Orlando Utilities Commission
Florida Municipal Power Agency
Kissimmee Utility Authority
Docket No. 910382-EM
Applicant Witness: T. E. Washburn
Exhibit No.___ (TEW-5)

Orlando Utilities Commission

Florida Municipal Power Agency

Kissimmee Utility Authority

KUA
KISSIMMEE
UTILITY
AUTHORITY

Joint Request for Power Supply Proposals

July 1990 Solicitation

FLORIDA MUNICIPAL POWER AUTHORITY
REQUESTS FOR PROPOSALS (RFP)

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1.0 INTRODUCTION

1.1 Summary

The Orlando Utilities Commission (OUC), the Florida Municipal Power Agency (FMPA) and the Kissimmee Utilities Authority (KUA), hereinafter referred to jointly as the UTILITIES, are soliciting through this joint Request for Proposals (RFP), the supply to the UTILITIES of 440 MW of firm base and intermediate load electric energy and capacity to become commercial (Acceptance Date) on January 1, 1997. This RFP outlines the basis for this request and provides information and instructions to Respondents to this solicitation.

Major elements of this RFP are as follows:

1. This Proposal will be evaluated against OUC's alternatives of (1) installing a second coal fired unit at its Stanton Energy Center where FMPA and KUA own a 31.4% interest in Unit 1 or (2) purchasing power from Utility Respondents to an RFP for purchased power being received simultaneously with this RFP. The aggregate of the evaluated cost effective Proposals in the final judgment of the UTILITIES from this RFP and from the Utility Respondents RFP must total at least 440 MW or no Proposal will be accepted.

2. Respondents must propose facilities using commercially proven technologies. Respondents shall be responsible for securing their own fuel supply. The fuel costs proposed by Respondents will be escalated at the same rate as OUC's projected long term coal costs provided in this RFP in Attachment A.

3. Respondents proposing sites outside OUC's service territory are responsible for making arrangements for the firm delivery of the electric energy and capacity to OUC's system. Proof of such arrangements as more specifically requested in Exhibit B.1.2 are a part of the response to this solicitation,

4. All generating facilities proposed in response to this RFP must be dispatchable and capable of Automatic Generation Control (AGC) from OUC's system control center.

5. All Respondents will be responsible for obtaining their own site and must agree to submit to the Florida Electrical Power Plant Siting Act procedure if applicable.

6. All Respondents will be responsible for complying with all applicable laws, regulations, ordinances, codes or any other requirements of local, state and federal governmental authorities.

7. The UTILITIES reserves the right at their sole discretion to select any Proposal, to reject any and all Proposals and to determine what is in their best interest.

8. All requested information is to be supplied in its entirety. To avoid disqualification on the basis of non-responsiveness, Respondents are cautioned to submit the Proposal in strict accordance with these instructions and the Proposal Forms. Prices must be submitted in the units specified on the Proposal Forms.

9. The Contract between the UTILITIES and the Respondent(s) resulting from responses to this RFP will provide for the option to purchase by the UTILITIES, at the end of the Contract term for the net book value, the facility(s) supplying the purchased power.

10. The term of the purchase power agreement shall be twenty five (25) years.

11. Form H of this RFP explains the procedure for making exceptions contained in the Contract section as well as submittal certifications.

12. The Respondents will certify on Form H, Exhibit H.1.1 that the minimum requirements for submittal of this Proposal as stated in Section 2.1.4 are included in their response.

1.2 Schedule

The following lists the dates for activities associated with this RFP:

1. Issue RFP	July 2,1990
2. Intent to Proposal Forms Due	August 15,1990
3. Last Day for Receipt of Questions for Pre-submittal Conference	August 22,1990
4. Pre-Submittal Conference	August 29,1990
5. Last Day for Transmission Study Requests & Written Request Regarding the RFP	September 14, 1990
6. Proposals Due	November 13,1990
7. Decision on Purchase Power vs Stanton Unit 2	March 12, 1991

1.3 Solicitation Objective

It is the objective of the UTILITIES to satisfy the electric needs of their respective customers with dependable and reliable service consistent with :

1. Lowest achievable cost through time;

2. Respect for the environment of Florida;

3. Reduce reliance on imported oil;

4. Adherence to all laws, rules, ordinances and regulations.

OUC's most current power supply plan is contained in its current Ten Year Site Plan which is prepared in accordance with Florida Statutes and regulations of the Department of Community Affairs. This plan is included in this solicitation as Appendix A. Information with respect to FMPA and KUA are included in Attachments B-1 and B-2.

This solicitation is part of the UTILITIES continuing efforts to meet their respective customer needs by soliciting the purchase of base and intermediate load electric energy and capacity which could assist the UTILITIES in accomplishing the objectives stated at the beginning of this section. Accordingly, the Proposals submitted in response to this solicitation will be evaluated for their ability to provide overall benefits. The Proposals will be evaluated under a comprehensive framework that will provide a balance between a number of price and non-price considerations. Non-price considerations to be evaluated include such items as, experience of the Respondent in other similar projects; financial resources of the Respondent; project viability; fuel supply reliability; contribution to UTILITIES' fuel mix; overall environmental impacts; ability to be licensed; operational considerations; any other factors that may affect the reliability, dependability and scheduling of the project. These non-price considerations are crucial to the evaluation in order that the UTILITIES ensure that this solicitation process produces a project/projects that will enable them to meet their service obligations to their customers in a timely and reliable manner.

1.4 Qualified Respondents

This RFP is open to any Respondent who currently owns, or proposes to develop a qualified Small Power Production Facility or Co-generation Facility as defined in CFR 18, Part 292, or Independent Power Production Facility, utility generating facility, municipal, cooperative, or public authority generating facility which meets the requirements described in this RFP.

1.5 Definitions

The following definitions and abbreviations are used throughout this Joint Request for Power Supply Proposals:

OUC - The Orlando Utilities Commission

FMPA - The Florida Municipal Power Agency

KUA - The Kissimmee Utility Authority

UTILITIES - The reference to OUC, FMPA and KUA jointly

RFP - The request to provide a Proposal to the UTILITIES for electric energy and capacity in accordance with the terms and conditions stated herein.

base and intermediate load -

The expected duty cycle that would be imposed on the plant. The generic characteristic of a base and intermediate load plant are (1) a nominal annual capacity factor of 65 %, (2) low energy costs and intermediate to high capital costs and (3) designed for high availability, high efficiency and flexible Performance.

Prudent Utility Practice -

The practices generally followed by the electric utility industry, as changed from time to time, which generally include but are not limited to, engineering and operating considerations, the use of equipment, practices, methods and adherence to applicable industry codes, standards and regulations.

Respondent - The party(ies) who are preparing the official response to this RFP.

Contract - The agreement between the UTILITIES and Respondent(s) offering the best Proposal(s) in response to this RFP. It may be referred to in the body of the RFP as "Contract" or "Power Purchase Agreement" or "agreement".

Proposals - The total of all the information and documentation provided in the response to this RFP.

Acceptance Date -

The date on which the UTILITIES will begin to receive the dependable capacity and energy as determined by acceptance tests to be described in detail in the Contract. For the purposes of this Proposal, the Acceptance Date is January 1, 1997.

2.0 Instructions to Respondents

2.1.0 Introduction

2.1.1 With this Request For Proposals dated July 2, 1990 OUC is soliciting Proposals on behalf of the UTILITIES, for 440 megawatts(MW) of base and intermediate load capacity to meet their respective load requirements beginning January 1, 1997. It is the intent of the UTILITIES to award power supply contracts for capacity and energy if the Proposals provided by Respondents to this request offer value to their respective customers as determined by evaluations made by the UTILITIES.

2.1.2 OUC's Ten Year Site Plan is included as Appendix A of this RFP. This plan shows the commercial operation date of OUC's coal fired Stanton Unit 2 as being January 1997. It will be against the construction and operating costs of this planned unit that all evaluations, both economic and non-economic will be judged. It is in fact the avoided unit for the purposes of evaluating these Proposals. The current construction cost estimate for Stanton Unit 2 is $522 million. The fuel prices used for evaluation purposes will be the base case coal prices for medium sulfur coal as shown in Attachment A.

2.1.3 A Respondent may propose facilities/facility offering all or a part of the solicited capacity.

2.1.4 The following is the list of minimum requirements that are required for submittal and require the certification of the Respondent on Form H, Exhibit H.1.1.:

1. The proposed facility is a commercially proven technology;

2. Proof of the ability to wheel and all associated costs, if applicable, are included in this Proposal;

3. The facility proposed will be dispatchable and capable of Automatic Generation Control;

4. A specific site has been identified;

5. The Respondent will submit to the requirements of the Florida Electrical Power Plant Siting Act if necessary;

6. The Proposal prices have been submitted in the units specified;

7. The term of the agreement for the sale of the capacity and energy to the UTILITIES is for 25 years;

8. If the facility is located outside Florida, only one intervening utility transmission system is necessary to deliver the power;

9. The Proposal includes all changes required in addenda;

10. The facility is capable of operating as a base and intermediate load plant and is not a peaking capacity design;

11. That the Proposal is firm for the twelve (12) months;

12. Interconnection and wheeling costs are included;

13. The Acceptance Date shall be January 1, 1997; and,

14. Evidence has been provided in the Proposal to show proof of access, procurement and transportation plans for primary and secondary fuel sources.

15. 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 this RFP.

2.1.5 If Proposals are not received that provide a benefit to the UTILITIES in the final judgement of OUC then OUC will proceed with the Need For Power determination and licensing activities necessary to begin the commercial operation (Acceptance Date) of Stanton Unit 2 on January 1, 1997.

2.1.6 No later than August 15, 1990 each Respondent intending to submit a Proposal must confirm its intentions by returning the Notice of Intent/Respondent Registration Form included in this solicitation as Exhibit A.1.1. This notice must be submitted in order to be eligible to submit a Proposal. This completed Form, when received by OUC, will provide the party to be contacted and an appropriate mailing address for all correspondence associated with this RFP. Please also note on this Form the provision for indicating intentions to attend the Pre-Submittal Conference.

2.2.0 Facility Requirements

2.2.1 General

(a) The capacity for which the UTILITIES anticipate contracting for is 440 MW of base and intermediate load capacity.

(b) In order to maximize system reliability and operating economy, all capacity must be dispatchable by automatic generation control (AGC) from OUC's system control center. AGC is the automatic regulation of generator output, within predetermined limits, within a pre- described electrical system; in this instance, OUC's system. This regulation is provided by responses to system frequency and other variables, primarily tie line flows. The regulation will be provided by OUC's system dispatch computer which will be connected to all generators under AGC through various types of communication links. The specified ramp rate for AGC control will be 1.5% /Min. of dependable capacity for normal operations and 2.5%/ Min. of dependable capacity during emergency operations. It is also a requirement of this RFP that reactive power be available for dispatch. To this end, generators shall be designed such that they can be operated at a power factor between .90 leading and .85 lagging.

(c) All facilities must be located in Florida, or if located outside Florida, there will be no more than one intervening transmission system between the system to which the facility supplying the capacity and energy under this RFP is connected and OUC's system. Transmission system is defined for this RFP as being the transmission facilities owned and operated under the control and management of one legal entity.

(d) OUC may reject facilities proposed in close proximity to existing OUC generating facilities (See Ten Year Site Plan in Appendix A for the location of OUC facilities) if in OUC's judgement the presence of such proposed facility would jeopardize or impair OUC's existing or future use of such facilities in light of environmental rules or regulations.

2.2.2 Base and Intermediate Load Capacity

(a) To comply with the needs for capacity and energy required in this solicitation, the facility/facilities must be capable of continuous full load operation consistent with Prudent Utility Practices for a base and intermediate load unit. An equivalent availability factor of 80 % is specified as the base value for this supply in Form G.1.1.

(b) In order to maximize the benefits to the UTILITIES the preferred minimum continuous dispatch level shall not be more than 33% of the dependable capacity.

(c) If the facility burns solid or liquid fuel, the operator must maintain on site a fuel inventory sufficient to operate reliably at a pro-forma dispatch schedule which will be provided by OUC's control center unit commitment program.

2.3.0 <u>Preparation of Proposal</u>

2.3.1 In order to evaluate more accurately each Proposal, it is absolutely necessary that every Respondent complete all items in the Proposal Form without exception or alteration. If there is additional information that a Respondent desires to present that will clarify or better explain his Proposal, reasonable additional data will be accepted and considered. If a Respondent feels his Proposal has unique and special provisions, the Respondent should explain in detail those provisions which make it unique and are not obvious. Clarity is paramount because neither OUC, FMPA nor KUA will meet with any Respondent to review or discuss their Proposals.

2.3.2 To avoid disqualification on the basis of non-responsiveness, all Respondents are cautioned to submit their Proposals in strict accordance with these instructions and on the forms provided. All prices shall be quoted in the manner specified in the Proposal Form.

2.3.3 Each Proposal shall be firm for 12 months and shall remain open from the due date specified in Section 2.6.1. After the 12 months for which the Proposal is held firm, Respondents may be requested to renew or reconfirm their Proposals until an agreement with the successful Respondent(s) is executed.

2.3.4 Proposals must be submitted in the legal name of the party who would be bound by any resulting Contract with the UTILITIES.

2.3.5 The Proposal Form is to be completed by the Respondent and signed and sealed by an officer who is authorized to bind the Respondent to a Contract based on the Proposal. Such authority shall be evidenced by proper execution of the Certificate of Counsel Form, Exhibit H.1.2.

2.3.6 Separate Proposals must be submitted for each different site or technology proposed by Respondent.

2.3.7 Payments for dependable capacity will begin after the Acceptance Date which will be defined in the Contract between the UTILITIES and the Operator.

2.3.8 Respondents are reminded that if they propose to interconnect with OUC's transmission system they are responsible for all interconnection costs up to the connection of the facilities directly to OUC's transmission system. Any interconnection with OUC's transmission system must be at either 115 kV or 230 kV. Respondents cost shall include, but not be limited to, generator breaker, main step-up power transformer, related equipment and structures to which OUC will connect any equipment necessary to complete the interconnection (i.e. wires, breakers, relays, meters, etc.). Reference is made to Form B for specific details regarding this matter.

2.3.9 Respondents are required to include all interconnection costs and firm wheeling costs with other utilities in their Proposal.

2.3.10 All exhibits associated with the response forms must have captioned in the upper right hand corner of every page, the following information.

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #________
Page _____ of _____

All pages associated with a particular response exhibit must be sequentially numbered.

2.4.0 Explanation to Respondents

2.4.1 Neither OUC, FMPA nor KUA will accept phone requests for clarification or interpretation. Written requests will be responded to in a timely manner and should be addressed to:

Orlando Utilities Commission
ATTN: Louis E. Stone, RFP Coordinator
P.O. Box 3193
Orlando, Florida 32802

In order to allow time for a response that would be compatible with the Pre-Proposal conference date, the latest date for receipt of written questions will be August 22, 1990. Requests may also be made by facsimile transmissions via OUC's FAX number which is 407-423-9198.

2.4.2 In the intent of fairness, OUC will mail to all registered Respondents the reply to all inquiries. Registered Respondent means those who have returned their Notice of Intent/Respondent Registration Form which is included as a part of this solicitation.

2.5.0 Pre-Submittal Conference

2.5.1 A pre-submittal conference for this RFP will be held on August 29, 1990 in Orlando at a place to be announced later. It is planned that an informal registration will begin at 8:30 A.M., with the meeting beginning at 9:30 A.M. You should confirm your attendance with Ms. Sylvia Waldo at 407-423-9100, Ext. 2376. Failure to return the Notice of Intent/Respondent Registration Form to confirm to OUC of your plans to attend the pre-submittal conference may be cause for you being barred from the conference due to facility limitations.

2.6.0 Proposal Submittal

2.6.1 The Respondent must submit one unbound original Proposal and 10 additional bound copies. Upon submittal, all copies become the property of OUC. Proposals must be received in a sealed package by OUC no later than 2:00 P.M. November 13, 1990 and clearly marked "PROPOSALS FOR POWER SUPPLY". Any Proposals received after that time will be returned to the sender unopened. Proposals will not be publicly opened at that time. They will be turned over to staff and consultants for review and evaluation. To ensure a timely submittal of Proposals, hand delivery is encouraged.

2.6.2 The Respondent must submit with each Proposal a non-refundable cashiers check made payable to ORLANDO UTILITIES COMMISSION in the amount of seven thousand five hundred dollars ($7,500). This fee is not refundable under any circumstance other than the withdrawal of a Proposal prior to the time and date set forth in 2.6.1 above. Any Proposal that does not include this fee in the amount and Form prescribed herein will be considered non-responsive and will be summarily rejected.

2.6.3 Delivery Instructions:

If hand carried or couriered deliver to:

Mr. T. C. Pope, Executive Vice President
Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32802

If mailed by certified or registered mail:

Mr. T. C. Pope, Executive Vice President
Orlando Utilities Commission
P.O. Box 3193
Orlando, Florida 32802

2.6.4 All Proposals received by OUC prior to the final time and date for submittal will remain sealed and unopened in OUC's possession.

2.6.5 Late Proposals, Modification of Proposals, Withdrawal of Proposals:

(a) No Proposal received after the time and date designated in Section 2.6.1 will be considered and will be returned to the Respondent unopened.

(b) Prior to the due date, any Proposal may be withdrawn by the Respondent or his Authorized Representative (as designated on Exhibit A.1.1) under the following conditions:

1. The Respondent or his Authorized Representative's identity is made known to OUC;

2. The Respondent or his Authorized Representative signs a receipt for the withdrawn Proposal;

3. A modified Proposal must be resubmitted by the due date and time set forth in Section 2.6.1.

(c) A Respondent may withdraw his Proposal at any time prior to the due time and date without forfeiting his evaluation fee.

No Proposals may be withdrawn nor any evaluation fees returned after the due time and date set for receipt of these RFP's in Section 2.6.1.

2.7.0 <u>Proposal</u> <u>Rejection</u>

2.7.1 Proposals will be considered non-responsive and subject to rejection for, but not limited to, the following reasons:

(a) Proposal is not received in its entirety by the due time and date as set forth in section 2.6.1 of these instructions;

(b) Proposal is not accompanied with the Proposal fee in the amount and Form prescribed;

(c) Proposal is not submitted on the forms and in the manner prescribed in this RFP;

(d) Proposal does not have sufficient information to allow an adequate evaluation;

2.7.2 OUC reserves the right, without qualification to select any Proposals or to reject any and all Proposals, or to waive any formality or technicality in Proposals received. Respondents who submit Proposals do so without recourse to OUC, FMPA, KUA or any and all contractors providing consulting services to OUC, FMPA or KUA with respect to this RFP solicitation or its evaluation.

2.7.3 Neither the UTILITIES jointly nor OUC, FMPA or KUA individually will reimburse any Respondent for any costs whatsoever incurred in the preparation and submission of a Proposal and/or in negotiations for a Power Purchase Agreement.

2.8.0 Confidentiality

2.8.1 OUC, FMPA and KUA come under the purview of the Florida Public Records Act, F.S. Chapter 119.

It is the responsibility of the Respondents to be thoroughly informed and familiar with the requirements of this statute. Confidential information desired to be withheld from the public must be clearly exempted under this statute or other applicable Florida Law.

2.9.0 Minimum Requirements

2.9.1 All information requested is necessary to evaluate the Proposals adequately. There are, however, certain minimum requirements as enumerated in Section 2.1.4 that must be acknowledged on Form H, Exhibit H.1.1. Any Proposal not containing this acknowledgement will be rejected.

2.10.0 Amendments

2.10.1 It is recognized by the UTILITIES that it may be necessary to revise this solicitation from time to time. Such right to issue revisions and/or amendments is reserved to the UTILITIES. These changes will be announced by addenda to this RFP and copies will be sent to all parties who have returned the Notice of Intent/Respondent Registration Form, Exhibit A.1.1. Acknowledgment of all addenda will be a requirement of the Proposal Form.

3.0 Contract Description

Upon the conclusion of the detailed evaluation of Proposals, the UTILITIES will announce its decision as to whether purchase of power being proposed under this solicitation or going forward with plans to install Stanton Unit 2 is in the best interests of its customers. If the purchase of power proposed under this solicitation is determined by the UTILITIES to be more beneficial than the installation of Stanton Unit 2, the UTILITIES will announce the Respondent(s) with whom it will initiate negotiations. After evaluation the UTILITIES will present to the Respondent(s) having the best Proposal(s) a draft Contract which will serve as the basis for discussions.

The commencement of negotiations does not imply any commitment on the part of the UTILITIES to enter any agreement. Neither the UTILITIES nor any Respondent will be bound in any respect until such time as a definitive Contract document containing mutually satisfactory terms and conditions is signed by the parties. If substantial agreement is not reached in 90 days after commencement of negotiations, negotiations may be terminated.

The UTILITIES anticipate that the terms and conditions generally described below will be included in the contracts with Respondent/ Respondents in the negotiations award group ("Operators"). The descriptions are not intended to be comprehensive, since the UTILITIES recognize that the variety of possible Proposals requires flexibility and that each negotiated Contract may be different depending on the particular characteristics of the proposed facility and the business arrangements proposed by each Respondent.

3.1 Pricing Provisions

The Contract will contain pricing provisions based on a pay-for--performance concept which relate the payments to the performance of the facility. The pay-for-performance concept will be adjusted to recognize performance of the facility during on-peak periods of the UTILITIES. This adjustment will provide for incentives and penalties for performance on peak above or below a base availability factor. The payments will be composed of capacity, energy, and operation and maintenance components. All costs, including firm wheeling costs and all revenue to be obtained by the Operator from the UTILITIES must be included in one of these components. The Contract will provide fixed capacity and fixed operation and maintenance payments indexed to the equivalent availability factor. Penalties and bonuses will be provided for, based on actual performance. The Contract will provide for a sharing of energy and operation and maintenance cost escalation risks between the UTILITIES and Operator, through the use of an indexing process.

3.2 Facility Design and Testing

The Contract will contain provisions governing the obligations of the parties with respect to facility design and testing. The specific obligations will depend upon the type of facility proposed.

If the proposed facility has not yet been constructed, the Contract will provide that the facility will be designed and constructed in accordance with the design of an architect/engineer selected by the Operator.

Operator will be responsible for arranging for the facility lenders to choose a qualified independent engineering firm to review and evaluate the facility. The evaluation by the independent engineering firm will be provided to the UTILITIES in writing, prior to the closing of the construction loan financing of the facility. Unless the UTILITIES agree, otherwise all recommendations by the independent engineering firm must be adopted. The UTILITIES have the right to monitor the construction, start-up and testing of the facility and to receive information adequate to review the progress of the project.

The Contract will specify an estimated dependable capacity in MW for summer and winter periods. The actual dependable capacity will be based on the continuous capability of the facility as determined by summer and winter capacity tests which will be agreed to during negotiations and included in the Contract. Additionally, the UTILITIES may require additional capacity tests to determine a new continuous capability of the facility at any time the facility fails to satisfactorily achieve and maintain an operating level equal to the dependable capacity.

3.3 Completion Security

The Contract will provide for the payment by Operator to the UTILITIES at the time of the execution of the Contract a deposit in an amount equal to Thirty Thousand Dollars ($30,000) per MW of estimated dependable capacity to ensure completion of the facility by the anticipated Acceptance Date. Commencing two months after the Contract anticipated Acceptance Date, and continuing each month for ten months or until the Acceptance Date, the UTILITIES will retain ten percent per calendar month of such deposit as liquidated damages for the impact of such delayed availability of depend able capacity on the UTILITIES. If after twelve calendar months from the anticipated Acceptance Date, the Acceptance Date has not occurred, the UTILITIES will retain all or part, of this deposit to offset damages the UTILITIES incur or reasonably expect to incur and may terminate the Contract for cause. If the Acceptance Date occurs less than twelve calendar months after the anticipated Acceptance Date, the UTILITIES will refund any deposit amount due the Operator.

3.4 Operating Security

The Contract will require that Operator provide and maintain throughout the term of the Contract a security for Operator's performance in an amount equal to Thirty Thousand Dollars ($30,000) per MW of the estimated dependable capacity for the winter period to ensure continued availability of the facility. At the UTILITIES option, such security will consist of either: (i) an unconditional and irrevocable direct pay letter of credit issued by a bank acceptable to the UTILITIES in form and substance acceptable to the UTILITIES or (ii) a payment or performance bond issued by a company acceptable to the UTILITIES for payment to the UTILITIES in form and substance acceptable to the UTILITIES in the event of a material breach by Operator.

If Respondents pricing pattern is such that an analyses by the UTILITIES shows that the UTILITIES may incur economic losses should the facility fail to operate for the full Contract term, then the Operating Security may be adjusted upward during the negotiations.

3.5 Right of First Refusal

The UTILITIES will have an exclusive right of first refusal, based on terms and conditions to be negotiated with the Operator, to purchase the facility if (i) the Operator or any of its subsidiaries, affiliates or other related entities propose to dispose of any interest in the facility other than by the sale and leaseback of the facility to provide financing for the facility, (ii) a bona fide offer is made which the Operator is prepared to accept to purchase or lease the facility or (iii) any transfer or sale of any interest in the Operator to any other entity other than an entity which is directly, or indirectly controlled by, or in control of, the Operator.

3.6 Option to Purchase:

The UTILITIES shall have the option to purchase the facility supplying the capacity and energy under this agreement at the termination date of the agreement at a price equal to the net book value (original cost less accumulated depreciation) of the facility.

3.7 Interconnection and Wheeling Agreements

OUC and Operator will enter into an interconnection agreement if the facility is to be located within OUC's service territory or is to be directly connected with OUC's transmission facilities. If the facility is not to be directly connected to OUC's system, Operator will be required to enter into an interconnection agreement with the interconnecting utility and enter into any firm wheeling agreements necessary to facilitate delivery of electric energy and capacity to the UTILITIES.

All costs associated with the design, construction, operation and maintenance of the interconnection facilities as well as all wheeling costs associated with the delivery of electric energy and capacity to the UTILITIES will be the responsibility of the Operator.

OUC will install and maintain, at Operator's expense, metering equipment and facilities for purposes of measuring the net electric energy and capacity delivered by Operator to the interconnection point.

Each party will be responsible, at Operator's expense, for the installation, maintenance and replacement of its own respective data acquisition equipment. The data acquisition will monitor data points deemed desirable by the UTILITIES or the Operator to implement the provisions of the Contract, be compatible at all times with the computer master equipment receiving the telemetry signals (including Automatic Generation Control), and supply status information, kWh, voltage, MW and MVAR analog information, as well as any other data required by the UTILITIES or the Operator from time to time. The UTILITIES will install and maintain, at Operator's expense, one or more exclusive remote terminal units and appropriate communications to provide telemetry and communications to and from OUC's system control center.

3.8 Dispatchability and Control

The Contract will contain terms governing the dispatch arrangement applicable to the facility as well as scheduling of outages. OUC will have the right to dispatch electric energy and capacity delivered from the facility to OUC's system in an economic manner as determined by OUC. For all proposed facilities directly connected to OUC's system, the Contract will contain terms governing control of reactive output by OUC. The Contract will specify that the ramp rate for normal operation will be 1.5%/Min. of dependable capacity and 2.5%/Min. of dependable capacity for emergency conditions.

3.9 Operation and Maintenance

The Contract will specify requirements for the Operator to employ qualified personnel for operation and maintenance of the facility. Detailed operation and maintenance plans and schedules will be developed by the Operator to include plans and schedules for major overhaul work on the generator, turbine, boilers, auxiliary equipment, and unit functional trip tests after overhauls. Plans for calibration of equipment, maintenance of spare parts inventories, and so forth will also be included. Periodic demonstrations of the integrity of protection equipment will be called for as well as periodic audits of operation and maintenance procedures and practices by qualified parties. Operator must have approved by the UTILITIES all scheduled outages and, to the extent possible, all forced outages.

3.10 Environmental and Regulatory Requirements

It will be the Operator's responsibility under the Contract to obtain and maintain all certifications, permits, licenses and approvals necessary to build, operate and maintain the facility. Operator will comply with all applicable laws, rules and regulations and, if the facility is a Qualifying Facility, the Operator will be responsible for maintaining that status. The costs of all such regulatory activities will be borne by the Operator.

3.11 Insurance and Indemnity

The Contract will require that the Operator carry certain insurance policies with a Twenty Million Dollar ($20,000,000) limit per occurrence, except for statutory obligations imposed by Workers' Compensation or Occupational Disease laws which will have a minimum limit of Five Hundred Thousand ($500,000) per accident. The Operator will be expected to carry General Liability, Broad Form Contractual Liability and Products/ Completed Operations Liability Insurance, and Comprehensive Automotive Liability Insurance. For any policy furnished by Operator, OUC, FMPA and KUA must be named as an Additional Named Insured and such policy must be endorsed to be primary to any insurance which may be maintained by or on behalf of OUC, FMPA or KUA.

The Operator will be an independent contractor and will provide broad Form indemnity protection for OUC, FMPA and KUA with obligation limits equal to the insurance requirements arising out of a single occurrence. Operator's costs to undertake the duty or obligation to defend OUC, FMPA and/or KUA in connection with the Operator's indemnity obligations will not be limited by or be subject to the limits for damages for injuries, deaths and property damage to be specified in this section.

3.12 Representations, Warranties and Covenants

The Contract will contain an Article on Representations, Warranties and Covenants that will have provisions covering, but not limited to, such things as: fuel supply and inventory; operating and maintenance standards; conformance with all laws, ordinances, rules and regulations; authority of parties to Contract and authority of persons to execute Contract and other similar representations and warranties normally contained in an agreement of this nature.

3.13 Facility Deferral

The UTILITIES and Operator will negotiate acceptable terms which will give the UTILITIES a right to postpone the Acceptance Date of the facility.

3.14 Termination

The UTILITIES and Operator will negotiate a termination charges schedule to be included in the Contract which will compensate Operator for the UTILITIES' right to terminate the Contract for its convenience, in whole or in part, at any time prior to the Acceptance Date, with prior written notice.

In addition to the UTILITIES' right to terminate for its convenience, the UTILITIES may terminate the whole or any part of the Contract for cause in the event of default. Such causes may be facility-specific.

At a minimum, the UTILITIES anticipate the following clauses would be included: (i) Operator fails to complete final closing by a negotiated milestone date, (ii) Operator fails to commence construction of the facility by a negotiated date, (iii) Operator abandons construction or operation of the facility at any time, (iv) Operator fails to execute fuel supply contracts by a negotiated date, (v) Operator fails to reach the Acceptance Date by the latter of twelve months after Operator's proposed Acceptance Date or thirty calendar days after OUC advises Operator that the interconnection facilities (for those facilities directly connecting to OUC's system) are sufficient to accept deliveries up to the estimated dependable capacity unless excused by force majeure, (vi) Operator fails to maintain a negotiated equivalent availability factor, (vii) Operator fails to perform as required under the Contract, (viii) Operator fails to secure or maintain firm wheeling arrangement(s), if applicable, (ix) Operator, its employees, or subcontractors, attempt to operate, maintain, or tamper with the interconnection facilities without the prior written consent of the UTILITIES; (x) Operator fails to secure and maintain all licenses and permits necessary to construct and operate the facility; and (xi) reasonable grounds for insecurity arise with respect to Operator's expected performance and Operator fails to furnish adequate assurance of due performance within thirty calendar days after a written request by the UTILITIES for such adequate assurance. In the event of termination for cause. the UTILITIES will have no liability to Operator for costs incurred by Operator as a result of the termination nor for any costs incurred by Operator following its receipt of a written termination notice.

3.15 Governing Law

Florida law will govern the Contract. The Agreement shall be interpreted, construed, and governed by the laws of the State of Florida. The parties will submit to the jurisdiction of courts located in, and venue will be stipulated to be in Orlando, Florida.

3.16 Force Majeure

A force majeure clause excusing non-performance due to events not within the reasonable control of the parties will be included. The UTILITIES will require a right to terminate the Contract if a force majeure event affecting Operator continues for longer than 180 days or if force majeure events affecting Operator, in the aggregate. result in a delay in performance of 360 days or longer. A force majeure event will not extend the term of the Contract. For purposes of determining capacity and fixed operation and maintenance pricing, an outage due to a forced majeure event will be deemed to be a forced outage. The UTILITIES will be relieved from making any payments for electric energy or capacity not received during a force majeure event.

3.17 Miscellaneous Terms

The Contract will contain such other terms and conditions as the parties may negotiate and which are customarily contained in similar contracts in the electric utility industry. Such terms may include, but not be limited to: definitions, billing and payment, records and audit, warranty, claims and disputes, taxes, notices and correspondence, order of interpretation, survival, assignment, equal employment opportunity and civil rights, non-waiver and complete agreement.

RESPONDENT FORM A

-Notice of Intent/Respondent Registration-

A. Notice of Intent/Respondent Registration. Any Respondent intending to submit a Proposal must return Exhibit A.1.1 to the Orlando Utilities Commission by 2:00 P.M. August 15,1990 to to be considered as a Respondent for this solicitation. Respondent must mail or courier this Exhibit to the address shown in Section 2.6.3 of this solicitation.

The Respondent's address provided in the Exhibit will be used by OUC to provide notices and additional information. Please note that documents cannot be couriered to postal box addresses. The authorized representative designated in the Exhibit will be the individual authorized to approve Proposal withdrawal as outlined in Section 2.6.5 (b).

Exhibit A.1.1 Respondent must submit the information in the format included at the end of this Form A.

