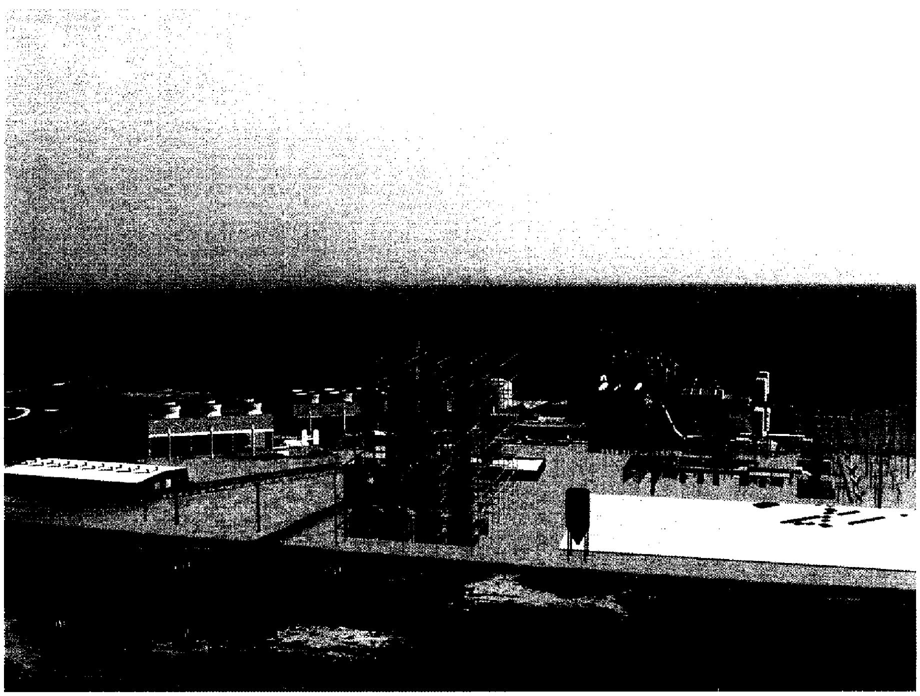
060155-EM

Florida Electrical Power Plant Siting Act
Need for Power Application

Curtis H. Stanton Energy Center Unit B

Unit B IGCC Plant



B&V Project 142728

Submitted by:
Orlando Utilities Commission
February 2006

OUC
The *Reliable* One

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Abbreviations

AC	air conditioning
ARP	Acid Rain Program
ARP	All-Requirements Project
ASD	adjustable speed drive
B&V	Black & Veatch
BACT	Best Available Control Technology
CAES	Compressed air energy storage
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CaO	calcium oxide
CCPI	Clean Coal Power Initiative
CDD	cooling degree-days
CFB	circulating fluidized bed
City	City of Orlando, Florida
CO	carbon monoxide
CO_2	carbon dioxide
COP	coefficient of performance
COS	carbonyl sulfide
CPWC	cumulative present worth cost
CRT	cathode ray tube
CTGs	Combustion turbine generators
DCS	distributed control system
DCSS	distillation condensation subsystem
DI	diffuse insolation
DNI	direct normal insolation
DOE	Department of Energy
DSM	Demand-Side Management
DX	direct exchange
EER	energy efficiency ratio
EF	energy factor
EGUs	electric generating units
EI	energy intensities
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	engineer, procure, and construct

ESA	Electricity Storage Association
EVA	Energy Ventures Analysis, Inc.
FBC	fluidized bed combustor
FCR	fixed charge rate
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FF	Fabric filter
FGD	flue gas desulfurization
FGT	Florida Gas Transmission
FIP	Federal Implementation Plan
FIRE	Florida Integrated Resource Evaluator
FMPA	Florida Municipal Power Agency
FMPP	Florida Municipal Power Pool
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
GE	General Electric
GSD	General Service Demand
GSLD	General Service Large Demand
GSND	General Service Nondemand
GWh	gigawatt-hour
H_2S	hydrogen sulfide
HAT	humid air turbine
HDD	heating degree-days
Hg	mercury
HPC	high-pressure compressor
HPT	high-pressure turbine
HRSG	heat recovery steam generator
HRVG	heat recovery vapor generator
HTHP	high temperature high pressure
HVAC	heating, ventilation, and air conditioning
IDC	interest during construction
IDEA	International District Energy Association
IGCC	integrated gasification combined cycle
IPPs	independent power producers
KBR	Kellogg Brown and Root, Inc.
KUA	Kissimmee Utility Authority

kW	kilowatt
LFG	Landfill gas
LNG	liquefied natural gas
LOLP	Loss of Load Probability
LPC	low-pressure compressor
LPT	low-pressure turbine
LRDB	Load and Resource Database
MAD	mean absolute deviation
MAPE	Mean Absolute Percent Error
MEF	Modified Energy Factor
mgd	million gallons per day
MMBD	million barrels per day
MSA	Metropolitan Statistical Area
MSL	mean sea level
MSW	municipal solid waste
MW	megawatts
MW_e	megawatt electrical
Na-S	sodium-sulfur
NBP	NO_x Budget Trading Program
NERC	North American Electric Reliability Council
NI	nuclear island
NO_x	nitrogen oxides
NRC	Nuclear Regulatory Commission
O&M	operation and maintenance
OIA	Orlando International Airport
OLS	Ordinary Least Squares
OPEC	Organization of Petroleum Exporting Countries
OTEC	ocean thermal energy conversion
OUC	Orlando Utilities Commission
OWC	oscillating water column
PAFC	phosphoric acid fuel cell
PC	pulverized coal
PDA	Process Development Allowance
PEF	Progress Energy Florida
PFBC	Pressurized fluidized bed combustion
PM	particulate matter
PPA	purchase power agreement

ppm	part per million
PR	Partial Requirements
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
PTC	production tax credit
PVs	photovoltaics
QFs	qualifying facilities
RDF	Refuse Derived Fuel
REEPS	Residential End-Use Planning System
RER	Regional Economic Research, Inc.
Reunion	Reunion Resort & Club
rpm	revolutions per minute
SAE	Statistically Adjusted End-Use
SCF	Southern Company - Florida LLC
SCR	Selective catalytic reduction
SCS	Southern Company Services
SDA	spray dryer absorber
SEER	seasonal energy efficiency ratio
SEGS	Solar Electric Generating Station
SES	Stirling Energy Systems
SIP	state implementation plan
SJRWMD	St. John's River Water Management District
SNCR	Selective non-catalytic reduction
SNL	Sandia National Laboratories
SO_2	sulfur dioxide
SPC	Southern Power Company
SPC-OG	Southern Power Company – Orlando Gasification LLC
SR	State Road
Stanton B	Stanton Energy Center
STG	steam turbine generator
TAPCHAN	tapered channel
TCEC Unit 1	Treasure Coast Energy Center Unit 1
TECO	Tampa Electric Company
TI	turbine island
tpy	tons per year
TWG	Transmission Working Group
ULSD	ultra-low sulfur diesel

VTG	vapor turbine generator
WECS	wave energy conversion system
WTE	waste-to-energy

1.0 Overview and Summary

1.1 Overview

The Orlando Utilities Commission (OUC) provides electric energy service to more than 160,000 customers, including over 138,000 residential customers in and around the City of Orlando, Florida (City). It operates as a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City. OUC has full authority over the management and control of the electric and water works plants in the City and has been approved by the Florida legislature to offer these services in Osceola County as well as Orange County. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission, and distribution systems, as well as water production, transmission, and distribution systems to meet the requirements of its customers.

OUC entered into an Interlocal Agreement with the City of St. Cloud in 1997, in which OUC assumed responsibility for supplying all of St. Cloud's loads for the term of the agreement, which has since been extended through 2032. The total system peak, including both OUC and St. Cloud, is forecasted to be 1,223 MW in the summer and 1,225 MW in the winter for 2006. The combined OUC and St. Cloud system annual peak demands are forecasted to grow at an average annual growth rate of approximately 2.7 percent through 2030. OUC maintains a mix of generating resources and power purchase agreements to meet a minimum reserve margin of 15 percent each year to ensure reliable electric service. Based on system load growth, retirement of older, inefficient generating capacity, and the expiration of existing power purchase agreements, OUC forecasts that it will need additional generating resources by the summer of 2010 to serve the forecast capacity requirements of the combined OUC and St. Cloud systems.

In response to the Clean Coal Power Initiative (CCPI) of the US Department of Energy (DOE), Southern Company Services (SCS) submitted a proposal on June 15, 2004, for funding of a Transport Gasification combined cycle demonstration project to be located at OUC's Stanton Energy Center (Stanton B). The Stanton B project proposes to demonstrate Transport Gasifier technology derived from the catalytic cracking technology of Kellogg Brown and Root, Inc. (KBR). The gasifier will provide syngas fuel to a 1x1 combined cycle power plant by gasifying subbituminous coal (sourced from the Powder River Basin [PRB] in Wyoming as well as other sources) at a heat rate of approximately 8,500 Btu/kWh. Transport Gasifier technology offers the advantage of efficiently operating with low rank coals (such as PRB subbituminous) in comparison to other gasification technologies. Subbituminous coals are the largest source of coal reserves in the United States.

On October 21, 2004, the DOE officially announced that it had selected SCS and its partners Southern Power Company (SPC), OUC, and KBR for negotiation of a $235 million cost-sharing cooperative agreement under the CCPI. The partners intend to proceed with project definition, design, construction, and commercial demonstration of the project, which includes the gasification unit and a 1x1 combined cycle unit that will be capable of firing coal derived syngas or natural gas. The gasifier will be jointly owned by OUC and Southern Power Company – Orlando Gasification LLC (SPC-OG), with OUC owning 35 percent and SPC-OG owning 65 percent. KBR will provide the Transport Gasification technology.

SPC-OG and OUC have agreed on how the project costs beyond the $235 million DOE cost-sharing cooperative agreement will be allocated. Stanton B is proposed to be executed in the four phases described previously. However, the project will be funded in three budget periods consisting of project definition, design/construction, and demonstration. The total cost of the gasifier, including the project definition, design/construction, and demonstration phases, is expected to be approximately $557 million, of which approximately $322 million will be funded by SPC-OG and OUC. SPC-OG will construct the combined cycle portion of the plant, which will be 100 percent owned by OUC, for a fixed engineer, procure, and construct (EPC) price of [redacted].

In addition to providing a reliable, cost-effective resource to meet OUC's growing electric capacity and energy needs, Stanton B will provide additional benefits to the State of Florida and the US power generation industry as a whole. First, the project will demonstrate the commercial viability of a new gasification technology using low rank coals such as PRB coal that are prevalent within the United States. By using an abundant US sourced fuel supply, OUC will help reduce the nation's dependence on foreign energy imports, such as oil and liquefied natural gas (LNG). The project will also have the ability to operate on both coal derived syngas as well as natural gas. As such, Stanton B will provide OUC with fuel diversity, while also maintaining very low emissions rates for a coal fired power plant. The gasification process provides the best capture of sulfur and mercury emissions from coal fired power generation facilities by removing these constituents prior to combustion, rather than after combustion, which is the typical practice at conventional coal fired power plants. The State of Florida will benefit from having a fuel source that is outside the hurricane susceptible natural gas producing regions within the Gulf Coast. Lastly, the DOE's participation in this project through its $235 million funding indicates the importance of the project in the long-term energy policy for the United States.

1.2 Summary

The remainder of this Need for Power Application is comprised of 16 additional sections plus three appendices, as outlined below:

- Section 2.0 - Utility System Description
- Section 3.0 - Forecast of Peak Demand and Energy Consumption
- Section 4.0 - Forecast of Facilities Requirements
- Section 5.0 - Economic Evaluation Criteria and Methodology
- Section 6.0 - Project Selection
- Section 7.0 - Description of the Project
- Section 8.0 - Supply-Side Alternatives
- Section 9.0 - Environmental Considerations
- Section 10.0 - Economic Analysis
- Section 11.0 - Sensitivity Analyses
- Section 12.0 - Demand-Side Management (DSM) Evaluation
- Section 13.0 - Impact to the Transmission System
- Section 14.0 - Strategic Considerations
- Section 15.0 - Consequences of Delay
- Section 16.0 - Financial Analysis
- Section 17.0 - Peninsular Florida Need
- Appendix A - Forecast of Peak Demand and Energy Consumption
- Appendix B – Comparison of Delivered Coal Costs
- Appendix C – Sensitivity Analyses Results

The information and analyses presented throughout this Application demonstrate that the proposed Stanton B satisfies the requirements set forth in Section 403.519, Florida Statutes. In particular, Stanton B is the most cost-effective alternative available to OUC to satisfy forecast capacity requirements in a reliable, environmentally responsible manner. In selecting Stanton B as its next generating resource, OUC considered all reasonable conservation and demand-side management measures available beyond its existing portfolio of energy conservation offerings, and none were found that could cost-effectively defer Stanton B.

2.0 Utility System Description

At the turn of the twentieth century, John M. Cheney, an Orlando, Florida, judge, organized the Orlando Water and Light Company and supplied electricity on a part-time basis with a 100 kW generator. Twenty-four hour service began in 1903. The population of the City of Orlando (City) had grown to roughly 10,000 by 1922 and Cheney, realizing the need for wider services than his company was capable of supplying, urged his friends to work and vote for a $975,000 bond issue to enable the citizens of Orlando to purchase and municipally operate his privately owned utility. The bond issue carried almost three to one, as did a subsequent issue for additional improvements. The citizens of Orlando acquired Cheney's company and its 2,795 electricity and 5,000 water customers for a total initial investment of $1.5 million.

In 1923, OUC was created by an act of the state legislature and was granted full authority to operate electric and water municipal utilities. The business was a paying venture from the start. By 1924, the number of customers had more than doubled and OUC had contributed $53,000 to the City. When Orlando citizens took over operation of their utility, the City's population was less than 10,000; by 1925, it had grown to 23,000. In 1925, more than $165,000 was transferred to the City, and an additional $111,000 was transferred in 1926.

Today, OUC operates as a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City. OUC has full authority over the management and control of the electric and water works plants in the City and has been approved by the Florida legislature to offer these services in Osceola County as well as Orange County. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission, and distribution systems, chilled water systems, as well as water production, transmission, and distribution systems to meet the requirements of its customers.

In 1997, OUC entered into an Interlocal Agreement with the City of St. Cloud in which OUC assumed responsibility for supplying all of St. Cloud's loads for the 25 year term of the agreement, which added an additional 150 square miles of service area. OUC also assumed management of St. Cloud's existing generating units and purchase power contracts. This agreement has been extended through 2032.

2.1 Existing Generation System

Presently, OUC has ownership interests in five electric generating plants, which are described further in this section. Table 2-1 summarizes OUC's generating facilities which include:

- Stanton Energy Center Units 1 and 2, and Stanton A.
- Indian River Plant Combustion Turbine Units A, B, C, and D.
- Progress Energy Florida (formerly Florida Power Corporation) Crystal River Unit 3 Nuclear Generating Facility.
- Lakeland Electric McIntosh Unit 3.
- Florida Power & Light Company (FPL) St. Lucie Unit 2 Nuclear Generating Facility.

The Stanton Energy Center is located 12 miles southeast of Orlando, Florida. The 3,280 acre site contains Units 1 and 2, as well as Stanton A, and the necessary supporting facilities. Stanton Unit 1 was placed in commercial operation on July 1, 1987, followed by Stanton Unit 2, which was placed in commercial operation on June 1, 1996. Both units are fueled by pulverized coal and operate at emission levels that are within the Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP) requirement standards for sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulates. Stanton Unit 1 is a 444 MW net coal fired facility. OUC has a 68.6 percent ownership share of this unit, which provides 302 MW of capacity to the OUC system. Stanton Unit 2 is a 446 MW net coal fired generating facility. OUC maintains a 71.6 percent (319 MW) ownership share of this unit.

OUC has entered into an agreement with Kissimmee Utility Authority (KUA), Florida Municipal Power Agency (FMPA), and Southern Company - Florida LLC (SCF) governing the ownership of Stanton A, a combined cycle unit at the Stanton Energy Center that began commercial operation on October 1, 2003. OUC, KUA, FMPA, and SCF are joint owners of Stanton A, with OUC maintaining a 28 percent ownership share, KUA and FMPA each maintaining 3.5 percent ownership shares, and SCF maintaining the remaining 65 percent of Stanton A's capacity.

Stanton A is a 2x1 combined cycle utilizing General Electric combustion turbines. Stanton A is dual fueled with natural gas as the primary fuel and No. 2 oil as the backup fuel. OUC maintains a 28 percent equity share of SEC A, while purchasing 52 percent as described further in Section 2.2.

Table 2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Net Capability	
				Pri	Alt	Pri	Alt			Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	18[1]	23.4[1]
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	18[1]	23.4[1]
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	85.3[2]	100.3[2]
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	85.3[2]	100.3[2]
Stanton Energy Center	1	Orange	ST	BIT	--	RR	--	07/87	Unknown	301.6[3]	303.7[3]
Stanton Energy Center	2	Orange	ST	BIT	--	RR	--	06/96	Unknown	319.3[4]	319.3[4]
Stanton Energy Center	A	Orange	CC	NG	FO2	PL	TK	10/03	Unknown	173.6[5]	184.8[5]
McIntosh	3	Polk	ST	BIT	--	RR	--	09/82	Unknown	133[6]	136[6]
Crystal River	3	Citrus	NP	UR	--	TK	--	03/77	Unknown	13	13
St. Lucie[7]	2	St. Lucie	NP	UR	--	TK	--	06/83	Unknown	51	52
St. Cloud[8]	1	Osceola	IC	NG	FO2	PL	TK	07/82	10/06	2	1.825
	2		IC	NG	FO2	PL	TK	12/74	10/06	5	5
	3		IC	NG	FO2	PL	TK	09/82	10/06	2	2
	4		IC	NG	FO2	PL	TK	08/61	10/06	3	3
	6		IC	NG	FO2	PL	TK	03/67	10/06	3	3
	7		IC	NG	FO2	PL	TK	09/82	10/06	6	6
	8		IC			PL	TK	04/77	10/06	6	6

(1)Reflects an OUC ownership share of 48.8 percent.
(2)Reflects an OUC ownership share of 79.0 percent.
(3)Reflects an OUC ownership share of 68.6 percent.
(4)Reflects an OUC ownership share of 71.6 percent.
(5)Reflects an OUC ownership share of 28.0 percent.
(6)Reflects an OUC ownership share of 40.0 percent.
(7)OUC owns approximately 6.1 percent of St. Lucie Unit No. 2. Reliability exchange divides 50 percent power from Unit No. 1 and 50 percent power from Unit No. 2.
(8)St. Cloud No. 8 is currently not operated and in standby, therefore, OUC receives no capacity from this unit. St. Cloud owns the units, but OUC controls their operation.

The Indian River Plant is located 4 miles south of Titusville on US Highway 1. The 160 acre Indian River Plant site contains three steam electric generating units (No. 1, 2, and 3) and four combustion turbine units (A, B, C, and D). The three steam turbine units were sold to Reliant in 1999. The combustion turbine units are primarily fueled by natural gas, with No. 2 fuel oil as an alternative. OUC has a partial ownership share of 48.8 percent, or 36 MW, in Indian River Units A and B as well as a partial ownership share of 79 percent (170 MW) in Indian River Units C and D.

Crystal River Unit 3 is an 835 MW net nuclear generating facility operated by Progress Energy Florida, formerly Florida Power Corporation. OUC has a 1.6015 percent ownership share in this facility, providing approximately 13 MW to the OUC system.

McIntosh Unit 3 is a 340 MW net coal fired unit operated by Lakeland Electric. McIntosh Unit 3 has supplementary oil and refuse-derived fuel burning capability and is capable of burning up to 20 percent petroleum coke. Lakeland Electric has ceased burning refuse-derived fuel at McIntosh Unit 3 for operational and landfill reasons. For purposes of the analyses performed in this Application, it was assumed that McIntosh Unit 3 would burn coal priced identically to that used for Stanton Units 1 and 2. OUC has a 40 percent ownership share in McIntosh Unit 3, providing approximately 133 MW of capacity to the OUC system.

St. Lucie Unit 2 is a 853 MW net nuclear generating facility operated by FPL. OUC has a 6.08951 percent ownership share in this facility, providing approximately 51 MW of generating capacity to OUC. A reliability exchange with St. Lucie Unit 1 results in half of the capacity being supplied by St. Lucie Unit 1 and half by St. Lucie Unit 2.

As part of the Interlocal Agreement with St. Cloud, OUC has operating control of St. Cloud's seven internal combustion generating units, which have a total summer rating of 27 MW. One of the seven St. Cloud internal combustion generating units (Unit 8) is not operated, but is kept in standby, so that the resulting net summer generating capacity from St. Cloud's internal combustion units is 21 MW. All of the St. Cloud units are scheduled to retire in October 2006.

2.2 Purchase Power Resources

OUC has a purchase power agreement (PPA) with SCF for 80 percent of SCF's ownership share of Stanton A. Under the original Stanton A PPA OUC, KUA, and FMPA agreed to purchase all of SCF's 65 percent capacity share of Stanton A for 10 years, although the utilities retained the right to reduce the capacity purchased from SCF by 50 MW each year, beginning in the sixth year of the PPA, as long as the total reduction in capacity purchased did not exceed 200 MW. The utilities originally had options to extend the PPA beyond its initial term. OUC, KUA, and FMPA have unilateral options to purchase all of Stanton A's capacity for the estimated 30 year useful life of the unit. Subsequent amendments to the original PPA allowed OUC to continue its capacity purchase through the 20th year of the PPA. Beginning with the 16th contract year and ending with the 20th contract year, OUC will maintain the irrevocable right to reduce the amount of capacity purchased by either 20 MW or 40 MW per year, as long as the total reduction in purchased capacity does not exceed 160 MW. Additionally, OUC has the option of terminating the PPA after the 20th contract year, which ends September 30, 2023. Rather than terminating the PPA, OUC may elect to continue the PPA for an additional 5 years under the *Extended Term* option beginning October 1, 2023, and ending September 30, 2028. OUC may subsequently continue the PPA for an additional 5 years under the *Further Extension* option beginning October 1, 2028, and ending September 30, 2033. For evaluation purposes it has been assumed that OUC will exercise both the Extended Term and Further Extension options of the Stanton A PPA.

St. Cloud has a Partial Requirements (PR) contract with Tampa Electric Company (TECO) for 15 MW, which expires December 31, 2012. As a result of the Interlocal Agreement with St. Cloud, OUC may schedule the TECO PR purchase.

2.3 Power Sales Contracts

OUC has had a number of power sales contracts with various entities over the past several years. However, OUC is currently contractually obligated to supply power to only FMPA through a unit power sales contract, which has been in place with FMPA since May 1, 1986. The contract expires December 31, 2006; OUC will provide FMPA with 22 MW during 2006.

2.4 Transmission System

OUC's existing transmission system consists of 28 substations interconnected through approximately 318 miles of 230 kV, 115 kV, and 69 kV lines and cables. OUC is fully integrated into the state transmission grid through its twenty-three 230 kV, one 115 kV, and three 69 kV metered interconnections with other generating utilities that are members of the Florida Reliability Coordinating Council (FRCC), as summarized in Table 2-2. Additionally, OUC is now responsible for St. Cloud's four substations, as well as approximately 51 miles of 230 kV and 69 kV lines and cables. As presented in Table 2-3, the St. Cloud transmission system includes three interconnections. OUC's transmission system, including St. Cloud, is shown on Figure 2-1.

Table 2-2
OUC Transmission Interconnections

Utility	kV	Number of Interconnections
FPL	230	2
Progress Energy Florida (PEF)	230	8
KUA	230	2
KUA/FMPA	230	2
Lakeland Electric	230	1
TECO	230	2
TECO/Reedy Creek Improvement District	230	2
PEF	69	1
St. Cloud	69	1
Southern Company	230	1
Reliant Energy	230	2
Reliant Energy	115	1

Table 2-3
St. Cloud Transmission Interconnections

Utility	kV	Number of Interconnections
OUC	69	1
PEF	230	1
KUA	69	1

STATE OF FLORIDA

OFFICE OF COMMISSION CLERK
ANN COLE
COMMISSION CLERK

Public Service Commission

* *

Docket No. : 060155-EM

Docket Title: Petition for determination of need for proposed Stanton Energy Center Combined Cycle Unit 8 electrical power plant in Orange County, by Orlando Utilities Commission

DN 01527-06: FIGURE 2-1, MAP OF ORLANDO UTILITIES COMMISSION TRANSMISSION LINES

[CLK NOTE: MAP PORTION OF TESTIMONY EXHIBIT CAN BE FOUND IN MAPS MICROFILM.]

The addition of a distribution transformer to the existing Kaley substation (No. 13) was completed in December 2004, and the new Lake Nona 230/15 kV substation was placed into service in March 2005. The addition of the new 230/25 kV St. Cloud south substation and bus tie transformer, and the 230/69 kV and associated 69 kV lines to the central substation were planned for completion in February 2006. The upgrade of the 69 kV tie line to KUA has been delayed because of a road widening project along its path.

To increase reliability and relieve higher fault current levels resulting from the closing of the Stanton 230 kV bus, oil circuit breakers at three substations (No. 10, No. 11, and No. 12) were upgraded to gas insulated models, and two distribution transformers and switchgears at substation No. 9 were replaced with new units.

To maintain reliable and economic service, OUC has developed the following schedule of transmission system upgrades:

- Relocating the bus tie transformer from the Stanton east bus to the Magnolia Ranch 69 kV substation.
- Addition of 230 kV lines between Stanton and Lake Nona via the Magnolia Ranch substation.
- Addition of a 69 kV line from Magnolia Ranch to State Road (SR) 15 in Orange County, Florida.

3.0 Forecast of Peak Demand and Energy Consumption

OUC utilized its internal knowledge of the service area and the expertise of Itron, Inc., to develop the long-term energy and demand forecast. The project scope was to develop a set of sales, energy, and demand forecast models that could support OUC's budgeting and financial planning process as well as long-term planning requirements. This section provides a summary of the methodology and results. A detailed description of the forecast methodology and assumptions is presented in Appendix A of this Need for Power Application.

3.1 Forecast Methodology

In developing the forecast, OUC utilized a Statistically Adjusted End-Use (SAE) approach developed by Itron. SAE modeling is a combination of econometric (linear regression) and end-use modeling. The methodology entails integrating end-use concepts into an econometric modeling framework that captures the impact of long-term structural change (such as changes in appliance saturation and efficiency) on long-term energy use and demand. This method is used by a number of electric and gas utilities.

In econometric forecasts, the usual approach is to specify sales as a function of weather conditions, economic conditions, and price to the extent that reasonable price coefficients can be estimated. The model is then used to generate a sales forecast for normal weather conditions and projected economic and price trends. This approach generally works well but will be less effective over long durations as it fails to capture the impact of changing end-use saturations and efficiency. The SAE approach entails constructing end-use variables (heating, cooling, and other use) that capture weather, economic, and price trends, as well as changes in end-use saturation and efficiency trends. In the residential model, the constructed heating and cooling variables also capture projected changes in housing square footage and improvements in thermal shell integrity. The constructed variables are then used in sales or average use forecast models developed using linear regression.

3.1.1 Residential Sector Model

The residential sales model consists of both an average use per household model and a customer forecast model. Monthly average use models were estimated for the period 1994 to 2004, which provided 10 years of historical data. The average use model variables include heating and cooling degree-days, price, household real income, household size, end-use saturation and efficiency trends, housing square footage, and changes in housing thermal shell integrity. The customer forecast model was driven by the number of households projected for the Orlando Metropolitan Statistical Area (MSA). Each of the most likely scenarios was based on normal weather.

Largely as a result of expected improvements in heat pump and central air conditioning efficiency, the residential average use projection is expected to be relatively flat, with average use increasing 0.6 percent per year from 2005 through 2025. The residential sales forecast is driven primarily by expected customer growth, with the number of new households in the Orlando MSA projected to increase 2.8 percent annually through 2025.

3.1.2 Nonresidential Sector Model

The nonresidential sector consists of the Small General Service (General Service Nondemand or GSND) and Large General Service (General Service Demand or GSD) revenue classes. The GSND class consists of commercial customers with a measured demand of less than 50 kW. The GSD class consists of commercial customers with a demand exceeding 50 kW. For all but the largest GSD customers (eight in total), GSD and GSND sales were forecasted using monthly sales forecast models estimated using linear regression. Inputs to the nonresidential model (both GSND and GSD) include actual output for the Orlando MSA, electric prices, heating and cooling degree-days, and nonresidential end-use saturation and efficiency trends. Forecasts for the largest eight customers were based on expected growth by the individual customers. For all but the Orlando International Airport and convention center, no sales growth was assumed. The GSD forecast was also adjusted to reflect expected growth in demand by the new Orlando convention center and hotels planned to serve the new convention center.

Economy.com projects relatively strong economic growth as reflected by gross regional output projections that exceed 4.3 percent over the forecast horizon (2005 through 2025). Real output projections translate into commercial sales growth of 2.3 percent in the Orlando service area and 3.1 percent in the St. Cloud service area.

Street lighting is projected from historical growth trends, with additional lighting load growth from OUC's new street lighting program.

3.1.3 Hourly Load and Peak Forecast

The system hourly load forecast was based on hourly load models constructed for OUC and St. Cloud. The hourly load models reflect daily weather conditions, seasons, months, day of the week, and holidays. The hourly load models were used to generate system level profiles through the forecast horizon. The system profiles were calibrated to the energy forecast for each retail company. The resulting hourly load forecasts are summed to generate a combined system hourly load forecast. Monthly and annual system peaks were then calculated from the hourly load forecasts.

Under normal weather conditions, OUC is just as likely to experience its annual peak demand during the winter as it is during the summer; St. Cloud is more likely to experience its annual peak during the winter. The combined system peak is most likely to occur in the winter.

3.2 Forecast Assumptions

The load forecast was based on economic, price, and weather assumptions. The economic assumptions were based on forecasts received from Economy.com and the University of Florida. For the residential sector, the primary economic drivers are population, the number of households, and real personal income. For the nonresidential sector, the primary economic driver is real output forecasts for the Orlando MSA. Price assumptions were based on forecast average annual retail electricity prices.

Weather is a key factor affecting electricity consumption for indoor cooling and heating. Monthly cooling degree-days (CDD) are used to capture cooling requirements while heating degree-days (HDD) are used to reflect electric heating needs. CDD and HDD are both calculated from a base temperature of 65° F.

3.3 Results

The base case load forecast for OUC is presented in Table 3-1; Table 3-2 presents the base case load forecast for St. Cloud. Table 3-3 presents the combined total system load for OUC and St. Cloud. The load forecast is identical to that presented by OUC in its 2005 Ten-Year Site Plan, filed with the Florida Public Service Commission in April 2005. In determining that OUC's 2005 Ten-Year Site Plan was "suitable for planning purposes" the Florida Public Service Commission reviewed OUC's load forecasting methodology and assumptions and found them to be appropriate.

Although not shown, OUC provided a chronological 8,760 hourly load forecast for the OUC and St. Cloud systems, as well as a combined total system load for OUC and St. Cloud for each year through 2025. This chronological load file is used in the economic analysis presented in Section 10.0.

Table 3-1
OUC Peak Demand and Net Energy for Load Forecast

Calendar Year	Summer (MW)	Winter (MW)	NEL (GWh)
2006	1,081	1,079	5,725
2007	1,112	1,110	5,892
2008	1,145	1,143	6,068
2009	1,177	1,175	6,237
2010	1,213	1,211	6,427
2011	1,250	1,248	6,623
2012	1,285	1,282	6,806
2013	1,320	1,317	6,990
2014	1,357	1,355	7,189
2015	1,393	1,391	7,381
2016	1,431	1,428	7,580
2017	1,469	1,466	7,781
2018	1,507	1,504	7,983
2019	1,545	1,542	8,185
2020	1,584	1,581	8,389
2021	1,623	1,620	8,598
2022	1,663	1,659	8,808
2023	1,703	1,699	9,020
2024	1,743	1,740	9,234
2025	1,784	1,780	9,449

Table 3-2
St. Cloud Peak Demand and Net Energy for Load Forecast

Calendar Year	Summer (MW)	Winter (MW)	NEL (GWh)
2006	120	124	514
2007	126	130	539
2008	133	137	566
2009	139	143	593
2010	146	151	623
2011	153	158	653
2012	160	165	682
2013	167	172	712
2014	174	180	743
2015	181	187	773
2016	189	195	805
2017	196	202	837
2018	203	210	869
2019	211	218	901
2020	219	226	933
2021	226	234	966
2022	234	242	1,000
2023	242	250	1,033
2024	250	258	1,067
2025	258	266	1,101

Table 3-3
Combined OUC and St. Cloud Peak Demand and Net Energy for Load Forecast

Calendar Year	Summer (MW)	Winter (MW)	NEL (GWh)
2006	1,201	1,203	6,239
2007	1,238	1,240	6,431
2008	1,278	1,280	6,634
2009	1,316	1,318	6,830
2010	1,359	1,362	7,049
2011	1,403	1,406	7,276
2012	1,445	1,447	7,488
2013	1,487	1,489	7,702
2014	1,531	1,535	7,933
2015	1,574	1,578	8,154
2016	1,620	1,623	8,385
2017	1,665	1,668	8,618
2018	1,710	1,714	8,852
2019	1,756	1,760	9,086
2020	1,803	1,807	9,322
2021	1,849	1,854	9,564
2022	1,897	1,901	9,807
2023	1,945	1,949	10,053
2024	1,993	1,998	10,301
2025	2,042	2,046	10,550

4.0 Forecast of Facilities Requirements

4.1 Existing Capacity Resources and Requirements

4.1.1 Existing Generating Capacity

Tables 4-1 and 4-2, which are presented at the end of this section, indicate that OUC and St. Cloud currently have a combined installed generating capability of 1,278 MW in the winter and 1,220 MW in the summer. OUC's existing generating capability (described in more detail in Section 2.0) consists of the following:

- A joint ownership share in the Stanton Energy Center (Units 1, 2, and Stanton A).
- Joint ownership shares of the Indian River combustion turbine units.
- Joint ownership shares of Crystal River Unit 3, McIntosh Unit 3, and St. Lucie Unit 2.

Additionally, the capacity from St. Cloud's diesel units is included as generating capability, consistent with the Interlocal Agreement described in Section 2.0.

4.1.2 Power Purchase Agreements

As described in Section 2.2, OUC schedules St. Cloud's power purchase from TECO. Corresponding with the construction of Stanton A, OUC entered into a PPA with SCF to purchase capacity from SCF's 65 percent ownership share of Stanton A. The original Stanton A PPA was for a term of 10 years and allowed OUC, KUA, and FMPA to purchase all of SCF's 65 percent capacity share of Stanton A for 10 years. The utilities retained the right to reduce the capacity purchased from SCF by 50 MW each year, beginning in the sixth year of the PPA, as long as the total reduction in capacity purchased did not exceed 200 MW. The utilities originally had options to extend the PPA beyond its initial term. OUC, KUA, and FMPA have unilateral options to purchase all of Stanton A's capacity for the estimated 30 year useful life of the unit. Subsequent amendments to the original PPA allowed OUC to continue its capacity purchase until the 16th year of the PPA. Beginning with the 16th contract year and ending with the 20th contract year, OUC will maintain the irrevocable right to reduce the amount of capacity purchased by either 20 MW or 40 MW per year, as long as the total reduction in purchased capacity does not exceed 160 MW. OUC has the option of terminating the PPA on September 30, 2023, or extending the PPA up to an additional 10 years through two separate 5 year extensions. For purposes of this analysis, it has been assumed that OUC will exercise its options and continue the Stanton A PPA for the duration of the planning period.

4.1.3 Power Sales Agreements

As described in Section 2.3, OUC will continue its unit power sale to FMPA in 2006, providing FMPA with 22 MW. The contract expires December 31, 2006.

4.1.4 Retirements of Generating Facilities

OUC has not scheduled any unit retirements over the planning horizon, but will continue to evaluate options on an ongoing basis. However, the diesel units owned by St. Cloud are scheduled to be retired in October 2006.

An additional factor affecting potential unit modifications and/or retirements is the EPA's Clean Air Interstate Rule (CAIR). The effect that CAIR will have on OUC's generating assets will be influenced by the ultimate CAIR state implementation plan (SIP) and is discussed further in Section 9.0.

4.2 Development of Reliability Criteria

Prudent business 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 than forecasted system demand or lower than anticipated available capacity. This section presents the development and analysis of the reliability criteria used by OUC.

The Florida Public Service Commission (FPSC) established a minimum reserve margin of 15 percent in Rule 25-6.035(1) Fla. Admin. Code for the purposes of sharing responsibility for grid reliability. OUC will adhere to the minimum 15 percent reserve margin for planning in both the summer and winter seasons. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. OUC plans to maintain the 15 percent reserve margin only for firm load obligations.

The electric utility industry uses a number of methods to calculate a utility's system reliability. Two basic methods, known as the Traditional Reserve Margin and the Loss of Load Probability, apply deterministic and probabilistic techniques, respectively, to calculate the reliability of a system. OUC uses the Traditional Reserve Margin for planning purposes. The two methods are described in more detail in the following subsections.

4.2.1 Traditional Reserve Margin

The most commonly used deterministic method is the Traditional Reserve Margin, which is calculated as follows:

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

With this equation, if either the net capacity or the net peak demand deviates from predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. This formula calculates the reserve margin at a specific point, but it does not indicate what the appropriate reserve margin is for a given system. Therefore, the appropriate reserve level must be determined by other means.

4.2.2 Loss of Load Probability

The second commonly used method of calculating the reliability of a utility system is the Loss of Load Probability (LOLP). This method is advantageous because it can measure how much capacity (and reserves) are needed to meet a target level of reliability (most utilities adopt a LOLP of 1 day in 10 years). Peninsular Florida has historically met the LOLP of 1 day in 10 years through the regional reserve sharing agreement. Since the Traditional Reserve Margin has thus far been able to adequately meet both criteria, OUC will continue to utilize the Traditional Reserve Margin.

4.3 Forecast Capacity Requirements

4.3.1 Generator Capabilities and Requirements Forecast

OUC has applied a minimum 15 percent reserve margin criterion to its own load and to St. Cloud's load, as well as the TECO partial requirements purchase. Tables 4-1 and 4-2 present the forecast reserve margins for the combined OUC and St. Cloud systems for the winter and summer seasons, respectively. The forecast peak demands in Tables 4-1 and 4-2 are consistent with those presented in Section 3.0.

Tables 4-1 and 4-2 indicate that OUC's reserve margin will fall below the 15 percent required reserve in the summer of 2010. At that time, OUC is forecasted to be 25 MW short of its minimum 15 percent margin. The deficit in capacity continues during the evaluation period. OUC's need for power is forecasted to exceed its total available capacity in the summer of 2014, when OUC's deficit will be 240 MW. A comparison of Tables 4-1 and 4-2 indicates that the summer season dictates OUC's capacity needs; therefore, the capacity additions selected in Section 10.0 of this Need for Power Application will be scheduled to meet summer reserve requirements.

4.3.2 Transmission Capability and Requirements Forecast

OUC continuously monitors and upgrades the bulk power transmission system as necessary to provide reliable electric service to its customers. OUC has adopted the North American Electric Reliability Council (NERC) Planning Standards as the basis for electric power transmission system planning for its needs and those of the City of St. Cloud. For the purposes of planning studies, OUC utilizes certain criteria that pertain to voltage and line and transformer loading. Criteria of 95 percent and 105 percent of nominal system voltage establish the lower and upper limits of acceptable voltage. Transmission lines are not allowed to exceed 100 percent of their continuous ratings during normal conditions or 100 percent of their emergency ratings during contingency outages. The bus tie transformer loading guideline is 100 percent of the unit's 65° C rating.

OUC's transmission group uses the following planning criteria to review the need and options for increasing the capability of the transmission system. During the course of a planning study, the OUC and St. Cloud transmission systems are subjected to a single contingency analysis that involves an outage of each of the 69 kV through 230 kV transmission lines. Bus tie transformers, tie lines with neighboring utilities, and off-system facilities known to cause internal problems are also included. If a violation of the voltage or loading criteria occurs, a permanent solution may be an upgrade or new construction. The revised system containing the improvement is then subjected to the same analysis as the original to ensure that no voltage or loading violations remain. OUC has recently changed its planning philosophy in situations where voltage or loading criteria are exceeded. Instead of using an operational procedure as the first step to correcting the problem, OUC will investigate permanent solutions such as new construction. As a short-term solution, operational remedies will continue to be used until new facilities can be put into service.

Table 4-1
Projected Reliability Levels – Winter

Calendar Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)	Total Peak Demand (MW)	Available Capacity (MW)				Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[6] (MW)
	OUC[1]	STC[1]			Installed[2]	Stanton A PPA[3]	TECO PR	Total	Required[4]	Available[5]	
2005/06	1,079	124	22	1,225	1,278	343	15	1,636	180	413	233
2006/07	1,110	130	0	1,240	1,257	343	15	1,615	186	377	191
2007/08	1,143	137	0	1,280	1,257	343	15	1,615	192	337	145
2008/09	1,175	143	0	1,318	1,257	343	15	1,615	198	299	102
2009/10	1,211	151	0	1,362	1,257	343	15	1,615	204	255	51
2010/11	1,248	158	0	1,406	1,257	343	15	1,615	211	211	0
2011/12	1,282	165	0	1,447	1,257	343	15	1,615	217	170	(47)
2012/13	1,317	172	0	1,489	1,257	343	0	1,600	223	111	(112)
2013/14	1,355	180	0	1,535	1,257	343	0	1,600	230	65	(165)
2014/15	1,391	187	0	1,578	1,257	343	0	1,600	237	22	(215)
2015/16	1,428	195	0	1,623	1,257	343	0	1,600	243	(23)	(266)
2016/17	1,466	202	0	1,668	1,257	343	0	1,600	250	(68)	(318)
2017/18	1,504	210	0	1,714	1,257	343	0	1,600	257	(114)	(371)
2018/19	1,542	218	0	1,760	1,257	343	0	1,600	264	(160)	(424)
2019/20	1,581	226	0	1,807	1,257	343	0	1,600	271	(207)	(478)
2020/21	1,620	234	0	1,854	1,257	343	0	1,600	278	(254)	(532)
2021/22	1,659	242	0	1,901	1,257	343	0	1,600	285	(301)	(586)
2022/23	1,699	250	0	1,949	1,257	343	0	1,600	292	(349)	(641)
2023/24	1,740	258	0	1,998	1,257	343	0	1,600	300	(398)	(698)
2024/25	1,780	266	0	2,046	1,257	343	0	1,600	307	(446)	(753)
2025/26	1,821	274	0	2,095	1,257	343	0	1,600	314	(495)	(809)
2026/27	1,863	282	0	2,145	1,257	343	0	1,600	322	(545)	(867)
2027/28	1,906	291	0	2,196	1,257	343	0	1,600	329	(596)	(926)
2028/29	1,949	299	0	2,249	1,257	343	0	1,600	337	(649)	(986)
2029/30	1,994	308	0	2,303	1,257	343	0	1,600	345	(703)	(1,048)

[1]Retail peak demand forecasts for 2006 through 2030 were extrapolated from the peak demand forecasts in Section 3.0 for OUC and St. Cloud.
[2]Includes OUC's equity portion of Stanton A, as well as St. Cloud's (STC's) diesel units, which are scheduled to retire in October 2006.
[3]Assumes the Stanton A PPA continues unchanged through the planning horizon. OUC has various capacity reduction and termination options related to the Stanton A PPA, as described in Section 2.2 of this Need for Power Application.
[4]Required reserves include 15 percent reserve margin on OUC retail peak demand and STC retail peak demand.
[5]Available reserves equal the difference between total available capacity and total peak demand, plus 15 percent of the TECO PR purchase.
[6]Calculated as the difference between available reserves and required reserves.

Table 4-2
Projected Reliability Levels – Summer

Calendar Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)	Total Peak Demand (MW)	Available Capacity (MW)				Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin(6) (MW)
	OUC(1)	STC(1)			Installed(2)	Stanton A PPA(3)	TECO PR	Total	Required(4)	Available(5)	
2006	1,081	120	22	1,223	1,220	322	15	1,557	180	336	156
2007	1,112	126	0	1,238	1,199	322	15	1,536	186	300	115
2008	1,145	133	0	1,278	1,199	322	15	1,536	192	260	69
2009	1,177	139	0	1,316	1,199	322	15	1,536	197	222	25
2010	1,213	146	0	1,359	1,199	322	15	1,536	204	179	(25)
2011	1,250	153	0	1,403	1,199	322	15	1,536	210	135	(75)
2012	1,285	160	0	1,445	1,199	322	15	1,536	217	93	(124)
2013	1,320	167	0	1,487	1,199	322	0	1,521	223	34	(189)
2014	1,357	174	0	1,531	1,199	322	0	1,521	230	(10)	(240)
2015	1,393	181	0	1,574	1,199	322	0	1,521	236	(53)	(289)
2016	1,431	189	0	1,620	1,199	322	0	1,521	243	(99)	(342)
2017	1,469	196	0	1,665	1,199	322	0	1,521	250	(144)	(394)
2018	1,507	203	0	1,710	1,199	322	0	1,521	257	(189)	(446)
2019	1,545	211	0	1,756	1,199	322	0	1,521	263	(235)	(498)
2020	1,584	219	0	1,803	1,199	322	0	1,521	270	(282)	(552)
2021	1,623	226	0	1,849	1,199	322	0	1,521	277	(328)	(605)
2022	1,663	234	0	1,897	1,199	322	0	1,521	285	(376)	(661)
2023	1,703	242	0	1,945	1,199	322	0	1,521	292	(424)	(716)
2024	1,743	250	0	1,993	1,199	322	0	1,521	299	(472)	(771)
2025	1,784	258	0	2,042	1,199	322	0	1,521	306	(521)	(827)
2026	1,825	266	0	2,091	1,199	322	0	1,521	314	(570)	(883)
2027	1,867	274	0	2,141	1,199	322	0	1,521	321	(620)	(941)
2028	1,910	282	0	2,192	1,199	322	0	1,521	329	(671)	(1,000)
2029	1,954	290	0	2,244	1,199	322	0	1,521	337	(723)	(1,060)
2030	1,999	299	0	2,298	1,199	322	0	1,521	345	(777)	(1,122)

(1)Retail peak demand forecasts for 2006 through 2030 were extrapolated from the peak demand forecasts in Section 3.0 for OUC and St. Cloud.
(2)Includes OUC's equity portion of Stanton A, as well as St. Cloud's (STC's) diesel units, which are scheduled to retire in October 2006.
(3)Assumes the Stanton A PPA continues unchanged through the planning horizon. OUC has various capacity reduction and termination options related to the Stanton A PPA, as described in Section 2.2 of this Need for Power Application.
(4)Required reserves include 15 percent reserve margin on OUC retail peak demand and STC retail peak demand.
(5)Available reserves equal the difference between total available capacity and total peak demand, plus 15 percent of the TECO PR purchase.
(6)Calculated as the difference between available reserves and required reserves.

5.0 Economic Evaluation Criteria and Methodology

This section presents the economic evaluation criteria and methodology used to demonstrate that Stanton B is part of OUC's least-cost capacity expansion plan to satisfy forecast capacity requirements throughout the 25 year evaluation period.

5.1 Economic Parameters

The economic parameters used in this analysis are summarized below and are presented on an annual basis. These parameters are applied consistently throughout this Need for Power Application.

5.1.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed operation and maintenance (O&M) escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.5 percent.

5.1.2 Cost of Capital

OUC uses a weighted average cost of capital for economic evaluations. The weighted average cost of capital is based on the debt/equity ratio (approximately 65/35), the embedded rate for new debt (projected to be 5.25 percent), and the return on equity (approximately 10.3 percent). OUC's weighted average cost of capital is approximately 7.0 percent.

5.1.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to OUC's weighted average cost of capital of 7.0 percent.

5.1.4 Interest During Construction Rate

The interest during construction (IDC) rate is assumed to be equal to the embedded debt rate of 5.25 percent.

5.1.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year FCR. The FCR calculation includes 0.10 percent for property insurance. Bond issuance fees and insurance costs are not included in the calculation of the levelized FCR, since these are already considered in OUC's embedded debt rate. Assuming a 30 year financing term, the resulting levelized FCR is 8.159 percent.

5.2 Fuel Price Forecast Methodology

Fuel price projections for coal, natural gas, and No. 2 fuel oil were developed for OUC by Energy Ventures Analysis, Inc. (EVA). The fuel price projections were provided for 2005 through 2030 for fuels currently being used by OUC, as well as for fuels that might be used by future units considered in the economic analysis described in Section 10.0.

Black & Veatch (B&V) has reviewed the forecasts developed in this section and believes that they are reasonable and appropriate for use in this Need for Power Application. However, developing meaningful long-range estimates can be difficult when dealing with volatile energy markets, such as those recently experienced. The fuel price forecasts in this section represent the base case forecasts used throughout this analysis; however, it should be recognized that actual fuel prices will differ from those outlined herein. This uncertainty is addressed in part by the fuel price sensitivities considered in Section 11.0.

5.2.1 Coal Price Forecast Methodology

EVA provided forecast prices for a variety of coals and coal types, including coals from every major commercial region in the United States plus imported coals. Forecasts were developed for Central Appalachian coals (ranging from very low sulfur to mid sulfur content), Northern Appalachian coals (including low, mid, and high sulfur content), PRB coals (very low sulfur content with both higher and lower heating values), and very low sulfur coals imported from Colombia and Venezuela. For each of the coal sources, EVA identified likely transportation modes and routes. In developing forecast transportation rates, EVA considered OUC's long-term rail contract, which specifies rates from most origins.

EVA's forecast of coal prices considered recent price increases compared to historical levels. These price increases were due to a number of factors. The price of eastern US coal rose because of the increased export of eastern US coal in response to rising international coal prices, a steady decline in eastern coal production capacity in response to previously low market prices, barriers to entry in the eastern US coal mining industry, and increased mining costs.

PRB coal prices also rose in 2005 because of various factors. Rail transportation disruptions reduced deliveries, causing a decrease in customer stocks and an increase in demand for 2006 delivery. Additionally, utilities in the eastern US switched to PRB coal in response to high costs for SO_2 emission allowances and higher prices for eastern US coals (as described previously). Overall, excess PRB capacity decreased because of previous capacity reductions and increased demand.

Prior to these events, EVA had forecasted rising coal prices. EVA further increased its price forecast to reflect rising production costs. However, the coal price forecasts provided by EVA assume that the current capacity shortage will be overcome by increased supply and prices will fall from their current elevated levels.

5.2.2 Natural Gas Price Forecast Methodology

The natural gas price forecast provided by EVA was based on an analysis of the supply and demand fundamentals for natural gas. The natural gas market in the United States is currently in a supply limited environment, with natural gas prices set by the marginal customer rather than the cost of supply. EVA's current position is that this supply limited environment and the associated high natural gas prices will continue into 2007. Beyond 2007, supply is expected to fill the supply and demand differential from various emerging resource areas, resulting in a decline in natural gas prices. The resource that is expected to have the greatest intermediate-term impact on natural gas prices is LNG. Imports of LNG are expected to increase because of a combination of scheduled first- and second-phase capacity expansions at existing US LNG terminals and a series of new LNG terminals in the United States.

Over the forecast period, the power sector will account for about 62 percent of the projected increased demand for natural gas. The expected increase in the power sector is the net result of two factors: projected economic growth (which drives electricity demand growth rates) and the recent dominance of natural gas fired units for capacity additions. Mitigating these factors will be the increased usage of coal fired, nuclear, and renewable capacity additions. Natural gas demand growth in other sectors is expected to be modest, primarily as a result of conservation in response to high fuel prices. Natural gas prices in Florida, with the exception of the transportation component, are affected by the same factors that impact natural gas prices throughout the United States.

5.2.3 Fuel Oil Forecast Methodology

EVA believes that world oil supplies will increase approximately 11.5 million barrels per day (MMBD) between now and the end of this decade. This projected increase, which should outpace increases in demand over the same period, is based on announced development projects. EVA's assessment is somewhat conservative, because other analysts believe the increase in supplies may be 5 MMBD higher. The increase in supplies forecast by EVA should enable the world oil market to restore spare capacity levels to the more acceptable 3 MMBD level.

Price-induced conservation has caused worldwide demand growth rates to decline from the record 3.2 percent, or 2.5 MMBD, realized in 2004. For the forecast period, demand is expected to grow at an average annual rate of 1.7 MMBD. Worthwhile to note is that China, India, and the United States will account for about 44 percent of the projected growth.

After 2015, the world will likely be 100 percent dependent on the Organization of Petroleum Exporting Countries (OPEC) for the incremental barrel, since non-OPEC production will begin to decline. In addition, all but six countries (Saudi Arabia, Iran, Iraq, Venezuela, the UAE, and Canada) will be at or past their peak production levels based on the current understanding of the world's reserve potential and industry technology. At such time, seven countries will account for 50 percent of the world's oil production, whereas the current 11 OPEC members account for 41 percent of worldwide oil production. Given such a scenario and based on the oil market's reaction to recent tight supply conditions, a significant (i.e., $15 to $20 per barrel) scarcity premium will likely reemerge in the later years of this forecast.

5.3 Fuel Price Forecasts

The following subsections present the annual price projections for coal, natural gas, and No. 2 fuel oil provided by EVA.

5.3.1 Coal

Low sulfur (1.8 lb SO_2/MBtu) Central Appalachian coal fuels the existing Stanton Units 1 and 2 and was assumed to be the fuel for the pulverized coal alternative considered in this analysis (described in Section 8.0). High sulfur (4.0 lb SO_2/MBtu) Northern Appalachian coal is used for the CFB alternative, while Stanton B will use PRB coal. The price forecasts (in real 2005 dollars) provided by EVA for these coals are presented in Table 5-1 and represent the delivered cost of coal, excluding railcars. Appendix B presents the forecasts for both commodity and transportation costs provided by EVA. OUC currently owns railcars for Stanton Units 1 and 2. The costs for railcars are accounted for separately in the capital cost estimates of the coal fired alternatives considered in this analysis, including Stanton B.

Table 5-1
Coal Price Forecasts (Delivered, Real 2005 \$/MBtu)

Calendar Year	Low Sulfur Central Appalachian (1.8 lb SO_2/MBtu, 12,500 Btu/lb)	High Sulfur Northern Appalachian (4.0 lb SO_2/MBtu, 13,000 Btu/lb)	High Btu Gillette PRB (0.8 lb SO_2/MBtu, 8,800 Btu/lb)
2006	2.77	2.38	2.50
2007	2.52	2.27	2.38
2008	2.53	2.37	2.43
2009	2.50	2.33	2.42
2010	2.49	2.32	2.44
2011	2.50	2.32	2.44
2012	2.52	2.32	2.43
2013	2.54	2.34	2.45
2014	2.55	2.35	2.45
2015	2.57	2.37	2.47
2016	2.59	2.37	2.46
2017	2.61	2.39	2.48
2018	2.71	2.49	2.66
2019	2.73	2.51	2.67
2020	2.75	2.52	2.67
2021	2.76	2.53	2.66
2022	2.79	2.55	2.68
2023	2.81	2.56	2.67
2024	2.84	2.58	2.68
2025	2.85	2.59	2.68
2026	2.87	2.59	2.67
2027	2.88	2.60	2.67
2028	2.90	2.61	2.66
2029	2.92	2.62	2.66
2030	2.94	2.63	2.65

5.3.2 Natural Gas

Natural gas is the primary fuel for Stanton A and OUC's Indian River combustion turbines, and will also be the primary fuel for the 1x1 7FA combined cycle alternative considered in this analysis (described in Section 8.0). The price forecast (in real 2005 dollars) provided by EVA for natural gas is presented in Table 5-2 and considers the Florida Gas Transmission (FGT) Zone 3 basis adder for Henry Hub, as well as fuel loss and usage charges. The methodology used to develop the natural gas transportation charges for delivery to the Stanton Energy Center is discussed in Section 5.4.

5.3.3 No. 2 Fuel Oil

No. 2 fuel oil is the secondary fuel for Stanton A as well as for OUC's Indian River combustion turbines, and will also be used as the primary fuel for the simple cycle combustion turbines considered in this analysis (described in Section 8.0). Forecasts for low sulfur No. 2 fuel oil (0.05 percent sulfur) provided by EVA (in real 2005 cents per gallon) are presented in Table 5-3.

5.4 Economic Evaluation Methodology

This section discusses the methodology applied by B&V to the fuel forecasts provided by EVA to develop the fuel costs used in the economic analysis in Section 10.0. Table 5-4, presented at the end of this section, presents the resulting fuel price projections used in the economic analysis of Stanton B.

5.4.1 Coal

EVA provided forecasts for low sulfur (1.8 lb SO_2/MBtu) Central Appalachian, high sulfur Northern Appalachian, and PRB coal. The Central Appalachian coal forecast is used for Stanton Units 1 and 2 as well as McIntosh Unit 3, and it has been assumed that this coal would be burned by the pulverized coal alternative described in Section 8.0. The Northern Appalachian coal was assumed to be burned by the CFB alternative. Stanton B will use the PRB coal. The nominal forecasts for these coal types are presented in Table 5-4 and were developed by applying the 2.5 percent annual inflation rate to the real delivered price projections provided by EVA.

Table 5-2
Natural Gas Price Forecast
(Real 2005 $/MBtu)

Calendar Year	Natural Gas[1] ($/MBtu)
2006	10.33
2007	7.33
2008	5.78
2009	5.73
2010	5.73
2011	5.74
2012	5.81
2013	5.87
2014	5.90
2015	5.97
2016	5.98
2017	5.95
2018	5.96
2019	5.97
2020	5.99
2021	6.03
2022	6.12
2023	6.21
2024	6.30
2025	6.40
2026	6.49
2027	6.58
2028	6.67
2029	6.76
2030	6.85

[1]Including FGT Zone 3 basis adder, fuel losses, and usage charges.

Table 5-3
No. 2 Fuel Price Forecast
(0.05 Percent Sulfur, Real 2005 Cents/Gallon)

Calendar Year	No. 2 Fuel Oil (cents/gallon)
2006	169.0
2007	140.3
2008	134.4
2009	134.4
2010	134.3
2011	135.7
2012	138.5
2013	141.3
2014	144.1
2015	146.9
2016	148.3
2017	149.7
2018	151.0
2019	152.4
2020	153.8
2021	155.2
2022	156.6
2023	158.0
2024	159.4
2025	160.8
2026	162.2
2027	163.7
2028	165.1
2029	166.5
2030	168.0

5.4.2 Natural Gas

B&V used the natural gas price forecast provided by EVA, which did not include delivery charges to the Stanton Energy Center. This is appropriate because OUC has already contracted for firm natural gas delivery for Stanton A and the Indian River combustion turbines through FGT. For the 1x1 7FA combined cycle considered in this analysis (described in Section 8.0), the FGT firm transportation service charges will be added as a fixed cost rather than included in the cost per MBtu of natural gas. Section 10.0 describes how the amount of incremental natural gas transportation capacity required for the combined cycle alternative was determined. The natural gas forecast presented in Table 5-4 was developed by applying the 2.5 percent annual inflation rate to the real natural gas price projections provided by EVA.

5.4.3 No. 2 Fuel Oil

EVA provided price projections for low sulfur No. 2 fuel oil (0.05 percent sulfur) on a cent per gallon basis, exclusive of delivery charges to the Stanton Energy Center. Based on recent historical information provided by OUC, a basis adder for delivery of fuel oil to Stanton Energy Center was developed. This adder was estimated to be $0.28 per barrel, or approximately 0.67 cents per gallon (assuming 42 gallons per barrel).

Low sulfur fuel oil would not likely meet the air permitting requirements of any new combustion turbine constructed by OUC. Ultra-low sulfur diesel (ULSD) will be required for vehicle use as early as June 2006, and power plants have recently been permitted on ULSD. Based on this information, it was determined that ULSD, with a sulfur content of 0.0015 percent, would be more appropriate for use in this analysis. B&V developed an incremental cost for ULSD that was added to the EVA projections of low sulfur No. 2 fuel oil. Data from the US Department of Energy's Energy Information Administration (EIA) was used to develop an incremental cost of approximately 6.1 cents/gallon.

After adjusting the EVA forecast to include the delivery adder and the incremental cost for ULSD, B&V converted the forecast prices (provided in cents/gallon) to $/MBtu by assuming a heat content of 140,000 Btu/gallon. The resulting annual forecasts were then converted from real 2005 dollars to nominal dollars, assuming the 2.5 percent annual inflation rate. The resulting fuel price forecasts are shown in Table 5-4.

5.4.4 Nuclear

EVA did not provide projections for nuclear fuel, which are required for OUC's ownership shares of St. Lucie Units 1 and 2 and Crystal River Unit 3. Section 8.0 includes a discussion of a new nuclear alternative. OUC provided historical prices for nuclear fuel, which B&V used as the basis for developing the forecasts presented in Table 5-4.

Table 5-4
Fuel Price Forecasts (Nominal $/MBtu)

Calendar Year	Low Sulfur Central Appalachian (1.8 lb SO_2/MBtu, 12,500 Btu/lb) - Delivered	High Sulfur Northern Appalachian (4.0 lb SO_2/MBtu, 13,000 Btu/lb) - Delivered	High Btu Gillette PRB (0.8 lb SO_2/MBtu, 8,800 Btu/lb) - Delivered	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur) - Delivered	Nuclear - Delivered
2006	2.84	2.44	2.57	10.58	15.60	0.50
2007	2.65	2.38	2.50	7.70	13.84	0.51
2008	2.72	2.55	2.61	6.23	13.73	0.523
2009	2.76	2.57	2.67	6.33	14.07	0.54
2010	2.82	2.62	2.76	6.48	14.42	0.55
2011	2.90	2.69	2.83	6.66	14.89	0.57
2012	2.99	2.76	2.89	6.90	15.50	0.58
2013	3.09	2.85	2.99	7.16	16.13	0.59
2014	3.18	2.93	3.06	7.37	16.79	0.61
2015	3.30	3.03	3.16	7.64	17.46	0.62
2016	3.39	3.11	3.23	7.84	18.03	0.64
2017	3.51	3.22	3.34	8.00	18.61	0.66
2018	3.73	3.43	3.66	8.22	19.22	0.67
2019	3.86	3.55	3.78	8.44	19.84	0.69
2020	3.98	3.65	3.87	8.67	20.47	0.71
2021	4.10	3.75	3.95	8.96	21.13	0.72
2022	4.25	3.88	4.07	9.32	21.81	0.74
2023	4.38	3.99	4.17	9.69	22.51	0.76
2024	4.53	4.12	4.29	10.08	23.23	0.78
2025	4.67	4.24	4.39	10.48	23.98	0.80
2026	4.82	4.36	4.49	10.89	24.74	0.82
2027	4.97	4.48	4.59	11.32	25.54	0.84
2028	5.12	4.61	4.70	11.76	26.35	0.86
2029	5.28	4.75	4.81	12.22	27.20	0.88
2030	5.45	4.88	4.92	12.70	28.07	0.90

6.0 Project Selection

OUC's decision to evaluate the economics of the proposed Stanton B project against other self-build capacity alternatives was based on a number of influencing factors, as discussed in the remainder of this section. A detailed description of Stanton B is presented in Section 7.0.

6.1 Clean Coal Power Initiative (CCPI)

The CCPI is managed by the US DOE's Office of Fossil Energy and was implemented by the National Energy Technology Laboratory. The CCPI was initiated by President Bush in 2002 as a demonstration program, with the ultimate goal of developing more efficient clean coal technologies for use in both new and existing power plants throughout the United States.

The CCPI was planned as a multi-year program, targeting technology developers, service corporations, research and development firms, energy producers, software developers, academia, and other interested parties. The CCPI requires that the private sector must share at least 50 percent of the cost of proposed projects, and the program is implemented in successive solicitations, or "rounds." The demonstrations selected must address needs not met by the private sector, promote technologies that have not been proven commercially, have fleet applicability, and provide substantial public benefit.

In August 2002, the DOE announced that it had received 36 proposals for projects with a total value of more than $5 billion in Round 1 of the CCPI. Projects were proposed in 20 states, and more than $1 billion was requested in federal cost-sharing. Of the 36 proposals received, approximately half were for advanced methods for reducing sulfur, nitrogen, and mercury pollutants.

In January 2003, the DOE announced that eight projects, with a total value of more than $1.3 billion, had been selected for federal funding in Round 1, with the DOE expected to contribute approximately $316 million and the private sector contributing the remainder. Three projects that were awarded DOE funding were based on compliance with President Bush's Clear Skies Initiative by reducing air pollution; three different projects were expected to reduce greenhouse gases (in line with President Bush's Global Climate Change Initiative), and the remaining two projects would attempt to reduce air pollution through advanced gasification and combustion systems to capitalize on the energy potential of waste coal piles in Pennsylvania and West Virginia.

In July 2004, the DOE announced that it had received 13 proposals for projects valued at nearly $6 billion in Round 2 of the CCPI. Proposals offered commercial demonstrations of coal gasification technology and improvements to efficiency, reliability, availability, environmental performance, and economic performance, as well as demonstration of potential technologies for management of carbon dioxide (CO_2). Other proposals involved mercury and multi-pollutant control technologies, efficiency improvements related to coal treatment and post-combustion technologies, as well as integrated combustion and control system advancements.

In October 2004, the DOE announced that four projects, with a total value of more than $1.8 billion, had been selected in Round 2, with the DOE expected to contribute approximately $297 million and the private sector contributing the remainder. Two of the projects selected in Round 2 of the CCPI will demonstrate multi-pollutant control technologies, while the other two projects, including the proposed Stanton B project, will demonstrate the next generation of integrated gasification combined cycle (IGCC) power plants.

In announcing the selection of the Stanton B project, Spencer Abraham, DOE Secretary of Energy, stated that the project, "…is a prime example of our Administration's effort to develop cutting-edge technologies to help meet our nation's future energy needs." Abraham further stated that, "Advancing the technology for clean coal will go a long way toward giving us [the United States] control of our energy future. And it will be an important part of safeguarding the environment for future generations."

Selection of the Round 2 projects was the result of an extremely competitive evaluation process. The Round 2 proposals were reviewed by 40 DOE technical evaluators. Given this evaluation process, as well as Secretary Abraham's statements quoted above, it is clear from the DOE's favorable response that the proposed Stanton B project is commercially viable and will become cost-effective (without DOE cost-sharing) as the technology develops.

6.2 Recent Statewide Capacity Solicitations

Additionally, OUC's decision on Stanton B was driven in part by the April 2005, Treasure Coast Energy Center Unit 1 (TCEC Unit 1) Need for Power Application (Docket No. 050256-EM) filed by FMPA. As part of the process of determining that TCEC Unit 1 represented its most cost-effective alternative available in compliance with Section 403.519, Florida Statutes, FMPA issued an RFP in September 2004. The RFP represented an invitation for qualified companies to submit proposals to supply capacity and energy to meet a portion of forecasted power requirements of FMPA's All-Requirements Project. Qualified bidders included electric utilities, independent power producers (IPPs), qualifying facilities (QFs), exempt wholesale generators, non-utility generators, and electric power marketers who have received certification by the Federal Energy Regulatory Commission (FERC).

As a result of the RFP, FMPA received bids from three companies with a total of four proposed plant configurations. The technologies offered included simple cycle power blocks, a 1x1 combined cycle configuration, and 2x1 combined cycle configurations. Although two of the proposals failed to satisfy the minimum requirements set forth in the RFP, FMPA carried forward all offers to its non-price factors and detailed economic evaluations.

FMPA's detailed economic evaluation indicated that the construction of a greenfield 1x1 combined cycle (TCEC Unit 1) would be more cost-effective than any of the proposals received. Furthermore, TCEC Unit 1 also compared favorably with the proposals with respect to contract flexibility, ability to dispatch, fuel risk, transmission technology, environmental effects, counterparty risks, credit risk, and construction schedule risk.

TCEC Unit 1 will be a 1x1 7FA combined cycle unit burning natural gas as its primary fuel, with No. 2 fuel oil as the backup fuel. Stanton B will also be a 1x1 7FA combined cycle unit, with modifications to the burners to allow the use of gasified coal as the primary fuel with the capability to operate on natural gas as well. The total project cost for TCEC Unit 1 (as presented in FMPA's April 2005, Need for Power Application) for 2008 commercial operation was estimated to be approximately \$217.7 million. As stated in the *Engineering, Procurement, and Construction Management Agreement Between Orlando Utilities Commission and Southern Power Company – Orlando Gasification LLC Respecting the Stanton Energy Center Combined Cycle Unit B Generating Facility* (the EPC Agreement) and described in Section 7.0, OUC will pay a guaranteed fixed price of [redacted] for the EPC portion of the 1x1 7FA combined cycle. OUC will be solely responsible for the additional costs related to the common facilities, which are expected to total approximately \$24.02 million, resulting in a total combined cycle project cost of [redacted] (in 2010 dollars). Once 2 years of escalation (assumed to be 2.5 percent annually) are added to the TCEC Unit 1 capital cost estimate to allow for a comparison in 2010 dollars, the estimated cost of the combined cycle portion of Stanton B would be approximately [redacted] less than that of TCEC Unit 1. Since Stanton B's combined cycle is lower in cost and the syngas produced further reduces costs, it can be concluded that Stanton B is the least-cost alternative when compared to the competitive marketplace.

6.3 Additional Considerations

OUC is confident with its decision to proceed with Stanton B for the reasons previously described. This confidence is bolstered by the fact that Stanton B will burn gasified subbituminous coal, or syngas, as its primary fuel, which is lower in cost per MBtu than natural gas. Figure 6-1 presents the costs for syngas and natural gas on a dollar per MBtu basis. The syngas costs include the levelized capital costs of the gasifier, OUC's demand payment described in Section 7.0, the cost for railcars discussed in Section 7.0, as well as incremental fixed and variable O&M costs. The incremental fixed and variable O&M costs were determined as the difference in cost for operating a natural gas fired 1x1 combined cycle unit. The natural gas price in Table 5-4 plus FGT's FTS-2 firm transportation rate was used as the basis for comparison. Figure 6-1 does not include the additional substantial benefit of the steam produced by the gasifier.

The discussion relative to the economics of constructing a 1x1 7FA combined cycle unit to this point has assumed operation on natural gas. With the inherent price volatility of natural gas, as evidenced by recent price spikes, OUC's ability to utilize the less expensive syngas in Stanton B will help to mitigate the risk of continued natural gas price volatility, while producing power in an environmentally conscious manner. In addition, Stanton B will diversify OUC's coal fuel supply by adding PRB subbituminous coal to its existing Central Appalachian bituminous coal resources. Such diversity also provides protection against fuel supply disruptions.

OUC has designed its generation system to take advantage of fuel diversity and the resulting system reliability and economic benefits. OUC's current winter generating capacity consists of approximately 60.4 percent bituminous coal, 5.2 percent nuclear, and 34.4 percent natural gas and fuel oil. The current summer generating capacity consists of approximately 62.9 percent bituminous coal, 5.3 percent nuclear, and 31.8 percent natural gas and fuel oil. The capability of Stanton B to burn both subbituminous coal-derived syngas and natural gas is consistent with the economic and fuel diversity aspects of OUC's generating system planning.

