ALTERNATIVES FOR MEETING GAINESVILLE'S ELECTRICAL REQUIREMENTS THROUGH 2022

Base Studies And Preliminary Findings

GRU
More than Energy

Gainesville Regional Utilities
December 2003

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GLOSSARY OF TERMS AND ABBREVIATIONS
(In Alphabetical Order of Abbreviation)

ABBREVIATION	TERM	DEFINITION
AAQS	Ambient Air Quality Standards	Legal levels for pollutants established by USEPA to protect public safety and welfare.
AF	Availability Factor	Percentage of time a generator is available to be called upon for maximum output.
BACT	Best Available Control Technology	Emission limit set for permitting purposes based on the cost-effectiveness of applicable technology.
Base Unit	Base Load Unit	A unit designed to run continuously. High capital costs and high efficiencies. These units are the least expensive to operate and slow to start.
Btu	British thermal unit	The amount of heat required to raise one pound of water one degree Fahrenheit; a convenient measure of the heat content of fuel.
CC	Combined Cycle	Adding a HRSG to a combustion turbine to create steam from exhaust gases to run a steam turbine generator.
CF	Capacity Factor	The percentage of theoretical maximum energy a generator actually makes; a function of dispatch and availability.
CFB	Circulating Fluidized Bed	A type of boiler that uses hot solids suspended in blown air to combust solid fuels – able to achieve low SOx and NOx emissions.
CT	Combustion Turbine	A machine similar to a jet engine that burns fuel to spin a turbine that turns a shaft connected to a generator; can be started quickly and is relatively inexpensive but has high heat rates and requires natural gas or #2 distillate oil to run.
Demand	Demand	The instantaneous need for electricity; a function of the number and type of electrical appliances that are switched on at any given moment, measured in Watts.
FDEP	Florida Department of Environmental Protection	State agency that regulates matters concerning environmental protection.
FERC	Federal Energy Regulatory Commission	Federal agency empowered by the laws of interstate commerce to regulate electrical transmission and gas pipeline system; no jurisdiction over municipal utilities.
FGD	Flue Gas Desulfurization	Equipment through which combustion gases flow and are treated to remove SOx; commonly called wet or dry scrubbers.

ABBREVIATION	TERM	DEFINITION
FOR	Forced Outage Rate	The probability that a generator will have to be taken off-line because of malfunction as a percentage of annual operating hours.
FPSC	Florida Public Service Comm.	The state agency charged with regulating electrical systems and electric rates in Florida pursuant to state legislative decisions; limited authority over municipal utilities.
GEAC	Gainesville Energy Advisory Committee	Unpaid volunteer advisory committee appointed by Gainesville City Commission.
HR	Heat Rate	The number of Btu's (British thermal units) required to make one kilowatt-hour, which has a heat content of 3413 Btu's.
HRSG	Heat Recovery Steam Generator	A device designed to create steam from the hot gases of a combustion turbine.
HVAC	Heating, cooling and ventilating systems	These are systems used to heat, cool and ventilate habitable space.
IGCC	Integrated Gasification CC	A pressure and temperature vessel that converts solid fuel to a synthetic gas that is combusted in associated combined cycle generators.
Intermediate Unit	Intermediate Unit	Optimal unit to run with capacity factors of 20 to 60%. These units are more expensive than base load units and less expensive than peakers.
IRP	Integrated Resource Plan	A planning process that addresses both reducing customer demands and increasing generation capacity as a way to meet electrical needs.
kgal	Kilogallon	A kilogallon is 1,000 gallons, a convenient unit of water sales and metering.
kWh	kilowatt-hour (Energy)	A kilowatt-hour is 1,000 Watt-hours. A Watt-hour is the product of instantaneous electrical demand times the duration of that demand. For example, a 100-Watt light bulb left on for 10 hours uses 1,000 Watt-hours, or 1 kilowatt-hour.
LF	Load Factor	An electric system's or customer's average rate of energy use divided by it's peak rate of energy use.
Load	Load (measured in MW)	The number and type of electrical appliances that are switched on at any given moment, measured in Watts; the rate of energy use
MACT	Maximum Achievable Control Technology	The maximum level of emission reduction regardless of cost-effectiveness.

mmBtu	One million British thermal units	One million British thermal units. A convenient measure for discussing fuel in the power industry. A Btu is the amount of heat required to raise one pound of water one degree Fahrenheit.
MW	Megawatt	A Megawatt is 1,000,000 Watts. A Watt is a measure of power, and is the product of voltage times current flow.
MW	Power	The ability to serve the amount of electrical load switched on at any given moment.
MWh	Megawatt-hour	A Megawatt-hour is 1,000,000 Watt hours. A Watt-hour is the product of instantaneous electrical demand times the duration of that demand. For example, a 100-Watt light bulb left on for 10 hours uses 1,000 Watt-hours.
NOx	Nitrogen Oxides	Chemicals formed from the nitrogen and oxygen in the air used to burn fuel in order to make electricity.
NPV	Net Present Value	A financial technique that allows costs and expenses that are expected to occur at different times in the future to be compared in terms of present value. The present value is calculated from a discount rate, which takes into account that a dollar today is worth more than a dollar tomorrow.
O&M	Operation and Maintenance	The costs associated with the operation and maintenance of a facility.
O_3	Ozone	A naturally occurring substance that is formed photochemically as a function of temperature, humidity and certain precursors.
PC	Pulverized Coal	A common form of solid fuel boiler that requires the coal or petroleum coke to be ground into an extremely fine powder and then blown into the furnace of the boiler.
Peaker	Peaking Unit	A low cost unit designed to start quickly. Typically have high heat rates and are expensive to operate.
Petcoke	Petroleum Coke	The residual left after the complete cracking of raw petroleum into various products such as gasoline, distilled oil, residual oil, etc. A very low ash, high Btu content solid fuel that tends to be very crumbly and feels dry.
PM	Particulate Matter	The dust that comes out in the gas stream after combustion. Usually defined as PM_{10} for permitting purposes.

PM_{10}	Particular Matter (Coarse)	Particulate matter that passes a 10-micron screen.
$PM_{2.5}$	Particulate Matter (Fine)	Particulate matter that passes a 2.5-micron screen.
PPA	Purchased Power Agreement	A bilateral wholesale contract with another power producer.
PV	Photovoltaic	A phenomena in special crystalline materials that transforms sunlight into electricity; solar cells.
SB	Subcritical	Simple steam cycles designed to operate at pressures below 2,400 psig.
SC	Supercritical	Simple steam cycles designed to operate above pressures of 3,600 psig.
SCR	Selective Catalytic Reduction	A device through which flue gas passes to remove NOx. A catalytic substrate is required in the presence of ammonia.
SNCR	Selective Non-Catalytic Reduction	A process to remove NOx from flue gas by adding ammonia under special conditions. Does not require a catalytic substrate.
SOx	Sulfur Oxides	Chemicals formed from the sulfur in a fuel as a result of combustion.
Therm	Therm	A therm is 100,000 Btu's
USEPA	United States Environmental Protection Agency	Federal agency charged to establish and enforce regulations pursuant to congressional decisions; has authority to issue permits.
VOC	Volatile Organic Compounds	Organic compounds that evaporate and may be found in air. For example paint solvents.

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EXECUTIVE SUMMARY

Gainesville Regional Utilities (GRU) will need additional electrical generation capacity to meet reliability requirements probably not sooner than 2008 and no later than 2012, with the most likely time frame being 2010. The basic economic, regulatory, and engineering assumptions and data required to develop an Integrated Resource Plan (IRP) to meet Gainesville's electric needs through 2022 have been compiled. An extensive public outreach process heavily influenced the development of the objectives to be met by GRU's IRP. The IRP's objectives are to:

1. Conserve natural resources;
2. Reduce total air emissions;
3. Reduce the carbon intensity of electricity generated;
4. Enhance the local economy with sustainable jobs and industry;
5. Assure reliable energy supplies; and
6. Minimize revenue requirements (the cost of electricity to consumers).

The alternatives evaluated included direct load control; photovoltaic generation; simple and combined cycle gas-fired combustion turbines; integrated gasification combined cycle turbines; and subcritical, supercritical, and fluidized bed steam cycle units of a wide range of sizes. Options for participation in shared solid fuel generation facilities were included. The fuels evaluated included solar energy, coal, petroleum coke, and biomass. Environmental controls as applicable to each technology were considered, including: low NO_x burners, selective catalytic reduction, and selective non-catalytic reduction for NO_x control; wet and dry scrubbers for SO_2 control; and electrostatic precipitators and fabric filter baghouses for particulate control. Considerations also were made for future injection of adsorbents for carbon and mercury control. Detailed studies also were made of the options for retrofitting Deerhaven Unit 2 with additional air emission control equipment. The evaluations required detailed consideration of heat rates, construction costs, fixed and variable O&M costs, by-product management, and fuel suitability. Transmission system upgrades and wheeling charges as applicable also were taken into account.

THE PRELIMINARY INTEGRATED RESOURCE PLAN

The preliminary IRP presented here does not constitute a final selection of alternatives. The final feasibility of some alternatives is dependent upon the outcome of work that is not yet completed. Work that is not yet completed includes:

1. Policy considerations by the Gainesville City Commission;
2. Additional research, design development and proof of assumptions;

3. The outcome of negotiations with potential joint project participants; and
4. Additional synthesis of ideas and options;

The preliminary IRP has several elements that work together to achieve the desired results. These elements include implementing additional energy conservation programs such as new demand response incentives; development of waste wood resources as a fuel supply; and leveraging GRU's existing Deerhaven site to attract investments that make additional emission controls and reductions in carbon intensity more affordable. Table 1 summarizes the proposed new elements to be added to GRU's existing energy portfolio.

ELEMENTS OF THE PRELIMINARY IRP

The preliminary IRP presented here minimizes the consumption of fossil fuels and groundwater through:

1. 1.8 MW of additional energy conservation programs;
2 The introduction of demand response incentives;
3. The use of reclaimed water from GRU's wastewater system;
4. Up to 30 MW of biomass capacity from utilizing waste wood as a fuel;
5. 34 MW of natural gas fired combined cycle combustion turbine capacity; and
6. 206 MW of additional clean and efficient, solid fossil fuel fired, base load generation capacity.

Energy Conservation, Demand Response, and Rate Designs

Roughly 1.8 MW of additional peak demand reductions from HVAC system programs have been identified as potentially feasible. Demand response programs combine Internet and existing metering technologies in new ways to provide customers with access to day-ahead and/or real time prices, which are expected to create behavioral changes. Further enhancements of GRU's current time-of-use rate and further study of the existing "increasing block" rate structures also have been identified as potential means to promote the efficient use of utility resources. Finally, the generation technologies indicated for capacity expansion are expected to substantially reduce fuel use per kilowatt-hour, which conserves energy.

Reclaimed Water

Groundwater consumption will be minimized under some of the generation expansion options included in the preliminary IRP options through the use of reclaimed water for boiler and cooling make-up water, and on-site process water needs. The construction of facilities to transport water from GRU's water reclamation facilities to the Deerhaven site also would offer the opportunity to provide reclaimed water services to customers along the transmission line.

Waste Wood Fuel

The preliminary IRP indicates that enough waste wood could be harvested within an economic hauling distance of Deerhaven to fuel up to 30 MW of electrical generation. Using a separate boiler for biomass, and using the resulting steam in the process design of a larger generating unit, can further enhance the cost-effectiveness of biomass utilization. This strategy captures economies of scale and simplifies operation and construction. However, the availability and cost to harvest, prepare and deliver waste wood for a fuel supply needs additional study and market testing in order to make it a viable solution.

Additional Generation Capacity

The preliminary IRP minimizes revenue requirements by selecting the most cost-effective mix of generation resources to serve the needs of GRU’s customers and to meet environmental requirements. Table 2 presents the theoretically optimal amount and timing of additional intermediate and base load generation capacity, constrained to the time it would take to permit and construct new facilities. Additional peaking generation capacity is not needed throughout the planning horizon. The optimal generation expansion plan consists of a portion of a combined cycle intermediate capacity (34 MW in 2008) and solid fuel base load generating capacity capable of burning coal and up to 20% petroleum coke (206 MW starting in 2010). Biomass capacity would be incorporated as supplemental steam capacity as part of any of the solid fuel options that would be constructed on the Deerhaven site. The timing and amount of additional capacity in the optimal plan calls for more capacity than would be needed simply to meet reserve margins, because it is in the best interests of GRU’s customers to invest in efficient generation capacity that uses less and lower priced fuels. The option of acquiring combined cycle resources sooner than 2008 through purchased power agreements will be evaluated.

SOLID FUEL GENERATION EXPANSION

There are four solid fuel generation options that could meet the revenue objectives of the IRP as shown in Table 3. Only the three options involving additional capacity at the Deerhaven site would result in net emission reductions from retrofitting Deerhaven 2, biomass generation capacity, and the use of reclaimed water. The single greenfield option shown does not include any of these benefits. The four options, ranked in order of low cost to high cost per kilowatt-hour are:

1. A portion of a 557 net MW supercritical unit, which would be feasible for GRU only through a joint participation project. One of the features of this option is that the potential joint project participants would be willing to take some of their share of capacity through a PPA, structured to include the same operational and regulatory risks of ownership that an equity participant (such as GRU) would assume. The PPA's also would be structured to provide GRU the option of taking back some of the participant's capacity if and when GRU wants it in the future. This provides GRU with very valuable strategic flexibility. Bond rating agencies tend to look favorably on projects in which native load customers meet debt service requirements, and a joint project, with appropriately structured PPA agreements, meets this requirement. Another advantage of a joint project would be the strategic alliances that would be forged. Under this option the cost of retrofitting Deerhaven 2, transmission upgrades and reclaimed water facilities would be shared by participants on a capacity ratio share. Any joint project at the Deerhaven site would involve complicated contracts related to common facilities and operational oversight by project participants, reducing GRU's autonomy to a significant degree. The cost to construct GRU's 206 MW share of this option as included in the optimum plan would be approximately $390,000,000 NPV ($2003), including capitalized interest. This includes the cost to install additional emission control equipment on Deerhaven 2.

2. A portion of a smaller 425 net MW supercritical solid fuel facility constructed at Deerhaven. This option has the same features as the 557 MW option described above with the exception that the option for reversion of capacity to GRU would not be included. This option does not provide sufficient capacity for the optimal generation case.

3. A 220 net MW CFB facility, self built by GRU at Deerhaven. This would provide more capacity than GRU would need in the earlier years. The ability to structure appropriate PPA agreements for some of this excess capacity would be an important consideration for the financial success of this option; this should be achievable in Florida's energy market. One of the advantages of this option is that after 2022, another CFB could be constructed to meet load requirements and/or to re-power Deerhaven Unit 1 or Deerhaven Unit 2. Table N-3 addresses the net reduction of air emissions that would result from two 220 CFB units.

4. A portion of a 557 net supercritical unit built on a Greenfield site. While this option does not include the expense of retrofitting Deerhaven Unit 2 with additional emission control equipment and a reclaimed water transmission facility, it has other costs associated with it especially from GRU's perspective. The mileage for hauling the fuels is greater, and GRU would have transmission wheeling expenses and associated capacity and line losses to absorb.

BENEFITS OF THE PRELIMINARY IRP

The three options in the preliminary IRP that involve the construction of additional generation capacity at Deerhaven will lower electrical costs, reduce local air emissions, reduce carbon intensity, enhance the local economy, and assure reliable energy supplies for the community. The greenfield option will have the benefits of lower electrical costs and assured generation capacity, but will not have the benefits from using biomass, additional emission control equipment on Deerhaven 2, and employment opportunities in the local community, and will rely upon Florida's transmission grid.

Lower Electrical Costs

As a basis of comparison, two "No-Build" scenarios for GRU's IRP were created to evaluate the effects of the optimal plan on base rates and customer costs. The two No-Build options differ in that although not currently mandated, one case assumes that new legislation and regulatory requirements would result in GRU's having to install additional air emission control equipment on Deerhaven 2 by 2010. This is a substantial additional capital and recurring operational cost for GRU's customers, with a NPV of $69,000,000. Under the most likely scenarios of fuel price increases and growth in load and energy sales, the optimal generation expansion plan in the preliminary IRP is expected to result in net savings of $277,000,000 NPV over the life of the facility, compared to the lowest cost No-Build scenario. If it is assumed in the No-Build scenario that Deerhaven 2 will have to have additional emission control equipment installed by 2010, the optimal plan in the preliminary IRP will result in net savings of $346,000,000 NPV over the life of the facility.

Table 4 compares the monthly average residential bills through 2022 for the optimal plan with the two No-Build cases. The optimal plan results in lower customer bills as a result of much lower fuel costs than the No-Build Cases. Over the planning horizon, the residential bill compound annual growth rate (CAAGR) for the optimal plan is 27% lower than the No-Build case and 48% lower than the No-Build case with a Deerhaven 2 retrofit.

Reduced Total Air Emissions

Three of the four cost-effective base load generation expansion options in the preliminary IRP would result in a net reduction of total NO_x and SO_2 emissions by retrofitting Deerhaven 2 with additional emission controls. The emission reduction potential is presented in Section J and summarized in Table 3.

Reduced Carbon Intensity

As shown in Table 3, three of the four cost-effective base load generation capacity expansion options in the preliminary IRP include biomass capacity.

Carbon intensity per unit of electricity produced will be reduced through high efficiency generation and supplemental steam generated from biomass fuels. Although biomass use generates slightly more carbon per unit of heat than coal or petroleum coke, biomass is generally considered carbon neutral.

Enhanced Local Economy

The energy conservation and Demand Response elements of the preliminary IRP will enhance the local economy by minimizing the electrical cost to operate businesses, and foster businesses in the energy conservation and energy management sectors. Construction of additional generation capacity at Deerhaven would also create over 100 skilled craft worker jobs and stimulate agricultural industry in north central Florida related to the harvesting, preparation and delivery of waste wood fuel. No attempt has been made to quantify the economic value of these opportunities at this time.

Reliable Energy Supplies

The expanded use of solid fuels in the preliminary IRP helps meet the community's desire for secure and reliable electric service. Solid fuels are relatively abundant in the USA, have less volatile prices, and are less vulnerable to supply interruptions. Solid fuels also can be stored, further enhancing reliability and flexibility for fuels purchasing. The options involving construction of capacity at Deerhaven avoid reliance on Florida's bulk transmission grid.

SITE CERTIFICATION PROCESS

Once a final generation expansion plan is selected, there are a number of environmental, economic, and public interest tests that have to be met as part of Florida's site certification process, which can take from 18 to 36 months. A "Certificate of Need" must be granted by the Florida Public Service Commission, which makes an independent assessment that the proposed facilities are needed and are the most cost-effective possible. Detailed modeling and analysis of the effects of the project on ambient air quality both locally and regionally will have to be performed, and the project will have to conform to all applicable air quality standards in order to get the necessary air emission permits. Detailed information will be required, including stack designs and heights, combustion characteristics of the units being proposed, and the height and shape of all other structures surrounding the stacks, and Best Available Control Technology (BACT) determinations. Other environmental impacts that will have to be addressed in the site certification process include: the potential for harm to endangered species; wetlands; traffic; noise; storm water management; and groundwater protection. Detailed site plans and design specifications will have to be submitted showing all generation units, by-product management and storage areas, process water facilities, fuel storage and management facilities, as well as all rail lines, roads, buildings and fences.

TABLE 1
(Same as Table N-1)
PRELIMINARY INTEGRATED RESOURCE PLAN

OBJECTIVE	PLAN ELEMENTS
MINIMIZE RESOURCE CONSUMPTION	1. Add Energy Conservation Programs 2. Introduce Demand Response Incentives 3. Develop Biomass Generation Capacity 4. Add Efficient, Clean Solid Fuel Generation Capacity at Deerhaven[1] 5. Expand Reclaimed Water Use
REDUCE TOTAL EMISSIONS	1. Add Efficient, Clean Solid Fuel Generation Capacity at Deerhaven[1] 2. Retrofit Deerhaven 2 with Additional Emission Control Equipment
REDUCE CARBON INTENSITY	1. Add Energy Conservation Programs 2. Introduce Demand Response Incentives 3. Develop Biomass Capacity 4. Add Efficient, Clean Solid Fuel Generation Capacity at Deerhaven[1]
MINIMIZE REVENUE REQUIREMENTS	1. Add Combined Cycle Capacity at Deerhaven 2. Add Efficient, Clean Solid Fuel Generation Capacity at Deerhaven[1] 3. Combine Additional Highly Efficient, Solid Fuel Capacity with: -Supplemental Biomass Capacity -Additional Emission Control Equipment on Deerhaven 2
ENHANCE THE LOCAL ECONOMY	1. Provide Employment (New Power Plant Jobs) 2. Foster Local Energy Conservation Service Businesses 3. Create Agricultural Employment (Biomass Harvesting and Preparation Jobs)
RELIABLE ENERGY SUPPLIES	1. Solid Fuel Is Abundant in the USA 2. Solid Fuel Is Less Vulnerable to Supply Interruptions 3. Capacity Sited at Deehaven Is Less Reliant on Electric Transmission Grid

1. See Table 3 for solid fuel generation options

TABLE 2
(Same as Table N-2)
THE OPTIMAL GENERATION EXPANSION PLAN[1]

YEAR	BASE	
	CC[2]	SOLID FUEL[3]
2004	--	--
2005	--	--
2006	--	--
2007	--	--
2008	34 MW	--
2009	--	--
2010	--	101 MW
2011	--	18 MW
2012	--	--
2013	--	37 MW
2014	--	11 MW
2015	--	9 MW
2016	--	5 MW
2017	--	16 MW
2018	--	--
2019	--	9MW
2020	--	--
2021	--	--
2022	--	--
TOTAL	34 MW	206 MW

1. Base forecast of load and energy, base forecast of energy prices. Bender's Decomposition methology selects optimal amount of generation to be added in any year.
2. Selects portion of 7FA Combined Cycle, natural gas fired unit.
3. Selects portion of 557 net MW, supercritical solid fuel unit constructed at Deerhaven plant site.

TABLE 3
(Same as Table N-3)
COMPARISON OF GRU's
POTENTIALLY FEASIBLE SOLID FUEL OPTIONS

CRITERIA	DEERHAVEN OPTIONS			GREENFIELD
	557 MW	425 MW	220 MW	557 MW
Total Cost per MWH[1]	$42.05	$43.92	$44.68	$47.96
Includes Deerhaven Retrofit	Yes	Yes	Yes	No
GRU's Capacity Share	140 MW (2010) 48 MW (option) 188 MW[2]	110 MW[2]	220 MW	140 MW[2] (no option)
Emission Reductions[3]				
NO_X	23%	34%	52%	0
SO_2	25%	34%	47%	0
Primary PM[4] (Tons/Year)	361	285	133	0
Biomass Capacity[5]	30 MW	30 MW	30 MW	0
Optimal Fuel Blend				
Coal/Petcoke	80/20	80/20	50/50	80/20
Reclaimed Water Use	4.5 MGD	3.5 MGD	TBD[6]	0
Boiler Type[7]	SCPC	SCPC	CFB	SCPC

1. Based on 2003 actual fuel cost, 80% capacity factor
2. Based on current discussion with participants in joint feasibility study.
3. Assumes Deerhaven 2 at 100% capacity burning high sulfur coal. For two CFB units, net emission reductions would be NO_X 30%; SO_2 27%; with a Particulate Matter increase of 270 tons per year.
4. NO_X and SO_2 reductions are expected to result in a net decrease in $PM_{2.5}$ due to reduced precursors of secondary PM formation, but the analyses have not been completed.
5. Preliminary results indicate that up to 30MW may be feasible, pending additional research on waste wood availability and detailed facility design.
6. To be determined.
7. Boiler Type: SCPC - supercritical pulverized coal type; and CFB - circulating fluidized bed.

TABLE 4
(Same as Table N-4)
AVERAGE RESIDENTIAL MONTHLY ELECTRIC BILLS UNDER ALTERNATIVE PLANS[1]

Year	Optimal Solid Fuel Case[2]	No-Build Case[3]	No-Build Case with DH2 Retrofit[4]
2004	$77	$77	$77
2005	$76	$76	$76
2006	$77	$77	$77
2007	$79	$79	$79
2008	$82	$83	$83
2009	$85	$85	$87
2010	$82	$86	$91
2011	$88	$91	$96
2012	$91	$92	$97
2013	$92	$94	$98
2014	$92	$95	$100
2015	$93	$98	$102
2016	$94	$101	$106
2017	$94	$103	$108
2018	$97	$106	$111
2019	$100	$111	$116
2020	$101	$113	$118
2021	$103	$115	$120
2022	$105	$118	$122
CAAGR	1.68%	2.30%	2.48%

1. Bender's methodology, base load forecast, base fuel price forecast. Electric bills estimated from extended GRU corporate model, subject to revision. Based on 1000 KWH typical residential consumption, including service, transmission and distribution charges.
2. Based on 7FA and 600 MW Supercritical Solid Fuel Generators.
3. Assumes purchased power from gas fired, highly-efficient CC technology
4. Same as for note 3 except includes dry scubbers for SO_X, selective catalytic NO_X reduction, and fabric filters installed on Deerhaven 2 in 2010.

SECTION A
INTRODUCTION

Gainesville Regional Utilities (GRU) is a municipal electric, gas, water, wastewater, and telecommunications utility system owned and operated by the City of Gainesville in Alachua County, Florida. GRU's electrical system (the System) includes generation, transmission, and distribution facilities serving 78,000 residential and 8,200 commercial customers. The System's service territory includes most of the Gainesville urban area.

PURPOSE AND SCOPE

The purpose of this report is to summarize the studies and information that form the basis of a preliminary plan to meet Gainesville's electrical requirements through the year 2022. These studies were prepared over several years through the efforts of GRU staff, consultants, and with the generous contribution of time from numerous citizens, local experts, and experts from other utility companies. For this assistance, GRU staff feels grateful and privileged to be part of a municipal organization.

The studies summarized here include: forecasts of electrical load and energy; details of the efficiency, cost, and age of GRU's generation fleet; fossil fuel and renewable energy availability, reliability and cost; assessments of environmental regulations and ambient air quality; measures that could be taken to reduce consumer consumption of electricity; and detailed assessments and simulations of the wide range of potentially feasible generation technologies. These studies were designed to implement an electrical system planning process called Integrated Resource Planning. The documents and resources employed to develop the information and plans presented in this report are stored in and may be reviewed at the GRU administration building.

WHY NOW?

Four compelling factors necessitate that GRU make long-range planning decisions in the near future. First, the domestic production of natural gas has leveled out and even decreased slightly. At same time, reliance on natural gas to produce electricity has increased and is expected to continue to increase. Imports of natural gas to meet the difference between supply and demand have grown. Second, the natural gas market has become substantially more volatile in recent years and natural gas prices have drastically increased. Third, the supply of natural gas to Gainesville is vulnerable to interruption due to the limited number of pipelines and the lack of storage and production capacity in Florida. Fourth and finally, forecasts indicate that GRU will need additional generation capacity by 2010. Some of the potentially feasible alternatives for the system will require at least that long to develop. It also is apparent that there may be opportunities to improve the costs of generation for GRU's customers.

INTEGRATED RESOURCE PLANNING

GRU has elected to adopt Integrated Resource Planning standards for electrical generation planning pursuant to the 1992 National Energy Policy Act (NEPA). Integrated Resource Planning (IRP) is different from conventional electrical utility planning because it doesn't simply focus on having adequate supply. IRP also considers a variety of ways to reduce consumer demand. The prevailing optimization criterion under NEPA standards is to minimize revenue requirements or rates while meeting environmental standards and maintaining adequate reliability. Under NEPA's voluntary standards, IRP includes the following considerations:

- Customer energy conservation and direct load control;
- Providing the opportunity for co-generation (using waste heat from generators);
- Offering to purchase power from independent producers at system avoided costs;
- Renewable sources of energy;
- Life cycle ownership costs;
- Rate designs; and
- Off system purchased power

While the considerations listed above seem fairly straightforward, their application has proven to be difficult. For example, the Federal Energy Regulatory Commission (FERC) has had to become involved in many disputes surrounding these issues, such as small generation interconnection standards. There also have been many safety and design issues; such as the implications that arise from solar electricity being pushed into a network the utility thinks is de-energized.

GRU has been a leader in embracing IRP standards throughout the past decade with its renewable energy projects, strategic rate designs, energy conservation programs, and aggressive involvement in power markets, seeking lower priced power options for its customers.

IRP BACKGROUND

It will help the reader of this report if the history behind the studies presented here are reviewed and placed in context. Key elements of this background include:

- The Gainesville Energy Advisory Committee;
- Previous Integrated Resource Plans;
- Repowering the downtown Kelly Generating Station;
- Local controversy about ambient air quality stemming from the construction of a cement plant in west Alachua County; and
- The “Good Guys”, an informal group of CEOs from consumer owned utilities in Georgia and Florida.

The Gainesville Energy Advisory Committee

The Gainesville Energy Advisory Committee (GEAC) was formed in 1978 to serve the Gainesville City Commission. The mission of GEAC is to advise the City commission on matters related to energy conservation. Consisting of unpaid volunteers appointed by the City Commission, GEAC has actively participated with staff over the years to plan energy conservation programs, develop rate designs, and work closely with staff on all of its IRP projects. For example, GEAC was instrumental in GRU’s launching its first “Green Energy” photovoltaic project in 1993. Green Energy allows customers to choose to pay a premium to support more expensive, but renewable, forms of energy. The initial Green Energy project has now grown to the point that GRU has over 2.3 MW of renewable energy generation capacity (landfill gas and photovoltaic solar), marketed as “GRUGreen” energy.

GEAC sponsored the workshops and public outreach projects conducted in the summer and fall of 2003 as part of this IRP. This sponsorship has included reviewing outreach presentations, brainstorming with staff on various ideas for getting the public involved in the workshops, and participating in the workshops. GEAC’s regular, advertised public meetings also have provided a convenient forum for GRU staff to interact with the numerous individuals in the community with special interests and knowledge about energy related matters.

GRU has been and will continue to be aggressive about promoting cost-effective energy conservation in the community. Energy savings from GRU’s existing conservation programs are estimated to conserve enough fuel to provide electricity to 6,000 of GRU’s average residential customers. However, additional energy conservation programs are an important part of this IRP. Details on the energy conservation programs GRU has conducted as well as additional potentially cost-effective future programs are discussed in more detail in subsequent sections of this report.

Previous Integrated Resource Plans

GRU has conducted two IRP studies prior to this one. The IRP process conducted in 1992 led to the installation of the simple cycle 75 MW Deerhaven Combustion Turbine Unit 3, which entered commercial service in 1996. This unit included innovative dry-low NO_X burners that had the lowest permitted levels of

NO_X emissions in Florida at that time. The 1992 IRP process included individually contacting and meeting with every GRU customer that potentially could be expected to use waste heat from co-generation (Reference 52). GRU has since been in regular contact with these customers and has submitted proposals for back-up emergency generation with two of them, although co-generation was not found to be cost-effective. Another IRP was conducted in 1999, resulting in GRU re-powering one of the units at the downtown Kelly power plant.

Repowering Kelly Unit 8

Kelly Unit 8 at the downtown Gainesville power plant was an oil and gas fired steam cycle power plant constructed in 1965. The boiler of this unit was abandoned in place, and replaced with a heat recovery steam generator (HRSG) that uses a combustion turbine equipped with dry low NO_X burners as a source of heat. Called a combined cycle (CC) combustion turbine, Kelly CC Unit 1 (110 MW) came on-line in May 2001 and added 68 additional megawatts of capacity to GRU's system with a much higher efficiency than the older unit. This unit is able to produce five times the energy as the old unit, with only half the total emissions. Compared with the unit it replaced, the efficiency of the new Kelly combined cycle unit saves as much fuel as would be required to provide electricity to 9,400 average GRU residential electrical customers. The success of this project strongly encouraged GRU to seek other opportunities to reduce costs while at the same time improving the environment and conserving resources.

Ambient Air Quality

The issuance of permits in 1998 for the construction of a coal-fired cement plant in western Alachua County sparked a countywide controversy regarding ambient air quality. The lasting impressions from this controversy were evident in GRU's public workshops in 2003. One of the outcomes of this issue was the Alachua County Commission's appointing of an Air Quality Commission (AQC), composed of prestigious local environmental scientists and professionals, to study issues related to ambient air quality in Alachua County. The AQC assembled available ambient air quality monitoring data; emission data from permitted sources; and performed estimates of non-point source air emissions. The AQC produced its findings and made recommendations in early 2000, mostly related to monitoring and data collection.

GRU has invested in pursuing these recommendations, including funding for additional ambient air monitoring, speciation studies for the particulate matter found in Alachua County's air, and updating the AQC study with the most recent data as part of this IRP. Speciation studies use the ratios of chemicals found in the particulates captured during monitoring to determine the probable source of these emissions.

One of the outcomes of the study was the observation that although air quality in Alachua County was good, GRU's coal-fired Deerhaven Unit 2 was the primary point source for sulfur emissions and a significant portion of point source emissions of NO_x. GRU conducted a substantial study of additional emission control equipment options and their cost for Deerhaven 2, completed in July 2000 (References 16 and 40). The study concluded that it was not prudent or cost-effective to install the additional equipment, as the investments would not make material changes to ambient air quality. Discussions concerning this study with GEAC led to a recently completed study by GRU of the deposition of mercury from Deerhaven 2 in the Santa Fe River basin (Reference 49).

The findings of these studies were presented during the public outreach process and taken into consideration as part of this IRP.

The “Good Guys”

The CEOs of some of the larger consumer owned electrical generating utilities in Georgia and Florida begin to have regular, informal meetings to discuss their common interests and concerns in 2002. The first outcome of these discussions was a mutual aid agreement for long-term generation outages. Through this agreement, the participants are self-insured against financial exposure in the event of long term, catastrophic outages (that rarely occur) of critical base load generation units. One of the issues of discussion was Florida's growing reliance on natural gas. As a result, five of the “Good Guys” companies embarked on a study of the feasibility of additional solid fuel generation capacity in Florida to meet their customers' needs.

In September of 2002, the Gainesville City Commission authorized GRU to participate in this study. The participants in this study, along with each organization's share of the funding, included the Florida Municipal Power Agency (25%), GRU (25%), JEA (20%), the Reedy Creek Improvement District (the municipal utility serving Disney World) - (10%) and Seminole Electric Cooperative, Inc. (20%). Each participant's share of the funding entitled it to a corresponding share option of any facility that might result. In parallel with the joint feasibility study, GRU commissioned its own independent studies to develop capacity costs for a wide range of technologies and to address emerging regulatory cap and trade emission programs as an alternative to retrofitting Deerhaven Unit 2. The results of the Joint Feasibility studies included the identification of two potential sites, one of which is GRU's Deerhaven Plant Site and the other a greenfield site in south Florida (References 5, 7, 50, and 51).

PUBLIC OUTREACH PROGRAM

Each year GRU updates its forecasts and provides a report to the Florida Public Service Commission certifying that it has adequate facilities and/or plans to meet its reliability obligations for electrical supply. This document is called a Ten-Year Site Plan, and the one GRU submitted in 2003 included a forecasted shortfall of GRU's minimum planning reserve margin of 15% in 2010 (Reference 35). In its submittal, GRU indicated that it would be willing and able to meet this shortfall with a combustion turbine, which is the lowest possible construction cost and most easily permitted alternative, pending the outcome of a full IRP.

With that in mind, and the long lead-time for constructing solid fuel facilities in Florida, GRU and GEAC began to plan with GEAC an extensive community involvement plan as a critical part of the IRP process. Preliminary plans for the outreach program were described to the Gainesville City Commission during the budget workshops in July 2003.

The outreach program was designed in two phases. Each phase was launched with three well-advertised community workshops held in geographically dispersed sectors of GRU's electric service area. Individual letters inviting residents to the workshops were mailed to each home in any subdivision with a boundary within 1 mile of the Deerhaven plant site. Properties not in subdivisions but within 1 mile of the boundary were also notified. The workshops were held at night to be convenient for working people, and refreshments were provided. All workshop material was posted on GRU's web site (www.gru.com) and full-page newspaper ads as well as press releases generated substantial publicity and media interest. A report summarizing this process may be found in Appendix A and all of the public notices, advertisements, workshop presentations, and related news articles, editorials and correspondence may be found accompanying this report as a digital compact disk.

Phase One Workshops

The phase one workshops included very basic information about GRU's forecast for the need, price, reliability and availability of various fuels, and a general discussion of IRP options, (i.e. reduce demand versus build generation capacity). The joint solid fuel feasibility study was also introduced during the presentation. Most of the phase one workshops' time was devoted to small, facilitated breakout groups asked to advise GRU about the options to consider and factors to use in evaluating them.

Phase Two Workshops

The phase two workshops were designed to answer the questions that emerged in the phase one workshops and to provide the results of a screening of the many options that had been identified. A key topic addressed in the phase two workshops was the status of Alachua County's air quality and the environmental performance of the coal-fired Deerhaven Unit 2. The results of screening the list of options developed during the phase one workshops down to a set of potentially feasible alternatives also were presented during the phase two workshops (see Section I). Much more time was spent presenting information during phase two workshops than during the first series. Time still was reserved for small, facilitated breakout groups that were asked to advise GRU on what they felt had been left out.

Other Public Participation

Immediately upon the onset of the phase one workshops GRU began getting requests for presentations to a wide range of civic groups. These groups included University of Florida professors, homeowner's associations, City and County advisory committees, and a wide range of civic and professional organizations. In addition to the six advertised formal workshops, as of November 2003, GRU staff gave 27 presentations that were generally abbreviated versions of the preceding phase one or two workshops. The IRP workshops were the topic of a locally produced and broadcast television talk show (North Florida Journal - WRUF). On December 6, 2003 an open house was held at the Deerhaven plant site to provide the public with an opportunity to view the plant operations first hand. The event was well advertised, and over 1,500 people of all ages participated.

REPORT ORGANIZATION

This report is organized into a series of chapters according to the general progression of topics and the flow of analysis. The Figures and Tables accompanying the text may be found at the end of each section in which they are discussed. The topics include:

1. Generation capacity needs, fuel price and availability, and environmental permitting issues;
2 Options for meeting electrical energy needs;
3. Screening to select potentially feasible options for detailed evaluation;
4. The assumptions and methodologies used for evaluating potentially feasible alternatives; and finally
5. A Preliminary IRP proposal, summarizing its options, costs and benefits.

A glossary of key terms and abbreviations used throughout this report also is provided immediately following the Table of Contents.

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SECTION B
HISTORY AND FORECASTS OF LOAD AND ENERGY

This section presents basic information about the use of electricity in Gainesville which forms the foundation of the IRP. The information presented here was taken from GRU's 2003 Ten Year Site Plan (Reference 35). This includes the history and forecast of the Electric System's customers, their energy consumption and peak demands.

METHODOLOGY OVERVIEW

The basic energy forecasting model is the number of customers (by rate class) times their average annual energy consumption (as measured at the customer's meter). GRU currently has four retail rate classes, as follows:

1. Residential (RES);
2. General service non-demand (GSN- small non-residential customers, such as small shops);
3. General service demand (GSD- non-residential customers with 50 kW or greater peak demands, such as office complexes and grocery stores); and
4. Large power (LP- non-residential customers with 1000 kW or greater such as hospitals and water treatment plants).

GRU also has three wholesale power contracts serving the Clay territory in the western portion of the Gainesville urban area, the City of Alachua, an incorporated municipality immediately adjacent to GRU's service territory to the north, and a partial requirements contract with Starke. GRU provides retail water, wastewater, natural gas and telecommunications throughout the entire Gainesville urban area, including the portion in Clay's electrical territory. GRU also provides retail natural gas service throughout the City of Alachua. GRU's contract to serve the Clay territory through the Farnsworth substation will expire in 2013, and the contract to serve the City of Alachua through the Alachua substation expires in December 2007. The Starke contract expires in December 2006.

Retail Load

The number of residential customers is forecast using independently prepared and published population forecasts. Adjustments are made for known territorial boundary changes. The number of commercial customers is forecast as a delayed response to the population forecast. The forecast of energy use per customer takes into account weather, price, and a number of other demographic and economic factors. Weather strongly affects customer demands and energy usage, so measures of weather are used to normalize historical data. All forecasts assume long-term average weather conditions. Electric usage in the residential customer classes is sensitive to price (usage demonstrates price elasticity), but statistically significant price elasticity has not been found in GRU's other rate classes. Price elasticity is empirically measured from historical responses to price, which include fuel adjustments as well as base electrical rates. Average income also has been found to correlate with average residential use. It should be noted, however, that it is not unusual to find low-income households consuming much more electricity than higher income households.

The basic peak demand forecast model is the annual energy consumption adjusted for transmission and distribution system losses and historical load factors. The highest net integrated peak demand recorded to date was 433 MW on July 17, 2002

Wholesale Load

Full requirements wholesale service to Clay and Alachua are included as part of this IRP. Residents and businesses in these areas use Gainesville's municipal services that are supported in part by revenues from the electrical system, and there are substantial economies of scale in the electric power business. If GRU were not providing power to these customers, purchases would be made from electrical generating sources in other regions of the state. The model used to forecast energy and demands for these areas are very similar to those described above.

Forecast Assumptions and Data Sources

The primary statistical tool used in developing forecasts is multiple regression analysis as implemented in the SAS statistical analysis software package. GRU has been using the modeling approach described here successfully for over 25 years. The data sources and assumptions used in this work are as follows:

1. All regression analyses were based on annual data. Historical data were assimilated for calendar years 1970 through 2002. System data, such as net energy for load, seasonal peak demands, customer counts and energy sales were obtained from GRU records and sources.

2. Estimates and projections of Alachua County population were obtained from the Florida Population Studies, January 2003 (Bulletin No. 134), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida.

3. Normal weather conditions were assumed. Forecast values of heating degree days and cooling degree days equal the mean (rounded to the nearest hundred) of historical data reported to NOAA by the Gainesville Municipal Airport Flight Service Station.

4. All income and price figures were adjusted for inflation, and indexed to a base year of 2002, using a price index developed to represent inflationary trends in Alachua County. This "Alachua County Price Index" is developed by comparing changes in the Consumer Price Index (U.S. Bureau of Labor Statistics) and the Florida Price Level Index (Florida Department of Education). Inflation is assumed to be 3% per year for each year of the forecast.

5. The U. S. Department of Commerce provided historical estimates of total income and per capita income for Alachua County. The BEBR projected income levels for Alachua County in The Florida Long-Term Economic Forecast 2002.

6. The Florida Long-Term Economic Forecast 2002 and Florida Population Studies, Bulletin 135, were used to estimate and project the number of persons per household (household size) in Alachua County.

7. The Florida Long-Term Economic Forecast 2002 was the source for historical estimates and projections of non-agricultural employment in Alachua County.

8. GRU's corporate model was the basis for projections of the average price of 1,000 kWh of electricity for all customer classes. GRU's corporate model evaluates projected revenue and revenue requirements for the forecast horizon and determines revenue sufficiency under prevailing prices. If revenue from present pricing is insufficient, pricing changes are programmed in and become GRU's official pricing program plan. Programmed price increases from the model for all retail customer classes are projected to be less than the rate of inflation, yielding declining real prices of electricity over the forecast horizon.

9. Estimates of energy and demand reductions resulting from demand-side management programs were incorporated into all retail forecasts.

10. The City of Alachua will generate approximately 8,077 MWh (9%) of its annual energy requirements with nuclear generation entitlement shares of Progress Energy Florida’s Crystal River Unit 3 and Florida Power and Light’s St. Lucie 2 power plants.

RETAIL CUSTOMER, ENERGY AND SEASONAL PEAK DEMAND FORECASTS

The number of customers, energy sales and seasonal peak demands were forecast from 2003 through 2022. Separate energy sales forecasts were developed for each major customer rate class: residential, general service non-demand, general service demand, large power, outdoor lighting, sales to Clay, and sales to Alachua. Separate forecasts of the number of customers were developed for residential, general service non-demand, general service demand and large power retail rate classifications. The basis for these independent forecasts originated with the development of least-squares regression models. The following describes the regression equations utilized to forecast energy sales and number of customers.

Residential Sector

The equation of the model developed to project residential average annual energy use (kilowatt-hours per year) specifies average use as a function of household income in Alachua County, residential price of electricity and weather variation, measured by heating degree days and cooling degree days. The form of this equation is as follows:

$$RESAVUSE = 4618.6 + 0.069\,(HHY02) - 10.33\,(RESPR02) + 0.69\,(HDD) + 0.92\,(CDD)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use
HHY02	=	Average Household Income
RESPR02	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days
CDD	=	Annual Cooling Degree Days

Adjusted R^2	=	0.9016
DF (error)	=	27
t - statistics:		
Intercept	=	3.87
HHY02	=	7.09
RESPR98	=	-2.58
HDD	=	4.09
CDD	=	4.99

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 Alachua County population, lagged one year. The residential customer model specifications are:

$$RESCUS = -28185 + 446.74\,(LAGPOP)$$

Where:

RESCUS	=	Number of Residential Customers

LAGPOP = Alachua County Population (thousands), lagged one year

Adjusted R^2 = 0.9980
DF (error) = 22
t - statistics:
Intercept = -37.35
LAGPOP = 108.11

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

General Service Non-Demand Sector

The general service non-demand (GSN) customer class includes non-residential customers with maximum annual demands less than 50 kilowatts (kW). In 1990, GRU began offering GSN customers the option to enter the General Service Demand (GSD) class. This option offers potential benefit to GSN customers that use high amounts of energy and 240 customers have elected voluntarily to transfer to the GSD class since 1990. A regression model was developed to project average annual energy use by GSN customers. The model includes, as independent variables, the cumulative number of optional demand customers and cooling degree days. The specifications of this model are as follows:

$$GSNAVUSE = 23.84 - 0.012(OPTDCUST) + 0.0014(CDD)$$

Where:

GSNAVUSE = Average annual energy usage by GSN customers
OPTDCUST = Cumulative number of Optional Demand Customers
CDD = Annual Cooling Degree Days
Adjusted R^2 = 0.6147
DF (error) = 21
t - statistics:
Intercept = 12.49
OPTDCUST = -5.77
CDD = 2.10

The number of general service non-demand customers was projected using an equation specifying customers as a function of Alachua County population, lagged one year. The specifications of the general service non-demand customer model are as follows:

$$GSNCUS = -4700.7 + 57.74\ (LAGPOP)$$

Where:

GSNCUS = Number of General Service Non-Demand Customers
LAGPOP = Alachua County Population (thousands), lagged on year

Adjusted R^2 = 0.9883
DF (error) = 23
t - statistics:
Intercept = -20.25
LAGPOP = 45.01

Forecasted energy sales to general service non-demand customers were derived from the product of projected number of customers and the projected average annual use per customer.

General Service Demand Sector

The general service demand customer class includes non-residential customers with established annual maximum demands generally 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 for residents of Alachua County. 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. Average energy use projections for general service demand customers result from the following model:

$$GSDAVUSE = 364.69 + 0.0077\,(PCY02) - 0.15\,(OPTDCUST)$$

Where:

GSDAVUSE = Average annual energy use by GSD Customers
PCY02 = Per Capita Income in Alachua County
OPTDCUST = Cumulative number of Optional Demand Customers

Adjusted R^2 = 0.7874
DF (error) = 21
t - statistics:
Intercept = 19.67
PCY02 = 8.71
OPTDCUST = -3.46

The annual average number of customers was projected based on the results of a regression model in which Alachua County population, lagged one year, was the independent variable. The specifications of the general service demand customer model are as follows:

$$GSDCUS = -445.4 + 5.57\,(LAGPOP)$$

Where:

GSDCUS	=	Number of General Service Demand Customers
LAGPOP	=	Alachua County Population (thousands), lagged one year
Adjusted R^2	=	0.9716
DF (error)	=	22
t - statistics:		
Intercept	=	-12.31
LAGPOP	=	28.09

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

Large Power Sector

The large power customer class currently includes approximately 18 customers with billing demands of at least 1,000 kW. Analyses of average annual energy use were based on historical observations from 1976 through 2002. The model developed to project average use by large power customers includes Alachua County nonagricultural employment and large power price of electricity as independent variables. Energy use, per customer, is expected to increase due to the periodic expansion of existing facilities. This growth is measured in the model by local employment levels. The specifications of the large power average use model are as follows:

$$LPAVUSE = 10421 + 16.92\,(NONAG) - 36.94\,(LPPR02)$$

Where:

LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
NONAG	=	Alachua County Nonagricultural Employment (000's)
LPPR02	=	Average Price for 1,000 kWh in the Large Power Sector
Adjusted R^2	=	0.9059
DF (error)	=	24
t - statistics:		
INTERCEPT	=	5.99
NONAG	=	1.82
LPPR02	=	-3.12

No new large power customers are projected to be added during the forecast period. 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.

Outdoor Lighting Sector

The outdoor lighting sector consists of streetlight, traffic light, and rental light accounts. Outdoor lighting energy sales account for approximately 1.25% of total energy sales. Outdoor lighting energy sales were forecast using a model which specified lighting energy as a function of the number of residential customers. The specifications of this model are as follows:

$$LGTMWH = -7908.2 + 0.43\,(RESCUS)$$

Where:

LGTMWH	=	Outdoor Lighting Energy Sales
RESCUS	=	Number of Residential Customers
Adjusted R^2	=	0.9715
DF (error)	=	11
t - statistics:		
Intercept	=	-5.81
RESCUS	=	20.24

FORECAST OF WHOLESALE ENERGY SALES

Energy sales from two wholesale customers are included as native sales in this IRP: Clay Electric Cooperative, Inc. (Clay) at the Farnsworth Substation with a peak summer demand of 14 MW, and the City of Alachua (Alachua) with at the Alachua No. 1 Substation and at the Hague Point of Service with a peak summer demand of 20 MW. Starke's wholesale contract sale of 3 MW is projected to expire by 2006 and is not included in the System forecast presented here. Approximately 9% of Alachua's 2002 energy requirements were met through generation entitlements of nuclear generating units operated by Progress Energy Florida and Florida Power and Light. Each of the two wholesale delivery points included as native load serves an urban area that is either included in, or adjacent to the Gainesville Urban Area.

Sales to Clay were modeled with an equation in which total county income was the independent variable. The form of this equation is as follows:

CLYMWH	=	*-31913 + 16.2 (COY02) + 4.23 (CDD)*

Where:

CLYMWH	=	Megawatt-Hour Sales to Clay
COY02	=	Total Personal Income (Alachua County)
CDD	=	Cooling Degree Days
Adjusted R^2	=	0.9651
DF (error)	=	25
t - statistics:		
Intercept	=	-3.07
COY02	=	26.47
CDD	=	1.25

Net energy requirements for Alachua were estimated using a model in which City of Alachua total income and cooling degree days were the independent variables. City of Alachua total income is the product of City of Alachua population and Alachua County per capita income. Population projections were developed by modeling City of Alachua population as a function of Alachua County population. The model used to develop projections of sales to the City of Alachua is of the following form:

ALANEL	=	*-36478 + 0.58 (ALAY02) + 7.54 (CDD)*

Where:

ALANEL	=	Net Energy Requirements of Alachua
ALAY02	=	City of Alachua Total Income
CDD	=	Cooling Degree Days
Adjusted R^2	=	0.9655
DF (error)	=	20
t - statistics:		
Intercept	=	-3.33
ALAPOP	=	24.82
CDD	=	2.02

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

Energy And Customer Forecast Results

Figure B-1 contains a plot of the history and forecast of the average residential customer's electrical energy usage based on the model presented above. The trend for average residential use to increase is readily apparent. Table B-1 contains the history and forecast of energy consumption for each retail customer class. GRU's average residential electrical consumption is the lowest among all other urban areas in Florida (see Figure F-1).

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, general service non-demand, general service demand, large power, outdoor lighting, sales to Clay, and sales to Alachua. Net energy for load was then forecast by applying a delivered efficiency factor for the System to total energy sales. The projected delivered efficiency factor was determined from an analysis of observed historical values from 1984 through 2002, and is projected to be approximately 95%.

The forecasts of seasonal peak demands were derived from forecasts of annual net energy for load. Winter peak demands are projected to occur in January of each year, and summer peak demands are projected to occur in July of each year. The average ratio of the most recent 19 years' monthly net energy for load for January and July, as a portion of annual net energy for load, was applied to projected annual net energy for load to obtain estimates of January and July net energy for load over the forecast horizon. The medians of the past 19 years' load factors for January and July were applied to January and July net energy for load projections, yielding seasonal peak demand projections. Load data has converged over time to a point that winter peak demands are forecast to be nearly equal for January and February. Likewise, the historical data indicates that summer peak demands are likely to be nearly equal in July and August. Adjustments to seasonal peak demands were included explicitly to account for impacts from demand-side management programs.

Transmission and distribution line loss improvement programs undertaken by GRU have resulted in relatively stable losses ranging from 4% to 6% of net generation. Post 1983 load factors and energy allocation factors are believed to reflect the most recent trends in appliance efficiencies, appliance penetrations, response to electricity prices and response to customer and utility induced conservation efforts.

Low Band and High Band Forecast Scenarios

Much of the error in long-term forecasts results from variation in expected customer growth, while a primary determinant of short-term forecast error is weather variation. GRU bands its forecasts with a long-term perspective for resource planning purposes by allowing assumptions underlying customer growth to vary. Projections of one independent variable in each customer class were allowed to vary from the base case assumptions in order to develop the banded forecasts. The fundamental variable used to develop alternative forecast scenarios was the series of population projections for Alachua County. Low band and high band forecast scenarios were derived from the same equations used to develop the base case forecasts. Low band and high band population scenarios were set to approximately equal the midpoints of the BEBR low-to-medium and medium-to-high population projections, respectively.

In the residential, general service non-demand, and general service demand revenue sectors, banded energy sales forecasts resulted from banded customer forecasts, which were developed from banded county population projections. Forecasts of average annual energy use per customer were not modified. In the large power sector, non-agricultural employment was the primary explanatory variable used to forecast use per customer. Employment projections were originally derived from population projections. Banded employment projections were input into the original equation yielding alternative energy sales scenarios for this class. Sales to Clay were modeled as a function of total Alachua County income. Total Alachua County income was projected as the product of per capita income and population. Banded income projections were input into the original equation yielding alternative forecasts of sales to Clay. Sales to the City of Alachua were modeled as a function of City of Alachua total income, which was derived from City of Alachua population and Alachua County per capita income. City of Alachua population was projected from a model which stated City of Alachua population to be a function of Alachua County population. Banded City of Alachua population projections, yielding banded City of Alachua income projections, were input into the original equation to obtain alternative scenarios of energy sales to the City of Alachua. Impacts of demand-side management programs were also allowed to vary based upon the ratio of low-to-base and base-to-high band population projections, respectively.

Banded Forecast Results

Figure B-2 is a plot displaying the results of the banded forecast on System net energy for load. Figure B-3 shows the banded forecast for summer peak demands, and Figure B-4 shows the forecast for winter peak demands. Because GRU is a summer peaking system, only the detailed results for the summer peak demand are provided here. Table B-2 tabulates the results for the summer peak base case, while Tables B-3 and B-4 tabulate the results for the high and low band cases. This range of results was used in the sensitivity analyses performed for this IRP.