NOTICE OF INTENT/RESPONDENT REGISTRATION
FORM A
EXHIBIT A.1.1

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #__________
Page _____ of _____

Date: ______________

The undersigned intends to respond to the UTILITIES CAPACITY RFP with a Proposal currently conceived as follows:

Facility Name: ____________________
Facility Location: ____________________
New or Existing Facility: ____________________
Generating Technology: ____________________

Fuel:
- Primary: ____________________
- Alternate Primary: ____________________
- Secondary: ____________________

Facility Classification:
- Utility: __________ Small Power Producer: __________
- Independent Power Producer: _____ Co-generator: __________ MW

Estimated Dependable Capacity:
- Summer __________ MW Winter __________

Thermal Host (if applicable): ____________________

Respondent:
- Company Name: ____________________
- Contact Person: ____________________
- Title/Position: ____________________
- Couriered Address: ____________________
- Mailing Address: ____________________
- Telephone: ____________________
- Fax: ____________________

Legal name of actual party which will be bound by any resulting Contract with THE UTILITIES if different from above: ____________________

The following representatives will be in attendance at the Pre-Submittal Conference, August 29, 1990 (name & title):

1)______________________________

2)______________________________

3)______________________________

4)______________________________

Form Completed by: ____________________ Phone: _______________

Signature: ____________________
Title: ____________________

NOTICE OF INTENT/RESPONDENT REGISTRATION
FORM A
EXHIBIT A.1.1

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #________
Page _____ of _____

Date: ______________

The undersigned intends to respond to the UTILITIES CAPACITY RFP with a Proposal currently conceived as follows:

Facility Name: ______________________________
Facility Location: ______________________________
New or Existing Facility: ______________________________
Generating Technology: ______________________________

Fuel:
- Primary: ______________________________
- Alternate Primary: ______________________________
- Secondary: ______________________________

Facility Classification:
- Utility: ______________ Small Power Producer: ______________
- Independent Power Producer: ______ Co-generator: ______________ MW

Estimated Dependable Capacity:
- Summer ______________ MW Winter ______________

Thermal Host (if applicable): ______________________________

Respondent:
- Company Name: ______________________________
- Contact Person: ______________________________
- Title/Position: ______________________________
- Couriered Address: ______________________________
  ____
- Mailing Address: ______________________________
  ____
- Telephone: ______________________________
- Fax: ______________________________

Legal name of actual party which will be bound by any resulting Contract with THE UTILITIES if different from above: ______________________________

The following representatives will be in attendance at the Pre-Submittal Conference, August 29, 1990 (name & title):

1)______________________________

2)______________________________

3)______________________________

4)______________________________

Form Completed by: ______________________ Phone: ______________

Signature: ______________________
Title: ______________________

UTILITIES CAPACITY RFP - FORM B
-System Planning-

B.1 Location - Electrical

Exhibit B.1.1. Respondent must indicate the following:

If the proposed interconnection point is within OUC's service area, identify the proposed interconnection point with OUC's system. The location will be shown on a section of a USGS map. Submittal must include sufficient technical data and information to permit OUC to estimate the interconnection costs and assess the impact of the facility on OUC's system. If during the preparation of the response to this RFP, Respondent has more than one choice as to where to interconnect with OUC's system, OUC will provide a budget estimate for each choice. Such budget estimate will be the value used in the evaluations. For this estimate study, OUC will charge $2500 (twenty five hundred dollars) for each choice studied. If such a study is desired by Respondent, the request must be made in writing. The request must contain sufficient technical data and detail to permit the study. Each request must be accompanied with a cashier's check in the amount of $2500 for each choice to be studied. NO REQUESTS FOR STUDY WILL BE ACCEPTED BY OUC AFTER 5:00 P.M. SEPTEMBER 14, 1990. OUC will use it best efforts to return the estimates within 30 days after receipt of such request by OUC.

If the proposed interconnection point is outside OUC's service territory, identify the utility interconnected with OUC which will deliver the electric energy and capacity.

Delivery of electric energy and capacity must be made to OUC at a tie into OUC's existing transmission system or through existing interconnections with other systems. Firm wheeling arrangements must be made by Respondent and all wheeling cost must be included in Respondent's price. Any cost impact to OUC's transmission system due solely to the interconnection with the project will be estimated by OUC for evaluation purposes but such costs will not be the responsibility of the Respondent.

If the facility will not be directly connected to OUC's system, Respondent must submit and locate on a one-line diagram of the host utility's transmission system the location of the proposed facility and the proposed interconnection point with the host utility. Submittal must include sufficient technical data and information related to the interconnection facilities, the host utility's system and the other intervening system to permit OUC to evaluate the impact of the facility (e.g., reliability, electric flows on other utilities and OUC's systems, impact on interconnections, etc.).

Exhibit B.1.2 If firm wheeling is required, Respondent must submit a plan for obtaining all firm wheeling arrangements necessary for the life of the agreement and indicate the current status. Respondent must, at a minimum, have had preliminary discussions and provide evidence of such with the wheeling entities. This evidence must be of such a nature that it would assure the UTILITIES that firm wheeling arrangements can be made with the wheeling entities within the time frame necessary to provide capacity and energy on the date specified in this RFP. It must also provide details regarding the technical feasibility of such wheeling.

Exhibit B.1.3 Respondent must provide preliminary generator capability curves and specify the reactive capability and control strategies for the proposed facility. Also required is the degree of control of reactive power that OUC will be given and any voltage or equipment limitation affecting OUC ability to control the reactive output.

Exhibit B.1.4 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #________
Page _____ of _____

EXHIBIT B.1.4

Circle the letter opposite the choice which most accurately reflects the characteristics of your Proposal:

Location:

A The proposed facility will be directly interconnected to OUC's transmission system.

B Power from the proposed facility must be wheeled in Florida from the South to OUC's system.

C Power from the proposed facility must be wheeled in Florida from the North to OUC's system.

D Power from the proposed facility must be wheeled from outside Florida to OUC's system.

Wheeling Services:

Please check the appropriate choice and fill in the blank.

Are wheeling services required? Yes [___] No [___]

If yes, wheeling utility involved:

Utility: ______________________________

RESPONDENT - FORM C

- Siting and Licensing -

C.1 Siting, Site Acquisition and Ownership

Exhibit C.1.1 Respondent must submit a general description of the site where the facility will be located, including, but not limited to, the facility name and address. Respondent will identify the plant location and any associated transmission facilities on a section of a USGS map. This could be the same map specified in B.1.1. Also indicate the name, address and phone number of the current owner of the property where the facility will be located.

Exhibit C.1.2 If the Respondent has (i) ownership of right, title or interest in all proposed facility lands and waters, (ii) possession of an executed Contract, (iii) option to acquire such right, title or interest, or (iv) proof of the right to use the power of eminent domain to acquire such right, title, or interest in the necessary lands and waters, Respondent must include as a part of this Form a legal opinion from its legal counsel indicating the applicable condition.

If the site is currently neither owned nor leased, Respondent must provide a detailed plan including a milestone schedule for site acquisition or lease. Specifically, Respondent must describe the following and include the expected date and outer limit date (the date on which the milestone event must be completed in order to ensure that the facility is commercially available on the obligatory Acceptance Date) for completion of each:

> Respondent is actively negotiating to purchase or lease site. Site is available for the term of the Contract.

> Respondent has unqualified option to purchase or lease the site.

> Purchase or lease option, if applicable.

> Site is owned or leased by the Respondent for the term of the Contract. Respondent must also provide rationale for site selection, including any site selection studies conducted.

Exhibit C.1.3 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

C.2 Licensing and Permitting

Exhibit C.2.1 Respondent must submit a statement or study from legal counsel or a qualified consultant listing all approvals, licenses, permits or variances and the specific requirements or potential requirements thereof that the Respondent must obtain to construct and operate the proposed facility, including zoning, land use and other discretionary local government approvals. Include all permits required to construct and operate any directly associated facilities, such as fuel handling and transportation facilities and transmission line and substation facilities. Permits must include but not necessarily be limited to: general permits and exemptions, including Florida Department of Environmental Regulation requirements (if the facility is located in Florida) and National Environmental Policy Act requirements, air quality permits, water quality, waste water, and wetlands permits, waste and hazardous waste disposal permits, and construction permits, including building permits. Independent power producers must include any approvals or other regulatory actions required under the Public Utilities Holding Company Act, Federal Energy Regulatory Commission (FERC), and state laws concerning certificates of public convenience and necessity.

Exhibit C.2.2 Respondent must provide a milestone schedule for licensing and permitting the facility. For each of the required federal, state and local permits, licenses, approvals and/or variances listed by Respondent in Exhibit C.2.1, indicate the current status of each, date of expected application, date of expected administrative acceptance, and date of expected receipt of final appropriate regulatory agency approval.

Exhibit C.2.3 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

C.3 Respondent Siting and Licensing Experience

Exhibit C.3.1 Respondent must list persons or companies involved in the acquisition and development of the site and in obtaining permits related to the construction and operation of the proposed facility. Respondent must describe in detail the experience and history of these persons and/or of the Respondent specifically related to site and permit acquisition. In particular, where all necessary approvals, licenses, permits or variances have not been applied for or obtained, provide a demonstration based on prior experience, if any, that the Respondent has the requisite ability, technical and financial resources, and experience to pursue successfully the necessary approvals, licenses, permits, and variances required for the facility.

C.4 Siting and Technology Environmental Issues

Exhibit C.4.1 Respondent must identify, in a list format, all siting and technology environmental issues or potential issues that could impact the facility licensing or development schedule or facility feasibility including an assessment of type and degree of local political, business and environmental support of and opposition to the facility. Respondent must also include any pending or threatened litigation that could materially, adversely affect the proposed site.

C.5 Determination and the Florida Electrical Power Plant Siting Act

Exhibit C.5.1 Respondent must agree to elect to file an application under the Florida Electrical Power Plant Siting Act (if the site is located in Florida, unless such election is legally impermissible in the opinion of Respondent's legal counsel. In such case, a copy of the legal opinion must be submitted). Additionally, Respondent must agree to support any of the UTILITIES regulatory proceedings related to this solicitation, as requested and without cost to the UTILITIES, if Respondent and UTILITIES enter a power supply agreement. Respondent must submit and execute an affidavit, signed by an officer who can contractually bind the Respondent, stating the following, as appropriate:

"The proposed facility will be located in the State of Florida. ____(NAME OF RESPONDENT____) hereby certifies that it will elect to file an application under the Florida Electrical Power Plant Siting Act and will support any UTILITIES' regulatory proceedings related to this solicitation, as requested and without cost to the UTILITIES, if ____(NAME OF RESPONDENT____) and the UTILITIES sign a Contract for such facility,"

or,

"The proposed facility will not be located in the State of Florida. ____(NAME OF RESPONDENT____) hereby certifies, however, that it will support any UTILITIES regulatory proceedings related to this solicitation, as requested and without cost to the UTILITIES, if ____(NAME OF RESPONDENT____) and the UTILITIES Contract for such facility."

C.6 Environmental Effects

Exhibit C.6.1 The Respondent must submit a mass balance for the facility showing the primary constituents of all air, liquid, and solid material streams between the proposed project and the environment and necessary major project components. All sources of natural resources (fuel, water, etc.) must be defined. All mass units should be average pounds per hour, and the fuel heat rate and electrical output should be included. The OUC Stanton Unit 2 is planned to operate with the following air emission limits:

SO_2................0.7 lb/MMBTU Input
Particulates.......0.03 lb/MMBTU Input
NO_x................0.5 lb/MMBTU Input

Respondents' Proposals will be evaluated against these base line emission quantities.

Exhibit C.6.2 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

C.7 Waste Treatment

Exhibit C.7.1. The Respondent must submit information related to all waste treatment processes. These should be described in detail including air emission controls, waste water treatment, and solid waste management alternatives. The descriptions should include technical data on the process, practical experience in the industry, and an evaluation of how the process will meet the regulatory requirements, (i.e., will the air emissions controls satisfy BACT).

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #__________
Page _____ of _____

EXHIBIT C.1.3

Circle the letter opposite the choice which most accurately reflects the characteristics of your Proposal.

<u>Site Acquisition</u>:

The statement which is applicable to the project Proposal is which of the following:

A Respondent has ownership of right, title or interest in all proposed facility lands and waters for the duration of the Contract.

B Respondent has entered into an agreement with a host facility under which space for Respondent's project will be provided for the duration of the Contract.

C Respondent has an unqualified option to acquire such right, title or interest by purchase or lease which is expressible up to the outer limit date on site acquisition specified in the Proposal.

D Respondent has proof of the right to use the power of eminent domain to acquire the site.

E Respondent had identified the site and is actively negotiating the purchase or lease.

Exhibit C.2.3

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #________________
Page __________ of __________

Licensing and Permitting:

Respondent must list all approvals, licenses, permits or variances that must be obtained to construct and operate the proposed facility and indicate the current status with a check mark:

Identification of Licenses/Permit	Required But Not Yet Applied For	Application Pending	Permit/ License Received

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #________
Page ____ of ____

ENVIRONMENTAL INFORMATION CHECKLIST

EXHIBIT C.6.2

I. PROJECT DESCRIPTION

A. Provide the following information:

State total area of project: __________________ acres.

Estimate the number of acres (to the nearest 1/10 acre) directly affected that are currently:

1. Developed...................... ________ acres
2. Open Space Woodlands/Recreation........... ________ acres
3. Wetlands...................... ________ acres
4. Floodplain.................... ________ acres
5. Coastal Area.................. ________ acres
6. Tidelands..................... ________ acres
7. Productive Resources
   Agriculture................... ________ acres
   Forestry...................... ________ acres
8. Other......................... ________ acres

II. ASSESSMENT OF POTENTIAL ADVERSE ENVIRONMENTAL IMPACTS

Instructions: Explain direct and indirect adverse impacts, including those arising from general construction and operations. For every answer explain why significant adverse impact is considered likely or unlikely to result. Positive impact may also be listed and explained.

Also, state the source of information or other basis for the answers supplied. Such environmental information should be acquired at least in part by field inspection.

Answers are not to be made on this form but identified as outlined in Section 2.3.10.

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #_________
Page _____ of _____

A. Open Space and Recreation

1. Might the project effect the condition, use, or access to any open space and/or recreation area? Explanation and Source:

2. Is the project site within 500 feet of any public open space, recreation, or conservation land? Explanation and Source:

B. Historic and Archaeological Resources

1. Might any site of structure of historic significance be effected by the project? Explanation and Source:

2. Might any archaeological site be effected by the project? Explanation and Source:

C. Ecological Effects

1. Might the project significantly effect fisheries or wildlife, especially any rate or endangered species? Explanation and Source:

2. Might the project significantly affect vegetation, especially any rare or endangered species of plant? Explanation and Source:

3. Agricultural Land. Has any portion of the site been in agricultural use within the last 15 years? If yes, specify use and acreage.

4. Amount (if any) wetland, salt marsh, or tideland to be dredged, filled, removed, or altered (other than by receipt of runoff) as a result of the project.
____________________ acres.

D. Water Quality and Quantity

1. Might the project result in significant changes in drainage patterns? Explanation and Source:

2. Might the project result in the introduction of any pollutants, including sediments, into marine waters, surface fresh waters or ground water? Explanation and Source:

3. Will any part of the project be located in flowed or filled tidelands, estuaries, or other waterways? Explanation and Source:

4. Is the project in the watershed of any surface water body used as a drinking water supply? Explanation and Source:

5. Are there any public or private drinking water wells within 1/2-mile radius of the proposed project? Explanation and Source:

6. Does the operation of the project result in any increased consumption of water?

   Approximate consumption ___________ gallons per day. Likely water source(s) ___________.

E. Solid Waste and Hazardous Materials

1. Estimate types and appropriate amounts of waste materials generated, including solid waste and construction debris from demolished structures. How/where will such waste be disposed of? Explanation and Source:

2. Might the project involve the generation, use, transportation, storage, release, or disposal of potentially hazardous materials? Explanation and Source:

F. Air Quality

1. Does the project include industrial processes that will release air contaminants to the atmosphere? If so, describe the process (type, material released, and quantity released).

2. Are there any other sources of air contamination associated with the project (e.g., traffic, material storage, construction dust)? Explanation and Source:

3. Are there any sensitive receptors (e.g., hospitals, schools, residential areas) which would be affected by air contamination caused by the project? Explanation and Source:

G. Noise

1. Might the project result in the generation of noise? (Include any source of noise during construction or operation, e.g., engine exhaust, pile driving, traffic.) Explanation and Source:

2. Are there any sensitive receptors (e.g., hospitals, schools, residential areas) which would be affected by any noise caused by the project? Explanation and Source:

H. Aesthetics

1. Are there any proposed structures which might be considered incompatible with existing adjacent structures in the vicinity in terms of size, physical proportion and scale, or significant differences in land use? Explanation and Source:

2. Might the project impair visual access to water from or other

I. Consistency With Present Planning

Discuss consistency with current federal, state and local land use, transportation, open space, recreation and environmental plans and policies. Consult with local or regional planning authorities where appropriate.

UTILITIES RFP - FORM D
- Financial and Corporate Information -

D.1 Financial Capability

Exhibit D.1.1 In order for the UTILITIES to assess the financial viability of the facility and the Respondent, Respondent must submit a complete description of plans for financing the facility, including the projected capital structure over the term of the Contract, the source(s) of equity and debt financing and the anticipated duration of equity involvement by the Respondent. Respondent must also submit the projected annual cash flow statements for the facility over the term of the Contract. The assumptions behind the financial information submitted must be included. Finally, Respondent must submit audited financial statements, if available, or other financial statements for the last two years on the principals of the Proposal. Information on the structure of Respondent (e.g., special purpose corporation, limited partnership) must also be provided.

Exhibit D.1.2 Respondent must demonstrate financial capability to construct the facility by submitting at least one of the following:

1. A letter of commitment for financing of the facility from a recognized financial institution or investment source.

2. A statement from the Respondent's certified public accountant that the Respondent has sufficient capability to finance the facility fully without relying upon external financial requirements.

3. Written commitments from individuals to purchase stock or partnership interests in the facility or demonstrated past performance in marketing stock or partnership interests in similar projects.

4. Presentation of equivalent evidence that the Respondent can successfully finance the facility.

Exhibit D.1.3 Respondent must submit a demonstration of its ability to obtain the minimum level of insurance/security as described in the Contract Description.

Exhibit D.1.4 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

EXHIBIT D.1.4

Circle the letter opposite the choice which most accurately reflects the characteristics of your Proposal.

Committed Capital:

- A At least 65 percent of the required capital is committed.
- B At least 40 percent of the required capital is committed.
- C At least 25 percent of the required capital is committed.
- D Less than 25 percent of the required capital is committed.

Debt/Equity:

As a percent of the total financing, the equity component, at the time of permanent project financing, will be as follows:

- A >20%
- B 20%
- C <20%

Debt Coverages Ratios:

Average debt coverage ratios over debt term are:

- A Greater than 2.10
- B 1.61 to 2.10
- C 1.10 to 1.60
- D Less than 1.10

UTILITIES CAPACITY RFP - FORM E
-Operations/Engineering-

E.1 Construction Capability

Exhibit E.1.1 Respondent must submit a plan of construction of the proposed facility by one or more qualified construction or development entities. The plan must provide a summary of construction management services to be performed and a detailed construction schedule.

Exhibit E.1.2 Respondent must submit a detailed estimate of the cost of design and construction, including capitalized working capital and all capitalized financing costs at the time of completion of the facility.

Exhibit E.1.3 Respondent must submit a delivery schedule of major equipment components, describing and specifying any major equipment already purchased or on-site.

E.2 Unit Performance

Exhibit E.2.1 Respondent must submit a detailed description of power generation facility performance. This description must include but not be limited to the following:

1. Facility generating and outage information in the format included at the end of this Form E. Such information must conform to the definitions of the North American Electric Reliability Council which have been summarized in Attachment D.

2. Net reactive capability of each unit including details of the unit's excitation system capabilities.

3. Guaranteed Input/Output coefficients A, B and C as shown on Exhibit G.

4. Regulated voltage range.

5. Start-up and shutdown operating restrictions such as soaking times, cooling times and MW output limitations.

6. Fuel/fuels used and heating value for each.

E.3 Experience

Exhibit E.3.1 Respondent must submit a listing of the qualifications and experience of the following:

1. Experience of proposed owner-operator(s) in operation and maintenance of similar generation facilities or third party operation and maintenance firm.

2. Identify the proposed architect-engineer(s) who will design the facility and their experience with facilities of similar technology and size.

3. Identify the proposed constructor(s) and proposed major contractors of the facility and their experience with facilities of similar technology and size.

4. Identify the experience of the technology to be used, including the number of units of similar size and equipment in operation in the U.S. and in the world and the number of years of operation of this technology; also include availability and forced outage rates for similar units.

Exhibit E.3.2 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

E.4 Operation and Maintenance Capability

Exhibit E.4.1 Respondent must describe the facility's maintenance organization and program and plans to carry out the program, including but not limited to training, schedule, record keeping, procedures, spare parts inventory and quality control. Indicate in this plan all provisions and mechanisms for coordinating maintenance scheduling with the UTILITIES. Respondent must include executed agreements or other plans for the reliable operation and maintenance of the facility for the duration of the Contract. Respondent must provide actual or estimated costs of this operation and maintenance plan. Respondent must also include a plan to fund unexpected operation and maintenance expenses.

E.5 Technology

Exhibit E.5.1 Confidence in a Respondent's pro forma operating data, capital costs, and operating costs is a function of the technological maturity (or track record) of the contemplated plant. Respondent must submit a description of the technology to be used in the facility, including the plant availability and plant maintainability design criteria in order to meet the proposed reliability. Respondent must include a discussion of the technical specification of the facility including but not limited to projected net and gross heat rates.

Exhibit E.5.2 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

E.6 Technical Documentation

Exhibit E.6.1 Respondent must submit documents detailing the heat balance, main one line, plot plan, general arrangement, relaying protection system (to OUC's interconnection point, if applicable), and site plan and include preliminary mechanical flow diagrams of any steam, water or other process for the proposed facility.

Exhibit E.6.2. Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

E.7 Schedule and Level of Development

Exhibit E.7.1 Respondent must submit a detailed milestone schedule for the design, construction, and permitting of the proposed facility, including licensing, design, and engineering phases, start and completion of construction and major intermediate milestones, start-up testing, initial synchronization and Acceptance Date. Respondent must include a discussion of the current status where applicable of each scheduled item.

E.8 Corporate Information and Management Experience

Exhibit E.8.1 Respondent must submit a detailed description of management background, including experience and record in development, design, construction, and operation of projects similar to the proposed facility. This Exhibit must include information for the entire development team, including architect/engineer, construction manager, operator, developer, owner, and contractors. Respondent must include a description of up to five of its most significant and relevant projects, including the following details: size (MW), location, Respondent's role in the project, technology used (coal, combined cycle, etc.) fuel type, actual net operating heat rate, equivalent availability factor, equivalent forced outage rate, type of project (qualifying facility, independent power producer, utility, etc.) and the amount, type and duration of Respondent's investment in the project.

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #________
Page _____ of _____

RESPONDENT FORM E
EXHIBIT E.2.1

FACILITY GENERATING AND OUTAGE INFORMATION

YEAR	EQUIVALENT AVAILABILITY FACTOR(%)	EQUIVALENT FORCED OUTAGE RATE(%)	SCHEDULED OUTAGES * PLANNED (PO) (DAYS/YR)	MAINTENANCE (MO) (DAYS/YR)
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				

* EQUIVALENT DAYS PER YEAR. FOR DEFINITIONS OF OUTAGE TYPES SEE ATTACHMENT D.

UTILITIES JOINT RFP
Facility Name
Respondent
Exhibit #________
Page _____ of _____

EXHIBIT E.3.2

Choose the statement which most accurately reflects the level of experience.

Respondent has developed:

A   A similar facility which has achieved an EAF of least 80%.

B   A similar facility which is currently in commercial operation.

C   A similar facility which is financed (financing closed).

D   A project which is currently in commercial operation which utilizes a different generating technology.

E   None of the above..

*   NOTE:

A similar facility shall mean a power producer utilizing the same generating technology and environmental controls located in a similar geographical setting (i.e. urban, suburban, rural).

EXHIBIT E.5.2

Circle the letter opposite the choice which most accurately reflects the characteristics of your Proposal.

Level of Development of Technology:

A A similar facility has achieved an average Equivalent Availability Factor (EAF) equal to or greater than 80% over five consecutive years.

B A similar facility has achieved an EAF of less than 80% but equal to or greater than 75% over five consecutive years.

C A similar facility has achieved an EAF of less than 75% but equal to or greater than 70% over five consecutive years.

D A similar facility is currently in commercial operation.

E A similar facility is under construction.

F None of the above.

Exhibit E.6.2

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Check the choice in the boxes shown below which most accurately reflects the status of studies/plans related to:

Status of:	Final (1)	Detailed (2)	Preliminary (3)	Not Applicable (4)
Site Survey and Evaulation				
Mechanical Arrangement and Elevations				
Energy, Process, and Other Balances				
Electrical One-line Diagrams				
Relay Protection Scheme				
Electrical Plan and Elevations				
Major Equipment List				
Bids Received for Major Equipment				
Makeup Water Supply Plan				
Condenser Water Supply Plan				
Solid Waste Disposal Plan				

(1) Drawings/plans have been certified for construction.

(2) Drawings/plans contain major equipment specifications and specifications have been prepared for bidding.

(3) Drawings/plans are conceptual in nature and are based, in whole or in portion, generic information.

(4) Respondent selecting "Not Applicable" category must demonstrate to OUC's satisfaction that the designated item(s) will not be required for the proposal.

RESPONDENT - FORM F
-Fuel Supply-

F.1 <u>Availability and Security of Fuel Supply</u>

Exhibit F.1.1 Respondent must provide a detailed fuel requirements plan including the following:

1. A description of the specific fuel characteristics that will be used to generate electricity. Include secondary or back-up fuels. If natural gas is proposed as the primary fuel the facility must have available a back up fuel that would preclude an outage or reduced rating during periods of supply curtailments. Additionally, if natural gas is proposed to be the primary fuel, the facility must have the capability to use coal or another alternate primary fuel as defined in Section 201 (b) of the Power Plant and Industrial Fuel Use Act.

2. Average and minimum fuel inventory for primary fuel source and secondary fuel source, if applicable, stated in days of supply at normal facility output. State the generation level used, and storage capacity planned for primary and secondary fuels, to be stored on-site. The plan must also include the ability to deal with supply interruptions of the primary fuel.

3. Inventory management.

Exhibit F.1.2 Respondent must provide a detailed fuel supply and transportation plan including the following:

1. Fuel transportation distance (maximum and average in miles), mode of transportation, and transporters (facility operators, fuel contractors, other).

2. Existing fuel supply contractors who will be relied on (list by name, address, expected annual quantity). If the plant is located in Florida, the gas transportation arrangements are of particular concern and must be thoroughly documented with agreements from responsible parties.

3. Plan and current status for attracting and contracting with new fuel suppliers, number of potential new contractors, maximum and average distance from proposed facility to fuel resource (miles).

4. Prior experience of the Respondent in securing similar fuel supplies. Provide a description of the expertise of proposed personnel and their experience in performing fuel procurement and transportation management and administrative activities, including number of personnel, education and training and prior experience.

5. Letter of commitment from an experienced supplier of fuel, to provide the fuel requirements, stating quantity, price and term of commitment.

6. Letter of commitment from fuel transporter to transport the required fuel, stating quantity, price and term of commitment.

Exhibit F.1.3 Respondent must provide a copy of a long term fuel contract or other evidence to demonstrate the long-term fuel prices and availability of fuel for the facility, if available. Respondent must include forecasts of delivered prices for both primary and secondary fuels over the term of the Contract along with the assumptions and methods used to develop these forecasts. Respondent must also include a discussion of the unique features in its agreements that would protect these price forecasts, potential fuel supply and fuel transportation arrangements.

Exhibit F.1.4 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

Exhibit F.1.5 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

UTILITIES JOINT RFP
Facility Name
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EXHIBIT F.1.4

Circle the letter opposite the choice which most accurately reflects the characteristics of your Proposal.

<u>Fuel Diversity:</u>

A The Proposal is for a hydro, wind or solar facility.

B The Proposal is for a waste fired facility.

C The Proposal is for a coal fired facility.

D The Proposal is for a natural gas fired facility.

E The Proposal is for an oil fired facility (No. 6 or distillate).

F Other (identify).

UTILITIES JOINT RFP
Facility Name
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EXHIBIT F.1.5

Circle the letter opposite the choice which most accurately reflects the characteristics of your Proposal.

Fuel Supply:

A The sponsor has experience in managing the procurement and transportation of fuel and has received letters of interest or has other evidence of access to fuel and transportation supplies for the full term of the project contract.

B The sponsor has no experience in managing the procurement and transportation of fuel but has received letters of interest or has other evidence of access to fuel and transportation supplies for the full term of the project contract or sponsor has experience but has no evidence of success.

C The sponsor has no experience in managing the procurement and transportation of fuel and has not received letters of interest or has no evidence of access to fuel and transportation supplies for the full term of the project contract.

RESPONDENT - FORM G
- Pricing Proposal -

G.1 Pricing Proposal

Respondent must submit on Exhibit G.1.1 a pricing Proposal which is consistent with the baseline pricing methodology as described below and in Attachment C, Proposal Baseline Pricing Methodology. All prices for capacity and energy are for net values delivered to OUC's transmission system.

Capacity Pricing

The UTILITIES prefer a levelized fixed price capacity payment component over the term of the Contract which compensates the Respondent for the use of its capital resources. A levelized payment will receive more favorable reception since any front end loading would result in an undesirable "rate shock." The payment should include an amortization of the original investment amount as well as a return on that investment. The UTILITIES propose to index this payment to the performance of the facility as measured by the equivalent availability factor.

The formula for determining the relationship between capacity payments and facility performance is explained in Attachment C, Proposal Baseline Pricing Methodology. The basic approach provides a monthly payment for a specified target range of equivalent availability factor calculated on a twelve-month rolling average. For the first 12 months of operation, prior to the development of a rolling average, the capacity payment each month will be the base capacity price (Pb). At the end of this first 12 months, there will be a true-up. This true-up will provide for reconciling the first year's equivalent availability factor with the base equivalent availability factor. Then each month's capacity payments for the first year will be recomputed using the 12 month factor. True up adjustments will then be made equally in the following 12 months. Payments will increase up to a maximum amount if a higher equivalent availability factor is achieved and will decrease for lower equivalent availability factors. At the UTILITIES option during negotiations, such methodology may be adjusted to recognize performance during the UTILITIES on-peak and off-peak hours.

Energy Pricing

The Operator shall be compensated for the net electrical output in KWHs received on OUC's system. The energy price is determined by multiplying the heat rate times the fuel compensation price (FCP). The Respondent will include the Input/Output coefficients A, B & C as a part of the Proposal data on Form G.1.1. The Respondent will set Base Fuel Compensation Price (BFCP) for an effective date which will serve as the basis for the future fuel compensation price (FCP) adjustments. A Current Fuel Index (FIc) will be calculated by OUC quarterly which will determine the adjustments made to the Base Fuel Compensation Price by dividing this value into the initial Fuel Index FIi. This current index is calculated by using the weighted average delivered cost of all coal delivered to OUC's Stanton Plant during the twelve calendar months ending three months prior to the quarter in which the fuel index will be used for adjusting the Base Fuel Compensation Price and will be reported in cents per million BTU (¢/MMBTU). The Fuel Index (FIc) for the quarter beginning July 1, 1990 is 190.1¢/MMBTU. This index was calculated on the weighted average cost of coal delivered to the Stanton Energy Center for the twelve months ending March 31, 1990. The Initial Fuel Index will be computed during Contract negotiations. The formulae are shown in detail in Attachment C.

<u>Operation and Maintenance Pricing</u>

Operation and maintenance payments will be divided into two components, fixed operation and maintenance payments and variable operation and maintenance payments. The fixed payment should compensate the Respondent for those costs which do not vary with the output of the facility. Most labor and maintenance costs may be in this category. As with capacity pricing, the UTILITIES propose to vary the payment based on the actual performance of the facility as measured by the equivalent availability factor. The same formula used for capacity payments will be used for fixed operation and maintenance payments. Variable payments, if any, should include the costs of those supplies or activities which are a function of the output of the facility dedicated to this supply agreement.

The specifics of the Operations and Maintenance Pricing are explained in detail in the Proposal Baseline Pricing Methodology, Attachment C.

Exhibits G.1.1 - G.1.4 Respondent must submit the information in the format included at the end of this Form G which includes a pricing Proposal for the first year of operation and a construction and operating data summary Form. Respondent must include projected values for subsequent years throughout the proposed Contract term.

G.2 <u>Pricing Proposal - Alternate Format</u>

Respondent may also propose alternate pricing scheme(s); however such scheme(s) must index any fixed payment portion of the price Proposal to the performance of the facility as measured by its equivalent availability factor. The UTILITIES will not accept any Proposals with take-or-pay energy payments or fixed capacity payment obligations which do not take into consideration the facility's performance.

Respondent should be aware that any additional pricing formula(s) it proposes will, at a minimum, also be used in the economic screening of facilities. Additionally, such analysis may be a basis for demanding increased operating security during contract negotiations.

Exhibit G.2.1 If an alternate pricing scheme is proposed, Respondent must use a grid similar to the ones used in Exhibits G.1.1 through G.1.4. Clearly label and define the rows of the matrix, including units, using an attachment if necessary.

G.3 Security for Payment in Excess of Value

Exhibit G.3.1 Respondent must indicate the nature of the guarantees and/or incentives for continued, reliable operation over the term of the Contract, e.g., escrow fund, irrevocable letter of credit, lien at parity with lenders, subordinated lien, corporate parent credit guarantee, etc.

