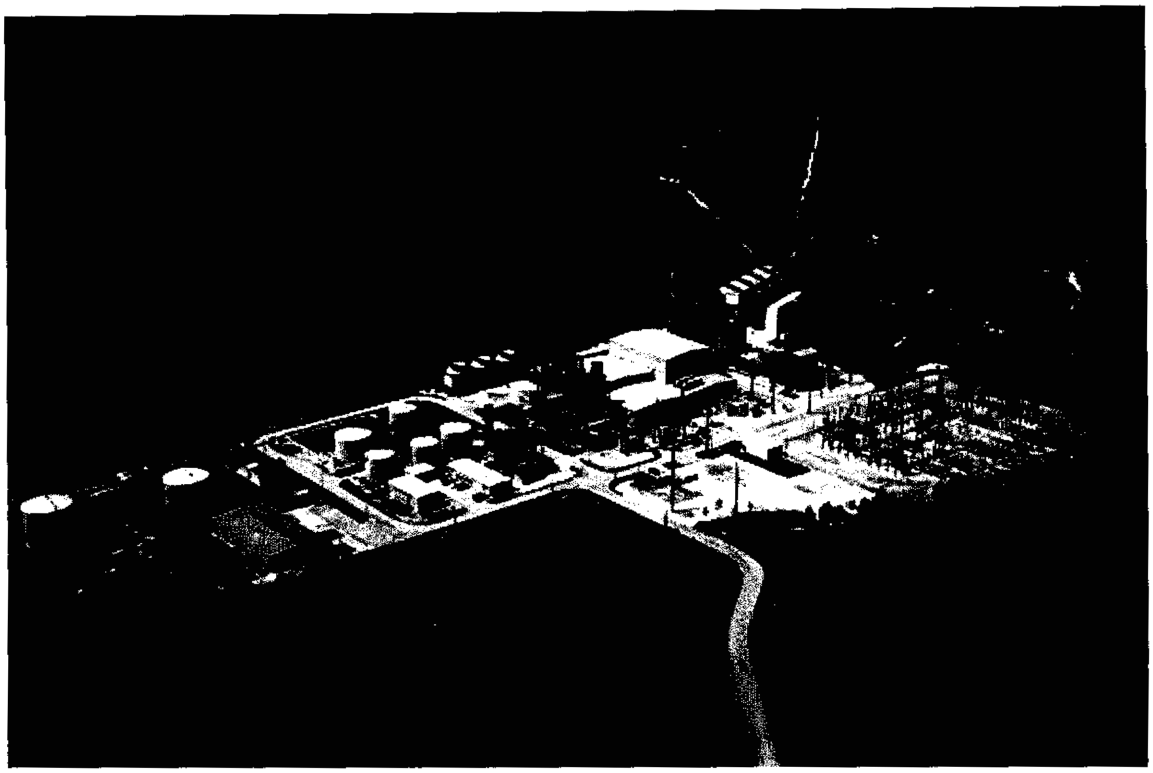
Florida Electrical Power Plant Siting Act
Need for Power Application

080253

Cane Island Power Park – Unit 4



Submitted by:

Florida Municipal Power Agency

May 2008

Florida Municipal Power Agency
Community Power. Statewide Strength.

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1.0 Executive Summary

Florida Municipal Power Agency (FMPA) submits this Need for Power Application in support of a proposed natural gas-fired "combined cycle" electric generating unit to be located at the existing Cane Island generating station in Osceola County, Florida. The analyses summarized below and discussed throughout this Application demonstrate that the new unit is needed to meet the growing electrical demands of FMPA's All-Requirements Power Supply Project (ARP). The proposed project also is an essential component of the ARP's Carbon Reduction Activities to address climate change issues.

1.1 The Applicant

FMPA is a joint action agency comprised of 30 municipal electric utilities. FMPA was created so that its members could cooperatively gain mutual advantage and meet present and projected electric energy requirements. As part of this empowerment, FMPA developed the ARP to secure an adequate, economical and reliable supply of electric capacity and energy to meet the wholesale power needs (above certain excluded resources) of the ARP member municipal utilities serving approximately 180,000 customers throughout Florida. ARP members purchase all their capacity and energy from the ARP. FMPA meets the ARP's needs through electricity generated by FMPA owned or co-owned facilities, as well as power purchases from generating ARP members (i.e., members with their own generating capacity and purchases) and other, non-ARP member utilities.

1.2 The Proposed New Unit

The new unit, to be known as Cane Island Unit 4, will be a high-efficiency, natural gas-fueled combined cycle unit, consisting of a combustion turbine and a heat recovery steam generator that will drive a steam turbine generator. The new unit will be capable of generating nominally 300 megawatts (MW), enough electricity to serve approximately 60,000 homes in Florida. All of the generation capacity from the unit will be committed to ARP members for retail sale to their customers.

1.3 The Power Plant Siting Act Process

The Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes, provides a "centrally coordinated, one-stop licensing process" for power plant projects. The PPSA provides a centralized process to ensure that all affected state and local agencies review a project before the Siting Board, consisting of the Governor and Cabinet, takes final action on the site certification application. The Commission's need determination is a critical step in the PPSA certification process. Along with the reports submitted by the Florida Department of Environmental Protection (DEP) and other agencies, the Commission's need determination allows the Siting Board to balance "the increasing demand for electrical power plants with the broad interests of the public."

1.4 The Commission's Need Determination

Section 403.519(3), Florida Statutes, sets forth the following criteria which the Commission must consider in making need determinations:

- The need for electric system reliability and integrity.
- The need for adequate electricity at a reasonable cost.
- The need for fuel diversity and supply reliability.
- Whether the proposed plant is the most cost-effective alternative available.
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available.
- Whether there are conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant.

The Legislature did not assign the weight this Commission is to give each of these factors. Rule 25-22.081, Florida Administrative Code, sets forth specific information that each Need for Power Application must include to allow the Commission to address the statutory factors. The required information is summarized below and discussed in detail in throughout this Application.

1.5 The Need for Cane Island Unit 4

The ARP's capacity needs have been growing rapidly. As discussed in Section 13.0 of the Need for Power Application, in the summer of 2011, FMPA's reserve margin is projected to decrease to -1.3 percent, or 286 MW below the required capacity. An additional 363 MW is needed to maintain an 18 percent reserve margin by the summer season of 2012. Many of the ARP's capacity and power purchase contracts are expiring, or nearing the end of their lifetime. By providing capacity necessary to meet the ARP's growing needs, Cane Island Unit 4 will contribute to the reliability and integrity of the FMPA/ARP electric system.

1.6 Analysis of Generating ("Supply Side") Alternatives

As discussed in Section 14.0 of this Application, FMPA has evaluated several supply side technologies, either as alternatives to Cane Island Unit 4 or as capacity resource options for installation following the proposed unit. As part of that analysis, FMPA evaluated renewable technologies, conventional technologies, and emerging technologies. Based on the results of production cost modeling of multiple economic scenarios, FMPA identified a new nominal 300 MW combined cycle generating facility as the most cost-effective alternative to meet the ARP's need for additional capacity.

Although FMPA is not subject to the Commission's "Bid Rule," the agency issued a competitive request for proposals (RFP) for purchase power options, as well as separate RFPs for renewable and solar energy resources. Based on FMPA's evaluation, none of the responses to the RFPs were cost-effective as compared to the self-build alternative. However, as a result of the renewable RFP, FMPA is pursuing a potential purchase of 58 MW of renewable energy from a new biomass facility. The ARP is also investigating a new solar initiative designed to achieve 100 MW of solar power within the next 10 years by installing solar photovoltaic technology at ARP member sites throughout Florida.

1.7 Analysis of Non-Generating ("Demand Side") Alternatives

As a wholesale supplier of electric energy to the ARP, FMPA is not directly responsible for demand-side management (DSM) programs. However, FMPA assists its members in the implementation of DSM. ARP members offer a variety of conservation and DSM programs to their consumers. The impact of these existing conservation and DSM programs are reflected in the load forecast presented in Section 5.0 of this Application.

FMPA issued an RFP for DSM proposals and is negotiating with two vendors which have proposed to work with ARP members to implement load control measures designed to reduce peak load demand by up to 44 MW within the next 9 years.

1.8 The ARP's Carbon Reduction Activities

On July 13, 2007, Governor Crist signed Executive Order 07-127 directing DEP to adopt new regulations requiring electric utilities to reduce carbon dioxide (CO_2) emissions. As yet, the specific regulatory framework has not been developed because DEP has not yet proposed or adopted any specific rules. Nevertheless, in light of the Governor's directive, the ARP is pursuing Carbon Reduction Activities to meet the dual challenge of providing reliable, affordable electricity while reducing emissions. Cane Island Unit 4 is an important component of that plan. Because it will be one of the highest efficiency plants in the state, Cane Island Unit 4 will displace less efficient units with higher CO_2 emission rates.

1.9 Integrated Fuel and Emission Allowance Cost Projections

The costs of meeting all existing environmental regulations have been included in all of the economic analyses presented in this application. This includes costs of pollution control technology and emission allowances. Because fuel and emission allowance costs are interrelated, fuel and emission allowance cost projections included in this application are fully integrated. That is, fuel price supply and demand were considered in tandem with potential allowance costs, along with numerous other market influences, to develop fully integrated fuel and emission allowance cost projections.

Emission allowance cost projections for sulfur dioxide and nitrogen oxides are included throughout this application whether for the reference case, high case or low case scenarios. In addition, although no CO_2 regulatory programs have been adopted as yet, in light of continuing discussion of potential CO_2 regulation, this Application presents additional economic analyses which incorporate the range of CO_2 cost estimates, and associated fuel forecasts, developed by the U.S. Department of Energy's Energy Information Agency. These analyses demonstrate that Cane Island Unit 4 is still FMPA's most cost-effective alternative even assuming a carbon-regulated environment.

1.10 Most Cost Effective Alternative

After extensive economic comparisons to other generating unit and nongeneration alternatives, Cane Island Unit 4 was determined to be the most cost effective alternative to meet FMPA's needs. Under the reference case, the expansion plan with Cane Island Unit 4 was $35.7 million lower in cumulative present worth costs (CPWC) than the plan without Cane Island Unit 4.

1.11 Adverse Consequences If Cane Island Unit 4 Is Not Built

Delaying Cane Island Unit 4 would result in reduced reliability and higher costs. If the proposed unit is delayed, FMPA's summer reserve margin will fall to -5.9 percent in 2012 which is well below FMPA's 18 percent reserve margin criterion and would not allow FMPA to meet firm load. If other capacity would be installed to retain FMPA's 18 percent summer reserve margin, cumulative present worth costs would increase by more than $37.5 million with a two year delay.

1.12 Conclusion

The proposed unit will ensure that the ARP has an adequate supply of power to serve its members' needs at a reasonable cost. The competitive RFPs, together with separate economic analyses presented in the Need for Power Application demonstrate Cane Island Unit 4 is the most cost-effective alternative to meet the ARP's power supply needs. The ARP already utilizes reasonably available DSM programs and renewable resources. Even with potential demand and energy reductions that could be achieved from additional conservation and renewable energy initiatives that FMPA is pursuing, Cane Island Unit 4 is the ARP's least cost alternative to reliably meet the ARP's power supply needs.

2.0 Introduction

This application demonstrates the Need for Cane Island Unit 4 under Section 403.519 F.S. Cane Island Unit 4 is a nominal 300 MW 1x1 7FA natural gas fired combined cycle generating unit to be constructed at the existing Cane Island Power Park (CIPP) site by the Florida Municipal Power Agency (FMPA) All-Requirements Power Supply Project (ARP). CIPP contains three existing units that are jointly owned by FMPA and Kissimmee Utility Authority (KUA). Unit 1 is a simple cycle combustion turbine, and Units 2 and 3 are combined cycles. Cane Island Unit 4 is scheduled for commercial operation on May 1, 2011.

Section 3.0 provides a description of FMPA and FMPA's existing facilities. FMPA is a joint action with the ARP that provides all power supply requirements for 15 municipally owned member utilities. FMPA's resources are a mix of FMPA-owned generating units (wholly and jointly), member-owned generating units, and purchase power.

Section 4.0 of this application provides the economic parameters and assumptions used throughout the application.

Section 5.0 presents FMPA load forecast, which indicates continued strong load growth that requires the addition of Cane Island Unit 4.

Cane Island Unit 4 will be fueled by natural gas. Section 6.0 demonstrates the availability of natural gas to provide a reliable fuel for Cane Island Unit 4 to maintain the integrity of FMPA's system.

Section 7.0 presents the fuel price projections used in the economic evaluations. The fuel price projections are based on the Department of Energy's (DOE's) Annual Energy Outlook (AEO) projections and include projections of sulfur dioxide (SO_2), nitrogen oxide (NO_x), and carbon dioxide (CO_2) emissions allowances.

Section 8.0 discusses the available natural gas transportation system to serve Cane Island Unit 4 and demonstrates that the natural gas transportation will be reliable.

Section 9.0 describes Cane Island Unit 4 and provides the detailed cost estimate, operating costs, and performance parameters for the unit. Section 9.0 demonstrates that Cane Island Unit 4 will be designed and constructed so that it will operate reliably and maintain the integrity of FMPA's system.

Cane Island Unit 4 will be fueled by natural gas supplied from two independent pipeline systems and will not use fuel oil as a back-up fuel. Section 10.0 demonstrates that Cane Island 4, without fuel oil backup, is the correct economic approach and will reliably maintain FMPA's system integrity.

Section 11.0 describes Cane Island Unit 4's impact on the transmission system and the evaluations conducted to demonstrate that its interconnection will not have an adverse impact on the transmission system. Both the Florida Regional Reliability Council (FRCC) and Progress Energy Florida have approved Cane Island Unit 4's interconnection to the transmission system.

Section 12.0 discusses the 18 percent summer reserve margin used by FMPA to determine the need for Cane Island Unit 4.

Section 13.0 demonstrates FMPA's need for additional capacity by applying the 18 percent reserve margin to FMPA's projected load growth and comparing the capacity requirements to FMPA's existing resources.

Section 14.0 describes the conventional and emerging generating unit alternatives that were compared to Cane Island Unit 4 and used in expansion plans to provide FMPA's capacity needs beyond those supplied by Cane Island Unit 4.

As a municipal utility, FMPA is not required to conduct a request for proposals (RFP) process. Nevertheless, in an effort to ensure that there were no lower cost or better alternatives than Cane Island Unit 4, FMPA conducted a purchase power RFP process, which is documented in Section 15.0.

In a further effort to identify lower cost or better alternatives to Cane Island Unit 4, FMPA conducted two additional RFP processes. One process was for renewable alternatives, and one process was for solar photovoltaic alternatives. As a result of these RFP processes, FMPA is continuing its efforts to obtain biomass and solar photovoltaic capacity. Section 16.0 describes these RFP processes and demonstrates that FMPA is utilizing available renewable energy sources and technologies to the extent reasonably possible.

Section 17.0 describes the RFP process and FMPA's ongoing efforts to negotiate one or more contracts for DSM resources. While FMPA will continue to evaluate additional conservation and DSM programs, the RFP indicates that currently no reasonable available conservation and DSM programs mitigate the need for Cane Island Unit 4.

Section 18.0 describes FMPA's actions to reduce CO_2 emissions. Section 18.0 demonstrates that with FMPA's existing and planned carbon reduction initiatives, FMPA can reduce CO_2 emissions to below 2000 levels by 2017.

Section 19.0 describes the methodology used to evaluate the cost effectiveness of Cane Island Unit 4.

Section 20.0 presents the economic analyses conducted that demonstrate that Cane Island Unit 4 is FMPA's least-cost alternative under a wide range of scenarios. Cane Island Unit 4 is FMPA's least-cost alternative, even with the addition of renewables and conservation.

Section 21.0 presents the cost and reliability impacts of delaying the installation of Cane Island Unit 4.

Section 22.0 demonstrates that FMPA can readily finance the addition of Cane Island Unit 4.

3.0 Description of Existing System

3.1 FMPA Structure

FMPA is a governmental wholesale power company composed of 30 municipal electric utilities. FMPA provides economies of scale in power generation and related services to support community-owned electric utilities. Of FMPA's 30 member municipal utilities, 15 are served by the All-Requirements Power Supply Project (ARP) to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the entire wholesale electric needs (excluding certain excluded resources)[1] of the 15 ARP members.

3.1.1 Organization and Governance

FMPA was created on February 24, 1978, by the signing of the Interlocal Agreement among its original members. This agreement specifies the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution; the Joint Power Act, Chapter 361, Part II, Florida Statutes; and the Florida Interlocal Cooperation Act of 1969, Section 163.01, Florida Statutes.

The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, constructing, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on the basis of mutual advantage to provide services and facilities that benefit the members. Such advantages include allowing FMPA to acquire and build facilities with the benefits of scale to lower costs for members, to provide integrated and less costly operational expertise, to manage an integrated transmission system on behalf of members, and to prevent the unnecessary duplication of facilities.

Each city commission, utility commission, or authority that is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility for developing and approving FMPA's budget for power supply projects other than the ARP, approving and financing projects, hiring a General Manager and General Counsel, establishing bylaws that govern how FMPA operates, and creating policies that implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, and Treasurer. The Executive Committee is composed of one representative from each of the 15 ARP participants. The Executive Committee has charge over the governance and

[1] Excluded resources are the ARP members' shares of the Crystal River Unit 3 and St. Lucie Unit 2 nuclear units.

management of the business of the ARP and approves the FMPA general budget, and all agency general budget amendments.

Municipal utilities are able to become members of the ARP if such membership is mutually beneficial to both the ARP and the municipal utility. Membership in the ARP is a contractually governed entitlement, and both the municipal utility and the ARP are required to fulfill obligations, specific to each member's All-Requirements Power Supply Project contract and its Capacity and Energy Sales Contract (C&E Contract) for members that own generation.

In general, ARP members are classified as either generating or non-generating members. All ARP members are required to purchase all of their capacity and energy from the ARP, with the exception of excluded resources that are generally the members' ownership share of Crystal River Unit 3 and St. Lucie Unit 2. Generating members are reimbursed in the form of credits for their capacity and energy contributions to the ARP. Once a municipal utility has joined the ARP, a contract is signed for a term of 30 years, and this contract is automatically renewed unless the member elects otherwise.

3.1.2 ARP Members

The 15 members of the ARP are identified below.

Bushnell

The City of Bushnell is located in central Florida in Sumter County. It joined the ARP in May 1986; its service area is 1.4 square miles.

Clewiston

The City of Clewiston is located in southern Florida in Hendry County. It joined the ARP in May 1991; its service area is approximately 5 square miles.

Fort Meade

The City of Fort Meade is located in central Florida in Polk County. It joined the ARP in February 2000; its service area is approximately 5 square miles. FMPA serves capacity and energy (C&E) requirements for the City of Fort Meade via the full requirements agreement currently in place with Tampa Electric Company (TECO). When the Fort Meade/TECO agreement terminates in January 2009, FMPA will serve the city from the ARP's portfolio of power supply resources.

Fort Pierce Utilities Authority

The City of Fort Pierce is located on Florida's east coast in St. Lucie County. Fort Pierce Utilities Authority (FPUA) joined the ARP in January 1998; its service area is approximately 35 square miles.

Green Cove Springs

The City of Green Cove Springs is located in northeast Florida in Clay County. It joined the ARP in May 1986; its service area is approximately 25 square miles.

Town of Havana

The Town of Havana is located in the panhandle of Florida in Gadsden County. It joined the ARP in July 2000; its service area is 4.5 square miles.

Jacksonville Beach

The City of Jacksonville Beach's electric department, more commonly known as Beaches Energy Services (Beaches), is located in northeast Florida in Duval County. Beaches joined the ARP in May 1986; its service area is approximately 45 square miles and includes portions of St. John's County.

Utility Board, City of Key West

The Utility Board of the City of Key West, also known as Keys Energy Services (KEYS), provides electric service to the lower Keys in Monroe County. KEYS joined the ARP in April 1998; its service area is approximately 45 square miles.

Kissimmee Utility Authority

Kissimmee is located in central Florida in Osceola County. The Kissimmee Utility Authority (KUA) joined the ARP in October 2002; its service area is approximately 85 square miles.

Lake Worth

Lake Worth is located on Florida's east coast in Palm Beach County. Lake Worth joined the ARP in October 2002; its service area is 12.5 square miles.

Leesburg

The City of Leesburg is located in central Florida in Lake County. It joined the ARP in May 1986; its service area is approximately 50 square miles.

Newberry

The City of Newberry is located in the northern part of Florida in Alachua County. It joined the ARP in December 2000; its service area is approximately 6 square miles.

Ocala

The City of Ocala is located in central Florida in Marion County. It joined the ARP in May 1986; its service area is approximately 161 square miles.

Starke

The City of Starke is located in north Florida in Bradford County. It joined the ARP in October 1997; its service area is 6.5 square miles.

Vero Beach

The City of Vero Beach is located on Florida's east coast in Indian River County. It joined the ARP in June 1997; its service area is approximately 40 square miles.

3.1.3 ARP Member City Locations

Figure 3-1 shows the ARP member city locations.

3.1.4 FMPA Power Supply Projects

In addition to the ARP, FMPA has four other power supply projects in operation: (i) the St. Lucie Project (ii) the Stanton Project, (iii) the Tri-City Project, and (iv) the Stanton II Project. These four projects are briefly discussed below.

St. Lucie Project

On May 12, 1983, FMPA purchased from Florida Power & Light (FPL) an 8.806 percent undivided ownership interest in St. Lucie Unit 2 (the St. Lucie Project), a nuclear generating unit. St. Lucie Unit 2 was declared in commercial operation on August 8, 1983, and in Firm Operation (as defined in the participation agreement) on August 14, 1983. Fifteen of FMPA's members are participants in the St. Lucie Project, with the following entitlements as shown in Table 3-1.

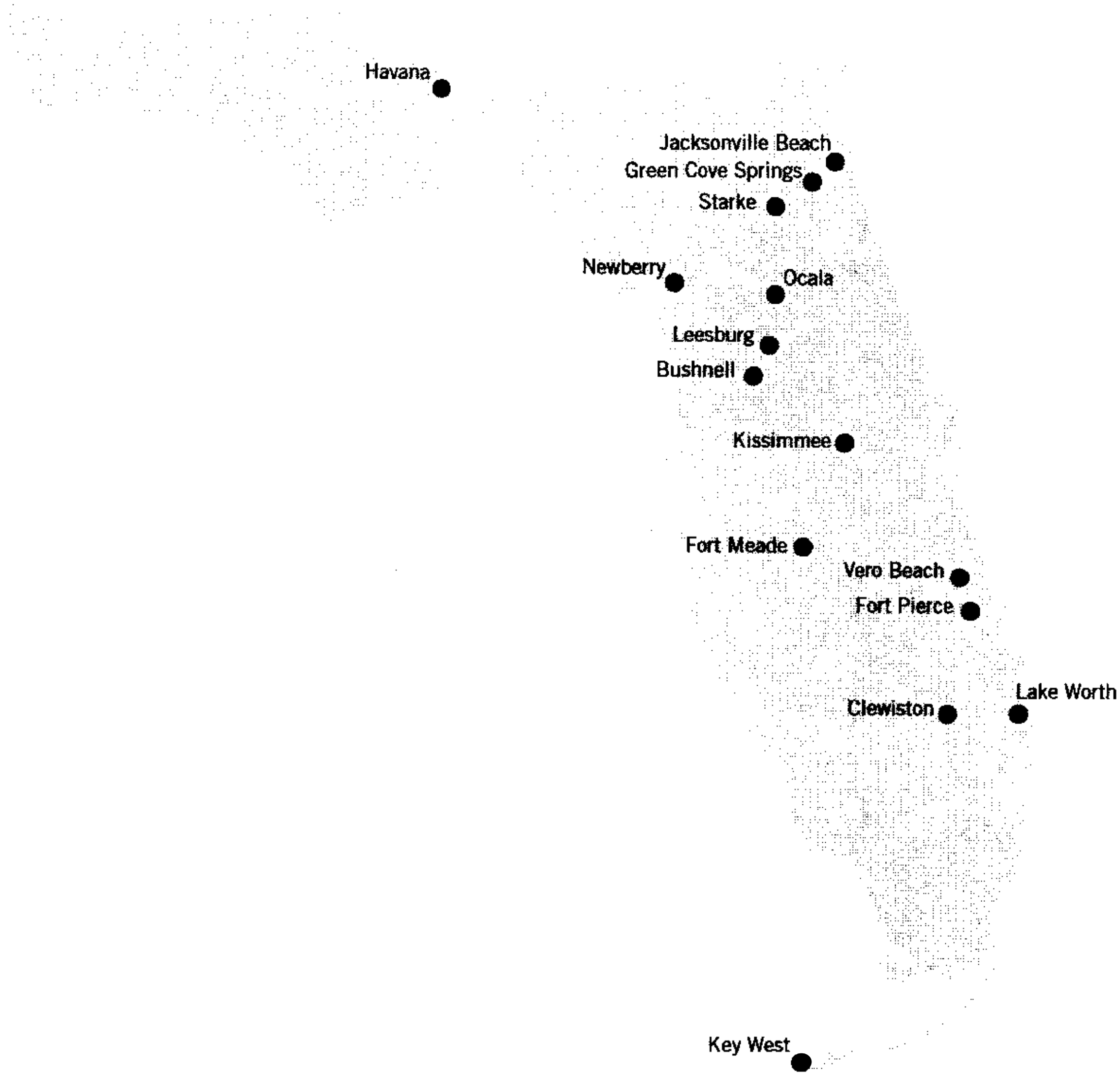

Figure 3-1
ARP Member Cities

Table 3-1
St. Lucie Project Participants

City	Percent Entitlement[1]	City	Percent Entitlement[1]
Alachua	0.431	Clewiston [2]	2.202
Fort Meade [2]	0.336	Fort Pierce [2]	15.206
Green Cove Springs [2]	1.757	Homestead	8.269
Jacksonville Beach [2]	7.329	Kissimmee [2]	9.405
Lake Worth [2]	24.870	Leesburg [2]	2.326
Moore Haven	0.384	Newberry [2]	0.184
New Smyrna Beach	9.884	Starke [2]	2.215
Vero Beach [2]	15.202		

(1) Percent entitlement of FMPA's 8.806 percent undivided ownership share.
(2) ARP member.

Stanton Project

On August 13, 1984, FMPA purchased from the Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton Unit 1 (the Stanton Project). Stanton Unit 1 went into commercial operation on July 1, 1987. Six of FMPA's members are participants in the Stanton Project, with the following entitlements as shown in Table 3-2.

Table 3-2
Stanton Project Participants

City	Percent Entitlement[1]	City	Percent Entitlement[1]
Fort Pierce [2]	24.390	Homestead	12.195
Kissimmee [2]	12.195	Lake Worth [2]	16.260
Starke [2]	2.439	Vero Beach [2]	32.521

(1) Percent entitlement of FMPA's 14.8193 percent undivided ownership share.
(2) ARP member.

Tri-City Project

On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton Unit 1. Three of FMPA's members are participants in the Tri-City Project, with the following entitlements as shown in Table 3-3.

Table 3-3
Tri-City Project Participants

City	Percent Entitlement(1)
Fort Pierce (2)	22.727
Homestead	22.727
Key West (2)	54.546

(1) Percent entitlement of FMPA's 5.3012 percent undivided ownership share.
(2) ARP member.

Stanton II Project

On June 6, 1991, under the Stanton II Project structure, FMPA purchased from OUC a 23.2367 percent undivided ownership interest in OUC's Stanton Unit 2, a coal fired unit virtually identical to Stanton Unit 1. The unit commenced commercial operation in June 1996. Seven of FMPA's members are participants in the Stanton II Project, with the following entitlements as shown in Table 3-4.

Table 3-4
Stanton II Project Participants

City	Percent Entitlement(1)	City	Percent Entitlement(1)
Fort Pierce (2)	16.4887	Homestead	8.2443
Key West (2)	9.8932	Kissimmee (2)	32.9774
St. Cloud	14.6711	Starke (2)	1.2366
Vero Beach (2)	16.4887		

(1) Percent entitlement of FMPA's 23.2367 percent undivided ownership share.
(2) ARP member.

3.2 FMPA ARP Generation

The ARP supply-side resources consist of a diversified mix of generation ownership and purchase power. These resources are described in the following subsections.

3.2.1 FMPA ARP Solely Owned Generation

This category of resources includes generation that is solely owned by ARP. These resources include the Stock Island CT 2, Stock Island CT 3, Stock Island CT 4, and Treasure Coast Energy Center Unit 1 (TCEC) units. TCEC, located near Fort Pierce, is currently under construction, with commercial operation planned for May 2008. TCEC is a 1x1 combined cycle with a GE 7FA combustion turbine. The unit is forecasted to have a summer capacity of approximately 296 MW. TCEC received site certification from the governor and cabinet in May 2006.

3.2.2 FMPA ARP Jointly Owned Generation

This category of resources includes fossil-fueled and nuclear generation that is jointly owned or purchased by the ARP as well as ARP member participation in the units. The fossil-fueled resources include the Stanton Energy Center (including the Stanton, Tri-City, and Stanton II projects, as well as Stanton Combined Cycle Unit A), Indian River, and Cane Island units.

A number of the ARP members own small amounts of capacity in Progress Energy Florida's (PEF's) Crystal River Unit 3. Likewise, a number of ARP members participate in the St. Lucie Project, which provides them capacity and energy from St. Lucie Unit 2. Capacity from these two nuclear units is classified as "excluded resources" in the ARP. As such, the ARP members pay their own costs associated with the nuclear units and receive the benefits of capacity and energy from these units. The ARP provides the balance of capacity and energy requirements for the members that participate in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

3.2.3 ARP Member Owned Generation

This category includes generation that is owned by ARP members either solely or jointly. The ARP purchases this capacity from ARP members and then commits and dispatches the generation to meet the total requirements of the ARP. FPUA, KEYS, KUA, Lake Worth, and Vero Beach have member owned generation.

3.3 Purchase Power Contracts

This category includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP members that were entered into prior to the member joining the ARP. Purchase power generation includes capacity and energy received from suppliers such as PEF, FPL, Calpine, and Southern Power Company. The power purchase contracts are briefly summarized below:

- PEF:
  - FMPA has a power contract with PEF for 30 MW in 2008, 75 MW in 2009, and 120 MW in 2010. The nominated capacity can be adjusted annually and also includes reserves.
- FPL:
  - FMPA has a long-term 45 MW purchase until June 2013. The FPL purchase includes reserves.
- Calpine:
  - FMPA has a contract with Calpine for 100 MW that ends in 2009.
- Southern Power Company:
  - FMPA has a contract to purchase 157 MW of peaking power from Southern Power Company's Oleander plant. The purchase has a term of 20 years.
  - FMPA has a contract to purchase 80 MW from Southern Power Company's (operating as Southern Company-Florida LLC) Stanton A combined cycle unit. The 80 MW includes KUA's capacity purchase. This purchase is currently set to expire in October 2023, with options for further extension. It has been assumed that this contract would be extended for the duration of the study period considered in this Application.

3.4 Unit Retirements

FMPA has identified certain member units for retirement because of their age and inefficiency. In this Application, these units will be considered retired as of the dates presented in Table 3-5.

Table 3-5
FMPA Planned Retirements

Unit Identification	Retirement Date	Summer Capacity Retired (MW)	Total Annual Summer Capacity Retired (MW)
Fort Pierce Unit 7	5/1/2008	29	
Fort Pierce Unit 8	1/24/2008	49	
Fort Pierce Combined Cycle	5/1/2008	31	
Fort Pierce D1 and 2	5/1/2008	5	114
Lake Worth Unit 3	5/1/2011	25	
Lake Worth Unit 5	5/1/2011	8	
Lake Worth GT 1	5/1/2011	27	
Lake Worth GT 2	5/1/2011	20	
Lake Worth D1-5	5/1/2011	10	89(1)
Hansel Combined Cycle	5/1/2012	47	47
Total Retirements			250

(1) Total Annual Summer Capacity Retired does not match sum of individual unit Summer Capacity Retired due to rounding.

3.5 Net ARP Capacity Resources

The ARP existing, approved, and currently planned resource capacity is presented in Table 3-6; values are presented for the years 2008 through 2014. There are no changes to the existing, approved, and currently planned resources after 2014. Table 3-6 reflects the establishment of Contract Rate of Delivery (CROD) by Vero Beach on January 1, 2010, as discussed in Section 13.0.

Table 3-6
ARP's Existing and Approved/Planned Resource Capacity[1]

Generating Resources	Summer Rating					
	2008	2009	2010	2011	2012	2013 - 2027
Excluded Resources (Nuclear) [2]	84	84	73	77	77	77
Stanton Coal Plant[3]	222	222	184	184	184	184
Stanton Combined Cycle Unit A[4]	45	45	45	45	45	45
Cane Island 1-3[4]	383	383	383	383	383	383
Indian River CTs	80	80	80	80	80	80
Stock Island 2-4	75	75	75	75	75	75
Key West Native Generation	41	41	41	41	41	41
Kissimmee Native Generation	47	47	47	47	0	0
Lake Worth Native Generation	89	89	89	0	0	0
Vero Beach Native Generation	138	138	0	0	0	0
TCEC	296	296	296	296	296	296
Total Generating Capacity[5]	1,500	1,500	1,314	1,229	1,182	1,182
Purchased Power						
PEF Partial Requirements	30	75	120	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	0
Calpine Purchase	100	100	0	0	0	0
Stanton A Purchase[6]	80	80	80	80	80	80
Southern Power Company Power Purchase Agreement	157	157	157	157	157	157
Total Purchased Power Resources[5]	412	457	402	282	282	237
Total Resources[5]	1,912	1,957	1,716	1,511	1,463	1,418

(1) Planned capacity prior to commercial operation of the Central Florida Power Project.
(2) Reduction in 2010 reflects the withdrawal of Vero Beach from the ARP. Increase in 2011 reflects planned upgrades.
(3) Reduction in 2010 reflects the withdrawal of Vero Beach from the ARP.
(4) Includes FMPA and KUA ownership capacity.
(5) Sums may not match FMPA totals due to rounding.
(6) Includes FMPA and KUA capacity purchased from Southern Company-Florida, LLC.

3.6 Florida Municipal Power Pool (FMPP)

The FMPP is a power pool composed of three members: OUC, Lakeland Electric, and FMPA. The member generating resources are centrally dispatched to meet the combined FMPP energy requirements.

The FMPP was formed in 1988. FMPP resources include the members' generating units as well as purchase power. Each FMPP member is responsible for maintaining sufficient capacity to serve its own load, including an adequate amount for reserves. The resources are committed and dispatched by OUC, which handles the day-to-day operations of the FMPP.

3.7 Operating and Spinning Reserve Requirements

Florida Reliability Coordinating Council (FRCC) operating reserve is maintained by the combined systems in Florida at a value equal to, or greater than, the summer gross FRCC capability rating of the largest generating unit in service in FRCC. Currently, the operating reserve requirement of the FMPP is 99 MW, which includes 25 MW of spinning reserves. FMPA's share of FMPP's operating reserves is 31.6 MW, which includes 7.9 MW of spinning reserves.

3.8 Transmission System

The Florida electric transmission grid is interconnected by high voltage transmission lines ranging from 69 kV to 500 kV. Florida's electric grid is tied to the rest of the continental United States at the Florida/Georgia/Alabama interface. FPL, PEF, JEA, and the City of Tallahassee own the transmission tie lines at the Florida/Georgia/Alabama interface. ARP members' transmission lines are interconnected with transmission facilities owned by FPL, PEF, OUC, JEA, Seminole Electric Cooperative (SEC), Florida Keys Electric Cooperative Association (FKEC), and TECO.

Capacity and Energy (C&E) resources for the ARP are transmitted to ARP members utilizing the transmission systems of FPL, PEF, TECO, and OUC. C&E resources for the cities of Jacksonville Beach, Green Cove Springs, Clewiston, Fort Pierce, Key West, Lake Worth, Starke, and Vero Beach are delivered by FPL's transmission system. C&E resources for the cities of Ocala, Leesburg, Bushnell, Newberry, and Havana are delivered by the PEF transmission system. C&E resources for KUA are delivered by the transmission systems of FPL, PEF, and OUC. C&E resources for the City of Fort Meade are delivered by the PEF and TECO transmission systems.

3.8.1 Member Transmission Systems

FPUA

FPUA operates an internal, looped 69 kV transmission system for system load and a 118 MW local power generating plant (shown in Table 3-5 with a retirement date of May 1, 2008). There are two interconnections with other utilities, both operated at 138 kV. FPUA's Hartman Substation interconnects to FPL's Midway and Emerson Substations. The second interconnection is from FPUA's Garden City (No. 2) Substation to County Line Substation No. 20, connected by a 7.5 mile, single-circuit, 138 kV line. FPUA and the City of Vero Beach jointly own County Line Substation, the 138 kV line connecting to Emerson Substation, and some parts of the tie between the two cities.

KEYS

KEYS owns, operates, and maintains an electric generation, transmission, and distribution system that supplies electric power and energy south of FKEC's Marathon Substation to the City of Key West. KEYS and FKEC jointly own a 64 mile, 138 kV transmission tie line from FKEC's Marathon Substation that interconnects to FPL's Florida City Substation at the Dade/Monroe county line. In addition, a second interconnection with FPL was completed in 1995, which consists of a jointly owned 21 mile, 138 kV tie line between the FKEC's Tavernier and Florida City Substations at the Dade/Monroe county line. KEYS owns a 49.2 mile, 138 kV radial transmission line from Marathon Substation to KEYS' Stock Island Substation. Two autotransformers at the Stock Island Substation provide transformation between 138 kV and 69 kV. KEYS has five 69 kV and four 138 kV substations that supply power at 13.8 and 4.16 kV to its distribution system. KEYS owns approximately 227 miles of 13.8 kV distribution line.

Lake Worth

The City of Lake Worth Utilities (LWU) has one 138 kV interconnection with FPL at the LWU-owned Hypoluxo Switching Station. A 3 mile radial 138 kV transmission line connects the Hypoluxo Switching Station to LWU's Main Plant Substation. In addition, a 2.4 mile radial 138 kV transmission line connects the Main Plant Substation to LWU's Canal Substation. Two 138/26 kV autotransformers are located at the Main Plant Substation, and one 138/26 kV autotransformer is located at Canal Substation. The utility owns and operates an internal 26 kV sub-transmission system to serve system load.

KUA

KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines. KUA's 230 kV and 69 kV transmission system includes interconnections with PEF, OUC, TECO, and the City of St. Cloud. KUA owns and operates 24.6 circuit miles of 230 kV and 46.9 circuit miles of 69 kV transmission lines. KUA and FMPA jointly own 21.6 circuit miles of 230 kV lines out of Cane Island Power Park. Electric capacity and energy supplied from KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to nine distribution substations. KUA has direct transmission interconnections with (1) PEF at PEF's 230 kV Intercession City Substation, 69 kV Lake Bryan Substation, and 69 kV Meadow Wood South Substation; (2) OUC at OUC's 230 kV Taft Substation and TECO/OUC's 230 kV Osceola Substation from the Cane Island Substation; and (3) the City of St. Cloud at KUA's 69 kV Carl A. Wall Substation.

Ocala

Ocala Electric Utility (OEU) owns and operates its bulk power supply system, which consists of three 230 kV to 69 kV substations, 13 miles of radial 230 kV and 48 miles of 69 kV transmission loop, and 18 distribution substations delivering power at 12.47 kV. The distribution system consists of 773 miles of overhead lines and 302 miles of underground lines.

OEU's 230 kV transmission system interconnects with PEF's Silver Springs Switching Station and Seminole Electric Cooperative Incorporated's (SECI's) Silver Springs North Switching Station. OEU's Dearmin Substation ties at PEF's Silver Springs Switching Station and OEU's Ergle Substation ties at SECI's Silver Springs North Switching Station. OEU also has a 69 kV tie from the Airport Substation with Sumter Electric Cooperative's Martel Substation. In addition, OEU owns and operates a 13 mile radial 230 kV transmission line from Ergle Substation to Shaw Substation. OEU is planning to add a second 230 kV tie by rerouting the existing Shaw to Ergle 230 kV line from Shaw Substation to a direct radial connecting to SECI's Silver Springs North Switching Station.

Vero Beach

The City of Vero Beach owns and operates an internal, looped, 69 kV transmission system for system load and a 138 MW local power generating plant. The City of Vero Beach has two 138 kV interconnections with FPL and one with FPUA. The City of Vero Beach's interconnection with FPL is at the City of Vero Beach's West Substation No. 7. The City of Vero Beach also has a second FPL interconnection from

County Line Substation No. 20. County Line Substation No. 20 is connected by two separate, single-circuit, 138 kV transmission lines to FPL's Emerson 230/138 kV substation and FPUA's Garden City (No. 2) Substation. The City of Vero Beach and FPUA jointly own County Line Substation No. 20, the connecting lines to FPL's Emerson Station, and some part of the tie between the two municipal utilities.

3.8.2 Transmission Agreements

FPL

The Network Service Agreement with FPL was executed in March 1996, and was subsequently amended to both conform to the Federal Energy Regulatory Commission's (FERC's) Pro Forma Tariff and to add additional members to the ARP. The FPL agreement provides for network transmission service for the ARP member cities located in FPL's service territory.

PEF

To provide transmission wheeling service for ARP member cities located in PEF's service territory, FMPA operates under an existing agreement with PEF. This agreement was executed in April 1985, and provides for network type transmission services.

OUC

OUC provides transmission service for the delivery of power and energy from FMPA's ownership in Stanton Unit 1, Stanton Unit 2, Stanton A combined cycle, and the Indian River combustion turbine units to the FPL and PEF interconnections for subsequent delivery to the ARP. Rates for such transmission wheeling service are based on OUC's costs of providing such transmission wheeling service and under the terms and conditions of the OUC-FMPA Firm Transmission Service contracts for the ARP.

3.9 Load and Electrical Characteristics

FMPA experiences both summer and winter demand peaks. Summer demands, which peak in the afternoons, are longer in duration than winter demands, which typically peak in the morning. In addition, summer peaks typically occur when many generation resources are experiencing ambient temperature performance impacts. As a result, the summer peaks govern FMPA planning capacity requirements.

3.10 Description of Existing Renewable Projects

3.10.1 FMPA Renewable Projects

FMPA purchases the electric output of the US Sugar plant in Clewiston, Florida. The plant operates on bagasse as its fuel source. Bagasse is the residue of sugar cane production, and its burning may be considered carbon dioxide (CO_2) neutral because CO_2 emissions from bagasse are equal to the CO_2 absorbed from the atmosphere by the sugar cane during its growing phase. US Sugar uses the bagasse to fuel its generation plants to provide power for its processes, and FMPA purchases the excess (unused) power from US Sugar's generators. In addition to the FMPA-purchased energy, the energy produced by US Sugar from bagasse offsets the energy that would have been produced by fossil fuels.

FMPA owns a portion of Stanton Energy Center Units 1 and 2, as described earlier in this section. These units have the capability to burn landfill gas from a nearby landfill. Through its contract with OUC, the landfill provides methane gas as a supplemental fuel source for Stanton Units 1 and 2.

3.10.2 ARP Member Renewable Projects

KEYS offers its residential and commercial customers the opportunity to participate in the GO GREEN program. The optional program involves contributing as little as $10 per month, and two "blends" of renewable energy are offered. Program participants will not be directly powered by renewable energy, but their participation will contribute to energy production from renewable sources somewhere in Florida (through the Florida Ever Green™ blend) or elsewhere in the United States (through the USA Green™ blend).

4.0 Economic Parameters

This section presents the economic evaluation criteria and methodology used to evaluate the economics of Cane Island 4 as part of FMPA's least-cost expansion plan to satisfy forecast capacity requirements throughout the 20 year evaluation period.

4.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and nonfuel variable O&M escalation rate were each assumed to be 2.3 percent.

4.2 Municipal Bond Interest Rate

The long-term tax exempt municipal bond interest rate was assumed to be 5.0 percent.

4.3 Present Worth Discount Rate

The present worth discount rate was assumed to be equal to the tax exempt municipal bond interest rate of 5.0 percent.

4.4 Interest During Construction Interest Rate

The interest during construction (IDC) rate was assumed to be 5.0 percent.

4.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR), represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year fixed charge rate.

Different generating technologies are assumed to have different economic lives and, therefore, different financing terms. Simple cycle combustion turbines are assumed to have a 25 year financing term, while natural gas fired combined cycle units are assumed to be financed over 30 years. Given the various economic lives and corresponding financing terms, different levelized FCRs were developed. All levelized FCR calculations assume a 2.0 percent bond issuance fee and include an assumed 0.50 percent annual property insurance cost and a 6 month debt service reserve fund earning interest at an interest rate equal to the bond interest rate[1]. The resulting 25 year fixed charge rate is 7.824 percent, and the 30 year fixed charge rate is 7.194 percent.

[1] The debt service reserve fund is a fund to cover 6 months of debt service obligations associated with capital expenditures.

5.0 Forecast of Electrical Demand and Consumption

5.1 Introduction

Under the ARP structure, FMPA agrees to meet all of the ARP members' power requirements. To secure sufficient capacity and energy, FMPA forecasts each ARP member's electrical power demand and energy requirements on an individual basis and integrates the results into a forecast for the entire ARP. The following discussion summarizes the load forecasting process and the results of the ARP members' load forecast.

5.2 Load Forecast Process

FMPA prepares its load and energy forecast by month and summarizes the forecast annually. The load and energy forecast includes projections of customers, demand, and energy sales by rate classification for each of the ARP members. The forecast process includes existing ARP member cities that FMPA currently supplies and ARP members that FMPA is scheduled to begin supplying in the future. Forecasts are prepared on an individual member basis and are then aggregated into projections of the total ARP demand and energy requirements.

Figure 5-1 illustrates the ARP members' load forecast process.

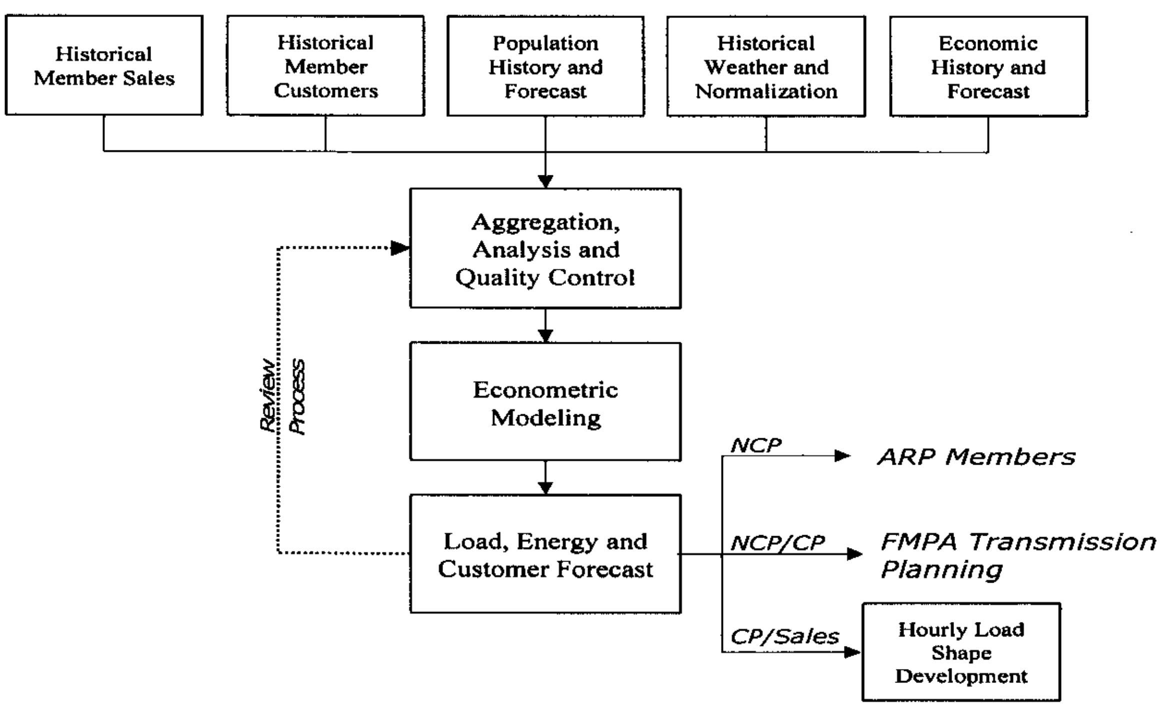

Figure 5-1
Load Forecast Process

In addition to the base case load and energy forecast, FMPA has prepared high and low case forecasts, which are intended to capture the majority of the uncertainty in certain driving variables, for each of the ARP members.

5.3 Load Forecast Overview

FMPA retained R. W. Beck, Inc. (Beck) to prepare a forecast of peak load and net energy for the ARP members. The load and energy requirement forecast is a critical input to many utility processes including, but not limited to, generation expansion planning, fuel and purchased power budgeting, transmission planning, financial planning and budgeting, and staffing. In addition, the load and energy forecast is submitted to the Florida Public Service Commission (FPSC) as part of the Ten Year Site Plan. Consequently, a rigorous and detailed process that relies on recognized standards of practice, as well as a thorough review of results by various parties, is essential to operations and long-term planning.

The load and energy forecast prepared by Beck (the Forecast) was prepared for a 20 year period, encompassing calendar years 2007 through 2026. The Forecast was prepared on a monthly basis using municipal utility data provided to FMPA by the ARP members and load data maintained by FMPA. Historical and projected economic and demographic data was provided by Economy.com, a nationally recognized provider of economic data. Also, Beck relied on ARP members and their staffs for information regarding local economic and demographic issues specific to each member. As discussed in Subsection 3.1.2, the load for the City of Fort Meade is currently served through a full requirements agreement with Tampa Electric Company (TECO). When the Fort Meade/TECO agreement terminates in January 2009, FMPA will serve the City of Fort Meade from ARP's portfolio of power supply resources. The Forecast reflects the addition of the Fort Meade requirements beginning in 2009. As discussed in Section 13.0, the City of Vero Beach has provided FMPA with its Notice of Establishment of a Contract Rate of Delivery (CROD). The Forecast was performed assuming that Vero Beach's CROD becomes effective on January 1, 2010.

In addition to the base case Forecast, Beck prepared high and low case forecasts of winter and summer peak demand and net energy for load (NEL). The high and low case forecasts reflect varying assumptions regarding the future values for population and measures of economic activity. The high and low case forecasts are intended to capture 90 percent of the uncertainty in these driving variables throughout the forecast horizon.

5.4 Load Forecast Methodology

The forecast of peak demand and NEL to be supplied by ARP relies on an econometric forecast of each ARP member's retail sales, combined with various assumptions regarding loss, load, and coincidence factors, generally based on the recent historical values for such factors, and summed across the ARP members.

Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience. In this approach, the significance of historical relationships is evaluated using commonly accepted statistical measures. Models that, in the view of the analyst, best explain the historical variation of energy consumption are selected. These historical relationships are generally assumed to continue into the future, barring any specific information or assumptions to the contrary. The selected models are then populated with projections of explanatory variables, resulting in projections of energy requirements.

Econometric forecasting can be a more reliable technique for long-term forecasting than trend-based approaches and other techniques, because the approach results in an explanation of variations in load rather than simply an extrapolation of history. As a result of this approach, utilities are more likely to anticipate departures from historical trends in energy consumption, given accurate projections of the driving variables. In addition, understanding the underlying relationships that affect energy consumption allows utilities to perform scenario and risk analyses, thereby improving decisions. The high and low scenarios developed as part of the forecast process are examples of this capability.

5.5 Model Specification

Forecasts of monthly sales were prepared by rate classification for each ARP member. In some cases, rate classifications were combined to eliminate the effects of class migration or redefinition. In this way, greater stability is provided in the historical period upon which statistical relationships are based.

For the residential class, the analysis of electric sales was separated into residential usage per customer and the number of customers, the product of which is total residential sales. This process is common for homogenous customer groups. For other rate classifications, the total sales series is the primary forecasted variable, and the customer forecast is generated for reporting purposes and to check the sensibility of the sales forecast.

Residential class models typically reflect that energy sales are dependent on, or driven by: (i) the number of residential customers, (ii) real personal income per household, (iii) real electricity prices, and (iv) weather variables. The number of residential customers was projected on the basis of the estimated historical relationship between the number of residential customers of the ARP members and the number of households in the ARP member's county.

For the general service class models, the econometric models reflect that energy requirements are best explained by: (i) real retail sales, total personal income, or gross domestic product (GDP) as a measure of economic activity and population in and around the ARP member's service territory, (ii) the real price of electricity, and (iii) weather variables. In the case of the general service non-demand class, retail sales was typically selected as the long-term driving variable either because it performed better by certain measures or because the resulting forecast was more sensible. Similarly, for the general service demand and industrial classes, total personal income or GDP was typically selected, except in cases where the forecast was based on an assumption (e.g., Clewiston's largest customer, US Sugar, and the US Navy base in Key West's service area).

Weather variables included heating and cooling degree-days (HDD and CDD, respectively) for the current month and for the prior month. Lagged degree-day variables were included to account for the typical billing cycle offset from calendar data. In other words, sales that are billed in any particular month are typically made up of electricity that was used during some portion of the current month and of the prior month.

5.6 Projection of Net Energy for Load and Peak Demand

5.6.1 ARP Member NEL and Peak Demand

The forecast of sales for each rate classification were summed to equal the total sales of each ARP member. Assumed ARP member distribution loss factors, typically based on a 5 year average of historical loss factors, were then applied to the total sales to derive monthly NEL measured at the delivery points of the ARP members. To the extent that historical loss factors were deemed anomalous, they were excluded from these averages.

Projections of summer and winter noncoincident peak (NCP) demand were developed by applying projected annual load factors to the forecasted NEL on an ARP member system basis. The projected load factors are based on the average relationship between annual NEL and the seasonal peak demand generally over the period 1997 to 2006 (i.e., a 10 year average).

Monthly peak demand was based on the average relationship between each monthly peak and the appropriate seasonal peak. This average relationship was computed after ranking the historical demand data within the summer and winter seasons and reassigning peak demands to each month based on the typical ranking of that month compared to the seasonal peak. This process avoids the distortion of the averages due to randomness as to the months in which peak weather conditions occur within each season. For example, a summer peak period can occur during July or August of any year. It is important that the shape of the peak demands reflects that only one of those two months is the peak month and that the other is typically some percentage less.

Projected coincident peak demands related to the total ARP, the ARP member groups, and the transmission providers were derived from projected NCP demand and monthly coincidence factors averaged generally over a 5 year period (2002 to 2006).

5.6.2 Transmission System Losses

The ARP members are supplied over the transmission systems of Florida Power & Light (FPL) and Progress Energy Florida (PEF). KUA is not a transmission customer of either FPL or PEF, so it is treated separately in calculating transmission system losses. Based on the transmission agreement in place with FPL, FMPA is charged for losses of 2.19 percent and supplies its own losses. Accordingly, load of ARP members in FPL's service territory is adjusted upward to account for 2.19 percent losses. The current agreement with PEF does not require FMPA to generate losses; however, FMPA compensates PEF for losses incurred on the PEF system. The current agreement with PEF ends in 2010. At that time, FMPA is expected to enter into another agreement similar to the FPL agreement where FMPA is expected to supply its own losses at an assumed loss factor of 2.17 percent. For 2011 and beyond, the load of ARP members on the PEF system is adjusted upward to account for 2.17 percent losses. Transmission losses to the KUA system were calculated using a 0.75 percent loss factor.

5.7 Principal Considerations and Assumptions

The development of the Forecast was based upon the following principal considerations and assumptions:

- The future influence on energy sales of the economic, demographic, and weather factors, on which the econometric models are based, was assumed to be similar to the estimated influence of such factors generally over the period 1992 through 2006.
- Although the econometric models implicitly account for the historical relationships between energy usage and the following factors to the extent they have occurred in the past, the Forecast does not explicitly reflect extraordinary potential future effects of: (a) increases in appliance design efficiency or building insulation standards, (b) development of substitute energy sources, (c) consumers switching to traditional or new types of

electrical appliances from other alternatives (e.g., electric vehicles), (d) consumers switching from electrical appliances to other alternatives, or (e) variations in load that might result from legal, legislative, regulatory, or policy actions.

- The recent average historical relationships between annual summer and winter noncoincident demands and annual NEL and between monthly NCP demands and annual winter and summer NCP demands were assumed to represent reasonable approximations of future load relationships between demands and energy requirements.

The Forecast also relies on historical and projected data from third parties and certain derivations of such data as discussed in the subsections below.

5.7.1 Historical ARP Member Data

Data for each ARP member on numbers of customer accounts, electric sales, and revenues by major rate classification are provided periodically to FMPA by the ARP members. The Forecast relies on such data maintained by FMPA spanning January 1992 through March 2007 (the Study Period). For a small portion of the Study Period, only total revenues were available, and the average revenue for each rate classification analyzed was assumed to vary the same as the total member system average revenue over that period.

5.7.2 Weather Data

Historical weather data has been provided by the National Oceanic and Atmospheric Administration (NOAA). Weather stations for which historical weather was obtained were selected on the basis of their quality and proximity to the ARP members. In most cases, the closest first-order weather station was the best source of weather data. First-order weather stations (usually airports) generally provide the highest quality and most reliable weather data.

The influence on electricity sales of weather has been represented through the use of two data series: HDD and CDD. Degree-days are derived by comparing the average daily temperature and a base temperature, typically 65° F, which was the base relied on herein. To the extent the average daily temperature exceeds 65° F, the difference between that average temperature and the base is the number of CDD for the day in question. Conversely, HDDs result from average daily temperatures which are below 65° F. Heating and cooling degree-days are then summed over the period of interest, in this case, months.

Weather conditions for the projected period are based on the most recent 30 year normals, as computed by NOAA for the period 1971 through 2000.

5.7.3 Economic Data

Economy.com, a nationally recognized provider of economic data, provided both historical and projected economic and demographic data. The data included economic and demographic data for the 16 counties in which the ARP members' service territories reside (the service territory of Beaches Energy Services includes portions of both Duval and St. Johns Counties). These data included county population, households, employment, personal income, retail sales, and GDP. Although all data were not necessarily utilized in each of the forecast equations, each was examined for its potential to explain changes in the ARP members' historical electric sales.

Historical and projected rates of change in two of the key economic drivers (i.e., number of households and personal income) in the Forecast are summarized in Table 5-1. Note: Personal income refers to the total income earned by the population in a county rather than average personal income per capita.

Table 5-1
Historical and Projected Growth (%) in Households and Personal Income

	Number of Households				Personal Income			
ARP Members	1995-2006	2007-2009	2010-2016	2017-2026	1995-2006	2007-2009	2010-2016	2017-2026
Bushnell	5.5	3.9	3.5	2.5	7.5	6.3	5.9	5.0
Clewiston	1.8	2.5	2.3	1.6	2.0	2.0	1.8	1.4
Fort Meade	2.1	1.7	2.3	2.4	3.8	3.3	4.5	5.3
Fort Pierce	3.5	3.2	4.1	3.2	3.8	5.3	5.2	2.9
Green Cove Springs	3.7	3.0	3.3	2.5	4.8	4.9	5.0	4.8
Havana	1.0	1.4	2.1	1.9	2.5	3.2	4.1	4.0
Jacksonville Beach	1.9	1.3	1.7	1.4	3.8	3.8	4.0	4.2
Key West[(1)]	-0.6	-0.3	-0.5	-0.9	2.2	2.3	2.1	1.7
Kissimmee	5.1	4.5	4.7	3.9	6.3	4.0	3.9	3.9
Lake Worth	2.0	2.1	3.1	3.0	3.8	3.5	4.2	4.3
Leesburg	4.6	4.1	4.5	3.8	5.7	3.4	3.2	3.3
Newberry	1.1	1.4	1.9	1.8	2.9	4.3	4.8	4.1
Ocala	3.0	4.3	4.1	3.5	4.4	4.3	5.1	4.4
Starke	1.5	1.7	1.7	1.1	3.0	2.0	1.9	1.6
Vero Beach	2.5	2.2	3.2	3.2	4.4	1.6	2.5	2.8

[(1)]Reported data reflects permanent residents only. Monroe County, the county that comprises Key West, has a significant percentage of seasonal residents, which has represented a growing portion of total residents over the recent historical period. While the projection reflects a decline in the number of permanent residents, this does not imply a decline in total residents.

5.7.4 Real Electricity Price Data

The real price of electricity was derived from a 12 month moving average of real average revenue for each ARP member, normalized for inflation based on the consumer price index (CPI). To the extent that average revenue data specific to a certain rate classification was unavailable, it was assumed to follow the trend of total average revenue of the ARP member. Projected electricity prices were assumed to increase at the rate of inflation. Consequently, the real price was projected to be essentially constant.

5.8 Uncertainty of the Forecast

The base case Forecast relies on a set of assumptions, provided by Economy.com, about future population and economic activity in the counties surrounding the ARP members. However, such projections are unlikely to exactly match the resulting data as future periods become history. While it is sensible to place significant weight on the base case, the Forecast also includes two scenarios reflecting higher and lower projections of population and economic activity.

Given that Economy.com does not publish information regarding the potential error of its projections, the scenarios rely on such statistics published by another provider, Woods & Poole Economics, Inc. (Woods & Poole), which relies on the same underlying data set and a similar economic forecasting methodology. Woods & Poole publishes several statistics that relate to the average amount by which various projections it has provided in the past are different from actual results. These statistics are used to develop optimistic and pessimistic scenarios of the trends in economic activity and population representing approximately 90 percent of potential outcomes.

The statistics utilized to generate the alternative scenarios are associated with economic projections at the state level, so that the forecasts of each ARP member can be summed to represent a consistent case for the ARP. However, the historical growth rates of the ARP members are not perfectly correlated. By its very nature, the aggregate economy and population comprising the load supplied from the ARP will exhibit significantly less volatility than any individual ARP member's service area. Therefore, care should be exercised when using these alternative growth scenarios because the plausible range of results for any individual ARP member may be considerably wider than that shown.

The ranges of resulting load forecasts imply that the load projections of the individual ARP members exhibit different levels of sensitivity to variation in the driving variables. This is due to differences in: (i) the responsiveness of the energy requirements of the ARP members to changes in the input assumptions and (ii) the percentage of the total ARP member sales that certain large customers comprise of various ARP members' total loads. These large customers' energy sales were forecasted separately based on information provided by the ARP members or FMPA staff, and such forecasts were assumed to be independent of changes in the local economy. Although this assumption is somewhat simplified, it does illustrate that the energy requirements of some of the ARP members are very dependent on the fortunes and actions of a few large customers.

Table 5-2 provides the amount by which Economy.com projections were adjusted from the base case assumptions, to develop the high and low cases. This amount of variation is intended to represent 90 percent of potential outcomes (1.7 standard deviations). Other economic data, such as retail sales and GDP, were assumed to vary to the same degree as income. As expected, the amount of potential variation is shown to grow through time, because uncertainty in these variables varies in rough proportion to the forecast horizon.

Table 5-2
Economic and Demographic Uncertainty

Year	Population (Percent)	Employment (Percent)	Income (Percent)	Income per Capita (Percent)
2008	3.4	5.1	7.7	6.4
2009	4.3	6.8	8.5	6.8
2010	5.1	8.5	9.4	7.2
2011	6.0	10.2	10.2	7.7
2012	6.8	11.9	11.1	8.1
2013	7.7	13.6	11.9	8.5
2014	8.5	15.3	12.8	8.9
2015	9.4	17.0	13.6	9.4
2016	10.2	18.7	14.5	9.8
2017	11.1	20.4	15.3	10.2
2018	11.9	22.1	16.2	10.6
2019	12.8	23.8	17.0	11.1
2020	13.6	25.5	17.9	11.5
2021	14.5	27.2	18.7	11.9
2022	15.3	28.9	19.6	12.3
2023	16.2	30.6	20.4	12.8
2024	17.0	32.3	21.3	13.2
2025	17.9	34.0	22.1	13.6
2026	18.7	35.7	23.0	14.0

5.9 Overview of Results

The following subsections present the summer peak demand, winter peak demand, and NEL for the base, high, and low load forecasts for the period 2008 through 2026. These results include transmission losses.

5.9.1 Base Load Forecast

The 2008 forecasted summer peak demand is 1,545 MW, winter peak demand is 1,427 MW, and annual NEL is 7,655 GWh. The 2026 forecasted summer peak demand is 2,077 MW, winter peak demand is 1,878 MW, and annual NEL is 10,233 GWh. The summer peak demand is projected to grow at a rate of 3.2 percent from 2008 to 2009 and at an average annual rate of 2.2 percent from 2010 through 2026. The winter peak demand is projected to grow at a rate of 3.2 percent from 2008 to 2009 and at an average annual rate of 2.2 percent from 2010 through 2026. The NEL is expected to grow at a rate of 3.1 percent from 2008 to 2009 and at an average annual rate of 2.2 percent from 2010 through 2026. The growth from 2008 to 2009 includes the addition of the Fort Meade load following the expiration of its existing full requirements agreement with TECO. Growth rates have been shown separately for the 2008 to 2009 and 2010 through 2026 periods to avoid distortion because of Vero Beach's establishment of CROD, effective January 1, 2010. All values decrease from 2009 to 2010 as a result of this removal of Vero Beach loads beginning in 2010. Detailed results for the base case Forecast are summarized in Table 5-3.

5.9.2 High and Low Load Forecasts

The base case Forecast consists of an estimate of the future values for each of the dependent variables, the electricity sales by rate classification for each of the members, and all of the derived load determinants, including NEL and peak demand. The base case Forecast represents the most likely estimate of future load levels. However, there is significant uncertainty in those projections, a large portion of which is related to the uncertainty in the projections of the independent variables. To account for this uncertainty, high and low forecasts were developed by simulating the energy sales models using varying assumptions regarding population and economic activity as discussed in Section 5.7. The remaining load determinants were then derived from these alternative forecasts of energy sales by classification, as in the base case Forecast. The high and low forecasts combine to form a band of uncertainty that is intended to capture approximately 90 percent (1.7 standard deviations) of occurrences. Detailed results for the high and low forecast are summarized in Table 5-4.

Table 5-3
Total ARP Demand and Energy Forecast
Base Case[(1)]

Year	Winter Peak (MW)	Summer Peak (MW)	NEL (GWh)
2008	1,427	1,545	7,655
2009	1,473	1,593	7,896
2010	1,319	1,462	7,237
2011	1,359	1,506	7,451
2012	1,389	1,539	7,612
2013	1,421	1,574	7,783
2014	1,453	1,610	7,960
2015	1,487	1,647	8,141
2016	1,522	1,685	8,326
2017	1,556	1,723	8,511
2018	1,591	1,761	8,695
2019	1,626	1,799	8,881
2020	1,661	1,838	9,070
2021	1,697	1,877	9,261
2022	1,733	1,917	9,454
2023	1,769	1,957	9,648
2024	1,805	1,997	9,843
2025	1,842	2,037	10,037
2026	1,878	2,077	10,233
Annual Growth Rates (%)			
2008-2009	3.2	3.2	3.1
2010-2026	2.2	2.2	2.2

[(1)]Forecast peak demands and NEL do not include any capacity or energy associated with serving Vero Beach after the CROD becomes effective.

Table 5-4
Total ARP Demand and Energy Forecast
High and Low Forecasts[1]

Year	High Forecast			Low Forecast		
	Winter Peak (MW)	Summer Peak (MW)	NEL (GWh)	Winter Peak (MW)	Summer Peak (MW)	NEL (GWh)
2008	1,457	1,579	7,842	1,396	1,509	7,466
2009	1,515	1,641	8,146	1,429	1,545	7,642
2010	1,365	1,515	7,514	1,271	1,407	6,955
2011	1,416	1,571	7,785	1,301	1440	7,111
2012	1,456	1,616	8,003	1,321	1,462	7,215
2013	1,498	1,662	8,232	1,341	1,484	7,325
2014	1,541	1,710	8,470	1,363	1,507	7,439
2015	1,586	1,760	8,715	1,385	1,531	7,556
2016	1,632	1,811	8,965	1,407	1,556	7,672
2017	1,679	1,863	9,219	1,429	1,580	7,787
2018	1,726	1,915	9,473	1,451	1,603	7,899
2019	1,774	1,968	9,732	1,472	1,626	8,009
2020	1,823	2,022	9,997	1,493	1,649	8,120
2021	1,873	2,077	10,267	1,515	1,672	8,230
2022	1,924	2,134	10,541	1,535	1,695	8,339
2023	1,975	2,191	10,820	1,556	1,717	8,446
2024	2,027	2,249	11,101	1,576	1,739	8,550
2025	2,079	2,307	11,386	1,596	1,760	8,652
2026	2,132	2,366	11,673	1,615	1,781	8,752
Annual Growth Rates (%)						
2008-2009	3.9	3.9	3.9	2.4	2.3	2.4
2010-2026	2.8	2.8	2.8	1.5	1.5	1.4

[1]Forecast peak demands and NEL do not include any capacity or energy associated with serving Vero Beach after the CROD becomes effective.