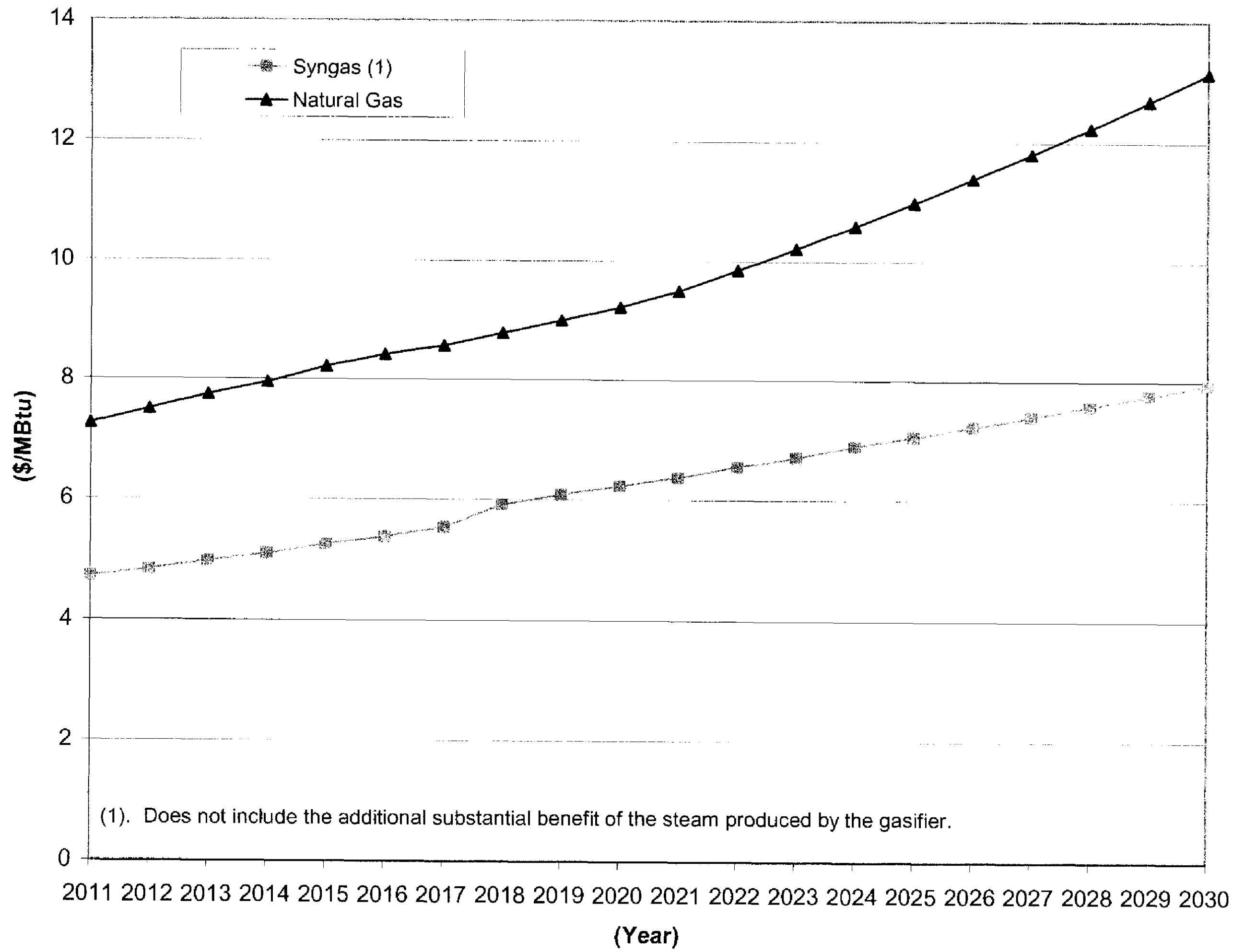


Figure 6-1
Cost per MBtu Comparison - Syngas and Natural Gas

7.0 Description of the Project

As described in Section 6.0, Stanton B is the result of a response to the US DOE's CCPI. On June 15, 2004, SCS submitted a proposal (on behalf of itself and its partners SPC, OUC, and KBR) for funding of an air blown Transport Gasification combined cycle demonstration project to be located at OUC's Stanton Energy Center. The demonstration project proposes to use Transport Gasifier technology developed by SCS, KBR, and the DOE over the past decade at the Power Systems Development Facility (PSDF) near Wilsonville, AL. The Transport Gasifier is derived from KBR's catalytic cracking technology that is used extensively in the petroleum industry. The gasifier will provide syngas to a 1x1 combined cycle power plant by gasifying subbituminous coal at a heat rate of approximately 8,500 Btu/kWh. Transport Gasifier technology offers the advantage of efficiently operating with low rank coals (such as PRB subbituminous) in comparison to other gasification technologies; the combined cycle unit will also be capable of firing natural gas.

On October 21, 2004, the US DOE officially announced that it had selected SCS and its partners, SPC, OUC, and KBR, for negotiation of a $235 million cost-sharing cooperative agreement under the CCPI. The gasifier will be jointly owned by OUC and SPC-OG, with OUC owning 35 percent and SPC-OG owning 65 percent; KBR will provide the technology used in the gasification process. SCS and SPC are subsidiaries of the Southern Company, a Fortune 500 company and one of the largest electric energy generators in the United States. SPC-OG and SCF are subsidiaries of SPC. The partners intend to proceed with project definition, design and construction, and commercial demonstration of Stanton B. The remainder of this section presents a more detailed description of Stanton B.

7.1 Description of the Stanton Energy Center

The Stanton Energy Center is a 3,280 acre power plant site located in Orange County, Florida near Orlando. Stanton Energy Center consists of three units and the necessary supporting facilities. Stanton Unit 1 is a pulverized coal unit that entered commercial operation on July 1, 1987. This unit is jointly owned by OUC, KUA, and FMPA. Stanton Unit 2 is a similar pulverized coal unit that entered commercial operation on June 1, 1996. Stanton Unit 2 is jointly owned by OUC and FMPA; OUC serves as the project manager and agent for both Stanton Units 1 and 2. Stanton A is a 2x1 natural gas fired combined cycle unit that entered commercial operation on October 1, 2003. Stanton A is jointly owned by SCF, OUC, KUA, and FMPA; it is operated and managed by SCF.

7.2 Transport Gasification Process and Syngas Supply

The proposed Stanton B will satisfy OUC's near-term needs for additional generation capacity and fuel diversity. In addition, Stanton B will demonstrate Transport Gasification technology on a commercial scale. Stanton B will be designed to fire either syngas or natural gas. Although the Transport Gasification will be demonstrated over a 4 year period, for evaluation purposes, it has been assumed that Stanton B will begin commercial operation on June 1, 2010, coincident with the beginning of the demonstration phase and the beginning of the availability guarantee presented in Section 7.10. Transport Gasification technology is unique in its ability to cost-effectively use lower rank coals with high moisture and higher ash content. Transport Gasification technology is air blown and includes the following systems, each of which is described in detail in this section, with an overall process flow diagram presented on Figure 7-1:

- Coal preparation and feeding.
- Gasifier.
- High temperature syngas cooling.
- Particulate collection.
- Low temperature gas cooling and mercury removal.
- Sulfur removal and recovery.
- Sour water treatment and ammonia recovery.
- Flare.

7.2.1 Coal Preparation and Feeding

Coal will be received using the existing coal receiving system and will be conveyed to a new stockout system. Coal will be taken from the live storage section of the pile and conveyed to the crusher shed for processing. At the crusher shed, coal will be screened, sampled, and crushed before being transported by conveyor to the crushed coal silos in the gasification process structure. A conveyor will transfer crushed coal from each storage silo to its dedicated pulverizer. Pulverizers will be of the roll mill crusher type and will use a recirculating hot inert gas to dry the coal. Pulverized coal will be collected and transferred to a surge bin, then fed to the gasifier as needed with a high-pressure coal feeder. The drying gas will be heated in a shell-and-tube heat exchanger with intermediate-pressure steam. Approximately 274,000 lb/h of PRB subbituminous coal will be used to produce syngas.

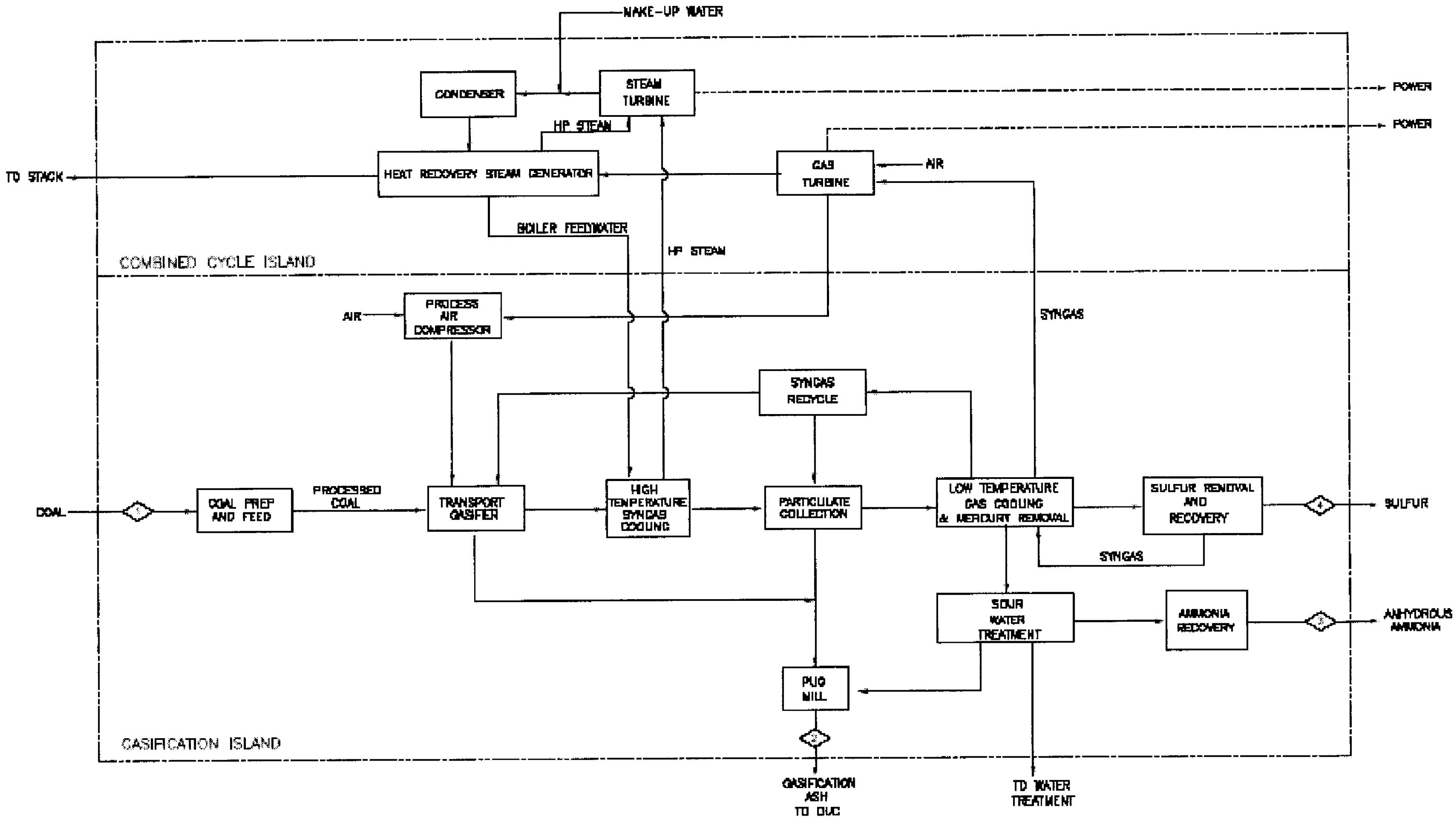


Figure 7-1
Process Flow Diagram

7.2.2 Gasifier

The Transport Gasifier will be approximately 160 feet tall and will be refractory lined with several sections. Pulverized coal and compressed air will be injected into the mixing zone or lower section of the riser and mixed with gasifier ash recycled through the J-valve. Approximately 25 percent of the compressed air requirement will be extracted from the combined cycle, while the remainder will be from process air compressors. Partial oxidation of the coal will occur within the gasifier, releasing heat to sustain gasifier operations and to form primarily carbon monoxide (CO). At the top of the gasifier, the particulate laden syngas will pass through two sections of the gasifier that will remove particulate and ash. The disengager will remove larger particles, while the cyclone will remove additional particulate. Gasification ash from the disengager will move by gravity down the standpipe to the J-valve. Gasification ash from the cyclone will be collected in the loop seal and also discharged into the standpipe. Once combined in the standpipe, the ash will be recycled to the mixing zone through the J-valve to increase carbon conversion of the process.

To maintain appropriate solids inventories within the gasifier, particulate and gasification ash will be removed from the lower standpipe area. Once removed, the gasification ash will be cooled by transferring heat to the condensate system, after which it will be depressurized. Syngas from the gasifier will be directed to the high temperature syngas cooling system. Figure 7-2 illustrates the major gasifier components.

7.2.3 High Temperature Syngas Cooling

Syngas from the gasifier cyclone will pass through the high temperature syngas cooler prior to being filtered. The cooler will generate high temperature, high-pressure superheated steam that will be combined with steam from the combined cycle heat recovery steam generator (HRSG) for use in the steam turbine generator (STG). The cooler will be fire tube heat exchangers with syngas flowing down through the vertical tube.

7.2.4 Particulate Collection

The next step in the syngas processing is particulate removal. Particulate can damage downstream equipment, including the gas turbine, and therefore must be removed. Rigid barrier type filter elements will be used for particulate removal. Two filter systems will remove ash. The gasification particulate ash will be cooled by transferring heat to the condensate system and then will be removed using a proprietary removal system. Recycled syngas will be used to periodically clean the filters.

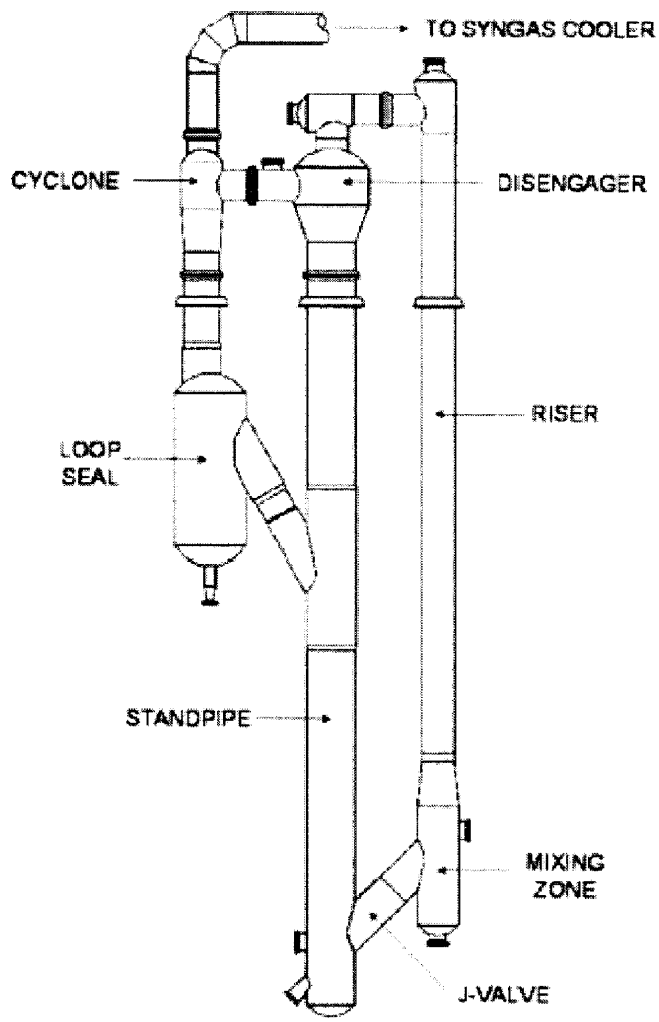


Figure 7-2
Major Gasifier Components

7.2.5 Low Temperature Syngas Cooling and Mercury Removal

Before the filtered syngas can be combusted in the combustion turbine, sulfur, mercury, and nitrogen based compounds must be decreased. Cooling the syngas facilitates the removal of these species, along with hydrocarbons, fluorides, and chlorides. Recuperative heat exchangers will be used to heat the syngas after the removal of these constituents to preserve thermal efficiency.

High and medium temperature coolers will reduce the temperature of the syngas to condense water and other hydrocarbons from the sour syngas. Water dissolves most nitrogen compounds, chloride, and fluoride with smaller amounts of CO_2, CO, hydrogen sulfide (H_2S), and carbonyl sulfide (COS). The aqueous condensables will be removed from the syngas in a knockout drum downstream of the coolers. The liquid waste stream will be sent to the sour water treatment system. An aqueous scrubber will further reduce ammonia and other constituents in the syngas. A COS hydrolysis unit will catalytically convert most of the COS to H_2S so that it can be removed in the sulfur removal system. This reaction will take place in an alumina-based catalyst. A second reactor with sulfur impregnated activated carbon will be used to remove mercury.

7.2.6 Sulfur Removal and Recovery

Syngas will leave the low temperature gas cooling and mercury removal systems at a temperature slightly above ambient. Syngas will be contacted with a solvent to remove a high percentage of sulfur in elemental form, which can be sold. The solvent will be regenerated and reused in the process. Sweet syngas will leave the contactor and be reheated in the recuperative heaters in the low temperature gas cooling system. Approximately 2 percent of the syngas will be extracted prior to reheating for use in cleaning the high temperature high pressure (HTHP) filters and for aeration within the gasifiers. At this point, the syngas will be ready for combustion in the combustion turbine.

7.2.7 Sour Water Treatment and Ammonia Recovery

Water will be collected from the coal preparation system, process air compressor intercoolers, low temperature syngas cooling system, and sulfur removal system and will be sent to the sour water treatment system. First, water will be filtered to remove particulate and then passed through an activated carbon bed to remove organic material. The water will then enter a degassing drum to remove light hydrocarbon gases, which will be sent to the vent gas recycle header. Filter cake and spent activated carbon will be collected for disposal.

The water will then be heated in a stripped water recuperator and passed to a heated H_2S stripper to remove H_2S, hydrogen cyanide, CO, and CO_2. These gases will also be passed into the vent gas recycle heater, compressed, and injected into the gasifier oxidation zone, where they will be consumed in the process. Water from the H_2S stripper will discharge to a steam heated ammonia stripper, where water will be further extracted to produce concentrated ammonia. Water extracted from this stripper will be recycled within the plant.

Two additional steam heated strippers will be used to concentrate the ammonia to commercial design specifications, producing commercial grade anhydrous ammonia that may be used within the Stanton Energy Center and/or sold to commercial markets. Commercial grade ammonia will be stored in a tank for periodic transportation by truck to commercial markets. Water from these strippers will also be recycled within the plant.

7.2.8 Flare

The final major system within the gasification unit is the flare. A multipoint flare system will be used to limit the visual impact from the flare. The multipoint flare will include multiple burners placed approximately 10 feet above the ground with a thermal barrier 20 feet tall. Natural gas will be used as a pilot fuel to keep the flare on standby at all times. During startup and plant upsets, syngas that is not used within the combustion turbine will be directed to the flare to be burned. The maximum flame height from the flare is expected to be approximately 40 feet.

7.3 Description of the Combined Cycle Unit

Stanton B will be a 1x1 F-class IGCC unit with a nominal rating of 283 MW on syngas and 229 MW on natural gas (at average ambient conditions). The unit will be installed at the Stanton Energy Center, which currently includes existing coal and gas fired generating units. This site was originally developed with consideration given to installing future units. Commercial operation of Stanton B is planned for June 1, 2010.

Stanton B will be primarily fueled by syngas derived from PRB coal in the Transport Gasifier, with the capability to burn natural gas as well. No fuel oil firing capability will be provided. The combustion turbine generator (CTG) will have an evaporative cooler to increase warm weather power generation and steam turbine bypass to the condenser for startup and upset conditions.

7.3.1 Mode of Operation

Subject to final approval by the Siting Board and the Florida Department of Environmental Protection (FDEP), Stanton B will be permitted for unlimited operation on natural gas and syngas. It is anticipated that Stanton B will operate as a baseload unit.

7.3.2 Combustion Turbine Generator

A number of manufacturers produce F-class combustion turbines. For evaluation purposes, the CTG was assumed to be a General Electric (GE) PG7241FA enhanced combustion turbine with modulating inlet guide vanes installed outdoors. The CTG will have enclosures for installation outdoors and will include the following major features:

- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Inlet air filter system and evaporative coolers.
- Lube oil systems.
- Static starting system.
- Steam injection system for power augmentation.
- Fire detection/CO_2 fire protection systems.
- Standard control and protection system.
- Off-line/on-line water wash system.
- Package electrical and electronics control compartment.

7.3.3 HRSG

The HRSG will be installed outdoors and will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG. The HRSG will be a three-pressure, reheat unit. A low-pressure economizer recirculation pump will be provided to maintain adequate HRSG exit gas temperatures to prevent corrosion. Cycle operating pressure will be a nominal 1,800 psig. Selective catalytic reduction (SCR) for NO_x emission control will be included within the HRSG. The HRSG will discharge to a metal exhaust stack approximately 205 feet in height. Two 100 percent capacity condensate pumps and boiler feedwater pumps will be included. Natural gas heating, utilizing a shell-and-tube heat exchanger with water from the HRSG feedwater as the heating source during normal operation and an electric heater for startup will be included.

7.3.4 Steam Turbine Generator

The STG will be a single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one high-pressure section with a nominal 1,800 psig throttle pressure, one intermediate-pressure section, and one low-pressure section. Turbine suppliers' standard auxiliary equipment, lubricating oil system, hydraulic oil system, and supervisory, monitoring, and control systems will be utilized. The steam turbine will be installed outdoors. Black start or emergency diesel generators will not be provided.

The steam turbine will exhaust axially into a horizontal, two-pass water cooled condenser. The surface condenser will condense steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. The condenser will be designed for full steam flow bypass around the steam turbine. A single synchronous generator will be included, which will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment, static excitation system, and supervisory, monitoring, and control systems will be utilized.

7.3.5 IGCC Startup

Stanton B will be designed to start in a load-serving manner or a cost-saving manner. If started in a load-serving manner, Stanton B will ramp to minimum load (from a cold start) in 5 hours to meet peak demand. If Stanton B is started in a cost saving manner, less natural gas will be used during startup and the unit will reach minimum load (from a cold start) in 26 hours. Starting Stanton B in a load-serving manner will generate 4,700 MWh of power during startup and will require 49,000 MBtu of natural gas. Starting the unit in a cost-saving manner will generate 900 MWh of power during startup and will require 17,500 MBtu of natural gas. Both types of startup require 15,000 MBtu of PRB coal as feedstock to produce syngas.

7.3.6 Cooling Water Systems

A six-cell, mechanical draft, counterflow cooling tower will be used for plant cooling. The cooling tower will be of fiberglass construction and will be installed on a reinforced concrete basin, which will include a pump intake structure housing two 50 percent capacity circulating water pumps and two 100 percent capacity auxiliary circulating water pumps. The auxiliary closed loop cooling water system will include three 50 percent capacity plate and frame type heat exchangers. A circulating water chemical feed system will also be included. The cooling tower will be equipped with drift eliminators.

7.3.7 Air Quality Control

Stanton B will be subject to FDEP's Prevention of Significant Deterioration (PSD) permitting program, which requires Best Available Control Technology (BACT) for the emissions of various pollutants. The combined cycle unit will include post-combustion emissions controls. Moreover, SCR will be demonstrated during the demonstration phase to further reduce NO_x emissions. Taken together, these design features will make Stanton B one of the most efficient and lowest polluting coal fired power plants in the United States. For purposes of the economic analysis, the estimated emissions from Stanton B are presented in Table 7-1. The actual permitted emissions rates have not been established; however, such permitted rates shall not exceed the estimated average emission rates presented in Table 7-1.

Table 7-1
Stanton B Emissions Rates
(Full Load, Average Conceptual Design Conditions)

NO_x	
Syngas	0.07 lb/MBtu
Natural Gas	0.018 lb/MBtu
SO_2	
Syngas	0.04 lb/MBtu
Natural Gas	0.0006 lb/MBtu
Hg	
Syngas	1.7 lb/TBtu
Natural Gas	0.00 lb/TBtu

7.3.8 Control System

The unit will be designed for control through a plant distributed control system (DCS). A Mark VI control system for control of the turbine will also be included. The DCS control cathode ray tube (CRT) monitors will be located in the main plant control room that will be in a new onsite administration/control building at the combined cycle unit.

7.3.9 Water Use

Water for cooling tower makeup will be reclaimed water (treated wastewater). Reclaimed water will be supplied by OUC at the combined cycle plant boundary from the existing Eastern Water Reclamation Facility, Orange County wastewater treatment plant. A maximum of 2.6 million gallons per day (mgd) of makeup water is expected to be required for Stanton B. The majority of this water supply will be for cooling tower makeup, which will utilize treated effluent.

Demineralizer water makeup and potable water will be supplied from existing OUC systems, which utilize ground water from onsite wells. Service, fire water, and evaporative cooler makeup will also be supplied from existing OUC systems, which use reclaimed water. Average ground water use is expected to be 0.18 mgd for Stanton B, which is within Stanton Energy Center's existing permit limit. Two water storage tanks will be provided. A 350,000 gallon demineralized water storage tank and a 300,000 gallon filtered water storage tank will be provided for the combined cycle plant.

7.3.10 Plant Process Wastewaters

There will be five major sources of wastewater: sanitary waste, HRSG blowdown, oil/water separator effluent, cooling tower blowdown, and other plant wastewaters from the combined cycle unit. Sanitary wastewaters will be directed to a new onsite septic system. HRSG blowdown will be routed to the cooling tower basin. Wastewaters with the potential for oil contamination will be routed to a new oil/water separator. Effluent from the oil/water separator and other combined cycle plant wastewaters will be combined and discharged to OUC's existing recycle basin. Cooling tower blowdown will be routed separately to the existing zero-discharge wastewater system.

Gasification wastewaters will consist of oil/water separator effluent, sanitary wastes, and rainwater runoff. Sanitary wastes will be directed to the combined cycle septic system. Rainwater runoff will be collected and sent to the existing Stanton Energy Center collection pond and then discharged to natural drainage courses. Oil/water separator effluent will be discharged to the combined cycle waste water system.

7.3.11 Storm Water Management

Storm water system design will be in accordance with FDEP, St. John's River Water Management District (SJRWMD), and Orange County requirements. The site will be graded for sheet flow storm water runoff directed to existing detention ponds. New detention ponds for the combined cycle plant or the gasification plant will not be required.

7.3.12 Transmission Interconnection

The combined cycle plant will be interconnected to OUC's 230 kV transmission system at the Stanton 230 kV transmission substation. The CTG and STG will each connect to separate 18 kV/230 kV generator step-up transformers. Auxiliary power will be provided by the auxiliary transformer, which will be fed from the high side of the collector bus. A new 230 kV transmission line approximately 0.65 mile in length located entirely on the existing Stanton site will connect the combined cycle plant collector bus switchyard to the existing Stanton 230 kV transmission substation.

7.3.13 Conceptual Design Conditions

Table 7-2 presents the conceptual design conditions for Stanton B.

Table 7-2
Conceptual Design Conditions for Stanton B

Condition	Value or Range
Maximum Temperature/Coincident Relative Humidity	100° F/47%
Minimum Temperature/Coincident Relative Humidity	19° F/100%
Average Temperature/Coincident Relative Humidity	70° F/76.5%
Site Elevation	Approximately 82 ft above mean sea level (MSL)
Location	Orlando, Florida

7.3.14 Site Arrangement

Figure 7-3 presents the arrangement and locations of the major equipment at the Stanton Energy Center.

7.3.15 Water Mass Balance

Figure 7-4 presents the conceptual water mass balance for Stanton B.

7.3.16 One-Line Diagram

Figure 7-5 presents the conceptual electrical one-line diagram of the electrical interconnections to the existing transmission system and electrical power distribution for Stanton B.

7.3.17 SCR Ammonia System

Ammonia will be required for NO_x control when SCR is in service. Anhydrous ammonia will be used and will be delivered to the site by tanker trucks (which include integral unloading pumps) or supplied from the gasification unit. The onsite ammonia system will include unloading facilities, ammonia storage tank, forwarding system, and vaporizing facilities. Vaporized ammonia will be injected into the combustion turbine exhaust gases prior to passage through the catalyst bed, which is installed in the HRSG.

STATE OF FLORIDA

OFFICE OF COMMISSION CLERK
ANN COLE
COMMISSION CLERK

Public Service Commission

* *

Docket No. : 060155-EM

Docket Title: Petition for determination of need for proposed Stanton Energy Center Combined Cycle Unit 8 electrical power plant in Orange County, by Orlando Utilities Commission

DN 01527-06: FIGURE 7-3, MAP OF GENERAL SITE ARRANGEMENT

[CLK NOTE: MAP PORTION OF TESTIMONY EXHIBIT CAN BE FOUND IN MAPS MICROFILM.]

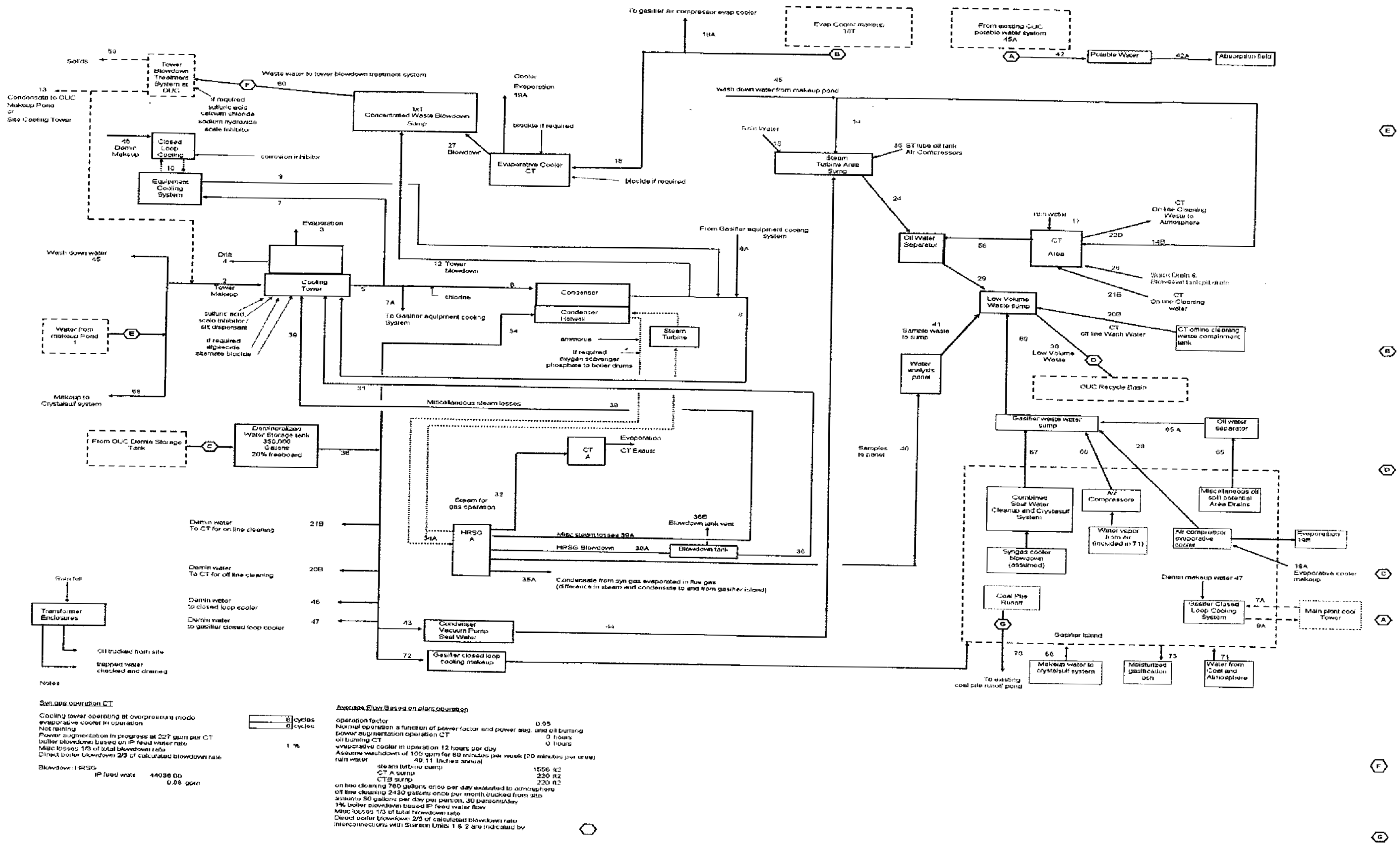


Figure 7-4
Water Mass Balance

Flow Calculation

Line No	Stream	CT syn gas Scenario Flow gpm	CT gas Scenario Flow gpm	Continuous 24 hour yearly Flow gpm	Average Flow yearly 24 hour flow based on plant operation	
	Flows are block flows unless otherwise noted					
1	Makeup water from OUC makeup pond	1853.2	1853.0	1853.21	1853.38	flow for site
1T	Total makeup water from OUC make pond	1853.2	1853.0	1853.21	1853.38	flow for site
2	Main Cooling tower makeup	1850.7	1850.5	1850.71	1850.70	flow per block
2T	Total site cooling tower makeup	1850.7	1850.5	1850.71	1850.70	flow for site
3	Cooling tower evaporation	1829.0	1829.0	1829.00	1829.00	flow per block
3T	Total site cooling tower evaporation	1829.0	1829.0	1829.00	1829.00	flow for site
4	Cooling tower drift	4.3	4.3	4.30	4.30	flow per block
4T	Total site cooling tower drift	4.3	4.3	4.30	4.30	flow for site
5	Circulating water pump discharge	86000.0	86000.0	86000.00	86000.00	flow per block
6	Condenser inlet	70000.0	70000.0	70000.00	70000.00	flow per block
7	Cooling water to equipment cooling water system	6000.0	6000.0	6000.00	6000.00	flow per block
7A	Cooling water to gasifier cooling water system	10000.0	10000.0	10000.00	10000.00	
7T	Spare					flow for site
8	Condenser and service water cooler discharge to tower	85772.0	85772.0	85772.00	85772.00	flow per block
9	Equipment cooling system return hot water form service water system	6000.0	6000.0	6000.00	6000.00	flow per block
9A	Equipment cooling system return hot water from gasifier	10000.0	10000.0	10000.00	10000.00	
9T	Spare					flow for site
10	Closed loop cooling flow	9500.0	9500.0	9500.00	9500.00	flow per block
11	spare					flow per block
11T	spare					flow for site
12	Cooling tower blowdown	228.0	228.0	228.00	228.00	flow per block
12T	Total site cooling tower blowdown	228.0	228.0	228.00	228.00	flow for site
13	Waste treatment condensate to OUC makeup pond or site tower	206.3	206.3	206.74	208.29	flow per block
13T	Spare					flow for site
14	Makeup pond water to steam turbine area for wash down	0.0	0.0	0.00	0.00	flow per block
14A	Spare					
14b	Makeup pond water to CT area	0.0	0.0	0.00	0.19	flow per block
15	Rain water to steam turbine area	0.0	0.0	0.00	0.09	flow per block
16	Spare					flow per block
17	Rain water to CT area	0.0	0.0	0.00	0.01	flow per block
17T	Total contained rain water	0.0	0.0	0.00	0.10	
18	Makeup water to CT evaporative cooler	27.4	27.4	13.71	27.43	flow per block
18A	gasifier air compressor evap cooler makeup	12.0	12.0	6.00	12.00	
18T	Total evap cooler makeup from OUC site	39.4	39.4	19.71	39.43	
19A	CT evaporative cooler evaporation	24.0	24.0	12.00	24.00	flow per block
19B	Crystalizer air compressor evap cooler evaporation	10.5	10.5	5.25	10.50	
19T	Total site evaporative cooler evaporation	34.5	34.5	17.25	34.50	flow for site
20A	Spare					flow per block
20B	CT off line cleaning wash water	0.0	0.0	0.06	0.05	flow per block
21A	Spare					flow per block
21B	CT on line wash water	0.0	0.0	0.54	0.51	flow per block
21T	Total site on line wash water	0.0	0.0	0.54	0.51	flow for site
22A	Spare					
22B	On line wash water to atmosphere	0.0	0.0	0.54	0.51	flow per block
23	Spare					
24	Steam turbine area to oil water separator	5.0	5.0	5.00	5.09	flow per block
25	Spare					
26	CT stack drain and blowdown tank pit drain	0.0	0.0	0.00	0.00	flow per block
27	CT evap cooler blowdown	3.4	3.4	1.71	3.43	flow per block
28	Crystalizer air compressor evap cooler blowdown	1.5	1.5	0.75	1.50	
29	Oil water separator to low volume sump	5.0	5.0	5.00	5.29	flow per block
30	Low volume waste to OUC recycle basin	133.6	133.6	132.93	133.98	flow for site
31	Total block boiler blow down	0.6	0.6	0.6	0.8	flow for site
32	Steam for gas burn for CT	0.0	334.5	0.00	20.10	flow per block
33	Spare					flow per block
33T	Total site power augmentation and CTB gas burn to atmosphere	0.0	334.5	0.00	20.10	flow for site
34	Makeup to Condenser Hotwell	50.3	355.6	50.3	68.6	flow per block
34a	Makeup for losses at HRSG	50.3	355.8	50.27	68.62	flow per block
34b	Spare					flow per block
35	Steam turbine lube oil tank and Air Compressors	0.0	0.0	0.00	0.00	flow per block
35A	Condensate from syn gas evaporated in flue gas	29.4	0.0	29.39	27.62	
36	HRSG Blowdown to tower	0.59	0.82	0.58	0.60	flow per block
36A	HRSG Blowdown	0.88	1.22	0.88	0.90	
36B	HRSG blowdown tank vent	0.29	0.40	0.29	0.30	
37	Spare					
37A	Spare					flow per block
37B	Spare					
38	Demin. water to process	55.3	380.8	55.87	74.19	flow per block
38T	Total site demin water to process	55.3	380.8	55.87	74.19	flow for site
39	Total HRSG miscellaneous losses	10.0	10.0	10.00	10.00	flow per block
39A	HRSG misc. losses	10.0	10.0	10.00	10.00	flow per block
39B	Spare					
40	Water analysis panel waste	10.0	10.0	10.00	10.00	
41	Panel waste to low volume sump	10.0	10.0	10.00	10.00	flow per block
42	Potable water to block from potable water supply	17.0	17.0	0.21	0.59	flow per block
42T	Potable water to site from potable water supply	17.0	17.0	0.21	0.59	flow for site
42A	Sewage to treatment from block	17.0	17.0	0.21	0.59	
42TA	Sewage to treatment for site	17.0	17.0	0.21	0.59	
43	Condenser vacuum pump seal water makeup	5.0	5.0	5.00	5.00	flow for site
44	Condenser vacuum pump seal water waste	5.0	5.0	5.00	5.00	flow per block
45	washdown water	0.0	0.0	0.00	0.19	flow per block
45A	From existing OUC potable/service water system	17.0	17.0	0.21	0.59	flow per block
46	CC Closed loop cooling water makeup	0.0	0.0	0.00	0.00	
47	Gasifier closed loop cooling water makeup	0.0	0.0	0.00	0.00	flow per block
48	Spare					
49	Spare					
50T	Spare					
51	Fire Protection water to site	0.0	0.0	0.00	0.00	flow per block
52	Spare					flow per site
53	Spare					flow per block/site
54	Spare					
55	Spare					
56	CT - A area sump to oil water separator	0.0	0.0	0.00	0.20	flow per block
57	Spare					
58	Spare					
59	Water in solids to land fill	23.1	23.1	22.97	23.14	flow per site
60	Conc. Waste sump to OUC tower blowdown sump	231.4	231.4	229.71	231.43	flow per site
61	Spare					
62	Spare					
63	Spare					
64	Spare					
65	Gasifier misc oil spill potential area drains to oil water separator	0.0	0.0			
65A	Gasifier misc oil spill potential area drains to oil water separator	0.0	0.0	0.00	0.00	
66	Gasifier air compressors	18.1	18.1	18.12	18.12	
67	Gasifier CrystaSulf and sour water cleanup combined waste	99.0	99.0	99.00	99.00	
68	Gasifier crystalsulf makeup	2.5	2.5	2.50	2.50	
69	Gasifier waste water sump to low volume waste sump	118.6	118.6	117.87	118.82	
70	Gasifier coal pile runoff to existing coal pile runoff pond	0.0	0.0	0.00	0.00	
71	Water Addition from the Coal and atmosphere	139.2	139.2	139.22	139.22	
72	Demin water makeup to gasifier Island closed loop cooling	0.0	0.0	0.00	0.00	
73	Moisturized gasification ash	24.6	24.6	24.60	24.60	
		2104.13	2409.39	2068.22	2106.92	total in
		2104.13	2409.39	2068.22	2106.92	total out
		0.00	0.00	0.00	0.00	difference

Average flow operating assumption

Operating factor		0.95	of a year
hours in year		8760	hours
hours CTA oil	d	0	hours
hours CTA power aug	b	0	hours
hours CTB gas	c	500	hours
hours syn operation	a	7872	hours
total hours in operation		8322	hours

Line No.	Stream	Average Flow yearly 24 hour flow based on plant operation gpm	syngas Scenario Flow gpm
	Flows are block flows unless otherwise noted		
1	Makeup water from OUC makeup pond	1853.4	1853.2
1T	Total makeup water from OUC make pond	1853.4	1853.2
2	Main Cooling tower makeup	1850.7	1850.7
2T	Total site cooling tower makeup	1850.7	1850.7
3	Cooling tower evaporation	1829.0	1829.0
3T	Total site cooling tower evaporation	1829.0	1829.0
4	Cooling tower drift	4.3	4.3
4T	Total site cooling tower drift	4.3	4.3
5	Circulating water pump discharge	86000.0	86000.0
6	Condenser inlet	70000.0	70000.0
7	Cooling water to equipment cooling water system	6000.0	6000.0
7A	Cooling water to gasifier cooling water system	10000.0	10000.0
7T	Spare	0.0	0.0
8	Condenser and service water cooler discharge to tower	85772.0	85772.0
9	Equipment cooling system return hot water form service water system	6000.0	6000.0
9A	Equipment cooling system return hot water from gasifier	10000.0	10000.0
9T	Spare	0.0	0.0
10	Closed loop cooling flow	9500.0	9500.0
11	spare	0.0	0.0
11T	spare	0.0	0.0
12	Cooling tower blowdown	228.0	228.0
12T	Total site cooling tower blowdown	228.0	228.0
13	Waste treatment condensate to OUC makeup pond or site tower	208.3	206.3
13T	Spare	0.0	0.0
14	Makeup pond water to steam turbine area for wash down	0.0	0.0
14A	Spare	0.0	0.0
14b	Makeup pond water to CT area	0.2	0.0
15	Rain water to steam turbine area	0.1	0.0
16	Spare	0.0	0.0
17	Rain water to CT area	0.0	0.0
17T	Total contained rain water	0.1	0.0
18	Makeup water to CT evaporative cooler	27.4	27.4
18A	gasifier air compressor evap cooler makeup	12.0	12.0
18T	Total evap cooler makeup from OUC site	39.4	39.4
19A	CT evaporative cooler evaporation	24.0	24.0
19B	Crystalizer air compressor evap cooler evaporation	10.5	10.5
19T	Total site evaporative cooler evaporation	34.5	34.5
20A	Spare	0.0	0.0
20B	CT off line cleaning wash water	0.1	0.0
21A	Spare	0.0	0.0
21B	CT on line wash water	0.5	0.0
21T	Total site on line wash water	0.5	0.0
22A	Spare	0.0	0.0
22B	On line wash water to atmosphere	0.5	0.0
23	Spare	0.0	0.0
24	Steam turbine area to oil water separator	5.1	5.0
25	Spare	0.0	0.0
26	CT stack drain and blowdown tank pit drain	0.0	0.0
27	CT evap cooler blowdown	3.4	3.4
28	Crystalizer air compressor evap cooler blowdown	1.5	1.5
29	Oil water separator to low volume sump	5.3	5.0
30	Low volume waste to OUC recycle basin	134.0	133.6
31	Total block boiler blow down	0.8	0.6
32	Steam for gas burn for CT	20.1	0.0
33	Spare	0.0	0.0
33T	Total site power augmentation and CTB gas burn to atmosphere	20.1	0.0
34	Makeup to Condenser Hotwell	68.6	50.3
34a	Makeup for losses at HRSG	68.6	50.3
34b	Spare	0.0	0.0
35	Steam turbine lube oil tank and Air Compressors	0.0	0.0
35A	Condensate from syn gas evaporated in flue gas	27.6	29.4
36	HRSG Blowdown to tower	0.6	0.6
36A	HRSG Blowdown	0.9	0.9
36B	HRSG blowdown tank vent	0.3	0.3
37	Spare	0.0	0.0
37A	Spare	0.0	0.0
37B	Spare	0.0	0.0
38	Demin. water to process	74.2	55.3
38T	Total site demin water to process	74.2	55.3
39	Total HRSG miscellaneous losses	10.0	10.0
39A	HRSG misc. losses	10.0	10.0
39B	Spare	0.0	0.0
40	Water analysis panel waste	10.0	10.0
41	Panel waste to low volume sump	10.0	10.0
42	Potable water to block from potable water supply	0.6	17.0
42T	Potable water to site from potable water supply	0.6	17.0
42A	Sewage to treatment from block	0.6	17.0
42TA	Sewage to treatment for site	0.6	17.0
43	Condenser vacuum pump seal water makeup	5.0	5.0
44	Condenser vacuum pump seal water waste	5.0	5.0
45	washdown water	0.2	0.0
45A	From existing OUC potable/service water system	0.6	17.0
46	CC Closed loop cooling water makeup	0.0	0.0
47	Gasifier closed loop cooling water makeup	0.0	0.0
48	Spare	0.0	0.0
49	Spare	0.0	0.0
50T	Spare	0.0	0.0
51	Fire Protection water to site	0.0	0.0
52	Spare	0.0	0.0
53	Spare	0.0	0.0
54	Spare	0.0	0.0
55	Spare	0.0	0.0
56	CT - A area sump to oil water separator	0.2	0.0
57	Spare pounds per minute	0.0	0.0
58	Spare	0.0	0.0
59	Water in solids to land fill	23.1	23.1
60	Conc. Waste sump to OUC tower blowdown sump	231.4	231.4
61	Spare	0.0	0.0
62	Spare	0.0	0.0
63	Spare	0.0	0.0
64	Spare	0.0	0.0
65	Gasifier misc oil spill potential area drains to oil water separator	0.0	0.0
65A	Gasifier misc oil spill potential area drains to oil water separator	0.0	0.0
66	Gasifier air compressors	18.1	18.1
67	Gasifier CrystaSulf and sour water cleanup combined waste	99.0	99.0
68	Gasifier crystalsulf makeup	2.5	2.5
69	Gasifier waste water sump to low volume waste sump	118.6	118.6
70	Gasifier coal pile runoff to existing coal pile runoff pond	0.0	0.0
71	Water Addition from the Coal and atmosphere	139.2	139.2
72	Demin water makeup to gasifier island closed loop cooling	0.0	0.0
73	Moisturized gasification ash	24.6	24.6
		2106.9	2104.1 total in
		2106.9	2104.1 total out
		0.0	0.0 difference

Figure 7-4 (continued)
Water Mass Balance

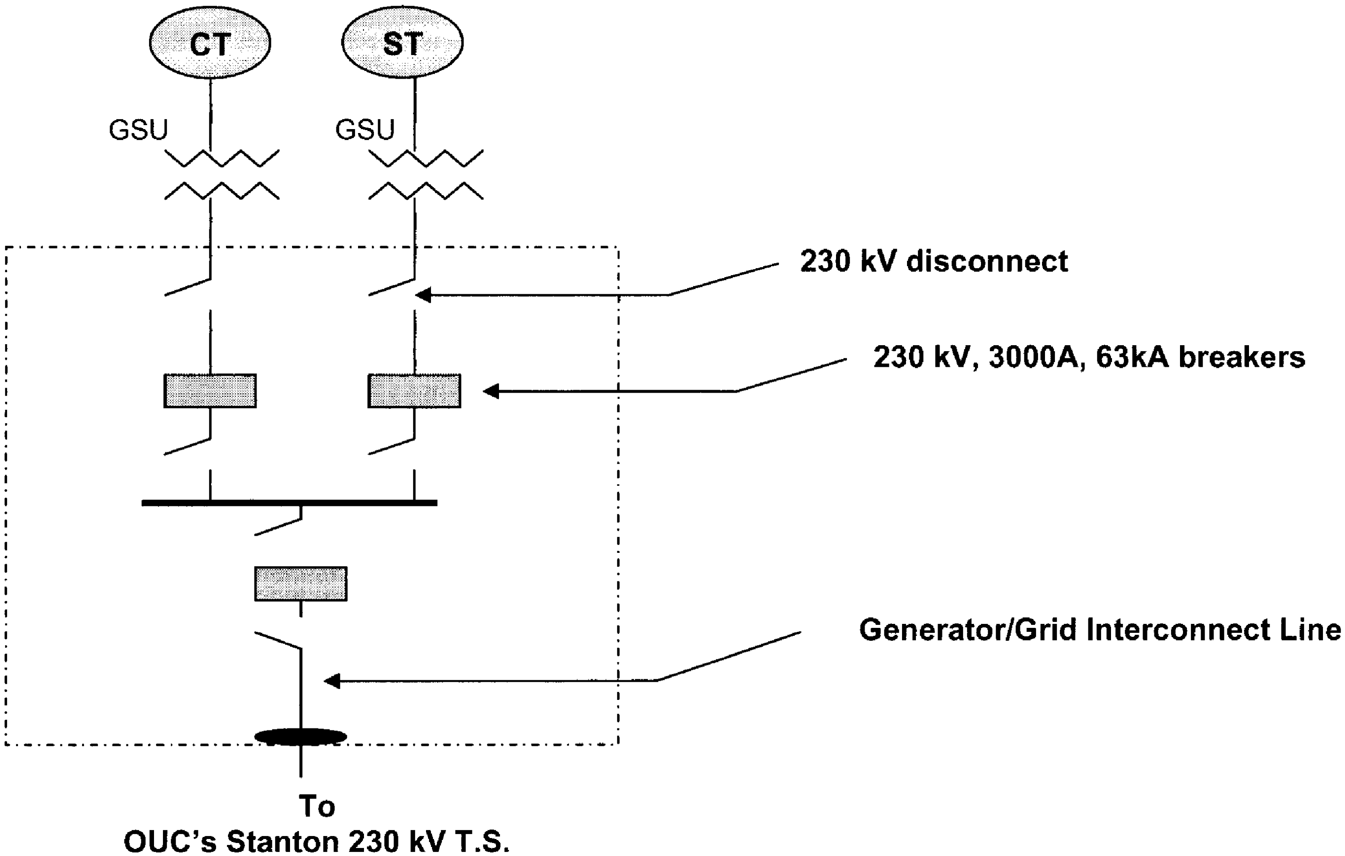


Figure 7-5
One-Line Diagram

7.4 Fuel Supply

OUC will be responsible for providing fuel for Stanton B. The fuel for Stanton B will be either syngas produced in the gasifier or natural gas. Syngas will be cleaned at the gasification plant prior to being burned in the combustion turbine. PRB coal will be the feedstock for the gasification plant to produce syngas.

Natural gas will be provided via the existing lateral into the FGT system. Gas compressors will not be required. Two full-capacity natural gas scrubbers/filters will be provided to remove impurities and condensate from the natural gas prior to it entering the combustion turbine.

7.4.1 Fuel Quantities

Hourly fuel consumption rates will depend on plant load, ambient conditions, and fuel type. Table 7-3 provides indicative estimates of average fuel consumption rates.

Table 7-3
Indicative Hourly Fuel Consumption Rates

Description of Operating Mode	Quantity
Average full load coal consumption, tph (8,760 Btu/lb coal)	137
Average full load syngas production, tph (125.7 MBtu/scf)	450
Average full load natural gas consumption, MBtu/h	1,800

7.4.2 Fuel Transportation, Delivery, and Metering

Natural gas will be delivered to the site by OUC from the existing Stanton Energy Center pipeline that interconnects with FGT and will be regulated, metered, and conditioned onsite. A new meter run and natural gas conditioning equipment will be installed. The natural gas conditioning equipment for the combined cycle plant will include two 100 percent fuel gas scrubbers, two filters, and a performance fuel gas shell and tube heater. Natural gas will also be provided to the gasifier via the existing Stanton Energy Center pipeline for use as flare pilot fuel and gasifier startup fuel.

PRB coal will be delivered to the existing unloading system that is used for Stanton Units 1 and 2. A new conveyor and stockout system will be installed. Approximately two to three unit trains per week will be required for continuous full load operation. Coal will be screened, crushed, and pulverized prior to delivery to the gasification plant coal storage silos.

7.5 DOE Funding for Stanton B

The proposed Stanton B project will be executed in four phases: project definition, design, construction, and demonstration. However, it will be funded in three budget periods consisting of project definition, design/construction, and demonstration, which will each be partially funded by the DOE. The demonstration period costs will occur after the start of commercial operation on syngas. The demonstration phase costs and associated DOE funding will be reflected in the economic analysis presented in Section 10.0.

The capital cost of Stanton B includes the costs of the gasification island, the costs of the combined cycle, and OUC's additional costs. The DOE awarded the right to negotiate a cooperative agreement to provide cost-sharing up to $235 million to offset costs associated with the design, construction, and demonstration of the gasification island. The gasification island will be 65 percent owned by SPC-OG and 35 percent owned by OUC. The cost of the gasification island includes the project definition, design/construction, and demonstration phases and is expected to total approximately $557 million, of which approximately $322 million will be funded by SPC-OG and OUC.

OUC will have 100 percent ownership of the combined cycle portion of Stanton B. Pursuant to the *Engineering, Procurement and Construction Management Agreement Between Orlando Utilities Commission and Southern Power Company – Orlando Gasification LLC Respecting the Stanton Energy Center Combined Cycle Unit B Generating Facility* (the EPC Agreement), SPC-OG will construct the combined cycle for a fixed EPC price of [redacted]. OUC will incur additional costs that are outside the gasification island and combined cycle scope of work. The additional costs are estimated to be $24.020 million (in 2010 dollars) and are summarized in Table 7-4. In addition, railcars for Stanton B are estimated to cost $27.734 million and will be purchased by OUC in 2010.

As stated in the *Orlando Gasification Project Construction and Ownership Participation Agreement Between Southern Power Company – Orlando Gasification LLC and Orlando Utilities Commission* (the Participation Agreement), SPC-OG and OUC have agreed to jointly fund a Process Development Allowance (PDA) of [redacted] to fund plant modifications and improvements following mechanical completion of the combined cycle portion of the project. OUC's obligation for this fund is [redacted], or 35 percent of the total PDA. This fund will be used for reliability, efficiency, and capacity improvements to the gasifier. While SPC-OG and OUC are obligated to

Table 7-4
Estimated OUC Additional Costs for Stanton B

Additional Cost Item	Cost (2010 $)
Project Development	
Preliminary engineering	$290,000
Licensing and permitting	$700,000
Public relations/community development	$50,000
Legal assistance	$500,000
Utility Interconnections	
Stanton substation addition	$2,340,000
Demineralized water supply	$550,000
Service water supply	$400,000
Cooling water supply pump station and pipeline	$4,200,000
Potable water supply pipeline	$50,000
Fire protection	$220,000
Low volume wastes	$30,000
Spare Parts and Plant Equipment	
Combustion turbine	$5,100,000
Balance of plant	$500,000
Plant equipment/tools	$280,000
Plant furnishings and supplies	$110,000
Project Management	
Project management	$600,000
Owner's engineer	$200,000
Site construction management	$350,000
Plant Startup/Construction Support	
Site mobilization	$250,000
Construction utilities	$100,000
O&M staff training	$120,000
Surveying	$20,000
Initial inventories	$60,000
Auxiliary power purchase	$40,000
Performance testing	$25,000
Emissions testing	$25,000
Construction all-risk insurance	$1,500,000
Advisory Fees/Legal Services	
Market and environmental consultants	$170,000
Legal services	$240,000
Contingency	
Unidentified scope increases/project requirements	$5,000,000
Total Additional Costs	**$24,020,000**

provide these funds, neither organization will set aside specific funded reserve accounts. Thus, the PDA is not included in the capital cost or the economic analysis, since it is for unidentified projects and its expenditure would only serve to increase the cost-effectiveness of the project.

As shown in Table 7-5, Stanton B is expected to have a total capital cost of approximately [redacted] (2010 dollars, not including interest during construction), or approximately [redacted]. Interest during construction is not included in the capital cost estimate and will therefore be accounted for separately during the economic evaluations, using the assumptions presented in Section 5.1.

Table 7-5
Total Stanton B Project Capital Cost

Capital Cost Item	Total Capital Cost (2010 $)
Gasifier Unit	[redacted]
Combined Cycle Unit(1)	[redacted]
Estimated OUC Additional Costs(2)	$24,020,000
Railcars(3)	$27,734,000
Total Capital Cost(4)	[redacted]
Total Capital Cost, $/kW(4)	[redacted]
DOE Funding (prior to commercial operation)	[redacted]
Total Capital Cost after DOE Funding(4)	[redacted]
Total Capital Cost after DOE Funding, $/kW(4)	[redacted]

(1)Guaranteed EPC price of [redacted] (for June 2010 operation).
(2)Estimated OUC additional costs of $24,020,000 (2010 dollars).
(3)Estimated costs for railcars of $27,734,000 (2010 dollars).
(4)Total capital cost does not include interest during construction.

The DOE will fund 50 percent of the cost of the gasification island prior to commercial operation, or [redacted]. Accounting for the DOE funding results in a total capital cost of [redacted], which SPC-OG and OUC must fund. Of the remaining gasification island costs prior to commercial operation, the Participation Agreement specifies that OUC will be responsible for [redacted]. OUC will also be responsible for the entire cost of the combined cycle, railcars, and associated additional costs for Stanton B.

The Participation Agreement specifies that SPC-OG will expend no more than [redacted] of the DOE funding to bring the gasifier island to commercial operation, exclusive of railcars and commissioning costs. Subtracting this amount from the DOE funding prior to commercial operation [redacted] would result in [redacted] of DOE funding available for use prior to commercial operation. According to the CCPI, OUC can use this funding to offset 50 percent of allowable costs prior to commercial operation.

The DOE allocated [redacted] to the demonstration phase of Stanton B. Up to 25.25 percent of the costs incurred during the demonstration phase will be reimbursed by the DOE up to the [redacted] allocated for the demonstration phase. The distribution assumed for this funding is included as a credit to the system production costs, as described in Section 10.0.

7.6 Facility Lease Payments

The Participation Agreement specifies that SPC-OG will make an annual lease payment to OUC in consideration of SPC-OG's ownership interest in the Stanton B facility site. This amount is expected to be $73,150 per year (in 2005 dollars) and is escalated annually at the general inflation rate.

7.7 Operations and Maintenance Costs

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

- Primary fuel will be syngas derived from PRB coal with the capability to burn natural gas.
- A baseload operating profile will be used.

7.7.1 Fixed O&M Costs

Fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administration costs. For Stanton B, the fixed O&M costs during the demonstration phase are estimated to be [redacted], based on the nominal rating of Stanton B on syngas operation. After the demonstration phase, fixed O&M costs are estimated to be [redacted] based on the nominal rating of Stanton B on syngas operation. Stanton B is estimated to require a staff of [redacted] O&M personnel for the IGCC facility.

7.7.2 Variable O&M Costs

Variable O&M costs include consumables, chemicals, lubricants, water, and major inspections and overhauls. Major inspection and overhaul costs can be covered under long-term service agreements with the turbine manufacturer, or each overhaul can be subcontracted to the turbine supplier or a third party maintenance provider. Similarly, gasifier major turnaround maintenance can also be contracted to a third party maintenance provider. As the plant will not be staffed to fully perform these major inspections, it is assumed that these tasks will be subcontracted.

Variable O&M costs vary as a function of plant generation. The variable O&M costs for Stanton B are estimated to be approximately [redacted] in 2004 dollars for syngas operation, and [redacted] in 2004 dollars for natural gas operation.

7.8 Project Completion Costs

Project completion costs include costs associated with data analysis and process evaluations during the demonstration phase, along with reporting to characterize the technical, environmental, and economic performance of the Transport Gasification technology. These activities are a mandatory requirement of the DOE's CCPI program, and estimates have been provided to complete such reporting. These costs are included in the economic analysis presented in Section 10.0 and are summarized in Table 7-6.

7.9 Net Output and Heat Rate

Table 7-7A presents a summary of the anticipated plant performance at average conceptual design conditions when operating on syngas derived from PRB coal, and Table 7-7B presents a summary of the anticipated plant performance when burning natural gas.

7.10 Equivalent Availability and Monthly Demand Payment

Equivalent availability is a measure of the capability of a generating unit to produce power, considering operational limitations such as equipment failures, repairs, routine maintenance, and scheduled maintenance. Equipment failures and other forced outages are not predictable. Gasification availability is expected to ramp up over the first 6 years because of first-of-a-kind development. After the ramp-up period, Stanton B is expected to have an equivalent forced outage rate of [redacted] when operating on syngas, and 3.5 percent when operating on natural gas. On average, over a 20 year period, the scheduled outages are expected to be [redacted] per year for syngas operation and 18 days (4.9 percent) per year on natural gas operation. Based on these expected forced outage and scheduled outage rates, the long run availability is expected to be [redacted] for syngas operation and 91.6 percent for natural gas operation.

Table 7-6 Estimated Stanton B Project Completion Costs	
Calendar Year	Amount (2004 $)
2010	[redacted]
2011	[redacted]
2012	[redacted]
2013	[redacted]
2014	[redacted]

Table 7-7A Estimated Stanton B Performance – Syngas		
Performance Point	Unit Output (MW)	Unit Heat Rate (Btu/kWh, HHV)
Full Load	283.0	8,461
Minimum Load	222.6	8,659

Table 7-7B Estimated Stanton B Performance – Natural Gas		
Performance Point	Unit Output (kW)	Unit Heat Rate (Btu/kWh, HHV)
Full Load	229.4	7,640
75 percent Load	172.1	7,951
Minimum Load	130.4	8,593

The *Gasification Island Capacity Purchase Agreement Between Orlando Utilities Commission and Southern Power Company – Orlando Gasification LLC* (the Purchase Agreement) includes the Baseline Availability Guarantee for the gasifier as well as the Monthly Demand Payment, which will be paid by OUC to SPC-OG for SPC-OG's ownership share of the gasification island. Beginning on the facility commercial operation date, OUC will make a Monthly Demand Payment of [redacted], for a contract term of 20 years for the right to use SPC-OG's ownership interest in the gasifier. As part of the consideration for the Monthly Demand Payment, SPC-OG will provide an availability guarantee to OUC for operation on syngas, which is summarized in Table 7-8.

Table 7-8
Stanton B Gasifier Availability Guarantee

Contract Year	Baseline Availability Guarantee
1	[redacted]
2	[redacted]
3	[redacted]
4	[redacted]
5	[redacted]
6	[redacted]
7 - 20	[redacted]

7.11 Schedule

Stanton B is planned to be available for operation during the summer 2010 peaking season. To achieve this plan, construction on both the gasification island and combined cycle unit is planned to start in late 2007. The combined cycle and gasification units are planned to be available in June 2010. The demonstration period is planned to last approximately 4 years from the commercial operation date. Figure 7-6 presents the construction schedule for the gasification island and combined cycle.

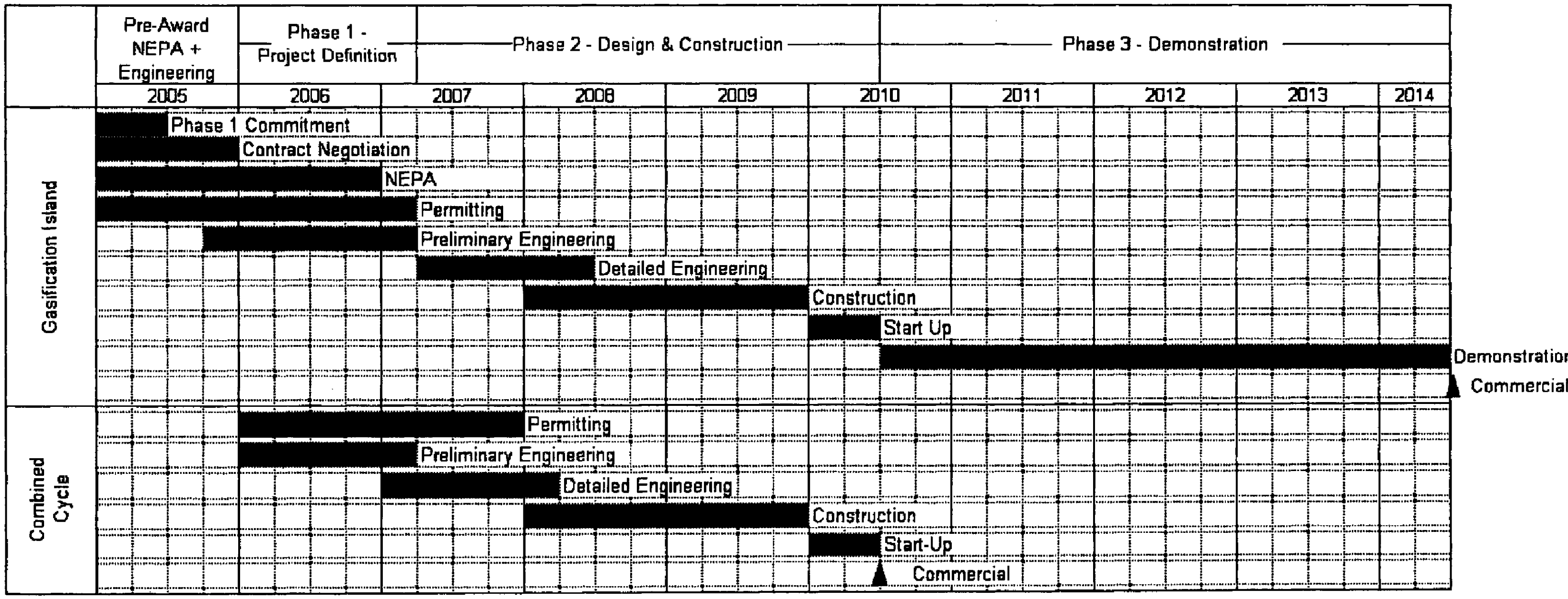


Figure 7-6
Gasification Island and Combined Cycle Construction Schedules

7.12 Fuel Procurement and Delivery

OUC is in the early stages of negotiation of the fuel supply for Stanton B. The scheduled commercial operation of Stanton B makes it premature to enter into final negotiations for the purchase and transportation of coal for Stanton B. The following section demonstrates the reliability of supply of coal at the mine and the ability of the rail transportation infrastructure to reliably deliver coal to Stanton B.

The source of coal for Stanton B is planned to be subbituminous rank coals from the Powder River Basin of Wyoming and Montana. The Powder River Basin is divided into two distinct subregions. The Northern Powder River Basin (NPRB) is comprised of mines located in Big Horn and Rosebud Counties of southeastern Montana. The four current mines are large-scale surface mining operations which produced about 37.8-million tons of coal in calendar year 2005. All mines are served by the Burlington Northern Santa Fe (BNSF) Railroad as the originating carrier for rail movements. The Northern Powder River Basin coals generally have a higher heating value than coals in the Southern Powder River Basin thus making them generally more desirable for long rail hauls.

The Southern Powder River Basin is centered in two counties (Campbell and Converse Counties of eastern Wyoming). Large-scale surface mines in these two counties produced approximately 407.3-million tons in calendar year 2005 which represents in excess of one-third (on a tonnage basis) of all coals produced in the United States. This region is the "Saudi Arabia of coal" in that the enormous availability of reserves, thickness of coal seams (which lie relatively close to the surface), and highly efficient mining practices contribute to economics of extraction that are unmatched in the world. Current production is from fifteen very large mining operations (ranging up to 90-million tons per year from a single mine), which are owned or controlled by six companies or ownership combinations. Mines located in the southern portion of the basin are competitively served by the Burlington Northern Santa Fe (BNSF) and Union Pacific (UP) railroads by means of the "Joint Line" (owned and maintained by both carriers with day-to-day operations and dispatch functions performed by BNSF). Six mines located within the northern portion of the regions are served only by (and are captive to) the BNSF.

Rail movements to the Stanton Energy Center will entail utilization of high efficiency unit trains comprised of aluminum-steel, air-door hopper rail cars designed for 286,000 pounds gross rail loading on four axles. Each railcar will transport a nominal 120 tons of coal in trains up to 125 cars in length (up to a nominal 15,000 tons of coal transported per trip cycle).

With BNSF as the originating rail carrier in the PRB, the routing of unit train movements will be BNSF-direct to Birmingham, Alabama via Lincoln, NE; Kansas City and Springfield, MO; and Memphis, TN. At Birmingham, the trains will be interchanged to CSX Transportation (CSXT) for continuation to the Stanton Energy Center (CSXT rail station at Taft, south of Orlando, FL) via one of the alternative routings.

- Birmingham, AL to Taft, FL via Atlanta, Cordele, and Waycross, GA and Jacksonville and Orlando, FL.
- Birmingham, AL to Taft, FL via Talladega, AL and La Grange, GA to join the above routing at Manchester, GA. Continuation over CSXT mainlines via Cordele and Waycross, GA and Jacksonville and Orlando, FL.
- Birmingham, AL to Taft, FL via Montgomery and Dothan, AL, and Bainbridge, Thomasville and Valdosta, GA to join the above routing at Waycross, GA or, as a partial routing alternative, running from Bainbridge, GA to Tallahassee, FL then eastwards to Jacksonville, FL. Continuation, in either case, will be via Jacksonville and Orlando, FL.

The projected one-way haul mileage for the above routings will range between 2,175 and 2,310 rail miles depending upon the locations of individual mines within the PRB and the CSXT routing alternatives between Birmingham, AL and Jacksonville, FL.

Assuming UP as the originating rail carrier, the routing of unit train movements will be UP-direct to an interchange to CSXT at either East St. Louis, IL or Memphis, TN. The UP routing will be via Joyce, O'Fallons, Gibbon, and Hastings, NE; Marysville and Topeka, KS; and Kansas City and St. Louis, MO; CSXT continuations from East St. Louis would incorporate a routing via Mt. Vernon, IL and Evansville, IN or, alternatively Vincennes, IN, then move south via Henderson, KY, Nashville and Chattanooga, TN to Atlanta, GA. From an interchange at Memphis, the CSXT routing continuation would move northwest to join the above route at Nashville, TN and then move south and east to Atlanta, GA. From Atlanta, GA, the routing would follow the present day Stanton Energy Center unit train routing via Cordele and Waycross, GA and Jacksonville and Orlando, FL to Taft Yard, FL. From Taft Yard, the movements would continue over the existing OUC rail line eastwards and then north for a distance of 20.6 miles to unloading facilities at Stanton Energy Center. The projected one-way haul mileages for the above routings will range between 2,145 and 2,470 rail miles depending upon mine locations within the Southern Powder River Basin, the location of the point of interchange between UP and CSXT, and CSXT routing alternatives to Atlanta, GA.

