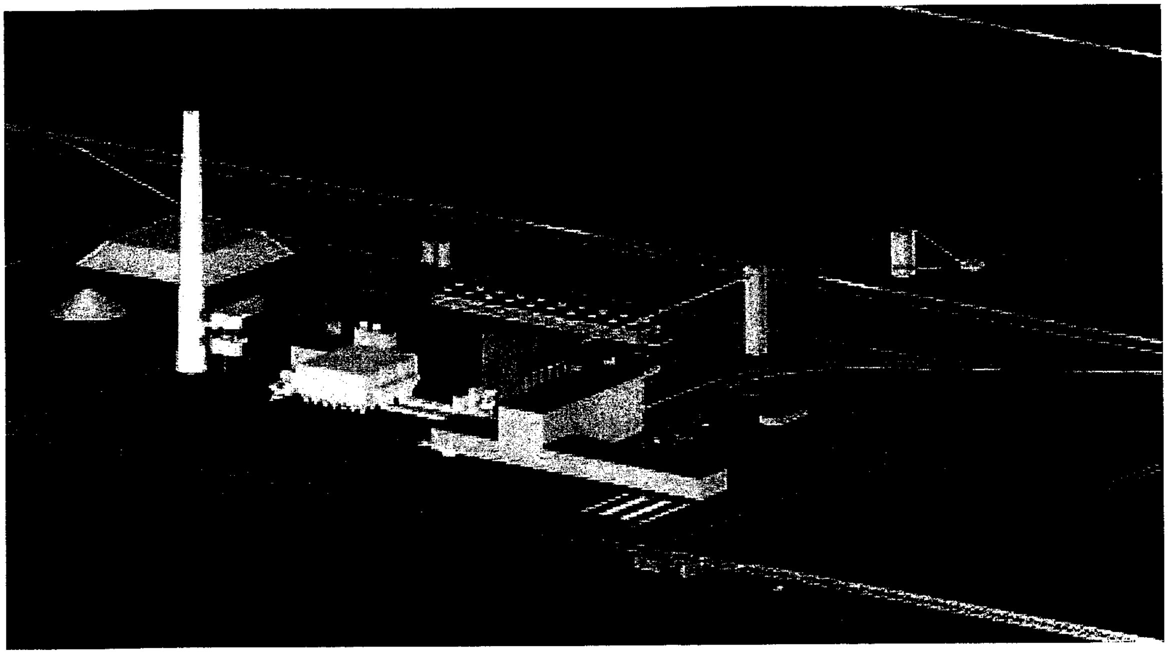
Florida Electrical Power Plant Siting Act
Need for Power Application

Taylor Energy Center

060635-EU



Submitted by:

Florida Municipal Power Agency

JEA

Reedy Creek Improvement District

City of Tallahassee

September 2006

Volume B

Florida Municipal Power Agency

JEA

REEDY CREEK
IMPROVEMENT DISTRICT

City of Tallahassee
Your Own Utilities℠

Prepared by:

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Abbreviations

AFUDC	Allowance for Funds Used During Construction
ARP	All-Requirements Project
ASD	Adjustable Speed Drive
Beaches	Beaches Energy Services
Beck	R. W. Beck, Inc.
C&E	Capacity and Energy
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CDD	Cooling Degree-Days
CFB	Circulating Fluidized Bed
CHP	Clearing House Prices
CO_2	Carbon Dioxide
COP	Coeffiency of Performance
CPWC	Cumulative Present Worth Cost
CROD	Contract Rate of Delivery
CT	Combustion Turbine
DSM	Demand-Side Management
DWH	Domestic Water Heater
DX	Direct Exchange
EER	Energy Efficiency Ratio
EF	Energy Factor
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
FGD	Flue Gas Desulfurization
FGT	Florida Gas Transmission Company
FIRE	Florida Integrated Resource Evaluator
FKEC	Florida Keys Electric Cooperative Association
FMPA	Florida Municipal Power Agency
FMPP	Florida Municipal Power Pool
FPL	Florida Power & Light
FPSC	Florida Public Service Commission
FPUA	Fort Pierce Utilities Authority
FRCC	Florida Reliability Coordinating Council
FTS	Firm Transportation Service
GDP	Gross Domestic Product

GE	General Electric
GRU	Gainesville Regional Utilities
GS	General Service
GSD	General Service Demand
GSLD	General Service Large Demand
HDD	Heating Degree-Days
HVAC	Heating, Ventilation, and Air Conditioning
IGCC	Integrated Gasification Combined Cycle
KEYS	Keys Energy Services
KUA	Kissimmee Utility Authority
LOLP	Loss of Load Probability
LWU	Lake Worth Utilities
MEF	Modified Energy Factor
NEL	Net Energy for Load
NO_x	Nitrogen Oxide
O&M	Operations and Maintenance
OEU	Ocala Electric Utility
OUC	Orlando Utilities Commission
PEF	Progress Energy Florida
petcoke	Petroleum Coke
PR	Partial Requirements
PRB	Powder River Basin
RCID	Reed Creek Improvement District
SCR	Selective Catalytic Reduction
SECI	Seminole Electric Cooperative
SEER	Season Energy Efficiency Ratio
SO_2	Sulfur Dioxide
Southern	Southern Power Company
TCEC	Treasure Coast Energy Center
TEC	Taylor Energy Center
TECO	Tampa Electric Company
WESP	Wet Electrostatic Precipitator
Woods & Poole	Woods & Poole Economics, Inc

B.1.0 FMPA Introduction

B.1.1 Florida Municipal Power Agency (FMPA) Overview

FMPA is a wholesale power company comprising 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 Project (ARP) to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the entire needs of the 15 ARP members. The total available summer net capability to meet ARP member demand is 1,753 MW, and the total available winter net capability is 1,827 MW in the near term.

Under the ARP structure, FMPA agrees to meet all of its members' power requirements. To secure sufficient capacity and energy, FMPA forecasts each ARP member's loads on an individual basis and integrates the results into a forecast of electrical power demand and energy consumption for the entire ARP. FMPA is a summer peaking system and expects significant growth during the forecast period. The firm summer peak demand is projected to increase from 1,467 MW in 2006 to 1,909 MW in 2024, and the firm winter peak is projected to increase from 1,427 MW in 2006 to 1,821 MW in 2024. These projections include the anticipated impact of Vero Beach's Notice of Establishment of Contract Rate of Delivery (CROD), effective January 1, 2010 (refer to Section B.3.3).

FMPA serves the capacity and energy requirements of its ARP members through five FMPA generation projects, existing member generation resources, and various capacity and power purchase agreements. Section B.2.2 provides a description of these resources. The total summer generating capacity presently available to FMPA is 1,753 MW. The total winter generating capacity presently available to FMPA is 1,827 MW. Most of this existing generation is fueled with natural gas or oil. Current projections indicate that 252 MW of ARP member generating capacity will be retired during the 30 year period of this analysis. Additionally, Vero Beach's generating resources will not be available to FMPA beginning January 1, 2010, coincident with Vero Beach's CROD notice. Section B.4.0 documents FMPA's projected need for capacity, taking into account the forecasted demand and the anticipated available capacity resources.

Taylor Energy Center (TEC) is being proposed as a joint development project by four municipal entities, including FMPA, JEA, Reedy Creek Improvement District (RCID), and the City of Tallahassee (collectively, the Participants). The Participants are developing TEC to realize the benefits associated with the economies of scale inherent in constructing and operating a large power plant. TEC will be developed on a site consisting of approximately 3,000 acres, to be located approximately 5 miles southeast of

Perry, in Taylor County, Florida. The land is bordered by Highway 27 on the north and the Fenholloway River on the west. The plant is proposed to be a 765 MW (net) supercritical pulverized coal unit with a net heat rate of 9,238 Btu/kWh when firing a blend of Latin American coal and petroleum coke (petcoke). Additional details regarding TEC are included in Section A.3.0 of this Application. FMPA's ownership interest in TEC will be 38.9 percent, or about 298 MW (net at average ambient operating conditions).

In addition to providing a reliable, cost-effective resource to meet FMPA's growing electric capacity and energy needs, TEC will provide additional benefits to the State of Florida. The project will use proven supercritical boiler technology and advanced pollution control equipment to limit emissions, while burning a variety of solid fuels including Powder River Basin (PRB) coal (which has the largest coal reserves of any region within the United States), as well as Central Appalachian coals, Latin American coals, and petcoke. TEC will provide FMPA and the other Participants with fuel diversity. The State of Florida will benefit from having the ability to source fuel from locations outside the hurricane-susceptible natural gas producing regions within the Gulf Coast. In addition, FMPA's customers will have access to an energy supply source with less price volatility than natural gas, which should help electric energy rates become more stable and predictable over time.

B.1.2 FMPA Summary

Information specific to FMPA is included in this Volume B. The remainder of Volume B of this Application is comprised of nine additional sections:

- Section B.2.0 - Description of FMPA's Existing System.
- Section B.3.0 - Forecast of FMPA's Electrical Demand and Consumption.
- Section B.4.0 – FMPA's Need for Capacity.
- Section B.5.0 – FMPA's Economic Analysis.
- Section B.6.0 – FMPA's Sensitivity Analyses.
- Section B.7.0 – FMPA's Demand-Side Management.
- Section B.8.0 – FMPA's Strategic Considerations.
- Section B.9.0 – FMPA's Consequences of Delay.
- Section B.10.0 – FMPA's Financial Analysis.

The information and analyses presented throughout this Volume B and the complete Application demonstrate that the proposed TEC satisfies the requirements set forth in Section 403.519, Florida Statutes. In particular, TEC is the most cost-effective alternative available to FMPA to satisfy forecast capacity requirements in a reliable, environmentally responsible manner. TEC will provide FMPA, and the State of Florida as a whole, with increased fuel diversity and supply reliability. In selecting TEC as a generating resource, FMPA considered all reasonable conservation and demand-side management (DSM) measures available beyond its existing portfolio of energy conservation offerings, and none were found that could cost-effectively defer TEC.

B.2.0 Description of FMPA's Existing System

B.2.1 FMPA Structure

FMPA is a wholesale power company comprised 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 ARP to secure an adequate, economical, and reliable supply of electric capacity and energy to meet the entire needs of the 15 ARP members.

B.2.1.1 Background

FMPA was created to provide a means by which 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 needs of the ARP members. ARP members, both with and without their own generating capacity, are required to purchase all of their capacity and energy from the ARP. ARP members with their own generating capacity are required to sell the electric capacity and energy of their generating resources to FMPA. In exchange for the sale of their electric capacity and energy, the generating members receive capacity and energy (C&E) payments from ARP members.

FMPA was created on February 24, 1978, by the signing of the Interlocal Agreement among its original members. This agreement specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution; the Joint Power Act, 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 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 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 of developing and approving FMPA's budget, 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, Treasurer, and an Executive Committee. The Executive Committee consists of 13 representatives, which include nine elected by the Board, the current Board Chairman, Vice Chairman, Secretary, and Treasurer. The Executive Committee meets regularly to control FMPA's day-to-day operations and to approve expenditures and contracts. The Executive Committee is also responsible for monitoring budgeted expenditure levels and ensuring that authorized work is completed in a timely manner.

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 C&E sales contract.

In general, members of the ARP 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 the members' ownership share of Crystal River 3 and St. Lucie 2. Generating members get reimbursements in the form of credits for their capacity contributions to the ARP. Once a municipal utility has joined the ARP, a contract is signed for a term of approximately 30 years, and this contract is automatically renewed unless the member elects otherwise.

B.2.1.2 ARP Members

Bushnell

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

Clewiston

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

Fort Meade

The City of Fort Meade is located in central Florida in Polk County. The City joined the ARP in February 2000. The City's service area is approximately 5 square miles. FMPA serves 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. FPUA's service area is approximately 35 square miles.

Green Cove Springs

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

Town of Havana

The Town of Havana is located in the panhandle of Florida in Gadsden County. The Town joined the ARP in July 2000. The Town's 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 and St. Johns Counties. Beaches joined the ARP in May 1986. Beaches' service area is approximately 45 square miles.

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. KEYS' 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. KUA's 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. Lake Worth's service area is 12.5 square miles.

Leesburg

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

Newberry

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

Ocala

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

Starke

Starke is located in north Florida in Bradford County. The City joined the ARP in October 1997. The City's 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. Vero Beach joined the ARP in June 1997. The City's service area is approximately 40 square miles.

On December 9, 2004, the City of Vero Beach sent FMPA its Notice of Establishment of Contract Rate of Delivery. The effect of the notice is that the ARP will no longer utilize the City's generating resources, and the ARP will commence serving Vero Beach on a partial requirements basis. The effective date of the notice is January 1, 2010. Since the City's generating resources are approximately the same as its forecast load when the CROD becomes effective, the effect on FMPA is not considered significant.

B.2.1.3 ARP Member City Locations

Figure B.2-1 shows the ARP member city locations.

B.2.2 FMPA Generation Projects

B.2.2.1 Overview of Existing Generation Projects

FMPA has five power supply projects in operation: (i) St. Lucie Unit No. 2 (the St. Lucie Project), (ii) the Stanton Project, (iii) the Tri-City Project, (iv) the Stanton II Project, and (v) the ARP.

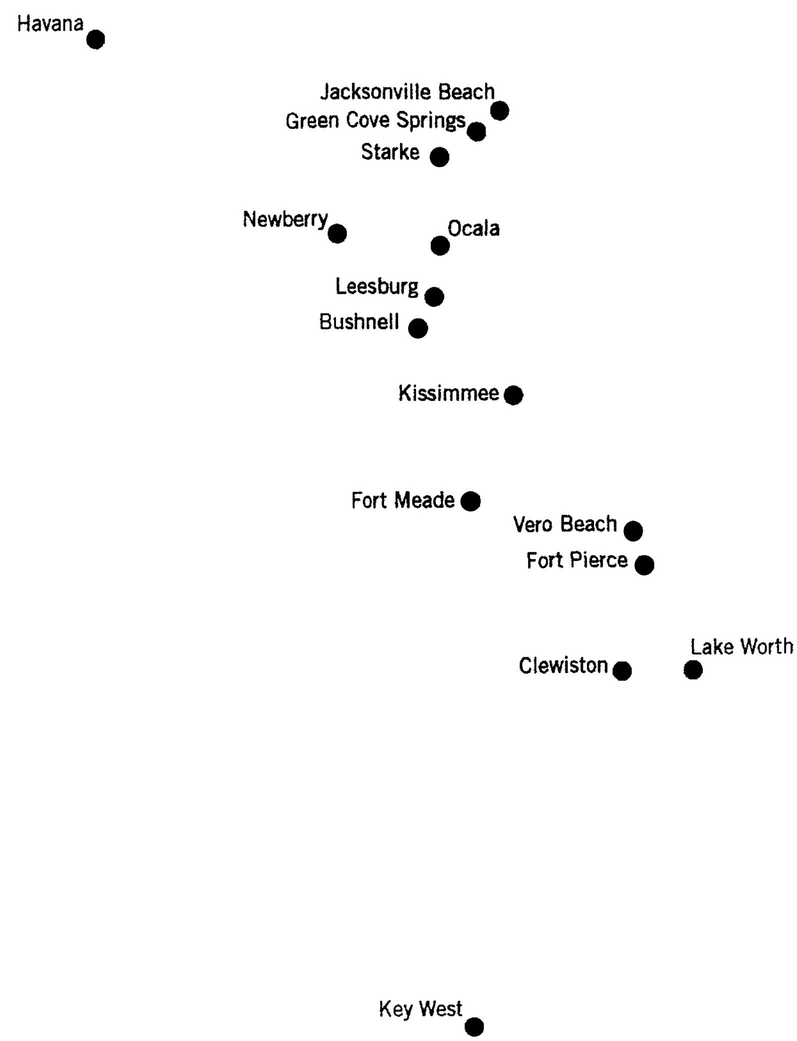

Figure B.2-1
ARP Member Cities

B.2.2.1.1 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 No. 2 (the St. Lucie Project), a nuclear generating unit. St. Lucie Unit No. 2 was declared in commercial operation on August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of FMPA's members are participants in the St. Lucie Project, with the following entitlements as shown in Table B.2-1.

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

B.2.2.1.2 Stanton Project. On August 13, 1984, FMPA purchased from the Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton Unit No. 1 (the Stanton Project). Stanton Unit No. 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 B.2-2.

Table B.2-2 Stanton Project Participants			
City	Percent Entitlement	City	Percent Entitlement
Fort Pierce	24.390	Homestead	12.195
Kissimmee	12.195	Lake Worth	16.260
Starke	2.439	Vero Beach	32.521

B.2.2.1.3 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 No. 1. Three of FMPA's members are participants in the Tri-City Project, with the following entitlements as shown in Table B.2-3.

Table B.2-3
Tri-City Project Participants

City	Percent Entitlement
Fort Pierce	22.727
Homestead	22.727
Key West	54.546

B.2.2.1.4 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 No. 2, a coal fired unit virtually identical to Stanton Unit No. 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 B.2-4.

Table B.2-4
Stanton II Project Participants

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

B.2.2.1.5 ARP. As previously discussed, under the ARP, FMPA currently serves all the power requirements (above certain excluded resources) for 15 of its members. Bushnell, Green Cove Springs, Jacksonville Beach, Leesburg, and Ocala were the original ARP members. Clewiston joined in 1991. In 1997, the cities of Vero Beach and Starke joined the ARP. In 1998, FPUA and Key West joined the ARP. The City of Fort Meade, the Town of Havana, and the City of Newberry joined in 2000. In 2002, KUA and Lake Worth joined the ARP. Vero Beach has provided notice to FMPA to establish a CROD effective January 1, 2010.

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 No. 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 the capacity and energy from these units. 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.

B.2.2.2 Unit Retirements

FMPA has identified certain member units that will be retired because of their age and inefficiency. These units will be considered retired in this Application as summarized in Table B.2-5.

Table B.2-5
FMPA Planned Retirements

Unit Identification	Retirement Date	Capacity Retired (MW)	Annual Capacity Retired (MW)
Key West Big Pine Diesel	7/1/2006	3	
Key West Cudjoe Diesel 2 and 3	7/1/2006	4	7
Ft. Pierce Unit 7	5/1/2008	24	
Ft. Pierce Unit 8	5/1/2008	50	
Ft. Pierce Combined Cycle	5/1/2008	31	
Ft. Pierce D1 and 2	5/1/2008	5	110
Hansel Combined Cycle	12/1/2011	48	48
Lake Worth Unit 3	6/1/2012	22	
Lake Worth Unit 5	6/1/2012	8	
Lake Worth GT 1	6/1/2012	26	
Lake Worth GT 2	6/1/2012	20	
Lake Worth D1-5	6/1/2012	10	87
Total Retirements		252	

B.2.2.3 ARP Power Supply Resources

The ARP existing, approved, and currently planned resource capacity is presented in Table B.2-6. Treasure Coast Energy Center (TCEC) Unit 1 is an approved capacity addition that will be located near Fort Pierce, with commercial operation planned for June 2008. TCEC Unit 1 is a 1x1 combined cycle with a GE 7FA combustion turbine (CT). The unit is forecasted to have a summer capacity of approximately 296 MW, and is included in Table B.2-6 beginning summer 2008. TCEC received Site Certification from the Governor and Cabinet in May 2006.

FMPA's current capacity plan prior to the installation of TEC calls for the installation of two additional CT units identical to Stock Island Unit 4, as shown in Table B.2-6. For purposes of this analysis, these combustion turbine units are assumed to be in service on June 1, 2010, and are therefore included as capacity resources beginning summer 2010.

B.2.2.4 Capacity and Power Purchase Contracts

The current system firm power supply purchase resources of the ARP include purchases from PEF, FPL, OUC, Lakeland Electric, Gainesville Regional Utilities (GRU), Calpine, Southern Company-Florida, LLC, and Southern Power Company. The power purchase contracts are briefly summarized below:

- PEF:
  - FMPA has a power contract with PEF for 40 MW in 2006, 30 MW in 2007 and 2008, 60 MW in 2009, and 40 MW in 2010. The nominated capacity can be adjusted annually and also includes reserves.
- FPL:
  - FMPA has two contracts with FPL, including a short-term 75 MW purchase through 2007 and a long-term 45 MW purchase until June 2013. The FPL short- and long-term purchases include reserves.
- OUC:
  - FMPA has a 22 MW purchase in 2006 with the OUC Indian River plant, which expires thereafter.
- Lakeland Electric:
  - FMPA has a 100 MW contract with Lakeland Electric that expires in 2008.

Table B.2-6
ARP's Existing and Approved/Planned Resource Capacity[(1)]

Generating Resources	Summer Rating								
	2006	2007	2008	2009	2010	2011	2012	2013	2014-2035
Excluded Resources (Nuclear)[(2)]	84	83	83	83	72	72	72	72	72
Stanton Coal Plant[(2)]	224	224	224	224	186	186	186	186	186
Stanton Combined Cycle Unit A[(3)]	42	42	42	42	42	42	42	42	42
Cane Island 1-3	388	388	388	388	388	388	388	388	388
Indian River CTs	82	82	82	82	82	82	82	82	82
Key West Units 2 and 3	31	31	31	31	31	31	31	31	31
Ft. Pierce Native Generation	110	110	0	0	0	0	0	0	0
Key West Native Generation	41	41	41	41	41	41	41	41	41
Kissimmee Native Generation	48	48	48	48	48	48	0	0	0
Lake Worth Native Generation	87	87	87	87	87	87	0	0	0
Vero Beach Native Generation	137	137	137	137	0	0	0	0	0
Stock Island Unit 4	42	42	42	42	42	42	42	42	42
Treasure Coast Energy Center	0	0	296	296	296	296	296	296	296
New Peaking Capacity	0	0	0	0	84	84	84	84	84
Total Generating Capacity[(4)]	1,313	1,313	1,499	1,499	1,397	1,397	1,264	1,264	1,264
Purchased Power									
PEF Partial Requirements	40	30	30	60	40	0	0	0	0
FPL Long-Term Partial Requirements	45	45	45	45	45	45	45	0	0
FPL Partial Requirements	75	75	0	0	0	0	0	0	0
OUC Indian River Purchase	22	0	0	0	0	0	0	0	0
Starke (Gainesville Regional Utilities [GRU])	3	0	0	0	0	0	0	0	0
Lakeland Purchase	100	100	0	0	0	0	0	0	0
Calpine Purchase	75	100	100	100	0	0	0	0	0
Stanton A Purchase[(5)]	80	80	80	80	80	80	80	80	0
Southern Power Company Power Purchase Agreement	0	0	157	157	157	157	157	157	157
Total Purchased Power Resources[(4)]	439	430	412	442	322	282	282	237	157
Total Resources[(4)]	1,753	1,742	1,910	1,940	1,719	1,679	1,545	1,500	1,421

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

- GRU:
  - FMPA has a 3 MW contract with GRU through 2006.
- Calpine:
  - FMPA has a contract with Calpine for 75 MW in 2006, and increases to 100 MW for 2007 through 2009.
- Southern Company-Florida, LLC:
  - FMPA has a contract for 80 MW of purchase power (including KUA's purchase share) from Stanton A that extends through 2013 for the initial term and has multiple 5-year extension options.
- Southern Power Company:
  - FMPA has a contract to purchase 157 MW of new peaking power from Southern Power Company's Oleander plant beginning in December 2007. The purchase has a term of 20 years.

B.2.2.5 Florida Municipal Power Pool (FMPP)

The FMPP is a power pool comprised 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.

B.2.3 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.

C&E resources for the ARP are transmitted to the 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.

B.2.3.1 Existing Transmission System

B.2.3.1.1 FPUA. FPUA is a municipally owned utility operating electric, water, wastewater, and natural gas utilities. The electric utility operates an internal, looped 69 kV transmission system for system load and a 118 MW local power generating plant. 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 that is operated and maintained by FPUA. County Line Substation is connected by two separate, single-circuit, 138 kV transmission lines to FPL's Emerson Substation and the City of Vero Beach's South Substation. County Line Substation and the connecting lines to Emerson and South Substations are operated by the City of Vero Beach. 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.

B.2.3.1.2 KEYS. KEYS owns, operates, and maintains an electric generation, transmission, and distribution system, which 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 FKEC's Tavernier and the Florida City Substation at the Dade/Monroe county line. KEYS owns and operates a 49.2 mile long 138 kV transmission line from Marathon Substation to KEYS' Stock Island Substation. The line loops in and out of KEYS' Big Pine and Big Coppitt Substations. 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 kV and 4.16 kV to its distribution system. KEYS owns approximately 227 miles of 13.8 kV and 2 miles of 4.16 kV distribution line.

B.2.3.1.3 Lake Worth. The City of Lake Worth Utilities (LWU) owns, operates, and maintains an electric generation, transmission, and distribution system, which supplies electric power and energy in and around the City of Lake Worth. The total generating capability, located at the Tom G. Smith power generating plant, is rated at approximately

86 MW. LWU has one 138 kV interconnection with FPL at the LWU-owned Hypoluxo Switching Station. A 3 mile, 138 kV transmission line connects the Hypoluxo Switching Station to LWU's Main Plant Substation. In addition, a 2.4 mile, 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, and one 138/26 kV autotransformer is located at Canal Substation. The utility operates an internal 26 kV subtransmission system to serve system load.

B.2.3.1.4 KUA. KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to nine distribution substations. KUA serves a total area of approximately 85 square miles. KUA owns and operates 22 miles of 230 kV and 41 miles of 69 kV transmission lines. KUA and FMPA jointly own 21.4 miles of 230 kV lines out of Cane Island Power Park. KUA has direct transmission interconnections with (1) PEF at PEF's 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 Cane Island Substation; and (3) the City of St. Cloud at KUA's 69 kV Carl A. Wall Substation.

B.2.3.1.5 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 230 kV and 48 miles of 69 kV transmission line, 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 and SEC's Silver Springs to Silver Springs North 230 kV tie lines. OEU's Dearmin Substation ties at PEF's Silver Springs Substation, 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 operates a 13 mile, 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 SEC's Silver Springs North Switching Station.

B.2.3.1.6 Vero Beach. The City of Vero Beach has a municipally owned electric utility. The utility operates an internal, looped 69 kV transmission system for system load and a 155 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, which connects to FPL's Emerson and Malabar Substations. 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. County Line Substation No. 20 is operated by the City of Vero Beach. The City of Vero Beach and FPUA jointly own County Line Substation No. 20, the connecting lines to FPL's Emerson Station, and part of the tie between the two municipal utilities.

B.2.3.2 Transmission Agreements

FMPA has contracts with PEF, FPL, and OUC to transmit the various ARP resources over the transmission systems of each of these three utilities. The Network Service Agreement with FPL was executed in March 1996, and was subsequently amended both to conform to 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. To provide transmission wheeling service for ARP member cities located in PEF's service territory, FMPA operates under an existing agreement with PEF, which was executed in April 1985 and provides for network type transmission services. FMPA also has several transmission wheeling agreements with OUC, which are associated with each FMPA generation resource located in OUC's system and provide for network type transmission service over OUC's system.

B.3.0 Forecast of FMPA's Electrical Demand and Consumption

B.3.1 Introduction

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

B.3.2 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 is currently supplying and ARP members that FMPA will supply in the future. Forecasts are prepared on an individual city basis and then aggregated into projections of FMPA's demand and energy requirements. Figure B.3-1 identifies FMPA's load forecast process:

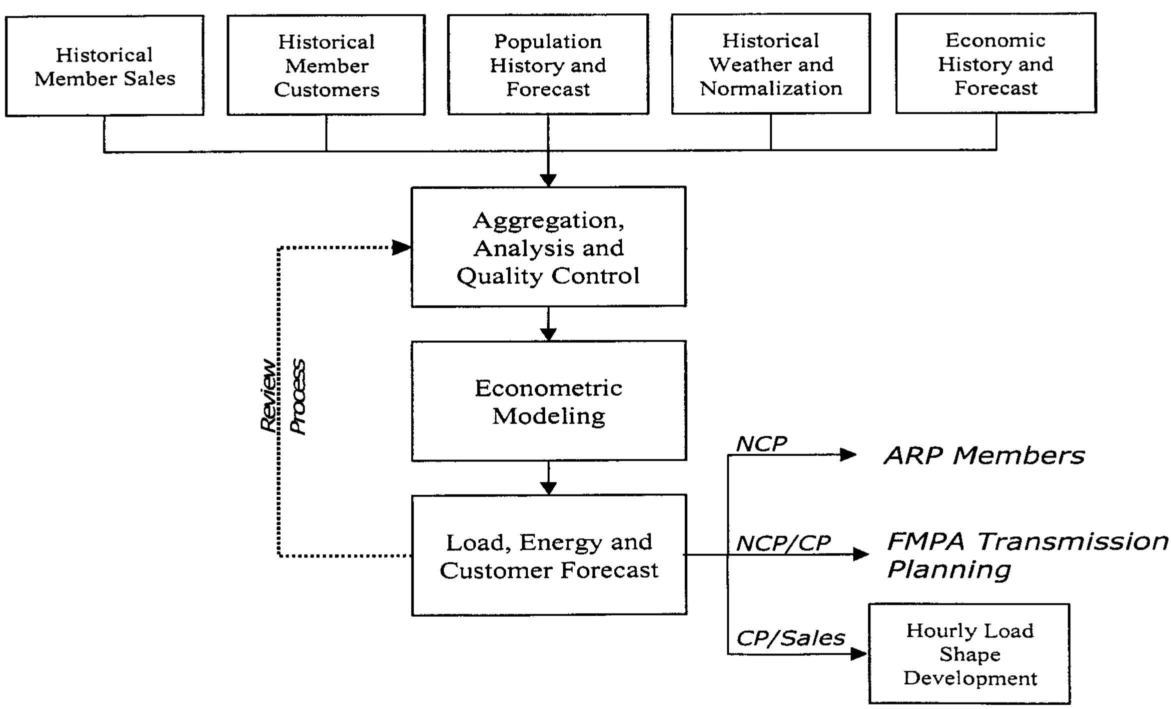

Figure B.3-1
Load Forecast Process

In addition to the base case load and energy forecast, FMPA has prepared high and low case forecasts for each of the ARP members, reflecting the majority of potential uncertainty in population and economic activity throughout the forecast horizon. This band provides an estimate of potential long-term variation in load levels to develop robust power supply plans.

B.3.3 Load Forecast Overview

FMPA retained R. W. Beck, Inc. (Beck) to prepare a forecast of peak load and net energy for the ARP. 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 FMPA operations and long-term planning.

The load and energy forecast prepared by Beck (Forecast) was prepared for a 20 year period, encompassing calendar years 2005 through 2024. 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 such data. Beck also relied on ARP members and their staffs for information regarding local economic and demographic issues specific to each member. As discussed in Subsection B.2.1.3, the City of Vero Beach has provided FMPA with its Notice of Establishment of 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. The high and low case forecasts reflect varying assumptions regarding the future values for population and measures of economic activity. These high and low case forecasts are intended to capture 90 percent of the uncertainty in these driving variables throughout the forecast horizon.

B.3.4 Load Forecast Methodology

To predict energy requirements, utilities need a forecasting methodology that explains variations in energy requirements. In addition, understanding relationships that affect energy consumption allows utilities to perform "what-if" analyses, thereby improving decisions. For this reason, electric utilities typically rely on econometric forecasting techniques. Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables, based on fundamental economic theory and experience. These historical relationships (models) are evaluated and then selected on their statistical ability to explain variations in energy consumption. Given projections of the explanatory variables, the selected models are then simulated to produce forecasts of energy consumption.

In general, monthly forecasts were prepared by rate classification. 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 were based. Table B.3-1 shows the lowest level of granularity at which the Forecast was developed for each ARP member.

Table B.3-1
Rate Classifications Analyzed

Member	Residential	General Service Non-Demand	General Service Demand	Large Demand	City/ Other	Lights
Bushnell	X	X	X			
Clewiston	X	X	X	X(1)		
Fort Meade	X	X				
Fort Pierce	X	X			X	X
Green Cove Springs	X	X	X	X	X	
Havana	X	X				
Jacksonville Beach	X	X	X		X	
Key West	X	X		X(2)	X(3)	
Kissimmee	X	X	X		X	X
Lake Worth	X	X	X			X
Leesburg	X	X			X	
Newberry	X	X			X	
Ocala	X	X		X	X	X
Starke	X	X				
Vero Beach	X	X		X(4)		X

(1)Represents a single customer, US Sugar, which was assumed to grow at 1.0 percent per year.
(2)Represents a single customer, the Key West Navy base, which was assumed to stay flat throughout the forecast horizon, other than weather influences.
(3)Represents churches, street and traffic lights, and rental lights.
(4)Represents a single industrial customer.

B.3.5 Model Specification

The following discussion summarizes the development of econometric models used to forecast load, energy sales, and customer accounts on a monthly basis. This overview will present a common basis upon which each classification of models was prepared.

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 reasonableness of the sales forecast.

Residential class models typically reflect that energy sales are dependent on, or driven by, the following: (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 based on the estimated historical relationship between the number of residential customers of the ARP members and the number of households in each 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 were typically selected as the long-term driving variable, either because it performed better by certain measures, or because the resulting forecast was more reasonable. Similarly, for the general service demand class, total personal income was typically selected. For the industrial class, GDP was the typical long-term driving variable, except in cases where the forecast was based on an assumption to address a single or few general service demand customers (e.g., Clewiston and Key West).

Weather variables include heating degree-days (HDD) and cooling degree-days (CDD) for the current month and for the prior month. Lagged degree-day variables are included to account for the typical billing cycle offset from calendar data. Specifically, 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.

B.3.6 Principal Considerations and Assumptions

B.3.6.1 Historical Member Data

FMPA staff provided historical data for each member. Data provided by FMPA staff included historical customers and sales by rate classification for each of the members. Additionally, revenue data for each ARP member was also provided. Generally, data utilized covered the period from January 1992, or the year a member joined ARP, through the end of fiscal year 2004 (September 2004).

B.3.6.2 Weather Data

Historical weather data was obtained from the National Oceanic and Atmospheric Administration (NOAA), which was generally used to supplement an existing weather database maintained by FMPA. Weather stations, from which historical weather was provided, were first selected by their quality, and second by their proximity to the member. 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. However, based on statistical measures, there were two cases (Jacksonville Beach and Vero Beach) in which weather from cooperative weather stations, which were closer than the first-order station to the members, appeared to be more reflective of select member weather conditions than the closest first-order weather station.

The weather's influence on electricity sales has been represented using two data series: HDD and CDD. Degree-days are derived by comparing the average daily temperature to a base temperature, typically 65° F, which was also used in this forecast. To the extent that the average daily temperature exceeds 65° F, the difference is the number of CDD required to cool the average daily temperature to 65° F. Conversely, HDD is the result of average daily temperatures below 65° F. HDD and CDD were then summed for each month for use in the models.

Since predicting future long-term weather patterns is impossible, normal weather conditions, as reported by the NOAA, were assumed in the projected period. Thirty year normal monthly HDD and CDD generally reflect average weather conditions over the 1971 through 2000 period.

B.3.6.3 Economic Data

Economy.com, a nationally recognized organization, provided both historical and projected economic and demographic data. The data included economic and demographic data for each of the 15 counties in which the ARP members have service territories. The data included county population, households, employment, personal income, retail sales, and GDP. Although all of the data was not necessarily used in each of the forecast equations, it was examined for its potential to explain changes in the members' historical electric sales. Historical and projected rates of change in two of the key economic drivers (number of households and personal income) in the Forecast are summarized in Table B.3-2. Note that personal income refers to the total income earned by the population in a county rather than average personal income per capita.

Table B.3-2
Historical and Projected Growth in Households and Personal Income

Member	Number of Households			Personal Income		
	1995-2004 (Percent)	2005-2014 (Percent)	2015-2024 (Percent)	1995-2004 (Percent)	2005-2014 (Percent)	2015-2024 (Percent)
Bushnell	5.4	3.4	3.4	6.1	4.7	3.9
Clewiston	1.5	2.2	2.6	2.2	2.5	3.0
Fort Meade	1.7	2.0	2.4	3.3	2.1	2.9
Fort Pierce	2.5	3.1	3.1	3.8	5.4	3.6
Green Cove Springs	3.2	2.5	2.9	3.9	2.1	3.4
Havana	0.9	0.8	1.5	2.2	1.7	1.9
Jacksonville Beach	1.5	1.1	2.0	2.9	1.7	2.5
Key West	-0.2	0.2	1.0	3.0	3.1	4.0
Kissimmee	4.7	4.3	3.7	5.5	3.7	4.2
Lake Worth	2.3	2.8	2.9	3.3	4.0	3.3
Leesburg	4.0	3.8	3.5	5.3	3.8	4.0
Newberry	1.4	2.2	2.4	2.8	3.5	2.9
Ocala	2.7	3.2	3.0	3.9	3.6	3.5
Starke	1.2	1.4	2.1	3.4	2.4	2.5
Vero Beach	2.3	2.0	2.6	4.2	3.1	3.0

B.3.6.4 Real Electricity Price Data

The real price of electricity was derived from a 12 month moving average of real average revenue, based on data provided by the FMPA staff. To the extent average revenue data specific to a certain rate classification was unavailable, it was assumed to follow the trend of total average revenue for the utility. While a longer lag is typically expected, particularly in the case of residential electricity use, the lack of data precluded a lengthier lag.

Projected electricity prices were assumed to increase at the rate of inflation. Consequently, the real electricity price was projected to be essentially constant.

B.3.7 Projection of Net Energy for Load and Peak Demand

The forecast of sales for each rate case classification were summed to equal the total sales of each member. An assumed loss factor, typically based on a 5 year average of historical loss factors (excluding anomalous loss factors), was then applied to the total sales to derive monthly NEL. Projections of summer and winter noncoincident peak demand were developed by applying projected annual load factors to the forecasted NEL on a total member system basis. The projected load factors were based on the average relationship between annual NEL and the seasonal peak demand generally over the period of 1995-2004 (a 10 year average).

Monthly peak demand was projected on the basis of 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 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 2 months is the peak month and that the other is typically some percentage less.

Projected coincident peak demands were derived from monthly coincidence factors averaged generally over a 5 year period (2000-2004). The historical coincidence factors were based on historical coincident peak demand data that is maintained by FMPA, supplemented with hourly load data that was analyzed to identify the demand values at the time of the various peaks. Similarly, the timing of the ARP and member group peaks was determined from an appropriate summation of the hourly load data.

B.3.8 Overview of Results

B.3.8.1 Base Load Forecast

The base case 2007 forecast winter peak demand is 1,458 MW, forecast summer peak demand is 1,499 MW, and forecast annual NEL is 7,480 GWh. The winter peak demand is projected to grow at an average annual growth rate of 2.6 percent from 2007 through 2009, and then grow at an annual rate of 2.1 percent from 2010 through 2024. The summer peak demand is projected to grow at an average annual growth rate of 2.5 percent from 2007 through 2009, and then grow at an annual rate of 2.1 percent from 2010 through 2024. NEL is expected to grow at an annual average growth rate of 2.5 percent from 2007 through 2009, and then grow at an annual average rate of 2.0 percent from 2010 through 2024. Growth rates for these periods are shown to avoid distortion in growth rates due to Vero Beach's establishment of CROD, effective January 1, 2010. The results of the Forecast are summarized in Table B.3-3.

B.3.8.2 High and Low Load Forecast

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 case forecasts were developed by simulating the energy sales models, using varying assumptions regarding population and economic activity, as discussed in Section B.3.9. 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. The results of the high and low forecasts are presented in Tables B.3-4 and B.3-5, respectively.

The high case 2007 forecast winter peak demand is 1,535 MW, forecast summer peak demand is 1,579 MW, and forecast annual NEL is 7,887 GWh. The winter peak demand is projected to grow at an average annual growth rate of 3.2 percent from 2007 through 2009, and then grow at an annual rate of 2.6 percent from 2010 through 2024. The summer peak demand is projected to grow at an average annual growth rate of 3.1 percent from 2007 through 2009, and then grow at an annual rate of 2.6 percent from 2010 through 2024. NEL is expected to grow at an annual average growth rate of 3.1 percent from 2007 through 2009, and then grow at an annual average rate of 2.5 percent from 2010 through 2024.

The low case 2007 forecast winter peak demand is 1,377 MW, forecast summer peak demand is 1,416 MW, and forecast annual NEL is 7,057 GWh. The winter peak demand is projected to grow at an average annual growth rate of 1.9 percent from 2007 through 2009, and then grow at an annual rate of 1.4 percent from 2010 through 2024. The summer peak demand is projected to grow at an average annual growth rate of 1.9 percent from 2007 through 2009, and then grow at an annual rate of 1.3 percent from 2010 through 2024. NEL is expected to grow at an annual average growth rate of 1.8 percent from 2007 through 2009, and then grow at an annual average rate of 1.3 percent from 2010 through 2024.

Table B.3-3
Base Demand and Energy Forecast

Year	Winter Peak MW)	Summer Peak (MW)	NEL (GWh)
2006	1,427	1,467	7,317
2007	1,458	1,499	7,480
2008	1,490	1,533	7,646
2009	1,535	1,576	7,858
2010	1,366	1,435	7,157
2011	1,394	1,466	7,308
2012	1,423	1,497	7,461
2013	1,454	1,529	7,621
2014	1,486	1,562	7,787
2015	1,518	1,596	7,950
2016	1,552	1,630	8,115
2017	1,585	1,665	8,279
2018	1,617	1,698	8,440
2019	1,650	1,732	8,602
2020	1,682	1,766	8,766
2021	1,716	1,801	8,936
2022	1,751	1,837	9,108
2023	1,786	1,873	9,282
2024	1,821	1,909	9,456

Table B.3-4
High Demand and Energy Forecast

Year	Winter Peak (MW)	Summer Peak (MW)	NEL (GWh)
2006	1,494	1,536	7,672
2007	1,535	1,579	7,887
2008	1,578	1,623	8,108
2009	1,635	1,678	8,378
2010	1,459	1,534	7,660
2011	1,498	1,575	7,863
2012	1,537	1,617	8,070
2013	1,579	1,660	8,287
2014	1,622	1,706	8,512
2015	1,666	1,752	8,735
2016	1,711	1,799	8,963
2017	1,757	1,846	9,192
2018	1,803	1,894	9,420
2019	1,848	1,941	9,651
2020	1,895	1,990	9,888
2021	1,944	2,040	10,131
2022	1,993	2,091	10,381
2023	2,044	2,144	10,636
2024	2,095	2,197	10,892

Table B.3-5
Low Demand and Energy Forecast

Year	Winter Peak (MW)	Summer Peak (MW)	NEL (GWh)
2006	1,357	1,395	6,949
2007	1,377	1,416	7,057
2008	1,398	1,438	7,166
2009	1,432	1,469	7,317
2010	1,267	1,332	6,633
2011	1,285	1,351	6,728
2012	1,304	1,371	6,824
2013	1,323	1,391	6,924
2014	1,343	1,412	7,028
2015	1,363	1,433	7,128
2016	1,384	1,454	7,227
2017	1,403	1,474	7,322
2018	1,422	1,493	7,413
2019	1,440	1,512	7,502
2020	1,459	1,531	7,591
2021	1,477	1,550	7,681
2022	1,496	1,569	7,772
2023	1,514	1,588	7,861
2024	1,532	1,606	7,948

B.3.9 Uncertainty of the Forecast

Although a forecast that is derived from point estimate projections of the driving variables obtained from reputable sources provides a sound basis for planning, there is significant uncertainty in the future level of such variables. To account for economic and demographic uncertainty, additional scenarios, referred to as the high and low cases, were developed to capture the impact on load of variations in these independent variables.

