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Tallahassee

March 5, 2001

Blanca Bayó
Director, Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399

RECEIVED-FPSC
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RECORDS AND REPORTING

Re: Stanton A Need for Power – Docket No. 010142-EM

BY HAND DELIVERY

Dear Ms. Bayó:

Enclosed for filing on behalf of Orlando Utilities Commission (OUC), Kissimmee Utility Authority (KUA), Florida Municipal Power Agency (FMPA), and Southern Company – Florida LLC (Southern-Florida) are:

1) the original and 15 copies of a notebook containing the prefiled direct testimony of the following witnesses: 02879-01

OUC, KUA, and FMPA	Southern-Florida
Frederick F. Haddad, Jr.	Douglas E. Jones
Paul Arsuaga	Thomas O. Anderson
William Herrington	Stephen L. Thumb
Jill Schuepbach	
Eric Fox	
Myron Rollins	
John E. Hearn	
Abani Kumar Sharma	

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DOCUMENT NO
02879-01

Jonathan Schaefer
Richard L. Casey

2) the original and 15 copies of Need for Power Application/Revisions, Volume 1G – Revisions. 02880-01

3) OUC's Second Request for Confidential Classification with diskette. 02881-01

Please stamp and return the extra copy of these documents.

By copy of this letter, one copy of each of these documents is being provided directly to Mr. Keating and Mr. Futrell. If you have any questions, please call.

Very truly yours,

Roy C. Young
Attorney for OUC, KUA, and FMPA

David Bruce May, Jr.
Attorney for Southern-Florida

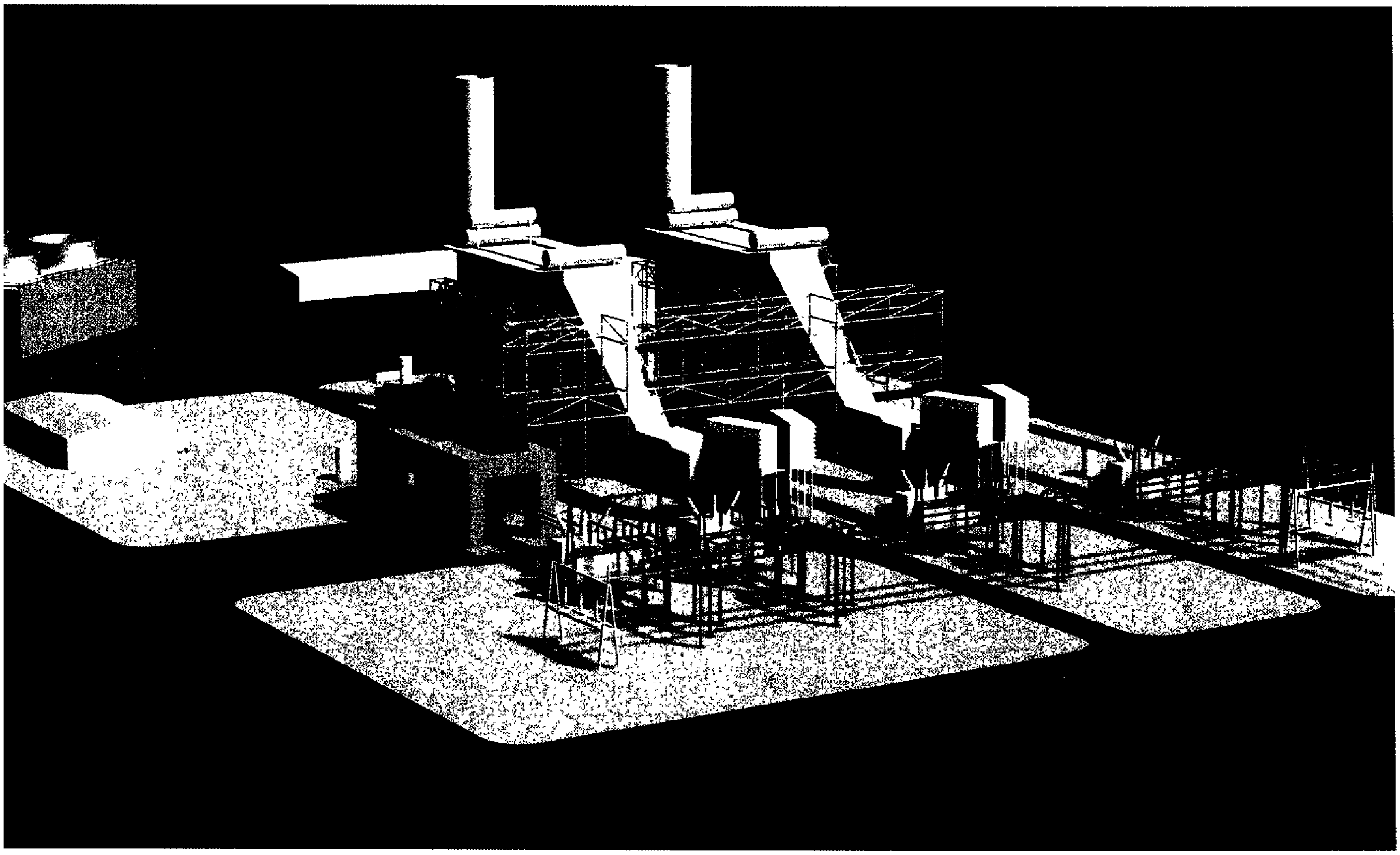
MRR
Enclosures

cc: Cochran Keating
Mark Futrell
Myron Rollins

Public Service Commission Docket No. 010142 - EM

Prefiled Testimony and Exhibits

010142-EM



Orlando Utilities Commission
Curtis H. Stanton Energy Center
Combined Cycle Unit A

&V Project 97185 March 2001

KUA KISSIMMEE UTILITY AUTHORITY

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BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF FREDERICK F. HADDAD, JR

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and address.

A My name is Frederick F. Haddad, Jr. My business address is 500 South Orange Avenue, Orlando, Florida 32802.

Q. By whom are you employed and in what capacity?

A I am employed by Orlando Utilities Commission (OUC) as Vice President of Power Resources.

Q. Please describe your responsibilities in that position.

A. I am responsible for all of OUC's power resources including the construction and operation of OUC's generation portfolio. I also manage the fuel procurement and financial hedging programs of OUC, and the wholesale power marketing division.

Q. Please state your educational background and professional experience.

A I have a bachelor's degree in engineering from the University of Central Florida, as well as an MBA from Rollins College. I am a licensed professional engineer in the State of Florida.

I have worked for OUC since 1977 and my responsibilities included serving as a Results Engineer, Assistant Superintendent of Operations, Superintendent of Indian River Power Plant in Titusville, Director of Stanton Energy Center near Orlando, Managing Director of Generation, and my current position as Vice President of Power Resources.

Q. **What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony is to describe OUC and discuss the restructuring of generating assets that OUC is undergoing. I will provide the background on how the Stanton A joint development project evolved. I will also discuss both the Joint Development and Power Supply Requests for Proposals. Additionally, I will explain the process used to evaluate the bids from the proposals, as well as self-build alternatives. I will also summarize the agreements resulting from negotiations with Southern-Florida and provide the current status of the negotiations. Finally, I will discuss OUC's fuel procurement strategy for the project and the status of those negotiations.

Q. **Are there sections of the Need for Power Application identified as Exhibit OUC-1__ and the revisions to the Need for Power Application identified as Exhibit OUC-2__ that you are sponsoring as your testimony?**

A. Yes I am sponsoring Sections 1A.3 1 1, 1A.3 2, 1A.3 4.3, 1A.3.9, 1A.4 0, 1A.6.1, 1A.6.2, 1A.6 4, 1A.6.5, Appendix 1A.A, Appendix 1A.B, and Section 1B.2.0.

Q. **Are there any corrections to these sections?**

A. No, only the revisions shown in Exhibit OUC-2__ which was a formatting error in Table 1B.2-1.

Q. Please briefly describe OUC.

A. OUC operates as a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City of Orlando. OUC is authorized to provide electric and water service in Orange County and electrical service to municipalities in Osceola County. In 1997, OUC entered into an interlocal agreement with the City of St. Cloud, in Osceola County, to take responsibility for supplying all of St. Cloud's electric loads for the term of the 25-year agreement. In addition, OUC is now responsible for the management of St. Cloud's existing generation and purchase power contracts. OUC is a utility as defined in the Florida Energy Efficiency and Conservation Act (FEECA) Section 366.82(1), Fla. Stat. and serves retail loads in OUC's service territory and serves St. Cloud's retail loads in St. Cloud's service territory.

Q. Please describe OUC's power supply resources.

A OUC jointly owns and operates the four natural gas and oil fueled Indian River Combustion Turbine Units, as well as the Stanton 1 and 2 coal-fueled units. OUC jointly owns 40 percent of Lakeland Electric's McIntosh Unit 3 coal-fueled unit. OUC is a joint participant with 6.1 percent ownership of Florida Power & Light's St. Lucie 2 nuclear unit and 1.6 percent of Florida Power Corporation's Crystal River 3 nuclear unit. In addition, OUC operates six small diesel generating units owned by the City of St. Cloud. OUC's total generating capacity, including the St. Cloud diesel units, is 1047 MW based on the summer rating

OUC has a power purchase agreement with Reliant Energy for 593 MW through September 30, 2001, and between 525 MW and 577.5 MW annually beginning October 1, 2001 through September 30, 2003. The Reliant Power Purchase Agreement contains options for up to an additional 500 MW from October 1, 2003 through September 30, 2007 In addition, OUC manages St. Cloud's 15 MW partial requirements purchase from Tampa Electric Company, which extends through 2012.

OUC has agreed to purchase KUA's excess entitlements from Stanton A which are estimated to be 40 MW for fiscal year 2004, 24 MW for fiscal year 2005, and 10 MW for fiscal year 2006.

Q. Please describe OUC's transmission system.

A. OUC's existing transmission system consists of 26 substations interconnected through approximately 302 miles of 230 kV and 115 kV lines and cables. OUC and its existing generating unit sites are fully integrated into the State transmission grid through its twelve 230 kV interconnections with other generating units that are members of the Florida Reliability Coordinating Council (FRCC).

Q. Does OUC have any long term power sales agreements?

A. Yes. OUC has long term power sales agreements with FMPA, Seminole Electric Cooperative (SEC), KUA, and Reedy Creek Improvement District (RCID). The details of these power sales agreements are presented in Tables 1B.2-4 through 1B.2-6 of the Need for Power Application, Exhibit OUC-1 __

Q. Please briefly describe the generation asset restructuring process you alluded to earlier.

A. The generation asset restructuring process is a continuing process by which OUC is attempting to maintain a cost-competitive asset basis over the long-term considering uncertainties as we approach a deregulated environment. A goal of this process is to include purchase power resources as a component of this asset base. Three major activities associated with this process have been undertaken. The first was the sale of the three Indian River Steam Units in 1999 in exchange for cash and a purchase power agreement with an energy component which is tied to actively traded energy hubs. The second phase was the development and implementation of a financial energy price-hedging program. This was approved by OUC's commission in February 2000. The third phase is to optimize the redeployment of proceeds from the sale of the Indian River Steam Units for both debt retirement and reinvestment into newer, more efficient generating technologies. Stanton A represents this redeployment strategy.

Q. Please briefly describe how the joint development project initiated.

A. OUC, KUA, and FMPA have had a long history of participation in joint development projects. Each utility had a need for capacity in the same timeframe as noted in Table 1A.2-1 of the Need for Power Application, Exhibit OUC-1 __. As a result, the three utilities agreed to pursue a joint development project that would be both flexible and achieve an economy of scale greater than what the individual utilities could achieve individually

Q. How did involvement in the joint development project evolve?

A. OUC was selected as the agent by KUA and FMPA to develop the project structure and lead the negotiations. Three independent paths were pursued to determine the best economic option for the participants consisting of joint development, power supply, and self-build.

Q. Please describe the joint development RFP?

A. The joint development RFP involved the exploration of joint development projects with large generating entities utilizing sites available at Stanton Energy Center and/or Cane Island. The RFP process began with a solicitation of interest, which was sent to 35 utilities and developers. All respondents to the solicitation of interest were sent a joint development RFP and given the option of responding to the power supply RFP as well, if they so desired.

WHH Enterprises was commissioned by OUC to independently evaluate the responses to the joint development RFP.

Q. Please describe the power supply RFP process.

A. To ensure that there were no other more cost-effective opportunities available, a second RFP was developed which solicited power supply proposals from any source and/or technology, other than units built on either the Stanton Energy Center or Cane Island site. The power supply RFP was advertised nationally and posted on the internet.

OUC contracted with R.W. Beck, Incorporated to independently evaluate proposals from the power supply RFP.

Q. Please describe the OUC self-build alternative evaluation process.

A. OUC contracted with Black & Veatch to provide detailed cost estimates for two configurations of 2 x 1 F-class combined cycle units. One configuration included a steam turbine with minimal duct firing, while the other configuration was sized with a larger steam turbine to maximize plant output.

Q. Describe the overall evaluation process.

A. There were two tiers of evaluation. First, WHH Enterprises and R.W. Beck, Incorporated, independently evaluated the RFPs using a ten-year levelized cost per megawatt-hour basis as presented in Volume 1E-Confidential Exhibit A __. The least-cost proposal from each RFP was compared with the self-build option prepared by Black & Veatch on a consistent ten-year levelized cost per megawatt-hour basis. The second tier of evaluation compared all viable alternatives submitted utilizing a standardized assumption base for offerings from the joint development RFP, power supply RFP, and self-build alternatives.

Q. How did the self-build capital cost compare to the capital cost in the Southern-Florida proposal?

The capital cost estimates based on current market conditions indicated that there was significant capital cost savings opportunity with the Southern-Florida proposal compared to the self-build estimates since Southern-Florida had previously reserved combustion turbines

Q. What was the result of comparing the least-cost proposals from the joint development RFP and the power supply RFP with the self-build alternative?

A. Ranking on a consistent ten-year levelized cost per megawatt-hour basis resulted in the Southern-Florida joint development proposal being the least-cost alternative compared to the least-cost power supply and the self-build alternative.

Q. Were there any other evaluations conducted?

A. Yes. Black & Veatch evaluated the Southern-Florida joint development proposal against a number of self-build alternatives on an individual system basis for OUC, KUA, and FMPA. The evaluations showed that the Southern-Florida joint development proposal was the most cost-effective alternative for each system.

Q. Were there also concerns with respect to combustion turbine delivery schedules for the self-build alternative?

A. Yes. At the time of the evaluation the delivery schedule for F-class combustion turbines which were not already on order was the first quarter of 2004, which obviously precluded the October 1, 2003 commercial operation date.

Q. Was there any other alternative available to obtain combustion turbines in the required timeframe to achieve October 1, 2003 commercial operation?

A. No. For OUC alone there were no other alternatives other than the Southern-Florida proposal. However, the inclusion of KUA and FMPA in the project offered a possible alternative of using KUA's option for two General Electric 7F combustion turbines that was obtained when KUA purchased the combustion turbine for Cane Island 3. This option expired prior to receipt of the proposals. However, KUA was able to extend the option through the evaluation period

Q. How did the cost of the combustion turbines under the KUA option compare to those in the self-build cost estimate?

A. The cost of the combustion turbines under KUA's option were $2 million more expensive than those assumed in the self-build alternative cost estimate.

Q. Please describe the Stanton A project.

A. The joint development project between Southern-Florida and OUC, KUA, and FMPA consists of a 633 MW combined cycle, natural gas fired unit to be constructed at OUC's existing Stanton Energy Center. OUC, KUA, and FMPA collectively will own 35 percent of the plant, with Southern-Florida owning the remaining 65 percent. OUC, KUA, and FMPA have the unilateral right to purchase the 65 percent of the unit capacity owned by Southern-Florida for the 30-year life of the plant. The capacity is initially purchased through a 10-year power purchase agreement (PPA) with four 5 year unilateral extension options. OUC, KUA, and FMPA have entitlements to both the ownership portion and the purchase power portion of 80 percent, 10 percent, and 10 percent, respectively.

Q. Please describe the features of the Stanton A combined cycle unit.

A Stanton A is a 2 x 1 General Electric 7FA combined cycle with duct firing and power augmentation to increase plant output Stanton A is fueled with natural gas as the primary fuel and No. 2 oil as the back-up fuel. The unit has the condenser sized such that the combustion turbines can be operated at full load without the steam turbine being in service. This plant configuration and design provides high efficiency and flexibility coupled with high reliability

Q. Please describe the unit's environmental features.

A. Stanton A will include selective catalytic reduction (SCR) to reduce NO_x emissions. Stanton A will also use treated sewage effluent as its source of cooling water and will treat wastewater on site such that there will be no off-site discharges. Similar to Stanton 1 and 2, Stanton A will be one of the most environmentally friendly units in the State

Q. Does Stanton A provide fuel diversification for OUC?

A. Yes. In fiscal 2000, OUC obtained 72 percent of their energy requirements from coal-fueled resources. Stanton A will add a much needed diversity component of highly efficient natural gas-fueled capacity to OUC's fuel mix.

Q. If natural gas prices were to remain at high levels could Stanton A use alternate fuels?

A. Yes. The ability to deliver coal to the existing coal-fueled units at Stanton Energy Center provides the unique opportunity for coal gasification if economic conditions dictated such a process. This fuel-switching ability will help to cap the exposure to natural gas prices.

Q. Please describe the Purchase Power Agreement with Southern-Florida.

A The entire Purchase Power Agreement (PPA) with Southern-Florida is contained in redacted form in Appendix 1A.A The un-redacted PPA has been provided in

Volume 1F-Confidential Exhibit B __. OUC, KUA, and FMPA will each sign identical PPAs

As previously stated, OUC, KUA and FMPA has the unilateral right to purchase Southern-Florida's 65 percent ownership share of the capacity from Stanton A for up to 30 years. The capacity charges for the initial 10-year term and the four 5-year extensions have been specified in the PPA. The capacity charge for the initial 10-year term and the first 5-year extension are fixed. The capacity charge for the three additional 5-year extensions will be either the specified capacity charge or the market price if Southern-Florida elects the market price pursuant to the provisions of the PPA.

OUC, KUA, and FMPA have the further flexibility to reduce their capacity levels during years six through ten of the PPA by either 25 or 50 MW per year, up to a maximum of 200 MW This provides additional economic benefit to OUC, KUA, and FMPA if future conditions merit such reductions.

Variable O&M and start-up costs are specified in the PPA. The PPA provides an availability guarantee for the purchased capacity, which increases its availability over that of a self-build alternative. During periods when Stanton A is unavailable, Southern-Florida may provide energy from alternate resources. During periods when Stanton A is available, Southern-Florida may provide energy from alternate resources provided that Stanton A is on-line and committed at least at its minimum load. OUC, KUA, and FMPA are entitled to schedule any and all ancillary resources from the unit

OUC will be the agent for providing fuel and managing gas transportation throughout the term of the PPA. Fuel cost for energy from the unit will be based on the actual cost of fuel burned.

Q. Please describe the Construction and Ownership Participation Agreement.

A. Southern-Florida is responsible for construction of Stanton A for a fixed price for the capital equipment costs and for a fixed price within a specified range for the balance of plant capital costs as specified in the Construction and Ownership Participation Agreement (COA). OUC, KUA, and FMPA will pay for the construction of the interconnection facilities and Southern-Florida will be responsible for constructing the interconnection facilities at a fixed price. The Project will pay OUC an annual lease fee for the site.

Q. Please discuss the fuel procurement strategy for Stanton A.

A. The primary fuel for Stanton A will be natural gas, with No. 2 oil as a back-up fuel. The No. 2 oil can be delivered by both truck and rail. OUC is currently in negotiations with Florida Gas Transmission Company (FGT) and Gulfstream for natural gas transportation. The FGT pipeline is located 2.5 miles south of Stanton Energy Center and intersects OUC's railroad and transmission corridor. This allows a lateral to be constructed to the site on the existing right-of-way FGT has indicated they have the ability to supply the transportation requirements for Stanton A. Gulfstream recently received final Federal Energy Regulatory Commission (FERC) approval. Gulfstream plans to be in commercial operation in time to serve Stanton A through an expansion of their original system. Final natural gas transportation for Stanton A will result in transportation from one or both of FGT and Gulfstream based on the overall terms and conditions negotiated.

OUC has not yet completed specific plans for the purchase of natural gas commodity but plans to mitigate price risks through financial energy price hedging programs.

Q. Please summarize the status of negotiations with Southern-Florida.

A. The major agreements including the PPA and the COA have been negotiated and are scheduled to be signed by the end of April.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for an Electrical Power Plant in Orange County by the Orlando Utilities Commission, the Kissimmee Utility Authority, the Florida Municipal Power Agency, and Southern Company - Florida LLC	))))))) /	Docket No. 010142-EM Filed: March 5, 2001

DIRECT TESTIMONY

of

DOUGLAS E. JONES

on behalf of

SOUTHERN COMPANY – FLORIDA LLC

INTRODUCTION

Q: Please state your name and business address.

A: My name is Douglas Jones and my business address is Southern Company Services, 270 Peachtree Street, Atlanta, Georgia 30303.

Q: By whom are you employed and in what position?

A: I am employed by Southern Company Services ("SCS") as Vice President of Energy Marketing. SCS is a wholly-owned subsidiary of The Southern Company ("Southern Company") and provides a comprehensive set of services to the Southern Company's operating companies, including engineering, fuel procurement, finance, accounting and marketing services. I am also a Vice President of Southern Power Company.

BACKGROUND AND QUALIFICATIONS

Q: Please summarize your educational background.

A: I hold a Bachelor of Science degree in Mechanical Engineering from Virginia Polytechnic Institute and State University and a Masters of Business Administration with a concentration in finance from Kennesaw State University.

Q: Please summarize your employment history and work experience.

A: I have 20 years of experience in the electric utility industry, all with Southern Company or one of its affiliates. Since 1980, I have held various positions with Southern Company or one of its affiliates in the areas of retail marketing, regulatory affairs and wholesale power marketing. I have served as Vice-President of Energy Marketing for Southern Company Services since 1998.

Q. What are your responsibilities as Vice President of Energy Marketing?

A. I am responsible for the competitive wholesale marketing activities for Southern Company's operating companies, including the Stanton A Project in which Southern Company - Florida LLC ("Southern - Florida") is participating.

SUMMARY AND PURPOSE OF TESTIMONY

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Southern - Florida. My testimony supports a petition filed on behalf of the Orlando Utilities Commission ("OUC"), the Kissimmee Utilities Authority ("KUA") and the Florida Municipal Power Agency ("FMPA") for a determination of need for a 633 MW natural gas fired combined-cycle generating unit in Orange County, Florida (the "Project"). Southern - Florida has joined in that petition as a non-need applicant because: it was the successful bidder in OUC's RFP for the joint-development project; it will be a 65% equity owner of the Project; and, it will operate the generating plant. In addition, Southern - Florida has entered into Power Purchase Agreements ("PPAs") under which Southern - Florida will sell, and OUC, KUA, and FMPA will purchase, all of the

Project capacity owned by Southern - Florida during the term of the agreement. Southern has also joined with OUC, KUA, and FMPA and applied for site certification of the Project under the Florida Electrical Power Plant Siting Act ("Siting Act").

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe Southern - Florida, its relationship with Southern Company, and its experience in the development, construction and operation of electrical generating facilities. My testimony also generally explains Southern - Florida's involvement in the Project.

Q: Are you sponsoring any exhibits to your testimony?

A: Yes, I am sponsoring Exhibit ___(DEJ-1) which charts the ownership structure of Southern – Florida.

