PLANNING STUDY OF THE EFFECTS OF GAINESVILLE'S LONG TERM ELECTRICAL ENERGY SUPPLY PLANS ON AMBIENT AIR QUALITY AND GREENHOUSE GAS EMISSIONS

Gainesville Regional Utilities
September 30, 2004

INTRODUCTION

Gainesville Regional Utilities (GRU) provides electricity to approximately 76% of the population of Alachua County. Its two power plants make it one of the largest industries in Alachua County. Due to the fossil fuels that are consumed by these plants, they are two of the largest stationary sources of air emissions in Alachua County. Some of these emissions are regulated, including sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM). By far, GRU is the largest source of SO_2 in Alachua County but a relatively small source of NO_X and PM when compared with other emission sources such as mobile and agricultural sources, respectively.[1] GRU's facilities also emit mercury (Hg) and carbon dioxide (CO_2), which are currently unregulated but the subject of pending regulations and/or public concern.

Due to increasing demands for electricity, the need to retire older generating units, and the need for cost effective baseload capacity, GRU staff anticipate that additional new demand side management programs and generation capacity will be needed to meet Gainesville's future electrical needs. After detailed consideration of a wide range of alternatives, the long range plan that staff has proposed to the community includes a project that would entail the installation of additional emission controls on the coal-fired Deerhaven Unit 2 (DH2)[2] and the construction of a new solid fuel fired generating unit at the Deerhaven plant, together referred to hereafter as the Proposed Project[3].

A set of assumptions related to the size of the additional unit, the technologies, and the fuels to be employed were made to assess the economic, environmental, and regulatory feasibility of the Proposed Project. The environmental studies summarized herein are based on these assumptions. It should be noted that the assumptions that have been made in these studies are subject to revision as the result of more detailed engineering design studies and competitive solicitations that await City Commission approval. Some of the studies summarized herein were performed as the result of suggestions made by members

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[1] Alachua County Air Quality Commission Findings and Recommendations (Alachua County Air Quality Commission (January 2000).
[2] DH2 is currently equipped with an electrostatic precipitator for particulate matter control.
[3] Alternatives For Meeting Gainesville's Electrical Requirements Through 2022 (Gainesville Regional Utilities, December 2003).

of the Gainesville Energy Advisory Committee and the Alachua County Environmental Protection Advisory Committee.

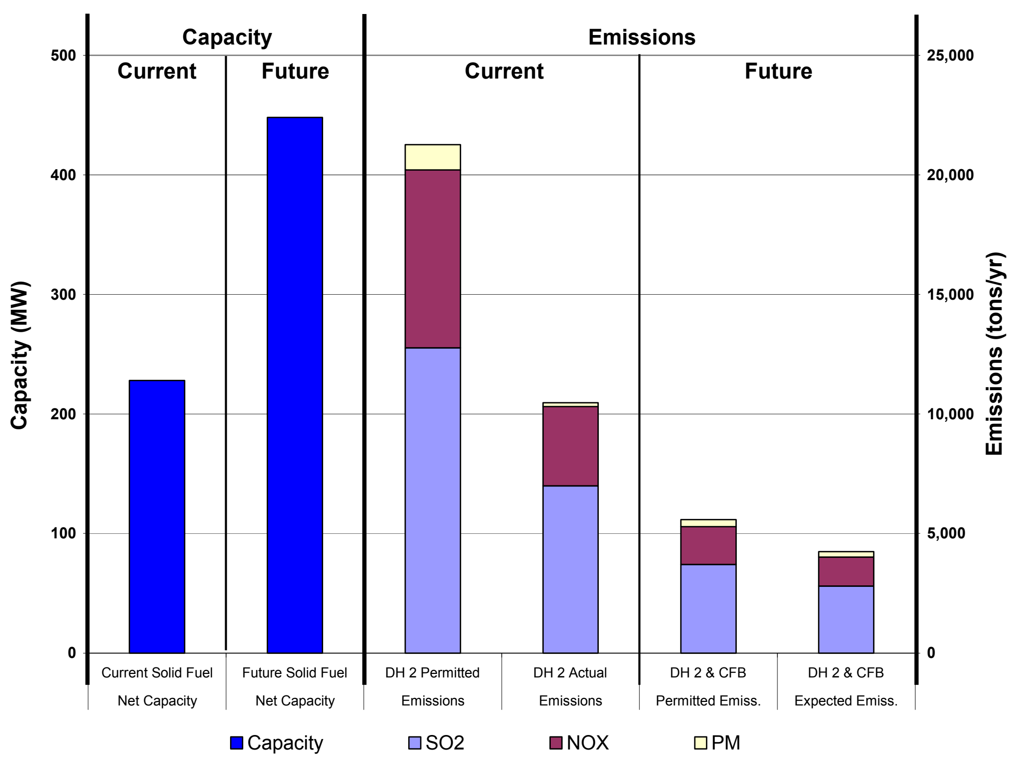
The Proposed Project as currently envisioned would result in significant overall emission reductions yet would double GRU's solid fuel generating capacity as illustrated in Table 1 and Figure 1. Note that these estimates assume a 50/50 blend of high sulfur coal and petroleum coke for future conditions. It would also provide increased fuel flexibility, access to a relatively abundant domestic supply of fuel, and price stability.

Table 1
Emission Reductions Associated with Doubling of Solid-Fuel Capacity at Deerhaven

Parameter	Deerhaven 2 Permitted Emissions (tons/yr)[1]	Deerhaven 2 Actual Emissions (tons/yr)[2]	Deerhaven 2 & CFB Future Permitted Emissions (tons/yr)[3]	Deerhaven 2 & CFB Expected Future Emissions (tons/yr)[4]
SO_2	12,761.6	6,992.6	3,707.5	2,800.4
NO_X	7,444.2	3,316.5	1,580.3	1,215.7
PM	1,063.5	162.9	296.3	227.9

1 Title V Operating Permit No. 0010006-002-AV.
2 2001/2002 average based on Annual Operating Reports.
3 Alternatives For Meeting Gainesville's Electrical Requirements Through 2022: Base Studies and Preliminary Findings, Table J-7 (GRU, December 2003). Assumes both units operate at 100% capacity factor.
4 Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J. R. Kelly Facilities and the Future 220 MW CFB, (Black & Veatch, June 2004).

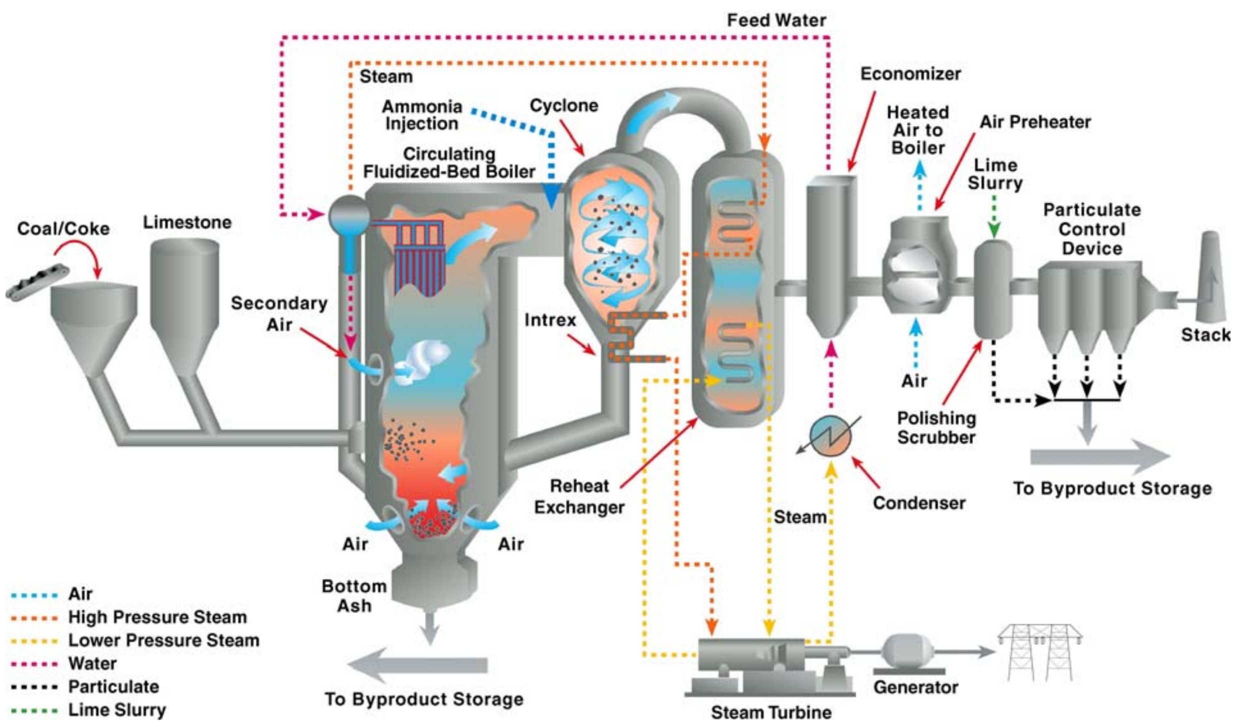
Figure 1
Twice the Solid Fuel Capacity with Less than Half the Emissions



The additional emission controls proposed for DH2 include selective catalytic reduction (SCR) for NO_X[4], flue gas desulfurization (FGD) for SO_2 and PM, and a fabric filter (FF) for PM control. Secondary $PM_{2.5}$ (particulates less than 2.5 microns in size) formation will be minimized indirectly via the substantial reductions of SO_2 and NO_X, which are precursors to $PM_{2.5}$ (e.g., sulfates, nitrates). Mercury reductions would be achieved through the combined use of the proposed pollution control technologies (i.e., SCR, FGD, FF) as well as the beneficial operating characteristics of the proposed new unit. There would be overall reductions in the amount of CO_2 emitted per unit of energy produced (i.e., carbon intensity) as a result of other offsetting projects that have already been implemented or that are planned for the future by GRU.

The proposed new unit is a circulating fluidized bed (CFB), a unit that is capable of burning a variety of fuels including, as GRU has proposed, coal, petroleum coke (petcoke)[5] and biomass[6]. It is anticipated that biomass (waste wood) would be used to generate up to 30 MW of the total electricity produced by this unit. Figure 2 shows a conceptual CFB generating unit.

