roads, transmission line construction, and other competing activities and may provide comparative opportunities in the future. Management for red-cockaded woodpeckers on State Forest lands have historically received less priority than on projects such as the Stanton and Martin-Marrietta sites.

1.2 Historical Perspective

During the 1960's, '70's, and early '80's, the Stanton site was managed for cattle, timber, and as a game hunting area. During this period the local landowners or leasees conducted prescribed winter burns, including the years of 1980 and 1982. OUC's fire management schedule was implemented after construction of Stanton 1 and included a control winter burn over the entire site in 1987 and 1991. Other activities in most of the management areas have generally been restricted, thus, providing good conditions for continued development of the longleaf pine ecosystem. Several unimproved dirt roads are used for research and security purposes. The FWS in a recent letter indicated that OUC has done a good job in managing habitat within the red-cockaded woodpecker management areas (Appendix A).

The overall management plan of the longleaf pine ecosystem on the Stanton site appears to be better implemented than on many other development sites. The extent of saw palmetto (*Serenou repens*) seems to be less extensive and the wiregrass community seems to be more extensive than during pre-construction monitoring. Longleaf pine (*Pinus palustris*) seedlings in the managed areas are more extensive than they were prior to 1984. While many formerly sparsely treed areas now include a well established younger age class of pine as a result of the timber management plan, a few other areas are much less dense in terms of either older or younger aged longleaf pines. Habitat conditions on the Stanton site appear to be similar to non-disturbed portions of the Big Econolockhatchee River Basin (Big Econ) (Brown et al., 1989), however, the Stanton site includes a much greater percentage of older aged longleaf pine than most areas. The

Martin-Marrietta site is the obvious exception and the habitat is similar to the Stanton site in many respects.

In addition to the habitat management schedule, monitoring studies on the Stanton site red-cockaded woodpecker population were initiated in 1980. To date, the following studies have been conducted:

- A. Reproductive studies on red-cockaded woodpeckers in 1981, 1982, 1984, 1987, 1989, 1990, and 1991;
- B. Population monitoring studies in addition to the above in 1983, 1986, and 1988;
- C. Home range and territory size studies in 1981, 1982, 1983/84, and 1986/87;
- D. Habitat use (same as "C" above);
- E. Population turnover studies during 1980-1991;
- F. Cavity tree use studies during 1980-1991;
- G. Other studies as determined from data; and
- H. Population status north of the Bee Line Expressway was determined for 1980-82, 1984, 1986, and 1988-1990. Other information on distribution of red-cockaded woodpeckers in this portion of Orange County was obtained from J. Exum (Personal Communication, 1984-1991).

From these studies a number of reports were generated including 13 project related reports, six refereed publications, and one presentation at a scientific seminar. The findings from these studies have been used for other projects in the area and by the FWS in the development of their guidelines.

2.0 POPULATION STATUS AND SUGGESTED ACTIONS

The primary responsibility of the following plan is on providing conditions capable of supporting an increased number of red-cockaded woodpecker breeding pairs on the Stanton site. The following section, however, takes a broader view and provides data and population trends for all red-cockaded woodpeckers located in habitat surrounding the Stanton site. Discussions are included on red-cockaded woodpecker population enhancement and management techniques.

Red-cockaded woodpecker populations in Orange County and throughout most of the species range have declined substantially over the last 10-15 years (Costa and Escano, 1990 and DeLotelle, Personal Observation). Present regulations often do not provide adequate protection of red-cockaded woodpecker populations on private land. As an example, abandoned territories on private lands often require little management, even though at some point in time they may be reactivated when surrounding population increases occur and in the long run are important for population maintenance. In addition, agencies involved in permitting development within the Big Econ River Basin have not provided or developed a comprehensive plan or strategy for maintaining the local red-cockaded woodpecker population. These factors will continue to lead to substantial population declines and probable disappearance of the population.

2.1 Population Ecology

In response to the declining population in the area, some limited discussion on the biology of red-cockaded woodpeckers taken from onsite studies is provided (see

primarily DeLotelle and Epting, In Press; and Alvarez, Lehman & Associates, Inc. and Environmental Science and Engineering, Inc., 1989). Red-cockaded woodpeckers are non-migratory and defend all purpose territories. These all purpose territories, which on the Stanton site average 275 acres (Table 1), include foraging habitat and cavity tree resources (DeLotelle et al., 1987; DeLotelle and Epting, 1988; and DeLotelle and Newman, 1983). Social groups (clans) contain between 2 and 5 individuals including the breeding pair, helpers, and offspring. Group size during nesting is 2.43 birds. A number of boundary locations have been consistently defended by the same groups in the same locale throughout the 11 years of monitoring indicating territory boundaries are relatively stable.

Nesting (2.85 eggs per nest) usually occurs between early May and late June, and on average produces about one young per nest compared to 1.6 fledgling in some northern populations (Table 2). Of the factors affecting breeding success, experience (i.e., age) of the breeder appears to be the most important influence (DeLotelle and Epting, In Press). During the study period from 1980 through 1991, on-site groups produced about 67 fledglings including 39 (58%) females and 28 (42%) males. These young birds often remained as helpers, mostly males, for up to 2 and 3 years. These helpers assist in territorial defense and incubate and feed the nestlings. Since 1984, all turnover of breeding males has been to male helpers either on the natal territory or a nearby territory. Most young females disperse near the end of the first year, usually during March and April, but may make extended forays into adjoining territories at other times as the birds mature. Dispersing males and females

TABLE 1. Population and Habitat Characteristics for Eleven Groups of Red-cockaded Woodpeckers on the Curtis H. Stanton Energy Center, Orlando, Florida, 1992

Group*	Size	Mean Reproduction All Years	Mean Reproduction Successful Years	N	Pine Basal Area (ft ²)	Total** Pine Stems	Territory Size (Acres)	% Lost From Impact
+A	2	1.33	1.33	3	3,551	14,709	383	41.7
+B	2	1.00	1.00	1	3,131	13,547	363	38.0
+++C	3	0.80	1.33	4	2,195	8,818	251	62.6
+++D	3	1.00	1.00	5	2,593	8,733	261	34.9
C/D	3	1.00	1.33	3	3,195	8,636	236	0.6
++E	3	0.89	1.33	9	4,333	13,490	299	3.8
F	2	1.00	1.14	9	3,177	10,418	255	13.0
G	2	1.00	1.60	9	2,673	6,452	215	3.2
***H	3	0.89	1.17	9	1,780	4,562	169	32.0
++I	3	1.63	1.63	8	3,778	10,961	239	3.6
++X	2	0.50	1.00	2	2,163	10,237	398	4.3
	2.54	1.00	1.26	5.6	2,961	10,051	279	21.6
	±0.52	±0.29	±0.22	±3.3	±766	±3,084	±73	±21.1

N = number of years studied for reproduction.

% = percent loss of pine trees.

ft² = feet squared.

*Predominant group size during the breeding season for the 10-year study period.

**Includes all pine stems over two inches in diameter at breast height (dbh).

***Territory impacted from off-site development.

+Territories abandoned.

++Territories impacted by pipeline construction.

+++Territories and clans combined during 1986.

Source: Alvarez, Lehman & Associates, Inc., 1991

TABLE 2. Comparison of Demographic and Ecological Factors for Red-cockaded Woodpecker Populations, Curtis H. Stanton Energy Center, Orlando, Florida, 1992

	Fledgling Rate	Fledgling* Survivorship		% Helpers	Breeder** Survivorship		Territory Size (Acres)	Pine Basal Area/Territory (Ft ²)
		M	F		M (%)	F		
This study	1.00	.85	.63	Moderate	84	79	275	3,000
North Carolina	1.47	.62	-	Low	73	56	143	10,700
South Carolina	1.70	.88	.36	High	78	68	156	8,500
South Georgia	1.13	Moderate		Low	79	64	154	8,300
North Georgia	1.70	-	-	-	72	51	-	High

*Survivorship after six months on natal territory.

**Breeder survivorship on resident territory.

M = Male

F = Female

% = percent

Ft² = square feet

Sources: DeLotelle, and Epting, In Press; Lennartz et al., 1987; Walters et al., 1989; U.S. Fish and Wildlife Service, 1990; Lennartz and Haeckel, 1987; Blue, 1985; and Repasky, 1984.

Compiled by: Alvarez, Lehman & Associates, Inc., 1991

often compete with the residents for breeding positions (DeLotelle and Epting, In Press).

Survivability of breeding males and females on resident territories is 9% and 19% higher, respectively, than northern populations (Table 2). Using these percentages on survivability suggests Stanton site breeding males survive about 6.1 years as breeders while north Georgia males survive only 3.6 years as breeders. The female side is more complicated because they may move from one breeding site to another, but here again Stanton site females survive within the population an estimated 5.1 years compared to 3.4 years in North Carolina. From these data it appears males that become helpers and then breeders will survive an average of 9-10 years. Female survival is more difficult to predict, but three females banded as breeders survived between 9 and 11 years. One male also survived as a breeder for 10 years and another is still alive after 11 breeding seasons (Exum, Personal Communication, 1991).

Comparing populations from a number of different regions in the U.S. indicates the Stanton site birds have a lower fledgling rate, higher fledgling survivorship, higher level of experience as a breeder, and higher adult survivorship than most other populations (Table 2). Genetic drift problems, as indicated by morphological and allozyme data, do not presently exist within the Stanton site population (Appendix B).

2.2 Population Trends

The core population north of the Bee Line Expressway, which includes the Stanton site, has declined from 24

occupied colonies in 1980 to 13 occupied colonies in 1991 (Figure 2). Nine of these occupied colonies occurred onsite in 1980 while six colonies are occupied now. Of the 11 colonies north of the Bee Line Expressway that are no longer occupied, six have been clear cut or the foraging habitat has been eliminated while five have become abandoned. At the same time the ratio of occupied to unoccupied colonies in the Bee Line Expressway core population has declined from 92% in 1980 to 76% in 1991.

In order to compare these trends to some meaningful numbers, a comparison of the Bee Line Expressway core population to the mean of 24 National Forest (FS) populations from 1976 to 1990 is provided (Figure 3). The Bee Line population has declined at a slower rate and less dramatically than the mean for the FS populations. A Statistical Analysis System (SAS) general linear model procedure for an unbalanced analysis of variance indicated that a significant effect of time ($P = 0.0315$) and between populations ($P = 0.0001$) exist on the proportion of occupied colonies. Using the ratio of occupied to unoccupied colonies, the only FS populations over a comparable time period that out performed the Bee Line Expressway population were the Apalachicola, the Francis Marion (excluding Hurricane Hugo impacts), and the Vernon NF. These populations contained an estimated 230 to 602 breeding units and overall population decline within the total sample was inversely related to population size ($r = -0.64$ without the central Florida and $r = -0.59$ with the central Florida population, $p < 0.05$). Of the NF populations (5) with 25 or fewer colonies, which would be comparable in size to the Bee

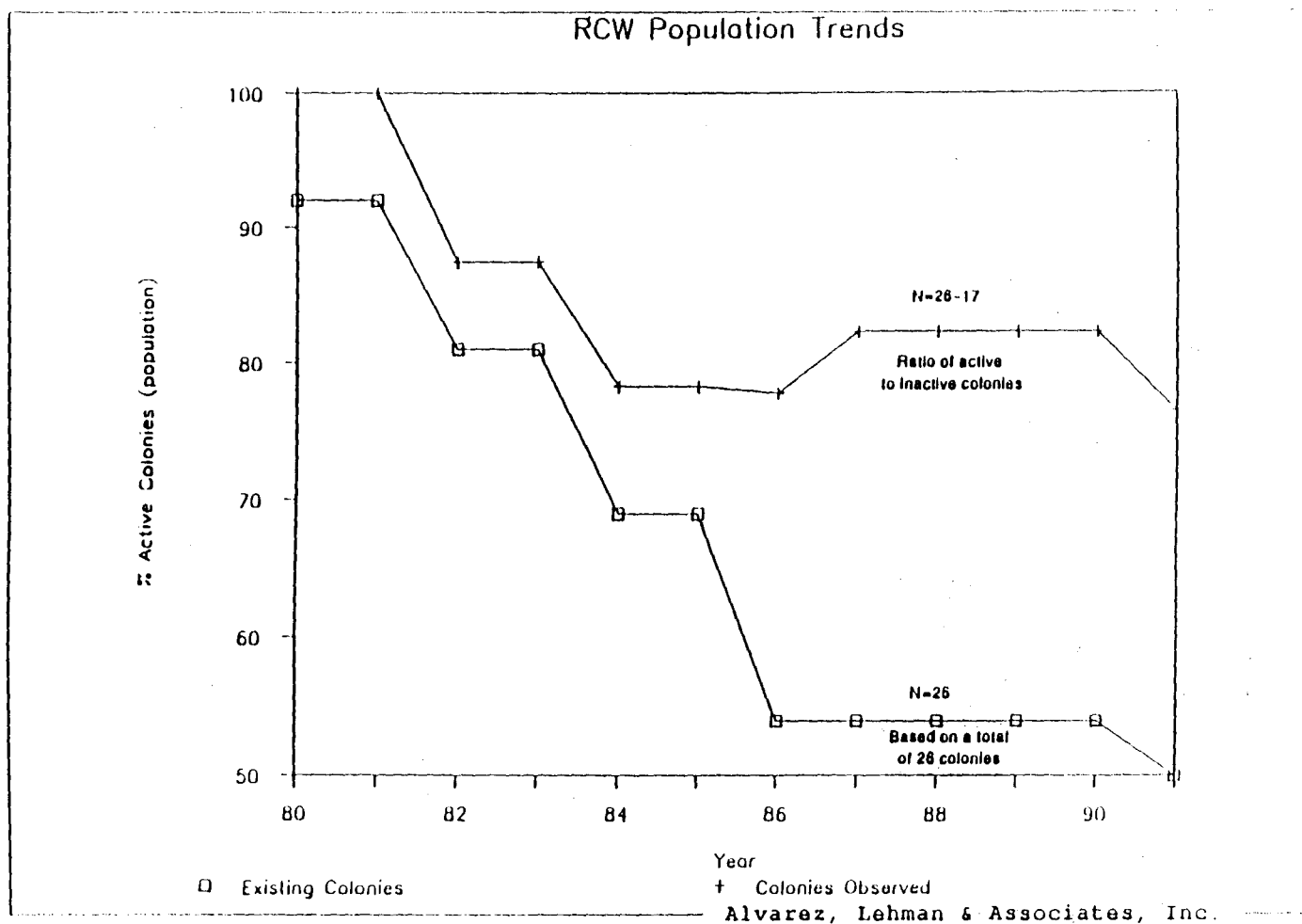


FIGURE 2. Population Trends in the Red-cockaded Woodpecker Population in Eastern Orange County, Curtis H. Stanton Energy Center, Orlando, Florida, 1992

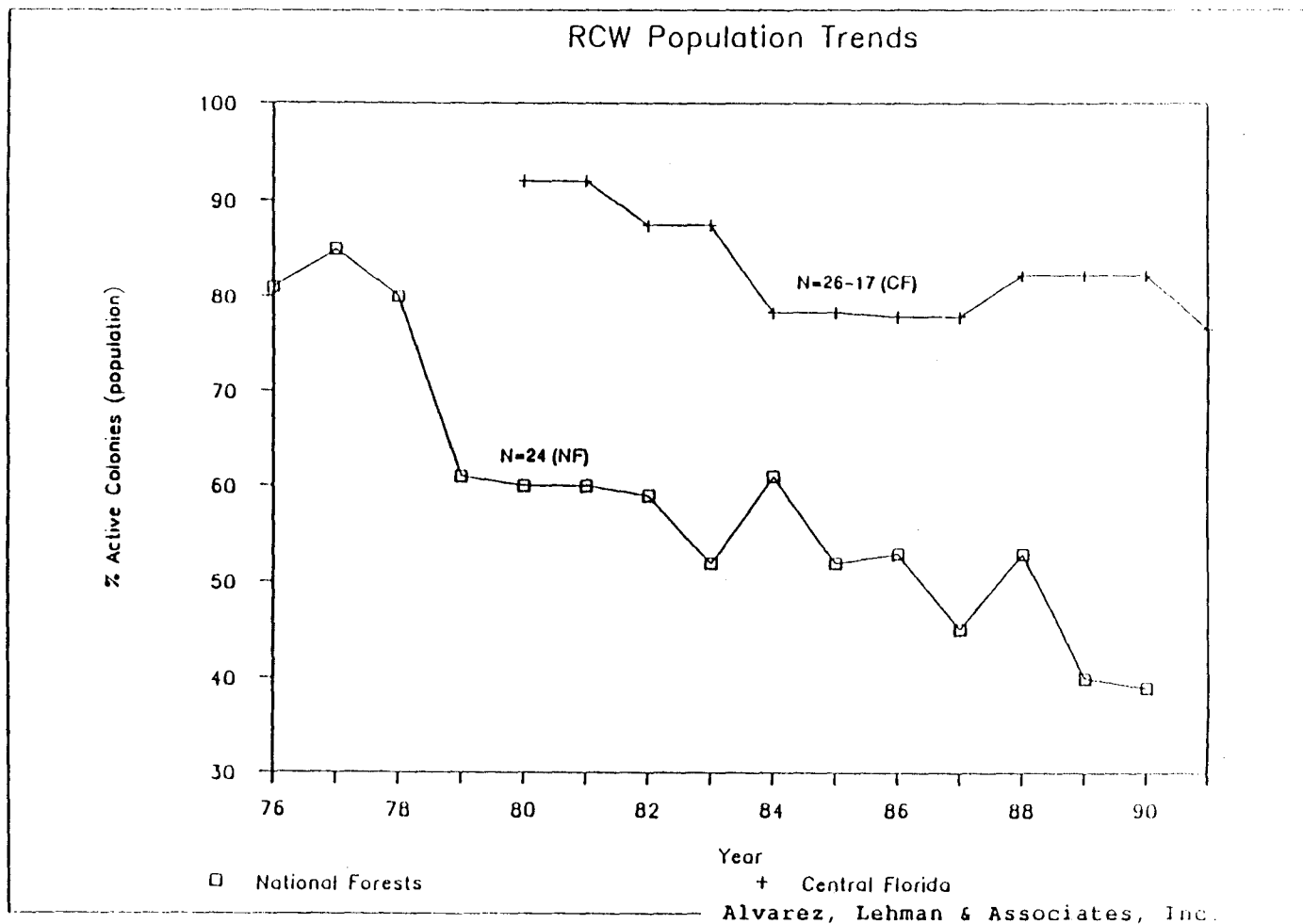


FIGURE 3. Comparison of Red-cockaded Woodpecker Population Trends North of the Bee Line Expressway with National Forest Populations in the Southeast U.S., Curtis H. Stanton Energy Center, Orlando, Florida, 1992

Line population, two have become extirpated while of the other three only 35% of colonies were occupied as of 1990. Habitat loss, fragmentation, degradation, and isolation are factors which negatively affected all of these populations, including the FS and the Orange County red-cockaded woodpeckers (Conner and Randolph, 1989 and Alvarez, Lehman & Associates, Inc., 1989). Habitat impacts that result in population densities of less than 1 to 3 groups per 1.6 square miles of woodpecker habitat may cause substantial population declines. However, colony abandonment can be caused by a variety of factors including habitat quality in terms of availability of old trees (DeLotelle and Newman, 1983) and hardwood invasion as well as social factors such as breeder turnover (Doer et al., 1989).

While the reproduction rate of the Bee Line Expressway population appears to be less than in other regions of the species range, the survivability of adults and fledglings appears to be much higher (Table 2). The low rate of nest loss here may be related to low densities of nest predators and competitors. Aerial predators are absent during the summer and nest and roost competitors appear to occur in low numbers throughout the year. All of these factors substantially increase the survival of adults and fledglings. These factors contribute to an increased probability of sustaining a small population of red-cockaded woodpeckers in this region of Florida. These factors plus enhancement activities, which result in increases in foraging habitat quality, suggest conditions in the area could be considered quite favorable for red-cockaded woodpeckers.

2.3 Population Maintenance and Stabilization

In an effort to evaluate the requirements necessary to support and maintain a population of red-cockaded woodpeckers here, a number of issues including population size, population density, dispersal, and habitat factors, were investigated. These factors must be accounted for in any comprehensive red-cockaded woodpecker population survivability model. The investigation will by necessity contain some parameters and estimates that are not precisely defined.

The distribution of red-cockaded woodpecker colonies in stable populations from Georgia, South Carolina, and the eastern part of Orange County (Figure 3) indicates most occupied colonies (89%) occur in densities of greater than four colonies (number of groups within a 1.24 mile radius). Converting this to a per acre basis, indicates a minimum value of one colony per 773 acres surrounded by at least three neighbors. Estimates in 1981 on the Stanton site ranged from a population density of 4 to 11 (1/773 acres to 1/281 acres), but presently exist at a population density of 3 to 10. The mean for the entire sample was one territory per 422 acres ($N = 75$).

The density distribution of colonies that continue to be occupied in Orange County also occurs in the range of 4 to 10 groups (Figure 4) (79%). The plot for abandoned colonies, however, indicates that most colony abandonments were occurring in the less dense parts of the population (1-3). Likewise, in these same areas, habitats had greater fragmentation by the conversion of pine habitats to other

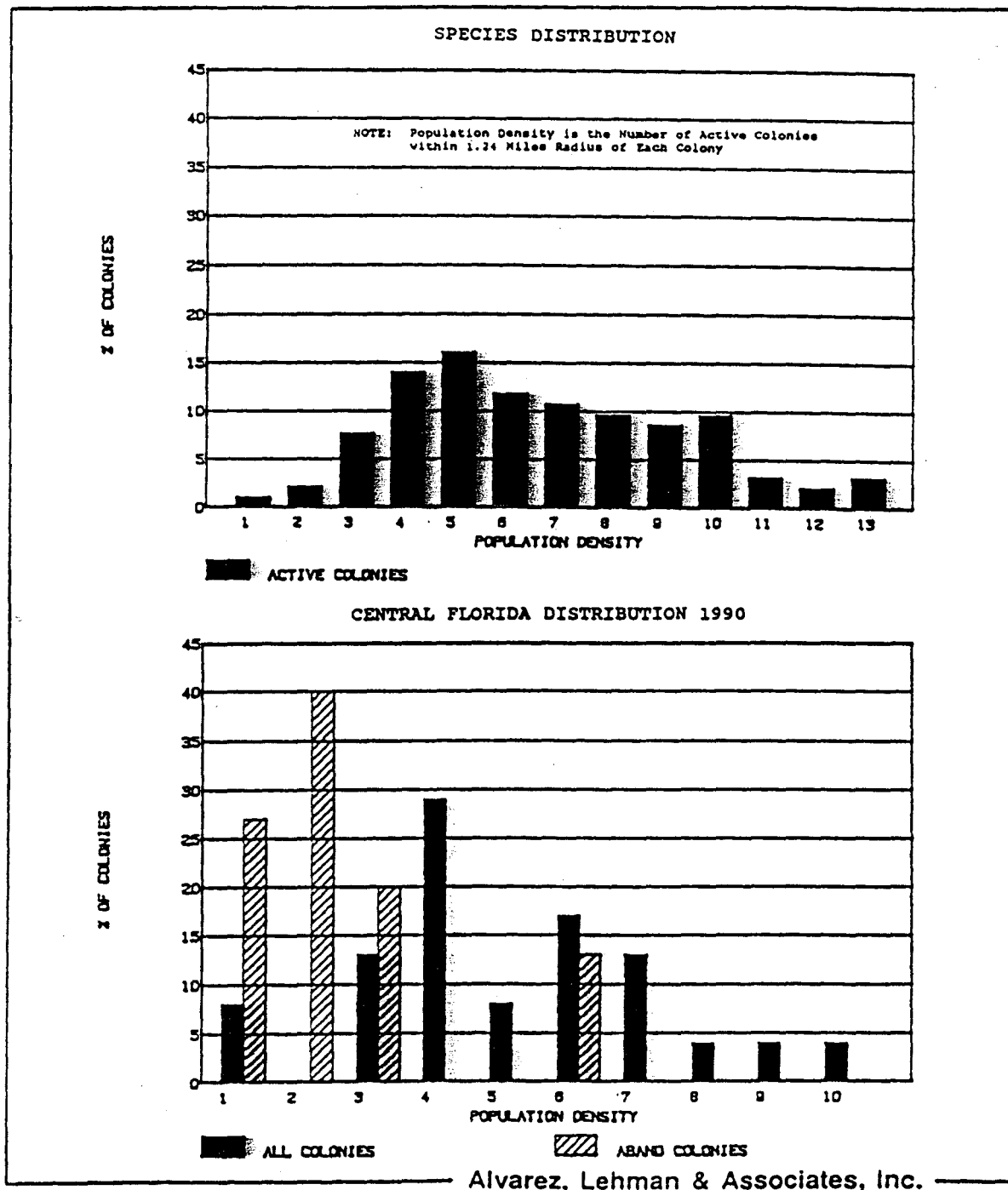


FIGURE 4. Population Density Characteristics in the Southeastern U.S. and Central Florida for Red-cockaded Woodpeckers, Curtis H. Stanton Energy Center, Orlando, Florida, 1992

land uses. Some colony losses occurred in areas with greater population densities, but this was apparently a function of the availability of nesting and roosting habitat (DeLotelle and Newman, 1983), direct removal of most or all of the colony and associated foraging habitat, or social factors similar to those described by Doer et al. (1989). A logistic regression ($N = 51$) for the entire Orange County red-cockaded woodpecker population showed a significant effect of isolation ($X^2 = 7.31$, $P = 0.007$) on colony abandonment. Colony abandonment as related to population density is, in part, a function of dispersal activity of young birds and the associated dispersal mortality.

The following discussion on dispersal activity of young female red-cockaded woodpeckers provides support to the above discussion. These data were provided by the North Carolina Research group (Walters, Personal Communication, 1991). Most young females disperse during the winter or early spring of their first year, to either become breeders in other territories or become floaters within a population (Walters et al., 1989). Young females disperse an average of 2.9 miles with a maximum distance of 20 miles (Walters et al., 1989). Dispersal distance of young females, however, is primarily toward the shorter distances with 70% moving 1.9 miles or less from their natal territory (Figure 5). Although some females disperse up to 20 miles, only 4% travel further than 10 miles. Dispersal distance, however, is also influenced by the density of groups in a given area (Walters et al., 1989). From a population perspective, most dispersal (76%) of young females is within the first three adjoining territories. It is assumed that dispersal distances of young females in central Florida will be similar to the North

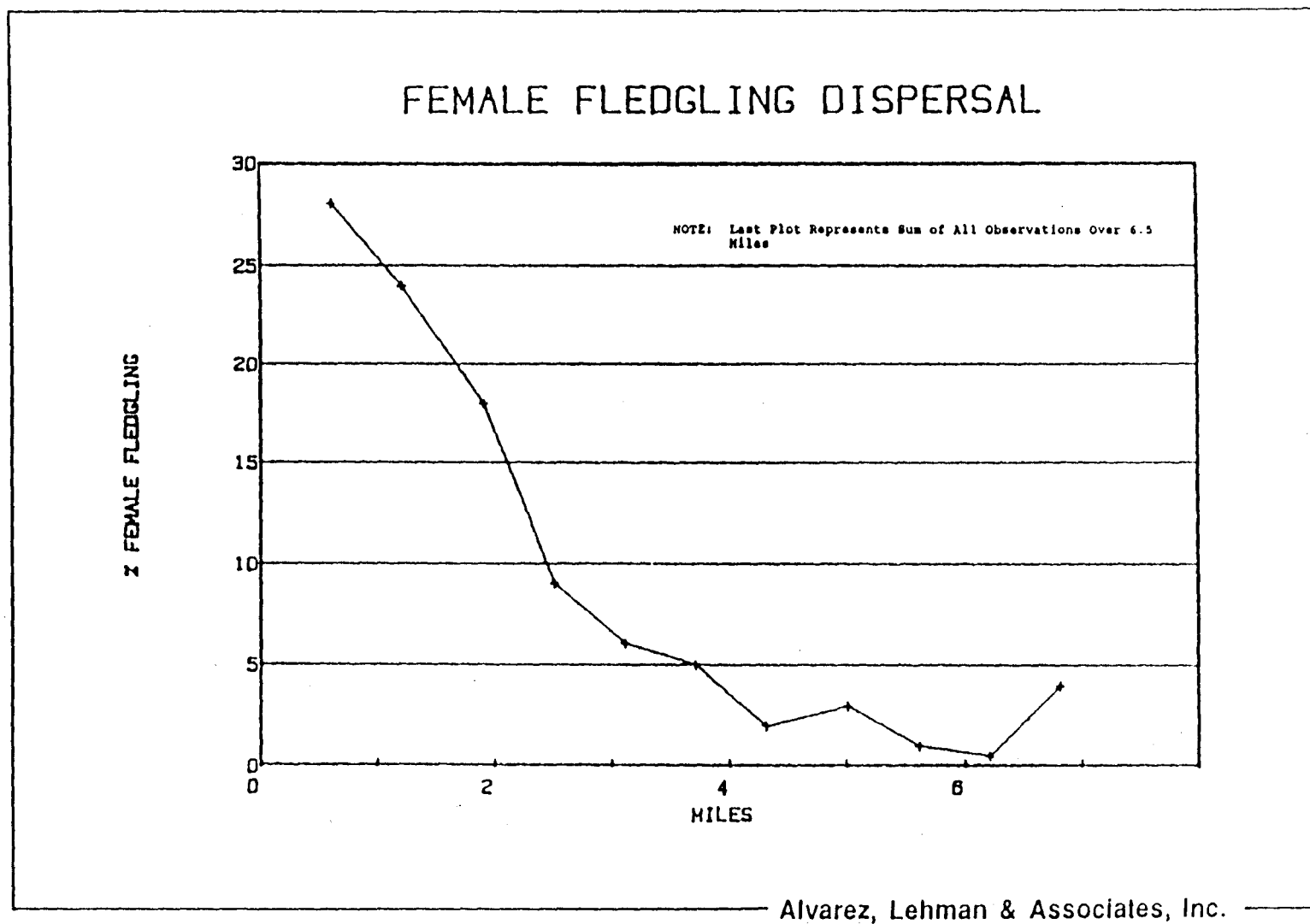


FIGURE 5. Fledgling Female Red-cockaded Woodpecker Dispersal Distance for North Carolina, (Walters, Personal Communication, 1990), Curtis H. Stanton Energy Center, Orlando, Florida, 1992

Carolina data, and observations from the Stanton site on this matter indicate a similar trend.