Q: Are you sponsoring any sections of the Need for Power Application for Stanton Energy Center Combined Cycle Unit A which has been identified as Exhibit OUC-1?

A: Yes, I am sponsoring that portion of Section 1A.1.0 that describes Southern - Florida.

OVERVIEW OF SOUTHERN - FLORIDA

Q: Please describe Southern - Florida and its affiliation with Southern Company.

A: Southern - Florida is a Delaware limited liability corporation authorized to transact business in Florida. Southern - Florida is a wholly-owned subsidiary of Southern Power Company ("Southern Power"). Southern Power is one of the six operating subsidiaries of Southern Company and was created to own and manage wholesale generating assets in the Southeast. The ownership structure of of Southern – Florida is shown in Exhibit ___ (DEJ-1).

Q: Please describe Southern Company's experience in the development and operation of electrical power plant projects.

A: Southern Company is the largest producer of electricity in the United States, and one of the largest in the world, with a proven record of designing, owning and operating electric power plants. With 69 plants, comprised of 278 units, Southern Company generates more than 31,000 MW of capacity in the southeast United States. Southern Company also has more than 26,000 miles of transmission lines that interconnect with major utilities. Through its subsidiaries and affiliates, Southern Company develops, builds, owns, and operates power production and delivery facilities, conducts energy trading and marketing activities, and provides other energy services in the United States and in international markets. In 2000, Southern Company had revenues of $23.4 billion dollars and net income of $1.4 billion dollars.

Q: Are Southern Company's resources, expertise, and core competencies in power plant development available to Southern - Florida?

A: Yes. Southern - Florida is a wholly-owned subsidiary of Southern Company and will have Southern Company's direct support in the areas of plant engineering, operations and maintenance, marketing, accounting, financial services and procurement.

Q: You previously stated that Southern – Florida is a wholly-owned subsidiary of Southern Power. Please describe Southern Power and its business objectives.

A: Southern Power was established to actively participate in the evolving competitive wholesale marketplace. Southern Power's strategic position in this wholesale market is enhanced by its abilities to: (i) centralize wholesale generation development within the Southern Company system, and (ii) capitalize on the core competencies of the Southern Company. These core competencies include over 70 years of experience in the engineering, construction, operation and maintenance of low-cost, clean, and reliable electric generation facilities.

Where appropriate market conditions exist, Southern Power is prepared to design, build and operate new wholesale generation facilities and sell output from those facilities under negotiated long-term bilateral contracts with other strong, well-respected electric utilities.

Q: Why is Southern - Florida interested in building and operating the Project in Florida?

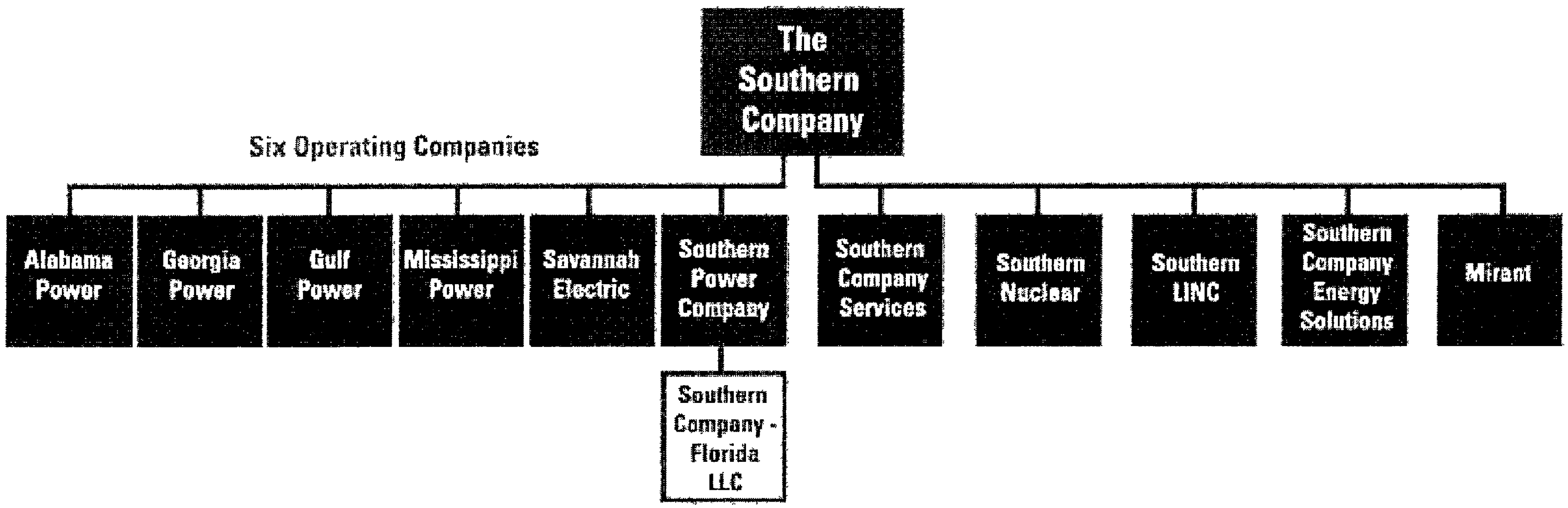
A: Southern - Florida is a subsidiary of Southern Power and was created to advance Southern Power's business objectives of building, owning and operating environmentally advanced, wholesale generating facilities and selling at wholesale the output produced therefrom. The Stanton A Project allows Southern - Florida to achieve those business objectives. By participating in the Project, Southern - Florida will jointly own and operate a highly efficient, environmentally advanced combined cycle generating unit and will sell capacity and energy produced to OUC, KUA and FMPA – all of which are strong and well-respected Florida electric utilities. The Project allows Southern - Florida to bring its significant plant development and operating experience into the Florida wholesale market to the benefit of OUC, KUA and FMPA. By developing and operating the Project, Southern - Florida will assist those utilities in reliably and economically meeting their retail obligations.

Q: Will Southern - Florida apply for the regulatory approvals necessary to sell its capacity and energy to OUC, KUA and FMPA under the PPAs?

A: Yes. Within the next month, Southern – Florida will file with the Federal Energy Regulatory Commission ("FERC") an application for exempt wholesale generator ("EWG") status under the Public Utility Holding Company Act of 1953. Southern - Florida also will apply for approval of market-based rates with the FERC.

Q: Does this conclude your direct testimony?

A: Yes.


The Southern Company
Six Operating Companies
Alabama Power
Georgia Power
Gulf Power
Mississippi Power
Savannah Electric
Southern Power Company
Southern Company - Florida LLC
Southern Company Services
Southern Nuclear
Southern LINC
Southern Company Energy Solutions
Mirant

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for an Electrical Power Plant in Orange County by the Orlando Utilities Commission, the Kissimmee Utility Authority, the Florida Municipal Power Agency, and Southern Company - Florida LLC	))))))) /	Docket No. 010142-EM Filed: March 5, 2001

DIRECT TESTIMONY

of

THOMAS O. ANDERSON

on behalf of

SOUTHERN COMPANY – FLORIDA LLC

INTRODUCTION

Q: Please state your name and business address.

A: My name is Thomas O. Anderson. My business address is 600 North 18th Street, Birmingham, Alabama 35203.

Q: By whom are you employed and in what position?

A: I am employed by Southern Company Services, Inc. ("SCS") as Manager of Generation Development.

Q: Please describe your duties with SCS.

A: As Manager of Generation Development, I am responsible for the development of new power plant projects by Southern Company-Florida, LLC ("Southern - Florida") and other Southern Company affiliates. My responsibilities include siting and development of financial business models for new generation. I am also responsible for various aspects of project management including engineering-procurement-construction ("EPC"), environmental, transmission, O&M, finance and other functions.

QUALIFICATIONS AND EXPERIENCE

Q: Please summarize your educational background.

A: I received a Bachelor's degree in Electrical Engineering from Auburn University in 1982.

Q: Please summarize your employment history and work experience.

A: I have been employed with SCS for approximately twenty-two years. I have worked in various areas including nuclear plant field support, design engineering, system planning, market analysis, finance, energy marketing and generation development. I have held a number of positions ranging from design engineer to engineering group manager to my current position as Manager of Generation Development. I have served as Manager of Generation Development with SCS since October 1998.

SUMMARY AND PURPOSE OF TESTIMONY

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Southern - Florida. My testimony supports the petition filed by the Orlando Utilities Commission ("OUC"), the Kissimmee Utilities Authority ("KUA"), the Florida Municipal Power Agency ("FMPA"), and Southern – Florida as a non-need applicant, for a determination of need for a 633 MW natural gas-fired combined cycle generating unit, which will be the third unit installed at the Stanton Energy Center in Orange County, Florida approximately 12 miles southeast of Orlando (the "Project" or "Stanton A").

Q: What are your responsibilities with respect to the Project?

A: My primary responsibilities are to ensure that all of the siting, environmental, EPC, transmission, O&M, financial, and other aspects of the Project meet Southern - Florida's financial and business goals. Additionally, I am responsible for ensuring that the major equipment is available to support the EPC schedule.

Q: What is the purpose of your testimony?

A: My testimony generally describes the Project, its performance characteristics, its environmental profile, and its EPC schedule. In addition, my testimony generally addresses the capital and O&M costs of the Project.

Q: Are you sponsoring any sections of The Need for Power Application for Stanton Energy Center Combined Cycle Unit A which has been identified as Exhibit OUC-1?

A. Yes, I am sponsoring Sections 1A.3.1.2, 1A.3.3, 1A.3.4.1, 1A.3.4.2, 1A.3.5, and 1A.3.7 of Exhibit OUC-1.

OVERVIEW OF THE PROJECT AND ITS OPERATION

Q: Please summarize the Project.

A: The Project is a natural gas-fired power plant utilizing advanced combustion turbine technology in combined cycle configuration with two heat recovery steam generators with duct-firing and power augmentation capability. The Project's rated new and clean capacity at average ambient site conditions is 633 MW, based on manufacturers' guarantees. The Project is projected to have a technical and economic life of 30 years.

Q. Please describe the generating technology of the Project.

A. The Project will consist of two General Electric PG-7241 FA combustion turbine generators ("CTGs"), two Deltak heat recovery steam generators ("HRSGs") with gas-fired duct burners, an ABB/Alstom STF30C single reheat condensing steam turbine generator ("STG"), and associated support systems. The CTGs will be equipped with dry low Nitrogen Oxide ("NOx") combustors, evaporative coolers and power augmentation capability. The CTGs are dual fuel units that will burn natural gas as the primary fuel and No. 2 distillate oil as the backup fuel. The HRSGs will be equipped with duct-firing capability and selective catalytic reduction ("SCR"). A CO catalyst spool will be included for possible future addition of CO catalyst.

Q. Please summarize the performance characteristics of the Project.

A: Stanton A will have three basic operating modes. The first mode is Normal Operation, where both CTGs will operate without supplemental duct firing of the HRSGs or CTG power augmentation. The second mode is Supplemental Firing Operation, where both

CTGs will operate at full load with supplemental duct firing of the HRSGs, but no CTG power augmentation. The third mode is Power Augmentation Operation, where both CTGs will operate at full load, with the necessary HRSG supplemental duct firing to support both full STG output and CTG power augmentation. The performance of these operating modes is dependent on the temperature, relative humidity and physical condition of the equipment. At certain temperatures, CTG Evaporative Cooling may be in operation during any of the three operating modes. The expected performance of Stanton A at various temperatures and operating modes is set forth in Table 1A.3-4 of Exhibit OUC-1 [Volume 1F – Confidential Exhibit B].

Q: Are there advantages to combined cycle technology?

A: Yes. Combined cycle generation technology is very efficient because it generates electrical energy from the input fuel both directly, through the combustion turbines, and indirectly, through the heat recovery steam generator and steam turbine. Furthermore, by reheating the steam between sections of the steam turbine, additional improvements in cycle efficiency can be achieved. Combined cycle technology simply makes the most of the input fuel, achieving increased efficiency in the generation of electrical energy from the available fuel source. For all of these reasons, the modern combined cycle power plant is one of the most efficient power cycles available today.

Another advantage of the combined cycle design is that it allows for greater flexibility in matching system operating characteristics over time. Because of its technological efficiency, it can readily be called on to meet varying operational load requirements in an economical manner. Thus, if required, Stanton A can function as a baseload or intermediate unit.

Q: Are there environmental advantages to the Project?

A: Yes. Combined cycle units operating on natural gas, like the Project, are one of the cleanest sources of fossil generation. Flue gas is the only byproduct of the combustion process, whether burning natural gas or distillate oil. Both are low sulfur, low ash fuels. Thus, sulfur and particulate emissions are virtually non-existent. NOx will be controlled by state-of-the-art NOx combustors and SCR equipment. Airborne emissions, therefore, will be limited by the use of relatively clean fuel and the appropriate application of control technologies.

In addition, combined cycle units use considerably less water than traditional steam turbine cycles. On average, combined cycle technology requires approximately one-half the amount of water used by a steam-only cycle. For these reasons, Stanton A's impact on the environment is relatively benign.

Q. When is the Project expected to achieve commercial in-service status?

A. Based on the present schedule, the expected commercial operation date is October 1, 2003.

Q: You previously stated that you are responsible for certain aspects of the EPC process for Stanton A. Please provide a general description of that process.

A: The EPC process ensures that a new generating plant is properly designed and constructed in a reliable, efficient and timely manner. The process fully integrates the engineering, procurement and construction phases of a generating project, and applies to virtually all aspects of a project from its inception to its commercial in-service date. Generally, the EPC process begins with the selection of a site and generating technology for a new plant. For a combined cycle plant, this can occur anywhere from two to four years prior to the scheduled commercial in-service date. Once the site and the generating technology are selected, the procurement process for major equipment can proceed. For combined cycle plants, the CTGs, the HRSGs and the STG are large, capital intensive pieces of equipment with long lead times – usually about a year and a half from the time of order to the time of delivery. Coincident with the procurement, detailed, site specific design begins, a process that is closely tied to procurement because the major equipment utilized has a direct impact on the scope of the design work. The detailed design typically takes about a year to a year and a half to complete. Near the completion of the design phase, planning begins for the physical construction of the plant. The planning phase is closely coordinated with the permitting phase. Once the necessary permit approvals are obtained and the project design process nears completion, the construction process commences. The construction of a combined cycle generating unit typically includes several sub-contracts, including site clearing and grading, foundation and concrete work, installation of major equipment and mechanical erection of the plant, and the start-up and testing of the plant. From receipt of the requisite permits, physical construction of a combined cycle generating unit takes approximately two years.

Q: What is the EPC schedule for Stanton A?

A: The Stanton A project's EPC schedule is set forth in Figure 1A.3-2 of Exhibit OUC-1.

Q: What is the status of the EPC schedule for Stanton A?

A: With respect to engineering, SCS has completed the conceptual engineering for the Project. The Site Plan, Plot Plan, Process Flow Diagram, Electrical One-line Diagram, Water Balance, Capital Cost Estimate and Operation and Maintenance Estimates are complete. With respect to procurement, all of the major equipment, including the CTGs, the HRSGs, and the STG, have been procured. With respect to construction, the construction of Stanton A is scheduled to take twenty-four months after the receipt of all required regulatory and environmental approvals.

Q: Are there advantages to having SCS manage the entire EPC process for the Stanton A Project?

A: Yes. SCS brings a wealth of experience, efficiency and accountability to the Project. SCS is the service provider for over 35,000 MW of generation built and/or operated by Southern Company and its affiliates, and consequently has extensive EPC management expertise. In addition to coal, nuclear, oil and gas generation, SCS has been actively engaged in building over 5,500 MW of new combined cycle generation since 1999 (exclusive of Stanton A). The design for Stanton A is based on SCS's reference plant design, which provides real benefits in terms of cost-savings, continuity, and efficiency. SCS has fully integrated all development phases for its referenced plant so that design, procurement and construction can be efficiently and effectively replicated without having to start each project anew. Furthermore, because SCS utilizes its own experienced staff to serve as EPC manager, single points of responsibility and accountability are established for any new generation project. When these advantages are brought to bear in the Stanton A Project, the experience, efficiency and accountability that SCS brings to the EPC process allows Southern – Florida to provide a fixed cost for the major equipment and a cap for the Balance of Plant cost for the Project.

Q. Are there other advantages to having SCS and Southern - Florida involved in the Project?

A. Yes. Southern Company, the parent company for both SCS and Southern - Florida, is an industry leader in the purchase of major equipment needed for natural gas-fired generation. The economies of scale associated with Southern Company's bulk procurement of equipment gives affiliates like Southern - Florida timely access to generating equipment and supplies which, in turn, allows Southern - Florida to meet Stanton A's desired commercial operation date at competitive prices.

PROJECT COSTS

Q: What are the projected capital costs for Stanton A?

A: OUC, KUA, and FMPA's direct construction costs for Stanton A are set forth in Table 1A.3-1 of Exhibit OUC-1 [Volume 1F – Confidential Exhibit B].

Q: What are the projected O&M costs of the Project?

A: The O&M costs for Stanton A are set forth in Sections 1A.3.4.1 and 1A.3.4.2 of Exhibit OUC-1 [Volume 1F – Confidential Exhibit B].

Q: Does this conclude your direct testimony?

A: Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF PAUL A. ARSUAGA

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. Paul A. Arsuaga, 800 North Magnolia Avenue, Suite 300, Orlando, Florida 32803-3472.

Q. What is your occupation?

A. I am presently a principal of and employed as a Senior Director by R. W. Beck, Inc.

Q. Please describe R. W. Beck, Inc.

A. R. W. Beck, Inc is a corporation of engineers and consultants. The firm was originally founded in 1942 for the purpose of rendering professional engineering and consulting services in planning, financing, designing and operating facilities for utilities and energy users.

Q. Please summarize your educational background and your experience in the electric utility industry.

A. I received a Bachelor of Science Degree in Electrical Engineering in 1969 from Tulane University, New Orleans, Louisiana. I also received a Master of Business Administration degree in 1975 from University of Hawaii, Honolulu, Hawaii I am a registered engineer in the states of Florida, Mississippi, and Missouri. I have over 30 years of experience in planning utility infrastructure, which includes 23 years associated with planning electric power facilities. Exhibit No. ___ (PAA-1) provides a brief description of my employment history and professional experience.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Orlando Utilities Commission ("OUC"), the Kissimmee Utility Authority ("KUA"), and the Florida Municipal Power Agency ("FMPA").

Q. What is the purpose of your testimony in this proceeding?

A The purpose of my testimony is:

(a) to discuss the tasks performed by the firm under my direction and supervision as authorized by OUC as agent for KUA and FMPA;

(b) to discuss the "Request for Power Supply Proposals" dated May 24, 2000 (the "RFP") issued by the OUC;

(c) to discuss the evaluation methodology and techniques employed in evaluating the responses to the RFP; and

(d) to discuss the results of the analysis and evaluation of the responses to RFP.

Q. Have you prepared exhibits to support your testimony?

A. Yes. In addition to Exhibit No. ___ (PAA-1) which I have mentioned, I have prepared, or had prepared under my supervision, the following exhibits:

(a) Exhibit No. ___ (PAA-2) The Form of the Proposal Evaluation used in Evaluating the Responses to the RFP (the "Evaluation Guidelines");

(b) Exhibit No. ___ (PAA-3) contained in Confidential Exhibit C ___. Status Report: Orlando Utilities Commission Proposal Evaluation – Stage Two Screening Results dated August 15, 2000 (the "August 15th Stage Two Screening Results"); and

(c) Exhibit No. ___ (PAA-4) contained in Confidential Exhibit C ___. Status Report: Orlando Utilities Commission Proposal Evaluation – Revised Stage Two Screening Results dated August 23, 2000 (the "Revised Stage Two Screening Results").

Q. In addition to your exhibits, are you also sponsoring portions of the Need for Power Application Exhibit OUC-1 ___ as your testimony?

A. Yes, I am sponsoring Appendix 1A C, which is the Request for Power Supply Proposals (RFPs) dated May 24, 2000. I am also sponsoring the Power Supply RFP evaluation contained in Confidential Exhibit A __ Volume 1E of the Need for Power Application consisting of the Stage One and August 8, 2000 Stage Two Screening Results.

Q. Will you please describe the assignment and the tasks that were authorized by OUC?

A. Yes In April 2000, the firm was authorized by OUC, acting in its own behalf and as agent for FMPA and KUA pertaining to the potential acquisition of additional generating resources, to provide independent consulting services to OUC in three general areas: first, the preparation of an RFP to solicit proposals to supply capacity and energy, second, the preparation of the Evaluation Guidelines documenting the criteria and methodology to be utilized in evaluating the responses to the request for proposals; and third, the review and evaluation of the power supply proposals and the preparation of reports.

Working closely with representatives of OUC, the RFP was prepared, was publicly disseminated on May 24, 2000 and is contained in Appendix 1A.C of the Need for Power Application Exhibit OUC-1 ______. Again, working closely with representatives of OUC, the proposal evaluation criteria and methodology set forth in the Evaluation Guidelines were developed and are set forth in Exhibit No. ___ (PAA-2)

At the direction of representatives of OUC, the Evaluation Guidelines, expressly provided, among other things, that the evaluation criteria and methodology be established to consider responses to the RFP and that such evaluation will not consider a "self-build" option, which I understood would be evaluated by OUC or another consultant, or responses to the Joint Development Solicitation, which I understood would be evaluated by OUC or another consultant. This exclusionary language contained in the Evaluation Guidelines is consistent with the language contained in the RFP that placed potential respondents on notice that

"...OUC has issued a separate solicitation on behalf of the Participants for joint development of a combined cycle power

> plant at the OUC Stanton site and/or FMPA's/KUA's Cane Island site and will not consider such proposals as a part of this RFP." (See page 18 of the RFP, Appendix 1A.C of the Need for Power Application Exhibit OUC-1 _____.)

In addition, at page 27 of the RFP, Appendix 1A.C of the Need for Power Application Exhibit OUC-1 __________, the respondents were informed that:

> "In addition to this RFP, OUC has issued a Joint Development Solicitation for a combined cycle project in which OUC will take an ownership position.... The proposals from the Joint Development Solicitation will be ranked and the proposals from this RFP will be ranked, and then the highest-ranking proposals from each solicitation will be ranked together against each other."

In summary, the firm's assignment, as authorized by the OUC, was limited to evaluating the responses to the May 24, 2000 RFP.

Q. Do you have any first-hand knowledge pertaining to the self-build option and the joint development solicitation?

A. Yes. I have very limited knowledge of the self-build option and the Joint Development Solicitation. While neither representatives of the firm nor I were authorized to and did not participate in the development of the self-build option and in the Joint Development Solicitation or the evaluation of any responses thereto, representatives of the firm met with representatives of the

OUC including a representative of WHH Enterprises to discuss and to agree on certain common assumptions which were to be used in both evaluation processes. The agreement on certain common assumptions was made in order that there would be a high degree of congruence between the RFP evaluation by Beck, and any similar analyses performed by others on any proposals received in response to the Joint Development Solicitation or the self-build option.

Q. What was the criteria used in evaluating the responses to the RFP?

A. The criteria is set forth in the Evaluation Guidelines Exhibit No ___ (PAA-2).

Q. What is the purpose of the Evaluation Guidelines?

A. In general, the Evaluation Guidelines are substantially completed prior to receiving proposals and serve as a guide for the evaluation and provide objectivity to the evaluation process That is not to say that once the evaluation guidelines are established they should never be altered or modified during the evaluation phase. Typically, as new factors become apparent during the evaluation, changes may be considered that would improve or streamline the evaluation process and yet maintain objectivity during the process.