Figure 2
What is a CFB? (Circulating Fluidized Bed)



[4] A neural network system will be installed prior to 2008 to optimize combustion and lower NO_X emissions.

[5] Petcoke is a by-product of the oil refining process that is used by several utilities in Florida (e.g., Jacksonville, Lakeland) as boiler fuel. It has a higher heating value and sulfur content than coal but its ash and mercury content are lower.

[6] In this instance, organic matter consisting of tree stumps and branches, and untreated lumber waste. Waste wood is currently burned openly; burning it in a CFB would reduce emissions significantly.

CFB technology has inherent abilities to control SO_2, NO_X and Hg emissions. The low combustion temperatures serve to minimize the formation of NO_X and the injection of limestone into the boiler controls SO_2 and metal (e.g., Hg) emissions. The recirculation of the hot solids and their long residence time ensures that the fuel is combusted well and the limestone is well utilized. Further SO_2 and PM emission reductions are achieved by passing the combustion gases through a polishing scrubber and a baghouse (i.e., fabric filter) before they enter the stack. Additional NO_X reductions, if needed, can be achieved with the installation of a selective non-catalytic reduction system.

The JEA[7] currently operates two (2) 300 MW CFB units at its Northside Power Plant in Jacksonville, FL. Table 2 shows JEA's CFB Emissions and compares them to the Federal Department of Energy's (DOE's) 2010 Roadmap Goals.

Table 2
JEA Northside Repowering CFB Emissions & 2010 DOE Roadmap Goals

	2010 DOE Road Map Goal	JEA Unit Performance
SO_2 Removal, %	99%	99.40%
NO_X, lb/mmBtu	0.05	0.04-0.06
Particulate, lb/mmBtu	0.005	0.0044
Mecury Removal	90%	91%*

* Rates vary depending on ratios of fuel

The following sections of this report summarize studies that were performed to address issues that the community has expressed an interest in during the on-going outreach program, including:

- What is the quality of the ambient air in Alachua County?
- How do GRU's power plants impact ambient air quality?
- How will the Proposed Project impact air quality?
- How will future environmental regulations affect GRU's existing facilities and Proposed Project?
- What are GRU's plans to deal with global climate change and CO_2 emissions?
- What impact does DH2 have on mercury deposition in the Santa Fe River Basin?
- Will mercury emissions increase as a result of burning more coal?
- What effect does the Proposed Project have on fine particulate matter?

AIR QUALITY

Air emissions and their impacts on surrounding ambient air quality in Class II[8] areas and air quality related values (e.g., visibility) in Class I areas are key considerations in seeking and obtaining community acceptance and regulatory approvals for power plants.

[7] JEA was formerly called the Jacksonville Electric Authority.
[8] EPA classifications for areas of the U.S. that are used for determining permit and emission control requirements. Class II areas allow limited development, for example Alachua County. Class I areas allow practically no emissions and therefore, no economic development. Class I areas are primarily national parks and wilderness areas such as the Okefenokee and Chassahowitzka National Wilderness Areas.

Regulatory approvals will not be granted unless GRU demonstrates that there will be 1) no exceedances of Ambient Air Quality Standards (AAQS)[9]and Prevention of Significant Deterioration (PSD) increments[10] and 2) no unacceptable impacts in Class I areas. Air modeling will be required as part of the permitting process to demonstrate the impacts of the Proposed Project.

It should be noted that ambient air quality is influenced by many factors including emissions from local, regional and global sources, chemical reactions in the atmosphere, terrain, and meteorological conditions (e.g., wind speed and direction, temperature, humidity, atmospheric mixing). Due to these factors, large mass emission reductions from a local source may not have proportionate effects on ambient air quality concentrations.

Air Quality in Alachua County

Alachua County's air currently meets the AAQS and, like all of Florida, has been designated by EPA as "in attainment" based on monitoring data[11]. Florida is one of only a few states able to make this claim. Ambient air quality monitoring is conducted by the Florida Department of Environmental Protection for ozone (two sites), PM_{10} (one site) and $PM_{2.5}$ (two sites); limited monitoring was also conducted by the Alachua County Environmental Protection Department for SO_2 and NO_X in 2000 and 2001. These data indicate that the ambient levels of these pollutants are generally well below the standards with the exception of ozone as shown in Table 3 and Figure 3. Ozone (O_3) is the parameter whose level is closest to the applicable AAQS.

Table 3
Ambient Air Quality Versus 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[1]	(ppm)	90%
O_3	(1-Hr Avg.)	0.12	(ppm)	0.089[2]	(ppm)	74%
PM_{10}	(24-Hr Avg.)	150	(ug/m^3)	46	(ug/m^3)	31%
PM_{10}	(Ann. Avg.)	50	(ug/m^3)	16	(ug/m^3)	32%
$PM_{2.5}$	(24-Hr Avg.)	65	(ug/m^3)	20	(ug/m^3)	31%
$PM_{2.5}$	(Ann. Avg.)	15	(ug/m^3)	9.6	(ug/m^3)	64%

1 Fourth highest 8-hour concentration measured at Paynes Prairie averaged with the fourth highest 8-hour concentration measured at Jonesville.
2 Highest 1-hour concentration measured at Paynes Prairie averaged with the highest 1-hour concentration measured at Jonesville.

Sources: SO_2 data (2000), and NO_2 data (2001) from Air Quality Trends in Alachua County, Brown & Cullen, October 2003.
O_3 data (2003), PM_{10} and $PM_{2.5}$ data (2003) from FDEP website.

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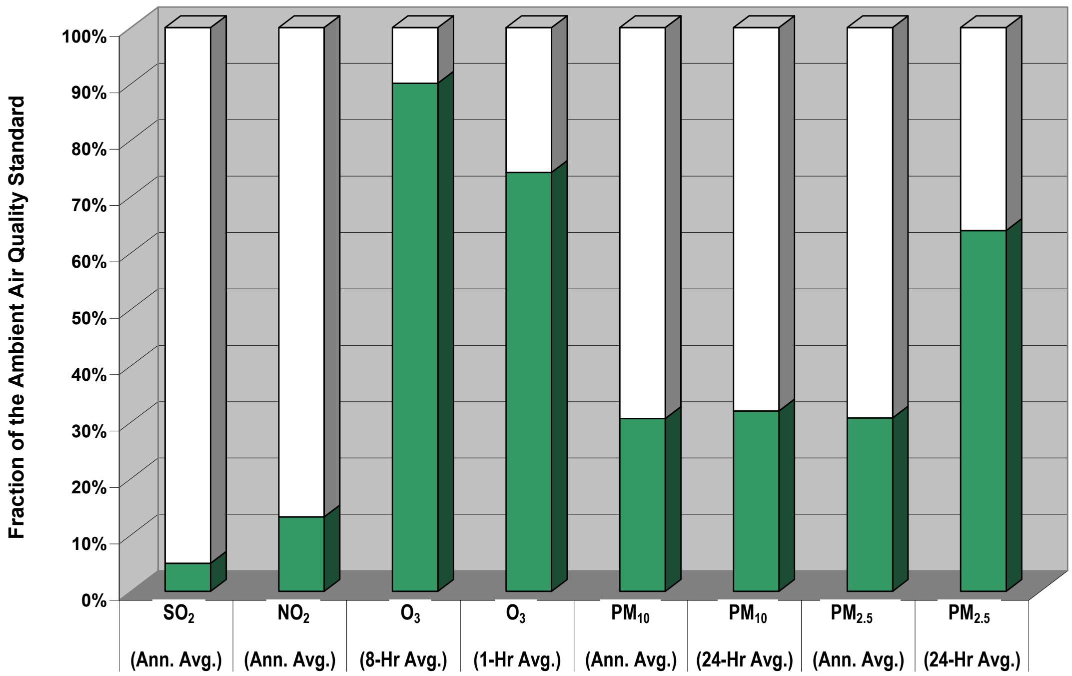
[9] Scientifically determined concentration limits for pollutants in the ambient air to protect public health and welfare with an adequate margin of safety.
[10] Maximum allowed increases in air pollution in attainment areas. These are designed to maintain air quality in areas that meet AAQS.
[11] www.dep.state.fl.us/secretary/news/2004/june/0629_air.htm; www.epa.gov/ozonedesignations/regions/region4desig.htm

Figure 3
Alachua County Ambient Air Quality



It should be noted that ozone is not emitted directly from a source. Rather, it forms as a result of complex chemical reactions involving NO_X and volatile organic compounds (VOCs) from natural and industrial sources in the presence of sunlight. These reactions take place over time and are influenced by many environmental factors (e.g., temperature, humidity, intensity of sunlight) making ozone a regional, not a local, issue.

In 2001, GRU conducted a limited monitoring program for VOCs in the Gainesville urban area[12]. VOCs include many compounds on EPA's list of hazardous air pollutants (HAPs). Although there are no AAQS for VOCs or HAPs, the Occupational Safety and Health Administration (OSHA) has established exposure limits designed to protect human health. During this program, the highest value measured for any compound was 10,000 times less than the chronic levels allowed in the workplace by OSHA. The highest VOC levels detected were not chemical compounds associated with GRU's power plants.

<u>GRU's Impacts on Alachua County's Air Quality – Current and Future</u>

GRU hired Black & Veatch[13] to model emissions from the Deerhaven and J.R. Kelly power plants to assess their potential impact on the ambient air quality in Alachua County under two scenarios as follows:

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[12] Volatile Organic Compounds Report (Harding ESE, Inc., Dec. 2001).
[13] Black & Veatch is an international consulting firm specializing in power production and permitting.

1) Current conditions ("base case") and
2) Future expected conditions ("future scenario").

The future scenario is based on today's concept of the Proposed Project and thus, the assumptions used in the modeling will likely change if, and when, the project evolves into a design phase. At that point specific emission control technologies and associated regulatory requirements (e.g., Best Available Control Technology[14]) will be identified and refined. Additional modeling will be conducted as part of the Site Certification permitting process if the project is approved by the City Commission.

Description of Models

Black & Veatch used approved EPA models to simulate the dispersion of emissions in the atmosphere and predict the ground-level concentrations of SO_2, NO_X, PM_{10}[15] and $PM_{2.5}$[16], for the specific averaging times specified by the AAQS. The concentrations were predicted for each pollutant, plant and combination of plants under current and future expected conditions. Mercury deposition modeling was also conducted and is discussed in the next section.