5.10 Price Elasticity of the Load Forecast

The econometric models that form the basis of the Forecast include the price of electricity as an important driver of load, typically through the use of a 12 month moving average of historical real average revenue. However, the Forecast assumes that the retail cost of electricity to the customers of the ARP members increases at the rate of general inflation, resulting in essentially flat real prices. Therefore, aside from the delayed influence of price changes in the recent past, which tends to depress loads somewhat, future loads are assumed to be generally unaffected by the cost of electricity.

To the extent that changes in the cost of electricity deviate significantly from the path of general inflation, actual future loads can be expected to deviate from the Forecast. A useful measure of the amount by which loads are impacted by changes in electricity prices is referred to as "elasticity." Elasticity is defined as the percentage by which one variable changes as the result of a 1 percent change in another, all else equal. The numerous econometric models that drive the Forecast reflect elasticity estimates that vary from approximately -0.5 to 0.0 (i.e., no discernable influence), which is similar to other empirical work performed in the electric utility industry. Assuming an average elasticity of -0.2, a 20 percent increase in the real price of electricity from recent levels, which are already quite elevated from the level exhibited 2 to 3 years ago, might result in loads that are approximately 4 percent lower. Similarly, a 20 percent decrease in the real price of electricity would result in loads that are 4 percent higher.

6.0 Natural Gas Availability

This section discusses the availability of natural gas based on information from the U.S. Energy Information Administration (EIA) and other sources. Due to projected increases in natural gas production and the importation of liquefied natural gas (LNG), natural gas supplies are projected to meet growing demand in the United States. There also are several new natural gas storage and pipeline projects that will help facilitate the increase in supply of natural gas to the Southeast region. For these and other reasons, Cane Island Unit 4 will have a reliable supply of natural gas.

6.1 Natural Gas Production

The fuel price projections presented in Section 7.0 for natural gas, fuel oil, and coal used in this Application were developed based on those included in the US Energy Information Administration (EIA) Annual Energy Outlook 2007 (AEO2007). AEO 2007 presents projections of energy supply, demand, and prices through 2030. The projections presented within AEO2007 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics.

The projected availability of natural gas relative to the fuel price projections in Section 7.0 is based on NEMS. The North American natural gas market is experiencing significant future natural gas development and production possibilities. Legislative and regulatory influences along with the impact of technology improvement is projected to drive the rate of natural gas field development and production. The Lower 48 Outer Continental Shelf (OCS) has significant leasing and development possibilities as presented in the AEO2007 reference case. The natural gas potential of available leasing and development fields along with the anticipated moratoria expiration of unavailable leasing and development fields provide significant potential for natural gas production.

Additionally, the impact of the proposed Alaska pipeline which will transport natural gas produced in Alaska to the lower 48 states and considerable offshore natural gas resources in the Gulf of Mexico is projected to provide supplementary natural gas domestically.

The natural gas production possibilities presented in the AEO2007 reference case provide suitable natural gas supply availability for Cane Island 4 based on the pricing methodology determined to transport natural gas into the FRCC region. The following sections present the AEO2007 reference case projections of traditional gas production.

6.1.1 Future Natural Gas Production

Total domestic natural gas production, including supplemental natural gas supplies, is projected to increase from 18.3 tcf in 2005 to 21.1 tcf in 2022, before declining to 20.6 tcf in 2030 in the AEO2007 reference case. Lower natural gas consumption in the last 18 years of the projection results in lower domestic natural gas production—primarily, offshore and onshore nonassociated conventional production—in the AEO2007 reference case.

In the AEO2007 reference case, lower 48 offshore production of natural gas grows from 3.4 tcf in 2005 to a peak of 4.6 tcf in 2015 as new resources come online in the Gulf of Mexico. After 2015, lower 48 offshore production declines to 3.3 tcf in 2030, as investment is projected to be inadequate to maintain production levels.

A large proportion of the onshore lower 48 conventional natural gas resource base has been discovered. Discoveries of new conventional natural gas reservoirs are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Accordingly, total lower 48 onshore conventional natural gas production is projected to decline in the AEO2007 reference case from 6.4 tcf in 2005 to 4.9 tcf in 2030.

Incremental production of lower 48 onshore natural gas is projected to come primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. Lower 48 unconventional production increases in the reference case from 8.0 tcf in 2005 to 10.2 tcf in 2030, when it accounts for 50 percent of projected domestic U.S. natural gas production.

The Alaska natural gas pipeline is expected to begin transporting natural gas to the lower 48 States in 2018. In 2030, Alaska's projected natural gas production totals 2.2 tcf in the reference case.

Considerable natural gas resources remain in the offshore Gulf of Mexico, especially in the deep waters. Deepwater natural gas production in the Gulf of Mexico is projected to increase in the reference case from 1.4 tcf in 2005 to a peak volume of 3.1 tcf in 2015, then decline to 2.1 tcf in 2030. Production in the shallow waters declines throughout the projection period, from 2.0 tcf in 2005 to 1.1 tcf in 2030.

6.1.2 Natural Gas Production in the Lower 48 Outer Continental Shelf

For the AEO2007 reference case, an OCS access case was prepared to examine the potential impacts of the lifting of Federal restrictions on access to the OCS in the Pacific, the Atlantic, and the eastern Gulf of Mexico. Currently, except for a relatively small tract in the eastern Gulf, resources in those areas are legally off limits to exploration and development. Mean estimates indicate that technically recoverable resources currently off limits in the lower 48 OCS total 18 billion barrels of crude oil and 77 tcf of natural gas as illustrated in Figure 6-1.

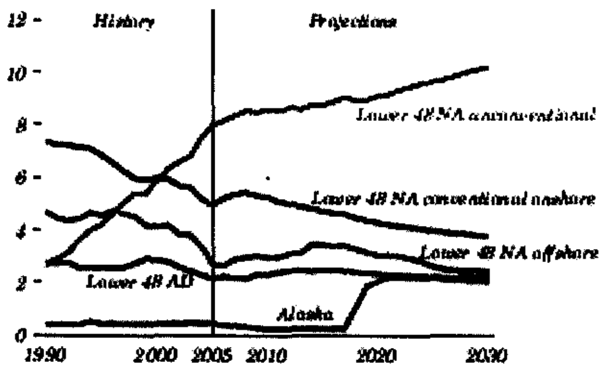

Figure 6-1
Forecasted Natural Gas Production by Source
(Source: www.eia.doe.gov)

Although existing moratoria on leasing in the OCS will expire in 2012, the AEO2007 reference case assumes that they will be reinstated, as they have in the past. Current restrictions are therefore assumed to prevail for the remainder of the projection period, with no exploration or development allowed in areas currently unavailable to leasing. The OCS access case assumes that the current moratoria will not be reinstated, and that exploration and development of resources in those areas will begin in 2012.

Assumptions about exploration, development, and production of economical fields (drilling schedules, costs, platform selection, reserves-to-production ratios, etc.) in the OCS access case are based on data for fields in the western Gulf of Mexico that are of similar water depth and size. Exploration and development on the OCS in the Pacific, the Atlantic, and the eastern Gulf are assumed to proceed at rates similar to those seen in the early development of the Gulf region. In addition, it is assumed that local infrastructure issues and other potential non-Federal impediments will be resolved after Federal access restrictions have been lifted. With these assumptions, technically recoverable undiscovered resources in the lower 48 OCS increase to 59 billion barrels of oil and

288 tcf of natural gas as compared with the reference case levels of 41 billion barrels and 210 tcf. As described below, Figure 6-2 illustrates the mix of OCS areas that is currently available and unavailable for leasing and development.

OCS areas	*Crude oil (billion barrels)*	*Natural gas (trillion cubic feet)*
Available for leasing and development		
Eastern Gulf of Mexico	*2.27*	*10.14*
Central Gulf of Mexico	*22.67*	*113.61*
Western Gulf of Mexico	*15.98*	*86.62*
Total available	***40.92***	***210.37***
Unavailable for leasing and development		
Washington-Oregon	*0.40*	*2.28*
Northern California	*2.08*	*3.58*
Central California	*2.31*	*2.41*
Southern California	*5.58*	*9.75*
Eastern Gulf of Mexico	*3.98*	*22.16*
Atlantic	*3.82*	*36.99*
Total unavailable	***18.17***	***77.17***
Total Lower 48 OCS	***59.09***	***287.54***

Figure 6-2
Technically Recoverable Undiscovered Gas in the Lower 48 OCS
(Source: www.eia.dov.gov)

Potential sources of natural gas for Cane Island 4 include the addition of natural gas recovered from available leasing and development areas. Additional sources of natural gas located in the lower 48 OCS present reasonable insurance of adequate availability of natural gas for Cane Island 4.

6.2 Liquefied Natural Gas (LNG)

LNG is natural gas that has been cooled to -260°F at atmospheric pressure, the point at which natural gas condenses to a liquid. When natural gas is converted to a liquid (LNG), its volume is reduced by a ratio of 600 to 1, allowing considerably more natural gas to be stored and shipped in its liquid form. The LNG is stored in double-walled tanks at atmospheric pressure and shipped aboard specially designed LNG storage vessels.

Upon the vessel's arrival at an LNG receiving facility, the LNG is pumped onshore in its liquid state and then stored in permanent double-walled tanks, or it is heated, vaporized, and regulated for temperature and pressure, and delivered as natural gas into a pipeline network. The former method provides the greatest flexibility where the LNG is stored until needed, acting similar in nature to deliveries from natural gas storage. In the latter instance, the gas must be received and used as a supplemental base load supply.

With U.S. natural gas production remaining relatively constant, imports of natural gas are projected to rise to meet an increasing share of domestic consumption. Most of the expected growth in U.S. natural gas imports is in the form of LNG. The LNG market is expected to be tight until 2012, because of supply constraints at a number of liquefaction facilities, delays in the completion of new liquefaction projects, and rapid growth in global LNG demand. The expansion of LNG supplies after 2012 will increase the opportunity for Cane Island 4 to receive natural gas from LNG terminals located in the southeastern United States.

6.2.1 Liquefied Natural Gas in the North America

The United States is the fourth leading importer of LNG in the world. Japan, South Korea, and Spain are the three leading importers of LNG. In 2006, the United States LNG imports totaled 583 Bcf and these imports were sourced from four countries: Trinidad and Tobago, Egypt, Nigeria, and Algeria. By the end of 2006, liquefaction capacity in the Atlantic Basin was about 3,129 Bcf. The increase in the Atlantic Basin's liquefaction capacity is due to expansions in Egypt, Trinidad and Tobago, and Nigeria. As indicated in Section 7.0, Fuel Emissions Allowance Price Projections, natural gas consumption in the United States in expected to increase significantly and most of the expected growth in natural gas consumption is expected to be in the form of LNG. It is anticipated that LNG receiving terminal capacity will increase from 1.4 Tcf in 2005 to 6.5 tcf in 2030.

As illustrated in Figure 6-3, Trinidad and Tobago, Egypt, Nigeria, and Algeria exported 389 Bcf, 120 Bcf, 57 Bcf, and 17 Bcf respectively of LNG to the United States.

Currently, the United States maintains four onshore LNG terminals: Distrigas Facility in Everett, Massachusetts; Dominion Cove Point LNG in Lusby, Maryland; Southern LNG in Elba Island, Georgia; and Trunkline LNG in Lake Charles, Louisiana. The United States also has one off-shore LNG terminal, The Gulf Gateway Energy Bridge. These existing energy terminals are shown in Figure 6-4. The Distrigas facility is owned by Suez, North America and receives the largest volume of any onshore terminal in the United States at 176 Bcf. The daily capacity of the Distrigas facility is 725 MMcf. By comparison, the Dominion Cove LNG facility received 117 Bcf in 2006 and plans are in place to expand the regasification capability of the facility to 657 Bcf by the fall of 2008. StatoilHydro, Shell, and BP currently share the capacity rights to the Dominion Cove LNG facility.

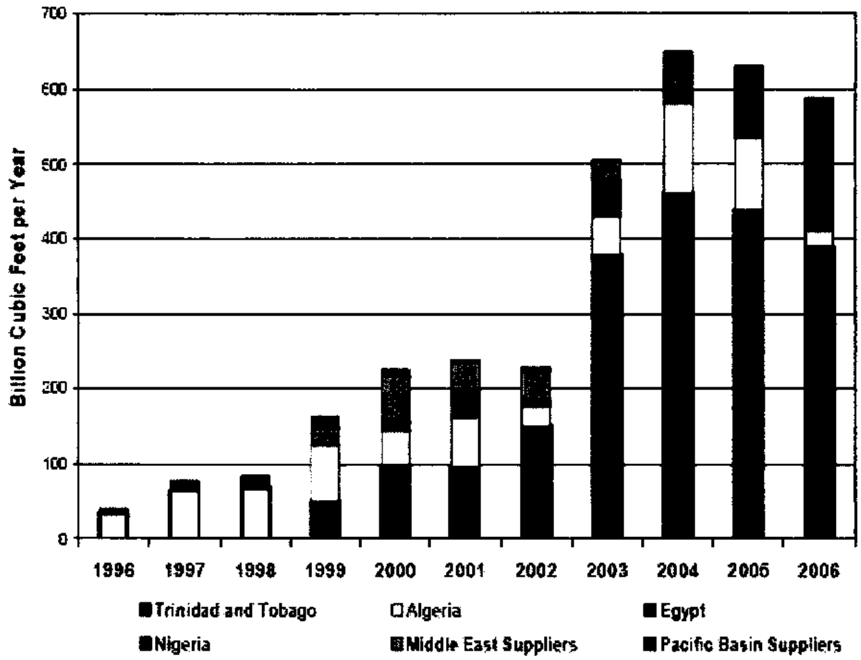

Figure 6-3
Top LNG Exporters to the United States
(Source: www.eia.doe.gov)

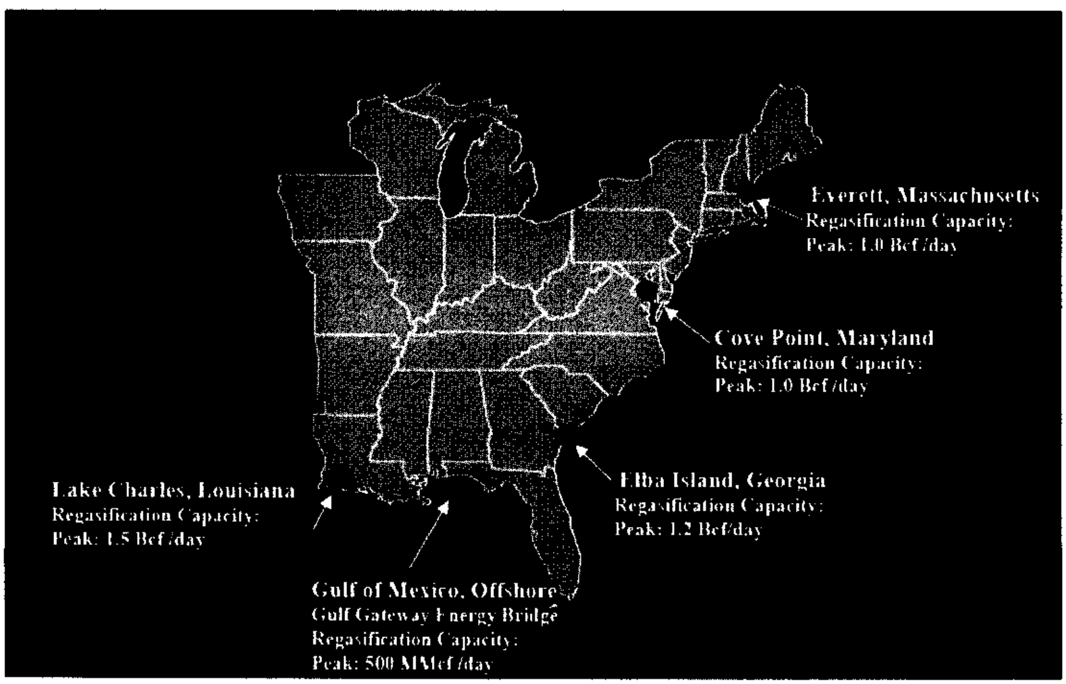

Figure 6-4
Current U.S LNG Import Terminals
(Source: www.eia.doe.gov)

Southern LNG and Trunkline LNG received 147 Bcf and 144 Bcf of LNG respectively in 2006. The United Kingdom based BG Group owns the capacity rights to the Southern and Trunkline LNG facilities. Both facilities have undergone recent expansions and plans are in place to further expand each facility. El Paso Corporation which owns Southern LNG and have formulated a plan to increase its regasification capacity from the current 1.2 Bcf/d to 2.1 Bcf/d by 2010 as well as constructing new pipeline connections to access new markets. The Southern Union Company owns Trunkline LNG which maintains a regasification capacity of 1.8 Bcf/d. Currently, the send out capacity of the Trunkline LNG facility is 0.3 Bcf/d, but plans are in place to increase the send out capacity to 2.1 Bcf/d by 2009.

6.2.2 Existing LNG Importing Countries for North America

The Atlantic LNG facility, located in Port Fortin, Trinidad and Tobago is the primary facility from which the United States receives LNG imports. In 2005, the liquefaction capacity of the Atlantic LNG facility was expanded to 720 Bcf. The expansion entailed the addition of a fourth operational train which is the single largest operational train in the world with the capacity to liquefy 240 Bcf of LNG. In May 1999, the initial imports from the Atlantic LNG facility destined for the United States were delivered to the Distrigas LNG facility in Everett, Massachusetts.

Algeria, which formerly was the largest exporter of LNG supply to the United States, exported a total 17 Bcf of LNG in 2006. This was a drastic reduction from the amount of LNG exported in 2005 of 97 Bcf.

Egypt began exporting LNG to the United States in 2005. During 2005, Egypt exported a total of 73 Bcf to the United States. In 2006, Egypt increased LNG exports to the United States by 47 Bcf or 64.8 percent to a total of 120 Bcf.

Nigeria increased LNG exports to the United States from 8 Bcf in 2005 to 57 Bcf in 2006 after increasing the liquefaction capacity on the Bonny Island facility.

6.2.2.1 Potential LNG Importing Countries for North America. A portion of the future growth in LNG consumption in the United States is anticipated to come from Equatorial Guinea, Norway, and the Middle East. Marathon Oil Corporation has begun operations of an LNG plant on Bioko Islam and deliveries to the United States were anticipated to start in 2007. The BG Group has contracted to market supplies from the one train facility which will be solely focused on the United States.

Additional supplies will arrive from Snohvit LNG project in Norway through a contract with StatoilHydro ASA. The Norwegian firm has contracted capacity for delivery to the Cove Point import terminal in Maryland. LNG deliveries to the terminal are scheduled to commence in 2008.

In the Middle East, Qatargas II is expected to begin operations in mid-2008. The liquefaction capacity of Qatargas II is 720 Bcf which will be solely marketed to markets within the Atlantic Basin.

New supplies are anticipated to come online in Yemen, Russia and Nigeria by early 2009.

6.2.2.2 Construction of New LNG Import Terminals in North America. The United States is expected to have adequate regasification capacity to meet domestic needs, with several existing LNG import terminals increasing capacity and new projects nearing completion. LNG import capacity was about 4.25 Bcf/d at the end of 2006 and about 5.3 Bcf/d at the end of 2007. It is projected that the regasified natural gas send out capacity of onshore facilities could grow to more than 10 Bcf/d by the middle of 2010, with about half of this send out capacity coming from new terminals.

The Freeport LNG terminal on Quintana Island, Texas is nearing completion and will mark the first new onshore terminal in the United States in more than 25 years. Operations are expected to begin in 2008, with deliverability of 1.5 Bcf/d. The terminal is owned by a partnership of Michael S. Smith and ConocoPhillips, Cheniere Energy, Dow Chemical, and Contango Oil and Gas companies. ConocoPhillips has contracted for 500 MMcf/d of the capacity until mid-2009 and 1 Bcf/d thereafter; Dow Chemical, 500 MMcf/d; and Mitsubishi Corp., 150 MMcf/d for 17 years starting in 2009. Freeport LNG has also received approval from the FERC to expand the terminal's regasification capacity to 4.0 Bcf/d, which would make it the largest regasification terminal in the United States.

Cheniere Energy, Incorporated, is nearing completion of its new Sabine Pass LNG terminal in Cameron Parish, Louisiana. That facility will have 2.6 Bcf/d of send out capacity. Total S.A. has reserved 1 Bcf/d of capacity for 20 years, while Chevron Corp. has reserved 700 MMcf/day for 20 years. As with the Freeport LNG terminal, operations are expected to begin in early 2008, and Cheniere Energy has received permission from FERC to expand the LNG terminal to 4.0 Bcf/d.

Sempra Energy's Cameron LNG facility on Lake Charles, Louisiana, is under construction with expected initial capacity of 1.5 Bcf/d and an estimated operation date of late 2008. Italy's Eni SpA has agreed to purchase 0.6 Bcf/d of capacity at the facility for 20 years, while Algeria's Sonantrach, Suez North America, and Merrill Lynch Commodities are nearing final capacity arrangements. While the first phase of construction is ongoing, Sempra has initiated regulatory applications for a second phase of construction that would increase regasification capacity to about 2.7 Bcf/d by 2010.

ExxonMobil has received approval from FERC and has begun construction of its Golden Pass project near Sabine Pass, Texas. In the first phase of operations, Golden Pass, majority owned by Qatar Petroleum, will have the capacity to deliver up to 1 Bcf/d into the pipeline grid. It will likely be employed for receiving LNG from Qatar starting in 2009. ExxonMobil has signed heads of agreement with Qatar for 2 Bcf/d of supply starting in 2009. However, clearly not all of this supply will be directed to the U.S. market.

Two offshore Massachusetts import facilities are being constructed that will provide natural gas to the New England market. Excelerate Energy owns one of the offshore facilities which is located in Massachusetts Bay about 13 miles off the Boston coastline. Northeast Gateway expects to receive its first deliveries in 2008. Additionally, Suez North America is close to starting construction of its Neptune LNG project, located in Federal waters 22 miles northeast of Boston and approximately 10 miles off the coast of Massachusetts' North Shore.

6.2.2.3 Gulf Coast LNG. LNG can be a viable alternative supply source to supplement the more traditional supply alternatives in North America. There are a number of LNG projects in the Gulf Coast area. Figure 6-5 (obtained from FNGA) illustrates the existing and proposed facilities.

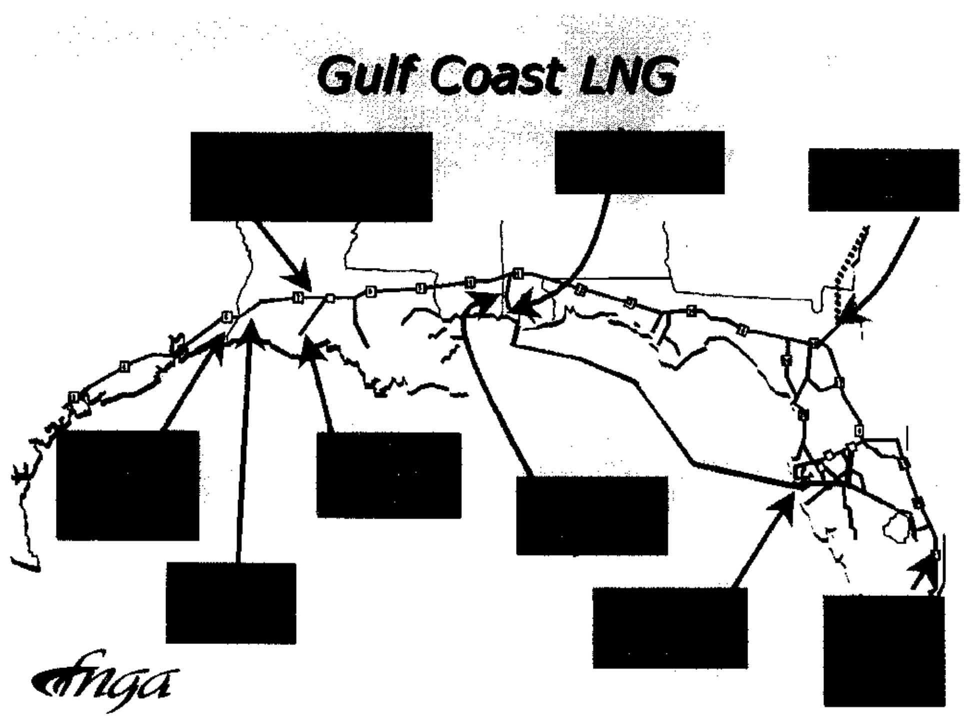

Figure 6-5
Existing & Proposed Gulf Cost LNG Projects
(Source: www.floridagas.org)

There are four viable options to supply Florida directly with LNG, recognizing the pipeline transportation limitations. These four options are: (1) Elba Island with deliveries to FGT via the Cypress pipeline; (2) Gulf LNG Clean Energy Project; (3) the Port Dolphin Project; and (4) the Calypso Project. The first two projects are onshore LNG storage facilities that either exist (Elba Island) or are under construction. The latter two are deep water port facilities that will gasify LNG onboard the delivering vessel. The Gulf LNG Clean Energy Project and the Dolphin Port Project are still obtaining the necessary permits and certifications. The following subsections discuss each of these projects.

6.2.2.3.1 Gulf LNG Clean Energy Project. The Gulf LNG Clean Energy Project is jointly owned. El Paso Corporation owns 50 percent of the facility. The remaining 50 percent is shared by The Crest Group, consisting of Houston-based investors, with a 30 percent ownership in the project, and Sonangol USA with 20 percent. Sonangol is the state-owned national oil company of Angola, responsible for the development of Angola's hydrocarbon resources.

The project received its Federal Energy Regulatory Commission (FERC) certificate in February 2007 and is currently under construction. The terminal includes the construction of two, 160,000 cubic meter storage tanks with a combined capacity of 6.6 billion cubic feet (Bcf); 10 vaporizers, providing a base send-out capacity of 1.3 Bcf/d and five miles of 36-inch pipeline. The pipeline will connect the terminal to Gulfstream, Destin Pipeline, FGT, and Transco. The terminal is expected to be placed into service in late 2011 at an estimated cost of $1.1 billion.

6.2.2.3.2 Elba Island. There is a planned expansion for the Elba Island LNG Terminal. Southern LNG plans to complete the expansion in two phases. Phase I of the project will add one 200,000 cubic meter storage tank which holds 1,250,000 barrels. The new tank will be complete by mid-year of 2010 and will add approximately 4.2 Bcf of LNG storage capacity to the terminal. Maximum send out capacity will be 0.405 Bcf/d. Phase I of the project will also include modifying the north and south docks to accommodate new larger vessels and to facilitate simultaneous unloading of two ships.

Phase II of the project will add an additional 200,000 cubic meter (1,250,000 barrel) storage tank. This tank will add approximately 4.2 Bcf storage capacity to the terminal in 2012 and increase send out by 0.495 Bcf/d. The liquefied natural gas for the expansion will be transported by ship from gas rich regions outside of the United States. Southern LNG's facilities at Elba Island will vaporize the LNG and inject the natural gas into Southern's existing pipeline. Figure 6-6 illustrates the relative proximity of Elba Island to the Cypress Pipeline.

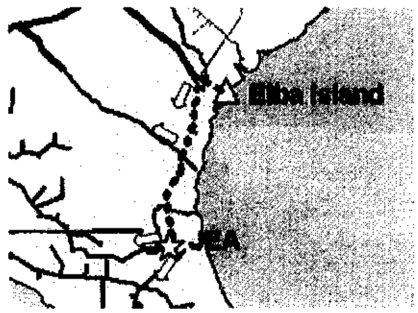

Figure 6-6
Cypress Pipeline
(Source: www.elpaso.com)

6.2.2.3.3 The Calypso System. Calypso LNG LLC (a subsidiary of SUEZ Energy International) is proposing the development of a submerged buoy system known as a "Deep Water Port" (DWP) located approximately 8 to 10 miles off the southeastern coast of Florida. The Calypso DWP will serve as an offshore delivery point for connection to specially built LNG tankers. The LNG tankers will vaporize stored LNG and send it through the buoy system into the FERC-permitted Calypso U.S. Pipeline, which will transport the natural gas onshore to deliver to the FGT system. When the offloading system is not in use, it resides approximately 120 feet under the ocean surface. The DWP will consist of two buoys approximately 2.6 miles apart. The DWP project will be located approximately 8 to 10 miles offshore from Port Everglades.

The Calypso Pipeline is planned to make landfall within Port Everglades and will connect with the existing FGT pipeline system approximately 6 miles inland. The project will be capable of delivering approximately 1 Bcf/d of natural gas directly into the Florida market.

The Maritime Administration (MARAD) and the Coast Guard announced in the Federal Register on November 2, 2007 the availability of the Draft Environmental Impact Statement (DEIS) for the Calypso LNG LLC, Calypso Natural Gas Deepwater Port (Calypso) license application. The application describes a project that would be located in the Federal waters of the Outer Continental Shelf in the OCS NG 17–06 (Bahamas) lease area, approximately 8 to 10 miles off the east coast of Florida to the northeast of Port Everglades, in a water depth of 800 to 950 feet. USCG and MARAD have 240 days from the date of the Notice of Application to hold one or more public license hearings in the adjacent coastal state of Florida. The Governor of Florida must approve, approve with conditions, or deny the DWPA license within 45 days of the last DWPA public hearing. If the Governor does not act within 45 days, approval will be conclusively presumed. Approval or denial of the license application by MARAD must occur not more than 90 days after the last public hearing.

The Environmental Resource Permit (ERP) was issued by the State of Florida to the original project owner (Tractebel) in April 2004. The Calypso Pipeline is one of the 21 US LNG projects approved by FERC.

6.2.2.3.4 Port Dolphin Energy. Port Dolphin Energy LLC, a wholly owned US subsidiary of the Norwegian based company Hoegh LNG AS, is proposing development of a submerged buoy system known as a "Deep Water Port" (DWP) The proposed project would consist of two submerged unloading and mooring buoys to receive an average of up to 800 million cubic feet per day of natural gas from LNG Shuttle and Regasification Vessels (SRVs), which are ocean going LNG vessels designed to regasify the LNG onboard and deliver natural gas to a subsea pipeline. The DWP would be connected to a 42 mile subsea pipeline that would bring the regasified natural gas from the offshore terminal to Port Manatee in Tampa Bay. The pipeline is planned to interconnect with Gulfstream and the facilities of TECO Energy, Inc. (TECO). The proposed offshore terminal would be located approximately 28 miles from the coast. Initial average daily throughput will be approximately 400 MMBtu/d of natural gas will have a capacity of 800 MMBtu/d of natural gas with peak delivery capacity of approximately 1.2 Bcf/d of natural gas.

Port Dolphin filed its DWPA with the USCG in March 2007 and expects the approval process for the Deepwater Port License and associated permits will take approximately 18 months. Construction of the proposed project would consist of two phases with operations of Port Dolphin beginning in the second quarter of 2011.

6.3 Natural Gas Reserves

The United States had 211,085 billion cubic feet of dry natural gas proved reserves as of December 31, 2006, the highest level since 1976. Proved reserves of natural gas increased by 3 percent from 2005 to 2006.

Texas led the nation in natural gas reserves additions in 2006 with a 9 percent increase in dry gas proved reserves due to rapid development of Barnett Shale reservoirs in the Newark East Field. Advances in horizontal drilling and hydraulic fracturing technology and relatively high natural gas prices supported this development. Alaska and Utah were second and third for dry natural gas proved reserves additions in 2006. Total U.S. reserves additions replaced 136 percent of 2006 dry gas production as illustrated in Figure 6-7.

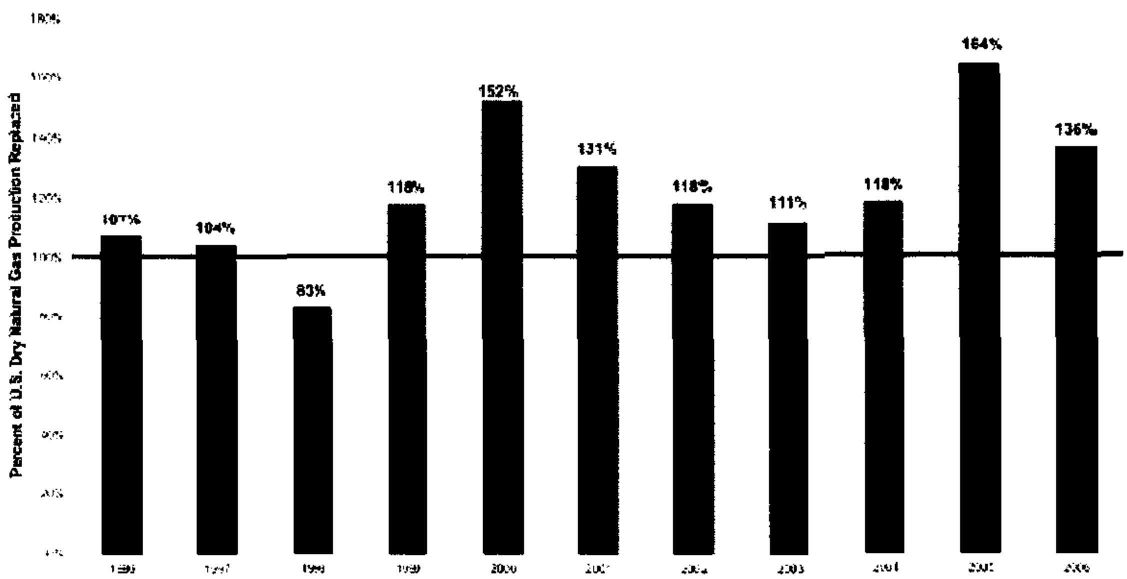

Figure 6-7
Replacement of Dry Natural Gas Productions by Reserve Additions 1996 - 2006
(Source: www.eia.dov.gov)

The proved reserves by State are shown on the map in Figure 6-8. Eight areas accounted for 81 percent of the Nation's dry natural gas proved reserves which amounts to about 171,000 bcf. The highest concentration of natural gas reserves clusters around the Gulf Coast states. Also, highest potential production of natural gas clusters around the Gulf Coast states. Strong potential exist in transporting natural gas reserves on the Transco Pipeline into the FRCC region making the necessary connection onto the Gulfstream Pipeline. Figure 6-8 illustrates the proved natural gas reserves in North America.

6.3.1 Natural Gas Demand

As established in the AEO2007 reference case, current natural gas prices are sufficiently high to reduce growth in consumption. The combination of increased natural gas supply, slower growth in demand, and the technological improvement in the development of other fuel resources leads to a decline in natural gas prices through 2013 as forecasted in the AEO2007 reference case. After 2013, wellhead natural gas prices increase largely as a result of rising costs, as technically recoverable U.S. natural gas resources decline from the current level. Figure 6-9 illustrates technically recoverable U.S natural gas resources as of January 1, 2005 in tcf.

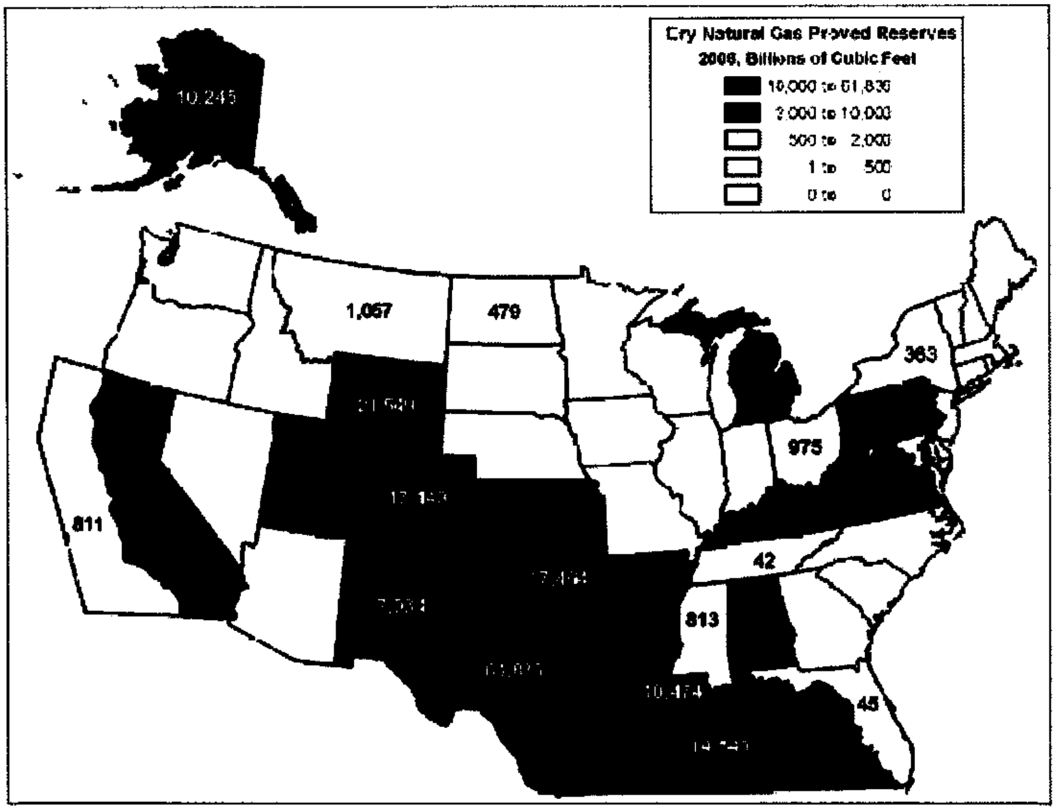

Figure 6-8
Dry Natural Gas Proved Reserves
(Source: www.eia.dov.gov)

Proved	Unproved	Total
192.5	1,148.5	1,341.0

Figure 6-9
Technically Recoverable U.S. Natural Gas Resources
(Source: www.eia.doe.gov)

Total natural gas consumption in the United States is projected to increase from 22.0 tcf in 2005 to 26.1 tcf in 2030 in the AEO2007 reference case. As outlined in the AEO2007 reference case, a portion of natural gas consumption will utilize LNG as the primary source of fuel. Much of the growth is expected before 2020, with demand for natural gas in the electric power sector growing from 5.8 tcf in 2005 to a peak of 7.2 tcf. Natural gas use in the electric power sector is projected to decline after 2020, to 5.9 tcf in 2030, as new coal-fired generating capacity displaces natural-gas-fired generation. Much of the projected decline in natural gas consumption for electricity generation results from higher delivered prices for natural gas in the reference case projection after 2020.

Continued growth in residential, commercial, and industrial consumption of natural gas is roughly offset by the projected decline in natural gas demand for electricity generation. As a result, overall natural gas consumption is almost flat between 2020 and 2030 in the AEO2007 reference case, and the natural gas share of total projected energy consumption drops from 23 percent in 2005 to 20 percent in 2030.

As forecast in the AEO2007 reference case, the growth in total U.S. generation fuel by natural gas and the reduction in natural gas consumption due to additional sources of fuel and fuel development technologies will create an unmatched capacity to demand relationship over the forecast period. The unmatched capacity to demand relationship will create additional sources of available natural gas that can be available to supply Cane Island 4.

6.4 Natural Gas Pipeline and Storage

Natural gas storage facilities are being developed along the Gulf Coast in numerous locations. The southeastern states of the United States account for approximately 38,127 of pipeline mileage with the State of Florida accounting for 4,746 miles of pipeline. As illustrated in Figure 6-10, Florida's total pipeline capacity is 3,600 MMcf/d based on the total capacity of all the pipelines that serve the Florida market. The total Florida pipeline capacity is served by four companies: Florida Gas Transmission, GulfSouth Pipeline, Gulfstream NG System, and Southern Natural Gas. These four pipelines will provide adequate natural gas transportation capacity along with the existing and proposed storage facilities will provide adequate transportation and storage capacity for the Florida market.

6.4.1 Natural Gas Storage Facilities in Florida

There are three facilities that can provide immediate benefit to the Florida market due to their respective locations. Figure 6-11 provides an overview of many of these developments (provided by FNGA).

Line	Description	Region		State		County		Capacity [1]
		From	To	From	To	From	To	MMcf/d
1	Florida Gas Trans Co	Southeast	Southeast	AL	FL	Escambia	Santa Rosa	2,224
2	Gulf South Pipeline Co	Southeast	Southeast	AL	FL	Baldwin	Escambia	125
3	Gulf South Pipeline Co	Southeast	Southeast	AL	FL	Baldwin	Escambia	45
4	Gulf South Pipeline Co	Southeast	Southeast	AL	FL	Escambia	Escambia	20
5	Gulfstream NG System	Southeast	Southeast	AL	FL	Mobile	Manatee	1,130
6	Southern Natural Gas Co	Southeast	Southeast	GA	FL	Decatur	Gadsden	9
7	Southern Natural Gas Co	Southeast	Southeast	GA	FL	Lowndes	Hamilton	47
8	**Total**							**3,600**

Note:
1. The capacity denotes the pipeline capacity for the State of Florida at the end of 2006.

Figure 6-10
Florida Pipeline Capacity
(Source: www.eia.doe.gov)

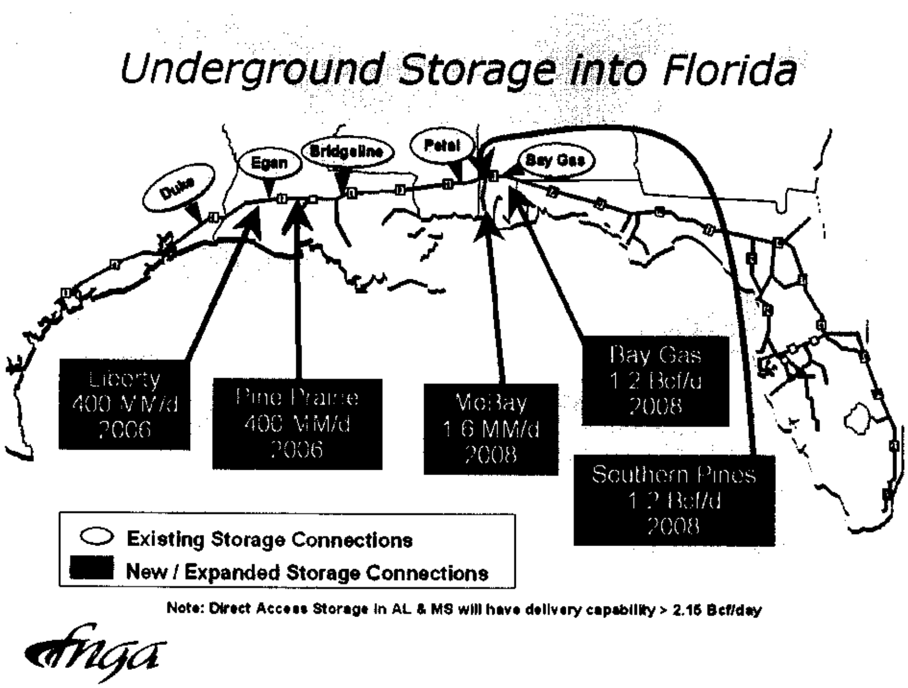

Figure 6-11
Underground Storage into Florida
(Source: www.floridagas.org)

6.4.1.1 Southern Pines Energy Center. Southern Pines Energy Center is being developed as a FERC-regulated natural gas storage facility. The project site has the capability to develop up to five 8 Bcf caverns for a total working gas capacity of 40 Bcf. Currently the project is constructing a 16.0 Bcf multi-cycle natural gas storage facility consisting of two underground storage caverns, each capable of storing up to 8.0 Bcf each. The first cavern entered commercial operation May 1, 2008 and the second is scheduled for commercial operation later in the year. A third cavern is planned for 2008 with commercial operation in 2010.

The natural gas storage facilities will include:

- Three salt caverns capable of storing 24 Bcf in an underground salt-dome (with the capability of constructing two additional caverns for a total of 5 caverns and 40.0 Bcf of storage capacity).
- Above ground facilities with 48,000 horsepower of compression for the three storage caverns and with 1.6 Bcf/d of maximum withdrawal capability and 0.8 Bcf/d of maximum injection capability. This configuration enables Southern Pines to cycle its working gas capacity a maximum of 12 times per year, thus providing its customers with the ultimate flexibility to quickly balance operational flows and meet peaking demands.
- Southern Pines will initially have direct interconnects to three existing interstate pipelines, Destin Pipeline Company ("Destin"), Florida Gas Transmission Company ("FGT") and Transcontinental Gas Pipe Line Corporation ("Transco"). An interconnection with the Southeast Supply Header is scheduled for service in second quarter 2008 as that pipeline is constructed.

FMPA will have 1 Bcf of capacity in this facility by the time that Cane Island 4 is constructed. This storage will provide significant capabilities for daily operations and provide supply back-up during times of supply interruptions. Figure 6-12 illustrates a map of the Southern Pines Energy Center.

6.4.1.2 MoBay Storage Hub LLC. MoBay Storage Hub LLC will provide high-deliverability, multi-cycle (HDMC) gas storage services to the Southeast market. Located at the confluence of major market and supply area pipeline systems, MoBay would initially connect with four major interstate pipelines systems serving the Southeast and Northeast markets. Currently, the combined pipeline take-away capacity at MoBay is 6.9 Bcf/d to the east and 3.9 Bcf/d to the west. MoBay would be the most southeasterly HDMC storage facility in the United States and the only storage facility directly connected to the Gulfstream Natural Gas System. The proposed MoBay compressor station will be located directly adjacent to Gulfstream Station 410 in Mobile County, Alabama. Working gas capacity will be 50 Bcf with maximum injection and withdrawal capability of 1 Bcf per day.

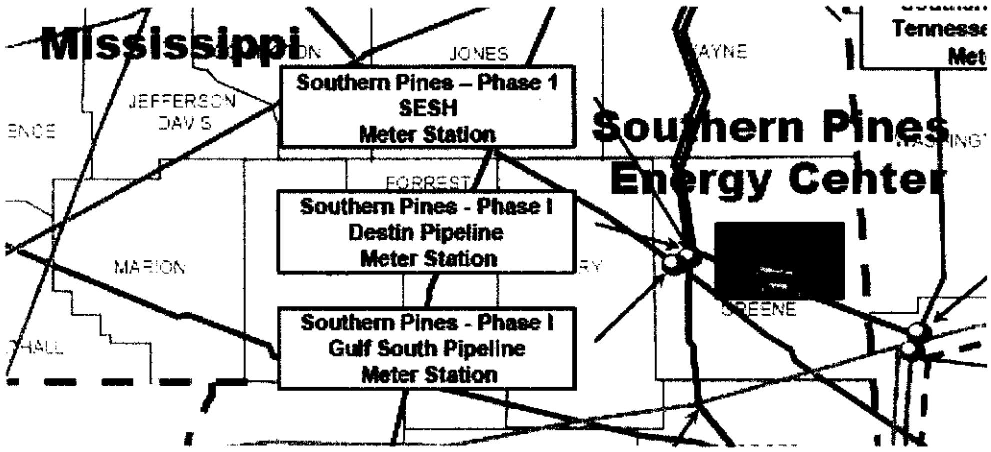

Figure 6-12
Southern Pines Energy Center
(Source: www.sgr-holdings.com)

Figure 6-13 illustrates the relative proximity of the Mobay Storage Hub to the relative gas pipeline interconnections.

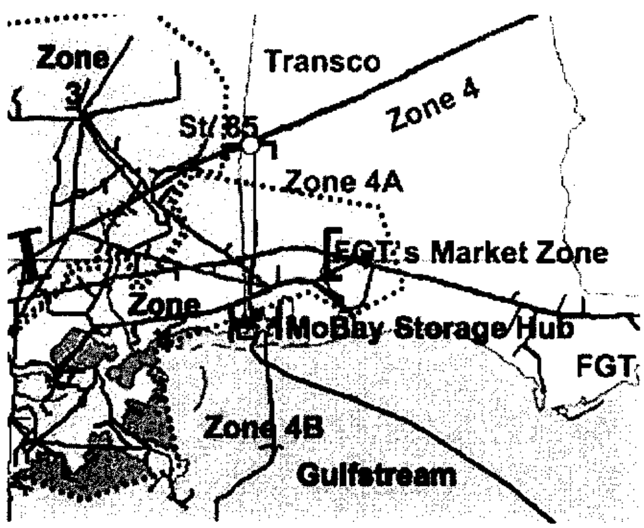

Figure 6-13
MoBay Storage Hub
(Source: www.falcongasstorage.com)

6.4.1.3 Bay Gas Storage. Bay Gas Storage is owned by EnergySouth Midstream, Inc. is based in Houston, Texas. Bay Gas currently operates two high-deliverability natural gas salt dome storage caverns with a combined total working gas capacity of 6.0 Bcf. Total injection capacity at the facility is 200 MMcf/d and withdrawal capacity is 610 MMcf/d.

A third storage cavern is currently under development and is expected to be operational by the spring of 2008 and will add approximately 5.0 Bcf of working gas capacity. Injection capacity at cavern three will be 250 MMcf/d and withdrawal capacity will be 600 MMcf/d. Total working gas capacity will increase from 6.0 Bcf to 11.0 Bcf upon completion of the third cavern. Figure 6-14 illustrates a map of the Bay Gas Storage Facility.

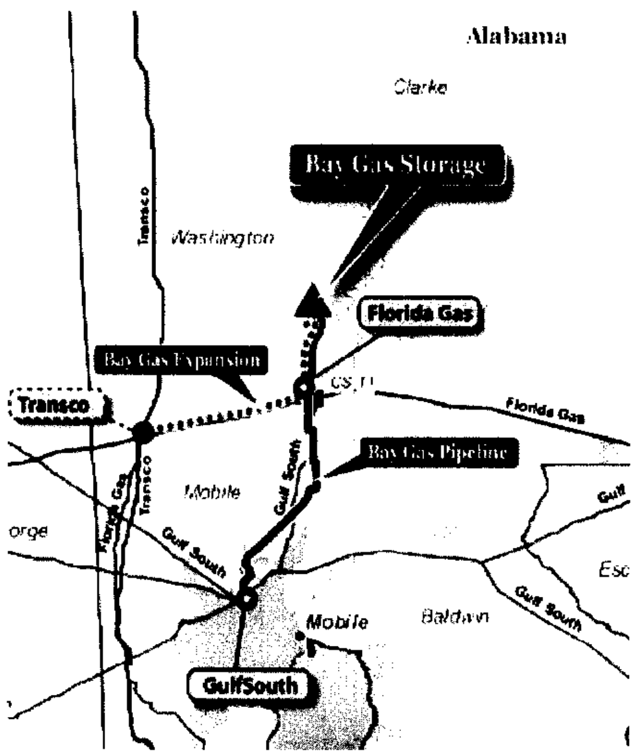

Figure 6-14
Bay Gas Storage Facility
(Source: www.esmidstream.com)

6.5 Southeast Supply Header

The Southeast Supply Header, LLC (SESH) is a joint venture between subsidiaries of CenterPoint Energy, Inc. and Spectra Energy. The 270 mile, 36 inch and 42 inch diameter pipeline has an estimated capacity of 1 Bcf/d. The pipeline will extend from the Perryville Hub in northeastern Louisiana to Gulfstream in southern Mobile County, Alabama and will have two interconnects with FGT, the combination of which will have a capacity of over 1 Bcf/d.

SESH will link the onshore natural gas supply basins of east Texas and northern Louisiana to Southeast markets now predominantly served by offshore natural gas supplies from the Gulf of Mexico. This pipeline will give customers an important alternative to offshore supply, which can be vulnerable to weather-related disruptions. The pipeline is scheduled for first deliveries in August, 2008. Figure 6-15 illustrates a map of the Southeast Supply Header route.

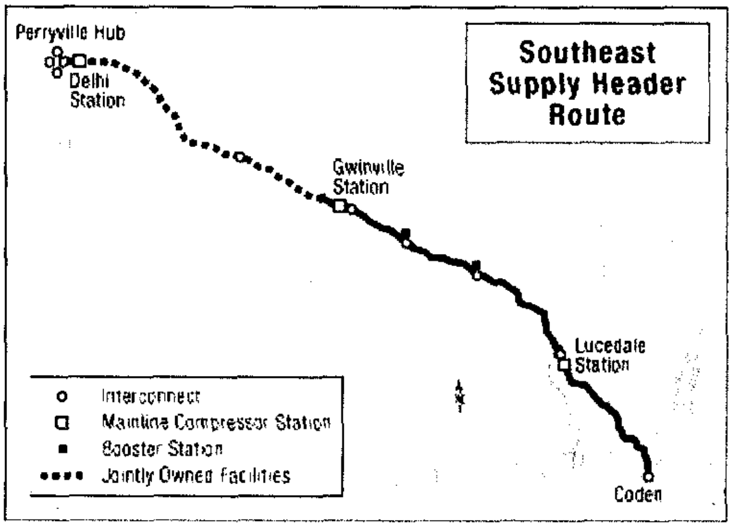

Figure 6-15
Southeast Supply Header Route Pipeline

6.5.1 *Floridian Natural Gas Storage Company*

The Floridian Natural Gas Storage Company LLC (FGS) facility is expected to be located in an industrial area near Indiantown in Martin County, FL. The FGS facility will ultimately consist of two above-ground liquid natural gas storage tanks each capable of storing up to 4 Bcf of natural gas, refrigeration compressors to cool the gas, and re-gasification equipment. Natural gas will be delivered to and from FGS using both the FGT and Gulfstream natural gas pipeline systems. FGS is expected to begin commercial operation in mid-2011.

FGS will be regulated by the FERC. In October 2007, FGS filed an abbreviated application pursuant to section 7(c) of the Natural Gas Act (NGA) and Parts 157 and 284 of FERC's regulations for a certificate of public convenience and necessity to construct and operate the FGS project; a blanket certificate to perform certain routine activities and operations; and a blanket certificate to provide open access storage services. The proposed project is currently under FERC review with a target decision date of October 23, 2008.

The addition of down stream storage facilities will effectively increase the capacities of the FGT/Gulfstream systems.

6.6 Summary of Natural Gas Availability

As discussed in the previous sections, while conventional production in the lower 48 states is projected to decline slightly, the natural gas industry has many alternatives available to ensure a reliable supply of natural gas for Cane Island 4. These include production in the outer continental shelf, production in Alaska, and delivery via pipeline to the lower 48 states. While the Alaskan gas may not be delivered directly to Cane Island 4, it will displace the use of other gas, allowing that gas to be delivered to Cane Island. In addition to domestic production, there is a robust LNG marketing developing along with associated delivery and storage systems. The United States has sufficient reserves to serve Cane Island 4 and these reserves are consistently being replaced as the gas has been consumed.

Natural gas storage facilities are being constructed which will allow for better management of gas volumes and increases in surety of supply. In addition, projects are under way to better provide for gathering of gas to the pipelines that serve Cane Island.

In total, ample natural gas is available to ensure a reliable supply for Cane Island 4.

7.0 Fuel and Emissions Allowance Price Projections

This section discusses the methodology used to develop projections for the prices of natural gas, distillate and residual fuel oils, and coal specific to the Florida Reliability Coordinating Council (FRCC) region that are considered in this Application. In addition to the reference case price projections, high and low price projections have been developed as well. The analyses presented throughout this Application also consider projections of emissions allowance prices. Development of these emissions allowance price projections are presented in this section as well.

7.1 Importance of Fully Integrated Fuel and Emissions Allowance Price Projections

The fuel and emissions allowance price projections considered throughout this Application (whether for the reference case, high case, low case, or the case in which existing and potential new emissions, such as CO_2, are treated as regulated emissions) represent fully integrated forecasts. That is, fuel price, supply, and demand are considered in tandem with potential costs associated with regulation of various emissions, along with numerous other market influences to develop fully integrated projections of fuel and emissions allowance prices. This is important for all scenarios considered, but especially so when considering the potential impacts associated with regulation of CO_2.

Regulations of emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg) are reflected in all of the fuel price projections considered throughout this Application. While there is currently no state or federal regulation of CO_2 emissions, several bills to regulate emissions of CO_2 (and other greenhouse gases) have been proposed to the 110th US Congress. As such, this Application considers potential regulation of CO_2 emissions as outlined in Sections 7.7 and 7.8.

7.2 Description of 2007 US Energy Information Administration Annual Energy Outlook Reference Case

The fuel price projections for natural gas, fuel oil, and coal used in this Application were developed based on those included in the US Energy Information Administration (EIA) Annual Energy Outlook 2007 (AEO2007). The AEO2007 presents projections of energy supply, demand, and prices through the year 2030. The projections presented within the AEO2007 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics. The discussion of the fuel price projections presented within this section is intended to be an overview of the AEO2007 and, therefore, focuses on the more salient aspects of the AEO2007 and elaborates on relevant conclusions and projections. The AEO2007 can be found on the EIA website at http://www.eia.doe.gov/oiaf/archive/aeo07, while documentation related to the EIA's NEMS program is located at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model%20documentation.

7.2.1 Consideration of State and Federal Legislation and Regulations in AEO2007

Analyses developed by the EIA are required to be policy neutral. Therefore, the projections in the AEO2007 are based on federal and state laws and regulations in effect on or before October 31, 2006 (with few exceptions). As stated in the AEO2007, the potential impacts of pending or proposed legislation, regulations, and standards – or of sections of legislation that have been enacted, but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself – are not reflected in the projections.

The AEO2007 does consider potential impacts of both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). The CAIR and CAMR were promulgated by the US Environmental Protection Agency (EPA) in March 2005 and published in the *Federal Register* as final rules in May 2005. CAIR will limit emissions of SO_2 and NO_x from power plants in the United States, while CAMR will limit emissions of Hg from power plants in the United States. Both the CAIR and CAMR are represented as regional cap-and-trade programs in AEO2007, as the document was developed before final decisions were made regarding the structure of state programs and participation in regional trading programs related to CAIR and CAMR.

7.3 AEO2007 Reference Case FRCC Natural Gas, Fuel Oil, and Coal Price Projections

The AEO2007 Reference Case forecast prices for natural gas and fuel oil delivered to the FRCC region are presented in Table 7-1[1]. Forecasts of prices for low sulfur Central Appalachian coal delivered to the Georgia/Florida region are presented in Table 7-2[2]. The fuel price projections shown in Tables 7-1 and 7-2 are presented in constant 2005 dollars per million British Thermal Units (MBtu). For the economic analysis presented in Section 20.0 of this Application, the fuel price projections were converted from those values shown in Tables 7-1 and 7-2 to nominal dollars per MBtu by applying the 2.3 percent general inflation rate.

The natural gas price projections presented in Table 7-1 represent the AEO2007 projections for natural gas delivered to the FRCC region and do not include any usage charges or any costs for firm or interruptible natural gas transportation. Discussion of how such costs were considered and factored into the economic analysis is presented in Section 19.3 of this Application.

Table 7-2 only presents forecast prices for coal delivered to the Georgia/Florida region from the Central Appalachia coal production region. Although the EIA provided forecast prices for coals from other production regions, this Application only considers coal delivered from Central Appalachia. The analyses presented throughout this Application assumes that low sulfur Central Appalachian coal will continue to be burned in Stanton Energy Center Units 1 and 2, which FMPA receives capacity from as described in Section 3.0 of this Application. These are the only solid fuel generating units (either existing or considered for capacity additions) evaluated in this Application.

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[1] Regional fuel price projections, such as those shown in Table 7-1 for FRCC, are not included in the AEO2007 report itself, but are available on the EIA Web site as Supplemental Tables (http://www.eia.doe.gov/oiaf/aeo/supplement/index.html). The FRCC fuel price projections corresponding to the AEO2007, from which the data in Table 7-1 were extracted, are presented in Supplemental Table 69.

[2] Supplemental Table 69 to the AEO2007, referenced previously, only presents forecasts of prices for coal delivered to the FRCC region on a composite basis (i.e. a single coal price forecast, with no differentiation between coal type/production region). EIA was able to provide forecast prices for coal delivered to the Georgia/Florida region from various coal production regions upon request. These projections are factored into the overall modeling and analysis used to generate the coal price projection shown in Supplemental Table 69 to the AEO2007.

Table 7-1
Annual Energy Outlook 2007 Reference Case Price Projections
Forecast of Natural Gas and Fuel Oil Delivered to the
Florida Reliability Coordinating Council Boundary(1)

Year	Natural Gas (2005 \$/MBtu) (2)	Distillate Fuel Oil (2005 \$/MBtu) (3)	Residual Fuel Oil (2005 \$/MBtu)
2007	7.65	16.12	8.48
2008	7.25	13.76	7.90
2009	6.69	12.67	7.26
2010	6.40	11.73	6.77
2011	5.92	10.91	6.39
2012	5.78	10.26	6.04
2013	5.64	9.48	5.87
2014	5.67	9.39	5.70
2015	5.61	9.45	5.78
2016	5.77	9.50	5.77
2017	5.96	9.67	5.89
2018	5.97	9.77	5.93
2019	5.98	9.95	6.10
2020	6.06	10.04	6.18
2021	6.02	10.16	6.30
2022	6.13	10.31	6.42
2023	6.22	10.28	6.35
2024	6.38	10.44	6.49
2025	6.37	10.48	6.52
2026	6.40	10.54	6.61
2027	6.49	10.72	6.65
2028	6.59	10.81	6.69
2029	6.63	10.97	6.80
2030	6.62	11.04	6.85

(1) Based on data presented in Supplemental Table 69 to the AEO2007 Reference Case.
(2) Natural gas price projections do not include usage charges or firm or interruptible transportation charges within the state. These costs are accounted for in the economic analysis as discussed in Section 19.0 of this Application.
(3) Distillate fuel oil price projections reflect the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004, which requires sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 parts per million (ppm) starting in mid-2007. NRLM also establishes a new ultra-low sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010.

Table 7-2
Annual Energy Outlook 2007 Reference Case Price Projections
Forecast of Low Sulfur Central Appalachian Coal Delivered to the Georgia/Florida Region[(1)]

Year	Low Sulfur Central Appalachian[(2)] (0.54 lb S/MBtu) (2005 $/MBtu)
2007	2.89
2008	2.88
2009	2.88
2010	2.93
2011	2.96
2012	2.88
2013	2.88
2014	2.90
2015	2.87
2016	2.87
2017	2.84
2018	2.75
2019	2.69
2020	2.68
2021	2.66
2022	2.70
2023	2.70
2024	2.70
2025	2.69
2026	2.67
2027	2.66
2028	2.66
2029	2.66
2030	2.67

(1) Based on data received directly from the EIA.
(2) EIA price projections for Central Appalachian coal delivered to the Georgia/Florida region only extend through 2017, as the AEO2007 Reference Case assumes production from the Eastern Interior region, as well as imports, will contribute to the decline in Appalachia's share of the market east of the Mississippi. Beyond 2017, prices were developed on the basis of minemouth projections from the AEO2007 Reference Case and the assumption that transportation costs will remain constant in 2005 dollars.

7.4 AEO2007 High and Low Price Case Natural Gas, Fuel Oil, and Coal Price Projections

The AEO2007 includes various cases in addition to the Reference Case. Each of these cases incorporates various changes to the reference case assumptions. Of the various cases considered by the EIA as part of the AEO2007, two cases are considered in this Application in addition to the Reference Case – the High Price Case and the Low Price Case. Both the High Price Case and the Low Price Case rely on assumptions consistent with the Reference Case, with the exception of assumptions related to crude oil and natural gas resources. The High Price Case reflects more pessimistic assumptions related to these resources, while the Low Price Case reflects more optimistic assumptions. Both the High Price and Low Price Cases are fully integrated NEMS simulations, consistent with the Reference Case.

The natural gas, fuel oil, and coal price projections corresponding to the AEO2007 High Price Case are presented in Table 7-3. For comparison purposes, the AEO2007 Reference Case price projections for natural gas, fuel oil, and coal are also presented in Table 7-3. Figures 7-1 through 7-4 present graphical comparisons of the High Price Case and Reference Case price projections shown in Table 7-3.

The natural gas, fuel oil, and coal price projections corresponding to the AEO2007 Low Price Case are presented in Table 7-4. For comparison purposes, the AEO2007 Reference Case price projections for natural gas, fuel oil, and coal are also presented in Table 7-4. Figures 7-5 through 7-8 present graphical comparisons of the Low Price Case and Reference Case price projections shown in Table 7-4.

The price projections in Tables 7-3 and 7-4 (and corresponding Figures 7-1 through 7-8) are not specific to the FRCC region. The following section discusses the methodology used to develop high and low fuel price projections specific to FRCC.