Q. Please describe the Evaluation Guidelines.

A. The Evaluation Guidelines set forth a three stage process to obtain the best resource opportunity for OUC, while working within time and resource constraints, and maintaining a fair process. The first stage was generally focused on eliminating proposals, which were not complete or did not satisfy minimum requirements. The second stage of the process was a busbar screening evaluation which allowed the proposals emerging from the Stage One Screening to be compared on the basis of readily quantified costs at various capacity factors. The third stage evaluation was to take into account non-price factors as well as price related factors.

Q. Was the third stage evaluation process completed?

A. No. After Stage Two Screening, representatives of OUC informed me that the Stage Two Screening was adequate and suspended work on Stage Three Screening activities

Q. Did the suspension of the Stage Three Screening have a material adverse impact on the respondents or on the evaluation process?

A. No Since the purpose of the Stage Three Screening was to further refine and reduce the number of proposals, not completing the Stage Three Screening, if anything, made more proposals available for comparison to the self-build and Joint Development option. I am not knowledgeable of what other factors, besides busbar costs, were used by OUC to compare the proposals with the Joint Development and self-build option The Stage Three Screening would have provided an evaluation of non-price factors of the proposals

Q. Please describe in more detail how the process was conducted for each stage.

A. In general, the Stage One Screening called for a general review of the responses of the respondents to insure completeness and to determine that the minimum proposal requirements set forth at Section 14 of the RFP have been supplied. This was accomplished by logging in each response and inventorying the contents of the proposal. If a respondent was determined to have omitted certain requested minimum requirements and such information was deemed by OUC not to materially change the original response, discussions with the respondent were initiated to obtain such information.

Upon completion of the Stage One review, a letter report was prepared and submitted to OUC. The letter report set forth the proposals which were determined to be complete, and should be considered in the next level of screening and the proposals which were deemed incomplete or unresponsive and should no longer be considered.

The Stage Two Screening consisted of a simple analysis to determine the annual cost of power under each proposal. Consistent with the Evaluation Guidelines, each proposal was evaluated using uniform assumptions over a representative range of capacity factors to determine the most economic resource at selected capacity factors. As a part of the Stage Two Screening using data and information contained in each respondent's proposal and using uniform assumptions, comparisons for each of the proposals were made at the selected capacity factors on an annual basis and on a levelized cumulative present value basis. During this stage, discussions were held with each of the respondents to verify certain data and to obtain clarification, if necessary. The results of the Stage Two Screening were summarized in letter reports and were submitted to OUC.

The Stage Three Screening envisioned a more comprehensive evaluation of the respondents' proposals taking into account both price and non-price factors in a quantitative manner. As stated previously, the Stage Three Screening activities were never completed. On August 8, 2000, representatives of OUC instructed Beck that essentially all work should stop on activities related to the Stage Three Screening.

Q. Based on your experience in evaluating power supply proposals, do you believe the evaluation criteria set forth in Exhibit No. ___ (PAA-2) to review, analyze and evaluate proposals was reasonable and fair, and in compliance with industry standards?

A. Yes.

Q. How many respondents submitted proposals to the RFP?

A. Four entities submitted proposals in response to the RFP prior to the 5:00 p.m. EDT deadline on July 11, 2000.

The proposal submitted by one respondent contained three alternatives. In an attempt to identify the best proposal, the three alternatives were evaluated separately.

Q. Were the proposals submitted by these entities evaluated pursuant to the provisions contained in the evaluation guidelines?

A. Yes. During the Stage One Screening, it was determined that each of the respondents had not satisfactorily complied with Section 14 (the Minimum Requirements) of the RFP. As mentioned in the Stage One Screening Report (Confidential Exhibit A _____), each of the respondents were contacted in an attempt to obtain the omitted information. Of the four respondents, one elected not to provide the requested information. In recognition of the respondent's election not to provide the requested information, the proposal was deemed to be non-compliant and R.W. Beck recommended that it not be evaluated further. The remaining three respondents provided the additional information required to meet the Minimum Requirements and R.W. Beck recommended the proposals be considered for the next level of evaluation. These findings were submitted to OUC for confirmation on August 2, 2000 as a part of the Stage One Screening Report (Confidential Exhibit A _______).

Q. In general terms, will you please describe the proposals submitted by the respondents?

A. Yes, with the exception of the proposal that was deemed non-compliant, the other respondents offered to sell varying amounts of physically firm power including ancillary services on a first call, non recallable basis for a period of at least five years. The amount of capacity offered to OUC ranged from a minimum of 150 MW specified in the RFP to 651.5 MW. A more complete listing of the specific proposals submitted by each of the respondents is contained in the August 8th Stage Two Screening Results, Confidential Exhibit A ____.

Q. Will you describe the results of the Stage Two Screening?

A. Yes. Based on the results of the Stage One Screening, OUC authorized the next level of evaluation to be performed on the three remaining proposals. Because of the expedited schedule imposed by OUC, telephonic discussions were held with representatives of each respondent to obtain further clarification. In situations where additional research on the part of the respondent was necessary, the respondents were advised to submit such information in writing no later than the end of the day on Friday, August 4, 2000.

On August 8, 2000, the first of three Stage Two Screening Reports was issued, which is contained in Confidential Exhibit A ______. As the result of receiving additional information from the respondents and revisions in the basic assumptions, the results of the analysis and evaluation were revised On August 15, 2000, the second Stage Two Screening Report, contained in Exhibit No. PAA-3 in Confidential Exhibit C ______, was submitted to OUC. As can be seen by comparing the tabulation in the Stage Two Screening Report dated August 8, 2000 to the second report dated August 15, 2000, the Levelized Annual Busbar Delivered Costs, expressed in $/MWh, calculated as a part of the evaluation analysis changed by small amounts for each respondent.

On August 23, 2000, a further revised Stage Two Screening Report, contained in Exhibit No. PAA-4 in Confidential Exhibit C ___, was submitted to the OUC which revised the Levelized Annual Busbar Delivered Costs calculated for one of the respondents. At the capacity factors discussed during meetings with OUC (70 percent to 80 percent) which OUC was planning to utilize for its evaluation of the Joint Development Proposals, there was no change in the relative position of the respondent's proposal with respect to levelized busbar costs. The result of the Stage Two Screening was that five proposal alternatives were available to be advanced to Stage Three Screening. This was consistent with Evaluation Guidelines on Page 5, "OUC may select up to 4 to 6 proposal alternatives for advancement to Stage Three Screening."

Q. **Did the August 23, 2000 revision have an adverse effect on the selection process?**

A. No, for two reasons. First, the change in busbar costs for the respondent's proposal was a reduction of approximately $0.5/MWh which was a relatively minor change of approximately 1.0 percent. Secondly, the respondent whose costs were reduced had the same relative position with respect to the other proposals in the August 23 Stage Two Screening at the capacity factors which I understand OUC used for comparison to the self-build and Joint Development option as the August 15 Stage Two Screening in Exhibit PAA-3 contained in Confidential Exhibit C ___.

Q. **Does this conclude your testimony?**

A. Yes, it does.

Professional Resume of Paul A. Arsuaga

EDUCATIONAL BACKGROUND:

Bachelor of Science Degree in Electrical Engineering
Tulane University. New Orleans, Louisiana, June, 1969

Masters Degree in Business Administration
University of Hawaii. Honolulu, Hawaii, August, 1975

PROFESSIONAL REGISTRATION:

Registered as a Professional Engineer in the States of Florida, Mississippi and Missouri.

EXPERIENCE:

1999-Present	Principal in the firm of R. W. Beck/R. W. Beck, Inc
1981-1999	Mr. Arsuaga, has been an employee with R. W. Beck, Inc. where his work involved planning electric power facilities. Since joining the Firm in 1981, he has prepared or supervised studies and reports which include numerous market price assessments, independent engineering reviews, evaluation of stranded costs, power supply studies for municipal utilities and joint action agencies, consulting engineer's reports for official statements, financial analyses, acquisitions, damage studies, and power purchase contract negotiations.
1977 - 1981	Employed by Kansas City Power and Light Company. Served as a corporate planning engineer for which he performed generation planning studies and managed a corporate model.
1969-1977	Communications Planning Officer in the United States Air Force Planned ground and tactical communications – electronic systems for the Air Force. This work involved economic evaluations relating to telephones, microwave and other types of telecommunications systems.

RELEVANT EXPERTISE

WHOLESALE POWER SUPPLY CONTRACTS AND NEGOTIATION

Mr. Arsuaga has been involved with evaluating wholesale power contracts for the Municipal Energy Agency of Mississippi; the City of St. Cloud, Florida; Alabama Municipal Electric Authority; and the Florida Municipal Power Agency

Mr. Arsuaga has been involved with developing an appropriate methodology for compensating members of a joint action agency for supplying power supply resources to an all-requirements project.

Mr. Arsuaga has been involved in developing stranded cost analyses for two different joint action agencies.

Mr. Arsuaga has been involved in directing a hold harmless analysis to determine the potential rate impact and hold harmless costs associated with making remaining members of a joint action agency of Mississippi whole after certain members terminate their power supply arrangements.

PLANNING FOR ELECTRIC UTILITY RESTRUCTURING

Mr. Arsuaga has directed two recent analyses for industrial clients relating to assisting them making capital decisions in a deregulated environment. This work involved developing scenarios for long-range sustainable pricing practices in a deregulated electric utility market for generation. It also involved preparing projections of both time-of-day marginal costs and market clearing prices for various market regions of the United States based on these pricing practices. These analyses take into account transmission import and export capabilities between market areas, load and resources in several NERC reliability regions, annual economic conditions, market behavior, reliability standards and other factors

Mr. Arsuaga was also recently involved in assisting a joint action agency with its input to the Public Service Commission staff's Proposed Transition Plan for Retail Competition in the Electric Industry, and in this capacity, has met with the staff to discuss restructuring.

MARKET PRICE ANALYSES

Mr. Arsuaga has supervised numerous projects involving the preparation and/or review of market price projections for both industrial and joint action agency clients. These projections have been prepared for four market regions in different NERC regions. Some of these projects have included developing and using various computer models of electric utility market regions to simulate various market pricing structures under a market based restructured electric utility environment. He has also reviewed and evaluated numerous market price projections prepared by other consultants as part of independent engineering reviews and work related to rate filings for stranded costs. Mr. Arsuaga is a member of the Firm's Market Pricing Task Force through which he has been involved in understanding, evaluating and communicating issues related to market pricing in the electric utility industry.

ELECTRIC POWER RESOURCE PLANNING

Mr. Arsuaga has an extensive background in preparing electric resource planning studies for municipal utilities and joint action agencies. He has either prepared or directed the preparation of electric resource planning studies for the Florida Municipal Power Agency ("FMPA"), the Municipal Energy Agency of Mississippi ("MEAM"), the Bahamas Electricity Corporation ("BEC"), the City of Tallahassee, Florida, the Utility Board of the City of Key West, Florida, the Sebring Utilities Commission, the Fort Pierce Utilities Authority, the City of Vero Beach, Florida, and a large improvement district. These studies, which make conclusions and recommendations regarding the client's participation in specific power supply projects, have included screening type analyses which focus on identifying a list of reasonably attainable potential alternatives, as well as comprehensive studies which cover power supply related areas such as load forecasts, reliability, environmental impact, economic/financial feasibility, bond requirements, rate impact, and risk analysis.

Mr. Arsuaga's studies have been utilized by clients in making decisions regarding numerous purchased power arrangements The following are examples of some projects associated with Mr. Arsuaga's power supply studies: MEAM was organized to provide lower cost power to municipal participants in eastern Mississippi; Mr. Arsuaga conducted an RFP process which lowered the electricity costs to the City of Hagerstown, MD and three other municipals by 15 percent.

REQUEST FOR PROPOSAL SERVICES

Mr. Arsuaga has been a lead team member or project manager on power supply solicitations involving the City of Tallahassee; the Florida Municipal Power Agency; City of Hagerstown, MD; the Alabama Municipal Electric Authority; the City of St. Cloud, Florida; Golden Spread Electric Cooperative, Inc. and the Municipal Energy Agency of Mississippi. This process included preparation of the Request for Proposal and evaluation manual, evaluation of the proposals and negotiations with the potential power suppliers. Mr. Arsuaga has also participated in meetings and discussions with state public commission staff's in Florida and Texas, and has testified in a Public Utility Commission Hearing relative to the RFP Process.

RELIABILITY STUDIES

Mr. Arsuaga has been involved in evaluating electric system reliability and determining reliability criteria for electric utilities. These studies have involved estimating various measures of reliability, such as loss of load probability (LOLP), loss of load hours (LOLH), and expected unserved energy (EUE) for isolated and interconnected power systems. He prepared a reliability study for the City of Tallahassee, Florida that involves modeling the reliability of the electric system including peninsular Florida and Georgia.

LITIGATION SUPPORT

Mr. Arsuaga has been involved in litigation support services associated with wholesale electric rate filings, territorial disputes, and damage studies.

He has prepared analyses and testimony for Case No. 87-00103 CIV before the U.S. District Court Southern District of Florida, Miami Division, City of Homestead vs. Imo Delaval and Transamerica Corporation, which was amicably settled. He has also prepared analyses and testimony in cases for the Municipal Electric Authority of Georgia, the City of Tallahassee FMPA, the Municipal Energy Agency of Mississippi and industrial clients relating to wholesale power costs, territorial issues and transmission access and deregulation issues.

Mr Arsuaga has testified before the Florida Public Service Commission with regard to territorial issues involving the Fort Pierce Utilities Authority and Florida Power & Light; before the Public Utility Commission of Texas with regard to the selection of resources through an RFP.

FINANCIAL PLANNING AND ANALYSIS

Mr Arsuaga has been involved with the preparation of numerous official statements for bond refunds, and the financing of new electric generation facilities including the North Carolina Eastern Municipal Power Agency ("NCEMPA"), the Utility Board of the City of Key West, the Florida Municipal Power Agency ("FMPA"), the Municipal Energy Agency of Mississippi ("MEAM"), the Municipal Electric Authority of Georgia ("MEAG"), and the City of Tallahassee Mr. Arsuaga has also assisted financial institutions with the evaluation of a merchant generation project in California; Arizona; Nevada; Texas; Mississippi; and Alberta, Canada Mr. Arsuaga's experience has enabled him to analyze the financial aspects of municipal projects including proforma results, adequacy of liquidated damages, bond indenture requirements, various financing methodologies, tax-exemption considerations, arbitrage and other financial related factors.

GAS FUEL SUPPLY

Mr. Arsuaga has performed various studies relating to gas fuel supply for Florida municipals to determine the most economic level of firm gas service and the most economic mix of firm transportation versus firm service with the Florida Gas Transmission Company ("FGT"). The analysis involved projecting the daily gas usage for the cities electric production facilities and determining the level of firm gas transportation and firm service that represented the lowest cost —

taking into account the cost of generating on alternative fuels, potential curtailments of interruptible gas, and take or pay gas supply charges. The Authority and City based nominations for FGT's Phase II and III gas pipeline expansions on these analyses.

COMPETITIVE ANALYSES, MERGERS AND ACQUISITIONS

Mr Arsuaga has performed analyses associated with determining the economic benefits of mergers and acquisitions for electric utilities. One such analysis evaluated the impact of acquiring an additional service territory for a municipal utility This analysis, which was submitted to the Florida Public Service Commission, indicated the impact on the municipal utility's existing and transferred customers of the proposed acquisition of an additional service territory.

Another analysis evaluated the impact on a municipal utility's customers of a proposed transfer and acquisition of service territories and associated customer accounts between the municipal utility and Florida Power & Light. This analysis included an evaluation of equipment value, incremental and decremental revenues, and potential load growth for the areas involved.

Mr. Arsuaga performed an evaluation for a municipal utility to address potential future events such as the commencement of purchased power contracts for which the City is committed, power supply sales, acquiring additional territory, and potential changes in administration costs

TRAINING AND INFORMATION PRESENTATIONS

Mr. Arsuaga has made numerous presentations before utility boards and city commissions relating to electric resource planning and was a guest lecturer on Integrated Resource Planning in an IEEE Power Generation Seminar lecture series. He prepared technical papers on the RFP process, and determining the market value of generation capacity in a deregulated utility environment, which were presented at technical conferences.

SELECTED CONSULTING EXPERIENCE

The Coalition for Choice in Electricity (CCE) -- Evaluating analysis performed by witnesses for FirstEnergy Corporation regarding generating asset evaluation and the impact of a new electric industry restructuring law on the company (2000)

Calpine Energy – Independent engineering reviews of six different merchant plant combined cycle projects for financial institutions to support financing (1999-2000).

Florida Municipal Power Agency – Prepared stranded cost analysis of generation resources and contracts (1999).

Major Generation Developer – Prepared a power market assessment of the FRCC to determine economic feasibility of new merchant plant generation (1999).

ATCO Power Canada – Evaluated market price projections and methodology by another consultant as part of an independent engineering review of a merchant plant generation project in Canada (1999)

Major Industrial Clients – Prepared market price projections to assist two different industrial clients with making capital decisions in a deregulated electric utility market (1998-1999)

Municipal Energy Agency of Mississippi – Assisted the Municipal Energy Agency of Mississippi with its input to the Mississippi Public Service Commission Staff's proposed Transition Plan for Retail Competition in the Electric Utility Industry (1998).

L.S. Power – Independent engineering review of a merchant plant combined cycle project for financial institutions to support financing (1998).

Municipal Energy Agency of Mississippi – Request for Proposal preparation and evaluations of power supply alternatives to replace existing arrangements (1997-1998).

City of Hagerstown, Maryland – Conducted a power supply solicitation which included the evaluation, solicitation and negotiation of power supply alternatives (1997-1998).

Golden Spread Electric Cooperative, Inc. – Conducted power supply solicitation, evaluated power supply solicitation, evaluated proposals, and testified at the Public Utility Commission hearing in support of certificate of need for an exempt wholesale generator ("EWG") combined cycle project (1995-1996).

City of St. Cloud, Florida – Project manager on power supply solicitation and negotiations for replacing the City's power supply arrangements to be more competitive (1995).

City of Tallahassee – Conducted a reliability study for the City of Tallahassee to determine expected unserved energy (EUE), loss of load probability (LOLP), taking into account interconnections with other utilities (1995).

SELECTED PUBLICATIONS AND SPEAKING ENGAGEMENTS

Arsuaga, P. A. and Davis, R. L – *"Should You be in the Generation Business, Finding the Hidden Value of Capacity,"* Power Gen Conference, Orlando, Florida, December 1998

Arsuaga, P. A. and Stein, S. - *"Using the Request for Proposal for Procuring Electric Resources in Today's Competitive Environment,"* International Joint Power Generation Conference and Exposition, Denver, Colorado, November 5, 1997

Arsuaga, P. A. – *"Integrated Resource Planning"* Guest lecturer in an IEEE Power Generation Seminar Lecture Series 1992.

RECORD OF TESTIMONY

Regulatory or Judicial Forum	Proceeding	Petitioner/Matter	Client	Subject of Testimony	Date
Public Utility Commission, Texas	SOAH Docket No. 473-95-1820, PUC Docket No. 15100	Golden Spread Electric Cooperative, Inc./ Determinations Required by 32K of the Public Utility Holding Act and for Certification of Contract	Golden Spread Electric Cooperative, Inc.	Independent Evaluation of Requests for Proposals by Section 32K of the Public Utility Holding Act and Certification of Contracts	1996
Florida Public Service Commission	Docket No. 891245-EU, 1992	Fort Pierce Utilities Authority/ Florida Power & Light	Fort Pierce Utilities Authority	Generation Capacity Adequacy relating to a change in service territory	1992

Proposer's Name: ______________________
Proposal No.: ______________________

Evaluator: ______________________
Date: ______________________

CONFIDENTIAL

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Proposal Evaluation

ORLANDO UTILITIES COMMISSION

Request for Power Supply Proposals

Dated May 24, 2000

__WARNING__

This document contains information that must be considered as highly confidential. Information contained herein and other information relating to this evaluation process must not be disclosed to anyone who is not directly associated with the evaluation.

TABLE OF CONTENTS

1.0. INTRODUCTION

The Orlando Utilities Commission ("OUC") has issued a Request For Proposals ("RFP") for the supply of an aggregate of 750 MW of physically firm, dispatchable capacity and energy beginning on or before October 1, 2003. The 750 MW of capacity will be shared between OUC, Florida Municipal Power Agency ("FMPA") and Kissimmee Utility Authority ("KUA") collectively (the "Participants") as follows:

Participant	Nominated Capacity (MW)
OUC	600
FMPA	75
KUA	75

OUC is acting as the agent for FMPA and KUA in all matters relating to the RFP process including evaluation of the proposals and contract negotiations. OUC is accepting proposals for base, intermediate and/or peaking generating resources that offer a capacity amount of at least 150 MW and an agreement term of at least five years with one five-year extension. The deadline for submission of proposals by companies that submitted a valid Notice of Intent to Propose is July 11, 2000.

Proposals received in response to the RFP will be evaluated in comparison with: (i) each other; (ii) proposals received by OUC in response to a solicitation for joint development of a combined cycle power plant between the Participants and a company at the OUC Stanton and/or KUA/FMPA Cane Island sites; and (iii) the Participants self-build option. This evaluation manual provides the general procedure that will be used to screen and analyze the proposals in accordance with the evaluation procedures outlined in Section 14 of the RFP. The schedule for the RFP process is as follows:

Issue RFP	May 24, 2000
Pre-Proposal Conference (Mandatory)	June 1, 2000 (10:00 A.M.)
Deadline for Proposers' Questions	June 5, 2000 (5:00 P.M.)
Response to Proposers' Questions	June 12, 2000 (5:00 P.M.)
Notice of Intent to Propose	June 15, 2000 (5:00 P.M.)
Proposal Due Date	July 11, 2000 (5:00 P.M.)
Commence Negotiations	August 21, 2000
Contract Approved	October 31, 2000
Commence Power Supply Services	October 1, 2003

R. W. Beck, Inc. ("Beck") will receive, log, and at the appropriate time, open the proposals. Beck will perform the three staged evaluation process, preparing and submitting a letter report to OUC at the conclusion of each stage for decision making by OUC prior to proceeding.

When the proposals are delivered, Beck will implement a Receipt, Logging and Handling procedure to check whether each proposer has complied with the established deadline for submittal.

- At Stage One Screening, proposals will be examined for general completeness and to verify that all Minimum Requirements set forth in the RFP have been adequately addressed. Proposals that do not satisfy the Minimum Requirements may be recommended for elimination from further consideration.
- Stage Two Screening will compare and rank proposals on a busbar cost basis. Proposals offering peaking, intermediate and base load capacity will be evaluated at appropriate capacity factors. This analysis will reflect only the cost for the proposal being analyzed and will not show the impact that the proposal will have on OUC's overall operational cost.
- Stage Three Screening will consist of a more comprehensive evaluation that will consider both price and non-price factors in a quantitative manner.

OUC will select candidates from the short-list for negotiations.

Questions and requests for clarifications may be issued to proposers at any time during the evaluation process. In cases where proposals are eliminated from the evaluation process, OUC may notify proposers of the elimination.

Since this manual is intended to serve as a guide for ranking the relative merits of proposals submitted, OUC reserves the right to modify the manual to reflect new criteria based on potential benefits offered by innovative proposals.

2.0 Receipt, Logging and Handling

Official submission of proposals will be made at the Beck office in Orlando, Florida. As stated in Sections 2 and 5 of the RFP, proposals are due by 5:00 P.M. Prevailing Eastern Time (PET) on Tuesday, July 11, 2000 ("Proposal Due Date"). When each proposal is received, the designated Beck representative will complete the Proposal Log form in Appendix A.1, noting the date and time of delivery, the carrier and the number of packages. The proposals will be placed in a pre-determined secure location where they will remain unopened until after the Proposal Due Date. Designated Beck representatives will then:

2.1 Open the proposals in alphabetical order of the bidding company's name.

Each official copy of each proposal will be assigned an identification number which will be affixed to the outside and inside of the front cover. The Arabic numbering system (1, 2, 3, etc.) will be used to identify proposals in alphabetical order of the bidding company's name; and an alpha numeric numbering system (A, B, C, etc.) will be used to identify each of the multiple copies. Labels bearing such identification should be prepared prior to the Proposal Due Date. The original and four copies of the proposal will be distributed as follows.

A. Beck (original)
B. OUC (working copy)
C. OUC (working copy)
D. Beck (working copy)
E. Beck (working copy)

2.2. Summarize the various proposals received on Appendix Form A.2.1 showing the proposal number, company name, type and term of proposal, annual amount of capacity offered, the amount and form of payment for the Proposal fee.

2.3 Place a copy of the following label on the front outside cover of each document.

WARNING
This document contains information that must be considered as highly confidential. Information contained herein and other information relating to this evaluation process must not be disclosed to anyone who is not directly associated with the evaluation.

2.4. File originals of proposals in a secured location.

2.5 Maintain a log of the distribution of each set of copies.

If for any reason a proposal is received after the Proposal Due Date specified in the RFP, it will be returned unopened. When a proposal is returned, the date and time of the receipt by Beck will be recorded on the form in Appendix A.1 and a covering letter signed by an authorized representative of OUC will be included with the returned package. The text of the letter will state that the proposal is being disqualified because it was received after the Proposal Due Date.

After the bids have been opened, OUC may release for public information, a list of those companies that submitted valid proposals and the total amount of megawatts for all proposals received. This information may also be published on the RFP Internet Website.

It should be noted that in accordance with Section 9 of the RFP, all information stamped "Proprietary Confidential Business Information" in the proposals will not be disclosed to third parties, unless such disclosures are required by law or by order of a court or government agency having appropriate jurisdiction.

3.0 Stage One Screening

The contents of each proposal will be checked against the Minimum Requirements in Section 14 of the RFP to determine if each item has been addressed adequately. A copy of the Minimum Requirements Checklist in Appendix B of this Evaluation Manual will be completed for each proposal.

Any proposer determined to have omitted requested Minimum Requirements information which, if submitted at this stage, will not materially change the original response in the opinion of OUC will be so informed in writing by facsimile or e-mail and will be requested to submit the omitted information in writing to Beck as soon as possible, but no later than three (3) business days from the date of the facsimile, or the proposal may be disqualified.

A Stage One Screening results letter report will be prepared which summarizes the results and identifies proposals determined to be complete with respect to the Minimum Requirements set forth in the RFP. The report will identify proposals which should be considered at the next screening stage and proposals which should no longer be considered by OUC. OUC will make the final decision on any disqualifications.

4.0 Stage Two Screening

At the Stage Two Screening level, a busbar analysis will be conducted to determine the annual cost of each proposal. Each proposal will be evaluated over a range of capacity factors to determine its most economic resources at each capacity factor operating category. As appropriate, comparisons will be made among each capacity factor grouping on an annual or a cumulative present value basis. The annual supply costs for each proposal will be calculated by applying the Delivered Capacity Rates and Delivered Energy Rates from RFP Form 4 - Pricing Proposal form, to the capacity and energy delivered to OUC. Such screening may be accomplished in dollars, dollars per kilowatt, and/or dollars per megawatt hour.

Spreadsheets used for the cost components will be developed by Beck. Adjustments to data will be made if, in the opinion of Beck, such action is warranted in order to maintain consistent assumptions among the proposals. A copy of the individual proposer's spreadsheet may be sent to the respective proposer along with a letter requesting the proposer to verify and/or comment on the interpretations used from the proposal. During the Stage Two Screening, proposers will be requested to provide clarifications in a timely manner when such clarifications are required.

OUC may select up to 4 to 6 proposal alternatives for advancement to the Stage Three Screening level. A total of 4 to 6 proposal alternatives (750 MW x 4= 3,000 MW) is anticipated to be selected for Stage 3 screening. A Stage Two Screening result letter report may be prepared to summarize the results of Stage Two Screening.

5.0 Stage Three Screening

At the Stage Three Screening level, price and non-price factors will be scored for each proposal using a weighted scoring system. The factors along with the maximum scores allocated to each category are summarized below:

5.1 Price Criteria (60 points)

5 year Present Worth Cost (30 points)
10 year Present Worth Cost (30 points)

5.2 Non-Price Criteria (40 points)

5.2.1 Components of Power Cost (2 points).
- All fixed costs are recovered in the capacity charge.
- All variable costs are recovered in the energy charge.

5.2.2 Flexibility and Term (10 points).
- OUC's sole option to increase or decrease contract purchases with reasonable notice.
- OUC's sole option to select type of purchases, payment provision, pricing method, etc.
- OUC's sole option to adjust the contract term.

5.2.3 Fuel Type (2 points)
- Fuel type increases OUC's fuel diversity.

5.2.4 Dispatchability (10 points)
- Includes no minimum take provisions (100% dispatchable).
- Available for economy transactions.
- Scheduling provisions allow for change within one hour.

5.2.5 Firm Supply (8 points)
- Includes suitable arrangements for firming capacity.
- Includes reasonable penalties for non-performance.
- Provides suitable guarantees.

5.2.6 Technology Risk (2 points)
- Offers commercially proven technology.

5.2.7 Environmental Effects (4 points)
- Includes extraordinary measures to minimize any adverse environmental impacts.
- Offers renewable generating resources.

5.2.8 Transmission (2 points)
- Utilizes no intermediate transmission systems.

Each of the above items represents an important factor in selecting the short-list of proposals. The proposals, which are in the best overall interest of OUC, must adequately address each issue.

A range of raw scores has been defined for each of the criteria listed above. Each proposal will be scored for each price and non-price criteria and the raw scores will be weighted such that the relative importance as defined by the maximum amount of points allocated to each factor is reflected in the final score. In situations where proposals are combined in order to provide the required 750 MW, the score for each non-price criterion for the combination of proposals will be calculated as the weighted average of the respective scores for each member proposal based on the amount of megawatts the member proposal contributes to the total megawatts in the combination. Appendix D contains the forms that will be used for scoring the proposals along with a summary scoring sheet.

The development of price scores will involve a two step process. First, each proposal will be evaluated individually based upon its ability to generate cash flows by selling to the electricity market above its variable operating costs. The criterion for ranking proposals under this first step will be the projected internal rate of return over 10 years, under the base case set of assumed market prices.

The second step will involve combining proposals into portfolios with each portfolio containing approximately 750 MW and evaluating and scoring the portfolios on an overall basis. For each proposal a portfolio will be developed by adding additional proposals from the highest ranked remaining proposals which sum to approximately 750 MW. These portfolios will then be scored based on the overall internal rate of return produced by each portfolio over a ten-year period.

For purposes of the price screening an internal rate of return of 8% for a 750 MW proposal or a portfolio of proposals amounting to 750 MW will be given a score of 60 points. To the extent the overall rate of return is higher or lower than 8% the score will be adjusted on a proportionate basis.

The proposals (and portfolios as applicable) will be ranked according to total weighted scores, beginning with the highest scoring proposal or portfolio. During the Stage Three Screening, proposers may be requested to provide additional clarifications in a timely manner.

The objective of the scoring and ranking system is not to provide a precision indication of the potential value of the proposals, but rather to provide a good relative comparison of the proposals to each other. The short-list will be limited to a number of proposals equal to an amount of capacity that is up to approximately 300 percent of Participant's requirements.

A Stage Three Screening result letter report including sensitivity analysis will be prepared to summarize the results of Stage Three Screening.

6.0 SENSITIVITY ANALYSIS

As an extension of the Stage Three Screening, various scenarios may be simulated to evaluate the potential effect of changes in certain major assumptions, including access to market power, higher and lower fuel costs, generation overbuild, generation underbuild, etc. on the ranking of proposals. The impact on the rankings of the portfolios resulting from these scenarios may be taken into account in developing the short-list.

ORLANDO UTILITIES COMMISSION
APPENDIX A.1
PROPOSAL RECEIPT LOG

Date and Time Received	Company Name	Carrier/Receipt#	No. of Packages/Type

ORLANDO UTILITIES COMMISSION
APPENDIX A.2
PROPOSAL SUMMARY LOG

POWER SUPPLY REQUIREMENTS PROPOSALS

Proposal No. *(Arabic No.)*	1. Company Name *(Alphabetical Order)*	2. Type/Term of Proposal *(System or Unit Purchase)*	3. Annual Capacity Amount(s) (MW)	Amount of Proposal Fee $	Payment Form

ORLANDO UTILITIES COMMISSION
APPENDIX B
MINIMUM REQUIREMENTS CHECKLIST

Proposer's Name:_______________________________ **Proposal No.:**___________

Type of Supply: _______________________________ **Capacity:** ___________

Each proposal must meet certain minimum requirements before it will receive further consideration. These Minimum Requirements are intended to demonstrate, to the reasonable satisfaction and at the sole discretion of OUC, that the proposer has the ability to deliver power as proposed.

	Yes	No	N/A	Unknown
1. The proposer attended the Pre-Proposal Conference	___	___	___	___
2. The proposer provides a fee of $5,000 for each priced proposal alternative in the form of a cashiers check payable to OUC.	___	___	___	___
3. The proposer offers to provide a minimum of 150 MW of unit or system capacity	___	___	___	___
4. (a) The proposer offers to provide physically firm power, including ancillary services, delivered to OUC's delivery points.	___	___	___	___
(b) The power will be available on a first call non-recallable basis.	___	___	___	___
5. The proposal offer will remain effective through December 31, 2000.	___	___	___	___
6. (a) The initial agreement period extends for at least five (5) years.	___	___	___	___
(b) Provisions are included that permit OUC the sole option to extend the agreement for at least a further five (5) years	___	___	___	___

ORLANDO UTILITIES COMMISSION
APPENDIX B
MINIMUM REQUIREMENTS CHECKLIST

	Yes	No	N/A	Unknown
7. (a) The proposed service commencement date is earlier than or within twelve (12) months later than October 1, 2003.	___	___	___	___
(b) Sufficient information is provided to demonstrate that the service can commence on the date proposed.	___	___	___	___
8. (a) If a unit supply is proposed, the proposal identifies the specific generating units and the contribution that each will make to the sale.	___	___	___	___
(b) If a system sale is proposed, the supply to OUC is equivalent to native load supply....	___	___	___	___
9. The proposer ensures that all emissions allowance requirements will be satisfied and that such costs are included in the Project.	___	___	___	___
10. The proposer declares ownership or contractual status of the unit, plant or system capacity.	___	___	___	___
11. The cost data including fuel cost and escalation rates were prepared using the applicable fuel price indices in RFP Attachment B unless energy prices are guaranteed.	___	___	___	___
12. The price for power provided in the completed Pricing Proposal Form (Form 4) reflects all costs and losses delivered to OUC's delivery points.	___	___	___	___
13. The proposer states a willingness to provide a Negotiation Security in the amount of $250,000 prior to commencing negotiations with OUC.	___	___	___	___

	Yes	No	N/A	Unknown
14. (a) The proposer completed the appropriate RFP Forms 2 through 6.	___	___	___	___
(b) The proposer provided the information requested in Attachment A.	___	___	___	___
(c) All forms requiring a signature were signed by a duly authorized official..........	___	___	___	___
15. The proposal includes scheduling provisions for the sale.	___	___	___	___
16. Any must-take provision does not exceed 25% of the proposed sale capacity on an annual basis.	___	___	___	___
17. (a) If proposal includes development of a new project, then the proposer has developed and has had in operation for a minimum of one year, at least one currently operating power supply project that is similar to or larger in size than the project being proposed.	___	___	___	___
(b) If proposal includes power from existing generating resources, then the proposer has successfully provided similar level of services to at least one electric utility for a minimum of one year.	___	___	___	___
18. If proposal includes power from an existing unit, then the proposer owns and operates the unit, plant or system capacity or has the unit(s), plant or system capacity under contract.	___	___	___	___
19. If proposer operates a proposed unit, plant or system capacity, then the proposal provides proof of operating experience as requested in RFP Attachment A.	___	___	___	___

Comments:

Busbar Cost Comparison Sheet

Proposer's Name:	**Proposal No.:**
Evaluator:	**Date:**

Those proposals and/or alternatives that are declared to be complete at the end of the Stage One Screening process will be further evaluated at the Stage Two Screening level. At this stage, a busbar analysis is conducted to determine the annual cost of each proposal and/or alternative delivered to OUC's transmission system. Each proposal will be evaluated over a range of capacity factors to determine its most economic operating capacity factor category. The calculations for this analysis are performed using electronic spreadsheets.

ORLANDO UTILITIES COMMISSION
APPENDIX D

STAGE THREE SCREENING

Power Supply Requirements

Proposal No. _____
Term _____

Name	Attribute to be Measured	Range of Raw Score	Actual Raw Score	Weighting Factor*	Estimated Maximum Score*	Weighted Score
Pricing Criteria						
0 - 5 years		0-30			30	
0 -10 years		0-30			30	
Subtotal					60	

Note: * *Estimated maximum score shown is based on 8 percent level of savings with respect to the affected costs. Should the projected savings for the proposal exceed this level, the actual score will exceed the estimated maximum score by a similar proportion.*

Power Supply Requirements

Name	Attribute to be Measured	Range of Raw Score	Actual Raw Score	Weighting Factor	Maximum Score	Weighted Score
Non-Price Criteria						
Components of Power Cost	• All fixed costs are in the demand portion of the rate and all variable costs are in the variable portion of the rate .... 1 • No ratchet provision included........ 1	0-2		1	2.0	
Flexibility & Term	• OUC's sole option to increase or decrease contract purchases with reasonable notice........ 5 • OUC's sole option to select type of purchases, payment provision, pricing method, etc........ 5	0-5 0-5		1	10.0	
Fuel Type	Reduces coal as a % of total energy mix over the Study Period • 30% or higher .... 2.0 • 20% - 29% .... 1.0 • 10% - 19% 0.5	0-2		1	2.0	
Dispatchability	• Includes no minimum take provisions (100% dispatchable)........ 4 • Available for economy transactions........ 3 • Scheduling provisions allow for change within one hour........ 3	0-4 0-3 0-3		1	10.0	
Firm Supply	• Includes a minimum capacity reserves of 20% and backup energy or equivalent arrangement........ 4 • Includes reasonable penalties for non-performance (dollar amount)........ 2 • Provides suitable guarantees (instrument)........ 2	0-4 0-2 0-2		1	8.0	

Power Supply Requirements

Name	Attribute to be Measured	Range of Raw Score	Actual Raw Score	Weighting Factor	Maximum Score	Weighted Score
Technology Risk	• Commercially proven technology .... 2 • Relatively new application of existing technology .... 1 • Relatively new technology .... 0 • Demonstration project 0	0-2		1	20	
Environmental Effects	• Includes measures beyond regulatory requirements to minimize any adverse environmental impacts .... 3 • Offers renewable generating resources 1	0-3 0-1		1	40	
Transmission	• Utilizes no intermediate transmission systems. .... 2 • Utilizes one intermediate transmission systems. .... 1 • Utilizes two or more intermediate transmission systems. 0	0-2		1	20	
Subtotal					40	
Proposal Total						

ORLANDO UTILITIES COMMISSION
APPENDIX D
STAGE THREE SCREENING SUMMARY

Power Supply Requirements **Proposal No. ____**

PRICE SCORE	Maximum Score	Actual Score: Raw Score	Actual Score: Weighted Score
Internal Rate of Return	60*	______	______
Subtotal Price Score	60*	______	______

NON-PRICE SCORE	Maximum Score	Actual Score: Raw Score	Actual Score: Weighted Score
Components of Power Cost	2.0	______	______
All fixed costs in capacity charge.			
All variable costs in energy charge.		______	______
Flexibility and Term	10.0	______	______
Sole option to change purchases.			
Sole option to select type of purchase, payment provision, pricing method, etc.		______	______
Sole option to adjust the contract term			
Fuel Type	2.0	______	______
Fuel diversity			
Dispatchability	10.0	______	______
No minimum take provisions			
Available for economy transactions			
Scheduling provisions			
Firm Supply	8.0	______	______
Suitable arrangements for firming capacity			
For unit sale: Performance penalty			
Corporate guarantee			
Technology Risk	2.0	______	______
Commercially proven technology			
Environmental Effects	4.0	______	______
Extraordinary measures			
Renewable resources			
Transmission	2.0	______	______
No intermediate transmission systems			
Subtotal Non-Price Score	40	______	______
TOTAL SCORE	100*	______	______

NOTE: * *Price Score and total score may be greater or less than 60 and 100, respectively, depending on the Internal Rate of Return Score.*

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF WILLIAM HERRINGTON

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO 010142-EM

MARCH 5, 2001

Q. Please state your name and address.

A. My name is William Herrington. My business address is 107 Island Drive, Howey-In-The-Hills, Florida.

Q. By whom are you employed and in what capacity?

A. I am the Principal of WHH Enterprises.

Q. Please describe your responsibilities in that position.

A. I have offered consulting services to the utility industry for the past four years.

Q. Please state your educational background and professional experience.

A. I have a bachelor's of science in mechanical engineering from the University of Florida. I am a registered professional engineer in the State of Florida since 1974. I have an MBA from Rollins College awarded in 1985, as well as post-graduate courses in finance at the University of Central Florida.

I was employed by the Orlando Utilities Commission (OUC) from 1969 to 1997. My duties during this time included Power Plant Engineer, Power Plant

Manager, Director of Power Production, and Senior Vice President of the Electric Business Unit of OUC.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the methodology used to evaluate and present the results of the evaluation of the responses to OUC, KUA, and FMPA's Request for Joint Development Proposals (RFP).

Q. Are there portions of the Need for Power Application contained in OUC-1__ that you are sponsoring as your testimony?

A. Yes. I am sponsoring the evaluation of the joint development proposals contained in Volume 1E-Confidential Exhibit A__.

Q. Please describe the evaluation process used to determine the least-cost joint development proposal.

A. Initially, each response to the RFP was reviewed to determine which were incomplete and which should be considered for evaluation. Those proposals found to be responsive were then ranked on a levelized cost per megawatt-hour basis over a ten-year period, beginning in 2004 and ending in 2013. Performing the evaluation in this regard accounts for the time value of the cash flows and allows for the evaluation of proposals with differing capacities. Analysis was performed at 60, 70, and 80 percent capacity factors.

Q. How many responses to the Joint Development RFP were evaluated?

A. Proposals were received from five bidders. One of the bidders' proposals did not include pricing and therefore was considered non-responsive and eliminated from further evaluation. The names of the bidders are presented in Volume 1E-Confidential Exhibit A ___.

Q. What were the results of the evaluation process?

A. The two lowest priced proposals were relatively similar in price with the Southern-Florida proposal being lowest at two of the capacity factors evaluated and another proposal being lowest at the third. The Southern-Florida proposal was judged to be the most responsive of all the proposals for the following reasons. The pricing of the extension options that was required by the RFP was included by Southern-Florida. However, pricing of the extension options was not provided in the second lowest priced proposal. The second lowest respondent was given the opportunity, in follow up questions, to price extension options but declined. Additionally, the Southern-Florida proposal had a guaranteed commercial operation date of October 1, 2003, while the second lowest cost proposal would not be commercially operational until October of 2006. A sensitivity analysis of the effect of various discount rates showed no changes to the base case ranking of the proposals. The rankings of the four proposals are presented in Volume 1E-Confidential Exhibit A ___.

Q. Overall, what do you conclude from your evaluation of the responses to the Joint Development RFP?

A. The evaluation showed that the Southern-Florida proposal was the most responsive as well as the least-cost and lowest risk of the responses to the Joint Development RFP. I recommended that the Southern-Florida proposal be evaluated against the highest ranked response to the Request for Power Supply Proposals.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for an Electrical Power Plant in Orange County by the Orlando Utilities Commission, the Kissimmee Utility Authority, the Florida Municipal Power Agency, and Southern Company - Florida LLC	)	Docket No. 010142-EM Filed: March 5, 2001

DIRECT TESTIMONY

of

STEPHEN L. THUMB

on behalf of

SOUTHERN COMPANY - FLORIDA LLC

INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen L. Thumb. My business address is 1901 North Moore Street, Suite 1200, Arlington, Virginia 22209.

Q. By whom are you employed and in what capacity?

A. I am employed by Energy Ventures Analysis, Inc. ("EVA"), where I am a principal.

Q. Please describe EVA.

A. EVA is a consulting firm that engages in a variety of projects for private and public sector clients. These consulting projects are related to energy and environmental issues. In the energy area, much of our work is related to analysis of the electric utility industry and fuel markets, particularly oil, natural gas and coal. Our clients in these areas include coal, oil, and natural gas producers, electric utility and industrial energy consumers, and gas pipelines and railroads. We also work for a number of public agencies, such as state regulatory commissions, the United States Environmental Protection Agency, and the United States Department of Energy, as well as intervenors in utility rate proceedings, such as consumer counsels and municipalities. Another group of clients include trade and industry associations, such as the Electric Power Research Institute, the Gas Research Institute and the Center for Energy and Economic Development. EVA has provided testimony to nine state public utility commissions, including the Florida Public Service Commission. Furthermore, the firm has filed testimony in a number of cases in both state and federal courts, as well as before the Federal Energy Regulatory Commission.

Q. Have you previously provided testimony before the Florida Public Service Commission?

A. Yes. I provided rebuttal testimony in Docket No. 960409-EI on fuel related matters on behalf of Tampa Electric Company.

QUALIFICATIONS AND BACKGROUND

Q. Please describe your educational background and experience.

A. I received a Bachelor of Science degree in chemical engineering from Northwestern University and a Masters Degree in Business Administration (concentration in Finance) from American University. In addition, I was qualified as a Certified Public Accountant in the state of West Virginia. Prior to joining EVA, I spent 15 years in the oil and gas industry working for Ashland Oil, Burlington Northern and Meridian Oil. I am currently a principal at EVA responsible for the firm's oil and gas practice. This work includes a wide range of assignments for a variety of clients, including electric utilities. I have either authored or coauthored 24 reports for EPRI (Electric Power Research Institute) and/or the Gas Research Institute on a variety of topics concerning fossil fuels. My resume is attached as Exhibit _____ (SLT-1).

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports portions of the Need for Power Application ("NPA") filed in this proceeding by OUC, KUA, FMPA and Southern - Florida. Specifically, my testimony describes how the fuel forecasts for this project were developed and provides EVA's expert opinion that the fuel forecasts used by Black & Veatch to evaluate whether the Stanton A unit is the most cost-effective alternative available to meet the capacity needs of OUC, KUA and FMPA, were reasonable.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit ____ (SLT-1) is a copy of my resume. Exhibit __ (SLT-2) is an update to the forecast for crude oil. Exhibit ___ (SLT-3) provides a comparison of natural gas price forecasts, which I refer to later in my testimony.

Q. Are you sponsoring any sections of the NPA?

A. No. I am only providing testimony as to the preparation and reasonableness of the fuel forecasts used in the NPA.

Q. Please summarize your testimony.

A. EVA, as a normal part of its practice, routinely prepares fossil fuel price forecasts. For the evaluation of the Stanton A project, EVA prepared a base case price forecast for natural gas, coal, petroleum coke and crude oil. Each of these price forecasts were used by Black & Veatch to prepare high, likely and low delivered price projections for a potential power project at the Stanton facility. EVA reviewed each of the high, likely and low price projections and determined that they represented a reasonable assessment of the outlook for the prices for these fuels. EVA's review process included comparing the high and low forecasts with similar material that had been developed by EVA, as well as comparing the natural gas price projections to forecasts prepared by other organizations.

THE FUELS FORECAST

Q. How did EVA become involved in this proceeding?

A. Southern - Florida and OUC retained EVA to provide an accurate forecast of prices for various fuels that potentially could be used by OUC, KUA and FMPA for a new generation plant at the Stanton site. This forecast, in turn, was used by OUC's consultant, Black & Veatch, to evaluate whether the Stanton A unit is the most cost-effective generating alternative available to OUC, KUA and FMPA.

Q. What function does a fuels forecast serve in a utility's evaluation of future generating alternatives?

A. Fuel prices, and their differentials, represent one of the economic factors used in evaluating the types of new generation that could be added to a utility's system when a need for new capacity exists. Fuel prices are also relevant to the determination of the most efficient method of operating a utility's existing and proposed generating units in compliance with environmental and system requirements.

Q. What information did EVA develop for Southern - Florida and OUC?

A. EVA prepared the following four constant dollar ($2001) price forecasts for the period 2000 through 2020: (a) natural gas prices at the Henry Hub, which is in Erath, Louisiana; (b) delivered coal prices to the Stanton site; (c) delivered petroleum coke prices to the Stanton site; and (d) West Texas Intermediate (WTI) crude oil prices.

Q. How was this information used in the economic assessment for the Stanton A Project?

A. While there are some unique aspects as to how each fuel forecast was used in this assessment, in broad terms Black & Veatch took the following steps to integrate EVA's fuel price projections into their economic model:

(1) Converted EVA's 2001 constant dollar price projections to 2000 constant dollar price projections in order to have all economic information on the same basis.

(2) Developed current dollar price forecasts by escalating the 2000 constant dollar price projections at the same escalation rate (i.e., 2.5 percent per year) as used for all other economic assumptions used in the assessment. This became the base case fuel price forecast.

(3) Developed high case current dollar price forecasts by using a two (2) percent higher inflation rate.

(4) Developed low case current dollar price forecasts by using a two (2) percent lower inflation rate.

Q. Were any other fuel price forecasts developed for this assessment?

A. Yes. As a basis for an additional sensitivity analysis, Black & Veatch first took actual 2000 fuel prices and escalated them at the 2.5 percent per year inflation rate used throughout the project. In addition, Black & Veatch examined the real price escalation rates used by the Energy Information Administration (EIA) and used these plus the project's standard 2.5 percent inflation rate to develop current dollar fuel price forecasts. While both of these approaches to developing additional price forecasts result in outlier projections among industry forecasts, they are useful in testing the overall robustness of the assessment.

Q. You mentioned that there were unique aspects to each fuel price forecast. Were there any unique aspects to the natural gas price forecast?

A. Yes. EVA developed a price forecast for natural gas supply at the Henry Hub. In order to arrive at a delivered gas price forecast to the Stanton site, Black & Veatch added $0.75 per million BTU as a transportation charge.

Q. Was this approach reasonable?

A. Yes. There are two alternatives for natural gas transportation to the Stanton site: the existing Florida Gas Transmission system; and, the planned Gulfstream pipeline, which has ordered pipe and is estimated to be completed in June of 2002. The average tariff for these two systems is close to the $0.75 per million BTU assumed by the project.

Q. Were there any unique aspects associated with the crude oil price forecast?

A. Yes. EVA developed a price forecast for WTI crude oil. In order to arrive at a delivered price forecast for the petroleum products (i.e., No. 2 distillate fuel oil and No. 6 residual fuel oil) that might be used for one of the generation alternatives considered for the Stanton site, Black & Veatch used existing relationships between cost of crude oil and the delivered cost of these petroleum products to arrive at long-term price projections for distillate and residual fuel oil at the

Stanton site.

Q. Was this approach reasonable?

A. Yes. The major determinant, particularly over the long term, of petroleum product prices is crude oil prices.

Q. One of your exhibits concerns crude oil prices. Please explain this exhibit.

A. Since the time EVA was requested to prepare a forecast of crude oil prices for Southern - Florida and OUC, EVA has updated its crude oil price forecast. In order to provide the parties interested in this project with the benefit of EVA's latest crude oil price forecast, Exhibit ____ (SLT-2) presents EVA's updated crude oil price forecast.

NATURAL GAS PRICE FORECAST

Q. How did EVA prepare its natural gas price forecast?

A. As part of its normal practice, EVA tracks both the short-term and long-term supply and demand fundamentals for natural gas in order to prepare natural gas price forecasts for a variety of clients. These natural gas price forecasts have been both at specified hubs and on a delivered basis. The natural gas price forecast prepared for Southern - Florida and OUC represents EVA's latest long-term gas price forecast.

Q. Explain the basis for EVA's long-term outlook for natural gas prices.

A. EVA's long-term forecast for natural gas prices is based upon an analysis of the supply and demand fundamentals for natural gas. With respect to demand, approximately 70 percent of the overall growth in gas demand over the next 20 years will come from the power sector. Non-power sector growth (i.e., residential, commercial and industrial) will be between less than 1.0 and 1.5 percent per year. On the supply side, increases in supply to meet increases in demand will come from a variety of sources and will not be limited to just increases in lower-48 production. For example, over approximately the next five years about 37 percent of incremental supply will come from Canadian imports from both Western Canada and offshore Eastern Canada, as well as increases in LNG imports. During the next five-year period the combination of gas from Prudhoe Bay, Alaska and the MacKenzie Delta, Canada plus additional imports from the rest of Canada will account for approximately 50 percent of incremental supplies. While there is less certainty over the various sources of supply in the latter half of the forecast period, significant contributions will come from the continued development of the Arctic regions, the further development of offshore Eastern Canada and additional LNG imports. Within the lower-48, major additions to supply are expected from the deepwater region of the Gulf of Mexico, the development of coal bed methane in at least eight basins, and the drilling for deeper reserves.

Q. How will gas prices in Florida be affected by the outlook for gas prices?

A. With the exception of transportation, gas prices within Florida are affected by the same factors that impact gas prices throughout the nation. This is the net result of the integrated nature of the North American gas infrastructure.

Q. Recently, the price of natural gas on the spot market has risen significantly. What are the primary factors causing this rise in gas prices?

A. The spot market for natural gas is still a relatively young industry. When it was deregulated initially, approximately 15 years ago, there was considerable excess deliverability (gas bubble), as a direct result of the change in regulatory status for the industry. Then came an era (1995 to 1999) of relatively balanced supply and demand. Today short-term increases in supply are having difficulty keeping pace with short-term increases in demand, hence the high prices. The primary reason for this current era for natural gas was the sharp decline in gas-directed drilling (i.e., from 650 to 371 rigs) in 1999, which caused deliverability to decline 1.5 to 2.5 BCFD. Unlike in the past, this decline in drilling was not due to a decline in gas prices. Rather the decline was due to external events, namely the 1998/1999 low oil price crisis. As a result of the low oil price crisis, exploration and production (E&P) firms suffered significant declines in profits and cash flow (i.e., up to 75 percent declines), which caused them to stop virtually all capital expenditures (i.e., both oil and gas drilling). As a result, in the near-term the E&P industry has had a difficult time making up: (a) for this lost deliverability, (b) offsetting declines in existing production and (c) matching increases in demand, particularly those associated with the severe winter weather.

Q. How has this impacted EVA's price forecast?

A. The combination of recent record drilling levels in both the U.S. and Canada, the reemergence of LNG imports and development of new supply areas, such as offshore Eastern Canada, eventually will bring near-term supply and demand back into balance. At present, EVA projects these high prices moderating over three years, however the severity, or lack of it, of winter weather over the next two years is a major unknown, since the difference between a mild and cold winter can be 500 to 800 BCF per year. As a result it could be five years before gas prices moderate. After this three to five year period gas prices should begin to moderate and reach values one would anticipate when supply and demand is in balance.

Q. Were the high, likely and low delivered gas price forecasts prepared by Black & Veatch reasonable?

A. Yes. EVA, as part of its normal practice, prepares high and low price forecasts for natural gas using a Monte Carlo technique which analyzes the potential range for a series of variables that impact natural gas supply and demand fundamentals and hence gas prices.

EVA compared and contrasted the Black & Veatch high and low gas price forecast with those generated by its Monte Carlo technique and found them to be reasonable.

Q. Are the Black & Veatch gas price forecasts in line with other recognized industry forecasts?

A. Yes. In Exhibit ____ (SLT-3) the gas price forecast for six other organizations are compared to the price forecasts prepared by Black & Veatch. This comparison is done for the year 2015, which is the only year for which information on all of the forecasts is available. In addition, each of the forecasts have been placed upon a common basis by including the appropriate transportation charge and using the standard inflation rate for the Stanton A project. As illustrated in Exhibit ___ (SLT-3) the Black & Veatch gas price forecasts are in the same range as the gas price forecasts prepared by other organizations.

COAL PRICE FORECAST

Q. How did EVA prepare its coal price forecast?

A. As part of its normal practice, EVA tracks both the short-term and long-term supply and demand for coal in order to prepare coal price forecasts for a variety of clients. The coal price forecasts have been both for mine mouth prices and delivered coal prices. In the case for the Stanton project, EVA examined the following five alternatives for supplying coal to the Stanton facility:

(1) Lower sulfur coal from Central Appalachia.

(2) High sulfur coal from Northern Appalachia.

(3) High sulfur coal from the Illinois Basin.

(4) Lower sulfur 8,800 BTU/lb coal from the Powder River Basin.

(5) Imported coal.

The lower sulfur coal from Central Appalachia was the least expensive. In addition, the Stanton facility currently uses this coal, which would allow for a common stockpile (i.e., reduces overall costs). Also, OUC currently has a rail contract (CSX) for coal deliveries, which could be used for additional coal deliveries (i.e., reduces overall costs). With respect to the other alternatives, the higher sulfur Northern Appalachian and Illinois Basin coal alternatives resulted in higher freight charges, partially offset by lower mine mouth costs. The net result was no reduction in costs and the proposed project was left with a higher sulfur coal. The Powder River Basin option was just too far to be economic (i.e., approximately 2,000 miles). Lastly, imported coal proved to be impractical because the inland transportation costs were too high.

Q. Recently, the price of coal on the spot market has risen. How has this impacted EVA's price forecast?

A. During the last half of 2000, the spot coal price for Central Appalachian coal (i.e., FOB rail car) has risen approximately 50 percent. This sharp increase in coal prices is in part due to the depressed coal prices that previously existed, which caused some decline in production, and in part to an increase in demand. EVA has incorporated this recent price phenomenon in its price forecast, which projects the coal prices to moderate within two years, as supply and demand comes back into balance, but coal prices are not projected to return to their previously depressed levels. The FOB rail car price for Central Appalachian coal represents approximately 60 percent of the forecasted delivered coal price to the Stanton facility.

Q. Were the high, likely and low delivered coal price forecasts prepared by Black & Veatch reasonable?

A. Yes. EVA, as part of its normal practice, prepares high and low price forecasts for coal. These forecasts analyze the potential range for a series of variables that impact coal supply and demand fundamentals and hence coal prices. EVA compared and contrasted the Black & Veatch high and low coal price forecast with those generated by EVA and found them to be reasonable.

PETROLEUM COKE PRICE FORECAST

Q. How did EVA prepare its petroleum coke price forecast?

A. Petroleum coke represents a niche market for fuels that tends to be regionally specific. On occasion, in the past, EVA has analyzed the supply and demand fundamentals for this niche market in order to prepare a petroleum coke price forecast for other clients. There are two types of petroleum coke: (1) a higher value petroleum coke, which is used for aluminum and steel production; and (2) a lower value petroleum coke, which is used as a fuel. For Southern - Florida and OUC, EVA updated its prior analysis for fuel grade petroleum coke. While supply is, in general, increasing as a result of refinery upgrades and greater use of heavier grades of crude, this is a thinly traded commodity that can be subject to rapid price escalation whenever demand increases. In general, production costs of petroleum coke prices are related to crude oil prices but the prices of fuel grade petroleum coke are capped by delivered coal prices.

Q. Were the high, likely and low petroleum coke prices prepared by Black & Veatch reasonable?

A. Yes. Based upon EVA's analysis of the market for fuel grade petroleum coke, the ranges of forecasts prepared by Black & Veatch were reasonable.

Q. Does this conclude your testimony?

A. Yes.

RESUME OF

STEPHEN L. THUMB

EDUCATION

C.P.A.	West Virginia, 1977
M.B.A.	Finance, American University, 1972 (cum laude)
B.S.	Chemical Engineering, Northwestern University, 1967

EXPERIENCE

Current Position

Stephen Thumb joined Energy Ventures Analysis in 1988 and became a partner in 1990. Mr. Thumb directs EVA's natural gas and oil practice. Mr. Thumb is responsible for the FUELCAST Service, which is a multi-client service providing semi-annual forecasts of demand, supply, and price for natural gas, coal, oil, and emission allowances. The types of projects in which Mr. Thumb has been involved are described below:

Natural Gas Procurement
Evaluates natural gas procurement strategies for consumers taking into account the changing regulatory environment. For example, the procurement must address the mix of long- and short-term supply contracts, the mix of firm and interruptible transportation, and the mix of services.

Natural Gas/Oil Industry Analyses
Evaluates the natural gas and oil industries for clients concerned about supply options and availability. Studies have focused on structural issues such as pipeline capacity.

Forecasting
Provides clients with general or customized forecasts of natural gas and oil prices. Natural gas price forecasts are developed on both a wellhead or burner tip basis. Oil prices are developed for crude and refined oil products.

Acquisition and Divestiture Analysis
Performs analyses for companies considering acquisitions or divestitures. One project involved an acquisition analysis of an independent exploration and production firm with substantial natural gas reserves in the northeastern geological provinces. Another involved the acquisition of an affiliate coal mining operation.

General Industry Studies
Authored or coauthored over 20 reports for EPRI and GRI on a wide variety of topics, including fuel switching, structural issues affecting regional basis differentials, the integration of natural gas within the power industry, the capability of pipelines to meet the requirement of new power generation units, the competition between gas and coal for new capacity and existing generation, and other topics.

Prior Experience

Before joining Energy Ventures Analysis, Mr. Thumb had 15 years of diversified industry experience having worked for three Fortune 100 companies. From 1982 to 1988, Mr. Thumb worked for Burlington Northern, Inc., most recently as Vice President of Planning for Meridian Oil, a wholly-owned subsidiary. Mr. Thumb's responsibilities included acquisitions, economic analysis, strategic plans, annual budgeting. Mr. Thumb's most significant accomplishment was the identification, analysis, and implementation of two major energy-related acquisitions (the El Paso Co. and Southland Royalty).

From 1974 to 1982, Mr. Thumb worked for Ashland Oil, Inc., most recently as Executive Assistant to the Chief Executive Officer. Mr. Thumb managed a number of special projects in the areas of operations and finance such as the development and marketing of a $200 million institutional drilling fund and an analysis of the firm's largest international oil production contract. Mr. Thumb also established a special employee incentive program for an oil and gas subsidiary in consultation with human resources and coordinated the redesign of an exploration and production accounting function.

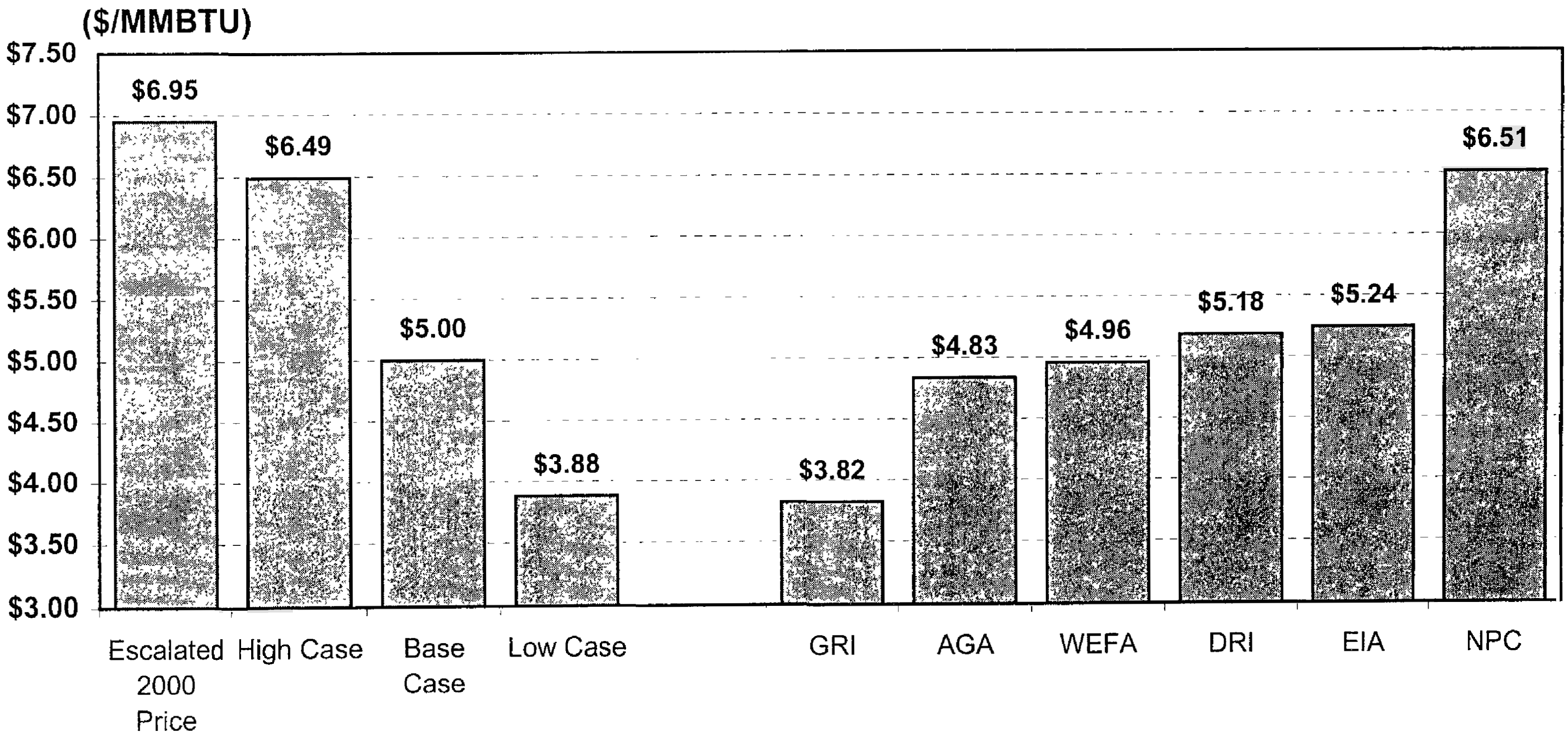
From 1972 to 1974, Mr. Thumb worked for Nuclear Fuel Services, a wholly-owned subsidiary of Getty Oil. Mr. Thumb, as Manager for Financial Planning, was responsible for the preparation of economic analyses and long- and short-term plans. He also assisted the controller in numerous accounting functions.

From 1967 to 1972, Mr. Thumb worked for the Division of Naval Reactors, a joint operation of the Atomic Energy Commission and the U.S. Navy, as an engineer in the fluid design section for surface ships and the radiological and chemical sections. From 1965 to 1967, Mr. Thumb worked at the Naval Ordinance Plant as a chemical and metallurgical technician.

UPDATED PETROLEUM PRODUCTS PRICE FORECAST

Year	1A.5-3	
	WTI-Constant	
	Initial	Update
2000	$30.26	$30.82
2001	$26.61	$27.36
2002	$23.70	$24.14
2003	$21.00	$21.00
2004	$19.50	$19.50
2005	$18.50	$18.50
2006	$17.50	$18.25
2007	$17.00	$18.25
2008	$16.50	$18.25
2009	$16.00	$18.25
2010	$16.00	$18.50
2011	$15.50	$18.50
2012	$15.50	$18.50
2013	$15.50	$18.50
2014	$15.54	$18.50
2015	$15.58	$18.50
2016	$15.66	$18.75
2017	$15.73	$18.75
2018	$15.81	$18.75
2019	$15.89	$18.75

COMPARISON TO OTHER FORECASTS
(Delivered Natural Gas Price-Current $)
2015



GRI: Gas Research Institute, AGA: American Gas Association, NPC: National Petroleum Council, WEFA: The WEFA Group, DRI: DRI
Source: Energy Information Administration, *Annual Energy Outlook 2001*, December 2000.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JILL SCHUEPBACH

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and address.

A. My name is Jill Schuepbach. My business address is 11401 Lamar Avenue, Overland Park, Kansas.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch as a Project Engineer.

Q. Please describe your responsibilities in that position.

A. As a Project Engineer for Black & Veatch, I am responsible for providing consulting services for utility and non-utility clients. The consulting services encompass a wide variety of tasks including: load forecasts, conservation and demand-side management evaluations, reliability criteria and evaluations, development of generation unit addition alternatives, optimal generation expansion modeling, production cost modeling, economic and financial evaluations, feasibility studies, pro forma analysis, and power market studies.

Q. Please state your educational background and professional experience.

A. I received a Bachelors of Science degree in Mechanical Engineering from the University of Missouri – Columbia. I have been employed by Black & Veatch since 1998 as a Project Engineer in the Energy Consulting Service Area. Since then I have provided planning services for several projects including many projects in Florida. I have provided system planning consulting services for the following Florida utilities: Lakeland Electric (Lakeland), Orlando Utilities Commission (OUC), JEA, Kissimmee Utility Authority (KUA), and Florida Municipal Power Agency (FMPA). In 1998, I assisted in preparing the Need for Power Application for Lakeland's McIntosh Unit 5. In 1999, I helped develop the Demand-Side Management Plans for OUC and JEA, and I am currently working on the Need for Power Application for Lakeland's and FMPA's McIntosh Unit 4. I have also assisted in the preparation of Ten-Year Site Plans for various Florida utilities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the methodology used to determine if there are any conservation and demand-side management measures available to OUC, KUA, and FMPA that would mitigate the need for Stanton A.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. Exhibit No. ___ (JAS-1) FIRE Model Results.

Q. In addition to your exhibit, are there sections of the Need for Power Application identified as Exhibit OUC-1__ and the revision to the Need for Power Application, Exhibit OUC-2__ that you are sponsoring as your testimony?

A. Yes. Sections 1A.8.0, 1B.5.2, 1C.5.2, and 1D.5.2

Q. Are you adopting these sections as part of your testimony?

A. Yes, I am.

Q. Are there any corrections to these sections?

A. No, only those minor word changes shown in Exhibit OUC-2__ and the minor change in the DSM test results for OUC stemming from the revision in the crude oil price and for KUA.