Throughout most of the species range, mortality rates of females, including breeding and younger birds, appears substantially higher than males (Lennartz and Heckel, 1988; and Walters et al., 1989). Thus, colonies that are isolated and located at more extreme distance from population centers should experience higher rates of colony abandonment or at least a greater frequency of single male colonies (Doer et al., 1989). Inversely, colonies in denser segments of the population should be occupied over a longer time period as result of dispersal based demographics. This is supported by studies conducted (Figure 4).

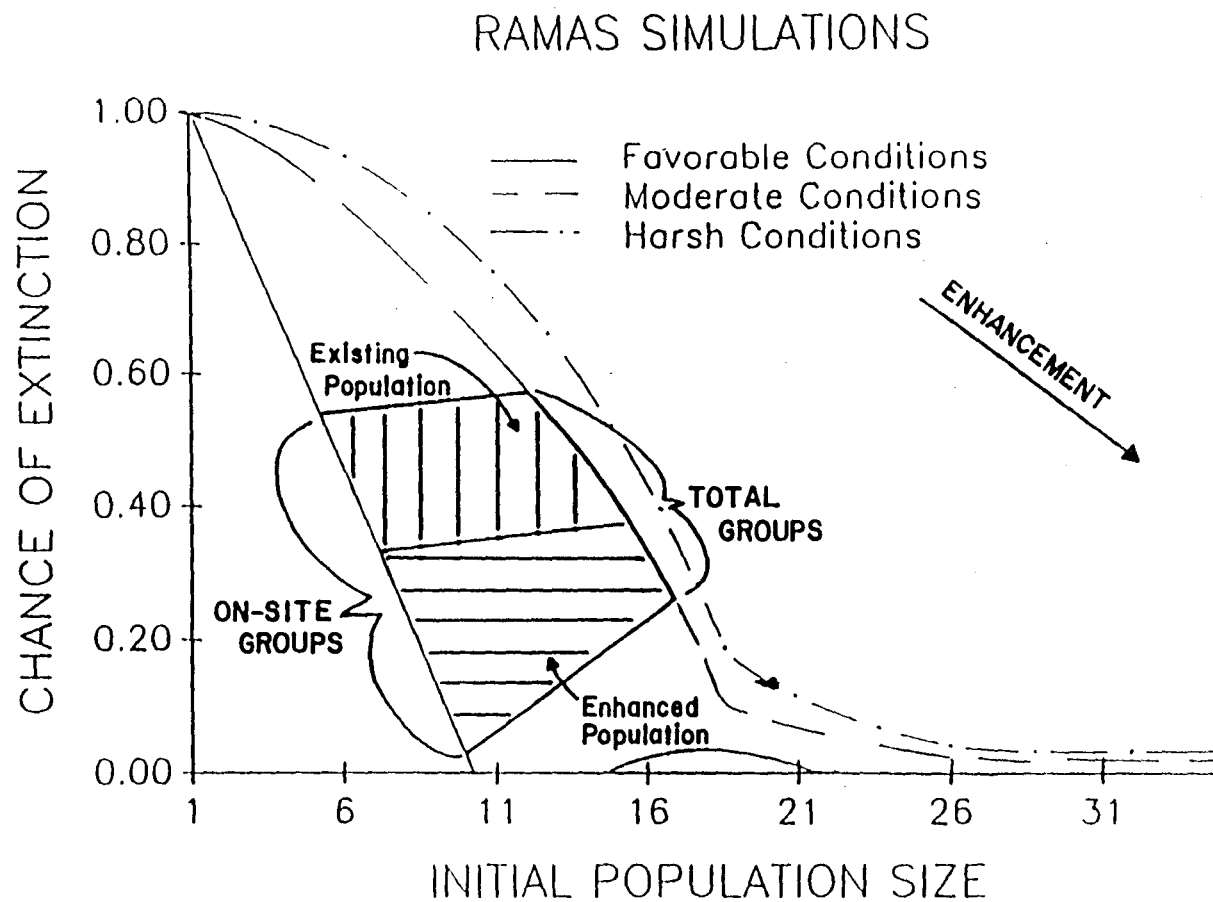
One final and important question is how many groups are required to sustain a population of red-cockaded woodpeckers over an extended period? An estimate of this parameter under a variety of demographics conditions is provided in Figure 6 (Appendix C describes the limitation of the model). The model represented by Figure 6 was modified from the RAMAS/age computer software of Applied Biomathematics. The RAMAS model simulates populations future and shows the expectation and the chances for growth and the risks of decline. The model may be parameterized to include migration, survival, fecundity, density dependence, age-structure, year-to-variation and covariation in vital rates. By running different inputs, various parameters can be explored as to their importance and what would happen under alternate strategies.

Figure 6 was modified from a product of the FGFWFC (Cox, 1991). The horizontal axis on the figure shows the

population size parameter extending from 1 to 31 breeding pairs and above. The three curvilinear lines extending diagonally across the figure represent different demographic conditions of survivability of adults and juveniles and reproductive rates. The vertical axis provides an estimated extinction potential for a 100-year period. As an example, there are 13 groups located north of the Bee Line, which for moderate conditions would have an extinction probability of about 0.53 over 100 years. This estimate was derived by entering the figure on the lower horizontal axis at 13 (a little left of the mid point between 11 and 16) and proceeding vertically until the curvilinear line representing moderate conditions is intersected. The 0.53 is obtained by then proceeding horizontally to the left until the vertical extinction line is intersected.

The fewer the number of breeding groups (i.e. 1-6 groups) the higher the extinction probability. As shown in the figure for populations of 1-6 groups, all three lines tend to converge on the 1.0 extinction probability. As reproduction and survivability of the population increase, the chance of extinction decreases, thus allowing smaller populations to have a greater chance of survival. It is worth noting that for populations with less than 20 groups the extinction probabilities change substantially with the addition or subtraction of each breeding group.

Favorable, moderate, or harsh conditions, are defined by adults and juveniles survivability and reproduction rate of the population. For example, assume conditions are moderate to favorable in this area of the county as suggested by Figure 3 on page 16. Further assume that habitat quality is also related to foraging resource and potential cavity tree



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FIGURE 6. Extinction Probabilities as Related to Population Size for Red-cockaded Woodpeckers, Curtis H. Stanton Energy Center, Orlando, Florida, 1992

resources but is most often a function of the latter (see Walters et al., 1991). Interpreting Figure 6 suggests that to be reasonably sure of sustaining the population for 100 years or more under moderate conditions, will require between 21-25 groups (also Walters, Personal Communication, 1991). Currently the Stanton site only supports six groups and could be expanded to support between 9-11 groups. Seven groups are known to exist in surrounding areas. Again, assuming 25 groups are required, with a territory size of about 275 acres each and with 10-20% of unusable habitat, a reserve size of approximately 8,250 acres would be necessary. Under favorable conditions, assuming present foraging habitat and population density criteria, the population size criteria could be reduced to 10 or 11 groups and would require a reserve size between 3,300 and 3,630 acres. More intense management of foraging habitat could reduce territory size requirements as suggested by data in Table 2 (i.e., territories with higher densities of foraging resources were nearly 45% smaller than Stanton site territories). The tree planting program as proposed under the mitigation plan for the Alafaya Trail will in time (15 years and beyond) improve foraging habitat quality to the extent that overall habitat conditions will be much more favorable. In addition, under these conditions, territory size may be reduced, thereby allowing more groups to exist in a given area as compared to existing conditions. Thus, reserve size should range between 8,250 acres on poor quality habitat as now exists to as low as 2,000 acres on high quality habitat which will be attained in the near future. Parameter errors within the RAMAS model which require more breeding pairs may extend all of these reserve size estimates.

3.0 METHODS OF ENHANCEMENT

A course of action is suggested below which will further current knowledge on developing enhancement techniques applicable to increasing the long-term survivability of the Orange County woodpecker population. This plan provides a methodology for performing a demonstration colony creation project, which could be used as a potential enhancement techniques on other lands in the area. In order for any comprehensive, far reaching plan on red-cockadedads in central Florida to be successful, cooperation on the part of a number of agencies including federal, state, county, and the private sector, will be required. The following discussion provides the criteria and methods for implementing the plan ranging from translocation of birds to foraging habitat improvements.

3.1 Population Enhancement

In evaluating translocation of a variety of species including many endangered and threatened animals, Griffith, et al., (1989) found that efforts of moving animals into excellent habitats and areas of moderate population density have a greater chance of success. The latter is apparently due to a threshold effect in which social interaction and mating success may be disrupted below certain population levels. Further, Lewin (1989) and the above study suggest that releases of many bird species appears to have a greater chance of successful population expansion and establishment when the number of breeding pairs is greater than seven in a given locale, habitat quality is good, and release is in the core of the species range. Active management is required and maintenance of high habitat quality must be assured. While foraging habitat may take a number of years to develop, the

nesting habitat for red-cockaded woodpeckers can be provided quickly assuming pine trees are available and meet cavity tree criteria. Based on available data, the Bee Line Expressway core population and surrounding habitat would appear to meet the above criteria.

Translocation of red-cockaded woodpeckers including males and females has met with varied success. Movement of red-cockaded woodpeckers has been attempted by Nesbitt et al. (1983); Odom, (1983); Reinman, J.P. (1984); and more recently by De Fazio et al. (1987) and several unreported attempts in Texas, Florida, and Georgia. For the most part, the movement and translocation of breeding males has met with little success. Territorial males apparently are reluctant to give up occupied sites and may return to their original area even though cavity trees and foraging habitats have been impacted.

The translocation of young females to colonies occupied by single males only has been much more successful and has been performed in South Carolina, Tennessee, Texas, and Florida. The Apalachicola NF often serves as the donor population for these translocations. Some movement of young (non-territorial) males has been attempted in Texas and South Carolina. Even in those instances where the young males did not stay within the new territory, they returned to their natal territory soon afterwards (Hooper, Personal Communication, 1991). The movement of young birds from outside the treatment population is called augmentation. Augmentation usually includes the movement of females, which are trapped and transported overnight to the target population and placed in a cavity tree within a territory containing a single or multiple males only. Alternately, young females and young non-breeding males have been moved

within populations to establish new breeding units in the same colony. The cavity for placement of the new bird or birds could be a natural or artificial cavity.

A method exists whereby cavities can be constructed in clusters to simulate colony conditions or in abandoned colonies (Copeyon et al., 1990) and have been occupied by red-cockaded woodpeckers in seven different populations throughout the species range (Costa, Personal Communication, 1991; and Hooper, Personal Communication, 1991). These same individuals indicated that the methodology can be successful and will work given the appropriate environmental conditions. Several of these projects have increased population size and population density. The Savannah River population, which included augmentation and cavity creation, has resulted in a population increase from about 1 functional group to 6 or 7 breeding groups. Near Thomasville, Georgia, as a result of a highway project, two colonies were created and one abandoned site was enhanced in March 1991 (Carter, Personal Communication, 1991). By this summer one site was occupied by a pair and the other two sites included one single male in each colony.

Combining all of the above elements together, strongly indicates a strategy exists whereby the Bee Line Expressway red-cockaded woodpeckers could be expanded to a density and size necessary to make the population more stable. This goal can be attained by staying as much as possible within the stable portion of the density profile in Figure 4 [i.e., dispersal distance of young birds (Figure 5)]; using established and evolving methodologies to develop new colony sites; introduce young birds primarily from the onsite population to the newly created colony sites if necessary;

and to apply this technology in surrounding areas should funding and adjacent lands become available for red-cockaded woodpecker enhancement techniques. The latter may depend on the desired population goal, population demographics, and other factors, but is not part of the present plan.

First, a demonstration project will be conducted on the Stanton site for one new colony site and provisioning in two existing colony sites and territories. One of the latter two colonies is abandoned and all trees with completed and recently used cavities are dead. One cavity will also be constructed in colony H in order to entice the breeding female from clan H to relocate from Colony I. Studies on available habitat including foraging habitat and colony habitat analysis will be conducted (Table 3). Certain aspects of this study have been performed and indicate there is enough habitat area to support these additional groups, but the data base needs to be expanded before final determination is made.

A demonstration colony creation project will be implemented on the northwest side of the Stanton site as part of mitigation for the construction of the Alafaya Trail on the east side of the facility (Figure 7). Once colony creation is completed and assuming successful results, the red-cockaded population expansion could be extended to include any lands in the area which are suitable as woodpecker habitat and the landowners desire to support this effort. The full extent of suitable habitat in surrounding areas has not been determined, however, several potential territories including potential colony sites and foraging habitat and other suitable foraging habitat have been observed adjacent to the Stanton site during aerial and

TABLE 3. Habitat Characteristics of Unoccupied Habitat on the Curtis H. Stanton Energy Center, Orlando, Florida, 1992

Pine Foraging Habitat+				
Stand ID	Area (Acres)	Density Trees/Acre	Age Years	Total Stems
5	52	13	47	676
6*	78	91	48	7,098
8	136	29	48	3,944
9	98	45	45	4,410
10	103	67	55	6,901
12	40	37	108	1,480
14*	22	47	44	1,034
15*	20	83	45	1,660
4	93	51	52	4,743
11	98	37	37	3,626
16	9	44	45	396
Sub Total:	11	749	49	35,968

Other**				
CD	48	375	--	18,000
B	61	519	--	31,685
WP	21	0	---	0
Sub Total:	3	130	---	NA

Potential Cavity Tree Resources			
Stand I.D.	DBH (Inches)	Total Trees Sampled	Age (Years)
10	13.60 ± 1.42	14	55-100++
9	14.43 ± 0.95	14	55-60++
12	13.46 ± 1.87	16	100-171
11	12.94 ± 0.88	11	100-129
4	14.35 ± 1.33	10	98-160

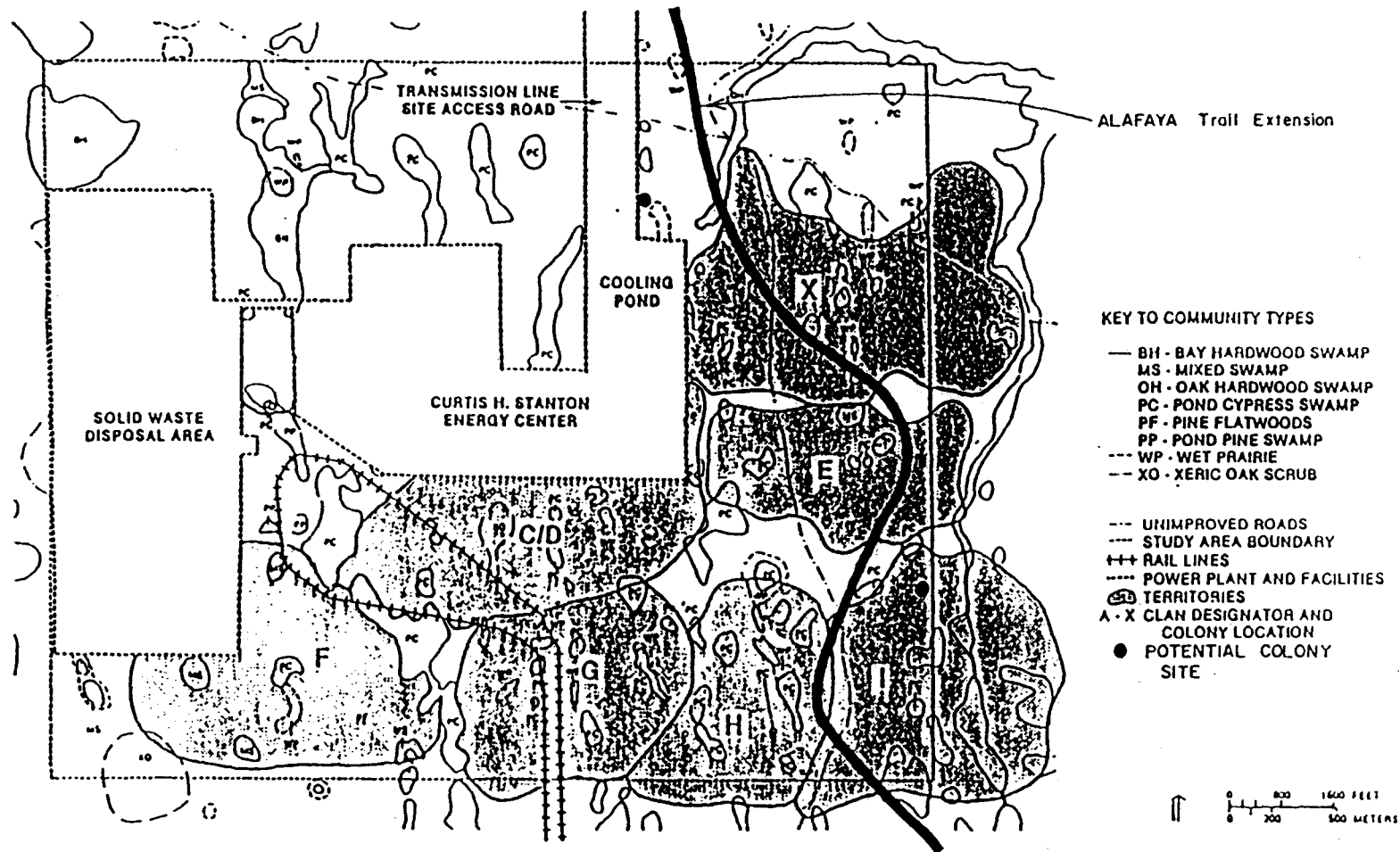
+ Habitat Characteristics Based mostly on 1981-1982 Data, and some field data from 1992.

* Stand Characteristics Estimated from Aerial Photograph.

**Includes Cypress Domes (CD), Bayhead (B) and Wet Prairies (WP).

++Age of pines estimated.

Source: Alvarez, Lehman & Associates, Inc., 1991



ORLANDO UTILITIES
COMMISSION

C. H. Stanton Energy Center

FIGURE 7. Location of Potential Colony Sites and Territories of Red-cockaded Woodpeckers on the Curtis H. Stanton Energy Center, Orlando, Florida, 1992

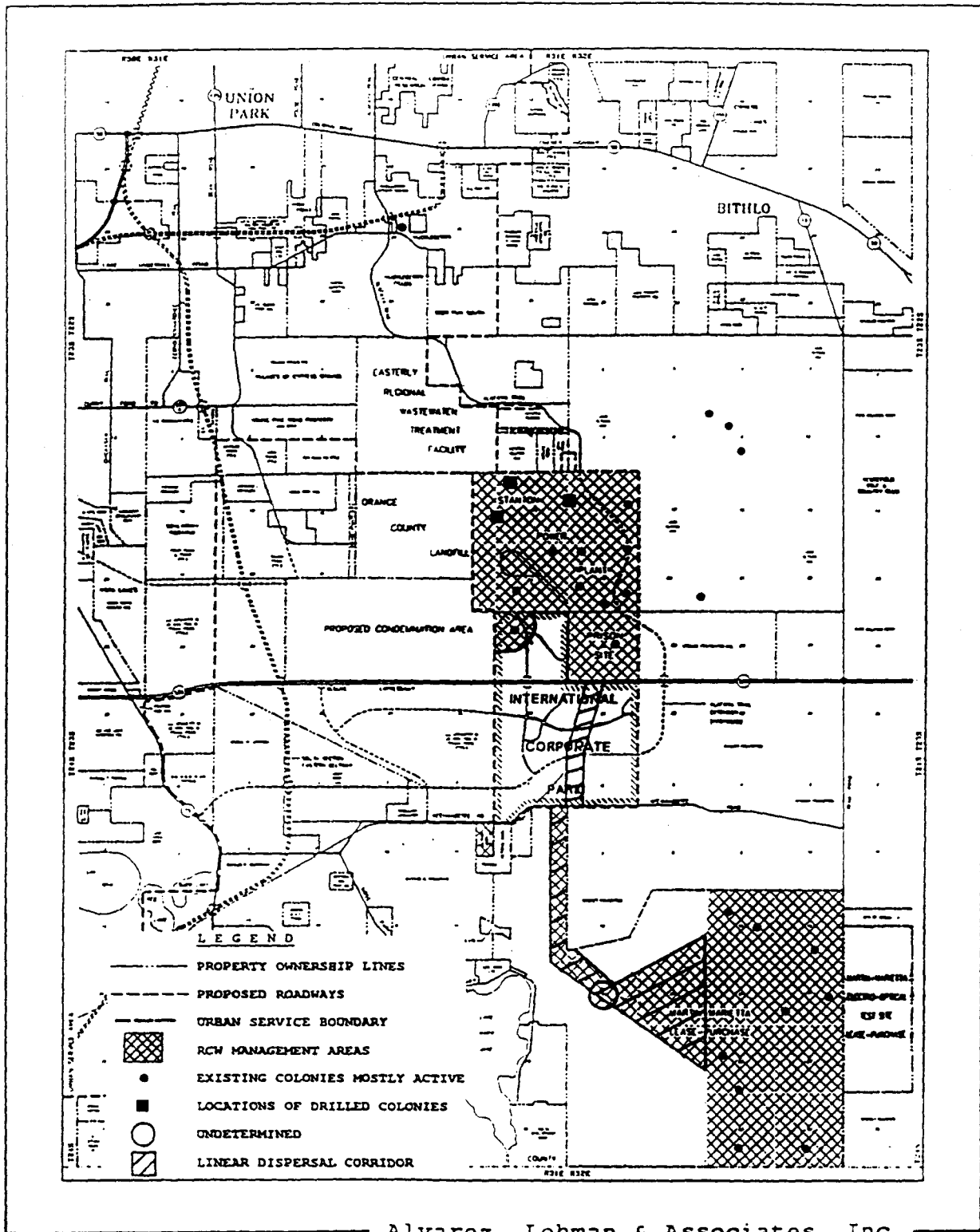


FIGURE 8. Location of Active and Potential Colony Sites and Dispersal Corridor for the Bee Line Expressway and Martin-Marrietta Core Populations, Curtis H. Stanton Energy Center, Orlando, Florida, 1992

LITERATURE CITED - Continued

Walters, J.R., Doer, P.D., and Carter, J.H., III. 1989. The Cooperative Breeding System of the Red-cockaded Woodpecker. Ethology. 78:275-305.

Wood, D.A. and Wenner, A.S. 1983. Status of the Red-cockaded Woodpecker in Florida: 1983 Update. Pages 89-91 in Wood, D.A. (ed) Proceedings of Red-cockaded Woodpecker Symposium. Florida Game and Fresh Water Fish Commission, U.S. Fish and Wildlife Service, U.S. Forest Service. Tallahassee, Florida.

APPENDICES

APPENDIX A

Letter to Mr. Buck Oven
from Don Palmer Dated July 2, 1991 on
Habitat Management from
U.S. Fish and Wildlife Service.

July 2, 1991

Mr. Buck Oven
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Oven:

This is in reference to Orlando Utilities Commission's (OUC) request for a supplemental certification for a transmission line and one additional electric coal-generated unit on the Stanton Energy Center (SEC) in Orlando. On June 27, 1991, a meeting was held at SEC to discuss the proposed transmission line, wetland impacts and proposed wetland mitigation. Also discussed was Department of Environmental Regulation's (DER) Condition of Certification for SEC's Unit 1, in particular condition 31 (Red-cockaded Woodpecker Management Plan).

We were asked at the meeting to provide our comments to you by July 15, 1991. Both the St. Johns and South Florida Water Management Districts and DER requested additional information from the applicant regarding wetland impacts, and informed the applicant that it would be necessary to increase the mitigation acreage.

At this time, we do not have specific comments with reference to the transmission line. We will provide comments to the U.S. Army Corps of Engineers through the Public Notice review process for a Section 404 Dredge and Fill Permit when the additional information requested by DER and the water management districts is available. We want to take this opportunity, however, to mention several issues involving Condition 31 which were discussed at the meeting.

In 1980-81, our office, in cooperation with the Florida Game and Fresh Water Fish Commission and OUC, agreed on a management plan for the red-cockaded woodpecker on SEC. Over the last ten years, OUC has done a good job in carrying out its management responsibilities for the woodpecker. The habitat on SEC has been burned to control understory growth, and the colonies have been continuously monitored by a qualified biologist. The results from the monitoring program have provided data on red-cockaded woodpeckers in peninsular Florida. However, as a result of the proposed Alafaya Trail extension through SEC, we are concerned that the management plan may not be as effective as once believed. We requested at the June 27 meeting that through the

supplemental permitting process, condition 31 be modified to strengthen the management plan. To further protect the 2000 plus acres of undeveloped property on SEC, OUC should place the land under a Conservation Easement and provide additional monitoring of the woodpeckers. Establishing an easement on the undeveloped land would significantly reduce our level of concern and insure that activities not clearly beneficial to the woodpecker would not be permitted.

The Service, in cooperation with International Corporate Park (ICP), has attempted to reduce the impact of this proposed roadway by reducing the width of the right-of-way from 180 feet to approximately 110 feet. This negotiation was done in good faith with the top management of ICP, and is our opinion the 110 foot roadway will have minimal effect on the woodpecker.

We believe the changes mentioned above should be initiated as soon as possible, and we suggest this supplemental site certification process may be the most appropriate place. We appreciate the opportunity to provide our comments on this phase of the certification process.

Sincerely,

Donald T. Palmer
Acting Field Supervisor

cc
Don Wood
Brian Barnett-FGC-Vero
SJWMD-Orlando-Lance Hart
SFWMD-Kissimee

DP/7-2-91/cm

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APPENDIX B

Letter to Roy DeLotelle, Alvarez, Lehman &
Associates, Inc., dated March 17, 1988,
from Peter Stangel on Stanton Site
Red-cockaded Woodpeckers

SREL

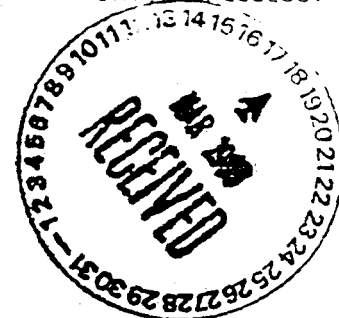
SAVANNAH RIVER ECOLOGY LABORATORY
DRAWER E
Aiken, SOUTH CAROLINA 29801

TELEPHONE 803/725-2472

UNIVERSITY OF GEORGIA
INSTITUTE OF ECOLOGY

March 17, 1988

Mr. Roy DeLotelle
Alvarez Lehman and Associates
2444 NE 1st Blvd.
Suite 500, Gainesville, FL 32609



Dear Roy:

At long last, here is some morphological and allozyme data from the Stanton Energy Center Red-cockaded population.

The attached xerox copy has the raw morphological data for the 13 individuals. Interpretation should be pretty straightforward, with most measurements paired, with the right side given first. The data is error-free as copied from my field notes. If you see any errors when compared to your records, please let me know. As I prepare the data on the rest of the populations, I will be able to provide you with additional information regarding the status of this population relative to other Florida and southeastern populations. Until then, feel free to use this data as you please.

I surveyed the 13 Stanton Red-cockaded's for 15 enzymes encoding 18 putative gene loci. The following loci were monomorphic, that is they exhibited no polymorphisms in the Stanton population: Mdh-1, Mdh-2, Ck-1, Ck-2, Pgm, Idh-1, Idh-2, Gpi, Adk, Mpi, aGpdh, Ada and Alb. Five enzymes were polymorphic: Ldh, Peptidase (Lgg substrate), aNp (an esterase), 6Pgd, and Nsp. Mean heterozygosity per locus (direct count) for the population was 0.047 (SE 0.024). The range of heterozygosity values for the other 23 sites I have sampled is 0.111-0.016. Thus the Stanton population falls in the middle of the spectrum. Mean number of alleles per locus at Stanton was 1.28 (SE 0.11), also typical for the other populations. Percent polymorphic loci (.95 level, that is considered polymorphic only if frequency of polymorphism exceeds 0.05) is 11.11. The range for the 23 others is 5.6 - 27.8. Stanton is again in the middle.

I am still working on the genetic distance diagrams, but preliminary results indicate that the Stanton birds fall out as being most closely related to the other Florida populations. One interesting result is that the Stanton population does exhibit an unusual polymorphism, at the 6Pgd locus.

The final numbers on these estimates will probably change a little as I make corrections in the data, etc. The data here do not contain any surprises, but fill an important category in

my analysis, i.e. that of a moderately small population. At present I think I may make a short collecting trip to Texas, Louisiana, and Alabama this summer to fill some gaps in the western part of the birds range. I should then be able to produce some conclusions regarding heterozygosity, relatedness of populations, etc. I will keep you posted.

Hope all is going well with you. Will you be able to work with the Stanton birds again this summer? I hope you were able to resolve the funding problems. Your recent article in the Bulletin looks good. Please send me a reprint when they are available.

Best Wishes,

A handwritten signature in cursive script, appearing to read "Peter".