Table 7-3
Natural Gas, Fuel Oil, and Coal Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

Year	Natural Gas - Henry Hub (2005 $/MBtu)		Fuel Oil - Electric Power (2005 cents/gallon) Distillate		Fuel Oil - Electric Power (2005 cents/gallon) Residual		Coal - Average Minemouth (2005 $/MBtu)	
	High Price Case	Reference Case	High Price Case	Reference Case	High Price Case	Reference Case	High Price Case	Reference Case
2007	7.31	7.23	199.97	197.82	109.52	107.69	1.18	1.18
2008	7.52	7.17	195.84	190.97	114.25	109.20	1.17	1.17
2009	7.17	6.60	190.79	176.19	114.29	104.67	1.17	1.16
2010	6.91	6.28	188.46	162.34	113.69	98.51	1.20	1.18
2011	6.74	5.83	184.27	149.50	116.94	92.91	1.19	1.16
2012	6.35	5.66	181.07	139.11	123.80	88.36	1.18	1.14
2013	6.28	5.49	180.65	128.84	130.24	81.69	1.16	1.13
2014	6.33	5.52	187.99	127.56	137.99	81.63	1.15	1.12
2015	6.36	5.46	194.16	128.43	144.79	83.82	1.15	1.11
2016	6.52	5.56	199.90	128.67	148.93	84.26	1.15	1.10
2017	6.72	5.78	203.56	130.93	156.07	85.88	1.15	1.09
2018	6.50	5.68	208.40	132.24	162.44	87.03	1.15	1.08
2019	6.21	5.62	209.00	135.24	164.01	89.92	1.16	1.08
2020	6.46	5.71	212.74	136.51	168.32	91.05	1.17	1.08
2021	6.71	5.71	210.46	138.13	169.76	93.25	1.19	1.09
2022	6.82	5.85	212.52	140.22	170.59	96.08	1.20	1.08
2023	7.10	5.98	211.25	139.76	173.43	94.59	1.20	1.08
2024	7.16	6.15	212.93	141.71	175.85	97.81	1.21	1.09
2025	7.29	6.14	211.92	142.21	178.37	98.50	1.22	1.09
2026	7.54	6.17	212.93	143.11	180.36	99.35	1.22	1.10
2027	7.69	6.25	213.87	145.43	181.53	100.81	1.22	1.11
2028	7.88	6.39	215.82	146.63	187.07	101.01	1.23	1.13
2029	8.04	6.48	216.21	148.95	186.41	102.53	1.23	1.13
2030	8.27	6.52	221.08	149.59	188.14	102.49	1.25	1.15

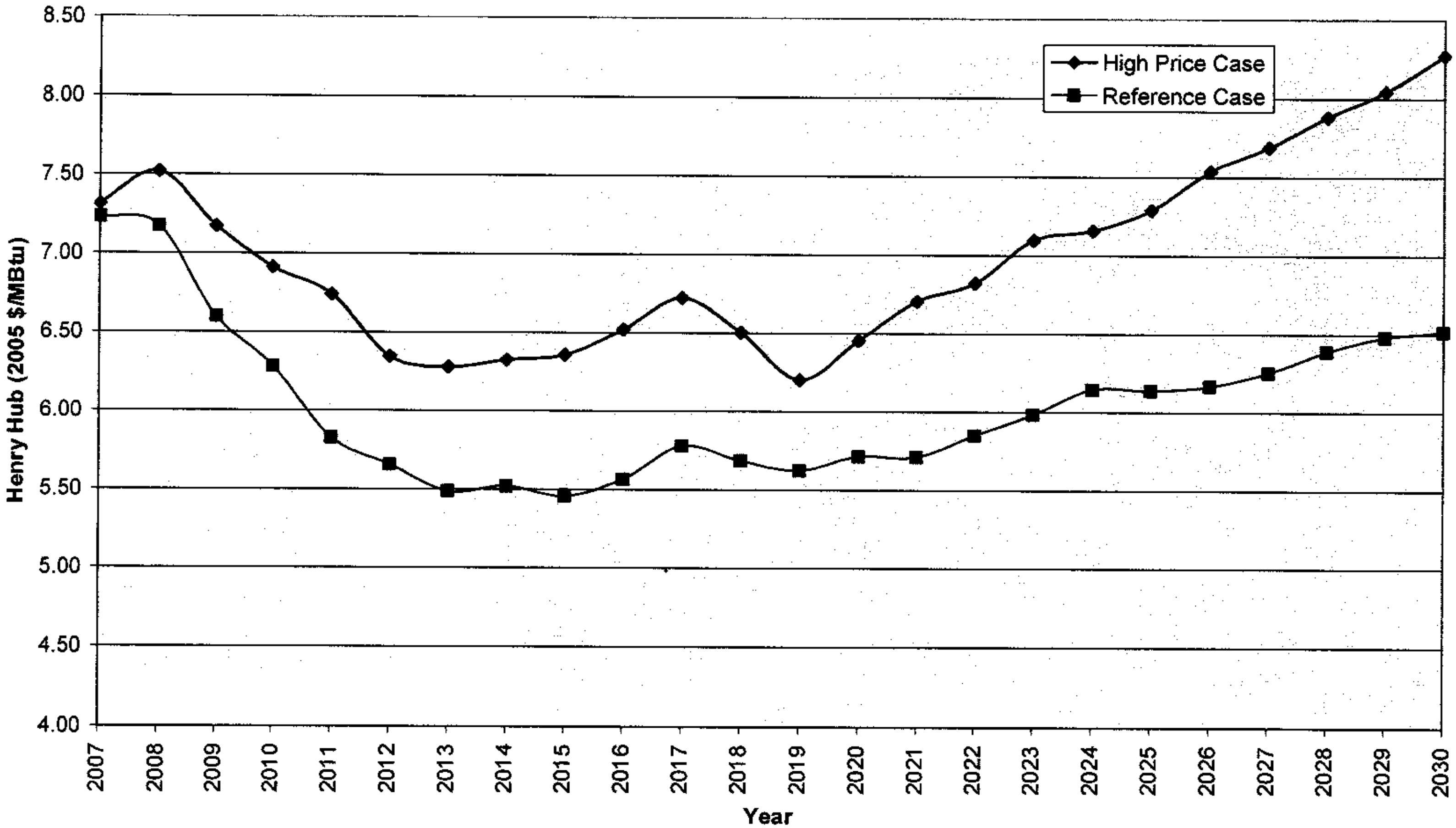

Figure 7-1
Comparison of Natural Gas Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

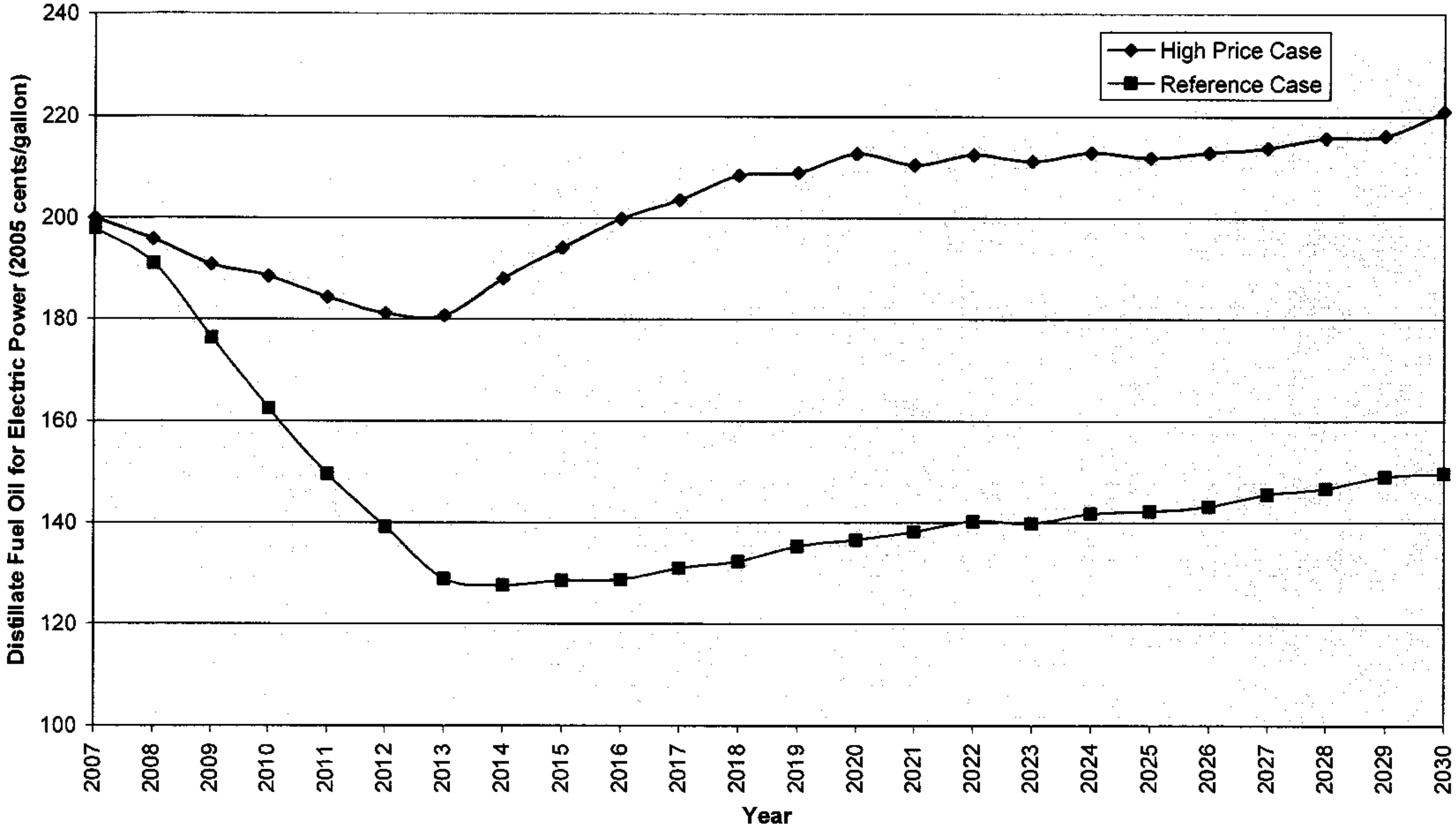

Figure 7-2
Comparison of Distillate Fuel Oil Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

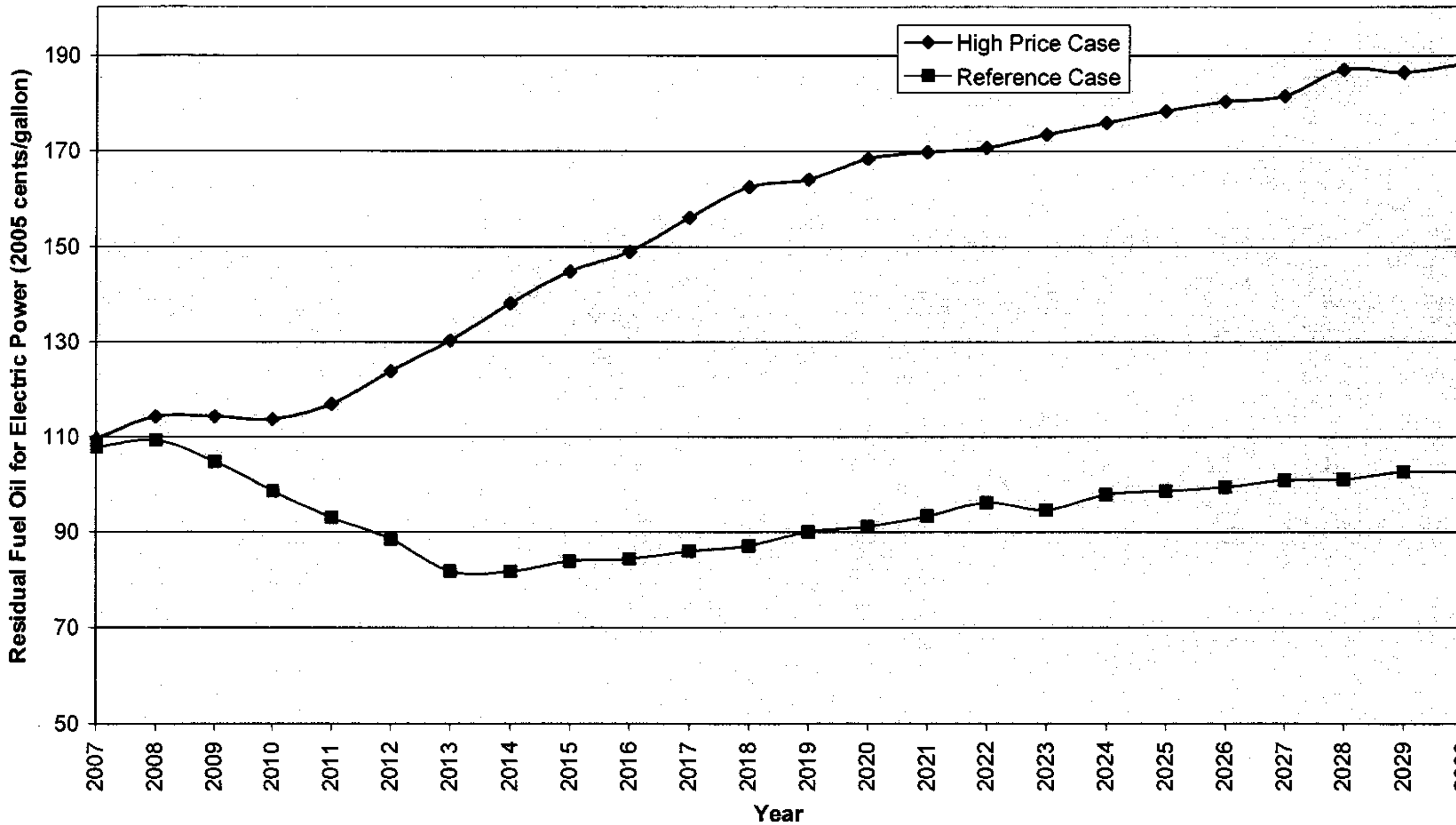

Figure 7-3
Comparison of Residual Fuel Oil Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

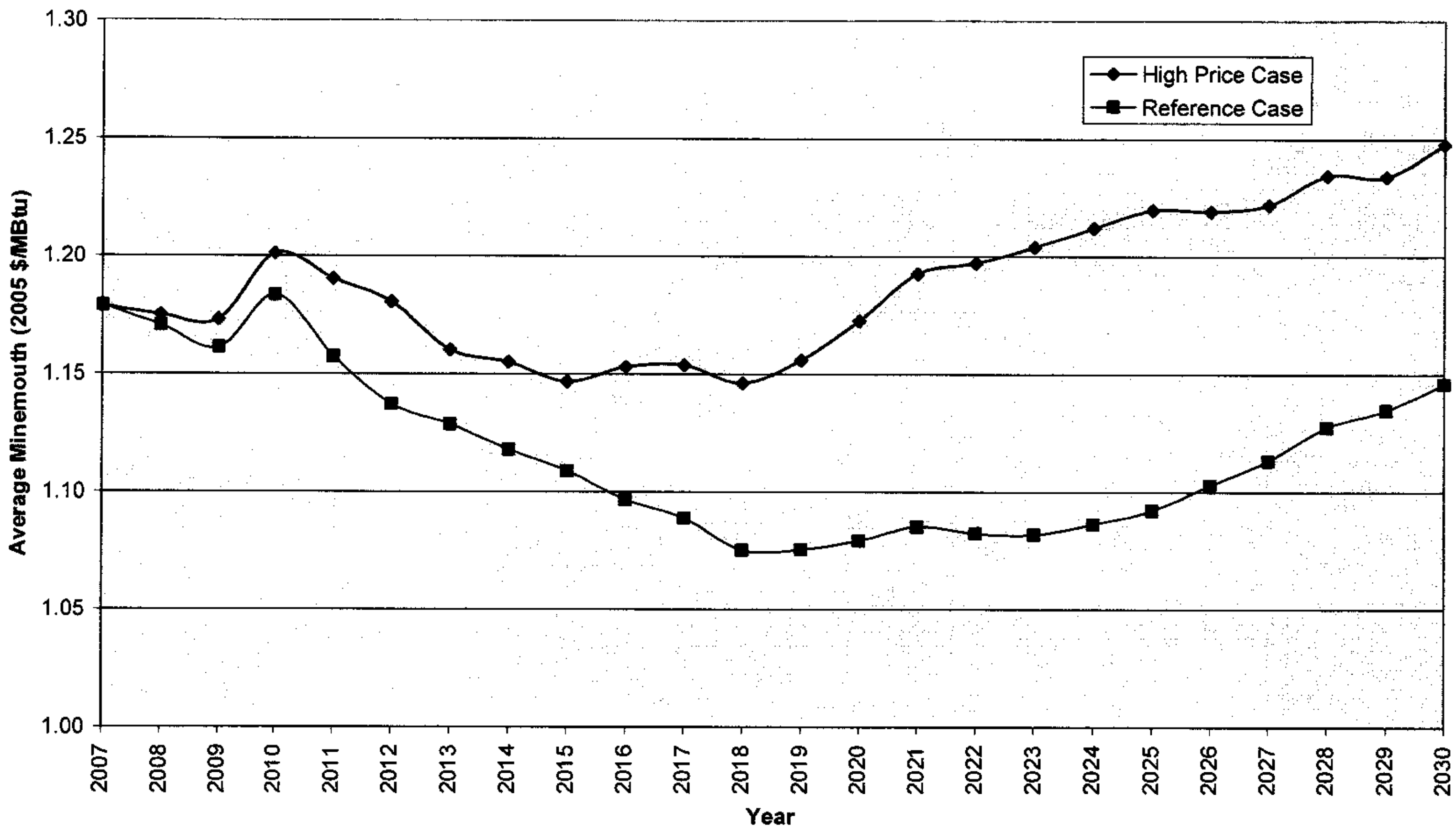

Figure 7-4
Comparison of Coal Price Projections
AEO2007 High Price Case and AEO2007 Reference Case

Table 7-4
Natural Gas, Fuel Oil, and Coal Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

Year	Natural Gas - Henry Hub (2005 $/MBtu)		Fuel Oil - Electric Power (2005 cents/gallon)				Coal - Average Minemouth (2005 $/MBtu)	
			Distillate		Residual			
	Low Price Case	Reference Case	Low Price Case	Reference Case	Low Price Case	Reference Case	Low Price Case	Reference Case
2007	6.99	7.23	197.77	197.82	107.81	107.69	1.18	1.18
2008	6.86	7.17	179.64	190.97	107.62	109.20	1.16	1.17
2009	6.12	6.60	154.68	176.19	97.02	104.67	1.14	1.16
2010	5.62	6.28	130.91	162.34	84.38	98.51	1.16	1.18
2011	5.23	5.83	112.16	149.50	73.79	92.91	1.13	1.16
2012	4.87	5.66	95.04	139.11	62.94	88.36	1.10	1.14
2013	4.59	5.49	84.14	128.84	58.27	81.69	1.08	1.13
2014	4.52	5.52	78.54	127.56	55.16	81.63	1.07	1.12
2015	4.41	5.46	75.42	128.43	53.12	83.82	1.05	1.11
2016	4.54	5.56	74.13	128.67	52.10	84.26	1.05	1.10
2017	4.61	5.78	70.12	130.93	52.88	85.88	1.03	1.09
2018	4.62	5.68	69.20	132.24	52.50	87.03	1.02	1.08
2019	4.66	5.62	71.92	135.24	52.65	89.92	1.01	1.08
2020	4.66	5.71	70.34	136.51	52.61	91.05	1.01	1.08
2021	4.82	5.71	70.75	138.13	53.29	93.25	1.01	1.09
2022	5.01	5.85	72.15	140.22	53.86	96.08	1.01	1.08
2023	5.06	5.98	72.53	139.76	53.57	94.59	1.01	1.08
2024	5.25	6.15	73.93	141.71	55.15	97.81	1.01	1.09
2025	5.20	6.14	78.01	142.21	56.31	98.50	1.00	1.09
2026	5.31	6.17	75.40	143.11	56.48	99.35	1.00	1.10
2027	5.38	6.25	75.86	145.43	55.77	100.81	1.00	1.11
2028	5.43	6.39	74.83	146.63	56.40	101.01	1.01	1.13
2029	5.47	6.48	74.72	148.95	54.79	102.53	1.01	1.13
2030	5.53	6.52	75.36	149.59	55.02	102.49	1.02	1.15

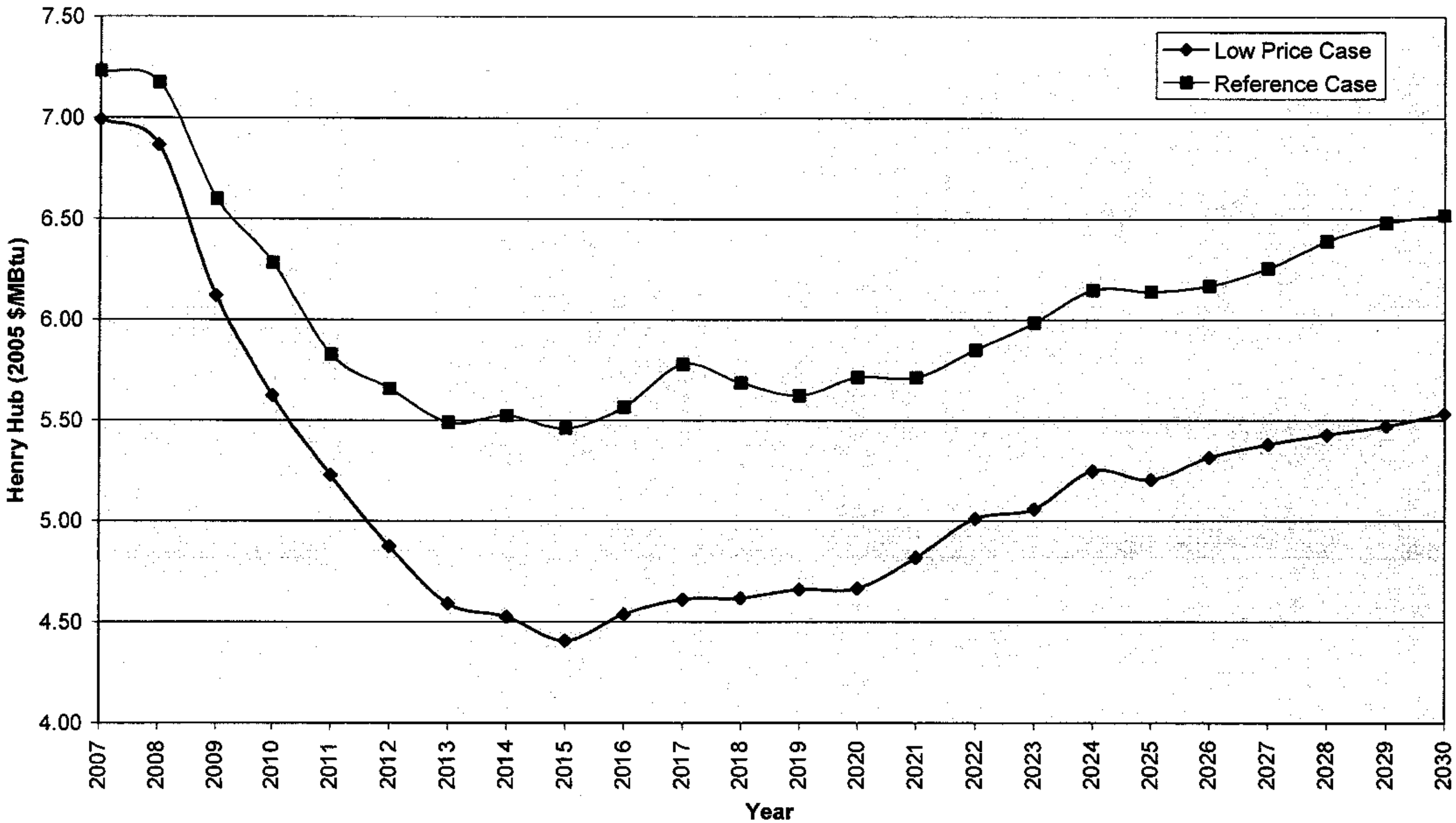

Figure 7-5
Comparison of Natural Gas Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

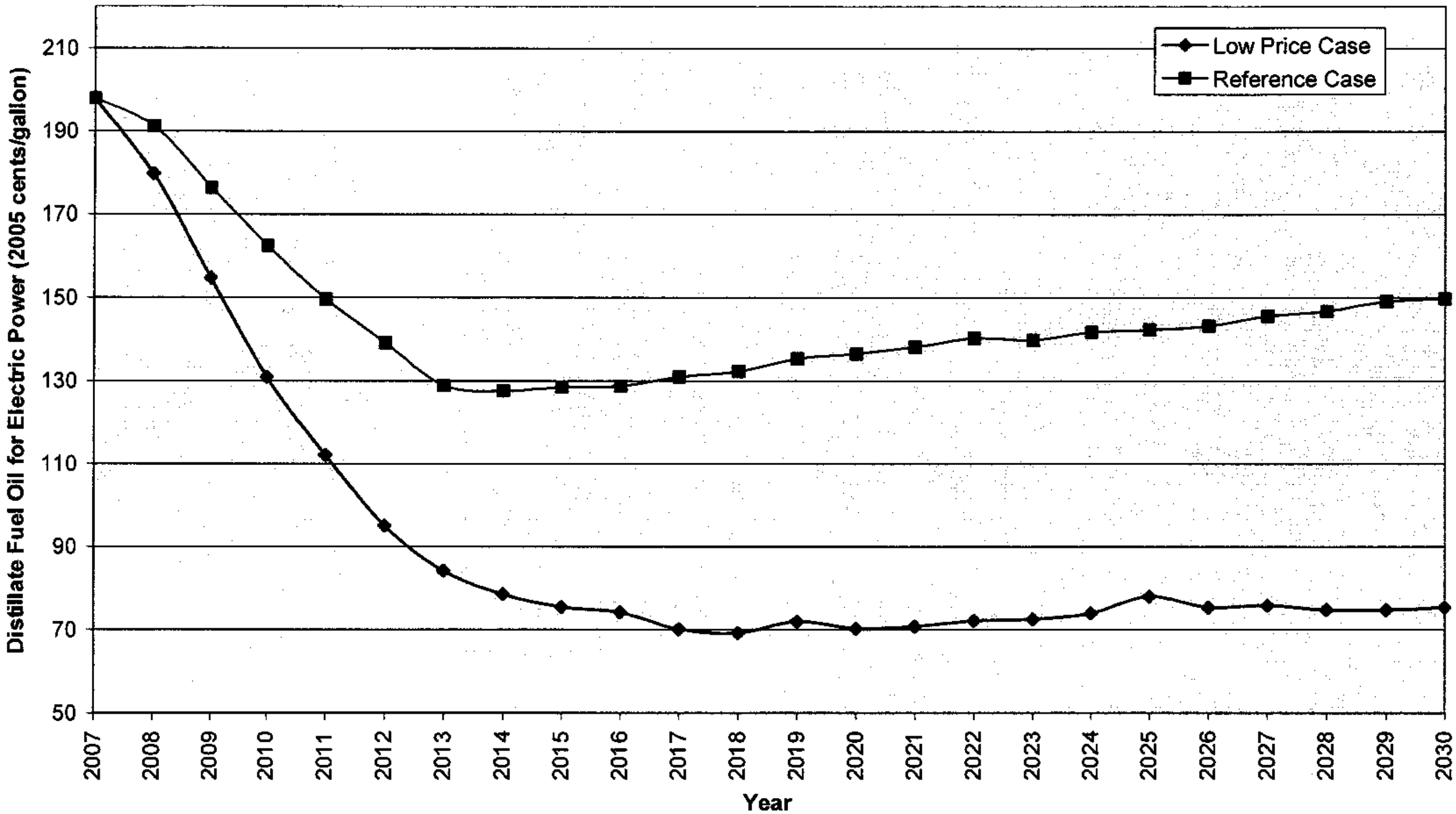

Figure 7-6
Comparison of Distillate Fuel Oil Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

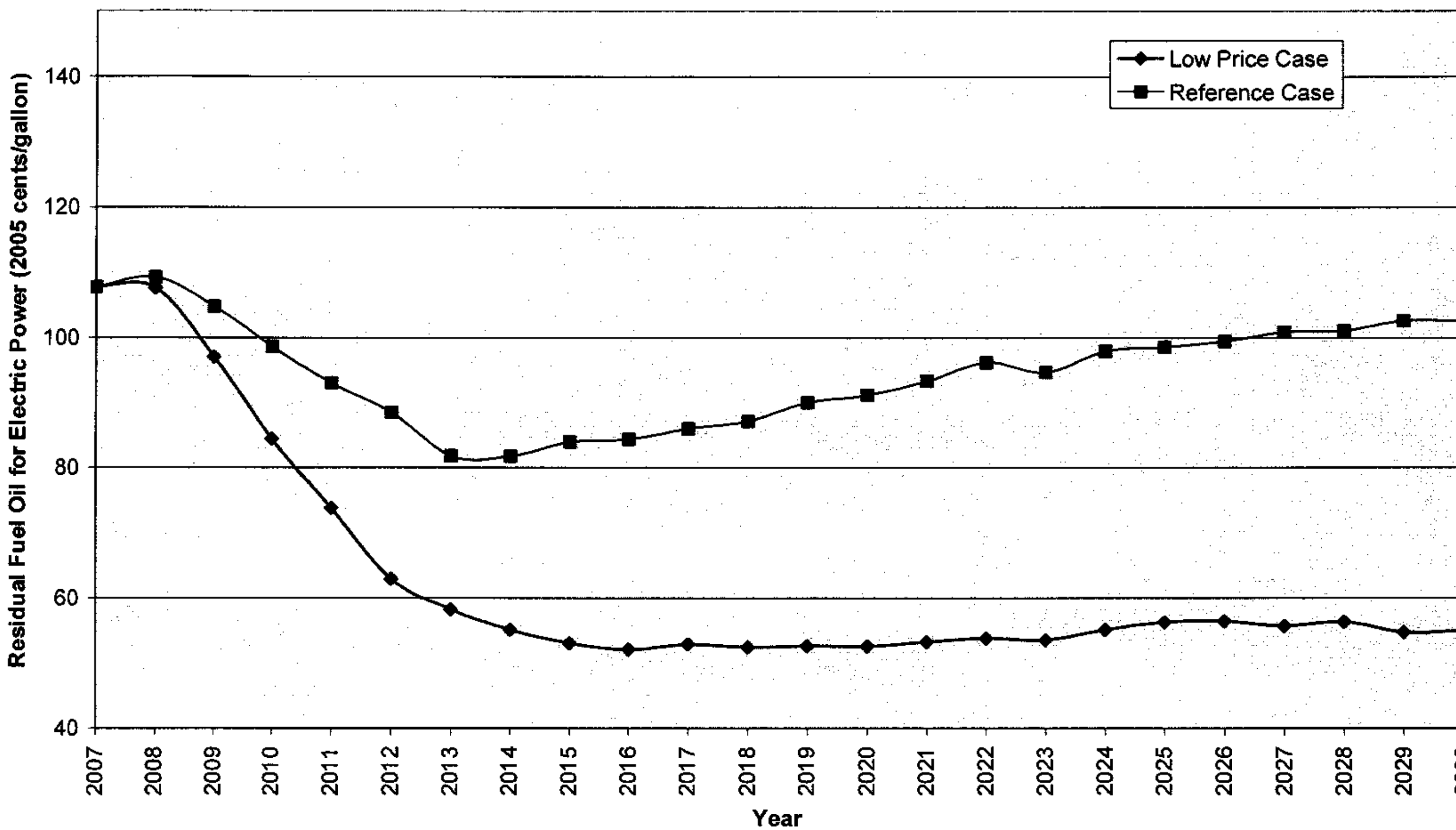

Figure 7-7
Comparison of Residual Fuel Oil Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

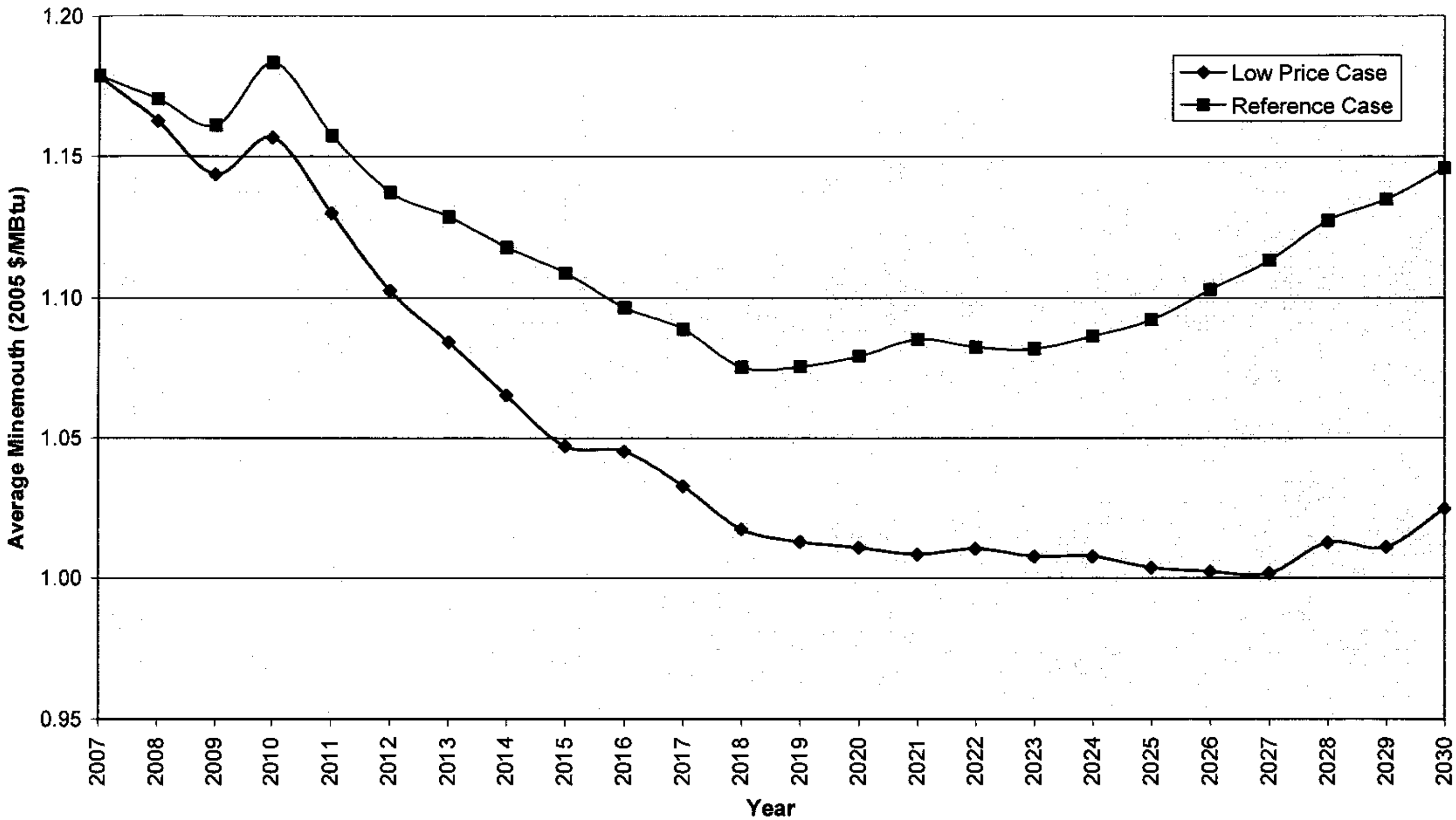

Figure 7-8
Comparison of Coal Price Projections
AEO2007 Low Price Case and AEO2007 Reference Case

7.5 FRCC High and Low Fuel Price Projections

As discussed in Section 7.4, the AEO2007 included High Price Case and Low Price Case fuel projections. Both the High and Low Price Case projections were developed on a national basis and, are therefore, not specific to the FRCC region. Adjustments were made to the High Price Case and Low Price Case natural gas, fuel oil, and coal price projections to develop high and low fuel price projections specific to the FRCC region. The following subsections discuss the methodology used to develop the FRCC-specific high and low fuel price projections and present the resulting annual natural gas, fuel oil, and coal price projections. Consideration of any additional intrastate transportation cost is discussed in Section 19.0.

7.5.1 High Fuel Price Projections for FRCC

7.5.1.1 High Natural Gas Prices. To develop natural gas price projections for the FRCC region, based on the AEO2007 High Price Case, the AEO2007 Reference Case natural gas price projections were analyzed to determine the annual differential between the FRCC-specific natural gas price projections presented in Table 7-1 and the Reference Case Henry Hub natural gas price projections presented in Table 7-3. The annual price differentials between natural gas delivered to the FRCC region and natural gas at Henry Hub derived from the Reference Case were held constant and added to the AEO2007 High Price Case Henry Hub natural gas price projections shown in Table 7-3. The resulting high natural gas price projections, specific to the FRCC region, are presented in Table 7-5.

7.5.1.2 High Distillate and Residual Fuel Oil Prices. High price projections for distillate and residual fuel oil, specific to the FRCC region, were developed by first converting the AEO2007 High Price and AEO2007 Reference Case projections (presented in Table 7-3) from cents per gallon to dollars per MBtu. The conversions were made by using the heat contents for distillate (138,690 Btu per gallon) and residual (149,690 Btu per gallon) used by the EIA. The annual transportation differentials for distillate and residual fuel oil between the AEO2007 Reference Case for the FRCC region (presented in Table 7-1) and for electric power usage in the United States as a whole (presented in Table 7-3) were determined. These annual transportation differentials for distillate and residual fuel oil were added to the AEO2007 High Price Case projections shown in Table 7-3 (after being converted to dollars per MBtu using the heat contents referenced previously). The resulting high distillate and residual fuel oil price projections, specific to the FRCC region, are presented in Table 7-5.

Table 7-5
Annual Energy Outlook 2007 High Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council(1)

Year	Natural Gas (2005 $/MBtu)(2)	Distillate Fuel Oil (2005 $/MBtu)	Residual Fuel Oil (2005 $/MBtu)	Low Sulfur Central Appalachian (0.54 lb S/MBtu) (2005 $/MBtu)
2007	7.74	16.27	8.60	2.89
2008	7.60	14.11	8.24	2.88
2009	7.26	13.72	7.90	2.89
2010	7.03	13.61	7.78	2.95
2011	6.84	13.42	8..00	2.99
2012	6.47	13.29	8.41	2.92
2013	6.43	13.22	9.11	2.91
2014	6.47	13.75	9.47	2.94
2015	6.52	14.19	9.85	2.91
2016	6.73	14.64	10.09	2.93
2017	6.90	14.91	10.58	2.90
2018	6.79	15.26	10.97	2.82
2019	6.56	15.27	11.05	2.77
2020	6.80	15.54	11.34	2.77
2021	7.02	15.38	11.41	2.77
2022	7.11	15.52	11.40	2.81
2023	7.33	15.43	11.62	2.82
2024	7.39	15.58	11.70	2.83
2025	7.53	15.51	11.86	2.82
2026	7.77	15.57	12.02	2.79
2027	7.93	15.65	12.04	2.77
2028	8.09	15.80	12.44	2.77
2029	8.19	15.82	12.40	2.76
2030	8.38	16.19	12.57	2.77

(1) Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (High Price Case), Table 13 (Reference Case), and Table 13 (High Price Case) in the AEO2007.
(2) Natural gas price projections do not include usage charges or intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 19.0 of this Application.

7.5.1.3 High Central Appalachian Coal Prices. The AEO2007 Reference Case Central Appalachian minemouth coal prices (annual dollars per ton)[3] were divided by the heat content of Central Appalachian coal (MBtu per ton),[4] resulting in Reference Case minemouth prices specific to Central Appalachian coal on a dollar per MBtu basis.

The AEO2007 Reference Case average minemouth coal prices for the United States were subtracted from the AEO2007 High Case average minemouth coal prices for the United States (each of which are presented in Table 7-3) to give an annual differential from the Reference Case to the High Case average US minemouth coal prices. This annual differential was applied to the Reference Case minemouth prices, specific to the Central Appalachian coal described above, to yield annual High Case minemouth prices, specific to Central Appalachian coal, on a dollar per MBtu basis.

An annual delivery adder (dollar per MBtu basis) that represents the cost of delivering Central Appalachian coal from the minemouth to the FRCC region was derived by calculating the difference between the annual Reference Case Central Appalachian minemouth prices and the AEO2007 Reference Case Central Appalachian coal prices for delivery to the FRCC Region. This annual delivery adder was applied to the High Case Central Appalachian coal minemouth prices, resulting in the High Price Case projections for Central Appalachian coal delivered to the FRCC region, which are presented in Table 7-5.

7.5.2 Low Fuel Price Projections for the FRCC

7.5.2.1 Low Natural Gas Prices. To develop natural gas price projections for the FRCC region, based on the AEO2007 Low Price Case, the AEO2007 Reference Case natural gas price projections were analyzed to determine the annual differential between the FRCC-specific natural gas price projections presented in Table 7-1 and the Reference Case Henry Hub natural gas price projections presented in Table 7-4. The annual price differentials between natural gas delivered to the FRCC region and natural gas at Henry Hub (derived from the Reference Case) were held constant and added to the AEO2007 Low Price Case Henry Hub natural gas price projections shown in Table 7-4. The resulting low natural gas price projections, specific to the FRCC region, are presented in Table 7-6.

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[3] http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_113.xls
[4] Table 71, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/coal.pdf

Table 7-6
Annual Energy Outlook 2007 Low Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council[(1)]

Year	Natural Gas (2005 $/MBtu)[(2)]	Distillate Fuel Oil (2005 $/MBtu)	Residual Fuel Oil (2005 $/MBtu)	Low Sulfur Central Appalachian (0.54 lb S/MBtu) (2005 $/MBtu)
2007	7.41	16.12	8.49	2.89
2008	6.95	12.94	7.79	2.87
2009	6.21	11.12	6.75	2.86
2010	5.74	9.46	5.83	2.90
2011	5.33	8.22	5.11	2.93
2012	4.99	7.08	4.34	2.85
2013	4.74	6.26	4.31	2.84
2014	4.67	5.86	3.93	2.85
2015	4.56	5.63	3.73	2.81
2016	4.74	5.57	3.62	2.82
2017	4.79	5.29	3.69	2.78
2018	4.90	5.22	3.62	2.69
2019	5.02	5.38	3.61	2.63
2020	5.01	5.27	3.61	2.61
2021	5.13	5.30	3.63	2.58
2022	5.29	5.40	3.60	2.63
2023	5.29	5.43	3.61	2.63
2024	5.48	5.55	3.64	2.62
2025	5.44	5.85	3.70	2.60
2026	5.55	5.66	3.75	2.57
2027	5.62	5.70	3.64	2.55
2028	5.63	5.63	3.71	2.55
2029	5.62	5.62	3.61	2.54
2030	5.64	5.69	3.68	2.55

[(1)] Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (Low Case), Table 13 (Reference Case), and Table 13 (Low Price Case) in the AEO2007.
[(2)] Natural gas price projections do not include usage charges or intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 19.0 of this Application.

7.5.2.2 Low Distillate and Residual Fuel Oil Prices. Low Price projections for distillate and residual fuel oil, specific to the FRCC region, were developed by first converting the AEO2007 Low Price and AEO2007 Reference Case projections (presented in Table 7-4) from cents per gallon to dollars per MBtu. The conversions were made by using the heat contents for distillate (138,690 Btu per gallon) and residual (149,690 Btu per gallon) used by the EIA. The annual transportation differentials for distillate and residual fuel oil between the AEO2007 Reference Case for the FRCC region (presented in Table 7-1) and for electric power usage in the United States as a whole (presented in Table 7-4) were determined. These annual transportation differentials for distillate and residual fuel oil were added to the AEO2007 Low Price Case projections shown in Table 7-4 (after being converted to dollars per MBtu using the heat contents referenced previously). The resulting low distillate and residual fuel oil price projections, specific to the FRCC region, are presented in Table 7-6.

7.5.2.3 Low Central Appalachian Coal Prices. The AEO2007 Reference Case Central Appalachian minemouth coal prices (annual dollars per ton)[5] were divided by the heat content of Central Appalachian coal (MBtu per ton),[6] resulting in Reference Case minemouth prices specific to Central Appalachian coal on a dollars per MBtu basis.

The AEO2007 Low Case average minemouth coal prices for the United States were subtracted from the AEO2007 Reference Case average minemouth coal prices for the United States (each of which are presented in Table 7-3) to give an annual differential from the Reference Case to the Low Case average US minemouth coal prices. This annual differential was applied to the Reference Case minemouth prices, specific to Central Appalachian coal described above, to yield annual Low Case minemouth prices, specific to Central Appalachian coal, on a dollar per MBtu basis.

An annual delivery adder (dollar per MBtu basis) that represents the cost of delivering Central Appalachian coal from the minemouth to the FRCC region was derived by calculating the difference between the annual Reference Case Central Appalachian minemouth prices and the AEO2007 Reference Case Central Appalachian coal prices for delivery to the FRCC region. This annual delivery adder was applied to the Low Case Central Appalachian coal minemouth prices, resulting in the Low Price Case projections for Central Appalachian coal delivered to the FRCC region, which are presented in Table 7-6.

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[5] http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_113.xls

[6] Table 71, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/coal.pdf

7.6 US Energy Information Administration Annual Energy Outlook 2007 Emissions Allowance Price Projections

As discussed in Subsections 7.6.1 and 7.6.2, the AEO2007 considers the potential impact of both CAIR and CAMR[7]. In addition to factoring the possible impacts of CAIR and CAMR into the fuel price projections, forecasts of emissions allowance prices for the emissions regulated by CAIR (SO_2 and NO_x) have been developed by the EIA. The emissions allowance price projections discussed in the remainder of this subsection were provided directly by the EIA and correspond to the assumptions used throughout the AEO2007 Reference Case.

The AEO2007 Reference Case projects a decrease in emissions of SO_2 from electricity generation on a nationwide basis, with SO_2 emissions projected to decrease from 10.2 million short tons in 2005 to 3.6 million short tons in 2030. The decrease in SO_2 emissions is due to both the use of lower sulfur coals as well as projected additions of flue gas desulfurization (FGD) equipment. AEO2007 projects a decrease in NO_x emissions from the electric power sector from 3.6 million short tons in 2005 to 2.3 million short tons in 2030. The decrease in NO_x emissions is due primarily to projected additions of selective catalytic reduction (SCR) equipment.

Table 7-7 presents the forecasts of SO_2 and NO_x emissions allowance prices that correspond to the AEO2007 Reference Case. Under CAIR, SO_2 emissions will be regulated beginning in 2010, while NO_x emissions will be regulated beginning in 2009. Table 7-7 presents emissions allowance prices beginning in 2009 for NO_x and 2010 for SO_2. The emissions allowance price projections shown in Table 7-7 are presented in constant 2005 dollars. For the economic analysis discussed in Section 20.0 of this Application, the SO_2 and NO_x emissions allowance price projections were converted from those values shown in Table 7-7 to nominal dollars by applying the 2.3 percent general inflation rate.

[7] Subsequent to completion of the AEO2007, the Federal District of Columbia Circuit Court of Appeals vacated the CAMR in a decision issued February 8, 2008. Since this Application does not consider the addition of any coal fired generating units as future resource alternatives, the impact of the current uncertainty associated with regulation of Hg emissions is insignificant in the analyses presented throughout this Application. Costs associated with emissions of Hg are not considered in this Application.

Table 7-7
Annual Energy Outlook 2007 Reference Case Price Projections Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions[1]

Year	SO_2 (2005 $/ton)	NO_x (2005 $/ton)
2009	N/A	2,418.26
2010	638.68	2,515.04
2011	668.61	2,597.21
2012	763.16	2,554.95
2013	830.88	2,492.67
2014	857.12	2,540.85
2015	907.46	2,435.00
2016	984.29	2,585.31
2017	996.25	2,375.41
2018	1,018.47	2,590.91
2019	1,010.27	2,585.00
2020	1,041.84	2,548.46
2021	971.79	2,750.34
2022	1,056.70	2,876.16
2023	1,095.09	2,900.99
2024	1,077.72	3,052.68
2025	1,074.07	3,117.82
2026	1,078.38	3,135.95
2027	1,040.12	3,137.37
2028	950.09	3,052.77
2029	881.57	3,134.10
2030	815.49	3,306.56

(1) Based on data received directly from the EIA.

7.6.1 AEO2007 High Case Emissions Allowance Price Projections

Table 7-8 presents the forecasts of SO_2 and NO_x emissions allowance prices that correspond to the AEO2007 High Price Case. Under CAIR, SO_2 emissions will be regulated beginning in 2010, while NO_x emissions will be regulated beginning in 2009. Table 7-8 presents emissions allowance prices beginning in 2009 for NO_x and 2010 for SO_2. The emissions allowance price projections shown in Table 7-8 are presented in constant 2005 dollars.

7.6.2 AEO2007 Low Case Emissions Allowance Price Projections

Table 7-9 presents the forecasts of SO_2 and NO_x emissions allowance prices that correspond to the AEO2007 Low Price Case. Under CAIR, SO_2 emissions will be regulated beginning in 2010, while NO_x emissions will be regulated beginning in 2009. Table 7-9 presents emissions allowance prices beginning in 2009 for NO_x and 2010 for SO_2. The emissions allowance price projections shown in Table 7-9 are presented in constant 2005 dollars.

7.7 EIA Analysis of Senate Bill 280

Several bills that regulate emissions of greenhouse gases (including CO_2, methane, nitrous oxide, and fluorinated gas) have been proposed to the 110th US Congress. In response to a request from Senators Joseph Lieberman and John McCain, the EIA developed an analysis entitled *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007,* which was published in July 2007. The following subsections discuss this analysis and summarize the EIA's conclusions regarding projected CO_2 emissions allowance prices and associated impacts to the price of natural gas.

When this Application was prepared, the *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, was one of two published analyses by the EIA of proposed legislation to regulate CO_2. The second analysis was published by the EIA in January 2008 and is titled *Energy Market and Economic Impacts of S.1766, the Low Carbon Economy Act of 2007.* The CO_2 emissions allowance prices and corresponding natural gas price projections presented in the EIA's analysis of S.280 are generally higher than those presented in the EIA's analysis of S.1766. As a result, the EIA's analysis of S. 280 was selected for consideration in this Application.

Table 7-8
Annual Energy Outlook 2007 High Case Price Projections
Forecast of Emissions Allowance Prices for CAIR-Regulated Emissions(1)

Year	SO_2 (2005 $/ton)	NO_x (2005 $/ton)
2009	N/A	2,544.51
2010	707.17	2,589.96
2011	682.52	2,562.14
2012	712.87	2,497.36
2013	777.20	2,631.19
2014	863.65	2,633.98
2015	897.87	2,586.85
2016	957.47	2,487.41
2017	981.64	2,425.62
2018	913.05	2,631.64
2019	877.94	2,888.74
2020	897.01	3,016.03
2021	853.94	3,019.92
2022	884.94	3,050.75
2023	823.99	3,016.33
2024	808.01	2,946.68
2025	713.86	2,954.61
2026	616.53	2,892.34
2027	469.41	3,030.20
2028	350.70	2,939.25
2029	345.18	3,021.89
2030	449.97	3,134.93

(1) Based on data received directly from the EIA.

Table 7-9
Annual Energy Outlook 2007 Low Case Price Projections
Forecast of Emissions Allowance Prices for
CAIR-Regulated Emissions[1]

Year	SO_2 (2005 $/ton)	NO_x (2005 $/ton)
2009	N/A	2,476.43
2010	801.81	2,474.15
2011	811.10	2,478.09
2012	845.68	2,311.12
2013	902.96	2,207.68
2014	891.80	2,341.90
2015	949.11	2,432.51
2016	942.98	2,464.27
2017	936.51	2,320.38
2018	979.70	2,296.82
2019	982.49	2,392.80
2020	1,003.22	2,481.91
2021	1,101.17	2,574.81
2022	1,118.30	2,392.99
2023	1,120.06	2,514.97
2024	1,182.69	2,497.17
2025	1,154.87	2,583.94
2026	1,185.48	2,699.60
2027	1,172.82	2,744.43
2028	1,192.40	2,852.55
2029	1,175.34	2,848.03
2030	1,186.60	2,995.74

(1) Based on data received directly from the EIA.

7.7.1 Overview of the Proposed Climate Stewardship and Innovation Act of 2007 (S.280)

The *Climate Stewardship and Innovation Act of 2007* was introduced to the 110th US Congress as S.280 on January 12, 2007, by Senator Lieberman (for himself and Senator McCain, Senator Lincoln, Senator Snowe, Senator Obama, Senator Collins, and Senator Durbin). The legislative intent of S.280 is as follows:

> **To provide for a program to accelerate the reduction of greenhouse gas emissions in the United States by establishing a market-driven system of greenhouse gas tradeable allowances, to support the deployment of new climate change-related technologies, and to ensure benefits to consumers from the trading in such allowances, and for other purposes.**

As proposed, S.280 would cover the commercial, industrial, electric generation, and transportation sectors (the covered sectors). The regulations would cover entities within the covered sectors in possession or control of a source of emissions that emits, from any single facility owned by the entity, over 10,000 metric tons of greenhouse gases per year, measured in units of CO_2 equivalents. Such an entity is referred to as a covered entity.

The annual greenhouse gas emission targets set forth in S.280, measured in units of CO_2 equivalents, are summarized below. According to the EIA, the 2012 to 2019 emissions caps are approximately equal to the calendar year 2004 US greenhouse gas emissions, the 2020 to 2029 emissions caps are approximately equal to the calendar year 1990 US greenhouse gas emissions, the 2030 to 2049 emissions caps are approximately equal to 22 percent below the calendar year 1990 US greenhouse gas emissions, and the 2050 and beyond emissions caps are approximately equal to 60 percent below the calendar year 1990 US greenhouse gas emissions. The emission caps are as follows:

- For calendar years after 2011 - 6,130 million metric tons, reduced by the amount of emissions of greenhouse gases in calendar year 2012 from noncovered entities.
- For calendar years after 2019 - 5,239 million metric tons, reduced by the amount of emissions of greenhouse gases in calendar year 2020 from noncovered entities.
- For calendar years after 2029 – 4,100 million metric tons, reduced by the amount of emissions of greenhouse gases in calendar year 2030 from noncovered entities.

- For calendar years after 2049 – 2,096 million metric tons, reduced by the amount of emissions of greenhouse gases in each such calendar year from noncovered entities.

Under S.280, individual covered entities must submit allowances equal to their emissions, but their CO_2 emissions are not otherwise limited. Entities could buy and sell allowances, or bank allowances for future use. Under limited conditions, covered entities could also borrow allowance credits against future emissions reductions. Additionally, there are various alternative means of compliance including the following:

- Submitting tradeable allowances from another nation's market in greenhouse gas emissions.
- Submitting a registered net increase in sequestration.
- Submitting a greenhouse gas emissions reduction (other than a registered net increase in sequestration).
- Submitting credits related to assisting developing countries achieve sustainable development and reduce their greenhouse gas emissions.

7.7.2 EIA Analysis of S.280 – Overview and Summary of Results[8]

In developing its analysis of S.280, the EIA ran each of the policy cases described below through its integrated NEMS program. NEMS is developed and maintained by the EIA's Office of Integrated Analysis and Forecasting to provide projections of domestic energy-economy markets over the long term and to perform policy analyses requested by decision makers in various US government agencies (including the White House, Congress, and offices within the US Department of Energy, among others). NEMS is the modeling tool used by the EIA to develop the AEO2007. For the S.280 analysis, the EIA made adjustments to the AEO2007 Reference Case, which are delineated in Appendix C of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007.* The adjustments encompass assumptions related to the treatment of ethanol and biodiesel, offshore wind technology, corn and biomass feedstock, interregional transmission cost structure, and biomass electricity generation.

[8] Refer to *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007,* for additional details regarding the various policy cases and the analysis as a whole.

The use of NEMS allows for a fully integrated analysis of potential greenhouse gas emission allowance prices and energy demand. As stated in the EIA's analysis of S.280:

> **NEMS endogenously calculates changes in energy-related CO_2 emissions in the analysis cases. The cost of using each fossil fuel includes the costs associated with the GHG *[greenhouse gas]* allowances needed to cover the emissions produced when they are used. The adjustments influence energy demand and energy-related CO_2 emissions. The GHG allowance price also determines the reductions in the emissions of other GHGs and from international offsets based on abatement cost relationships...With emission allowance banking, NEMS solves for the time path of permit prices such that cumulative emissions match the cumulative emissions target without requiring allowance borrowing and with price escalation consistent with the average cost of capital to the electric power sector.**

The EIA analysis of S.280 includes several various policy cases and projections of associated CO_2 emissions allowance prices. The policy cases considered by the EIA in the analysis of S.280 are described as follows:

- S.280 Core--Represents the primary policy case.
- No International--Assumes that offsets from international sources are not available.
- Fixed 30 Percent Offsets--Assumes that offsets meet a fixed, 30 percent share of allowances.
- Unlimited Offsets--Assumes that an unlimited share of allowance obligations can be met by offsets.
- Low Discount--Assumes lower discount rate (4.0 percent) for allowance banking than S.280 Core (7.0 percent).
- High Auction--Assumes increased allowance auction share compared to S.280 Core.
- No Nuclear--Assumes no nuclear generating plant additions beyond the Reference Case level.
- Commercial Covered--Assumes that all commercial sector entities are covered.
- S.280 High Technology--S.280 Core with integrated high technology case assumptions (rather than Reference Case AEO2007).

In October 2007, the EIA published a supplement to its July 2007 analysis of S.280[9]. The supplemental analysis addressed topics related to the scenarios considered in recent EIA modeling and concerns related to prospects for building new coal fired power plants; additional scenarios restricting the availability of nuclear, biomass, and coal with carbon capture and sequestration (CCS) technology, the time horizon and state/regional detail in energy modeling; and EIA's analysis of natural gas. The additional policy cases presented in the supplemental analysis are as follows:

- Reference Nuclear and Biomass (RefNB)--Nuclear and biomass are held to their reference case (AEO2007) levels through 2030.
- Reference Nuclear and Biomass plus no CCS (RefNB+noCCS)--Further limits the RefNB case to preclude the deployment of coal with CCS prior to 2030.
- RefNBLNG+NoCCS--Further limits the RefNB+noCCS to hold liquefied natural gas (LNG) to its reference case (AEO2007) level through 2030.

The following tables and figures summarize results of the evaluations of the nine policy cases considered by the EIA in its analysis of S.280. Tables 7-10 through 7-13 present projections of annual natural gas, distillate fuel oil, residual fuel oil, and coal prices, respectively, for use in the electric power sector for each of the nine policy cases, as well as the corresponding annual price projections presented in the AEO2007 Reference Case. The annual natural gas price projections are presented in constant 2005 dollars per thousand cubic feet (mcf); the distillate and residual fuel oil prices are presented in constant 2005 cents per gallon; and the annual coal price projections are presented in constant 2005 dollars per MBtu. Annual natural gas and coal price projections are presented beginning in 2012, which is the initial year of CO_2 emissions regulations contemplated in S.280. It is important to note that the price projections for the nine policy cases presented in Tables 7-10 through 7-13 include the cost of CO_2 emissions allowances, while no such costs are included in the annual price projections for the AEO2007 Reference Case. Table 7-14 presents projections of annual CO_2 emissions allowance prices for each of the nine policy cases, in constant 2005 dollars per metric ton CO_2 equivalent, beginning in 2012. Figure 7-9 through Figure 7-13 present graphical depictions of the data in Tables 7-10 through 7-14, respectively.

[9] Refer to Supplement to *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, located at http://www.eia.doe.gov/oiaf/servicerpt/biv/index.html.

Table 7-10
Natural Gas Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 $/mcf – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

Year	AEO 2007 Reference Case	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	$5.86	$6.58	$6.87	$6.21	$6.55	$6.68	$6.56	$6.52	$6.53	$6.26	$6.58	$6.63	$6.68
2013	$5.66	$6.31	$6.52	$5.95	$6.32	$6.50	$6.33	$6.34	$6.30	$6.06	$6.37	$6.46	$6.45
2014	$5.70	$6.34	$6.46	$5.97	$6.43	$6.43	$6.33	$6.28	$6.28	$5.96	$6.64	$6.54	$6.98
2015	$5.66	$6.28	$6.59	$6.02	$6.42	$6.49	$6.38	$6.30	$6.27	$6.04	$6.59	$7.03	$6.95
2016	$5.76	$6.41	$6.65	$6.14	$6.54	$6.58	$6.50	$6.37	$6.37	$6.03	$6.72	$7.08	$7.06
2017	$5.96	$6.60	$6.80	$6.35	$6.69	$6.67	$6.65	$6.54	$6.59	$6.17	$6.97	$7.30	$7.31
2018	$5.89	$6.59	$6.80	$6.28	$6.78	$6.63	$6.59	$6.53	$6.60	$6.14	$7.00	$7.42	$7.39
2019	$5.84	$6.66	$6.87	$6.30	$6.82	$6.59	$6.62	$6.60	$6.61	$6.10	$7.11	$7.53	$7.49
2020	$5.93	$6.73	$7.07	$6.45	$6.94	$6.62	$6.76	$6.70	$6.66	$6.23	$7.23	$7.58	$7.61
2021	$5.89	$6.83	$7.26	$6.58	$7.03	$6.64	$6.74	$6.78	$6.80	$6.31	$7.32	$7.75	$7.91
2022	$6.01	$7.05	$7.41	$6.82	$7.21	$6.75	$6.74	$6.95	$7.00	$6.51	$7.64	$8.04	$8.18
2023	$6.12	$7.21	$7.59	$6.96	$7.38	$6.86	$6.70	$7.10	$7.18	$6.63	$7.90	$8.38	$8.52
2024	$6.23	$7.31	$7.37	$7.18	$7.58	$6.92	$6.73	$7.26	$7.30	$6.76	$8.11	$8.73	$8.86
2025	$6.22	$7.50	$7.65	$7.31	$7.74	$7.04	$6.89	$7.47	$7.45	$6.87	$8.05	$8.97	$9.11
2026	$6.24	$7.67	$7.93	$7.42	$7.97	$7.16	$7.01	$7.61	$7.62	$7.04	$8.45	$9.29	$9.52
2027	$6.33	$7.77	$8.36	$7.62	$8.22	$7.33	$7.06	$7.74	$7.74	$7.18	$8.73	$9.63	$9.87
2028	$6.43	$7.89	$8.57	$7.71	$8.52	$7.38	$7.07	$7.87	$7.88	$7.35	$8.95	$9.99	$10.17
2029	$6.50	$8.08	$8.55	$7.78	$8.78	$7.42	$7.16	$8.09	$8.02	$7.52	$9.33	$10.37	$10.53
2030	$6.51	$8.38	$8.85	$7.82	$9.09	$7.44	$7.23	$8.34	$8.32	$7.73	$9.57	$10.74	$11.07

Table 7-11
Distillate Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 Cents/Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

Year	AEO 2007 Reference Case	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	138.38	150.81	155.56	145.62	151.04	153.78	151.17	150.77	150.65	149.25	151.91	153.01	153.37
2013	126.90	140.64	144.63	134.99	140.66	143.13	141.15	140.70	140.37	138.55	141.48	143.50	143.58
2014	125.75	140.23	144.86	134.90	140.57	143.09	140.48	140.29	140.27	137.92	141.72	143.56	144.48
2015	126.60	141.08	147.04	135.99	142.05	144.17	141.08	141.38	141.01	138.80	143.12	145.56	146.04
2016	127.42	142.87	149.27	137.23	143.55	145.10	142.06	142.74	142.30	139.33	144.86	148.00	148.17
2017	130.13	146.48	153.04	140.95	147.39	148.21	144.64	146.66	146.16	142.43	148.55	151.72	151.44
2018	131.88	149.20	156.12	143.69	150.13	149.98	146.54	149.07	148.62	144.79	151.49	154.84	154.55
2019	135.33	154.94	161.04	147.60	155.81	155.11	151.76	154.22	153.85	147.89	156.89	159.26	159.26
2020	136.50	156.33	163.88	149.96	157.80	156.15	153.18	156.33	155.76	150.82	158.96	162.93	163.08
2021	137.70	160.20	167.78	152.41	161.85	159.22	155.74	160.01	159.55	154.11	163.01	167.23	167.50
2022	139.90	164.24	173.70	155.08	165.42	162.04	156.09	164.59	163.12	158.00	167.24	171.98	172.27
2023	140.18	166.71	176.96	157.90	168.51	163.55	156.02	167.03	165.69	160.17	170.12	174.98	175.50
2024	141.66	171.02	176.34	161.14	173.01	166.88	157.46	171.27	170.09	163.26	174.57	179.65	180.12
2025	142.54	174.90	180.54	164.02	176.96	169.04	160.00	175.38	173.85	167.08	178.49	183.99	184.16
2026	143.87	178.84	185.27	167.38	180.97	171.97	163.17	179.12	177.59	169.80	182.84	188.92	189.27
2027	144.86	183.24	190.41	172.75	185.01	174.80	168.67	183.32	181.63	173.76	187.18	193.56	193.98
2028	147.71	187.35	196.04	176.52	189.17	178.53	172.25	187.66	186.18	177.15	191.91	198.96	199.49
2029	149.97	192.21	201.33	180.87	194.52	182.77	177.60	191.98	190.66	182.01	197.74	204.96	204.96
2030	152.83	196.35	206.68	184.46	199.96	185.79	179.66	196.70	194.73	185.92	202.73	210.01	210.03

Table 7-12
Residual Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 Cents/Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

Year	AEO 2007 Reference Case	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	88.00	136.63	146.49	123.72	137.14	140.36	134.85	137.03	136.08	148.38	134.76	134.86	137.19
2013	80.80	119.45	125.27	108.51	119.44	125.64	120.15	119.48	119.05	132.56	116.99	118.50	120.70
2014	81.65	129.07	130.50	113.75	129.72	132.52	130.20	127.53	127.77	138.28	123.61	128.10	133.31
2015	83.14	134.78	140.80	130.67	136.85	141.32	138.89	135.63	131.42	141.62	137.62	134.27	136.61
2016	83.66	140.00	151.68	132.75	142.25	146.57	141.92	141.16	136.13	145.59	142.55	144.66	148.71
2017	85.53	145.54	156.15	139.48	149.91	151.24	146.35	145.43	144.34	155.55	148.76	152.19	156.92
2018	86.97	151.24	164.27	145.33	154.68	153.74	155.81	151.46	150.69	166.16	156.69	159.13	162.04
2019	89.71	161.00	179.15	151.62	162.13	163.70	160.14	160.72	160.99	175.69	165.20	167.15	167.98
2020	90.57	166.47	187.23	154.63	165.02	165.81	163.20	165.43	166.45	178.82	167.07	169.19	169.72
2021	92.55	173.85	190.12	159.55	172.16	173.81	169.20	174.29	174.56	178.59	174.62	175.82	177.07
2022	95.20	177.54	193.81	165.33	176.54	176.00	169.90	177.37	177.49	184.93	178.36	182.64	183.41
2023	94.37	183.59	202.56	165.59	181.17	179.55	165.70	183.48	182.81	194.85	182.78	187.58	186.80
2024	97.35	191.20	206.38	173.04	185.58	183.56	170.53	192.58	188.73	197.82	187.76	193.27	194.29
2025	98.67	198.35	215.47	178.08	193.44	190.21	173.65	199.55	199.19	202.90	195.98	199.65	201.40
2026	99.04	206.59	223.24	183.29	199.62	193.86	182.59	207.22	206.53	208.84	207.00	206.19	207.31
2027	100.18	212.29	232.15	187.29	209.87	199.08	189.10	220.94	214.81	212.89	210.84	214.09	213.38
2028	102.34	221.36	242.32	193.80	214.48	203.03	194.26	224.84	222.35	216.25	214.72	224.25	219.15
2029	102.90	231.45	248.25	200.23	225.03	207.89	203.75	231.09	227.84	219.61	228.46	233.95	229.00
2030	104.92	234.75	251.97	202.88	230.76	211.31	206.63	236.99	234.34	223.72	238.98	238.65	236.54

Table 7-13
Coal Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 $/MBtu – Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

Year	AEO 2007 Reference Case	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	$1.65	$2.86	$3.29	$2.36	$2.85	$3.12	$2.86	$2.85	$2.84	$2.75	$2.95	$3.07	$3.08
2013	$1.62	$2.89	$3.26	$2.39	$2.88	$3.15	$2.89	$2.89	$2.89	$2.78	$2.99	$3.17	$3.18
2014	$1.61	$2.93	$3.38	$2.44	$2.97	$3.20	$2.94	$2.93	$2.93	$2.82	$3.06	$3.28	$3.29
2015	$1.60	$2.98	$3.52	$2.49	$3.06	$3.26	$2.98	$2.99	$2.97	$2.81	$3.15	$3.40	$3.40
2016	$1.59	$3.09	$3.66	$2.56	$3.18	$3.32	$3.00	$3.10	$3.04	$2.83	$3.26	$3.52	$3.53
2017	$1.58	$3.20	$3.82	$2.63	$3.30	$3.38	$3.02	$3.22	$3.16	$2.93	$3.39	$3.67	$3.68
2018	$1.57	$3.32	$3.99	$2.70	$3.42	$3.44	$3.08	$3.33	$3.27	$3.02	$3.52	$3.82	$3.84
2019	$1.58	$3.45	$4.17	$2.79	$3.56	$3.51	$3.19	$3.47	$3.40	$3.13	$3.67	$4.00	$4.02
2020	$1.57	$3.59	$4.35	$2.88	$3.72	$3.58	$3.32	$3.61	$3.54	$3.24	$3.84	$4.19	$4.21
2021	$1.57	$3.75	$4.56	$2.99	$3.88	$3.66	$3.33	$3.77	$3.69	$3.37	$4.02	$4.39	$4.42
2022	$1.58	$3.93	$4.79	$3.11	$4.07	$3.74	$3.19	$3.95	$3.86	$3.52	$4.23	$4.63	$4.66
2023	$1.60	$4.11	$5.02	$3.23	$4.27	$3.83	$3.09	$4.13	$4.03	$3.68	$4.44	$4.87	$4.91
2024	$1.61	$4.31	$4.79	$3.37	$4.48	$3.91	$3.01	$4.33	$4.23	$3.84	$4.68	$5.14	$5.18
2025	$1.62	$4.52	$5.04	$3.53	$4.71	$4.01	$3.15	$4.55	$4.44	$4.02	$4.97	$5.43	$5.48
2026	$1.64	$4.74	$5.29	$3.68	$4.96	$4.11	$3.28	$4.78	$4.65	$4.20	$5.23	$5.76	$5.80
2027	$1.65	$4.99	$5.65	$3.85	$5.23	$4.21	$3.42	$5.02	$4.89	$4.41	$5.51	$6.09	$6.14
2028	$1.67	$5.27	$5.95	$4.04	$5.55	$4.31	$3.56	$5.30	$5.16	$4.63	$5.86	$6.47	$6.52
2029	$1.68	$5.54	$6.26	$4.23	$5.88	$4.42	$3.72	$5.56	$5.43	$4.88	$6.20	$6.88	$6.95
2030	$1.70	$5.85	$6.63	$4.45	$6.25	$4.52	$3.90	$5.84	$5.72	$5.12	$6.59	$7.30	$7.39

Table 7-14
CO_2 Emission Allowance Price Projections from EIA Analysis of S.280
(2005 \$/Metric Ton CO_2 Equivalent)