Exhibit G.3.2 Respondent must submit the information requested on the exhibit form bearing this identification found at the end of this Section.

G.4 Benefits of Selecting Respondent

Exhibit G.4.1 The UTILITIES wish to be aware of actual and potential benefits, both direct and indirect, that may result from the development, construction, and operation of the facility in order to assess properly the overall impact of each Proposal and to assure that appropriate considerations are given. List, describe and/or quantify in terms of dollars and non-tangible items, those benefits that will occur if the Respondent is awarded a Contract for the proposed facility. These benefits could include, at a minimum, benefits involving business practices, technical issues, financial/economic improvements, environmental impacts and social factors, and benefits to Florida citizens, businesses, and government bodies, including the use of Florida resources.

UTILITIES JOINT RFP
Facility Name
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PRICING PROPOSAL

Proposal Baseline Methodology

Form G

Exhibit G.1.1.

Acceptance Date : January 1997

CAPACITY PRICE	*Base Capacity Price $/MW/Month	Base Equivalent Availability Factor (%)	Availability Incentive/Penalty Rate (R) $/MW/MO Per % Variance Above or Below Base Range
VALUES		80	

ENERGY PRICE	*Base Fuel Compensation Price $/MMBTU	Input/Output Curve Coefficients		
		A	B	C
VALUES				

FIXED O&M PRICE	*Base Fixed O&M Price $/MW/Month	Escalation(1) For Adjusting Fixed O&M	Availability Incentive/Penalty Rate (F) $/MW/MO Per % Variance Above or Below Base Range
VALUES		5.2%	

VARIABLE O&M PRICE	*Base Variable O&M Price $/MW/HR	Escalation(1) For Adjusting Variable O&M
VALUES		5.2%

* Price and cost information for the initial year of operation (base year). Values should be expressed in nominal dollars. Projected values for subsequent years through the proposed contract term are to be provided on the following pages as part of the Construction and Operation Data Summary Form.

(1) This escalation rate will be used during evaluation. Actual escalation index will be negotiated.

UTILITIES JOINT RFP
Facility Name
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Form G
Exhibit G.1.2

SECTION B: GUARANTEED MAXIMUM PRICE DATA

Year	Fuel Cost $/MMBTU	Fixed O&M $/MW/MO	Variable O&M $/MWH	Capital* Improvements & Changes in Working Capital ($)
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				

* This amount should be included in the Fixed O&M cost projection. If not, state where this cost has been included in the pricing proposal.

UTILITIES JOINT RFP
Facility Name
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Form G
Exhibit G.1.3

SECTION D: OPERATING PERIOD DATA

I) Capital Structure:

Year	Debt	Equity
1997		
1998		
1999		
2000		
2001		
2002		
2003		
2004		
2005		
2006		
2007		
2008		
2009		

Year	Debt	Equity
2010		
2011		
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		

II) Other Data:

Projected Term of Operating Period Loan:	Years
Projected Rate of Operating Period Debt:	%
Tax Life of Project:	Years

UTILITIES JOINT RFP
Facility Name
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Page ______ of ______

Construction & Operating Data

Summary Form

Form G
Exhibit G.1.4

Acceptance Date : January 1997

Location:

INPUTS:

Projected Escalation Rate(s) During Construction:	Projected Construction Financing Rate During Construction:
Sources of Debt:	
Sources of Equity:	
Completion Security to be Provided: (see solicitation, Section 3.3)	

SECTION A: CONSTRUCTION PERIOD CASH FLOWS

Year	Construction Cash Flows (Nominal $)	Construction Period Interest	Interconnection Estimate *	Capitalized Working Capital (fuel & spare parts inventory)	TOTAL
1991	$	$	$	$	$
1992					
1993					
1994					
1995					
1996					
1997					
				TOTAL INSTALLED	$

Year	% of Debt in Construction Financing	% of Equity in Construction Financing
1991	%	%
1992		
1993		
1994		
1995		
1996		
1997		

* Excluding costs associated with interconnection of facility directly to OUC system.

UTILITIES JOINT RFP
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EXHIBIT G.3.2

Circle the letter opposite the choice which most accurately reflects the characteristics of your Proposal.

Security:

The credit vehicle the Respondent will employ to guarantee continued, reliable operation over the term of the contract.

A Escrowed Fund

B Letter of Credit

C Parity Lien

D Second Lien

E Corporate Guarantee

UTILITIES CAPACITY RFP - FORM H

- Proposal Submission Letter and Contractual Issues -

H.1 Proposal Submittal Certifications

Exhibit H.1.1 Respondent must submit a certification letter in the format included at the end of this Form H.

Exhibit H.1.2 Respondent must submit a Certificate of Counsel Form in the format included at the end of this Form H.

H.2 Contractual Issues

Exhibit H.2.1 Written exceptions, if any, to the concepts contained in Section 3.0, including replacement language, must be submitted with the Proposal. If written exceptions are not submitted, the UTILITIES will assume the concepts contained in the Contract language, as stated are acceptable.

Exhibit H.2.2 Written Alternatives, if any, to the concepts contained in Section 3.0 must be submitted with this Proposal. Items contained in this Exhibit may be substituted for the current Contract language at the UTILITIES sole discretion.

UTILITIES CAPACITY RFP

Form H

Exhibit H.1.1

The undersigned certifies that (a) the information submitted as part of its Proposal to the UTILITIES is complete and accurate, (b) the concepts contained in the Contract descriptions are acceptable, except as specifically noted in the written exceptions, if any, (c) the Proposal has been submitted in the legal name of the entity which would be bound by any resulting Contract, (d) the minimum requirements specified in Section 2.1.4 are included as a part of this submittal, and (e) the offer submitted is firm and will remain open for 12 months from November 13, 1990.

Name of Legal Entity:____

State of Incorporation:____

Business Address:____

Signature:________________________

Date:________________________

Title:________________________

Telephone:________________________

UTILITIES JOINT RFP
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UTILITIES CAPACITY RFP

Form H

Exhibit H.1.2

CERTIFICATE OF COUNSEL
(Where Respondent is a Corporation)

I do hereby certify that the Proposal has been duly and lawfully executed by the Respondent acting by and through all officers and agents thereunto respectfully required for the valid execution thereof, and that such officer and/or agents were thereunto lawfully authorized.

____
Signature of Counsel for Respondent

____
Type or print name of Counsel

____
Type or print address of Counsel

CERTIFICATE OF COUNSEL
(Where Respondent is an Individual or Partnership)

I do hereby certify that the Proposal has been duly and lawfully executed by the Respondent, or if the Respondent be a partnership by a partner thereunto duly and lawfully authorized.

____
Signature of Counsel for Respondent

____
Type or print name of Counsel

____
Type or print address of Counsel

- ATTACHMENT A -

FUEL PRICE FORECASTS

FUEL PRICE FORECASTS SUMMARY

FIGURE II-3: BASE FORECAST OF FUEL PRICE

FIGURE II-4: HIGH-BAND FORECAST OF FUEL PRICES

FIGURE II-5: LOW-BAND FORECAST OF FUEL PRICES

FUEL PRICE FORECASTS & METHODOLOGY

FIGURE B-1: BASE FUEL FORECAST

FIGURE B-2: HIGH FUEL PRICE FORECAST

LOW FUEL PRICE FORECAST

PAGES 1 THRU 7 - PENINSULAR FLORIDA FUELS FORECASTS
(1988 - 2007)

- ATTACHMENT B-1 -

FLORIDA MUNICIPAL POWER AGENCY DESCRIPTION

FMPA SUMMARY OF PROJECT PARTICIPATION

FMPA SUMMARY OF CURRENT POWER SUPPLY ARRANGEMENTS

ATTACHMENT B-2

KISSIMMEE UTILITY AUTHORITY - DESCRIPTION OF EXISTING SYSTEM

ATTACHMENT "A" - KUA - Historical and Projected Peak Demands

FIGURE 1 - KUA's EXISTING TRANSMISSION SYSTEM AS OF 6/90

ATTACHMENT C

PROPOSAL BASELINE PRICING METHODOLOGY

ATTACHMENT D

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL DEFINITIONS

ATTACHMENT A

FUEL PRICE FORECASTS

This Attachment is the fuel price forecasts developed at the last annual Planning Hearing conducted by the Florida Public Service Commission held in Tallahassee, Florida in March 1989. The data is from studies conducted in 1988.

The fuel costs used for evaluation purposes will be the base case for medium sulfur coal. The other prices are moot as far as evaluations are concerned but the entire portion on fuel price forecasts is included for information and clarity only.

FUEL PRICE FORECASTS
SUMMARY

A banded 30-year delivered fuel price forecast was developed by the FCG for residual and distillate fuel oil, natural gas, coal and nuclear fuel. Present day prices were based on the current experience of the FCG utilities. Real price increases were determined through a scenario approach which considered the major factors influencing fuel prices including fuel availability and the influence of the Organization of Petroleum Exporting Countries (OPEC). The annual nominal fuel prices used in the study's economic analysis were calculated by applying the appropriate annual general inflation rates.

Supply assumptions for natural gas are based on Federal Energy Regulatory Commission (FERC) approval of and completion by Florida Gas Transmission of the proposed Phase II expansion of the Florida Gas Transmission Pipeline System. The expanded 925 million cubic feet per day pipeline is estimated to have about 600 million cubic feet per day of natural gas available to peninsular Florida's electric utilities on an average annual daily basis throughout the planning period.

The delivered coal price was divided into mine-mouth and transportation components before applying the escalators. The same delivered fuel price was assumed for all existing, certified and generic future generating units which utilize the same type of fuel. A graph of the base fuel price forecast in nominal dollars is shown in Figure II-3. Forecast prices for high, medium and low sulfur fuel were developed for both residual oil and coal. The graphs show low sulfur residual oil and high sulfur coal prices since these are the sulfur levels of the fuels expected to be burned in the new generating alternatives analyzed in these studies. The price differences between the various fuels are expected to increase in the future. This is caused by expected higher escalation in oil and gas prices compared to coal prices.

The scenario approach was also used to develop high-band and low-band fuel forecasts[1] for use in the Avoided Unit Study sensitivity analyses. These forecasts in nominal dollars are shown in Figures II-4 and II-5.

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1 The base fuel price forecast and the sensitivity bands are listed in Form 1.2. Discussions of the base fuel forecast, the high and low-bands and the scenario methodology are given in A.1.

FIGURE II-3: BASE FORECAST OF FUEL PRICE
(Nominal Dollars)

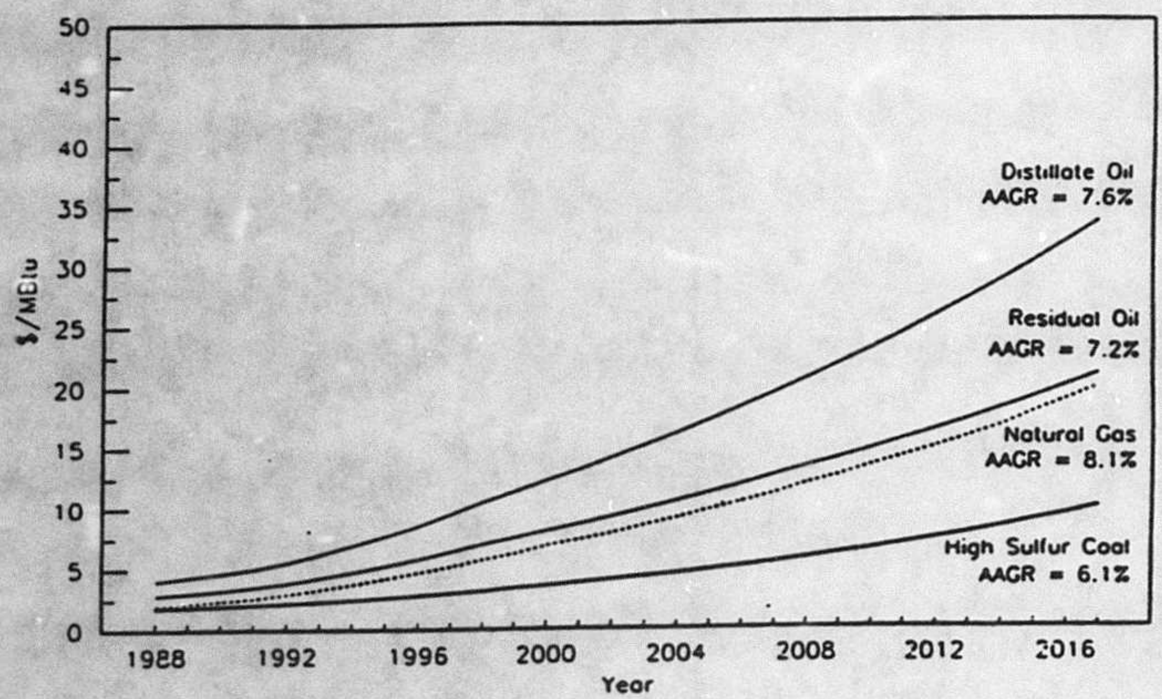


FIGURE II-4: HIGH-BAND FORECAST OF FUEL PRICES
(Nominal Dollars)

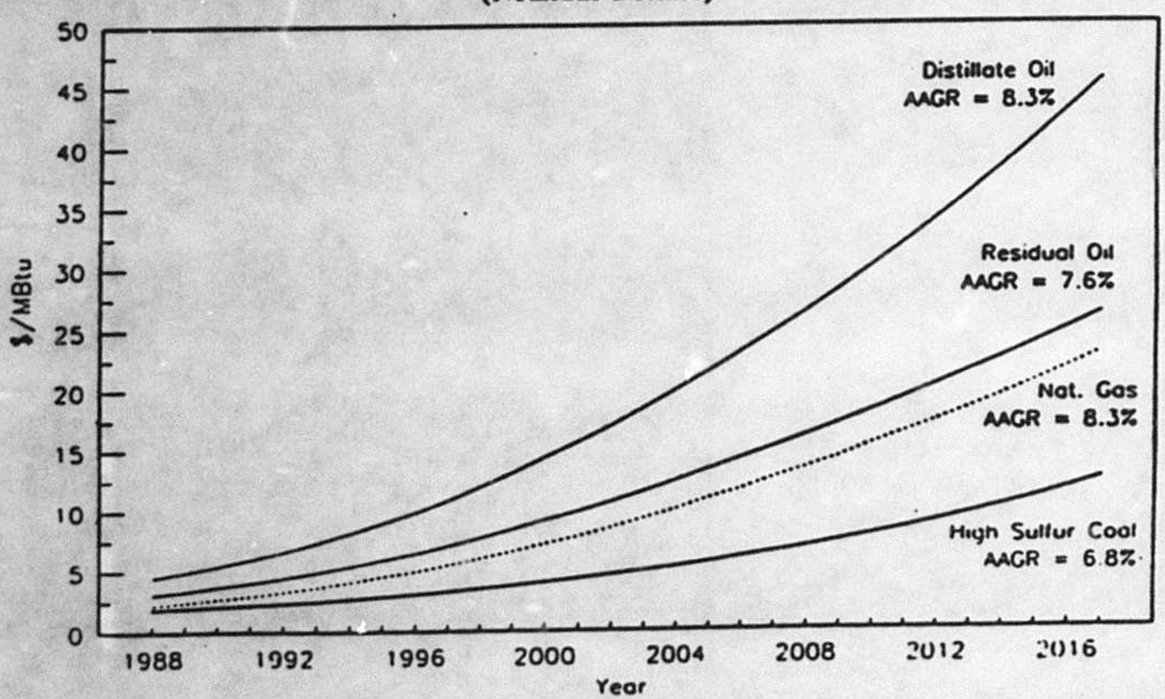
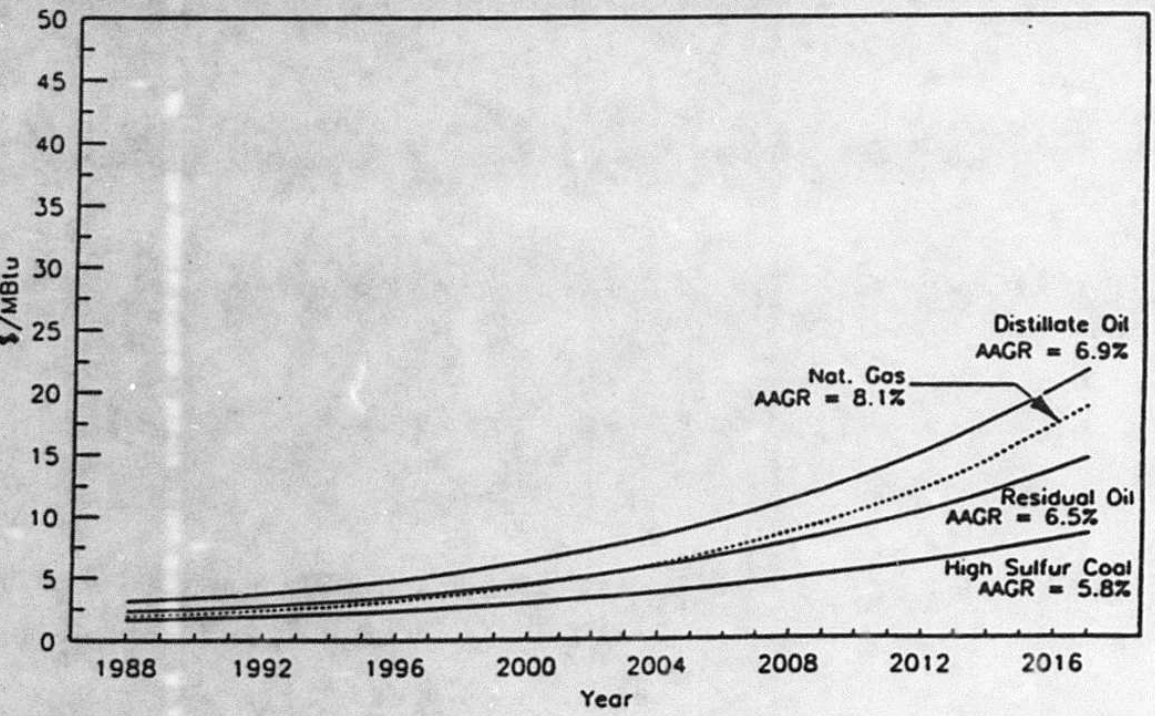


FIGURE II-5: LOW-BAND FORECAST OF FUEL PRICES
(Nominal Dollars)



FUEL PRICE FORECASTS & METHODOLOGY

The FCG developed a 30-year banded fuel price forecast for residual and distillate fuel oil, natural gas and coal. A summary of the annual fuel prices and escalators can be found in Appendix 1, FCG Studies Form 1.2, Pages 1 through 7. Additionally, the FCG developed a forecast for the volume of natural gas available to electric utilities in peninsular Florida and a nuclear fuel price forecast for existing nuclear units.

The FCG assembled a group of fuel forecasting experts from the peninsular Florida utilities to develop the fuel price forecasts. The forecasters adopted a scenario approach to project high, low and base case supply, demand and price assumptions for each fossil fuel. Each scenario described a related set of world market events which, if they occurred, would affect the supply, demand and price of fuels over time in a specific manner. The base case scenario describes market conditions which are considered the most likely to occur and result in the most likely forecast of fuel prices. The high and low price scenarios are considered less likely to occur and describe market conditions which result in higher or lower fuel prices as compared to the base case.

The result of the scenario development process was a set of real fuel prices in constant 1988 dollars for each fuel type. These prices were arrived at by consensus of the forecasters based on the scenarios. The real fuel price forecasts for the base, high and low scenarios are shown in Figures B-1, B-2 and B-3, respectively. The real price forecasts were then inflated using the general rate of inflation (Appendix C) to obtain fuel prices in nominal dollars. These nominal fuel prices are shown in graphical form in the Base Assumptions section of the report (Section II-B) and in tabular form in Appendix I, FCG Studies, Form 1.2.

The base case or most likely crude oil price scenario assumes that OPEC's current limited supply agreement will continue. When coupled with declining non-OPEC supply, OPEC should regain control of the market and real crude oil prices should increase rapidly through the 1990s. The rate of real price increases should tend to diminish in the late 1990s due to a resurgence in non-OPEC supply. The rate of crude oil price increases should diminish even further in the latter period of the forecasting horizon as competition from alternative sources of energy limits OPEC's ability to increase the real price of crude oil.

The low range crude oil price scenario assumes a loosely held agreement among OPEC countries. In this scenario, competition among OPEC countries will result in relatively low crude oil prices throughout the planning horizon.

The high range crude oil price scenario assumes a strong supply agreement between all OPEC and some non-OPEC countries which restricts world oil supply to a level sufficient to force supply and demand for crude oil to equilibrate at a higher price than current levels. OPEC rapidly regains control of the market and real crude oil prices begin to rise until the latter part of the forecasting horizon, reflecting continuing adherence to a strong supply agreement. Real crude oil price increases will moderate slightly towards the end of the planning horizon as competition begins to arise from alternative energy sources.

Assuming the base case crude oil scenario develops, residual fuel oil should generally sell at a slight discount to crude oil, while distillate fuel oil should generally sell at a premium to crude oil. Should the low range crude oil scenario develop, residual fuel oil should sell at almost the same price as crude oil, while distillate fuel oil should sell at an even larger premium to crude oil. If the high range crude oil scenario develops, residual fuel oil should sell at a larger discount to crude oil and distillate fuel oil would sell at only a small premium.

Over the long term, the price of natural gas should generally be competitive with residual fuel oil in the incremental boiler fuel market. However, for the next two to three years, delivered natural gas prices should be below this long-term equilibrium. Over time, natural gas market prices should rise and approach residual fuel oil prices, reflecting declines in the domestic supply of natural gas. Assuming the low range crude oil and corresponding residual fuel oil scenario develops, natural gas prices should escalate faster than residual fuel oil prices, resulting in natural gas prices exceeding residual fuel prices by the late 1990s. Assuming the high range crude oil and corresponding residual fuel oil scenario develops, natural gas prices should remain competitive with residual fuel throughout the planning horizon.

Supply assumptions for natural gas are based on FERC approval and completion of Florida Gas Transmission's proposed Phase II expansion of the Florida Gas Transmission Pipeline System. The expanded 925 million cubic feet per day pipeline is estimated to have about 600 million cubic feet per day of natural gas available to peninsular Florida's electric utilities on an average annual daily basis throughout the planning horizon.

Unlike petroleum where world supply is volatile and demand is fairly stable, coal supply is generally very stable and relatively unaffected by world events which impact the price of oil, while the demand for coal could react slightly to significant increases or decreases in the cost of oil and natural gas. The coal market is characterized by many small companies with abundant reserves in all sulfur grades and excess production capacity. In the base case, the demand for coal will remain stable for a few years then increase moderately to partially fill the additional capacity requirements in the utility industry. Real mine mouth prices for coal will remain relatively stable through the early 1990s then increase slightly as the cost and ability of industry to open new mines will place upward pressure on real mine mouth prices.

Coal prices will tend to be lower in the low range scenario compared with the base case scenario as the coal industry tries to maintain market share against the relatively low cost for oil and natural gas. In the high range scenario, coal prices tend to increase slightly compared with the base case scenario as suppliers attempt to increase market share and capture some of the increase in the cost of oil and natural gas without giving up individual market share to competing coal suppliers.

Since the exact location of a future coal burning facility was not known, it was assumed that both water borne and direct rail transport would be available at any proposed site. This assumed competition resulted in coal transportation costs escalating only with the cost of fuel.

A base case fuel price forecast for nuclear fuel was developed based on the design and characteristics of the five existing units in peninsular Florida.

FIGURE B-1: BASE FUEL FORECAST
(Constant 1988 Dollars)

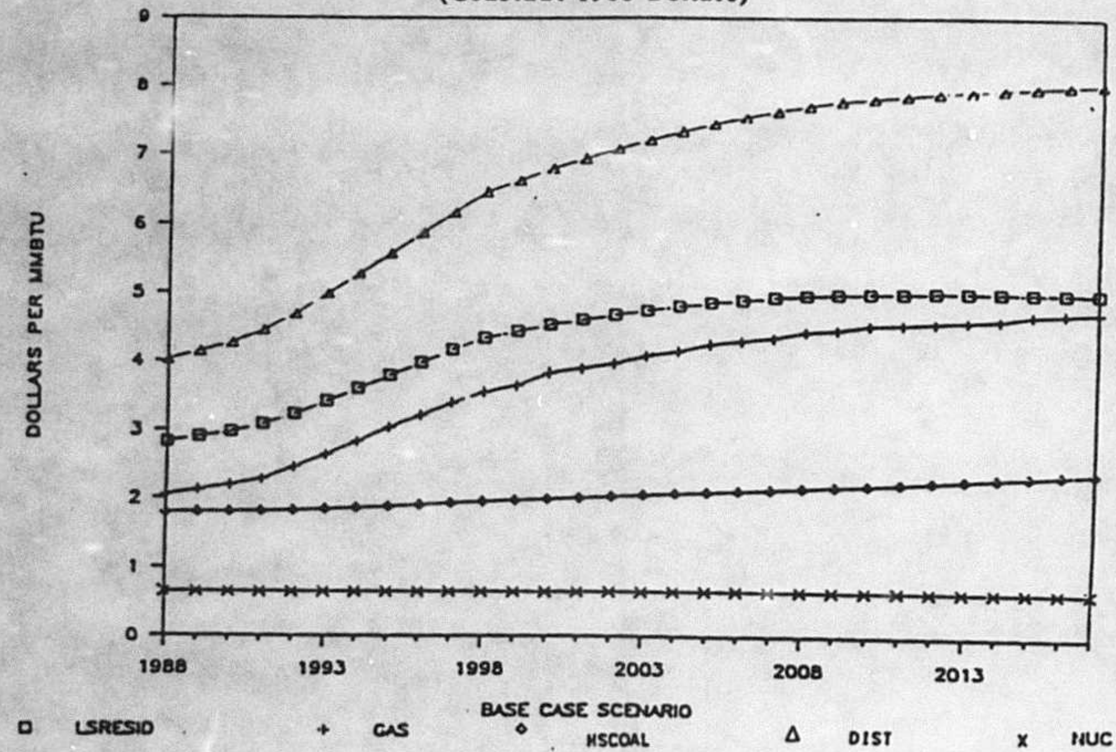


FIGURE B-2: HIGH FUEL PRICE FORECAST
(Constant 1988 Dollars)

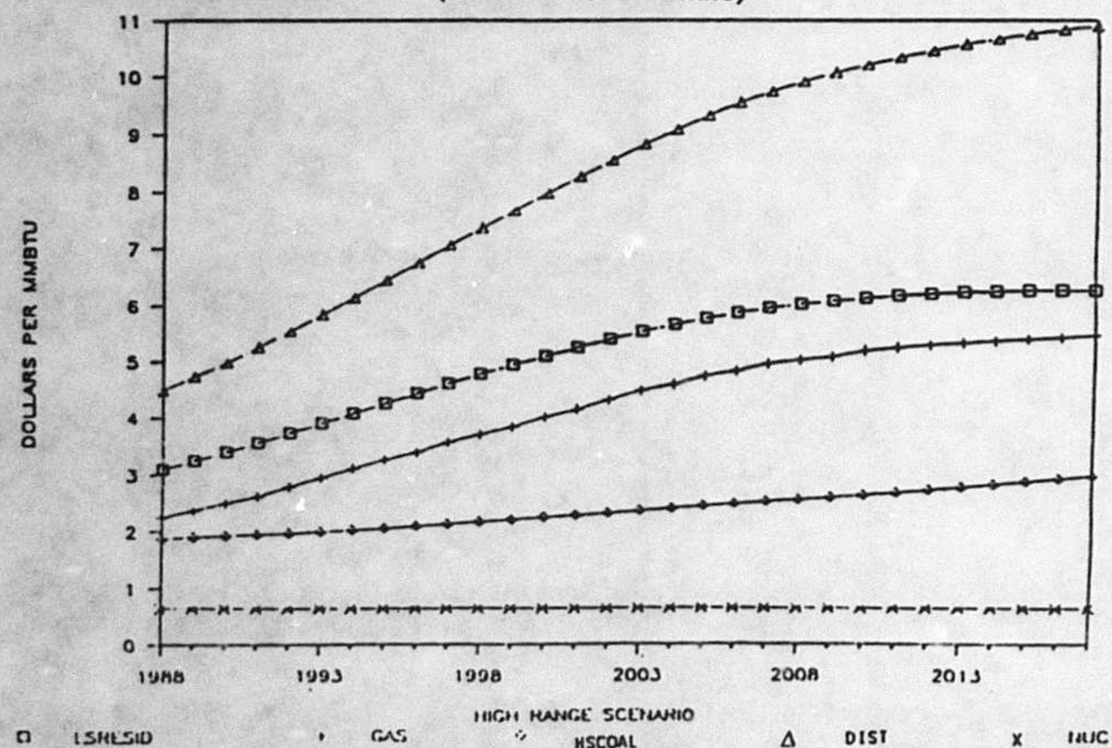
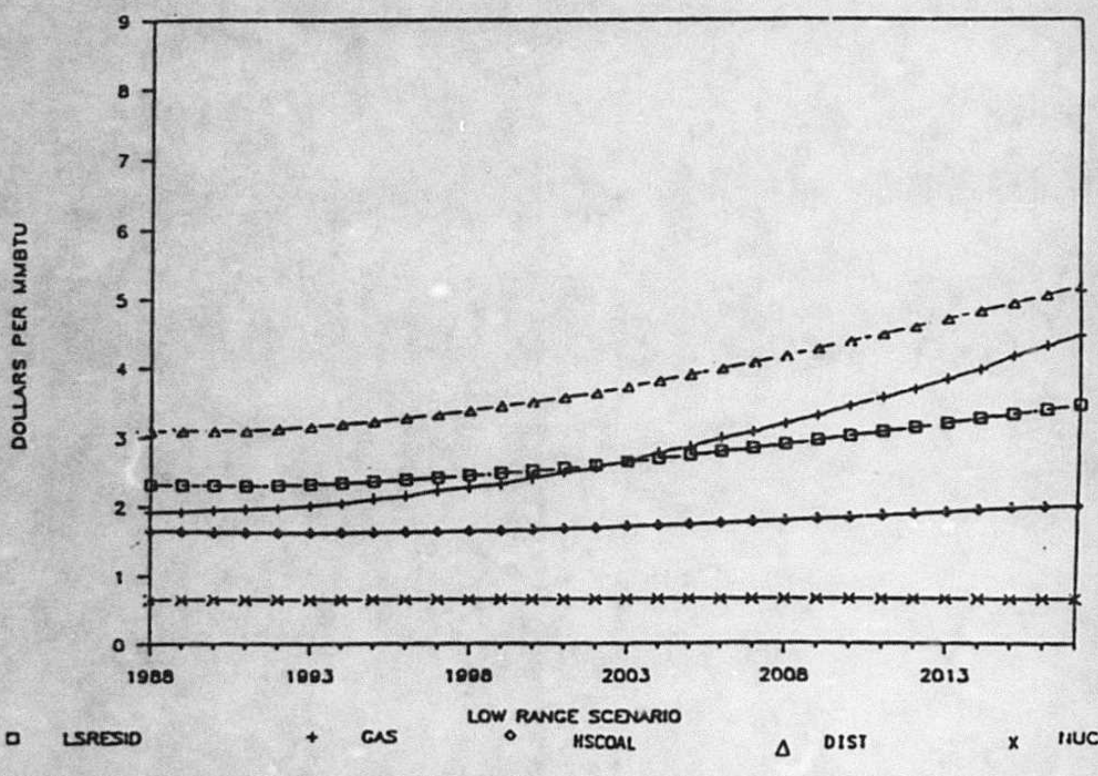


FIGURE B-3: LOW FUEL PRICE FORECAST
(Constant 1988 Dollars)



PENINSULAR FLORIDA

FUELS FORECAST (1988 - 2007)
(AVERAGE 1988 BASE PRICE AS OF MARCH 1, 1988)
BASE CASE OIL AND GAS PRICES

	RESIDUAL OIL (BY SULFUR CONTENT)									DISTILLATE OIL			NATURAL GAS	
	LESS THAN 0.7%			0.7 - 2.0%			GREATER THAN 2.0%							
YEAR	$/BBL	c/MBTU	ESCALATION %	$/BBL	c/MBTU	ESCALATION %	$/BBL	c/MBTU	ESCALATION %	$/BBL	C/MBTU	ESCALATION %	c/MBTU	ESCALAT %
1988	17.81	283	0.00	17.06	271	0.00	15.82	251	0.00	23.37	403	0.00	205	0.0
1989	19.05	302	6.96	18.25	290	6.95	16.92	269	6.94	25.11	433	7.43	220	7.7
1980	20.37	323	6.94	19.51	310	6.94	18.09	287	6.92	26.97	465	7.41	238	8.0
1991	22.02	350	8.13	21.10	335	8.12	19.55	310	8.10	29.29	505	8.62	258	8.4
1992	24.21	384	9.92	23.19	368	9.91	21.49	341	9.88	32.35	558	10.44	292	13.0
1993	26.91	427	11.16	25.77	409	11.14	23.87	379	11.12	36.13	623	11.69	330	12.9
1994	29.84	474	10.89	28.57	454	10.87	26.46	420	10.85	40.25	694	11.41	372	12.9
1995	33.03	524	10.69	31.62	502	10.68	29.28	465	10.66	44.76	772	11.20	420	12.9
1996	36.49	579	10.48	34.93	554	10.47	32.34	513	10.45	49.68	856	10.98	468	11.4
1997	40.24	639	10.29	38.52	611	10.28	35.66	566	10.27	55.02	949	10.76	520	11.0
1998	44.20	702	9.85	42.31	672	9.84	39.17	622	9.83	60.70	1047	10.32	575	10.4
1999	47.56	755	7.59	45.52	723	7.58	42.14	669	7.58	65.57	1131	8.02	622	8.2
2000	51.13	812	7.51	48.94	777	7.51	45.30	719	7.50	70.78	1220	7.94	687	10.3
2001	54.62	867	6.83	52.28	830	6.83	48.39	768	6.83	75.91	1309	7.26	736	7.2
2002	58.35	926	6.83	55.85	887	6.83	51.69	821	6.82	81.42	1404	7.25	788	7.1
2003	62.20	987	6.59	59.53	945	6.59	55.10	875	6.59	87.13	1502	7.01	851	7.9
2004	66.21	1051	6.45	63.37	1006	6.45	58.65	931	6.45	93.11	1605	6.86	909	6.7
2005	70.35	1117	6.25	67.33	1069	6.25	62.31	989	6.24	99.30	1712	6.66	978	7.6
2006	74.61	1184	6.06	71.41	1134	6.06	66.09	1049	6.06	105.73	1823	6.47	1041	6.3
2007	79.02	1254	5.91	75.63	1201	5.91	69.99	1111	5.91	112.40	1938	6.31	1106	6.2
2008 & BEYOND	83.58	1327	5.76	79.99	1270	5.76	74.03	1175	5.76	119.32	2057	6.16	1185	7.1