Peter Stangel

9229	2	1	24.0	24.0	5.91	5.71	16.94	117	115	25.69	25.28	7.67	7.88	7.55	8.02
			24.0	24.0	5.91	5.71	16.94	117	115	25.69	25.28	7.67	7.88	7.55	8.02
9184	1	1	51.0	5.90	6.76	16.94	117	118	25.60	25.56	7.65	7.54	7.56	8.10	
			25.0	25.0	3.1	3.1	17	15	08	09					
5688	1	2	49.0	6.17	5.91	16.43	120	120	23.93	23.91	6.91	7.09	7.20	7.42	
			23.0	23.0	4.3	4.3	13	11	13	11					
3710	1	1	52.5	5.94	6.92	16.90	119	120	26.45	25.75	7.70	7.93	7.82	7.91	
			25.0	25.0	3.2	3.2	16	14	11	11					
5675	1	2	49.0	5.65	6.15	14.71	118	119	24.57	24.49	7.59	7.79	7.53	7.60	
			23.0	25.0	2.0	2.1	08	09							
2587	1	1	51.5	6.26	7.09	16.43	120	120	24.98	25.18	7.30	7.31	7.45	7.53	
			24.0	23.0	3.3	3.3	13	13	10	10					
6510	1	1	44.0	5.94	6.38	17.27	115	114	24.43	25.19	7.30	7.70	7.39	7.65	
			24.0	24.5		17	15	09	07						
6511	1	1	41.5	6.57	6.75	17.37	119	118	24.81	23.85	7.73	7.81	7.67	7.72	
			24.0	24.5		12	16	12	10						
6512	1	1	44.5	6.24	6.70	15.47	113	115	25.10	24.90	7.42	7.62	7.48	7.45	
			24.0	24.0		14	18	09	08						
6513	1	1	41.5	5.96	6.99	16.21	112	112	25.06	24.80	7.49	7.58	7.50	7.82	
			25.0	24.0		24	26	08	11						
6514	1	1	41.0	5.90	6.32	16.43	108	110	23.73	23.53	7.36	7.18	7.37	7.54	
			24.0	24.5		14	13	10	10						
			Set	Wt	bill depth	bill width	cul length	wing	left wing	tail	tail	tail	tail	tail	tail
6515	1	2	43.5	6.17	7.30	17.74	117	118	23.60	23.88	7.26	7.36	7.54	7.73	
			25.0	25.0					09	10					
6516	1	1	44.0	6.22	7.28	16.91	115	117	25.47	25.93	7.86	7.49	7.83		
			24.0	24.5		15	15	09	07						
6517	1	1	44.0	6.31	6.29	16.87	115	118	24.15	24.82	7.34	7.88	7.55	8.03	

Handwritten signature

H-3
E-2
E-2
F-2
C-2
X-1

Handwritten note

Sex	Age	Wt	Bill depth	Bill width	Bill length	Wing	Left wing	Right wing	Left tarsus	Right tarsus	Left toe 1	Right toe 1	Left toe 2	Right toe 2
1	2	41.0	6.62	6.68	17.33	112	114	24.79	24.65	7.41	7.48	7.46	7.55	
1	2	42.5	5.60	6.85	17.18	112	111	24.13	24.54	7.28	7.40	7.41	7.42	
1	1	41.0	6.00	6.65	16.31	115	113	24.04	24.06	7.04	7.22	7.16	7.27	
1	1	43.5	6.08	7.30	17.58	111	112	24.80	25.08	7.36	7.44	7.58	7.73	
1	2	41.5	5.86	7.13	17.04	111	113	23.86	24.63	7.55	7.42	7.50	7.53	
1	2	43.0	5.51	6.43	15.51	109	110	23.27	23.73	7.21	6.88	6.99	7.60	
1	1	42.0	5.68	6.58	17.00	106	109	24.93	25.09	7.44	7.56	7.37	7.22	
1	2	41.5	5.86	7.12	15.22	110	108	24.71	23.85	7.34	7.50	7.91	7.44	
1	1	41.0	5.65	6.99	16.47	109	109	25.09	25.55	7.39	7.31	7.23	7.45	
1	1	42.5				108	109	23.90	24.48	7.54	7.49	7.62	7.79	

Sex 1 = Male
2 = Female
Age 1 = adult
2 = juvenile

all lengths are in
all weights in

APPENDIX C

Letter to Roy DeLotelle,
Alvarez, Lehman & Associates, Inc.,
dated April 12, 1991. from Jim Cox,
Florida Game and Fresh Water Fish Commission,
on Modeling of Red-cockaded Woodpecker Populations

FLORIDA GAME AND FRESH WATER FISH COMMISSION

WILLIAM G. BOSTICK, JR.
Winter Haven

DON WRIGHT
Orlando

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Clewiston

ROBERT M. BRANTLY, Executive Director
ALLAN L. EGBERT, Ph.D., Assistant Executive Director



FARRIS BRYANT BUILDING
222 South Meridian Street
Tallahassee, Florida 32399-1000
(904) 488-1900

April 12, 1991

Mr. Roy Delotelle
Alvarez, Lehman, and Associates
2444 NE 1st Blvd.
Gainesville, FL 32609

Dear Roy:

Here is the graph I mentioned that shows the results of some very simplistic modeling of red-cockaded woodpecker populations. Plotted on the Y-axis is the chance that a population will be extinguished within 100 years, and plotted on the X-axis is the initial size of the population in terms of the number of breeding females. The demographic variables that went into the model were those presented by Reed et al. (1988). Minimum viable population size of the red-cockaded woodpecker. J. Wildl. Manage., 52:385-391). There are many problems with my model (not to mention errors in the paper by Reed et al.), but I think that the take-home message is fairly small populations appear to have good chances of persistence under good environmental conditions. Proper management is a key to the maintenance of small populations. Of course, there are a number of other things that need to be included before such models can be considered realistic, particularly for a species such as red-cockaded woodpeckers where social interactions may be very important to reproduction and survival.

I look forward to receiving the map that you described. Call me if you have any questions about the graph.

Sincerely,

Jim Cox
Nongame Biologist

ENV 8-3-1

APPENDIX D
Mitigation Procedures

ATTACHMENT A

PINE TREE PLANTING PROGRAM

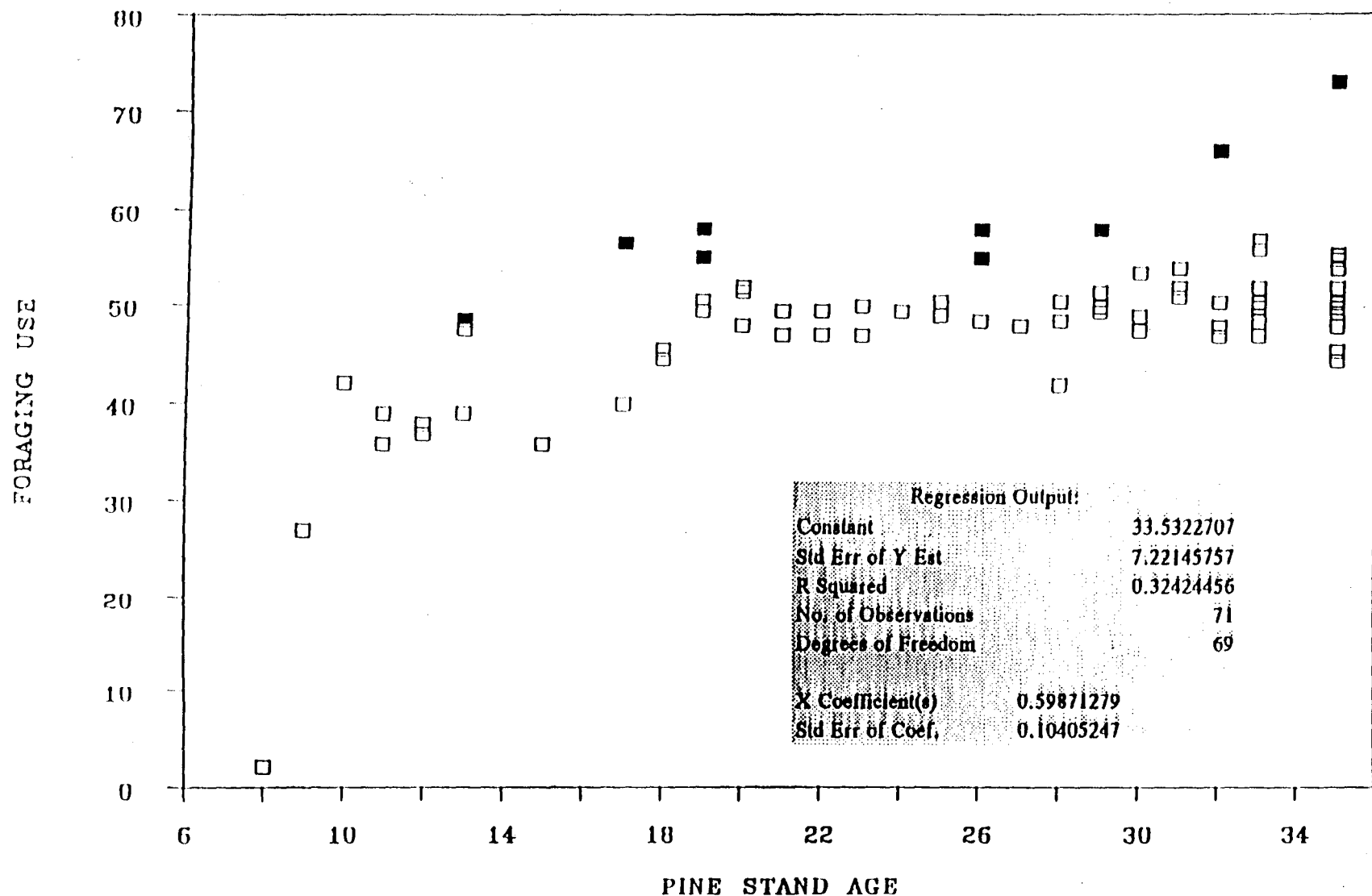
RATIONALE ---- The relative importance of younger pine stands to foraging RCW's is shown in Figure 1-A (See Table 1 for list of assumptions and relevant factors). As indicated by the shaded blocks in the figure, foraging use of young, dense pine stands occurs at a much higher rate in poor quality territories than comparable stands in good quality territories. Average pine tree density throughout territory X is about 26 trees per acre. Thus, in territory X and others with low pine density it would be expected, based on Figure 1-A that substantial foraging use of young pine stands would occur within 15 years of age.

- ACTIVITIES --- 1. Three flatwoods areas of slightly over 4 acres each will be planted with 500/1-2 inch diameter at breast height (dbh) longleaf pine trees (See figure 1-B). These three areas will be situated in proximity to each of the stormwater runoff ponds. The pine trees for these areas will be obtained from sources other than the Stanton Energy Center. Pine trees will be planted on about 10 foot centers and trees will be replanted to ensure 80% survivability of trees. Trees will not be planted in rows but will be irregularly spaced to simulate natural conditions. Trees will be watered periodically during the first year to increase survivability and growth. Other activities such as use of herbicides or fertilizers may be undertaken to promote more rapid growth of pines. Trees will be planted in territory X on the same side of the road as the colony; in territory E and territory H.
2. In addition, a tree planting program on about 100 acres will be undertaken as indicated on Figure 1-B. The exact locations may be altered somewhat depending on access and the suitability of planting areas. One area (A) in territory X of about 50 acres will be planted at a density of about 500 seedlings per acre. Potted seedlings will be used and spot application of herbicide will be used

Attachment A

prior to planting. Here again the area to be planted in territory X will be on the same side of the proposed Alafaya Trail as the colony.

Another 50 acre area (B) in the northwest section of the property will also be planted with potted seedlings following the above procedure.



Data Sources: Hooper & Harolow, 1986; DeLotelle et. al., 1987; and Tim Beaty Personal Communication, 1991
 Compiled by: Alvarez, Lehman & Associates, Inc., 1991

FIGURE 1-A. Observed - Expected Foraging Use Compared To Age Of Live Pines In Forest Stands, Age 8 -35 Years, Orlando Utilities Commission, Orlando, Florida 1991

TABLE 1

LIST OF IMPORTANT FACTORS FOR FIGURE 1-A
ORLANDO, FLORIDA, 1991

1. The ten shaded stands come from nine (9) different territories in three (3) different population of RCW's (N=41 total territories).
2. All pine stands except the 29 year old stand came from poor quality territories.
3. High use in this 29 year stand may be related to location effects of colony site and territorial interaction sites.
4. The average density of good quality territories is 201 pines per acre.
5. Fifty-eight percent (58%) (range= 34-78%) of poor quality territories had an average density of 20.5 pines per acre.
6. In these young pine stands on the Stanton site, foraging use was on the younger trees and not a few scattered old trees located in the young stand. In addition, younger pine stands averaging 24 years of age accounted for 35% of foraging use in one territory for a North Florida study.
7. Average pine stand age in these nine (9) territories was 53 years (range=34-78 years). For the total pine stands the average age per territory was 51 years (35-89 years).
8. Two regressions lines were developed:
 - a. One for the shaded blocks: $r^2=73\%$, intercept 40.21; slope 0.76.
 - b. One for the sample of open blocks: $r^2=45\%$; intercept 30.53; slope 0.65.
9. Based on these two different regressions, young, dense pine stands situated in poor quality territories are 28% more important to RCW's than young stands in the total sample.
10. The data points for each stand were developed from the observed foraging use (% of total observations in a territory) minus the expected foraging use (% of territory occupied by a stand).
11. The 50 on the vertical axis represents equal foraging use to equal availability.
12. Stands with significant hardwood component were deleted from the sample.

ATTACHMENT B

RED-COCKADED WOODPECKER ROADWAY MONITORING STUDY

RATIONALE----- The monitoring program outlined below is similar to previous monitoring activities conducted during past studies on the Stanton site. The number of hours for sampling per clan is slightly less than previous years, but will be adequate to determine the reaction of RCW's to the road and traffic and to determine use of habitats relative to the placement of the road alignment within the respective territories.

TIME PERIOD -- Two years before road completion clans will be monitored by banding individuals and censusing during the winter and nesting season. Nesting season monitoring will include an evaluation of nesting attempts and successes.

TIME PERIOD -- During the first five years after the road is opened to traffic monitor clan membership and territorial movements.

- ACTIVITIES --- 1. Determine mortality rates of adults and fledglings for the entire Stanton site population:
- A. Band all on-site birds annually or as required;
 - B. Census clan members during the nesting season and the winter. Nesting season monitoring will include banding of nestlings and determination of nesting success. Individual colony sites will be visited weekly during the nesting season. All clans on the Stanton site will be monitored for nesting success. During nesting, group size, the number of eggs and the number of fledglings will be determined. Monitoring during nesting will be similar to those studies described in the Stanton site Red-cockaded Woodpecker Management Plan.
2. Monitor clan movements to determine frequency of road crossings, reaction to vehicles and use of territories.

Attachment B

- A. Observe three clans (X, E & I) during territorial movements for 100 hours each during two years of monitoring (total hours 300).
- B. The scope of home range, territory size, and habitat use studies will be similar to those described in the Stanton site Red-cockaded Woodpecker Management Plan. Clan members will be followed from the roost cavity tree in the morning until mid-afternoon (1500 hours). On each day of observation, the locations of the clan will be plotted at 5-minute time intervals on photocopies of aerial photographs. All observations will be summarized on one photocopy. Home range and territory configuration will be based on the location of territorial interaction sites and the frequency of use. Crossing of the road will be noted as well as the behavior of the birds in response to the road and traffic. General traffic levels at the time of crossing will be noted.

ATTACHMENT C
TECHNIQUES FOR CONSTRUCTING CAVITIES
AND CREATING COLONY SITE FOR RED-COCKADED WOODPECKERS

RATIONALE ---- Although the techniques for the construction of RCW cavities is relatively new, it has proven very successful to date in both population studies in South Carolina and North Carolina. After hurricane Hugo hit the Francis Marion National Forest, a total of 279 inserts, 127 drilled cavities, and 132 drilled starts were installed with substantial use occurring by roosting and nesting groups (Attachment D). This technique has not been attempted in a small RCW population such as Orange County.

Table 1 provides a breakdown by stand of the available and unoccupied habitat on the north side of the Stanton site. As shown in the table there are about 27,600 pine stems within an estimated area of 688 acres including wetlands. The area on the east side of the Alafaya Trail and west of the Hart Branch is included in the estimate. We propose to initiate three colonies and attempt to assist in getting two of the sites occupied by RCW's. The third site will be open to dispersing birds and may become occupied in the future.

- ACTIVITIES ---
1. Three potential colony sites were selected based on availability of large older pines for cavity construction (Figure 2). In each of these colony sites three completed cavities and two start holes will be completed according to Copeyon (1990). In addition, colony sites were selected to allow the greatest distance between sites within the limits imposed by the distribution of pine habitat.
 2. Cavities will be closed and monitored for six months to prevent RCW'S from being trapped in sap flow and to allow proper maintenance of cavity trees. Once cavities are constructed they will be inspected within a week of construction and then every 4-6 weeks for six months or until sap flow has completely ceased. Once sap flow has ceased the cavities may be opened to bird occupancy.
 3. In previous studies employing the use of artificially constructed cavities birds were allowed to move into cavities at their own

Attachment C

pace. These studies, however, occurred in large dense RCW populations or in populations with very limited cavity resources. Thus, while the cavities will be opened to birds after six months, young males and females from within the Stanton site population will be moved to the new colony sites. Should colony sites not be occupied naturally, young females may be obtained from the Apalachicola National Forest through an approved procedure if females are not available from the on-site population. In the event that successful clan establishment in the new colonies does not occur immediately the procedure will be continued for at least three years following cavity construction. At the end of three years the project will be re-evaluated to determine future activities. All newly established colonies will be monitored to determine survivability of resident birds and to evaluate reproduction.

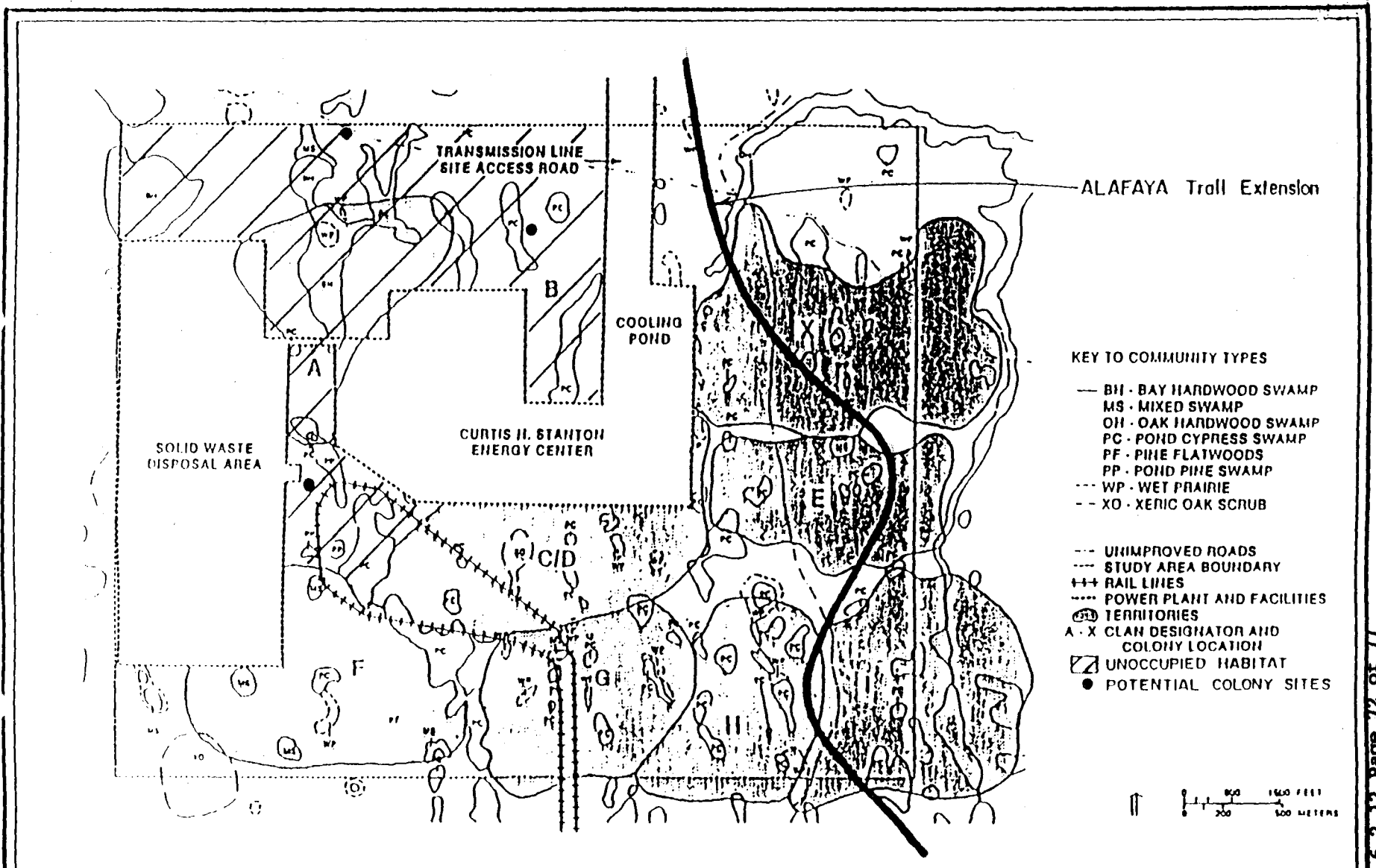


Figure 2. Location of Potential Colony Sites
on the Stanton Energy Center, Orlando, Florida

Source: Alvarez, Lehman & Associates, Inc., 1991

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C. H. Stanton Energy Center

Table 2. Habitat Characteristics of Unoccupied
Habitat on the North End of the Stanton
Energy Center, Orlando, Florida 1991.

PINE				
Stand I.D.	Area (acres)	Density Trees/acre	Age (Years)	Total Stems
5	52	13	47	676
6*	78	91	48	7,098
8	136	29	48	3,944
9	98	45	45	4,410
10	103	67	55	6,901
12	40	37	108	1,480
14*	22	47	44	1,034
15*	20	83	45	1,660
16	9	44	45	396
Sub Total:	9	558	---	27,599
other**				
CD	48	375	--	18,000
B	61	519	--	31,685
WP	21	0	0	0
Sub Total	3	130	---	NA

* Stand Characteristics Estimated From Aerial Photograph

** Includes Cypress Domes, Bayhead and Wet Prairies

Source: Alvarez, Lehman & Associates, Inc. 1991

ATTACHMENT D

Report on the Use of Artificial Cavities by Red-cockaded
Woodpeckers in the Francis Marion National Forest

Reply To: 1630

Date: September 12, 1990

Subject: 1990 Breeding Season Estimate of the RCW Population in the Francis Marion National Forest

To: Don Eng	Craig Watson	Jeff Walters
Jim Brotherton	Danny Carlson	Dave Allen
Glen Stapleton	Ron Escano	
Jerry Henderson	Kay Franzreb	
Oscar Stewart	Gary Henry	
Mike Lennartz	Charlie Van Sickle	

The following estimates of the red-cockaded woodpecker population in Francis Marion National Forests were derived from a stratified random sample of colony sites during the breeding season in 1990. The stratification was based on damage to the forest (high, medium and low) and on colony type (natural, drilled, inserts, drill and insert, artificial and natural). We sampled 25% (n = 90) of the colonies. We called a colony any surviving or rehabilitated aggregate of cavity trees; n = 362. The following numbers are estimates. At this time I have not put confidence intervals on these estimates.

Estimates for RCW population during breeding season 1990. Based on stratified random sample (25%) across high, medium and low damage classes.

Parameter	TYPE OF COLONY					TOTAL
	Natural	Drilled	Insert	Drill and Insert	Artificial and Natural	
Number of Colonies	140	38	88	5	91	362
Adults	256	54	103	10	153	576
2 + bird colony	112	27	31	5	62	236
1 bird colony	16	0	42	0	21	79
0 bird colony	12	11	15	0	8	47
Number nests	87	24	27	5	37	180
Young fledged	130	27	39	5	79	280
Young fledge/2 + bird colony	1.2	1.0	1.3	1.0	1.3	1.2

The breeding season population was estimated to include 236 clans (colony sites with ≥ 2 adults). Additionally, there were an estimated 79 single bird "clans". Forty-seven of the 362 colonies were estimated to have no birds.

Total number of adults were estimated at 576 birds during the breeding season. This is down from the 700 total birds and the 250 2-bird clans that Craig Watson and I estimated existed after Hugo based on total counts. This lower estimate could be a result of statistical variation and/or post-Hugo mortality. Given the severe weather in late December, I am surprised the breeding season estimate was not lower.

Seventy-six percent of the functional clans (≥ 2 adults) nested and produced an estimated 280 fledglings. This is very encouraging given the losses to the foraging habitat, cavity trees and birds. Such clan performance (1.2 young/clan) would have been good for a high density area like Cordesville prior to Hugo, but overall reproduction per clan in FMNF was probably close to twice that number prior to Hugo.

Our foraging observations suggest that most foraging (82%) was being done on standing live trees rather than dead material. This is encouraging because if the birds had been foraging on the recently dead material that would not be available next year, we might expect a major decline in reproduction in the near future when the dead material was not longer suitable for foraging.

Prior to the breeding season 279 inserts, 127 drilled cavities, and 132 drilled starts had been installed in 131 former colony sites that had lost all their cavity trees to Hugo and another 91 colonies that lost a significant proportion of their cavity trees. About 27% of the functional clans were in totally artificial colonies and another 26% were in colonies with both natural and artificial cavities. Forty-three percent of the nests were in artificial cavities. Fledgling production was as good in artificial cavities as in natural cavities.

The above estimates suggest that 162 clans perished since Hugo and another 79 had only 1 bird during the 1990 breeding season. The breeding season number of "functional" clans (236) was 49% of the pre-Hugo number. I expect some of the "functional" clans will be lost over the next few years, but that perhaps some of the 1 bird colonies will pick up a mate and that some of the zero bird colonies will be colonized. Until more is known about the remaining foraging habitat, mortality rate of cavity trees and outlook for future cavity trees on a colony by colony basis, it's not possible to make a knowledgeable prediction as to whether the population will suffer an additional net loss, net increase, or stabilization in the population over the next decade.



ROBERT G. HOOPER
Research Wildlife Biologist

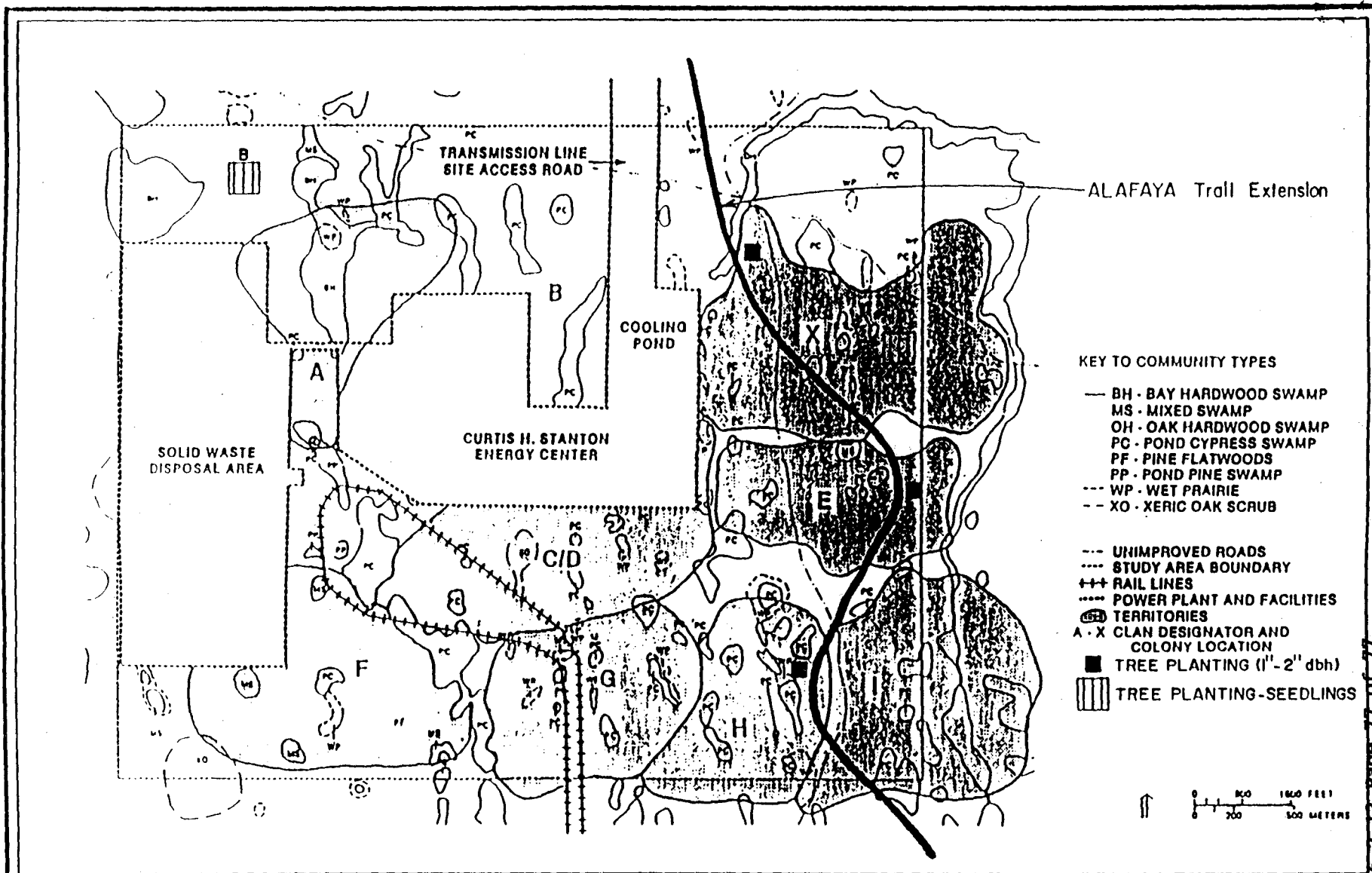


Figure 1-B. Pine Tree Planting Locations for Red-cockaded Woodpecker Mitigation, Orlando, Florida, 1991.

Source: Alvarez, Lehman & Associates, Inc. 1991

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C. H. Stanton Energy Center

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413-88-11

PRELIMINARY ANALYSIS OF
ENVIRONMENTAL ISSUES AFFECTING
THE ALAFAYA TRAIL EXTENSION

Submitted to:

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Janin Associates, Inc.
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January 29, 1986

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Associate Scientist

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President

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1.0 INTRODUCTION

An extension of the Alafaya Trail is being planned that will link with the proposed International Corporate Park (ICP) development site and the Bee-Line Expressway. This extension will be a generally north-south route through Sections 18, 19, 29 and 30, Township 23S, Range 32E, Orange County, Florida. As part of the development process, Breedlove, Dennis & Associates, Inc. conducted a preliminary environmental evaluation of the area in the vicinity of the proposed extension right-of-way.

This report identifies potentially jurisdictional wetlands pursuant to U.S. Army Corps of Engineers (ACOE), the Florida Department of Environmental Regulation (FDER), Orange County, and the St. Johns River Water Management District (SJRWMD) regulations. In addition, an assessment was made of the status of red-cockaded woodpeckers near the alignment right-of-way.

2.0 ENVIRONMENTAL SETTING

2.1 Vegetation

The area in which the proposed road extension is to be built is generally vegetated by pine flatwoods in the uplands with pond cypress (Taxodium ascendens) and blackgum (Nyssa sylvatica var. biflora) dominant forested wetlands and wet weather prairies occurring in shallow depressions.