Year	S. 280 Core	S. 280 No International	S. 280 Fixed 30% Offset	S. 280 No Nuclear	S. 280 Low Discount	S. 280 Unlimited Offset	S. 280 High Auction	S. 280 Commercial Covered	S. 280 High Technology	S. 280 Ref NB	S. 280 RefNB + noCCS	S. 280 RefNBLNG + noCCS
2012	\$13.21	\$18.00	\$7.76	\$13.14	\$16.06	\$13.25	\$13.14	\$13.09	\$12.13	\$14.06	\$15.31	\$15.47
2013	\$13.86	\$17.88	\$8.38	\$13.78	\$16.70	\$13.91	\$13.79	\$13.80	\$12.83	\$14.65	\$16.54	\$16.71
2014	\$14.44	\$19.31	\$9.06	\$14.76	\$17.37	\$14.60	\$14.44	\$14.44	\$13.42	\$15.51	\$17.86	\$18.05
2015	\$15.09	\$20.86	\$9.78	\$15.94	\$18.06	\$15.06	\$15.23	\$15.02	\$13.38	\$16.75	\$19.29	\$19.49
2016	\$16.29	\$22.53	\$10.56	\$17.22	\$18.78	\$15.34	\$16.45	\$15.84	\$13.68	\$18.09	\$20.83	\$21.05
2017	\$17.60	\$24.33	\$11.41	\$18.60	\$19.54	\$15.69	\$17.77	\$17.11	\$14.78	\$19.54	\$22.50	\$22.74
2018	\$19.00	\$26.27	\$12.32	\$20.08	\$20.32	\$16.38	\$19.19	\$18.47	\$15.96	\$21.10	\$24.30	\$24.56
2019	\$20.52	\$28.38	\$13.31	\$21.69	\$21.13	\$17.69	\$20.72	\$19.95	\$17.24	\$22.79	\$26.24	\$26.52
2020	\$22.17	\$30.65	\$14.37	\$23.43	\$21.98	\$19.11	\$22.38	\$21.55	\$18.62	\$24.61	\$28.34	\$28.64
2021	\$23.94	\$33.10	\$15.52	\$25.30	\$22.85	\$19.24	\$24.17	\$23.27	\$20.11	\$26.58	\$30.61	\$30.93
2022	\$25.85	\$35.74	\$16.76	\$27.32	\$23.77	\$17.84	\$26.11	\$25.13	\$21.71	\$28.71	\$33.06	\$33.41
2023	\$27.92	\$38.60	\$18.10	\$29.51	\$24.72	\$16.79	\$28.19	\$27.15	\$23.45	\$31.01	\$35.70	\$36.08
2024	\$30.16	\$36.29	\$19.55	\$31.87	\$25.71	\$15.96	\$30.45	\$29.32	\$25.33	\$33.49	\$38.56	\$38.97
2025	\$32.57	\$39.19	\$21.11	\$34.42	\$26.74	\$17.23	\$32.89	\$31.66	\$27.35	\$36.16	\$41.64	\$42.08
2026	\$35.17	\$42.32	\$22.80	\$37.17	\$27.81	\$18.61	\$35.52	\$34.20	\$29.54	\$39.06	\$44.98	\$45.45
2027	\$37.99	\$45.71	\$24.63	\$40.15	\$28.92	\$20.10	\$38.36	\$36.93	\$31.91	\$42.18	\$48.57	\$49.09
2028	\$41.03	\$49.37	\$26.60	\$43.36	\$30.07	\$21.71	\$41.43	\$39.89	\$34.46	\$45.56	\$52.46	\$53.01
2029	\$44.31	\$53.32	\$28.73	\$46.83	\$31.28	\$23.45	\$44.74	\$43.08	\$37.22	\$49.20	\$56.66	\$57.25
2030	\$47.85	\$57.58	\$31.02	\$50.58	\$32.53	\$25.32	\$48.32	\$46.52	\$40.19	\$53.14	\$61.19	\$61.83

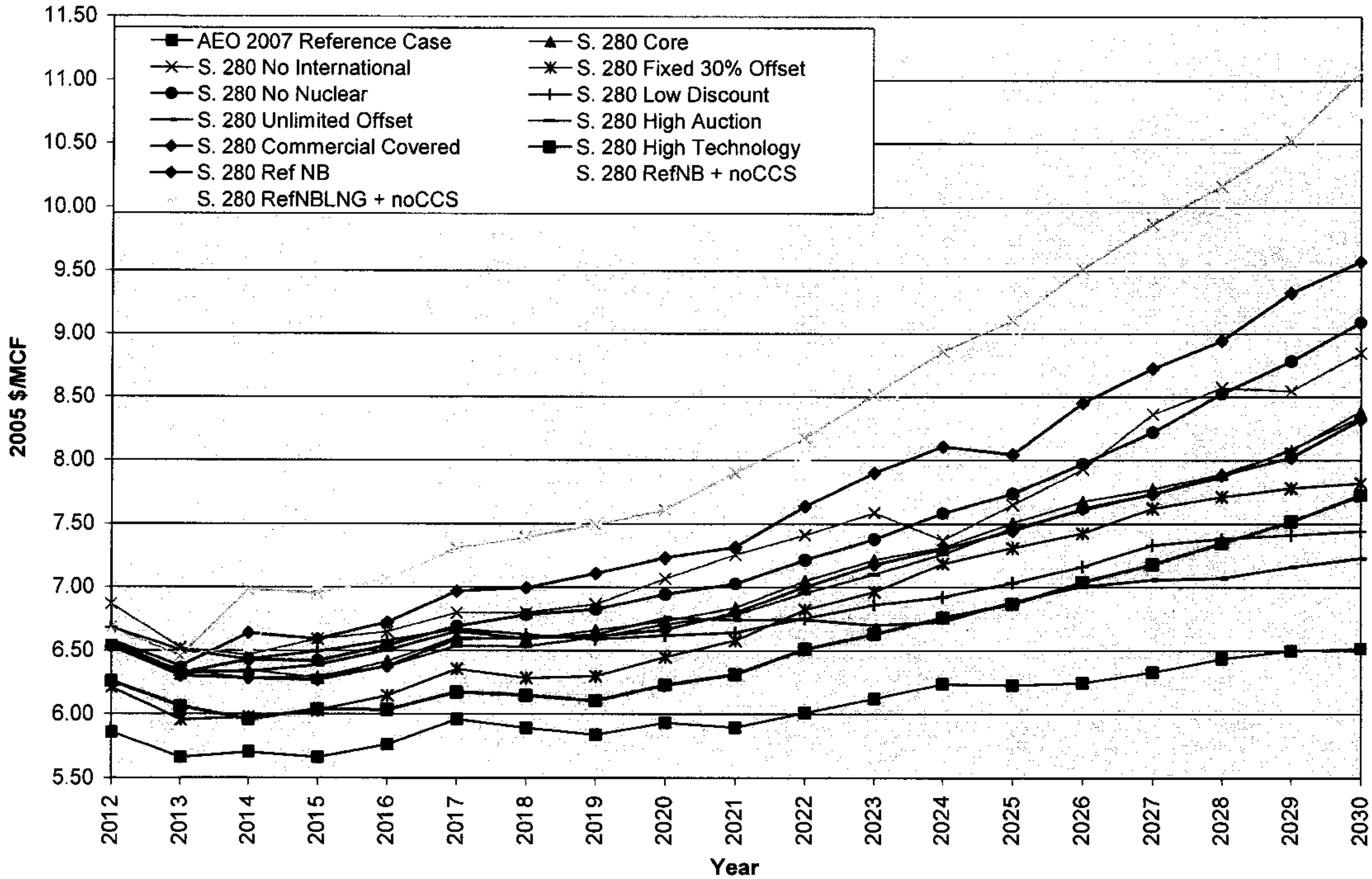

Figure 7-9
Natural Gas Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 $/mcf - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

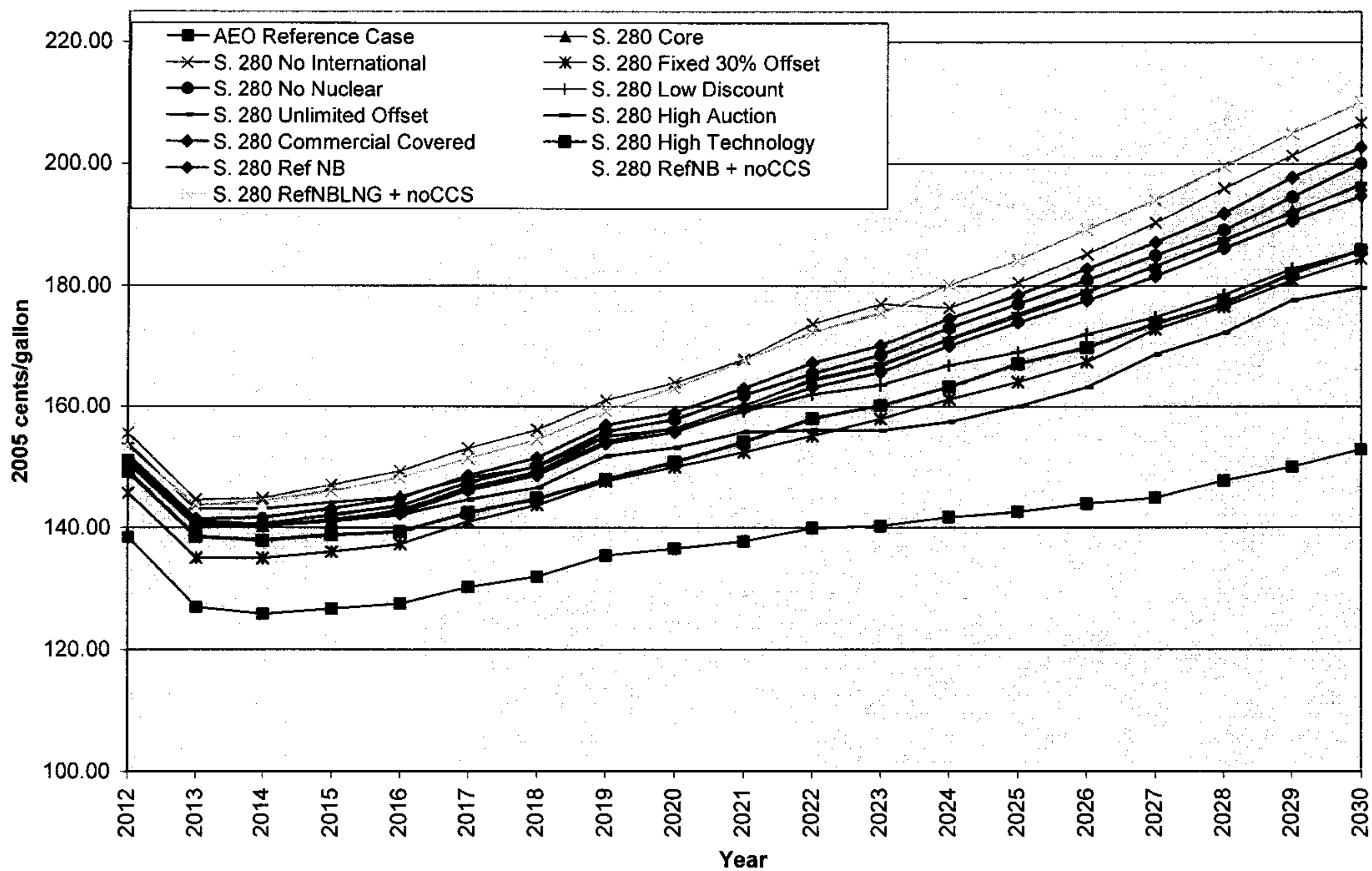

Figure 7-10
Distillate Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 Cents/Gallon - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

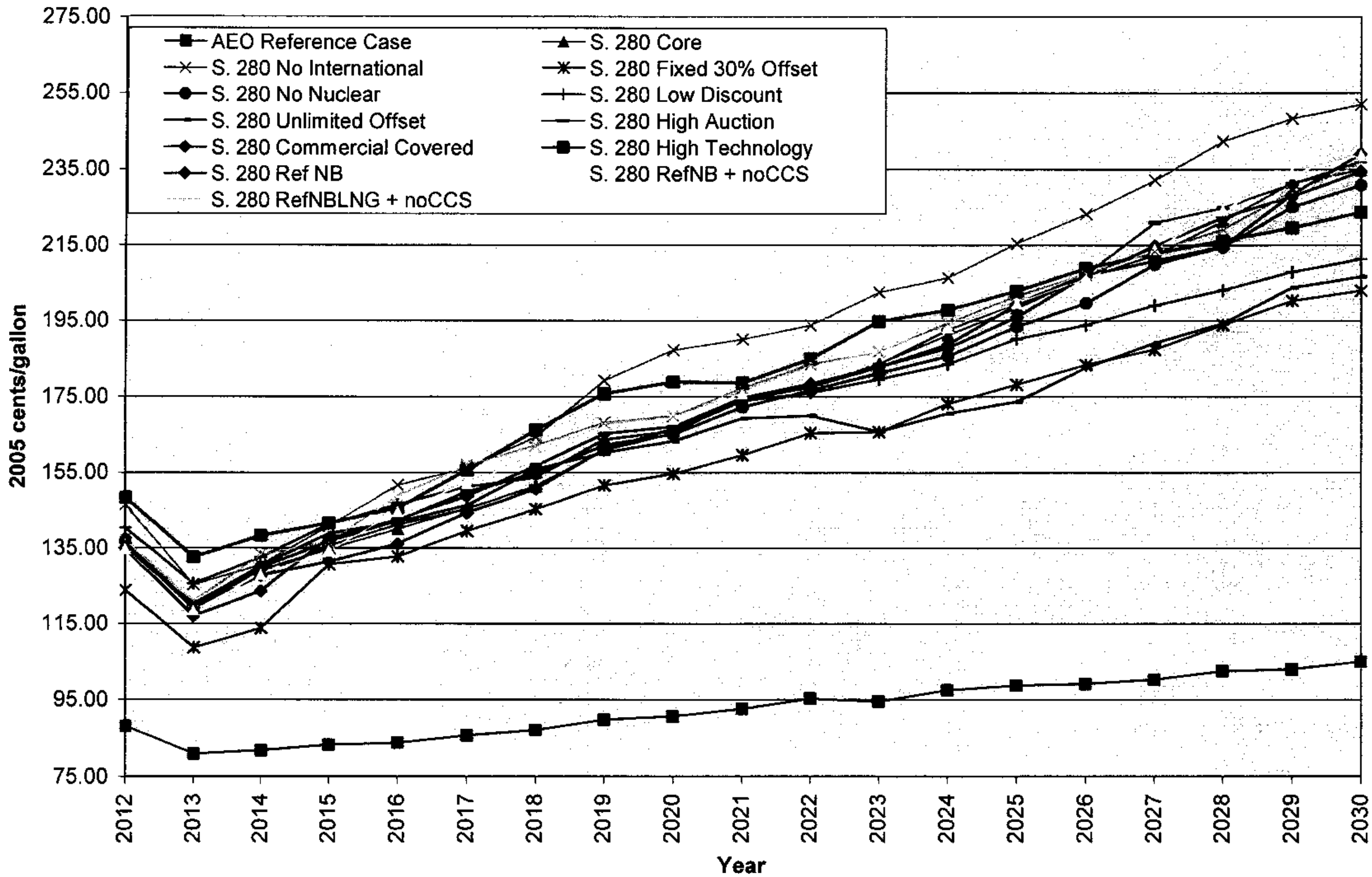

Figure 7-11
Residual Fuel Oil Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 Cents/Gallon - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

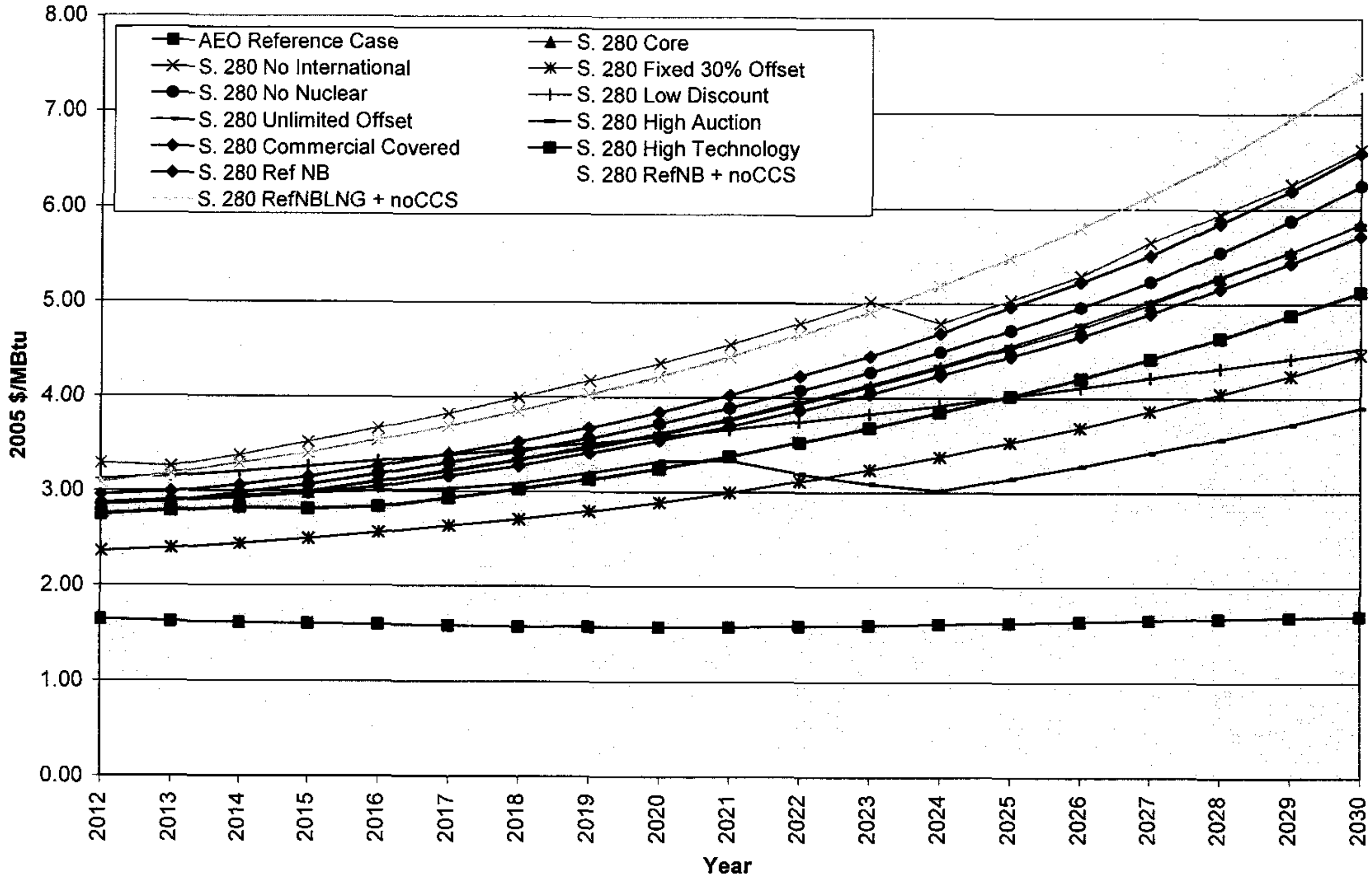

Figure 7-12
Coal Price Projections for AEO2007 Reference Case and EIA Analysis of S.280
(Delivered 2005 $/MBtu - Electric Power Sector, Including Cost of CO_2 Allowances for S.280 Cases)

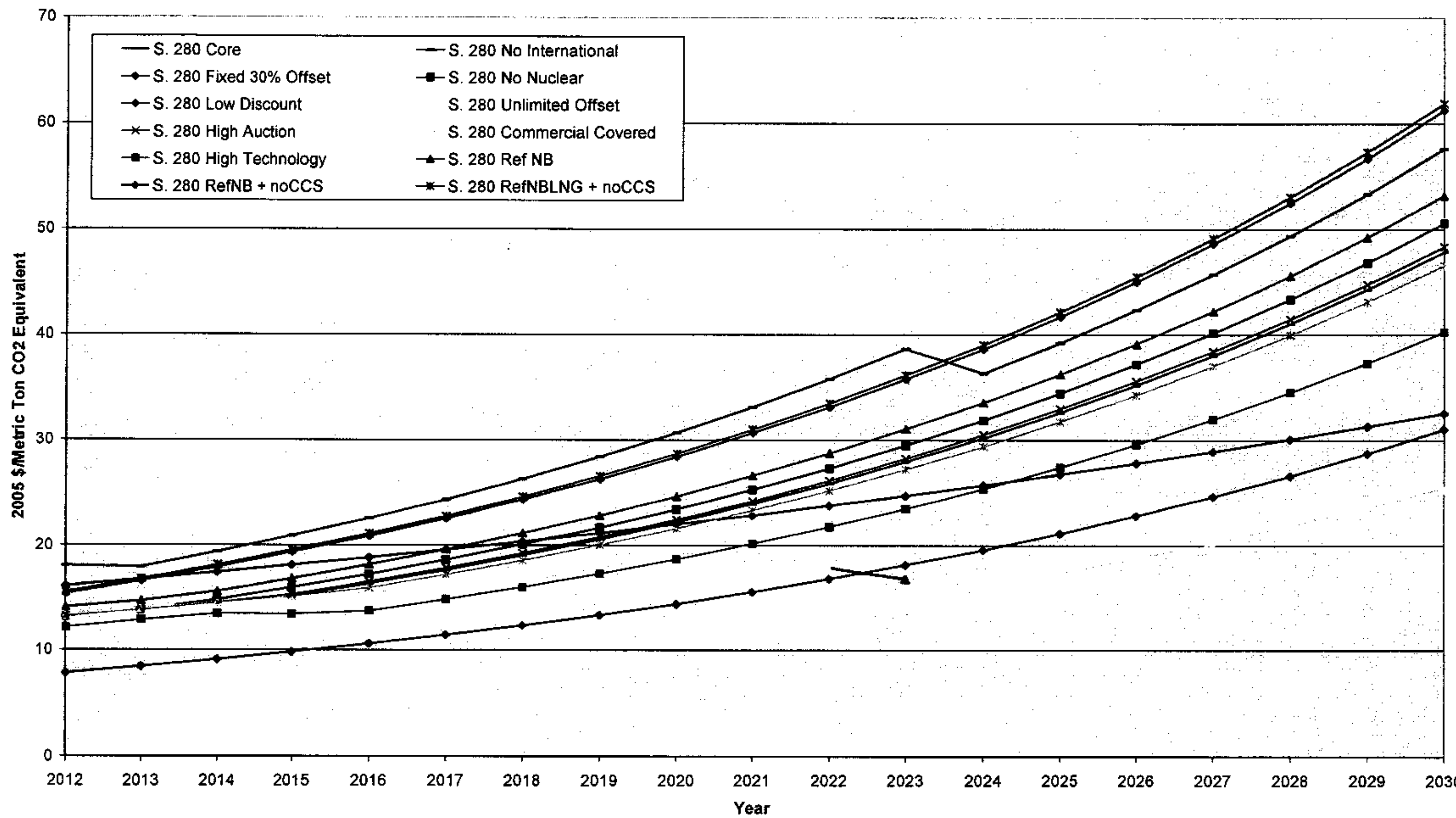

Figure 7-13
CO_2 Emissions Allowance Price Projections from EIA Analysis of S.280 (2005 \$/Metric Ton CO_2 Equivalent)

An analysis of Tables 7-10 through 7-14 (supplemented by Figures 7-9 through 7-13) shows that projected impacts on natural gas prices and corresponding CO_2 emissions allowance price projections differ depending upon the policy cases considered in the EIA analysis of S.280. When compared across the nine policy cases, the projected natural gas, fuel oil, and coal prices (including the cost of CO_2 emissions allowances) and the annual projections of CO_2 emissions allowance prices corresponding to the S.280 Core case fall within (and towards the upper end of) the boundaries set by the other eight policy cases.

7.8 Consideration of EIA Analysis of Senate Bill 280

As discussed in Section 7.7, the EIA developed an analysis of potential economic impacts of the *Climate Stewardship and Innovation Act of* 2007, which was introduced to the 110th US Congress as S.280 on January 12, 2007 by Senator Lieberman (for himself and Senator McCain, Senator Lincoln, Senator Snowe, Senator Obama, Senator Collins, and Senator Durbin). The EIA's analysis included projections of natural gas, fuel oil, and coal prices, along with projected prices for CO_2 emissions for 12 various policy cases involving different assumptions related to the structure of how S.280 may be implemented if ultimately enacted by Congress. The fuel price projections, as well as the CO_2 emissions allowance price projections, for each of the 12 policy cases are presented throughout Section 7.7. Analysis of the various policy cases and corresponding fuel and emissions allowance prices indicates that the S.280 Core Case (as defined by the EIA) reflects projected impacts on fuel and emission allowance prices that fall within the boundaries set by the other 11 policy cases. These relative projected impacts, taken in combination with the S.280 Core Case being considered by the EIA as representative of the primary policy case, resulted in the selection of the S.280 Core Case for further analysis in this Application.

The natural gas, fuel oil, and coal price projections for the S.280 Core Case presented in Section 7.7 include the annual costs of CO_2 emissions allowance prices, consistent with the presentation of data in EIA's analysis of S.280. Table 7-15 presents the natural gas, fuel oil, and coal price projections from the S.280 Core Case, excluding the annual costs of CO_2 emissions allowance prices as projected by the EIA.

Also presented in Table 7-15 are projections of natural gas, fuel oil, and coal prices, including the EIA's projected annual costs of CO_2 emissions allowances for the S.280 Core Case. It should be noted that these natural gas and fuel oil price projections differ from those presented in Section 7.7 because the natural gas, fuel oil, and coal prices presented in Table 7-15 are in constant 2005 dollars per MBtu, while those presented in Section 7.7 are in constant 2005 dollars per mcf for natural gas and constant 2005 cents per gallon for fuel oil.

Table 7-15
S. 280 Core Case Natural Gas, Fuel Oil, and Coal Price Projections
Compared to Non-Adjusted Fuel Price Forecasts (2005 \$/MBtu)

Year	Natural Gas		Distillate Fuel Oil		Residual Fuel Oil		Coal	
	Including Costs of CO_2 Emissions Allowances	Excluding Costs of CO_2 Emissions Allowances	Including Costs of CO_2 Emissions Allowances	Excluding Costs of CO_2 Emissions Allowances	Including Costs of CO_2 Emissions Allowances	Excluding Costs of CO_2 Emissions Allowances	Including Costs of CO_2 Emissions Allowances	Excluding Costs of CO_2 Emissions Allowances
2012	6.40	5.70	10.87	9.92	9.13	8.10	2.86	1.62
2013	6.14	5.40	10.14	9.14	7.98	6.90	2.89	1.59
2014	6.17	5.40	10.11	9.07	8.62	7.50	2.93	1.57
2015	6.11	5.31	10.17	9.08	9.00	7.83	2.98	1.56
2016	6.23	5.37	10.30	9.12	9.35	8.08	3.09	1.56
2017	6.42	5.49	10.56	9.29	9.72	8.35	3.20	1.55
2018	6.40	5.40	10.76	9.38	10.10	8.62	3.32	1.54
2019	6.47	5.39	11.17	9.69	10.76	9.15	3.45	1.52
2020	6.54	5.37	11.27	9.67	11.12	9.39	3.59	1.51
2021	6.64	5.38	11.55	9.82	11.61	9.75	3.75	1.50
2022	6.85	5.48	11.84	9.97	11.86	9.84	3.93	1.50
2023	7.01	5.54	12.02	10.00	12.26	10.09	4.11	1.49
2024	7.10	5.51	12.33	10.15	12.77	10.42	4.31	1.48
2025	7.29	5.57	12.61	10.25	13.25	10.71	4.52	1.46
2026	7.46	5.60	12.89	10.35	13.80	11.06	4.74	1.44
2027	7.55	5.55	13.21	10.46	14.18	11.22	4.99	1.43
2028	7.67	5.50	13.51	10.54	14.79	11.59	5.27	1.43
2029	7.85	5.51	13.86	10.65	15.46	12.00	5.54	1.40
2030	8.15	5.62	14.16	10.69	15.68	11.95	5.85	1.37

7.8.1 S.280 Core Case Fuel Prices Delivered to the FRCC Region

Projections of natural gas, fuel oil, and coal prices for the FRCC region that consider the potential impacts of CO_2 regulations, consistent with the EIA S.280 Core Case, were developed for analysis in this Application. To develop such fuel price forecasts, the AEO2007 Reference Case fuel prices delivered to the US electric power sector were analyzed and compared to the corresponding S.280 Core Case fuel price projections presented in Table 7-15 (excluding the costs of CO_2 emissions allowances, which are accounted for elsewhere in the economic analysis included in this Application). Annual percent differentials between the AEO2007 Reference Case fuel price projections and corresponding fuel price projections from the S.280 Core Case were calculated for natural gas, distillate and residual fuel oil, and coal. The annual price differentials were applied to the natural gas, distillate and residual fuel oil, and coal price projections for the FRCC region (shown in Tables 7-1 and 7-2) to develop projections of fuel prices delivered to the FRCC region that reflect the potential impact of S.280 related to the regulation of CO_2 emissions (consistent with the EIA S.280 Core Case). The resulting projections of fuel prices for 2012 through 2030, in constant 2005 dollars per MBtu, specific to the FRCC region are presented in Table 7-16. Prior to 2012, the natural gas, fuel oil, and coal price projections presented in Tables 7-1 and 7-2 remain unaffected, since the analysis assumes that CO_2 regulations will begin in 2012.

7.8.2 Carbon Dioxide Emissions Allowance Prices

The EIA's projected CO_2 emissions allowance prices corresponding to the S.280 Core Case are presented in Table 7-17. The EIA developed its projections of CO_2 emissions allowance prices in constant 2005 dollars per metric ton, which are shown in the second column of Table 7-12 and match those presented previously in Section 7.7 (Table 7-14). The annual CO_2 emissions allowance price projections in constant 2005 dollars per short ton are shown in the third column of Table 7-17.

Table 7-16
Forecast of Fuel Prices Delivered to FRCC Considering
Potential Impact of S.280 (EIA S.280 Core Case)
(2005 $/MBtu)

Year	Natural Gas	Distillate Fuel Oil	Residual Fuel Oil	Low Sulfur Central Appalachian Coal
2012	$5.79	$10.15	$8.23	$2.86
2013	$5.54	$9.33	$7.31	$2.85
2014	$5.53	$9.26	$7.74	$2.86
2015	$5.42	$9.27	$8.01	$2.83
2016	$5.54	$9.34	$8.22	$2.84
2017	$5.66	$9.52	$8.50	$2.80
2018	$5.65	$9.62	$8.74	$2.71
2019	$5.69	$9.88	$9.25	$2.64
2020	$5.67	$9.86	$9.49	$2.61
2021	$5.67	$10.02	$9.82	$2.57
2022	$5.78	$10.17	$9.84	$2.60
2023	$5.81	$10.20	$10.12	$2.58
2024	$5.83	$10.37	$10.38	$2.56
2025	$5.90	$10.48	$10.65	$2.53
2026	$5.93	$10.57	$11.03	$2.47
2027	$5.89	$10.70	$11.13	$2.44
2028	$5.84	$10.77	$11.53	$2.43
2029	$5.82	$10.88	$11.95	$2.38
2030	$5.91	$10.95	$11.95	$2.35

Table 7-17
Projected CO_2 Emission Allowance Prices
EIA S.280 Core Case

Year	2005 $/Metric Ton	2005 $/Short Ton
2012	13.21	11.98
2013	13.86	12.57
2014	14.44	13.10
2015	15.09	13.69
2016	16.29	14.78
2017	17.60	15.96
2018	19.00	17.24
2019	20.52	18.62
2020	22.17	20.11
2021	23.94	21.72
2022	25.85	23.45
2023	27.92	25.33
2024	30.16	27.36
2025	32.57	29.55
2026	35.17	31.91
2027	37.99	34.46
2028	41.03	37.22
2029	44.31	40.20
2030	47.85	43.41

8.0 Natural Gas Transportation

The Cane Island site is served by two separate existing natural gas pipelines owned by Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System, LLC (Gulfstream). These natural gas transportation supply systems, along with additional natural gas pipeline systems that serve the state of Florida as a whole, are discussed in this section.

8.1 Florida Gas Transmission

FGT, a subsidiary of Citrus Corporation (Citrus Corp.), operates a 5,000 mile natural gas pipeline system that extends from south Texas to south Florida with a current mainline capacity of 2.1 billion cubic feet (Bcf) per day. FGT offers natural gas transportation service for third parties. Citrus Corp is 50 percent owned by Southern Union Company (NYSE:SUG) and 50 percent owned by El Paso Corporation (NYSE:EP). The FGT system is illustrated in Figure 8-1.

Figure 8-1
FGT System
(Source: http://www.crosscountryenergy.com/about/fgt.shtml)

8.1.1 Existing FGT System

The FGT pipeline system transports natural gas to cogeneration facilities, electric utilities, independent power producers, municipal generators, and local distribution companies through a 5,000 mile natural gas pipeline that extends from south Texas to south Florida. It delivers 2.1 Bcf of natural gas per day to more than 240 delivery points, consisting of more than 50 natural gas fired electric generation facilities. FGT's total receipt point capacity is in excess of 3.0 Bcf per day and includes interconnects with 10 interstate and 10 intrastate pipelines to facilitate receiving supplies of natural gas into its pipeline system. The pipeline has extensive access to diverse natural gas supplies, including the offshore Gulf of Mexico region.

The pipeline enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the primary pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns in a southeasterly direction to a point in southern Brevard County, where it turns south generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa, St. Petersburg, and Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

FGT has completed numerous system expansions over the recent years since its major Phase III expansion in 1995. Below is a summary of these projects that were of sufficient significance to warrant a "phase" designation:

- Phase IV expansion project completed in May 2001. This project consisted of approximately 205 miles of various diameter pipelines, additional compression totaling 48,570 horsepower, and four new delivery points (including three new measurement stations) in the states of Mississippi, Alabama, and Florida. The Phase IV expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 272,000 MBtu per day at an estimated cost of $268 million.
- Phase V expansion project completed in May 2003. This project consisted of approximately 166 miles of pipeline and 133,000 horsepower of compression, including three new compressor stations, to its existing system in the states of Mississippi, Alabama, and Florida. The Phase V expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 428 million cubic feet (MMcf) per day at an estimated cost of $452 million.

- Phase VI expansion project completed in November 2003. This project consisted of approximately 33 miles of pipeline and 18,600 horsepower of compression to its existing system in the states of Louisiana, Mississippi, Alabama, and Florida. The Phase VI expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 121 MMcf per day at an estimated cost of $100 million.
- Phase VII expansion project construction completed in May 2007, except for modifications to a compressor station that were completed in December 2007. This project consisted of approximately 33 miles of pipeline and 9,800 horsepower of compression to its existing system in the state of Florida. The Phase VII expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 160 MMcf per day at an estimated cost of $104 million. This expansion will provide access to an additional natural gas supply from the SNG LNG Elba Island LNG import terminal near Savannah, Georgia.

8.1.2 Market Area Pipeline Interconnections

FGT's pipeline system has three pipeline interconnections that are capable of making natural gas deliveries within the state of Florida. FGT has two interconnections with Gulfstream: one interconnection in Osceola County and the other in Hardee County. Both of these interconnections offer delivery of Gulf Coast supplies directly into FGT's system in its market area of central Florida. Southern Natural Gas (SNG) also has an interconnection with FGT in Duval County at Cypress. This interconnection allows the delivery of natural gas off of the SNG system, the majority of which comes from SNG's Elba Island LNG import terminal located in Savannah, Georgia.

8.1.3 Planned FGT System Expansions

As presented previously in the summary of system expansions, FGT has continuously added pipeline capacity to increase its ability to offer firm transportation service into the state of Florida and meet the growing demand for natural gas within the state. FGT conducted an Open Season ending on February 15, 2008, for a proposed Phase VIII expansion project. On February 11, 2008, FGT announced that Florida Power & Light Company (FPL) had agreed to become the anchor shipper of a proposed natural gas pipeline expansion project through a 25 year service agreement for 400 MMcf per day of capacity. FGT intends to seek regulatory approval to build the proposed Phase VIII system expansion at an estimated cost of $2 billion to provide approximately 800 MMcf per day of increased natural gas capacity to Florida. The proposed Phase VIII expansion includes construction of approximately 500 miles of additional large diameter pipeline and the installation of approximately 170,000 horsepower of additional compression. The Phase VIII expansion will increase the capacity of FGT's mainline facilities from the Mobile Bay, Alabama, area to southern Florida to provide additional firm transportation service capacity throughout Florida. Pending regulatory approvals, FGT is anticipating a spring 2011 in-service date for the project. The FPL commitment will help ensure that the Phase VIII expansion will be built, filling 50 percent of the incremental capacity that is planned.

During the Open Season period, FMPA submitted a request for firm capacity of 30,000 MBtu per day to serve Cane Island 4. This submittal was a nonbinding request for capacity. Subsequent discussions have occurred where FGT required a binding volume commitment from FMPA to meet its material commitment schedule. FMPA was not prepared to make a binding commitment in the timeline necessary to meet this requested deadline. As a result, FGT formally withdrew its offer of capacity from the Phase VIII expansion on May 1, 2008.

8.1.4 Projected FGT Natural Gas Transportation Costs

FGT's Phase VIII Open Season states that the Phase VIII expansion project will provide incremental firm natural gas transportation service under a proposed FTS-3 Rate Schedule, the details of which have not yet been released. FGT has provided an estimate of the demand charge component for incremental firm transportation capacity from the eastern area of Zone 3 to Cane Island under a proposed new FTS-3 Rate Schedule on a confidential basis. That estimated firm incremental transportation cost has been used in the economic evaluations in this Application. Commodity and fuel rates are projected to be comparable to the current FTS-2 rate structure, with minimal change. A stipulation in the Open Season was that all transportation arrangements entered into as a part of this expansion would be for a minimum commitment of 25 years.

8.2 Gulfstream

Gulfstream is a joint development between Williams and Spectra Energy. The Gulfstream system consists of a 691 mile pipeline that was placed in service in May 2002; the pipeline is illustrated on Figure 8-2.

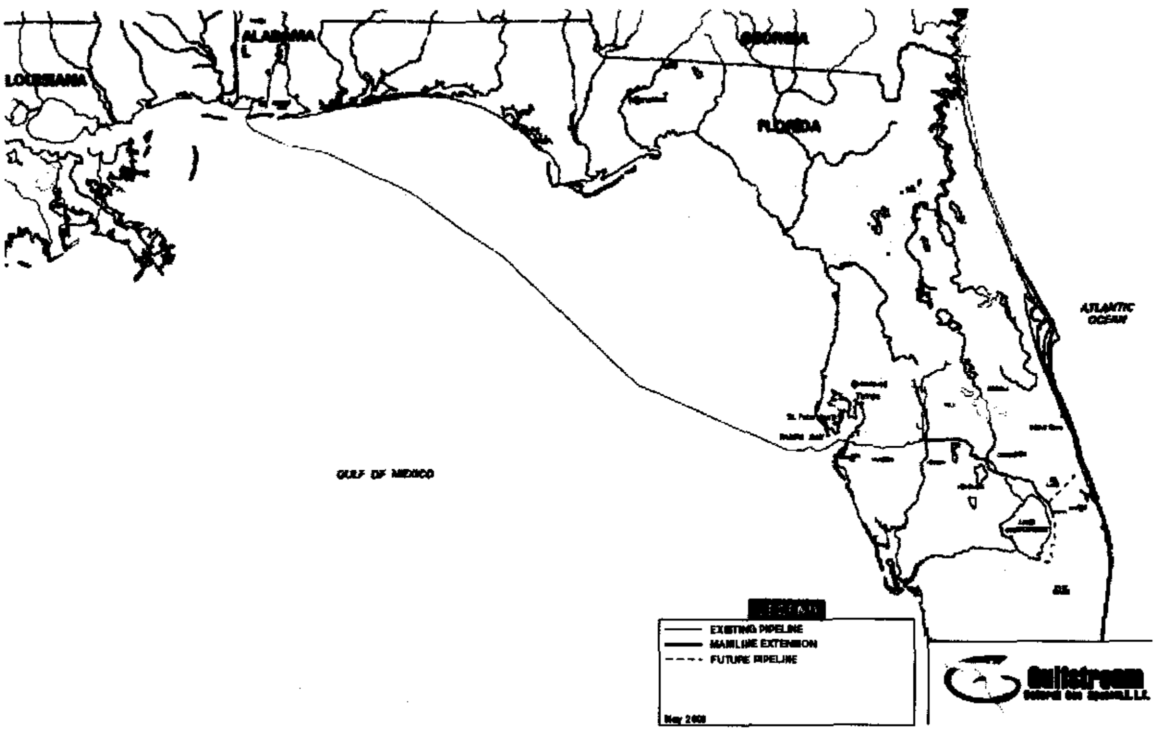

Figure 8-2
Gulfstream System
(Source: http://www.gulfstreamgas.com/images/gulfstream05_03.pdf)

8.2.1 Existing Gulfstream System

The Gulfstream pipeline originates near Pascagoula, Mississippi, and Mobile, Alabama, and crosses the Gulf of Mexico with more than 430 miles of 36 inch diameter pipeline to Manatee County, Florida. Once onshore, 240 miles of 30 inch to 36 inch diameter mainline crosses Manatee, Hardee, Polk, Osceola, Highlands, Okeechobee, and Martin counties in Florida. Gulfstream can serve customers on both the east and west coasts of Florida, as well as the interior of the peninsula. The Gulfstream system went into service with a capacity of 1.1 Bcf per day of gas. The initial subscribed capacity was less than 200 MMBtu/s, leaving approximately 900 MBtu per day of capacity available for new and existing customers. The pipeline was constructed to serve existing and prospective electric generation and industrial projects in central and southern Florida.

Gulfstream has undertaken several system extensions/expansions since its initial in-service date of May 2002. These system expansions were projects designed to connect Gulfstream to facilities located remotely from its initial routing. These project expansions are as follows:

- The Phase II extension of the Gulfstream pipeline was placed into service in February 2005. The 110 mile extension was designed to provide 350,000 dekatherms per day of firm natural gas transportation service for

FPL's Martin and Manatee power plant expansions. The new pipeline traverses five counties: Polk, Hardee, Highlands, Okeechobee, and Martin.

- The Phase III project is scheduled for completion in July 2008. The Phase III project extends the Gulfstream pipeline approximately 35 miles south from Martin to Palm Beach County (approximately 8.8 miles in Martin County and approximately 26.2 miles in Palm Beach County). The extension is designed to deliver 345,000 MBtu per day of firm natural gas transportation service for FPL's West County Energy Center. This volume commitment used the remaining system capacity of 1,095,000 MBtu per day, up from the previous utilized level of 753,000 MBtu per day.
- The Phase IV expansion project is scheduled for completion in January 2009. The Phase IV project will add compression and extend the pipeline to a new market, increasing Gulfstream's mainline capacity from 1.1 Bcf per day to 1.25 Bcf per day by early 2009. The Phase IV expansion project will include construction of approximately 17.5 miles of 20 inch diameter pipeline, as well as the installation of an additional 45,000 horsepower of compression: 15,000 horsepower at an existing compressor station in Coden, Alabama, and 30,000 horsepower at a new station in Manatee County, Florida. The Phase IV expansion project will increase Gulfstream's system capacity by approximately 155,000 MBtu per day to a total of 1.25 Bcf per day.

8.2.2 Market Area Pipeline Interconnections

Gulfstream's pipeline system has two pipeline interconnections that are capable of delivering natural gas within the state of Florida. FGT has two interconnections with Gulfstream, one in Osceola County and one in Hardee County. Both of these interconnections offer delivery of Gulf Coast supplies directly into Gulfstream's system via displacement in the system's market delivery area of central Florida.

8.2.3 Planned Gulfstream System Expansions

Gulfstream conducted an Open Season from June 1 to August 31, 2007, to gauge market interest in an expansion of its existing natural gas pipeline system to serve Florida's rapidly growing natural gas market. The expansion will be designed for up to 750,000 MBtu per day of incremental firm transportation service. The new service from the mainline expansion is anticipated to be available beginning in late 2011.

During the Open Season period, FMPA submitted a request for a volume of 20,000 MBtu per day of firm capacity to serve Cane Island 4. This submittal was a non-binding request for capacity. Subsequent discussions are anticipated to define the specific details of the arrangement for inclusion into a binding Precedent Agreement between FMPA and Gulfstream.

Prior to formally executing a Precedent Agreement, FMPA will analyze each of the possible pipeline options available for serving the Cane Island facilities and will examine the economic and operational benefits of each. As a result, the actual transportation capacity agreed to in the Precedent Agreement may vary from that requested in the Open Season.

8.2.4 Projected Gulfstream Natural Gas Transportation Costs

Gulfstream has indicated that the ultimate project configuration will be determined once a final commitment has been obtained from participating shippers and after subsequent engineering and project development is conducted to optimize the expansion's design. The final transportation rates will be based on the optimized design.

8.3 Cypress Pipeline

Cypress pipeline is a specific section of the Southern Natural Gas (SNG) system, a subsidiary of El Paso Corporation. This pipeline was placed into service on May 1, 2007. The new pipeline provided an incremental 220,000 MBtu per day of takeaway capacity from Elba Island, SNG's LNG facility near Savannah, Georgia. From Elba Island, the 167 mile, 24 inch pipeline extends the SNG system into southern Georgia and northern Florida and interconnects with the FGT system near Jacksonville, Florida. The Cypress pipeline is illustrated on Figure 8-3.

Figure 8-3
Cypress Pipeline
(Source: http://www.elpaso.com/cypresspipeline/default.shtm)

8.3.1 *Planned Cypress Pipeline Expansions*

Currently, there are two planned expansions of the Cypress pipeline:

- Phase 2 will include the addition of 10,350 horsepower of compression at the new compressor station in Glynn County, Georgia; be in service in May 2008. Phase 2 will increase the capacity an additional 116 MBtu per day from 220,000 MBtu per day up to 336,000 MBtu per day.
- Phase 3 will consist of approximately 10 miles of 30 inch diameter pipeline, the addition of 10,350 hp of compression at the new compressor station in Liberty County, Georgia, and an additional 10,350 hp of compression at the new compressor station in Nassau County, Florida. Phase 3 is scheduled for completion by May 2010. Phase 3 will increase the capacity an additional 164 MBtu per day from 336,000 MBtu per day up to a total of 500,000 MBtu per day.

8.4 Projected Availability of Natural Gas Transportation Capacity

As discussed previously, the Florida natural gas transportation system has become increasingly diverse and interconnected. Natural gas transportation providers have a long history of expanding the system to meet the needs of Florida's natural gas transportation customers. With all of the proposed natural gas supply expansion projects under way, FMPA is confident that adequate natural gas transportation capacity will be available to provide reliable service for Cane Island 4. The site being served by both FGT and Gulfstream offers FMPA the opportunity to choose the best transportation capacity option available. Constructing a new generating unit in an area served by two pipelines enhances the reliability of delivering natural gas to Cane Island 4.

9.0 Project Overview

9.1 Description of Project

FMPA's Cane Island 4 will be a 1x1 F class combined cycle unit with a nominal rating of 300 MW at average temperature conditions. The unit will be installed at the existing Cane Island Power Park (CIPP) site located near Intercession City, Florida.

9.1.1 Mode of Operation

Subject to final approval by the Siting Board and the Florida Department of Environmental Protection (FDEP), Cane Island 4 will be permitted for unlimited operation on natural gas in combined cycle mode. The Combustion Turbine Generator (CTG) will have an evaporative cooler to increase warm weather power generation and a steam turbine bypass to the condenser to allow CTG operation if an extended steam turbine generator outage occurs. Cane Island 4 is expected to operate in a cycling and intermediate mode.

9.1.2 Combustion Turbine Generator

The CTG will be a GE PG7241FA enhanced combustion turbine with modulating inlet guide vanes. The CTG will have enclosures for outdoor installation and will include the following major features:

- Dry low NO_x combustion system.
- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Inlet air filter system with silencers and evaporative coolers.
- Lube oil systems.
- Static starting system.
- Fire detection/CO_2 fire protection systems.
- Mark VIe control system with remote work station.
- Off-line/on-line water wash system.
- Package electrical and electronics control compartment.

9.1.3 Heat Recovery Steam Generator

The heat recovery steam generator (HRSG) will be installed outdoors and will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three-pressure, reheat unit with supplemental duct firing by natural gas only to maximize unit output. Cycle operating pressure will be a nominal 2,100 psig. SCR for NO_x emission control will be included within the HRSG. Space will be included for a possible future carbon monoxide (CO) catalyst. The HRSG will discharge to a metal exhaust stack. A stack damper will be included to minimize heat loss during shutdowns. Two 100 percent capacity condensate pumps and boiler feedwater pumps will be included. Natural gas heating, utilizing HRSG intermediate-pressure feedwater as the heating source during normal operation and an electric heater for startup, will be included.

9.1.4 Steam Turbine Generator

The steam turbine will be a GE A14 tandem-compound single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one high-pressure section with a nominal 2,100 psig throttle pressure, one intermediate-pressure section, and one low-pressure section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control systems will be utilized. A surface condenser will be provided for condensing steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. The condenser will be designed for full steam flow bypass around the steam turbine. Provisions for installation of a blanking plate will be included to allow isolation of the steam turbine from the condenser. A single synchronous generator will be included that will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment; supervisory, monitoring, and control systems; and a static excitation system will be utilized. The steam turbine will be provided with enclosures as required for outdoor installation.

A safe shutdown generator will be provided to supply power to shut down and maintain the plant in a safe condition when plant auxiliary power is lost. The engine generator will use diesel as fuel.

9.1.5 Cooling Tower

A multiple cell, mechanical draft, counterflow cooling tower will be used for plant cooling. The cooling tower will be of fiberglass construction and installed on a reinforced concrete basin that will include a pump intake structure housing two 50 percent capacity circulating water pumps and one 100 percent capacity auxiliary cooling water pump. A circulating water chemical feed system also will be included. The cooling tower will be equipped with high efficiency drift eliminators.

9.1.6 Air Quality Control

Cane Island 4 will be subject to FDEP's Prevention of Significant Deterioration (PSD) permitting program, which requires Best Available Control Technology (BACT) for emissions of various pollutants. This concept has been coupled with the selection of a combined cycle process utilizing an advanced combustion turbine. Compared to more conventional simple cycle generating plants, combined cycle units have lower heat rates and, therefore, generate more electrical output (megawatts) per unit of fuel consumed. As a result, air pollutant emissions per megawatt output are minimized. Pollution prevention also is incorporated into the project design by the use of natural gas, which minimizes emissions of SO_2 and particulate matter. In addition, advanced dry low-NO_x combustion technology will be used to minimize NO_x emissions while ensuring that CO and volatile organic compounds emissions are within accepted limits. Moreover, SCR will be installed to further reduce NO_x emissions. Taken together, these design features will make Cane Island 4 one of the most efficient and lowest emissions power plants in the state of Florida.

9.1.7 Control System

The unit will be designed for control through a plant distributed control and information system (DCIS). A Mark VIe control system for control of the turbine will also be included. The DCIS control screens will be located in the existing main plant control room in the plant administration/control building.

9.1.8 Water Use

Water for cooling tower makeup is expected to be reclaimed water (treated wastewater). Reclaimed water will be supplied from the Toho Water Authority via an existing pipeline. In addition, four new onsite wells will be provided for backup cooling tower makeup water supply. It is expected that a maximum of approximately 3.0 million gallons per day (mgd) will be required. Average cooling water makeup is expected to be about 2.4 to 2.5 mgd, based on 24 hour per day operation.

Service water, evaporative cooler makeup water, potable water, and fire protection water will be supplied from the existing CIPP service water system. This system will provide chlorinated well water from existing onsite wells plus one new well. Fire protection water and service water will be stored onsite in new fire water/service water storage tanks. The new fire protection water system will include two new fire water storage tanks to provide two independent dedicated fire water supply sources, two fire water pumps, a hydrant system, dry-pipe sprinkler or foam system for the steam turbine generator lube oil piping, and other fire protection systems in accordance with National Fire Protection Association (NFPA) recommendations. The new system will also connect with the existing CIPP fire protection system. Two 500,000 gallon combined service water and fire water storage tanks, each with a reserve capacity of 300,000 gallons dedicated to fire water, will be installed. Two new fire water pumps will be included, each one capable of supplying 2,000 to 2,500 gallons per minute (gpm) of water to the systems.

Demineralized water will be provided from the existing water treatment system for steam cycle makeup. A new demineralized water tank will be installed.

9.1.9 Project Process Wastewaters

There will be five major sources of wastewater: sanitary waste, oil/water separator effluent, cooling tower blowdown, treated chemical wastewaters, and evaporative cooler blowdown. Sanitary wastes will be routed to the existing site septic system. Oil/water separator effluent will be directed to an onsite percolation pond. Other wastewaters, consisting primarily of cooling tower blowdown, will be returned to the Toho Water Authority pipeline.

9.1.10 Storm Water Management

The existing CIPP Unit 3 storm water management system will be expanded to handle Unit 4. Storm water system design will be in accordance with FDEP, South Florida Water Management District (SFWMD), and Osceola County requirements. Storm water runoff will be collected in an onsite detention pond for percolation into the groundwater.

9.1.11 Transmission Interconnection

The project will interconnect to the existing CIPP substation. The CIPP substation is connected to the KUA, OUC, TECO, and PEF 230 kV transmission systems through four existing transmission lines. The CTG and STG will each connect to separate 18 kV/230 kV generator step-up transformers. The CTG and the STG will each have generator breakers. Auxiliary power will be provided by auxiliary transformers connected to each generator's 18 kV isolated phase bus duct. The CIPP 230 kV substation will be modified and expanded by one bay to interconnect the CTG and STGs via a collector bus. Existing onsite transmission lines will be rerouted to accommodate the new unit.

9.1.12 Site Design Conditions

Table 9-1 presents the conceptual design conditions for the project site.

Table 9-1
Conceptual Design Conditions for the Project Site

Condition	Value or Range	Reference
Maximum Temperature Coincident Relative Humidity	102° F 33%	National Climatic Data Center
Minimum Temperature Coincident Relative Humidity	19° F 58%	National Climatic Data Center
Average Temperature Coincident Relative Humidity	73° F 80%	National Climatic Data Center
Wind Loading	Basic Wind Speed: 110 mph, Wind-Borne Debris Region, Importance Factor (Iw): 1.15, Exposure C	ASCE 7-05
Seismic Zone	Not applicable	FBC does not consider seismic loads for building codes.
Site Elevation	Average 82 feet above msl	Site Arrangement Drawing
Location	Outdoors, Corrosive Environment	Site Arrangement Drawing

9.1.13 Site Plan

Figure 9-1 presents the conceptual site plan and shows the arrangement and locations of the major equipment for each unit.

9.1.14 Water Mass Balance

Figure 9-2 presents the preliminary water mass balance for CIPP Unit 4.

9.1.15 Overall One-Line Diagram

Figure 9-3 presents the conceptual electrical one-line diagram showing the arrangement of the electrical interconnections to the existing transmission system and electrical power distribution for the project.

9.1.16 Cycling Design Features

Cane Island 4 will include several design features for cycling load operation. The STG will be selected in combination with the HRSG to provide a reasonable design throttle pressure to ensure satisfactory cycling operation. Because the unit is going to be designed for cycling operation, a nominal throttle pressure of 2,100 psig will be used for design purposes. In comparison to a higher design throttle pressure such as 2,400 psig, a 2,100 psig operating pressure allows reduced wall thicknesses in HRSG drums and piping, thereby reducing thermal stresses and allowing reduced warm-up times. This reduces overall startup time and increases ramp rates when changing loads.

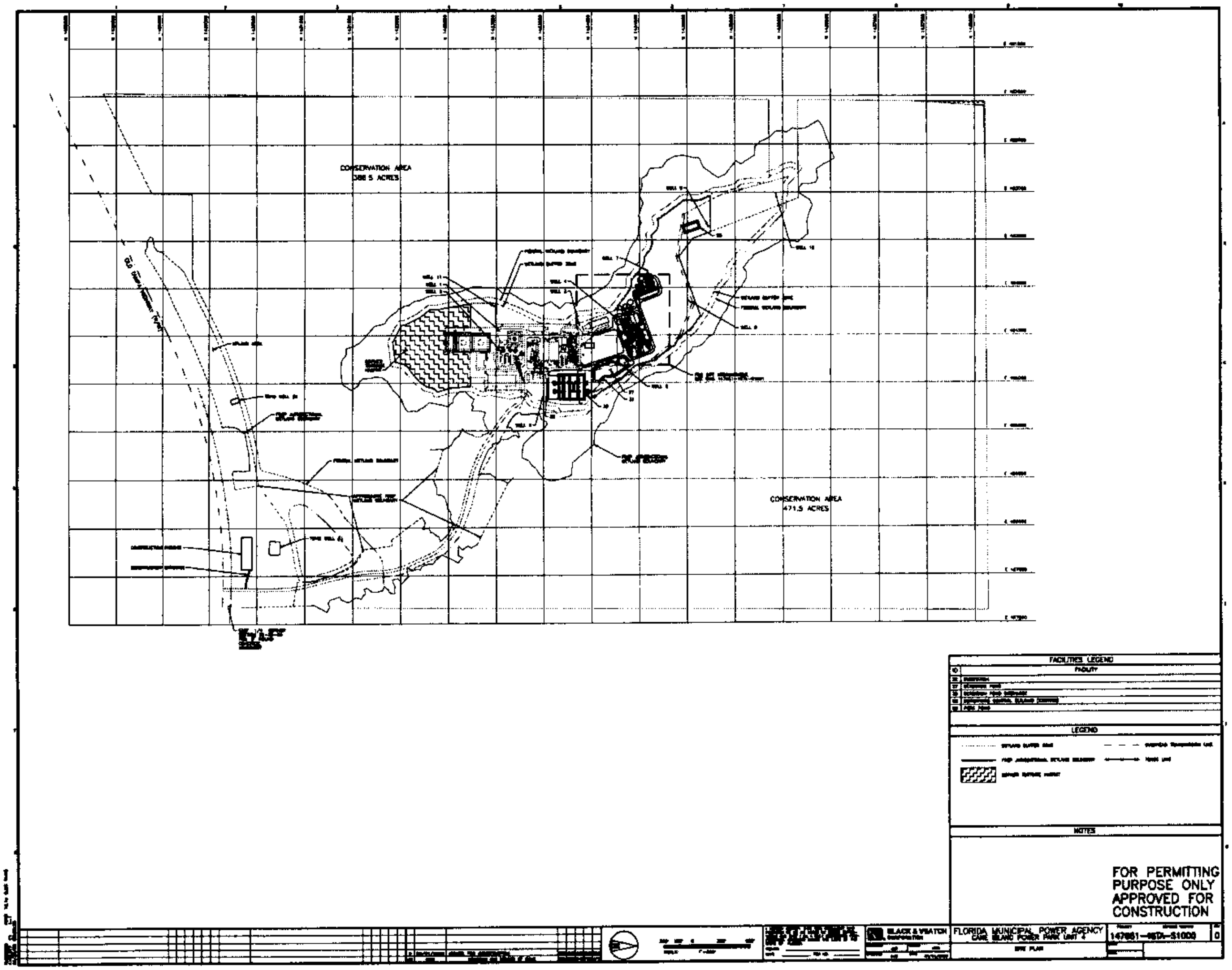

Figure 9-1
Conceptual Site Plan

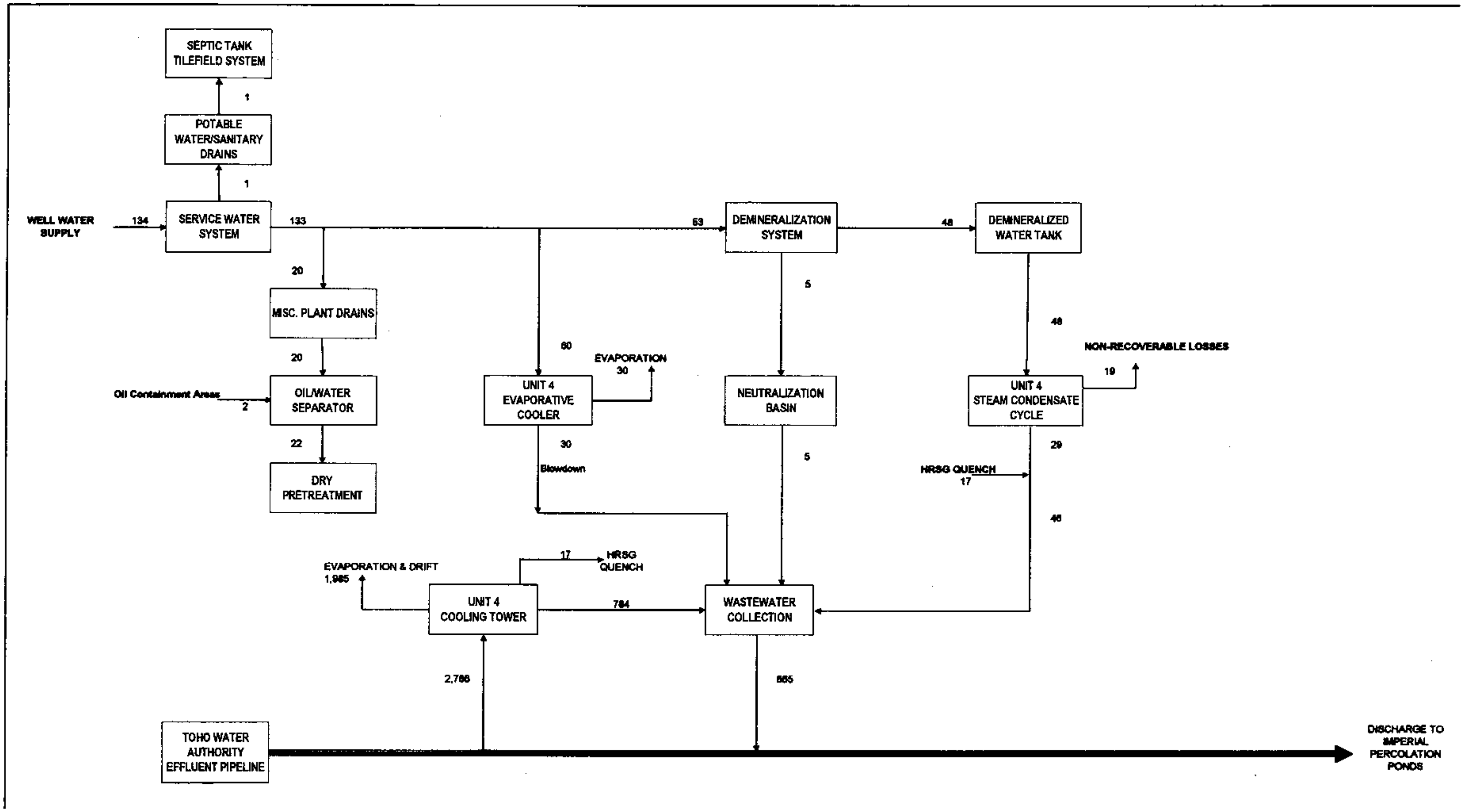

Figure 9-2
Preliminary Water Mass Balance

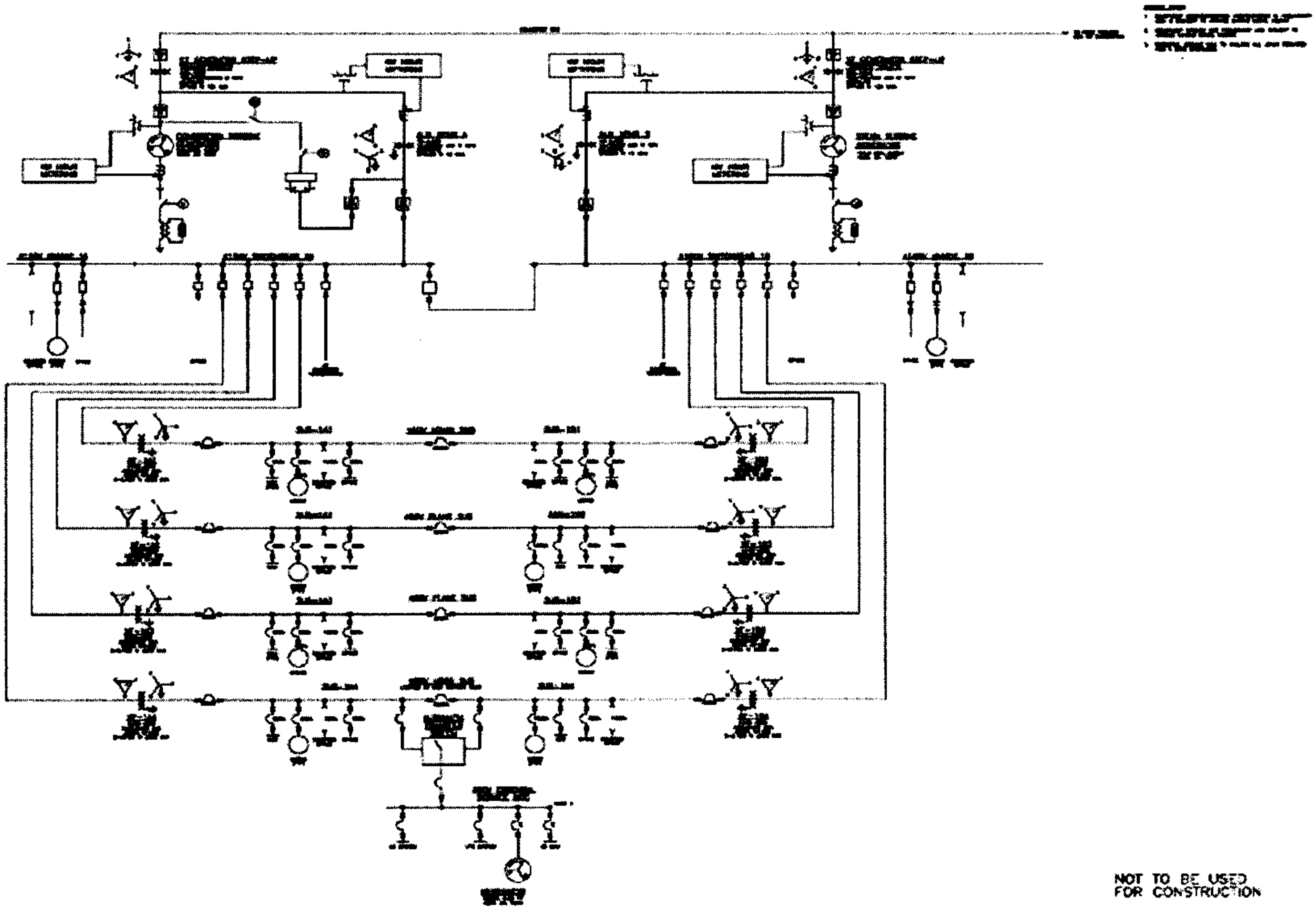

Figure 9-3
Conceptual One-Line Diagram

HRSG design features to facilitate cycling operation will include nozzle arrangement and connections, use of full penetration welds, separation of headers, and use of higher strength drum and header materials to enable thinner wall construction to reduce stress from temperature gradients. Unit design also will include a stack damper for heat retention, automated vent and drain valves to control pressure and drain condensate during shutdowns and startups, a condensate polisher to facilitate condensate quality during startup, and 100 percent bypass systems to enable steam/turbine temperature matching.

9.1.17 Ammonia Systems

Ammonia will be required in the SCR process for NO_x control. Vaporized ammonia will be injected into the combustion turbine exhaust gases before they pass through the catalyst bed, which will be installed in the HRSG. The onsite ammonia system will include unloading facilities, ammonia storage tank, forwarding system, and vaporizing facilities. Aqueous ammonia will be delivered to the site by tanker trucks that will include integral unloading pumps. The aqueous ammonia will be stored as a liquid in a nominal 40,000 gallon tank, which provides for four full tanker truck deliveries. The liquid ammonia will be forwarded to the HRSG, vaporized, and injected upstream of the catalyst.

9.1.18 Capability for Future Expansion

The site will have the capability for the future installation of an additional combined cycle unit. Refer to the Cane Island Site Plan (Figure 9-1), which shows the site with space to the north of Unit 4 to allow installation of one future similar sized combined cycle unit.

9.1.19 Fuel Supply

The fuel for Cane Island 4 will be natural gas. Natural gas is available onsite from existing FGT and Gulfstream pipelines. The existing pipeline pressure is more than adequate for supply to the combustion turbine; therefore, gas compressors will not be included. The quality of the pipeline gas and the final requirements of the combustion turbine manufacturer will be reviewed during detailed design to ensure that any additional conditioning equipment (other than typical heating, pressure control, and filtering type equipment) will not be required.

9.1.19.1 Natural Gas Quantities. Hourly fuel consumption rates will depend on plant load, ambient conditions, and whether supplemental firing is being used. Table 9-2 provides indicative estimates of average fuel consumption rates.

