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Abbreviations and Acronyms

\$/kW-Yr	Dollars per kilowatt per Year
\$/MWh	Dollars per megawatt
ACESA	American Clean Energy and Security Act
ACI	Activated Carbon Injection
ACSR	Aluminum Conductor Steel Reinforced
AEO2009	Annual Energy Outlook 2009
Alachua	City of Alachua
American Renewables	American Renewables, LLC
Application	Need for Power Application
ARRA	American Recovery and Reinvestment Act
BayCorp	BayCorp Holdings, Ltd.
BEBR	Bureau of Economic and Business Research
BOP	Balance-of-Plant
CAFE	Corporate Average Fuel Economy
CCCT	Combined Cycle Combustion Turbine
CCS	Carbon Capture Sequestration
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
CI	Confidence Intervals
City Commission	Gainesville City Commission
Clay	Clay Electric Cooperative
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Commission	Florida Public Service Commission
CPI	Consumer Price Index
CR3	Crystal River 3
CTG	Combustion Turbine Generator
DEP	Florida Department of Environmental Protection
DLN	Dry Low NO_x
DSM	Demand-Side Management
EGEAS	Electrical Generation Expansion Analysis System

EIA	Energy Information Administration
EMI	Energy Management, Inc.
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
FAC	Florida Administration Code
FCR	Fixed Charge Rate
FD	Forced Draft
FGD	Flue Gas Desulfurization
FIT	Feed-in-Tariff
FMPA	Florida Municipal Power Agency
FPL	Florida Power & Light
FRCC	Florida Reliability Coordinating Council, Inc.
G2	G2 Energy Marion, LLC
GE	General Electric
GEAC	Gainesville Energy Advisory Committee
GHG	Greenhouse Gas
GIS	Geographic Information System
GREC	Gainesville Renewable Energy Center
GREC LLC	Gainesville Renewable Energy Center, LLC
GRU	Gainesville Regional Utilities
GSD	General Service Demand
GSN	General Service Nondemand
GSU	Generator Step-Up
GWh	Gigawatt-Hours
Hg	Mercury
HP	High-Pressure
HPC	High-Pressure Compressor
HPT	High-Pressure Turbine
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
Hz	Hertz
ICF	ICF Consulting
ID	Induced Draft
IDC	Interest During Construction

IFAS	Institute of Food and Agricultural Sciences
IGCC	Integrated Gasification Combined Cycle
IPT	Intermediate-Pressure Turbine
IRP	Integrated Resource Planning
JRK	John R. Kelly
kV	Kilovolts
kW	Kilowatts
kWh	Kilowatt-Hours
LCOE	Levelized Cost of Energy
LED	Light Emitting Diode
LNG	Liquefied Natural Gas
LPC	Low-Pressure Compressor
MBtu	Million British Thermal Units
MCM	Thousand Circular Mils
MSW	Municipal Solid Waste
MVA	Megavolt-Ampere
MVAR	Megavolt-Ampere Reactive
MW	Megawatts
MWh	Megawatt-Hour
NEMA	National Electric Manufacturers Association
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
ORNL	Oak Ridge National Laboratory
PA	Primary Air
PDS	Power Delivery Substations
PEF	Progress Energy Florida
Petcoke	Petroleum Coke
PPA	Power Purchase Agreement
PPSA	Florida Electrical Power Plant Siting Act

PSC	Public Service Commission (the Commission) when Florida PSC
PSD	Prevention of Significant Deterioration
PV	Photovoltaic
REC	Renewable Energy Credit
RFP	Request for Proposal
RIM	Rate Impact Measure
rpm	Revolutions Per Minute
RPS	Renewable Portfolio Standard
RUC	Regional Utilities Committee
SAS	Statistical Analysis System
SCA	Site Certification Application
SCCT	Simple Cycle Combustion Turbine
ScFt	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SEC	South Energy Center
Seminole	Seminole Electric Cooperative
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SWG	Stability Working Group
System	Electric Power Production, Transmission, and Distribution System
TC2F	Tandem Compound Two Flow
TRC	Total Resource Cost
TWG	Transmission Working Group
Tyr	Tyr Energy
ZLD	Zero Liquid Discharge

1.0 Executive Summary

Gainesville Regional Utilities (GRU) and Gainesville Renewable Energy Center, LLC (GREC LLC) are submitting this Need for Power Application (Application) in support of the proposed Gainesville Renewable Energy Center (GREC) facility. The analyses summarized below and discussed throughout this Application demonstrate that the woody waste-fueled biomass facility will provide GRU with reliable, clean, economical power while further diversifying GRU's fuel supply.

1.1 The Applicants

GRU is a municipal electric, natural gas, water, wastewater, and telecommunications utility that is owned and operated by the City of Gainesville in Alachua County, located in north-central Florida. GRU's General Manager reports directly to the elected members of the Gainesville City Commission (City Commission) which sets policy and has fiduciary responsibility for the utility. GRU's existing electric generation includes coal, gas, nuclear, and renewable energy resources. GRU's present summer net generating capability is approximately 608 megawatts (MW) and its winter net generating capability is approximately 623 MW.

GREC LLC is a subsidiary of American Renewables, LLC (American Renewables), a private, for-profit renewable power producer. American Renewables is jointly owned by affiliates of BayCorp Holdings, LTD (BayCorp), Energy Management, Inc. (EMI) and Tyr Energy (Tyr). These entities are more fully described in Section 9.0 of this Application.

1.2 The Proposed Biomass Facility

The GREC facility will consist of a nominal 100 MW net capacity steam unit. GREC is designed to use clean woody biomass and is scheduled to come on line December 1, 2013. The plant will be located on GRU's existing Deerhaven Power Plant site within the City of Gainesville's corporate limits in Alachua County, Florida. The fuel supply will consist primarily of residuals from timber harvesting in north-central Florida, but will also include materials from urban forestry, land clearing, and mill waste. The GREC biomass facility will be owned and operated by GREC LLC. GRU will receive power from the GREC facility under a 30 year power purchase agreement (PPA) with a fixed nonfuel energy charge per megawatt-hour (MWh) that covers construction, debt service, and all fixed operations and maintenance (O&M) costs.

The decision to enter into the PPA with GREC LLC is the result of an extensive integrated planning process, including 43 public workshops and Gainesville City Commission meetings, several dozen presentations to civic and community groups, as well as a competitive bidding process to select the project developer. One of the most important outcomes of this process was the decision made by the Gainesville City Commission to pursue only renewable energy resources for additional generating capacity as opposed to coal, petroleum coke, and natural gas alternatives.

1.3 The Power Plant Siting Act Process

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

1.4 The Commission's Need Determination

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

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

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

1.5 The Need for the Gainesville Renewable Energy Center

Although the GREC is not immediately needed to meet GRU's 15 percent reserve margin planning criterion, GREC's capacity is needed to improve and maintain the reliability of GRU's system. GRU's system is unique because the lowest cost fossil fueled unit, Deerhaven Unit 2, serves approximately 50 percent of GRU's system peak demand. The capacity from GREC is needed to replace the capacity from Deerhaven Unit 2 during maintenance and forced outages. Deerhaven Unit 2 is aging and will be 32 years old when GREC goes into service in late 2013. With increased age, the availability of Deerhaven Unit 2 is expected to decrease. Furthermore, most of the remainder of GRU's capacity is older than Deerhaven Unit 2 and will be retired during the term of the GREC PPA, requiring the capacity from GREC to meet GRU's 15 percent reserve margin planning criterion.

In addition to filling a capacity need, the GREC is needed by GRU's system to diversify GRU's existing fuel mix, which is dominated by coal (and therefore is potentially at risk under future carbon dioxide [CO_2] regulations), and natural gas, which is highly volatile in price and availability and also, to a lesser degree than coal, potentially at risk under future CO_2 regulations. The GREC is needed to minimize the effects of these potentially costly and regulation-constrained fuels.

1.6 Analysis of Generating (Supply-Side) Alternatives

The GREC LLC PPA was evaluated on a levelized cost basis against comparable supply-side alternatives over the term of the GREC LLC PPA, with results summarized in Table 12-1. The supply-side alternatives were evaluated considering seven different scenarios of fuel cost, capital cost, and CO_2 regulation. On a levelized cost basis, the lowest cost natural gas alternative was 11 percent higher in cost than the GREC LLC PPA for the expected case without CO_2 regulation. For all other sensitivity cases, natural gas alternatives were higher in cost than the GREC LLC PPA by 5 percent to 210 percent.

Although it is uncertain that any type of coal unit could be permitted in Florida at this time, coal units with carbon capture and sequestration are from 31 percent to 104 percent higher in levelized cost than GREC. As would be expected, coal fired units without any consideration for CO_2 costs or carbon emissions control technologies are projected to be lower in cost than the GREC LLC PPA.

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

GRU has invested significant effort in developing the demand-side management (DSM) programs currently offered to its customers and is considered the leading utility in the State in this area. Since 1980, GRU has offered incentives and services as DSM tools for energy conservation and demand reduction. DSM programs are available for all retail customers, including commercial and industrial customers. In addition, GRU continues to offer standardized interconnection procedures and compensation for excess energy production for both residential and non-residential customers who install distributed resources, and also offers rebates to residential customers for the installation of photovoltaic generation. GRU also has several programs to improve the adequacy and reliability of the transmission and distribution systems, which also result in decreased energy losses.

1.8 Integrated Fuel and CO_2 Emissions Allowance Cost Projections

Although no CO_2 regulatory programs have been adopted to date, considering the ongoing discussions about potential CO_2 regulation, this Application presents additional economic analyses that incorporate a range of CO_2 emissions allowance cost estimates, and associated fuel forecasts, developed by the US Department of Energy's Energy Information Administration (EIA). These analyses demonstrate that the GREC LLC PPA provides increased economic advantages, assuming a carbon-regulated environment and a range of costs associated with CO_2 emissions allowances.

Fuel and emissions allowance costs are interrelated. Therefore, fuel and CO_2 emissions allowance cost projections included in this Application are fully integrated. That is, the EIA price projections consider fuel supply and demand in tandem with potential CO_2 emissions allowance costs, along with numerous other market influences, to develop fully integrated fuel and CO_2 emissions allowance cost projections.

1.9 Most Cost-Effective Alternative

The levelized cost analyses performed for purposes of this Application indicate that the GREC PPA is the most cost-effective alternative when compared to natural gas generating units and a coal alternative that includes carbon capture and sequestration technology. No coal alternatives were lower in cost than the GREC PPA if CO_2 costs are considered.

1.10 Adverse Consequences if the GREC is Delayed

Delay of the GREC biomass facility would result in economic, reliability, and potential regulatory consequences. Adverse consequences of delaying the GREC biomass facility include:

- Increased costs resulting from not being eligible for renewable energy grants,
- Increased costs associated with replacement power, and
- Adverse indirect economic impacts associated with construction and operation jobs created by the GREC.

The GREC PPA will enhance GRU's system reliability. A delay in the operation of the GREC will, therefore, have a detrimental impact from a system reliability perspective. The GREC PPA will also provide GRU with increased ability to comply with potential legislation and regulations related to renewable energy standards and regulations of CO_2 emissions in a reliable and cost-effective manner.

1.11 Conclusion

The proposed GREC facility will ensure that GRU has an adequate supply of power to serve its customers' needs at a reasonable cost while enhancing system reliability. The addition of cost-effective biomass capacity and energy will further diversify GRU's fuel mix and substantially contributes towards meeting the policy objectives of the Gainesville City Commission. The project will also enhance fuel diversity and supply reliability by utilizing multiple biomass fuel supply options.

2.0 Introduction

This Application demonstrates the need for the GREC biomass facility pursuant to the requirements outlined within Section 403.519 of the Florida Statutes. The GREC facility will consist of a new nominal rated 100 MW net biomass-fired electric generating facility, consisting of a biomass fuel handling system, a biomass-fired boiler, a condensing steam turbine generator (STG) with evaporative cooling towers, and auxiliary support equipment. The facility will utilize a zero liquid discharge (ZLD) system to eliminate industrial wastewater discharges, in accordance with the site's current restrictions pursuant to its current certification. The facility will be designed in accordance with standards normally used in the utility industry so that the facility will, with standard O&M practices, be designed to provide full service over its 42 year design life.

Section 3.0 provides a description of GRU and its existing facilities. This general overview discusses GRU's existing generating units, PPAs, transmission and distribution system, wholesale energy sales, and distributed generation resources.

Section 4.0 presents GRU's load forecast and discusses various sensitivity load forecasts that were developed in addition to the base load forecast.

Section 5.0 discusses the reliability criteria used by GRU, and indicates GRU's need for capacity by applying the 15 percent reserve margin to GRU's load forecast and comparing the capacity requirements to GRU's existing generating resources.

Section 6.0 provides the economic parameters and assumptions used throughout the Application.

Section 7.0 presents the fuel price projections used in the economic evaluations. The fuel price projections are based on the US Department of Energy's EIA Annual Energy Outlook 2009 (AEO2009) projections and also include projections of CO_2 emissions allowance prices.

Section 8.0 discusses the integrated resource planning (IRP) process used by GRU that has culminated in the decision to pursue the PPA with GREC LLC.

Section 9.0 describes the GREC biomass facility and the PPA between GRU and GREC LLC. Section 9.0 demonstrates that there will be a reliable supply of fuel for the GREC facility and that the GREC facility will provide clean, reliable power to GRU.

Section 10.0 discusses the generating unit alternatives with which the GREC PPA was compared.

Section 11.0 describes the methodology used to evaluate the cost-effectiveness of the GREC biomass facility.

Section 12.0 presents the results of the economic analyses conducted. These analyses demonstrate that GRU's PPA with GREC LLC provides the most economic power under the wide range of cases considered.

Section 13.0 describes GRU's current DSM programs, renewable energy projects that have been encouraged by GRU, and efficiency improvements to supply-side resources that have helped to reduce demand and energy requirements.

Section 14.0 describes the evaluations conducted to demonstrate that interconnection of the GREC facility will not have an adverse impact on the Florida Reliability Coordinating Council's bulk electric transmission system.

Section 15.0 summarizes the strategic considerations taken into account by GRU when evaluating whether to pursue a commitment to the PPA with GREC LLC.

Section 16.0 discusses the adverse consequences of delaying the GREC facility.

Section 17.0 describes the financial capability of GREC LLC and demonstrates that GRU has the financial resources to commit to the GREC LLC PPA.

3.0 Description of Existing System

GRU operates a fully vertically integrated electric power production, transmission, and distribution system (herein referred to as the System), which is wholly owned by the City of Gainesville. In addition to retail electric service, GRU also provides wholesale electric service to the City of Alachua (Alachua) and Clay Electric Cooperative (Clay). GRU's distribution system serves its retail territory of approximately 124 square miles and approximately 93,000 customers. The general locations of GRU electric facilities and the electric system service area are shown in Figure 3-1.

3.1 Existing Generation Resources

The existing generating facilities operated by GRU are summarized in Table 3-1. The present summer net generating capability is approximately 608 MW, and the winter net generating capability is approximately 623 MW.[1] Currently, the System's energy is produced by three fossil fuel steam turbines, six simple cycle combustion turbines, one combined cycle unit, a 1.4079 percent ownership share of the Crystal River 3 (CR3) nuclear unit operated by Progress Energy Florida (PEF), and a small distributed generation unit at the South Energy Center.

The System has two primary generating plant sites: Deerhaven and John R. Kelly (JRK). Each site is comprised of both steam turbine and gas turbine generating units. The JRK Station also includes a combined cycle unit.

[1] Net capability is that specified by the "SERC Guideline Number Two for Uniform Generator Ratings for Reporting." The winter rating will normally exceed the summer rating because generating plant efficiencies are increased by lower ambient air temperatures and lower cooling water temperatures.

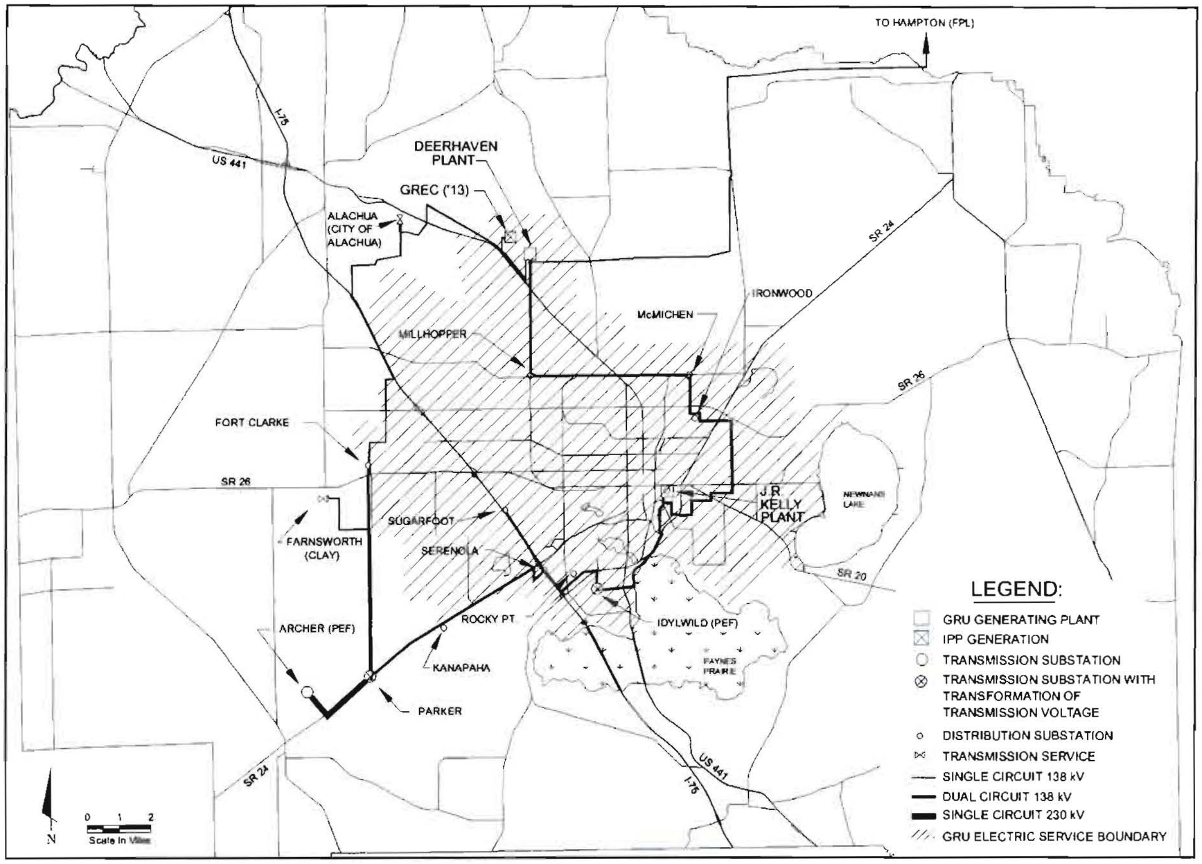

Figure 3-1
Gainesville Regional Utilities Electric System Map

Table 3-1
EXISTING GENERATING FACILITIES (as of Summer 2009)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Commercial	Expected	Gross Capability		Net Capability		
	Unit		Unit	Primary Fuel		Alternate Fuel		In-Service	Retirement	Summer	Winter	Summer	Winter	
Plant Name	No.	Location	Type	Type	Trans.	Type	Trans.	Month/Year	Month/Year	MW	MW	MW	MW	Status
J. R. Kelly		Alachua County								**180.0**	**189.0**	**177.2**	**186.2**	
	FS08	Sec. 4, T10S, R20E	CA	WH	PL			[4/65 ; 5/01]	2051	38.0	38.0	37.0	37.0	OP
	FS07	(GRU)	ST	NG	PL	RFO	TK	8/61	10/13	24.0	24.0	23.2	23.2	OP
	GT04		CT	NG	PL	DFO	TK	5/01	2051	76.0	82.0	75.0	81.0	OP
	GT03		GT	NG	PL	DFO	TK	5/69	05/19	14.0	15.0	14.0	15.0	OP
	GT02		GT	NG	PL	DFO	TK	9/68	09/18	14.0	15.0	14.0	15.0	OP
	GT01		GT	NG	PL	DFO	TK	2/68	02/18	14.0	15.0	14.0	15.0	OP
Deerhaven		Alachua County								**437.0**	**447.0**	**415.1**	**426.1**	
	FS02	Secs. 26,27,35	ST	BIT	RR			10/81	2031	235.0	235.0	222.1	222.1	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK	8/72	08/22	88.0	88.0	83.0	83.0	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK	1/96	2046	76.0	82.0	75.0	81.0	OP
	GT02		GT	NG	PL	DFO	TK	8/76	2026	19.0	21.0	17.5	20.0	OP
	GT01		GT	NG	PL	DFO	TK	7/76	2026	19.0	21.0	17.5	20.0	OP
Crystal River	3	Citrus County Sec. 33, T17S, R16E	ST	NUC	TK			3/77	2037	**12.2**	**12.4**	**11.6**	**11.9**	OP
South Energy Center Distributed Generation	GT1	Alachua County SEC. 10, T10S, R20E	CT	NG	PL			5/09		**4.5**	**4.5**	**4.1**	**4.1**	OP
System Total												**608.0**	**628.3**	

Unit Type
CA = Combined Cycle Steam Part
CT = Combined Cycle or Cogeneration Combustion Turbine Part
GT = Gas Turbine
ST = Steam Turbine

Fuel Type
BIT = Bituminous Coal
DFO = Distillate Fuel Oil
NG = Natural Gas
NUC = Uranium
RFO = Residual Fuel Oil
WH = Waste Heat

Transportation Method
PL = Pipe Line
RR = Railroad
TK = Truck

Status
OP = Operational

3.1.1 Steam Turbine Generation

The System's steam turbines are powered by fossil fuels, and CR3 is nuclear powered. The fossil fueled steam turbines comprise 54.8 percent of the System's net summer capability and produced 84.6 percent of the electric energy supplied by the System in 2008. These units range in size from 23.2 MW to 228.4 MW. The combined cycle unit, which includes a heat recovery steam generator/turbine and combustion turbine set, comprises 18.4 percent of the System's net summer capability and produced 8.5 percent of the electric energy supplied by the System in 2008. The System's 11.6 MW share of CR3 comprises 1.9 percent of the System's net summer capability and produced 5.7 percent of total electric energy in 2008. The System's share of CR3 will increase to 11.981 MW in 2010 and to 13.911 MW in 2012 as the result of capacity upgrades planned by PEF. Deerhaven Unit 2 and CR3 are used for baseload purposes, while JRK Unit 7, JRK Combined Cycle Unit 1, and Deerhaven Unit 1 are used for intermediate loading.

3.1.2 Gas Turbines

The System's six industrial gas turbines make up 24.9 percent of the System's summer generating capability and produced 1.3 percent of the electric energy supplied by the System in 2008. These simple cycle combustion turbines are utilized for peaking purposes because their energy conversion efficiencies are considerably lower than steam units. As a result, they yield higher operating costs and are, consequently, unsuitable for baseload operation. Gas turbines are advantageous in that they can be started and placed on line quickly. The System's gas turbines are most economically used as peaking units during high demand periods when baseload units, intermediate load units, and economy power cannot serve all of the System's loads.

3.1.3 Internal Combustion (Piston/Diesel)

The two reciprocating internal combustion engines operated by the System at the Southwest Landfill were decommissioned in 2008 because of a diminished fuel supply.

3.1.4 Environmental Considerations

All of the System's steam turbines, except for CR3, utilize recirculating freshwater cooling systems with mechanical draft cooling towers for the condensing of steam. CR3 uses a once-through cooling system aided by helper towers. Currently, only Deerhaven Unit 2 has flue gas cleaning equipment consisting of a "hot-side" electrostatic precipitator and a recently completed selective catalytic reduction (SCR) system to reduce nitrogen oxides (NO_x), and a dry flue gas desulfurization unit with fabric filters, which reduces sulfur dioxide (SO_2), mercury, and particulates. Operation of this equipment resulted in a decrease in the net output of 6 MW.

3.2 Existing Plant Descriptions

3.2.1 John R. Kelly Generating Station

The JRK Station is located in southeast Gainesville near the downtown business district and consists of one combined cycle unit, one fossil fuel fired steam turbine, three simple cycle gas turbines, and the associated cooling facilities, fuel storage, pumping equipment, and transmission and distribution equipment.

3.2.2 Deerhaven Generating Station

The Deerhaven Station is located 6 miles northwest of Gainesville. The original site, which was certified pursuant to the Power Plant Siting Act, includes a 1,146 acre parcel of partially forested land. The facility consists of two steam turbines, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment, and transmission equipment. As amended, the certified site now includes coal unloading and storage facilities and a zero discharge water treatment plant, which treats effluent from both steam units. A potential expansion area, owned by the System and adjacent to the certified Deerhaven plant site, was incorporated into the Gainesville City limits February 12, 2007 (Ordinance 0-06-130), and consists of an additional 2,328 acres, for a total of 3,474 acres.

3.2.3 South Energy Center

The South Energy Center is located on the site of the new Shands at University of Florida (UF) Cancer Hospital. This facility includes a 4.1 MW natural gas fired turbine capable of supplying 100 percent of the hospital's electric and thermal needs. The South Energy Center will provide electricity, chilled water, steam and medical gases to the hospital. The unique design is 75 percent efficient at primary fuel conversion to useful energy and greatly reduces emissions compared to traditional generation. Commercial operation of the South Energy Center began in May 2009 and the Cancer Hospital is expected to open in November 2009.

3.3 Power Purchase Agreements

The following power purchase resources are included in the System's portfolio of available capacity.

GRU has entered into a 15 year contract to receive 3 MW of landfill gas fueled capacity at the Marion County Baseline Landfill, from G2 Energy Marion, LLC (G2). The generation facility began commercial operation on January 1, 2009. G2 expects to complete a capacity expansion of 0.8 MW by December 2009, bringing net output to 3.8 MW.

GRU negotiated a contract with PEF for 50 MW of baseload capacity. This contract began January 1, 2009, and continues through December 31, 2013. Extensions of this contract are subject to negotiation. An additional 25 MW of baseload capacity was contracted from January 1, 2009 through December 31, 2010, and another additional 25 MW of baseload capacity was contracted for March through August of 2009 and 2010, respectively.

In March 2009, GRU became the first utility in the United States to offer a European style solar feed-in tariff (FIT). Under this program, GRU agrees to purchase 100 percent of the distributed solar power produced from any private installation at a fixed rate for a contract term of 20 years. The FIT rate has a built-in subsidy to incentivize the installation of solar in the community and help create a strong solar marketplace. GRU's FIT costs are recovered through fuel adjustment charges and have been limited to the equivalent of a 0.6 percent base rate increase. This limit translates to an annual capacity stop-loss to purchase no more than 4 MW. GRU's FIT capacity is fully subscribed through 2016. Solar capacity thus obtained is assumed to have a 35 percent coincidence factor.

In sum, purchased power resources contribute 102.2 MW of net capability for the summer of 2009. The combination of owned generation and purchased power provides 710.2 MW of available capacity.

3.4 GRU's Transmission System

GRU's bulk electric power transmission network consists of a 230 kilovolt (kV) radial and a 138 kV loop that connects the following:

- GRU's two generating stations.
- GRU's nine distribution substations.
- One 230 kV and two 138 kV interties with PEF.
- A 138 kV intertie with Florida Power & Light Company (FPL).
- A radial interconnection with Clay at Farnsworth Substation.
- A loop-fed interconnection with Alachua at Alachua No. 1 Substation.

Refer to Figure 3-1 for line geographical locations and Figure 3-2 for electrical connectivity and line numbers.

3.4.1 Transmission Lines

The ratings for all of GRU's transmission lines are presented in Table 3-2. Refer to Figure 3-2 for a one-line diagram of GRU's electric system, including how the GREC will be interconnected.