Economy.com does not publish information regarding the potential error of their projections. Instead, Beck relied on such statistics from another provider, Woods & Poole Economics, Inc (Woods & Poole), which relies on the same underlying data set and a somewhat similar methodology. Woods & Poole publishes several statistics that define the average amount by which various projections they have provided in the past are different from the actual results for the first several years of the forecast horizon. Statistics related to projections at the state level were used to develop adjustments to the independent variables used in the base case forecast. The amount of potential error was linearly extrapolated beyond the period published by Woods & Poole.

Table B.3-6 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 one might expect, the amount of potential variation is shown to grow through time, since uncertainty in these variables varies in rough proportion to the forecast horizon.

Table B.3-6
Economic and Demographic Uncertainty

Year	Population (Percent)	Employment (Percent)	Income (Percent)	Income per Capita (Percent)
2006	3.4	5.1	7.7	6.4
2007	4.3	6.8	8.5	6.8
2008	5.1	8.5	9.4	7.2
2009	6.0	10.2	10.2	7.7
2010	6.8	11.9	11.1	8.1
2011	7.7	13.6	11.9	8.5
2012	8.5	15.3	12.8	8.9
2013	9.4	17.0	13.6	9.4
2014	10.2	18.7	14.5	9.8
2015	11.1	20.4	15.3	10.2
2016	11.9	22.1	16.2	10.6
2017	12.8	23.8	17.0	11.1
2018	13.6	25.5	17.9	11.5
2019	14.5	27.2	18.7	11.9
2020	15.3	28.9	19.6	12.3
2021	16.2	30.6	20.4	12.8
2022	17.0	32.3	21.3	13.2
2023	17.9	34.0	22.1	13.6
2024	18.7	35.7	23.0	14.0

B.4.0 FMPA's Need for Capacity

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.

FMPA adheres to 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.

B.4.1 Reliability Criteria

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), which 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 and other purchases that include reserves. These two methods are discussed below.

B.4.1.1 Reserve Margin

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 partial requirements (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:

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

B.4.1.2 Loss of Load Probability

The second commonly used method of calculating the reliability of a utility system is the LOLP method. This method is advantageous in that it can result in a measure of how much capacity (and reserves) 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. Therefore, FMPA uses the reserve margin method as the planning criterion that produces the most conservative reliability level.

B.4.2 Forecast Capacity Requirements

To determine FMPA's need for capacity, a forecast of net system capacity and system peak demand was developed for the summer and winter peaks. The forecast system peak demand (developed by Beck) is discussed in Section B.3.0 and extends through the year 2024. For the purposes of this analysis, the projection was extended to year 2025 by applying the annual growth rate from 2023 to 2024 to year 2024 values. As discussed in Section A.8.0, the system peak demand was held constant at the 2025 value through the end of the study period (2035).

Capacity and energy delivered to the East Cities (Clewiston, Fort Pierce, Green Cove Springs, Jacksonville Beach, KEYS, Lake Worth, Starke, and Vero Beach) is delivered over the FPL transmission system. The system peak demand forecast provided by Beck does not include the losses associated with delivery over FPL's transmission system (assumed to be 2.28 percent). FMPA must plan to install sufficient capacity to meet the sum of the forecast peak demand plus the FPL transmission losses for the East Cities. Therefore, the system peak demand used in this section to estimate reliability levels includes an estimate of the transmission losses experienced over FPL's transmission system for the East Cities.

Capacity and energy delivered to the West Cities (Bushnell, Fort Meade, Havana, Leesburg, Newberry, and Ocala) is delivered over the PEF transmission system. FMPA's network service agreement with PEF provides for transmission system losses.

The net system capacity includes existing generation resources, existing system purchases, system sales, reserves associated with PR purchases, scheduled capacity additions, and scheduled unit retirements. Section B.2.0 provides a description of FMPA's existing capacity resources. FMPA currently has plans to retire 252 MW of existing resources in the period of this analysis as identified in Table B.2-5. In addition to the retirements identified in Table B.2-5, the City of Vero Beach's existing resources will not be available to FMPA after January 1, 2010, due to establishment of CROD (as discussed in Section B.2.1.3). FMPA does not currently have any load subject to curtailment or interruption. In addition, FMPA currently does not have any firm off-system sales.

FMPA's current firm power supply purchases include purchases from PEF, FPL, OUC, Lakeland Electric, GRU, Calpine, Southern Company-Florida, LLC, and Southern Company. The power purchases are summarized in Section B.2.0.

The projected reliability levels for the winter base case and the summer base case (based on FMPA's currently available capacity resources, which are described in Section B.2.0) are presented in Tables B.4-1 and B.4-2, respectively. Table B.4-1 shows that FMPA's capacity will fall below its required 15 percent reserve margin in the winter of 2012/13. At this time, FMPA's reserve margin is projected to fall to 11.4 percent, or 52 MW below the capacity required to maintain a 15 percent reserve margin. In the following winter season, 2013/14, FMPA's reserve margin is projected to fall to a negative 0.2 percent (net capacity less than projected load), or 227 MW below the capacity required to maintain a 15 percent reserve margin. Projected winter capacity deficits continue to increase beyond 2013/14.

Table B.4-2 shows that FMPA's capacity will initially fall below its required 18 percent reserve margin in the summer of 2007. At that time, FMPA's reserve margin is projected to fall to 16.6 percent, or 20 MW below the capacity required to maintain an 18 percent reserve margin. FMPA would likely enter into a short-term seasonal purchase to maintain its reserve margin in 2007. The addition of the 296 MW TCEC combined cycle unit in June 2008 would raise FMPA's projected reserve margin above 18 percent in the period of 2008/2009, and the addition of simple cycle CTs in the summer of 2010 would satisfy forecast capacity requirements for FMPA through the summer of 2011. In the summer of 2011, FMPA's reserve margin is projected to decrease to 13.9 percent, or 59 MW below the capacity required to maintain an 18 percent reserve margin. Projected summer capacity deficits continue to increase beyond 2011.

Table B.4-1
Projected Reliability Levels - Winter/Base Case

Year	2006 Net Generating Capacity (MW)	Non-Partial Reqrmnt. Purchases (MW)	Partial Reqrmnt. Purchases (MW)	Net Firm Planned Capacity Retirements(1) (MW)	Net Firm Capacity Adds.(2) (MW)	Net System Capacity (MW)	System Peak Demand(3)		Reserve Margin(4)		Excess/(Deficit) to Maintain 15 Percent Reserve Margin	
							Before Int. & LM (MW)	After Int. & LM (MW)	Before Int. & LM (%)	After Int. & LM (%)	Before Int. & LM (MW)	After Int. & LM (MW)
2006/2007	1,391	286	150	0	0	1,827	1,475	1,475	26.5	26.5	153	153
2007/2008	1,391	343	75	0	0	1,809	1,508	1,508	21.0	21.0	86	86
2008/2009	1,391	343	105	(118)	318	2,039	1,554	1,554	33.4	33.4	267	267
2009/2010	1,391	243	85	(322)	318	1,715	1,379	1,379	25.9	25.9	142	142
2010/2011	1,391	243	45	(322)	415	1,772	1,408	1,408	26.7	26.7	159	159
2011/2012	1,391	243	45	(367)	415	1,727	1,438	1,438	20.7	20.7	80	80
2012/2013	1,391	243	45	(464)	415	1,630	1,468	1,468	11.4	11.4	(52)	(52)
2013/2014	1,391	157	0	(464)	415	1,499	1,501	1,501	-0.2	-0.2	(227)	(227)
2014/2015	1,391	157	0	(464)	415	1,499	1,534	1,534	-2.3	-2.3	(265)	(265)
2015/2016	1,391	157	0	(464)	415	1,499	1,566	1,566	-4.3	-4.3	(302)	(302)
2016/2017	1,391	157	0	(464)	415	1,499	1,600	1,600	-6.3	-6.3	(341)	(341)
2017/2018	1,391	157	0	(464)	415	1,499	1,632	1,632	-8.2	-8.2	(378)	(378)
2018/2019	1,391	157	0	(464)	415	1,499	1,665	1,665	-10.0	-10.0	(416)	(416)
2019/2020	1,391	157	0	(464)	415	1,499	1,698	1,698	-11.7	-11.7	(454)	(454)
2020/2021	1,391	157	0	(464)	415	1,499	1,732	1,732	-13.5	-13.5	(493)	(493)
2021/2022	1,391	157	0	(464)	415	1,499	1,767	1,767	-15.2	-15.2	(533)	(533)
2022/2023	1,391	157	0	(464)	415	1,499	1,802	1,802	-16.8	-16.8	(574)	(574)
2023/2024	1,391	157	0	(464)	415	1,499	1,837	1,837	-18.4	-18.4	(614)	(614)
2024/2025	1,391	157	0	(464)	415	1,499	1,873	1,873	-20.0	-20.0	(655)	(655)

(1)Assumes retirements described in Section 2.0.
(2)Firm capacity additions include TCEC Unit 1 combined cycle (June 2008) and two new peaking units (June 2010).
(3)Reflects adjustments to forecast peak demand to account for transmission losses over FPL's transmission system as described previously in this section.
(4)Reserve margin calculated as (Net System Capacity - PR Purchases) - (System Peak Demand - PR Purchases) / (System Peak Demand - PR Purchases).

Table B.4-2
Projected Reliability Levels - Summer/Base Case

Year	2006 Net Generating Capacity (MW)	Non-Partial Reqrmnt. Purchases (MW)	Partial Reqrmnt. Purchases (MW)	Net Firm Planned Capacity Retirements(1) (MW)	Net Firm Capacity Adds.(2) (MW)	Net System Capacity (MW)	System Peak Demand(3)		Reserve Margin(4)		Excess/(Deficit) to Maintain 18 Percent Reserve Margin	
							Before Int. & LM (MW)	After Int. & LM (MW)	Before Int. & LM (%)	After Int. & LM (%)	Before Int. & LM (MW)	After Int. & LM (MW)
2006	1,314	279	160	0	0	1,753	1,484	1,484	20.3	20.3	31	31
2007	1,314	280	150	(1)	0	1,742	1,516	1,516	16.6	16.6	(20)	(20)
2008	1,314	337	75	(111)	296	1,910	1,550	1,550	24.4	24.4	95	95
2009	1,314	337	105	(111)	296	1,940	1,594	1,594	23.3	23.3	78	78
2010	1,314	237	85	(296)	380	1,719	1,449	1,449	19.8	19.8	25	25
2011	1,314	237	45	(296)	380	1,679	1,480	1,480	13.9	13.9	(59)	(59)
2012	1,314	237	45	(430)	380	1,545	1,511	1,511	2.3	2.3	(230)	(230)
2013	1,314	237	0	(430)	380	1,500	1,544	1,544	-2.8	-2.8	(322)	(322)
2014	1,314	157	0	(430)	380	1,421	1,579	1,579	-10.0	-10.0	(442)	(442)
2015	1,314	157	0	(430)	380	1,421	1,613	1,613	-11.9	-11.9	(483)	(483)
2016	1,314	157	0	(430)	380	1,421	1,646	1,646	-13.7	-13.7	(522)	(522)
2017	1,314	157	0	(430)	380	1,421	1,680	1,680	-15.4	-15.4	(562)	(562)
2018	1,314	157	0	(430)	380	1,421	1,714	1,714	-17.1	-17.1	(602)	(602)
2019	1,314	157	0	(430)	380	1,421	1,748	1,748	-18.7	-18.7	(642)	(642)
2020	1,314	157	0	(430)	380	1,421	1,782	1,782	-20.3	-20.3	(682)	(682)
2021	1,314	157	0	(430)	380	1,421	1,817	1,817	-21.8	-21.8	(723)	(723)
2022	1,314	157	0	(430)	380	1,421	1,853	1,853	-23.3	-23.3	(766)	(766)
2023	1,314	157	0	(430)	380	1,421	1,890	1,890	-24.8	-24.8	(809)	(809)
2024	1,314	157	0	(430)	380	1,421	1,926	1,926	-26.2	-26.2	(852)	(852)
2025	1,314	157	0	(430)	380	1,421	1,963	1,963	-27.6	-27.6	(895)	(895)

(1)Assumes retirements described in Section 2.0.
(2)Firm capacity additions include TCEC Unit 1 combined cycle (June 2008) and two new peaking units (June 2010).
(3)Reflects adjustments to forecast peak demand to account for transmission losses over FPL's transmission system as described previously in this section.
(4)Reserve margin calculated as (Net System Capacity - PR Purchases) - (System Peak Demand - PR Purchases) / (System Peak Demand - PR Purchases).

B.5.0 FMPA's Economic Analysis

A detailed economic analysis was performed to evaluate the cost-effectiveness of FMPA's participation in TEC and to determine the least-cost capacity expansion plan to meet FMPA's forecast capacity requirements during the planning horizon, as presented in Section B.4.0. This section presents the assumptions and methodology used in the economic analysis, as well as the results of the base case analysis.

The economic analysis described herein compares the economics of the least-cost capacity expansion plan (utilizing conventional and emerging supply-side alternatives), including FMPA's share of capacity and energy from TEC, versus the economics of the least-cost expansion plan for FMPA's system (utilizing conventional and emerging supply-side alternatives) that does not include participation in TEC. The capacity associated with FMPA's share of TEC, as well as construction of any of the supply-side alternatives presented in Section A.6.0, is only sufficient to satisfy FMPA's forecast capacity requirements for a portion of the expansion planning horizon. To meet the forecast capacity requirements, multiple unit additions were selected from FMPA's supply-side alternatives considered for individual participation that passed the supply-side screening described in Section A.6.6. Analyses of FMPA's joint participation in supply-side alternatives other than TEC are presented as sensitivity cases in Section B.6.0.

B.5.1 Expansion Planning and Production Costing Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model that Black & Veatch developed as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. Both POWROPT and its detailed chronological production costing module, POWRPRO, have been used in numerous Need for Power Applications filed with the FPSC, including FMPA's TCEC Unit 1 Need for Power Application approved in July 2005, and the OUC Stanton B Need for Power Application approved in May 2006.

POWROPT operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans to satisfy forecast capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of generating unit alternatives and purchase power options, in conjunction with existing capacity resources, while maintaining user-defined reliability criteria. All capacity expansion plans were analyzed over a 30 year period from 2006 through 2035.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's POWRPRO was used to obtain the annual production cost for the expansion plan. POWRPRO is a computer-based chronological production costing model developed for use in power supply systems planning. POWRPRO simulates the hour-by-hour operation of a power supply system over a specified planning period. Required inputs are carried forward from those used in POWROPT and include the performance characteristics of generating units, fuel costs, and the system hourly load profile for each year.

POWRPRO summarizes each unit's operating characteristics for every year of the planning horizon. These characteristics include, among others, each unit's annual generation, fuel consumption, fuel cost, average net operating heat rate, the number of hours the unit was on line, the capacity factor, variable operations and maintenance (O&M) costs, and the number of starts and associated costs. Fixed O&M costs were included only for new unit additions, since fixed O&M costs for existing units are generally considered sunk costs that will not vary from one expansion plan to another. Additionally, annual capacity charges and fixed O&M costs were not included for TCEC, which is being developed by FMPA. Similarly, the annual capacity charges for FMPA's power purchases from PEF, FPL, OCU, Lakeland Electric, GRU, Calpine, Southern Company-Florida, LLC., and Southern Power Company were not included, since they also represent sunk costs. In addition, fixed costs for firm natural gas transportation capacity from Florida Gas Transmission Company (FGT) for existing units are considered sunk costs and were not included. The operating costs of each unit were aggregated to determine the annual operating costs for each year of the expansion plan. Capital costs, fixed O&M costs, and incremental costs for natural gas transportation (for combined cycle capacity addition alternatives) were then added for each capacity addition selected, at which point the cumulative present worth cost (CPWC) of each expansion plan was calculated.

The CPWC calculation accounts for annual system costs (fuel and energy, fixed O&M for capacity additions, nonfuel variable O&M, startup, and levelized capital) for each year of the expansion planning period and discounts each back to 2006 at the present worth discount rate of 5.0 percent. These annual present worth costs were then summed over the 2006 through 2035 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various capacity expansion plans, and the plan with the lowest CPWC is considered the least-cost capacity expansion plan.

B.5.2 Least-Cost Capacity Expansion Analysis

The economic analysis consisted of comparing the economics of the optimal capacity expansion plan, including FMPA's participation in TEC, versus the optimal capacity expansion plan not including participation in TEC. As described previously in this section, Black & Veatch first used its optimum generation expansion program, POWROPT, to select unit additions from FMPA's supply-side alternatives considered for individual participation, which was presented in Section A.6.0. Once the least-cost expansion plan for each case was determined, POWRPRO was used to determine the annual total system costs and to develop a comparison of CPWCs associated with each expansion plan.

B.5.2.1 Peak Demand and Energy Growth

As presented in Section B.3.0, a forecast of peak demand and NEL was provided for FMPA's system through 2024, which was extrapolated through 2025 by applying the peak demand and NEL growth rates between 2023 and 2024 to the 2024 forecasts. For evaluation purposes (as discussed in Section A.8.0), loads would be held constant beyond 2025.

B.5.2.2 Supply-Side Candidate Unit Additions

As described in Section B.4.0, FMPA's forecast capacity requirements are dictated by projected capacity shortfalls in the summer season of each year of the planning period. On a weather-normalized basis, FMPA's summer peak typically occurs in July of a given calendar year; however, FMPA's actual summer peak could occur as early as June. To ensure that new capacity additions are available to meet forecast summer reserve margin requirements, all unit additions considered for FMPA's individual ownership (as presented in Section A.6.0) are assumed to be installed by May 1.

Section A.6.0 presented capital and O&M costs for the greenfield and brownfield units considered for FMPA's individual ownership. It has been assumed that the existing Cane Island and Lake Worth sites could be used for future capacity additions and that the TCEC site, currently under development, would be able to accommodate future capacity additions as well.

B.5.2.3 Fuel Price Projections

As described in Section A.4.0 of this Application, projections of delivered fuel prices were developed by the TEC Fuels Committee. The base case fuel price projections presented in Section A.4.0 have been used for the evaluations presented in this section. For the purposes of analysis, FMPA's existing coal fired units (Stanton 1 and 2) are assumed to burn compliant Eastern Kentucky coal both before and after implementation of assumed emissions control technology retrofits in 2010 (as described in Subsection B.5.2.4). The coal fired candidate units (circulating fluidized bed [CFB] and integrated gasification combined cycle [IGCC]) for FMPA are assumed to burn high-sulfur, Western Kentucky coal.

For all capacity expansion plan evaluations, it was necessary to account for natural gas transportation capacity associated with the new combined cycle unit alternatives. FMPA currently has a contract in place with FGT for firm natural gas transportation to fuel its existing natural gas fired units. For the 1x1 combined cycle option included in Section A.6.0, it was assumed that FMPA would purchase firm transportation in accordance with FGT's tariff so that 6.0 percent of the daily natural gas transportation allocation would be adequate to operate the unit at full load for an hour, based on the performance at average ambient conditions. This would require 37,323 MBtu of firm natural gas per day. Using the Firm Transportation Service (FTS) reservation charge of $0.769 per MBtu (pursuant to FGT's April 2006, effective rates for incremental Firm Market Area Transportation), firm transportation costs of $2.92 per kW-month were added to the fixed O&M costs of the 1x1 combined cycle alternative. It has been assumed that FMPA will not purchase firm natural gas transportation capacity from FGT for simple cycle CTs but, instead, will utilize an interruptible service rate assumed to be $0.37 per MBtu, which was added to the annual commodity price forecasts for natural gas provided in Section A.4.0. Any natural gas required in addition to the firm natural gas transportation for the existing and new units is priced at the interruptible service rate.

B.5.2.4 Emissions Cost Considerations

To reflect the economic effects of the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) (as described in Section A.5.0), the forecast prices of emissions allowances were incorporated into the fuel costs for each unit, including existing units that will be regulated under CAIR and CAMR, beginning with the first phases of CAIR and CAMR. The allowance price forecasts presented in Section A.5.0 provide emissions costs on a dollar per ton (dollar per pound for mercury [Hg]) basis. These costs were used to calculate a fuel cost adder for both existing units and candidate units based on the emissions rates of each individual unit. As a result, each generating unit was modeled using different prices for fuel because of differences in emissions rates. The forecast market value of the allowances allocated to FMPA's existing units was not included in the economic analysis, since it represents the same credit for each capacity expansion plan.

Emissions rates for some of FMPA's existing units may be modified through fuel switching or retrofits for emissions control to help meet the nitrogen oxide (NO_x), sulfur dioxide (SO_2), and Hg reductions mandated by CAIR and CAMR. Since complete emission control strategies, the resulting reductions in emissions rates, and the generating unit output and performance impacts from potential emissions control measures are not entirely known at this time, no changes in emissions rates or unit output and performance were considered in this analysis other than for Stanton Units 1 and 2 operated by OUC. OUC's current strategy is to reduce the SO_2 and NO_x emissions rates at Stanton Units 1 and 2 from current levels through the implementation of emissions control technology retrofits in 2010.

Table B.5-1 presents the combined SO_2, NO_x, and Hg emissions cost adders for FMPA's existing units. In years when units are no longer available to FMPA, through either retirement or, in the case of Vero Beach, through their Notice of Establishment of Contract Rate of Delivery, "N/A" is used to indicate the adders are no longer applicable as the resources are not included in FMPA's dispatch model. SO_2, NO_x, and Hg emissions cost adders for candidate units are presented in Table B.5-2. The emissions cost adders for both existing and candidate units are added to the delivered fuel price projections to develop a total fuel cost (per MBtu) specific to each unit that includes forecast SO_2, NO_x, and Hg allowance prices.

B.5.2.5 Dispatch Assumptions

Nonfuel variable O&M and forecast emissions allowance costs were included in the unit dispatch modeling in POWROPT and POWRPRO, along with the fuel costs. These costs were included in the dispatch modeling to ensure the most cost-effective dispatch of both existing and new generating units.

Table B.5-1
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Existing Units
(Nominal \$/MBtu)

Calendar Year	Cane Island CT 1	Cane Island CC 2	Cane Island CC 3	Vero ST 3	Vero ST 4	SEC A	Vero CC 5	Hansel CC	LWU CC	LWU CT 1	Stanton 1	Stanton 2	Stock Island CT 4
2009	$0.10	$0.06	$0.01	$0.14	$0.13	$0.02	$0.05	$0.37	$0.37	$1.01	$0.50	$0.19	$0.01
2010	$0.14	$0.08	$0.02	$0.20	$0.18	$0.02	$0.06	$0.51	$0.51	$1.42	$0.17	$0.15	$0.01
2011	$0.15	$0.08	$0.02	N/A	N/A	$0.02	N/A	$0.54	$0.54	$1.48	$0.17	$0.16	$0.01
2012	$0.16	$0.09	$0.02	N/A	N/A	$0.02	N/A	N/A	$0.56	$1.54	$0.18	$0.17	$0.01
2013	$0.16	$0.09	$0.02	N/A	N/A	$0.02	N/A	N/A	N/A	N/A	$0.19	$0.18	$0.01
2014	$0.18	$0.10	$0.02	N/A	N/A	$0.03	N/A	N/A	N/A	N/A	$0.21	$0.19	$0.01
2015	$0.28	$0.15	$0.03	N/A	N/A	$0.04	N/A	N/A	N/A	N/A	$0.33	$0.30	$0.02
2016	$0.30	$0.17	$0.03	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.35	$0.32	$0.02
2017	$0.26	$0.14	$0.03	N/A	N/A	$0.04	N/A	N/A	N/A	N/A	$0.33	$0.30	$0.02
2018	$0.27	$0.15	$0.03	N/A	N/A	$0.04	N/A	N/A	N/A	N/A	$0.36	$0.33	$0.02
2019	$0.35	$0.20	$0.04	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.42	$0.39	$0.03
2020	$0.42	$0.24	$0.05	N/A	N/A	$0.06	N/A	N/A	N/A	N/A	$0.49	$0.45	$0.03
2021	$0.40	$0.22	$0.05	N/A	N/A	$0.06	N/A	N/A	N/A	N/A	$0.49	$0.45	$0.03
2022	$0.39	$0.21	$0.04	N/A	N/A	$0.06	N/A	N/A	N/A	N/A	$0.49	$0.45	$0.03
2023	$0.50	$0.27	$0.06	N/A	N/A	$0.07	N/A	N/A	N/A	N/A	$0.61	$0.56	$0.04
2024	$0.74	$0.41	$0.08	N/A	N/A	$0.11	N/A	N/A	N/A	N/A	$0.82	$0.76	$0.06
2025	$0.81	$0.45	$0.09	N/A	N/A	$0.12	N/A	N/A	N/A	N/A	$0.91	$0.84	$0.06
2026	$0.87	$0.48	$0.10	N/A	N/A	$0.13	N/A	N/A	N/A	N/A	$0.98	$0.90	$0.07
2027	$0.94	$0.52	$0.10	N/A	N/A	$0.14	N/A	N/A	N/A	N/A	$1.05	$0.97	$0.08
2028	$1.01	$0.56	$0.11	N/A	N/A	$0.15	N/A	N/A	N/A	N/A	$1.13	$1.04	$0.08
2029	$1.09	$0.60	$0.12	N/A	N/A	$0.16	N/A	N/A	N/A	N/A	$1.20	$1.11	$0.09
2030	$1.16	$0.64	$0.13	N/A	N/A	$0.17	N/A	N/A	N/A	N/A	$1.29	$1.19	$0.09
2031	$1.25	$0.69	$0.14	N/A	N/A	$0.19	N/A	N/A	N/A	N/A	$1.38	$1.27	$0.10
2032	$1.33	$0.74	$0.15	N/A	N/A	$0.20	N/A	N/A	N/A	N/A	$1.47	$1.36	$0.11
2033	$1.43	$0.79	$0.16	N/A	N/A	$0.21	N/A	N/A	N/A	N/A	$1.57	$1.45	$0.11
2034	$1.53	$0.85	$0.17	N/A	N/A	$0.23	N/A	N/A	N/A	N/A	$1.68	$1.55	$0.12
2035	$1.64	$0.91	$0.18	N/A	N/A	$0.24	N/A	N/A	N/A	N/A	$1.80	$1.66	$0.13

CC = Combined Cycle; ST = Steam Turbine.

Table B.5-2
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Candidate Units
(Nominal $/MBtu)

Calendar Year	TEC	Simple Cycle Units[1]	GE 7FA 1x1 Combined Cycle	CFB	IGCC
2009	$0.08	$0.01	$0.01	$0.10	$0.07
2010	$0.15	$0.01	$0.01	$0.19	$0.10
2011	$0.16	$0.01	$0.01	$0.20	$0.11
2012	$0.16	$0.01	$0.01	$0.20	$0.11
2013	$0.17	$0.01	$0.01	$0.21	$0.11
2014	$0.18	$0.01	$0.01	$0.22	$0.12
2015	$0.28	$0.02	$0.02	$0.36	$0.20
2016	$0.30	$0.02	$0.02	$0.38	$0.21
2017	$0.27	$0.02	$0.02	$0.34	$0.18
2018	$0.30	$0.02	$0.02	$0.37	$0.19
2019	$0.36	$0.03	$0.03	$0.46	$0.25
2020	$0.42	$0.03	$0.03	$0.53	$0.30
2021	$0.42	$0.03	$0.03	$0.52	$0.28
2022	$0.41	$0.03	$0.03	$0.51	$0.27
2023	$0.54	$0.04	$0.04	$0.67	$0.35
2024	$0.74	$0.06	$0.06	$0.93	$0.52
2025	$0.84	$0.06	$0.07	$1.05	$0.57
2026	$0.91	$0.07	$0.07	$1.13	$0.61
2027	$0.98	$0.08	$0.08	$1.22	$0.66
2028	$1.05	$0.08	$0.08	$1.31	$0.71
2029	$1.13	$0.09	$0.09	$1.41	$0.76
2030	$1.21	$0.09	$0.09	$1.51	$0.82
2031	$1.29	$0.10	$0.10	$1.62	$0.88
2032	$1.39	$0.11	$0.11	$1.73	$0.94
2033	$1.49	$0.11	$0.12	$1.86	$1.01
2034	$1.59	$0.12	$0.12	$1.99	$1.08
2035	$1.71	$0.13	$0.13	$2.13	$1.15

[1]Simple cycle resources considered for FMPA include LM6000, LMS100, GE 7EA, and GE 7FA.

B.5.2.6 Analysis of FMPA's Participation in TEC

The evaluation of FMPA's participation in TEC was performed by modeling the capacity expansion plan presented in FMPA's 2006 Ten-Year Site Plan through 2010, which included the addition of Stock Island CT 4 (summer 2006), TCEC Unit 1 (summer 2008), and two currently unsited CTs (summer 2010). TEC was modeled as a committed resource beginning May 1, 2012. FMPA's 2006 Ten-Year Site Plan also included unspecified seasonal purchases for the summers of 2011 and 2013; however, these unspecified seasonal purchases were not included in the analyses performed for this Application. Instead, POWROPT was used to determine the set of optimum capacity additions both before and after the construction of TEC from the conventional technologies considered for individual ownership by FMPA, as presented in Section A.6.0. The generating alternatives assumed to be available to meet FMPA's initial forecast capacity requirements (summer 2011) included the LM6000 CT, the LMS100 CT, the 7EA CT, the 7FA CT, and the 1x1 7FA combined cycle. Given the time required to permit, license, and construct a solid-fuel unit, the CFB option would not be available to operate earlier than 2012. Additionally, given its current developmental status, it has been assumed that the IGCC option would not be available before 2018. This would allow for 3 years of successful commercial operation of the next generation of IGCC units, such as the OUC's Stanton B IGCC, which is scheduled to begin operation on June 1, 2010, followed by an assumed 2 year engineering, permitting, and licensing process and 3 year construction schedule.

B.5.2.6.1 TEC Capital Cost. As described in Sections A.3.0 and A.8.0, the installed capital cost for TEC would be $1,752.4 million in 2012 dollars, inclusive of escalation and interest during construction. It was assumed that FMPA would be responsible for a percentage of the capital costs equal to FMPA's ownership share of 38.9 percent. FMPA's total share of the TEC installed cost is $681.7 million in 2012 dollars, which includes the costs for engineering, procurement, and construction (EPC); allowance for funds used during construction (AFUDC); land; community contribution; initial coal inventory; and owner's costs for TEC. Table B.5-3 presents a summary of FMPA's share of the capital costs for TEC.

B.5.2.6.2 Transmission Considerations. As described in Section A.3.0, FMPA will be utilizing the transmission system of PEF for delivery from the Perry Substation to FMPA's transmission system. FMPA's network service agreement with PEF is based upon FMPA's network load and not upon FMPA's individual capacity resources. FMPA's network transmission losses are supplied through the PEF system and not by specific FMPA capacity resources. FMPA's transmission costs are therefore equivalent among individual resource plans since FMPA's network load does not change between plans.

Therefore, FMPA's ownership share of TEC and the corresponding net plant heat rate have not been adjusted for transmission losses in this analysis. The net output and net plant heat rate for FMPA's share of TEC are summarized in Table B.5-4.

Table B.5-3
TEC Capital Cost – FMPA's Share
(All Costs in 2012 Dollars)

Description	Entire Unit ($1,000s)	FMPA's Share[(1)] ($1,000s)
EPC Cost	$1,420,892	$552,727
AFUDC	$135,413	$52,676
Owner's Cost	$116,994	$45,511
Initial Coal Inventory	$39,010	$15,175
Community Contribution	$20,000	$7,780
Land Cost	$20,100	$7,819
Total	**$1,752,409**	**$681,687**

[(1)]Reflects FMPA's 38.9 percent ownership share of TEC.

Table B.5-4
FMPA's Share of TEC, Average Ambient Conditions
Output and Performance

Output (MW)	Net Plant Heat Rate (Btu/kWh)
297.8	9,238
290.8	9,238
230.5	9,428
152.8	9,933
106.0	10,535

B.5.2.6.3 Operations and Maintenance Costs. Section A.3.0 presented the fixed and nonfuel variable O&M costs for TEC. It was assumed that FMPA would be responsible for a share of the O&M costs for TEC equal to FMPA's ownership share of 38.9 percent. Total fixed O&M costs for TEC include an adder for ongoing capital expenditures of $2.97 per kW-year in 2012 dollars, which escalates 2.0 percent higher than the general inflation rate. Excluding the adder for ongoing capital expenditures, the total annual cost for TEC's fixed O&M is $17.7 million in 2005 dollars. FMPA's share of the fixed O&M cost for TEC is $6.89 million or about $23.88 per kW-year (net) in 2005 dollars. Section A.3.0 presented the nonfuel variable O&M cost for TEC before transmission losses as $1.36 per MWh in 2005 dollars. FMPA's net nonfuel variable O&M cost for TEC is also $1.36 per MWh in 2005 dollars, since FMPA will not incur transmission losses on its share of TEC.

B.5.2.6.4 TEC Scheduled Maintenance and Forced Outages. As presented in Section A.3.0, TEC is expected to have an average of 16 scheduled maintenance days per year. Scheduled maintenance is assumed to begin on October 1 of every year after 2012. The scheduled maintenance period is consistent for all of the economic evaluations presented in this Application. TEC is assumed to have an equivalent forced outage rate of 5.23 percent.

B.5.2.6.5 Community Contribution. For the purposes of this analysis, the TEC Participants are assumed to pay a community contribution of $2.5 million per year, in addition to an initial contribution of $20.0 million (included in the capital cost) described previously in this section. Similar to the other fixed costs for TEC, it was assumed that FMPA would be responsible for a percentage of the annual community contribution equivalent to its ownership share of TEC. FMPA's share of the annual community contribution is approximately $973,000 in 2012 dollars. The community contribution is included as an additional annual cost to FMPA, escalated at the general inflation rate of 2.5 percent per year after May 1, 2012.

B.5.2.7 Analysis of Alternative Expansion Plans to Participation in TEC

The evaluation of the capacity expansion plan without FMPA's participation in TEC was performed by modeling the capacity expansion plan presented in FMPA's 2006 Ten-Year Site Plan through 2010, which included the addition of Stock Island CT 4 (summer 2006), TCEC Unit 1 (summer 2008), and two currently unsited CTs (summer 2010). FMPA's 2006 Ten-Year Site Plan also included unspecified seasonal purchases for the summers of 2011 and 2013; however, these unspecified seasonal purchases were not included in the analyses performed for this Application. Instead, POWROPT was used to determine the set of optimum capacity additions from the conventional technologies considered for individual ownership by FMPA (as presented in Section A.6.0), to meet the forecast capacity requirements identified in Section B.4.0. As described earlier in this section, all conventional supply-side alternatives were assumed to be available to meet FMPA's need for capacity in the summer of 2011, except for the CFB and IGCC alternatives which, as described in Subsection B.5.2.6, were first assumed available in 2012 (for the CFB option) and 2018 (for the IGCC option).

B.5.3 Cumulative Present Worth Cost Analysis

The previous sections described the assumptions and methodology that were used in POWROPT to select least-cost capacity expansion plans for a scenario that included FMPA's participation in TEC and another scenario in which it was assumed that TEC would not be constructed. Once these least-cost capacity expansion plans were identified, POWRPRO was used to determine the total annual system costs and to develop a comparison of the CPWCs associated with each expansion plan.

B.5.3.1 Analysis of the Capacity Expansion Plan with TEC

The least-cost capacity expansion plan, assuming that FMPA participates in TEC in May 2012, includes construction of a brownfield LMS100 CT in 2011, greenfield CFB units in 2014 and 2019, and a brownfield LM6000 CT in 2025.

B.5.3.2 Analysis of Alternative Capacity Expansion Plan

The least-cost capacity expansion plan without FMPA's participation in TEC includes construction of a brownfield LMS100 CT in 2011; greenfield CFB units in 2012, 2014, and 2018; and a brownfield LMS100 CT in 2024.

B.5.3.3 Comparison of Cumulative Present Worth Costs

As shown in Table B.5-5, the CPWC of the least-cost capacity expansion plan that includes FMPA's participation in TEC is $8,927.9 million. Table B.5-6 indicates that the CPWC of the least-cost capacity expansion plan without TEC is $9,331.5 million. A comparison of the CPWCs of the two plans demonstrates that the expansion plan that includes FMPA's participation in TEC is the least-cost plan by $403.6 million over the 2006 through 2035 planning period.

Table B.5-5 Expansion Plan Economic Summary - With TEC COD May 1, 2012

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	6.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	681,687	49,450
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/19	842,898	61,144
LM6000	38,800	12	05/01/25	63,291	5,678

Year	Production Cost: Fuel and Energy Cost ($1,000)	Production Cost: O&M Variable ($1,000)	Production Cost: O&M Fixed ($1,000)	Production Cost: *Total Production Cost ($1,000)*	Capital Cost and Other Project Costs: Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$4,577	$0	$0	$0	$0	$4,577	$343,864	$2,100,027
2012	$280,003	$27,323	$6,482	$313,808	$39,920	$973	$0	$0	$592	$41,484	$355,293	$2,365,152
2013	$287,725	$22,944	$9,404	$320,073	$56,268	$997	$0	$0	$924	$58,189	$378,262	$2,633,975
2014	$285,963	$22,849	$17,458	$326,269	$92,543	$1,022	$0	$0	$966	$94,530	$420,800	$2,918,789
2015	$296,457	$23,756	$21,820	$342,032	$110,310	$1,047	$0	$0	$1,009	$112,367	$454,399	$3,211,699
2016	$316,365	$25,228	$22,365	$363,958	$110,310	$1,073	$0	$0	$1,055	$112,438	$476,396	$3,504,165
2017	$332,390	$26,810	$22,924	$382,124	$110,310	$1,100	$0	$0	$1,102	$112,513	$494,637	$3,793,369
2018	$350,569	$28,250	$23,497	$402,316	$110,310	$1,128	$0	$0	$1,152	$112,590	$514,906	$4,080,088
2019	$344,113	$29,210	$32,931	$406,254	$151,352	$1,156	$0	$0	$1,204	$153,712	$559,966	$4,377,050
2020	$357,010	$30,815	$38,196	$426,020	$171,454	$1,185	$0	$0	$1,258	$173,897	$599,917	$4,680,048
2021	$374,623	$32,415	$39,151	$446,189	$171,454	$1,215	$0	$0	$1,314	$173,983	$620,171	$4,978,362
2022	$398,131	$34,185	$40,129	$472,445	$171,454	$1,245	$0	$0	$1,373	$174,072	$646,517	$5,274,539
2023	$434,590	$36,227	$41,133	$511,950	$171,454	$1,276	$0	$0	$1,435	$174,165	$686,115	$5,573,888
2024	$474,778	$38,245	$42,161	$555,183	$171,454	$1,308	$0	$0	$1,500	$174,262	$729,445	$5,876,988
2025	$510,459	$40,557	$44,069	$595,085	$175,266	$1,341	$0	$0	$1,567	$178,174	$773,259	$6,182,993
2026	$529,349	$42,109	$45,600	$617,058	$177,133	$1,374	$0	$0	$1,638	$180,145	$797,202	$6,483,450
2027	$543,760	$43,456	$46,740	$633,956	$177,133	$1,408	$0	$0	$1,712	$180,253	$814,209	$6,775,704
2028	$570,398	$44,745	$47,908	$663,052	$177,133	$1,444	$0	$0	$1,789	$180,365	$843,417	$7,064,026
2029	$594,686	$46,264	$49,106	$690,056	$177,133	$1,480	$0	$0	$1,869	$180,481	$870,537	$7,347,448
2030	$611,863	$47,397	$50,334	$709,594	$177,133	$1,517	$0	$0	$1,953	$180,603	$890,197	$7,623,469
2031	$640,558	$48,704	$51,592	$740,855	$172,556	$1,555	$0	$0	$2,041	$176,152	$917,006	$7,894,264
2032	$668,561	$50,281	$52,882	$771,724	$170,314	$1,594	$0	$0	$2,133	$174,041	$945,765	$8,160,251
2033	$686,517	$51,345	$54,204	$794,065	$170,314	$1,633	$0	$0	$2,229	$174,176	$968,242	$8,419,593
2034	$720,420	$52,600	$55,559	$828,579	$170,314	$1,674	$0	$0	$2,329	$174,318	$1,002,896	$8,675,426
2035	$753,874	$54,133	$56,948	$864,955	$170,314	$1,716	$0	$0	$2,434	$174,464	$1,039,420	$8,927,949

Table B.5-6 Expansion Plan Economic Summary - Without TEC

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
CFB	580,300	44	05/01/12	709,133	51,441
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/18	822,340	59,653
LMS100	65,500	17	05/01/24	104,768	9,400

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*					Ongoing	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	.$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$4,577	$0	$0	$0	$0	$4,577	$343,864	$2,100,027
2012	$288,673	$31,863	$8,427	$328,963	$41,253	$0	$0	$0	$0	$41,253	$370,216	$2,376,287
2013	$301,899	$29,601	$12,374	$343,874	$58,259	$0	$0	$0	$0	$58,259	$402,133	$2,662,076
2014	$299,054	$29,024	$20,503	$348,581	$94,534	$0	$0	$0	$0	$94,534	$443,115	$2,961,993
2015	$309,757	$29,969	$24,941	$364,667	$112,301	$0	$0	$0	$0	$112,301	$476,968	$3,269,451
2016	$332,320	$31,710	$25,564	$389,594	$112,301	$0	$0	$0	$0	$112,301	$501,895	$3,577,571
2017	$351,489	$33,457	$26,203	$411,149	$112,301	$0	$0	$0	$0	$112,301	$523,451	$3,883,621
2018	$339,065	$34,369	$35,489	$408,923	$152,342	$0	$0	$0	$0	$152,342	$561,265	$4,196,155
2019	$354,747	$35,978	$40,709	$431,434	$171,954	$0	$0	$0	$0	$171,954	$603,388	$4,516,144
2020	$379,688	$37,781	$41,727	$459,195	$171,954	$0	$0	$0	$0	$171,954	$631,149	$4,834,917
2021	$398,981	$39,611	$42,770	$481,362	$171,954	$0	$0	$0	$0	$171,954	$653,316	$5,149,173
2022	$423,573	$41,772	$43,839	$509,184	$171,954	$0	$0	$0	$0	$171,954	$681,138	$5,461,210
2023	$464,435	$43,857	$44,935	$553,227	$171,954	$0	$0	$0	$0	$171,954	$725,181	$5,777,604
2024	$500,834	$46,219	$46,948	$594,002	$178,246	$0	$0	$0	$0	$178,246	$772,247	$6,098,489
2025	$537,248	$48,922	$48,568	$634,738	$181,354	$0	$0	$0	$0	$181,354	$816,092	$6,421,444
2026	$559,892	$50,488	$49,782	$660,162	$181,354	$0	$0	$0	$0	$181,354	$841,516	$6,738,603
2027	$578,256	$52,008	$51,027	$681,292	$181,354	$0	$0	$0	$0	$181,354	$862,645	$7,048,243
2028	$603,915	$53,911	$52,302	$710,128	$181,354	$0	$0	$0	$0	$181,354	$891,481	$7,352,995
2029	$631,759	$55,236	$53,610	$740,606	$181,354	$0	$0	$0	$0	$181,354	$921,959	$7,653,159
2030	$649,846	$56,624	$54,950	$761,420	$181,354	$0	$0	$0	$0	$181,354	$942,773	$7,945,483
2031	$680,174	$58,516	$56,324	$795,014	$176,777	$0	$0	$0	$0	$176,777	$971,791	$8,232,455
2032	$712,770	$59,945	$57,732	$830,447	$174,535	$0	$0	$0	$0	$174,535	$1,004,982	$8,515,097
2033	$733,973	$61,285	$59,175	$854,433	$174,535	$0	$0	$0	$0	$174,535	$1,028,968	$8,790,704
2034	$767,959	$63,126	$60,655	$891,740	$174,535	$0	$0	$0	$0	$174,535	$1,066,275	$9,062,704
2035	$805,068	$64,556	$62,171	$931,795	$174,535	$0	$0	$0	$0	$174,535	$1,106,330	$9,331,483

B.6.0 FMPA's Sensitivity Analyses

Several sensitivity analyses were performed to supplement FMPA's base case economic analysis and to demonstrate the robustness of the capacity expansion plans, including FMPA's participation in TEC. These analyses measured the impact of varying the key assumptions used in the base case economic analysis, as well as the effects of considerations not included in the base case.