NOTE: HEAT CONTENT RESIDUAL OIL: 6.30 MBTU / BBL
HEAT CONTENT DISTILLATE : 5.80 MBTU / BBL

PENINSULAR FLORIDA

FUELS FORECAST (1988 - 2007)

(AVERAGE 1988 BASE PRICE AS OF MARCH 1, 1988)

LOW CASE OIL AND GAS PRICES

	RESIDUAL OIL (BY SULFUR CONTENT)									DISTILLATE OIL			NATURAL GAS	
	LESS THAN 0.7%			0.7 - 2.0%			GREATER THAN 2.0%							
			ESCALATION			ESCALATION			ESCALATION			ESCALATION		ESCALAT
YEAR	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	C/MBTU	%	c/MBTU	%
1988	14.60	232	0.00	14.04	223	0.00	13.10	208	0.00	18.01	311	0.00	192	0.0
1989	15.17	241	3.90	14.59	232	3.91	13.61	216	3.91	18.78	324	4.28	201	4.4
1980	15.78	250	4.00	15.17	241	4.00	14.16	225	4.01	19.60	338	4.38	212	5.7
1991	16.39	260	3.90	15.76	250	3.90	14.71	233	3.91	20.44	352	4.27	222	4.7
1992	17.26	274	5.27	16.59	263	5.27	15.48	246	5.27	21.60	372	5.66	236	6.1
1993	18.25	290	5.77	17.55	279	5.77	16.38	260	5.77	22.93	395	6.17	252	6.8
1994	19.33	307	5.87	18.58	295	5.87	17.34	275	5.86	24.37	420	6.26	269	6.8
1995	20.51	326	6.13	19.72	313	6.13	18.40	292	6.12	25.96	448	6.53	291	8.0
1996	21.84	347	6.49	21.00	333	6.49	19.59	311	6.48	27.74	478	6.89	312	7.3
1997	23.32	370	6.75	22.42	356	6.75	20.91	332	6.75	29.72	512	7.13	342	9.4
1998	24.89	395	6.73	23.93	380	6.73	22.32	354	6.73	31.84	549	7.12	367	7.5
1999	26.56	422	6.72	25.53	405	6.71	23.82	378	6.71	34.10	588	7.11	395	7.5
2000	28.33	450	6.68	27.24	432	6.68	25.41	403	6.67	36.51	630	7.07	430	8.7
2001	30.23	480	6.69	29.04	461	6.69	27.11	430	6.68	39.10	674	7.09	467	8.7
2002	32.25	512	6.68	31.00	492	6.68	28.92	459	6.67	41.87	722	7.08	504	7.7
2003	34.54	548	7.12	33.21	527	7.12	30.97	492	7.11	45.03	776	7.53	551	9.3
2004	36.99	587	7.09	35.56	564	7.09	33.16	526	7.08	48.40	835	7.50	607	10.1
2005	39.65	629	7.18	38.11	605	7.17	35.54	564	7.17	52.08	898	7.59	658	8.4
2006	42.48	674	7.15	40.83	648	7.14	38.08	604	7.13	56.01	966	7.56	720	9.4
2007	45.51	722	7.12	43.74	694	7.12	40.78	647	7.11	60.23	1038	7.53	781	9.4
2008 & BEYOND	48.73	773	7.08	46.83	743	7.07	43.66	693	7.07	64.73	1116	7.48	854	9.2

NOTE: HEAT CONTENT RESIDUAL OIL: 6.30 MBTU / BBL
HEAT CONTENT DISTILLATE : 5.80 MBTU / BBL

PENINSULAR FLORIDA

FUELS FORECAST (1988 - 2007)
(AVERAGE 1988 BASE PRICE AS OF MARCH 1, 1988)
HIGH CASE OIL AND GAS PRICES

	RESIDUAL OIL (BY SULFUR CONTENT)									DISTILLATE OIL			NATURAL GAS	
	LESS THAN 0.7%			0.7 - 2.0%			GREATER THAN 2.0%							
YEAR	$/BBL	c/MBTU	ESCALATION %	$/BBL	c/MBTU	ESCALATION %	$/BBL	c/MBTU	ESCALATION %	$/BBL	C/MBTU	ESCALATION %	c/MBTU	ESCALAT %
1988	19.58	311	0.00	18.73	297	0.00	17.30	275	0.00	26.10	450	0.00	225	0.0
1989	21.38	339	9.18	20.44	324	9.16	18.88	300	9.12	28.69	495	9.92	247	9.9
1980	23.36	371	9.28	22.33	354	9.26	20.62	327	9.22	31.56	544	10.01	272	10.1
1991	25.49	405	9.10	24.36	387	9.09	22.49	357	9.05	34.67	598	9.84	296	8.7
1992	27.99	444	9.80	26.75	425	9.78	24.68	392	9.75	38.32	661	10.54	332	12.0
1993	30.79	489	10.01	29.42	467	10.00	27.14	431	9.96	42.44	732	10.75	368	11.0
1994	33.82	537	9.85	32.31	513	9.83	29.80	473	9.80	46.93	809	10.58	409	10.9
1995	37.11	589	9.72	35.45	563	9.71	32.68	519	9.68	51.83	894	10.45	453	10.8
1996	40.66	645	9.54	38.83	616	9.53	35.78	568	9.50	57.14	985	10.26	496	9.4
1997	44.49	706	9.44	42.49	674	9.43	39.15	621	9.41	62.94	1085	10.13	549	10.6
1998	48.61	772	9.24	46.41	737	9.23	42.76	679	9.21	69.19	1193	9.93	600	9.2
1999	52.97	841	8.97	50.56	803	8.95	46.57	739	8.93	75.87	1308	9.66	654	9.0
2000	57.56	914	8.67	54.94	872	8.66	50.60	803	8.63	82.97	1430	9.35	719	9.9
2001	62.32	989	8.27	59.48	944	8.26	54.76	869	8.24	90.39	1559	8.95	779	8.4
2002	67.35	1069	8.07	64.28	1020	8.06	59.17	939	8.04	98.30	1695	8.75	853	9.4
2003	72.61	1153	7.81	69.29	1100	7.80	63.77	1012	7.78	106.63	1839	8.48	931	9.1
2004	78.04	1239	7.48	74.46	1182	7.47	68.52	1088	7.45	115.32	1988	8.14	1003	7.6
2005	83.65	1328	7.18	79.80	1267	7.17	73.42	1165	7.15	124.36	2144	7.84	1089	8.5
2006	89.39	1419	6.87	85.28	1354	6.86	78.44	1245	6.84	133.71	2305	7.52	1166	7.1
2007	95.29	1512	6.59	90.89	1443	6.58	83.59	1327	6.56	143.38	2472	7.23	1259	7.9
2008 & BEYOND	101.32	1608	6.34	96.64	1534	6.33	88.87	1411	6.31	153.37	2644	6.97	1342	6.5

NOTE: HEAT CONTENT RESIDUAL OIL: 6.30 MBTU / BBL
HEAT CONTENT DISTILLATE : 5.80 MBTU / BBL

PENINSULAR FLORIDA

FUELS FORECAST (1988 - 2007)
(AVERAGE 1988 BASE PRICE AS OF MARCH 1, 1988)
BASE CASE COAL PRICES

	LOW SULFUR COAL LESS THAN 1.0%			MEDIUM SULFUR COAL 1.0 - 2.0%			HIGH SULFUR COAL GREATER THAN 2.0%		
YEAR	$/TON	c/MBTU	ESCALATION %	$/TON	c/MBTU	ESCALATION %	$/TON	c/MBTU	ESCALATION %
1988	47.10	196	0.00	44.53	184	0.00	42.86	179	0.00
1989	49.20	205	4.45	46.51	194	4.45	44.76	187	4.45
1980	51.46	214	4.61	48.65	203	4.61	46.83	195	4.61
1991	53.93	225	4.80	50.99	212	4.80	49.07	204	4.80
1992	57.04	238	5.76	53.92	225	5.76	51.90	216	5.76
1993	60.57	252	6.19	57.26	239	6.19	55.11	230	6.19
1994	64.39	268	6.31	60.88	254	6.31	58.59	244	6.31
1995	68.55	286	6.45	64.81	270	6.45	62.37	260	6.45
1996	73.08	305	6.62	69.09	288	6.62	66.50	277	6.62
1997	77.94	325	6.65	73.69	307	6.65	70.92	295	6.65
1998	83.14	346	6.67	78.60	327	6.67	75.65	315	6.67
1999	88.33	368	6.24	83.50	348	6.24	80.37	335	6.24
2000	93.88	391	6.28	88.75	370	6.28	85.42	356	6.28
2001	99.61	415	6.11	94.17	392	6.11	90.64	378	6.11
2002	105.71	440	6.13	99.94	416	6.13	96.19	401	6.13
2003	112.23	468	6.17	106.10	442	6.17	102.12	426	6.17
2004	119.16	496	6.17	112.65	469	6.17	108.42	452	6.17
2005	126.50	527	6.16	119.60	498	6.16	115.11	480	6.16
2006	134.30	560	6.17	126.97	529	6.17	122.20	509	6.17
2007	142.61	594	6.19	134.82	562	6.19	129.76	541	6.19
2008 & BEYOND	151.48	631	6.22	143.21	597	6.22	137.84	574	6.22

NOTE: HEAT CONTENT OF COAL : 24.00 MBTU / TON

PENINSULAR FLORIDA

FUELS FORECAST (1988 - 2007)

(AVERAGE 1988 BASE PRICE AS OF MARCH 1, 1988)

LOW CASE COAL PRICES

	LOW SULFUR COAL LESS THAN 1.0%			MEDIUM SULFUR COAL 1.0 - 2.0%			HIGH SULFUR COAL GREATER THAN 2.0%		
YEAR	$/TON	c/MBTU	ESCALATION %	$/TON	c/MBTU	ESCALATION %	$/TON	c/MBTU	ESCALATION %
1988	43.54	181	0.00	41.14	171	0.00	39.61	165	0.00
1989	44.98	187	3.31	42.52	177	3.31	40.93	171	3.31
1980	46.68	195	3.79	44.13	184	3.79	42.48	177	3.79
1991	48.45	202	3.79	45.81	191	3.79	44.09	184	3.79
1992	50.73	211	4.70	47.96	200	4.70	46.16	192	4.70
1993	53.29	222	5.04	50.38	210	5.04	48.49	202	5.04
1994	56.09	234	5.25	53.03	221	5.25	51.04	213	5.25
1995	59.16	246	5.47	55.93	233	5.47	53.83	224	5.47
1996	62.47	260	5.60	59.06	246	5.60	56.84	237	5.60
1997	66.04	275	5.72	62.44	260	5.72	60.09	250	5.72
1998	69.89	291	5.83	66.08	275	5.83	63.60	265	5.83
1999	73.96	308	5.82	69.92	291	5.82	67.30	280	5.82
2000	78.29	326	5.86	74.02	308	5.86	71.24	297	5.86
2001	83.05	346	6.07	78.51	327	6.07	75.56	315	6.07
2002	88.01	367	5.98	83.21	347	5.98	80.08	334	5.98
2003	93.39	389	6.11	88.29	368	6.11	84.97	354	6.11
2004	99.15	413	6.17	93.74	391	6.17	90.22	376	6.17
2005	105.29	439	6.19	99.54	415	6.19	95.81	399	6.19
2006	111.84	466	6.22	105.74	441	6.22	108.16	424	6.22
2007	118.87	495	6.28	112.38	468	6.28	129.76	451	6.28
2008 & BEYOND	126.37	527	6.31	119.47	498	6.31	114.99	479	6.31

NOTE: HEAT CONTENT OF COAL : 24.00 MBTU / TON

PENINSULAR FLORIDA

FCG STUDIES FORM 1.2

FUELS FORECAST (1988 - 2007)
(AVERAGE 1988 BASE PRICE AS OF MARCH 1, 1988)
HIGH CASE COAL PRICES

	LOW SULFUR COAL LESS THAN 1.0%			MEDIUM SULFUR COAL 1.0 - 2.0%			HIGH SULFUR COAL GREATER THAN 2.0%		
YEAR	$/TON	c/MBTU	ESCALATION %	$/TON	c/MBTU	ESCALATION %	$/TON	c/MBTU	ESCALATION %
1988	49.28	205	0.00	46.59	194	0.00	44.84	187	0.00
1989	51.91	216	5.34	49.08	204	5.34	47.24	197	5.34
1980	54.83	228	5.63	51.84	216	5.63	49.89	208	5.63
1991	57.90	241	5.60	54.74	228	5.60	52.69	220	5.60
1992	61.62	257	6.42	58.26	243	6.42	56.07	234	6.42
1993	65.73	274	6.67	62.14	259	6.67	59.81	249	6.67
1994	70.22	293	6.83	66.39	277	6.83	63.90	266	6.83
1995	75.11	313	6.96	71.01	296	6.96	68.34	285	6.96
1996	80.38	335	7.02	75.99	317	7.02	73.14	305	7.02
1997	86.05	359	7.05	81.35	339	7.05	78.30	326	7.05
1998	92.19	384	7.14	87.16	363	7.14	83.89	350	7.14
1999	98.71	411	7.06	93.32	389	7.06	89.82	374	7.06
2000	105.69	440	7.07	99.92	416	7.07	96.17	401	7.07
2001	113.01	471	6.93	106.84	445	6.93	102.83	428	6.93
2002	120.80	503	6.89	114.21	476	6.89	109.92	458	6.89
2003	129.15	538	6.91	122.10	509	6.91	117.52	490	6.91
2004	138.03	575	6.87	130.50	544	6.87	125.60	523	6.87
2005	147.47	614	6.84	139.42	581	6.84	134.18	559	6.84
2006	157.51	656	6.81	148.91	620	6.81	143.32	597	6.81
2007	168.23	701	6.81	159.05	663	6.81	153.08	638	6.81
2008 & BEYOND	179.68	749	6.81	169.87	708	6.81	163.50	681	6.81

NOTE: HEAT CONTENT OF COAL : 24.00 MBTU / TON

PENINSULAR FLORIDA

FCG STUDIES FORM 1.2

FUELS FORECAST (1988 - 2007)

AS OF MARCH 1, 1988

	NUCLEAR		FIRM PURCHASES	
YEAR	c/MBTU	ESCALATION %	$/MWh	ESCALATION %
1988	65.00	0.00	20.41	0.00
1989	67.73	4.20	21.32	4.45
1980	70.64	4.30	22.30	4.61
1991	73.61	4.20	23.37	4.80
1992	77.22	4.90	24.72	5.76
1993	81.15	5.09	26.25	6.19
1994	85.37	5.20	27.90	6.31
1995	89.90	5.31	29.70	6.45
1996	94.66	5.29	31.67	6.62
1997	99.68	5.30	33.77	6.65
1998	104.96	5.30	36.03	6.67
1999	110.42	5.20	38.27	6.24
2000	116.16	5.20	40.68	6.28
2001	122.09	5.11	43.16	6.11
2002	128.32	5.10	45.81	6.13
2003	134.86	5.10	48.63	6.17
2004	141.74	5.10	51.64	6.17
2005	148.97	5.10	54.82	6.16
2006	156.56	5.09	58.20	6.17
2007	164.55	5.10	61.80	6.19
2008 & BEYOND	172.94	5.10	65.64	6.22

ATTACHMENT B-1

FLORIDA MUNICIPAL POWER AGENCY

DESCRIPTION

The Florida Municipal Power Agency ("FMPA") is a non-profit, joint action agency formed by 28 municipal electric utilities for the primary purpose of jointly planning, financing and operating electric power supply projects, which includes generating plants, transmission facilities, and fuel supplies. Formed pursuant to Florida Statutes, FMPA has the authority to issue tax-exempt bonds or other obligations for the purpose of financing or refinancing the costs of such projects.

Due to the diverse needs of municipal electric systems, FMPA established itself as a project-oriented agency. Under this structure, each member has the option whether or not to participate in a project. Members may participate in more than one project; however, each of FMPA's projects is independent from the other, and no revenues or funds available from one project can be used to pay the costs of any other project. FMPA currently has four power supply projects in operation: (1) the St. Lucie Project provides nuclear capacity and energy to 16 participants through an 8.806% ownership share in Florida Power and Light's ("FPL") St. Lucie Unit 2; (2) the Stanton Project provides coal-fired capacity and energy to five participants through a 14.8193% ownership share in Orlando Utilities Commission's ("OUC") Stanton Energy Center Unit No. 1; (3) the Tri-City Project provides coal-fired capacity and energy to three participants through a 5.3012% ownership share in OUC's Stanton Energy Center Unit No. 1; and (4) the All-Requirements Project supplies full requirements power (above certain excluded resources) to five FMPA members. Power is supplied from a 6.506% ownership share of OUC's Stanton Energy Center Unit No. 1, a 39% ownership share of OUC's two new .37 MW combustion turbines, and wholesale purchases from Florida Power Corporation ("FPC"), FPL, and others. Table 1 provides a listing of the FMPA members and a summary of their participation in each of the four FMPA power supply projects.

Table 2 provides summary information on the current power supply arrangements and peak loads of the FMPA members. Future power supply projects undertaken by FMPA will involve obtaining additional resources for the All-requirements Project and/or creating a new project for FMPA members that are not participants in the All-Requirements Project. For resources involving joint participation with OUC, FMPA currently plans to have OUC serve as FMPA's agent for dispatching purposes.

TABLE 1

FLORIDA MUNICIPAL POWER AGENCY
SUMMARY OF PROJECT PARTICIPATION

Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Project
1 City of Alachua	X			
2 City of Bartow				
3 City of Bushnell				X
4 City of Clewiston	X			
5 City of Fort Meade	X			
6 Fort Pierce Utilities Authority	X	X	X	
7 Gainesville Regional Utilities				
8 City of Green Cove Springs	X			X
9 City of Havana				
10 City of Homestead	X	X	X	
11 City of Jacksonville Beach	X			X
12 Key West City Electric System			X	
13 Kissimmee Utility Authority	X			
14 Lakeland Electric & Water Utilities				
15 City of Lake Worth	X	X		
16 City of Leesburg	X			X
17 City of Moore Haven	X			
18 City of Mount Dora				
19 City of Newberry	X			
20 Utilities Commission, City of New Smyrna Beach	X			
21 City of Ocala				X
22 Sebring Utilities Commission	X			
23 City of St. Cloud				
24 City of Starke	X	X		
25 City of Tallahassee				
26 City of Vero Beach	X	X		
27 City of Wauchula				
28 City of Williston				
Total FMPA 1989 Project Capacity/Summer Demand (MW)	75	62	22	393

Total FMPA 1989 Capacity
and Sales = 552 MW

TABLE 2

FLORIDA MUNICIPAL POWER AGENCY
SUMMARY OF CURRENT POWER SUPPLY ARRANGEMENTS

	Member	Type of System (1)	Resources (2)	1989 Summe Peak (MW
1	City of Alachua	Full Req.	Nuclear, St. Lucie, Purchases	11
2	City of Bartow	Full Req.	Full Req. from FPC	60
3	City of Bushnell	Full Req.	FMPA All-Req., Nuclear, St. Lucie	3
4	City of Clewiston	Full Req.	Full Req. Purchases, St. Lucie (3)	17
5	City of Fort Meade	Full Req.	Full Req. from FPC, St. Lucie (3)	8
6	Ft. Pierce Utilities Auth.	Part. Gen.	Gas, Oil, Stanton, Tri-City, St. Lucie	95
7	Gainesville Reg. Utilities	Generating	Coal, Gas, Oil, Nuclear	296
8	City of Green Cove.Springs	Full Req.	FMPA All-Req., St. Lucie	17
9	City of Havana	Full Req.	Full Req. from Talguin Cooperative	5
10	City of Homestead	Part. Gen.	Gas, Oil, Stanton, Tri-City, St. Lucie	50
11	City of Jacksonville Beach	Full Req.	FMPA All-Req. St. Lucie	102
12	Key West City Electric Sys.	Part. Gen.	Oil, Tri-City	85
13	Kissimmee Utility Auth.	Partial Gen.	Gas, Oil, Nuclear, Coal, St. Lucie	141
14	Lakeland Electric & Water Utilities	Generating	Coal, Gas, Oil	409
15	City of Lake Worth	Part. Gen.	Gas, Oil, Stanton, St. Lucie	69
16	City of Leesburg	Full Req.	FMPA All-Req., Nuclear	74
17	City of Moore Haven	Full Req.	Full Req. Purchases, St. Lucie (3)	3
18	City of Mount Dora	Full Req.	Full Req. from FPC	15
19	City of Newberry	Full Req.	Full Req. from FPC, St. Lucie (3)	4
20	Utilities Commission, City of New Smyrna Beach	Part. Gen.	Gas, Oil Nuclear, St. Lucie, Purchases	64
21	City of Ocala	Full Req.	FMPA All-Req., Nuclear	197
22	Sebring Utilities Comm.	Part. Gen.	Gas, Oil, Nuclear, Purch., St. Lucie (3)	40
23	City of St. Cloud	Part. Gen.	Gas, Oil, Purchases	47
24	City of Starke	Part. Gen.	Gas, Oil, Stanton, St. Lucie, Purchases	12
25	City of Tallahassee	Generating	Gas, Oil, Nuclear, Purchases	423
26	City of Vero Beach	Part. Gen.	Gas, Oil, Stanton, St. Lucie	108
27	City of Wauchula	Full Req.	Full Req. from FPC	11
28	City of Williston	Full Req.	Full Req. from FPC	5
29	Total FMPA Non-coincident Load			2,371

(1) Full Req. - Member purchases all power requirements (above certain resources).
Partial Gen. - Member owns generation and purchases remaining requirements.
Generating - Member owns generation sufficient to serve its entire load and purchases for economics.

(2) Current power supply resources including types off fuel used by owned generation participation in FMPA project, wholesale purchases from investor owned utilities, and purchases from other municipal or cooperative utilities.

(3) St. Lucie Project entitlements are currently delivered to another FMPA member.

ATTACHMENT B-2

KISSIMMEE UTILITY AUTHORITY, KISSIMMEE, FLORIDA

DESCRIPTION OF EXISTING SYSTEM

GENERAL

Kissimmee Utility Authority (KUA) operates an electric utility system for the production and distribution of electricity to approximately 32,000 customers within its service area. The City's electric system was established in 1910 under laws of the State of Florida and the City Charter. In 1985, the KUA was created as an independent utility authority. The KUA is comprised of a five member Board of Directors. The staff is headed by the General Manager.

DESCRIPTION OF SERVICE AREA

The KUA service area encompasses 85 square miles including the City of Kissimmee and some adjoining areas. The service area is bordered on the north by the Orange-Osceola county line and the City of St. Cloud service area on the east. Otherwise, KUA's service area is surrounded by Florida Power Corporation's service area. The City is located approximately 15 miles south of the City of Orlando and approximately 18 miles southeast of Walt Disney World.

EXISTING GENERATING UNITS

KUA owns and operates the Roy G. Hansel Generating Station consisting of nine operating diesel generators with a combined capability of 20.8 MW. The diesel generators were installed at various times beginning in 1960. All of the units, except the two which were rebuilt in 1983, are capable of operation on either natural gas or No. 2 oil.

KUA has constructed a combined cycle plant (Units 21, 22 and 23) adjacent to the Roy G. Hansel Diesel Plant. The combined cycle plant went into commercial operation in December 1983. The combined cycle plant 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 combustion turbine has a base load rating ranging from 32.8 MW at 95° F ambient temperature to 41.6 MW at 30° F ambient temperature. The steam turbines each have a nominal capability of 10 MW. The combined cycle plant has dual fuel capability for natural gas and No. 2 oil.

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.

KUA also is a participant through the Florida Municipal Power Agency in the St. Lucie 2 nuclear unit owned by Florida Power & Light with an ownership share of 0.828 percent. A reliability exchange splits KUA's capacity and energy entitlement from St. Lucie 2 between St. Lucie 1 and 2. KUA receives approximately 3.2 MW from each unit.

KUA owns a 4.8193 percent interest in the Orlando Utilities Commission Stanton Energy Center Unit 1. The unit is a nominal 415 MW pulverized coal unit which began commercial operation in 1987. KUA ownership share is approximately 20 MW.

KUA is also a participant in the Orlando Utilities Commission Indian River Combustion Turbine Project which involves a 12.2 percent ownership in two 37.4 MW International Standards Organization (ISO) rating General Electric Frame 6 combustion turbines. KUA receives approximately 9.1 MW from the project at ISO rating.

In summary, KUA currently has a total installed capacity of approximately 123 MW in winter and approximately 115 MW in the summer. But since the peak demand of the system exceeds the installed capacity, KUA has entered into capacity purchase contracts with various other electric utilities in the State. A description of these contracts are given below:

KUA has a 20 MW capacity purchase agreement with Orlando Utility Commission which extends to November 30, 2003. This agreement includes an additional 50 MW of optional capacity on an as-available basis. The cost of purchase power is comprised of demand, an energy charge, and fuel costs.

KUA has a Stratified Partial Requirement Contract with Florida Power Corporation which is valid for the next 15 years. The amount and type (Peaking, Intermediate, and Base) of capacity varies over the years. The current capacity amount begins with 15 MW in 1990 and increases to 97 MW by 1994. KUA retains the right to increase or lower the MW amounts by up to 20% in the 5 year horizon years.

KUA also has a firm Schedule "D" capacity contract with Tampa Electric Company for an amount of 30 MW through the end of 1990. Currently negotiations are proceeding to increase this purchase amount by another 5 MW beginning May 1, 1990.

In addition to the above firm purchase contracts, KUA also has economy interchange contracts with approximately 20 other electric utilities in the State of Florida for hourly transactions of electrical capacity and energy.

FUTURE GENERATION EXPANSION PLANS

During the past eight to ten years KUA has been experiencing a double digit growth in its peak demands. It is anticipated that a similar growth pattern (may be only slightly lower than the previous ten years) will continue in KUA's service area. Attachment "1" shows the historical and projected peak demands for KUA.

To meet the future customers' demand KUA staff is continually evaluating various available generation expansion options. In addition to the Stratified Partial Requirement Power Purchase from Florida Power Corporation (which is to extend for a minimum of 15 years) the following alternative capacity option have been identified or are being evaluated at this time.

- In December 1989, KUA's Board of Directors approved the concept of KUA constructing a gas turbine in the capacity range of 35 to 40 MW. The gas turbine will be built at a new site which will have the ultimate capacity of accommodating up to 500 MW of GT or Combined Cycle Capacity.

- Propose to participate as a joint owner in Orlando Utilities Commission's coal fired Stanton Unit No. 2. OUC indicates the in-service date for Stanton Unit 2 to be in the 1996/1997 time frame. KUA is interested in up to 50 MW from Stanton Unit 2.

- Recently KUA has received an offer from Lakeland Electric & Water Utilities to participate in certain of their repowering projects. The project involves converting some old steam turbine units into combined cycle mode by installing new gas turbine units at the front end and to install heat recovery steam generators (boilers) to capture the GT exhausts for running the steam turbines. The participation details are yet to be ironed out. KUA staff is currently evaluating the same.

- Tampa Electric Company (TECO) is planning to refurbish the oil fired units at their Hooker's Point Station in the near future. TECO has offered to sell up to 100 MW of firm Schedule "D" power to KUA and other utilities from those refurbished units. KUA staff,with the help of consultants, is evaluating the offer and hope to arrive at some recommendation within the next two months.

In addition to the above alternatives KUA's staff also will be in constant lookout for any other opportunities for cheaper power that may present themselves from time to time in the future.

EXISTING TRANSMISSION SYSTEM

The existing transmission system is shown on Figure 1. KUA is served by the Roy G. Hansel Diesel Station with a capacity of approximately 20.8 MW, the combined cycle plant with a capacity of approximately 58.7 MW, and four interconnections to other utilities. One 69 kV interconnection is at Florida Power Corporation's Lake Bryan Substation. A second interconnection, at 230 kV, is at the Orlando Utilities Commission's Taft Substation. A 69 kV interconnection through a 230/69 kV transformer comprises the third interconnection. The fourth interconnection, through a 230/69 kV is at the City of St. Cloud's power plant and is currently used primarily to supply power to St. Cloud. St. Cloud has completed an interconnection with Florida Power Corporation, which will allow KUA to import power via this interconnection. However, at this time KUA cannot import power from Florida Power Corporation through the St. Cloud system due to transmission limitations within the St. Cloud system. This limitation should be removed by late 1990.

Florida Power Corporation 69 kV Interconnection

The existing Florida Power Corporation 69 kV interconnection, which connects Florida Power Corporation's Lake Bryan Substation and KUA's Airport Substation via Lake Cecil Substation (May 1990), is constructed with 336.4 Mcm AAC conductor for approximately half its length and 795 Mcm AAC conductor on the remaining half. The import capacity of this line is presently limited to the capacity of the 336.4 Mcm conductor. Replacing the 336.4 Mcm conductor with 795 Mcm AAC conductor would significantly increase the import capacity.

The maximum import capacity of this line is dependent upon the ambient conditions which exist at the time of peak load. The 336.4 Mcm AAC conductor has a rating of approximately 52 MW for summer peak loads and a rating of approximately 71 MW for winter peak loads. These ratings assume a maximum operating temperature of 80 C.

The maximum import capacity of the 795 Mcm AAC conductor is approximately 91 MW for summer peak loads and approximately 125 MW for winter peak loads based on a maximum operating temperature of 80° C. Since Lake Bryan is tied to strong sources at both. Windermere Substation and Intercession City Substation, it is assumed that this tie line will load to its thermal limit. Detailed load flow analysis would be required to determine the exact capacity of this tie line.

The City of St. Cloud currently has entitlement to 15 MW of capacity of this interconnection as per a clause in an earlier agreement. If the City of St. Cloud participates in the re-conductoring, their entitlement will increase to 25 MW.

Taft 230 kV Interconnection

The existing Taft 230 kV interconnection, which connects Taft Substation to KUA's Marydia Substation, is constructed with 795 Mcm ACSR conductor. The maximum import capacity of this line is approximately 300 MW for summer peak loads and approximately 360 MW for winter peak loads.

Taft 69 kV Interconnection

The existing Taft 69 kV interconnection consists of a 230/69 kV 90/120/150 MVA transformer at Taft Substation with 1590 ACSR conductor from Taft Substation to Buenaventura Lakes Substation. The transmission line capacity is approximately equal to the transformer capacity.

St. Cloud 69 kV Interconnection

The City of St. Cloud is presently served by the 69 kV interconnection to the Hansel Plant Substation (via Carl Wall Substation after May 1990) in addition to their own generation which consists of approximately 29 MW of diesel capacity. The existing 69 kV interconnection is presently limited by the 18/24/30 MVA St. Cloud transformer. A second 18/24/30 MVA transformer was installed in 1987; however, it is not presently energized. After its installation, the interconnection will be limited to approximately 40 MW due to voltage drop resulting from the 336 Mcm conductor. The power flow through the St. Cloud interconnection is normally into St. Cloud, but the scheduled addition of a 230 kV interconnection with Florida Power Corporation will enable import into KUA. When the Florida Power Corporation interconnection is complete, KUA will have a 45 MW entitlement, through that interconnection.

PROJECTED TRANSMISSION SYSTEM

Recently KUA has authorized Black & Veatch, its engineering consultants, to perform a transmission system study for KUA's transmission and substation future needs during the next 20 years. The transmission study will also incorporate the necessary interconnection to the proposed gas turbine site.