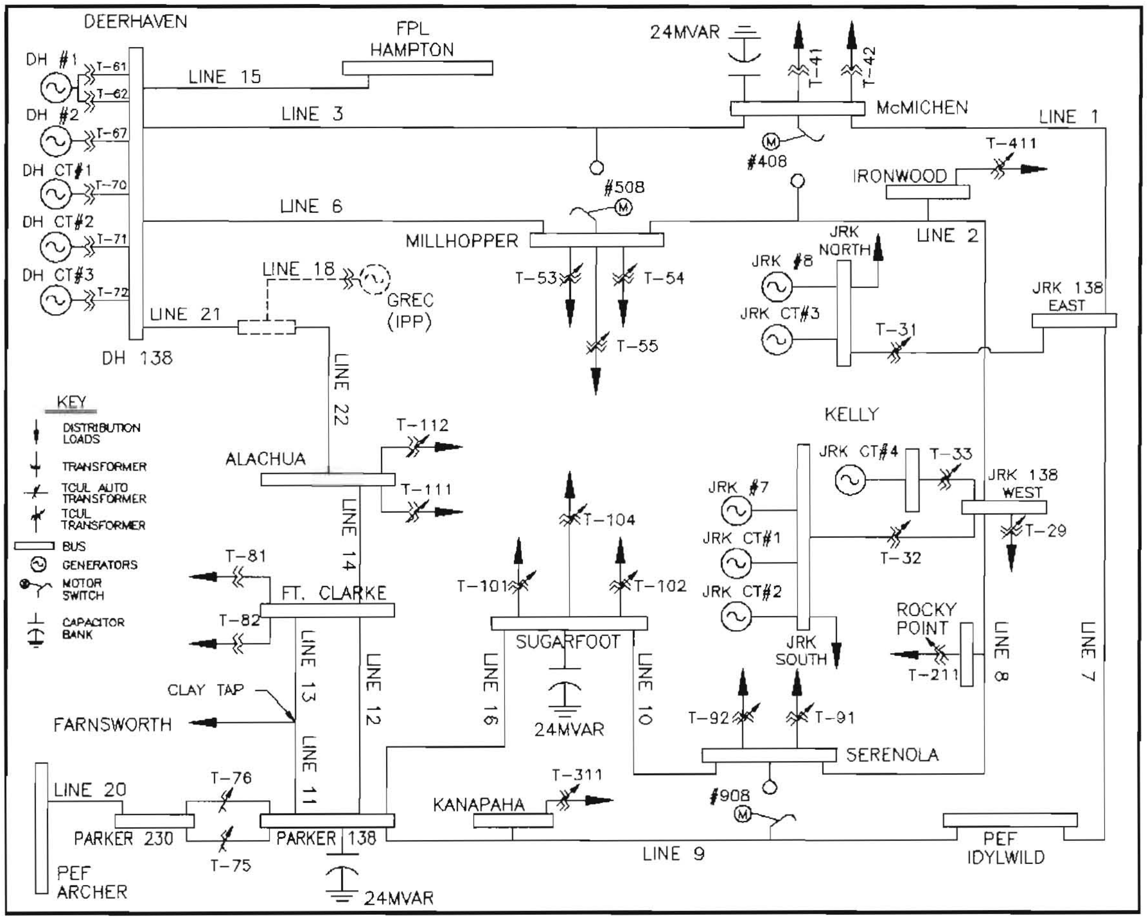

Figure 3-2
Gainesville Regional Utilities Electric System One-Line Diagram

Table 3-2
Transmission Line Ratings
(Summer Power Flow Ratings)

Line Number	Description	Normal 100° C (MVA)	Limiting Device	8-Hour Emergency 125° C (MVA)	Limiting Device
1	McMichen - Depot East	236.2	Conductor	282.0	Conductor
2	Millhopper - Depot West	236.2	Conductor	282.0	Conductor
3	Deerhaven - McMichen	236.2	Conductor	282.0	Conductor
6	Deerhaven - Millhopper	236.2	Conductor	282.0	Conductor
7	Depot East - Idylwild	236.2	Conductor	282.0	Conductor
8	Depot West - Serenola	236.2	Conductor	282.0	Conductor
9	Idylwild - Parker	236.2	Conductor	236.2	Conductor
10	Serenola - Sugarfoot	236.2	Conductor	282.0	Conductor
11	Parker - Clay Tap	143.6	Switch	186.0	Switch
12	Parker - Ft. Clarke	236.2	Conductor	282.0	Conductor
13	Clay Tap - Ft. Clarke	143.6	Switch	186.0	Switch
14	Ft. Clarke - Alachua	287.3	Switch	356.0	Conductor
15	Deerhaven - Hampton	224.0(1)	Transformers	270.0	Transformers
16	Sugarfoot - Parker	236.2	Conductor	282.0	Conductor
17	Clay Tap - Farnsworth	236.2	Conductor	282.0	Conductor
18	GREC - GREC Interconnection	236.2	Conductor	282.0	Conductor
20	Parker - Archer (T75, T76)	224.0	Transformers	300.0	Transformers
21	Alachua - GREC Interconnection	287.3	Switch	356.0	Conductor
22	GREC Interconnection - Deerhaven	287.3	Switch	356.0	Conductor
xx	Idylwild - PEF	150.0(2)	Transformer	168.0(2)	Transformer

(1)These two transformers are located at the FPL Bradford Substation and are the limiting elements in the Normal and Emergency ratings for this intertie.
(2)This transformer, along with the entire Idylwild Substation, is owned and maintained by PEF.

Assumptions:
100° C for normal conductor operation.
125° C for emergency 8 hour conductor operation.
40° C ambient air temperature.
2 ft/sec wind speed.
Transformers T75 and T76 normal limits are based on a 65 °C temperature rise rating.

The criteria for normal and emergency loading are taken to be as follows:

- Normal loading: conductor temperature not to exceed 100° C (212° F).
- Emergency 8 hour loading: conductor temperature not to exceed 125° C (257° F).

The present transmission network is summarized in Table 3-3.

Table 3-3
GRU's Transmission Network

Line	Circuit Miles	Conductor
138 kV double circuit	80.01	795 MCM ACSR
138 kV single circuit	16.30	1192 MCM ACSR
138 kV single circuit	20.91	795 MCM ACSR
230 kV single circuit	2.53	795 MCM ACSR
Total	119.75	

Notes:
MCM = thousand circular mills.
ACSR = aluminum conductor steel reinforced

Annually, GRU participates in Florida Reliability Coordinating Council, Inc. (FRCC) studies that analyze multilevel contingencies. Contingencies are occurrences that depend on changes or uncertain conditions and, as used herein, represent various equipment failures that may occur. All single and double circuit common pole contingencies have no identifiable problems.

Contingency simulations revealed the system effects of serving peak summer load with assumed outages of both Deerhaven Unit 2 and the Archer 230 kV tie line. The results identified GRU bus voltages that would fall below acceptable levels. These were addressed by installing two three-phase, 138 kV, 24.6 megavolt-ampere reactive (MVAr) capacitor banks: one at the Parker Transmission Substation (May 2009) and another at the McMichen Substation (July 2009).

According to the FRCC, which is responsible for the integrity and stability of the entire Florida transmission grid, with these new capacitor banks GRU could plan to import approximately 250 MW before exceeding the bus voltage standard for reliability.

3.4.2 State Interconnections

The System is currently interconnected with PEF and FPL at four separate points. The System interconnects with PEF's Archer Substation via a 230 kV transmission line to the System's Parker Substation with 224 megavolt-ampere (MVA) of transformation capacity from 230 kV to 138 kV. The System also interconnects with PEF's Idylwild Substation with two separate circuits via a 150 MVA 138/69 kV transformer at the Idylwild Substation. The System interconnects with FPL via a 138 kV tie between FPL's Hampton Substation and the System's Deerhaven Substation. This interconnection has a transformation capacity at Bradford Substation of 224 MVA.

3.5 GRU's Distribution System

The System has six loop-fed and three radial-fed distribution substations connected to the transmission network: Ft. Clarke, Kelly, McMichen, Millhopper, Serenola, Sugarfoot, Ironwood, Kanapaha, and Rocky Point substations, respectively. Parker is GRU's only 230 kV transmission voltage substation. The locations of these substations are shown on Figure 3-1.

The six major distribution substations are connected to the 138 kV bulk power transmission network with looped feeds that prevent the outage of a single transmission line from causing major outages in the distribution system. Ironwood, Kanapaha, and Rocky Point are served by a single tap to the 138 kV network, which would require distribution switching to restore customer power if the single transmission line that is tapped experiences an outage. GRU serves its retail customers through a 12.47 kV distribution network. The distribution substations, their present rated transformer capabilities, and the number of circuits for each are listed in Table 3-4.

The System has three power delivery substations with single 33.6 MVA transformers that are directly radial-tapped to GRU's looped 138 kV system. Currently, Ft. Clarke, Kelly, McMichen, and Serenola substations consist of two transformers of approximately equal size, allowing these stations to be loaded under normal conditions to 80 percent of the capabilities shown in Table 3-4. Millhopper and Sugarfoot substations currently consist of three transformers of equal size, allowing both of these substations to be loaded under normal conditions to 100 percent of the capability shown in Table 3-4. One of the two 22.4 MVA transformers at Ft. Clarke has been repaired with rewinding to a 28.0 MVA rating. This makes the normal rating for this substation 50.4 MVA.

Table 3-4
Substation Transformation and Circuits

Substations	Normal Transformer Rated Capability	Current Number of Circuits
Distribution		
Ft. Clarke	50.4 MVA	4
J.R. Kelly[(1)]	168.0 MVA	20
McMichen	44.8 MVA	6
Millhopper	100.8 MVA	10
Serenola	67.2 MVA	8
Sugarfoot	100.8 MVA	9
Ironwood	33.6 MVA	3
Kanapaha	33.6 MVA	3
Rocky Point	33.6 MVA	3
Transmission		
Parker	224 MVA	5
Deerhaven	No transformations- All 138 kV circuits	4

[(1)]J.R. Kelly is a generating station as well as two distribution substations. One substation has 14 distribution feeders directly fed from two 12.47 kV generator buses with connection to the 138 kV loop by two 56 MVA transformers. The other substation (Kelly West) has 6 distribution feeders fed from a single, loop-fed 56 MVA transformer.

In 2007, GRU expanded its JRK Station generation-transmission-distribution substation configuration to include a third 56 MVA 138/12.47 kV transformer located on the south side of the plant (referred to as Kelly West). This expansion has enhanced reliability by reassigning load to a point on the system not directly tied to the generator buses of the plant. The additional transformer capacity will allow for load growth in Gainesville's downtown area.

3.6 Wholesale Energy Sales

The System provides full requirements wholesale electric service to Clay through a contract between GRU and Seminole Electric Cooperative (Seminole), of which Clay is a member. The System began the 138 kV service at Clay's Farnsworth Substation in February 1975. This substation is supplied through a 2.37 mile radial line connected to the System's transmission facilities at Parker Road near SW 24th Avenue.

The System also provides full requirements wholesale electric service to Alachua. The Alachua No. 1 Substation is supplied by GRU's looped 138 kV transmission system. The System provides approximately 94 percent of Alachua's energy requirements, with the remainder being supplied by Alachua's generation entitlements from PEF's CR3 and FPL's St. Lucie 2 nuclear units. Energy supplied to Alachua by these nuclear units is wheeled over GRU's transmission network. Alachua and GRU agreed to a 2 year extension of the original contract that expired on December 31, 2008.

Wholesale sales to Clay and Alachua have been included as native load for purposes of projecting GRU's needs for generating capacity and associated reserve margins.

4.0 Forecast of Electrical Demand and Energy

GRU developed forecasts for the number of customers, energy sales, and seasonal peak demands for 2009 through 2044. Separate energy sales forecasts were developed for each of the following customer segments: residential, general service non-demand (GSN), general service demand (GSD), large power, outdoor lighting, sales to Seminole for Clay, and sales to Alachua. Separate forecasts of the number of customers were developed for residential, GSN, GSD, and large power retail rate classifications. The basis for these independent forecasts originated with the development of least-squares regression models. All modeling was performed by GRU using the Statistical Analysis System (SAS).[1] The remainder of this section describes forecast assumptions, the development of regression equations utilized to forecast energy sales and number of customers, the basis for NEL and seasonal peak demand projections, as well as the development of banded energy and demand forecasts.

4.1 Forecast Assumptions and Data Sources

The following assumptions and data sources were used by GRU in developing load forecasts through 2044:

(1) All regression analyses were based on annual data. Historical data was compiled for calendar years 1970 through 2008. System data, such as NEL, seasonal peak demands, customer counts, and energy sales, was obtained from GRU records and sources.

(2) Estimates and projections of Alachua County population were obtained from the "Florida Population Studies," March 2008 (Bulletin No. 150), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida.

(3) Historical weather data was used to fit regression models. The forecast assumed normal weather conditions, including normal heating degree days and cooling degree days that were equal to the mean of data reported to the National Oceanic and Atmospheric Association (NOAA) by the Gainesville Municipal Airport station from 1984 to 2008.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2008, using the US Consumer Price Index for All Urban Consumers from the US Department of Labor, Bureau of Labor Statistics. Inflation was assumed to average approximately 2.5 percent per year for each year of the forecast.

[1] SAS is the registered trademark of SAS Institute, Inc., Cary, NC.

(5) The US Department of Commerce provided historical estimates of total income and per capita income for Alachua County. Forecast values of per capita income for Alachua County were obtained from Global Insight.

(6) Historical estimates of household size were obtained from the BEBR, and projected levels were estimated from a logarithmic trend.

(7) The Florida Agency for Workforce Innovation and the US Department of Labor provided historical estimates of nonagricultural employment in Alachua County. Forecast values of nonagricultural employment were obtained from Global Insight.

(8) The average price of electricity for all customer classes for all customer classes was projected to increase 3 percent per year.

(9) Estimates of energy and demand reductions resulting from planned DSM were subtracted from all retail forecasts.

10) Alachua will generate (via generation entitlement shares of PEF and FPL nuclear units) approximately 8,077 MWh (6 percent) of its annual energy requirements.

4.2 Development of Regression Equations

4.2.1 Residential Sector

The equation of the model developed to project residential average annual energy use (kilowatt-hours [kWh] per year) specifies average use as a function of household income in Alachua County, residential price of electricity, heating degree days, and cooling degree days.

Projections of the average annual number of residential customers were developed from a linear regression model stating the number of customers as a function of the Alachua County population, the number of persons per household, the historical series of Clay customer transfers, and an indicator variable for customer counts recorded under the billing system used prior to 1992.

The product of forecasted values of average use and number of customers yielded the projected energy sales for the residential sector.

4.2.2 General Service Non-Demand Sector

The GSN customer class includes nonresidential customers with maximum annual demands of less than 50 kilowatts (kW). In 1990, GRU began offering GSN customers the option to elect the GSD rate classification. This option offers potential benefit to GSN customers that use high amounts of energy and have good load factors. Since 1990, 428 customers have elected to transfer to the GSD rate class. The forecast assumes that additional GSN customers will voluntarily elect the GSD classification, but at a more modest pace than has been observed historically. A regression model was developed to project average annual energy use by GSN customers. The model includes cumulative number of optional demand customers and cooling degree days as independent variables.

The number of GSN customers was projected using an equation specifying customers as a function of Alachua County population, Clay non-demand transfer customers, and the number of optional demand customers.

Forecasted energy sales to GSN customers were derived from the product of the projected number of customers and the projected average annual use per customer.

4.2.3 General Service Demand Sector

The GSD customer class includes nonresidential customers with established annual maximum demands typically of at least 50 kW, but less than 1,000 kW. Average annual energy use per customer was projected using an equation specifying average use as a function of per capita income (Alachua County) and the number of optional demand customers. A significant portion of the energy load in this sector is from large retailers such as department stores and grocery stores, whose business activity is related to income levels of area residents.

The annual average number of customers was projected using a regression model that includes the Alachua County population, Clay demand customer transfers, and the number of optional demand customers as independent variables.

The forecast of energy sales to GSD customers was the resultant product of the projected number of customers and the projected average annual use per customer.

4.2.4 Large Power Sector

The large power customer class currently includes11 customers that maintain an average monthly billing demand of at least 1,000 kW. Analyses of average annual energy use were based on historical observations from 1976 through 2008. The model that was developed to project average use by large power customers includes Alachua County nonagricultural employment and the large power price of electricity as independent variables. Energy use per customer has been observed to increase over time, presumably due to the periodic expansion or increased utilization of existing facilities. This growth is measured by local employment levels in the model.

The forecast of energy sales to the large power sector was derived from the product of projected average use per customer and the projected number of large power customers, which is projected to remain constant at eleven.

4.2.5 Outdoor Lighting Sector

The outdoor lighting sector consists of streetlight, traffic light, and rental light accounts. Outdoor lighting energy sales account for approximately 1.3 percent of total energy sales. Outdoor lighting energy sales were forecast using a model that specified lighting energy as a function of the natural log of the number of residential customers.

4.2.6 Wholesale Energy Sales

The System provides control area services to two wholesale customers: Clay at the Farnsworth Substation (Clay-Farnsworth); and Alachua at the Alachua No. 1 Substation. Approximately 6 percent of City of Alachua's 2008 energy requirements were met through generation entitlements of nuclear generating units operated by PEF and FPL. These wholesale delivery points serve an urban area that is either included in, or adjacent to, the Gainesville urban area. These loads are considered part of the System's native load for facilities planning through the forecast horizon. GRU provides other utilities services in the same geographic areas served by Clay and Alachua, and continued electrical service will avoid duplicating facilities. Furthermore, the populations served by Clay and Alachua benefit from services provided by the City of Gainesville, which are in part supported by transfers from the System.

Clay-Farnsworth net energy requirements were modeled with an equation in which Alachua County population was the independent variable. Output from this model was adjusted to account for the history of load that has been transferred between GRU and Clay-Farnsworth, yielding energy sales to Clay. Historical boundary adjustments between Clay and GRU have reduced the duplication of facilities in both companies' service areas.

Net energy requirements for Alachua were estimated using a model in which Alachua's population was the independent variable. BEBR provided historical estimates of Alachua's population. This variable was projected from a trend analysis of the component populations within Alachua County.

To obtain a final forecast of the System's sales to Alachua, projected annual net energy requirements were reduced by 8,077 MWh to reflect Alachua's nuclear generation entitlements.

4.3 Net Energy for Load and Seasonal Peak Demands

The forecast of total system energy sales was derived by summing energy sales projections for each customer class: residential, GSN, GSD, large power, outdoor lighting, sales to Clay, and sales to Alachua. NEL was then forecast by applying a delivered efficiency factor for the System to total energy sales. The projected delivered efficiency factor used in this forecast was 0.96. Historical delivered efficiencies were examined from the past 25 years to make this determination. Prior to calculating NEL, the impact of energy savings from conservation programs was accounted for in energy sales to each customer class.

The forecasts of seasonal peak demands were derived from forecasts of the annual NEL. Winter peak demands were projected to occur in January of each year, and summer peak demands are projected to occur in August of each year, although historical data suggested that the summer peak is nearly as likely to occur in July. The average ratio of the most recent 25 years of monthly NEL for January and August, as a portion of annual NEL, was applied to projected annual NEL to obtain estimates of January and August NEL over the forecast horizon. The medians of the past 25 years' load factors for January and August were applied to January and August NEL projections, yielding seasonal peak demand projections. Forecast seasonal peak demands include the net impacts from planned conservation programs.

4.4 Forecast Error Bands

Probabilistic bands around the forecasts of NEL and summer peak demand were also developed. The historical forecast error from 1992 through 2008 was analyzed to determine both the standard deviation of the historical forecast error and the trajectory of forecast error over time. For example, the average error of forecasts of summer peak demand was approximately -0.1 percent 5 years into the future, about 1.1 percent 10 years into the future, and roughly 2.3 percent 15 years into the future. This trend was extrapolated 36 years for this Application. The standard deviation of all 153 data points in the historical error fan for summer peak demand was 4.57 percent. The standard deviation of NEL for historical forecast errors was 4.13 percent.

From the standard normal distribution table, the z-values for a 95 percent confidence interval are +/- 1.96. The sum of [(standard deviation of forecast error multiplied by the z-value plus a constant representing increasing error through time) was multiplied by the base case forecast value] and added to (or subtracted from) the base case value to determine the high (or low) value in each forecast year. Use of the standard normal table allowed for the development of confidence intervals of any magnitude, and in this case, a 68 percent confidence interval was also developed from z-values of +/- 1.00.

4.5 Forecast Results, Tables, and Figures

Table 4-1 presents historical and forecast NEL, including 68 percent and 95 percent confidence intervals (CIs) for the base case NEL. Figure 4-1 depicts this same information graphically. Table 4-2 gives historical and forecast summer peak demand, with 68 percent and 95 percent confidence intervals for the base case summer peak demand. Figure 4-2 depicts this same information graphically.

Table 4-1
Historical and Forecast Net Energy for Load (GWh)

Year	History	Lower (95% CI)	Lower (68% CI)	Base	Upper (68% CI)	Upper (95% CI)
1989	1,323					
1990	1,363					
1991	1,411					
1992	1,424					
1993	1,502					
1994	1,519					
1995	1,648					
1996	1,659					
1997	1,661					
1998	1,779					
1999	1,798					
2000	1,868					
2001	1,882					
2002	2,008					
2003	2,015					
2004	2,049					
2005	2,082					
2006	2,099					
2007	2,122					
2008	2,079					
2009		1,903	1,985	2,045	2,106	2,187
2010		1,897	1,978	2,044	2,109	2,190
2011		1,908	1,990	2,061	2,133	2,214
2012		1,925	2,008	2,085	2,162	2,245
2013		1,943	2,026	2,110	2,193	2,277
2014		1,961	2,045	2,135	2,224	2,309
2015		1,979	2,064	2,160	2,256	2,342
2016		1,994	2,081	2,183	2,285	2,372
2017		2,009	2,097	2,205	2,314	2,401
2018		2,025	2,113	2,228	2,344	2,432
2019		2,038	2,127	2,249	2,370	2,459
2020		2,047	2,137	2,265	2,394	2,483
2021		2,055	2,146	2,280	2,415	2,505
2022		2,063	2,154	2,295	2,436	2,527
2023		2,071	2,162	2,310	2,457	2,549
2024		2,078	2,170	2,325	2,479	2,571
2025		2,087	2,180	2,341	2,502	2,594
2026		2,095	2,188	2,356	2,524	2,617
2027		2,103	2,197	2,372	2,546	2,640
2028		2,111	2,205	2,387	2,569	2,663
2029		2,118	2,213	2,402	2,591	2,686
2030		2,125	2,221	2,417	2,612	2,708
2031		2,132	2,229	2,431	2,634	2,731
2032		2,139	2,236	2,446	2,656	2,753
2033		2,146	2,243	2,460	2,678	2,775
2034		2,152	2,250	2,475	2,700	2,798
2035		2,158	2,257	2,489	2,721	2,820
2036		2,165	2,264	2,503	2,743	2,842
2037		2,171	2,271	2,518	2,765	2,865
2038		2,178	2,279	2,533	2,788	2,889
2039		2,184	2,285	2,547	2,810	2,911
2040		2,190	2,291	2,561	2,831	2,933
2041		2,196	2,298	2,576	2,854	2,956
2042		2,202	2,305	2,590	2,876	2,979
2043		2,208	2,311	2,605	2,899	3,002
2044		2,215	2,318	2,620	2,922	3,026

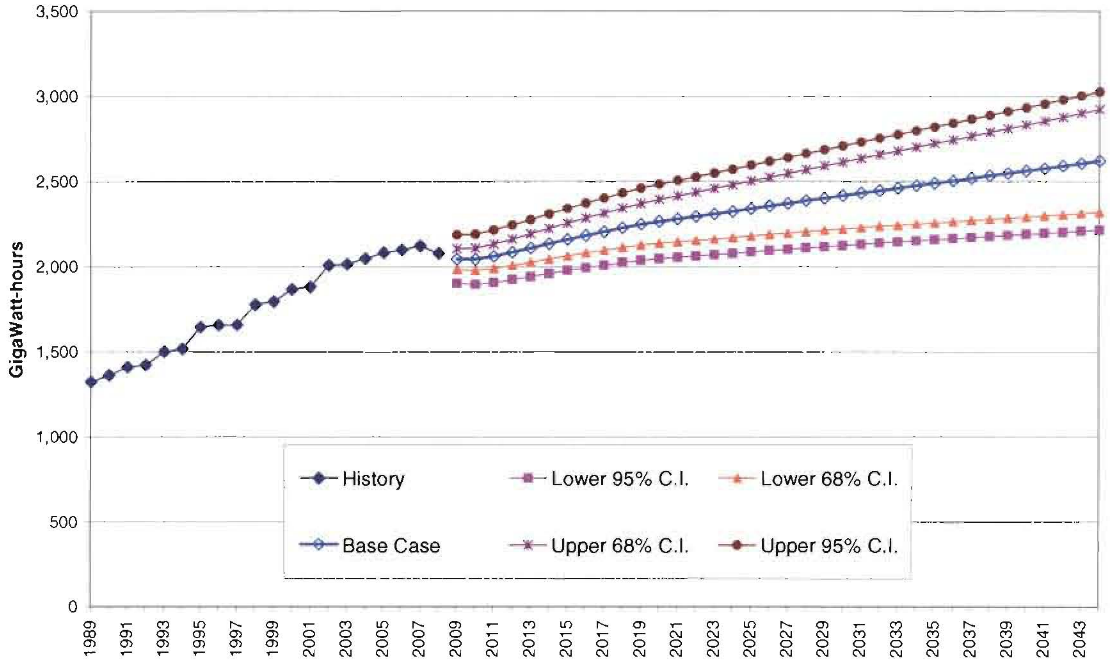

Figure 4-1
Net Energy for Load

Table 4-2
Historical and Forecast Summer Peak Demand (MW)

Year	History	Lower (95% CI)	Lower (68% CI)	Base	Upper (68% CI)	Upper (95% CI)
1989	296					
1990	305					
1991	297					
1992	320					
1993	339					
1994	331					
1995	361					
1996	365					
1997	373					
1998	396					
1999	419					
2000	425					
2001	409					
2002	433					
2003	417					
2004	432					
2005	465					
2006	464					
2007	481					
2008	457					
2009		406	425	441	458	477
2010		403	422	439	456	475
2011		403	422	441	459	478
2012		404	424	443	462	482
2013		405	425	445	466	485
2014		407	426	448	469	489
2015		408	427	450	473	492
2016		410	430	453	477	497
2017		412	432	457	482	502
2018		414	434	460	486	506
2019		415	435	463	490	510
2020		416	436	465	493	514
2021		416	437	466	496	517
2022		416	437	468	499	519
2023		417	437	469	502	522
2024		417	438	471	504	525
2025		418	438	473	507	528
2026		418	439	475	510	531
2027		419	439	476	513	534
2028		419	440	478	516	537
2029		419	440	480	519	540
2030		420	441	481	522	543
2031		420	441	483	524	546
2032		420	441	484	527	549
2033		420	442	486	530	551
2034		421	442	487	533	554
2035		421	442	489	535	557
2036		421	442	490	538	560
2037		421	443	492	541	563
2038		421	443	493	544	566
2039		421	443	495	547	568
2040		422	443	496	549	571
2041		422	444	498	552	574
2042		422	444	499	555	577
2043		422	444	501	558	580
2044		422	444	503	561	583

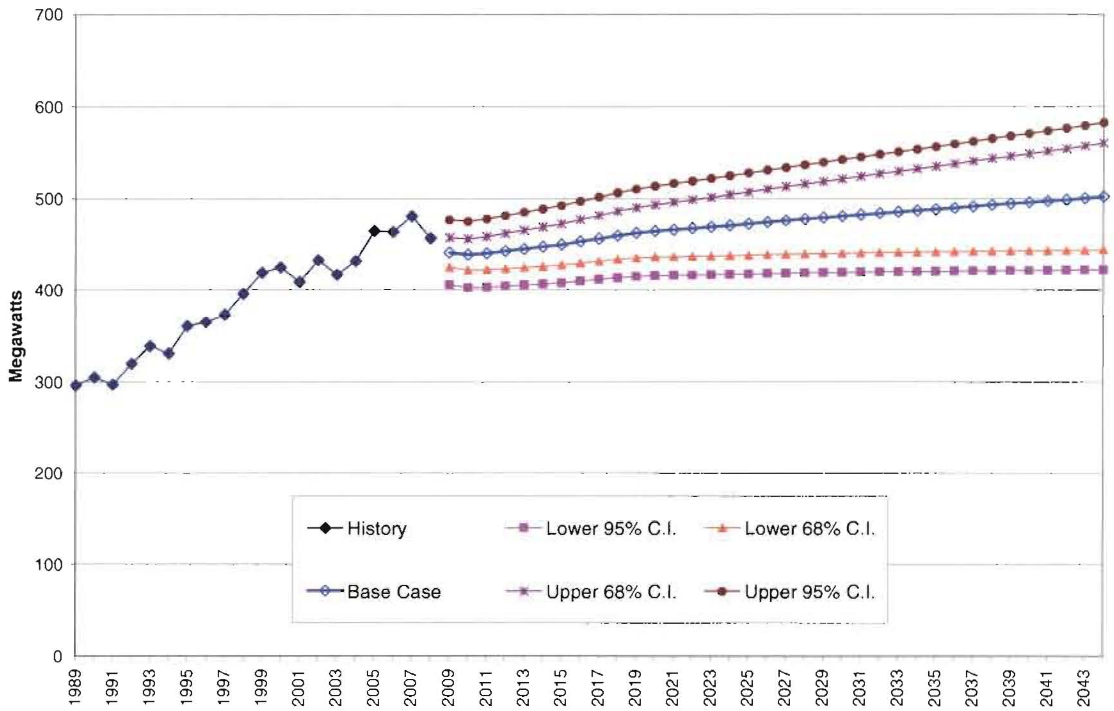

Figure 4-2
Summer Peak Demand

5.0 Reliability Criteria and Capacity Requirements

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

5.1 Reserve Sharing Requirements

Section 25-6.035, FAC, requires that Florida utilities maintain a minimum 15 percent planned reserve margin for purposes of equitable sharing of energy reserves. The investor owned utilities in the State of Florida have entered into a stipulation to maintain 20 percent reserve margins, while the municipal utilities in the State generally maintain reserve margins of no less than 15 percent.

5.2 Reserve Margin Requirements

GRU uses a minimum 15 percent planning reserve margin in both the summer and winter. Based on GRU's load forecast and available capacity, the summer peak demand dictates capacity additions to maintain reserve margin requirements. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. GRU plans to maintain its seasonal reserve margins for firm load obligations. The reserve margin is calculated as follows:

$$\frac{\text{System Net Capacity - System Firm Peak Demand}}{\text{System Firm Peak Demand}}$$

5.3 Capacity Requirements

Table 5-1 presents GRU's projected capacity requirements based on the existing generating capacity resources discussed in Section 3.0 and the base case load forecast discussed in Section 4.0. As shown in Table 5-1, GRU is projected to require additional capacity in order to maintain reserve margin requirements beginning in 2023.

Table 5-2 presents GRU's projected capacity requirements based on the existing generating capacity resources discussed in Section 3.0 and the base case load forecast discussed in Section 4.0, and reflects the capacity that will be provided by the GREC biomass PPA (including GRU's planned initial sale of 50 MW from the facility). As shown in Table 5-2, after factoring in the capacity from the GREC biomass facility GRU's projected need for additional capacity in order to maintain reserve margin requirements is deferred until 2032.

Table 5-1
GRU Projected Capacity Requirements (Without the GREC LLC PPA)

Year	GRU[1] Owned Summer Net Generating Capacity (MW)	Renewable Energy Sources			(15) Other PPAs PEF (MW)	Total Available Summer Capacity (MW)	Summer Peak Demand (MW)	15% Reserve Margin (MW)	Total Summer Peak Demand Including Reserves (MW)	Excess/ (Deficit) Capacity to Maintain Reserve Margin (MW)
		(12) FIT Solar PV (MW)	LFG G2 Energy, LLC (MW)	GREC LLC PPA (MW)						
2009	608 [2]	1	3	0	98	710	441	66	507	203
2010	608 [3]	3	4 [13]	0	98	713	439	66	505	208
2011	608	4	4	0	49 [16]	665	441	66	507	158
2012	620 [4]	6	4	0	49	678	443	66	509	168
2013	620	7	4	0	49	679	445	67	512	168
2014	597 [5]	8	4	0	0 [17]	609	448	67	515	93
2015	597	10	4	0	0	610	450	68	518	93
2016	597	11	4	0	0	611	453	68	521	90
2017	597	12	4	0	0	612	457	69	526	87
2018	583 [6]	13	4	0	0	599	460	69	529	70
2019	555 [7]	13	4	0	0	572	463	69	532	39
2020	555	14	4	0	0	572	465	70	535	37
2021	555	15	4	0	0	573	466	70	536	37
2022	555	15	4	0	0	574	468	70	538	35
2023	472 [8]	16	4	0	0	491	469	70	539	(48)
2024	472	17	4	0	0	492	471	71	542	(50)
2025	472	18	4	0	0	493	473	71	544	(51)
2026	472	18	4	0	0	493	475	71	546	(53)
2027	437 [9]	19	4	0	0	459	476	71	547	(88)
2028	437	20	4	0	0	460	478	72	550	(90)
2029	437	20	0 [14]	0	0	456	480	72	552	(96)
2030	437	20	0	0	0	456	481	72	553	(97)
2031	437	20	0	0	0	456	483	72	555	(99)
2032	205 [10]	20	0	0	0	225	484	73	557	(332)
2033	205	20	0	0	0	225	486	73	559	(334)
2034	205	20	0	0	0	225	487	73	560	(335)
2035	205	20	0	0	0	225	489	73	562	(338)
2036	205	20	0	0	0	225	490	74	564	(339)
2037	191 [11]	20	0	0	0	211	492	74	566	(355)
2038	191	20	0	0	0	211	493	74	567	(356)
2039	191	20	0	0	0	211	495	74	569	(359)
2040	191	20	0	0	0	211	496	74	570	(360)
2041	191	20	0	0	0	211	498	75	573	(362)
2042	191	20	0	0	0	211	499	75	574	(363)
2043	191	20	0	0	0	211	501	75	576	(365)

(1) GRU's assets including photovoltaic (PV) and efficiency and capacity improvements and retirements.
(2) This capacity reflects MW reductions in net capacity due to auxiliary power to run Deerhaven Unit 2's new (May 2009) Air Quality Control Systems to significantly reduce NO_X, SO_2, particulates, & mercury emissions.
(3) GRU's 0.3859 MW share of efficiency improvement in CR3 net output.
(4) Net 9.4 MW capacity increase from steam turbine and other efficiency improvement in Deerhaven Unit 2 and GRU's 1.93 MW share of capacity increase in CR3 net output (Steam Generator replacement).
(5) John R. Kelly Steam Unit 7 retires.
(6) John R. Kelly GT 1 retires.
(7) John R. Kelly GT 2 & GT 3 retire.
(8) Deerhaven Steam Unit 1 retires.
(9) Deerhaven GT 1 & GT 2 retire.
(10) Deerhaven Steam Unit 2 retires.
(11) CR3 retires.
(12) Total from Feed-In Tariff for Solar PV capacity adjusted for coincidence as well as annual increases in Feed-In Tariff capacity and follow-on net metered PV.
(13) Additional net 0.775 MW delivered capacity from G2 Energy Power Purchase Agreement (PPA).
(14) End of net delivered 3.68 MW from G2 Energy PPA.
(15) Total from Other PPAs adjusting for losses.
(16) End of PEF's 50 MW summer PPA (48.94 MW delivered).
(17) End of PEF's 50 MW summer PPA (48.94 MW delivered).

Table 5-2
GRU Projected Capacity Requirements (With the GREC LLC PPA)

Year	GRU [1] Owned Summer Net Generating Capacity (MW)	Renewable Energy Sources			(17) Other PPAs PEF (MW)	Total Available Summer Capacity (MW)	Summer Peak Demand (MW)	15% Reserve Margin (MW)	Total Summer Peak Demand Including Reserves (MW)	Excess/ (Deficit) Capacity to Maintain Reserve Margin (MW)
		(12) FIT Solar PV (MW)	LFG G2 Energy, LLC (MW)	GREC LLC PPA (MW)						
2009	608 [2]	1	3	0	98	710	441	66	507	203
2010	608 [3]	3	4 [13]	0	98	713	439	66	505	208
2011	608	4	4	0	49 [18]	665	441	66	507	158
2012	620 [4]	6	4	0	49	678	443	66	509	168
2013	620	7	4	0	49	679	445	67	512	168
2014	597 [5]	8	4	50 [15]	0 [19]	659	448	67	515	143
2015	597	10	4	50	0	660	450	68	518	143
2016	597	11	4	50	0	661	453	68	521	140
2017	597	12	4	50	0	662	457	69	526	137
2018	583 [6]	13	4	50	0	649	460	69	529	120
2019	555 [7]	13	4	50	0	622	463	69	532	89
2020	555	14	4	50	0	622	465	70	535	87
2021	555	15	4	50	0	623	466	70	536	87
2022	555	15	4	50	0	624	468	70	538	85
2023	472 [8]	16	4	50	0	541	469	70	539	2
2024	472	17	4	100 [16]	0	592	471	71	542	50
2025	472	18	4	100	0	593	473	71	544	49
2026	472	18	4	100	0	593	475	71	546	47
2027	437 [9]	19	4	100	0	559	476	71	547	12
2028	437	20	4	100	0	560	478	72	550	10
2029	437	20	0 [14]	100	0	556	480	72	552	4
2030	437	20	0	100	0	556	481	72	553	3
2031	437	20	0	100	0	556	483	72	555	1
2032	205 [10]	20	0	100	0	325	484	73	557	(232)
2033	205	20	0	100	0	325	486	73	559	(234)
2034	205	20	0	100	0	325	487	73	560	(235)
2035	205	20	0	100	0	325	489	73	562	(238)
2036	205	20	0	100	0	325	490	74	564	(239)
2037	191 [11]	20	0	100	0	311	492	74	566	(255)
2038	191	20	0	100	0	311	493	74	567	(256)
2039	191	20	0	100	0	311	495	74	569	(259)
2040	191	20	0	100	0	311	496	74	570	(260)
2041	191	20	0	100	0	311	498	75	573	(262)
2042	191	20	0	100	0	311	499	75	574	(263)
2043	191	20	0	100	0	311	501	75	576	(265)

(1) GRU's assets including PV and efficiency & capacity improvements and retirements.
(2) This capacity reflects MW reductions in net capacity due to auxiliary power to run Deerhaven Unit 2's new (May 2009) Air Quality Control Systems to significantly reduce NO_X, SO_2, particulates, & mercury emissions.
(3) GRU's 0.3859 MW share of efficiency improvement in CR3 net output.
(4) Net 9.4 MW capacity increase from steam turbine and other efficiency improvement in Deerhaven Unit 2 and GRU's 1.93 MW share of capacity increase in CR3 net output (Steam Generator replacement).
(5) John R. Kelly Steam Unit 7 retires.
(6) John R. Kelly GT 1 retires.
(7) John R. Kelly GT 2 & GT 3 retire.
(8) Deerhaven Steam Unit 1 retires.
(9) Deerhaven GT 1 & GT 2 retire.
(10) Deerhaven Steam Unit 2 retires.
(11) CR3 retires.
(12) Total from Feed-In Tariff for Solar PV capacity adjusted for coincidence as well as annual increases in Feed-In Tariff capacity and follow-on net metered PV.
(13) Additional net 0.775 MW delivered capacity from G2 Energy Purchased Power Agreement (PPA).
(14) End of net delivered 3.68 MW from G2 Energy PPA.
(15) Addition of 100 MW from GREC LLC PPA and start of 10 year resale of 50 MW from GREC.
(16) End of GREC LLC PPA 50 MW Resale.
(17) Total from Other PPAs adjusting for losses.
(18) End of PEF's 50 MW summer PPA (48.94 MW delivered).
(19) End of PEF's 50 MW summer PPA (48.94 MW delivered).

6.0 Economic Parameters

This section presents the economic parameters and methodology used to develop the levelized cost of electricity from the proposed biomass project, as well as the alternatives to which the proposed project is being compared in this Application.

6.1 Inflation and Escalation Rates

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

6.2 Municipal Bond Interest Rate

The tax exempt municipal bond interest rate is based on GRU's current cost of debt of 4.2 percent.

6.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax exempt municipal bond interest rate of 4.2 percent.

6.4 Interest During Construction Rate

The interest during construction rate (IDC) is assumed to be 4.2 percent.

6.5 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.

Different generating technologies are assumed to have different economic lives and, therefore, different financing terms. Simple cycle combustion turbines are assumed to have a 20 year financing term, combined cycle units are assumed to be financed over 25 years, and solid fuel units are assumed to be financed over 30 years. Given the various economic lives and corresponding financing terms, different levelized FCRs were developed. All levelized FCR calculations assume the 4.2 percent tax exempt municipal bond interest rate, a 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund equal to 100 percent of the average annual debt service requirement earning interest at an interest rate equal to the bond interest rate of 4.2 percent. The resulting 20 year FCR is approximately 8.43 percent, the 25 year FCR is approximately 7.35 percent, and the 30 year FCR is approximately 6.66 percent.

7.0 Fuel and Emissions Allowance Price Projections

This section discusses the methodology used to develop projections for the prices of natural gas and coal specific to the Florida Reliability Coordinating Council (FRCC) region that are considered in this Application. In addition to the reference case price projections, high and low price projections have been developed. The analyses presented throughout this Application also consider projections of CO_2 emissions allowance prices. The development of CO_2 emissions allowance price projections are also discussed in this section.

7.1 Importance of Fully Integrated Fuel and Emissions Allowance Price Projections

The fuel and CO_2 emissions allowance price projections considered throughout this Application represent fully integrated forecasts. That is, fuel price supply and demand are considered in tandem with potential costs associated with the regulation of various emissions, along with numerous other market influences, to develop fully integrated projections of fuel and emissions allowance prices. This is especially important when considering the potential impacts associated with acquiring any allowances for existent regulated emissions and considering the potential impacts of the CO_2 regulations.

Although there is currently no State or Federal regulation of CO_2 emissions, several bills to regulate CO_2 emissions (and other greenhouse gases [GHGs]) have been proposed to the US Congress. On June 26, 2009, the *American Clean Energy and Security Act of 2009* (commonly referred to as H.R. 2454) passed the US House of Representatives. While H.R. 2454 has not yet passed through the US Senate, it is considered the leading bill to regulate CO_2 emissions. As such, this Application considers the potential regulation of CO_2 emissions as discussed in Sections 7.6 and 7.7.

7.2 Description of 2009 US Energy Information Administration Annual Energy Outlook Reference Case

The fuel price projections for natural gas, fuel oil, and coal used in this Application were developed based on those included in the EIA's Annual Energy Outlook 2009 (AEO2009)[1]. The AEO2009 presents projections of energy supply, demand, and prices through 2030. The projections presented in the AEO2009 are based on results

[1] The version of AEO2009 is that published by the EIA in April 2009 and represents the updated AEO2009 to reflect the provisions of the American Recovery and Reinvestment Act (ARRA) that were enacted in mid-February 2009.

from the EIA's National Energy Modeling System (NEMS). NEMS is a computer based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics. The discussion of the fuel price projections presented in this section is intended to be an overview of the AEO2009 and, therefore, focuses on the more salient aspects of AEO2009 and elaborates on relevant conclusions and projections.

The AEO2009 in its entirety can be found on the EIA web site at http://www.eia.doe.gov/oiaf/servicerpt/stimulus/index.html while documentation on the NEMS can be found at http://tonto.eia.doe.gov/FTPROOT/modeldoc/m057(2009).pdf.

7.2.1 Consideration of State and Federal Legislation and Regulations in AEO2009

Analyses developed by the EIA are required to be policy neutral. Therefore, the projections in the AEO2009 generally are based on Federal and State laws and regulations in effect on or before November 2008. As stated in the AEO2009, the potential impacts of pending or proposed legislation, regulations, and standards – and sections of existing legislation that require implementing regulations or funds that have not been appropriated– are not reflected in the projections.

7.3 AEO2009 Reference Case FRCC Natural Gas and Coal Price Projections

The AEO2009 Reference Case forecast prices for natural gas and coal delivered to the FRCC region are presented in Table 7-1. The fuel price projections shown in Table 7-1 are presented in constant 2007 dollars per million British Thermal Units (MBtu). For the economic analysis presented in Section 12.0 of this Application, the fuel price projections were extrapolated beyond 2030, based on the average annual escalation rate in fuel prices for 2026 through 2030, and then converted to nominal dollars per MBtu by applying the 2.5 percent general inflation rate.

Table 7-1
Annual Energy Outlook 2009 Reference Case Price Projections Forecast of Natural Gas and Coal Delivered to the FRCC(1)

Year	Natural Gas (2007 $/MBtu)	Coal (2007 $/MBtu)
2009	4.99	3.03
2010	5.61	2.75
2011	6.32	2.76
2012	6.99	2.66
2013	6.81	2.68
2014	7.05	2.67
2015	7.24	2.67
2016	7.44	2.68
2017	7.57	2.65
2018	7.74	2.60
2019	7.98	2.61
2020	8.18	2.61
2021	8.42	2.60
2022	8.54	2.60
2023	8.38	2.60
2014	8.40	2.61
2025	8.18	2.63
2026	8.28	2.65
2027	8.43	2.66
2028	8.74	2.66
2029	8.95	2.66
2030	9.19	2.67

(1) Based on data presented in Supplemental Table 79 to the AEO2009 Reference Case updated with provisions of the ARRA.

7.4 AEO2009 High and Low Price Case Natural Gas and Coal Price Projections

The AEO2009 includes various cases in addition to the Reference Case. Each of these cases incorporates various changes to the Reference Case assumptions. Of the various cases considered by the EIA as part of the AEO2009, two cases have been carried forward to the analyses considered in this Application in addition to the Reference Case – the High Price Case and the Low Price Case. Both the High Price Case and the Low Price Case rely on assumptions consistent with the Reference Case, with the exception of assumptions related to crude oil and natural gas resources. The High Price Case reflects more pessimistic assumptions related to these resources; the Low Price Case reflects more optimistic assumptions. Both the High Price Case and Low Price Case are fully integrated NEMS simulations, consistent with the Reference Case.

It should be noted that the additional cases provided by the EIA as part of the AEO2009 were not developed to reflect the provisions of the ARRA discussed previously in this section. As a result, the AEO2009 Reference Case published in March 2009 (which does not reflect provisions of ARRA) has been used to develop high and low price projections for purposes of this Application. To develop high fuel price projections, annual price differences between the March 2009 AEO Reference Case and High Price Case were calculated for natural gas and coal. Similarly, low price projections were developed by calculating annual price differences between the March 2009 AEO Reference Case and Low Price Case for natural gas and coal.

The following section discusses the methodology used to develop high and low fuel price projections specific to the FRCC.

7.5 FRCC High and Low Fuel Price Projections

The following subsections discuss the methodology used to develop the FRCC-specific high and low fuel price projections and present the resulting annual natural gas and coal price projections.

7.5.1 High and Low Fuel Price Projections for the FRCC

7.5.1.1 High and Low Natural Gas Prices. To develop natural gas price projections for the FRCC region based on the AEO2009 High Price Case, the March 2009 AEO Reference Case and High Price Case natural gas price projections were analyzed to determine the annual price differentials. These differentials were then added to the FRCC-specific natural gas price projections presented in Table 7-1.

To develop natural gas price projections for the FRCC region based on the AEO2009 Low Price Case, the March 2009 AEO Reference Case and Low Price Case natural gas price projections were analyzed to determine the annual price differentials. These differentials were then subtracted from the FRCC-specific natural gas price projections presented in Table 7-1.

The resulting high and low natural gas price projections specific to the FRCC region are presented in Table 7-2.

7.5.1.2 High and Low Coal Prices. To develop coal price projections for the FRCC region based on the AEO2009 High Price Case, the March 2009 AEO Reference Case and High Price Case coal price projections were analyzed to determine the annual price differentials. These differentials were then added to the FRCC-specific coal gas price projections presented in Table 7-1.

To develop coal price projections for the FRCC region based on the AEO2009 Low Price Case, the March 2009 AEO Reference Case and Low Price Case coal price projections were analyzed to determine the annual price differentials. These differentials were then subtracted from the FRCC-specific coal price projections presented in Table 7-1.

The resulting high and low coal price projections specific to the FRCC region are presented in Table 7-2.

7.6 EIA Analysis of H.R. 2454

Several bills to regulate emissions of GHGs (including CO_2) have been proposed to the US Congress in recent years. In response to a request from Senators Henry A. Waxman and Edward J. Markey, the EIA developed an analysis entitled *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009,* which was published in August 2009. The following subsections discuss this analysis and summarize the conclusions EIA arrived at regarding projected CO_2 emissions allowance prices and associated impacts to the prices of natural gas and coal. Given that it is the most current comprehensive, fully integrated analysis of the leading proposed legislation to regulate CO_2 emissions (with the legislation having passed though the US House of Representatives on June 26, 2009), the EIA's analysis of H.R. 2454 was selected for consideration in this Application.

Table 7-2
High and Low Case Price Projections
Forecast of Natural Gas and Coal Delivered to the FRCC

Year	Natural Gas (2007 $/MBtu)		Coal (2007 $/MBtu)	
	High Price	Low Price	High Price	Low Price
2009	4.99	4.99	3.03	3.03
2010	5.84	5.03	2.77	2.72
2011	6.57	5.65	2.78	2.72
2012	7.23	6.14	2.68	2.60
2013	7.16	5.98	2.71	2.62
2014	7.52	6.15	2.71	2.60
2015	7.85	6.32	2.73	2.62
2016	8.06	6.58	2.73	2.63
2017	8.23	6.73	2.70	2.60
2018	8.40	6.88	2.66	2.55
2019	8.50	7.15	2.67	2.56
2020	8.55	7.68	2.67	2.56
2021	8.68	8.29	2.66	2.55
2022	8.81	8.48	2.66	2.54
2023	8.82	8.22	2.66	2.54
2024	8.75	8.10	2.66	2.54
2025	8.47	7.79	2.68	2.56
2026	8.54	7.87	2.69	2.57
2027	8.62	7.96	2.70	2.58
2028	8.98	8.34	2.70	2.58
2029	9.28	8.57	2.70	2.58
2030	9.55	8.64	2.71	2.58

7.6.1 EIA Analysis of H.R. 2454 – Overview and Summary of Results[2]

In developing its analysis of H.R. 2454, the EIA ran each of the policy cases described below through its integrated NEMS program. NEMS is developed and maintained by the EIA's Office of Integrated Analysis and Forecasting to provide projections of domestic energy-economy markets in the long term and perform policy analyses requested by decision makers in various US government agencies (including the White House, Congress, and offices within the US Department of Energy, among others). NEMS is the modeling tool used by the EIA in developing its AEO2009. For the H.R. 2454 analysis the EIA made adjustments to the AEO2009 Reference Case (updated in April 2009 to reflect the provision of the ARRA) that are delineated in Appendix B of the *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009.*

The use of NEMS allows for a fully integrated analysis of potential GHG emissions allowance prices and energy demand. As stated in the EIA's analysis of H.R. 2454:

> **NEMS endogenously calculates changes in energy-related CO_2 emissions in the analysis cases. The cost of using each fossil fuel includes the costs associated with the GHG allowances needed to cover the emissions produced when they are used. These adjustments influence energy demand and energy-related CO_2 emissions. The GHG allowance price also determines the reductions in projected baseline emissions of other GHGs based on assumed abatement cost relationships. With emission allowance banking, NEMS solves for the time path of permit prices such that cumulative emissions match the cumulative emissions target with price escalation consistent with the average cost of capital to the electric power sector.**

The EIA analysis of H.R. 2454 includes various policy cases and projections of associated CO_2 emissions allowance prices. The policy cases considered by the EIA in the analysis of H.R. 2454 (which the EIA refers to as ACESA [American Clean Energy and Security Act]) are described as follows:

- **ACESA Basic Case**--Represents an environment where key low emissions technologies (nuclear, fossil with carbon capture and sequestration [CCS], and various renewables]) are developed and deployed on a large scale in a timeframe consistent with the emissions

[2] Refer to *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* for additional detail regarding the various policy cases and the analysis as a whole.

reduction requirements of ACESA without encountering any major obstacles.

- **ACESA Zero Bank Case**--Similar to the ACESA Basic Case, but it assumes that there is no accumulation of excess allowances for use beyond 2030.
- **ACESA High Offsets Case**--Similar to the ACESA Basic Case except it assumes that covered entities use the maximum allowable amount of international offsets beginning in 2012.
- **ACESA High Cost Case**--Similar to the ACESA Basic Case except the costs of nuclear, fossil with CCS, and biomass generating technologies are assumed to be 50 percent higher.
- **ACESA No International Case**--Similar to the ACESA Basic Case, but it represents an environment in which the use of international offsets is severely limited by cost, regulation, and/or slow progress in reaching international agreements or arrangements covering offsets in key countries and sectors.
- **ACESA No International/Limited Case**--Combines the treatment of offsets in the ACESA No International Case with an assumption that the deployment of key technologies, including nuclear, fossil with CCS, and biomass, cannot expand beyond their Reference Case levels beyond 2030.
- **ACESA High Tech Case**--Similar to the ACESA Basic Case except that it incorporates more aggressive assumptions about technological improvements and their role in reducing GHG emissions.
- **ACESA Low Discount Case**--Similar to the ACESA Basic Case except that it assumes a 5 percent discount rate for allowance banking decisions.
- **ACESA 35CAFE2016 Case**--Similar to the ACESA Basic Case except that it also incorporates an accelerated schedule for raising the combined fuel economy standards for cars and light trucks to 35 miles per gallon in 2016.
- **ACESA High Banking Case**--Similar to the ACESA Basic Case, but it assumes that a greater level of allowances is banked.
- **ACESA Limited Alternatives Case**--Represents an environment in which the deployment of key technologies, including nuclear, fossil with CCS, and biomass, is limited to Reference Case levels.

The following tables and figures summarize the results of the evaluations of the 11 policy cases considered by the EIA in its analysis of H.R. 2454. Tables 7-3 and 7-4 present projections of annual natural gas and coal prices, respectively, as well as the corresponding annual price projections presented in the AEO2009 Reference Case. The annual natural gas price projections are presented in constant 2007 dollars per MBtu for pricing at Henry Hub, and the annual coal price projections are presented in constant 2007 dollars per MBtu for average minemouth prices. Annual natural gas and coal price projections are presented beginning in 2012, which is the initial year of CO_2 emissions regulations contemplated in H.R. 2454. Table 7-5 presents projections of annual CO_2 emissions allowance prices for each of the 11 policy cases, in constant 2007 dollars per metric ton CO_2 equivalent, beginning in 2012. Figure 7-1 through Figure 7-3 present graphical depictions of the data in Tables 7-3 through 7-5, respectively. Analysis of Tables 7-3 through 7-5 (supplemented by Figures 7-1 through 7-3) shows that projected impacts on natural gas prices and corresponding CO_2 emissions allowance price projections differ depending on the policy cases considered in the EIA analysis of H.R. 2454.

Table 7-3
Natural Gas Price Projections for AEO2009 Reference Case and EIA Analysis of H.R. 2454
(2007 $/MBtu – Henry Hub)

Year	AEO 2009 Reference Case[(1)]	H.R. 2454 Basic	H.R. 2454 Zero Bank	H.R. 2454 High Offsets	H.R. 2454 High Cost	H.R. 2454 No Int Offsets	H.R. 2454 No Int Offsets/ Lim Alt	H.R. 2454 Accelerated CAFE	H.R. 2454 Low Discount	H.R. 2454 Lim Alt	H.R. 2454 High Tech	H.R. 2454 High Bank
2012	5.60	5.75	5.67	5.68	5.75	5.65	6.32	5.71	5.73	5.63	5.66	5.52
2013	5.74	5.97	5.83	5.84	5.98	5.77	6.66	5.94	5.98	5.87	5.88	5.70
2014	5.92	6.13	5.97	5.98	6.13	5.90	7.03	6.11	6.17	6.04	5.99	5.85
2015	6.16	6.40	6.21	6.22	6.43	6.38	7.78	6.36	6.45	6.34	6.20	6.22
2016	6.38	6.60	6.41	6.44	6.63	6.67	8.02	6.55	6.66	6.55	6.32	6.40
2017	6.60	6.72	6.58	6.58	6.81	6.83	8.23	6.68	6.81	6.76	6.40	6.53
2018	6.82	6.81	6.72	6.75	6.97	6.87	8.45	6.74	6.88	6.94	6.48	6.62
2019	7.12	6.90	6.92	6.94	7.14	6.93	8.57	6.83	7.03	7.12	6.59	6.70
2020	7.47	7.05	7.11	7.14	7.34	7.08	8.66	7.00	6.95	7.37	6.83	6.90
2021	7.72	6.89	7.01	7.02	7.22	6.88	8.47	6.87	6.77	7.30	6.66	6.75
2022	7.74	6.73	6.85	6.87	7.13	6.69	8.56	6.71	6.83	7.26	6.52	6.67
2023	7.55	6.68	6.83	6.86	7.15	6.68	8.61	6.66	6.87	7.36	6.50	6.62
2024	7.56	6.69	6.90	6.94	7.20	6.76	8.49	6.67	6.93	7.47	6.49	6.59
2025	7.51	6.62	6.90	6.91	7.22	6.75	8.37	6.60	6.85	7.53	6.46	6.53
2026	7.64	6.69	6.92	6.96	7.37	6.76	8.59	6.66	6.89	7.65	6.37	6.59
2027	7.92	6.78	7.02	7.01	7.49	6.87	8.72	6.76	6.96	7.87	6.41	6.68
2028	8.29	7.00	7.12	7.14	7.72	7.00	8.75	6.98	7.13	8.19	6.57	6.87
2029	8.54	7.21	7.32	7.32	7.97	7.21	8.75	7.18	7.30	8.51	6.84	7.14
2030	8.83	7.36	7.39	7.34	8.13	7.28	8.78	7.37	7.35	8.78	7.11	7.35

(1) April 2009 update of AEO2009 reflecting ARRA provisions, as described previously in Section 7.0 of this Application.

Table 7-4
Coal Price Projections for AEO2009 Reference Case and EIA Analysis of H.R. 2454
(2007 $/MBtu – Average Minemouth)

Year	AEO 2009 Reference Case[(1)]	H.R. 2454 Basic	H.R. 2454 Zero Bank	H.R. 2454 High Offsets	H.R. 2454 High Cost	H.R. 2454 No Int Offsets	H.R. 2454 No Int Offsets/ Lim Alt	H.R. 2454 Accelerated CAFE	H.R. 2454 Low Discount	H.R. 2454 Lim Alt	H.R. 2454 High Tech	H.R. 2454 High Bank
2012	1.37	1.35	1.35	1.36	1.35	1.36	1.42	1.36	1.35	1.36	1.35	1.35
2013	1.37	1.35	1.36	1.36	1.35	1.30	1.40	1.35	1.35	1.36	1.35	1.35
2014	1.38	1.35	1.36	1.36	1.34	1.32	1.40	1.35	1.34	1.36	1.35	1.35
2015	1.38	1.35	1.37	1.36	1.35	1.34	1.36	1.35	1.35	1.37	1.35	1.34
2016	1.38	1.34	1.36	1.36	1.34	1.34	1.36	1.34	1.34	1.37	1.34	1.34
2017	1.38	1.33	1.36	1.36	1.33	1.34	1.35	1.33	1.34	1.36	1.33	1.34
2018	1.38	1.34	1.36	1.35	1.33	1.31	1.33	1.34	1.35	1.36	1.33	1.34
2019	1.37	1.34	1.35	1.34	1.32	1.31	1.32	1.34	1.34	1.36	1.34	1.35
2020	1.37	1.36	1.34	1.34	1.33	1.33	1.33	1.36	1.35	1.37	1.34	1.37
2021	1.38	1.37	1.36	1.35	1.35	1.33	1.36	1.38	1.36	1.38	1.36	1.38
2022	1.38	1.39	1.36	1.36	1.34	1.33	1.38	1.39	1.37	1.39	1.37	1.37
2023	1.38	1.39	1.37	1.37	1.34	1.32	1.39	1.39	1.37	1.39	1.37	1.38
2024	1.39	1.39	1.38	1.37	1.34	1.34	1.37	1.39	1.38	1.38	1.37	1.37
2025	1.39	1.38	1.38	1.39	1.35	1.34	1.35	1.37	1.38	1.37	1.36	1.35
2026	1.39	1.36	1.38	1.38	1.35	1.34	1.35	1.37	1.38	1.35	1.34	1.34
2027	1.39	1.36	1.37	1.37	1.34	1.33	1.36	1.35	1.38	1.33	1.33	1.32
2028	1.39	1.35	1.36	1.37	1.35	1.34	1.39	1.35	1.37	1.32	1.31	1.31
2029	1.40	1.33	1.36	1.36	1.35	1.34	1.38	1.33	1.36	1.31	1.29	1.27
2030	1.40	1.30	1.36	1.36	1.34	1.32	1.45	1.30	1.35	1.29	1.27	1.23

(1) April 2009 update of AEO2009 reflecting ARRA provisions, as described previously in Section 7.0 of this Application.