As described in Section B.5.0, the base case economic analysis compared the CPWC of the optimal capacity expansion plan, including FMPA's participation in TEC, to the optimal capacity expansion plan without participation in TEC. For the base case analysis that included participation in TEC, the proposed TEC was treated as a committed unit starting May 1, 2012, while in the base case analysis without TEC, no candidate units were committed. POWROPT, Black & Veatch's optimal generation and capacity expansion model, was used to select the least-cost expansion plan to meet FMPA's capacity needs. Once the optimal capacity expansion plan was developed for each case, POWRPRO (Black & Veatch's production costing model) was used to determine each plan's production costs, which were used to develop an overall CPWC for each plan.

The general methodology used in the sensitivity analyses is similar to the methodology used in the base case analysis. POWROPT was used to determine the optimal capacity expansion plan for all cases considered under the various assumptions described in this section. POWRPRO was then utilized to calculate production costs of each plan, to compare each plan's CPWC and to determine the least-cost expansion plan. The remainder of this section presents the methodology and results of the sensitivity analyses.

B.6.1 Input Parameter Sensitivities

The sensitivities described in this section reflect changes to the base case input assumptions including fuel prices, load forecast, capital costs, emissions allowance prices, and potential environmental regulations related to carbon dioxide (CO_2) emissions.

B.6.1.1 High Fuel Price Forecast

The high fuel price sensitivity analysis is based on Hill & Associates' high fuel price forecasts and the corresponding emissions allowance price forecasts. The high fuel price forecasts are presented in Section A.4.0, while the emissions allowance price forecasts corresponding to the high fuel price forecast are presented in Section A.5.0.

As in the base case analysis described in Section B.5.0, the costs of emissions allowances were added to the fuel prices for both the existing and candidate units in the high fuel price sensitivity. Table B.6-1 presents the emissions cost adders for FMPA's existing units, and Table B.6-2 presents the emissions adders for the candidate units under the high fuel price sensitivity. In years when existing units are no longer available to FMPA through retirement or, in the case of Vero Beach, through its Notice of Establishment of Contract Rate of Delivery, "N/A" is used to indicate that the adders are no longer applicable, since the resources are not included in FMPA's dispatch model.

Under the high fuel price forecast scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield LMS100 unit in 2011 and greenfield CFB units in 2014, 2019, and 2025. The optimal capacity expansion plan for the case without participation in TEC consists of a brownfield LMS100 unit in 2011; greenfield CFB units in 2012, 2014, and 2018; and a greenfield 1x1 IGCC unit in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $9,979.6 million and $10,343.1 million, respectively. A comparison of these CPWCs shows that the expansion plan with TEC is the least-cost plan by $363.5 million over the evaluation period.

B.6.1.2 Low Fuel Price Forecast

The low fuel price sensitivity analysis is based on Hill & Associates' low fuel price forecasts and the corresponding emissions allowance price forecasts. The low fuel price forecasts are presented in Section A.4.0, while the emissions allowance price forecasts corresponding to the low fuel price forecast are presented in Section A.5.0.

As in the base case analysis described in Section B.5.0, the costs of emissions allowances were added to the fuel prices for both the existing and candidate units in the low fuel price sensitivity. Table B.6-3 presents the emissions cost adders for FMPA's existing system, and Table B.6-4 presents the emissions cost adders for the candidate units under the low fuel price sensitivity. In years when existing units are no longer available to FMPA through retirement or, in the case of Vero Beach, through its Notice of Establishment of Contract Rate of Delivery, "N/A" is used to indicate that the adders are no longer applicable since the resources are not included in FMPA's dispatch model.

Under the low fuel price forecast scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of brownfield LMS100 units in 2011 and 2014, a brownfield GE 7FA CT unit in 2015, a greenfield CFB unit in 2019, and a brownfield LM6000 unit in 2025. The optimal capacity expansion plan for the case without participation in TEC consists of a brownfield LMS100 unit in 2011, two brownfield LMS100 units in 2012, a brownfield GE 7FA CT unit in 2013, and greenfield CFB units in 2014 and 2020.

Table B.6-1
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Existing Units - High Fuel Forecast
(Nominal \$/MBtu)

Calendar Year	Cane Isl CT 1	Cane Isl CC 2	Cane Isl CC 3	Vero ST 3	Vero ST 4	SEC A	Vero CC 5	Hansel CC	LWU CC	LWU CT 1	Stanton 1	Stanton 2	Stock Island CT 4
2009	\$0.11	\$0.06	\$0.01	\$0.14	\$0.13	\$0.02	\$0.05	\$0.38	\$0.38	\$1.04	\$0.52	\$0.20	\$0.01
2010	\$0.15	\$0.08	\$0.02	\$0.21	\$0.19	\$0.02	\$0.07	\$0.53	\$0.53	\$1.45	\$0.17	\$0.16	\$0.01
2011	\$0.15	\$0.09	\$0.02	N/A	N/A	\$0.02	N/A	\$0.55	\$0.55	\$1.51	\$0.18	\$0.16	\$0.01
2012	\$0.17	\$0.09	\$0.02	N/A	N/A	\$0.02	N/A	N/A	\$0.59	\$1.62	\$0.20	\$0.18	\$0.01
2013	\$0.18	\$0.10	\$0.02	N/A	N/A	\$0.03	N/A	N/A	N/A	N/A	\$0.21	\$0.19	\$0.01
2014	\$0.19	\$0.11	\$0.02	N/A	N/A	\$0.03	N/A	N/A	N/A	N/A	\$0.23	\$0.21	\$0.02
2015	\$0.34	\$0.19	\$0.04	N/A	N/A	\$0.05	N/A	N/A	N/A	N/A	\$0.37	\$0.34	\$0.03
2016	\$0.31	\$0.17	\$0.03	N/A	N/A	\$0.05	N/A	N/A	N/A	N/A	\$0.36	\$0.33	\$0.02
2017	\$0.32	\$0.18	\$0.04	N/A	N/A	\$0.05	N/A	N/A	N/A	N/A	\$0.38	\$0.35	\$0.03
2018	\$0.40	\$0.22	\$0.04	N/A	N/A	\$0.06	N/A	N/A	N/A	N/A	\$0.46	\$0.42	\$0.03
2019	\$0.42	\$0.23	\$0.05	N/A	N/A	\$0.06	N/A	N/A	N/A	N/A	\$0.48	\$0.44	\$0.03
2020	\$0.53	\$0.29	\$0.06	N/A	N/A	\$0.08	N/A	N/A	N/A	N/A	\$0.59	\$0.54	\$0.04
2021	\$0.61	\$0.34	\$0.07	N/A	N/A	\$0.09	N/A	N/A	N/A	N/A	\$0.68	\$0.62	\$0.05
2022	\$0.69	\$0.38	\$0.08	N/A	N/A	\$0.10	N/A	N/A	N/A	N/A	\$0.74	\$0.68	\$0.06
2023	\$0.63	\$0.35	\$0.07	N/A	N/A	\$0.09	N/A	N/A	N/A	N/A	\$0.73	\$0.67	\$0.05
2024	\$0.81	\$0.45	\$0.09	N/A	N/A	\$0.12	N/A	N/A	N/A	N/A	\$0.88	\$0.81	\$0.07
2025	\$0.90	\$0.50	\$0.10	N/A	N/A	\$0.13	N/A	N/A	N/A	N/A	\$0.99	\$0.91	\$0.07
2026	\$0.98	\$0.54	\$0.11	N/A	N/A	\$0.15	N/A	N/A	N/A	N/A	\$1.08	\$0.99	\$0.08
2027	\$1.07	\$0.59	\$0.12	N/A	N/A	\$0.16	N/A	N/A	N/A	N/A	\$1.17	\$1.08	\$0.09
2028	\$1.17	\$0.65	\$0.13	N/A	N/A	\$0.17	N/A	N/A	N/A	N/A	\$1.26	\$1.17	\$0.09
2029	\$1.26	\$0.70	\$0.14	N/A	N/A	\$0.19	N/A	N/A	N/A	N/A	\$1.36	\$1.26	\$0.10
2030	\$1.37	\$0.76	\$0.15	N/A	N/A	\$0.20	N/A	N/A	N/A	N/A	\$1.47	\$1.35	\$0.11
2031	\$1.48	\$0.82	\$0.16	N/A	N/A	\$0.22	N/A	N/A	N/A	N/A	\$1.58	\$1.46	\$0.12
2032	\$1.59	\$0.88	\$0.18	N/A	N/A	\$0.24	N/A	N/A	N/A	N/A	\$1.70	\$1.57	\$0.13
2033	\$1.72	\$0.95	\$0.19	N/A	N/A	\$0.26	N/A	N/A	N/A	N/A	\$1.83	\$1.69	\$0.14
2034	\$1.86	\$1.03	\$0.21	N/A	N/A	\$0.28	N/A	N/A	N/A	N/A	\$1.97	\$1.83	\$0.15
2035	\$2.01	\$1.12	\$0.22	N/A	N/A	\$0.30	N/A	N/A	N/A	N/A	\$2.13	\$1.97	\$0.16

Table B.6-2
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Candidate Units - High Fuel Forecast
(Nominal $/MBtu)

Calendar Year	TEC	Simple Cycle Units[1]	GE 7FA 1x1 Combined Cycle	CFB	IGCC
2009	$0.08	$0.01	$0.01	$0.11	$0.07
2010	$0.16	$0.01	$0.01	$0.20	$0.10
2011	$0.16	$0.01	$0.01	$0.20	$0.11
2012	$0.17	$0.01	$0.01	$0.22	$0.12
2013	$0.18	$0.01	$0.01	$0.23	$0.12
2014	$0.20	$0.02	$0.02	$0.25	$0.14
2015	$0.33	$0.03	$0.03	$0.42	$0.24
2016	$0.31	$0.02	$0.03	$0.39	$0.22
2017	$0.32	$0.03	$0.03	$0.40	$0.23
2018	$0.40	$0.03	$0.03	$0.51	$0.28
2019	$0.42	$0.03	$0.03	$0.53	$0.29
2020	$0.52	$0.04	$0.04	$0.65	$0.37
2021	$0.59	$0.05	$0.05	$0.75	$0.43
2022	$0.66	$0.06	$0.06	$0.84	$0.48
2023	$0.65	$0.05	$0.05	$0.82	$0.45
2024	$0.80	$0.07	$0.07	$1.01	$0.57
2025	$0.92	$0.07	$0.07	$1.15	$0.63
2026	$1.00	$0.08	$0.08	$1.26	$0.69
2027	$1.09	$0.09	$0.09	$1.37	$0.75
2028	$1.18	$0.09	$0.09	$1.49	$0.82
2029	$1.28	$0.10	$0.10	$1.61	$0.89
2030	$1.39	$0.11	$0.11	$1.74	$0.96
2031	$1.50	$0.12	$0.12	$1.88	$1.03
2032	$1.62	$0.13	$0.13	$2.03	$1.12
2033	$1.75	$0.14	$0.14	$2.19	$1.21
2034	$1.89	$0.15	$0.15	$2.37	$1.30
2035	$2.05	$0.16	$0.16	$2.56	$1.41

[1]Simple cycle resources considered for FMPA include LM6000, LMS100, GE 7EA, and GE 7FA.

Table B.6-3
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Existing Units - Low Fuel Forecast
(Nominal $/MBtu)

Calendar Year	Cane Island CT 1	Cane Island CC 2	Cane Island CC 3	Vero ST 3	Vero ST 4	SEC A	Vero CC 5	Hansel CC	LWU CC	LWU CT 1	Stanton 1	Stanton 2	Stock Island CT 4
2009	$0.10	$0.06	$0.01	$0.13	$0.12	$0.01	$0.04	$0.36	$0.08	$0.98	$0.49	$0.19	$0.01
2010	$0.14	$0.08	$0.02	$0.19	$0.17	$0.02	$0.06	$0.48	$0.11	$1.33	$0.16	$0.14	$0.01
2011	$0.14	$0.08	$0.02	N/A	N/A	$0.02	N/A	$0.50	$0.11	$1.38	$0.16	$0.15	$0.01
2012	$0.15	$0.08	$0.02	N/A	N/A	$0.02	N/A	N/A	$0.12	$1.50	$0.18	$0.16	$0.01
2013	$0.16	$0.09	$0.02	N/A	N/A	$0.02	N/A	N/A	N/A	N/A	$0.18	$0.17	$0.01
2014	$0.17	$0.09	$0.02	N/A	N/A	$0.02	N/A	N/A	N/A	N/A	$0.20	$0.18	$0.01
2015	$0.26	$0.14	$0.03	N/A	N/A	$0.04	N/A	N/A	N/A	N/A	$0.30	$0.27	$0.02
2016	$0.17	$0.09	$0.02	N/A	N/A	$0.03	N/A	N/A	N/A	N/A	$0.24	$0.22	$0.01
2017	$0.19	$0.11	$0.02	N/A	N/A	$0.03	N/A	N/A	N/A	N/A	$0.27	$0.25	$0.02
2018	$0.25	$0.14	$0.03	N/A	N/A	$0.04	N/A	N/A	N/A	N/A	$0.32	$0.29	$0.02
2019	$0.28	$0.16	$0.03	N/A	N/A	$0.04	N/A	N/A	N/A	N/A	$0.35	$0.32	$0.02
2020	$0.29	$0.16	$0.03	N/A	N/A	$0.04	N/A	N/A	N/A	N/A	$0.36	$0.32	$0.02
2021	$0.31	$0.17	$0.03	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.39	$0.35	$0.03
2022	$0.33	$0.18	$0.04	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.40	$0.36	$0.03
2023	$0.36	$0.20	$0.04	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.46	$0.42	$0.03
2024	$0.38	$0.21	$0.04	N/A	N/A	$0.06	N/A	N/A	N/A	N/A	$0.49	$0.45	$0.03
2025	$0.43	$0.24	$0.05	N/A	N/A	$0.06	N/A	N/A	N/A	N/A	$0.56	$0.52	$0.03
2026	$0.44	$0.24	$0.05	N/A	N/A	$0.07	N/A	N/A	N/A	N/A	$0.58	$0.53	$0.04
2027	$0.46	$0.26	$0.05	N/A	N/A	$0.07	N/A	N/A	N/A	N/A	$0.61	$0.57	$0.04
2028	$0.49	$0.27	$0.05	N/A	N/A	$0.07	N/A	N/A	N/A	N/A	$0.65	$0.60	$0.04
2029	$0.52	$0.29	$0.06	N/A	N/A	$0.08	N/A	N/A	N/A	N/A	$0.69	$0.64	$0.04
2030	$0.55	$0.31	$0.06	N/A	N/A	$0.08	N/A	N/A	N/A	N/A	$0.73	$0.68	$0.04
2031	$0.59	$0.32	$0.07	N/A	N/A	$0.09	N/A	N/A	N/A	N/A	$0.78	$0.72	$0.05
2032	$0.62	$0.34	$0.07	N/A	N/A	$0.09	N/A	N/A	N/A	N/A	$0.82	$0.76	$0.05
2033	$0.66	$0.36	$0.07	N/A	N/A	$0.10	N/A	N/A	N/A	N/A	$0.87	$0.81	$0.05
2034	$0.70	$0.39	$0.08	N/A	N/A	$0.10	N/A	N/A	N/A	N/A	$0.92	$0.86	$0.06
2035	$0.74	$0.41	$0.08	N/A	N/A	$0.11	N/A	N/A	N/A	N/A	$0.98	$0.91	$0.06

Table B.6-4
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Candidate Units - Low Fuel Forecast
(Nominal $/MBtu)

Calendar Year	TEC	Simple Cycle Units[1]	GE 7FA 1x1 Combined Cycle	CFB	IGCC
2009	$0.08	$0.01	$0.01	$0.10	$0.07
2010	$0.14	$0.01	$0.01	$0.18	$0.10
2011	$0.15	$0.01	$0.01	$0.19	$0.10
2012	$0.16	$0.01	$0.01	$0.20	$0.11
2013	$0.17	$0.01	$0.01	$0.21	$0.11
2014	$0.17	$0.01	$0.01	$0.21	$0.12
2015	$0.26	$0.02	$0.02	$0.33	$0.18
2016	$0.19	$0.01	$0.01	$0.24	$0.12
2017	$0.21	$0.02	$0.02	$0.27	$0.14
2018	$0.27	$0.02	$0.02	$0.34	$0.18
2019	$0.30	$0.02	$0.02	$0.38	$0.20
2020	$0.30	$0.02	$0.02	$0.38	$0.21
2021	$0.33	$0.03	$0.03	$0.41	$0.22
2022	$0.34	$0.03	$0.03	$0.43	$0.23
2023	$0.40	$0.03	$0.03	$0.50	$0.26
2024	$0.43	$0.03	$0.03	$0.54	$0.28
2025	$0.51	$0.03	$0.03	$0.63	$0.31
2026	$0.53	$0.04	$0.04	$0.65	$0.32
2027	$0.56	$0.04	$0.04	$0.69	$0.34
2028	$0.60	$0.04	$0.04	$0.74	$0.36
2029	$0.63	$0.04	$0.04	$0.78	$0.38
2030	$0.67	$0.04	$0.05	$0.83	$0.40
2031	$0.72	$0.05	$0.05	$0.88	$0.43
2032	$0.76	$0.05	$0.05	$0.94	$0.45
2033	$0.81	$0.05	$0.05	$1.00	$0.48
2034	$0.86	$0.06	$0.06	$1.06	$0.51
2035	$0.91	$0.06	$0.06	$1.13	$0.54

[1]Simple cycle resources considered for FMPA include LM6000, LMS100, GE 7EA, and GE 7FA.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $7,890.9 million and $8,265.5 million, respectively. A comparison of these CPWCs shows that the expansion plan with TEC is the least-cost plan by $374.6 million over the evaluation period.

B.6.1.3 High Load and Energy Growth

Load and energy growth sensitivities are important analyses that help to demonstrate the robustness of future capacity additions, since load growth is a fundamental variable in determining an optimal capacity expansion plan. The high load and energy growth sensitivity demonstrates the effects of planning to meet capacity and energy requirements in a case where both load and energy grow at a rate that is higher than the expected rate used in the base case economic evaluation presented in Section B.5.0. This scenario requires the addition of more generation to meet reserve margin requirements and, therefore, results in increased CPWCs compared to the base case capacity expansion plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section B.3.0. Tables B.6-5 and B.6-6 present FMPA's projected reliability levels under the high load and energy growth scenario for the winter and summer seasons, respectively.

Although the need for capacity additions is shown as early as 2006 in Tables B.6-5 and B.6-6, this need was not considered in the development of optimal capacity expansion plans, since construction and development schedules would preclude the addition of any of the supply-side alternatives presented in Section A.6.0 to meet this need. The need for capacity in both cases (with and without TEC) was not considered until 2008. In the base case analysis presented in Section B.5.0, the TCEC unit would be added in 2008 and two new peaking units would be added in the summer of 2010, as indicated in FMPA's 2006 Ten-Year Site Plan. Since the high load forecast shows a deficit starting in 2008, the two new peaking units added in the summer of 2010 in the base case have not been added in this case; instead, POWROPT was allowed to optimize additions to meet the projected capacity need starting in 2008.

Under the high load and energy growth sensitivity analysis, the optimal capacity expansion plan with TEC in 2012 consists of a brownfield LM6000 unit in 2008; a brownfield GE 7FA CT unit in 2010; a brownfield LMS100 unit in 2011; greenfield CFB units in 2014, 2017, and 2021; and a brownfield LM6000 unit in 2025. The optimal capacity expansion plan without participation in TEC consists of a brownfield LM6000 unit in 2008, a brownfield GE 7FA CT unit in 2010, a brownfield LMS100 unit in 2011, a greenfield CFB unit in 2012, a brownfield LMS100 unit in 2013, greenfield CFB units in 2014 and 2018, and a greenfield 1x1 IGCC unit in 2022.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $10,392.7 million and $10,853.3 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $460.6 million over the evaluation period.

B.6.1.4 Low Load and Energy Growth

The low load and energy growth sensitivity demonstrates the effects of planning to meet capacity and energy requirements in a case where both load and energy grow at a rate that is lower than the expected rate used in the base case economic evaluation. This scenario requires the addition of less generation to meet reserve margin requirements and, therefore, results in decreased CPWCs over the planning period compared to the base case capacity expansion plan. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section B.3.0. Tables B.6-7 and B.6-8 present FMPA's projected reliability levels under the low load and energy growth scenario for the winter and summer seasons, respectively. In the base case analysis presented in Section B.5.0, the TCEC unit would be added in 2008 and two new peaking units would be added in the summer of 2010, as indicated in FMPA's 2006 Ten-Year Site Plan. Since the low load forecast shows no deficit until 2012 after TCEC is added, the two new peaking units added in the summer of 2010 in the base case have not been added in this case; instead, POWROPT was allowed to optimize additions to meet the projected capacity need starting in 2012.

Under the low load and energy growth sensitivity analysis, the optimal capacity expansion plan with TEC in 2012 consists of a brownfield LMS100 unit in 2011 and a greenfield CFB unit in 2016. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 unit in 2011, a greenfield CFB unit in 2012, a second greenfield CFB unit in 2014, and a brownfield LM6000 unit in 2025.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $7,539.6 million and $7,952.2 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $412.6 million over the evaluation period.

B.6.1.5 High Capital Costs

In the high capital cost sensitivity, the capital costs for the candidate units and the proposed TEC are increased by 20 percent. Considering an increase in capital costs helps capture uncertainty related to the future costs of material, labor, and equipment. Increasing capital costs can change the emphasis on the timing of capital intensive units and may result in the selection of units with relatively lower capital costs but higher operating and production costs earlier than units with relatively higher capital costs but lower operating and production costs.

Table B.6-5
Projected Reliability Levels for High Load and Energy Growth - Winter

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements[1] (MW)	Net Firm Capacity Additions/ Reductions[2] (MW)	Net System Capacity (MW)	System Peak Demand[3]		Reserve Margin[4]		Excess/(Deficit) to Maintain 15 Percent Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2006/07	1,391	286	150	0	0	1,827	1,554	1,554	19.5%	19.5%	62	62
2007/08	1,391	343	75	0	0	1,809	1,597	1,597	13.9%	13.9%	(16)	(16)
2008/09	1,391	343	105	(118)	318	2,039	1,654	1,654	24.8%	24.8%	152	152
2009/10	1,391	243	85	(321)	318	1,715	1,474	1,474	17.4%	17.4%	33	33
2010/11	1,391	243	45	(321)	318	1,675	1,513	1,513	11.1%	11.1%	(58)	(58)
2011/12	1,391	243	45	(366)	318	1,630	1,552	1,552	5.2%	5.2%	(148)	(148)
2012/13	1,391	243	45	(463)	318	1,533	1,594	1,594	-3.9%	-3.9%	(293)	(293)
2013/14	1,391	157	0	(463)	318	1,402	1,638	1,638	-14.4%	-14.4%	(481)	(481)
2014/15	1,391	157	0	(463)	318	1,402	1,682	1,682	-16.6%	-16.6%	(532)	(532)
2015/16	1,391	157	0	(463)	318	1,402	1,728	1,728	-18.8%	-18.8%	(585)	(585)
2016/17	1,391	157	0	(463)	318	1,402	1,774	1,774	-20.9%	-20.9%	(638)	(638)
2017/18	1,391	157	0	(463)	318	1,402	1,820	1,820	-22.9%	-22.9%	(690)	(690)
2018/19	1,391	157	0	(463)	318	1,402	1,866	1,866	-24.9%	-24.9%	(744)	(744)
2019/20	1,391	157	0	(463)	318	1,402	1,913	1,913	-26.7%	-26.7%	(798)	(798)
2020/21	1,391	157	0	(463)	318	1,402	1,962	1,962	-28.5%	-28.5%	(854)	(854)
2021/22	1,391	157	0	(463)	318	1,402	2,012	2,012	-30.3%	-30.3%	(911)	(911)
2022/23	1,391	157	0	(463)	318	1,402	2,063	2,063	-32.0%	-32.0%	(970)	(970)
2023/24	1,391	157	0	(463)	318	1,402	2,114	2,114	-33.7%	-33.7%	(1,029)	(1,029)
2024/25	1,391	157	0	(463)	318	1,402	2,167	2,167	-35.3%	-35.3%	(1,090)	(1,090)

(1)Assumes retirements described in Section 2.0.
(2)Firm capacity addition only includes TCEC Unit 1 combined cycle (June 2008).
(3)Reflects adjustments to forecast peak demand to account for transmission losses over FPL's transmission system as described previously in this section.
(4)Reserve margin calculated as (Net System Capacity - PR Purchases) - (System Peak Demand - PR Purchases) / (System Peak Demand - PR Purchases).

Table B.6-6
Projected Reliability Levels for High Load and Energy Growth - Summer

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements(1) (MW)	Net Firm Capacity Additions/ Reductions(2) (MW)	Net System Capacity (MW)	System Peak Demand(3)		Reserve Margin(4)		Excess/(Deficit) to Maintain 18 Percent Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2006	1,313	279	160	0	0	1,753	1,554	1,554	14.3%	14.3%	(52)	(52)
2007	1,313	280	150	(1)	0	1,742	1,597	1,597	10.1%	10.1%	(115)	(115)
2008	1,313	337	75	(111)	296	1,910	1,641	1,641	17.2%	17.2%	(13)	(13)
2009	1,313	337	105	(111)	296	1,940	1,697	1,697	15.3%	15.3%	(43)	(43)
2010	1,313	237	85	(296)	296	1,635	1,549	1,549	5.9%	5.9%	(177)	(177)
2011	1,313	237	45	(296)	296	1,595	1,590	1,590	0.3%	0.3%	(273)	(273)
2012	1,313	237	45	(430)	296	1,461	1,633	1,633	-10.8%	-10.8%	(457)	(457)
2013	1,313	237	0	(430)	296	1,416	1,676	1,676	-15.5%	-15.5%	(562)	(562)
2014	1,313	157	0	(430)	296	1,337	1,722	1,722	-22.4%	-22.4%	(695)	(695)
2015	1,313	157	0	(430)	296	1,337	1,769	1,769	-24.4%	-24.4%	(750)	(750)
2016	1,313	157	0	(430)	296	1,337	1,816	1,816	-26.4%	-26.4%	(806)	(806)
2017	1,313	157	0	(430)	296	1,337	1,864	1,864	-28.3%	-28.3%	(862)	(862)
2018	1,313	157	0	(430)	296	1,337	1,911	1,911	-30.1%	-30.1%	(918)	(918)
2019	1,313	157	0	(430)	296	1,337	1,959	1,959	-31.8%	-31.8%	(975)	(975)
2020	1,313	157	0	(430)	296	1,337	2,008	2,008	-33.4%	-33.4%	(1,033)	(1,033)
2021	1,313	157	0	(430)	296	1,337	2,059	2,059	-35.1%	-35.1%	(1,092)	(1,092)
2022	1,313	157	0	(430)	296	1,337	2,110	2,110	-36.7%	-36.7%	(1,154)	(1,154)
2023	1,313	157	0	(430)	296	1,337	2,163	2,163	-38.2%	-38.2%	(1,216)	(1,216)
2024	1,313	157	0	(430)	296	1,337	2,217	2,217	-39.7%	-39.7%	(1,279)	(1,279)
2025	1,313	157	0	(430)	296	1,337	2,271	2,271	-41.1%	-41.1%	(1,343)	(1,343)

(1)Assumes retirements described in Section 2.0.
(2)Firm capacity addition only includes TCEC Unit 1 combined cycle (June 2008).
(3)Reflects adjustments to forecast peak demand to account for transmission losses over FPL's transmission system as described previously in this section.
(4)Reserve margin calculated as (Net System Capacity - PR Purchases) - (System Peak Demand - PR Purchases) / (System Peak Demand - PR Purchases).

Table B.6-7
Projected Reliability Levels for Low Load and Energy Growth - Winter

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements[1] (MW)	Net Firm Capacity Additions/ Reductions[2] (MW)	Net System Capacity (MW)	System Peak Demand[3]		Reserve Margin[4]		Excess/(Deficit) to Maintain 15 Percent Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2006/07	1,391	286	150	0	0	1,827	1,394	1,394	34.8%	34.8%	246	246
2007/08	1,391	343	75	0	0	1,809	1,415	1,415	29.4%	29.4%	193	193
2008/09	1,391	343	105	(118)	318	2,039	1,448	1,448	44.0%	44.0%	389	389
2009/10	1,391	243	85	(321)	318	1,715	1,280	1,280	36.4%	36.4%	256	256
2010/11	1,391	243	45	(321)	318	1,675	1,298	1,298	30.1%	30.1%	189	189
2011/12	1,391	243	45	(366)	318	1,630	1,317	1,317	24.7%	24.7%	123	123
2012/13	1,391	243	45	(463)	318	1,533	1,336	1,336	15.3%	15.3%	4	4
2013/14	1,391	157	0	(463)	318	1,402	1,356	1,356	3.4%	3.4%	(157)	(157)
2014/15	1,391	157	0	(463)	318	1,402	1,376	1,376	1.9%	1.9%	(181)	(181)
2015/16	1,391	157	0	(463)	318	1,402	1,397	1,397	0.4%	0.4%	(204)	(204)
2016/17	1,391	157	0	(463)	318	1,402	1,417	1,417	-1.0%	-1.0%	(227)	(227)
2017/18	1,391	157	0	(463)	318	1,402	1,436	1,436	-2.3%	-2.3%	(249)	(249)
2018/19	1,391	157	0	(463)	318	1,402	1,454	1,454	-3.6%	-3.6%	(270)	(270)
2019/20	1,391	157	0	(463)	318	1,402	1,472	1,472	-4.8%	-4.8%	(291)	(291)
2020/21	1,391	157	0	(463)	318	1,402	1,491	1,491	-5.9%	-5.9%	(312)	(312)
2021/22	1,391	157	0	(463)	318	1,402	1,509	1,509	-7.1%	-7.1%	(334)	(334)
2022/23	1,391	157	0	(463)	318	1,402	1,528	1,528	-8.2%	-8.2%	(355)	(355)
2023/24	1,391	157	0	(463)	318	1,402	1,546	1,546	-9.3%	-9.3%	(376)	(376)
2024/25	1,391	157	0	(463)	318	1,402	1,564	1,564	-10.3%	-10.3%	(396)	(396)

(1) Assumes retirements described in Section 2.0.
(2) Firm capacity addition only includes TCEC Unit 1 combined cycle (June 2008).
(3) Reflects adjustments to forecast peak demand to account for transmission losses over FPL's transmission system as described previously in this section.
(4) Reserve margin calculated as (Net System Capacity - PR Purchases) - (System Peak Demand - PR Purchases) / (System Peak Demand - PR Purchases).

Table B.6-8
Projected Reliability Levels for Low Load and Energy Growth - Summer

Year	Net Generating Capacity (MW)	Non-Partial Requirements Purchases (MW)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements(1) (MW)	Net Firm Capacity Additions/ Reductions(2) (MW)	Net System Capacity (MW)	System Peak Demand(3)		Reserve Margin(4)		Excess/(Deficit) to Maintain 18 Percent Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2006	1,313	279	160	0	0	1,753	1,411	1,411	27.3%	27.3%	116	116
2007	1,313	280	150	(1)	0	1,742	1,433	1,433	24.2%	24.2%	79	79
2008	1,313	337	75	(111)	296	1,910	1,455	1,455	33.0%	33.0%	207	207
2009	1,313	337	105	(111)	296	1,940	1,486	1,486	32.9%	32.9%	206	206
2010	1,313	237	85	(296)	296	1,635	1,345	1,345	23.1%	23.1%	64	64
2011	1,313	237	45	(296)	296	1,595	1,364	1,364	17.5%	17.5%	(6)	(6)
2012	1,313	237	45	(430)	296	1,461	1,384	1,384	5.8%	5.8%	(164)	(164)
2013	1,313	237	0	(430)	296	1,416	1,404	1,404	0.9%	0.9%	(241)	(241)
2014	1,313	157	0	(430)	296	1,337	1,425	1,425	-6.2%	-6.2%	(345)	(345)
2015	1,313	157	0	(430)	296	1,337	1,446	1,446	-7.6%	-7.6%	(370)	(370)
2016	1,313	157	0	(430)	296	1,337	1,467	1,467	-8.9%	-8.9%	(395)	(395)
2017	1,313	157	0	(430)	296	1,337	1,488	1,488	-10.1%	-10.1%	(419)	(419)
2018	1,313	157	0	(430)	296	1,337	1,507	1,507	-11.3%	-11.3%	(442)	(442)
2019	1,313	157	0	(430)	296	1,337	1,526	1,526	-12.4%	-12.4%	(464)	(464)
2020	1,313	157	0	(430)	296	1,337	1,545	1,545	-13.5%	-13.5%	(486)	(486)
2021	1,313	157	0	(430)	296	1,337	1,564	1,564	-14.5%	-14.5%	(508)	(508)
2022	1,313	157	0	(430)	296	1,337	1,583	1,583	-15.5%	-15.5%	(531)	(531)
2023	1,313	157	0	(430)	296	1,337	1,602	1,602	-16.5%	-16.5%	(553)	(553)
2024	1,313	157	0	(430)	296	1,337	1,620	1,620	-17.5%	-17.5%	(575)	(575)
2025	1,313	157	0	(430)	296	1,337	1,639	1,639	-18.4%	-18.4%	(597)	(597)

(1)Assumes retirements described in Section 2.0.
(2)Firm capacity addition only includes TCEC Unit 1 combined cycle (June 2008).
(3)Reflects adjustments to forecast peak demand to account for transmission losses over FPL's transmission system as described previously in this section.
(4)Reserve margin calculated as (Net System Capacity - PR Purchases) - (System Peak Demand - PR Purchases) / (System Peak Demand - PR Purchases).

Under the high capital cost scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield LMS100 unit in 2011, a greenfield CFB unit in 2014, a brownfield LM6000 unit in 2019, and a greenfield CFB unit in 2020. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 unit in 2011, greenfield CFB units in 2012 and 2014, a brownfield LMS100 unit in 2018, and a greenfield CFB unit in 2020.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are \$9,222.9 million and \$9,634.5 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by \$411.6 million over the evaluation period.

B.6.1.6 Low Capital Costs

In the low capital cost sensitivity, the capital costs for the candidate units and the proposed TEC are decreased by 20 percent. Considering a decrease in capital costs helps capture uncertainty related to the future costs of material, labor, and equipment. Decreasing capital costs can change the emphasis on the timing of capital intensive units and may result in the selection of units with relatively higher capital costs but lower operating and production costs earlier than units with relatively lower capital costs but higher operating and production costs.

Under the low capital cost scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield LMS100 unit in 2011, greenfield CFB units in 2014 and 2019, and a brownfield LM6000 unit in 2025. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 unit in 2011, greenfield CFB units in 2012, 2014, and 2018, and a brownfield LMS100 unit in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are \$8,632.6 million and \$9,024.0 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by \$391.4 million over the evaluation period.

B.6.1.7 High Emissions Allowance Prices

The base economic analysis presented in Section B.5.0 utilizes the base fuel and corresponding emissions allowance price forecasts provided by Hill & Associates. Historically, prices for emissions allowances have been volatile, and this sensitivity demonstrates the effects of higher allowance prices than the forecasts provided by Hill & Associates.

In the high emissions allowance price sensitivity case, the base case allowance price forecasts provided by Hill & Associates were increased by 25 percent on an annual basis, while the fuel price forecasts were left unchanged from those provided by Hill & Associates in the base case. Increasing the allowance prices results in a higher fuel cost adder for the fuels being burned in the existing and candidate generating units. The increase in allowance prices results in a greater economic incentive to operate units with lower emissions rates for electric generation, and also results in higher CPWCs relative to the base case economic analysis. Table B.6-9 presents the emissions allowance prices used in the high emissions allowance price sensitivity analysis. Tables B.6-10 and B.6-11 present the emissions cost adders included for FMPA's existing and candidate units, respectively, for the high emissions allowance price sensitivity. In years when existing units are no longer available to FMPA through retirement or, in the case of Vero Beach, through its Notice of Establishment of Contract Rate of Delivery, "N/A" is used to indicate that the adders are no longer applicable since the resources are not included in FMPA's dispatch model.

In the high emissions allowance price scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield LMS100 unit in 2011, greenfield CFB units in 2014 and 2019, and a brownfield LM6000 unit in 2025. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 unit in 2011; greenfield CFB units in 2012, 2014, and 2018; and a brownfield LMS100 unit in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $9,050.0 million and $9,458.5 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $408.5 million over the evaluation period.

B.6.1.8 Low Emissions Allowance Prices

In the low emissions allowance price sensitivity case, the base case allowance price forecasts provided by Hill & Associates were decreased by 25 percent on an annual basis, while the fuel price forecasts were left unchanged from those provided by Hill & Associates in the base case. Decreasing the allowance prices results in a lower fuel cost adder for the fuels being burned in existing and candidate generating units. The decrease in allowance prices reduces the economic incentive to operate units with lower emissions rates for electric generation, and also results in lower CPWCs relative to the base case economic analysis. Table B.6-9 presents the emissions allowance prices used in the low emissions allowance price sensitivity analysis. Tables B.6-12 and B.6-13 present the emissions cost adders included for FMPA's existing and candidate units, respectively, for

Table B.6-9
High and Low Allowance Prices
(Nominal Dollars)

Calendar Year	High Sensitivity			Low Sensitivity		
	SO_2 ($/ton)	NO_x ($/ton)	Hg ($/lb)	SO_2 ($/ton)	NO_x ($/ton)	Hg ($/lb)
2009	--	$2,864	--	--	$1,718	--
2010	$480	$3,994	$21,103	$288	$2,397	$12,662
2011	$490	$4,189	$21,491	$294	$2,513	$12,894
2012	$566	$4,358	$17,393	$340	$2,615	$10,436
2013	$581	$4,463	$22,743	$348	$2,678	$13,646
2014	$754	$4,834	$13,549	$452	$2,900	$8,129
2015	$1,075	$7,721	$26,165	$645	$4,632	$15,699
2016	$1,247	$8,346	$17,456	$748	$5,008	$10,473
2017	$1,398	$7,163	$16,616	$839	$4,298	$9,970
2018	$1,465	$7,413	$33,133	$879	$4,448	$19,880
2019	$1,493	$9,725	$32,251	$896	$5,835	$19,351
2020	$1,629	$11,726	$33,057	$978	$7,036	$19,834
2021	$1,778	$11,146	$36,152	$1,067	$6,688	$21,691
2022	$1,913	$10,650	$38,114	$1,148	$6,390	$22,869
2023	$2,076	$13,676	$69,280	$1,246	$8,206	$41,568
2024	$2,379	$20,578	$71,286	$1,427	$12,347	$42,771
2025	$2,437	$22,318	$113,955	$1,462	$13,391	$68,373
2026	$2,479	$24,131	$125,244	$1,487	$14,479	$75,146
2027	$2,621	$26,022	$137,025	$1,573	$15,613	$82,215
2028	$2,769	$27,991	$149,318	$1,661	$16,795	$89,591
2029	$2,923	$30,043	$162,139	$1,754	$18,026	$97,284
2030	$3,082	$32,180	$175,509	$1,849	$19,308	$105,305
2031	$3,250	$34,469	$189,980	$1,950	$20,681	$113,988
2032	$3,428	$36,921	$205,645	$2,057	$22,153	$123,387
2033	$3,615	$39,547	$222,602	$2,169	$23,728	$133,561
2034	$3,812	$42,360	$240,956	$2,287	$25,416	$144,574
2035	$4,021	$45,373	$260,824	$2,412	$27,224	$156,495

Table B.6-10
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Existing Units - High Allowance Prices
(Nominal $/MBtu)

Calendar Year	Cane Island CT 1	Cane Island CC 2	Cane Island CC 3	Vero ST 3	Vero ST 4	SEC A	Vero CC 5	Hansel CC	LWU CC	LWU CT 1	Stanton 1	Stanton 2	Stock Island CT 4
2009	$0.13	$0.07	$0.01	$0.17	$0.16	$0.02	$0.06	$0.46	$0.10	$1.26	$0.63	$0.24	$0.01
2010	$0.18	$0.10	$0.02	$0.25	$0.23	$0.03	$0.08	$0.64	$0.14	$1.77	$0.21	$0.19	$0.01
2011	$0.19	$0.10	$0.02	N/A	N/A	$0.03	N/A	$0.67	$0.15	$1.85	$0.22	$0.20	$0.02
2012	$0.20	$0.11	$0.02	N/A	N/A	$0.03	N/A	N/A	$0.15	$1.93	$0.23	$0.21	$0.02
2013	$0.20	$0.11	$0.02	N/A	N/A	$0.03	N/A	N/A	N/A	N/A	$0.24	$0.22	$0.02
2014	$0.22	$0.12	$0.02	N/A	N/A	$0.03	N/A	N/A	N/A	N/A	$0.26	$0.24	$0.02
2015	$0.35	$0.19	$0.04	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.41	$0.37	$0.03
2016	$0.38	$0.21	$0.04	N/A	N/A	$0.06	N/A	N/A	N/A	N/A	$0.44	$0.40	$0.03
2017	$0.33	$0.18	$0.04	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.42	$0.38	$0.03
2018	$0.34	$0.19	$0.04	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.45	$0.41	$0.03
2019	$0.44	$0.24	$0.05	N/A	N/A	$0.07	N/A	N/A	N/A	N/A	$0.53	$0.48	$0.04
2020	$0.53	$0.29	$0.06	N/A	N/A	$0.08	N/A	N/A	N/A	N/A	$0.61	$0.56	$0.04
2021	$0.51	$0.28	$0.06	N/A	N/A	$0.08	N/A	N/A	N/A	N/A	$0.61	$0.56	$0.04
2022	$0.48	$0.27	$0.05	N/A	N/A	$0.07	N/A	N/A	N/A	N/A	$0.61	$0.56	$0.04
2023	$0.62	$0.34	$0.07	N/A	N/A	$0.09	N/A	N/A	N/A	N/A	$0.77	$0.70	$0.05
2024	$0.93	$0.52	$0.10	N/A	N/A	$0.14	N/A	N/A	N/A	N/A	$1.03	$0.95	$0.07
2025	$1.01	$0.56	$0.11	N/A	N/A	$0.15	N/A	N/A	N/A	N/A	$1.14	$1.05	$0.08
2026	$1.09	$0.60	$0.12	N/A	N/A	$0.16	N/A	N/A	N/A	N/A	$1.22	$1.12	$0.09
2027	$1.18	$0.65	$0.13	N/A	N/A	$0.17	N/A	N/A	N/A	N/A	$1.31	$1.21	$0.09
2028	$1.27	$0.70	$0.14	N/A	N/A	$0.19	N/A	N/A	N/A	N/A	$1.41	$1.30	$0.10
2029	$1.36	$0.75	$0.15	N/A	N/A	$0.20	N/A	N/A	N/A	N/A	$1.51	$1.39	$0.11
2030	$1.45	$0.81	$0.16	N/A	N/A	$0.22	N/A	N/A	N/A	N/A	$1.61	$1.49	$0.12
2031	$1.56	$0.86	$0.17	N/A	N/A	$0.23	N/A	N/A	N/A	N/A	$1.72	$1.59	$0.12
2032	$1.67	$0.92	$0.19	N/A	N/A	$0.25	N/A	N/A	N/A	N/A	$1.84	$1.70	$0.13
2033	$1.79	$0.99	$0.20	N/A	N/A	$0.27	N/A	N/A	N/A	N/A	$1.97	$1.82	$0.14
2034	$1.91	$1.06	$0.21	N/A	N/A	$0.28	N/A	N/A	N/A	N/A	$2.10	$1.94	$0.15
2035	$2.05	$1.14	$0.23	N/A	N/A	$0.30	N/A	N/A	N/A	N/A	$2.25	$2.08	$0.16

Table B.6-11
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Candidate Units - High Allowance Prices
(Nominal $/MBtu)

Calendar Year	TEC	Simple Cycle Units(1)	GE 7FA 1x1 Combined Cycle	CFB	IGCC
2009	$0.10	$0.01	$0.01	$0.13	$0.09
2010	$0.19	$0.01	$0.01	$0.24	$0.13
2011	$0.20	$0.02	$0.02	$0.25	$0.13
2012	$0.20	$0.02	$0.02	$0.25	$0.14
2013	$0.21	$0.02	$0.02	$0.27	$0.14
2014	$0.22	$0.02	$0.02	$0.28	$0.15
2015	$0.36	$0.03	$0.03	$0.45	$0.24
2016	$0.37	$0.03	$0.03	$0.47	$0.26
2017	$0.34	$0.03	$0.03	$0.42	$0.23
2018	$0.37	$0.03	$0.03	$0.47	$0.24
2019	$0.45	$0.04	$0.04	$0.57	$0.31
2020	$0.53	$0.04	$0.04	$0.67	$0.37
2021	$0.52	$0.04	$0.04	$0.66	$0.35
2022	$0.51	$0.04	$0.04	$0.64	$0.34
2023	$0.67	$0.05	$0.05	$0.84	$0.44
2024	$0.93	$0.07	$0.08	$1.17	$0.65
2025	$1.05	$0.08	$0.08	$1.31	$0.71
2026	$1.13	$0.09	$0.09	$1.42	$0.77
2027	$1.22	$0.09	$0.10	$1.53	$0.83
2028	$1.31	$0.10	$0.10	$1.64	$0.89
2029	$1.41	$0.11	$0.11	$1.76	$0.96
2030	$1.51	$0.12	$0.12	$1.89	$1.02
2031	$1.62	$0.12	$0.13	$2.02	$1.10
2032	$1.73	$0.13	$0.14	$2.17	$1.17
2033	$1.86	$0.14	$0.15	$2.32	$1.26
2034	$1.99	$0.15	$0.16	$2.49	$1.35
2035	$2.13	$0.16	$0.17	$2.67	$1.44

(1)Simple cycle resources considered for FMPA include LM6000, LMS100, GE 7EA, and GE 7FA.