Table 9-2
Indicative Hourly Fuel Consumption Rates

Description of Operating Mode	MBtu/h (HHV)
Average ambient, natural gas fuel, supplemental firing off, full load	1,743
Average ambient, natural gas fuel, supplemental firing on, full load	2,308

9.1.19.2 Natural Gas Transportation, Delivery, and Metering. Natural gas will be regulated, metered, and conditioned onsite. A new meter run, pressure reduction station, and natural gas conditioning equipment will be included. The natural gas conditioning equipment will include a fuel gas scrubber, two coalescing gas filters, and a performance fuel gas heater.

9.2 Project Procurement and Implementation Plan

FMPA will implement the addition of Cane Island 4 to CIPP through purchase of the major rotating equipment and contracts for engineering, procurement, and construction services for the installation of the power block and interfaces with the existing units. KUA will provide the substation modifications required to connect Unit 4 to the CIPP substation.

The CTG and the STG were purchased from GE through an option available under the Treasure Coast Energy Center Unit 1 Combustion Turbine Generator Purchase Order.

A contract or contracts will be executed to provide the project engineering, balance of procurement, construction, and startup. Contracts will be with firms that are experienced and qualified to implement combined cycle projects of the size and complexity of Cane Island 4. Contracts will be released in the spring of 2008 to allow for the procurement of equipment and materials that require long lead times. Equipment lead times have increased significantly in the last year because of world demand for power plant equipment.

9.3 Capital Cost

The capital cost estimate was based on building a new 1x1 7FA combined cycle generating unit at the existing CIPP near Intercession City, Florida. The capital cost estimate includes direct costs for purchased equipment and materials, construction contract costs, and indirect costs. Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.

Construction costs were developed on the basis of an EPC contract. It was assumed that construction would be performed using a 50 hour work week, with some 60 hour work weeks. Local labor craft rates used included payroll, payroll taxes, and benefits. Construction indirects and construction equipment costs were included in the construction and service contracts portion of the estimate.

Indirect costs associated with construction were included in the base cost estimate. General indirect costs included all necessary services required for checkouts, testing services, and commissioning. Insurance for general liability was included. Contractor engineering, contractor field construction management, technical direction, contingency, profit, equipment transportation costs, startup, and commissioning were also included.

Owner's cost were estimated on the basis of FMPA's experience with other similar projects. These cost items include the following:

- Transmission system upgrades and interconnection lines.
- Project development, preliminary engineering, permitting, and legal costs.
- Consultant engineering and construction management services to act as owner's engineer.
- Rolling stock.
- Initial inventories of furniture, equipment, supplies, and consumables.
- Operating and maintenance (O&M) mobilization.
- Owner's project management and oversight.
- Builder's risk insurance.
- Fuel cost for operational testing.
- Owner's contingency.

Table 9-3 provides a summary of the capital cost estimate.

Table 9-3 Cane Island 4 In-Service Capital Cost Estimate ($000)	
Item	
Combustion Turbine/Steam Turbine	48,400
EPC	246,900
Contingency	25,000
Owner's Costs	69,500
Total Project Costs	389,800
Interest During Construction	31,800
Total Installed Capital Cost	421,600

9.4 Operating and Maintenance Cost

O&M costs include fixed and variable costs. Fixed costs are independent of plant operation; variable costs are directly related to the plant operation. The O&M cost estimates were based on the following assumptions:

- Natural gas fuel.
- Cooling tower makeup water provided by the Toho Water Authority, as treated sewage effluent.
- Potable water and service water from the existing service water system, which provides chlorinated water from existing onsite wells.
- A full-time staff of 6 personnel consistent with staffing levels agreed upon by FMPA and KUA.
- An operating profile consisting of up to 200 starts per year and an average capacity factor of 50 percent.

9.4.1 Fixed O&M Costs

Fixed costs include labor, payroll burden, fixed routine maintenance, and administration costs. For Cane Island 4, the fixed costs were estimated to be $4.56/kW per year (2008 dollars), assuming an average annual net output of approximately 307.2 MW.

9.4.2 Variable O&M

Variable O&M costs include consumables, chemicals, lubricants, water, and major inspections and overhauls. Major inspection and overhaul costs can be covered under long-term service agreements with the turbine manufacturer, or each overhaul can be subcontracted to the turbine supplier or a third party maintenance provider. As the plant is not staffed to fully perform these major inspections, it was assumed that these will be subcontracted to the turbine supplier or a third party O&M provider. Variable O&M costs vary as a function of plant generation. The variable O&M cost for Cane Island 4 was estimated to be $3.30/MWh in 2008 dollars.

9.5 Heat Rate

Table 9-4 summarizes the anticipated plant performance on the basis of the heat balances developed for various operating conditions for the project. The heat balances and the plant performance are for Cane Island 4 using standard GE data for a 1x1 7FA combined cycle plant. This performance is considered representative of F class combined cycle performance. Performance degradation of 2.7 percent for output and 1.5 percent for heat rate has been included in the estimated performance.

Table 9-4
Estimated 1x1 F Class Combined Cycle Performance (Natural Gas)

Performance Point	Unit Output (kW)	Unit Heat Rate (Btu/kWh, HHV)
Winter (19° F and 58% relative humidity) (Full Load)	329,800	7,435
Summer (102° F and 33% relative humidity) (Full Load)	299,600	7,445
Average (73° F and 80% relative humidity) (Full Load with Duct Firing)	307,200	7,420
Average (73° F and 80% relative humidity) (Full Load without Duct Firing)	246,990	6,969
Average (73° F and 80% relative humidity) (75% Load)	192,110	7,289
Average (73° F and 80% relative humidity) (50% Load)	140,990	7,923

9.6 Emissions

The estimated emissions for Cane Island 4 are presented on Table 9-5. The estimated emissions include operation of an SCR.

Table 9-5
Cane Island 4 Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165

[1]Emissions are at full load at 73° F, reflect operation on natural gas, and include the effects of SCR and dry-low NO_x combustors.

9.7 Availability

Equivalent availability is a measure of the capacity of a generating unit to produce power considering operational limitations such as equipment failures, repairs, routine maintenance, and scheduled maintenance activities. Equipment outages and forced outages are not predictable and, because of this, a forced outage of 2 percent was assumed for each year. Scheduled outages will be determined by the hours of operation and number of starts. While various F class turbine manufacturers determine the basis for scheduled outage intervals somewhat differently, they all have fairly consistent maintenance programs that typically consist of combustion inspections, hot gas path inspections, and major overhauls. Based on the expected operating profile for the plant, the equivalent availability for Cane Island 4 was estimated to be 94 percent. On average, 14 maintenance days per year and a 2 percent forced outage rate have been assumed.

9.8 Schedule

Cane Island 4 is planned to be available for operation during the summer 2011 peaking season. To achieve this plan, construction is planned to start during July 2009. A 22 month construction schedule is planned to provide a commercial operation date of May 1, 2011. Detailed engineering activities will be required in advance of July 2009 to achieve the planned commercial operation date. These activities are planned to commence during the second quarter of 2008. Similarly, procurement activities such as specification, equipment proposal solicitation, and contract negotiation for the HRSG and other long-lead time equipment items, will occur during 2008 to allow for delivery of this equipment to support the schedule. A summary level schedule is provided in Figure 9-4.

Cane Island Power Park Unit 4
Summary Level Schedule

25-Apr-08

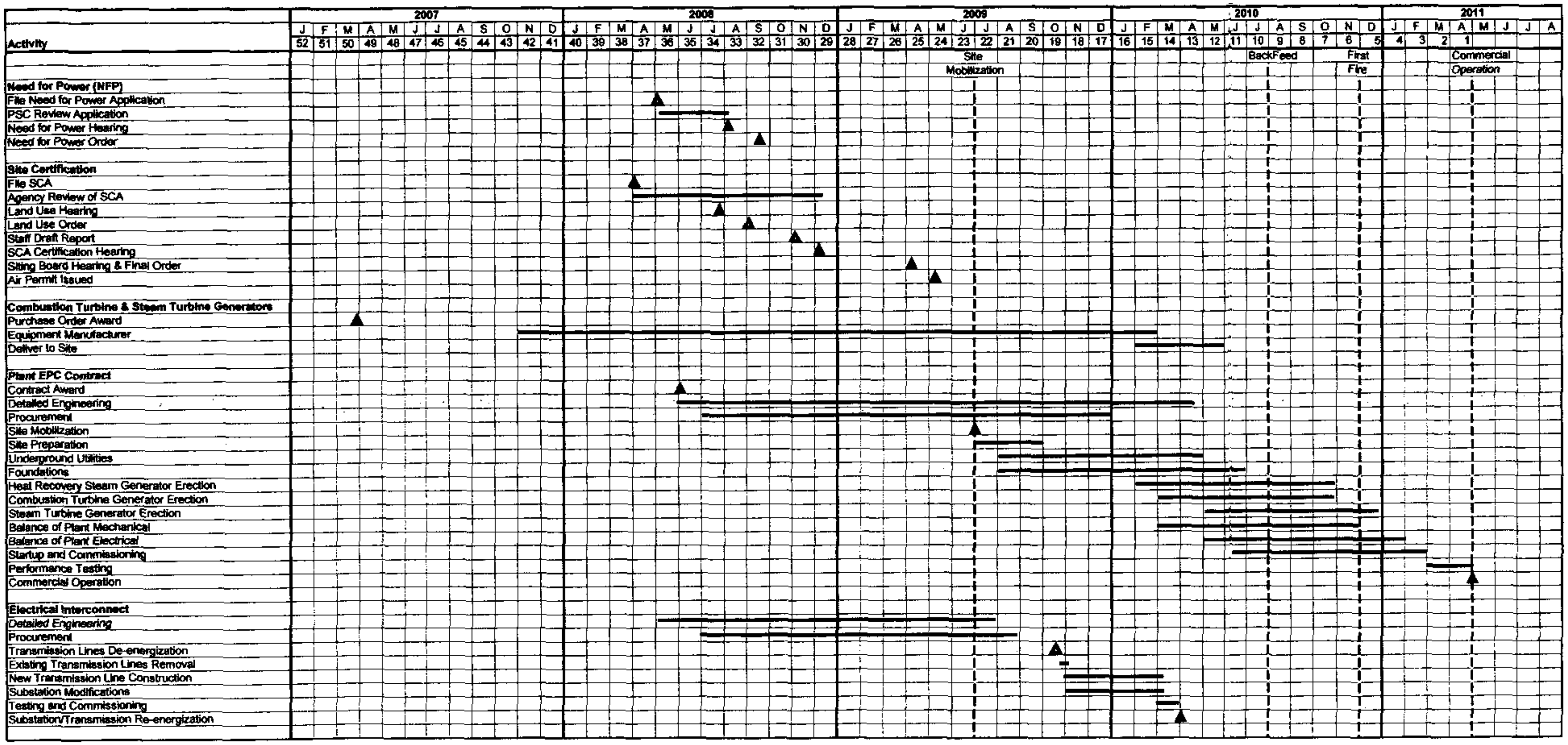

Figure 9-4
Cane Island 4 Schedule

10.0 Oil Backup Analysis

This section reviews issues relevant to dual fuel capability for Cane Island 4 within the current operating environment in Peninsular Florida. In reviewing the projected operation of Cane Island 4, FMPA has concluded that the incremental benefit of including oil backup capability in this unit are overshadowed by the incremental costs, maintenance, and limited reliability benefits associated with this capability. The natural gas transportation system for Florida has become significantly more diversified in recent years; both in delivery capability as well as receipt point access to supply. As a result, the delivery of natural gas in Florida has become much more reliable. Moreover, the large amount of natural gas generation with oil backup in the state makes the availability of oil when it might be needed more uncertain. Furthermore, Cane Island 4 is currently connected to two independent sources of supply; making the disruption of Cane Island 4's natural gas supply much more unlikely.

10.1 Historical Rationale Regarding Oil Backup

The Florida Public Service Commission (FPSC) must take into account the need for electric system reliability and integrity, including fuel supply reliability. Historically, utilities proposed dual fuel capability because natural gas was supplied to Florida through a single natural gas pipeline. The single pipeline was subject to disruptions affecting the supply for all the natural gas usage in the state. The possibility of natural disasters (such as hurricanes that could affect the predominant supply source in the Gulf of Mexico) has caused speculation of natural gas curtailments within the State of Florida. However, as the natural gas transportation network has expanded and supply sources more diverse, the probability that a hurricane or other natural disaster could or would disrupt natural gas supplies to the state has decreased.

In recent years, the FPSC has approved the need for natural gas fueled projects with oil backup as proposed. Those projects were generally served by a single natural gas pipeline. However, the FPSC approved Florida Power & Light Company's Manatee Unit 3 project without oil backup. Like the Cane Island site, Manatee Unit 3 has access to natural gas transportation service from both FGT and Gulfstream.

10.2 Federal Requirements

There are no federal requirements for oil backup for natural gas fueled generating plants. There are federal requirements, however, that mandate certain generating power plants are required to have dual fuel capability. Title II of the Power Plant and Industrial

Fuel Use Act of 1978 (FUA), as amended (42 U. S. C. 8301 et seq.), provides that no new baseload electric power plant fueled with natural gas or other petroleum products may be constructed or operated without the capability of use coal or another alternate fuel as a primary energy source. For the purpose of this requirement, a baseload facility is defined as one whose annual generation in kilowatt-hours exceeds its capacity multiplied by 3,500 hours (40 percent capacity factor). To meet the requirement of coal capability, the owner or operator of such facilities proposing to use natural gas or petroleum as its primary energy source shall certify (pursuant to FUA Section 201(d), and Section 501.60(a)(2) of DOE's regulations to the Secretary of Energy prior to construction or prior to operation as a baseload power plant) that such power plant has the capability to use coal or another alternate fuel. This certification is met for Cane Island 4 and other natural gas fueled combined cycles through the ability to be modified to burn syngas produced by coal. This requirement does not require Cane Island 4 to possess the capability to switch fuel in real time, but only requires that the plant be capable of generating electricity while burning the alternate fuel.

10.3 NERC Requirements

There are no NERC requirements that require Cane Island 4 to have oil backup.

10.4 Florida Gas Supply

Section 8.0 provides a detailed description of the natural gas transportation system in Florida. Initially, peninsular Florida was served by a single natural gas pipeline owned by FGT. As natural gas consumption in the state has grown, the natural gas transportation network has become much more diverse as described in Section 8.0. Currently, peninsular Florida is served by the FGT pipeline, the Gulfstream pipeline, and the Cypress pipeline. The pipelines provide geographic diversity, which mitigates potential disruption from hurricanes and other natural disasters. Proposed expansions by FGT and Gulfstream will provide even more diversity. In addition to the redundancy afforded by multiple pipelines, diversity has increased regarding the receipt of gas into the serving pipelines with the introduction of significant new storage and supply sources as described in Section 6.0. Geographic diversity of supply and storage makes it increasingly unlikely that a single hurricane or other natural disaster will interrupt the supply flow of natural gas to Florida. The reliability of natural gas supply to Florida is markedly improved over what it was just a few short years ago.

10.5 Disadvantages of Dual Firing

The potential increased reliability available using fuel oil backup must be carefully balanced with the disadvantages of installing and maintaining such backup. The cost disadvantages include both capital and operation costs. The capital costs required for oil backup are generally greater than appear at first blush due to the capital costs for fuel oil handling and storage facilities and for the associated costs for providing the demineralized water necessary to meet air quality requirements for combustion turbine operation using fuel oil. The estimated capital costs for adding oil backup to Cane Island 4 are presented in Table 10-1.

In addition to the increased capital cost, there are also costs associated with:

- Increased demineralized water consumption resulting from water injection when operating on fuel oil.
- Increased air permitting requirements.
- Increased operations and maintenance costs to maintain and test the added equipment including test firing on fuel oil.
- Increased permit requirements due to increased water consumption and wastewater disposal.
- Increased environmental compliance requirements during operation of the plant.
- Increased probability of forced outage due to increased equipment complexity.
- Deterioration of stored fuel resulting in chance of failure when switching to fuel oil or starting on fuel oil.

10.6 Fuel Oil Delivery Limitations

Another disadvantage that should be considered to the further reliance on fuel oil as backup in Florida relates to its availability during times of crisis. If a situation arose requiring significant consumption of fuel oil for power generation, the ability of the existing infrastructure to deliver the quantities required could be overwhelmed.

The most recent data available for the Florida system indicates that 39,600 MW of generation can be fueled with natural gas. Of this amount, nearly 29,000 MW of generation is capable of switching from gas to fuel oil. Using an average conversion efficiency (heat rate) of 9,000 Btu/KWh for capacity operating on fuel oil, the hourly consumption at full load equates to a consumption rate of 1,890,000 gallons per hour.

Table 10-1
Cost to Add Liquid Fuel Firing for Cane Island 4

Item	Estimated Cost, $
GE CTG Scope Addition	1,100,000
GE Scope Erection/BOP	370,000
Fuel Oil Storage Tanks, FP, and Berms	1,500,000
Fuel Oil Unloading	--
Fuel Oil Forwanding Skid	160,000
Piping and Electrical - Plant to Tanks	950,000
Demineralized Storage	1,250,000
Reverse Osmosis Unit	1,080,000
Water Treatment Building	230,000
False Start Drain Tank	50,000
Wastewater Additions	100,000
Demin Water Pumping	50,000
Service Water Pumping	50,000
EPC Contractor Markups	580,000
Startup and Commissioning Fuel Usage	2,500,000
Fill of Fuel Oil Tank for Commercial Operation	2,500,000
Interest and Bond Fees on Capital	560,000
Total	13,030,000

As shown in Table 10-2, based on a maximum pumping rate for the typical fuel delivery truck in the Florida market, approximately 315 trucks pumping at full capacity would be required to supply the needed fuel for each hour of the pipeline outage with several times that number being required to maintain the pumping capacity. While it would be unlikely that the entire dual fuel capacity would be needed at the same time, the number of trucks required would still be staggering. In addition, the fuel oil sources would likely come from the Gulf Coast and subject to much the same natural disaster exposure experienced by the natural gas supply. It is likely that natural gas supply flow to Florida would be restored before the fuel oil capacity.

Table 10-2
Fuel Oil Requirements

Item	Quantity	Unit
Dual Fuel Capability	29,000	MW
Heat Rate	9,000	Btu/KWh
Calorific Value	5.8	MBtu/bbl
Hourly Fuel Oil Burn	261,000	MBtu/hour
Hourly Fuel Oil Flow	1,890,000	Gallons/hour
Typical Size of Truck	4,500	Gallons
Maximum Pumping Rate	6,000	Gallons/hour
Required Number of Trucks	315	Trucks/hour

10.7 Existing FMPA Dual Fuel Capability

All of FMPA's existing natural gas fueled generation has oil backup. For the summer of 2008, this will amount to 1,032 MW. When Cane Island 4 comes online in the summer of 2011, it will comprise approximately 19.9 percent of FMPA's peak demand, which is only slightly more than FMPA's 18 percent reserve margin. With all of FMPA's existing natural gas fueled generation with oil backup and Cane Island 4 only representing FMPA's reserve margin, the installation of Cane Island 4 will maintain reliability for FMPA's system and Florida as a whole.

10.8 Cane Island Site

The Cane Island site is unique in several ways. First, it is served by both FGT and Gulfstream, thereby decreasing the probability that the supply of natural gas would be disrupted simultaneously on each pipeline. The Cane Island site contains three existing units, all of which have oil backup. If there were a severe limitation on the volume of natural gas available, the gas that was available could be used in Cane Island 4 and the other three Cane Island units would operate on fuel oil. The Cane Island facility would be 100 percent available in this scenario.

Gas supply to the Cane Island site historically has been extremely reliable. Since the first unit at Cane Island went into operation in 1995, oil has been burned at Cane Island a total of 77 hours. The 77 hours of operation on oil is equivalent to 0.07 percent increase in the forced outage rate. No reliability evaluation could ever justify the expenditure of $13.0 million for a 0.07 percent improvement in the forced outage rate of a 300 MW combined cycle.

10.9 Conclusion

The increase in gas fired generation in Florida has resulted in diminishing returns with regard to the installation of oil as a backup fuel. Further use of oil as a backup fuel will do little to increase reliability and certainly is not cost effective relative to the small increase in demonstrated reliability. The natural gas supply system in Florida has become increasingly diverse and reliable. With two independent suppliers of natural gas (FGT and Gulfstream) to the Cane Island Site, Cane Island 4 will have a reliable fuel supply. Consistent with previous FPSC decisions regarding backup fuel for sites with two natural gas supplies, the addition of fuel oil for backup at Cane Island 4 is not justified.

11.0 Transmission System Impacts

Cane Island 4 will be interconnected to the existing Cane Island substation which is interconnected to the jointly owned FMPA and Kissimmee Utility Authority (KUA) transmission system. FMPA completed a study evaluating the connection of the Cane Island 4 associated with Generator Interconnection Service (GIS) to the FMPA/KUA Transmission System. In addition, FMPA completed an attendant request for Network Resource Interconnection Service (NRIS) with Progress Energy Florida (PEF).

The proposed interconnection and integration of Cane Island 4 have been evaluated and approved by FRCC, which found that the project will be reliable and adequate, and that it will not adversely impact the FRCC transmission system. PEF also has approved the request for NRIS. The following sections describe the interconnection, the system impact analysis, and the FRCC and PEF approvals.

11.1 Description of Interconnection

The existing Cane Island plant and its associated transmission lines are jointly owned by KUA and FMPA. Cane Island has existing direct transmission interconnections with Kissimmee Utility Authority (KUA), Orlando Utilities Commissions (OUC), Tampa Electric Company (TECO), and PEF. Two 230kV transmission lines routed to the north of Cane Island connect to the TECO Osceola and OUC Taft Substations respectively. A 230kV line routed to the east of Cane Island plant connects to Clay Street Substation jointly owned by FMPA and KUA. Another 230kV line routed to the west connects to Intersection City Substation owned by PEF.

The Cane Island 230kV substation station will be reconfigured and expanded by one bay to interconnect the Cane Island 4 combustion turbine generator (CTG) and steam turbine generator (STG) via a collector bus. Existing on-site transmission lines will be rerouted to accommodate the new unit. The CTG and STG will each connect to separate 18kV/230kV generator step-up transformers. The CTG and STG will each have generator breakers. Auxiliary power will be provided by auxiliary transformers connected to each generator's 18kV isolated phase bus duct.

11.2 System Impact Analysis

The purpose of the study conducted by FMPA was to identify thermal overloads and voltage limit violations, to identify any circuit breaker short circuit capability limits, and to identify any instability or inadequately damped response to system disturbances resulting from Cane Island 4.

The study included Load Flow Analysis of the transmission service request to provide Cane Island 4 with NRIS, Short Circuit Analysis, and Dynamic Stability Analysis. FRCC provided the evaluation of the Steady State Analysis with the load flow screening results.

The purpose of the short circuit analysis was to determine the impact of increased fault currents as a result of Cane Island 4 addition. The analysis result indicates that fault current levels were close to the 40 kA interruptible rating at the Cane Island 230kV substation. FMPA plans to remedy the situation by replacing the 230kV circuit breakers at Cane Island substation with 2 cycle, 63 kA breakers. The cost associated with replacing the breakers is included in the Owner's Costs portion of the Cane Island 4 capital cost estimate in Table 9-3.

The dynamic stability analysis simulations resulted in delayed clearing faults which indicate no instability or inadequately damped response to system disturbances or any adverse impact to the system.

11.3 FRCC and PEF Approval

FRCC's Transmission Working Group (TWG) and Stability Working Group (SWG) evaluated the proposed interconnection and integration of the Cane Island 4. The TWG reviewed the Steady State, Stability, and Short Circuit Analysis of the proposed interconnection and integration. Based on the review and analysis conducted by TWG and SWG, the FRCC Planning Committee approved the proposed interconnection and integration plan finding that, with currently scheduled system upgrades, it will be reliable and adequate and that it will not adversely impact the reliability of the FRCC transmission system. PEF likewise approved FMPA's request for NRIS.

12.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand and to maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated availability of capacity. This section presents the development and analysis of the reliability criteria used by FMPA.

A number of methods are used in the electric utility industry to calculate a utility's system reliability. One method is the reserve margin and another is the Loss of Load Probability (LOLP); these approaches apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. FMPA uses a reserve margin for planning purposes that accounts for partial requirements (PR) and other purchases that include reserves. The two methods are discussed in the following subsections.

12.1 Reserve Sharing Requirements

Section 25-6.035 of the Florida Administration Code (FAC) requires that Florida utilities maintain a minimum 15 percent planned reserve margin for purposes of equitable sharing of energy reserves. Section 25-6.035 indicates that this 15 percent minimum requirement is not for setting a prudent level of reserves for long-term planning or reliability purposes.

12.2 Reserve Margin Requirements

12.2.1 Traditional

FMPA uses a minimum 18 percent reserve margin in the summer and a minimum 15 percent reserve margin in the winter. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. FMPA plans to maintain its seasonal reserve margins for firm load obligations. The higher reserve margin in the summer helps mitigate risk from the summer peak periods, which are generally much longer in duration than the winter peak periods.

The most commonly used deterministic method is the reserve margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity - System Firm Peak Demand (After Interruptible Load)}}{\text{System Firm Peak Demand (After Interruptible Load)}}$$

FMPA has several PR purchases in which the supplying utility is responsible for providing reserves. Therefore, FMPA subtracts the PR services from the net capacity and peak demand. The formula used by FMPA to calculate its reserve margin is based on the following, which considers that the PR purchases include their own reserves:

$$\frac{(\text{System Net Capacity - PR}) - (\text{System Net Peak Demand - PR})}{(\text{System Net Peak Demand - PR})}$$

12.2.1.1 Demand Response Considerations. Special consideration needs to be given to the portion of planned reserve requirements that can be covered by demand response (DR). Because DR grows as a portion of planned reserves, the frequency that DR is exercised increases. Depending upon the nature of the DR, increased frequency of its use can result in customer dissatisfaction, even to the extent that they leave the DR program, which can further exasperate reserve issues. Progress Energy Florida encountered this situation a few years ago, when many customers left their direct load control program.

FMPA has not specifically evaluated this limit for its system. The DR levels potentially anticipated in this application do not appear to be great enough to cause this problem. If, in the future, greater DR levels are implemented, limits on prudent DR levels may be encountered. Though FMPA has not evaluated this limit specifically, general observations indicate that the prudent upper DR level may be approximately half of the planning reserve margin.

12.2.1.2 Renewable Considerations. The inclusion of significant amounts of renewable energy that is neither dispatchable nor controllable raises questions with respect to its contribution to system reliability. Solar and wind are primary examples of this type of capacity. Currently, FMPA is not anticipating adding wind capacity to its system, but is actively pursuing the addition of solar photovoltaic capacity. As discussed in Section 13.0, FMPA's capacity addition requirements are driven by summer peak loads. An analysis of solar photovoltaic's capacity factor over the expected times of FMPA's summer peak indicates that solar photovoltaic generation would have an average capacity factor of approximately 33 percent.

For this Application, 33 percent of the nameplate capacity for solar photovoltaic was counted as firm capacity in order to calculate reserve margins. At a 10 MW solar photovoltaic nameplate level, the contribution to firm reserves and its attendant effect on reliability would be minimal. With significantly higher levels of photovoltaic generation, this approach will require additional evaluation, especially with respect to system reliability. The results of this additional evaluation may result in a requirement for some level of backup capacity or DR for photovoltaic capacity. In addition, further evaluation may indicate a need to limit the amount of photovoltaic capacity proportionate to the planning reserve margin, as discussed in the previous subsection for DR.

12.3 LOLP

LOLP is the second commonly used method of calculating the reliability of a utility system. This method is advantageous in that it can result in a measure of how much capacity is needed to meet a target level of reliability (typically, an LOLP criterion of no more than 1 day in 10 years is used). FRCC utilizes a reserve margin criterion (Resource Adequacy Standard) for capacity planning purposes that results in resource levels that meet an LOLP criterion of no more than 1 day in 10 years. The Resource Adequacy Standard calls for a reserve margin of 15 percent versus firm load.

The calculation of LOLP for an individual utility is difficult because of the need to properly evaluate the level of assistance from neighboring utilities. For FMPA, this problem is compounded since the ARP comprises 15 individual utilities. An LOLP evaluation for FMPA has not been conducted. Several years have passed since an LOLP evaluation was conducted for FRCC. The last evaluation confirmed that FRCC's LOLP met the 1 day in 10 years criterion.

12.4 Reliability Criteria Summary

For evaluation purposes for this Application, an 18 percent summer reserve margin and 15 percent winter reserve margin were used for capacity addition requirements. For evaluation purposes for this Application, all of the DR was used to reduce firm load requirements in order to calculate the reserve requirements, and 33 percent of the nameplate capacity of solar photovoltaic capacity was counted as firm capacity.

13.0 Capacity Requirements

This section presents FMPA's projected annual capacity requirements necessary to maintain the 18 percent summer reserve margin criteria, taking into consideration existing and future planned capacity resources as described in Section 3.0 and the base case load forecast presented in Section 5.0. The projected need for capacity is used as the basis for the analyses presented in Section 20.0.

Available net system capacity resources consider existing generation resources, contractual power purchases, and any reserves associated with partial requirements (PR) purchases, scheduled capacity additions and unit re-ratings, and scheduled unit retirements. Section 3.0 provides a description of FMPA's existing capacity resources and planned retirements. In addition to these retirements, the City of Vero Beach's existing resources will not be available to FMPA after January 1, 2010, as a result of the establishment of the CROD.[1] Currently, FMPA is projected to continue serving approximately 21 MW of the City of Vero Beach's summer loads on an annual basis, as part of the CROD, beginning January 1, 2010.

FMPA's current firm power supply purchases include those from PEF, FPL, Calpine, Southern Company-Florida, LLC, and Southern Power Company. The power purchases are summarized in Section 3.3. Currently, FMPA has no firm contractual wholesale power sales agreements.

As shown in Section 5.0, FMPA's forecast annual peak demands are projected to occur in the summer of each year. As a result, the capacity additions necessary to maintain the forecast capacity requirements are driven by projected summer peak demands. The load forecast developed by RW Beck (presented in Section 5.0) extends through the year 2026. For the purposes of the analyses presented throughout this Application, the load forecast was extended to the year 2027 by applying the annual growth rate from 2025 to 2026 to the year 2026 forecast.

Table 13-1 indicates that FMPA's capacity is initially projected to fall below its required 18 percent reserve margin in the summer of 2010. At that time, FMPA's reserve margin is projected to fall to 17.7 percent, or 3 MW below the capacity required to maintain an 18 percent reserve margin. By the summer of 2011, FMPA's reserve margin is projected to fall to -1.3 percent, or 286 MW below the capacity required to maintain an 18 percent reserve margin. Projected summer capacity deficits continue to increase beyond 2011, growing to an estimated deficit of 1,098 MW by 2027.

[1] Ultimately, the CROD will be based on Vero Beach's peak demand from December 1, 2008 through November 30, 2009.

Table 13-1
Projected Reliability Levels – Summer – Base Case Load Forecast

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Reductions(1) (MW)	Net Firm Capacity Additions(2) (MW)	Net System Capacity (MW)	System Peak Demand(3) (MW)	Reserve Margin(4) (%)	Excess/(Deficit) to Maintain 18% Reserve Margin (MW)
2008	1,318	337	75	(114)	296	1,912	1,545	25.0%	103
2009	1,318	337	120	(114)	296	1,957	1,593	24.7%	98
2010	1,318	237	165	(300)	296	1,717	1,483	17.7%	(3)
2011	1,318	237	45	(389)	296	1,508	1,527	-1.3%	(286)
2012	1,318	237	45	(426)	296	1,470	1,560	-5.9%	(363)
2013	1,318	237	0	(426)	296	1,425	1,594	-10.6%	(456)
2014	1,318	237	0	(426)	296	1,425	1,630	-12.6%	(498)
2015	1,318	237	0	(426)	296	1,425	1,668	-14.5%	(542)
2016	1,318	237	0	(426)	296	1,425	1,705	-16.4%	(587)
2017	1,318	237	0	(426)	296	1,425	1,744	-18.2%	(632)
2018	1,318	237	0	(426)	296	1,425	1,782	-20.0%	(677)
2019	1,318	237	0	(426)	296	1,425	1,820	-21.7%	(722)
2020	1,318	237	0	(426)	296	1,425	1,859	-23.3%	(768)
2021	1,318	237	0	(426)	296	1,425	1,898	-24.9%	(814)
2022	1,318	237	0	(426)	296	1,425	1,938	-26.4%	(861)
2023	1,318	237	0	(426)	296	1,425	1,978	-27.9%	(908)
2024	1,318	237	0	(426)	296	1,425	2,018	-29.3%	(955)
2025	1,318	237	0	(426)	296	1,425	2,057	-30.7%	(1,002)
2026	1,318	237	0	(426)	296	1,425	2,098	-32.0%	(1,050)
2027	1,318	237	0	(426)	296	1,425	2,139	-33.4%	(1,098)

(1)Reflects annual capacity retirements described in Section 3.0, changes to the ratings of existing nuclear generating resources, and the loss of City of Vero Beach's generating units associated with CROD, all described in Section 3.0.
(2)Firm capacity additions reflect commercial operation of TCEC Unit 1 combined cycle (May 2008).
(3)City of Vero Beach's forecast capacity requirements are no longer included beginning January 1, 2010, when the CROD becomes effective, except for approximately 21 MW of the City of Vero Beach's load resulting from the CROD.
(4)Reserve margin calculated as (Net System Capacity - Partial Requirements Purchases) - (System Peak Demand - Partial Requirements Purchases) / (System Peak Demand - Partial Requirements Purchases).

14.0 Supply-Side Alternatives

This section presents the conventional and emerging supply-side technologies that were considered by FMPA. Estimated performance characteristics, emissions profiles, capital and operating costs, availability, and construction schedules are presented.

14.1 Conventional and Emerging Technologies

The conventional and emerging generating options that were evaluated as potential sources of future capacity for FMPA are discussed in this section. In addition to a general description, a summary of projected performance, emissions, capital cost, O&M costs, startup costs, construction schedules, scheduled maintenance requirements, and forced outage rates have been developed for each option.

Cost and performance estimates have been developed for several conventional self-build generation technologies that are proven, commercially available, and widely used in the power industry. Additionally, cost and performance estimates were developed for the LMS100 simple cycle combustion turbine, which may be considered an emerging technology. An emerging technology is a technology that cannot be considered conventional for various reasons, as discussed further in this analysis.

Although the combustion turbines and the combined cycle alternatives discussed herein assume a specific manufacturer (GE) and specific models (e.g., aeroderivative and frame combustion turbines), doing so is not intended to limit the alternatives considered solely to GE models. Rather, such assumptions were made to provide indicative cost, output, and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

Based on currently developing policy in the state and concern over CO_2 emissions, solid fuel generating facilities have not been included as generating unit alternatives. In addition, nuclear units are not included beyond the potential identified joint ownership opportunities with FPL and PEF, as described in Section 19.0, because of the large size of the nuclear units and the need to have another entity develop and manage the projects.

The capital cost estimates developed include both direct and indirect costs. An allowance for possible general owner's cost items, as summarized in Table 14-1, has been included in the cost estimates.

Table 14-1
Possible Owner's Costs

Project Development • Site selection study • Land purchase/rezoning for greenfield sites • Transmission/gas pipeline right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management	**Owner's Contingency** • Owner's uncertainty and costs pending final negotiation • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (i.e., interconnection contract costs) **Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management
Spare Parts and Plant Equipment • Combustion turbine materials, gas compressors, supplies, and parts • Steam turbine materials, supplies, and parts • Boiler materials, supplies, and parts • BOP equipment/tools • Rolling stock • Plant furnishing and supplies	**Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property **Utility Interconnections** • Natural gas service • Gas system upgrades • Electrical transmission • Water supply • Wastewater/sewer
Plant Startup/Construction Support • Owner's site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of natural gas not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Financing (included in fixed charge rate, but not in direct capital cost)** • Financial advisor, lender's legal, market analyst, and engineer • Loan administration and commitment fees • Debt service reserve fund

14.1.1 Generating Alternatives Assumptions

14.1.1.1 General Capital Cost Assumptions. Unless otherwise discussed for each site, the following general assumptions were applied in developing the cost and performance estimates:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, laydown, and staging.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be preengineered unless otherwise specified.
- Construction power is available at the boundary of the site(s).
- The LMS100 is assumed to have standard SCR. The LM6000, 7EA, and 7FA simple cycle combustion turbines will have hot SCR. Except for the LMS100, the simple cycle units will not include a CO catalyst, but will have a spool piece for future installation.
- GE 7FA combined cycle plants will include SCR and space for a potential CO catalyst to reduce emissions.
- Standard sound enclosures will be included for the combustion turbines.
- Natural gas pressure is assumed to be adequate for the 7EA simple cycle and the 7FA simple and combined cycle alternatives. Gas compressors will be included for the LM6000 and LMS100 aeroderivative combustion turbines. A regulating and metering station is assumed to be part of the owner's cost for each alternative.
- Demineralized water will be supplied by a demineralized water treatment system for the combined cycle option.
- The LMS100 and the combined cycle alternatives will utilize cooling towers. Groundwater or treated sewage effluent will be used as cooling water.
- The LMS100 has an intercooled compressor and will not utilize inlet cooling. The LM6000 will include the SPRINT option and will also include inlet chillers. The frame machines (simple cycle turbines and combined cycles) will utilize evaporative cooling.
- Field erected service/fire water storage tanks are included.

14.1.1.2 Fuel Assumptions.

- Fuel gas is 100 percent methane with 0.2 grain of sulfur per 100 standard cubic feet (scf), with a heat content of 21,515 Btu/lb, lower heating value (LHV).

14.1.1.3 Direct Cost Assumptions.

- Total direct capital costs are expressed in 2008 dollars unless otherwise noted.
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on an EPC contracting philosophy.
- Spare parts for startup are included. Initial inventory of spare parts for use during operation is included in the owner's costs.
- Permitting and licensing are included in the owner's costs.

14.1.1.4 Indirect Cost Assumptions. The following items are assumed in the capital cost estimate:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.
- Interest during construction and financing fees will be accounted for separately in the economic evaluation and, therefore, are not included in the capital cost or owner's cost estimates.

14.1.1.5 Meteorological Conditions. An average annual temperature and relative humidity of 70° F and 72 percent, respectively, were used for developing performance estimates for use in production cost modeling. Additionally, a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent) were used to develop seasonal performance estimates.

14.1.1.6 Performance Degradation. Power plant output and heat rate performance will degrade with hours of operation because of factors such as blade wear, erosion, corrosion, and increased tube leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance when compared to the unit's new and clean performance. The degradation that cannot be recovered is referred to herein as nonrecoverable degradation, and estimates have been developed to capture its impacts. Nonrecoverable degradation will vary from unit to unit, so specific nonrecoverable output and heat rate factors have been developed and are presented in Table 14-2. The degradation percentages are applied one time to the new and clean performance data, and reflect lifetime aggregate nonrecoverable degradation.

Table 14-2
Nonrecoverable Degradation Factors

Unit Description	Degradation Factor	
	Output (%)	Heat Rate (%)
GE LM6000 Simple Cycle	3.2	1.75
GE LMS100 Simple Cycle	3.2	1.75
GE 7EA Simple Cycle	3.2	1.75
GE 7FA Simple Cycle	3.2	1.75
GE 1x1 7FA Combined Cycle	2.7	1.50

14.1.2 Existing Sites

The generating unit alternatives considered throughout this Application, with the exception of the combined cycles, were developed on a greenfield basis. Future combined cycle units would likely be installed at either FMPA's TCEC or CIPP sites. These sites are discussed below.

A final Determination of Need Order was issued for Unit 1 at the TCEC site by the FPSC on July 27, 2005. This site will have adequate acreage to accommodate up to four (including Unit 1) 1x1 GE 7FA combined cycle units. Site certification for TCEC was issued in May 2006 for Unit 1 and ultimate certification for 1,200 MW. TCEC is located within Phase III - north of the Midway Industrial Park in St. Lucie County, Florida. The TCEC site is in southwest Ft. Pierce, 8 miles northwest of Port St. Lucie, and occupies 68.1 acres.

The CIPP site is located approximately 5 miles west of the city limits of Kissimmee, Florida. The site currently has three natural gas and No. 2 oil fueled generating units, including Cane Island 1 (a simple cycle LM6000 combustion turbine), Cane Island 2 (a 1x1 7EA combined cycle), and Cane Island 3 (a 1x1 7FA combined cycle), with a total installed summer capacity of 388 MW. The units are jointly owned by KUA and FMPA. Cane Island 4, which will be wholly owned by FMPA, will add an additional 300 MW of summer capacity.

The Cane Island site was designed for approximately 1,000 MW of combustion turbine and combined cycle capacity and is served by the FGT and Gulfstream natural gas pipeline systems. The site is interconnected at 230 kV with PEF, OUC, TEC, and KUA. The site uses treated sewage effluent from the Toho Water Authority for cooling water; the site also has rights for additional cooling water from Toho Water Authority.

14.1.3 Simple Cycle Combustion Turbine Alternatives

CTGs are sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A simple cycle combustion turbine generates power by compressing ambient air and then heating the pressurized air to approximately 2,000° F or more, by burning oil or natural gas, with the hot gases then expanding through a turbine. The turbine drives both the compressor and an electric generator. A typical combustion turbine would convert 30 to 35 percent of the fuel to electric power. A substantial portion of the fuel energy is wasted in the form of hot gases (typically 900° F to 1,100° F) exiting the turbine exhaust. When the combustion turbine is used to generate power and no energy is captured and utilized from the hot exhaust gases, the power cycle is referred to as a "simple cycle" power plant.

Combustion turbines are mass flow devices, and their performance changes with changes in the ambient conditions at which the unit operates. Generally speaking, as temperatures increase, combustion turbine output and efficiency decrease because of the lower density of the air. To lessen the impact of this negative characteristic, most of the newer combustion turbine-based power plants often include inlet air cooling systems to boost plant performance at higher ambient temperatures.

Combustion turbine pollutant emission rates are typically higher on a part per million (ppm) basis at part load operation than at full load. This limitation has an effect on how much plant output can be decreased without exceeding pollutant emissions limits. In general, combustion turbines can operate at a minimum load of about 50 percent of the unit's full load capacity while maintaining emission levels within required limits.

Advantages of simple cycle combustion turbine projects include low capital costs, short design and construction schedules, and the availability of units across a wide range of capacities. Combustion turbine technology also provides rapid startup and modularity for ease of maintenance.

The primary drawback of combustion turbines is that, due to the cost of natural gas and fuel oil, the variable cost per MWh of operation is high compared to other conventional technologies. As a result, simple cycle combustion turbines are often the technology of choice for meeting peak loads in the power industry, but are not usually economical for baseload or intermediate service.

Three different commercially proven combustion turbine sizes were evaluated, as well as the LMS100. The GE LM6000 has a nominal output in the range of 50 MW at International Organization for Standardization (ISO) conditions with the SPRINT™ design feature included. The GE 7EA has a nominal output of about 85 MW, while the GE 7FA has a nominal output of about 170 MW at ISO conditions.

14.1.3.1 GE SPRINT LM6000 Combustion Turbine. The GE SPRINT LM6000 was selected as a potential simple cycle alternative because of its modular design, efficiency, and size. It is a two-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine.

The LM6000 consists of a five-stage low-pressure compressor (LPC); a 14-stage, variable geometry, high-pressure compressor (HPC); an annular combustor; a two-stage, air-cooled, high-pressure turbine (HPT); a five-stage, low-pressure turbine (LPT); and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the LP rotor. The HPC and HPT are assembled on the other shaft, forming the HP rotor.

The LM6000 uses the LPT to power the output shaft. The LM6000 design permits direct coupling to 3,600 rpm generators for 60 Hz power generation. The gas turbine drives its generator through a flexible, dry type coupling connected to the front, or "cold" end, of the LPC shaft. The LM6000 gas turbine generator set has the following attributes:

- Full power in approximately 10 minutes.
- Cycling or peaking operation.
- Synchronous condenser capability.
- Compact, modular design.
- More than 5 million operating hours.
- More than 450 turbines sold.
- 97.8 percent documented availability.
- LM6000 SPRINT™ spray intercooling for power boost.
- Dual fuel capability.

The capital cost estimate was derived utilizing GE's Next-Gen package for the LM6000. This package includes more factory assembly, resulting in less construction time. Table 14-3 presents the operating characteristics of the LM6000 SPRINT combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent), and annual average temperature conditions (70° F with a relative humidity of 72 percent). High temperature SCR would be used to control NO_x to 2 ppmvd while operating on natural gas. Table 14-4 presents estimated emissions for the LM6000.

Table 14-3
GE LM6000 PC SPRINT Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)(1)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (24° F) (Full Load)	47.4	9,637
Summer (98° F) (Full Load)	46.2	10,171
Average (70° F and 72% relative humidity) (Full Load)	47.3	9,933
Average (70° F and 72% relative humidity) (75% Load)	26.5	11,304
Average (70° F and 72% relative humidity) (50% Load)	17.5	13,444

(1)Net capacity and net plant heat rate include degradation factors, inlet chilling is considered on full load cases above 60° F, and performance is preliminary.
(2)Heat rate assumes operation on natural gas.

Table 14-4
GE LM6000 PC SPRINT Estimated Emissions(1)

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	29
CO, lb/MBtu	0.0648

(1)Emissions are at full load at 70° F, reflect operation on natural gas, and include the effects of SCR.

14.1.3.2 GE 7EA Combustion Turbine. The GE 7EA combustion turbine is a highly reliable, mid-sized combustion turbine developed specifically for 60 Hz applications. With design emphasis placed on energy efficiency, availability, performance, and maintainability, the GE 7EA is a proven technology with approximately 800 units installed worldwide, and more than a million hours of operation. The simple, mid-sized design of the GE 7EA lends to flexibility in plant layout and easy, low-cost addition of increments of power when phased capacity expansion is necessary. The unit has a 3,600 rpm shaft speed and is directly coupled to the generator.

The GE 7EA is fuel-flexible and can operate on natural gas, LNG, distillate fuel oil, and treated residual fuel oil. The 7EA is an ideal generating unit for sites that require efficient peaking generation or reliable capacity from multiple units. The 7EA is rated at 85.4 MW, which is greater than the LM6000, but less than the 7FA. For this analysis, it has been assumed that the GE 7EA will be dual-fueled, capable of firing either natural gas or ULSD.

Table 14-5 presents the operating characteristics of the GE 7EA combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). The 7EA will utilize dry-low NO_x combustors and SCR to control NO_x to 2 ppmvd on natural gas. Table 14-6 presents estimated emissions for the 7EA.

Table 14-5
GE 7EA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (24° F) (Full Load)	89.7	11,793
Summer (98° F) (Full Load)	72.4	12,399
Average (70° F and 72% RH) (Full Load)	78.4	12,134
Average (70° F and 72% RH) (75% Load)	58.7	13,214
Average (70° and 72% RH) (50% Load)	39.0	16,100

RH = Relative humidity.

[1]Net capacity and net plant heat rate include degradation factors, evaporative cooling is considered at full load cases above 60° F, and performance is preliminary.

Table 14-6 GE 7EA Estimated Emissions[1]	
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0073
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165
[1]Emissions are at full load at 70° F and include the effects of SCR.	

14.1.3.3 GE 7FA Combustion Turbine. The GE 7FA combustion turbine, originally introduced in 1986, is the result of a multi-year development program using technology advanced by GE Aircraft Engines and GE's Corporate Research and Development Center. The development program facilitated the application of technologies such as advanced bucket cooling techniques, compressor aerodynamic design, and new alloys for F class gas turbines, enabling these machines to attain higher firing temperatures (2,400° F) than previous generating units.

The GE 7FA combustion turbines have an 18-stage compressor and a 3-stage turbine and feature cold-end drive and axial exhaust, which is beneficial for combined cycle arrangements. With reduced cycle time for installation and startup, the GE 7FA can be installed relatively quickly. The packaging concept of the GE 7FA features consolidated skid-mounted components, controls, and accessories, which reduce piping, wiring, and other onsite interconnection work.

The GE 7FA combustion turbine has also exhibited outstanding environmental characteristics. Because of the higher specific output of these machines, smaller amounts of NO_x and CO are emitted per unit of power produced for the same exhaust concentrations as other generating technologies. GE 7FA turbines have accumulated more than 900,000 operating hours using dry low NO_x burners, which will be part of the NO_x control strategy when operating on natural gas. Evaporative cooling will be used for inlet cooling.

Table 14-7 presents the operating characteristics of the GE 7FA combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). The 7FA will utilize dry low NO_x combustors and SCR to control NO_x to 2 ppmvd on natural gas. Table 14-8 presents estimated emissions for the 7FA.

Table 14-7
GE 7FA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[(1)]	Net Plant Heat Rate (Btu/kWh, HHV)[(1)]
Winter (24° F) (Full Load)	177.0	10,585
Summer (98° F) (Full Load)	148.5	11,065
Average (70° F and 72% relative humidity) (Full Load)	160.0	10,826
Average (70° F and 72% relative humidity) (75% Load)	119.8	11,816
Average (70° and 72% relative humidity) (50% Load)	79.6	14,223

[(1)]Net capacity and net plant heat rate include degradation factors, evaporative cooling is considered at full load cases above 60° F, and performance is preliminary.

Table 14-8
GE 7FA Estimated Emissions[(1)]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0073
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165

[(1)]Emissions are at full load at 70° F and include the effects of SCR and dry low NO_x combustors.

14.1.3.4 GE LMS100 Combustion Turbine. The GE LMS100 is a new combustion turbine; the first LMS100 began commercial operation in July 2006. At the time this Application was prepared, only about half a dozen LMS100 units had been ordered from GE. After the reliability of the LMS100 has been successfully demonstrated, it will likely replace the use of two-unit blocks of LM6000s in the future.

The LMS100 is currently the most efficient simple cycle gas turbine in the world. In simple cycle mode, the LMS100 has an efficiency of 46 percent, which is 10 percent greater than the LM6000. It has a high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and is expected to have high availability, though this availability must be commercially demonstrated before the LMS100 can be considered a conventional alternative.

The LMS100 is an aeroderivative turbine and has many of the same characteristics of the LM6000. The former uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air optimizes the performance of the turbine and increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle combustion turbines at full load.

There are two main differences between the LM6000 and the LMS100. The LM6000 uses the SPRINT intercooling system to cool the compressor with a micro-mist of water, while the LMS100 cools the compressor air with an external heat exchanger after the first stage of compression. Unlike the LM6000, which has a HP turbine and a power turbine, the LMS100 has an additional IP turbine to increase output efficiency.

As a packaged unit, the LMS100 consists of a 6FA turbine compressor, which outputs compressed air to the intercooling system. The intercooling system cools the air, which is then compressed in a second compressor to a high pressure, heated with combusted fuel, and then used to drive the two-stage IP/HP turbine described above. The exhaust stream is then used to drive a five-stage power turbine. Exhaust gases are at a temperature of less than 800° F, which allows the use of a standard SCR system for NO_x control.

Table 14-9 presents the operating characteristics of the LMS100 combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). Standard SCR will be used to control NO_x to 2 ppmvd while operating on natural gas. Table 14-10 presents estimated emissions for the LMS100.

Table 14-9
GE LMS100 Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (24° F) (Full Load)	95.6	8,961
Summer (98° F) (Full Load)	86.4	9,360
Average (70° F and 72% relative humidity) (Full Load)	96.5	9,095
Average (70° F and 72% relative humidity) (75% Load)	72.1	9,543
Average (70° F and 72% relative humidity) (50% Load)	47.8	10,609

(1)Net capacity and full load net plant heat rate include degradation factors, evaporative cooling is not considered, and performance is preliminary.

Table 14-10
GE LMS100 Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/TBtu	N/A
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	11.4
CO, lb/MBtu	0.025

(1)Emissions are at full load at 70° F and include the effects of SCR and CO catalyst.

14.1.4 GE 7FA 1x1 Combined Cycle

Combined cycle power plants use one or more CTGs and one or more STGs to produce energy. Combined cycle power plants operate according to a combination of both the Brayton and Rankine thermodynamic power cycles. HP steam is produced when the hot exhaust gas from the CTG is passed through an HRSG. The HP steam is then expanded through a steam turbine, which spins an electric generator. It is assumed that duct firing will be used in the combined cycle option.

Combined cycle configurations have several advantages over simple cycle combustion turbines. Advantages include increased efficiency and potentially greater operating flexibility if duct burners are used. Disadvantages of combined cycles relative to simple cycles include a small reduction in plant reliability and an increase in the overall staffing and maintenance requirements because of added plant complexity.

The 1x1 combined cycle generating unit includes one GE 7FA CTG, one HRSG, and one STG and will include evaporative cooling. The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three-pressure, reheat unit with supplemental duct firing to maintain full steam turbine generator load at all ambient conditions. SCR and dry low NO_x burners will be included to control NO_x to 2 ppmvd, and space for a CO catalyst will be included.

The steam turbine is expected to be a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one HP section, one IP section, and a two-flow LP section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control systems are included. A single synchronous generator is included, which will be direct coupled to the steam turbine. The STG will be located outdoors, with a building provided for the major auxiliary electrical power equipment.

Expected output, performance, and emissions for the 1x1 GE 7FA combined cycle alternative are the same as those of Cane Island 4, which is described in Section 10.0.

14.1.5 Capital Costs, O&M Costs, Schedule, and Maintenance Summary

The capital costs, O&M costs, schedule, forced outage, and maintenance estimates for the generating alternatives are summarized in Table 14-11. All costs are provided in 2008 dollars unless otherwise noted. The EPC cost includes engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. The assumed owner's cost allowance is representative of typical owner's costs as outlined in Table 14-1, exclusive of escalation, financing fees, and interest during construction, which will be accounted for separately in the economic analyses.

Table 14-11
Capital Costs, O&M Costs, and Schedules for the Generating Alternatives
(All Costs in 2008 Dollars, Unless Otherwise Noted)

Supply Alternative	EPC Cost ($millions)[1]	Owner's Cost ($millions)[1]	Total Cost ($millions)[1]	Total Cost ($/kW) at 70° F	Fixed O&M ($/kW-yr)	Nonfuel Variable O&M ($/MWh)	Construction Schedule (months)	Scheduled Maintenance (days)	Forced Outage (percent)
GE LM6000 SC	44.3	11.1	55.3	1,169.8	26.47	3.64	10	10	2.0
GE LMS100 SC	69.3	17.3	86.7	898.3	13.45	3.29	12	10	2.0
GE 7EA SC	52.3	13.1	65.3	833.0	16.39	11.28	12	10	2.0
GE 7FA SC	83.1	20.8	103.9	649.4	8.41	15.57	12	10	2.0
1x1 GE 7FA CC[2]	Refer to Note (2)	Refer to Note (2)	421.6[3]	1,372.4[3]	4.56	3.30	22	14	2.0

[1]Unless otherwise noted, the total cost is an overnight 2008 estimate that does not include interest during construction.
[2]The estimated cost, availability, and construction schedule for the 1x1 GE 7FA CC are consistent with those presented for Cane Island 4 in Section 10. The 1x1 GE 7FA CC alternative is intended to represent a future unit alternative beyond the addition of Cane Island 4, not an alternative to the addition of Cane Island 4.
[3]The estimated capital cost for the 1x1 GE 7FA CC includes escalation and interest during construction and is presented in 2011 in-service dollars.

Fixed and nonfuel variable O&M costs are also provided in 2008 dollars. Fixed costs include labor, maintenance, and other fixed expenses excluding backup power, property taxes, and insurance. Nonfuel variable costs include outage maintenance, consumables, and replacements dependent on unit operation. Construction schedules are indicative of typical construction durations for the alternative technology and plant size. Actual costs and schedules will vary from the preliminary estimates provided in Table 14-11.

The scheduled and forced outage assumptions for the generating alternatives are also presented in Table 14-11.

15.0 Power Supply Request for Proposals

To evaluate potentially cost-effective power supply alternatives for the construction of Cane Island 4, FMPA issued a request for power supply proposals (RFP) on behalf of the ARP on June 22, 2007. The power supply RFP served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the ARP beginning on January 1, 2011, and continuing over a period of at least 10 years. The RFP requested a minimum of 50 MW (up to a maximum of 300 MW) and required that the proposed capacity and energy be delivered to the PEF transmission system.

The power supply RFP was distributed directly to 14 utilities and independent power producers. Additionally, the RFP was posted on FMPA's Web site, which allowed industry publications to pick it up for further distribution.

The RFP is presented in Appendix A.

15.1 Overview of the Power Supply RFP

The power supply RFP allowed for proposals for capacity and energy for contract periods of 10 years or greater from existing specified resources, a portfolio supply of resources with appropriate guarantees, or a generating facility or facilities to be constructed for a unit power sale. All proposals were required to identify specific resources at specific sites. The RFP also required that proposals based on resources outside the PEF transmission system identify the transmission contracts for the transmission path that would be utilized from the resource(s) to the PEF transmission system interface. For unit-contingent purchases, all available unit data (e.g., performance, availability, capacity, fuel type, etc.) for the specific unit(s) were required to be provided by the bidder.

The power supply RFP contemplated a bid and negotiate proposal evaluation process, with the information that was submitted by each qualified proposer (by the August 17, 2007 proposal due date) used to develop a short-list of proposals from which selection(s) could be made for negotiations. Qualified proposals would be evaluated on the basis of both pricing and nonpricing factors. The first stage of the evaluation process would include a comparison of each proposal submittal, with the following minimum requirements set forth in the power supply RFP:

1. For a generating unit power sale, FMPA's rights must be equal to or superior to any other party's rights to such unit(s) output (i.e., as long as the unit(s) from which the capacity is purchased is available, FMPA has the right to the output of the unit(s) for the duration of the contract).

2. All proposals for capacity must commence on January 1, 2011.
3. All proposals must have contract periods of not less than 10 years.
4. All proposals must remain in effect until December 6, 2007, or later if the purchase is to be finalized pending a transmission service request.
5. The capacity amount offered to FMPA shall be not less than 50 MW or greater than 300 MW. Acceptable offers from all proposers must total at least 300 MW for FMPA to proceed with purchases under this RFP. Proposals that require FMPA to provide natural gas must identify the natural gas delivery point.
6. All generating units providing the proposed capacity must be in commercial operation at least 2 months prior to the required delivery commencement date of the term of the proposed power supply.
7. Proposals must identify and include the location of each capacity resource and name the originating control area. Resources must be delivered to the PEF transmission system. Proposers proposing power supply from a resource(s) located outside of the PEF balancing authority must also identify the firm transmission contract path from the power supply(ies) to the PEF transmission system.
8. The proposer must commit in the proposal that all emissions allowance requirements will be satisfied and must include costs for emissions allowances in the proposal.
9. The proposer must declare ownership or contractual status of a unit or plant, as described in Section 15 of the RFP.
10. The proposer must complete the appropriate RFP forms and provide all appropriate information requested in Attachment B to the RFP. All forms requiring a signature must be signed by a duly authorized official of the proposer.
11. The proposer must commit in the proposal to provide an adequate Proposal Security prior to entering short-list negotiations and an adequate Performance Security upon execution of a contract, in accordance with Section 16 of the RFP.
12. Each proposal must clearly describe any contractual limits on energy utilization or physical limitations on the operation of the resource, as described in Attachment B of the RFP.
13. Each proposal must include scheduling provisions for the sale.
14. Each proposal must contain the appropriate Proposal Fee in accordance with Section 10 of the RFP.

15. Proposals for new construction projects must not be contingent upon participation by other third parties to support the project.
16. Proposers that propose to develop a power generating project to provide power to FMPA must have developed, and have had in operation for a minimum of 1 year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers offering to provide FMPA with power from an existing generating resource must have successfully provided similar levels of services to at least one electric utility for a minimum of 1 year.

15.2 Results of the Power Supply RFP

One of the requirements set forth in the power supply RFP was mandatory attendance at the pre-bid conference prior to submitting a response to the RFP. The mandatory pre-bid conference was held on June 28, 2007 at FMPA's offices in Orlando, Florida. No potential bidders attended the pre-bid conference, nor did any entities submit notices of intent to bid, which were required (as stated in the RFP) to be submitted no later than July 3, 2007. The schedule set forth in the power supply RFP required that all bids in response to the RFP be submitted by August 17, 2007. No bidders responded to the power supply RFP; therefore, the power supply RFP process was terminated on November 5, 2007.

16.0 Renewable Energy

FMPA recognizes the importance of integrating renewable energy into its power supply portfolio to serve the requirements of the ARP. In addition to existing renewable energy resources, several new renewable energy projects are currently being evaluated by FMPA. This section discusses existing renewable energy sources available to FMPA. In addition, this section discusses FMPA's request for proposals (RFP) for renewable capacity and energy and its RFP for solar photovoltaic (PV) equipment or power purchase agreements, as well as potential new renewable energy projects being evaluated by FMPA outside of the RFP processes. Through the RFP processes described below, FMPA has performed a thorough evaluation of reasonably available renewable energy sources.

16.1 Existing FMPA Renewable Energy Resources

FMPA purchases power on an as-available basis from a cogeneration plant owned and operated by the US Sugar Corporation that is fueled by sugar bagasse, a byproduct of sugar production. As US Sugar utilizes its renewable generating facility to serve its own energy requirements, the ARP also avoids having to serve the US Sugar load using more carbon intensive generating resources.

Landfill gas (LFG) obtained from the Orange County landfill is used as a supplemental fuel source in coal fueled Stanton Energy Center Units 1 and 2. FMPA has an ownership share in both Stanton Units 1 and 2.

Table 16-1 presents the historical annual quantities of energy purchased from the US Sugar facility and produced from FMPA's ownership share of Stanton Energy Center Units 1 and 2 using landfill gas.

Table 16-1
Historical Renewable Energy Generation – Existing ARP Renewable Resources

	Annual Energy (MWh)							
Resource	2000	2001	2002	2003	2004	2005	2006	2007
US Sugar	1,076	206	921	388	1,923	3,168	5,263	5,532
Stanton Energy Center (LFG)	0	27,754	25,527	29,069	29,945	25,706	19,882	(1)
Total	1,076	27,960	26,448	29,457	31,868	28,874	25,145	(1)

(1) Data for 2007 not yet available.

16.2 FMPA RFP for Renewable Capacity and Energy

On June 29, 2007, FMPA issued a RFP for Renewable Capacity and Energy (Renewables RFP) on behalf of the ARP. The Renewables RFP, which is presented in its entirety as Appendix B to this Application, served as an invitation for qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of the ARP beginning on January 1, 2011 or earlier and continuing over a period of at least 5 years. The RFP requested a minimum of 1.0 MW and required that the proposed capacity and energy be delivered to either the FPL or PEF transmission systems.

The renewable RFP was distributed directly to 26 entities and notification of the RFP was posted in 2 industry publications. Additionally, the RFP was posted on FMPA's website which allowed industry publications to pick it up for further distribution.

The Renewable RFP requested resources where the sole source of fuel used for the production of energy for sale to FMPA was from one or more of the following sources:

- Hydrogen produced from sources other than fossil fuels.
- Biomass (including waste to energy and landfill gas).
- Solar energy.
- Geothermal energy.
- Wind energy.
- Ocean energy.
- Hydroelectric power.
- Waste heat from a commercial or industrial process.
- Any other technologies utilizing fuel/energy sources deemed by FMPA to be renewable in nature.

The Renewables RFP contemplated a bid-and-negotiate proposal evaluation process, with information from each qualified proposer submitted in response to the RFP by the August 29, 2007 proposal due date used to develop a short-list of proposals from which selection(s) could be made for negotiations. Qualified proposals would be evaluated based on both pricing and non-price factors. The first stage of the evaluation process would include a comparison of each proposal submittal with the minimum requirements set forth in the power supply RFP, which were as follows:

1. The proposal contains the appropriate Proposal Fee in accordance with Section 9 of the RFP.
2. The proposal is for at least 1 MW and begins delivery no later than January 1, 2011.

3. The proposal shall remain valid to the later of March 28, 2008, or the date of receipt of all regulatory approvals required for the proposal and any related transmission service.
4. The proposal is priced inclusive of the Proposer supplying and arranging for all third party transmission into the FMPA system (qualified network resource under FPL's and/or PEF's Open Access Transmission Tariff) and located in the State of Florida. The Proposer has identified the means of assuring firm delivery of capacity resources.
5. The Proposer has agreed to pay for all necessary transmission upgrades to provide for interconnection and delivery service to the FMPA system.
6. For proposals involving a sale to more than one utility from the same resource(s), FMPA's rights to the output shall be equal to, or greater than, the rights of all other customers served by the resource(s).
7. The Proposer ensures that all emissions allowance requirements will be satisfied and that any associated costs shall be borne by the Proposer.
8. The Proposer demonstrates ownership or contractual rights to the generating system capacity identified as supplying the sale.
9. Resources providing the proposed capacity, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply.
10. The Proposer has completed the appropriate RFP Forms 1 through 4. All forms requiring a signature must be signed by a duly authorized official representing the Proposer.
11. The Proposer has provided a Letter of Commitment to establish an acceptable Proposal Security as solely determined by FMPA within ten (10) days of being notified that his proposal is on the short-list of proposals.
12. Proposers shall have successfully provided under contract to at least one electric utility for a minimum period of one year, similar services to the services they are providing to FMPA and have included information in the proposal to demonstrate this experience.
13. The Proposer agrees to assist FMPA to obtain final contract approval from their respective governing bodies in public sessions, where required.
14. The Proposer agrees to provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for a Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW) of the capacity

offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals.

15. Pricing information must be provided by Proposers in sufficient detail for FMPA to fully analyze each proposal.
16. The Proposer must provide agreements and disclose sufficient information relating to the provision of fuels, critical spare parts, technical service and support, and maintenance plans to permit FMPA to evaluate the proposals for reliability.
17. If the Proposer is proposing an energy-only, must take, non-dispatchable, or any other arrangement that would require FMPA to take energy from the Proposer at levels that may not be scheduled by FMPA, then the proposal must contain a projected schedule of energy to be provided under the proposal. Such schedules must contain sufficient detail to permit an analysis of hourly energy patterns by day and month over the proposed contract period.

16.2.1 Summary of RFP Responses

The optional pre-bid conference was held on July 11, 2007 at the FMPA offices, and was attended by potential bidders. Of the attendees, six companies submitted a Notice of Intent to Bid Form on July 16, 2007. After receiving notice of intents to bid, each of the potential bidders was contacted to obtain additional information and to encourage them to follow up on their intent to submit a proposal. Three bids were submitted by the August 29, 2007 deadline. After receiving the bids, those proposers who had submitted the Notice of Intent to Bid but had not submitted a bid were contacted, but none decided to submit a proposal. The proposals received by FMPA included (i) a 58 MW summer rated biomass circulating fluidized bed (CFB) plant proposed to burn waste wood and other materials including recycled pallets, and paper derived fuel; (ii) 10 MW of roof-mounted PV systems; and (iii) a 1 MW to 3 MW centralized PV system.

16.2.2 Renewables RFP Response Evaluation Process

The first phase of the evaluation involved a screening of bids received with the minimum requirements as described in Section 20 of the Renewables RFP and as listed in Section 16.2. This evaluation, which was completed on September 12, 2007, indicated that two (2) of the proposals had not clearly met certain of the minimum requirements. Questions were submitted to the two proposers that had not clearly met all of the minimum requirements to obtain additional information. At this point, it was determined that FMPA would continue to consider all three of the proposals received. A preliminary quantitative evaluation was completed for all three proposals on October 19, 2007. Based on the preliminary evaluation, FMPA short listed all three proposers and meetings were held with the proposers on October 31 through November 2 of 2007. After the meetings a second set of questions were submitted to the proposers. Responses to the questions were received between November 14, 2007 and November 27, 2007. The centralized PV proposer indicated that they could not support the original price offered and provided a higher price verbal offer. After the second set of responses to questions was received, the evaluations were updated.

The updated results were summarized in a report dated December 12, 2007, which indicated that the levelized busbar costs for the three renewable alternatives were projected to be above FMPA's avoided cost. The biomass proposal was projected to be the lowest cost of the three proposals on a dollar per MWh basis.

Nevertheless, in spite of their higher costs, FMPA decided to continue negotiations with two of the proposers as part of its commitment to renewable energy sources. As of the time of the updated evaluation, the bidder proposing the centralized PV system did not supply the required proposal security. As a result, no further meetings were held with this proposer.

After the preliminary screening update, meetings were again held with the rooftop PV and biomass renewable proposers. Prior to the meetings, the proposers provided draft agreements, which were reviewed at the meetings.