Table 7-5
EIA Projections of CO_2 Emissions Allowance Prices per Analysis of H.R. 2454
(2007 $/metric ton)

Year	H.R. 2454 Basic	H.R. 2454 Zero Bank	H.R. 2454 High Offsets	H.R. 2454 High Cost	H.R. 2454 No Int Offsets	H.R. 2454 No Int Offsets/ Lim Alt	H.R. 2454 Accelerated CAFE	H.R. 2454 Low Discount	H.R. 2454 Lim Alt	H.R. 2454 High Tech	H.R. 2454 High Bank
2012	17.93	11.23	11.59	19.98	29.42	52.71	17.80	22.86	20.53	15.70	20.56
2013	19.26	12.06	12.45	21.46	31.60	56.61	19.12	24.00	22.05	16.87	22.08
2014	20.69	12.96	13.37	23.05	33.94	60.80	20.53	25.20	23.68	18.12	23.71
2015	22.22	13.91	14.36	24.76	36.45	65.30	22.05	26.46	25.44	19.46	25.46
2016	23.86	14.94	15.42	26.59	39.15	70.13	23.68	27.78	27.32	20.90	27.35
2017	25.63	16.05	16.56	28.56	42.04	75.32	25.43	29.17	29.34	22.44	29.37
2018	27.52	17.24	17.79	30.67	45.15	80.89	27.31	30.63	31.51	24.10	31.55
2019	29.56	18.51	19.11	32.94	48.50	86.88	29.34	32.16	33.84	25.89	33.88
2020	31.75	19.88	20.52	35.37	52.08	93.30	31.51	33.77	36.35	27.80	36.39
2021	34.10	21.35	22.04	37.99	55.94	100.21	33.84	35.46	39.04	29.86	39.08
2022	36.62	22.94	23.67	40.80	60.08	107.62	36.34	37.23	41.93	32.07	41.97
2023	39.33	24.63	25.42	43.82	64.52	115.59	39.03	39.09	45.03	34.44	45.08
2024	42.24	26.46	27.30	47.07	69.30	124.14	41.92	41.04	48.36	36.99	48.41
2025	45.37	28.41	29.32	50.55	74.43	133.33	45.02	43.10	51.94	39.73	52.00
2026	48.73	30.52	31.49	54.29	79.93	143.20	48.35	45.25	55.78	42.67	55.84
2027	52.33	32.77	33.82	58.31	85.85	153.79	51.93	47.51	59.91	45.82	59.98
2028	56.20	35.20	36.32	62.62	92.20	165.17	55.78	49.89	64.35	49.22	64.42
2029	60.36	37.80	39.01	67.26	99.02	177.40	59.90	52.38	69.11	52.86	69.18
2030	64.83	40.60	41.90	72.23	106.35	190.52	64.34	55.00	74.22	56.77	74.30

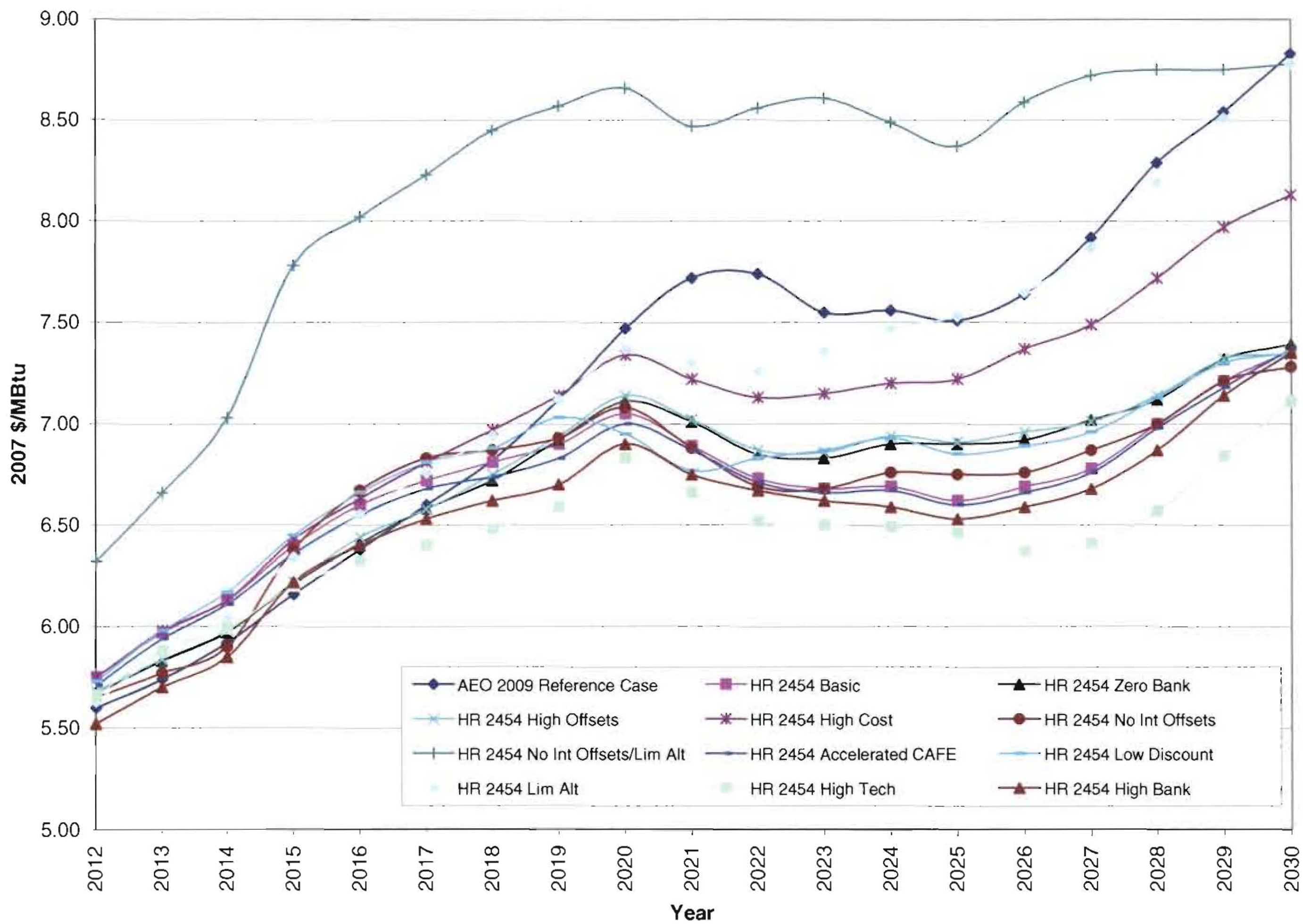

Figure 7-1
Natural Gas Price Projections for AEO2009 Reference Case and EIA Analysis of H.R. 2454
(2007 $/MBtu – Henry Hub)

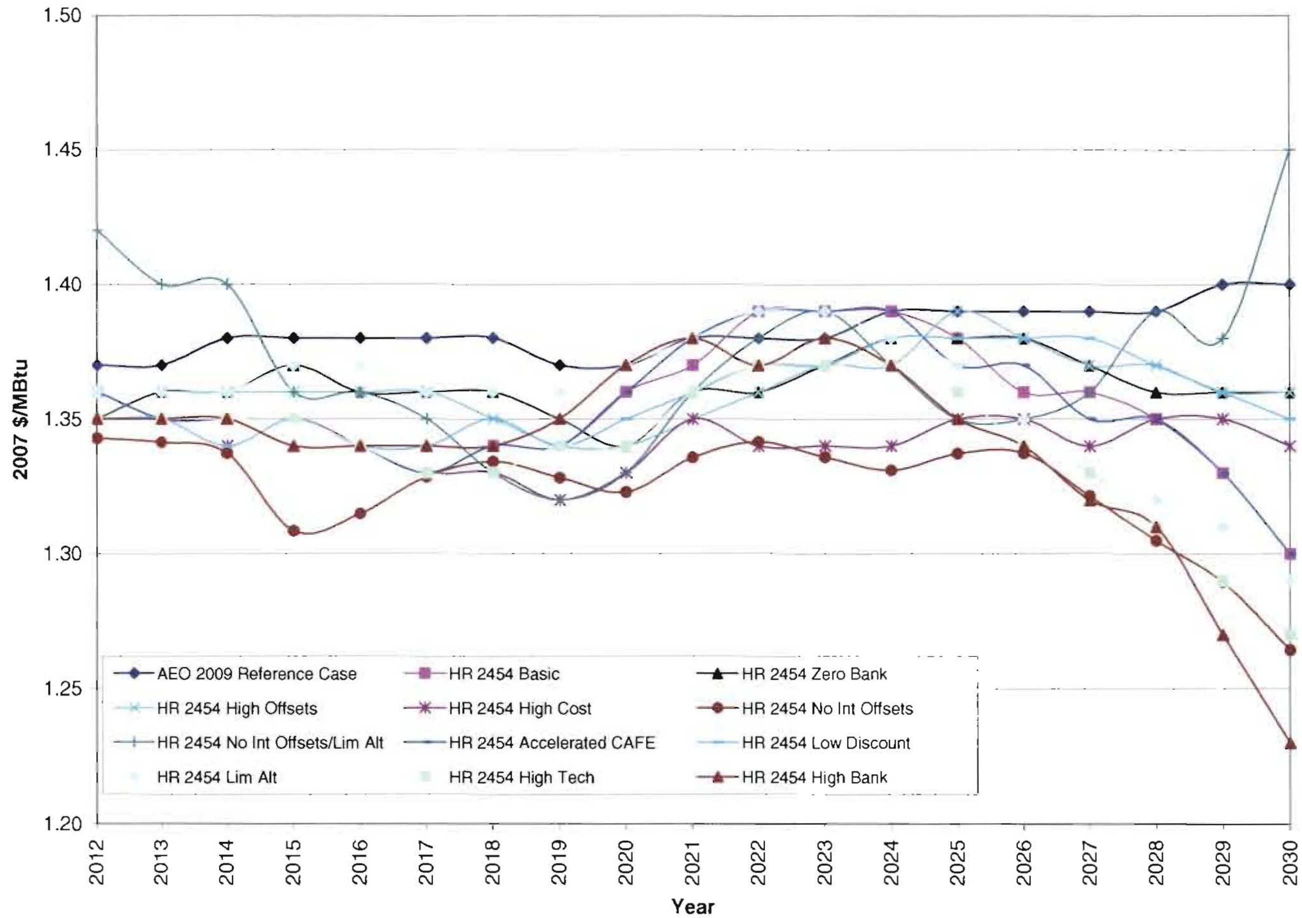

Figure 7-2
Coal Price Projections for AEO2009 Reference Case and EIA Analysis of H.R. 2454
(2007 $/MBtu – Average Minemouth)

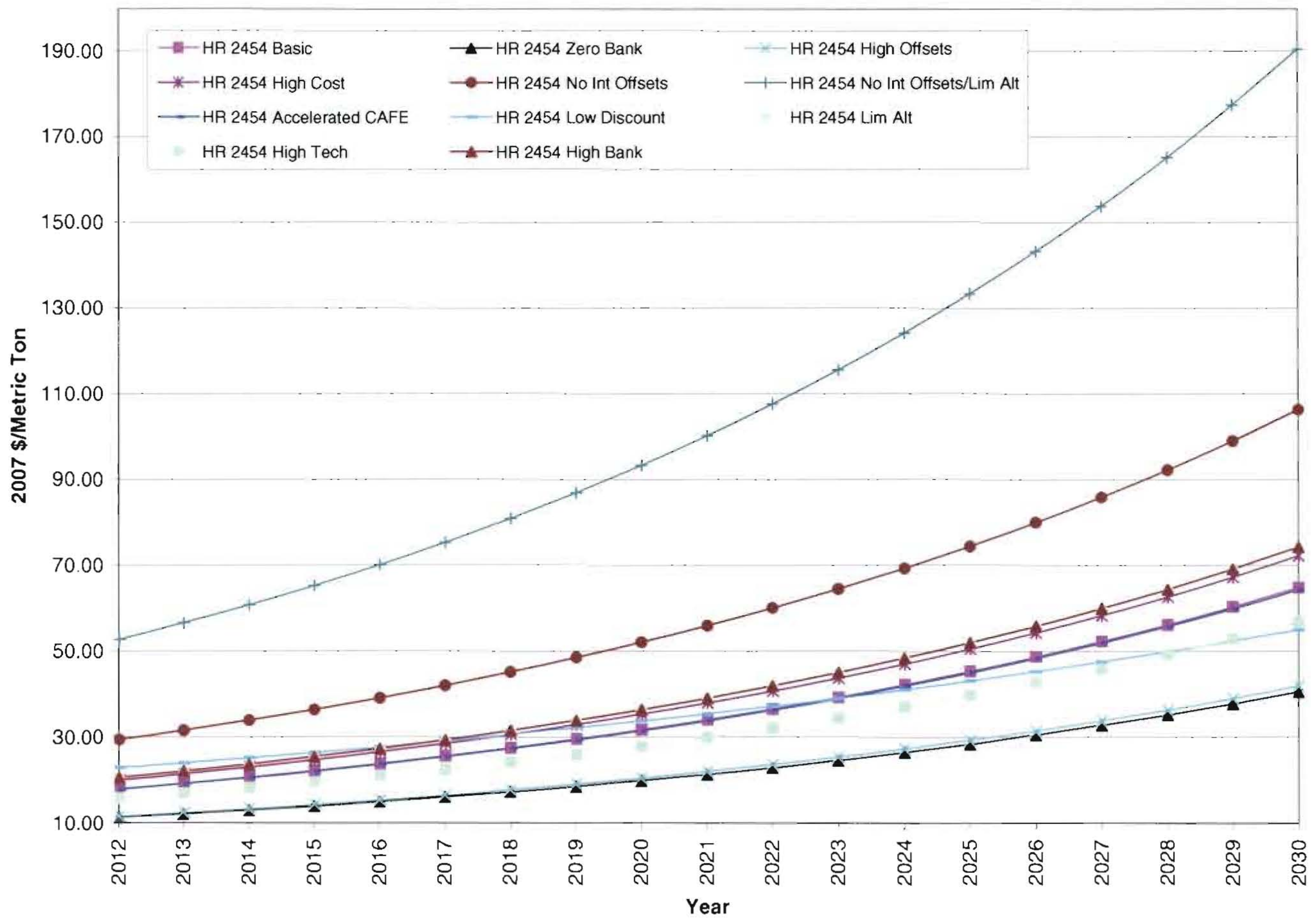

Figure 7-3
CO_2 Emissions Allowance Price Projections per EIA Analysis of H.R. 2454
(2007 $/Metric Ton)

7.7 Consideration of EIA Analysis of H.R. 2454

As discussed in Section 7.6, the *American Clean Energy and Security Act of 2009* has passed though the US House of Representatives. The EIA's analysis of H.R. 2454 included projections of natural gas and coal prices, along with projected prices for CO_2 emissions, for 11 policy cases involving different assumptions related to the structure of how H.R. 2454 may be implemented if ultimately enacted. The fuel price projections, as well as the CO_2 emissions allowance price projections, for each of the 11 policy cases are presented throughout Section 7.6.

Of the 11 policy cases evaluated by the EIA in its analysis of H.R. 2454, two were selected for further evaluation in this Application for the following reasons:

- The EIA considers the H.R. 2454 Basic Case as being representative of an environment where key low emissions technologies (nuclear, fossil with carbon capture and sequestration [CCS], and various renewables) are developed and deployed on a large scale in a time frame consistent with the emissions reduction requirements of ACESA without encountering any major obstacles. Additionally, the impact on natural gas and coal price projections, along with the resulting projections of CO_2 emissions allowance prices, for the H.R. 2454 Basic Case are bracketed by the 10 other policy cases. For these reasons, the H.R. 2454 Basic Case was selected for further analysis in this Application.
- The impacts on natural gas and coal price projections, along with the resulting projections of CO_2 emissions allowance prices, are most pronounced in the H.R. 2454 No International/Limited Case. Therefore, this case was selected for a high CO_2 price case for further evaluation in this Application.

7.7.1 H.R. 2454 Fuel Price Projections for the FRCC

To develop natural gas and coal price projections for the FRCC region based on the EIA's analysis of H.R. 2454, the April 2009 AEO Reference Case and the price projections described earlier in this section from the EIA's analysis of H.R. 2454 were analyzed to determine the annual price differentials. These differentials were then added to the FRCC-specific natural gas price projections presented in Table 7-1.

The resulting natural gas and coal price projections specific to the FRCC region reflecting the EIA's analysis of H.R. 2454 are presented in Table 7-6.

Table 7-6
H.R. 2454 Fuel Price Projections
Forecast of Natural Gas and Coal Delivered to the FRCC

Year	Natural Gas (2007 $/MBtu)		Coal (2007 $/MBtu)	
	H.R. 2454 Basic Case	H.R. 2454 No International/ Limited Alternatives	H.R. 2454 Basic Case	H.R. 2454 No International/ Limited Alternatives
2012	7.14	7.71	2.64	2.72
2013	7.04	7.73	2.66	2.71
2014	7.26	8.16	2.63	2.68
2015	7.48	8.86	2.63	2.65
2016	7.66	9.09	2.64	2.65
2017	7.70	9.20	2.60	2.62
2018	7.73	9.37	2.56	2.55
2019	7.77	9.44	2.58	2.56
2020	7.76	9.36	2.60	2.56
2021	7.59	9.17	2.60	2.59
2022	7.53	9.36	2.60	2.59
2023	7.51	9.44	2.61	2.61
2024	7.53	9.33	2.62	2.59
2025	7.29	9.03	2.62	2.60
2026	7.33	9.22	2.62	2.61
2027	7.29	9.23	2.62	2.63
2028	7.46	9.21	2.62	2.66
2029	7.61	9.16	2.60	2.64
2030	7.72	9.14	2.57	2.72

8.0 GRU Resource Planning Process

The purpose of this section is to provide the Florida Public Service Commission with a sense of the extensiveness and depth of the IRP studies and the public participation and City Commission deliberations that have culminated in GRU's decision to pursue its PPA from the proposed GREC biomass facility.

8.1 Summary of Recent Activities

Load and energy forecasts developed early in 2003 indicated that GRU would need additional baseload capacity by 2011, which was not too soon to begin considering alternatives with long lead times, especially solid fuel alternatives. The ensuing community discussion was extensive and in-depth, and included evaluations of nearly every demand and supply resource alternative; analysis and simulations of local air quality; and consideration of climate change trends. The entire process led to at least eight major policy decisions that resulted in the decision to proceed with the GREC. These policy decisions included the following:

1. Electric rate designs intended to promote energy conservation.
2. Adoption of the total resource cost (TRC) test for DSM planning.
3. Adoption of a DSM plan that would reduce load growth by 60 percent.
4. Commitment to the goal of meeting the Kyoto Protocol.
5. Exclusion of coal and petroleum coke as fuel sources for additional new capacity.
6. Consideration of PPAs in lieu of self-built generation facilities.
7. Energy efficient combined heat and power (CHP) distributed generation.
8. Implementation of the first utility European style solar FIT in the USA.

The combined effect of the DSM programs, the addition of 7.1 MW of generation from CHP and landfill gas to energy projects, the ongoing addition of 4 MW per year of solar PV capacity through the solar FIT, and the effects of the recent economic downturn have delayed the need for additional generation capacity to meet planning reserve margin criteria (15 percent) until 2023.

Reserve margins are not the only criterion for additional generation capacity. The cost to produce electricity, the age and reliability of the units, and other economic and environmental factors are additional criteria to consider. GRU's most economical and largest unit, the coal fired Deerhaven Unit 2, is 28 years old, and any unplanned outage imposes significant replacement power costs on GRU's rate payers. One third of GRU's generating resources, including its other intermediate load steam plant, are older gas fired units with relatively poor heat rates and an average age of 38 years. The GREC will provide a long-term, economic, baseload generating resource, and will also help offset the cost of Deerhaven Unit 2 outages and volatile fuel prices. Furthermore, the GREC will not only help Gainesville meet its policy objectives for reducing GHGs, it will also provide a significant hedge against the costs of any forthcoming regulations mandating renewable portfolio standards or any form of carbon constraint.

8.2 Public Participation and Policy Directives

The IRP process culminating in this request for a Determination of Need for the proposed GREC was launched by the City Commission's September 2002 authorization for GRU to participate in a joint planning study with consumer owned utilities in Florida to investigate solid fuel alternatives. A wide ranging public participation component was added to the IRP process, with a public participation program sponsored by the Gainesville Energy Advisory Committee (GEAC) in the summer and fall of 2003. The GEAC is a standing citizen's advisory committee created by ordinance, whose members are appointed by the City Commission. This public participation was ongoing through May 2009, at which point the PPA with GREC LLC was approved unanimously by the City Commission. To date, there have been more than 43 community workshops and formal presentations to policymakers, including the GEAC, the City Commission's Regional Utilities Committee (RUC), the Alachua County Board of County Commissioners, and 27 televised City Commission meetings dedicated to Gainesville's long-term energy supply strategy. In addition, there have been several dozen less formal meetings with civic groups throughout the community.

Table 8-1 provides a timeline of significant milestones in the process described previously.

Table 8-1
Public Participation Timeline

Date	Milestone
Sep 23, 2002	The City Commission authorizes participation in a joint study of solid fuel generation feasibility with FMPA, Seminole, JEA, OUC, and Reedy Creek Utilities.
Summer, Fall 2003	GEAC sponsors six workshops at various city locations to solicit ideas and input on DSM programs and generation alternatives.
Dec 15, 2003	A formal IRP study entitled *Alternatives For Meeting Gainesville's Electrical Requirements Through 2022: Base Study And Preliminary Findings* is presented to the City Commission
Jan 31, 2005	Staff recommends to City Commission to proceed with a 240 MW circulating fluidized bed (CFB), with capability to burn up to 30 MW of biomass
Jun 14, 2005	Staff is authorized to solicit an independent study of DSM potential and IRP analysis of selected generation expansion plans.
Jun 27, 2005	Gainesville signs the Mayors' Climate Protection Agreement with an objective of meeting the Kyoto Protocol for GHG reduction.
Apr 12, 2006	The TRC test for DSM planning and ICF and GDS recommendation for "All Source Solicitation" is approved.
Aug 21, 2006	The budget is approved for a DSM plan to reduce load growth by 60 percent (since re-approved).
Jun 18, 2007	After the results of the "All Source Solicitation" are presented, a decision is made not to pursue coal or petroleum coke and to consider PPAs in addition to ownership options
Summer 2007	University of Florida School of Forest Resources performs biomass fuel study.
Oct 8, 2007	A two step process for biomass solicitation is initiated.
Jan 28, 2008	Biomass proposals are evaluated and short listed to three.
May 12, 2008	American Renewables (previously Nacogdoches Power) proposal for 100 MW net fluidized bed biomass facility is selected (now named GREC).
Summer, Fall 2008	Consideration and eventual decline of opportunity for minority participation in PEF's proposed nuclear facility to be located in Levy County.
Apr 16, 2009	The Forest Stewardship Incentive Plan is approved.
May 7, 2009	The City Commission approves the PPA with GREC, LLC.

8.3 Alternative Evaluations

The IRP studies throughout the process described previously ranged from technology feasibility screening studies and busbar comparisons to full blown generation optimization studies using the Electric Power Research Institute (EPRI) *Electrical Generation Expansion Analysis System (EGEAS).* Table 8-2 summarizes the alternatives considered through the period 2003 and 2004. Table 8-3 summarizes the alternatives evaluated through the period 2005 through 2009. The first column in Table 8-3 summarizes the alternatives evaluated using generation optimization software, specifically EGEAS.

The concern and commitment of the City Commission to managing GHG emissions led to a vote to join the Mayors' Climate Protection Agreement in June 2005. As part of that initiative, GRU conducted a carbon inventory, and the decision was made to define the system for which carbon was being managed to the City of Gainesville's operations, which included electric, natural gas, water, and wastewater utilities serving the entire Gainesville community, as well as traffic, recreation, police, fire, and public works.

8.3.1 Conservation Cost-Effectiveness Criteria Policy

Independent studies and reviews of GRU's EGEAS work were conducted by R.W. Beck, ICF Consulting (ICF), and GDS Associates (GDS). The substantial difference in DSM potential resulting from the application of the TRC test, instead of the rate impact measure (RIM) test, was clarified by ICF's DSM potential study. The TRC test for DSM planning was adopted by the City Commission in April 2006. As a result of the input from these consultants and the ongoing discussion about the relative merits of various technologies to manage air emissions, such as gasification, integrated gasification combined cycle (IGCC), and plasma arc, an "All Source Solicitation" was issued in 2006 as a way to garner information on state-of-the-art power generation.

Table 8-2
Electric Generation Alternatives Considered
Preliminary Work in 2003

Source: Technology Assessment Generation (TAG) Guide, an EPRI Product
with Updates Provided by Black & Veatch

A. Coal - Fueled Technologies

1. Pulverized Coal (PC)
   - o Conventional PC
     - Subcritical - Regenerable FGD
     - Subcritical - Spray Dryer FGD, PRB Coal
     - Subcritical - Wet Limestone FGD
     - Supercritical - Wet Limestone FGD
   - o Advanced PC
     - Supercritical - State of the Art Power Plant
       - * Advanced Limestone FGD
       - * Spray Dryer FGD, PRB Coal

2. Fluidized Bed Combustion (FBC)
   - o Atmospheric FBC
     - Bubbling Bed
     - Circulating Bed
     - Bubbling Bed, PRB Coal
     - Circulating Bed, PRB Coal
   - o Pressurized FBC
     - Combined Cycle
     - Turbocharged-Circulating Bed
     - Turbocharged-Bubbling Bed

3. Coal Gasification
   - o Integrated-Gasification-Combined-Cycle
   - o Non-Integrated-Gasification-Combine-Cycle
     - GCC on One Site
     - GCC with Gas Plant at Second Site

B. Nuclear Technology

4. Pressurized Vessel

5 Boiling Water Reactor

6. Advanced Design

7. Breeder Reactor

C. Liquid/Gas - Fueled Technologies

8. Combustion Turbine
   - o Distilled Fuel
     - Conventional
     - Advanced
   - o Natural Gas Fuel
     - Conventional
     - Advanced
   - o Steam Injected
     - 50 MW
     - 150 MW

9. Combustion Turbine - Combined Cycle (CT-CC)
   - o Distilled Fuel
     - Conventional
     - Advanced, Reheat Steam Cycle
   - o Natural Gas Fuel
     - Conventional
     - Advanced, Reheat Steam Cycle

10. Fuel Cells
    - o Phosphoric Acid
      - First gen Dispersed
      - Second gen. Dispersed
      - Second gen. Central Dispersed
    - o Molten Carbonate - First Gen. Dispersed

D. Renewable Resource Plants

11. Geothermal
    - o Binary Plant
    - o Dry Steam Plant

12 Solar Energy Conversion
   - o Solar - Thermal
     - Parabolic Trough/Gas Hybrid
   - o Solar Photovoltaic Central Station
     - Flat Plate
     - High Concentration

13. Wind Turbines
    - High Production Volume

14. Biomass Technologies
    - o Stoker
    - o CFB
    - o Gasifier

15. Municipal Solid Waste
    - o Mass Burn
    - o Refuse-Derived Fuel

E. Partnerships

16. Confidentiality Agreements with Each Company
    - o Single Combined Cycle EA class GE, 115 MW
    - o Double Combined Cycle F class GE, 450 MW
    - o Combined Cycle G class Westinghouse, 347 MW
    - o Combined Cycle H class GE, 370 MW

F. Purchases

17. Confidentiality Agreements with Each Company
    - o Single Combined Cycle F class GE
    - o Double Combined Cycle F class GE
    - o Combined Cycle G class Westinghouse
    - o Combined Cycle H class GE
    - o Pressurized Circulating Fluidized Bed

Table 8-3
Generation Alternatives Considered (2005-2009)

IRP Generator Data - Future Options (vintage September 2005)	Request For Letters of Interest + Others (vintage May 2007)	RFP for Biomass Fueled Generation Facility (Responses Received Dec. 14, 2007)	Binding Proposals for Biomass Plant (Responses Received April 11, 2008)
GreenWave DLC	GRU Self Build 50 MW BFB/STG	Covanta Energy Corporation	Covanta Energy Corporation
Photovoltaic	GRU Self Build 100 MW BFB/STG	Envortus Inc.	Nacogdoches Power, LLC
GE 7EA SCCT	Allied SynGas Corporation 86.7 - 248 MW British Gas/Lurgi/3 gasifiers/ 2-90 MW CTs/2 HRSG w duct firing/ 125MW STG	Green Power Systems	Sterling Planet
Merchant GE 7EA SCCT	Biomass Gas & Electric 75 MW Pyrolysis/CC (GE F6)	Horizon Energy Systems	
GE 7FA SCCT	Celunol production of ethanol using waste heat and biomass	Kreb & Sisler	
Merchant GE 7FA SCCT	CQ Incorporated 22 MW BFB/STG	Nacogdoches Power, LLC	
GE 7EA CCCT	Econo-Power International Corporation	NRG Energy Inc.	
Merchant GE 7EA CCCT	Florida Renewable Resource Conservation and Development Council: 78 MW Harvest and Delivery of Woody Biomass resource	Railex Merchant Energy Infrastructure Group	
GE 7FA CCCT	(EPIC) 21 to +247 MW Chinese Gasifiers	Sterling Planet	
Merchant GE 7FA CCCT	Nacogdoches 100 MW BFB/CFB /STG	Taylor Biomass Energy, LLC	
DH1+7FA+HRSG CC	NRG 100-300 MW Plasma Gasification/CC	Timberland Harvesters, LLC	
DH CFB SNCR + DH2 retrofitted w Low NOx Burners, Wet FGD, SCR, & Fabric Filter	Green Power Systems 34 MW Plasma Arc / 2 reactors / 4 boilers / 1 steam turbine		
DH CFB SNCR, within 5 yrs			
DH CFB SNCR, after 5 yrs			
DH CFB SNCR + DH2 retrofitted w Low NOx Burners, Wet FGD, SCR, & Fabric Filter			
DH FGD/SCR/PC + DH2 retrofitted w Low NOx Burners, Wet FGD, SCR, & Fabric Filter			
DH FGD/SCR/PC, within 5 yrs			
DH FGD/SCR/PC, after 5 yrs	New River Solid Waste Association 0 - 100 MW Solid Waste Landfill		