Pine flatwoods (11) are dominated by longleaf pine (Pinus palustris) in the overstory with broomsedge (Andropogon spp.), Indiangrass (Sorghastrum nutans) and saw palmetto (Serenoa repens) in the subcanopy. Pond pine (P. serotina) often occurs in the transition zone between flatwoods and cypress strands. Wetlands are dominated by pond cypress and blackgum in the canopy and contain a wide variety of subcanopy species, depending on depth and periodicity of inundation. The more shallowly inundating wetlands are vegetated with wax myrtle (Myrica cerifera), St. John's wort (Hypericum fasciculatum), bidewort (Ericecaulon spp.) and beakrush (Rhynchospora corniculata) in the subcanopy, while the more deeply inundating domes are characterized by vegetation such as pickerelweed (Pontedaria cordata), swamp fern (Blechnum serrulatum), and cattails (Typha latifolia).

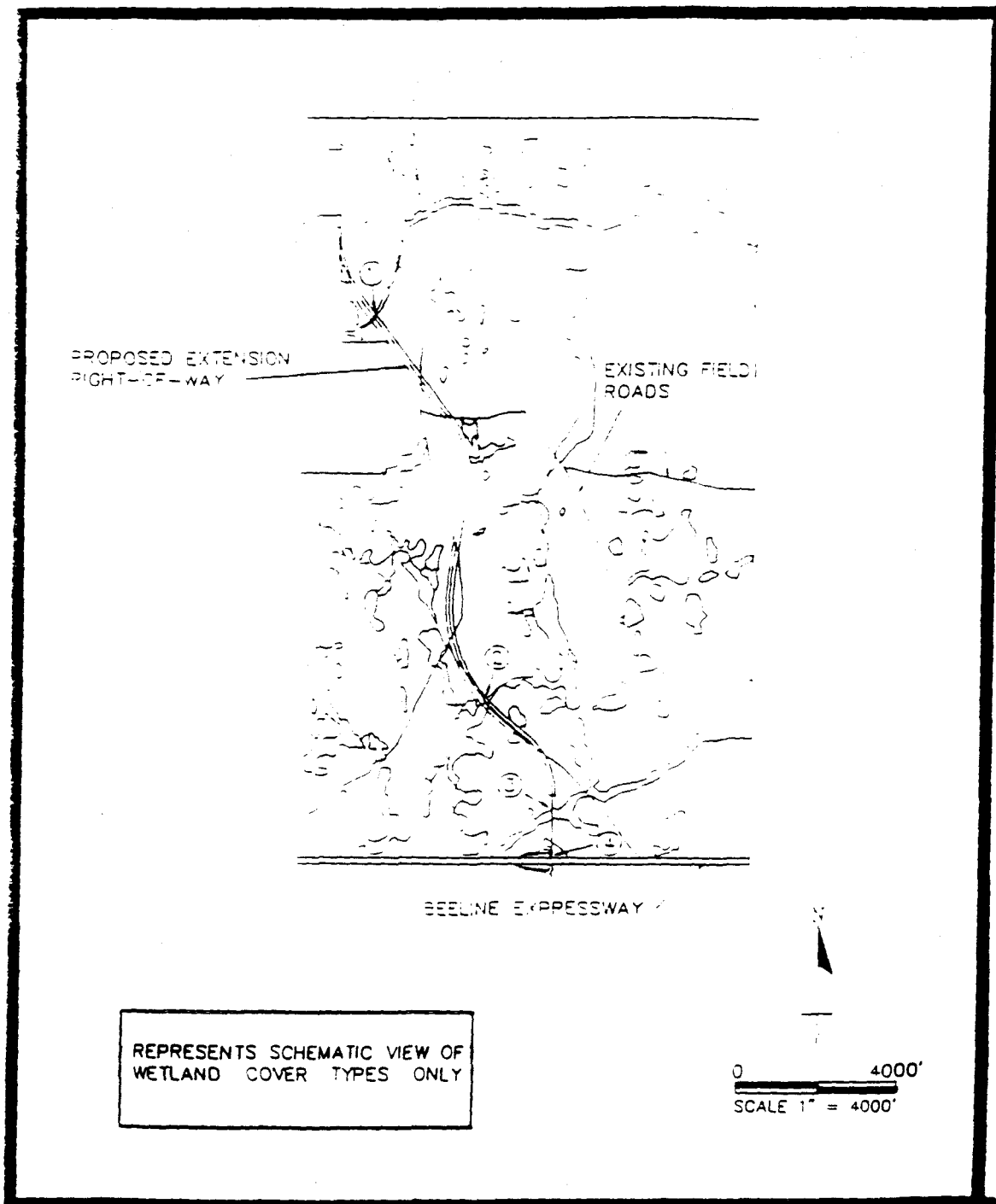
3.0 METHODOLOGY

The entire north-south Hialeah Trail extension right-of-way was either driven or walked to evaluate potential environmental constraints. No evaluation of the east-west tie-in to this right-of-way was performed since its exact location had not been determined by the time of this analysis. Species of vegetation, depth of organics, degree of flooding, and degree of alteration were noted for all wetlands to be impacted by the right-of-way. In addition, trees within approximately 150 feet on either side of the center line were evaluated for the presence of active or inactive red-cockaded woodpecker colonies. A more extensive analysis was conducted around red-cockaded woodpecker colonies which had already been identified by previous environmental evaluations on the Orlando Utility Commission (OUC) and the Orange Correctional Institution project sites. An examination of cavity trees found within several hundred feet of the right-of-way was made to determine their status.

4.0 WETLAND IMPACTS

The proposed Ajafaya Trail extension has been carefully designed to avoid existing wetlands and red-cockaded woodpecker colonies. Therefore, few of the cypress domes or strands within the north-south corridor have been proposed for impact. Wetland cover types were mapped and wetlands proposed for impact are shown on Figure 1. Four wetland systems appear to be scheduled for impact by the proposed alignment. The northern-most wetland (#1) to be impacted is a hardwood swamp containing laurel oak (Quercus laurifolia), cabbage palm (Sabal palmetto), red maple (Acer rubrum), and dahoon (Ilex cassine). Approximately 3 inches of organics were present within the hardwood swamp and at the time of the site inspection (December 11, 1985), water was about 3 inches deep. This hardwood swamp carries a diversity of understory species including saw palmetto, cordgrass (Spartina bakerii), beakrushes and maidencane (Panicum hemitomon). The swamp apparently originates from a flatwoods cypress dome and flows into the Econlockhatchee River via the Hart branch.

The proposed alignment crosses impacted wetland #2 at a currently existing field road crossing. The wetland is almost exclusively vegetated by short pond cypress trees in the canopy. Organic soils are thin and inundation is shallow and infrequent. There is some invasion of



BASED ON CIR PHOTOGRAPHY
JANUARY 1984

BREEDLOVE, DENNIS AND ASSOCIATES, INC.
JANUARY 1986

**FIGURE 1. WETLANDS TO BE IMPACTED BY THE PROPOSED ALAFAYA TRAIL
EXTENSION, ORANGE COUNTY, FLORIDA.** Page 6.2-558

land species within the cypress strand itself. However, the thin strand does appear to connect via an extremely narrow traverse into the Lower Branch of the Econlockhatchee River.

Impacted Wetlands 3 and 4 consist of a wetland strand of the Green Branch and an adjacent dome that drains into it. Most of the wetland strand contains no organics and is dry for most of the year, although 6 to 8 inches of water are present during rainy season peaks, as evidenced by lichen lines and watermarks. Isolated pockets of submerged herbaceous vegetation, including pickerelweed and swamp fern, are present in the pond cypress/black gum dominated strand. Invasion by transitional species of vegetation including wax myrtle and high bush blueberry (Vaccinium corymbosum), occurs throughout the strand. The nearby mixed wetland forest that drains into the Green Branch is also dominated by cypress and blackgum and apparently contains several inches of water during the height of the rainy season.

5.0 WETLAND JURISDICTION

5.1 U.S. Army Corps of Engineers

The U.S. Army Corps of Engineers (ACOE), under Section 404 of the Clean Water Act, exerts regulatory authority for dredge and fill activities over the "waters of the U.S." and its wetlands. Wetlands are defined as "those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions" (33 CFR Part 323/2).

The ACOE exerts jurisdiction over wetlands connected to "waters of the U.S." and adjacent wetlands; and isolated wetlands with importance to interstate commerce. The wetlands that are to be impacted by the proposed alignment apparently connect to the Econlockhatchee and would be under ACOE jurisdiction. Isolated wetlands on the project site should not be considered important to interstate commerce and should not be jurisdictional. Definitive determination of the status of these areas will require a site inspection from a representative of the ACOE.

5.2 Florida Department of Environmental Regulation

The FDER exercises regulatory jurisdiction over dredge and fill activities in "waters of the State" to their "landward extent" as determined by the dominance of certain wetland indicator species defined in

Chapters 17-4 and 17-12 of the Florida Administrative Code (F.A.C.). The stated legislative intent of Chapter 403, Florida Statutes, for regulating these areas is to protect and preserve water quality and wildlife habitat. Critical issues in determining FDER Chapter 17-4 and 17-12 regulatory jurisdiction are regular and periodic inundation as evidenced by dominance of the specified wetland indicator species (Section 17-04.022 F.A.C.), and connection to a recognized waterbody.

Some of the wetlands on the project site are isolated, and therefore not subject to FDER jurisdiction. However, the wetlands proposed to be impacted apparently have a hydrological connection to the Econlockhatchee River would be considered jurisdictional. Definitive determination of jurisdiction will require a site inspection by a representative from FDER.

6.3 St. Johns River Water Management District

Pursuant to Rules adopted December 7, 1983, by the St. Johns River Water Management District governing the management and storage of surface waters (40C-4), the District regulates areas deemed hydrologically sensitive. Wetlands are defined as:

hydrologically sensitive areas which are identified by being inundated or saturated by surface or ground water with a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas (Section 40C-4.021(11)).

In considering if a permit can be issued the District evaluates whether any adverse impact to off-site wetlands systems will result from the construction or operation of the stormwater management system. Specifically, will any wetlands which have a "direct hydrologic connection" as defined in 40C-4 to off-site waterbodies that are impacted by the stormwater system affect any aquatic or wetland dependent species occurring in off-site wetland systems? Section 10.7.3 of the Applicant's Handbook states"

In determining whether a system located in or discharging into a wetland will be harmful, the District's consideration of the propriety of proposed on-site aquatic and wetland-dependent species. This assessment of off-site impacts by the District will be based upon a review of pertinent literature and a general understanding of the ecological resources of the site. Specifically, the District will consider:

- (a) Impacts to the habitat of aquatic and wetland dependent species.
- (b) Declines in abundance of aquatic and wetland dependent species.
- (c) Impacts to the food sources of aquatic and wetland dependent species.

In permitting the stormwater management system for the project, any impact to the "connected wetlands" will be evaluated based on the criteria above. All of the wetlands proposed for impact would apparently fall into this category. Confirmation of the extent of any regulatory jurisdiction would require an on-site inspection by personnel of the St. Johns River Water Management District.

5.4 Orange County Conservation Areas

The conservation element of the Orange County Growth Management Policy, as amended (Ordinance 81-22, November 1982), was evaluated to determine if any parts of the project site would qualify and should be designated as conservation areas. The intent of the conservation policy is "to protect areas which are sensitive to development impacts and which provide natural processes that help maintain the County's environmental quality." In order to qualify as a potential conservation area, the land must have all of the following characteristics:

1. Soils that are defined as unsuitable, non-rated, or very low potential for development;
2. Dominance of vegetative species as listed in the ordinance; and
3. Seasonal inundation.

Once potential conservation areas are delineated, each must be evaluated further to determine if the parcel performs significant beneficial biological and/or physical functions and is viable. As directed in County Ordinance 80-5, as amended, the "significance of a potential conservation area will be assessed based on the extent, the type and magnitude of environmental function the area performs, and the degree of interconnections to other conservation areas." Further, the "viability of a potential conservation area is the ability or likelihood of the conservation area to be able to continue to perform its beneficial environmental functions."

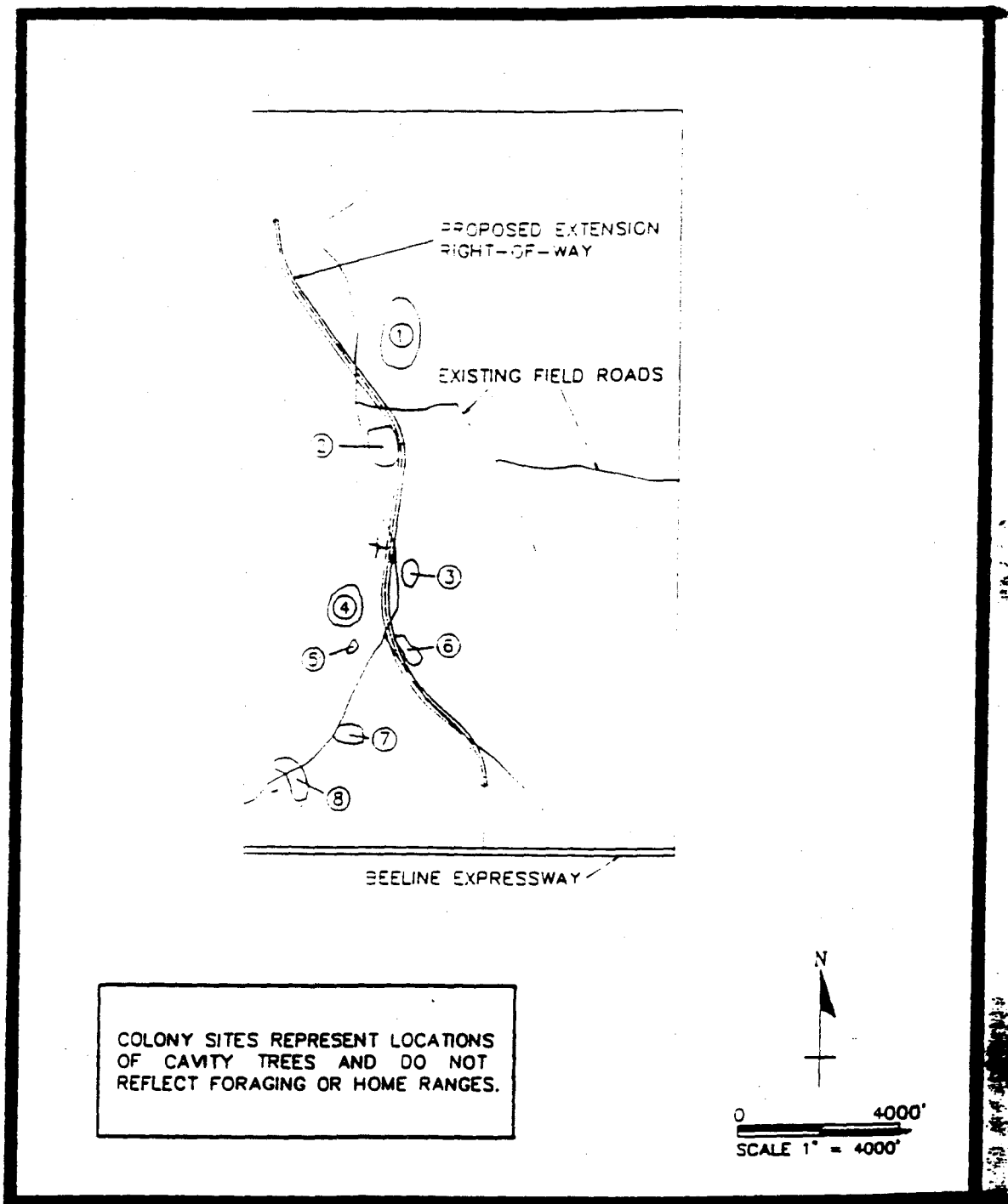
All the impacted wetlands would be under potential Orange County jurisdiction. Evaluations should be made for each of these wetlands to obtain information pertinent to a determination as to whether the wetland performs significant beneficial biological and/or physical functions and is viable. Orange County should be expected to claim these areas as Conservation Areas. Definitive determination of their status will require a site inspection by a representative from Orange County.

6.0 STATUS OF THE RED-COCKADED WOODPECKER

The proposed Alafaya Trail Extension has been designed with particular consideration to red-cockaded woodpecker colony sites that were identified during previous investigations. However, a few cavity trees and portions of the edges of existing colony sites will be impacted at several places along the alignment (Figure 2).

Dimensions of these colony sites are based on locations of cavity trees and do not represent foraging areas or home ranges of the birds within those colonies. Red-cockaded woodpecker colony site 2 contains several old cavity trees, start holes and inactive cavity trees. At least 2 cavity trees, both of which are apparently start-holes will be removed during construction of the proposed alignment. However, all of the active red-cockaded woodpecker cavity trees within colony no. 2 will be avoided by the right-of-way.

Colony site no. 6 will also be slightly impacted by the proposed right-of-way. A tree with a start-hole will be removed by the proposed alignment as well as an old, inactive cavity tree. Most of the old cavity trees within this colony have apparently been abandoned, but the woodpeckers could have constructed new cavity trees in the immediate vicinity.



BREEDLOVE, DENNIS AND ASSOCIATES, INC.
JANUARY 1986

Potential
FIGURE 2. RED-COCKADED WOODPECKER COLONY SITES NEAR THE
PROPOSED ALAFAYA TRAIL EXTENSION, ORANGE COUNTY,
FLORIDA.
evaluated

Since most of the habitat in which the proposed alignment is to traverse is upland in nature, a general loss of some foraging habitat for red-cockaded woodpeckers is to be expected. Although the relative amount of habitat lost would be minimal, any removal of trees contradicts with the management plans developed by the OUC and approved by the Florida Game and Fresh Water Fish Commission in 1981. This plan called for the preservation of all pine trees on the project site to provide foraging habitat and cavity trees for future utilization. The amount of habitat removed by the proposed alignment would not be expected to significantly decrease available foraging or nesting habitat, but the construction impacts themselves, could effect the behavior of the red-cockaded woodpecker.

Definitive information on the effects of development on red-cockaded woodpeckers are inclusive. Red-cockaded woodpeckers have survived and reproduced in Department of Transportation (DOT) right-of-ways near major highways, and have at least tolerated the nearby construction of the Curtis Stanton Energy Center. However, long term data are not available on development activities and the magnitude of their effects on red-cockaded woodpeckers.

7.0 CONCLUSIONS

7.1 Wetland Impacts

The wetlands to be impacted by the north-south extension to the Alafaya Trail (1-4 in Figure 1) are apparently connected to "waters of the State". Construction in these wetlands would therefore require dredge and fill permits from the ACOE, FDER, SJRWMD and Orange County.

7.2 Impacts to Red-Cockaded Woodpeckers

The red-cockaded woodpecker management plan, as submitted by the OUC, includes a provision that requires approval by a wildlife biologist for any deviations in the scope of the plan. Technically any harvesting of timber would constitute a deviation from that plan. Though there will be some loss of habitat due to the construction of the Alafaya Trail extension, there may be more important long term effects on the behavior of the red-cockadeds due to increased human activity.

The present red-cockaded woodpecker research project on the OUC property showed that there may have been an initial reduction in productivity following construction on the Curtis Stanton Energy Center (Roy S. Delotelle pers. comm.). This productivity has been affected by higher rates of productivity in recent years, and there may have been an "acquired" tolerance of human activity. Though these data are not

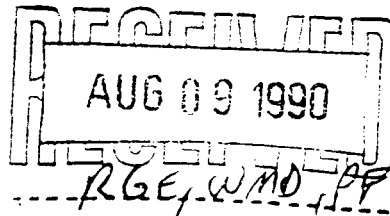
conclusive, there could be some decrease in reproductive success because of the construction and utilization of the new extension to Alafaya Trail.

The primary colony to be affected is colony 2 (Figure 2). The current alignment would remove or come very close to 2 start holes and impact potential foraging habitat of the colony. Although there could be additional cavity trees to the east of the proposed alignment, moving the alignment further to the east would appear beneficial from this cursory analysis. This would probably necessitate the impact of 2 isolated cypress domes, but this could be considered warranted given the circumstances.

Though no woodpeckers from colony 3 will apparently be displaced by the alignment, there is probably some utilization by red-cockaded in the immediate vicinity. No red-cockaded woodpeckers were seen in the cavity trees observed in colony site 3, but the presence of a relatively fresh start hole indicates some recent activity. A more thorough examination of this colony site would need to be conducted to fully understand the ramifications of the road construction.

Two active colony sites are present near the area in which the east-west tie-in to the Alafaya Trail extension would be place. A careful positioning of this alignment will be necessary in order to minimize the impact on existing colonies.

With the exception of colony site 2, there should be a minimum amount of direct impacts to the red-cockadedads based on the current alignment. A shift of the alignment further to the east in this area would probably be more suitable, though this needs to be evaluated in the field. In addition, though long-term behavioral impacts are not expected to be drastic, there could be some initial decline in reproductive success due to construction impacts.



43-90-01

ASSESSMENT OF POTENTIAL EFFECTS OF
THE ALAFAYA TRAIL EXTENSION ON
RED-COCKADED WOODPECKERS,
CURTIS H. STANTON ENERGY CENTER
ORLANDO, FLORIDA

Submitted To:

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August 7, 1990

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This report addresses the potential impacts of the proposed Alafaya Trail Extension on the existing population of red-cockaded woodpeckers. Alvarez, Lehman & Associates, Inc. was not involved in either the roadway alternative evaluation nor the particular route selection through the Stanton Energy Center. The report is intended to evaluate the potential for impacts from the proposed right-of-way.

The report was prepared on behalf of Orlando Utilities Commission under the supervision of the following team of project professionals. Please contact these individuals regarding any questions or comments you may have regarding this report.

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1.0 INTRODUCTION

1.1 Project Description

The extension of Alafaya Trail as a two-lane roadway is proposed from its current terminus at the entrance of the Orlando Utilities Commission Curtis H. Stanton Energy Center power plant to International Corporate Park (ICP). The 4.2 mile roadway would extend southerly through Sections 18 and 25 on the east side of the Stanton Energy Center, across the northeast corner of the Florida Department of Corrections (DOC) prison facility, south to the Bee Line Expressway through agricultural land, then southwest through the proposed Magnolia Ranch development to ICP. Alafaya Trail is to be constructed by ICP Associates as a condition of the Development Order (DO) that was issued by Orange County for ICP in 1986. In addition to providing traffic capacity for ICP, Alafaya Trail will serve a public need for furnishing access to the Stanton Energy Center from the south and the prison on the north.

The alignment selection process began in 1985 when four alternatives were studied. Three of the alignments involved substantial wetland impacts. The remaining alignment went through several red-cockaded woodpecker (Picoides borealis) colony sites on the Stanton Site, but it would have minimal wetland impacts. The latter alignment was selected as the preferred alternative after further modification to avoid three red-cockaded colony sites. The alignment traversed through five territories of red-cockaded. Four of these territories are on the Stanton site, and one is on the prison site. The alignment, including the two-lane Alafaya Trail extension and associated water and sewer pipelines, went

through the public review process and was approved with the ICP DO.

Permits were obtained in 1987 for the construction of the utility lines within the right-of-way that would provide water and sewer services for both DOC and ICP. The pipeline alignment follows the Alafaya Trail alignment through the Stanton Energy Center before turning southwest through the prison to ICP. The majority of the corridor was cleared on the Stanton Energy Center in 1988 to accommodate construction of the pipeline.

Final engineering of the roadway was completed in 1989 and permit applications were prepared. The Wetland Resource Permit (Dredge and Fill Permit) application is under review by the U.S. Army Corps of Engineers and the St. Johns River Water Management District. The U.S. Fish & Wildlife Service (USFWS) became involved in this permitting process and requested an additional review of the potential impacts to red-cockaded birds from the corridor associated with construction of the roadway.

1.2 Population Characteristics (Orange County)

During the spring of 1990 studies were conducted to determine the distribution and population trends of red-cockaded woodpeckers in Orange County. These studies included ground and aerial surveys and contacts with various agencies. The red-cockaded population in Orange County has declined from about 50 groups in 1980 to about 24 groups in 1990. The remaining population in 1990 apparently exist near and on the Stanton Energy Center and the Martin Marrietta/Britt Ranch site. These two areas contain

approximately 13 and 10 groups, respectively, and are about nine miles apart. Some areas in the far eastern part of the county have not been surveyed. Population decline during this 10 year period resulted from habitat destruction and isolation of individual colonies from the remainder of the population. Of the colonies near the Stanton Energy Center, six are within one mile of the proposed Alafaya Trail Extension and represent 25 percent(%) of the known active colonies in Orange County.

1.3 Population Trends on the Stanton Site

Population trends on the Stanton Site are available from 1980 through the breeding season of 1990. Over this 10 year period the number of breeding groups residing on the Stanton site has varied between nine groups in 1980-81 to six groups in 1986. From the 1986 period through 1990, the population has remained stable at seven groups. Associated with this moderate change in the number of groups is a somewhat greater variability in the number of individuals.

The number of individuals during the breeding season ranged from a high of 2.6 individuals per group to a low of 2.0 individuals. The frequency of extra adults (i.e. helper males) during the breeding season shows some consistent trends over years, apparently varying with mortality rates of breeders and the previous year reproduction output. Overall group size during the post-breeding period (June-August) ranged from a high of 4.0 birds per group in 1982 to a low of 2.4 birds per group in 1984. Group size during the summer for the last three years has averaged about 3.3 birds. Breeder survivability on territories and within the population is higher than most other populations studied with

males averaging 83% and females 78% over the ten year period. Although reproduction is less than other populations, this is apparently compensated for by high survivorship of the breeders.

2.0 METHODS

In order to evaluate the potential impacts of the proposed Alafaya Trail Extension, data collected on habitat characteristics and behavior patterns of individuals and groups were reviewed from past studies on the Stanton Energy Center. The methods described below were employed during 1986-1987 on flight and other behavior of red-cockadeds on the Stanton site. Additional data were collected during 1988, 1989 and 1990. Data used for development of territory maps was collected during 1986-1987. Additional data collected since that time were not used to update territory configuration or size.

Foraging and flight behavior of 39 birds, including 10 breeding males, 10 breeding females, 5 helper males, 3 associated females, and 11 fledglings, were studied. Data were recorded on each individual and used for comparisons between clans (groups) of similar composition. Thus, this program studied four clans consisting of a pair, two clans consisting of a pair and an auxiliary female, and three clans with a pair and male helpers. One other group consisted of a pair plus two fledglings and was studied during the nesting and post-fledgling period only. Of the groups studied, all except one contained fledglings. The sex of unbanded fledglings was determined by the presence in males or absence in females of the juvenile red crown feathers.

Flight distances were determined by flagging trees used for takeoffs and landings by red-cockaded woodpeckers. Initially, flights were timed and measured by tape and pacing. Subsequently, flight distances could be determined by pacing distances or by use of a stop watch.

Each tree used by a foraging red-cockaded woodpecker was visually divided into four equal parts: top, upper middle, lower middle, and bottom. Takeoff and landing heights were recorded for each bird based on the above criteria. If a bird could be identified, at five-minute intervals the following information was recorded: foraging heights, as determined above; foraging method, and flight takeoff and landing heights.

A literature search and contact of experts was also conducted to document any studies which could be useful in evaluating behavior and potential for highway mortality.

3.0 RESULTS

3.1 Population and Habitat Description on the Stanton Site

Population and habitat characteristics for red-cockadedads on the Stanton site are described in Table 1. Compared to habitats studied elsewhere in the red-cockadedads range (Hooper *et al.*, 1982; Porter, 1984), pine foraging habitats on the Stanton site are generally of poor quality (less dense and smaller tree size). On average, territories of red-cockadedads on the Stanton site contain about 40% of territories located in the northern part of the species range. As shown in Table 1, average basal area of pine per territory was 2,986 feet² with an average pine stem density of 10,113 per territory.

In particular, pine resources in the territories along the Alafaya Trail Extension contained a basal area of 2,163 feet² (Clan X), 4,333 feet² (Clan E), 3,778 (Clan I) and 2,464 feet² (Clan H). Territory sizes for these four groups averaged 276 acres and are similar to other on-site groups. Colony resources in terms of old trees (90 years of age or older) are abundant in all these territories except X. Overall, these territories are similar to other on-site territories.

Population parameters such as group size and reproductive rates are also shown in Table 1. Group size and reproductive rates for the groups along the Trail were not substantially different from other groups. However, Clan X lacked a breeding female in 1988 and 1989. The other three groups usually consisted of the two breeders and one helper plus the preceding years fledglings.

TABLE 1. Population and Habitat Characteristics for Eleven Groups of Red-cockaded Woodpeckers on the Curtis H. Stanton Energy Center, Orlando, Florida, 1990

Group*	Mean Reproduction All Years	Mean Reproduction Successful Years	N	Pine Basal Area (ft ²)	Total** Pine Stems	Territory Size (Acres)	† Lost From Impact	
-A	2	1.33	1.33	3	3,551	14,709	383	-
+B	2	1.00	1.00	1	3,131	13,547	363	-
+++C	3	0.80	1.33	4	2,195	8,818	251	-
+++D	3	1.00	1.00	5	2,593	8,733	261	-
C/D	3	1.00	1.33	3	2,784	7,526	236	-
++E	3	0.89	1.33	9	4,333	13,490	299	3.8
F	2	1.00	1.14	9	3,177	10,418	255	-
G	2	1.00	1.60	9	2,673	6,452	215	-
++H	3	0.88	1.17	3	2,464	6,316	169	0.6
++I	3	1.63	1.63	8	3,778	10,961	239	3.6
++X	2	0	-	1	2,163	10,237	398	4.3
	2.54	0.96	1.28	5.5	2,986	10,110	279	3.08
	±0.52	±0.39	±0.22	±3.3	±685	±2,885	±73	±1.68

N = number of years studied for reproduction.

† = percent loss of pine trees.

ft² = feet squared.

*Predominant group size during the breeding season for the 10 year study period.

**Includes all pine stems over two inches in diameter at breast height (dbh).

+Territories abandoned.

++Territories impacted by pipeline construction.

+++Territories and clans combined during 1986.