Table B.6-12
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Existing Units - Low Allowance Prices
(Nominal $/MBtu)

Calendar Year	Cane Island CT 1	Cane Island CC 2	Cane Island CC 3	Vero ST 3	Vero ST 4	SEC A	Vero CC 5	Hansel CC	LWU CC	LWU CT 1	Stanton 1	Stanton 2	Stock Island CT 4
2009	$0.08	$0.04	$0.01	$0.10	$0.09	$0.01	$0.03	$0.27	$0.06	$0.76	$0.38	$0.15	$0.01
2010	$0.11	$0.06	$0.01	$0.15	$0.14	$0.02	$0.05	$0.38	$0.08	$1.06	$0.13	$0.12	$0.01
2011	$0.11	$0.06	$0.01	N/A	N/A	$0.02	N/A	$0.40	$0.09	$1.11	$0.13	$0.12	$0.01
2012	$0.12	$0.07	$0.01	N/A	N/A	$0.02	N/A	N/A	$0.09	$1.16	$0.14	$0.13	$0.01
2013	$0.12	$0.07	$0.01	N/A	N/A	$0.02	N/A	N/A	N/A	N/A	$0.14	$0.13	$0.01
2014	$0.13	$0.07	$0.01	N/A	N/A	$0.02	N/A	N/A	N/A	N/A	$0.16	$0.14	$0.01
2015	$0.21	$0.12	$0.02	N/A	N/A	$0.03	N/A	N/A	N/A	N/A	$0.24	$0.22	$0.02
2016	$0.23	$0.13	$0.03	N/A	N/A	$0.03	N/A	N/A	N/A	N/A	$0.26	$0.24	$0.02
2017	$0.20	$0.11	$0.02	N/A	N/A	$0.03	N/A	N/A	N/A	N/A	$0.25	$0.23	$0.02
2018	$0.20	$0.11	$0.02	N/A	N/A	$0.03	N/A	N/A	N/A	N/A	$0.27	$0.25	$0.02
2019	$0.26	$0.15	$0.03	N/A	N/A	$0.04	N/A	N/A	N/A	N/A	$0.32	$0.29	$0.02
2020	$0.32	$0.18	$0.04	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.37	$0.33	$0.03
2021	$0.30	$0.17	$0.03	N/A	N/A	$0.05	N/A	N/A	N/A	N/A	$0.37	$0.34	$0.02
2022	$0.29	$0.16	$0.03	N/A	N/A	$0.04	N/A	N/A	N/A	N/A	$0.37	$0.34	$0.02
2023	$0.37	$0.21	$0.04	N/A	N/A	$0.06	N/A	N/A	N/A	N/A	$0.46	$0.42	$0.03
2024	$0.56	$0.31	$0.06	N/A	N/A	$0.08	N/A	N/A	N/A	N/A	$0.62	$0.57	$0.04
2025	$0.61	$0.34	$0.07	N/A	N/A	$0.09	N/A	N/A	N/A	N/A	$0.69	$0.63	$0.05
2026	$0.65	$0.36	$0.07	N/A	N/A	$0.10	N/A	N/A	N/A	N/A	$0.73	$0.67	$0.05
2027	$0.71	$0.39	$0.08	N/A	N/A	$0.10	N/A	N/A	N/A	N/A	$0.79	$0.73	$0.06
2028	$0.76	$0.42	$0.08	N/A	N/A	$0.11	N/A	N/A	N/A	N/A	$0.84	$0.78	$0.06
2029	$0.81	$0.45	$0.09	N/A	N/A	$0.12	N/A	N/A	N/A	N/A	$0.90	$0.83	$0.07
2030	$0.87	$0.48	$0.10	N/A	N/A	$0.13	N/A	N/A	N/A	N/A	$0.97	$0.89	$0.07
2031	$0.93	$0.52	$0.10	N/A	N/A	$0.14	N/A	N/A	N/A	N/A	$1.03	$0.95	$0.07
2032	$1.00	$0.55	$0.11	N/A	N/A	$0.15	N/A	N/A	N/A	N/A	$1.10	$1.02	$0.08
2033	$1.07	$0.59	$0.12	N/A	N/A	$0.16	N/A	N/A	N/A	N/A	$1.18	$1.09	$0.09
2034	$1.15	$0.64	$0.13	N/A	N/A	$0.17	N/A	N/A	N/A	N/A	$1.26	$1.17	$0.09
2035	$1.23	$0.68	$0.14	N/A	N/A	$0.18	N/A	N/A	N/A	N/A	$1.35	$1.25	$0.10

Table B.6-13
Combined SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Candidate Units - Low Allowance Prices
(Nominal $/MBtu)

Calendar Year	TEC	Simple Cycle Units[(1)]	GE 7FA 1x1 Combined Cycle	CFB	IGCC
2009	$0.06	$0.01	$0.01	$0.08	$0.05
2010	$0.11	$0.01	$0.01	$0.14	$0.08
2011	$0.12	$0.01	$0.01	$0.15	$0.08
2012	$0.12	$0.01	$0.01	$0.15	$0.08
2013	$0.13	$0.01	$0.01	$0.16	$0.09
2014	$0.13	$0.01	$0.01	$0.17	$0.09
2015	$0.21	$0.02	$0.02	$0.27	$0.15
2016	$0.22	$0.02	$0.02	$0.28	$0.16
2017	$0.20	$0.02	$0.02	$0.25	$0.14
2018	$0.22	$0.02	$0.02	$0.28	$0.14
2019	$0.27	$0.02	$0.02	$0.34	$0.19
2020	$0.32	$0.03	$0.03	$0.40	$0.22
2021	$0.31	$0.02	$0.02	$0.39	$0.21
2022	$0.31	$0.02	$0.02	$0.39	$0.20
2023	$0.40	$0.03	$0.03	$0.50	$0.26
2024	$0.56	$0.04	$0.05	$0.70	$0.39
2025	$0.63	$0.05	$0.05	$0.79	$0.43
2026	$0.68	$0.05	$0.05	$0.85	$0.46
2027	$0.73	$0.06	$0.06	$0.92	$0.50
2028	$0.79	$0.06	$0.06	$0.99	$0.53
2029	$0.85	$0.07	$0.07	$1.06	$0.57
2030	$0.91	$0.07	$0.07	$1.13	$0.61
2031	$0.97	$0.07	$0.08	$1.21	$0.66
2032	$1.04	$0.08	$0.08	$1.30	$0.70
2033	$1.12	$0.09	$0.09	$1.39	$0.75
2034	$1.19	$0.09	$0.09	$1.49	$0.81
2035	$1.28	$0.10	$0.10	$1.60	$0.87

[(1)]Simple cycle resources considered for FMPA include LM6000, LMS100, GE 7EA, and GE 7FA.

the low emissions allowance price sensitivity. In years when existing units are no longer available to FMPA through retirement or, in the case of Vero Beach, through its Notice of Establishment of Contract Rate of Delivery, "N/A" is used to indicate that the adders are no longer applicable since the resources are not included in FMPA's dispatch model.

In the low emissions allowance price scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield LMS100 unit in 2011, greenfield CFB units in 2014 and 2019, and a brownfield LM6000 unit in 2025. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 unit in 2011; greenfield CFB units in 2012, 2014, and 2018; and a brownfield LMS100 unit in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $8,807.6 million and $9,178.6 million, respectively. A comparison of the CPWCs shows that the case with/without TEC is the least-cost plan by $371.0 million over the evaluation period.

B.6.1.9 Carbon Dioxide Regulation Sensitivity

This sensitivity, which is presented for information purposes only, considers the potential economic impact associated with a regulatory environment in which emissions of CO_2 would be subject to a cap-and-trade program, similar to that contemplated under CAIR and CAMR. To date, the United States has not mandated any reductions in CO_2 emissions through nationwide environmental regulations. However, in the last few years, legislation has been proposed suggesting various approaches to regulating CO_2 emissions in the United States. Section A.4.0 presented a description of Hill & Associates' assumptions utilized in developing the fuel price forecast and corresponding emissions allowance price forecasts for a scenario in which CO_2 emissions are regulated and a cap-and-trade market evolves for CO_2 allowances. As described in Section A.4.0 and discussed further in Section A.5.0, the assumptions supporting Hill & Associates' regulated-CO_2 sensitivity case fuel and emissions allowance price forecasts are based on the utility industry complying with the proposed McCain-Lieberman *Climate Stewardship Act of 2005* (S. 342, introduced to the 109th Congress).

Similar to the methodology described throughout this Application for consideration of the SO_2, NO_x, and Hg emissions allowance price forecasts, adders for the regulated-CO_2 emissions allowance price forecasts were developed for each existing and candidate unit being considered. Tables B.6-14 and B.6-15 present the CO_2 cost adders for FMPA's existing and candidate units, respectively, for the CO_2 regulation sensitivity. Tables B.6-16 and B.6-17 present the combined adders for CO_2, SO_2, NO_x, and Hg for FMPA's existing and candidate units, respectively, for the CO_2 regulation

Table B.6-14
CO_2 Emissions Adders for FMPA's Existing Units – Regulated-CO_2 Sensitivity Case
(Nominal $/MBtu)

Calendar Year	Cane Island CT 1	Cane Island CC 2	Cane Island CC 3	Vero ST 3	Vero ST 4	SEC A	Vero CC 5	Hansel CC	LWU CC	LWU CT 1	Stanton 1	Stanton 2	Stock Island CT 4
2009	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2010	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011	$0.00	$0.00	$0.00	N/A	N/A	$0.00	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012	$0.31	$0.30	$0.29	N/A	N/A	$0.30	N/A	N/A	$0.30	$0.31	$0.51	$0.51	$0.29
2013	$0.63	$0.61	$0.60	N/A	N/A	$0.61	N/A	N/A	N/A	N/A	$1.06	$1.06	$0.59
2014	$0.83	$0.81	$0.79	N/A	N/A	$0.81	N/A	N/A	N/A	N/A	$1.39	$1.39	$0.78
2015	$0.79	$0.76	$0.75	N/A	N/A	$0.76	N/A	N/A	N/A	N/A	$1.32	$1.32	$0.74
2016	$0.83	$0.80	$0.79	N/A	N/A	$0.80	N/A	N/A	N/A	N/A	$1.38	$1.38	$0.77
2017	$0.74	$0.71	$0.70	N/A	N/A	$0.71	N/A	N/A	N/A	N/A	$1.23	$1.23	$0.69
2018	$0.21	$0.20	$0.19	N/A	N/A	$0.20	N/A	N/A	N/A	N/A	$0.34	$0.34	$0.19
2019	$0.30	$0.29	$0.28	N/A	N/A	$0.29	N/A	N/A	N/A	N/A	$0.50	$0.50	$0.28
2020	$0.23	$0.22	$0.22	N/A	N/A	$0.22	N/A	N/A	N/A	N/A	$0.38	$0.38	$0.21
2021	$0.27	$0.26	$0.26	N/A	N/A	$0.26	N/A	N/A	N/A	N/A	$0.45	$0.45	$0.25
2022	$0.59	$0.57	$0.55	N/A	N/A	$0.57	N/A	N/A	N/A	N/A	$0.98	$0.98	$0.55
2023	$0.76	$0.74	$0.72	N/A	N/A	$0.73	N/A	N/A	N/A	N/A	$1.27	$1.27	$0.71
2024	$0.60	$0.59	$0.57	N/A	N/A	$0.58	N/A	N/A	N/A	N/A	$1.01	$1.01	$0.56
2025	$0.70	$0.68	$0.66	N/A	N/A	$0.68	N/A	N/A	N/A	N/A	$1.17	$1.17	$0.65
2026	$0.75	$0.72	$0.71	N/A	N/A	$0.72	N/A	N/A	N/A	N/A	$1.25	$1.25	$0.70
2027	$0.83	$0.80	$0.78	N/A	N/A	$0.80	N/A	N/A	N/A	N/A	$1.38	$1.38	$0.77
2028	$0.91	$0.88	$0.86	N/A	N/A	$0.88	N/A	N/A	N/A	N/A	$1.52	$1.52	$0.85
2029	$1.00	$0.96	$0.94	N/A	N/A	$0.96	N/A	N/A	N/A	N/A	$1.66	$1.66	$0.93
2030	$1.09	$1.05	$1.03	N/A	N/A	$1.05	N/A	N/A	N/A	N/A	$1.81	$1.81	$1.01
2031	$1.19	$1.15	$1.12	N/A	N/A	$1.14	N/A	N/A	N/A	N/A	$1.97	$1.97	$1.10
2032	$1.29	$1.25	$1.22	N/A	N/A	$1.25	N/A	N/A	N/A	N/A	$2.15	$2.15	$1.20
2033	$1.41	$1.36	$1.33	N/A	N/A	$1.36	N/A	N/A	N/A	N/A	$2.35	$2.35	$1.31
2034	$1.54	$1.49	$1.45	N/A	N/A	$1.48	N/A	N/A	N/A	N/A	$2.56	$2.56	$1.43
2035	$1.68	$1.62	$1.58	N/A	N/A	$1.62	N/A	N/A	N/A	N/A	$2.79	$2.79	$1.56

Table B.6-15
CO_2 Emissions Adders for FMPA's Candidate Units –
Regulated-CO_2 Sensitivity Case
(Nominal $/MBtu)

Calendar Year	TEC	Simple Cycle Units(1)	GE 7FA 1x1 Combined Cycle	CFB	IGCC
2009	$0.00	$0.00	$0.00	$0.00	$0.00
2010	$0.00	$0.00	$0.00	$0.00	$0.00
2011	$0.00	$0.00	$0.00	$0.00	$0.00
2012	$0.53	$0.29	$0.29	$0.52	$0.52
2013	$1.09	$0.59	$0.59	$1.07	$1.07
2014	$1.43	$0.78	$0.78	$1.41	$1.40
2015	$1.35	$0.74	$0.74	$1.33	$1.33
2016	$1.42	$0.77	$0.77	$1.40	$1.40
2017	$1.26	$0.69	$0.69	$1.24	$1.24
2018	$0.35	$0.19	$0.19	$0.35	$0.35
2019	$0.52	$0.28	$0.28	$0.51	$0.51
2020	$0.39	$0.21	$0.21	$0.39	$0.38
2021	$0.47	$0.25	$0.25	$0.46	$0.46
2022	$1.00	$0.55	$0.55	$0.99	$0.99
2023	$1.30	$0.71	$0.71	$1.28	$1.28
2024	$1.04	$0.56	$0.56	$1.02	$1.02
2025	$1.20	$0.65	$0.65	$1.18	$1.18
2026	$1.28	$0.70	$0.70	$1.26	$1.26
2027	$1.42	$0.77	$0.77	$1.40	$1.39
2028	$1.56	$0.85	$0.85	$1.54	$1.53
2029	$1.71	$0.93	$0.93	$1.68	$1.68
2030	$1.86	$1.01	$1.01	$1.83	$1.83
2031	$2.03	$1.10	$1.10	$2.00	$1.99
2032	$2.21	$1.20	$1.20	$2.18	$2.17
2033	$2.41	$1.31	$1.31	$2.38	$2.37
2034	$2.63	$1.43	$1.43	$2.59	$2.58
2035	$2.87	$1.56	$1.56	$2.82	$2.81

(1)Simple cycle resources considered for FMPA include LM6000, LMS100, GE 7EA, and GE 7FA.

Table B.6-16
Combined CO_2, SO_2, NO_x, and Hg Emissions Cost Adders for FMPA's Existing Units – Regulated-CO_2 Sensitivity Case
(Nominal $/MBtu)

Calendar Year	Cane Island CT 1	Cane Island CC 2	Cane Island CC 3	Vero ST 3	Vero ST 4	SEC A	Vero CC 5	Hansel CC	LWU CC	LWU CT 1	Stanton 1	Stanton 2	Stock Island CT 4
2009	$0.08	$0.05	$0.01	$0.11	$0.10	$0.01	$0.04	$0.29	$0.06	$0.81	$0.40	$0.16	$0.01
2010	$0.11	$0.06	$0.01	$0.15	$0.13	$0.02	$0.05	$0.38	$0.08	$1.04	$0.13	$0.12	$0.01
2011	$0.11	$0.06	$0.01	N/A	N/A	$0.02	N/A	$0.39	$0.09	$1.09	$0.14	$0.13	$0.01
2012	$0.41	$0.35	$0.30	N/A	N/A	$0.31	N/A	N/A	$0.37	$1.26	$0.63	$0.62	$0.30
2013	$0.73	$0.67	$0.61	N/A	N/A	$0.63	N/A	N/A	N/A	N/A	$1.19	$1.18	$0.60
2014	$0.92	$0.86	$0.80	N/A	N/A	$0.82	N/A	N/A	N/A	N/A	$1.51	$1.50	$0.79
2015	$0.98	$0.87	$0.77	N/A	N/A	$0.79	N/A	N/A	N/A	N/A	$1.53	$1.51	$0.75
2016	$1.04	$0.92	$0.81	N/A	N/A	$0.83	N/A	N/A	N/A	N/A	$1.61	$1.59	$0.79
2017	$0.96	$0.84	$0.72	N/A	N/A	$0.74	N/A	N/A	N/A	N/A	$1.47	$1.45	$0.70
2018	$0.40	$0.31	$0.22	N/A	N/A	$0.23	N/A	N/A	N/A	N/A	$0.58	$0.56	$0.21
2019	$0.50	$0.40	$0.31	N/A	N/A	$0.32	N/A	N/A	N/A	N/A	$0.74	$0.72	$0.30
2020	$0.45	$0.35	$0.24	N/A	N/A	$0.25	N/A	N/A	N/A	N/A	$0.65	$0.63	$0.23
2021	$0.48	$0.38	$0.28	N/A	N/A	$0.29	N/A	N/A	N/A	N/A	$0.71	$0.69	$0.27
2022	$0.79	$0.68	$0.58	N/A	N/A	$0.60	N/A	N/A	N/A	N/A	$1.25	$1.23	$0.56
2023	$0.99	$0.86	$0.74	N/A	N/A	$0.77	N/A	N/A	N/A	N/A	$1.58	$1.55	$0.73
2024	$1.05	$0.83	$0.62	N/A	N/A	$0.65	N/A	N/A	N/A	N/A	$1.48	$1.44	$0.60
2025	$1.17	$0.94	$0.71	N/A	N/A	$0.75	N/A	N/A	N/A	N/A	$1.69	$1.65	$0.69
2026	$1.26	$1.01	$0.76	N/A	N/A	$0.80	N/A	N/A	N/A	N/A	$1.81	$1.77	$0.74
2027	$1.37	$1.10	$0.84	N/A	N/A	$0.88	N/A	N/A	N/A	N/A	$1.99	$1.94	$0.82
2028	$1.50	$1.21	$0.93	N/A	N/A	$0.97	N/A	N/A	N/A	N/A	$2.17	$2.12	$0.90
2029	$1.63	$1.31	$1.01	N/A	N/A	$1.06	N/A	N/A	N/A	N/A	$2.36	$2.31	$0.98
2030	$1.76	$1.43	$1.10	N/A	N/A	$1.15	N/A	N/A	N/A	N/A	$2.56	$2.50	$1.07
2031	$1.91	$1.55	$1.20	N/A	N/A	$1.25	N/A	N/A	N/A	N/A	$2.77	$2.71	$1.16
2032	$2.07	$1.68	$1.31	N/A	N/A	$1.36	N/A	N/A	N/A	N/A	$3.00	$2.94	$1.27
2033	$2.24	$1.82	$1.42	N/A	N/A	$1.48	N/A	N/A	N/A	N/A	$3.26	$3.19	$1.38
2034	$2.43	$1.98	$1.55	N/A	N/A	$1.61	N/A	N/A	N/A	N/A	$3.53	$3.46	$1.50
2035	$2.63	$2.15	$1.69	N/A	N/A	$1.76	N/A	N/A	N/A	N/A	$3.83	$3.76	$1.64

Table B.6-17
Combined CO_2, SO_2, NO_x, and Hg Emission Cost Adders for FMPA's Candidate Units – Regulated-CO_2 Sensitivity Case
(Nominal $/MBtu)

Calendar Year	TEC	Simple Cycle Units [1]	GE 7FA 1x1 Combined Cycle	CFB	IGCC
2009	$0.06	$0.01	$0.01	$0.08	$0.06
2010	$0.12	$0.01	$0.01	$0.15	$0.08
2011	$0.12	$0.01	$0.01	$0.15	$0.08
2012	$0.63	$0.30	$0.30	$0.65	$0.59
2013	$1.20	$0.60	$0.60	$1.21	$1.14
2014	$1.53	$0.79	$0.79	$1.53	$1.47
2015	$1.55	$0.75	$0.75	$1.58	$1.46
2016	$1.62	$0.79	$0.79	$1.65	$1.54
2017	$1.48	$0.70	$0.70	$1.51	$1.39
2018	$0.56	$0.21	$0.21	$0.61	$0.48
2019	$0.73	$0.30	$0.30	$0.78	$0.65
2020	$0.63	$0.23	$0.23	$0.68	$0.54
2021	$0.69	$0.27	$0.27	$0.74	$0.60
2022	$1.24	$0.56	$0.56	$1.28	$1.13
2023	$1.57	$0.73	$0.73	$1.62	$1.45
2024	$1.47	$0.60	$0.60	$1.56	$1.32
2025	$1.69	$0.69	$0.69	$1.80	$1.51
2026	$1.81	$0.74	$0.74	$1.93	$1.62
2027	$1.99	$0.82	$0.82	$2.11	$1.78
2028	$2.18	$0.90	$0.90	$2.31	$1.95
2029	$2.37	$0.98	$0.98	$2.51	$2.12
2030	$2.57	$1.07	$1.07	$2.72	$2.30
2031	$2.79	$1.16	$1.16	$2.95	$2.50
2032	$3.03	$1.27	$1.27	$3.20	$2.72
2033	$3.29	$1.38	$1.38	$3.47	$2.95
2034	$3.57	$1.50	$1.50	$3.76	$3.21
2035	$3.87	$1.64	$1.64	$4.08	$3.49

(1) Simple cycle resources considered for FMPA include LM6000, LMS100, GE 7EA, and GE 7FA.

sensitivity. Tables B.6-14 through B.6-17 were developed utilizing the emissions allowance prices developed by Hill & Associates for the CO_2 regulation sensitivity, which are included in Section A.5.0. In years when existing units are no longer available to FMPA through retirement or, in the case of Vero Beach, through its Notice of Establishment of Contract Rate of Delivery, "N/A" is used to indicate that the adders are no longer applicable since the resources are not included in FMPA's dispatch model.

In this sensitivity case, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield LMS100 unit in 2011, greenfield CFB units in 2014 and 2019, and a brownfield LM6000 unit in 2025. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 unit in 2011; greenfield CFB units in 2012, 2014, and 2018; and a brownfield LMS100 unit in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $9,427.7 million and $9,798.1 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $370.4 million over the evaluation period.

B.6.1.10 Summary of the Sensitivity Cases for Input Parameters

Table B.6-18 summarizes the results of the sensitivity analyses described in this section. Appendix B.1 presents the CPWC summary sheets for all the cases presented in Table B.6-18. The optimal capacity expansion plan with participation in TEC in 2012 was the least-cost plan in each of the scenarios. Overall, these results demonstrate the robustness and flexibility of the expansion plan with TEC to overcome variations and deviations from the base case assumptions.

B.6.2 External Parameter Sensitivities

The sensitivities described in this section reflect changes to the base case external parameter assumptions, including the opportunity to participate in joint development capacity additions other than TEC, consideration of different types of generating technologies to meet capacity needs, and consideration of an alternative coal source for TEC. For each of the sensitivities described in this section, the base case input parameters (fuel prices, emissions allowance prices, load forecast, and capital cost estimates) have not been altered.

Table B.6-18
Summary of Sensitivity Analyses
(Varying Base Case Input Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	With TEC	Without TEC	Differential CPWC Savings with TEC
Base Case	8,927.9	9,331.5	403.6
High Fuel Prices	9,979.6	10,343.1	363.5
Low Fuel Prices	7,890.9	8,265.5	374.6
High Load and Energy Growth	10,392.7	10,853.3	460.6
Low Load and Energy Growth	7,539.6	7,952.2	412.6
High Capital Cost	9,222.9	9,634.5	411.6
Low Capital Cost	8,632.6	9,024.0	391.4
High Emissions Allowances Costs	9,050.0	9,458.5	408.5
Low Emissions Allowances Costs	8,807.6	9,178.6	371.0
Regulated CO_2	9,427.7	9,798.1	370.4

B.6.2.1 3x1 CC Joint Development Project

To demonstrate that participation in TEC in May 2012 is part of the least-cost capacity expansion plan for FMPA, sensitivities were developed assuming that FMPA had the option to participate in other jointly owned projects with different generating technologies. Since participation in another jointly owned generation project would provide FMPA with similar economies of scale to participation in TEC, this sensitivity allows a more comparable evaluation of the economics of different generating technologies than the base case analysis.

In this sensitivity, it was assumed that FMPA would participate in a jointly owned 3x1 7FA combined cycle unit with a commercial operation date of May 1, 2012, in lieu of participation in TEC. In this analysis, FMPA would retain the same expected ownership share percentage in the 3x1 7FA combined cycle unit as in the proposed TEC, which provides FMPA with a similarly sized amount of capacity compared to FMPA's share of the proposed TEC. Section A.6.0 presented cost, performance, and availability estimates for the jointly owned 3x1 7FA combined cycle option.

The jointly owned 3x1 combined cycle unit is assumed to be located at the TEC site to make the alternative as similar as possible to TEC. All relevant costs associated with the development of a generating alternative at the TEC site were considered and included for the 3x1 combined cycle alternative, including the community contribution assumed for TEC described in Section B.5.0.

Table B.6-19 presents the output and performance of FMPA's share of the jointly owned 3x1 combined cycle alternative. FMPA's share of the fixed O&M cost for the 3x1 combined cycle alternative is $1.8 million or about $5.03 per kW-year (net) in 2006 dollars. As described in Section B.5.0, an adder for firm natural gas transportation of $2.89 per kW-month was included to provide FMPA's system with an additional 43,598 MBtu/day of firm natural gas transportation. Section A.6.0 presented the nonfuel variable O&M cost for the 3x1 combined cycle option before transmission losses as $4.29 per MWh.

Table B.6-19
FMPA's Share of a Jointly Owned
3x1 7FA Combined Cycle Unit
Output and Performance
(Average Ambient Conditions)

Output (MW)	Net Plant Heat Rate (Btu/kWh)
352.9	7,412
287.0	7,006
225.7	7,282
166.6	7,877
62.2	10,826

The optimal capacity expansion plan involving participation in the 3x1 combined cycle option consists of a brownfield LMS100 unit in 2011 and greenfield CFB units in 2014 and 2020, with a CPWC of $9,571.9 million. A comparison of the CPWCs for this case and the base case capacity expansion plan that includes participation in TEC (presented in Section B.5.0) shows that this plan is $644.0 million higher in CPWC than the expansion plan that includes participation in TEC.

B.6.2.2 Three-Train 1x1 IGCC Joint Development Project

In this sensitivity, it was assumed that FMPA would participate in a jointly owned three-train 1x1 IGCC unit with a commercial operation date of May 1, 2012, in lieu of participation in TEC. Although it is unlikely that the Participants would construct an IGCC unit prior to 2018 for the reasons described in Sections A.6.0 and B.5.0, it is important to compare the emerging IGCC technology with the supercritical pulverized coal technology proposed for TEC in an economic analysis, to demonstrate that participation TEC is part of the least-cost expansion plan for FMPA.

In this analysis, FMPA would retain the same expected ownership share percentage in the three-train 1x1 IGCC unit as in the proposed TEC, which would provide FMPA with a similarly sized amount of capacity compared to FMPA's share of the proposed TEC. Section A.6.0 presented cost, performance, and availability estimates for the jointly owned three-train 1x1 IGCC.

The jointly owned three-train 1x1 IGCC unit is assumed to be located at the TEC site to make the alternative as similar as possible to TEC. All relevant costs associated with the development of a generating alternative at the TEC site were considered and included for the three-train 1x1 IGCC alternative, including the community contribution assumed for TEC described in Section B.5.0.

Table B.6-20 presents the output and performance of FMPA's share of the jointly owned three-train 1x1 IGCC alternative. FMPA's share of the fixed O&M cost for the three-train 1x1 IGCC alternative is $12.9 million or about $38.41 per kW-year (net) in 2006 dollars. Section A.6.0 presented the nonfuel variable O&M cost for the 3x1 combined cycle option before transmission losses as $5.86 per MWh.

The optimal capacity expansion plan involving participation in the three train 1x1 IGCC in 2012 consists of a brownfield LMS100 unit in 2011 and greenfield CFB units in 2014 and 2020, with a CPWC of $9,127.7 million. A comparison of the CPWCs for this case and the base case capacity expansion plan that includes participation in TEC (presented in Section B.5.0) shows that this plan is $199.8 million higher in CPWC than the capacity expansion plan that includes participation in TEC.

B.6.2.3 Second Jointly Owned Pulverized Coal Unit

Currently, there are no coal fired generation projects identified that FMPA could participate in before TEC. Furthermore, FMPA has no firm plans for participation in a large, jointly developed pulverized coal unit in the near term. As such, no additional pulverized coal units were considered as supply-side alternatives after construction of TEC in the base case analysis. This sensitivity considers the possibility of joint participation in a second pulverized coal unit located at either the TEC site or another unidentified site in Florida.

Table B.6-20
FMPA's Share of a Jointly Owned Three-Train
1x1 IGCC Unit Output and Performance
(Average Ambient Conditions - 100 Percent Petcoke)

Output (MW)	Net Plant Heat Rate (Btu/kWh)
336.1	10,018
261.0	10,576
182.8	11,601

The costs and performance of a second supercritical pulverized coal unit are assumed to be identical to those presented for TEC in Section A.3.0, to reflect indicative estimates for a large coal unit. Section B.5.0 presents FMPA's share of the capital and O&M costs for TEC, which are assumed to be the same as those for the second pulverized coal option. Since the TEC Participants would not likely engage in the construction of another pulverized coal unit with a construction schedule that overlaps the construction of TEC, the second pulverized coal unit was not assumed to be available until 2016, to allow for a 4 year construction schedule for the second potential unit.

In this sensitivity case, the optimal capacity expansion plan for the case with TEC in 2012 consists of brownfield LMS100 units in 2011 and 2014, a brownfield LM6000 unit in 2015, participation in a supercritical pulverized coal unit in 2016, and a greenfield CFB unit in 2023.

The CPWC for the expansion plan with TEC and a second jointly owned pulverized coal unit is $8,613.4 million, which represents a decrease in CPWC of $314.5 million over the evaluation period, compared to the base case TEC CPWC.

B.6.2.4 All Natural Gas Capacity Expansion Plan

To develop a more complete understanding of the economics associated with the expansion plan (including FMPA's participation in TEC), a sensitivity case was developed to reflect costs associated with a capacity expansion plan that only includes natural gas fired capacity expansion alternatives.

In this scenario, POWROPT and POWRPRO were used to determine the least-cost capacity expansion plan for the case without TEC, if the CFB and IGCC supply-side alternatives are not considered as alternatives to meet FMPA's capacity needs. This sensitivity analysis results in higher CPWCs relative to the base case expansion plans because of the higher costs of natural gas generation compared to solid fuel alternatives.

In this sensitivity case, the optimal capacity expansion plan (including only natural gas fired capacity additions) consists of a brownfield LMS100 unit in 2011, a brownfield 1x1 7FA combined cycle unit in 2012, a brownfield LMS100 unit in 2014, a brownfield 7FA CT unit in 2015, and a brownfield 1x1 7FA combined cycle unit in 2019.

The CPWC for the all natural gas capacity expansion plan is $10,014.0 million. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $1,086.1 million over the evaluation period.

B.6.2.5 Direct-Fired Biomass Supply-Side Alternative

This sensitivity includes the 30 MW direct-fired biomass (stoker-fired) alternative presented in Section A.6.0 in the cases with and without TEC as a committed unit in 2011, since this is the first year that FMPA would need capacity under the base case assumptions. In these cases, FMPA's projected deficit was reduced by 30 MW, corresponding to the additional capacity provided from the direct-fired biomass alternative beginning in 2011.

Cost and performance estimates for the direct-fired biomass alternative are presented in Section A.6.0. The unit was modeled as a "must run" unit, without consideration of emissions allowance costs, to allow for a conservative economic analysis and because biomass emissions are highly dependent on the type of biomass utilized in power generation.

In this sensitivity case, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield LMS100 unit in 2011 and greenfield CFB units in 2014 and 2020. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 unit in 2011; greenfield CFB units in 2012, 2014, and 2019; and a brownfield LM6000 unit in 2025.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $9,007.7 million and $9,409.0 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $401.3 million over the evaluation period. However, as compared to the base case TEC CPWC, including the 30 MW biomass resource in 2011 increases the CPWC by $79.8 million.

B.6.2.6 Powder River Basin Coal for TEC

The base case economic analysis and all other sensitivity analyses performed assume that TEC will burn a blend of Latin American coal and petcoke. However, as described in Section A.3.0, TEC will be designed to be capable of burning blends of PRB coal and petcoke, as well as blends of Central Appalachian coal and petcoke. This sensitivity assumes that TEC will burn a blend of PRB coal and petcoke, and is based on the corresponding operating cost and performance estimates provided by Sargent & Lundy, which were presented in Section A.3.0.

Hill & Associates' forecast of Latin American coal prices is lower than the forecasts of PRB coal prices, and the corresponding operating costs of TEC are expected to be lower when burning a blend of Latin American coal and petcoke than when burning a blend of PRB coal and petcoke. However, this sensitivity is intended to demonstrate that the additional flexibility of TEC resulting from its capability to burn multiple types of coal allows TEC to be a cost-effective alternative, if the preferred (Latin American) coal source is unavailable for any reason.

The optimal capacity expansion plan involving operation of TEC on a blend of PRB coal and petcoke consists of brownfield LMS100 units in 2011 and 2012 and greenfield CFB units in 2015 and 2021. This plan has a CPWC of $8,951.5 million. A comparison of the CPWCs for this case and the base case capacity expansion plan that includes participation in TEC (presented in Section B.5.0) shows that the plan with TEC's operation on a blend of PRB coal and petcoke is $23.6 million higher in CPWC than the plan with TEC's operation on a blend of Latin American coal and petcoke, but is still lower in CPWC than the base case capacity expansion plan without participation in TEC by $380.0 million over the evaluation period.

B.6.2.7 Summary of the Sensitivity Cases for External Parameters

Appendix B.1 presents the CPWC summary sheets for all the cases presented in Table B.6-21. The optimal capacity expansion plan with TEC in 2012 was the least-cost plan in each of the scenarios, except for the second jointly owned pulverized coal unit sensitivity. Overall, these results demonstrate the robustness and flexibility of the expansion plan with TEC to overcome external variations and deviations from the base case assumptions.

B.6.3 Analysis of RFP Responses

As described in Section A.7.0, Southern Power Company (Southern) responded to the Participants' RFP and provided bids for a pulverized coal unit and a 2x1 combined cycle unit. Southern's proposed costs and estimated performance for the units are confidential. Although both of Southern's bids were determined by R.W. Beck not to be least-cost to TEC on a levelized cost basis, each bid has been evaluated for FMPA's system as a sensitivity to further assess the cost-effectiveness of FMPA's participation in TEC. This section briefly describes the bids and the resulting optimal capacity expansion plans under each scenario.

Table B.6-21
Summary of Sensitivity Analyses
(Varying External Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
3x1 Combined Cycle Joint Development	9,571.9	8,927.9	644.0
Three-Train 1x1 IGCC Joint Development	9,127.7	8,927.9	199.8
Second Jointly Owned Pulverized Coal Unit	8,613.4	8,927.9	(314.5)
All Natural Gas Capacity Expansion Plan	10,014.0	8,927.9	1,086.1
Biomass Supply-Side Addition with TEC	9,007.7	8,927.9	79.8
Biomass Supply-Side Addition without TEC	9,409.0	8,927.9	481.1
PRB Coal for TEC	8,951.5	8,927.9	23.6

B.6.3.1 Southern's Pulverized Coal Unit Bid

Southern's pulverized coal unit bid was considered a committed unit for FMPA, and all costs and performance for the unit were made to be consistent with Southern's bid. The optimal expansion plan for FMPA's system with Southern's pulverized coal bid, which was considered a committed unit in 2012, consisted of a brownfield LMS100 unit in 2011 and greenfield CFB units in 2014 and 2020, with a CPWC of $9,502.9 million. A comparison of CPWCs shows that the base case expansion plan with FMPA's participation in TEC is $575.0 million lower in CPWC than the expansion plan with Southern's pulverized coal bid over the evaluation period.

B.6.3.2 Southern's 2x1 Combined Cycle Bid

Southern's 2x1 combined cycle unit bid was considered a committed unit for FMPA, and all costs and performance for the unit were made to be consistent with Southern's bid. The optimal expansion plan for FMPA's system with Southern's 2x1 combined cycle bid, which was considered a committed unit in 2012, consisted of a brownfield LMS100 unit in 2011 and greenfield CFB units in 2014 and 2020, with a CPWC of $9,619.1 million. A comparison of CPWCs shows that the base case expansion plan with FMPA's participation in TEC is $691.2 million lower in CPWC than the expansion plan with Southern's pulverized coal bid over the evaluation period.

B.6.3.3 Summary of the Sensitivity Cases for FMPA's Share of the RFP Responses

As shown in Table B.6-22, FMPA's optimal capacity expansion plan with TEC in 2012 was the least-cost plan compared to FMPA's share of both of Southern's bids.

Table B.6-22
Summary of FMPA's Share of Southern's Bids

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
Southern's Pulverized Coal Unit	9,502.9	8,927.9	575.0
Southern's 2x1 Combined Cycle Unit	9,619.1	8,927.9	691.2

B.7.0 FMPA's Demand-Side Management

According to Section 403.519 of the Florida Statutes, in its determination of need, the FPSC must take into consideration conservation measures that might mitigate the need for the proposed plant. To address this requirement, FMPA has tested potential demand-side management (DSM) measures for cost-effectiveness. Measures were evaluated using the Florida Integrated Resource Evaluator (FIRE) model previously relied upon by the FPSC. The FIRE model evaluates the economic impact of existing and proposed conservation measures by determining the relative cost-effectiveness of the measures compared to an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation (now Progress Energy Florida [PEF]) and is used by several utilities in Florida. The FIRE model has been used in numerous Need for Power filings, including the FMPA TCEC Unit 1 Need for Power Application, Docket No. 050256-EM, approved by the FPSC in July 2005, and the OUC Stanton Energy Center Unit B Combined Cycle Need for Power Application, Docket No. 060155-EM, which was approved by the FPSC in May 2006.