Table 8-3 (Continued)
Generation Alternatives Considered (2005-2009)

IRP Generator Data - Future Options (vintage September 2005)	Request For Letters of Interest + Others (vintage May 2007)	RFP for Biomass Fueled Generation Facility (Responses Received Dec. 14, 2007)	Binding Proposals for Biomass Plant (Responses Received April 11, 2008)
25% share of DH 439MW FGD/SCR/SC + DH2 retrofitted w Low NOx Burners, Wet FGD, SCR, & Fabric Filter	Orlando Utilities Commission, open # of MW, Interested in Any Renewable Energy Technology, willing to swap Coal Capacity		
25% share of South Florida 439MW FGD/SCR/SC	Progress Energy Florida 50 MW Base Load Capacity: composed of 3400MW of Coal & Nuclear Capacity, plus 300 MW of Renewable Generation		
25% share of DH 557MW FGD/SCR/SC + DH2 retrofitted w Low NOx Burners, Wet FGD, SCR, & Fabric Filter	Robran Industries, Inc. 185 MW gasification-oxidation rotary kiln and/or Geoplasma reactors / HRSG / rankine-cycle STG / closed-cycle no stack - no atmospheric emissions		
25% share of South Florida 557MW FGD/SCR/SC	Siemens Power Generation, Inc. 232 MW SFG gasification / SGT6-5000F		
(PC/SC) DH2 retrofitted w Low NOx Burners, Wet FGD, SCR, & Fabric Filter	Southern Power Company or through a wholly owned subsidiary, 280/98 @ GRU MW One air-blown transport gasifier TRIG / GE 7FA+e, 1x1 + HRSG / STG or 570 / 143 @ GRU MW Gasifier TRIG IGCC, GE 7FA+e, 2x1		
(CFB) DH2 retrofitted w Low NOx Burners, Dry FGD, SCR, & Fabric Filter	Railex PolyGeneration, LLC - Railex Energy Group, Inc., 260 - 300 MW IGCC polygeneration of power and fuels		
DH IGCC + DH2 retrofitted w Low NOx Burners, Dry FGD, SCR, & Fabric Filter	Timberland Harvesters Inc. 50 MW P. Gasifier/BFB /STG		
DH IGCC + DH2 retrofit retrofitted w Low NOx Burners, Wet FGD, SCR, & Fabric Filter	Whole Tree Energy 100 MW Bottom blown, injection ram, steam generator / STG		
Biomass (wood waste)			
Notes: DLC = direct load control; SCCT = simple cycle combustion turbine; CCCT = combined cycle combustion turbine; DH = Deerhaven; HRSG = heat recovery steam generator; SNCR = selective non-catalytic reduction; FGD = flue gas desulfurization; SCR = selective catalytic reduction; PC = pulverized coal; SC = supercritical; BFB = bubbling fluidized bed; STG = steam turbine generator;			

8.3.2 Feasibility of Power Purchase Agreement Alternatives

The "All Source Solicitation" issued in late 2006 did not require binding proposals and resulted in a wide range of technologies and contractual structures being proposed. The responses to this solicitation, received in early 2007, are summarized in the third column of Table 8-3. Lessons learned from evaluating the responses and engaging in discovery with each bidder were primarily of a financial and risk management nature. Some of the proposals indicated that the advantages of tax-exempt financing available to municipal utilities did not offer as strong a financial incentive for renewable and innovative technologies as did incentives available to the private sector. This was partially due to reduced spreads between taxable and tax-exempt debt interest rates, but mostly due to the ability to obtain production tax credits and take advantage of depreciation (for entities with sufficient tax liabilities). Another lesson from the "All Source Solicitation" was that there were no commercially viable technologies to remove carbon (although one proposal including an oxygen blown boiler with extensive vapor compression was received).

8.3.3 Fossil Fuels Excluded

The decision to not consider additional capacity, including coal and petroleum coke, by the City Commission in May 2007 was driven largely by environmental concerns about climate change, even though studies at the time found coal and petroleum coke options to be among the least cost options. It should be noted that Governor Crist's Executive Orders in 2007 rendered coal and petroleum coke options moot for all intents and purposes. The fuel source that the GRU staff was instructed to pursue by the City Commission was biomass.

8.3.4 Competitive Biomass Solicitation

Although GRU had performed three biomass availability studies in the past, it was deemed prudent to take a comprehensive look at the resource assuming competition and modeling transportation costs explicitly. The University of Florida's School of Forest Resources (Dr. Carter, Principle Investigator) was contracted to perform this work, which included geographic information system (GIS) simulation of travel based on detailed maps of vegetation cover and type, and assuming that JEA and the City of Tallahassee also constructed biomass power plants. Completed in the summer of 2007, this work was made available on the Internet during subsequent solicitations.

The final biomass capacity solicitation was designed as a two-step process to ensure maximum participation given that the solicitation requirements were fairly broad. The first step was non-binding and intended to shortlist proposers for the second, binding step; this is summarized in the third column of Table 8-3. Fuels specifications were limited to biomass, but allowed refuse derived waste. The proposals were evaluated with weighted factors to be applied to a number of factors representing indicative price, financial risk, and environmental emissions. The nine proposals received were shortlisted and the bidders were asked to submit binding proposals. The fourth column of Table 8-3 indicates the three short-listed proposals. The ensuing public discussion of evaluation factors and their weights resulted in a number of factors representing price, financial risk, resource sustainability sensitivity, and local economic impacts. Table 8-4 summarizes the many combinations and permutations of biomass fired generation alternatives that were evaluated throughout the solicitation process.

8.4 Biomass Resource Evaluations

GRU commissioned four biomass resource studies to determine if sufficient fuel might be available within reach of a biomass plant constructed within the GRU System.

8.4.1 Post – Cunilio Study

An unsolicited report entitled "Biomass Options for GRU" was prepared in January 1998 by A. Green, T. Cunilio, and S. Peres for the GEAC. The report provided a guide to the energy crop resource base, the technologies possible for use by GRU, and the local professionals involved in the national and local arenas of biomass energy. In 2004 GRU hired Don M. Post and Tom V. Cunilio to perform a resource study to explore the feasibility of burning up to 30 MW of biomass in a 240 MW coal fired CFB that was eventually proposed to the City Commission in January 2005. The study was entitled "Biomass Options for GRU – Part II," and it demonstrated that within Alachua County there is a sustainable supply of all types of waste wood amounting to a minimum of 1,424 tons per day, including timber harvest residuals and urban forestry, but excluding refuse derived fuel (RDF)and stumps.

8.4.2 Black & Veatch Study

The GRU staff also commissioned Black & Veatch to perform a separate study of biomass resource availability in March 2004. In Section 3.2 of a report entitled "Supplementary Study Of Generating Alternatives For Deerhaven Generating Station," Black & Veatch examined the viability of obtaining sufficient woody biomass to sustain a biomass fuel steam generator of 35 MW up to 150 MW. The study involved a review of the Post – Cunilio study described above as well as the US Department of Energy "Oak Ridge National Laboratory (ORNL) Biomass Supply Curves." ORNL has researched the availability and cost of biomass fuels for many years and recently published a study that shows county level resource data for quantities and costs of various

Table 8-4
Summary of Biomass Generation Alternatives

No	Technology	Technology Status	Location	Initial Rating	Comments
			Stand Alone Options		
1	Stoker grate combustion	Commercial	Stand-alone	Very good	Most common biomass technology
2	Bubbling fluidized bed combustion	Commercial	Stand-alone	Good	Generally lower emissions than stoker combustion, but higher cost
3	Circulating fluidized bed combustion	Commercial	Stand-alone	Fair	More appropriate for larger units
4	Combustion based cogeneration	Commercial	Stand-alone	Fair	Sites may be limited based on IRP
5	Gasification close-coupled boiler	Commercial	Stand-alone	Fair	Very few advantages over direct combustion
6	Gasification with engine	Commercial	Stand-alone	Fair	Limited to smaller applications
7	Gasification combined cycle	Demonstration	Stand-alone	Fair	Recent difficulties with demonstration projects
8	Pyrolysis combined cycle	Development	Stand-alone	Fair	Good potential, but still in R&D stage
9	Pulverized fuel combustion	Commercial	Stand-alone	Poor	Not ideal with wood fuel
10	Anaerobic digestion	Demonstration	Stand-alone	Poor	Not proven at this scale with this feedstock
11	Pyrolysis with engine	Demonstration	Stand-alone	Poor	Smaller applications
12	Small modular biopower	Demonstration	Stand-alone	Poor	Technology still in early stages
13	Direct fired combustion turbine	Development	Stand-alone	Poor	Far-term technology
14	Indirect fired combustion turbine	Development	Stand-alone	Poor	Far-term technology
15	Stirling engine	Development	Stand-alone	Poor	Still under development
16	Whole-tree-energy	Development	Stand-alone	Poor	Technology development has slowed substantially
17	Cellulosic ethanol production	Development	Stand-alone	Poor	Far-term technology
			Cofiring Options		
18	Direct cofiring: blended/separate feed	Commercial	Unit 1	Poor	Biomass ash concerns
19	Direct cofiring: blended/separate feed	Commercial	Unit 2	Good	Up to 10% of heat input typically considered OK
21	Direct cofiring: blended/separate feed	Commercial	Unit 3 - CFB	Very good	A new CFB unit could be designed to have built-in fuel flexibility
20	Direct cofiring: blended/separate feed	Commercial	Unit 3 - PC	Good	Should be somewhat lower cost to integrate direct cofiring in new unit
22	Direct cofiring: torrefied wood	Development	Unit 1	Poor	Biomass ash concerns
23	Direct cofiring: torrefied wood	Development	Unit 2	Good	Could be easily blended with exisitng coal at minimal capital cost.
25	Direct cofiring: torrefied wood	Development	Unit 3 - CFB	Poor	Torrefaction is unnecessary step for CFB
24	Direct cofiring: torrefied wood	Development	Unit 3 - PC	Good	Could be easily blended with exisiting coal at minimal capital cost
26	Indirect cofiring: gasification	Demonstration	Unit 1	Fair	Potential to totally repower unit
30	Indirect cofiring: gasification	Demonstration	Unit 2	Good	Potential to use as reburn gas for NOx control is appealing
38	Indirect cofiring: gasification	Demonstration	Unit 3 - CFB	Poor	Direct cofiring would be substantially lower cost with few disadvantages
34	Indirect cofiring: gasification	Demonstration	Unit 3 - PC	Good	Potential to use as reburn gas for NOx control is appealing
27	Indirect cofiring: pyrolysis	Development	Unit 1	Fair	Could make use of existing oil-firing equipment
31	Indirect cofiring: pyrolysis	Development	Unit 2	Good	Could make use of existing oil-firing equipment
39	Indirect cofiring: pyrolysis	Development	Unit 3 - CFB	Poor	Direct cofiring would be substantially lower cost with few disadvantages
35	Indirect cofiring: pyrolysis	Development	Unit 3 - PC	Fair	Could make use of oil-firing equipment
28	Indirect cofiring: separate boiler	Commercial	Unit 1	Poor	High capital cost but only limited run hours
32	Indirect cofiring: separate boiler	Commercial	Unit 2	Good	Eliminates any negative impacts of biomass on existing equipment
40	Indirect cofiring: separate boiler	Commercial	Unit 3 - CFB	Poor	Direct cofiring would be substantially lower cost with few disadvantages
36	Indirect cofiring: separate boiler	Commercial	Unit 3 - PC	Fair	Seemingly better options
29	Indirect cofiring: separate combustor	Unknown	Unit 1	Poor	High capital cost but only limited run hours
33	Indirect cofiring: separate combustor	Unknown	Unit 2	Fair	Hot flue gas duct would be very large
41	Indirect cofiring: separate combustor	Unknown	Unit 3 - CFB	Poor	Direct cofiring would be substantially lower cost with few disadvantages
37	Indirect cofiring: separate combustor	Unknown	Unit 3 - PC	Poor	Hot flue gas duct would be very large

Note: Above options may be used simultaneously for multiple units (for example cofiring 15 MW in both Unit 2 and the new Unit 3)

Cofiring technology descriptions:

Direct cofiring: blended/separate feed	Biomass is either blended with coal feed prior to firing or injected as a separate feed
Direct cofiring: torrefied wood	Torrefied biomass is similar to charcoal. It can be pulverized and is a hydrophobic product. Torrefaction could be done off-site by a third party.
Indirect cofiring: gasification	Combustible syn-gas produced by biomass gasifier would be ducted to coal unit, possibly as a reburn gas for NOx control
Indirect cofiring: pyrolysis	Pyrolysis produces a synthetic bio-oil. Possibility to make use of existing fuel oil firing system at very low cost. Bio-oil could be produced offsite by third party.
Indirect cofiring: separate boiler	Generated steam from biomass boiler to be injected into the main plant steam cycle at an appropriate location
Indirect cofiring: separate combustor	Combustion flue gases from separate biomass combustor would be ducted into coal boiler

biomass fuels. The Black & Veatch study also examined the "National Renewable Energy Laboratory – Urban Wood Waste Assessment." The Black & Veatch study concluded that, based on the ORNL curves, within a 50 mile radius the available resources could support up to 150 MW of biomass fueled capacity on a sustainable basis.

8.4.3 ICF Consulting

A report entitled "City of Gainesville Electricity Supply Needs" was commissioned in late 2005 to examine several aspects of the need for electric generating capacity, including DSM potential, IGCC, and a biomass fueled power plant. Chapter 5 of this study was dedicated to fuel resources. ICF Consulting reviewed prior studies, as well as the "EIA Annual Energy Outlook 2006 Biomass Supply Curves." ICF found enough fuel for more than 100 MW of biomass fueled capacity within 35 and 50 mile radiuses.

8.4.4 University of Florida, School of Forest Resources and Conservation, Institute of Food and Agricultural Sciences

This study was commissioned by GRU through the University of Florida, School of Forest Resources and Conservation, Institute of Food and Agricultural Sciences (IFAS) in 2007, with Dr. Douglas R. Carter as the principal investigator, and Dr. Matthew Langholtz as the co-principal investigator. The final report was entitled "Biomass Resource Assessment Part I: Availability and Cost Analysis of Woody Biomass For Gainesville Regional Utilities." The study involved detailed GIS simulations of timber operations, and haul trip costs assuming that three 40 MW biomass plants were competing for fuel in the north-central Florida region. The study found that sufficient woody biomass exists within the Gainesville territory for a 100 MW woody biomass generator plant. Part II of this study considered municipal solid waste (MSW), which is not a type of fuel the GREC facility is designed to accommodate and which is not allowed under the GRU PPA with GREC LLC.

8.5 Selection of the Proposed GREC Project

GRU's Request for Biomass Proposals (RFP) issued in October 2007 set forth a two-step process to solicit biomass-fueled electric generation. The first step allowed non-binding proposals with indicative pricing to be submitted in order to ensure the maximum competitive participation and the widest range of technologies and business plans. These were ranked based on factors including price, risk control, environmental emissions, applicant qualification, and technical merit. The proposals received from Step 1 of the selection process are listed in the third column of Table 8-3.

On January 28, 2008, the City Commission invited the three top-ranked respondents from Step 1 of the RFP selection process to submit binding proposals for the second step of the process. These three respondents were Nacogdoches Power, LLC (now American Renewables), Covanta Energy, and Sterling Planet, Inc. Binding proposals were due April 11, 2008.

On March 24, 2008, GRU evaluation staff presented a proposed evaluation methodology to the City Commission. Following deliberation and input from City Commissioners, the City Commission approved the 14 overall factors and associated factor weights to be applied in the evaluation of the binding biomass proposals to be received in Step 2 of the RFP process. The 14 factors and factor weights, summarized in Table 8-5, constituted three broader criteria with the following associated weights:

1. Environmental 30 percent
2. Economics 37 percent
3. Risk and Reliability 33 percent

The GRU evaluation team finalized the details of how the factors were to be evaluated prior to the due date for submission of the binding proposals. The methodologies used were of necessity quite different for each factor, but typically involved scoring a number of sub-factors for each of the factors. The RFP and associated addenda included information requests for the data needed to evaluate each sub-factor. The binding proposals were received on April 11, 2008. The three proposals received presented a total of eight options, all of which were fueled 100 percent with biomass. These eight options consisted of the following:

Covanta Energy (all facilities at the Deerhaven site):

- 50 MW net PPA.
- 50 MW net GRU Financed and Owned Engineer, Procure, and Construct (EPC).
- 58 MW gross PPA with auxiliary power purchase.
- 58 MW gross GRU EPC with auxiliary power purchase.

Nacogdoches Power (now American Renewables):

- PPA for 50 percent of 100 MW net facility at the Deerhaven site.
- PPA for 100 percent of 100 MW net facility at an alternative site (undisclosed).
- PPA for 100 percent of 100 MW net facility at the Deerhaven site.

Sterling Planet, Inc:

- PPA for 30 MW net facility at Deerhaven site.

The GRU evaluation team scored the proposed options and determined that the 100 MW PPA with GREC LLC for 100 percent of the output from a biomass-fueled facility at the Deerhaven site was the best long-term option for GRU. Final results and recommendations were presented to the City Commission at open meetings on April 28 and May 12, 2008. At the May 12 meeting, the City Commission voted unanimously to authorize GRU to negotiate a PPA with GREC LLC for 100 percent of the output of a 100 MW net biomass-fueled facility to be constructed and operated by GREC LLC at the Deerhaven site.

Table 8-5
Gainesville City Commission Approved Factor Weights for Binding Responses to GRU Biomass RFP

Criteria / Factor	Weight
(1) Environmental: Environmental Attributes Consistent with the Gainesville Community	**30.00**
Environmental Emissions	10.00
Project Commitment to Sustainable Forest Resource Management	7.00
Project Site Requirements	5.00
By-product/Waste Production and Disposition	8.00
(2) Economics: Cost Effective Renewable Capacity and/or Energy Benefits	**37.00**
Project All-in Production Cost	25.00
Project Variable Production Costs	5.00
Anticipated Project In-Service Date and/or Energy Delivery	4.00
Local Economic Impact	3.00
(3) Risk & Reliability: Enhanced and Reliable Energy Supply	**33.00**
Technology Readiness and Project Reliability	5.00
Fuel Requirements and Sources	3.00
Project Size and Design	5.00
Experience and Resources of Project Developer/Sponsor	5.00
Proposed Contractual Terms and Conditions	10.00
Proposer's Financial Strength	5.00
Grand Total	**100.00**

Note: Each of the above Factors was given a raw numerical score from 1 to 5.

9.0 Project Overview

This section discusses the proposed GREC biomass facility and provides information related to the project developers, a description of the facilities, the PPA between GRU and GREC LLC, the supply of fuel to the GREC, resale opportunities for power from the GREC facility that may be available and beneficial to GRU, and the schedule for development and completion of the GREC facility.

It should be noted that elements of the PPA between GRU and GREC LLC are confidential. As such, the information presented throughout this Application is limited to information that is not confidential.

9.1 Project Developers

The GREC facility will be designed, constructed, owned, and operated by GREC LLC, a subsidiary of American Renewables, LLC, a private, for-profit renewable power producer that is currently under contract to construct a similar facility for Austin Energy (Texas) and is developing another similar facility in Hamilton County, Florida. American Renewables is jointly owned by affiliates of BayCorp, EMI and Tyr. The entities are described as follows.

- BayCorp is a merchant energy company that owns power assets, as well as natural gas and oil production and development assets. BayCorp owns and operates a hydroelectric generation facility and is developing additional generation in Vermont; through its subsidiary, Great Bay Power Marketing, Inc., BayCorp supplies wholesale power in the New England power market; and through its subsidiary BayCorp Resources, BayCorp owns and operates interests in oil and natural gas development and production projects located throughout Texas.
- EMI is a privately held energy company with more than 30 years of experience in energy conservation and energy development. In 1986, EMI developed, financed, and constructed Alexandria Power Associates, a 15 MW biomass-fired electric generating facility in Alexandria, New Hampshire. Following the Alexandria project, EMI developed six natural gas-fired electric generation projects totaling more than 860 MW of capacity and including the first true independent and merchant power projects in New England. EMI is also currently developing the Cape Wind Project, a 468 MW offshore wind project to be located in Nantucket Sound off the southern coast of Cape Cod, Massachusetts.

- Owned by ITOCHU Corporation, a $52 billion international trading conglomerate and its US based subsidiary, ITOCHU International, Inc., Tyr focuses on acquiring and owning equity interests in North American independent power assets and providing asset management services to facilities in which it is an owner. Tyr's current portfolio includes interests in CalPeak Power (California), Chesapeake Commonwealth Energy (Virginia), and Fox Energy (Wisconsin). Worldwide, ITOCHU owns interests in independent power facilities in Saudi Arabia, Indonesia and Japan in addition to the United States. Tyr's sister company, North American Energy Services, also a subsidiary of ITOCHU International, Inc., is the industry's largest independent, third-party provider of power plant O&M services, providing services to almost 300 MW of biomass fueled power plants across the US.

The GREC's project developers have a long and successful track record of energy and power asset development and operation, as well as a robust development pipeline looking forward. Collectively, the project developers have acquired or developed more than $7.6 billion of energy and infrastructure assets, and have a pipeline or deployment budget of $2.5 billion for US renewable power plants over the next 5 years.

9.2 Description of Facilities

The GREC facility will be located within the confines of GRU's existing Deerhaven Power Plant site on property leased from the City of Gainesville (d/b/a GRU). GRU will have title to 100 percent of the plant's output, including all environmental attributes (such as renewable energy credits, carbon offsets, etc.).

The facility will be a new nominal rated 100 MW net (116 MW gross) biomass-fired electric generating facility, consisting of a biomass fuel handling system, a biomass-fired boiler, a condensing steam turbine generator with evaporative cooling towers and auxiliary support equipment. The facility will also utilize a zero liquid discharge (ZLD) system to eliminate industrial wastewater discharges in accordance with the site's current restrictions pursuant to its current certification. The facility will be designed in accordance with standards normally used in the utility industry so that the facility will, with standard O&M practices, be designed to provide full service over its 42 year design life.

The facility will utilize a fluidized bed boiler to produce superheated steam. The boiler will be equipped with a baghouse to control particulate matter. An aqueous ammonia injection selective non-catalytic reduction (SNCR) or a selective catalytic reduction (SCR) system will be provided for NO_x control. The slightly more expensive

SCR system was considered for purposes of evaluating the economics of the GREC LLC PPA throughout this Application. Superheated steam from the boiler will be admitted to a single steam turbine with four extractions for feedwater heating. The steam turbine will generate electricity before exhausting axially into the condenser with cooling water provided from the wet evaporative cooling tower.

Electric power will be produced in the steam turbine generator at the nominal generator voltage. The facility will increase the voltage at an on-site substation and transmit the power through aerial transmission lines to the interconnection point with GRU's looped 138 kV transmission system. GRU's transmission system is interconnected with PEF and FP&L. When the steam turbine generator is off-line, station service power will be obtained by backfeeding from GRU's system.

A unique feature of the agreement between GREC LLC and GRU is that it is not a "must take" unit. The unit can be turned down or taken off-line to meet operational or economic requirements. If, however, the unit is dispatched at less than available capacity, the fixed non-fuel energy charges would still be invoiced based on the energy that was available, but not called upon. Therefore, the variable cost for dispatch is the fuel cost and variable operations and maintenance (O&M) charge per MWh. A substantial portion of GRU's agreement with GREC LLC is dedicated to empirically establishing the available capacity of the unit for each season and performance incentives for maintaining that availability. The overall guaranteed annual availability is 95 percent in the four summer months and 90 percent on an annual basis.

9.3 Power Purchase Agreement

GRU has entered into a 30 year contract (from the date of completion) to purchase 100 percent of the output of the GREC biomass facility. GRU has been careful to structure the agreement with GREC LLC to ensure that it would not be viewed as a long-term financial liability by bond rating agencies, with the resulting requirements for debt service coverage, etc. Preliminary reviews with Moody's and Standard & Poor's indicate that they will view the agreement as only having limited financial liability related to performance obligation bonds, for example, and as such will not require substantial debt service coverage. The facility will be subject to Alachua County's tangible property taxes. Table 9-1 summarizes the billing elements in the PPA. The facility must be in operation before January 1, 2014 to receive the most favorable benefits of the ARRA, which may commonly be referred to as the HR 1 Stimulus Package, for open-loop biomass energy projects. There is no associated long-term liability of production tax credits ending after 10 years under this scenario.

Table 9-1
Billing Elements of the Power Purchase Agreement Between GRU and GREC LLC

Billing Element	Description	Method of Escalation
Non-Fuel Energy Charges	Paid only for available energy. There will be no fixed capacity charges associated with the generating facility. This charge includes all costs except fuel and variable O&M.	Does not change, fixed 30 years
Fuel Charge	Actual cost per delivered ton times a guaranteed heat rate. A target cost is set at the beginning of each year based on the prior year's actual costs and the savings from this target are shared with GREC LLC as are any costs over the target. See the fuel cost discussion.	Market based (probably less than Consumer Price Index [CPI])
Variable O&M	Paid only for energy delivered to GRU. There is no variable O&M obligation if energy is not delivered.	CPI (beginning 2009)
Equivalent Taxes	Tangible property taxes will be a direct pass-through on an annual basis. Taxes will depend on the final valuation and assignment of costs to system components (certain items are tax-exempt). Tangible property taxes are depreciated as opposed to real property taxes, which tend to appreciate.	Depreciates over time

9.4 Fuel Handling and Supply

The primary fuels for the GREC will be forest residue, mill residue, pre-commercial tree thinnings, used pallets, and urban wood waste which includes woody tree trimmings that are generated by landscaping contractors, power line clearance contractors, and other non-forestry related sources of woody debris. Supplementary fuels could include herbaceous plant matter, agricultural residues, diseased trees, woody storm debris, whole tree chips, and pulpwood chips. The facility is not designed to use any form of treated wood, municipal solid waste, coal, petroleum coke, oil, or tires. Limited quantities of natural gas will be used for start-up fuel.

The biomass fuel handling system will consist of three truck tippers, two sets of screens and hogs, an automatic stacker/reclaimer system and a manual stacker/reclaimer system. Biomass fuel will be transported by truck to the GREC facility. Fuel will be transported into and out of on-site storage via a series of conveyors. The GREC will have two 100 percent capacity conveyors leading from the storage piles to the boiler metering bins. From the metering bins, the fuel will be gravity fed into air swept distribution feeders and then blown by combustion air into the boiler.

GREC LLC has spent significant resources working with the forestry industry in north-central Florida, sometimes accompanied by GRU staff. GRU has been advised that GREC LLC is in a position to enter into a number of long-term contracts with favorable pricing, with put and call options exceeding 100 percent of the fuel required for the facility. GREC LLC does not intend to fix the price for 100 percent of the fuel in order to take advantage of opportunity fuels from storms, land development, etc. The cost drivers for forest derived fuel are the grower's premium (10 to 20 percent), diesel fuel (10 to 20 percent), equipment costs, and labor. GREC LLC may be able to extract a tipping fee for some of the fuel, which is credited to the GREC's production cost. Experience around the state suggests that this form of fuel supply is relatively stable, with increases well below the CPI, and will provide an excellent hedge against gas price volatility. GRU will have full audit review of all aspects of fuel procurement and cost. The unique aspects of the GREC related to forest stewardship are described within the strategic considerations discussed in Section 15.0 of this Application.

9.5 Power Resale

GRU is seeking to ascertain the level of interest that other utilities might have in becoming a counter party to take a share of the renewable energy output from the GREC for the initial period of operation. GRU envisions structuring an arrangement whereby the counter party(s) will share the costs borne by GRU on a pro rata basis with the addition of wheeling fees and transmission losses required for the delivery of power to the border of GRU's control area and the incidental cost of the risks associated with this wheeling. GRU will consider reselling 50 percent of the facility's output for the initial 10 years of GREC's operation.

9.6 Project Schedule

The GREC is planned for commercial operation beginning December 1, 2013. Current estimates of major milestone dates associated with development and construction of the GREC are outlined in Table 9-2.

Table 9-2
GREC Project Schedule

Activity	Finish Date
Site Activities for Permitting Support Completed	September 11, 2009
File Florida Public Service Commission Need Determination Application	September 18, 2009
Preliminary Engineering Activities Completed	October 23, 2009
File Prevention of Significant Deterioration (PSD) Application	October 23, 2009
File Site Certification Application (SCA)	October 23, 2009
File Gainesville Site Plan Application	January 22, 2010
PSC Need Determination Final Order	February 2, 2010
Gainesville Site Plan Final Approval	June 11, 2010
Site Certification Approval	October 22, 2010
Complete Project Financing	November 30, 2010
Construction Start	December 1, 2010
Initial Synchronization	September 1, 2013
Commercial Operation	December 1, 2013

10.0 Supply-Side Alternatives

10.1 Introduction

Cost and performance estimates have been developed for natural gas and pulverized coal generation technologies that are proven, commercially available, and widely used in the power industry.