The Industrial Source Complex Short-Term (ISCST3) model was used for SO_2, NO_X and PM/ PM_{10}. Note that all PM was assumed to be PM_{10}. This is a conservative assumption because a portion of the total PM will be larger than PM_{10}. The ISCST3 air dispersion model is a steady state, straight-line model. Plume information is not retained from one hour of meteorological data to the next and the plume is assumed to be instantaneously transported to its final downwind distance each hour. Additionally, the ISCST3 air dispersion model does not possess the advanced ability to represent the complex chemical transformation processes that take place in the atmosphere after a plume leaves the stack. According to Black and Veatch, the ISCST3 air dispersion model is the "workhorse" of the industry. It is currently the preferred and most widely used model for assessing impacts from numerous types of sources upon surrounding ambient air quality.

The California Puff (CALPUFF) model was used for $PM_{2.5}$. CALPUFF is a time-dependent plume model. Plume information is retained from one hour of meteorological data to the next and the model requires time to transport the plume downwind. Additionally, the CALPUFF model possesses the advanced ability to represent the complex chemical transformation processes that take place in the atmosphere after a plume leaves the stack. Because of this ability, CALPUFF was the preferred model to assess the impacts of $PM_{2.5}$ since it can handle both the direct emissions of $PM_{2.5}$

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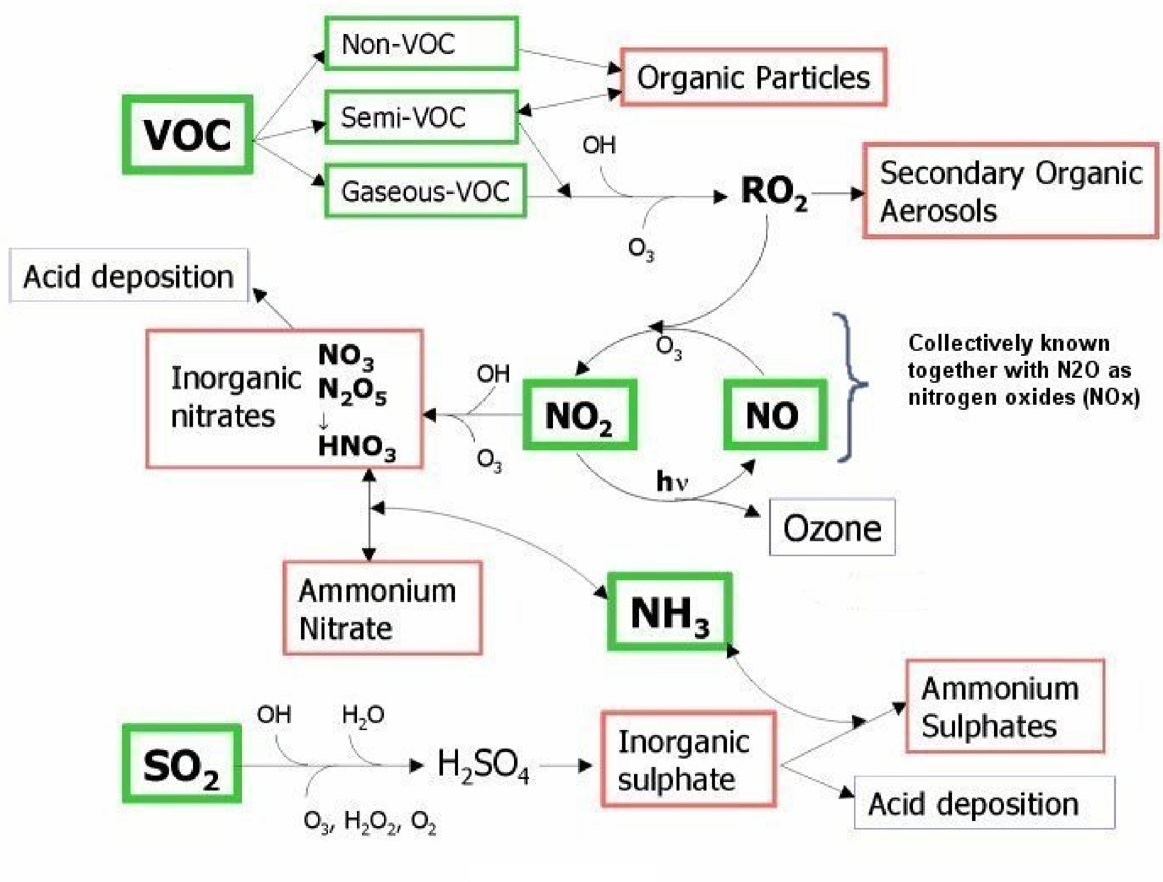
[14] This is a case-by-case determination for reducing air pollutant emissions using the most recent determinations for similar units as a starting point.
[15] PM_{10} is particulate matter that consists of particles with diameters less than or equal to 10 microns in size. This size is considered respirable.
[16] $PM_{2.5}$ is particulate matter that consists of particles with diameters less than or equal to 2.5 microns in size. EPA data indicates that these particles are composed primarily of sulfates, nitrates, organic compounds, and ammonium compounds. These fine particles have the potential to penetrate more deeply into the respiratory system and are believed to cause adverse health effects, especially the organic particles such as those associated with vehicular exhaust.

(primary) and the formation of $PM_{2.5}$ (secondary)[17] after gases (e.g., SO_2 and NO_X) leave the stack and undergo chemical reaction in the atmosphere. Figure 4 illustrates these reactions. It should be noted that, while this modeling was conducted to characterize local scale impacts, $PM_{2.5}$ is largely a regional scale pollutant. Currently, there are no EPA-approved models or regulatory requirements for modeling $PM_{2.5}$ on a local scale.

Figure 4
Transformation of Precursor Gases to Particles



Source: Adapted from Meteorilogical Service of Canada (MSC) http://www.msc-smc.ec.gc.ca/saib/smog/pm_summary/pm_fig4_e.html

Description

The many complex reactions by which precursor gases (green boxes) form particles (red boxes) are schematized here in a highly simplified form. Oxidizing agents like the hydroxyl radical (OH) and ozone (O3) play a significant role in many of these reactions. It can also be seen that particle formation is closely linked to the processes that produce acid rain and ground-level ozone.

Since emissions of SO_2, NO_X and PM all have the ability to contribute to the model-predicted $PM_{2.5}$ concentrations, all three pollutants are modeled within CALPUFF.

[17] EPA studies indicate that the secondary species contributes 50% or more to ambient $PM_{2.5}$

While NO_X and SO_2 emissions are transformed into their $PM_{2.5}$ counterparts (i.e., sulfates and nitrates) internally within the model, the total PM emissions must be partitioned into size categories externally before being input into the model. In this case, the particle size distribution and size-specific emission factors were based on the actual data for DH2[18] and AP-42[19] for units DH1, JRK 7 and the proposed new unit. Where partitioning data was not available for a unit (e.g., combustion turbine), all PM was assumed to be $PM_{2.5}$ and partitioned evenly in the different size categories that were modeled.

Actual/predicted stack parameters and estimated emission rates and actual hourly meteorological data were input into the models. Different meteorological data periods were used for the ISCST3 and CALPUFF models due to the availability and quality of pre-processed data. For the ISCST3 model five years (1990-1994) of surface data (from the Gainesville Regional Airport) and upper air data (from Waycross, GA) were used. The CALPUFF model used the 1990 mesoscale meteorological data sets developed by Pennsylvania State University in conjunction with the National Center for Atmospheric Research.

Scenarios Modeled

Two Base Case Scenarios were modeled:

1. Permitted Maximum: All units are assumed to be operated at the permitted emission rates burning "worst-case" fuels (e.g., fuel oil and coal) for the maximum operating hours allowed per year. This scenario is not realistic because GRU does not operate the units at their permitted emission levels all year long. However, it would represent higher impacts than those associated with actual operations.

2. Expected Operations: All units are assumed to be operated under calendar year 2003 conditions. This scenario represents more realistic operations and reflects differences in energy demands, fuel constraints and economic dispatch of units.

In addition, four potential Future Scenarios[20] were modeled:

1. Addition of a 475 mw (gross) solid fuel fired unit and emission controls on DH2. All units were assumed to be operating under permitted conditions.

2. Addition of a 660 mw (gross) solid fuel fired unit and emission controls on DH2. All units were assumed to be operating under permitted conditions.
3. Addition of a 220 mw (net) solid fuel fired unit and emission controls on DH2. All units operating under "worst case" permitted condition (see above).

[18] A Study To Assess The Impact Of Power Plant Particulate Emissions On Alachua County's Air Quality (University of Florida, January 2003).
[19] Compilation of Air Pollutant Emission Factors, Table 1.3-4 (EPA, September 1998).
[20] Alternatives For Meeting Gainesville's Electrical Requirements Through 2022 (Gainesville Regional Utilities, December 2003).

4. Addition of a 220 mw (net) solid fuel fired unit and emission controls on DH2. The new unit was assumed to operate at an 85% (net) capacity factor; all other units were assumed to operate as they did in 2003.

Future Scenarios 1 and 2 above were proposed as part of a joint project with the Florida Municipal Power Association and would have resulted in joint ownership and control of the new unit with other participating utilities. At the December 15, 2003 meeting, the City Commission expressed a preference for a smaller unit that would be owned and controlled solely by the City of Gainesville. Therefore, Future Scenarios 1 and 2 were eliminated from further consideration and are not discussed herein.

Future Scenarios 3 and 4 considered a smaller unit and assumed that DH2 would continue to burn coal while the new unit would burn a blend of fuels consisting approximately of 50% petroleum coke and 50% coal. Although up to 30 mw of biomass capacity is being considered for the new unit, it was not included in this modeling due to the current uncertainties (e.g., amounts, emission rates, etc.) associated with it.

Modeling Process

The ISCST3 and CALPUFF models predict the concentration of various emissions in the air for a grid of points distributed on a map of the area being modeled. These points are then contoured to show the patterns of concentration, in this case, for Alachua County. A sample contour is presented in Appendix A.

Black and Veatch determined the "base case" and "future scenario" maximum model-predicted ground-level concentration impacts for each pollutant, facility, and combination of facilities for the years included in the modeling. This data was presented in tabular format in the various Black and Veatch reports[21] and is included herein as Appendix B ("base case-permitted" versus "future scenario-permitted") and Appendix C ("base case – 2003 operation" versus "future scenario – based on 2003 operation"). These tables represent the highest concentrations out of all five modeling years.