Source: Alvarez, Lehman & Associates, Inc., 1990

3.2 Impacts on Colony and Foraging Resources

Impacts from habitat removal resulted in the loss of a limited amount of foraging habitat and potential cavity tree resources. Potential cavity trees are defined as any longleaf pine (Pinus palustris) tree greater than 90 years of age. Potential cavity tree resources for these groups was previously evaluated by DeLotelle and Newman (1983). Here, we include all potential trees within an area inside a centered circle encompassing 43 acres around the nest cavity tree, which is equivalent in size to the largest colony measured on the Stanton site. The colony includes all periodically active cavity trees, abandoned cavity trees and start-hole trees plus a 200 foot buffer zone extending from the outer most cavity trees. Equivalent potential cavity tree resources for the four colonies are:

- X - 47 trees;
- E - 233 trees;
- H - 868 trees; and
- I - 254 trees.

Based on review of aerial photographs and the existing layout of the corridor, less than 4% of these trees were lost during the clearing of the corridor. The largest loss, percentage wise, occurred in colony X, but only represented 11% of available old trees.

The existing corridor travels in proximity to four colony areas. The closest cavity tree to the corridor occurs in colony X and I (225 feet and 5 feet, respectively, for both trees). In colony H, the closest cavity tree is 806 feet from the corridor. One cavity tree (#17) in colony X

was identified by Breedlove Dennis & Associates, Inc. (BDA) (undated aerial photography overlay of Alafaya Trail Extension) as occurring to the west of the main colony area. Surveys at the map location for this plotted tree revealed no cavity trees of any status. In colony E, cavity tree number eight identified on the map is an uncompleted cavity.

Loss of active, start-hole or abandoned cavity trees did not occur as a result of the clearing of the corridor. In colonies X, and H none of the colony area was impacted by the corridor clearing. The alignment through territory E does pass between one tree with an uncompleted cavity and the remainder of the cavity trees. This particular tree is leaning at an approximate angle of 30 degrees from vertical and is probably no longer used by any of the residents in clan E. No birds were known to roost in this cavity tree during the ten year study. No cavity tree removal will occur as a result of the 180 foot roadway corridor.

Approximately 41.7 acres of foraging habitat (pine forest) was lost due to corridor clearing. The greatest impact occurred in territory X (15.6 acres) and the least in Clan H (1.3 acres). The percentage of territory distributed by the corridor alignment ranged from 4.3% to 0.6% (Table 1). A review of aerial photographs for the alignment indicated that the foraging habitats lost were of medium quality or less. Approximately 1,330 pine trees were lost due to these activities. An additional 63 pine trees will be lost due to construction of surface runoff ponds.

3.3 Highways as an Impediment to Red-cockaded Movement

BDA (Epperson and Dennis, 1990) conducted a study of the

literature and of expert opinions on the probability of red-cockadededs flying across roadways. This research included a variety of literature and expert opinions. These varied literature and expert opinions document that red-cockadededs will fly across the roadways and that no significant impediment to movement should occur as a result of highway traffic or noise. Our review of these literature sources and contact with several of these experts (e.g. Mr. Bob Hooper) revealed no substantial differences in opinion from that of the BDA report.

3.4 Potential for Red-cockaded Mortality Associated with Highway Traffic

There are four behavior activities engaged in by red-cockadededs which were evaluated for the potential of automobile bird strikes. These behavior activities include:

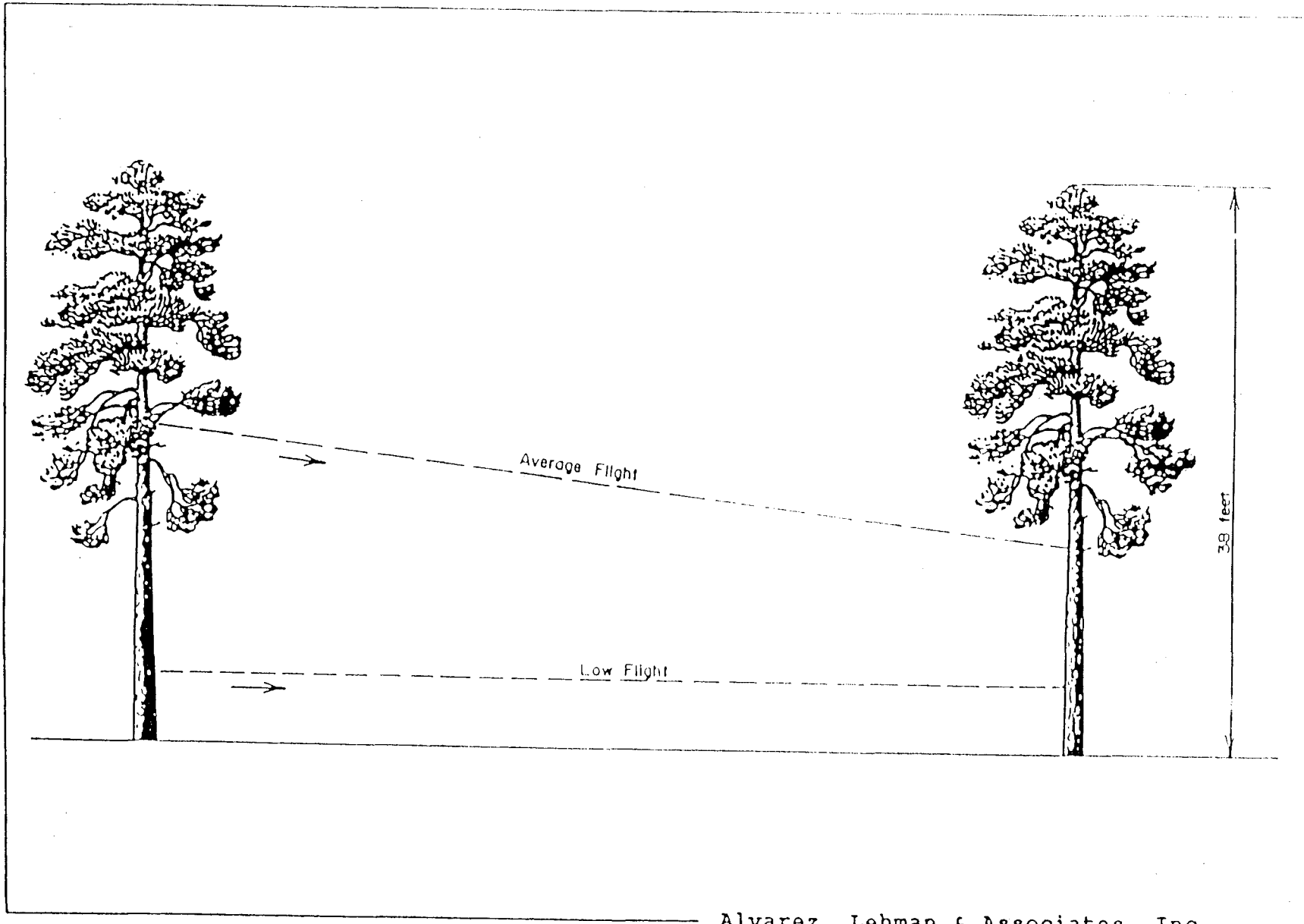
1. habitat patch searches;
2. interpatch group flights;
3. territorial defense; and
4. nestling and fledgling feeding by adults.

These are the major activities performed by red-cockadededs involving substantial flight movements which could involve crossings of the proposed Alafaya Trail. Intruder expulsion involving alien red-cockadededs from outside the territory and resident group is not discussed in the following narrative. Habitat patch searches usually consist of individual birds moving from tree to tree in search of

food. The group as a whole usually maintains a relatively continuous location in a specific area. Each bird moves from tree to tree during this process. The group may drift in certain directions during this activity. Interpatch movement involves the whole group in which all members relocate from one habitat patch to another. Territorial defense here pertains to those situations where all group members are actively involved in defending their territory from an adjacent group. For nesting, the focus is on activities during gathering of food by parents and helpers for the feeding of nestlings and fledglings. During any of these activities red-cockadedads may engage in flights across the proposed Alafaya Trail.

Because females generally forage lower on the tree than the males, the following discussion is oriented toward females. Within habitat patches, flight distance for females and males averaged 91 ± 44 feet. Landing and takeoff heights of the females averaged 21.7 and 14.9 feet respectively (Figure 1). However, of the landings and takeoffs observed ($N = 636$), 16% of the takeoffs and 48% of the landings occurred below 8.6 feet. Some of these flights from tree to tree were just above the groundcover which was about three feet in height. Thus, any flight activity during intrapatch movements could place female red-cockadedads at risk for striking larger trucks and some large automobiles. This risk factor, however, may be mitigated as discussed below.

Interpatch flights by red-cockadedads averaged 367 ± 117 feet and accounted for most of the major movements of the group. No quantitative data on relative heights during flights or landings were collected during these activities. Our general observation were that during these movements

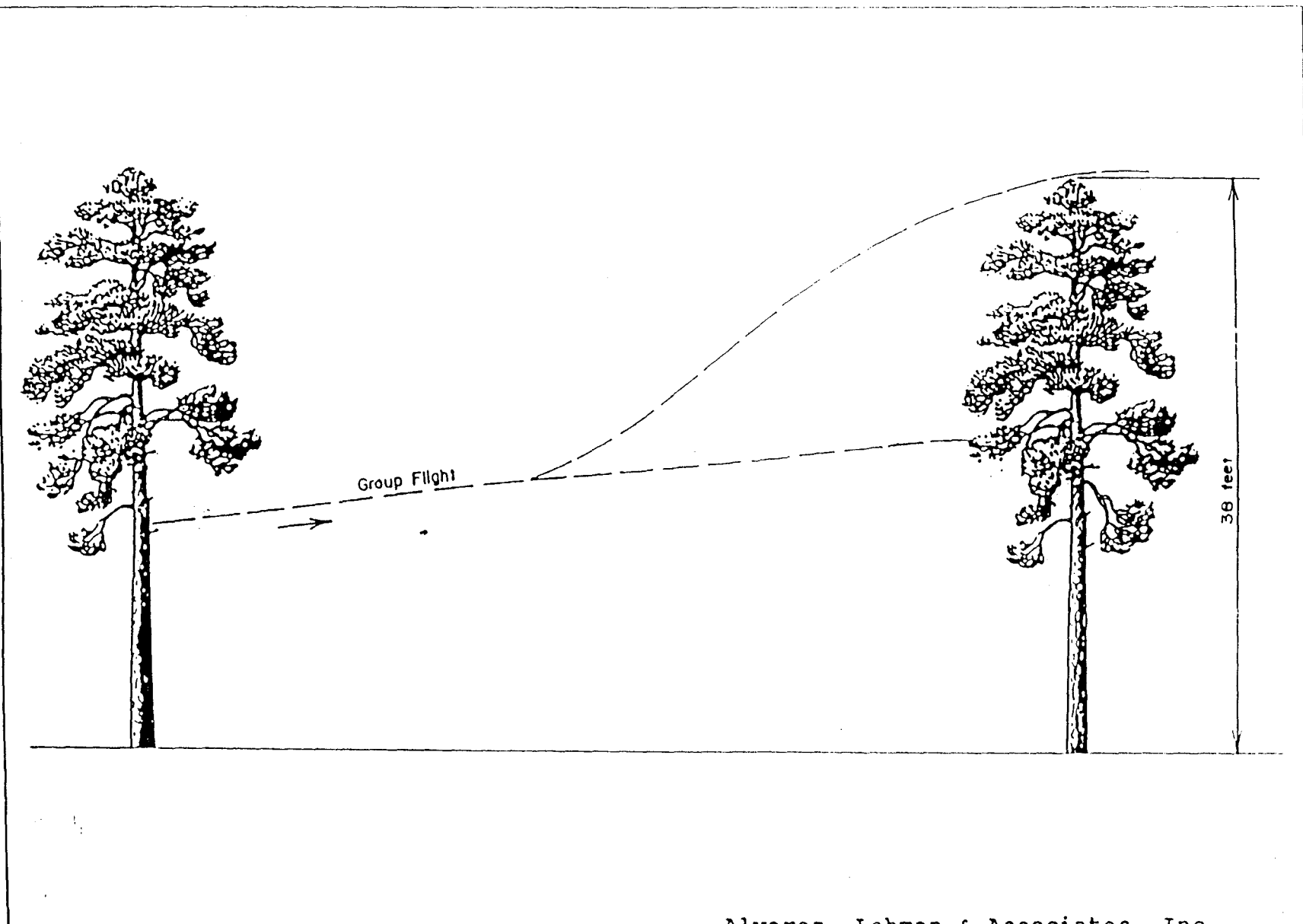


Alvarez, Lehman & Associates, Inc.

FIGURE 1. Female Flight Patterns for Intrapatch Movements on the Curtis H. Stanton Energy Center, Orlando, Florida, 1990

red-cockadedads fly from mid-tree height (20 feet) or higher and often times well above the crown of the tree (Figure 2). Observation of red-cockadedad movement patterns during this activity were consistent between groups and the sexes. In addition, we have observed group members crossing the existing railroad line (N = 9) and the observed patterns suggest that these movements are similar to interpath group movements with individuals flying at tree top level (38 feet) or higher. Since flying across the proposed corridor is more similar in distance to interpatch distance, it appears the birds will fly at mid-tree height or higher. Thus, it seems that the natural flight behavior of the bird will preclude most instances of potential bird strikes with vehicles.

Flight characteristics (i.e. flight height) during responses to intrusion by neighbors are similar to those described for interpatch movements, but averaged $1,218 \pm 587$ feet in length. During interactions individual group members fly and chase each other in and among trees from near ground level to tree top level and higher. No difference among the sexes has been noted, but it is often impossible to determine which birds are involved with each other and to separate the respective individuals. Most interactions with group neighbors occurred at similar locations and within a relative small area. Most of the corridor cuts across territory X and E (Figure 3). Between groups H and I, the roadway, however, will travel right along much of the historic territory boundary between these groups. Territorial interactions are thus likely to occur along this segment of the road between groups H and I. Most of the interaction behavior will probably occur in and among the trees on one side of the road or the other. The probability of bird strikes with



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FIGURE 2. Red-cockaded Woodpecker Group Flight Patterns for Interpatch Movements on the Curtis H. Station Engery Center, Orlando, Florida, 1990

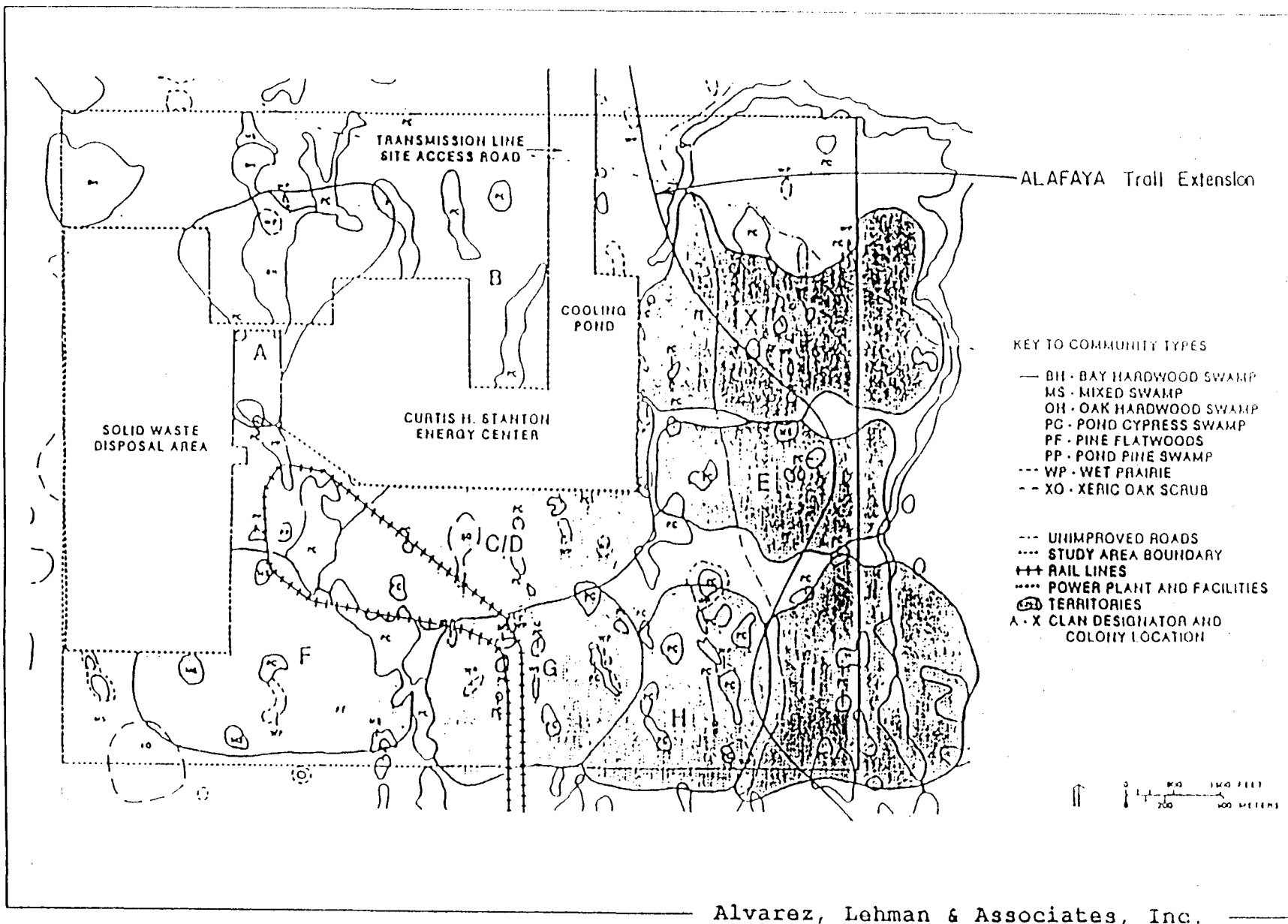


FIGURE 3. Territories of Red-cockaded Woodpeckers During 1986-1987 on the Curtis H. Stanton Energy Center, Orlando, Florida, 1990

automobiles during the behavior appears to be small. The set back from the tree line to the paved surface (28-30 feet) should allow enough area for most birds to move in without coming in contact with vehicles.

During nestling feeding some group members are likely to fly across the proposed roadway. Since the proposed roadway between clans H and I will travel along the historic territory boundary, it is unlikely that individuals from these groups will fly across the corridor during nesting activities. For clan X the proposed corridor is approximately 1200 feet from this years nest tree. Based on data collected on feeding trip distances during 1987, roughly 2% of clan X's activity during nesting will occur at this distance or greater (Alvarez, Lehman & Associates, Inc. and Environmental Science and Engineering, Inc., 1988). In clan E the corridor is 975 feet from the nest tree. Approximately 12% of the feeding activity of group members will be at this distance or greater. Flight heights during trips to and from the nest are generally at tree top height or slightly lower. Thus, it does not appear that a significant probability exists that bird vehicle strikes will occur during nesting activity because of the expected low frequencies of crossings and relative high flight patterns.

Once the nestling fledge they spend about one to two weeks in which their movement activity relative to adults is much reduced. During this period the adults continue to feed the fledglings at a rate similar to nestling feeding. The fledgling usually spends this period high in the tree perched on a large limb or the main trunk, on occasions they do perch low in the tree. The adults forage in a somewhat circular pattern around the young birds, usually within about

a 20 acre area. As the young bird matures this pattern stops and the group conducts a more typical foraging route. Most feeding to young during the first two weeks occurs within about 800 to 1000 feet of the fledgling. It is possible during this period that red-cockadedads would fly across the corridor. We have no data available which would indicate one way or the other. The probability of young birds being struck by automobiles during this period seems remote because they are usually perched high in the tree and usually fly from tree top to tree top. We assume adult flight patterns will follow those previously described.

4.0 CONCLUSIONS

Red-cockadededs are cooperative breeders which typically have high survivability of adults and low reproduction. As such, any action which negatively affects survivability may have a substantial effect on a given population. The population characteristics of red-cockadededs in the Orange County area make this population more susceptible to negative impacts than larger populations. The population is small and is primarily divided into two different areas. Because of these two characteristics, this population as well as others in a similar situation, may be more susceptible to habitat impacts and losses. The impacts imposed by the existing corridor, however, are relative minor and do not constitute a significant impact on the habitat for either foraging or cavity tree resources.

The potential for automobile bird strikes is difficult to evaluate. Expert opinion cited by BDA revealed many instances of colonies occurring near and adjacent to highways. No studies have been conducted to evaluate the mortality rates of birds occurring in colonies adjacent to roads as compared to those at a greater distance. While colonies adjacent to roads apparently continued to be active, most populations in which these observations occur, continue to decline (Costa and Escano, 1989). We do not suggest that roadways are the cause of the decline, but merely point out that without more specific observation, these opinions can not be used to justify the fact that roads have no impact on red-cockaded populations.

The discussion in Section 3.4 suggests that the potential for traffic related mortality of red-cockadededs

appears to be low. The particular behavior and movement through the various habitats usually places red-cockadedads at greater heights than most vehicles. Our general observation, that when crossing large areas or habitats red-cockadedads fly at mid-tree height or higher, suggests the probability of highway mortality is low.

No substantial effect on the resident population on the Stanton Energy Center is likely to occur as a result of habitat losses. Corridor clearing removed 41 acres of foraging habitat and less than 4% loss of potential cavity tree resources. Based on the available data in our records, loss of cavity trees or fragmentation of colony sites will not occur as a result of the roadway completion.

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- Porter, M. W. 1984. Home range and Foraging Requirements of the Red-cockaded woodpecker (Picoides borealis) in Pine Habitats of North Florida. M.S. Thesis, University of Florida, Gainesville, Florida. 58 pp.

ALA

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May 9, 1991

Mr. Don Palmer
U.S. Fish & Wildlife Service
3100 University Blvd. South
Suite 120
Jacksonville, Florida 32216

Re: Alafaya Trail Extension, Orlando Utilities Commission,
Stanton Energy Center (SEC)

Dear Mr. Palmer:

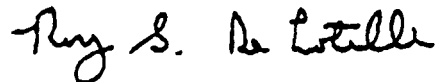
Enclosed is a copy of the figure which was faxed to your office showing the area of urban design along the Alafaya Trail Extension on the SEC site. A meeting was held on May 8, 1991 between International Corporate Park, Inc. (ICP) and the Orange County representative, Mr. George Cole. Mr. Cole agreed that an urban design would be acceptable to the County through the area designated on the figure. Speed limits through the entire length of the road on the SEC property will probably be set at 45 miles per hour.

Other mitigation ideas previously discussed and provided to the U.S. Corps of Engineers will be part of the agreement between the Corps and ICP. These items include the tree planting program, colony creation, and the monitoring activities.

If a meeting can not be arranged to discuss this alternative until June maybe we can handle these discussions on the Alafaya Trail by telephone. At any rate if you have any further questions on this matter please give me a call.

Sincerely yours,

ALVAREZ, LEHMAN & ASSOCIATES, INC.



Roy S. DeLotelle, M.S.
Project Manager

RSD/dkm/palmer5.9

Enclosure

cc: Mr. Jim Clark, ICP (no enclosure)

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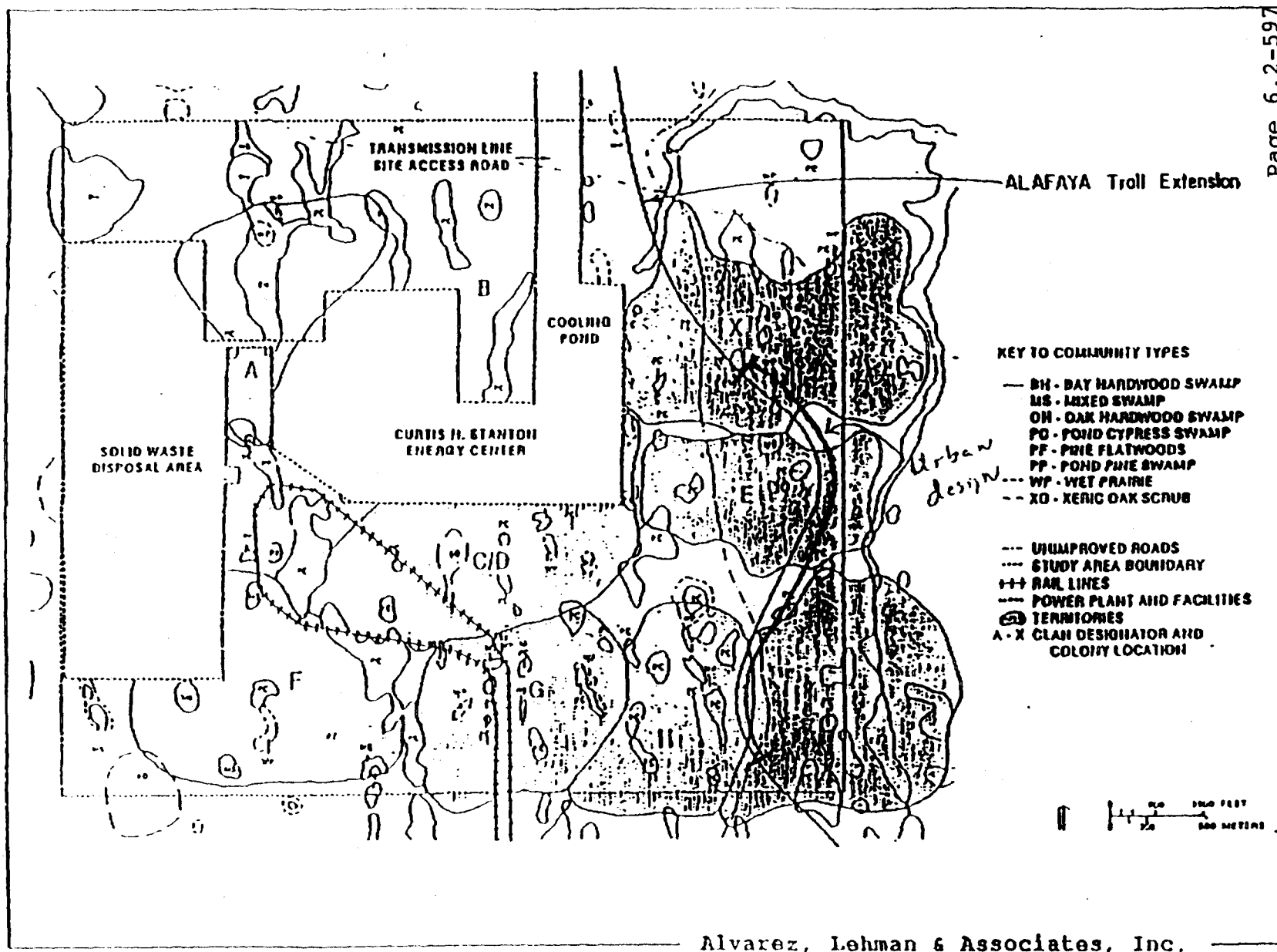


FIGURE 3. Territories of Red-cockaded Woodpeckers During 1986-1987 on the Curtis H. Stanton Energy Center, Orlando, Florida, 1990

6.3 Associated Linear Facilities

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

RFM-1

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 for Unit 2 related construction is included in Subsection 10.6.1.1. Additionally, a Joint Application for Construction Activities in Waters of the State for construction related to the extension of Alafaya Trail from its existing terminus at the Stanton Energy Center to International Corporate Park is included in Subsection 10.6.1.2.

RFM-1

10.6 State Permit Applications or Approvals

10.6.1 Joint Application for Permit: Dredge, Fill, Structures

10.6.1.1 Joint Application for Permit: Dredge, Fill, Structures For Unit 2 and Associated Facilities.

RFM-1

10.6.1.2 Joint Application for Permit: Dredge, Fill, Structures for the Alafaya Trail Extension Traversing the Stanton Energy Center Property.

RFM-1

RFM-1
021792

10.6-2

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.

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

I N T E R N A T I O N A L C O R P O R A T E P A R K &
NAME

9 3 3 L E E R D S U I T E 4 0 0
STREET

O R L A N D O F L 3 2 8 1 0
CITY STATE ZIP

TELEPHONE NUMBER (Day) (407) 629-6660 (ICP) (Night) ()

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

Ms. Kathleen S. Hale
GREINER, INC.
225 E. Robinson St., Suite 255
Orlando, FL 32801-1913

Telephone Number (407) 422-0353

3. NAME OF WATERWAY AT LOCATION OF THE ACTIVITY.

Hart Branch, Cowpen Branch & Green Branch

DER Code _____
W/X Code _____

4. LOCATION WHERE PROPOSED ACTIVITY EXISTS OR WILL OCCUR.

Bee Line Expwy-10.5 miles E. of SR 436
Street, road or other descriptive location

N/A
Incorporated city or town

Orange
County

18,19,29

30,32
Section

28°27'30"
Latitude

Tax Assessors Description: (if known)

Map No.

Subdiv. No.

Lot No.

23S
Township

32E
Range

81°08'15"
Longitude

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

See Attachment "A" - Adjoining Property Owners

6. PROPOSED USE

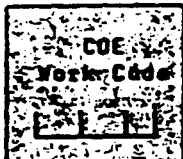
Private Single Dwelling []
Commercial []

Private Multi-dwelling []
Other [] (Explain in remarks)

Public [X]

7. DESCRIPTION OF PROJECT (Use additional sheets, if necessary)

- A. Structures: 1. New work ☒ Maintenance of existing structure ☐
 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 6'x24' arch culvert in Green Br., 2-1/2" RCP in Cowpen Br., 6'x20' arch culvert in Part Br.

- B. Excavation or Dredging: New Work ☒ Maintenance work ☐ Total acreage involved 1.37
2.67

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 Alafaya Trail Extension Length varies ft. Width varies ft. Depth varies ft.

4. Cubic yards: Total for project 13,893 ACOE
5,781 FDER
 a. 5,781 ACOE cyd. waterward/ 8,112 ACOE cyd. landward of ordinary/mean high water
1,795 (demucking) 9,417 (demucking)
 b. Type of material to be excavated/dredged sand with silt and clayey sand

C. Fill:

1. Amount of material
8,712 FDER
18,997 ACOE
 a. Cubic yards placed waterward of ordinary/mean high water 1,795 (Backfilling)
8,711 FDER
 b. Cubic yards placed landward of ordinary/mean high water 106,957 ACOE
9,417 (Backfilling)
 c. Total acreage to be filled 2.43 FDER Total acreage of wetlands involved 2.43 FDER
16.16 ACOE 17.26 ACOE
 2. Containment for fill
 a. Dikes ☐ b. Seawall, etc. ☐ c. Other (please explain) On site
Uplands with vegetated slopes
 3. Type of fill material to be used clean sand
 4. Source of fill material to be used offsite uplands

FE
AC

DER
Code
253
403

8. Date activity is proposed to commence March 1990 ; to be completed July 1991.

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

A. Denied (date) _____

B. Issued (date) _____

C. Other (please explain) SJRWMD MSSW Permit Application to be submitted I/9/90

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 Attachment "B" - Environmental Report

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)

☒ 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)

See Attachment "C"

James G. Clark
Signature

Sworn and subscribed before me at STATE OF FLORIDA, ORANGE County,
this 9th day of JANUARY, 1990

Patricia A. Baker

Notary Public, State of Florida at Large
My Commission Expires September 17, 1990
Bonded thru Huckleberry & Associates

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 all of the required state, federal or local permits before 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.