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

The following subsections provide general descriptions, thermal performance estimates, O&M cost estimates, and capital cost estimates for the following power generation technologies:

- GE LMS100 Simple Cycle Combustion Turbine (SCCT).
- 1x1 GE 7EA Combined Cycle Combustion Turbine (CCCT).
- 125 MW (net) Pulverized Coal (PC).
- 125 MW (net) (PC) with Carbon Capture and Sequestration (CCS).

10.1.1 General O&M Basis

O&M cost estimates are based on vendor estimates and recommendations, and estimated performance information. The cost estimates are divided into fixed and variable O&M costs. Fixed O&M costs, expressed as dollars per unit of net capacity per year ($/kW-yr), do not vary directly with plant power generation and consist of wages and wage related overheads for the permanent plant staff, routine equipment maintenance, and other fees. Variable O&M costs, expressed as dollars per unit of net generation ($/MWh) tend to vary in near direct proportion to the output of the unit. Variable O&M includes costs associated with equipment outage maintenance, utilities, chemicals, reagents, and other consumables. Fuel costs are determined separately and are not included in either fixed or variable O&M costs.

10.1.2 General Capital Cost Basis

Overnight capital cost estimates were generated for the technologies listed above. The capital cost estimates are presented in overnight 2009 US dollars. The estimates were developed based on an EPC contracting strategy and consider the use of local Gainesville, Florida labor rates.

The capital cost estimates were generated on a consistent basis. Assumptions used to develop the performance estimates were also used in the development of the capital cost estimates. These assumptions are broken down into the major capital cost estimate components consisting of general assumptions, direct assumptions, and indirect cost assumptions. General assumptions include assumptions that are general in nature and consistently apply to the cost estimates developed for each of the supply-side alternatives considered. Direct costs include the costs associated with the purchase of equipment, equipment erection, equipment supplier's technical advisory services, and contractors' services. General indirect costs include relay checkouts and testing; instrumentation and control equipment calibration and testing; and systems and plant startup, including startup personnel during testing and the initial operation period.

10.1.3 Consideration of Owner's Costs

The capital cost estimates developed include both direct and indirect costs. An allowance for possible general owner's cost items, as summarized in Table 10-1, has been included in the cost estimates.

10.1.4 Meteorological Conditions

An average annual temperature and relative humidity of 70° F and 72 percent, respectively, were used for developing performance estimates for use in the levelized cost of energy analyses. Additionally, a summer temperature of 98° F (relative humidity of 54.9 percent) was used to develop seasonal performance estimates.

10.1.5 Performance Degradation

Power plant output and heat rate performance will degrade with hours of operation because of factors such as blade wear, erosion, corrosion, and increased tube leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance when compared to the unit's new and clean performance. The degradation that cannot be recovered is referred to herein as nonrecoverable degradation, and estimates have been developed to capture its impacts. Nonrecoverable degradation

Table 10-1
Possible Owner's Costs

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

will vary from unit to unit, so specific nonrecoverable output and heat rate factors have been developed and are presented in Table 10-2. The degradation percentages are applied one time to the new and clean performance data for the SCCT and CCCT alternatives, and reflect lifetime aggregate nonrecoverable degradation. Output and performance estimates for the pulverized coal alternative reflect degradation.

Table 10-2
Nonrecoverable Degradation Factors

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

10.2 GE LMS100 Simple Cycle Combustion Turbine

10.2.1 General Description

The LMS100 is the first intercooled combustion turbine generator (CTG) system developed specifically for the power generation industry, combining the best of two technologies: heavy-duty CTG technology and aeroderivative CTG technology.

The LMS100 features a heavy-duty low-pressure compressor (LPC) derived from GE Power Systems' MS6001FA heavy-duty CTG compressor; its core, which includes the high-pressure compressor (HPC), combustor, and high-pressure turbine (HPT) is derived from GE Aircraft Engines'CF6-80C2 and CF6–80E1 aircraft engines. The design of the new two-stage intermediate-pressure turbine (IPT) and new five-stage power turbine is based on the latest aeroderivative CTG technology. The compressed air from the LPC is cooled in either an air-to-air or air-to-water heat exchanger (intercooler) and ducted to the HPC. The cooled flow requires less work from the HPC, increasing overall efficiency and power output. The cooler LPC exit temperature air, used for turbine cooling, allows higher firing temperatures, resulting in increased power output and overall efficiency. The LMS100 has the following characteristics:

- High full- and part-load efficiency.
- Low hot-day lapse rate.
- High availability.
- Low maintenance cost.
- Designed for cycling applications.
- Ten minutes to full power.

10.2.2 Preliminary Thermal Performance Estimates

Preliminary thermal performance and emissions estimates were developed for the GE LMS100 SCCT for both average and summer design conditions corresponding to 70° F/72 percent relative humidity and 98 °F/54.9 percent relative humidity, respectively, as provided in Table 10-3.

10.2.3 O&M Cost Estimates

10.2.3.1 O&M Assumptions. The assumptions for fixed and variable O&M costs are as follows:

(1) The O&M estimates are in 2009 US dollars.

(2) The GE LMS100 simple cycle unit is estimated to start approximately 100 times per year and operate approximately 875 hours per year (10 percent capacity factor).

(3) The location was assumed to be the Deerhaven Generating Plant site.

(4) Plant staff wage rates are based on an operator salary of $66,000 per year.

(5) The payroll burden rate used was 40 percent. The payroll burden is intended to capture the costs for payroll taxes and benefits provided by the utility on behalf of the employees, in addition to direct salary. Not included in the burden rate are any costs for corporate services such as payroll, accounting, legal, and corporate tax administration.

(6) Property insurance and property taxes are not included.

(7) Office and administrative expenses are estimated to be 5 percent of the total staff salary.

(8) Estimated employee training cost and incentive pay/bonuses are included.

(9) Routine equipment maintenance costs are estimated based on Black & Veatch project experience and manufacturer input.

(10) Contract services include costs for services not directly related to power production.

(11) The variable O&M cost analysis is based on a repeating maintenance schedule over the life of the plant and costs are estimated through at least one major overhaul of equipment.

(12) Combustion turbine borescope inspections, combustion inspections, hot gas path inspections, and major engine overhauls are based on original equipment manufacturer (OEM) pricing and recommended repair and replacement intervals.

(13) SCR is included for NO_x control.

(14) SCR uses anhydrous ammonia.

Table 10-3
GE LMS100 Simple Cycle Performance and Emissions Estimates

Parameter	Ambient Condition	
	Average Day	Summer Design
Meteorological Conditions		
Average Ambient Temperature, °F	70	98
Average Ambient Relative Humidity, percent	72	54.9
Estimated Thermal Performance		
Load Condition, percent	100	100
Inlet Cooling Method (2)	Evaporative	Evaporative
CTG Water Injection	Yes	Yes
Gross CTG Output, MW	102.3	92.9
Auxiliary Load, MW	2.7	2.6
New and Clean Net Power Output, MW	99.6	90.3
New and Clean Net Plant Heat Rate (HHV), Btu/kWh	9,099	9,328
Degraded Net Power Output, MW	96.4	87.4
Degraded Net Plant Heat Rate (HHV), Btu/kWh	9,258	9,491
Estimated Emissions (3)		
NO_x as NO_2, lb/MBtu	0.0089	0.0090
SO_2, lb/MBtu	0.0011	0.0011
CO_2, lb/MBtu	114.8	114.8

(1) Performance and emissions values provided are based on fuel gas as 100 percent methane with a sulfur content of 0.5 grains/100 standard cubic feet at a pressure of 400 pounds per square inch gage and a temperature of 77 °F. Values provided are based on the use of standard GE LMS100 combustors.
(2) Evaporative cooling efficiency is assumed to be 85 percent.
(3) Emissions values include the effects of SCR rated for 2.5 parts per million volumetric at 15%O_2, NO_x, and CO catalyst rated for 10 parts per million volumetric at 15% O_2 CO. No emissions controls are included for CO_2.

(15) Costs associated with an oxidation catalyst are included.

(16) Water treatment costs are included for cycle makeup, cooling tower makeup and service water where needed.

(17) The following were assumed for costs:

- $400/ton for anhydrous ammonia.
- $0.95/1,000 gallons for raw water.
- $3.00/1,000 gallons for demineralized water.
- $4.94/1,000 gallons for sewage charge.

10.2.3.2 O&M Estimate. The fixed and nonfuel variable costs, based on the assumptions listed above, are provided in Table 10-4 and are expressed in thousands of 2009 US dollars.

Table 10-4
GE LMS100 O&M Cost Estimates

Parameter	**$ 2009 ($000)**
Fixed Costs	
Labor	1,302.4
Maintenance	86.4
Other Expenses [1]	179.7
Total Annualized Fixed Costs	*1,568.5*
Variable Costs	
Outage Maintenance	314.3
Utilities	15.0
Chemical Usage	25.4
Total Annual Variable Costs	*354.8*
O&M Cost Summary	
Annual Net Generation, MWh [2, 3]	**84,446**
Fixed Costs per net unit of Capacity, $/kW-yr [2]	**16.27**
Variable Costs per net unit of Output, $/MWh [2, 3]	**4.20**

(1) Other expenses include office and administrative expenses, training, and bonus and incentive pay.
(2) Based on average day performance conditions presented in Table 10-3.
(3) Based on a 10 percent capacity factor.

10.2.4 Preliminary Capital Cost Estimates

The following subsections provide the general, direct, and indirect capital cost assumptions.

10.2.4.1 General Capital Cost Assumptions.

(1) The site is the Deerhaven Generating Plant site.

(2) Protection or relocation of existing fish and wildlife habitat; threatened and endangered species; or historical, cultural, and archaeological artifacts is not included.

(3) The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.

(4) Spread footings are assumed for all equipment foundations. Stabilization of the existing subgrade is not anticipated.

(5) Construction power is available at the site boundary.

(6) Natural gas supply is assumed to be a pipeline connection at the site boundary.

(7) Natural gas will be available at the site boundary at the required volume and pressure according to the CTG OEM requirements. Fuel oil will be delivered by truck to the storage tank. The fuel oil storage facility is capable of 48 hours of full load operation.

10.2.4.2 Direct Cost Assumptions.

(1) The plant will feature one dual-fueled GE LMS100 CTG. The primary fuel will be natural gas, and the backup fuel will be No. 2 fuel oil. The cost of unloading and delivery to the project site is included.

(2) The CTG includes a standard sound enclosure. A gantry or bridge crane for servicing the CTG is not included.

(3) An inlet air evaporative cooling system has been included.

(4) SCR has been included for NO_x control. The CTG will also use a water injection system for NO_x control and power augmentation. CTG combustors will be of the standard type.

(5) An oxidation catalyst is included for carbon monoxide (CO) control.

(6) The cost of the stack has been included in the cost estimate.

(7) A continuous emissions monitoring system (CEMS) has been included in the cost estimate for monitoring stack emissions.

(8) The source of service water will be groundwater. Demineralized water will be provided by onsite contract demineralizer trailers.

(9) Field erected tanks consisting of the following:
- Service/fire water storage tank.
- Fuel oil storage tank.
- Demineralized water storage tank.

(10) Fire protection will consist of the major equipment vendor's standard fire suppression system. Fire protection for major transformers will be water deluge system.

(11) The buildings are pre-engineered.

(12) A sanitary sewer system is included.

(13) A plant communications system has been included in the cost estimate.

(14) Plant heat rejection will be accomplished through a closed cycle cooling system which includes all necessary heat exchangers and fin-fan coolers.

10.2.4.3 Indirect Cost Assumptions.

(1) General indirect costs include all necessary services required for checkouts, testing services, and commissioning.

(2) An allowance for insurance has been included in the cost estimate. Insurance includes builder's risk and general liability.

(3) Engineering and related services costs are included.

(4) Field construction management services include field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.

(5) Technical direction and management of start-up 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 are included.

(6) Contractors' contingency and profit are included in the estimate.

(7) Transportation costs for delivery to the job site are included in the base plant estimate.

(8) Spare parts for startup and use during operation are included. Major hot gas path parts are not included.

10.2.4.4 Capital Cost Estimate. The preliminary capital cost estimate, based on the assumptions previously discussed, is provided in Table 10-5.

Table 10-5
GE LMS100 Capital Cost Estimate

Component	$ 2009 ($000)	$ 2009 $/kW (1)
Purchase Contracts	56,821	629
Construction Contracts	11,725	130
Total Direct Costs	*68,646*	*760*
Total Indirect Costs	*20,501*	*227*
Total EPC Capital Costs	**89,047**	**923.6**
Total Including Owner's Costs	**111,309**	**1,154.5**

(1) Values presented are based on net plant output at average day ambient conditions.

10.3 1x1 GE 7EA Combined Cycle Combustion Turbine

10.3.1 General Description

The GE PG7121EA (7EA) model is a highly reliable, mid-size modular CTG developed specifically for 60 hertz (Hz) applications. With design emphasis placed on energy efficiency, availability, performance, and maintainability, the GE 7EA is a proven technology with approximately 750 units installed or on order worldwide, with tens of millions of accumulated hours. The simple, medium sized design of the GE 7EA offers flexibility in plant layout and easy, low cost addition of increments of power when phased capacity expansion is necessary. The GE 7EA is fuel flexible, and can operate on natural gas, liquefied natural gas (LNG), distillate, and treated residual oil. The GE 7EA can be used for SCCT and CCCT, and industrial and cogeneration application.

In a 1x1 combined cycle configuration, one heat recovery steam generator (HRSG), one STG, and one GE 7EA CTG form the unit configuration. The STG for the GE 7EA CCCT unit is nominally rated at 50 MW gross output, and is a single flow, condensing type with intermediate-pressure admission. The generator is designed for three-phase, 60 cycle operation at a 90 percent power factor.

10.3.2 Thermal Performance Estimates

Thermal performance and emissions estimates were developed for the 1x1 GE 7EA CCCT for both average and summer design conditions corresponding to 70 °F/72 percent relative humidity and 98 °F/54.9 percent relative humidity, respectively, as provided in Table 10-6.

10.3.3 Preliminary O&M Cost Estimates

10.3.3.1 O&M Assumptions. The assumptions for fixed and variable O&M costs are as follows:

(1) The O&M estimates are in 2009 US dollars.

(2) The 1x1 GE 7EA combined cycle unit is estimated to start approximately 50 times per year and operate approximately 5,250 hours per year (60 percent capacity factor).

(3) The location was considered to be the Deerhaven Generating Plant site.

(4) Plant staff wage rates are based on an Operator salary of $66,000 per year.

(5) Payroll burden rate used was 40 percent. The payroll burden is intended to capture the costs for payroll taxes and benefits provided by the utility on behalf of the employees, in addition to direct salary. Not included in the burden rate are any costs for corporate services such as payroll, accounting, legal, and corporate tax administration.

(6) Property insurance and property taxes are not included.

(7) Office and administrative expenses are estimated to be 5 percent of the total staff salary.

(8) Estimated employee training cost and incentive pay/bonuses are included.

(9) Routine equipment maintenance costs are estimated based on Black & Veatch project experience and manufacturer input.

(10) Contract services include costs for services not directly related to power production.

(11) The variable O&M cost analysis is based on a repeating maintenance schedule over the life of the plant and costs are estimated through at least one major overhaul of equipment.

(12) Combustion turbine borescope inspections, combustion inspections, hot gas path inspections, and major engine overhauls are based on OEM pricing and recommended repair and replacement intervals.

Table 10-6
1x1 GE 7EA Combined Cycle Performance and Emissions Estimates

Parameter	Ambient Condition	
	Average Day	Summer Design
Meteorological Conditions		
Average Ambient Temperature, °F	70	98
Average Ambient Relative Humidity, percent	72	54.9
Estimated Thermal Performance (1)		
Load Condition, percent	100	100
Inlet Cooling Method (2)	Evaporative	Evaporative
Steam Cycle Heat Rejection Method	Wet Mechanical Draft	Wet Mechanical Draft
CTG Water Injection	No	No
Gross CTG Output, MW	81.0	74.8
Gross STG Output, MW	44.4	42.6
Total Gross Output, MW	125.5	117.4
Auxiliary Load, MW	3.3	3.2
New and Clean Net Power Output, MW	122.2	114.2
New and Clean Net Plant Heat Rate (HHV), Btu/kWh	7,794	7,866
Degraded Net Power Output, MW	118.9	111.1
Degraded Net Plant Heat Rate (HHV), Btu/kWh	7,911	7,984
Estimated Emissions (3)		
NO_x as NO_2, lb/MBtu	0.0090	0.0090
SO_2, lb/MBtu	0.0011	0.0011
CO_2, lb/MBtu	114.8	114.8

(1) Performance and emissions values provided are based on fuel gas as 100 percent methane with a sulfur content of 0.5 grains/100 standard cubic feet at a pressure of 400 pounds per square inch gage and a temperature of 77 °F. Values provided are based on the use of GE 7EA dry low NO_x (DLN) combustors.
(2) Evaporative cooling efficiency is assumed to be 85 percent.
(3) Emissions values include effects of SCR rated for 2.5 parts per million volumetric at 15% O_2, NO_x, and CO catalyst rated for 10 parts per million volumetric at 15% O_2 CO. No emissions controls are included for CO_2.

(13) STG, HRSG, and other BOP maintenance costs are based on Black & Veatch project experience and vendor data and recommendations.

(14) SCR included for NO_x control.

(15) SCR uses anhydrous ammonia.

(16) Costs associated with an oxidation catalyst are included.

(17) Water treatment costs are included for cycle makeup, cooling tower makeup and service water where needed.

(18) The following were assumed for costs:

- $400/ton for anhydrous ammonia.
- $0.95/1,000 gallons for raw water.
- $3.00/1,000 gallons for demineralized water.
- $4.94/1,000 gallons for sewage charge.

10.3.3.2 O&M Estimate. The fixed and variable costs, based on the assumptions listed above, are provided in Table 10-7 and are expressed on thousands of 2009 US dollars.

10.3.4 Preliminary Capital Cost Estimates

The following subsections provide the general, direct, and indirect capital cost assumptions.

10.3.4.1 General Capital Cost Assumptions.

(1) The site is the Deerhaven Generating Plant site.

(2) Protection or relocation of existing fish and wildlife habitat; threatened and endangered species; or historical, cultural, and archaeological artifacts is not included.

(3) The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.

(4) Pilings are included under major equipment. Spread footings were assumed for all other foundations. Further stabilization of the existing subgrade is not included.

(5) Construction power is available at the site boundary.

(6) Natural gas supply is assumed to be a pipeline connection at the site boundary.

(7) Natural gas will be available at the site boundary at the required volume and pressure according to the CTG OEM requirements. No. 2 fuel oil will be delivered by truck to a fuel oil storage tank sized for five full load days of operation of the unit.

Table 10-7
GE 1x1 7EA O&M Cost Estimates

Parameter	$ 2009 ($000)
Fixed Costs	
Labor	2,497.5
Maintenance	138.0
Other Expenses [1]	329.0
Total Annualized Fixed Costs	*2,964.5*
Variable Costs	
Outage Maintenance	1,811.6
Utilities	351.3
Chemical Usage	216.8
Total Annual Variable Costs	*2,379.7*
O&M Cost Summary	
Annual Net Generation, MWh [2, 3]	**677,020**
Fixed Costs per net unit of Capacity, $/kW-yr [2]	**24.93**
Variable Costs per net unit of Output, $/MWh [2, 3]	**3.51**

[1]Other expenses include office and administrative expenses, training, and bonus and incentive pay.
[2]Based on average day performance conditions presented in Table 10-6.
[3]Based on a 65 percent capacity factor.

10.3.4.2 Direct Cost Assumptions.

(1) The plant will feature one dual fueled GE 7EA CTG, one HRSG, and one condensing STG. The primary fuel will be natural gas, and the backup fuel will be No. 2 fuel oil. The cost of unloading and delivery to the project site is included.

(2) The CTG includes a standard enclosure. A gantry or bridge crane for servicing the CTG and STG is included.

(3) An inlet air evaporative cooling system has been included.

(4) The HRSG does not include duct firing. An oxidation catalyst for CO control and SCR equipment to control NO_x emissions are included with the HRSG pricing.

(5) CEMS has been included in the cost estimate for monitoring stack emissions.

(6) The source for cooling tower makeup and cycle makeup will be ground water. Onsite water treatment includes a pretreatment system followed by a reverse osmosis and demineralization system for cycle makeup treatment.

(7) Field erected tanks consisting of the following are included:

- Demineralized water storage tank.
- No. 2 fuel oil storage tank.
- Condensate storage tank.
- Raw water / fire water storage tank.

(8) Automatic fire protection will consist of the CTG OEM supplied standard CO_2 fire suppression system; water deluge of the transformers; dry-pipe fire protection of the cooling tower; wet-pipe sprinkler system in the buildings, except in the control room, which will have fire detection equipment only; and hydrant protection for site.

(9) Major buildings included in the costs estimate are as follows:

- A central control/electrical building is included for the site that is sized to enclose a control room, battery room, motor control center, meal room and toilets, locker room, and various offices.
- The estimate includes an administration/workshop/warehouse building, which will provide administration offices, storage and workshop areas, instrument shop, a locker room, and a drawing room.
- - A water treatment building is included that is sufficient for the enclosure of the water treatment equipment and fire water pumps.
- All buildings will be pre-engineered metal structures.

(10) A sanitary waste treatment (septic) system is included.

(11) A wet, mechanical draft cooling tower will provide cycle heat rejection.

(12) A wastewater collection system is included.

(13) An emergency diesel generator for safe shutdown is included.

10.3.4.3 Indirect Cost Assumptions.

(1) General indirect costs include all necessary services required for checkouts, testing services, and commissioning.

(2) An allowance for insurance has been included in the cost estimate. Insurance includes builder's risk and general liability.

(3) Engineering and related services costs are included.

(4) Field construction management services include field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.

(5) 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 are included.

(6) Contractors' contingency and profit are included in the estimate.

(7) Transportation costs for delivery to the job site are included in the base plant estimate.

(8) Spare parts for startup and use during operation are included. Major hot gas path parts are not included.

10.3.4.4 Capital Cost Estimate. The preliminary capital cost estimate, based on the assumptions provided above, is provided in Table 10-8.

Table 10-8
GE 1x1 7EA Combined Cycle Capital Cost Estimate

Component	**$ 2009 ($000)**	**$ 2009 $/kW [(1)]**
Purchase Contracts	71,604	627
Construction Contracts	39,081	342
Total Direct Costs	*110,686*	*969*
Total Indirect Costs	*43,416*	*380*
Total EPC Capital Costs	**154,102**	**1,296**
Total Including Owner's Costs	**192,628**	**1,620**

[(1)]Values presented are based on net plant output at average day ambient conditions.

10.4 Pulverized Coal

Currently, it is uncertain whether a coal unit of any type could be permitted in Florida, and certainly, recent experience has indicated that new coal units cannot be permitted in Florida. In spite of this uncertainty, GRU has included a pulverized coal unit for purposes of evaluating its cost compared to the GREC. The three major coal technologies that could be considered are pulverized coal, fluidized bed, and integrated coal gasification. In addition, a size compatible with GRU's system was selected. The 125 MW pulverized coal unit was selected for several reasons. From a size standpoint, there are significant economies of scale associated with coal units resulting in a desire to have the largest unit possible. The 125 MW size is slightly larger than the GREC, but the 125 MW unit will have lower output than the GREC if CCS is required. In this size range, fluidized bed units are generally competitive with pulverized coal units, but in general pulverized coal units have slightly better heat rates, reducing CO_2 emissions and currently, there is more experience with pulverized coal units in meeting the lowest possible emission rates for pollutants. Current efforts for integrated coal gasification units have focused on the 7F combustion turbine technology, resulting in much larger units. In addition, integrated coal gasification units have generally been more costly than pulverized coal units. Other technologies such as oxycombustion have yet to become commercial.

Because of the uncertainty relating to permitting requirements, two versions of the pulverized coal unit have been evaluated. The first is the 125 MW pulverized coal unit with emissions controls to reduce the emission of SO_2, NO_x, mercury (Hg), and particulates to the lowest reasonable levels. The second version is the same 125 MW coal unit with CCS. Because CCS is not currently considered a commercial process in Florida, the estimates developed for it encompass greater uncertainty than for the standard pulverized coal unit. The following presents the details of the pulverized coal alternative.

With pulverized coal technology, coal that is sized to roughly 20 mm (3/4 inch) top size is fed to pulverizers that finely grind the coal to a size so that no less than 70 percent of the coal passes through a 200 mesh screen (70 microns). This pulverized coal, suspended in the primary air stream supplied by forced draft fans, is pneumatically transported to coal burners. At the burner, this mixture of primary air and coal is further mixed with secondary air, and with the presence of sufficient heat for ignition, the coal burns in suspension with the expectation that combustion will be complete before the burner flame contacts the backwall or sidewalls of the furnace. Current pulverized fuel combustion technology also includes features to minimize unintended products of combustion. Low NO_x burners or air and fuel staging can be used to reduce NO_x, and carefully controlling air-fuel ratios can reduce CO emissions.

As a result of the high combustion temperature of pulverized coal at the burners, the furnace enclosure is constructed of membrane waterwalls to absorb the radiant heat of combustion. This heat absorption in the furnace is used to evaporate the preheated boiler feedwater that is circulated through the membrane furnace walls. The steam from the evaporated feedwater is separated from the liquid feedwater and routed to a series of additional heat transfer surfaces in the steam generator.

Once the products of pulverized coal combustion (ash and flue gas) have been cooled sufficiently by the waterwall surfaces so that the ash is no longer molten but in solid form, heat transfer surfaces, predominantly of the convective type, absorb the remaining heat of combustion. These convective heat transfer surfaces include the superheaters, reheaters, and economizers located within the steam generator enclosure downstream of the furnace. The final section of boiler heat recovery is in the air preheater, where the flue gas leaving the economizer surface is further cooled by regenerative or recuperative heat transfer to the incoming combustion air.

Although steam generating surfaces are designed to preclude the deposition of molten or sticky ash products, on-line cleaning systems are provided to enable the removal of ash deposits as they occur. These on-line cleaners are typically soot blowers that utilize either high-pressure (HP) steam or air to dislodge ash deposits from heat transfer surfaces or, in cases with extreme ash deposition, utilize HP water to remove molten ash deposits from evaporative steam generator surfaces. The characteristics of the coal, such as ash content and ash chemical composition, dictate the type, quantity, and frequency of use of these on-line ash cleaning systems. Ash characteristics also dictate the steam generator design regarding the maximum flue gas temperatures that can be tolerated entering convective heat transfer surfaces. The design must ensure that ash in the flue gas stream has been sufficiently cooled so that it will not rapidly agglomerate or bond to convective heat transfer surfaces. In the case of very hard and erosive ash components, flue gas velocities must be sufficiently slow so that the ash does not rapidly erode heat transfer surfaces.

With pulverized coal combustion technology, the majority of the solid ash components in the coal are carried in the flue gas stream all the way through the furnace and convective heat transfer components to enable collection with particulate removal equipment (electrostatic precipitators or fabric filters) downstream of the air preheaters. Typically, no less than 80 percent of the total ash is carried out of the steam generator for collection downstream. Roughly 15 percent of the total fuel ash is collected from the furnace as bottom ash, and 5 percent is collected in hoppers located below the steam generator economizer and regenerative air heaters.

10.4.1 Thermal Performance Estimates

Thermal performance and emissions estimates were developed for a 125 MW (net) subcritical pulverized coal unit at average day conditions corresponding to 70 °F/ 72 percent relative humidity as provided in Table 10-9. Performance for pulverized coal generating units is relatively insensitive to ambient conditions, and therefore only average ambient condition performance estimates were developed.

Table 10-9
125 MW (net) Subcritical PC Performance and Emissions Estimates

Parameter	Value
Meteorological Conditions	
Average Ambient Temperature, °F	70
Average Ambient Relative Humidity, percent	72
Assumed Coal Quality	
Carbon, percent	63.61
Hydrogen, percent	4.9
Sulfur, percent	0.67
Nitrogen, percent	1.37
Oxygen, percent	7.27
Moisture, percent	6.5
Chlorine, percent	0.09
Ash, percent	15.59
Calorific Value (HHV), Btu/lb	11,800
Estimated Thermal Performance	
Load Condition, percent	100
Steam Cycle Heat Rejection Method	Wet Mechanical Draft
Gross STG Output, MW	139.7
Auxiliary Load, MW	14.7
Net Power Output, MW	125
Net Plant Heat Rate (HHV), Btu/kWh	10,000
Net Plant Thermal Efficiency (HHV), percent	34.1
Estimated Emissions (1)	
NO_x, lb/MBtu	0.050
SO_2, lb/MBtu	0.060
Hg, lb/MBtu	1.27 E-6
CO_2, lb/MBtu	205.0

(1) Emissions estimates are based on the use of an SCR system and low NO_x burners for NO_x control, a wet FGD system for SO_2 control, activated carbon injection for Hg control, and a baghouse for PM_{10} control. No emissions controls are included for CO_2.

10.4.2 O&M Cost Estimates

10.4.2.1 O&M Assumptions. The assumptions for fixed and variable O&M costs are as follows:

(1) The O&M estimates are in 2009 US dollars.

(2) The plant will operate with a capacity factor of 85 percent and have minimal starts.

(3) The location is the Deerhaven Generating Plant site.

(4) Plant staff wage rates are based on an perator salary of $66,000 per year.

(5) The payroll burden rate used was 40 percent. The payroll burden is intended to capture the costs for payroll taxes and benefits provided by the utility on behalf of the employees in addition to direct salary. Not included in the burden rate are any costs for corporate services such as payroll, accounting, legal, and corporate tax administration.