DEMAND-SIDE MANAGEMENT PROGRAMS

Demand and energy forecasts and generation expansion plans outlined in this report are adjusted to include impacts from GRU's Demand-Side Management (DSM) programs. The System forecast reflects historical program implementations recorded from 1980 through 2002, as well as projected program implementations scheduled through 2022. This information is tabulated in Table B-5. It should be noted that DSM reductions already achieved are projected to diminish through time due to equipment retirement. More specifically, the type and vintage of program achievements are tracked, and energy conservation from installed appliances is adjusted to reflect the end of the useful life for that device. More details about GRU's conservation programs are provided in Section F. GRU's DSM programs were designed for the purpose of conserving the resources utilized by the System in a manner most cost effective to the customers of GRU. DSM programs are available for all retail customers, including commercial and industrial customers, and are designed to effectively reduce and control the growth rates of electric consumption and weather sensitive peak demands.

GRU is active in the following residential conservation efforts: energy audits; low income household weatherization and natural gas extension; promotion of natural gas in residential construction; promotion of natural gas for displacement of electric water heating, space heating and space cooling in existing structures; and promotion of solar water heating. GRU offers the following conservation services to its non-residential customers: energy audits; lighting efficiency and maintenance services; and promotion of natural gas for water heating, space cooling and dehumidification.

GRU continues to monitor the potential for additional conservation efforts including programs addressing high-efficiency air conditioning, heat recovery, duct leakage, heat pipes, reflective roof coatings, thermal storage and window shading. GRU also is developing a 10 kW photovoltaic project at the Gainesville Regional Airport to promote the use of renewable energy. This project will be funded through voluntary customer contributions and avoided utility costs. GRU is pursuing grant funding for photovoltaic installations through the Department of Community Affairs' PV for Schools Educational Enhancement Program. GRU also provides green energy to its customers from a blend of renewable energy sources including landfill gas, solar, and wind.

FIGURE B-1

Residential Electric Energy Usage

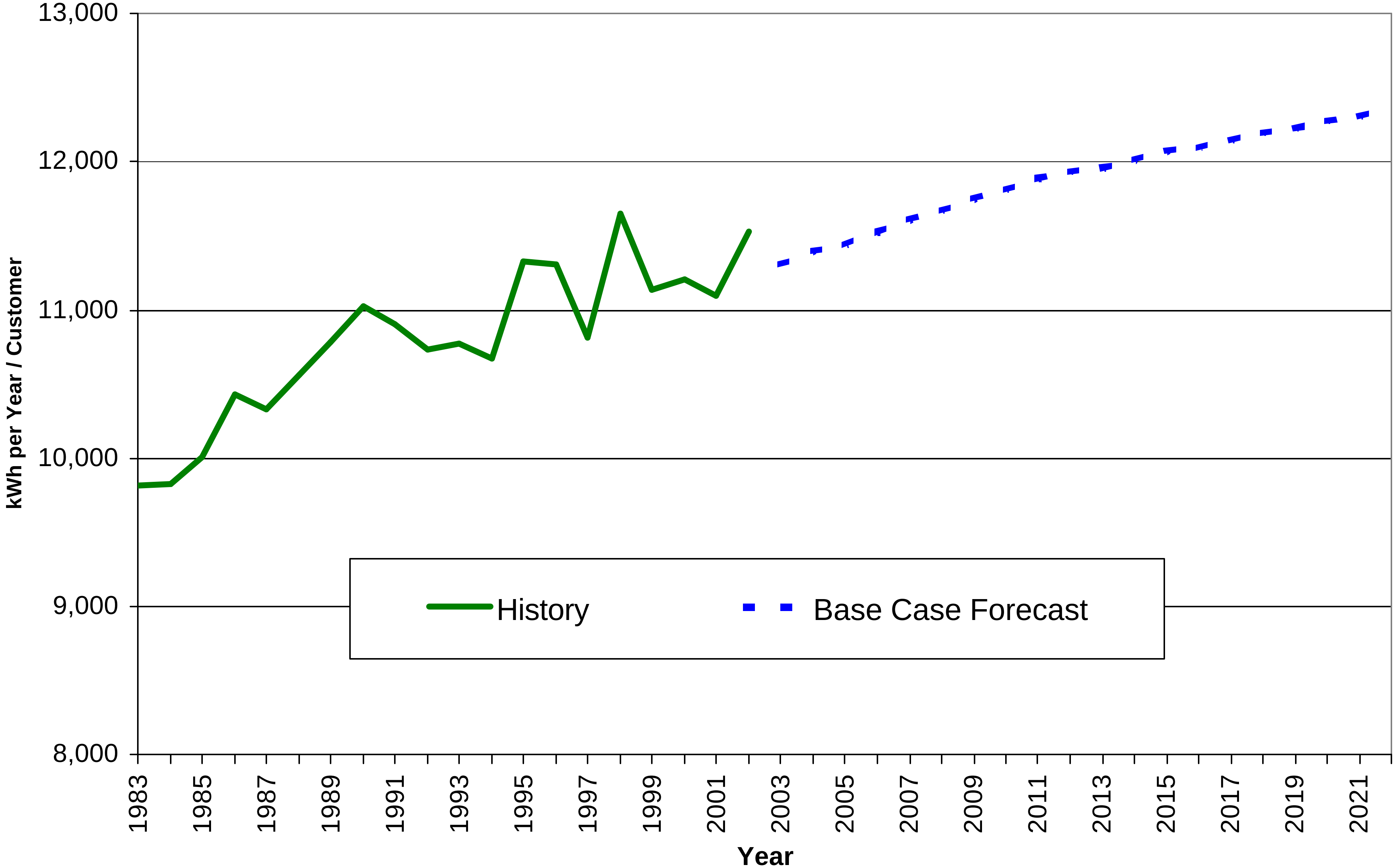

FIGURE B-2

History and Forecast of Net Energy for Load

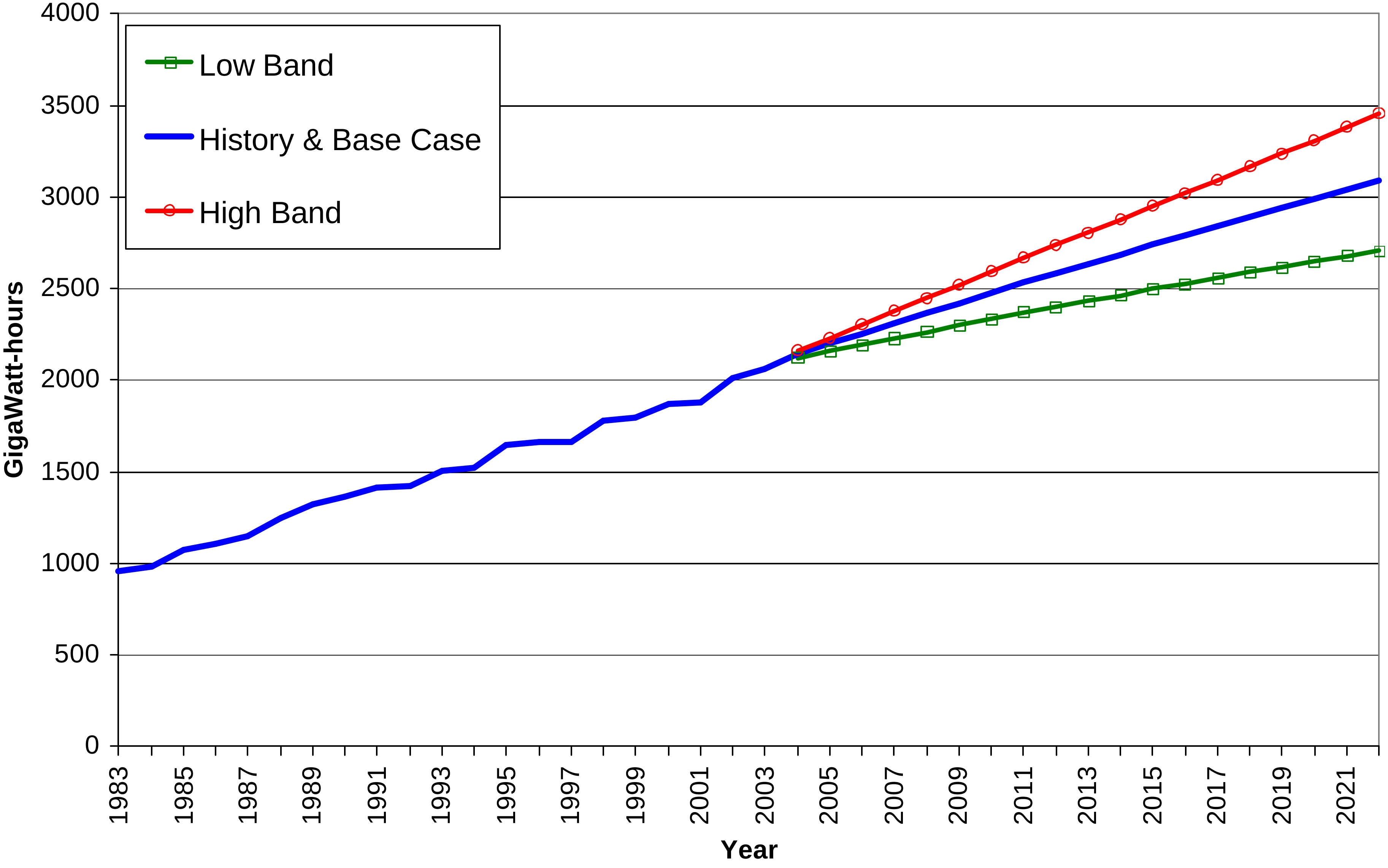

FIGURE B-3

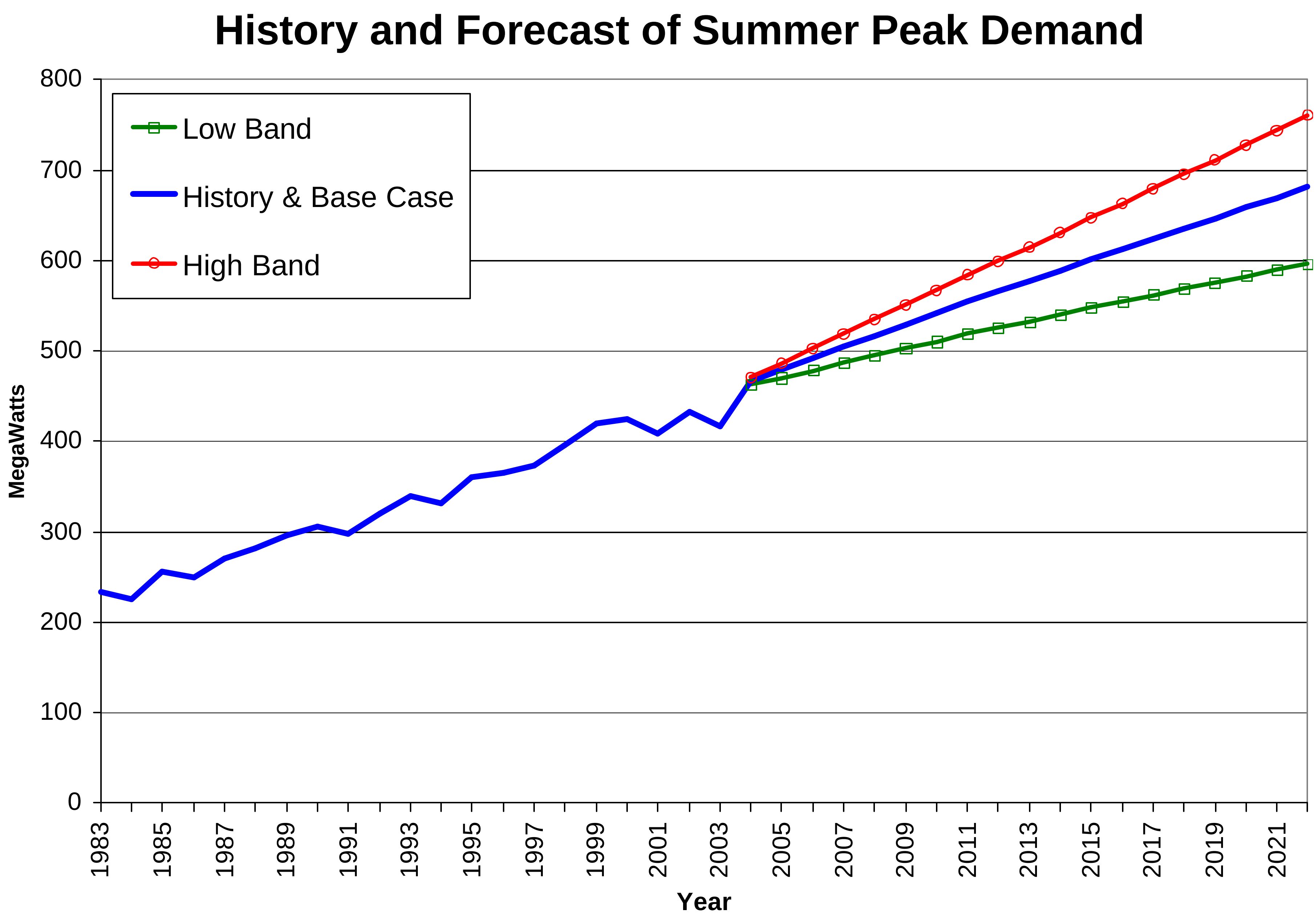
History and Forecast of Summer Peak Demand
Low Band
History & Base Case
High Band
MegaWatts
Year
0
100
200
300
400
500
600
700
800
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021

FIGURE B-4

History and Forecast of Winter Peak Demand

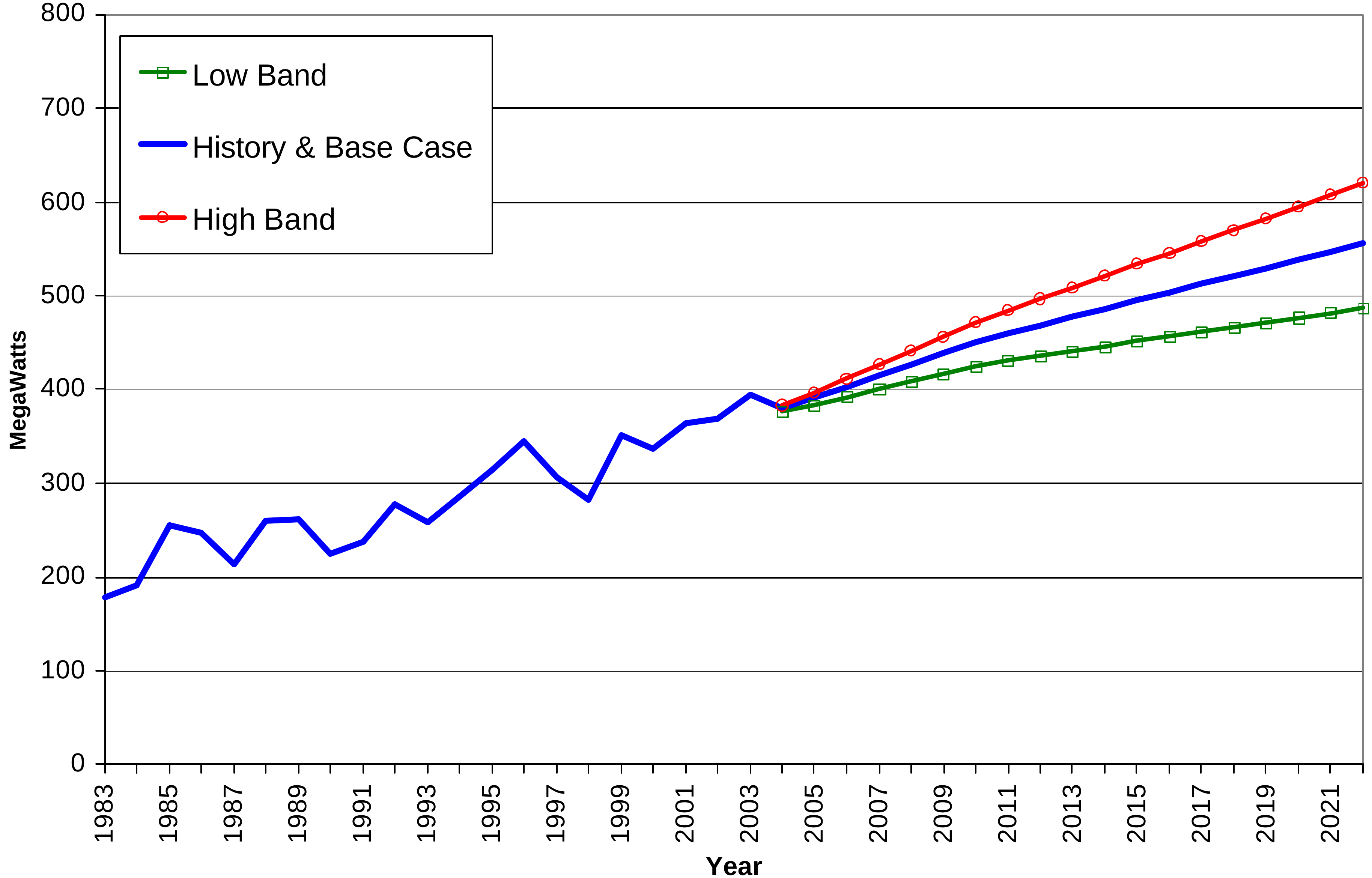

TABLE B-1
2003 Base Case Electric System Forecast

Calendar		Residential		GS Non-Demand		GS Demand		Large Power		Lighting	Clay	Alachua	Total	NEL	Win Peak	Sum Peak
Year	Avg Usage	Custs	MWh	Custs	MWh	Custs	MWh	Custs	MWh	MWh	MWh	MWh	MWh	MWh	MW	MW
1983	9822	42093	413452	4538	120921	400	197017	12	96919	15862	25450	0	869621	954428	179	234
1984	9829	44041	432872	4788	127339	423	221298	12	96517	15648	26479	0	920153	983002	191	225
1985	10006	45755	457812	4746	132684	484	248616	12	100618	15881	28547	2399	986557	1070363	255	256
1986	10428	47203	492215	4981	140747	504	256787	14	111696	15859	29945	5744	1052993	1105995	248	249
1987	10330	48750	503576	5257	147354	506	264055	13	111096	16202	34381	5985	1082649	1151042	214	270
1988	10565	50558	534144	5528	154796	531	281517	14	116997	16026	34090	32963	1170533	1246015	260	282
1989	10782	52090	561645	5699	160675	551	297779	13	119551	16179	40764	35672	1232265	1323303	262	296
1990	11023	53930	594458	5828	168813	566	312274	14	126339	15835	47199	37556	1302474	1362705	225	305
1991	10906	55177	601739	5949	166331	578	324645	14	127581	16346	49965	39787	1326394	1410927	238	297
1992	10739	55130	609647	6115	160008	615	346653	13	128089	16378	50111	42782	1353668	1423592	278	320
1993	10778	59064	636563	6338	166239	660	357379	13	131577	16489	47013	47031	1402291	1501843	259	339
1994	10670	60862	649386	6369	175303	690	382525	13	134473	17773	43303	47346	1450109	1518916	285	331
1995	11329	62130	703871	6588	188677	717	401329	13	136775	18467	48555	52785	1550459	1647578	314	361
1996	11313	63427	717546	6745	178111	794	416062	15	148396	19243	49947	54781	1584086	1659108	345	365
1997	10817	65152	704780	6973	181631	778	416615	15	150881	20619	47210	57174	1578910	1661055	306	373
1998	11649	66722	777270	7081	195175	788	444986	15	156638	21214	46433	61763	1703479	1779021	282	396
1999	11137	68543	763361	7265	190995	830	456898	17	173202	21699	44819	63781	1714755	1797594	351	419
2000	11202	70335	787923	7488	193506	880	480032	17	171942	22284	51178	68465	1775330	1868496	337	425
2001	11092	72391	802975	7646	191756	957	504965	17	172759	23237	52214	72338	1820244	1882256	364	409
2002	11527	73827	850987	7777	195740	1001	525041	18	178121	23751	58337	84000	1915977	2008451	369	433
CAAGR 93-02	0.75%	2.51%	3.28%	2.30%	1.83%	4.74%	4.37%	3.36%	3.42%	4.14%	2.43%	6.66%	3.53%	3.28%	4.01%	2.76%
CAAGR 83-02	0.85%	3.00%	3.87%	2.88%	2.57%	4.95%	5.29%	2.08%	3.25%	2.15%	4.46%		4.25%	3.99%	3.88%	3.30%
2003	11304	75862	857543	8029	199498	1039	548013	18	182850	24626	60791	85656	1958977	2060887	364	448
2004	11396	78846	898494	8281	205143	1076	571092	18	184276	25908	64075	89526	2038515	2144563	380	467
2005	11442	80320	919008	8462	209073	1104	588554	18	186644	26542	66908	92900	2089629	2198337	391	479
2006	11525	81794	942669	8642	212957	1133	606601	18	188246	27176	69945	96559	2144153	2255697	403	492
2007	11609	83224	966161	8817	216813	1161	624419	18	189804	27790	72861	100073	2197920	2312261	415	505
2008	11668	84654	987711	8992	220560	1188	641973	18	190871	28405	75683	103507	2248709	2365692	427	517
2009	11747	86039	1010690	9161	223959	1216	659442	18	191796	29000	78744	107193	2300823	2420518	438	529
2010	11811	87423	1032594	9330	227307	1243	677340	18	192750	29595	81998	111074	2352657	2475048	450	541
2011	11888	88808	1055753	9499	230079	1270	696185	18	193579	30190	86084	115882	2407752	2533010	460	554
2012	11932	90149	1075626	9662	232867	1297	713194	18	194253	30766	89353	119799	2455859	2583619	469	566
CAAGR 03-12	0.60%	1.94%	2.55%	2.08%	1.73%	2.50%	2.97%		0.67%	2.50%	4.37%	3.80%	2.54%	2.54%	2.85%	2.62%
2013	11957	91489	1093915	9825	235528	1324	730233	18	194894	31342	92723	123792	2502429	2632611	477	577
2014	12011	92829	1114938	9988	238167	1350	748065	18	195492	31918	96343	128129	2553052	2685869	486	589
2015	12072	94125	1136251	10146	240638	1376	766148	18	196028	32475	100178	132676	2604394	2739881	495	601
2016	12096	95420	1154220	10303	243161	1403	783533	18	196746	33032	103656	136804	2651152	2789072	504	612
2017	12144	96716	1174536	10461	245581	1429	800959	18	197463	33589	107150	141007	2700285	2840761	512	624
2018	12193	97966	1194533	10612	247826	1454	818248	18	198178	34127	110717	145281	2748909	2891914	521	635
2019	12222	99217	1212597	10764	249905	1480	835416	18	198893	34664	114364	149627	2795466	2940893	529	646
2020	12275	100468	1233215	10916	252082	1505	853091	18	199577	35202	118022	154025	2845214	2993229	538	658
2021	12305	101674	1251152	11062	254092	1531	870653	18	200290	35720	121708	158499	2892113	3042568	547	669
2022	12361	102836	1271191	11202	255938	1555	888097	18	200971	36220	125515	163023	2940955	3093950	555	681
CAAGR 13-22	0.37%	1.31%	1.68%	1.47%	0.93%	1.81%	2.20%		0.34%	1.62%	3.42%	3.11%	1.81%	1.81%	1.71%	1.87%
CAAGR 03-22	0.47%	1.61%	2.09%	1.77%	1.32%	2.15%	2.57%		0.50%	2.05%	3.89%	3.45%	2.16%	2.16%	2.25%	2.23%

TABLE B-2

HISTORY AND FORECAST OF SUMMER PEAK DEMAND
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
1993	355	23	316	0	0	10	0	6	339
1994	347	21	310	0	0	9	0	7	331
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	440	28	397	0	0	8	0	7	425
2001	423	28	381	0	0	7	0	7	409
2002	446	32	401	0	0	7	0	7	433
2003	460	33	415	0	0	6	0	6	448
2004	479	35	432	0	0	6	0	6	467
2005	490	36	443	0	0	6	0	5	479
2006	503	38	454	0	0	6	0	5	492
2007	515	39	466	0	0	6	0	4	505
2008	525	41	476	0	0	5	0	3	517
2009	537	42	487	0	0	5	0	3	529
2010	548	44	497	0	0	5	0	2	541
2011	561	46	508	0	0	5	0	2	554
2012	573	48	518	0	0	5	0	2	566
2013	585	49	528	0	0	6	0	2	577
2014	597	51	538	0	0	6	0	2	589
2015	609	53	548	0	0	6	0	2	601
2016	620	55	557	0	0	6	0	2	612
2017	633	57	567	0	0	7	0	2	624
2018	644	58	577	0	0	7	0	2	635
2019	655	60	586	0	0	7	0	2	646
2020	668	62	596	0	0	8	0	2	658
2021	679	64	605	0	0	8	0	2	669
2022	691	66	615	0	0	8	0	2	681

TABLE B-3
HISTORY AND FORECAST OF SUMMER PEAK DEMAND
HIGH BAND

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1993	355	23	316	0	0	10	0	6	339
1994	347	21	310	0	0	9	0	7	331
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	440	28	397	0	0	8	0	7	425
2001	423	28	381	0	0	7	0	7	409
2002	446	32	401	0	0	7	0	7	433
2003	462	34	416	0	0	6	0	6	450
2004	483	36	435	0	0	6	0	6	471
2005	497	37	449	0	0	6	0	5	486
2006	513	39	463	0	0	6	0	5	502
2007	529	41	478	0	0	6	0	4	519
2008	543	43	491	0	0	6	0	3	534
2009	559	45	506	0	0	5	0	3	551
2010	574	47	520	0	0	5	0	2	567
2011	591	50	533	0	0	6	0	2	583
2012	607	52	547	0	0	6	0	2	599
2013	623	54	561	0	0	6	0	2	615
2014	640	56	575	0	0	6	0	3	631
2015	657	59	588	0	0	7	0	3	647
2016	672	61	602	0	0	7	0	2	663
2017	688	63	616	0	0	7	0	2	679
2018	706	66	629	0	0	8	0	3	695
2019	722	68	643	0	0	8	0	3	711
2020	738	70	657	0	0	8	0	3	727
2021	756	73	671	0	0	9	0	3	744
2022	773	76	685	0	0	9	0	3	761

TABLE B-4

HISTORY AND FORECAST OF SUMMER PEAK DEMAND
LOW BAND

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1993	355	23	316	0	0	10	0	6	339
1994	347	21	310	0	0	9	0	7	331
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	440	28	397	0	0	8	0	7	425
2001	423	28	381	0	0	7	0	7	409
2002	446	32	401	0	0	7	0	7	433
2003	458	33	413	0	0	6	0	6	446
2004	474	34	428	0	0	6	0	6	462
2005	481	35	435	0	0	6	0	5	470
2006	488	36	442	0	0	6	0	4	478
2007	497	37	450	0	0	6	0	4	487
2008	502	38	456	0	0	5	0	3	494
2009	510	39	463	0	0	5	0	3	502
2010	517	41	469	0	0	5	0	2	510
2011	526	42	477	0	0	5	0	2	519
2012	533	43	483	0	0	5	0	2	526
2013	539	44	488	0	0	5	0	2	532
2014	547	46	494	0	0	5	0	2	540
2015	556	47	501	0	0	6	0	2	548
2016	562	48	506	0	0	6	0	2	554
2017	570	50	512	0	0	6	0	2	562
2018	577	51	518	0	0	6	0	2	569
2019	584	52	523	0	0	7	0	2	575
2020	592	53	530	0	0	7	0	2	583
2021	598	55	534	0	0	7	0	2	589
2022	606	56	541	0	0	7	0	2	597

TABLE B-5

Demand Side Management Impacts
Cumulative Beginning 1980

Year	Energy MWh	Winter kW	Summer kW
1980	254	168	168
1981	575	370	370
1982	1,054	687	674
1983	2,356	1,339	1,212
1984	8,024	3,074	2,801
1985	16,315	6,719	4,619
1986	25,416	10,470	7,018
1987	30,279	13,287	8,318
1988	34,922	15,918	9,539
1989	38,824	18,251	10,554
1990	43,661	21,033	11,753
1991	48,997	24,204	12,936
1992	54,898	27,574	14,317
1993	60,934	31,358	15,677
1994	61,955	33,845	15,913
1995	63,167	36,339	16,235
1996	62,148	36,325	15,761
1997	65,185	36,979	15,795
1998	68,065	37,406	15,726
1999	71,172	37,761	15,492
2000	70,967	35,842	14,866
2001	70,536	34,002	13,788
2002	70,700	32,534	13,111
2003	69,798	30,925	12,371
2004	69,763	29,605	11,838
2005	68,838	27,855	11,138
2006	67,372	25,697	10,437
2007	65,352	23,347	9,542
2008	62,824	20,511	8,599
2009	61,188	18,124	7,931
2010	59,578	15,791	7,229
2011	63,154	16,677	7,583
2012	66,152	17,549	7,759
2013	69,453	18,441	8,046
2014	72,715	19,330	8,330
2015	75,931	20,197	8,596
2016	78,872	21,061	8,773
2017	82,061	21,963	9,023
2018	85,337	22,913	9,337
2019	88,976	23,843	9,735
2020	92,169	24,744	9,996
2021	95,361	25,644	10,258
2022	98,554	26,545	10,519

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SECTION C
EXISTING GENERATION FLEET AND PROJECTED RESERVE MARGINS

The type, age, and capacity of generating facilities owned and operated by GRU are tabulated in Table C-1. The general location of the System's two electric generating plant sites and connections to Florida's bulk power transmission grid are shown in Figure C-1. Two types of generating units are located at the System's two generating plant sites: steam turbines and gas turbines.

The J.R. Kelly Station Generating is located in southeast Gainesville near the downtown business district and consists of one combined cycle unit, one steam turbine unit, three simple cycle combustion turbines, and associated cooling facilities, fuel storage, pumping equipment, transmission and distribution equipment. All of these units are primarily gas fired, but with the ability to use oil as a back-up fuel. The combined cycle unit (Kelly CC 1) is a combination of a simple cycle gas turbine, a heat recovery steam generator (to capture the waste heat from the gas turbine and generate steam), and a steam turbine generator. It is located at the downtown John R. Kelly Station. Note that the Kelly CC 1 is composed of two units in Table C-1 (FS08 and CT4), since it can be run as a simple cycle combustion turbine if necessary.

The Deerhaven Generating Station is located six miles northwest of Gainesville. The facility consists of two steam turbines and three simple cycle gas turbines, and associated cooling facilities, fuel storage, pumping equipment and transmission equipment. All of these units are primarily gas fired with the ability to use oil as a back-up fuel, with the exception of Deerhaven Unit 2, which is coal fired primarily but uses some natural gas for flame stabilization. With the addition of Deerhaven 2 in 1981, the site now includes coal unloading and storage facilities and a brine concentration plant, which treats all of the process wastewater and stormwater contaminated by plant materials and activities. As a result of this practice, there is no discharge of "industrial wastewater" to surface waters or ground water. All of the by-product management and fuel storage areas are clay lined, and groundwater is closely monitored throughout the site. The original site was 1,146 acres, and 2,317.6 acres of buffer/potential expansion areas have been purchased to the north and east of the original Deerhaven plant site, for a current total of 3,463.6 acres.

The present summer net capability of the System is 610 MW and the winter net capability is 629 MW. 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. To summarize, the System's energy is currently produced by three fossil fuel steam turbines, six simple-cycle combustion turbines, one combined-cycle unit, and a 1.4% ownership share of the Crystal River 3 nuclear unit, which is operated by Progress Energy Florida (PEF).

STEAM TURBINES

The System's three operational simple cycle steam turbines are powered by fossil fuels and Crystal River 3 is nuclear powered. The fossil fueled steam turbines comprise 54.7% of the System's net summer capability and produced 76.0% of the electric energy supplied by the System in 2002. These units range in size from 23.2 MW to 228.4 MW. The recently installed combined-cycle unit comprises 18.4% of the System's net summer capability and produced 14.9% of the electric energy supplied by the System in 2002. The System's 11.0 MW share of Crystal River 3 nuclear unit comprises 1.8% of the System's net summer capability and produced 5.1% of total electric energy in 2002.

Both Deerhaven 2 and Crystal River 3 are used for base load purposes, while Kelly 7, Kelly CC1 and Deerhaven 1 are used for intermediate loading. The remainder of the System’s capacity is in the form of peaking units.

GAS TURBINES

The System's six industrial gas turbines make up 25.1% of the System's summer generating capability and produced 4.0% of the electric energy supplied by the System in 2002. Gas turbines are advantageous in that they can be started and placed on line in thirty minutes or less. The System's gas turbines are most economically used as peaking units during high demand periods when base and intermediate units cannot serve all of the System loads. These units are utilized for peaking purposes in part because their energy conversion efficiencies are considerably lower than steam units. As a result, they yield higher operating costs and are consequently unsuitable for base load operation.

COOLING AND EMISSION CONTROL

All of the System's steam turbines, except for Crystal River 3, utilize re-circulating cooling towers with a mechanical draft for the cooling of condensed steam. Crystal River 3 uses a once-through cooling system aided by helper towers. Deerhaven 2 has flue gas cleaning equipment and electrostatic precipitation.

RESERVE MARGINS

Reserve margins as discussed for this IRP represent generation capacity in excess of forecasted peak demands. They are required to accommodate forecasting errors due to weather, customer growth, or customer consumption, and to accommodate any units that might be out-of-service during peak periods. Table C-2 summarizes the reserve margin criteria employed by various utilities in Florida. Higher reserve margins will result in higher cost from carrying excess capacity. The planning reserve margin employed by GRU is 15%.

Table C-3 contains the projected reserve margins for the high, base and low band forecasts of peak summer demand presented in Section B, assuming no generating capacity is added to the System. Unit retirements scheduled after 2010 are included in the analysis. The base case forecast calls for additional capacity in the summer of 2010, the low band forecast for the summer of 2012, and the high band forecast for the summer of 2008. Figure C-2 presents the same information in the form of a graph.

FIGURE C-1

Gainesville Regional Utilities Electric Facilities

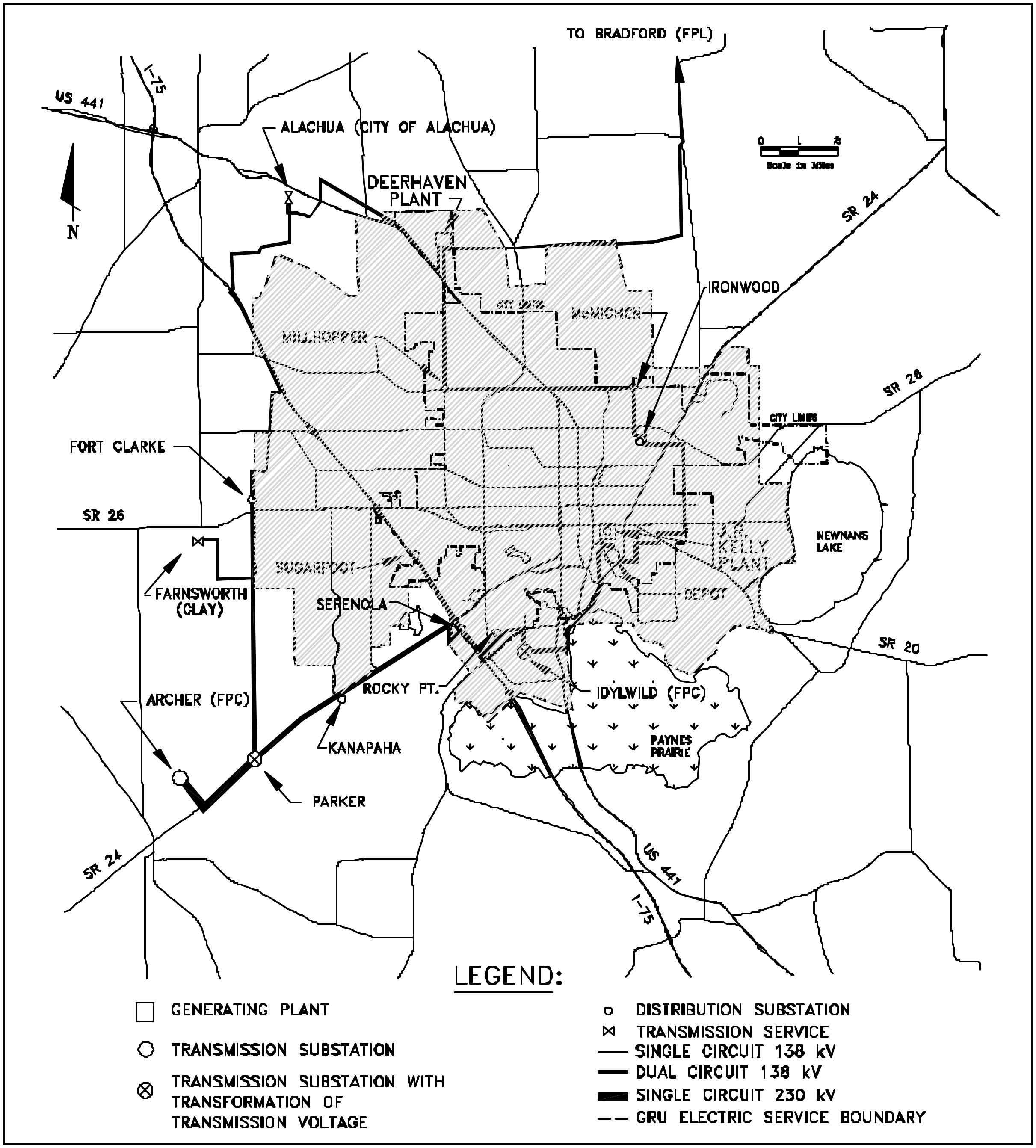


FIGURE C-2

Summer Peak Capacity Requirements

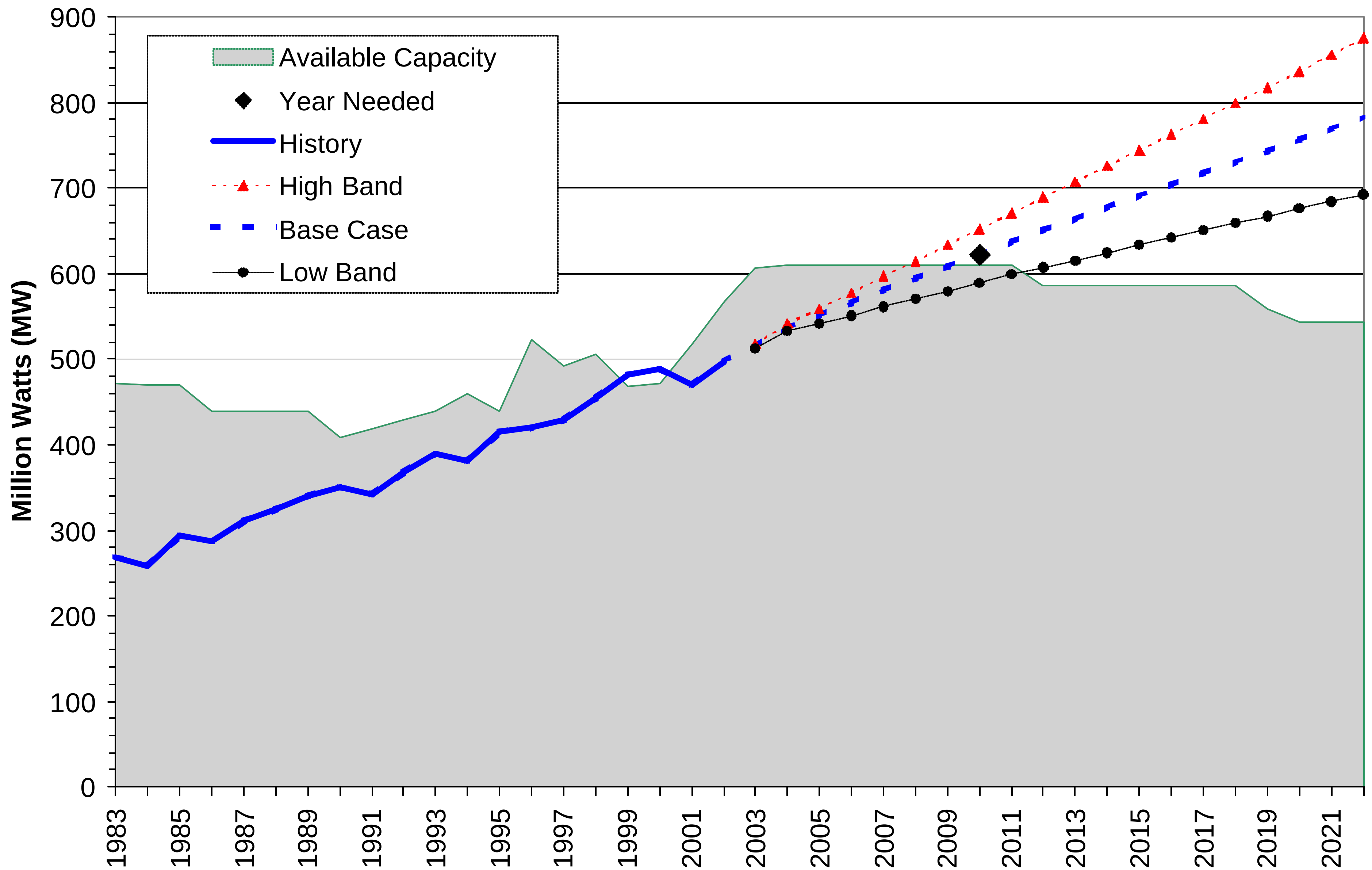


TABLE C-1
EXISTING GENERATING FACILITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								Alt.							
								Fuel	Commercial	Expected	Gross Capability		Net Capability		
	Unit		Unit	Primary Fuel		Alternate Fuel		Storage	In-Service	Retirement	Summer	Winter	Summer	Winter	
Plant Name	No.	Location	Type	Type	Trans.	Type	Trans.	(Days)	Month/Year	Month/Year	MW	MW	MW	MW	Status
J. R. Kelly		Alachua County											177	186	
		Section 4													
	FS08	Township 10 S	CA	WH	PL				[4/65 ; 5/01]	2051	38	38	37	37	OP
	FS07	Range 20 E	ST	NG	PL	RFO	TK		8/61	2011	24	24	23	23	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	2051	76	82	75	81	OP
	GT03		GT	NG	PL	DFO	TK		5/69	2019	14	15	14	15	OP
	GT02		GT	NG	PL	DFO	TK		9/68	2018	14	15	14	15	OP
	GT01		GT	NG	PL	DFO	TK		2/68	2018	14	15	14	15	OP
Deerhaven		Alachua County									451	461	422	432	
		Sections 26,27,35													
	FS02	Township 8 S	ST	BIT	RR				10/81	2031	249	249	228	228	OP
	FS01	Range 19 E	ST	NG	PL	RFO	TK		8/72	2023	88	88	83	83	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	76	82	75	81	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	19	21	18	20	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	19	21	18	20	OP
Crystal River	3	Citrus County	ST	NUC	TK				3/77	2037	11	11	11	11	OP
(818/815)		Section 33													
		Township 17 S													
		Range 16 E													
		(FPC)													
SW Landfill		Alachua County									2.52	2.52	2.28	2.28	
		Section 19													
	SW-1	Township 11 S	RE	LFG	PL				11/03	11/18	0.84	0.84	0.76	0.76	OP
	SW-2	Range 18 E	RE	LFG	PL				11/03	11/18	0.84	0.84	0.76	0.76	OP
	SW-3	(GRU)	RE	LFG	PL				11/03	11/18	0.84	0.84	0.76	0.76	OP
System Total													612	631	

Unit Type
CA = Combined Cycle Steam Part
CT = Combined Cycle Combustion Turbine Part
GT = Gas Turbine
ST = Steam Turbine
RE = Reciprocating Engine

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

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

Status
OP = Operational

TABLE C-2

PLANNING RESERVE MARGIN CRITERIA FOR FLORIDA UTILITIES

Company	Winter	Summer
Progress Energy Florida	20%	20%
Florida Power and Light	20%	20%
Gulf Power Company	15%	15%
Tampa Electric Company	20%	20%
Florida Municipal Power Agency	15%	18%
Gainesville Regional Utilities	15%	15%
JEA	15%	15%
Kissimmee Utility Authority	15%	15%
Lakeland Electric	22%	20%
Orlando Utilities Commission	15%	15%
City of Tallahassee	17%	17%
Seminole Electric Cooperative	15%	15%

TABLE C-3
FORECAST OF GRU RESERVE MARGINS

	Available	Low Band		Base Case		High Band	
	Capacity	Summer	Reserve	Summer	Reserve	Summer	Reserve
Year	MW	MW	Margin	MW	Margin	MW	Margin
1993	419			339	24%		
1994	439			331	33%		
1995	419			361	16%		
1996	502			365	38%		
1997	472			373	27%		
1998	508			396	28%		
1999	472			419	13%		
2000	472			425	11%		
2001	517			409	26%		
2002	567			433	31%		
2003	607			417	46%		
2004	612	462	32%	467	31%	471	30%
2005	612	470	30%	479	28%	486	26%
2006	612	478	28%	492	24%	502	22%
2007	612	487	26%	505	21%	519	18%
2008	612	494	24%	517	18%	534	15%
2009	612	502	22%	529	16%	551	11%
2010	612	510	20%	541	13%	567	8%
2011	611	519	18%	554	10%	583	5%
2012	588	526	12%	566	4%	599	-2%
2013	588	532	10%	577	2%	615	-4%
2014	588	540	9%	589	0%	631	-7%
2015	588	548	7%	601	-2%	647	-9%
2016	588	554	6%	612	-4%	663	-11%
2017	588	562	5%	624	-6%	679	-13%
2018	588	569	3%	635	-7%	695	-15%
2019	559	575	-3%	646	-13%	711	-21%
2020	545	583	-6%	658	-17%	727	-25%
2021	545	589	-8%	669	-19%	744	-27%
2022	545	597	-9%	681	-20%	761	-28%

SECTION D
AMBIENT AIR QUALITY

Environmental considerations are a key factor in the siting of new facilities. Air quality, availability of resources (e.g., land and water), waste generation and ecological impacts are just a few. This chapter focuses on the air issue only; other issues are addressed elsewhere in the report.

AMBIENT AIR QUALITY STANDARDS (AAQS)

Ambient air quality standards are restrictions that limit the concentration of an air pollutant that may be allowed to exist in the ambient air for any specific period of time. "Primary" standards are established with substantial safety margins to protect public health. "Secondary" standards are intended to protect public welfare, including property, plant and animal life, visibility and atmospheric clarity. The current federal/state AAQS are presented in Table D-1.

Alachua County Ambient Air Quality

Areas that meet all AAQS are designated as "attainment areas". Those that do not are designated as "non-attainment". Florida is one of only two states east of the Mississippi River, and the only highly urbanized state, that currently meets all AAQS (Reference 27). Alachua County is in an "attainment area" as illustrated in Table D-2 and Figure D-1, which compare ambient air quality data with the AAQS (References 1 and 10).

The Environmental Defense group, a non-profit environmental organization, publishes reports on community air quality on their Scorecard web site. Table D-3 presents Alachua County's Scorecard; it generally characterizes the air quality in Alachua County as "good". This table also provides the internet address for the Environmental Defense Web site. Note that when the Web site is first entered it ranks Alachua County's regulated emissions compared with the cleanest/best and dirtiest/worst counties in the United States. It is important to remember that this comparison is being made across all counties in the U. S. and the state, and does not take into consideration their degree of industrialization or urbanization, or the actual health risk. Proceed further into the site to obtain health and safety information.

Table D-4 summarizes the amount of emissions by type and source in Alachua County (Reference 1). The issues surrounding each type of emission are discussed below.

OZONE

Ozone can damage lung tissue, reduce lung function and sensitize the lungs to other irritants. Ozone is not emitted directly by power plants and is not a regulated emission. It is formed through a highly complex series of reactions between nitrogen oxides (NO_x) and volatile organic compounds (VOCs) from both natural and industrial sources in the presence of sunlight, as illustrated in Figure D-2. These reactions take place over time and are influenced by many factors, including wind speed and direction, humidity, precipitation, temperature, sunlight intensity and concentrations of NO_x and VOCs. For example, Alachua County's worst ozone conditions occurred in May, 1998, coincident with hot, dry weather (Reference 1).

Although ozone levels in Alachua County are a substantial fraction of the AAQS, this is a common situation in Florida as a result of natural conditions (References 1 and 43). For example, Figure D-3 shows the correlation between ozone concentration in Alachua Country and neighboring Baker and Marion Counties, which is one indication that ozone is a regional, not a local, issue (Reference 1).

MERCURY

Mercury is a pollutant of concern due to its potential health effects, primarily through its ingestion by fish, which is then ingested by people Mercury can be emitted from industrial and natural sources in inorganic or elemental forms on a scale ranging from global to local. The inorganic forms include reactive and non-reactive mercury. Reactive mercury can be transformed into methylmercury through biological mediation as illustrated in Figure D-4. Methylmercury is toxic and accumulates in fish and is passed up through the food chain.

Trace levels of mercury are found in coal and, when combusted, eventually wind up in ash or are emitted in flue gas. Electrostatic precipitators, scrubbers, and baghouses can remove some mercury, as can boiler designs using limestone for combustion (see Section J). Deerhaven 2, GRU's only coal unit, has electrostatic precipitators and only low sulfur compliance coal is burned. In a 1999 USEPA study, Deerhaven 2 had the 16^{th} lowest mercury content coal compared with 449 other power plants as shown in Figure D-5. The percentage of mercury in Deerhaven 2's stack gas that is reactive has never been measured, but 40% is a typical estimate.

Fish consumption advisories for mercury exist in nearly every water body in Florida including the Santa Fe River. Several years ago the Gainesville Energy Advisory Committee recommended that GRU evaluate whether or not Deerhaven Unit 2 was a significant contributor of mercury in the Santa Fe River watershed. A study was designed to evaluate the sensitivity of mercury deposits from Deerhaven 2 in the Santa Fe River basin to the percent assumed to be reactive, and to compare Deerhaven 2 as a source of mercury compared with background deposition levels (References 8 and 49). Figure D-6 presents the results of the mercury deposition study and illustrates that Deerhaven 2 contributes approximately 1% to 2.5% of total mercury deposition to the Santa Fe River Basin at 40% reactive mercury emissions in the flue gas. The contribution is only 2% to 5% at 100% reactive mercury emissions. The contribution of the Deerhaven 2 plant to mercury in the Santa Fe River Basin is negligible.

PARTICULATE MATTER (PM)

Particulate matter, or PM, is the term for particles found in the air, including dust, dirt, soot, smoke, and liquid droplets. Particles can be suspended in the air for long periods of time. Some particles are large or dark enough to be seen as soot or smoke. Others are so small that individually they can only be detected with an electron microscope.

Some particles are directly emitted into the air. They come from a variety of sources such as cars, trucks, buses, factories, construction sites, tilled fields, unpaved roads, stone crushing, and the burning of wood. These are called "primary particulates." Other particles may be formed in the air from the chemical change of gases. They are indirectly formed through secondary reactions when NOx and SO_X react with sunlight and water vapor. These also are called "secondary particulates."

Health Concerns

Exposure to particulate matter can affect breathing, aggravate existing respiratory and cardiovascular disease, cause irritation and damage lung tissue. USEPA has established AAQS for coarse and fine particulate matter. Coarse PM are particles with a diameter less than or equal to 10 microns (PM_{10}). Fine PM are particles less than or equal to 2.5 microns in diameter ($PM_{2.5}$). Fine PM can penetrate deeper into the lungs than coarse PM and therefore, has a greater potential to impact human health. Although the AAQS is expressed in terms of a mass concentration, not all $PM_{2.5}$ have the same health effects because of differences in the toxicity of the different types of $PM_{2.5}$ particles and materials that may adsorb onto them.

Recent EPA studies indicate that half or more of ambient $PM_{2.5}$ is composed of secondary species. The majority of $PM_{2.5}$ contributed by power generation is secondary $PM_{2.5}$ formed from the oxidation on SO_2 and NO_x emissions. Reductions of SO_2 and NO_x emissions by the utility industry as mandated by various existing and proposed regulatory and legislative programs are expected to result in a related decrease in secondary $PM_{2.5}$ derived from sulfates and nitrates.

Speciation Studies in Alachua County

As shown in Table D-4, the major sources of PM in Alachua County are vehicular emissions, natural sources and stationary area sources (e.g., painting, fireplaces, and agricultural applications). Studies were conducted during 2000 and 2001 to evaluate the size, contribution and sources of PM in Alachua County and correlate them to ambient air samples using a “fingerprinting analysis” to match the ambient particulates to those known to originate from a specific source (Reference 20). A chemical mass balance model was used to estimate the mass concentration that each source contributed to the ambient air sample. For purposes of this study, fly ash from the Deerhaven Unit 2 electrostatic precipitator was used rather than actual stack emission samples to establish the “fingerprint” of coal emissions. As illustrated in Figures D-7 and D-8, Deerhaven Unit 2’s contribution to both $PM_{2.5}$ and PM_{10} ambient concentrations were minimal. Table D-5 provides the percent contribution by different sources as estimated by these studies. The study also indicated that Deerhaven Unit 2’s fly ash had its’ greatest mass size distribution between 3.2 and 10.0 microns, not in the $PM_{2.5}$ range.

In 2002, GRU commissioned UF to conduct a follow-up study to refine the results of the initial study using Deerhaven 2 stack emissions and additional source profiles to establish the “fingerprint” of coal emissions (References 44 and 45). This study confirmed that Deerhaven 2 is a minimal contributor to ambient PM concentrations in Alachua Country and indicated that Deerhaven 2 emissions were significantly less than (approximately one-tenth) permitted emission rates. This is consistent with annual tests conducted for compliance purposes. The study also showed a bimodal particle size distribution with one in the greater than 10 micron range and the other smaller one in the less than 0.1 micron range, but with most of the mass in the greater than 10 micron size. The results are consistent with EPA studies of coal-fired power plants.

SULFUR DIOXIDE (SO_2)

Sulfur dioxide is released primarily from burning fuels that contain sulfur. SO_2 in high concentrations can affect breathing and may aggravate existing respiratory and cardiovascular disease. Table D-4 indicates that stationary point sources are the major SO_2 emission sources in Alachua County. Of these, GRU is the largest, notwithstanding that it burns a low-sulfur coal and low-sulfur fuel oils to produce electricity for its customers. SO_2 monitoring indicates that ambient concentrations are well within the regulatory standards as shown in Table D-2.

NITROGEN OXIDES (NO_x)

Table D-4 indicates that vehicular emissions are the largest source of NO_x in Alachua County. Recent NO_x monitoring indicates that ambient concentrations were well within the regulatory standard.

CARBON MONOXIDE (CO)

Carbon monoxide is a colorless, odorless and poisonous gas produced by the incomplete burning of fossil fuels. When CO enters the bloodstream, it reduces the delivery of oxygen to the body and can cause impairment of visual perception, manual dexterity, learning ability and death (in high concentrations). Vehicular emissions are the largest source of CO emissions in Alachua County as shown in Table D-4. There is no ambient air quality monitoring data available.

VOLATILE ORGANIC COMPOUNDS (VOC)

Volatile organic compounds include many specific chemicals that may cause adverse health effects such as cancer or reproductive toxicity. Natural sources (e.g., pine trees) are the largest source of VOCs in Alachua County as indicated in Table D-4. Additional sources of VOCs include vehicular emissions, and industrial, commercial and residential sources that use solvents and paints. Power plants are not typically sources for VOC compounds. Although there are no AAQS for VOCs, OSHA has established acute and chronic exposure limits designed to protect human health. VOC monitoring conducted throughout Gainesville by GRU indicate ambient concentrations several orders of magnitude less than OSHA limits (Reference 40A).

FIGURE D-1

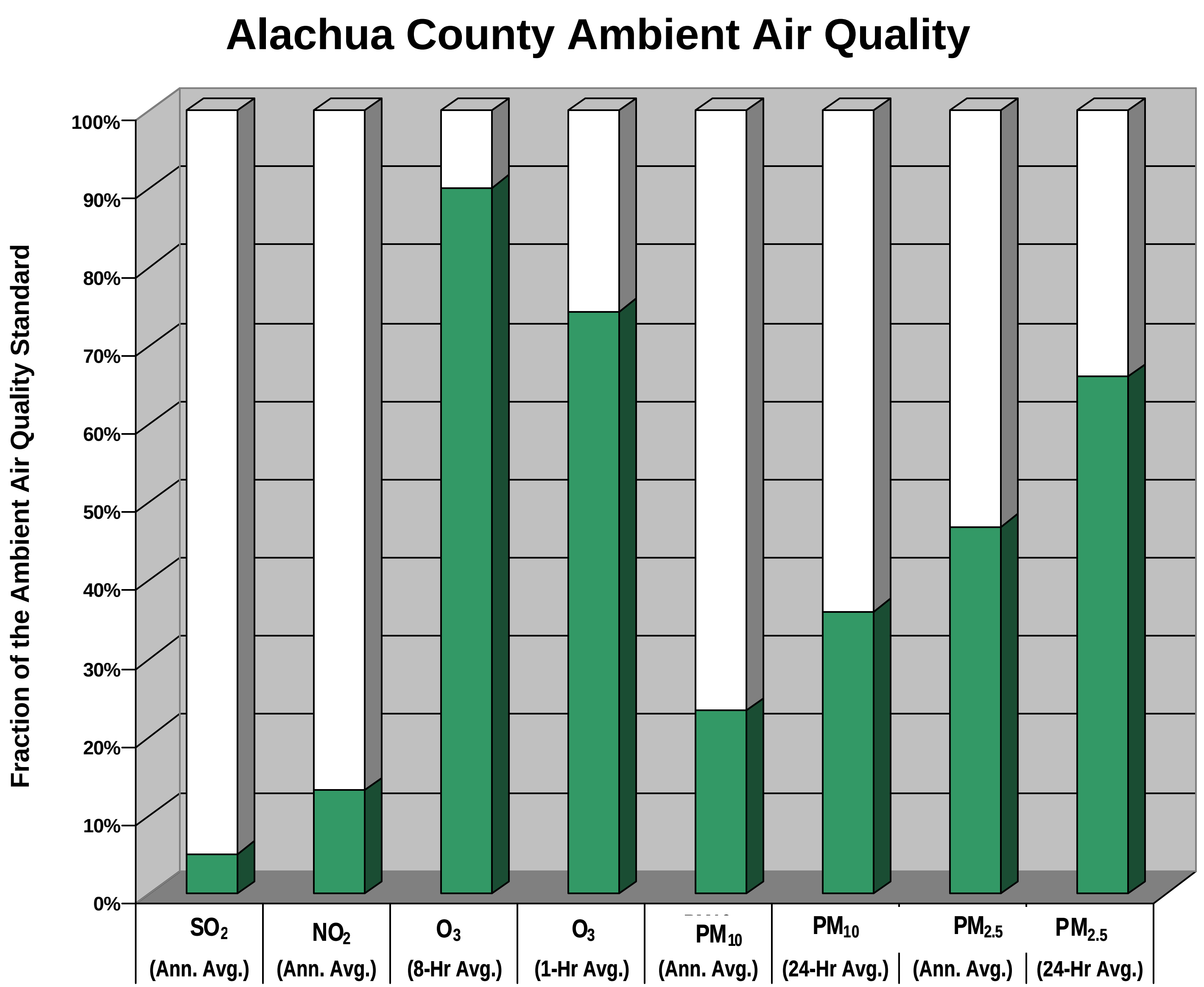

Alachua County Ambient Air Quality
Fraction of the Ambient Air Quality Standard
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
SO_2 (Ann. Avg.)
NO_2 (Ann. Avg.)
O_3 (8-Hr Avg.)
O_3 (1-Hr Avg.)
PM_{10} (Ann. Avg.)
PM_{10} (24-Hr Avg.)
$PM_{2.5}$ (Ann. Avg.)
$PM_{2.5}$ (24-Hr Avg.)

FIGURE D-2

OZONE FORMATION

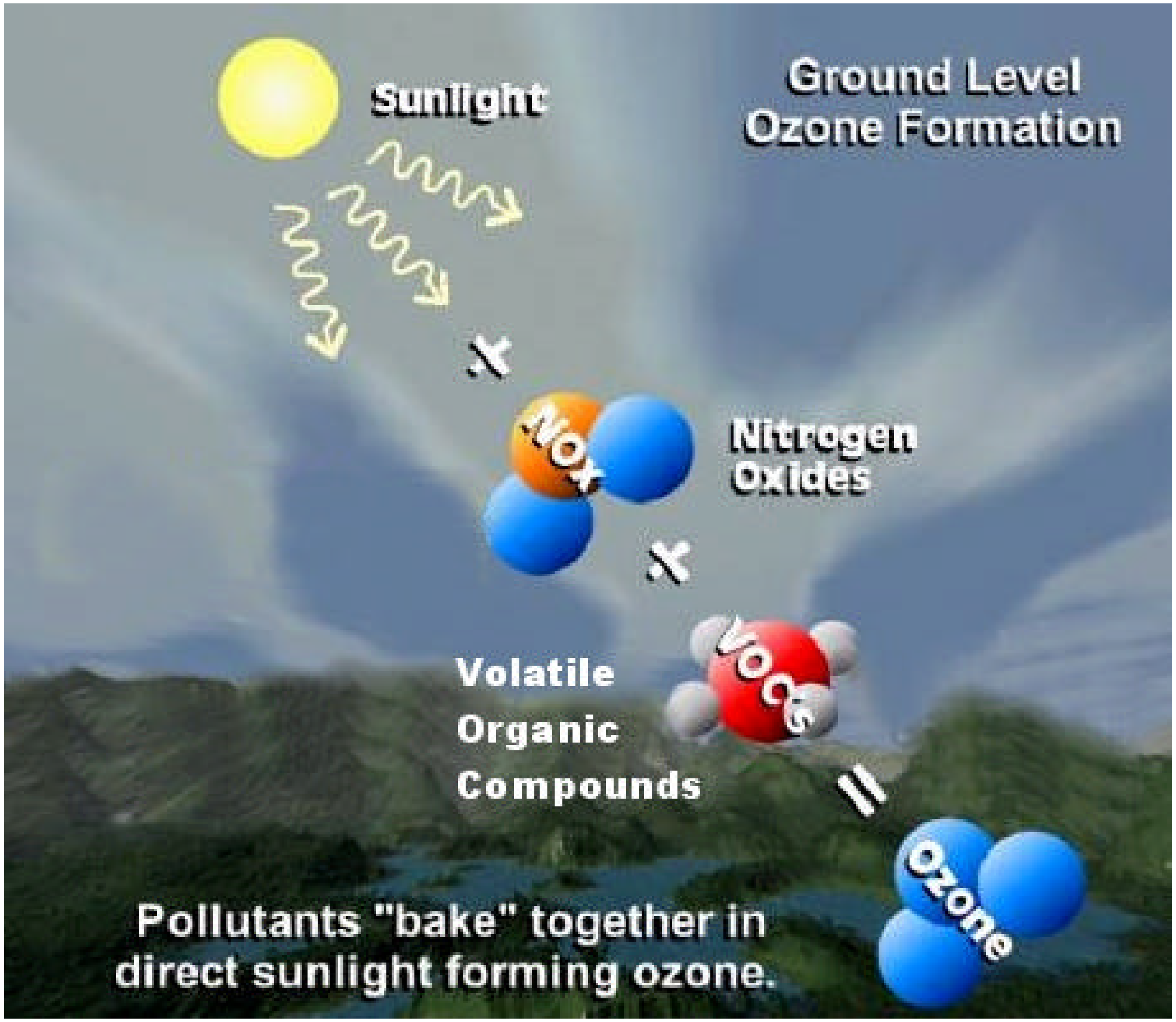
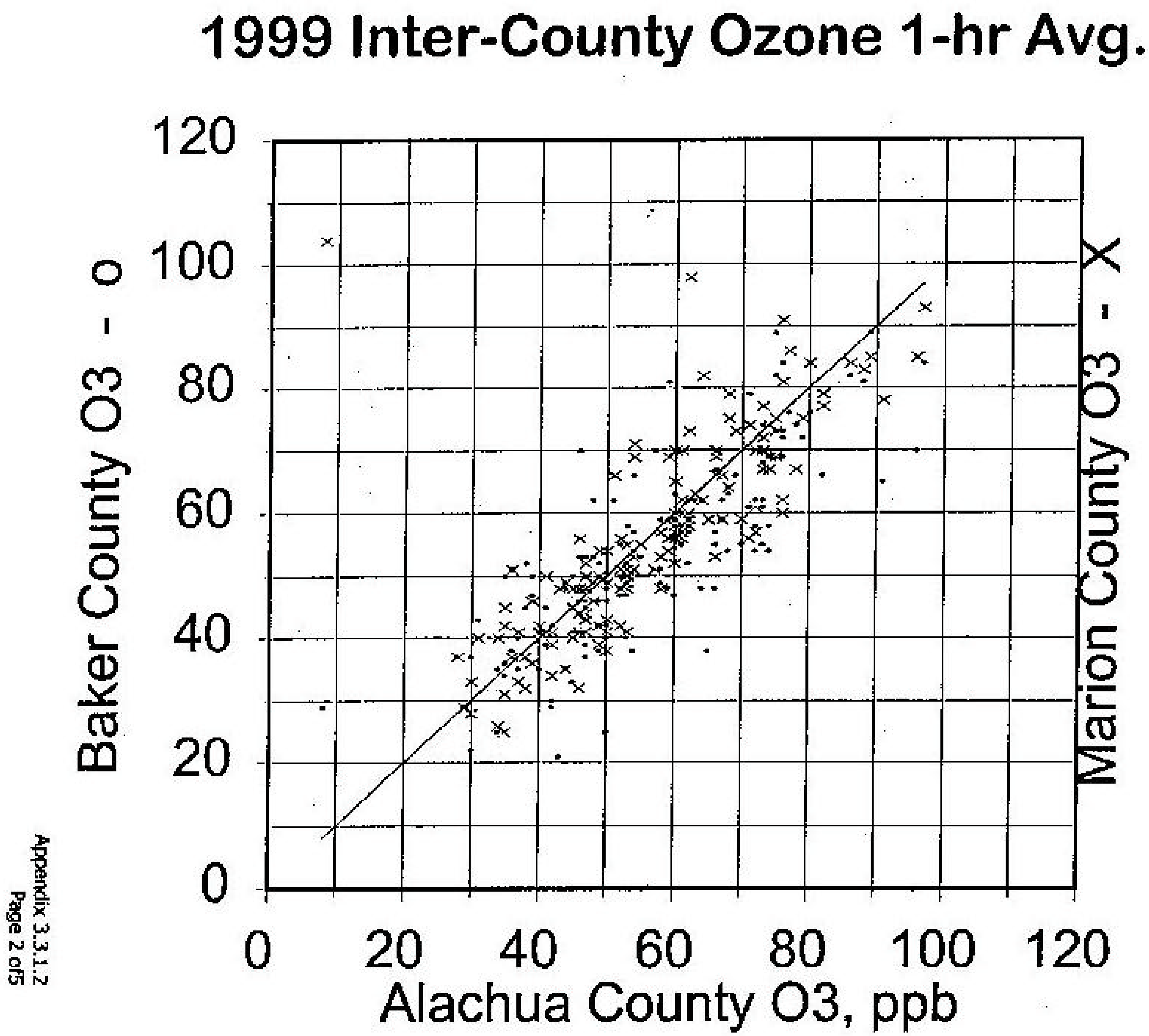


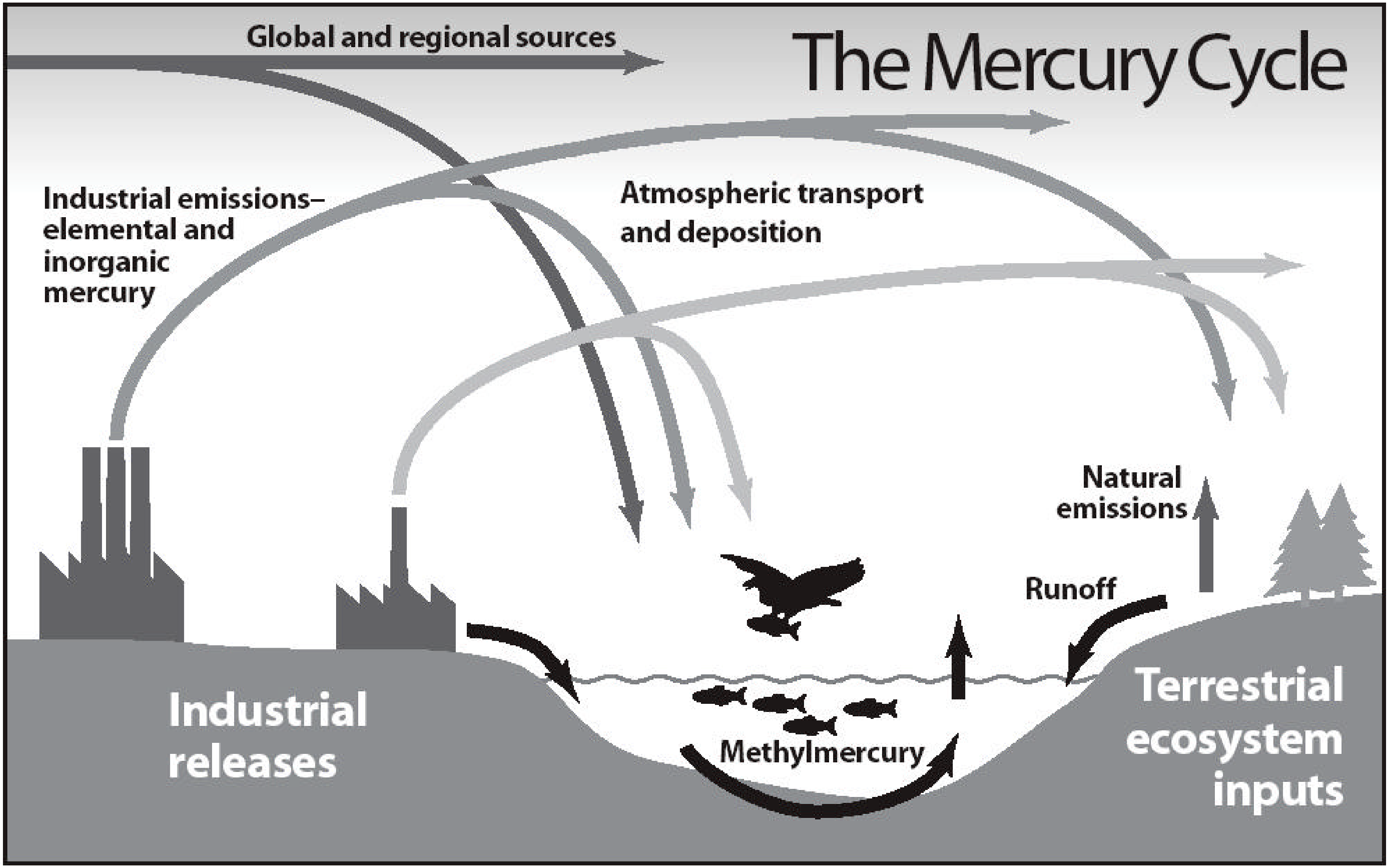
FIGURE D-3

OZONE IS A REGIONAL ISSUE



SOURCE: Alachua County Air Quality Commission Findings & Recommendations, Alachua Commission, January 2000

FIGURE D-4



***Natural Emissions include volcanoes, geysers, wildfires, erosion, and earthquakes.**

FIGURE D-5

Deerhaven's Mercury Performance

Deerhaven Coal Contains Less Mercury than 96% of U. S. Coal-fired Plants

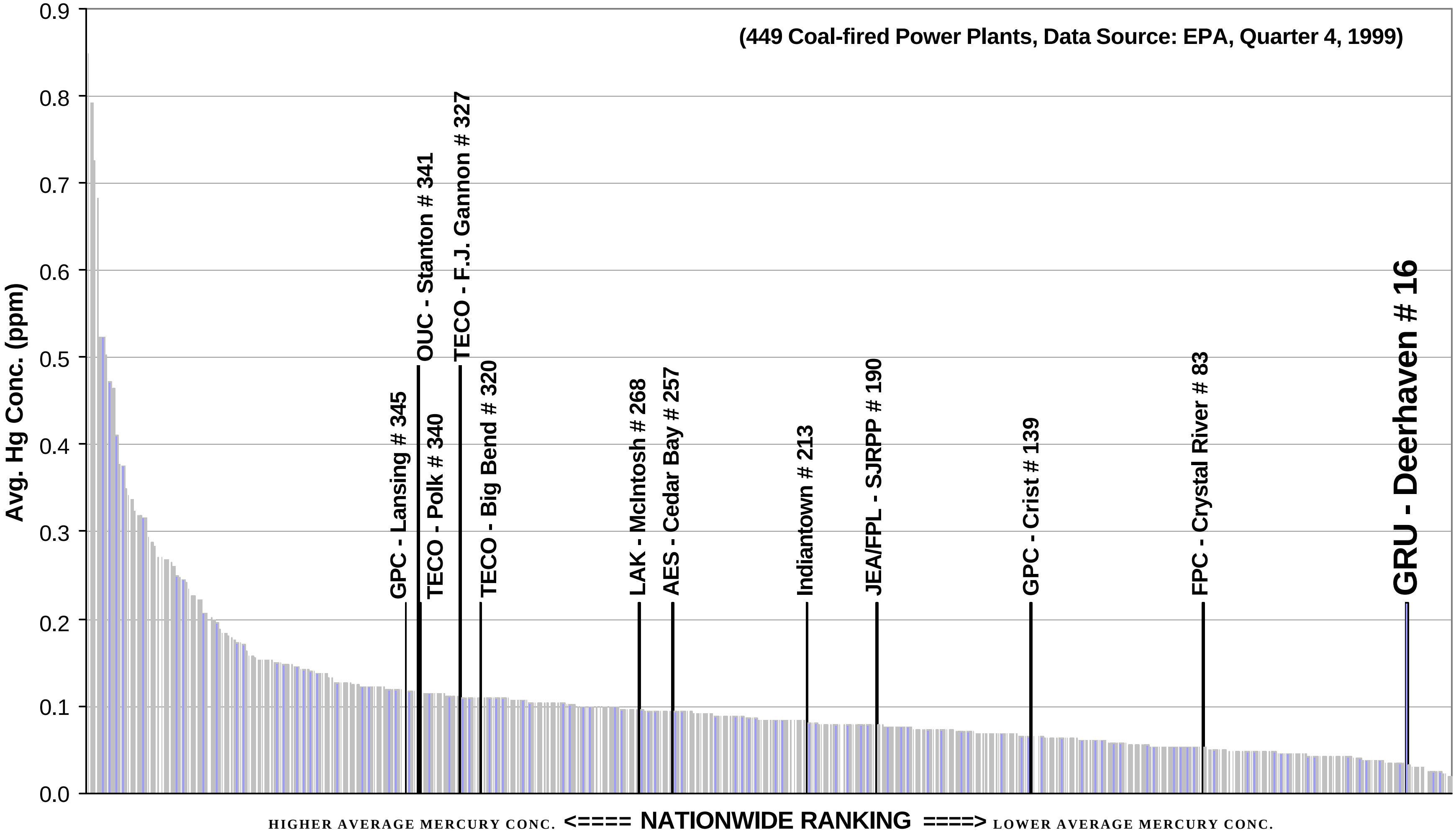
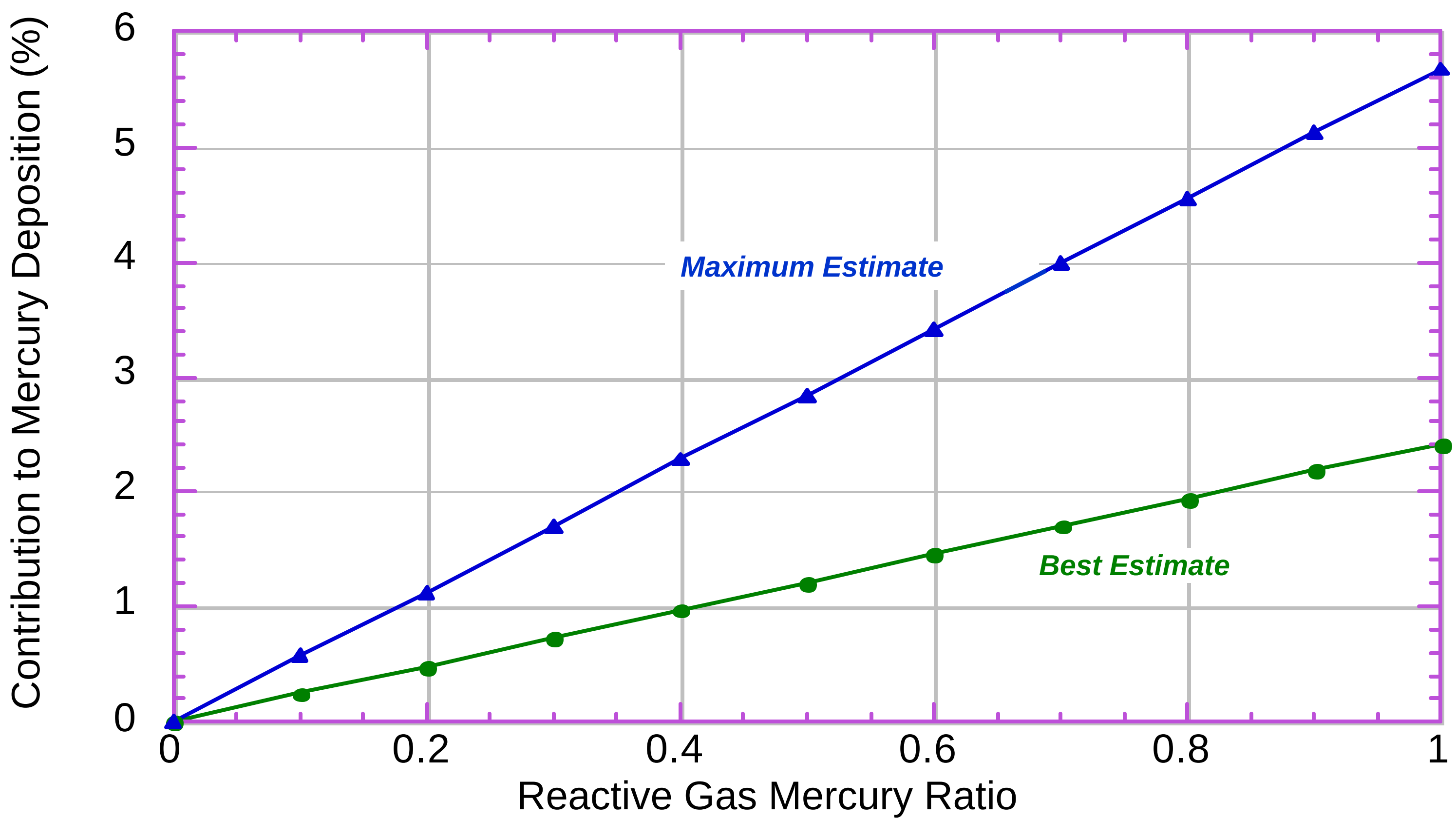


FIGURE D-6

Results from GEAC Recommended Mercury Santa Fe River Deposition Study



Source: <u>Potential Rates of Deerhaven 2 Mercury Deposition in the Santa Fe River Basin of North Central Florida,</u> C. Pollman, Tetra Tech, Inc., October 22, 2003 45

FIGURE D-7

DEERHAVEN'S CONTRIBUTION TO
AMBIENT PARTICULATE CONCENTRATION

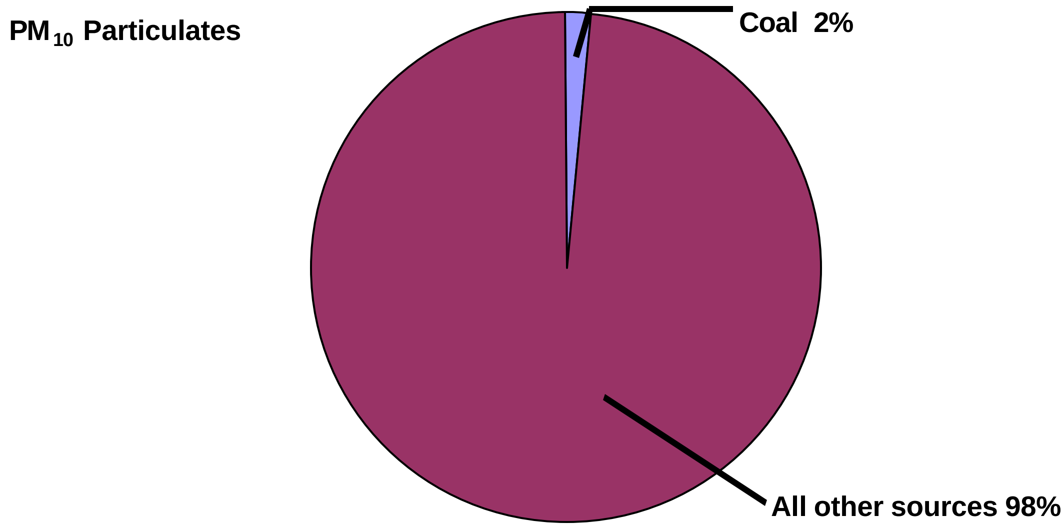
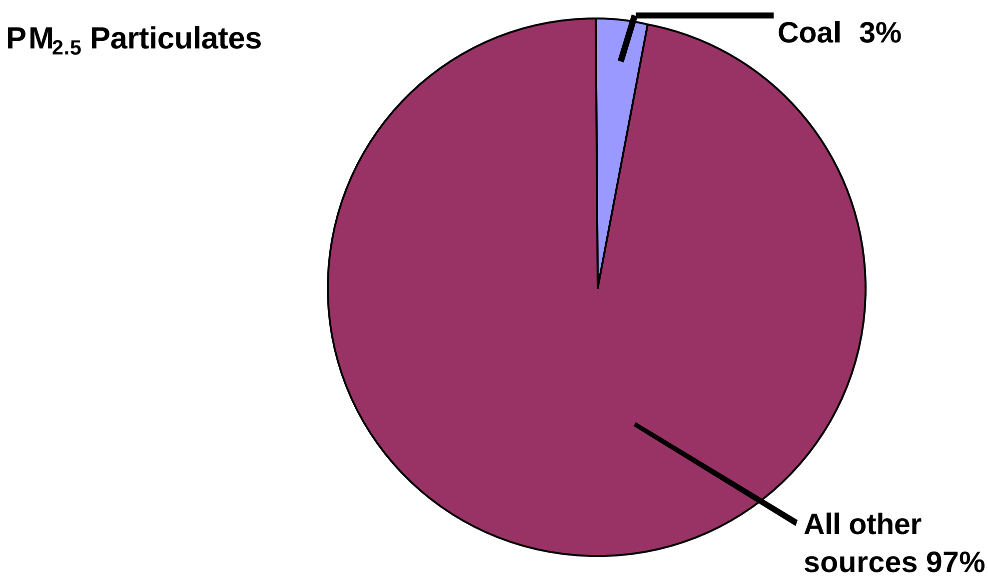


FIGURE D-8



Source: Air Quality Trends in Alachua County, Brown & Cullen, Inc., October 2003

TABLE D-1

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

POLLUTANT EXPOSURE	STANDARD VALUE *		STANDARD TYPE
Carbon Monoxide (CO)			
8-hour Average	9 ppm	(10 mg/m^3)	Primary
1-hour Average	35 ppm	(40 mg/m^3)	Primary
Nitrogen Dioxide (NO_2)			
Annual Arithmetic Mean	0.053 ppm	(100 µg/m^3)	Primary & Secondary
Ozone (O_3)			
1-hour Average	0.12 ppm	(235 µg/m^3)	Primary & Secondary
8-hour Average	0.08 ppm	(157 µg/m^3)	Primary & Secondary
Lead (Pb)			
Quarterly Average	1.5 µg/m^3		Primary & Secondary
Particulate (PM_{10}) *Particles with diameters of 10 micrometers or less*			
Annual Arithmetic Mean	50 µg/m^3		Primary & Secondary
24-hour Average	150 µg/m^3		Primary & Secondary
Particulate ($PM_{2.5}$) *Particles with diameters of 2.5 micrometers or less*			
Annual Arithmetic Mean	15 µg/m^3		Primary & Secondary
24-hour Average	65 µg/m^3		Primary & Secondary
Sulfur Dioxide (SO_2)**			
Annual Arithmetic Mean	0.02 ppm	(60 µg/m^3)	Primary
24-hour Average	0.10 ppm	(260 µg/m^3)	Primary
3-hour Average	0.50 ppm	(1300 µg/m^3)	Secondary

* Parenthetical value is an approximately equivalent concentration.
** Florida's Standards (more stringent than federal standards)

TABLE D-2

AMBIENT AIR QUALITY VS. STANDARDS

Parameter		Regulatory Std.		Ambient Level		% of Standard
SO_2	**(Ann Avg)**	0.02	(ppm)	0.001	(ppm)	5%
NO_2	**(Ann Avg)**	0.053	(ppm)	0.0070	(ppm)	13%
O_3	**(8-Hr Avg)**	0.08	(ppm)	0.072	(ppm)	90%
O_3	**(1-Hr Avg)**	0.12	(ppm)	0.089	(ppm)	74%
PM_{10}	**(24-Hr Avg)**	150	(ug/m3)	35	(ug/m3)	23%
PM_{10}	**(Ann Avg)**	50	(ug/m3)	18	(ug/m3)	36%
$PM_{2.5}$	**(24-Hr Avg)**	65	(ug/m3)	31	(ug/m3)	47%
$PM_{2.5}$	**(Ann Avg)**	15	(ug/m3)	9.9	(ug/m3)	66%

Source: Air Quality Trends in Alachua County, Brown & Cullen, Inc., October 2003.

Notes: SO_2 data from 2000, NO_2 data from 2001, Ozone data from 2003, PM_{10} and $PM_{2.5}$ data from 2002.

TABLE D-3

Alachua County Scorecard

Air Quality	
Days with Good Air Quality	92%
Days with Moderate Air Quality	8%
Unhealthful Days for Sensitive People	0%
Air Quality Index	
Maximum Air Quality Index*	85
90th Percentile Air Quality Index*	49
Median Air Quality Index*	31

***Index Ratings 0-50 Good; 50-100 Moderate; 100+ Unhealthful**

Instructions: Go to the Environmental Defense group's report at www.scorecard.org. Step 1: Use "Find your community" feature (enter Zip Code). Step 2: Click on "How clean is your air?"

TABLE D-4

EMISSION INVENTORY BY SOURCE CATEGORY IN TONS, ALACHUA COUNTY (Tons/Year)

Major Source Category	CO	NO_X	SO_2	VOC	PM_{10}
Stationary Point	279	4,482	7,056	511	170
Stationary Area	22,278	190	219	4,394	307
On-Road Vehicles	62,827	9,106	386	4,597	331
Off-Road Vehicles & Engines	19,334	2,131	464	2,886	234
Natural	264	379	0.3	26,534	379
Other	10,873	166	6	803	12,039
Total	95,855	16,455	8,131	39,725	13,460

Source: Alachua County Air Quality Commission Report, January 2000

TABLE D-5

Source Contributions to Ambient Particulate Concentrations

Source	PM_{10}	$PM_{2.5}$
asphalt	12.45%	2.53%
cement	19.56%	3.79%
coal-fired	1.78%	3.16%
distillate oil	0.36%	0.13%
fertilizer	1.78%	0.51%
field burning	8.89%	2.78%
marine	14.23%	20.21%
oil-fired	0.36%	0.09%
residual oil	0.53%	0.25%
soil	10.67%	0.25%
transportation	14.23%	25.27%
unidentified	12.45%	23.88%
unpaved road	1.78%	0.63%
wood burning	0.89%	16.42%
incinerator	0.04%	0.08%
natural gas heater	0.02%	0.03%
Totals	100.00%	100.00%

Source: Air Quality Trends in Alachua County, Brown & Cullen, Inc., October 2003

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SECTION E
REGULATORY AND STRATEGIC CONSIDERATIONS

Planning for GRU's electric system must take into consideration the regulatory and business environment within which it must operate. The major agencies whose mandates, rules, regulations and procedures have bearing on the System are the:

1. Federal Energy Regulatory Commission (FERC);
2. Florida Public Service Commission (FPSC);
3. United States Environmental Protection Agency (USEPA);
4. Florida Department of Environmental Protection (FDEP);
5. Suwanne River Water Management District (SWRMD); and
6. City and County Local Planning Authorities (LPA's).

The key regulatory permitting issues to be considered in IRP planning include environmental permits, consumptive water use permits, solid and liquid management and disposal; and comprehensive land use plans. The issues that potentially could result in new regulations are: deregulation of the electric utility industry; greenhouse gas policies; renewable energy portfolio requirements; renewable energy investment subsidies; multi-pollutant reduction proposals; and maximum achievable control technology (MACT) for mercury (Hg). Another key strategic issue is the future power market within which GRU will be operating.

PERMITTING ISSUES AND PROCESSES

Permitting issues will be mentioned only at a very general level in this section. More details are provided in Section J. The permitting process for a combustion turbine can take up to 12 months. A new steam unit may need 18 months or longer to permit, and involves many agencies and technical experts.

Air Permits

Although USEPA has approved FDEP's program for issuance of Prevention of Significant Deterioration (PSD) construction and Title V operation permits, the USEPA has retained review authority and can over-ride FDEP's ability to issue Title V permits. Emission levels will be set as Best Available Control Technology (BACT), which differs depending on the constituent, fuel, and technology. Cost effectiveness also is considered in BACT determinations. Alachua County has good air quality and there are no anticipated limits on additional generation based on ambient air quality. The primary area of concern for permitting at Deerhaven is the Class I airshed over the Okeefenokee Swamp and the Chassakowitzka National Wildlife Refuge, to which different factors apply. Preliminary work indicates that substantial amounts of solid fuel generation installed at the Deerhaven site, along with additional emission control equipment for Deerhaven 2, is likely to be permittable, especially since a net reduction of emissions is potentially feasible. The greenfield site considered as part of the joint feasibility study does not provide the opportunity to have net reductions in emissions, and also impinges on a Class 1 air shed.

Water

The use of reclaimed water from either the Main Street Wastewater Treatment Plant or the Kanapaha Water Reclamation Facility would greatly reduce the need for additional groundwater withdrawal capacity should additional generation capacity be constructed at the Deerhaven Generating Station. Groundwater still would be used and would be required as a back-up water supply. The Deerhaven plant site is certified as having zero discharge of process water. runoff. The site is equipped with a brine concentrator and water is reduced to solids for disposal in an on-site, lined landfill. A small amount of wastewater is sent from the Deerhaven site to GRU's wastewater collection system for treatment and eventual disposal. The greenfield site requires ground water use and deep well wastewater disposal.

Site Certification

Many aspects of air, water, solids handling, and land use permitting are folded into a single agency process under Florida's Power Plant Siting Act (Florida Statutes Chapter 163). Any affected jurisdiction or agency has standing in that process, which is managed by the Florida Department of Environmental Protection. A part of the site certification process is to obtain a certificate of need. This is a procedure ensure that the proposed project is in the public's best interest. Bidding the project and capacity need out to the private sector and other utilities to be sure the least cost option is implemented is one part of obtaining that certification.

STRATEGIC ISSUES

Deregulation

Deregulation of the wholesale power market and transmission grid to promote free access and competition already has occurred through federal legislation being implemented by FERC. Additional changes to the transmission system and the manner in which transmission congestion is resolved are forthcoming. The proposals to date for forming regional transmission systems with independent operators are being carefully monitored by GRU especially with regard to this IRP.

Retail choice for electric providers has been implemented in several states, with mixed success. The California power crisis definitely has cooled the public and political ardor for taking this step. It is GRU's observation that the effects of the perceived threat of retail competition have resulted in major cost savings throughout the electric industry, and it must be assumed that retail choice is still a tempting step to seek further potential benefits. GRU has put into place several strategies in preparation for such eventualities that protect the General Fund Transfer and avoid stranded cost. A modern, cost-efficient and reliable generation fleet is the best possible hedge against additional deregulation, as well as the best choice for the community.

Renewable Portfolios and Grants

Fourteen states have passed laws requiring electric utilities to include a percentage of renewable energy in their generation mix. A number of proposed federal bills have included similar provisions (usually requiring only a few percent of capacity as renewable energy). The Renewable Energy Production Incentive (REPI) is a federal payment of $.015 per kWh for the production of electricity from renewable energy. GRU has received this funding for its existing photovoltaic facility. REPI funding has to be allocated each year, and it was renewed this year. Funding is distributed on a first come, first served basis in two tiers. Wind and solar energy are the first tier and have the highest funding priority. Landfill gas and biomass are in the second tier and usually there is not enough money to reimburse them, although payment in arrears is possible.

Greenhouse Gases

Greenhouse gases trap heat in the earth's biosphere and affect global heat balances that affect weather and climate. These gases include water vapor, carbon dioxide, methane, ozone, nitrous oxides, flurocarbons, and particulates among others. Methane is an extremely potent greenhouse gas, with 21 times more effect per pound than carbon. The concentrations of these substances in the atmosphere have been increasing due to global industrialization, and many believe have begun a process of global warming has begun (References 2 and 22). The rate at which this is occurring is difficult to discern because it is also generally believed that the 21st century is coming out of a little ice age, which causes confounding of the data and its interpretation. This confusion is probably one of the reasons why clear pubic policy directives have not been legislated in America.

A number of legislative proposals related to electric generation have addressed reducing the production of carbon dioxide, including proposals for a carbon cap and trade program or a carbon tax. The strategy implicit in all of the proposals to date has been to reduce the carbon intensity of the manufacture of electricity.

Gainesville has been actively aware of these issues and is one of the few utility participants in the Cities for Climate Protection program. Table E-1 summarizes the CO_2 reductions GRU has achieved thus far. The key strategies for reducing carbon intensity are energy conservation, fuel use efficiency, carbon sequestration, and finally, using renewable energy. The CO_2 emitted from using biomass is considered carbon neutral in most protocols for quantifying carbon intensity, because the biomass would eventually rot, emitting CO_2 in that manner anyway. Therefore, using biomass avoids additional carbon from fossil fuels.

Multi-Pollutant Proposals

A number of regulatory and legislative initiatives have been proposed to apply more stringent emission limitations for a wide range of parameters to existing generation facilities. Although currently there is no mandate that would require GRU to install additional emission control equipment on its existing generation fleet, studies have been performed to ascertain the effect various regulatory changes might have (References 5, 6, 7). For planning purposes, it is prudent to consider a scenario in which GRU will have to install additional emission control equipment on Deerhaven Unit 2 by 2010, including, at a minimum, dry scrubbers for SO_2, selective catalytic reduction for NO_X and a fabric filter for particulate control.

Mercury Maximum Achievable Control Technology (MACT)

Regulations on mercury emission are expected to be forthcoming in December 2003. The prevailing proposals are to require maximum achievable mercury control technology (MACT) and/or cap and trade programs similar to the SO_2 allowance program established under the 1990 Clean Air Act Amendments. Scrubbers, CFB boilers, and/or injection of activated carbon upstream of a particulate filter are leading mercury control technologies at this time.

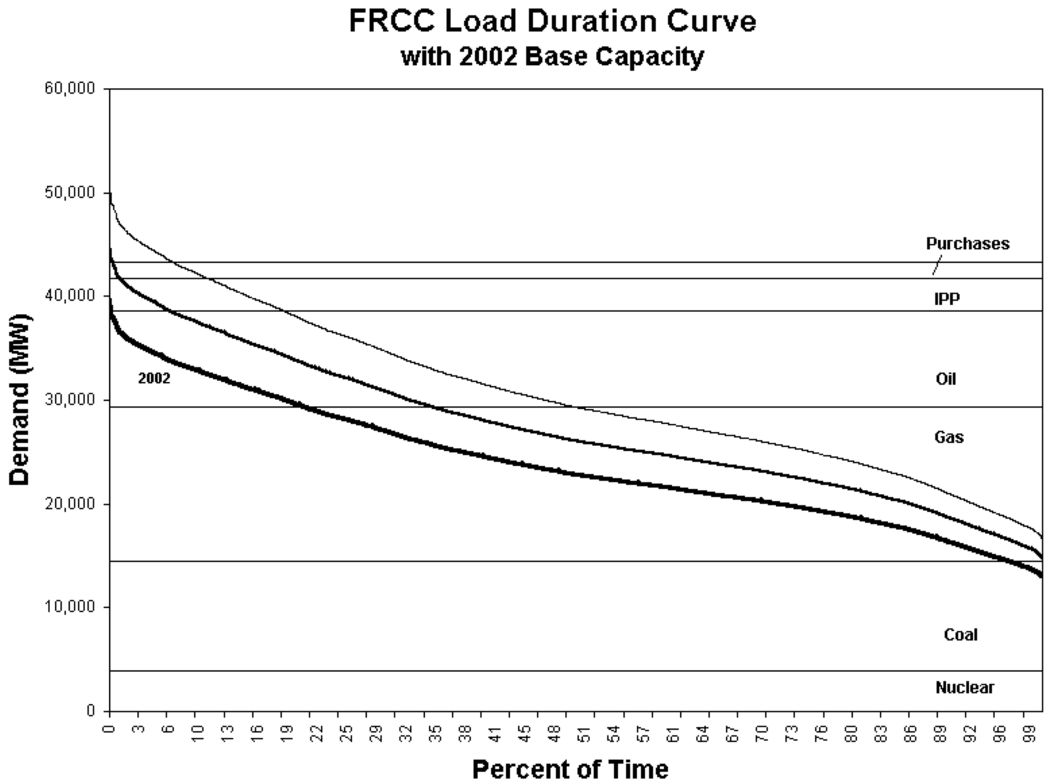
FUTURE POWER MARKETS

The answer to the key question “build or buy?” is strongly affected by the projected future conditions of the wholesale power market in the southern United Stated and Florida. Furthermore, any generation expansion program may result in some capacity being installed in advance of the need to optimize construction costs and possibly capture economies of scale. This excess capacity can be used to generate revenues through either purchased power agreements (PPA’s) or spot market transactions. The potential value of any excess capacity depends on the characteristics of the generation fleet and fuel costs of the market into which the power can be sold. The markets available to GRU are in Florida, and to a lesser degree, Alabama, Georgia, and South Carolina. The further away an area is the more economically disadvantaged power from Gainesville is, due to multiple (“pan-caked”) transmission wheeling charges and line losses. The FERC is currently engaged in forming Regional Transmission Organizations that will ameliorate pancaking charges, but the various proposals related to this have yet to come to fruition.

Figures E-1 and E-2 are a summary of the current and future market conditions in the Florida Reliability Coordinating Council (FRCC- peninsular Florida), and Southeast Electric Reliability Coordinating Council (SERC- southeast USA) regions for current (2002) and future (2012) conditions of generation mix. They were developed from load duration curves and generation plans submitted by all utilities as part of regulatory proceedings, both at FPSC and SERC. The projected load duration curve for a variety of projected years is given. Finally, horizontal bands are shown that represent the amount of capacity that uses each type of fuel, in the order of preferred dispatch. This reflects the planned amount of capacity in each region. Inspection of these graphs indicate that coal base capacity will be needed at least 96% of the time in 2003 and 100% of the time in 2012. It also indicates that excess (for sale) capacity available for PPA purchases under GRU's No-Build scenarios will be forthcoming mostly from gas-fired units.

More specifically, The graph in Figure E-1 show the level of demand for Florida versus the percentage of time that level of demand is imposed by Florida's consumers. Examining the lower right portion of each graph, the load duration curve intersects the amount of coal based capacity for only a very small percentage of time in the 2002 base capacity graph, and even less time in the 2012 capacity graph. This indicates that there is a market for low production cost (coal) capacity generation nearly all of the time.

FIGURE E-1
CURRENT (2002) AND FUTURE (2012) MARKET CONDITIONS IN THE FRCC



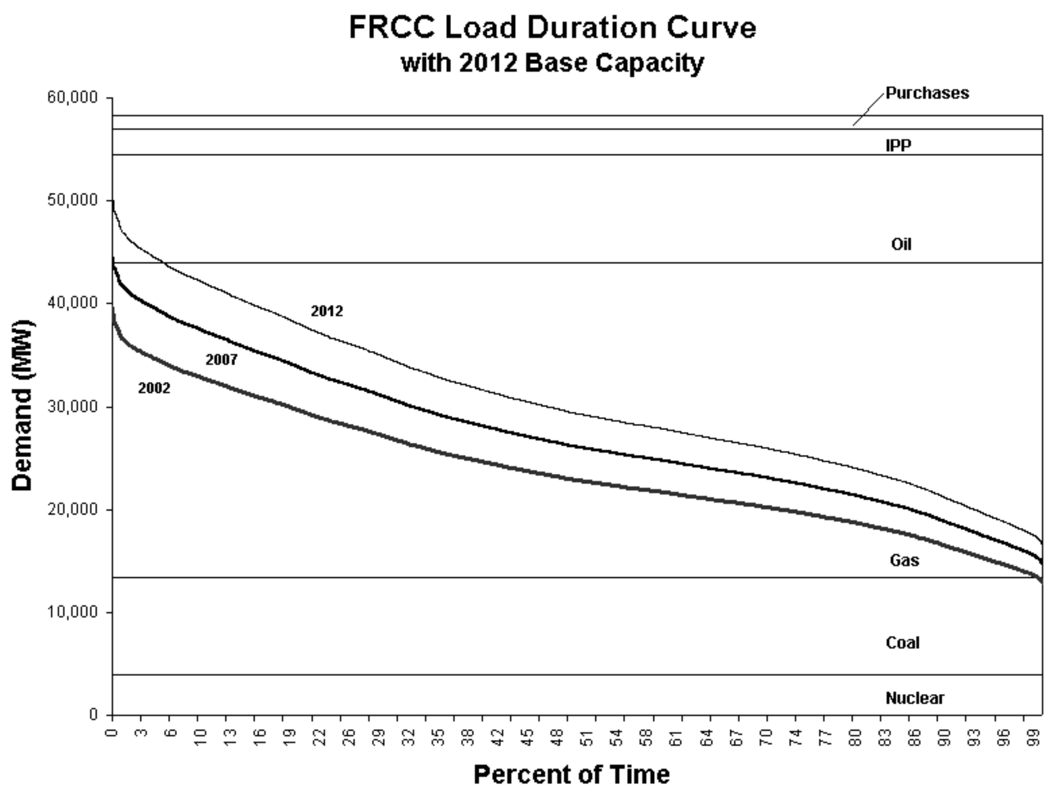
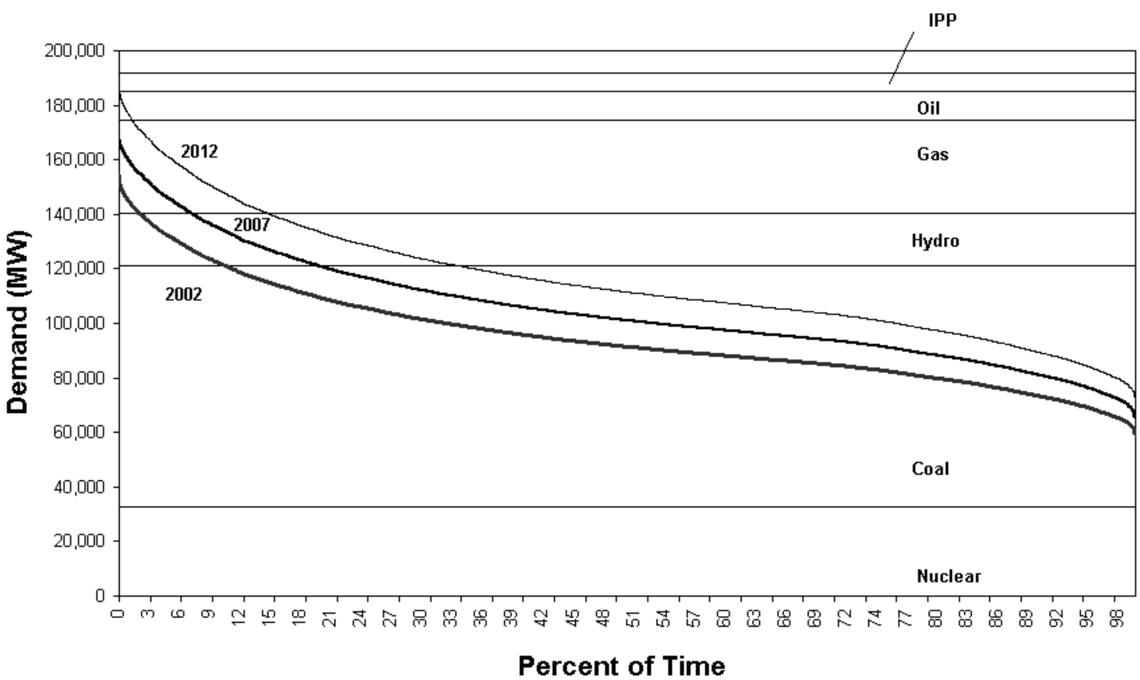


FIGURE E-2
CURRENT (2002) AND FUTURE (2012) MARKET CONDITIONS IN THE SERC

SERC Load Duration Curve
with 2012 Base Capacity



SERC Load Duration Curve
with 2002 Base Capacity

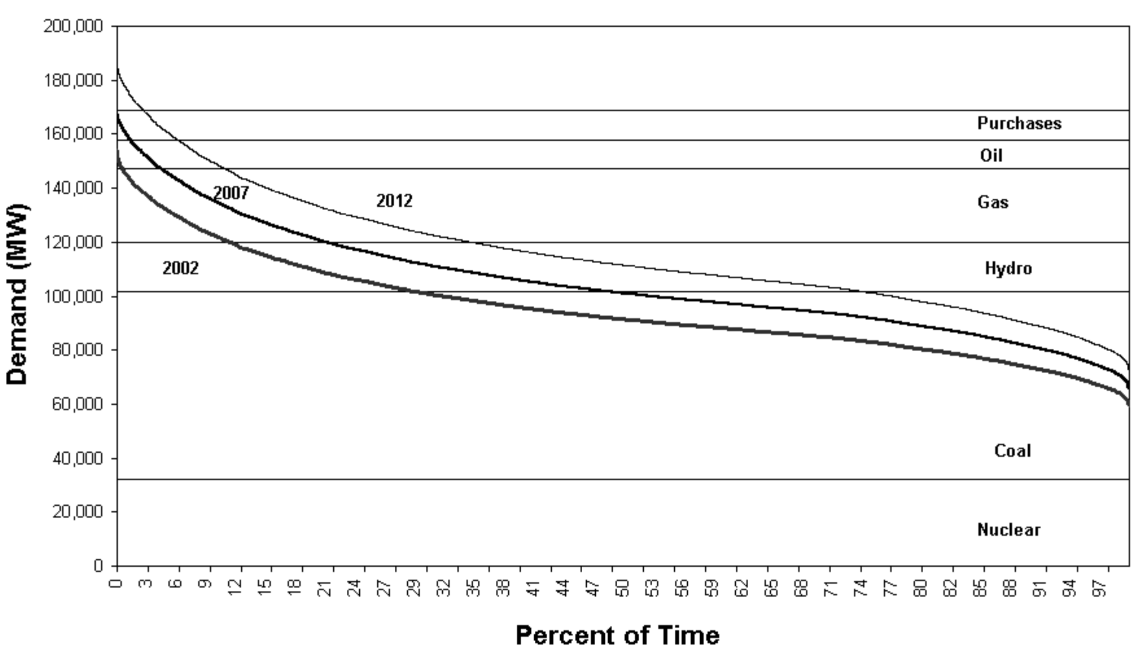


TABLE E-1

GRU CO_2 REDUCTIONS
(TONS/YEAR)

PROJECTED	TONS/YEAR
Landfill Gas to Energy Project*	420,000
Kelly CC1 Repowerin	117,000
Demand-Side Management	74,000
Forest Protection (10,000 acres)	32,000
Solar at the Airport (proposed)	16
Systems Control Center PV	12
Solar in Schools (proposed)	5

* Includes adjustment for methane pursuant to the Kyoto protocol

SECTION F
ENERGY CONSERVATION POTENTIAL

Energy conservation, or demand side management (DSM), plays a key role in meeting the energy and power resources needs of our community. Energy conservation programs already have delayed the need for future capacity additions and avoided the emissions that would be associated with the avoided generation. As a result, GRU has the lowest average residential electrical consumption per customer among utilities serving urban areas in Florida (see Figure F-1).

EXISTING CONSERVATION SERVICES

Table F-1 lists GRU's current residential and commercial energy conservation services and programs. Along with aggressive promotion of natural gas services, GRU is involved with the construction industry and is the only electric utility in Florida with solar water heating rebates. Past programs that have addressed high efficiency included air conditioning systems, high efficiency refrigerators, insulating water heaters, home insulation and a variety of other energy conservation measures that are no longer included in GRU's programs because of changing efficiency standards and market saturation. GRU also has promulgated customer information on a wide range of energy conservation topics, including weatherization, do-it-yourself energy audits, passive solar design, efficient construction techniques, and commercial equipment sizing and selection.

Most of GRU's programs are designed to encourage the implementation of energy conservation measures that meet the Rate Impact Measure (RIM) cost-effectiveness test. Programs that meet the RIM test for the electric system not only help participating customers, but also have a positive impact on utility rates, thereby helping all utility customers. Regardless of cost effectiveness, GRU is required to perform energy audits and is committed to providing site-specific customer assistance, as described here. GRU offers this assistance in response to customer needs and expectations, high bill complaints, and the need to hurdle the institutional barriers of conservation in the rental sector. GRU also promotes the use of natural gas appliances, which provide environmental benefits through high source energy efficiency and the clean nature of natural gas combustion. These customer service oriented programs generally are not cost-effective from the electric RIM perspective, but result in overall reduced use of fossil fuels and customer satisfaction.

Low-Income Household Energy Conservation/Community Services

Low-income customers spend a relatively high proportion of their income on utility services, but historically do not take advantage of opportunities to reap the benefits of energy conservation programs. GRU is working to provide better services to low-income households through synergistic relationships with community service providers such as the Central Florida Community Action Agency. GRU employees volunteer their labor to assist in weatherizing low-income households through the Florida Fix program. GRU is also assisting a community service provider in installing solar water heaters on low-income households under the Florida Department of Community Affairs sponsored Front Porch Sunshine effort. GRU's customers contribute more than $50,000 per year through Project SHARE by making voluntary contributions through their utility bills to assist customers in paying utility bills during times of need. The Salvation Army disburses these funds to those with the greatest needs on a one-time basis.

Payment -Troubled Customer Assistance Services

Up to 15% of GRU customers pay their bills late. Many of these customers appear on the pending cut-off list each and every month. Some call GRU on a daily basis to determine if their service is pending disconnection. These payment-troubled customers repeat a cycle of shuffling funds around payment deadlines to the detriment of themselves and their creditors. GRU provides assistance to payment troubled customers by providing consultation on energy efficiency and establishing a link between these customers and sources of assistance such as the Weatherization Assistance Program (WAP) and the Low-Income Community Assistance Program (LICAP). GRU has prepared booklets and videos on budgeting for utility costs and provides them free of charge to customers and the public library.

COST EFFECTIVENESS METHODOLOGY

The methodologies used in this IRP for evaluating the cost-effectiveness of energy conservation are widely used throughout the industry. For example, the information developed is typically required for cost recovery submittals by regulated utilities to their Public Utility Commissions. The methodology centers on three key concepts – how much does it cost to induce the conservation, how much generation resource and fuel consumption is avoided, and the distribution and type of benefits from a variety of perspectives. A complicating factor is that the value of the resources conserved depends on the time and season that the conservation occurs.

The values presented for energy conservation in this section are based upon an update of work initially done for GRU's 1995 Demand-Side Management Plan (References 29, 30,31,32,33,34). The value of energy conservation is based on avoiding the next planned generation unit addition and reduced fuel use. New values for avoided costs will be determined as a result of this IRP process when the type and capacity of the next generation unit addition is selected. These values can then be benchmarked against the existing values to determine how they affect the economics of the energy conservation programs that were identified in the update of GRU's energy conservation plan as "Potentially Cost-Effective" (Table F-9). The overall premise made in this Section is that the new values will be similar to those presented here.

Benefits and Costs of Conservation

Ascertaining the optimal level of resources to commit to conservation, or more appropriately, determining the value of demand-side management (DSM), requires careful consideration of relevant associated costs and benefits. Thus, the following discussion focuses on identifying the relevant impacts of energy conservation and how such impacts are manifested as either additional costs or benefits for utility customers.

Clearly, the consequence of successful energy conservation is a reduction, within some delineated time period, in energy consumption and peak demands on generation resources. The obvious and immediate impact of the reduction in energy consumption is a corresponding reduction of energy sales revenue. Reductions of both the revenue that GRU receives to cover variable costs (such as fuel that won't be used) and the revenue GRU receives to cover the fixed costs that GRU incurs (such as for distribution lines) will occur. Over short periods of time, GRU may not be able to reduce its fixed costs to a level comparable to the reduction in revenue. As a consequence, this short-term insufficiency in revenue available to cover fixed costs, caused by energy conservation, has to be made-up by all customers. Thus, this revenue insufficiency or "lost sales" revenue is one of the most prominent <u>costs</u> of energy conservation.

On the other hand, over longer time periods, GRU has some ability to adjust plant expansion and operations plans. As a result, less plant investment will be needed and fixed costs can be lowered in the future, in anticipation of energy savings generated by conservation implemented presently. Expected energy savings result in less fixed costs for GRU and this is the most prominent <u>benefit</u> of energy conservation.

Cost Effectiveness - Three Perspectives

Cost effective means simply that benefits exceed costs. Before attempting to quantify costs or benefits, it becomes important to distinguish where the impact of costs or benefits of energy conservation is borne. For example, lost revenues caused by energy conservation is a cost to all utility ratepayers. However, even though rates for all customers are increased, customers that adopt energy conservation actually will see a lower energy bill than they would have without energy conservation. If the "adopting" customer's energy reduction is substantial enough to exceed the billing impact caused by lost revenues, all ratepayers benefit. (This is generally the case when residential customers reduce on peak energy use, for example).

Regardless of the level of impact, the point of the example is that the burden of costs of DSM or the virtue of benefits from DSM depends on the perspective taken. There are three generally accepted perspectives from which to evaluate the costs and benefits of DSM. The three perspectives have given rise to three different, but methodologically consistent, tests for cost effectiveness. The differences in the tests stem from the specific costs and benefits that are considered in each test. The three tests are the:

1. Participant (PAR) Test;
2. Rate Impact (RIM) Test; and
3. Total Resource Cost (TRC) Test.

The PAR Test assesses the impact of DSM from the perspective of the "participating" or "adopting" customer. Consequently, the DSM benefit of most concern is that from savings that will occur in the energy bill. Other benefits may include: utility rebates that may be offered; tax credits that various taxing jurisdictions may offer; and, any other quantifiable benefits that accrue to the customer as a consequence of implementing DSM. Relevant participant costs include: equipment and/or material purchase and installation costs; operating and maintenance costs on any acquired equipment; and any other quantifiable costs that are incurred by the customer as a consequence of implementing an energy conservation measure.

The RIM Test is designed to measure the impact on the rates that GRU must charge to all customers resulting from DSM. Thus, the RIM Test assesses DSM from the perspectives commonly referred to as of both the utility and of "all ratepayers." The most important benefit of DSM from this perspective is avoiding plant expansion and operations costs. These "avoidable" costs include: avoided investment in generating units; avoided generating unit operations and maintenance costs; avoided fuel costs, net of fuel cost savings foregone as a consequence of not constructing a more efficient generating unit than utilized; transmission and distribution system costs; and, any other quantifiable benefits that accrue to GRU as a consequence of implementing DSM. When DSM results in a shifting of energy consumption, additional potential for benefit exists if there are revenue gains due to "off-peak" sales. Relevant utility costs include: lost sales revenues, explained previously; the cost of inducements or incentives the utility may have to offer; costs of overheads and program administration; and, any other quantifiable costs that are incurred by the utility as a consequence of implementing DSM.

Finally, the TRC Test is an overall general measure of cost effectiveness without specific regard as to where the respective impacts of costs and benefits lie. The TRC can be said to measure the cost effectiveness of DSM with regard to total resources retained within GRU's service area as a consequence of DSM. DSM is cost effective from this perspective if more resources, specifically financial resources, remain within the service area because of the DSM, regardless of how those extra resources are distributed among customers within the service area and regardless of how the costs for that DSM is allocated to customers within the service area. Consequently, the TRC Test considers many of the same costs and benefits listed previously. Specifically, benefits include: all of the avoided generation, transmission, distribution and fuel costs relevant to GRU and any other quantifiable benefits realized by the service area as a consequence of implementing DSM. Relevant costs of DSM include: all of the hardware costs relevant to the DSM participant; program costs relevant to GRU; and, any other quantifiable costs that are incurred by the service area population as a consequence of implementing DSM.

Methodology for Cost Effectiveness Tests - The DSM/FIRE Model

To facilitate analyses that gave consistent and valid treatment to all relevant parameters in the tests, an automated analytical computer model was employed for the analysis. The model utilized was the Florida Integrated Resource Evaluator (FIRE), originally developed to satisfy the Florida Public Service Commission's requirements. FIRE is a spread-sheet based computer program developed particularly to assist in determining the cost-effectiveness of demand-side programs in the reporting format that was specified by the Florida Public Service Commission (FPSC).

The FIRE model relies upon discounted cash-flow techniques, where money is adjusted for "time value," and upon reasonable assumptions about other relevant economic conditions. Some other very basic and imperative premises of the model are:

1. System load is increasing due to load growth. Therefore, reductions in load due to DSM will result in permanently reduced need for system expansion.

2. Finite load reductions, regardless of magnitude, can be directly related to reduced need for finite and equal amounts of system capacity expansion.

3. Decreases or increases in revenue due to DSM will impact rate levels and will be passed on to all customers.

FIRE computes cost effectiveness for a DSM measure by dividing its total benefits by its total costs from the perspective of each of the three tests described previously. As a result, the net value (or net cost) of DSM can be indicated for each perspective. This feature of the model and the fact that value of DSM is dependent upon the time at which it occurs, prompted application of the model in a manner that ascertained the value of a kW and the value of a kWh with regard to <u>when</u> the DSM occurs. This was accomplished by evaluating or "testing" unitized DSM programs that had savings of 1 kW and 1 kWh savings in each of the time periods of consequence (summer peak, winter peak, and off-peak).

FIRE MODEL DATA, ASSUMPTIONS AND RESULTS

Economic Assumptions

The economic assumptions used in the model are outlined in Table F-2. Since FIRE was used to determine generic values of energy conservation rather than evaluate specific DSM measures, utility program costs, customer hardware costs and tax credits were not relevant. However, the costs associated with production or avoided production were relevant and are summarized in the notes accompanying Table F-2.

Technical and Utility Rate Assumptions

Assumptions regarding load impact, in-service dates and facility lives are shown in Table F-2. Rate assumptions are presented in Table F-3 and were based upon current rates, less fuel cost recovered through fuel adjustment rates. Projected rate changes were based upon corporate model results developed for the FY 1995-2001 budgetary planning horizon.

Natural Gas System Impacts

Since GRU also owns and operates a natural gas distribution system, and potential energy savings are available through "fuel-switching" programs, the value of 1 therm of natural gas had to be considered parallel to the value of 1 kW and/or 1 kWh. Consequently, a simple procedure was developed to determine the value of natural gas from the three cost effectiveness perspectives. This procedure considered the current cost of 1 therm of natural gas over the next twenty years. As shown in Table F-5, a fuel-switching program would result in the consumption of that 1 therm (compared with none previously). The cost of the therm, $0.617/therm in 1995, is a cost borne entirely by the participating customer. Accordingly, the utility (GRU) receives $0.617 sales revenue for this therm, of which it pays $0.328 to its natural gas supplier for the gas GRU sold. Thus, the value of that 1 therm sale is a benefit of $0.289 for GRU, a cost of $0.617 to the participant, and a cost of $0.328 to the GRU service area since that amount is not retained within the service area. Table F-5 shows the annual values of 1 therm over the study period and their cumulative present values for each of the three cost effectiveness perspectives.

Time Sensitivity Cases, 1995 and 2002 DSM Implementations

The base case FIRE model has a twenty-year study horizon and evaluates DSM assuming 1995 implementation. Because it was recognized that "value-of-deferral" methodology employed by the model discounts, somewhat, the value of DSM when the DSM occurs far in advance of the in-service date of the avoided unit, it was decided that DSM also should be evaluated wherein DSM implementation could be designed to occur closer to the in-service date of the avoided unit. For this iteration, the model was run with an assumption of DSM implementation in 2002, two years before the in-service date of the avoided unit. These results will be presented, along with the base case results, later in this chapter.

FIRE Results

The results of the two cases mentioned above, along with results from all the runs of FIRE conducted as part of this study, are summarized in Table F-6. A more complete treatment of GRU's cost-effectiveness methodology can be found in a volume titled "The Value Of Conservation For Gainesville Regional Utilities, Attachment A To Docket No. 930553 Before The Florida Public Service Commission, Cost-Effectiveness Goals Results Report", submitted to the FPSC on December 23, 1994 (Reference 30).

ENERGY CONSERVATION MEASURES CONSIDERED

GRU evaluated a wide variety of energy conservation measures (ECM) for cost effectiveness in residential and commercial market segments (Reference 33). The residential ECM list presented in Table F-7 and commercial ECM list presented in Table F-8 contains both the energy conservation measures the Florida Public Service Commission requires regulated utilities to evaluate for cost-effectiveness potential and additional ECMs deemed appropriate by GRU.

POTENTIALLY COST-EFFECTIVE PROGRAMS

Additional programs to capture all of the cost-effective energy conservation potential in our service area have been identified. Table F-9 summarizes the targeted end-use of these potentially cost-effective programs, and Table F-10 summarizes the potential impacts of these programs by 2010. These will result in 1.8 MW more summer peak demand reduction than already has been included in GRU's forecast of load and energy. The value and timing of these programs depends upon the type of generation unit chosen in this Integrated Resource Planning Process. The evaluation presented here needs to be updated pending the outcome of this IRP, which will strongly affect the value of avoided capacity.

One of the potentially cost-effective programs listed in Table F-9 is "Demand Response". Demand Response uses day-ahead or real time prices as incentive to induce energy conservation and power demand reductions. A Demand Response program provides either a standard offer to the private sector to reduce the demand for energy in the community during peak demand periods, or a day-ahead or real time price signal. There have been examples of successful, dispatchable peak demand reduction programs based on Internet communication protocols. There are enabling technologies, called energy management control systems, already present in large commercial buildings capable of prioritizing and shedding non-essential loads when the price is right.

A Demand Response program could provide business opportunities and create jobs in the community to install control equipment, monitor energy use and power demand, actuate the control sequence and verify energy use and power demand reductions. This program has the potential to create opportunities to the private sector to work with the utility in demand-side management and energy conservation.

COMPARISON WITH OTHER UTILITIES

An independent study was commissioned to compare GRU's energy conservation goals with those of the investor-owned and municipal utilities of Florida required to file plans with the Florida Public Service Commission (Reference 18). The comparison assumed that GRU would include the additional programs identified in Tables F-9 and F-10. The study identified each of the cost-effective DSM programs offered by the Florida IOU's and categorized these programs into similar equipment and customer target areas and evaluated and compared the cost-effectiveness of these similar programs as they are conducted by the Florida IOU's. The second goal of this project was to evaluate the impact of meeting each of the IOU's projected 2005 Summer Peak load, Winter Peak load, and the annual GWh produced.

The DSM Program documents for each of the utilities included in the study were examined. The cost-effective Residential and Commercial DSM Programs were identified and the relevant utility parameters that affected the determination of the cost-effectiveness of these programs were listed for future analysis. Table F-11 presents the most common conservation programs being implemented in Florida. Table F-12 compares GRU's plan as a percentage of demand reduction with the other utilities in the study. GRU's percentage reduction of load and energy from DSM is in the midpoint of the range seen for other Florida electric utilities.

Out of the list in Table F-11 above, GRU does not offer a Commercial HVAC Efficiency program, a Residential Load Management program, a Residential New Construction program, a Residential Window Film program, a Commercial Lighting program with cash incentives, or a Commercial Motors program. Residential load management (Direct Load Control – see Section L) has been studied in detail as part of this IRP and not found to be cost-effective for GRU's system unless it can be implemented for $1.00/kW-month, which is several times less than the cost experienced by other utilities. This different result is due to GRU's unique summer peak load profile. Most Florida utilities have peaks in the winter, which are infrequent and have short duration.

FIGURE F-1

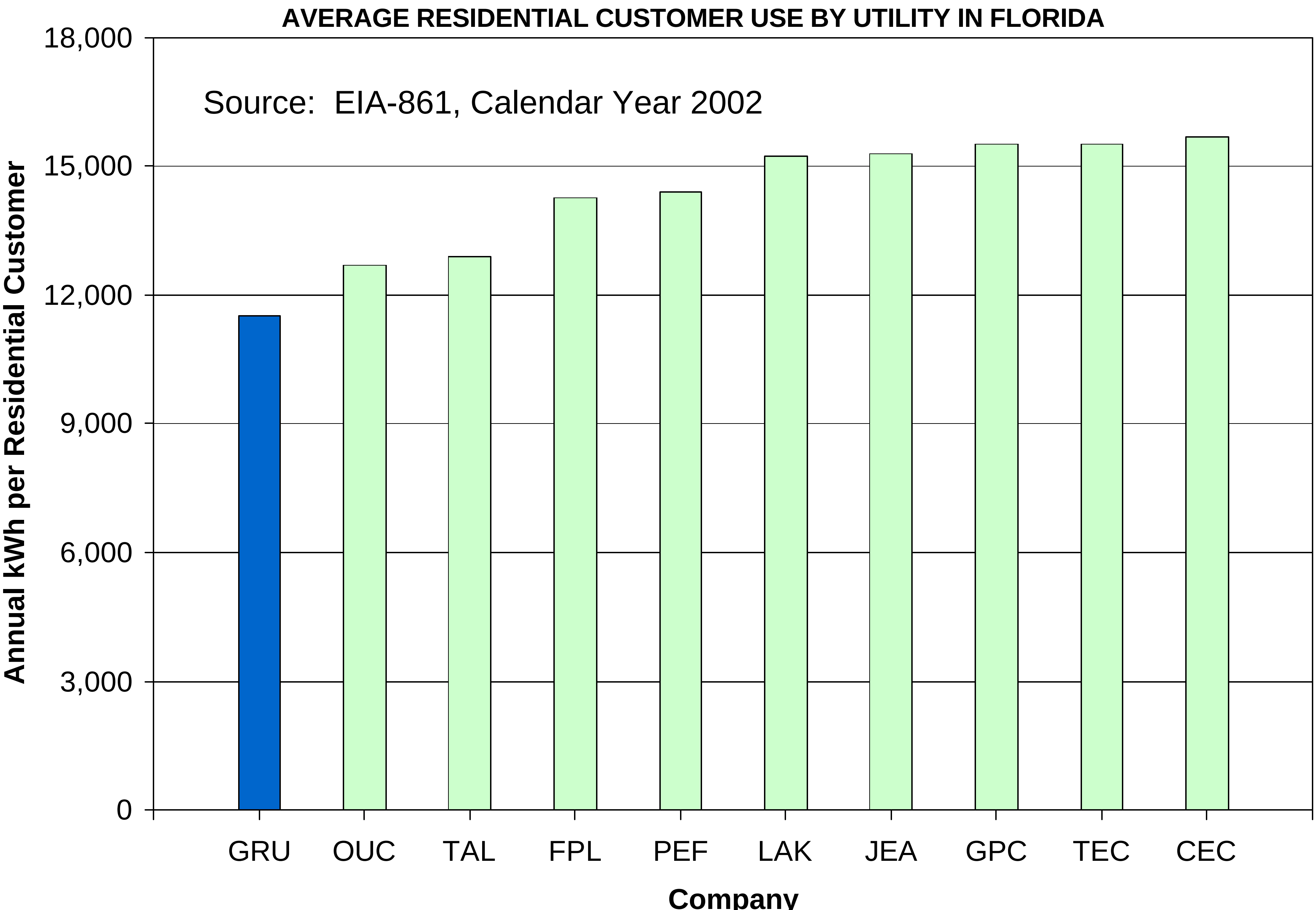

AVERAGE RESIDENTIAL CUSTOMER USE BY UTILITY IN FLORIDA
Source: EIA-861, Calendar Year 2002
Annual kWh per Residential Customer
18,000
15,000
12,000
9,000
6,000
3,000
0
GRU
OUC
TAL
FPL
PEF
LAK
JEA
GPC
TEC
CEC
Company

TABLE F-1

CURRENT ENERGY CONSERVATION PROGRAMS

RESIDENTIAL	COMMERCIAL
Conservation Surveys	Conservation Surveys
Self-Audit Materials	Commercial Lighting Service
New Construction Consultation	Solar Water Heating Rebates
Green Building Program	Solar Electric Interconnection and Buyback
Customer Consultation	Gas Air Conditioning Rebate
Low-Income Weatherization	Gas Dehumidification Rebate
Solar Water Heating Rebates	Gas Water Heating Rebate
Solar Electric Interconnection and Buyback	
Gas Water Heating Rebate	
Gas Heating Rebate	
Gas Range Rebate	
Gas Dryer Rebate	
Gas New Construction Rebate	

TABLE F-2

ECONOMIC ASSUMPTIONS

ECONOMIC PARAMETER	ASSUMED VALUE
Utility Program Costs	na
Customer Hardware Costs	na
Customer Tax Credit	na
Avoided T&D Facilities Costs	$104.94/kW
Avoided Transmission O&M Costs	$0.93/kW/Year
Avoided Distribution O&M Costs	$5.22/kW/Year
Avoided Generating Unit Costs	$1,452.00/kW
Avoided Generator Fixed Costs	$5.52/kW/Year
Avoided Generator Variable Costs	$0.00490/kWh
Avoided Generator Fuel Cost (1994)	$0.01864/kWh
Avoided Fuel Cost Escalation Rate	3.90%/Year
Inflation Rate for All Other Parameters	4.00%/Year
Utility Cost of Capital	8.75%

a. Avoided Transmission and Distribution Facilities Cost - Developed from the average investment in T&D facilities installed, over three-year period (FY 1991-93) that could have been avoided if conservation equaled load growth.
b. Avoided Transmission O & M Costs - Developed by dividing FY 1993 Transmission O&M costs of approximately $607,000, by estimated Transmission capacity of 650 MW.
c. Avoided Distribution O&M Costs - Estimated to be 5% of T&D Facilities cost.
d. Avoided Generating Unit Cost - Estimated 1995 cost of constructing pulverized coal generating unit provided by Stone & Webster from data compiled by the Electric Power Research Institute (EPRI).
e. Avoided Generator Fixed and Variable Operating Costs - Estimated unit operating costs provided by Stone & Webster from data compiled by the EPRI.
f. Avoided Generator Fuel Costs - Based upon delivered coal costs in 1995 being comparably priced to coal delivered under current GRU terms and conditions.
g. Avoided Fuel Cost Escalation Rate - Based upon FY 1995 GRU Fuel Price Forecast.
h. Inflation Rate - Assumed inflation rate for GRU's long and short term planning.
i. Utility Cost of Capital - Weighted average cost of funds available to GRU. Based upon 70% debt funded at 6.5% annual interest and 30% equity (customer/owner contributed) at 14.0% annual cost.

TABLE F-3

TECHNICAL ASSUMPTIONS

TECHNICAL ELEMENT	ASSUMED VALUE
Load Reduction at Meter	1 kW, 1 MWh[1]
Participating Customers	1,000[2]
Line Loss Percentage	6.00%
Line Loss Multiplier	1.0042
Generator Life	40 Years
T&D Life	40 Years
Base Year of Study	1995
In-Service Year of T&D	1995
In-Service Year of Generator	2004

1. kW evaluated to assess demand (facility) impacts over the respective time periods while kWh evaluated energy impacts over the time periods.
2. Impact of 1,000 participating customers evaluated to overcome problems of rounding and scale.

TABLE F-4

UTILITY ELECTRIC RATE ASSUMPTIONS

RATE COMPONENT	ASSUMED VALUE
NON-DEMAND BILLED CUSTOMERS	
Non-Fuel Energy Cost in Bill	$ 0.050/kWh
Demand Charge in Bill	0
DEMAND-BILLED CUSTOMERS	
Non-Fuel Energy Cost in Bill	$ 0.030/kWh
Demand Charge in Bill	$ 4.900/kW

TABLE F-5

PRESENT WORTH OF 1 THERM OF NATURAL GAS

Year	Participant Cost ($/Th)	Value to GRU Custs Cost ($/Th)	Cost to Community Cost ($/Th)
1995	($0.617)	$0.289	($0.328)
1996	(0.642)	0.301	(0.341)
1997	(0.667)	0.313	(0.354)
1998	(0.694)	0.326	(0.369)
1999	(0.722)	0.339	(0.383)
2000	(0.751)	0.352	(0.399)
2001	(0.781)	0.366	(0.415)
2002	(0.812)	0.381	(0.431)
2003	(0.845)	0.396	(0.448)
2004	(0.878)	0.412	(0.466)
2005	(0.913)	0.428	(0.485)
2006	(0.950)	0.446	(0.504)
2007	(0.988)	0.463	(0.525)
2008	(1.028)	0.482	(0.546)
2009	(1.069)	0.501	(0.567)
2010	(1.111)	0.521	(0.590)
2011	(1.156)	0.542	(0.614)
2012	(1.202)	0.564	(0.638)
2013	(1.250)	0.586	(0.664)
2014	(1.300)	0.610	(0.690)
Present Value	(7.674)	3.599	(4.075)

TABLE F-6
FIRE MODEL RESULTS
(NPV $ 1995)

ITEM	1995 INSTALLATION NonDemand	1995 INSTALLATION Demand	2002 INSTALLATION NonDemand	2002 INSTALLATION Demand
PARTICIPANT PERSPECTIVE				
1 kW Summer ($/kW)	$0.000	$655.000	$0.000	$323.000
1 kWh Summer ($/kWh per year)	0.855	0.633	0.432	0.323
1 kWh Winter ($/kWh per year)	0.855	0.633	0.432	0.323
1 kWh Off-Peak ($/kWh per year)	0.855	0.633	0.432	0.323
TRC PERSPECTIVE				
1 kW Summer ($/kW)	$801.00	$801.00	$801.00	$801.00
1 kWh Summer ($/kWh per year)	0.470	0.470	0.251	0.251
1 kWh Winter ($/kWh per year)	0.282	0.282	0.142	0.142
1 kWh Off-Peak ($/kWh per year)	0.279	0.279	0.147	0.147
RIM PERSPECTIVE				
1 kW Summer ($/kW)	$801.00	$146.00	$801.00	$478.00
1 kWh Summer ($/kWh per year)	-0.385	-0.163	-0.181	-0.072
1 kWh Winter ($/kWh per year)	-0.573	-0.351	-0.290	-0.181
1 kWh Off-Peak ($/kWh per year)	-0.576	-0.354	-0.285	-0.176

TABLE F-7
RESIDENTIAL ENERGY CONSERVATION MEASURES

HIGH EFF. AIR SOURCE HEAT PUMP	GROUND SOURCE HEAT PUMP
TWO SPEED HEAT PUMP	REDUCE DUCT LEAKAGE ELEC.HEAT
REDUCE DUCT LEAKAGE HEAT PUMP	SETBACK/PRGRAM THERM ELEC HT
SETBACK/PROGRAM. THERMOST HP	DLC FOR ELECTRIC HEAT
DLC FOR ELECTRIC HEAT PUMP	GAS FURNACE
CEILING INSULATION (R-0 TO R-19)	CEILING INSULATION (R-11 TO R-30)
CEILING INSULATION (R-19 TO R-30)	CEILING INSULATION (R-30 TO R-38)
WALL INSULATION (R-0 TO R-11)	WTHERSTRIP/CAULK(BLOW DOOR)
WINDOW FILM/REFLECTIVE GLASS	LOW EMISSIVITY GLASS
SHADE SCREENS	REFLECTIVE ROOF COATINGS
ATTIC RADIANT BARRIERS	HIGH EFFICIENCY CENTRAL AC
TWO SPEED CENTRAL AC	WHOLE HOUSE FANS ELEC. HEAT
WHOLE HOUSE FANS HEAT PUMP	HIGH EFFICIENCY ROOM AC
AC/HEAT PUMP MAINTENANCE ELEC. HEAT	AC/HEAT PUMP MAINTENANCE
DLC of CENTRAL AC ELEC. HEAT	DLC of CENTRAL AC HEAT PUMP
LANDSCAPE SHADING ELEC. HEAT	CEILING FANS ELEC. HEAT
GAS AIR CONDITIONING	HIGH EFF. ELECTRIC WATER HEATER
INTEGRAL HEAT PUMP WATER HEATER	ADD-ON HEAT PUMP WATER HEATER
SOLAR WATER HEATER	HEAT RECOVERY WATER HEATER
WATER HEATER TANK WRAP	WATER HEATER PIPE INSULATION
HEAT TRAP	LOW FLOW SHOWERHEAD
DLC of ELECTRIC WATER HEATER	GAS WATER HEATER
COMPACT FLOURESCENT	EFFICIENT INCANDESCENT
HIGH PRESSURE SODIUM (OUTDOOR)	MOTION DETECTORS
LOW PRESSURE SODIUM FLOODLIGHT	BEST CURRENT REFRIG. FF
BEST CURRENT REFRIG. MANUAL	REMOVE SECOND REFRIGERATOR
BEST CURRENT FREEZER FROST FREEZER	BEST CURRENT FREEZER MANUAL
REMOVE SECOND FREEZER	HIGH EFFICIENCY CLOTHES DRYER
HIGH EFFICIENCY CLOTHES WASHER	HIGH EFFICIENCY POOL PUMPS
DOWN-SIZED POOL PUMPS W/OVERSIZED PIPING	DLC of POOL PUMPS

TABLE F-8

COMMERCIAL ENERGY CONSERVATION MEASURES

INSTALL HE CHILLER	INSTALL HE CHILLER
INSTALL HE CHILLER & ASD	RPL LE DX W/HE DX
RPL LE RM AC W/HE RM AC	INSTALL COOL STORAGE
HEAT PIPE ENHANCED DX	HOTEL OCCUPANCY SENSORS
2-SPEED MOTOR - COOLING TOWER	SPEED CONTROL - COOLING TOWER
AC MAINTENANCE – CHILLER	AC MAINTENANCE - DX
AIR DUCT/WATER PIPE INSUL – CHILLER	AIR DUCT/WATER PIPE INSUL - DX
ENRG MGT SYSTEM – CHILLER	ENRG MGT SYSTEM - DX
TEMP SETUP/SETBACK – CHILLER	TEMP SETUP/SETBACK - DX
REP ER HEAT W/ GAS HEAT	GAS-FIRED COOLING
INC ROOF INSULATION	ADD WIND FILM
LIGHT ROOF	DUCT LEAKAGE REPAIR - DX AC
VAV W/INLET V – CHILLER	VAV W/INLET V - DX AC
ASD CON W/VAV – CHILLER	ASD CON W/VAV - DX AC
TIME/PROG CON – CHILLER	TIME/PROG CON - DX AC
HE VN MOTORS – CHILLER	HE VN MOTORS - DX AC
MAKEUP AIR/EX – CHILLER	MAKEUP AIR/EX - DX AC
4'-34W FL W/ HYBRID BAL #1	4'-34W FL W/ HYBRID BAL #2
4'-34W FL W/ ELECTRONIC BAL #1	4'-34W FL W/ ELECTRONIC BAL #2
8'-60W FL W/ELEC BALLAST #1	8'-60W FL W/ELEC BALLAST #2
T8 LAMPS/ELEC BALLAST #1	T8 LAMPS/ELEC BALLAST #2
REF/DE-L FL: 4'-40W, ELEC B	REF/DE-L FL: 4'-34&40W, ELEC B
REF/DE-L FL: 8'-75W, ELEC B	REF/DE-L FL: 8'-60W, ELEC B
REF/DE-L FL: 4'-34&40W, HYBRID B #1	REF/DE-L FL: 4'-34&40W, HYBRID B #2
REF/DE-L FL: 4'-34&40W, ELEC B #1	REF/DE-L FL: 4'-34&40W, ELEC B #2
REF/DE-L FL: 8'-60W, ELEC BAL #1	REF/DE-L FL: 8'-60W, ELEC BAL #2
4'-34W FL/DIMMING BALLASTS #1	4'-34W FL/DIMMING BALLASTS #2
HPS (70/100/150/250W)	HPS (70/100/150/250W), ELEC BAL
HPS (35W)	METAL HALIDE (32W)
COMPACT FL (15/18/27W)	TWO COMPACT FL LAMPS (18W)
ENERGY MANAGEMENT SYSTEM	OCCUPANCY SENSORS
DAYLIGHTING DESIGN	PHOTOELECTRIC CONTROL
LPS SECURITY LIGHTS	MULTIPLEX: AIR COOL
MULTIPLEX: AIR COOL/ AMB SUBC	MULTIPLEX: AIR COOL/ MECH SUBC
MULTIPLEX: AIR COOL/ AMB&MECH SUBC	MULTIPLEX: AIR CO/EXT LIQ SUCT HX
OPEN-DRIVE REFRIG (ASD)	ANTI-CONDENS HEAT CONTROL
HI R-VALUE GLASS DOORS	ENERGY MANAGEMENT SYSTEM
DUAL PATH SUPERMARKET AC	HEAT PUMP WATER HEATER
SOLAR WATER HEATER	HEAT RECOVERY WATER HEATER
DHW HEATER INSULATION	DHW HEAT TRAP
LO FLO/VARI FLO SHOWERHEAD	DHW CIRCULATION PUMP
GAS WATER HEATER	CONVECTION OVENS
ENERGY EFFICIENT ELEC FRYERS	GAS COOKING

TABLE F-9
ADDITIONAL POTENTIALLY COST-EFFECTIVE DEMAND SIDE MANAGEMENT PROGRAMS

Low-Income Solar Water Heater Assistance	Under Development
Duct Leakage Repair	Potentially Cost-Effective
Demand Response	Potentially Cost-Effective
High Efficiency Central AC Rebates	Potentially Cost-Effective
High Efficiency Room AC Rebates	Potentially Cost-Effective
Heat Recovery Unit Rebates	Potentially Cost-Effective
Duct Leakage Repair Rebates	Potentially Cost-Effective
Central AC Maintenance Rebates	Potentially Cost-Effective
Heat Pipe Enhanced AC Rebates	Potentially Cost-Effective
Mobile Home Reflective Roof Coating Rebates	Potentially Cost-Effective
Thermal Energy Storage System Rebate	Potentially Cost-Effective

TABLE F-10

ENERGY CONSERVATION PROGRAM IMPACTS

Program Impacts to Date	Impact
Summer	14 MW
Winter	34 MW
Energy	70,000 MWh/yr
Projected Additional Impacts by 2010	
Summer	5.4 MW
Winter	2.4 MW
Energy	10,500 MWh/yr

Note that GRU's current forecast only includes 3.6 MW of additional summer peak demand reduction. These programs are listed in the Program Status section as potentially feasible should achieve the additional 1.8 MW of summer peak Capacity.

TABLE F-11
COMMON PROGRAMS OR COMPONENTS

Program Name	Number of Utilities Offering Program
Residential Duct Test and Repair	5
Commercial Custom Incentives	5
R&D and Special Projects	5
Commercial HVAC Efficiency	4
Commercial Lighting	4*
Residential HVAC Efficiency	3
Residential Load Management	3
Residential New Construction	3
Residential Window Film	3
Commercial Curtailable or Interruptible Rate	3
Commercial Motors	3
Commercial Thermal Storage	3
Commercial Window Film	3

* GRU does not offer direct cash incentives for Commercial Lighting Improvements. However, GRU does provide a service that is similar to a Shared Savings Contractor, so that the facility does not have to come up with any funding to implement the approved lighting measures.

TABLE F-12

2005 DSM GOAL PERCENTAGES FOR FLORIDA IOU'S AND MUNICIPALS

	Summer Peak Percentage	Winter Peak Percentage	GWh Reduction Percentage
FPC			
Residential	NA	NA	0.27%
Commercial	NA	NA	0.03%
Total	1.13%	2.70%	0.30%
FPL			
Residential	NA	NA	0.53%
Commercial	NA	NA	0.22%
Total	2.36%	1.67%	0.75%
GULF			
Residential	NA	NA	0.85%
Commercial	NA	NA	0.12%
Total	6.94%	7.36%	0.97%
TECO			
Residential	NA	NA	0.27%
Commercial	NA	NA	0.38%
Total	1.21%	1.86%	0.66%
JEA			
Residential	0	0	0
Commercial	0	0	0
Total	0	0	0
OUC			
Residential	0	0	0
Commercial	0	0	0
Total	0	0	0
GRU			
Residential	NA	NA	0.64%
Commercial	NA	NA	0.03%
Total	1.71%	0.97%	0.66%

Source: Capehart, B.L., (October 31 2003) "The Potential for Cost-Effective DSM Programs: An Evaluation of the Cost-Effective DSM Programs of the IOU's in Florida"

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SECTION G
DEMAND RESPONSE PROGRAMS

One solution for reducing the need for generation capacity for any utility is to consider incentives for customers to reduce demand when the supply is limited or the cost is high. Encouraging customers to consider and behave according to the time-value of electricity can take many forms, from real time and day ahead prices to rate design. Collectively, this is known as Demand Response. 75 percent of the total demand response resource is “simply turning things off” (Reference 24). This section will summarize the review of Demand Response programs that was performed as part of this IRP. Potential candidates for future GRU rate designs and implementation also are discussed.

Many participants in the Community Outreach workshops made suggestions for reducing electrical use during peak demand that fell into the Demand Response category. Comments from the workshops included such suggestion as:

- Demand reduction should be considered as an alternative
- Re-price time-of-use rates to focus more on peak times
- Offer interruptible service to residents
- GRU should develop a program of interaction with other agencies to reduce their demand
- Implement mandatory participation (i.e. mandatory time of use rates)

A complete list of citizen comments pertaining to Demand Response Programs can be found in Appendix A.

BACKGROUND

Demand Response Programs depend on customer behavior to interrupt or shed load in order to balance the supply and demand for electricity. Demand response is customer behavior that results from a signal (usually price) that impacts the load, or demand. Demand Response Programs can take a wide variety of formats. This section will discuss the role of price in determining consumer behavior.

Complications with such programs include providing the adequate technology to cause and measure the demand response. Sufficient customer education and the ability to communicate with the customer to encourage behavior modification are crucial to the success of Demand Response programs.

THE ROLE OF PRICING IN CONSUMER BEHAVIOR

There are several key factors encouraging utilities to adopt demand response programs. The most obvious are system reliability and efficiency, cost avoidance, risk management, and customer satisfaction (earning credit to off-set utility bills). Environmental concerns and the potential that demand response programs can reduce burdens placed on the air, land and water from electricity generation also are important determinants.

Technological Advances

The emergence of demand response programs is the first step toward empowering customers to make wise decisions about their energy use and to make investments that reduce their levels of consumption. However, in order to take advantage of these programs, technologies must be developed and deployed that allow customers to receive accurate price signals that form the basis of decisions to reduce or shift consumption to off-peak periods. The vast majority of customers are neither aware that wholesale energy prices vary based on time of day, nor do they have any financial incentive to shift usage to times of lower cost. The success of demand response initiatives depends upon the implementation of a cost-effective system that can send signals to customers, confirm curtailment activities, or directly control loads or generation at customer sites. Internet technologies have emerged as a successful tool for these applications (Reference 24).

Demand response programs include rates and programs that reflect real time or day ahead pricing tariffs, emergency load curtailment, voluntary demand response, demand bidding, and direct load control. Customers who can respond quickly to high prices or shift their consumption to lower-price periods can reduce their electricity bills. Typical real-time programs across the U. S. include customers with several MWs of demand, of which GRU has only a few. Customers that participate in emergency load curtailment programs must reduce their consumption in response to directions from the provider. In exchange for reductions, customers receive discounted electricity rates or are paid directly for the reductions.

Voluntary demand response programs also pay customers to reduce their load upon request by system operators, but the customer does not have a contractual obligation to curtail demand. Demand bidding programs let the customers set their own reservation bids for a specified level of load curtailment. If customer bids are at or below market clearing prices in the whole market, the customer must reduce demand by this amount and then receive payment for the reductions. Verification that demand reductions occurred are an essential part of the program. Direct load control programs remotely cycle off customer appliances, such as air conditions, water heaters, and pool pumps during times of high peak demand. The demand response alternatives considered for further review and application for GRU are shown in the Table G-1 below.

Barriers to Program Implementation

Technology

Metering costs are a burden to the design of rates. Rate designs that require additional information will require technology upgrades in metering. Residential rate designs are more sensitive to meter costs due to the relative cost of the unit compared with potential savings. New technology costs would be required to be passed on to the customer potentially through the customer charge based on GRU's current practices.

The primary costs of participating in demand response programs are the need to install interval meters, communications, and software to monitor and access customer loads on a near real-time basis. In the GRU system large customers already have advanced meters installed that can be used to participate in the programs. Constant two-way communication through the Internet, cell phones or radio signals will be needed feed price information to the consumer.

Penalties and Perception

Customers are wary of risk from participation in demand response programs. These risks include potential for lost business during curtailment, risk of crucial system loss, unavailability of backup generation, unknown cost of participation, or risks incurring financial penalties. Customers are risk-averse and concerned about exposing themselves to price volatility. Currently, the majority of customers do not experience the time-varying costs of their consumption decisions. Consequently, the have no incentive to modify use decisions in ways that would enhance system reliability, provide them with income, or improve the efficiency of the markets in which electricity is traded.

There is a notable shift in customer interest between voluntary programs and programs that contain penalty provisions. Customers are understandably less interested in the price responsive programs that contain penalties.

Customer Awareness and Education

Another barrier to the implementation of demand response programs is customer education. Demand response programs cannot be successful if customers do not understand the value of demand response. The majority of customers currently do no directly experience or understand the time-varying costs of their consumption decisions and so have no incentive to modify these decisions. Consumers that understand variations in price will respond by either increasing or decreasing consumption. However, few utilities provide access have the advanced metering and enabling technologies needed to take advantage of real time prices. When education and program explanations are provided customers frequently continue to prefer predictable, and even higher fixed price options over variable prices.

Participation and Implementation

Monitoring prices and actively participating in demand response programs, particularly market-based programs, takes time and effort, in addition to corporate commitment and oversight. This type of participation is daunting for the customer and utility provider and there can be a strong reluctance to move into unknown or uncertain business areas.

There are valid concerns about the administrative costs of participating in demand response programs, particularly dynamic pricing programs, such as real-time pricing. Utility companies too small to hire staff or procure services to monitor wholesale market price fluctuations and to participate actively in real time markets or demand response programs have found that the time and effort exceeds the benefits of participation. Consultants and other advisors may be needed to help manage the process. The cost of this assistance may make participation cost prohibitive.

DEMAND RESPONSE PROGRAM ALTERNATIVES

The demand response alternatives that were considered as part of this IRP are show in Table G-1, together with the advantages and disadvantages of each. The selection of alternatives was developed to incorporate a broad variety of options.

POTENTIALLY FEASIBLE RATE DESIGN ALTERNATIVES

Each option from Table G-1 was evaluated for applicability for the customer base and the utility. Six categories for evaluation were utilized, as shown in Table G-2. The consideration of whether the program was equitable to all customers and understandable was rated. If a program was likely to benefit those that would have otherwise participated, known as free riders, it was rated lower. Similarly if a program was considered too complicated for customers to easily use, it also was given a low rating. The degree of difficulty to implement the rate or pricing was evaluated, as well as the cost on implementation. Those options with high costs of implementation were rated lower than those with lower costs. Technology and the availability to the Gainesville market, as well as an estimate of participating customer satisfaction, were evaluated.

Each of the six categories was ranked on a scale of 0 to 3 with 3 being the most advantageous. Each category (equitable, understandable, ease of implementation, cost of implementation, available technology and participating customer satisfaction) was rated equally. Pricing and rate designs fell into two distinct groups for total matrix score; those that scored 10 and below; and, those that scored above 10. The exception to this is the Green Pricing option that meets the criteria based on the components of the alternative evaluation matrix G-2. Further discussion of Green Pricing is not included in this section because it is already being offered to customers.

The Conservation Contribution rate is the lowest ranked rate, with a score of 10. This rate is not considered further at this time. The concern with this rate was the potential distraction from, and confusion with, the newly established Green Pricing. Similarly, without specific conservation programs identified for funding with this source it may not be attractive to customers.

The alternatives that were selected for further review scored 12 or above on Table G-2. These include optional time of use rates, demand response programs, block or tiered rate evaluation, and prepaid meters.

The four options that are to be considered further for further rate design analyses are:

- Time of Use Rates
- Demand Response
- Block or Tiered Rate
- Prepaid meters

Time of Use

GRU's voluntary Time-of-Use rate has been offered since the early 1980s. It is under-utilized and the rate is not an attractive option for residential customers in its current form. There is no Time-of-Use rate for non-residential customers. The existing Time-of-Use rate has the following design:

Peak periods include:
Summer

May 15 through October 15, 12:00 noon through 9:00 p.m., weekends and holidays included

Winter

January 1 through February 28, 7:00 a.m. through 11:00 a.m., and 6:00 p.m. through 10:00 p.m., weekends and January 1 are excluded.

Off-peak periods include:

All periods not included in peak periods

Because of the high cost of time-of-use meters, the customer pays the standard customer charge of $4.66 plus an additional charge of $3.20 per month. The Residential Time-of-Use rate could be modified to increase attractiveness to customers. Revisions such as a shorter peak period with a lower differential between the peak and non-peak rates would be more attractive. The current rate will be reviewed and compared with industry standards. A Commercial Time-of-Use Rate could be analyzed to be implemented in conjunction with other Commercial Programs. The number of Non-residential customers that would benefit from this rate, and the potential system benefits, and the applicability of this program, will be determined.

Demand Response (Incentives)

These programs are designed to interrupt customer power supply by the utility. This type of control involves customers who own equipment that can be turned off or cycled off during peak demand periods and is especially useful in the summer months on air conditions, water heaters, and pool pumps. This rate type is best suited for Non-residential accounts in the GRU system. When deemed desirable, the customer cycles or shuts-off appliances or equipment units for a limited number of hours on a limited number of occasions. It does not require complex technology or a commitment to dedicated energy management control equipment. The only technologically sophisticated aspect of Demand Response is the verification that customer demand reductions indeed occurred.

This program could use GRU’s current MV90 metering at 15-minute intervals. Customers could be provided incentives that are paid through monthly credits on their utility bills. These incentives would be determined by GRU and based on several factors including the type of equipment being used, the average amount of load reduction net, the degree of control given to the utility by the customer, and the value of the load reduction to the utility. Customer credits could be granted either exclusively during the load control season or all year as a reminder of the customer’s value to the utility. Non-response after a “strike price” is reached would have to incur a penalty. There are a number of business entities that could act as an entrepreneur between GRU and the end-use customer, such as energy management control service companies.

Tiered/Block Rates

GRU currently has a tiered system for both residential and non-residential customers. Any modification of the current rate requires the assumption that either the increase in price per kWh at the threshold (750 for residential and 1,500 for non-residential) is not sufficient to impact demand, or that the thresholds for the tier are inappropriately placed. The residential tier was amended in 2002 and these items were given detailed consideration. The following discussion defines potential for future review of this rate type. However, in light of limited data since the last restructuring of the rate, it is not possible to determine definitively what the impacts of the 2002 changes have been.

Three options have potential for further analyses. These options are include increasing the residential threshold; making the difference between the two rates more extreme by lowering the lower rate and increasing the upper rate; and adding another tier.

Options

1. Modify the residential tier to be the average residential use (1,000 kWh)
   If sufficient education and customer awareness were provided, this modification would send a price signal that would modify behavior that is above mean consumption.

2. Increase the second tier rate
   In conjunction with decreasing the lower tier, this design would encourage maintenance of consumption below the threshold rate. The second tier rate would have to be sufficiently higher than the first to impact behavior. If sufficient education and customer awareness were provided, this modification would send a price signal that would modify behavior that exceeds the threshold.

3. Add another tier in the rate structure
   This option would act to further modify use at higher levels. This alternative is not recommended at this time pending the opportunity to evaluate the results of the rate design changes made in 2002.

Prepaid Meters

Meters that must be paid in advance of service are available. It is recommended that a demonstration project be designed and implemented to illustrate the potential advantages. Prepaid meters allow the customers to evaluate usage on an immediate basis.

TABLE G-1
DEMAND RESPONSE PROGRAM ALTERNATIVES

TYPE	ADVANTAGES	DISADVANTAGES
Creative Rates and Pricing		
Peak shaving	Could be contracted for to reduce peak consumption, payment for shedding only	No net energy savings, unpopular with customers, needs to be audited, monitored and verified
Time of use rates	Already set up. Could incent reduction of peak.	More expensive metering. Not used by customers, billing issues. Need incentives or change structure
Real time pricing (Example - Gulf Power)	Awareness needed, may reduce peak use. More successful for commercial customers	Premature, More successful for commercial customers. High capital cost for implementation (metering and automated control)
Demand response – uses MV90 metering at 15 minute intervals	Energy Management Control Systems could prioritize load shedding. Potentially 50 MW in commercial accounts through Energy Management Control Systems. Customer determines response. Need to set a strike price and pay for response only, or penalty for non-response.	Availability of technology. Limited for residential.
Interruptible load (true)—also, paying for shed load as opposed to credit regardless of interruption (which is controlled by the utility) (Unsolicited Proposal received)	Certain commercial customers would be suitable for interruptible loads, potentially if paired with ATTENGEN!	Need to be able to actually interrupt. Unpopular because customer does not control. Difficulty to administer. Customer education necessary
Coincidental demand (Example - JEA) Also known as peak sharing. Sum demand of use at all locations	Potential to reduce peak use. Customer satisfier. Superimpose on load shape.	Need advanced metering. Does not necessarily benefit utility.

TABLE G-1 (Continued)
DEMAND RESPONSE PROGRAM ALTERNATIVES

TYPE	ADVANTAGES	DISADVANTAGES
Aggregate billing (Example - JEA)	Groups General Service Demand together to qualify for Large Power discounts. Potential for Energy Component of Rate	Physical requirements. Takes more facilities (such as transformers) to serve multiple sites
Coincident peak billing - demand rate based on coincidence with GRU peak (seasonal, daily, hourly)	Less infrastructure necessary than real time pricing. Suitable for commercial, offices, intermittent users such as churches, schools.	Not reasonable for Residential. Metering costs from $30 to $200, requires customer involvement and feedback
Green pricing (generation technologies, negawatts)	Offers pricing to those who want to participate without penalizing others. Optional program	Increased cost for participants, optional
Conservation Incentive Rate	Offers pricing to those who want to participate and contribute without penalizing others. Optional program. Provides funds for conservation programs that would not otherwise be offered	Increased cost for participates, optional
Increased rates	Provides incentive for behavior modification. Funds societal costs	Not popular with Community
Block/Tier rates (Currently break at 750 kWh, and 1.500 for General Service Demand)	Possible incentives. Could be based on mean usage	Complicated, needs analysis for justification. May not result in behavior modification. This rate structure was amended in 2002
Prepaid meters	Direct illustration of impacts of behavior. Provides direct feedback to customer	Cost of technology, possible customer inconvenience

Further investigation warranted

TABLE G-1 (Continued)
DEMAND RESPONSE PROGRAM ALTERNATIVES

TYPE	ADVANTAGES	DISADVANTAGES
Redesign of Customer charge	Enables “rewards” to customers with multiple services. May encourage customers to procure other GRU services. Could be designed to be less regressive for low consumers.	Some customers outside electric territory, others do not have other services (water, wastewater, gas, GRUCOM)
Unified rate (one demand/one energy charge for all demand metered customers)	Equitable, easy to administer, would require rebates to ensure fairness (could be combined with Coincident peak Demand rate)	Community acceptance, Fair share, penalizes intermittent users (churches, schools). Considered in 2002
End Uses – Commercial		
HVAC (Using Energy Management Control Systems)	Advantageous for commercial accounts. This approach has more impact per commercial customer. Dynamic Scheduling of HVAC use using Energy Management Control Systems	Not currently suitable for residential applications
Process control	As customers with demand suitable for this type of system are added, process control will be researched and offered	Limited Application, due to customer types. Perhaps only Metal Container Corporation. Potentially unpopular with customers.
Motors, Air Compressors (mostly for HVAC and water pumping)	Incentives for motor efficiency would be mostly for water pumping and HVAC	This would reduce energy use, but not necessarily impact the peak
Lighting	Commercial users would have greater impact on this program	More suited for Commercial Lighting

Further investigation warranted

TABLE G-1 (Continued)
DEMAND RESPONSE PROGRAM ALTERNATIVES

TYPE	ADVANTAGES	DISADVANTAGES
Refrigeration efficiency incentives	Could reduce use, but load is not necessarily coincidental with peak.	Customer dissatisfier. Most customers who would utilize this program (supermarkets) already have programmatic controls. For residential viable only if old unit is surrendered.
Cool roofs (To replace flat roof construction with felt, gravel and tar)	Many opportunities due to prevalence of this type of construction and vintage of roofs. Install a single ply membrane, foam of polymers	Capital intensive
Thermal energy storage	Reduced peak but maintains the use	Need a large demand rate and current rates do not provide an incentive for this.
End Uses – Residential		
Solar - Thermal (Residential 40% use is for cooling and 25% for water heating) – Existing Program	Clean, available, cost effective, renewable, and environmentally popular.	42% of single-family homes within the GRU service area have insufficient amounts of sunlight for solar use. Freezing. Intermittent sunlight, Capital Costs, impact of trees
Air Conditioning	Good potential for peak efficiency and sizing	Potential for Free Riders, regulation and permitting
Water heating (only 10% of current use is for water heating)	Potential for heat recovery from AC units,	Current gas penetration is good, Price of Gas, may reduce electric system and overall utility revenues.

Further investigation warranted

TABLE G-1 (Continued)
DEMAND RESPONSE PROGRAM ALTERNATIVES

TYPE	ADVANTAGES	DISADVANTAGES
Roofs-metal	Long-lasting depending upon construction type. Must have absorptivity, reflectivity and emissivity. Potential for mobile homes	Expensive, quality control
Wood burning stoves	Charming, back-up heat source	Particulates. Low efficiency
Solar - Electric	Renewable, cost will decline in future	Capital costs, 35 cents a kWh
Distributed technologies		
Smart house/home automation		
Co-gen (heat, electricity)-fuel cells, ICE, micro turbines	Useful for absorption cooling air conditioning (which is not readily available in Florida). Future potential. Fuel cells have zero emissions	Not as efficient as centralized generation, more emissions, fuel cells need fossil fuels. Better in cold climates
Sterling (heat) engines	Uses any source of heat	Inefficient. Expensive
Plasma	Future Potential	Future Technology. Not commercially viable
Wind power (use of green pricing)	Renewable technology. Can be purchased. Potential to sell energy and get green tags	Not feasible in Florida
Avoidance Technologies		
Rebates: appliances, chillers	Incent market penetration of load reducing technology	Free riders
Duct Repair and Air Conditioner Maintenance and Sizing	Incent repair and maintenance to reduce load. Provide education	Free riders

Further investigation warranted

TABLE G-1 (Continued)
DEMAND RESPONSE PROGRAM ALTERNATIVES

TYPE	ADVANTAGES	DISADVANTAGES
Roofs-metal	Long-lasting depending upon construction type. Must have absorptivity, reflectivity and emissivity. Potential for mobile homes	Expensive, quality control
Offer end-use services (financing),	Provide education	Market available. Many not be part of GRU core mission
Performance contracting	Already have a program in commercial lighting. Customer satisfier	Many not be part of GRU core business, liability, licensing of contractors
Windows (50% of all heat gain in through windows)	Incentives for spectrally selective low emissivity coatings, High performance glass	Effective but expensive
Insulation (Gainesville area has the highest penetration of Energy Star homes per capita)	Potential for education. Successful with new construction	Retrofitting existing structures more difficult
Distributed generation	Decentralization	Not energy efficient
Back-up generation	Already provided - ATTENGEN! program	
Net metering	Already provided for PV. Future potential with an industry-wide standard	Only addresses inverter controlled technology
Energy ratings	Education potential	
Three phase conversion	Very few areas remain	Market (cost of appliances) already provided incentive for residential
Solar water heating	Already provide incentives	
Occupancy sensors	Customer satisfier	Expensive
Educational programs including: Community education workshops, videos, cds, Web sites, downloads	GRU already committed to education. Additional Potential	Not all customers feel this is useful.
Appliance maintenance programs		Free riders, Many not be part of GRU core business, liability, licensing of contractors

Further investigation warranted

TABLE G-1 (Continued)
DEMAND RESPONSE PROGRAM ALTERNATIVES

TYPE	ADVANTAGES	DISADVANTAGES
Energy Audits	Already provided, could be expanded	No incentive for customer to follow recommendations.
Ceiling fans	Customer education potential	Free riders. May not be part of GRU core business.
Peak shaving w/ customer generation		

Further investigation warranted

TABLE G-2

ALTERNATIVES EVALUATION

TYPE	Equitable	Understandable	Ease of Implementation	Cost of Implementation	Available Technology	Participating Customer Satisfaction	Total Score
Peak shaving	1	2	0	1	1	0	5
Time of use rates (optional)	3	2	1	1	3	2	12
Real time pricing	3	1	0	0	1	1	6
Demand response	3	2	2	2	2	2	13
Interruptible load	2	1	1	1	3	0	8
Coincidental demand	3	1	1	1	2	1	9
Aggregate billing	0	2	1	2	2	3	10
Coincident peak billing	0	2	1	2	2	3	10
Green pricing (optional)	3	3	1	2	3	2	14
Conservation Incentive Rate	3	1	0	2	2	2	10
Increased rates	2	1	0	2	3	0	8
Block/Tier rates	2	2	2	2	3	1	12
Prepaid meters	3	3	1	2	2	2	13
Redesign of Customer charge	2	1	2	2	3	0	10
Unified rate	2	0	0	0	3	2	7

Rated on a scale of 0 to 3, with 3 being the most advantageous

Further investigation warranted

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SECTION H
FUEL AND ENERGY RESOURCES

This section presents key information on fuel and energy resources used in the IRP. These resources include conventional fuels such as coal, petroleum coke, natural gas, oil and uranium (for nuclear reactors), and renewable forms of energy such as solar, biomass, wind, tidal, oceanic, and geothermal energy. The information items addressed include the sources and relative abundance of each fuel type, the susceptibility of each type to supply interruption and the ability to store fuel, which can mitigate supply interruptions. Finally, the history of GRU's delivered fuel price, forecasting methodology, and resulting forecasts are presented.

THE RELATIVE ABUNDANCE AND RELIABILITY OF FUELS

One way to measure the relative domestic abundance of a fuel is to compare the U. S. rate of use to the level of proven reserves. An indicator of a fuel's potential for extended interruptions is the ability to transport and store it. Table H-1 summarizes these factors for fossil fuels as compared with nuclear and renewable sources of energy.

The years of reserve shown in Table H-1 for each fuel type were calculated from data in the U. S. Department of Energy's Energy Information Administration's Annual Energy Outlook 2002, based upon current U. S. consumption for all end uses, and proven reserve levels. Therefore, the fuel use for transportation, chemicals, manufacturing etc. are included in addition to fuel use for generating electricity. Experts tend to disagree on these figures because reserve levels are based on existing levels of geological knowledge, production cost, and production methods. Despite this range of opinion, the results clearly highlight a number of major long-term planning issues and concerns.

Oil

Oil provides 52% of the fossil energy consumed in the U. S. More than half of it (53%) is imported, and this percentage is increasing. As shown in Table H-1, existing U. S. oil reserves are capable of supporting an additional 16 years of consumption at current rates before reserves are depleted. This illustrates that oil is in relatively short supply. Typically, oil is transported from the well head to the point of consumption via truck, railroad, barge, or ship. Oil consuming generators, in general, have an on site storage capacity of 20 to 30 days. Domestic supplies of oil have many modes of transport to Deerhaven, and the biggest risk of supply interruption is due to international disputes.

Natural Gas

Natural gas (methane) provides 25% of the fossil energy consumed in the U. S. A substantial portion (18%) is imported, predominately from Canada, with the bulk of the remaining imports being transported as liquified natural gas (LNG). The percentage of natural gas being imported is growing due to of increased demands and the apparent leveling out of production capability in the U. S. Demands for natural gas have increased substantially in the U. S. due in part to the large amount of gas-fired electric generation constructed in the U. S. in the past decade, at the expense of fuel diversity.

LNG is produced from methane gas through a cryogenic process, which transforms the gas into a liquid. Then it is shipped from overseas in special refrigerated ships, then re-gasified and distributed through existing natural gas pipelines. Ironically, huge quantities of natural gas are being flared off in South America, Africa and the middle east, as an unwanted by-product of oil production. A number of investors are making big investments in LNG production and shipping capacity to capture this opportunity, but the systems required are expensive and have lengthy development requirements.

As shown in Table H-1, there remains about a half century of domestic reserves of natural gas at current rates of consumption. It is generally accepted that the recent pronounced price volatility for natural gas is a result of supply and demand imbalances that are strongly affected by weather (gas is a common heating fuel) and the price of substitution fuels (see Figure H-3). Future technological advances in the transportation and storage of LNG could impact future reserve levels. However, this could be associated with higher costs.

Currently, there is no natural gas production or substantial storage capacity in Florida. As a result, peninsular Florida relies on just two major supply pipelines, only one of which serves Gainesville. Natural gas supplies are therefore more subject to interruption of supplies due to transportation.

Coal

Coal provides 23% of the total fossil energy consumed in the U. S. The U. S. is currently a net exporter of coal. As shown in Table H-1, coal is vastly more abundant than other forms of fossil fuel. Coal is transported to Florida by rail and barge, and substantial quantities can be stored on site. If need be, it can be moved by front end loaders and trucks. Coal transportation and supply are sensitive to rail and mine strikes, but historically stockpiles have been sufficient to overcome such occurrences.

Nuclear

Nuclear energy provides about 20% of the electricity used in the U. S. Uranium provides a somewhat moderate reserve base of about half a century at current rates of production of fuel grade material. A substantial amount of the uranium produced in the U. S. is shipped overseas. Theoretically, breeder reactors could theoretically provide nuclear fuel indefinitely. Uranium can be inventoried adequately to manage most supply disruptions. Building a new nuclear generator within the U. S., at present, is considered very problematic.

Renewable Energy

A comprehensive study on renewable energy resources in Florida was performed by the Florida Public Service Commission (FPSC) and the Florida Department of Environmental Protection and published in January, 2003 (Reference 28). The report is titled "An Assessment of Renewable Electric Generating Technologies for Florida" and is available on the Internet at the following Web site address:

www.psc.state.fl.us/industry/electric_gas/Renewable_Energy_Assessment.pdf

Solar and biomass are the most abundant and cost effective forms of renewable energy in north central Florida. Florida is otherwise relatively poor in indigenous renewable energy resources. Wind, wave, ocean thermal and tidal energy are generally low and diffuse and widely accepted as being not cost effective to harness here. Geothermal energy, as is used in some areas to make steam, is not available in Florida either, although water-to-air and ground coupled heat pumps are using a very low grade form of geothermal energy to make the consumption of electricity more efficient.

Solar

The solar flux in Florida is actually less than in other parts of the country due to moisture in the atmosphere (humidity and cloud cover). The desert regions of the U. S. have about 30% more available solar energy than Florida. Cloud cover in Florida also limits the feasibility of using concentrating solar collectors. The nature of solar energy is well understood and technologies that use it will be discussed in later sections in more detail, particularly photovoltaic solar conversion, flat plate collectors for solar water heating, and concentrating collectors.

Biomass

GRU commissioned a study of the potential availability of biomass for utilization at the Deerhaven site (Reference 23). The study addressed the potential for the harvest of waste wood as well as the potential for developing crops specifically for energy production. The study addressed a 25-mile radius around the Deerhaven site and specifically excluded collected yard waste and any other sources that might include treated lumber. Table H-2 summarizes the results of the assessment of waste wood potential. Approximately half the estimated quantities are from within Alachua County. The materials should be available year round, with some effects of weather on the activities that produce these by-products. The study estimated a delivered cost of $13 to $22 per ton. If half of the estimated volumes of waste wood can be harvested cost-effectively, about 30 MW of electric generating capacity could be supported.

The biomass study revealed a surprising amount of local investment in maulers, tub grinders, and even blowers to accelerate in-field combustion. Most of the waste wood fuel resource is currently unused, although some is used for boiler fuel. The study also recommended that should GRU elect a biomass option, GRU should accept for purchase only suitably ground and dried material, leaving it to the private sector to harvest, collect, sort, grind, dry, store and deliver the final product. The study also pointed out that the ash from combusting wood is a very valuable soil amendment, with a market value of $50 to $60 per ton at the plant.

If the waste wood sources identified in Table H-1 cannot be sustained due to slowed development or changes in silviculture, energy crops represent back-up potential. Energy crops are grouped into two categories: herbaceous and woody. Both types have been grown experimentally for many years in this region by the University of Florida Agronomy Department and the School of Forest Resources and Conservation. The yields below in Table H-2 are expressed as dry matter per acre per year.

Hydrogen

A few participants at the IRP public outreach meetings asked GRU to consider hydrogen as a potential form of clean, renewable energy, particularly suited for combustion and fuel cells. Hydrogen is not a source of energy such as coal, gas, oil, the sun or the wind. However, it can be used as an energy carrier, like gasoline or electricity, to deliver energy to an end use. Hydrogen could be a clean fuel for combustion engines because the only by-products of hydrogen combustion are heat, water vapor and a small quantity of nitrogen oxides. It is rarely found in nature in the molecular form (as H_2); instead it is incorporated into other chemical compounds and requires a large input of energy from another source to free it from these compounds.

The two most common methods of producing hydrogen are steam reformation of fossil fuels and electrolysis of water. The majority of hydrogen used in industrial processes and as fuel is produced through steam reformation of natural gas or coal. The hydrogen used in the space shuttle booster rockets is derived from steam reformation of natural gas. The cost of steam reformed hydrogen is about three times the cost of the natural gas used to produce it. Electrolysis of water is an inefficient process and requires energy expenditure approximately ten times the energy embodied in the resulting fuel. Other methods of producing hydrogen include sunlight, plasma and microorganisms cultured under particular conditions. These methods are not commercially viable at this time due to expense or lack of commercially available processes.

The cost effectiveness of hydrogen as an energy carrier in distributed generation will depend on the development and commercial availability of enabling technologies, such as fuel cells, and the ability to use the waste heat from these energy conversion technologies to drive other processes (e.g. absorption cooling, dehumidification, etc.). Hydrogen manufacture takes more energy than using the hydrogen can produce (no net energy). Accordingly, hydrogen technologies were not considered as part of this IRP.

FUEL PRICE FORECAST METHODOLOGY

Base Case

Forecast prices for each type of fossil fuel analyzed by GRU generally were developed in two parts. Short-term monthly forecasts extending through 2005 were developed in-house by GRU's Fuels Department staff using a variety of information sources. Long-term fuel price forecasts were developed based upon forecasts of the U.S. Department of Energy's Energy Information Administration (EIA) as published in the Annual Energy Outlook 2003 (AEO2003)(Reference 26). In essence, the end-point of the GRU short-term forecasts became the starting point for the long-term forecasts. The AEO2003 price forecasts are provided in "real dollars" (inflation adjusted) and for purposes of GRU's forecasts, were converted to "nominal dollars" using the gross domestic product chain-type price index from AEO2003. All forecast results presented here are expressed in terms of nominal dollars. Fossil fuel transportation costs were forecast separately from fuel commodity costs for rail and gas pipeline supply to Deerhaven.

Forecast fuel commodity costs and transportation costs were summed to develop forecast delivered fuel costs. The price forecast developed for each fuel type is discussed below. Figure H-1 compares the history and base case forecast for each fuel type.

Coal

Coal is the primary fuel used by GRU to generate electricity, historically comprising nearly 70% of total net generation. To meet environmental requirements, GRU has purchased a low sulfur, high Btu eastern coal for use at its Deerhaven site. GRU's reliance on this premium coal limits the number of potential suppliers. During 2003, GRU purchased most of its required coal under relatively long term contracts (as opposed to spot markets). A revised coal procurement plan (developed in late 2002 and early 2003) resulted in reduced contracted coal purchases for 2004 for approximately 60% of GRU's requirements. Renegotiated contracts with existing suppliers also resulted in lower prices in exchange for extended contract terms. GRU will purchase the remainder of its coal requirements on the spot market and seek to identify new suppliers of lower cost coal.

This IRP required forecasts for three types of coal: low sulfur (1.2%) compliance coal, which is presently used by the System; fluidized bed combustion coal (CFB); a high sulfur (2%) coal, and petroleum coke (4%-6% sulfur).

GRU's delivered price for coal involves a commodity component and a freight (rail transportation) component. The short-term forecast price of compliance coal was based on GRU's contractual options with its coal suppliers. The long-term forecast price of compliance coal was developed using growth rates for U.S. average mine mouth prices from the AEO2003 forecast applied to the end-point of the short-term forecast. Base line prices for high sulfur coal and petroleum coke were estimated by utilizing a combination of acknowledged transactions and confidential state of the trade discussions with buyers and sellers of coal as reported in Coal Week. These short-term projections for high sulfur coal and petroleum coke were extended using the same growth rates that were used for compliance coal. Projected prices from the AEO2003 for Low Mining Cost and High Mining Cost were used to develop growth rates for the low band and high band coal price forecasts, respectively.

GRU's long term contract with CSXT sets pricing for delivery of coal through 2019. The short-term forecast of the cost to transport coal, in dollars per ton, was based on actual rates from the pertinent coal supply districts for aluminum cars and four-hour loading facilities based on known contractual provisions. The long-term forecast of transportation rates was developed by applying the long term Rail Cost Adjustment Factor indices, adjusted and unadjusted, to the short term forecast. The indices were based on forecasts supplied by Fieldston, a coal transportation consulting company.

Based on the above factors, the delivered price for compliance coal delivered to GRU is expected to increase at an average annual rate of 1.6% from 2003 through 2022. Prices for high sulfur coal and petroleum coke are expected to increase at rates of 1.8% per year and 1.9% per year, respectively, from 2003 through 2012.

Natural Gas

GRU procures natural gas for power generation and for retail distribution through its gas system. In 2002, GRU purchased approximately 7.6 million MMBtu for use by both systems. GRU power plants used 73% of the total purchased for GRU during 2002, while the distribution system used the remaining 27%. The volatility and price of natural gas are of deep concern to GRU. For example, in the past five years, the delivered price of natural gas has increased from $2.00/mmBtu to $5.00/mmBtu, equal to an escalation rate of about 10.7% per year.

GRU purchases natural gas via arrangements with producers and marketers connected with the Florida Gas Transmission (FGT) interstate pipeline. The commodity portion of GRU's delivered cost of gas is known as the weighted average cost of gas (WACOG). GRU also incurs transportation costs from FGT for a fuel charge, a transportation (usage) charge and a reservation (capacity) charge. These transportation costs, when added to the WACOG, yield GRU's delivered cost of natural gas.

GRU considered four sources of short-term projections for developing its forecasted WACOG: NYMEX trading prices, the EIA Short-Term Energy Outlook, Infinite Consulting, Inc., and Cambridge Energy Research Associates (CERA). The CERA forecast was deemed to best match GRU's expectation of the short-term natural gas market through 2005. Commodity costs were escalated after that using escalators for average lower 48 wellhead prices from the AEO2003. Note that natural gas has a very pronounced seasonal cost cycle, which is modeled for purposes of simulating hourly generation dispatch. This level of detail is not shown here.

<u>Oil</u>

GRU does not have access to waterborne deliveries of oil and there are no pipelines in this area. Consequently, GRU relies on "spot," or as needed, purchases from nearby vendors. The cost for purchasing and then trucking relatively insignificant quantities of oil to GRU's generating sites usually makes oil an expensive and less favored fuel for GRU. Short-term commodity price projections for No. 6 (residual oil) were based on New York Mercantile Exchange crude oil futures prices. An historical relationship between crude oil prices and residual oil prices was applied to the crude oil futures to determine projected residual oil prices. Additional cost components for freight and vendor profit were added to the commodity prices to derive the delivered residual oil price forecast. Short-term commodity price projections for No. 2 (distillate oil) were based on NYMEX diesel fuel futures prices. Additional cost components for pollution tax, freight, and vendor profit were added to the commodity price projections to derive the delivered distillate oil price forecast. Projected prices from the AEO2003 for Low World Oil Price and High World Oil Price for Electric Power were used to develop growth rates for the low and high band oil price forecasts, respectively.

During calendar year 2002, No. 2 oil was used to produce 0.16% of GRU's total net generation. The compound average annual growth rate for the price of distillate oil delivered to GRU is projected to be approximately 2.3% per year from 2003 through 2022, while the actual volume of oil used is expected to be low.

During calendar year 2002, No. 6 oil was used to produce 2.46% of GRU's total net generation. The compound average annual growth rate for the price of residual oil delivered to GRU is projected to be approximately 1.9% per year from 2003 through 2022, while the volume of oil used is expected to be low.

Nuclear Fuel

GRU's nuclear fuel price forecast includes a component for fuel and a component for fuel disposal. The projection for the price of the fuel component is based on Florida Power Corporation's (FPC) forecast of nuclear fuel prices. The projection for the cost of fuel disposal is based on a trend analysis of actual costs to GRU. The price of nuclear fuel is projected to increase approximately 2.3% per year from 2003 through 2022. No low band or high band forecasts were developed for nuclear fuel.

HIGH AND LOW PRICE CASES

The IRP process employed by GRU requires that various plans and scenarios be tested under extreme fuel price scenarios. Projected price growth rates from the AEO2003 for Slow Technology Progress (high prices) and Rapid Technology Progress (low prices) were used to develop banded forecasts for coal and oil. This methodology is particularly sensitive to the starting price of the forecast series, but is appropriate especially for relatively non-volatile price trends. The growth rates for low, base and high bands were applied to the various price projections for 2004 to forecast future prices. No banded forecasts were developed for nuclear fuel.

The extreme volatility of natural gas necessitated additional modeling of the first year of the natural gas forecast series. Low band and high band estimates for delivered prices for 2004 became the starting points for the long-term banded forecasts. These estimates were derived from a time-trend analysis of historical prices from 1990 through 2003. The time-trend analysis resulted in a regression equation that included an intercept term and an independent variable corresponding to the year associated with each year's price. The standard error of the independent variable was applied to its parameter estimate and the equation, with alternate parameter estimates, was used to compute low and high values for 2004. Statistically speaking, the forecasted 2004 annual average price "low band" price has an 84% chance of being exceeded, while the forecasted annual average "high band" price has only a 16% chance of being exceeded.

No probabilities can be assigned to estimate the relative likelihood of other fuel price forecast bands. Figures H-2, H-3, H-4, and H-5 contain the history and banded fuel forecast used in the IRP for coal and nuclear fuel, natural gas, distillate oil and residual oil, respectively. Coal and nuclear data are shown on the same plot for convenience sake only. Tables H-4, H-5, and H-6 provide the base, high and low annual average forecast price for each of these fuels, respectively. All data are reported as nominal delivered prices (not adjusted for inflation).

FIGURE H-1

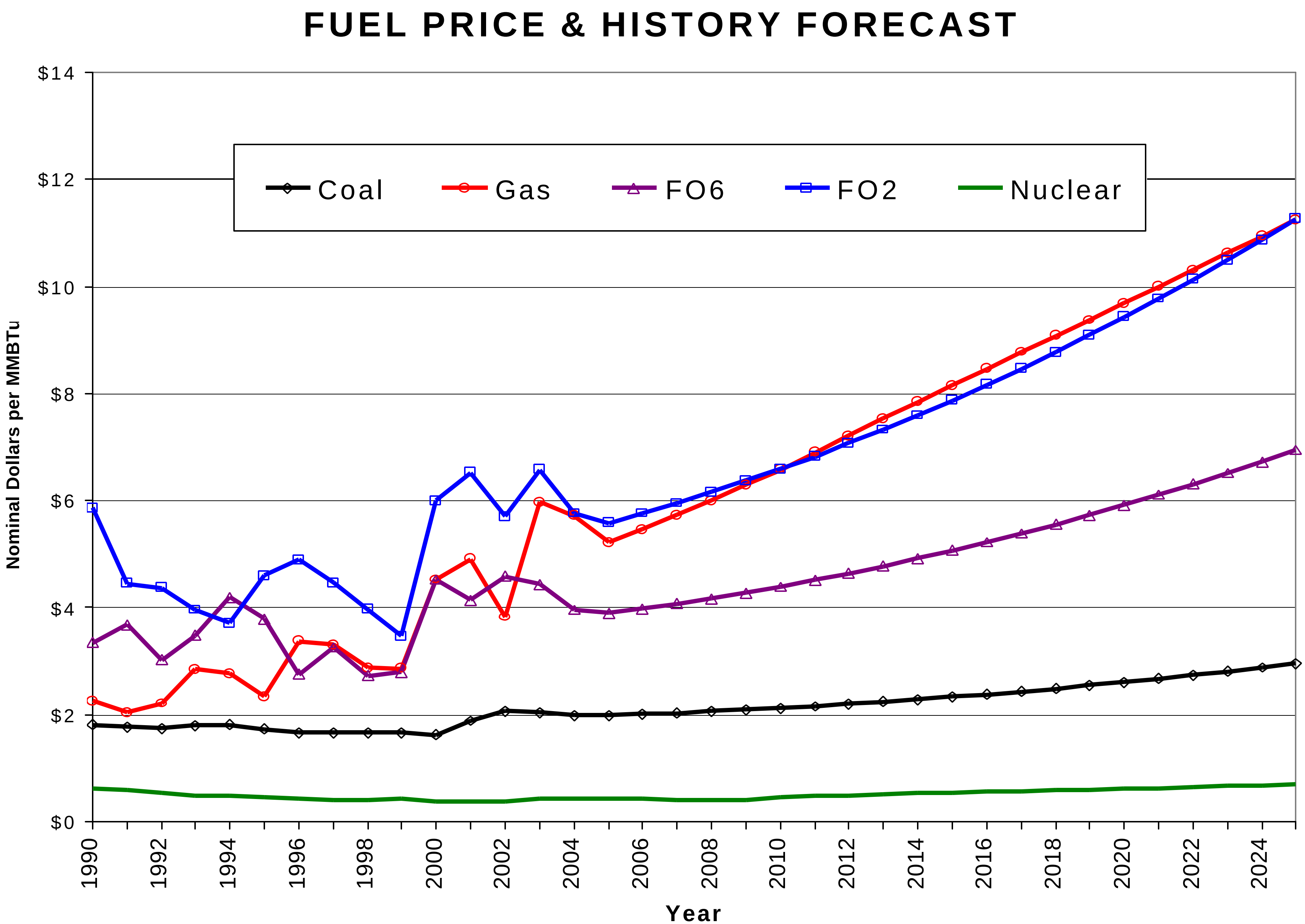

FUEL PRICE & HISTORY FORECAST
Coal
Gas
FO6
FO2
Nuclear
$14
$12
$10
$8
$6
$4
$2
$0
Nominal Dollars per MMBTu
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
Year

FIGURE H-2

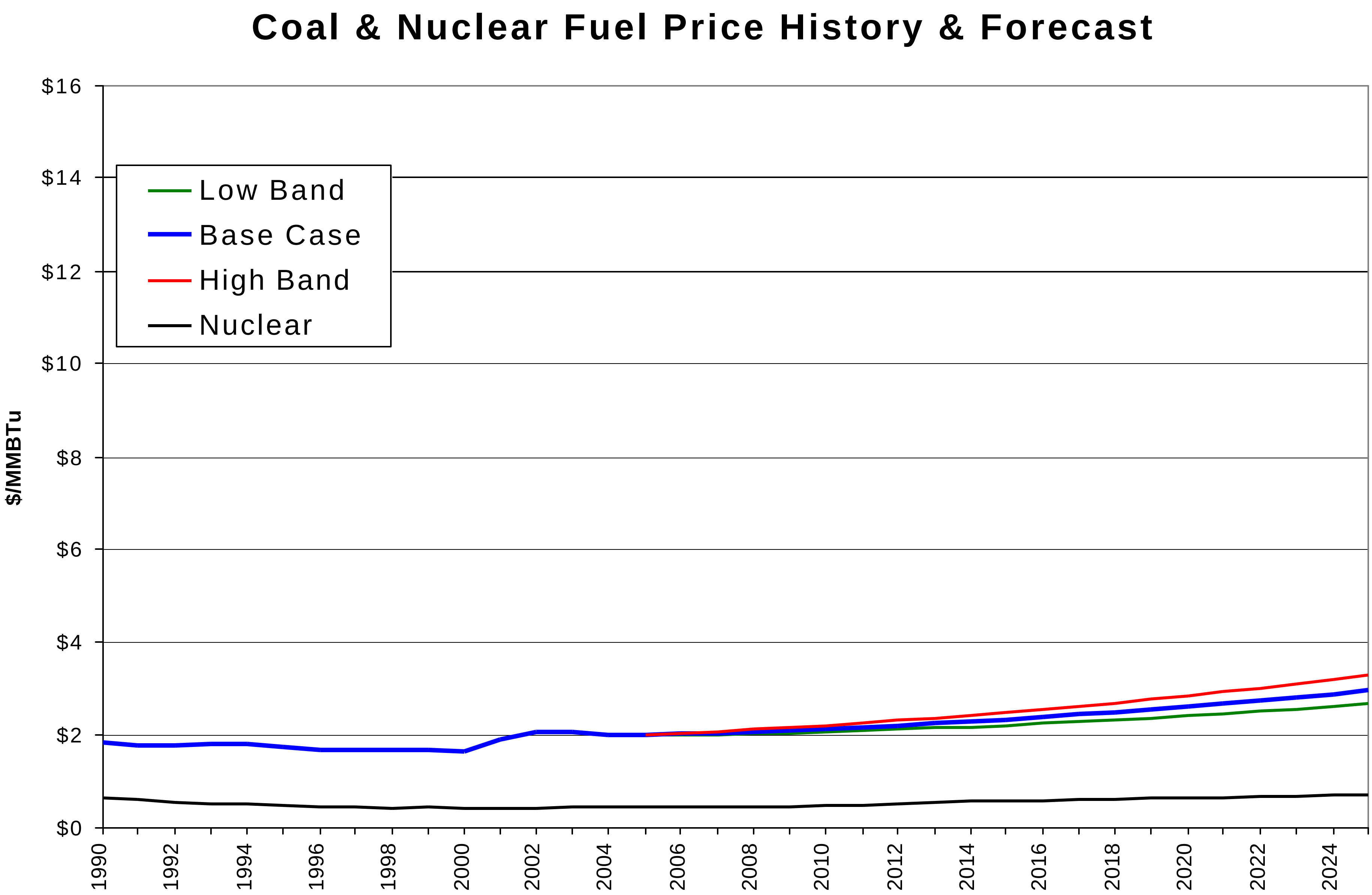
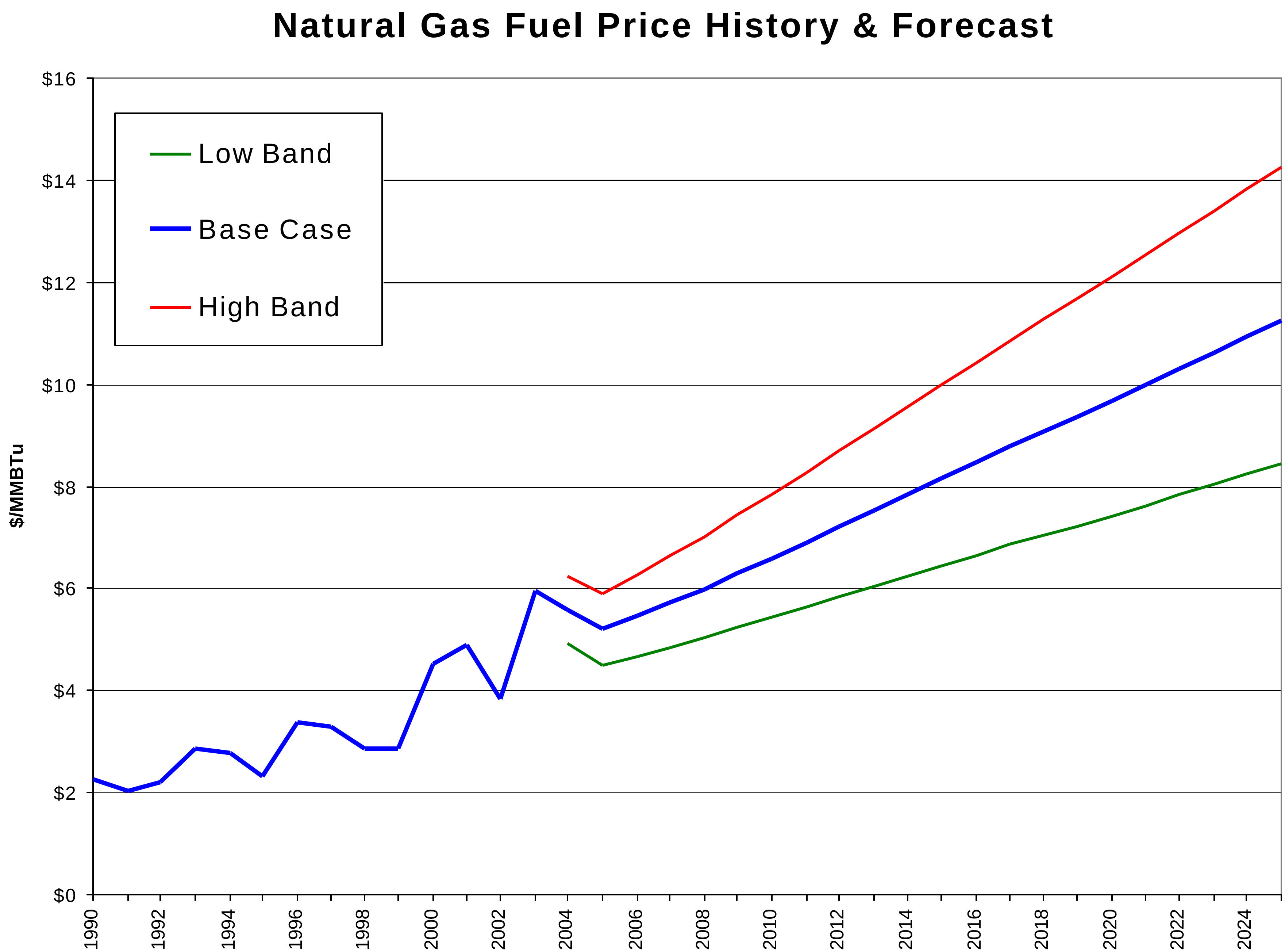

Coal & Nuclear Fuel Price History & Forecast
$16
$14
$12
$10
$8
$6
$4
$2
$0
$/MMBTu
Low Band
Base Case
High Band
Nuclear
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

FIGURE H-3



Natural Gas Fuel Price History & Forecast
Low Band
Base Case
High Band
$/MMBTu
$16
$14
$12
$10
$8
$6
$4
$2
$0
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

FIGURE H-4

Distillate Oil Fuel Price History & Forecast

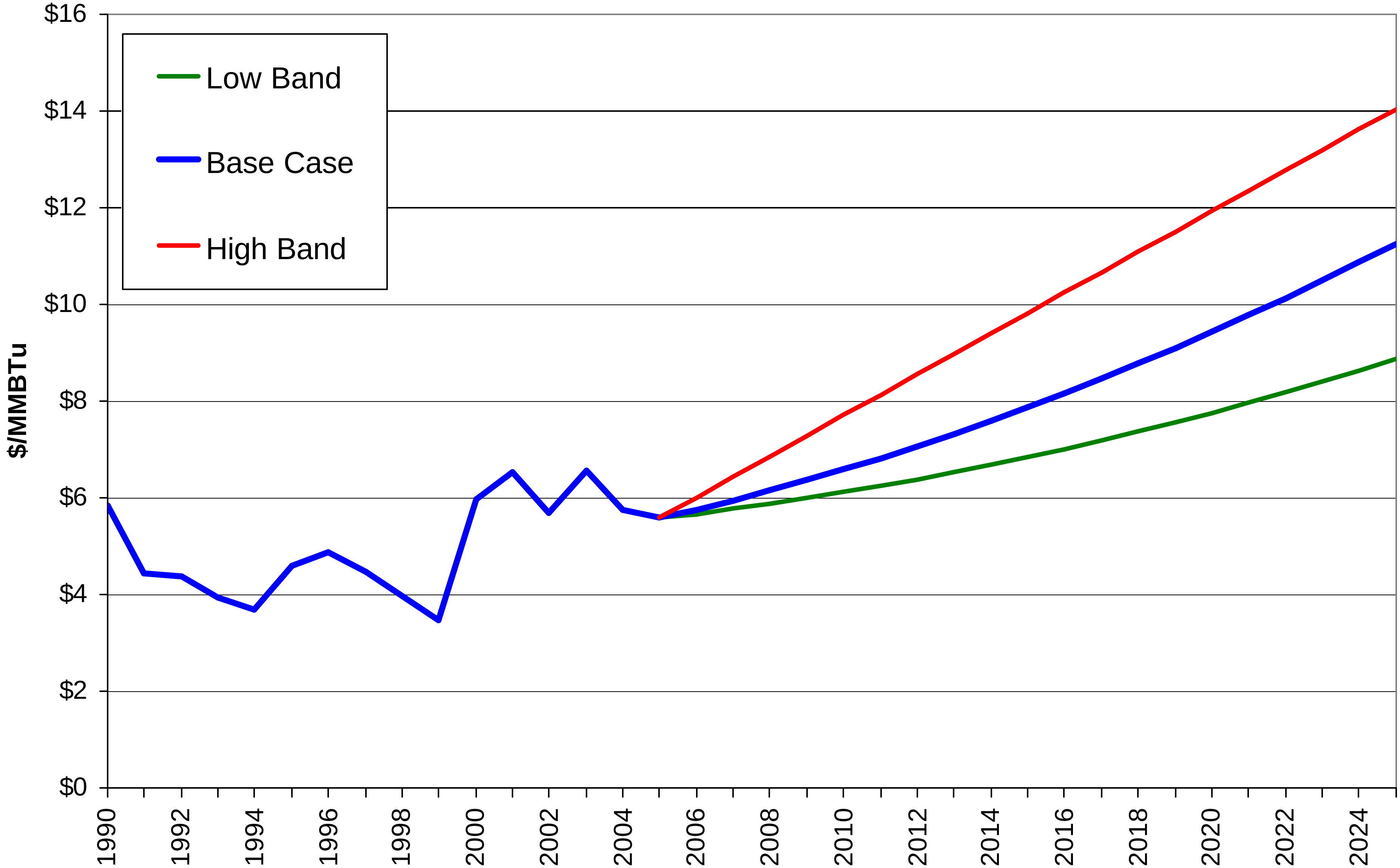


FIGURE H-5

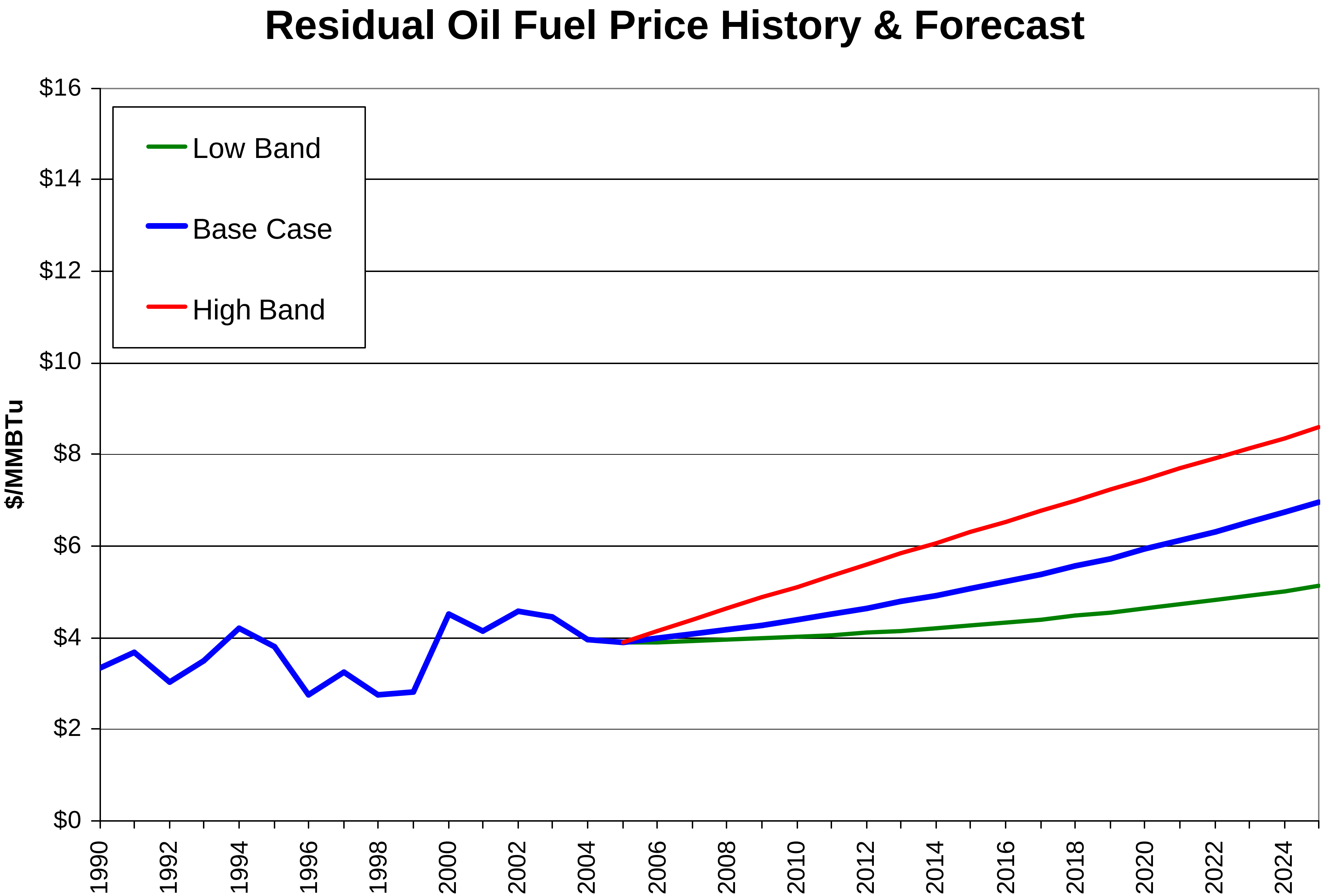

Residual Oil Fuel Price History & Forecast
Low Band
Base Case
High Band
$/MMBTu
$16
$14
$12
$10
$8
$6
$4
$2
$0
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

TABLE H-1

ABUNDANCE AND
RELIABILITY OF FUELS

Fuel	Years of Reserve	Transportation	Storage
Oil	16	Rail, Barge, Ship	20-30 days
Gas	52	Pipelines	None
Coal	480	Rail, Barge	50-75 days
Nuclear	39[a]	Diverse	550 days
Solar	Renewable	Local	None
Biomass	Renewable	Local	20-30 days

a. Breeder reactors could make nuclear power available indefinitely

TABLE H-2
Waste Wood Potential

Source	Tons/Day[1] Air Dried	Heat Valve (Btu/lb)
Planted Pine Logging Residue (w/ stumps)	706	9,000
Hardwood Logging Residue	198	8,000
Oak-Pine Logging Residue	52	8,500
Natural Pine Logging Residue	28	9,000
Tree Trimming Waste Wood[2]	185	8,000
Total	1,424	

1. 25% moisture
2. Excludes urban yard waste

Source: Cunilio and Post, (November 21, 2003) “Biomass Options for GRU – Part II”

TABLE H-3
BIOMASS CROPS AND THEIR FUEL CHARACTERISTICS

CROP	YIELD Tons/acre-yr	COST $/Ton	WATER %	HEAT BTU/lb
GRASSES:				8,178
Elephant grass	16-22	$25	22%	nd
Energycane	11.7-19	nd	nd	8,668
Sugarcane	15-25	$23	17%	8,000
Switchgrass	9-10	$17	15%	
WOODY SPECIES:				
Giant Leucaena	12-15	$15-20	35%	8,494
Cottonwood	12.5	$33	35%	4,728
Eucalyptus	11-15	$35	35%	8,370
Slash Pine	6-9	$33-45	35%	9,000
TYPICAL:	14	$26	28%	7,900

Source: Cunilio and Post, (November 21, 2003) “Biomass Options for GRU – Part II”

TABLE H-4

BASE CASE FUEL PRICE FORECAST
(Nominal Dollars per MMBTu - Delivered)

Year	Coal	Gas	FO6	FO2	Nuclear	High Sulfur Coal	Petroleum Coke
1990	1.81	2.25	3.35	5.86	0.62		
1991	1.77	2.04	3.68	4.45	0.58		
1992	1.74	2.21	3.02	4.37	0.53		
1993	1.80	2.85	3.48	3.96	0.47		
1994	1.81	2.77	4.19	3.71	0.49	1.83	
1995	1.73	2.33	3.79	4.60	0.45	1.75	
1996	1.66	3.37	2.75	4.89	0.42	1.65	
1997	1.66	3.30	3.26	4.46	0.41	1.64	
1998	1.66	2.87	2.73	3.97	0.40	1.63	
1999	1.66	2.86	2.79	3.47	0.44	1.57	
2000	1.63	4.53	4.52	5.99	0.38	1.58	
2001	1.89	4.91	4.15	6.53	0.38	1.60	
2002	2.06	3.82	4.58	5.69	0.38	1.78	
2003	2.04	5.97	4.44	6.57	0.42	1.82	1.25
2004	1.99	5.72	3.95	5.76	0.42	1.85	1.14
2005	1.98	5.21	3.89	5.58	0.42	1.85	1.14
2006	2.01	5.46	3.98	5.76	0.42	1.87	1.15
2007	2.03	5.73	4.07	5.95	0.41	1.89	1.16
2008	2.06	5.99	4.17	6.15	0.42	1.92	1.17
2009	2.09	6.28	4.28	6.37	0.42	1.95	1.18
2010	2.12	6.58	4.39	6.59	0.47	1.98	1.20
2011	2.16	6.90	4.51	6.82	0.47	2.02	1.21
2012	2.20	7.21	4.64	7.07	0.49	2.06	1.23
2013	2.24	7.53	4.77	7.33	0.53	2.10	1.26
2014	2.28	7.84	4.92	7.59	0.54	2.14	1.28
2015	2.33	8.15	5.07	7.87	0.55	2.18	1.30
2016	2.38	8.46	5.22	8.16	0.56	2.23	1.33
2017	2.43	8.78	5.38	8.46	0.58	2.28	1.36
2018	2.49	9.08	5.55	8.77	0.59	2.33	1.39
2019	2.55	9.37	5.73	9.09	0.60	2.38	1.43
2020	2.61	9.68	5.92	9.43	0.62	2.44	1.47
2021	2.67	9.99	6.11	9.77	0.63	2.50	1.50
2022	2.74	10.31	6.31	10.13	0.65	2.56	1.54
2023	2.81	10.62	6.51	10.49	0.66	2.62	1.59
2024	2.88	10.93	6.72	10.87	0.68	2.69	1.63
2025	2.96	11.25	6.94	11.26	0.70	2.76	1.68

TABLE H-5

HIGH BAND FUEL PRICE FORECAST
(Nominal Dollars per MMBTu - Delivered)

Year	Coal	Gas	FO6	FO2	Nuclear	High Sulfur Coal	Petroleum Coke
1990	1.81	2.25	3.35	5.86	0.62		
1991	1.77	2.04	3.68	4.45	0.58		
1992	1.74	2.21	3.02	4.37	0.53		
1993	1.80	2.85	3.48	3.96	0.47		
1994	1.81	2.77	4.19	3.71	0.49	1.83	
1995	1.73	2.33	3.79	4.60	0.45	1.75	
1996	1.66	3.37	2.75	4.89	0.42	1.65	
1997	1.66	3.30	3.26	4.46	0.41	1.64	
1998	1.66	2.87	2.73	3.97	0.40	1.63	
1999	1.66	2.86	2.79	3.47	0.44	1.57	
2000	1.63	4.53	4.52	5.99	0.38	1.58	
2001	1.89	4.91	4.15	6.53	0.38	1.60	
2002	2.06	3.82	4.58	5.69	0.38	1.78	
2003	2.04	5.97	4.44	6.57	0.42	1.87	1.30
2004	1.99	6.25	3.95	5.76	0.42	1.89	1.19
2005	1.99	5.91	3.89	5.58	0.42	1.90	1.20
2006	2.03	6.27	4.14	6.01	0.42	1.93	1.22
2007	2.07	6.65	4.38	6.43	0.41	1.97	1.24
2008	2.11	7.03	4.63	6.86	0.42	2.01	1.27
2009	2.15	7.43	4.87	7.28	0.42	2.05	1.29
2010	2.20	7.84	5.11	7.71	0.47	2.10	1.32
2011	2.25	8.28	5.35	8.13	0.47	2.14	1.35
2012	2.30	8.70	5.59	8.56	0.49	2.19	1.38
2013	2.36	9.14	5.83	8.98	0.53	2.25	1.42
2014	2.42	9.57	6.06	9.40	0.54	2.30	1.46
2015	2.48	9.99	6.30	9.83	0.55	2.36	1.50
2016	2.55	10.42	6.53	10.25	0.56	2.42	1.54
2017	2.62	10.85	6.76	10.67	0.58	2.49	1.59
2018	2.69	11.27	6.99	11.09	0.59	2.55	1.64
2019	2.76	11.67	7.22	11.51	0.60	2.63	1.69
2020	2.84	12.11	7.45	11.94	0.62	2.70	1.75
2021	2.93	12.54	7.68	12.36	0.63	2.77	1.80
2022	3.01	12.97	7.91	12.78	0.65	2.85	1.86
2023	3.10	13.40	8.13	13.20	0.66	2.94	1.92
2024	3.20	13.83	8.36	13.62	0.68	3.02	1.99
2025	3.29	14.26	8.58	14.04	0.70	3.11	2.06

TABLE H-6

Low Band Fuel Price Forecast
Nominal Dollars per MMBTu - Delivered

Year	Coal	Gas	FO6	FO2	Nuclear	High Sulfur Coal	Petroleum Coke
1990	1.81	2.25	3.35	5.86	0.62		
1991	1.77	2.04	3.68	4.45	0.58		
1992	1.74	2.21	3.02	4.37	0.53		
1993	1.80	2.85	3.48	3.96	0.47		
1994	1.81	2.77	4.19	3.71	0.49	1.83	
1995	1.73	2.33	3.79	4.60	0.45	1.75	
1996	1.66	3.37	2.75	4.89	0.42	1.65	
1997	1.66	3.30	3.26	4.46	0.41	1.64	
1998	1.66	2.87	2.73	3.97	0.40	1.63	
1999	1.66	2.86	2.79	3.47	0.44	1.57	
2000	1.63	4.53	4.52	5.99	0.38	1.58	
2001	1.89	4.91	4.15	6.53	0.38	1.60	
2002	2.06	3.82	4.58	5.69	0.38	1.78	
2003	2.04	5.97	4.44	6.57	0.42	1.77	1.20
2004	1.99	4.93	3.95	5.76	0.42	1.80	1.09
2005	1.97	4.51	3.89	5.58	0.42	1.79	1.08
2006	1.99	4.67	3.91	5.68	0.42	1.81	1.08
2007	2.00	4.85	3.93	5.78	0.41	1.83	1.08
2008	2.02	5.03	3.95	5.88	0.42	1.84	1.08
2009	2.04	5.23	3.98	6.00	0.42	1.87	1.09
2010	2.06	5.43	4.02	6.12	0.47	1.89	1.09
2011	2.08	5.65	4.06	6.25	0.47	1.91	1.10
2012	2.11	5.84	4.10	6.39	0.49	1.94	1.11
2013	2.13	6.05	4.15	6.54	0.53	1.97	1.12
2014	2.17	6.25	4.20	6.69	0.54	2.00	1.13
2015	2.20	6.45	4.26	6.85	0.55	2.03	1.14
2016	2.23	6.65	4.33	7.02	0.56	2.07	1.15
2017	2.27	6.86	4.40	7.19	0.58	2.10	1.17
2018	2.31	7.05	4.47	7.38	0.59	2.14	1.19
2019	2.35	7.22	4.55	7.57	0.60	2.18	1.21
2020	2.40	7.42	4.63	7.76	0.62	2.22	1.23
2021	2.45	7.63	4.72	7.97	0.63	2.27	1.25
2022	2.50	7.83	4.82	8.18	0.65	2.31	1.28
2023	2.55	8.03	4.91	8.40	0.66	2.36	1.30
2024	2.60	8.23	5.02	8.63	0.68	2.41	1.33
2025	2.66	8.44	5.13	8.87	0.70	2.47	1.36

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SECTION I
SCREENING OF ALTERNATIVES

The IRP public outreach program identified a broad range of ideas for ways to meet Gainesville's long term electrical energy needs that resulted in a set of factors to be considered in the IRP evaluation (see Appendix A). The list of alternatives developed could be categorized either as means by which to reduce the use of electricity, thereby avoiding some of the need for additional capacity, or means by which to increase electrical supply. The number of alternatives identified for consideration was quite large, and it was necessary to screen these alternatives to a manageable list of potentially feasible alternatives for further definition and analysis. The major categories of alternatives identified were:

1. Energy Conservation;
2. Renewable Resources; and
3. Generation Using Conventional Fuels

Appendix A contains a more detailed report on the outreach program.

SCREENING FACTORS

The methodology applied to screen the list of possible alternatives down to a list of potentially feasible alternatives was to apply the factors identified during the public outreach program in a progressively detailed manner to the possible alternatives. The factors that participants in GRU's outreach program identified as most important were:

1. Environmental Protection;
2. Health and Safety;
3. Cost (Rate Effects);
4. Reliability/Self Sufficiency;
5. Resource Conservation;
6. Emerging Technologies; and
7. Economic Benefits to the Community

Because of the anecdotal and qualitative nature of the outreach program, the factors listed above could not be assigned specific importance rankings or weightings. The following discussion is intended to convey the sense of the discussions related to each of these factors. This discussion formed the basis of the relative rankings assigned to several of the alternatives as part of the screening process.

Environmental Protection

Air quality was a key concern, followed by groundwater resource protection. In particular, the potential health effects of air borne particulate matter were of concern to some workshop participants. Other individuals voiced strong concerns about the overall ambient air quality in Alachua County, and explained how they developed. A few individuals also voiced concern about global warming and green house gas emissions. One or two individuals linked the availability of electrical capacity to overall urban and population growth. One person questioned the environmental consequences of fossil fuel extraction methods.

Information presented by staff included the relative abundance of domestic fuel sources and the vulnerability of these supplies to interruption. These issues prompted a number of topics for discussion, and highlighted public ambivalence about the relative abundance and stable price of coal versus the environmental consequences of the use of that fuel. Nearly every session included advocates for the use nuclear fuel.

Health and Safety

Health and safety was primarily associated with air quality and the protection of groundwater supplies. A few individuals identified electricity as a service that actually improves health and safety through lighting, food preservation and protection from weather exposure (heat and cold).

Cost (Low Rates)

Affordability was a prevalent theme heard throughout the outreach program. Several requests for programs to assist low and fixed income households were heard. A few individuals raised ancillary cost issues such as the fairness of existing rate structures, and the potential for cross-subsidy within and across rate classes.

Reliability/Self Sufficiency

A number of themes related to reliability and self-sufficiency were heard. The basic theme was that when the switch is pushed, people want the lights to go on. The momentous electrical outage in the northeast United States during the summer of 2003 prompted a number of questions concerning the transmission grid in Florida. The practical implications of adding capacity in the community versus distant location that would necessitate relying on the grid were frequently discussed.

Resource Conservation

The limited supplies of fossil fuels, and cost of constructing additional electrical capacity, and the environmental consequences of combustion technologies resulted in almost universally expressed preference for resource conservation (fuel and water conservation). A common question was whether GRU had done everything possible to promote energy conservation through information and incentive programs.

Emerging Technologies

Almost every conceivable emerging technology had an advocate. A common underlying theme was that if only everyone understood it, and enough people adopted it, technology would radically reduce cost and resource use. Most participants seemed interested in new ideas and were willing to see GRU pursue innovative options.

Economic Benefits To the Community

At nearly every session the role of the local utility in providing financial support to the City of Gainesville for public services was raised. A few individuals understood the relationship between investments in local energy technologies and jobs. The desire for GRU's activities to result in local employment also was expressed.

ENERGY CONSERVATION

The many forms of energy conservation are discussed in Section F, as well as the policy implications of how the benefits of conservation accrue to conservers and electric ratepayers. Section F also summarizes the methodologies and results used to estimate the potential load and energy savings from conservation programs and demand side management. From this analysis the following conclusions were drawn regarding the potential role of energy conservation in meeting Gainesville's long-term electrical requirements.

1. There are roughly 1.8 MW of summer peak demand reductions and 10,500 MWH per year of additional energy conservation programs that are not currently included in GRU's forecast of peak demand reductions that could potentially meet the Rate Impact Measure test of cost-effectiveness. These additional reductions could potentially be obtained through the programs listed in Table F-9, which were primarily related to HVAC equipment.

2. Many demonstration projects and new programs around the country indicate that Demand Response programs have the

potential to provide dispatchable reductions in peak system demands. These programs, often based on Internet technologies, do not have the onerous cost of real time metering, pricing and dedicated electronic communication systems. Unfortunately, there is no way to reliably predict the reductions that are obtainable without a full-scale market trial.

3. Further refinement of recent rate design modifications has the potential to induce customer conservation in a fair and equitable manner. Although the new rate designs have not been in place long enough to quantify their effects, with the passage of time it should be possible to detect their effects, if any.

Voluntary changes in customer end-use efficiency and energy using behavior are unlikely to satisfy GRU's long-term capacity requirements.

RENEWABLE RESOURCES

Table I-1 summarizes the screening of renewable forms of energy large category. As discussed in Chapter F, GRU currently promotes the use of flat-plate solar (thermal) water heaters through financial rebates and information. This is cost effective technology in the appropriate setting. Section H addresses renewable resources available in north central Florida in more detail.

Solar

Photovoltaic (PV) electrical generation was a commonly favorite technology. Most people are familiar with PV devices in the form of calculators, toys, and even limited public service applications (such as highway communication systems). This technology was selected for further analysis.

Passive solar design was proffered several times as an energy conservation technique. GRU provides information on this use of renewable energy as a cost-effective consideration for new home construction and window management.

Although concentrating collectors were not mentioned during the public outreach workshops, GRU staff did review this technology. The humidity and cloud cover of Florida do not lend themselves well to this technology, which is better suited to arid climates.

Biomass

In the late 1980s and early 1990s, Alachua County underwent a public participation process to site a new landfill. Burning refuse to make electricity as a way to reduce the volume of waste was publicly discussed at that time. The overwhelming adverse public reaction to refuse-derived fuel makes GRU unwilling to further entertain that option. Although landfill gas is a refuse-derived fuel, the digestion process does not yield the same potential for toxic release as combustion. GRU is engaged in the use and development of landfill gas at this time. Energy crops and waste wood are potential sources of energy that were selected for further analysis. Data suggest that enough waste wood could be harvested to sustain roughly 30 MW of electrical generation (see Section H). Although substantial, this is not sufficient to meet GRU's long-term resource requirements. It does, however, have strategic value in reducing carbon intensity, serving as a hedge against future renewable portfolio standards, and in generating Green Power premiums.

Wind, Tidal and Wave energy, and geothermal heat are too diffuse in Florida for any form of viable development.

GRUGreen

GRU recognizes that some customers want to invest in promoting renewable technologies, which are typically more expensive than conventional forms of energy. Accordingly, GRU is a leader in developing programs that allow customers to pay a premium to support such technologies. For example, GRU's landfill gas to energy program was developed on the expectation that although the cost of production is roughly 50% more than conventional fuels, customer contributions through GRUGreen purchases will recompense the system.

GENERATION FROM CONVENTIONAL FUELS

Natural gas, coal, petroleum coke, oil, and nuclear (uranium) are considered conventional fuels for the purpose of this study. Some of the alternatives preferred during the public outreach process rely upon conventional fuels for their operation, so they were included here. Section H provides more information on these types of fuels.

Table I-2 summarizes the results of the screening process. All of the natural gas and oil technologies were selected for further analysis. Simple cycle and combined cycle combustion turbines fired with natural gas and/or oil are common in the power industry. The coal and petroleum coke alternatives are either common in the industry or becoming so, and thus were selected for further analysis. GRU is actively engaged in promoting distributed generation through its AttenGen! program. The cost-effective application of this concept in Gainesville is for emergency back up. There are one or two customers that GRU has opened a dialogue with regarding dispatchable emergency back up. No customers for co-generation have been found, although all possible candidates were individually contacted in early 1994.

Microturbines are much more expensive than conventional (small) reciprocating engines, and only are justified in climates allowing cost-effective heat recovery. Plasma reduction has yet to be proven commercially viable, and biomass co-firing creates problems in conventional boilers due to fuel feeding problems, corrosivity, and lost capacity. Hydrogen is produced by steam reformation of natural gas or of decomposition of water using electricity. As such, it is not an electrical resource, unless used in fuel cells, which are currently uneconomical.

GENERATION COST FOR SELECTED OPTIONS

Figure I-1 contains a chart comparing the levelized annual cost for generating electricity from alternatives selected through the screening process for further analysis. The results are expressed as $/kWh ($2003) and are shown in Figure I-1 with capital cost, operation and maintenance, and fuel cost broken out separately. The fuel cost for biomass is unknown, so the cost of natural gas was employed as a surrogate. A question mark also is displayed along side the cost of nuclear power to flag the unresolved nature of waste disposal issues.

Figure I-2 displays the same results as Figure I-1 but in terms of a residential monthly bill for a customer using a typical monthly usage of 1000 kWh. The value shown assumes that all of the customer’s electricity comes from that generation source, and includes residential monthly service charges and costs associated with transmission and distribution.

These results allow a simple rank ordering of costs: Coal and nuclear technologies rank lowest (except for coal gasifiers), followed by gasification biomass and combined cycle combustion turbines, with simple cycle gas turbines and photovoltaics the most expensive.

ENVIRONMENT, HEALTH AND SAFETY

One way to include explicitly some of the factors of concern identified through public outreach in an analysis of alternatives is through the use of environmental externality cost factors. Environmental externality cost factors attempt to measure the societal costs of environmental emissions, such as those listed in Table I-3. There are no standardized ways to measure these external costs, and the economies of various environmental parameters vary from region to region.

Seven states and the Bonneville Power Administration (a federal power agency in the Pacific Northwest) have developed or adopted externality values for use in their regulatory proceedings. Table I-4 contains the factors used by these agencies for common environmental emissions from power plants (NO_X, SO_X, PM_{10}, CO and CO_2). For the purposes of this IRP screening study, the emissions associated with the generation of 1000 kWh of each of the alternatives selected for further analysis were estimated. The highest environmental externality cost from each column was then applied to recalculate the generation cost associated with each selected alternative.

The results are shown in Figure I-3. The "?" is placed next to biomass to highlight a key policy issue. Under many protocols addressing climate warming, biomass fuels are considered carbon neutral, although CO_2 is in fact emitted. Figure I-3 presents results for biomass both ways.

If biomass is considered carbon neutral, then biomass and nuclear have the lowest societal cost associated with environmental emissions. If not, biomass in ranked as one of the more costly options from a societal perspective. Pulverized coal and combined cycle gas have the least environmental cost after nuclear, using the methodology described.

SUMMARY OF SCREENING RESULTS

Table I-5 summarizes the results from preliminary analysis of the alternatives selected for further analysis, using the factors identified during the public outreach process. The implications of locating additional solid-fuel fired capacity at Deerhaven versus a greenfield site in south Florida are addressed in this table as well. Each alternative was rated by staff on a scale of 0 (worst) to 2 (best) for each of the factors. The following discussion addresses each of the evaluation criteria.

<u>Long Term Capacity.</u> In regard to long-term capacity, energy conservation, photovoltaics, gas CT's, and biomass were rated as having the worst potential for meeting GRU's long-term capacity needs. Conservation and biomass have limited availability, photovoltaics do not operate at night or well on cloudy days, and CTs are only cost-effective for meeting peak demands.

<u>Economic $/MWh</u>. This factor reflects the cost to produce electricity from each of the alternatives. The rankings in Table I-5 correspond to Figures I-2 and I-3.

<u>Economic + Societal $/MWh.</u> This factor reflects the cost to produce electricity from each alternative, but with the maximum value of environmental externalities from Table I-4 for each of the emissions associated with each alternative included. The economic rankings including environmental externalities correspond to Figure I-4, assuming that biomass is carbon neutral.

<u>Fuel Price Volatility, Security, And Storage Ability.</u> These factors were scored for each alternative based on information presented in Section H. Only alternatives located in Gainesville were considered grid independent. As described in Section J only alternatives located in Gainesville are considered as creating local

jobs and support for local services, and the having potential to reduce local air emissions.

Final rankings were based on the number of twos each alternative scored. The two top ranking alternatives from the screening analysis are energy conservation and additional solid fuel capacity at Deerhaven. The three second ranking alternatives are photovoltaic energy, biomass generation, and solid fuel capacity (coal) at a greenfield site.

FIGURE I-1
Generation Cost For Selected Options

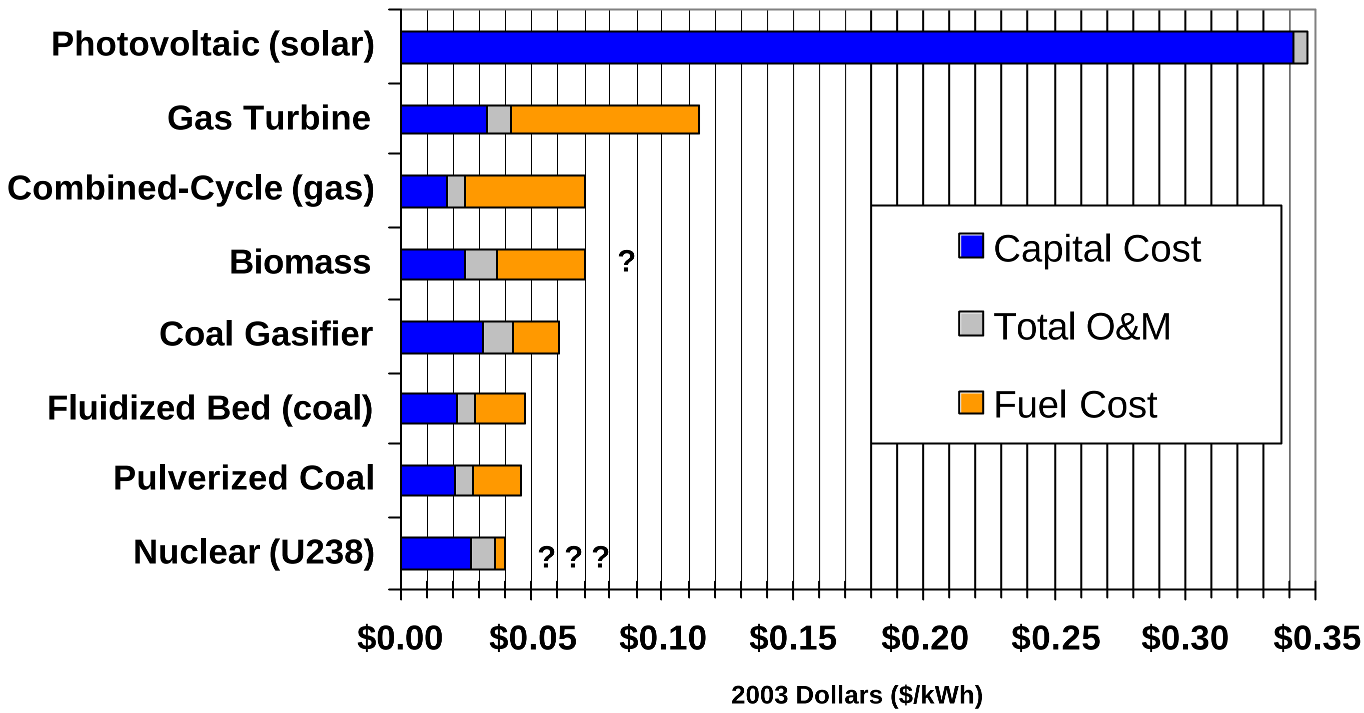

FIGURE I-2
Monthly Electric Bill for Selected Options
(1,000 KiloWatt-hours)

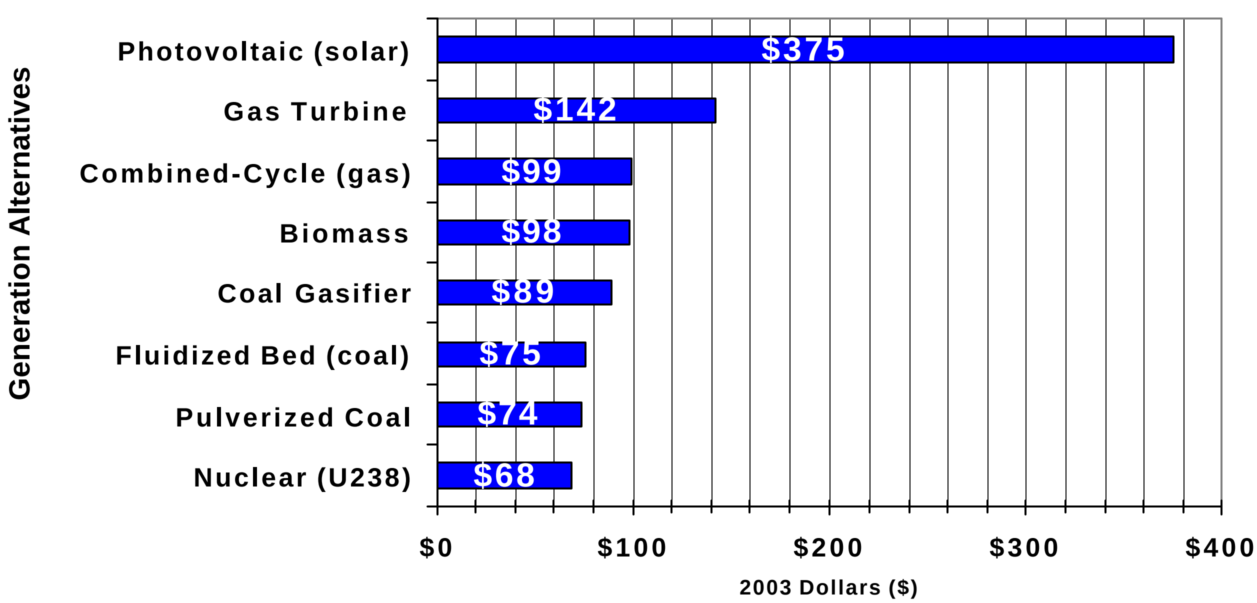

FIGURE I-3

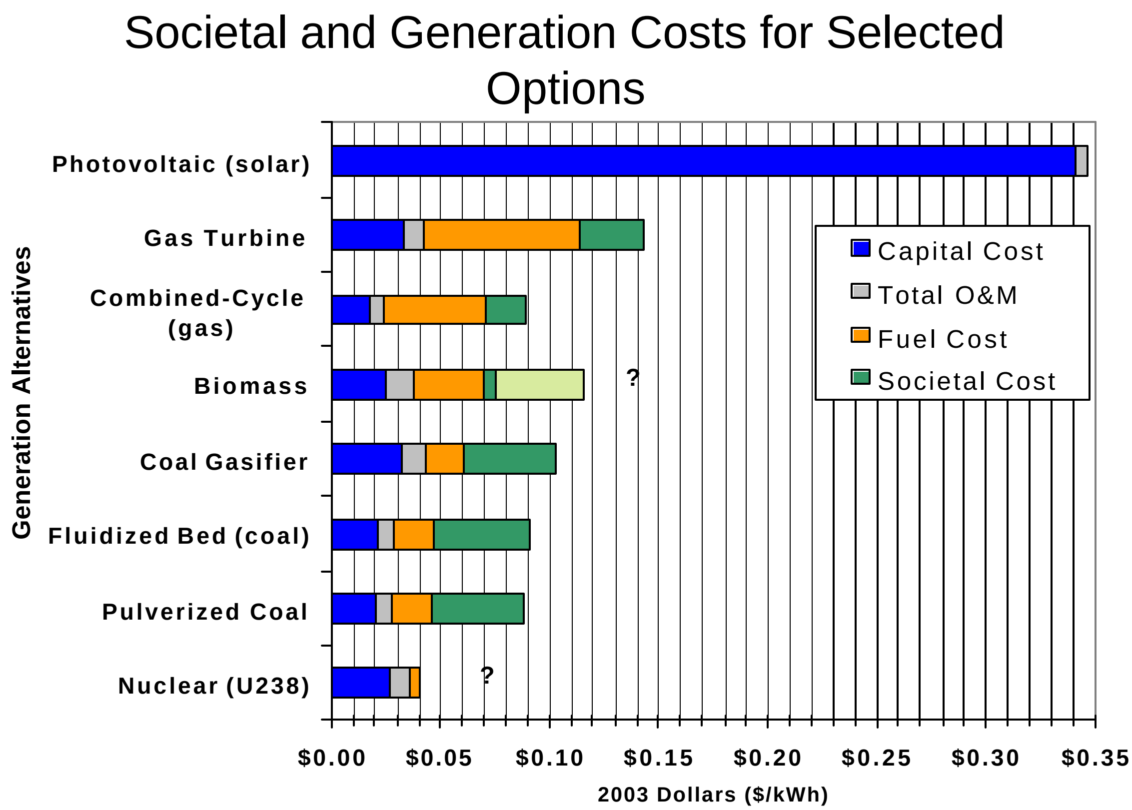

TABLE I-1

RENEWABLES SCREENING

Source	Screening Outcome
Solar	
Flat-Plate Water Heaters	Continue Rebates
Photovoltaic	Further analysis
Passive Solar Design	Continue Information Program
Concentrating Collectors	Not viable in Florida
Biomass	
Refuse Derived Fuel	Community rejected
Landfill Gas	Adopt
Energy Crops	Further analysis
Waste wood	Further analysis
Wind	Not viable in Florida
Tidal and Wave	Not viable in Florida
Geothermal	Not viable in Florida

TABLE I-2

CONVENTIONAL FUELS SCREENING

TYPE	SCREENING OUTCOME
Natural Gas & Oil	
Peakers (CT)	Further analysis
Combined Cycle (CC)	Further analysis
Coal & Petroleum Coke	Further analysis
Gasifiers (IGCC)*	Further analysis
Pulverized Coal (PC)	Further analysis
Fluidized Bed (CFB)*	Further analysis
PC – Supercritical*	Further analysis
Distributed Generation	
Emergency Back-up*	AttenGen!
Dispatchable Back-up	AttenGen!
Cogeneration	No customers found
Microturbines*	Not viable in Florida
Fuel Cells*	R & D Stage
Nuclear	Further analysis
Plasma Reduction*	R & D Stage
Biomass Co-Firing*	R & D Stage
Hydrogen Production*	Not an Electrical Resource

*Emerging Technology

TABLE I-3

Societal Costs of Environmental Emissions

Direct Cost	Indirect Cost
Health Costs	Activity Curtailment
Lost Wages	Wage Differentials
Crop Yields	Real Estate
Fish Harvest	Visibility
Building Maintenance	Endangered Species

TABLE I-4

Societal Cost Used By Other States ($/lb)

STATE	NOx	SO_2	PM_{10}	CO	CO_2
California PUC	3.76	0.86	2.31		
Massachusetts DPU	**3.6**	**0.85**			**0.01**
Minnesota PUC	**0.03 - 0.82**	**0.00 - 0.15**	**0.08 - 1.19**	0.48	**0.00 - 0.01**
Nevada PSC	**3.40**	**0.78**	**2.09**		**0.01**
New York PSC	**0.92**	**0.42**		**0.46**	**0.00**
Oregon PSC	**1.00 - 2.50**	**0.00**			**0.01 -** 0.02
Wisconsin PSC					**0.01**
BPA	**0.03**	**0.75**			
MAXIMUM	**3.76**	**0.86**	**2.31**	**0.51**(2)	**0.02**

Sources: 1) Issues and Methods in Incorporating Environmental externalities into the Integrated Resource Planning Process, November 1994, National Renewable Energy Laboratory, Golden, CO
2) FY 2001 Sustainability Report, September 2001, National Renewable Energy Laboratory, Golden, CO

TABLE I-5

SCREENING SUMMARY
FOR DISCUSSION

Rating Scale
0 = Worst
1 = Good
2 = Best

EVALUATION FACTORS	Leased Capacity	Energy Conservation	Photovoltaic	Gas-CT	Gas-CC	Biomass*	Coal-S. FL	Coal-Deerhaven**	Nuclear
Long-Term Capacity	2	0	0	1	2	0	2	2	2
Economic $/MWh	1	2	0	0	1	1	2	2	1
Econ.+Societal $/MWh	1	2	0	1	1	2	1	1	1
Fuel Price Volatility	0	2	2	0	0	1	2	2	2
Fuel Trans. Security	0	2	2	0	0	2	2	2	1
Fuel Storage Ability	0	2	0	0	0	2	2	2	2
Grid Independent	0	2	2	2	2	2	0	2	0
Reduce Local Emissions	2	2	2	0	1	1	1	2	1
Local Econ. Benefits	0	2	2	2	2	2	0	2	0
Number of Ones:	2	0	0	2	3	3	2	1	4
Number of Twos:	2	8	5	2	3	5	5	8	3

*Fuel supply price very uncertain and assumes zero societal cost for CO_2
** Includes Deerhaven 2 retrofit

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CHAPTER J
AIR AND WATER RESOURCE MANAGEMENT

It takes three things to make electricity using combustion technology: fuel, air and water. This section addresses the standards and control devices for air emission control to be considered in the design and evaluation of various generation alternatives. It also addresses the consumptive use of water for cooling and boiler feedwater. Both of these are critical factors as related to solid fuel power plants either at a greenfield site or at the Deerhaven Plant site.

AIR EMISSION PERMITTING

In Florida, the Prevention of Significant Deterioration (PSD) and the Site Certification are the key permits affecting the construction of new power generation facilities. The Site Certification is a combined permitting process that incorporates all of the environmental regulatory permitting requirements into one permit. The Florida Department of Environmental Protection (FDEP) administers both the Site Certification and the PSD permitting process in accordance with USEPA rules. Permitting under the PSD rules requires, among other things, a demonstration that Best Available Control Technology (BACT) will be installed. There are many factors that play a role in the BACT determination, including boiler type and fuel characteristics. The extent to which a project may reduce emissions from other sources also would be an important factor in the PSD determination process. The performance levels of additional emission control equipment installed on existing facilities as part of a PSD proposal are negotiable. BACT evaluation and approval requires a "top down" analysis of available control technologies to control regulated pollutants. This analysis includes a review of recent BACT determinations made by regulatory agencies for recent and similar projects.

Pollutants that typically would be considered in a BACT analysis for a solid fuel-fired power plant include sulfur dioxide, sulfuric acid mist, reduced sulfur compounds, hydrogen fluoride, nitrogen oxides, particulate matter (including various metals and represented as PM_{10}), volatile organic compounds (VOC), mercury and lead. Recent BACT determinations for the primary criteria pollutants (NO_x, SO_2, CO, VOC and PM_{10}) are listed in Table J-1.

When the emissions of the pollutants listed in Table J-1 are controlled to the levels shown, it would be expected that hydrochloric acid and hydrogen fluoride emissions would be reduced by greater than 90 percent by the wet scrubber system and that emissions of lead would be reduced by greater than 99 percent by the fabric filter.

In addition to the BACT review discussed above, controls for Hazardous Air Pollutants (HAPs) also are required under Maximum Available Control Technology (MACT) requirements of Clean Air Act Section 112(g). EPA has proposed MACT standards for mercury and nickel. For other HAP's a case-by-case MACT analysis is a required part of the PSD permit application. For most HAPs, the case-by-case MACT analysis is relatively straightforward and the level of control listed above will provide sufficient removal. However, the emissions of mercury may require a detailed analysis examining various control alternatives, such as sorbent injection. Typically, this involves using activated carbon as the sorbent, followed by an air filtration system such as fabric filtration.

Currently, there are regulations such as the Regional Haze Rule and new standards for ozone and $PM_{2.5.}$ Also, there are proposals for new legislation aimed at reducing emissions from industrial facilities. The foremost of these proposals is the Bush Administration's Clear Skies plan. Another proposal, legislation in the U.S. Senate proposed by Senator Jeffords, is receiving less attention at this time. Both proposals would require reductions of NO_x, SO_2, and mercury, while the Jeffords plan also includes CO_2. In addition, there is currently a bi-partisan proposal in the U.S. Senate proposing a trading program for CO_2. Depending on the legislation passed, if any, emission reductions of NO_x, SO_2, and mercury could possibly be achieved through a cap-and-trade program, rather than on a facility-by-facility basis. To the extent future regulation and reduction of CO_2 is required, combustion efficiency will become an issue. It is probable this issue will have to be addressed during the permitting process, regardless of any regulatory requirements, as part of the alternative technology discussion. For that reason, the technology evaluations will include a comparison of air emissions, including CO_2.

The emission control systems and emission rates shown in Table J-1 were identified in this IRP as assumptions for the control of air emissions from a new pulverized coal-fired boiler. To the extent that a CFB boiler is considered, the emission rates presented also were used as targets for emission controls. In addition, controls for $PM_{2.5}$ and aerosols may be required given the potential future regulatory requirements. It is possible that sufficient controls can be achieved through optimization of the fabric filter and scrubber assumptions. However it would be prudent to plan for (i.e., provide space for construction) the possible need to install sorbent injection for control of mercury and the possible addition of a wet Electrostatic Precipitator (ESP) for control of fine particulates and aerosols.

It should be noted that these suggested controls and emission rates are for early planning only and it is possible that upon completing a BACT analysis for the Project, the emission rates and selected controls may vary from those stated here.

PARTICULATES (PM)

The two primary particulate removal devices are ESPs and fabric filters (also referred to as baghouses). Either alternative likely would perform adequately for application to a solid fuel generation facility. Typically, neither is required for a gas-fired facility. However, for a new facility an ESP would be more sensitive to varying ash characteristics, would be more costly if the addition of mercury control is necessary, and would have higher auxiliary power requirements. Conversely, a fabric filter has low sensitivity to ash characteristics, is more adaptable for the control of mercury (activated carbon injection), and has relatively low auxiliary power requirements, although a higher draft pressure loss across the filter would have some affect on the Induced Draft (ID) fans.

NO_X CONTROL

Nitrogen oxides emitted from combustion are a function of the temperature and oxygen availability during combustion (hotter temperatures make more NO_X) as well as the fuel-bound nitrogen (particularly a consideration when burning oil). NO_x controls considered in this IRP include burner and firebox designs, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR).

SCR and SNCR systems are applicable to combustion turbines in some circumstances. The state of the art in combustion turbine design is the use of special burner designs that spread the flame and control the air/fuel ratios very carefully, such as the dry low NO_x burners in two of GRU's combustion turbines. Water is injected into combustion turbines while burning oil as well, as a way to reduce NO_x.

Great strides have been made on pulverized coal (PC) boilers in the reduction of NO_x emissions. Technologies employed apply to the design of new boilers and include improved combustion technology, process-optimization software, SCR, and SNCR.

Boiler manufacturers employ varying methods of NO_x control in their boiler design. The use of low NO_x burners, overfire air, windbox and ductwork baffles, and turning vanes are common. Such requirements can be imposed on the boiler manufacturer to a reasonable level without significantly increasing boiler cost. The addition of SCR or SNCR downstream may be necessary to achieve the regulated level of NO_x emissions.

Various suppliers of neural network process-optimization software are available for boiler controls. Such software can continuously tune the boiler operating and environmental control parameters to optimize system efficiency, thereby minimizing emissions. The effects of this software depend on the system being controlled, but are worth considering as an option.

SCR will be required to achieve the low NO_x emission levels that will be required on a new solid fuel unit burning pulverized coal (PC). These systems are installed between the economizer outlet and the air heater, and inject ammonia as a reducing agent into the flue gas stream passing over a catalyst. Reductions of NO_x of 80% to 90% are achievable. However, regulations addressing the emission of unreacted ammonia, or ammonia slip, are becoming more restrictive.

SNCR is not an effective control technology for PC boilers due to its lower removal efficiency, as compared with the SCR, higher operating costs due to inefficient reagent usage, difficult distribution, fouling potential, and difficult ammonia slip control. However, SNCR is applicable to circulating fluidized bed (CFB) boiler designs.

CFB boilers manage NO_x formation as the result of their unique use of solids to control the temperature at which combustion occurs. Instead of a furnace cavity with heat transfer to the water tubes through radiation and convection, a mix of limestone, ash, and a small concentration of fuel are continuously combusting while circulating through the boiler. A cyclone solid/air separator allows the spent air to exit the system, while the hot solids and burning fuel are kept circulating. Fuels burn slowly and the system can be tuned to achieve NO_x levels low enough to allow polishing with SNCR. More recent CFB designs avoid the use of SNCR by minimizing NO_x formation at the expense of sulfur removal, using downstream sulfur removal with a flash absorption bed recycle.

SO_2 CONTROL

SO_2 emission controls considered in this IRP include fuel selection, wet and dry scrubbers, and the use of calcium carbonate in CFB boilers. Combustion turbines fired on gas do not require SO_2 removal systems due to the relatively low sulfur content of the fuel. For PC boilers, the two primary technologies used for high SO_2 removal efficiencies are wet and dry flue gas desulfurization (FGD or scrubber) systems. Wet scrubbers use calcium carbonate solutions, whereas a dry scrubber uses a lime spray. Sorbent injection systems that feed reactive sorbent directly into the boiler or the flue gas ducts have also been employed, but such systems would not have sufficient removal efficiency to comply with BACT requirements. The required SO_2 emission to be achieved is expected to be 0.12 lb/MMBtu. A fuel containing 2% sulfur with a heating value of 11,435 Btu/lb HHV would produce approximately 3.50 lb/MMBtu of SO_2 gas. The required removal efficiency would then be approximately 97%. Lime spray (dry) scrubbers have been claimed to remove up to 95% of SO_2; however, a guaranteed continuous removal efficiency of 90% is considered reasonably achievable. Therefore, a dry scrubber would not be acceptable for a PC boiler burning a 2% sulfur coal. Lime spray dryers have been primarily used for facilities firing lower sulfur fuels, or as polishing units on CFB boilers.

A wet FGD system is located downstream of the particulate collection device. The scrubber waste product is generally a mixture of calcium sulfites and calcium sulfates having a water content of approximately 50%. Fly ash is then mixed with this waste to stabilize the product for disposal. In addition, complete reaction to 100% calcium sulfate can be employed to produce gypsum, a potentially saleable byproduct.

CFB boilers result in sulfites in the bottom and fly ash, which has a high component of calcium carbonate. The use of this material as a soil stabilization amendment is gaining in acceptance, but the market for it is less mature than the market for gypsum.

Other desulfurization systems and multi-pollutant control technologies are in varying degrees of development and implementation; the progress of such technologies should be monitored and will need to be addressed in a BACT analysis. It should be noted that wet scrubbers result in a visible water vapor plume from the stack.

MERCURY CONTROL

There are alternative methods currently being studied for controlling mercury emissions. Wet scrubbers reduce mercury by 40%-60%. The efficacy of CFB boilers in removing mercury is still being researched, but is expected to be at least as high as wet scrubbers, due to the sorbent capacity of the limestone and the presence of activated carbon in the circulating bed. The most prominent new technology is the adsorption of mercury on activated carbon. It is not clear at this time what the regulated limits will be for emissions of mercury. In lieu of stated limits, it may be reasonable to assume that an activated carbon injection system upstream of the particulate collector (preferably a baghouse), combined with downstream wet FDG, will be sufficient to control emissions of mercury.

CARBON CONTROL

Carbon dioxide is considered to be a greenhouse gas contributing to global warming. The amount of carbon dioxide emitted per kilowatt-hour depends first, on the type of fuel burned, and second, upon the conversion efficiency by which the heat contact of a fuel is transformed into electricity. Figure J-1 compares various fuels with regard to their carbon content per unit heat. Strategies for managing carbon emissions include:

a) Energy conservation;
b) Carbon sequestration;
c) Using renewable sources of energy;
d) Using carbon adsorption chemistry.

Section E contains the results of GRU's carbon reduction achievements to date from employing the first three strategies listed above. The following discussion reviews the factors currently being considered as part of this IRP.

Renewable Energy and Conservation

As described more fully in Section F, GRU has implemented energy conservation programs and developed renewable energy projects to offset the use of fossil fuels in generating electricity. These programs and projects reduce the emission of carbon dioxide from GRU electric generation facilities. Customers have the opportunity to support these renewable energy projects through purchasing green power (GRUGreen^{SM} Energy). The premiums from these sales will go to support electrical production from renewable energy. Conservation programs and renewable energy projects have been developed and implemented to the extent to which they are cost effective or meet customer needs (See Section E and Table E-1).

Biomass Fuels

GRU is investigating the potential to use biomass resources to produce electric energy as part of this IRP. As discussed in Section F, although CO_2 is released during the combustion of biomass fuels, it is considered carbon neutral because most biomass would naturally decompose; and the use of biomass as a fuels avoids the use of fossil fuel that are a net increase in atmospheric carbon. Section H describes the research that suggests that up to 30 MW of biomass fuel production may be sustainable.

GRU is investigating the potential for using biomass resources to produce electric energy. Although CO_2 is released during the combustion of biomass fuels, other biomass in the areas from which the fuel was produced is sequestering carbon from the atmosphere at a rate roughly equivalent to the rate of release. Another perspective on carbon dioxide production is that any CO_2 release to the atmosphere will result in a net short-term increase in emissions, regardless of the source.

Carbon Sequestration

Managing land to promote carbon fixation (via photosynthesis) is one method of carbon sequestration. GRU is sequestering carbon with approximately 7,000 acres of forest around the Murphree Water Treatment Plant and 3,500 acres around the Deerhaven Generating Station. GRU, the St. John's River Water Management District, the Suwannee River Water Management District, and the Natural Resource Conservation Service bought development rights to the land surrounding the Murphree Plant in order to protect the municipal water supply. Assuring these forests remain in silvicultural production managed for optimal wood production will effectively sequester the largest amount of carbon possible. GRU also gives away trees as part of its vegetation management system, with the goal of planting "the right trees in the right place" to avoid damage to utility infrastructure.

Chemical Carbon Absorption

The use of carbon adsorption chemistry to remove carbon dioxide from boiler flue gas was identified in a study commissioned by GRU in 2002 (Reference 17). The process with the most promise identified at that time involved the use of special sorbents in a wet scrubber. The process is quite expensive, has not been commercially demonstrated, nor has it been applied to a large-scale test site.

POTENTIAL FOR NET REDUCTIONS OF EMISSIONS

Some preliminary evaluations were performed as part of this IRP to ascertain the potential for obtaining a net reduction of emissions from the Deerhaven site while increasing the total generation capacity. The concept being explored is to retrofit Deerhaven Unit 2 as part of the construction of new solid fuel facilities. This opportunity does not exist at a Greenfield site. To offset the high operating costs of the emission controls, it was assumed that a relatively high sulfur content fuel would be used. The analysis presented here assumes a 2.73% coal versus the 0.70% compliance coals currently being burned, or some combination of pet coke and coal resulting in the same general sulfur content, unless otherwise mentioned. It would be beneficial to employ the same fuels and emission technology as part of a Deerhaven 2 retrofit as in any new capacity to simplify fuel handling, operations, and by-products management.

Table J-2 contains the assumptions used in emission reduction analysis. Tables J-3 and J-4 contain the results of the analysis for a 475 MW (gross) and 600 MW (gross) supercritical unit. Tables J-5 and J-6 contain a similar analysis for one and two 240 MW (gross) circulating fluidized bed units, respectively, assuming that the Deerhaven 2 retrofit involves dry scrubbers, which would necessitate the continued use of low sulfur compliance coal in that unit. Tables J-7 and J-8 contain a similar analysis for one and two 240 MW (gross) circulating fluidized bed units, respectively, assuming that the Deerhaven 2 retrofit involves wet scrubbers, which would allow the use of high sulfur coal in that unit. Results are summarized in each case assuming that both Deerhaven 2 and the new unit would run at 100% capacity all of the time. This is not actually possible, as units need time off-line for maintenance. Another scenario, with Deerhaven 2 operating at 69% capacity also is shown which is far more realistic.

These results indicate that substantial emission reductions for SO_2 and NO_x are potentially achievable with very substantial increases in generation capacity. If Deerhaven 2's PM historical emissions were at the permitted level (.10 lb/mm

Btu) instead of the actual level of .022 lb/mm Btu, net reductions in PM_{10} also would be achievable. However, when compared against historical PM emissions, net increases of primary PM_{10} are expected to occur. These increases are relatively small. Secondary PM_{10} is likely to be reduced as a result of the reductions in SO_2 and NO_x, which are precursors to secondary particulate formation.

WATER RESOURCES

Condenser cooling, which constitutes the largest heat load in a power plant, is accomplished by either a wet or dry system. Wet systems are further divided into once-through systems and circulating systems with an evaporative cooling tower. The system selection depends primarily on site characteristics, but also on environmental/permitting considerations, efficiency and economics.

Cooling Cycles

In once-through cooling systems water is withdrawn from a body of water such as a river, lake, or the ocean, pumped to the condenser and returned to the body of water at a higher temperature due to sensible heat transfer in the condenser. No site locations suitable for once-through surface water cooling were identified in the course of the study, so the site characteristics essentially precluded consideration of this option.

Evaporative cooling tower systems pump water heated in the process of cooling steam through a cooling tower, after which it is once again used to cool steam. In the cooling tower, the cooling water is brought into contact with ambient air. In the cooling tower, most of the heat is rejected by evaporation of the warm water and the remainder by heating the incoming air. As the water evaporates, it concentrates the dissolved solids in the water. To control this concentration buildup, a portion of the water in the circulating loop is removed as blowdown.

The quantity of the blowdown is based on the original water quality and the cooling water treatment regime, but must be sufficient to maintain dissolved solids concentrations sufficiently low to prevent scale formation. A small portion of water also is lost as ”drift”. Drift is the name applied to the small droplets of liquid water entrained in the exhaust air stream from the cooling tower. Drift eliminators are employed to minimize water lost through drift. To compensate for the water lost from evaporation, blowdown, and drift, an outside water supply must provide makeup water to the cooling system.

Mechanical Versus Natural Draft Towers

Evaporative cooling tower systems can be broken down further into mechanical draft systems and natural draft systems. Mechanical draft towers use some type of mechanical means, such as fans, to move the air through the tower.

Natural draft towers do not use mechanical means such as fans to provide airflow through the tower. Instead, air is induced through the fill by means of the small density difference between the warm moist air inside the tower and the cooler ambient air outside the tower. Because in many instances the temperature/density difference between the air inside the tower and outside the tower is quite small, natural draft towers can be very tall (500 feet would not be unusual for a large natural draft tower). Natural draft towers are typically hyperbolic in shape, as that this shape offers the best strength and resistance to wind loading.

Typically, air-cooled systems simply use an air-cooled condenser wherein the steam turbine exhausts to the condenser and the exhaust steam is condensed inside the tubes by air flowing over the tubes on the outside. These are mechanical draft devices, as fans are required to move the large quantity of required air. Advantages of air cooled systems include: no makeup water requirement, maintenance is less expensive as the equipment is simple; no water treatment chemicals are required; no cooling tower blowdown to handle, and no misting or fogging as may occur with wet towers. However, the disadvantages are significant. The main disadvantage is that the heat is being rejected to the ambient air dry bulb temperatures as opposed to the lower wet bulb temperatures as is the case with a cooling tower. This means that the condenser steam pressure is not as low as with a wet cooling system and thus the cycle efficiency is lower. Therefore, to produce the same amount of power more fuel is required, and all of the power generation equipment has to be sized larger to accommodate it. In addition, the fan parasitic power requirements to move the large quantity of air is substantial.

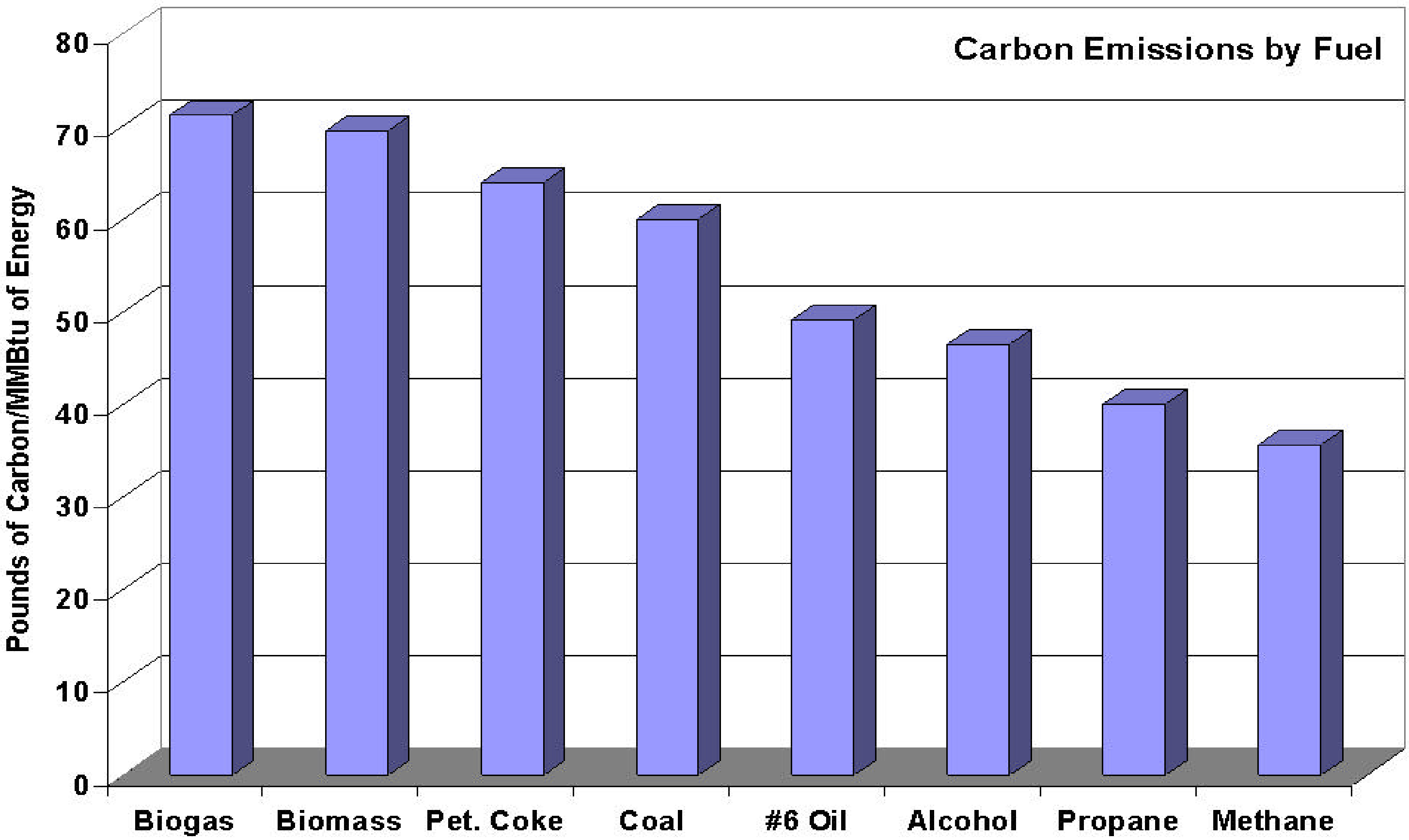
To illustrate the impact of some of these considerations, preliminary heat balances were run for two 475 MW net supercritical cycle power plants, one with an air-cooled condenser and the other with a wet-cooled natural draft tower. The parasitic loads associated with the air-cooled plant were approximately nine megawatts more than for the wet-cooled plant, while the heat rate for the air-cooled plant was 2.4% higher. For these reasons, it is recommended that a wet-cooled system be selected for the plant in question if sufficient water is available for makeup. Fortunately, all of the potential sites identified appear to have makeup water available, so a wet-cooled system with its inherent advantages should be feasible.

WATER SOURCES

Table J-5 compares the sources of water and the disposal options assumed for the Greenfield and Deerhaven sites. Reclaimed water could be made available from either the Kanapaha Water Reclamation Facility (WRF) or the Main Street WRF. The costs of the water transmission facilities were included in the Deerhaven site options. Construction of these facilities will allow reclaimed water services to be provided to customers along the transmission route. Groundwater will continue to be utilized in existing facilities at the Deerhaven site and will be required as a backup water source in the event reclaimed water is not available.

Figure J-1

Carbon Content of Fuels



Source: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories Workbook

TABLE J-1
Recent BACT Emission Limits

Pollutant	Typical BACT (PPM)	Typical Control Device
PM_{10}	0.015	Fabric Filter
NO_x	0.07	Boiler Optimization/Selective Catalytic Reduction
SO_2	0.12	Wet Lime/Limestone Scrubber
CO	0.15	Good Combustion Practice
VOC	0.005	Good Combustion Practice

TABLE J-2
ASSUMPTIONS USED FOR NETTING ANALYSIS[1]

ITEM	ASSUMPTION
Existing Low Sulfur Coal Characteristics	
Percent Sulfur	0.7% by weight
Heat Content	13,000 Btu/lb, HHV
Sulfur Content	0.955 lb SO_2/MMBtu
Future High Sulfur Coal Characteristics	
Percent sulfur	2.73% by weight
Heat Content	12,335 Btu/lb, HHV
Sulfur Content	4.43 lb SO_2/mm Btu
Future Petcoke Characteristics	
Percent sulfur	5.0% by weight
Heat Content	15,000 Btu/lb, HHV
Sulfur Content	7.77 lb SO_2 /mmBtu
Deerhaven 2 Characteristics	
Maximum Hour Heat Input	2,428 mmBtu/hr
Annual Heat Input@100% CF[2]	21,269,280 mmBtu/yr
Retrofit SO_2 Emission Rate (wet scrubber)[3]	0.220 lb/mmBtu
Retrofit SO_2 Emission Rate (dry scrubber)[4]	0.120 lb/mmBtu
Retrofit NO_x Emission Rate (SCR)	0.080 lb/mmBtu
Retrofit PM_{10} Emission Rate (Fabric Filter)	0.015 lb/mmBtu
New 475 MW Unit Characteristics	
Maximum Hour Heat Input	4,396 mmBtu/hr
Annual Heat Input @ 100% CF	38,508,960 mmBtu/yr
SO_2 Emission Rate	0.120 lb/mmBtu
NO_x Emission Rate	0.070 lb/mmBtu
PM_{10} Emission Rate	0.015 lb/mmBtu
New 244 MW CFB Characteristics	
Fuel	50% Petcoke/50% Coal
Maximum Hourly Heat Input	2,082 mmBtu/hr
Annual Heat Input @ 100% CF	18,238,320 MMBtu/yr
SO_2 Emission Rate	0.150 lb/mmBtu
NO_x Emission Rate	0.080 lb/mmBtu
PM_{10} Emission Rate	0.015 lb/mmBtu

1. Preliminary, not to be used for permitting purposes.
2. 100% CF = 8,760 hours per year at full capacity.
3. 2.73% Sulfur Fuel
4. 0.7% Sulfur Fuel

TABLE J-3

NETTING ANALYSIS FOR NEW 475 MW UNIT

Parameter	Units	SO_2	NO_x	PM
HISTORICAL ACTUAL EMISSION RATES				
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg. @ 69% CF)	ton/yr	6,992.6	3,316.5	162.9
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg.)	1b/mmBtu	0.955	0.453	0.022
FUTURE EMISSION RATES WITHOUT ADDITIONAL CONTROLS				
Deerhaven Unit 2 Future Emissions (With Existing Controls, Future Coal @ 100% CF)	ton/yr	47,073.5	4,814.4	236.5
Deerhaven Unit 2 Future Emissions (With Existing Controls, Future Coal)	1b/mmBtu	4.43	0.453	0.022
New Unit Uncontrolled Emissions @ 100% CF	ton/yr	85,228.6	13,478.1	173,290.3
New Unit Uncontrolled Emissions	1b/mmBtu	4.43	0.700	9.000
FUTURE EMISSION RATES WITH ADDITIONAL CONTROLS				
New Unit Control Efficiency	%	97.3	90.0	99.8
GRU Deerhaven Unit 2 Additional Control Efficiency	%	95.0	82.3	32.5
Controlled GRU Deerhaven Unit 2	1b/mmBtu	0.220	0.080	0.015
New Unit Controlled Emissions	1b/mmBtu	0.120	0.070	0.015
Deerhaven Unit 2 @ 100% CF				
Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	2,339.6	850.8	159.5
New Unit Controlled Emissions @ 100% CF	ton/yr	2,310.5	1,347.8	288.8
New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	4,650.2	2,198.6	448.3
Net Change in Emissions(5)	ton/yr	-2,342.4	-1,117.9	285.4
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 100%CF)	%	-33.5	-33.7	175.2
Deer Haven Unit 2 @ 69% CF				
Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	1,614.3	587.0	110.1
New Unit Controlled Emissions @ 100% CF	ton/yr	2,310.5	1,347.8	288.8
New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	3,924.9	1,934.8	398.9
Net Change in Emissions(6)	ton/yr	-3,067.7	-1,381.7	236.0
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 69% CF)	%	-43.9	-41.7	144.9

5) [New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]

(6) [New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]

Abbreviations:

CF = Capacity Factor

SER = Significant Emission Rate

TABLE J-4

NETTING ANALYSIS FOR NEW 600 MW UNIT

Parameter	Units	SO_2	NO_x	PM
HISTORICAL ACTUAL EMISSION RATES				
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg. @ 69% CF)	ton/yr	6,992.6	3,316.5	162.9
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg.)	1b/mmBtu	0.955	0.453	0.022
FUTURE EMISSION RATES WITHOUT ADDITIONAL CONTROLS				
Deerhaven Unit 2 Future Emissions (With Existing Controls, Future Coal @ 100% CF)	ton/yr	47,073.5	4,814.4	236.5
Deerhaven Unit 2 Future Emissions (With Existing Controls, Future Coal)	1b/mmBtu	4.43	0.453	0.022
New Unit Uncontrolled Emissions @ 100% CF	ton/yr	107,657.2	17,025.0	218,893.0
New Unit Uncontrolled Emissions	1b/mmBtu	4.43	0.700	9.000
FUTURE EMISSION RATES WITH ADDITIONAL CONTROLS				
New Unit Control Efficiency	%	97.3	90.0	99.8
GRU Deerhaven Unit 2 Additional Control Efficiency	%	95.0	82.3	32.5
Controlled GRU Deerhaven Unit 2	1b/mmBtu	0.220	0.080	0.015
New Unit Controlled Emissions	1b/mmBtu	0.120	0.070	0.015
Deerhaven Unit 2 @ 100% CF				
Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	2,339.6	850.8	159.5
New Unit Controlled Emissions @ 100% CF	ton/yr	2,918.6	1,702.5	364.8
New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	5,258.2	2,553.3	524.3
Net Change in Emissions[5]	ton/yr	-1,734.4	-763.2	361.4
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 100%CF)	%	-24.8	-23.0	221.9
Deer Haven Unit 2 @ 69% CF				
Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	1,614.3	587.0	110.1
New Unit Controlled Emissions @ 100% CF	ton/yr	2,918.6	1,702.5	364.8
New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	4,532.9	2,289.5	474.9
Net Change in Emissions[6]	ton/yr	-2,459.7	-1,027.0	312.0
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 69% CF)	%	-35.2	-31.0	191.5

(5) [New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]
(6) [New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]

Abbreviations:
CF = Capacity Factor
SER = Significant Emission Rate

TABLE J-5

NETTING ANALYSIS FOR ONE NEW 220 MW CFB UNIT (50% Petcoke/50% High Sulfur Coal) and DH2 Retrofitted With a Dry Scrubber, SCR and Fabric Filter (100% Low Sulfur Coal)

Parameter	Units	SO_2	NO_x	PM
HISTORICAL ACTUAL EMISSION RATES				
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg. @ 69% CF)	ton/yr	6,992.6	3,316.5	162.9
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg.)	lb/mmBtu	0.955	0.453	0.022
FUTURE EMISSION RATES WITHOUT ADDITIONAL CONTROLS				
Deerhaven Unit 2 Future Emissions (With Existing Controls, Existing Coal @ 100% CF)	ton/yr	10,156.1	4,817.5	234.0
Deerhaven Unit 2 Future Emissions (With Existing Controls, Existing Coal)	lb/mmBtu	0.955	0.453	0.022
New Unit Uncontrolled Emissions @ 100% CF	ton/yr	55,627	1,368	36,477
New Unit Uncontrolled Emissions	lb/mmBtu	6.1	0.15	4
FUTURE EMISSION RATES WITH ADDITIONAL CONTROLS				
New Unit Control Efficiency (Combined boiler and add-on controls)	%	97.5	46.7	> 99.5
GRU Deerhaven Unit 2 Additional Control Efficiency	%	87.4	82.3	31.8
Controlled GRU Deerhaven Unit 2	lb/mmBtu	0.120	0.080	0.015
New Unit Controlled Emissions	lb/mmBtu	0.150	0.080	0.015
Deerhaven Unit 2 @ 100% CF				
Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	1,276.2	850.8	159.5
New Unit Controlled Emissions @ 100% CF	ton/yr	1,367.9	729.6	136.8
New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	2,644.0	1,580.3	296.3
Net Change in Emissions (5)	ton/yr	-4,348.6	-1,736.2	133.4
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 100%CF)	%	-62.2	-52.4	81.9
Deerhaven Unit 2 @ 69% CF				
Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	880.5	587.0	110.1
New Unit Controlled Emissions @ 100% CF	ton/yr	1,367.9	729.6	136.8
New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	2,248.5	1,316.6	246.9
Net Change in Emissions (6)	ton/yr	-4,744.1	-1,999.9	84
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 69% CF)	%	-67.8	-60.3	51.6

5) [New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]
(6) [New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]

Abbreviations:
- CF = Capacity Factor
- SER = Significant Emission Rate

TABLE J-6

NETTING ANALYSIS FOR TWO NEW 220 MW CFB UNITS
(50% Petcoke/50% High Sulfur Coal) and
DH2 Retrofitted With a Dry Scrubber, SCR and Fabric Filter
(100% Low Sulfur Coal)

Parameter	Units	SO_2	NO_x	PM
HISTORICAL ACTUAL EMISSION RATES				
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg. @ 69% CF)	ton/yr	6,992.6	3,316.5	162.9
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg.)	lb/mmBtu	0.955	0.453	0.022
FUTURE EMISSION RATES WITHOUT ADDITIONAL CONTROLS				
Deerhaven Unit 2 Future Emissions (With Existing Controls, Existing Coal @ 100% CF)	ton/yr	10,156.1	4,817.5	234.0
Deerhaven Unit 2 Future Emissions (With Existing Controls, Existing Coal)	lb/mmBtu	0.955	0.453	0.022
New Units Uncontrolled Emissions @ 100% CF	ton/yr	111,254	2,736	72,953
New Units Uncontrolled Emissions	lb/mmBtu	6.1	0.15	4
FUTURE EMISSION RATES WITH ADDITIONAL CONTROLS				
New Units Control Efficiency (Combined boiler and add-on controls)	%	97.5	46.7	> 99.5
GRU Deerhaven Unit 2 Additional Control Efficiency	%	87.4	82.3	31.8
Controlled GRU Deerhaven Unit 2	lb/mmBtu	0.120	0.080	0.015
New Units Controlled Emissions	lb/mmBtu	0.150	0.080	0.015
Deerhaven Unit 2 @ 100% CF				
Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	1,276.2	850.8	159.5
New Units Controlled Emissions @ 100% CF	ton/yr	2,735.7	1,459.1	273.6
New Units @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	4,011.9	2,309.8	433.1
Net Change in Emissions (5)	ton/yr	-2,980.7	-1,006.7	270.2
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 100%CF)	%	-42.6	-30.4	165.9
Deerhaven Unit 2 @ 69% CF				
Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	880.5	587.0	110.1
New Units Controlled Emissions @ 100% CF	ton/yr	2,735.7	1,459.1	273.6
New Units @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	3,616.3	2,046.1	383.6
Net Change in Emissions (6)	ton/yr	-3,376.3	-1,270.4	220.7
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 69% CF)	%	-48.3	-38.3	135.5

5) [New Units @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]
(6) [New Units @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]

Abbreviations:
CF = Capacity Factor

TABLE J-7

NETTING ANALYSIS FOR ONE NEW 220 MW CFB UNIT
(50% Petcoke/50% High Sulfur Coal) and
DH2 Retrofitted With a Wet Scrubber, SCR and Fabric Filter
(100% High Sulfur Coal)

Parameter	Units	SO_2	NO_x	PM
HISTORICAL ACTUAL EMISSION RATES				
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg. @ 69% CF)	ton/yr	6,992.6	3,316.5	162.9
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg.)	lb/mmBtu	0.955	0.453	0.022
FUTURE EMISSION RATES WITHOUT ADDITIONAL CONTROLS				
Deerhaven Unit 2 Future Emissions (With Existing Controls, Existing Coal @ 100% CF)	ton/yr	10,156.1	4,814.5	234.0
Deerhaven Unit 2 Future Emissions (With Existing Controls, Existing Coal)	lb/mmBtu	0.955	0.453	0.022
New Unit Uncontrolled Emissions @ 100% CF	ton/yr	55,627	1,368	36,477
New Unit Uncontrolled Emissions	lb/mmBtu	6.1	0.15	4
FUTURE EMISSION RATES WITH ADDITIONAL CONTROLS				
New Unit Control Efficiency (Combined boiler and add-on controls)	%	97.5	46.7	> 99.5
GRU Deerhaven Unit 2 Additional Control Efficiency	%	77.0	82.3	31.8
Controlled GRU Deerhaven Unit 2	lb/mmBtu	0.220	0.080	0.015
New Unit Controlled Emissions	lb/mmBtu	0.150	0.080	0.015
Deerhaven Unit 2 @ 100% CF				
Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	2,339.6	850.8	159.5
New Unit Controlled Emissions @ 100% CF	ton/yr	1,367.9	729.5	136.8
New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	3,707.5	1,580.3	296.3
Net Change in Emissions (5)	ton/yr	-3,285.1	-1,736.2	133.4
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 100%CF)	%	-47.0	-52.4	81.9
Deerhaven Unit 2 @ 69% CF				
Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	1,614.3	587.0	110.1
New Unit Controlled Emissions @ 100% CF	ton/yr	1,367.9	729.5	136.8
New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	2,982.2	1,316.6	246.9
Net Change in Emissions (6)	ton/yr	-4,010.4	-1,999.9	84.0
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 69% CF)	%	-57.4	-60.3	51.5

5) [New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]

(6) [New Unit @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]

Abbreviations:

CF = Capacity Factor

SER = Significant Emission Rate

TABLE J-8

NETTING ANALYSIS FOR TWO NEW 220 MW CFB UNITS (50% Petcoke/50% High Sulfur Coal) and DH2 Retrofitted With a Wet Scrubber, SCR and Fabric Filter (100% High Sulfur Coal)

Parameter	Units	SO_2	NO_x	PM
HISTORICAL ACTUAL EMISSION RATES				
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002Avg. @ 69% CF)	ton/yr	6,992.6	3,316.5	162.9
Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001 / 2002 Avg.)	lb/mmBtu	0.955	0.453	0.022
FUTURE EMISSION RATES WITHOUT ADDITIONAL CONTROLS				
Deerhaven Unit 2 Future Emissions (With Existing Controls, Existing Coal @ 100% CF)	ton/yr	10,156.1	4,817.5	234.0
Deerhaven Unit 2 Future Emissions (With Existing Controls, Existing Coal)	lb/mmBtu	0.955	0.453	0.022
New Units Uncontrolled Emissions @ 100% CF	ton/yr	111,254	2,736	72,953
New Units Uncontrolled Emissions	lb/mmBtu	6.1	0.15	4
FUTURE EMISSION RATES WITH ADDITIONAL CONTROLS				
New Units Control Efficiency (Combined boiler and add-on controls)	%	97.5	46.7	> 99.5
GRU Deerhaven Unit 2 Additional Control Efficiency	%	77.0	82.3	31.8
Controlled GRU Deerhaven Unit 2	lb/mmBtu	0.220	0.080	0.015
New Units Controlled Emissions	lb/mmBtu	0.150	0.080	0.015
Deerhaven Unit 2 @ 100% CF				
Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	2,339.6	850.8	159.5
New Units Controlled Emissions @ 100% CF	ton/yr	2,735.7	1,459.1	273.6
New Units @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF	ton/yr	5,075.4	2,309.8	433.1
Net Change in Emissions (5)	ton/yr	-1,917.2	-1,006.7	270.2
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 100%CF)	%	-27.4	-30.4	165.9
Deerhaven Unit 2 @ 69% CF				
Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	1,614.3	587.0	110.1
New Units Controlled Emissions @ 100% CF	ton/yr	2,735.7	1,459.1	273.6
New Units @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF	ton/yr	4,350.1	2,046.1	383.6
Net Change in Emissions (6)	ton/yr	-2,642.5	-1,270.4	220.7
PSD SER	ton/yr	40	40	25
Project Subject to PSD Review	(Yes/No)	No	No	Yes
Net Change in Emissions (Controlled Unit 2 @ 69% CF)	%	-37.8	-38.3	135.5

5) [New Units @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 100% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]
(6) [New Units @ 100% CF + Controlled GRU Deerhaven Unit 2 @ 69% CF] - [Deerhaven Unit 2 Actual 2001/2002 Emissions (AOR 2001/2002 Avg. @ 69%)]

Abbreviations:
CF = Capacity Factor
SER = Significant Emission Rate

TABLE J-9

WATER RESOURCE ASSUMPTIONS[1]
FOR THE
ADDITIONAL CAPACITY DEERHAVEN SITES AND GREENFIELD

ITEM	DEERHAVEN		GREENFIELD
Water Supply	Ground Water Reclaimed Wastewater		Ground Water (High TDS)
Cooling System	Evaporative		Evaporative
Blow-Down Disposal	Zero Discharge (Brine Concentrator)		Deep Well Injection
Stormwater Disposal	Zero Discharge (Brine Concentrator)		Deep Well or Surface Water Discharge
Water Requirements @475 MW (gross)	Ground Reclaimed Total	2.2 MGD 3.5 MGD 5.7 MGD	5.9 MGD[2]
@600 MW (gross)	Ground Reclaimed Total	2.2 MGD 4.5 MGD 6.7 MGD	6.7 MGD

1. Not for permitting purposes
2. Higher solids limit cycling

Source: Sargent Lundy, 2003, Table 4-8

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SECTION K
BULK POWER TRANSMISSION SYSTEM CAPACITY

GRU's bulk power transmission network consists of a 138 kV loop connecting the following:

1) J. R. Kelly and Deerhaven generating stations;
2) Nine distribution substations;
3) Three interties with Progress Energy Florida Inc.;
4) An intertie with the Florida Power and Light Company;
5) An interconnection with Clay Electric Cooperative Inc. at the Farnsworth Substation; and
6) An interconnection with the City of Alachua at Alachua's substation No. 1.

Refer to Figure C-1 for line geographical locations and Figure K-1 for electrical connectivity and line numbers.

TRANSMISSION LINES

The ratings for all of GRU's transmission lines are given in GRU's 2003 Ten-Year Site Plan (Reference 35). The load ratings for GRU's transmission lines were developed in Appendix 6.1 of GRU's Long-Range Transmission Planning Study (Reference 39). Figure K-2 provides a one-line diagram of GRU's electric system. The criteria for normal and emergency loading are taken to be:

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

The present transmission network consists of the following:

Line	Circuit Miles	Conductor
138 KV double circuit	100.20	795 MCM ACSR
138 KV single circuit	16.74	1192 MCM ACSR
138 KV single circuit	20.74	795 MCM ACSR
230 KV single circuit	2.60	795 MCM ACSR
Total	140.28	

As part of an analysis in September and October of 2002 the transmission system was subjected to scenario analysis. Each scenario represents a system configuration with different contingencies modeled. A contingency is an occurrence that depends on chance or uncertain conditions and, as used here, represents various equipment failures that may occur. The following conclusions were drawn from this reliability contingencies analysis:

- Single contingency transmission line and generator outages (the failure of any one generator or any one transmission line) – No identifiable problems
- All right-of-way outages (two lines - common pole) – No problems with GRU's 138 kV/24 MVAR capacitor on line
- Meeting future load and interchange requirements – No identifiable problems through 2009

STATE INTERCONNECTIONS

The System is currently interconnected with Progress Energy Florida (PEF) and Florida Power and Light (FPL) at a total of four separate points. The System interconnects with FPE's Archer Substation via a 230 kV transmission line to the System's Parker Substation with 224 MVA of transformation capacity from 230 kV to 138 kV. The System also interconnects with FPE's Idylwild Substation with two separate circuits via a 168 MVA 138/69 kV transformer at the Idylwild Substation. The System interconnects with FPL via a 138 kV tie between FPL's Bradford Substation and the System's Deerhaven Substation. This interconnection has a thermal capacity of 222 MVA.

ADDITIONAL CAPACITY AT DEERHAVEN

GRU actively participates in all of the Florida Reliability Coordinating Council's (FRCC) regional planning initiatives within Florida. The reliability of the bulk power grid is assessed looking ten years into the future. The North American Electric Reliability Council (NERC) Planning Guidelines are adhered to under various contingency simulations. Capital projects are introduced to address issues not complying with criteria. In addition, GRU performs planning studies internally. All initiatives undertaken are intended to assure that GRU's grid reliability adheres to industry planning criteria. At present, the GRU Bulk Power grid is capable of reliably accommodating all existing generation capability.

Building more than 300 MW of additional generation capacity within the existing GRU Bulk Power grid will require transmission system upgrades. The expansion plan presented below will accommodate both a 475 MW and 600 MW capacity expansion at the existing GRU Deerhaven generation site. Under either option, the incremental capacity addition would be injected into a newly constructed 230 kV switchyard. The existing 138 kV Deerhaven switchyard and the new 230 kV switchyard would be tethered together via two 230 / 138 kV transformers. Accommodating either option will require the following two system improvements:

- 29.6 miles of new 230 kV circuit construction
- Re-conductor 33.78 miles of existing 138 kV circuitry for 138 kV operation at an increased ampacity

The new 230 kV circuit construction would create a new Deerhaven – Bradford 230 kV circuit. The existing Deerhaven – Bradford 138 kV circuit would remain in service. Both circuits would be placed physically on a newly constructed Double Circuit Tower configuration utilizing the existing Right of Way. Approximate cost estimates have been provided utilizing 2003 dollars. The actual final costs could vary from these figures. Potential participants in a joint project also have requested that a tie to Seminole Electric Cooperative Inc. at Keystone be considered as an enhancement of the Bradford upgrade.

To achieve an increased capacity at a 138 kV operating voltage, the following four existing GRU 138 kV circuits would be re-conducted:

- Deerhaven – Millhopper 138 kV
- Millhopper – Depot W 138 kV
- Deerhaven – McMichen 138 kV
- McMichen – Depot E 138 kV

The existing 795 ACSR Drake conductor would be replaced with a 795 ACSS Suwannee conductor. Suwannee is designed for a conductor operating temperature of 250^{o}C, providing 2000 amperes of thermal capacity. All existing towers would be reused. Approximate cost estimates for the required upgrade are provided in Table K-1.

WHEELING CHARGES

For scenarios involving facilities at a greenfield site in south Florida, the following transmission wheeling charges and system loss factors were applied:

1.	Firm Point-To-Point Transmission Service	$13,080/MW-yr
2.	Reactive Supply and Voltage Control from Generation Sources Firm Point-To-Point Transmission Service	$1.2096/kW-yr
3.	FPL's Transmission System average losses.	2.19 (%)

FIGURE K-1

Gainesville Regional Utilities Electric System One-Line Diagram

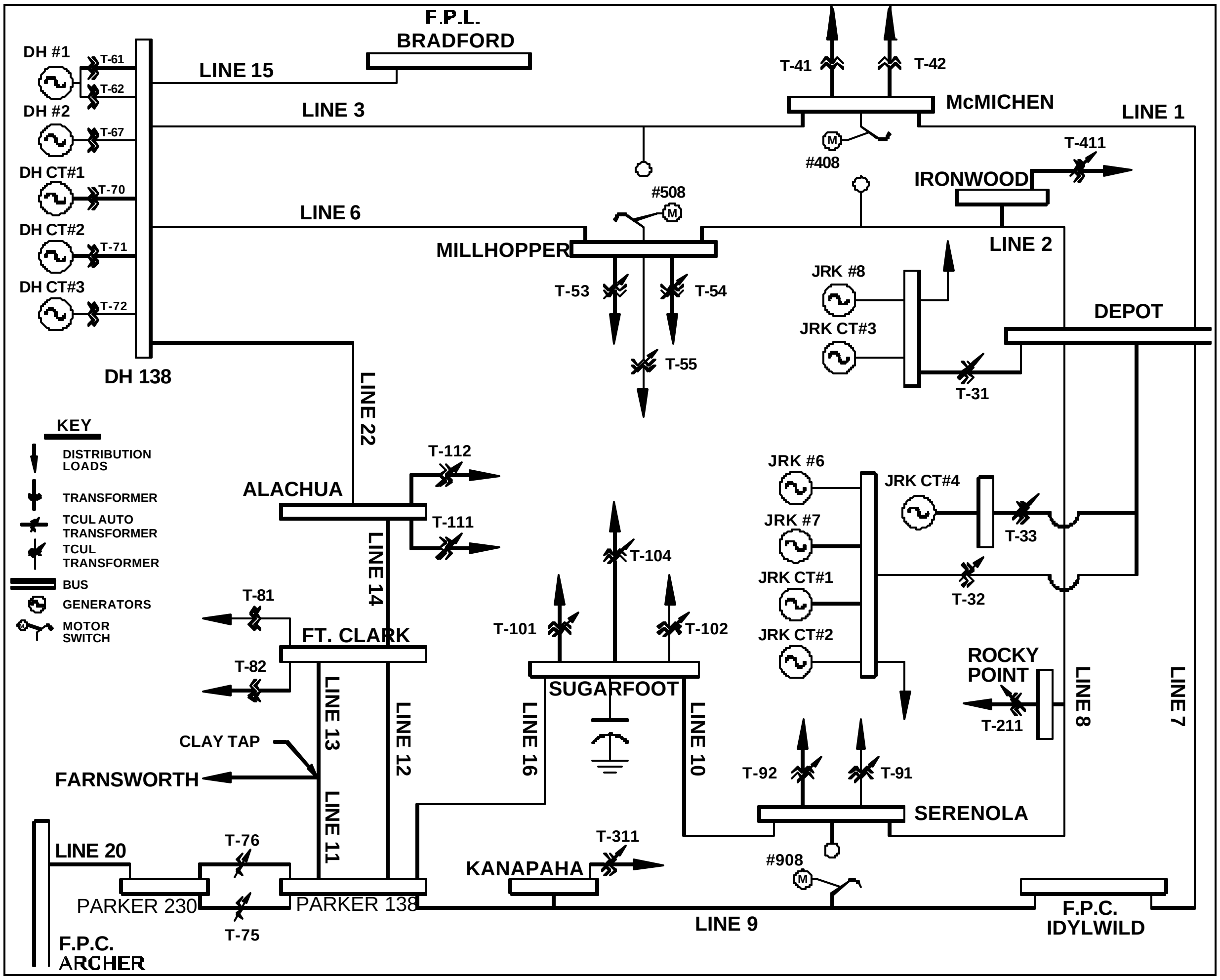

TABLE K-1

ACCOMMODATING ADDITIONAL CAPACITY AT DEERHAVEN
GRU TRANSMISSION SYSTEM IMPROVEMENTS

Required System Improvements		Cost Estimate (2003 Dollars)
29.6 Miles of new 230 kV circuit construction		
Bradford 230 kV switchyard work		$2,112,000
DH - Bradford 138 / 230 kV DCT		$11,691,000
Re-conductor 33.78 miles of existing 138 kV circuitry for 138 kV operation at increased ampacity		$2,378,000
	Total	$16,181,000

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SECTION L
POTENTIALLY FEASIBLE
GENERATION TECHNOLOGIES

This section provides a more detailed description of the potentially feasible technologies considered as a result of the screening process in Section I. It also presents the cost and operating characteristics for these technologies used for the IRP. The information presented in this section follows the conventions listed below:

1). Cost is presented as cost per net kW. This takes into account capacity used for auxiliary loads such as feed water pumps, electrostatic precipitators, etc. Values are presented as "over-night" construction costs in 2003 dollars.

2). Costs include the emission controls required to meet standards and permitting requirements. More discussion of these controls is presented in Chapter J of this report.

3). Costs assume construction at the Deerhaven Power Plant site unless otherwise noted.

Finally, to fully optimize generation resources in order to minimize revenue requirements, GRU's existing resources also must be modeled. The operating characteristics of GRU's existing fleet as employed in the IRP also are presented in this section.

POTENTIALLY FEASIBLE ALTERNATIVES

Table L-1 summarizes the technologies included in detailed economic analysis as part of the IRP. Detailed assumptions for each of these technology scenarios are provided in Table L-2. Note that Table L-2 has the specific details required to model each technology correctly as it is implemented. For example, the option that includes re-powering Deerhaven 1 is modeled by retiring the existing unit (81.0 MW) and adding a reconfigured unit (231.1 MW) for a net gain of 150.1 MW. Corresponding changes in O&M expenses are also modeled. Also note that the option for adding additional smaller units (i.e. 220 MW CFB) in later years is shown in Table L-2 without the Deerhaven 2 retrofit, which need be done only once.

The information assembled in Table L-2 was developed from internal operating records for existing facilities and a variety of studies done specifically for GRU (References 4,5,6,7 and 8) and for the Joint Feasibility studies described in Section A (References 50 and 51).

FUEL CONSIDERATIONS

One objective of this IRP is to manage primary energy supply and pricing risks by fuel diversification. Delivered fuel prices in Florida are relatively high and the use of the most efficient means of power generation, such as supercritical designs, may be financially prudent. High efficiencies also result in low emissions of pollutants, and therefore are likely to be considered environmentally responsible when evaluated in the regulatory permitting process. Design features must be incorporated into any generating plant to suit the particular fuels to be fired, especially where those fuels contain high levels of contaminants such as sulfur and vanadium, as is the case with petroleum coke, or high levels of chlorides, as is the case for biomass.

Natural Gas And Oil

Simple cycle and combined cycle combustion turbines require the use of either a gaseous or light liquid fuel (distillate oil No. 2). As indicated in Chapter H, both of these fuels have the disadvantage of high volatile cost, and increasing reliance upon offshore imports. Despite this disadvantage, these alternatives had significant operating and cost advantages as peaking units that warranted detailed evaluations of these technologies in the development of GRU's long-term IRP.

Coal Compared with Petroleum Coke

As already described, there are a multitude of mines in the coal fields stretching through the Appalachians that could offer multiple, alternative sources of coal. A coal contract from a power plant of a medium-to-large size (>400 MW) would allow a variety of mines to establish a new long wall or other mining operation to feed as part of a long-term contract. Importation of the aggressively priced Columbian, South African or Australian coals may be difficult due to transportation limitations at Deerhaven and the greenfield site. The large reserves of domestic coals in the eastern U.S. should effectively control the risks of long-term rises in primary energy prices for a coal-fired power plant.

Conventional subcritical and supercritical boiler designs are limited in the amount of petroleum coke (pet coke) that can be burned due to their accompanying emission control efficiencies. Non-conventional boiler or combustion turbine designs (CFB and IGCC, for example) can use higher percentages of pet coke due to their inherently different emission control capabilities. Compared with bituminous coal, petroleum coke (pet coke) has a higher heat content per pound, higher sulfur content, and lower ash content. Pet coke also has different grindability characteristics. However, pet coke does have substantial cost advantages.

The subcritical and supercritical boiler design alternatives considered in this study assume that coal will be the principal fuel, with up to 20% (by energy) of petroleum coke blended with the coal. CFB and IGCC designs are technologies suitable for the use of petroleum coke as the principal fuel.

The gasifier based IGCCs of the type that would suit the fuel available to Florida also are better suited to very high sulfur fuels than are CFB or pulverized coal plants. Most of the IGCCs in commercial service around the world have been specifically built to fire 100% petroleum coke or similar oil refinery by-products. A typical IGCC includes an air product plant (for pure oxygen to be used in the gasifier) and a sulfuric acid production plant to manage the SO_2 generated in the gasifier. The high temperature ducting between the gasifier and the combustion turbine is very critical and imposes site layout constraints. Although complicated and expensive to construct and maintain, IGCC technology is well suited to sulfur capture and would require less flue gas clean-up equipment to meet environmental objectives than pulverized coal boiler technologies.

Continuous 100% petroleum coke firing by a large CFB has not yet been demonstrated, but it is an objective for the two large JEA Northside CFBs. The first ten years' experience with circulating fluidized beds in power plant applications have been characterized by mixed experiences in fire-side corrosion/erosion of boiler tubing. Sulfur and vanadium levels can be higher in petroleum coke than in coals, which contribute to this corrosion. Only long-term experience will determine if CFB tube life is affected when firing these high sulfur and high vanadium fuels.

Predicting petroleum coke prices to any degree of certainty for the relevant years, from 2010 and beyond, is very difficult since petroleum coke is a by-product of the petroleum processing industry. Until recent improvements in emission control and combustion technologies, the demand for petroleum coke has been limited, and the potential supply relatively large. Competition for this fuel supply in the future could substantially affect supply and cost due to improved emission controls. Since petroleum coke is a byproduct of petroleum processing, there is always a potential for advances in petroleum processing technology to change the petroleum coke supply and/or quality, which adds further uncertainty to the long-term supply of petroleum coke.

Biomass

Biomass is most cost effective if considered for supplemental steam production. This would consist of a separate steam-generating unit in support of the main generating facility. The cost of biomass fuel is highly dependent upon the geographical proximity of the source. Due to the wide range of heat contents, chemical constituents, moisture content, and fuel cleanliness, stoker grate or bubbling fluid bed boiler designs are suitable for the combustion of such fuel.

The Phase 1 Joint Feasibility Study (Reference 50), anticipating that the availability of biomass fuel would be relatively small, recommended a bubbling bed design, with its steam combined with that of a nominally 500 MW coal or petcoke boiler to power a single large turbine generator set. This allows the widest possible range of wastes while simplifying operation, reducing carbon intensity, and providing "green" power that is expected to have a market value premium of $10 per MWh or more. Also, this configuration allows the biomass ash to be managed (sold) as a valuable source of agricultural phosphorous and potassium.

Fuel processing for burning wood wastes should be located separately from the power plant site. This allows for fuel cleaning, classification, and processing in a controlled environment, which would not impact the power plant operation. Fuel can be delivered in a sized and de-watered state, which can be more easily handled without an excessive stockpile or fuel handling facilities. This also eliminates the need for a wash pond for trees that may be contaminated with mud or other debris. Production of "pelletized" biomass fuels is common in Europe and allows the use of biomass fuels in conventional pulverized coal boilers. The pelletizing process is specially designed to improve grindability and requires a large supply of very clean hardwood sawdust as a feedstock. This feedstock does not present the chloride problems associated with other biomass materials.

Urban biomass wastes would require screening for lead based paints, arsenic contamination of pressure treated wood, and other special pollutants. Urban wood wastes were eliminated from consideration in order to reduce the need for excessive sorting and/or special landfill requirements.

The selection of a scheme to utilize biomass and alternative resources would depend on both the quantity and type of biomass. Cost-effective collection and transportation of biomass fuels normally limit their use to within dozens, rather than hundreds, of miles of their points of production. The biomass availability will vary depending on the particular site eventually selected (Deerhaven versus greenfield).

SIMPLE AND COMBINED CYCLE COMBUSTION TURBINES

Basically, combustion turbines (CT) are jet engines that turn a shaft. Relatively inexpensive to install, they require high-grade fuels (natural gas or distillate oil) to operate. Typically, they are designed to run with a capacity factor of less than 15% as quick start peaking units. They require maintenance and overhauls after far fewer duty hours than steam cycle machines, as the turning vanes are operating in a very hot and abrasive environment.

Combined cycle (CC or CCCT) machines employ a heat recovery steam generator to capture the exhaust heat from the CT part of the system to make steam. This steam is used to power a steam turbine generator set. The combined cycle's efficiency is very high, but with higher costs than CTs yet lower costs than solid fuel fired plants. They have relatively short maintenance cycles compared with steam cycle units and longer start-up times than CTs. They are typically installed as intermediate units with design capacity factors of about 40%.

PULVERIZED SOLID FUEL – SUBCRITICAL AND SUPERCRITICAL

In the period from 1960 to 1985 the design of coal and oil-fired units of above 250 MW capacity for the U. S. and the United Kingdom (U. K.) generally settled on turbine stop valve main steam conditions of 2,400 psig and 1,000 ^{0}F, with reheating to 1,000 ^{0}F. Occasionally 2,400 psig/1,050 ^{0}F designs were employed.

These conditions were intended to give reasonably good unit efficiencies, while keeping the boiler water and steam circuits sufficiently below the critical point to allow the use of conventional boiler technology. Boiler drums have both water and steam phases in a "drum," and recirculation of water through the evaporation or "boiling" section of the boiler. Because the cycle has a water phase, it is termed a "subcritical" design.

Once-through boilers have been traditional in continental Europe, and do not require differentials between water and steam phases to operate. Therefore, it was more logical for steam pressures to continue to be raised beyond 2,400 psig in the quest for greater unit efficiency. This is called a "supercritical" boiler design, so named because historically, enthalpy nomograms for steam have labeled the conditions under which steam exhibits liquid characteristics as "supercritical." In Japan, the Ministry of Trade and Industry encouraged a relatively early and universal change to supercritical steam conditions, and virtually all steam boiler/turbine units above 350 MW operating in Japan use supercritical steam conditions.

While the bulk of coal-fired units in the U.S. used subcritical drum boiler designs, some supercritical units were built. American supercritical units of 600 MW, 800 MW and 1,300 MW capacity entered service between 1968 and 1990. While there has been relatively little construction in the past 15 years of coal-fired capacity in the U.S. and the U.K. (the two countries that have traditionally favored subcritical, drum technology), construction of new coal capacity has continued in the global economy. For example, of new coal-fired units commissioned in Organization for Economic Cooperation and Development (OECD) countries between 1995 and 2000, some 20,000 MW of were supercritical, representing 85% of the total capacity constructed.

Supercritical Reliability And Costs

As with most new technologies, early supercritical units experienced various reliability problems. Between the first commercial demonstration of the supercritical technology in America in 1956, and the mid-1970's, substantial experience was accumulated, some of which was disappointing. However, most of the supercritical units built in that period continue in operation today, and many now have good availability records.

The duty of tubes in all coal-fired boilers is severe and there are constant demands on boiler designers to control costs by aggressive compromises between tube costs, heat transfer performance and tube life. As one might expect, tube life is an issue requiring careful attention under the increase of temperatures and pressures from subcritical to supercritical conditions. Thus, for example, a 1987 North American Electricity Reliability Council (NERC) report, "Boiler Tube Failure Trends," compared subcritical and supercritical tube lives. It could be concluded from those results from 15 years ago that equivalent forced outage rates from tube failures had been higher with supercritical, than with subcritical units, but that the era of the original design was a significant factor and that figures were already trending closely together. Operational data from supercritical designs within the past ten years indicate no reliability disadvantages from supercritical design.

To achieve the best thermodynamic results from supercritical cycles requires high temperatures as well as high pressures. Higher temperatures necessitated the use of austenitic steels for boiler tubing, and it is well known that very high sulfur fuels could accelerate fire-side corrosion for such steels. More sophisticated ferritic materials later came into use and experience is being accumulated for long-term material behavior with high sulfur fuels. A common solution to earlier boiler tube internal corrosion problems was to add oxygen to the boiler feed water. Combined with the correct metals under supercritical conditions this results in a layer of "magnetite" on the inside surface of the boiler tubes, which protects them from corrosion.

CIRCULATING FLUIDIZED BEDS

During the mid to late 1980s, fluidized bed combustion was introduced into the generation industry as an alternative to stoker fired units. This technology, utilized primarily in the chemical and process industries, soon proved to be an effective and efficient method of combustion for a wide range of fuels. Recognized for its fuel flexibility, as well as its ability to reduce sulfur dioxide and nitrogen oxide emissions, it became synonymous with "best available technology" in solid-fuel combustion. It has been utilized on coal, coke, residual oil, bio-mass, and refuse derived fuels and in generating unit sizes ranging up to 300 MW.

Bubbling Fluid Bed (BFB)

This approach allows for combustion of the widest range of fuel densities and heat contents. It also is the most forgiving when considering fuel-sizing constraints and waste removal. For these reasons BFB technology has been utilized to combust wood wastes, agricultural crop residues, petroleum coke, residual oil, coal, refuse derived fuel (RDF), auto shredded residue, cow manure, bagasse, plastics, cardboard, and other commercial waste materials. The primary drawbacks in utilizing this technology are the initial capital costs (as compared with conventional technology), high parasitic loads due to fluidization systems, and size restrictions due to physical design constraints.

Circulating Fluid Bed (CFB)

CFB units require more stringent sizing and combustion consistency than BFB units, due to combustion of fuel throughout the boiler instead of primarily the dense bed area. Due to the "thermal fly-wheel" effect provided by the hot bed materials, the CFB units still have broader fuel flexibility than the PC type units. The CFB units also are capable of larger unit sizing than the more flexible BFB design. Although there are CFB installations up to 300 MW, the maximum reliable size CFB unit generally considered as demonstrated technology is 250 MW.

GASIFIER TECHNOLOGY

Gasifiers take an energy feedstock and submit it to temperature and pressure in a controlled atmosphere to create a synthetic fuel. The net amount of carbon dioxide produced per mmBtu produced is equal to the feedstock materials. The concentrated exit gases allow sulfuric acid production to control the sulfur content in the synthetic fuel, and metals and solids exit as dust or slag material. NO_X control is a function to the technology used to combust the synthetic fuel. Large gasifiers have been in development for over a century, for various process and chemical manufacturing applications.

Approximately a dozen different designs currently are commercially available for the large scale gasification of a wide range of feed stocks, ranging from black and brown coals, through oils and oil refinery wastes, to sewage sludges. Designs are available which are "blown" with air, oxygen, steam and/or mixtures of these.
Fuel may be fed as dry powder or as slurry. The gasifier may hold the feedstock in a bed, or the gasification may take place with the feedstock entrained in the gas flow.

Integrated Gasification Combined Cycle (IGCC)

The alloys used in the hot section components of gas turbines would be very rapidly attacked by contaminants in coal such as sodium, potassium, vanadium, chlorides and sulfates. However, there is the potential to gasify coal and use the resulting uncontaminated fuel gas in an integrated design to drive gas turbines, especially considering the relative abundance of solid fuels.

IGCCs require large quantities of air and/or oxygen at pressure, and, as a gas turbine has the compression of large quantities of air as an integral part of its thermodynamic cycle, the opportunity exists to integrate the gasification of coal with a combined cycle gas turbine design to produce an efficient and environmentally clean means of using coal to generate electricity. IGCC plants are notable, compared with PC or CFB, for:

1. High efficiency (a heat rate of 8,500 Btu HHV/kWh)
2. Low environmental emissions, even without fitting SCR or FGD equipment.
3. Complex and relatively expensive plant.

Because of their intrinsic ability to capture sulfur in fuels (recovering 99.5% of sulfur as a saleable elemental sulfur or sulfuric acid by-product), IGCCs are especially commercially attractive for high sulfur fuels. IGCCs are being installed in a number of petroleum coke-fired applications, because of their ability to cope with the high levels of sulfur and other contaminants in that fuel, with acceptable environmental emissions.

For electricity generation from coal, four alternative equipment systems are perhaps most applicable. Three of those are suited to the coals likely to be chosen for this project. These are the British Gas/Lurgi fixed bed gasifier system (as currently being demonstrated by global Energy, on east Kentucky coals and refuse derived Fuel, at their 540 MW Clark county, KY site), and two entrained flow systems, being demonstrated by Shell and by Chevron-Texaco at various sites (including the Tampa Electric Polk plant, which uses the Chevron-Texaco variation of this technology).

Evaluations performed in the Phase 1 Joint Feasibility Study determined that IGCC was not potentially feasible due to economic reasons, and hence dropped from further consideration (Reference 50).

TABLE L-1

POTENTIALLY FEASIBLE ELECTRIC GENERATION TECHNOLOGIES EVALUATED WITH EGEAS

TECHNOLOGY	TYPICAL APPLICATION	DESCRIPTION	SPECIFIC MODEL USED	
			SIZE (MW)	MODEL
Direct Load Control	Peak Load	Meet Peak Loads by turning off customer appliances remotely	Up to 19	GreenWave DLC
Photovoltaic	Daytime Intermediate	Converts sunlight directly into electricity. Only 30% peak coincidence factor. Very conservative cost estimate, assuming economies from large centralized installation.	13	Multi-crystalline cell material, non tracking, ground mounted
Combustion Turbine Simple-Cycle (SCCT)	Peak Load	Internal Combustion Machine with low NO_X Burners – Simple Cycle (no heat recovery)	77.5 166.0	7EA-GE SCCT 7FA-GE SCCT
Combustion Turbine Combined-Cycle (CCCT)	Intermediate Load	Internal Combustion Machine with low NO_X Burners – Simple Cycle with a heat recovery steam generator (HRSG) to improve efficiency and longer run times	120.5 243.0	7EA-GE CCCT 7FA-GE CCCT
Re-powering Deerhaven Unit 1 with a CCCT	Intermediate Load	Retire Deerhaven 1's steam boiler and replace it with steam derived from a heat recovery system generator (HRSG) using waste heat from a suitably-sized combustion turbine (Low NO_X).	150.1	7FA-GE CCCT (Re-powered Capacity of 231.1 MW)
Steam Cycle: Subcritical Boiler Pulverized Fuel	Base Load	Operation at 2400 PSIG and 1000^{O}F. Conventional technology similar to DH2. Includes Wet Scrubber, SCR, and Filter Fabric. Also includes retrofit of DH2 with Wet Scrubber, SCR, and Filter Fabric.	220	Up to 20% Pet Coke design

TABLE L-1 CONTINUED POTENTIALLY FEASIBLE ELECTRIC GENERATION TECHNOLOGIES EVALUATED WITH EGEAS				
Steam Cycle: Supercritical Boiler Pulverized Fuel	Base Load	Operation at 3600 PSIG and 1050^{O}F to improve thermal efficiency. Includes Wet Scrubber, SCR, and Filter Fabric. Also includes retrofit of DH2 with Wet Scrubber, SCR, and Filter Fabric.	439 557	Up to 20% Pet Coke design Up to 20% Pet Coke design
		Without cost of DH2 retrofit but at Greenfield site in south Florida. Includes transmission capacity reservation charges.	439 557	Up to 20% Pet Coke design Greenfield Site Up to 20% Pet Coke design Greenfield Site
Steam Cycle: Circulating Fluidized Bed (CFB)	Base Load	Steam boiler with combustion occurring in a hot bed of limestone kept in motion with combustion air. CFB includes Dry Scrubber for SO_X, SNCR for NO_X control and Fabric Filter. Cost to simultaneous retrofit DH2 with Dry Scrubbers, SCR, and Filter Fabric included.	220	Up to 50% Pet Coke design
Steam Cycle: Bubbling Bed Boiler Design	Base Load	Similar to CFB design without circulating bed material. Suitable for combustion of biomass.	7	Estimated from literature sources
Integrated Gasification Combined Cycle	Base Load	Requires front-end gasification process to create a synfuel capable of running a combined cycle combustion turbine. Requires oxygen plant and an acid production plant to handle waste sulfur.	250	Similar to demonstration plant in south Florida

TABLE L-2: IRP Generator Data: Existing Facilities and Future Options

Generator Name or Description	Generator Capacity (MW)	Reserve Margin Multiplier	Levelized Carrying Charge (%)	Mature Forced Outage (%)	Full Load Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Capital Cost Escalator (%)	Fixed Operation and Maintenance Costs ($/kW-yr)	Fixed Operation and Maintenance Escalator (%)	Variable Operation and Maintenance Costs ($/MWh)	Variable Operation and Maintenance Escalator (%)	Life (years)	Book Life (years)	Fuel Name	Starting Fuel Price ($/MBtu)	Winter Capacity Multiplier	Summer Capacity Multiplier
Deerhaven Unit 1	81.000	1.0247	-	2.5	11,960	-	-	13.537	3.0	2.810	3.0	21	-	NG D	5.97	-	-
Deerhaven Unit 2	218.000	1.0477	-	4.5	10,138	-	-	21.230	3.0	0.940	3.0	28	-	LSB	2.04	-	-
Deerhaven CT 1	18.000	1.0000	-	15.0	14,814	-	-	0.132	3.0	6.241	3.0	23	-	NG D	5.97	-	-
Deerhaven CT 2	18.000	1.0000	-	15.0	14,814	-	-	0.132	3.0	6.241	3.0	23	-	NG D	5.97	-	-
Deerhaven CT 3	75.000	1.0000	-	10.0	11,989	-	-	0.124	3.0	0.575	3.0	43	-	NG D	5.97	1.051948	0.9740260
J R Kelly Unit 7	20.000	1.1600	-	7.5	12,427	-	-	16.685	3.0	6.159	3.0	8	-	NG K	5.97	-	-
J R Kelly Combined Cycle 1	110.000	1.0000	-	10.0	8,200	-	-	15.524	3.0	3.668	3.0	48	-	NG K	5.97	-	-
J R Kelly CT 1	14.000	1.0000	-	15.0	16,333	-	-	2.103	3.0	26.407	3.0	15	-	NG K	5.97	-	-
J R Kelly CT 2	14.000	1.0000	-	15.0	16,733	-	-	2.103	3.0	26.407	3.0	15	-	NG K	5.97	-	-
J R Kelly CT 3	14.000	1.0000	-	15.0	16,733	-	-	2.103	3.0	26.407	3.0	16	-	NG K	5.97	-	-
Land Fill Gas IC 1	0.760	1.0000	-	5.0	12,000	-	-	0.165	3.0	4.000	3.0	6	-	LFG	0.36	-	-
Land Fill Gas IC 2	0.760	1.0000	-	5.0	12,000	-	-	0.165	3.0	4.000	3.0	12	-	LFG	0.36	-	-
Land Fill Gas IC 3	0.760	1.0000	-	5.0	12,000	-	-	0.165	3.0	4.000	3.0	15	-	LFG	0.36	-	-
Crystal River Unit 3	11.000	1.0000	-	5.0	10,500	-	-	191.200	1.0	-	-	34	-	NUCC	0.42	-	-
GreenWave DLC	5.000	1.0000	-	5.0	-	-	-	56.250	3.0	-	-	-	-	-	-	-	-
Photovoltaic	5.000	0.3330	8.2234	5.0	-	4,150.00	3.0	10.660	3.0	-	-	40	35	-	-	-	-
GE 7EA SCCT	77.518	1.0000	8.6437	3.5	11,915	445.058	3.0	3.096	3.0	5.213	3.0	40	35	NG D	5.97	1.101680	0.9491602
Merchant GE 7EA SCCT	75.820	1.0000	12.0555	3.5	12,182	455.021	3.0	17.775	3.0	5.330	3.0	40	30	NG D	5.97	1.101680	0.9491602
GE 7FA SCCT	156.695	1.0000	8.6437	4.0	10,705	311.432	3.0	1.934	3.0	6.819	3.0	40	35	NG D	5.97	1.095757	0.9521215
Merchant GE 7FA SCCT	153.260	1.0000	12.0555	4.0	10,945	318.405	3.0	16.587	3.0	6.972	3.0	40	30	NG D	5.97	1.095757	0.9521215
GE 7EA CCCT	120.480	1.0000	9.0145	2.0	7,749	862.389	3.0	19.281	3.0	3.276	3.0	40	35	NG D	5.97	1.080683	0.9596584
Merchant GE 7EA CCCT	117.840	1.0000	12.8038	2.0	7,923	881.698	3.0	34.322	3.0	3.349	3.0	40	30	NG D	5.97	1.080683	0.9596584
GE 7FA CCCT	243.020	1.0000	9.0145	2.0	7,030	593.772	3.0	10.081	3.0	3.824	3.0	40	35	NG D	5.97	1.080558	0.9597212
Merchant GE 7FA CCCT	237.700	1.0000	12.8038	2.0	7,187	607.067	3.0	24.916	3.0	3.910	3.0	40	30	NG D	5.97	1.080558	0.9597212
DH1+7FA+hrsg CC	231.100	1.0000	8.6437	2.0	7,357	557.984	3.0	6.274	3.0	4.059	3.0	40	35	NG D	5.97	1.085677	0.9571614
DH CFB SNCR + DH2 retrofit	220.000	1.0000	9.4189	4.0	9,910	1,831.914	3.0	27.677	3.0	3.510	3.0	40	35	5050 CFB/Pcok	1.53	-	-
DH CFB SNCR, within 5 yrs	220.000	1.0000	9.4189	4.0	9,910	1,365.000	3.0	27.677	3.0	3.510	3.0	40	35	5050 CFB/Pcok	1.53	-	-
DH CFB SNCR, after 5 yrs	220.000	1.0000	9.4189	4.0	9,910	1,496.250	3.0	27.677	3.0	3.510	3.0	40	35	5050 CFB/Pcok	1.53	-	-
DH FGD/SCR/PC + DH2 retrofit	220.000	1.0000	9.4189	4.0	9,832	2,040.098	3.0	25.218	3.0	2.540	3.0	40	35	8020 HSB/Pcok	1.73	-	-
DH FGD/SCR/PC, within 5 yrs	220.000	1.0000	9.4189	4.0	9,832	1,492.050	3.0	25.218	3.0	2.540	3.0	40	35	8020 HSB/Pcok	1.73	-	-
DH FGD/SCR/PC, after 5 yrs	220.000	1.0000	9.4189	4.0	9,832	1,623.300	3.0	25.218	3.0	2.540	3.0	40	35	8020 HSB/Pcok	1.73	-	-
25% share of DH 439MW FGD/SCR/SC + DH2 retrofit	109.750	1.0000	9.4189	4.0	9,480	1,787.580	3.0	28.733	3.0	1.900	3.0	40	35	8020 HSB/Pcok	1.73	-	-
25% share of South Florida 439MW FGD/SCR/SC	107.350	1.0000	9.4189	4.0	9,692	1,779.685	3.0	54.728	3.0	1.943	3.0	40	35	8020 HSB/Pcok	1.93	-	-
25% share of DH 557MW FGD/SCR/SC + DH2 retrofit	139.250	1.0000	9.4189	4.0	9,442	1,637.580	3.0	28.733	3.0	1.900	3.0	40	35	8020 HSB/Pcok	1.73	-	-
25% share of South Florida 557MW FGD/SCR/SC	136.200	1.0000	9.4189	4.0	9,653	1,626.327	3.0	54.728	3.0	1.943	3.0	40	35	8020 HSB/Pcok	1.93	-	-
(PC/SC) DH2 retrofited w Low NOx Burners, Wet FGD, SCR, & Fabric Filter	215.400	1.0000	-	4.5	10,760	-	-	32.650	3.0	3.110	3.0	40	-	8020 HSB/Pcok	1.73	-	-
(CFB) DH2 retrofited w Low NOx Burners, Dry FGD, SCR, & Fabric Filter	215.400	1.0000	-	4.5	10,760	-	-	28.580	3.0	2.720	3.0	40	-	LSB	2.04	-	-
Biomass (wood waste)	7.000	1.0000	9.4189	15.0	15,000	2,250.000	3.0	59.300	3.0	7.600	3.0	40	35	Wood	0.91	-	-

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SECTION M
ELECTRIC GENERATION ECONOMIC ANALYSIS

The selection of alternatives for additional generation capacity requires careful consideration of environmental issues (Section E), regulatory issues (Section D), fuel availability and cost (Section H), and cost factors (Section L). Furthermore, any evaluation requires an answer to the question “compared with what”? In this IRP various generation alternatives are compared among themselves and with alternatives for not expanding GRU’s generation capacity (“No-Build” alternatives). This section describes the methodology and analytical tools used to evaluate the economics associated with each alternative and to optimize the size and timing of capacity additions and deletions. These same analytical tools and data were used to develop the model of the No-Build alternatives. Finally, the results of a preliminary sensitivity study based on the base, high and low band forecasts of load, energy, and fuel prices are presented.

FINANCIAL ASSUMPTIONS

The basic criterion used in the analysis was to minimize the net present value of revenue requirements to be borne by GRU’s customers. Net present value (NPV) methodologies convert varying cash flows through time to a uniform “figure of merit”, which in this IRP is equivalent 2003 dollars. The NPV uses a discount rate that takes into account the time value of money. In order to project the future cash flows associated with each alternative, a number of assumptions are required in order to model project financing and to take into account the escalation of capital requirements, labor expenses and material costs.

The discount rate applied in this study was based on a weighted cost of capital approach that applies GRU’s customers’ cost of capital to any equity used in financing projects. The debt-to-equity ratio employed in this study was based on preliminary discussions with GRU’s financial advisors. Table M-1 summarizes the economic factors and assumptions used in this IRP.

Following are some additional planning and financial assumptions that are basic to the results presented here.

1. No capacity will be added except as needed to serve GRU’s customers in Alachua County.
2. For scenarios in which only portions of a generation unit are added in any one year, the excess capacity will be sold at a price that exactly equals cost (a wash). No net revenues from wholesale sales of excess capacity were included in any scenario. Section E addresses the current and future market for purchased power agreements (PPA).

EGEAS

EGEAS is an acronymn for "Electric Generation Expansion Analysis System," which is the name of an IRP optimization software system developed by the Electric Power Research Institute. The primary purpose of EGEAS is to find the best possible integrated resource plan for meeting forecasted electrical load and energy by either expanding an electric system's generating capacity; retiring units; and/or reducing load via demand-side management. Optimized plans may be derived for each sensitivity or scenario case and for each objective function specified. The objective function specified for EGEAS in this IRP was to minimize long-term revenue requirements (customer costs). In addition, EGEAS includes enhanced production costing capabilities that can produce a detailed simulation of the specified expansion plans.

EGEAS includes two rigorous optimization tools: Generalized Benders' Decomposition (Benders) and dynamic programming. Generalized Benders' Decomposition is a non-linear optimization technique based on an iterative interaction between a linear master problem and a non-linear probabilistic production costing subproblem. It is not constrained to pick unit sizes based on how they have to be constructed. Dynamic programming (DP) is an optimization technique based on an enumeration of possible capacity additions and a standard dynamic programming technique for selecting the optimal path (set of installation steps). Benders was used extensively in the IRP results presented here due to its ability to provide insight into the optimal amounts of capacity GRU might need, regardless of the sizes various alternatives come in. DP will be used extensively to optimize a limited range of options using increments of generation indicated by contractual or engineering considerations.

Each of the optimization tools supports constraints that limit the range of plans. Reliability constraints eliminate plans with insufficient or over abundant reserve capacity, energy, or loss-of-load probability. Economic constraints eliminate plans that are economically infeasible (low earning assets ratio, low interest coverage ratio, or a large increase in system average price). Additionally, special (tunnel) constraints can be set to specify upper and lower limits on the cumulative number of resources, or year-by-year additions of a particular resource type, installed up through a given year. Tunnel constraints, for example, are used to model changes to Deerhaven 2's cost profile as the consequence of retrofitting it with additional emission control equipment when another unit is constructed (as applicable).

In order to optimize a generation plan, EGEAS simulates economic unit dispatches for every hour of every day in the study period. The production costing capabilities in EGEAS include:

1. four levels of capacity (rated, operating, emergency, and reserves), changing capacity levels by year and month,

2. loading points (up to 5) for capacities, heat rates, and forced outages,
3. automatic and prescribed maintenance scheduling,
4. spinning reserve designations and options,
5. monthly fuel limitations,
6. fuel targets (minimum, maximum and target percentages),
7. costs (fixed O&M, variable O&M, and T&D costs),
8. dispatch modifier costs, and
9. limited energy resource data (by year and by month, typically applicable to hydro projects).

For DSM resources additional capabilities include:

1. customer costs,
2. rebound benefits,
3. direct customer benefits,
4. benefits related to rate changes,
5. transmission and distribution costs and savings,
6. price elasticity by customer class, and
7. customer class rates (demand, energy and customer charges).

Benders' Methodology

With the generalized Benders' decomposition methodology, the generation expansion optimization problem is decoupled into a linear master problem and a non-linear subproblem. Benders alternates between the two problems, with each passing new information to the other. The master problem determines a trial expansion plan based on a linear formulation of the optimization problem. If the problem were indeed linear, the optimization would be complete with no need for further iterations. However, the problem is not linear, so the master problem sends the trial expansion plan to the subproblem for evaluation. The subproblem simulates the trial expansion plan and generates additional linear constraints to better approximate the non-linear cost and unserved energy functions. The subproblem sends these constraints back to the master problem for the next iteration. The iterative process continues until the method converges to an optimum solution.

Dynamic Methodology

The dynamic programming methodology involves the structuring of an optimization problem into multiple stages. These stages, which themselves are smaller optimization problems, are solved recursively to obtain a solution to the overall multi-stage problem. The optimization can start with either the first or last stage, using a forward or backward induction process, respectively. At each stage, a finite set of states, defined by one or more state variables, describes the possible choices. Each state contains the information necessary for making future decisions without regard to how the state was reached.

For the generation expansion optimization problem in EGEAS, each stage is a year of the study period. Each state is defined by the cumulative number of resources of each planning alternative installed in or before the current year. Figure M-1 shows a set of states for a problem with two planning alternatives and a 6-year study period. In year 2 for example, there are 2 states: state (1,0) has 1 fossil unit and 0 gas turbines; state (0,2) has 0 fossil units and 2 gas turbines. Each state indicates how many resources have been built, but not when they were built.

In Figure M-1, the lines between the states indicate valid transitions. Because the number of alternatives are cumulative values, they cannot decrease from one year to the next. Thus, the transition from state (0,2) in year 2 to state (0,1) in year 3 is not valid. Each set of lines connecting a state in year 1 with a state in the last study year represents an expansion plan.

A block diagram of the EGEAS tool is depicted in Figure M-2 and the multiple criteria and options that can be fed to the model. The results are depicted by a list of alternative plans each with an expansion schedule and life cycle costs indicated for further analysis by the planners.

The block diagram in Figure M-3 attempts to show a more complete picture of the process GRU employed to arrive at the best alternative for this IRP. There are multiple feedback loops and redundant processes to ensure that no opportunity is missed. A redesign of the rates may affect the way in which customers use energy, which would in turn affect the load shape of the aggregate load, and therefore change the optimal method of supplying capacity and energy to serve the modified load.

Selecting Optimum Units

EGEAS balances the selection of a resource with how it will fit into a dispatch queue (or “stack”) when it is first installed and over its useful life. The optimal mix of resources requires a combination of base, intermediate, and peaking generation units, based on the tradeoff between capital cost, operational flexibility, and fuel costs. The analysis illustrated in Figure M-4 will help explain this tradeoff.

Using all the assumptions contained in Section L (Table l-2) and using actual fuel costs from 2003, the cost per MWh to generate electricity from a selection of generation technologies is plotted in Figure M-4, as a function of capacity factor. At low capacity factors, combined cycle units are less expensive than solid fuel units. EGEAS takes this into account, and as a result, the optimization studies to date suggest that additional intermediate and base load capacity is cost-effective for GRU, but not additional peaking capacity.

Sensitivity to Forecast Assumptions

Table M-2 illustrates how the different load and energy forecasts help determine the optimal plan. The range of forecasts is wide enough (for example, ± 25 MW by 2010) that it easily encompasses any effects of additional energy conservation programs. The amount of solid fuel capacity varies from 156 MW for the low case to 257 MW for the high case forecast of load. Table M-3 illustrates how different fuel price forecasts affect the optimal plan to meet the base load and energy forecast. The desirability of solid fuel capacity is enhanced as fuel prices increase. Table M-4 presents a matrix of fuel and load forecasts containing the difference between the optimal plan and the corresponding No-Build alternative (assuming no retrofit of Deerhaven 2 for emission control). The differences are expressed in terms of NPV savings over the life of the facilities. The economic benefits of the optimal plan are quite large. For example, the base load, base fuel price scenario calls for about 206 MW of solid fuel capacity will have a net savings of $277,000,000 NPV. The capital cost of the optimal plan is about $390,000,000 including capitalized interest. From a review of the optimization studies, the optimal conventional generation solution for GRU appears to be:

1. 25-35 MW of CCCT capacity in 2008
2. 100-120 MW of Solid Fuel capacity in 2010
3. Options on an additional 100 MW of Capacity through 2022

These assumptions may change pending dynamic modeling and negotiations with potential joint project participants.

NO-BUILD ALTERNATIVES

Two “No-Build” alternatives were developed to compare any proposed generation expansion plans with the alternative of relying on other producers for GRU’s electrical needs in the future. The No-Build alternatives assume that GRU optimizes its electrical portfolio and contracts for all of its additional reserve margin capacity requirements through 2022 from the open market with purchased power agreements (PPA). The only difference between the two No-Build scenarios is that one includes the capital and O&M cost to install additional emission control equipment on Deerhaven Unit 2 (see Section E). A conservative (low) set of assumptions for the No-Build cases were developed to avoid over estimating the benefits of solid fuel alternatives. The assumptions used were that:

1. Throughout the study period, all of the capacity available on the market for PPA acquisition will be gas-fired. Florida has an excess of gas-fired generation and all of the Ten-Year Site Plans submitted to the FPSC call only for additional gas capacity to meet future loads.

2. All PPAs would be for power generated strictly from the largest, most efficient gas-fired generation units currently in the market or planned for future construction.
3. PPA's would allow GRU to purchase energy and capacity at exactly the cost to construct and finance them using IOU regulated rates of return for equity and taxable debt for the remainder. This is the minimum cost for a sustainable merchant operator.

An optimal mix of the most efficient gas-fired, simple cycle and combined cycle combustion turbines for GRU's No-Build cases was developed using Bender's methodology. The technologies chosen for these cases as the most-cost-effective were 7FA SCCT and CCCT (see Section L) commercially available gas-fired machines.

Table M-5 contains the EGEAS results that form the basis of the No-Build, No-Retrofit case. The No-Build, DH 2 Retrofit case differs only in the assumption that a dry scrubber for SO_2 reduction, selective catalytic reduction for NOx removal, and a fabric filter baghouse are installed on Deerhaven Unit 2 beginning in 2010. The construction cost for these facilities was conservatively estimated at $63,400,000 ($2003) including capitalized interest during construction. The annual O&M cost was estimated to be $2,450,000 dollars per year ($2003), net of the sale of excess SO_2 allowances. The retrofit, which is currently not mandated, is a $69,000,000 NPV cost for GRU's customers.

ELECTRIC RATES AND BILLS

EGEAS produces operating and capital cost information that is best understood in terms of the effects that the various plans have on a typical GRU customer's bill. This required incorporating EGEAS results into GRU's corporate model in order to consider all of the factors that influence electric rates. For the IRP, the corporate model was extended through 2022 as an analytical tool for the IRP. Note that EGEAS evaluates alternatives over the life of any capacity installed.

GRU's corporate model uses forecasted sales of electricity, the costs of the transmission and distribution system, and administrative systems and overheads together with general fund transfer requirements, bond indenture covenants for coverage ratios, and fund balances to balance the required uses of funds with revenues. Throughout the planning horizon, the model is used to schedule rate changes that maintain the required debt service coverage ratios while addressing fundamental system strategies such as debt to equity ratios and fund balances. It is routinely used for budgeting, managing debt, and setting rates.

For this IRP, sales and revenue projections were taken from "Budget Year 2004: Forecast of Customers, Sales and Revenues" (Reference 36). Expenses and capital requirements are from projections in the FY 2004 Budget (Reference 36).

Base rate changes were optimized for each case, and then combined with output from EGEAS that optimizes and models the operation and maintenance costs for GRU's entire generation fleet, including fuel costs. The results were then used to calculate typical monthly residential electric bills, assuming consumption of 1000 kWh per month.

FIGURE M-1

ALTERNATIVE STATE DIAGRAM

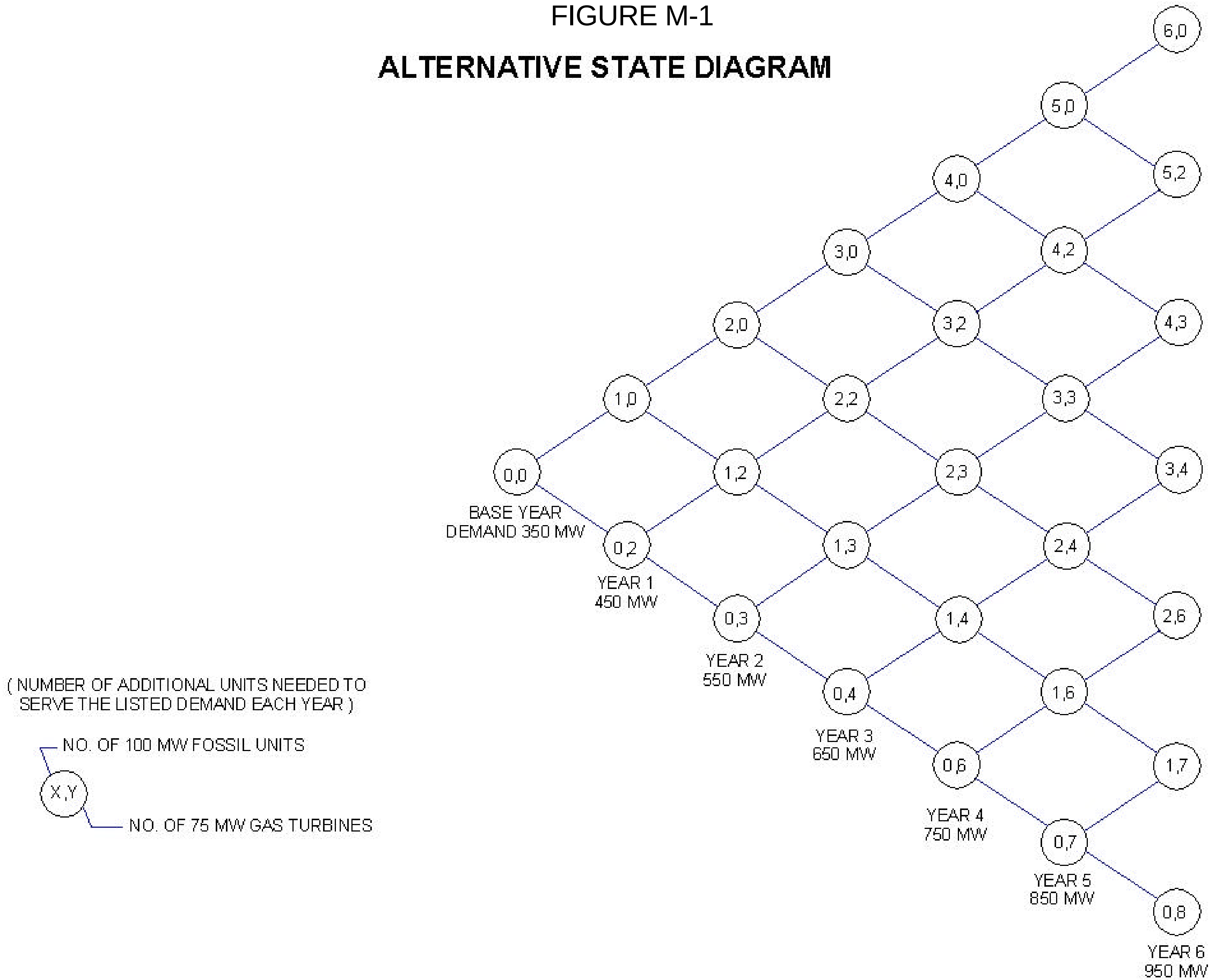
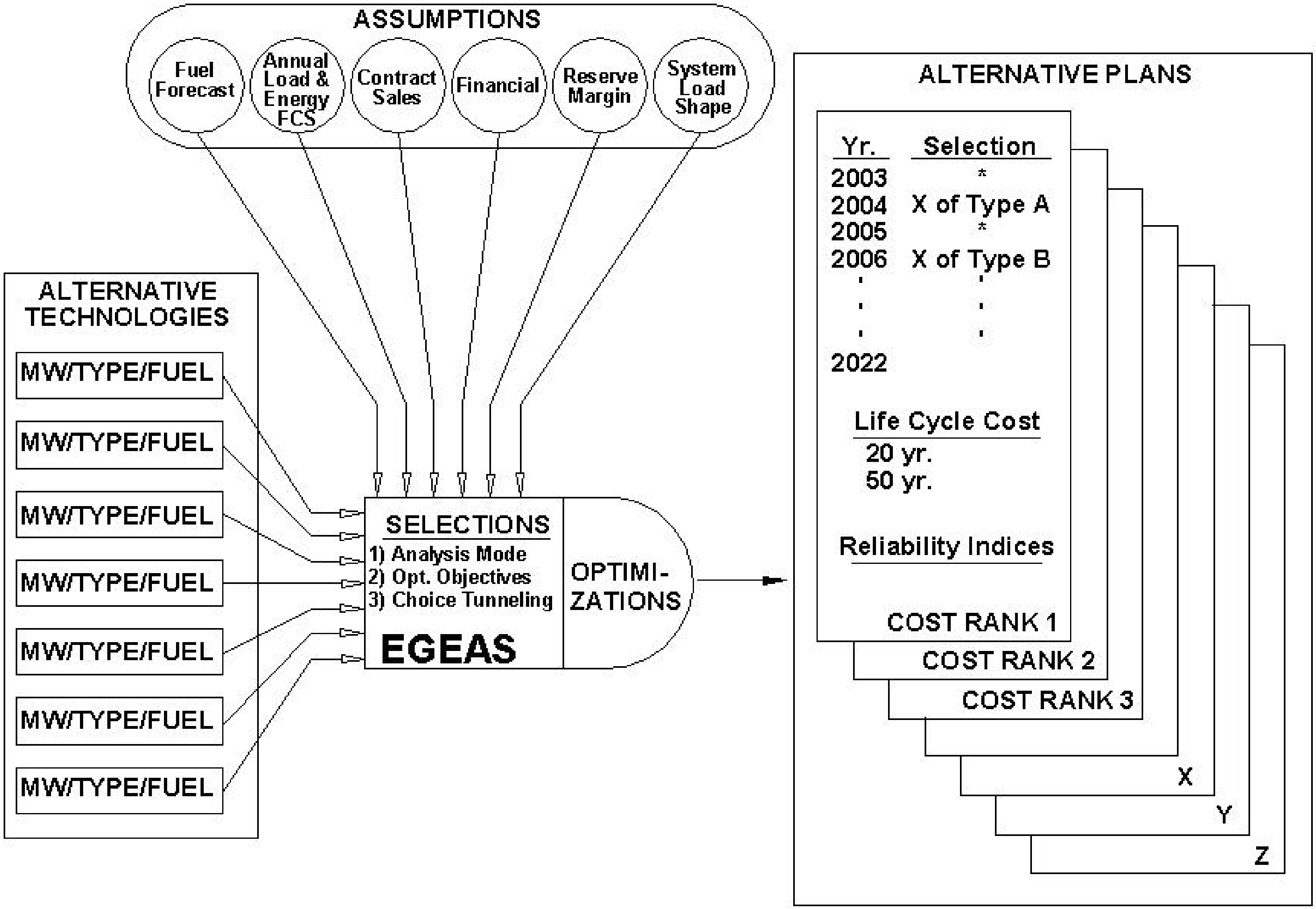


FIGURE M-2



ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

FIGURE M-3

IRP PROCESS

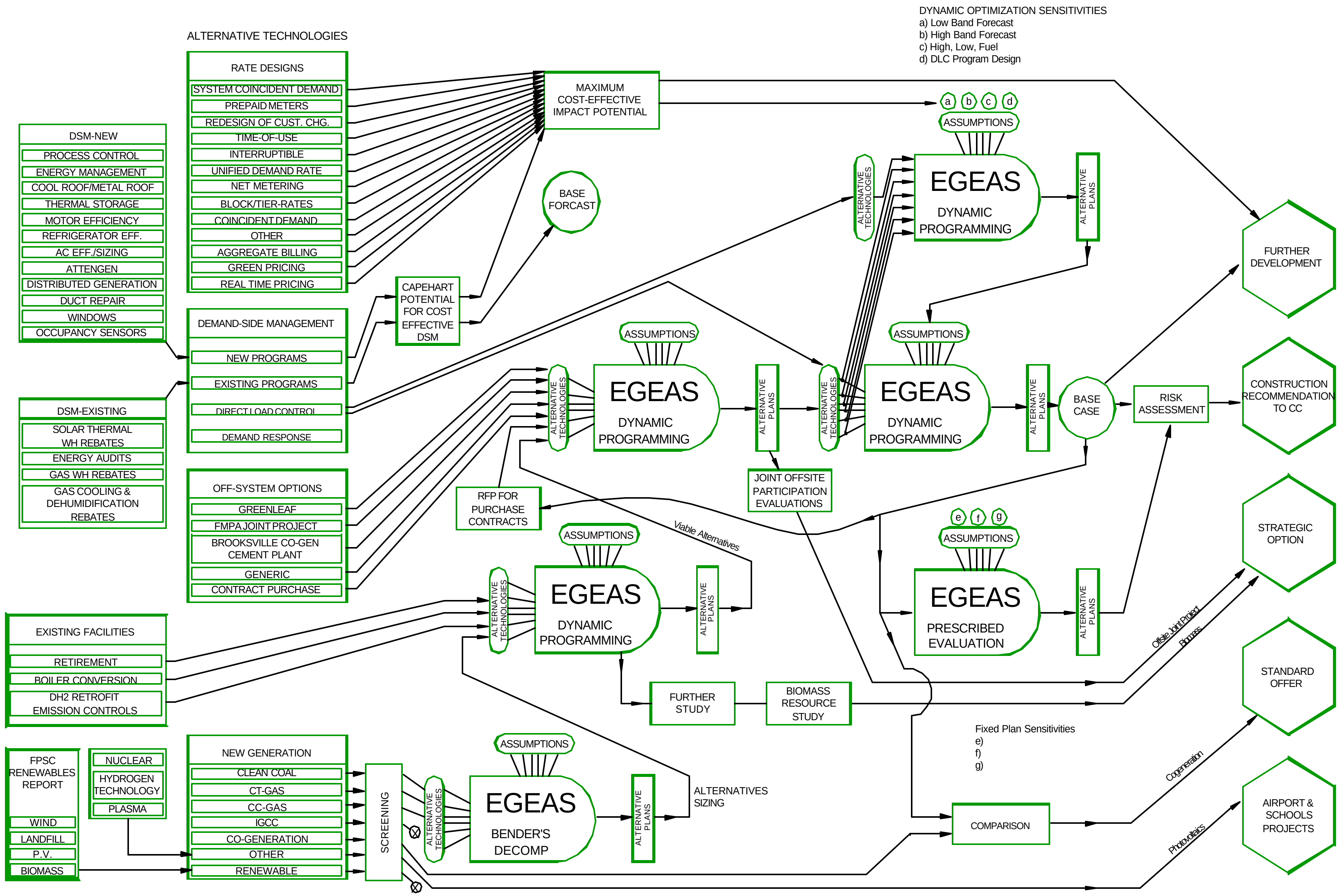


FIGURE M-4
RUN TIME DETERMINES THE BEST TYPE OF UNIT
($/MWh, Actual 2003 Fuel Costs)

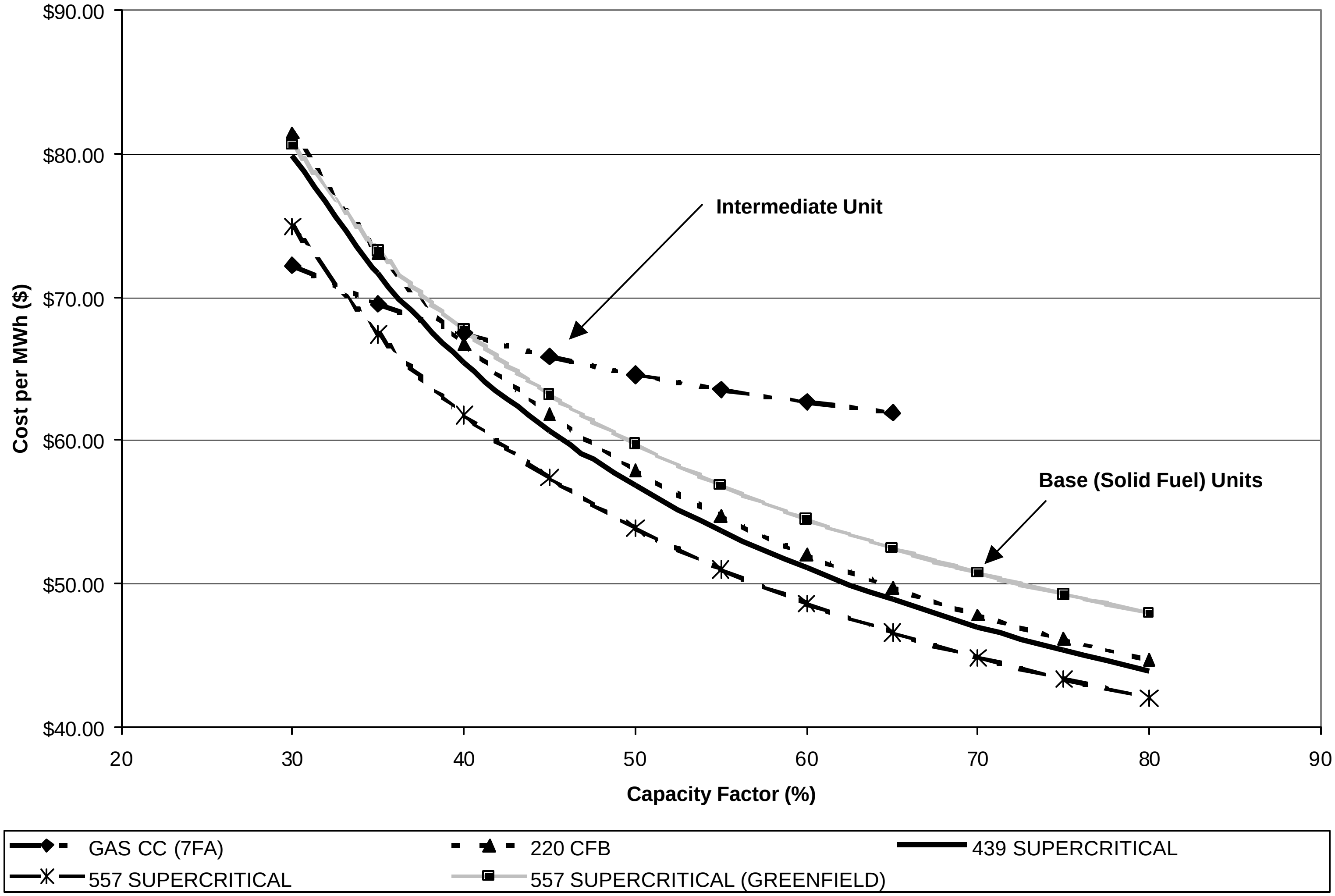


TABLE M-1

FINANCIAL FACTORS AND ASSUMPTIONS

Parameter	Assumption
Customer Discount Rate	9%
Tax-Exempt Interest Rate	6.5%
Taxable Debt Interest Rate	9.25%
Financing Term	
Base Units	35 years
Intermediate and Peaking	30 years
Debt to Equity Ratios	
Municipal	80/20
IOU	50/50
IOU Return on Equity	11.0%
Insurance	0.5
GRU Discount Rate[1]	7.0%
Construction Cost Escalation	3.0%
Fixed and Variable Non-Fuel O&M Esc.	3.0%
Capitalized Interest During Construction[2]	
Solid Fuel Plants	15.48%
Combined Cycle	10.24%
Simple Cycle	5.44%

1. Based on municipal debt to equity ratios, customer discount rate applied to equity, and tax-exempt interest rate applied to debt.
2. Addition project cost to avoid burdening rate base before project enters commercial service.

TABLE M-2

EFFECT OF LOAD FORECAST ON OPTIMAL GENERATION PLAN[1]
(Base Fuel Price Forecast)

Load Forecast	Combined Cycle[2]	Solid Fuel[3]	Total New Generation[4]
Low	16 MW	156 MW	172 MW
Base	34 MW	206 MW	240 MW
High	68 MW	257 MW	325 MW

1. Bender's methodology (any amount, any time)
2. Fractions of 7 FA Class facilities
3. Fractions of 600 MW Supercritical Class facilities
4. By 2022

TABLE M-3

EFFECT OF FUEL FORECAST ON OPTIMAL GENERATION PLAN[1]
(Base Load And Energy Forecast)

Fuel Forecast	Combined Cycle[3]	Solid Fuel[4]	Total New Generation[5]
Low[2]	106 MW	133 MW	239 MW
Base	34 MW	206 MW	240 MW
High	22 MW	235 MW	257 MW

1. Bender's methodology (any amount, any time)
2. Low gas price forecast, base coal price forecast (This combination results in the minimum spread in price per mmBTU through time)
3. Fractions of 7FA Class
4. Fractions of 600 MW Supercritical Class
5. By 2022

TABLE M-4

SAVINGS RESULTING FROM OPTIMAL GENERATION
UNDER LOW, BASE, AND HIGH PLANNING
(NPV x $1,000,000)[1]

Load Forecast	Fuel Price Forecast		
	Low[2]	Base	High
Low	$89	$183	$284
Base	$141	$277	$409
High	$190	$363	$530

1. Difference between optimal plan with Deerhaven 2 retrofit (net emission reductions) and No-Build Case without any Deerhaven retrofit. Bender's methodology.
2. Low gas price forecast, base coal price forecast (This combination results in the minimum spread in price per mmBTU through time)
3. Add $69,000,000 NPV to savings to represent the No-Build with Deerhaven retrofit case.

TABLE M-5

NO-BUILD CASE – FLORIDA'S ENERGY MARKETS[1]

EGEAS: No Build Option, Base Load & Energy, Low Fuel Price Forecast, CT & CC Market Sources

													Long Term PPA		
Year	Capital Fixed Charge (M$)	(7F) Capacity CT (MW)	(7F) Capacity CC (MW)	(7F) Total Capacity (MW)	Capacity Factor %	Generation (GWh)	Fuel (k$)	Variable O& M (k$)	Fixed O&M (k$)	Fuel ($/MWh)	Hourly Market (Fuel + Var O&M) ($/MWh)	(Fuel + F&V O&M) ($/MWh)	(Fuel + F&V O&M + Capital) ($/MWh)	(Fuel and Variable O&M) ($/MWh)	Capital & Fixed O&M ($/kW-yr)
2004	0.796	0.000	10.741	10.741	53.24	49.958	2,008	201	255	40.19	44.22	49.32	65.25	44.22	97.85
2005	0.796	0.000	10.741	10.741	56.14	52.681	2,002	219	263	38.00	42.16	47.15	62.26	42.16	98.59
2006	1.312	0.000	10.741	10.741	59.80	56.112	2,236	240	271	39.85	44.13	48.96	72.34	44.13	147.38
2007	3.426	0.000	17.111	17.111	118.46	89.295	3,728	393	444	41.75	46.15	51.12	89.49	46.15	226.17
2008	4.980	0.000	42.464	42.464	174.97	207.496	9,075	940	1,135	43.74	48.27	53.74	77.74	48.27	144.00
2009	4.980	0.000	60.556	60.556	232.28	295.048	13,546	1,377	1,667	45.91	50.58	56.23	73.11	50.58	109.77
2010	6.957	0.000	60.556	60.556	239.64	305.302	14,648	1,467	1,718	47.98	52.78	58.41	81.20	52.78	143.26
2011	6.957	0.000	82.253	82.253	296.40	407.275	20,504	2,018	2,403	50.34	55.30	61.20	78.28	55.30	113.80
2012	9.580	0.000	82.253	82.253	303.19	416.767	21,886	2,126	2,475	52.51	57.61	63.55	86.54	57.61	146.56
2013	12.161	0.000	109.391	109.391	351.02	525.464	28,825	2,761	3,390	54.86	60.11	66.56	89.71	60.11	142.16
2014	12.321	0.000	135.305	135.305	399.24	627.718	35,895	3,397	4,318	57.18	62.59	69.47	89.10	62.59	122.97
2015	14.243	0.000	136.872	136.872	448.37	655.846	38,936	3,655	4,499	59.37	64.94	71.80	93.52	64.94	136.93
2016	14.243	0.000	155.059	155.059	501.51	741.139	45,728	4,255	5,251	61.70	67.44	74.53	93.74	67.44	125.72
2017	17.979	0.000	155.059	155.059	514.68	762.783	48,753	4,512	5,409	63.91	69.83	76.92	100.49	69.83	150.83
2018	21.121	0.000	186.777	186.777	557.78	872.055	57,661	5,312	6,709	66.12	72.21	79.91	104.13	72.21	149.00
2019	22.582	0.000	215.574	215.574	609.81	990.561	67,575	6,214	7,977	68.22	74.49	82.55	105.34	74.49	141.76
2020	23.409	5.255	225.304	230.559	661.34	1,035.090	73,164	6,716	8,719	70.68	77.17	85.60	108.21	77.17	139.35
2021	24.338	19.116	225.304	244.420	679.37	1,065.038	78,059	7,167	9,336	73.29	80.02	88.79	111.64	80.02	137.77
2022	67.414	43.967	225.304	269.271	704.98	1,103.107	83,847	7,713	10,016	76.01	83.00	92.08	153.19	83.00	287.55

1. Results from Bender's constrained only to gas-fired alternatives. Priced at cost of fuel and merchant plant financial structure. Includes tranmission charges.

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SECTION N
PRELIMINARY INTEGRATED RESOURCE PLAN

The preceding sections of this report have presented the basic assumptions, data, forecasts, and methodologies as well as a wide range of community interests and objectives for an Integrated Resource Plan (IRP) to meet Gainesville's electrical energy needs through the year 2022. The results of the work performed to date have identified a set of energy conservation, renewable energy, and conventional fuel alternatives and options that accommodate the diverse interests of GRU's customers and community.

The preliminary IRP presented here does not constitute a final selection of alternatives. The final feasibility of the alternatives is dependent upon the outcome of work that is not yet completed. The purpose of presenting this preliminary information is to identify issues or concerns that have not yet been addressed, and to determine if the proposed IRP is consistent with the desires of the Gainesville City Commission and the community before proceeding further. Work that is not yet completed includes:

1. Policy considerations by the Gainesville City Commission;
2. Additional research, design development and proof of assumptions;
3. The outcome of negotiations with potential joint project participants; and
4. The synthesis of ideas and options.

PLANNING OBJECTIVES

The public outreach process described in Section A and Appendix A heavily influenced the development of the objectives to be met by GRU's IRP. The IRP's objectives are to:

1. Conserve natural resources;
2. Reduce total air emissions;
3. Reduce the carbon intensity of electricity generated;
4. Minimize revenue requirements (the cost of electricity to consumers);
5. Enhance the local economy with sustainable jobs and industry; and
6. Assure reliable energy supplies.

The preliminary IRP has several elements that work together to achieve these results. These elements include implementing additional energy conservation programs, introducing new demand response incentives, development of waste wood resources as a fuel supply, and leveraging GRU's existing Deerhaven site to attract investments that make additional emission controls and reductions in carbon intensity more affordable.

ELEMENTS OF THE PRELIMINARY IRP

The preliminary IRP presented here has the following elements:

1. 1.8 MW of additional energy conservation programs;
2 The introduction of demand response incentives;
3. The use of reclaimed water from GRU's wastewater system;
4. Up to 30 MW of biomass capacity from utilizing waste wood as a fuel;
5. 34 MW of natural gas fired combined cycle combustion turbine capacity; and
6. 206 MW of additional clean and efficient, solid fossil fuel fired, base load generation capacity.

Table N-1 matches the elements of the preliminary IRP to the planning objectives outlined above. The relationship between each of these elements and the planning objectives they help achieve are described below.

CONSERVE NATURAL RESOURCES

The plan presented here conserves natural resources by minimizing the consumption of fossil fuels and groundwater through the following elements of the preliminary IRP:

1. Additional energy conservation programs;
2 The introduction of demand response incentives;
3. Additional clean and efficient solid fuel fired generation;
4. Utilizing waste wood as a fuel; and
5. Using reclaimed water from GRU's wastewater system.

Additional Energy Conservation Programs

Energy conservation programs that pass the rate impact measure test have a beneficial effect on all ratepayers' costs and therefore are cost-effective investments for GRU electric customers. Roughly 1.8 MW of additional peak demand reductions from HVAC system programs have been identified as potentially feasible (see Section F). Details of the incentives and program designs remain to be developed, but other utilities have had experiences that will provide invaluable assistance to GRU.

Demand Response Incentives

Demand response programs provide economic (price) signals to affect consumer behavior. Internet and existing metering technologies can be combined in new ways to provide customers with access to day-ahead and/or real time prices. This provides incentives for the private sector to implement and manage affordable demand reductions. Larger commercial and industrial customers are more likely to participate in such programs, although there are examples of residential programs as well. Fundamentally, GRU would commit to a level of incentive (similar to a buy-back price) that meets the rate impact measure test as long as the results are verifiable and the programs are co-branded as being provided by GRU. Demonstration projects will be required to test levels of consumer acceptance and for the measurement of the potential for peak demand and energy reductions. Further enhancements of GRU's current time-of-use rate and further studies of GRU's existing "increasing block" rate structures also have been identified as potential means by which to promote the efficient use of utility resources (see Section G).

Efficient New Generation Capacity

The preliminary IRP includes additional generation capacity that would capture the benefits of new technology and/or economies of scale, which would result in reductions in fuel use per kilowatt-hour of electricity. The theoretically optimal generation expansion plan for GRU is shown in Table N-2. There are a number of cost-effective options for expanding GRU's generation capacity, some of which include acquiring a portion of a larger unit. Larger generating units tend to have the lowest possible heat rates (highest efficiency) that result in substantial energy conservation and cost savings per unit of energy output. A group of consumer owned utility companies have already conducted joint feasibility studies, and construction of a large new unit at Deerhaven is their preferred alternative (References 50 and 51). Generation expansion alternatives will be discussed in more detail later in this Section.

Waste Wood Fuel

Using waste wood as a boiler fuel replaces fossil fuel with a renewable source of energy. Studies to date suggest that enough waste wood could be harvested within an economical hauling distance of Deerhaven to fuel up to 30 MW of electrical generation (see Section H). However, the availability and cost to harvest, prepare, and deliver waste wood for a fuel supply needs additional study and market testing to make it a viable solution. Using a separate boiler, and using the resulting steam in the process design of a larger generating unit can further enhance the cost-effectiveness of biomass utilization. This strategy thus captures economies of scale and simplifies operation and construction. The potential participants in a joint project are willing to share in biomass facilities as a part of developing a larger project, if a joint project is the final option chosen.

Reclaimed Water

Groundwater consumption will be minimized by the use of reclaimed water for boiler and cooling make-up water and on-site process water needs. The construction of facilities to transport water from GRU's water reclamation facilities to the Deerhaven site would also offer the opportunity to provide reclaimed water services to customers along the transmission line.

REDUCE TOTAL AIR EMISSIONS

The preliminary IRP includes three generation expansion options that will result in a net reduction of total NO_x and SO_2 emissions by retrofitting Deerhaven 2 with additional emission controls. The potential for these generation options to reduce total emissions is presented in Section J and summarized in Table N-3.

REDUCE CARBON INTENSITY

Carbon intensity per unit of electricity produced can be reduced through high efficiency generation and supplemental steam generated from biomass fuels. Three of the four generation expansion options summarized in Table N-3 will enable biomass to be included in the facilities' design. Although biomass use generates slightly more carbon per unit of heat input than coal or petroleum coke, biomass is generally considered carbon neutral as discussed in Section E.

MINIMIZE REVENUE REQUIREMENTS

The preliminary IRP minimizes revenue requirements by selecting the most cost-effective mix of demand side management and generation resources to serve the needs of GRU's customers and to meet environmental requirements. Table N-4 compares the average monthly residential electric bill from the theoretically optimum generation expansion plan to two No-Build alternatives, one of which includes additional emission control equipment for Deerhaven Unit 2. The generation expansion plan will result in substantial cost saving for GRU's customers.

ENHANCE THE LOCAL ECONOMY

The preliminary IRP has a number of elements that will enhance the local economy by minimizing the electrical cost to operate businesses, and provide business and employment opportunities related to energy conservation and demand side management. Clean, reliable and affordable sources of energy are an important component of any healthy economy. As shown in Table N-3, the preliminary IRP also has options that involve constructing additional capacity at the Deerhaven site. These options will further enhance the local economy by providing power plant employment opportunities and stimulating agricultural industry in north central Florida. Over 100 skilled craft jobs would be created to operate and maintain the new generation facilities. These jobs will be compensated at higher than median salaries for the region, which would improve the local tax base to support community services and infrastructure. No attempt has been made to quantify these benefits to date.

RELIABLE FUEL SUPPLIES

The expanded use of solid fuels in the preliminary IRP helps meet the community's desire for secure and reliable electric service. Solid fuels are relatively abundant in the USA, have less volatile prices, and are less vulnerable to supply interruptions. Solid fuels also can be stored, further enhancing reliability and flexibility for fuels purchasing. The options involving construction of capacity at Deerhaven also avoid reliance on Florida's bulk transmission grid.

GENERATION EXPANSION OPTIONS

The preliminary IRP minimizes revenue requirements by selecting the most cost-effective mix of generation resources to serve the needs of GRU's customers and to meet environmental requirements. This required forecasts of load, energy and energy prices, as well as details about all of the alternatives that needed to be considered (see Sections B, H, I, L, and M). Fifteen (15) different technology alternatives were characterized in detail for this IRP in a variety of configurations and locations (Deerhaven or a greenfield site).

Alternatives and Factors Considered

A wide range of ideas and options were developed during the first phase of the public outreach program sponsored by the Gainesville Energy Advisory Committee (see Appendix A). These ideas and options were then screened down to a list of potentially feasible alternatives (see Section I). The alternatives evaluated included direct load control, photovoltaic generation, simple and combined cycle gas-fired combustion turbines, integrated gasification combined cycle turbines, and subcritical, supercritical, and fluidized bed steam cycle units in a wide range of sizes. The fuels evaluated included solar energy, coal, petroleum coke, and biomass (see Section H). The optimization studies performed to date have not explicitly modeled biomass capacity, pending additional data, but biomass capacity can be incorporated as supplemental steam capacity as part of any of the solid fuel options that would be constructed on the Deerhaven site.

Environmental controls as applicable to each technology had to be considered as well, including low NO_x burners, selective catalytic reduction, and selective non-catalytic reduction for NO_x control, wet and dry scrubbers for SO_2 control, and electrostatic precipitators and filter fabric baghouses for particulate control. Considerations also were made for future injection of adsorbents for carbon and mercury control. Detailed studies also were made of the options for retrofitting Deerhaven Unit 2 with additional air emission control equipment. The evaluations required detailed consideration of heat rates, construction costs, fixed and variable O&M costs, by-product management, and fuel suitability. Transmission system upgrades and wheeling charges as applicable also were taken into account.

Joint Participation

Unfortunately, GRU can not use the amount of capacity the most efficient and least costly technologies provide. To overcome this barrier, staff has coordinated with other consumer-owned electric utilities in Florida to develop generation alternatives that would be shared, to be constructed at either Deerhaven or a greenfield site (See Section A). The benefits of a shared, or joint participation project, at the Deerhaven site include:

1. Constructing new, highly efficient, clean, and cost-effective generation capacity at a lower cost per MW than if an individual utility built a smaller unit sized only to meet its needs.
2. Cost savings from developing an existing site and shorter lower transportation distances from coal and petroleum coke fuel resources. These savings allow potential joint project participants to share in the expense of:
   - Retrofitting Deerhaven 2 with additional air emission control equipment; and
   - Constructing water transmission facilities to bring reclaimed water to the Deerhaven site, which also would make reclaimed water services available to more areas in Gainesville.

A general understanding as to the terms and conditions for a joint project has been reached with the potential participants. The potential participants prefer to develop a large, supercritical solid fuel fired facility at the Deerhaven site that could burn a mix of coal and petroleum coke (the 557 MW option in Table N-3). Because many items of financing and governance yet remain to be resolved, an option that meets the IRP objectives without a joint participation agreement also was developed (the 220 MW CFB option in Table N-3).

The Theoretically Optimal Generation Plan

Studies performed with EGEAS's Benders methodology (see Section M) as well as other analyses have allowed staff to better determine GRU's generation resource requirements. Table N-2 presents the theoretically optimal amount and timing of additional intermediate and base load generation capacity, constrained to the time it would take to permit and construct new facilities. The optimal generation expansion plan includes a portion of a combined cycle intermediate capacity unit (34 MW in 2008), and solid fuel, base load generating capacity capable of burning coal and up to 20 percent petroleum coke (206 MW starting in 2010). No additional peaking capacity is required. The timing and amount of additional capacity in the optimal plan calls for more capacity than would be needed simply to meet reserve margins because it is in the best interests of GRU's customers to invest in efficient generation capacity that uses lower priced fuels.

The optimal plan includes a portion of the capacity from a large (F class) combined cycle combustion turbine. Currently, there is an excess of this type of capacity in Florida and pending additional market research and analysis, it is most likely to be cost-effectively obtained through a PPA with another utility. The option of acquiring combined cycle resources sooner than 2008 is likely to result in additional cost savings and will be evaluated.

The optimal plan also calls for solid fuel capacity, with the most cost-effective being a portion of the capacity from a 557 MW supercritical solid fuel unit, constructed at the Deerhaven site. There is a distinct shortage of any form of solid fuel generation capacity in Florida, necessitating construction and ownership on GRU's part, either jointly or alone.

Solid Fuel Options

There are at least four cost-effective solid fuel generation options that could meet the revenue objectives of the IRP. The three most cost-effective solid fuel options involving construction at the Deerhaven Site and the most cost-effective greenfield site option are summarized in Table N-3. Only the three options involving additional capacity at the Deerhaven site would result in; net emission reductions from retrofitting Deerhaven 2, biomass generation capacity, and the use of reclaimed water. The single greenfield option does not include these features. Also, the greenfield option would not enhance Gainesville's local economy and would make GRU's generation resources reliant upon Florida's bulk transmission grid

Table N-3 includes other key features of the various solid fuel alternatives and the portion of capacity GRU would be entitled to with each alternative. The four options, ranked in order of low to high cost per kilowatt-hour are:

1. A portion of a 557 net MW supercritical unit, which would be feasible for GRU only through a joint participation project. One of the features of this option is that the potential joint project participants would be willing to take some of their share of capacity through a PPA, structured to include the same operational and regulatory risks of ownership that an equity participant (such as GRU) would assume. The PPA's also would be structured to provide GRU the option of taking back some of the participant's capacity if and when GRU wants it in the future. This provides GRU with very valuable strategic flexibility. Bond rating agencies tend to look favorably on projects in which native load customers meet debt service requirements, and a joint project, with appropriately

structured PPA agreements, meets this requirement. Another advantage of a joint project would be the strategic alliances that would be forged. Under this option the cost of retrofitting Deerhaven 2, transmission upgrades and reclaimed water facilities would be shared by participants on a capacity ratio share. Any joint project at the Deerhaven site would involve complicated contracts related to common facilities and operational oversight by project participants, reducing GRU's autonomy to a significant degree.

2. A portion of a smaller 425 net MW supercritical solid fuel facility constructed at Deerhaven. This option has the same features as the 557 MW option described above, with the exception that the option for reversion of capacity to GRU would not be included. This option does not provide sufficient capacity for the optimal generation case.

3. A 220 net MW CFB facility, self built by GRU at Deerhaven. This would provide more capacity than GRU would need in the earlier years. The ability to structure appropriate PPA agreements for some of this excess capacity would be an important consideration for the financial success of this option; which should be achievable in Florida's energy market. One of the advantages of this option is that after 2022, another CFB could be constructed to meet load requirements and/or to repower Deerhaven Unit 1, an older, gas fired steam unit. Table N-3 addresses the net reduction of air emissions that would result from two 220 CFB units.

4. A portion of a 557 net supercritical unit built on a greenfield site. While this option does not include the expense of retrofitting Deerhaven Unit 2 with additional emission control equipment and a reclaimed water transmission facility, it has other costs associated with it especially from GRU's perspective. The mileage for hauling the fuels is greater, and GRU would have transmission wheeling expenses and associated capacity and line losses to absorb.

The option for starting with a relatively small share in a larger unit, with an option to take over additional capacity when and if needed, is particularly valuable when considered in light of the sensitivity analyses presented in Section M. For example, at the extreme and very unlikely ranges of the load and energy forecast, the optimal plan would include as little as 156 MW and as much as 257 MW of solid fuel capacity by 2022. From a review of the sensitivity studies, the optimal generation expansion solution for GRU appears to be:

1. 25-35 MW of CCCT capacity in 2008;
2. 100-120 MW of Solid Fuel capacity in 2010; and
3. Options on an additional 100 MW of Capacity through 2022

Effects On Costs

GRU's corporate model was extended to 2022 to project base rates and customer electric costs for the IRP. The corporate model uses forecasted sales of electricity, the costs of the transmission and distribution system, administrative systems and overheads, etc. to balance the required uses of funds with revenues. As a basis of comparison, two "No-Build" scenarios for GRU's IRP were created to compare the effects of the optimal plan on base rates and customer costs (see Section M). These scenarios assume GRU meets its long-term energy needs with an optimized portfolio of purchased power agreements.

The two No-Build options differ in that one case assumes that new legislation and regulatory requirements would result in GRU having to install additional air emission control equipment on Deerhaven 2 by 2010. This is a substantial additional capital and recurring operational cost for GRU's customers, with a Net Present Value (NPV) of $69,000,000 that is currently not in GRU's budget (see Section M).

Table N-4 compares the monthly average residential bills through 2022 for the optimal plan with the two No-Build cases. The total cost for electricity is less under the optimal plan, even though the cost to construct the 206 MW called for would be roughly $390,000,000 NPV, including capitalized interest ($2003). The optimal plan results in lower customer bills as a result of much lower fuel costs than the No-Build Cases. As shown in Table N-4, the projected average residential monthly electric bill resulting from the optimal plan is less than in either of the No-Build cases after 2008. Over the planning horizon, the residential bill compound annual growth rate (CAAGR) for the optimal plan is 27 percent lower than the No-Build case and 48 percent lower than the No-Build case with a Deerhaven 2 retrofit.

Under the most likely scenarios of fuel price increases and growth in load and energy sales, the optimal generation expansion plan in the preliminary IRP is expected to result in net savings of $277,000,000 NPV over the life of the facility (see Section M). If Deerhaven 2 has to have additional emission control equipment installed by 2010, the optimal plan in the preliminary IRP would result in net savings of $346,000,000 NPV over the life of the facility.

In addition to financial benefits, the lower cost, optimal plan also provides the following substantial additional benefits:

1. Local emission reductions;
2. Protection from volatile gas prices;
3. Expanded use of reclaimed water;
4. Opportunity to utilize biomass;
5. Employment opportunities in power and agricultural industries;
6. Reliable long term fuel supplies; and
7. Less reliance on the bulk transmission grid.

SITE CERTIFICATION PROCESS

Once a final generation expansion plan is selected, there are a number of environmental, economic, and public interest tests that have to be met before any form of construction can begin. These tests are part of Florida's site certification process, which is quite lengthy and expensive, taking anywhere from 18 to 36 months.

One part of the process is called a "Certificate of Need," which is granted by the Florida Public Service Commission. This regulatory procedure compares the proposed facilities with the plans of other utilities in Florida, examines the nature of the load to be served, and ascertains that the proposed facilities are the most cost-effective possible. GRU's planning assumptions and methodologies will be reviewed in this process. Investor owned utilities are required to issue a formal request of proposals to see if a more cost-effective alternative than the one selected is available, an option GRU is likely to take to provide another proof of assumptions.

Construction and operating air permits will be required as discussed in Section J. Detailed modeling and analysis of the effects of the project on ambient air quality both locally and regionally will have to be performed and the project will have to conform to all applicable air quality standards. Detailed information will be required, including stack designs and heights, combustion characteristics of the units being proposed, and the height and shape of all other structures surrounding the stacks. The air permitting process also includes scrutiny of the designs that are submitted to be sure they represent the Best Available Control Technology (BACT) standards.

Other environmental impacts will be addressed in the site certification process, including evaluation of the potential for harm to endangered species, wetlands, traffic, noise, stormwater management, and groundwater protection. Detailed site plans will be submitted, showing all generation units, by-product management and storage areas, process water facilities, fuel storage and management facilities, as well as all rail lines, roads, buildings and fences. Designs will be developed and provided in enough detail to allow the environmental impacts to be evaluated.

TABLE N-1
PRELIMINARY INTEGRATED RESOURCE PLAN

OBJECTIVE	PLAN ELEMENTS
MINIMIZE RESOURCE CONSUMPTION	1. Add Energy Conservation Programs 2. Introduce Demand Response Incentives 3. Develop Biomass Generation Capacity 4. Add Efficient, Clean Solid Fuel Generation Capacity at Deerhaven[1] 5. Expand Reclaimed Water Use
REDUCE TOTAL EMISSIONS	1. Add Efficient, Clean Solid Fuel Generation Capacity at Deerhaven[1] 2. Retrofit Deerhaven 2 with Additional Emission Control Equipment
REDUCE CARBON INTENSITY	1. Add Energy Conservation Programs 2. Introduce Demand Response Incentives 3. Develop Biomass Capacity 4. Add Efficient, Clean Solid Fuel Generation Capacity at Deerhaven[1]
MINIMIZE REVENUE REQUIREMENTS	1. Add Combined Cycle Capacity at Deerhaven 2. Add Efficient, Clean Solid Fuel Generation Capacity at Deerhaven[1] 3. Combine Additional Highly Efficient, Solid Fuel Capacity with: -Supplemental Biomass Capacity -Additional Emission Control Equipment on Deerhaven 2
ENHANCE THE LOCAL ECONOMY	1. Provide Employment (New Power Plant Jobs) 2. Foster Local Energy Conservation Service Businesses 3. Create Agricultural Employment (Biomass Harvesting and Preparation Jobs)
RELIABLE ENERGY SUPPLIES	1. Solid Fuel Is Abundant in the USA 2. Solid Fuel Is Less Vulnerable to Supply Interruptions 3. Capacity Sited at Deehaven Is Less Reliant on Electric Transmission Grid

1. See Table N-3 for solid fuel generation options

TABLE N-2
THE OPTIMAL GENERATION EXPANSION PLAN[1]

YEAR	BASE	
	CC[2]	SOLID FUEL[3]
2004	--	--
2005	--	--
2006	--	--
2007	--	--
2008	34 MW	--
2009	--	--
2010	--	101 MW
2011	--	18 MW
2012	--	--
2013	--	37 MW
2014	--	11 MW
2015	--	9 MW
2016	--	5 MW
2017	--	16 MW
2018	--	--
2019	--	9MW
2020	--	--
2021	--	--
2022	--	--
TOTAL	34 MW	206 MW

1. Base forecast of load and energy, base forecast of energy prices. Bender's Decomposition methology selects optimal amount of generation to be added in any year.
2. Selects portion of 7FA Combined Cycle, natural gas fired unit.
3. Selects portion of 557 net MW, supercritical solid fuel unit constructed at Deerhaven plant site.

TABLE N-3
COMPARISON OF GRU's
POTENTIALLY FEASIBLE SOLID FUEL OPTIONS

CRITERIA	DEERHAVEN OPTIONS			GREENFIELD
	557 MW	425 MW	220 MW	557 MW
Total Cost per MWH[1]	\$42.05	\$43.92	\$44.68	\$47.96
Includes Deerhaven Retrofit	Yes	Yes	Yes	No
GRU's Capacity Share	140 MW (2010) 48 MW (option) 188 MW[2]	110 MW[2]	220 MW	140 MW[2] (no option)
Emission Reductions[3]				
NO_X	23%	34%	52%	0
SO_2	25%	34%	47%	0
Primary PM[4] (Tons/Year)	361	285	133	0
Biomass Capacity[5]	30 MW	30 MW	30 MW	0
Optimal Fuel Blend				
Coal/Petcoke	80/20	80/20	50/50	80/20
Reclaimed Water Use	4.5 MGD	3.5 MGD	TBD[6]	0
Boiler Type[7]	SCPC	SCPC	CFB	SCPC

1. Based on 2003 actual fuel cost, 80% capacity factor
2. Based on current discussion with participants in joint feasibility study.
3. Assumes Deerhaven 2 at 100% capacity burning high sulfur coal. For two CFB units, net emission reductions would be NO_X 30%; SO_2 27%; with a Particulate Matter increase of 270 tons per year.
4. NO_X and SO_2 reductions are expected to result in a net decrease in $PM_{2.5}$ due to reduced precursors of secondary PM formation, but the analyses have not been completed.
5. Preliminary results indicate that up to 30MW may be feasible, pending additional research on waste wood availability and detailed facility design.
6. To be determined.
7. Boiler Type: SCPC - supercritical pulverized coal type; and CFB - circulating fluidized bed.

TABLE N-4
AVERAGE RESIDENTIAL MONTHLY ELECTRIC BILLS UNDER ALTERNATIVE PLANS[1]

Year	Optimal Solid Fuel Case[2]	No-Build Case[3]	No-Build Case with DH2 Retrofit[4]
2004	$77	$77	$77
2005	$76	$76	$76
2006	$77	$77	$77
2007	$79	$79	$79
2008	$82	$83	$83
2009	$85	$85	$87
2010	$82	$86	$91
2011	$88	$91	$96
2012	$91	$92	$97
2013	$92	$94	$98
2014	$92	$95	$100
2015	$93	$98	$102
2016	$94	$101	$106
2017	$94	$103	$108
2018	$97	$106	$111
2019	$100	$111	$116
2020	$101	$113	$118
2021	$103	$115	$120
2022	$105	$118	$122
CAAGR	1.68%	2.30%	2.48%

1. Bender's methodology, base load forecast, base fuel price forecast. Electric bills estimated from extended GRU corporate model, subject to revision. Based on 1000 KWH typical residential consumption, including service, transmission and distribution charges
2. Based on 7FA and 600 MW Supercritical Solid Fuel Generators
3. Assumes purchased power from gas fired, highly-efficient CC technology
4. Same as for note 3 except includes dry scubbers for SO_X, selective catalytic NO_X reduction, and fabric filters installed on Deerhaven 2 in 2010

APPENDIX A
PUBLIC OUTREACH PROCESS SUMMARY

Public Outreach

The public outreach program was initiated in the summer of 2003 to support the Integrated Resource Planning process. As preliminary results of several feasibility studies became available, GRU felt it was important to gain a better understanding of the ideas and perspectives of the utility's customers concerning how to meet the projected need for electricity.

A community outreach program was pursued for several reasons:

- To share information with customers about why additional generation was needed and what the various options might be
- To hear customer ideas and better understand and respond to questions and concerns
- To continue to improve customer satisfaction

Customers were expected to have an interest in the following:

- Environmental quality issues, especially air quality
- New generation (including renewables) and how it would fit into an overall program for maintaining reliable electric service, including the dependability and availability of fuel supplies
- Conservation, demand-side management and how those fit into GRU's program
- Keeping electricity affordable

Goals

The primary goals of the outreach program were to:

- Share information about the need for additional generation and options that might be available for meeting the need
- Involve GRU's customers and community members in the decision-making process, including the definition of the problem or opportunity, identification of alternative solutions, and evaluation of those alternatives
- Identify a course of action that could be embraced by a broad spectrum of the community

Activities

The public outreach program was developed with the assistance of a consultant experienced in the creation of similar programs for electric utilities throughout Florida. The program included a number of different activities designed to:

- Clearly present the need for additional generation
- Be responsive to customers and local groups' interests and need for information
- Address customers' needs for objective, reliable information on alternatives and the implications of different choices
- Provide timely and accurate information to the local media
- Keep the community informed of progress and provide timely notice of opportunities to participate in the planning process
- Keep employees informed

The following describes the activities that comprised the public outreach program over the period from August through early December 2003:

Initial announcement of the need for additional generation

To kick off the public outreach process, GRU issued a press release and contacted representatives of key business, environmental, and other community interests groups to explain the need for additional generation, describe the planning and public outreach processes, hear initial reactions, and extend an invitation to participate in the upcoming community workshops. Most people were contacted by telephone, although some were sent a letter or email.

In the Outreach Appendix there is a list of contacts, letters and emails, and a number of articles that appeared in the local media as a result of the press release.

GEAC sponsored workshops

On June 17, during a presentation to GEAC, GRU staff outlined a plan for public outreach to support the IRP process. GEAC agreed to sponsor a series of community workshops that were designed to assist GRU staff in the definition, evaluation and selection of alternatives for meeting Gainesville's future generation needs. Two series of community workshops were held, one series in September and another in October 2003. The workshops were held in the evening and on separate dates and in separate locations throughout the City. The dates and locations were as follows:

<u>First Series of Community Workshops</u>

September 2, 2003 Millhopper Branch Library
September 9, 2003 Williams Elementary School
September 18, 2003 Tower Road Branch Library

<u>Second Series of Community Workshops</u>

October 7, 2003 Millhopper Branch Library
October 9, 2003 Tower Road Branch Library
October 21, 2003 Williams Elementary School

At the first series of workshops, GRU introduced the Integrated Resource Planning (IRP) process and the need for new generation by 2010. Workshop participants were invited to share their views concerning:

- Options GRU should consider
- Factors that should be used in the evaluation of options
- How GRU could improve the presentation and communication with the community

At the second series of workshops, GRU summarized what was heard from the community and presented preliminary results of the evaluation of a wide range of alternatives. Workshop participants were again invited to share their views. They were asked

- Has GRU overlooked anything?
- What are your remaining questions and concerns?

At each workshop, participants were asked to complete evaluation forms. The information obtained was then used to fine tune the presentation and adjust the workshop format as needed. Workshop sign-in sheets were used to develop a mailing list of interested persons. These mailing lists have been used throughout the public outreach process to share information and notify individuals of other participation opportunities.

Also at each workshop, GRU distributed copies of the presentation and other relevant literature including brochures about the Deerhaven and Kelly generating stations, GRU's commitment to environmental stewardship, the GRUGreen Energy program, home energy audits and other conservation services.

Copies of the Power Point presentations and summaries of community comments and ideas heard at all six workshops are included in the Outreach Appendix. Examples of the methods and materials GRU used to publicize and promote the workshops also are included.

Web site, telephone line and email address

GRU's Web site has been used as an important communication tool throughout the public outreach process. Community workshops were advertised on the Web site, and copies of the Power Point presentations used for the community workshops were made available on the web site a day or so in advance of the start of each workshop series. A short survey also was included. The survey was designed to be filled out online and sent directly to GRU and is included in the Outreach Appendix.

In addition to the web site, a special email address and a direct telephone line were established to help GRU customers communicate their views. Samples of these are included in the Outreach Appendix.

Direct mail

Direct mail has been used throughout the public outreach process. It was used in the initial announcement of the planning process. Workshop sign-in sheets were used to augment a mailing list, which has since been used to notify individuals of other workshops and the Deerhaven open house. An invitation to the Deerhaven open house was included in bill stuffers in November, which is sent to about 85,000 GRU customers.

Media

GRU communications staff has kept the media informed throughout the process. Paid advertising of outreach activities and news stories appeared in the Gainesville Sun. An editorial pertinent to the IRP process and two opinion editorials, one by Mike Kurtz, GRU's General Manager, also were published in the Sun. All are included in the Outreach Appendix. In addition, local TV stations carried stories about the community workshops. WRUF TV 5 produced an hour-long segment about the IRP during their show *North Florida Journal*. Ed Regan, GRU's Assistant General Manager for Strategic Planning, served as a panelist on the show.

Print advertising and public service announcements (PSAs) on local radio stations were used to publicize the community workshops. Print and radio advertising were used to promote the Deerhaven open house. Samples are included in the Outreach Appendix.

Presentations to civic groups and community organizations

GRU staff notified various community groups of their availability and responded to a number of invitations to make a presentation on the IRP process. The Power Point presentations developed for the workshops were adapted to the needs of different audiences for these outreach efforts. The Outreach Appendix includes a list of the meetings at which GRU presented. Questions asked and comments made by individuals in the audience were noted and shared with the IRP team during weekly conference calls and samples are included in the Outreach Appendix.

Employee Communications

The public outreach program included an effort to keep employees informed so they could help spread the word about the community workshops and be prepared to answer questions from their friends and neighbors. An email distributed to all employees about the IRP process and the associated public outreach program is included in the Outreach Appendix.

Deerhaven open house, including plant tours

When it became apparent that the option of building a new generating unit at the Deerhaven Generating Station would be given serious consideration, a Deerhaven open house was planned including tours of the existing plant.

The Deerhaven open house was held Saturday, December 6, 2003, from 9:00 AM to 3:00 PM. Based on security data, about 1500 customers attended the event. In addition to plant tours and information on the IRP process, the following activities, exhibits and displays were provided:

- Green Energy – sign up, register to win “GRUgreen Your Home” prizes
- Energy & Water Conservation - Homefix, EPA Award, Green Bldg/Summer House, solar rebates
- Reclaimed water and Chapman’s Pond and Nature Trails
- Air Monitoring Efforts
- Pictures of CFBs, IGCCs and other facilities
- Conceptual future power plant (guiding principles for any unit proposed)
- Forestry – Project Habitat, Stewardship forest, Treeline USA/flag
- Depot Stormwater Park Cleanup
- Kelly Plant Repowering Display
- Telecommunications exhibit
- Electric Truck/Prius Hybrid
- Bucket truck rides, including rechargeable battery display
- Safety City – an electric safety demonstration
- Customer Services
- IRP Community Workshop Materials
- Gas – rebates, services (hula hoops for children)
- Fire Truck/On site demo

- Florida Wildlife Exhibit
- Albert & Alberta mascots from UF
- Fish for Success Exhibit
- Florida Solar Energy Research and Education Foundation Exhibit

City Commission Workshop

One or more City Commission workshops are expected to discuss the results of the IRP process. As this report was being written, the first workshop is scheduled for December 15, 2003.

Outreach Appendix

The compact disk* accompanying this document contains electronic copies of all the printed materials used or generated during the public outreach process, including announcements, advertisements, news articles and editorials. Copies of the presentation materials developed for the workshops as well as other groups are also included.

Note: When accessing this document via the Internet, the above mentioned compact disk is a separate .pdf file which is available for download.