Modeling Results

The impact of GRU's existing power plants ("base case") on the ambient air quality is relatively small. This is due, in part, to the fact that DH2, GRU's coal-fired unit, was

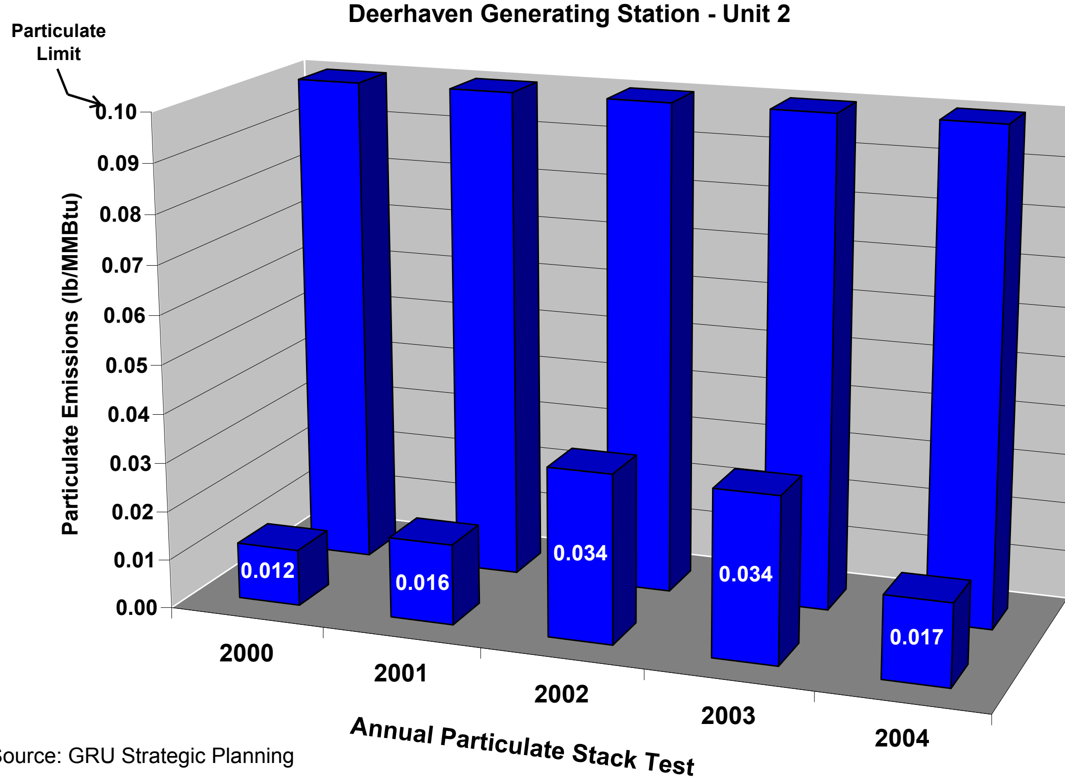
[21] Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities (Black & Veatch, January 2004)
Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities and the Future 220 MW CFB (Black & Veatch, February 2004)
Gainesville Regional Utilities Final $PM_{2.5}$ Air Quality Modeling Study (Black & Veatch, February 2004)
Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities and the Future 220 MW CFB Assessing Past Actual Annual Emissions and Expected Future Annual Emissions (Black & Veatch, June 2004)
Gainesville Regional Utilities Final $PM_{2.5}$ Air Quality Modeling Study Assessing Past Actual Annual Emissions and Expected Future Annual Emissions (Black & Veatch, June 2004)

permitted under a section (Subpart D) of the Clean Air Act that resulted in relatively low emission rates of SO_2, NO_X and PM as compared to older coal-fired power plants. Furthermore, the electrostatic precipitator (ESP) on DH2 has controlled PM emissions to well below permitted levels as shown in Figure 5. A University of Florida study of particulates in Alachua County[22] confirmed that coal combustion was a minimal contributor to ambient PM concentrations in Alachua County.

Figure 5

Gainesville Regional Utilities

Deerhaven Generating Station - Unit 2



Source: GRU Strategic Planning

The Proposed Project ("future scenario") would have a net air quality benefit (defined as a reduction in ground-level air quality impacts) for all pollutants as shown in Tables 4 and 5 with one exception. Under the comparison of future expected conditions to actual 2003 operations there was a very slight increase of PM/ PM_{10} ambient air concentration. The increase was .02 compared to an ambient concentration of 20 micrograms per cubic meter. This is because emissions from DH2 are already very low and the emission reductions from retrofitting DH2 were not sufficient to offset the emissions increase from the CFB. Also as shown in Tables 4 and 5, there is an expected decrease in $PM_{2.5}$ due to the reduced emissions of SO_2 and NO_X, which are precursors to secondary particulate formation.

[22] Composition, Particle Size, and Source of Ambient Aerosol in Alachua County (Paradee Chuaybamadee, UT, 2002)

Table 4
Summary of Ambient Air Quality
Changes Due to Proposed Project

Permit Limit Scenarios

(µg/m3)[1]

Parameter	FAAQS	Base Case Contributions[2]	Future Contributions[2]
NO_X - Annual Average	100	2.65	2.00
SO_2 - Annual Average	60	7.27	6.88
PM/PM_{10} - Annual Average	50	0.37	0.29
$PM_{2.5}$ - Annual Average	15	0.49	0.46

1 Highest point of concentration in Alachua County
2 Both plants

Table 5
Summary of Ambient Air Quality
Changes Due to Proposed Project

Actual/Expected Operation Scenarios

(µg/m3)$_1$

Parameter	FAAQS	Base Case Contributions[2]	Future Contributions[2]
NO_X - Annual Average	100	0.60	0.37
SO_2 - Annual Average	60	1.27	0.79
PM/PM_{10} - Annual Average	50	0.05	0.07
$PM_{2.5}$ - Annual Average	15	0.038	0.031

1 Highest point of concentration in Alachua County
2 Both plants

In summary, the modeling demonstrates that GRU's power plants are currently only slightly affecting ambient air quality. The Proposed Project would reduce the public's exposure to SO_2, NO_X and $PM_{2.5}$. GRU's operations contribute levels of pollutant concentrations that are below the thresholds of detectable health effects. Although there is a slight increase in the PM/PM_{10} ambient concentration the impact is insignificant when compared to the AAQS (50 micrograms per cubic meter) and existing ambient conditions.

MERCURY

Mercury is released into the environment by natural sources such as volcanoes and soils, as well as manmade processes (e.g., anthropogenic sources), including fuel combustion, cement and chlorine manufacturing, and mining among other things. Mercury emissions from U.S. power plants comprise approximately 1% of the total world emissions and are dwarfed by global contributors as illustrated in Figure 6. U.S. electric utilities released approximately 48 tons of mercury in 1999[23]. By comparison, China's coal fired plants emit more than 495 tons annually with an expected increase of 40+ tons over the next 2-5 years[24].

Figure 6

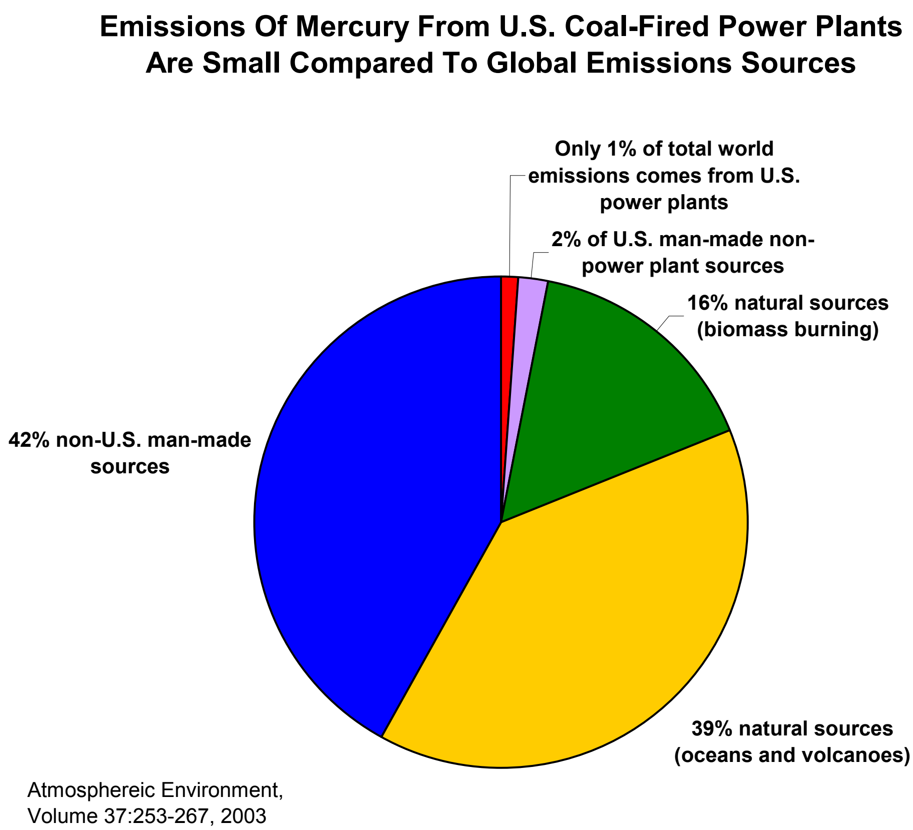


Figure 7 presents U.S. emissions of anthropogenic mercury and illustrates that since 1990 emissions have been reduced by more than 45% primarily due to regulations on municipal waste combustion, medical waste incineration and the use of mercury in products such as batteries, paints and pesticides.