Q. What methodology was used to evaluate demand-side management (DSM) for OUC, KUA, and FMPA?

A The explicit evaluation of all available conservation and demand-side management measures is very expensive. Historically in the last few years, conservation and demand-side management measures have not been found to be cost-effective for municipal utilities, as evidenced by the Need for Power Dockets for Cane Island 3 and McIntosh 5, and the Conservation Goals Dockets for JEA and OUC. In addition, cost and performance information for DSM measures is difficult and expensive to obtain. In order to reduce the cost of evaluating DSM measures and ensure that all reasonable measures have been evaluated, Black & Veatch has used the data and results from the Florida

Power and Light Company's (FPL's) Conservation Goal's Docket No 991788-EG. FPL has done extensive evaluations having evaluated approximately 250 DSM measures in that Docket. It has been assumed that if the DSM measures found to be most cost-effective by FPL were not found to be cost-effective for OUC, KUA, and FMPA, then none of the 250 DSM measures evaluated by FPL would be cost-effective for OUC, KUA, and FMPA. Using this approach eliminated specific evaluations of hundreds of DSM measures that weren't cost-effective.

Q. How is the cost-effectiveness of DSM measures evaluated?

A. Black & Veatch used the PSC-approved Florida Integrated Resource Evaluator (FIRE) model which provides output in the form of the Rate Impact Test, the Total Resource Test, and the Participant's Test.

Q. Please describe how the FIRE Model works.

A. The FIRE Model evaluates the benefits and costs of DSM measures from several perspectives based on a comparison to costs for an avoided unit, which in this case is Stanton A. The model starts by evaluating the cost of the avoided unit in terms of capital cost, O&M costs, and fuel costs. Additional system costs, which could be avoided, are also evaluated, including transmission system capital and O&M costs and distribution system capital and O&M costs. The avoidance of these costs are considered benefits of the DSM measure being evaluated.

Next, the model evaluates the cost of the DSM measure being evaluated from several perspectives. The first perspective is the utility's cost for the DSM measure being evaluated These costs include the actual cost of installing or implementing the measure paid by the utility. These costs are incurred through incentives paid for by the utility. Examples include rebates, subsidies, installation costs, and administrative costs associated with developing and maintaining the DSM program as well as lost revenues Costs are also incurred by the participants. These costs can include the cost of purchase and installation of the measure, as well as costs associated with maintaining it.

The model compares these costs with the benefits and savings associated with the DSM measure. Again, these benefits and savings are evaluated from several perspectives From the utility perspective, these savings and benefits stem from avoided generation and load shifting. From the participants' perspective, these savings and benefits stem from reduced electric bills from both lower rates and reduced consumption. The participant also benefits from any rebates and subsidies.

Q. Please describe in more detail the Rate Impact Test, the Total Resource Test, and the Participant Test referenced earlier.

A The Rate Impact Test (RIM) evaluates the above benefits and costs from the utility rate perspective. The RIM test compares the utility's savings from the measure such as avoided generation and fuel costs to the utility's cost for the measure such as costs for installation and utility rebates and subsidies. Thus if the utility saves more from the program than the program costs, the RIM test is greater than 1 (the benefit/cost ratio is greater than 1), and rates to all customers will be lower. Generally, utilities require the RIM test to be greater than 1 before they will consider the DSM measure In other words, if the program does not lower rates, utilities generally will not implement it.

The Total Resource Test evaluates the above benefits and costs from a combined perspective of the customer and the utility For the Total Resource Test, only costs external to the customer and the utility are considered. For instance, rebates for a measure paid by the utility to the customer are merely a transfer between the utility and the customer and have no effect on the benefit/cost ratio; whereas fuel cost savings paid to external fuel suppliers would have an effect on the benefit/cost ratio In general, if the result of the Total Resource Test is greater than 1, society as a whole would benefit but some groups in society may be harmed.

Finally, the Participant Test evaluates benefits and costs solely from the perspective of the customer, or participant. If the benefit/cost ratio is greater than 1, the customer saves more money on the measure than they spend on it. In general, unless the Participant Test is greater than 1, there is no incentive for the customer, or participant, to participate

Generally, for a DSM program to be successful, the program should pass (have benefit/cost ratio greater than 1) all three tests, the RIM Test, the Total Resource Test, and the Participant Test

Q. Specifically, what were the results of Black & Veatch's evaluations of DSM measures for OUC, KUA, and FMPA?

A. Black & Veatch evaluated the most cost-effective measures in FPL's Conservation Goal's Docket that weren't already being implemented by OUC, KUA, and FMPA for both residential and commercial/industrial sectors. In all cases the most cost-effective of FPL's measures were found to not be cost-effective based on the RIM test. As such, it is assumed that none of FPL's conservation measures that aren't already being implemented by OUC, KUA, and FMPA would be cost-effective for any of the three utilities Each utility bases cost-effectiveness on the RIM test.

Q. What factors preclude DSM measures from proving cost-effective?

A. The cost-effectiveness of many DSM measures has decreased over the years for various reasons. This is especially true when evaluating potentially cost-effective DSM measures for municipal utilities, which are subject to lower cost tax exempt financing Additionally, the cost of installing new generation has decreased, while the efficiency of the new units has increased. Combining these two factors with government mandates, which force appliance manufacturers to increase the efficiencies of their products, reduces the potential of energy savings through an external DSM measure.

Q. How does the recent spike in natural gas prices affect the cost-effectiveness of DSM measures?

A For DSM measures that result primarily in capacity reduction without significant energy reduction, such as Direct Load Control, the increase in fuel prices would have little effect because the cost-effectiveness is primarily driven by savings in avoided unit capacity charges.

For DSM measures that primarily reduce energy consumption, such as appliance efficiency measures, increases in fuel prices will have a greater effect. However, appliance efficiency has already improved tremendously in most areas. Further incremental improvements in efficiency are fairly expensive and result in relatively small incremental savings in energy consumption.

Q. Is there a natural gas price above which DSM measures for OUC, KUA, and FMPA become cost-effective?

A. Cost-effectiveness is specific to each utility and DSM measure. The DSM measures are evaluated using the base case fuel forecast shown in Table 1A.5-5 of the revised Need for Power Application Exhibit OUC-2 __. As such, there is no single natural gas price that determines cost-effectiveness Exhibit JAS-1 represents the RIM, Participant, and Total Resource Test results for the DSM measures evaluated by the FIRE Model for each utility for the base case and high fuel price projections presented in Table 1A.5-6 of the revised Need for Power Application Exhibit OUC-2__. As expected, the high fuel price case has little effect on the RIM test especially for the load shifting alternatives which are the residential direct load control (Res-DLC) and the commercial off-peak battery charging (Comm-OPBC). Where there is more energy conservation involved such as the Residential Build Smart measure (Res-Build Smart) there is relatively more impact from the higher fuel prices, but the RIM test is still significantly below 1.0.

Q. Does this conclude your prefiled testimony.

A. Yes it does.

FIRE Model Results

Load Shifting Programs

	RIM	Part	TRC
OUC			
Base Case			
Res - DLC	0.49	1.00	2.33
Comm - OPBC	0.98	0.00	0.62
High Fuel Case			
Res - DLC	0.49	1.00	2.34
Comm - OPBC	0.98	0 00	0 62
KUA			
Base Case			
Res - Build Smart	0.44	0 71	0 32
Comm - OPBC	0.37	0 04	0.61
High Fuel Case			
Res - Build Smart	0.51	0.79	0.41
Comm - OPBC	0.38	0.04	0 61
FMPA			
Base Case			
Res - DLC	0.40	1.00	1.81
Comm - OPBC	0.53	0.02	0.49
High Fuel Case			
Res - DLC	0.40	1.00	1.82
Comm - OPBC	0.53	0.02	0.49

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF ERIC FOX

ON BEHALF OF OUC

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. My name is Eric Fox. My business address is 20 Park Plaza, Suite 910, Boston, Massachusetts, 02116.

Q. By whom are you employed and in what capacity?

A. I am employed by Regional Economic Research, Inc (RER). I am a Vice President in the Company's Forecasting Division.

Q. Please describe your responsibilities in that position

A. I am responsible for managing forecast support work and forecast project implementations for electric and gas utilities. I am also responsible for the day-to-day operation of RER's Boston office. I also provide forecast training through workshops sponsored by RER and other organizations such as EPRI and the Institute of Business Forecasting, and forecasting consulting services to electric and gas utilities.

Q. Please state your educational background and professional experience.

A. I received my M.A. in Economics from San Diego State University in 1984 and my B.A. in Economics from San Diego State University in 1981. After graduating, I started work at San Diego Gas & Electric as an Analyst in the Forecasting Department. I have been involved in energy forecasting and analysis, load research, rate design, and DSM program evaluation since that time. In 1994 I joined RER as a Project Manager. I was promoted to Vice President in 1999.

I have provided testimony for regulatory proceedings for forecasting and rate related matters.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the load forecast prepared for Orlando Utilities Commission (OUC).

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1__ that you are sponsoring as your testimony?

A. Yes. Section 1B.4.0 and Appendix 1B.A.

Q. Are you adopting these sections as part of your testimony?

A. Yes, I am.

Q. Are there any corrections to these sections?

A. No.

Q. Please describe the methodology used in developing OUC's sales forecast.

A. The sales forecast is developed from a set of structured regression models that can be used for both forecasting monthly sales and customers for the OUC budget period and over the longer term, 20-year forecast horizon. Forecast models are estimated for each of the major rate classifications including: 1) residential, 2) general service non-demand (small commercial customers), 3) general service demand service (large commercial and industrial customers), and 4) street lighting. Models are estimated using monthly sales data covering the period 1991 through 1999.

The baseline statistical forecast is adjusted for known large load additions that cannot be accounted for by the underlying regression model. These load additions are based on discussions with OUC marketing staff and include adjustments for large individual projects such as the expansion at Universal Studios, a new convention center, and expected expansion at the Orlando International Aiport. Finally, sales are adjusted for losses to yield a net energy for load forecast. A separate set of forecast models was prepared for the OUC and St. Cloud service territories.

Q. How are long-term appliance saturation and efficiency trends captured by the forecast models?

To capture long-term structural changes, end-use concepts are blended into the regression model specification. This approach, known as a Statistically Adjusted Engineering (SAE) model, entails specifying end-use variables –

heating, cooling, and base use – and utilizing these variables in sales regression models. This approach allows us to capture the impact changes in technology saturation and efficiency gains have on long-term sales and demand.

Q. How was peak demand projected?

A. A set of hourly regression models is used to forecast hourly demand over the twenty-year forecast period. System hourly demand is forecasted as a function of the retail energy forecast, expected weather conditions, hours of light, day of the week, and holidays. The winter and summer peak demand is then calculated as the maximum hourly demand occurring in the winter and summer period. A separate set of forecast models are developed for OUC and St. Cloud.

Q. How is the impact of conservation reflected in the load forecast?

A. The effects of existing conservation programs are implicitly included in the forecast. Program activity is captured both in the historical sales data and reflected in saturation and efficiency trends to the extent programs have impact historical appliance purchase behavior. Future efficiency trends due to expected changes in appliance standards are embedded in the end-use model variables.

As a result of projected economic, price, and appliance trends, average use is projected to increase at a relatively low rate. For OUC residential average use is expected to increase 0.8 percent per year through 2005, and further slows to just 0.5 percent growth through 2015. St. Cloud residential average use growth is slightly lower. Nonresidential average use also increases relatively slowly over the forecast horizon. Forecasted sales growth is primarily driven by projected customer growth.

Q. What are the results of OUC's demand and energy forecasts.

A. OUC and St. Cloud's combined summer peak demand is forecast to increase from 1,062 MW in 2000 to 1,679 MW in 2020 for a compound annual growth rate of 2.3 percent which is significantly lower than the historical growth rate of 4.3 percent over the past five years.

Similarly, the winter peak is forecast to grow from 1,051 MW in 2000 to 1,697 by 2020, or a compound annual average growth rate of 2.4 percent which is also considerably lower than the historical growth rate of 3.7 percent over the past five years.

OUC and St. Cloud's net energy for load is expected to grow at a compound annual average growth rate of 2.3 percent over the twenty year forecast period which compares with a historical growth rate of 4.1 percent over the past five years.

While the economy (and thus energy and demand growth) is expected to slow from the pace experienced over the last five years, regional economic growth will remain relatively strong over the long-term forecast horizon. The number of households in the Orlando MSA is expected to increase 1.9 percent per year and employment 2.1 percent annually over the forecast horizon. In a recent analysis, Regional Financial Associates (now Economy.com) ranked the Orlando MSA 16 out of 321 MSAs in terms of current and projected economic growth.

Q. Did you develop any alternative load forecasts to be used to perform sensitivity analyses?

A. Yes. In addition to the base case forecast, two long-term forecast scenarios were developed in order to bound the potential outcome. High forecast assumes stronger population, employment and regional output growth than in the base case. Further the high case assumes stronger growth in computer loads as reflected by the commercial base use variables. The low case is driven by slower population, employment, and output growth. The result is that retail energy demand grows roughly 0.7 percent faster in the high case and 0.6 percent slower in the low case. The high and low forecast scenarios are presented in Table 1B.4-20 of the Need for Power Application Exhibit OUC-1__.

Q. In your opinion are the assumptions in the load forecasts reasonable for planning purposes?

A. Given the uncertainty associated with long-term forecasting, the forecast assumptions are relatively conservative. In the base case, average use forecast projections are relatively flat with customer growth driving most of the sales forecast growth. The forecast is driven by economic projections provided by Regional Financial Associates (RFA). RFA has an excellent reputation in regional modeling and forecasting. The economic projections are in line with projections from the University of Florida. Long-term population forecast from the University of Florida are used to drive household growth after 2010.

The forecast scenarios provide a means to help bound forecast uncertainty. High and low growth economic assumptions yields a reasonable bound around the base case forecast with retail sales growing 0.7 percent faster in the high case and 0.6 percent slower in the low case.

Q. Does this complete your prefiled testimony?

A. Yes it does it.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MYRON ROLLINS

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. My name is Myron Rollins. My business address is 11401 Lamar Avenue, Overland Park, Kansas.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation. My current position is Project Manager.

Q. Please describe your responsibilities in that position.

A. As a project manager, I am responsible for the management of various projects for utility and non-utility clients. These projects encompass a wide variety of services for the power industry. The services include load forecasts, conservation and demand-side management, reliability criteria and evaluation, development of generating unit addition alternatives, fuel forecasts, screening evaluations, production cost simulations, optimal generation expansion modeling, economic and financial evaluation, sensitivity analysis, risk analysis, power purchase and sales evaluation, strategic considerations, analyses of the effects of the 1990 Clean Air Act Amendments, feasibility studies, qualifying facility and independent power producer evaluations, power market studies, and power plant financing.

Please state your educational background and experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Missouri - Columbia. I also have two years of graduate study in nuclear engineering at the University of Missouri – Columbia. I am a licensed professional engineer and a Senior Member of the Institute of Electrical and Electronic Engineers.

I have over twenty-four years of experience in the power industry specializing in generation planning and project development. In the past ten years, I have been the project manager for over 100 projects, the vast majority of which are for Florida utilities. Florida utilities for which I have worked include Lakeland – Electric, Kissimmee Utility Authority, Florida Municipal Power Agency, Orlando Utilities Commission, JEA, City of St. Cloud, Utilities Commission of New Smyrna Beach, Sebring Utilities Commission, City of Homestead, Florida Power Corporation, and Seminole Electric Cooperative.

I was responsible for the development of Black & Veatch's POWRPRO chronological production costing program and RECOM unit commitment program, and POWROPT optimal generation expansion program. I am also responsible for power market analysis and project feasibility studies. I have been responsible for need for power certification on a number of power plants in Florida including Stanton 1 and 2, Cedar Bay, Cane Island 3, McIntosh 5 and the Brandy Branch Combined Cycle Conversion. I also participated in the need for power certification for the Hardee and Hines projects I have presented expert testimony on several occasions before the Missouri and Florida Public Service

Commissions and have presented numerous papers on strategic planning and cogeneration.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the economic assumptions and fuel price projections used in the evaluation of the Southern-Florida joint development project. In addition, I will discuss the need for capacity for OUC, KUA and FMPA based on their reliability criteria. I will also discuss other supply-side alternatives considered for each utility, demand-side management, the consistency of the project with Peninsular Florida's needs, and the consequences of delaying the commercial operation of Stanton A.

My testimony will also show that OUC, KUA, and FMPA have adequately explored alternative generating technologies under a number of different load and fuel price scenarios, demonstrating that Stanton A is the most cost effective alternative, and that the project will provide necessary electricity at a reasonable cost, while contributing to the electric system reliability and integrity of OUC, KUA, and FMPA, as well as Peninsular Florida

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1 _____ and the revisions to the Need for Power Application identified as Exhibit OUC-2 _____ that you are sponsoring?

A. Yes. Sections 1A 1, 1A.2, 1A 3.5, 1A.3.8, 1A 5, 1A.6 3, 1A 7, 1A 9, 1A 10, 1A.11, 1B.1, 1B 3, 1B.6, 1B.7, 1B 8, 1C.1, 1C 3, 1C 6, 1C.7, 1C.8, 1D.1, 1D.3, 1D 6, 1D.7, and 1D.8 and Appendices 1A D, 1A.E, 1B B, 1C.A, and 1D A.

Are you adopting these sections as part of your testimony?

A Yes, I am

Q. Are there any corrections to these sections?

A. No other than the revisions in OUC-2 _____. The revisions to OUC-2 ___ result from updates to the crude oil forecast, provided by EVA, from application of appropriate escalation rates from the Annual Energy Outlook and from the addition of insurance costs in the FMPA fixed charge rate. While several numbers changed, the results remained the same. OUC-2 _____ also corrected some typographical errors.

Evaluation Methodology

Q. Please briefly describe the process that led to the determination that participation in the Southern-Florida joint development project represents the most cost-effective alternative to meet OUC, KUA, and FMPA's capacity need.

A. OUC, KUA, and FMPA went through a multi-stage process to develop the most cost-effective generation expansion plan that meets their respective need for capacity. This process included issuing a request for power supply proposals and a request for joint development proposals. The responses to these request for proposals were evaluated and ranked on a levelized cost per megawatt hour basis. OUC also evaluated a self-build alternative in the same manner. The Southern-Florida proposal was found to be the most cost-effective, and was selected for further negotiations. These negotiations led to development of a Power Purchase Agreement (PPA), as well as other agreements associated with the project The next step in the evaluation process was to develop individual optimal generation expansion plans for each utility over a 20-year period for a base case and a number of sensitivity cases.

The results of this multi-staged process showed the Southern-Florida joint development proposal was the most cost-effective alternative to allow OUC, KUA, and FMPA to meet their capacity needs

Economic Criteria

Q. Please describe the economic criteria used in the evaluations.

A. A consistent set of economic criteria were used for the evaluations. A general inflation rate of 2.5 percent was assumed and the general inflation rate was used as the escalation rate for O&M and capital costs. An interest rate of 6 0 was assumed for interest during construction.

Levelized fixed charge rates were developed to apply to the capital costs for new generating units. The fixed charge rate was based on the estimated weighted average cost of capital for OUC of 8 percent with a capital recovery period of 20 years plus one percent for insurance. The resultant annual fixed charge rate is 11.19 percent. KUA's fixed charge rate was assumed to be equal with OUC's. A present worth discount rate of 8 percent equal to the estimated weighted average cost of capital was used for OUC and KUA.

FMPA traditionally finances their generating units entirely with tax exempt municipal bonds. The estimated long term tax exempt municipal bond rate is assumed to be 6 percent. The fixed charge rate assuming a 2.9 percent bond issuance fee, a one year debt service reserve fund earning interest at the 6 percent bond rate, one percent for insurance and a 30 year bond term is 8.602 percent. Due to the relative small amount of equity required for Stanton A, FMPA plans on using the FMPA Pooled Loan Project to finance FMPA's 3.5 percent ownership share of Stanton A. The estimated interest rate over a 20-year period from FMPA's Pooled Loan Project is 5.0 percent resulting in a fixed charge rate of 9.02 percent including one percent for insurance. A present worth discount rate of 6 percent equal to the long term bond rate was used for FMPA.

Q. **Do you believe these economic criteria are reasonable and appropriate for evaluating Stanton A for OUC, KUA, and FMPA?**

A. Yes I believe these economic criteria are reasonable and appropriate for OUC, KUA, and FMPA.

Fuel Price Projections

Q. **Please describe the process undertaken to arrive at the various fuel price forecasts presented in the Need for Power Application.**

A. EVA developed a base case forecast in constant dollars for natural gas, crude oil, petroleum coke, and coal as presented in the testimony of Stephen Thumb. The projections for petroleum coke and coal were on a delivered basis. The fuel price projections were converted to normal dollars by applying the 2.5 percent general inflation rate to obtain the delivered cost. For evaluation purposes, an assumed \$0.75/MBtu was added to Henry Hub natural gas price to obtain a delivered price. Nuclear fuel prices were based on OUC's 2000 actual costs escalated at the general inflation rate. No.2 and No. 6 oil price projections were developed by applying the ratio of OUC's actual 2000 costs to the projected 2000 crude oil prices The base case fuel price projections were used for OUC, KUA, and FMPA.

High and low fuel forecasts were developed for each fuel type in the base case forecast, with the exception of petroleum coke. For the high scenario, an additional 2 percent was added to each year's escalation rate, while for the low scenario, the annual escalation rate was reduced by 2 percent. For petroleum coke, EVA provided specific high and low forecasts which were used for the respective fuel price scenarios.

Several other fuel price scenarios were developed. First, fuel prices were assumed to remain constant in real terms. OUC's actual 2000 delivered costs for No. 2 and No. 6 oil, nuclear, and coal were assumed to escalate at the 2.5 percent general inflation rate. For natural gas, the general inflation rate of 2.5 percent was added to the 2000 commodity price and \$0.75/MBtu was added for transportation. Since OUC did not purchase any petroleum coke in 2000, the base case forecast supplied by EVA for 2000 was used as the starting point, with the 2.5 percent general inflation applied.

A fuel price scenario was also analyzed which incorporated projections from the Energy Information Administration's *2001 Annual Energy Outlook (AEO)*. The AEO fuel price forecast provided a constant dollar delivered forecast for coal, as well as for No. 2 and No. 6 oil. AEO's well head projection for natural gas was used and $0.75/MBtu was added to each year's well head price to determine the delivered natural gas forecast. Since AEO did not provide projections for petroleum coke or nuclear fuel, the base case forecasts for these fuels were used. The 2.5 percent general inflation rate was included in all the fuel price projections.

The final fuel scenario was developed by applying the escalation rates presented in the AEO forecast to the average price paid by OUC in 2000 for natural gas, coal, and No. 2 and No.6 oil. Again, a $0.75/Mbtu transportation charge was added to each year's natural gas forecast to determine the delivered price. Since AEO forecasts were not available for either petroleum coke or nuclear fuel, the base case forecast for these fuels were used.

Q. **Do you believe the five fuel forecasts developed adequately reflect any fuel price scenarios that may reasonably be expected?**

A. Yes, I believe the fuel forecasts developed and analyzed adequately reflect any fuel price scenarios that may be reasonably expected. The various forecasts reflect a wide range of fuel prices.

Q. **Were any demand-side management (DSM) measures in addition to their existing programs found to be cost effective for OUC, KUA and FMPA?**

A. No. Based on the rate impact test (RIM) there were no additional DSM measures beyond those in their existing programs that were found to be cost effective

Q. Do you feel that the RIM test is the appropriate criterion for determining if DSM measures are cost effective?

A. Yes. For municipalities, I believe that it is appropriate to require that DSM measures pass the RIM test. Programs that do not pass the RIM test will result in increased rates. I also believe that it is appropriate for DSM measures to be required to pass the participant and total resource tests as well.

Generating Unit Alternatives

Q. What generating units were considered as alternatives to Stanton A?

A. A large number of generating unit alternatives were considered including renewable technologies, waste to energy technologies, advanced technologies, energy storage systems, and conventional technologies. Cost and performance characteristics were developed for each of the alternatives.