The remainder of this section summarizes FMPA's existing DSM programs and presents a discussion of the FIRE model and the methodology used to determine the potential cost-effectiveness of new DSM measures. A description is provided for each of the DSM measures included in the FIRE model evaluation, and the results of the FIRE model cost-effectiveness evaluations are also presented.

B.7.1 Existing DSM and Conservation Programs

As a wholesale supplier, FMPA does not directly provide demand-side programs to retail customers. Demand-side programs are provided to retail customers by ARP members. These programs are designed to increase efficiency, enable direct load control of residential appliances, encourage time-of-use rates, and attain further conservation through industrial and commercial audits.

FMPA's members have implemented several marketing strategies to promote conservation programs. Some of those marketing strategies include providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, and schools. Additionally, FMPA's members provide inserts with customers' bills to publicize available conservation programs. The following is a combined list of conservation programs offered by or being reviewed by ARP members:

- Energy audit program.
- High-pressure sodium outdoor lighting conversion.
- Energy Star® program participation.

- Energy services for energy upgrades.
- Green energy programs.
- Load profiling for commercial customers.
- Fix-up program for the elderly and handicapped.

A brief description of each conservation program is provided in the following subsections. The exact implementation varies from member to member, and not all programs are offered by all members.

B.7.1.1 Energy Audit Programs

Energy audits are conducted in accordance with FPSC rules and are offered to residential, commercial, and industrial customers. The audit consists of a walk-through Home Energy Survey; the following materials are available upon customer request:

- Electric outlet gaskets.
- Socket protectors.
- Water flow restrictors.
- Electric water heater jacket.
- Low-flow shower heads.

Home Energy Surveys also include information on water heater temperature reduction and the installation of the water blanket upon customer request.

B.7.1.2 High-Pressure Sodium Outdoor Lighting Conversion

This program involves eliminating mercury vapor street and yard lighting. The mercury vapor fixtures are converted to high-pressure sodium fixtures whenever maintenance is required on the mercury vapor lights.

B.7.1.3 Energy Star®

FMPA has a partnership agreement with Energy Star®. Energy Star® is a government backed program, established to help businesses and homes save money and protect the environment at the same time. Energy Star® identifies household products and other equipment that meets the strict energy efficiency guidelines set by the US Environmental Protection Agency (EPA) and the US Department of Energy. Additionally, Energy Star® works with businesses to improve their energy and financial performance with its proven energy management strategy. Partnering with Energy Star® and working together through FMPA makes it convenient and cost-effective for FMPA's members to bring the benefits of energy efficiency to their hometown utility.

B.7.1.4 Energy Services for Energy Upgrades

FMPA acts as a liaison between customers and contractors to bring them together to implement energy upgrades. Typically, project-type services such as lighting retrofits; heating, ventilating, and air conditioning (HVAC) upgrades; and energy management system services are provided.

B.7.1.5 Green Energy Program

FMPA and its members are reviewing Green Energy programs that may be a benefit to their customers. Renewable sources include solar thermal, solar photovoltaic, wind energy, and bioenergy. Although the electricity derived from the renewable energy source may not be directly provided to the customer, renewable energy is produced somewhere within the state or nation to offset electricity generated by fossil fuel sources.

B.7.1.6 Load Profiling for Commercial Customers

Load profiling involves the expert study of a company's energy use. The utility provides the customer with a clear picture of its power use, including patterns and trends during specific hours. Potential adjustments to the company's operations are presented in order to conserve energy, save costs, and improve efficiency.

B.7.1.7 Fix-Up Program for the Elderly and Handicapped

The program seeks and receives grants for the Community Block Development and Weatherization Program. This is a low-income program, and participants are chosen according to grant mandates. Energy auditors recommend homes for the weatherization program.

B.7.2 FIRE Model Assumptions

The cost-effectiveness evaluation performed with the FIRE model was based on the following assumptions about the electric system:

- System demand is growing. Demand reductions caused by DSM will result in the reduced need for system expansion.
- Individual demand reductions can be related to a reduced need for system generation expansion.
- The generation reduction will be evaluated with respect to specified generation.

- Decreases or increases in revenue as a result of demand-side programs will affect rate levels and will be passed on to all customers.
- Additional conservation that occurs after the next deferred generating unit will affect subsequent units.

B.7.2.1 FIRE Model Inputs

There are two types of FIRE model input files. The first input file contains data specific to the utility's next proposed unit, the avoided unit. The second input file contains data specific to the DSM measure being tested for cost-effectiveness. Input data for the avoided unit is on a per kW basis, allowing the potential DSM measures to be tested individually to evaluate cost-effectiveness.

B.7.2.2 FIRE Model Outputs

FIRE model results are presented in the form of three cost-effectiveness tests, all of which are based on a comparison of discounted present worth benefits to costs for each specific DSM measure. Each of the following three tests is designed to measure costs and benefits from a different perspective:

- The *Total Resource Test* measures the benefit-to-cost ratio of a specific measure by comparing the total benefits (both the participant's and the utility's) to the total costs (equipment costs, utility costs, participant costs, etc.).
- The *Participant Test* measures the impact of the DSM measure on the participating customer. Benefits to the participant may include bill reductions, incentives, and tax credits. Participants' costs may include equipment costs, O&M expenses, equipment removal, etc. The Participant Test is important because customers will not participate in a program if it is not cost-effective from their perspective.
- The *Rate Impact Test* is an indicator of the expected impact on customer rates resulting from a DSM measure. The test statistic is the ratio of the utility's benefits (avoided supply costs and increased revenues) compared to the utility's costs (implementation costs, incentives paid, increased supply costs, and revenue losses). A value of less than 1.0 indicates an upward pressure on electricity rates as a result of the DSM program. Like many other Florida utilities, FMPA views the Rate Impact Test as the primary test for determining the cost-effectiveness of a DSM measure on its system.

B.7.3 Analysis of DSM Alternatives

FMPA considers it important to evaluate additional DSM measures that may potentially be cost-effective, and thereby benefit FMPA's customers. This section presents the general assumptions that were used in the FIRE model cost-effectiveness analysis, which is described in detail in Section B.7.2.

The evaluated DSM measures can be divided into the following four main categories:

- New Residential Construction.
- New Commercial and Industrial Construction.
- Existing Residential Construction.
- Existing Commercial and Industrial Construction.

These main categories were further classified as one of the following subcategories:

- Appliance Efficiency.
- Building Envelope.
- Direct Load Control.
- HVAC Efficiency.
- Lighting.
- Water Heating Efficiency.

B.7.3.1 General Assumptions

General assumptions were developed to compare all DSM measures on an equivalent economic basis. These assumptions were developed from input received from FMPA and other appropriate sources. General cost-effective analysis assumptions and their sources are presented in Table B.7-1. The estimated capital cost for TEC and its projected performance are presented in Table B.7-2.

B.7.3.2 Descriptions and Assumptions of DSM Measures

This subsection provides a brief summary of each DSM measure evaluated for cost-effectiveness.

B.7.3.2.1 DSM Measures for Residential Construction. These measures can be implemented in the construction of new houses and other residential structures, as well as in existing houses and residential structures. Individual cost-effectiveness results for each of the measures are provided for each of the three FIRE model outputs (Total Resource Test, Participant Test, and Rate Impact Test).

Table B.7-1
General Cost-Effective Analysis Assumptions and Sources

- The study period for the cost-effectiveness evaluation encompasses 10 years (2006-2015).
- The economic parameters and fuel forecasts are consistent with those presented in Section A.4.0, with the addition of emissions allowance adders described in Section A.8.0.
- The system average fuel cost was derived from the production cost model used for economic evaluations in Section B.5.0.
- Residential electric rates were based on KUA rates.
- Commercial electric rates were based on the City of Leesburg's rates.

Table B.7-2
Generating Unit Characteristics for the Avoided Unit
(All values represent FMPA's share of the TEC)

Item	
Total Capital Cost (2012 \$) (1)	\$681,687,000
O&M Cost - Baseload Duty	
Fixed O&M Cost (2006 \$/kW-yr) (2), (3)	\$25.42
Variable O&M Cost (2006 \$/MWh) (3)	\$1.40
Net Plant Capacity at 72° F (MW) (3)	297.77
Net Heat Rate at 72° F (Btu/kWh-HHV) (3)	9,541

(1)Capital cost does not include interest during construction.
(2)Includes an adder for ongoing capital expenditures, levelized over the assumed economic life of TEC.
(3)Values after accounting for transmission losses applicable to TEC.

B.7.3.2.1.1 Appliance efficiency measures for new and existing residential construction.

Energy Efficient Clothes Washer. This measure assumes that an Energy Star qualified clothes washer is installed, rather than a standard efficiency model. The standard efficiency model was assumed to have a Modified Energy Factor (MEF) of 1.04, while the high efficiency model was assumed to have an MEF of 1.42.

Energy Efficient Refrigerator (Frost-Free). This measure assumes that an Energy Star qualified frost-free refrigerator is installed, rather than a standard efficiency unit.

Energy Efficient Refrigerator (Manual Defrost). This measure assumes that an Energy Star qualified manual defrost refrigerator is installed, rather than a standard efficiency unit.

B.7.3.2.1.2 Building envelope measures for new and existing residential construction.

Light-Colored Roof Material. This measure assumes that white galvanized steel roofing is installed instead of standard black asphalt shingles.

B.7.3.2.1.3 Direct load control measures for new and existing residential construction.

On-Call Direct Load Control. This measure assumes that FM/VHF switches are installed to cycle off central air conditioning, central heating, electric water heaters, and pool pumps during peak times. Table B.7-3 shows the assumed incentives that would be offered for the 15 minute and extended peak times. The 15 minute savings option allows the utility to cycle off the appliances for up to 15 minutes of every 30 minute period. The extended savings option allows the utility to cycle off the air conditioner for up to 3 hours, and the other appliances for up to 4 hours.

B.7.3.2.1.4 HVAC efficiency measures for new and existing residential construction.

High Efficiency Central Air Conditioning. A high efficiency central air conditioning unit with a Seasonal Energy Efficiency Ratio (SEER) of 18.0 was assumed to be installed instead of a standard unit with an SEER of 13.0.

High Efficiency Room Air Conditioning. This measure assumes that a high efficiency room air conditioning unit with an energy efficiency ratio (EER) of 12.6 is installed, rather than a standard efficiency unit with an EER of 8.3.

B.7.3.2.1.5 Lighting measures for new and existing residential construction.

Compact Fluorescent Lights. This measure assumes that two each of 9 watt, 15 watt, and 26 watt compact fluorescent light bulbs are installed, instead of the same number of 40 watt, 60 watt, and 100 watt incandescent light bulbs. Table B.7-4 summarizes the bulb replacements.

Table B.7-3
On-Call Direct Load Control Incentives

15 Minute Savings		
Appliance	Season	Savings
Central Air Conditioner	April - October	$21/year
Central Heater	November - March	$10/year
Extended Savings		
Appliance	Season	Savings
Central Air Conditioner	April - October	$63/year
Central Heater	November - March	$20/year
Water Heater	All year	$18/year
Pool Pump	All year	$36/year

Source: www.fpl.com.

Table B.7-4
Incandescent Bulb Replacement

Current Incandescent Bulbs to be Replaced		Proposed Compact Fluorescent Replacements	
Bulb Type	Total Power Drawn, watts	Bulb Type	Total Power Drawn, watts
Two 40 watt bulbs	80	Two 9 watt bulbs	18
Two 60 watt bulbs	120	Two 15 watt bulbs	30
Two 100 watt bulbs	200	Two 26 watt bulbs	52
Total	400	Total	100

High-Pressure Sodium Lighting (Outdoor). This measure assumes that one 70 watt high-pressure sodium lighting fixture is installed in place of one 100 watt outdoor incandescent fixture.

B.7.3.2.1.6 Water heating efficiency measures for new and existing residential construction.

Domestic Water Heater Pipe Insulation. This measure assumes that 70 feet of hot water piping insulation is installed.

High Efficiency Electric Water Heater. This measure assumes that a high efficiency water heater with an energy factor (EF) of 0.95 is installed, rather than a standard efficiency unit with an EF of 0.92.

Add-On Heat Pump Water Heater. This measure assumes that an add-on heat pump water heater is installed.

Heat Recovery Water Heater. This measure assumes that a supplemental heat recovery water heater is installed and connected to the air conditioner exhaust heat.

Supplemental Solar Water Heater. This measure assumes that a supplemental solar water heater is installed.

B.7.3.2.1.7 Appliance efficiency measures for existing residential construction only.

High Efficiency Residential Pool Pump. This measure assumes that a standard efficiency (82.5 percent) pool filter motor and circulation pump are replaced with a premium efficiency motor (85.5 percent).

Low-Flow Showerhead. This measure assumes that a low-flow showerhead is installed in place of an existing showerhead.

Energy Efficient Freezer (Manual). This measure assumes that an Energy Star qualified manual defrost freezer is installed, rather than a standard efficiency unit.

B.7.3.2.1.8 Appliance removal measures for existing residential construction only.

Remove Second Freezer. This measure consists of the removal of a second freezer.

Remove Second Refrigerator. This measure consists of the removal of a second refrigerator.

B.7.3.2.1.9 Building envelope measures for existing residential construction only.

Ceiling Insulation (R-0 to R-19). This measure only applies to existing dwellings with no ceiling insulation and assumes the installation of R-19 rated insulation in the ceiling.

Ceiling Insulation (R-11 to R-30). This measure only applies to existing dwellings with R-11 ceiling insulation and involves the installation of insulation with an R-value of R-19, for a total R-value of R-30.

Low Emissivity Glass. For this measure, double-pane glass with an argon gas fill and a low emissivity coating on the inner surface of the outer pane is installed in place of single- and double-pane clear glass windows. This measure reduces heat transmission through windows.

Window Film/Reflective Windows. This measure assumes that window films are installed on single-pane windows.

Window Shade Screens. This measure assumes that four windows are installed with retractable shade screens.

B.7.3.2.1.10 HVAC efficiency measures for existing residential construction only.

Air Conditioning System Maintenance. This measure assumes that an existing air conditioner is serviced by a professional.

B.7.3.2.1.11 Water heating efficiency measures for existing residential construction only.

Domestic Water Heater Heat Trap. This measure consists of the installation of a heat trap on the inlet and outlet piping of an electric resistance water heater.

Domestic Water Heater Tank Insulation. This measure consists of the installation of a water heater jacket with an R-value of at least 6.7.

B.7.3.2.2 DSM Measures for Commercial and Industrial Construction. These measures can be implemented in the construction of new commercial and industrial buildings and structures, as well as in existing buildings and structures. Individual cost-effectiveness results for each of the measures are provided for each of the three FIRE model outputs (Total Resource Test, Participant Test, and Rate Impact Test).

B.7.3.2.2.1 Appliance efficiency measures for new and existing commercial and industrial construction.

Energy Efficient Electric Fryer. This measure assumes that a high efficiency electric fryer with an electric demand of 2.4 kW is installed, rather than a standard efficiency unit with an electric demand of 2.8 kW.

B.7.3.2.2.2 Direct load control measures for new and existing commercial and industrial construction.

Business On-Call. This measure assumes that FM/VHF switches are installed to cycle off air conditioning units for 15 minutes out of every 30 minute period, during peak times from April through October.

B.7.3.2.2.3 HVAC efficiency measures for new and existing commercial and industrial construction.

High Efficiency Chiller. This measure assumes that a high efficiency screw chiller with a coefficient of performance (COP) of 5.9 is installed, instead of a standard efficiency reciprocating chiller with a COP of 4.2 for the GSD rate class. For the GSLD rate class, a high efficiency centrifugal chiller with a COP of 6.4 is installed, instead of a standard efficiency centrifugal chiller with a COP of 5.6. The chillers for the GSD rate class were assumed to be 100 tons; chillers for the GSLD rate class were assumed to be 200 tons.

High Efficiency Chiller with ASD. This option consists of installing an adjustable speed drive (ASD) controller onto high efficiency centrifugal chillers. The same assumptions apply here as in the high efficiency chiller option. The high efficiency chiller with an ASD is compared to a high efficiency chiller without an ASD to estimate savings.

High Efficiency DX Air Conditioning Units. This measure assumes that a high efficiency direct exchange (DX) air conditioning unit (5 ton for GS, 20 ton for GSD, and 100 ton for GSLD) with an EER rating of 13.0 is installed rather than the standard of 10.3.

High Efficiency Room Air Conditioning Units. This measure assumes that a high efficiency room air conditioning unit with an EER of 12.6 is installed, rather than a standard efficiency unit with an EER of 8.3. The room air conditioning unit was assumed to have a cooling rating of 17,000 Btu/h.

High Efficiency Motors - Chiller. This measure assumes that a high efficiency motor (96 percent efficiency) is installed, rather than a standard efficiency motor (91 percent efficiency) in a chiller.

High Efficiency Motors - DX Air Conditioning. This measure assumes that a high efficiency motor (94 percent efficiency) is installed, rather than a standard efficiency motor (87 percent efficiency) in a DX air conditioning unit.

Leak Free Ducts. This measure consists of the utilization of aerosol duct sealing on a commercial building's duct system. Cooling and ventilation demand and energy savings are estimated to be 3.0 percent. The buildings were assumed to have floor areas of 5,000 ft^2, 20,000 ft^2, and 100,000 ft^2 for the GS, GSD, and GSLD rate classes, respectively.

Cool Thermal Storage. This measure assumes that a chiller (50 ton for GSD and 150 ton for GSLD) is augmented with a cooled water thermal storage system. The system is sized for 4 hours at full chiller capacity. The chiller was assumed to have a COP of 4.75 for the GSD rate class and a COP of 5.9 for the GSLD rate class. It was also assumed that existing pumps would be capable of circulating the stored chilled water through the air conditioning system during peak hours, so there would be no assumed energy savings or energy use increase from the pumps.

B.7.3.2.2.4 Lighting measures for new and existing commercial and industrial construction.

Incandescent Replacement with Compact Fluorescent. This measure assumes that a new commercial building uses ten 15 watt, 18 watt, and 27 watt compact fluorescent lamps, instead of the same number of 60 watt, 75 watt, and 100 watt incandescent lamps. Table B.7-5 summarizes the lamp replacements.

Incandescent Replacement with 2x18 Watt Compact Fluorescent. This measure consists of the installation of ten 2 x 18 watt compact fluorescent fixtures, instead of the installation of ten 1 x 150 watt incandescent fixtures.

Table B.7-5
Incandescent Lamp Replacement

Current Incandescent Lamp to be Replaced		Proposed Compact Fluorescent Replacements	
Lamp Type	Total Power Drawn, watts	Lamp Type	Total Power Drawn, watts
Ten 60 watt bulbs	600	Ten 15 watt bulbs	150
Ten 75 watt bulbs	750	Ten 18 watt bulbs	180
Ten 100 watt bulbs	1,000	Ten 27 watt bulbs	270
Total	2,350	Total	600

B.7.3.2.2.5 Water heating efficiency measures for new and existing commercial and industrial construction.

Heat Pump Water Heater. This measure assumes that a heat pump water heater is installed in combination with an electric resistance water heater. The electric resistance water heater was assumed to have a COP of 0.92, while the heat pump water heater was assumed to have a COP of 3.0.

Heat Recovery Water Heater. This measure consists of an electric water heater that utilizes a supplemental heat source from the cooling system waste heat recovered from a double-bundle chiller or condenser heat exchanger.

B.7.3.2.2.6 Appliance efficiency measures for existing commercial and industrial construction only.

Low or Variable Flow Showerhead. This retrofit measure consists of installing low or variable flow showerheads in place of existing showers and faucets to reduce the flow of hot water.

Multiplex Refrigeration System with No Subcooling. This measure assumes that an existing grocery store replaces an existing single compressor system with a multiplex refrigeration system. The single compressor system was assumed to have an EER of 9.0, while the multiplex system was assumed to have an annual EER of 11.0.

Multiplex Refrigeration System with Ambient Subcooling. This measure assumes that an existing grocery store replaces an existing single compressor system with a multiplex system with ambient subcooling. The single compressor was assumed to have an EER of 9.0, while the multiplex system with ambient subcooling was assumed to have an EER of 11.22.

Multiplex Refrigeration System with Mechanical Subcooling. This measure assumes that an existing grocery store replaces an existing single compressor system with a multiplex system with mechanical subcooling. The single compressor was assumed to have an EER of 9.0, while the multiplex system with mechanical subcooling was assumed to have an EER of 12.65.

Multiplex Refrigeration System with Ambient and Mechanical Subcooling. This measure consists of various air-cooled refrigeration systems that are compared to a stand-alone compressor system. Systems include a multiplex system with or without ambient or mechanical subcooling and an external liquid suction heat exchanger, in addition to an open-drive refrigeration system. This measure was assumed applicable to restaurant, grocery, warehouse, and hospital market segments.

B.7.3.2.2.7 Building envelope measures for existing commercial and industrial construction only.

Light-Colored Roof - Air Chiller. This measure assumes that commercial buildings with a black, flat roof with an albedo of 0.05 install a light-colored Energy Star rated white membrane with an albedo of 0.75. The roofs were assumed to have areas of 10,000 ft^2 and 50,000 ft^2 for the GSD and GSLD rate classes, respectively. Savings were calculated based on using standard efficiency air-cooled screw chillers with COP values of 3.0·(100 ton for the GSD rate class and a 200 ton chiller for the GSLD rate class).

Light-Colored Roof - DX Air Conditioning. This measure assumes that commercial buildings with a black, flat roof with an albedo of 0.05 would install a light-colored Energy Star rated white membrane with an albedo of 0.75. The roofs were assumed to have areas of 5,000 ft^2, 10,000 ft^2, and 50,000 ft^2 for the GS, GSD, and GSLD rate classes, respectively. Savings were calculated based on using standard efficiency DX air conditioning units with EER ratings of 8.9 (100 ton for GSLD, 20 ton for GSD, and 5 ton for GS).

Light-Colored Roof - Water Chiller. This measure assumes that commercial buildings with a black, flat roof with an albedo of 0.05 would install a light-colored Energy Star rated white membrane with an albedo of 0.75. The roofs were assumed to have areas of 10,000 ft^2 and 50,000 ft^2 for the GSD and GSLD rate classes, respectively. Savings were calculated based on using standard efficiency water cooled reciprocating chillers with COP values of 4.0 (100 ton chiller for the GSD rate class and a 200 ton chiller for the GSLD rate class).

Roof Insulation – Chiller. This measure assumes that buildings with an existing R-value of 2.53 upgrade the roof insulation to an average R-value of 10.0. The roofs were assumed to have areas of 10,000 ft^2 and 50,000 ft^2 for the GSD and GSLD rate classes, respectively.

Roof Insulation – DX Air Conditioning. This measure assumes that buildings with an existing R-value of 2.53 upgrade the roof insulation to an average R-value of 10.0. The roofs were assumed to have areas of 5,000 ft^2, 10,000 ft^2, and 50,000 ft^2 for the GS, GSD, and GSLD rate classes, respectively.

Window Film – Chiller. This option consists of installing window film on existing construction. The shading coefficient was assumed to improve from 0.85 to 0.23 and the U-value from 1.06 to 0.69.

Window Film - DX Air Conditioning. This option consists of installing window film on existing construction. The shading coefficient was assumed to improve from 0.85 to 0.23 and the U-value from 1.06 to 0.69. Energy savings were calculated as the reduction in DX air conditioning power and energy demand.

B.7.3.2.2.8 HVAC efficiency measures for existing commercial and industrial construction only.

Two-Speed Motor for Cooling Tower. This measure assumes that one 5 hp, two-speed motor is installed in an existing cooling tower.

Speed Control for Cooling Tower Motors. This measure assumes that an adjustable speed drive is installed on one 5 hp cooling tower motor.

B.7.3.2.2.9 Lighting measures for existing commercial and industrial construction only.

4 Foot Fluorescent with Electronic Ballast Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 2 (40 watt) fluorescent fixtures (with standard ballasts) with twenty 4 foot by 2 (34 watt) fluorescent lamps with electronic ballasts.

8 Foot Fluorescent with Electronic Ballast Replacement. This measure assumes that a commercial building replaces twenty 8 foot by 2 (75 watt) fluorescent fixtures (with standard ballasts) with twenty 8 foot by 2 fluorescent lamps with electronic ballasts, for a total fixture rating of 95 watt.

4 Foot T8 with Electronic Ballast Lamp Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 2 (40 watt) fluorescent fixtures with twenty 4 foot by 2 T8 (32 watt) fluorescent lamps and an electronic ballast, for a total fixture rating of 60 watt.

4 Foot Fluorescent with Reflector Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 4 (40 watt) fluorescent fixtures with twenty 4 foot by 2 (40 watt) fluorescent lamps with a reflector.

4 Foot Fluorescent with T8 and Reflector Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 4 (40 watt) fluorescent fixtures with twenty 4 foot by 2 T8 (32 watt) fluorescent lamps with a reflector.

4 Foot 34 Watt with Reflector Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 4 (40 watt) fixtures with four 4 foot by 2 (40 watt) fixtures with reflectors and sixteen 4 foot by 2 (34 watt) fixtures with reflectors.

8 Foot 75 Watt Delamping with Reflector Kit and Electronic Ballasts. This measure assumes that a commercial building replaces twenty 8 foot by 2 (75 watt) fixtures with twenty 4 foot by T8 lamps (32 watt) and a reflector kit, and electronic ballasts.

High-Pressure Sodium Lighting (70 Watt/100 Watt/150 Watt/250 Watt) Replacement. This measure considers a mix of five each of 70 watt, 100 watt, 150 watt, and 250 watt high-pressure sodium lamps/fixtures, replacing the same mix of 100 watt, 175 watt, 250 watt, and 400 watt mercury vapor lamps/fixtures. Table B.7-6 summarizes the proposed changes.

Outdoor High-Pressure Sodium Lighting (70 Watt) Replacement. This measure considers replacing five 150 watt incandescent lamps with five 70 watt high-pressure sodium fixtures.

B.7.3.2.2.10 Water heating efficiency measures for existing commercial and industrial construction only.

Water Heater Insulation. This is a retrofit measure consisting of wrapping an existing water tank with additional insulation.

Water Heater Heat Trap. This retrofit measure reduces hot water energy loss caused by backflow through the pipes from natural convection.

Off-Peak Battery Charging. This measure typically applies to golf courses and requires that they charge golf carts during off-peak hours (at night). The customer must purchase the equipment to automatically start and control the charging process.

B.7.4 Results of the FIRE Model Cost-Effectiveness Evaluations

The following tables (Tables B.7-7 through B.7-10) present the results of the FIRE model DSM cost-effectiveness analyses of the DSM measures described previously in this section. The tables include the three tests used by the FIRE model to determine cost-effectiveness - the Total Resource Test, the Participant Test, and the Rate Impact Test - each of which is described in Section B.7.2. Cost-effectiveness results are categorized as discussed in Section B.7.3. As indicated in Tables B.7-7 through B.7-10, none of the potential new DSM measures evaluated are cost-effective, based on the Rate Impact Test. Therefore, it can be concluded that there are no cost-effective DSM measures that would mitigate the need for TEC. FMPA will continue to evaluate the potential for cost-effective DSM measures.

Table B.7-6
Incandescent Bulb Replacement

Mercury Vapor Fixtures to be Replaced		High-Pressure Sodium Fixture Replacements	
Fixture Type	Total Power Drawn, watts	Fixture Type	Total Power Drawn, watts
Five 100 watt bulbs	500	Five 70 watt bulbs	350
Five 175 watt bulbs	875	Five 100 watt bulbs	500
Five 250 watt bulbs	1,250	Five 150 watt bulbs	750
Five 400 watt bulbs	2,000	Five 250 watt bulbs	1,250
Total	4,625	Total	2,850

Table B.7-7
FIRE Model Cost-Effectiveness Results for
New and Existing Residential Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
Efficient Clothes Washer - Existing - Residential	0.30	1.19	0.36
Efficient Clothes Washer - New - Residential	0.30	1.33	0.39
Energy Efficient Refrigerator (Frost-Free) - Existing - Residential	0.29	0.57	0.17
Energy Efficient Refrigerator (Frost-Free) - New - Residential	0.23	1.66	0.34
Energy Efficient Refrigerator (Manual) - Existing - Residential	0.28	0.68	0.20
Energy Efficient Refrigerator (Manual) - New - Residential	0.23	1.51	0.31
Building Envelope Measures			
Light-Colored Roof Material - Existing - Residential	0.30	0.20	0.06
Light-Colored Roof Material - New - Residential	0.30	0.81	0.25
Direct Load Control Measures			
On-Call Direct Load Control - Existing - Residential	0.04	1.00	0.07
On-Call Direct Load Control - New - Residential	0.04	1.00	0.07
HVAC Efficiency Measures			
High Efficiency Central Air Conditioning - Existing - Residential	0.24	0.48	0.12
High Efficiency Central Air Conditioning - New - Residential	0.11	1.00	0.20
High Efficiency Room Air Conditioning - Existing - Residential	0.30	0.52	0.16
High Efficiency Room Air Conditioning - New - Residential	0.30	5.25	1.35
Lighting Measures			
Compact Fluorescent Lights - Existing - Residential	0.23	55.40	0.85
Compact Fluorescent Lights - New - Residential	0.30	22.16	3.07
High-Pressure Sodium Lighting (Outdoor) - Existing - Residential	0.25	4.88	0.71
High-Pressure Sodium Lighting (Outdoor) - New - Residential	0.26	4.88	0.80
Water Heating Efficiency Measures			
Domestic Water Heater Pipe Insulation - Existing - Residential	0.18	0.55	0.12
Domestic Water Heater Pipe Insulation - New - Residential	0.18	0.16	0.04
High Efficiency Electric Water Heater - Existing - Residential	0.31	1.07	0.33
High Efficiency Electric Water Heater - New - Residential	0.16	1.00	0.33
Add-On Heat Pump Water Heater - Existing - Residential	0.30	2.07	0.60
Add-On Heat Pump Water Heater - New - Residential	0.30	2.75	0.80
Heat Recovery Water Heater - Existing - Residential	0.29	1.76	0.50
Heat Recovery Water Heater - New - Residential	0.29	1.76	0.50
Supplemental Solar Water Heater - Existing - Residential	0.30	0.31	0.09
Supplemental Solar Water Heater - New - Residential	0.30	0.31	0.09

Table B.7-8
FIRE Model Cost-Effectiveness Results for
Existing Residential Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
High Efficiency Pool Pump - Existing - Residential	0.23	0.25	0.07
Low-Flow Showerhead - Existing - Residential	0.28	37.12	3.17
Energy Efficient Freezer (Manual) - Existing - Residential	0.28	0.84	0.24
Appliance Removal Measures			
Remove Second Freezer - Existing - Residential	0.29	1.00	7.70
Remove Second Refrigerator - Existing - Residential	0.29	1.00	8.44
Building Envelope Measures			
Ceiling Insulation (R0-R19) - Existing - Residential	0.30	2.26	0.66
Ceiling Insulation (R19-R30) - Existing - Residential	0.29	0.93	0.27
Low Emissivity Glass - Existing - Residential	0.30	1.74	0.53
Window Film/Reflective Windows - Existing - Residential	0.30	1.16	0.35
Window Shade Screens - Existing - Residential	0.31	2.10	0.63
HVAC Efficiency Measures			
Air Conditioning System Maintenance - Existing - Residential	0.10	6.60	0.30
Water Heating Efficiency Measures			
Domestic Water Heater Heat Trap - Existing - Residential	0.15	1.00	0.36
Domestic Water Heater Tank Insulation - Existing - Residential	0.24	6.82	0.80

Table B.7-9
FIRE Model Cost-Effectiveness Results for
New and Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
Energy Efficient Electric Fryer - Existing - GSND	0.35	0.23	0.08
Energy Efficient Electric Fryer - Existing - GSD	0.35	0.23	0.08
Energy Efficient Electric Fryer - Existing - GSLD	0.35	0.23	0.08
Energy Efficient Electric Fryer - New - GSND	0.35	0.81	0.28
Energy Efficient Electric Fryer - New - GSD	0.35	0.81	0.28
Energy Efficient Electric Fryer - New - GSLD	0.35	0.81	0.28
Direct Load Control Measures			
Business On-Call Direct Load Control - Existing - GSND	0.02	1.00	0.17
Business On-Call Direct Load Control - Existing - GSD	0.04	1.00	1.37
Business On-Call Direct Load Control - Existing - GSLD	0.04	1.00	1.37
Business On-Call Direct Load Control - New - GSND	0.02	1.00	0.17
Business On-Call Direct Load Control - New - GSD	0.04	1.00	1.37
Business On-Call Direct Load Control - New - GSLD	0.04	1.00	1.37
HVAC Efficiency Measures			
High Efficiency Chiller - Existing - GSD	0.37	1.51	0.56
High Efficiency Chiller - Existing - GSLD	0.37	0.50	0.19
High Efficiency Chiller - New - GSD	0.37	9.27	3.40
High Efficiency Chiller - New - GSLD	0.37	2.56	0.95
High Efficiency Chiller w/ASD - Existing - GSD	0.37	2.99	1.10
High Efficiency Chiller w/ASD - Existing - GSLD	0.37	3.18	1.18
High Efficiency Chiller w/ASD - New - GSD	0.37	2.99	1.10
High Efficiency Chiller w/ASD - New - GSLD	0.37	3.18	1.18
High Efficiency DX Air Conditioning Units - Existing - GSND	0.36	0.81	0.30
High Efficiency DX Air Conditioning Units - Existing - GSD	0.37	0.63	0.23
High Efficiency DX Air Conditioning Units - Existing - GSLD	0.37	0.69	0.26
High Efficiency DX Air Conditioning Units - New - GSND	0.39	1.36	0.53
High Efficiency DX Air Conditioning Units - New - GSD	0.37	0.53	0.19
High Efficiency DX Air Conditioning Units - New - GSLD	0.37	1.01	0.38
High Efficiency Room Air Conditioning Units - Existing - GSND	0.36	1.63	0.57
High Efficiency Room Air Conditioning Units - New - GSND	0.35	1.00	1.43
High Efficiency Motors - Chiller - Existing - GSD	0.37	1.65	0.61
High Efficiency Motors - Chiller - Existing- GSLD	0.37	1.64	0.61
High Efficiency Motors - Chiller - New - GSD	0.37	9.90	3.53

Table B.7-9 (Continued)
FIRE Model Cost-Effectiveness Results for
New and Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
High Efficiency Motors - Chiller - New - GSLD	0.37	9.87	3.53
High Efficiency Motors - DX Air Conditioning - New - GSND	0.32	1.00	1.40
High Efficiency Motors - DX Air Conditioning - New - GSD	0.36	12.84	3.80
High Efficiency Motors - DX Air Conditioning - New - GSLD	0.37	12.29	4.31
High Efficiency Motors - DX Air Conditioning - Existing - GSND	0.35	1.04	0.36
High Efficiency Motors - DX Air Conditioning - Existing - GSD	0.36	2.14	0.76
High Efficiency Motors - DX Air Conditioning - Existing - GSLD	0.37	2.05	0.75
Leak Free Ducts - Existing - GSND	0.35	0.48	0.17
Leak Free Ducts - Existing - GSD	0.37	0.48	0.18
Leak Free Ducts - Existing - GSLD	0.37	0.48	0.18
Leak Free Ducts - New - GSND	0.32	0.18	0.07
Leak Free Ducts - New - GSD	0.36	0.18	0.07
Leak Free Ducts - New - GSLD	0.37	0.18	0.07
Cool Thermal Storage - Existing - GSD	0.23	2.38	0.07
Cool Thermal Storage - Existing - GSLD	0.23	2.36	0.07
Cool Thermal Storage - New - GSD	0.23	2.06	0.06
Cool Thermal Storage - New - GSLD	0.23	1.65	0.05
Lighting Measures			
Incandescent Replacement w/Compact Fluorescent - Existing - GSND	0.41	33.95	6.68
Incandescent Replacement w/Compact Fluorescent - Existing - GSD	0.41	33.83	6.68
Incandescent Replacement w/Compact Fluorescent - Existing - GSLD	0.41	33.76	6.68
Incandescent Replacement w/Compact Fluorescent - New - GSND	0.42	33.95	9.54
Incandescent Replacement w/Compact Fluorescent - New - GSD	0.42	33.83	9.54
Incandescent Replacement w/Compact Fluorescent - New - GSLD	0.42	33.76	9.54
Incandescent Replacement w/2x18 Watt Compact Fluorescent - Existing - GSND	0.38	8.68	2.28
Incandescent Replacement w/2x18 Watt Compact Fluorescent - Existing - GSD	0.38	8.65	2.28
Incandescent Replacement w/2x18 Watt Compact Fluorescent - Existing - GSLD	0.38	8.63	2.28
Incandescent Replacement w/2x18 Watt Compact Fluorescent - New - GSND	0.40	5.90	2.28
Incandescent Replacement w/2x18 Watt Compact Fluorescent - New - GSD	0.40	5.88	2.28
Incandescent Replacement w/2x18 Watt Compact Fluorescent - New - GSLD	0.40	5.87	2.28

Table B.7-9 (Continued)
FIRE Model Cost-Effectiveness Results for
New and Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Water Heating Efficiency Measures			
Heat Pump Water Heater - Existing - GSND	0.19	1.00	0.66
Heat Pump Water Heater - Existing - GSD	0.18	1.00	0.87
Heat Pump Water Heater - Existing - GSLD	0.27	1.00	0.96
Heat Pump Water Heater - New - GSND	0.23	1.00	1.39
Heat Pump Water Heater - New - GSD	0.19	1.00	1.34
Heat Pump Water Heater - New - GSLD	0.29	1.00	1.35
Heat Recovery Water Heater - Existing - GSND	0.30	1.00	1.00
Heat Recovery Water Heater - Existing - GSD	0.41	2.75	1.08
Heat Recovery Water Heater - Existing - GSLD	0.41	2.75	1.08
Heat Recovery Water Heater - New - GSND	0.32	1.00	1.39
Heat Recovery Water Heater - New - GSD	0.41	2.75	1.08
Heat Recovery Water Heater - New - GSLD	0.41	2.75	1.08

Table B.7-10
FIRE Model Cost-Effectiveness Results for
Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
Low or Variable Flow Showerhead - Existing - GSND	0.43	184.29	8.58
Low or Variable Flow Showerhead - Existing - GSD	0.43	183.75	8.58
Low or Variable Flow Showerhead - Existing - GSLD	0.43	183.44	8.58
Multiplex Refrigeration with No Subcooling - Existing - GSD	0.50	0.47	0.24
Multiplex Refrigeration with No Subcooling - Existing - GSLD	0.50	0.47	0.24
Multiplex Refrigeration with Ambient Subcooling - Existing - GSD	0.50	0.52	0.26
Multiplex Refrigeration with Ambient Subcooling - Existing - GSLD	0.50	0.52	0.26
Multiplex Refrigeration with Mechanical Subcooling - Existing - GSD	0.07	0.11	0.01
Multiplex Refrigeration with Mechanical Subcooling - Existing - GSLD	0.07	0.11	0.01
Multiplex Refrigeration: Ambient and Mechanical Subcooling - Existing - GSD	0.50	0.00	0.86
Multiplex Refrigeration: Ambient and Mechanical Subcooling - Existing - GSLD	0.50	0.00	0.86
Building Envelope Measures			
Light-Colored Roof - Air Chiller - Existing - GSD	0.37	3.21	1.18
Light-Colored Roof - Air Chiller - Existing - GSLD	0.37	1.28	0.47
Light-Colored Roof - DX Air Conditioning - Existing - GSND	0.36	0.41	0.15
Light-Colored Roof - DX Air Conditioning - Existing - GSD	0.37	0.82	0.30
Light-Colored Roof - DX Air Conditioning - Existing - GSLD	0.37	0.81	0.30
Light-Colored Roof - Water Chiller - Existing - GSD	0.37	2.62	0.97
Light-Colored Roof - Water Chiller - Existing - GSLD	0.37	0.86	0.32
Roof Insulation - Chiller - Existing - GSD	0.37	0.40	0.15
Roof Insulation - Chiller - Existing - GSLD	0.37	0.08	0.03
Roof Insulation - DX Air Conditioning - Existing - GSND	0.36	0.66	0.24
Roof Insulation - DX Air Conditioning - Existing - GSD	0.37	0.33	0.12
Roof Insulation - DX Air Conditioning - Existing - GSLD	0.37	0.07	0.02
Window Film - Chiller - Existing - GSD	0.37	3.31	1.18
Window Film - Chiller - Existing - GSLD	0.37	3.30	1.18
Window Film - DX Air Conditioning - Existing - GSND	0.23	1.00	0.40
Window Film - DX Air Conditioning - Existing - GSD	0.37	3.79	1.36
Window Film - DX Air Conditioning - Existing - GSLD	0.37	3.78	1.36

Table B.7-10 (Continued)
FIRE Model Cost-Effectiveness Results for
Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
HVAC Efficiency Measures			
Two-Speed Motor for Cooling Tower - Existing - GSD	0.36	3.42	1.15
Two-Speed Motor for Cooling Tower - Existing - GSLD	0.36	3.41	1.15
Speed Control for Cooling Tower Motors - Existing - GSD	0.36	1.22	0.44
Speed Control for Cooling Tower Motors - Existing - GSLD	0.36	1.22	0.44
Lighting Measures			
4 ft Fluorescent w/Electronic Ballast Replacement - Existing - GSND	0.43	0.54	0.23
4 ft Fluorescent w/Electronic Ballast Replacement - Existing - GSD	0.43	0.54	0.23
4 ft Fluorescent w/Electronic Ballast Replacement - Existing - GSLD	0.43	0.54	0.23
8 ft Fluorescent w/Electronic Ballast Replacement - Existing - GSND	0.33	2.02	0.61
8 ft Fluorescent w/Electronic Ballast Replacement - GSD	0.33	2.02	0.61
8 ft Fluorescent w/Electronic Ballast Replacement - GSLD	0.33	2.01	0.61
4 ft T8 Lamp Replacement - Existing - GSND	0.24	1.44	0.31
4 ft T8 Lamp Replacement - Existing - GSD	0.24	1.43	0.31
4 ft T8 Lamp Replacement - Existing - GSLD	0.24	1.43	0.31
4 ft Fluorescent with Reflector Replacement - Existing - GSND	0.36	4.41	1.26
4 ft Fluorescent with Reflector Replacement - Existing - GSD	0.36	4.40	1.26
4 ft Fluorescent with Reflector Replacement - Existing - GSLD	0.36	4.39	1.26
4 ft T8 Fluorescent with Reflector Replacement - Existing - GSND	0.37	5.21	1.51
4 ft T8 Fluorescent with Reflector Replacement - Existing - GSD	0.37	5.19	1.51
4 ft T8 Fluorescent with Reflector Replacement - Existing - GSLD	0.37	5.18	1.51
4 ft 34 Watt w/Reflector Replacement - Existing - GSND	0.36	4.89	1.41
4 ft 34 Watt w/Reflector Replacement - Existing - GSD	0.36	4.87	1.41
4 ft 34 Watt w/Reflector Replacement - Existing - GSLD	0.36	4.86	1.41
8 ft 75 Watt Delamping w/Reflector Kit - Existing - GSND	0.38	4.61	1.46
8 ft 75 Watt Delamping w/Reflector Kit - Existing - GSD	0.38	4.60	1.46
8 ft 75 Watt Delamping w/Reflector Kit - Existing - GSLD	0.38	4.59	1.46
High-Pressure Sodium (70W/100W/150W/250W) Replacement - Existing - GSND	0.44	0.47	0.21
High-Pressure Sodium (70W/100W/150W/250W) Replacement - Existing - GSD	0.44	0.47	0.21
High-Pressure Sodium (70W/100W/150W/250W) Replacement - Existing - GSLD	0.44	0.47	0.21
Outdoor High-Pressure Sodium (70 Watt) Replacement - Existing - GSND	0.43	0.44	0.19

Table B.7-10 (Continued)
FIRE Model Cost-Effectiveness Results for
Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Outdoor High-Pressure Sodium (70 Watt) Replacement - Existing - GSD	0.43	0.44	0.19
Outdoor High-Pressure Sodium (70 Watt) Replacement - Existing - GSLD	0.43	0.44	0.19
Water Heating Efficiency Measures			
Domestic Water Heater Insulation - Existing - GSND	0.40	21.70	2.41
Domestic Water Heater Insulation - Existing - GSD	0.40	21.64	2.41
Domestic Water Heater Insulation - Existing - GSLD	0.40	21.60	2.41
Domestic Water Heater Heat Trap - Existing - GSND	0.17	1.00	0.37
Domestic Water Heater Heat Trap - Existing - GSD	0.36	1.00	1.35
Domestic Water Heater Heat Trap - Existing - GSLD	0.31	1.00	0.82
Off-Peak Battery Charging - FPL - Existing - GSD	0.03	2.63	0.08
Off-Peak Battery Charging - FPL - Existing - GSLD	0.04	2.61	0.08

B.8.0 FMPA's Strategic Considerations

In addition to cost-effectively meeting FMPA's capacity needs, there were several strategic considerations and advantages associated with the TEC project, which led FMPA to consider participation in the TEC project as its next baseload generating unit. These strategic considerations include both economic and non-economic attributes and are discussed in the remainder of this section.