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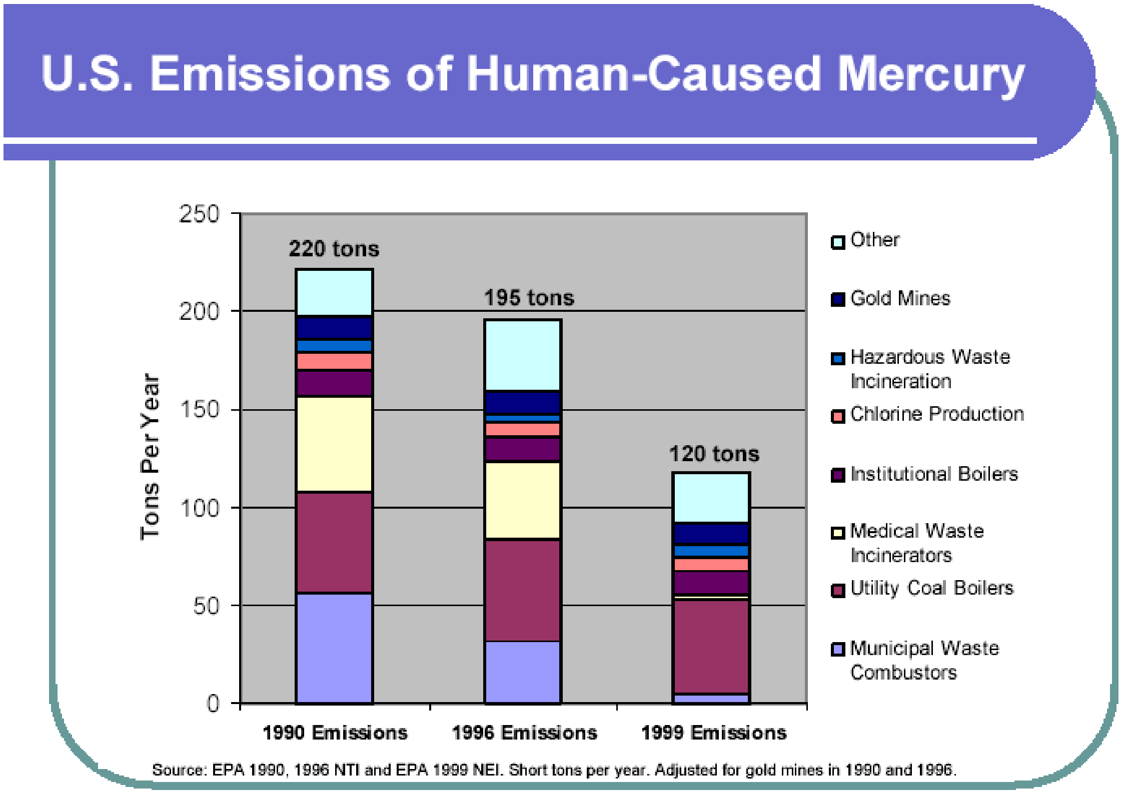
[23] Control of Mercury Emissions from Coal-Fired Electric Utility Boilers, EPA Office of Research and Development, www.epa.gov/ttn/atw/utility/hgwhitepaperfinal.pdf

[24] Atmospheric Environment, 2003

Figure 7



Recently, regulations have been proposed to limit mercury emissions from power plants.[25] According to EPA, existing pollution controls such as FGDs and SCRs are currently reducing mercury emissions by approximately 36% on a national average. The actual reductions achieved by a particular unit are highly dependent on the rank (e.g., bituminous, subbituminous, lignite) and chlorine content of the coal that is burned, the species of mercury that exists in the combustion gases, and the type of device used to control particulate emissions (e.g., ESP, FF). Further reductions are expected as more utilities install control technologies to comply with the new regulatory requirements and as mercury-specific technologies (e.g., injection of sorbent such as powdered activated carbon) become commercially available. Currently, sorbent injection technologies are not in commercial operation on power plants and thus, their capabilities and costs have not been fully demonstrated. However, the first full-scale commercial demonstration project for activated carbon injection was initiated by the Department of Energy in April 2004 and is projected to be completed in 2009. The Department of Energy expects to spend a number of years after that evaluating the technology.

Current DH2 emissions on average approximately 71 lbs of mercury annually (2001-2003 period) as reported in the Toxic Release Inventory. This reporting assumes the hot-

[25] Clean Air Mercury Rule (Federal Register, January 20, 2004) and Supplemental Proposal (Federal Register, March 16, 2004)

side ESP on DH2 provides a small degree (12%) of Hg removal[26]. Table 6 compares historical Hg emissions to the potential future Hg emissions from the Proposed Project. Despite doubling solid fuel generation capacity, Hg emissions are estimated to decrease by about 72%. These projected decreases are expected as co-benefits of installing SO_2, PM and NO_X controls on DH2 and as a result of CFB technology.

Table 6
Estimated Annual Mercury Emissions from Proposed Project

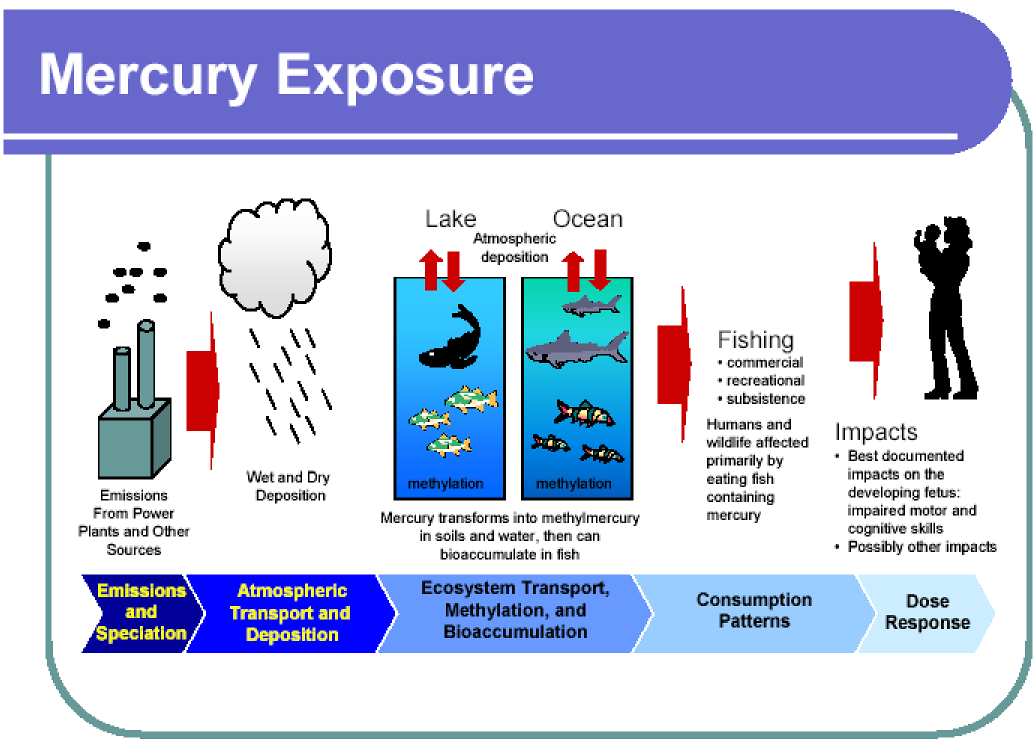
Current	Future[1]
71 lbs	20 lbs

1. High sulfur coal, Hg content from EPA ICR, See Appendix D

Mercury Modeling

Figure 8 illustrates the cycle of mercury in the environment. As shown, over time mercury can be transformed into methylmercury, a neurotoxin that can impair the human nervous system development and function.

Figure 8



Source: First-Ever Rule to Reduce Mercury Emissions from Power Plants, Decision Phase, Presentation by EPA Administrator, Mike Leavitt, 8/10/2004

[26] Guidance for Reporting Toxic Chemicals: Mercury and Mercury Compounds Category, Table 4-2, EPA 260-B-01-004, August 2001.

Power plants emit two primary forms of mercury: reactive (oxidized) and non-reactive (elemental)[27]. They do not emit methylmercury. Reactive mercury is water soluble and can be converted to methylmercury relatively easily in the presence of certain types of bacteria. Elemental mercury is not water soluble and thus is not washed out of the atmosphere. It disperses into the global Hg cycle and is subject to long-range transport beyond the source region. According to the Electric Power Research Institute approximately 30-49% of mercury from coal-fired power plants is reactive[28].

There are potential health concerns associated with the ingestion of mercury-contaminated fish by pregnant women and people who regularly and frequently eat such fish. Fish consumption advisories have been issued to provide guidance on the type and amount of fish that can be safely eaten[29]. The Santa Fe River, like all bodies of water in Florida, is subject to a fish consumption advisory.

Black & Veatch and Tetra Tech, Inc.[30] performed a study for GRU to evaluate the potential contribution of current DH2 emissions to background mercury deposition in the Santa Fe River Basin. Mercury transport and deposition were modeled using SO_2 as a surrogate for mercury emissions because the ISCST3 model cannot directly characterize mercury and because mercury behaves as gaseous SO_2. The model implemented an option that allowed for the deposition of a gas via dry and wet processes. Deposition velocities were provided by Tetra Tech, Inc. Mercury emission estimates were based on DH2 historical coal consumption and mercury concentration data.

All mercury was assumed to be emitted through the stack without any removal by the electrostatic precipitator (ESP). According to Electric Power Research Institute (EPRI), mercury removal rates for units burning bituminous coal and equipped with an ESP were found to average 11%[31]. The study was designed to assess the sensitivity of the results to the percentage that is in a reactive form, up to 100%. As stated previously, only about 30-49% of mercury from coal-fired plants is reactive.

The Black & Veatch modeling[32] combined with the TetraTech study[33] indicated the DH2 emissions potentially contribute only 1.2%-2.8% to the background mercury deposition in the Santa Fe River Basin assuming stack emissions containing 50% of reactive mercury as indicated in Figure 9. This suggests that most of the mercury deposited locally is from sources outside the region.