Q. Please describe the process through which alternatives were selected for detailed analysis.

A. The generating unit alternatives considered were evaluated and screened with respect to availability of resources and commercial development. Generating unit alternatives which were deemed to be commercially available and have adequate resources available were considered for further evaluation All of the conventional alternatives as well as solar thermal, solar photovoltaic, fuel cells, and supercritical coal units met these criteria. They were compared to similar conventional alternatives on a levelized $/MWh basis. The conventional alternatives were lower in cost on a $/MWh basis and thus only the conventional alternatives were considered for further evaluation.

Q. What conventional alternatives were considered?

A. In general, the conventional alternatives considered included pulverized coal units, fluidized bed units, combined cycle units, and simple cycle combustion turbine units. Specific alternatives were developed for each utility considering their ownership of existing sites, potential for joint participation, and size.

Q. Were specific alternatives developed for direct comparison to Stanton A?

A. Yes Initially Black & Veatch developed cost estimates for two 2 x 1 Siemens-Westinghouse 501 F combined cycle units. One configuration incorporated minimum duct firing, while the other configuration incorporated the greatest amount of duct firing possible resulting in a larger unit. The scope and cost estimate for these units are contained in the Need for Power Application Exhibit OUC-1 _______, Appendices 1A.D and 1A.F respectively. OUC used these cost estimates to compare the cost of a self-build alternative to proposals received from the joint development and power supply RFPs.

Q. Could OUC obtain combustion turbines in time to achieve the specified October 1, 2003 commercial operation date?

A. No. The delivery schedule for new Siemens-Westinghouse combustion turbines was the beginning of 2004. Thus, a 2005 commercial operation date would be the earliest possible commercial operation date Nevertheless the capital cost estimates based on current market prices were useful to OUC in order to indicate the capital cost savings in the proposals in response to the joint development RFP OUC was also able to evaluate the benefit of the earlier commercial operation dates provided in the proposals.

Q. Were there any other alternatives available to OUC, KUA and FMPA that could be directly compared to Stanton A?

A. Possibly KUA had an option for two General Electric 7 F combustion turbines which was obtained when KUA purchased the combustion turbine for Cane Island 3. The original option for the combustion turbine was scheduled to expire before the proposals from the joint development RFP were due. KUA was able to extend the option for the combustion turbines through the evaluation period for the joint development RFP. Thus, a technically identical self-build alternative utilizing KUA's extended option for combustion turbines with a delivery schedule that would support an October 1, 2003 commercial operation date was available. The estimated cost for the technically identical alternative was based on the actual cost of the combustion turbines under option to KUA. The performance of the self-build alternative was assumed to be identical to Stanton A.

Q. Were there any other possible obstacles to the construction of the self-build alternative for a commercial operation date of October 1, 2003?

A Yes First, KUA's combustion turbine option had a provision indicating that the delivery date for the combustion turbines could be subject to General Electric's prior sales Second, the option was not specific as to whether the combustion turbines could be used for a power plant constructed at Stanton Energy Center In the event that the combustion turbines could not be used at Stanton, the project could have been constructed at Cane Island. Finally, OUC would have had to been able to engage a firm to design and construct the project for the October 1, 2003 commercial operation date. While adequate time existed for the design and construction of the project, many of the firms providing design and construction services are fully booked through 2003. Nevertheless, cost and performance estimates were developed and used to evaluate the technically identical self-build alternative to Stanton A.

Q. Are the combustion turbines under KUA's extended option still available?

A. No. The extended option has expired.

Expansion Planning Methodology

Q. Please describe the process used to determine the least cost expansion plan.

A. POWROPT, an optional generation expansion model is used to determine the least cost expansion plan.

Q. Please describe how POWROPT works.

A. POWROPT is an optional generation expansion model. POWROPT models the utility's existing generating units as well as candidate units. The units are committed and dispatched in a least cost manner as in actual utility operation The simulation calculates fuel and O&M costs on an hourly basis and accumulates the costs on an annual basis. The model projects hourly loads for every year throughout the planning period based on the load forecast. As loads grow and additional capacity is required to meet reserve margin requirements, the model evaluates all combinations of candidate units available to meet the capacity requirements and selects the plan that results in the lowest cumulative present worth costs considering system fuel and O&M costs and annual capital costs obtained by applying an annual fixed charge rate to the capital cost for the new unit installation costs. POWROPT then uses the user specified present worth discount rate to calculate the cumulative present worth of each possible expansion plan that meets the reserve margin requirements and then ranks the expansion plans based on cumulative present worth costs

Q. What planning period is used for the evaluations?

A. A 20-year planning period from 2000 through 2019 is used

Q. Is the planning period appropriate?

A. Yes. A 20-year planning period is appropriate and 20-year planning periods have often been used by utilities for evaluating expansion plans.

Q. How are the POWROPT results used?

A. The expansion plans developed by POWROPT are modeled by POWRPRO, Black & Veatch's hourly chronological production costing model. POWRPRO provides detailed fuel and O&M costs by unit These costs are summarized on an annual basis and included with the annual capital costs and any other costs to provide detailed annual costs which are also discounted using the present worth discount rate to provide cumulative present worth costs

Q. Please discuss the sensitivity analyses evaluated.

A. Because the evaluations are based on projections of fuel costs, load forecasts and other parameters which are difficult to accurately project, varying scenarios of fuel cost projections and load forecasts are made and evaluated to determine the robustness of the expansion plan under varying projections for the future. The sensitivity analyses are conducted identically to the base case analyses.

Reliability Criteria

Q. Please explain the concept of a "reliability criteria" and why it is important for planning purposes.

A. To serve native load, a utility must have firm capacity resources in excess of its expected firm peak demand. This margin of capacity over firm peak load is needed because factors affecting either demand or supply could cause load to go unserved if a utility maintained only enough resources to meet its expected firm peak demand. On the demand side, higher than expected demand can occur due to a greater number of customers on the system, greater than expected usage per customer, extreme weather conditions, or lower than anticipated demand-side measure impacts. On the supply side, generation capacity could be unavailable due to factors such as forced or scheduled outages on generation equipment, unanticipated transmission constraints limiting power imports, generator deratings due to equipment failures, and unanticipated constraints on fuel supplies or water supplies

Due to uncertainties involved with projecting both demand and available supply, utilities maintain a "margin" of firm capacity resources over and above the anticipated peak level of firm demand. Traditionally in the industry, reserve levels of 15 percent are typical, with some utilities having adopted an even higher reserve margin. The appropriate level of reserve margin varies by utility, but generally, the smaller the utility and the fewer number of interconnections with other utilities, the greater is the reserve margin

<u>OUC Reliability Criteria</u>

Q. What is the target reserve margin adopted by OUC.

A. OUC has adopted a 15 percent reserve margin level. This is based on the work of the Florida Reliability Coordinating Council (FRCC) which has found that a planned reserve margin criterion of 15 percent is adequate for Peninsular Florida. The 15 percent reserve margin has also been established as a minimum planned reserve margin in Rule 25-6.035(1) Florida Administrative Code for purposes of reserve sharing. Therefore, OUC believes this to be the minimum level it should maintain, consistent with prudent utility planning and Florida regulations.

Q. How does the need to meet this reliability criteria impact the timing and need for additional capacity resources for OUC?

A. In order to maintain a 15 percent reserve margin requirement, OUC will likely encounter capacity shortfalls beginning in the summer of 2002 Initially, these capacity needs are small enough that they will likely be met through seasonal power purchases. However, by the winter of 2004, the earliest that new capacity can be brought on-line, the forecast deficit grows to 564 MW with the expiration of the Reliant PPA, and either remains relatively steady or increases thereafter. By the summer of 2019, OUC will require an additional 879 MW of capacity in order to maintain its required reserve margin.

Q. What generating unit alternatives did OUC consider?

A. OUC considered units that were appropriate in size and technology for OUC's system. For installation by October 1, 2003, OUC considered the Southern-Florida joint development project as well as a technically identical combined cycle unit based on KUA's option for General Electric 7 F combustion turbines. Due to the delivery schedule for F class combustion turbines and the construction and licensing requirements for solid fuel units, no other alternatives were considered available which could meet an October 1, 2003 commercial operation date. Other combustion turbine based technologies including simple cycle 7 F combustion turbines and 2 x 1 501 F combined cycle units were assumed to be available for June 1, 2005 commercial operation date. A circulating fluidized bed unit was assumed to be available in 2005 and an identical pulverized coal unit to Stanton 2 was assumed to be available for commercial operation by June 1, 2006.

OUC Economic Evaluation and Sensitivity Analyses

Q. What was the conclusion of the detailed economic analysis performed in POWROPT/POWRPRO?

A The economic analysis indicates that participation in the joint development project with Southern-Florida is the most economical option available to OUC.

On a cumulative present worth basis, participation in the joint development project results in a $6.611 million saving as compared to the second least-cost expansion plan.

Q. What were the results of the sensitivity analyses for OUC?

A. The sensitivity analyses demonstrate that participation in the joint development project with Southern-Florida is a very sound decision for OUC. The joint development project proves to be the least-cost alternative in all but two of the sensitivity scenarios.

Q. What conclusions did you draw from this analysis?

A. Based on the results of the extensive screening analysis and production costing analysis, participation with Southern-Florida in the joint development project proves to be the most cost effective option for OUC's ratepayers under the most likely future conditions expected on the system. It is also the most cost-effective alternative for all but two of the sensitivity scenarios analyzed. Based on these facts, I conclude that the joint development project with Southern-Florida represents the most cost effective option for OUC's ratepayers.

KUA Reliability Criteria

Q. What is the target reserve margin adopted by KUA.

A. KUA has adopted a 15 percent reserve margin level. The FRCC has found that a planned reserve margin criterion of 15 percent is adequate for Peninsular Florida The 15 percent reserve margin has also been established as a minimum planned reserve margin in Rule 25-6.035(1) Florida Administrative Code for purposes of reserve sharing. Therefore, KUA believes this to be the minimum level it should maintain, consistent with prudent utility planning and Florida regulations.

Q. How does the need to meet this reliability criteria impact the timing and need for additional capacity resources for KUA?

A. In order to maintain a 15 percent reserve margin requirement, KUA will likely encounter capacity shortfalls beginning in the summer of 2004. Initially, these capacity needs are small (11 MW); however, by the summer of 2019, KUA will require an additional 216 MW of capacity in order to maintain its required reserve margin

KUA Generating Unit Alternatives

Q. What generating unit alternatives did KUA consider?

A. Generating unit alternatives considered by KUA were based on sole and joint ownership of alternatives that were judged to be appropriate sizes and technology for KUA's system. Alternatives considered include joint participation in the Southern-Florida joint development project, joint participation in an identical self-build project, joint ownership in a pulverized coal, simple and combined cycle units, as well as sole ownership in simple cycle units.

Q. What was the conclusion of the detailed economic analysis performed in POWROPT/POWRPRO?

A The economic analysis indicates that participation in the joint development project with Southern-Florida is the most economical option available to KUA On a cumulative present worth basis, participation in the joint development project results in a $1.621 million saving as compared to the second least-cost expansion plan.

Q. What were the results of the sensitivity analyses?

A. The sensitivity analyses demonstrate that participation in the joint development project with Southern-Florida is a very sound decision for KUA. The joint development project proves to be the least-cost alternative in all but one of the sensitivity scenarios.

Q. What conclusions did you draw from this analysis?

A. Participation with Southern-Florida in the joint development project proves to be the most cost effective option for KUA's ratepayers under the most likely future conditions expected on the system. It is also the most cost-effective alternative for all but one of the sensitivity scenarios analyzed. Based on these facts, I conclude that the joint development project with Southern-Florida is the most cost effective option for KUA's ratepayers

Q. What is the target reserve margin adopted by FMPA.

A. FMPA has adopted an 18 percent reserve margin in summer and 15 percent in winter FRCC has determined that a 15 percent reserve margin is adequate for Peninsular Florida and the PSC has established 15 percent as the minimum reserve margin in Rule 25-6 035(1), Florida Administrative Code, for purposes of reserve sharing. FMPA's 18 percent reserve margin in summer provides additional assurance of reliability of supply.

Q. How does the need to meet this reliability criteria impact the timing and need for additional capacity resources for FMPA?

A. In order to maintain an 18 percent summer reserve margin requirement, FMPA will likely encounter capacity shortfalls beginning in the summer of 2003. Initially, these capacity needs are small (39 MW) and, due to the delivery schedule of combustion turbines, must be satisfied with purchased power. However, by the summer of 2019, FMPA will require an additional 617 MW of capacity in order to maintain its required reserve margin.

FMPA Generating Unit Alternatives

Q. What generating unit alternatives did FMPA consider?

A. Generating unit alternatives considered by FMPA were based on sole and joint ownership of alternatives that were judged to be appropriate sizes and technology for FMPA's system. Alternatives considered include joint participation in the Southern-Florida joint development project, joint participation in an identical self-build project, joint ownership in pulverized coal and combined cycle units, as well as sole ownership in the simple cycle units.

Q. What was the conclusion of the detailed economic analysis performed in POWROPT/POWRPRO?

A. The economic analysis indicates that participation in the joint development project with Southern-Florida is the most economical option available to FMPA in order to help satisfy its 18 percent summer reserve margin criteria. On a cumulative present worth basis, participation in the joint development project results in a $38.7 million saving as compared to the second least-cost expansion plan

Q. **What were the results of the sensitivity analyses?**

A. The sensitivity analyses demonstrate that participation in the joint development project with Southern-Florida is a very sound decision for FMPA. The joint development project proves to be the least-cost alternative in all but two of the sensitivity scenarios.

Q. What conclusions did you draw from this analysis?

A. Participation with Southern-Florida in the joint development project proves to be the most cost effective option for FMPA's ratepayers under the most likely future conditions expected on the system. It is also the most cost-effective alternative for all but one of the sensitivity scenarios analyzed. Based on these facts, I conclude that the joint development project with Southern-Florida is the most cost effective option for FMPA's ratepayers

Peninsular Florida Need

Q. Is the proposed project consistent with Peninsular Florida's needs?

A. Yes. The Florida Reliability Coordinating Council (FRCC) is responsible for coordinating power supply reliability in Peninsular Florida for the North American Electric Reliability Council. The FRCC has selected a minimum 15 percent reserve margin criterion to ensure reliability for Peninsular Florida As part of its reliability coordination activities, the FRCC provides an annual summary and report of Peninsular Florida Ten Year Site Plans. The most recent planning summary conducted by FRCC is the 2000 Load and Resource Plan for the State of Florida.

As shown in Section 1A.9 of the Need for Power Application Exhibit OUC-1 ___, Peninsular Florida reserve margins are projected to exceed the 15 percent planning criteria through 2009. Without the inclusion of units that have not yet received certification under the Power Plant Siting Act, this reserve margin would drop below 15 percent in 2004. Thus, the joint development venture with Southern-Florida makes a critical contribution to maintaining Peninsular Florida reliability at acceptable levels.

Q. In your opinion, will the joint development project with Southern-Florida contribute to maintaining reliability and integrity for the OUC, KUA, FMPA, and Peninsular Florida systems?

A. Yes. The joint development project utilizes proven F-class combined cycle technology and will provide a reliable source of power to contribute to the OUC, KUA, FMPA, and Peninsular Florida capacity requirements.

Consequences of Delay

Q. What would be the consequences of a significant delay or non-approval of the joint development project?

A. In the event that the commercial operation of the joint development project were delayed or not approved, OUC, KUA, and FMPA would experience adverse consequences, both from an economic as well as a reliability perspective.

A delay in the commercial operation of the joint development project would force OUC, KUA, and FMPA to incur additional costs to replace the capacity and energy that Stanton A would otherwise provide. The only generating unit alternative available to meet the October 1, 2003, commercial operation date of Stanton A is an LM 6000. The LM 6000 has a 30 percent higher heat rate than Stanton A, and is considerably more expensive on a $/kW basis. Additionally, the assumption that a LM 6000 could be available for commercial operation by October of 2003 may be optimistic based on actual delivery schedules. If in fact the delivery schedule would preclude installation of an LM 6000 in a timely fashion, OUC, KUA, and FMPA would be forced to look to purchasing power as a means of satisfying their capacity and energy requirements. In addition to the price of purchase power being uncertain, its availability is perhaps even more questionable

In the event that commercial operation of Stanton A is delayed significantly, OUC, KUA, and FMPA would face a collective capacity shortfall of 214 MW by the summer of 2004 even with OUC exercising the full 500 MW available from the Reliant PPA.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JOHN E. HEARN

ON BEHALF OF OUC

DOCKET NO. 010142-EM

March 5, 2001

Q. Please state your name and address.

A. My name is John E. Hearn. My business address is 500 South Orange Avenue, Orlando, Florida, 32802.

Q. By whom are you employed and in what capacity?

A. I am employed by Orlando Utilities Commission (OUC) as Vice President and Chief Financial Officer.

Q. Please describe your responsibilities in that position.

A. I am responsible for the financial operations of OUC. Among my duties are financial planning and project financing.

Q. Please state your educational background and professional experience.

A. I am a graduate of the University of Central Florida with a bachelor's degree in accounting. I am also a certified public accountant in the State of Florida. I previously served as finance director for the City of Kissimmee. I have been with OUC for 14 years.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss OUC's existing conservation and demand-side management programs and to discuss OUC's ability to finance Stanton A.

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1__ that you are sponsoring as your testimony?

A. Yes. Sections 1B.5.1 and 1B.9.0.

Q. Are there any corrections to these sections?

A. No.

Q. Please describe OUC's current conservation programs that reduce peak demands and energy consumption?

A. Significant changes have occurred in the market during the last 5 years. Today there is much more emphasis on competition as the electric industry prepares for deregulation. Economic conditions have changed significantly, for example, the cost of power plants and interest rates have decreased drastically. As a result, conservation programs are not always as cost-effective, but greater emphasis is placed on customer satisfaction. OUC's existing programs include the following:

- Residential Energy Survey Program
- Residential Heat Pump Program
- Residential Weatherization Program
- Low Income Home Energy Fixup Program
- Educational Outreach Program

- Commercial Energy Survey Program

These programs are provided because they have been proven to meet the needs of OUC's customers and contribute to reduction of energy consumption and peak demand. OUC will continue to evaluate DSM programs to identify programs that add customer value.

Q. How does OUC intend to finance its ownership share of Stanton A?

A. No final decision has been made as to the method of financing. As with other recent projects, OUC will assess whether the project should be financed with long-term debt, short-term debt, internally generated funds, or a combination of these sources. As a municipal utility, OUC could finance the project in whole or in part with tax-exempt debt.

Q. Does OUC have the capability to finance the project with long term debt if required?

A. Yes. OUC is financially very healthy. Our debt service coverage ratio for fiscal year 2000 was 2.23. We have strong credit ratings on all of our senior debt consisting of AA+ by Fitch, Aa1 by Moody's, and AA by Standard & Poor's. In fact, no municipal utility in the United States has higher credit ratings. In light of this financial health, OUC has the capacity to finance the project entirely through long-term debt if that proves to be the most appropriate option.

Q. In general, how does OUC recover costs in rates?

A. Rates are developed on a cost of service basis. Base rates are set to recover capital costs including the amortization of debt and a return on equity, O&M costs, and administrative and general costs. Fuel and purchase power costs including capacity and energy charges are recovered through a fuel charge.

Q. How do OUC's wholesale power sales affect rates?

A. OUC's wholesale power sales are generally structured such that fuel is a pass through. The nonfuel revenue from wholesale power sales reduces base rates.

Q. How did the sale of the Indian River Steam Units affect OUC's rate making process?

A. The sale of the Indian River Steam Units resulted in unique opportunities for OUC.

The proceeds from the sale of the Indian River Steam Units were allocated in three areas. First, the outstanding debt related to the Indian River Steam Units was eliminated. This was accomplished by reducing other borrowing to offset the remaining debt on the Indian River Steam Units. Next, two funds were set up with the remaining proceeds. The first fund was for approximately $45 million and along with the interest from the second fund is used to offset the higher cost of the Reliant Power Purchase Agreement (Reliant PPA) over the four year term so that the net cost under the Reliant PPA would be the same as if OUC had not sold the Indian River Steam Units. The balance representing approximately $140 million comprises the second fund which is earmarked either to retire existing generation debt or for new generation such as Stanton A.

Q. How will the cost for OUC's ownership share of Stanton A be recovered?

A. The capital and O&M costs for OUC's ownership share of Stanton A will be recovered through base rates. As mentioned above, the capital may be paid from funds from the sale of the Indian River Steam Units. The fuel cost will be recovered through the fuel charge.

Q. How will the cost for OUC's entitlement to purchase power from Stanton A be recovered?

A. OUC's costs for our entitlement to the purchase power from Stanton A will be recovered through the fuel charge.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF ABANI KUMAR SHARMA

ON BEHALF OF KUA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. My name is Abani (Ben) Kumar Sharma. My business address is 1701 West Carroll Street, Kissimmee, Florida, 34741.

Q. By whom are you employed and in what capacity?

A. I am employed by Kissimmee Utility Authority (KUA) as Director of Power Supply.

Q. Please describe your responsibilities in that position

A I am responsible for KUA's Power Supply Department The department has a staff of 80 employees and an annual operating budget of $47 million The department consists of three divisions, which include the power production division, system control division, and the bulk system planning division. As part of my responsibilities, I am also involved in the planning, permitting and construction of new generation facilities, fuel supply and transportation contracting, and purchase power negotiations and contracting. As Director of Power Supply, I am accountable to the President, General Manager, and CEO on all matters concerning the department. I have held this position for eleven and one-half years.

Q. **Please state your professional experience and educational background.**

A. I have more than 27 years of professional engineering experience including 22 years of utility experience. Prior to joining KUA, I was employed by the City of Tallahassee Electric Department during the years 1979 through 1989. I began my employment with the City of Tallahassee Electric Department as a System Planning Engineer. I was promoted to Superintendent of Planning in 1981 and after certain reorganization in the department renamed as Superintendent of Planning in 1988. During my period of employment with the City of Tallahassee Electric Department, I was responsible for performing various planning and engineering activities including preparation of Ten-Year Site Plans, initiation of the Jackson Bluff Hydro Electric Project, including completion of the feasibility study, acquisition of DOE grants of $1.75 million and obtaining the construction and operating license from FERC.

My background includes 4 years of experience with Southern Engineering Company of Atlanta, Georgia. I was responsible for preparation of distribution expansion plans, long-range capacity expansion plans, system design studies and preparation of Power Requirements Studies necessary for cooperatives to acquire REA (now RUS) and Cooperative Financing Corporation (CFC) loans.

I am a registered professional engineer in the States of Florida and Georgia I graduated with a bachelor's degree in electrical engineering in 1962 from Banaras Engineering College in Banaras, India, and a master's degree in electrical engineering in 1965 from the Georgia Institute of Technology in Atlanta, Georgia.

From 1996 to 2000, I also served as Chairman of Florida Gas Utility (FGU), a non-profit organization which procures natural gas and manages natural gas transportation for its members. Currently FGU has 22 municipal members and three full service industrial members.

As for my community involvement, I was President of the Rotary Club of Kissimmee-West during 1998-1999.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide a description of KUA, discuss KUA's need for Stanton A, describe KUA's benefits from its participation in Stanton A, and to discuss KUA's ability to finance Stanton A. I also will show that Stanton A will provide reliability and integrity to KUA's system, that Stanton A will provide adequate electricity at a reasonable cost to KUA, and that Stanton A is the most cost-effective alternative available to KUA.

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1__ that you are sponsoring as your testimony?

A Yes. Sections 1C.2.0 and 1C.9.0.

Q. Are there any corrections to these sections?

A. No.

Q. Please describe the structure of KUA?

A. Kissimmee Utility Authority (KUA) operates as an independent utility authority owned by the City of Kissimmee and is directed by a five-member Board of Directors plus the mayor of the City of Kissimmee who serves as a non-voting member. KUA serves retail customers in Osceola County. The retail customers are located within and outside of the city limits of Kissimmee. The primary goal of KUA is to provide reliable electric service to its customers at the lowest possible cost in an environmentally acceptable manner. In order to accomplish this, KUA has diversified its power supply resources, which are based on KUA's own generation, offsite generation through joint participation projects, and long- and short-term purchase power contracts. Since becoming an independent utility authority, KUA has maintained stable management and has been operated in a very business-like environment

Q. What generating units does KUA own?

A. KUA owns and operates or has ownership interest in generating units comprised of several technologies, including nuclear, coal fired, diesel, simple cycle combustion turbine, and combined cycle. KUA owns and operates eight diesel generating units and a combined cycle generating unit at the Roy B. Hansel Generating Station in downtown Kissimmee. KUA is a 50 percent owner of Cane Island Unit 1, a simple cycle General Electric LM 6000 combustion turbine, and Cane Island Unit 2, a 1 x 1 General Electric 7EA combined cycle project. KUA has a 12.2 percent (9 MW) ownership in

OUC's Indian River Combustion Turbine Units A and B and a 0.68 percent (6 MW) ownership in Florida Power Corporation's Crystal River Unit 3. KUA also has a 4.8 percent ownership share (21 MW) in OUC's Stanton Energy Center Unit 1. In total, KUA owns 172 MW of capacity based on summer ratings.

Q. Does KUA have any entitlement to capacity from FMPA projects?

A. Yes. KUA has entitlement to approximately 7 MW of the St. Lucie 2 nuclear unit and 8 MW of the Stanton 1 and 33 MW of the Stanton 2 coal-fueled units. While these entitlements are officially purchase power, they are essentially ownership shares.

Q. In addition to the entitlement capacity from FMPA, does KUA have any other purchase power?

A. Yes. KUA is purchasing 20 MW through 2003 from Orlando Utilities Commission (OUC).

Q. Does KUA have any generating units under construction?

A. Yes. KUA is constructing Cane Island Unit 3 which is a 250 MW 1 x 1 General Electric 7F combined cycle unit with a scheduled commercial operation date of June 28, 2001. Cane Island 3 received its Need Order on October 7, 1998, and construction commenced in late November of 1999.

Q. Why is KUA interested in joint participation in Stanton A?

A. KUA has a need for additional capacity beginning in the summer of 2004 As a smaller utility, it is difficult for KUA to obtain the economies of scale that larger utilities have available to them To mitigate this disadvantage, KUA has historically used joint participation to obtain the economies of scale from larger projects. This joint participation has been both through participation in projects managed by others such as Stanton 1 and 2, Crystal River 3, and St. Lucie 2, and joint participation in projects managed by KUA such as Cane Island 1, 2, and 3.

OUC and FMPA also have a need for capacity by the summer of 2004. The three utilities decided to jointly explore capacity addition alternatives to benefit from economies of scale as they have on several other existing projects.

Q. Please discuss KUA's need for Stanton A.

A KUA has historically been one of the fastest growing utilities in the United States with a 5.7 percent annual growth rate in peak demand over the last ten years Rapid growth is projected to continue with a 3.7 percent annual growth rate in peak demand projected through the end of the 20-year planning period. The development of the proposed World Exposition Center (Expo Center) is projected to contribute significantly to KUA's load growth. KUA is currently using a 15 percent reserve margin for planning purposes. By the summer of 2004, KUA is projected to require additional capacity to meet its reserve margin requirements. Additional capacity is projected to be required regardless of the status of the Expo Center.

Q. Will KUA fully utilize its entire entitlement in Stanton A beginning in the summer of 2004?

A. KUA is projected to need 11 MW of additional capacity beginning in the summer of 2004 to meet its minimum reserve requirement of 15 percent. Joint participation in Stanton A provides approximately 59 MW of summer capacity to KUA. In order to better take advantage of the benefits of joint participation, KUA and OUC have agreed that OUC will purchase a portion of KUA's excess entitlements.

Q. Is Stanton A the most cost-effective option for KUA?

A. As presented in the Need for Power Application, Exhibit OUC-1 __, KUA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. Appropriate alternatives to Stanton A have been evaluated to determine if they are lower in cumulative present worth revenue requirements. Stanton A has proven to be KUA's most cost-effective option through all evaluations as well as a thorough test of the marketplace. Furthermore, the flexibility incorporated in the joint ownership and power purchase agreement for Stanton A provides significant additional benefits to KUA, especially in light of future uncertainties such as the uncertainty associated with the development of the Expo Center and possible deregulation of the utility industry. Also, KUA believes that Stanton A represents minimal cost and performance risk to its customers due to the proven performance of the "F" class combined cycle technology.

Q. How does KUA intend to finance its ownership share of the construction of Stanton A?

A. KUA has not made a final decision regarding the financing of KUA's 3.5 percent ownership share of Stanton A. The relatively small amount of equity required may come from a number of sources including retained earnings, tax exempt bond proceeds from either existing or future issues, short term commercial paper or similar instruments, or the FMPA Pooled Loan Project.

Q. What is KUA's overall financial position?

A. KUA is in strong financial position and can support any of the methods of financing discussed above. In Fiscal 2000, KUA operating revenues were $90.2 million with an operating income of $7.2 million. KUA's debt service coverage ratio was 1.77 for Fiscal 2000.

Q. Does Stanton A contribute to providing KUA with adequate electricity at a reasonable cost?

A. Yes. The timeframe for Stanton A provides a unique opportunity for KUA to obtain the economies of scale of a large, highly efficient generating unit with an amount of capacity appropriate for KUA's system requirements, thus providing adequate electricity at lower cost than would be available without such a joint participation arrangement.

Q. Does Stanton A contribute to the reliability and integrity of KUA's system?

A. Yes. Stanton A provides KUA's additional capacity requirements beginning in the summer of 2004, and its proven technology will provide reliable power for KUA's system.

Q. Generally describe how KUA sets its rates.

A. KUA sets its rates on a cost of service basis by customer class. The rates consist of a base rate component, a fuel component, and a cost of power adjustment comprised of adjustments in the cost of purchase power and fuel. The cost of power adjustment is determined monthly by KUA's Board of Directors. It may be revised monthly or held constant for several months.

Q. How will the costs for KUA's ownership participation in Station A be recovered?

A. The capital and O&M costs of KUA's ownership participation in Stanton A will ultimately be recovered in base rates. The relatively small amount of capital and O&M cost associated with KUA's ownership share in Stanton A may not require a specific adjustment in base rates. The fuel costs associated with KUA's ownership share of Stanton A will be recovered in the cost of power adjustment. Depending upon the price of natural gas, the cost of power adjustment may decrease with Stanton A.

Q. How will the costs for the purchase power portion of KUA's entitlement in Stanton A be recovered?

A. The capacity and fuel costs for KUA's entitlement in the Stanton A PPA will be recovered through cost of power adjustment.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JONATHAN SCHAEFER

ON BEHALF OF KUA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. My name is Jonathan Schaefer and my business address is1701 West Carroll Street, Kissimmee, Florida 34741.

Q. By whom are you employed and in what capacity?

A. I am employed by the Kissimmee Utility Authority as a Planning Engineer in the Bulk System Planning division.

Q. Please describe your responsibilities in that position

A. I am responsible for the preparation of the customer, energy and peak load forecast. In addition, I am also responsible for the preparation of a residential and commercial customer survey. I also assist in the preparation of the fuel and purchased power budget, ten-year site plan and evaluation of power supply alternatives.

Q. Please state your educational background and professional experience.

A. I earned a Master of Science in Industrial Engineering from the University of Central Florida in Orlando, Florida, a Bachelor of Science in Industrial Engineering from Geneva College in Beaver Falls, Pennsylvania, and I am a candidate for a Master of Science in Systems Management from the Florida Institute of Technology

While employed with KUA, I have also attended a short course in econometrics at the University of California at Berkeley, and several courses on applied business forecasting moderated by Business Forecast Systems.

I have been employed at KUA for seven years as a Planning Engineer. Prior to that I was employed by R.W. Beck, Incorporated, for six years as a consultant.

Q. **What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony is to address KUA's need for power in light of the long-term load and energy forecast and existing demand-side management programs.

Q. **Are there sections of the Need for Power Application identified as Exhibit OUC-1__ that you are sponsoring as your testimony?**

A. Yes. Sections 1C.4.0 and 1C.5.1.

Q. **Are you adopting these sections as part of your testimony?**

A. Yes, I am.

Q. **Are there any corrections to these sections?**

A. No.

Q. Please describe the methodology used in forecasting KUA's energy consumption and power demand.

A. KUA prepares a detailed long-term customer, energy consumption, and power demand forecast using a combination of econometrics, exponential smoothing and linear trending coupled with expert judgement. The detailed forecast is developed on a fiscal year basis (October through September), and serves as a primary driver in annual planning activities.

The econometric models and associated statistical relationships were developed to forecast annual changes in customers and electricity consumption by rate classification as function of demographic, weather and economic factors such as income, temperature, and real price of electricity.

To mitigate the effect of migration among general service demand rate classifications, the general service demand forecast includes all demand rate classifications: demand, large demand, time of use, interruptible, large time of use and contract rate customers. The historical data on accounts billed revealed that no significant change in the number of general service demand accounts has occurred since the rate re-classification in October of 1990. Because of this the customer growth in the general service demand classification was held flat. An econometric model was built for general service demand. However, even though statistically the model was a good fit for the historical period, the projected sales increased too rapidly. These results are unreasonable because the conclusion drawn is that general service demand use per customer is also increasing rapidly, a conclusion that is not supported by historical data. At this point, we met with

City of Kissimmee planners, and gathered information on large facilities scheduled to be built in our service territory over the next 5 years. Using planning level estimates of energy consumption per thousand square feet and information provided by City planners, a schedule of spot loads to be phased into our load forecast evenly over a 5 year period was prepared. Also included was an estimate of the World Expo Center beginning phased construction in fiscal year 2001. At the end of the 5 year period, the energy sales in the general service demand rate classification was escalated at 1 percent per year, which was the lowest annual growth experienced in the previous 5 year period. The peak load forecast is derived by applying average system load factors for winter and summer peak demand to the forecast net energy for load.

Q. What was the source for the input data for the econometric forecast models?

A. Historical customer and energy sales information was taken from our billed revenue report, and monthly peak load information was taken from our monthly operations and maintenance report. Economic and population forecasts from the Bureau of Economic and Business Research (BEBR) were included in the analysis as econometric variables. The BEBR economic forecast was utilized through 2010. To develop economic data beyond 2010, the economic data were adjusted by using their rate of change with respect to population in the base case. Weather data was provided the National Climatic Data Center weather station located at the Orlando International Airport. The real price of electricity was calculated by taking projected rate increases from our Finance Department and deflating them by an estimate of the CPI.

Q. Were cases other than the base case analyzed?

A. Yes, in addition to the base case, a high and low load forecast case was analyzed for sensitivity purposes. These were developed by evaluation of BEBR's high and low economic forecast. For data beyond 2010, the rate of change with respect to the population ratio was maintained in the high and low cases.

Q. How is the impact of conservation reflected in the load forecast?

A . The effects of existing conservation programs are implicitly included in the forecast.

Q. In your opinion are the assumptions in the base case load forecast reasonable for planning purposes?

A. Yes.

Q. Describe KUA's current conservation programs that reduce peak demands and energy consumption.

A. KUA is committed to conservation and load management programs and continues to evaluate old and new demand side management (DSM) programs for the electric system that add value for their customers. KUA conservation programs were originally established for the City of Kissimmee under the Florida Energy Efficiency and Conservation Act (FEECA) program. A list of these programs includes the following:

- Residential Load Management (SAVE)
- Residential and Energy Audit
- Fix up program

- High pressure sodium street lighting/private area lighting conversion
- Elimination of electric strip heating

Q. Does this conclude your prefiled testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF RICHARD L. CASEY

ON BEHALF OF FMPA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. My name is Richard L. Casey. My business mailing address is 8553 Commodity Circle, Orlando, Florida, 32819.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Municipal Power Agency (FMPA) as System Planning Manager.

Q. Please describe your responsibilities in that position.

A. As the System Planning Manager for FMPA, I am responsible for conducting and supervising system planning needs. As System Planning Manager, I have responsibility for managing the Agency's planning functions for its expanding 1,000 MW All-Requirements Power Supply Project including production of annual load forecasts, annual reporting to regulatory bodies, transmission planning, demand-side planning, and generation planning. I manage the development, issuance, and evaluation of requests for proposals involving both short-term and long-term purchases and generation construction options I am also responsible for negotiation of contracts with successful bidders. I am directly responsible for development, modeling, and production of annual O&M budgets for four of the five FMPA power supply projects totaling over $100 million

Q. Please state your educational background and professional experience.

A. I received a Bachelors of Science degree in electrical engineering from Lamar University, in Beaumont, Texas. I am a member of the Institute for Electronic & Electrical Engineers (IEEE).

My past 29 years in the electric utility industry have encompassed many facets of the business including distribution engineering and operations, coal mining and rate design and administration. Before joining FMPA, I served as a Transmission Services Consultant for Texas Utilities Electric Co. which required the analysis, development, negotiation, and administration of various contractual arrangements including transmission wheeling service and interconnection agreements, joint transmission line ownership agreements, and microwave interconnection agreements.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide a description of FMPA and the All-Requirements Power Supply Project (All-Requirements Project). I will also discuss the process by which FMPA became involved in the Stanton A joint development project. I will summarize FMPA's load forecast and existing DSM programs. I will summarize the reliability criteria used by FMPA. I will discuss FMPA's ability to finance Stanton A. I will describe the proposed contribution of Stanton A to the reliability and integrity of FMPA's and Peninsular Florida's system I will demonstrate that FMPA adequately explored and evaluated the availability of purchased power options through the two RFP processes. Finally, I will demonstrate that Stanton A provides adequate electricity at a reasonable cost and is the most cost-effective alternative available to FMPA.

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1__ and the revisions to the Need for Power Application identified as OUC-2___ that you are sponsoring as your testimony?

A. Yes. Sections 1D.2.0, 1D.4.0, 1D.5.1, and 1D.9.0.

Q. Are there any corrections to these sections?

A. No, only the one revision in OUC-2__ indicates that there are nine instead of eight members of the St. Lucie Project that are members of the All-Requirements Project

Q. Please describe the purpose and structure of FMPA.

A The Florida Municipal Power Agency (FMPA or Agency) was created on February 24, 1978, under the provisions of the Florida Constitution, the Joint Power Act, and the Florida Interlocal Cooperation Act of 1969. FMPA was formed to allow its members to cooperate with each other, on the basis of mutual advantage, to provide services and facilities in a manner and in a form of governmental organization relevant to geographic, economic, population, and other factors influencing the needs and development of local communities Specifically, FMPA is involved in the joint financing, construction, acquisition, ownership, management, and operation of electric generation resources. FMPA is governed by a Board of Directors consisting of one representative from each of the 29 municipal members which hires a general manager and establishes operations and policies.

Q. Please summarize FMPA's existing generation system including purchased power and transmission arrangements.

A. FMPA is a project-oriented, joint action agency where each project stands on its own. FMPA currently has five power supply projects in operation: (i) the St. Lucie Project near Fort Pierce, (ii) the Stanton Project in East Orlando, (iii) the Tri-City Project in East Orlando, (iv) the Stanton II Project in East Orlando, and (v) the All-Requirements Project located throughout Florida. The need for Stanton A is based upon the All-Requirements Project participants' load growth and need for power.

Q. Please describe the All-Requirements Project.

A. The All-Requirements Project was formed on May 1, 1986, initially with five municipal participants and several other municipals have joined over time The All-Requirements Project participants now consist of.

- City of Bushnell
- City of Clewiston
- City of Fort Meade
- Fort Pierce Utilities Authority
- City of Green Cove Springs
- Town of Havana
- City of Jacksonville Beach

- City of Key West
- City of Leesburg
- City of Newberry
- Ocala Electric Utility
- City of Starke
- City of Vero Beach

Presently Lake Worth Utilities is planned to join in 2002. Under the All-Requirements Project, the Agency is contractually obligated to serve all the power requirements (above certain excluded resources) for the 13 municipal members, which, in turn, are contractually obligated to purchase all their requirements from the Agency to serve retail loads in Florida. Tables 1D.2-4 1D.2-5, and 1D.2-6 of the Need for Power Application Exhibit OUC-1 __ display the existing All-Requirements power supply resources which are owned, purchased from All-Requirements Project participants, and purchased under other contracts with a current total net summer capability of 1203 MW. As a joint operating agency, engaged in the business of generating and transmitting electric energy, the FMPA All-Requirements project is an "Electric Utility" under 403.503(13) Fla. Stat.

FMPA is planning on participating in Lakeland Electric's proposed McIntosh Unit 4 with a projected commercial operation date of June 2005. Currently, Lakeland Electric and FMPA are evaluating proposals for either construction of a unit at the McIntosh site or purchased power. The proposals are based on solid-fueled units. For evaluation purposes, a 100 MW participation is assumed for FMPA

The capacity and energy for the All-Requirements Project is transmitted to the members primarily utilizing the transmission systems of Florida Power & Light (FPL), Florida Power Corporation (FPC), and Orlando Utilities Commission (OUC) FMPA divides the All-Requirements Project members into two categories: members located in the FPL service area (east cities) and members located in the FPC service area (west cities). Network transmission service for the east cities is provided under an existing agreement with FPL. FMPA began purchasing network transmission service from FPL effective April 1, 1996 Network transmission for the west cities is provided under an agreement with FPC

Q. Why is FMPA interested in joint participation in Stanton A?

A Historically FMPA has jointly participated in projects to obtain economies of scale. These are FPL's St. Lucie Unit 2, OUC's Stanton 1 and 2, OUC's Indian River Combustion Turbines A, B, C, and D, and KUA's Cane Island Units 1, 2, and 3. FMPA along with OUC and KUA identified a need for additional capacity by the summer of 2004 and again decided to investigate joint participation for additional power supplies. To further the benefits of joint participation FMPA, along with the OUC, KUA, and Lakeland Electric formed the Florida Municipal Power Pool (FMPP) to economically dispatch the FMPP members' power supply resources.

Q. What is FMPA's need for the Stanton Energy Center Combined Cycle Project?

A. FMPA's All-Requirements Project has been growing rapidly through the addition of new municipal members, with Lake Worth also anticipated to join in 2002 FMPA's peak demand is projected to grow at a 1.8 percent annual rate from 2000 through the end of the planning period in 2019. The forecast loads are shown in Tables 1D 6-1 and 1D.6-2 of the Need for Power Application Exhibit OUC-1 __. The projected load growth assumes no new members will join after Lake Worth in 2002. FMPA uses an 18 percent summer reserve margin and a 15 percent winter reserve margin as reliability criterion. FMPA's reserve margin is projected to drop to 7.3 percent by the summer of 2004, dictating the need to add capacity.

Q. Describe the methodology used in forecasting FMPA's electric power peak demands and energy production?

A. Several techniques are used to develop portions of the load forecast including: 1) econometric modeling, 2) aggregate econometric modeling of system requirements, 3) statistical analysis techniques, 4) incremental load analysis and 5) informed judgement. The forecast methodology varies from member to member to provide the most reliable forecast consistent with available data. Generally, FMPA used Forecast Pro to forecast peak demand and energy requirement loads for its member cities. The forecasts are compared and checked for reasonableness by FMPA and any known unusual incremental load additions or reductions are integrated into the overall forecast.

Q. Were sensitivity scenarios to the base load forecast evaluated?

A Uncertainty in assumptions dictate the development of high and low load forecasts to ensure that the addition of Stanton A is the most cost-effective option under reasonable alternative conditions that model the future The high load growth sensitivity assumes an initial value that is 2.9 percent higher than the base case value, as this has been the historical standard deviation from predicted values. For the following years, there is an increase in nominal projected growth of 100 percent of the base case increase for each year The low load growth sensitivity assumes an initial value that is 2.9 percent lower than the base case value, as this has been the historical standard deviation from predicted values. For the following years, there is a decrease in nominal projected growth of 50 percent of the base case increase for each year.

Q. **Please describe FMPA's current conservation programs that reduce peak demands and energy consumption?**

A. FMPA staff and member cities promote conservation programs through a number of methods including providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, schools, and so forth. Additionally, bill inserts are utilized to keep customers aware of available conservation programs. FMPA is also assisting in the development of renewable energy resources by participating in the Utility Photovoltaic Group (UPG). UPG is a non-profit organization formed to accelerate the commercialization of photovoltaic systems for the benefit of electric utilities and their customers. The following is a combined list of conservation programs offered by FMPA members:

- Residential Energy Audits Program
- High-Pressure Sodium Outdoor Lighting Conservation
- Assistance for Commercial/Industrial Audits
- Commercial Time-of-Use Program

- Natural Gas Promotion
- Fix-Up Program for the Elderly and Handicapped
- Residential Load Management Program

Q. How does FMPA intend to finance its ownership share of the construction of Stanton A?

A. FMPA typically relies on debt financing to fund capital additions to its system. The All-Requirements Project is planning to use the FMPA Pooled Loan Project to obtain the financing for FMPA's 3.5 percent ownership share of Stanton A. The FMPA Pooled Loan Project is a financing pool in which participating members or the Agency itself can obtain loans for electric system projects. The All-Requirements Project can borrow the necessary funds at an interest rate of approximately 5 percent for a period of twenty years.

Q. Is Stanton A the most cost-effective option for FMPA?

A FMPA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. As discussed in the Need for Power Application Exhibit OUC-1__, FMPA has evaluated appropriate alternatives to Stanton A to determine if they are lower in cumulative present worth revenue requirements. As demonstrated in the Application, Stanton A has proven to be FMPA's most cost-effective option through all evaluations as well as a thorough test of the marketplace. These evaluations are described in more detail in the testimony of Myron Rollins

Q. Will Stanton A provide FMPA adequate electricity at a reasonable price?

A. Yes. In addition, the flexibility associated with the combination of purchase power from and ownership in Stanton A further enhances the cost-effectiveness of the project.

Q. Will Stanton A provide reliability and integrity to FMPA's system?

A. Yes. The proven reliability of the equipment to be utilized in Stanton A coupled with the reliability guarantee in the Power Purchase Agreement will contribute to the reliability and integrity of FMPA's system.

Q. Explain in general how the All-Requirements project recovers costs through rates.

A. The All-Requirements project recovers all costs through billing rates. Billing rates consist of customer, demand capacity charges, transmission capacity charge, and energy charge components. These rates are set annually based on expected costs and then are adjusted for any over or under recovery of expenses on a twelve month basis for the capacity charges and on a six month basis for the energy charges.

Q. How will the costs of FMPA's ownership share of Stanton A be recovered in rates?

A. The fixed costs will be recovered through the demand and transmission capacity charge and the variable costs will be recovered through the energy charge

Q. How will the costs from FMPA's purchase power entitlement in Stanton A be recovered in rates?

A. The fixed costs will be recovered through the demand and transmission capacity charge and the variable costs will be recovered through the energy charge

Q. Does this conclude your prefiled testimony?

A Yes it does.