B.8.1 FMPA's Fuel Diversity

TEC will provide an increase in fuel diversity for FMPA's system and Florida as a whole. The project will have the ability to source solid fuels from both domestic and international coal-producing regions, including the PRB, Central Appalachian, and Latin America, as well as petcoke from the Gulf Coast region and the Caribbean. Historically, coals from these regions and petcoke have experienced significantly less fluctuation in price and generally have less volatile commodity prices than oil and natural gas on an annual basis. As a result, TEC will not only provide additional solid fuel capacity for FMPA and Florida, but it will also provide further fuel diversification through the capability to source coal and petcoke from numerous different regions via different transportation modes and routes. This additional choice in fuel for FMPA's generating fleet will provide more flexibility to respond to fuel price fluctuations that exist within all fuel markets due to extenuating events that occur from time to time.

Additionally, the low cost baseload energy from TEC will help FMPA and Florida reduce their dependence on volatile, higher cost energy from natural gas and oil. Figures B.8-1 and B.8-2 show FMPA's projected capacity resources by fuel type in 2006 and 2013, respectively. Figures B.8-3 and B.8-4 show FMPA's projected energy resources by fuel type in 2006 and 2013, respectively.

B.8.2 Reliability of FMPA's Fuel Supply

The addition of solid-fueled generation increases the reliability of FMPA's fuel supply. The plant design will allow for up to at least 90 days of coal and petcoke inventory, minimizing the short-term supply disruptions that occurred with natural gas as a result of hurricanes affecting the Gulf Coast supply region. Furthermore, onsite fuel storage minimizes the short-term disruptions of fuel transportation systems.

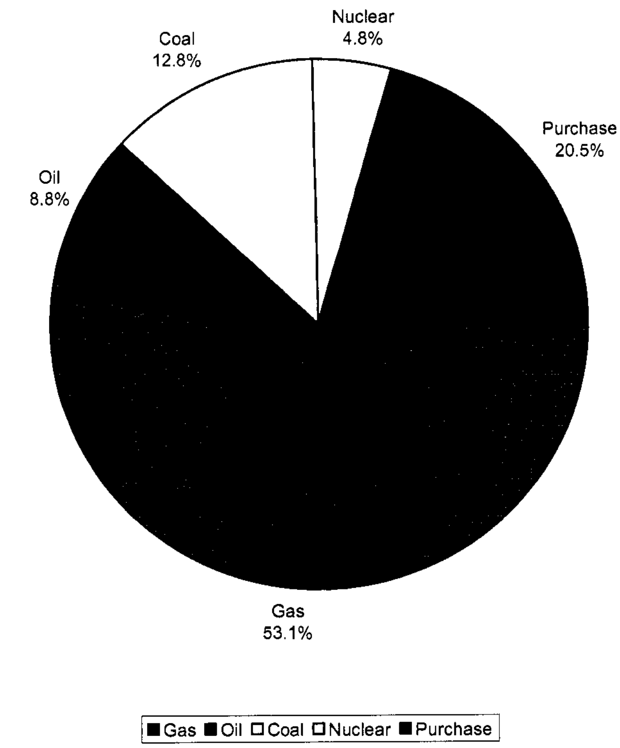

Figure B.8-1
FMPA's 2006 Capacity Resources by Fuel Type

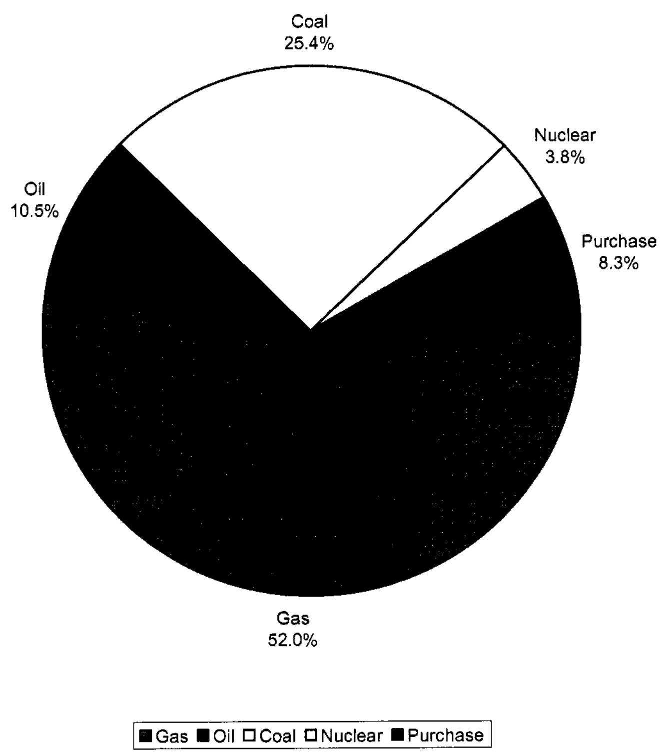

Figure B.8-2
FMPA's 2013 Capacity Resources by Fuel Type

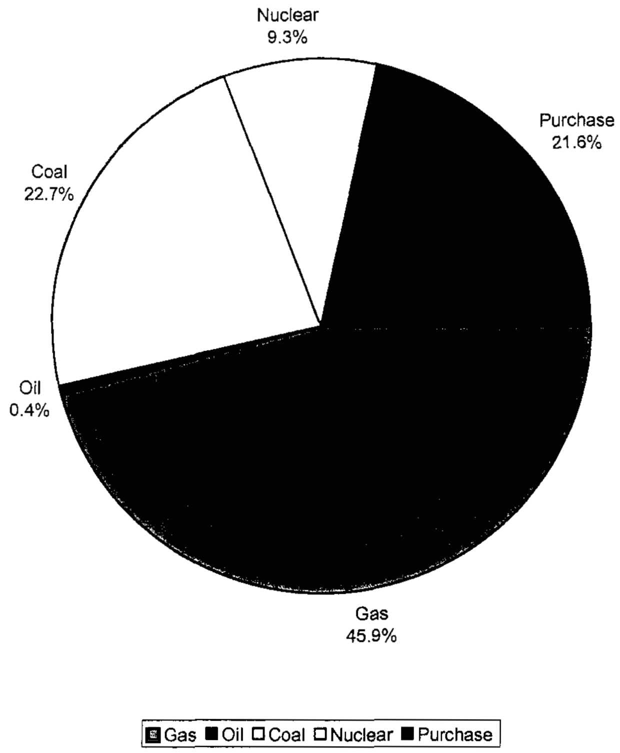

Figure B.8-3
FMPA's 2006 Energy Resources by Fuel Type

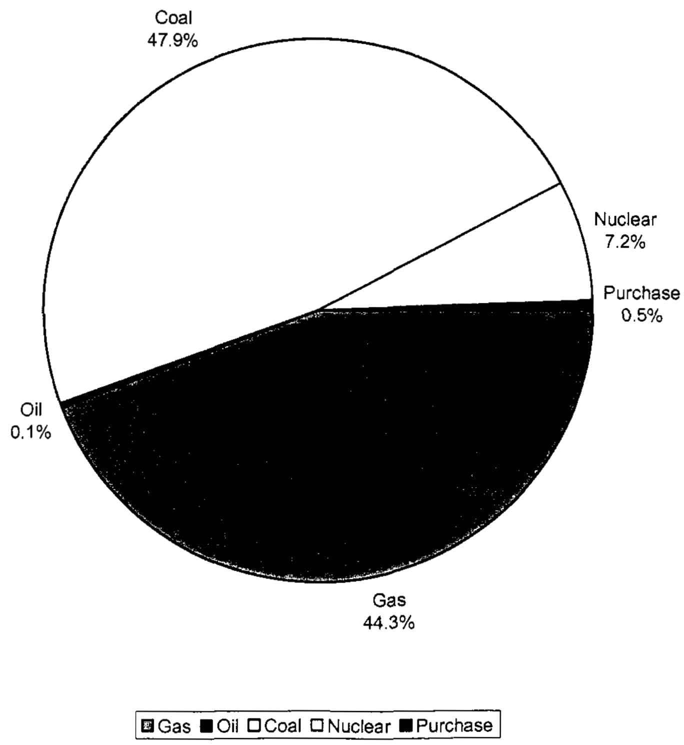

Figure B.8-4
FMPA's 2013 Energy Resources by Fuel Type

B.8.3 Stability of FMPA's Electric Rates

TEC will help to satisfy the need for low cost, baseload energy within FMPA's service territory and the State of Florida as a whole. Additional low cost, baseload energy from TEC will help stabilize electric rates for consumers and businesses. Electric rate stability will be beneficial for long-term planning and should also help facilitate more stable growth within the economy.

B.8.4 Long Service Life

Although economic evaluations have been conducted through 2035 for this Application, TEC will be designed for, and is expected to have, a service life significantly greater than the 23 years of operation captured by the analysis period. The benefits of TEC's expected actual service life of 35 to 50 or more years have not been captured in the economic analysis, but are expected to be realized by FMPA and the other Participants. Therefore, the total cost savings and benefits of TEC are understated in the economic analysis.

B.8.5 Supercritical Clean Coal Technology

By using supercritical pulverized coal boiler technology (which operates at a higher steam pressure than subcritical pulverized coal boilers) with Best Available Control Technology (BACT) pollution control systems, TEC will be among the most efficient and cleanest coal plants within the State of Florida. Supercritical clean coal technology is proven, has been in commercial service for decades, and provides at least a 2 percent lower heat rate in comparison to subcritical pulverized coal technology. This improvement in heat rate means that more energy can be generated with the same fuel input. The lower heat rate also translates into lower emissions from fuel combustion, because less fuel is needed for the same quantity of kilowatt-hours of energy output.

In addition, TEC will include BACT pollution control equipment to further reduce emissions per unit of fuel input. Combustion and post-combustion pollution controls will include low NO_x burners, selective catalytic reduction (SCR), wet flue gas desulfurization (FGD), wet electrostatic precipitator (WESP), baghouse, and a zero liquid discharge. As a result, TEC will have very low emissions rates.

B.8.6 Demonstrated Technology

Supercritical pulverized coal technology is a demonstrated technology that has been in commercial use for decades and has proven to be a reliable, baseload technology. Selection of a demonstrated technology is important to minimize risk to FMPA's customers. The use of supercritical pulverized coal, as a demonstrated technology, allows the Participants to achieve economies of scale inherent in larger generating units. Moreover, demonstrated technology is generally more favored by financing institutions and bond investors.

B.8.7 Environmental Considerations

As described in Section A.5.0, CAIR and CAMR will require much of the United States, including the State of Florida, to make significant reductions in the emissions of NO_x, SO_2, and Hg. With high natural gas prices, coal fired facilities will likely be the most economical type of generation to meet capacity requirements for utilities throughout the CAIR region. Generally, conventional coal fired generation produces higher emissions of NO_x, SO_2, and Hg than natural gas or fuel oil generation. As a result of the planned pollution control measures to be implemented on TEC as listed above and described in more detail in Section A.3.0, the proposed TEC project is designed to have lower emissions of NO_x, SO_2, and Hg than other coal fired power plants currently in operation.

B.8.8 Geographic Diversity

For FMPA, the other Participants, and the State of Florida as a whole, TEC will provide geographic diversity, because it will be constructed on a greenfield site. The greenfield site provides FMPA with additional baseload generation without increasing the concentration of its generation resources at one location. This diversity should increase reliability and availability of generating resources, particularly if a hurricane or other extreme condition causes forced outages in a localized area.

B.9.0 FMPA's Consequences of Delay

The proposed TEC is unique compared to the other supply-side alternatives considered in this analysis, because the project is significantly further along in the development process than the other options presented in Section A.6.0 and considered to meet FMPA's capacity and energy needs. As a result, the consequences of delaying the commercial operation of TEC are significant from an economic and reliability standpoint for FMPA. This section describes the negative consequences of delaying the TEC project.

B.9.1 Economic Consequences

If the commercial operation of TEC is delayed, FMPA would be required to replace the capacity and energy available from its share of the unit. A seasonal purchase would be required in 2012 to maintain its target 18 percent reserve margin. The capacity expansion plan including TEC delayed 1 year until May 1, 2013, includes an LMS100 unit in 2011, a seasonal purchase of 143 MW in 2012, and TEC as a committed resource beginning May 1, 2013. The summer seasonal purchase was modeled with an assumed energy cost of $164.09 per MWh (escalating at 2.5 percent annually) and a capacity cost of $7.50 per kW-month (with no escalation) in 2012 dollars. Following operation of TEC in May 2013, the remainder of the capacity expansion plan includes a CFB unit in 2014, a second CFB unit in 2019, and an LM6000 unit in 2025. The CPWC of this plan is $8,953.8 million, which is about $25.9 million higher in CPWC over the planning period than the base case plan with TEC in 2012 (presented in Section B.5.0). The CPWC of the plan with TEC delayed 1 year is still $377.7 million lower in cost than the lowest cost plan without TEC, presented in Section B.5.0.

B.9.2 Reliability Consequences

If TEC is delayed and no additional generating capacity is installed to meet FMPA's forecast capacity requirements by 2012, FMPA's summer reserve margin will fall to approximately 14 percent (59 MW less than the 18 percent summer reserve criterion) in 2011 and to approximately 2 percent (230 MW less than the 18 percent summer reserve criterion) in 2012. Operation of FMPA's system below its reserve margin criteria will increase the probability that FMPA will not be able to serve its retail customers and will expose FMPA's retail customers to potentially high purchase power costs.

B.10.0 FMPA's Financial Analysis

FMPA has several funding sources available that may be used to finance the development and construction of the TEC. These include internal funds, pooled loans, and new long-term debt issuances. Given its approximate 39 percent ownership stake in the project, FMPA will be responsible for financing an estimated $681.7 million of the total cost. These total costs include interest during construction, the owner's costs, land acquisition, and a community contribution.

FMPA typically finances its capital projects using three funding sources. During preliminary design, engineering, and permitting, FMPA may draw on its working capital within the ARP fund. As the initial development concludes and construction commences, FMPA may rely on its pooled loan commercial paper to get the construction process underway. The pooled loans could be expected to be used for financing up to the first $100 million of costs. Once the project is well defined and construction underway, FMPA would need to initiate a revenue bond issuance for long-term project funding. For large projects such as a coal fired power plant, FMPA would expect to issue either fixed or floating rate revenue bonds with a term of 30 years. Based on the project's favorable economics and its excellent credit rating, FMPA believes there will be no problems issuing debt to cover its share of the project cost. FMPA has recently initiated bond offerings with tax-exempt interest rates well below the rates assumed for the economic analysis.

FMPA 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. In addition, to protect against fluctuations in the interest rate, FMPA employs interest rate swap contracts that are based on well established indices for its floating rate debt. As of fiscal year end 2005, FMPA had $954 million in outstanding long-term bonds, which includes $276 million in ARP debt. Over the last 5 years, FMPA has had average long-term debt of approximately $940 million.

The detailed financing for TEC is expected to result in debt service requirements that are less than the assumed debt service presented in the economic parameters in Section A.4.0.

Appendix B.1 – FMPA's CPWC Summary Sheets

Table B.1-1 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - High Fuel Price

Case Description	
Fuel Forecast:	High Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	682,049	49,476
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/19	842,898	61,144
CFB	580,300	44	05/01/25	977,503	70,908

	Production Cost				Capital Cost and Other Project Costs							
		O&M										
Year	Fuel and Energy Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$413,241	$70,683	$0	$483,924	$0	$0	$0	$0	$0	$0	$483,924	$483,924
2007	$433,041	$54,482	$0	$487,523	$0	$0	$0	$0	$0	$0	$487,523	$948,231
2008	$469,600	$30,993	$0	$500,593	$0	$0	$0	$0	$0	$0	$500,593	$1,402,284
2009	$430,834	$31,549	$0	$462,383	$0	$0	$0	$0	$0	$0	$462,383	$1,801,707
2010	$338,169	$34,039	$0	$372,209	$0	$0	$0	$0	$0	$0	$372,209	$2,107,924
2011	$353,561	$36,355	$645	$390,560	$4,577	$0	$0	$0	$0	$4,577	$395,137	$2,417,524
2012	$315,659	$31,471	$6,482	$353,612	$39,938	$973	$0	$0	$592	$41,502	$395,114	$2,712,365
2013	$326,152	$23,877	$9,404	$359,432	$56,294	$997	$0	$0	$924	$58,215	$417,648	$3,009,179
2014	$320,732	$22,855	$17,458	$361,045	$92,569	$1,022	$0	$0	$966	$94,557	$455,602	$3,317,548
2015	$333,633	$23,742	$21,820	$379,195	$110,337	$1,047	$0	$0	$1,009	$112,393	$491,588	$3,634,430
2016	$357,380	$25,257	$22,365	$405,002	$110,337	$1,073	$0	$0	$1,055	$112,465	$517,467	$3,952,110
2017	$380,448	$26,875	$22,924	$430,247	$110,337	$1,100	$0	$0	$1,102	$112,539	$542,786	$4,269,466
2018	$406,236	$28,270	$23,497	$458,003	$110,337	$1,128	$0	$0	$1,152	$112,616	$570,619	$4,587,208
2019	$392,201	$29,228	$32,931	$454,359	$151,378	$1,156	$0	$0	$1,204	$153,738	$608,097	$4,909,695
2020	$409,957	$30,859	$38,196	$479,011	$171,480	$1,185	$0	$0	$1,258	$173,923	$652,934	$5,239,471
2021	$438,196	$32,424	$39,151	$509,770	$171,480	$1,215	$0	$0	$1,314	$174,009	$683,779	$5,568,380
2022	$474,432	$34,195	$40,129	$548,757	$171,480	$1,245	$0	$0	$1,373	$174,099	$722,856	$5,899,529
2023	$503,634	$36,183	$41,133	$580,950	$171,480	$1,276	$0	$0	$1,435	$174,192	$755,141	$6,228,995
2024	$544,686	$38,082	$42,161	$624,929	$171,480	$1,308	$0	$0	$1,500	$174,288	$799,217	$6,561,086
2025	$536,275	$40,767	$53,474	$630,516	$219,076	$1,341	$0	$0	$1,567	$221,984	$852,500	$6,898,449
2026	$545,047	$43,260	$59,961	$648,268	$242,388	$1,374	$0	$0	$1,638	$245,400	$893,669	$7,235,263
2027	$560,264	$44,693	$61,460	$666,417	$242,388	$1,408	$0	$0	$1,712	$245,508	$911,925	$7,562,592
2028	$591,256	$46,391	$62,997	$700,644	$242,388	$1,444	$0	$0	$1,789	$245,621	$946,264	$7,886,072
2029	$617,696	$47,715	$64,572	$729,983	$242,388	$1,480	$0	$0	$1,869	$245,737	$975,720	$8,203,739
2030	$638,291	$48,764	$66,186	$753,241	$242,388	$1,517	$0	$0	$1,953	$245,858	$999,099	$8,513,527
2031	$670,295	$50,025	$67,841	$788,161	$237,812	$1,555	$0	$0	$2,041	$241,407	$1,029,568	$8,817,562
2032	$701,278	$51,372	$69,537	$822,186	$235,570	$1,594	$0	$0	$2,133	$239,296	$1,061,483	$9,116,094
2033	$724,565	$52,512	$71,275	$848,352	$235,570	$1,633	$0	$0	$2,229	$239,432	$1,087,784	$9,407,455
2034	$762,135	$53,875	$73,057	$889,067	$235,570	$1,674	$0	$0	$2,329	$239,573	$1,128,641	$9,695,364
2035	$799,807	$55,362	$74,883	$930,052	$235,570	$1,716	$0	$0	$2,434	$239,720	$1,169,772	$9,979,556

Table B.1-2 Expansion Plan Economic Summary - Without Taylor Energy Center - High Fuel Prices

Case Description	
Fuel Forecast:	High Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
CFB	580,300	44	05/01/12	709,133	51,441
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/18	822,340	59,653
Single 1X1 IGCC	726,200	41	05/01/24	1,189,898	86,315

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*					Ongoing	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	*Unit Capital* Cost ($1,000)	*Community* Contribution ($1,000)	*Transmission* Charge ($1,000)	*Seasonal* Purchase ($1,000)	Capex Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$413,241	$70,683	$0	$483,924	$0	$0	$0	$0	$0	$0	$483,924	$483,924
2007	$433,041	$54,482	$0	$487,523	$0	$0	$0	$0	$0	$0	$487,523	$948,231
2008	$469,600	$30,993	$0	$500,593	$0	$0	$0	$0	$0	$0	$500,593	$1,402,284
2009	$430,834	$31,549	$0	$462,383	$0	$0	$0	$0	$0	$0	$462,383	$1,801,707
2010	$338,169	$34,039	$0	$372,209	$0	$0	$0	$0	$0	$0	$372,209	$2,107,924
2011	$353,561	$36,355	$645	$390,560	$4,577	$0	$0	$0	$0	$4,577	$395,137	$2,417,524
2012	$327,943	$36,259	$8,427	$372,629	$41,253	$0	$0	$0	$0	$41,253	$413,882	$2,726,369
2013	$345,654	$30,770	$12,374	$388,798	$58,259	$0	$0	$0	$0	$58,259	$447,057	$3,044,085
2014	$339,195	$29,090	$20,503	$388,787	$94,534	$0	$0	$0	$0	$94,534	$483,321	$3,371,216
2015	$350,039	$30,057	$24,941	$405,037	$112,301	$0	$0	$0	$0	$112,301	$517,338	$3,704,696
2016	$374,766	$31,827	$25,564	$432,157	$112,301	$0	$0	$0	$0	$112,301	$544,458	$4,038,946
2017	$399,311	$33,568	$26,203	$459,082	$112,301	$0	$0	$0	$0	$112,301	$571,383	$4,373,022
2018	$383,771	$34,422	$35,489	$453,682	$152,342	$0	$0	$0	$0	$152,342	$606,024	$4,710,479
2019	$394,719	$36,064	$40,709	$471,492	$171,954	$0	$0	$0	$0	$171,954	$643,445	$5,051,712
2020	$428,350	$37,822	$41,727	$507,898	$171,954	$0	$0	$0	$0	$171,954	$679,852	$5,395,083
2021	$459,919	$39,652	$42,770	$542,341	$171,954	$0	$0	$0	$0	$171,954	$714,295	$5,738,671
2022	$496,426	$41,806	$43,839	$582,071	$171,954	$0	$0	$0	$0	$171,954	$754,025	$6,084,099
2023	$528,343	$43,862	$44,935	$617,139	$171,954	$0	$0	$0	$0	$171,954	$789,093	$6,428,377
2024	$505,822	$51,137	$58,334	$615,293	$229,733	$0	$0	$0	$0	$229,733	$845,026	$6,779,503
2025	$521,875	$57,299	$65,955	$645,128	$258,269	$0	$0	$0	$0	$258,269	$903,397	$7,137,008
2026	$550,212	$59,655	$67,603	$677,470	$258,269	$0	$0	$0	$0	$258,269	$935,739	$7,489,678
2027	$567,258	$61,516	$69,294	$698,067	$258,269	$0	$0	$0	$0	$258,269	$956,336	$7,832,948
2028	$591,978	$63,760	$71,026	$726,764	$258,269	$0	$0	$0	$0	$258,269	$985,033	$8,169,681
2029	$621,713	$65,247	$72,802	$759,761	$258,269	$0	$0	$0	$0	$258,269	$1,018,030	$8,501,123
2030	$640,594	$66,905	$74,622	$782,121	$258,269	$0	$0	$0	$0	$258,269	$1,040,389	$8,823,714
2031	$668,934	$68,756	$76,487	$814,178	$253,692	$0	$0	$0	$0	$253,692	$1,067,870	$9,139,059
2032	$702,859	$70,257	$78,399	$851,516	$251,450	$0	$0	$0	$0	$251,450	$1,102,966	$9,449,258
2033	$726,499	$72,053	$80,359	$878,912	$251,450	$0	$0	$0	$0	$251,450	$1,130,362	$9,752,024
2034	$757,648	$74,062	$82,368	$914,078	$251,450	$0	$0	$0	$0	$251,450	$1,165,529	$10,049,343
2035	$797,752	$75,699	$84,427	$957,879	$251,450	$0	$0	$0	$0	$251,450	$1,209,329	$10,343,145

Table B.1-3 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Low Fuel Prices

Case Description	
Fuel Forecast:	Low Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	679,287	49,275
LMS100	65,500	17	05/01/14	81,841	7,343
7FA CT	72,400	14	05/01/15	92,445	8,294
CFB	580,300	44	05/01/19	842,898	61,144
LM6000	38,800	12	05/01/25	63,291	5,678

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*					Ongoing	*Total Capital*	Total System	Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$312,342	$59,953	$0	$372,294	$0	$0	$0	$0	$0	$0	$372,294	$372,294
2007	$315,861	$47,002	$0	$362,863	$0	$0	$0	$0	$0	$0	$362,863	$717,878
2008	$330,722	$28,197	$0	$358,919	$0	$0	$0	$0	$0	$0	$358,919	$1,043,428
2009	$286,524	$29,417	$0	$315,941	$0	$0	$0	$0	$0	$0	$315,941	$1,316,350
2010	$249,410	$26,365	$0	$275,775	$0	$0	$0	$0	$0	$0	$275,775	$1,543,230
2011	$259,905	$28,855	$645	$289,405	$4,577	$0	$0	$0	$0	$4,577	$293,982	$1,773,573
2012	$240,457	$24,401	$6,482	$271,341	$39,803	$973	$0	$0	$592	$41,368	$312,709	$2,006,921
2013	$247,542	$22,352	$9,404	$279,297	$56,094	$997	$0	$0	$924	$58,015	$337,312	$2,246,642
2014	$270,118	$23,197	$10,334	$303,648	$61,023	$1,022	$0	$0	$966	$63,010	$366,658	$2,494,811
2015	$286,022	$25,834	$11,587	$323,443	$69,004	$1,047	$0	$0	$1,009	$71,061	$394,504	$2,749,112
2016	$307,278	$26,325	$12,201	$345,804	$71,731	$1,073	$0	$0	$1,055	$73,859	$419,663	$3,006,748
2017	$326,792	$29,015	$12,506	$368,314	$71,731	$1,100	$0	$0	$1,102	$73,933	$442,247	$3,265,321
2018	$345,813	$30,544	$12,819	$389,175	$71,731	$1,128	$0	$0	$1,152	$74,010	$463,185	$3,523,240
2019	$338,176	$30,598	$21,986	$390,759	$112,773	$1,156	$0	$0	$1,204	$115,132	$505,892	$3,791,525
2020	$350,702	$31,838	$26,976	$409,517	$132,875	$1,185	$0	$0	$1,258	$135,317	$544,834	$4,066,704
2021	$370,856	$33,505	$27,651	$432,012	$132,875	$1,215	$0	$0	$1,314	$135,404	$567,415	$4,339,640
2022	$393,937	$35,665	$28,342	$457,944	$132,875	$1,245	$0	$0	$1,373	$135,493	$593,437	$4,611,500
2023	$423,645	$37,771	$29,051	$490,467	$132,875	$1,276	$0	$0	$1,435	$135,586	$626,053	$4,884,645
2024	$450,440	$39,704	$29,777	$519,922	$132,875	$1,308	$0	$0	$1,500	$135,682	$655,604	$5,157,062
2025	$482,750	$42,279	$31,376	$556,405	$136,686	$1,341	$0	$0	$1,567	$139,594	$695,999	$5,432,493
2026	$500,207	$43,335	$32,589	$576,132	$138,553	$1,374	$0	$0	$1,638	$141,565	$717,697	$5,702,985
2027	$512,816	$44,546	$33,404	$590,765	$138,553	$1,408	$0	$0	$1,712	$141,673	$732,439	$5,965,888
2028	$534,416	$46,151	$34,239	$614,806	$138,553	$1,444	$0	$0	$1,789	$141,785	$756,591	$6,224,529
2029	$556,726	$47,339	$35,095	$639,160	$138,553	$1,480	$0	$0	$1,869	$141,902	$781,062	$6,478,820
2030	$574,268	$48,378	$35,972	$658,618	$138,553	$1,517	$0	$0	$1,953	$142,023	$800,641	$6,727,073
2031	$597,428	$49,880	$36,872	$684,180	$133,976	$1,555	$0	$0	$2,041	$137,572	$821,752	$6,969,739
2032	$622,327	$51,183	$37,793	$711,303	$131,735	$1,594	$0	$0	$2,133	$135,461	$846,764	$7,207,884
2033	$641,996	$52,199	$38,738	$732,933	$131,735	$1,633	$0	$0	$2,229	$135,597	$868,530	$7,440,518
2034	$668,875	$53,762	$39,707	$762,344	$126,806	$1,674	$0	$0	$2,329	$130,809	$893,153	$7,668,356
2035	$697,294	$55,084	$40,699	$793,077	$118,825	$1,716	$0	$0	$2,434	$122,975	$916,052	$7,890,907

Table B.1-4 Expansion Plan Economic Summary - Without Taylor Energy Center - Low Fuel Prices

Case Description	
Fuel Forecast	Low Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
LMS100	65,500	17	05/01/12	77,901	6,989
LMS100	65,500	17	05/01/12	77,901	6,989
7FA CT	72,400	14	05/01/13	87,991	7,895
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/20	864,010	62,675

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Seasonal	Ongoing Capex	*Total Capital*	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Purchase ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$312,342	$59,953	$0	$372,294	$0	$0	$0	$0	$0	$0	$372,294	$372,294
2007	$315,861	$47,002	$0	$362,863	$0	$0	$0	$0	$0	$0	$362,863	$717,878
2008	$330,722	$28,197	$0	$358,919	$0	$0	$0	$0	$0	$0	$358,919	$1,043,428
2009	$286,524	$29,417	$0	$315,941	$0	$0	$0	$0	$0	$0	$315,941	$1,316,350
2010	$249,410	$26,365	$0	$275,775	$0	$0	$0	$0	$0	$0	$275,775	$1,543,230
2011	$259,905	$28,855	$645	$289,405	$4,577	$0	$0	$0	$0	$4,577	$293,982	$1,773,573
2012	$267,542	$30,028	$2,308	$299,878	$16,176	$0	$0	$0	$0	$16,176	$316,054	$2,009,417
2013	$289,282	$30,712	$3,645	$323,639	$26,096	$0	$0	$0	$0	$26,096	$349,735	$2,257,967
2014	$290,163	$30,227	$11,863	$332,254	$64,966	$0	$0	$0	$0	$64,966	$397,220	$2,526,821
2015	$299,601	$32,281	$16,085	$347,967	$82,734	$0	$0	$0	$0	$82,734	$430,700	$2,804,455
2016	$318,994	$32,735	$16,488	$368,216	$82,734	$0	$0	$0	$0	$82,734	$450,950	$3,081,299
2017	$339,418	$36,236	$16,900	$392,554	$82,734	$0	$0	$0	$0	$82,734	$475,288	$3,359,190
2018	$362,696	$37,754	$17,322	$417,772	$82,734	$0	$0	$0	$0	$82,734	$500,506	$3,637,890
2019	$388,835	$39,858	$17,755	$446,448	$82,734	$0	$0	$0	$0	$82,734	$529,182	$3,918,527
2020	$380,036	$40,124	$27,267	$447,427	$124,689	$0	$0	$0	$0	$124,689	$572,116	$4,207,484
2021	$388,470	$41,144	$32,501	$462,115	$145,409	$0	$0	$0	$0	$145,409	$607,524	$4,499,713
2022	$415,506	$43,693	$33,313	$492,512	$145,409	$0	$0	$0	$0	$145,409	$637,921	$4,791,953
2023	$445,775	$45,883	$34,146	$525,805	$145,409	$0	$0	$0	$0	$145,409	$671,214	$5,084,801
2024	$470,463	$48,297	$35,000	$553,759	$145,409	$0	$0	$0	$0	$145,409	$699,168	$5,375,320
2025	$506,805	$50,885	$35,875	$593,564	$145,409	$0	$0	$0	$0	$145,409	$738,973	$5,667,757
2026	$526,049	$52,031	$36,771	$614,852	$145,409	$0	$0	$0	$0	$145,409	$760,261	$5,954,291
2027	$541,416	$53,830	$37,691	$632,936	$145,409	$0	$0	$0	$0	$145,409	$778,345	$6,233,672
2028	$564,370	$55,540	$38,633	$658,543	$145,409	$0	$0	$0	$0	$145,409	$803,952	$6,508,503
2029	$587,382	$56,820	$39,599	$683,801	$145,409	$0	$0	$0	$0	$145,409	$829,210	$6,778,470
2030	$605,317	$58,260	$40,589	$704,166	$145,409	$0	$0	$0	$0	$145,409	$849,575	$7,041,896
2031	$631,186	$59,990	$41,603	$732,780	$140,832	$0	$0	$0	$0	$140,832	$873,612	$7,299,876
2032	$657,673	$61,328	$42,644	$761,645	$129,233	$0	$0	$0	$0	$129,233	$890,878	$7,550,427
2033	$677,875	$62,763	$43,710	$784,347	$119,313	$0	$0	$0	$0	$119,313	$903,660	$7,792,471
2034	$708,055	$64,690	$44,802	$817,547	$116,718	$0	$0	$0	$0	$116,718	$934,265	$8,030,796
2035	$737,560	$66,055	$45,922	$849,538	$116,718	$0	$0	$0	$0	$116,718	$966,255	$8,265,544

Table B.1-5 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - High Load and Energy Growth

Case Description	
Fuel Forecast:	Base Case
Load Forecast	High Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000	38,800	12	05/01/08	41,597	3,732
7FA CT	72,400	14	05/01/10	81,708	7,331
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	681,687	49,450
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/17	802,283	58,198
CFB	580,300	44	05/01/21	885,570	64,239
LM6000	38,800	12	05/01/25	63,291	5,678

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*					Ongoing Capex	*Total Capital*	Total System	Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$435,009	$61,083	$0	$496,092	$0	$0	$0	$0	$0	$0	$496,092	$496,092
2007	$426,013	$57,934	$0	$483,947	$0	$0	$0	$0	$0	$0	$483,947	$956,993
2008	$440,088	$32,057	$562	$472,707	$2,498	$0	$0	$0	$0	$2,498	$475,206	$1,388,019
2009	$380,442	$33,437	$857	$414,736	$3,732	$0	$0	$0	$0	$3,732	$418,468	$1,749,507
2010	$319,640	$34,119	$1,450	$355,209	$8,653	$0	$0	$0	$0	$8,653	$363,862	$2,048,857
2011	$335,514	$37,359	$2,418	$375,291	$15,640	$0	$0	$0	$0	$15,640	$390,931	$2,355,162
2012	$310,247	$31,627	$8,299	$350,174	$50,983	$973	$0	$0	$592	$52,547	$402,721	$2,655,679
2013	$323,236	$26,919	$11,267	$361,422	$67,331	$997	$0	$0	$924	$69,252	$430,674	$2,961,750
2014	$322,571	$26,815	$19,367	$368,753	$103,606	$1,022	$0	$0	$966	$105,593	$474,347	$3,282,807
2015	$337,621	$27,882	$23,777	$389,280	$121,373	$1,047	$0	$0	$1,009	$123,430	$512,710	$3,613,304
2016	$363,775	$30,041	$24,371	$418,188	$121,373	$1,073	$0	$0	$1,055	$123,501	$541,689	$3,945,854
2017	$354,105	$30,860	$33,400	$418,366	$160,437	$1,100	$0	$0	$1,102	$162,640	$581,006	$4,285,556
2018	$362,345	$32,560	$38,463	$433,367	$179,571	$1,128	$0	$0	$1,152	$181,850	$615,217	$4,628,132
2019	$396,580	$34,668	$39,424	$470,672	$179,571	$1,156	$0	$0	$1,204	$181,930	$652,602	$4,974,221
2020	$428,715	$37,119	$40,410	$506,244	$179,571	$1,185	$0	$0	$1,258	$182,013	$688,258	$5,321,838
2021	$418,293	$38,476	$50,714	$507,484	$222,690	$1,215	$0	$0	$1,314	$225,219	$732,703	$5,674,281
2022	$432,731	$41,058	$56,648	$530,437	$243,810	$1,245	$0	$0	$1,373	$246,428	$776,865	$6,030,172
2023	$476,698	$43,662	$58,064	$578,425	$243,810	$1,276	$0	$0	$1,435	$246,521	$824,946	$6,390,093
2024	$527,426	$46,560	$59,516	$633,502	$243,810	$1,308	$0	$0	$1,500	$246,618	$880,119	$6,755,801
2025	$573,543	$49,706	$61,858	$685,108	$247,622	$1,341	$0	$0	$1,567	$250,529	$935,638	$7,126,064
2026	$593,216	$51,433	$63,834	$708,483	$249,489	$1,374	$0	$0	$1,638	$252,500	$960,983	$7,488,249
2027	$609,653	$53,119	$65,430	$728,202	$249,489	$1,408	$0	$0	$1,712	$252,608	$980,811	$7,840,303
2028	$640,153	$54,840	$67,065	$762,058	$246,990	$1,444	$0	$0	$1,789	$250,223	$1,012,281	$8,186,351
2029	$665,604	$56,540	$68,742	$790,886	$245,756	$1,480	$0	$0	$1,869	$249,105	$1,039,991	$8,524,943
2030	$684,332	$57,915	$70,461	$812,708	$240,836	$1,517	$0	$0	$1,953	$244,306	$1,057,013	$8,852,688
2031	$716,690	$59,747	$72,222	$848,660	$233,849	$1,555	$0	$0	$2,041	$237,445	$1,086,104	$9,173,418
2032	$746,901	$61,475	$74,028	$882,403	$231,607	$1,594	$0	$0	$2,133	$235,334	$1,117,737	$9,487,771
2033	$768,974	$62,696	$75,878	$907,548	$231,607	$1,633	$0	$0	$2,229	$235,469	$1,143,017	$9,793,926
2034	$805,521	$64,550	$77,775	$947,846	$231,607	$1,674	$0	$0	$2,329	$235,610	$1,183,457	$10,095,819
2035	$840,421	$66,181	$79,720	$986,322	$231,607	$1,716	$0	$0	$2,434	$235,757	$1,222,079	$10,392,718

Table B.1-6 Expansion Plan Economic Summary - Without TEC - High Load Forecast

Case Description	
Fuel Forecast:	Base Case
Load Forecast	High Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000	38,800	12	05/01/08	41,597	3,732
7FA CT	72,400	14	05/01/10	81,708	7,331
LMS100	65,500	17	05/01/11	75,997	6,818
CFB	580,300	44	05/01/12	709,133	51,441
LMS100	65,500	17	05/01/13	79,845	7,164
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/18	822,340	59,653
Single 1X1 IGCC	726,200	41	05/01/22	1,132,510	82,152

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy Cost	O&M		*Total Production Cost*	Unit Capital Cost	Community Contribution	Transmission Charge	Seasonal Purchase	Ongoing Capex Cost	*Total Capital Cost*	Total System Cost	Cumulative Present Worth Cost
Year	($1,000)	Variable ($1,000)	Fixed ($1,000)	*($1,000)*	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	*($1,000)*	($1,000)	($1,000)
2006	$435,009	$61,083	$0	$496,092	$0	$0	$0	$0	$0	$0	$496,092	$496,092
2007	$426,013	$57,934	$0	$483,947	$0	$0	$0	$0	$0	$0	$483,947	$956,993
2008	$440,088	$32,057	$562	$472,707	$2,498	$0	$0	$0	$0	$2,498	$475,206	$1,388,019
2009	$380,442	$33,437	$857	$414,736	$3,732	$0	$0	$0	$0	$3,732	$418,468	$1,749,507
2010	$319,640	$34,119	$1,450	$355,209	$8,653	$0	$0	$0	$0	$8,653	$363,862	$2,048,857
2011	$335,514	$37,359	$2,418	$375,291	$15,640	$0	$0	$0	$0	$15,640	$390,931	$2,355,162
2012	$319,749	$36,226	$10,245	$366,220	$52,316	$0	$0	$0	$0	$52,316	$418,536	$2,667,480
2013	$335,606	$33,628	$14,915	$384,149	$74,130	$0	$0	$0	$0	$74,130	$458,280	$2,993,170
2014	$333,692	$33,094	$23,447	$390,233	$112,760	$0	$0	$0	$0	$112,760	$502,993	$3,333,616
2015	$348,725	$34,468	$27,959	$411,152	$130,528	$0	$0	$0	$0	$130,528	$541,680	$3,682,788
2016	$377,913	$36,973	$28,658	$443,544	$130,528	$0	$0	$0	$0	$130,528	$574,071	$4,035,218
2017	$403,429	$39,161	$29,374	$471,964	$130,528	$0	$0	$0	$0	$130,528	$602,492	$4,387,482
2018	$394,839	$39,949	$38,739	$473,526	$170,569	$0	$0	$0	$0	$170,569	$644,095	$4,746,138
2019	$415,649	$41,821	$44,040	$501,511	$190,180	$0	$0	$0	$0	$190,180	$691,691	$5,112,957
2020	$448,400	$44,241	$45,141	$537,782	$190,180	$0	$0	$0	$0	$190,180	$727,962	$5,480,627
2021	$476,178	$46,918	$46,270	$569,366	$190,180	$0	$0	$0	$0	$190,180	$759,547	$5,845,982
2022	$460,922	$53,915	$59,110	$573,948	$245,324	$0	$0	$0	$0	$245,324	$819,271	$6,221,299
2023	$492,404	$58,624	$66,454	$617,482	$272,333	$0	$0	$0	$0	$272,333	$889,815	$6,609,523
2024	$541,078	$62,056	$68,115	$671,249	$272,333	$0	$0	$0	$0	$272,333	$943,582	$7,001,601
2025	$584,273	$65,931	$69,818	$720,022	$272,333	$0	$0	$0	$0	$272,333	$992,354	$7,394,309
2026	$607,035	$67,763	$71,563	$746,362	$272,333	$0	$0	$0	$0	$272,333	$1,018,695	$7,778,244
2027	$629,082	$69,782	$73,352	$772,216	$272,333	$0	$0	$0	$0	$272,333	$1,044,549	$8,153,177
2028	$654,587	$72,215	$75,186	$801,988	$269,834	$0	$0	$0	$0	$269,834	$1,071,823	$8,519,579
2029	$682,842	$74,008	$77,066	$833,915	$268,601	$0	$0	$0	$0	$268,601	$1,102,516	$8,878,527
2030	$703,928	$75,839	$78,993	$858,760	$263,680	$0	$0	$0	$0	$263,680	$1,122,440	$9,226,560
2031	$734,091	$78,356	$80,967	$893,414	$256,693	$0	$0	$0	$0	$256,693	$1,150,107	$9,566,190
2032	$767,328	$80,291	$82,992	$930,610	$254,451	$0	$0	$0	$0	$254,451	$1,185,061	$9,899,477
2033	$791,688	$82,031	$85,066	$958,785	$249,643	$0	$0	$0	$0	$249,643	$1,208,428	$10,223,152
2034	$825,693	$84,648	$87,193	$997,534	$247,288	$0	$0	$0	$0	$247,288	$1,244,822	$10,540,699
2035	$863,544	$86,460	$89,373	$1,039,378	$247,288	$0	$0	$0	$0	$247,288	$1,286,665	$10,853,289