Signature of Applicant

1-9-90
Date

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 NOT a Joint Permit!

You Must Obtain All Required Local, State, and Federal

Authorizations or Permits Before Commencing Work!!

For your information: 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.

ATTACHMENT "A"

ADJOINING PROPERTY OWNERS

D.O.C.

State of Florida
Dept. of Corrections
1311 Winewood Blvd.
Tallahassee, FL 32399-2500

Mr. Ned Terry 904/487-1330
Mr. Ralph Kenyon

O.U.C.

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

Mr. Wendell Dixon 407/423-9100

Deseret Ranches of Florida

Star Route
Box 1250
Melbourne, FL 32904

Mr. John King 407/892-5646

ATTACHMENT "B"
ENVIRONMENTAL REPORT

1. BACKGROUND

International Corporate Park (ICP) plans to extend Alafaya Trail from its present terminus near S.R. 50 to a point one-half mile south of the Bee Line Expressway. This work will consist of constructing 4.2 miles of two-lane rural roadway improvements for Alafaya Trail and a new bridge structure over the Bee Line Expressway.

Construction start date is based on the Development Order approved by Orange County. At the conclusion of this construction, these improvements will be turned over to Orange County in compliance with ICP's Development Order. Entities which will be served by this roadway extension include the Orlando Utilities Commission Curtis H. Stanton Power Plant, the Florida Department of Corrections prison facility and International Corporate Park, a 3,000-acre proposed business/industrial park.

2. PROJECT STATUS

Alafaya Trail is currently under final design with construction anticipated to begin in early 1990. Initially, only two lanes of Alafaya Trail will be built at first although at a later date, additional lanes will be added to form a divided four-lane roadway. The future Alafaya Trail/Bee Line Expressway interchange is expected to be constructed in the mid-1990s.

The proposed Alafaya Trail alignment was set after an exhaustive study to minimize environmental impacts to wetlands and protected wildlife such as the red-cockaded woodpecker. On May 1, 1989, a Public Hearing concerning this project was held before the Orange County Board of County Commissioners to brief interested parties on the project and to

gain the County's initial concurrence of the alignment and typical section before proceeding with the design work. The Commissioners voted to approve this alignment.

3. Previous permit activities within this project limit involved installation of two 24-inch diameter pipelines consisting of a water main and a force main. Permitting included State of Florida Department of Environmental Regulation Permit Number CS48-138524 covering the construction of the sewage collection/transmission system and a Nationwide Permit from the U.S. Army Corps of Engineers (87NW780363) for construction of the water main and wastewater force main. St. Johns River Water Management District did not require a permit for construction of these pipelines. A 90-foot right-of-way has been previously cleared for approximately two miles starting at the north end of the project.
4. As part of this project, approximately 2.43 acres of FDER jurisdictional wetlands, 20.29 acres of St. Johns River Water Management District jurisdictional wetlands and 17.26 acres of U.S. Army Corps of Engineers jurisdictional wetlands will be affected.
5. This project will require the following quantities of dredge and fill:

	<u>ACOE</u>	<u>FDER</u>	
Landward dredge	8,112 CY	0	CY
Waterward dredge	5,781 CY	5,781	CY
Landward fill	106,957 CY	8,711	CY
Waterward fill	18,997 CY	8,712	CY

5. Fill source(s) will be clean, compactible soil material from an upland source.

6. All necessary turbidity and erosion control measures will be implemented during construction to minimize water quality degradation on adjacent wetlands. Visual monitoring for potential turbidity problems will be conducted throughout the construction activities.
7. During construction, all bare ground will be seeded, sodded and/or otherwise appropriately treated to prevent runoff of suspended solids into adjacent water bodies.
8. Attached is Table 1 listing each wetland by agency jurisdiction with the amount of wetland encroachment (by acreage) and the wetland vegetation community affected by the Alafaya Trail Extension.

Table 1

ALAFAYA TRAIL JURISDICTIONAL WETLANDS

Wetland Number ^a	FLUCFCS Category ^b	Project Impact Acreage	Agency Jurisdiction ^c
3	621	0.23	ACOE, SJRWMD
4	621	0.07	ACOE, SJRWMD
5	643	0.05	ACOE, SJRWMD
5A	621	0.32	SJRWMD
7B	621	0.06	ACOE, SJRWMD
10	630	0.41	ACOE, SJRWMD FDER
10	630	0.13	SJRWMD, FDER
11	621	0.09	ACOE, SJRWMD
11	621	0.71	SJRWMD
12	621	0.55	ACOE, SJRWMD
12	643	0.41	SJRWMD
13	621	0.56	ACOE, SJRWMD FDER
13	621	0.32	SJRWMD
14	621	0.50	ACOE, SJRWMD FDER
15	621	0.58	ACOE, SJRWMD
15	643	0.20	ACOE, SJRWMD
16	621	0.87	ACOE, SJRWMD
17	643	0.35	ACOE, SJRWMD
20	621	0.21	ACOE, SJRWMD
21	621	0.03	ACOE, SJRWMD
23B	643	0.16	ACOE, SJRWMD
24	621	1.14	ACOE, SJRWMD
25	621	0.83	ACOE, SJRWMD FDER
26	510	0.17	ACOE
26A	643	0.06	ACOE
27	510	0.03	ACOE
29	643	0.25	ACOE
31	510	0.04	ACOE
32	510	0.09	ACOE
41A	643	0.13	ACOE
41B	643	0.26	SJRWMD
42	643	0.08	ACOE, SJRWMD
43	643	1.38	ACOE, SJRWMD
43		0.67	SJRWMD, FDER
44	643	0.97	ACOE, SJRWMD
45	643	0.27	ACOE, SJRWMD
46	643	0.15	ACOE, SJRWMD
47	643	2.58	ACOE, SJRWMD

Wetland Number ^a	FLUCFCS Category ^b	Project Impact Acreage	Agency Jurisdiction ^c
48	643	0.60	ACOE, SJRWMD
48	643	0.16	SJRWMD
49	643	0.41	ACOE, SJRWMD
50	643	0.40	ACOE, SJRWMD
51	643	0.35	ACOE, SJRWMD
52	643	1.34	ACOE, SJRWMD
52	643	0.23	SJRWMD
53	643	0.97	ACOE, SJRWMD
54	643	0.37	SJRWMD
55	643	0.11	SJRWMD

TOTAL IMPACT (AC):

	510	621	630	643	TOTAL
ACOE	0.38	5.72	0.41	10.75	17.26
SJRWMD	--	7.07	0.54	12.68	20.29
FDER	--	1.89	0.54	--	2.43

^aSee Permit Drawings (Sheet 2 of 15) for location of Wetlands

^b510 - Drainage Ditch
621 - Cypress
630 - Mixed wetland forest
643 - Wet prairie

^cACOE - Army Corps of Engineers
SJRWMD - St. Johns River Water Management District
FDER - Florida Department of Environmental Regulation

ATTACHMENT "C"

LEGAL DESCRIPTIONS

Legal Description: Interchange North of Bee Line

Commence at the Southwest corner of Section 29, Township 23 South, Range 32 East, Orange County, Florida; thence run N.00°04'38"W. along the West line of the Southwest 1/4 of said Section 29 a distance of 64.19 feet to a point on the North right of way line of the Bee Line Expressway (S.R. 528); thence leaving said West line run N.78°29'51"E. along aforementioned North right of way line a distance of 333.58 feet for a POINT OF BEGINNING; said point also being on a curve concave Northwesterly having a radius of 864.93 feet and a central angle of 13°31'01"; thence leaving said Northerly right of way from a tangent bearing of N.58°57'30"E. run Northeasterly along the arc of said curve a distance of 204.05 feet to the point of tangency; thence run N.45°26'30"E. 564.35 feet to the point of curvature of a curve concave Southeasterly having a radius of 640.00 feet and a central angle of 26°02'37"; thence run Easterly along the arc of said curve 290.91 feet to the point of tangency; thence run N.71°29'07"E. 395.54 feet to the point of curvature of a curve concave Northwesterly having a radius of 460.00 feet and a central angle of 67°13'46"; thence run Northerly along the arc of said curve a distance of 539.75 feet to the point of tangency; thence run N.04°15'21"E. 460.03 feet; thence run N.00°26'30"E. 100.00 feet; thence run S.89°33'30"E. 47.20 feet; thence run N.00°26'30"E. 49.94 feet to the point of curvature of a curve concave Southwesterly having a radius of 2,201.83 feet and a central angle of 26°55'05"; thence run, Northwesterly along the arc of said curve a distance of 1,034.44 feet; thence leaving said curve run S.61°10'52"W. 1,454.96 feet to the point of curvature of a curve concave Southeasterly having a radius of 910.00 feet and a central angle of 20°36'38"; thence run Southwesterly along the arc of said curve a distance of 327.35 feet to the point of tangency; thence run S.40°34'14"W. 230.78 feet to a point on the aforementioned West line of the Southwest 1/4 of Section 29; thence run N.00°04'38"W. along said West line of the Southwest 1/4 of Section 29 a distance of 276.32 feet; thence leaving said West line run N.40°34'14"E. 21.12 feet to the point of curvature of a curve concave Southeasterly having a radius of 1,090.00 feet and a central angle of 20°36'38"; thence run Northeasterly along the arc of said curve a distance of 392.09 feet to the point of tangency; thence run N.61°10'52"E. 1,454.96 feet to a point on a curve concave Southwesterly having a radius of 2,201.83 feet and a central angle of 26°55'05"; thence from a chord bearing of N.44°37'14"W. run Northwesterly along the arc of said curve a distance of 1,034.44 feet to the point of tangency; thence run N.58°04'47"W. 1,017.85 feet to a point on the West line of the Northwest 1/4 of the aforementioned Section 29; thence run N.00°15'55"E. along said West line of the Northwest 1/4 of Section 29 a distance of 211.46 feet; thence leaving said West line run S.58°04'47"E. 1,128.83 feet to the point of curvature of a curve concave Southwesterly having a radius of 2,381.83 feet and a central angle of 58°31'17"; thence run Southeasterly along the arc of said curve a distance of 2,432.78 feet to the point of tangency; thence run S.89°33'30"E. 50.49 feet; thence run S.01°50'56"E. 541.33 feet to the point of curvature of a curve concave Northeasterly having a radius of 460.00 feet and a central angle of 42°42'34"; thence run Southeasterly along the arc of said curve a distance of 342.89 feet to the point of tangency; thence run S.44°53'34"E. 1,216.48 feet to the point of curvature of a curve concave Northeasterly having a radius of 626.20 feet and a central angle of 45°00'00"; thence run Southeasterly along the arc of said curve a distance of 491.81 feet to the point of tangency; thence run S.89°33'30"E. 909.80 feet to a point on the South line of the aforementioned Section 29; thence run S.89°35'34"W. along the South line of said Section 29 a distance of 2,436.71 feet to a point on the North right of way line of the Bee Line Expressway (S.R. 528); thence leaving said South line of Section 29 run the following courses and distances along said North right of way line: N.78°00'30"W. 1,151.69 feet; thence run S.78°29'51"W. 617.85 feet to the POINT OF BEGINNING.

Containing 71.189 acres, more or less.

LEGAL DESCRIPTION SECTION 32

Begin at the Southwest corner of Section 32, Township 23 South, Range 32 East, Orange County, Florida; thence run N.00°00'48"W. along the West line of the Southwest 1/4 of said Section 32 a distance of 30.00 feet to a point on a curve concave Northwesterly having a radius of 1,875.81 feet and a central angle of 89°21'32"; thence leaving said West line from a tangent bearing of N.89°48'02"E. run Northeasterly along the arc of said curve a distance of 2,925.53 feet to the point of tangency; thence run N.00°26'30"E. 382.18 feet to a point of curvature of a curve concave Southwesterly having a radius of 25.00 feet and a central angle of 90°00'00"; thence run Northwesterly along the arc of said curve a distance of 39.27 feet to the point of tangency; thence run N.89°33'30"W. 116.12 feet to the point of curvature of a curve concave Northeasterly having a radius of 2,339.83 feet and a central angle of 24°42'48"; thence run Northwesterly along the arc of said curve a distance of 1,009.23 feet to the point of tangency; thence run N.64°50'42"W. 815.73 feet to the point of curvature of a curve concave Southwesterly having a radius of 1,225.24 feet and a central angle of 00°52'29"; thence run Northwesterly along the arc of said curve a distance of 18.71 feet to a point on said curve said point also being on the West line of the Southwest 1/4 of said Section 32; thence leaving said curve run N.00°00'48"W. along the West line of the Southwest 1/4 of said Section 32 a distance of 53.07 feet to the West 1/4 corner of said Section 32; thence run N.00°09'42"E. along the West line of the Northwest 1/4 of said Section 32 a distance of 79.47 feet to a point on a curve concave Southwesterly having a radius of 1,347.24 feet and a central angle of 09°27'16"; thence leaving said West line from a tangent bearing of S.68°01'48"E. run Southeasterly along the arc of said curve 222.31 feet to the point of reverse curvature of a curve concave Northeasterly having a radius of 3,000.00 feet and a central angle of 06°16'10"; thence run Southeasterly along the arc of said curve 328.27 feet to the point of tangency; thence run S.64°50'42"E. 230.96 feet to the point of curvature of a curve concave Northeasterly having a radius of 2,243.83 feet and a central angle of 24°42'48"; thence run Southeasterly along the arc of said curve a distance of 967.82 feet to the point of tangency; thence run S.89°33'30"E. 216.07 feet to the point of curvature of a curve concave Northwesterly having a radius of 25.00 feet and a central angle of 90°00'00"; thence run Northeasterly along the arc of said curve a distance of 39.27 feet to the point of tangency; thence run N.00°26'30"E. 689.99 feet; thence run N.89°33'30"W. 47.07 feet; thence run N.00°26'30"E. 100.00 feet; thence run N.01°50'56"W. 626.90 feet to the point of curvature of a curve concave Southwesterly having a radius of 460.00 feet and a central angle of 68°45'11"; thence run

Northwesterly along the arc of said curve a distance of 551.9 feet to the point of tangency; thence run N.70°36'07"W. 400.84 feet to the point of curvature of a curve concave Northeasterly having a radius of 640.00 feet and a central angle of 26°02'37"; thence run Northwesterly along the arc of said curve a distance of 290.91 feet to the point of tangency; thence run N.44°33'30"W. 353.36 feet to the point of curvature of a curve concave Southwesterly having a radius of 1,342.40 feet and a central angle of 25°23'15"; thence run Northwesterly along the arc of said curve a distance of 594.81 feet to a point on said curve and on the South right of way line of the Bee Line Expressway (S.R. 528); thence leaving said curve run the following courses and distance along said South right of way line; thence run S.77°36'51"E. 811.60 feet; thence run N.78°29'51"E. 1,328.77 feet; thence run S.89°33'30"E. 5,430.32 feet; thence leaving said right of way line run S.89°17'45"W. 1,718.43 feet to the point of curvature of a curve concave Southeasterly having a radius of 5,639.58 feet and a central angle of 03°06'15"; thence run Southwesterly along the arc of said curve a distance of 305.55 feet to the point of reverse curvature of a curve concave Northwesterly having a radius of 11,549.16 feet and a central angle of 04°15'00"; thence run Southwesterly along the arc of said curve a distance of 856.68 feet to the point of tangency; thence run N.89°33'30"W. 1,265.00 feet to the point of curvature of a curve concave Southeasterly having a radius of 460.00 feet and a central angle of 45°00'00"; thence run Southwesterly along the arc of said curve a distance of 361.28 feet to the point of tangency; thence run S.45°26'30"W. 1,285.30 feet to the point of curvature of a curve concave Southeasterly having a radius of 460.00 feet and a central angle of 41°11'09"; thence run Southwesterly along the arc of said curve a distance of 330.66 feet to the point of tangency; thence run S.04°15'21"W. 460.03 feet; thence run S.00°26'30"W. 100.00 feet; thence run N.89°33'30"W. 47.20 feet; thence run S.00°26'30"W. 1,384.63 feet to the point of curvature of a curve concave Northwesterly having a radius of 2,055.81 feet and a central angle of 89°20'10"; thence run Southwesterly along the arc of said curve a distance of 3,205.44 feet to a point on said curve, said point also being on the West line of the Northwest 1/4 of Section 5, Township 24 South, Range 32 East Orange County, Florida; thence run N.00°32'51"W. along said West line a distance of 150.00 feet to the POINT OF BEGINNING;

Together with

Begin at the Northwest corner of Section 33, Township 23 South, Range 32 East, Orange County, Florida; thence run S.89°03'58"E. along the North line of the Northwest 1/4 of said Section 33 a distance of 1,405.12 feet; thence leaving said North line run S.00°26'30"W. 80.35 feet to the North right of way line of the Bee Line Expressway (S.R. 528); thence run the following courses and distances along said North right of way line; thence run N.89°33'30"W. 4,480.51 feet; thence run N.00°26'30"E. 9.33 feet; thence run N.78°00'30"W. 175.03 feet to a point on the North line of Section 32, Township 23 South, Range 32 East, Orange County, Florida; thence run N.89°35'38"E. along said North line a distance of 3,247.19 feet to the POINT OF BEGINNING.

Containing 87.405 acres, more or less.

LEGAL DESCRIPTION SECTION 30

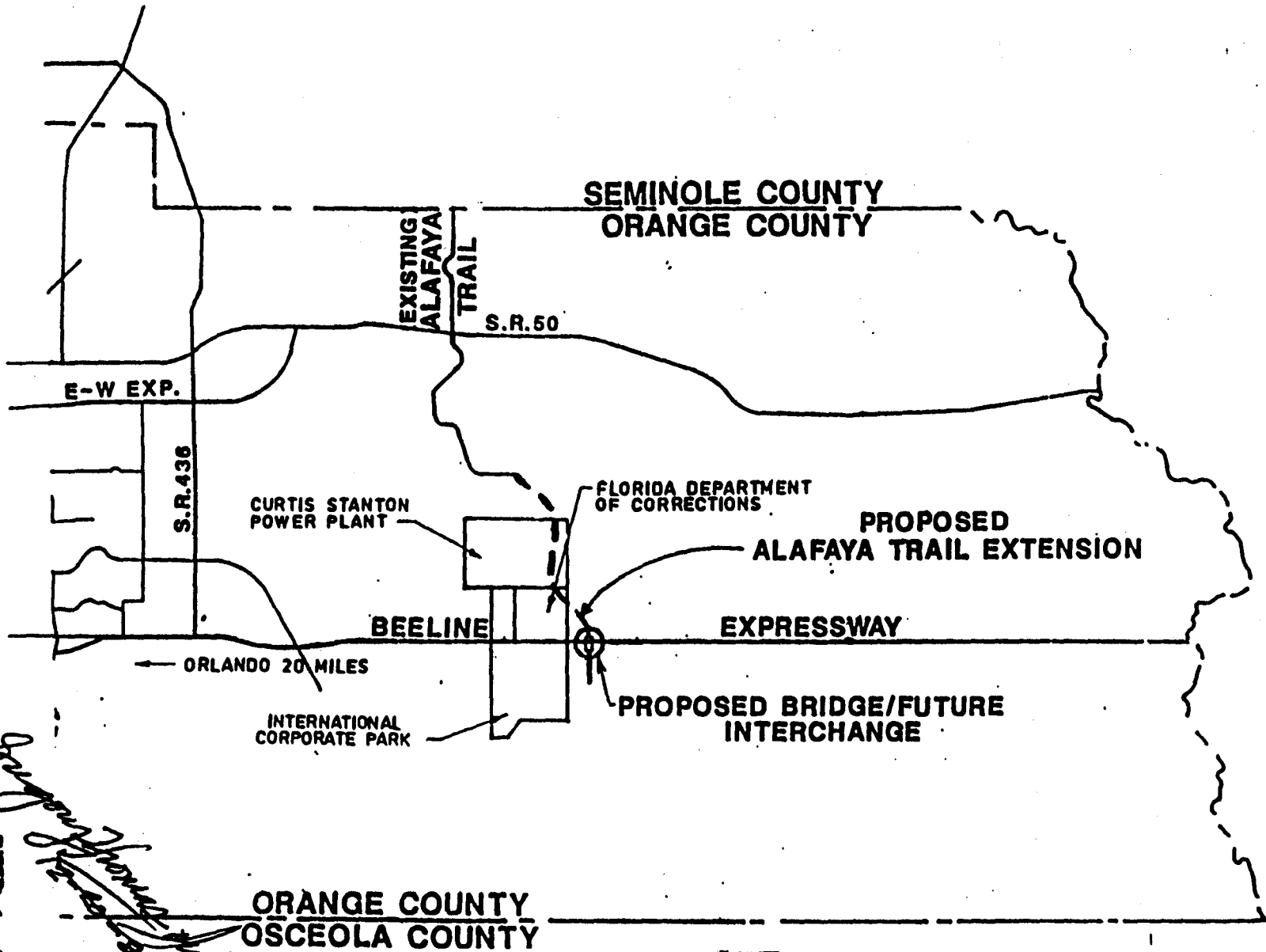
Right of Way description (180 foot wide) Alafaya Trail Extension situate in the Northeast 1/4 of Section 30, Township 23 South, Range 32 East, Orange County, Florida; being more particularly bounded and described as follows:

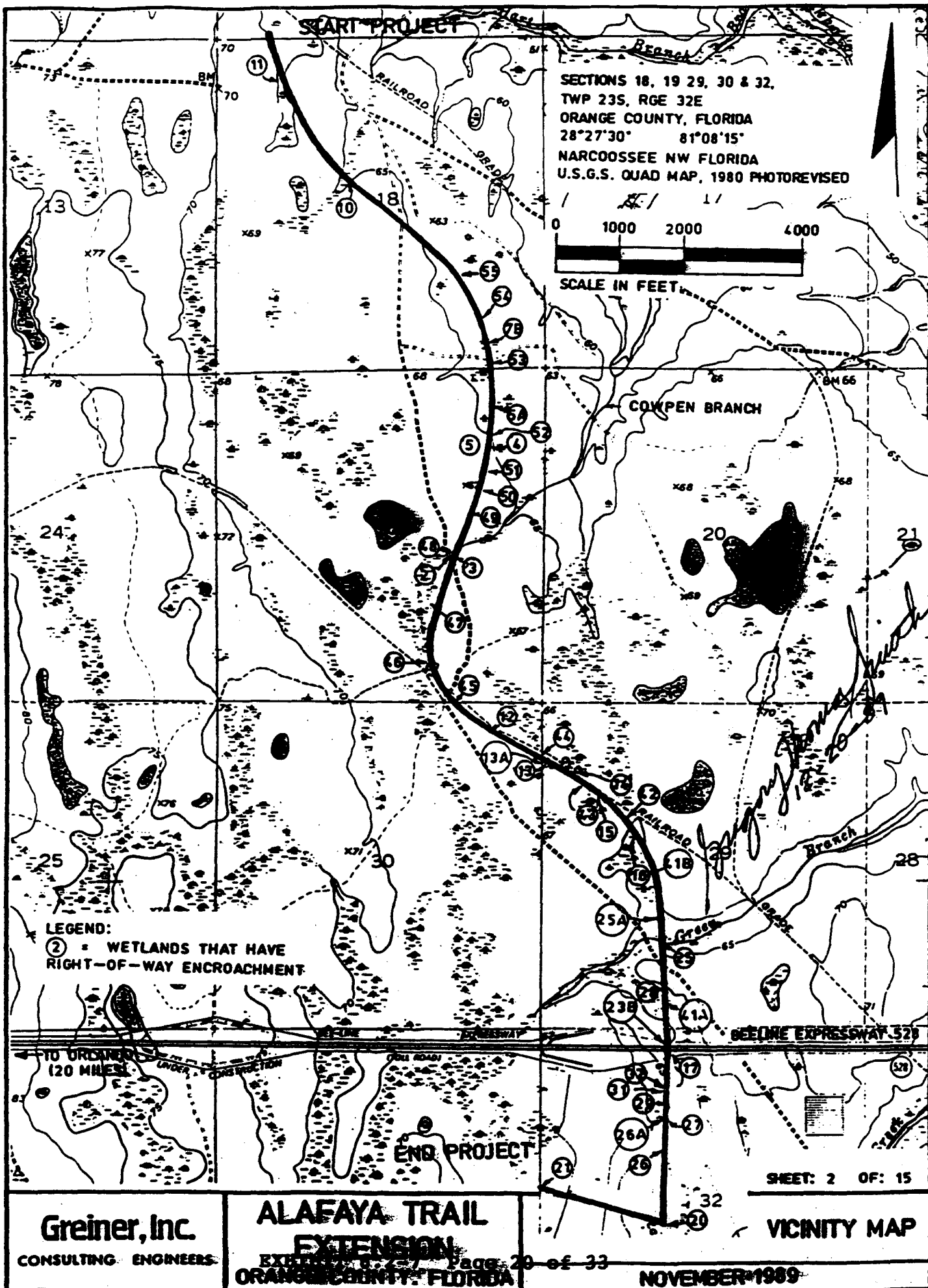
Commence at the Northeast corner of Section 30, Township 23 South, Range 32 East, Orange County, Florida; thence run S.00 15'55"W. along the East line of the Northeast 1/4 of said Section 30 a distance of 742.18 feet for a POINT OF BEGINNING; thence continue S.00 15'55"W. along said East line a distance of 211.46 feet; thence leaving said line run N.58 04'47"W. 1,027.60 feet to the point of curvature of a curve concave Northeasterly having a radius of 2,173.48 feet and a central angle of 16 39'34"; thence run Northwesterly along the arc of said curve 631.97 feet to a point on the North line of the Northeast 1/4 of said Section 30; thence leaving said curve run N.89 51'23"E. along said North line of Section 30 a distance of 248.49 feet to a point on a curve concave Northeasterly having a radius of 1,993.48 feet and a central angle of 11 56'34"; thence from a tangent bearing of S.46 08'13"E. run Southeasterly along the arc of said curve 415.52 feet to the point of tangency; thence run S.58 04'47"E. 916.63 feet to the POINT OF BEGINNING.

LEGAL DESCRIPTION SECTIONS 18 & 19

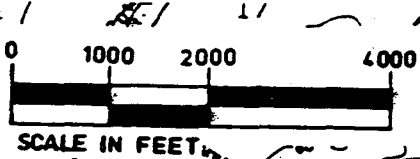
Centerline description of a portion of Alafuya Trail extension situate in Section 18 and 19, Township 23 South, Range 32 East, Orange County, Florida; the right of way of said road lying 90 feet right and 90 feet left of the following described centerline said centerline being more particularly described as follows:

Commence at the Northwest corner of Section 18, Township 23 South, Range 32 East, Orange County, Florida; thence run N.89°51'54"E. along the North line of the Northwest 1/4 of Section 18, Township 23 South, Range 32 East, Orange County, Florida, a distance of 924.99 feet to the POINT OF BEGINNING of the centerline of this description; thence along said centerline run S.00°02'52"W. a distance of 10.31 feet to the point of curvature of a curve concave Northeasterly having a radius of 1,762.95 feet and a central angle of 42°43'57"; thence run Southeasterly along the arc of said curve 1,314.85 feet to the point of tangency; thence run S.42°41'05"E. 3,365.36 feet to the point of curvature of a curve concave Southwesterly having a radius of 3,274.05 feet and a central angle of 32°12'44"; thence run Southeasterly along the arc of said curve 1,840.71 feet to a point on the South line of the Southeast 1/4 of Section 18, Township 23 South, Range 32 East, said point also being S.89°48'48"W. a distance of 849.02 feet from the Southeast corner of said Section 18; thence continue along the arc of said curve through a central angle of 37°09'56"; a distance of 2,123.74 feet to the point of tangency; thence run S.26°41'35"W. 979.10 feet to the point of curvature of a curve concave Easterly having a central angle of 70°19'25"; thence run Southerly along the arc of said curve having a radius of 2,083.48 feet, a distance of 2,557.23 feet to the South line of the Southeast 1/4 of said Section 19 and the POINT OF TERMINATION of said centerline; said point being S.89°51'23"W. a distance of 1,235.45 feet from the Southeast corner of Section 19, Township 23 South, Range 32 East; the side lines of said right of way to terminate on the North line of said Section 18 and on the South line of Section 19.





SECTIONS 18, 19 29, 30 & 32,
TWP 23S, RGE 32E
ORANGE COUNTY, FLORIDA
28°27'30" 81°08'15"
NARCOOSSEE NW FLORIDA
U.S.G.S. QUAD MAP, 1980 PHOTOREVISED



LEGEND:
② = WETLANDS THAT HAVE
RIGHT-OF-WAY ENCROACHMENT

TO ORANGE
(20 MILES)

END PROJECT

DELINE EXPRESSWAY 528

SHEET: 2 OF: 15

Greiner, Inc.