As a result of further negotiations, the rooftop PV proposer offered reduced pricing which was still above FMPA's avoided costs. FMPA is continuing negotiations with the rooftop PV proposer for an open-ended contract for up to 10 MW at FMPA's discretion. The proposer has agreed to continue discussions on this basis.

Negotiations with the biomass proposer have continued over the course of an additional three meetings during March and April 2008. FMPA has explored different pricing arrangements over the course of the negotiations.

FMPA's ARP Executive Committee has approved continued negotiations for a power purchase from the biomass facility. Because the cost of biomass energy is higher than FMPA's avoided cost, before entering into a final contract with the proposer, FMPA will need to assess the cost penalty associated with the project. Furthermore, FMPA's ultimate commitment to utilizing biomass energy to serve its energy requirements will depend on whether biomass continues to be considered a renewable and carbon neutral energy source in Florida. FMPA will also need to examine the actions of other utilities in Florida in meeting their renewable targets to ensure that FMPA's rates remain cost competitive. The time frame for implementation of a biomass resource would depend on the time necessary to complete negotiations and obtain all required regulatory approvals and permits and approval of mutually agreeable commercial terms by FMPA.

FMPA's ARP Executive Committee also has approved continued negotiations for an open ended power purchase of up to 10 MW at FMPA's discretion from the roof-mounted PV systems bidder. While the cost of this alternative appears to be higher on a $/MWh basis than the least cost solar PV bid discussed in Section 16.3, there may be special circumstances for which roof-mounted PV systems would be desirable. Again, FMPA would need to assess the cost penalty associated with the project, and negotiate mutually agreeable commercial terms. FMPA intends that this contract work in concert with the contract discussed in Section 16.3 such that up to 10 MW in total of solar PV be installed.

In addition, FMPA received an unsolicited proposal from the centralized photovoltaic proposer on February 19, 2008. Because the proposed pricing was higher than other photovoltaic proposals that FMPA had received pursuant to the RFP for Solar PV Equipment or Power Purchase Agreements discussed in Section 16.3, this proposal was not pursued further.

16.3 FMPA RFP for Solar PV Equipment or Power Purchase Agreements

FMPA issued an RFP specifically for solar PV equipment or purchase power agreements (Solar RFP) on December 5, 2007 with a bid due date of January 7, 2008. The RFP in its entirely is presented in Appendix C. The bidders were invited to submit bids for the installation of 10 MW of solar PV capacity by the end of 2008, with the potential for up to 100 MW of solar PV capacity by 2013. The Solar RFP invited bidders to submit proposals ranging from the supply of PV equipment, to the installation of turnkey solar project, to a power purchase contract for energy generated by a solar system. Twenty-six bids were received – 12 offering a power purchase agreement (PPA), 13 offering turnkey, or EPC, installation of the equipment, and 7 offering to sell the equipment directly.

FMPA solicited the expertise of the Orlando Utilities Commission (OUC) staff, and Florida Solar Energy Center (FSEC) staff to be on a bid review team. The team met in January 2008 to review and rank the bids received in response to the solar RFP. The results of the review team meeting were compiled and finalized. A short list of eight proposals representing a mix of power purchase agreements, turnkey installations, and self build options was approved by the ARP Executive Committee in January 2008.

Further quantitative analysis was done on the eight responses. All of the proposals were found to be above FMPA's avoided costs and therefore more expensive than traditional resources. Consistent with Florida's environmental goals, however, FMPA is committed to developing a reasonably balanced mix of power resources including renewable technologies such as solar energy. FMPA staff's detailed evaluation showed the proposal of Sun Edison LLC to be the preferred proposal. This proposal was followed, in order, by Sunpower Corporation and then MMA Renewable Ventures. The Sun Edison proposal was structured as a 20 year power purchase agreement (PPA) so that there would be no up-front capital outlay. The Sunpower proposal was found to be very similar to Sun Edison in structure in that it was also proposing a PPA using FMPA sites. MMA Renewable Ventures proposed to develop their own site and sell energy to FMPA via a 20 year PPA. On March 27, 2008, the ARP Executive Committee approved the RFP ranking of proposals listed above.

On April 4, 2008, FMPA staff issued an e-mail soliciting interest from FMPA's ARP member cities to identify those members which might have an interest in locating a solar photovoltaic (PV) installation in their community. The various sites selected will require the execution of agreements between the property owner, FMPA, and the contractor.

Staff is currently working with Sun Edison to develop a contract to bring to the ARP Executive Committee for their approval in May 2008. Staff anticipates approval for the initial 10 MW. For PV capacity greater than 10 MW, the ARP will need to give significant consideration to the additional costs of PV compared to other alternatives and the actual performance of the initial 10 MW in the ARP system.

16.4 Additional Renewable Energy Resources

In addition to FMPA's existing renewable energy projects and the renewable energy resources being considered as part of the RFP processes described previously in this section, FMPA is considering participation in certain additional renewable energy projects as described below.

16.4.1 Bio-Fuels

FMPA is currently evaluating the feasibility of operating several of its generating units using bio-fuels. General Electric (GE) has reported that initial trials have proven satisfactory operation in several models of generation units. FMPA's initial investigation centers at the Stock Island facility in Key West, since all of the units located at that facility use fuel oil exclusively as the energy source.

Initial trials will be performed using three, 20 MW GE frame 5 combustion turbines. The tests will be based on 100 percent bio-diesel fuel or a blend of bio-diesel. As of the date this Application was prepared, fuel samples had been sent for testing to confirm the fuel's heat rate and contamination. The next step will be obtaining a permit for the testing from the Florida Department of Environmental Protection.

A major technical drawback under evaluation is performing the modifications necessary to store fuel and operate the units. Bio-fuel is a solvent and may react negatively with tank coatings, hoses, valves, and seals. The second major concern is that more fuel must be delivered to the machine to operate the unit for the same power output as conventional fuel.

16.4.2 Landfill Gas

FMPA is following the progress of the permitting and development of a major landfill gas generation facility to determine the feasibility of a long term contract for the electrical output. Landfill gas projects typically range in size between 1 MW to 10 MW. However, the prospective facility is planned for a 15 MW combustion turbine and is currently being permitted. FMPA is awaiting an update from the developer and may negotiate with the owner to receive the electric output.

16.4.3 Plasma Arc Technology

FMPA is evaluating a proposal for construction of a solid waste-to-energy facility using plasma arc technology at the St. Lucie County landfill with a target commercial operation date of 2011. The facility would treat and destroy solid waste created by the County either currently in its landfill or delivered to the landfill and generate synthesis gas (syngas). The intent would be for FMPA to purchase the syngas to burn in a combined cycle power plant to be constructed and operated by FMPA or develop a power purchase agreement for energy and capacity. FMPA has signed a Letter of Intent with the developer, Geoplasma, LLC.

16.4.4 Customer-Owned Renewable Resources

To assist in the development of renewable resources by customers of ARP Members, FMPA on behalf of its ARP Members is currently working towards developing standardized interconnection standards, agreements, and processes for net metering customer-owned renewable generation in ARP Member cities. The FMPA Executive Committee has held two workshops to discuss a net metering policy and implementation of the net metering policy for FMPA and the ARP members. FMPA anticipates the adoption before the fall of 2008 of an ARP net metering policy that will permit ARP members to net meter, and permit the ARP to purchase energy for customer-owned renewable generation systems. Interconnection for customer owned renewable generating systems will be at distribution voltage levels pursuant to interconnection standards adopted by each ARP member.

17.0 Conservation and Demand-Side Management

FMPA recognizes the importance of encouraging its members to reduce electricity demand through conservation and demand-side management (DSM) programs. As a wholesale supplier, FMPA historically has not directly provided conservation or DSM programs to retail customers - such programs have been provided to the retail customers by the ARP members. This section discusses existing conservation and DSM programs currently offered by ARP members. In addition, this section discusses FMPA's request for proposals (RFP) for demand-side management resources (DSM RFP) as well as potential new conservation and DSM initiatives under consideration by FMPA outside of the DSM RFP process. As discussed below, ARP members are utilizing reasonably available conservation measures and are continuing to evaluate other conservation measures that may further reduce their energy demands.

17.1 Existing ARP Member Conservation and DSM Programs

ARP member cities currently offer several conservation and DSM programs. Table 17-1 presents a matrix of these programs. The details of the conservation and DSM programs are presented below. FMPA will continue to offer services as needed to assist members in increasing the promotion and use of conservation programs to retail customers and will assist all of its members in the evaluation of any new programs to ensure their cost effectiveness.

17.1.1 Energy Audit Programs

Several ARP member cities offer customers free energy audits of their home or business. Customers gain an understanding of why they consume their billed energy. The customer receives advice on ways to conserve and reduce their bill. The customer may be advised on the feasibility of installing more insulation or more energy efficient appliances.

As examples, Keys Energy Services provided 108 audits in 2007. While conducting an audit, the utility also offers to wrap water heaters with an insulating blanket. During 2007, Beaches Energy (City of Jacksonville Beach) performed 326 residential and commercial audits, Ocala performed 831 residential audits and 109 commercial audits, Havana provided 25 audits, KUA performed approximately 1,800 residential and commercial energy audits, Leesburg performed 35 energy audits, and Newberry performed approximately 10 energy audits.

Table 17-1
Existing ARP Member DSM Programs

	DSM Measures (1 of 3)					
	Energy Audit Program	Energy Saving Tips	Appliance and Other Rebates	Load Profiling for Commercial Customers	Fix-Up Programs	Tree Planting Incentive
Beaches	X	X				
Bushnell		X				X
Clewiston						
Fort Meade						
Fort Pierce	X	X			X	
Green Cove Springs		X				
Havana	X	X				
KEYS	X	X				X
KUA	X	X	X			X
Lake Worth						
Leesburg		X				X
Newberry						
Ocala	X	X	X	X	X	X
Starke						
Vero Beach		X				

	DSM Measures (2 of 3)					
	Solar Projects	Solar Promotion	Net Metering	On-Line Energy Audits	Green Energy	Compact Fluorescent Bulbs
Beaches			X	X		X
Bushnell				X		
Clewiston				X		
Fort Meade				X		
Fort Pierce						X
Green Cove Springs				X		
Havana						
KEYS	X	X	X	X	X	
KUA						X
Lake Worth				X		
Leesburg						
Newberry				X		
Ocala			X	X		X
Starke						
Vero Beach		X		X		

Table 17-1 (Continued)
Existing ARP Member DSM Programs

	DSM Measures (3 of 3)				
	ESCO Projects	City Wide Energy Conservation	Energy Star Program	Bio-Diesel Fleet	LED Traffic Signals
Beaches			X		
Bushnell					
Clewiston					
Fort Meade			X		
Fort Pierce		X	X		
Green Cove Springs			X		
Havana					
KEYS		X	X	X	X
KUA			X		
Lake Worth					
Leesburg	X	X	X		X
Newberry			X		
Ocala			X		X
Starke			X		
Vero Beach					

17.1.2 Energy Saving Tips

Advice on energy conservation is available from utility staff and or literature. For example, in addition to distributing traditional pamphlets, bill inserts and website information, Keys Energy Services works with the schools to promote conservation among students. Keys Energy Services hosts an annual conservation art contest and winning art work illustrates their conservation calendar. The utility also hosts theater shows on conservation to elementary students.

At Beaches Energy, a monthly newsletter with many energy saving tips is published and provided to customers. In the fall of 2007 four elementary schools participated in an art contest featuring energy conservation tips with the winners published in a calendar.

KUA provides free Energy Tips books and energy conservation calendars to its customers. These materials contain information on various ways that customers can conserve power. KUA also sponsors community activities and offers training to organizations.

The City of Clewiston runs a radio spot two to three times per week on a local radio station encouraging customers to have their heating and air conditioning systems inspected annually and to change the air filters regularly to reduce energy usage. The radio spot also encourages customers to contact the city for additional energy conservation tips.

17.1.3 Appliance and Other Rebates

The City of Ocala offers rebates to residential and small commercial customers to upgrade to more efficient heating, ventilation, and air conditioning (HVAC) units. Ocala also offers a residential attic insulation rebate. To date, 21 customers have participated in the HVAC rebate program, and 25 customers have participated in the attic insulation rebate program.

KUA has implemented a series of rebate programs for its customers. These programs include rebates for repairing duct leaks, performing annual maintenance of HVAC units, installing insulation in single-family homes and small businesses, and installing LED exit signs in businesses.

17.1.4 On-Line Energy Audits

Many of the ARP members offer an on-line energy audit service as a link from the city's web site. Each month, Webtrends provides activity data for the main FMPA Energy Depot website. The data is an overview of the FMPA site as a whole and represents a summation of the activity from all participating FMPA Member sites during the month. Each participating Member also receives a report of new user profiles/audits on that Member's individual utility energy depot site. The Energy Depot Online Energy Audit includes the following features:

1. Personal Energy Profile--Allows customers to conduct online do-it-yourself home energy audits. Customers can choose from a comprehensive "Full Audit" or a quick "EZ Audit". The Energy Profile is a true home energy audit analysis with sound engineering calculations in a customer-friendly setting.
2. Energy Calculator--Allows customers to very quickly estimate the annual energy use and cost to operate the complete range of home electric and natural gas systems including everything from HVAC systems to minor appliances.
3. Energy Library--A systematically organized library of fact sheets on a wide range of home energy systems and efficiency opportunities. The library also includes the top 100 frequently asked questions and answers on home energy use.
4. Energy Advisor--An email question and answer tool that allows customers to receive answers to any remaining energy questions.

The total number of audits performed (EZ Audits or Full Audits) from the initial program startup in March 2007 through December 2007 was 1,659.

17.1.5 Load Profiling for Commercial Customers

The City of Ocala installs a recording meter to monitor the customer's electric consumption. Commercial customers can request monthly reports of their electric consumption profile.

17.1.6 Fix-Up Programs

Qualifying customers and homes can apply for assistance in having their home remodeled with additional insulation and weatherization. Fort Pierce Utilities Authority provides the energy audit for someone requesting consideration for home insulation upgrades. If the audit results in qualifying the home, a grant up to $10,000 is provided through the City of Fort Pierce. At present, 16 homes are being upgraded each year. The actual energy savings from the program are difficult to quantify, as some homes show significant improvement and others yield little benefit.

The City of Ocala has a similar program and retrofitted 44 homes during 2007.

17.1.7 ENERGY STAR® Program

Several ARP members participate in the ENERGY STAR® program and associated campaigns. ENERGY STAR®, which is backed by the US Environmental Protection Agency and Department of Energy, provides strategies and tools to help utilities promote different energy-saving campaigns. As an ENERGY STAR® partner, utilities recognize the importance of energy conservation in meeting their communities' power needs, minimizing customers' power bills, and conserving natural resources. Utilities participate in the ENERGY STAR® program by including links on their websites, posters and displays in their lobbies, as well as providing other promotional materials to their customers on ENERGY STAR® programs, appliances, conservation tools, and other features.

17.1.8 Compact Fluorescent Bulbs

Member cities that participate in this program give away and promote compact fluorescent light (CFL) bulbs to their customers. Since the fall of 2007, Beaches Energy has given away approximately 15,000 promotional CFL bulbs to residential and commercial customers.

17.1.9 ESCO Projects

An ESCO company is an energy services company specializing in the installation of energy efficient projects. The company provides professional energy auditing services and will arrange for financing and installation of projects for the customer. The ESCO is paid for its services through proven savings on energy. ARP Members participate in the program through a contract executed by FMPA.

As an example, the City of Leesburg had energy audits of the city's buildings performed by FMPA's ESCO affiliate. The initial projects undertaken had less than a four year payoff.

Lake/Sumter Community College is an electric customer of the City of Leesburg. A similar energy audit on the campus identified $500,000 in worthwhile projects. The City of Leesburg used a pooled loan provided by FMPA to provide a low interest loan to the Community College to support the implementation of the activities recommended by the energy audit.

17.1.10 City Wide Energy Conservation

Some member cities have set an example of energy conservation to their communities by implementing conservation projects throughout city owned facilities. As an example, the City of Jacksonville Beach has installed CFL bulbs where applicable in city facilities and installed sensor lighting in closets and rest rooms.

17.1.11 LED Traffic Signals

Several cities have undertaken a conservation measure to convert their traffic signals from using incandescent bulbs to bulbs made with light emitting diodes (LED).

17.1.12 Green Initiatives at FMPA Facilities

FMPA's headquarters in Orlando was designed for energy efficiency. This includes providing natural lighting along with energy efficient indirect lighting. The building's HVAC system is composed of a chilled water system and a variable air volume air distribution system. The building was constructed of lightweight, highly insulated material, which slows heat gain. The facility includes ENERGY STAR® certified appliances and office electronics.

17.2 FMPA RFP for Demand-Side Management Resources

On July 27, 2007, FMPA issued a Request for Proposals (RFP) for Demand Side Management resources (DSM RFP) on behalf of the ARP. The DSM RFP, which is presented in its entirety as Appendix D to this Application, served as an invitation for qualified companies to submit proposals for DSM resources. DSM resources include any facility, program, or service implemented for retail customers that serves to permanently reduce or shift the time of consumption of electric energy and/or electric demand. The RFP requested a minimum contract term of one-year beginning no earlier than June 1, 2008. On-peak demand and reductions must be at least 1,000 kW for third party proposers, and 500 kW for customer proposers.

The DSM RFP was distributed directly to 35 DSM providers and notification of the RFP was posted in one industry publication. Additionally, the RFP was posted on FMPA's website which allowed industry publications to pick it up for further distribution.

The following provides a listing of some of the information required to be submitted in response to the DSM RFP:

1. A listing of previous clients that have received similar services to those outlined by the RFP. The listing was to include a description of the DSM resource offered, the amount of capacity or energy involved, and a contact name and telephone number. The RFP advised potential respondents that preference will be given to firms with demonstrated experience with Florida municipal utility clients.

2. Firm name, description of core business services and primary client base and the name of the firm's parent company, if applicable. If the firm has an office in Florida, they were to give the location (address and phone number) and identify the office(s) that will be assigned to this project. If the respondent is an affiliation of two or more independent companies, they were to identify each company, their role in this project, and to provide the information described above for each company.
3. Proposals were required to include a pricing proposal, describing the payments the Proposer expected to receive over the term of the Agreement. The pricing proposal also was required to include:
    - An annual capacity price in $/kW for the amount of reduced demand, as well as an annual energy price in $/MWh for the amount of reduced energy. The RFP advised that the proposed demand and energy pricing should be net of any retail rate savings that the Host Customer(s) may receive that result from the demand and energy reductions.
    - A description of how the results obtained from the Measurement and Verification plan (M&V Plan) would be used to adjust payments made to the proposer over the term of the proposal.
    - An assessment of costs to be incurred by the Host Customer for the implementation of the DSM Measure(s).
    - Documentation of the derivation of the Host Customer costs for use in the economic evaluation of the Proposal.
4. Proposals were required to include an effective Measurement and Verification Plan (M&V Plan) to provide the basis for determining the level of demand and energy reductions produced as a result of the DSM Measure implementations. The M&V Plan was required to fully describe all calculations and procedures that will be used to determine demand and energy reductions, including, but not limited to: engineering estimates; auditing procedures; pre- and post-installation metering facilities and monitoring and recording procedures; quality assurance procedures; weather adjustments; and any other assumptions or measurements proposed by the Proposer. Additionally, the Proposer was required to describe how each of the following factors are addressed by the M&V Plan: Free Riders (as defined in Appendix A of the RFP), Free Drivers (as defined in Appendix A of the RFP), Persistence of reduction, consumption

rebound, state and federal efficiency standards and codes, diversity of demand reductions, coincidence with on-peak demands, naturally occurring conservation, degradation of DSM Measure efficiency, age of existing equipment/facilities to be affected by the DSM Measure(s), and projected demand and energy impacts of the existing facilities over the term of the proposal. The RFP also advised potential respondents that they would be expected to submit an annual report on demand and energy reductions, which are calculated consistent with the M&V Plan, prior to receipt of any demand and energy payments to be made by FMPA.

17.2.1 Summary of RFP Responses

FMPA received four (4) proposals by the September 26, 2007 due date specified in the DSM RFP. Of the proposals received, three offered programs to reduce FMPA's capacity or energy requirements – two using demand-response and the third through an ESCO arrangement. The fourth proposal was an offer to provide computer software and equipment, which was not the type of proposal being sought by FMPA. The three proposals retained for evaluation are described below.

The first demand response type proposal was projected to reduce the ARP's peak demand by 20 MW - 35 MW over a 5-year period. FMPA would pay a contractual rate for demand and energy reductions. The bidder would monitor FMPA's load from its 24 hour centralized control center and would curtail load when notified by FMPA. The bidder would bear the cost associated with monitoring and equipment installations. The bidder would guarantee MW reductions and would pay FMPA penalties for failure to deliver the reductions. Reductions would be measured against average kW usage during peak periods over the three highest usage days of the last 10 days.

The second demand response bidder's current offer is up to 44 MW of demand reduction over an 8-year period. The bidder would curtail load when notified by FMPA. The curtailment would be measured against the average of the participating facilities' single highest hourly demands for each of the four summer months of the previous year. The payment to the customer for the curtailment would be based on the average curtailment for all hours of the events occurring during the month. The bidder would guarantee MW reductions and would pay FMPA penalties for failure to deliver the reductions. FMPA would be responsible for metering costs for each participating customer.

The proposed ESCO arrangement would set up an ESCO that would work directly with ARP members' customers such as schools, colleges, and large commercial and industrial customers to reduce energy usage by changing equipment, sequence of operation, or run times to reduce a customer's energy use. The customers would pay for a guaranteed level of energy reduction that would be guaranteed by the proposer.

17.2.2 DSM RFP Response Evaluation Process

On October 26, 2007, FMPA submitted clarifying questions to the three qualified proposers described previously. Responses to the questions were received over the period November 3, 2007 through November 20, 2007. Based on these responses, FMPA completed an evaluation of the DSM proposals on December 3, 2007. The evaluation compared pricing for each of the definitive proposals against the cost of conventional capacity. FMPA concluded that both of the demand response proposals offered definitive proposals for demand response programs that were projected to reduce the ARP's demand. Of these two, the pricing for one of the proposals was clearly lower and could potentially reduce FMPA's demand related costs compared to supply-side alternatives. The third proposal, the ESCO, did not provide a specific energy reduction or pricing after clarifying questions had been asked except to project that participating customers could reduce energy consumption by 15 percent to 20 percent. None of the proposals offered definitive energy efficiency or conservation programs.

Based on the initial evaluation of the DSM proposals, FMPA decided to meet with the three qualified DSM proposers to further clarify DSM programs that could reduce FMPA's costs and potentially help FMPA reduce greenhouse gas emissions. FMPA met with all of the proposers in January 2008 and has followed up with all of them with further meetings and/or phone calls. FMPA continued to negotiate agreements with all three proposers.

In order to evaluate both price and non-price attributes of each of the demand response program proposers, FMPA prepared a comparison matrix including such non-price factors such as measurement and verification of the curtailment, notice requirement, technical approach, local office presence, etc. Based on this review, both were approved for further negotiation. In addition, FMPA is continuing discussions with the ESCO proposer relating to their energy efficiency/conservation type proposal.

Based on responses to the DSM RFP and subsequent discussions with proposers, FMPA is examining the possibility of implementing a demand response program that, based on information provided by one of the proposers, could potentially reduce the ARP coincident peak demand by approximately 44 MW by 2016, with the following assumed implementation schedule:

- 15 MW in 2009.
- 7 MW in 2010 (22 MW cumulative).
- 4 MW in 2011 (26 MW cumulative).
- 4 MW in 2012 (30 MW cumulative).
- 4 MW in 2013 (34 MW cumulative).
- 4 MW in 2014 (38 MW cumulative).
- 4 MW in 2015 (42 MW cumulative).
- 2 MW in 2016 (44 MW cumulative).

At this point FMPA envisions that curtailment could occur between noon and 8:00 p.m. between the months of May and October. Up to six hours continuous could be curtailed, with maximums of up to 30 hours curtailed in any month and up to 60 hours curtailed in total during a calendar year.

17.3 Additional Conservation and DSM Initiatives

FMPA is considering several conservation and DSM initiatives in addition to those described previously in this section.

17.3.1 Publix Demand Response Program

FMPA has been working with Publix Super Markets on a demand response program. The program would call for Publix to receive a notice from the FMPA dispatch center and turn on their standby generators during peak load periods and system emergency load periods. This program is similar to the programs that investor owned utilities have implemented with Publix and other major commercial enterprises with large standby generators. The benefit of the program to Publix is that the company is paid an incentive in line with FMPA's avoided cost. As Publix must exercise its generators regularly, this generates no net increase in greenhouse gases while avoiding the generation of greenhouse gases and other emissions on the utility's part. The use of Publix standby generators would be during periods that the utility would otherwise be forced to use generation from its more inefficient units.

17.3.2 Potential ARP-Funded Energy Conservation Program

FMPA is considering undertaking a program to assist its Members in implementing energy conservation measures. Under this program, FMPA could collect funds through its rates that would be allocated among the ARP Members. As an example, the Members could utilize these funds to purchase CFL bulbs that could be distributed to retail customers at reduced or no cost.

17.3.3 Florida Municipal Energy Efficiency Coalition

FMPA is a member of a new group of Florida public power utilities, called Florida Municipal Energy Efficiency Coalition (FMEC). This group was formed in August of 2006 to explore new options for efficiency programs that can result in greater energy conservation and savings to customers. Other members of FMEC are Gainesville Regional Utilities, JEA, Lakeland Electric, Orlando Utilities Commission, Tallahassee, and Florida Municipal Electric Association. The utilities have agreed to develop consistent data and share best practices as they evaluate DSM programs to save energy that are specific to the state of Florida.

17.3.4 Florida Energy Sustainability Consortium

FMPA is also participating in the Florida Energy Sustainability Consortium. The consortium, made up of Florida universities together with industry, proposes a statewide collaboration to coordinate and unify efforts in research, development, technology commercialization, education, outreach, and technology transfer in energy.

FMPA believes the Florida Energy Sustainability Consortium will bring substantial benefits to the Member cities and the communities they serve. FMPA expects the Consortium to help it build consensus and understanding of issues related to the state proposed GHG reduction program. Likewise, FMPA believes that Florida must pull together the best ideas from energy production, emission control, generation efficiency, customer efficiency and renewable production. It is FMPA's understanding that the Florida Energy Sustainability Consortium will not only bring utility representatives together but representatives from state agencies as well as representatives from various other industry sectors.

17.3.5 Demonstration of Energy-Efficient Developments Programs

FMPA is also a member of the American Public Power Association's Demonstration of Energy-Efficient Developments (DEED) program. Through FMPA's membership in this program, all of FMPA's members are also DEED members. DEED is a research and development program funded by and for public power utilities. Established in 1980, DEED encourages activities that promote energy innovation, improve efficiencies, and lower costs of energy to public power customers.

18.0 Carbon Reduction Activities

18.1 Introduction

On July 13, 2007, Governor Crist issued Executive Order 07-127, entitled "Immediate Action to Reduce Greenhouse Gas Emissions within Florida." This order directs the Department of Environmental Protection (DEP) to adopt rules requiring CO_2 emission reductions from electric utilities. Although the DEP has not yet adopted any rules in response to the Governor's order, the ARP is committed to responsibly reducing its CO_2 emissions. This section summarizes the ARP's historical CO_2 emissions, as well as actions the ARP has taken or may take that will help reduce the ARP's CO_2 emissions. Specifically, Section 18.2 summarizes the ARP's carbon footprint. Section 18.3 summarizes actions the ARP has taken that will reduce the ARP's CO_2 emissions. Finally, Section 18.4 summarizes future planned actions, including the addition of Cane Island Unit 4, as well as other potential actions that would reduce the ARP's carbon footprint.

18.2 The ARP's Carbon Footprint

The Governor's Executive Order 07-127 sets goals for utilities to reduce their greenhouse gas emissions to 2000 levels by 2017, to 1990 levels by 2025, and by 80 percent of 1990 levels by 2050. This section describes a preliminary CO_2 emissions inventory developed for 1990 and 2000 to determine the baseline carbon footprint of the ARP in those years.

18.2.1 Methodology

Because the DEP has not established any guidelines on reporting of greenhouse gases as of the date of this filing, the emissions inventory was performed using the guidelines set forth in the DOE's final "General Guidelines for Voluntary Reporting of Greenhouse Gases (1605(b)) Program" issued in April 2006, and "Technical Guidelines for Voluntary Reporting of Greenhouse Gases (1605(b)) Program" (the Technical Guidelines) issued in January 2007.[1]

[1] The DOE initiated the Voluntary Reporting of Greenhouse Gases Program (the GHG Program) during 1994 in response to Section 1605(b) of the Energy Policy Act of 1992, which required the DOE to issue guidelines establishing such a program. The DOE developed both general guidelines and technical guidelines for the GHG Program. The technical guidelines define the permissible methods of calculating and reporting emissions quantities and reductions under the GHG Program.

The 1605(b) Guidelines categorize emissions for electric utilities as occurring from either direct or indirect sources. Direct emissions are those emissions that the utility is directly responsible for producing; that is, the utility produces these emissions through operation of its own generating units. Indirect emissions are those emissions associated with purchased power.

The collective 1990 and 2000 emissions for all 15 ARP members were developed using the equity share approach set forth in the 1605(b) Guidelines. Under this approach, a utility includes the percentage of the total emissions produced from a jointly owned facility that corresponds with its ownership percentage of that resource.

Where available, data from continuous emissions monitors (CEMs) were used to estimate direct emissions. However, as CEMS were not required to be installed on plants until after 1990, these data were not available for the 1990 computation. Additionally, some small generating units are not required to install CEMS, so CEMs data were not available for all generators for 2000. Where CEMs data were not available, emission factors provided in the 1605(b) Guidelines or other publicly available sources were used. Likewise, such publicly available emission factors were used to estimate emissions from purchase power.

18.2.2 Final Adjustments

The first step in determining the total emissions quantities for each year involved determining whether all energy sources had been captured for that year. The sum of all energy generated and purchased, net of wholesale energy sold to other entities, theoretically should be at least equal to the utility's energy requirements (some excess of energy sources above energy requirements may exist because of losses).

For computing total generation associated with direct emissions, the generation and consumption data from Global Energy Decisions' *Velocity Suite* were used for all units. This provided a consistent source of generation for all resources.

For both 1990 and 2000, however, the sum of the total energy sources amounted to less than the total energy requirements. For purposes of the analysis, CO_2 emissions were computed for the "missing" energy amount using the regional emissions factor assigned to purchased power for that year.

18.2.3 Emissions Totals

The total CO_2 emissions inventoried consist of the sum of the direct emissions, indirect emissions, and any adjustments. The computed total CO_2 emissions are shown in Table 18-1.

Table 18-1
Summary of ARP CO_2 Emissions in 1990 and 2000[1]

Item	Units	1990	2000
Total Energy Sources	GWh	3,142	6,426
Total Energy Requirements	GWh	4,663[2]	6,467
Surplus/(Shortfall)	GWh	(1,521)	(41)
Surplus/(Shortfall)	%	(32.6)	(0.6)
Direct CO_2 Emissions	000 Short Tons	1,442	2,538
Indirect CO_2 Emissions	000 Short Tons	836	2,139
Adjustments[3]	000 Short Tons	1,203	30
Total CO_2 Emissions	000 Short Tons	3,481	4,707

[1]Analysis performed as if all 15 current ARP members were ARP members in 1990 and 2000.
[2]Energy requirements estimated for 1990. Actual energy requirements for the ARP members in 1990 were not available.
[3]Adjustments reflect CO_2 emissions computed for additional energy amounts necessary to balance total energy sources and total energy requirements and were computed using the regional emissions factor assigned to purchased power for Florida applicable to that year.

18.3 Historical Carbon Reduction Activities

18.3.1 Generation Efficiency

Historically, the ARP has consistently sought to improve the efficiency of its generating fleet, which can have the added benefit of reducing carbon intensity (quantity of CO_2 per unit of energy produced). The ARP's actions have displaced generation from older, member-owned generating resources with newer, more efficient units. Table 18-2 below contains a list of the units that either have been or are scheduled to be retired, the retirement year, and the average CO_2 emissions eliminated by retiring these resources. Additional member-owned generation will be displaced with operation of Cane Island Unit 4.

Table 18-2
Recent and Scheduled Retirements of Member-Owned Generating Resources

Unit Name	Owner	Fuel Type	Retirement Year	Annual CO_2 Emissions (Short Tons)(1)
Hansel IC 8, 14-20	KUA	No. 2 Oil	2005	1,800
Big Pine Key IC 1	Keys Energy Services	No. 2 Oil	2006	400
Cudjoe Key IC 2-3	Keys Energy Services	No. 2 Oil	2006	1,500
H. D. King CC 5/9	Fort Pierce	Natural Gas	2008	11,100
H. D. King ST 7-8	Fort Pierce	Natural Gas	2008	20,400
H. D. King IC 1-2	Fort Pierce	No. 2 Oil	2008	200
Total				**35,400**

(1)Based on the average annual tons of CO_2 emitted during the years 2001 through 2005.

As appropriate and cost effective, FMPA has also sought to replace energy obtained from purchased power with more efficient means. Emissions for purchased power that are not tied to specific generating plants or units can be much higher than the carbon intensity of energy produced by efficient, natural gas-fired resources. As examples, FMPA has either recently replaced or is planning to replace energy from purchases from the City of Lakeland, Progress Energy Florida (PEF), and Florida Power & Light Company (FPL) with new generating resources or purchases from specific, gas-fired facilities.

FMPA has added several new generating resources in recent years through both ownership and facility-specific purchased power contracts. These new resources provide CO_2 emission reduction benefits to the ARP by allowing the ARP (1) to displace the operation of other, less efficient owned generating resources, and (2) to reduce the amount of more carbon-intensive energy it purchases from other entities. These new resources are described in more detail below.

- **Cane Island CC3**. Cane Island CC3 commenced operation in 2002. This 246 MW, natural gas-fired, combined cycle facility is jointly owned by KUA and FMPA, with all of its output going to the ARP. During its first 5 years of commercial operation, Cane Island CC3 emitted an average of approximately 0.21 short tons of CO_2 per MWh less than other ARP generating resources and approximately 0.22 short tons of CO_2 per MWh less than all energy sources for the ARP.

- **Stanton Energy Center CCA**. Stanton Energy Center CCA commenced operation in 2003. KUA and FMPA each owns a 3.5 percent share of this 600 MW, natural gas-fired, combined cycle facility, and each also purchases an additional 6.5 percent share from Southern Company, with the total 20 percent share going to the ARP. During its first 3 complete years of commercial operation, Stanton Energy Center CCA emitted an average of approximately 0.26 short tons of CO_2 per MWh less than other ARP generating resources and approximately 0.28 short tons of CO_2 per MWh less than all other energy sources for the ARP.
- **Calpine (Osprey) Purchase**. FMPA has a contract with Calpine that provided 75 MW in 2006. The purchase increased to 100 MW in 2007 and expires in 2009. During 2006, each MWh of energy purchased from Calpine produced approximately 0.19 short tons of CO_2 less than the average of the ARP generating units and approximately 0.23 short tons of CO_2 less than other purchases.
- **Stock Island CT4**. In 2006, the ARP commenced operation of its Stock Island CT4 in Key West. If operating at full load, every MWh of energy generated from Stock Island CT4 in lieu of other on-island resources can reduce FMPA's CO_2 emissions output by up to 0.17 short tons.
- **Southern Purchase**. FMPA has a contract to purchase 156 MW of new peaking power from Southern Company's Oleander plant beginning in December 2007. Since the unit has only been in operation since December 2007, actual emission data are not yet available; however, as a new efficient GE 7FA simple cycle combustion turbine, the Oleander purchase will reduce CO_2 emissions compared to other less efficient FMPA peaking resources or purchased power.

FMPA also currently receives renewable energy from two renewable resources. These resources also provide CO_2 reduction benefits to the ARP, as described below.

- **U.S. Sugar**. Energy purchased from the U.S. Sugar Corporation is considered carbon neutral because it uses renewable, carbon-neutral bagasse as its primary fuel source. Over the period 2000 through 2006, the U.S. Sugar purchase is estimated to have reduced CO_2 emissions for the ARP by an average of approximately 1,300 short tons per year. As U.S. Sugar utilizes its generating facility to serve its own energy requirements, the ARP indirectly avoids having to serve the U.S. Sugar load using more carbon intensive generating resources.

- **<u>Landfill Gas (Stanton Energy Center)</u>**. The Stanton Energy Center utilizes landfill gas to supplement the fuel requirements for the coal fired Units 1 and 2. The reportable CO_2 content for landfill gas/municipal solid waste (MSW) varies according to the plastic content of the underlying waste product. The national average CO_2 emissions factor for MSW (as provided by the DOE) is 92 pounds of CO_2 per MBtu of MSW consumed and is based on a plastic content of 16 percent. As the plastic content of the landfill gas burned by Stanton Energy Center Units 1 and 2 could not be obtained, the default factor was assumed. On the basis of this factor, CO_2 emissions for the ARP were estimated to have been reduced by approximately 19,700 short tons per year over the period 2001 through 2006 by consuming landfill gas instead of coal.

18.3.2 Demand Side Management

FMPA is a wholesale supplier of electricity to the 15 ARP member cities. As such, FMPA does not directly implement DSM to retail customers. The individual ARP members actually provide the DSM programs to their customers. Several ARP members offer various DSM programs, including the following:

- Energy audits.
- Energy savings tips.
- Energy Star programs.
- Green energy programs.
- Solar projects and net metering.
- Solar promotion.
- Appliance rebates.
- Compact fluorescent bulb promotions.
- ESCO projects.
- City-wide energy conservation.
- LED traffic signals.
- Load profiling for commercial customers.
- Fix-up programs for the elderly and handicapped.

To the extent these measures help to reduce FMPA's energy requirements, they have a corresponding CO_2 reduction benefit to the ARP.

18.4 Future Planned and Potential Carbon Reduction Activities

18.4.1 Treasure Coast Energy Center

FMPA's Treasure Coast Energy Center Unit 1 (TCEC Unit 1) is scheduled to commence operation in May 2008. This nominal 300 MW, natural gas-fired combined cycle unit represents FMPA's largest self-owned generating project to date. It is estimated that TCEC Unit 1 will reduce FMPA's CO_2 emissions by displacing less efficient generating units and power purchases on FMPA's system.

18.4.2 Cane Island Unit 4

Cane Island Unit 4 also will significantly reduce FMPA's total future CO_2 emissions. Cane Island Unit 4 will displace the operation of less efficient generating resources. By operating this more efficient unit, FMPA will reduce the average CO_2 emitted per MWh produced for its system. Additionally, Cane Island Unit 4 will reduce FMPA's purchase power requirements and associated higher CO_2 emissions.

Additionally, the need for Cane Island Unit 4 resulted from the cancellation of the Taylor Energy Center (TEC), the coal fired project that was jointly proposed by FMPA, JEA, Reedy Creek Improvement District, and the City of Tallahassee. The CO_2 emissions rate for the TEC was estimated between 200 and 215 lb/MBtu, or between 0.92 and 0.99 short tons/MWh based on the average heat rate of 9,238 Btu/kWh, depending on the type of coal consumed. By contrast, the estimated CO_2 emissions rate for Cane Island Unit 4 of approximately 115 lb/MBtu, or 0.43 short tons/MWh based on the average heat rate of approximately 7,420 Btu/kWh (including duct firing), is significantly lower.

18.4.3 Nuclear Uprates

FMPA's capacity shares of the Crystal River 3 and St. Lucie 2 nuclear units will increase as a result of upgrades to the facilities being undertaken by PEF and FPL, respectively. FMPA or members that own shares of these facilities will receive proportional increases in their capacity allotments based on their ownership percentage. The total planned incremental capacity increase for each unit and the ARP members' allocation of these capacity increases are shown below.

	Crystal River 3		St. Lucie 2	
	Total Uprate	ARP Allocation	Total Uprate	ARP Allocation
2008	12 MW	0.3 MW	--	--
2009	28 MW	0.8 MW	--	--

	Crystal River 3		St. Lucie 2	
	Total Uprate	ARP Allocation	Total Uprate	ARP Allocation
2010	--	--	--	--
2011	140 MW	4.0 MW	--	--
2012	--	--	100 MW	5.8 MW

This increase in nuclear capacity will provide a CO_2 emissions reduction benefit to FMPA.

18.4.4 Future Nuclear Ownership

FMPA is currently investigating the feasibility of acquiring an ownership share in future nuclear resources proposed to be built in Florida as discussed in Section 19.4. FMPA is currently in discussions with PEF concerning potential participation in the Levy County nuclear project. Since nuclear generation does not produce CO_2, acquiring additional nuclear ownership could bring significant CO_2 emissions reduction benefits to the ARP as early as 2016.

18.4.5 System Loss Reduction

FMPA encourages the concept of asset management for both itself and member utilities. Asset management involves investigating methods of utilizing existing assets to improve efficiency, lower costs, or improve revenue. CO_2 reductions can be obtained through management of the ARP's generating assets and aggregated electrical load.

Losses are an aggregated component of the electric load of the member utilities. As losses are controlled and reduced, so is the need for additional electrical generation. Therefore, reducing losses reduces CO_2 emissions and can reduce or delay the need for constructing additional generating resources. FMPA is leading an effort among the members to investigate losses and for members to invest in loss reduction.

18.4.6 Potential Future Renewable Resources

18.4.6.1 Potential Biomass Generation. As part of its efforts to reduce its overall CO_2 emissions, FMPA has issued RFPs for renewable resources as discussed in Section 16.0. Based on the results of the RFPs, FMPA has decided to enter into negotiations for a purchase from a biomass facility. The biomass unit, which would utilize renewable, carbon-neutral resources, would further reduce FMPA's CO_2 emissions. As discussed in Section 16.0, however, there are several issues that must be resolved before FMPA can commit to the potential biomass purchase.

18.4.6.2 Potential Solar Photovoltaic Project. FMPA has decided to enter into negotiations for the installation of 10 MW of solar PV technology on ARP member systems as discussed in Section 16.0. However, there are several issues that must be resolved before FMPA can commit to the PV purchase, as discussed in Section 16.0. FMPA will additionally explore the feasibility of acquiring up to an additional 90 MW of PV systems. The addition of PV systems would further reduce FMPA's CO_2 emissions. FMPA's decision to pursue additional solar capacity beyond the initial 10 MW would depend on successful negotiation for and implementation of the initial 10 MW project. The time frame for implementation of solar capacity would depend on the time necessary to complete negotiations and obtain all required regulatory approvals and permits.

18.4.6.3 Potential Use of Biofuels at Stock Island. FMPA is currently investigating the feasibility of operating several of the generating units at the Stock Island facility in Key West using biodiesel fuel. These units currently operate using fuel oil. If ultimately implemented, the switch from fuel oil to biodiesel fuel for these units could reduce FMPA's CO_2 emissions.

18.4.7 Potential Future Conservation Programs

18.4.7.1 DSM Request for Proposals. In July 2007, FMPA issued an RFP for DSM activities as discussed in Section 17.0. Four proposals were received, and FMPA is continuing to negotiate with three of the proposers. To the extent any of these measures, if ultimately implemented, help to reduce FMPA's future energy requirements, they would have a corresponding CO_2 reduction benefit to the ARP.

18.4.7.2 Potential ARP-Funded Energy Conservation Program. As a wholesale energy provider, FMPA does not directly implement demand-side conservation measures. However, FMPA is considering undertaking a program to assist its members in implementing energy conservation measures. Under this program, FMPA could collect funds through its rates that would be allocated among the ARP members. As an example, the members could utilize these funds to purchase compact fluorescent light bulbs that could be distributed to retail customers at reduced or no cost. These measures would help to reduce FMPA's energy requirements, which would have a corresponding CO_2 reduction benefit to the ARP.

18.5 Conclusion

The ARP has demonstrated a strong track record in improving the efficiency of its generating fleet, and it is committed to exploring new ways to improve efficiency and to reduce CO_2 emissions in a cost-effective manner. Because Cane Island Unit 4 will be one of the most efficient generating units in the state, it will enable the ARP to displace generation from less efficient units and thereby reduce CO_2 emissions. While the specifics of any state CO_2 regulatory regime will not be known for some time, FMPA's preliminary analyses indicate that the least cost expansion plan with Cane Island Unit 4 would enable FMPA to achieve the 2017 CO_2 emissions target level in Executive Order 07-127.

19.0 Evaluation Methodology

Detailed economic analyses were performed to evaluate the economics of Cane Island Unit 4 as part of FMPA's least-cost expansion plan to satisfy forecast capacity requirements throughout the 20 year evaluation period considered in this Application. This section discusses the evaluation methodology used in the economic analyses. The result of the analyses are presented in Section 20.0.

19.1 Expansion Planning Simulation

Optimal generation expansion planning and production cost modeling was performed using STRATEGIST, a computer software system developed by NewEnergy Associates, LLC (NewEnergy). STRATEGIST is a proven and effective modeling program for optimal generation expansion planning and production cost modeling. According to NewEnergy, over 50 utilities now use STRATEGIST for integrated corporate strategic planning, including least-cost expansion planning. NewEnergy was recently acquired by Ventyx.

STRATEGIST includes an automatic expansion planning module that can determine the optimal balanced demand and supply plan for a utility system under a prescribed set of constraints and assumptions. STRATEGIST evaluates all combinations of generating unit alternatives and purchase power options in conjunction with existing capacity resources to satisfy forecast capacity requirements while maintaining user-defined reliability criteria. STRATEGIST simulates the hourly operation of a utility system to determine the cost and reliability effects of adding resources to the system or modifying the load through DSM programs. The simulation of the utility system operation is accomplished using dynamic programming, a mathematical technique useful for making a sequence of interrelated decisions for determining the combination of decisions that optimizes the desired outcome. In this Application, all expansion plans were analyzed over a 20 year period from 2008 through 2027.

19.2 Fuel and Emission Allowance Price Forecasts

Section 7.0 presents the fuel and emissions allowance price forecasts used throughout this Application, including price forecasts for various sensitivity cases. The fuel and emissions allowance price forecasts presented in Section 7.0 were developed in constant 2005 dollars. For purposes of the economic analyses presented throughout this Application, the constant 2005 dollars price projections were converted to nominal dollars using the 2.3 percent general inflation rate discussed in Section 4.0.

To consider the costs associated with emissions of SO_2, NO_x, and CO_2, the emissions rates for every existing generating resource, as well as new capacity additions being considered, were included in the dispatching decisions made by STRATEGIST. Because each generating unit, whether existing or being considered as a supply-side alternative, has a unique emissions profile, the annual emissions allowance costs vary for each unit. Including emissions allowance costs in this manner allows the analysis to take into consideration the "all-in" production costs for each unit, including fuel costs, nonfuel costs, and costs associated with emissions of regulated emissions or potential CO_2 emissions.

19.3 Firm Natural Gas Transportation Costs

As discussed in Section 8.0, the Cane Island site is currently served by both FGT and Gulfstream. FMPA has made various nonbinding requests for incremental firm natural gas transportation associated with proposed expansions of both FGT's and Gulfstream's natural gas transportation systems. For purposes of the analyses presented throughout this Application, it has been assumed that FMPA would secure an additional 20,000 MBtu per day of firm natural gas transportation capacity at a cost of $1.28/MBtu beginning in 2011. FMPA has made no commitments to the amount of incremental firm natural transportation that may be acquired from either FGT or Gulfstream and will continue to evaluate the optimal amount of incremental firm natural gas transportation capacity.

For scenarios in which renewable generation is included as described in Section 20.0, the amount of additional firm natural gas transportation is reduced to 16,000 MBtu per day in proportion to the level of renewable generation.

If additional natural gas transportation is required beyond the existing and additional natural gas transportation capacity, it was assumed to be available at the ITS rate of $0.598/MBtu.

19.4 New Nuclear Generating Units

FMPA is continuing to evaluate the potential to participate in future nuclear generating units that may be constructed in Florida. Four new nuclear generating units have been proposed to the FPSC since October 2007, including FPL's Turkey Point Units 6 and 7 (Docket No. 070650) and Progress Energy Florida's Levy County Units 1 and 2 (Docket No. 080148). The FPSC has issued a need determination for Turkey Point Units 6 and 7 and a need determination proceeding is pending for Levy County Units 1 and 2. For purposes of the analyses presented throughout this Application, it has been assumed that FMPA will receive 28 MW of nuclear capacity from Levy County Unit 1 in June

2016 and 28 MW from Levy Unit 2 in January 2017, and 50 MW of nuclear capacity from Turkey Point Unit 6 in June 2018 and 50 MW of nuclear capacity in June 2020.

19.5 DSM Costs

Since FMPA is continuing to negotiate with both DSM vendors, as discussed in Section 17.0, the costs included in the scenarios that include DSM are based on the DSM vendor with the lowest cost and the greatest amount of DSM. These costs are included in the cumulative present worth costs (CPWC) discussed below, but have not been presented separately because of confidentiality requirements.

19.6 Cumulative Present Worth Cost Analysis

Economic comparisons between competing expansion plans were developed on a CPWC basis. The CPWC calculation accounted for annual system costs (fuel and energy, fixed O&M, nonfuel variable O&M, startup, and levelized capital costs for new unit additions) for each year of the expansion planning period and discounted each back to 2008 using the 5.0 percent present worth discount rate discussed in Section 4.0. In addition, costs for emissions allowances, natural gas transportation, and DSM are included These annual present-worth costs were then totaled over the 2008 through 2027 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various expansion plans, and the plan with the lowest CPWC is considered the least-cost expansion plan for any given scenario considered.

20.0 Economic Evaluation

Detailed economic analyses were performed to evaluate the cost-effectiveness of the addition of Cane Island 4 to help satisfy forecast capacity and energy requirements of FMPA's ARP. Numerous evaluations were conducted in order to consider reference case fuel price and load forecasts as well as sensitivities related to fuel prices, load forecasts, capital costs, and regulation of CO_2 emissions. Additionally, the cost-effectiveness of Cane Island 4 was evaluated under several scenarios involving new renewable energy resources available to FMPA and reductions in coincident peak demand resulting from implementation of a new demand-side management program. The remainder of this section describes each of the scenarios evaluated and presents the corresponding cumulative present worth cost (CPWC) for expansion plans with and without the addition of Cane Island 4 in May 2011.

The economic analyses described herein compare the economics of the least-cost expansion plan including Cane Island 4 in May 2011 versus the economics of the least-cost expansion plan that does not include Cane Island 4 in May 2011. For comparison purposes, the addition of Cane Island 4 in May 2011 was treated as a committed resource, and the optimal expansion model, STRATEGIST, was allowed to select among the supply-side alternatives presented in Section 14.0 to develop the least-cost expansion plan to meet capacity requirements beyond 2011. For cases in which Cane Island 4 was not treated as a committed resource in 2011, STRATEGIST was allowed to select among the supply-side alternatives presented in Section 14.0, including a 1x1 combined cycle identical to Cane Island 4 as early as May 2013.

20.1 Overview of Evaluation Scenarios

The economics of the addition of Cane Island 4 were considered for several cases among four distinct scenarios as outlined below. The results of the economic analyses for each case considered for each scenario are presented in subsequent subsections.

20.1.1 Scenario 1 – Conventional Expansion Scenario

The *Conventional Expansion Scenario* considers the addition of only conventional, (fossil-fueled) generating resources, with the exception of the new nuclear generating resources discussed in Section 19.0. As described previously in this section, the economics of an expansion plan including the addition of Cane Island 4 as a committed resource in May 2011 were evaluated against the economics of an expansion plan that includes a 1x1 combined cycle identical to Cane Island 4 as a generating unit alternative as early as May 2013. The Scenario 1 evaluations were performed for several sensitivity cases described as follows.

20.1.1.1 Reference Case. The *Reference Case* considers the reference case fuel and emission allowance price projections included in Section 7.0 and base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in the reference case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.2 High Fuel Price Case. The *High Fuel Price Case* considers the high fuel price and corresponding emissions allowance price projections presented in Section 7.0. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.3 Low Fuel Price Case. The *Low Fuel Price Case* considers the low fuel price and corresponding emissions allowance price projections presented in Section 7.0. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.4 High Load Case. The *High Load Case* considers the high load forecast presented in Section 5.0. Fuel and emissions allowance price projections used in this case correspond to the reference case projections included in Section 7.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.5 Low Load Case. The *Low Load Case* considers the low load forecast presented in Section 5.0. Fuel and emissions allowance price projections used in this case correspond to the reference case projections included in Section 7.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.6 High Capital Case. The *High Capital Cost Case* reflects an increase of 20 percent in the capital cost of Cane Island 4 presented in Section 9.0 as well as the capital costs of all other generating unit alternatives presented in Section 14.0. Fuel and emissions allowance price projections used in this case correspond to the reference case projections included in Section 7.0. The base case load forecast presented in Section 5.0 was used in the high capital cost case.

20.1.1.7 Regulated CO_2 Case. The *Regulated CO_2 Case* considers the fuel and CO_2 emissions allowance price projections corresponding to the EIA's analysis of S.280 as presented in Section 7.0. The CO_2 emissions allowance prices used in this case correspond to the *S.280 Core* analysis. The SO_2 and NO_x emissions allowance prices for this case correspond to the reference case emissions allowance price projections presented in Section 7.0. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.8 High Fuel with Regulated CO_2 Case. The *High Fuel with Regulated CO_2 Case* considers the high fuel price projections in Section 7.0 and also considers the CO_2 emissions allowance price projections corresponding to the EIA's analysis of S.280 (also presented in Section 7.0). The CO_2 emissions allowance prices used in this case correspond to the *S.280 Core* analysis. The SO_2 and NO_x emissions allowance prices for this case correspond to the high case emissions allowance price projections presented in Section 7.0. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.1.9 High Regulated CO_2 Case. The *High Regulated CO_2 Case* considers CO_2 emissions allowance price projections based on the US Environmental Protection Agency (EPA) analysis of S.2191, the *Climate Security Act of 2007* (now referred to as the *Lieberman-Warner Climate Security Act of 2008*). In March 2008, the EPA published its analysis in response to the request by Senators Lieberman and Warner. The analysis considered several scenarios and used various models to develop numerous forecasts of CO_2 emissions allowance prices[1]. The CO_2 emissions allowance price projections used in the *High Regulated CO_2 Case* correspond to the EPA's *S.2191 Scenario* using the EPA *IGEM* model. This analysis was selected because the resulting CO_2 emissions allowance prices fall within and towards the upper bound of the range of CO_2 allowance price projections developed by the EPA for the various scenarios considered in their analysis of S.2191.

The EPA analysis of S.2191 presented CO_2 emissions allowance price projections in 2005 dollars per ton in 5-year intervals beginning in 2015 and extending through 2050. For analysis purposes, the 2005 dollars per ton price projections were converted to nominal dollars using the 2.3 percent general inflation rate presented in Section 4.0, and linear interpolation was used between the 5-year intervals to develop annual price projections. Forecasts for 2012 through 2014 were developed by determining the average annual escalation rate between 2015 and 2020 and de-escalating the 2015 price projection by the appropriate number of years. The resulting CO_2 emissions allowance price projections for 2012 through 2027 that were used in the *High Regulated CO_2 Case* are presented in Table 20-1. For comparison purposes, Table 20-1 also presents the CO_2 emissions allowance price projections used in the *Regulated CO_2 Case*, which were based on the EIA S.280 Core case projections presented in Section 7.0.

[1] Refer to www.epa.gov/climatechange/economics/economicanalyses.html for the EPA analysis of S.2191.

Table 20-1
Projected CO_2 Emission Allowance Prices
EPA S.2191 Scenario and EIA S.280 Core
(Nominal $/Ton)

Year	EPA S.2191 Scenario	EIA S.280 Core
2012	$40.54	$14.05
2013	$43.54	$15.08
2014	$46.76	$16.08
2015	$50.21	$17.19
2016	$53.93	$18.98
2017	$57.91	$20.97
2018	$62.19	$23.17
2019	$66.79	$25.60
2020	$71.73	$28.28
2021	$77.03	$31.25
2022	$82.72	$34.52
2023	$88.83	$38.14
2024	$95.39	$42.15
2025	$102.43	$46.57
2026	$110.04	$51.44
2027	$118.21	$56.83

The fuel, SO_2, and NO_x emissions allowance prices for this case correspond to the reference case price projections presented in Section 7.0. The use of fuel and emissions allowance price projections developed independently by the EIA and EPA results in a non-integrated forecast. Nevertheless, this scenario provides an indication of the potential effect of a higher-cost CO_2 regualtory regime than that assumed in the Regulated CO_2 Case described above. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for Cane Island 4 used in this case is presented in Section 9.0, while the capital costs for all other generating unit alternatives are presented in Section 14.0.

20.1.2 Scenario 2 – Renewable Expansion Scenario

The *Renewable Expansion Scenario* considers the addition of the new renewable energy resources being considered by FMPA (including biomass and solar PV) as discussed in Section 16.0 in addition to conventional generating resources and the new nuclear generating resources. As with Scenario 1, the *Renewables Expansion Scenario* evaluates the economics of an expansion plan including the addition of Cane Island 4 as a committed resource in May 2011 against the economics of an expansion plan that includes a 1x1 combined cycle identical to Cane Island 4 as a generating unit alternative as early as May 2013. Scenario 2 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Section 20.1.1.

The *Renewables Expansion Scenario* assumes the installation of a 58 MW biomass unit with a commercial operation date of January 1, 2012 and the installation of 10 MW solar photovoltaics with commercial operation dates of January 1, 2010. The characteristics of these renewable resources are more fully described in Section 16.0. As discussed in Section 12.0, the 10 MW of solar photovoltaics were assumed to provide 3.3 MW of firm capacity to FMPA's system.

20.1.3 Scenario 3 – DSM Expansion Scenario

The *DSM Expansion Scenario* considers the addition of the new DSM program being evaluated by FMPA as discussed in Section 17.0 in addition to conventional generating resources and the new nuclear generating resources. Existing ARP conservation and DSM programs as discussed in Section 17.1 are embedded in FMPA's base case load forecast. As with Scenario 1, the *DSM Expansion Scenario* evaluates the economics of an expansion plan including the addition of Cane Island 4 as a committed resource in May 2011 against the economics of an expansion plan that includes a 1x1 combined cycle identical to Cane Island 4 as a generating unit alternative as early as May 2013. Scenario 3 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Section 20.1.1.

The projected peak demand savings included in the *DSM Expansion Scenario* are presented in Section 17.2.2. For evaluation purposes, the cumulative 44 MW savings is projected to be maintained through the end of the study period. As presented in Section 13.0 FMPA's 2011 summer capacity requirements are 286 MW. With the *DSM Expansion Scenario*, FMPA's 2011 summer capacity requirements are reduced to 260 MW.

20.1.4 Scenario 4 – Renewables and DSM Expansion Scenario

The *Renewables and DSM Expansion Scenario* considers the addition of both the new renewable energy resources and the new DSM program being evaluated (as considered in Scenarios 3 and 4, respectively) in addition to conventional generating resources and the new nuclear generating resources. As with the other scenarios, the *Renewables and DSM Expansion Scenario* evaluates the economics of an expansion plan including the addition of Cane Island 4 as a committed resource in May 2011 against the economics of an expansion plan that includes a 1x1 combined cycle identical to Cane Island 4 as a generating unit alternative as early as May 2013. Scenario 4 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Section 20.1.1.

20.2 Results of the Economic Evaluations

CPWC evaluations were performed for the various scenarios and cases within each of the scenarios as discussed previously. The CPWC associated with each of the expansion plans for each of the cases and scenarios are presented in this section.

20.2.1 CPWC Results of Scenario 1 Evaluations

The results of the CPWC evaluations for Scenario 1 are presented in Table 20-2. Analysis of the CPWC associated with each of the cases presented in Table 20-2 indicates that expansion plans including the addition of Cane Island 4 in May 2011 are the most cost-effective expansion plans for all cases considered.

20.2.2 CPWC Results of Scenario 2 Evaluations

The results of the CPWC evaluations for Scenario 2 are presented in Table 20-3. Analysis of the CPWC associated with both of the cases presented in Table 20-3 indicates that expansion plans including the new renewable resources being considered by FMPA as well as the addition of Cane Island 4 in May 2011 are the most cost-effective expansion plans for the two cases considered.

20.2.3 CPWC Results of Scenario 3 Evaluations

The results of the CPWC evaluations for Scenario 3 are presented in Table 20-4. Analysis of the CPWC associated with both of the cases presented in Table 20-4 indicates that expansion plans including the new DSM program being considered by FMPA as well as the addition of Cane Island 4 in May 2011 are the most cost-effective expansion plans for the two cases considered.

Table 20-2
CPWC Summaries for Scenario 1
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$6,873,504	$6,909,247	$35,763
High Fuel	$7,521,022	$7,558,293	$37,271
Low Fuel	$6,215,140	$6,243,170	$28,030
High Load	$7,780,149	$7,801,735	$21,586
Low Load	$5,994,755	$6,076,238	$81,483
High Capital Cost	$6,984,600	$7,022,491	$37,891
Regulated CO_2	$7,708,642	$7,714,841	$36,200
High Fuel with Regulated CO_2	$8,556,917	$8,594,522	$37,605
High Regulated CO_2	$9,347,371	$9,387,259	$39,888

Table 20-3
CPWC Summaries for Scenario 2
($000)

Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$7,159,378	$7,193,530	$34,153
Regulated CO_2	$7,953,638	$7,987,190	$33,552

Table 20-4 CPWC Summaries for Scenario 3 ($000)			
Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$6,856,721	$6,909,460	$52,739
Regulated CO_2	$7,692,426	$7,745,238	$52,812

20.2.4 CPWC Results of Scenario 4 Evaluations

The results of the CPWC evaluations for Scenario 4 are presented in Table 20-5. Analysis of the CPWC associated with both of the cases presented in Table 20-5 indicates that expansion plans including the new renewable resources and DSM program being considered by FMPA as well as the addition of Cane Island 4 in May 2011 are the most cost-effective expansion plans for the two cases considered.

Table 20-5 CPWC Summaries for Scenario 4 ($000)			
Case	CPWC of Expansion Plan Including Cane Island 4 in 2011	CPWC of Expansion Plan Without Cane Island 4 in 2011	CPWC Savings for Expansion Plan with Cane Island 4 in 2011
Reference Case	$7,139,004	$7,177,545	$38,341
Regulated CO_2	$7,932,282	$7,972,993	$40,711

20.3 Conclusions

The CPWC results summarized previously in this section demonstrate that the addition of Cane Island 4 in May 2011 is included in the least cost expansion plan for each of the 15 different scenarios and cases evaluated. When combined with both the new renewable resources and the new DSM program being considered by FMPA, Cane Island 4 provides a cost-effective resource addition to the FMPA system to serve the forecast capacity requirements of the ARP.

21.0 Consequences of Delay

As demonstrated by the economic evaluations presented in this Application, the addition of Cane Island Unit 4 in 2011 represents the most cost-effective addition to satisfy FMPA's forecast capacity requirements to reliably serve the ARP members. The consequences of delaying the commercial operation of Cane Island 4 are significant from an economic and reliability standpoint for FMPA. This section describes the negative consequences of delaying the addition of Cane Island Unit 4.

21.1 Economic Consequences

If the commercial operation of Cane Island 4 is delayed, FMPA would be required to replace the capacity and energy that would otherwise be provided by a new, efficient combined cycle generating unit. The economic consequence of delaying the commercial operation of Cane Island Unit 4 for 2 years (from May 2011 until May 2013) is approximately $35.7 million in CPWC, compared to the next most cost effective expansion plan that meets FMPA's 2011 capacity requirements with simple cycle combustion turbines based on *Reference Case* assumptions.

21.2 Reliability Consequences

As shown in Section 13.0, FMPA is projected to require a significant amount of capacity in the summer of 2011 to maintain its reserve margin requirements. If Cane Island Unit 4 is delayed and no additional generating capacity is installed to meet FMPA's forecast capacity requirements by 2011, FMPA's summer reserve margin will fall to approximately -1.3 percent (or 286 MW less than the 18 percent summer reserve criterion) in 2011. The projected capacity deficit in the summer of 2011 is equivalent to nearly all of the capacity that will be provided by Cane Island Unit 4. With a projected negative reserve margin in 2011, FMPA would not be able to serve firm load with resources under FMPA's control. This would increase the probability that FMPA will not be able to provide FMPA's members with capacity to serve their retail customers and will expose FMPA to potentially high purchase power costs.

22.0 Financial Analysis

FMPA's All-Requirements Power Supply Project (ARP) has several available funding sources that may be used to finance the development and construction of Cane Island 4; these include internal funds, pooled loans, and new long-term debt issuances. FMPA is anticipating the need to finance approximately $450 million for construction of Cane Island 4, including direct and indirect engineering, procurement, and construction costs; owner's costs, which include spare parts associated with a long-term service agreement; bond issuance fees; and interest during construction.

FMPA typically finances its capital projects using two funding sources. During preliminary design, engineering, and permitting, FMPA may draw upon its Initial Pooled Loan Project. The Initial Pooled Loan Project is an ongoing FMPA project that provides FMPA and its members loans at very competitive rates. The pooled loans could be expected to finance up to the first $100 million of costs. Once the project is well defined during the engineering, procurement, and construction activities, FMPA could and would ultimately initiate a revenue bond issuance for long-term project funding. For large projects such as a natural gas combined cycle power plant, FMPA would expect to issue either fixed or floating rate revenue bonds or both. The term on the bonds could range between 20 and 30 years. FMPA will likely issue bonds with a term of 20 years to accelerate the amortization of the project. Based on Cane Island 4's favorable economics and the ARP's excellent credit rating, FMPA believes that there will be no problems issuing debt to cover the project cost. FMPA has recently initiated bond offerings with tax-exempt interest rates consistent with or below the rates assumed for the economic analysis.

The ARP has a credit rating of A+ from Fitch and an A1 from Moody's Investors Service. Typically, FMPA purchases bond insurance on its long-term bonds to increase its rating to AAA and Aaa, respectively. As of fiscal year end 2007, FMPA had $1.303 billion in outstanding long-term debt, which includes $637 million in ARP debt.

The actual financing for Cane Island 4 is expected to result in debt service requirements that are less than the assumed debt service presented in the economic parameters in Section 4.0. Although a 5 percent tax exempt rate has been used in recent Need for Power Applications, current and near-term interest rate market conditions are expected to remain favorable to FMPA and tax-exempt financing. The liquidity of the municipal bond market may influence bond rates when the bonds are actually issued.

Appendix A
Request for Power Supply Proposals

FLORIDA MUNICIPAL POWER AGENCY
(All-Requirements Power Supply Project)

Request for
Power Supply Proposals
June 22, 2007
(RFP #0607G)

Pre-bid Meeting: Mandatory Attendance (June 28, 2007)

Proposals are Due August 17, 2007

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FLORIDA MUNICIPAL POWER AGENCY
Request for Power Supply Proposals

June 22, 2007

1. Introduction

The Florida Municipal Power Agency ("FMPA" or "Agency") is issuing this Request for Proposals ("RFP") as an invitation to qualified companies to submit proposals for the supply of capacity and energy to meet a portion of the projected power requirements of FMPA's All-Requirements Power Supply Project ("ARP"). FMPA is requesting proposals for up to 300 MW of capacity to commence service January 1, 2011 for contract periods of ten (10) years or greater. Acceptable offers from all proposers must total at least 300 MW for FMPA to proceed with purchases under this RFP. Proposals that require FMPA to provide natural gas must identify the natural gas delivery point. Resources providing the proposed capacity, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply arrangement.

FMPA prefers system or unit purchase power proposals that are priced as base load solid fueled resources since FMPA's studies have shown such resources are part of FMPA's least cost plans. 50 MW is the minimum amount for a single offer. Proposals received in response to this RFP will be evaluated in comparison with (i) options that are available to FMPA under existing power supply arrangements and (ii) self-build combined cycle alternatives that are being developed and will serve as a benchmark in the evaluation process. As explained below, resources must be delivered to the Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF") transmission system. Proposals outside of the PEF system must include firm electric transmission to the PEF transmission system for the firm portion of the bid for the life of the proposal, and the firm transmission service must be available starting January 1, 2011.

The deadline for receipt of proposals by FMPA is 3:00 P.M. eastern prevailing time ("EPT") Friday, August 17, 2007. A mandatory Pre-Bid Meeting is planned for June 28, 2007. Qualified companies that wish to attend the Pre-Bid Meeting must register before 5:00 P.M. EPT on June 26, 2007 as described in Section 4.