Table B.1-7 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Low Load and Energy Growth

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Low Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	681,687	49,450
CFB	580,300	44	05/01/16	782,715	56,778

Year	Production Cost				Capital Cost and Other Project Costs						Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Cost ($1,000)	*Total Capital Cost ($1,000)*		
2006	$322,996	$64,433	$0	$387,429	$0	$0	$0	$0	$0	$0	$387,429	$387,429
2007	$346,832	$54,975	$0	$401,807	$0	$0	$0	$0	$0	$0	$401,807	$770,102
2008	$346,896	$29,641	$0	$376,537	$0	$0	$0	$0	$0	$0	$376,537	$1,111,633
2009	$302,974	$27,611	$0	$330,585	$0	$0	$0	$0	$0	$0	$330,585	$1,397,204
2010	$262,855	$27,074	$0	$289,929	$0	$0	$0	$0	$0	$0	$289,929	$1,635,730
2011	$272,166	$29,793	$645	$302,603	$4,577	$0	$0	$0	$0	$4,577	$307,180	$1,876,413
2012	$248,921	$23,295	$6,482	$278,698	$39,920	$973	$0	$0	$592	$41,484	$320,183	$2,115,339
2013	$254,161	$19,136	$9,404	$282,701	$56,268	$997	$0	$0	$924	$58,189	$340,890	$2,357,603
2014	$273,353	$19,941	$9,639	$302,934	$56,268	$1,022	$0	$0	$966	$58,256	$361,189	$2,602,070
2015	$289,417	$20,907	$9,880	$320,204	$56,268	$1,047	$0	$0	$1,009	$58,325	$378,528	$2,846,072
2016	$279,261	$20,877	$18,342	$318,479	$94,379	$1,073	$0	$0	$1,055	$96,508	$414,987	$3,100,838
2017	$277,944	$21,864	$22,924	$322,732	$113,046	$1,100	$0	$0	$1,102	$115,249	$437,980	$3,356,916
2018	$288,428	$22,813	$23,497	$334,738	$113,046	$1,128	$0	$0	$1,152	$115,326	$450,064	$3,607,529
2019	$309,120	$23,859	$24,085	$357,064	$113,046	$1,156	$0	$0	$1,204	$115,406	$472,470	$3,858,090
2020	$328,640	$25,037	$24,687	$378,363	$113,046	$1,185	$0	$0	$1,258	$115,489	$493,852	$4,107,519
2021	$343,096	$26,038	$25,304	$394,438	$113,046	$1,215	$0	$0	$1,314	$115,575	$510,013	$4,352,843
2022	$359,695	$27,310	$25,937	$412,942	$113,046	$1,245	$0	$0	$1,373	$115,664	$528,607	$4,595,004
2023	$385,668	$28,654	$26,585	$440,907	$113,046	$1,276	$0	$0	$1,435	$115,757	$556,665	$4,837,875
2024	$416,029	$29,884	$27,250	$473,162	$113,046	$1,308	$0	$0	$1,500	$115,854	$589,016	$5,082,624
2025	$440,676	$31,328	$27,931	$499,935	$113,046	$1,341	$0	$0	$1,567	$115,954	$615,889	$5,326,352
2026	$459,375	$32,536	$28,629	$520,540	$113,046	$1,374	$0	$0	$1,638	$116,058	$636,598	$5,566,279
2027	$473,914	$33,459	$29,345	$536,718	$113,046	$1,408	$0	$0	$1,712	$116,166	$652,884	$5,800,626
2028	$495,109	$34,466	$30,079	$559,654	$113,046	$1,444	$0	$0	$1,789	$116,278	$675,932	$6,031,694
2029	$516,931	$35,629	$30,831	$583,390	$113,046	$1,480	$0	$0	$1,869	$116,395	$699,785	$6,259,524
2030	$534,585	$36,456	$31,601	$602,643	$113,046	$1,517	$0	$0	$1,953	$116,516	$719,159	$6,482,512
2031	$557,846	$37,494	$32,391	$627,732	$108,469	$1,555	$0	$0	$2,041	$112,065	$739,797	$6,700,976
2032	$582,259	$38,654	$33,201	$654,114	$106,228	$1,594	$0	$0	$2,133	$109,954	$764,068	$6,915,863
2033	$602,673	$39,425	$34,031	$676,129	$106,228	$1,633	$0	$0	$2,229	$110,090	$786,219	$7,126,450
2034	$628,976	$40,438	$34,882	$704,296	$106,228	$1,674	$0	$0	$2,329	$110,231	$814,527	$7,334,231
2035	$657,619	$41,596	$35,754	$734,970	$106,228	$1,716	$0	$0	$2,434	$110,378	$845,348	$7,539,605

Table B.1-8 Expansion Plan Economic Summary - Without Taylor Energy Center - Low Load and Energy Growth

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Low Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
CFB	580,300	44	05/01/12	709,133	51,441
CFB	580,300	44	05/01/14	744,999	54,042
LM6000	38,800	12	05/01/25	63,291	5,678

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*					Ongoing	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$322,996	$64,433	$0	$387,429	$0	$0	$0	$0	$0	$0	$387,429	$387,429
2007	$346,832	$54,975	$0	$401,807	$0	$0	$0	$0	$0	$0	$401,807	$770,102
2008	$346,896	$29,641	$0	$376,537	$0	$0	$0	$0	$0	$0	$376,537	$1,111,633
2009	$302,974	$27,611	$0	$330,585	$0	$0	$0	$0	$0	$0	$330,585	$1,397,204
2010	$262,855	$27,074	$0	$289,929	$0	$0	$0	$0	$0	$0	$289,929	$1,635,730
2011	$272,166	$29,793	$645	$302,603	$4,577	$0	$0	$0	$0	$4,577	$307,180	$1,876,413
2012	$256,851	$27,553	$8,427	$292,832	$41,253	$0	$0	$0	$0	$41,253	$334,084	$2,125,712
2013	$266,107	$25,416	$12,374	$303,897	$58,259	$0	$0	$0	$0	$58,259	$362,156	$2,383,090
2014	$259,415	$24,884	$20,503	$304,802	$94,534	$0	$0	$0	$0	$94,534	$399,336	$2,653,376
2015	$267,232	$25,531	$24,941	$317,704	$112,301	$0	$0	$0	$0	$112,301	$430,005	$2,930,561
2016	$283,194	$26,736	$25,564	$335,494	$112,301	$0	$0	$0	$0	$112,301	$447,795	$3,205,468
2017	$296,508	$27,927	$26,203	$350,638	$112,301	$0	$0	$0	$0	$112,301	$462,940	$3,476,140
2018	$310,491	$29,132	$26,858	$366,481	$112,301	$0	$0	$0	$0	$112,301	$478,783	$3,742,744
2019	$332,040	$30,354	$27,530	$389,923	$112,301	$0	$0	$0	$0	$112,301	$502,225	$4,009,084
2020	$350,482	$31,752	$28,218	$410,452	$112,301	$0	$0	$0	$0	$112,301	$522,753	$4,273,110
2021	$364,967	$33,185	$28,923	$427,075	$112,301	$0	$0	$0	$0	$112,301	$539,376	$4,532,559
2022	$384,587	$34,507	$29,646	$448,741	$112,301	$0	$0	$0	$0	$112,301	$561,042	$4,789,579
2023	$414,842	$36,076	$30,388	$481,306	$112,301	$0	$0	$0	$0	$112,301	$593,608	$5,048,568
2024	$443,528	$37,749	$31,147	$512,424	$112,301	$0	$0	$0	$0	$112,301	$624,725	$5,308,155
2025	$471,370	$39,462	$32,780	$543,613	$116,113	$0	$0	$0	$0	$116,113	$659,725	$5,569,230
2026	$489,373	$40,702	$34,029	$564,103	$117,980	$0	$0	$0	$0	$117,980	$682,083	$5,826,300
2027	$506,327	$42,056	$34,880	$583,263	$117,980	$0	$0	$0	$0	$117,980	$701,242	$6,078,006
2028	$531,132	$43,225	$35,752	$610,109	$117,980	$0	$0	$0	$0	$117,980	$728,089	$6,326,903
2029	$553,451	$44,428	$36,645	$634,525	$117,980	$0	$0	$0	$0	$117,980	$752,504	$6,571,897
2030	$570,837	$45,646	$37,561	$654,045	$117,980	$0	$0	$0	$0	$117,980	$772,024	$6,811,277
2031	$598,943	$46,873	$38,501	$684,317	$113,403	$0	$0	$0	$0	$113,403	$797,719	$7,046,846
2032	$625,811	$48,117	$39,463	$713,391	$111,161	$0	$0	$0	$0	$111,161	$824,553	$7,278,743
2033	$645,583	$49,327	$40,450	$735,359	$111,161	$0	$0	$0	$0	$111,161	$846,520	$7,505,482
2034	$677,626	$50,572	$41,461	$769,659	$111,161	$0	$0	$0	$0	$111,161	$880,820	$7,730,174
2035	$708,247	$51,833	$42,497	$802,578	$111,161	$0	$0	$0	$0	$111,161	$913,739	$7,952,163

Table B.1-9 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - High Capital Costs

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	78,600	17	05/01/11	91,197	8,182
TEC	NA	NA	05/01/12	818,025	59,340
CFB	696,360	44	05/01/14	893,999	64,851
LM6000	46,560	12	05/01/19	65,491	5,876
CFB	696,360	44	05/01/20	1,036,812	75,210

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Seasonal	Ongoing Capex	*Total Capital*	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Purchase ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$5,492	$0	$0	$0	$0	$5,492	$344,779	$2,100,744
2012	$280,003	$27,323	$6,482	$313,808	$47,904	$973	$0	$0	$592	$49,468	$363,277	$2,371,827
2013	$287,725	$22,944	$9,404	$320,073	$67,522	$997	$0	$0	$924	$69,443	$389,516	$2,648,648
2014	$285,963	$22,849	$17,458	$326,269	$111,052	$1,022	$0	$0	$966	$113,039	$439,309	$2,945,989
2015	$296,457	$23,756	$21,820	$342,032	$132,372	$1,047	$0	$0	$1,009	$134,429	$476,461	$3,253,121
2016	$316,365	$25,228	$22,365	$363,958	$132,372	$1,073	$0	$0	$1,055	$134,500	$498,458	$3,559,131
2017	$332,390	$26,810	$22,924	$382,124	$132,372	$1,100	$0	$0	$1,102	$134,575	$516,699	$3,861,234
2018	$350,569	$28,250	$23,497	$402,316	$132,372	$1,128	$0	$0	$1,152	$134,652	$536,968	$4,160,238
2019	$376,687	$30,044	$24,822	$431,552	$136,316	$1,156	$0	$0	$1,204	$138,676	$570,228	$4,462,642
2020	$368,068	$30,715	$34,880	$433,663	$188,594	$1,185	$0	$0	$1,258	$191,037	$624,700	$4,778,158
2021	$372,308	$32,392	$40,304	$445,003	$213,459	$1,215	$0	$0	$1,314	$215,987	$660,990	$5,096,106
2022	$395,746	$34,093	$41,311	$471,150	$213,459	$1,245	$0	$0	$1,373	$216,077	$687,227	$5,410,932
2023	$431,785	$36,114	$42,344	$510,243	$213,459	$1,276	$0	$0	$1,435	$216,170	$726,412	$5,727,864
2024	$472,367	$38,203	$43,403	$553,974	$213,459	$1,308	$0	$0	$1,500	$216,266	$770,240	$6,047,914
2025	$509,029	$40,511	$44,488	$594,028	$213,459	$1,341	$0	$0	$1,567	$216,366	$810,394	$6,368,615
2026	$529,349	$42,109	$45,600	$617,058	$213,459	$1,374	$0	$0	$1,638	$216,470	$833,528	$6,682,763
2027	$543,760	$43,456	$46,740	$633,956	$213,459	$1,408	$0	$0	$1,712	$216,579	$850,535	$6,988,056
2028	$570,398	$44,745	$47,908	$663,052	$213,459	$1,444	$0	$0	$1,789	$216,691	$879,742	$7,288,795
2029	$594,686	$46,264	$49,106	$690,056	$213,459	$1,480	$0	$0	$1,869	$216,807	$906,863	$7,584,044
2030	$611,863	$47,397	$50,334	$709,594	$213,459	$1,517	$0	$0	$1,953	$216,928	$926,522	$7,871,329
2031	$640,558	$48,704	$51,592	$740,855	$207,966	$1,555	$0	$0	$2,041	$211,562	$952,417	$8,152,580
2032	$668,561	$50,281	$52,882	$771,724	$205,276	$1,594	$0	$0	$2,133	$209,003	$980,727	$8,428,401
2033	$688,517	$51,345	$54,204	$794,065	$205,276	$1,633	$0	$0	$2,229	$209,139	$1,003,204	$8,697,107
2034	$720,420	$52,600	$55,559	$828,579	$205,276	$1,674	$0	$0	$2,329	$209,280	$1,037,859	$8,961,858
2035	$753,874	$54,133	$56,948	$864,955	$205,276	$1,716	$0	$0	$2,434	$209,426	$1,074,382	$9,222,875

Table B.1-10 Expansion Plan Economic Summary - Without Taylor Energy Center - High Capital Costs

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	78,600	17	05/01/11	91,197	8,182
CFB	696,360	44	05/01/12	850,960	61,729
CFB	696,360	44	05/01/14	893,999	64,851
LMS100	78,600	17	05/01/18	108,405	9,726
CFB	696,360	44	05/01/20	1,036,812	75,210

	Production Cost				Capital Cost and Other Project Costs							Cumulative
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Present Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$5,492	$0	$0	$0	$0	$5,492	$344,779	$2,100,744
2012	$288,673	$31,863	$8,427	$328,963	$49,503	$0	$0	$0	$0	$49,503	$378,466	$2,383,161
2013	$301,899	$29,601	$12,374	$343,874	$69,911	$0	$0	$0	$0	$69,911	$413,785	$2,677,230
2014	$299,054	$29,024	$20,503	$348,581	$113,441	$0	$0	$0	$0	$113,441	$462,021	$2,989,944
2015	$309,757	$29,969	$24,941	$364,667	$134,761	$0	$0	$0	$0	$134,761	$499,428	$3,311,880
2016	$332,320	$31,710	$25,564	$389,594	$134,761	$0	$0	$0	$0	$134,761	$524,355	$3,633,789
2017	$351,489	$33,457	$26,203	$411,149	$134,761	$0	$0	$0	$0	$134,761	$545,911	$3,952,972
2018	$369,472	$35,255	$27,625	$432,352	$141,290	$0	$0	$0	$0	$141,290	$573,642	$4,272,397
2019	$398,762	$37,261	$28,701	$464,723	$144,488	$0	$0	$0	$0	$144,488	$609,211	$4,595,474
2020	$388,528	$37,945	$38,486	$464,959	$194,833	$0	$0	$0	$0	$194,833	$659,792	$4,928,714
2021	$395,818	$39,498	$44,000	$479,317	$219,698	$0	$0	$0	$0	$219,698	$699,015	$5,264,952
2022	$418,827	$41,699	$45,100	$505,626	$219,698	$0	$0	$0	$0	$219,698	$725,324	$5,597,231
2023	$460,106	$43,809	$46,228	$550,143	$219,698	$0	$0	$0	$0	$219,698	$769,840	$5,933,110
2024	$499,471	$46,207	$47,383	$593,062	$219,698	$0	$0	$0	$0	$219,698	$812,760	$6,270,829
2025	$537,248	$48,922	$48,568	$634,738	$219,698	$0	$0	$0	$0	$219,698	$854,436	$6,608,958
2026	$559,892	$50,488	$49,782	$660,162	$219,698	$0	$0	$0	$0	$219,698	$879,860	$6,940,568
2027	$578,256	$52,008	$51,027	$681,292	$219,698	$0	$0	$0	$0	$219,698	$900,989	$7,263,971
2028	$603,915	$53,911	$52,302	$710,128	$219,698	$0	$0	$0	$0	$219,698	$929,826	$7,581,832
2029	$631,759	$55,236	$53,610	$740,606	$219,698	$0	$0	$0	$0	$219,698	$960,303	$7,894,479
2030	$649,846	$56,624	$54,950	$761,420	$219,698	$0	$0	$0	$0	$219,698	$981,118	$8,198,692
2031	$680,174	$58,516	$56,324	$795,014	$214,206	$0	$0	$0	$0	$214,206	$1,009,220	$8,496,718
2032	$712,770	$59,945	$57,732	$830,447	$211,516	$0	$0	$0	$0	$211,516	$1,041,963	$8,789,760
2033	$733,973	$61,285	$59,175	$854,433	$211,516	$0	$0	$0	$0	$211,516	$1,065,949	$9,075,273
2034	$767,959	$63,126	$60,655	$891,740	$211,516	$0	$0	$0	$0	$211,516	$1,103,255	$9,356,706
2035	$805,068	$64,556	$62,171	$931,795	$211,516	$0	$0	$0	$0	$211,516	$1,143,311	$9,634,469

Table B.1-11 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Low Capital Costs

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	52,400	17	05/01/11	60,798	5,455
TEC	NA	NA	05/01/12	545,350	39,560
CFB	464,240	44	05/01/14	595,999	43,234
CFB	464,240	44	05/01/19	674,319	48,915
LM6000	31,040	12	05/01/25	50,633	4,543

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*					Ongoing Capex	*Total Capital*	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$3,661	$0	$0	$0	$0	$3,661	$342,948	$2,099,309
2012	$280,003	$27,323	$6,482	$313,808	$31,936	$973	$0	$0	$592	$33,500	$347,309	$2,358,477
2013	$287,725	$22,944	$9,404	$320,073	$45,014	$997	$0	$0	$924	$46,935	$367,008	$2,619,303
2014	$285,963	$22,849	$17,458	$326,269	$74,034	$1,022	$0	$0	$966	$76,022	$402,291	$2,891,589
2015	$296,457	$23,756	$21,820	$342,032	$88,248	$1,047	$0	$0	$1,009	$90,305	$432,337	$3,170,278
2016	$316,365	$25,228	$22,365	$363,958	$88,248	$1,073	$0	$0	$1,055	$90,376	$454,334	$3,449,199
2017	$332,390	$26,810	$22,924	$382,124	$88,248	$1,100	$0	$0	$1,102	$90,451	$472,575	$3,725,504
2018	$350,569	$28,250	$23,497	$402,316	$88,248	$1,128	$0	$0	$1,152	$90,528	$492,844	$3,999,938
2019	$344,113	$29,210	$32,931	$406,254	$121,082	$1,156	$0	$0	$1,204	$123,441	$529,695	$4,280,847
2020	$357,010	$30,815	$38,196	$426,020	$137,163	$1,185	$0	$0	$1,258	$139,606	$565,626	$4,566,526
2021	$374,623	$32,415	$39,151	$446,189	$137,163	$1,215	$0	$0	$1,314	$139,692	$585,881	$4,848,345
2022	$398,131	$34,185	$40,129	$472,445	$137,163	$1,245	$0	$0	$1,373	$139,782	$612,227	$5,128,813
2023	$434,590	$36,227	$41,133	$511,950	$137,163	$1,276	$0	$0	$1,435	$139,875	$651,825	$5,413,202
2024	$474,778	$38,245	$42,161	$555,183	$137,163	$1,308	$0	$0	$1,500	$139,971	$695,154	$5,702,053
2025	$510,459	$40,557	$44,069	$595,085	$140,213	$1,341	$0	$0	$1,567	$143,120	$738,206	$5,994,186
2026	$529,349	$42,109	$45,600	$617,058	$141,706	$1,374	$0	$0	$1,638	$144,718	$761,776	$6,281,291
2027	$543,760	$43,456	$46,740	$633,956	$141,706	$1,408	$0	$0	$1,712	$144,826	$778,782	$6,560,829
2028	$570,398	$44,745	$47,908	$663,052	$141,706	$1,444	$0	$0	$1,789	$144,938	$807,990	$6,837,041
2029	$594,686	$46,264	$49,106	$690,056	$141,706	$1,480	$0	$0	$1,869	$145,055	$835,111	$7,108,929
2030	$611,863	$47,397	$50,334	$709,594	$141,706	$1,517	$0	$0	$1,953	$145,176	$854,770	$7,373,965
2031	$640,558	$48,704	$51,592	$740,855	$138,045	$1,555	$0	$0	$2,041	$141,640	$882,495	$7,634,569
2032	$668,561	$50,281	$52,882	$771,724	$136,251	$1,594	$0	$0	$2,133	$139,978	$911,702	$7,890,976
2033	$688,517	$51,345	$54,204	$794,065	$136,251	$1,633	$0	$0	$2,229	$140,114	$934,179	$8,141,195
2034	$720,420	$52,600	$55,559	$828,579	$136,251	$1,674	$0	$0	$2,329	$140,255	$968,833	$8,388,338
2035	$753,874	$54,133	$56,948	$864,955	$136,251	$1,716	$0	$0	$2,434	$140,401	$1,005,357	$8,632,586

Table B.1-12 Expansion Plan Economic Summary - Without Taylor Energy Center - Low Capital Costs

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	52,400	17	05/01/11	60,798	5,455
CFB	464,240	44	05/01/12	567,306	41,152
CFB	464,240	44	05/01/14	595,999	43,234
CFB	464,240	44	05/01/18	657,872	47,722
LMS100	52,400	17	05/01/24	83,815	7,520

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*					Ongoing	*Total*	Total	Cumulative Present
Year	Energy Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$3,661	$0	$0	$0	$0	$3,661	$342,948	$2,099,309
2012	$288,673	$31,863	$8,427	$328,963	$33,002	$0	$0	$0	$0	$33,002	$361,965	$2,369,413
2013	$301,899	$29,601	$12,374	$343,874	$46,607	$0	$0	$0	$0	$46,607	$390,481	$2,646,921
2014	$299,054	$29,024	$20,503	$348,581	$75,627	$0	$0	$0	$0	$75,627	$424,208	$2,934,042
2015	$309,757	$29,969	$24,941	$364,667	$89,841	$0	$0	$0	$0	$89,841	$454,508	$3,227,021
2016	$332,320	$31,710	$25,564	$389,594	$89,841	$0	$0	$0	$0	$89,841	$479,435	$3,521,353
2017	$351,489	$33,457	$26,203	$411,149	$89,841	$0	$0	$0	$0	$89,841	$500,990	$3,814,271
2018	$339,065	$34,369	$35,489	$408,923	$121,874	$0	$0	$0	$0	$121,874	$530,796	$4,109,838
2019	$354,747	$35,978	$40,709	$431,434	$137,563	$0	$0	$0	$0	$137,563	$568,997	$4,411,590
2020	$379,688	$37,781	$41,727	$459,195	$137,563	$0	$0	$0	$0	$137,563	$596,758	$4,712,993
2021	$398,981	$39,611	$42,770	$481,362	$137,563	$0	$0	$0	$0	$137,563	$618,925	$5,010,707
2022	$423,573	$41,772	$43,839	$509,184	$137,563	$0	$0	$0	$0	$137,563	$646,747	$5,306,989
2023	$464,435	$43,857	$44,935	$553,227	$137,563	$0	$0	$0	$0	$137,563	$690,790	$5,608,378
2024	$500,834	$46,219	$46,948	$594,002	$142,597	$0	$0	$0	$0	$142,597	$736,598	$5,914,450
2025	$537,248	$48,922	$48,568	$634,738	$145,083	$0	$0	$0	$0	$145,083	$779,821	$6,223,052
2026	$559,892	$50,488	$49,782	$660,162	$145,083	$0	$0	$0	$0	$145,083	$805,245	$6,526,540
2027	$578,256	$52,008	$51,027	$681,292	$145,083	$0	$0	$0	$0	$145,083	$826,374	$6,823,161
2028	$603,915	$53,911	$52,302	$710,128	$145,083	$0	$0	$0	$0	$145,083	$855,211	$7,115,515
2029	$631,759	$55,236	$53,610	$740,606	$145,083	$0	$0	$0	$0	$145,083	$885,688	$7,403,869
2030	$649,846	$56,624	$54,950	$761,420	$145,083	$0	$0	$0	$0	$145,083	$906,503	$7,684,947
2031	$680,174	$58,516	$56,324	$795,014	$141,421	$0	$0	$0	$0	$141,421	$936,435	$7,961,479
2032	$712,770	$59,945	$57,732	$830,447	$139,628	$0	$0	$0	$0	$139,628	$970,075	$8,234,303
2033	$733,973	$61,285	$59,175	$854,433	$139,628	$0	$0	$0	$0	$139,628	$994,061	$8,500,561
2034	$767,959	$63,126	$60,655	$891,740	$139,628	$0	$0	$0	$0	$139,628	$1,031,368	$8,763,656
2035	$805,068	$64,556	$62,171	$931,795	$139,628	$0	$0	$0	$0	$139,628	$1,071,423	$9,023,955

Table B.1-13 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - High Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	681,687	49,450
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/19	842,898	61,144
LM6000	38,800	12	05/01/25	63,291	5,678

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Seasonal	Ongoing Capex	*Total Capital*	Total System	Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Purchase ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$343,161	$30,436	$0	$373,597	$0	$0	$0	$0	$0	$0	$373,597	$1,566,330
2010	$294,185	$30,194	$0	$324,379	$0	$0	$0	$0	$0	$0	$324,379	$1,833,197
2011	$306,387	$33,326	$645	$340,358	$4,577	$0	$0	$0	$0	$4,577	$344,935	$2,103,463
2012	$281,412	$27,344	$6,482	$315,238	$39,920	$973	$0	$0	$592	$41,484	$356,722	$2,369,655
2013	$289,511	$22,958	$9,404	$321,872	$56,268	$997	$0	$0	$924	$58,189	$380,061	$2,639,757
2014	$288,153	$22,855	$17,458	$328,466	$92,543	$1,022	$0	$0	$966	$94,530	$422,997	$2,926,058
2015	$300,619	$23,764	$21,820	$346,202	$110,310	$1,047	$0	$0	$1,009	$112,367	$458,569	$3,221,656
2016	$320,747	$25,238	$22,365	$368,350	$110,310	$1,073	$0	$0	$1,055	$112,438	$480,788	$3,516,818
2017	$336,560	$26,816	$22,924	$386,300	$110,310	$1,100	$0	$0	$1,102	$112,513	$498,813	$3,808,464
2018	$354,598	$28,285	$23,497	$406,380	$110,310	$1,128	$0	$0	$1,152	$112,590	$518,970	$4,097,445
2019	$350,874	$29,211	$32,931	$413,016	$151,352	$1,156	$0	$0	$1,204	$153,712	$566,728	$4,397,993
2020	$365,479	$30,830	$38,196	$434,505	$171,454	$1,185	$0	$0	$1,258	$173,897	$608,401	$4,705,277
2021	$382,338	$32,406	$39,151	$453,894	$171,454	$1,215	$0	$0	$1,314	$173,983	$627,877	$5,007,297
2022	$406,863	$34,205	$40,129	$481,197	$171,454	$1,245	$0	$0	$1,373	$174,072	$655,270	$5,307,484
2023	$444,602	$36,178	$41,133	$521,912	$171,454	$1,276	$0	$0	$1,435	$174,165	$696,078	$5,611,180
2024	$489,104	$38,144	$42,161	$569,409	$171,454	$1,308	$0	$0	$1,500	$174,262	$743,671	$5,920,191
2025	$527,340	$40,058	$44,069	$611,468	$175,266	$1,341	$0	$0	$1,567	$178,174	$789,641	$6,232,678
2026	$547,279	$41,398	$45,600	$634,277	$177,133	$1,374	$0	$0	$1,638	$180,145	$814,422	$6,539,625
2027	$562,561	$43,093	$46,740	$652,394	$177,133	$1,408	$0	$0	$1,712	$180,253	$832,647	$6,838,498
2028	$590,449	$44,358	$47,908	$682,715	$177,133	$1,444	$0	$0	$1,789	$180,365	$863,080	$7,133,541
2029	$616,296	$45,993	$49,106	$711,396	$177,133	$1,480	$0	$0	$1,869	$180,481	$891,877	$7,423,911
2030	$635,136	$47,103	$50,334	$732,573	$177,133	$1,517	$0	$0	$1,953	$180,603	$913,175	$7,707,057
2031	$665,304	$48,312	$51,592	$765,208	$172,556	$1,555	$0	$0	$2,041	$176,152	$941,360	$7,985,044
2032	$694,907	$49,980	$52,882	$797,768	$170,314	$1,594	$0	$0	$2,133	$174,041	$971,809	$8,258,356
2033	$717,282	$51,144	$54,204	$822,630	$170,314	$1,633	$0	$0	$2,229	$174,176	$996,806	$8,525,349
2034	$752,512	$52,499	$55,559	$860,570	$170,314	$1,674	$0	$0	$2,329	$174,318	$1,034,888	$8,789,342
2035	$787,113	$54,192	$56,948	$898,253	$170,314	$1,716	$0	$0	$2,434	$174,464	$1,072,717	$9,049,955

Table B.1-14 Expansion Plan Economic Summary - Without Taylor Energy Center - High Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
CFB	580,300	44	05/01/12	709,133	51,441
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/18	822,340	59,653
LMS100	65,500	17	05/01/24	104,768	9,400

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*					Ongoing	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$343,161	$30,436	$0	$373,597	$0	$0	$0	$0	$0	$0	$373,597	$1,566,330
2010	$294,185	$30,194	$0	$324,379	$0	$0	$0	$0	$0	$0	$324,379	$1,833,197
2011	$306,387	$33,326	$645	$340,358	$4,577	$0	$0	$0	$0	$4,577	$344,935	$2,103,463
2012	$290,189	$31,871	$8,427	$330,487	$41,253	$0	$0	$0	$0	$41,253	$371,740	$2,380,861
2013	$303,534	$29,577	$12,374	$345,485	$58,259	$0	$0	$0	$0	$58,259	$403,744	$2,667,795
2014	$301,319	$29,021	$20,503	$350,843	$94,534	$0	$0	$0	$0	$94,534	$445,377	$2,969,243
2015	$314,170	$29,942	$24,941	$369,053	$112,301	$0	$0	$0	$0	$112,301	$481,354	$3,279,528
2016	$337,279	$31,690	$25,564	$394,533	$112,301	$0	$0	$0	$0	$112,301	$506,835	$3,590,681
2017	$355,860	$33,456	$26,203	$415,520	$112,301	$0	$0	$0	$0	$112,301	$527,821	$3,899,287
2018	$344,379	$34,348	$35,489	$414,216	$152,342	$0	$0	$0	$0	$152,342	$566,558	$4,214,767
2019	$361,816	$35,957	$40,709	$438,482	$171,954	$0	$0	$0	$0	$171,954	$610,435	$4,538,494
2020	$388,412	$37,747	$41,727	$467,885	$171,954	$0	$0	$0	$0	$171,954	$639,839	$4,861,657
2021	$407,281	$39,606	$42,770	$489,657	$171,954	$0	$0	$0	$0	$171,954	$661,610	$5,179,902
2022	$432,050	$41,769	$43,839	$517,658	$171,954	$0	$0	$0	$0	$171,954	$689,612	$5,495,822
2023	$475,266	$43,771	$44,935	$563,972	$171,954	$0	$0	$0	$0	$171,954	$735,926	$5,816,904
2024	$515,442	$46,073	$46,948	$608,463	$178,246	$0	$0	$0	$0	$178,246	$786,709	$6,143,797
2025	$554,489	$48,332	$48,568	$651,389	$181,354	$0	$0	$0	$0	$181,354	$832,742	$6,473,342
2026	$579,689	$49,683	$49,782	$679,154	$181,354	$0	$0	$0	$0	$181,354	$860,508	$6,797,658
2027	$597,257	$51,716	$51,027	$700,000	$181,354	$0	$0	$0	$0	$181,354	$881,354	$7,114,013
2028	$625,426	$53,539	$52,302	$731,267	$181,354	$0	$0	$0	$0	$181,354	$912,621	$7,425,993
2029	$653,860	$54,996	$53,610	$762,467	$181,354	$0	$0	$0	$0	$181,354	$943,820	$7,733,274
2030	$674,630	$56,358	$54,950	$785,939	$181,354	$0	$0	$0	$0	$181,354	$967,292	$8,033,200
2031	$706,079	$58,194	$56,324	$820,597	$176,777	$0	$0	$0	$0	$176,777	$997,373	$8,327,727
2032	$739,025	$59,603	$57,732	$856,360	$174,535	$0	$0	$0	$0	$174,535	$1,030,895	$8,617,657
2033	$764,281	$61,093	$59,175	$884,549	$174,535	$0	$0	$0	$0	$174,535	$1,059,084	$8,901,331
2034	$800,332	$63,020	$60,655	$924,007	$174,535	$0	$0	$0	$0	$174,535	$1,098,542	$9,181,562
2035	$838,710	$64,594	$62,171	$965,476	$174,535	$0	$0	$0	$0	$174,535	$1,140,011	$9,458,523

Table B.1-15 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Low Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	681,687	49,450
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/19	842,898	61,144
LM6000	38,800	12	05/01/25	63,291	5,678

	Production Cost				Capital Cost and Other Project Costs							
		O&M										
Year	Fuel and Energy Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$340,997	$30,317	$0	$371,314	$0	$0	$0	$0	$0	$0	$371,314	$1,564,358
2010	$291,785	$30,219	$0	$322,004	$0	$0	$0	$0	$0	$0	$322,004	$1,829,271
2011	$304,018	$33,395	$645	$338,059	$4,577	$0	$0	$0	$0	$4,577	$342,636	$2,097,735
2012	$278,609	$27,293	$6,482	$312,385	$39,920	$973	$0	$0	$592	$41,484	$353,869	$2,361,798
2013	$286,198	$22,931	$9,404	$318,533	$56,268	$997	$0	$0	$924	$58,189	$376,722	$2,629,528
2014	$283,406	$22,840	$17,458	$323,704	$92,543	$1,022	$0	$0	$966	$94,530	$418,235	$2,912,605
2015	$292,424	$23,746	$21,820	$337,989	$110,310	$1,047	$0	$0	$1,009	$112,367	$450,356	$3,202,909
2016	$311,858	$25,201	$22,365	$359,424	$110,310	$1,073	$0	$0	$1,055	$112,438	$471,863	$3,492,591
2017	$328,540	$26,798	$22,924	$378,263	$110,310	$1,100	$0	$0	$1,102	$112,513	$490,775	$3,779,538
2018	$346,119	$28,231	$23,497	$397,847	$110,310	$1,128	$0	$0	$1,152	$112,590	$510,437	$4,063,768
2019	$338,172	$29,182	$32,931	$400,284	$151,352	$1,156	$0	$0	$1,204	$153,712	$553,996	$4,357,564
2020	$349,966	$30,816	$38,196	$418,978	$171,454	$1,185	$0	$0	$1,258	$173,897	$592,875	$4,657,006
2021	$366,487	$32,410	$39,151	$438,048	$171,454	$1,215	$0	$0	$1,314	$173,983	$612,031	$4,951,404
2022	$390,340	$34,189	$40,129	$464,659	$171,454	$1,245	$0	$0	$1,373	$174,072	$638,731	$5,244,014
2023	$424,081	$36,192	$41,133	$501,405	$171,454	$1,276	$0	$0	$1,435	$174,165	$675,571	$5,538,763
2024	$460,439	$38,844	$42,161	$541,444	$171,454	$1,308	$0	$0	$1,500	$174,262	$715,706	$5,836,153
2025	$494,442	$41,120	$44,069	$579,631	$175,266	$1,341	$0	$0	$1,567	$178,174	$757,805	$6,136,042
2026	$512,452	$42,541	$45,600	$600,593	$177,133	$1,374	$0	$0	$1,638	$180,145	$780,737	$6,430,294
2027	$524,574	$43,738	$46,740	$615,052	$177,133	$1,408	$0	$0	$1,712	$180,253	$795,304	$6,715,762
2028	$549,447	$44,986	$47,908	$642,341	$177,133	$1,444	$0	$0	$1,789	$180,365	$822,706	$6,997,004
2029	$572,580	$46,488	$49,106	$668,174	$177,133	$1,480	$0	$0	$1,869	$180,481	$848,655	$7,273,302
2030	$588,308	$47,625	$50,334	$686,267	$177,133	$1,517	$0	$0	$1,953	$180,603	$866,870	$7,542,091
2031	$614,268	$48,835	$51,592	$714,695	$172,556	$1,555	$0	$0	$2,041	$176,152	$890,847	$7,805,160
2032	$641,628	$50,255	$52,882	$744,765	$170,314	$1,594	$0	$0	$2,133	$174,041	$918,806	$8,063,566
2033	$660,140	$51,301	$54,204	$765,645	$170,314	$1,633	$0	$0	$2,229	$174,176	$939,821	$8,315,295
2034	$689,496	$52,617	$55,559	$797,672	$170,314	$1,674	$0	$0	$2,329	$174,318	$971,990	$8,563,244
2035	$720,256	$54,112	$56,948	$831,317	$170,314	$1,716	$0	$0	$2,434	$174,464	$1,005,781	$8,807,594

Table B.1-16 Expansion Plan Economic Summary - Without Taylor Energy Center- Low Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
CFB	580,300	44	05/01/12	709,133	51,441
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/18	822,340	59,653
LMS100	65,500	17	05/01/24	104,768	9,400

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*					Ongoing	*Total*	Total	Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$340,997	$30,317	$0	$371,314	$0	$0	$0	$0	$0	$0	$371,314	$1,564,358
2010	$291,785	$30,219	$0	$322,004	$0	$0	$0	$0	$0	$0	$322,004	$1,829,271
2011	$273,495	$30,177	$7,906	$311,578	$4,577	$0	$0	$0	$0	$4,577	$316,155	$2,076,987
2012	$276,963	$30,295	$12,073	$319,331	$41,253	$0	$0	$0	$0	$41,253	$360,584	$2,346,060
2013	$300,293	$29,619	$12,374	$342,286	$58,259	$0	$0	$0	$0	$58,259	$400,545	$2,630,720
2014	$296,742	$29,018	$20,503	$346,262	$94,534	$0	$0	$0	$0	$94,534	$440,796	$2,929,068
2015	$305,544	$29,974	$24,941	$360,458	$112,301	$0	$0	$0	$0	$112,301	$472,759	$3,233,813
2016	$327,826	$31,729	$25,564	$385,119	$112,301	$0	$0	$0	$0	$112,301	$497,420	$3,539,186
2017	$347,353	$33,469	$26,203	$407,025	$112,301	$0	$0	$0	$0	$112,301	$519,326	$3,842,826
2018	$333,428	$34,371	$35,489	$403,288	$152,342	$0	$0	$0	$0	$152,342	$555,630	$4,152,221
2019	$347,950	$36,019	$40,709	$424,678	$171,954	$0	$0	$0	$0	$171,954	$596,632	$4,468,627
2020	$371,380	$37,798	$41,727	$450,905	$171,954	$0	$0	$0	$0	$171,954	$622,859	$4,783,213
2021	$390,590	$39,635	$42,770	$472,995	$171,954	$0	$0	$0	$0	$171,954	$644,948	$5,093,445
2022	$415,077	$41,785	$43,839	$500,701	$171,954	$0	$0	$0	$0	$171,954	$672,654	$5,401,595
2023	$453,898	$43,854	$44,935	$542,687	$171,954	$0	$0	$0	$0	$171,954	$714,641	$5,713,391
2024	$485,343	$46,884	$46,948	$579,174	$178,246	$0	$0	$0	$0	$178,246	$757,420	$6,028,114
2025	$520,074	$49,582	$48,568	$618,224	$181,354	$0	$0	$0	$0	$181,354	$799,578	$6,344,534
2026	$541,992	$50,869	$49,782	$642,644	$181,354	$0	$0	$0	$0	$181,354	$823,997	$6,655,090
2027	$557,975	$52,314	$51,027	$661,315	$181,354	$0	$0	$0	$0	$181,354	$842,669	$6,957,560
2028	$582,608	$54,131	$52,302	$689,042	$181,354	$0	$0	$0	$0	$181,354	$870,395	$7,255,104
2029	$608,499	$55,462	$53,610	$717,571	$181,354	$0	$0	$0	$0	$181,354	$898,925	$7,547,769
2030	$625,905	$56,836	$54,950	$737,692	$181,354	$0	$0	$0	$0	$181,354	$919,045	$7,832,735
2031	$653,746	$58,579	$56,324	$768,649	$176,777	$0	$0	$0	$0	$176,777	$945,426	$8,111,922
2032	$684,796	$59,901	$57,732	$802,429	$174,535	$0	$0	$0	$0	$174,535	$976,964	$8,386,684
2033	$703,963	$61,223	$59,175	$824,361	$174,535	$0	$0	$0	$0	$174,535	$998,896	$8,654,236
2034	$735,640	$63,104	$60,655	$859,399	$174,535	$0	$0	$0	$0	$174,535	$1,033,934	$8,917,987
2035	$771,467	$64,481	$62,171	$898,119	$174,535	$0	$0	$0	$0	$174,535	$1,072,654	$9,178,584

Table B.1-17 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Regulated - CO2

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	681,069	49,405
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/19	842,898	61,144
LM6000	38,800	12	05/01/25	63,291	5,678