ATTACHMENT "1"

Kissimmee Utility Authority

Historical and Projected Peak Demands

YEAR	PEAK DEMAND (MW)	
1984	85	
1985	121	
1986	128	
1987	115	
1988	131	
1989	148	
1990	200	*
1991	192	
1992	206	
1993	219	
1994	232	
1995	246	
1996	259	
1997	272	
1998	286	
1999	300	
2000	315	
2001	329	
2002	344	
2003	359	
2004	374	
2005	390	
2006	404	
2007	419	
2008	434	
2009	450	
2010	466	

* 1989/90 Extreme Cold Weather - Winter Peak

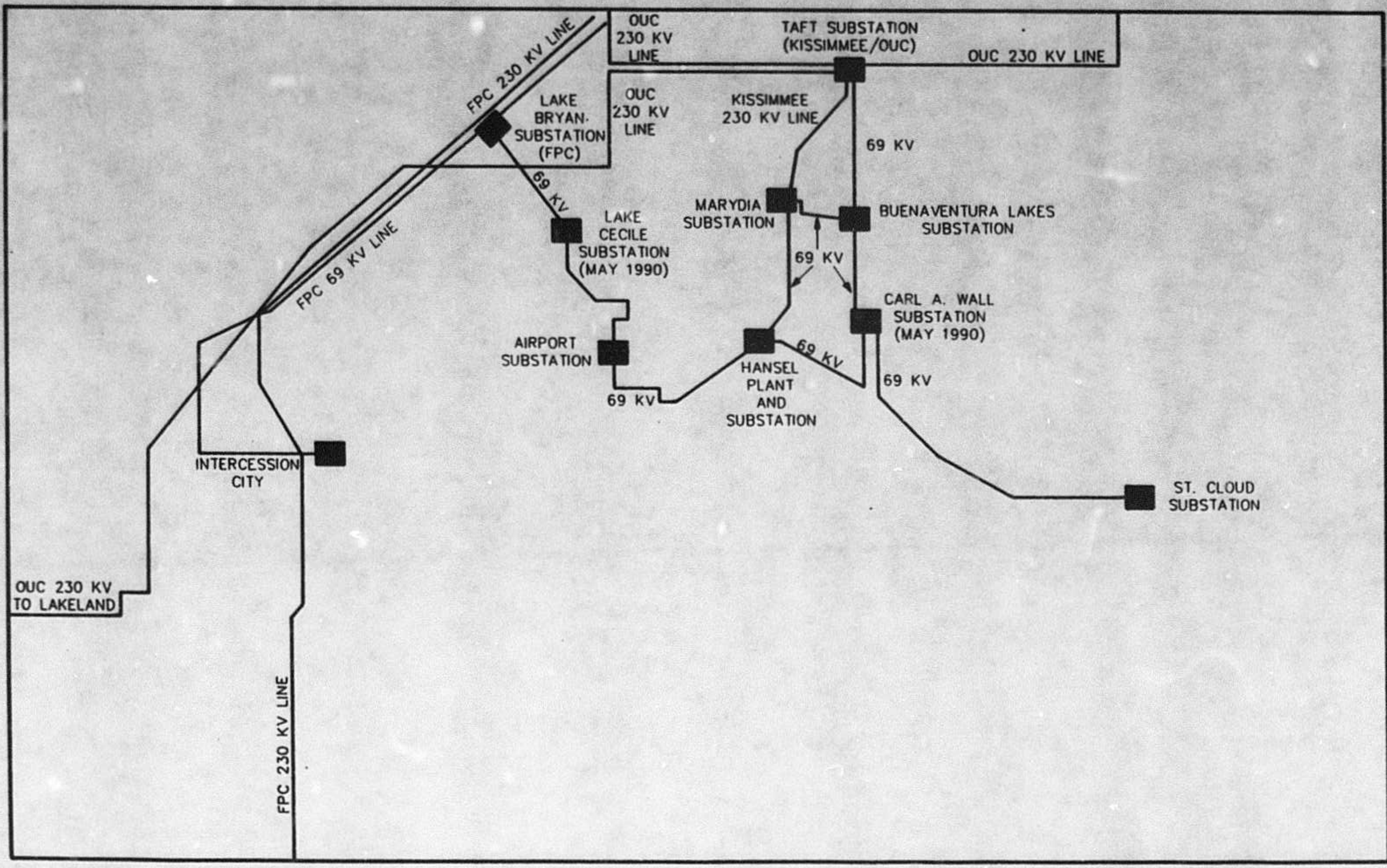


FIGURE 1

EXISTING TRANSMISSION SYSTEM
AS OF JUNE 1990

ATTACHMENT C

PROPOSAL BASELINE PRICING METHODOLOGY

C.1 Capacity Pricing

The baseline pricing methodology indexes the payments made for capacity in any given month to the performance of the facility as measured by the achieved equivalent availability factor. Penalties and incentives are provided depending on the variance from the base equivalent availability factor. This base equivalent availability factor for this Proposal shall be 80 % and is shown on Exhibit G.1.1. There will be a dead band of plus or minus 1 percent where there will be no indexing and the base capacity price will apply in that instance. The penalty and incentive rate will be the same and will be expressed in dollars per megawatt per month per percent excursion, either above or below, the dead band. This penalty or incentive will be subtracted from or added to the base capacity price to determine the capacity price for each month. There will be a maximum capacity price which will be 1.05 times the proposed base capacity price.The following description of components should clarify this methodology.

Description of Components

EAFa = Actual equivalent availability factor in percent; calculated on a twelve month rolling average basis. See Attachment D for definition of equivalent availability factor.

EAFb = The base equivalent availability factor in percent; this value for this Proposal is specified to be 80 %. The Base capacity price should be based on achieving this level of performance.

Pb = Base capacity price which when multiplied by the net dependable capacity will provide the desired monthly capacity payment if the actual equivalent availability factor, calculated on a twelve month rolling average basis, achieved is within the target range (base factor plus or minus 1 %). Respondent must provide its base capacity price (Pb) on Exhibit G.1.1.

Pmax = The maximum capacity price to be paid which will be 1.05 X Pb.

R = This is the capacity incentive/penalty rate ($/MW/month per % variance above/below base range) for achieving an equivalent availability factor higher or lower than the base range. Superior performance will increase the base capacity price based on how much the actual availability exceeds the base value. Inferior performance will decrease the base capacity price based on how much the actual availability is below the base value.

i.e. if the performance is above the base range capacity price = Pb + R X (EAFa - (EAFb + 1)) up to a maximum of 1.05 X Pb.

i.e. If the performance is below the base range capacity price = Pb - R X ((EAFb - 1) - EAFa)

C.2 Energy Pricing

The energy price methodology is based on the underlying requirement that the capacity and energy to be supplied under this solicitation is for base and intermediate capacity needs. With that predicate, it is a requirement that the energy prices be comparable with OUC's coal energy costs. Simulated production cost programs show that Stanton Unit 2 would have a capacity factor of .75 during its early life with expectations to average .70 during the 25 year term specified. With the energy price provisions contained in this solicitation, comparable capacity factors can be expected. The energy price will be determined hourly by multiplying the net heat rate times the fuel compensation price (FCP). The net heat rate for this Contract would be defined as the number of BTUs required to deliver one kilowatt-hour (KWH) of energy to OUC's system. This value will vary with respect to the output level of the facility as determined by the Input/Output curve of the Form $Y=A+BX+CX^2$ where (1) the coefficients A, B and C are provided on Form G.1.1 of this RFP, (2) Y is in BTU's and (3) X is the facility net electrical output in KWH at point of delivery to OUC's system, as measured on mutually agreeable metering facilities for one hour. Accordingly, the heat rate is $(Y/X)=(A/X)+B+CX$.

The Fuel Compensation Price (FCP) is determined by an adjustment to the Base Fuel Compensation Price (BFCP). The BFCP is provided by the Respondent as a part of his response in Form G.1.1. The adjustment is made quarterly by the use of a current Fuel Index (FIc). The FIc is calculated each calendar quarter by using the weighted average cost of coal delivered to OUC's Stanton Plant during the twelve calendar months ending three months prior to the quarter for which the FIc is used for adjustment to the BFCP. The FIc to be used for energy adjustment pricing for the third quarter of 1990 would be the average weighted cost of coal delivered to the Stanton Plant for the twelve months ending March 31,1990. These costs are reported in cents per million BTU (C/MMBTU). The FIc for the example given is 190.1¢/MMBTU. For the purposes of this Proposal, this value shall be the initial Fuel Index (FIi) for the purpose of setting the maximum BFCP. When negotiations for an agreement are undertaken, a current value will be set. The formula showing this computation is as follows:

$$FCP = \frac{FIc}{FIi} \times BFCP$$

Description of components:

FIi = Initial Fuel Index
FIc = Current Fuel Index for adjustment to the FCP for the subsequent quarter.

BFCP = The base fuel compensation price as proposed by Respondent.

C.3 Operation and Maintenance Pricing

C.3.1 It is the intent of the UTILITIES to pay for the fixed maintenance and operations costs by indexing them to two variables. These two variables are the equivalent availability factor and a recognized index such as the CPI or an appropriate hourly earnings index. The Respondent must submit a base fixed operation and maintenance price (FMOB) expressed in dollars per megawatt per month ($/MW/Mo) for the first year of operation on Exhibit G.1.1. This base price will first be adjusted by the index adjustment; and then by the equivalent availability factor (either positive or negative as the case may be) using the same formula proposed to index the capacity price. The equivalent availability factor for adjusting the capacity payments and the fixed operating and maintenance payments is specified to be 80% as shown on Exhibit G.1.1.

Therefore the computation of the fixed operation and maintenance cost per MW is as follows:

If the equivalent availability factor is above the specified base range:

$$FOMP = FOMB \times (1 + \frac{In-Io}{Io}) + F \times (EAFa - (EAFb + 1))$$

If the equivalent availability factor is below the specified base range:

$$FOMP = FOMB \times (1 + \frac{In-Io}{Io}) - F \times ((EAFb - 1) - EAFa)$$

Description of Components

FOMB = The base fixed operation and maintenance price per month per MW of net dependable capacity.

FOMP = The adjusted fixed operation and maintenance price paid per MW of net dependable capacity per month.

Io = Initial value of operation and maintenance index.

In = Value of operation and maintenance index in month n.

F = The incentive/penalty rate in \$/MW/Month/% variance above/below base range as proposed by the Respondent in G.1.1. The explanation and application is the same as the component R described in the capacity section above.

C.3.2 The pricing arrangement for variable operation and maintenance costs is similar to that shown for fixed operation and maintenance costs except there will be no indexing for performance. The Respondent will submit a base variable operation and maintenance price expressed in dollars per megawatt-hour (\$/MWH) for the first year of operation on Exhibit G.1.1. Respondent should also propose an applicable recognized index to be used in setting the price for variable operation and maintenance costs for subsequent years.

Therefore in period n, variable operation and maintenance cost per MWH delivered will be:

$$VOMP = VOMB \times \left(1 + \frac{In - Io}{Io}\right)$$

Description of Components

VOMP = Variable operation and maintenance price per MWH delivered.

VOMB = Base variable operation and maintenance price per MWH delivered.

In = Value of variable operation and maintenance index in period n.

Io = Initial value of operation and maintenance index.

Attachment D

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL DEFINITIONS

D.1 Equations

D.1.1 Equivalent Availability Factor (EAF)
[(AH - (EUDH + EPDH))/PH] x 100 (%)

D.1.2 Equivalent Forced Outage Rate (EFOR)
[(FOH + EFDH)/(FOH + SH)] x 100 (%)

D.2 Operation and Outage States

D.2.1 Forced Derating (D1. D2, D3)

An unplanned component failure (immediate, delayed, postponed) or other condition that requires that the load on the unit be reduced immediately or before the next weekend.

D.2.2 Forced Outage (U1, U2, U3, SF)

An unplanned component failure (immediate, delayed, postponed, start-up failure) or other condition that requires the unit be removed from service immediately or before the next weekend.

D.2.3 Maintenance Derating (D4)

The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

D.2.4 Maintenance Outage (MO)

The removal of a unit from service to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage. Typically, a MO may occur any time during the year, have flexible start dates, and may or may not have a predetermined duration.

D.2.5 Planned Derating (PD)

The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

D.2.6 Planned Outage (PO)

The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined duration (e.g., annual overhaul, inspections, testing).

D.2.7 Scheduled Derating Extension (DE)

The extension of a maintenance or planned derating.

D.2.8 Scheduled Outage Extension (SE)

The extension of a maintenance or planned outage.

D.3 Time

D.3.1 Available Hours (AH)

Period Hours (PH) less Planned Outage Hours (POH), Forced Outage Hours (FOH), and Maintenance Outage Hours (MOH).

D.3.2 Equivalent Forced Derated Hours (EFDH)[1]

The product of the Forced Derated Hours (FDH) and the Size of Reduction, divided by Net Maximum Capacity (NMC).

D.3.3 Equivalent Planned Derated Hours (EPDH)[1]

The product of Planned Derated Hours (PDH) and the Size of Reduction divided by the Net Maximum Capacity (NMC).

D.3.4 Equivalent Unplanned Derated Hours (EUDH)[1]

The product of the Unplanned Derated Hours (UDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

D.3.5 Forced Derated Hours (FDH)

Sum of all hours experienced during Forced Deratings (D1, D2, D3).

---

[1] Equivalent hours are computed for each derating and then summed. Size of reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating is the difference in the Net Available Capacity of the unit prior to the initiation of the derating and the reported Net Available Capacity as a result of the derating.

D.3.6 Forced Outage Hours (FOH)

Sum of all hours experienced during Forced Outages (U1, U2, U3, SF).

D.3.7 Maintenance Outage Hours (MOH)

Sum of all hours experienced during Maintenance Outages (MO) and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).

D.3.8 Period Hours (PH)

Number of hours a unit was in active state (assume 8,760 hours).

D.3.9 Planned Derated Hours (PDH)

Sum of all hours experienced during Planned Deratings (PD) and Scheduled Derating Extensions (DE) of any Planned Deratings (PD).

D.3.10 Planned Outage Hours (POH)

Sum of all hours experienced during Planned Outages (PO) and Scheduled Outage Extensions (SE) of any Planned Outages (PO).

D.3.11 Service Hours (SH)

Total number of hours a unit was electrically connected to the system.

D.3.12 Unplanned Derated Hours (UDH)

Sum of all hours experienced during Forced Deratings (D1, D2, D3). Maintenance Deratings (D4), and Scheduled Derating Extensions (DE) of any Maintenance Derating (D4).

D.4 Electric Energy and Capacity

D.4.1 Gross Available Capacity (GAC)

Greatest capacity at which a unit can operate with a reduction imposed by a derating.

D.4.2 Gross Dependable Capacity (GDC)

GMC modified for seasonal limitations over a specified period of time.

D.4.3 **Gross Maximum Capacity (GMC)**

Maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal, or other deratings.

D.4.4 **Net Available Capacity (NAC)**
GAC less the unit capacity utilized for that unit's station service or auxiliaries.

D.4.5 **Net Dependable Capacity (NDC)**
GDC less the unit capacity utilized for that unit's station service or auxiliaries.

D.4.6 **Net Maximum Capacity (NMC)**
GMC less the unit capacity utilized for that unit's station service or auxiliaries.

Appendix A

Ten Year Site Plan

Table of Contents

Description of Existing Facilities

The Orlando Utilities Commission (OUC) operates, maintains and controls the electric and water system facilities owned by the City of Orlando. The system supplies electricity to customers in and around the city. At the close of 1989, a total of 115,162 active metered electric services existed within the 224 square mile service area.

OUC's generating system has been designed over the years to take advantage of fuel diversity and the resultant economic benefits. The two generating plants operated by OUC are an example. The Indian River plant which began operation in 1960 utilizes gas or oil as fuel. The plant consists of three steam units and two combustion turbines with a combined OUC owned net winter capacity of 691 MW. Of the steam capacity, 136 MW is committed as a unit power sale to the Florida Municipal Power Agency (FMPA) until the year 2000 when it begins ramping down. Also, OUC owns approximately 48.8% of the combustion turbine capacity with the remainder owned by FMPA and Kissimmee Utility Authority (KUA). The Stanton Energy Center is the other plant operated by OUC. It consists of one 440 MW net (winter) coal-fired unit which became commercially available in 1987. OUC retains a 68.5542% (302 MW net) share of this unit. The remainder is owned by the FMPA and KUA.

OUC's long standing 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 1.6015% ownership share (13 MW net) of the Crystal River Unit No. 3 nuclear plant. In 1982, a 40% ownership of the McIntosh Unit No. 3 meant an increase of 136 MW net to OUC's generating mix. In addition to using coal to fire its boiler, this unit can also consume refuse derived fuel (RDF). Approximately 5 MW can be produced from the RDF at the unit's rated capacity. The city of Lakeland's municipal solid waste (MSW) is the fuel source. After the pre-treatment of the MSW to remove large non-burnable items and magnetic metals, the remaining refuse is shredded to achieve the size of less than 1 inch and then blown into the boiler for consumption. A 6.08951% share of the St. Lucie Unit No. 2 added 52 MW net of nuclear capacity in 1983. The resultant total capacity mix by fuel type that exists on the OUC system today is:

gas/oil	58%
coal/refuse	37%
nuclear	5%

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 FMPA's All Requirements Project members to form the Florida Municipal Power Pool. This arrangement allows the operations personnel to pool the generating resources of the members for the purposes of saving fuel and maintenance costs, improving operating reliability, reducing outage expenses and providing flexibility in an emergency.

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, 15 of which serve customer loads. OUC is fully integrated into the state transmission grid through its eight interconnections with neighboring utilities.

Forms IA, IB, IC and the system maps provide more detailed information about the power plants and the transmission system.

Orlando Utilities Commission

Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel		Com'l	Exptd	Gen Max	Net Capability*		Fuel Transp	
	Unit					In-Service	Retrmnt	Nameplate	Summer	Winter		
Plant	No.	Location	Type	Pri	Alt	Mo/Yr	Mo/Yr	kW	MW	MW	Pri	Alt
Indian River		5 miles south of Titusville, FL on U.S. Highway 1, Section 12, T23S, R35E, Brevard County						721,600	674	691		
	1		FS	NG(1)	HO(1)	2/60	Unknown	86,700	88	90	PL	WA
	2		FS	NG(1)	HO(1)	12/64	Unknown	207,600	201	205	PL	WA
	3		FS	NG(1)	HO(1)	2/74	Unknown	344,500	349	350	PL	WA
	CTA**		CT	NG	LO	6/89	Unknown	41,400	18	23	PL	TK
	CTB**		CT	NG	LO	7/89	Unknown	41,400	18	23	PL	TK

* Short Term Ratings
** OUC's ownership share is 48.8%
(1) These units are permitted to use and capable of using natural gas and/or oil as their primary fuel.

Orlando Utilities Commission

Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
						Com'l	Exptd	Gen Max	Net Capability*			
	Unit			Fuel		In-Service	Retrmnt	Nameplate	Summer	Winter	Fuel Transp	
Plant	No.	Location	Type	Pri	Alt	Mo/Yr	Mo/Yr	kW	MW	MW	Pri	Alt
** Stanton Energy Center	1	Sections 13, 14, 23, 24, T23S, R31E and Sections 18, 19, T23S, R32E, Orange County	FS	C		7/87	Unknown	464,580	302	302	RR	

* Short Term Ratings
** OUC's Ownership Share is 68.5542%

Orlando Utilities Commission
Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
						Com'l	Exptd	Gen Max	Net Capability*			
	Unit			Fuel		In-Service	Retrmnt	Nameplate	Summer	Winter	Fuel Transp	
Plant	No.	Location	Type	Pri	Alt	Mo/Yr	Mo/Yr	kW	MW	MW	Pri	Alt
** Crystal River	3	Section 33, T17S, R16E, Citrus County	N	N	-	3/77	Unknown	890,460	13	13	-	-

* Short term ratings
** OUC's ownership share is 1.6015%

Orlando Utilities Commission
Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
						Com'l	Exptd	Gen Max	Net Capability*			
	Unit			Fuel		In-Service	Retrmnt	Nameplate	Summer	Winter	Fuel Transp	
Plant	No.	Location	Type	Pri	Alt	Mo/Yr	Mo/Yr	kW	MW	MW	Pri	Alt
** McIntosh	3	4-5/28S/24E Polk County	FS	C	HO	9/82	Unknown	363,870	133	136	RR	TK

* Short term ratings
** OUC's ownership share is 40.0%

Orlando Utilities Commission
Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel		Com'l	Exptd	Gen Max	Net Capability*		Fuel Transp	
	Unit					In-Service	Retrmnt	Nameplate	Summer	Winter		
Plant	No.	Location	Type	Pri	Alt	Mo/Yr	Mo/Yr	kW	MW	MW	Pri	Alt
** St. Lucie	2	16/36S/41E St. Lucie County	N	N	-	8/83	Unknown	850,000	51	52	-	-
			Total System as of December 31, 1989						1173	1194		

* Short term ratings
** OUC's ownership share is 6.08951%

FCG Form 1B

Orlando Utilities Commission
Existing Generation: Land Use and Investment
For the Period Ending September 30, 1989

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Land Area		Plant Capital Investment in ($1,000)			
Plant Name	Total Acres	In Use Acres	Land	Site Improvements	Buildings & Equipment	Total
Indian River	95[1]	52	431	19,666	81,010	101,107
Stanton Energy Center[2]	3,250[1]	1,100	11,030[2]	148,655[2]	260,324[2]	420,009[2]
Crystal River #3[3]	4,738[1]	3,608	-	2,398[3]	11,838[3]	14,236[3]
McIntosh #3[4]	518[1]	414	889[4]	36,885[4]	57,597[4]	95,371[4]
St. Lucie #2[5]	1,132[1]	388	44[5]	25,581[5]	78,487[5]	104,112[5]

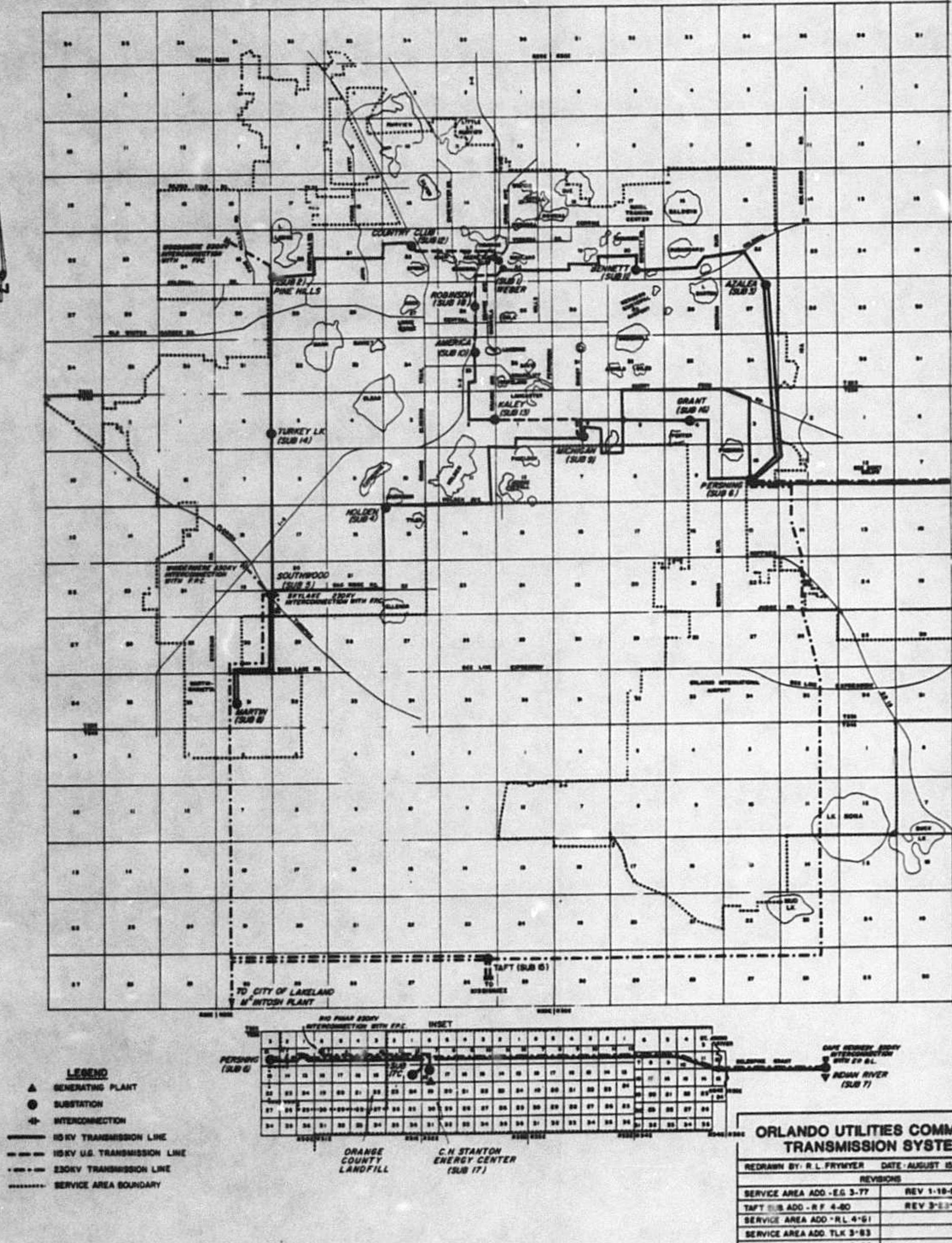
Notes:

1 Land area for total project
2 OUC's portion of Stanton Energy Center
3 OUC's portion of Crystal River #3
4 OUC's portion of McIntosh #3
5 OUC's portion of St. Lucie #2

FCG Form 1C

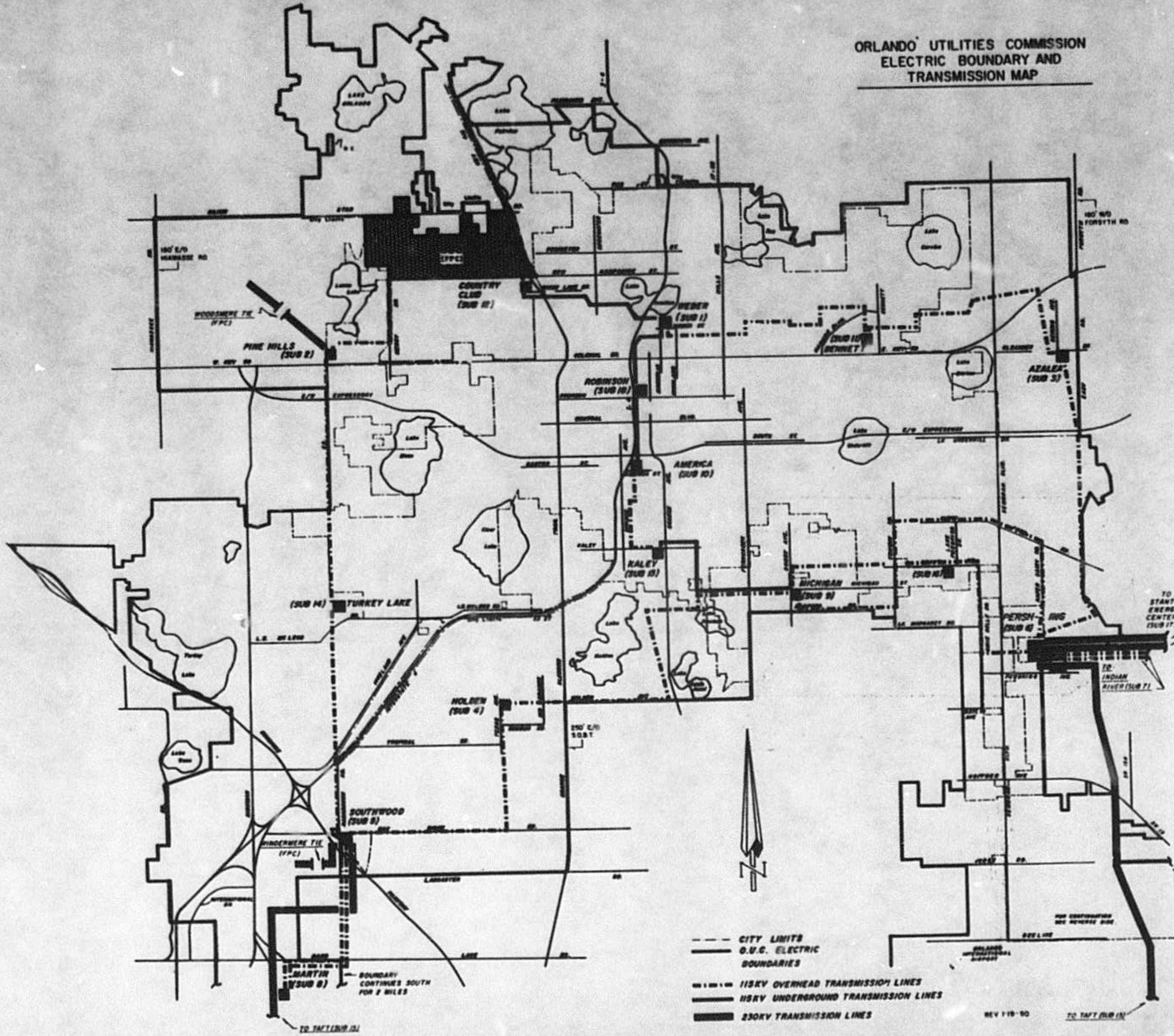
Orlando Utilities Commission
Existing Generating Facilities
Environmental Considerations for Steam Generating Units

(1) Plant Name	(2) Unit	(3) Flue Gas Cleaning Particulate	(4) Flue Gas Cleaning SOx	(5) Flue Gas Cleaning NOx	(6) Cooling Type
Indian River	1	No	LS	No	OTS
Indian River	2	No	LS	No	OTS
Indian River	3	No	LS	No	OTS
Stanton Energy Center	1	EP	S	Burner Design	WCTN
Crystal River	3	N/A	N/A	N/A	OTS
McIntosh	3	EP	S	FGR	WCTM
St. Lucie	2	N/A	N/A	N/A	OTS



ORLANDO UTILITIES COMMISSION
TRANSMISSION SYSTEM

REDRAWN BY: R.L. FRYMYER	DATE: AUGUST 15, 1980
REVISIONS	
SERVICE AREA ADD - E.G. 3-77	REV 1-10-90
TAFT SUB ADD - R.F. 4-80	REV 3-[illegible]-90
SERVICE AREA ADD - R.L. 4-81	
SERVICE AREA ADD. TLK 3-83	
SERV. AREA ADD TLK 3-87	


ORLANDO UTILITIES COMMISSION
ELECTRIC BOUNDARY AND
TRANSMISSION MAP
COUNTRY CLUB (SUB 12)
(FPC)
WOODSMERE TIE (FPC)
PINE HILLS (SUB 2)
WEBER (SUB 1)
(SUB 15) BENNETT
AZALEA (SUB 3)
160' E/O FORSYTH RD.
ROBINSON (SUB 18)
AMERICA (SUB 10)
KALEY (SUB 13)
MICHIGAN (SUB 9)
(SUB 16)
PERSHING (SUB 6)
TO STANTON ENERGY CENTER (SUB 17)
TO INDIAN RIVER (SUB 7)
(SUB 14) TURKEY LAKE
HOLDEN (SUB 4)
SOUTHWOOD (SUB 5)
WINDERMERE TIE (FPC)
MARTIN (SUB 8)
BOUNDARY CONTINUES SOUTH FOR 2 MILES
TO TAFT (SUB 5)
CITY LIMITS
O.U.C. ELECTRIC BOUNDARIES
115KV OVERHEAD TRANSMISSION LINES
115KV UNDERGROUND TRANSMISSION LINES
230KV TRANSMISSION LINES
REV 1-19-90
TO TAFT (SUB 5)

Documentation of Forecasting
Methodology and Results

I. Introduction

Orlando Utilities Commission (OUC) uses the System for Hourly and Annual Peak and Energy Simulation (SHAPES-PC) end-use forecasting model from Battelle of Columbus, Ohio. OUC staff has developed the extensive data base required by the SHAPES-PC model. The SHAPES-PC model has been further enhanced to produce 8,760 hour load shapes. OUC staff developed a typical weather year and calibrated this new module to the SHAPES-PC end-use forecasting model.

II. Retail Sales

The SHAPES-PC model produces forecasts of energy and demand for the residential, commercial, industrial, and miscellaneous sectors (street lights and OUC use). Since OUC does not have commercial and industrial rate classes, these forecasts had to be treated in a different manner. The commercial and industrial sector sales forecasts were combined together and then allocated to the general service non-demand and demand classes based on historical ratios.

A. Residential

Historically, the average number of residential customers has increased at an average annual rate of 3.1 percent for the period from 1980 through 1989. The average number of residential customers for the period 1990 through 1999 was projected as a function of service area population.

OUC's service area population was projected using Orange County population projections obtained from Fishkind and Associates. Historically, service area population has grown at an average annual rate of 2.6 percent for the 1980 through 1989 period. Service area population is projected to grow at an average annual rate of 2.4 percent for the period 1990 through 1999.

The SHAPES-PC model was used to project residential customers. SHAPES-PC uses the following model to estimate residential customers:

$$Cus_t = (AGE_t^a * POP_t * BHSR^a * HSRT_t^a) * CHR_t$$

Where:

t	=	the forecast year
a	=	the age category
CUS	=	the residential customer forecast
AGE	=	the fraction of population in a given age category
POP	=	the service area population forecast
BSHR	=	the base year headship ratio
HSRT	=	the headship ratio trend
CHR	=	the customer per household ratio

The projected average number of residential customers is expected to grow at an average annual rate of 3.0 percent from 1990 to 1999.

Historically, residential sales have increased at an average annual rate of 2.9 percent for the 1980 through the 1989 period. SHAPES-PC uses the following general equation to project annual appliance usage for seventeen types of residential appliances:

$AE_t^a = NAP_t^a * ADJCL_t^a * AUI^a$

Where:	t	=	the forecast year
	a	=	the appliance type
	AE	=	the annual energy for appliance in year t
	NAP	=	the forecasted appliance stock for type a in year t
	ADJCL	=	the adjusted connected load for appliance a in year t
	AUI	=	the annual hours of integral use for appliance a

Projected residential sales are the summation of the individual appliance usages for a given year. Residential sales are expected to grow at an average annual rate of 2.9 percent from 1990 to 1999.