2. FMPA Description

FMPA was created and exists pursuant to its Interlocal Agreement among its 30 members, which specifies the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10, Florida Constitution; Part II, Chapter 361, Florida Statutes, as amended, the "Joint Power Act"; and/or Section 163.01, Florida Statutes, as amended, the "Florida Interlocal Cooperation Act of 1969." The Florida Constitution and the Joint Power Act provide the authority for municipal and other electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Each municipal electric system that is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility of developing and approving FMPA's budget, approving and financing projects, hiring a General Manager and a General Counsel, and establishing bylaws that govern how FMPA operates and policies that implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, Treasurer and an Executive Committee. The Executive Committee consists of nine directors elected by the Board plus the current Chairman of the Board, the Vice Chairman, the Secretary, and the Treasurer (13 total). The Executive Committee meets regularly to manage and govern FMPA's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for monitoring budgeted expenditure levels and assuring that authorized work is completed in a timely manner.

3. All-Requirements Power Supply Project

Under the ARP, FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either Florida Power & Light Company ("FPL") or PEF. The most recent members, Kissimmee Utility Authority and the City of Lake Worth, Florida, joined the ARP in 2002.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in PEF's Crystal River Unit 3. A number of ARP members also participate in the FMPA St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. These nuclear resources are referred to as "Excluded Resources." The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the FMPA Stanton, Tri-City and Stanton II Projects.

The third category of resources is participant-owned generation. Capacity included in this category is generation owned by the ARP Participants either solely or jointly. FMPA purchases this capacity from the ARP Participants and then commits and dispatches the generation as a part of the ARP portfolio of power-supply resources to meet the total requirements of the ARP.

The fourth category of resources is purchased power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP Participants, which were entered into prior to the ARP Participant joining the ARP.

4. RFP Schedule

FMPA's timetable for this RFP process is shown below. Note that all times shown are based on the eastern prevailing time ("EPT") on the dates indicated; however, the dates shown are only estimates and may be modified at any time by FMPA. Approval for contract execution must come from the Executive Committee of the ARP. Likewise, the selection of the primary supplier must be approved by the Executive Committee of the ARP.

RSVP for Pre-Bid Meeting	June 26, 2007 [5 P.M.]
Pre-Bid Meeting (Mandatory)	June 28, 2007 [10 A.M.]
Notice of Intent to Bid Form Due to FMPA	July 3, 2007 [5 P.M.]
Deadline for Proposer Questions	August 6, 2007 [3 P.M.]
Sealed Proposal(s) Due Date	August 17, 2007 [3 P.M.]
RFP Short List	September 14, 2007
Primary Supplier Selected	October 12, 2007
Contract Developed and Finalized	November 9, 2007
Contract(s) Approved For Execution	December 6, 2007

Pre-Bid Meeting

The FMPA has scheduled a Pre-Bid Meeting for Wednesday, June 28, 2007, 10:00 A.M. EPT, at the offices of the FMPA, 8553 Commodity Circle, Orlando, FL 32819-9002. The purpose of the Pre-Bid Meeting is to provide any required clarifications to this RFP and to provide any additional information deemed necessary in order for Proposers to submit their best proposal. Attendance at the Pre-Bid Meeting is required. Although verbal responses to questions may be provided during the meeting, only written responses will be considered official.

Qualified companies that wish to attend the Pre-Bid Meeting must register with the FMPA by submitting a written list of attendees via e-mail, facsimile or mail to the address provided in Section 10. All registrations must arrive before 5:00 P.M. EPT on June 26, 2007. FMPA is not obligated to consider registrations received after the deadline.

5. Potential Power Supply Requirements

FMPA is accepting a variety of proposal types for capacity and energy in whole megawatt quantities for part or all of the basic capacity requirements along with the flexibility to increase and decrease the purchase amounts. As previously mentioned, FMPA has a variety of power supply options under existing purchase agreements as well as the option to build new generating capacity on sites in Florida. Accordingly, FMPA will consider power supply proposals for contract periods of ten years or greater from (i) existing specified resources, (ii) a portfolio supply of resources with appropriate guarantees; or (iii) a generating facility or facilities to be constructed for a unit power sale. In any event, all proposals must identify the specific resources at specific sites. Proposals based on supply resources located outside the PEF transmission system must also identify the transmission contracts for the transmission path that will be utilized from the resource(s) to the PEF transmission system interface as more fully described in Section 8.

FMPA prefers a purchase that will be subject to unavailability only due to planned maintenance or forced outages. Financially firm resources will not be acceptable to FMPA. FMPA prefers a 100% dispatchable resource for intermediate and peaking capacity.

6. Proposals for Unit Contingent Purchases

Proposals involving a unit contingent purchase must include all available data including historical (if applicable) and projected equivalent forced outage rate ("EFOR") and equivalent maintenance outage rate ("EMOR") per the North American Electric Reliability Council ("NERC") definitions, maintenance schedules, net capacity, heat rate, fuel type, and other pertinent data for the specific unit(s). All proposals for a capacity/energy sale shall be on a firm first call, non-recallable basis equivalent to native load delivered to the PEF transmission system interface. Details on the information required for each type of proposal are specified in Attachment B.

All proposals shall include scheduling provisions of the sale. For all resources, the schedule should be established no more than one (1) day in advance with the ability to change the schedule within one (1) hour before the schedule commences except under FMPA emergency conditions when changes may be required as soon as physically possible if the resource is available. FMPA is seeking proposals that allow operating flexibility for the resources. Proposals must clearly describe any contractual limitations on energy usage (MWh) by day, month or year. As part of the scheduling provisions, the supplier will be required to fax to FMPA's dispatchers (currently contracted to the Orlando Utilities Commission ("OUC")) on a daily basis a schedule of estimated prices for the energy to be delivered for that day and the next day.

7. Self-Build Resource

The Self-Build Resource for this RFP is a 300 MW F-class 1 x 1 combined cycle unit ("Combined Cycle Unit") at a greenfield or brownfield site, depending on site selection, in Florida with an on line date of January 1, 2011.

8. Transmission Arrangements

Eight (8) of the fifteen (15) ARP Participants are geographically located within FPL's service area, and the other seven (7) ARP Participants are located within PEF's service area. All fifteen (15) ARP Participants are supplied their full-requirements power supply from FMPA and such power is delivered to the ARP Participants over the transmission systems of FPL or PEF, respectively. Network-type transmission arrangements are currently in place that enable FMPA to provide service over both the FPL and PEF systems.

FMPA capacity needs are provided on a system basis; however, the utilization of FMPA's transmission agreements with FPL and PEF must be separately planned. FMPA has determined for this proposal evaluation that all of the proposed capacity and energy must be delivered into the PEF transmission system.

All proposals for potential power supplies, where the supply resources originate from outside the PEF transmission system's balancing authority, should be priced based on the Proposer supplying and paying for firm transmission service from the source(s) of supply to the PEF transmission system balancing authority interface, including the cost of any transmission upgrades required to obtain this firm delivery service. Where resources originate outside the State of Florida, proposals must consider the limits and allocation of interface capacity among the owners of the transmission lines that make up the Florida-Southern interface.

FMPA also requires that the Proposers be responsible for the following costs: (i) all costs associated with interconnecting generating resources to the transmission system; (ii) all transmission upgrades required to facilitate the interconnection of generating resources; and (iii) all transmission upgrades required to facilitate the designation by FMPA of the Proposer's supply resources as a qualified network resource under PEF's Open Access Transmission Tariff ("OATT"). To the extent that transmission credits are provided for upgrades provided by Proposers on the PEF transmission system, these will be credited back to the Proposer.

FMPA may evaluate the potential impact of transmission congestion, redispatch, and losses that may occur between the Proposer's supply resources and FMPA's network loads and may adjust the proposals to take such impacts into consideration. FMPA encourages Proposers to supply any information that the Proposers may have related to the potential impact of transmission congestion, redispatch and losses.

FMPA will give preference to a transmission service arrangement that (i) consists of no more than one intermediate transmission path (between the generating switchyard and the PEF transmission system balancing authority), and (ii) includes the assignment of tariff-provided transmission reassignments/ redirection/resale rights solely to FMPA for the life of the agreement.

9. Notice to Proposers

All Proposers are required to provide written notification of their intent to submit a proposal no later than July 3, 2007 at 5:00 P.M. EPT. A Notice of Intent to Bid Form is included herein as RFP Form 1. On the Notice of Intent to Bid Form, Proposers must indicate the agreement term(s) on which the proposal(s) will be based. All sections of the Notice of Intent to Bid Form must be completed in full, signed by an authorized representative of the Proposer, and submitted to FMPA by facsimile (407-355-5796) or mail (as listed Section 10), and not via the Internet, to the attention of Mr. Bill May.

10. Submittal of Proposals

Sealed proposal packages will be received until August 17, 2007 at 3:00 P.M. EPT ("Proposal Due Date") at the offices of FMPA. **ANY PROPOSAL SUBMITTED VIA THE INTERNET WILL NOT BE ACCEPTED.** Each Proposer is required to submit a completed Proposal Summary (RFP Form 2), a Minimum Requirements Form (Form 3), a Pricing Proposal Form (Form 4) and a Checklist (Form 5) as part of the proposal package. The forms are listed in the last section of this RFP. The proposing company's name and the words "Request for Power Supply Proposals RFP # 0607G" must be clearly identified on the outside of each proposal package. FMPA reserves the right to reject all proposals received after the Proposal Due Date.

One original and three (3) copies of each proposal should be sealed and delivered to the following address:

Mr. Bill May
Manager of Power Supply
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819-9002

An electronic copy of the complete Proposal, the pricing terms and all spreadsheets included in the proposal should be submitted in Microsoft Office Professional Edition 2003 or compatible format on CD or DVD to Bill.May@fmpa.com.

The proposals must remain in effect and valid until December 6, 2007 or later if the purchase is to be finalized pending a transmission service request. The proposal packages will be opened after the Proposal Due Date. Each proposal package must be accompanied by a non-refundable Proposal Fee (in the form of a cashier's check made payable to FMPA) in the amount of $2,500 per proposal. If a Proposer submits alternative arrangements, each alternative will be considered a separate proposal. A Proposer submitting multiple proposals is required to supply a $2,500 Proposal Fee for each proposal.

FMPA is willing to consider alternatives that involve a pass through of fuel and variable operation and maintenance costs or a contractually fixed energy charge. For alternatives involving a pass through of fuel costs, a contractually fixed heat rate is preferred. Fuel forecasts for natural gas, coal and No. 2 oil fuels are provided in Attachment A and will be used as the basis for comparison to the Self-Build Resource.

For Proposers that are not fixing the energy charge, if the capacity/energy sale proposal is based on a pass-through fuel cost arrangement, the proposal energy price should be based upon the fuel forecast provided on Attachment A. The Henry Hub gas fuel price forecast and oil fuel price to be used for purposes of FMPA's evaluation have been included. The proposal should include all factors to determine a total price based on the Henry Hub gas price and/or oil price and an explanation of the relationship of the energy rate to fuel prices and explain how gas transportation will be provided. The Proposer should specify the gas delivery point for the resource, if applicable to the proposal. If any of this information is Proprietary Confidential Business Information, it should be so noted. If the proposal is based on a contractually-fixed total energy cost, the proposal must include all information pertinent to the pricing and its escalation. To the extent the Proposer wants to make an exception to the fuel forecast, such exception must be fully described and supported with appropriate examples. FMPA may or may not reflect these exceptions in the evaluation.

With respect to fixed and variable operation and maintenance expenses ("O&M") and environmental related charges, all charges must be itemized to show different components of costs. All assumptions used in calculating such costs must be clearly stated. Proposers need to list components of costs and other performance parameters so that FMPA can verify that such costs are comparable to the Self-Build Resource. Typical components that may be included are the following:

A. Fixed Operating Expenses (labor, general equipment maintenance, insurance, property taxes, major maintenance, capital expenditures, and administrative costs).

B. Variable O&M (maintenance charge costs related to use, allowances and other consumables).

C. Heat Rate (minimum load level, full load, and intermediate levels at winter, summer and average ambient temperatures.

D. Availability and forced outage rate.

E. Other operating data and restrictions such as ramp rates, start-up costs, minimum load, etc. that may affect operating flexibility and expenses.

FMPA prefers purchases that provide guarantees with respect to various major performance parameters such as output, heat rate, availability, forced outages, fixed and variable operating expenses and fuel prices. Compensation to the seller will be adjusted if guaranteed performance parameters are not achieved. Proposals for new generating unit sales should include prices with and without fuel oil backup facilities necessary to maintain continuous operation at full output for 72 hours.

11. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

FMPA reserves the right to:

- Reject any and all proposals for any reason, or no reason, received in response to this RFP;
- Reject any proposal for failure to extend the validity date if requested;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a proposal;
- Negotiate an arrangement for power supply with more than one Proposer at a time;

- Not select the proposal with the lowest apparent price;
- Request clarifications from Proposers at any time; and
- Negotiate with any Proposer that submits a written proposal.

12. Interpretations and Addenda

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing or by the Internet to the following:

By Fax:	Mr. Paul Arsuaga (407) 648-8382
By E-Mail:	parsuaga@RWBeck.com
By Mail or Courier:	Mr. Paul Arsuaga R. W. Beck, Inc. 1000 Legion Place, Suite 1100 Orlando, FL 32801

Only FMPA written responses to Proposers questions will be considered official. A verbal response by FMPA will not be considered an official response. Written responses to questions and requests for interpretations may be provided to all Proposers by posting on the Internet Website. All written questions must be received by FMPA on or before August 6, 2007 at 3:00 P.M. EPT. Inquiries after this date may not receive responses. All addenda issued in connection with this RFP will be placed on the Internet Website (www.fmpa.com), at the time of issue and it shall be the responsibility of those Proposers to regularly check the "Important Updates" page for addenda.

13. Errors, Modifications or Withdrawal of Proposal

Each Proposer should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which must be followed by all Proposers. Modifications (other than minor additions and/or corrections) to proposals already received by FMPA will only be accepted prior to the Proposal Due Date. Proposals may be withdrawn by giving written notice (no Internet notices) to FMPA prior to the Proposal Due Date. In such cases, a full refund of the Proposal Fee will be provided by FMPA. Proposals withdrawn after the Proposal Due Date may result in forfeiture of the proposal fees.

14. Proprietary Confidential Business Information

FMPA is a governmental entity subject to the Florida Public Records Law (Chapter 119, Florida Statutes). Some, or all, of the materials or information provided by Proposer to FMPA will be considered a "public record" which FMPA, by law, is obligated to disclose upon request of any person for inspection and copying, unless the public record or the information is otherwise specifically exempt by statute. Should a Proposer provide any materials which it believes, in good faith, contain information which would be exempt from disclosure or copying under Florida law, the Proposer shall indicate that belief by typing or printing, in bold letters, the phrase "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" both on the initial page and on the face of each affected page of such material and shall submit both a complete and a redacted version of such material. Should any person request to examine or copy any material so designated, only the redacted version of the affected material or page(s) thereof will be produced. If the person requests to examine or copy the complete version of the affected material or page(s), FMPA shall notify the affected Proposer of that request, and the Proposer, within thirty-six (36) hours of receiving such notification, shall either permit or refuse to permit such disclosure or copying. If a Proposer refuses to permit disclosure or copying, Proposer agrees to, and shall, hold harmless, indemnify and defend FMPA for all expenses, costs, damages, and penalties of any kind whatsoever which may be incurred by FMPA, or assessed or awarded against FMPA, in regard to FMPA's refusal to permit disclosure or copying of such material. If litigation is filed in relation to such request and a Proposer is not initially named as a party, the Proposer shall promptly seek to intervene as a defendant in such litigation to defend its claim regarding the confidentiality of such material. This provision shall take precedence over any provisions or conditions of the Proposer's proposal and any provision of any other document relating to the disclosure of materials or information considered by the provider to be confidential or proprietary and shall constitute FMPA's sole obligation with regard to maintaining confidentiality of material or documents, of any kind, or any other information provided by the Proposer or its Affiliates or Sub Contractors.

15. Proposer Qualifications

FMPA will accept proposals from any electric utility, independent power producer ("IPP"), qualifying facility ("QF"), exempt wholesale generator, or non-utility generator, or electric power marketer who has received certification as such by the FERC. Proposers unfamiliar to FMPA may be required to provide proof of experience.

Proposers offering capacity/energy sales from an existing unit(s) must own and operate the unit, plant or system capacity or must have the unit(s), plant or system capacity under contract. FMPA may require proof of such contracts as well as proof of contracts for sales from a portfolio of resources. Any contracts submitted with the proposal may have the price and other sensitive information deleted before submittal to FMPA. For proposals involving a new project, Proposer should supply information on the status of the project including site development, permitting, purchase of land options, etc.

Electric power plant operators must provide proof of operating experience as requested in Attachment B. Respondents are encouraged to provide the following information with their proposals: most recent audited financial statement; Form 10K of parent company, where appropriate; most recent Dunn & Bradstreet report; description of pending litigation; summary of project experience; and most recent annual report.

16. Proposal Security and Performance Security

FMPA requires that the Proposer provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for a Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW) of the capacity offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals. The Proposal Security will be forfeited if the Proposer changes its proposal in a material adverse manner after being short-listed or fails to establish a contract Performance Security prior to contract execution with the Proposer. The Proposal Security is to remain in effect until the later of the date to which proposals remain valid or to such time that FMPA executes a contract with the Proposer providing for the Performance Security or FMPA executes an agreement with a different Proposer or combination of Proposers to meet its requirements, or decides to reject all proposals. The letter of commitment will state further that the financial institution will commit to be a guarantor for a Performance Security established by the Proposer when the contract is executed that will minimize FMPA's exposure to direct and consequential damage due to failure of the Proposer to fulfill the terms and conditions of the contract awarded. The amount of the Performance Security will be a percentage of the revenues over the remaining life of the contract.

17. Default and Damages Provisions

FMPA will negotiate the conditions of default and damages with the successful Proposer(s). Proposers should include suggested default and damage provisions in their proposals.

18. Disqualification of Proposals

Proposal(s) may be disqualified at any point if bribery, conflict of interest, or interference in the evaluation process is/are suspected or determined, at FMPA's sole discretion.

19. Public Entity Crimes Statement

Pursuant to Section 287.133(2)(a), FLORIDA STATUTES, all bidders should be aware of the following:

> "A person or affiliate who has been placed on the convicted vendor list following a conviction for a public entity crime may not submit a bid on a contract to provide any goods or services to a public entity, may not submit a bid on a contract with a public entity for the construction or repair of a public building or public work, may not submit bids on leases of real property to a public entity, may not be awarded or perform work as a contractor, supplier, subcontractor, or consultant under a contract with any public entity, and may not transact business with any public entity in excess of the threshold amount provided in Section 287.017, for CATEGORY TWO for a period of 36 months from the date of being placed on the convicted vendor list."

20. Collusion

By offering a submission pursuant to this Invitation to Bid, the Proposer certifies the Proposer has not divulged, discussed, or compared his bid with other Proposers and has not colluded with any other bidder or parties to this bid whatsoever. Also, the Proposer certifies, and in the case of a joint bid, each party thereto certifies, as to his own organization, that in connection with this bid:

(1) Any prices and/or cost data submitted have been arrived at independently, without consultation, communication, or agreement for the purpose of restricting competition, as to any matter relating to such prices and or cost data, with any other Proposer or with any competitor.

(2) Any prices and/or cost data quoted for this bid have not knowingly been disclosed by the Proposer and will not knowingly be disclosed by the Proposer prior to the scheduled opening directly or indirectly to any other Proposer or to any competitor.

(3) No attempt has been made or will be made by the Proposer to induce any other person or firm to submit or not to submit a bid for the purpose of restricting competition.

(4) The only person or persons interested in this bid, principal or principals is/are named therein and that no person other than therein mentioned has any interest in this bid or in the contract to be entered into and;

(5) No person or agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee accepting bona fide employees or established commercial agencies maintained by the Proposer for the purpose of doing business.

21. Evaluation Process

In the initial stages of the evaluation process, cost estimates to be developed concurrently for the Self-Build Resource will be used as a benchmark for screening alternatives. Repricing of proposals is not anticipated. Therefore, Proposers should provide their lowest cost offer on the Proposal Due Date.

The proposal evaluation process will be performed on a bid and negotiate basis. Information provided from each qualified Proposer by the Proposal Due Date will be used to develop a short-list of proposals from which selection(s) could be made for direct negotiations. No additional Proposer data will be considered after the Proposal Due Date, except for clarifications requested by FMPA and possible transmission system study results obtained from FPL, PEF, and/or any other affected transmission provider. FMPA will evaluate the proposals in terms of price and non-price factors. The first stage of the evaluation process for qualified Proposers may consist of a check of each proposal against the minimum requirements of the RFP. After the minimum requirements screening, initial price screening of proposals may be accomplished by comparing such proposals using a capacity factor analysis. Those proposals may then be screened by comparison with options that are available to FMPA under existing power purchase arrangements and with options delaying the Self-Build Resource. Screenings may be performed on a present value busbar cost basis. Price and non-price evaluations may be conducted next. During the evaluation process, FMPA may develop scenarios which include combining proposals from one or more Proposers.

Price and non-price evaluations may include a preliminary analysis of transmission limitations to verify that Proposers have properly addressed the limitations and included appropriate costs. Once a short-list of Proposers is developed, FMPA may inform PEF of the potential short-listed Proposers as possible power suppliers to FMPA in order to secure transmission services.

Additional system studies, which incorporate proposed power supply resources, may be used to verify the sufficiency of the transmission systems and their interfaces and determine if additional transmission system facilities may be required. Should FMPA or others determine, based on their studies, that additional transmission facilities or costs are required to accommodate particular proposed power supplies, each affected Proposer may then be contacted by FMPA with this information to explore possible alternatives, if any, to address the problem. To the extent that these problems cannot be resolved, the proposal may be rejected or the evaluation may reflect this cost uncertainty. Proposers will remain responsible for all transmission upgrades required to facilitate the designation by FMPA of the Proposer's supply resources as a qualified network resource under the PEF OATT whether or not such costs can be estimated. Proposals may be eliminated at this point based solely on a determination that additional transmission facilities are required and that there is insufficient time to complete the installation of such facilities. Any costs associated with such transmission system studies performed by FMPA, PEF, or FPL will be the responsibility of FMPA.

Proposals that remain on the short-list may be analyzed on an overall system cost basis. From this analysis, the Proposer(s) may be selected for participation in negotiations. The Proposer(s) selected will be notified for commencement of negotiations. Selection and rejection of proposals and notification of Proposers at all stages will remain entirely within FMPA's discretion. FMPA intends to notify Proposers not selected under this solicitation within a reasonable amount of time.

FMPA may evaluate the potential impact of transmission congestion and losses that may occur between the Proposer's supply resources and FMPA's network loads and may adjust the proposals to take such impacts into consideration. FMPA encourages Proposers to supply any information that the Proposers may have related to the potential impact of transmission congestion, redispatch and losses.

<u>Minimum Requirements for All Proposals</u>

Each proposal must satisfy certain minimum requirements before it will receive any further evaluation. The Proposer must demonstrate in its submittal that the following minimum requirements have been met:

1. For a generating unit power sale, FMPA's rights must be equal to or superior to any other party's rights to such unit(s) output (i.e. as long as the unit(s) from which the capacity is purchased is available, FMPA has the right to the output of the unit(s) for the duration of the contract).

2. All proposals for peaking capacity must commence on January 1, 2011.

3. All proposals must have contract periods of not less than 10 years.

4. All proposals must remain in effect until December 6, 2007, or later if the purchase is to be finalized pending a transmission service request.

5. The capacity amount offered to FMPA shall be not less than 50 MW or greater than 300 MW. Acceptable offers from all Proposers must total at least 300 MW for FMPA to proceed with purchases under this RFP. Proposals that require FMPA to provide natural gas must identify the natural gas delivery point.

6. All generating units providing the proposed capacity must be in commercial operation at least two (2) months prior to the required delivery commencement date of the term of the proposed power supply.

7. Proposals must identify and include the location of each capacity resource and name the originating control area. Resources must be delivered to the PEF transmission system. Proposers proposing power supply from a resource(s) located outside of the PEF balancing authority must also identify the firm transmission contract path from the power supply(s) to the PEF transmission system.

8. The Proposer must commit in the proposal that all emissions allowance requirements will be satisfied and must include costs for emission allowances in the proposal.

9. The Proposer must declare ownership or contractual status of a unit, or plant as described in Section 15.

10. The Proposer must complete the appropriate RFP Forms 1 through 5 and provide all appropriate information requested in Attachment B. All forms requiring a signature must be signed by a duly authorized official of the Proposer.

11. The Proposer must commit in the proposal to provide an adequate Proposal Security prior to entering short-list negotiations and an adequate Performance Security upon execution of a contract in accordance with Section 16.

12. Each proposal must clearly describe any contractual limits on energy utilization or physical limitations on the operation of the resource as described in Attachment B.

13. Each proposal must include scheduling provisions for the sale.

14. Each proposal must contain the appropriate Proposal Fee in accordance with Section 10.

15. Proposals for new construction projects must not be contingent upon participation by other third parties to support the project.

16. Proposers that propose to develop a power generating project to provide power to FMPA must have developed, and have had in operation for a minimum of one (1) year, at least one (1) currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers offering to provide FMPA with power from an existing generating resource must have successfully provided similar levels of services to at least one (1) electric utility for a minimum of one (1) year.

Price Criteria

FMPA will evaluate the proposal(s) as an alternative to the Self-Build Resource or increasing the amount of purchases under the existing ARP arrangements. The net present value of the revenue requirements to FMPA over the contract period for each proposal will be compared with: (a) the net present value of revenue requirements over the contract period for the most attractive arrangement to increase purchases under the existing ARP contracts; and/or (b) the net present value of revenue requirements over the contract period for the Self-Build Resource. Scores will then be applied to each proposal to reflect the projected cost differential between the proposal and the benchmark option.

Non-Price Criteria

Each proposal may be evaluated based on a list of non-price criteria, which FMPA has or will develop. A score will be assigned to each criterion based on the extent to which the proposal satisfies FMPA's preferences. The non-price score and price related score for each proposal may be used to determine the ranking of proposals.

The proposals may be evaluated in accordance with the following non-price criteria:

Components of Power Cost -	To evaluate risk, FMPA prefers proposers that identify the true fixed and variable costs for the resources providing the power (e.g., the Proposer should identify the amount of fixed cost in the capacity charge and the amount of variable costs [fuel, variable operation and maintenance expenses, etc.] in the energy charge).
Contract Flexibility -	FMPA prefers proposals with reasonable notice provisions that give FMPA the sole right to increase or decrease the contract term and the amount of purchases.
Dispatchability -	FMPA prefers provisions for capacity that would permit FMPA flexibility to schedule and dispatch the resources to optimize the economics of its resource mix and to take advantage of economy transactions.
Firm Supply -	Proposals will be evaluated on the availability of generating resources and penalties for nonperformance.
Experience	FMPA prefers Proposers with experience providing services similar to that requested.
Transmission -	FMPA prefers generating resources that minimize the number of intermediate transmission systems. Power must be delivered to the PEF transmission system.
Technology -	Proposals utilizing commercially proven technologies are preferable.

22. Final Contract

Any final contract(s) that results from the proposal evaluation and negotiation processes will be submitted to the Board of Directors and/or Executive Committee of FMPA for approval. The tentative date for approval of contract(s) is shown in Section 4, RFP Schedule.

23. RFP Forms and Attachments

Form 1	-	Notice of Intent to Bid Form
Form 2	-	Proposal Summary Form
Form 3	-	Minimum Requirements Form
Form 4	-	Pricing Proposal Form
Form 5	-	Checklist
Attachment A	-	Natural Gas and Oil Price Forecast
Attachment B	-	Required Data to be Submitted with Proposals

RFP Form 1

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Notice of Intent to Bid Form

Due: July 3, 2007 (5:00 PM EPT)

Date: ______________

Project Proposer Name: ______________________________
Title: ______________________________
Company Name: ______________________________
Address: ______________________________
____
Telephone: ______________________________
Fax: ______________________________
E-Mail: ______________________________
Project Name: ______________________________
Project Location: ______________________________
Agreement Term: ______________________________
Generation Technology: ______________________________
Primary Fuel: ______________________________
Specific Entity to Contract With FMPA: ______________________________

Respondent Classification: (Utility, Qualified Facility, Exempt Wholesale Generator, Power Marketer, etc.)

Respondent Qualifications: Describe similar projects developed by Proposer, noting project capacity, location, contract commencement date, contract term, etc.
(Attach additional sheets as needed)

____
____
____
____
____
____
____
____
____

Proposer's Signature: ______________________________
(Duly Authorized)

RFP Form 2

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Proposal Summary Form

1. Company/Proposer ______________________________

2. Name of Contact ______________________________

3. Mailing Address ______________________________

4. Telephone ______________________________
   Fax ______________________________
   E-Mail ______________________________

5. Proposed Contract Start Date ______________________________

6. Proposed Contract End Date ______________________________

7. Proposed Contract Capacity Listing by Resource

Unit Name and Number	Summer MW Rating	Winter MW Rating	Fuel Type	Location	Proposed Capacity Delivered[1] (MW)	Transmission Path
				Total Capacity (MW)		

[1] *Capacity delivered into the PEF system.*

8. Proposer certifies that they have reviewed all Addenda including Addenda ___ through ___.

9. Certification: Proposer hereby certifies that all of the statements and representations made in this proposal package, including attached documents, are true to the best of the Proposer's knowledge and belief. Proposer agrees to be bound by its representations and the terms and conditions of the Request for Proposals:

Signed: ______________________________

(Typed): ______________________________

Title: ______________________________
(Duly Authorized)

Date: ______________________________

RFP Form 3
Page 1 of 2

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Minimum Requirements Form

In submitting this form, we agree to the items below and/or have provided documents to attest to the information provided as requested below.

Duly Authorized Signature: ______________________ ______________________
(Date)

If the proposer is an entity proposing a capacity sale from existing resources, the proposer must provide sufficient documentation to demonstrate that over time the source utility or entity will have sufficient capacity to sell to FMPA as well as to serve its own load, if applicable, and other commitments.

All proposers must demonstrate the following by attaching appropriate information to this form:

1. For a generating unit power sale, FMPA's rights must be equal to or superior to any other party's rights to such unit(s) output (i.e. as long as the unit(s) from which the capacity is purchased is available, FMPA has the right to the output of the unit(s) for the duration of the contract).

2. All proposals for peaking capacity must commence on January 1, 2011.

3. All proposals must have contract periods of not less than 10 years.

4. All proposals must remain in effect until December 6, 2007, or later if the purchase is to be finalized pending a transmission service request.

5. The capacity amount offered to FMPA shall be not less than 50 MW or greater than 300 MW. Acceptable offers from all Proposers must total at least 300 MW for FMPA to proceed with purchases under this RFP. Proposals that require FMPA to provide natural gas must identify the natural gas delivery point..

RFP Form 3
Page 2 of 2

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Minimum Requirements Form

(Continued)

6. All generating units providing the proposed capacity must be in commercial operation at least two (2) months prior to the required delivery commencement date of the term of the proposed power supply.

7. Proposals must identify and include the location of each capacity resource and name the originating control area. Resources must be delivered to the PEF transmission system. Proposers proposing power supply from a resource(s) located outside of the PEF balancing authority must also identify the firm transmission contract path from the power supply(s) to the PEF transmission system.

8. The Proposer must commit in the proposal that all emissions allowance requirements will be satisfied and must include costs for emission allowances in the proposal.

9. The Proposer must declare ownership or contractual status of a unit, or plant as described in Section 15.

10. The Proposer must complete the appropriate RFP Forms 1 through 5 and provide all appropriate information requested in Attachment B. All forms requiring a signature must be signed by a duly authorized official of the Proposer.

11. The Proposer must commit in the proposal to provide an adequate Proposal Security prior to entering short-list negotiations and an adequate Performance Security upon execution of a contract in accordance with Section 16.

12. Each proposal must clearly describe any contractual limits on energy utilization or physical limitations on the operation of the resource as described in Attachment B.

13. Each proposal must include scheduling provisions for the sale.

14. Each proposal must contain the appropriate Proposal Fee in accordance with Section 10.

15. Proposals for new construction projects must not be contingent upon participation by other third parties to support the project.

16. Proposers that propose to develop a power generating project to provide power to FMPA must have developed, and have had in operation for a minimum of one (1) year, at least one (1) currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers offering to provide FMPA with power from an existing generating resource must have successfully provided similar levels of services to at least one (1) electric utility for a minimum of one (1) year.

RFP Form 4
Page 1 of 4

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Capacity Pricing Proposal Form

The Proposer must itemize the capacity pricing as required into various price components (i.e., capital, fixed O&M, etc.) Columns A through E may be used for variations in capacity price by time of day, day of week, month, or season for example. These components should be described on the next page. The Proposer is not required to use all columns provided.

Delivered Capacity Rate								
Period 12 Mo. Ended April 30,	A $/kW-mo.	B $/kW-mo.	C $/kW-mo.	D $/kW-mo.	E $/kW-mo.	Total A-E $/kW-mo.	Capacity kW	Total $000
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Capacity Pricing Proposal Form

Describe the components of and the methodology for determining the capacity rates.

RFP Form 4
Page 3 of 4

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Energy Pricing Proposal Form

The Proposer must itemize the energy pricing as required into various price components (i.e., fuel, variable O&M, etc.) The columns F through I are provided to allow the Proposer to list separate price components and may be used for variations in energy price by time of day, day of week, month, or season for example. These components should be described on the next page. The Proposer is not required to use all columns provided.

Delivered Energy Rate									
Period 12 Mo. Ended April 30,	Fuel Cost $/mmBtu	Heat Rate mmBtu/ MWh	F $/MWh	G $/MWh	H $/MWh	I $/MWh	Total F-I $/MWh	Projected Energy MWh	Total $000
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									

RFP Form 4
Page 4 of 4

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Energy Pricing Proposal Form

Describe the components of and the methodology for determining the energy rates.

RFP Form 5
Page 1 of 1

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR POWER SUPPLY PROPOSALS

Checklist

All RFP Forms checked below have been included as part of the response package *.

RFP Form 2 - Proposal Summary Form ____________

RFP Form 3 - Minimum Requirements Form ____________

RFP Form 4 - Pricing Proposal Form ____________

Signature of Proposer: ______________________________

Name of Project: ______________________________

(*) *RFP Form 1 is the Notice of Intent to Bid Form which is sent to FMPA prior to, and separately from, the proposal package.*

ATTACHMENT A

RFP Fuel Forecast
(Generic Florida Location)

Year	Natural Gas Price Forecast (Commodity Only) (Nominal $/mmBtu)	No 2 Oil Price Forecast (Delivered) (Nominal $/mmBtu)	Coal Price Forecast (Delivered) (Nominal $/mmBtu)
2010	$7.08	$10.33	$2.71
2011	$6.60	$10.45	$2.64
2012	$6.38	$10.51	$2.52
2013	$6.44	$10.43	$2.36
2014	$6.40	$10.55	$2.42
2015	$6.32	$10.81	$2.42
2016	$6.32	$11.30	$2.48
2017	$6.50	$11.67	$2.55
2018	$6.80	$12.19	$2.62
2019	$7.11	$12.59	$2.68
2020	$7.12	$13.08	$2.66
2021	$7.35	$13.51	$2.62
2022	$7.73	$14.06	$2.68
2023	$8.19	$14.55	$2.91
2024	$8.68	$15.05	$3.11
2025	$9.19	$15.57	$3.24
2026	$9.73	$16.11	$3.37
2027	$10.30	$16.66	$3.51
2028	$10.91	$17.24	$3.65
2029	$11.56	$17.83	$3.80
2030	$12.24	$18.45	$3.96

ATTACHMENT B

Required Supply Proposal Data

The following is required for all supply proposals as is applicable. The required data should be provided in sections numbered in accordance with the specific items detailed below. Each section should begin on a new page. Information provided, but not in the requested format, may be disregarded and the proposal rejected for incompleteness. General information (e.g., promotional material, 'boiler plate', etc.) may be provided with the proposal, but only the formatted information will be considered in the event of conflicting data. Any proposal that lacks requested information may be deemed incomplete and may be rejected in FMPA's sole discretion. FMPA may request additional data or clarifying information from respondents.

Information requirements are specified for two types of proposals: (i) Section B-1 for those involving sales from specific generating unit(s) (a "Generating Unit Sale"); or (ii) Section B-2 a firm sale from a utility system (a "System Sale"). All proposals must include the information requirements in Section B-3.

B-1 Generating Unit(s) Power Sale

B-1.1 Identity of Proposer Contact

Provide the full name, business address, telephone, E-Mail address if available, and facsimile number of contact person from whom additional information can be requested.

B-1.2 General Description of Supply Proposals

(a) Provide a general overall executive summary of the supply proposals. The description must include identification of each major component of involved electric generating unit, including unit type, unit manufacturer, date of manufacture, manufacturer's nameplate capacity rating, any reratings that have occurred since date of manufacture, location of resources, primary and secondary fuel type, term of contract, sites where similar units have been installed for commercial operation, and other relevant information.

(b) Fully describe the scheduling requirements and dependable capacity of the proposed resource.

B-1.3 Location of Generating Unit(s)

Identify the geographic location of the project and indicate whether or not such area is an attainment or a non-attainment air quality area. If no specific location has been identified, so state. Provide a segment of a USGS map showing geographical location of each generating unit with interconnections and transmission lines indicated.

B-1.4 Capacity and Expected Energy Production

(a) Specify the amount of firm capacity offered. Please specify net electrical output at eighty-seven degrees Fahrenheit (87°F) and seventy-four percent (74%) relative humidity available for four (4) continuous hours at the most efficient level of operation. Please further specify a heat rate curve reflecting net output capacity and net heat rate including the average heat rate at the minimum operating capacity and an incremental heat rate curve between minimum and maximum operating capacity.

(b) Indicate the expected total net kilowatt-hours to be delivered to the PEF transmission system under the contract, by hour, for a typical day's operation. Take into account step-up transformer losses, transmission losses to the interface, capacity degradation, and auxiliary loads. Identify limiting conditions (if any).

(c) Show separately, the amount of capacity provided for reserves, or firming service. FMPA may wish to purchase unreserved capacity and reserves, or firming service, separately.

B-1.5 Schedule

Specify the time frame when capacity is available. If capacity is provided by a new generating facility, include a schedule for environmental permitting, design, procurement, construction and commissioning of the project, as applicable.

B-1.6 Proposed Agreement Term

(a) Specify proposed contract term.

(b) Specify any and all proposed provisions for renewal or extension, and cancellation notice, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

B-1.7 Scheduling Requirements

(a) Specify: (1) annual availability in hours; (2) annual planned maintenance in hours; (3) expected annual full forced outages in hours; (4) expected annual partial forced outages in hours; (5) frequency, in months, and duration, in days, of periodic (less frequently than annually) major overhauls and/or recommended hours of operation between major overhauls.

(b) Specify the expected calendar months for annual planned maintenance to occur.

(c) Please specify any other scheduling requirements.

B-1.8 History of Existing Facilities

(a) If the proposed facility is an existing generator(s), provide a narrative describing the project's operating history. Include construction start date, test operation start date, commercial operation date, monthly capacity factors, non-fuel operations and maintenance expenses, and net heat rates by month, for at least three (3) years or since commercial operation date if later. Also include major equipment additions and enhancements.

(b) If the proposed facility is comprised of an existing generator(s), provide a narrative describing the project's maintenance history, including: (i) monthly and annual scheduled outages, (ii) number and duration of forced outages, (iii) forced and planned outage rates, (iv) dates and causes of all major equipment breakdowns by year, etc., and (v) all known equipment deficiencies.

B-1.9 FMPA Rights

Verify that no party has superior rights to FMPA.

B-1.10 Fuel Information

Fully describe the fuel source(s) for any proposed generating facility, and any fuel supply contracts, including price and escalation provisions, interruptibility, obligation to deliver, penalties for non-delivery, and dispatchability. Specify project fuel type(s), and associated fuel supply information to the extent known, including number and delivery capability of suppliers. The Proposer should specify the gas delivery point for the resource and describe gas transportation arrangements if the Proposer is supplying this. If the fuel source requires any emission allowances, the Proposer shall specify if entitlements are now held for the required allowances. If entitlements to required allowances are not held, the Proposer shall identify the source from which allowances will be obtained, and any separate charge proposed to be assessed. Proposals for new generating unit sales should include prices with and without fuel oil backup facilities necessary to maintain continuous operation for 72 hours at full output.

B-1.11 Operations and Maintenance Expense

Fully describe and itemize all components of operations and maintenance expenses that are included in the proposal and state all assumptions used in the calculation of such expenses. At a minimum, pricing must include the following components to the extent applicable:

(a) Fixed operation and maintenance costs including labor, general equipment maintenance, insurance, property taxes, major maintenance, capital expenditures, and administrative costs.

(b) Variable operation and maintenance costs including limestone, ash and scrubber sludge disposal, ammonia, catalyst replacement, SO_2, NO_X, and mercury allowances, CO_2 taxes (if applicable), water related costs, and other consumables.

(c) If the fuel source requires any emission allowances, the Proposer shall specify if entitlements are now held for the required allowances. If entitlements to required allowances are not held, the Proposer shall identify the source from which allowances will be obtained, and any separate charge proposed to be assessed.

B-2 System Sale

B-2.1 Identity of Proposer Contract

Provide the full name, business address, telephone, and facsimile number of contract person from whom additional information can be requested.

B-2.2 General Description of Supply Proposals

(a) Provide a general overall summary of the supply proposals. The description must include identification of each resource in the electric system from which sale is being made (the "System").

(b) Describe the amount of capacity to be provided, the amount of total resources, and projected loads (including the proposal sale) on the System for each year of the proposed contract. Describe any scheduling requirement of the resource.

B-2.3 Location of Generating Facilities

Identify the geographic location of the generating resources on the System and the transmission system that interconnects these resources. Identify the transmission path and intervening transmission systems required to deliver the power to the PEF transmission system.

B-2.4 Capacity and Expected Energy Production

(a) Specify the amount of delivered capacity and maximum energy offered on typical days, months and years, taking into account seasonality of supply (if any) and transmission losses.

(b) Please indicate the firmness of the sale (i.e. verify that no other parties will have superior rights).

B-2.5 Proposed Agreement Term

(a) Specify proposed contract term.

(b) Specify any and all proposed provisions for renewal or extension, and cancellation notice, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

B-2.6 Scheduling Requirement

Indicate all scheduling requirements applicable to the proposed system sale.

B-3 General Information

B-3.1 Financial Information

(a) Identify any and all Proposer affiliates.

(b) Provide audited financial statements, if available, or other financial statements for the last three (3) years. Such information must be provided for all entities, including affiliates involved in the transaction. For investor owned utilities, this would include as a minimum, FERC Form 1's and SEC 10K forms. Proposers should also provide where appropriate, the most recent Dunn and Bradstreet report, a description of pending litigation and the most recent annual report.

B-3.2 Pricing Information

(a) Specify on the RFP Form 4 - Proposal Pricing form, all proposed payment components and proposed incentive amounts, if any, and the conditions which engage such provisions. FMPA requires that proposals clearly distinguish energy and capacity pricing components. For example fixed components may include fixed O&M capital, etc. Energy components may include fuel, variable O&M, etc.

(b) Specify annual payment stream components, whether explicitly specified or driven by escalation factors. If price escalation factors are proposed, please identify what attribute the proposed factor is to represent (e.g., general inflation, general economic growth, etc.), proposed index or other source data to define the escalator (e.g., CPI, change in GDP, etc.), and Proposer's current projection of designated escalator for each applicable time period.

B-3.3 Proposed Financial Security Arrangements

(a) Please describe the Proposal Security and the Performance Security.

(b) Please provide name and credit rating of financial institution providing letter of commitment.

B-3.4 Transmission

Delivery of power must be into the PEF transmission system. Proposers are required to provide the following supporting data relating to transmission availability:

(a) A detailed description of the proposed wheeling and interconnection arrangements to deliver power into the PEF transmission system, including, but not limited to, contract path and estimated cost of such wheeling services.

(b) Interconnection points at which resources used for sale are interconnected with the transmission provider in whose balancing authority the resource is located.

(c) A description of any required new interconnection facilities and estimated costs and cost responsibility for such facilities.

(d) A description of upgrades on the PEF, FPL and on third party transmission systems that may be required to accommodate the project and an estimate of costs that is included in the pricing.

(e) Backup information that would verify the reasonableness of assumptions and cost data associated with transmission service required for delivery of the proposed capacity and energy from the source(s) of supply to the point of delivery and detailed analyses which will demonstrate that the Proposer's proposal can be qualified as a "network resource" under the PEF transmission tariff. Such analyses must show all assumptions, including, among other things, contract paths, contracting parties, interface capability, intervening parties, and transfer capabilities. FMPA may verify the transmission studies provided by the Proposer by performing its own load flow studies. Therefore, proposers are encouraged to submit a hard copy of the transmission analysis results plus the load flow cases in raw data ASCII IBM compatible format (i.e., PTI's PSS/E, GE's PSLF, IEEE common), along with all assumptions used in creating each case and any special instructions for reading the data.

B-3.5 Summary of Proposer's Qualification

(a) Provide a description of the Proposer's qualifications and experience applicable to the developing, designing, financing, constructing, operating and maintaining of the proposed project.

(b) Identify and describe existing generation facilities currently in commercial service on which proposer has contracted, including (i) the name, address, telephone number, and specific contact of the owner of such facilities; (ii) a description of the facility and its location; (iii) the Proposer's scope of work relating to the project; and (iv) total contract value and duration.

B-3.6 Additional Information

Please provide any additional information that Proposer believers will assist FMPA in an accurate and fair evaluation of the proposed project.

B-3.7 Guaranty for Firm Power

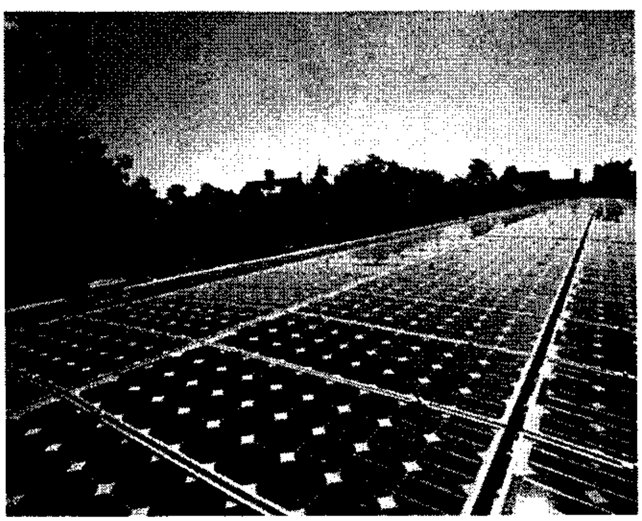
Describe the formula or mechanism whereby the power and energy will be compensated or replaced, and/or the capacity or energy payments reduced when or if the project fails to provide firm power when required by FMPA.

Appendix B
Request for Proposals Renewable Capacity and Energy

Florida Municipal Power Agency

(All-Requirements Power Supply Project)

Request for Proposals
Renewable Capacity and Energy
June 29, 2007
(RFP # 0607R)



Pre-Bid Meeting July 11, 2007

Proposals are Due August 29, 2007

Florida Municipal Power Agency

REQUEST FOR PROPOSALS, RENEWABLE CAPACITY AND ENERGY

FLORIDA MUNICIPAL POWER AGENCY
Request for Proposals, Renewable Capacity and Energy

June 29, 2007

1. Introduction

The Florida Municipal Power Agency ("FMPA" or "Agency") is issuing this Request for Proposals ("RFP") as an invitation to qualified companies to submit proposals for the supply of renewable capacity and energy or energy only to meet a portion of the projected power requirements of FMPA's All-Requirements Power Supply Project ("ARP"). FMPA is seeking proposals from qualified and eligible bidders with prior operating experience with the proposed resource type that the Proposer is offering. Proposals must be at least 1 MW. The minimum term will be five (5) years. Although delivery of firm, reliable capacity and energy is required to begin no later than January 1, 2011, FMPA will consider projects that can begin delivery of capacity and energy or energy only earlier than this date. Resources providing the proposed firm capacity and energy, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply.

For purposes of this RFP, renewable resources will include a facility that is or will be interconnected for synchronous operation and delivery of electricity to an electric utility where the sole source of fuel used for the production of energy for sale to FMPA is from one or more of the following sources.

- hydrogen produced from sources other than fossil fuels
- biomass (including waste to energy and landfill gas)
- solar energy
- geothermal energy
- wind energy
- ocean energy
- hydroelectric power
- waste heat from a commercial or industrial process
- Any other technologies utilizing fuel/energy sources deemed by FMPA to be renewable in nature

A Pre-Bid meeting will be held at the office of FMPA on July 11, 2007 and Proposals are due by 3 P.M. EPT on August 29, 2007.

2. FMPA Description

The Florida Municipal Power Agency was created and exists pursuant to its Interlocal Agreement among its 30 members, which specifies the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10, Florida Constitution; Part II, Chapter 361, Florida Statutes, as amended, the "Joint Power Act"; and/or Section

163.01, Florida Statutes, as amended, the "Florida Interlocal Cooperation Act of 1969." The Florida Constitution and the Joint Power Act provide the authority for municipal and other electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Each municipal electric system that is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board has the responsibility of developing and approving FMPA's budget, approving and financing projects, hiring a General Manager and a General Counsel, and establishing bylaws that govern how FMPA operates and policies that implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary, Treasurer and an Executive Committee. The Executive Committee consists of nine directors plus the current Chairman of the Board, the Vice Chairman, the Secretary, and the Treasurer (13 total). The Executive Committee meets regularly to manage and govern FMPA's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for monitoring budgeted expenditure levels and assuring that authorized work is completed in a timely manner.

3. All-Requirements Power Supply Project

Under the ARP, FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either FPL or PEF. The most recent members, Kissimmee Utility Authority and the City of Lake Worth, Florida, joined the ARP in 2002.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in PEF's Crystal River Unit 3. A number of ARP members also participate in the St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. These nuclear resources are referred to as "Excluded Resources." The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the FMPA Stanton, Tri-City, and Stanton II Projects.

The third category of resources is participant-owned generation. Capacity included in this category is generation owned by the ARP Participants either solely or jointly. FMPA purchases this capacity from the ARP Participants and then commits and dispatches the generation as a part of the ARP portfolio of power-supply resources to meet the total requirements of the ARP.

The fourth category of resources is purchased power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP Participants, which were entered into prior to the ARP Participant joining the ARP.

4. RFP Schedule

The FMPA timetable for this RFP process is shown below. The dates and times are presently only estimates and may be changed at any time at the sole discretion of FMPA. All times in this RFP are shown in Eastern Prevailing Time ("EPT"). Approval for contract execution must come from the Risk Oversight Committee ("ROC") and the Executive Committee ("EC") of the ARP.

Public Notice of RFP	-	June 29, 2007
RFP Available for Distribution	-	June 29, 2007
Pre-Bid Meeting	-	July 11, 2007 [10 A.M.]
Notice of Intent to Propose Due to FMPA	-	July 16, 2007 [3 P.M.]
Deadline for Proposer Questions	-	August 15, 2007 [3 P.M.]
Sealed Proposal(s) Due Date	-	August 29, 2007 [3 P.M.]
RFP Short List *	-	October 5, 2007
Presentation of Results to the ROC		December 6, 2007
Primary Suppliers referred to EC for approval	-	January 24, 2008
Contract Developed and Finalized	-	February 29, 2008
Contract(s) Approved for Execution -		March 28, 2008

* Depends on number of bidders and alternatives received.

5. Potential Power Supply Requirements

FMPA is requesting renewable energy proposals in part to meet its future load and capacity requirements as summarized in the table below. Proposals for renewable capacity and energy or energy-only resources are requested, which together with its other resources, FMPA could use to meet its future demand, net energy requirements, and reliability requirements. Firm energy resources will be given a preference; however, non-firm resources will be considered at the discretion of FMPA. FMPA is seeking proposals from Proposers to provide a highly reliable resource of capacity and energy or energy only from an identifiable generating resource(s) deliverable to the PEF or FPL transmission systems.

Proposers are required to explain in detail specifically how they will assure FMPA of their ability to reliably provide wholesale power to FMPA. FMPA reserves the right to determine the amount of dependable capacity associated with each proposal for calculating the capability of the proposed resource(s) to meet its required capacity reserve requirements. Bids that permit FMPA to satisfy its capacity and energy requirements through the use of multiple resources and a diversity of technologies and fuel types may be preferred for reliability purposes.

The Proposer must agree to allow FMPA the right to retain all renewable energy credits or attributes (for example, "REC" or "green tags" credits, but not including any federal or state income tax credits) for power delivered to FMPA under the proposal. Facilities must be located in the State of Florida. Proposers may be required to certify power to be delivered per future State of Florida renewable energy standards.

The Proposer must take into consideration FMPA minimum load conditions and "must run" or "must take" resource obligations. FMPA is looking for the Proposer to develop, finance, build, own and operate the proposed project. FMPA is open to consider any pricing arrangement including all-in energy pricing or multi-part rates that include separate demand and energy price components. The preferred pricing should be fixed rates for the term offered. The details and presentation format of the data required to be submitted as a part of proposals in response to this RFP are specified in Attachment A.

Proposals may require Performance Security described in Section 15 to protect FMPA's members from potential failure to perform. FMPA reserves all rights to limit the amount of firm capacity from a single proposal or from proposals in aggregate to protect FMPA's members from potential failure to perform.

6. Transmission Arrangements

Eight (8) of the fifteen (15) ARP Participants are geographically located within FPL's service area, and the other seven (7) ARP Participants are located within PEF's service area. All fifteen (15) ARP Participants are supplied their full-requirements power supply from FMPA and such power is delivered to the ARP Participants over the transmission systems of FPL or PEF, respectively. Network-type transmission arrangements are currently in place that enable FMPA to provide service over both FPL's and PEF's systems.

FMPA capacity needs are provided on a system basis; however, the utilization of FMPA's transmission agreements with FPL and PEF must be separately planned. FMPA has determined for this proposal evaluation that all of the proposed capacity and energy must be delivered into the FPL or PEF transmission systems ("Network").

All proposals for firm power supplies, where the supply resources originate from outside the Network's balancing authorities, should be priced based on the Proposer supplying and paying for firm transmission service from the source(s) of supply to the Network balancing authority interface, including the cost of any transmission upgrades required to obtain this firm delivery service. Firm transmission may not be required for as-available energy-only resources.

FMPA also requires that the Proposers be responsible for the following costs: (i) all costs associated with interconnecting generating resources to the transmission system; (ii) all transmission upgrades required to facilitate the interconnection of generating resources; and (iii) for firm resources, all transmission upgrades required to facilitate the designation by FMPA of the Proposer's supply resources as a qualified network resource under FPL's and/or PEF's Open Access Transmission Tariff ("OATT"). To the extent that transmission credits are provided for upgrades provided by Proposers on the FPL and/or PEF system, these will be credited back to the Proposer.

FMPA may evaluate the potential impact of transmission congestion, redispatch, and losses that may occur between the Proposer's supply resources and FMPA's network loads and may adjust the proposals to take such impacts into consideration. FMPA encourages Proposers to supply any information that the Proposers have related to the potential impact of transmission congestion, redispatch and losses.

FMPA will give preference to a transmission service arrangement that (i) consists of no more than one intermediate transmission path (between the generating switchyard and the Network balancing authority), and (ii) includes the assignment of tariff-provided transmission reassignments/redirection/resale rights solely to FMPA for the life of the agreement.

7. Notice of Intent to Bid

All Proposers are required to provide written notification of their intent to submit a proposal no later than July 16, 2007 at 3:00 P.M. EPT. A Notice of Intent to Bid Form is included herein as RFP Form 1. On the Notice of Intent to Bid Form, Proposers must indicate the agreement term(s) on which the proposal(s) will be based. All sections of the Notice of Intent to Bid Form must be completed in full, signed by an authorized representative of the Proposer, and submitted to FMPA by facsimile or mail (not via the Internet) to the attention of Mr. Bill May.

8. Pre-Bid Meeting

FMPA has scheduled a Pre-Bid Meeting for Wednesday, July 11, 2007, 10:00 A.M. EPT, at the offices of FMPA, 8553 Commodity Circle, Orlando, FL 32819-9002. The purpose of the Pre-Bid Meeting is to provide any required clarifications to this RFP and to provide any additional information deemed necessary in order for Proposers to submit their best proposal. Attendance at the Pre-Bid Meeting is optional. Although verbal responses to questions may be provided during the meeting, only written responses will be considered official.

Qualified companies that wish to attend the Pre-Bid Meeting should register with FMPA by submitting a written list of attendees via e-mail, facsimile or mail to the address provided in Section 9 before 5:00 P.M. EPT on July 10, 2007.

9. Submittal of Proposals

Sealed proposal packages will be received until August 29, 2007 at 3:00 P.M. EPT ("Proposal Due Date") at the offices of FMPA. **ANY PROPOSAL SUBMITTED VIA THE INTERNET WILL NOT BE ACCEPTED.** Each Proposer is required to submit a completed Proposal Summary (RFP Form 2), a Minimum Requirements Form (Form 3), a Pricing Proposal Form (Form 4) and a Checklist (Form 5) as part of the proposal package. The forms are listed in Section 21 of this RFP. The proposing company's name and the words "Request for Proposals Renewable Capacity and Energy RFP #0607R" must be clearly identified on the outside of each proposal package. FMPA reserves the right to reject all proposals received after the Proposal Due Date.

One original and three (3) copies of each proposal should be sealed and delivered to the following address:

Mr. Bill May
Manager of Power Supply
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819-9002

An electronic copy of the complete Proposal, the pricing terms and all spreadsheets included in the proposal should be submitted in Microsoft Office Professional Edition 2003 or compatible format on CD or DVD.

The proposals must remain in effect and valid until March 28, 2008 or later if the purchase is to be finalized pending a transmission service request. The proposal packages will be opened after the Proposal Due Date. Each proposal package must be accompanied by a non-refundable Proposal Fee (in the form of a cashier's check made payable to FMPA) in the amount of $500 per proposal. If a Proposer submits alternative arrangements, each alternative will be considered a separate proposal. A Proposer submitting multiple proposals is required to supply a $500 Proposal Fee for each proposal.

FMPA is willing to consider alternatives that involve a pass through of fuel and variable operation and maintenance costs or a contractually fixed energy charge. For alternatives involving a pass through of fuel costs, a contractually fixed heat rate is preferred. If the proposal is based on a contractually-fixed total energy cost, the proposal must include all information pertinent to the pricing and its escalation.

With respect to fixed and variable operation and maintenance expenses ("O&M"), all charges must be itemized to show different components of costs. All assumptions used in calculating such costs must be clearly stated. Proposers need to list components of costs and other performance parameters. Typical components that may be included are the following:

- Fixed Operating Expenses (labor, general equipment maintenance, insurance, property taxes, major maintenance, capital expenditures, administrative costs).
- Variable O&M (maintenance charge costs related to use, allowances and other consumables).
- For resources that involve fuel-to-power conversion, heat rate (minimum load level, full load, and intermediate levels at winter, summer and average ambient temperatures) and heat content (Btu/lb) of fuel source.
- Availability and forced outage rate.
- Other operating data/restrictions such as ramp rates, start-up costs, minimum load, etc. that may affect operating flexibility and expenses.

FMPA prefers purchases that provide guarantees with respect to various major performance parameters such as output, heat rate, availability, forced outages, fixed and variable operating expenses and fuel prices. Compensation to the Seller will be adjusted if guaranteed performance parameters are not achieved. FMPA prefers purchases that are dispatchable by FMPA.

10. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

FMPA reserves the right to:

- Reject any and all proposals for any reason, or no reason, received in response to this RFP;
- Reject any proposal for failure to extend the validity date if requested;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a proposal;
- Negotiate an arrangement for power supply with more than one Proposer at a time;
- Not select the proposal with the lowest apparent price;
- Request clarifications from Proposers at any time; and
- Negotiate with any Proposer that submits a written proposal.

11. Interpretations and Addenda

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing or by e-mail to the following:

Mr. Paul Arsuaga
1000 Legion Place, Suite 1100
Orlando, FL 32803
Phone: (407) 648-3502
Fax: (407) 648-8382
E-Mail: parsuaga@rwbeck.com

Only FMPA written responses to Proposers questions will be considered official. A verbal response by FMPA will not be considered an official response. Written responses to questions and requests for interpretations may be provided to all Proposers by posting on the Internet Website. All written questions must be received by FMPA on or before August 15, 2007 at 3:00 P.M. EPT. Inquiries after this date may not receive responses. All addenda issued in connection with this RFP will be placed on the "Important Updates" page on the Internet Website (www.fmpa.com), at the time of issue and it shall be the responsibility of those Proposers to regularly check the "Important Updates" page for addenda.

12. Errors, Modification or Withdrawal of Proposal

Each Proposer should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which must be followed by all Proposers. Modifications to proposals already received by FMPA will only be accepted prior to the Proposal Due Date. Proposals may be withdrawn by giving written notice (no Internet notices) to FMPA prior to the Proposal Due Date. In such cases, a full refund of the Proposal Fee will be provided by FMPA.

13. Proprietary Confidential Business Information

FMPA is a governmental entity subject to the Florida Public Records Law (Chapter 119, Florida Statutes). Some, or all, of the materials or information provided by the Proposer to FMPA will be considered a "public record" which FMPA, by law, is obligated to disclose upon request of any person for inspection and copying, unless the public record or the information is otherwise specifically exempt by statute. Should a Proposer provide any materials which it believes, in good faith, contain information which would be exempt from disclosure or copying under Florida law, the Proposer shall indicate that belief by typing or printing, in bold letters, the phrase "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" both on the initial page and on the face of each affected page of such material and shall submit both a complete and a redacted version of such material. Should any person request to examine or copy any material so designated, only the redacted version of the affected material or page(s) thereof will be produced. If the person requests to examine or copy the complete version of the affected material or page(s), FMPA shall notify the affected the Proposer of that request, and the Proposer, within thirty-six (36) hours of receiving such notification, shall either permit or refuse to permit such disclosure or copying. If the Proposer refuses to permit disclosure or copying, the Proposer agrees to, and shall, hold harmless, indemnify and defend FMPA for all expenses, costs, damages, and penalties of any kind whatsoever which may be incurred by FMPA, or assessed or awarded against FMPA, in regard to the Proposer's refusal to permit disclosure or copying of such material. If litigation is filed in relation to such request and the Proposer is not initially named as a party, the Proposer shall promptly seek to intervene as a defendant in such litigation to defend its claim regarding the confidentiality of such material. This provision shall take precedence over any provisions or conditions of the Proposer's proposal and any provision of any other document relating to the disclosure of materials or information considered by the provider to be confidential or proprietary and shall constitute FMPA's sole obligation with regard to maintaining confidentiality of material or documents, of any kind, or any other information provided by the Proposer or its Affiliates or Sub Contractors.

14. Proposer Qualifications

FMPA will accept proposals from any electric utility, independent power producer ("IPP"), qualifying facility ("QF"), exempt wholesale generator, or non-utility generator, or electric power marketer who has received certification as such by the FERC. Proposers unfamiliar to FMPA may be required to provide proof of experience.

Proposers offering capacity/energy sales from an existing unit(s) must own and operate the unit, plant or system capacity or must have the unit(s), plant or system capacity under contract. FMPA may require proof of such contracts as well as proof of contracts for sales from a portfolio of resources. Any contracts submitted with the proposal may have the price and other sensitive information deleted before submittal to FMPA. For proposals involving a new project, Proposer should supply information on the status of the project including site development, permitting, purchase of land options, etc.

Electric power plant operators must provide proof of operating experience as requested in Attachment A. Respondents are encouraged to provide the following information with their proposals: most recent audited financial statement; Form 10K of parent company, where appropriate; most recent Dunn & Bradstreet report; description of pending litigation; summary of project experience; and most recent annual report.

15. Proposal Security and Performance Security

FMPA requires that the Proposer provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW) of the capacity offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals. The Proposal Security will be forfeited if the Proposer changes its proposal in a material adverse manner after being short-listed or fails to establish contract Performance Security prior to contract execution with the Proposer. The Proposal Security is to remain in effect until the later of the date to which proposals remain valid or to such time that FMPA executes a contract with the Proposer providing for the Performance Security or FMPA executes an agreement with a different

Proposer or combination of Proposers to meet its requirements, or decides to reject all proposals. The letter of commitment will state further that the financial institution will commit to be a guarantor for a Performance Security established by the Proposer when the contract is executed that will minimize FMPA's exposure to direct and consequential damage due to failure of the Proposer to fulfill the terms and conditions of the contract awarded. The amount of the Performance Security will be a percentage of the revenues over the remaining life of the contract.

16. Default and Damages Provisions

FMPA will negotiate the conditions of default and damages with the successful Proposer(s). Proposers should include suggested default and damage provisions in their proposals.

17. Disqualification of Proposals

Proposal(s) may be disqualified at any point if bribery, conflict of interest, or interference in the evaluation process is/are suspected or determined, at FMPA's sole discretion.

18. Public Entity Crimes Statement

Pursuant to Section 287.133(2)(a), FLORIDA STATUTES, all bidders should be aware of the following:

> "A person or affiliate who has been placed on the convicted vendor list following a conviction for a public entity crime may not submit a bid on a contract to provide any goods or services to a public entity, may not submit a bid on a contract with a public entity for the construction or repair of a public building or public work, may not submit bids on leases of real property to a public entity, may not be awarded or perform work as a contractor, supplier, subcontractor, or consultant under a contract with any public entity, and may not transact business with any public entity in excess of the threshold amount provided in Section 287.017, for CATEGORY TWO for a period of 36 months from the date of being placed on the convicted vendor list."

19. Collusion

By offering a submission pursuant to this Invitation to Bid, the Proposer certifies the Proposer has not divulged, discussed, or compared his bid with other Proposers and has not colluded with any other bidder or parties to this bid whatsoever. Also, the Proposer certifies, and in the case of a joint bid, each party thereto certifies, as to his own organization, that in connection with this bid:

(1) Any prices and/or cost data submitted have been arrived at independently, without consultation, communication, or agreement for the purpose of restricting

competition, as to any matter relating to such prices and or cost data, with any other Proposer or with any competitor.

(2) Any prices and/or cost data quoted for this bid have not knowingly been disclosed by the Proposer and will not knowingly be disclosed by the Proposer prior to the scheduled opening directly or indirectly to any other Proposer or to any competitor.

(3) No attempt has been made or will be made by the Proposer to induce any other person or firm to submit or not to submit a bid for the purpose of restricting competition.

(4) The only person or persons interested in this bid, principal or principals is/are named therein and that no person other than therein mentioned has any interest in this bid or in the contract to be entered into and;

(5) No person or agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee accepting bona fide employees or established commercial agencies maintained by the Proposer for the purpose of doing business.

20. Evaluation Process

Repricing of proposals is not anticipated; therefore, Proposers should provide their lowest cost offer on the Proposal Due Date. The proposal evaluation process will be performed on a bid and negotiate basis. Information provided from each qualified Proposer by the Proposal Due Date will be used to develop a short-list of proposals from which selection(s) could be made for direct negotiations. No additional Proposer data will be considered after the Proposal Due Date, except for clarifications requested by FMPA and possible transmission system study results obtained from FMPA, FPL, PEF, and/or any other affected transmission provider. FMPA will evaluate the proposals in terms of price and non-price factors. The first stage of the evaluation process for qualified Proposers will consist of a check of each proposal against the minimum requirements of the RFP. After the minimum requirements screening, initial price screening of proposals for short- or medium-term arrangements may be accomplished by comparing such proposals using a capacity factor analysis. Those proposals may be ranked on economics and risks with other renewable proposals and may then be compared with sources of power that are available to FMPA. Screenings may be performed on a nominal and present value busbar cost basis. Price and non-price evaluations may be conducted next. During the evaluation process, FMPA may develop scenarios that include combining proposals from one or more Proposers. One or more renewable proposals may be selected based on recommendations from the Risk Oversight Committee.

Price and non-price evaluations may include a preliminary analysis of transmission limitations to verify that Proposers have properly addressed the limitations and included appropriate costs. Once a short-list of Proposers is developed, FMPA may inform PEF or FPL, as appropriate, of the potential short-listed Proposers as possible power suppliers to FMPA in order to secure FMPA network transmission services.