Unloading of the unit trains will utilize the existing railcar bottom-dump receiving systems. These systems have a rated capability to rates of 3,500 tons per hour when handling eastern bituminous coals. Handling of PRB coals will modestly derate these capabilities due to differences in coal densities and handling characteristics between bituminous and subbituminous coals. The projected unloading time for a design basis unit train (15,000 tons of coal in a 125 car train) will be about 5 hours.

As indicated, the Northern and Southern Power River Basin coals have enormous reserve and mining capabilities and the BNSF, UP, and CSXT rail systems provide multiple routing alternatives. The combination of mining and transportation ensure a reliable and economical coal supply for Stanton B.

8.0 Supply-Side Alternatives

This section presents the supply-side technologies that were considered by OUC as alternatives to Stanton B. These alternatives include renewable technologies, conventional technologies, emerging technologies, advanced technologies, energy storage technologies, and distributed generation technologies.

This section also includes a screening analysis of the supply-side alternatives, which will identify the technologies considered in the detailed economic analysis in Section 10.0. The screening analysis was performed using the levelized costs of each technology considered, based on the economic parameters presented in Section 5.1 (7.0 percent present worth discount rate, 2.5 percent annual escalation rate, and 8.159 percent levelized FCR), as well as the fuel forecasts discussed in Section 5.4 (unless stated otherwise). The levelized cost analysis converts fixed and variable costs into a single cost per MWh, assuming a given capacity factor.

8.1 Renewable Technologies

Renewable energy technologies are diverse; they include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. The technical feasibility and cost of energy from nearly every form of renewable energy has improved since the early 1980s. However, most renewable energy technologies struggle to compete economically with conventional fossil fuel technologies and, in most countries, the renewable fraction of total electricity generation remains small. Nevertheless, the field is rapidly expanding from occupying niche markets to making meaningful contributions to the world's electricity supply.

This section provides an overview and analysis of various renewable energy technologies, including the following:

- Solid biomass (direct-fired and co-firing).
- Biogas (anaerobic digestion and landfill gas).
- Waste-to-energy (WTE) (mass burn and refuse derived fuel [RDF]).
- Wind.
- Solar (solar thermal and solar photovoltaic).
- Geothermal.
- Hydroelectric.
- Ocean energy (ocean thermal energy conversion, wave, and tidal).

Generally, each technology is described with respect to its operating principles, applications, resource availability, cost and performance characteristics, and environmental impacts. Estimates for costs and performance parameters were based on Black & Veatch project experience, vendor inquiries, and a literature review. Capital costs are in 2005 dollars and reflect the total project cost, including direct and indirect costs. Owner's costs were not included in the total project cost because such costs vary significantly for renewable technologies.

8.1.1 Biomass

Biomass is any material of recent biological origin; the most common form is wood. Electricity generation from biomass is the second most prolific source of renewable electric generation after hydroelectric power . Solid biomass power generation options include direct-fired biomass and co-fired biomass, as described in the following subsections.

8.1.1.1 Direct-Fired Biomass. According to the US Department of Energy, there is about 35,000 MW of installed biomass combustion capacity worldwide.[1] Combined heat and power applications in the pulp and paper industry comprise the majority of this capacity.

Operating Principles

Direct biomass combustion power plants in operation today use the same steam Rankine cycle introduced commercially 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Furnaces used in biomass combustion include spreader stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Advanced technologies, such as integrated biomass gasification combined cycle and biomass pyrolysis, are currently under development and were not considered viable supply-side alternatives in this analysis. There are no integrated gasification combined cycle plants currently operating with biomass as a primary fuel.

[1] US Department of Energy, Oak Ridge National Laboratory, "Biomass Frequently Asked Questions," available at: http://bioenergy.ornl.gov/faqs

Applications

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels, biomass plants are commonly less efficient than modern fossil fuel plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

Resource Availability

To be economically feasible, dedicated biomass plants are located either at the source of a fuel supply (such as at a sawmill) or within 100 miles of numerous suppliers. Wood and wood waste are the primary biomass resources and are typically concentrated in areas of high forest product industry activity. In rural areas, agricultural production can often yield significant fuel resources that can be collected and burned in biomass plants. These agricultural resources include bagasse, corn stover, rice hulls, wheat straw, and other residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, biomass is typically comprised of wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Locally grown and collected biomass fuels are relatively labor intensive and can provide substantial employment benefits to rural economies. In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with transportation and delivery of the fuel.

Based on recent biomass resource assessments with which Black & Veatch is familiar, the expected cost of clean wood residues in the region can vary by up to 40 percent, depending on the type of residue, quantity, and hauling distance. A base delivered value of $2.00/MBtu was assumed in this analysis.

Cost and Performance Characteristics

Table 8-1 presents typical characteristics of a 30 MW stoker boiler biomass plant with Rankine cycle using wood waste as fuel.

Table 8-1
Direct Biomass Combustion Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	30
Net Plant Heat Rate (HHV, Btu/kWh)	14,500
Capacity Factor (percent)	70 to 90
Economics ($2005)	
Total Project Cost ($/kW)	2,250 to 3,250
Fixed O&M ($/kW-yr)	70
Variable O&M ($/MWh)	10
Levelized Cost[(1)] ($/MWh)	92 to 118
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	7,000

[(1)]The low ends of the levelized costs are based on a 90 percent capacity factor and a capital cost of $2,250/kW. The high ends of the levelized costs are based on a 70 percent capacity factor and a capital cost of $3,250/kW. Fuel cost is assumed to be $2.00/MBtu.

Environmental Impacts

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target use of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that both fuel harvesting and collection practices are sustainable and do not adversely affect the environment.

Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass combustion, a nearly equal amount of carbon dioxide is absorbed from the atmosphere during the biomass growth phase. Further, biomass fuels contain little sulfur compared to coal and, therefore, produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury, cadmium, and lead. However, biomass combustion still must include technologies to control emissions of NO_x, particulate matter (PM), and CO to maintain BACT standards.

8.1.1.2 Biomass Co-Firing.

Operating Principles

One of the most economical methods to burn biomass is to co-fire it with coal in existing plants. Co-fired projects are usually implemented by retrofitting a biomass fuel feed system to an existing coal plant, although greenfield facilities can also be designed to accept a variety of fuels.

As discussed in the previous section, a major challenge to biomass power is that the dispersed nature of the feedstock and high transportation costs generally preclude plants larger than 50 MW. By comparison, coal power plants rely on the same basic power conversion technology but can have much higher unit capacities, exceeding 1,000 MW. As a result of this larger capacity, modern coal plants are able to obtain higher efficiency at a lower cost. Through co-firing, biomass benefits from this higher efficiency at a more competitive cost than a stand-alone, direct-fired biomass plant.

Applications

There are several methods of biomass co-firing that can be used to produce energy on a commercial scale. Provided that they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. For these types of boilers, simply mixing the fuel into the coal pile may be sufficient enough to co-fire biomass.

Cyclone boilers and pulverized coal (PC) boilers (the most common in the utility industry) require a smaller fuel size than stokers and fluidized beds and may necessitate processing of the biomass prior to combustion. There are two basic approaches to co-firing in this case: co-feeding the biomass through the coal processing equipment or separately processing and then injecting the biomass. The first approach blends the fuels and feeds the mixture to the coal processing equipment (crushers, pulverizers, etc.). In a cyclone boiler, up to 10 percent of the coal heat input can be replaced with biomass using this method. Pulverizers in a PC boiler are not designed to process relatively low density biomass, and fuel replacement is generally limited to approximately 2 or 3 percent if the fuels are mixed. The second approach (separate biomass processing and injection) allows higher co-firing percentages (10 to 15 percent) in a PC unit, but costs more than processing a fuel blend.

Even at these limited co-firing rates, plant owners and operators have raised numerous concerns about the negative effects of co-firing on plant operations. These include the following:

- Negative impact on plant capacity.
- Negative impact on boiler performance.

- Ash contamination decreasing the quality of coal ash.
- Increased O&M costs.
- Minimal NO_x reduction potential (usually proportional to biomass heat input).
- Boiler fouling/slagging because of the high alkali in biomass ash (more of a concern with fast growing biomass, such as energy crops).
- Potentially negative impacts on SCR air pollution control equipment (catalyst poisoning).

These concerns have hampered the adoption of widespread biomass co-firing by electric utilities in the United States. However, most of these concerns can be addressed through proper system design, fuel selection, and limits on the amount of co-firing.

Coal and biomass co-firing can also be considered in the design of new power plants. Designing the plant to accept a diverse fuel mix allows the boiler to incorporate biomass fuel, ensuring high efficiency with low O&M impacts. Fluidized bed technology is often the preferred boiler technology since it has inherent fuel flexibility. There are many fluidized bed units around the world that burn a wide variety of fuels, including biomass. An example is a 240 MW circulating fluidized bed (CFB) in Finland, which burns a mixture of wood, peat, and lignite. This unit is capable of burning anywhere from 100 percent biomass to 100 percent coal.

Resource Availability

For viability, the candidate coal plant should be located within 100 miles of suitable biomass resources. The United States has a larger installed biomass power capacity than any other county in the world. The United States-based biomass power plants provide 7,000 MW of capacity to the national power grid. Coal power generation accounted for 1.96 trillion kWh in 2004, which comprised 51.4 percent of the total generation in the United States. Conversion of as little as 5 percent of this generation to biomass co-firing would increase electricity production from biomass by nearly 400 percent.

The local resources available for biomass co-firing are the same as those for dedicated biomass plants. Biomass is assumed to be available for $2.00/MBtu.

Cost and Performance Characteristics

Table 8-2 presents typical characteristics for a biomass and coal co-fired plant. The characteristics are based on co-firing 20 MW of biomass (separate injection) in a new 750 MW PC power project. Except for fuel, the characteristics are provided on an incremental basis (changes that would be expected compared to the coal plant). The primary capital cost for the project would be related to the biomass material handling system.

Table 8-2
Co-Fired Biomass Technology Characteristics

Performance	
Typical Duty Cycle	Typically baseload, depends on host
Net Plant Capacity (MW)	20
Net Plant Heat Rate (Btu/kWh)	Increase 0.2 to 0.5 percent
Capacity Factor (percent)	Unchanged
Economics (Incremental Costs in $2005)	
Total Project Cost(1) ($/kW)	200 to 400
Total Project Cost(2) ($/kW)	8 to 16
Fixed O&M(1) ($/kW-yr)	5 to 10
Fixed O&M(2) ($/kW-yr)	0.2 to 0.4
Variable O&M ($/MWh)	Unchanged
Levelized Cost(3) ($/MWh)	33 to 38 (incremental cost)
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)(4)	>2,000 MW

(1)Based on biomass capacity.
(2)Based on total plant capacity (750 MW).
(3)The low end of the levelized cost is based on a net biomass capacity of 20 MW, heat rate increase of 0.2 percent, capital cost of $200/kW, and fixed O&M of $5/kW-yr. The high end of the levelized cost is based on a net plant capacity of 30 MW, heat rate increase of 0.5 percent, capital cost of $400/kW, and fixed O&M cost of $10/kW-year.
(4)Estimate for the biomass portion of plants that co-fire coal and biomass. Actual capacity is unknown.

Environmental Impacts

As with direct-fired biomass plants, the biomass fuel supply must be collected in a sustainable manner. Assuming this is the case, co-firing biomass in a coal plant generally has overall positive environmental effects. The clean biomass fuel typically reduces emissions of SO_2, CO, NO_x, and heavy metals, such as mercury.

8.1.2 Biogas

Biogas technology refers to the process of generating electricity with gas captured from the anaerobic digestion of manure or naturally occurring landfill gas. The following subsections describe the formation of these fuels and their ability to produce renewable energy.

8.1.2.1 Anaerobic Digestion.

Operating Principles

Anaerobic digestion is a naturally occurring process that occurs when bacteria decompose organic materials in the absence of oxygen. The byproduct of this decomposition is comprised of 50 to 80 percent methane. The most common applications of anaerobic digestion are industrial wastewater, animal manure, or human sewage as feedstock. According to *Bioenergy News*, the publication of the Bioenergy Association of New Zealand, Inc., the projected total installed capacity of anaerobic digestion will grow from 185 MW in 2004 to 575 MW in 2013. It is estimated that 203 MW will be installed in Western Europe, 68 MW in North America, and 46 MW in Australia.[2]

Applications

Anaerobic digestion is commonly used in municipal wastewater treatment as a first-stage treatment process for sewage sludge. Increasingly stringent agricultural manure and sewage treatment management regulations are the primary drivers for the heightened interest in anaerobic digestion technologies. Use of anaerobic digestion technologies in wastewater treatment applications results in less biosolids residue compared to aerobic (digestion in the presence of oxygen) technologies. Power production from digestion facilities is typically a secondary consideration.

The Los Angeles Department of Water and Power has announced a new agreement to purchase power from a proposed 40 MW anaerobic digestion facility that will process 3,000 tons per day of municipal green waste, such as landscape trimmings and food waste to produce biogas for power production. The proposed facility, which is

[2] The World Biomass Report, *Bioenergy News*, December 2004, http://www.bioenergy.org.nz.

scheduled to be on line by 2009, would be the largest of its kind. There are various other high solids digestion systems installed worldwide, primarily in Europe and Japan.

Biogas produced by anaerobic digestion can be used for power generation, direct heat applications, and absorption chilling. Reciprocating engines are the most common power conversion device, although demonstrations with microturbines and fuel cells have also been successful.

Resource Availability

For on-farm manure digestion, the resource is readily accessible and only minor modifications to existing manure management techniques are required to produce biogas suitable for power generation. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central digestion facility. For central plant digestion of manure from several sources, the availability and close proximity of a large number of livestock operations is necessary to provide a sufficient manure feed rate to the facility. However, the larger size of regional facilities does not necessarily guarantee better economics, because of higher manure transportation costs. For anaerobic digestion of municipal sewage wastes, the resource is readily available at the wastewater treatment plant.

Cost and Performance Characteristics

Table 8-3 presents typical characteristics of farm-scale dairy manure anaerobic digestion systems using reciprocating engine technology.

Environmental Impacts

Anaerobic digesters provide the following positive environmental impacts:

- Reduce pathogens in the waste stream.
- Eliminate odor problems.
- Reduce methane emissions relative to atmospheric decomposition of manure, which are a significant contributor to greenhouse gas emissions.
- Help prevent nutrient overloading in the soil resulting from manure spreading.

8.1.2.2 Landfill Gas.

Operating Principles

Landfill gas (LFG) is produced by the decomposition of the organic portion of landfill waste. LFG typically has a methane content in the range of 45 to 55 percent and is considered an environmental risk. There is increased political and public pressure to reduce air and ground water pollution and to hedge the risk of explosion associated with LFG. From a generating perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines, small gas turbines, or other devices. LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy (WTE) technologies. Currently, there are more than 600 LFG energy recovery systems installed in 20 countries.

Table 8-3
Farm-Scale Anaerobic Digestion Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.085
Capacity Factor (percent)	70 to 90
Economics ($2005)	
Total Project Cost ($/kW)	2,300 to 3,800
Variable O&M ($/MWh)	15
Levelized Cost[(1)] ($/MWh)	48 to 78
Technology Status	
Commercial Status	Commercial
Installed Worldwide Capacity (MW)	6,300

[(1)]The low end of the levelized cost is based on a capacity factor of 90 percent and capital cost of $2,300/kW. The high end of the levelized cost is based on a capacity factor of 70 percent and capital cost of $3,800/kW.

Applications

LFG can be used to generate electricity and process heat or can be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. There are several types of commercial power generation technologies that can be easily modified to burn LFG. Internal combustion engines are by far the most common generating technology choice. Approximately 75 percent of the landfills that generate electricity use internal combustion engines.[3] Depending on the scale of the gas collection facility, it may be feasible to generate power via a combustion turbine or a boiler and steam turbine. Testing with microturbines and fuel cells is also under way, although these technologies do not appear to be economically viable for power generation.

[3] EPA Landfill Methane Outreach Program, http://www.epa.gov/lmop/proj/index.htm.

Resource Availability

Gas production at a landfill is dependent on the depth and age of waste in place and the amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and at least 25 inches of annual precipitation.

Cost and Performance Characteristics

The economics of installing an LFG energy facility depend heavily on the characteristics of the candidate landfill. The payback period of an LFG energy facility at a landfill which has an existing gas collection system can be as short as 2 to 5 years, especially if environmental credits are available. However, the cost of installing a new gas collection system at a landfill can prohibit installing an LFG facility. Table 8-4 presents cost and performance estimates for typical LFG projects using reciprocating engines.

Table 8-4
Landfill Gas Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.2 to 15
Capacity Factor (percent)	70 to 90
Economics ($2005)	
Total Project Cost ($/kW)	1,300 to 2,700
Variable O&M ($/MWh)	15
Levelized Cost[1] ($/MWh)	36 to 61
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	1,100

[1]The low end of the levelized cost is based on a net plant capacity of 15 MW, a 90 percent capacity factor, and a capital cost of $1,300/kW. The high end is based on a net plant capacity of 0.2 MW, a 70 percent capacity factor, and a $2,700/kW capital cost.

Environmental Impacts

LFG combustion releases pollutants similar to many other fuels, but is generally perceived as environmentally beneficial. Since LFG is principally composed of methane, if not combusted, LFG is released into the atmosphere as a greenhouse gas. As a greenhouse gas, methane is 23 times more harmful than CO_2. Collecting the gas and converting the methane to CO_2 through combustion greatly reduces the potency of LFG as a source of greenhouse gas emissions.

8.1.3 Waste-to-Energy

WTE technologies can use a variety of refuse types and technologies to produce electrical power. The economic feasibility of a WTE facility, though, is difficult to assess. Costs are highly dependent on transportation, processing, and tipping fees associated with a particular location. Values discussed in the following subsections should be considered representative of the technology at a generic site.

8.1.3.1 Municipal Solid Waste Mass Burn. There are currently 65 WTE plants in the US using mass burn technology to generate electricity. These plants burn municipal solid waste (MSW) in an "as-discarded" form, with minimal or no preprocessing of the waste. Because of concerns about environmental pollutants (particularly dioxin), opposition to new MSW projects has increased greatly. In addition, costs for MSW facilities have often exceeded initial estimates. Since 1996, only one new MSW facility has come on line in the United States, and it was later shut down because of lack of waste resources.

Operating Principles

Converting refuse or MSW to energy can be accomplished by a variety of technologies. The degree of refuse processing determines the method used to convert MSW to energy. Refuse with limited processing to remove noncombustible and oversize items is typically combusted in a waterwall furnace similar to coal and biomass furnaces. The MSW is fed to a reciprocating grate in the boiler. The combustion generates steam in the walls of the furnace, which is converted to electrical energy via a STG system. Other furnaces used in mass burning applications include refractory furnaces, rotary kiln furnaces, and controlled air furnaces for smaller modular units.

Applications

The avoided cost of waste disposal is a primary component in determining the economic viability of a WTE facility. High costs of land and waste transportation increase the feasibility of an MSW facility. The 65 operating mass burn plants have an annual capacity to process 22.1 million tons of waste. Large MSW facilities typically process 500 to 3,000 tons of MSW per day (the average amount produced by 200,000 to 1,200,000 residents), although there are a number of facilities operating in the 200 to 500 tons per day size range. The average design capacity of mass burn plants operating in the United States is approximately 1,000 tons of waste per day.[4]

Resource Availability

MSW plants are high capital cost projects that require an inexpensive and abundant fuel source to operate profitably. For this reason, plants are typically sited near large population centers or in areas of high priced land. The average American generates about 4 to 5 pounds of garbage per day, most of which would otherwise be sent to a landfill.[5]

Cost and Performance Characteristics

Table 8-5 provides the typical ranges of performance and cost for a facility burning 1,600 tons of MSW per day.

Environmental Impacts

One of the most significant environmental benefits of burning MSW is that it reduces landfill deposits. The combustion byproducts produced when MSW is burned are similar to those of most organic combustion materials. Particulate matter must be abated, and NO_x can form if the combustion temperature is too high. Unlike coal, the sulfur emissions from MSW are low. One MSW emission that is atypical of fossil fuels is dioxin, which the EPA has ruled to be carcinogenic. This issue has been intensely debated in the scientific community, but MSW projects face opposition as a result of the ruling.

8.1.3.2 Refuse Derived Fuel (RDF).

Operating Principles

RDF is an evolution of MSW technology. Rather than burning trash in its bulky native form, trash is processed and converted to fluff or pellets for ease of handling and improved combustibility.

[4] Integrated Waste Services Association, "The 2004 IWSA Directory of Waste-to-Energy Plants," available at: http://www.wte.org/2004_Directory/IWSA_2004_Directory.html, accessed August 2004.
[5] EPA, available at http://www.epa.gov/epaoswer/osw/basifact.htm, accessed August 2004.

Table 8-5
MSW Mass Burning Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	40
Net Plant Heat Rate (HHV Btu/kWh)	16,500
MSW Consumption (tons per day)	1,600
Capacity Factor (percent)	75 to 85
Economics ($2005)	
Total Project Cost ($/kW)	5,000 to 7,000
Fixed O&M ($/kW-yr)	250 to 350
Variable O&M ($/MWh)	65 to 85
Levelized Cost(1) ($/MWh)	77 to 168
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	1,856

(1)The low end of the levelized cost is based on a capacity factor of 85 percent, capital cost of $5,000/kW, fixed O&M of $250/kW-year, and variable O&M of $65/MWh. The high end of the levelized cost is based on a capacity factor of 75 percent, capital cost of $7,000/kW, fixed O&M of $350/kW-year, and variable O&M of $85/MWh. Includes a tipping fee of $50 per ton with an assumed 4,720 Btu/lb heating value.

Applications

RDF is preferred over MSW in many WTE applications because it can be combusted with the same technology used to combust coal. Spreader stoker fired boilers, suspension fired boilers, fluidized bed boilers, and cyclone furnace units have all been used to generate steam from RDF. Fluidized bed combustors are often preferred for RDF energy applications because of their high combustion efficiency, capability to burn RDF with minimal processing, and inherent ability to effectively reduce NO_x and SO_2 emissions.

There are 15 operating RDF plants in the United States, with an annual capacity to process 7.7 million tons of waste. Typical RDF facilities process 500 to 2,000 tons of RDF per day (the average amount produced by 200,000 to 800,000 residents). The average design capacity of RDF plants operating in the United States is approximately 1,300 tons of waste per day.[6]

Cost and Performance Characteristics

Table 8-6 provides the typical ranges for performance and cost of an RDF facility burning 1,400 tons of waste per day.

Table 8-6
RDF Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	40
Net Plant Heat Rate (HHV Btu/kWh)	16,500
RDF Consumption (tons per day)	1,400
Capacity Factor (percent)	75-85
Economics ($2005)	
Total Project Cost ($/kW)	7,000 to 9,000
Fixed O&M ($/kW-yr)	450 to 550
Variable O&M ($/MWh)	70 to 90
Levelized Cost[(1)] ($/MWh)	163 to 262
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	636

[(1)]The low end of the levelized cost is based on a capacity factor of 85 percent, capital cost of $7,000/kW, fixed O&M of $450/kW-year, and variable O&M of $70/MWh. The high end of the levelized cost is based on a capacity factor of 75 percent, capital cost of $9,000/kW, fixed O&M of $550/kW-year, and variable O&M of $90/MWh. Includes a tipping fee of $50 per ton with an assumed 5,500 Btu/lb heating value.

Environmental Impacts

RDF has many of the same environmental obstacles as MSW and provides the same environmental benefits. However, RDF plants using fluidized bed technology can potentially achieve lower emissions than mass burn plants.

[6] Integrated Waste Services Association, 2004.

8.1.4 Wind

Operating Principles

Wind power systems convert the movement of air to power by means of a rotating turbine and a generator. Wind power has been the fastest growing energy source of the last decade, in percentage terms, with around 30 percent annual growth in worldwide capacity over the last 5 years. Cumulative worldwide wind capacity is now estimated to be more than 50,000 MW. In the United States, wind turbine capacity is expected to be more than 9,000 MW by the start of 2006. The US wind market has been driven by a combination of growing state mandates and the production tax credit (PTC), which provides an economic incentive for wind power. The PTC has been renewed several times and is currently set to expire on December 31, 2007.

Applications

Typical utility scale wind energy systems consist of multiple wind turbines that range in size from 1 to 2 MW. Wind energy system installations may total 5 to 300 MW, although the use of single, smaller turbines is also common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Furthermore, offshore wind energy projects are now being built in Europe and are planned in the United States, encouraging the development of larger turbines (up to 5 MW) and larger wind farm sizes.

Wind is an intermittent resource, with average capacity factors ranging from 25 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and energy capture characteristics of the wind turbine. Capacity factor directly affects economic performance; thus, reasonably strong wind sites are required for cost-effective installations. Since wind is intermittent, it cannot be relied upon as firm capacity for peak power demands. To provide a dependable resource, wind energy systems may be coupled with some type of energy storage to provide power when required, but this is not common and adds considerable expense to a system.

Resource Availability

Turbine power output is proportional to the cube of wind speed, which makes small differences in wind speed very significant. Wind strength is rated on a scale from Class 1 to Class 7, as shown in Table 8-7. The state of Florida's wind resources are generally categorized as Class 1 or 2 and, therefore, are not considered viable for power production.

Table 8-7
US DOE Classes of Wind Power

Wind Power Class	Height Above Ground: 50 m (164 ft)[1]	
	Wind Power Density (W/m^2)	Speed[2] (m/s)
1	0 to 200	0 to 5.60
2	200 to 300	5.60 to 6.40
3	300 to 400	6.40 to 7.00
4	400 to 500	7.00 to 7.50
5	500 to 600	7.50 to 8.00
6	600 to 800	8.00 to 8.80
7	800 to 2000	$\geq$ 8.80

(1)Vertical extrapolation of wind speed based on the 1/7 power law, as defined in Appendix A of the *Wind Energy Resource Atlas of the US, 1991.*
(2)Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea level conditions. To maintain the same power density, wind speed must increase 3 percent per 1,000 m (5 percent per 5,000 ft) elevation.

Cost and Performance Characteristics

Table 8-8 provides typical characteristics for a 50 to 100 MW wind farm. Substantially higher costs are necessary for wind projects that require grid upgrades or long transmission tie lines. Capital costs for new onshore wind projects had remained relatively stable for several years, but current demand has driven up the cost by as much as 40 percent. Additionally, due to the increased demand and impending PTC expiration, the current earliest delivery date for new turbines is 2008. Significant gains have been made in recent years in identifying and developing sites with better wind resources and improving turbine reliability. As a result, the average capacity factor for all installed wind projects in the United States has increased from 20 percent in 1998 to nearly 30 percent in 2003.[7]

Environmental Impacts

Wind is a clean generation technology from the emissions perspective. However, there are still environmental considerations associated with wind turbines. Opponents of wind energy frequently cite visual impacts and noise as drawbacks. Turbines are approaching and exceeding heights of 400 feet and, for maximum wind capture, tend to be located on ridgelines and other elevated topography. Turbines can cause avian fatalities and other wildlife impacts if sited in sensitive areas. To some degree, these issues can be partially mitigated through proper siting, environmental review, and public involvement during the planning process.

8.1.5 Solar

Solar radiation can be captured in numerous ways with a variety of technologies. The two major groups of technologies are solar thermal and solar photovoltaics (PVs).

8.1.5.1 Solar Thermal.

Operating Principles

Solar thermal technologies convert the sun's energy to electricity by capturing heat. Technological advances have expanded solar thermal applications to high magnitude energy collection and power conversion on a utility scale. The leading solar thermal technologies include parabolic trough, parabolic dish, power tower (central receiver), and solar chimney.

[7] Based on annual wind generation and capacity data from the Energy Information Administration's *Renewable Energy Projections 2004*.

Table 8-8
Wind Technology Characteristics

	Wind Farm
Performance	
Typical Duty Cycle	As Available
Net Plant Capacity (MW)	50 to 100
Capacity Factor (percent)	10 to 15[1]
Economics ($2005)	
Total Project Cost ($/kW)	1,300 to 1,600
Fixed O&M ($/kW-yr)	30
Levelized Cost[2] ($/MWh)	102 to 195
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	7,200[3]

(1)Representative of low wind speed site in southeast United States.
(2)The low end of the levelized cost is based on a net plant capacity of 100 MW, capacity factor of 15 percent, and capital cost of $1,000/kW. The high end of the levelized cost is based on a net plant capacity of 50 MW, capacity factor of 10 percent, and capital cost of $1,400/kW.
(3)Estimate as of October 2005. Expected capacity by the end of 2005 is 9,200 MW.

With adequate resources, solar thermal technologies are appropriate for a wide range of intermediate- and peak-load applications, including central station power plants and modular power stations in both remote and grid-connected areas. Commercial solar thermal parabolic trough plants in California currently generate more than 350 MW.

Most solar thermal systems (parabolic trough, parabolic dish, and central receiver) transfer the heat in solar insolation to a heat transfer fluid, typically a molten salt or heat transfer oil. By using thermal storage or by combining the solar generation system with a fossil fired system (a hybrid solar/fossil system), a solar thermal plant can provide dispatchable electric power.

Unlike the three other solar thermal technologies, solar chimneys do not generate power using a thermal heat cycle. Instead, they generate and collect hot air in a large (several square miles) greenhouse. A tall chimney is located in the center of the greenhouse. As the air in the greenhouse is heated by the sun, it rises and enters the chimney. The natural draft produces a wind current that rotates a collection of air turbines.

Applications

The larger solar thermal technologies (parabolic trough, central receiver, and solar chimney) are currently not economically competitive with other central station generation options (such as a natural gas fired combined cycle units). Parabolic dish engine systems are small and modular and can be placed at load sites, directly offsetting retail electricity purchases. However, these systems have not been used in commercial applications.

Of the four technologies, parabolic trough represents the vast majority of installed capacity, primarily in the southwest US desert. There are nine Solar Electric Generating Station (SEGS) parabolic trough plants in the Mojave Desert that have a combined capacity of 354 MW. Other parabolic trough plants are being developed, including a 64 MW plant in Nevada and several 50 MW plants in Spain.

Parabolic dish engine systems of approximately 25 kW have been developed and are now being actively marketed. Recently, installation was completed on a six-dish test deployment at Sandia National Laboratories (SNL) in Albuquerque, New Mexico. On August 2, 2005, Southern California Edison publicly announced the completion of negotiations on a 20 year PPA with Stirling Energy Systems (SES) for between 500 to 850 MW of capacity of dish/Stirling units. On September 7, 2005, SES announced a contract with San Diego Gas & Electric to provide between 300 and 900 MW of solar power using the dish technology. Pricing for these PPAs remains confidential. If large deployments of dish/Stirling systems materialize, they are expected to drastically reduce capital and O&M costs and increase system reliability.

The US government has funded two utility-scale central receiver power plants: Solar One and its retrofit, Solar Two. Solar Two was a 10 MW installation near Barstow, California, but it is no longer operating, because of reduced federal support and high operating costs.

The first commercial chimney project has been proposed in Australia. Originally, this project was planned to be 200 MW with a chimney 1 km (0.62 mile) tall and a greenhouse 5 km (3.1 miles) in diameter. The estimated cost of that system was $700 million. More recently, the project has been scaled down to 50 MW. Cost and dimension data for the scaled down system are not available.

Resource Availability

Solar radiation reaching the earth's surface, often called insolation, has two components: direct normal insolation (DNI) and diffuse insolation (DI). DNI, which typically comprises about 80 percent of the total insolation, is that part of the radiation which comes directly from the sun. DI is the part that has been scattered by the atmosphere or is reflected off the ground or other surfaces. On a cloudy day, all of the radiation is diffuse. The vector sum of DNI and DI is termed global insolation. Systems that concentrate solar energy use only DNI, while nonconcentrating systems use global insolation. Concentrating solar thermal systems (troughs, dishes, and central receivers) use DNI. Lower latitudes with minimum cloud coverage offer the greatest solar concentrator potential. Florida DNI ranges from 4.5 to 5.5 $kW/m^2/day$. Some locations in the southwest United States can have DNI as high as 8.5 $kW/m^2/day$.

A general feature of solar thermal systems and solar technologies is that peak output typically occurs on summer days when electrical demand is high. Solar thermal systems that include storage allow dispatch that can improve the ability to meet peaking requirements. Land requirements for solar thermal systems are about 5 to 8 acres/MW.

Cost and Performance Characteristics

Representative characteristics for the four solar thermal power plant technologies previously described are presented in Table 8-9.

8.1.5.2 Solar Photovoltaic. PVs have achieved considerable consumer acceptance over the last few years. PV module production tripled between 1999 and 2002. PV installations reached a worldwide output of over 927 MW in 2004. Worldwide grid-connected residential and commercial installations grew from 120 MW per year in 2000 to 770 MW per year in 2004.[8] The majority of these installations were in Japan and

[8] Installed PV Power as of the end of 2004, http://www.oja-services.nl/iea-pvps/isr/01.htm.

Table 8-9
Solar Thermal Technology Characteristics[1]

	Parabolic Trough	Parabolic Dish	Central Receiver	Solar Chimney
Performance				
Typical Duty Cycle	Peaking - Intermediate	As Available - Peaking	Peaking - Intermediate	Intermediate - Baseload
Net Plant Capacity (MW)	100	1.2	50	200
Integrated Storage	6 hours	None	6 hours	Yes
Capacity Factor (percent)	35 to 40	20 to 25	35 to 40	60 to 80
Economics ($2005)				
Total Project Cost ($/kW)	3,500 to 4,500	3,000 to 4,000	4,000 to 5,000	3,500 to 4,500
Variable O&M ($/MWh)	20 to 25	10 to 20	25 to 30	10 to 20
Levelized Cost[2] ($/MWh)	120 to 170	140 to 238	140 to 192	60 to 107
Technology Status				
Commercial Status	Commercial	Demonstration	R&D	R&D
Installed US Capacity (MW)	~350	< 1	10[3]	< 1

R&D = Research and Development.

[1] Parabolic trough cost estimates have the highest degree of uncertainty for near-term applications. Other technologies assume significant deployment.
[2]The low ends of the levelized costs are based on the higher capacity factors and the lower capital and O&M costs. The high ends of the levelized costs are based on the lower capacity factors and higher capital and O&M costs.
[3]No longer operating.

Germany, where strong subsidy programs have made the economics of PV attractive. Large-scale (>100 kW) PV installations have been added at a rate of about 5 MW per year over the last 2 years.[9]

Operating Principles

The amount of power produced by PV installations depends on the material used and the intensity of the solar radiation incident on the cell. Single or polycrystal silicon cells are most widely used today. Single crystal cells are manufactured by growing single crystal ingots, which are then sliced into thin cell-sized material. The cost of the crystalline material is significant. The production of polycrystalline cells can cut material costs, with some reduction in cell efficiency. Thin film cells significantly reduce cost per unit area, but result in lower efficiency cells. Gallium arsenide cells are among the most efficient solar cells and have other technical advantages, but they are also more costly and typically are used only where high efficiency is required even at a high cost, such as space applications or in concentrating PV applications.

Applications

The modularity, simple operation, and low maintenance requirements of solar PV makes it ideal for distributed, remote, or off-grid applications. Most PV applications are smaller than 1 kW, although larger, utility-scale installations are becoming more prevalent. There are more than 50 PV systems worldwide with capacities greater than 1 MW, including three systems in Germany between 5 and 6.3 MW. The largest system in the United States is Tucson Electric's Springerville PV plant, with nearly 4.6 MW of capacity.

Resource Availability

Most PV systems installed today are flat plate systems that use global insolation. Concentrating PV systems, which use DNI, are being developed, but are not considered commercial at this time. Global insolation on latitude tilt surfaces in Florida range from 5 to 6 kW/m^2/day, compared with up to 7 kW/m^2/day in the southwest United States.

Cost and Performance Characteristics

Table 8-10 presents cost and performance characteristics of a 4 kW residential and a 50 kW commercial fixed-tilt, single crystalline PV system.

[9] Paul Maycock, "PV Market Update," *Renewable Energy World*, July-August 2003.

Table 8-10
Solar PV Technology Characteristics

	Residential	Commercial
Performance		
Typical Duty Cycle	As Available, Peaking	As Available, Peaking
Net Plant Capacity (kW)	4	50
Capacity Factor (percent)	18	20
Economics ($2005)		
Total Project Cost ($/kW)	8,500 to 12,500	7,500 to 9,500
Fixed O&M ($/kW-yr)	45	20
Variable O&M(1) ($/MWh)	52	23
Levelized Cost(2) ($/MWh)	609 to 843	443 to 548
Technology Status		
Commercial Status	Commercial	
Installed US Capacity (MW)	365	

(1)Includes inverter replacement after 10 years.
(2)The lower levelized costs are based on the low ends of the total project costs, and the high levelized costs are based on the high ends of the total project costs.

Environmental Impacts

A key attribute of solar PV cells is that they have virtually no emissions after installation. Some thin film technologies have the potential for discharge of heavy metals during manufacturing; however, proper monitoring and control can adequately address this issue.

8.1.6 Geothermal

Operating Principles

Geothermal resources can provide energy for power production and other applications by using heat from the earth to generate steam and drive turbine generators. The global installed capacity for geothermal power plants is approximately 8,900 MW_e (megawatt electrical). Additionally, about 16,000 MW_{th} is used in direct heat applications. It is estimated that geothermal resources using today's technology could support between 35,500 and 72,000 MW_e of electrical generating capacity worldwide. Using enhanced technology that is currently under development, global geothermal resources have the potential to support between 65,500 and 138,000 MW_e.[10]

[10] *Renewable Energy World*, 2002.

It is estimated that US geothermal resources could support between 6,300 and 11,700 MW_e of electric power with current technology and 15,000 to 25,000 MW_e with advanced technology.

Applications

In addition to generation of electricity and direct space heating applications, hot water and saturated steam from a geothermal resource can be used for a wide variety of process heat applications.

Resource Availability

Geothermal power is limited to locations where geothermal pressure reserves are discovered. Well temperature profiles determine the potential for geothermal development and the type of geothermal power plant installation. High energy sites are suitable for electricity production, while low energy sites are suitable for direct heating. Most of the geothermal resources in the United States are concentrated in the west and southwest parts of the country. There are minimal geothermal resources available east of the Mississippi River, and no resources suitable for power generation or direct heat applications in Florida.

Cost and Performance Characteristics

For representative purposes, a binary cycle power plant is characterized in Table 8-11. In a binary cycle plant, a working fluid is boiled by heat transferred from a geothermal source across a heat exchanger, and then expanded through a turbine. Capital costs of geothermal facilities can vary widely since the drilling of individual wells can cost as much as $4 million, and the number of wells drilled depends on the success of finding the resource.

Environmental Impacts

Dissolved minerals and hazardous noncondensable gases in geothermal fluids can be an environmental concern if not addressed properly (fluid reinjection addresses many concerns). Geothermal power plants with modern emission control technologies have minimal environmental impact; they emit less than 0.2 percent of the CO_2, less than 1 percent of the SO_2, and less than 0.1 percent of the particulates of a clean fossil fuel plant. There is the potential for geothermal production to cause ground subsidence. This is rare in dry steam resources, but possible in liquid-dominated fields. However, carefully applied reinjection techniques can effectively mitigate this risk.

Table 8-11 Geothermal Technology Characteristics	
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	30
Capacity Factor (percent)	70 to 90
Economics ($2005)	
Total Project Cost ($/kW)	2,500 to 4,000
Fixed O&M ($/kW-yr)	200 to 300
Levelized Cost[1] ($/MWh)	64 to 128
Technology Status	
Commercial Status	Commercial
Installed US Capacity[2] (MW)	2,534

[1]The low end of the levelized cost is based on a capacity factor of 90 percent, capital cost of $2,500/kW, and fixed O&M cost of $200/kW-year. The high end of the levelized cost is based on a capacity factor of 70 percent, capital cost of $4,000/kW, and fixed O&M cost of $300/kW-year.
[2]With the currently available technology, there are no viable geothermal power plant sites east of the Mississippi River.

8.1.7 Hydroelectric

Operating Principles

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing it through a turbine. The amount of kinetic energy captured by a turbine is dependent on the head (distance the water is falling) and the flow rate of the water. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. If a dam is not feasible, it is possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such "run-of-river" applications allow for hydroelectric generation without the impact of damming the waterway. The existing worldwide installed capacity for hydroelectric power is by far the largest source of renewable energy at 740,000 MW.[11]

[11] International Energy Agency, 2002.

Applications

Hydroelectric projects are divided into a number of categories on the basis of their size. Micro hydroelectric projects generate below 100 kW. Systems generating 100 kW and 1.5 MW are classified as mini hydroelectric projects. Small hydroelectric systems generate between 1.5 and 30 MW. Medium hydroelectric projects generate up to 100 MW, and large hydroelectric projects generate more than 100 MW. Medium and large hydroelectric projects are good resources for baseload power generation if they have the ability to store a large amount of potential energy behind a dam and release it consistently throughout the year. Small hydroelectric projects generally do not have large storage reservoirs and are not dependable as dispatchable resources.

Resource Availability

A hydroelectric resource can be defined as any flow of water that can be used to capture the kinetic energy. Projects that store large amounts of water behind a dam can regulate the release of water through turbines and generate electricity regardless of the season. These facilities can generally serve baseloads. Run-of-river projects do not impound the water but, instead, divert a part or all of the current through a turbine to generate electricity. At "run-of-river" projects, power generation varies with seasonal flows and can sometimes help serve summer peak loads.

All hydroelectric projects are susceptible to drought. In fact, the variability in hydropower output is rather large, even when compared to other renewable resources. The aggregate capacity factor for all hydroelectric plants in the United States has ranged from a high of 47 percent to a low of 31 percent.[12]

Florida has a small number of potential sites for hydropower development. The majority of these sites are in small river basins, and most have potential capacities between 1 and 10 MW. The total hydroelectric potential of Florida is about 43 MW.[13]

Cost and Performance Characteristics

Hydroelectric generation is regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable, but construction techniques and costs continue to change. Capital costs are highly dependent on site characteristics and vary widely. Table 8-12 provides ranges for performance and cost estimates for hydroelectric projects for two categories: new projects at undeveloped sites and additions or upgrades to hydroelectric projects at existing sites. These values are for

[12] Based on analysis of data from Energy Information Administration, *Renewable Energy Annual 2002*.
[13] Idaho National Engineering and Environmental Laboratory, "US Hydropower Resource Assessment for Florida," 1998.

representative comparison purposes only. Capacity factors are highly resource dependent and can range from 10 to more than 90 percent. Capital costs also vary widely with site conditions.

Table 8-12
Hydroelectric Technology Characteristics

	New	Incremental
Performance		
Typical Duty Cycle	Varies with Resource	Varies with Resource
Net Plant Capacity (MW)	<50	1 to 160
Capacity Factor (percent)	40 to 60	40 to 60
Economics ($2005)		
Total Project Cost ($/kW)	2,500 to 3,900	600 to 2,900
Fixed O&M ($/kW-yr)	5 to 25	5 to 25
Variable O&M ($/MWh)	5 to 6	3.5 to 6
Levelized Cost(1) ($/MWh)	52 to 121	17 to 95
Technology Status		
Commercial Status	Commercial	Commercial
Installed US Capacity (MW)	79,842	NA

(1)The low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. The high end of the levelized cost is based on the lower capacity factors and the higher capital and O&M costs.

Environmental Impacts

The damming of rivers for small- and large-scale hydroelectric applications may have significant environmental impacts. One major issue involves the migration of fish and disruption of spawning habits. For dam projects, one of the common solutions to this problem is the construction of "fish ladders" to aid the fish in bypassing the dam when they swim upstream to spawn.

A second issue involves flooding existing valleys that often contain wilderness areas, residential areas, or archeologically significant remains. There are also concerns about the consequences of disrupting the natural flow of water downstream and disrupting the natural course of nature.

8.1.8 Ocean Energy

Ocean energy resources can be captured in numerous ways with a variety of technologies. The current areas of research and development are wave energy, ocean thermal energy conversion (OTEC), and tidal energy.

8.1.8.1 Wave.

Operating Principles

The kinetic energy of ocean waves can be converted to electric power using a wave energy conversion system (WECS). Many hundreds of WECS technologies have been suggested, but only a very small proportion of these have been evaluated beyond the concept stage. Of these, only a small number have been developed beyond laboratory testing to deployment as prototypes in real sea conditions. WECSs are generally categorized as shore-based (onshore and near-shore) or offshore systems.

Onshore and Near-Shore Applications

There are two basic shore-based wave energy designs: oscillating water column (OWC) devices and overtopping-tapered channel (TAPCHAN) devices.

OWC devices generate electricity from the wave-induced rise and fall of a water column. The energy in this water column is extracted via a moving air column using an air turbine. The main disadvantages with onshore systems, such as OWC, is that their construction is dependent on local conditions and the available wave power is low at the shoreline. Onshore devices also require a small tidal range and a suitable shoreline with a reservoir location. The onshore systems have an advantage over the near-shore and offshore systems because of their accessibility for maintenance and transmission. The most developed example of this design is Wavegen's 500 kW LIMPET device, which has been operating since 2001.

TAPCHAN devices generate electricity using conventional low head hydropower turbines. A tapering channel concentrates and funnels waves up a channel and increases their height so that they then spill into a reservoir. Since these devices are driven by water flowing from a reservoir back to the sea, this device produces a more stable power output.

Near-shore systems that can be built around existing breakwater structures include the Energetech device, which uses a parabolic wall to focus wave energy onto the collector and a Dennis-Auld turbine. In general, near-shore devices have the advantage that they can access higher wave power without the need for extensive electricity transmission. However, like onshore devices, their shoreline location may affect their adoption because of their aesthetically displeasing appearance.

Offshore Applications

There is much greater diversity of offshore WECSs than near-shore systems. The most common offshore WECSs are pneumatic devices, overtopping devices, float-based devices, and moving body devices. In general, offshore devices can access the greatest amount of wave power, but require extensive power transmission and maintenance since they are located in a more extreme environment.

Pneumatic devices generate electricity using air movement, often using an OWC concept similar to that of shore-based devices. Overtopping devices generate electricity using the same basic methodology as the shore-based versions. Float-based devices generate electricity using the vertical motion of a float rising and falling with each wave. The float motion is reacted against an anchor or other structure so that power can be extracted. Moving body devices use a solid body moving in response to wave action to generate electricity.

Float-based devices are the most common of all proposed designs. Well developed European designs that are still under consideration include a 1 MW demonstration plant consisting of four 250 kW buoys planned for 2006 at Makah Bay, Washington. A commercial ocean wave project being constructed off the northern coast of Portugal in 2005 will consist of three 750 kW machines. The Portuguese consortium in charge of the project intends to order 30 additional machines before the end of 2006, subject to performance of the first three.[14] A PowerBuoy float-based device is under development, and the first 50 kW unit of a 1 MW demonstration system was installed in June 2004 at Kaneohe Bay, Oahu, in Hawaii. This project has $2.8 million in additional funding from the US Navy. Additionally, a 2 to 5 MW wave power station in France was recently begun, along with a 1.25 MW wave power station in northern Spain.[15]

Cost and Performance Characteristics

Since there has not been large-scale commercialization of any of these technologies, there is a wide range of projected costs. These costs, and performance estimates, are based on theoretical calculations and are highly uncertain.

Environmental Impacts

WECSs are generally not considered to be environmentally harmful. However, there are some concerns with WECSs, including degradation of marine habitat and adverse visual impacts. These concerns may be mitigated through careful siting of projects.

[14] Ocean Power Delivery Press Release, May 19, 2005. Accessed at: http://www.oceanpd.com/docs/OPD%20Enersis%20Press%20Release.pdf.
[15] Ocean Power Technologies Press Release, June 20, 2005. Accessed at: http://www.oceanpowertechnologies.com/pdf/french_wave_project.pdf.

8.1.8.2 Ocean Thermal Energy Conversion.

Operating Principles

An OTEC plant uses the temperature difference between warm surface water and cold deep water to generate electricity via a heat engine system. There are multiple configurations under development, but all OTEC facilities operate on the same basic principle. Comparatively warm surface water is used to heat a working fluid to create vapor and drive a turbine generator. Cold ocean water at depths exceeding 3,000 feet is then used to condense the working fluid. When compared to other renewable technologies, one of the greatest advantages of OTEC is the capability to provide baseload continuous power output.

Applications

OTEC is currently in active research and development by several organizations and corporations around the world. Most of these facilities are operated by laboratories or research organizations and receive the majority of their funding through grants, research foundations, or federal programs. The OTEC plants constructed or proposed to date have ranged from 18 kW to 10 MW net.

OTEC plants allow a wide range of other services to be derived from the supply of cold deep ocean water, including desalinated water, air conditioning and industrial cooling, aquaculture, and chilled soil agriculture. Many of the current approaches to commercializing OTEC exploit the added value that these services bring for a small incremental increase in cost. Since air conditioning and aquaculture can generally use only a small amount of the water required for the OTEC plant, the main added-value service is normally desalinated water.

Resource Availability

OTEC requires warm ocean surface water and cold deep ocean water with a temperature difference exceeding 36° F. Water cold enough to provide the required temperature difference is normally only found at depths of greater than 3,000 feet. In addition, surface water temperature requirements limit development to tropical waters. Land-based applications require steep underwater slopes to minimize the length of cold water piping. If offshore OTEC facilities are considered, the number of suitable locations for OTEC expands. However, offshore applications would require substantial underwater electricity transmission.

Cost and Performance Characteristics

In general, OTEC plants must be large to be economically viable, but there are no large demonstration plants to provide real-world cost data. Table 8-13 presents the estimated performance and costs for onshore and offshore closed cycle OTEC facilities.

Table 8-13
Ocean Thermal Energy Technology Characteristics

	Onshore	Offshore
Performance		
Typical Duty Cycle	Baseload	Baseload
Net Plant Capacity (MW)	10	100
Capacity Factor (percent)	90	90
Economics ($2005)		
Total Project Cost ($/kW)	10,000 to 15,000	2,500 to 5,000
Variable O&M ($/MWh)	13 to 25	13 to 25
Levelized Cost[1] ($/MWh)	135 to 210	47 to 93
Technology Status		
Commercial Status	Initial Demonstration	Development
Installed US Capacity (MW)	0	0

[1]The lower levelized costs are based on the low ends of the total project costs, and the higher levelized costs are based on the high ends of the total project costs.

Environmental Impacts

There remain some important questions about the environmental impacts of OTEC plants. The most frequently raised points are: changes to thermal, salinity, and nutrient gradients within the vicinity; leakage of working fluid from closed cycle OTEC plants or of the chlorine used for controlling bio-fouling; fatalities of small organisms such as plankton; and the effects on commercial fishing.

8.1.8.3 Ocean Tidal.

Operating Principles

The generation of electrical power from ocean tides is similar to traditional hydroelectric generation. A tidal power plant consists of a tidal pond created by a dam, a powerhouse in the dam containing a turbo-generator, and a sluice gate in the dam to allow the tidal flow to enter and leave. Opening the sluice gate in the dam allows the rising tidal waters to fill the tidal basin. At high tide, these gates are closed, and the tidal basin behind the dam is filled to capacity. After the ocean waters have receded, the tidal basin is released through a turbo-generator in the dam. Power may be generated during ebb tide, flood tide, or both.

Resource Availability

Because of the intermittent, although predictable, nature of the tidal resource, tidal power is typically used as an intermediate generation source for utilities. The capacity factor of tidal energy facilities may be expected to be around 25 percent. A few utility-scale facilities have been developed around the world. The largest facilities are a 240 MW plant in France and an 18 MW plant in Canada.

Times and amplitudes of high and low tide are predictable, although these characteristics will vary considerably by region. Economic studies suggest that tidal power will be most economical at sites where the mean tidal range exceeds about 16 feet. In the United States, these conditions only exist in Maine and Alaska, which precludes the rest of the country from the economic generation of power from this resource.

Cost and Performance Characteristics

Costs to develop a tidal energy facility are extremely site-specific and can vary considerably.

Environmental Impacts

Utilization of tidal energy for power generation has the environmental advantage of a zero emission technology. However, the environmental and aesthetic impact that the facility has on the coastline must be carefully evaluated. The main barriers to the increased use of tidal energy are the high cost and long period for the construction of the tidal generating system and concerns about impacts on sensitive estuarine ecosystems.

8.2 Conventional Technologies

This section presents a description of the conventional generating options that were evaluated as potential sources of future capacity for OUC. In addition to a general description, a summary of projected performance, emissions, capital cost, O&M costs, startup costs, and other operating parameters have been developed for each option.

Cost and performance estimates have been developed for several conventional self-build generation technologies that are proven, commercially available, and widely used in the power industry. Cost and performance estimates for emerging technologies are presented in Section 8.3. The conventional technologies considered include three simple cycle combustion turbines, a combined cycle configuration, a CFB unit, and a pulverized coal unit (assumed to be identical to OUC's existing Stanton Energy Center Unit 2).

To provide indicative output and performance data, the combustion turbines and the combined cycle alternatives discussed herein assume a specific manufacturer (GE) and specific models (i.e., aeroderivative and frame combustion turbines). These assumptions are not intended to limit the alternatives considered solely to GE models. Several manufacturers offer similar generating technologies with similar attributes, and the performance data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

The capital cost estimates were developed on an EPC basis and include both direct and indirect costs. An allowance for general owner's cost items, as summarized in Table 8-14, has been included in the cost estimates. It is assumed that all conventional generating unit alternatives would be constructed at the existing Stanton Energy Center. In this regard, numerous assumptions have been made as summarized below, with more detailed information regarding each alternative presented in the remainder of this subsection.

8.2.1 Conventional Alternatives – General Assumptions

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be preengineered unless otherwise specified.
- Construction power is available at the site boundary.
- Fixed O&M estimates include labor, maintenance, and other fixed expenses. Variable costs include outage maintenance, consumables, and replacements dependent upon operation.
- Fixed O&M estimates reflect reduced labor expenses associated with utilizing existing staff at the Stanton Energy Center.
- Combustion turbines will be dual-fueled, with ultra-low sulfur No. 2 fuel oil as the primary fuel and natural gas as the backup fuel since it is uneconomical to purchase firm natural gas transportation for simple cycle operation. The cost of fuel unloading and delivery to the site is included.
- Simple cycle frame machines and combined cycle combustion turbines will include dry-low NO_x combustors, SCR, and water injection to control NO_x. The aeroderivative simple cycle units will include SCR and water injection for NO_x control.

Table 8-14
Possible Owner's Costs

- Permitting and licensing
- Public relations/community development
- Spare parts and supplies
- Site mobilization
- O&M staff training
- Lubricants/fluids/liquids for startup and testing
- Cost of fuel not recovered in power sales
- Construction all-risk insurance
- Owner's contingency
- Bid documents preparation and selection of contractors and suppliers
- Project management
- Project engineering
- Site construction management
- Environmental consulting
- Legal fees
- Electrical transmission interconnection
- Additional water supply/wastewater disposal pipeline
- Land / right of way
- Pre-commercial O&M staff
- Startup, testing, and commissioning
- Fuel infrastructure

- Except for the LMS100, CO catalysts will not be included for the simple cycle combustion turbines. The combined cycle configuration will include a CO catalyst.
- Sound enclosures are included for the combustion turbines.
- Natural gas will be available at the site boundary at adequate pressure (no additional gas compression is necessary) for the 7FA and 7EA simple cycle alternatives. Gas compressors are included for the LM6000 and LMS100 options.
- The existing Stanton Energy Center water supply will be used to provide circulating water, service water, potable water, and demineralized water. Costs for additional pipelines are included as part of the owner's cost.
- Cooling tower blowdown will be directed to the existing recycle basin. Excess blowdown will be processed by the existing brine concentrators and existing equipment.
- The LMS100 has an inter-cooled compressor and will not utilize inlet cooling. The LM6000 will include the SPRINT option (which is also inter-cooling) and inlet chillers. The frame machines (simple cycle turbines and combined cycles) will utilize evaporative cooling.
- The combined cycle option will include full steam bypass for operation in simple cycle mode.
- Costs for transmission interconnections are included as part of the owner's cost.
- Field erected storage tanks include the following:
  - Service/fire water storage tank.
  - Fuel oil storage tank (3 days' storage capacity).
  - Demineralized water storage tank (3 days' storage capacity).

8.2.2 Conventional Alternatives - Direct Cost Assumptions

- Total direct capital costs are expressed in 2005 dollars with no escalation.
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on an EPC contracting philosophy.
- Spare parts for use during operation are included in the owner's costs.
- Permitting and licensing are included in the owner's costs.

8.2.3 Conventional Alternatives - Indirect Cost Assumptions

The following indirect cost items are included in the capital cost estimate:

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

8.2.4 Meteorological Conditions

An average annual temperature and relative humidity of 72° F and 87 percent, respectively, were used for developing performance estimates for use in production cost modeling. Additionally, a summer temperature of 100° F (relative humidity of 47 percent) was used to develop summer performance estimates.

8.2.5 Performance Degradation

Power plant output and heat rate performance will degrade compared to the unit's new and clean performance as hours of operation increase because of factors such as blade wear, erosion, corrosion, and increased leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance. The degradation that cannot be recovered is referred to herein as "nonrecoverable degradation," and estimates have been developed to capture its effects. Nonrecoverable degradation will vary from unit to unit, so specific nonrecoverable output and heat rate factors have been developed and are presented in Table 8-15.

Table 8-15
Nonrecoverable Degradation Factors

Unit Description	Degradation Factor	
	Output (Percent)	Heat Rate (Percent)
GE LM6000 Simple Cycle	3.2	1.75
GE LMS100 Simple Cycle	3.2	1.75
GE 7EA Simple Cycle	3.2	1.75
GE 7FA Simple Cycle	3.2	1.75
GE 1x1 7FA Combined Cycle	2.7	1.50
Subcritical Pulverized Coal	NA	1.50
CFB	NA	1.50

8.2.6 Simple Cycle Combustion Turbines

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

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

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

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

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

The following presents a description of the three simple cycle combustion turbine options considered as supply-side alternatives.

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

The LM6000 consists of a 5-stage low-pressure compressor (LPC), a 14-stage variable geometry high-pressure compressor (HPC), an annular combustor, a 2-stage air-cooled high-pressure turbine (HPT), a 5-stage low-pressure turbine (LPT), and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the low-pressure rotor. The HPC and HPT are assembled on the other shaft, forming the high-pressure rotor

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

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

The capital cost was estimated assuming that GE's *Next-Gen* package would be used for the LM6000. This package includes more factory assembly, which decreases construction time. Table 8-16 presents the operating characteristics of the LM6000 SPRINT combustion turbine; Table 8-17 presents estimated emissions for the LM6000.

Table 8-16
GE LM6000 PC SPRINT Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)(1)	Full Load Net Plant Heat Rate (Btu/kWh, HHV)(1,2)
Summer (100° F)(3)	45.7	9,807
Average (72° F)(3)	46.5	9,649
Average (72° F)	43.7	9,618

(1)Net capacity and net plant heat rate include degradation factors.
(2)Heat rate and net capacity assume operation on fuel oil.
(3)Includes inlet chilling.

Table 8-17
GE LM6000 PC SPRINT Estimated Emissions(1)

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu (HHV)	0.0079
SO_2, lb/MBtu (HHV)	0.0012
Hg, lb/MBtu (HHV)	NA
CO_2, lb/MBtu (HHV)	159.8
CO, ppmvd at 15% O_2	6
CO, lb/MBtu (HHV)	0.0144

(1)Emissions are at full load at 72° F, ultra low sulfur fuel oil operation, and include the effects of SCR.

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

The GE 7EA is fuel-flexible; it can operate on natural gas, LNG, distillate fuel oil, and treated residual fuel oil. The 7EA is an ideal generating unit for sites that require efficient peaking generation or reliable capacity from multiple units. The GE 7EA is rated at 85.4 MW (new and clean, International Organization for Standardization [ISO] conditions), which is greater than the GE LM6000, but less than the GE 7FA.

Table 8-18 presents the operating characteristics of the 7EA combustion turbine; Table 8-19 presents estimated emissions for the 7EA.

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

The GE 7FA combustion turbines have an 18-stage compressor and a 3-stage turbine and feature cold-end drive and axial exhaust, which is beneficial for combined cycle arrangements. Net operating efficiencies of 56 percent can be achieved by the GE 7FA combustion turbine in combined cycle mode. With reduced cycle time for installation and startup, the GE 7FA can be installed relatively quickly. The packaging concept of the GE 7FA features consolidated skid-mounted components, controls, and accessories, which reduce piping, wiring, and other onsite interconnection work.

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

Table 8-20 presents the operating characteristics of the 7FA combustion turbine; Table 8-21 presents estimated emissions for the 7FA.

Table 8-18 GE 7EA Combustion Turbine Characteristics		
Ambient Condition	Net Capacity (MW)[1]	Full Load Net Plant Heat Rate (Btu/kWh, HHV)[1,2]
Summer (100° F)[3]	74.9	12,306
Average (72° F)[3]	79.5	12,142

[1]Net capacity and net plant heat rate include degradation factors.
[2]Heat rate and net capacity assume operation on fuel oil.
[3]Includes evaporative cooling.

Table 8-19 GE 7EA Estimated Emissions[1]	
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu (HHV)	0.0079
SO_2, lb/MBtu (HHV)	0.0012
Hg, lb/MBtu (HHV)	NA
CO_2, lb/MBtu (HHV)	159.8
CO, ppmvd at 15% O_2	18.2
CO, lb/MBtu (HHV)	0.0436

[1]Emissions are at full load at 72° F, ultra low sulfur fuel oil operation, and include the effects of SCR.

Table 8-20
GE 7FA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Full Load Net Plant Heat Rate (Btu/kWh, HHV)[1,2]
Summer (100° F)[3]	157.5	11,253
Average (72° F)[3]	166.6	11,132

[1]Net capacity and full load net plant heat rate include degradation factors.
[2]Heat rate and net capacity assumes operation on fuel oil.
[3]Includes evaporative cooling.

Table 8-21
GE 7FA Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu (HHV)	0.008
SO_2, lb/MBtu (HHV)	0.0012
Hg, lb/MBtu (HHV)	NA
CO_2, lb/MBtu (HHV)	159.8
CO, ppmvd at 15% O_2	14
CO, lb/MBtu (HHV)	0.034

[1]Emissions are at full load at 72° F, ultra low sulfur fuel oil operation, and include the effects of SCR.

8.2.7 General Electric 1x1 7FA Combined Cycle

In the 1x1 combined cycle, a reheat HRSG and a steam turbine generator are installed with a GE 7FA combustion turbine to form the combined cycle configuration. The combined cycle will be dual fueled (natural gas as primary fuel with fuel oil as backup fuel) and will include evaporative cooling on the combustion turbine. In the HRSG, the heat energy in the exhaust flow of the gas turbine is used to produce steam to drive the steam turbine generator. Changing the GE 7FA simple cycle to combined cycle increases the electric output and increases the plant efficiency.

The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three-pressure, reheat unit with full duct firing on natural gas at temperatures above 60° F. SCR equipment will be included to control NO_x to 2 ppmvd while the unit is burning natural gas, and a CO catalyst will be included to reduce emissions.

The steam turbine is expected to be a single flow turbine operating at 3,600 rpm. Turbine suppliers' standard auxiliary equipment, lubricating oil system, hydraulic oil system, and supervisory, monitoring, and control systems will be included. A cooling tower will also be included. A single synchronous generator will be included, which will be direct coupled to the steam turbine. The STG will be located outdoors, with a building provided for the major auxiliary electrical power equipment.

Table 8-22 presents the operating characteristics of the 1x1 7FA combined cycle; Table 8-23 presents estimated emissions for the 1x1 7FA.

8.2.8 Circulating Fluidized Bed

In a circulating fluidized bed boiler, a portion of the combustion air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone (for sulfur capture), and ash. The bottom of the bed is supported by water cooled membrane walls with specially designed air nozzles that distribute the air uniformly. The fuel and limestone are fed into the lower bed where, in the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air, and the balance of the combustion air is introduced at the top of the lower, dense bed. Such staged combustion limits the formation of NO_x.

Table 8-22
GE 7FA 1x1 Combined Cycle Characteristics

Ambient Condition	Net Capacity (MW)[1]	Full Load Net Plant Heat Rate (Btu/kWh, HHV)[1,2]
Summer (100° F)[3, 4]	290.2	7,483
Average (72° F)[3, 4]	298.9	7,431

[1]Net capacity and full load net plant heat rate include degradation factors.
[2]Heat rate assumes operation on natural gas.
[3]Includes evaporative cooling.
[4]Output and performance include the effects of full duct firing.

Table 8-23
GE 1x1 7FA Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu (HHV)	0.0073
SO_2, lb/MBtu (HHV)	0.0006
Hg, lb/MBtu (HHV)	NA
CO_2, lb/MBtu (HHV)	114.8
CO, ppmvd at 15% O_2	0.16
CO, lb/MBtu (HHV)	0.0036

[1]Emissions are at full load at 72° F, natural gas operation, and include the effects of SCR and a CO catalyst.

The bed fluidizing air velocity is greater than the terminal velocity of most of the particles in the bed and, therefore, fluidizing air elutriates the particles through the combustion chamber to the U-beam separators at the furnace exit. The captured solids, including any unburned carbon and un-utilized calcium oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. The circulation of internal solids provides longer residence time for fuel and limestone, resulting in good combustion and improved sulfur capture.

One of the key and most recognized advantages of CFB technology is its ability to burn a wide variety of low grade fuels such as peat, coal wastes, sludges, municipal wastes, biomass, oil shales, and petroleum coke, in addition to high grade coals. CFBs can be designed to burn these fuels individually or in combination, providing the end-user with flexibility in choosing the best economic mix to minimize generation costs. CFBs are also widely recognized as being inherently low in emissions, due in large part to low combustion temperatures, which reduce thermal NO_x formation, and the ability to introduce limestone directly into the furnace to control SO_2 emissions. CFB technology has matured to the point that operating plants have demonstrated availability comparable to the most modern solid fuel-fired plants.

The unit will include two steam generators (CFB boilers) and a single condensing STG, with draft fans and breeching equipment. Each steam generator will be an enclosed CFB steam generator with soot blowers to remove ash and slag buildup. The STG will include a standard sound enclosure and will be housed in an engineered generation building that will include a control room, electrical equipment room, battery room, motor control center, switchgear room, and various offices. The STG will include two radial flow fans to supply primary air.

For heat rejection, the unit will use a surface condenser, mechanical draft cooling tower, circulating water pumps, and auxiliary cooling water heat exchangers. Selective non-catalytic reduction (SNCR) will be used to control NO_x emissions, and a fabric filter will be used to control particulate emissions. A dry scrubber will be included for additional SO_2 removal.

Table 8-24 presents the operating characteristics of the CFB. Table 8-25 presents estimated emissions for the CFB assuming operation on 100 percent bituminous coal.

8.2.9 Pulverized Coal

Although supercritical units are generally more efficient than subcritical units, supercritical units generally have the disadvantage of a larger generating capacity; efficiency comes at the cost of considerations of economies of scale. On the basis of anticipated capacity requirements for OUC, a subcritical unit identical to Stanton Unit 2 is the only pulverized coal generating unit being considered. Subcritical units of this size increase system reliability since the system is not subject to the loss of a single large unit.

Table 8-24
CFB Unit Characteristics

Ambient Condition	Net Capacity (MW)[1]	Full Load Net Plant Heat Rate (Btu/kWh, HHV)[1,2]
Summer (100° F)	300.0	9,364
Average (72° F)	301.6	9,314

[1]Performance assumes operation on 100 percent high sulfur bituminous coal.
[2]Plant performance includes degradation.

Table 8-25
CFB Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	21.8
NO_x, lb/MBtu (HHV)	0.09
SO_2, lb/MBtu (HHV)	0.08
Hg, lb/TBtu (HHV)	1.55
CO_2, lb/MBtu (HHV)	207.7
CO, ppmvd at 15% O_2	45.7
CO, lb/MBtu (HHV)	0.115

[1]Emissions include the effects of SNCR and SO_2 dry scrubbing.

In the subcritical power generation process, a subcritical pressure steam generator and a condensing STG are used to convert the fuel to electrical energy by using steam to drive the turbine in the STG. The steam generator is started on fuel oil as an ignition fuel. As the combustion process occurs in the steam generator, coal is gradually mixed in with the ignition fuel. The steam generator will be an indoor drum type, balanced draft, with single reheat, and fueled with the coal that is currently burned at Stanton Units 1 and 2. It will be equipped with fuel oil igniters, soot blowers, and forced draft fans.

The steam cycle configuration will include seven feedwater heaters, a deaerator, and turbine driven feedwater pumps. The assumed steam pressure for the subcritical unit will be 2,535 psig. Water for the unit will be provided by the existing water supply. Circulating water will come from the existing makeup water supply storage pond.

For heat rejection, the subcritical coal unit will use a surface condenser, counterflow natural draft cooling tower, circulating water pumps, and auxiliary cooling water heat exchangers.

The subcritical pulverized coal unit will include a wet flue gas desulfurization (FGD) scrubber process to remove SO_2 emissions. The scrubber would be designed to meet BACT requirements. The SO_2 scrubber would produce calcium sulfate (gypsum) as a byproduct, which is acceptable for producing wallboard. The production of gypsum would help reduce the solid waste stream from a subcritical pulverized coal generating facility.

The unit will employ SCR to reduce NO_x emissions. The SCR uses ammonia in the presence of a catalyst to remove NO_x from the flue gas. The SCR would be designed to meet BACT requirements. The subcritical pulverized coal unit will also include an electrostatic precipitator to reduce emissions of particulate matter.

The operating characteristics and emissions estimates for a subcritical pulverized coal unit are presented in Tables 8-26 and 8-27, respectively.

8.2.10 Capital Costs, O&M Costs, Schedules, and Availability

The capital costs, O&M costs, schedules, and availability for the generating alternatives are summarized in Table 8-28. All costs are provided in 2005 dollars. The EPC cost is inclusive of engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. A base allowance of 30 percent for Owner's costs is also included, with the site-specific additions or reductions discussed previously. Actual Owner's costs can vary significantly in Black & Veatch's experience; however, the assumed allowance is representative of typical Owner's costs exclusive of escalation, financing fees, and interest during construction.

Table 8-26
Pulverized Coal Unit Characteristics

Ambient Condition	Net Capacity (MW)[1]	Full Load Net Plant Heat Rate (Btu/kWh, HHV)[1,2]
Summer (100° F)	445.0	9,414
Average (72° F)	446.9	9,369

[1]Performance assumes operation on 100 percent bituminous coal.
[2]Plant performance includes degradation.

Table 8-27
Pulverized Coal Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	16.9
NO_x, lb/MBtu (HHV)	0.07
SO_2, lb/MBtu (HHV)	0.10
Hg, lb/TBtu (HHV)	1.29
CO_2, lb/MBtu (HHV)	204.5
CO, ppmvd at 15% O_2	39.7
CO, lb/MBtu (HHV)	0.10

[1]Emissions include the effects of SCR and SO_2 emissions control.