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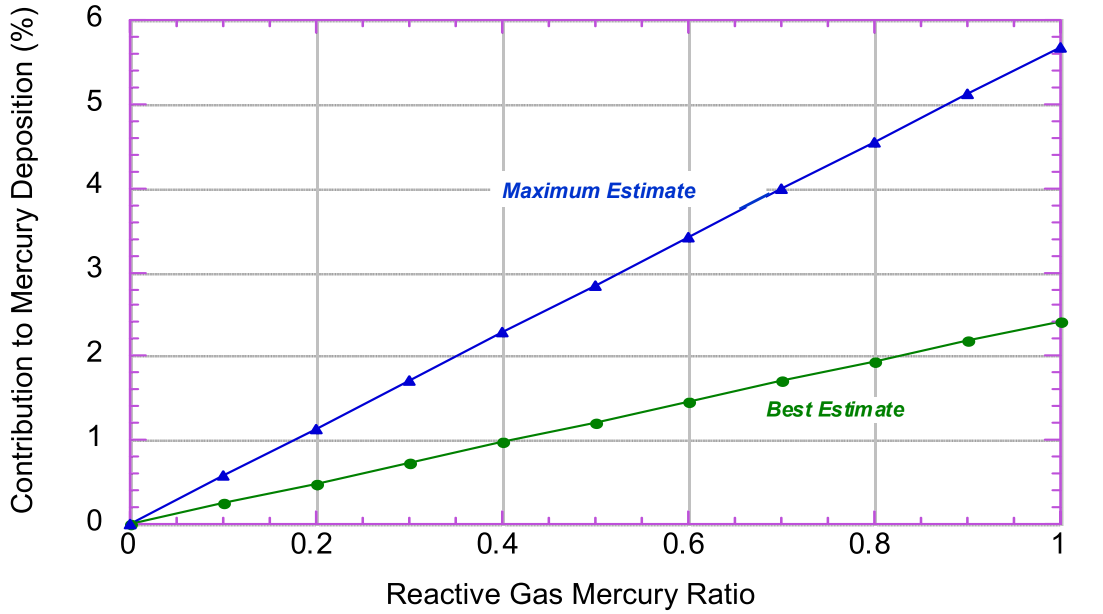
[27] Reactive mercury (Hg^{2+}) is electrically charged; elemental mercury (Hg^0) is electrically neutral.
[28] Potential Rates of Deerhaven 2 Mercury Deposition In The Santa Fe River Basin of North Central Florida (Tetra Tech Inc., C. Pollman, October 2003).
[29] www.doh.state.fl.us/environment/hsee/fishconsumptionadvisories/fish_consumption_guide.htm
[30] Tetra Tech, Inc., R&D Division, specializes in developing and applying models to study environmental issues (e.g., mercury, acid deposition, human health impacts).
[31] Potential Rates of Deerhaven 2 Mercury Deposition In The Santa Fe River Basin of North Central Florida (Tetra Tech Inc., C. Pollman, October 2003).
[32] Final Gainesville Regional Utilities Mercury Modeling Study for Deerhaven Unit 2 (Black & Veatch, October 2003).
[33] Potential Rates of Deerhaven 2 Mercury Deposition In The Santa Fe River Basin of North Central Florida (Tetra Tech Inc., C. Pollman, October 2003).

Figure 9

Results from GEAC Recommended Mercury Santa Fe River Deposition Study



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

GREENHOUSE GASES

Global climate change is a well documented phenomenon. The earth's climate has always been and continues to be in a state of change. Some of the current warming that the earth is experiencing has been attributed to increasing greenhouse gas (GHG)[34] emissions due to human activities, but there is considerable disagreement as to how much. GHGs include water vapor, carbon dioxide, methane, nitrous oxide and ozone from natural and human-related sources as well as chlorofluorocarbons (CFCs) and sulfur hexafluoride (SF_6) that have been created by man (Figure 10). Not all GHGs have the same global warming potential (i.e., contribution to the enhancement of the natural greenhouse effect). For example, methane is 23 times more potent than CO_2 (per unit of mass) in contributing to this human-related effect.[35] Although CO_2 has a lower global warming potential, it is released from sources in greater amounts than any of the other GHGs as shown in Figure 11. As illustrated in Figure 12 the transportation sector is the largest source of energy-related CO_2 emissions.

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[34] These are gases that trap the outgoing radiation from the earth and warm the earth's atmosphere.
[35] Intergovernmental Panel on Climate Change (IPCC), Third Assessment Report, 2001.

Figure 10
Greenhouse Gases in the Atmosphere

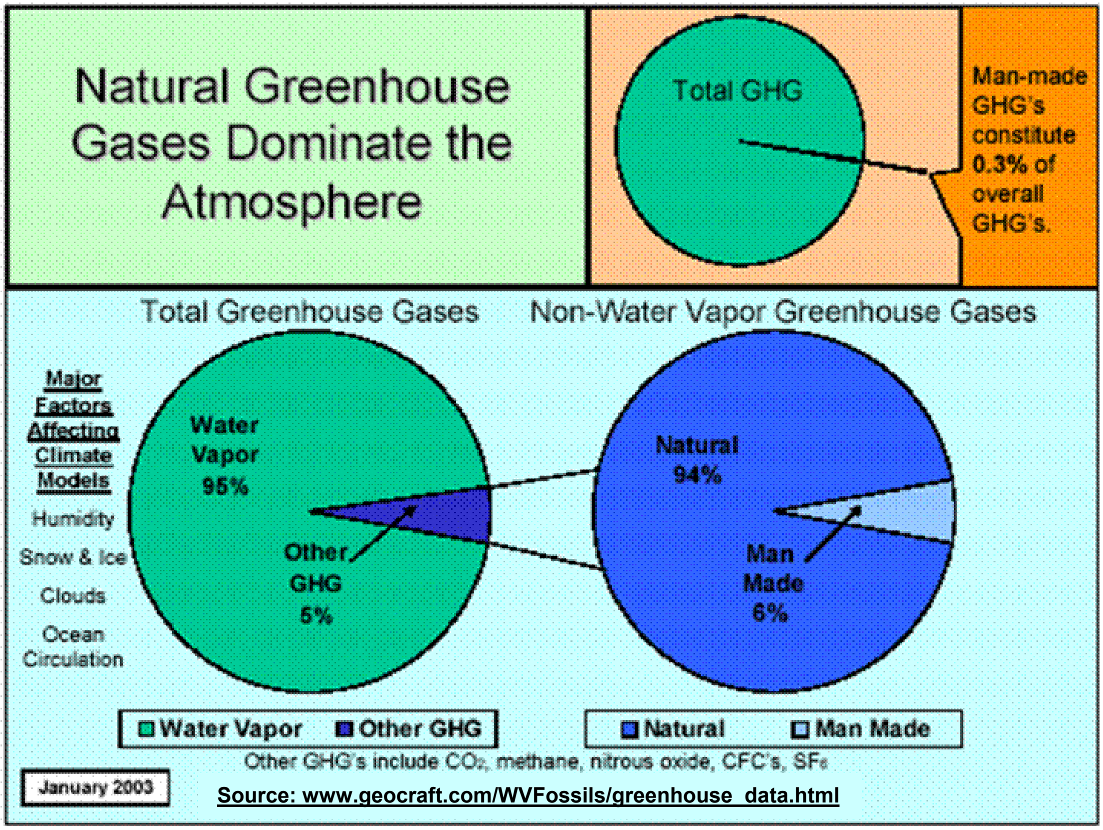


Figure 11
U.S. Human-Related Sources of Greenhouse Gases
(X1000 Metric Tons as Carbon)

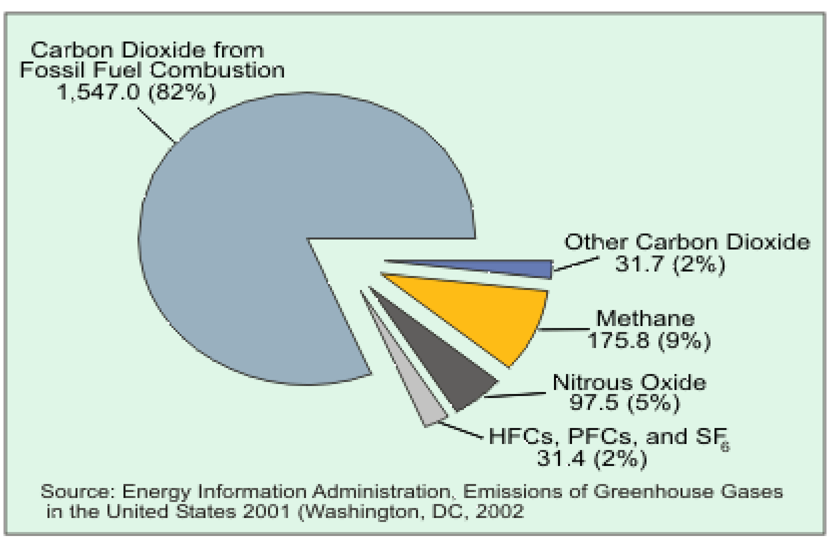
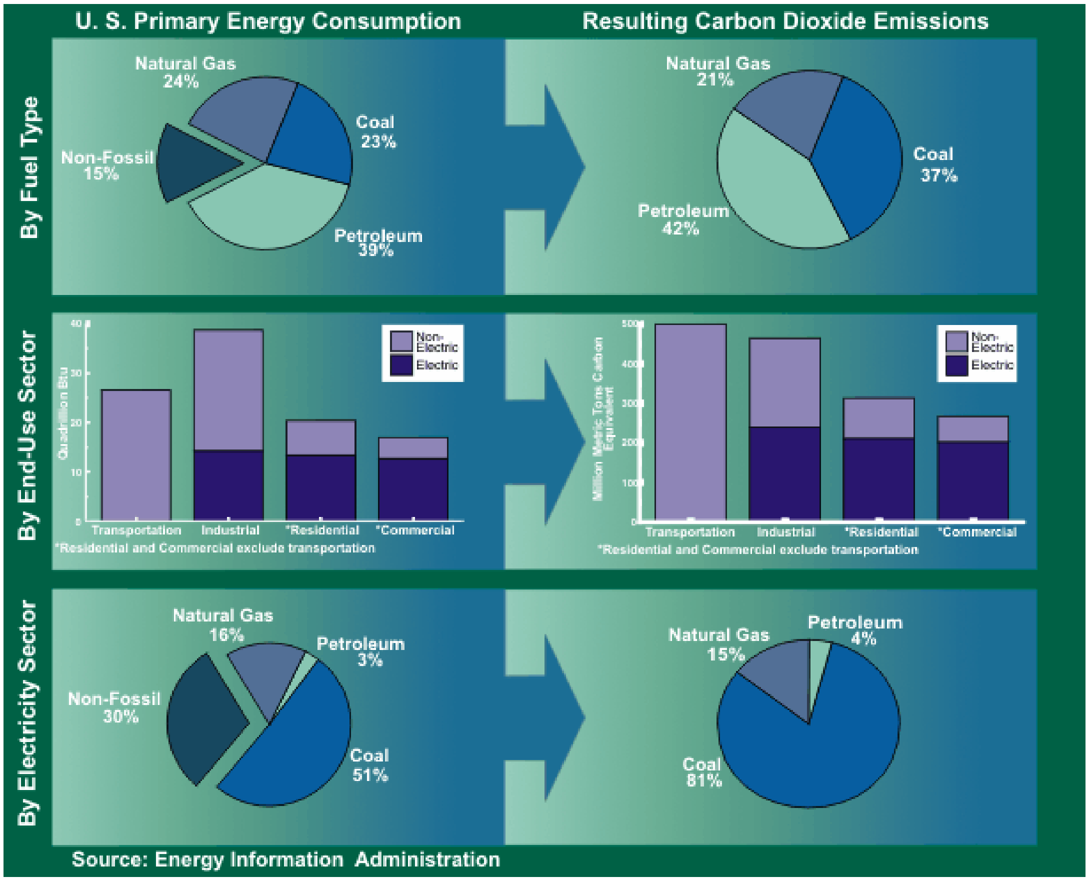


Figure 12
US Sources of Energy-Related CO_2 Emissions



Carbon dioxide is a substantial fraction of the natural atmosphere. It does not directly impact human health at current and predicted ambient concentrations and thus is not regulated as a pollutant. The major concern is the role that it and other GHGs may play in global climate change.