B. Commercial

SHAPES-PC 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 sales are the sum of baseload, heating, and cooling components. The following equations are used to project these components of commercial sales:

$$AEB_t^c = EIB_t^c * EMP_t^c * PAF_t^c$$
$$AEC_t^c = EIC_t^c * EMP_t^c * PAF_t^c$$
$$AEH_t^c = EIH_t^c * EMP_t^c * PAF_t^c$$

Where:	c	=	the commercial customer category
	t	=	the forecast year
	AEB	=	the annual baseload energy forecast
	AEC	=	the annual cooling energy forecast
	AEH	=	the annual heating energy forecast
	EIB	=	the baseload energy intensity for customer category c in year t
	EIC	=	the cooling energy intensity for customer category c in year t
	EIH	=	the heating energy intensity for customer category c in year t
	EMP	=	the employment forecast for customer category in year t
	PAF	=	the price adjustment factor for customer c in year t

OUC's service area commercial employment historical data and projections were developed using Orange County commercial employment data obtained from Fishkind and Associates.

The commercial sales sector forecast that is developed from these equations is then combined with the industrial sector sales forecast to produce the general service non-demand and general service demand sales forecasts which will be discussed later.

C. 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 considered to be weather sensitive like the residential and commercial sectors. Annual industrial energy sales are projected using the following formula:

$$AE_t^i = EI_t^i * EMP_t^i * (1\text{-}FSG_t^i) * PAF_t^i$$

Where:	i	=	the industrial customer category
	t	=	the forecast year
	AE	=	the annual energy forecast
	EI	=	the energy intensity per employee
	EMP	=	the industrial employment forecast
	FSG	=	the fraction of annual energy self-generated
	PAF	=	the price adjustment factor

The history and forecast of industrial employment data for the OUC service area was developed in the same way as the commercial employment forecast.

The industrial sales sector forecast that is developed from this formula is combined with the commercial sector forecast to generate the general service non-demand and general service demand sales forecasts.

D. General Service Non-Demand

Historically, the average number of General Service Non-Demand (GSND) customers has increased at an average annual rate of 4.5 percent from 1980 through 1989. The average number of GSND customers for the 1990-1999 period was projected as a function of service area employment associated with GSND customers. 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:

GSNDCUS = 2576.566 + 0.06870 (EMPL)

Where:	GSNDCUS	=	Average number of general service non-demand customers
	EMPL	=	OUC service area general service non-demand employment forecast

The coefficient of determination (r^2) for the above model is 0.994.

The commercial sector employment forecast is allocated to the GSND and GSD customer classes according to historical ratios, i.e., 84.4 percent to the GSND class and 15.6 percent to the GSD class. Historical service area employment was obtained from Fishkind and Associates data for Orange County. For the historical period, OUC service area employment for the GSND class grew at an average annual rate of 6.1 percent. GSND employment for the forecast period is projected to grow at an average annual rate of 3.1 percent. Average GSND customers are expected to grow at an average annual rate of 3.0 percent for the same forecast period.

The general service non-demand class is a mixture of both commercial and industrial customers as defined by the SHAPES-PC model. Therefore, GSND sales are projected as a percentage of the SHAPES-PC model's sales forecast for the commercial and industrial sectors. The GSND percentage of commercial and industrial sales was based on historical data of 17.6 percent of commercial sales and 4.3 percent of industrial sales.

Historically, GSND sales have grown at an average annual rate of 6.2 percent. During the 1990 through 1999 period, GSND sales are projected to grow at an average annual rate of 5.2 percent.

E. General Service Demand

For the historic period, the number of General Service Demand (GSD) customers grew at a 4.9 percent average annual rate. Multiple regression analysis was used to develop an econometric model to project the average number of GSD customers. The following equation was used:

GSDCUS = 490.289 + 0.0622 (EMPL)

Where:	GSDCUS	=	Average number of general service demand customers
	EMPL	=	OUC service area general service demand employment forecast

The coefficient of determination (r^2) for the above equation is 0.985.

The industrial sector employment forecast is allocated to the GSND and GSD customer classes according to historical ratios, i.e., 79.2 percent to the GSND class and 20.8 percent to the GSD class. As with the GSND class, historical service area employment was obtained from Fishkind and Associates data for Orange County. For the historic period, OUC's service area employment for the GSD class grew at an average annual rate of 6.1 percent. GSD employment for the forecast period is projected to grow at an average annual rate of 3.5 percent. Average GSD customers are expected to grow at an average annual rate of 2.9 percent for the same forecast period.

The general service demand 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 sales was based on historical data of 82.4 percent of commercial sales and 95.7 percent of industrial sales.

Historically, GSD sales have grown at an average rate of 5.8 percent. For the forecast period, GSD sales are expected to grow at an average annual rate of 5.0 percent.

F. Street, Highway, and Traffic Lights

Total street and highway lighting use was determined from historical trends incorporating the effects of OUC's Street Light Conversion Program. This program is aimed at the replacement of high energy use lighting. For the forecast period, street and highway lighting will remain at 21 GWH. This is actually a decrease in usage per fixture since OUC is projecting an increasing number of street lights. Other sales to ultimate customers (traffic lights) have been projected to remain at 3 GWH annually throughout the forecast period.

G. OUC Use and Losses

OUC Use is projected to be 5 GWH during the forecast period. Distribution and transmission losses are projected to be about 5 percent of retail sales.

H. Total Retail Sales

The sum of the consumption in all of the individual classes equals total OUC retail sales. Historically, retail sales have grown at an average annual rate of 4.7 percent. For the forecast period, retail sales are projected to grow at an average annual rate of 4.3 percent. Retail sales plus OUC Use and losses equals Net Energy for Load (NEL).

III. 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 majority of the time the winter peak has been the annual peak. In six out of the last ten years, the winter peak has been the higher seasonal peak.

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. A "typical" weather year is developed by choosing historical months which most closely resemble "normal" or "typical" weather. The temperature of each hour of the typical weather year is used to determine 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 weather sensitive. A weather sensitive portion of demand for a given temperature is added to the non-weather sensitive portion of demand equalling total demand for appliances like air conditioning and heating.

In the commercial sector, the hourly demand forecast is a function of the hourly load profile and the annual commercial energy forecast. The hourly load profile is also a function of the hourly temperature of the typical weather year.

In the industrial sector, the hourly demand is a function of the hourly load profile and the annual industrial energy forecast. The industrial sector is not felt to be weather sensitive.

The hourly demand for OUC Use and street, highway, and traffic lights are a function of their annual energy forecasts and their load profile relationships to the other sectors.

Total peak demand is the sum of the hourly demands for all sectors, adjusted for losses. Summer peak demand, for the 1990 to 1999 period, is expected to grow at an average annual rate of 4.1 percent. Winter peak demand is projected to grow at an average annual rate of 4.1 percent for the 1990/91 to 1999/2000 period.

IV. Conservation and Demand-Side Programs

Throughout its history, the Orlando Utilities Commission has demonstrated a strong commitment to serving the needs of its customers in the most efficient manner. In order to maintain this commitment OUC has undertaken many conservation programs which help its customers use both energy and demand in more effective ways.

OUC has recently reviewed its conservation effort and again has made a strong commitment for the 90's. This was done in response to the Florida Public Service Commission's (PSC) and FEECA requirement that specific utilities refile all of their conservation programs for approval. These revised conservation programs will become OUC's programs for the 1990's. These updated programs detail how OUC plans to reduce its weather sensitive peaks and reduce annual energy usage. Table I shows OUC's projections of energy and demand savings from these conservation programs.

Listed below are the conservation programs which were submitted to the PSC to meet the FEECA requirements.

- Residential Energy Survey Program
- Commercial Energy Survey Program
- Residential Efficient Heating - Heat Pump Program
- Residential Weatherization Program
- Low Income Residential Home Fix-up Program
- Residential Efficient Water Heating Program
- Commercial Efficient Lighting Program
- Street Lighting and Outdoor Lighting Conversion Program
- Energy Education and School Outreach Program
- New Construction Inspection Research Program

The basic premise for all of these programs is that an energy survey is performed first. Therefore, very small energy savings and no demand savings results from the survey itself. The energy and demand reductions come from the remaining programs.

Along with the above programs OUC is always looking for new ways to provide service beyond expectations by finding new programs to help its customers use electricity more efficiently.

V. 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 forecasting model. OUC staff is constantly striving to improve and update the extensive data base used by the SHAPES-PC model.

The 8,760 hour load module is the most recent addition to the forecasting model. During the coming year a pre and post demand side management processor will be added to the SHAPES-PC model. Both of these new additions to the model will better enable the OUC staff to analyze demand side planning options.

As part of the continuing effort to improve the data base, OUC surveys its residential 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 survey was sent out. The results of this survey were included in the recent forecast.

FCG Forms 2, 3, 4, and 5 and Graphs 1 and 2 give additional details of historical and projected data.

Table I
Accumulated Projected Conservation Savings

Year	Net Energy For Load Savings GWH	Summer Peak Demand Savings MW	Year	Winter Peak Demand Savings MW
1990	59	14	1990/91	13
1991	65	16	1991/92	15
1992	72	18	1992/93	16
1993	80	20	1993/94	19
1994	87	22	1994/95	21
1995	96	24	1995/96	24
1996	106	27	1996/97	26
1997	116	30	1997/98	29
1998	126	32	1998/99	32
1999	135	35	1999/00	34

Orlando Utilities Commission

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					General Service Non-Demand		
Year	Population	Members Per Household	GWH	Average[1] No. of Customers	Average KWH Consumption Per Customer	GWH	Average[1] No. of Customers	Average KWH Consumption Per Customer
1980	201,950	2.72	918	74,247	12,364	187	8,746	21,381
1981	204,920	2.72	954	75,449	12,649	192	8,972	21,374
1982	208,510	2.72	870	76,650	11,355	196	9,167	21,325
1983	211,660	2.71	936	78,203	11,969	211	9,734	21,677
1984	217,680	2.68	962	81,344	11,836	235	10,363	22,628
1985	226,090	2.68	1,012	84,178	12,023	261	11,013	23,703
1986	228,350	2.63	1,061	86,815	12,221	278	11,680	23,801
1987	235,140	2.60	1,085	90,533	11,985	285	12,384	23,014
1988	243,200	2.58	1,114	94,138	11,834	296	12,726	23,260
1989	253,970	2.59	1,187	97,923	12,119	322	12,950	24,882
1990	261,740	2.56	1,214	102,227	11,876	334	13,221	25,274
1991	269,490	2.55	1,263	105,774	11,941	353	13,665	25,822
1992	276,370	2.51	1,320	110,168	11,982	370	14,111	26,211
1993	282,570	2.52	1,339	111,931	11,963	386	14,455	26,710
1994	289,450	2.51	1,377	115,147	11,959	406	14,767	25,506
1995	297,000	2.50	1,416	118,632	11,936	429	15,181	28,267
1996	305,200	2.49	1,462	122,741	11,911	455	15,691	28,970
1997	312,560	2.47	1,504	126,533	11,886	480	16,248	29,512
1998	319,070	2.45	1,541	130,008	11,853	504	16,751	30,078
1999	324,750	2.44	1,574	133,160	11,820	527	17,224	30,598

1 Use average of end-of-month customers for the calendar year.

Orlando Utilities Commission

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(10)	(11)	(12)	(13)	(14)	(15)	(16)
	General Service-demand					
Year	GWH	Average[1] No. of Customers	Average KWH Consumption Per Customer	Street & Highway Lighting GWH	Other Sales to Ultimate Consumers GWH	Total Sales to Ultimate Consumers GWH
1980	1,075	1,536	699,870	21	2	2,203
1981	1,143	1,664	686,671	21	2	2,312
1982	1,160	1,709	678,813	21	3	2,250
1983	1,237*	1,761	702,442	20	3	2,407*
1984	1,313*	1,852	708,963	20	3	2,533*
1985	1,417	1,930	734,303	19	3	2,712
1986	1,485	2,007	739,910	20	3	2,847
1987	1,565	2,177	718,879	21	3	2,959
1988	1,663	2,276	730,668	22	3	3,098
1989	1,789	2,369	755,020	21	4	3,323
1990	1,855	2,464	752,841	22	3	3,428
1991	1,968	2,544	773,585	21	3	3,608
1992	2,059	2,629	783,188	21	3	3,773
1993	2,145	2,691	797,101	21	3	3,894
1994	2,249	2,748	818,413	21	3	4,056
1995	2,379	2,823	842,721	21	3	4,248
1996	2,515	2,918	861,892	21	3	4,456
1997	2,640	3,021	873,883	21	3	4,648
1998	2,761	3,111	887,496	21	3	4,830
1999	2,875	3,195	899,844	21	3	5,000

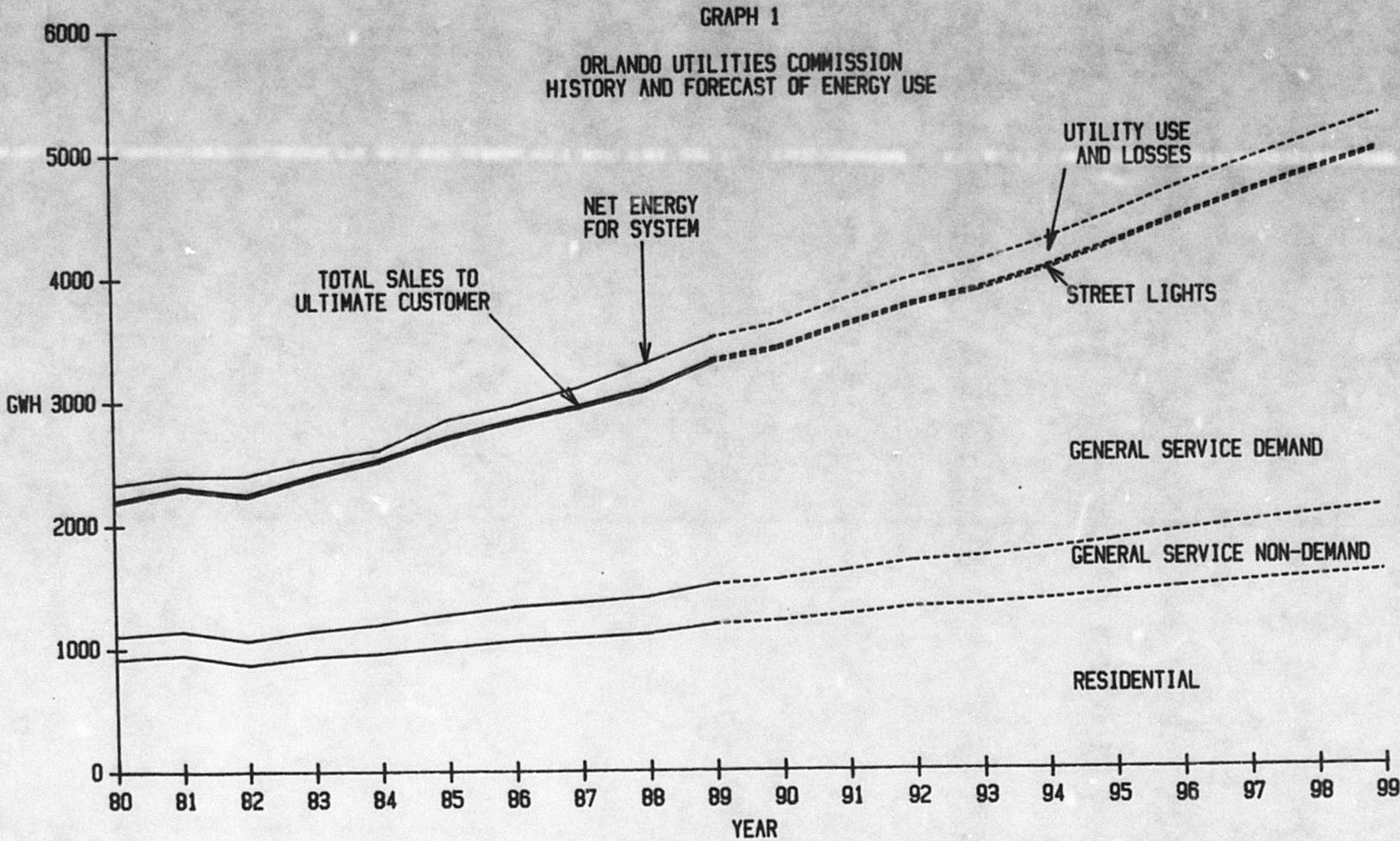
* Change due to customer billing adjustment.
[1] Use average of end-of-month customers for the calendar year.

Orlando Utilities Commission

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(17) Year	(18) Sales For Resale[2] GWH	(19) Utility Use & Losses GWH	(20) Net Energy For Load[3] GWH	(21) Other Customers (Average No.)	(22) Total No. of Customers
1980	0	128	2,331	0	82,993
1981	0	92	2,404	0	84,421
1982	0	153	2,403	0	87,556
1983	0	117	2,524	0	89,698
1984	0	73	2,606	0	93,559
1985	0	135	2,847	0	97,121
1986	0	115	2,962	0	100,502
1987	0	146	3,105	0	105,094
1988	0	191	3,289	0	109,140
1989	0	180	3,508	0	113,242
1990	0	186	3,614	0	117,912
1991	0	195	3,803	0	121,983
1992	0	204	3,977	0	126,908
1993	0	210	4,104	0	129,077
1994	0	219	4,275	0	132,662
1995	0	229	4,477	0	136,636
1996	0	240	4,696	0	141,350
1997	0	250	4,898	0	145,802
1998	0	259	5,089	0	149,870
1999	0	268	5,268	0	153,579

[2] To Class III and Class V Systems.
[3] Must agree with Form 3A, Row (20); Form 4 totals of columns Col. (9); Form 5, Totals of Cols. (3), (5), (7) for 1989, 1990, and 1991.


GRAPH 1
ORLANDO UTILITIES COMMISSION
HISTORY AND FORECAST OF ENERGY USE
6000
5000
4000
GWH 3000
2000
1000
0
UTILITY USE
AND LOSSES
NET ENERGY
FOR SYSTEM
TOTAL SALES TO
ULTIMATE CUSTOMER
STREET LIGHTS
GENERAL SERVICE DEMAND
GENERAL SERVICE NON-DEMAND
RESIDENTIAL
80
81
82
83
84
85
86
87
88
89
90
91
92
93
94
95
96
97
98
99
YEAR

Orlando Utilities Commission

Energy Sources

	ENERGY SOURCES			Actual 1988	Actual 1989	1990	1991	1992	1993
(1)	Annual Energy Interchange[1]		GWH	(752)	(1102)	(1432)	(1406)	(1327)	(1332)
(2)	Nuclear		GWH	488	406	418	508	458	472
(3)	Coal		GWH	2490	2662	2897	2890	2873	2792
(4)	Residual -	Total	GWH	303	315	254	327	372	496
(5)		Steam	GWH	303	315	254	327	372	496
(6)		CC	GWH	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0
(8)		Diesel	GWH	0	0	0	0	0	0
(9)	Distillate -	Total	GWH	0	8	0	0	0	7
(10)		Steam	GWH	0	7	0	0	0	0
(11)		CC	GWH	0	0	0	0	0	0
(12)		CT	GWH	0	1	0	0	0	7
(13)		Diesel	GWH	0	0	0	0	0	0
(14)	Natural Gas -	Total	GWH	753	1212	1470	1477	1594	1662
(15)		Steam	GWH	753	1205	1447	1441	1548	1599
(16)		CC	GWH	0	0	0	0	0	0
(17)		CT	GWH	0	7	23	36	46	63
(18)		Diesel	GWH	0	0	0	0	0	0
(19)	Other-specify -	Refuse	GWH	7	7	7	7	7	7
(20)	Net Energy For Load[2]		GWH	3289	3508	3614	3803	3977	4104

[1] Do not include economy interchange for 1990-1999.
[2] Must agree with Form 2, Col. (20); Form 4, Col. (9); Form 5, Total of Cols. (3), (5), and (7) for 1989, 1990, and 1991.

Orlando Utilities Commission

Energy Sources

	ENERGY SOURCES			1994	1995	1996	1997	1998	1999
(1)	Annual Energy Interchange[1]		GWH	(1419)	(1427)	(1403)	(1539)	(1793)	(1801)
(2)	Nuclear		GWH	456	418	509	456	472	456
(3)	Coal		GWH	2996	3149	2764	4217	4380	4327
(4)	Residual -	Total	GWH	536	595	982	301	445	594
(5)		Steam	GWH	536	595	982	301	445	594
(6)		CC	GWH	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0
(8)		Diesel	GWH	0	0	0	0	0	0
(9)	Distillate -	Total	GWH	26	33	70	19	18	23
(10)		Steam	GWH	0	0	0	0	0	0
(11)		CC	GWH	0	0	0	0	0	0
(12)		CT	GWH	26	33	70	19	18	23
(13)		Diesel	GWH	0	0	0	0	0	0
(14)	Natural Gas -	Total	GWH	1673	1702	1767	1437	1560	1662
(15)		Steam	GWH	1542	1521	1553	1330	1457	1533
(16)		CC	GWH	0	0	0	0	0	0
(17)		CT	GWH	131	181	214	107	103	129
(18)		Diesel	GWH	0	0	0	0	0	0
(19)	Other-specify -	Refuse	GWH	7	7	7	7	7	7
(20)	Net Energy For Load[2]		GWH	4275	4477	4696	4898	5089	5268

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[1] Do not include economy interchange for 1990-1999.
[2] Must agree with Form 2, Col. (20); Form 4, Col. (9); Form 5, Total of Cols. (3), (5), and (7) for 1989, 1990, and 1991.

Orlando Utilities Commission
Fuel Requirements

	FUEL REQUIREMENTS			Actual 1988	Actual 1989	1990	1991	1992	1993
(1)	Nuclear		BTU x 10^{12}	5	5	5	6	5	5
(2)	Coal		1000 TON	683	1061	1138	1136	1128	1098
(3)	Residual -	Total	1000 BBL	517	530	403	517	587	783
(4)		Steam	1000 BBL	517	530	403	517	587	783
(5)		CC	1000 BBL	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0
(8)	Distillate -	Total	1000 BBL	12	18	0	0	0	14
(9)		Steam	1000 BBL	12	14	0	0	0	0
(10)		CC	1000 BBL	0	0	0	0	0	0
(11)		CT	1000 BBL	0	4	0	0	0	14
(12)		Diesel	1000 BBL	0	0	0	0	0	0
(13)	Natural Gas -	Total	1000 MCF	8071	12678	15631	15631	16886	17604
(14)		Steam	1000 MCF	8071	12581	15342	15187	16305	16830
(15)		CC	1000 MCF	0	0	0	0	0	0
(16)		CT	1000 MCF	0	97	289	444	581	774
(17)		Diesel	1000 MCF	0	0	0	0	0	0
(18)	Other-specify -	Refuse	BTUx10^6	78879	71580	68074	68074	61004	68074
(19)	Annual Avg. Fossil Net H.R.		BTU/KWH	10299	10283	10208	10199	10200	10207

Orlando Utilities Commission
Fuel Requirements

	FUEL REQUIREMENTS			1994	1995	1996	1997	1998	1999
(1)	Nuclear		$BTU x 10^{12}$	5	5	6	5	5	5
(2)	Coal		1000 TON	1178	1231	1091	1625	1683	1669
(3)	Residual -	Total	1000 BBL	846	942	1549	478	705	939
(4)		Steam	1000 BBL	846	942	1549	478	705	939
(5)		CC	1000 BBL	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0
(8)	Distillate -	Total	1000 BBL	52	67	140	38	35	48
(9)		Steam	1000 BBL	0	0	0	0	0	0
(10)		CC	1000 BBL	0	0	0	0	0	0
(11)		CT	1000 BBL	52	67	140	38	35	48
(12)		Diesel	1000 BBL	0	0	0	0	0	0
(13)	Natural Gas -	Total	1000 MCF	17842	18205	18981	15396	16678	17755
(14)		Steam	1000 MCF	16250	16389	16068	14087	15410	16168
(15)		CC	1000 MCF	0	0	0	0	0	0
(16)		CT	1000 MCF	1592	1816	2913	1309	1268	1587
(17)		Diesel	1000 MCF	0	0	0	0	0	0
(18)	Other-specify -	Refuse	$BTU x 10^{6}$	68074	61004	68074	68074	61004	68074
(19)	Annual Avg. Fossil Net H.R.		BTU/KWH	10223	10214	10250	10159	10133	10140

FCG Form 3C

Orlando Utilities Commission

Generating Capability Unavailability for the Year of 1989

(1) Month	Capability Unavailable at Time of Monthly Peak --MW			
	(2) Forced Outage	(3) Scheduled Maintenance	(4) Other Reasons	(5) Net Dependable Capability
January	13	0	0	1181
February	0	26	0	1168
March	13	252	0	929
April	13	528	0	632
May	13	201	0	959
June	13	201	0	959
July	0	25	0	1148
August	18	0	0	1155
September	13	0	0	1160
October	0	302	0	871
November	0	349	0	824
December	0	0	56	1138

Orlando Utilities Commission

History and Forecast of Seasonal Peak Demand and Annual Net Energy for Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Summer Peak Demand - MW					Annual Net Energy for Load GWH			Load Factor
	Firm								
Year	Retail	Wholesale	Total[1]	Interrupt	Total	Retail	Wholesale	Total[2]	%
1980	437	0	487	0	487	2,331	0	2,331	54.5
1981	502	0	502	0	502	2,404	0	2,404	54.6
1982	493	0	493	0	493	2,403	0	2,403	55.6
1983	539	0	539	0	539	2,524	0	2,524	53.5
1984	544	0	544	0	544	2,606	0	2,606	54.7
1985	596	0	596	0	596	2,847	0	2,847	54.5
1986	599	0	599	0	599	2,962	0	2,962	56.5
1987	634	0	634	0	634	3,105	0	3,105	55.9
1988	651	0	651	0	651	3,289	0	3,289	57.5
1989	681	0	681	0	681	3,508	0	3,508	58.8
1990	704	0	704	0	704	3,614	0	3,614	58.6
1991	740	0	740	0	740	3,803	0	3,803	58.7
1992	768	0	768	0	768	3,977	0	3,977	58.9
1993	794	0	794	0	794	4,104	0	4,104	59.0
1994	823	0	823	0	823	4,275	0	4,275	59.3
1995	863	0	863	0	863	4,477	0	4,477	59.2
1996	904	0	904	0	904	4,696	0	4,696	59.1
1997	940	0	940	0	940	4,898	0	4,898	59.5
1998	975	0	975	0	975	5,089	0	5,089	60.0
1999	1,007	0	1,007	0	1,007	5,268	0	5,268	59.7

1 Must agree with summer peak months on Form 5, Columns (2) (4), (6) for 1989, 1990 and 1991 Form 7A, Column (8).
2 Must agree with Form 2 Column (20); Form 3A, Row (20); Form 5, Total of columns (3), (5), (7) for 1989, 1990, and 1991.

Orlando Utilities Commission

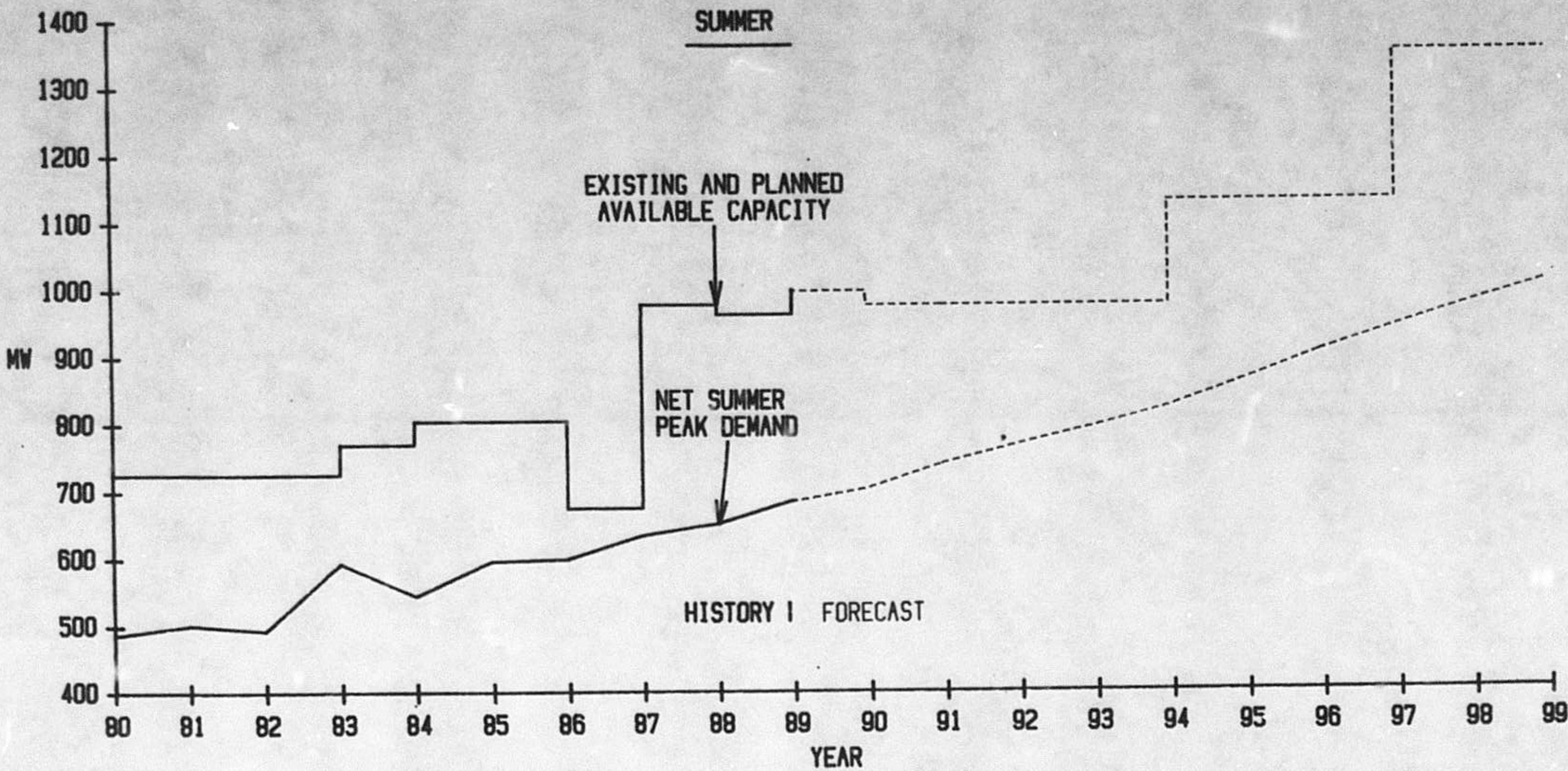
History and Forecast of Seasonal Peak Demand and Annual Net Energy for Load

(11)	(12)	(13)	(14)	(15)	(16)
	Winter Peak Demand - MW				
Year	Retail	Firm Wholesale	Total	Interrupt	Total[3]
1980-81	535	0	535	0	535
1981-82	541	0	541	0	541
1982-83	474	0	474	0	474
1983-84	518	0	518	0	518
1984-85	688	0	688	0	688
1985-86	690	0	690	0	690
1986-87	558	0	558	0	558
1987-88	631	0	631	0	631
1988-89	693	0	693	0	693
1989-90	774	0	774	0	774
1990-91	782	0	782	0	782
1991-92	823	0	823	0	823
1992-93	848	0	848	0	848
1993-94	883	0	883	0	883
1994-95	923	0	923	0	923
1995-96	966	0	966	0	966
1996-97	1,006	0	1,006	0	1,006
1997-98	1,044	0	1,044	0	1,044
1998-99	1,082	0	1,082	0	1,082
1999-00	1,118	0	1,118	0	1,118

[3] Must agree with winter peak months on Form 5, Columns (4), (6) for 1989-90 and 1990-91 and Form 7B, Column (8).

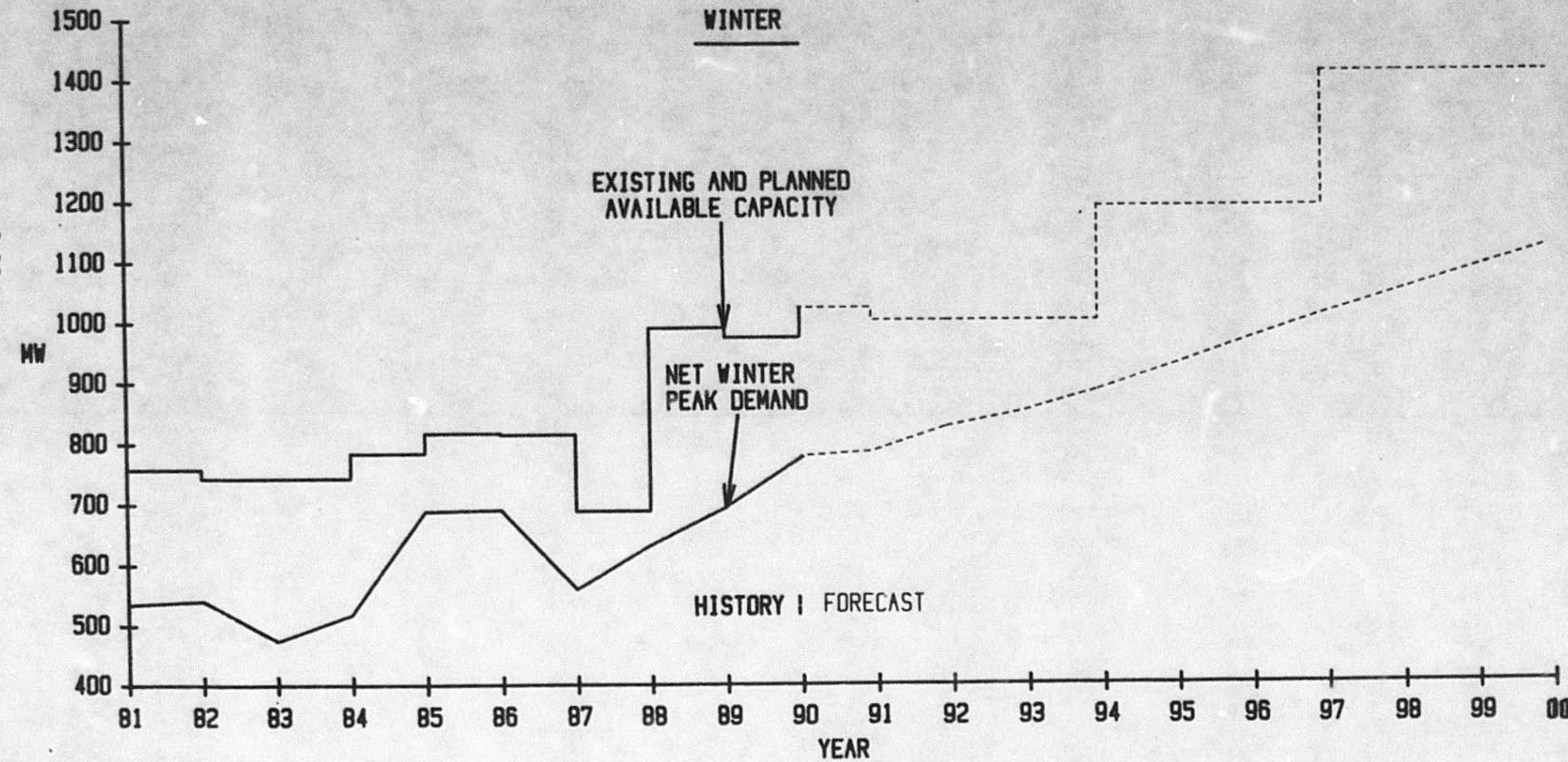
GRAPH 2-1

ORLANDO UTILITIES COMMISSION
HISTORY AND FORECAST OF NET HOURLY INTEGRATED DEMAND
AND CAPACITY ADDITIONS



GRAPH 2-2

ORLANDO UTILITIES COMMISSION
HISTORY AND FORECAST OF NET HOURLY INTEGRATED DEMAND
AND CAPACITY ADDITIONS



FCG Form 5

Orlando Utilities Commission

Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual		Forecast			
	1989		1990		1991	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	473	240	741	296	782	312
February	693	242	633	264	667	278
March	632	268	616	276	643	291
April	533	240	647	275	679	290
May	613	301	651	305	681	321
June	648	328	701	322	734	339
July	661	350	700	343	733	361
August	681	356	704	342	740	360
September	649	326	664	327	696	344
October	623	293	658	300	689	316
November	500	248	596	273	628	287
December	774	308	705	294	744	310
Total		3,508		3,617		3,809

Documentation of Facilities Requirements

The future needs of OUC were addressed in a 1988 joint integrated resource planning study with Southern Electric International (SEI). Both supply and demand-side options were evaluated in an effort to find a plan of action that would provide for the projected energy needs of OUC's customers in a reliable and economic manner. The uncertainty of future events was recognized and the economic scenario approach was used to test the robustness of the strategy. Certain sensitivity analyses were also conducted to test the effect of changes in key assumptions.

Study Methodology

Fig. 3-1 indicates the sequence of events or steps that were followed as the study progressed.

The first step was to develop the underlying assumptions which were used throughout. This included obtaining forecasts of economic factors from nationally recognized forecasting services, developing the economic scenarios, running load and energy forecast models, preparing forecasts of financing rates, preparing fuel price and transportation cost forecasts and preparing capital and O&M costs and operating characteristics for both supply side and demand side options.

This was followed by analyzing and choosing an appropriate generation system reliability measure or combination of measures which would be suitable. For OUC, a dual reliability criteria for use in its generation expansion studies has been adopted. The first criterion, percent reserve margin, is a conventional, easily understood method for determining capacity adequacy at a particular instance in time such as summer or winter peaks. However, it does not sufficiently address forced outages of generating units nor can it capture the off-peak load change impacts on reliability. Currently, on OUC's system there is a reliability concern during the spring and fall maintenance periods. Because of the small number of relatively large generators, an outage to any one unit can have a significant impact during the time when the loads are still relatively high. The second criterion, expected unserved energy (EUE) unassisted, uses a probabilistic method to assess the amount of energy that will not be served during the year with existing resources and must be purchased. It analyzes all 8760 hours during the year and accounts for the unplanned outages of units. The resultant unserved energy and percent reserve level were further studied to determine the point at which customer costs were minimized in order to serve that energy need. A 15% reserve margin above the annual system peak and an EUE of .5% of total energy served were found to satisfy the main objectives for a reliability criteria on OUC's system.

The next steps, which were done in parallel, were to investigate a menu of supply side and demand side options and screen the lists so as to reduce the number to a manageable level prior to more detailed evaluation.

The menu of supply side options were subjected to a non-quantifiable screening process. Those options that were technically not mature and that did not have applicability to the central Florida area were dropped from the list. The remaining options were further screened by separating them into three categories - base, intermediate, and peaking duty - and performing a levelized life-cycle revenue requirements analysis and comparing the levelized costs of these options at various capacity factors. This is often referred to as a busbar cost analysis or economic screening. The options in each category with the lowest cost were recommended for more detailed analysis in the supply side option evaluation. The list of generation alternatives studied is included as Table 3-1.

The purpose of this evaluation was to identify the types and mix of supply side resources that could best serve the energy requirements of OUC under each of the economic scenarios studied. The main decision criterion for determining the economic optimal mix of generation was the minimization of the accumulated present worth of revenue requirements (PWRR) which was calculated to perpetuity to capture the effects of additions in the latter years of the study. Revenue requirements includes the capital, fuel and other operating and maintenance costs for a particular plan. A base plan consisting of peaking, intermediate and base load capacity was developed using conventional technologies. To determine if any emerging or advanced technology options were economically viable, they were substituted for the conventional options and the studies were redone. For each scenario, the supply side plan with the lowest PWRR was selected to be used in the integration studies.

The demand side options were screened in a two phase process. The first was an intuitive selection process involving a set of non-quantifiable criteria to which relative weights were assigned. The purpose of this phase was to eliminate options that did not meet OUC or customer needs. Each option received a quantified ranking based on its ability to satisfy the weighted criteria. The top ranked options were further analyzed in the second phase using a stand alone cost/benefit type of analysis of each option based on the peaker methodology for determining cost avoidance. Table 3-2 shows the demand-side programs analyzed in the 2nd phase. The options that were borderline or showed positive benefits after this economic feasibility determination, were recommended for more detailed evaluation in the integration studies.

Figure 3-1
Flow Chart of Study Procedure

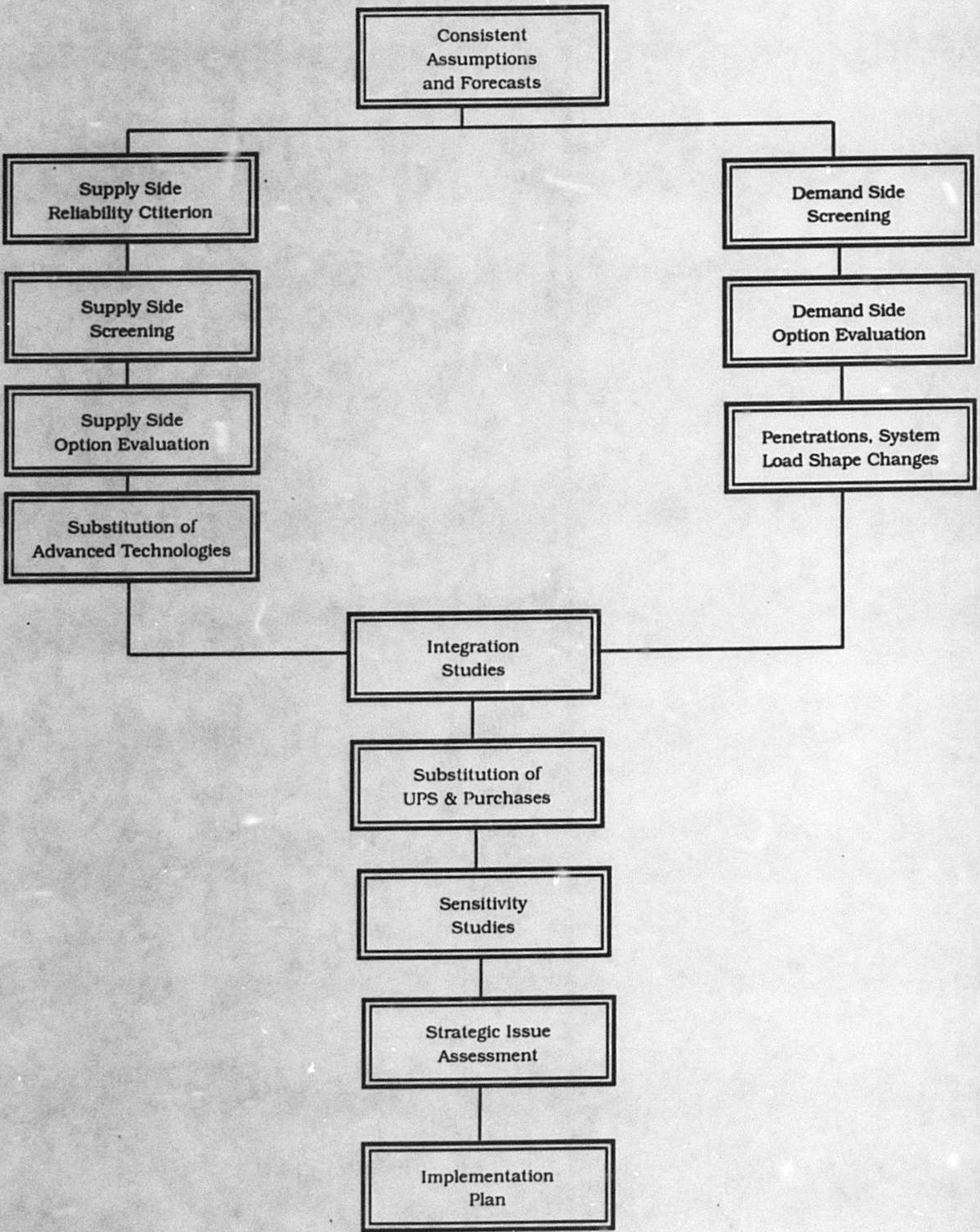


Table 3-1
Technologies Selected For Analysis

- Conventional pulverized coal
- Advanced pulverized coal
- Atmospheric fluidized-bed combustion
- Integrated gasification combined cycle
- Fuel cell
- Combustion turbines (conventional and advanced)
- Combined-cycle (conventional and advanced)
- Compressed air energy storage, 8 hour discharge
- Advanced battery, 3 hour discharge
- Photovoltaic
- Lead acid battery, 3 hour discharge
- Superconducting magnetic energy storage, 3 hour discharge
- Superconducting magnetic energy storage with hot superconductors, 3 hour discharge

Table 3-2
Demand-Side Programs Selected for Cost Benefit Analysis

- Conventional Heat Pumps
- High Efficiency Heat Pumps
- Insulation
- High Efficiency Air Conditioning
- High Efficiency Lighting
- Time-Of-Use Rates
- Technical Assistance
- Swimming Pool Pump Controls
- Energy Audits
- Demand Subscription Rates
- Thermal Storage
- Air Conditioning Control
- Water Heater Control

Based on the experience of other utilities and based on our own analysis of these factors, the following parameters were developed for the integration studies: the penetration of each demand side option over the duration of the study; the cost of equipment, installation, marketing and incentives; distribution plant savings; and the system load shape changes that resulted from these penetrations. The supply side evaluations were repeated using these assumptions.

Because of the fact that demand side options more than likely will change the total energy sales and may also change the level of goods and services that customers receive from the use of electricity, the decision criteria for measuring the value of integrated resource plans had to be expanded to include PWRR per unit of energy.

Not only is it desirable to minimize the PWRR per unit of energy but the total revenue requirement should not increase if the level of goods and services that customers receive is less than or equal to what it is without the demand side options. The best integrated plan for each scenario was selected using this criteria.

Further detailed economic analyses of the integrated plans were performed for each scenario to evaluate unit power sales (UPS) and purchases. From these was chosen a plan which contained the best combination of supply and demand side options and UPS and represented a view of the future that had the most likelihood of occurring.

Using this plan as a base strategy, a sensitivity analysis was performed to gain further confidence in the decisions. Sensitivities in the price of oil and natural gas, in the load forecast because of abnormal weather conditions and in the capital cost of base load units, were performed. Having survived these economic tests, the selected plan was then viewed from a strategic issue standpoint. Such concerns as rate shock, risks of selling UPS, operating experience with new technologies, environmental and permitting issues, the supply and availability of oil and natural gas in Florida, were addressed.

A schedule was developed to provide a definitive approach to implement the recommended strategy and to monitor the process in order to be ready to react to changes in key assumptions and objectives.

This schedule included permitting and construction dates for supply side options, implementation dates for demand side options and dates for obtaining joint owners and UPS customers.

The factors to be monitored include the load and energy forecasts, the target levels of reliability criteria, purchased power costs, unit forced outage rates and maintenance schedules, construction costs, joint owners and UPS customers, progress of advanced technology, fuel prices and availability of natural gas.

Original Results

The recommendation from the SEI study was that OUC pursue a plan of action during the 1990-1999 time frame that included both supply and demand side strategies. Additional combustion turbine capacity was projected to meet the immediate forecasted system energy needs. Two 38MW turbines were selected -- one to be installed in 1991 and the other in 1992. Base load capacity needs were identified by 1995 at which time the jointly owned 415MW Stanton Energy Center #2 coal unit would be operational. The demand side strategy recommended the implementation of a voluntary residential time-of-use rate and a commercial thermal energy storage promotion program.

Strategy Refinement

The study recommendations were intended to be dynamic in that the major assumptions would be periodically updated and the corresponding results revised if necessary. In the two years subsequent to the SEI study, changes have occurred to cause a strategy refinement. The need for combustion turbine capacity has been deferred to late 1993. The two turbines have each been upgraded to 77MW size to take advantage of anticipated off-system sales opportunities. Coal-fired, base load capacity will still be the next major generation addition on the OUC system. As was the case with the CT's, SEC #2 will also be delayed. Its new commercial date is anticipated in 1997. OUC intends to retain 75% of the unit's capacity and offer the remaining 25% for joint ownership. Further, 110MW of OUC's share will be considered for a unit power sale for a period of time after which it will revert back to OUC to meet the growing needs of its customers.

The two demand side programs are still being considered as potential additions to the current and planned OUC conservation efforts. A survey of customer opinion regarding voluntary residential time-use-rates is being considered as a prudent initial step in the implementation of such a program. A negative customer response would indefinitely postpone the project.

Thermal energy storage systems will be demonstrated and researched as a means of providing information to OUC customers to assist them in making decisions which will be mutually beneficial to both parties. OUC has initiated the program with the use of an off-peak ice-making system to offset air conditioning load demands during on-peak hours in its recently completed construction office -- warehouse building. The City of Orlando's new 200,000 square foot City Hall building is being planned for a similar ice-storage system for cooling. OUC is participating in this project from a technical standpoint only. The knowledge gained from these installations will be an important element in the success of the overall program.

Purchase power options will continually be reviewed as an alternative to the risk of construction of future power plants.

The following forms summarize the future facility requirements of OUC.

Orlando Utilities Commission

Planned and Prospective Generating Facility Additions and Changes for 1990-1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Const	Com'l	Gen Max	Net Capability[2]		Fuel Transp.		
Plant Name	Unit No.	Location	Type	Pri	Alt	Start Mo/Yr	In-Service Mo/Yr[1]	Nameplate KW	Summer MW	Winter MW	Pri	Alt	Status
Indian River	CT-C	5 miles south of	CT	NG	LO	11/92	11/93		77	95	PL	TK	P
Indian River	CT-D	Titusville, FL on U.S. Highway 1, Section 12, T23S, R35E, Brevard County	CT	NG	LO	11/92	11/93		77	95	PL	TK	P
Stanton Energy Center*	#2	Section 13, 14, 23, 24, T23S, R31E, and Sections 18, 19, T23S, R32E, Orange County	FS	C	-	10/93	1/97		220	220	RR	-	P

* OUC's ownership share of a 440 MW nominally rated coal fired unit is 75.0% or 330 MW. A 110 MW unit power sale is assumed.

1 Or retirements in parentheses.
2 Show retirements in parentheses to indicate negative values

Orlando Utilities Commission

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

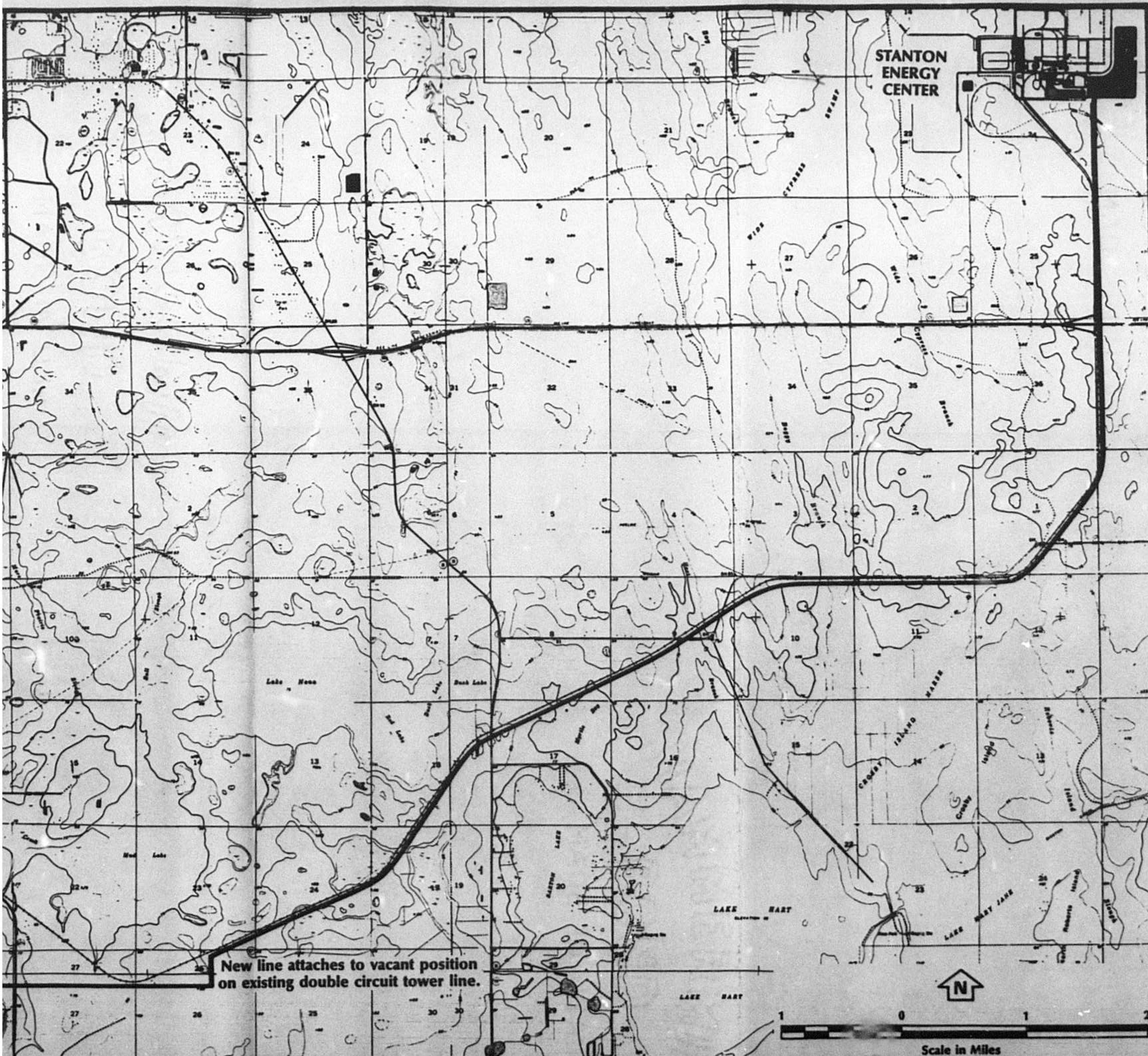
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
			Long Term								
		Firm	Non Firm	Firm	Firm						
		Inter State	Inter State	Intra State	Qualifying	Total	Firm				
	Total	Capacity	Capacity	Capacity	Capacity	Available	Peak	Margin Before		Margin After	
	Installed	Import	Import	Import	Import	Capacity	Demand	Maintenance		Maintenance	
Year	Capacity	(MW)	(MW)	(MW)	(MW)	(MW)	MW	MW	% of PK	MW	% of PK
1990	1173	0	0	(197)	0	976	704	272	39	272	39
1991	1173	0	0	(197)	0	976	740	236	32	236	32
1992	1173	0	0	(197)	0	976	768	208	27	208	27
1993	1173	0	0	(197)	0	976	794	182	23	182	23
1994	1327	0	0	(197)	0	1130	823	307	37	307	37
1995	1327	0	0	(197)	0	1130	863	267	31	267	31
1996	1327	0	0	(197)	0	1130	904	226	25	226	25
1997	1547	0	0	(197)	0	1350	940	410	44	410	44
1998	1547	0	0	(197)	0	1350	975	375	38	375	38
1999	1547	0	0	(197)	0	1350	1007	343	34	343	34

FCG Form 7B

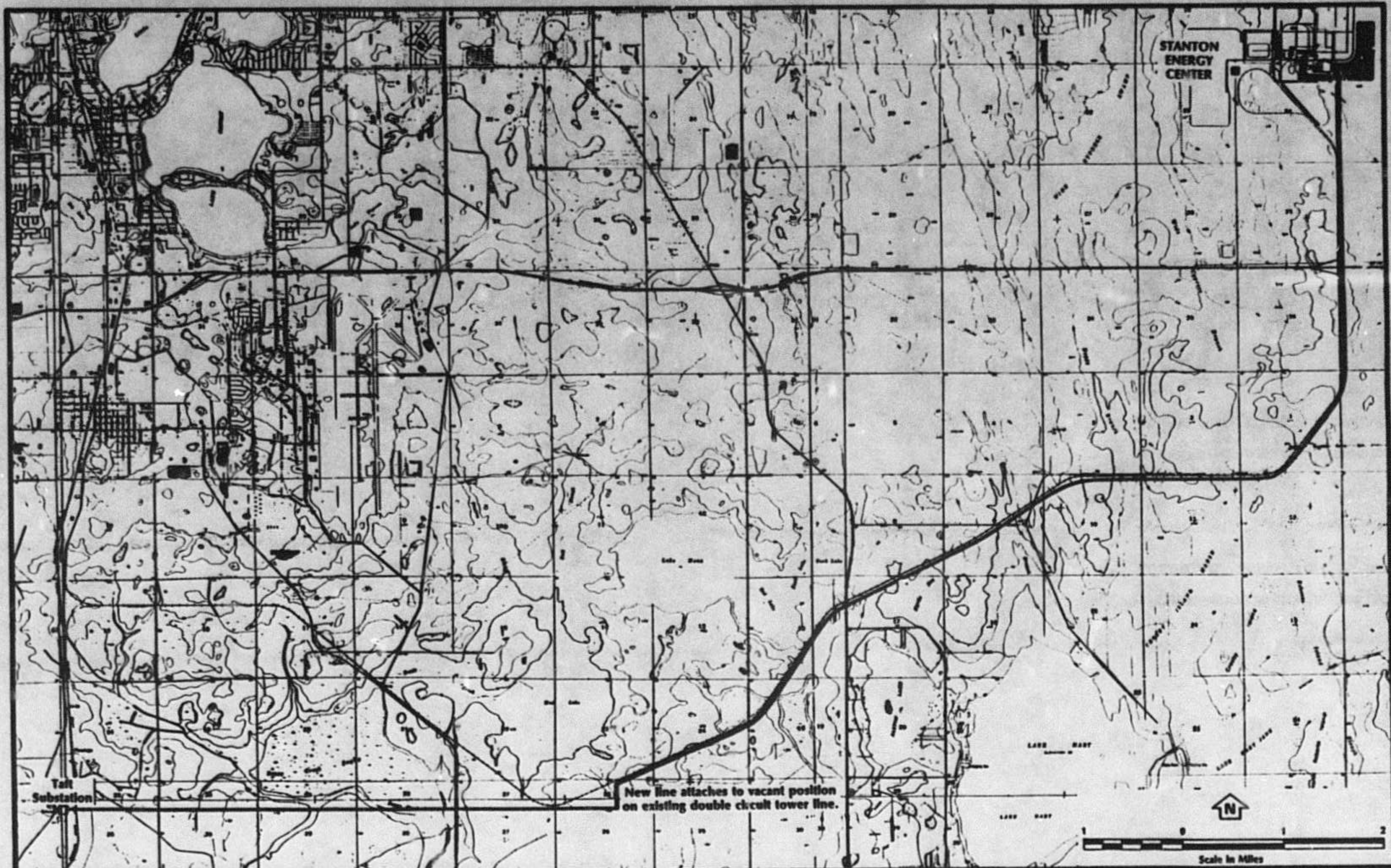
Orlando Utilities Commission

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity	Firm Inter State Capacity Import (MW)	Long Term Non Firm Inter State Capacity Import (MW)	Firm Intra State Capacity Import (MW)	Firm Qualifying Capacity Import (MW)	Total Available Capacity (MW)	Firm Peak Demand MW	Margin Before Maintenance MW	Margin Before Maintenance % of PK	Margin After Maintenance MW	Margin After Maintenance % of PK
1989/90	1194	0	0	(176)	0	1018	774	244	32	244	32
1990/91	1194	0	0	(197)	0	997	782	215	27	215	27
1991/92	1194	0	0	(197)	0	997	823	174	21	174	21
1992/93	1194	0	0	(197)	0	997	848	149	18	149	18
1993/94	1384	0	0	(197)	0	1187	883	304	34	304	34
1994/95	1384	0	0	(197)	0	1187	923	264	29	264	29
1995/96	1384	0	0	(197)	0	1187	966	221	23	221	23
1996/97	1604	0	0	(197)	0	1407	1006	401	40	401	40
1997/98	1604	0	0	(197)	0	1407	1044	363	35	363	35
1998/99	1604	0	0	(197)	0	1407	1082	325	30	325	30



**LOCATION OF THE STANTON ENERGY CENTER
TO TAFT SUBSTATION TRANSMISSION LINE CORRIDOR**



Base Map: USGS, Lake Jessamine, Pine Castle, Narcoossee NW, Kissimmee, St. Cloud North, and Narcoossee, Florida, Quadrangles.

LOCATION OF THE STANTON ENERGY CENTER
TO TAFT SUBSTATION TRANSMISSION LINE CORRIDOR

Figure 4-1

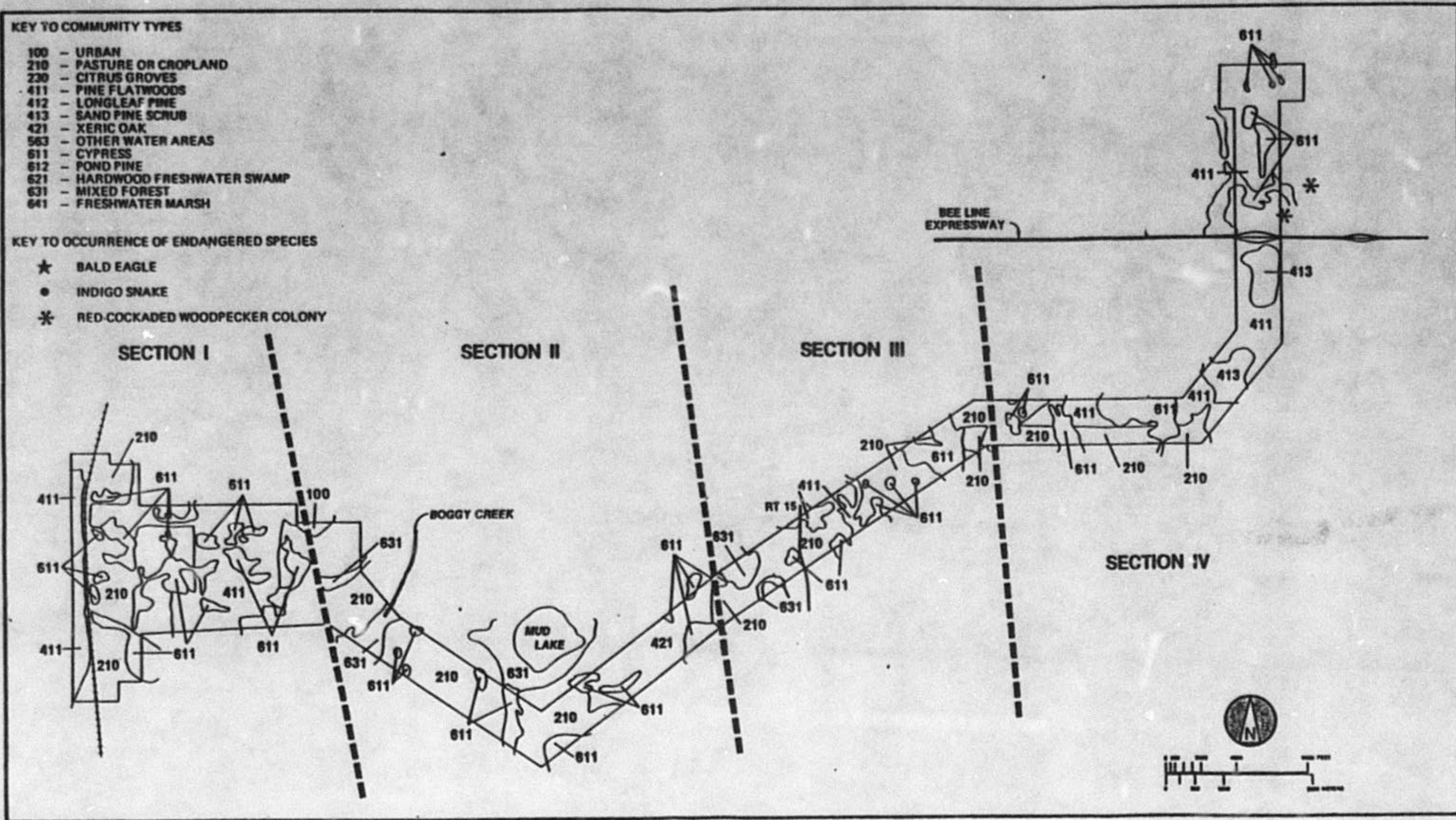
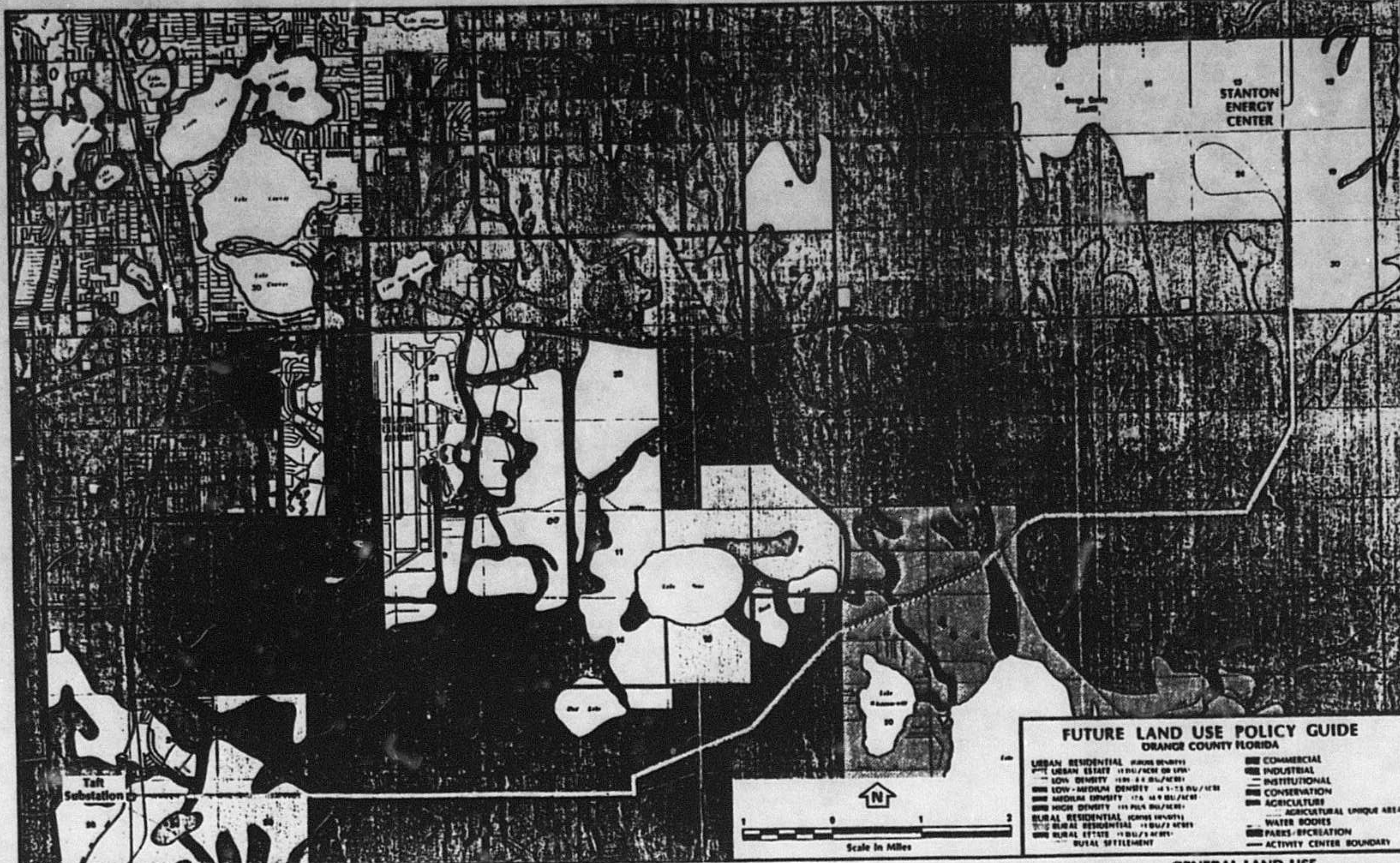


Figure 4-2 VEGETATIVE COMMUNITIES AND OCCURRENCE OF ENDANGERED SPECIES WITHIN THE RAILROAD CORRIDOR



Source: Future Land Use Policy Guide, Board of County Commissioners, Orange County Florida, August 1, 1985.