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*					Ongoing	*Total*	Total	Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$367,075	$64,422	$0	$431,497	$0	$0	$0	$0	$0	$0	$431,497	$431,497
2007	$372,279	$52,433	$0	$424,712	$0	$0	$0	$0	$0	$0	$424,712	$835,984
2008	$400,197	$30,420	$0	$430,617	$0	$0	$0	$0	$0	$0	$430,617	$1,226,567
2009	$341,101	$30,320	$0	$371,421	$0	$0	$0	$0	$0	$0	$371,421	$1,547,414
2010	$290,192	$30,206	$0	$320,398	$0	$0	$0	$0	$0	$0	$320,398	$1,811,006
2011	$302,672	$33,359	$645	$336,676	$4,577	$0	$0	$0	$0	$4,577	$341,253	$2,078,387
2012	$298,123	$27,710	$6,482	$332,315	$39,890	$973	$0	$0	$592	$41,454	$373,769	$2,357,299
2013	$332,407	$23,722	$9,404	$365,532	$56,223	$997	$0	$0	$924	$58,144	$423,676	$2,658,398
2014	$356,391	$23,164	$17,458	$397,013	$92,498	$1,022	$0	$0	$966	$94,486	$491,499	$2,991,064
2015	$365,135	$23,934	$21,820	$410,889	$110,265	$1,047	$0	$0	$1,009	$112,322	$523,211	$3,328,330
2016	$387,899	$25,366	$22,365	$435,630	$110,265	$1,073	$0	$0	$1,055	$112,394	$548,024	$3,664,769
2017	$398,154	$26,910	$22,924	$447,988	$110,265	$1,100	$0	$0	$1,102	$112,468	$560,456	$3,992,456
2018	$358,542	$28,243	$23,497	$410,282	$110,265	$1,128	$0	$0	$1,152	$112,545	$522,827	$4,283,586
2019	$356,956	$29,204	$32,931	$419,092	$151,307	$1,156	$0	$0	$1,204	$153,667	$572,758	$4,587,332
2020	$357,906	$30,833	$38,196	$426,936	$171,409	$1,185	$0	$0	$1,258	$173,852	$600,787	$4,890,770
2021	$380,475	$32,405	$39,151	$452,031	$171,409	$1,215	$0	$0	$1,314	$173,938	$625,969	$5,191,872
2022	$444,414	$34,609	$40,129	$519,152	$171,409	$1,245	$0	$0	$1,373	$174,028	$693,180	$5,509,426
2023	$493,258	$38,100	$41,133	$572,490	$171,409	$1,276	$0	$0	$1,435	$174,120	$746,611	$5,835,170
2024	$508,470	$40,039	$42,161	$590,669	$171,409	$1,308	$0	$0	$1,500	$174,217	$764,886	$6,152,996
2025	$545,302	$42,200	$44,069	$631,571	$175,221	$1,341	$0	$0	$1,567	$178,129	$809,700	$6,473,422
2026	$563,147	$43,395	$45,600	$652,142	$177,088	$1,374	$0	$0	$1,638	$180,100	$832,241	$6,787,085
2027	$584,405	$44,322	$46,740	$675,466	$177,088	$1,408	$0	$0	$1,712	$180,208	$855,674	$7,094,223
2028	$617,377	$45,400	$47,908	$710,685	$177,088	$1,444	$0	$0	$1,789	$180,320	$891,005	$7,398,813
2029	$650,566	$46,780	$49,106	$746,453	$177,088	$1,480	$0	$0	$1,869	$180,437	$926,889	$7,700,581
2030	$676,303	$47,786	$50,334	$774,422	$177,088	$1,517	$0	$0	$1,953	$180,558	$954,980	$7,996,690
2031	$713,292	$48,917	$51,592	$813,802	$172,511	$1,555	$0	$0	$2,041	$176,107	$989,908	$8,289,012
2032	$751,413	$50,405	$52,882	$854,700	$170,269	$1,594	$0	$0	$2,133	$173,996	$1,028,695	$8,578,323
2033	$783,291	$51,468	$54,204	$888,963	$170,269	$1,633	$0	$0	$2,229	$174,132	$1,063,094	$8,863,071
2034	$827,170	$52,682	$55,559	$935,411	$170,269	$1,674	$0	$0	$2,329	$174,273	$1,109,684	$9,146,145
2035	$873,224	$54,300	$56,948	$984,472	$170,269	$1,716	$0	$0	$2,434	$174,419	$1,158,891	$9,427,693

Table B.1-18 Expansion Plan Economic Summary - Without Taylor Energy Center - Regulated - CO_2

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
CFB	580,300	44	05/01/12	709,133	51,441
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/18	822,340	59,653
LMS100	65,500	17	05/01/24	104,768	9,400

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*					Ongoing	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$367,075	$64,422	$0	$431,497	$0	$0	$0	$0	$0	$0	$431,497	$431,497
2007	$372,279	$52,433	$0	$424,712	$0	$0	$0	$0	$0	$0	$424,712	$835,984
2008	$400,197	$30,420	$0	$430,617	$0	$0	$0	$0	$0	$0	$430,617	$1,226,567
2009	$341,101	$30,320	$0	$371,421	$0	$0	$0	$0	$0	$0	$371,421	$1,547,414
2010	$290,192	$30,206	$0	$320,398	$0	$0	$0	$0	$0	$0	$320,398	$1,811,006
2011	$302,672	$33,359	$645	$336,676	$4,577	$0	$0	$0	$0	$4,577	$341,253	$2,078,387
2012	$307,568	$32,186	$8,427	$348,181	$41,253	$0	$0	$0	$0	$41,253	$389,434	$2,368,988
2013	$347,836	$30,289	$12,374	$390,499	$58,259	$0	$0	$0	$0	$58,259	$448,758	$2,687,912
2014	$368,907	$28,942	$20,503	$418,352	$94,534	$0	$0	$0	$0	$94,534	$512,886	$3,035,054
2015	$377,768	$29,913	$24,941	$432,622	$112,301	$0	$0	$0	$0	$112,301	$544,923	$3,386,316
2016	$403,291	$31,640	$25,564	$460,495	$112,301	$0	$0	$0	$0	$112,301	$572,796	$3,737,963
2017	$415,767	$33,374	$26,203	$475,344	$112,301	$0	$0	$0	$0	$112,301	$587,645	$4,081,547
2018	$345,534	$34,365	$35,489	$415,387	$152,342	$0	$0	$0	$0	$152,342	$567,729	$4,397,680
2019	$365,240	$35,971	$40,709	$441,919	$171,954	$0	$0	$0	$0	$171,954	$613,873	$4,723,230
2020	$378,446	$37,808	$41,727	$457,980	$171,954	$0	$0	$0	$0	$171,954	$629,934	$5,041,389
2021	$403,585	$39,642	$42,770	$485,997	$171,954	$0	$0	$0	$0	$171,954	$657,950	$5,357,875
2022	$467,147	$42,155	$43,839	$553,142	$171,954	$0	$0	$0	$0	$171,954	$725,095	$5,690,049
2023	$520,336	$45,761	$44,935	$611,032	$171,954	$0	$0	$0	$0	$171,954	$782,986	$6,031,663
2024	$530,384	$48,104	$46,948	$625,436	$178,246	$0	$0	$0	$0	$178,246	$803,682	$6,365,610
2025	$567,726	$50,577	$48,568	$666,871	$181,354	$0	$0	$0	$0	$181,354	$848,224	$6,701,281
2026	$588,705	$51,713	$49,782	$690,200	$181,354	$0	$0	$0	$0	$181,354	$871,554	$7,029,761
2027	$612,222	$52,907	$51,027	$716,155	$181,354	$0	$0	$0	$0	$181,354	$897,509	$7,351,915
2028	$645,956	$54,528	$52,302	$752,786	$181,354	$0	$0	$0	$0	$181,354	$934,140	$7,671,250
2029	$682,181	$55,702	$53,610	$791,493	$181,354	$0	$0	$0	$0	$181,354	$972,847	$7,987,981
2030	$706,462	$57,022	$54,950	$818,434	$181,354	$0	$0	$0	$0	$181,354	$999,787	$8,297,983
2031	$745,605	$58,782	$56,324	$860,711	$176,777	$0	$0	$0	$0	$176,777	$1,037,488	$8,604,356
2032	$787,383	$60,008	$57,732	$905,123	$174,535	$0	$0	$0	$0	$174,535	$1,079,658	$8,908,000
2033	$817,834	$61,414	$59,175	$938,424	$174,535	$0	$0	$0	$0	$174,535	$1,112,959	$9,206,104
2034	$864,285	$63,302	$60,655	$988,242	$174,535	$0	$0	$0	$0	$174,535	$1,162,777	$9,502,721
2035	$914,457	$64,644	$62,171	$1,041,272	$174,535	$0	$0	$0	$0	$174,535	$1,215,807	$9,798,097

Table B.1-19 Expansion Plan Economic Summary - With Joint 3x1 CC in 2012

Case Description	
Fuel Forecast	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
GE 3X1 7FA CC	190,182	36	05/01/12	239,552	18,961
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/20	864,010	62,675

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*					Ongoing	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$4,577	$0	$0	$0	$0	$4,577	$343,864	$2,100,027
2012	$312,037	$32,100	$10,580	$354,717	$19,511	$973	$0	$0	$0	$20,483	$375,200	$2,380,007
2013	$334,518	$29,566	$15,356	$379,440	$25,779	$997	$0	$0	$0	$26,776	$406,216	$2,668,696
2014	$335,881	$29,375	$23,253	$388,509	$62,054	$1,022	$0	$0	$0	$63,076	$451,584	$2,974,346
2015	$346,672	$30,310	$27,454	$404,435	$79,821	$1,047	$0	$0	$0	$80,869	$485,304	$3,287,178
2016	$372,123	$32,249	$27,834	$432,206	$79,821	$1,073	$0	$0	$0	$80,895	$513,101	$3,602,177
2017	$394,581	$34,011	$28,224	$456,816	$79,821	$1,100	$0	$0	$0	$80,922	$537,737	$3,916,581
2018	$418,823	$35,724	$28,624	$483,171	$79,821	$1,128	$0	$0	$0	$80,949	$564,120	$4,230,704
2019	$450,409	$37,941	$29,033	$517,383	$79,821	$1,156	$0	$0	$0	$80,977	$598,360	$4,548,027
2020	$442,648	$38,886	$38,521	$520,054	$121,776	$1,185	$0	$0	$0	$122,961	$643,015	$4,872,794
2021	$452,884	$40,354	$43,730	$536,968	$142,497	$1,215	$0	$0	$0	$143,711	$680,679	$5,200,212
2022	$480,997	$42,680	$44,517	$568,194	$142,497	$1,245	$0	$0	$0	$143,741	$711,936	$5,526,358
2023	$521,539	$44,786	$45,324	$611,650	$142,497	$1,276	$0	$0	$0	$143,773	$755,422	$5,855,946
2024	$554,931	$45,973	$46,151	$647,056	$142,497	$1,308	$0	$0	$0	$143,804	$790,860	$6,184,565
2025	$605,538	$49,864	$46,999	$702,401	$142,497	$1,341	$0	$0	$0	$143,837	$846,238	$6,519,450
2026	$629,663	$51,165	$47,868	$728,697	$142,497	$1,374	$0	$0	$0	$143,871	$872,568	$6,848,312
2027	$652,951	$52,335	$48,759	$754,045	$142,497	$1,408	$0	$0	$0	$143,905	$897,950	$7,170,624
2028	$683,575	$54,024	$49,672	$787,271	$142,497	$1,444	$0	$0	$0	$143,940	$931,211	$7,488,959
2029	$703,164	$54,117	$50,608	$807,889	$142,497	$1,480	$0	$0	$0	$143,976	$951,866	$7,798,859
2030	$738,003	$56,443	$51,567	$846,013	$142,497	$1,517	$0	$0	$0	$144,013	$990,027	$8,105,834
2031	$773,625	$58,243	$52,551	$884,418	$137,920	$1,555	$0	$0	$0	$139,474	$1,023,893	$8,408,193
2032	$807,544	$59,618	$53,558	$920,721	$135,678	$1,594	$0	$0	$0	$137,272	$1,057,992	$8,705,743
2033	$836,947	$60,811	$54,591	$952,349	$135,678	$1,633	$0	$0	$0	$137,311	$1,089,661	$8,997,607
2034	$876,516	$62,736	$55,650	$994,902	$135,678	$1,674	$0	$0	$0	$137,352	$1,132,255	$9,286,438
2035	$916,710	$64,203	$56,736	$1,037,649	$135,678	$1,716	$0	$0	$0	$137,394	$1,175,043	$9,571,910

Table B.1-20 Expansion Plan Economic Summary - With Joint IGCC in 2012

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
Three Train 1X1 GE IGCC	761,973	53	05/01/12	949,243	68,858
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/20	864,010	62,675

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*								
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	. Present Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$4,577	$0	$0	$0	$0	$4,577	$343,864	$2,100,027
2012	$260,643	$36,060	$11,033	$307,736	$52,912	$973	$0	$0	$0	$53,885	$361,621	$2,369,874
2013	$265,346	$35,792	$16,354	$317,492	$75,677	$997	$0	$0	$0	$76,673	$394,165	$2,649,999
2014	$261,765	$35,840	$24,582	$322,187	$111,952	$1,022	$0	$0	$0	$112,973	$435,160	$2,944,533
2015	$274,034	$37,194	$29,122	$340,349	$129,719	$1,047	$0	$0	$0	$130,766	$471,115	$3,248,218
2016	$294,842	$38,802	$29,850	$363,494	$129,719	$1,073	$0	$0	$0	$130,792	$494,286	$3,551,667
2017	$313,455	$40,765	$30,596	$384,816	$129,719	$1,100	$0	$0	$0	$130,819	$515,635	$3,853,148
2018	$330,557	$42,761	$31,361	$404,679	$129,719	$1,128	$0	$0	$0	$130,847	$535,525	$4,151,349
2019	$359,978	$44,651	$32,145	$436,773	$129,719	$1,156	$0	$0	$0	$130,875	$567,648	$4,452,385
2020	$349,311	$46,225	$42,016	$437,552	$171,674	$1,185	$0	$0	$0	$172,858	$610,411	$4,760,684
2021	$355,031	$48,073	$47,619	$450,722	$192,394	$1,215	$0	$0	$0	$193,609	$644,331	$5,070,618
2022	$377,228	$50,369	$48,809	$476,405	$192,394	$1,245	$0	$0	$0	$193,639	$670,044	$5,377,573
2023	$415,126	$52,521	$50,029	$517,676	$192,394	$1,276	$0	$0	$0	$193,670	$711,346	$5,687,931
2024	$450,675	$55,075	$51,280	$557,030	$192,394	$1,308	$0	$0	$0	$193,702	$750,732	$5,999,876
2025	$489,043	$58,013	$52,562	$599,619	$192,394	$1,341	$0	$0	$0	$193,735	$793,353	$6,313,832
2026	$510,202	$59,492	$53,876	$623,570	$192,394	$1,374	$0	$0	$0	$193,768	$817,338	$6,621,879
2027	$523,726	$61,485	$55,223	$640,434	$192,394	$1,408	$0	$0	$0	$193,803	$834,236	$6,921,321
2028	$546,920	$63,567	$56,603	$667,091	$192,394	$1,444	$0	$0	$0	$193,838	$860,929	$7,215,630
2029	$575,287	$65,013	$58,019	$698,319	$192,394	$1,480	$0	$0	$0	$193,874	$892,192	$7,506,102
2030	$592,350	$66,857	$59,469	$718,676	$192,394	$1,517	$0	$0	$0	$193,911	$912,587	$7,789,066
2031	$619,834	$69,050	$60,956	$749,840	$187,817	$1,555	$0	$0	$0	$189,372	$939,212	$8,066,418
2032	$650,808	$70,569	$62,480	$783,857	$185,576	$1,594	$0	$0	$0	$187,169	$971,026	$8,339,510
2033	$670,492	$72,356	$64,042	$806,889	$185,576	$1,633	$0	$0	$0	$187,209	$994,098	$8,605,777
2034	$702,031	$74,525	$65,643	$842,199	$185,576	$1,674	$0	$0	$0	$187,250	$1,029,449	$8,868,383
2035	$736,973	$76,029	$67,284	$880,286	$185,576	$1,716	$0	$0	$0	$187,292	$1,067,578	$9,127,747

Table B.1-21 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Second PC Unit Available

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	681,687	49,450
LMS100	65,500	17	05/01/14	81,841	7,343
LM6000	38,800	12	05/01/15	49,443	4,436
Second Jointly Owned Pulverized Coal Unit	NA	NA	05/01/16	751,541	54,517
CFB	580,300	44	05/01/23	930,402	67,491

Year	Production Cost				Capital Cost and Other Project Costs						Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
	Fuel and Energy Cost ($1,000)	O&M		*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Cost ($1,000)	*Total Capital Cost ($1,000)*		
		Variable ($1,000)	Fixed ($1,000)									
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,277	$33,353	$645	$339,275	$4,577	$0	$0	$0	$0	$4,577	$343,852	$2,100,017
2012	$279,985	$27,321	$6,482	$313,788	$39,920	$973	$0	$0	$592	$41,484	$355,273	$2,365,127
2013	$287,738	$22,944	$9,404	$320,086	$56,268	$997	$0	$0	$924	$58,189	$378,275	$2,633,961
2014	$313,322	$23,900	$10,334	$347,556	$61,197	$1,022	$0	$0	$966	$63,184	$410,740	$2,911,966
2015	$333,570	$25,527	$11,608	$370,706	$66,588	$1,047	$0	$0	$1,009	$68,645	$439,351	$3,195,176
2016	$314,672	$21,628	$18,301	$354,601	$104,540	$2,147	$0	$0	$1,708	$108,395	$462,996	$3,479,415
2017	$310,868	$21,030	$21,805	$353,703	$122,564	$2,201	$0	$0	$2,122	$126,886	$480,589	$3,760,405
2018	$322,155	$22,305	$22,350	$366,810	$122,564	$2,256	$0	$0	$2,218	$127,037	$493,847	$4,035,398
2019	$348,515	$23,823	$22,909	$395,247	$122,564	$2,312	$0	$0	$2,317	$127,193	$522,440	$4,312,459
2020	$378,430	$25,020	$23,481	$426,931	$122,564	$2,370	$0	$0	$2,422	$127,355	$554,286	$4,592,412
2021	$397,079	$26,683	$24,068	$447,830	$122,564	$2,429	$0	$0	$2,531	$127,523	$575,354	$4,869,167
2022	$420,029	$28,390	$24,670	$473,089	$122,564	$2,490	$0	$0	$2,645	$127,698	$600,787	$5,144,394
2023	$412,738	$29,265	$35,052	$477,054	$167,866	$2,552	$0	$0	$2,764	$173,182	$650,236	$5,428,090
2024	$434,104	$30,989	$40,830	$505,923	$190,055	$2,616	$0	$0	$2,888	$195,559	$701,482	$5,719,570
2025	$469,751	$33,044	$41,851	$544,646	$190,055	$2,681	$0	$0	$3,018	$195,754	$740,400	$6,012,571
2026	$490,208	$33,993	$42,897	$567,098	$190,055	$2,748	$0	$0	$3,154	$195,957	$763,055	$6,300,159
2027	$499,063	$35,175	$43,970	$578,208	$190,055	$2,817	$0	$0	$3,296	$196,168	$774,376	$6,578,115
2028	$525,076	$36,209	$45,069	$606,354	$190,055	$2,887	$0	$0	$3,444	$196,386	$802,741	$6,852,532
2029	$548,427	$37,154	$46,196	$631,777	$190,055	$2,960	$0	$0	$3,599	$196,614	$828,390	$7,122,232
2030	$562,538	$38,185	$47,351	$648,074	$190,055	$3,034	$0	$0	$3,761	$196,850	$844,923	$7,384,216
2031	$588,836	$39,273	$48,534	$676,643	$185,478	$3,109	$0	$0	$3,930	$192,518	$869,161	$7,640,881
2032	$614,649	$40,257	$49,748	$704,654	$183,237	$3,187	$0	$0	$4,107	$190,531	$895,185	$7,892,644
2033	$632,252	$41,289	$50,991	$724,532	$183,237	$3,267	$0	$0	$4,292	$190,795	$915,327	$8,137,813
2034	$661,080	$42,361	$52,266	$755,707	$178,308	$3,348	$0	$0	$4,485	$186,141	$941,848	$8,378,072
2035	$690,727	$43,349	$53,573	$787,649	$172,916	$3,432	$0	$0	$4,687	$181,035	$968,684	$8,613,410

Table B.1-22 Expansion Plan Economic Summary - All Natural Gas Capacity Expansion Plan

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
7FA 1X1	205,100	30	05/01/12	247,136	19,561
LMS100	65,500	17	05/01/14	81,841	7,343
7FA SC	72,400	14	05/01/15	92,445	8,294
7FA 1X1	205,100	30	05/01/19	293,754	23,251

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Seasonal	Ongoing Capex	*Total Capital*	Total System	Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Purchase ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$4,577	$0	$0	$0	$0	$4,577	$343,864	$2,100,027
2012	$311,908	$32,325	$9,442	$353,675	$19,912	$0	$0	$0	$0	$19,912	$373,587	$2,378,803
2013	$338,494	$30,512	$13,661	$382,667	$26,379	$0	$0	$0	$0	$26,379	$409,046	$2,669,505
2014	$366,292	$31,464	$14,436	$412,191	$31,308	$0	$0	$0	$0	$31,308	$443,499	$2,969,682
2015	$389,822	$33,381	$15,530	$438,733	$39,289	$0	$0	$0	$0	$39,289	$478,022	$3,277,820
2016	$419,755	$35,348	$15,981	$471,084	$42,016	$0	$0	$0	$0	$42,016	$513,100	$3,592,819
2017	$450,366	$37,464	$16,118	$503,949	$42,016	$0	$0	$0	$0	$42,016	$545,965	$3,912,033
2018	$477,785	$39,230	$16,259	$533,274	$42,016	$0	$0	$0	$0	$42,016	$575,291	$4,232,376
2019	$503,918	$40,033	$25,129	$569,081	$57,623	$0	$0	$0	$0	$57,623	$626,704	$4,564,731
2020	$537,454	$41,586	$29,614	$608,654	$65,267	$0	$0	$0	$0	$65,267	$673,921	$4,905,107
2021	$570,488	$43,499	$29,831	$643,818	$65,267	$0	$0	$0	$0	$65,267	$709,085	$5,246,189
2022	$609,441	$46,217	$30,053	$685,712	$65,267	$0	$0	$0	$0	$65,267	$750,979	$5,590,221
2023	$656,627	$48,758	$30,281	$735,665	$65,267	$0	$0	$0	$0	$65,267	$800,932	$5,939,665
2024	$700,779	$50,911	$30,514	$782,205	$65,267	$0	$0	$0	$0	$65,267	$847,472	$6,291,807
2025	$751,356	$53,772	$30,753	$835,882	$65,267	$0	$0	$0	$0	$65,267	$901,148	$6,648,422
2026	$787,090	$55,171	$30,998	$873,259	$65,267	$0	$0	$0	$0	$65,267	$938,526	$7,002,142
2027	$816,503	$56,219	$31,250	$903,972	$65,267	$0	$0	$0	$0	$65,267	$969,239	$7,350,043
2028	$856,330	$57,856	$31,507	$945,693	$65,267	$0	$0	$0	$0	$65,267	$1,010,960	$7,695,640
2029	$897,786	$59,397	$31,771	$988,954	$65,267	$0	$0	$0	$0	$65,267	$1,054,221	$8,038,864
2030	$930,992	$60,534	$32,042	$1,023,567	$65,267	$0	$0	$0	$0	$65,267	$1,088,834	$8,376,476
2031	$976,918	$62,326	$32,319	$1,071,563	$60,690	$0	$0	$0	$0	$60,690	$1,132,253	$8,710,834
2032	$1,025,471	$63,984	$32,603	$1,122,058	$58,448	$0	$0	$0	$0	$58,448	$1,180,507	$9,042,840
2033	$1,063,459	$65,195	$32,895	$1,161,549	$58,448	$0	$0	$0	$0	$58,448	$1,219,997	$9,369,614
2034	$1,115,904	$67,132	$33,193	$1,216,229	$53,520	$0	$0	$0	$0	$53,520	$1,269,749	$9,693,519
2035	$1,171,269	$68,906	$33,500	$1,273,674	$45,538	$0	$0	$0	$0	$45,538	$1,319,212	$10,014,017

Table B.1-23 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Direct-Fired Biomass in 2011

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	681,687	49,450
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/20	864,010	62,675
BIOMASS	84,555		05/01/11	96,446	6,996

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Biomass Fuel, VOM, & FOM	Ongoing Capex	*Total Capital*	Total System	Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Cost ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$368,293	$64,408	$0	$432,701	$0	$0	$0	$0	$0	$0	$432,701	$432,701
2007	$384,626	$56,758	$0	$441,384	$0	$0	$0	$0	$0	$0	$441,384	$853,067
2008	$401,192	$30,287	$0	$431,478	$0	$0	$0	$0	$0	$0	$431,478	$1,244,431
2009	$342,215	$30,273	$0	$372,488	$0	$0	$0	$0	$0	$0	$372,488	$1,566,200
2010	$292,237	$30,334	$0	$322,571	$0	$0	$0	$0	$0	$0	$322,571	$1,831,580
2011	$297,962	$32,430	$645	$331,037	$9,273	$0	$0	$7,773	$0	$17,046	$348,084	$2,104,312
2012	$271,366	$25,929	$6,482	$303,777	$46,916	$973	$0	$11,870	$592	$60,351	$364,128	$2,376,030
2013	$279,734	$21,839	$9,404	$310,977	$63,264	$997	$0	$12,167	$924	$77,352	$388,329	$2,652,008
2014	$275,395	$21,939	$17,458	$314,792	$99,539	$1,022	$0	$12,471	$966	$113,998	$428,789	$2,942,230
2015	$287,629	$22,783	$21,820	$332,232	$117,307	$1,047	$0	$12,783	$1,009	$132,146	$464,378	$3,241,572
2016	$307,170	$24,294	$22,365	$353,828	$117,307	$1,073	$0	$13,102	$1,055	$132,537	$486,365	$3,540,158
2017	$323,530	$25,707	$22,924	$372,161	$117,307	$1,100	$0	$13,430	$1,102	$132,939	$505,100	$3,835,480
2018	$339,895	$27,158	$23,497	$390,551	$117,307	$1,128	$0	$13,766	$1,152	$133,352	$523,903	$4,127,208
2019	$367,501	$28,852	$24,085	$420,438	$117,307	$1,156	$0	$14,110	$1,204	$133,776	$554,214	$4,421,120
2020	$357,732	$29,787	$33,754	$421,273	$159,261	$1,185	$0	$14,463	$1,258	$176,166	$597,440	$4,722,867
2021	$364,267	$31,348	$39,151	$434,765	$179,982	$1,215	$0	$14,824	$1,314	$197,335	$632,100	$5,026,918
2022	$385,129	$33,281	$40,129	$458,539	$179,982	$1,245	$0	$15,195	$1,373	$197,795	$656,334	$5,327,592
2023	$421,909	$35,082	$41,133	$498,124	$179,982	$1,276	$0	$15,575	$1,435	$198,268	$696,391	$5,631,425
2024	$462,163	$37,154	$42,161	$541,478	$179,982	$1,308	$0	$15,964	$1,500	$198,753	$740,231	$5,939,007
2025	$497,085	$39,540	$43,215	$579,840	$179,982	$1,341	$0	$16,363	$1,567	$199,253	$779,093	$6,247,320
2026	$518,249	$40,797	$44,295	$603,341	$179,982	$1,374	$0	$16,772	$1,638	$199,766	$803,107	$6,550,003
2027	$533,254	$42,116	$45,403	$620,773	$179,982	$1,408	$0	$17,191	$1,712	$200,293	$821,066	$6,844,718
2028	$556,286	$43,670	$46,538	$646,494	$179,982	$1,444	$0	$17,621	$1,789	$200,835	$847,329	$7,134,378
2029	$582,229	$44,919	$47,701	$674,849	$179,982	$1,480	$0	$18,062	$1,869	$201,392	$876,242	$7,419,657
2030	$599,482	$46,058	$48,894	$694,434	$179,982	$1,517	$0	$18,513	$1,953	$201,965	$896,399	$7,697,601
2031	$624,795	$47,640	$50,116	$722,551	$175,405	$1,555	$0	$18,976	$2,041	$197,977	$920,527	$7,969,435
2032	$654,032	$48,896	$51,369	$754,296	$173,163	$1,594	$0	$19,451	$2,133	$196,340	$950,637	$8,236,793
2033	$674,195	$49,876	$52,653	$776,724	$173,163	$1,633	$0	$19,937	$2,229	$196,962	$973,687	$8,497,594
2034	$703,121	$51,412	$53,969	$808,503	$173,163	$1,674	$0	$20,435	$2,329	$197,602	$1,006,105	$8,754,244
2035	$737,017	$52,648	$55,319	$844,984	$173,163	$1,716	$0	$20,946	$2,434	$198,259	$1,043,243	$9,007,697

Table B.1-24 Expansion Plan Economic Summary - Without Taylor Energy Center - Direct-Fired Biomass in 2011

Case Description	
Fuel Forecast	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
CFB	580,300	44	05/01/12	709,133	51,441
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/19	842,898	61,144
LM6000	38,800	12	05/01/25	63,291	5,678
BIOMASS	84,555		05/01/11	96,446	6,996

Year	Production Cost: Fuel and Energy Cost ($1,000)	Production Cost: O&M Variable ($1,000)	Production Cost: O&M Fixed ($1,000)	Production Cost: *Total Production Cost ($1,000)*	Capital Cost and Other Project Costs: Unit Capital Cost ($1,000)	Capital Cost and Other Project Costs: Community Contribution ($1,000)	Capital Cost and Other Project Costs: Transmission Charge ($1,000)	Capital Cost and Other Project Costs: Biomass Fuel, VOM, & FOM Cost ($1,000)	Capital Cost and Other Project Costs: Ongoing Capex Cost ($1,000)	Capital Cost and Other Project Costs: *Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$368,293	$64,408	$0	$432,701	$0	$0	$0	$0	$0	$0	$432,701	$432,701
2007	$384,626	$56,758	$0	$441,384	$0	$0	$0	$0	$0	$0	$441,384	$853,067
2008	$401,192	$30,287	$0	$431,478	$0	$0	$0	$0	$0	$0	$431,478	$1,244,431
2009	$342,215	$30,273	$0	$372,488	$0	$0	$0	$0	$0	$0	$372,488	$1,566,200
2010	$292,237	$30,334	$0	$322,571	$0	$0	$0	$0	$0	$0	$322,571	$1,831,580
2011	$297,962	$32,430	$645	$331,037	$9,273	$0	$0	$7,773	$0	$17,046	$348,084	$2,104,312
2012	$279,830	$30,406	$8,427	$318,663	$48,249	$0	$0	$11,870	$0	$60,119	$378,782	$2,386,965
2013	$293,756	$28,276	$12,374	$334,406	$65,255	$0	$0	$12,167	$0	$77,422	$411,828	$2,679,643
2014	$288,957	$27,933	$20,503	$337,393	$101,530	$0	$0	$12,471	$0	$114,001	$451,394	$2,985,165
2015	$300,337	$28,897	$24,941	$354,175	$119,297	$0	$0	$12,783	$0	$132,080	$486,255	$3,298,609
2016	$321,801	$30,667	$25,564	$378,032	$119,297	$0	$0	$13,102	$0	$132,400	$510,432	$3,611,970
2017	$342,210	$32,276	$26,203	$400,689	$119,297	$0	$0	$13,430	$0	$132,727	$533,416	$3,923,847
2018	$361,494	$34,002	$26,858	$422,354	$119,297	$0	$0	$13,766	$0	$133,063	$555,417	$4,233,124
2019	$356,206	$35,274	$36,376	$427,856	$160,339	$0	$0	$14,110	$0	$174,449	$602,305	$4,552,540
2020	$367,636	$36,674	$41,727	$446,037	$180,441	$0	$0	$14,463	$0	$194,904	$640,941	$4,876,258
2021	$387,669	$38,413	$42,770	$468,851	$180,441	$0	$0	$14,824	$0	$195,265	$664,117	$5,195,710
2022	$410,639	$40,663	$43,839	$495,141	$180,441	$0	$0	$15,195	$0	$195,636	$690,777	$5,512,163
2023	$450,025	$42,698	$44,935	$537,658	$180,441	$0	$0	$15,575	$0	$196,016	$733,674	$5,832,262
2024	$490,779	$45,033	$46,058	$581,871	$180,441	$0	$0	$15,964	$0	$196,405	$778,276	$6,155,652
2025	$525,401	$47,718	$48,064	$621,183	$184,253	$0	$0	$16,363	$0	$200,616	$821,799	$6,480,866
2026	$545,658	$49,244	$49,695	$644,597	$186,120	$0	$0	$16,772	$0	$202,892	$847,489	$6,800,276
2027	$566,213	$50,773	$50,937	$667,922	$186,120	$0	$0	$17,191	$0	$203,311	$871,234	$7,112,998
2028	$589,865	$52,501	$52,211	$694,577	$186,120	$0	$0	$17,621	$0	$203,741	$898,318	$7,420,088
2029	$615,968	$53,990	$53,516	$723,474	$186,120	$0	$0	$18,062	$0	$204,182	$927,656	$7,722,106
2030	$636,252	$55,323	$54,854	$746,428	$186,120	$0	$0	$18,513	$0	$204,633	$951,061	$8,017,000
2031	$663,998	$57,106	$56,225	$777,329	$181,543	$0	$0	$18,976	$0	$200,519	$977,848	$8,305,761
2032	$692,717	$58,613	$57,631	$808,962	$179,301	$0	$0	$19,451	$0	$198,752	$1,007,714	$8,589,171
2033	$718,043	$59,940	$59,072	$837,055	$179,301	$0	$0	$19,937	$0	$199,238	$1,036,293	$8,866,741
2034	$749,095	$61,624	$60,548	$871,267	$179,301	$0	$0	$20,435	$0	$199,737	$1,071,004	$9,139,947
2035	$781,969	$63,138	$62,062	$907,169	$179,301	$0	$0	$20,946	$0	$200,247	$1,107,416	$9,408,990

Table B.1-25 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 on PRB

Case Description	
Fuel Forecast	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost *($1,000)*	Construction and Development Period *(months)*	Month/Day/Year Installed *(mm/dd/yy)*	Installed Cost *($1,000)*	Levelized Cost *($1,000)*
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/12	679,664	49,303
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/19	842,898	61,144
LM6000	38,800	12	05/01/25	63,291	5,678

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Seasonal	Ongoing Capex	*Total Capital*	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Purchase ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$4,577	$0	$0	$0	$0	$4,577	$343,864	$2,100,027
2012	$275,891	$27,384	$6,482	$309,757	$39,822	$973	$0	$0	$591	$41,385	$351,142	$2,362,054
2013	$282,745	$23,055	$9,404	$315,204	$56,121	$997	$0	$0	$922	$58,041	$373,244	$2,627,312
2014	$279,343	$22,930	$17,458	$319,731	$92,396	$1,022	$0	$0	$964	$94,382	$414,113	$2,907,600
2015	$291,310	$23,774	$21,820	$336,904	$110,164	$1,047	$0	$0	$1,007	$112,218	$449,122	$3,197,108
2016	$311,273	$25,330	$22,365	$358,969	$110,164	$1,073	$0	$0	$1,053	$112,290	$471,258	$3,486,419
2017	$329,716	$26,911	$22,924	$379,551	$110,164	$1,100	$0	$0	$1,100	$112,364	$491,915	$3,774,032
2018	$350,557	$28,258	$23,497	$402,313	$110,164	$1,128	$0	$0	$1,149	$112,441	$514,754	$4,060,666
2019	$343,966	$29,284	$32,931	$406,182	$151,205	$1,156	$0	$0	$1,201	$153,563	$559,744	$4,357,510
2020	$355,367	$30,930	$38,196	$424,492	$171,307	$1,185	$0	$0	$1,255	$173,748	$598,240	$4,659,662
2021	$376,264	$32,463	$39,151	$447,878	$171,307	$1,215	$0	$0	$1,312	$173,834	$621,712	$4,958,716
2022	$399,252	$34,350	$40,129	$473,732	$171,307	$1,245	$0	$0	$1,371	$173,923	$647,655	$5,255,414
2023	$439,994	$36,297	$41,133	$517,424	$171,307	$1,276	$0	$0	$1,432	$174,016	$691,440	$5,557,087
2024	$480,452	$38,317	$42,161	$560,930	$171,307	$1,308	$0	$0	$1,497	$174,112	$735,042	$5,862,512
2025	$515,253	$40,727	$44,069	$600,049	$175,119	$1,341	$0	$0	$1,564	$178,024	$778,073	$6,170,422
2026	$534,442	$42,198	$45,600	$622,240	$176,986	$1,374	$0	$0	$1,635	$179,995	$802,235	$6,472,776
2027	$553,787	$43,526	$46,740	$644,053	$176,986	$1,408	$0	$0	$1,708	$180,103	$824,155	$6,768,600
2028	$578,384	$44,956	$47,909	$671,248	$176,986	$1,444	$0	$0	$1,785	$180,215	$851,463	$7,059,673
2029	$604,850	$46,343	$49,106	$700,299	$176,986	$1,480	$0	$0	$1,865	$180,331	$880,630	$7,346,381
2030	$624,234	$47,487	$50,334	$722,055	$176,986	$1,517	$0	$0	$1,949	$180,452	$902,507	$7,626,219
2031	$652,489	$48,926	$51,592	$753,007	$172,409	$1,555	$0	$0	$2,037	$176,001	$929,008	$7,900,558
2032	$682,567	$50,359	$52,882	$785,808	$170,167	$1,594	$0	$0	$2,129	$173,890	$959,697	$8,170,463
2033	$705,736	$51,467	$54,204	$811,407	$170,167	$1,633	$0	$0	$2,225	$174,025	$985,433	$8,434,410
2034	$737,065	$52,801	$55,559	$845,425	$170,167	$1,674	$0	$0	$2,325	$174,166	$1,019,591	$8,694,501
2035	$772,507	$54,221	$56,948	$883,676	$170,167	$1,716	$0	$0	$2,429	$174,313	$1,057,988	$8,951,536

Table B.1-26 Expansion Plan Economic Summary - With Taylor Energy Center in May of 2013

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LMS100	65,500	17	05/01/11	75,997	6,818
TEC	NA	NA	05/01/13	698,054	50,637
CFB	580,300	44	05/01/14	744,999	54,042
CFB	580,300	44	05/01/19	842,898	61,144
LM6000	38,700	12	05/01/25	63,128	5,664

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and	O&M		Total					Ongoing	Total	Total	Present
Year	Energy Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	Production Cost ($1,000)	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Cost ($1,000)	Capital Cost ($1,000)	System Cost ($1,000)	Worth Cost ($1,000)
2006	$368,232	$64,424	$0	$432,656	$0	$0	$0	$0	$0	$0	$432,656	$432,656
2007	$384,678	$56,755	$0	$441,433	$0	$0	$0	$0	$0	$0	$441,433	$853,069
2008	$400,134	$30,430	$0	$430,564	$0	$0	$0	$0	$0	$0	$430,564	$1,243,603
2009	$341,429	$30,474	$0	$371,903	$0	$0	$0	$0	$0	$0	$371,903	$1,564,866
2010	$292,771	$30,231	$0	$323,001	$0	$0	$0	$0	$0	$0	$323,001	$1,830,600
2011	$305,290	$33,352	$645	$339,287	$4,577	$0	$0	$0	$0	$4,577	$343,864	$2,100,027
2012	$323,887	$34,975	$985	$359,847	$6,818	$0	$0	$6,435	$0	$13,253	$373,100	$2,378,440
2013	$304,956	$26,327	$6,644	$337,927	$40,808	$997	$0	$0	$620	$42,425	$380,352	$2,648,749
2014	$285,963	$22,849	$17,458	$326,269	$93,730	$1,022	$0	$0	$966	$95,718	$421,987	$2,934,366
2015	$296,457	$23,756	$21,820	$342,032	$111,498	$1,047	$0	$0	$1,009	$113,554	$455,586	$3,228,041
2016	$316,365	$25,228	$22,365	$363,958	$111,498	$1,073	$0	$0	$1,055	$113,626	$477,583	$3,521,236
2017	$332,390	$26,810	$22,924	$382,124	$111,498	$1,100	$0	$0	$1,102	$113,700	$495,824	$3,811,134
2018	$350,569	$28,250	$23,497	$402,316	$111,498	$1,128	$0	$0	$1,152	$113,777	$516,093	$4,098,514
2019	$344,113	$29,210	$32,931	$406,254	$152,539	$1,156	$0	$0	$1,204	$154,899	$561,153	$4,396,106
2020	$357,010	$30,815	$38,196	$426,020	$172,641	$1,185	$0	$0	$1,258	$175,084	$601,104	$4,699,704
2021	$374,623	$32,415	$39,151	$446,189	$172,641	$1,215	$0	$0	$1,314	$175,170	$621,359	$4,998,588
2022	$398,131	$34,185	$40,129	$472,445	$172,641	$1,245	$0	$0	$1,373	$175,260	$647,705	$5,295,309
2023	$434,590	$36,227	$41,133	$511,950	$172,641	$1,276	$0	$0	$1,435	$175,353	$687,303	$5,595,177
2024	$474,778	$38,245	$42,161	$555,183	$172,641	$1,308	$0	$0	$1,500	$175,449	$730,632	$5,898,770
2025	$510,459	$40,557	$44,069	$595,085	$176,443	$1,341	$0	$0	$1,567	$179,351	$774,436	$6,205,241
2026	$529,349	$42,109	$45,600	$617,058	$178,305	$1,374	$0	$0	$1,638	$181,317	$798,375	$6,506,140
2027	$543,760	$43,456	$46,740	$633,956	$178,305	$1,408	$0	$0	$1,712	$181,425	$815,382	$6,798,815
2028	$570,398	$44,745	$47,908	$663,052	$178,305	$1,444	$0	$0	$1,789	$181,537	$844,589	$7,087,538
2029	$594,686	$46,264	$49,106	$690,056	$178,305	$1,480	$0	$0	$1,869	$181,654	$871,710	$7,371,341
2030	$611,863	$47,397	$50,334	$709,594	$178,305	$1,517	$0	$0	$1,953	$181,775	$891,369	$7,647,726
2031	$640,558	$48,704	$51,592	$740,855	$173,728	$1,555	$0	$0	$2,041	$177,324	$918,179	$7,918,867
2032	$668,561	$50,281	$52,882	$771,724	$171,487	$1,594	$0	$0	$2,133	$175,213	$946,937	$8,185,185
2033	$688,517	$51,345	$54,204	$794,065	$171,487	$1,633	$0	$0	$2,229	$175,349	$969,414	$8,444,841
2034	$720,420	$52,600	$55,559	$828,579	$171,487	$1,674	$0	$0	$2,329	$175,490	$1,004,069	$8,700,972
2035	$753,874	$54,133	$56,948	$864,955	$171,487	$1,716	$0	$0	$2,434	$175,637	$1,040,592	$8,953,780