The Proposed Project would result in increased carbon dioxide emissions. GRU recognizes that reducing or sequestering CO_2 emissions from its generating units and industrial sources in general will require switching to natural gas or implementation of new technologies. These technologies are currently very limited, costly, and may not be able to secure regulatory approvals or financing[36]. However, other approaches, such as reducing emissions of precursors to GHGs (e.g., NO_X, soot) or offsetting the carbon intensity[37] of energy production are recognized methods of addressing CO_2 issues.

Table 7 and 8 present GRU's annual energy savings and CO_2 reductions attributable to projects such as demand side management (conservation), solar, landfill gas-to-energy, forest protection and efficiency improvements through the repowering project at the J.R.

[36] Wisconsin Public Service Commission, Docket No. 05-CE130, November 2002.
[37] Amount of carbon dioxide released to the atmosphere per unit of product.

Kelly power plant. These calculations are based on the carbon emission factors developed by the Intergovernmental Panel on Climate Change and acceptable CO_2 reduction measures per various protocols (e.g., Kyoto) and agencies (e.g., U.S. Department of Energy).

Table 7

Substantial Savings from Energy Conservation Initiatives

(MWh/Year)

• Kelly CC-1[1]	90,730
• Conservation Programs	70,000
• Landfill Gas to Energy[2]	10,775
• Solar at the Airport	15
• Systems Control Center PV	11
• Customer Owned PV	6
• Solar at the Schools	5

1 2002 CC1 steam turbine generation
2 Assumes two units operating at a 75% capacity factor.

Table 8

GRU CO_2 Offsets (tons/yr)

Waste Wood Fuel (Proposed)[1]	271,776
Kelly CC1 Repowering[2]	90,524
Demand-Side Management	74,000
Landfill Gas to Energy Project[3]	57,120
Forest Protection (10,000 acres)[4]	33,917
Solar at the Airport (proposed)	16
Systems Control Center Solar	12
Solar in Schools	5

1 30 MW of DH3
2 Assumes avoidance of DH2 coal-fired generation by 2002 CC1 steam turbine generation efficiency gains.
3 Assumes two units operating at a 75% capacity factor. Adjusted for methane reduction credit using 2001 IPPC Global Warming Potentials.
4 Assumes average 3.39 tons CO_2/acre/yr

Table 9 illustrates GRU's CO_2 intensity reductions taking these projects and the proposed biomass fuel for the CFB into consideration. GRU will continue to evaluate and implement cost-effective projects that will contribute to further reductions in carbon intensity. The financial risk associated with carbon taxes or future regulations have been addressed in a separate document[38].

Table 9

GRU CO_2 Intensity Reductions

Year	Without CO_2 Reduction Projects (lb-CO_2/Gross MWh)	With CO_2 Reduction Projects (lb-CO_2/Gross MWh)
2003	1,997.9	1,820.4
2012	1,959.7 [1]	1,720.9 [2]

1 Actual emissions from 2003, without CO_2 reduction projects. Includes projected emissions from DH3 (CFB) including CO_2 from wood combustion in DH3.

2 Actual emissions from 2003, with CO_2 reduction projects. Includes projected emissions from DH3 (CFB), does not include CO_2 from wood combustion in DH3.

Note: DH3 emissions assume an 84.92% capacity factor, and a fuel mix (by heat input) of 38.96% coal, 47.38% pet coke, and 13.66% wood.

FUTURE REGULATORY CONSIDERATIONS

Several regulatory initiatives have been introduced that will affect the operation of GRU's existing and new electric generating units (EGUs). These initiatives and their anticipated impact are discussed briefly below.

Regulatory Initiatives

Clean Air Interstate Rule (CAIR) - This will regulate SO_2 and NO_X emissions from EGUs in 28 eastern states and the District of Columbia and is intended to address the issue of "local emissions causing regional pain". One example would be downwind $PM_{2.5}$ problems as the result of the conversion over time of SO_2 to sulfates. CAIR proposes to use a two phase cap and trade program to reduce SO_2 emissions from coal and oil fired units by approximately 50% in 2010 (Phase I) and 70% in 2015 (Phase II). The reductions would be based on reducing an EGU's existing Acid Rain allowances. NO_X from oil, gas and coal-fired units would also be reduced by roughly the same percentages based on a regional NO_X baseline. For each ton of SO_2 and NO_X emitted an EGU would

[38] Alternatives For Meeting Gainesville's Electrical Requirements Through 2022 (Gainesville Regional Utilities, December 2003).

have to hold an allowance which could be traded between EGUs. This type of system is currently in-place for SO_2 emissions.

Mercury Rule – EPA has proposed two approaches for regulating mercury from coal-fired EGUs and has stated its intent that both approaches accomplish the same degree of overall mercury reduction. The first approach would establish a maximum achievable control technology (MACT) standard for new and existing EGUs and would be implemented in 2008; the second is a two phase cap and trade approach with emission reduction target dates of 2010 and 2018. Under the latter approach, mercury reductions would be achieved through a co-benefit approach. That is, the controls that are installed to meet Phase I SO_2 and NO_X caps under CAIR would also reduce mercury. It is estimated that in Phase I nationwide mercury emissions would be reduced by approximately 29% and in Phase II by 70%.

Regional Haze and Best Available Retrofit Technology (BART) Rules – These rules would require states to reduce the visibility impacts of EGUs built between 1962 and 1977 on Class I areas. Two approaches have been proposed: a unit-specific BART for any EGU that is shown to have a significant impact on visibility in Class I areas and the utilization of the CAIR cap and trade program to meet BART requirements.

Impacts of Initiatives on GRU Operations

GRU has compared the current (i.e., 2003) and projected air emissions from the J.R. Kelly and Deerhaven power plants with the future requirements under two scenarios: 1) no new generating capacity is built and increased demands are met through purchased power or conservation and 2) the Proposed Project is implemented[39].

This comparison indicates that the current generating plants (System) will not be able to meet the Phase I or Phase II regulatory requirements without reducing their emissions and/or purchasing allowances. If the Proposed Project is implemented the System will be able to comply with the Phase I regulatory requirements. Phase II compliance would depend on the final outcome of the rules, but current evaluations of the System including the Proposed Project's expected performance indicate that Phase II requirements would likely be met, but without a lot of margin. A number of strategies could potentially provide the needed margins, such as sorbent injection, SNCR, or polishing scrubbers.

SUMMARY AND CONCLUSIONS

This report summarizes a series of studies performed to evaluate the environmental consequences of the proposed modifications of Gainesville Regional Utilities (GRU's) solid fuel generating facilities. The Proposed Project includes additional emission controls for the Deerhaven coal-fired generating unit (DH2) and an additional 220 MW (net) solid fuel fired generating unit at the same plant site. Although this proposed

[39] GRU Air Emission Reductions from the Deerhaven #3 Project Compared to Existing and Projected Clean Air Acts Requirements, Robert L. Kappelmann, September 2004

facility will be designed to use waste wood, coal, and petroleum coke, the air quality studies were performed assuming only coal and petroleum coke fuels, a worst case scenario for SO_2.

Two basic sets of comparisons were performed. One set compared existing air permit limitations to anticipated future air permit limitations, and the other set compared current operations (that result in substantially less emissions than permitted) to future expected operating conditions. Analyses performed included mass balance studies of emissions, and modeling of concentrations of emissions in the air for various regulatory required averaging periods. Data characterizing background conditions were also assembled. A mercury deposition study was performed to evaluate the maximum potential impact of Deerhaven 2 on the Santa Fe River basin. Finally, the carbon dioxide emissions and carbon intensity of GRU's overall long-term energy plan were evaluated.

Regulated Emissions (see Table 1): The Proposed Project would reduce the permitted levels of SO_2 and NO_X emissions in excess of 70%. Comparing historical operations to expected future operations, SO_2 and NO_X would be reduced roughly 50%, with a relatively small increase in PM/PM_{10}.

Air Quality (see Table 10): Current emissions of NO_X, SO_2, PM_{10} and $PM_{2.5}$ from GRU's generating facilities contribute only slightly to Alachua County's ambient concentrations. The Proposed Project would reduce GRU's small contribution to ambient concentrations of NO_X, SO_2, and $PM_{2.5}$. The reduction in $PM_{2.5}$ would be a result of reduced SO_2 and NO_X, which are precursors to the secondary formation of fine particulates. The Proposed Project will slightly increase GRU's contribution to ambient PM_{10} concentrations by .02 µg/m3 at the maximum point of concentration, which is about one-thousandth of the reported background condition in Alachua County.

Mercury and Carbon (see Table 11): Although the Proposed Project would result in increased emissions of carbon dioxide, the demand side management and renewable energy offsets in the overall long term plan would result in an overall reduction of carbon dioxide intensity (lbs. CO_2/MWh). The Proposed Project would result in an estimated 72% reduction of total mercury emissions.