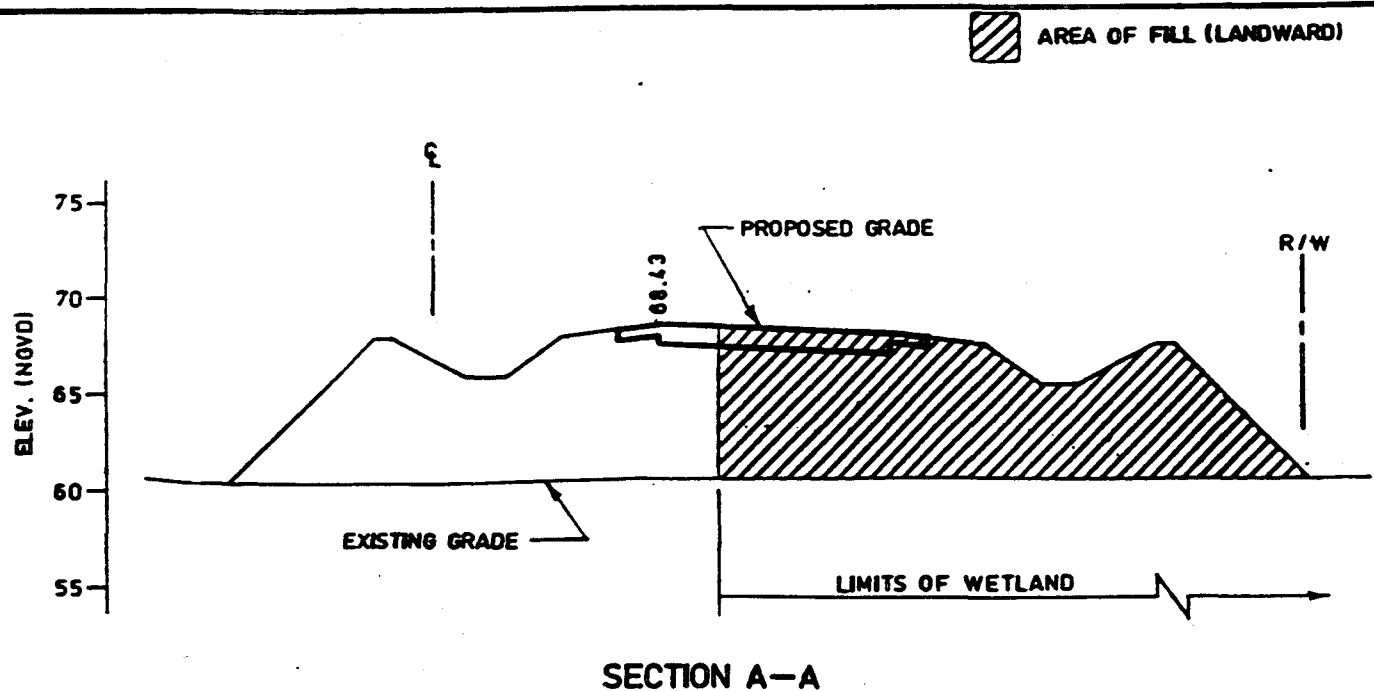
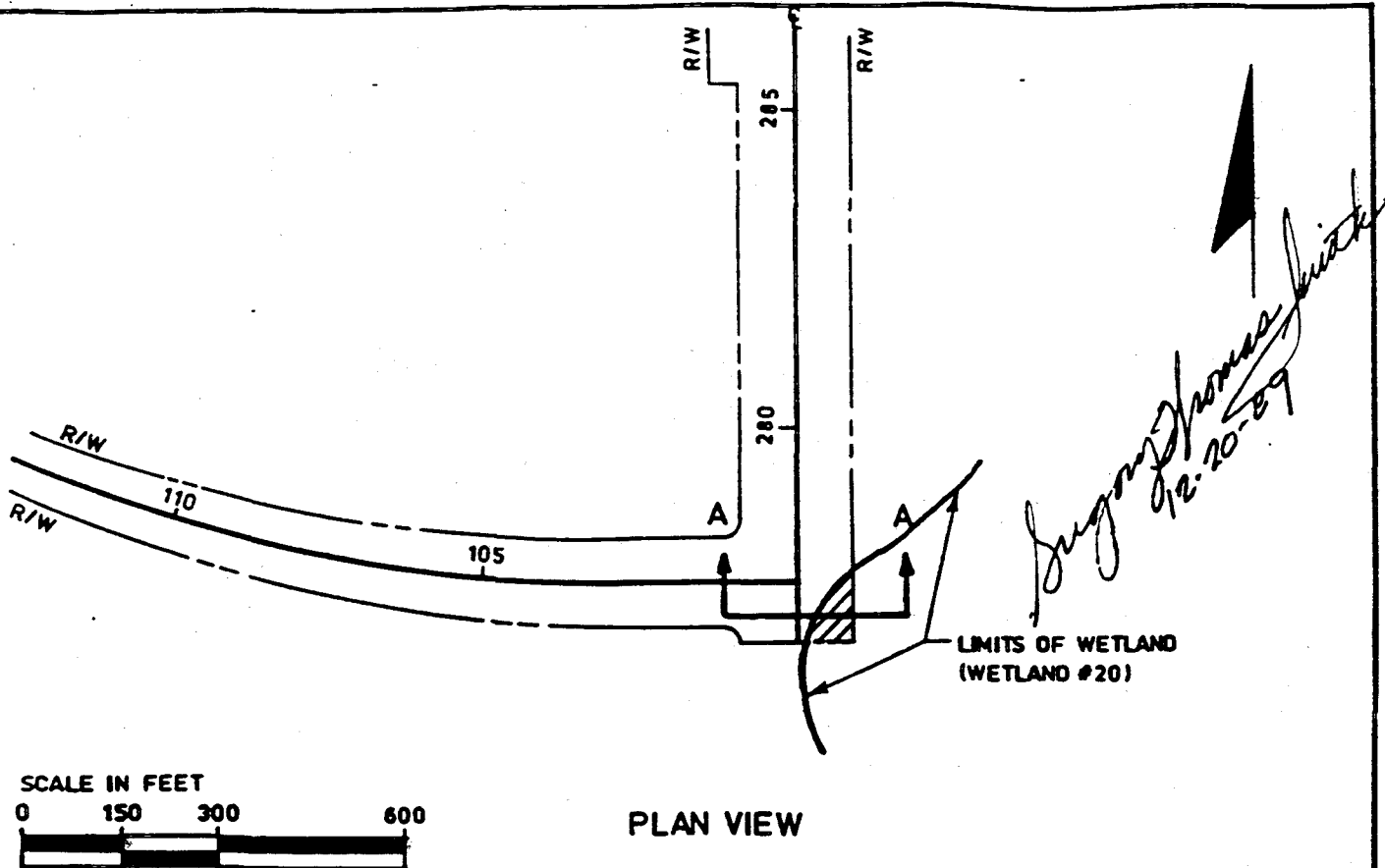
CONSULTING ENGINEERS

ALAFAYA TRAIL
EXTENSION

EXTENSION 8.257 Page 20 of 33
ORANGE COUNTY, FLORIDA

VICINITY MAP

NOVEMBER 1989



SHEET: 3 OF: 15

Greiner, Inc.

CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**

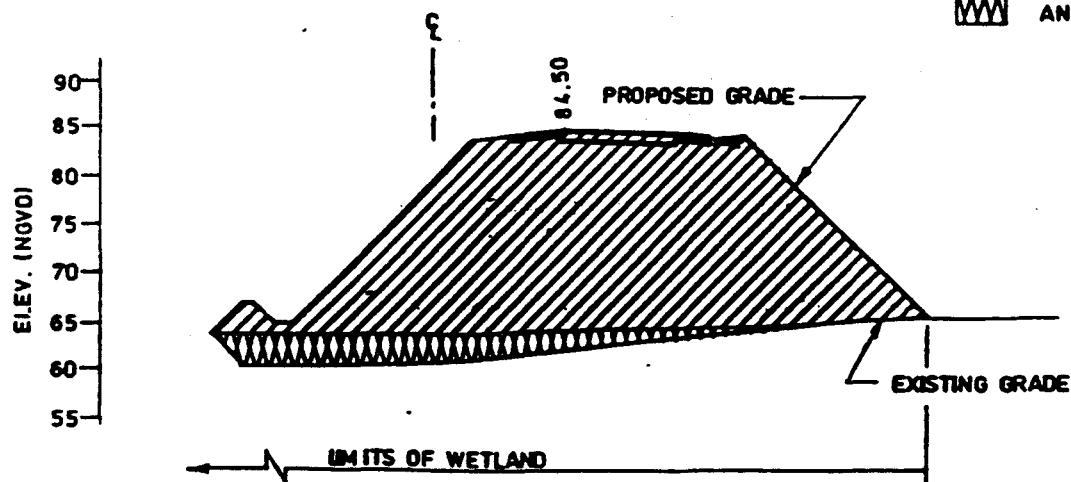
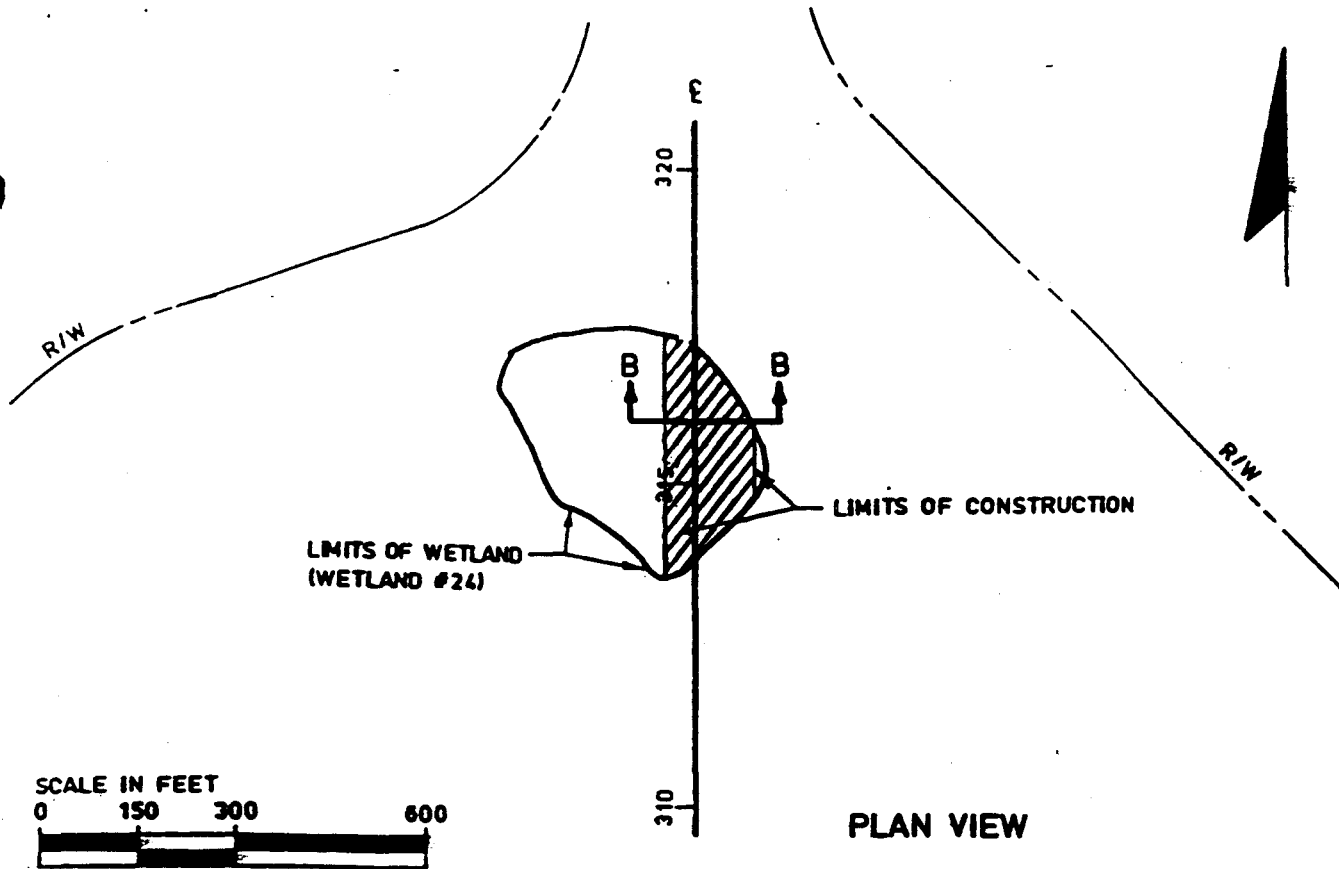
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE

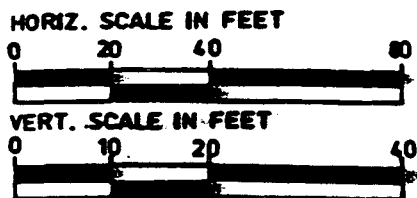
STA. 277 + 00

NOVEMBER 1989

Page 31 of 33



-  AREA OF FILL (LANDWARD)
-  AREA OF DEMUCKING AND BACKFILL



Gregory Thomas Smith
12-20-89

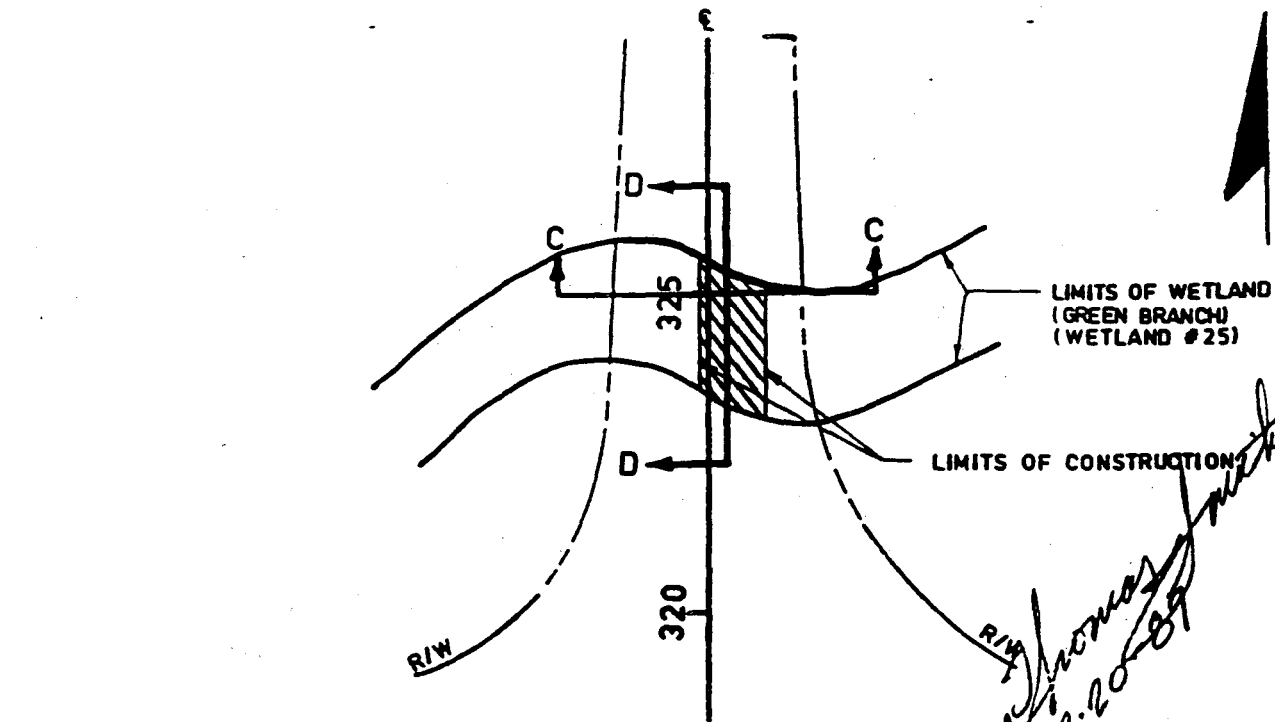
SHEET: 4 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

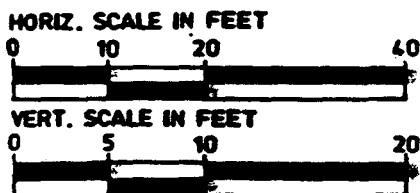
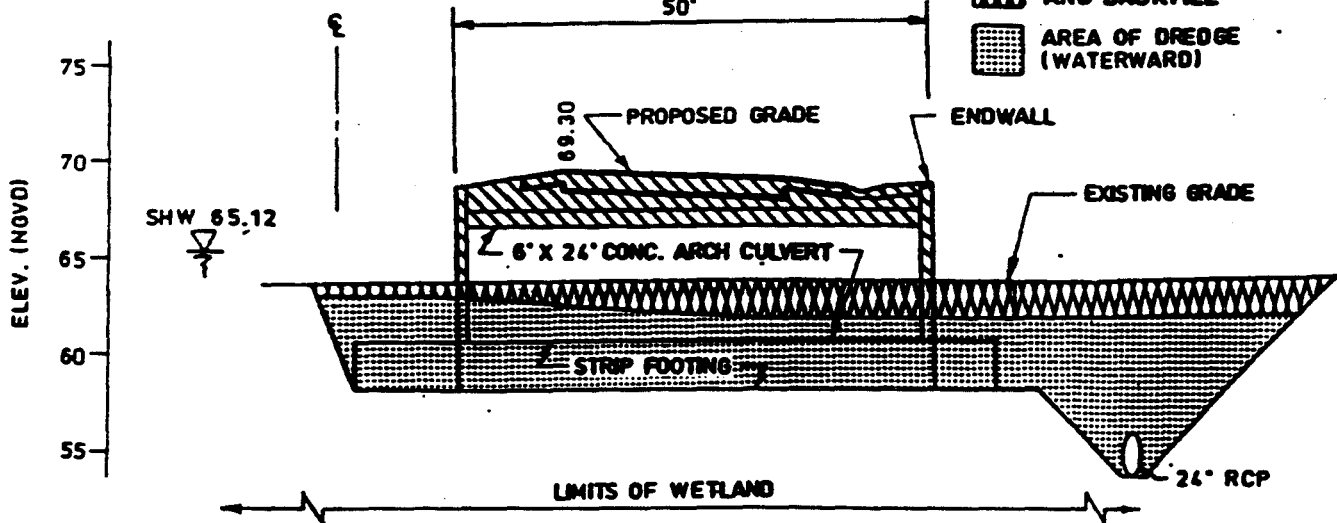
**ALAFAYA TRAIL
EXTENSION**

PLAN AND PROFILE
STA. 316 + 00

ORANGE COUNTY, FLORIDA 22 of 33 NOVEMBER 1989



PLAN VIEW



SECTION C-C

NOTE: DREDGED AREA TO BE FILLED TO EXISTING GRADE EXCEPT UNDER ARCH CULVERT.

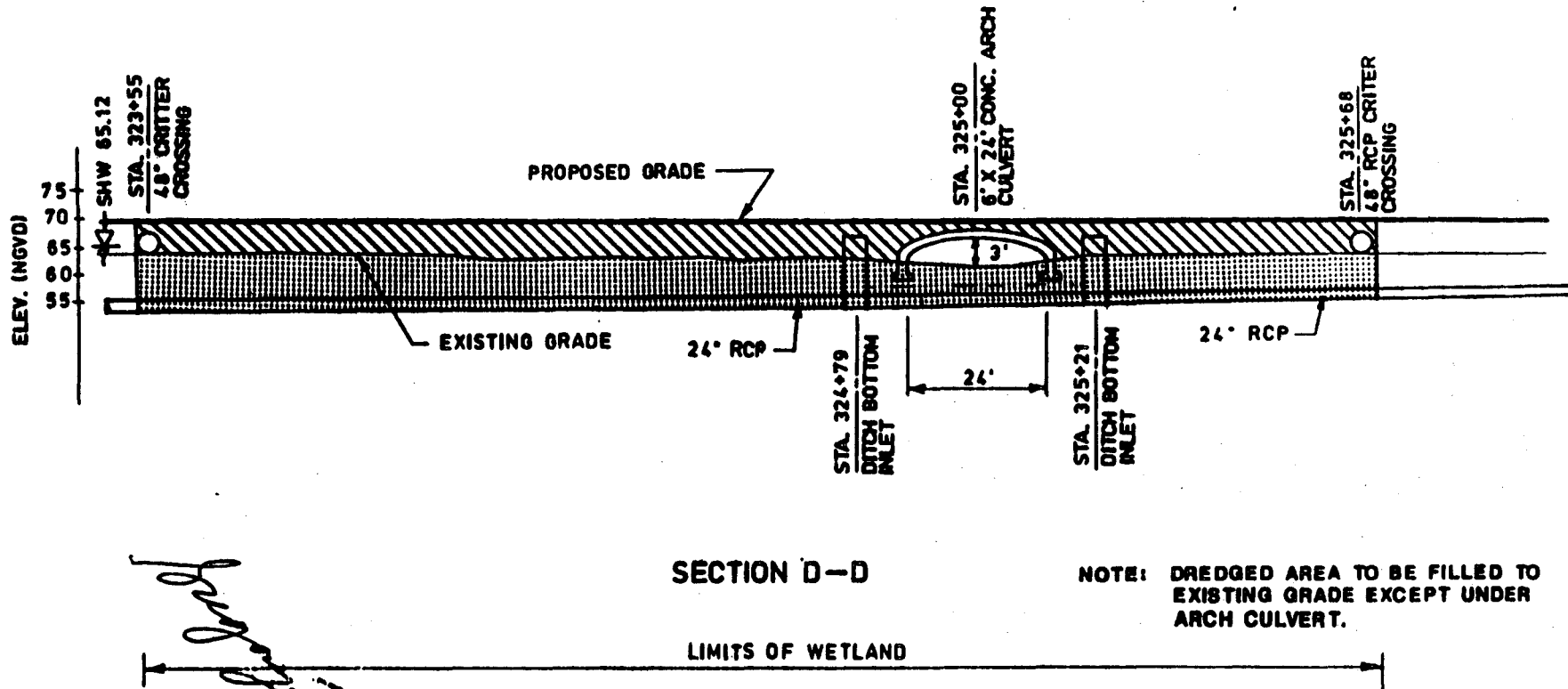
SHEET: 5 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

ALAFAYA TRAIL
EXTENSION
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 325 + 00

23 of 33 NOVEMBER 1989



Handwritten signature and date: 12-22-89

LIMITS OF WETLAND
(WETLAND #42)

LIMITS OF WETLAND
(WETLAND #16)

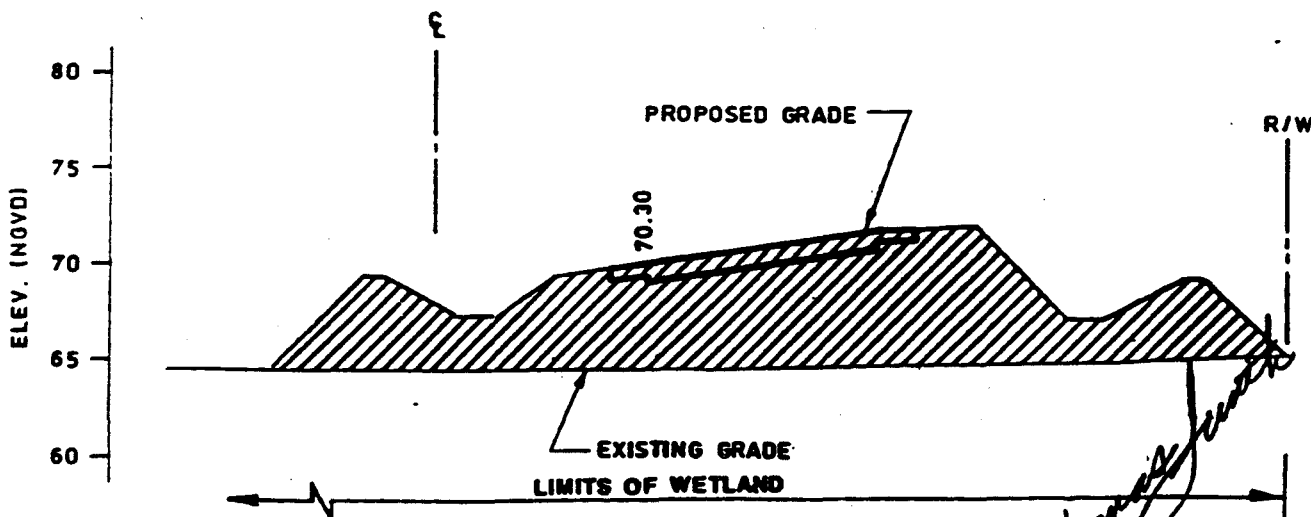
LIMITS OF CONSTRUCTION

LIMITS OF WETLAND
(WETLAND #418)

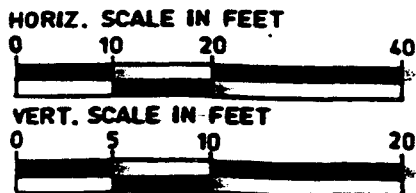


PLAN VIEW

AREA OF FILL (LANDWARD)



SECTION E-E



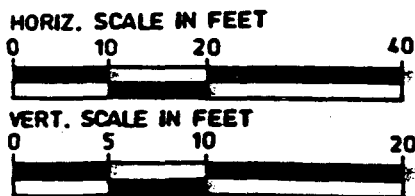
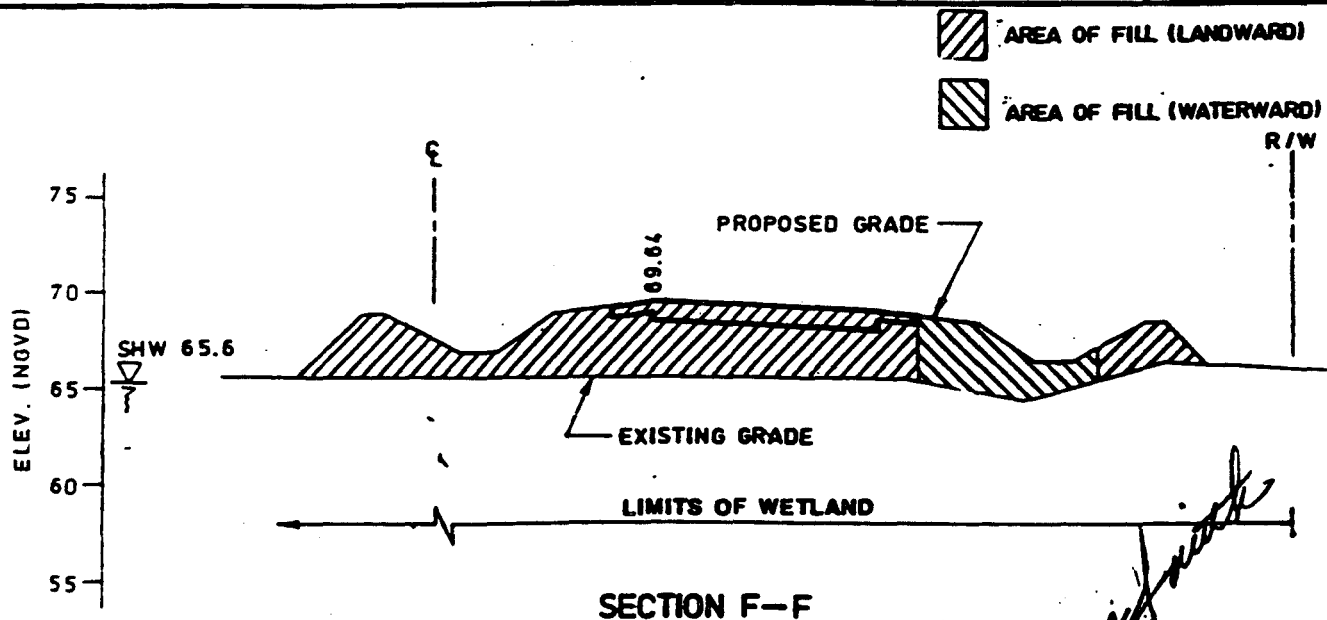
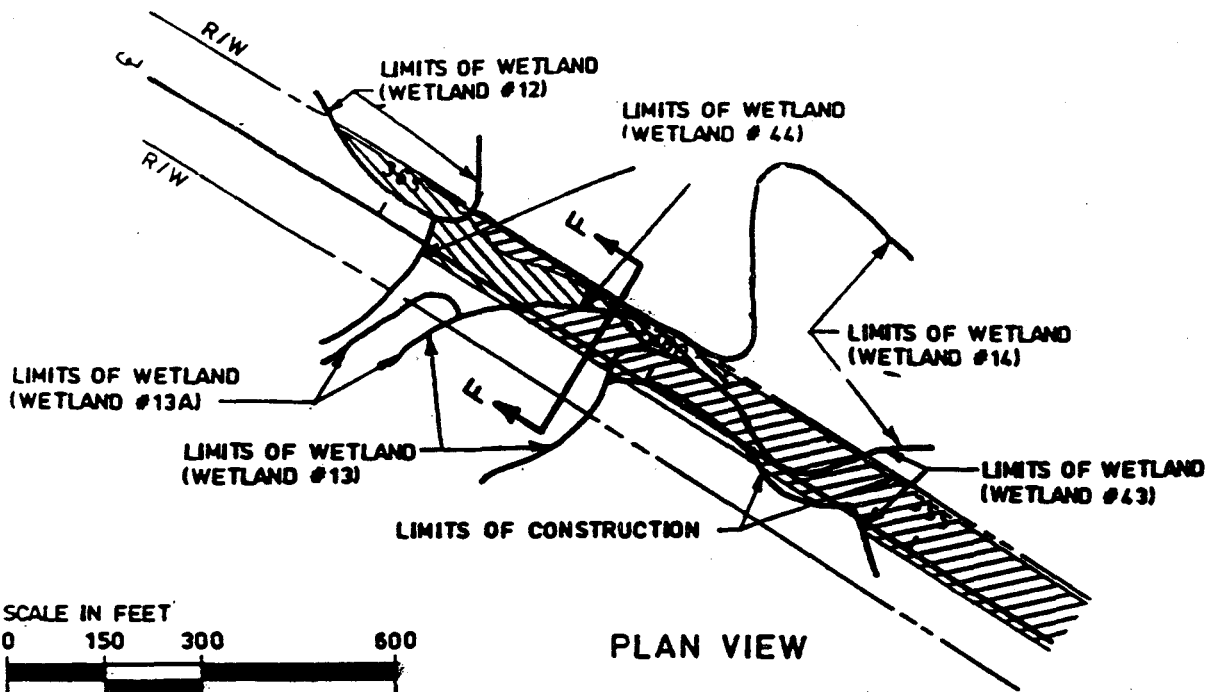
Gregory Thomas
12-20-89

SHEET: 7 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 343 + 00
NOVEMBER 1989