GENERAL LAND USE
STANTON ENERGY CENTER TO
TAFT SUBSTATION TRANSMISSION CORRIDOR

Figure 4-3

Table A-1
Mammalian Species In Various Habitats of the Project Area

Species	Common Name	Xeric Oak Scrub	Bayhead Cypress Dome	Pine Flat woods
Didelphis virginiana	Virginia opossum	C		C
Cryptotis parva	Least shrew		R	R
Scalopus aquaticus	Eastern mole		C	R
Pipistrellus subflavus	Eastern pipistrelle	U	U	U
Eptesicus fuscus	Big brown bat	U	U	U
Lasiurus borealis	Red bat	U	U	U
Lasiurus seminolus	Seminole bat	U	U	U
Lasiurus intermedius	Northern yellow bat	U	U	U
Nycticeius humeralis	Evening bat	U	U	U
Plecotus rafinesquii	Rafinesque's big-eared bat	U	U	U
Tadarida brasiliensis	Brazilian free-tailed bat	U	U	U
Dasypus novemcinctus	Nine-banded armadillo	A	A	A
Sylvilagus floridanus	Eastern cottontail	C		C
Sylvilagus palustris	Marsh rabbit	C		C
Oryzomys palustris	Rice rat		R	R
Reithrodontomys humulis	Harvest mouse			R
Peromyscus polionotus	Old-field mouse			R
Peromyscus gossypinus	Cotton mouse	A	A	C
Peromyscus nuttalli	Golden mouse		R	R
Sigmodon hispidus	Cotton rat	A	R	A
Neotoma floridana	Eastern woodrat		R	
Sciurus carolinensis	Gray squirrel		O	
Sciurus niger	Fox squirrel		R	R
Glaucomys volans	Southern flying squirrel		C	
Vulpes vulpes	Red fox			O
Urocyon cinereoargenteusnus	Gray fox	O	C	C
Procyon lotor	Raccoon	A	A	A
Spilogale putorius	Eastern spotted skunk	A	A	A
Mephitis mephitis	Striped skunk	A	A	A
Lynx rufus	Bobcat	O	O	O
Sus scrofa	Wild hog		O	O
Odocoileus virginianus	White-tailed deer	A	A	A

Key: A = Abundant
C = Common
O = Occasional
R = Rare
U = Undetermined

SOURCE: ESE, 1981

Table A-2
Amphibian and Reptilian Species In Various Habitats of the Project Area

Species	Common Name	Xeric Oak Scrub	Bayhead Cypress Dome	Pine Flat woods
Notophthalamus viridescens	Peninsula newt	X	X	X
Scaphiopus holbrooki	Eastern spadefoot toad	X		X
Rana areolata	Gopher frog	X		
Rana grylio	Pig frog		X	
Rana utricularia	Southern leopard frog		X	X
Gastrophryne carolinensis	Eastern narrow-mouth toad	X	X	X
Bufo querecius	Oak toad	X		X
Bufo terrestris terrestris	Southern toad	X	X	X
Acris gryllus dorsalis	Florida cricket frog	X	X	X
Hyla cinerea cinerea	Green treefrog	X	X	X
Hyla femoralis	Pine woods treefrog	X	X	X
Hyla gratiosa	Barking treefrog		X	X
Hyla squirella	Squirrel treefrog	X	X	X
Pseudacris nigrita	Chorus frog			X
Limnaoedus ocularis	Little grass frog		X	X
Terrapene carolina bauri	Florida box turtle	X		X
Gopherus polyphemus	Gopher tortoise	X		X
Anolis sagrei	Brown anole	X		
Anolis carolinensis	Green anole	X	X	X
Sceloporus undulatus	Fence lizard	X		
Sceloporus woodi	Florida scrub lizard	X		
Leiolopisma laterale	Ground skink	X	X	X
Eumeces inexpectatus	Southeastern five-lined skink	X	X	
Cnemidophorus sexlineatus	Six-lined racerunner	X		
Ophisaurus ventralis	Eastern glass lizard			X
Ophisaurus longicauda	Slender glass lizard	X		X
Nerodia sipedon	Banded water snake		X	
Virginia stripula	Rough earth snake		X	X
Storeria occipitomaculata	Red-bellied snake	X		X
Storeria dekayi	Brown snake			X
Heterodon platyrhinos	Eastern hognose snake	X		
Heterdon simus	Southern hognose snake	X		
Diadophis punctatus	Ringneck snake	X	X	X
Farancia abacura	Mud snake		X	
Coluber constrictor	Black racer	X	X	X

Table A-2
Amphibian and Reptilian Species In Various Habitats of the Project Area

Species	Common Name	Xeric Oak Scrub	Bayhead Cypress Dome	Pine Flat woods
Pituophis melanoleucus	Pine snake		X	X
Masticophis flagellum	Eastern coachwhip	X		X
Opheodrys aestivus	Rough green snake	X	X	
Elaphe obsoleta	Rat snake		X	
Drymarchon corais couperi	Indigo snake	X	X	X
Lampropeltis elapsoides	Scarlet kingsnake	X	X	X
Lampropeltis getulus getulus	Eastern kingsnake		X	X
Cemophora coccinea	Scarlet snake	X		
Tantilla relicta relicta	Peninsula crowned snake	X		
Micrurus fulvius fulvius	Eastern coral snake	X		
Agkistrodon piscivorus conanti	Florida cottonmouth		X	
Sistrurus miliarius barbouri	Dusky pigmy rattlesnake	X	X	X
Crotalus adamanteus	Eastern diamondback rattlesnake	X		X

SOURCE: ESE, 1981

Table A-3
Seasonal Occurrence of Birds in Pine Flatwoods of the Project Area

Species	Common Name	Seasonal Status*	Season: Summer 1980	Winter 1980-81	Spring 1981
Bubulcus ibis	Cattle egret	P	**	**	
Cahartes aura	Turkey vulture	P	**	**	
Coragyps atratus	Black vulture	P	**	**	
Accipiter striatus	Sharp-shinned hawk	P		**	
Buteo jamaicensis	Red-tailed hawk	P		1	
Buteo lineatus	Red-shouldered hawk	P	**	1	
Circus cyaneus	Marsh hawk	W		1	
Pandion haliaetus	Osprey	P		**	
Falco sparverius	American kestrel	W		**	
Colinus virginianus	Bobwhite	P	2	**	
Charadrius vociferus	Killdeer	P		3	
Zenaida macroura	Mourning dove	P	1		
Columbina passerina	Ground dove	P			
Caprimulgus carolinensis	Chuck-will's widow	S			
Chordeiles minor	Common nighthawk	S			
Colaptes auratus	Common flicker	P	2	1	
Dryocopus pileatus	Pileated woodpecker	P	2		
Centurus carolinus	Red-bellied woodpecker	P	12	7	
Melanerpes erythrocephalus	Red-headed woodpecker	P		1	
Sphyrapicus varius	Yellow-bellied sapsucker	W		1	
Picoides villous	Hairy woodpecker	P		1	
Picoides pubescens	Downy woodpecker	P		4	
Picoides borealis	Red-cockaded woodpecker	P		4	
Tyrannus tyrannus	Eastern kingbird	S			
Myiarchus crinitus	Great crested flycatcher	S			
Sayornis phoebe	Eastern phoebe	W			
Iridoprocne bicolor	Tree swallow	W		**	
yanocitta cristata	Blue jay	P		5	
Corvus brachyrhynchos	Common crow	P	5		
Corvus ossifragus	Fish crow	P			
Parus carolinensis	Carolina chickadee	W		2	
Parus bicolor	Tufted titmouse	P	2	2	
Sitta pusilla	Brown-headed nuthatch	P		3	
Regulus calendula	Ruby-crowned kinglet	W		1	
Troglodytes aedon	House wren	W		1	
Thryothorus ludovicianus	Carolina wren	P		2	
Mimus polyglottos	Mockingbird	P	3	3	
Dumetella carolinensis	Gray catbird	W			
Turdus migratorius	American robin	W		12	
Sialia sialis	Eastern bluebird	P	2	5	

Table A-3
Seasonal Occurrence of Birds in Pine Flatwoods of the Project Area

Species	Common Name	Seasonal Status*	Season: Summer 1980	Season: Winter 1980-81	Season: Spring 1981
Polioptila caerulea	Blue-gray gnatcatcher	P	1	1	
Lanius ludovicianus	Loggerhead shrike	P		1	
Vireo griseus	White-eyed vireo	P			
Dendroica coronata	Yellow-rumped warbler	W		41	
Dendroica pinus	Pine warbler	P	7	6	
Dendroica discolor	Prairie warbler	W		1	
Dendroica palmarum	Palm warbler	W		12	
Geothlypis trichas	Common yellowthroat	P	1	9	
Sturnella magna	Eastern meadowlark	P		5	
Agelaius pheoniceus	Red-winged blackbird	P		30	
Quiscalus major	Boat-tailed grackle	P			
Quiscalus quiscula	Common grackle	P			
Piranga rubra	Summer tanager	S			
Cardinalis cardinalis	Cardinal	P	4	1	
Carduelis tristis	American goldfinch	W			
Pipilo erythrophthalmus	Rufous-sided towhee	P	9	6	
Passerculus sandvicensis sandvicensis	Savannah sparrow	W			
Aimophila aestivalis	Bachman's sparrow	P	1	2	
Density per 100 Acres			135	422	
Number of Species			19	39	

* Seasonal Status:

P = Permanent resident

W = Winter resident

S = Summer resident

T = Transient

** Observed on site but not during quantitative surveys.

Source: ESE, 1981.

Table A-4
Seasonal Occurrence of Birds in Xeric Scrub Oak of the Project Area

Species	Common Name	Seasonal Status*	Season: Summer 1980	Winter 1980-81	Spring 1981
Cathartes aura	Turkey vulture	P			
Coragyps atratus	Black vulture	P			
Accipiter striatus	Sharp-shinned hawk	P		1	
Buteo jamaicensis	Red-tailed hawk	P		1	
Buteo lineatus	Red-shouldered hawk	P			
Falco sparverius	American kestrel	P			
Colinus virginianus	Bobwhite	P			
Charadrius vociferus	Killdeer	P		1	
Zenaida macroura	Mourning dove	P			
Columbina passerina	Ground dove	P			
Chordeiles minor	Common nighthawk	S			
Colaptes auratus	Common flicker	P	3		
Centurus carolinus	Red-bellied woodpecker	P	4	3	
Picoides villous	Hairy woodpecker	P			
Picoides pubescens	Downy woodpecker	P			
Picoides borealis	Red-cockaded woodpecker	P			
Tyrannus tyrannus	Eastern kingbird	S			
Myiarchus crinitus	Great crested flycatcher	S			
Sayornis phoebe	Eastern phoebe	W			
Iridoprocne bicolor	Tree swallow	W			
Cyanocitta cristata	Blue Jay	P	4	11	
Aphelocoma coerulescens	Florida scrub jay	P	5	9	
Corvus brachyrhynchos	Common crow	P		2	
Parus carolinensis	Carolina chickadee	W			
Parus bicolor	Tufted titmouse	P			
Sitta pusilla	Brown-headed nuthatch	P			
Regulus calendula	Ruby-crowned kinglet	W		2	
Troglodytes aedon	House wren	W			
Thryothorus ludovicianus	Carolina wren	P	3	1	
Mimus polyglottos	Mockingbird	P	2	1	
Dumetella carolinensis	Gray catbird	W			
Toxostoma rufum	Brown thrasher	P	1	5	
Turdus migratorius	American robin	W		2	
Sialia sialis	Eastern bluebird	P			
Polioptila caerulea	Blue-gray gnatcatcher	P		1	
Lanius ludovicianus	Loggerhead shrike	P	1	1	
Vireo griseus	White-eyed vireo	P	2	1	
Dendroica coronata	Yellow-rumped warbler	W		25	
Dendroica discolor	Prairie warbler	W			
Dendroica palmarum	Palm warbler	W		3	
Geothlypis trichas	Common yellowthroat	P	1	8	

Table A-4
Seasonal Occurrence of Birds in Xeric Scrub Oak of the Project Area

Species	Common Name	Seasonal Status*	Season: Summer 1980	Winter 1980-81	Spring 1981
Sturnella magna	Eastern meadowlark	P	1		
Agelaius pheoniceus	Red-winged blackbird	P	7		
Quiscalus quiscula	Common grackle	P			
Cardinalis cardinalis	Cardinal	P	2		
Pipilo erythrophthalmus	Rufous-sided towhee	P	15	21	
Aimophila aestivalis	Bachman's sparrow	P			
Density of Birds per 100 Acres			128	248	
Number of Species			13	19	

* Seasonal Status:

P = Permanent resident

W = Winter resident

S = Summer resident

T = Transient

Source: ESE, 1981

Table A-5
Seasonal Occurrence of Birds in Forested Wetlands of the Project Area

Species	Common Name	Seasonal Status*	Season: Summer 1980	Season: Winter 1980-81	Season: Spring 1981
Cathartes aura	Turkey vulture	P			
Coragyps atratus	Black vulture	P			
Accipiter cooperii	Cooper's hawk	P			
Buteo lineatus	Red-shouldered hawk	P		1	
Colinus virginianus	Bobwhite	P			
Meleagris gallopavo	Turkey	P			
Philohela minor	American woodcock	W			
Coccyzus americanus	Yellow-billed cuckoo	S			
Otus asio	Screech owl	P			
Bubo virginianus	Great horned owl	P			
Strix varia	Barred owl	P			
Caprimulgus carolinensis	Chuck-will's widow	S			
Caprimulgus vociferus	Whip-poor-will	W			
Archilochus colubris	Ruby-throated hummingbird	S			
Colaptes auratus	Common flicker	P	1		
Dryocopus pileatus	Pileated woodpecker	P	1	2	
Centurus carolinus	Red-bellied woodpecker	P	9	4	
Sphyrapicus various	Yellow-bellied sapsucker	W		1	
Picoides pubescens	Downy woodpecker	P	1	1	
Myiarchus crinitus	Great crested flycatcher	S	1		
Tyrannus tyrannus	Eastern kingbird	S	2		
Sayornis phoebe	Eastern phoebe	W		1	
Iridoprocne bicolor	Tree swallow	W			
Cyanocitta cristata	Blue jay	P	1	1	
Corvus brachyrhynchos	Common crow	P			
Corvus ossifragus	Fish crow	P			
Parus carolinensis	Carolina chickadeew	W		2	
Parus bicolor	Tufted titmouse	P	4	5	
Sitta pusilla	Brown-headed nuthatch	P		4	
Troglodytes aedon	House wren	W		2	
Thryothorus ludovicianus	Carolina wren	P	2	3	
Toxostoma rufum	Brown thrasher	P			
Turdus migratorius	American robin	W		2	
Sialia sialis	Eastern bluebird	P	2	26	
Catharus guttatus	Hermit thrush	W			
Catharus fuscescens	Veery	T			
Polioptila caerulea	Blue-gray gnatcatcher	P	2		
Regulus calendula	Ruby-crowned kinglet	W		4	
Vireo griseus	White-eyed vireo	P	4	1	
Vireo flavifrons	Yellow-throat vireo	W			
Vireo solitarius	Solitary vireo	W			

Table A-5
Seasonal Occurrence of Birds in Forested Wetlands of the Project Area

Species	Common Name	Seasonal Status*	Season: Summer 1980	Season: Winter 1980-81	Season: Spring 1981
Vireo olivaceus	Red-eyed vireo	T			
Mniotilta varia	Black and white warbler	W		1	
Protonotaria citrea	Prothonotary warbler	W			
Parula americana	Northern parula	T			
Dendroica coronata	Yellow-rumped warbler	W		101	
Dendroica dominica	Yellow-throated warbler	W		1	
Dendroica palmarum	Palm warbler	W		25	
Geothlypis trichas	Common yellowthroat	P	1	1	
Setophaga ruticilla	American redstart	T	1		
Piranga rubra	Summer tanager	S			
Cardinalis cardinalis	Cardinal	P	9	3	
Carduelis tristis	American goldfinch	W			
Pipilo erythrophthalmus	Rufous-sided towhee	P	9	1	
Aimophila aestivalis	Bachman's sparrow	P	3		
Melospiza georgiana	Swamp sparrow	W		1	
Density of Birds per 100 Acres			133	485	
Number of Species			17	24	

* Seasonal Status:

P = Permanent resident

W = Winter resident

S = Summer resident

T = Transient

Source: ESE, 1981

Table A-6
Listed Species in Orange County

Species Number	Latin Name	Common Name	Species Listing Status					County Occurence					
			CITES	USFWS	State	FNAI	FCREPA	BR	LK	OR	OS	SE	VO
001	Geolycosa xera	McCrone's burrowing wolf spider	-	-	-	S?	T	-	X	X	X	X	X
002	Phidippus xerus	Jumping spider	-	-	-	S?	R	-	X	X	-	-	-
003	Latrodectus bishopi	Red widow spider	-	-	-	S?	SSC	-	X	X	-	-	-
005	Aphodius aegrotus	Scarab beetle (Horn)	-	-	-	S?	E	X	X	X	-	X	X
006	Aphodius laevigatus	Scarab beetle (Haldeman)	-	-	-	S?	R	X	X	X	-	X	X
012	Diplotaxis rufa	Scarab beetle (Linell)	-	-	-	S?	R	-	-	X	-	-	X
013	Hypotrichia spissipes	Scarab beetle (LeConte)	-	-	-	S?	R	X	X	X	-	X	X
016	Peltotrupes profundus	Scarab beetle (Howden)	-	-	-	S?	R	-	-	X	X	X	X
020	Trigonopelastes floridana	Scrub palmetto flower beetle	-	UR2	-	S?	-	-	-	X	-	-	-
023	Dromogomphus armatus	Southeastern rakeleg	-	-	-	S?	R	-	-	X	-	-	-
024	Gomphus cavillaris	Sandhill clubtail	-	-	-	S?	SSC	-	-	X	-	X	X
025	Progomphus alachuensis	Tawny sand clubtail	-	-	-	S?	SSC	-	X	X	-	X	X
026	Libellula jesseana	Purple chaser	-	-	-	S?	-	-	-	X	-	X	X
027	Didymops floridensis	Maidencane cruiser	-	-	-	S?	SSC	-	-	X	-	X	X
028	Orthotrichia instabilis	Changeable ortho. microcaddisfly	-	-	-	S?	R	-	-	X	-	-	-
029	Oxyethira janella	Little entrance microcaddisfly	-	-	-	S?	T	-	-	X	-	-	-
031	Triaenodes furcella	Little fork triaenode caddisfly	-	-	-	S?	T	-	-	X	-	-	-
033	Procambarus acherontis	Palm Springs cave crayfish	-	UR2	-	S1	T	-	-	X	-	X	-
042	Rana areolata aesopus	Florida gopher frog	-	UR2	SSC	S3	T	X	X	X	X	X	X
043	Notophthalmus perstriatus	Striped newt	-	-	-	S3	R	-	X	X	-	X	X
046	Stema Antillarum	Least tern	-	-	T	S3	T	X	X	X	-	-	X
052	Casmerodius albus	Great egret	-	-	-	S4	SSC	X	X	X	X	X	X
053	Egretta caerulea	Little blue heron	-	-	SSC	S4	SSC	X	X	X	X	X	X
055	Egretta thula	Snowy egret	-	-	SSC	S4	SSC	X	X	X	X	X	X
056	Egretta tricolor	Louisiana heron	-	-	SSC	S4	SSC	X	X	X	X	X	X
057	Ixobrychus exilis	Least bittern	-	-	-	S4	SSC	X	-	X	-	-	X
058	Nycticorax nycticorax	Black-crowned night heron	-	-	-	S3?	SSC	X	X	X	X	X	X
059	Nycticorax violaceus	Yellow-crowned night heron	-	-	-	S3	SSC	X	X	X	X	X	X
060	Mycteria americana	Wood stork	-	E	E	S2	E	X	X	X	X	X	X
063	Plegadis falcinellus	Glossy ibis	-	-	-	S2	SSC	X	X	X	X	X	X
064	Accipiter cooperii	Cooper's hawk	-	-	-	S3?	SSC	X	X	X	X	X	X
065	Buteo brachyurus	Short-tailed hawk	-	-	-	S3	R	X	X	X	X	X	X
066	Elanoides forficatus	Swallow-tailed kite	-	UR5	-	-	-	X	X	X	X	X	X

Table A-6
Listed Species in Orange County

Species Number	Latin Name	Common Name	Species Listing Status					County Occurence					
			CITES	USFWS	State	FNAI	FCREPA	BR	LK	OR	OS	SE	VO
068	Haliaeetus leucocephalus	Southern bald eagle	-	E	T	S2S3	T	X	X	X	X	X	X
069	Rostrhamus sociabilis	Snail kite	-	E	E	S1	E	X	X	X	X	X	X
070	Falco columbarius	Merlin	II	-	-	SU	UND	X	X	X	X	X	X
071	Falco pergrinus tundrus	Peregrine falcon	I	T	E	S2	E	X	X	X	X	X	X
072	Falco sparverius	Southeastern American kestrel	II	UR2	T	S3?	T	X	X	X	X	X	X
073	Polyborus plancus audubonii	Audubon's crested caracara	-	T	T	S2	T	X	-	X	X	X	X
074	Pandion haliaetus	Osprey	II	-	-	S3S4	T	X	X	X	X	X	X
075	Aramus guarauna	Limpkin	-	-	SSC	S3	SSC	X	X	X	X	X	X
076	Grus canadensis	Sandhill crane	II	-	T	S2S3	T	X	X	X	X	X	X
078	Aphelocoma coerulescens	Florida scrub jay	-	T	T	S3	T	X	X	X	-	X	X
079	Aimophila aestivalis	Bachman's sparrow	-	UR2	-	S?	-	X	X	X	X	X	X
088	Campephilus principalis	Ivory-billed woodpecker	-	E	E	SX	E	X	X	X	X	X	X
089	Picoides borealis	Red-cockaded woodpecker	-	E	T	S2	E	X	X	X	X	X	X
090	Picoides villosus	Hairy woodpecker	-	-	-	S3?	SSC	X	X	X	X	X	X
091	Athene cunicularia	Florida burrowing owl	-	-	SSC	S3	SSC	X	X	X	X	X	X
094	Mustela frenata peninsulae	Florida weasel	-	UR2	-	S3?	R	X	X	X	X	X	X
096	Ursus americanus floridanus	Florida black bear	-	UR2	T	S3	T	X	X	X	X	X	X
097	Eptesicus fuscus	Big brown bat	-	-	-	S3	R	X	X	X	X	X	X
098	Lasiurus cinereus	Hoary bat	-	-	-	SU	R	-	-	X	-	-	-
099	Plecotus rafinesquii	Southeastern big-eared bat	-	UR2	-	S3?	R	X	X	X	X	X	X
100	Sorax longirostris long	Southeastern shrew	-	-	-	S4	R	X	X	X	X	X	X
102	Neofiber alleni	Round-tailed muskrat	-	UR2	-	S3?	SSC	X	X	X	X	X	X
103	Peromyscus floridanus	Florida mouse	-	UR2	SSC	S3	T	X	X	X	X	X	X
105	Sciurus niger shermani	Sherman's fox squirrel	-	UR2	SSC	S2	T	X	X	X	-	X	X
117	Alligator mississippiensis	American alligator	II	T(S/A)	SSC	S4	SSC	X	X	X	X	X	X
118	Drymarchon corais couperi	Eastern indigo snake	-	T	T	S3	SSC	X	X	X	X	X	X
119	Lampropeltis calligaster	Mole snake	-	-	-	S2S3	R	-	X	X	-	X	X
121	Pituophis melanoleucus mugitis	Florida pine snake	-	UB2	SSC	S?	-	X	X	X	-	-	X
122	Stilosoma extenuatum	Short-tailed snake	-	UR2	T	S3	E	-	X	X	-	X	-
132	Gopherus polyphamus	Gopher tortoise	-	UR2	SSC	S2	T	X	X	X	X	X	X
133	Persea borbonia var. humilis	Dwarf redbay, redbay persea	-	UR5	-	-	-	-	X	X	X	X	X
135	Warea amplexifolia	Clasping warea	-	E	E	S1	-	-	X	X	X	-	-
137	Paronychia chartacea	Paper-like nailwort	-	T	-	S2	-	-	X	X	-	-	-

Table A-6
Listed Species in Orange County

Species Number	Latin Name	Common Name	Species Listing Status: CITES	USFWS	State	FNAI	FCREPA	County Occurence: BR	LK	OR	OS	SE	VO
140	Clitoria fragrans	Butterfly-pea	-	UR2	-	S3	-	X	X	X	X	X	X
141	Lupinus aridorum	Scrub lupine	-	E	E	S1	-	-	-	X	-	-	-
144	Asclepias curtissii	Curtis milkweed	-	-	T	S3	T	X	X	X	X	X	-
149	Drosera intermedia	Water sundew	-	-	T	S3	R	-	X	X	X	-	-
151	Eriogonum floridanum	Scrub buckwheat	-	-	T	-	T	-	X	X	X	-	-
152	Polygonella myriophylla	Small's jointweed	-	UR5	-	S2S3	-	-	-	X	X	-	-
158	Salix floridana	Florida willow	-	UR2	T	S2	R	-	X	X	-	-	-
159	Ilex opaca var. arenicola	Scrub holly	-	UR5	-	S3	-	-	X	X	X	-	-
160	Agalinis pupurea var. cart.	Carter's large purple foxglove	-	UR2	-	-	-	X	X	X	X	X	X
161	Agalinis stenophylla	Narrow-leaved false foxglove	-	UR2	-	-	-	X	X	X	X	X	X
164	Bonamia grandiflora	Florida bonamia	-	T	E	S3	T	-	X	X	X	X	X
167	Peltandra sagittifolia	Spoon-flower	-	-	-	S3	R	X	X	X	X	X	X
169	Coelorachis tuberculosa	Florida jointtail	-	UR2	-	S3	-	X	X	X	-	X	X
170	Nemastylis floridana	Fall-flowering ixia	-	UR2	E	S2	T	X	X	X	X	X	X
172	Nolina brittoniana	Britton's beargrass	-	UR2	-	S2	-	-	X	X	-	-	-
175	Rhapidophyllum hystrix	Needle palm	-	UR5	C	-	T	X	X	X	X	X	X
176	Zamia umbrosa	East-coast coontie	II	-	C	-	T	X	X	X	X	X	X
178	Ophioglossum palmatum	Hand fern	-	UR5	E	S1	E	X	-	X	-	X	-
179	Asplenium plenum	Double spleenwort	-	UR2	T	SU	-	X	X	X	X	X	X

Source: The East Central Florida Regional Planning Council, November 1989.

Status Codes for USWFS State and Cities Listings

[1]E	=	Endangered
T	=	Threatened
T(S/A)	=	Threatened Due to Similarity of Appearance
SSC	=	Species of Special Concern
C	=	Commercially Exploited
I	=	Appendix I Species
II	=	Appendix II Species
UR1	=	Under review for federal listing, with substantial evidence in existence indicating at least some degree of biological vulnerability and/or threat.
UR2	=	Under review for listing, but substantial evidence of biological vulnerability and/or threat is lacking.
UR3	=	Still formally under review for listing, but no longer being considered for listing due to existing pervasive evidence of extinction.
UR4	=	Still formally under review for listing, but no longer being considered for listing because current taxonomic understanding indicates species in an invalid tax on and thus ineligible for listing.
UR5	=	Still formally under review for listing, but no longer considered for listing because recent information indicates species is more widespread or abundant than previously believed.

Status Codes for FNAI Listings
Florida Natural Areas Inventory
Element Rank Explanations

An element is any exemplary or rare component of the natural environment, such as a species, plant community, bird rookery, spring, sinkhole, cave, or other ecological feature. An element occurrence (EO) is a single extant habitat which sustains or otherwise contributes to the survival of a population or a distinct, self-sustaining example of a particular element. The major function of the Florida Natural Areas Inventory is to define the state's elements of natural diversity, then collect information about each element occurrence.

The Florida Natural Areas Inventory assigns 2 ranks for each element. The global element rank is based on a element's worldwide status; the state element rank is based on the status of the element in Florida. Element ranks are based on many factors, the most important ones being estimated number of element occurrences (EOs), estimated abundance (number of individuals for species; area for natural communities), range, estimated adequately protected EOs, relative threat of destruction, and ecological fragility.

Global Element Rank (priority)

GI	-	Critically imperiled globally because of extreme rarity (5 or fewer occurrences or less than 1000 individuals) or because of extreme vulnerability to extinction due to some natural or man-made factor.
G2	-	Imperiled globally because of rarity (6 to 20 occurrences or less than 3000 individuals) or because of vulnerability to extinction due to some biological or man-made factor.
G3	-	Either very rare and local throughout its range (21-100 occurrences or less than 10,000 individuals) or found locally in a restricted range or vulnerable to extinction because of other factors.
G4	-	apparently secure globally (may be rare in parts of range)
G5	-	demonstrably secure globally
GH	-	of historical occurrence throughout range, may be rediscovered (e.g., ivory-billed woodpecker)
G#?	-	Tentative rank (e.g., G2?)
G#G#	-	range of rank; insufficient data to assign specific global rank (e.g., G2G3)
G#T#	-	rank of taxonomic subgroup such as subspecies of variety; numbers have same definition as above (e.g., G3T1)
G#Q	-	rank of questionable species - ranked as species but questionably whether it is species or subspecies; numbers have same definitions as above (e.g., G2Q)
G#T#Q#	-	same as above, but validity as subspecies or variety is questioned
GU	-	due to lack of information, no rank or range can be assigned (e.g., GUT2).
G?	-	not yet ranked (temporary)

State Element Rank (priority)

Definition parallels global element rank: substitute "S" for "G" in above global ranks, and "in state" for "globally" in above global rank definitions.

Additional state element ranks:

SA	-	accidental in Florida, i.e., not part of the established biota
SE	-	an exotic species established in state; may be native elsewhere in North

Status Codes for FCREPA Listings
Definitions of Status Categories

Categories used to designate the status of the organisms included in the Florida List of Rare and Endangered Species are defined below. In the case of species or subspecies whose ranges extend outside the state, the category to which the form is assigned is based on the status of its population in Florida. Thus, a plant or animal whose range barely reaches the state ("peripheral species") may be classified as Endangered, Threatened, or Rare as a member of the Florida biota, although it may be generally common elsewhere in its range.

In the following definitions, "species" is used in a general sense to include: 1) full taxonomic species, 2) subspecies or varieties (plants), and 3) particular populations of a species or subspecies that do not have formal taxonomic status. This use of the term agrees with that of the Endangered Species Act of 1973.

Endangered. Species in danger of extinction if the deleterious factors affecting their populations continue to operate. These are forms whose numbers have already declined to such a critically low level or whose habitats have been so seriously reduced or degraded that without active assistance their survival in Florida is questionable.

Threatened. Species that are likely to become endangered in the State within the foreseeable future if current trends continue. This category includes 1) species in which most or all populations are decreasing because of over exploitation, habitat loss, or other factors; 2) species whose populations have already been heavily depleted by deleterious conditions and which, while not actually endangered, are nevertheless in a critical state; and 3) species which may still be relatively abundant but are being subjected to serious adverse pressures throughout their range.

Rare. Species which, although not presently endangered or threatened as defined above, are potentially at risk because they are found only within a restricted geographic area or habitat in the State or are sparsely distributed over a more extensive range.

Species of Special Concern. Species that do not clearly fit into one of the foregoing categories yet warrant special attention. Included in this category are 1) species that, although they are perhaps presently relatively abundant and widespread in the State, are especially vulnerable to certain types of exploitation or environmental changes and have experienced long-term population declines and 2) species whose status in Florida has a potential impact on endangered or threatened populations of the same or other species outside the State.

Status Undetermined. Species that are suspected of falling in one of the above categories but for which available data are insufficient to provide an adequate basis for their assignment to a specific category.

Recently Extirpated. Species that have disappeared from Florida since 1600 but still exist elsewhere.

Recently Extinct. Species that have disappeared from the state since 1600 through extinction.