(6) Property insurance and property taxes are not included.

(7) Office and administrative expenses are estimated to be 5 percent of the total staff salary.

(8) Estimated employee training cost and incentive pay/bonuses are included.

(9) Routine equipment maintenance costs are estimated based on Black & Veatch project experience and manufacturer input.

(10) Contract services include costs for services not directly related to power production.

(11) The variable O&M cost analysis is based on a repeating maintenance schedule over the life of the plant, and costs are estimated through at least one major overhaul of equipment.

(12) STG, boiler, and other BOP maintenance costs are based on Black & Veatch project experience and vendor data and recommendations.

(13) SCR is included for NO_x control.

(14) Activated Carbon Injection (ACI) was included for Hg control.

(15) SCR uses anhydrous ammonia.

(16) A wet scrubber using limestone was included for SO_2 control.

(17) A fabric filter baghouse system was included for particulate control.

(18) Water treatment costs are included for cycle makeup, cooling tower makeup and service water, where needed.

(19) The following were assumed for costs:

- $400/ton for anhydrous ammonia.
- $0.95/1,000 gallons for raw water.
- $3.00/1,000 gallons for demineralized water.

- $4.95/1,000 gallons for sewage charge.
- $28/ton for limestone.
- $6/ton for ash disposal.
- $100/bag for baghouse bag.
- $50/cage for baghouse cage.

10.4.2.2 O&M Estimate. The fixed and variable costs, based on the assumptions listed above, are provided in Table 10-10 and are expressed on thousands of 2009 US dollars.

Table 10-10
125 MW (net) PC O&M Cost Estimates

Parameter	**$ 2009 ($000)**
Fixed Costs	
Labor	6,376
Maintenance	1,116
Other Expenses [(1)]	774
Total Annualized Fixed Costs	*8,266*
Variable Costs	
Outage Maintenance	730
Utilities	919
Chemical Usage	536
Ash and FGD Byproduct Disposal	465
Desulfurization Equipment	252
Particulate Removal	153
SCR	685
ACI	858
Total Annual Variable Costs	*4,598*
O&M Cost Summary	
Annual Net Generation, MWh [(2, 3)]	**930,750**
Fixed Costs per net unit of Capacity, $/kW-yr [(2)]	**66.12**
Variable Costs per net unit of Output, $/MWh [(2, 3)]	**4.94**

[(1)]Other expenses include office and administrative expenses, training, and bonus and incentive pay.
[(2)]Based on average day performance conditions presented in Table 10-9.
[(3)]Based on an 85 percent capacity factor.

10.4.3 Capital Cost Estimates

The following subsections provide the general, direct, and indirect capital cost assumptions.

10.4.3.1 General Capital Cost Assumptions.

(1) The plant site is the Deerhaven Generating Plant site.

(2) The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.

(3) Pilings are included under major equipment. Spread footings were assumed for all other foundations. Further stabilization of the existing subgrade is not included.

(4) Construction power is available at the site boundary.

(5) The protection or relocation of existing fish and wildlife habitat; threatened and endangered species; or historical, cultural, and archaeological artifacts is not expected and, therefore, is not included.

(6) Initial inventory of coal, limestone, anhydrous ammonia, and diesel fuel are excluded from the capital cost estimate, but are included in the owner's cost estimate.

(7) Fuel considered will be of similar quality to the fuel presented in Table 10-9.

(8) Offsite development is not included.

10.4.3.2 Direct Cost Assumptions.

(1) The plant would feature one 125 MW (net) unit with one subcritical pulverized coal steam generator (boiler) and one condensing STG.

(2) The subcritical boiler would be drum type, balanced draft, single reheat, and fueled with pulverized coal. Ignition fuel would be No. 2 fuel oil. Steam soot blowers would be used. The boiler would be equipped with three pulverizers, with one serving as a spare. The boiler related equipment such as draft fans, breeching, and structural steel were included in this estimate. The boiler would be fully enclosed.

(3) The STG would be rated at 125 MW (net), and would be inclusive of a standard sound enclosure. The generator would be hydrogen cooled; an allowance has been included for bulk hydrogen and CO_2 gas storage systems. The turbine would be a 3,600 revolution per minute (rpm), tandem compound two flow (TC2F), single-reheat machine.

(4) One each of motor driven forced draft (FD) and induced draft (ID) fans is included. One motor driven primary air (PA) fan would be provided per pulverizer.

(5) NO_x emissions would be controlled by an SCR system. SO_2 emissions would be controlled by a wet FGD. Fabric filter equipment would limit particulate emissions.

(6) Anhydrous ammonia will be provided for use in the SCR system.

(7) Steam vent silencers are not included.

(8) Low NO_x burners are included.

(9) The fire water system includes a diesel fire water pump, motor driven fire water pump, and a jockey fire water pump.

(10) The boiler feed system includes two half-capacity motor driven boiler feed pumps.

(11) The water source will be groundwater.

(12) The feedwater heater cycle design will include three low-pressure (LP) feedwater heaters, a deaerating feedwater heater, and two HP feedwater heaters for a six heater cycle.

(13) Material handling systems are included, with an allowance for a coal handling system and a limestone handling system.

(14) A clarifier is included for the pretreatment system. A demineralizer and condensate polisher is also included in the pulverized coal estimates. The other standard chemical equipment required on a new site is also included. This includes cycle sampling and analysis equipment, wastewater treatment equipment, and a site sanitary treatment system.

(15) Field erected tanks consist of the following:
- Fuel oil storage tank.
- Service/fire water storage tanks.
- Condensate tank - stainless steel.
- Demineralized water storage tank.
- Neutralization tank.

(16) Major solid waste disposal design considerations include the following:
- Bottom ash and pulverizer rejects would be trucked from the plant area to an ash disposal area.
- A pressure type pneumatic fly ash transport system, including a fly ash storage silo, will be provided.
- Trucks and landfill area mobile equipment are not included in these estimates. Rolling stock is included in the owner's costs.
- The dewatered sludge for the wet limestone FGD cases is assumed to be trucked to the ash disposal area.

(17) A multi-cell, rectangular, fiberglass mechanical draft, counterflow, cooling tower is included. Cooling tower fans are assumed to be single speed, non-reversing. The circulating water system would include two 50 percent nominal capacity vertical pumps.

(18) CEMS is included.

(19) A concrete chimney is included.

(20) A bridge crane for servicing the STG is included.

(21) Two full capacity air compressors would be provided to supply service and control air. Two central air receivers are included, with miscellaneous air receivers in various plant locations of significant air consumption. Two full capacity heatless air dryers are included to provide control air. All air to non-heated plant areas is from the dried control air supply.

(22) A diesel driven generator is included for safe shutdown power.

(23) The condenser would be a single-pass, two-shell, dual pressure condenser. Condenser tubing would be stainless steel.

(24) Three half-capacity, vertical wet suction, can-type, condensate pumps are included.

(25) Two full-capacity mechanical condenser vacuum pumps are included.

(26) The estimates include a diesel main fire pump, motor driven fire pump, boiler area booster fire pump, jockey pump, and a boiler area jockey pump.

(27) Fuel oil storage and pumping facilities are included.

(28) One generator step-up (GSU) transformer is included.

(29) Two main auxiliary transformers are included.

(30) One generator breaker is included.

(31) An allowance for a substation has not been included in the cost estimate.

(32) Assumptions on major structures include the following:

- Construction facilities.
- Administration building.
- Plant warehouse maintenance building.
- Control center building.
- Water treatment building.

(33) Piling is assumed for major equipment and buildings only.

(34) A single No. 2 fuel oil fired auxiliary boiler is included.

(35) Building heating, ventilation, and air conditioning (HVAC) allowance is included.

(36) Concrete circulating water pipe is assumed. Termination piping at the condenser and cooling tower would be coated carbon steel.

(37) The steam generator building would include a single elevator.

(38) Office furniture, maintenance warehouse bins and shelving, laboratory equipment and furnishings, and machine shop equipment are included in the owner's cost.

10.4.3.3 Indirect Cost Assumptions.

(1) General indirect costs include all necessary services required for checkouts, testing services, and commissioning.

(2) An allowance for insurance has been included in the cost estimate. Insurance includes builder's risk and general liability.

(3) Engineering and related services costs are included.

(4) Field construction management services include field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.

(5) technical direction and management of start-up 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 are included.

(6) Contractors' contingency and profit are included in the estimate.

(7) Transportation costs for delivery to the job site are included in the base plant estimate.

(8) Spare parts for startup and operation are included. Major hot gas path parts are not included.

10.4.3.4 Capital Cost Estimate. The capital cost estimate, based on the assumptions provided above, is provided in Table 10-11.

Table 10-11
125 MW (net) PC Capital Cost Estimate

Component	**\$ 2009 (\$000)**	**\$ 2009 \$/kW (1)**
Purchase Contracts	241,516	1,932
Construction Contracts	109,198	874
Total Direct Costs	*350,714*	*2,806*
Total Indirect Costs	*148,198*	*1,186*
Total EPC Capital Costs	**498,912**	**3,991**
Total Including Owner's Costs	**623,640**	**4,989**

(1)Values presented are based on net plant output at average ambient conditions.

10.5 Pulverized Coal with Carbon Capture and Sequestration

CO_2 capture for pulverized coal power generation would typically take place "post-combustion" based on the current state of technology development. In post-combustion capture, CO_2 is removed from the flue gas after combustion, then compressed and transported by high pressure pipeline to a sequestration facility. Since the volume of gas to be treated is very large and the concentration of CO_2 in the flue gas is relatively low, a chemical solvent is required for absorption. Oxy-fuel combustion is another technology that is being developed for PC power generation, however this technology is still in the early stages of development and is significantly less developed than post-combustion processes.

Based on currently developed post-combustion technology, the most likely solvent that would be used would be an amine-based chemical solvent. Ammonia solution is another solvent option that is currently under development, but is currently less developed than amine-based solvents for CO_2 removal. It should be noted that there are currently no power plants in the US that capture CO_2 using an amine-based or other process at the scale of a 125 MW coal plant or larger.

The assumed CO_2 capture plant process consists of flue gas preparation, CO_2 absorption, CO_2 stripping (solvent regeneration), and CO_2 compression. The flow process would begin at the flue gas discharge from the plant emissions controls equipment, where a blower with a cooler would be used to pass the flue gas upward through an absorber. Cool amine solution would be distributed evenly downward through the absorber onto packing material, allowing the solvent to selectively capture

CO_2 from the gas. The resulting flue gas would be discharged from the top of the absorber to the atmosphere. The CO_2-rich solvent would be collected at the bottom of the absorber, pre-heated via an amine/amine heat exchanger, and pumped into the top of a stripper. CO_2 would be stripped from the solvent by steam from a reboiler. The resulting high-purity CO_2 stream would then be compressed and transported to storage.

Energy requirements for amine-based CO_2 removal include a significant amount of low-pressure steam to strip CO_2 from the solvent, and electricity for the blowers and fans necessary for flue gas circulation through the capture process. Significant additional energy is required for CO_2 compression and cooling water circulation.

As SO_2 will degrade amine-based solvents, some enhancement of the limestone FGD system would be required compared to the non-CO_2 capture case in order to further reduce SO_2 levels to less than 10 ppm.

Because the use of CO_2 capture technology has not been demonstrated in the power industry at a significant scale, there is inherent risk in implementing CO_2 capture in its current state of development. It is expected that improvements and optimizations will be forthcoming from current and future development work. At this time, capital and operating costs are very high, but opportunities exist to reduce these costs somewhat as the process is optimized through demonstration and operating experience.

Once captured, CO_2 may be stored by means of geological sequestration. Long-term sequestration of CO_2 in significant quantities has yet to be proven as a definitive technology and may not be feasible in some geographic regions. Currently there are three options for the long-term geologic sequestration of CO_2; conventional oil and gas reserves for enhanced oil recovery (EOR), coal seams for enhanced coal bed methane (ECBM) production, and storage in deep saline reservoirs. In the US, deep saline reservoirs appear to be the best suited geologic sink for long-term carbon sequestration. Information from the Southeast Regional Carbon Sequestration Partnership (SECARB) appears to indicate that the best possibility for sequestration near the Gainesville area would be in the saline aquifer regions in the southern part of Florida. For purposes of this cost estimate, it has been assumed that a 100-mile pipeline length would be required extending to the south of the power plant in order to reach an appropriate and feasible sequestration site. Significantly more investigation and development would be required to ultimately locate an appropriate site.

Table 10-12 provides estimated impacts to selected cost and performance data provided in Section 10.4 for the 125 MW subcritical PC plant. As stated in Section 10.4, since carbon capture and sequestration for pulverized coal power plants is not yet considered a commercial process, the estimates developed for it encompass greater uncertainty than for a standard pulverized coal unit.

Table 10-12
Estimated Impacts of Addition of Carbon Capture and Sequestration to Subcritical PC Plant Performance and Cost

Parameter	Value
Estimated Performance	
Assumed Carbon Capture Percentage	85-90
Net Plant Output, MW	94
Net Plant Heat Rate (HHV), Btu/kWh	13,300
Estimated Capital Cost	
Total EPC capital cost increase for CO_2 capture and compression equipment, ($000's) 2009	350,000
EPC Capital cost of 100-mile CO_2 pipeline to sequestration site, ($000's) 2009	60,000
EPC cost to develop sequestration site	Not included
Non-Fuel O&M Costs	
Total fixed and variable O&M costs for CO_2 capture equipment ($ 2009, thousands), per year	15,100

11.0 Evaluation Methodology

To compare the cost-effectiveness of GRU's PPA with GREC LLC discussed in Section 9.0 of this Application to the supply-side alternatives discussed in Section 10.0 of this Application, levelized cost of energy (LCOE) analyses were performed. The LCOE analyses calculate the all-in (capital, fixed and variable O&M, and fuel costs), levelized cent/kWh cost of alternatives based on assumed capacity factors and the cost and performance characteristics of the alternatives. The process of levelization produces a cents/kWh cost for each alternative that has the same present value as the stream of variable, year-by-year busbar costs; therefore, alternatives can be compared to one another based on the levelized costs. The LCOE analyses take into consideration the economic parameters and fuel price projections presented previously in this Application and, therefore, all LCOE analyses are internally consistent. The LCOE analyses have been performed over the period 2014 through 2043, which represents the term of GRU's PPA with GREC LLC.

The remainder of this section presents more description of how the LCOE analyses were performed and how the fuel and CO_2 emissions allowance price projections used in the LCOE analyses were developed.

11.1 Description of the Levelized Cost of Energy Analyses

As described previously, the economics of the proposed GREC were compared to the economics of alternative generating technologies based on LCOE analyses. The LCOE analyses account for all costs associated with GRU's PPA with GREC LLC, and similarly account for all costs associated with the alternative generating technologies. Costs associated with the GREC PPA include those discussed in Section 9.0 of this Application. Costs associated with the alternative generating technologies include capital costs, fuel costs, and O&M costs. As discussed in Section 12.0 of this Application, additional sensitivity cases were evaluated to reflect potential costs associated with future regulation of CO_2 emissions. The levelized cost per kWh is the parameter used for comparing the economics of GRU's PPA with GREC LLC to the generating unit alternatives.

11.2 Fuel and CO_2 Emissions Allowance Price Forecasts

Section 7.0 presents the fuel and CO_2 emissions allowance price forecasts used throughout this Application, including price forecasts for various sensitivity cases. The fuel and CO_2 emissions allowance price forecasts presented in Section 7.0 were developed in constant 2007 dollars through the year 2030. For purposes of the economic analyses presented in Section 12.0 and discussed throughout this Application, the projections were extrapolated beyond 2030, based on the average annual escalation rate over the last 5 years of each price projection. The CO_2 emissions allowance price projections were converted from metric to short tons. The resulting price projections were then converted from constant 2007 dollars to nominal dollars using the 2.5 percent general inflation rate discussed in Section 6.0. The resulting fuel and CO_2 price projections are summarized in Table 11-1.[1]

[1] The columns of Table 11-2 labeled *HR* 2454 and *HR 2454 Lim Alt/No Int Offsets* correspond to the cases considered in the EIA's analysis of HR 2454, which is discussed in Section 7.0 of this Application.

Table 11-1
Fuel and CO_2 Emissions Allowance Price Projections

Year	Natural Gas (Nominal $/MBtu) Reference	High Price	Low Price	HR 2454 Basic	HR 2454 Lim Alt/No Int Offsets	Coal (Nominal $/MBtu) Reference	High Price	Low Price	HR 2454	HR 2454 Lim Alt/No Int Offsets	CO_2 (Nominal $/ton) HR 2454 Basic	HR 2454 Lim Alt/No Int Offsets
2014	8.38	8.94	7.31	8.63	9.70	3.17	3.22	3.09	3.13	3.19	22.31	65.56
2015	8.82	9.56	7.70	9.11	10.79	3.25	3.33	3.19	3.21	3.23	24.56	72.17
2016	9.30	10.07	8.22	9.57	11.35	3.34	3.41	3.28	3.29	3.31	27.04	79.45
2017	9.69	10.54	8.61	9.85	11.78	3.39	3.46	3.33	3.33	3.35	29.76	87.46
2018	10.16	11.02	9.03	10.14	12.30	3.41	3.49	3.35	3.36	3.35	32.76	96.28
2019	10.73	11.43	9.62	10.45	12.69	3.51	3.59	3.44	3.47	3.45	36.07	105.99
2020	11.27	11.79	10.59	10.69	12.91	3.60	3.68	3.53	3.58	3.53	39.70	116.68
2021	11.90	12.26	11.71	10.73	12.96	3.68	3.76	3.60	3.67	3.66	43.71	128.45
2022	12.37	12.76	12.28	10.90	13.55	3.76	3.85	3.68	3.77	3.76	48.12	141.41
2023	12.43	13.09	12.20	11.15	14.02	3.86	3.95	3.77	3.87	3.88	52.97	155.67
2014	12.78	13.31	12.33	11.45	14.19	3.97	4.05	3.86	3.98	3.95	58.31	171.37
2025	12.75	13.21	12.15	11.37	14.09	4.10	4.18	3.99	4.08	4.05	64.19	188.65
2026	13.24	13.65	12.58	11.72	14.75	4.23	4.30	4.11	4.19	4.17	70.67	207.67
2027	13.82	14.12	13.04	11.94	15.13	4.36	4.42	4.23	4.30	4.31	77.79	228.62
2028	14.69	15.08	14.01	12.52	15.46	4.47	4.53	4.33	4.40	4.46	85.64	251.67
2029	15.40	15.98	14.75	13.11	15.76	4.58	4.65	4.44	4.47	4.55	94.27	277.05
2030	16.22	16.85	15.25	13.63	16.14	4.71	4.78	4.55	4.54	4.79	103.78	304.99
2031	17.06	17.76	16.00	14.16	16.50	4.84	4.91	4.67	4.64	4.97	114.25	335.75
2032	17.95	18.72	16.78	14.70	16.88	4.98	5.04	4.79	4.73	5.14	125.77	369.61
2033	18.88	19.73	17.61	15.27	17.26	5.11	5.18	4.92	4.83	5.33	138.45	406.89
2034	19.87	20.80	18.48	15.86	17.66	5.25	5.32	5.04	4.93	5.52	152.42	447.92
2035	20.90	21.93	19.38	16.47	18.06	5.39	5.46	5.18	5.03	5.71	167.79	493.10
2036	21.99	23.11	20.34	17.10	18.47	5.54	5.61	5.31	5.14	5.92	184.71	542.83
2037	23.13	24.36	21.34	17.76	18.89	5.69	5.76	5.45	5.24	6.13	203.34	597.57
2038	24.34	25.68	22.39	18.45	19.32	5.85	5.91	5.59	5.35	6.34	223.84	657.83
2039	25.61	27.06	23.49	19.16	19.76	6.01	6.07	5.74	5.46	6.57	246.42	724.18
2040	26.94	28.53	24.65	19.90	20.21	6.17	6.24	5.88	5.57	6.80	271.27	797.21
2041	28.34	30.07	25.86	20.66	20.67	6.34	6.40	6.04	5.69	7.05	298.63	877.61
2042	29.82	31.69	27.13	21.46	21.14	6.51	6.58	6.19	5.81	7.30	328.74	966.12
2043	31.37	33.41	28.47	22.29	21.63	6.69	6.75	6.36	5.93	7.56	361.90	1,063.55

12.0 Economic Evaluation

As discussed in Section 11.0 of this Application, LCOE analyses were performed to provide a basis for comparison of the economics of GRU's PPA for capacity and energy from the proposed GREC facility to the economics of the generating unit alternatives. Numerous evaluations were conducted in order to consider various fuel price projections including and excluding the potential impact of possible future regulations of CO_2 emissions, the impact of variations to the capital costs of the generating unit alternatives, and to compare the economics of the GREC LLC PPA to a pulverized coal unit that included the necessary equipment for CCS. The remainder of this section describes each of the cases evaluated and presents the corresponding LCOE for the GREC PPA compared to the other alternatives.

12.1 Overview of Cases Considered

Projections of fuel and CO_2 emissions allowance prices and estimates of generating unit costs and performance characteristics have been presented in previous sections of this Application, along with information related to the GREC LLC PPA. To develop a robust basis for comparing the economics of the GREC LLC PPA to the economics of the generating unit alternatives, a number of different cases were considered. These cases are described as follows:

- The *No CO_2* case considers the reference case fuel price projections summarized in Section 11.0 of this Application as well as the generating unit alternative cost and performance estimates presented in Section 10.0.
- The *No CO_2 – High Fuel Price* case considers the high fuel price projections summarized in Section 11.0 of this Application as well as the generating unit alternative cost and performance estimates presented in Section 10.0.
- The *No CO_2 – Low Fuel Price* case considers the low fuel price projections summarized in Section 11.0 of this Application as well as the generating unit alternative cost and performance estimates presented in Section 10.0.
- The *No CO_2 – High Capital Cost* case considers the reference case fuel price projections summarized in Section 11.0 of this Application as well as a 20 percent increase to the generating unit alternative capital cost estimates presented in Section 10.0.

- The *No CO_2 – Low Capital Cost* case considers the reference case fuel price projections summarized in Section 11.0 of this Application as well a 20 percent decrease to the generating unit alternative capital cost estimates presented in Section 10.0.
- The *HR 2454 Basic CO_2* case considers the CO_2 emissions allowance and fuel price projections corresponding to the EIA's analysis of HR 2454 for the *Basic* case (discussed in Section 7.0 and summarized in Section 11.0 of this Application) as well as the generating unit alternative cost and performance estimates presented in Section 10.0.
- The *HR 2454 High CO_2* case considers the CO_2 emissions allowance and fuel price projections corresponding to the EIA's analysis of HR 2454 for the *Limited Technology/No International Offsets* case (discussed in Section 7.0 and summarized in Section 11.0 of this Application) as well as the generating unit alternative cost and performance estimates presented in Section 10.0.

The alternative cases summarized in the preceding bulleted list need to be viewed in proper context to the proposed GREC facility. That is, because the price terms of the GREC LLC PPA are fixed, they are not subject to the fuel price and capital cost variations that are considered in the LCOE analyses of the generating unit alternatives. Further, given that the proposed GREC biomass unit will have net CO_2 emissions of zero, cases that consider potential regulation of CO_2 emissions and associated allowance prices do not impact the LCOE of the GREC LLC PPA.

12.2 Results of the LCOE Analyses

Table 12-1 summarizes the results of all of the LCOE analyses that were performed, with results presented as percent differences compared to the LCOE of the GREC LLC PPA.

Table 12-1
LCOE Matrix
(Differences Compared to the LCOE of the GREC PPA)

Case	Generating Unit Alternative				
	GREC LLC PPA	Simple Cycle LMS100	1x1 7EA Combined Cycle	Pulverized Coal (no CCS)	Pulverized Coal (with CCS)
No CO_2	Base	103%	11%	-14%	48%
No CO_2 – High Fuel Price	Base	108%	16%	-14%	49%
No CO_2 – Low Fuel Price	Base	96%	5%	-15%	47%
No CO_2 – High Capital Cost	Base	118%	15%	-6%	66%
No CO_2 – Low Capital Cost	Base	88%	8%	-22%	31%
HR 2454 Basic CO_2	Base	125%	31%	56%	81%
HR 2454 High CO_2	Base	210%	103%	196%	104%

12.3 Summary of the LCOE Analyses Results

Analysis of Table 12-1 and Table 12-2 indicates the following:

- The LCOE of the GREC LLC PPA is lower in cost than the natural gas alternatives for all of the cases.
- The LCOE of the natural gas alternatives range from approximately 5 percent to 210 percent higher than the GREC LLC PPA.
- The LCOE of the GREC LLC PPA is lower in cost than the pulverized coal alternative without CCS for cases reflecting cost associated with future regulations of CO_2 emissions. The LCOE of the pulverized coal alternatives in these cases ranges from 56 percent to 196 percent higher than the LCOE of the GREC LLC PPA.
- The LCOE of the pulverized coal unit that includes CCS is higher than the LCOE of the GREC LLC PPA, ranging from 31 percent to 104 percent higher in LCOE.
- Overall, the LCOE of the GREC LLC PPA is the lowest among the natural gas and coal alternatives in 23 of the 28 cases considered.

13.0 Demand-Side Management and Supply-Side Efficiency

As discussed previously in this Application, GRU does not forecast a need for capacity to maintain reserve margin requirements until 2023 under its base case load forecast. The GREC biomass facility proposed herein offers significant benefits to GRU as discussed throughout this Application, despite the timing of the projected need for capacity to maintain reserve margin requirements. Given the timing of the projected need for capacity, GRU has not specifically performed any analyses to demonstrate that there are no conservation or (DSM measures that may mitigate the need for the GREC biomass facility. However, GRU has invested significant effort in developing the DSM programs currently offered to its customers. The remainder of this section describes GRU's current DSM programs, renewable energy projects that have been encouraged by GRU, and efficiency improvements to supply-side resources that have helped to reduce demand and energy requirements.

13.1 Planning Criteria and Program Goals

Since 1980, GRU has offered incentives and services as DSM tools to encourage energy conservation and demand reduction. DSM programs are available for all retail customers, including commercial and industrial customers. These programs, since their inception in 1980, have resulted in cumulative energy savings of 151 GWh and cumulative peak demand savings of 30 MW. Through 2008, and are projected to achieve 366 GWh in cumulative energy savings and 108 MW in cumulative peak demand savings through 2025.

Prior to 2006, GRU applied the RIM test to evaluate the cost-effectiveness of DSM programs. In 2006, GRU implemented the TRC test as an alternative measure to assess a conservation program's value. GRU looked at all available options for conservation programs, systematically analyzed their cost-effectiveness, and deployed many new conservation programs. GRU offers a wide variety of energy conservation rebates and incentives and is regarded as the energy conservation leader in Florida.

In 2005, ICF was hired to provide independent consultation on options for meeting the electric supply needs of the Gainesville community. ICF foresaw the need for additional electric generation in the coming years, and its report analyzed four alternatives that would best meet this need. These alternatives included various electric generation types, fuel types, and levels of DSM.

One alternative proposed by ICF included "Maximum DSM" coupled with a 75 MW biomass plant. The "Maximum DSM" component included a plan for year-by-year energy and demand reduction schedule to be achieved through new DSM programs. The year-by-year energy and demand savings has become the yardstick by which GRU measures progress with DSM.

Upon review and consideration of ICF's report, on April 12, 2006, the City Commission instructed staff as follows:

"1. Include the Total Resource Cost test as a consideration to pursue all cost effective and feasible demand side measures including demand response, energy efficiency, load management, and incentive rate design options. Ensure that the needs of low-income customers are addressed in demand-side management programs.

2. Have GRU staff conduct a thorough examination of all DSM options and present a plan to the commission to develop and implement all cost effective DSM and demand response measures..."

Per the Gainesville City Commission's direction, new DSM programs are now analyzed using the TRC test in addition to the RIM test. The TRC test differs slightly from the RIM test in that the TRC test measures the net costs of the DSM program as a resource option based on the total costs of the program, including both the participants' and the utility's costs, whereas the RIM test includes the impact on utility rates.

In 2009, GRU offered 23 rebate and incentive programs to encourage energy and peak demand reductions. Participation in these programs is expected to decrease peak demand by 2.5 MW and decrease total energy consumption by 17 GWh in 2009. GRU's conservation results to date and goals for the future are shown in Table 13-1.

Table 13-1
Demand-Side Management Impacts[1]

Calendar Year	Energy Reduction (GWh)		Summer Demand Reduction (MW)	
	Goal per ICF Study	GRU Actual/Planned	Goal per ICF Study	GRU Actual/Planned
1980		0		0
1981		1		0
1982		1		1
1983		2		1
1984		8		3
1985		16		5
1986		25		7
1987		30		8
1988		35		10
1989		39		11
1990		44		12
1991		49		13
1992		55		14
1993		61		16
1994		67		17
1995		72		18
1996		76		19
1997		80		19
1998		84		20
1999		89		20
2000		93		21
2001		97		21
2002		102		22
2003		106		22
2004		109		23
2005		113		23
2006	125	117	27	24
2007	129	131	29	27
2008	134	151	30	30
2009	144	169	34	33
2010	158	181	38	37
2011	174	193	44	42
2012	193	206	50	48
2013	213	218	57	53
2014	234	230	65	59
2015	256	242	72	65
2016	273	255	77	69
2017	290	267	82	73
2018	307	279	88	78
2019	323	292	95	82
2020	340	304	102	86
2021	346	317	104	91
2022	351	329	106	95
2023	356	341	107	99
2024	362	354	109	103
2025	367	366	111	108

[1] The data presented for 1980 to 2008 is historical data, and the data presented for 2009 through 2025 is forecasted data.

13.2 Retail Rate Design

During the fiscal year 2007 budget process, the City Commission set a policy to decrease load growth by 60 percent through a robust DSM plan. A component of that plan was the design of rates to support the conservation policy. Prior to this process, GRU's residential electric rate consisted of a monthly customer charge, two blocks with a break at 750 kWh, and the fuel adjustment. GRU's electric rate for small commercial customers with less than 50 kW of monthly peak demand (GSN) consisted of a monthly customer charge, two blocks with a break at 1,500 kW, and the fuel adjustment. In 2007, a third block was added to residential rates, resulting in a first tier for 0 to 250 kWh priced at $0.028 per kWh, the second for 251 to 750 kWh priced at $0.067 per kWh, and the third for all energy used over 750 kWh priced at $0.102 per kWh. The first tier was priced below cost, and the third tier was priced at almost twice cost to discourage use at the higher levels. The first tier of 0 to 1,500 kWh for customers in the GSN category is priced at $0.070 per kWh and $0.103 per kWh for all energy used above that amount. Tools, in the form of education and conservation programs with rebate incentives, were given to customers to allow them to better achieve the savings. This structure is still in place today. The utility has seen a decrease in the average monthly use per household from 936 kWh in fiscal year 2006 to 838 kWh in fiscal year 2008 as a result of conservation efforts, price elasticity, and the economic downturn.

13.3 Existing Residential DSM Programs

In fiscal year 2009, GRU offered 17 incentive and rebate programs to encourage energy conservation. These programs are shown in Table 13-2.

GRU continues to review the efforts of conservation leaders in the industry and has conducted fact-finding trips to California, Texas, Vermont, and New York to maximize these efforts. GRU plans to continue to expand its DSM programs as a way to cost-effectively meet customer needs and hedge against potential future carbon tax or cap-and-trade programs.

In fiscal year 2010, GRU plans to implement home energy reports for residential customers as a method to align behavioral changes with energy conservation. These reports provide a comparison of personal household energy consumption against energy consumption of households of similar type in their neighborhood. The reports give consumers feedback as to how they compare to similar households and provide tips on conserving energy and information on GRU's rebate programs. This type of motivational tool has shown consistent and cost-effective energy and demand reductions for utilities in California and Washington.

Table 13-2
DSM Services Offered to Residential Consumers in 2009

1	High Efficiency Central Air Conditioning (Rebates)
2	High Efficiency Room Air Conditioning (Rebates)
3	Central Air Conditioner Maintenance (Rebates)
4	Reflective Roof Coating for Mobile Homes (Rebates)
5	Solar Water Heating (Rebates)
6	Solar PV (Rebates with Net Metering)
7	Natural Gas Appliance (Rebates)
8	Home Performance with the Federal Energy Star Program (Rebates)
9	Energy Star Building Practices of the EPA (Incentives)
10	Green Building Practices (Incentives)
11	Heating/Cooling Duct Repair (Rebates)
12	Variable Speed Pool Pumps (Rebates)
13	Energy Efficiency for Low-Income Households (Grants)
14	Attic and Raised-Floor Insulation (Rebates)
15	Refrigerator Buy Back (Rebates)
16	Compact Fluorescent Light Bulbs (Giveaways)
17	Energy Efficiency Low-Interest Loans (Interest Buy Down)

13.4 Existing Non-Residential DSM Programs

In fiscal year 2009, GRU offered six incentive and rebate programs to encourage energy conservation among non-residential customers. These programs are shown in Table 13-3.

The custom business rebate encompasses a broad spectrum of projects, promoting creativity in energy reduction measures that do not otherwise fit a conventional rebate program. For rebate eligibility, an independent analysis of the efficiency measure is created by a professional engineer or certified energy auditor. Dependent upon the demand reduction, total energy savings, customer cost, and life cycle of the project, GRU will pay a rebate of up to 50 percent of the project cost, up to a maximum of $40,000. In fiscal year 2008, the custom business rebate was GRU's most cost-effective program for energy and demand reductions.

Table 13-3
DSM Services Offered to Non-Residential Customers in 2009

1	Solar Water Heating (Rebates)
2	Solar PV (Net Metering)
3	Natural Gas for Water Heating and Space Heating (Rebates)
4	Vending Machine Motion Sensors (Giveaways)
5	Efficient Exit Lighting (Rebates)
6	Custom Business Rebates for Energy Efficiency Retrofits (Rebates)

13.5 Public Infrastructure

The South Energy Center (SEC) is GRU's newest generation asset. Located at the new Shands at UF Cancer Hospital site, this innovative facility is the first CHP plant of its type in the southeast. The SEC provides 100 percent of the power, steam, chilled water, and medical gas needs of the hospital. Steam is generated as a byproduct of power production; steam required by the hospital is provided via underground pipes, while surplus steam is used to power a steam turbine centrifugal chiller. The unique design is 75 percent efficient (contributing to GRU's energy efficiency goals) and greatly reduces emissions compared to traditional generation contributes to GRU's energy conservation goals. The site also offers expansion capability to provide services to other nearby public facilities.

GRU has plans to complete feasibility studies for other potential CHP sites, distributed chilled water, and thermal storage. If implemented, these facilities will service publicly owned entities.

GRU has supported City of Gainesville infrastructure improvements such as light emitting diode (LED) stoplights and LED crosswalk signals. GRU successfully partnered with the City of Gainesville in pursuing federal funds for a demonstration PV array atop the GRU Administration Building and LED pedestrian lighting at several city owned facilities. GRU continues to upgrade generation assets in pursuit of maximum efficiency and minimal emissions; for example, a major retrofit recently completed on GRU's Deerhaven Unit 2 will significantly reduce SO_2 and NO_x emissions.

13.6 Measurement and Verification

GRU places considerable resources into DSM programs. Therefore, it is important that GRU measures and verifies the savings of these programs to ensure that resources are allocated correctly. In 2008, GRU collaborated with an independent consultant to provide third-party measurement and verification of four of GRU's most consequential residential programs. The results from this study were then used to reallocate funds and resources to programs that yielded the best value.

In fiscal year 2008, GRU installed data recorders at approximately 130 residential sites throughout Gainesville. These data recorders track kW, VARS, and time continuously and transmit their data, via a modem, to GRU's server once a week. Using software and the data from the recorders, GRU is able to isolate major appliance energy usage on an individual and collective basis to better understand how customers use their appliances and what impact they have on GRU's system. These data recorders are also used to create peak coincidence factors, which aid in determining high efficiency appliance efficacy.

Through measurement and verification, GRU has found that the demand and energy savings from the High Efficiency Central Air Conditioning program are much higher than anticipated; the demand and energy savings for the Duct Sealing and Attic Insulation programs are slightly higher than anticipated; and the demand and energy savings for the Refrigerator Recycling program are lower than anticipated. GRU plans to continue third-party measurement and verification of other DSM programs in fiscal year 2010.

13.7 Renewable Energy

GRU continues to offer standardized interconnection procedures and compensation for excess energy production for both residential and non-residential customers who install distributed resources and offers rebates to residential customers for the installation of PV generation. The solar FIT has replaced PV rebates as the incentive for non-residential customers to implement distributed solar generation.

Grants and voluntary customer contributions have made several renewable projects possible within GRU's service area. A combination of customer contributions and State and Federal grants allowed GRU to add its 10 kW PV array at the Electric System Control Center in 1996. GRU secured grant funding through the Department of Community Affairs' PV for Schools Educational Enhancement Program for PV systems that were installed at two middle schools in 2003.

13.8 Supply-Side Efficiency Improvements

GRU has several programs to improve the adequacy and reliability of the transmission and distribution systems, which will also result in decreased energy losses. These include the installation of distribution capacitors, purchase of high efficiency distribution transformers, and reconductoring of the feeder system.

13.8.1 Transformers

For the past 18 years, GRU has been purchasing overhead and underground transformers with a higher efficiency than the National Electrical Manufacturers Association (NEMA) TP-1 Standard. Higher efficiency means fewer kW losses or power lost as a result of the design of the transformer. Since 1988, there have been 18,073 high-efficiency transformers installed on GRU's distribution system. A study was initiated to compare the kW losses of GRU's transformer design to a design based on NEMA TP-1 Efficiency Standard for Transformers. The results of this investigation showed that relative to the standard design, GRU experienced the following savings:

- Average Annual Demand Loss Savings 2.8 MW
- Average Annual Energy Saved 24,900 MWh
- Peak Demand Savings 6.2 MW

13.8.2 Reconductoring

GRU has been continuously improving the feeder system by reconductoring feeders from 4/0 copper to 795 MCM aluminum overhead conductor. Also, in specific areas, the feeders have been installed underground using 1,000 MCM underground cable. The following is a comparison of the resistance for the types of conductors used on GRU's electric distribution system:

- 795 MCM Aluminum Overhead Conductor 0.13 ohms/mile
- 1,000 MCM Aluminum Underground Cable 0.13 ohms/mile
- 4/0 Copper Overhead Conductor 0.31 ohms/mile

Calculations with average loading on the conductors show the total savings due to moving from 4/0 copper to an aluminum conductor (795 or 1000 MCM) as follows:

- Average Annual Demand Savings 2.4 MW
- Average Annual Energy Saved 21,000 MWh
- Peak Demand Savings 7.9 MW

13.8.3 Capacitors

GRU strives to maintain an average power factor of 0.98 by adding capacitors where necessary on each distribution feeder. Without these capacitors, the average uncorrected power factor would be 0.92.

The percentage of loss reduction can be calculated as shown:

- % Loss Reduction = [1-(Uncorrected pf/Corrected pf)^2] x 100
- % Loss Reduction = [1-(0.92/0.98)^2] x 100
- % Loss Reduction = 11.9

In general, overall system losses have stabilized near 4 percent of net generation, as reflected in the forecasted relationship of total energy sales to net energy for load.

14.0 Transmission System Impacts

The GREC facility will be interconnected to the existing GRU system. In August 2009, GRU completed and submitted to FRCC the combined Feasibility and Impact Studies for the GREC interconnection to the GRU system. The FRCC Transmission Working Group (TWG) and Stability Working Group (SWG) evaluated the proposed interconnection and determined that the proposed interconnection of the GREC to serve GRU's load is reliable, adequate and does not adversely impact the FRCC Region. The FRCC Planning Committee subsequently approved the interconnection on September 8, 2009.

GRU's Feasibility and Impact Studies referenced above followed the "fast track regional assessment" provision of the "TSR and GISR Regional Deliverability Evaluation Process" because the capacity of the proposed generating unit is less than 200 MW. Base and study cases were created and shared with other Florida utilities and the FRCC staff for review in accordance with the Deliverability Evaluation Process referenced above. The studies were performed by simulating the following conditions:

- Steady-State Analysis:
  - Base cases representing:
    1. Summer peak conditions for 2013 through 2018.
    2. Winter peak conditions for 2013/2014.
  - Study cases developed by modeling GREC connected to the Alachua-Deerhaven 138 kV line.
- Short Circuit Analysis:
  - Base case representing summer 2013 from the 2008 FRCC Short Circuit Databank.
  - Study case developed by modeling GREC at full output.
- Stability Analysis (dynamic simulations):
  - Base cases represented summer 2016 at 100 percent and 50 percent of peak load conditions.
  - Study case developed by modeling GREC at maximum capability.

All cases with GREC interconnected to the GRU system were reviewed by the TWG and SWG with the following findings:

- The system remained within all required thermal and voltage limits.
- All fault currents remained within the capability limits of all circuit breakers.
- The regional system was stable with controlled load loss as allowed by the North American Electric Reliability Corporation (NERC) Reliability Standards.

15.0 Strategic Considerations

The GREC will provide numerous benefits to GRU from an economic, environmental, and regulatory perspective. This section discusses several strategic considerations taken into account by GRU in making its decision to pursue the PPA with GREC LLC.

15.1 Long-Term Production Cost Benefits

The pricing structure in GRU's PPA with GREC LLC is roughly two-thirds fixed over the 30 year term of the PPA, and the remaining variable portion is not nearly as volatile as natural gas or even spot coal prices. GRU's long-term average cost per MWh from the GREC facility is affected by the degree to which the unit is dispatched at full available capacity. The guaranteed heat rate of the GREC and the expected delivered fuel cost (the unit's incremental dispatch cost) places the facility toward the top of GRU's merit order dispatch profile (even ignoring the value of renewable energy credits [RECs], possible future carbon credits, or other potentially valuable environmental attributes), and GRU anticipates dispatching the unit to the limit of its availability.

15.2 Rate Implications

Although the fully loaded cost of the output from the GREC may initially be higher than conventional combined cycle capacity, over the term of the PPA, the unit cost will become more economical, even without consideration of the long term benefit provided as replacement capacity for units that are scheduled to be retired. The point in time at which this crossover in relative ranking of price occurs depends on the cost of natural gas and the economic value of RECs and possible future carbon credits. Until that occurs, the PPA with GREC LLC will result in upward pressure on GRU's fuel adjustment charges.

GRU has discussed this situation with the City Commission in the form of a risk assessment (independent of the fuel and CO_2 emissions allowance price projections discussed previously in this Application), measured as the effect on a 1,000 kWh residential bill. Table 15-1 summarizes the risk assessment presented to the City Commission on May 7, 2009, prior to the unanimous vote to approve the project. These results translate to the percentages shown in Table 15-2. The City Commission decided that these short-term cost increases were more than offset by the long-term benefits to ratepayers and the community.

Table 15-1
Biomass Plant Risk Assessment[1]

Natural Gas Price Forecast	Value of Environmental Attributes	Impact on 1,000 kWh Residential Bill (/Month)	
		2014	2019
Low	\$0.00/MWh	\$10.53	\$6.22
	\$12.00/MWh	\$8.32	\$4.12
Base	\$0.00/MWh	\$8.31	\$2.85
	\$12.00/MWh	\$6.10	\$0.75
High	\$0.00/MWh	\$6.10	\$(0.53)
	\$12.00/MWh	\$3.88	\$(2.63)

[1]No adjustment for the value of avoided capacity. Value of environmental attributes includes combined REC and CO_2 offset values.

Table 15-2
Biomass Plant Risk Assessment[1]

Scenario	Increase of 1,000 kWh Residential Bill	
	2014	2019
Low Natural Gas Price	5.8%	2.5%
Base Case	4.3%	0.5%
High Natural Gas Price	2.7%	-2.5%

[1] No adjustment for the value of avoided capacity. Includes \$12.00/MWh value for RECs and CO_2 offsets.

The above risk assessment assumes that GRU resells 50 percent of the GREC's output for the period 2014 through 2023. Four municipal organizations in Florida have expressed interest in purchasing this output, and GRU was involved in related discussions at the time this Application was filed.

15.3 Long-Term Firm Capacity Benefits

The PPA with GREC LLC will add value to GRU's generation portfolio initially by materially improving the age distribution of the System's generation fleet. Figure 15-1 illustrates GRU's generation capacity versus unit age, which clearly indicates that fully two-thirds of the capacity is 28 years of age or older. As presented in Section 5.0 of this Application, GRU anticipates needing additional capacity by 2023, with the shortfalls increasing through time due to load growth, but primarily by the retirement of older units. Capacity from the PPA with GREC LLC is projected to satisfy GRU's reserve margin capacity requirements through 2032 based on the base case load forecast discussed in Section 4.0 of this Application.

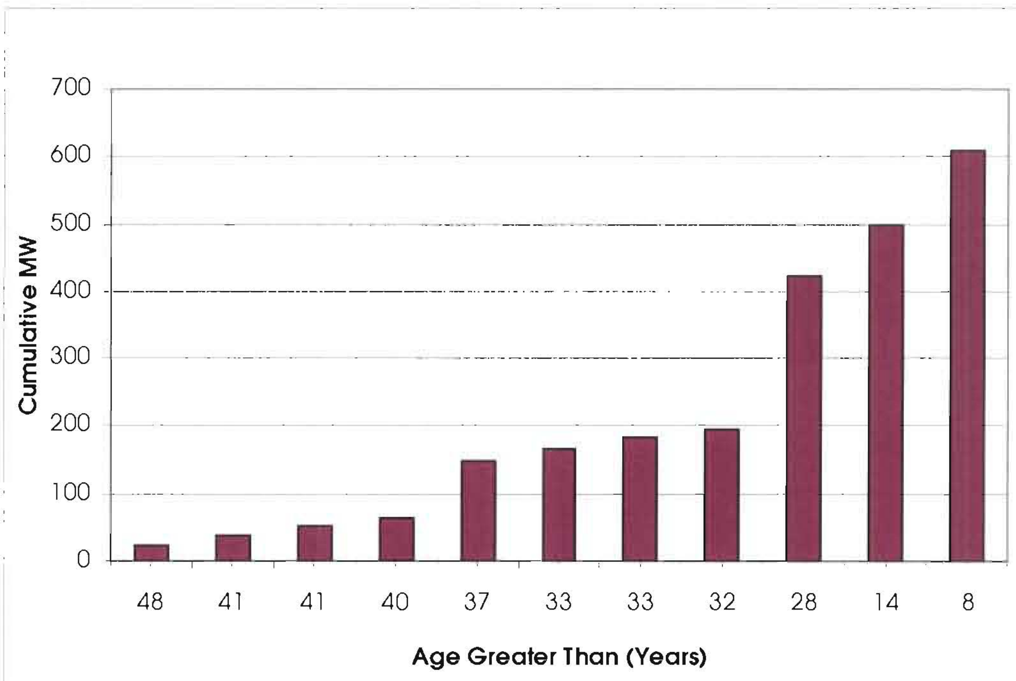

Figure 15-1
Existing Generation Capacity versus Age

The capacity provided by the GREC will significantly improve generating system reliability because of GRU's unique situation of having a single unit (Deerhaven Unit 2) that is very large relative to GRU's peak demand and reserve margin. The capacity from Deerhaven Unit 2 currently represents 50 percent of GRU's 2009 projected system peak demand and loss of this unit represents a significant economic cost and reduced reliability to GRU's system. The GREC's capacity significantly improves this reliability issue from both a firmness of capacity perspective and from the perspective of exposure to high costs of replacement power, since Deerhaven Unit 2 is the lowest cost fossil fuel generator on GRU's system. This is especially important because Deerhaven Unit 2 will be 33 years old when the GREC begins commercial operation and, if not retired, will be 63 years old by the end of the PPA between GRU and GREC LLC. As coal fueled generating units age, the probability of major extended unit outages increases.

15.4 Regulatory Hedge Benefits

Even assuming that GRU keeps only 50 percent of the output of the GREC, the System will be able to produce 21 percent of its energy requirements from renewable energy by 2014. This includes renewable energy from the G2 landfill gas to energy project and the energy from the solar FIT program. This amount of renewable energy is sufficient to meet any of the renewable energy portfolio standards that have been seriously considered at a state or federal level to date. The accompanying carbon credits will provide a very valuable hedge against future carbon constraint legislation as well.

15.5 Fuel Price Volatility Reduction

The commodity price paid to growers for timber harvest residuals is expected to be relatively independent of commodity price swings in the paper pulp and chip and saw markets. To some extent, these markets are inversely related; for example, when paper pulp markets become soft, growers are incentivized to thin their stands (fuel for the GREC) to grow larger trees for the chip and saw market. The most volatile cost for the production and delivery of fuel is the cost of diesel fuel, which represents roughly 5 to 10 percent of the total fuel cost. As a result, the fuel cost for the GREC is expected to be much less volatile than conventional fossil fuels and to escalate much more slowly. Furthermore, the GREC has the advantage of being able to take advantage of opportunity fuels, such as debris from hurricanes, forest fires, ecosystem restoration, land clearing, and insect invasions.

15.6 Fuel Diversification Benefits

Currently, GRU relies on a single rail carrier for coal and one major pipeline for natural gas. Oil supplies are received in a fairly diverse manner, but represent a small fraction of GRU's energy production. The GREC will greatly add to the diversity of GRU's fuel supply, providing benefits in terms of diversity of transportation, mitigating fuel price volatility, and contributing to Florida's overall energy independence. By 2014, the GREC is expected to provide 18.7 percent of GRU's energy supply, even assuming 50 percent of the capacity is resold to another utility. By 2023, following the expected expiration of any initial power resale, this fraction will increase substantially. The GREC will receive fuel deliveries from a number of different directions and a very redundant fleet of third party owned processing equipment and trucks.

15.7 Forest Stewardship Programs

Once the City Commission selected GREC LLC as the leading respondent to the RFP process in May 2008, a vibrant public debate ensued. At issue was how to minimize the potential for the fuel acquisition process to reduce ecosystem biodiversity in the region. An ad hoc advisory committee of forestry and ecosystem experts from both industry and academia was assembled to address this issue, which resulted in two significant results.

The first is a set of very stringent minimum standards for forest-derived fuel acquisition that are part of the PPA between GREC LLC and GRU. Examples of these standards include: acquiring material from timber operations performed according to the Florida Division of Forestry best management practices; not utilizing stumps (which would promote soil erosion); not utilizing material derived from the conversion of natural forest to a plantation forest; not utilizing fuel derived from non-native species unless harvested as part of a forest restoration project; source certification and accountability by truckload; and requiring suppliers to attend an annual sustainability and best practices seminar organized by the GREC procurement staff.

The second is what may be the first utility-sponsored Forest Stewardship Incentive Plan in the US. This plan provides a supplemental payment per ton of fuel delivered for growers operating under an approved independent forest certification program that provides a level of biological protection substantially better than the Division of Forestry best management practices. Currently, two such programs are approved and will earn the grower an additional $0.50 per ton or $1.00 per ton depending on the program. Once the grower receives certification, it will be issued a contract by GRU that will entitle it to the incentive payment and will remain in effect as long as the certification is kept current. The administration of the program is subject to City Commission policy and GRU staff, while GREC LLC will administer the day-to-day operation of the program. Incentive payments are at the sole expense of GRU.

15.8 Other Benefits for the Community

Other aspects of the GREC contribute to the well-being of the Gainesville area in terms of jobs, cleaner air, and utility rates. Not the least of these benefits is the contribution that the GREC will make to supporting Gainesville's ethics for recycling and GHG reduction. Some of the tangible benefits associated with the GREC facility include:

- Less exposure to construction and operating risk.
- Creation of over 500 new jobs in the region.
- Substantial reduction in open burning of waste biomass.
- Zero surface water discharge of industrial wastewater.
- Reducing landfill requirements.
- Promoting ecosystem restoration (removal of undesirable vegetation).
- Promoting the removal of hazardous fire fuel adjacent to urban development.
- Supporting a major regional industry – Silviculture.

16.0 Consequences of Delay

This section discusses the consequences of delaying commercial operation of the GREC biomass facility beyond its planned December 2013 commercial operation date. Delay of the facility would result in economic, reliability, and potential regulatory consequences.

16.1 Economic Consequences

There are a number of economic consequences associated with the delay of the GREC. The most important economic consequence of delay is that if the project is not in commercial operation by January 1, 2014, it will not be eligible to obtain the Renewable Energy Grant contained in H.R. 1 (ARRA 2009) Sec. 1603. The increase in GRU's cost of power from not obtaining the Renewable Energy Grant will be $8.10/MWh, amounting to $6.4 million per year.

In addition to the costs resulting from not obtaining the Renewable Energy Grant, the GREC PPA contains a clause to adjust the nonfuel energy charge by escalation indices to the time of construction commencement. Based on the escalation rate of 2.5 percent assumed in this Application, the cost of delay is $29.6 million per year of delay.

Another economic consequence of delay is that if the GREC is delayed, it will not be available to displace replacement power costs for GRU's Deerhaven 2 during outages.

In addition to the above direct economic consequences of delay, there are numerous indirect consequences of delay. The GREC will directly employ an estimated 42 people in the operation of the project, with an estimated payroll of $4 million per year. In addition, an estimated 400 to 500 people will be employed to obtain the fuel supply, with an estimated payroll of $18 million per year. The GREC will employ more than 400 people at peak construction, with an estimated payroll of $1.5 million per week during the peak construction period. Over the entire construction cycle, construction payroll will total approximately $102 million. These indirect benefits will be postponed with a delay in the construction and operation of GREC. Most of these indirect benefits will be in the Gainesville region.

16.2 Reliability Consequences

The GREC is not required for GRU to maintain its 15 percent planning reserve criterion for several years. However, there are significant reliability benefits to GRU's system associated with the operation of the GREC, and delay of the GREC would also delay those benefits. GRU's system is unique because Deerhaven Unit 2's generating capacity comprises 50 percent of GRU's peak demand. Outages of Deerhaven Unit 2 have a marked effect on GRU's system reliability. The addition of the GREC significantly increases GRU's system reliability; consequently, delay in the operation of the GREC reduces GRU's system reliability.

16.3 Potential Regulatory Consequences

Currently, there are proposed legislation and regulations at both the federal and state levels to impose RPS and regulation of CO_2 emissions. Wood waste biomass is the lowest cost dispatchable generating alternative for meeting both of these requirements. Unfortunately, the supply of wood waste is finite, and economics dictate that the generating plant needs to be located near the source of fuel to minimize transportation costs. The first plants sited in an area will essentially claim the surrounding fuel supply. If the GREC is delayed, the opportunity arises for other projects to be built that would utilize the GREC's sources of fuel. It is vitally important for the GREC to proceed on schedule to allow GRU to meet the potential legislation and regulations in a reliable and cost-effective manner.

17.0 Financial Analysis

The successful completion and operation of the proposed GREC biomass facility will depend on many factors, including, but not limited to, the following:

- The experience and financial capability of the project developers who will own, operate, and maintain the plant.
- The strength/quality of the PPA.
- The credit quality of the PPA counterparty.
- The experience of construction contractors and the strength/quality of the construction contracts.

The project developers intend to pursue a traditional project financing approach for the GREC, which will involve senior long-term debt and additional equity as necessary. The senior bank debt will be secured by first priority liens on substantially all of the assets and commercial agreements of the GREC, as well as a pledge of the equity in the GREC. Additional equity will flow into the project as needed from both strategic and tax-motivated equity investors.

In addition to the project developers' experience, an important aspect of the ability to finance the facility is the credit quality of the counterparty purchasing the plant's output, in this case GRU. This section discusses the experience and financial capability of both parties to this transaction.

17.1 Project Developers

The GREC facility will be designed, constructed, owned and operated by GREC LLC, a subsidiary of American Renewables, LLC, a private, for-profit renewable power producer that is currently under contract to construct a similar facility for Austin Energy (Texas) and is developing another, similar facility in Hamilton County, Florida. American Renewables is jointly owned by affiliates of BayCorp, EMI, and Tyr. The entities are described as follows:

- BayCorp is a merchant energy company that owns power assets, as well as natural gas and oil production and development assets. BayCorp owns and operates a hydroelectric generation facility and is developing additional generation in Vermont; through its subsidiary, Great Bay Power Marketing, Inc., Baycorp supplies wholesale power in the New England power market; and through its subsidiary BayCorp Resources, Baycorp owns and operates interests in oil and natural gas development and production projects located throughout Texas.

- EMI is a privately held energy company with more than 30 years of experience in energy conservation and energy development. In 1986, EMI developed, financed, and constructed Alexandria Power Associates, a 15 MW biomass-fired electric generating facility in Alexandria, New Hampshire. Following the Alexandria project, EMI developed six natural gas-fired electric generation projects totaling more than 860 MW of capacity and including the first true independent and merchant power projects in New England. EMI is also currently developing the Cape Wind Project, a 468 MW offshore wind project to be located in Nantucket Sound off the southern coast of Cape Cod, Massachusetts.
- Owned by ITOCHU Corporation, a $52 billion international trading conglomerate and its US based subsidiary, ITOCHU International, Inc., Tyr focuses on acquiring and owning equity interests in North American independent power assets and providing asset management services to facilities in which it is an owner. Tyr's current portfolio includes interests in CalPeak Power (California), Chesapeake Commonwealth Energy (Virginia), and Fox Energy (Wisconsin). Worldwide, ITOCHU owns interests in independent power facilities in Saudi Arabia, Indonesia and Japan in addition to the United States. Tyr's sister company, North American Energy Services, also a subsidiary of ITOCHU International, Inc., is the industry's largest independent, third-party provider of power plant O&M services, providing services to almost 300 MW of biomass-fueled power plants across the US.

The GREC's project developers have a long and successful track record of energy and power asset development and operation, as well as a robust development pipeline looking forward. Collectively, the project developers have acquired or developed more than $7.6 billion of energy and infrastructure assets, and have a pipeline or deployment budget of $2.5 billion for US renewable power plants over the next 5 years.

17.2 GRU's Financial Capability

As discussed throughout this Application, GRU has entered into a 30 year PPA with GREC LLC for capacity, energy, and environmental attributes from the proposed GREC biomass facility. Given that this transaction is structured as a PPA rather than GRU obtaining an equity share in the facility, the annual costs for GRU's participation are not tied to an investment in a self-build asset, and as such, the ability to finance construction of a new generating unit is not being contemplated in this Application. However, for informational purposes, because GRU is the counterparty to the PPA upon which GREC LLC will obtain project financing, the remainder of this section discusses GRU's current financial position.

GRU management has been diligent in its maintenance of reserve balances and financial indicators, and its rates are considered to be competitive in the Florida market. The superiority of financial management at GRU has been recognized by both Standard & Poor's and Moody's, as indicated by their issuing bond ratings of AA and Aa2, respectively. As one of the top 13 highest rated municipal utilities among more than 400 municipal utilities rated in the country, GRU stands out with these superior ratings. GRU has maintained a total debt service coverage ratio of 2.0 times, a fixed charge coverage of 1.5 times, and an equity ratio of 20 to 30 percent in the fiscal year ending 2009. These economic indicators are projected to continue to improve in later years. All of these ratios are well within the range of other organizations with the same bond ratings from Standard & Poor's and Moody's that GRU has been issued.