Gregory Thomas
12.20.09

SHEET: 8 OF: 15

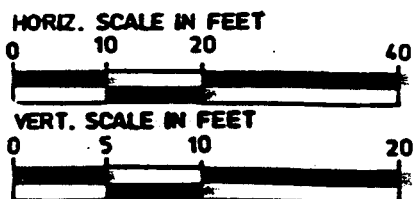
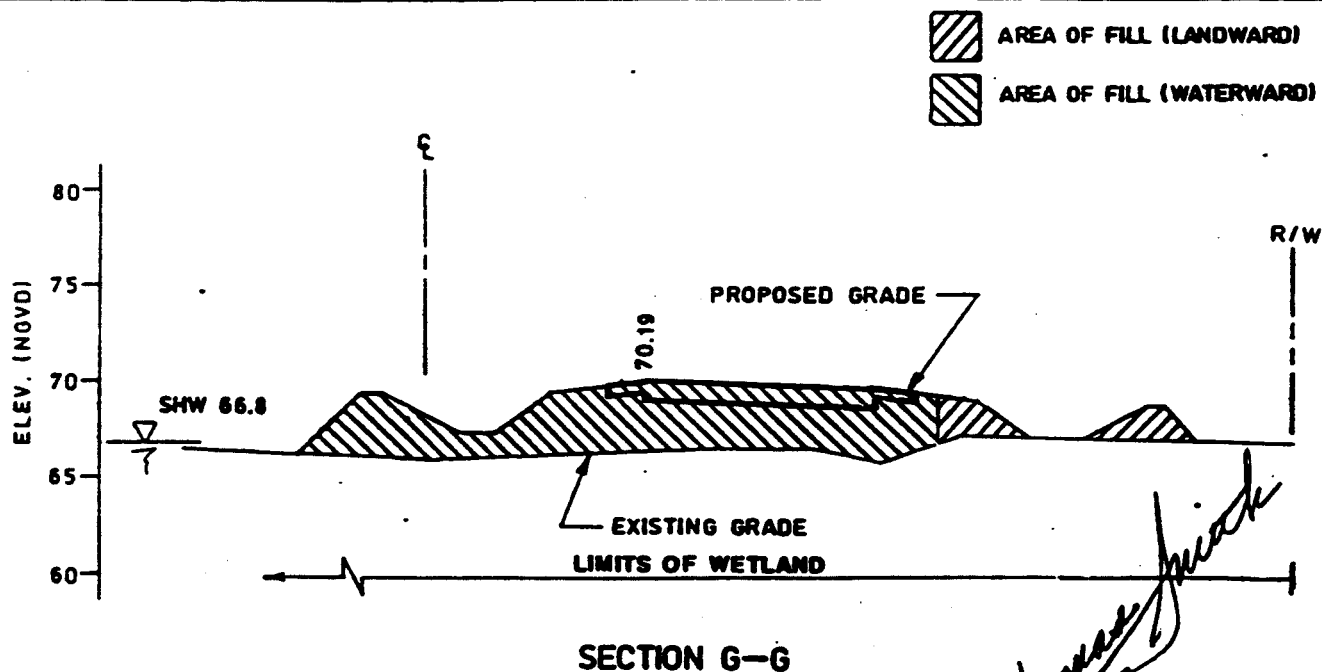
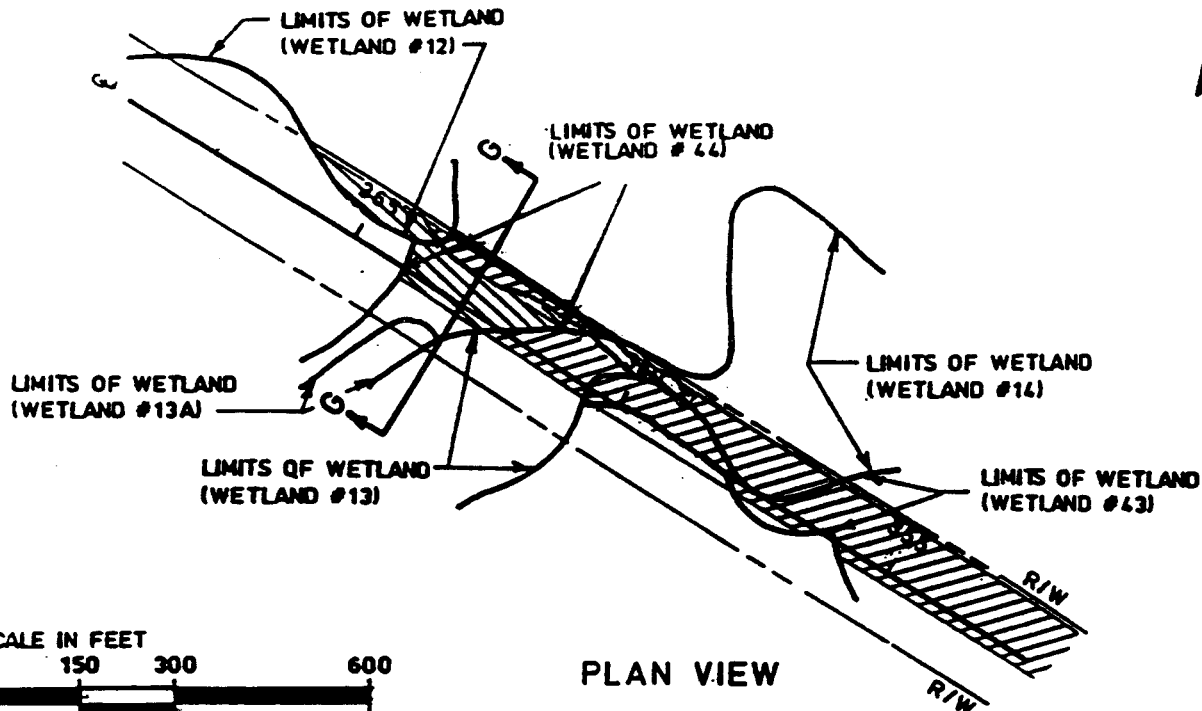
Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**

ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 361 + 00

26 of 33: NOVEMBER 1999



Gregory Thomas
12-20-89

SHEET: 9 OF: 15

Greiner, Inc.

CONSULTING ENGINEERS

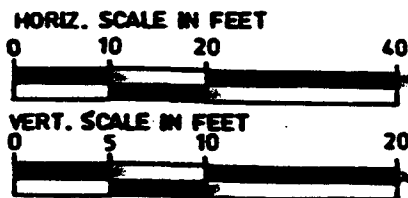
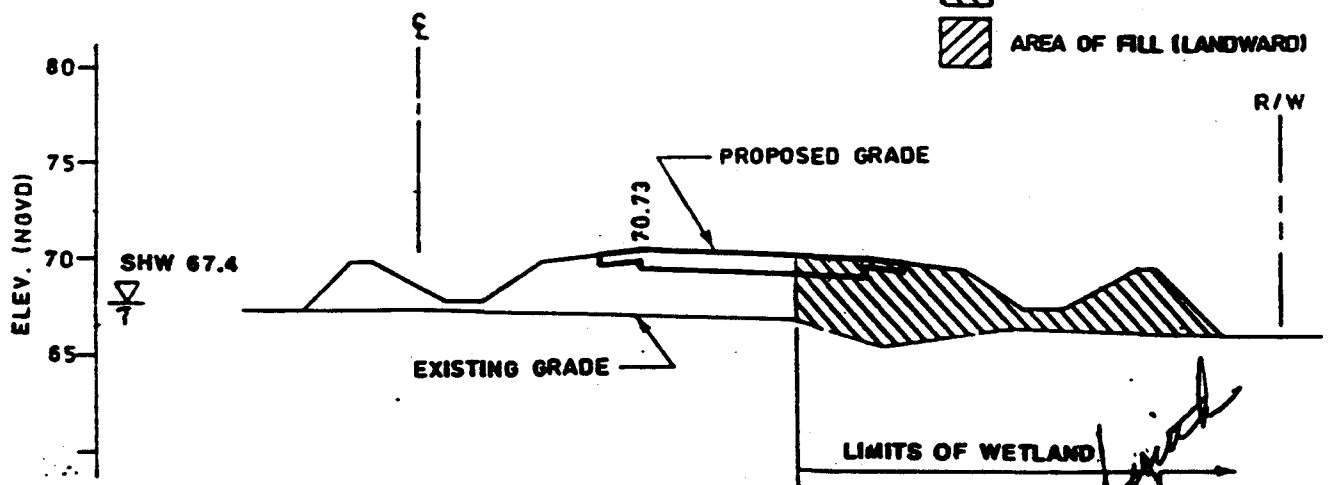
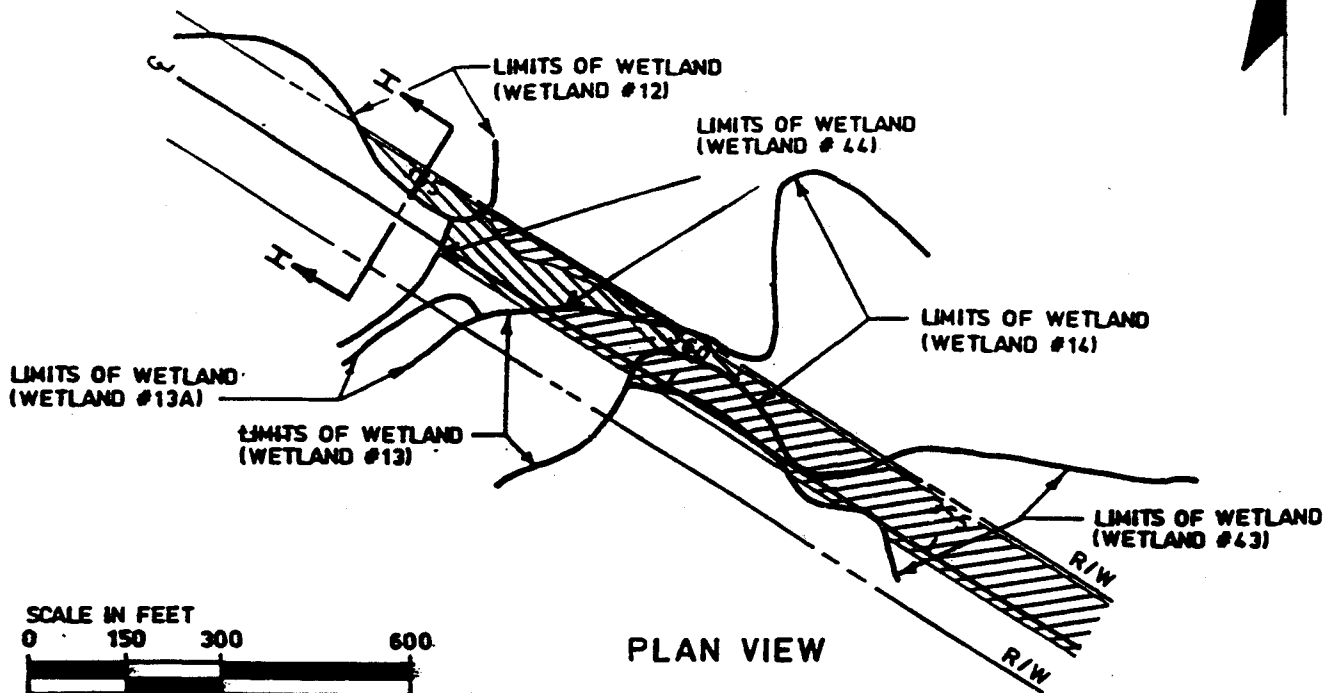
ALAFAYA TRAIL
EXTENSION

ORANGE COUNTY, FLORIDA

PLAN AND PROFILE

STA. 363 + 00

NOVEMBER 1989



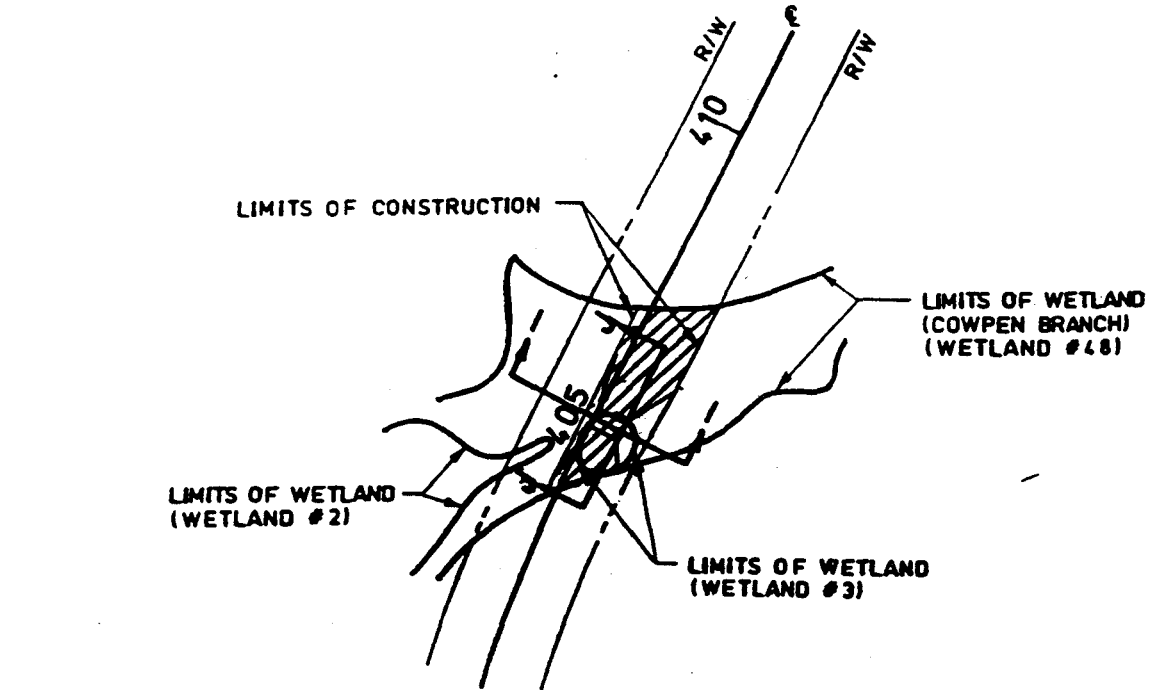
Barry Thomas
12-20-89

SHEET: 10 OF: 15

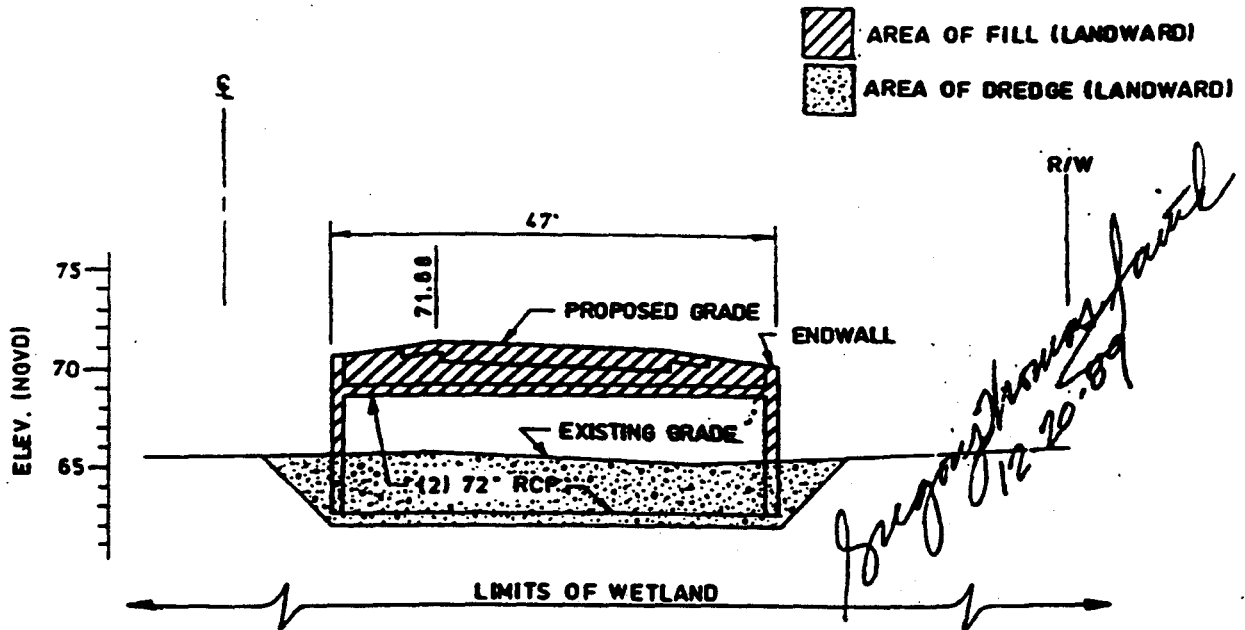
Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 365 + 00
NOVEMBER 1989



PLAN VIEW



SHEET: 11 OF: 15

Greiner, Inc.
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**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA. 405+00

29 of 33 NOVEMBER 1989

Greiner, Inc.
CONSULTING ENGINEERS

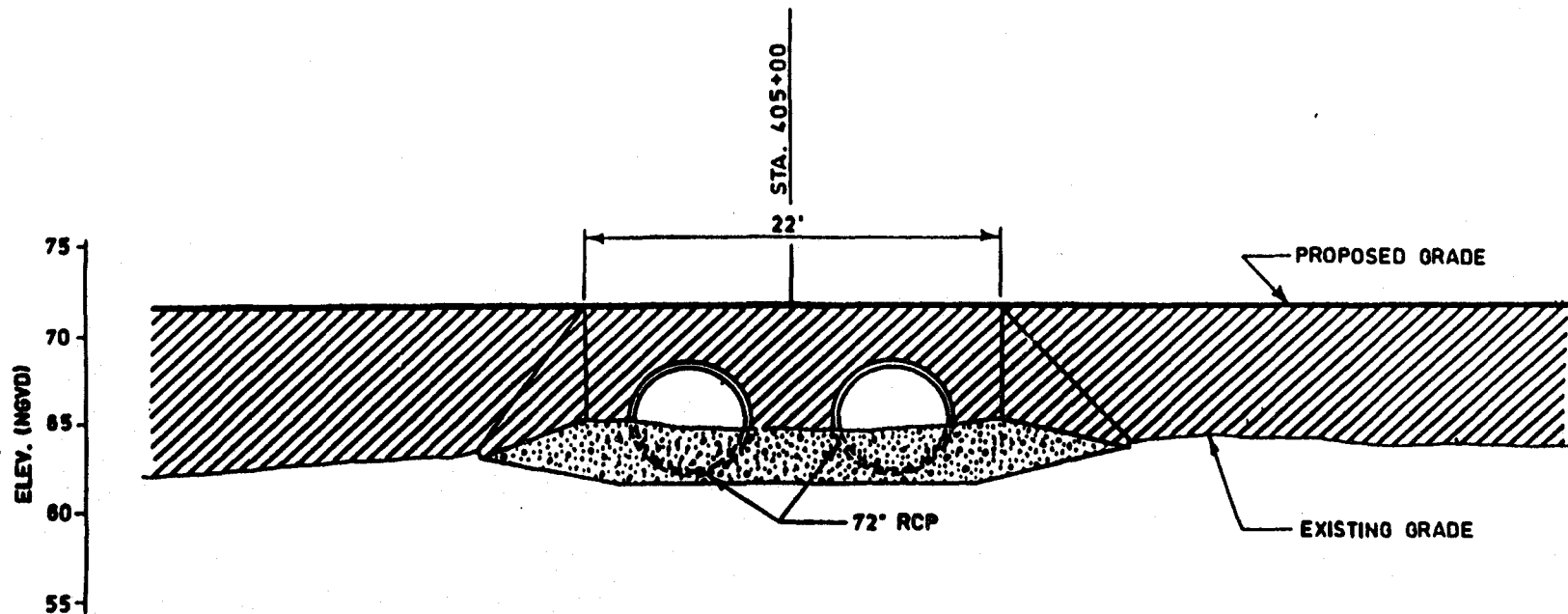
ALAFAYA TRAIL
EXTENSION
ORANGE COUNTY, FLORIDA

NO. OF 33 NOVEMBER 1988

SECTION J-J

SHEET: 12 OF: 15

AREA OF FILL (LANDWARD)
AREA OF DREDGE (LANDWARD)



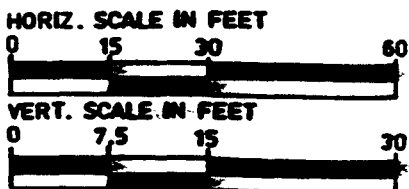
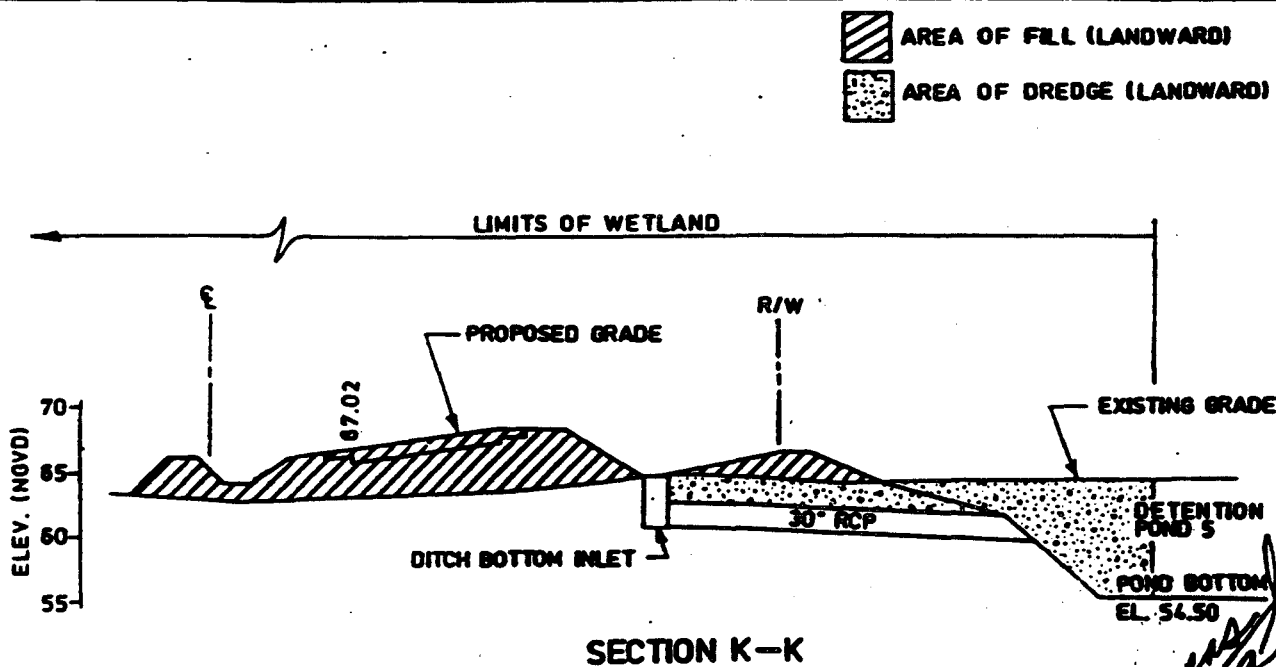
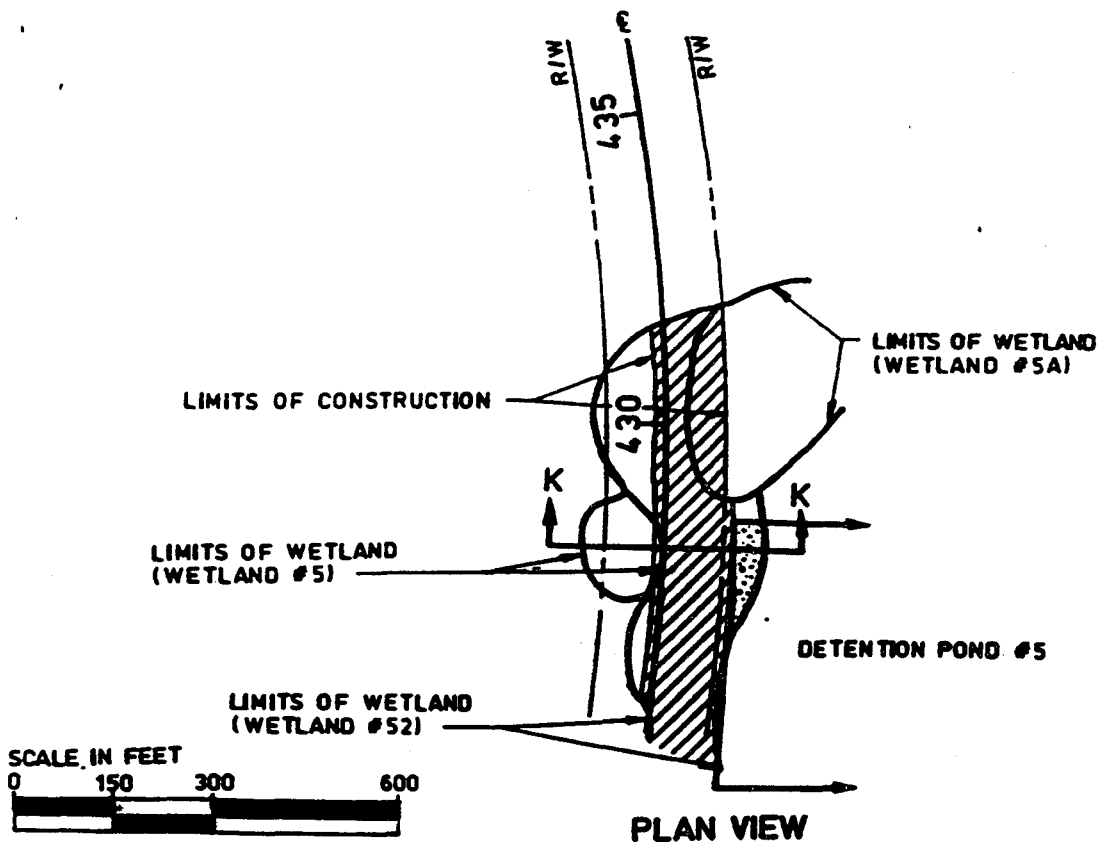
SECTION J-J

NOTE: DREDGED AREA TO BE FILLED TO
EXISTING GRADE EXCEPT IN
CULVERTS.

LIMITS OF WETLAND

Handwritten note:
Dredged area to be filled to existing grade except in culverts.





Gregory Thomas Smith
12.20.89

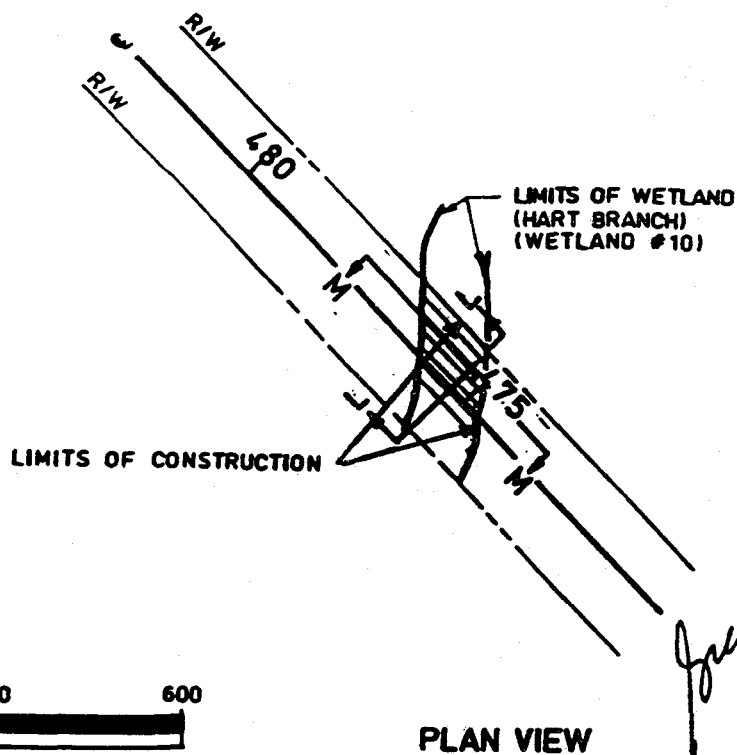
SHEET: 13 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

**ALAFAYA TRAIL
EXTENSION**
ORANGE COUNTY, FLORIDA

PLAN AND PROFILE
STA 428 + 00
NOVEMBER 1989

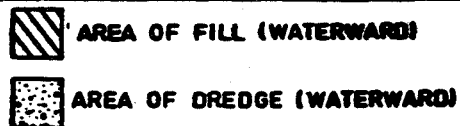
FIGURE K-227 228 21 OF 33



ETLAND
CH)
10)

LIMITS OF CONSTRUCTION

PLAN VIEW



AREA OF FILL (WATERWARD)

AREA OF DREDGE (WATERWARD)

ELEV. (NOVO)

SHW 65.2

SECTION L-L

LIMITS OF WETLAND

NOTE: DREDGED AREA TO BE FILLED TO EXISTING GRADE EXCEPT UNDER ARCH CULVERT.

SHEET: 14 OF: 15

Greiner, Inc.
CONSULTING ENGINEERS

ALAFAYA TRAIL EXTENSION

ORANGE COUNTY, FLORIDA

PLAN AND PROFILE

STA. 475 + 52

NOVEMBER 1989

Greiner, Inc.
CONSULTING ENGINEERS

ALAFAYA TRAIL
EXTENSION
ORANGE COUNTY, FLORIDA

SECTION M-M

NOVEMBER 1988

ELEV. (MSL)
70
65
60
55
50

SHW 65.2

STA. 474+37
DITCH BOTTOM
INLET

PROPOSED GRADE

EXISTING GRADE

48" RCP

STA. 479+30
48" RCP
CUTTER CROSSING

STA. 475+52
6' X 20' CONC. ARCH
CULVERT

STA. 475+75
48" RCP
CUTTER CROSSING

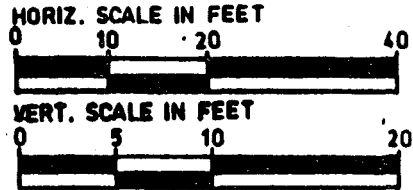
STA. 475+80
DITCH BOTTOM
INLET

LIMITS OF WETLAND

AREA OF FILL (WATERWARD)
AREA OF DREDGE (WATERWARD)

SECTION M-M

NOTE: DREDGED AREA TO BE FILLED TO
EXISTING GRADE EXCEPT UNDER
ARCH CULVERT.



Bryan Thomas Smith
12-20-89

SHEET 15 OF 15