Table 8-28
Capital Costs, O&M Costs, Schedules, and Availability for the Generating Alternatives

Supply Alternative[1]	EPC Cost ($Millions)	Owner's Cost ($Millions)	Total Cost ($Millions)	Total Cost[2] ($/kW)	Fixed O&M[2] ($/kW-yr)	Variable O&M[2] ($/MWh)	Construction/ Development Schedule[3] (Months)	Maintenance[4] (Days)	Forced Outage (Percent)
LM6000 SC	33.68	10.10	43.78	942	15.37[5]	4.85[5]	12	10	3.0
LMS100 SC	56.78	17.03	73.81	804	8.26[5]	5.28[5]	17	10	3.0
7EA SC	43.95	13.18	57.13	718	7.98[5]	26.16[5]	13	10	3.0
7FA SC	60.83	18.25	79.08	475	4.19[5]	29.19[5]	14	10	3.0
1x1 7FA CC	159.95	47.98	207.93	696	5.72	6.18	30	14	5.0
CFB	426.73	150.96	577.69	1,915	38.55	4.13	41	21	7.0
Subcritical PC	554.02	189.14	743.16	1,663	24.89	1.85	50	20	7.0

(1)All costs are presented in 2005 dollars.
(2)Costs reflect operation at 72° F.
(3)Includes time for equipment procurement, planning, and permitting if applicable.
(4)Reflects an average maintenance schedule.
(5)O&M costs reflect operation on fuel oil.

Fixed and variable O&M costs are also provided in 2005 dollars. Fixed costs include labor, maintenance, and other fixed expenses excluding backup power, property taxes, and insurance. Variable costs include outage maintenance, consumables, and replacements dependent upon operation.

Construction schedules are indicative of typical construction durations for the alternative technology and plant size. Actual costs and schedules will vary from the preliminary estimates provided.

8.3 Emerging Technologies

Emerging technologies are technologies that are either just starting or are about to start commercial operation. With emerging technologies, utilities would generally like to see some history of successful commercial operation before making a commitment to install. The LMS100 and nuclear alternatives have been classified as emerging technologies. While there are many nuclear units in operation, a new domestic nuclear unit has not been ordered in more than 25 years. A number of issues, including licensing, create uncertainty about the schedule that would be required to bring a new nuclear unit into commercial operation. The following subsections describe the emerging technologies.

8.3.1 General Electric LMS100 Combustion Turbine

The LMS100 is a new GE unit that has the disadvantage of not being commercially proven. Due to the lack of commercial demonstration, the LMS100 is considered an emerging technology. After the reliability of the LMS100 has been successfully demonstrated, it will likely be used in place of two unit blocks of LM6000s.

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

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

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

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

Table 8-29 presents the operating characteristics of the LMS100 combustion turbine, Table 8-30 presents estimated emissions for the LMS100. The estimated capital and O&M costs, schedule, maintenance requirements, and expected forced outage rate are presented in Table 8-28.

8.3.2 Nuclear Fission

A uranium-fueled nuclear fission process has been used to create energy in the United States for several decades. Inside a nuclear reactor, uranium atoms are bombarded by neutrons. Each time a neutron is absorbed by a uranium atom, the atom becomes unstable and splits, a process known as fission. During this process, the atom produces additional neutrons, usually two and a half for each fission. These neutrons split more uranium atoms, creating more neutrons. This scenario perpetuates, resulting in a chain reaction. The fission process generates heat in the reactor core. The generated heat is transferred to water, which is circulated to the steam generator.

Currently, nuclear power in the United States faces obstacles related to public perception, capital costs, and environmental issues concerning disposal of spent fuel. Combined, these factors explain why nuclear plants have fallen out of favor as a generating resource. However, rising fuel prices, greenhouse gas emission concerns, and increasing energy demand may make nuclear fission a viable option for producing power in the future.

Westinghouse and General Electric are currently developing and licensing nuclear units with the Nuclear Regulatory Commission (NRC). The two units are the Westinghouse AP-1000 and the General Electric ESBWR. The AP-1000 was approved by the NRC in 2004, and the NRC is expected to approve the ESBWR in 2007.

Table 8-29 GE LMS100 Combustion Turbine Characteristics		
Ambient Condition	Net Capacity (MW)[1]	Full Load Net Plant Heat Rate (Btu/kWh, HHV)[1,2]
Summer (100° F)	83.6	9,068
Average (72° F)	91.8	8,837

[1]Net capacity and full load net plant heat rate include degradation factors.
[2]Heat rate and net capacity assume operation on fuel oil.

Table 8-30 GE LMS100 Estimated Emissions[1]	
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu (HHV)	0.0079
SO_2, lb/MBtu (HHV)	0.0005
Hg, lb/MBtu (HHV)	NA
CO_2, lb/MBtu (HHV)	159.8
CO, ppmvd at 15% O_2	15.5
CO, lb/MBtu (HHV)	0.0372

[1]Emissions are at full load at 72° F, ultra low sulfur fuel oil operation, and include the effects of SCR and CO catalyst.

The units consist of a nuclear island (NI), turbine island (TI), radwaste building, cooling tower, and additional yard facilities. The units described in this section are assumed to be located at a greenfield site in central Florida.

The TI consists of the steam turbine and the switchgear building. The switchgear building includes standard electrical equipment and switchgear for a large nuclear unit.

The radwaste building has both liquid and solid radwaste treatment systems. In addition to the treatment systems, costs for the radwaste building include communications, lighting, and security systems.

The cooling tower is one of the major yard facilities and is assumed to be a mechanical draft cooling tower with a pump house and retention pond. Other yard facilities include transformers, fuel and chemical storage systems, a makeup water treatment building, grounding system, radwaste tunnel, and a service building.

Since the large capacity of a nuclear unit would not be practical to meet OUC's capacity needs, it is assumed that OUC would jointly own the unit with other utilities who would develop and manage the project.

Nuclear units have virtually no emissions, and there will be no emissions control equipment included with the plant. Currently there is no way to dispose of spent fuel rods after the fission process, but the operating costs of the nuclear unit include such costs in the future. The output and performance of the AP-1000 and ESBWR nuclear units are presented in Table 8-31.

8.4 Advanced Technologies

Advanced technologies include developmental technologies near commercial status that offer the potential for cost and efficiency improvements over conventional technologies. The technologies evaluated include advanced combustion, fuel cell, and coal.

8.4.1 Advanced Combustion Turbine Technologies

When used in a combined cycle configuration, combustion turbines have many advantages, including low capital cost, high efficiency, and short construction periods. This section describes several advanced combustion turbines that can improve output, performance, and efficiency in combined cycle configurations. Operation of a combustion turbine approaches an idealized thermodynamic cycle called the air-standard Brayton cycle. The Brayton cycle is an all-gas cycle that uses air and combustion gases as the working fluid, as opposed to the Rankine cycle, which is a vapor-based cycle. Three Brayton cycles show promise as advanced technologies: the humid air turbine (HAT) cycle, Kalina cycle, and Cheng cycle.

Table 8-31
Nuclear Unit – Performance and Costs

	Westinghouse AP-1000	GE ESBWR
Commercial Status	Development	Development
Construction Period (months)	72	72
Performance		
Net Capacity (MW)	1,200	1,578
Net Plant Heat Rate (Btu/kWh)	9.715	9,715
Capacity Factor (percent)	80 to 90	80 to 90
Economics, $2005		
Total Project Cost ($/kW)	2,054	1,733
Fixed O&M ($/kW-yr)	61	61
Levelized Cost(1) ($/MWh)	52 to 48	48 to 52

(1)The low end of the levelized cost is based on a 90 percent capacity factor, and the high end is based on an 80 percent capacity factor.

8.4.1.1 Humid Air Turbine Cycle. The HAT cycle is an intercooled, regenerative cycle burning natural gas with a saturator. The saturator adds considerable amounts of moisture to the compressor discharge air so that the combustor inlet flow contains 20 to 40 percent water vapor. The warm humidified air from the saturator is then further heated by the turbine exhaust in a recuperator before being sent to the combustor. The water vapor adds to the turbine output, while intercooling reduces the compressor work requirement. The heat addition in the recuperator reduces the amount of fuel heat input required. Although the HAT cycle may offer future energy efficiencies and cost savings, it is a developmental technology that is not ready for commercial application. Table 8-32 presents typical performance and cost characteristics for the HAT cycle.

8.4.1.2 Kalina Cycle. The Kalina cycle is a combined cycle plant configuration that injects ammonia into the vapor side of the cycle. The ammonia/water working fluid provides thermodynamic advantages because of the nonisothermal boiling and condensing behavior of the working fluid's two-component mixture. Ammonia has a lower boiling point than water, which allows the cycle to start spinning the steam turbine at much lower temperatures than conventional systems. This capability allows more effective heat acquisition, regenerative heat transfer, and heat rejection.

Table 8-32
HAT Cycle Performance and Costs

Commercial Status	Development
Construction Period (months)	20 to 28
Performance	
Plant Capacity (MW)	250 to 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 to 80
Economics ($2005)	
Total Project Cost ($/kW)	500 to 800
Fixed O&M ($/kW-yr)	5 to 10
Variable O&M ($/MWh)	2 to 4
Levelized Cost(1) ($/MWh)	65 to 77

(1)The low end of the levelized cost is based on an 80 percent capacity factor, 650 MW plant capacity, capital cost of $500/kW, fixed O&M cost of $5/kW-year, and variable O&M cost of $2/MWh. The high end of the levelized cost is based on a 60 percent capacity factor, 250 MW plant capacity, capital cost of $800/kW, fixed O&M cost of $10/kW-year, and variable O&M cost of $4/MWh.

The cycle is similar in nature to the combined cycle process, except that exhaust gas from the combustion turbine enters a heat recovery vapor generator (HRVG). Fluid (70 percent ammonia, 30 percent water) from the distillation condensation subsystem (DCSS) enters the HRVG to be heated. A portion of the mixture is removed at an intermediate point from the HRVG and is sent to a heat exchanger, where it is heated with vapor turbine exhaust from the intermediate-pressure vapor turbine. The moisture returns to the HRVG, where it is mixed with the balance of flow, superheated, and expanded in the vapor turbine generator (VTG). Additional vapor enters the HRVG from the high-pressure vapor turbine, where it is reheated and supplied to the inlet of the intermediate-pressure vapor turbine. The vapor exhausts from the vapor turbine and condenses in the DCSS. The Kalina cycle is still a developmental technology for large-scale applications. There are currently four plants operating worldwide that use this technology. Capital costs are still high, and power outputs are limited to under 5 MW. The Kalina cycle could be retrofit to an existing plant or gas compressor station to capture waste heat. Table 8-33 presents typical performance and cost characteristics for the Kalina cycle.

Table 8-33
Kalina Cycle Performance and Costs

Commercial Status	Development
Construction Period (months)	26 to 29
Performance	
Plant Capacity (MW)	50 to 500
Net Plant Heat Rate (Btu/kWh)	6,700
Capacity Factor (percent)	60 to 80
Economics ($2005)	
Total Project Cost ($/kW)	800 to 1,000
Fixed O&M ($/kW-yr)	4 to 11
Variable O&M ($/MWh)	2 to 4
Levelized Cost(1) ($/MWh)	70 to 82

(1)The low end of the levelized cost is based on a 500 MW plant capacity, 80 percent capacity factor, capital cost of $800/kW, fixed O&M cost of $4/kW-year, and variable O&M cost of $2/MWh. The high end of the levelized cost is based on a 50 MW plant capacity, 60 percent capacity factor, capital cost of $1000/kW, fixed O&M cost of $11/kW-year, and variable O&M cost of $4/MWh.

8.4.1.3 Cheng Cycle. The Cheng cycle is a steam-injected gas turbine, which increases efficiency over the gas turbine cycle by injecting large volumes of steam into the combustor and/or turbine section. The basic Cheng cycle is composed of a compressor, combustor, turbine, generator, and HRSG. The HRSG provides injection steam to the combustor as well as process steam. The amount of steam injection is limited to the allowable loading of the turbine blades.

The typical application of the Cheng cycle is in a cogeneration facility, but it has also been proposed as a retrofit for simple cycle combustion turbines. Table 8-34 presents typical performance and cost characteristics for the Cheng cycle.

8.4.2 Fuel Cell

Fuel cell technology has been developed by government agencies and private corporations. Fuel cells are an important part of space exploration and are receiving considerable attention as an alternative power source for automobiles. In addition to these two applications, fuel cells continue to be considered for power generation to meet permanent and intermittent power demands.

Table 8-34 Cheng Cycle Performance and Costs	
Commercial Status	Development (larger units)
Construction Period (months)	20 to 28
Performance	
Plant Capacity (MW)	25 to 250
Net Plant Heat Rate (Btu/kWh)	8,000 to 9,000
Capacity Factor (percent)	60 to 80
Economics ($2005)	
Total Project Cost ($/kW)	1,200 to 2,500
Fixed O&M ($/kW-yr)	6 to 11
Variable O&M ($/MWh)	2 to 4
Levelized Cost(1) ($/MWh)	87 to 128

(1)The low end of the levelized cost is based on a 250 MW plant capacity, 8,000 Btu/kWh net plant heat rate, 80 percent capacity factor, capital cost of $1,200/kW, fixed O&M cost of $6/kW-year, and variable O&M cost of $2/MWh. The high end of the levelized cost is based on a 25 MW plant capacity, 9,000 Btu/kWh net plant heat rate, 60 percent capacity factor, capital cost of $2,500/kW, fixed O&M cost of $11/kW-year, and variable O&M cost of $4/MWh.

8.4.2.1 Operating Principles. Fuel cells convert hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cell power systems have the promise of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Fuel cells can sustain high efficiency operation even at part load. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements.

There are four major fuel cell types under development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). PAFC plants range from around 200 kW to 11 MW in size and have efficiencies on the order of 40 percent. PAFC cogeneration facilities can attain efficiencies approaching 88 percent when the thermal energy from the fuel cell is utilized for low grade energy recovery. The development of solid oxide fuel cell gas turbine combined cycles could potentially allow electrical conversion efficiencies of 60 to 70 percent.

8.4.2.2 Applications. Most fuel cell installations generate less than 1 MW. Commercial fuel cell plants are typically fueled by natural gas, which is converted to hydrogen gas in a reformer. However, if available, hydrogen gas can be used directly. Other fuel sources under investigation include methanol, biogas, ethanol, and other hydrocarbons.

In addition to the potential for high efficiency, the environmental benefits of fuel cells remain the primary reasons for their development. High capital cost, short fuel cell stack life, and uncertain reliability, the primary disadvantages of fuel cell systems, continue to be the focus of research and development. The cost for these systems is expected to drop significantly as development efforts continue, partially spurred by interest from the automotive transportation sector.

8.4.2.3 Performance and Cost Characteristics. The performance and cost characteristics of a typical fuel cell plant are shown in Table 8-35. A significant cost is required to replace the fuel cell stack every 3 to 5 years because of degradation. The stack alone can represent up to 40 percent of the initial capital cost. Most fuel cell technologies are still developmental, and power produced by commercial models is not competitive.

8.4.3 Advanced Coal Technologies

8.4.3.1 Pressurized Fluidized Bed. Coal fired plants continue to supply a large portion of the energy requirements in the United States. Current research is focused on making the conversion of energy from coal more clean and efficient. Pressurized fluidized bed systems have been developed to improve coal conversion efficiency.

Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology in which combustion occurs in a pressure vessel at 10 to 15 atm. The PFBC process involves burning crushed coal in a limestone or dolomite bed. High combustion efficiency and excellent sulfur capture are advantages of this technology. In combined cycle configurations, PFBC exhaust is expanded to drive both the compressor and combustion turbine generator. HRSGs transfer heat from this exhaust to generate steam in addition to the steam generated from the PFBC boiler. Overall thermal efficiencies of PFBC combined cycle configurations are 45 to 47 percent. Second generation PFBC systems are in the development stage. Since this technology is in the development stage, it is difficult to accurately quantify the capital costs. This technology is not yet mature enough to be considered for a new generation project. Table 8-36 presents typical performance and cost characteristics for PFBC.

Table 8-35
Fuel Cell Technology Characteristics

Commercial Status	Development/Early Commercial
Performance	
Net Capacity per Unit (kW)	100 to 250
Net Plant Heat Rate (Btu/kWh)	7,000 to 9,500
Capacity Factor (percent)	30 to 70
Economics ($2005)	
Total Project Cost ($/kW)	5,000 to 7,000
Fixed O&M(1) ($/kW-yr)	500 to 700
Variable O&M ($/MWh)	5 to 10
Levelized Cost(2) ($/MWh)	253 to 707

(1)Includes costs for cell stack replacement every 4 years.
(2)The low end of the levelized costs are based on a 250 kW plant capacity, 7,000 Btu/kWh net plant heat rate, 70 percent capacity factor, capital cost of $5,000/kW, fixed O&M cost of $500/kW-year, and variable O&M cost of $5/MWh. The high end of the levelized costs are based on 100 kW plant capacity, 9,500 Btu/kWh net plant heat rate, 30 percent capacity factor, capital cost of $7,000/kW, fixed O&M cost of $700/kW-year, and variable O&M cost of $10/MWh.

Table 8-36
Pressurized Fluidized Bed Combustion Performance and Costs

Commercial Status	Development
Construction Period (months)	32 to 38
Performance	
Plant Capacity (MW)	150 to 350
Net Plant Heat Rate (Btu/kWh)	8,000 to 9,000
Capacity Factor (percent)	60 to 80
Economics, $2005	
Total Project Cost ($/kW)	1,800 to 2,400
Fixed O&M ($/kW-yr)	20 to 35
Variable O&M ($/MWh)	4 to 5
Levelized Cost(1) ($/MWh)	63 to 92

(1)The low end of the levelized cost is based on a 350 MW plant capacity, 8,000 Btu/kWh net plant heat rate, 80 percent capacity factor, capital cost of $1,800/kW, fixed O&M cost of $20/kW-year, and variable O&M cost of $4/MWh. The high end of the levelized cost is based on a 150 MW plant capacity factor, 9,000 Btu/kWh, 60 percent capacity factor, capital cost of $2,400/kW, fixed O&M cost of $35/kW-year, and variable O&M cost of $5/MWh.

8.4.3.2 Advanced Supercritical Cycle. Supercritical cycles operate above the critical point of water, where there is no distinction between water and steam. Supercritical cycles have been developed to improve Rankine cycle efficiency.

In the industry, supercritical has typically referred to a cycle with main steam conditions of 3,500 psig and 1,050° F, with single reheat at 1,075° F. Advanced supercritical cycles generally involve steam conditions with higher temperatures and pressures than the current industry standard, within limits set by current materials. Currently, this limit is thought to be steam conditions around 4,700 psig at 1,130° F, with double reheat at 1,165° F. Maximum thermal efficiency may approach 47 percent.

8.4.3.3 Ultrasupercritical Cycle. Ultrasupercritical represents a step change to temperatures and pressures above those in advanced supercritical. Main steam conditions of 5,500 psig and 1,300° F are being investigated. Operation at these conditions will require the development of more advanced materials. This technology is still in the research and development stage. Thermal efficiency is predicted to be between 52 and 55 percent.

8.5 Energy Storage Technologies

Energy storage technologies convert and store electricity, increasing the value of power by allowing better utilization of off-peak baseload generation and the mitigation of instantaneous power fluctuations. Different types of technologies are available that provide a variety of storage durations. Storage durations range from microseconds (superconducting magnets, flywheels, and batteries), to minutes (flywheels and batteries), to hours and seasonal storage (pumped hydroelectric, batteries, and compressed air). An analysis of technologies that could be used on a commercial level is provided in the following sections.

8.5.1 Pumped Hydroelectric Energy Storage

Pumped hydroelectric energy storage is the oldest and most prevalent of the commercial scale energy storage options. More than 22,000 MW of pumped storage generation has been installed in the United States.[16] A pumped storage hydroelectric facility requires a reservoir/dam system similar to a conventional hydroelectric facility. During times of minimal load demand, excess low cost energy is used to pump water from a lower reservoir to an upper reservoir above a dam. When energy is required during the high cost, peak electrical demand periods, the water in the upper reservoir is released through a turbine to produce electricity.

[16] US Department of Energy, *EPRI*, "Renewable Energy Technology Characterizations," December 1997.

Capital cost and project lead time are the primary considerations for implementation of this storage technology. Capital costs are typically very high on a dollar per kW basis, and a 4 or 5 year construction period is common for larger pumped storage facilities. Additionally, it is difficult to gain environmental approvals for damming up the nation's river systems or developing reservoirs on mountain tops. Geographic and geologic conditions largely preclude many areas from consideration of this technology. Table 8-37 presents typical performance and cost estimates for pumped hydroelectric energy storage.

Table 8-37
Pumped Hydroelectric Energy Storage Performance and Costs

Commercial Status	Commercial
Construction Period (months)	12 to 60
Performance	
Plant Capacity (MW)	30 to 1,500
Capacity Factor (percent)	10 to 15
Economics ($2005)	
Total Project Cost ($/kW)	1,500 to 2,600
Fixed O&M ($/kW-yr)	5 to 13
Variable O&M ($/MWh)	2 to 5
Levelized Cost[(1)] ($/MWh)	155 to 343

[(1)]The low end of the levelized cost is based on a 1,500 MW plant capacity, 15 percent capacity factor, capital cost of $1,500/kW, fixed O&M cost of $5/kW-year, and variable O&M cost of $2/MWh. The high end of the levelized cost is based on a 30 MW plant capacity, 10 percent capacity factor, capital cost of $2,600/kW, fixed O&M cost of $13/kW-year, and variable O&M cost of $5/MWh. The cost of off-peak energy is assumed to be $30/MWh.

8.5.2 Battery Storage

A battery storage system consists of the battery, dc switchgear, dc/ac converter and charger, transformer, ac switchgear, and a building to house the components. During peak power demand periods, the battery system can discharge power to the utility system for about 4 to 5 hours. The batteries are then recharged during non-peak hours. In addition to the high initial cost, a battery system would require replacement every 4 to 10 years, depending on the duty cycle.

Currently, most utility scale battery systems are lead-acid batteries. The Electricity Storage Association (ESA) Web site lists five lead-acid battery systems larger than 1 MWh, with the largest being the 10 MW, 40 MWh system at Chino, California.[17] The site also provides information on other emerging battery technologies. The sodium-sulfur (Na-S) technology being developed in Japan is moving toward commercial status. The ESA site discusses the use of Na-S technology at over 30 sites in Japan totaling 20 MW. Recently, Appalachian Power Company announced the planned deployment of a 1.2 MW Na-S battery energy system near Charleston, West Virginia.[18] Table 8-38 provides the cost and performance characteristics of a 5 MW (15 MWh) system.

Table 8-38
Lead-Acid Battery Energy Storage - Performance and Costs

Commercial Status	Commercial
Construction Period (months)	12 to 18
Performance	
Plant Capacity (MW)	5
Energy Capacity (MWh)	15
Capacity Factor (percent)	10 to 15
Economics ($2005)	
Total Project Cost ($/kW)	2,800 to 3,200
Fixed O&M ($/kW-yr)	30
Variable O&M(1) ($/MWh)	430 to 470
Levelized Cost(2) ($/MWh)	821 to 1033

(1)Includes battery replacement at 10 years.
(2)The low end of the levelized cost is based on a capacity factor of 15 percent, capital cost of $2,800/kW, and variable O&M cost of $430/MWh. The high end of the levelized cost is based on a capacity factor of 10 percent, capital cost of $3,200/kW, and variable O&M cost of $470/MWh.

8.5.3 Compressed Air Energy Storage

Compressed air energy storage (CAES) is a technique used to supply electrical power to meet peak loads within an electric utility system. This method uses the power surplus from baseload coal and nuclear plants during off-peak periods to compress

[17] Electricity Storage Association, www.electricitystorage.org/.
[18] AEP Substation to Get Commercial-Scale Energy Storage System, *Power Engineering*, October 2005.

and store air in an underground formation. The compressed air is later heated (with a fuel) and expanded through a gas turbine expander to produce electrical power during peak demand. A simple compressed air storage plant consists of an air compressor, turbine, generator unit, and a storage vessel. Exhaust gas heat recuperation can be added to increase efficiency.

The thermodynamic cycle for a compressed air storage facility is similar to that of a simple cycle gas turbine. Typically, gas turbines will consume 50 to 60 percent of their net power output to operate an air compressor. In a compressed air storage plant, the air compressor and the turbine are not connected, and the total power generated from the gas turbine is supplied to the electrical grid. By using off-peak energy to compress the air, the need for expensive natural gas or fuel oil is reduced by as much as two thirds, compared with conventional gas turbines.[19] This results in a very attractive heat rate for CAES plants, ranging from 4,000 to 5,000 Btu/kWh. Since fuel (typically natural gas) is supplied to the system during the energy generation mode, CAES plants actually provide more electrical power to the grid than was used to compress the air.

The location of a CAES plant must be suitable for cavern construction or for the reuse of an existing cavern. However, suitable geology is widespread throughout the United States, with more than 75 percent of the land area containing appropriate geological formations.[20] There are three types of formations that can be used to store compressed gases: solution mined reservoirs in salt, conventionally mined reservoirs in salt or hard rock, and naturally occurring porous media reservoirs (aquifers).

The basic components of a CAES plant are proven technologies, and CAES units have a reputation for achieving good availability. The first commercial-scale CAES plant in the world was a 290 MW plant in Huntorf, Germany. This plant has been operating since 1978, providing 2 hours of generation with 8 hours of charging. In 1991, a 110 MW CAES facility was installed in McIntosh, Alabama. This plant remains the only US CAES installation, although several new plants have been announced recently. Table 8-39 shows the performance and cost characteristics of a CAES system.

8.6 Distributed Generation Technologies

There are several advantages associated with using distributed generation technology as a portion of a utility's generation capacity. In general, distributed generation options are small, reliable units that can help a utility to adequately meet peak demands. Distributed generation alternatives can also be used to provide baseload for smaller utilities. Two types of distributed generation technologies were analyzed.

[19] Nakhamkin, M., Anderson, L., Swenson, E., "AEC 110 MW CAES Plant: Status of Project," *Journal of Engineering for Gas Turbines and Power*, October 1992, Vol. 114.
[20] Mehta, B., "Compressed Air Energy Storage: CAES Geology," *EPRI Journal*, October/November 1992.

Table 8-39 Compressed Air Energy Storage Performance and Costs	
Commercial Status	Commercial
Construction Period, months	26 to 29
Performance	
Net Plant Capacity (MW)	100 to 500
Net Plant Heat Rate (Btu/kWh)	4,000 to 5,000
Capacity Factor (percent)	10 to 25
Economics ($2005)	
Total Project Cost ($/kW)	480 to 730
Fixed O&M ($/kW-yr)	5 to 16
Variable O&M ($/MWh)	3 to 6
Levelized Cost[1] ($/MWh)	102 to 194

[1]The low end of the levelized cost is based on a 500 MW plant capacity, 4,000 Btu/kWh net plant heat rate, 25 percent capacity factor, capital cost of $480/kW, fixed O&M cost of $5/kW-year, and variable O&M cost of $3/MWh. The high end of the levelized cost is based on a 100 MW plant capacity, 5,000 Btu/kWh net plant heat rate, 10 percent capacity factor, capital cost of $730/kW, fixed O&M cost of $16/kW-year, and variable O&M cost of $6/MWh. Assumes $30/MWh off-peak energy.

8.6.1 Reciprocating Engines

Reciprocating engines are proven prime movers for electric generation, industrial processes, and many other applications. Reciprocating engines operate according to either an Otto or Diesel thermodynamic cycle, very much like a personal automobile. These cycles use similar mechanics to produce work, but differ in the way that they combust fuel.

Reciprocating engines contain multiple pistons that are individually attached by connecting rods to a single crankshaft. Fuel is burned at the other end of the piston's sealed combustion chambers. A mixture of fuel and air is injected into the combustion chamber, where, after compression, an explosion is caused. The explosion provides energy to force the pistons down; this linear motion is translated into the angular rotation of the crankshaft by the connecting rods. The combustion chambers are vented and the piston pushes the exhaust gases out, completing the two rotations of the crankshaft. The process is repeated and work is performed.

Reciprocating engine generator sets are commonly used in generation of power either for emergency backup or peak load shaving. However, there is also a well established market for installation of generator sets as the primary power source for small power systems and isolated facilities that are located away from the transmission grid.

When used for power generation, medium speed engines (less than 1,000 rpm) are typically used since they are more efficient and have lower O&M costs than smaller, higher speed machines. Reciprocating engines have relatively constant efficiency rates from 100 to 50 percent load, they have excellent load following characteristics, and they can maintain guaranteed emission rates down to approximately 25 percent load, thus providing superior part-load performance. Typical startup times for larger reciprocating engines are on the order of 15 minutes. However, some engines can be configured to start up and be completely operational within 10 seconds for use as emergency backup power.

Spark ignition engines are designed to operate on gaseous fuels such as natural gas, propane, and waste gases from industrial processes. Compression ignition engines are designed to operate on liquid fuels such as diesel fuel oil and biodiesel. Because they have such flexibility, engine generators are well suited for use as conventional or renewable power generation. Table 8-40 provides performance and cost characteristics for typical reciprocating engine installations.

8.6.2 Microturbines

The microturbine is essentially a small version of the combustion turbine. It is typically offered in the size range of 30 to 60 kW. These turbines were initially developed in the 1960s by Allison Engine Co. for ground transportation. The first major field trial of this technology was in 1971 with the installation of turbines in six Greyhound buses. By 1978, the busses had traveled more than a million miles, and the turbine engine was viewed by Greyhound management as a technical breakthrough. Since this initial application, microturbines have been used in many applications, including small-scale electric and heat generation in industry, waste recovery, and continued use in vehicles.

Microturbines operate on a principle similar to that of larger combustion turbines. Atmospheric air is compressed and heated with the combustion of fuel, then expanded across turbine blades, which in turn operate a generator to produce power. The turbine blades operate at very high speeds in these units, up to 100,000 rpm, versus the slower speeds observed in large combustion turbines. Another key difference between the large combustion turbines and the microturbines is that the compressor, turbine, generator, and

Table 8-40
Reciprocating Engine Technology Characteristics

Engine Type	Spark Ignition (Natural Gas)	Compression Ignition (Diesel)
Commercial Status	Commercial	Commercial
Performance		
Net Plant Capacity (kW)	1 to 5,000	1 to 10,000
Net Plant Heat Rate (Btu/kWh)	9,700	7,800
Capacity Factor (percent)	30 to 70	30 to 70
Economics ($2005)		
Total Project Cost ($/kW)	450 to 1,100	350 to 800
Variable O&M ($/MWh)	15 to 25	15 to 25
Levelized Cost(1) ($/MWh)	109 to 154	175 to 212

(1)The low ends of the levelized costs are based on the higher plant capacities and capacity factors, and the lower capital and O&M costs. The high ends of the levelized costs are based on the lower plant capacities and capacity factors, and the higher capital and O&M costs.

electric conditioning equipment are all contained in a single unit about the size of a refrigerator, versus a unit about the size of a railcar. The thermal efficiency of these smaller units is currently in the range of 20 to 30 percent, depending on manufacturer, ambient conditions, and the need for fuel compression; however, efforts are under way to increase the thermal efficiency of these units to around 40 percent.

Potential applications for microturbines are very broad, given the fuel flexibility, size, and reliability of the technology. The units have been used in electric vehicles, distributed generation, and resource recovery applications. These systems have been used in many remote power applications around the world to bring reliable generation outside of the central grid system. In addition, these units are currently being used in several landfill sites to generate electricity with landfill gas fuel to power the facilities on the site. For example, the Los Angeles Department of Water and Power recently installed an array of 50 microturbine generators at the Lopez Canyon landfill. The project has a net output of 1,300 kW.

Microturbines offer fuel flexibility; fuels suitable for combustion include natural gas, ethanol, propane, biogas, and other renewable fuels. The minimum requirement for fuel heat content is around 350 Btu/scf, depending upon microturbine manufacturer.

Microturbine costs are often discussed as being about $1,000 per kilowatt, but this is typically just the bare engine cost. Auxiliary equipment, engineering, and construction costs can be significant. Table 8-41 provides performance and cost characteristics for typical microturbine installations.

Table 8-41
Microturbine Technology Characteristics

Commercial Status	Early Commercial
Performance	
Net Capacity per Unit (kW)	15 to 60
Net Plant Heat Rate (Btu/kWh)	12,200
Capacity Factor (percent)	30 to 70
Economics ($2005)	
Total Project Cost ($/kW)	950 to 1,700
Variable O&M ($/MWh)	10 to 20
Levelized Cost[1] ($/MWh)	130 to 190

[1]The low end of the levelized cost is based on 60 kW plant capacity, 70 percent capacity factor, capital cost of $950/kW, and variable O&M cost of $10/MWh. The high end of the levelized cost is based on 15 kW plant capacity, 30 percent capacity factor, capital cost of $1,700/kW, and variable O&M cost of $20/MWh.

8.7 Supply-Side Screening

A supply-side screening was performed on each of the alternatives described previously in this section. The supply-side screening considers each alternative's feasibility, levelized cost, and overall reliability to meet OUC's capacity needs. The levelized cost for each alternative is determined on a dollar per MWh basis and includes capital costs, fuel costs, and O&M costs. The levelized cost is calculated to reflect an all-in cost for capacity at a given capacity factor and is used to make screening level comparisons of different technologies.

The alternatives that appear favorable in the supply-side screening will be evaluated further in the economic analysis presented in Section 10.0. The following subsections present the results of the supply-side screening for the various types of alternatives considered.

8.7.1 Renewable Technologies

Before a supply-side alternative can be appropriately considered for analysis on a levelized cost basis, the technology's reliability and feasibility to meet OUC's capacity needs must be established. Many of the renewable technologies considered are still in the research and development stage. As a result of a lack of commercial demonstration, the parabolic dish, central receiver, solar chimney, and ocean thermal technologies were eliminated from further economic evaluation.

Unlike most of the conventional alternatives, renewable technologies are highly dependent on the availability and sufficiency of the various resources utilized for electric power production. Renewable technologies may be commercially viable in some areas of the United States, but unfeasible in other regions because of the high level of dependence on resource availability. Based on transmission considerations, renewable technology alternatives considered in this analysis were limited to a geographic location in central Florida. Therefore, wind energy, solar parabolic trough, geothermal, and hydroelectric technologies were eliminated from further economic analysis. While landfill gas is available at the Orange County Landfill, OUC presently burns the available landfill gas in Stanton Units 1 and 2. Thus, additional landfill gas generation will not be considered.

If an alternative is both commercially proven and feasible based on resource availability, it can be appropriately considered on a levelized cost basis. The levelized costs of the remaining renewable alternatives were compared with the costs of conventional alternatives as shown on Figures 8-1 and 8-2, which are presented at the end of this section. Table 8-42 presents the midpoint of the range of levelized costs presented earlier in this section. Although potentially feasible, MSW mass burn, refuse-derived fuel, direct-fired biomass, and solar PV technologies were eliminated from further economic analysis on a levelized cost basis.

The only two remaining renewable technologies that were determined to be both feasible and economically viable were co-fired biomass and anaerobic digestion. Co-fired biomass was considered as an incremental 20 MW of capacity from an existing 750 MW pulverized coal unit. This capacity addition is not sufficient to displace the need for Stanton B. Additionally, OUC does not have full ownership in a pulverized coal unit, which precludes a single point decision on unit modifications such as biomass co-firing. As a result, biomass co-firing was not considered for further economic analysis.

The levelized cost of anaerobic digestion is equal to the cost of the pulverized coal unit at an 85 percent capacity factor. The anaerobic digester presented in Table 8-3 has a capacity of only 85 kW. Even if several of these facilities were available, they would not displace the need for Stanton B. As a result, the anaerobic digester was not considered for further economic analysis.

Table 8-42
Renewable Alternative Screening Results

Technology	Average 2010 Levelized Cost ($/MWh)
Direct-Fired Biomass	105
Co-Fired Biomass	35
Anaerobic Digestion	63
Landfill Gas	49
MSW Mass Burn	123
Refuse-Derived Fuel	213
Wind	148
Solar Parabolic Trough	145
Solar Parabolic Dish	189
Central Receiver	166
Solar Chimney	83
Solar PV Residential	726
Solar PV Commercial	495
Geothermal	96
New Hydroelectric	86
Incremental Hydroelectric	56
Ocean Thermal Onshore	173
Ocean Thermal Offshore	70

Figures 8-1 and 8-2, which are presented at the end of this section, show the levelized cost ranges of the renewable alternatives presented in Table 8-42 compared to the levelized costs of peak and base conventional alternatives presented in Figures 8-3 and 8-4. While none of the renewable alternatives are viable alternatives to Stanton B, it is instructive to look at their levelized costs relative to conventional alternatives. Figure 8-1 is a comparison of peak load alternatives. The central receiver, parabolic dish, parabolic trough, and wind alternatives look favorable compared to the conventional peak load alternatives. Unfortunately, the renewable alternatives cannot be considered firm capacity. Even if partial storage is added as in the case of the parabolic trough, the alternatives cannot be considered firm. Figure 8-1 does show why parabolic trough and wind technologies have been installed in other parts of the country where conditions are more favorable to their installation.

Figure 8-2 indicates the relatively favorable costs for landfill gas, anaerobic digestion, biomass cofiring, and incremental hydroelectric. Unfortunately, the lack of resource availability precludes them from being viable alternatives to Stanton B. Figure 8-2 also demonstrates why these renewable alternatives have been installed in regions of the country where resources are available.

OUC has initiated a more detailed study of renewable alternatives that potentially could be available in OUC's service area. While it is unlikely that the study will be able to identify significant capacity levels of cost-effective renewable generation, OUC wants to ensure that any cost-effective renewable capacity that can reliably provide power to OUC's customers is considered in OUC's future capacity plans.

8.7.2 Conventional and Emerging Technologies

All of the conventional and emerging technologies presented previously in this section were compared on a levelized cost basis using the economic parameters in Section 5.0. Figures 8-3 and 8-4, presented at the end of this section, show the results of the supply-side screening for peaking and baseload alternatives, respectively.

All of the conventional and emerging alternatives were considered in the detailed economic analyses in Section 10.0, except for nuclear. Although the nuclear alternative appears very attractive for baseload generation in the screening curve on Figure 8-4, it was not considered in the economic evaluations in Section 10.0 for a number of reasons. First, it is assumed that the nuclear alternative would not be available for commercial operation for at least 15 years because of the time frame for project development, licensing, and construction. Thus, the first year that the nuclear alternative would be assumed to be available is 2021. Second, the size of the nuclear alternative is such that it would need to be developed and managed by an entity significantly larger than OUC. Therefore, OUC would have no control over the schedule for the project. Finally, while the capital costs for the nuclear alternative appear very attractive, they are based primarily on vendor estimates. No new domestic nuclear units have been started in more than 25 years. While it may be possible to achieve the estimated costs, they represent a tremendous reduction from the $5,800/kW that the last US nuclear unit cost.

The LMS100 simple cycle combustion turbine is also classified as an emerging technology. The first unit is scheduled to be in commercial operation in 2006. If three years of demonstrated performance were desired before making a commitment to install a LMS100, it could be in commercial operation by 2011. Therefore, no restrictions were placed on the selection of the LMS100 in the economic analysis in Section 10.0.

A screening curve for Stanton B with and without DOE funding is also shown on Figure 8-4. The screening curve was developed without considering the potentially lower Stanton B availability during the first years of operation.

8.7.3 Advanced Technologies

Advanced technologies were screened by development status and feasibility. The advanced combustion, fuel cell, and coal technologies are still considered developmental stage technologies. Because of the early developmental stage of these technologies and the uncertainty relating to reliability and cost, these advanced technologies were not considered for further evaluation.

8.7.4 Energy Storage Systems

Energy storage systems offer the ability to shift demand during on-peak times to off-peak, thereby lowering demand during peak times. As such, these technologies can only serve peaking loads, not intermediate or baseload demands. Energy storage technologies include pumped hydroelectric, lead-acid battery, and compressed air. Each of these technologies stores energy collected during off-peak hours and then releases the energy during peak demand periods. Energy storage systems were screened by development status and average levelized cost. Each energy storage technology is considered commercially proven. However, each has a much higher average levelized cost than the conventional alternatives. In addition, because these technologies rely on storing energy during off-peak periods, they are limited to only peaking applications and, therefore, have lower availability than other conventional alternatives. As a result, no energy storage technologies were considered for further evaluation.

8.7.5 Distributed Generation Technologies

Distributed generation technologies include reciprocating engines and microturbines. These technologies are typically used for small demand applications. Reciprocating engines are considered proven commercially, while microturbines are in early commercial deployment. However, these technologies have a significantly higher average cost than the conventional alternatives and were not considered for further evaluation.

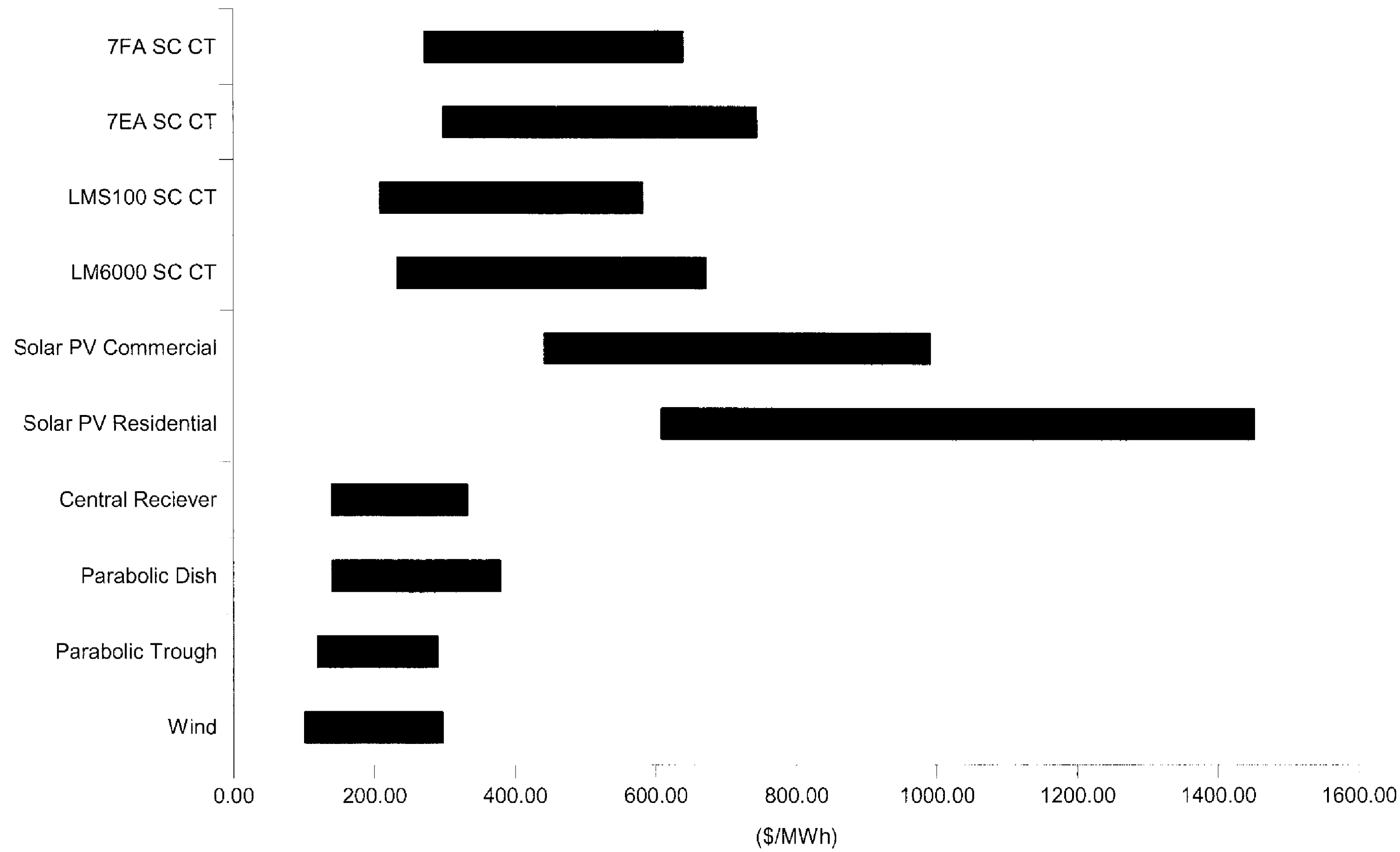


Figure 8-1
Comparison of Conventional and Renewable Peak Load 2010 Levelized Costs

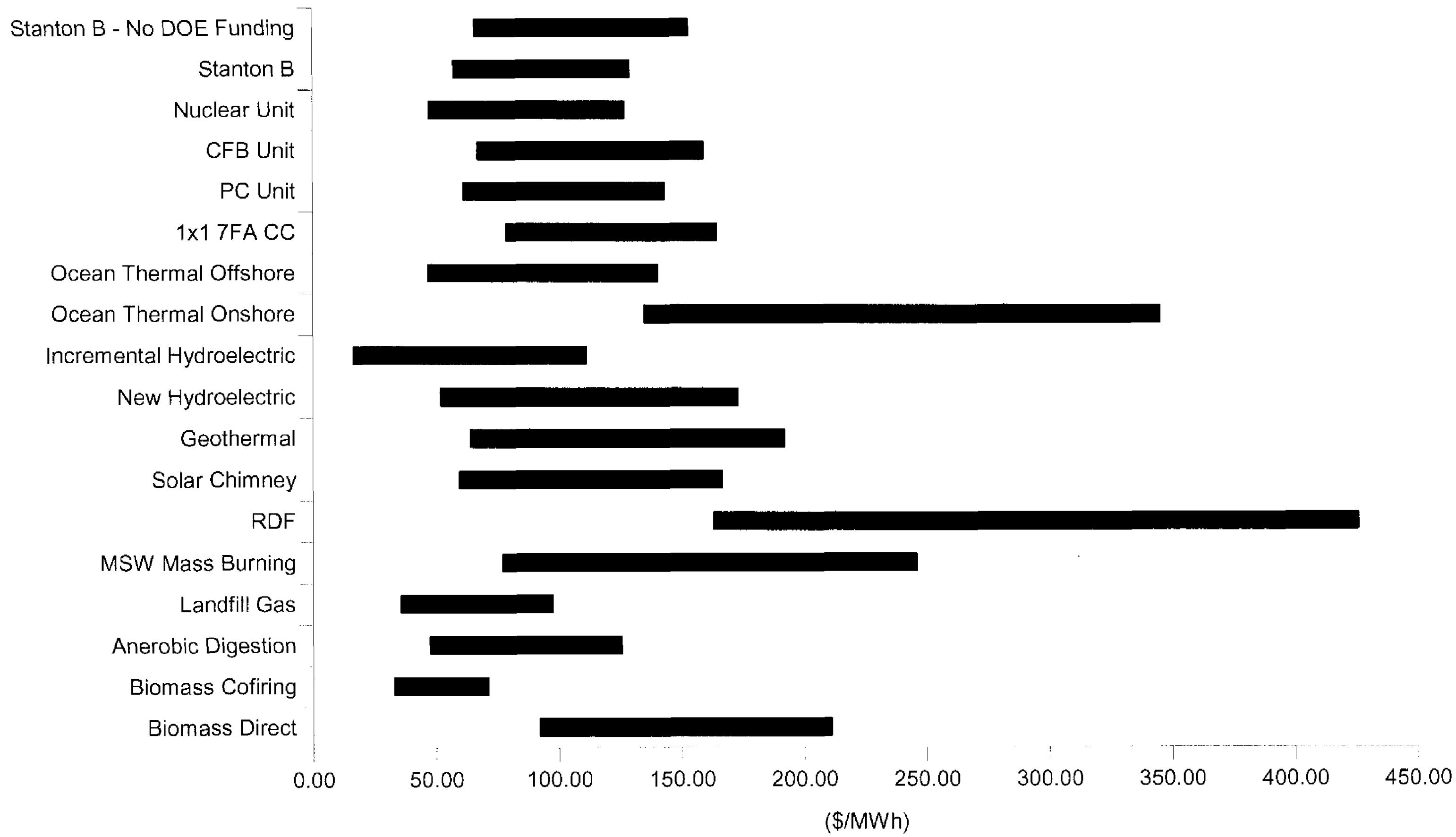


Figure 8-2
Comparison of Conventional and Renewable Base Load 2010 Levelized Costs

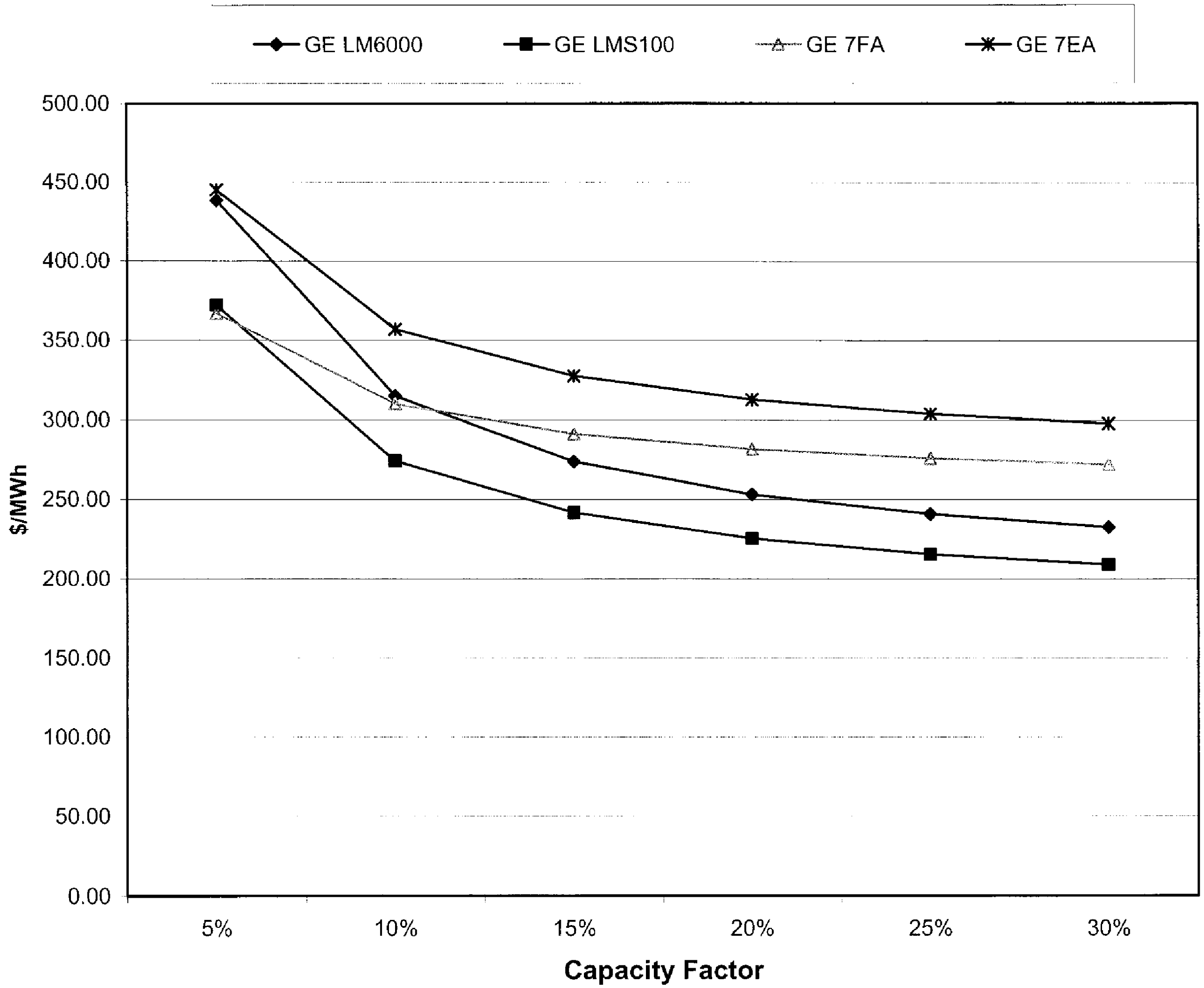


Figure 8-3
Conventional Alternative Peak Load Levelized Cost Curves

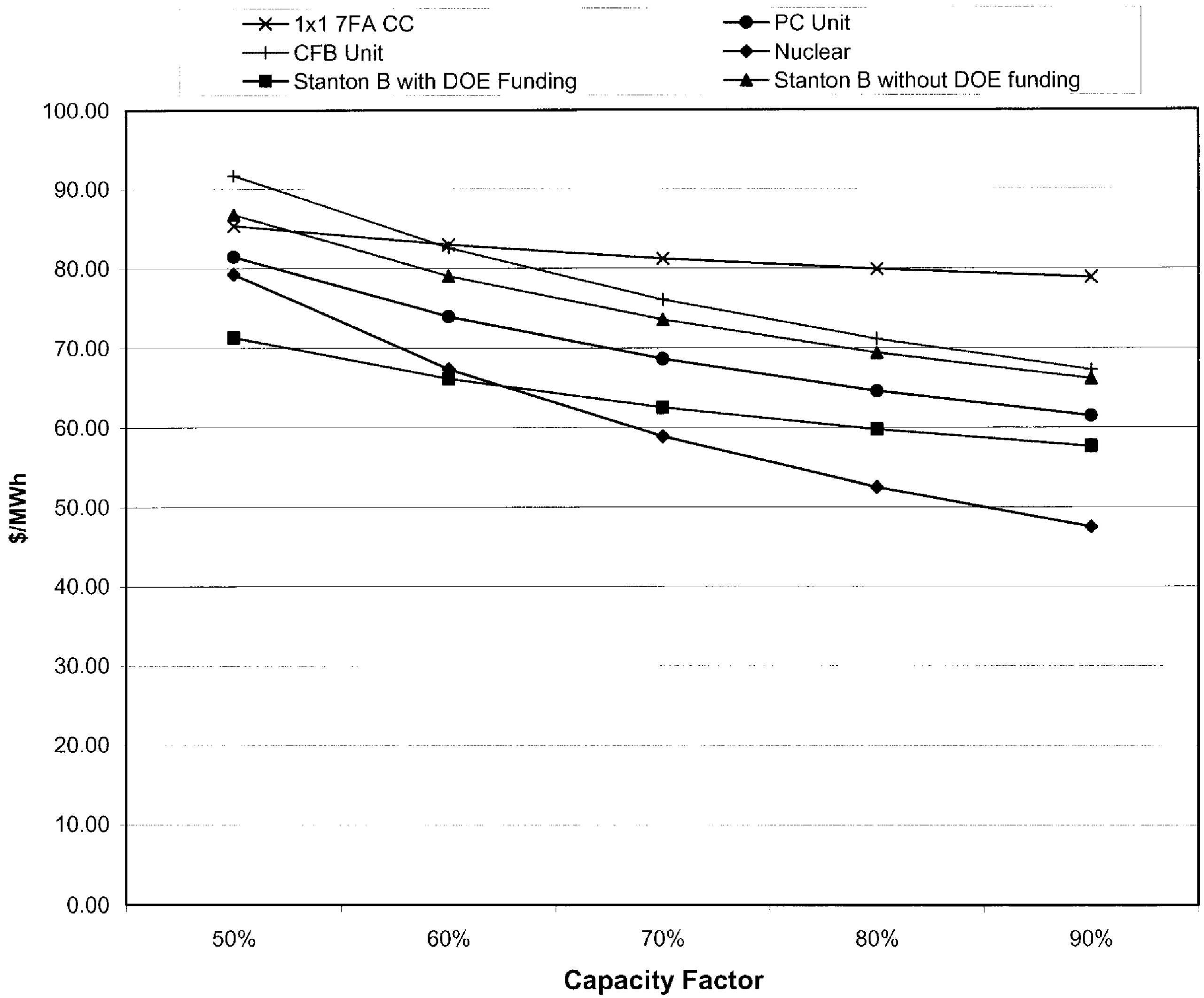


Figure 8-4
Conventional Alternative Base Load Levelized Cost Curves

9.0 Environmental Considerations

In May 2005, the Environmental Protection Agency (EPA) published as final its Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). These programs established new emissions reductions for SO_2, NO_x, and mercury (Hg) beginning in 2009 and 2010. This section provides an overview of the new CAIR and CAMR programs, outlines the EPA model rule, and explains the FDEP proposed approach for adopting and allocating allowances under these programs. This section also provides estimates of the allocation of allowances to OUC using various allocation methodologies and stated assumptions, along with projected allowance price forecasts.

9.1 Clean Air Interstate Rule Overview

On May 12, 2005, the EPA published the final CAIR mandating reductions in SO_2 and NO_x emissions in 28 states and the District of Columbia. The EPA structured CAIR to compel emission reductions from electric generating units (EGUs) and encourage participation in an interstate cap-and-trade market to address the interstate transport of precursor emissions that significantly contribute to downwind non-attainment areas for the new 8 hour and $PM_{2.5}$ national ambient air quality standards. While modeling was performed to determine the geographical extent of individual sources contributing to these downwind non-attainment areas, the EPA designated entire states (and thereby EGUs situated within these states) as being subject to regulation under CAIR. Thus, whether some or all of their emissions significantly contribute to downwind ozone and $PM_{2.5}$ non-attainment areas, individual EGUs located within the State of Florida have been included in and subject to CAIR.

The CAIR program seeks to achieve emission reductions by establishing permanent cumulative EGU emission caps in two phases under three separate programs: an annual SO_2 emissions program, an annual NO_x emissions program, and a seasonal NO_x emissions program. These programs are presented in Table 9-1.

CAIR seeks to maintain SO_2 and NO_x emissions within the program caps through the establishment of emissions "budgets." Each affected state will receive a proportional distribution of the overall cap for each phase of each program. States may individually choose which sources to regulate, as well as whether to mandate controls or allow participation in EPA's recommended model cap-and-trade program. States that choose to participate in the proposed interstate cap-and-trade program will also decide how to allocate allowances from their respective NO_x annual and seasonal budgets. States will ultimately set forth their chosen measures for achieving compliance with the emission budgets in SIPs to be submitted to the EPA for approval by September 2006.

Table 9-1
CAIR Program Emission Caps

	2009	2010 through 2014	2015 and beyond
SO_2 Annual (tons)		3.6 million	2.5 million
NO_x Annual (tons)	1.5 million	1.5 million	1.3 million
NO_x Seasonal (tons)	0.58 million	0.58 million	0.48 million

Florida is subject to regulation under all three CAIR programs and has been provided with the emission budgets illustrated in Table 9-2.

Table 9-2
CAIR Emission Budgets for Florida

	2009	2010 through 2014	2015 and beyond
SO_2 Annual (tons)		253,450	177,415
NO_x Annual (tons)	99,445[(1)]	99,445[(1)]	82,871
NO_x Seasonal (tons)	47,912	47,912	39,926

[(1)]CAIR also apportions an additional 8,335 tons of annual NO_x emissions from the Supplemental Compliance Pool.

Although the EPA originally proposed apportioning the regionwide NO_x annual and seasonal budgets according to each state's cumulative EGUs' share of recent historic heat input, the final CAIR apportioned these budgets on a fuel-adjusted heat input basis, which reduced gas and oil fired EGU heat input data compared to coal fired EGUs. These fuel adjustment factors (0.4 for gas and 0.6 for oil) have resulted in enhanced budgets for states with significant coal fired capacity, such as Ohio, compared to states that have predominately gas and oil fired generation, such as Florida. Several Florida utilities petitioned the EPA to reconsider application of these fuel adjustment factors in establishing state NO_x budgets and also questioned the basis for including the entire state in the CAIR program. The EPA granted this petition, published a notice on December 2, 2005, seeking additional comments on these issues, and expects to issue a decision by March 15, 2006.

Regulated EGUs are defined in CAIR as stationary fossil fuel-fired boilers, or stationary fossil fuel-fired combustion turbines, serving at any time a generator with a nameplate capacity of more than 25 MW that produces electricity for sale. Pursuant to this definition, Table 9-3 lists the OUC units that will be subject to regulation under the CAIR program.

Table 9-3
CAIR Regulated EGUs

Plant Name	Units (EPA ID Number)
Indian River	A, B, C, D
Stanton Energy Center	1, 2, A, B
C.D. McIntosh	3

Until Florida officially submits its proposed SIP to the EPA, it cannot be conclusively determined whether all of OUC's EGUs will be regulated, nor can it be determined whether they must meet strict emission limits or may participate in the interstate emissions trading program. FDEP staff initially indicated that Florida would choose to allow participation in the CAIR SO_2 annual, NO_x annual, and NO_x seasonal trading programs and would probably adopt an allowance allocation methodology similar to that proposed in the EPA's model rule. However, the FDEP now proposes to adopt an NO_x allocation plan that would differ from the EPA's model rule in several respects. Ultimately, the EPA must approve Florida's SIP for it to become effective. If this SIP is not approved, Florida would have to implement the trading program proposed in the Federal Implementation Plan (FIP) published by the EPA on August 24, 2005.

The emissions trading option, if adopted, would provide OUC some flexibility in choosing its compliance options. Since allowances are fully transferable, entities owning multiple regulated sources may aggregate their allowances and then choose the most cost-effective units to control to achieve compliance across and amongst their collective generation portfolios. OUC can choose to reduce hours of operations and buy wholesale power, switch fuels and/or install emission control equipment to reduce its total emissions to either meet their allowance allocation, or achieve further reductions to free up allowances for sale or future use. Alternatively, it may be more cost-effective to purchase allowances to authorize emissions above the allocated limit. Ultimately, OUC's sole compliance requirement is to possess sufficient allowances in its CAIR program accounts to cover its total emissions of SO_2 and NO_x for each program at the end of each compliance period.

With regard to how CAIR will be incorporated into other ongoing SO_2 emissions trading programs, it is important to understand that although CAIR will utilize the same allowances allocated under the Clean Air Act Title IV Acid Rain Program (ARP) for its annual SO_2 trading program, both programs will continue in force and effect. Thus, all OUC Title IV affected units will have to comply with the requirements of both the Acid Rain and CAIR programs for annual SO_2 emissions. The CAIR seasonal NO_x emissions trading program will replace the current NO_x SIP Call trading programs when it takes effect in May 2009.

9.1.1 Allocations of Allowances under CAIR

The allocation of allowances to regulated EGUs under the CAIR proposed NO_x and SO_2 cap-and-trade programs will ultimately be determined by each regulated state. All regulated states must submit their SIPs by September 11, 2006, and until then the structure of each overall CAIR trading program will not be finally determined.

Accordingly, the following estimations of allowances for the OUC regulated units are based on the EPA's model program allocation methodology using calculation inputs from the EPA databases maintained at the CAIR technical documents Web site and preliminary data presented by the FDEP at its November 29, 2005, workshop in Tampa. These estimates are only advisory predictions, and the calculations and assumptions have not been confirmed with agency personnel.

9.1.1.1 Calculation of Allowances under the CAIR Annual SO_2 Program.

The CAIR SO_2 model trading program incorporates and runs concurrently with the ARP. Most sources governed by CAIR already receive allocations of SO_2 allowances under the ARP, and the very same ARP allowances are to be used to comply with CAIR. Affected sources must comply with both ARP and CAIR.

To calculate CAIR annual SO_2 allowance allocations, the number of ARP allowances allocated to each regulated CAIR SO_2 unit must be determined. ARP allowance allocations are found in 40 CFR §73.10, Table 2. Since CAIR does not begin until 2010, the ARP 2010 allocations must be used to determine the number of annual allowances to be allocated under CAIR. For this analysis, the calculations consider the entire allotment of the ARP allowances to each regulated CAIR unit. The calculations do not account for any auction or other deduction.

It is then necessary to consider the value of the ARP allowances under CAIR. Under ARP, each allowance permits the holder to emit 1 ton of SO_2, regardless of when the allowance was originally allocated or acquired. However, CAIR reductions require sources to annually retire (submit) multiple allowances for each ton of SO_2 emitted. Additionally, the value of an allowance under CAIR will vary depending on its vintage year (year of initial allocation or issuance). Table 9-4 outlines the value of allowances based upon the retirement scheme under the CAIR SO_2 model trading program.

Table 9-4
Value of the CAIR SO_2 Allowances

Vintage Year	Value of Allowance (tons)
Pre-2010	1
2010 through 2014	0.5
2015 and beyond	0.35

The CAIR SO_2 model rule is designed to sequentially satisfy the requirements of both the ARP and the CAIR annual SO_2 cap-and-trade program. This is accomplished by conducting the year-end retirement accounting by first deducting all requisite ARP deductions, and then making the additional deductions required to comply with CAIR. Practically speaking, compliance with CAIR will ensure a source's compliance with ARP; however, compliance with ARP will not ensure compliance with the CAIR annual SO_2 program.

Table 9-5 presents the estimated annual ARP allowance allocations and corresponding values in terms of authorized emissions in tons per year for the OUC regulated EGUs under the concurrent ARP and CAIR trading programs. Table 9-5 was generated using the ARP allocation table set forth in 40 CFR 73.10. Allowance values in this table reflect OUC's proportional ownership interest in each unit receiving allowances or 79 percent for Indian River Unit D, 68.6 percent for Stanton Unit 1, and 40 percent for McIntosh Unit 3. OUC will not receive any SO_2 allowance allocations for Indian River Units A, B, and C nor for Stanton Unit 2 or Stanton A under CAIR because these units do not currently receive allocations under the existing ARP.

9.1.1.2 Calculation of Allowances under the CAIR Annual NO_x Program.

The EPA's model cap-and-trade program for annual NO_x emissions recommends that each state establish set-aside accounts of allowances for new units to use under each phase of the program. It recommends that states allocate the remaining allowances to its regulated EGUs proportionately using historical baseline heat input rates for each regulated EGU, adjusted for the primary fuel. The allowance allocation to regulated EGUs is based on the ratio of each individual regulated EGU's baseline fuel-adjusted heat input to an established overall state baseline fuel-adjusted heat input for all regulated EGUs in the state. The model rule differentiates between units that commenced

Table 9-5 Valuation of SO_2 Allowance Allocations to OUC Units[1]					
Facility	EPA Emission Unit	ARP Allocation 2005 through 2009 (ton/yr) [2]	ARP Allocation after 2010 (ton/yr) [2]	Phase I CAIR Allocation (2010 through 2014) (tons/yr)	Phase II CAIR Allocation (after 2015) (tons/yr)
Indian River	D	(639) 505	(640) 506	253	177
Stanton Energy Center	1	(11,290) 7,745	(11,314) 7,761	3,881	2,716
C.D. McIntosh	3	(9,928) 3,971	(9,948) 3,979	1,990	1,393
TOTALS		(21,857) 12,221	(21,902) 12,246	6,123	4,286

[1]CAIR allowance valuations represent OUC proportionate share of total number of tons of emissions authorized by allowances allocated to each unit based on a Phase I retirement ratio of 2:1 and Phase II retirement ratio of 2.86:1.
[2]Entire unit allocations are shown in parenthesis under ARP columns.

operation before January 1, 2001, which use heat input data, and those that started after that date, which use modified heat output data (converted heat input based on a unit's energy output adjusted by a Btu/kWh multiplier).

The FDEP has announced a proposed allocation scheme that would differ from the EPA model rule in several respects. Similar to the EPA model rule, the FDEP is proposing to allocate NO_x allowances to existing units using the fuel-adjusted methodology and a modified output-based standard for new units for Phase I. However, it has proposed an initial new source set-aside of 5.0 percent for 2009 through 2011 and then a 3.0 percent set-aside beginning in 2012. An additional change to the model rule is FDEP's proposal to use the highest 3 of the most recent 5 years of data for the annual reallocation of allowances beginning in 2012. Florida then proposes to move to a fuel-neutral output-based allocation methodology for all affected units when Phase II is implemented in 2015.

Specifically, FDEP's proposed allocation methodology is summarized as follows:

- Phase I state budget of 99,445 tons:
  - 2009: Set aside 5.0 percent of the state budget (4,972 tons) for distribution to new units (began operations after 2000) based on their 2008 emissions. The remaining 94,473 ton allowance, along with the one-time 8,335 ton compliance pool allowances, will then be distributed proportionately between existing (pre-2001) units on a fuel-adjusted basis using the average of the 3 highest years of heat input during 2000 through 2004 for each unit baseline.

Allocations to existing units will be made by October 31, 2006. Allocations to new units from the set-aside will be made by July 1, 2008.

- 2010 through 2011: Set aside 5.0 percent of the budget (4,972 tons) for distribution to new units (began operations 2001 to 2010) based on their 2009 and 2010 emissions. Allocate the remaining 94,473 ton allowance proportionately between existing (pre-2001) units on a fuel-adjusted basis using the average of the 3 highest years of heat input during 2000 through 2004 for each unit baseline. All existing units will be allocated their allowances for this compliance period by no later than October 31, 2006. Allocations to new units from the set-aside will be made by July 1 of the year immediately preceding each compliance year.
- 2012-2014: Set aside 3.0 percent of the budget (2,983 tons) for new units (began operations no more than 8 years prior to the compliance year) for distribution based on their previous year's emissions. Then allocate the remaining 96,462 ton allowance proportionately between existing (pre-2001) units on a fuel-adjusted basis using the average of the 3 highest years of heat input during 2000 through 2004 for unit baseline and new units that have established a sufficient baseline on a modified heat-output basis using the average of the 3 highest years of heat output data (gross electrical output converted to heat input using fuel weighted factors) for the 5 year period beginning 9 years prior to the compliance year. Compliance year 2012 allowances will be allocated by late 2008. Compliance year 2013 and 2014 allowances will be allocated 4 years in advance.

- Phase II state budget of 82,871 tons:
  - 2015 onward: Set aside 3.0 percent of the budget (2,486 tons) for distribution to new units (began operations no more than 8 years prior to the compliance year), based on their emissions in the year immediately preceding the compliance year. Annually allocate the remaining 80,385 ton allowance proportionately between all existing units and new units on an output basis (non-fuel-adjusted), based on a rolling baseline consisting of the average of the 3 highest years of gross electrical output for the 5 year period beginning 6 years prior to the allocation year. FDEP will allocate these allowances 3 years in advance of each compliance year.

Tables 9-6 and 9-7 present OUC's estimated annual NO_x allowance allocations during Phase I and II of CAIR, based on recommended methodologies, data presented in recent FDEP workshops, and the assumptions noted below.

The calculations and assumptions made in estimating OUC's allocations in Phase I (Table 9-6) are based on workshop data posted on the FDEP Division of Air Resource Management, Rules, Statutes and Guidance Memoranda Web site (www.dep.state.fl.us/air/rules.htm). Pursuant to both the EPA and FDEP proposed methodologies, each existing (began operation before January 1, 2001) unit's baseline was calculated by averaging the three highest annual heat inputs during the 2000 through 2004 control period, which were adjusted by a multiplier according to primary fuel (100 percent for coal, 60 percent for oil, and 40 percent for all other fuels).

New units that commenced commercial operations after January 1, 2001, (including Stanton A) will be allocated allowances from the set-aside pool on the basis of their proportionate contribution of NO_x emissions to the total emissions from all new units in the state during the year immediately preceding the compliance year. These allowances will be allocated by July 1 of the compliance year. The FDEP has released a projection of NO_x emissions from new units during Phase I of CAIR. Table 9-8 presents these new unit emission projections and the ratio of allowances that would be available in the new unit pool based on a 5.0 percent set-aside during 2009 through 2011 and 3.0 percent during 2012 through 2014.

Once a new unit has operated 5 years and established a modified heat output baseline (essentially a converted heat input that accounts for energy output[1]) during Phase I, or a gross electrical output baseline during Phase II, it will be added to the overall total state baseline and will be allocated allowances from the main allowance pool.

It is worth noting that under the EPA model rule, existing units will always be entitled to allowance allocations based on their 2000 through 2004 baselines (regardless of whether they are subsequently retired or otherwise change their operations). Thus, the addition of each new unit to the state baseline under this model rule would cause each pre-existing EGU's allocations to decline according to the number and size of new units that have been added each year. Although Florida essentially adopts this approach for its Phase I allocations, and will add the modified heat output data from new units that began operations in 2001 through 2003 to its state baseline, which affects allocations for

[1] A converted control period heat input equals the control period gross electrical output of the generators served by the units multiplied by the fuel multiplier (7,900 Btu/kWh for coal and 6,675 Btu/kWh for all other fuels) and then divided by 1,000,000 Btu/kWh.

Table 9-6
Phase I NO_x Annual Allowance Allocations

Facility	EPA Emission Unit ID	Estimated Total 2009 Allocation(1) (4) (tons)	Estimated Total 2010 through 2011 Allocation(2) (4) (tons)	Estimated Total 2012 through 2014 Allocation(3) (4) (tons)
Indian River	A	0	0	0
	B	0	0	0
	C	(18) 15	(17) 13	(17) 14
	D	(22) 17	(20) 16	(21) 16
Stanton Energy Center	1	(2,881) 1,976	(2,647) 1,816	(2703) 1,854
	2	(2,824) 2,022	(2,595) 1,858	(2,649) 1,897
	A	0	0	410
C.D. McIntosh	3	(2,156) 862	(1,981) 792	(2023) 809
TOTALS		4,892	4,495	5,000

(1)Based on 5.0 percent set-aside for new units, proportionate share of compliance pool.
(2)Based on 5.0 percent set-aside for new units, no compliance pool distribution.
(3)Based on 3.0 percent set-aside for new units, no compliance pool distribution, no added new units.
(4)Reflects OUC allocation based on equity interest in unit; total allowance allocation to unit shown in parenthesis.

Table 9-7
Phase II NO_x Annual Allowance Allocations[(1)(2)]

Facility	EPA Emission Unit ID	Estimated Total 2015 Allocation (tons)	Estimated Total 2020 Allocation (tons)	Estimated Total 2025 Allocation (tons)
Indian River	A	6	6	4
	B	6	5	3
	C	16	11	7
	D	20	18	11
Stanton Energy Center	1	828	607	457
	2	921	803	663
	A	463	471	284
C.D. McIntosh	3	243	196	113
TOTALS		2,503	2,117	1,542

(1)Reflects OUC allocation based on equity interest in unit.
(2)Based on estimated OUC unit generation and State of Florida generation (adjusted to reflect portion of state total generation that can be attributable to "new" units).

Table 9-8
Phase I New Unit Set-Aside Allowance Pool

Compliance Year	Projected New Units NO_x Emissions (tpy)	Allowances Set-Aside	Ratio Allowances to Emissions
2009	10,727	4,972	0.4635
2010	12,390	4,972	0.4013
2011	14,198	4,972	0.3502
2012	16,882	2,893	0.1767
2013	20,362	2,893	0.1465
2014	20,774	2,893	0.1436

compliance years 2012 through 2014, this report's calculations assume that Florida's baseline will remain static during the entire initial phase. Florida's proposed Phase II rolling gross electrical output baseline (average 3 highest of 5 year period beginning 6 years prior to the allocation year) would not cause a unit's share to diminish over time. Instead, it would benefit those units that are more efficient in terms of total electrical output versus emissions and, therefore, would benefit units burning cleaner fuels and/or installing emissions controls. Calculations for Phase II account for increased state baseline heat input based on load growth projections.[2]

9.1.1.3 Calculation of Allowances under the CAIR Seasonal NO_x Program. CAIR's seasonal NO_x trading program only applies to emissions from regulated EGUs occurring between May 1 and September 30 each year. Other than this different compliance time period, the administration and allocation of allowances under this seasonal program is essentially the same as provided under the annual program. Accordingly, the basis of the calculations and assumptions made in estimating OUC units' allocations followed the same recommended model rule methodology described previously. Table 9-9 presents the estimated allowance allocations under Phase I of the CAIR seasonal NO_x trading program. Estimates for seasonal NO_x allocations during Phase II are presented in Table 9-10.

It should be noted that emissions of NO_x from affected units during this seasonal period are regulated under both the CAIR annual and seasonal NO_x programs; separate allowances must be secured under each individual program for each ton of NO_x emitted during the May through September ozone season. However, as noted earlier, the CAIR seasonal program is intended to replace and supersede the current NO_x SIP Call trading program, and banked allowances originally allocated under the existing NO_x SIP Call program can be used for compliance in the upcoming CAIR seasonal NO_x program.

9.1.1.4 Summary of the CAIR Estimated Allowance Allocations. OUC's anticipated allowance allocations under CAIR Phase I and II annual SO_2, annual NO_x, and seasonal NO_x programs are summarized in Table 9-11. These allowance allocation estimates were based on the FDEP's proposed allocation methodology described above; however, they do not include any allocations from the new unit set-aside pool. These estimates are only predictions, and the calculations and assumptions have not been confirmed with agency personnel.

[2] Calculation of load growth comes from the "2005 Regional Load and Resource Plan" published in July 2005 by the Florida Reliability Coordinating Council (FRCC).

Table 9-9 Phase I NO_x Seasonal Allowance Allocations[1]			
Facility	EPA Emission Unit ID	Estimated Total 2009 through 2011 Allocation (tons)	Estimated Total 2012 through 2014 Allocation (tons)
Indian River	A	0	0
	B	0	0
	C	(10) 8	(11) 8
	D	(12) 10	(13) 10
Stanton Energy Center	1	(1,203) 825	(1,228) 842
	2	(1,200) 859	(1,225) 877
	A	0	193
C.D. McIntosh	3	(1,089) 436	(1,112) 445
TOTALS		2,138	2,375

[1] Reflects OUC allocation based on equity interest in unit; total allowance allocation to unit shown in parenthesis.

Table 9-10 Phase II NO_x Seasonal Allowance Allocations[1]				
Facility	EPA Emission Unit ID	Estimated Total 2015 Allocation (tons)	Estimated Total 2020 Allocation (tons)	Estimated Total 2025 Allocation (tons)
Indian River	A	3	3	2
	B	3	2	2
	C	10	7	4
	D	13	11	7
Stanton Energy Center	1	386	283	213
	2	436	381	314
	A	223	227	137
C.D. McIntosh	3	137	111	64
TOTALS		1,211	1,025	743

[1] Reflects OUC allocation based on equity interest in unit.

Table 9-11
Total CAIR Estimated Allowance Allocations

	Phase I			Phase II		
	2009	2010 through 2011	2012 through 2014	2015 through 2019	2020 through 2024	2025 and beyond
SO_2 (tons)	N/A	6,123	6,123	4286	4286	4286
NO_x Annual (tons)	4,892	4,495	5,000	2,503	2,117	1,542
NO_x Seasonal (tons)	2,138	2,138	2,492	1,211	1,025	743

9.2 Clean Air Mercury Rule Overview

On March 15, 2005, the EPA issued the final CAMR. The rule limits the emissions of Hg from affected coal fired utility units (greater than 25 MW) located in all 50 states from current levels of 48 tons per year (tpy) to 15 tpy. Like the various CAIR programs, CAMR is a two-phase emission reduction program, with the first phase effective in 2010 capping nationwide Hg emissions to 38 tpy, and the second phase effective in 2018 capping total Hg emissions at 15 tpy.

Similar to the framework of CAIR, each state is assigned a mercury emissions budget under CAMR and must submit a SIP detailing the control programs that will be implemented to meet its specified state budget for reductions from coal fired utility units. Collectively, the budgets for all 50 states establish the "cap" for each phase of the emission trading program. The initial Phase I cap of 38 tons scheduled to take effect in 2010 was based on the maximum reduction in Hg emissions that could be achieved through installation of FGD and SCR, otherwise known as the "co-benefit" of mercury reduction achieved through control of SO_2 and NO_x emissions under the proposed CAIR rulemaking. The Phase II cap of 15 tons of Hg emissions per year scheduled to take effect in 2018 is based on additional controls being installed and allows for commercial development of emerging Hg control technologies. The Florida budget for Hg emissions is 1.233 tons in 2010 and 0.487 tons in 2018.

CAMR sets forth a model trading rule for states to use in implementing the cap-and-trade program. States are not required to adopt this model trading rule and may choose to achieve the mandated reductions by using another approach, such as imposing strict limits on individual units, or even requiring reductions beyond what is established in their budget. In this regard, Florida has announced it is considering not participating in the EPA-administered cap-and-trade program. Instead, it would adopt rules specifying Hg emission limiting standards and compliance schedules for coal fired EGUs, giving consideration to reductions achievable through existing and emerging technologies, and utility plans for CAIR implementation. Ultimately, Florida's program would be designed to ensure compliance with its annual state budget for Hg emissions of 1.233 tons in Phase I and 0.487 tons in Phase II.

CAMR also establishes "standards of performance" for Hg emissions from new coal fired utility units constructed, modified, or reconstructed after January 30, 2004. These standards differ according to categorization of the unit's coal rank and process type: bituminous, subbituminous, lignite, coal refuse, and IGCC. These new source limits are intended to serve as the "backstop" for the model trading program by setting the minimum control levels that must be achieved by new coal-fired units, as a prerequisite to participation in the CAMR trading program.

The EPA received several petitions to reconsider its final CAMR and in response to petitions filed by a group of states, environmental groups, and Indian nations, agreed to reopen several issues for additional public comment. As part of its reconsideration notice, EPA also proposed to revise most of its new source performance standards for Hg emissions from utility units. The final CAMR and subsequent proposed revised standards are shown in Table 9-12.

Table 9-12
CAMR New Unit Performance Standards

Coal Rank/Process Type	Final Rule Emission Limit	Proposed Revised Limit	Best Demonstrated Technology
Bituminous	0.0026 ng/J (21×10^{-6} lb/MWh)	20×10^{-6} lb/MWh	Fabric filter (FF) + FGD (wet or dry)
Subbituminous w/Wet FGD (mean annual >25"/yr)	0.0055 ng/J (42×10^{-6} lb/MWh)	66×10^{-6} lb/MWh	FF + wet FGD
Subbituminous w/Dry FGD (mean annual ≤25"/yr)	0.0103 ng/J (78×10^{-6} lb/MWh)	97×10^{-6} lb/MWh	FF + spray dryer absorber (SDA), or ESP + SDA
Lignite	0.0183 ng/J (145×10^{-6} lb/MWh)	175×10^{-6} lb/MWh	FF + SDA, or ESP + wet FGD, or fluidized bed combustor (FBC) + ESP
Coal Refuse	0.00017 ng/J (1.4×10^{-6} lb/MWh)	1.0×10^{-6} lb/MWh	FBC + FF
IGCC	0.0025 ng/J (20×10^{-6} lb/MWh)		

CAMR faces multiple legal challenges and is bound for review in the courts. As of the writing of this report, 13 states and numerous environmental interest groups have filed lawsuits seeking to have the courts invalidate CAMR. Some of the major issues to be litigated include (1) whether the EPA has authority to regulate Hg emissions under a cap-and-trade program, (2) the EPA's basis for revoking the December 2000 regulatory determination, (3) whether the EPA followed the proper delisting petition process for an air toxin, and (4) whether proven technologies widely exist that are capable of lowering Hg pollution to levels below those established in the rule. Recently, the District of Columbia Circuit Court denied a petition to stay (suspend) the rule, and, as a result, CAMR remains in effect until these pending legal issues are resolved. Accordingly, utilities such as OUC will proceed with development of Hg control compliance strategies that are in accordance with the final CAMR requirements and schedule.

9.2.1 Allocations of Allowances Under CAMR

The EPA's model trading rule sets forth a recommended approach for allocating allowances that states may adopt, where existing units receive allocations based on a historical heat input basis adjusted for the type of coal used, and new units will be allocated allowances on a modified output basis as part of the periodic updating of total annual allocations in future years. Similar to the model CAIR annual NO_x trading program described previously, the CAMR model cap-and-trade program recommends that each state establish set-aside accounts of allowances for new units to use under each phase of the program (5.0 percent in Phase I and 3.0 percent in Phase II). It also recommends that states allocate the remaining allowances to regulated EGUs proportionately using historical baseline heat input rates for each regulated EGU. The model CAMR rule differentiates between units that commenced operation before January 1, 2001, which use heat input data, and those that started after that date, which use "converted" heat input data (calculated by multiplying the unit's gross energy output by a heat rate conversion factor of 7,900 Btu/kWh).

The EPA recommends that allocations for the first 5 compliance years (2010 through 2014) be based on historical heat inputs for existing sources. Annual allowances for 2015 and later will be allocated 6 years in advance from the state's Hg budget taking into account output data from new units with established baselines. Thus, allowances allocated to existing units will slowly decline as their share of total calculated heat input decreases with the entry of new units.

As the distributors of allowances, states may alternatively choose to establish their own allocation methods regarding cost (free or auction), frequency (permanent or periodic), basis (heat-input or power output), and the use and size of set-asides (for new units, incentives, or relief purposes). However, CAMR does require that allowances be allocated to existing units no less than 3 years prior to the allowance vintage year (first year it can be used for compliance) to provide sources sufficient time to plan for compliance.

As previously mentioned, Florida has announced that it may choose not to participate in the EPA-administered Hg cap-and-trade program. The FDEP has provided little information regarding what alternative program it proposes in place of the model cap-and-trade program or how it would be implemented, other than to indicate it would most likely be through the permitting process.

Since CAMR only regulates coal fired EGUs (boilers or combustion turbines serving generators greater than 25 MW that produce electricity for sale), only Stanton Unit 1, Unit 2, and McIntosh Unit 3 would be regulated under this program. Assuming that Florida does establish its own alternative program, OUC would not be allocated allowances and would not be able to participate in the EPA's model trading program.

If Florida abandons its current plans to establish an alternative program, and/or the EPA does not approve Florida's SIP, estimates of allowances that would be allocated to OUC under each phase of CAMR pursuant to the EPA's recommended model rule methodology are summarized as follows:

- Phase I state budget of 1.233 tons:
  - 2010 through 2017: 5.0 percent of the budgeted allowances (0.06165 tons or 1,973 ounces) would be set aside for new units. The remaining allocation budget of 1.17135 tons would yield 37,483 ounces of annual Hg allowances for allocation to existing units (commenced operation before January 1, 2001), based on baseline heat input rates for each unit from 2000 to 2004, adjusted for the types of coal fired in each unit (multiplied by 1.0 for bituminous, 1.25 for subbituminous, and 3.0 for lignite coals). New units (commenced operation after January 1, 2001) would be added to the baseline beginning with compliance year 2015 using "converted" heat input data (calculated by multiplying the unit's gross energy output by a heat rate conversion factor of 7,900 Btu/kWh).
  - 2015 through 2017: 3.0 percent of the budgeted allowances (0.03699 tons or 1,184 ounces) would be set aside for annual allocation to new units. The remaining budget of 1.19601 tons would yield 38,272 ounces of annual Hg allowances for allocation to existing units and new units added to the baseline.
- Phase II state budget 0.487 tons:

- 2018 onwards: 3.0 percent of the budgeted allowances (0.01461 tons or 568 ounces) would be set aside for annual allocation to new units. The remaining budget of 0.47239 tons would yield 15,116 ounces of annual Hg allowances for allocation to existing units and new units added to the baseline.

New units that commenced commercial operations after January 1, 2001, will be allocated allowances from the set-aside pool based on their proportionate contribution of Hg emissions to the total emissions from all new coal fired EGUs in the state during the year immediately preceding the compliance year. As new units enter into service and establish a baseline (average of the highest 3 of initial 5 years of converted heat input data), they will be allocated allowances in proportion to their share of the total calculated heat input (existing unit heat input plus new units' modified heat input). Since retired units will continue to receive allowances indefinitely under the EPA model rule, allowances allocated to existing units will slowly decline as their share of total calculated heat input decreases with the entry of new units.

While Florida has announced that it does not intend to participate in the EPA-administered CAMR cap-and-trade program, Table 9-13 presents the estimated allocations that would be made under the EPA model methodology and that could occur if Florida abandons its current plans to establish an alternative program and/or the EPA does not approve Florida's SIP. The estimates shown in Table 9-13 are based on data presented in the EPA's "Final CAMR Unit Hg Allocations" database and reflect OUC's proportional interest in the affected coal units.[3]

9.3 Allowance Price Forecast

The flexibility of the EPA's model cap-and-trade program and the likelihood of its adoption by the State of Florida make future allowance prices an important parameter in OUC's environmental regulation compliance planning. Since CAIR and CAMR only require state-by-state caps, with allowances issued to individual units, OUC must consider several different methods for meeting the mandated reductions in NO_x and SO_2 under CAIR. These methods include purchasing allowances from the cap-and-trade market, adding emissions control equipment to meet CAIR reductions, or installing emissions control equipment to exceed CAIR reductions and either banking or selling the additional allowances. This section presents the allowance price forecasts for NO_x and SO_2. NO_x allowance prices are forecast for both annual and seasonal markets. The methodology for the base case NO_x price forecast is discussed in the following section.

[3] Data found at www.epa.gov/ttn/atw/utility/utilitoxpg.hmtl.

Table 9-13
CAMR Model Rule Allowance Allocations

Facility	Unit	Estimated Unit Base Line Heat Input (MBtu)	Estimated Phase I Mercury Allowances[1] (ounces)	Estimated Phase II Mercury Allowances[1] (ounces)
Stanton Energy Center	1[2]	32,425,289	(1,499) 1,028	(592) 406
	2[3]	31,783,134	(1,469) 1,052	(580) 415
McIntosh	3[4]	29,663,651	(1,371) 548	(541) 216
Totals			2,628	1,037

[1] Reflects OUC allocation based on equity interest in unit; total allowance allocation to unit shown in parenthesis.
[2]Reflects an OUC ownership share of 68.6 percent.
[3]Reflects an OUC ownership share of 71.6 percent.
[4]Reflects an OUC ownership share of 40.0 percent.

9.3.1 CAIR NO_x Allowance Price Forecast

The CAIR NO_x allowance price forecasting model developed by B&V examines all of the utility boilers listed by the EPA within the states affected by CAIR. The model examines each unit individually according to its current emissions control equipment, the feasibility of adding emissions control equipment, and the cost-effectiveness of adding such equipment. For each boiler type, different combinations and permutations of applicable emissions control equipment, including conventional types of boiler combustion control and SCR equipment, were examined to determine both their cost-effectiveness and their feasibility for use in meeting the emissions reductions standards established by CAIR.

After determining the most cost-effective means of reducing NO_x emissions to meet each phase of CAIR, the costs of all of the possible emissions reductions were ranked in order of cost-effectiveness. Assuming that boiler owners add emissions control equipment in the most cost-effective manner, the model was designed to create allowance price curves based on the marginal cost of emission control equipment. As the curves are created, the model separates the CAIR annual NO_x markets and the seasonal NO_x markets.

Given that boilers in states with NO_x seasonal markets can trade with other allowance holding entities located in seasonal markets and that boilers in states with NO_x annual markets can trade with other allowance holding entities located in annual markets, the model subsidizes both of the markets on the basis of the projected price of selling allowances. The NO_x allowance prices are determined by comparison of the marginal cost of adding emissions control equipment when the total emission cap is achieved.

The market price forecast for allowances is assumed to escalate by the average annual increase between the CAIR Phase I and Phase II prices to reflect open market price predictions by investors or utilities, and to escalate at the general inflation rate (2.5 percent) after Phase II.

The annual NO_x allowance prices for CAIR (in 2005 dollars per ton) are \$2,312 (year 2009) and \$2,959 (year 2015) for Phase I and Phase II, respectively. The seasonal NO_x allowance prices for CAIR (in 2005 dollars per ton) are \$2,188 (year 2009) and \$2,682 (year 2015) for Phase I and Phase II, respectively.

The annual price forecasts for OUC to purchase NO_x allowances for seasonal markets, annual markets, and both markets are presented in Table 9-14. The prices for seasonal NO_x allowances are slightly lower than the prices for annual allowances throughout the study period. Allowance prices for the years 2006 through 2008 were not developed for OUC. During the period before CAIR Phase I, the best indicator for future allowance prices is the NO_x Budget Trading Program (NBP), which is an ozone season cap-and-trade program intended to help states meet their individual SIPs under an EPA rule that took effect in 2003. Prices for NO_x in this program varied from about \$8,000 per ton in April 2003 to around \$3,000 per ton in August 2003. Since that time, prices have remained around \$3,000 per ton. States that do not use these allowances prior to CAIR Phase I will be able to put them towards meeting the seasonal CAIR requirements. All forecast prices are in nominal dollars.

9.3.2 SO_2 Allowance Price Forecast

The process for estimating the market price for SO_2 allowances is similar to the process used to estimate the NO_x allowance prices. The main difference in methodology is that FGD is the only recognized method for SO_2 removal. As a result, the price for SO_2 allowances is reflected in the cost of the last generator that would have to add a scrubber so that total SO_2 emissions in the market trading pool would meet the emissions reductions associated with CAIR.

The current SO_2 emission rates in the United States were estimated, taking into consideration current utilization of banked SO_2 allowances. The annual emissions associated with the estimation are consistent with the cap under the current Phase II ARP legislation.

In prioritizing the retrofit installation of scrubbers to achieve the emission reductions called for under CAIR, two factors were taken into account. The first was that capital and operating costs of dry scrubber systems applicable to generators burning subbituminous coal are, in general, 20 percent less expensive than the wet scrubber

Table 9-14
Forecast OUC NO_x Allowance Price
Nominal Prices in $/ton Removed

Calendar Year	Annual NO_x Allowance ($/ton)	Seasonal NO_x Allowance ($/ton)	Weighted NO_x Allowance Cost ($/ton)[(1)]
2009	2,552	2,415	3,558
2010	2,726	2,561	3,793
2011	2,911	2,716	4,043
2012	3,109	2,880	4,309
2013	3,321	3,053	4,593
2014	3,547	3,238	4,896
2015	3,788	3,433	5,218
2016	3,882	3,519	5,349
2017	3,980	3,607	5,482
2018	4,079	3,697	5,620
2019	4,181	3,790	5,760
2020	4,286	3,884	5,904
2021	4,393	3,981	6,052
2022	4,502	4,081	6,203
2023	4,615	4,183	6,358
2024	4,730	4,288	6,517
2025	4,849	4,395	6,680
2026	4,970	4,505	6,847
2027	5,094	4,617	7,018
2028	5,221	4,733	7,193
2029	5,352	4,851	7,373
2030	5,486	4,972	7,558

[(1)]Reflects allowance prices on an annual basis purchasing both annual and seasonal allowances.

systems typically required when burning higher sulfur bituminous coal. The typical removal efficiency for retrofit dry FGD systems is 95 percent. The second factor was that the addition of scrubbers to unscrubbed generators burning bituminous coal generally allows the owner to switch to a higher sulfur coal and reduce fuel costs. The typical removal efficiency for a retrofit wet FGD system applied to higher sulfur coal is 98 percent.

Despite the higher capital cost of the wet FGD system, its higher removal efficiency, higher pre-control emission rate, and fuel cost savings will generally produce a lower cost per ton removed than the cost per ton resulting from the addition of scrubbers to generators burning subbituminous coal. In addition, significant economies-of-scale in the capital and fixed operating costs of scrubbers will affect the prioritization of generators and emission control measures.

To achieve the 2010 emission limit called for in CAIR, B&V estimates that scrubbers will be installed on all bituminous units down to 250 MW and a portion of the bituminous units sized between 100 MW and 250 MW. The typical capital and operating costs of a wet scrubber installation for generators in the 100 MW to 250 MW size range are $300 per kW and $16 per kW-year. The associated Phase I allowance price, net fuel savings, from the switch to higher sulfur coal is $985 per ton removed (in 2005 dollars).

Inherent in this estimate is no further switching from bituminous to subbituminous or western coal. That assumption is supported by the EPA's own projections of coal use and the risk of higher uncontrollable mercury emissions associated with western coal.

To achieve the Phase II limit stipulated by CAIR in 2015, B&V reasons that some bituminous coal users will want to burn medium to low sulfur coal in their generators with scrubbers before scrubbers have been added to the units below 100 MW. However, international demand for coals that tend to be lower in sulfur content may preclude this tendency.

The associated Phase II allowance price is $1,350 per ton removed (in 2005 dollars). The market price for SO_2 allowances is assumed to escalate at the general inflation rate until the start of CAIR Phase I. After CAIR implementation, allowance prices are assumed to escalate by the average annual increase between the CAIR Phase I and Phase II to reflect open market price predictions by investors or utilities. Costs were calculated assuming a 1.11 percent escalation rate for scrubber capital cost, in addition to the general inflation rate, after CAIR Phase II. The annual price forecasts for OUC to purchase SO_2 allowances for the annual market are presented in Table 9-15.

Table 9-15
Forecast OUC SO_2 Allowance Price
Nominal Prices in $/ton Removed

Calendar Year	Annual SO_2 Allowance ($/ton)
2010	1,114
2011	1,217
2012	1,328
2013	1,450
2014	1,583
2015	1,728
2016	1,747
2017	1,767
2018	1,786
2019	1,806
2020	1,826
2021	1,846
2022	1,867
2023	1,888
2024	1,909
2025	1,930
2026	1,951
2027	1,973
2028	1,995
2029	2,017
2030	2,039

9.4 Consideration of Allowance Pricing in Economic Analysis

The allowance price forecasts summarized in this section will influence OUC's strategic capacity expansion planning efforts in the future. Section 10.0 includes a description of the methodology used to identify OUC's most cost-effective capacity expansion plan based on the assumptions presented throughout this Application. Of these assumptions, one of the most influential is the fuel price forecast presented in Section 5.0. However, in determining a utility's most economic capacity expansion plan to satisfy future capacity requirements, it is prudent to add forecast emission allowance prices to the fuel price forecast for existing units, as well as potential capacity additions, or candidate units. It is important to note that only the forecast allowance prices for SO_2 and NO_x are considered in the economic analysis (Section 10.0), consistent with what is governed by the EPA's final CAIR ruling. As discussed in Section 9.2, although the EPA has finalized its ruling on CAMR, Florida has indicated it is considering not participating in a cap-and-trade program for Hg emissions. Additionally, it is assumed that all mercury reductions required in CAMR Phase I will be achieved as a co-benefit of CAIR emissions control additions. Because of these issues and the pending legal challenges to CAMR, Hg emission costs were not considered in this analysis. Control of mercury emissions for new unit additions is assumed to be adequate to meet permitting requirements.

Using the emissions allowance price forecasts applied to both the emission rates for OUC's existing generating units and the estimated emission rates for the candidate units considered in this analysis, it is possible to develop estimated costs associated with emissions of SO_2 and NO_x, which can be added to each unit's fuel price. These costs, presented in nominal dollars in Table 9-16A for existing units and Table 9-16B for candidate units, were added to the base case fuel forecasts used in the economic analysis in Section 10.0, as well as in the sensitivity analyses presented in Section 11.0. Consistent with the timing of CAIR, cost adders on a \$/MBtu basis for emissions are included beginning in 2009.

Table 9-16A
Combined SO_2 and NO_x Emissions Adders by Existing Unit
(Nominal $/MBtu)

Calendar Year	Stanton 1	Stanton 2	Stanton A	C.D. McIntosh 3	Indian River A	Indian River B	Indian River C	Indian River D
2009	$0.783	$0.302	$0.024	$0.778	$0.228	$0.228	$0.165	$0.176
2010	$1.029	$0.462	$0.026	$1.134	$0.244	$0.244	$0.251	$0.240
2011	$1.102	$0.496	$0.028	$1.216	$0.260	$0.260	$0.270	$0.257
2012	$1.180	$0.532	$0.030	$1.305	$0.277	$0.277	$0.290	$0.276
2013	$1.264	$0.572	$0.032	$1.400	$0.295	$0.295	$0.311	$0.295
2014	$1.354	$0.614	$0.034	$1.503	$0.314	$0.314	$0.334	$0.316
2015	$1.450	$0.660	$0.036	$1.613	$0.335	$0.335	$0.359	$0.339
2016	$1.482	$0.673	$0.037	$1.647	$0.344	$0.344	$0.366	$0.347
2017	$1.515	$0.687	$0.038	$1.681	$0.352	$0.352	$0.374	$0.354
2018	$1.549	$0.701	$0.039	$1.717	$0.361	$0.361	$0.382	$0.362
2019	$1.583	$0.715	$0.040	$1.753	$0.370	$0.370	$0.389	$0.370
2020	$1.618	$0.730	$0.041	$1.790	$0.379	$0.379	$0.397	$0.378
2021	$1.654	$0.745	$0.042	$1.828	$0.389	$0.389	$0.406	$0.386
2022	$1.691	$0.761	$0.043	$1.866	$0.398	$0.398	$0.414	$0.394
2023	$1.729	$0.776	$0.044	$1.906	$0.408	$0.408	$0.423	$0.403
2024	$1.768	$0.793	$0.045	$1.946	$0.419	$0.419	$0.431	$0.412
2025	$1.807	$0.809	$0.046	$1.988	$0.429	$0.429	$0.440	$0.421
2026	$1.848	$0.826	$0.047	$2.030	$0.440	$0.440	$0.450	$0.430
2027	$1.889	$0.843	$0.048	$2.073	$0.451	$0.451	$0.459	$0.440
2028	$1.932	$0.861	$0.049	$2.118	$0.462	$0.462	$0.469	$0.449
2029	$1.975	$0.879	$0.051	$2.163	$0.474	$0.474	$0.479	$0.459
2030	$2.020	$0.897	$0.052	$2.209	$0.485	$0.485	$0.489	$0.470

Table 9-16B
Combined SO_2 and NO_x Emissions Adders by Candidate Unit
(Nominal $/MBtu)

Calendar Year	Stanton B (natural gas)	Stanton B (syngas)	LM6000 CT	LMS100 CT	7EA CT	7FA CT	1x1 7FA CC	PC	CFB
2009	$0.032	$0.125	$0.014	$0.014	$0.014	$0.014	$0.013	$0.125	$0.160
2010	$0.034	$0.155	$0.016	$0.015	$0.016	$0.016	$0.014	$0.188	$0.215
2011	$0.037	$0.166	$0.017	$0.016	$0.017	$0.017	$0.015	$0.202	$0.231
2012	$0.039	$0.177	$0.018	$0.017	$0.018	$0.018	$0.016	$0.217	$0.247
2013	$0.042	$0.190	$0.019	$0.019	$0.019	$0.019	$0.017	$0.233	$0.265
2014	$0.045	$0.203	$0.020	$0.020	$0.020	$0.021	$0.018	$0.250	$0.284
2015	$0.047	$0.217	$0.022	$0.021	$0.022	$0.022	$0.020	$0.269	$0.304
2016	$0.049	$0.222	$0.022	$0.022	$0.022	$0.022	$0.020	$0.275	$0.311
2017	$0.050	$0.227	$0.023	$0.022	$0.023	$0.023	$0.021	$0.280	$0.317
2018	$0.051	$0.232	$0.023	$0.023	$0.023	$0.024	$0.021	$0.286	$0.324
2019	$0.052	$0.238	$0.024	$0.023	$0.024	$0.024	$0.022	$0.292	$0.331
2020	$0.054	$0.243	$0.024	$0.024	$0.024	$0.025	$0.022	$0.298	$0.339
2021	$0.055	$0.249	$0.025	$0.024	$0.025	$0.025	$0.023	$0.304	$0.346
2022	$0.056	$0.254	$0.026	$0.025	$0.026	$0.026	$0.023	$0.310	$0.354
2023	$0.058	$0.260	$0.026	$0.026	$0.026	$0.027	$0.024	$0.317	$0.362
2024	$0.059	$0.266	$0.027	$0.026	$0.027	$0.027	$0.024	$0.324	$0.370
2025	$0.061	$0.272	$0.028	$0.027	$0.028	$0.028	$0.025	$0.330	$0.378
2026	$0.062	$0.279	$0.028	$0.028	$0.028	$0.029	$0.026	$0.337	$0.386
2027	$0.064	$0.285	$0.029	$0.028	$0.029	$0.029	$0.026	$0.344	$0.395
2028	$0.065	$0.292	$0.030	$0.029	$0.030	$0.030	$0.027	$0.352	$0.403
2029	$0.067	$0.298	$0.030	$0.030	$0.030	$0.031	$0.028	$0.359	$0.412
2030	$0.069	$0.305	$0.031	$0.030	$0.031	$0.031	$0.028	$0.366	$0.422

10.0 Economic Analysis

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

Section 7.0 of this Need for Power Application presents a description of the proposed Stanton B, while Section 8.0 provides an overview of various supply-side alternatives considered to meet OUC's capacity requirements. As described in Section 1.0, OUC's opportunity to partner with SPC-OG and participate in Stanton B is a result of participation in the DOE's CCPI. The economic analysis described herein compares the economics of the least-cost capacity expansion plan involving Stanton B with the economics of the lowest cost expansion plan that does not include Stanton B. The capacity associated with Stanton B, as well as construction of any other supply-side alternative, is only sufficient to satisfy OUC's forecast capacity requirements for a portion of the expansion planning horizon. Subsequent unit additions were selected from the supply-side alternatives that passed the initial screening described in Section 8.0.

10.1 Expansion Planning and Production Costing Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model B&V 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. POWROPT and its detailed chronological production costing module, POWRPRO, have both been used in numerous Need for Power Applications filed with the Florida Public Service Commission, including FMPA's Treasure Coast Energy Center Unit 1 Need for Power Application filed in April 2005.

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 25 year period from 2006 through 2030.

After the optimal generation expansion plan was selected using POWROPT, B&V'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 O&M costs, and the number of starts and associated costs. Fixed O&M costs were included only for new unit additions, as the fixed O&M costs for existing units are generally considered sunk costs that will not vary from one expansion plan to another. The annual capacity charges for the Stanton A and the TECO Partial Requirements Purchase Power Agreements likewise were not included, as they also represent sunk costs. Similarly, fixed costs for firm natural gas transportation capacity from FGT for existing units are considered sunk costs and are not included. The operating costs of each unit are aggregated to determine annual operating costs for each year of the expansion plan. Capital costs, fixed O&M costs, and fixed costs for natural gas transportation (for combined cycle) are then added for each capacity addition selected, at which point the cumulative present worth cost (CPWC) of each expansion plan can be calculated.

The CPWC calculation accounts for annual system costs (fuel and energy, fixed O&M for capacity additions, non-fuel variable O&M, startup costs, and levelized capital costs) for each year of the expansion planning period and discounts each back to 2006 at the present worth discount rate of 7.0 percent. These annual present worth costs are then summed over the 2006 through 2030 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.

10.2 Least-Cost Capacity Expansion Analysis

The economic analysis consisted of comparing the economics of the optimal capacity expansion plan including Stanton B with the optimal capacity expansion plan not including Stanton B. As described previously in this section, B&V first used its optimum generation expansion program, POWROPT, to select unit additions from the supply-side alternatives presented in Section 8.0. Once the least-cost expansion plan associated with each unit addition was determined, POWRPRO was used to determine the annual total system costs and develop a comparison of CPWCs associated with each expansion plan.

For all capacity expansion plan evaluations, it was necessary to account for natural gas transportation capacity associated with new combined cycle units. OUC currently has contracts in place with FGT for firm natural gas transportation to fuel Stanton A as well as the Indian River combustion turbines. For the 1x1 combined cycle option included in Section 8.0, it was assumed that OUC would purchase firm transportation 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 37,018 MBtu of firm natural gas per day. Assuming the FTS-2 reservation charge of $0.7618 per MBtu (pursuant to FGT's September, 2004, Market Area Transportation Settlement Rates), firm transportation costs of $2.87 per kW-month were added to the fixed O&M of the 1x1 combined cycle alternative. It has been assumed that OUC will not purchase firm natural gas transportation capacity from FGT for Stanton B 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 5.0. Any natural gas required in addition to the firm natural gas transportation for existing and new units is priced at the interruptible service rate.

As described in Section 8.0, the simple cycle combustion turbine supply-side alternatives are assumed to operate on ultra-low sulfur diesel fuel oil and have the capability to operate on natural gas as well. Since these units will not burn natural gas as a primary fuel, no firm natural gas transportation costs were added to the simple cycle fixed O&M costs.

10.2.1 Analysis of Stanton B

The evaluation of Stanton B was performed by modeling Stanton B as a committed resource beginning June 1, 2010. POWROPT was used to determine the set of optimum capacity additions beyond Stanton B from the conventional technologies presented in Section 8.0, as additional capacity is expected to be required beginning in the summer of 2015 to satisfy forecast capacity requirements. All conventional alternatives plus the LMS100 (which has been characterized in Section 8.0 as an emerging technology) are assumed to be available for installation to meet OUC's forecast capacity requirements beyond Stanton B.

10.2.1.1 Distribution of DOE Funding for Stanton B. As discussed throughout this Need for Power Application, Stanton B will be partially funded by the US DOE through the CCPI. A detailed description of DOE funding for Stanton B is presented in Section 7.0. Overall, the DOE has awarded the right to negotiate a cooperative agreement in the amount of $235 million for project definition, design, construction, and demonstration of the Transport Gasification process for Stanton B. Of this $235 million, the DOE will share in up to 50 percent of the costs associated with gasification prior to the demonstration phase, or [redacted]. The *Orlando Gasification Project Construction and Ownership Participation Agreement Between Southern Power Company – Orlando Gasification LLC and Orlando Utilities Commission* (the Construction and Ownership Participation Agreement) guarantees that no more than [redacted] of the [redacted] will be expended by SPC-OG to bring the gasifier to commercial operation. This results in [redacted] of DOE funding being available for use prior to commercial operation to offset allowable costs prior to commercial operation. The remaining [redacted] of DOE funding will be distributed during the 4 year demonstration period.

As delineated by the DOE, OUC will receive funding during the demonstration phase in an amount equal to 25.25 percent of the fuel, O&M, project completion, and startup costs associated with Stanton B's operation on syngas. These costs were determined and the allowed amount was credited to OUC on an annual basis during the demonstration period.

10.2.1.2 Stanton B Capital Cost. The Construction and Ownership Participation Agreement guarantees that OUC's equity portion of the gasifier will not exceed [redacted] in nominal dollars and the *Engineering, Procurement and Construction Management Agreement Between OUC and Southern Power Company - Orlando Gasification LLC Respecting the Stanton Energy Center Combined Cycle Unit B Generating Facility* (the EPC Agreement) guarantees that the capital cost of the 1x1 combined cycle will not exceed [redacted] in nominal dollars. The guaranteed cost for the combined cycle is on an EPC basis, and does not include a number of items (identified as OUC's additional costs and presented in Section 7.0). The estimated total for these additional costs is $24,020,000 in 2010 dollars.

The Construction and Ownership Participation Agreement and the EPC Agreement include fixed payment schedules in nominal dollars for the gasifier and the combined cycle, respectively. These payment schedules do not include the addition of IDC to the installed costs for Stanton B. The IDC added to the capital and OUC's additional costs for the combined cycle are [redacted] and $2,766,428, respectively, totaling [redacted]. The IDC added to the capital cost of the gasifier is [redacted]

In addition to IDC, the estimated cost of railcars ($27,734,000) is added to the installed costs in 2010. OUC's resulting installed costs for the combined cycle, additional costs, railcars, and for the gasifier were levelized using the 8.159 percent levelized fixed charge rate discussed in Section 5.0. Table 10-1 summarizes OUC's share of the project costs, broken down into two phases.

Table 10-1
Stanton B Project Capital Cost – OUC Share (Nominal Dollars)

Description	Cost ($1,000)
Stanton B – Combined Cycle Costs	
Capital for Combined Cycle	[redacted]
IDC for Combined Cycle	[redacted]
Stanton B – OUC's Additional Costs	
Additional Costs	$24,020
IDC for Additional Costs	$2,766
Stanton B – Railcar Costs	$27,734
Stanton B – Gasification Island Costs	
Capital for Gasifier	[redacted]
IDC for Gasifier	[redacted]
Stanton B – DOE Cost-Sharing	[redacted]
Total Installed Cost	[redacted]

10.2.1.3 Stanton B Monthly Demand Payment. OUC will pay SPC-OG a monthly demand payment in the amount of [redacted] for each month of the 20 year contract term. The monthly demand payment allows OUC to utilize SPC-OG's 65 percent ownership in the Stanton B gasification facility.

10.2.1.4 Facility Lease Payment. SPC-OG will pay OUC an annual payment of $73,150 in 2005 dollars. This payment will escalate with inflation and is included in the economic analysis.

10.2.1.5 Project Completion Costs. The DOE project completion costs were not included in the O&M for Stanton B but were instead identified as a separate cost component. SPC-OG provided an expected schedule of costs during the demonstration period, which is included in the economic analysis.

10.2.1.6 Stanton B Availability. As described in Section 7.0, the availability of the gasifier is expected to ramp up over the first 6 years of operation. Over the long run (after the first 6 years of operation), the gasification portion of Stanton B is expected to have an equivalent forced outage rate of [redacted], while the combined cycle is expected to have an equivalent forced outage rate of 3.5 percent. The 20 year average of scheduled maintenance is expected to be [redacted] for the gasifier and 18 days for the combined cycle portions of Stanton B.

To reflect the capability of Stanton B to operate on natural gas when the gasification process is unavailable, as well as to capture the difference between the scheduled maintenance requirements of the gasification and combined cycle portions of Stanton B, the production cost models (POWROPT and POWRPRO) were structured to allow only natural gas operation of Stanton B when the gasifier is unavailable. That is, Stanton B was modeled with performance and operating costs for both syngas and natural gas. Operation on syngas was limited by the equivalent forced outage rate and scheduled maintenance of the gasifier, and it was assumed that Stanton B will only operate on natural gas when the gasifier will be out of service for scheduled maintenance or when the gasifier is unavailable because of a forced outage and the combined cycle is not. Modeling in this fashion reflects the actual operating flexibility of the proposed Stanton B unit.

Section 7.10 of this Need for Power Application presents a description of the availability guarantees for the Stanton B gasifier. POWROPT and POWRPRO are not allowed to dispatch Stanton B on syngas beyond the annual availability guarantee, nor will the models assign availability below the guaranteed availability.

10.2.1.7 Other Operational Considerations. As described in Section 7.3, Stanton B can be started in either a cost saving manner or a load serving manner. The latter requires more fuel to start than the former, but generates significantly more energy that can be sold during startup. Both types of starts generate power that will be available to meet load and energy requirements. A credit was included in the evaluation to reflect the sale of energy generated during the startup of Stanton B. The number of unit starts was determined, and a generation credit was developed assuming that the energy generated during each startup was available for sale at $35/MWh (in 2005 dollars). While operating on syngas, Stanton B was modeled using the cost saving manner, which will generate 900 MWh of energy each start, as opposed to the load serving manner, which will generate 4,700 MWh of energy each start. If the gasifier is unavailable and Stanton B is firing natural gas, the startup will generate 250 MWh of energy, which was also considered.

10.2.2 Analysis of Alternate Expansion Plans

B&V utilized POWROPT to determine the least-cost capacity expansion plan not involving Stanton B. To determine this plan, POWROPT selected generating unit alternatives from among the supply-side alternatives identified in Section 8.0 of this Need for Power Application to meet the forecast capacity requirements identified in Section 4.0. Because of the time required to permit, license, and construct certain types of units, some units will not be available for operation in 2010. However, these units may be available to fill in OUC's future capacity needs during the planning horizon. Given the time required to permit, license, and construct a solid-fuel unit, neither the pulverized coal nor CFB options would be available to operate earlier than 2012. All conventional alternatives plus the LMS100 (which has been characterized in Section 8.0 of this Need for Power Application as an emerging technology) are assumed to be available to be installed to meet OUC's initial forecast 2010 capacity requirements.

10.2.3 Analysis of Emission Costs

To reflect the economic effects of the future regulatory programs described in Section 9.0, the costs of emission allowances were incorporated into the fuel costs for each unit, including existing units, at the start of the first phase of the CAIR. The allowance price forecast presented in Section 9.3 provides emission costs on a dollar per ton basis. These costs were used to calculate a fuel cost adder for both existing units and candidate units based on each unit's emission rates. As a result, each unit was modeled using different prices for fuel because of differences in emission rates. The value of allowances allocated to OUC's existing units was not included in the economic analysis since it would be the same for each plan.

10.2.4 Dispatch Assumptions

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

10.3 Cumulative Present Worth Cost Analysis

The previous section described how POWROPT was used to select least-cost capacity expansion plans for two scenarios: one involving construction of Stanton B and one assuming Stanton B 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 cumulative present worth costs associated with each expansion plan.

10.3.1 Analysis of Stanton B Capacity Expansion Plan

The least-cost capacity expansion plan, which assumes availability of Stanton B in June 2010, includes construction of a 7FA combustion turbine in 2015, followed by a second 7FA CT in 2018, a subcritical pulverized coal unit in 2021, an LM6000 CT in 2029, and a 7EA CT in 2030.

10.3.2 Analysis of Alternate Capacity Expansion Plan

The least-cost capacity expansion plan without Stanton B consists of construction of a 7FA CT in 2010, followed by a subcritical pulverized coal unit in 2013, a 7EA CT in 2021, a second 7FA CT in 2023, and a 1x1 7FA combined cycle unit in 2026.

10.3.3 Comparison of Cumulative Present Worth Costs

As shown in Table 10-2 the CPWC of the expansion plan including Stanton B is approximately \$5,506.8 million in 2030. Table 10-3 indicates that the CPWC of the alternate expansion plan, without Stanton B, is approximately \$5,519.8 million in 2030. Comparison of the CPWC of the two plans shows the expansion plan with Stanton B is the least-cost plan by approximately \$12.9 million over the planning period.

Table 10-2 Expansion Plan Economic Summary - With Stanton B

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Unit Addition	Generation Additions: 2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B(1)	N/A	33	06/01	2010	[redacted]	
7FA CT	81,059	14	06/01	2015	103,862	8,474
7FA CT	81,059	14	06/01	2018	111,848	9,126
PULVERIZED COAL UNIT	761,738	50	06/01	2021	1,177,755	96,093
LM6000 CT	44,879	12	06/01	2029	81,073	6,615
7EA CT	58,563	13	06/01	2030	108,558	8,857

Year	Production Cost: Fuel and Energy Cost ($1,000)	O&M: Variable ($1,000)	O&M: Fixed(2) ($1,000)	Start-Up ($1,000)	Total Production Cost ($1,000)	Capital Cost, DOE Contributions, and Other Stanton B Project Costs: Unit Capital Cost ($1,000)	OUC IGCC Demand Payment(3) ($1,000)	Project Completion Cost(4) ($1,000)	DOE Funding(5) ($1,000)	Startup Credit and Lease(6) ($1,000)	Total Capital Cost ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]				$223,288	[redacted]						$223,288	$223,288
2007	[redacted]				$204,538	[redacted]						$204,538	$414,445
2008	[redacted]				$210,520	[redacted]						$210,520	$598,322
2009	[redacted]				$251,505	[redacted]						$251,505	$803,624
2010	[redacted]				$272,613	[redacted]						$291,831	$1,026,261
2011	[redacted]				$289,337	[redacted]						$321,796	$1,255,697
2012	[redacted]				$304,448	[redacted]						$335,871	$1,479,502
2013	[redacted]				$326,798	[redacted]						$359,119	$1,703,143
2014	[redacted]				$354,425	[redacted]						$399,739	$1,935,795
2015	[redacted]				$376,110	[redacted]						$424,517	$2,166,705
2016	[redacted]				$397,359	[redacted]						$449,251	$2,395,081
2017	[redacted]				$426,816	[redacted]						$478,697	$2,622,506
2018	[redacted]				$457,774	[redacted]						$515,009	$2,851,177
2019	[redacted]				$490,550	[redacted]						$551,513	$3,080,035
2020	[redacted]				$529,685	[redacted]						$590,508	$3,309,044
2021	[redacted]				$530,587	[redacted]						$647,903	$3,543,874
2022	[redacted]				$537,354	[redacted]						$694,601	$3,779,159
2023	[redacted]				$571,885	[redacted]						$728,952	$4,009,927
2024	[redacted]				$603,044	[redacted]						$760,172	$4,234,834
2025	[redacted]				$642,875	[redacted]						$799,965	$4,456,031
2026	[redacted]				$688,678	[redacted]						$845,608	$4,674,552
2027	[redacted]				$723,221	[redacted]						$880,199	$4,887,132
2028	[redacted]				$765,339	[redacted]						$922,243	$5,095,294
2029	[redacted]				$823,302	[redacted]						$984,002	$5,302,866
2030	[redacted]				$865,690	[redacted]						$1,034,461	$5,506,807

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments

Table 10-3 Expansion Plan Economic Summary - Without Stanton B

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions

Unit	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
7FA SC	81,059	14	06/01	2010	91,799	7,490
PC	761,738	50	06/01	2013	966,638	78,868
7EA SC	58,563	13	06/01	2021	86,926	7,092
7FA SC	81,059	14	06/01	2023	126,546	10,325
1x1 7FA CC	213,127	30	06/01	2026	364,691	29,755

Year	Production Cost: Fuel and Energy Cost ($1,000)	O&M: Variable ($1,000)	O&M: Fixed(1) ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Capital Cost: Unit Capital Cost ($1,000)	Emissions Costs ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$209,405	$11,947	$0	$1,936	$223,288	$0	$0	$0	$0	$0	$0	$223,288	$223,288
2007	$190,257	$12,914	$0	$1,367	$204,538	$0	$0	$0	$0	$0	$0	$204,538	$414,445
2008	$195,023	$14,405	$0	$1,093	$210,520	$0	$0	$0	$0	$0	$0	$210,520	$598,322
2009	$235,211	$15,565	$0	$729	$251,505	$0	$0	$0	$0	$0	$0	$251,505	$803,624
2010	$259,675	$16,942	$463	$883	$277,964	$7,490	$0	$0	$0	$0	$4,391	$282,355	$1,019,032
2011	$282,794	$19,150	$810	$1,038	$303,791	$7,490	$0	$0	$0	$0	$7,490	$311,281	$1,240,970
2012	$299,869	$20,130	$830	$918	$321,746	$7,490	$0	$0	$0	$0	$7,490	$329,236	$1,460,354
2013	$296,089	$19,222	$8,796	$2,254	$326,362	$86,358	$0	$0	$0	$0	$53,730	$380,092	$1,697,056
2014	$294,541	$17,985	$14,763	$3,034	$330,323	$86,358	$0	$0	$0	$0	$86,358	$416,681	$1,939,568
2015	$317,512	$19,292	$15,132	$3,167	$355,103	$86,358	$0	$0	$0	$0	$86,358	$441,461	$2,179,694
2016	$336,052	$20,362	$15,510	$3,006	$374,931	$86,358	$0	$0	$0	$0	$86,358	$461,289	$2,414,190
2017	$361,106	$22,057	$15,898	$3,290	$402,351	$86,358	$0	$0	$0	$0	$86,358	$488,709	$2,646,372
2018	$390,448	$23,489	$16,296	$2,900	$433,132	$86,358	$0	$0	$0	$0	$86,358	$519,490	$2,877,031
2019	$416,716	$25,173	$16,703	$3,112	$461,703	$86,358	$0	$0	$0	$0	$86,358	$548,061	$3,104,457
2020	$445,437	$27,660	$17,121	$3,630	$493,848	$86,358	$0	$0	$0	$0	$86,358	$580,206	$3,329,471
2021	$479,043	$30,737	$18,101	$3,127	$531,008	$93,450	$0	$0	$0	$0	$90,516	$621,524	$3,554,740
2022	$505,729	$31,862	$18,953	$3,247	$559,791	$93,450	$0	$0	$0	$0	$93,450	$653,241	$3,776,015
2023	$543,122	$34,773	$20,065	$3,783	$601,744	$103,775	$0	$0	$0	$0	$99,504	$701,247	$3,998,012
2024	$579,224	$37,394	$21,028	$3,607	$641,253	$103,775	$0	$0	$0	$0	$103,775	$745,028	$4,218,439
2025	$622,051	$40,807	$21,554	$3,590	$688,002	$103,775	$0	$0	$0	$0	$103,775	$791,777	$4,437,372
2026	$656,086	$42,739	$29,770	$7,792	$736,386	$133,530	$0	$0	$0	$0	$121,221	$857,607	$4,658,994
2027	$688,885	$44,253	$35,793	$8,673	$777,604	$133,530	$0	$0	$0	$0	$133,530	$911,134	$4,879,045
2028	$731,714	$46,975	$36,414	$9,735	$824,838	$133,530	$0	$0	$0	$0	$133,530	$958,368	$5,095,361
2029	$780,979	$50,630	$37,049	$10,477	$879,136	$133,530	$0	$0	$0	$0	$133,530	$1,012,666	$5,308,980
2030	$832,445	$54,555	$37,699	$10,908	$935,607	$133,530	$0	$0	$0	$0	$133,530	$1,069,137	$5,519,757

Notes:
(1) Fixed costs are included only for new unit additions.

11.0 Sensitivity Analyses

Several sensitivity analyses were performed to supplement the base case economic analysis and to demonstrate the robustness of the capacity expansion plans, including Stanton B. These analyses measure the impact of varying key assumptions used to develop the base case economic analysis, and the impacts of considerations not included in the base case. As described in Section 10.0, the base case economic analysis compared the CPWC of the optimal capacity expansion plan including Stanton B to the optimal capacity expansion plan without Stanton B. For the base case analysis including Stanton B, the proposed Stanton B was treated as a committed unit in 2010, while in the base case analysis without Stanton B, 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 OUC's capacity needs. Once the optimal expansion plan was developed for each case, POWRPRO (Black & Veatch's production costing model) was used to determine each plan's optimal dispatch and the associated costs.

The sensitivity analyses were performed in a manner similar to 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 used to calculate production costs of each plan to compare cumulative present worth costs. The remainder of this section presents the methodology and results of the sensitivity analyses.

11.1 High Fuel Price Escalation

In the high fuel price sensitivity analysis, the annual escalation in the base case fuel forecast was increased. The annual escalation in fuel prices was increased by 2.0 percentage points for the coal, fuel oil, and natural gas forecasts described in Section 5.0. The forecast for nuclear fuel prices was not changed because of the historical stability of nuclear fuel prices. Table 11-1 presents the fuel prices used to perform the high fuel price escalation sensitivity analysis. As described in Section 10.0, the costs of emission allowances under the future regulatory programs described in Section 9.0 were added to the fuel prices presented in Table 11-1 for both existing and candidate units.

Table 11-1
High Fuel Price Projections
(Nominal $/MBtu)

Year	Delivered Central Appalachian Bituminous Coal	Delivered Northern Appalachian Bituminous Coal	Delivered PRB Subbituminous Coal	Commodity Natural Gas	Delivered Ultra-Low Sulfur Diesel Oil
2006	2.84	2.44	2.57	10.58	14.87
2007	2.71	2.43	2.55	7.92	13.39
2008	2.84	2.65	2.72	6.57	13.54
2009	2.94	2.73	2.84	6.80	14.15
2010	3.06	2.84	2.99	7.11	14.79
2011	3.21	2.97	3.12	7.45	15.59
2012	3.37	3.11	3.26	7.88	16.56
2013	3.56	3.28	3.44	8.33	17.59
2014	3.73	3.43	3.59	8.74	18.68
2015	3.94	3.62	3.78	9.24	19.83
2016	4.14	3.79	3.94	9.68	20.89
2017	4.37	4.00	4.15	10.07	22.00
2018	4.73	4.35	4.64	10.55	23.17
2019	5.00	4.58	4.88	11.06	24.40
2020	5.25	4.81	5.09	11.58	25.70
2021	5.52	5.04	5.31	12.21	27.06
2022	5.83	5.31	5.58	12.95	28.49
2023	6.13	5.57	5.83	13.73	30.00
2024	6.47	5.88	6.12	14.56	31.59
2025	6.80	6.16	6.39	15.44	33.26
2026	7.15	6.47	6.66	16.37	35.03
2027	7.52	6.78	6.95	17.34	36.89
2028	7.91	7.12	7.25	18.38	38.84
2029	8.32	7.47	7.57	19.47	40.90
2030	8.75	7.84	7.90	20.62	43.06

Under these assumptions, the optimal capacity expansion plan for the case with Stanton B in 2010 consists of a 7FA CT in 2015, a subcritical pulverized coal unit in 2018, a second 7FA CT in 2026, a 7EA CT in 2029, and an LM6000 CT in 2030. The optimal capacity expansion plan for the case without Stanton B consists of a 7FA CT in 2010, a subcritical pulverized coal unit in 2013, a CFB unit in 2021, a 7EA CT in 2027, and a second 7FA CT in 2028.

The CPWCs for the expansion plan with Stanton B and the plan without Stanton B are approximately $6,503.4 million and $6,526.8 million, respectively. A comparison of these CPWCs shows that the expansion plan with Stanton B is the least-cost plan by approximately $23.3 million over the evaluation period.

11.2 Low Fuel Price Escalation

In the low fuel price sensitivity analysis the annual escalation was decreased in the base case fuel forecast. The annual escalation in fuel prices was decreased by 2.0 percentage points for the coal, fuel oil, and natural gas forecasts described in Section 5.0. The forecast for nuclear fuel prices was not varied because of the historical stability of nuclear fuel prices. Table 11-2 presents the fuel prices used to perform the low fuel price escalation sensitivity analysis. As described in Section 10.0, the costs of emission allowances under the future regulatory programs described in Section 9.0 were added to the fuel prices presented in Table 11-2 for both existing and candidate units.

Under these assumptions, the optimal capacity expansion plan for the case with Stanton B in 2010 consists of a 7FA CT in 2015, a second 7FA CT in 2018, a third 7FA CT in 2021, a fourth 7FA CT in 2024, a fifth 7FA CT in 2027, and an LMS100 in 2029. The optimal capacity expansion plan for the case without Stanton B consists of a 7FA CT in 2010, a subcritical pulverized coal unit in 2013, a second 7FA CT in 2021, a third 7FA CT in 2024, an LMS100 in 2027, a 7EA CT in 2029, and an LM6000 CT in 2030.

The CPWCs for the expansion plan with Stanton B and the plan without Stanton B are approximately $4,761.0 million and $4,726.2 million, respectively. A comparison of these CPWCs shows that the expansion plan without Stanton B is the least-cost plan by approximately $34.8 million over the evaluation period.

11.3 High Load and Energy Growth

The high load and energy growth scenario shows the effects of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and, therefore, results in increased cumulative present worth costs as compared to the least-cost, base case capacity expansion plan. The high load and energy

Table 11-2
Low Fuel Price Projections
(Nominal $/MBtu)

Year	Delivered Central Appalachia Bituminous Coal	Delivered Northern Appalachia Bituminous Coal	Delivered Powder River Basin Subbituminous Coal	Commodity Natural Gas	Delivered Ultra-Low Sulfur Diesel Oil
2006	2.84	2.44	2.57	10.58	14.87
2007	2.59	2.33	2.45	7.48	12.78
2008	2.61	2.45	2.51	5.90	12.40
2009	2.60	2.42	2.51	5.87	12.45
2010	2.59	2.42	2.55	5.89	12.50
2011	2.62	2.43	2.55	5.94	12.66
2012	2.64	2.44	2.56	6.03	12.93
2013	2.68	2.48	2.59	6.13	13.21
2014	2.70	2.49	2.60	6.18	13.48
2015	2.74	2.52	2.63	6.28	13.76
2016	2.77	2.54	2.64	6.32	13.93
2017	2.81	2.58	2.67	6.32	14.10
2018	2.93	2.70	2.88	6.36	14.27
2019	2.97	2.73	2.91	6.41	14.45
2020	3.00	2.75	2.92	6.45	14.62
2021	3.03	2.77	2.92	6.53	14.80
2022	3.07	2.81	2.95	6.66	14.98
2023	3.11	2.83	2.96	6.79	15.16
2024	3.15	2.87	2.99	6.92	15.34
2025	3.18	2.89	2.99	7.06	15.52
2026	3.22	2.91	3.00	7.19	15.71
2027	3.25	2.94	3.01	7.32	15.90
2028	3.29	2.96	3.02	7.46	16.09
2029	3.32	2.99	3.02	7.60	16.28
2030	3.36	3.01	3.03	7.74	16.47

growth scenario is based upon the high load and energy growth forecast presented in Appendix A. Tables 11-3 and 11-4 provide the projected reliability levels for the winter and summer, respectively. In this scenario, additional capacity is required to meet OUC's 15 percent reserve margin before 2010; however, it is assumed that new generation will not be constructed before 2010. To make the analysis as realistic as possible, POWROPT was used to select unit additions no earlier than 2010 and any forecast capacity requirements prior to 2010 were assumed to be met through short-term capacity purchases.

Under the high load and energy growth sensitivity analysis, the optimal capacity expansion plan with Stanton B in 2010 consists of a 7FA CT in 2012, a second 7FA CT in 2014, a third 7FA CT in 2016, a subcritical pulverized coal unit in 2018, a fourth 7FA CT in 2023, a 7EA CT in 2025, a second subcritical pulverized coal unit in 2026, and a second 7EA CT in 2030. The optimal capacity expansion plan without Stanton B consists of two 7FA CTs in 2010, a subcritical pulverized coal unit in 2013, a third 7FA CT in 2018, a second subcritical pulverized coal unit in 2020, a 1x1 7FA combined cycle in 2025, a 7EA CT in 2028, a second 7EA CT in 2029, and a third 7EA CT, and an LM6000 CT in 2030.

The CPWCs for the expansion plan with Stanton B and the plan without Stanton B are $6,680.3 and $6,677.9 million, respectively. A comparison of the CPWCs shows that the case without Stanton B is the least-cost plan by $2.4 million over the evaluation period. Better utilization of the larger pulverized coal unit installed in 2013 in the plan without Stanton B resulted in the cost savings.

11.4 Low Load and Energy Growth

The low load and energy growth scenario shows the effects of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generating capacity than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Appendix A. Tables 11-5 and 11-6 provide the projected reliability levels for the winter and summer, respectively.

Under the low load and energy growth sensitivity, the optimal capacity expansion plan with Stanton B in 2010 consists of a 7FA CT in 2021, a 7EA CT in 2027, and an LM6000 CT in 2029. The optimal capacity expansion plan without Stanton B consists of a subcritical pulverized coal unit in 2013 and an LMS100 CT in 2028.

Table 11-3
High Growth Projected Reliability Levels – Winter

Calendar Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)	Total Peak Demand (MW)	Available Capacity (MW)				Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[5] (MW)
				Installed[1]	Stanton A PPA[2]	TECO PR	Total	Required[3]	Available[4]	
2005/06	1,225	22	1,247	1,278	343	15	1,636	184	392	208
2006/07	1,284	0	1,284	1,257	343	15	1,615	193	333	141
2007/08	1,346	0	1,346	1,257	343	15	1,615	202	271	69
2008/09	1,412	0	1,412	1,257	343	15	1,615	212	206	(6)
2009/10	1,480	0	1,480	1,257	343	15	1,615	222	137	(85)
2010/11	1,538	0	1,538	1,257	343	15	1,615	231	79	(151)
2011/12	1,598	0	1,598	1,257	343	15	1,615	240	19	(221)
2012/13	1,661	0	1,661	1,257	343	0	1,600	249	(61)	(310)
2013/14	1,726	0	1,726	1,257	343	0	1,600	259	(126)	(384)
2014/15	1,793	0	1,793	1,257	343	0	1,600	269	(193)	(462)
2015/16	1,858	0	1,858	1,257	343	0	1,600	279	(258)	(537)
2016/17	1,926	0	1,926	1,257	343	0	1,600	289	(326)	(614)
2017/18	1,995	0	1,995	1,257	343	0	1,600	299	(395)	(695)
2018/19	2,068	0	2,068	1,257	343	0	1,600	310	(468)	(778)
2010/20	2,143	0	2,143	1,257	343	0	1,600	321	(543)	(864)
2020/21	2,216	0	2,216	1,257	343	0	1,600	332	(616)	(948)
2021/22	2,291	0	2,291	1,257	343	0	1,600	344	(691)	(1,034)
2022/23	2,369	0	2,369	1,257	343	0	1,600	355	(769)	(1,124)
2023/24	2,449	0	2,449	1,257	343	0	1,600	367	(849)	(1,216)
2024/25	2,532	0	2,532	1,257	343	0	1,600	380	(932)	(1,312)
2025/26	2,618	0	2,618	1,257	343	0	1,600	393	(1,018)	(1,411)
2026/27	2,707	0	2,707	1,257	343	0	1,600	406	(1,107)	(1,513)
2027/28	2,799	0	2,799	1,257	343	0	1,600	420	(1,199)	(1,618)
2028/29	2,893	0	2,893	1,257	343	0	1,600	434	(1,293)	(1,727)
2029/30	2,992	0	2,992	1,257	343	0	1,600	449	(1,392)	(1,840)

(1)Includes OUC's equity portion of Stanton A, as well as St. Cloud's (STC's) diesel units (scheduled to retire in October 2006).
(2)Assumes the Stanton A PPA continues unchanged through the planning horizon. OUC has various capacity reduction and termination options related to the Stanton A PPA, as described in Section 2.2 of this Need for Power Application.
(3)Required reserves include 15 percent reserve margin on OUC retail peak demand and STC retail peak demand.
(4)Available reserves equal the difference between total available capacity and total peak demand, plus 15 percent of the TECO PR purchase.
(5)Calculated as the difference between available reserves and required reserves.

Table 11-4
High Growth Projected Reliability Levels – Summer

Calendar Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)	Total Peak Demand (MW)	Available Capacity (MW)				Reserves (MW)		Excess/ (Deficit) Capacity to Maintain 15% Reserve Margin[5] (MW)
				Installed[1]	Stanton A PPA[2]	TECO PR	Total	Required[3]	Available[4]	
2006	1,223	22	1,245	1,220	322	15	1,557	183	315	131
2007	1,282	0	1,282	1,199	322	15	1,536	192	256	64
2008	1,344	0	1,344	1,199	322	15	1,536	202	194	(7)
2009	1,409	0	1,409	1,199	322	15	1,536	211	129	(82)
2010	1,476	0	1,476	1,199	322	15	1,536	221	62	(159)
2011	1,534	0	1,534	1,199	322	15	1,536	230	5	(226)
2012	1,594	0	1,594	1,199	322	15	1,536	239	(55)	(295)
2013	1,656	0	1,656	1,199	322	0	1,521	248	(135)	(383)
2014	1,721	0	1,721	1,199	322	0	1,521	258	(200)	(458)
2015	1,788	0	1,788	1,199	322	0	1,521	268	(267)	(535)
2016	1,853	0	1,853	1,199	322	0	1,521	278	(332)	(610)
2017	1,920	0	1,920	1,199	322	0	1,521	288	(399)	(687)
2018	1,990	0	1,990	1,199	322	0	1,521	298	(469)	(767)
2019	2,062	0	2,062	1,199	322	0	1,521	309	(541)	(850)
2020	2,139	0	2,139	1,199	322	0	1,521	321	(618)	(939)
2021	2,212	0	2,212	1,199	322	0	1,521	332	(691)	(1,022)
2022	2,287	0	2,287	1,199	322	0	1,521	343	(766)	(1,109)
2023	2,364	0	2,364	1,199	322	0	1,521	355	(843)	(1,198)
2024	2,444	0	2,444	1,199	322	0	1,521	367	(923)	(1,290)
2025	2,527	0	2,527	1,199	322	0	1,521	379	(1,006)	(1,385)
2026	2,613	0	2,613	1,199	322	0	1,521	392	(1,092)	(1,484)
2027	2,701	0	2,701	1,199	322	0	1,521	405	(1,180)	(1,586)
2028	2,793	0	2,793	1,199	322	0	1,521	419	(1,272)	(1,691)
2029	2,888	0	2,888	1,199	322	0	1,521	433	(1,367)	(1,800)
2030	2,986	0	2,986	1,199	322	0	1,521	448	(1,465)	(1,913)

(1)Includes OUC's equity portion of Stanton A, as well as St. Cloud's (STC's) diesel units (scheduled to retire in October 2006).
(2)Assumes the Stanton A PPA continues unchanged through the planning horizon. OUC has various capacity reduction and termination options related to the Stanton A PPA, as described in Section 2.2 of this Need for Power Application.
(3)Required reserves include 15 percent reserve margin on OUC retail peak demand and STC retail peak demand.
(4)Available reserves equal the difference between total available capacity and total peak demand, plus 15 percent of the TECO PR purchase.
(5)Calculated as the difference between available reserves and required reserves.

Table 11-5
Low Growth Projected Reliability Levels – Winter

Calendar Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)	Total Peak Demand (MW)	Available Capacity (MW)				Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[5] (MW)
				Installed[1]	Stanton A PPA[2]	TECO PR	Total	Required[3]	Available[4]	
2005/06	1,184	22	1,206	1,278	343	15	1,636	178	432	254
2006/07	1,201	0	1,201	1,257	343	15	1,615	180	417	237
2007/08	1,217	0	1,217	1,257	343	15	1,615	183	400	218
2008/09	1,234	0	1,234	1,257	343	15	1,615	185	383	198
2009/10	1,251	0	1,251	1,257	343	15	1,615	188	366	179
2010/11	1,278	0	1,278	1,257	343	15	1,615	192	339	148
2011/12	1,305	0	1,305	1,257	343	15	1,615	196	312	116
2012/13	1,333	0	1,333	1,257	343	0	1,600	200	267	67
2013/14	1,362	0	1,362	1,257	343	0	1,600	204	238	34
2014/15	1,391	0	1,391	1,257	343	0	1,600	209	209	0
2015/16	1,417	0	1,417	1,257	343	0	1,600	213	183	(29)
2016/17	1,443	0	1,443	1,257	343	0	1,600	216	157	(60)
2017/18	1,470	0	1,470	1,257	343	0	1,600	220	130	(90)
2018/19	1,497	0	1,497	1,257	343	0	1,600	225	103	(122)
2010/20	1,525	0	1,525	1,257	343	0	1,600	229	75	(154)
2020/21	1,549	0	1,549	1,257	343	0	1,600	232	51	(182)
2021/22	1,574	0	1,574	1,257	343	0	1,600	236	26	(210)
2022/23	1,599	0	1,599	1,257	343	0	1,600	240	1	(239)
2023/24	1,624	0	1,624	1,257	343	0	1,600	244	(24)	(268)
2024/25	1,650	0	1,650	1,257	343	0	1,600	248	(50)	(298)
2025/26	1,676	0	1,676	1,257	343	0	1,600	251	(76)	(328)
2026/27	1,703	0	1,703	1,257	343	0	1,600	255	(103)	(358)
2027/28	1,730	0	1,730	1,257	343	0	1,600	259	(130)	(389)
2028/29	1,757	0	1,757	1,257	343	0	1,600	264	(157)	(421)
2029/30	1,785	0	1,785	1,257	343	0	1,600	268	(185)	(453)

(1)Includes OUC's equity portion of Stanton A, as well as St. Cloud's (STC's) diesel units (scheduled to retire in October 2006).
(2)Assumes the Stanton A PPA continues unchanged through the planning horizon. OUC has various capacity reduction and termination options related to the Stanton A PPA, as described in Section 2.2 of this Need for Power Application.
(3)Required reserves include 15 percent reserve margin on OUC retail peak demand and STC retail peak demand.
(4)Available reserves equal the difference between total available capacity and total peak demand, plus 15 percent of the TECO PR purchase.
(5)Calculated as the difference between available reserves and required reserves.

Table 11-6
Low Growth Projected Reliability Levels – Summer

Calendar Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)	Total Peak Demand (MW)	Available Capacity (MW)				Reserves (MW)		Excess/ (Deficit) Capacity to Maintain 15% Reserve Margin[5] (MW)
				Installed[1]	Stanton A PPA[2]	TECO PR	Total	Required[3]	Available[4]	
2006	1,182	22	1,204	1,220	322	15	1,557	177	355	178
2007	1,198	0	1,198	1,199	322	15	1,536	180	340	160
2008	1,215	0	1,215	1,199	322	15	1,536	182	323	141
2009	1,232	0	1,232	1,199	322	15	1,536	185	306	122
2010	1,248	0	1,248	1,199	322	15	1,536	187	290	103
2011	1,275	0	1,275	1,199	322	15	1,536	191	263	72
2012	1,302	0	1,302	1,199	322	15	1,536	195	236	41
2013	1,330	0	1,330	1,199	322	0	1,521	200	191	(9)
2014	1,359	0	1,359	1,199	322	0	1,521	204	162	(41)
2015	1,388	0	1,388	1,199	322	0	1,521	208	133	(75)
2016	1,414	0	1,414	1,199	322	0	1,521	212	107	(105)
2017	1,440	0	1,440	1,199	322	0	1,521	216	81	(135)
2018	1,467	0	1,467	1,199	322	0	1,521	220	54	(166)
2019	1,494	0	1,494	1,199	322	0	1,521	224	27	(197)
2020	1,522	0	1,522	1,199	322	0	1,521	228	(1)	(229)
2021	1,546	0	1,546	1,199	322	0	1,521	232	(25)	(257)
2022	1,571	0	1,571	1,199	322	0	1,521	236	(50)	(285)
2023	1,596	0	1,596	1,199	322	0	1,521	239	(75)	(314)
2024	1,621	0	1,621	1,199	322	0	1,521	243	(100)	(343)
2025	1,647	0	1,647	1,199	322	0	1,521	247	(126)	(373)
2026	1,673	0	1,673	1,199	322	0	1,521	251	(152)	(403)
2027	1,700	0	1,700	1,199	322	0	1,521	255	(179)	(434)
2028	1,727	0	1,727	1,199	322	0	1,521	259	(206)	(465)
2029	1,754	0	1,754	1,199	322	0	1,521	263	(233)	(496)
2030	1,782	0	1,782	1,199	322	0	1,521	267	(261)	(528)

(1)Includes OUC's equity portion of Stanton A, as well as St. Cloud's (STC's) diesel units (scheduled to retire in October 2006).
(2)Assumes the Stanton A PPA continues unchanged through the planning horizon. OUC has various capacity reduction and termination options related to the Stanton A PPA, as described in Section 2.2 of this Need for Power Application.
(3)Required reserves include 15 percent reserve margin on OUC retail peak demand and STC retail peak demand.
(4)Available reserves equal the difference between total available capacity and total peak demand, plus 15 percent of the TECO PR purchase.
(5)Calculated as the difference between available reserves and required reserves.

The CPWCs for the expansion plan with Stanton B and the plan without Stanton B are $4,494.5 million and $4,528.6 million, respectively. A comparison of CPWCs shows that the case with Stanton B is the least-cost plan by $34.1 million over the evaluation period.

11.5 High Capital Costs

The high capital cost sensitivity analysis increases the costs for candidate units and the proposed Stanton B. The increase in capital costs helps capture uncertainty about future costs of material, labor, and equipment. The installed cost for each of the supply-side alternatives presented in Section 8.0 was increased by 10.0 percent. Since the EPC cost of Stanton B is fixed, OUC's additional costs were increased by 10.0 percent.

Under these assumptions, the optimal capacity expansion plan for the case with Stanton B in 2010 consists of a 7FA CT in 2015, a second 7FA CT in 2018, a third 7FA CT in 2021, and a subcritical pulverized coal unit in 2024. The optimal capacity expansion plan for the case without Stanton B consists of a 7FA CT in 2010, a subcritical pulverized coal unit in 2013, a 7EA CT in 2021, a second 7FA CT in 2023, and a 1x1 7FA combined cycle in 2024.

The CPWCs for the expansion plan with Stanton B and the plan without Stanton B are approximately $5,541.6 million and $5,583.8 million, respectively. A comparison of these CPWCs shows that the expansion plan with Stanton B is the least-cost plan by approximately $42.2 million over the evaluation period.

11.6 Gasification Ash Utilization

As described in Section 7.0, the Transport Gasification process produces gasification ash. This gasification ash has a potential use as supplementary fuel in Stanton Units 1 and 2. While not included in the base case analysis, the gasification ash produced by Stanton B may be blended with the coal burned in the Stanton coal units if technically feasible or sold on the open market. This sensitivity analysis assumes that gasification ash will be blended with the Central Appalachian bituminous coal currently being burned in Stanton Units 1 and 2. Preliminary estimates indicate that while operating at full load, Stanton B will produce 18,300 pounds of gasification ash per hour, and that the ash will have an approximate heating value of 4,000 Btu/lb.

Since the use of gasification ash is only applicable to the expansion plan with Stanton B, this sensitivity case considers the base case expansion plans for the cases with and without Stanton B. The amount of gasification ash produced in the case with Stanton B was determined, and an annual credit was applied to offset the cost of bituminous coal currently being burned at Stanton Units 1 and 2. While this sensitivity case considers the possibility of burning gasification ash at the Stanton site, it can be assumed that the economic benefits of selling the ash on the open market will result in similar savings to OUC.

The CPWCs for the expansion plan with Stanton B in 2010 and the plan without Stanton B are approximately $5,491.5 million and $5,519.8 million, respectively. A comparison of these costs shows that the expansion plan with Stanton B is the least-cost plan by approximately $28.3 million over the evaluation period. Table 11-7 presents the development of the annual credits to OUC if it is possible to burn gasification ash at the Stanton site.

11.7 High Emission Allowance Prices

The allowance price forecasts presented in Section 9.0 are based on the fundamental assumption that the market for allowances in future regulatory programs will directly correlate with costs for adding emission control equipment. Historically, prices for emission allowances have been volatile, and this sensitivity case is based on assumed higher allowance prices.

In the high emission allowance price sensitivity case, the base case allowance prices were increased by 25 percent on an annual basis. Increasing allowance prices results in a higher fuel cost adder for the fuels being burned in existing and candidate generating units. The increase in allowance prices results in a greater incentive to operate units with lower emissions rates for electric generation, and also causes higher CPWCs relative to the base case economic analysis. Table 11-8 presents the emission allowance prices used in the high allowance price sensitivity analysis.

In this sensitivity case, the optimal capacity expansion plan for the case with Stanton B in 2010 consists of a 7FA CT in 2015, a second 7FA CT in 2018, a subcritical pulverized coal unit in 2021, an LM6000 CT in 2029, and a 7EA CT in 2030. The optimal capacity expansion plan for the case without Stanton B consists of a 7FA CT in 2010, a subcritical pulverized coal unit in 2013, a 7EA CT in 2021, a second 7FA CT in 2023, and a 1x1 7FA combined cycle in 2024.

The CPWCs for the expansion plan with Stanton B and the plan without Stanton B are approximately $5,631.2 million and $5,649.1 million, respectively. A comparison of these CPWCs shows that the expansion plan with Stanton B is the least-cost plan by approximately $17.9 million over the evaluation period.

Table 11-7
Gasification Ash Burned at Stanton Site

Year	Gasification Ash Produced (pounds/year)	Heating Value of Gasification Ash (MBtu/year)	Delivered Stanton Bituminous Coal Nominal ($/MBtu)
2010	62,295,689	249,183	2.836
2011	86,726,628	346,907	2.647
2012	94,261,104	377,044	2.724
2013	102,757,428	411,030	2.764
2014	108,849,132	435,397	2.819
2015	117,505,764	470,023	2.902
2016	126,162,396	504,650	2.990
2017	130,170,096	520,680	3.091
2018	130,811,328	523,245	3.179
2019	132,254,100	529,016	3.295
2020	130,170,096	520,680	3.392
2021	125,360,856	501,443	3.514
2022	123,757,776	495,031	3.730
2023	121,834,080	487,336	3.862
2024	125,841,780	503,367	3.979
2025	126,483,012	505,932	4.100
2026	124,399,008	497,596	4.247
2027	126,963,936	507,856	4.377
2028	128,727,324	514,909	4.532
2029	126,803,628	507,215	4.672
2030	133,696,872	534,787	4.816

Table 11-8
High Allowance Prices
Nominal Prices in $/ton Removed

Calendar Year	Weighted NO_x Allowance Cost ($/ton)[1]	Annual SO_2 Allowance Cost ($/ton)
2009	4,447.91	NA
2010	4,740.87	1,393.05
2011	5,053.18	1,520.79
2012	5,386.11	1,660.25
2013	5,741.05	1,812.49
2014	6,119.44	1,978.70
2015	6,522.83	2,160.14
2016	6,685.90	2,184.12
2017	6,853.05	2,208.36
2018	7,024.38	2,232.88
2019	7,199.98	2,257.66
2020	7,379.98	2,282.72
2021	7,564.48	2,308.06
2022	7,753.60	2,333.68
2023	7,947.44	2,359.58
2024	8,146.12	2,385.77
2025	8,349.77	2,412.26
2026	8,558.52	2,439.03
2027	8,772.48	2,466.11
2028	8,991.79	2,493.48
2029	9,216.59	2,521.16
2030	9,447.00	2,549.14

(1)Reflects allowance prices on an annual basis purchasing both annual and seasonal allowances.

11.8 Low Emission Allowance Prices

The low emission allowance price sensitivity case assumed lower allowance prices. In this sensitivity case, the base case allowance prices were decreased by 25 percent on an annual basis. Decreasing 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 results in a lower incentive to operate units with lower emissions rates for electric generation, and also causes lower CPWCs relative to the base case economic analysis. Table 11-9 presents the emission allowance prices used in the low allowance price sensitivity case.

Under these assumptions, the optimal capacity expansion plan for the case with Stanton B in 2010 consists of a 7FA CT in 2015, a second 7FA CT in 2018, a subcritical pulverized coal unit in 2021, an LM6000 CT in 2029, and a 7EA CT in 2030. The optimal capacity expansion plan for the case without Stanton B consists of a 7FA CT in 2010, a subcritical pulverized coal unit in 2013, a 7EA CT in 2021, a second 7FA CT in 2023, and a 1x1 7FA combined cycle in 2024.

The CPWCs for the expansion plan with Stanton B and the plan without Stanton B are approximately $5,378.6 million and $5,389.1 million, respectively. A comparison of these CPWCs shows that the expansion plan with Stanton B is the least-cost plan by approximately $10.5 million over the evaluation period.

11.9 Allowances Prices Not Considered in Dispatch

As described in Section 10.0, the forecast prices of allowances are included in the price of fuel burned by existing and candidate generating units. By including these costs as adders to fuel prices, POWROPT and POWRPRO effectively considered allowance prices in the development of optimal capacity expansion plans and optimal dispatch order, respectively. This sensitivity analysis reflects the economics of optimization and dispatch without consideration of allowance prices.

In this sensitivity case, the optimal capacity expansion plans, with and without Stanton B, were developed without allowances included as adders to the cost of each unit's fuel. Instead, SO_2 and NO_x emissions were determined on an annual basis, and the cost of allowances was included in the economic analysis after the dispatch was determined. This sensitivity analysis results in higher CPWCs relative to the base case costs, since there is no incentive to dispatch units with lower emissions rates to generate energy.

Table 11-9
Low Allowance Prices
Nominal Prices in $/ton Removed

Calendar Year	Weighted NO_x Allowance Cost ($/ton)[1]	Annual SO_2 Allowance Cost ($/ton)
2009	2,668.74	NA
2010	2,844.52	835.83
2011	3,031.91	912.47
2012	3,231.67	996.15
2013	3,444.63	1,087.49
2014	3,671.66	1,187.22
2015	3,913.70	1,296.09
2016	4,011.54	1,310.47
2017	4,111.83	1,325.02
2018	4,214.63	1,339.73
2019	4,319.99	1,354.60
2020	4,427.99	1,369.63
2021	4,538.69	1,384.84
2022	4,652.16	1,400.21
2023	4,768.46	1,415.75
2024	4,887.67	1,431.46
2025	5,009.86	1,447.35
2026	5,135.11	1,463.42
2027	5,263.49	1,479.66
2028	5,395.08	1,496.09
2029	5,529.95	1,512.69
2030	5,668.20	1,529.49

[1]Reflects allowance prices on an annual basis purchasing both annual and seasonal allowances.

Under these assumptions, the optimal capacity expansion plan for the case with Stanton B in 2010 consists of a 7FA CT in 2015, a second 7FA CT in 2018, a third 7FA CT in 2021, and a subcritical pulverized coal unit in 2024. The optimal capacity expansion plan for the case without Stanton B consists of a 7FA CT in 2010, a subcritical pulverized coal unit in 2013, a 7EA CT in 2021, a second 7FA CT in 2023, and a 1x1 7FA combined cycle in 2024.

The cumulative present worth costs for the expansion plan with Stanton B and the plan without Stanton B are approximately $5,548.7 million and $5,554.1 million, respectively. Comparison of these cumulative present worth costs shows that the expansion plan with Stanton B is the least-cost plan by approximately $5.4 million over the evaluation period.

11.10 No Coal Fired Capacity Expansion Options

To develop a more complete understanding of the economics associated with the expansion plan including Stanton B, a sensitivity case was developed to reflect costs without future coal fired generation capacity at the Stanton site. While coal fired generation will likely appear favorable to OUC in the future, impending regulatory programs and permitting difficulties give merit to the consideration of capacity expansion plans without coal fired generation.

In this scenario, POWROPT and POWRPRO were used to determine the least-cost capacity expansion plan for the cases with and without Stanton B if the pulverized coal and CFB supply-side alternatives were not considered for installation. This sensitivity analysis results in higher CPWCs relative to the base case expansion plans, because of the higher fuel costs of natural gas and fuel oil generation.

In this sensitivity analysis, the optimal capacity expansion plan with Stanton B in 2010 consists of a 7FA CT in 2015, a second 7FA CT in 2018, a third 7FA CT in 2021, a fourth 7FA CT in 2024, and a 1x1 7FA combined cycle in 2027. The expansion plan without Stanton B consists of a 7FA CT in 2010, a second 7FA CT in 2013, a 1x1 7FA combined cycle in 2016, a second 1x1 7FA combined cycle in 2022, a third 7FA CT in 2027, and a 7EA CT in 2029.

The CPWCs for the expansion plan with Stanton B and the plan without Stanton B are approximately $5,567.6 million and $5,688.3 million, respectively. A comparison of these CPWCs shows that the expansion plan with Stanton B is the least-cost plan by approximately $120.1 million over the evaluation period.

11.11 Summary of the Sensitivity Cases

Table 11-10 summarizes the results of the sensitivity analyses described in this section. Appendix C presents the CPWC summary sheets for all the cases presented in Table 11-10. The optimal capacity expansion plan with Stanton B in 2010 was the least-cost plan in all of the scenarios except for two - the low fuel price case and the high load and energy growth sensitivity case. Overall, these results demonstrate the robustness and flexibility of the expansion plan with Stanton B to overcome variations and deviations from the base case assumptions.

Table 11-10
Summary of Sensitivity Analyses

	Expansion Plan CPWC Cost ($ million)		
Sensitivity Case	With Stanton B	Without Stanton B	Differential CPWC Savings with Stanton B
Base Case	5,506.8	5,519.8	12.9
High Fuel Price	6,503.4	6,526.6	23.3
Low Fuel Price	4,761.0	4,726.2	-34.8
High Load and Energy Growth	6,680.3	6,677.9	-2.4
Low Load and Energy Growth	4,494.5	4,528.6	34.1
High Capital Cost	5,541.6	5,583.8	42.2
Gasification Ash	5,491.5	5,519.8	28.3
High Emission Allowances	5,631.2	5,649.1	17.9
Low Emission Allowances	5,378.6	5,389.1	10.5
Allowances Not Considered in Dispatch	5,548.7	5,554.0	5.4
No Coal Fired Capacity Expansion Options	5,567.6	5,688.3	120.7

12.0 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 could mitigate or delay the need for the proposed plant. To address this requirement, OUC has tested potential 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) and is used by several utilities in Florida.

The remainder of this section summarizes OUC'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.

12.1 Existing DSM Programs

Throughout its history, OUC has demonstrated a strong commitment to serve its customers' conservation needs. OUC has undertaken many conservation programs to meet customer needs and expectations. OUC's 2005 Demand-Side Management Plan was approved by the FPSC on September 1, 2004. Upon reviewing the Plan, the FPSC determined that there were no cost-effective conservation measures available for use by OUC, so the FPSC established and approved zero DSM and conservation goals for OUC's residential and commercial/industrial sectors through 2014 (Docket No. 040035-EG). Nevertheless, OUC proposed to continue its existing programs, because it had determined that these programs were in the overall best interest of its customers.

The DSM programs that were voluntarily continued and offered by OUC to its customers during 2005 included ones that resulted in energy and/or demand reductions that were quantifiable, as well as programs that were not quantifiable but aided OUC's customers in reliability, energy conservation, and education. Table 12-1 presents a listing of the programs that were offered by OUC in 2005, which are described further in this section.

Table 12-1
Conservation Programs Offered by OUC - 2005

Quantifiable Conservation Programs
Residential Energy Survey Program (Walk-Through, Video or DVD, and On-Line)
Residential Energy Efficiency Rebate Program (Duct Repair, Attic Insulation, Weatherization)
Residential Low-Income Home Energy Fix-Up Program
Residential Insulation Billed Solution Program
Residential Efficient Electric Heat Pump Program
Residential Gold Ring Program
Commercial Energy Survey Program
Commercial Indoor Lighting Retrofit Program
Nonquantifiable Conservation Programs
Residential Energy Conservation Rate
Commercial OUConsumption Online Program
Commercial OUConvenient Lighting Program
Commercial Power Quality Analysis Program
Commercial Infrared Inspections Program
OUCooling
Green Pricing Initiative Program
Photovoltaic Generation Pilot Program

In general, DSM programs have decreased in cost-effectiveness, although recent increases in fuel costs have started to reverse this trend. The decrease in cost-effectiveness of DSM programs is a result of numerous factors. OUC has offered conservation programs in one form or another since the early 1980s. As each program continues, participation tends to gradually decrease. The market for the program becomes saturated, since most of the customers that are willing to participate will have done so in the early stages of the program. The impact of DSM programs has diminished as government mandates have forced manufacturers to increase efficiency standards, thereby decreasing the incremental amount of achievable energy savings. Finally, the efficiency of new generation has increased and the cost of installing new generation is less than it was a few years ago, while interest rates still continue to be near all-time lows, reducing the carrying costs of power plants. All of these factors have contributed to DSM programs being less cost-effective and lower levels of customer participation.

12.1.1 Quantifiable Conservation Programs

12.1.1.1 Residential Energy Survey Program. This program is designed to provide residential customers with recommended energy efficiency measures and practices. The Residential Energy Survey Program consists of three measures, including the Residential Energy Walk-Through Survey, the Residential Energy Survey Video and DVD, and an interactive On-Line Energy Survey.

The Residential Energy Walk-Through Survey includes a complete examination of the attic; heating, ventilation, and air conditioning (HVAC) system; air duct and air returns; window caulking; weather stripping; water heater; faucets; toilets; and lawn sprinkler systems. Literature on other OUC programs is also provided to residential customers. The participant is given a choice to receive either a low-flow showerhead or a compact fluorescent bulb. OUC energy analysts are presently using this walk-through type audit as a means of motivating OUC customers to participate in other conservation programs and qualify for appropriate rebates.

The Residential Energy Survey Video was first offered in 2000 by OUC and is now available to OUC customers in an interactive DVD format. The video (or DVD) is free and is distributed to OUC customers by request. The measure was developed to further assist OUC customers in surveying their homes for potential energy saving opportunities. The video walks the customer through a complete visual assessment of energy and water efficiency in his or her home. A checklist brochure to guide the customer through the audit accompanies the video. The video has many benefits over the walk-through survey, including the convenience of viewing the video at any time without a scheduled appointment and the ability to watch the video numerous times.

In addition to the Energy Walk-Through and the Video Surveys, OUC offers customers an interactive On-Line Energy Survey. The interactive On-Line Energy Survey is available on OUC's Web site, www.OUC.com.

One of the primary benefits of the Residential Energy Survey Program is the education it provides to customers on energy conservation measures and ways their lifestyle can directly affect their energy use. Customers participating in the Energy Survey Program are informed about conservation measures that they can implement. Customers will benefit from the increased efficiency in their homes, which will decrease their electric and water bills.

Participation in the Walk-Through Energy Survey has been consistently strong over the past 10 years and interest in both the Energy Survey Video and DVD, as well as the interactive On-Line Energy Survey, has been high since the measures were first introduced. Feedback from customers that have taken advantage of the surveys has been very positive.

12.1.1.2 Residential Energy Efficiency Rebate Program. This program rewards customers who have invested in weather stripping, insulation, duct repairs, or other energy-saving measures for their single-family homes. OUC will rebate customers up to $75 for the purchase of caulking, weather stripping, window tinting, and solar screening. Additionally, OUC offers customers a rebate of up to $75 for repairs made to leaking ducts. Furthermore, OUC offers a rebate of $100 to upgrade the customer's attic insulation to R-19 or R-30.

12.1.1.3 Residential Low-Income Home Energy Fix-Up Program. This program targets residential customers with a total annual family income of less than $25,000. Each customer must request a free Residential Energy Survey. Ordinarily, Energy Survey recommendations require a customer to spend money replacing or adding energy conservation measures, which low-income customers may not have the discretionary income to implement.

OUC's program pays 85 percent of the total contract cost for home weatherization for the following measures:

- Attic insulation.
- Exterior and interior caulking.
- Weather-stripping of doors and windows.
- Minor air conditioning/heating supply and return air duct repairs.
- Water heater and hot water pipe insulation.
- Minor water leakage repair.
- Installation of water flow restrictors.

Under this program, OUC will arrange for a licensed, approved contractor to perform the necessary repairs and will pay 85 percent of the bill. The remaining 15 percent can be paid on the participant's monthly electric bill over a period of time and interest free. The purpose of the program is to reduce the energy cost for low-income households, particularly those households with elderly persons, disabled persons, and children, by improving the energy efficiency of their homes and ensuring a safe and healthy community.

Through this program, OUC helps to lower the bills of low-income customers who may have difficulty paying their bills. Reducing the bill of the low-income customer may improve the customer's ability to pay the bill, thereby decreasing costly service disconnect fees and late charges. OUC believes that this program will help to achieve and maintain high customer satisfaction.

12.1.1.4 Residential Insulation Billed Solutions Program. This measure is available to OUC residential customers who utilize some type of electric heat and/or air conditioning. To qualify, customers must request a free Residential Energy Survey and have a satisfactory credit rating with OUC. The program allows customers who insulate their attics to an R-19 level to pay for the insulation on their monthly utility bill for up to 2 years without being required to put any money down and, in addition, the customer will receive a $100 rebate. OUC directly pays the total cost for installation when the customer makes payments to OUC as part of their monthly utility bill. Feedback from customers that have taken advantage of the program has been very positive.

12.1.1.5 Residential Efficient Electric Heat Pump Program. This program provides rebates to qualifying customers who install heat pumps having a seasonal energy efficiency ratio (SEER) of 18.0 (or greater). Customers will be able to obtain rebates ranging from $100 to $300, depending on the SEER rating of the heat pump selected. Customers will benefit from the increased energy conservation in their homes, which will decrease their electric bills. One of the main benefits of this program is the ductwork and insulation level improvements made by contractors when installing energy efficient heat pumps.

12.1.1.6 Residential Gold Ring Program. The Residential Gold Ring Program is closely aligned with Energy Star Ratings. In developing the program, OUC partnered with local home builders to construct new homes according to Energy Star standards. Features may include high efficiency heat pumps, heat recovery water heaters, R-30 attic insulation, interior air ducts, double pane windows, window shading, etc.

The contractor is required to qualify its homes to Energy Star standards by having the homes rated by a certified rater. In return for each Energy Star home certification, the builder receives a rebate of $200 or $100 for townhomes. In addition, OUC will help support the builder's efforts through additional advertising and other promotional strategies.

Gold Ring Homes can use 20 to 30 percent less energy than other homes. Gold Ring homeowners benefit from lower energy bills and qualification for all FHA, VA, and Energy Efficient Mortgage Programs. This allows the homeowner to increase his or her income-to-debt ratio by 2 percent and makes it easier to qualify for a mortgage.

12.1.1.7 Commercial Energy Survey Program. This program is focused on increasing the energy efficiency and energy conservation of commercial buildings and includes a survey comprised of a physical walk-through inspection of the commercial facility performed by highly trained and experienced energy experts. The commercial customer who has a Commercial Energy Survey receives a report at the time of the survey and the book *Business Energy Efficiency Guide* which shows more ways for businesses to profit from energy management. Within 30 days of the audit, the customer receives a written report detailing cost-effective recommendations to make the facility more energy and water efficient. Customers are encouraged to participate in other OUC commercial programs and directly benefit from energy conservation, which decreases their electric and water bills.

12.1.1.8 Commercial Indoor Lighting Retrofit Program. This program reduces energy consumption for the commercial customer through the replacement of older fluorescent and incandescent lighting with newer, more efficient lighting technologies. A special alliance between OUC and the lighting contractor enables OUC to offer the customer a discounted project cost. An additional feature of the program allows the customer to pay for the retrofit through the monthly savings that the project generates. Upfront capital funding is not required to participate in this program. The project payment appears on the participating customer's utility bill as a line-item. After the project has been completely paid, the participating customer's annual energy bill will decrease by the approximate amount of projected energy cost savings.

12.1.2 Additional Conservation Programs

The following programs are offered by OUC to its customers, resulting in energy savings and increased reliability. Although the programs are neither directly nor easily quantifiable, each program provides a valuable service to OUC's customers.

12.1.2.1 Residential Energy Conservation Rate. Beginning in October 2002, OUC modified its residential rate structure to a two-tiered block structure to encourage energy conservation. Residential customers using more than 1,000 kWh per month pay a higher rate for the additional energy usage. The purpose of this rate structure is to make OUC customers more energy-conscientious and to encourage conservation of energy resources.

12.1.2.2 Commercial OUConsumption Online Program. This program enables businesses to check their energy usage and demand from a desktop computer, thereby allowing businesses to manage their energy load. Customers are able to analyze the metered interval load data for multiple locations, compare energy usage among facilities, and measure the effectiveness of various energy efficiency efforts. The data can also be downloaded for further analysis. Participants must cover the cost of additional infrastructure at the meter(s) and are responsible for a $35.00 per month per channel fee for this service.

12.1.2.3 Commercial OUConvenient Lighting Program. OUConvenient Lighting provides complete outdoor lighting services for commercial applications, including industrial parks, sports complexes, and residential developments. Each lighting package is customized for each participant, allowing the participant to choose among light fixtures. OUC handles all of the upfront financial costs and maintenance. The participant then pays a low monthly fee for each fixture. OUC also retrofits existing fixtures to new light sources or higher output units, increasing efficiency as well as providing preventive and corrective maintenance.

Recent OUConvenient Lighting projects include the Rosen Hotels & Resorts, Baldwin Park Development Co., and the Orange County Convention Center, among many others. In St. Cloud, OUConvenient Lighting worked with developers to provide lighting solutions to the Stevens Plantation project, which is planned to include 800 single-family homes, up to 250,000 square feet of neighborhood retail, and a 100 acre business park with up to 1 million square feet of office and light manufacturing space.

OUConvenient Lighting also recently experienced participation outside of OUC's service territory. The program provided services to the Reunion Resort & Club (Reunion), located in Osceola County near Walt Disney World. As part of OUConvenient Lighting's work with Reunion, streetlights were provided for stretches of several major highways, as well as all the major roadways between Reunion neighborhoods.

12.1.2.4 Commercial Power Quality Analysis Program. This program enables OUC to ensure the highest possible power quality to commercial customers. There are five general categories of power irregularities, including overvoltage, undervoltage, outages, electric noise, and harmonic distortion. Under the Power Quality Analysis program, trained and experienced service personnel help the customer isolate any problems and find appropriate solutions. The goals of this program include making the maximum effort to solve power quality problems through monitoring and interpretive analysis, identifying solutions that will lead to corrective action, and providing ongoing follow-up services to monitor results.

12.1.2.5 Commercial Infrared Inspections Program. This program was developed to help customers uncover potential reliability and power quality problems. A highly trained and experienced technician performs the inspection using state-of-the-art equipment. The infrared inspection detects thermal energy and measures the temperature of wires, breakers, and other electrical equipment components. The information is transferred into actual images, and those images reveal potential problem areas and hot spots that are invisible to the naked eye. This information allows the customer to make repairs to faulty equipment and prevent untimely breakdowns, equipment damage, and lost profits. Following the inspection, the customer receives a detailed analysis and written report, which includes a complete description of diagnostic recommendations.

12.1.2.6 OUCooling. OUCooling was originally formed in 1997 as a partnership between OUC and Trigen-Cinergy Solutions, and helps to lower air conditioning-related electric charges and reduce capital and operating costs. During 2004, OUC bought

Trigen-Cinergy's rights and is now the sole owner of OUCooling. OUCooling will fund, install, and maintain a central chiller plant for each business district participating in the program. The main benefits to the businesses are lower energy consumption, increased reliability, and no environmental risks associated with the handling of chemicals. Other benefits for the businesses include avoided initial capital cost, lower maintenance costs, a smaller mechanical room (therefore more rental space), no insurance requirements, improved property resale value, and availability of maintenance personnel for other duties.

OUCooling operates two chilled water plants that serve customers in downtown Orlando as well as in Parramore. Underground "loops" run from each facility to buildings partnered with OUCooling. In Parramore and downtown Orlando alone, about 10 miles of underground pipes have the capacity to deliver 15,000 tons of chilled water to businesses – enough chilled water to cool about 6,000 residential homes. The 17.6 million gallon chilled water storage tank at the Orange County Convention Center is the largest in the world. The tank works in tandem with 20 water chillers and feeds a cooling loop that can handle more than 33,000 gallons of 37° F water per minute.

OUC's first chiller plant was installed at Lockheed Martin Corp. The plant was built in 1999 and serves eight customers. After that project, OUC began operation of a chilled water system serving downtown Orlando. In 1999, the downtown project won three awards. In 2000, the Downtown Orlando Partnership gave its Award of Excellence to OUC, based on the chilled water plant. The downtown Orlando "district cooling" division now provides air conditioning service to more than a dozen large commercial customers with a combined 2 million square feet of space.

In 2002, the International District Energy Association (IDEA) presented OUCooling a first-place award for signing up more customer square footage for its chilled-water business than any other company in 2001. OUCooling signed up 9 million square feet of new customer space in 2001. IDEA is an association representing more than 900 district heating and cooling executives, managers, engineers, consultants, and equipment suppliers from 20 countries.

OUC envisions building other chiller plants serving commercial campuses, hotels, retail shopping centers, and tourist attractions. OUC recently received three awards from the Associated Builders and Contractors Inc. for one of the top construction projects in Orlando. The awards included the Eagle Award for mechanical work, General Contractor Award of Merit, and the Subcontractor Award of Merit. OUCooling was also featured in the January-February 2003 issue of *Relay*, Florida's energy and electric utility magazine.

12.1.2.7 Green Pricing Initiative. OUC offers its customers an opportunity to participate in its Green Pricing Initiative, a pilot program developed to increase the role of renewable energy among OUC's customers. Participation in this program helps add renewable energy to OUC's generation portfolio, improves regional air and water quality, and assists OUC in developing additional renewable energy resources. Program participants pay an additional $5.00 on their monthly utility bills in return for 200 kWh to support funding to add additional renewable energy to OUC's portfolio. Participation will help OUC develop cleaner alternative energy resources, such as solar, wind, and biomass. The annual per customer participation of 2,400 kWh is equivalent to the environmental benefit of planting 3 acres of forest, taking three cars off the road, preventing the use of 27 barrels of oil, or bicycling more than 30,575 miles instead of driving.

12.1.2.8 Photovoltaic Generation Pilot Program. OUC has initiated its Photovoltaic Generation Pilot Program to customers on standby service in which onsite generation consists of PV capacity. A PV system is a solar electric generating system that contains solar PV panels, batteries (optional), a static power converter, wiring, fuses, wiring devices, conduit, circuit breakers, transfer or disconnect switches, etc., for making the physical connections required to install the PV system and connect it to the normal wiring system. The program is available to the first 150 kW of residential PV generation and 350 kW of general service PV generation located in either the OUC or City of St. Cloud service territories.

Participating customers will be reimbursed for any export power supplied by the PV system at a rate equal to the applicable per kWh standby base and fuel energy charges in the event that the PV system is grid-integrated. If the customer qualifies for buyback credits, OUC will furnish and install such metering facilities as OUC determines to be appropriate to measure the electricity delivered by the customer to OUC's delivery system. The customer will receive both a monthly per kW credit as well as a flat monthly credit for the ownership and use of the PV system.

12.2 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.

12.2.1 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.

12.2.2 FIRE Model Outputs

FIRE model results are presented in the form of three cost-effectiveness tests, all of which are based on the 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, OUC views the Rate Impact Test as the primary test for determining the cost-effectiveness of a DSM measure on its system.

12.3 Analysis of DSM Alternatives

OUC considers it important to evaluate additional DSM measures that may potentially be cost-effective, and thereby benefit OUC customers. This section presents the general assumptions that were used in the FIRE model cost-effectiveness analysis, which is described in detail in Section 12.2. The specific DSM measures to be evaluated and the corresponding assumptions were extracted from the *2004 Demand-Side Management Measure Evaluations* that Black & Veatch compiled for OUC in support of the 2004 numeric conservation goals filing with the FPSC.

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.

12.3.1 General Assumptions

General assumptions were developed to compare all DSM measures on an equivalent economic basis. These assumptions were extracted from input received from OUC and other appropriate sources. General cost-effective analysis assumptions and their sources are presented in Table 12-2. The estimated capital cost for Stanton B and its projected performance are presented in Table 12-3.

Table 12-2
General Cost-Effective Analysis Assumptions and Sources

- The study period for the cost-effectiveness evaluation encompasses 10 years (2006-2015).
- The fuel forecast is presented in Section 5.0.
- Economic parameters are presented in Section 5.0.
- The system average fuel cost was derived from the production cost model used for economic evaluations in Section 10.0.
- Retail electric rates were based on OUC's existing rates.
- The nonfuel cost in residential customers' bills was based on OUC's existing residential rate schedule.
- The nonfuel cost in commercial customers' bills was based on OUC's existing GSND, GSD, and GSLD rate schedules.
- The customer demand charge was based on OUC's existing rate schedules.
- The distribution capital cost was based on OUC's existing costs.
- The distribution fixed O&M cost was based on OUC's existing costs.

Table 12-3
Generating Unit Characteristics for the Avoided Unit

Item	
Total Capital Cost(1) (2010 $)	[redacted]
O&M Cost - Baseload Duty	
Fixed O&M Cost(2) (2010 $/kW-yr)	[redacted]
Variable O&M Cost (2010 $/MWh)	[redacted]
Net Plant Capacity at 72° F (MW)	283
Net Heat Rate at 72° F (Btu/kWh-HHV)	8,461
Construction Period (months)	24

(1) Capital cost does not include interest during construction.
(2) Includes monthly demand payment for OUC's use of SPC-OG's ownership of the gasification island.

12.3.2 Descriptions and Assumptions of DSM Measures

This subsection provides a brief summary of each DSM measure evaluated for cost-effectiveness. The DSM measures and assumptions were derived from the *2004 Demand-Side Management Measure Evaluations* for OUC, as previously described.

12.3.2.1 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).

12.3.2.1.1 Appliance efficiency measures for new and existing residential.

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

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.

12.3.2.1.2 Building envelope measures for new and existing residential.

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

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.

12.3.2.1.3 Direct load control measures for new and existing residential.

On-Call Direct Load Control. This measure assumes that FM/VHF switches are installed to cycle off central AC, central heating, electric water heaters, and pool pumps during peak times. Table 12-4 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 up to 4 hours.

12.3.2.1.4 HVAC efficiency measures for new and existing residential.

High Efficiency Central AC. A high efficiency central AC unit with a SEER of 18.0 was assumed to be installed instead of a standard unit with a SEER of 13.0.

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

12.3.2.1.5 Lighting measures for new and existing residential.

Compact Fluorescent Lights. This measure assumes that two each of 40 W, 60 W, and 100 W incandescent light bulbs are installed instead of the same number of 9 W, 15 W, and 26 W compact fluorescent light bulbs. Table 12-5 summarizes the bulb replacements.

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

12.3.2.1.6 Water heating efficiency measures for new and existing residential.

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.

12.3.2.1.7 Appliance efficiency measures for existing residential only.

High Efficiency Residential Pool Pump. This measure assumes that a standard efficiency (82.5 percent) pool filter motor and circulation pump is 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.

Table 12-4
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 12-5
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
(2) 40 watt bulbs	80	(2) 9 watt bulbs	18
(2) 60 watt bulbs	120	(2) 15 watt bulbs	30
(2) 100 watt bulbs	200	(2) 26 watt bulbs	52
TOTAL	400	TOTAL	100

12.3.2.1.8 Appliance removal measures for existing residential 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.

12.3.2.1.9 Building envelope measures for existing residential 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.

12.3.2.1.10 HVAC efficiency measures for existing residential only.

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

12.3.2.1.11 Water heating efficiency measures for existing residential 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.

12.3.2.2 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).

12.3.2.2.1 Appliance efficiency measures for new and existing commercial and industrial.

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.

12.3.2.2.2 Direct load control measures for new and existing commercial and industrial.

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

12.3.2.2.3 HVAC efficiency measures for new and existing commercial and industrial.

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 AC Units. This measure assumes that a high efficiency direct exchange (DX) AC 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 AC Units. This measure assumes that a high efficiency room AC unit with an EER of 12.6 is installed rather than a standard efficiency unit with an EER of 8.3. The room AC 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 AC. 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 AC 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 AC system during peak hours, so there would be no assumed energy savings or energy use increase from the pumps.

12.3.2.2.4 Lighting measures for new and existing commercial and industrial.

Incandescent Replacement with Compact Fluorescent. This measure assumes that a new commercial building uses ten 15 W, 18 W, and 27 W compact fluorescent lamps instead of the same number of 60 W, 75 W, and 100 W incandescent lamps. Table 12-6 summarizes the lamp replacements.

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

Table 12-6 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
(10) 60 watt bulbs	600	(10) 15 watt bulbs	150
(10) 75 watt bulbs	750	(10) 18 watt bulbs	180
(10) 100 watt bulbs	1,000	(10) 27 watt bulbs	270
TOTAL	2,350	TOTAL	600

12.3.2.2.5 Water heating efficiency measures for new and existing commercial and industrial.

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.

12.3.2.2.6 Appliance efficiency measures for existing commercial and industrial 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.

12.3.2.2.7 Building envelope measures for existing commercial and industrial 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 AC. 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 AC 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 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 AC. This measure assumes that buildings with an existing R-value of 2.53 upgrade 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 AC. 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 AC power and energy demand.

12.3.2.2.8 HVAC efficiency measures for existing commercial and industrial 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.

12.3.2.2.9 Lighting measures for existing commercial and industrial only.

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

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

4 Foot Fluorescent with Electronic Ballast Replacement. This measure assumes that a commercial building replaces 20 4 foot by 2 (40 W) fluorescent fixtures with standard ballasts with twenty 4 foot by 2 (34 W) 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 W) fluorescent fixtures with standard ballasts with twenty 8 foot by 2 fluorescent lamps with electronic ballasts, with a total fixture rating of 95 W.

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

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

High-Pressure Sodium Lighting (70 W/100 W/150 W/250 W) Replacement. This measure considers a mix of five each of 70 W, 100 W, 150 W, and 250 W high-pressure sodium lamps/fixtures replacing the same mix of 100 W, 175 W, 250 W, and 400 W mercury vapor lamps/fixtures. Table 12-7 summarizes the proposed changes.

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

Table 12-7
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
(5) 100 watt bulbs	500	(5) 70 watt bulbs	350
(5) 175 watt bulbs	875	(5) 100 watt bulbs	500
(5) 250 watt bulbs	1,250	(5) 150 watt bulbs	750
(5) 400 watt bulbs	2,000	(5) 250 watt bulbs	1,250
TOTAL	4,625	TOTAL	2,850

12.3.2.2.10 Water heating efficiency measures for existing commercial and industrial measures 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.

12.4 Results of the FIRE Model Cost-Effectiveness Evaluations

The following tables (Tables 12-8 through 12-11) 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 12.2. Cost-effectiveness results are categorized as discussed in Section 12.3. As indicated in Tables 12-8 through 12-11, none of the potential new DSM measures evaluated are cost-effective based on the Rate Impact Test. OUC will continue to evaluate the potential for cost-effective DSM measures.

Table 12-8
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	0.78	0.28	0.22
Efficient Clothes Washer - New - Residential	0.81	0.32	0.26
Energy Efficient Refrigerator (Frost-Free) - Existing - Residential	0.57	0.14	0.08
Energy Efficient Refrigerator (Frost-Free) - New - Residential	0.48	0.39	0.21
Energy Efficient Refrigerator (Manual) - Existing - Residential	0.56	0.16	0.09
Energy Efficient Refrigerator (Manual) - New - Residential	0.49	0.36	0.20
Building Envelope Measures			
Light Colored Roof Material - Existing - Residential	0.71	0.05	0.03
Light Colored Roof Material - New - Residential	0.71	0.19	0.14
Direct Load Control Measures			
On-Call Direct Load Control - FPL Data - Existing - Residential	0.80	1.00	1.44
On-Call Direct Load Control - FPL Data - New - Residential	0.80	1.00	1.44
HVAC Efficiency Measures			
High Efficiency Central AC - Existing - Residential	0.61	0.11	0.06
High Efficiency Central AC - New - Residential	0.34	1.00	0.75
High Efficiency Room AC - Existing - Residential	0.67	0.12	0.09
High Efficiency Room AC - New - Residential	0.67	1.24	0.83
Lighting Measures			
Compact Fluorescent Lights - Existing - Residential	0.70	0.00	0.15
Compact Fluorescent Lights - New - Residential	0.70	0.00	0.15
High-Pressure Sodium (Outdoor) - Existing - Residential	0.50	0.00	0.03
High-Pressure Sodium (Outdoor) - New - Residential	0.50	0.00	0.04
Water Heating Efficiency Measures			
DWH Pipe Insulation - Existing - Residential	0.47	0.13	0.08
DWH Pipe Insulation - New - Residential	0.47	0.04	0.02
High Efficiency Electric Water Heater - Existing - Residential	0.94	0.25	0.24
High Efficiency Electric Water Heater - New - Residential	0.94	1.00	2.54
Add-On Heat Pump Water Heater - Existing - Residential	0.47	0.49	0.23
Add-On Heat Pump Water Heater - New - Residential	0.48	0.65	0.31
Heat Recovery Water Heater - Existing - Residential	0.50	0.42	0.21
Heat Recovery Water Heater - New - Residential	0.50	0.42	0.21
Supplemental Solar Water Heater - Existing - Residential	0.50	0.07	0.04
Supplemental Solar Water Heater - New - Residential	0.49	0.07	0.04

Table 12-9
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	0.56	0.06	0.04
Energy Efficient Freezer (Manual) - Freezer - Existing - Residential	0.54	0.20	0.11
Low-Flow Showerhead - Existing - Residential	0.46	8.80	3.10
Appliance Removal Measures			
Remove Second Freezer - Residential	0.48	1.00	20.29
Remove Second Refrigerator - Residential	0.47	1.00	21.92
Building Envelope Measures			
Low Emissivity Glass - Existing - Residential	0.69	0.41	0.29
Window Film/Reflective Windows - Existing - Residential	0.68	0.28	0.19
Window Shade Screens - Existing - Residential	0.74	0.50	0.37
Ceiling Insulation (R0-R19) - Existing - Residential	0.68	0.54	0.37
Ceiling Insulation (R19-R30) - Existing - Residential	0.67	0.22	0.15
HVAC Efficiency Measures			
AC System Maintenance - Existing - Residential	0.10	2.12	0.16
Water Heating Efficiency Measures			
DWH Heat Trap - Existing - Residential	0.25	1.00	0.80
DHW Tank Insulation - Existing - Residential	0.41	1.62	0.62

Table 12-10
FIRE Model Cost-Effectiveness Results for
New and Existing Commercial & Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
Energy Efficient Electric Fryer - Existing - GSND	0.66	0.07	0.05
Energy Efficient Electric Fryer - Existing - GSD	0.65	0.07	0.05
Energy Efficient Electric Fryer - Existing - GSLD	0.66	0.07	0.05
Energy Efficient Electric Fryer - New - GS	0.74	0.34	0.26
Energy Efficient Electric Fryer - New - GSD	0.73	0.34	0.26
Energy Efficient Electric Fryer - New - GSLD	0.74	0.34	0.26
Direct Load Control Measures			
Business On-Call Direct Load Control - Existing - GSND	0.90	1.00	3.04
Business On-Call Direct Load Control - Existing - GSD	0.43	1.00	30.61
Business On-Call Direct Load Control - Existing - GSLD	0.43	1.00	30.61
Business On-Call Direct Load Control - New - GSND	0.92	1.00	3.10
Business On-Call Direct Load Control - New - GSD	0.43	1.00	31.30
Business On-Call Direct Load Control - New - GSLD	0.43	1.00	31.30
Heating, Ventilation, and Air Conditioning Efficiency Measures			
High Efficiency Chiller - Existing - GSD	0.66	0.45	0.30
High Efficiency Chiller - Existing - GSLD	0.67	0.15	0.10
High Efficiency Chiller - New - GSD	0.67	2.76	1.85
High Efficiency Chiller - New - GSLD	0.68	0.76	0.51
High Efficiency Chiller w/ASD - Existing - GSD	0.67	0.89	0.60
High Efficiency Chiller w/ASD - Existing - GSLD	0.68	0.94	0.64
High Efficiency Chiller w/ASD - New - GSD	0.67	0.89	0.60
High Efficiency Chiller w/ASD - New - GSLD	0.68	0.94	0.64
High Efficiency DX AC Units - Existing - GSND	0.67	0.24	0.16
High Efficiency DX AC Units - Existing - GSD	0.66	0.19	0.12
High Efficiency DX AC Units - Existing - GSLD	0.67	0.20	0.14
High Efficiency DX AC Units - New - GS	0.60	0.43	0.26
High Efficiency DX AC Units - New - GSD	0.66	0.16	0.10
High Efficiency DX AC Units - New - GSLD	0.67	0.30	0.20
High Efficiency Room AC Units - Existing - GSND	0.66	0.48	0.32
High Efficiency Room AC Units - New - GS	0.45	1.00	4.02

Table 12-10 (Continued)
FIRE Model Cost-Effectiveness Results for
New and Existing Commercial & Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
High Efficiency Motors - Chiller - Existing - GSD	0.66	0.49	0.32
High Efficiency Motors - Chiller - Existing- GSLD	0.67	0.48	0.32
High Efficiency Motors - Chiller - New - GSD	0.67	2.95	1.96
High Efficiency Motors - Chiller - New - GSLD	0.68	2.92	1.96
High Efficiency Motors - DX AC - New - GS	0.51	1.00	4.37
High Efficiency Motors - DX AC - New - GSD	0.66	3.81	2.44
High Efficiency Motors - DX AC - New - GSLD	0.67	3.62	2.41
High Efficiency Motors - DX AC - Existing - GSND	0.65	0.30	0.20
High Efficiency Motors - DX AC - Existing - GSD	0.66	0.63	0.42
High Efficiency Motors - DX AC - Existing - GSLD	0.67	0.60	0.40
Heating, Ventilation, and Air Conditioning Efficiency Measures			
Leak Free Ducts - Existing - GSND	0.65	0.14	0.09
Leak Free Ducts - Existing - GSD	0.66	0.14	0.09
Leak Free Ducts - Existing - GSLD	0.67	0.14	0.09
Leak Free Ducts - New - GSND	0.63	0.05	0.04
Leak Free Ducts - New - GSD	0.65	0.05	0.04
Leak Free Ducts - New - GSLD	0.67	0.05	0.04
Cool Thermal Storage - Existing - GSD	0.70	0.65	0.40
Cool Thermal Storage - Existing - GSLD	0.70	0.65	0.40
Cool Thermal Storage - New - GSD	0.94	0.95	0.88
Cool Thermal Storage - New - GSLD	0.94	0.76	0.71
Lighting Measures			
Incandescent Replacement w/ Compact Fluorescent - Existing - GSND	0.64	16.67	7.72
Incandescent Replacement w/ Compact Fluorescent - Existing - GSD	0.74	14.20	7.72
Incandescent Replacement w/ Compact Fluorescent - Existing - GSLD	0.75	14.02	7.72
Incandescent Replacement w/ Compact Fluorescent - New - GS	0.65	16.67	10.08
Incandescent Replacement w/ Compact Fluorescent - New - GSD	0.76	14.20	10.08
Incandescent Replacement w/ Compact Fluorescent - New - GSLD	0.77	14.02	10.08

Table 12-10 (Continued)
FIRE Model Cost-Effectiveness Results for
New and Existing Commercial & Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Incandescent Replacement w/ 2 18W Compact Fluorescent - Existing - GS	0.59	4.24	2.13
Incandescent Replacement w/ 2 18W Compact Fluorescent - Existing - GSD	0.68	3.64	2.13
Incandescent Replacement w/ 2 18W Compact Fluorescent - Existing - GSLD	0.69	3.59	2.13
Incandescent Replacement w/ 2 18W Compact Fluorescent - New - GS	0.62	2.89	1.77
Incandescent Replacement w/ 2 18W Compact Fluorescent - New - GSD	0.72	2.48	1.77
Incandescent Replacement w/ 2 18W Compact Fluorescent - New - GSLD	0.73	2.45	1.77
Water Heating Efficiency Measures			
Heat Pump Water Heater - Existing - GSND	0.74	1.00	3.26
Heat Pump Water Heater - Existing - GSD	0.61	1.00	5.56
Heat Pump Water Heater - Existing - GSLD	0.56	1.00	3.48
Heat Pump Water Heater - New - GSND	0.83	1.00	6.78
Heat Pump Water Heater - New - GSD	0.63	1.00	8.41
Heat Pump Water Heater - New - GSLD	0.59	1.00	4.85
Heat Recovery Water Heater - Existing - GSND	0.48	1.00	3.08
Heat Recovery Water Heater - Existing - GSD	0.65	0.81	0.53
Heat Recovery Water Heater - Existing - GSLD	0.66	0.80	0.53
Heat Recovery Water Heater - New - GSND	0.50	1.00	4.33
Heat Recovery Water Heater - New - GSD	0.65	0.82	0.54
Heat Recovery Water Heater - New - GSLD	0.66	0.81	0.54

Table 12-11
FIRE Model Cost-Effectiveness Results for
Existing Commercial & Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
Low or Variable Flow Showerhead - Existing - GSND	0.51	67.59	15.45
Low or Variable Flow Showerhead - Existing - GSD	0.64	53.77	15.45
Low or Variable Flow Showerhead - Existing - GSLD	0.65	53.00	15.45
Multiplex Refrigeration with No Subcooling - Existing - GSD	0.65	0.14	0.09
Multiplex Refrigeration with No Subcooling - Existing - GSLD	0.66	0.14	0.09
Multiplex Refrigeration with Ambient Subcooling - Existing - GSD	0.65	0.15	0.10
Multiplex Refrigeration with Ambient Subcooling - Existing - GSLD	0.66	0.15	0.10
Multiplex Refrigeration with Mechanical Subcooling - Existing - GSD	0.70	0.04	0.03
Multiplex Refrigeration with Mechanical Subcooling - Existing - GSLD	0.71	0.04	0.03
Multiplex Refrigeration: Ambient and Mechanical Subcooling - Existing - GSD	0.65	0.00	0.48
Multiplex Refrigeration: Ambient and Mechanical Subcooling - Existing - GSLD	0.66	0.00	0.48
Building Envelope Measures			
Light Colored Roof - Water Chiller - GSD	0.66	0.95	0.63
Light Colored Roof - Air Chiller - Existing - GSLD	0.67	0.38	0.25
Light Colored Roof - Water Chiller - Existing - GSD	0.66	0.78	0.52
Light Colored Roof - Water Chiller - Existing - GSLD	0.67	0.25	0.17
Light Colored Roof - DX AC - Existing - GSND	0.66	0.12	0.08
Light Colored Roof - DX AC - Existing - GSD	0.66	0.24	0.16
Light Colored Roof - DX AC - Existing - GSLD	0.67	0.24	0.16
Roof Insulation - Chiller - Existing - GSD	0.66	0.12	0.08
Roof Insulation - Chiller - Existing - GSLD	0.67	0.02	0.02
Roof Insulation - DX AC - Existing - GSND	0.67	0.19	0.13
Roof Insulation - DX AC - Existing - GSD	0.66	0.10	0.06
Roof Insulation - DX AC - Existing - GSLD	0.67	0.02	0.01
Window Film - Chiller - Existing - GSD	0.66	0.98	0.65

Table 12-11 (Continued)
FIRE Model Cost-Effectiveness Results for
Existing Commercial & Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Window Film - Chiller - Existing - GSLD	0.67	0.97	0.65
Window Film - DX AC - Existing - GSND	0.27	1.00	0.87
Window Film - DX AC - Existing - GSD	0.66	1.13	0.74
Window Film - DX AC - Existing - GSLD	0.67	1.11	0.74
Heating, Ventilation, and Air Conditioning Efficiency Measures			
2-Speed Motor for Cooling Tower - Existing - GSD	0.66	1.02	0.67
2-Speed Motor for Cooling Tower - Existing - GSLD	0.66	1.00	0.67
Speed Control for Cooling Tower Motors - Existing - GSD	0.66	0.36	0.24
Speed Control for Cooling Tower Motors - Existing - GSLD	0.66	0.36	0.24
Lighting Measures			
4' Fluorescent w/ Electronic Ballast Replacement - Existing - GSND	0.59	0.28	0.17
4' Fluorescent w/ Electronic Ballast Replacement - Existing - GSD	0.72	0.22	0.17
4' Fluorescent w/ Electronic Ballast Replacement - Existing - GSLD	0.73	0.22	0.17
8' Fluorescent w/ Electronic Ballast Replacement - Existing - GSND	0.52	0.98	0.51
8' Fluorescent w/ Electronic Ballast Replacement - GSD	0.59	0.85	0.51
8' Fluorescent w/ Electronic Ballast Replacement - GSLD	0.60	0.84	0.51
4' T8 Lamp Replacement - Existing - GSND	0.38	0.68	0.28
4' T8 Lamp Replacement - Existing - GSD	0.42	0.61	0.28
4' T8 Lamp Replacement - Existing - GSLD	0.42	0.61	0.28
4' Fluorescent with Reflector Replacement - Existing - GSND	0.56	2.15	1.11
4' Fluorescent with Reflector Replacement - Existing - GSD	0.64	1.86	1.11
4' Fluorescent with Reflector Replacement - Existing - GSLD	0.64	1.83	1.11
4' Fluorescent with Reflector Replacement - Existing - GSND	0.57	2.54	1.33
4' Fluorescent with Reflector Replacement - Existing - GSD	0.66	2.19	1.33
4' Fluorescent with Reflector Replacement - Existing - GSLD	0.66	2.16	1.33
4' 34W w/ Reflector Replacement - Existing - GSND	0.57	2.38	1.24
4' 34W w/ Reflector Replacement - Existing - GSD	0.65	2.06	1.24
4' 34W w/ Reflector Replacement - Existing - GSLD	0.66	2.03	1.24
8' 75W Delamping w/ Reflector Kit - Existing - GSND	0.59	2.25	1.24
8' 75W Delamping w/ Reflector Kit - Existing - GSD	0.68	1.94	1.24
8' 75W Delamping w/ Reflector Kit - Existing - GSLD	0.68	1.91	1.24

Table 12-11 (Continued)
FIRE Model Cost-Effectiveness Results for
Existing Commercial & Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
High Pressure Sodium (70W/100W/150W/250W) Replacement - Existing - GSND	0.61	0.24	0.15
High Pressure Sodium (70W/100W/150W/250W) Replacement - Existing - GSD	0.75	0.20	0.15
High Pressure Sodium (70W/100W/150W/250W) Replacement - Existing - GSLD	0.76	0.19	0.15
Outdoor High Pressure Sodium (70W) Replacement - Existing - GSND	0.59	0.23	0.14
Outdoor High Pressure Sodium (70W) Replacement - Existing - GSD	0.73	0.18	0.14
Outdoor High Pressure Sodium (70W) Replacement - Existing - GSLD	0.74	0.18	0.14
Water Heating Efficiency Measures			
Domestic Water Heater Insulation - Existing - GSND	0.49	7.96	2.86
Domestic Water Heater Insulation - Existing - GSD	0.61	6.33	2.86
Domestic Water Heater Insulation - Existing - GSLD	0.62	6.24	2.86
DWH Heat Trap - Existing - GSND	0.40	1.00	1.29
DWH Heat Trap - Existing - GSD	0.53	1.00	3.27
DWH Heat Trap - Existing - GSLD	0.49	1.00	2.00
Off-Peak Battery Charging - FPL - Existing - GSD	0.90	1.17	1.04
Off-Peak Battery Charging - FPL - Existing - GSLD	0.89	1.17	1.03

13.0 Impact to the Transmission System

Transmission planning for Florida in general and Central Florida specifically is an ongoing and constantly changing process as loads continue to grow and new generation and substations are added to meet that growth. Changes to one part of the system affect another part of the system and vice versa. As such, transmission system additions are rarely only a result of the addition of a specific new generating unit (such as Stanton B). There are currently numerous transmission studies underway evaluating the Central Florida transmission system. Future transmission system additions are continuously being evaluated to develop the lowest cost solutions to additional load growth that also maintain a high level of reliability.

13.1 Current Transmission Situation

OUC and the other Central Florida utilities as well as the Florida Reliability Coordinating Council (FRCC) are continuously studying the Central Florida transmission system. The need for these studies was heightened in 2005 when actual loads on the Central Florida transmission system would have caused overloads on certain transmission elements during contingency conditions. Currently there are two regional studies underway to address these issues as well as to plan for future load growth in Central Florida.

One study includes FPL, OUC, and PEF and is entitled *OUC Stanton – PEF Area FPL, OUC, and PEF 2005 Joint Study of 2010 Time-Frame*. This study is focused on the area north and east of Orlando. The second study includes PEF, TECO, OUC, Reedy Creek Improvement District, Seminole Electric Cooperative, FMPA, Lakeland Electric, FPL, and KUA and is entitled *Florida Central Coordinated Study (2008-2012)*. This study is focused on the area south and west of Orlando along the I-4 corridor including Polk County. A third study is being conducted by OUC on the OUC 115 kV system. OUC also continues to study the transmission issues independently as do most of the other utilities.

The most recent preliminary study results available are contained in the draft *OUC Stanton-PEF Area FPL, OUC and PEF 2005 Joint Study of 2010 Time-Frame Study, January 2006*. The purpose of this assessment is to determine an optimal regional transmission plan for the study participants to serve the area north and east of Orlando in 2010 and beyond. This area is generally served by PEF and FPL. It is fast growing and there are a limited number of generating units located in the area. Due to the large amount of generation located in Polk County, generation additions at Stanton will help support this area and serve to mitigate the effects of load flow from generation located in Polk County.

This study assumed the following OUC projects would be in place by 2010:

- Relocation of the Stanton 230/69 kV transformer to a new Magnolia Ranch 230 kV substation with the corresponding operating voltage change from 69 kV to 230 kV of the existing 230 kV Stanton to Magnolia Ranch transmission line.
- Magnolia Ranch to Lake Nona 230 kV transmission line.

The study identified two phases of projects to be added to the system. The Phase I projects are as follows:

- Construct a 230 kV line between Bithlo and Stanton with an interconnection with FPL and PEF.
- Reconductor the Stanton West-Curry Ford 230 kV line with 1272 ACSS/TW.
- Install a Bithlo 230/69 kV transformer.
- Loop one of the two Sanford-Poinsett 230 kV lines into the Bithlo 230 kV bus.

The study results call for the Phase I projects to be constructed by the winter of 2009; however, the study results are still preliminary and have yet to be approved by the entire study team. The projects are also subject to negotiation between the study team members with respect to responsibility for cost, design, and operation. The study identified Phase II projects as follows:

- Install an Alafaya 230/69 kV transformer.
- Loop the Sanford-Poinsett 230 kV line into the Alafaya 230 kV bus.
- Loop the same Sanford-Poinsett 230 kV line into the Winter Springs 230 kV bus.
- Reconnect the 69 kV systems east of the north-south Winter Springs-Rio Pinar 230 kV corridor to transfer as much load as is practical over to the new Bithlo and Alafaya 230/69 kV transformers.

The proposed Phase II projects will be reevaluated prior to final commitment to construction. The system will be continuously monitored while the other proposed additions are installed and the load grows. The short circuit portion of the study also concluded that the substation breakers at the Stanton Substation would need to be upgraded.

13.2 Impact of Stanton B

The potential impact on the Central Florida transmission system of a capacity addition at Stanton was first evaluated by OUC in 2004 based on a capacity addition in 2008. All cases evaluated, including those which included capacity additions at Stanton, indicated overload conditions on portions of the transmission system when considering base and contingency conditions. The case that included Stanton B indicated the following overload conditions for the summer of 2008:

- Osceola-Lake Agnes 230 kV transmission line.
- Rio Pinar-Econ 230 kV transmission line (PEF).
- Stanton West-Curry Ford 230 kV transmission line.
- Azalea A and B-Pershing 115 kV transmission lines.

While Stanton B had an influence like every other element of the transmission system, many of the overloads were on elements of the transmission system that are well removed from the Stanton Energy Center, as seen on Figure 2-1. The following represents the preliminary list of upgrades identified to alleviate the above overloads:

- Reconductor Stanton West-Curry Ford 230 kV transmission line with 1272 ACSS/TW.
- Reconductor Azalea A and B-Pershing 115 kV transmission lines with 954 ACSR.
- Upgrade Rio Pinar-Econ 230 kV transmission line (PEF).
- Upgrade Pershing A and B bus tie transformers to 500 MVA each.
- Provide upgrades of facilities identified by the FRCC Transmission Working Group (TWG).
- Upgrade Michigan-Kaley 115 kV underground cable or operational switching.

As indicated by the preliminary list of upgrades summarized above, only the proposed reconductoring of the Stanton West-Curry Ford 230 kV line is directly connected to the Stanton Substation. To date, none of the proposed upgrades have been installed. Instead, the additional studies described in Section 13.1 have been undertaken to develop alternatives that reduce cost and increase reliability on a regional basis.

Table 13-1 presents the estimated impacts of Stanton B determined by comparing the case with the Phase I projects in Section 13.1 with and without Stanton B. Table 13-1 presents the results of the load flow analysis showing the transmission system elements which exceed 100 percent of the normal continuous rating of the elements.

Table 13-1
Impact of Stanton B

Contingency	Overload Element	Percent of Normal Continuous Rating: Without Stanton B	Percent of Normal Continuous Rating: With Stanton B
Azalea – Pershing 115 kV Line Circuit 1	Azalea – Pershing 115 kV Line Circuit 2	103	103
Azalea – Pershing 115 kV Line Circuit 2	Azalea – Pershing 115 kV Line Circuit 1	103	103
Pershing 230/115 kV Transformer No. 1	Pershing 230/115 kV Transformer No. 2	101	108
Pershing 230/115 kV Transformer No. 2	Pershing 230/115 kV Transformer No. 1	-	105
Bradford – Duval 230 kV Line (FPL)	Lawtey – Mining 115 kV Line (FPL)	103	103
	Maxville – Mining 115 kV Line (FPL)	109	109

As shown in Table 13-1, the Phase I projects generally solve overload situations in Central Florida. Also, as indicated in Table 13-1, Stanton B has minimal impact either positively or negatively on the transmission system with the Phase I projects in place. It should be noted that the two largest impacts associated with Stanton B impact the existing Pershing 230/115 kV transformers during contingency conditions. OUC is conducting a study of the 115 kV system which addresses this issue as well as other issues associated with the 115 kV system.

Table 13-2 presents the results of the evaluation of statewide transmission system losses including Southern Company's system for the previously discussed load flow case in 2010 with and without Stanton B. As indicated Stanton B has minimal impact on losses for the statewide transmission system, but the impact that does exist reduces statewide losses.

Table 13-2
Transmission System Losses

Loss	Without Stanton B	With Stanton B
MW	3,733.6	3,733.5
MVAR	59,223.8	59,212.5

13.3 Economic Analysis of Transmission System Requirements

Costs associated with necessary substation modifications to accommodate Stanton B in the Stanton Substation are included in OUC's additional costs in Table 7-4. Costs for upgrades to the transmission system beyond the Stanton Substation are not included in the economic analysis because it is difficult to determine what (if any) costs are a direct result of Stanton B. Additionally, since all alternatives considered in the economic analyses in Section 10.0 are assumed to be located at Stanton, the costs for any offsite transmission upgrades would be the same in all plans.

14.0 Strategic Considerations

In addition to cost-effectively meeting OUC's capacity needs, there were several strategic considerations and advantages associated with the project, which led OUC to propose Stanton B as its next generating unit. These strategic considerations include both economic and noneconomic attributes and are discussed in the remainder of this section.

14.1 Clean Coal Demonstration

As described in Section 7.0, the partners involved in the development of Stanton B were selected for the negotiation of a $235 million cost-sharing cooperative agreement from the DOE under the CCPI. The project was selected because the proposed Transport Gasification combined cycle technology offers significant advantages over other clean coal technologies. In addition, the Stanton site was attractive because of OUC's successful experience in implementing advanced environmental technologies.

14.1.1 Air Blown Technology

The Transport Gasification technology proposed in the gasification process for Stanton B is air blown, while other clean coal gasification projects are oxygen blown. In addition to simplifying the gasification process, the air blown Transport Gasification technology eliminates the need for an onsite oxygen plant. Oxygen plants are expensive to construct and operate, and have special operating considerations to maintain safety. By eliminating the oxygen plant, Stanton B will reduce capital cost and require less site space.

14.1.2 Low Rank Coal Operation

The proposed Stanton B will operate using low rank coals that have lower heating values and higher moisture content than coal used in other clean coal gasification technologies. Neither of the two IGCC units operating in the United States currently use subbituminous coal, but Stanton B will operate on subbituminous PRB coal. The United States has a larger reserve of lower rank subbituminous coal than the bituminous coal used at other IGCC facilities. Therefore, Stanton B will utilize one of the largest domestic fuel supplies and thereby reduce dependence on foreign fuel imports. In addition to having greater availability than bituminous coal, subbituminous PRB coal is generally less expensive than bituminous coal on a delivered dollar per MBtu basis. For example, as presented in Section 5.0, the projected 2006 cost of PRB coal delivered to Stanton is $2.50/MBtu, compared to $2.77/MBtu for the Central Appalachian coal currently being burned in Stanton Units 1 and 2. Commercial demonstration of clean coal technology using subbituminous coal will allow utilities in the United States to consider IGCC as an alternative to conventional coal generation.

14.1.3 Emission Controls

Stanton B will demonstrate sulfur removal technology that results in lower SO_2 emissions compared to conventional coal units. In addition, the sulfur removal technology will create elemental sulfur, which may be sold as a byproduct. Stanton B will demonstrate the use of SCR on IGCC technology. Finally, Stanton B will demonstrate ammonia removal technology, which is expected to produce marketable ammonia. The demonstration of these emission controls will allow future coal units to be constructed with lower emissions, while producing salable byproducts.

14.2 Fuel Diversity

Stanton B will provide an increase in fuel diversity to OUC's system and Florida as a whole. The ability to use coal or natural gas efficiently in the same unit provides both supply and economic diversity. If either fuel is unavailable, the other fuel may be used. If the generation cost of one fuel becomes greater than the other, the other can be used, resulting in reduced cost. As a combined cycle unit, Stanton B can efficiently utilize either syngas or natural gas at heat rates much lower than conventional steam units.

The use of subbituminous coal provides diversity to OUC's coal supplies, which currently consist of only bituminous coal. The unit would be the first unit in the state to burn subbituminous coal, thus diversifying the state's coal supply. The use of coal by Stanton B will reduce OUC's and Florida's dependence on high cost natural gas.

14.3 Fuel Supply

The addition of coal fueled generation increases the reliability of OUC's fuel supply. Coal for approximately 45 days of Stanton B operation will be stored onsite, reducing the potential supply disruptions associated with natural gas like those experienced with Hurricanes Katrina and Rita.

14.4 Gasification Byproducts

One strategic advantage of Stanton B is the nature of its byproducts. Stanton B is being permitted for onsite disposal of byproducts; however, the byproducts are expected to be produced in forms that can be salable. If the byproducts are indeed produced in salable forms and the markets are available, these byproducts would not be landfilled. Stanton B may produce elemental sulfur in a salable form. SPC-OG will be responsible for the off-take of the sulfur. SPC-OG will either sell the sulfur, if it is in salable form, or dispose of it. If the sulfur is disposed in the Stanton landfill, SPC-OG will pay OUC for the disposal costs. No benefits to OUC for payment of disposal costs have been included in the economic analysis in Section 10.0. Stanton B is also expected to produce salable ammonia. Again, SPC-OG will be responsible for either selling the ammonia or disposing it.

Stanton B will also produce gasification ash as a byproduct of the Transport Gasification process which is expected to have a heating value of 4,000 Btu/lb. OUC will be responsible for its disposal. The gasification ash is being permitted for disposal at the Stanton landfill. The significant heating value of the gasification ash offers a potential benefit to the project. It may be possible to mix the gasification ash with the coal for Stanton Units 1 and 2 and burn it in those units. It may also be possible to sell the gasification ash. Currently, ash that does not have any heating value is being sold from Stanton Units 1 and 2. No credit for the sale of ash or disposal costs has been included in the economic analysis in Section 10.0 for Stanton B, Stanton Units 1 and 2, or other coal unit alternatives at Stanton.

The possibility of selling byproducts from Stanton B compared to byproducts from conventional coal unit alternatives represents significant economic and environmental advantages.

14.5 Fuel Price Volatility

The use of coal for Stanton B greatly reduces OUC's exposure to fuel price volatility compared to natural gas. Furthermore, the cost of PRB coal is less volatile than the cost of the bituminous coal being burned at Stanton for the following reasons:

- PRB coal is the most abundant source of coal in the country and the most economical to mine. Therefore, it is not subject to as much price fluctuation as other coal basins in the United States.
- Transportation costs account for over two thirds of the delivered cost of PRB coal to Florida as compared to less than one third of the delivered cost for bituminous coal. Except for general inflation escalators, rail transportation costs remain fixed through long-term contracts with the railroads and therefore are not subject to market price fluctuations.

14.6 Economy Energy Sales Potential

OUC, along with FMPA and Lakeland, are members of the Florida Municipal Power Pool (FMPP). FMPP dispatches the member's generating resources as a single entity and splits the savings through joint dispatch among members. The installation of

Stanton B will make additional economy energy available to FMPP from OUC's existing units. The availability of this economy energy to FMPP will provide additional revenue to OUC, thus decreasing costs to OUC's retail customers as well as lowering costs for FMPA and Lakeland.

14.7 Unit Reliability

Although Stanton B will be a first-of-a-kind commercial IGCC unit, it is designed to operate in two modes to ensure reliable electric generation. Stanton B can operate in combined cycle mode on syngas or natural gas and includes a steam turbine bypass to the condenser for startup and upset conditions. Operationally, Stanton B will be very reliable. More important, however, is that OUC has obtained reliability guarantees from SPC-OG for the gasifier. This ensures that OUC will be reimbursed up to the full demand payment for the gasifier if it does not meet guaranteed availability levels. SPC-OG also has the option to supply makeup energy to meet the guaranteed availability levels for the gasifier. This further increases the availability of reliable energy to OUC's customers.

14.8 Environmental Considerations

As described in Section 9.0, CAIR and CAMR will require the eastern United States 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 has higher emissions of NO_x, SO_2, and Hg than natural gas or fuel oil generation. As a clean coal unit, the proposed Stanton B is designed to have lower emissions of NO_x, SO_2, and Hg than conventional coal fired generation. Other commercial IGCC units have demonstrated emission levels approaching the emissions of natural gas fired generation. Stanton B will allow OUC to capture the economic advantages of coal generation with lower emissions than conventional coal generation.

Stanton B will also use less cooling water per kW than conventional coal fired units. The Transport Gasification technology will help conserve the state's water resources. Stanton B will have a smaller footprint than conventional coal units, which will result in less disruption to the environment. Additionally, IGCC technology is better suited for CO_2 capture than conventional coal units, if this is required in the future. IGCC technology produces less CO_2 than conventional coal units, which will give it an economic advantage if CO_2 is taxed in the future.

14.9 Capital Cost Guarantees

OUC's capital cost for both the combined cycle and OUC's ownership share of the gasifier is fixed and guaranteed by SPC-OG. The guaranteed capital costs remove OUC's risk and exposure to power plant construction costs. These costs can be volatile, as demonstrated by cost increases after Hurricanes Katrina and Rita. The costs and availability of steel, nickel, copper, concrete, and other commodities have been very volatile and highly dependent on the actions of China and other Asian countries. Besides the potential for increased commodity costs, there are significant risks of higher costs from material shortages and the effect that may have on the detailed scheduling of construction. Since construction of a power plant must take place in a sequential order, significant cost increases can occur if material shortages disrupt this sequence.

If a large number of planned coal fueled units are constructed concurrently in Florida, there may be a significant shortage of skilled labor. Construction of a coal unit requires significantly more labor per kW than other fossil fueled power plants. Labor shortages for power plant construction can have a compounding effect on power plant construction costs. Not only are higher wages and incentives required to attract labor, but the productivity of the labor force decreases as lower quality laborers enter the workforce. Fixed price guarantees for Stanton B shelter OUC from these risks and can result in significant savings, especially when considering that increased capital costs also result in long-term debt service costs as these increased capital costs are financed.

14.10 Strength of Southern Power Company as a Partner

Another strategic consideration and benefit of Stanton B is the financial and resource strength of Southern Power Company as a partner with OUC at Stanton B. The financial and performance risks of Stanton B would be very significant to OUC if it were constructing Stanton B on its own. On a relative basis, the risks of participation to Southern Power Company are minor. Southern Power Company's size and strength allow it to guarantee OUC's cost and performance, making the project feasible for OUC.

15.0 Consequences of Delay

The proposed Stanton B is unique compared to other supply-side alternatives because the DOE awarded SPC, KBR, and OUC the right to negotiate a cooperative agreement to receive $235 million in cost-sharing under the CCPI. As a result, the consequences of delaying the commercial operation of Stanton B are significant from a project risk, economic, and reliability standpoint for OUC. This section describes the negative consequences of delaying the Stanton B project.

15.1 Project Risk Consequences

As delineated in the *Orlando Gasification Project Construction and Ownership Participation Agreement Between Southern Power Company – Orlando Gasification LLC and Orlando Utilities Commission*, if the need for power determination and supplemental site certification pursuant to the Florida Electrical Power Plant Siting Act is not granted or other criteria are not met before June 1, 2007, and if these delays are beyond the reasonable control of SPC-OG, then SPC-OG has the right to terminate ownership agreements with OUC. If SPC-OG exercises this right, SPC-OG will retain the right, but not the obligation to maintain the DOE Agreement and all Project Agreements entered into by SPC-OG as Agent as of such date, for its own account, or any of its Affiliates' accounts.

Under such circumstances, OUC risks losing the DOE cost-sharing and would need to undertake considerations to meet its 15 percent reserve margin criterion in 2010. While SPC-OG is wholly committed to the development and construction of Stanton B, delaying the project would expose OUC to significant project risks.

15.2 Economic Consequences

If the commercial operation of the project is delayed, OUC would be required to replace the capacity and energy available from Stanton B. If the commercial operation of Stanton B is delayed by 1 year, the optimal capacity expansion plan with Stanton B installed in 2011 will consist of a 7FA CT in 2010, a 7FA CT in 2018, a subcritical pulverized coal unit in 2021, an LM6000 CT in 2029, and a 7EA CT in 2030. The CPWC of this expansion plan is approximately $5,516.3 million over the planning period. The CPWC of this plan is $9.4 million more than the base case plan presented in Section 10.0.

15.3 Reliability Consequences

If Stanton B is delayed and no other generating capacity is installed to meet OUC's demand by 2010, then OUC's reserve margin will fall to approximately 13 percent. This is below OUC's reserve criterion of 15 percent. If the reserve margin is inadequate, OUC may not be able to serve the retail load or may have to purchase power at extremely high costs to serve the retail load.

16.0 Financial Analysis

OUC has numerous funding sources that may be used to finance the development and construction of Stanton B. OUC's total expected investment requirement, net of DOE cost-sharing, as applicable for the combined cycle unit, OUC's additional costs, and its ownership share of the gasification unit is estimated to be approximately [redacted], including an allowance for funds used during construction. OUC may use a combination of internal funds, short-term debt financing, or a long-term bond issuance to finance a large capital project such as Stanton B. As discussed below, the Stanton B investment represents a relatively small percentage of OUC's total asset base, and OUC has multiple resources available to fund this investment.

As of September 30, 2005, OUC reported total assets of approximately \$2.547 billion, with approximately \$1.766 billion in total utility plant assets, net of accumulated depreciation and amortization. The Stanton B capital investment represents an increase in OUC's total asset base of approximately 12 percent. While the Stanton B investment is significant, it represents a relatively small percentage of OUC's total asset base.

OUC currently has significant unrestricted net assets including cash and related investments that may be used to fund the Stanton B investment. As of September 30, 2005, OUC reported unrestricted net assets of approximately \$244 million. As such, OUC has significant internal cash resources that may be relied upon to fund a large portion of the Stanton B capital investment.

OUC may also issue additional short- or long-term debt to fund portions of the Stanton B capital investment. OUC's capitalization includes approximately \$1.352 billion in net long-term debt and \$762.5 million in equity. OUC has very good credit ratings of AA from Fitch Investors Service and Standard & Poor's, and Aa1 with Moody's Investors Service. In addition, OUC has had two recent bond issuances: one is a short-term issuance and the other is a long-term issuance. During the fourth quarter of 2005, OUC issued \$40 million in revenue refunding bonds due in 2010 at an interest rate of 3.66 percent. During December 2005, OUC issued \$120 million in long-term bonds at an interest rate of 4.66 percent. After these issuances, all of OUC's ratings agencies reaffirmed OUC's credit ratings and maintained a stable outlook on OUC's debt. Further debt issuances could be accommodated if required.

Based on the size of the capital investment, OUC's cash and investment assets, and its excellent credit rating, which was recently reaffirmed, OUC has the ability and required financial resources to fund the Stanton B capital investment.

17.0 Peninsular Florida Needs

This section describes the consistency of Stanton B with the power requirements of peninsular Florida. The information in this section is based in part on the *2005 Regional Load and Resource Plan* (2005 L&RP) for the State of Florida, compiled by the FRCC and published in July 2005. The FRCC is responsible for coordinating power supply reliability in peninsular Florida for NERC. The 2005 L&RP summarizes utility loads and resources, by type of capacity, through the year 2014. The report also includes utility load forecast data and proposed generation expansion plans, retirements, and capacity re-rates.

17.1 Peninsular Florida Capacity and Reliability Needs

The need for Stanton B can be evaluated by comparing the existing and planned capacity in peninsular Florida with the capacity resources required to meet peak load plus reserve requirements. Table 17-1 lists the peak demand and available capacity for the summer and winter as presented by the FRCC. The FRCC presents available capacity as existing capacity, less planned retirements, plus all planned additions (including those that have yet to be approved under the Florida Electrical Power Plant Siting Act). Column (10) of Table 17-1 indicates that, including the expected demand reductions associated with load management and interruptible load, summer reserve margins are projected to range from 19.0 percent to 24.7 percent over the 2005 through 2014 time period. Comparable winter reserve margins are expected to range between 21.3 percent and 25.6 percent. However, Column (7) indicates that without factoring in the expected demand reductions associated with load management and interruptible load, summer reserve margins are projected to be 15 percent or less for 8 of the next 10 years, and winter reserve margins are projected to be 15 percent or less for 5 of the next 10 years.

The forecasted reserve margins in Table 17-1 assume that all projects listed as coming on-line in the next 10 years by FRCC members in their 2005 FRCC Load and Resource Database (LRDB) submittal will materialize. As submitted in the LRDB, there is no differentiation between planned capacity additions requiring approval under the Florida Electrical Power Plant Siting Act and those which do not. Table 17-2 illustrates that if the capacity additions included in the LRDB that will require approval under the Florida Electrical Power Plant Siting Act are not considered in the projections of installed capacity, forecasted capacity reserve margins decrease dramatically. Capacity additions that have received approval subsequent to the FRCC LRDB process, such as FPL's Turkey Point 5 and FMPA's Treasure Coast Energy Center Unit 1, have been included in the projection of installed capacity.

Table 17-1
2005 Regional Load and Resource Plan--Peninsular Florida Peak Demand and Available Capacity

(1) Calendar Year	(2) Projection of Installed Capacity (MW)	(3) Net Contracted Firm Interchange (MW)	(4) Projected Firm Net to Grid from NUG (MW)	(5) Total Available Capacity (MW)	(6) Total Peak Demand (MW)	(7) Reserve Margin w/o Load Management and Int. Load (MW)	(7) Percent of Peak	(8) Load Management and Interruptible Load (MW)	(9) Firm Peak Demand (MW)	(10) Reserve Margin w/Load Management and Int. Load (MW)	(10) Percent of Peak
Summer Peak Demand											
2005	43,578	1,577	5,339	50,494	43,495	6,999	16.1	2,990	40,505	9,989	24.7
2006	44,638	1,552	4,901	51,090	44,680	6,410	14.3	2,746	41,934	9,156	21.8
2007	46,202	1,552	4,014	51,768	45,962	5,806	12.6	2,743	43,219	8,549	19.8
2008	47,362	1,552	3,979	52,893	47,108	5,785	12.3	2,744	44,364	8,529	19.2
2009	49,103	1,552	3,579	54,233	48,344	5,889	12.2	2,754	45,590	8,643	19.0
2010	51,531	1,355	3,012	55,898	49,556	6,342	12.8	2,753	46,803	9,095	19.4
2011	53,175	1,355	2,907	57,437	50,796	6,641	13.1	2,775	48,021	9,416	19.6
2012	55,805	1,355	2,840	60,000	52,055	7,945	15.3	2,797	49,258	10,742	21.8
2013	57,535	1,355	2,371	61,261	53,270	7,991	15.0	2,821	50,449	10,812	21.4
2014	59,168	1,355	1,706	62,229	54,524	7,705	14.1	2,851	51,673	10,556	20.4
Winter Peak Demand											
2005/06	47,465	1,752	5,191	54,408	46,717	7,691	16.5	3,390	43,327	11,081	25.6
2006/07	48,408	1,752	5,420	55,580	47,994	7,586	15.8	3,386	44,608	10,972	24.6
2007/08	50,385	1,752	4,239	56,376	49,139	7,237	14.7	3,381	45,758	10,618	23.2
2008/09	51,065	1,752	4,239	57,056	50,414	6,642	13.2	3,386	47,028	10,028	21.3
2009/10	53,884	1,752	3,152	58,787	51,700	7,087	13.7	3,384	48,316	10,471	21.7
2010/11	56,598	1,555	3,137	61,289	53,030	8,259	15.6	3,405	49,625	11,664	23.5
2011/12	57,668	1,555	3,034	62,257	54,370	7,887	14.5	3,425	50,945	11,312	22.2
2012/13	60,573	1,555	2,592	64,719	55,718	9,001	16.2	3,453	52,265	12,454	23.8
2013/14	62,727	1,555	2,308	66,589	57,094	9,495	16.6	3,452	53,642	12,947	24.1
2014/15	63,686	1,555	1,693	66,933	58,493	8,440	14.4	3,450	55,043	11,890	21.6

Table 17-2
Peninsular Florida Installed Capacity and Reserve Margins of Existing Facilities and Additions Which Do Not Require Approval Under the Florida Electrical Power Plant Siting Act(1)

(1) Calendar Year	(2) Projection of Installed Capacity (MW)	(3) Net Contracted Firm Interchange (MW)	(4) Projected Firm Net to Grid from NUG (MW)	(5) Total Available Capacity (MW)	(6) Total Peak Demand (MW)	(7) Reserve Margin w/o Load Management and Int. Load (MW)	(7) Reserve Margin w/o Load Management and Int. Load Percent of Peak	(8) Load Management and Interruptible Load (MW)	(9) Firm Peak Demand (MW)	(10) Reserve Margin w/Load Management and Int. Load (MW)	(10) Reserve Margin w/Load Management and Int. Load Percent of Peak
Summer Peak Demand											
2005	43,578	1,577	5,339	50,494	43,495	6,999	16.1	2,990	40,505	9,989	24.7
2006	44,638	1,552	4,901	51,090	44,680	6,410	14.3	2,746	41,934	9,156	21.8
2007	46,202	1,552	4,014	51,768	45,962	5,806	12.6	2,743	43,219	8,549	19.8
2008	47,362	1,552	3,979	52,893	47,108	5,785	12.3	2,744	44,364	8,529	19.2
2009	47,680	1,552	3,579	52,811	48,344	4,467	9.2	2,754	45,590	7,221	15.8
2010	48,525	1,355	3,012	52,892	49,556	3,336	6.7	2,753	46,803	6,089	13.0
2011	48,860	1,355	2,907	53,122	50,796	2,326	4.6	2,775	48,021	5,101	10.6
2012	49,391	1,355	2,840	53,586	52,055	1,531	2.9	2,797	49,258	4,328	8.8
2013	49,826	1,355	2,371	53,552	53,270	282	0.5	2,821	50,449	3,103	6.2
2014	50,191	1,355	1,706	53,252	54,524	(1,272)	(2.3)	2,851	51,673	1,579	3.1
Winter Peak Demand											
2005/06	47,465	1,752	5,191	54,408	46,717	7,691	16.5	3,390	43,327	11,081	25.6
2006/07	48,408	1,752	5,420	55,580	47,994	7,586	15.8	3,386	44,608	10,972	24.6
2007/08	49,204	1,752	4,239	55,195	49,139	6,056	12.3	3,381	45,758	9,437	20.6
2008/09	49,702	1,752	4,239	55,693	50,414	5,279	10.5	3,386	47,028	8,665	18.4
2009/10	50,610	1,752	3,152	55,514	51,700	3,814	7.4	3,384	48,316	7,198	14.9
2010/11	51,284	1,555	3,137	55,976	53,030	2,946	5.6	3,405	49,625	6,351	12.8
2011/12	51,809	1,555	3,034	56,398	54,370	2,028	3.7	3,425	50,945	5,453	10.7
2012/13	52,059	1,555	2,592	56,206	55,718	488	0.9	3,453	52,265	3,941	7.5
2013/14	52,446	1,555	2,308	56,309	57,094	(786)	(1.4)	3,452	53,642	2,667	5.0
2014/15	52,675	1,555	1,693	55,923	58,493	(2,571)	(4.4)	3,450	55,043	880	1.6

(1) Represents existing generating resources, planned retirements, and planned capacity additions not requiring approval under Florida Electric Power Plant Siting Act. However, subsequent to the data collection period of the 2005 L&RP, FPL's Turkey Point 5 (6/2007) and FMPA's Treasure Coast Energy Center (6/2008) received approval and are included in the projected installed capacity.

Column (10) of Table 17-2 shows summer capacity reserve margins decrease to 13 percent in 2010, and decrease further to 3.1 percent in 2014 when additions requiring approval under the Florida Electrical Power Plant Siting Act are omitted. Similarly, winter reserve margins decrease to 14.9 percent in 2009/10, and decrease further to 1.6 percent in 2014/15. Note that these reserve margins include the expected demand reductions associated with load management and interruptible load. If the expected demand reductions associated with load management and interruptible loads do not materialize as projected, Column (7) of Table 17-2 indicates that the summer reserve margins would decrease to 14.3 percent in 2006, fall to 0.5 percent in 2013, and become negative in 2014. Likewise, without load management and interruptible loads, winter reserve margins decrease to 12.3 percent in 2007/08 and become negative in 2013/14. Thus, approval and construction of Stanton B will help fill the capacity shortfall projected in the State that emerges after accounting for projects that have not yet received approval under the Florida Electrical Power Plant Siting Act.

The projections of reserve margins in peninsular Florida in Table 17-2 should be viewed in light of the target reserve margin levels of the subject utilities. Table 17-3 indicates that on a weighted average basis, the summer and winter reserve margins for peninsular Florida utilities are 18.9 percent and 18.8 percent, respectively. The data from Table 17-2 indicate that in the summer of 2010 and winter of 2010/2011, when Stanton B would be in commercial operation, the reserve margin projections of 13.0 percent and 12.8 percent, respectively, are less than the target reserve margin standards. This means that an additional 2,757 MW will be required to be approved and constructed by the summer of 2010 and 2,979 MW will be required in the winter of 2010/2011 if target reliability levels are to be met. Stanton B will partially fill this projected capacity shortfall in peninsular Florida.

17.2 Existing Fuel Mix

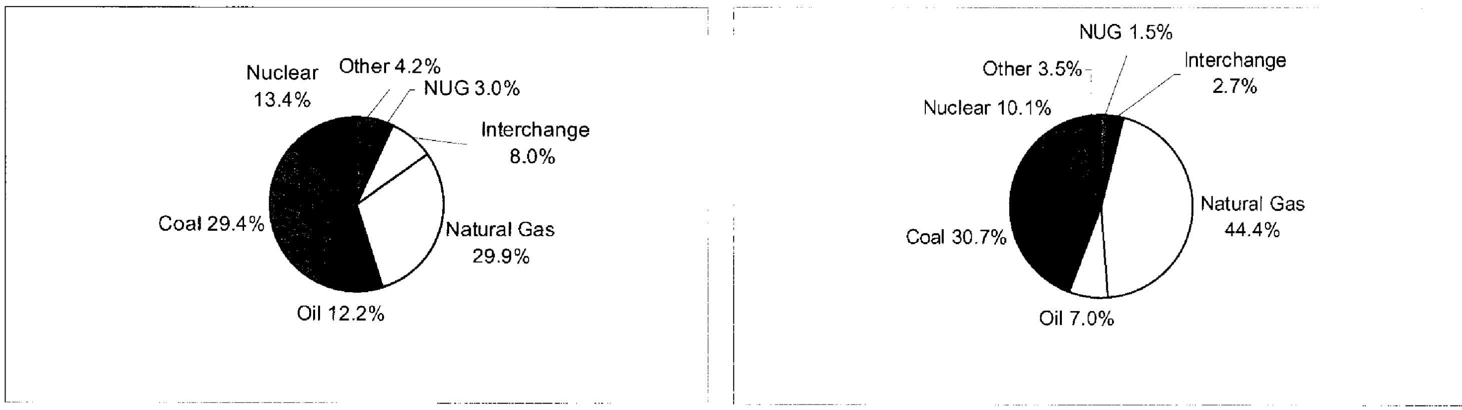
The need for Stanton B is seen not only through comparison of existing generating capacity and capacity resource additions with forecast peak demand, but also through an evaluation of the existing and projected fuel mix throughout the State of Florida. Florida is already heavily dependent upon natural gas and is projected to grow more dependent. The FPSC's Department of Economic Regulation published its *Review of Florida Electric Utility 2005 Ten-Year Site Plans* in December 2005. Figure 17-1, extracted from the FPSC's Review, indicates that in 2004 natural gas accounted for 29.9 percent of Florida's energy generation, while in 2014 the percentage of natural gas is projected to increase to 44.4 percent of total generation. Coal usage in Florida is projected to increase only slightly from 29.6 percent in 2004 to 30.7 percent in 2014 in spite of the addition of six planned, but not yet certified, coal units in that period of time.

This growing dependence upon natural gas exposes the State to the greater volatility of natural gas. This conclusion is bolstered by the rapid price escalation for natural gas supply encountered beginning in late August of 2005, as a result of hurricane Katrina. Following this event, Henry Hub spot prices for natural gas rose to a September average of $11.96/MBtu and further rose to an average of $13.35/MBtu in December (oilenergy.com).

Table 17-3
Peninsular Florida Weighted Average Reserve Requirement

Utility	Net Capacity (MW) [1]		Reserve Requirement (%) [2]	
	Summer	Winter	Summer	Winter
Florida Keys Electric Cooperative Association [3]	27	27	15%	15%
Florida Municipal Power Agency [4]	1,429	1,503	18%	15%
Florida Power & Light Company	18,940	20,158	20%	20%
Gainesville Regional Utilities	611	630	15%	15%
JEA	3,255	3,477	15%	15%
Lakeland, City of	913	995	15%	15%
New Smyrna Beach Utility, Commission of [3]	66	70	15%	15%
Orlando Utilities Commission	1,199	1,257	15%	15%
Progress Energy Florida	8,341	9,184	20%	20%
Reedy Creek Improvement District [3]	43	44	15%	15%
Seminole Electric Cooperative	1,819	1,917	15%	15%
St. Cloud, City of	21	21	15%	15%
Tallahassee, City of [3]	652	699	17%	15%
Tampa Electric Company	4,090	4,423	20%	20%
US Corps of Engineers – Mobile [3]	39	39	15%	15%
Total Net Capacity	41,444	44,443		
Weighted Average Reserve Requirement			18.9%	18.8%

(1) Source: 2005 FRCC Load and Resource Plan.
(2) Source: 2005 Ten-Year Site Plans.
(3) Are not required to file Ten-Year Site Plans. Reserve requirements are assumed to be 15 percent.
(4) Includes members of the All-Requirements Project.



2004

2014

Figure 17-1
Energy Generation by Fuel Type – State of Florida

Appendix A
Forecast of Peak Demand and Energy Consumption

Appendix A
Forecast of Peak Demand and Energy Consumption

OUC retained Itron, formerly Regional Economic Research, Inc. (RER), to assist in the development of forecasts of peak demand and energy consumption. The project scope was to develop a set of sales, energy, and demand forecast models that could support OUC's budgeting and financial planning process as well as long-term planning requirements. OUC utilized its internal knowledge of the service area with the expertise of Itron in the development of the forecast models.

A.1 Forecast Methodology

There are two primary forecasting approaches used in forecasting electricity requirements: econometric-based modeling (such as linear regression) and end-use models (such as EPRI's REEPS and COMMEND models). In general, econometric forecast models provide better forecasts in the short-term time frame, and end-use models are better at capturing long-term structural change resulting from competition across fuels, and changes in appliance stock and efficiency.

The difficulty of end-use modeling is that these models are extremely data-intensive and provide relatively poor short-term forecasts. End-use models require detailed information on appliance ownership, efficiency of the existing stock, new purchase behavior, utilization patterns, commercial floor-stock estimates by building type, and commercial end-use saturations and intensities in both new and existing construction. It typically costs several hundred thousand dollars to update and to maintain such a detailed database. Lack of detailed end-use information precluded developing end-use forecasts for the OUC/St. Cloud service territories. Furthermore, since there is virtually no retail natural gas in the OUC service territory, end-use modeling would provide little information on cross-fuel competition - one of the primary benefits of end-use modeling.

Since end-use modeling was not an option, the approach adopted was to develop linear regression sales models. To capture long-term structural changes, end-use concepts are blended into the regression model specification. This approach, known as a SAE model, entails specifying end-use variables (heating, cooling, and other use) and utilizing these variables in sales regression models. While the SAE approach loses some end-use detail, it adequately forecasts short-term energy requirements, and it provides a reasonable structure for forecasting long-term energy requirements.

A.1.1 Residential Sector Model

The residential model consists of both an average use per household model and a customer forecast model. Monthly average use models were estimated over the period encompassing 1994 to 2004. This provides 10 years of historical data, with more than enough observations to estimate strong regression models. Once models were estimated, the residential energy requirement in month T was calculated as the product of the customer and average use forecast:

$$\text{Residential Sales}_T = \text{Average User Per Household}_T \times \text{Number of Customers}_T$$

A.1.1.1 Residential Customer Forecast. The number of customers was forecasted as a simple function of household projections for the Orlando MSA. Models were estimated using MSA-level data, since county level economic data is only available on an annual basis. Not surprisingly, the historical relationship between OUC customers and households in the Orlando MSA is extremely strong. The OUC customer forecast model had an adjusted R^2 of 0.99, with an in-sample Mean Absolute Percent Error (MAPE) of 0.2 percent. For St. Cloud, the model performance was not as strong, given the "noise" in the historical monthly billing data. The adjusted R^2 was 0.89, with an in-sample MAPE of 3.5 percent. Since St. Cloud is a relatively small part of OUC's service territory, the 3.5 percent average customer forecast error represents a relatively small number of total system customers.

A.1.1.2 Average Use Forecast. The SAE modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$), depicted as follows:

$$\text{Use}_{y,m} = \text{Heat}_{y,m} + \text{Cool}_{y,m} + \text{Other}_{y,m}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for end-use elements provides the following econometric equation:

$$\text{Use}_m = a + b_1 \times \text{XHeat}_m + b_2 \times \text{XCool}_m + b_3 \times \text{XOther}_m + \varepsilon_m$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. The estimated model can then be thought of as an SAE model, where the estimated slopes are the adjustment factors.

XHeat captures the factors that affect residential space heating. These variables include the following:

- Heating degree-days.
- Heating equipment saturation levels.
- Heating equipment operating efficiencies.
- Average number of days in the billing cycle for each month.
- Thermal integrity and footage of homes.
- Average household size, household income, and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier as follows:

$$\mathbf{XHeat}_{y,m} = \mathbf{HeatIndex}_{y} \times \mathbf{HeatUse}_{y,m}$$

where:

$XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m).

$HeatIndex_y$ is the annual index of heating equipment.

$HeatUse_{y,m}$ is the monthly usage multiplier.

The heat index is defined as a weighted average energy intensity measured in kWh. Given a set of starting end-use energy intensities (EI), the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), and building structural index (*StructuralIndex*). Formally, the heating equipment index is defined as follows:

$$\mathbf{HeatIndex}_y = \mathbf{StructuralIndex}_y \times \sum_{\mathbf{Type}} \mathbf{EI}^{\mathbf{Type}} \times \frac{\left(\mathbf{Sat}_y^{\mathbf{Type}} \Big/ \mathbf{Eff}_y^{\mathbf{Type}} \right)}{\left(\mathbf{Sat}_{98}^{\mathbf{Type}} \Big/ \mathbf{Eff}_{98}^{\mathbf{Type}} \right)}$$

StructuralIndex is based on EIA square footage projections and thermal shell efficiency for the southeast census region. EIA's current projections show average square footage increasing slightly faster than thermal shell integrity improvements.

Electric heating saturation in the OUC service area is relatively high with approximately 85 percent of the homes using electric space heat. Heat pumps account for nearly half the existing stock and are projected to increase as a share of heating equipment over time. Given that heat pumps are significantly more efficient than resistance heat, efficiency gains are expected to outstrip increasing heat saturation, which in turn slows expected residential heating sales growth.

Heating sales are also driven by the factors that impact utilization of the appliance stock. Heating use depends on weather conditions, household size, household income, and prices. The heat use variable is constructed as follows:

$$\text{HeatUse}_{y,m} = \left(\frac{\text{HDD}_{y,m}}{\text{HDD}_{98}}\right) \times \left(\frac{\text{HHSize}_{y}}{\text{HHSize}_{98}}\right)^{0.25} \times \left(\frac{\text{Income}_{y}}{\text{Income}_{98}}\right)^{0.20} \times \left(\frac{\text{Price}_{y,m}}{\text{Price}_{98}}\right)^{-0.30}$$

where:

HDD is the number of heating degree days in year (y) and month (m).

HHSize is the average household size in a year (y).

Income is the average real income per household in a year (y).

Price is the average real price of electricity in month (m) and year (y).

By construction, $HeatUse_{y,m}$ has an annual sum that is close to 1.0 in the base year (1998). The index changes over time with changes in HDD, HHSize, Income, and Price. In this form, the coefficients represent end-use elasticity estimates. The elasticity estimates are based on short-term estimates embedded in the EPRI end-use forecasting model REEPS (Residential End-Use Planning System) and elasticities used by EIA in their long-term energy forecast model. The elasticities are also validated by evaluating out-of-sample model fit statistics using different elasticity estimates.

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree-days.
- Cooling equipment saturation levels.
- Cooling equipment operating efficiencies.

- Thermal integrity and footage of homes.
- Average household size, household income, and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier as follows:

$$\mathbf{XCool}_{y,m} = \mathbf{CoolIndex}_{y} \times \mathbf{CoolUse}_{y,m}$$

where:

$XCool_{y,m}$ is the estimated cooling energy use in year (y) and month (m).
$CoolIndex_y$ is the cooling equipment index.
$CoolUse_{y,m}$ is the monthly usage multiplier.

The cooling equipment index is calculated as follows:

$$\mathbf{CoolIndex}_y = \mathbf{StructuralIndex}_y \times \sum_{Type} \mathbf{EI}^{Type} \times \frac{\left(\mathbf{Sat}_y^{Type} / \mathbf{Eff}_y^{Type} \right)}{\left(\mathbf{Sat}_{98}^{Type} / \mathbf{Eff}_{98}^{Type} \right)}$$

As air conditioning saturation increases, the index increases. As efficiency increases, the index decreases. Again, because of the high current saturation of air conditioning, the index is largely driven by increasing overall air conditioning efficiency. A slight increase in the structural index (as a result of increasing square footage) results in a small increase in the cooling equipment index over time.

The cooling utilization variable is constructed similar to that of the heating use variable. CoolUse is defined as follows:

$$\mathbf{CoolUse}_{y,m} = \left(\frac{\mathbf{CDD}_{y,m}}{\mathbf{CDD}_{98}} \right) \times \left(\frac{\mathbf{HHSize}_y}{\mathbf{HHSize}_{98}} \right)^{0.25} \times \left(\frac{\mathbf{Income}_y}{\mathbf{Income}_{98}} \right)^{0.20} \times \left(\frac{\mathbf{Price}_{y,m}}{\mathbf{Price}_{98}} \right)^{-0.30}$$

where:

CDD is the number of cooling degree days in year (y) and month (m).

Monthly estimates of nonweather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by the following:

- Appliance and equipment saturation levels.
- Appliance efficiency levels.
- Average household size, real income, and real prices.

The explanatory variable for other uses is defined as follows:

$$\mathbf{XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m}}$$

The first term on the right hand side of this expression ($OtherEqpIndex_{y,m}$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in price, income, and household size on appliance utilization. The appliance index is defined as follows:

$$\mathbf{OtherIndex_{y,m} = EI^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{Eff_y^{Type}} \right)}{\left(Sat_{98}^{Type} \Big/ \frac{1}{Eff_{98}^{Type}} \right)} \times MoMult_m^{Type}}$$

where:

EI is the energy intensity for each appliance (annual kWh).
Sat represents the fraction of households who own an appliance type.
$MoMult_m$ is a monthly multiplier for the appliance type in month (m).
Eff is the average operating efficiency for water heaters.

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration. Saturation and efficiency trends are based on EIA projections for the southeast census region.

Economic activity is captured through the OtherUse variable, where OtherUse is defined as follows:

$$\textbf{OtherUse}_{y,m} = \left(\frac{\textbf{HHSize}_y}{\textbf{HHSize}_{98}}\right)^{0.25} \times \left(\frac{\textbf{Income}_y}{\textbf{Income}_{98}}\right)^{0.20} \times \left(\frac{\textbf{Price}_{y,m}}{\textbf{Price}_{98}}\right)^{-0.30}$$

Increase in household income translates into an increase in XOther, while increases in electricity prices result in a decrease in XOther. Decreasing household size (number per household) translates into a decrease in XOther.

A.1.1.3 Estimate Models. To estimate the forecast models, monthly average residential usage is regressed on XCool, XHeat, and XOther. Lagged *Use* values of XCool and Xheat are also included in the specification since these variables are constructed with calendar-month weather data, but the dependent variable (residential average use) is based on revenue-month sales. July residential sales, for example, reflect usage in both calendar months June and July. The end-use variables worked extremely well in the regression models. For OUC, the residential adjusted R^2 is 0.93 with an in-sample MAPE of approximately 4.1 percent. The mean absolute deviation (MAD) is 43.2 kWh compared to a residential monthly average usage of 1,070 kWh. All the model coefficients are highly significant (exhibited by t-statistics greater than 2.0). The St. Cloud model also explains average usage well with an R^2 of 0.91. The model coefficients are highly significant.

A.1.2 Nonresidential Sector Models

The nonresidential sector is segmented into two revenue classes:

- *Small General Service (GS Nondemand or GSND).*
- *Large General Service (GS Demand or GSD).*

The GSND class consists of small commercial customers with a measured demand of less than 50 kW. The GSD class consists of those customers with monthly maximum demand exceeding 50 kW.

The SAE approach is also used to develop models to forecast electricity sales for commercial nondemand and demand classes. The commercial SAE model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$) as follows:

$$\textbf{Sales}_{y,m} = \textbf{Heat}_{y,m} + \textbf{Cool}_{y,m} + \textbf{Other}_{y,m}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation:

$$\mathbf{Sales_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m}$$

The model parameters are then estimated using linear regression.

The constructed variables XHeat, XCool, and XOther capture structural as well as market condition changes. The end-use variables include the following:

- Heating and cooling degree-days.
- End-use saturation and efficiency trends.
- Real regional output.
- Price.

The end-use variables are represented as the product of an annual equipment index (Index) and a monthly usage multiplier (Use). The variables are defined as follows:

$$\mathbf{XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m}}$$

$$\mathbf{XCool_{y,m} = HeatIndex_y \times HeatUse_{y,m}}$$

$$\mathbf{XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m}}$$

The heating equipment index captures change in end-use saturation and efficiency. The heating index is defined as follows:

$$\mathbf{HeatIndex_y = HeatSales_{98} \times \frac{\left(HeatShare_y / Eff_y\right)}{\left(HeatShare_{98} / Eff_{98}\right)}}$$

In this expression, 1998 is defined as the base year. The ratio on the right is equal to 1.0 in 1998. As end-use saturation increases, the index increases; as efficiency increases, the index decreases. The starting heating sales estimate (HeatSales98) is derived from the EIA end-use forecast database for the southeast census region. Similarly, projections of saturation and efficiency changes are based on EIA's long-term outlook for the southeast region.

The heating variable XHeat is constructed by interacting the index variable (HeatIndex) with a variable that captures short-term stock utilization (HeatUse). Temperature data, prices, and regional output are incorporated into the HeatUse variable. The calculated heat utilization variable is computed as: follows:

$$\text{HeatUse}_{y,m} = \left(\frac{\text{HDD}_{y,m}}{\text{HDD}_{98}}\right) \times \left(\frac{\text{Output}_{y}}{\text{Output}_{98}}\right)^{0.20} \times \left(\frac{\text{Price}_{y,m}}{\text{Price}_{98}}\right)^{-0.20}$$

where:

HDD is the number of heating degree days in year (y) and month (m).

Output is real gross regional product in year (y) and month (m).

Price is the average real price of electricity in year (y) and month (m).

As constructed, HeatUse is also an index value with a value of 1.0 in 1998. Furthermore, in this functional form, the coefficients of 0.2 and -0.2 can be interpreted as elasticities. A 1.0 percent change in output will translate into a 0.2 percent increase in the HeatUse index. A 1.0 percent increase in real price will translate into a -0.2 percent change in HeatUse.

The cooling variable (XCool) is constructed in a similar manner. Cooling requirements are driven by the following:

- Cooling degree-days.
- Cooling equipment saturation levels.
- Cooling equipment operating efficiencies.
- Business activity (as captured by regional output).
- Price.

The following cooling variable is the product of an equipment-based index and monthly usage multiplier:

$$\text{CoolIndex}_{y} = \text{CoolSales}_{98} \times \frac{\left(\text{CoolShare}_{y} / \text{Eff}_{y}\right)}{\left(\text{CoolShare}_{98} / \text{Eff}_{98}\right)}$$

where:

CoolIndex$_y$ is an index of the cooling equipment.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Saturation and efficiency trends are derived from the EIA end-use database for the southeast census region. Given the nearly 100 percent saturation in air conditioning, the index is driven downwards by improving air conditioning efficiency.

The CoolUse variable is constructed similar to the HeatUse variable. CoolUse captures the interaction of temperature (*CDD*), regional output (*Output*), and price. The output and price elasticity are estimated be 0.2 and -0.2, respectively. The constructed use variable is defined as follows:

$$\mathbf{CoolUse}_{y,m} = \left(\frac{\mathbf{CDD}_{y,m}}{\mathbf{CDD}_{98}}\right) \times \left(\frac{\mathbf{Output}_{y}}{\mathbf{Output}_{98}}\right)^{0.20} \times \left(\frac{\mathbf{Price}_{y,m}}{\mathbf{Price}_{98}}\right)^{-0.20}$$

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (1998). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will vary to reflect changes in commercial output and prices.

Monthly estimates of nonweather sensitive sales can be derived in a similar fashion as space heating and cooling. Based on end-use concepts, other sales are driven by the following:

- Equipment saturation levels.
- Equipment efficiency levels.
- Average number of days in the billing cycle for each month.
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$\mathbf{XOther}_{y,m} = \mathbf{OtherIndex}_{y,m} \times \mathbf{OtherUse}_{y,m}$$

The first term embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$\mathbf{OtherIndex}_{y,m} = \sum_{Type} \mathbf{OtherSales}_{98}^{Type} \times \left(\frac{\mathbf{Share}_{y}^{Type} / \mathbf{Eff}_{y}^{Type}}{\mathbf{Share}_{98}^{Type} / \mathbf{Eff}_{98}^{Type}} \right)$$

where:

OtherSales represents starting base year non-HVAC sales.
Share represents saturation of other office equipment.
Eff is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the primary commercial non-HVAC end-uses. End-uses embedded in OtherIndex include lighting, water heating, cooking, refrigeration, office equipment, and miscellaneous equipment. The equipment categories are based on EIA categorizations. Economic drivers interact with the OtherIndex through the utilization variable OtherUse. OtherUse is defined as follows:

$$\mathbf{OtherUse}_{y,m} = \left(\frac{\mathbf{Output}_{y}}{\mathbf{Output}_{98}} \right)^{0.20} \times \left(\frac{\mathbf{Price}_{y,m}}{\mathbf{Price}_{98}} \right)^{-0.20}$$

A.1.2.1 GSND Sales Forecast. The GSND sales forecast is derived from a total sales forecast model where sales are specified as a function of regional output, (real) price, heating and cooling degree-days, and end-use indices to account for changes in commercial sector end-use saturation and efficiency.

A.1.2.2 GSND Sales Models. GSND sales models are estimated for OUC and St. Cloud. Both models explain historical monthly sales variations. The adjusted R^2 for the OUC GSND sales model is 0.98 and the adjusted R^2 for St. Cloud is 0.82. The estimated end-use variable coefficients are statistically significant at the 5 percent level of confidence in both models.

A.1.2.3 GSD Models. The GSD class represents the largest nonresidential customer class. Over the last 5 years, OUC has seen its strongest sales gains in this customer class, with GSD sales growth averaging 2.9 percent annually for the combined OUC and St. Cloud service territories. While overall sales growth will slow significantly over the forecast period, GSD sales are expected to continue a relatively strong sales growth through the forecast horizon.

The GSD models include XCool and XOther. Low t-statistics on the heating variables indicate that there is relatively little electric space heating in the GSD class. In the OUC model, XCool and XOther are highly significant with t-statistics over 2.0. The adjusted R^2 is 0.95 with an in-sample MAPE of 2.7 percent. The St. Cloud end-use variables are also statistically significant with t-statistics over 2.0. The St. Cloud model has an adjusted R^2 of .0.93 with a MAPE of 3.6 percent.

The eight largest OUC customers (GSLD) are backed out of OUC GSD sales data and forecasted separately. The companies include a defense contractor, the Orlando International Airport (OIA), two regional medical centers, a sewage treatment facility, the convention center, and two theme parks. Forecasts are based on discussions with customer support staff. For all customers, except the airport and the convention center, the sales forecasts are held constant at the 2004 level. The OIA and convention center forecasts are based on airport and convention center expansion plans. The GSLD forecast is combined with the other GSD forecast to develop a total GSD forecast.

OUC's own electric use (OUC Use) is also forecasted separately. The forecast is primarily driven by expected demand for OUC's chilled water cooling plants in the metropolitan Orlando area. OUC chiller-related electricity requirements are backed out of the GSD sales forecast since chilled water sales are expected to directly displace GSD air conditioning load.

A.1.2.3.1 Street Lighting Sales. Street lighting sales are forecasted using a simple regression model that relates street lighting sales to population projections. The model has an adjusted R^2 of 0.97 with a MAPE of 3.6 percent. The forecast also includes sales from the *OUC Convenient Lighting Program*, which targets outdoor lighting use. It is assumed that the Convenient Lighting Program will grow by about 2.5 GWh a year through the forecast period.

A.1.3 Hourly Load and Peak Forecast

In order to capture the load diversity across the two retail companies, separate system hourly load forecasts are estimated for OUC and St. Cloud. The hourly load forecasts are then combined to generate a total system hourly load forecast. Summer and winter peak demands are then calculated from the combined utility system hourly load forecast.

The system load profiles are based on a set of hourly load models using load data covering the January 1996 to December 2004 period. Historical hourly loads are first expressed as a percentage of the total daily energy as follows:

$$\textbf{Fraction}_{\textbf{dh}} = \textbf{Load}_{\textbf{hd}} \div \textbf{Energy}_{\textbf{d}}$$

where:

$Load_{hd}$ = the system load in hour (h) and day (d).
$Energy_d$ = the system energy in day (d).

Hourly fraction models are then estimated using the Ordinary Least Squares (OLS) regression where the hourly models are specified as a function of daily weather conditions, months, day of the week, and holidays. A second model is estimated for daily energy ($Energy_d$) where daily energy is specified as a function of daily temperatures, day of the week, holidays, seasons, and a trend variable to account for underlying growth over the estimation period.

The hourly fraction and daily energy models are used to simulate hourly fractions and daily energy for normal daily weather conditions. Normal daily temperatures are calculated by first ranking each year from the hottest to coldest day. The ranked data are then averaged to generate the hottest average temperature day to the coolest average temperature day. Daily normal temperatures are then mapped back to a representative calendar day based on a typical daily weather pattern. The hottest normal temperature is mapped to July and the coldest normal temperature to January.

Given weather normal hourly fractions (*WNFraction*) and weather normal daily energy (*WNDailyEnergy*), it is possible to calculate weather normal load for hour (h) in day (d) as follows:

$$\textbf{WNLoad}_{\textbf{dh}} = \textbf{WNFraction}_{\textbf{dh}} \times \textbf{WNDailyEnergyt}_{\textbf{dh}}$$

The system 8,760 hourly load forecast is generated by combining the weather normal system load shape with the energy forecast using *MetrixLT*. The energy forecast is allocated to each hour based on the weather normal hourly profile. Separate hourly load forecasts are derived for OUC and St. Cloud.

Under normal daily weather conditions OUC is just as likely to experience a winter peak as it is a summer peak. OUC experiences a "needle-like" peak in the winter months on the 1 or 2 days where the low temperature falls below freezing. The needle peak is largely driven by backup resistant heat built into the residential heat pumps.

A separate hourly load forecast is estimated for St. Cloud. Given that St. Cloud is dominated by the residential sector, St. Cloud is even more likely to peak during the winter season.

The hourly OUC and St. Cloud forecasts are aggregated to yield total system hourly load requirements. Forecasted seasonal peaks are then derived by finding the maximum hourly demand in January (for the winter peak) and July (for the summer peak).

A.2 Forecast Assumptions

The forecast is driven by a set of underlying demographic, economic, weather, and price assumptions. Given long-term economic uncertainty, the approach was to develop a set of reasonable, but conservative, set of forecast drivers.

A.2.1 Economics

The economic assumptions are derived from forecasts from Economy.com and the University of Florida. Economy.com's monthly economic forecast for the Orlando MSA is used to drive the forecast.

A.2.1.1 Employment and Regional Output. The nonresidential forecast models are driven by nonmanufacturing and regional output forecasts. Economy.com's employment forecasts were used. Table A-1 shows the annual employment and gross state product projections.

A.2.1.2 Population, Households, and Income. The primary economic drivers in the residential forecast model are population, the number of households, and real personal income. Economy.com's projections for the Orlando MSA were used, and the projections are presented in Table A-2.

A.2.2 Price Assumption

An aggregate retail price series was used as a proxy for effective prices in each of the model specifications. Since retail rates (across rate schedules) have generally moved in the same direction, an average retail price variable captures price movement across all the customer classes. The average annual price series is provided in Table A-3.

Table A-1
Employment and Gross Regional Output Projections – Orlando MSA

Year	Total Employment (thousands)	Nonmanufacturing Employment (thousands)	Gross Product (billion $)
1990	610.7	520.6	33.9
1995	714.3	631.9	41.5
2000	909.6	803.6	56.6
2005	992.7	882.5	63.7
2010	1,144.0	1,029.2	79.0
2015	1,339.0	1,212.0	98.0
2020	1,578.0	1,443.9	121.7
2025	1,830.0	1,665.5	149.2
Average Annual Increase			
90-95	3.2%	4.0%	4.1%
95-00	5.0%	4.9%	6.4%
00-05	1.8%	1.9%	2.4%
05-10	2.9%	3.1%	4.4%
10-15	3.2%	3.3%	4.4%
15-20	3.3%	3.6%	4.4%
20-25	3.0%	2.9%	4.2%

Table A-2 Population, Household, and Income Projections – Orlando MSA			
Year	Real Income per Household	Households (thousands)	Population (thousands)
1990	$59,818	501.0	1,240.6
1995	$60,505	542.7	1,428.3
2000	$71,064	629.7	1,656.3
2005	$71,650	718.0	1,879.5
2010	$74,532	813.1	2,097.8
2015	$77,879	942.1	2,385.0
2020	$81,241	1,095.5	2,739.8
2025	$85,068	1,248.9	3,118.6
Average Annual Increase			
90-95	0.2%	1.6%	2.9%
95-00	3.3%	3.0%	3.0%
00-05	0.2%	2.7%	2.6%
05-10	0.8%	2.5%	2.2%
10-15	0.9%	3.0%	2.6%
15-20	0.8%	3.1%	2.8%
20-25	0.9%	2.7%	2.6%

Table A-3
Historical and Forecasted Price Series
Average Annual Price

Year	Real Price (cents/kWh)
2000	5.3
2005	5.4
2010	5.3
2015	5.1
2020	4.8
2025	4.5
Annual Increase	
95-00	3.7%
00-05	0.4%
05-10	-0.4%
10-15	-0.8%
15-20	-1.2%
20-25	-1.3%

The price series is calculated by first deflating historical monthly revenues by the Consumer Price Index. Real revenues are then divided by retail sales to yield a monthly revenue per kWh value. Since revenue is itself a function of sales, it is inappropriate to regress sales directly on revenue per kWh. To generate a price series, a 12 month moving average of the real revenue per kWh series is calculated. This is a more appropriate price variable, as it assumes that households and businesses respond to changes in electricity prices that have occurred over the prior year.

A.2.3 Weather

Weather is a key factor affecting electricity consumption for indoor cooling and heating. Monthly CDDs are used to capture cooling requirements while HDDs account for variation in usage due to electric heating needs. CDDs and HDDs are calculated from the daily average temperatures for Orlando.

CDD is calculated using a 65° F base. First, a daily CDD is calculated as follows:

$$\mathbf{CDD_d = (AvgTemp_d - 65)\ when\ \ AvgTemp_d \rangle = 65}$$

CDD_d has a value equal to the average daily temperature minus 65 when the average daily temperature is greater than or equal to 65° F, and equals zero if average daily temperature is less than 65° F. The daily CDD values are then aggregated to yield a monthly CDD as follows:

$$\mathbf{CCD_m = \Sigma CDD_{md}}$$

For each month, a normal CDD estimate is calculated using a 10 year average of the monthly values calculated from 1995 through 2004:

$$\mathbf{CDD_{nm} = \Sigma CDD_m \div 10}$$

Heating degree-days are calculated in a similar manner. Daily HDD is first derived using a base temperature of 65° F as follows:

$$\mathbf{HDD_d = (65 - AvgTemp_d)\ when\ AvgTemp_d \langle = 65}$$

HDD_d equals 65° F minus the average daily temperature if the average daily temperature is less than or equal to 65° F, and equals zero if the daily temperature is greater than 65° F. Aggregate monthly HDD (HDD_m) is then calculated by summing daily HDD over each month:

$$HDD_m = \Sigma HDD_{md}$$

The monthly normal HDD is calculated as a 10 year average of the calendar month HDD as follows:

$$HDD_{nm} = \Sigma HDD_m \div 10$$

A.3 Base Case Load Forecast

A long-term annual budget forecast was developed through 2025. As outlined in the methodology section, the sales forecast is developed from a set of structured regression models that can be used for forecasting both monthly sales and customers for the forecast horizon. Forecast models are estimated for each of the major rate classifications including the following:

- Residential.
- GSND (small commercial customers).
- GSD (large commercial and industrial customers).
- Street lighting.

Models are estimated using monthly sales data covering the 1994 through 2004 period for the OUC residential model and the 1996 through 2004 period for the OUC nonresidential models; the shorter nonresidential estimation period is a result of customer migration from GSND to GSD prior to 1996. St. Cloud residential and GSD sales models are estimated using monthly data from 1996 through 2004; the GSND sales forecast model is estimated using monthly data from 1998 through 2004. Monthly sales data quality largely dictated the estimation period.

To support production-costing modeling, an 8,760 hourly load forecast is derived for each of the forecast years. The hourly load forecasts are based on a set of hourly and daily energy statistical models. The models are estimated from hourly system load data over the January 1996 to December 2004 period. A separate set of models is estimated for OUC and St. Cloud. Seasonal peak demand forecasts are derived as the maximum hourly demand forecast occurring in the summer and winter months. Table A-4 summarizes the annual net energy for load and seasonal peak demand forecasts for the combined OUC and St. Cloud service territories.

Table A-4
System Peak (Summer and Winter) and
Net Energy for Load (Total of OUC and St. Cloud)

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)	Load Factor (%)
1995	861	876	4,377	57.0%
2000	1,025	971	5,290	58.9%
2005	1,166	1,168	6,059	59.2%
2010	1,359	1,362	7,050	59.1%
2015	1,574	1,578	8,154	59.0%
2020	1,803	1,807	9,322	58.9%
2025	2,042	2,046	10,550	58.9%
Average Annual Increase				
95-00	3.5%	2.1%	3.9%	-
00-05	2.6%	3.8%	2.8%	-
05-10	3.1%	3.1%	3.1%	-
10-15	3.0%	3.0%	3.0%	-
15-20	2.8%	2.7%	2.7%	-
20-25	2.5%	2.5%	2.5%	-

A.3.1 Base Case Economic Outlook

Between 1995 and 2005, the population has grown at an average annual rate of 2.8 percent, and gross output has grown at an average annual rate of 4.4 percent. Orlando's economic growth has consistently exceeded economic growth in both the state and the nation. Orlando is expected to exceed overall state economic growth through the next 10 years.

Much of this growth has been fueled by significant gains in the service sector, which has seen employment expand by nearly 100 percent since 1990. Moreover, employment in the service sector accounts for over half of total employment. Hotels and tourism-related activities, as well as call centers, have continued to grow.

Two of the largest regional employers are Walt Disney and Universal Studios. Universal Studios has doubled in size with the addition of *Islands of Adventure*, *CityWalk*, and the related hotel complex. The expanded Orange County convention center opened in 2003, which will help increase regional convention and tourism activity.

To accommodate growing convention, tourism, and regional business activity, the OIA is anticipating a major expansion program that will ultimately double the capacity of the airport. In 2001, OIA served 28 million passengers. The airport saw a decrease in the number of passengers after September 11, 2001. In 2003, OIA served 27.3 million passengers, which was a 2.5 percent increase over the prior year and almost at pre-September 2001 levels. In 2004, OIA served 31.1 million passengers, exceeding pre-September 2001 levels. The OIA expects strong growth (in excess of 3.0 percent a year) over the next decade.

A.3.1.1 Economic Projections. Relatively inexpensive labor and housing costs and strong in-migration from both other states and other nations will continue to fuel the regional economic expansion long into the future. The number of households in the Orlando MSA is projected to increase from 629,700 in 2000 to 1,248,900 by 2025, representing an average annual growth rate of 2.8 percent. Employment is projected to grow at 2.8 percent over the same period.

Traditionally, the cost of doing business in Orlando has been below the average cost throughout the United States, with the cost of living in Orlando slightly lower than the average cost of living in the United States. The combination of these and other factors will sustain Orlando as one of the fastest growing metropolitan areas in the United States. Long-term growth will be driven by the high quality of life, the relatively low costs of both doing business and living, strong net migration, and an environment that is conducive to business development. Increasing concentrations of high-tech and medical-related industries will help to diversify the local economy.

Economic projections are based on Economy.com's economic outlook for Orlando and the State of Florida. Projections are in line with economic projections by the University of Florida.

A.3.2 Forecast Results

Based upon the previously discussed economic assumptions, total retail sales for OUC are expected to increase from 4,696 GWh in 2000 to 9,180 GWh by 2025. St. Cloud sales are projected to increase from 343 GWh to 1,012 GWh over this same time period.

A.3.2.1 Residential Forecast. With high electric end-use saturation and projected appliance efficiency-gains, residential average use is projected to increase relatively slowly over the forecast period. For OUC, average use per customer is forecasted to grow at 0.6 percent. Residential sales growth will be driven largely by the addition of new customers. With relatively strong population projections for the region, residential customers are expected to increase at an average annual rate of 2.7 percent for OUC and at a 3.7 percent for St. Cloud between 2000 and 2025. The OUC and St. Cloud residential sales forecasts are shown in Tables A-5 through A-8, respectively.

A.3.2.2 Small Commercial Sales Forecast. GSND sales are projected to grow at an average annual rate of 0.5 percent and 3.9 percent for OUC and St. Cloud, respectively, between 2000 and 2025. Projected GSND sales are driven by regional nonmanufacturing employment and output growth. Average use is projected to be relatively flat, particularly for OUC. Average use growth is partly constrained by size limitation; as customers exceed the 50 kW rate class cutoff, they migrate to the appropriate GSD rate. For OUC, average GSND use has actually trended downward over the last few years. Small commercial customer growth accounts for most of the GSND sales gains. The GSND customer forecast is driven by regional nonmanufacturing employment projections. The number of GSND customers is projected to grow at an average annual growth rate of 1.2 percent and 3.6 percent, respectively, for OUC and St. Cloud from 2000 through 2025. Tables A-5 through A-8 show annual GSND forecasts for OUC and St. Cloud.

A.3.2.3 Large Nonresidential Sales Forecast. GSD represents the largest commercial and industrial customers. GSD sales are expected to grow 2.8 percent between 2000 and 2005. While sales are projected to slow from this pace, sales are projected to continue to show relatively strong gains as a result of new major developments coming on line and overall strong regional output growth. Average use actually declines over the forecast period as smaller customers migrate from GSND to GSD. The GSD customer forecast is driven by total employment projections and total sales by projected regional gross output. Tables A-5 through A-8 summarize the annual GSD forecasts for OUC and St. Cloud.

Table A-5
OUC Long-Term Sales Forecast (GWh)

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1,380	316	2,157	27	--	55	3,935
2000	1,583	293	2,705	31	--	84	4,696
2005	1,820	271	3,112	38	9	121	5,371
2010	2,109	287	3,749	43	21	155	6,214
2015	2,502	303	4,105	47	34	159	7,150
2020	2,994	318	4,568	52	50	159	8,141
2025	3,529	334	5,039	57	62	159	9,180
Average Annual Increase							
95-00	2.8%	-1.5%	4.6%	2.8%	--	8.8%	3.6%
00-05	2.8%	-1.5%	2.8%	4.2%	--	7.6%	2.7%
05-10	3.0%	1.2%	3.8%	2.5%	18.5%	5.1%	3.0%
10-15	3.5%	1.1%	1.8%	1.8%	10.1%	0.5%	2.8%
15-20	3.7%	1.0%	2.2%	2.0%	8.0%	0.0%	2.6%
20-25	3.3%	1.0%	2.0%	1.9%	4.4%	0.0%	2.4%

Table A-6
OUC Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	108,702	14,572	2,965	126,239
2000	125,891	15,506	4,412	145,809
2005	141,788	16,959	5,360	163,107
2010	160,734	17,919	6,067	184,420
2015	185,719	18,944	6,948	211,611
2020	215,801	20,040	8,018	243,859
2025	245,860	21,153	9,135	276,148
Average Annual Increase				
95-00	3.0%	1.3%	8.3%	2.9%
00-05	2.4%	1.8%	4.0%	2.3%
05-10	2.5%	1.1%	2.5%	2.5%
10-15	3.0%	1.1%	2.7%	2.8%
15-20	3.0%	1.1%	2.9%	2.9%
20-25	2.6%	1.1%	2.6%	2.5%

Table A-7 St. Cloud Long-Term Sales Forecast (GWh)					
Year	Residential	GS Nondemand	GS Demand	St. Lighting	Total Retail
1995	180	19	56	-	254
2000	238	26	76	3	343
2005	328	31	101	4	464
2010	404	41	119	5	569
2015	504	50	138	5	697
2020	626	59	158	7	850
2025	759	68	177	8	1,012
Average Annual Increase					
95-00	5.7%	6.5%	6.3%	-	6.2%
00-05	6.6%	3.6%	5.9%	5.9%	6.2%
05-10	4.3%	5.8%	3.3%	4.6%	4.2%
10-15	4.5%	4.0%	3.0%	0.0%	4.1%
15-20	4.4%	3.4%	2.7%	5.4%	4.0%
20-25	3.9%	2.9%	2.3%	2.9%	3.6%

Table A-8
St. Cloud Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	13,659	1,293	120	15,072
2000	16,470	1,610	163	18,242
2005	21,646	2,214	229	24,089
2010	25,151	2,534	275	27,960
2015	29,902	2,933	322	33,157
2020	35,556	3,417	369	39,342
2025	41,204	3,922	415	45,541
Average Annual Increase				
95-00	3.8%	4.5%	6.3%	3.9%
00-05	5.6%	6.6%	7.0%	5.7%
05-10	3.0%	2.7%	3.7%	3.0%
10-15	3.5%	3.0%	3.2%	3.5%
15-20	3.5%	3.1%	2.8%	3.5%
20-25	3.0%	2.8%	2.4%	3.0%

A.4 Net Peak Demand and Net Energy for Load

Hourly load models are used to forecast the 8,760 hours of each of the forecast years. Underlying hourly load growth is driven by the aggregate energy forecast. Thus, forecasted peaks grow at roughly the same rate as the energy forecast. Tables A-9 and A-10 show seasonal peak demands and net energy for load forecasts for OUC and St. Cloud, respectively.

A.5 High and Low Load Scenarios

In addition to the base case, two long-term forecast scenarios contributed to the potential demand outcome. High and low case scenarios are based on long-term population trends projected by the University of Florida. The high and low forecast scenarios are based on the University of Florida's population projections for counties served by Orlando and St. Cloud. In the high case scenario, the population is forecasted to increase 3.4 percent on a compounded basis between 2005 and 2025. This compares with the University of Florida's base case population projections of 2.3 percent. The high population growth scenario results in a forecasted long-term annual energy growth rate of 3.9 percent, with system peak demand that is 486 MW higher than the base case by 2025. In the low case scenario, energy increases 1.7 percent on a compounded basis through 2025. Peak demand is 396 MW lower than the base case by 2025. The low case scenario assumes weak regional population growth, with the population growing just 1.2 percent over the forecast horizon. Table A-11 shows a comparison of the high, base, and low load scenarios.

Table A-9
OUC Net Peak Demand (Summer and Winter) and
Net Energy for Load (History and Forecast)

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2000	941	882	4,922
2005	1,051	1,049	5,568
2010	1,213	1,211	6,427
2015	1,393	1,391	7,381
2020	1,584	1,581	8,389
2025	1,784	1,780	9,449
Average Annual Increase			
95-00	3.4%	2.0%	3.7%
00-05	2.2%	3.5%	2.5%
05-10	2.9%	2.9%	2.9%
10-15	2.8%	2.8%	2.8%
15-20	2.6%	2.6%	2.6%
20-25	2.4%	2.4%	2.4%

Table A-10
St. Cloud Net Peak Demand (Summer and Winter) and
Net Energy for Load (History and Forecast)

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	63	76	274
2000	84	89	369
2005	115	119	491
2010	146	151	623
2015	181	187	773
2020	219	226	933
2025	258	266	1,101
Average Annual Increase			
95-00	5.9%	3.2%	6.1%
00-05	6.5%	6.0%	5.9%
05-10	4.9%	4.9%	4.9%
10-15	4.4%	4.4%	4.4%
15-20	3.9%	3.9%	3.8%
20-25	3.3%	3.3%	3.4%

Table A-11
Scenario Peak Forecasts
OUC and St. Cloud

High Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2005	1,166	1,168	6,059
2010	1,476	1,480	7,660
2015	1,788	1,793	9,206
2020	2,139	2,143	10,991
2025	2,527	2,532	12,985
Average Annual Increase			
05-10	4.8%	4.8%	4.8%
10-15	3.9%	3.9%	3.7%
15-20	3.6%	3.6%	3.6%
20-25	3.4%	3.4%	3.4%
Base Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2005	1,166	1,168	6,059
2010	1,359	1,362	7,050
2015	1,574	1,578	8,102
2020	1,803	1,807	9,267
2025	2,042	2,046	10,492
Average Annual Increase			
05-10	3.1%	3.1%	3.1%
10-15	3.0%	3.0%	2.8%
15-20	2.8%	2.7%	2.7%
20-25	2.5%	2.5%	2.5%
Low Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2005	1,166	1,168	6,059
2010	1,248	1,251	6,474
2015	1,388	1,391	7,144
2020	1,522	1,525	7,823
2025	1,647	1,650	8,462
Average Annual Increase			
05-10	1.4%	1.4%	1.3%
10-15	2.1%	2.1%	2.0%
15-20	1.9%	1.9%	1.8%
20-25	1.6%	1.6%	1.6%

Appendix B
Comparison of Delivered Coal Costs

Table B-1. Comparison of Coal Price Components (Real 2005 $/Ton)

Calender Year	Low Sulfur Central Appalachian			High Sulfur Northern Appalachian			Powder River Basin		
	Commodity Cost	Transportation Cost	Total Delivered Cost	Commodity Cost	Transportation Cost	Total Delivered Cost	Commodity Cost	Transportation Cost	Total Delivered Cost
2006	$47.79	$21.38	$69.17	$37.14	$24.83	$61.97	$11.34	$32.71	$44.05
2007	$41.62	$21.37	$62.99	$34.13	$24.81	$58.94	$9.18	$32.69	$41.87
2008	$40.11	$23.13	$63.24	$34.93	$26.57	$61.50	$8.28	$34.43	$42.71
2009	$39.57	$23.02	$62.59	$34.02	$26.45	$60.47	$8.33	$34.30	$42.63
2010	$38.94	$23.36	$62.30	$33.52	$26.78	$60.30	$8.39	$34.60	$42.99
2011	$39.30	$23.25	$62.55	$33.62	$26.66	$60.28	$8.45	$34.46	$42.91
2012	$39.74	$23.15	$62.89	$33.82	$26.55	$60.37	$8.51	$34.33	$42.84
2013	$39.95	$23.46	$63.41	$34.02	$26.85	$60.87	$8.57	$34.61	$43.18
2014	$40.28	$23.36	$63.64	$34.23	$26.74	$60.97	$8.64	$34.48	$43.12
2015	$40.70	$23.66	$64.36	$34.49	$27.03	$61.52	$8.71	$34.74	$43.45
2016	$41.09	$23.55	$64.64	$34.76	$26.91	$61.67	$8.78	$34.60	$43.38
2017	$41.49	$23.83	$65.32	$35.03	$27.18	$62.21	$8.85	$34.85	$43.70
2018	$41.89	$25.76	$67.65	$35.30	$29.43	$64.73	$8.92	$37.84	$46.76
2019	$42.31	$26.01	$68.32	$35.58	$29.68	$65.26	$8.99	$38.06	$47.05
2020	$42.79	$25.90	$68.69	$35.91	$29.55	$65.46	$9.06	$37.91	$46.97
2021	$43.27	$25.78	$69.05	$36.25	$29.42	$65.67	$9.11	$37.76	$46.87
2022	$43.77	$26.00	$69.77	$36.59	$29.64	$66.23	$9.16	$37.95	$47.11
2023	$44.27	$25.88	$70.15	$36.94	$29.51	$66.45	$9.21	$37.80	$47.01
2024	$44.78	$26.10	$70.88	$37.30	$29.71	$67.01	$9.26	$37.98	$47.24
2025	$45.31	$25.98	$71.29	$37.66	$29.58	$67.24	$9.31	$37.83	$47.14
2026	$45.84	$25.85	$71.69	$38.02	$29.45	$67.47	$9.36	$37.68	$47.04
2027	$46.39	$25.73	$72.12	$38.39	$29.32	$67.71	$9.42	$37.53	$46.95
2028	$46.94	$25.62	$72.56	$38.77	$29.19	$67.96	$9.47	$37.38	$46.85
2029	$47.51	$25.50	$73.01	$39.15	$29.07	$68.22	$9.53	$37.23	$46.76
2030	$48.09	$25.39	$73.48	$39.54	$28.95	$68.49	$9.58	$37.09	$46.67

Table B-2. Comparison of Coal Price Components (Real 2005 $/MBtu)

Calender Year	Low Sulfur Central Appalachian			High Sulfur Northern Appalachian			Powder River Basin		
	Commodity Cost	Transportation Cost	Total Delivered Cost	Commodity Cost	Transportation Cost	Total Delivered Cost	Commodity Cost	Transportation Cost	Total Delivered Cost
2006	$1.91	$0.86	$2.77	$1.43	$0.95	$2.38	$0.64	$1.86	$2.50
2007	$1.66	$0.85	$2.52	$1.31	$0.95	$2.27	$0.52	$1.86	$2.38
2008	$1.60	$0.93	$2.53	$1.34	$1.02	$2.37	$0.47	$1.96	$2.43
2009	$1.58	$0.92	$2.50	$1.31	$1.02	$2.33	$0.47	$1.95	$2.42
2010	$1.56	$0.93	$2.49	$1.29	$1.03	$2.32	$0.48	$1.97	$2.44
2011	$1.57	$0.93	$2.50	$1.29	$1.03	$2.32	$0.48	$1.96	$2.44
2012	$1.59	$0.93	$2.52	$1.30	$1.02	$2.32	$0.48	$1.95	$2.43
2013	$1.60	$0.94	$2.54	$1.31	$1.03	$2.34	$0.49	$1.97	$2.45
2014	$1.61	$0.93	$2.55	$1.32	$1.03	$2.35	$0.49	$1.96	$2.45
2015	$1.63	$0.95	$2.57	$1.33	$1.04	$2.37	$0.49	$1.97	$2.47
2016	$1.64	$0.94	$2.59	$1.34	$1.04	$2.37	$0.50	$1.97	$2.46
2017	$1.66	$0.96	$2.61	$1.35	$1.05	$2.39	$0.50	$1.98	$2.48
2018	$1.68	$1.03	$2.71	$1.36	$1.13	$2.49	$0.51	$2.15	$2.66
2019	$1.69	$1.04	$2.73	$1.37	$1.14	$2.51	$0.51	$2.16	$2.67
2020	$1.71	$1.04	$2.75	$1.38	$1.14	$2.52	$0.51	$2.15	$2.67
2021	$1.73	$1.03	$2.76	$1.39	$1.13	$2.53	$0.52	$2.15	$2.66
2022	$1.75	$1.04	$2.79	$1.41	$1.14	$2.55	$0.52	$2.16	$2.68
2023	$1.77	$1.04	$2.81	$1.42	$1.13	$2.56	$0.52	$2.15	$2.67
2024	$1.79	$1.04	$2.84	$1.43	$1.14	$2.58	$0.53	$2.16	$2.68
2025	$1.81	$1.04	$2.85	$1.45	$1.14	$2.59	$0.53	$2.15	$2.68
2026	$1.83	$1.03	$2.87	$1.46	$1.13	$2.59	$0.53	$2.14	$2.67
2027	$1.86	$1.03	$2.88	$1.48	$1.13	$2.60	$0.54	$2.13	$2.67
2028	$1.88	$1.02	$2.90	$1.49	$1.12	$2.61	$0.54	$2.12	$2.66
2029	$1.90	$1.02	$2.92	$1.51	$1.12	$2.62	$0.54	$2.12	$2.66
2030	$1.92	$1.02	$2.94	$1.52	$1.11	$2.63	$0.54	$2.11	$2.65

Appendix C
Sensitivity Analyses Results

Table C-1 Expansion Plan Economic Summary - With Stanton B - High Fuel Escalation

Case Description	
Fuel Forecast	High Escalation
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs)	30
Plant Life (yrs)	30

Generation Additions						
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B[1]	N/A	33	06/01	2010	[redacted]	
7FA CT	81,059	14	06/01	2015	103,862	8,474
PULVERIZED COAL UNIT	761,738	50	06/01	2018	1,093,663	89,232
7FA CT	81,059	14	06/01	2026	136,276	11,119
7EA CT	58,563	13	06/01	2029	105,911	8,641
LM6000 CT	44,879	12	06/01	2030	83,099	6,780

Year	Production Cost: Fuel and Energy Cost ($1,000)	O&M: Variable ($1,000)	O&M: Fixed[2] ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Capital Cost, DOE Contributions, and Other Stanton B Project Costs: Unit Capital Cost ($1,000)	OUC IGCC Demand Payment[3] ($1,000)	Project Completion Cost[4] ($1,000)	DOE Funding[5] ($1,000)	Startup Credit and Lease[6] ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]				$222,915	[redacted]						$222,915	$222,915
2007	[redacted]				$209,034	[redacted]						$209,034	$418,274
2008	[redacted]				$219,447	[redacted]						$219,447	$609,947
2009	[redacted]				$265,398	[redacted]						$265,398	$826,591
2010	[redacted]				$291,114	[redacted]						$309,845	$1,062,970
2011	[redacted]				$312,933	[redacted]						$344,458	$1,308,564
2012	[redacted]				$334,751	[redacted]						$364,810	$1,551,652
2013	[redacted]				$364,816	[redacted]						$399,912	$1,800,697
2014	[redacted]				$400,948	[redacted]						$446,263	$2,060,426
2015	[redacted]				$429,847	[redacted]						$478,273	$2,320,575
2016	[redacted]				$462,852	[redacted]						$514,745	$2,582,245
2017	[redacted]				$505,756	[redacted]						$557,636	$2,847,174
2018	[redacted]				$523,975	[redacted]						$628,235	$3,126,118
2019	[redacted]				$546,450	[redacted]						$687,730	$3,411,501
2020	[redacted]				$596,549	[redacted]						$737,648	$3,697,574
2021	[redacted]				$637,531	[redacted]						$778,712	$3,979,815
2022	[redacted]				$687,926	[redacted]						$829,160	$4,260,680
2023	[redacted]				$743,236	[redacted]						$884,365	$4,540,647
2024	[redacted]				$795,941	[redacted]						$937,105	$4,817,903
2025	[redacted]				$860,793	[redacted]						$1,001,919	$5,094,942
2026	[redacted]				$941,548	[redacted]						$1,089,078	$5,376,380
2027	[redacted]				$1,006,916	[redacted]						$1,159,095	$5,656,317
2028	[redacted]				$1,087,263	[redacted]						$1,239,385	$5,936,062
2029	[redacted]				$1,189,160	[redacted]						$1,346,158	$6,220,030
2030	[redacted]				$1,272,709	[redacted]						$1,437,421	$6,503,413

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.

Table C-2 Expansion Plan Economic Summary - Without Stanton B - High Fuel Escalation

Case Description	
Fuel Forecast:	High Escalation
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions						
Unit	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
7FA CT	81,059	14	06/01	2010	91,799	7,490
PULVERIZED COAL UNIT	761,738	50	06/01	2013	966,638	78,868
CFB UNIT	592,131	41	06/01	2021	906,474	73,959
7EA CT	58,563	13	06/01	2027	100,807	8,225
LMS100 CT	75,855	17	06/01	2028	134,074	10,939

	Production Cost					Capital Cost							
	Fuel and Energy	O&M			*Total*								Cumulative
Year	Cost ($1,000)	Variable ($1,000)	Fixed(1) ($1,000)	Start-Up ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Present Worth Cost ($1,000)
2006	$209,068	$11,924	$0	$1,923	$222,915	$0	$0	$0	$0	$0	$0	$222,915	$222,915
2007	$194,722	$12,917	$0	$1,395	$209,034	$0	$0	$0	$0	$0	$0	$209,034	$418,274
2008	$203,872	$14,442	$0	$1,133	$219,447	$0	$0	$0	$0	$0	$0	$219,447	$609,947
2009	$249,047	$15,575	$0	$776	$265,398	$0	$0	$0	$0	$0	$0	$265,398	$826,591
2010	$279,258	$16,961	$463	$922	$297,604	$7,490	$0	$0	$0	$0	$4,391	$301,995	$1,056,982
2011	$308,707	$19,177	$810	$1,143	$329,837	$7,490	$0	$0	$0	$0	$7,490	$337,327	$1,297,491
2012	$333,868	$20,231	$830	$1,027	$355,956	$7,490	$0	$0	$0	$0	$7,490	$363,446	$1,539,670
2013	$334,582	$19,284	$8,796	$2,535	$365,197	$86,358	$0	$0	$0	$0	$53,730	$418,928	$1,800,557
2014	$337,771	$18,001	$14,763	$3,454	$373,989	$86,358	$0	$0	$0	$0	$86,358	$460,347	$2,068,484
2015	$369,674	$19,293	$15,132	$3,629	$407,729	$86,358	$0	$0	$0	$0	$86,358	$494,087	$2,337,234
2016	$398,622	$20,405	$15,510	$3,525	$438,063	$86,358	$0	$0	$0	$0	$86,358	$524,421	$2,603,823
2017	$436,220	$22,071	$15,898	$3,993	$478,183	$86,358	$0	$0	$0	$0	$86,358	$564,541	$2,872,033
2018	$480,291	$23,417	$16,296	$3,572	$523,575	$86,358	$0	$0	$0	$0	$86,358	$609,933	$3,142,850
2019	$521,949	$25,035	$16,703	$3,990	$567,677	$86,358	$0	$0	$0	$0	$86,358	$654,035	$3,414,251
2020	$568,122	$27,563	$17,121	$4,744	$617,550	$86,358	$0	$0	$0	$0	$86,358	$703,908	$3,687,239
2021	$581,370	$32,510	$27,668	$5,313	$646,863	$160,317	$0	$0	$0	$0	$129,720	$776,583	$3,968,708
2022	$603,510	$35,305	$35,679	$7,212	$681,706	$160,317	$0	$0	$0	$0	$160,317	$842,024	$4,253,931
2023	$656,580	$37,437	$36,571	$8,689	$739,277	$160,317	$0	$0	$0	$0	$160,317	$899,594	$4,538,719
2024	$709,948	$39,558	$37,485	$8,247	$795,238	$160,317	$0	$0	$0	$0	$160,317	$955,555	$4,821,434
2025	$771,931	$41,993	$38,423	$8,635	$860,982	$160,317	$0	$0	$0	$0	$160,317	$1,021,299	$5,103,831
2026	$840,801	$44,747	$39,383	$8,861	$933,793	$160,317	$0	$0	$0	$0	$160,317	$1,094,110	$5,386,570
2027	$908,016	$47,680	$41,008	$8,495	$1,005,199	$168,542	$0	$0	$0	$0	$165,139	$1,170,338	$5,669,222
2028	$981,764	$50,328	$43,219	$9,609	$1,084,920	$179,481	$0	$0	$0	$0	$174,956	$1,259,875	$5,953,593
2029	$1,070,206	$53,839	$44,822	$11,287	$1,180,154	$179,481	$0	$0	$0	$0	$179,481	$1,359,635	$6,240,403
2030	$1,159,306	$57,305	$45,942	$10,450	$1,273,003	$179,481	$0	$0	$0	$0	$179,481	$1,452,484	$6,526,756

Notes:
(1) Fixed costs are included only for new unit additions.

Table C-3 Expansion Plan Economic Summary - With Stanton B - Low Fuel Escalation

Case Description	
Fuel Forecast	Low Escalation
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B[1]	N/A	33	06/01	2010	[redacted]	
7FA CT	81,059	14	06/01	2015	103,862	8,474
7FA CT	81,059	14	06/01	2018	111,848	9,126
7FA CT	81,059	14	06/01	2021	120,448	9,827
7FA CT	81,059	14	06/01	2024	129,710	10,583
7FA CT	81,059	14	06/01	2027	139,683	11,397
LMS100 CT	75,655	17	06/01	2029	137,426	11,213

	Production Cost					Capital Cost, DOE Contributions, and Other Stanton B Project Costs							
		O&M											
Year	Fuel and Energy Cost ($1,000)	Variable ($1,000)	Fixed[2] ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	OUC IGCC Demand Payment[3] ($1,000)	Project Completion Cost[4] ($1,000)	DOE Funding[5] ($1,000)	Startup Credit and Lease[6] ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]				$222,915	[redacted]						$222,915	$222,915
2007	[redacted]				$200,016	[redacted]						$200,016	$409,846
2008	[redacted]				$201,821	[redacted]						$201,821	$586,124
2009	[redacted]				$238,327	[redacted]						$238,327	$780,669
2010	[redacted]				$255,501	[redacted]						$275,171	$990,596
2011	[redacted]				$267,594	[redacted]						$301,051	$1,205,241
2012	[redacted]				$277,010	[redacted]						$309,381	$1,411,395
2013	[redacted]				$292,874	[redacted]						$322,750	$1,612,387
2014	[redacted]				$312,945	[redacted]						$358,259	$1,820,898
2015	[redacted]				$328,250	[redacted]						$376,658	$2,025,775
2016	[redacted]				$342,021	[redacted]						$393,913	$2,226,020
2017	[redacted]				$361,017	[redacted]						$412,898	$2,422,185
2018	[redacted]				$381,781	[redacted]						$439,016	$2,617,113
2019	[redacted]				$402,364	[redacted]						$463,327	$2,809,377
2020	[redacted]				$428,059	[redacted]						$488,920	$2,998,989
2021	[redacted]				$450,613	[redacted]						$517,248	$3,186,463
2022	[redacted]				$469,706	[redacted]						$540,421	$3,369,522
2023	[redacted]				$500,973	[redacted]						$571,564	$3,550,465
2024	[redacted]				$522,123	[redacted]						$599,115	$3,727,721
2025	[redacted]				$555,162	[redacted]						$636,521	$3,903,725
2026	[redacted]				$598,839	[redacted]						$680,051	$4,079,463
2027	[redacted]				$636,828	[redacted]						$724,920	$4,254,540
2028	[redacted]				$665,139	[redacted]						$757,890	$4,425,606
2029	[redacted]				$704,242	[redacted]						$803,456	$4,595,093
2030	[redacted]				$737,785	[redacted]						$841,730	$4,761,037

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.

Table C-4 Expansion Plan Economic Summary - Without Stanton B - Low Fuel Escalation

Case Description	
Fuel Forecast:	Low Escalation
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions						
Unit	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
7FA CT	81,059	14	06/01	2010	91,799	7,490
PULVERIZED COAL UNIT	761,738	50	06/01	2013	966,638	78,868
7FA CT	81,059	14	06/01	2021	120,448	9,827
7FA CT	81,059	14	06/01	2024	129,710	10,583
LMS100 CT	75,655	17	06/01	2027	130,804	10,672
7EA CT	58,563	13	06/01	2029	105,911	8,641
LM6000 CT	58,563	12	06/01	2030	108,439	8,848

	Production Cost					Capital Cost							
	Fuel and Energy	O&M			*Total*		Other	Other	Other	Other	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed(1) ($1,000)	Start-Up ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Capital Expenditures ($1,000)	Capital Expenditures ($1,000)	Capital Expenditures ($1,000)	Capital Expenditures ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$209,068	$11,924	$0	$1,923	$222,915	$0	$0	$0	$0	$0	$0	$222,915	$222,915
2007	$185,778	$12,892	$0	$1,345	$200,016	$0	$0	$0	$0	$0	$0	$200,016	$409,846
2008	$186,410	$14,385	$0	$1,026	$201,821	$0	$0	$0	$0	$0	$0	$201,821	$586,124
2009	$222,113	$15,537	$0	$677	$238,327	$0	$0	$0	$0	$0	$0	$238,327	$780,669
2010	$241,333	$16,950	$463	$800	$259,547	$7,490	$0	$0	$0	$0	$4,391	$263,938	$982,026
2011	$258,092	$19,162	$810	$916	$278,980	$7,490	$0	$0	$0	$0	$7,490	$286,470	$1,186,275
2012	$269,476	$20,139	$830	$836	$291,280	$7,490	$0	$0	$0	$0	$7,490	$298,770	$1,385,359
2013	$261,586	$19,252	$8,796	$1,892	$291,526	$86,358	$0	$0	$0	$0	$53,730	$345,257	$1,600,367
2014	$256,489	$17,955	$14,763	$2,422	$291,629	$86,358	$0	$0	$0	$0	$86,358	$377,987	$1,820,359
2015	$272,338	$19,280	$15,132	$2,654	$309,404	$86,358	$0	$0	$0	$0	$86,358	$395,762	$2,035,628
2016	$283,538	$20,401	$15,510	$2,419	$321,868	$86,358	$0	$0	$0	$0	$86,358	$408,226	$2,243,149
2017	$298,975	$22,087	$15,898	$2,574	$339,534	$86,358	$0	$0	$0	$0	$86,358	$425,892	$2,445,487
2018	$317,794	$23,596	$16,296	$2,170	$359,856	$86,358	$0	$0	$0	$0	$86,358	$446,214	$2,643,612
2019	$333,500	$25,363	$16,703	$2,329	$377,895	$86,358	$0	$0	$0	$0	$86,358	$464,253	$2,836,260
2020	$349,978	$27,848	$17,121	$2,676	$397,623	$86,358	$0	$0	$0	$0	$86,358	$483,981	$3,023,956
2021	$369,772	$31,053	$18,156	$2,299	$421,280	$96,185	$0	$0	$0	$0	$92,120	$513,400	$3,210,036
2022	$384,020	$32,190	$19,049	$2,459	$437,718	$96,185	$0	$0	$0	$0	$96,185	$533,903	$3,390,887
2023	$405,647	$35,230	$19,526	$2,623	$463,026	$96,185	$0	$0	$0	$0	$96,185	$559,211	$3,567,919
2024	$424,054	$37,658	$20,668	$2,404	$484,784	$106,768	$0	$0	$0	$0	$102,390	$587,174	$3,741,643
2025	$447,624	$41,356	$21,658	$2,356	$512,994	$106,768	$0	$0	$0	$0	$106,768	$619,763	$3,913,013
2026	$474,121	$45,910	$22,199	$2,494	$544,725	$106,768	$0	$0	$0	$0	$106,768	$651,493	$4,081,371
2027	$499,446	$50,076	$23,520	$2,198	$575,239	$117,441	$0	$0	$0	$0	$113,026	$688,264	$4,247,596
2028	$519,185	$52,009	$24,662	$2,176	$598,032	$117,441	$0	$0	$0	$0	$117,441	$715,472	$4,409,087
2029	$548,217	$57,044	$25,951	$2,476	$633,688	$126,082	$0	$0	$0	$0	$122,507	$756,196	$4,568,604
2030	$576,942	$60,962	$27,863	$2,531	$668,298	$134,929	$0	$0	$0	$0	$131,269	$799,567	$4,726,236

Notes:
(1) Fixed costs are included only for new unit additions.

Table C-5 Expansion Plan Economic Summary - With Stanton B - High Load and Energy Growth

Case Description	
Fuel Forecast	High Growth
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Generation Additions						
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B(1)	N/A	33	06/01	2010	[redacted]	[redacted]
7FA CT	81,059	14	06/01	2012	96,446	7,869
7FA CT	81,059	14	06/01	2014	101,329	8,267
7FA CT	81,059	14	06/01	2016	106,459	8,686
PULVERIZED COAL UNIT	761,738	50	06/01	2018	1,093,663	89,232
7FA CT	81,059	14	06/01	2023	126,546	10,325
7EA CT	58,563	13	06/01	2025	95,950	7,829
PULVERIZED COAL UNIT	761,738	50	06/01	2026	1,332,522	108,720
7EA CT	58,563	13	06/01	2030	108,558	8,857

	Production Cost					Capital Cost, DOE Funding, and Other Stanton B Project Costs							
	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed(2) ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	OUC IGCC Demand Payment(3) ($1,000)	Project Completion Cost(4) ($1,000)	DOE Funding(5) ($1,000)	Startup Credit and Lease(6) ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]	[redacted]	[redacted]	[redacted]	$230,016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$230,016	$230,016
2007	[redacted]	[redacted]	[redacted]	[redacted]	$217,263	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$217,263	$433,066
2008	[redacted]	[redacted]	[redacted]	[redacted]	$229,313	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$229,313	$633,356
2009	[redacted]	[redacted]	[redacted]	[redacted]	$276,486	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$276,486	$859,051
2010	[redacted]	[redacted]	[redacted]	[redacted]	$304,153	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$323,253	$1,105,659
2011	[redacted]	[redacted]	[redacted]	[redacted]	$323,283	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$355,477	$1,359,110
2012	[redacted]	[redacted]	[redacted]	[redacted]	$344,445	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$380,238	$1,612,478
2013	[redacted]	[redacted]	[redacted]	[redacted]	$374,491	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$414,967	$1,870,899
2014	[redacted]	[redacted]	[redacted]	[redacted]	$413,617	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$471,604	$2,145,377
2015	[redacted]	[redacted]	[redacted]	[redacted]	$449,342	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$508,862	$2,422,164
2016	[redacted]	[redacted]	[redacted]	[redacted]	$477,492	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$542,128	$2,697,754
2017	[redacted]	[redacted]	[redacted]	[redacted]	$520,334	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$588,468	$2,977,331
2018	[redacted]	[redacted]	[redacted]	[redacted]	$523,163	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$643,773	$3,263,174
2019	[redacted]	[redacted]	[redacted]	[redacted]	$538,708	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$696,261	$3,552,098
2020	[redacted]	[redacted]	[redacted]	[redacted]	$584,009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$741,426	$3,839,635
2021	[redacted]	[redacted]	[redacted]	[redacted]	$625,848	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$783,300	$4,123,539
2022	[redacted]	[redacted]	[redacted]	[redacted]	$669,480	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$826,943	$4,403,654
2023	[redacted]	[redacted]	[redacted]	[redacted]	$733,300	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$896,653	$4,687,511
2024	[redacted]	[redacted]	[redacted]	[redacted]	$785,832	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$953,543	$4,969,630
2025	[redacted]	[redacted]	[redacted]	[redacted]	$857,735	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,030,024	$5,254,440
2026	[redacted]	[redacted]	[redacted]	[redacted]	$879,864	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,119,052	$5,543,624
2027	[redacted]	[redacted]	[redacted]	[redacted]	$903,456	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,187,700	$5,830,470
2028	[redacted]	[redacted]	[redacted]	[redacted]	$972,804	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,257,020	$6,114,196
2029	[redacted]	[redacted]	[redacted]	[redacted]	$1,064,042	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,348,021	$6,398,556
2030	[redacted]	[redacted]	[redacted]	[redacted]	$1,139,867	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,429,162	$6,680,311

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.

Table C-6 Expansion Plan Economic Summary - Without Stanton B - High Load and Energy Growth

Case Description	
Fuel Forecast:	Base Case
Load Forecast	High Growth

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions

Unit	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
7FA CT	81,059	14	06/01	2010	91,799	7,490
7FA CT	81,059	14	06/01	2010	91,799	7,490
PULVERIZED COAL UNIT	761,738	50	06/01	2013	966,638	78,868
7FA CT	81,059	14	06/01	2018	111,848	9,126
PULVERIZED COAL UNIT	761,738	50	06/01	2020	1,149,029	93,749
1x1 7FA CC	213,127	30	06/01	2025	355,796	29,029
7EA CT	58,563	13	06/01	2028	103,327	8,430
7EA CT	58,563	13	06/01	2029	105,911	8,641
7EA CT	58,563	13	06/01	2030	108,558	8,857
LM6000 CT	44,879	12	06/01	2030	83,099	6,780

	Production Cost					Capital Cost							
	Fuel and Energy	O&M			*Total*						*Total*		Cumulative
Year	Cost ($1,000)	Variable ($1,000)	Fixed[1] ($1,000)	Start-Up ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	*Capital Cost ($1,000)*	Total System Cost ($1,000)	Present Worth Cost ($1,000)
2006	$215,787	$12,349	$0	$1,879	$230,016	$0	$0	$0	$0	$0	$0	$230,016	$230,016
2007	$202,176	$13,835	$0	$1,253	$217,263	$0	$0	$0	$0	$0	$0	$217,263	$433,066
2008	$212,465	$15,917	$0	$930	$229,313	$0	$0	$0	$0	$0	$0	$229,313	$633,356
2009	$258,130	$17,684	$0	$673	$276,486	$0	$0	$0	$0	$0	$0	$276,486	$859,051
2010	$291,129	$19,784	$926	$865	$312,703	$14,980	$0	$0	$0	$0	$8,783	$321,486	$1,104,311
2011	$319,618	$23,505	$1,619	$973	$345,716	$14,980	$0	$0	$0	$0	$14,980	$360,695	$1,361,482
2012	$344,984	$25,210	$1,660	$827	$372,680	$14,980	$0	$0	$0	$0	$14,980	$387,660	$1,619,796
2013	$340,899	$23,695	$9,647	$2,206	$376,447	$93,848	$0	$0	$0	$0	$61,220	$437,668	$1,892,354
2014	$340,917	$21,803	$15,635	$2,917	$381,273	$93,848	$0	$0	$0	$0	$93,848	$475,121	$2,168,878
2015	$370,737	$23,770	$16,026	$2,713	$413,246	$93,848	$0	$0	$0	$0	$93,848	$507,094	$2,444,704
2016	$399,128	$25,858	$16,426	$2,787	$444,199	$93,848	$0	$0	$0	$0	$93,848	$538,047	$2,718,219
2017	$434,225	$28,922	$16,837	$3,000	$482,984	$93,848	$0	$0	$0	$0	$93,848	$576,832	$2,992,268
2018	$475,823	$31,675	$17,822	$2,509	$527,829	$102,974	$0	$0	$0	$0	$99,198	$627,027	$3,270,675
2019	$518,010	$35,599	$18,676	$2,331	$574,616	$102,974	$0	$0	$0	$0	$102,974	$677,589	$3,551,851
2020	$526,278	$35,367	$28,588	$4,900	$595,132	$196,723	$0	$0	$0	$0	$157,939	$753,071	$3,843,905
2021	$526,933	$32,750	$36,133	$5,500	$601,317	$196,723	$0	$0	$0	$0	$196,723	$798,040	$4,133,151
2022	$567,318	$34,990	$37,037	$5,501	$644,846	$196,723	$0	$0	$0	$0	$196,723	$841,569	$4,418,219
2023	$615,963	$38,841	$37,963	$5,457	$698,224	$196,723	$0	$0	$0	$0	$196,723	$894,947	$4,701,537
2024	$663,866	$41,864	$38,912	$4,696	$749,339	$196,723	$0	$0	$0	$0	$196,723	$946,061	$4,981,442
2025	$705,214	$43,828	$47,529	$7,422	$803,994	$225,752	$0	$0	$0	$0	$213,743	$1,017,736	$5,262,855
2026	$762,917	$48,244	$53,975	$10,251	$875,388	$225,752	$0	$0	$0	$0	$225,752	$1,101,140	$5,547,410
2027	$824,312	$53,158	$55,051	$10,542	$943,063	$225,752	$0	$0	$0	$0	$225,752	$1,168,815	$5,829,694
2028	$888,486	$57,693	$56,810	$11,088	$1,014,077	$234,183	$0	$0	$0	$0	$230,695	$1,244,772	$6,110,656
2029	$968,550	$64,748	$59,103	$12,641	$1,105,042	$242,824	$0	$0	$0	$0	$239,249	$1,344,291	$6,394,230
2030	$1,050,897	$70,958	$62,257	$11,642	$1,195,754	$249,604	$0	$0	$0	$0	$243,135	$1,438,889	$6,677,902

Notes:
(1) Fixed costs are included only for new unit additions.

Table C-7 Expansion Plan Economic Summary - With Stanton B - Low Load and Energy Growth

Case Description	
Fuel Forecast	Base Case
Load Forecast	Low Growth

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Generation Additions						
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B[1]	N/A	33	06/01	2010	[redacted]	
7FA CT	81,059	14	06/01	2021	120,448	9,827
7EA CT	58,563	13	06/01	2027	100,807	8,225
LM6000 CT	44,879	12	06/01	2029	81,073	6,615

	Production Cost					Capital Cost, DOE Contributions, and Other Stanton B Project Costs							
		O&M											
Year	Fuel and Energy Cost ($1,000)	Variable ($1,000)	Fixed[2] ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	OUC IGCC Demand Payment[3] ($1,000)	Project Completion Cost[4] ($1,000)	DOE Funding[5] ($1,000)	Startup Credit and Lease[6] ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]				$217,307	[redacted]						$217,307	$217,307
2007					$194,762							$194,762	$399,328
2008					$194,804							$194,804	$569,477
2009					$228,055							$228,055	$755,637
2010					$243,360							$262,804	$956,129
2011					$257,860							$290,641	$1,163,352
2012					$268,966							$300,658	$1,363,693
2013					$283,948							$315,607	$1,560,237
2014					$305,093							$350,506	$1,764,235
2015					$317,681							$361,250	$1,960,731
2016					$331,654							$375,187	$2,151,457
2017					$348,815							$392,304	$2,337,838
2018					$371,243							$414,774	$2,522,002
2019					$390,639							$434,187	$2,702,175
2020					$417,754							$461,128	$2,881,008
2021					$433,667							$482,886	$3,056,028
2022					$455,415							$508,664	$3,228,331
2023					$482,098							$535,239	$3,397,773
2024					$501,767							$554,968	$3,561,968
2025					$528,866							$582,071	$3,722,916
2026					$565,556							$618,717	$3,882,804
2027					$592,488							$650,417	$4,039,888
2028					$620,114							$681,448	$4,193,700
2029					$658,191							$723,323	$4,346,282
2030					$683,595							$751,565	$4,494,451

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.

Table C-8 Expansion Plan Economic Summary - Without Stanton B - Low Load and Energy Growth

Case Description	
Fuel Forecast	Base Case
Load Forecast	Low Growth

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions

Unit	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
PULVERIZED COAL UNIT	761,738	50	06/01	2013	966,638	78,868
7EA CT	58,563	13	06/01	2028	103,327	8,430

Year	Production Cost: Fuel and Energy Cost ($1,000)	O&M: Variable ($1,000)	O&M: Fixed(1) ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Capital Cost: Unit Capital Cost ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$203,543	$11,739	$0	$2,025	$217,307	$0	$0	$0	$0	$0	$0	$217,307	$217,307
2007	$181,080	$12,154	$0	$1,528	$194,762	$0	$0	$0	$0	$0	$0	$194,762	$399,328
2008	$180,439	$13,044	$0	$1,321	$194,804	$0	$0	$0	$0	$0	$0	$194,804	$569,477
2009	$213,366	$13,649	$0	$1,040	$228,055	$0	$0	$0	$0	$0	$0	$228,055	$755,637
2010	$231,254	$14,354	$463	$1,253	$247,324	$0	$0	$0	$0	$0	$0	$247,324	$944,319
2011	$248,718	$16,008	$810	$1,325	$266,861	$0	$0	$0	$0	$0	$0	$266,861	$1,134,588
2012	$261,331	$16,319	$830	$952	$279,431	$0	$0	$0	$0	$0	$0	$279,431	$1,320,784
2013	$254,346	$15,824	$8,796	$2,877	$281,843	$78,868	$0	$0	$0	$0	$46,240	$328,084	$1,525,098
2014	$252,759	$15,199	$14,763	$4,385	$287,106	$78,868	$0	$0	$0	$0	$78,868	$365,974	$1,738,098
2015	$267,340	$15,825	$15,132	$4,047	$302,344	$78,868	$0	$0	$0	$0	$78,868	$381,212	$1,945,453
2016	$280,985	$16,564	$15,510	$4,390	$317,450	$78,868	$0	$0	$0	$0	$78,868	$396,318	$2,146,920
2017	$300,334	$17,789	$15,898	$4,567	$338,588	$78,868	$0	$0	$0	$0	$78,868	$417,456	$2,345,251
2018	$319,634	$18,345	$16,296	$3,644	$357,918	$78,868	$0	$0	$0	$0	$78,868	$436,786	$2,539,189
2019	$337,637	$19,328	$16,703	$3,824	$377,491	$78,868	$0	$0	$0	$0	$78,868	$456,359	$2,728,562
2020	$358,115	$20,632	$17,121	$3,978	$399,846	$78,868	$0	$0	$0	$0	$78,868	$478,714	$2,914,216
2021	$374,083	$21,746	$17,549	$3,702	$417,079	$78,868	$0	$0	$0	$0	$78,868	$495,947	$3,093,970
2022	$392,953	$22,501	$17,987	$3,840	$437,281	$78,868	$0	$0	$0	$0	$78,868	$516,149	$3,268,807
2023	$414,914	$23,886	$18,437	$4,536	$461,772	$78,868	$0	$0	$0	$0	$78,868	$540,640	$3,439,960
2024	$435,895	$24,754	$18,898	$3,964	$483,511	$78,868	$0	$0	$0	$0	$78,868	$562,379	$3,606,348
2025	$458,070	$25,904	$19,370	$3,946	$507,290	$78,868	$0	$0	$0	$0	$78,868	$586,158	$3,768,425
2026	$483,876	$27,598	$19,855	$4,394	$535,723	$78,868	$0	$0	$0	$0	$78,868	$614,591	$3,927,247
2027	$508,634	$28,911	$20,351	$3,758	$561,654	$78,868	$0	$0	$0	$0	$78,868	$640,522	$4,081,942
2028	$532,625	$29,983	$21,516	$4,155	$588,280	$87,299	$0	$0	$0	$0	$83,811	$672,090	$4,233,642
2029	$563,435	$32,023	$22,529	$4,797	$622,784	$87,299	$0	$0	$0	$0	$87,299	$710,083	$4,383,431
2030	$588,842	$33,065	$23,092	$4,073	$649,072	$87,299	$0	$0	$0	$0	$87,299	$736,371	$4,528,604

Notes:
(1) Fixed costs are included only for new unit additions.

Table C-9 Expansion Plan Economic Summary - With Stanton B - High Capital Costs

Case Description	
Fuel Forecast	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Generation Additions						
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B[1]	N/A	33	06/01	2010	[redacted]	
7FA CT	89,165	14	06/01	2015	114,249	9,322
7FA CT	89,165	14	06/01	2018	123,033	10,038
PULVERIZED COAL UNIT	837,912	50	06/01	2021	1,295,531	105,702
LM6000 CT	49,366	12	06/01	2029	89,180	7,276
7EA CT	64,420	13	06/01	2030	119,414	9,743

	Production Cost					Capital Cost, DOE Contributions, and Other Stanton B Project Costs							
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	OUC IGCC Demand Payment[3] ($1,000)	Project Completion Cost[4] ($1,000)	DOE Funding[5] ($1,000)	Startup Credit and Lease[6] ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]				$223,288	[redacted]							$223,288
2007	[redacted]				$204,538	[redacted]							$414,445
2008	[redacted]				$210,520	[redacted]							$598,322
2009	[redacted]				$251,505	[redacted]							$803,624
2010	[redacted]				$272,613	[redacted]							$1,026,358
2011	[redacted]				$289,337	[redacted]							$1,255,951
2012	[redacted]				$304,448	[redacted]							$1,479,902
2013	[redacted]				$326,798	[redacted]							$1,703,679
2014	[redacted]				$354,425	[redacted]							$1,936,458
2015	[redacted]				$376,110	[redacted]							$2,167,756
2016	[redacted]				$397,359	[redacted]							$2,396,675
2017	[redacted]				$426,816	[redacted]							$2,624,606
2018	[redacted]				$457,774	[redacted]							$2,853,988
2019	[redacted]				$490,550	[redacted]							$3,083,667
2020	[redacted]				$529,685	[redacted]							$3,313,443
2021	[redacted]				$530,587	[redacted]							$3,551,032
2022	[redacted]				$537,354	[redacted]							$3,790,243
2023	[redacted]				$571,885	[redacted]							$4,024,679
2024	[redacted]				$603,044	[redacted]							$4,253,015
2025	[redacted]				$642,875	[redacted]							$4,477,416
2026	[redacted]				$688,678	[redacted]							$4,698,931
2027	[redacted]				$723,221	[redacted]							$4,914,309
2028	[redacted]				$765,339	[redacted]							$5,125,087
2029	[redacted]				$823,302	[redacted]							$5,335,186
2030	[redacted]				$865,690	[redacted]							$5,541,643

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.

Table C-10 Expansion Plan Economic Summary - Without Stanton B - High Capital Costs

Case Description	
Fuel Forecast	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions

Unit	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
7FA CT	89,165	14	06/01	2010	100,979	8,239
PULVERIZED COAL UNIT	837,912	50	06/01	2013	1,063,302	86,755
7EA CT	64,420	13	06/01	2021	95,618	7,802
7FA CT	89,165	14	06/01	2023	139,201	11,357
1x1 7FA CC	234,439	30	06/01	2026	401,160	32,731

Year	Production Cost: Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed(1) ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Capital Cost: Unit Capital Cost ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$209,405	$11,947	$0	$1,936	$223,288	$0	$0	$0	$0	$0	$0	$223,288	$223,288
2007	$190,257	$12,914	$0	$1,367	$204,538	$0	$0	$0	$0	$0	$0	$204,538	$414,445
2008	$195,023	$14,405	$0	$1,093	$210,520	$0	$0	$0	$0	$0	$0	$210,520	$598,322
2009	$235,211	$15,565	$0	$729	$251,505	$0	$0	$0	$0	$0	$0	$251,505	$803,624
2010	$259,675	$16,942	$463	$883	$277,964	$8,239	$0	$0	$0	$0	$4,830	$282,794	$1,019,367
2011	$282,794	$19,150	$810	$1,038	$303,791	$8,239	$0	$0	$0	$0	$8,239	$312,030	$1,241,840
2012	$299,869	$20,130	$830	$916	$321,746	$8,239	$0	$0	$0	$0	$8,239	$329,985	$1,461,722
2013	$296,089	$19,222	$8,796	$2,254	$326,362	$94,994	$0	$0	$0	$0	$59,103	$385,465	$1,701,770
2014	$294,541	$17,985	$14,763	$3,034	$330,323	$94,994	$0	$0	$0	$0	$94,994	$425,317	$1,949,308
2015	$317,512	$19,292	$15,132	$3,167	$355,103	$94,994	$0	$0	$0	$0	$94,994	$450,097	$2,194,131
2016	$336,052	$20,362	$15,510	$3,006	$374,931	$94,994	$0	$0	$0	$0	$94,994	$469,925	$2,433,017
2017	$361,106	$22,057	$15,898	$3,290	$402,351	$94,994	$0	$0	$0	$0	$94,994	$497,345	$2,669,302
2018	$390,448	$23,489	$16,296	$2,900	$433,132	$94,994	$0	$0	$0	$0	$94,994	$528,126	$2,903,796
2019	$416,716	$25,173	$16,703	$3,112	$461,703	$94,994	$0	$0	$0	$0	$94,994	$556,697	$3,134,806
2020	$445,437	$27,660	$17,121	$3,630	$493,848	$94,994	$0	$0	$0	$0	$94,994	$588,842	$3,363,169
2021	$479,043	$30,737	$18,101	$3,127	$531,008	$102,795	$0	$0	$0	$0	$99,568	$630,575	$3,591,718
2022	$505,729	$31,862	$18,953	$3,247	$559,791	$102,795	$0	$0	$0	$0	$102,795	$662,586	$3,816,159
2023	$543,122	$34,773	$20,065	$3,783	$601,744	$114,153	$0	$0	$0	$0	$109,454	$711,198	$4,041,306
2024	$579,224	$37,394	$21,028	$3,607	$641,253	$114,153	$0	$0	$0	$0	$114,153	$755,406	$4,264,803
2025	$622,051	$40,807	$21,554	$3,590	$688,002	$114,153	$0	$0	$0	$0	$114,153	$802,154	$4,486,606
2026	$656,086	$42,739	$29,770	$7,792	$736,386	$146,883	$0	$0	$0	$0	$133,343	$869,729	$4,711,360
2027	$688,885	$44,253	$35,793	$8,673	$777,604	$146,883	$0	$0	$0	$0	$146,883	$924,487	$4,934,636
2028	$731,714	$46,975	$36,414	$9,735	$824,838	$146,883	$0	$0	$0	$0	$146,883	$971,721	$5,153,966
2029	$780,979	$50,630	$37,049	$10,477	$879,136	$146,883	$0	$0	$0	$0	$146,883	$1,026,019	$5,370,402
2030	$832,445	$54,555	$37,699	$10,908	$935,607	$146,883	$0	$0	$0	$0	$146,883	$1,082,490	$5,583,811

Notes:
(1) Fixed costs are included only for new unit additions.

Table C-11 Expansion Plan Economic Summary - With Stanton B - Gasification Ash Utilization

Case Description	
Fuel Forecast:	Base Case
Load Forecast:	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $:	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Generation Additions						
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B[1]	N/A	33	06/01	2010	[redacted]	
7FA CT	81,059	14	06/01	2015	103,862	8,474
7FA CT	81,059	14	06/01	2018	111,848	9,126
PULVERIZED COAL UNIT	761,738	50	06/01	2021	1,177,755	96,093
LM6000 CT	44,879	12	06/01	2029	81,073	6,615
7EA CT	58,563	13	06/01	2030	108,558	8,857

	Production Cost					Capital Cost, DOE Contributions, and Other Stanton B Project Costs							
	Fuel and Energy	O&M			*Total Production*		OUC	Project		Gasification Ash	*Total Capital*	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed[2] ($1,000)	Start-Up ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	IGCC Demand Payment[3] ($1,000)	Completion Cost[4] ($1,000)	DOE Funding[5] ($1,000)	Startup Credit and Lease[6] ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	[redacted]				$223,288	[redacted]						$223,288	$223,288
2007	[redacted]				$204,538	[redacted]						$204,538	$414,445
2008	[redacted]				$210,520	[redacted]						$210,520	$598,322
2009	[redacted]				$251,505	[redacted]						$251,505	$803,624
2010	[redacted]				$272,613	[redacted]						$291,115	$1,025,715
2011	[redacted]				$289,337	[redacted]						$320,776	$1,254,424
2012	[redacted]				$304,448	[redacted]						$334,728	$1,477,468
2013	[redacted]				$326,798	[redacted]						$357,831	$1,700,307
2014	[redacted]				$354,425	[redacted]						$398,336	$1,932,142
2015	[redacted]				$376,110	[redacted]						$422,948	$2,162,198
2016	[redacted]				$397,359	[redacted]						$447,516	$2,389,692
2017	[redacted]				$426,816	[redacted]						$476,843	$2,616,237
2018	[redacted]				$457,774	[redacted]						$513,033	$2,844,029
2019	[redacted]				$490,550	[redacted]						$549,444	$3,072,029
2020	[redacted]				$529,685	[redacted]						$588,410	$3,300,225
2021	[redacted]				$530,587	[redacted]						$645,821	$3,534,300
2022	[redacted]				$537,354	[redacted]						$692,473	$3,768,865
2023	[redacted]				$571,885	[redacted]						$726,792	$3,998,949
2024	[redacted]				$603,044	[redacted]						$757,863	$4,223,173
2025	[redacted]				$642,875	[redacted]						$797,572	$4,443,708
2026	[redacted]				$688,678	[redacted]						$843,182	$4,661,603
2027	[redacted]				$723,221	[redacted]						$877,646	$4,873,566
2028	[redacted]				$765,339	[redacted]						$919,574	$5,081,126
2029	[redacted]				$823,302	[redacted]						$981,291	$5,288,126
2030	[redacted]				$865,690	[redacted]						$1,031,513	$5,491,485

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups, facility lease payments, and credit for gasification ash.

Table C-12 Expansion Plan Economic Summary - With Stanton B - High Allowance Prices

Case Description	
Fuel Forecast	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

	Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B[1]	N/A	33	06/01	2010	[redacted]	[redacted]
7FA CT	81,059	14	06/01	2015	103,862	8,474
7FA CT	81,059	14	06/01	2018	111,848	9,126
PULVERIZED COAL UNIT	761,738	50	06/01	2021	1,177,755	96,093
LM6000 CT	44,879	12	06/01	2029	81,073	6,615
7EA CT	58,563	13	06/01	2030	108,558	8,857

	Production Cost					Capital Cost, DOE Contributions, and Other Stanton B Project Costs							
	Fuel and Energy	O&M			*Total*		OUC	Project			*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed[2] ($1,000)	Start-Up ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	IGCC Demand Payment[3] ($1,000)	Completion Cost[4] ($1,000)	DOE Funding[5] ($1,000)	Startup Credit and Lease[6] ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	[redacted]	[redacted]	[redacted]	[redacted]	$223,288	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$223,288	$223,288
2007	[redacted]	[redacted]	[redacted]	[redacted]	$204,538	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$204,538	$414,445
2008	[redacted]	[redacted]	[redacted]	[redacted]	$210,520	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$210,520	$598,322
2009	[redacted]	[redacted]	[redacted]	[redacted]	$259,379	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$259,379	$810,052
2010	[redacted]	[redacted]	[redacted]	[redacted]	$281,789	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$300,829	$1,039,553
2011	[redacted]	[redacted]	[redacted]	[redacted]	$298,513	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$330,840	$1,275,437
2012	[redacted]	[redacted]	[redacted]	[redacted]	$315,747	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$346,953	$1,506,626
2013	[redacted]	[redacted]	[redacted]	[redacted]	$338,331	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$371,138	$1,737,753
2014	[redacted]	[redacted]	[redacted]	[redacted]	$365,449	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$410,764	$1,976,821
2015	[redacted]	[redacted]	[redacted]	[redacted]	$389,094	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$437,502	$2,214,793
2016	[redacted]	[redacted]	[redacted]	[redacted]	$410,590	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$462,483	$2,449,896
2017	[redacted]	[redacted]	[redacted]	[redacted]	$439,907	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$491,787	$2,683,540
2018	[redacted]	[redacted]	[redacted]	[redacted]	$471,671	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$528,906	$2,918,380
2019	[redacted]	[redacted]	[redacted]	[redacted]	$504,824	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$565,787	$3,153,162
2020	[redacted]	[redacted]	[redacted]	[redacted]	$544,992	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$605,815	$3,388,107
2021	[redacted]	[redacted]	[redacted]	[redacted]	$544,968	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$662,297	$3,628,154
2022	[redacted]	[redacted]	[redacted]	[redacted]	$552,087	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$709,335	$3,868,430
2023	[redacted]	[redacted]	[redacted]	[redacted]	$586,999	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$744,051	$4,103,978
2024	[redacted]	[redacted]	[redacted]	[redacted]	$618,508	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$775,636	$4,333,461
2025	[redacted]	[redacted]	[redacted]	[redacted]	$659,457	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$816,547	$4,559,243
2026	[redacted]	[redacted]	[redacted]	[redacted]	$705,791	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$862,720	$4,782,186
2027	[redacted]	[redacted]	[redacted]	[redacted]	$742,077	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$899,055	$4,999,319
2028	[redacted]	[redacted]	[redacted]	[redacted]	$784,266	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$941,170	$5,211,754
2029	[redacted]	[redacted]	[redacted]	[redacted]	$841,604	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,002,361	$5,423,199
2030	[redacted]	[redacted]	[redacted]	[redacted]	$886,305	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,055,077	$5,631,204

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.

Table C-13 Expansion Plan Economic Summary - Without Stanton B - High Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escelation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions						
Unit	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
7FA CT	81,059	14	06/01	2010	91,799	7,490
PULVERIZED COAL UNIT	761,738	50	06/01	2013	966,638	78,868
7EA CT	58,563	13	06/01	2021	86,926	7,092
7FA CT	81,059	14	06/01	2023	126,546	10,325
1x1 7FA CC	213,127	30	06/01	2026	364,691	29,755

	Production Cost					Capital Cost							
	Fuel and Energy	O&M			*Total Production*	Unit Capital	Other Capital	Other Capital	Other Capital	Other Capital	*Total Capital*	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed(1) ($1,000)	Start-Up ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Expenditures ($1,000)	Expenditures ($1,000)	Expenditures ($1,000)	Expenditures ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$209,405	$11,947	$0	$1,936	$223,288	$0	$0	$0	$0	$0	$0	$223,288	$223,288
2007	$190,257	$12,914	$0	$1,367	$204,538	$0	$0	$0	$0	$0	$0	$204,538	$414,445
2008	$195,023	$14,405	$0	$1,093	$210,520	$0	$0	$0	$0	$0	$0	$210,520	$598,322
2009	$242,961	$15,689	$0	$730	$259,379	$0	$0	$0	$0	$0	$0	$259,379	$810,052
2010	$269,003	$17,072	$463	$879	$287,417	$7,490	$0	$0	$0	$0	$4,391	$291,809	$1,032,672
2011	$292,827	$19,323	$810	$1,039	$313,999	$7,490	$0	$0	$0	$0	$7,490	$321,489	$1,261,889
2012	$311,461	$20,460	$830	$912	$333,663	$7,490	$0	$0	$0	$0	$7,490	$341,153	$1,489,213
2013	$307,057	$19,465	$8,796	$2,249	$337,568	$86,358	$0	$0	$0	$0	$53,730	$391,298	$1,732,894
2014	$305,142	$18,018	$14,763	$2,942	$340,865	$86,358	$0	$0	$0	$0	$86,358	$427,223	$1,981,542
2015	$329,651	$19,407	$15,132	$3,228	$367,418	$86,358	$0	$0	$0	$0	$86,358	$453,776	$2,228,366
2016	$348,835	$20,552	$15,510	$3,061	$387,959	$86,358	$0	$0	$0	$0	$86,358	$474,317	$2,469,484
2017	$373,929	$22,248	$15,898	$3,300	$415,375	$86,358	$0	$0	$0	$0	$86,358	$501,733	$2,707,854
2018	$403,711	$23,699	$16,296	$2,892	$446,598	$86,358	$0	$0	$0	$0	$86,358	$532,955	$2,944,493
2019	$430,836	$25,471	$16,703	$3,339	$476,349	$86,358	$0	$0	$0	$0	$86,358	$562,707	$3,177,996
2020	$460,074	$27,890	$17,121	$3,634	$508,719	$86,358	$0	$0	$0	$0	$86,358	$595,077	$3,408,777
2021	$494,466	$30,942	$18,101	$3,112	$546,622	$93,450	$0	$0	$0	$0	$90,516	$637,138	$3,639,705
2022	$522,424	$32,125	$18,953	$3,281	$576,783	$93,450	$0	$0	$0	$0	$93,450	$670,233	$3,866,736
2023	$560,351	$35,052	$20,065	$3,733	$619,201	$103,775	$0	$0	$0	$0	$99,504	$718,705	$4,094,260
2024	$596,615	$37,635	$21,028	$3,576	$658,854	$103,775	$0	$0	$0	$0	$103,775	$762,629	$4,319,894
2025	$640,520	$41,119	$21,554	$3,538	$706,730	$103,775	$0	$0	$0	$0	$103,775	$810,505	$4,544,006
2026	$674,295	$42,813	$29,770	$7,699	$754,577	$133,530	$0	$0	$0	$0	$121,221	$875,797	$4,770,328
2027	$708,226	$44,509	$35,793	$8,684	$797,213	$133,530	$0	$0	$0	$0	$133,530	$930,743	$4,995,115
2028	$751,916	$47,216	$36,414	$9,710	$845,256	$133,530	$0	$0	$0	$0	$133,530	$978,786	$5,216,040
2029	$801,690	$50,753	$37,049	$10,398	$899,890	$133,530	$0	$0	$0	$0	$133,530	$1,033,420	$5,434,037
2030	$854,286	$54,714	$37,699	$10,901	$957,598	$133,530	$0	$0	$0	$0	$133,530	$1,091,129	$5,649,149

Notes:
(1) Fixed costs are included only for new unit additions.

Table C-14 Expansion Plan Economic Summary - With Stanton B - Low Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast:	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Generation Additions						
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B[1]	N/A	33	06/01	2010	[redacted]	[redacted]
7FA CT	81,059	14	06/01	2015	103,862	8,474
7FA CT	81,059	14	06/01	2018	111,848	9,126
PULVERIZED COAL UNIT	761,738	50	06/01	2021	1,177,755	96,093
LM6000 CT	44,879	12	06/01	2029	81,073	6,615
7EA CT	58,563	13	06/01	2030	108,558	8,857

	Production Cost					Capital Cost, DOE Contributions, and Other Stanton B Project Costs							
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	OUC IGCC Demand Payment[3] ($1,000)	Project Completion Cost[4] ($1,000)	DOE Funding[5] ($1,000)	Startup Credit and Lease[6] ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]	[redacted]	[redacted]	[redacted]	$223,288	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$223,288	$223,288
2007	[redacted]	[redacted]	[redacted]	[redacted]	$204,538	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$204,538	$414,445
2008	[redacted]	[redacted]	[redacted]	[redacted]	$210,520	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$210,520	$598,322
2009	[redacted]	[redacted]	[redacted]	[redacted]	$245,841	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$245,841	$799,001
2010	[redacted]	[redacted]	[redacted]	[redacted]	$262,809	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$282,332	$1,014,391
2011	[redacted]	[redacted]	[redacted]	[redacted]	$279,636	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$312,612	$1,237,279
2012	[redacted]	[redacted]	[redacted]	[redacted]	$293,192	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$324,854	$1,453,743
2013	[redacted]	[redacted]	[redacted]	[redacted]	$315,785	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$347,000	$1,669,837
2014	[redacted]	[redacted]	[redacted]	[redacted]	$342,721	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$387,996	$1,895,654
2015	[redacted]	[redacted]	[redacted]	[redacted]	$362,240	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$410,688	$2,119,041
2016	[redacted]	[redacted]	[redacted]	[redacted]	$383,540	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$435,433	$2,340,393
2017	[redacted]	[redacted]	[redacted]	[redacted]	$412,232	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$464,112	$2,560,889
2018	[redacted]	[redacted]	[redacted]	[redacted]	$443,039	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$500,286	$2,783,022
2019	[redacted]	[redacted]	[redacted]	[redacted]	$473,621	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$534,584	$3,004,856
2020	[redacted]	[redacted]	[redacted]	[redacted]	$514,507	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$575,329	$3,227,978
2021	[redacted]	[redacted]	[redacted]	[redacted]	$514,803	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$632,119	$3,457,087
2022	[redacted]	[redacted]	[redacted]	[redacted]	$523,407	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$680,655	$3,687,649
2023	[redacted]	[redacted]	[redacted]	[redacted]	$556,841	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$713,921	$3,913,658
2024	[redacted]	[redacted]	[redacted]	[redacted]	$587,195	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$744,323	$4,133,876
2025	[redacted]	[redacted]	[redacted]	[redacted]	$626,123	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$783,212	$4,350,441
2026	[redacted]	[redacted]	[redacted]	[redacted]	$669,784	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$826,713	$4,564,079
2027	[redacted]	[redacted]	[redacted]	[redacted]	$703,383	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$860,416	$4,771,881
2028	[redacted]	[redacted]	[redacted]	[redacted]	$745,989	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$902,893	$4,975,676
2029	[redacted]	[redacted]	[redacted]	[redacted]	$802,849	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$963,549	$5,178,933
2030	[redacted]	[redacted]	[redacted]	[redacted]	$843,825	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,012,597	$5,378,563

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.

Table C-15 Expansion Plan Economic Summary - Without Stanton B - Low Allowance Prices

Case Description	
Fuel Forecast	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions

Unit	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
7FA CT	81,059	14	06/01	2010	91,799	7,490
PULVERIZED COAL UNIT	761,738	50	06/01	2013	966,638	78,868
7EA CT	58,563	13	06/01	2021	86,926	7,092
7FA CT	81,059	14	06/01	2023	126,546	10,325
1x1 7FA CC	213,127	30	06/01	2026	364,691	29,755

Year	Production Cost					Capital Cost						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] ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	*Total Capital Cost ($1,000)*		
2006	$209,405	$11,947	$0	$1,936	$223,288	$0	$0	$0	$0	$0	$0	$223,288	$223,288
2007	$190,257	$12,914	$0	$1,367	$204,538	$0	$0	$0	$0	$0	$0	$204,538	$414,445
2008	$195,023	$14,405	$0	$1,093	$210,520	$0	$0	$0	$0	$0	$0	$210,520	$598,322
2009	$229,428	$15,684	$0	$728	$245,841	$0	$0	$0	$0	$0	$0	$245,841	$799,001
2010	$249,148	$16,770	$463	$882	$267,264	$7,490	$0	$0	$0	$0	$4,391	$271,656	$1,006,246
2011	$272,230	$19,120	$810	$1,079	$293,239	$7,490	$0	$0	$0	$0	$7,490	$300,729	$1,220,661
2012	$288,104	$20,057	$830	$915	$309,906	$7,490	$0	$0	$0	$0	$7,490	$317,396	$1,432,155
2013	$285,621	$19,224	$8,796	$2,258	$315,899	$86,358	$0	$0	$0	$0	$53,730	$369,629	$1,662,342
2014	$283,096	$17,876	$14,763	$3,035	$318,770	$86,358	$0	$0	$0	$0	$86,358	$405,128	$1,898,130
2015	$305,170	$19,185	$15,132	$3,113	$342,601	$86,358	$0	$0	$0	$0	$86,358	$428,959	$2,131,455
2016	$323,178	$20,257	$15,510	$3,006	$361,952	$86,358	$0	$0	$0	$0	$86,358	$448,310	$2,359,353
2017	$347,769	$21,925	$15,898	$3,281	$388,873	$86,358	$0	$0	$0	$0	$86,358	$475,231	$2,585,132
2018	$376,635	$23,301	$16,296	$2,907	$419,139	$86,358	$0	$0	$0	$0	$86,358	$505,497	$2,809,579
2019	$401,722	$24,846	$16,703	$3,119	$446,390	$86,358	$0	$0	$0	$0	$86,358	$532,748	$3,030,650
2020	$430,103	$27,381	$17,121	$3,646	$478,249	$86,358	$0	$0	$0	$0	$86,358	$564,607	$3,249,614
2021	$462,966	$30,499	$18,101	$3,118	$514,685	$93,450	$0	$0	$0	$0	$90,516	$605,201	$3,468,967
2022	$489,508	$31,669	$18,953	$3,244	$543,374	$93,450	$0	$0	$0	$0	$93,450	$636,824	$3,684,682
2023	$526,529	$34,734	$20,065	$3,840	$585,169	$103,775	$0	$0	$0	$0	$99,504	$684,672	$3,901,431
2024	$561,365	$37,327	$21,028	$3,815	$623,535	$103,775	$0	$0	$0	$0	$103,775	$727,310	$4,116,616
2025	$603,022	$40,633	$21,554	$3,680	$668,889	$103,775	$0	$0	$0	$0	$103,775	$772,664	$4,330,264
2026	$635,824	$42,544	$29,770	$7,890	$716,028	$133,530	$0	$0	$0	$0	$121,221	$837,248	$4,546,625
2027	$668,871	$44,155	$35,793	$8,713	$757,532	$133,530	$0	$0	$0	$0	$133,530	$891,062	$4,761,828
2028	$710,929	$46,866	$36,414	$9,777	$803,986	$133,530	$0	$0	$0	$0	$133,530	$937,516	$4,973,438
2029	$759,960	$50,622	$37,049	$10,535	$858,167	$133,530	$0	$0	$0	$0	$133,530	$991,697	$5,182,633
2030	$810,500	$54,500	$37,699	$10,948	$913,647	$133,530	$0	$0	$0	$0	$133,530	$1,047,177	$5,389,081

Notes:
(1) Fixed costs are included only for new unit additions.

Table C-16 Expansion Plan Economic Summary - With Stanton B - No Allowances in Dispatch

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B(1)	N/A	33	06/01	2010	[redacted]	
7FA CT	81,059	14	06/01	2015	103,862	8,474
7FA CT	81,059	14	06/01	2018	111,848	9,126
7FA CT	81,059	14	06/01	2021	120,448	9,827
PULVERIZED COAL UNIT	761,738	50	06/01	2024	1,268,313	103,482
					0	0

Year	Production Cost: Fuel and Energy Cost ($1,000)	Production Cost: O&M Variable ($1,000)	Production Cost: O&M Fixed(2) ($1,000)	Production Cost: Start-Up ($1,000)	Production Cost: Emission Costs ($1000)	Production Cost: *Total Production Cost* *($1,000)*	Capital Cost, DOE Contributions, and Other Stanton B Project Costs: Unit Capital Cost ($1,000)	OUC IGCC Demand Payment(3) ($1,000)	Project Completion Cost(4) ($1,000)	DOE Funding(5) ($1,000)	Startup Credit and Lease(6) ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$223,288	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$223,288	$223,288
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$204,538	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$204,538	$414,445
2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$210,520	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$210,520	$598,322
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$251,685	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$251,685	$803,771
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$273,663	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$294,170	$1,028,192
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$294,542	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$331,006	$1,264,195
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$307,276	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$340,817	$1,491,296
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$330,809	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$355,450	$1,712,652
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$357,045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$402,303	$1,946,796
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$378,206	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$426,636	$2,178,858
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$399,115	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$450,971	$2,408,109
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$428,995	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$480,833	$2,636,549
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$461,179	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$518,339	$2,866,698
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$492,739	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$553,601	$3,096,423
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$532,510	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$593,241	$3,326,492
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$568,876	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$635,591	$3,556,859
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$603,560	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$674,145	$3,785,216
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$654,743	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$725,249	$4,014,811
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$639,258	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$813,224	$4,255,415
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$647,209	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$821,374	$4,482,531
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$698,840	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$872,827	$4,708,086
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$731,374	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$905,514	$4,926,780
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$770,933	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$944,972	$5,140,072
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$828,783	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$959,859	$5,342,552
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$871,476	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,045,416	$5,548,652

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, rail cars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.

Table C-17 Expansion Plan Economic Summary - Without Stanton B - No Allowances in Dispatch

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions

Unit	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
7FA CT	81,059	14	06/01	2010	91,799	7,490
PULVERIZED COAL UNIT	761,738	50	06/01	2013	966,638	78,868
7EA CT	58,563	13	06/01	2021	86,926	7,092
7FA CT	81,059	14	06/01	2023	126,546	10,325
1x1 7FA CC	213,127	30	06/01	2026	364,691	29,755

Year	Production Cost					Capital Cost						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] ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	Other Capital Expenditures ($1,000)	*Total Capital Cost ($1,000)*		
2006	$209,405	$11,947	$0	$1,936	$223,288	$0	$0	$0	$0	$0	$0	$223,288	$223,288
2007	$190,257	$12,914	$0	$1,367	$204,538	$0	$0	$0	$0	$0	$0	$204,538	$414,445
2008	$195,023	$14,405	$0	$1,093	$210,520	$0	$0	$0	$0	$0	$0	$210,520	$598,322
2009	$207,029	$15,494	$0	$784	$251,685	$0	$0	$0	$0	$0	$0	$251,685	$803,771
2010	$221,058	$16,899	$463	$956	$278,769	$7,490	$0	$0	$0	$0	$4,391	$283,161	$1,019,793
2011	$240,780	$19,130	$810	$1,075	$304,590	$7,490	$0	$0	$0	$0	$7,490	$312,080	$1,242,302
2012	$255,066	$20,199	$830	$933	$323,310	$7,490	$0	$0	$0	$0	$7,490	$330,800	$1,462,728
2013	$251,974	$18,997	$8,796	$2,214	$329,980	$86,358	$0	$0	$0	$0	$53,730	$383,710	$1,701,684
2014	$250,911	$17,921	$14,763	$4,185	$339,659	$86,358	$0	$0	$0	$0	$86,358	$426,017	$1,949,630
2015	$265,687	$18,747	$15,132	$3,080	$359,293	$86,358	$0	$0	$0	$0	$86,358	$445,651	$2,192,034
2016	$282,811	$19,934	$15,510	$3,475	$380,692	$86,358	$0	$0	$0	$0	$86,358	$467,050	$2,429,459
2017	$306,185	$21,706	$15,898	$3,595	$408,100	$86,358	$0	$0	$0	$0	$86,358	$494,458	$2,664,372
2018	$333,076	$23,003	$16,296	$3,098	$438,387	$86,358	$0	$0	$0	$0	$86,358	$524,745	$2,897,365
2019	$356,393	$24,623	$16,703	$3,335	$466,447	$86,358	$0	$0	$0	$0	$86,358	$552,805	$3,126,760
2020	$383,033	$27,087	$17,121	$4,010	$498,721	$86,358	$0	$0	$0	$0	$86,358	$585,079	$3,353,663
2021	$412,586	$30,145	$18,101	$3,125	$534,574	$93,450	$0	$0	$0	$0	$90,516	$625,090	$3,580,225
2022	$437,152	$31,325	$18,953	$3,286	$563,868	$93,450	$0	$0	$0	$0	$93,450	$657,319	$3,802,882
2023	$474,072	$34,697	$20,065	$4,225	$608,499	$103,775	$0	$0	$0	$0	$99,504	$708,003	$4,027,017
2024	$505,669	$37,079	$21,028	$3,810	$645,465	$103,775	$0	$0	$0	$0	$103,775	$749,240	$4,248,690
2025	$545,546	$40,404	$21,554	$3,673	$691,614	$103,775	$0	$0	$0	$0	$103,775	$795,389	$4,468,622
2026	$576,219	$42,152	$29,770	$7,779	$738,443	$133,530	$0	$0	$0	$0	$121,221	$859,664	$4,690,775
2027	$608,120	$43,915	$35,793	$8,627	$781,182	$133,530	$0	$0	$0	$0	$133,530	$914,712	$4,911,690
2028	$648,021	$46,584	$36,414	$9,553	$828,032	$133,530	$0	$0	$0	$0	$133,530	$961,562	$5,128,728
2029	$694,425	$50,247	$37,049	$10,379	$882,090	$133,530	$0	$0	$0	$0	$133,530	$1,015,620	$5,342,969
2030	$741,574	$54,133	$37,699	$10,879	$937,158	$133,530	$0	$0	$0	$0	$133,530	$1,070,688	$5,554,052

Notes:
(1) Fixed costs are included only for new unit additions.

Table C-18 Expansion Plan Economic Summary - With Stanton B - No Coal Fired Capacity Options

Case Description	
Fuel Forecast	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B[1]	N/A	33	06/01	2010	[redacted]	[redacted]
7FA CT	81,059	14	06/01	2015	103,862	8,474
7FA CT	81,059	14	06/01	2018	111,848	9,126
7FA CT	81,059	14	06/01	2021	120,448	9,827
7FA CT	81,059	14	06/01	2024	129,710	10,583
1x1 7FA CC	213,127	30	06/01	2027	373,808	30,499

	Production Cost					Capital Cost, DOE Contributions, and Other Stanton B Project Costs							
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	OUC IGCC Demand Payment[3] ($1,000)	Project Completion Cost[4] ($1,000)	DOE Funding[5] ($1,000)	Startup Credit and Lease[6] ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]	[redacted]	[redacted]	[redacted]	$223,288	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$223,288	$223,288
2007	[redacted]	[redacted]	[redacted]	[redacted]	$204,538	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$204,538	$414,445
2008	[redacted]	[redacted]	[redacted]	[redacted]	$210,520	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$210,520	$598,322
2009	[redacted]	[redacted]	[redacted]	[redacted]	$251,505	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$251,505	$803,624
2010	[redacted]	[redacted]	[redacted]	[redacted]	$272,613	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$291,831	$1,026,261
2011	[redacted]	[redacted]	[redacted]	[redacted]	$289,337	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$321,796	$1,255,697
2012	[redacted]	[redacted]	[redacted]	[redacted]	$304,448	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$335,871	$1,479,502
2013	[redacted]	[redacted]	[redacted]	[redacted]	$326,798	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$359,119	$1,703,143
2014	[redacted]	[redacted]	[redacted]	[redacted]	$354,425	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$399,739	$1,935,795
2015	[redacted]	[redacted]	[redacted]	[redacted]	$376,110	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$424,517	$2,166,705
2016	[redacted]	[redacted]	[redacted]	[redacted]	$397,359	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$449,251	$2,395,081
2017	[redacted]	[redacted]	[redacted]	[redacted]	$426,816	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$478,697	$2,622,506
2018	[redacted]	[redacted]	[redacted]	[redacted]	$457,774	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$515,009	$2,851,177
2019	[redacted]	[redacted]	[redacted]	[redacted]	$490,550	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$551,513	$3,080,035
2020	[redacted]	[redacted]	[redacted]	[redacted]	$529,685	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$590,508	$3,309,044
2021	[redacted]	[redacted]	[redacted]	[redacted]	$566,364	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$633,092	$3,538,506
2022	[redacted]	[redacted]	[redacted]	[redacted]	$600,129	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$670,858	$3,765,749
2023	[redacted]	[redacted]	[redacted]	[redacted]	$649,480	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$720,084	$3,993,709
2024	[redacted]	[redacted]	[redacted]	[redacted]	$688,311	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$765,289	$4,220,130
2025	[redacted]	[redacted]	[redacted]	[redacted]	$743,346	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$824,705	$4,448,168
2026	[redacted]	[redacted]	[redacted]	[redacted]	$816,946	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$898,158	$4,680,269
2027	[redacted]	[redacted]	[redacted]	[redacted]	$839,765	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$938,906	$4,907,027
2028	[redacted]	[redacted]	[redacted]	[redacted]	$870,179	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$981,908	$5,128,657
2029	[redacted]	[redacted]	[redacted]	[redacted]	$936,162	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,047,746	$5,349,675
2030	[redacted]	[redacted]	[redacted]	[redacted]	$993,871	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,105,554	$5,567,632

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.

Table C-19 Expansion Plan Economic Summary - Without Stanton B - No Coal Fired Capacity Options

Case Description	
Fuel Forecast:	Base Case
Load Forecast:	Base Case
Initial Unit Addition:	

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escelation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life:	30

Generation Additions							
Unit	Size (MW)	2006 Capital Cost ($1,000)	Construction Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
7FA CT		81,059	14	06/01	2010	91,799	7,490
7FA CT		81,059	14	06/02	2013	98,858	8,066
1x1 7FA CC		213,127	30	06/03	2016	284,896	23,245
1x1 7FA CC		213,127	30	06/04	2022	330,392	26,957
7FA CT		81,059	14	06/05	2027	139,683	11,397
7EA CT		58,563	13		2029	105,911	8,641

	Production Cost					Capital Cost							
	Fuel and Energy	O&M			Total Production	Unit Capital	Other Capital	Other Capital	Other Capital	Other Capital	Total Capital	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed[1] ($1,000)	Start-Up ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Expenditures ($1,000)	Expenditures ($1,000)	Expenditures ($1,000)	Expenditures ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$209,405	$11,947	$0	$1,936	$223,288	$0	$0	$0	$0	$0	$0	$223,288	$223,288
2007	$190,257	$12,914	$0	$1,367	$204,538	$0	$0	$0	$0	$0	$0	$204,538	$414,445
2008	$195,023	$14,405	$0	$1,093	$210,520	$0	$0	$0	$0	$0	$0	$210,520	$598,322
2009	$235,211	$15,565	$0	$729	$251,505	$0	$0	$0	$0	$0	$0	$251,505	$803,624
2010	$259,675	$16,942	$463	$883	$277,964	$7,490	$0	$0	$0	$0	$4,391	$282,355	$1,019,032
2011	$282,794	$19,150	$810	$1,038	$303,791	$7,490	$0	$0	$0	$0	$7,490	$311,281	$1,240,970
2012	$299,869	$20,130	$830	$916	$321,746	$7,490	$0	$0	$0	$0	$7,490	$329,236	$1,460,354
2013	$328,059	$22,502	$1,349	$956	$352,865	$15,556	$0	$0	$0	$0	$12,219	$365,084	$1,687,710
2014	$361,738	$26,567	$1,744	$1,106	$391,155	$15,556	$0	$0	$0	$0	$15,556	$406,711	$1,924,419
2015	$393,123	$29,605	$1,787	$1,082	$425,597	$15,556	$0	$0	$0	$0	$15,556	$441,153	$2,164,377
2016	$403,549	$29,006	$9,197	$3,858	$445,610	$38,800	$0	$0	$0	$0	$29,184	$474,794	$2,405,738
2017	$419,477	$29,553	$14,492	$5,272	$468,794	$38,800	$0	$0	$0	$0	$38,800	$507,594	$2,646,893
2018	$447,523	$31,271	$14,591	$4,903	$498,288	$38,800	$0	$0	$0	$0	$38,800	$537,089	$2,885,367
2019	$477,474	$34,192	$14,692	$5,412	$531,769	$38,800	$0	$0	$0	$0	$38,800	$570,570	$3,122,133
2020	$511,600	$38,061	$14,794	$6,196	$570,651	$38,800	$0	$0	$0	$0	$38,800	$609,452	$3,358,489
2021	$547,802	$41,681	$14,898	$6,315	$610,695	$38,800	$0	$0	$0	$0	$38,800	$649,495	$3,593,895
2022	$571,243	$42,043	$22,553	$9,932	$645,771	$65,757	$0	$0	$0	$0	$54,605	$700,376	$3,831,137
2023	$600,825	$43,619	$28,041	$12,109	$684,594	$65,757	$0	$0	$0	$0	$65,757	$750,351	$4,068,679
2024	$636,803	$46,073	$28,203	$13,117	$724,195	$65,757	$0	$0	$0	$0	$65,757	$789,952	$4,302,397
2025	$682,778	$50,280	$28,366	$14,963	$776,387	$65,757	$0	$0	$0	$0	$65,757	$842,144	$4,535,257
2026	$734,670	$55,364	$28,532	$15,813	$834,380	$65,757	$0	$0	$0	$0	$65,757	$900,137	$4,767,870
2027	$780,506	$59,679	$29,404	$16,742	$886,331	$77,154	$0	$0	$0	$0	$72,439	$958,770	$4,999,425
2028	$829,694	$63,221	$30,100	$18,358	$941,373	$77,154	$0	$0	$0	$0	$77,154	$1,018,527	$5,229,320
2029	$890,472	$68,899	$30,302	$19,796	$1,009,470	$85,795	$0	$0	$0	$0	$82,220	$1,091,690	$5,459,609
2030	$949,068	$73,674	$30,507	$21,131	$1,074,380	$85,795	$0	$0	$0	$0	$85,795	$1,160,175	$5,688,333

Notes:
(1) Fixed costs are included only for new unit additions.

Table C-20 Expansion Plan Economic Summary - With Stanton B - One Year Delay

Case Description	
Fuel Forecast	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	7.0%
Capital Escalation Rate:	2.5%
Base Year for $	2006

Financial Parameters	
Fixed Charge Rate:	8.159%
Interest During Construction:	5.25%
Finance Term (yrs):	30
Plant Life (yrs):	30

Generation Additions						
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day Installed (mm/dd)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Stanton B[1]	N/A	33	06/01	2011	[redacted]	
7FA CT	81,059	14	06/01	2010	91,799	7,490
7FA CT	81,059	14	06/01	2018	111,848	9,126
PULVERIZED COAL UNIT	761,738	50	06/01	2021	1,177,755	96,093
LM6000 CT	44,879	12	06/01	2029	81,073	6,615
7EA CT	58,563	13	06/01	2030	108,558	8,857

	Production Cost					Capital Cost, DOE Contributions, and Other Stanton B Project Costs							
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Start-Up ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	OUC IGCC Demand Payment[3] ($1,000)	Project Completion Cost[4] ($1,000)	DOE Funding[5] ($1,000)	Startup Credit and Lease[6] ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	[redacted]				$223,288	[redacted]						$223,288	$223,288
2007					$204,538							$204,538	$414,445
2008					$210,520							$210,520	$598,322
2009					$251,505							$251,505	$803,624
2010					$277,964							$284,165	$1,020,412
2011					$299,407							$325,876	$1,252,757
2012					$306,269							$346,165	$1,483,421
2013					$329,247							$367,138	$1,712,057
2014					$358,993							$399,933	$1,944,821
2015					$380,837							$431,766	$2,179,674
2016					$399,018							$449,949	$2,408,405
2017					$427,945							$478,758	$2,635,859
2018					$457,774							$514,025	$2,864,093
2019					$490,550							$550,529	$3,092,543
2020					$529,685							$589,523	$3,321,170
2021					$530,587							$646,919	$3,555,643
2022					$537,354							$693,617	$3,790,595
2023					$571,885							$727,967	$4,021,051
2024					$603,044							$759,188	$4,245,667
2025					$642,875							$798,981	$4,466,592
2026					$688,678							$844,624	$4,684,859
2027					$723,221							$879,215	$4,897,201
2028					$765,339							$921,258	$5,105,141
2029					$823,302							$983,017	$5,312,505
2030					$865,690							$1,033,477	$5,516,252

Notes:
(1) Stanton B includes costs for the combined cycle, OUC's additional costs, railcars, and gasifier.
(2) Fixed O&M is only applied to new unit additions.
(3) Reflects OUC's Payment for full use of the gasifier.
(4) Reflects costs for DOE project completion.
(5) Reflects DOE funding for 25.25 percent of allowable costs during the demonstration period.
(6) Reflects the sale of energy generated during Stanton B startups and facility lease payments.