The Proposed Project would contribute to improvements in ambient air quality and reduce the net carbon dioxide produced per unit of electricity. Other benefits of the Proposed Project would include greater fuel flexibility and price stability and the ability to comply with Phase I of the USEPA proposed Clean Air Interstate and Mercury control rules. It would also position the system to comply with Phase II of these rules.

Finally, the Proposed Project would provide the community with certainty regarding the timing and extent of emission reductions in the event that EPA's regulations are not promulgated or are challenged after they are promulgated.

Table 10
Summary of Air Modeling Results
NO_X, SO_2 and PM

Annual Average µg/m^3

Parameter	NO_X	SO_2	PM_{10}	$PM_{2.5}$
Air Quality Standard	100	60	50	15
Alachua County Level[a]	5	8	16	9.6
GRU's Permitted Maximum Contribution[b]	2.65	7.67	0.37	.49[c]
GRU's Future Permitted Maximum Contribution[b]	2.0	6.9	0.29	.46[c]
GRU's Operations Maximum Contribution[b]	0.6	1.27	0.05	.038[c]
GRU's Future Expected Operations Maximum Contribution[b]	0.37	0.79	0.07	.031[c]

a Alachua County Air Quality Findings and Recommendations, Alachua County Air Quality Commission, January 2000. Updated 2003.
b Point of maximum concentration from isopleths modeled from all of GRU's generation units, at maximum permitted conditions.
c $PM_{2.5}$ including direct emissions plus secondary particulates formed from NO_X and SO_2 downstream of emissions source.

Table 11
Summary of Carbon Dioxide and Mercury

Scenario	Carbon Intensity[a] lbs CO_2/MWh	Mercury lbs/year
Baseline Conditions	1,820	71[b]
Future Conditions	1,721	20[c]

a Includes offsets from demand side management programs, forestry management, landfill gas to energy, use of waste wood for fuel (future), and solar projects.
b Based on current coals and operations.
c Based on high sulfur coals and petroleum coke used under future conditions of Proposed Project.

Appendix A

Contour Sample
Average Annual NO_X Contributions From GRU Generation - 2003 Operations

GRU Facility

Alachua County Boundary

Scale (km)

0 2 4 6 8 10

BLACK & VEATCH

Source: USGS 1:250,000 Scale Topographic Map of Alachua County, Florida

Appendix B-1

Maximum Concentration Impacts in Alachua County (Current Permitted to Expected Future Permitted)

NO_X Annual Average (μg/m^3)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	2.30	1.64	-29%
J.R. Kelly	1.24	1.24	0%
Both	2.65	2.00	-25%
FAAQS[c]	100		

a Assumes all units operated at the current permitted conditions on worst-case fuels
b Assumes the addition of a 220 MW (net) CFB, installation of additional emission controls on DH2 and all units operating at permitted conditions on worst-case fuels.
c Model Used: ISCST3
d Florida Ambient Air Quality Standard

Source: Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities and the Future 220 MW CFB (Black & Veatch, February 2004)

Appendix B-2

Maximum Concentration Impacts in Alachua County

(Current Permitted to Expected Future Permitted)

SO_2 Annual Average ($\mu g/m^3$)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	6.86	6.42	-6%
J.R. Kelly	3.03	3.03	0%
Both	7.67	6.88	-10%
FAAQS[d]	60		

SO_2 24-Hour Average ($\mu g/m^3$)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	114.03	100.52	-12%
J.R. Kelly	39.15	39.15	0%
Both	114.03	100.52	-12%
FAAQS[d]	260		

SO_2 3-Hour Average ($\mu g/m^3$)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	341.76	332.27	-3%
J.R. Kelly	140.83	140.83	0%
Both	341.76	332.27	-3%
FAAQS[d]	1,300		

a Assumes all units operated at the current permitted conditions on worst-case fuels
b Assumes the addition of a 220 MW (net) CFB, installation of additional emission controls on DH2 and all units operating at permitted conditions on worst-case fuels.
c Model Used: ISCST3
d Florida Ambient Air Quality Standard

Source: Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities and the Future 220 MW CFB (Black & Veatch, February 2004)

Appendix B-3

Maximum Concentration Impacts in Alachua County (Current Permitted to Expected Future Permitted)

PM/PM_{10} Annual Average ($\mu g/m^3$)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	0.34	0.26	-24%
J.R. Kelly	0.15	0.15	0%
Both	0.37	0.29	-22%
FAAQS[d]	50		

PM/PM_{10} 24-Hour Average ($\mu g/m^3$)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	5.46	4.32	-21%
J.R. Kelly	3.06	3.06	0%
Both	5.46	4.32	-21%
FAAQS[d]	150		

a Assumes all units operated at the current permitted conditions on worst-case fuels
b Assumes the addition of a 220 MW (net) CFB, installation of additional emission controls on DH2 and all units operating at permitted conditions on worst-case fuels.
c Model Used: ISCST3
d Florida Ambient Air Quality Standard

Source: Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities and the Future 220 MW CFB (Black & Veatch, February 2004)

Appendix B-4

Maximum Concentration Impacts in Alachua County (Current Permitted to Expected Future Permitted)

$PM_{2.5}$ Annual Average (µg/m^3)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	0.17	0.14	-18%
J.R. Kelly	0.36	0.36	0%
Both	0.49	0.46	-6%
FAAQS[c]	15		

$PM_{2.5}$ 24-Hour Average (µg/m^3)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	3.68	2.91	-21%
J.R. Kelly	4.00	4.00	0%
Both	4.06	4.04	0%
FAAQS[d]	65		

a Assumes all units operated at the current permitted conditions on worst-case fuels
b Assumes the addition of a 220 MW (net) CFB, installation of additional emission controls on DH2 and all units operating at permitted conditions on worst-case fuels.
c Model Used: CALPUFF
d Florida Ambient Air Quality Standard

Source: Gainesville Regional Utilities Final $PM_{2.5}$ Air Quality Modeling Study (Black & Veatch, February 2004)

Appendix C-1

Maximum Concentration Impacts in Alachua County
(2003 Actual Operation to Future Expected Operation)

NO_X Annual Average ($\mu g/m^3$)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	0.60	0.36	-40%
J.R. Kelly	0.04	0.04	0%
Both	0.60	0.37	-38%
FAAQS[d]	100		

a Based on 2003 actual operations
b Assumes the addition of a 220 MW (net) CFB operating at 85% capacity factor; installation of additional emission controls on DH2; and all exiting units operating as they did in 2003.
c Model Used: ISCST3
d Florida Ambient Air Quality Standard

Source: Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities and the Future 220 MW CFB, Assessing Past Actual Annual Emissions and Expected Future Actual Annual Emissions (Black & Veatch, June 2004)

Appendix C-2

Maximum Concentration Impacts in Alachua County
(2003 Actual Operation to Future Expected Operation)

SO_2 Annual Average ($\mu g/m^3$)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	1.27	0.78	-39%
J.R. Kelly	0.04	0.04	0%
Both	1.27	0.79	-38%
FAAQS[d]	60		

a Based on 2003 actual operations

b Assumes the addition of a 220 MW (net) CFB operating at 85% capacity factor; installation of additional emission controls on DH2; and all exiting units operating as they did in 2003.

c Model Used: ISCST3

d Florida Ambient Air Quality Standard

Source: Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities and the Future 220 MW CFB, Assessing Past Actual Annual Emissions and Expected Future Actual Annual Emissions (Black & Veatch, June 2004)

Appendix C-3

Maximum Concentration Impacts in Alachua County
(2003 Actual Operation to Future Expected Operation)

PM/PM_{10} Annual Average ($\mu g/m^3$)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	0.05	0.07	40%
J.R. Kelly	0.01	0.01	0%
Both	0.05	0.07	40%
FAAQS[d]	50		

a Based on 2003 actual operations
b Assumes the addition of a 220 MW (net) CFB operating at 85% capacity factor; installation of additional emission controls on DH2; and all exiting units operating as they did in 2003.
c Model Used: ISCST3
d Florida Ambient Air Quality Standard

Source: Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities and the Future 220 MW CFB, Assessing Past Actual Annual Emissions and Expected Future Actual Annual Emissions (Black & Veatch, June 2004)

Appendix C-4

Maximum Concentration Impacts in Alachua County (2003 Actual Operation to Future Expected Operation)

$PM_{2.5}$ Annual Average (µg/m^3)

	Base Case[a]	Future Scenario[b,c]	Net Change
Deerhaven	0.027	0.026	-4%
J.R. Kelly	0.014	0.014	0%
Both	0.038	0.031	-18%
FAAQS[d]	15		

a Based on 2003 actual operations

b Assumes the addition of a 220 MW (net) CFB operating at 85% capacity factor; installation of additional emission controls on DH2; and all exiting units operating as they did in 2003.

c Model Used: CALPUFF

d Florida Ambient Air Quality Standard

Source: Gainesville Regional Utilities Final $PM_{2.5}$ Air Quality Modeling Study, Assessing Past Actual Annual Emissions and Expected Future Actual Annual Emissions (Black & Veatch, June 2004)

Appendix D

Projected Mercury Emissions

	Fuel Burned		Fuel Specific Hg Concentration[1,2]		Technology Specific Hg Removal[3,4,5]				Hg Stack Emissions	Hg Emission Rate
	Coal (tons/yr)	Coke (tons/yr)	Coal (ppm)	Coke (ppm)	CFB SDA FF (%)	HSESP (%)	SCR FF DFGD (%)	Overall (%)	(lbs)	(lb/TBtu)
DH2[6]	548,582.81	0	0.11			12%	90%	91.2%	10.62	0.75
DH3[7]	299,091.26	263,659.32	0.11	0.05	90.0%			90.0%	9.22	0.59
DH2+DH3	847,674.07	263,659.32						90.7%	19.84	0.67

1 DH2 mean Hg content in coal from EPA Mercury ICR, 1999.
2 DH3 mean Hg content in coke from EPA Mercury ICR, 1999.
3 DH3 CFB Hg removal efficiency based on EPA-600/R-01-109, April 2002.
4 DH2 HSESP Hg removal efficiency from EPA-260-B-01-004, August 2001.
5 DH2 Hg removal efficiency with SCR, FF, and WFGD from Table B-1 of EPRI Technical Report, "A Framework for Assessing the Cost-Effectiveness of Electric Power Sector Mercury Control Policies", May 2003.
6 DH2 operation same as 2003.
7 DH3 operation 85% capacity factor, 50% coal, 50% pet coke.