Additional system studies, which incorporate proposed power supply resources, may be used to verify the sufficiency of the transmission systems and their interfaces and determine if additional transmission system facilities may be required. Should FMPA or others determine, based on their studies, that additional transmission facilities or costs are required to accommodate particular proposed power supplies, each affected Proposer will then be contacted by FMPA with this information to explore possible alternatives, if any, to address the problem. To the extent that these problems cannot be resolved, the proposal may be rejected or the evaluation will reflect this cost uncertainty. Proposers will remain responsible for all transmission upgrades required to facilitate the designation by FMPA of the Proposer's supply resources as a qualified network resource under the FPL and/or PEF OATT whether or not such costs can be estimated. Proposals may be eliminated at this point based solely on a determination that additional transmission facilities are required and that there is insufficient time to complete the installation of such facilities. Any costs associated with such transmission system studies performed by FMPA, PEF, or FPL will be the responsibility of FMPA.

Proposals that remain on the short-list will be analyzed on an overall system cost basis. From this analysis, the Proposer(s) will be selected for participation in negotiations. The Proposer(s) selected will be notified for commencement of negotiations. Selection and rejection of proposals and notification of Proposers at all stages will remain entirely within FMPA's discretion. FMPA intends to notify Proposers not selected under this solicitation within a reasonable amount of time. Selected proposals will be presented to the Executive Committee for approval.

FMPA may evaluate the potential impact of transmission congestion and losses that may occur between the Proposer's supply resources and FMPA's network loads and resources and may adjust the proposals to take such impacts into consideration. FMPA encourages Proposers to supply any information that the Proposers may have related to the potential impact of transmission congestion, redispatch and losses.

Minimum Requirements for All Proposals

Each proposal must satisfy certain minimum requirements before it will receive any further evaluation. The Proposer must demonstrate in its submittal that the following minimum requirements have been met:

1. The proposal contains the appropriate Proposal Fee in accordance with Section 9.
2. The proposal is for at least 1 MW and begins delivery no later than January 1, 2011.
3. The proposal shall remain valid to the later of March 28, 2008, or the date of receipt of all regulatory approvals required for the proposal and any related transmission service.
4. Proposals for firm capacity and energy are priced inclusive of the Proposer supplying and arranging for all third party transmission into the FMPA system (qualified network resource under FPL's and/or PEF's Open Access Transmission

Tariff) and located in the State of Florida. The Proposer has identified the means of assuring firm delivery of capacity resources.

5. The Proposer has agreed to pay for all necessary transmission upgrades to provide for interconnection and delivery service to the FMPA system.

6. For proposals involving a sale to more than one utility from the same resource(s) identified as supplying the sale to the FMPA, FMPA's rights to the output shall be equal to, or greater than, the rights of all other customers served by the resource(s).

7. The Proposer ensures that all emissions allowance requirements will be satisfied and that any associated costs shall be borne by the Proposer.

8. The Proposer demonstrates ownership or contractual rights to the generating system capacity which is identified as supplying the sale.

9. Resources providing the proposed firm capacity and energy, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply.

10. The Proposer has completed the appropriate RFP Forms 1 through 4. All forms requiring a signature must be signed by a duly authorized official representing the Proposer.

11. The Proposer has provided a Letter of Commitment to establish an acceptable Proposal Security as solely determined by FMPA within ten (10) days of being notified that his proposal is on the short-list of proposals.

12. Proposers shall have successfully provided under contract to at least one electric utility for a minimum period of one year, similar services to the services they are providing to FMPA and have included information in the proposal to demonstrate this experience.

13. The Proposer agrees to assist FMPA to obtain final contract approval from their respective governing bodies in public sessions, where required.

14. The Proposer agrees to provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for a Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW) of the capacity offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals.

15. Pricing information must be provided by Proposers in sufficient detail for FMPA to fully analyze each proposal.

16. The Proposer must provide agreements and disclose sufficient information relating to the provision of fuels, critical spare parts, technical service and support, and maintenance plans to permit FMPA to evaluate the proposals for reliability.

17. If the Proposer is proposing an energy-only, must take, non-dispatchable, or any other arrangement that would require FMPA to take energy from the Proposer at

levels that may not be scheduled by FMPA, then the proposal must contain a projected schedule of energy to be provided under the proposal. Such schedules must contain sufficient detail to permit an analysis of hourly energy patterns by day and month over the proposed contract period.

Price Criteria

FMPA will evaluate the power supply proposals against each other and other power supply alternatives available to FMPA to determine the lowest priced proposals. Impacts that a power supply proposal will have on the operation of the existing and planned resources of FMPA will also be considered. The costs may be compared on an annual basis as well as cumulatively over multiple time periods.

Non-Price Criteria

Each proposal may be compared to the preferences of FMPA under various selected criteria and a score will be assigned based on the ability of the proposal to satisfy FMPA's preferences. The maximum score allocated to each criterion will be weighted such that the relative importance of each criterion is reflected in the proposal's total non-price score.

The following criteria will be assessed in the detailed evaluation stage:

Competitiveness.......FMPA prefers proposals that offer pricing mechanisms that will assure that the proposed sale will remain competitively priced in comparison to other wholesale power sales in the region.

Flexibility..................FMPA prefers proposals that would provide FMPA with sole rights to extend the contract at the end of the initial term at a predetermined price. Proposals are also preferred which do not impose constraints with respect to load factor, minimum demand, etc. and that can begin delivery of capacity and energy prior to January 1, 2011.

Firm Supply..............FMPA prefers proposals that offer assurances relating to resource reliability and transmission availability and provide financial security to cover penalties for non-performance. For reliability purposes, FMPA also prefers proposals with multiple units.

Dispatchability.........FMPA prefers proposals that are fully dispatchable by FMPA.

Technology...............Proposals utilizing commercially proven and diverse technologies are preferable.

Environmental Impact.......................The potential environmental impacts to FMPA from the purchases are difficult to quantify, but where a clear demonstration can be made by the Proposer that a particular proposal will reduce environmental impacts to FMPA compared to other alternatives, this will be taken into consideration.

From this detailed analysis, proposals will be ranked. A short-list of proposals will be developed and Proposer(s) will be selected for participation in negotiations. The Proposer(s) selected will be notified for commencement of negotiations.

Selection and elimination of proposals and subsequent notification of Proposers at all stages of the evaluation will be at FMPA's discretion. FMPA intends to notify Proposers of those proposals that are eliminated from further consideration under this solicitation within a reasonable amount of time.

21. RFP Forms

Form 1 -	Notice of Intent to Bid Form
Form 2 -	Proposal Summary Form
Form 3 -	Minimum Requirements Form
Form 4 -	Proposal Pricing Form
Form 5 -	Check-List
Attachment A	Required Data for Proposal

RFP Form 1
Page 1 of 2

FLORIDA MUNICIPAL POWER AGENCY

Notice of Intent to Bid Form

Due: July 16, 2007 (3:00 PM EPT)

Date:_____________

Company Name: ______________________________

Name of Contact Person: ______________________________

Mailing Address: ______________________________

____

Telephone: ______________________________

Fax: ______________________________

E-Mail: ______________________________

Agreement Term: ______________________________

Name of Interconnecting Utility: ______________________________

Location of Proposed Project: ______________________________

Power Generation Technology: ______________________________

Primary Fuel: ______________________________

Bidder Classification: Type of Bidder (Utility, Qualified Facility, Exempt Wholesale Generator, Power Marketer, etc.):

____

Bidder Qualifications: Describe similar power supply services provided by stating: capacity, location, contract commencement date, contract term, etc.

(Attach additional sheets as needed)

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RFP Form 1
Page 2 of 2

FLORIDA MUNICIPAL POWER AGENCY

Notice of Intent to Bid Form

Due: July 16, 2007 (3:00 PM EPT)

Is there any information on this form considered to be confidential or proprietary? *(Please Describe).*

____

____

Bidder's Signature: ____
(Duly Authorized)

RFP Form 2
Page 1 of 2

FLORIDA MUNICIPAL POWER AGENCY

Proposal Summary Form

1. Company ______________________
2. Name of Utility for Interconnection ______________________
3. Name of Contact ______________________
4. Mailing Address ______________________
5. Telephone ______________________
   Fax ______________________
   E-Mail ______________________
6. Proposed Contract Start Date ______________________
7. Proposed Contract End Date ______________________
8. Brief Description of Proposal

Nameplate Rating (MW)	Unit Firm Dependable Rating-Summer (MW)	Unit Firm Dependable Rating-Winter (MW)	Equivalent Forced Outage Rate (EFOR)[1]	Amount of Unit Presently Under Contract to Others (MW)	Annual Hours Maintenance	Projected Capacity Factor [2]
(a)	(b)	(c)	(d)	(e)	(f)	(g)

[1] Equivalent forced outage rate calculated in accordance with NERC Guidelines.

[2] Based on Unit Firm Dependable Rating - Summer.

RFP Form 2
Page 2 of 2

FLORIDA MUNICIPAL POWER AGENCY

Proposal Summary Form

9. Control Area(s) in which potential resources may be located.

10. Certification: The bidder hereby certifies that all of the statements and representations made in this proposal package, including attached documents, are true to the best of the bidder's knowledge and belief. The bidder agrees to be bound by its representations and the terms and conditions of the Request for Proposals:

Signed: ______________________________

(Typed): ______________________________

Title: ______________________________
(Duly Authorized)

Date: ______________________________

RFP Form 3
Page 1 of 2

FLORIDA MUNICIPAL POWER AGENCY

Minimum Requirements Form

In submitting this form, we agree to the items below and/or have provided documents to attest to the information provided as requested below. We have also provided references to the proposal in the form of section numbers, page numbers, etc., for information relating to each item.

Name of Company: ____________________________

Duly Authorized Signature: ____________________________ ____________________
(Date)

Each bidder must demonstrate the following by providing appropriate information in the proposal:

1. The proposal contains the appropriate Proposal Fee in accordance with Section 9.
2. The proposal is for at least 1 MW and begins delivery no later than January 1, 2011.
3. The proposal shall remain valid to the later of March 28, 2008, or the date of receipt of all regulatory approvals required for the proposal and any related transmission service.
4. Proposals for firm capacity and energy are priced inclusive of the Proposer supplying and arranging for all third party transmission into the FMPA system (qualified network resource under FPL's and/or PEF's Open Access Transmission Tariff) and located in the State of Florida. The Proposer has identified the means of assuring firm delivery of capacity resources.
5. The Proposer has agreed to pay for all necessary transmission upgrades to provide for interconnection and delivery service to the FMPA system.
6. For proposals involving a sale to more than one utility from the same resource(s) identified as supplying the sale to the FMPA, FMPA's rights to the output shall be equal to, or greater than, the rights of all other customers served by the resource(s).
7. The Proposer ensures that all emissions allowance requirements will be satisfied and that any associated costs shall be borne by the Proposer.
8. The Proposer demonstrates ownership or contractual rights to the generating system capacity which is identified as supplying the sale.
9. Resources providing the proposed firm capacity and energy, whether an existing plant or proposed new resources, must be in operation at least two (2) months prior to the start date of the proposed power supply.

RFP Form 3
Page 2 of 2

FLORIDA MUNICIPAL POWER AGENCY

Minimum Requirements Form

10. The Proposer has completed the appropriate RFP Forms 1 through 4. All forms requiring a signature must be signed by a duly authorized official representing the Proposer.

11. The Proposer has provided a Letter of Commitment to establish an acceptable Proposal Security as solely determined by FMPA within ten (10) days of being notified that his proposal is on the short-list of proposals.

12. Proposers shall have successfully provided under contract to at least one electric utility for a minimum period of one year, similar services to the services they are providing to FMPA and have included information in the proposal to demonstrate this experience.

13. The Proposer agrees to assist FMPA to obtain final contract approval from their respective governing bodies in public sessions, where required.

14. The Proposer agrees to provide a letter of commitment from a financial institution with a credit rating of at least A- by S&P, A3 by Moody's or A- from Fitch to be a guarantor for a Proposal Security to be established by the Proposer equal to five dollars ($5) per kilowatt (kW) of the capacity offered in the proposal within ten (10) days of being notified that the proposal is on the short-list of proposals.

15. Pricing information must be provided by Proposers in sufficient detail for FMPA to fully analyze each proposal.

16. The Proposer must provide agreements and disclose sufficient information relating to the provision of fuels, critical spare parts, technical service and support, and maintenance plans to permit FMPA to evaluate the proposals for reliability.

17. If the Proposer is proposing an energy-only, must take, non-dispatchable, or any other arrangement that would require FMPA to take energy from the Proposer at levels that may not be scheduled by FMPA, then the proposal must contain a projected schedule of energy to be provided under the proposal. Such schedules must contain sufficient detail to permit an analysis of hourly energy patterns by day and month over the proposed contract period.

RFP Form 4
Page 1 of 2

FLORIDA MUNICIPAL POWER AGENCY

Proposal Pricing Form

Capacity Pricing

Summarize separate capacity components below which comprise the total delivered cost of capacity for each contract year below, expressed in $/kW-month. If the proposal does not provide for a separate capacity charge, indicate "N/A" below.

FMPA						
	Component of Delivered Capacity Rate ($/kW-mo.)					
12 Mo. Period Ending December 31	A	B	C	D	E	Total A-E
2011						
2012						
2013						
2014						
2015						
2016						

Using the previously identified components, describe the methodology for determining the monthly capacity charges including how billing demand is determined. Clearly state whether each cost component is a pass through or contractually fixed.

RFP Form 4
Page 2 of 2

FLORIDA MUNICIPAL POWER AGENCY

Proposal Pricing Form

Energy Pricing

To the extent that the proposal reflects energy pricing on the basis of a fuel cost and a heat rate, indicate the appropriate values for each contract year below. If the proposal reflects energy pricing consisting of one or more discrete energy components associated with delivery into FMPA, identify the components and resulting total as indicated.

FMPA							
12 Mo. Period Ending December 31	**Fuel Cost** **$/MMBtu** *(if applicable)*	**Heat Rate** **MMBtu/ MWh** *(if applicable)*	**Components of Delivered Energy Rate ($/MWh)**				
			F	**G**	**H**	**I**	**Total F-I**
2011							
2012							
2013							
2014							
2015							
2016							

Using previously identified components describe the methodology for determining the monthly energy charge including methodology for determining billing units and any potential adjustments. Clearly state whether each cost component is a pass through or contractually fixed. For pass-through costs, provide applicable caps or indices.

____

____

____

____

FLORIDA MUNICIPAL POWER AGENCY

Checklist

All RFP Forms checked below have been included as part of the proposal *.

RFP Form 2 - Proposal Summary Form ____________

RFP Form 3 - Minimum Requirements Form ____________

RFP Form 4 - Pricing Proposal Form ____________

Signature of Bidder:

____

Name of Project:

____

(*) *RFP Form 1 is the Notice of Intent to Propose Form which is sent to FMPA prior to, and separately from, the proposal.*

ATTACHMENT A

Required Data for Proposal

The following data are required for all renewable capacity and energy proposals as applicable. The required data shall be provided in sections numbered in accordance with the specific items detailed below. Each section should begin on a new page. Information provided by bidders that is not in the requested format, may be disregarded and the proposal rejected for incompleteness. General information (e.g., promotional material, "boiler plate", etc.) may be provided with the proposal, but only the formatted information will be considered. Any proposal that does not contain the requested information may be deemed incomplete and may be rejected in FMPA's sole discretion. FMPA may request additional data or clarifying information from bidders.

A-1 Identity of Bidder Contact

Provide the full name, job title, business address, telephone number, and facsimile number of contact person from whom additional information relating to this proposal may be requested.

A-2 General Description of Proposal

a) Provide a general overall summary of the proposal. Identify and describe the type of proposal being offered.
b) If applicable, describe in detail how the bidder will provide for ancillary services. Describe any additional requirement for remote terminal units (RTU's), communication lines, etc. Bidder will be responsible for cost of procuring, installing and maintaining this equipment.

A-3 Location of Generating Facilities

Identify the geographic location of the applicable generating resource(s) and the transmission system which interconnects these resources.

ATTACHMENT A

Required Data for Proposal

A-4 Capacity and Expected Energy Production

Please verify that FMPA's rights to the output of the generating resources which are to supply capacity and energy to FMPA shall be equal to or greater than the rights of all other firm wholesale customers served by the generating resources. Describe limiting conditions (if any).

Please provide a narrative describing the facility's operating history, if any; construction start date; test operation start date; commercial operation date; monthly capacity factors; non-fuel operation and maintenance expenses; net full load heat rate; availability factor; forced outage rates; maintenance schedule; etc.

A-5 Schedule

If there are any limitations on the availability of capacity, specify the time frame when capacity will be available (or unavailable).

A-6 Proposed Agreement Term

(a) Specify proposed contract term.

(b) Specify any and all proposed provisions for contract renewal, extension, or termination, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

A-7 Third Party Information

Identify any other firm capacity and energy commitments during the proposed contract term to other parties, and provide a description of FMPA's rights compared to the rights of the other parties. Provide copies of all existing contracts for sale of power to other parties from the unit (price data and other sensitive information may be deleted from the copies).

ATTACHMENT A

Required Data for Proposal

A-8 Historical Fuel Information

Where applicable, please describe the following:

(a) Primary and alternate fuel source for each generating unit.

(b) Historical monthly average fuel prices in $/MMBtu for each applicable generating unit for the last three (3) years.

(c) Average monthly heat rate by unit, including separately MMBtu's and net generation for the last three (3) years.

A-9 Financial Information

(a) Identify any and all bidder affiliates.

(b) Provide audited financial statements, if available, or other financial statements for the last three years. Such information must be provided for all entities, including affiliates involved in the transaction. For investor owned utilities, this would include as a minimum FERC Forms 1's and SEC 10K Forms. Bidders should also provide where appropriate, the most recent Dunn and Bradstreet report, a description of pending litigation, and the most recent annual report.

ATTACHMENT A

Required Data for Proposal

A-10 Pricing Information

(a) Specify on the RFP Form 4 - Proposal Pricing Form, all proposed payment components and proposed incentive amounts, if any, and the conditions which engage such provisions. FMPA requires that proposals clearly distinguish between energy-based and capacity-based pricing components. Please include all costs including: generation, planning reserves, and third party transmission costs into the FMPA system.

(b) Specify annual payment stream components, whether explicitly specified or driven by escalation factors. If price escalation factors are proposed, please identify what attribute the proposed factor is meant to represent (e.g., general inflation, general economic growth, etc.), proposed index or other source data to define the escalator (e.g., CPI, change in GDP, etc.), and bidder's current projection of the designated escalator for each applicable time period.

(c) If the energy price in the proposal is based on a "pass-through" fuel cost arrangement the bidder should provide an explanation of the relationship of energy pricing to actual fuel costs and show an example calculation. The bidder shall also include such information as: projected prices for each type of fuel used; projected annual amount of MWh contributed and MMBtu's utilized by each resource for the proposed contract period; average net heat rate (HHV) for each contributing resource; fuel transportation costs and contract information explaining how transportation costs are determined; and any information on existing fuel contracts. If any of this information is Proprietary Confidential Business Information, it shall be so indicated by the bidder and FMPA will maintain confidentiality in accordance with Section 13. If the proposed energy price is based on a contractually fixed total energy rate, the bidder shall include all information pertinent to the pricing and its escalation.

ATTACHMENT A

Required Data for Proposal

A-11 Transmission

Any bidder proposing to transmit power and energy over the facilities of a third party will be required by FMPA to provide:

(a) A detailed description of the proposed transmission and interconnection arrangements, including, but not limited to, contract path and estimated cost of such services.

(b) A description of any required new interconnection facilities and estimated costs and cost responsibility for such facilities.

(c) A description of upgrades on the FMPA system and third party transmission systems which may be required to accommodate the project and an estimate of costs.

(d) It is the responsibility of the bidder to make all necessary arrangements and bear all the associated costs of firm transmission service of the power into FMPA. Any required transmission system upgrades required to accommodate the delivery of power under the proposal is also the bidder's responsibility.

(e) Provide supporting data relating to the availability of long or short term ATC for the proposed transactions.

A-12 Additional Information

Please provide any additional information which the bidder believes will assist FMPA in an accurate and fair evaluation of the proposal.

Appendix C

Request for Proposals for Solar Photovoltaic Equipment or Power Purchase Agreement

FLORIDA MUNICIPAL POWER AGENCY

REQUEST FOR PROPOSALS
FOR
Solar Photovoltaic Equipment or Power Purchase Agreement

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002
(407) 355-7767 Fax (407) 355-5796

Request for Proposal No. 2007-106

December 2007

REQUEST FOR PROPOSALS

(This is not an order)

RETURN TO: Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819
Attn: Tom Reedy

RFP FMPA 2007-106

Date Issued: December 5, 2007

Telephone: (407) 355-7767

SEALED PROPOSALS MUST PHYSICALLY BE IN THE FLORIDA MUNICIPAL POWER AGENCY OFFICE PRIOR TO PROPOSAL OPENING AT 1:00 P.M. ON JANUARY 7, 2008, WHICH WILL BE IN THE FMPA 1ST FLOOR CONFERENCE ROOM LOCATED IN THE FMPA BUILDING AT 8553 COMMODITY CIRCLE, ORLANDO, FLORIDA 32819.

- Proposals shall be submitted along with the provided Proposer Information Form which must be manually signed.
- Proposals shall be sealed in an envelope with the proposal number, opening date, and time clearly indicated.
- Proposals received after the opening date and time will be rejected and returned unopened.
- The attached Invitation shall become part of any purchase order resulting from this Request for Proposal.

DESCRIPTION

December 2007

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR PROPOSALS FOR SOLAR PHOTOVOLTAIC EQUIPMENT OR POWER PURCHASE AGREEMENT

See attached Request for Proposal, General Conditions, Specifications, and Proposal Forms for detailed description.

It is the intent and purpose of the Florida Municipal Power Agency that this Request for Proposal promotes competitive bidding. It shall be the proposer's responsibility to advise if any language, requirements, etc. or any combination thereof, inadvertently restricts or limits the requirements stated in this Request for Proposal to a single source. Such notification must be submitted in writing and must be received by not later than ten (10) days prior to the proposal opening date.

ADVERTISEMENT

December 2007

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR PROPOSALS FOR SOLAR PHOTOVOLTAIC EQUIPMENT
OR POWER PURCHASE AGREEMENT

FMPA RFP 2007-106

Sealed proposals will be received by the Florida Municipal Power Agency (FMPA), 8553 Commodity Circle, Orlando, Florida 32819 until 1:00 p.m., January 7, 2008, when at that time Proposals will be opened publicly by a FMPA representative.

The proposal is for Solar Photovoltaic Equipment or Power Purchase Agreement as more fully described in the RFP package.

RFP packages for this project may be obtained from FMPA at the above address, by telephone (407) 355-7767, or via Internet download at *http://www.fmpa.com/html/news/rfp/2007-106.pdf*

No proposal may be altered, withdrawn, or resubmitted after the scheduled closing time for receipt of proposals. Proposals received after the day and time stated above will not be considered and will be returned to the proposer unopened.

Proposals will be accepted for Solar Photovoltaic Equipment or Power Purchase Agreement from companies who have established, through demonstrated expertise and experience that they are qualified to provide the equipment and services as specified.

The Florida Municipal Power Agency reserves the right to reject any and all proposals in total or in part and/or to waive defects in proposals.

Roger Fontes
General Manager
Florida Municipal Power Agency

FLORIDA MUNICIPAL POWER AGENCY
Request for Proposals
Solar Photovoltaic Equipment or Power Purchase Agreement

1. Introduction

Florida Municipal Power Agency (FMPA) is interested in installing solar photovoltaic (PV) power systems in several member cities. FMPA and its member cities may install as much as 100 MW over 5 years and desires to establish standard module sizes with associated mounting hardware and inverters. As an alternative, FMPA is also interested in a Power Purchase Agreement for similar amounts. As such, FMPA invites sealed responses from qualified firms for the provision of the necessary equipment and services as more fully described in Section 4.

2. FMPA Description

Formed by the Florida Legislature in February 1978, the Florida Municipal Power Agency is a non-profit, joint action agency created to serve the needs of municipal electric utilities in Florida. Of the 33 municipal systems in the State, 30 are FMPA members who participate at varying levels in Agency activities.

Member utilities of the Agency serve approximately 750,000 customers. Each member appoints one representative to the Board of Directors which governs the Agency's activities. Currently FMPA has five power supply projects and one pooled financing project. Fifteen members currently purchase all of their power requirements from the Agency (All-Requirements Project or ARP). Five members participate in other FMPA power supply projects.

3. The All Requirements Project

Under the ARP, FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either Florida Power & Light (FPL) or Progress Energy Florida (PEF). The most recent members, Kissimmee Utility Authority and the City of Lake Worth, joined the ARP in 2002. A list of ARP member cities is included as Appendix A.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in PEF's Crystal River Unit 3. A number of ARP members also participate in the FMPA St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. These nuclear resources are referred to as "Excluded Resources." The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the FMPA Stanton, Tri-City, and Stanton II Projects.

The third category of resources is participant-owned generation. Capacity included in this category is generation owned by the ARP Participants either solely or jointly. FMPA purchases this capacity from the ARP Participants and then commits and dispatches the generation as a part of the ARP portfolio of power-supply resources to meet the total requirements of the ARP.

The fourth category of resources is purchased power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP Participants, which were entered into prior to the ARP Participant joining the ARP.

4. General Description of Services Sought

FMPA is soliciting proposals for solar photovoltaic (PV) equipment (panels, inverters, and mounting hardware) for as much as 100 MW over a 5 year period. In the first year (2008), however, FMPA intends to install 10 MW of PV power systems at selected FMPA locations. FMPA is seeking a firm or a team of firms to provide cost effective PV solar power systems and establish a long term relationship with the solar PV developer. At this time and for the purpose of this RFP, the proposer should assume installing equipment in 300 - 500 kW blocks.

The Proposer has the option of providing the following proposals to FMPA:

I. Solar PV equipment only as described below or a
II. Turnkey installation or a
III. Solar purchased power contract

The selected bidder will be asked to assist FMPA to further develop the project depending on the success of the initial program.

I. Solar PV equipment:

FMPA will accept bids for solar modules, inverters, mounting hardware (ground mount and roof mount) and monitoring equipment either individually or as a package. With this proposal, installation of the PV power system would be performed by FMPA. All PV power equipment included in the proposal must have a design review and approval from the Florida Solar Energy Center (FSEC). There are no fees associated with this design and approval.

Prices for certain wind conditions i.e. 110/ 120/ 130/ 140 mph wind should be included as part of the proposal, since FMPA has not yet selected the PV sites. Prices for 500 kW roof-mount equipment assuming 110/ 120/ 130/ 140 mph wind should be provided in addition to prices for 500 kW ground-mount assuming 110/ 120/ 130/ 140 mph wind.

System warranties must be provided on the individual components. A minimum of a 5 year minimum warranty on the equipment must be provided. The method for implementing a warranty provision must be clearly established and handled by the system supplier as the single point of contact for warranty services.

Solar Module:

The preferred panel will be a crystalline panel (either single or poly crystalline) and preference will be given to this technology. Other panel technology will be evaluated against this preference. The PV modules must meet industry-accepted standards for performance, reliability, safety. Evidence to support these criteria must be contained in the supplier's System Manual, which shall include all applicable information concerning the equipment and installation. PV modules and panels must be listed and in compliance with UL standard 1703, Standard for Safety: Flat-Plate Photovoltaic Modules and Panels. PV modules must also meet or exceed IEC 61215 and any other relevant standards.

The PV equipment must be able to withstand high wind loads and potential damage from flying debris.

Inverters:

A single inverter or a cluster of inverters rated for a total output of between 300 kW and 500 kW will be preferred. The inverter(s) must be listed and in compliance with Underwriters Laboratories (UL) 1741-2005, "Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources," and all elements of the IEEE 1547 interconnection standards.

Hardware:
Both roof mount and ground mount hardware systems are desired. Generally, FMPA is interested in fixed mounts (non tracking) but will entertain responses proposing tracking systems. The system hardware must be in compliance with UL 1741.

Monitoring Equipment:

The proposal shall also include a web-based data acquisition and display system that allows FMPA to monitor, analyze and display historical and real-time solar electricity generation data for all installed sites. The system shall allow FMPA to monitor as a minimum, system performance, system availability, capacity factor and degradation.

II. Turnkey Installation:
Proposals will also be accepted for a turnkey installation. The selected bidder shall design and engineer the solar PV systems to maximize the solar energy resources at selected sites. The following outlines the general requirements of the bidder for this type of project:

- Provide and install complete PV power system
- All PV power system designs supplied for this project must have a design review and approval from the Florida Solar Energy Center (FSEC)
- Specify layout and location of the system at each site for the purpose of this bid, assume a "standard" greenhouse site conditions with no unused geotechnical or environmental issues.
- Must install similar systems and equipment at each site in order to reduce cost and improve reliability
- Interconnect to the utility grid
- Deliver, assemble and install the equipment at each site
- Conduct acceptance testing on each system and a minimum of one-hour training for each site on the operation and maintenance of the system
- Provide required documentation and System Manual
- Minimize the risk of vandalism, theft and personal injury in the installation and operation of the system
- Due to possible high wind loads and subsequent potential for damage from flying debris, all PV arrays must be securely installed to the ground or roof structure (as appropriate) as dictated by site conditions. Since FMPA has not yet selected the PV sites, the proposer should provide prices assuming 110/ 120/ 130/ 140 mph wind.
- All PV arrays should be oriented in such a way as to maximize annual energy production.

Turnkey Project System Configuration and Operational Requirements
Each PV power system covered in this RFP shall include an array of PV modules and support structures and enclosure, an inverter and associated balance-of-system (BOS) components including wiring, conduit, over current devices, surge suppression and grounding equipment, load

sub panels and metering equipment. The selected bidder shall supply all equipment, materials, permits and labor necessary to install the solar PV systems and integrate them with other power sources.

The selected bidder shall install PV modules, inverters and other components that meet the Florida Solar Energy Center Standards.

Turnkey Project Electrical Interconnections
The selected bidder shall supply and install all equipment required to interconnect the solar PV systems to the utility distribution system. The selected bidder shall fulfill all application, study, and testing procedures to complete the interconnection process. All costs associated with utility interconnection shall be borne by the selected bidder.

Monitoring
The selected bidder shall provide a turnkey data acquisition and display system that allows FMPA to monitor, analyze and display historical and live solar electricity generation data for all installed sites. The system shall allow FMPA to monitor as a minimum, system performance, system availability, capacity factor and degradation. The cost for the monitoring system shall be separately itemized.

Turnkey Project Commissioning and Acceptance Test

- During the start-up, FMPA and/or its independent engineer, shall observe and verify each system's performance.

- Required commissioning and acceptance test services includes: starting up the solar PV systems until it achieves the performance requirements and conducting the successful delivery of power within thirty days following completion of a system.

Turnkey Project Operation and Maintenance Manuals, and As-Built Drawings:
The selected bidder shall provide 2 sets of site-specific operation, maintenance, and parts manuals for each installed solar PV system. The manuals shall cover all components, options, and accessories supplied. They shall include maintenance, trouble-shooting, and safety precautions specific to the supplied equipment at that site. The bidders shall also provide 2 sets of as-built drawings in AutoCAD 14 or higher. These requirements shall be delivered prior to acceptance of the site-specific system.

Warranties and Guarantees:

System warranties must be provided on the individual components. A minimum of a 5 year minimum warranty on the equipment must be provided. The method for implementing a warranty provision must be clearly established and handled by the system supplier as the single point of contact for warranty services.

III. Purchase Power Contract:

FMPA will also accept a long-term Purchased Power Agreement ("PPA") of 10 years or longer from a 3rd party solar PV project with an option to purchase and own the project at a future date. Under a PPA, FMPA would only pay for the energy actually delivered from the project. FMPA encourages the submission of innovative contract structures and will consider other contract arrangements. FMPA will not have any preferred panel technology with a purchase power contract.

5. RFP Schedule

FMPA's timetable for this Request For Proposal (RFP) process is shown below. Note that all times shown are based on Eastern Daylight Savings time (EDT) or Eastern Standard Time (EST), as appropriate; however, the dates shown are only estimates and may be modified at any time by FMPA.

Public Notice of RFP	December 5, 2007
RFP Available for Distribution	December 5, 2007
Sealed Proposal(s) Due Date	January 7, 2008 at 1:00PM
Proposer(s) Selected	January 21, 2008
Approval and Ratification by FMPA Executive Committee	January 24, 2008

6. Notice to Proposers

Sealed responses will be received until 1:00 P.M. (Eastern time) on January 7, 2008 ("Due Date") at the offices of Florida Municipal Power Agency. Each proposer is required to submit a Proposer Information Form (included in this RFP package), and any other information necessary to allow a complete evaluation of the response. Registered respondents will be notified through the issue of RFP addenda of any change in the Proposal Due Date or other necessary revision to information contained in this RFP. This RFP and all addenda will be posted on FMPA's web site, http://www.fmpa.com/html/news/rfp/2007-106.pdf. FMPA reserves the right to reject all responses received after the Due Date.

One original and five (5) copies of the response package should be sealed and delivered to the following address:

Mr. Tom Reedy
AGM, Member Services
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

"Solar Photovoltaic Equipment or Power Purchase Agreement, FMPA RFP 2007-106" must be clearly legible on the outside of the sealed envelope.

7. Duration of Offer

Proposals submitted in response to this RFP are irrevocable for one hundred twenty (120) days following the closing date. This period may be extended at FMPA's request only by written agreement of the proposer. The content of this RFP and the proposal of the successful proposer will be included by reference in any resulting contract.

8. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

FMPA reserves the right to:

- Reject any and all responses to this RFP;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a response;
- Not select the proposal with the lowest price; and
- Seek and reflect clarifications to responses

9. Proposal Contents

Proposers are to include with their proposal a complete description of their understanding of the equipment and services requested. This description should be as definitive as possible to allow reasonable understanding and evaluation of the proposal.

The proposal should include a description of any special qualifications of the personnel who will be providing services which are indicative of working familiarity with providing the requested services and any experience with municipalities or municipal electric utilities.

Proposers should identify the specific details of how they will provide the equipment and services outlined in Section 4. The following information should be provided:

a. A listing of previous clients that have received similar equipment and services to those outlined by this RFP. The listing should include a description of the PV resource offered, the amount of capacity or energy involved, and a contact name and telephone number.

b. Firm name, description of core business services and primary client base and the name of the firm's parent company, if applicable. If the firm has an office in Florida, give the location (address and phone number) and identify the office(s) that will be assigned to this project, if appropriate. If the respondent is an affiliation of two or more independent companies, identify each company, their role in this project, and provide the information described above for each company.

c. The cost of the equipment and services bid.

d. Describe how your firm could assist FMPA and its members in refining their plans for PV capacity.

e. Describe any other value added services your firm can bring to FMPA and its members.

f. Indicate the time required to deliver the equipment or to complete the work (as appropriate) outlined in Section 4. While a specific schedule will be part of the negotiations with the top ranked firm(s), each proposer should provide a discussion, based on their knowledge of the industry, on the general time requirements.

g. Any other information that will assist FMPA in evaluating the proposal.

10. Interpretations and Addenda

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing to the following:

By Fax:	Mr. Tom Reedy (407) 355-5794
By Mail or Courier:	Mr. Tom Reedy AGM, Member Services Florida Municipal Power Agency 8553 Commodity Circle Orlando, Florida 32819
By E Mail:	tom.reedy@fmpa.com

Only written responses provided by FMPA to proposers' questions will be considered official. A verbal response by FMPA will not be considered an official response. Written responses to questions and requests for interpretations will be provided to all proposers. Copies of all addenda issued in connection with this RFP will be sent to all potential proposers and posted on FMPA's web site.

11. Errors, Modifications or Withdrawal of Proposal

Each proposer should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which should be followed by all respondents. Modifications to responses already received by FMPA will only be accepted prior to the Due Date. Responses may be withdrawn by giving written notice to FMPA prior to the Due Date.

12. Proprietary Confidential Business Information

All responses shall become property of FMPA. FMPA will not disclose to third parties any information that is clearly labeled "Proprietary Confidential Business Information" in a response unless such disclosures are required by law or by order of the court or government agency having appropriate jurisdiction. Each page of Proprietary Confidential Business Information must be clearly labeled "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" at the top of the page. FMPA reserves the right to disclose information contained in responses to its consultant(s) for the sole purpose of assisting in the proposal evaluation process. FMPA will require the consultant(s) to maintain the confidentiality of the document.

13. Proposer Qualifications

FMPA will accept responses from firms knowledgeable in providing the services desired. Proposers unfamiliar to FMPA may be required to provide proof of experience.

14. Default and Damages Provisions

FMPA will negotiate the conditions of default and damages with the successful proposer. The respondent is requested to include default and damages provisions in its proposal.

15. Evaluation Process

The responses will be evaluated based on information provided by each respondent by the Due Date. No additional data will be considered after the Due Date, except for clarifications requested by FMPA. The first stage of the evaluation process for qualified proposers will consist of a check of each proposal against the minimum requirements, as listed in this section of the RFP. All respondents that meet the minimum requirements will then be evaluated and ranked according to FMPA's interpretation of the responses submitted and FMPA's needs.

Selection and rejection of responses and notification of respondents at all stages will remain entirely within FMPA's discretion. FMPA intends to notify respondents not selected under this solicitation within a reasonable amount of time.

<u>Minimum Requirements</u>

Each response must satisfy certain minimum requirements before it will receive any further evaluation. The respondent must demonstrate in its submittal that the following minimum requirements have been met:

1) The proposer must supply a completed Proposer Information Form.

2) Information required by Section 9 (a)

3) Information required by Section 9 (b)

4) Information required by Section 9 (c)

<u>Additional Requirements</u>

In addition to the above minimum requirements, FMPA will consider all other information provided as listed in Section 9 of this RFP in the selection and ranking of the proposals.

<u>Evaluation Criteria</u>

A score will be assigned to each of the criteria described in Section 9 based on the extent to which the response satisfies FMPA's preferences. The total score will be used to determine the ranking of proposals.

16. Public Entity Crimes Statement

Pursuant to Section 287.133(2)(a), FLORIDA STATUTES, all respondents should be aware of the following:

"A person or affiliate who has been placed on the convicted vendor list following a conviction for a public entity crime may not submit a bid on a contract to provide any goods or services to a public entity, may not submit a bid on a contract with a public entity for the construction or repair of a public building or public work, may not submit bids on leases of real property to a public entity, may not be awarded or perform work as a contractor, supplier, subcontractor, or consultant under a contract with any public entity, and may not transact business with any public entity in excess of the threshold amount provided in Section 287.017, for CATEGORY TWO for a period of 36 months from the date of being placed on the convicted vendor list."

17. Collusion

By offering a submission pursuant to this Request for Proposals, the respondent certifies the respondent has not divulged, discussed, or compared his response with other respondents and has not colluded with any other respondent or parties to this response whatsoever. Also, the respondent certifies, and in the case of a joint response, each party thereto certifies, as to his own organization, that in connection with this response:

(1) Any prices and/or cost data submitted have been arrived at independently, without consultation, communication, or agreement for the purpose of restricting competition, as to any matter relating to such prices and or cost data, with any other respondent or with any competitor.

(2) Any prices and/or cost data quoted for this response have not knowingly been disclosed by the respondent and will not knowingly be disclosed by the respondent prior to the scheduled opening directly or indirectly to any other respondent or to any competitor.

(3) No attempt has been made or will be made by the respondent to induce any other person or firm to submit or not to submit a response for the purpose of restricting competition.

(4) The only person or persons interested in this response, principal or principals is/are named therein and that no person other than therein mentioned has any interest in this response or in the contract to be entered into and;

(5) No person or agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee excepting bona fide employees or established commercial agencies maintained by the Respondent for the purpose of doing business.

Appendix A

Member Cities of the All Requirements Project

Bushnell
Clewiston
Fort Meade
Fort Pierce
Green Cove Springs
Havana
Jacksonville Beach
Key West
Kissimmee
Lake Worth
Leesburg
Newberry
Ocala
Starke
Vero Beach

PROPOSER INFORMATION FORM
FMPA RFP 2007-106

_____ We DO NOT take exception to the Proposal Specifications.

_____ We TAKE exception to the Proposal Specifications as follows:

____

____

____

____

Company Name:

____

By: ____
(Authorized Person's Signature)

____
(Print or type name and title of signer)

Company Address

____

____

Telephone Number: Toll Free Number:

____

Email: ____

Fax Number: ____
Date:

Appendix D
Request for Proposals for Demand-Side Management Resources

FLORIDA MUNICIPAL POWER AGENCY

REQUEST FOR PROPOSALS
FOR
Demand Side Management Resources

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002
(407) 355-7767 Fax (407) 355-5796

Request for Proposal No. 0607D

July 2007

REQUEST FOR PROPOSALS

(This is not an order)

RFP FMPA 0607D

R
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T TO:
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Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819
Attn: Tom Reedy

Date Issued: July 27, 2007

Telephone: (407) 355-7767

SEALED PROPOSALS MUST PHYSICALLY BE IN THE FLORIDA MUNICIPAL POWER AGENCY OFFICE PRIOR TO PROPOSAL OPENING AT 1:00 P.M. ON SEPTEMBER 26, 2007, WHICH WILL BE IN THE FMPA 1ST FLOOR CONFERENCE ROOM LOCATED IN THE FMPA BUILDING AT 8553 COMMODITY CIRCLE, ORLANDO, FLORIDA 32819.

- Proposals shall be submitted on the forms provided and must be manually signed.
- Proposals shall be sealed in an envelope with the proposal number, opening date, and time clearly indicated.
- Proposals received after the opening date and time will be rejected and returned unopened.
- The attached Invitation shall become part of any purchase order resulting from this Request for Proposal.

DESCRIPTION

July 2007

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR PROPOSALS FOR DEMAND SIDE MANAGEMENT RESOURCES

See attached Request for Proposal, General Conditions, Specifications, and Proposal Forms for detailed description.

It is the intent and purpose of the Florida Municipal Power Agency that this Request for Proposal promotes competitive bidding. It shall be the proposer's responsibility to advise if any language, requirements, etc. or any combination thereof, inadvertently restricts or limits the requirements stated in this Request for Proposal to a single source. Such notification must be submitted in writing and must be received by not later than ten (10) days prior to the proposal opening date.

ADVERTISEMENT

July 2007

FLORIDA MUNICIPAL POWER AGENCY
REQUEST FOR PROPOSALS FOR DEMAND SIDE MANAGEMENT RESOURCES

FMPA RFP 0607D

Sealed proposals will be received by the Florida Municipal Power Agency (FMPA), 8553 Commodity Circle, Orlando, Florida 32819 until 1:00 p.m., September 26, 2007, when at that time Proposals will be opened publicly by a FMPA representative.

The proposal is for Demand Side Management Resources as more fully described in the RFP package.

RFP packages for this project may be obtained from FMPA at the above address, by telephone (407) 355-7767, or via Internet download at *http://fmpa.com/html/news/reg_rfp_607D.html*

No proposal may be altered, withdrawn, or resubmitted after the scheduled closing time for receipt of proposals. Proposals received after the day and time stated above will not be considered and will be returned to the proposer unopened.

Proposals will be accepted for Demand Side Management Resources from companies who have established, through demonstrated expertise and experience that they are qualified to provide the services as specified.

The Florida Municipal Power Agency reserves the right to reject any and all proposals in total or in part and/or to waive defects in proposals.

Roger Fontes
General Manager
Florida Municipal Power Agency

FLORIDA MUNICIPAL POWER AGENCY
Request for Proposals
Demand Side Management Resources

1. Introduction

The Florida Municipal Power Agency (FMPA) is interested in acquiring demand-side management (DSM) resources. For purposes of this RFP, DSM resources will include any facility, program, or service implemented for retail customers that serves to permanently reduce or shift the time of consumption of electric energy and / or electric demand. As such, FMPA invites sealed responses from qualified firms for the provision of these services as more fully described in Section 4.

2. FMPA Description

Formed by the Florida Legislature in February, 1978, the Florida Municipal Power Agency is a non-profit, joint action agency created to serve the needs of municipal electric utilities in Florida. Of the 33 municipal systems in the State, 30 are FMPA members who participate at varying levels in Agency activities.

Member utilities of the Agency serve approximately 750,000 customers. Each member appoints one representative to the Board of Directors which governs the Agency's activities. Currently FMPA has five power supply projects and one pooled financing project. Fifteen members currently purchase all of their power requirements from the Agency (All-Requirements Project or ARP). Five members participate in other FMPA power supply projects.

3. The All Requirements Project

Under the ARP, FMPA currently provides all the power requirements (above certain excluded resources) for fifteen of its members. Initially, the first five members of the ARP were non-generating utilities which had previously received all of their power requirements from full requirements contracts with either Florida Power & Light (FPL) or Progress Energy Florida (PEF). The most recent members, Kissimmee Utility Authority and the City of Lake Worth, Florida, joined the ARP in 2002. A list of ARP member cities is included as Appendix B.

Current supply side resources for the ARP are classified into four main areas, the first of which is nuclear capacity. A number of the ARP members own small amounts of capacity in PEF's Crystal River Unit 3. A number of ARP members also participate in the FMPA St. Lucie Project providing them capacity and energy from St. Lucie Unit No. 2. These nuclear resources are referred to as "Excluded Resources." The ARP provides the balance of capacity and energy requirements for the members with participation in these nuclear units. The nuclear units are considered in the capacity planning for the ARP.

The second category of resources is owned generation. This category includes generation that is solely or jointly owned by the ARP as well as ARP member participation in the FMPA Stanton, Tri-City, and Stanton II Projects.

The third category of resources is participant-owned generation. Capacity included in this category is generation owned by the ARP Participants either solely or jointly. FMPA purchases this capacity from the ARP Participants and then commits and dispatches the generation as a part of the ARP portfolio of power-supply resources to meet the total requirements of the ARP.

The fourth category of resources is purchased power. This includes power purchased directly by the ARP as well as existing purchase power contracts of individual ARP Participants, which were entered into prior to the ARP Participant joining the ARP.

4. General Description of Services Sought

FMPA solicits Proposals for demand-side management ("DSM") facilities and/or services that result in permanent reductions of electric energy usage or demand through improvements in efficiency or shifting demand away from on-peak periods to off-peak periods of existing residential, commercial, industrial, and governmental retail customers. Through this RFP, FMPA solicits demand-side proposals as alternatives to construction of new power plants. FMPA seeks a minimum contract term of at least one (1) year for each Demand Proposal, with the term beginning no earlier than June 1, 2008. Definitions for capitalized terms used herein are provided in the attached Appendix A.

This RFP is open to any Proposer who can demonstrate financial credentials appropriate to back the proposal submitted and who has demonstrated ability to provide successful DSM facilities and/or services similar to those being proposed. Proposals will be accepted from qualified third-party providers of DSM facilities and/or services ("Third-Party Proposer") and from retail customers of the ARP members ("Customer Proposer"). Proposals must be able to demonstrate that the total capacity requirements and/or the energy production and purchase power costs of the ARP will be reduced as a direct result of DSM Measures installed by Third Party Proposers in one or more retail electric customer dwellings/facilities within the electric service areas of one or more ARP members or as a direct result of DSM Measures installed by a Customer Proposer that is an electric retail customer of a ARP member.

Proposals submitted by Third Party Proposers must provide On-Peak Demand Reductions of at least 1,000 kilowatts and proposals submitted by Customer Proposers must provide On-Peak Demand Reductions of at least 500 kilowatts. Proposers can meet this requirement by adding the On-Peak Demand Reductions for all proposed DSM Measures, with appropriate adjustments for complementary effects between DSM Measures. Proposers must provide documentation of all calculations used to account for complementary effects between DSM Measures; failure to provide such documentation or failure to perform such calculations when applicable may result in the disqualification of Proposer's proposal.

Proposals submitted by Customer or Third Party Proposers must be able to demonstrate sufficient financial resources to implement the proposed DSM Measure(s). Proposals submitted by Customer Proposers also must demonstrate a firm commitment for installation of the DSM Measure at the Host Customer site. Proposals submitted by Third Party Proposers for installation of DSM Measure(s) at a single Host Customer's facility, or at a limited number of Host Customers' facilities, must be able to demonstrate a firm commitment from the Host Customer(s) for installation of the DSM Measure(s) at the Host Customer(s) site, and must also be able to demonstrate that sufficient financial resources are firmly committed from either the Third Party Provider and/or the Host Customer(s).

Proposals submitted from Third Party Proposers that intend to offer DSM Measures to the general body of retail customers of one or more of the ARP members must submit a comprehensive marketing plan by which it will inform these customers of the availability and advantages of the DSM Measures proposed. Marketing plans, at a minimum, must include: identified target market, Electric

End-Use appliance/process saturation, eligible customers, customer acceptance, DSM Measure diffusion by month and year, source and validity of market research assumptions, general marketing tactics, and sample marketing materials (where appropriate).

Proposals that fail to demonstrate sufficient financial resources of the Proposer and/or the Host Customer(s), or fail to demonstrate the existence of a firm commitment on the part of the Host Customer(s), or fail to include an adequate description of the marketing plan may be disqualified from consideration. Successful Proposers will be required to provide adequate security to ensure completion of the installation of the DSM Measure(s) by the beginning of the contract term. The installation period may be extended for Proposers proposing comprehensive DSM programs that will be offered to the general body of retail ratepayers of the ARP members, but only to the extent that such extension is in the best interest of the ARP. If a Proposer offers firm demand and energy reductions, and the Proposer fails to meet its obligations, the Proposer should be prepared to hold FMPA and its members harmless from resulting increased costs incurred by the ARP in obtaining replacement power.

The total amount of DSM Resources that the ARP may ultimately contract for as a result of this RFP will depend upon issues that may include: the relative cost-effectiveness of the Proposals submitted, technical maturity of the proposed DSM Measure(s), coincidence of demand reduction with the ARP peak demands, the complementary effect of demand and energy reductions between Proposals, market potential of DSM Measure(s), and any other factors that FMPA may identify as potentially affecting the cost-effective implementation of DSM in the ARP member systems. FMPA reserves the right to select any, all, or none of the proposals submitted under this RFP.

Even though FMPA is administering this RFP, depending on the nature of the Proposal, a successful Proposer could ultimately execute agreements for DSM facilities and/or DSM services with either FMPA and/or the ARP Member(s). Any successful Proposer may begin the installation of DSM Measures after a final agreement has been reached with FMPA and/or the FMPA Member(s) and the agreement, and a mechanism for the recovery of any costs of FMPA and/or the FMPA Member(s) related to the agreement are approved by the ARP, its members, and any other regulatory authority having jurisdiction. If any successful Proposer elects to begin any construction related to the installation of DSM Measures before the final agreement and a cost recovery mechanism have received such approval, that Proposer will assume any and all risks and liabilities associated with that construction, including but not limited to the removal, at the request of a Host Customer, of any facilities installed if such approval is denied.

Eligible DSM Measures

Proposals may be submitted for the implementation of DSM Measures in the following retail customer categories: residential, commercial, industrial, and governmental. Proposed DSM Measure(s) must affect existing Electric End-Uses. Electric End-Uses being installed in facilities which would be considered Free Riders are not eligible for proposals made in response to this RFP. All DSM Measures must be installed on the premises of the ARP members' electric retail customers. DSM Measure(s) installed outside of the ARP members' electric service territories are not eligible for this RFP.

For the purpose of this RFP, acceptable DSM Measures are those that permanently reduce the demand for electric energy by improving the electrical efficiency of an existing and on-going Electric End-Use, or by shifting existing electric loads from on-peak periods to off-peak periods. Only technologies that are normally expected to operate during On-Peak Demand hours are eligible for demand reduction payments. Any DSM Measures that reduce electric energy or demand consumption by reducing Host Customer's own production or level of operation (e.g., closing a branch office, downsizing production, etc.) are not acceptable.

Any Energy Efficiency or Load Shifting Measure that is required by law, is required by building or other codes, or in the opinion of FMPA represents standard industry practice, is not eligible.

FMPA reserves the right in its sole discretion to select the DSM Measures that will qualify for consideration. The DSM Measures must be technically proven, commercially available, and subject to measurement and verification. A maintenance and replacement plan must be submitted for any DSM Measure with a Service Life less than the length of any agreement resulting from this RFP.

Proposals ineligible for this RFP could include, but are not limited to, those that:

1. Are neither Energy Efficiency Measures nor Load Shifting Measures;
2. Include self-generation of electricity;
3. Relocate electric load to other facilities or to other utility companies;
4. Shift electric load to load provided by another fuel (e.g., electric water heater being replaced by a natural gas water heater);
5. Reduce customer's production of goods or services; or
6. Result in a loss of functional usefulness of customer equipment or facilities.

Customers currently receiving payments from ARP members for DSM Measure(s) or Programs are ineligible to participate in this RFP. For instance, a customer currently receiving incentives through an interruptible retail rate may not be included in a proposal.

5. RFP Schedule

FMPA's timetable for this Request For Proposal (RFP) process is shown below. Note that all times shown are based on Eastern Daylight Savings time (EDT) or Eastern Standard Time (EST), as appropriate; however, the dates shown are only estimates and may be modified at any time by FMPA.

Public Notice of RFP	July 27, 2007
RFP Available for Distribution	July 27, 2007
Sealed Proposal(s) Due Date	September 26, 2007
Short List of Proposers	November 5, 2007
Proposer(s) Selected	December 21, 2005
Contract Developed and Finalized	Spring, 2008

6. Notice to Proposers

Sealed responses will be received until 1:00 P.M. (Eastern time) on September 26, 2007 ("Due Date") at the offices of Florida Municipal Power Agency. Each proposer is required to submit a Proposer Information Form (included in this RFP package), other forms included in this package as appropriate, and any other information necessary to allow a complete evaluation of the qualifications of the respondent. Registered respondents will be notified through the issue of RFP addenda of any change in the Proposal Due Date or other necessary revision to information contained in this RFP. This RFP and all addenda will be posted on FMPA's web site, *http://fmpa.com/html/news/rfp.html*. FMPA reserves the right to reject all responses received after the Due Date.

One original and five (5) copies of the response package should be sealed and delivered to the following address:

Mr. Tom Reedy
AGM, Member Services
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

"Demand Side Management Resources, FMPA RFP 0607D" must be clearly legible on the outside of the sealed envelope.

7. Duration of Offer

Proposals submitted in response to this RFP are irrevocable for one hundred eighty (180) days following the closing date. This period may be extended at FMPA's request only by written agreement of the proposer. The content of this RFP and the proposal of the successful proposer will be included by reference in any resulting contract.

8. Right of Rejection

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

FMPA reserves the right to:

- Reject any and all responses to this RFP;
- Waive any requirement in this RFP;
- Not disclose the reason for rejecting a response;
- Not select the proposal with the lowest price; and
- Seek and reflect clarifications to responses

9. Proposal Contents

Proposers are to include with their proposal a complete description of their understanding of the services requested. This description should be as definitive as possible to allow reasonable understanding and evaluation of the proposal.

The proposal should include a description of any special qualifications of the personnel who will be providing services which are indicative of working familiarity with providing the requested services and any experience with municipalities or municipal electric utilities.

Proposers should identify the specific details of how they will provide the services outlined in Section 4, above. The following information should be provided:

a. A listing of previous clients that have received similar services to those outlined by this RFP. The listing should include a description of the DSM resource offered, the amount of capacity or energy involved, and a contact name and telephone number. Preference will be given to firms with demonstrated experience with Florida municipal utility clients.

b. A description of any special qualifications of the personnel to be providing services which are indicative of working familiarity with the DSM programs. Proposers should submit information documenting qualifications of all team members and the team members that have successfully designed, financed, installed, operated, and maintained similar DSM Measures. FMPA will give preference to proposals with a detailed management plan and identified technical experience and support.

c. Firm name, description of core business services and primary client base and the name of the firm's parent company, if applicable. If the firm has an office in Florida, give the location (address and phone number) and identify the office(s) that will be assigned to this project. If the respondent is an affiliation of two or more independent companies, identify each company, their role in this project, and provide the information described above for each company.

d. Describe how your firm could assist FMPA and its members in refining their plans for DSM programs.

e. Describe any value added services your firm can bring to FMPA and its members.

f. Indicate the time required to complete the work outlined in Section 4. While a specific schedule will be part of the negotiations with the top ranked firm(s), each proposer should provide a discussion, based on their knowledge of the industry, on the general time requirements.

g. Proposers must propose a minimum contract term of at least one (1) year for each Demand Proposal, with the term beginning no earlier than June 1, 2008.

h. Proposers must propose at least 1,000 kW per Proposal from Third-Party Proposers, or at least 500 kW per Proposal from Customer Proposers.

i. Each proposed DSM Measure must be either an Energy Efficiency Measure or a Load

Shifting Measure relating to an existing Electric End-Use. The Proposer must provide a comprehensive description of each DSM Measure, including:

a. Equipment, facility and installation costs for the DSM Measure;

b. Annual maintenance cost for the DSM Measure;

c. Cost to decommission existing equipment and facilities at the Host Customer's site;

d. Service life of the DSM Measure;

e. Plan and projected costs to renew or replace DSM Measure to provide at least 20 years of service;

f. The Host Customer's financial contribution to the implementation and maintenance of the DSM Measure;

g. Projected monthly demand and energy DSM reductions guaranteed by the Proposer;

h. Estimated demand reductions by hour of the day for each month over the term of the Proposal for the following day types: monthly peak day, average typical weekday, and average weekend day.

j. Proposals must include a pricing proposal, which describes the payments the Proposer expects to receive over the term of the Agreement. The pricing proposal shall include an annual capacity price in $/kW for the amount of reduced demand. The pricing proposal shall also include an annual energy price in $/MWh for the amount of reduced energy. The proposed demand and energy pricing should be net of any retail rate savings that the Host Customer(s) may receive that result from the demand and energy reductions. The pricing proposal shall include a description of how the results obtained from the Measurement and Verification Plan ("M&V Plan") will be used to adjust payments made to the Proposer over the term of the proposal. Additionally, the Proposal shall include an assessment of costs to be incurred by the Host Customer for the implementation of the DSM Measure(s). Documentation of the derivation of the Host Customer costs shall be included with all Proposals. These costs will be used in the economic evaluation of the Proposal. FMPA desires proposals that link the timing of payments to the timing of value received by the ARP.

k. Proposals must include an effective Measurement and Verification Plan ("M&V Plan") that will provide the basis for determining the level of demand and energy reductions produced as a result of the DSM Measure implementations. The M&V Plan shall fully describe all calculations and procedures that will be used to determine demand and energy reductions, including, but not limited to: engineering estimates; auditing procedures; pre- and post-installation metering facilities and monitoring and recording procedures; quality assurance procedures; weather adjustments; and any other assumptions or measurements proposed by the Proposer. Additionally, the Proposer shall describe how each of the following factors are addressed by the M&V Plan: Free Riders (as defined in

Appendix A), Free Drivers (as defined in Appendix A), Persistence of reductions, consumption rebound, state and federal efficiency standards and codes, diversity of demand reductions, coincidence with on-peak demands, naturally occurring conservation, degradation of DSM Measure efficiency, age of existing equipment/facilities to be affected by the DSM Measure(s), and projected demand and energy impacts of the existing facilities over the term of the proposal. The Proposer will be expected to submit an annual report on demand and energy reductions, which are calculated consistent with the M&V Plan, prior to receipt of any demand and energy payments to be made by FMPA.

l. Proposals that intend to offer DSM Measures or programs to the general body of retail customers of one the FMPA Members must submit a comprehensive marketing plan. The marketing plan must demonstrate how retail customers will be informed of the availability and advantages of the DSM programs. Marketing plans, at a minimum, must include: identified target market, Electric End-Use appliance/process saturation, eligible customers, customer acceptance, DSM Measure diffusion by month and year, source and validity of market research assumptions, general marketing tactics, and sample marketing materials (where appropriate). Marketing plans that are well researched and documented will be preferred. The marketing plan should demonstrate that there is sufficient market potential to achieve the proposed participation levels and demand and energy reductions. In addition, FMPA will consider the Proposer's plans for penetrating the market, including service area coverage and strategies that are appropriate for the Electric End-Use sector targeted, marketing plans that have been used successfully by the Proposer in previous efforts to market DSM Measures, and marketing plans that clearly describe how all elements of the proposal can be delivered.

m. The financing plan contained in a Proposal is an indicator of whether the project will be adequately funded and thus completed. Information concerning the financing of the proposal should be provided for all Proposals.

10. Interpretations and Addenda

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing to the following:

By Fax:	Mr. Tom Reedy (407) 355-5794
By Mail or Courier:	Mr. Tom Reedy AGM, Member Services Florida Municipal Power Agency 8553 Commodity Circle Orlando, Florida 32819
By E Mail:	tom.reedy@fmpa.com

Only written responses provided by FMPA to proposers' questions will be considered official. A verbal response by FMPA will not be considered an official response. Written responses to questions and requests for interpretations will be provided to all proposers. Copies of all addenda issued in connection with this RFP will be sent to all potential proposers and posted on FMPA's web site.

11. Errors, Modifications or Withdrawal of Proposal

Each proposer should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which should be followed by all respondents. Modifications to responses already received by FMPA will only be accepted prior to the Due Date. Responses may be withdrawn by giving written notice to FMPA prior to the Due Date.

12. Proprietary Confidential Business Information

All responses shall become property of FMPA. FMPA will not disclose to third parties any information that is clearly labeled "Proprietary Confidential Business Information" in a response unless such disclosures are required by law or by order of the court or government agency having appropriate jurisdiction. Each page of Proprietary Confidential Business Information must be clearly labeled "PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION" at the top of the page. FMPA reserves the right to disclose information contained in responses to its consultant(s) for the sole purpose of assisting in the proposal evaluation process. FMPA will require the consultant(s) to maintain the confidentiality of the document.

13. Proposer Qualifications

FMPA will accept responses from firms knowledgeable in providing the services desired. Proposers unfamiliar to FMPA may be required to provide proof of experience.

14. Default and Damages Provisions

FMPA will negotiate the conditions of default and damages with the successful proposer. The respondent is requested to include default and damages provisions in its proposal.

15. Evaluation Process

The responses will be evaluated based on information provided by each respondent by the Due Date. No additional data will be considered after the Due Date, except for clarifications requested by FMPA. The first stage of the evaluation process for qualified proposers will consist of a check of each proposal against the minimum requirements, as listed in this section of the RFP. All respondents that meet the minimum requirements will then be evaluated and ranked according to FMPA's interpretation of the responses submitted and FMPA's needs.

Selection and rejection of responses and notification of respondents at all stages will remain entirely within FMPA's discretion. FMPA intends to notify respondents not selected under this solicitation within a reasonable amount of time.

Minimum Requirements

Each response must satisfy certain minimum requirements before it will receive any further evaluation. The respondent must demonstrate in its submittal that the following minimum requirements have been met:

1) The proposer must supply a completed Proposer Information Form.

2) Information required by Section 9 (a)

3) Information required by Section 9 (c)

4) Information required by Section 9 (j)

5) Information required by Section 9 (k)

Additional Requirements

In addition to the above minimum requirements, FMPA will consider all other information provided as listed in Section 9 of this RFP in the selection and ranking of the proposals.

Evaluation Criteria

A score will be assigned to each of the criteria described in Section 9 based on the extent to which the response satisfies FMPA's preferences. The total score will be used to determine the ranking of proposals.

14. Public Entity Crimes Statement

Pursuant to Section 287.133(2)(a), FLORIDA STATUTES, all respondents should be aware of the following:

"A person or affiliate who has been placed on the convicted vendor list following a conviction for a public entity crime may not submit a bid on a contract to provide any goods or services to a public entity, may not submit a bid on a contract with a public entity for the construction or repair of a public building or public work, may not submit bids on leases of real property to a public entity, may not be awarded or perform work as a contractor, supplier, subcontractor, or consultant under a contract with any public entity, and may not transact business with any public entity in excess of the threshold amount provided in Section 287.017, for CATEGORY TWO for a period of 36 months from the date of being placed on the convicted vendor list."

15. Collusion

By offering a submission pursuant to this Request for Proposals, the respondent certifies the respondent has not divulged, discussed, or compared his response with other respondents and has not colluded with any other respondent or parties to this response whatsoever. Also, the respondent certifies, and in the case of a joint response, each party thereto certifies, as to his own organization, that in connection with this response:

(1) Any prices and/or cost data submitted have been arrived at independently, without consultation, communication, or agreement for the purpose of restricting competition, as to any matter relating to such prices and or cost data, with any other respondent or with any competitor.

(2) Any prices and/or cost data quoted for this response have not knowingly been disclosed by the respondent and will not knowingly be disclosed by the respondent prior to the scheduled opening directly or indirectly to any other respondent or to any competitor.

(3) No attempt has been made or will be made by the respondent to induce any other person or firm to submit or not to submit a response for the purpose of restricting competition.

(4) The only person or persons interested in this response, principal or principals is/are named therein and that no person other than therein mentioned has any interest in this response or in the contract to be entered into and;

(5) No person or agency has been employed or retained to solicit or secure this contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee excepting bona fide employees or established commercial agencies maintained by the Respondent for the purpose of doing business.

16. *Subcontracted Services*

Proposer's response should indicate which, if any, of the services to be provided would be subcontracted by the consultant to independent contractors.

17. Final Contract

Any final contract(s) that result from the response evaluation and negotiation process will be submitted to the Executive Committee of FMPA for approval. It is anticipated that any contract(s) will be approved during the Spring of 2008.

18. Permits and Licenses

Successful proposer(s) will be required to provide proof of any licenses and permits required by Federal, State, or local law or ordinance.

Appendix A

DSM-Related Definitions

Bid Price - the stream of annual payments proposed by Proposer to be paid for Contract DSM Resources.

Customer Proposer — An ARP member customer submitting a proposal to provide DSM Resources that will be completely installed in facilities receiving electric service from an ARP member and owned, operated, or leased by the customer.

Demand-Side Management (DSM) or DSM Measures — Technologies or measures designed to reduce or control the consumption of electricity by Host Customers.

DSM Resources — Demand reductions measured in kilowatts (kW) and associated energy reductions measured in kilowatt-hours (kWh) resulting from the installation of DSM Measures.

DSM Resources Security — Security given by Proposer to ensure that Contract DSM Resources are installed, operational, and verified as operational.

Electric End Use — The result or product of the application of electric energy, including irrigation, refrigeration, lighting, space cooling, space heating, dehumidification, air compression, pumping, curing, drying, heating, melting, cooling, and refining.

Energy Efficiency Measure — A measure that improves the electric efficiency of an existing and on-going Electric End-Use.

Free Driver — Retail customers who undertake DSM activities on their own without participating in a DSM program.

Free Riders — Host Customers that participate in a DSM program implemented by a Proposer who would have undertaken a DSM Measure even if they were not provided an incentive to participate in the Proposer's DSM program.

Host Customer — A retail customer, served by one of the ARP's members, at whose facilities Proposer installs DSM Measures.

Load Shifting Measure — A DSM Measure that shifts existing electrical loads from on-peak periods to off-peak periods.

On-Peak Demand — Integrated hourly demands occurring on week days in the months of June through October, between the hours of 7 AM to 11 PM p.m. EPT.

On-Peak Demand Reductions — The average of the demand reduction during the above-noted On-Peak Demand periods.

Persistence — A measure of the level of demand or energy savings degradation over the life of a DSM measure. Persistence is a function of both consumer behavior and equipment efficiency degradation.

Service Life — The useful life of a DSM Measure installed by a Proposer.

Third Party Proposer — An energy service company or other entity, other than a Customer Proposer, that submits a proposal to provide DSM measures for one or more of the ARP's members' customers.

Appendix B

Member Cities of the All Requirements Project

Bushnell
Clewiston
Fort Meade
Fort Pierce
Green Cove Springs
Havana
Jacksonville Beach
Key West
Kissimmee
Lake Worth
Leesburg
Newberry
Ocala
Starke
Vero Beach

STATEMENT OF NO RESPONSE

General Manager
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819

We, the undersigned, have declined to submit a proposal on your Request for Proposals Number 0607D, September 26, 2007, FLORIDA MUNICIPAL POWER AGENCY DEMAND SIDE MANAGEMENT RESOURCES - for the following reasons:

______We do not offer this service/product.
______Our schedule would not permit us to perform.
______Unable to meet specifications.
______Unable to meet bond requirements.
______Other

Company Name:

By:
(Authorized Person's Signature)

____
(Print or type name and title of signer)

Company Address:

Telephone Number:

Toll Free Number:

Fax Number:

Date:

PROPOSER INFORMATION FORM
FMPA RFP 0607D

_____ We DO NOT take exception to the Proposal Specifications.

_____ We TAKE exception to the Proposal Specifications as follows:

Company Name:

By: ____________________
(Authorized Person's Signature)

____
(Print or type name and title of signer)

Company Address

Telephone Number: Toll Free Number:

Email: ____________________

Fax Number:

Date: