ICF CONSULTING

# City of Gainesville

City of Gainesville
Electricity Supply Needs

(RFP No. 2005-147)

# DRAFT

**February 13, 2006**

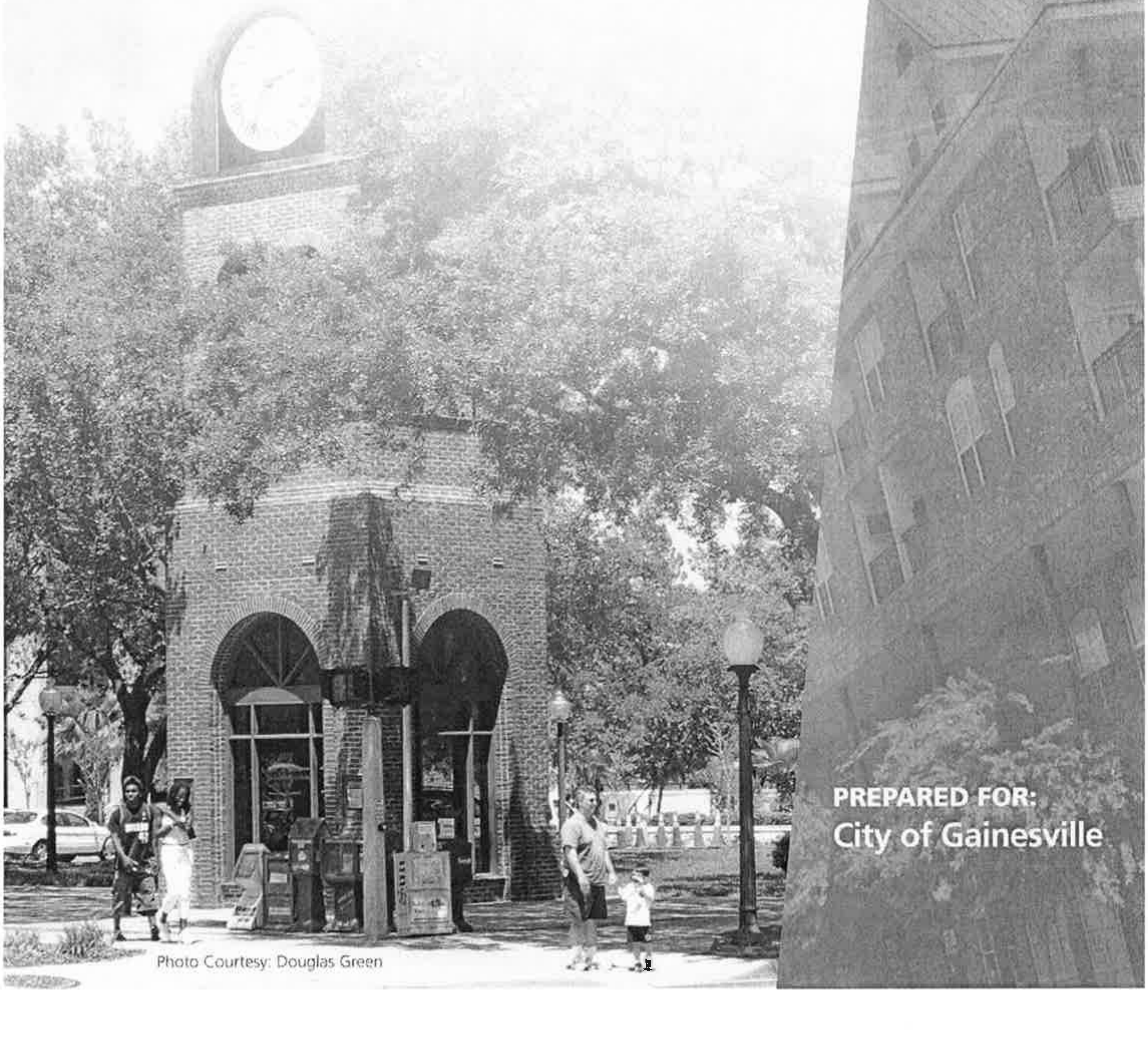

Photo Courtesy: Douglas Green

**PREPARED FOR:**
City of Gainesville

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## Use of This Document

The Document is a draft report. ICF is still reviewing the results and changes are expected.

# EXECUTIVE SUMMARY

## FOUR OPTIONS AND SENSITIVITY ANALYSIS

After consultation with the City with respect to which options to analyze, ICF examined the following four resource options: (1) the construction by 2012 of a 220 MW Circulating Fluidized Bed Combustion plant (CFB) capable of using coal, petroleum coke and up to 30 MW of biomass without major degradation of plant performance; (2) the construction of a 220 MW Integrated Gasification Combined Cycle (IGCC) with similar fuel and on-line date characteristics; (3) a 75 MW biomass only plant also on-line by 2012 with maximum DSM, where maximum DSM is defined as the economic choice among 19 programs under the most adverse supply side circumstances – i.e., high natural gas prices and high $CO_2$ allowance prices; and (4) maximum DSM.

This analysis explicitly examined for each of the options 36 future scenarios which results in 144 combinations of scenarios and options (4x36). The analysis in each case was conducted for 20 years starting in 2006 resulting in 2,880 years of data (20x144). Most scenarios represent future conditions that will differ from historic conditions in some key respects:

- **$CO_2$ Emmission Regulations** – Currently, $CO_2$ emissions are not regulated in Florida or on a federal basis. In contrast, two thirds of the scenarios examined assume $CO_2$ emission regulations will be in place after 2010 based on ICF's expectation that such regulations are likely[1].

- **Slower Electricity Demand Growth Before DSM** – Electricity demand growth before DSM is forecast to be less than historical levels. For example, the Base Case forecast growth rate is 2.1 percent per year, and is two thirds the ten year rolling average growth rate between 1985 and 2005. A high case is also examined, but this case also assumes a slowing in demand growth before DSM.

- **Higher Natural Gas Prices** – In 2005, annual average Henry Hub, Louisiana natural gas prices were \$8.37/MMBtu which was an all time record high price. The Base Case delivered natural gas price is \$6.10/MMBtu in 2003\$. In comparison, however, the ten year average price was \$3.42/MMBtu (1995-2004 nominal\$). This forecast of long term high natural gas price is expected to strongly affect decisions across the grid. The higher real natural gas prices will compound the effect of general inflation to the extent GRU ratepayers are sensitive to both real and nominal effects. For example, general inflation alone would cause

[1] This can be thought of as a two-thirds chance $CO_2$ regulations will be in place since each of the 36 cases is treated as equally likely.

gas prices to double over the study horizon from the long term average. Also, the year to year volatility would likely increase as base prices increase.

- **Coal Prices** – Delivered coal prices are forecast to be at or below recent levels, favoring coal options all else equal. This low to steady price is reinforced by: (1) the use of low cost petroleum coke at approximately 45 percent of the total fuel input, and (2) increased fuel flexibility due to flue gas desulfurization. The study did not fully examine an all petroleum coke option and this could further lower fossil fuel prices since this is the least cost fuel option. This option was not examined since it might not be technically feasible and/or petroleum coke supply may not be sufficiently available to achieve these high levels.

- **Financing Costs** – ICF examined only one financing scenario with very low financing costs for GRU compared to most U.S. utilities. This reflects current conditions at GRU.

If one takes a different view of likely economic and regulatory uncertainties, the results can differ.

Some of the options examined represent in some cases significant changes and/or involve difficult to quantify risks for the City of Gainesville:

- **DSM** – The DSM program examined here involves levels of expenditures, expertise, and performance that the most advanced municipal utilities (e.g., Austin, Texas) have taken roughly 10 years to achieve. The City of Gainesville is not at these levels at this time, and failure to achieve these reductions can lead to faster than expected load growth and greater reliance on purchase power and/or peaking units. Thus, special attention is directed to ICF's forecast of purchase power prices.

- **Local Biomass** – The local biomass option has not been fully explored by GRU since none of its current generation capacity can use biomass. There are significant economic and technical uncertainties regarding biomass including uncertainties affecting transportation, delivered cost, fuel variability and quality, plant reliability, and the potential for $CO_2$ controls to enhance the relative economics of this option which is considered a zero $CO_2$ emission option.

- **IGCC** – This is an advanced generation technology with significant perceived risks even when using conventional fossil fuels. There are also risks related to high levels of biomass. There are also significant issues with respect to actual capital costs after factoring in these risks. ICF's extra contingencies for these risks are described in Chapter 4. ICF also assumes financing costs are the same for IGCC as for other GRU options because of the potential availability of federal loan guarantees. ICF does not believe cash grants will be available in any significant amount for defraying IGCC costs.

Accordingly, ICF recommends that the City factor into its decision making these qualitative issues.

## DSM OPTION

The maximum DSM option had lower costs averaging approximately $30/MWh in real 2003 dollars. By 2025, DSM had decreased reserve requirements by 71 MW or about nine percent. DSM did not delay the need for new capacity since the effects were concentrated at the end of the horizon but did decrease the need. Total generation requirements in MWh decreased on an average only about 0.1 BkWh per year. In comparison, a 220 MW baseload plant produces 1.6 BkWh and on average GRU's energy needs are 2.8 BkWh. Thus, on an energy basis savings are on average 4 percent of GRU requirements.

**Figure ES-1**
**Maximum DSM Effects on GRU Supply and Demand Balance (MW) – Base Case Demand Growth**

| Year | Before DSM | | | | DSM Effects | After DSM | | |
|---|---|---|---|---|---|---|---|---|
| | Peak Demand | Peak Demand Plus Reserve Require-ments | Existing Capacity Net of Retire-ments[1] | Deficit/ Surplus Relative to Existing Capacity | Decrease in Peak Demand | Peak Demand | Peak Demand Plus Reserve Requirements | Deficit/ Surplus Relative to Existing Capacity |
| 2006 | 470 | 541 | 611 | 71 | 1 | 469 | 540 | 71 |
| 2007 | 483 | 555 | 611 | 56 | 2 | 481 | 554 | 57 |
| 2008 | 495 | 569 | 611 | 42 | 6 | 489 | 563 | 48 |
| 2009 | 508 | 584 | 611 | 27 | 9 | 499 | 574 | 37 |
| 2010 | 520 | 598 | 602 | 4 | 12 | 508 | 584 | 19 |
| 2011 | 532 | 612 | 579 | -32 | 17 | 515 | 593 | -13 |
| 2012 | 544 | 626 | 579 | -46 | 22 | 522 | 600 | -21 |
| 2013 | 556 | 639 | 579 | -60 | 28 | 528 | 608 | -28 |
| 2014 | 569 | 654 | 579 | -75 | 34 | 535 | 616 | -36 |
| 2015 | 580 | 667 | 579 | -88 | 40 | 540 | 621 | -42 |
| 2016 | 592 | 681 | 579 | -102 | 44 | 548 | 630 | -51 |
| 2017 | 603 | 693 | 579 | -115 | 49 | 554 | 637 | -58 |
| 2018 | 614 | 706 | 551 | -155 | 54 | 560 | 644 | -93 |
| 2019 | 625 | 719 | 537 | -182 | 59 | 566 | 651 | -115 |
| 2020 | 636 | 731 | 537 | -195 | 63 | 573 | 659 | -122 |
| 2021 | 648 | 745 | 537 | -209 | 65 | 583 | 671 | -134 |
| 2022 | 659 | 758 | 537 | -221 | 66 | 593 | 682 | -145 |
| 2023 | 671 | 772 | 454 | -318 | 68 | 603 | 694 | -240 |
| 2024 | 683 | 785 | 454 | -332 | 69 | 614 | 706 | -252 |
| 2025 | 694 | 798 | 454 | -344 | 71 | 623 | 717 | -263 |

[1] 15% reserve margin.

**Figure ES-2**
**Maximum DSM**

| Year | Decrease in MW Peak Demand | Decrease in MWh Demand | Annual Costs (2003$/millions) | Annual Costs (2003 $/MWh) |
|---|---|---|---|---|
| 2006 | 1 | 2 | 0.1 | 31.1 |
| 2007 | 2 | 4 | 0.1 | 31.1 |
| 2008 | 6 | 16 | 0.5 | 31.1 |
| 2009 | 9 | 25 | 0.8 | 31.1 |
| 2010 | 12 | 36 | 1.1 | 31.1 |
| 2011 | 17 | 49 | 1.5 | 31.1 |
| 2012 | 22 | 64 | 2.0 | 31.1 |
| 2013 | 28 | 80 | 2.5 | 31.1 |
| 2014 | 34 | 97 | 3.0 | 31.1 |
| 2015 | 40 | 114 | 3.6 | 31.1 |
| 2016 | 44 | 128 | 4.0 | 31.1 |
| 2017 | 49 | 141 | 4.4 | 31.1 |
| 2018 | 54 | 155 | 4.8 | 31.1 |
| 2019 | 59 | 168 | 5.2 | 31.1 |
| 2020 | 63 | 182 | 5.6 | 31.1 |
| 2021 | 65 | 186 | 5.8 | 31.1 |
| 2022 | 66 | 190 | 5.9 | 31.1 |
| 2023 | 68 | 195 | 6.1 | 31.1 |
| 2024 | 69 | 199 | 6.2 | 31.1 |
| 2025 | 71 | 203 | 6.3 | 31.1 |

## REPORTING PERIODS

ICF analyzed the 20 year period 2006 – 2025[2]. However, two other periods are also reported:

- **2012 – 2025** – This is the period when the options become available, and hence, the period that the City can most affect by its decisions today. Not only are the generation options assumed to have a long lead time coming on-line only by 2012, but most DSM savings also occur after 2012 and thereafter. 2006 – 2011 should not be affected in a significant way by Commission decisions among the resource options.

- **2012 – 2020** – One might imagine that by 2015, the City could make a new decision that would be on-line by 2021. In this scenario, the City would have ten years to gather more information including three during which it could gauge which the effects of the resources coming on-line in 2012. Furthermore, the post-2020 period is especially uncertain.

[2] A longer period can be analyzed by extrapolating from the last years of analyses, e.g., 2026 – 2030 can be based on 2020 – 2025. Furthermore, capital cost recovery was assumed extended by 2025.

## REVENUE REQUIREMENTS

ICF presents two measures of revenue requirements:

- **Cash Going Forward Production Related Costs** – This includes fuel, allowance costs, variable and fixed non-fuel O&M, incremental capital costs, allowance allocation, import costs and export revenues. Since additional revenue requirements exist, this measure tends to understate the percent change. However, this measure has the advantage of focusing on the elements most directly affected by City decisions.

- **Total Electric** – This adds to the above measure of production costs including transmission, distribution, G&A and other electric costs, many of which are assumed constant, regardless of the resource choice. These costs account for about half of cash going forward production related costs and hence, roughly a third of the revenue requirements.

### Revenue Requirements – Average Across Cases

All four options have revenue requirements within approximately five to seven percent of each other. The lowest cost options also have the greater qualitative risks:

- DSM alone has the lowest net present value of revenue requirements. DSM is very cost effective if it can be achieved. DSM costs are approximately $30/MWh versus approximately $40-$55/MWh for the generation options. However, this approach exposes GRU to greater reliance on purchase power costs and effective implementation of DSM. These effects all muted since GRU is able to purchase coal power. If coal powerplant construction is less than forecast, this option can be more costly.

- Biomass and DSM have only slightly higher costs than DSM alone. Biomass alone is a relatively expensive generation option at approximately $55/MWh versus $40/MWh and $49/MWh for IGCC and CFB, respectively. However, the cost impact is offset by DSM and the plant's small size. Importantly, the effect of biomass is mitigated by the ability to buy coal power in the spot markets. If wholesale spot markets are not flush with coal power, then the costs of this option could be more affected by oil and gas power.

- IGCC has the lowest average costs among the solid fuel options. So much IGCC is built gridwide, and GRU peaking costs are low because of GRU's low financing costs, even if GRU does not build one, it can benefit from IGCC by buying power in the spot market. If the market place is not as forthcoming as forecast, failure to build this plant could increase the costs of this option. This option has large perceived risk.

- CFB has the higher costs than IGCC but is the most proven technology. Thus, there is a trade off between risk and potential IGCC savings. Furthermore, an all petcoke fuel would close one-quarter of this difference with the other options.

**Figure ES-3**
**Selected Generation Production Revenue Requirements – NPV[1] (millions)**

| Period | Option | | | |
|---|---|---|---|---|
| | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
| 2006 – 2025 | 3,179 | 3,022 | 2,952 | 2,943 |
| 2012 – 2025 | 2,687 | 2,488 | 2,402 | 2,393 |
| 2012 – 2020 | 2,270 | 2,138 | 2,114 | 2,105 |

[1]Nominal discount rate of 5.4 percent. As of the first year of that period, i.e., 2006 or 2012. Includes generation going forward production costs only.

**Figure ES-4**
**Selected Generation Production Revenue Requirements – Change From Least Cost Case[1]**

| Period | Option | | | |
|---|---|---|---|---|
| | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
| 2006 – 2025 | +236 | +79 | +9 | -- |
| 2012 – 2025 | +294 | +94 | +9 | -- |
| 2012 – 2020 | +165 | +33 | +10 | -- |

[1]Nominal discount rate of 5.4 percent. Includes generation going forward production costs only.

**Figure ES-5**
**Selected Generation Production Revenue Requirements – Ranking**

| Period | Option | | | |
|---|---|---|---|---|
| | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
| 2006 – 2025 | #4 | #3 | #2 | #1 |
| 2012 – 2025 | #4 | #3 | #2 | #1 |
| 2012 – 2020 | #4 | #3 | #2 | #1 |

[1]Use of existing plants, purchase power, new CTs. Includes generation going forward production costs only.

**Figure ES-6**
**Selected Generation Production Revenue Requirements – Difference Between Best and Worst Option (%)[1]**

| Period | Selected Generation Production | Total Revenue Requirement |
|---|---|---|
| 2006 – 2025 | 8 | 5 |
| 2012 – 2025 | 12 | 7 |
| 2012 – 2020 | 8 | 5 |

[1]Nominal discount rate of 5.4 percent. Includes generation going forward production costs only.

The Biomass Maximum DSM and DSM only have lower variability in outcomes.

**Figure ES-7**
**Long-Term Variability**

| Period | Standard Deviation of NPV for all 36 Scenarios (millions NPV) | | | |
|---|---|---|---|---|
| | CFB | IGCC | Bio-DSM | DSM Only |
| 2006 – 2025 | 169 | 144 | 128 | 151 |
| 2012 – 2025 | 221 | 190 | 159 | 184 |
| 2012 – 2020 | 119 | 101 | 81 | 97 |

**Figure ES-8**
**Long-Term Variability**

| Period | Standard Deviation of NPV for all 36 Scenarios (%) | | | |
|---|---|---|---|---|
| | CFB | IGCC | Bio-DSM | DSM Only |
| 2006 – 2025 | 8 | 8 | 7 | 8 |
| 2012 – 2025 | 11 | 11 | 9 | 11 |
| 2012 – 2020 | 9 | 9 | 7 | 9 |

## REVENUE REQUIREMENTS – NO $CO_2$ REGULATIONS

The absence of $CO_2$ tends to decrease the gap between the CFB option and the other options since it is the most $CO_2$ intensive. However, the effect is small since even with $CO_2$ coal is dominating the grid.

**Figure ES-9**
**Selected Generation Production Revenue Requirements No $CO_2$ (millions NPV)[1]**

| Period | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
|---|---|---|---|---|
| 2006 – 2025 | 3,032 | 2,919 | 2,871 | 2,832 |
| 2012 – 2025 | 2,490 | 2,348 | 2,295 | 2,246 |
| 2012 – 2020 | 2,180 | 2,083 | 2,067 | 2,034 |

[1]Includes generation going forward production costs only.

Figure ES-10
Selected Generation Production Revenue Requirements - Change From Least Cost Option - No $CO_2$ (millions NPV)[1]

| Period | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
|---|---|---|---|---|
| 2006 – 2025 | +200 | +87 | +39 | -- |
| 2012 – 2025 | +244 | +102 | +49 | -- |
| 2012 – 2020 | +146 | +49 | +33 | -- |

[1]Includes generation going forward production costs only.

## REVENUE REQUIREMENTS – NO $CO_2$ AND HIGH GAS PRICES

The effect of higher gas prices is small because coal is already dominating the grid with base case gas prices.

Figure ES-11
Selected Generation Production Revenue Requirements No $CO_2$ High Gas (millions NPV)[1]

| Period | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
|---|---|---|---|---|
| 2006 – 2025 | 3,077 | 2,965 | 2,922 | 2,900 |
| 2012 – 2025 | 2,519 | 2,378 | 2,335 | 2,308 |
| 2012 – 2020 | 2,197 | 2,100 | 2,094 | 2,076 |

[1]Includes generation going forward production costs only.

Figure ES-12
Selected Generation Production Revenue Requirements – Change From Least Cost Option – No $CO_2$ (millions NPV)[1]

| Period | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
|---|---|---|---|---|
| 2006 – 2025 | +177 | +65 | +22 | -- |
| 2012 – 2025 | +212 | +1 | +28 | -- |
| 2012 – 2020 | +121 | +24 | +18 | -- |

[1]Includes generation going forward production costs only.

## AIR EMISSIONS

Between 2006 and 2025, the biomass-maximum DSM and maximum DSM options have lower local $CO_2$ emissions by approximately 25 to 30 percent, or 11 to 13 million tons lower than the IGCC and the CFB options (see Figure ES-13). These are the least

$CO_2$-intensive options. However, this difference may be muted by GRU purchases of coal power off system.

**Figure ES-13**
**GRU $CO_2$ Emissions (million tons) – Average Across 36 Scenarios**

| Period | Option | | | |
|---|---|---|---|---|
| | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
| 2006 – 2025 | 42 | 41 | 29 | 30 |

Between 2006 and 2025, GRU $SO_2$ emissions are three to seven thousand tons lower for the DSM options. On an annual basis this is 150 to 350 tons per year lower. This does not account for $SO_2$ emissions from non-GRU plants. Today, GRU emits 7000 tons per year and still complies with $PM_{2.5}$ standards. Accordingly, this difference is very small. This is because new options are highly controlled for all pollutants except $CO_2$ for which post combustion controls do not exist or are not practical.

**Figure ES-14**
**GRU $SO_2$ Emissions (thousand tons) – Average Across 36 Scenarios**

| Period | Option | | | |
|---|---|---|---|---|
| | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
| 2006 – 2025 | 47 | 47 | 44 | 40 |

Between 2006 and 2025, $NO_x$ emissions are one to six thousand tons lower or 50 to 300 tons per year lower. GRU currently emits 4000 tons per year and hence this difference is very small. Furthermore, the GRU area is in compliance with ozone, $NO_x$ and $PM_{2.5}$ limits.

**Figure ES-15**
**GRU $NO_x$ Emissions (thousand tons) – Average Across 36 Scenarios**

| Period | Option | | | |
|---|---|---|---|---|
| | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
| 2006 – 2025 | 38 | 33 | 32 | 32 |

Between 2006 and 2025, Hg emissions are about one ton for all options.

Figure ES-16
GRU Hg Emissions (tons) – Average Across 36 Scenarios

| Period | Option | | | |
|---|---|---|---|---|
| | CFB | IGCC | Biomass Maximum DSM | Maximum DSM |
| 2006 – 2025 | 1 | 1 | 1 | 1 |

## SOCIOECONOMIC IMPACTS

Chapter 7 presents the socioeconomic impacts modeled for the four resource options. The main impacts of these options appear to be the potential for job creation in the local economy. The total number of jobs estimated for these options are summarized in the Figure below.

Figure ES-17
Jobs

| Options | Construction Phase | | | | Operations and Maintenance Phase | | | |
|---|---|---|---|---|---|---|---|---|
| | Direct | Indirect | Induced | Total | Direct | Indirect | Induced | Total |
| **CFB** | 1332 | 312 | 450 | **2,094** | 55 | 15 | 30 | **100** |
| **IGCC** | 1261 | 295 | 426 | **1,983** | 46 | 12 | 25 | **83** |
| **Biomass** | 482 | 113 | 163 | **758** | 295 | 56 | 83 | **435** |
| **DSM*** | 1916 | 308 | 295 | **2,518** | --- | --- | --- | --- |

*DSM option does not entail construction of any power plant. Hence the jobs created by this option should be interpreted as jobs in the local economy for all the DSM programs modeled in IPM. See Chapter 7 for more details on the DSM option as well definitions of the types of jobs modeled.

All four options modeled have the potential to create significant local jobs in Alachua county. Jobs created during the construction phase are expected to be temporary because they will be available for four years during the construction of the plant. Jobs created by the operation and maintenance of the plant options will be permanent with long-term economic benefits for the local Alachua economy. The 220 MW CFB and the 220 MW IGCC plant options are expected to require similar investments, thereby creating employment opportunities that are quite similar. The 75 MW biomass plant option will require less investments during the construction phase thereby creating fewer temporary construction jobs. However, the biomass technologies are more labor intensive than the other conventional coal technologies. Therefore, running the 75 MW biomass plant is expected to require more O&M labor, thereby creating more long-term jobs in the local economy (435 jobs for biomass as opposed to 100 and 83 jobs for the CFB and IGCC plant options, respectively). Finally, the DSM option is expected to create substantially more jobs over the entire life of the program. The program will create about 2,500 jobs in Alachua County during 2006 to 2025.

## CONCLUSIONS

ICF's draft conclusions include:

- Reserve Requirements – All the options show revenue requirements within 5 to 7 percent of each other when measured against total electric revenue requirements. The lower cost options have higher qualitative risks:

  - Maximum DSM – Maximum DSM has the lowest costs of any option examined. However, the amount of savings on average is 4 percent of total demand and it does not defer capacity needs, though it lowers them. Achieving these savings require a substantial upgrade in the DSM programs at GRU. DSM alone exposes GRU to reliance on purchase power. This turns out not to have an adverse effect since GRU is purchasing coal power, in particular IGCC coal power. If substantial and sustained coal additions are not forthcoming gridwide to both keep up with demand growth and overcome the legacy of oil and gas reliance in Florida.

  - Maximum DSM – 75 MW Biomass has modestly higher costs than maximum DSM alone since biomass alone is the highest cost generation option examined. This cost increase is mitigated by the small size of the biomass plant and forecasts of plentiful coal power in the spot markets.

  - IGCC has the lowest cost among the generation options and is forecast to be widely chosen gridwide. The IGCC option's costs are within one to two percent of the maximum DSM option.

  - CFB – CFB has costs intermediate between IGCC and biomass only. CFB costs are 23 percent above IGCC. Accordingly, the costs of this option are higher than the other options. However, this option has less risks in terms of implementation or reliance on purchase power. If IGCC costs are higher than estimated, then this cost disadvantage could be less. Furthermore, if all petroleum coke is an option, the NPV of its costs could be decreased by $50 million.

The coal options have higher CO2 emissions but the effects due to higher non-CO2 emissions are small. Biomass has the largest effect on local jobs in the long run.

# CHAPTER ONE
# APPROACH, OPTIONS, AND METRICS

## OBJECTIVE OF STUDY

ICF Consulting was engaged to provide the City of Gainesville independent consultation on options for meeting the electrical supply needs of the Gainesville community. The goal is to provide the information needed to support a decision by the City including evaluation of potential trade offs on such issues as revenue requirement impacts, revenue requirement uncertainty, environmental impacts, health impacts, etc. The range of resource options covers both the demand and supply side.

## RESOURCE OPTIONS ANALYZED

Under its contract, ICF was engaged to examine four electricity options, one of which was pre-specified. After consultation with the City Commission and interested members of the Gainesville community, the following four options were chosen for analysis[3]:

- **220 MW CFB Flexible Solid Fuel Plant** – Under this option, GRU builds a Circulating Fluidized Bed Combustion (CFB)[4] power plant likely coming on-line in 2012. This plant is capable of using coal, petroleum coke, and up to 30 MW (approximately 14 percent) of biomass. The 30 MW level for biomass usage prevents major effects on the plant's performance, e.g., deterioration of plant capacity, thermal efficiency, etc. during very high biomass usage. The plant could use even greater biomass, though the plant's performance could be adversely affected. ICF provides some scoping level assessments of the derates and the steps that can be undertaken to ameliorate them in a later chapter. The CFB option is the same as the GRU IRP choice whose analysis is required under ICF's contract[5].

- **220 MW IGCC Flexible Solid Fuel Plant** – Under this option, GRU builds an Integrated Gasification Combined Cycle (IGCC) solid fuel power plant capable of gasifying and using coal, petroleum coke, and biomass. This

[3] Under each option, the utility can purchase or sell power on the wholesale market subject to existing transmission limits and/or add combustion turbines as needed to assure reliable operation and compliance with the reserve margin obligations of the utility.
[4] This option is sometimes referred to as FBC.
[5] The current GRU coal power plant uses pulverized coal technology. Approximately 315,000 MW of such power plants are operating in the U.S. with roughly 10 million MW – years of operating experience. The current Deerhaven coal unit has a capacity of approximately 220 MW which is similar to the capacity level of the proposed plant. CFB is a more recent solid fuel technology which is more flexible with respect to solid fuel choice compared to pulverized coal power plant technology.

plant uses very advanced coal generation technology similar to Tampa Electric's Polk power plant. Polk is the country's only operating utility IGCC, though others are under active consideration and some are used in the U.S. industrial sector and abroad. The size of the plant was chosen not only to be comparable to the CFB plant, but also because smaller plants exhibit large diseconomies of scale. The advantages and disadvantages of this technology are discussed in a later chapter.

- **"Maximum" DSM** – Under this option, a set of DSM programs are specified which are economic under very adverse supply side conditions. Namely, we identify DSM options which are economic under very high fuel and $CO_2$ allowance prices. Residual incremental power needs are met via a least cost combination of existing GRU plants and short-term wholesale power purchases.

- **75 MW Biomass Plant Plus Maximum DSM** – Under this option, maximum DSM is combined with a 75 MW biomass plant. This plant would have a similar technology as the 220 MW CFB plant, and would theoretically be able to use multiple solid fuel options. However, in this study, the plant would only be able to use biomass. The 75 MW size was chosen based on a number of considerations including: (1) other biomass plant sizes including a 75 MW plant in Florida, (2) biomass availability which is limited and uncertain, and which could create transportation problems, (3) economies of scale which favor at least moderate size, and (4) the desire to distinguish the option from the 220 MW solid fuel options which can use biomass.

## OTHER SUPPLY SIDE RESOURCE OPTIONS CONSIDERED

ICF also considered alternative power supply options. The review of the consideration of the options provides insight into our decision making *vis~a~vis* our recommendations to the City. The options considered, but not chosen included:

- **220 MW Natural Gas Combined Cycle** – Under this alternative option, GRU would build a natural gas-fired combined cycle power plant. This plant would use a technology similar to GRU's last major power plant addition. This option was almost included and it was "a close call" as to whether it should be in the "final four" because it had several attractive features including:[6]

[6] Our understanding is that the natural gas combined cycle option is under consideration in a parallel process.

- **Lower $CO_2$ Emissions** – This option allows for coverage of a fuller range of $CO_2$ emissions outcomes. The likely $CO_2$ emissions of the CFB on fossil fuel is approximately 1.5 million tons per year, compared to 1.3 million tons for the IGCC, 0.9 million tons for the combined cycle, and zero for the DSM and biomass.

- **Lower Emissions and Possible Health Impacts** – The natural gas-fired combined cycle plant has the lowest emission and possible local health impacts of any option involving fossil fuel.

- **Lower Capital Costs** – The size of the combined cycle capital investment is only approximately $150 million, versus approximately $450 to $550 million for the solid fuel options. The lower capital costs can be a huge advantage offsetting higher fuel costs, especially if the current phase of high oil and natural gas prices ends faster than expected. Thus, while the current high fuel costs may appear to make the natural gas option a "straw man", the lower capital costs combined with environmental and health considerations make the gas option a real option that the City may choose.

- **Financial Advantage of Municipals** – If electric power including the capital component will have to be purchased at open market prices from entities without the financing advantages of municipals, the financial advantage of municipals would be lost. Municipals are exempt from paying income tax and can issue tax free bonds.

- **Flexibility and Options for Deferring Decisions** – Once the combined cycle comes on-line, it can be converted to an IGCC and provided a solid fuel option – e.g., biomass, coal, petroleum coke, etc. Thus, the decision on solid fuel can be deferred, e.g., until $CO_2$ regulations are imposed, additional information as available about the future course of natural gas prices, etc., demand growth uncertainty is resolved, etc.

- **Proven Technology** – There is little perceived technology risk and little fuel risk in terms of delivery.

- **Financial Community Receptivity** – The financial community is currently involved in financing new combined cycles today. There will be no major issues regarding lowered bond rating associated with technology risk. Florida is adding 7,000 MW of gas-fired combined cycles (i.e., under construction, permitted, under study, or on hold), and in the U.S., approximately 100,000 MW are planned, permitted, under construction, or under study.

- **Economic Size** – The smallest sized combined cycle using the current Frame F technology, the most prevalent advanced high efficiency combined cycle technology, is approximately 220 MW[7]. Thus, a natural gas plant with a size similar to the CFBC is feasible and, in fact, close to optimal in terms of capital cost economies of scale.

- **Flexibility and Electricity Demand Growth** – Unless GRU's electricity demand growth slows, 220 MW represents 12 to 16 years of growth in peak demand. Thus, a smaller plant would require frequent decisions, while the 220 MW size is not so large as to preclude decisions in ten years or so for a new plant with different technology.

- **Supercritical Pulverized Coal Power Plant** – Nearly all U.S. coal plants are designed to use pulverized coal, and supercritical plants are designed to increase the plant's thermal efficiency (compared to the more typical sub-critical pulverized coal plant) having the water in the water wall tubes at temperatures and pressures above the critical fluid to gas change in phase point. The plant is highly controlled for sulfur dioxide ($SO_2$), nitrogen, oxides ($NO_x$), and mercury (Hg). Beyond the technical description, this type of coal plant is actively being considered by other utilities and is modeled as an option for other southeastern U.S. utilities. This plant has lower per unit capital cost than other GRU solid fuel options especially assuming a much larger plant can be built and the power delivered, e.g., 800 MW versus the 220 MW size being considered. However, this plant type is less flexible in the fuel that can be used, especially regarding petroleum coke and biomass. This option was rejected for this study for a number of reasons discussed in a later chapter including the desire to consider GRU-only options, i.e., not consider a jointly owned power plant.

- **Peaking Combustion Turbine Natural Gas-Fired Power Plant** – This plant is similar to a combined cycle except it has lower thermal efficiency and lower capital costs. Since GRU's financing costs are so low, the annual control costs of this option are very low for GRU. Also, this plant has a shorter lead time than other plants. This option is provided both to GRU and to other southeastern utilities in the modeling. Since its per MWh production cost is much higher than the combined cycle, and hence, while it helps meet the companies' need for reserve capacity to handle its

[7] The actual optimal size in terms of available equipment is likely to be closer to 250 MW. A Frame G is larger at approximately 365 – 385 MW.

peak requirements, it provides little to address the GRU's need for electrical energy. This must be produced by other plants or imported.

- **Power Purchases and Sales Reflecting Short-Term Market Conditions –** Wholesale power import and export options are modeled in each hour as are capacity or reliability transactions for the peak. Together with the construction of new combustion turbine peakers, power exchanges are the default supply options for GRU. The modeling is consistent with the expectation that the extent current physical limitations on the power grid will remain. Furthermore, such limits cannot be violated. Thus, under any scenario where it is economic to purchase power, the model will do so as needed and vice versa. The smaller the capacity of the resource option for GRU, the greater the potential reliance on spot wholesale power purchases. Today, spot off-system power is primarily oil and gas fired. A critical issue is whether this will continue or will sufficient coal be built to provide lower cost wholesale power costs.

  Florida has much less merchant power plant capacity than other U.S. regions due to state law which greatly restricts the construction of merchant plants. Merchant plants are defined as power plants not dedicated to a utility buyer. Thus, one important dimension of relying on spot market purchases is that while electrical energy may be available from multiple suppliers in most hours, it may be difficult to obtain on short notice capacity for reserve margin requirements (i.e., for the summer super peak period) even though physically ICF estimates approximately 300 MW can be imported to GRU. This adds to the risk associated with waiting to make decisions regarding securing enough capacity for reserve margin. This risk is not fully captured in the modeling which assumes GRU always meets its reserve margin because it is difficult to measure the leverage of sellers when faced with buyers unable to meet their peak needs. The importance of meeting the reserve margin requirement is highlighted by the fact reserve margin requirements must be met for a given demand growth level either by added supply or effectively forced conversion of part of the City's electricity supply to interruptible status. This interruption would most likely be during the peak air conditioning season and in the extreme could raise numerous issues including public health concerns.

- **Solar Thermal –** This option was rejected since there is too little Florida experience with the central station solar and its cost is very high, especially considering back-up costs to cover the utility's reliability needs when the solar plants output is less than the plant's rated maximum and the low capacity factors of such plants in Florida relative to other prime U.S. locations – e.g., the U.S. desert Southwest.



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- **Nuclear** – This option was rejected since nuclear power plants are way too large and complex for GRU. We decided after consultation with the City to not consider jointly owned power plants. However, we provide discussion of this option. Furthermore, it is less likely that near-term jointly owned nuclear plant options will be available relative to large jointly owned pulverized coal plants due to permitting, regulatory, and financing uncertainties and the very long lead times for such plants.

- **Wind** – Wind was rejected for Florida due to the lack of prime wind resources.

## FLORIDA GENERATION ADDITIONS

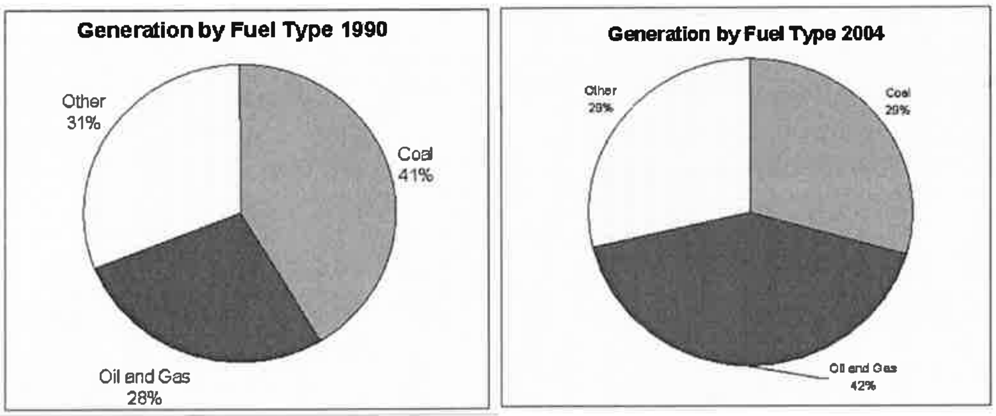
Florida utilities are in the process of adding new plants which can be relevant as a point of comparison and because of their effects on wholesale power market prices. Put another way, other entities are also facing similar issues. Among the units under construction or recently added, nearly all use natural gas combined cycle or simple cycle technology (see Figure 1-1). These plants generally reflect decisions made before or early in the recent period of very high natural gas prices which started in 2000.

**Figure 1-1**
**Recently Operational and Firmly Planned Capacity is Almost Exclusively Natural Gas-Fired**

| Model Region | Plant Name | Unit Name | Capacity Type | Retrofit Size | On-Line Date |
|---|---|---|---|---|---|
| Florida Power & Light | Fort Myers Expansion | Generator: 3 | Combustion Turbine | 340 | 6/1/2003 |
| Florida Power & Light | Sanford Expansion | Generator: 2 | Combined Cycle | 1,116 | 6/15/2003 |
| Florida Power & Light | Lake Worth Generation | Generator: 1 | Combustion Turbine | 212 | 12/1/2004 |
| Florida Power & Light | Martin Expansion | Generator: 2 | Combined Cycle | 547 | 6/1/2005 |
| Florida Power & Light | Manatee | Generator: 3 | Combined Cycle | 1,100 | 6/1/2005 |
| Florida Power & Light | Okeelanta Cogeneration[1] | | Steam Turbine - Agricultural Crop Byproducts/Straw/Energy Crops | 65 | 5/1/2006 |
| Florida Power & Light | Stock Island[1] | | Combustion Turbine | 42 | 6/1/2006 |
| Florida Power & Light | Turkey Point[1] | | Combined Cycle | 1,150 | 6/1/2007 |
| Florida Power & Light - SUB-TOTAL | | | | 4,572 | |
| | | | | | |
| Jacksonville Electric | Brandy Branch | Generator: 2 | Combined Cycle | 570 | 5/1/2005 |
| | | | | | |
| Orlando Utilities CO | Stanton Energy Center | Generator: 1 | Combined Cycle | 633 | 10/1/2003 |
| | | | | | |
| Progress Energy | Hines Energy Comp | Generator: 1 | Combined Cycle | 554 | 12/1/2003 |
| Progress Energy | Hines Energy Comp | Generator: 2 | Combined Cycle | 500 | 12/1/2005 |
| Progress Energy - SUB-TOTAL | | | | 1,054 | |
| | | | | | |
| Tampa Electric CO | Gannon | Generator: 1 | Combined Cycle | 750 | 6/1/2003 |
| Tampa Electric CO | Osprey Energy Center | Generator: 1 | Combined Cycle - Cogen | 530 | 5/1/2004 |
| Tampa Electric CO | Gannon | Generator: 2 | Combined Cycle | 1,125 | 6/1/2004 |
| Tampa Electric CO - SUB-TOTAL | | | | 2,405 | |
| | | | | | |
| **GRAND TOTAL** | | | | **9,234** | |

As a result of this trend of building natural gas combined cycles, the share of oil and gas in Florida's generation mix has risen from 28 to 42 percent between 1990 and 2004. This is significant because wholesale spot sales and purchases by GRU will reflect the costs of the marginal not average source of supply which will be almost always oil and natural gas-fueled power plants. Oil and natural gas plants are the marginal or incremental source since their variable costs are by far the highest and are the price setting source in nearly all on-peak hours[8]. In order to access sources of baseload power, one must undertake the obligation of investing in or long-term contracting for such power.

**Figure 1-2**
**State of Florida – Energy Generation by Fuel Type – 1990 and 2004 – Shows Very Large Increase in Oil and Gas Generation**




Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, page 11

More recently, announced new power plant projects in Florida show a much greater reliance on coal. Whereas none of the recent additions have been coal-fired, nearly half of the announced future planned generation capacity in Florida is coal-fired. This very large and very recent increase in the reliance on coal among planned projects is mirrored in many parts of the U.S. Among the announced coal plants are:

- Stanton IGCC – This proposed IGCC coal plant is jointly being pursued by the Orlando Municipal Utility and Southern Company.
- Seminole
- Jacksonville FMPA
- JEA CFB

None of the plants have actually broken ground. A critical issue in this study is the future of the wholesale power market in Florida and the extent to which will be coal or oil/gas driven. It should also be noted that none of the existing plants using combined cycle technology have chosen to retrofit gasification technology.

[8] On-peak is Monday – Friday, 6 AM – 11 PM.

**Figure 1-3**
**FRCC Announced Builds[1]**

| Company | Plant | Planned Capacity | Fuel Type | Type of Plant | On-line Date |
|---|---|---|---|---|---|
| Hillsborough Co | Hills Co. Resource Recovery Facility | 17 | Garbage | Resource Recovery Facility | N/A |
| Florida Power & Light | SW St. Lucie Coal – 2 Units | 1700 | Coal | Conventional | 2012, 2014 |
| Southern Co. | Demonstration Project at Stanton | 285 | Coal | Integrated Gasification Combined Cycle | 2010 |
| Seminole Electric | Unit 3 at Palatka | 750 | Coal | Pulverized/ Conventional | 2012 |
| JEA/FMPA | Coal Project | 800 | Coal | Conventional | 2012 |
| Gainesville Regional Util. | Deerhaven expansion | 220 | Coal | Coal Fluidized Bed/Biomass/ Other | 2011[2] |
| Progress Energy | Hines Unit 5 | 540 | Gas | Combined Cycle | 2009 |
| Seminole Electric | Unknown – 2 units | 364 | Gas | CC | 2008, 2009 |
| Pasco Co | Pasco Co. Resource Recovery Facility | 20 | Garbage | RRF | N/A |
| Palm Beach Co | Palm Beach Co Resource Recovery Facility | 28 | Garbage | RRF | 2010 |
| JEA | Circulating Fluidized Bed | 250 | Coal | CFB | 2013 |
| Progress Energy | Hines Unit 6 | 540 | Gas | CC | 2010 |
| Progress Energy | Central Florida Nuclear | N/A | Nuclear | Nuclear | 2015 |
| Progress Energy | Unknown CC | 536 | Gas | CC | 2012 |
| Tampa Electric Co | Undetermined | 502 | Gas | CC | 2013 |
| Seminole Electric | Unknown – 3 Units | 546 | Gas | CC | 2013, 2014 |
| Progress Energy | Unknown CCs – 2 Units | 1,072 | Gas | CC | 2013, 2014 |
| JEA/Biomass Industries Group | Unknown – 2 Units | 240 | E-grass | Biomass | N/A |

[1]Provided for information purposes only. Model will choose builds by scenario for non-GRU power companies.
[2]Revised by ICF. 2012 may be most likely.
Source: Florida's Energy Plan, Department of Environmental Protection 1/17/06 page 20

**Figure 1-4**
**FRCC Announced Builds Summary**

| Type | Planned Capacity |
|---|---|
| Coal | 4005 |
| Gas / Other | 4405 |
| Total | 8410 |

## NEW POWER PLANTS AND MODELING ANALYSIS

In the modeling analysis, the construction of new power plants by other utilities will be determined by the model, unless the plant is already under construction or otherwise determined to be a firm addition. Therefore, in each scenario, new power plants will reflect the economics facing utilities and the assumption they are trying to minimize costs. The reason we have decided not to base capacity expansion for other entities on announcements is that nationwide, most planned projects do not come to fruition or are substantially delayed. This is critical, especially for a 20-year study. If utilities do not respond economically wholesale power costs will be higher than forecast.

## SENSITIVITY ANALYSIS

ICF analyzed the performance of the four resource options using a large amount of sensitivity analysis to account for the largest economic and regulatory uncertainties facing Gainesville. These include:

- **Fossil Fuel Prices** – ICF analyzed Base, Low, and High fuel price scenarios where the focus is on future long-term natural gas prices. Natural gas prices have risen greatly since 2000 and especially since 2004 along with oil prices and are highly uncertain. Coal issues will also be addressed including the effect of having multiple sources for coal and the option to use petroleum coke and biomass. These important issues are discussed in the fuel chapter.

- **$CO_2$ Emission Regulations** – ICF analyzed Base, Low, and High $CO_2$ emission allowance prices and associated emission allowance allocations. ICF considers $CO_2$ to be the key uncertainty *vis~a~vis* future air emission regulations. Furthermore, the range of possible $CO_2$ outcomes is especially broad across the four resource options examined in detail. This contrasts with other air emissions in which the range across options is very narrow, i.e., emission levels are very similar. $CO_2$ is a greenhouse gas and is not currently regulated in the U.S. and the nature of potential future programs is highly uncertain. Regulations exist in some developed countries and there is significant potential that future controls will be enacted. ICF reports GRU $CO_2$ emissions and recognizes that regardless of the regulations, $CO_2$ emissions will be a key issue for the Gainesville community.

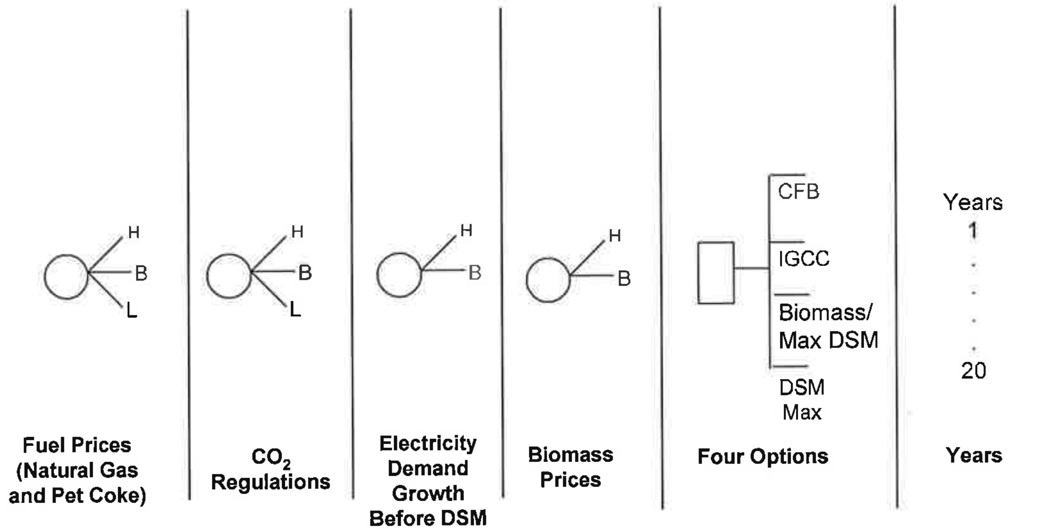
- **Electricity Demand Growth Before DSM** – ICF analyzes Base and High electricity demand growth before DSM. Both scenarios assume growth will be below historical levels (i.e., below the ten year rolling average historical level), and hence, this partly explains the lack of a low case. Furthermore, each of the two electricity demand projections is further decreased by incremental DSM choices in the DSM scenario. ICF believes the GRU Base Case projection of electricity demand growth is conservative and this too contributed to having only two demand growth levels before DSM scenarios. Lastly, the decision not to add a third case also reflects the need to limit the number of scenarios to a manageable level.

- **Biomass Fuel Prices** – ICF analyzes Base and High cost biomass price scenarios. ICF believes the risks of higher than expected costs of using biomass are greater than lower than expected costs. Furthermore, there is the need to limit the number of scenarios, and hence, we are not examining a low case. Lastly, all generation options have the ability to use biomass, and hence, there is a thorough examination of biomass which ICF considers the key renewable generation option for Gainesville. Accordingly, ICF did not analyze a third biomass price trajectory.

As a result, there are 36 scenarios reflecting 3 fuel price cases, 3 $CO_2$ price cases, 2 electricity demand before DSM cases, and two biomass cases (3 x 3 x 2 x 2 = 36). For example, base fossil fuel prices, base $CO_2$ regulations, base demand growth before DSM, and base biomass prices would be one scenario, etc. In addition for each scenario, we will examine each of the four options. This results in 144 scenario/option combinations and 2,880 years worth of modeling analysis (2,880 = 20 x 144). See Figure 1-5.

ICF has not assigned probabilities to each of the outcomes. Rather, to simplify the analysis, we are treating each scenario as equally likely. Thus, the probability of each case is effectively one divided by 36 or 2.8 percent.

**Figure 1-5**
**The Scope of the Analysis is at Its Maximum Involving 2,880[1] Years of Analysis**




[1]3 x 3 x 2 x 2 x 4 x 20 = 2,880
H = High, B = Base, L = Low

It is worth mentioning that two options that use more complex decision analysis approaches including assigning explicit probabilities to each scenario were considered and rejected. In these approaches, all generation decisions were delayed by five years such that no new generation resource would come on-line until 2016 or 2017. In spite of being rejected, these options are useful in conceptualizing the challenges facing the City of Gainesville. These two options were:

- **Maximum DSM/ Delay Generation Decisions 5 years[9]/ Make Decisions Assuming 100% Resolution of Uncertainty – Include Biomass 75 MW Plant as One of the Generation Options** – This alternative is graphically summarized in Figure 1-6[10]. The decisions for today would be: (1) solid fuel CFB coming on line 2011/2012, (2) solid fuel IGCC coming on line 2011/2012, (3) 75 MW biomass plant on-line 2011/2012, and (4) waiting, pursuing maximum DSM, and then making a decision among the three generation options at a future date (2011/2012) with that unit coming on-line 2016/2017. This analysis would use the

[9] Hence, generation additions would be delayed ten years or more due to the large lead time for siting, permitting, designing, contracting, financing, and testing new power plants.
[10] Graphically, uncertainties are represented as circles and decisions as squares. The expected values of the options across various metrics are still evaluated, but after the resolution of uncertainty, the optimal decisions are taken for each state of the world. This can have a greater or lesser value depending on the exact circumstances.

simplifying assumption that uncertainties are fully and completely resolved by 2011/2012, and at that time the best decision is made for the state of the world at that time.

- **Maximum DSM/ Delay Generation Decisions 5 years/ Make Decisions Assuming 100% Resolution of Uncertainty – Include 220 MW Natural Gas Combined Cycle as One of the Generation Options** – This alternative is graphically summarized in Figure 1-7. It is the same as the above option except that the natural gas combined cycle option replaces the 75 MW biomass plant.

There are several advantages of this type of approach. First, the benefit of waiting is explicitly taken into account since in each state of the world the best option is chosen lowering costs or improving performance on other metrics. Second, the cost of waiting is also explicitly estimated. In the interim, the extra five years of exposure to wholesale power market fluctuations is captured as demand grows and an increasing share of GRU power supply is bought from other utilities' power plants. The cost of waiting also includes the challenge of making reliability purchases of peaking capacity from other utilities. To illustrate this point, by 2017, GRU electricity demand could be as much as 26 to 43 percent higher than expected 2006 levels.[11]

The disadvantages of this formal alternative delay analysis are several and ultimately this approach was rejected. First, while learning occurs over time about the future state of the world, 100% resolution of uncertainty is clearly an overstatement made for analytic convenience. One certainty is that uncertainty will not be fully resolved. Furthermore, agreeing on the degree to which uncertainty is resolved is very difficult. Second, it is more complicated to understand and describe this approach and requires explicit quantitative probability assessments to fully implement. Third, this option is not directly comparable to the up-front options which reflect uncertainty. Fourth, some aspects of the risks of relying on the spot markets are hard to characterize. This is especially regarding reliability purchases in a state which formally discourages merchant plants[12]. This discourages the existence of extra capacity available to meet demand during peak periods.

[11] 26 percent corresponds to 2.1 percent growth over 11 years and 43 percent corresponds to 3.3 percent which equals historic growth rates. At the high case demand rate of 2.8 percent, growth would be 35 percent. All of these increases would be mitigated by DSM, and hence, the estimates are "as much as".
[12] Florida law prohibits merchant plants with steam capacity in excess of 75 MW.

**Figure 1-6**
**Alternative Approach to Analyzing Options – Delay and Then Build Biomass Plant**

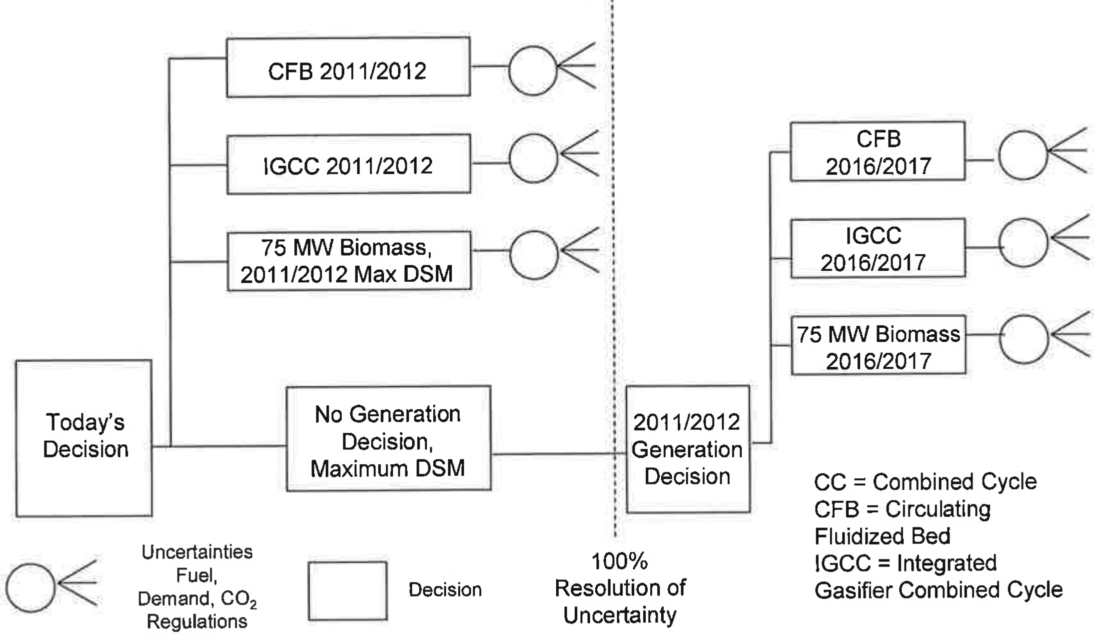
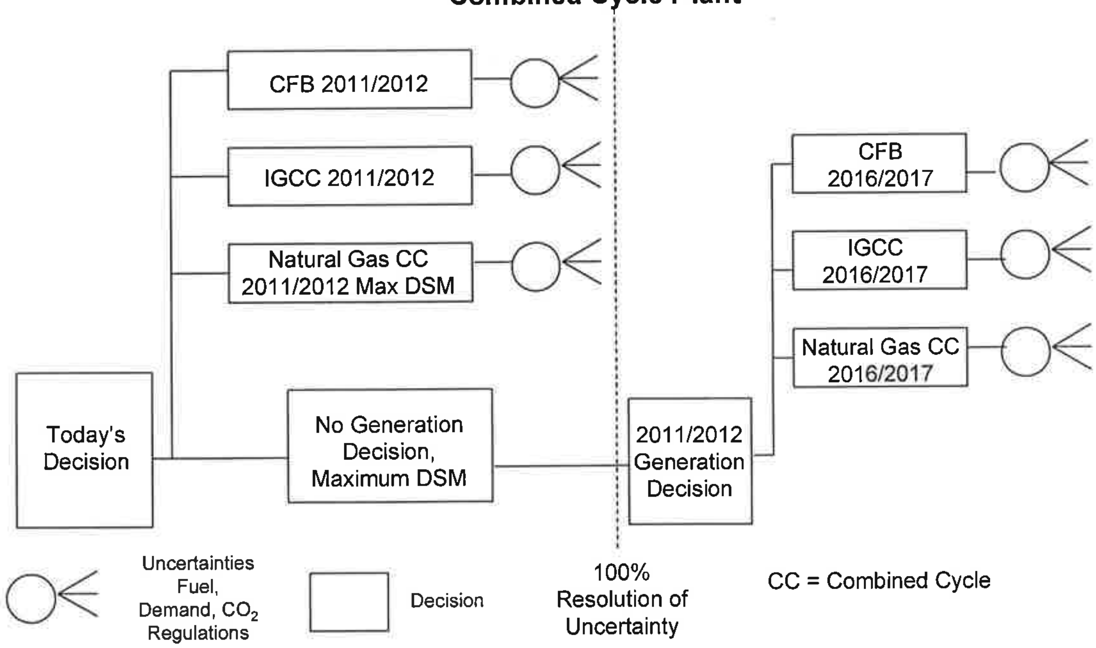



**Figure 1-7**
**Alternative Approach to Analyzing Options – Delay and Then Build Natural Gas Combined Cycle Plant**



## METRICS

The goal of the study is to provide an assessment of the four options that will allow the City of Gainesville to make decisions regarding future supply options. Each option was evaluated according to a range of metrics including:

- Revenue Requirements – Average
- Revenue Requirements – Long-term Variability
- Revenue Requirements – Annual Fluctuations
- Residual Emissions and Health/Environmental Impacts – $CO_2$, $SO_2$, $NO_x$, Hg, resulting PM 2.5,
- Capital Costs –
- Local Economic Impacts –
- Technological and Implementation Risk –

## ANALYTIC APPROACH

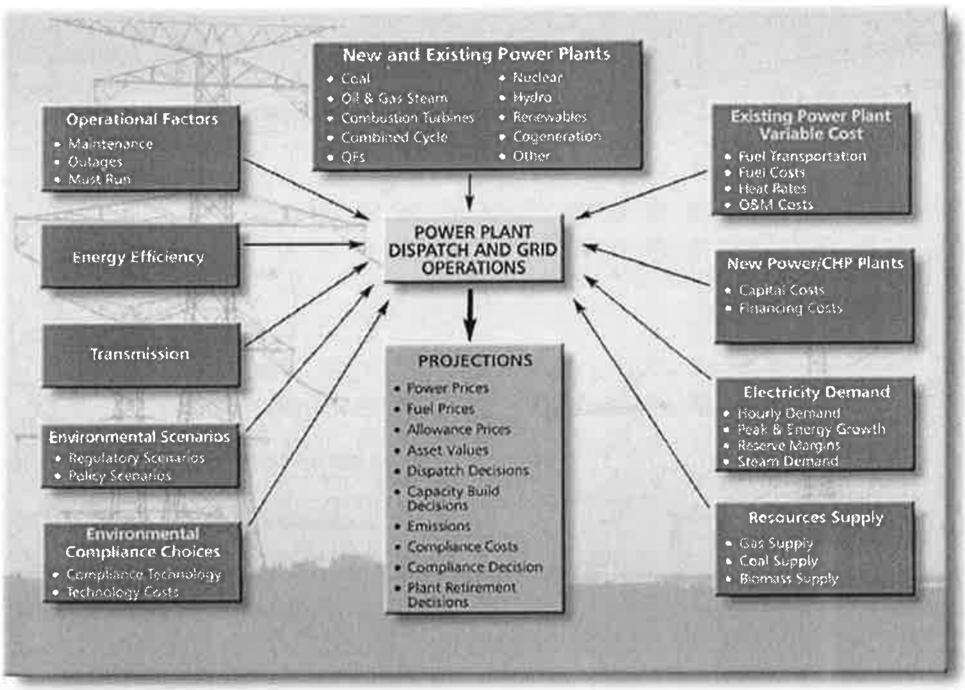
The overall analytic approach is for GRU and other utilities to make decisions which minimize costs given that one of the four options has been chosen. This is the commonly accepted analytic approach to studies considering the range of both demand and supply side options. This analysis requires a very large number of calculations that can only be done using a computer model. ICF chose to use its IPM® model, while GRU uses AEGIS, a different proprietary computer model. Both models minimize production costs including allowance costs. ICF's IPM® model is widely accepted in both the private and public sector and has undergone extensive review since it is the main tool used by the U.S. EPA.

ICF's IRP and forward short-term power market assessment will be derived utilizing the Integrated Planning Model (IPM®). The model simultaneously, for all selected regions including a GRU region, solves the following parameters consistent with a least cost solution (Figure 1-8):

- Power plant dispatch
- Fuel use, emissions, and environmental compliance
- Capacity expansion, mothballing, and retirement – except for GRU where we will specify four options

- Inter-regional transmission flows1
- Hourly spot electrical energy prices
- Annual spot pure capacity prices which can heuristically be allocated to super peak demand hours

**Figure 1-8**
**The IPM® Modeling Framework Analyzes Supply and Demand Resources on Equal Footing**




The IPM® modeling will cover not only GRU, but also the rest of Florida and regions north of Florida. Florida will be disaggregated into nine zones including GRU as one of the zones (Figure 1-9). Transmission flows will be determined by the model. Transmission limits for non-firm (i.e., economy energy) and firm capacity are shown below (see Figure 1-10). GRU's import capability for non-firm energy is substantial. At the extreme, GRU could import 2.3 BkWh. In comparison, its 2006 energy requirements are approximately 2.1 BkWh.[13]

[13] While GRU's need to block power is much less today, it is larger over time due to demand growth.

**Figure 1-9**
**FRCC Region Will be Modeled Along With Neighboring Areas Accounting for Wholesale Transactions**

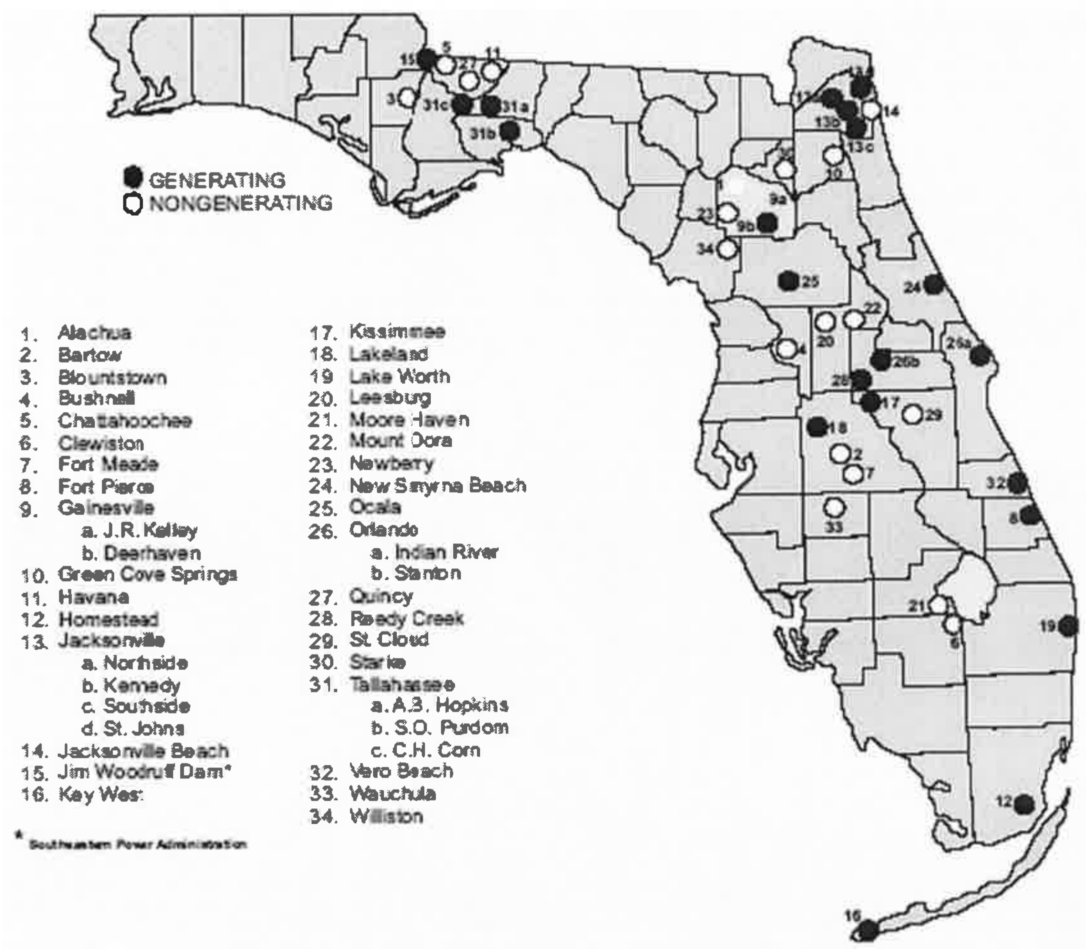
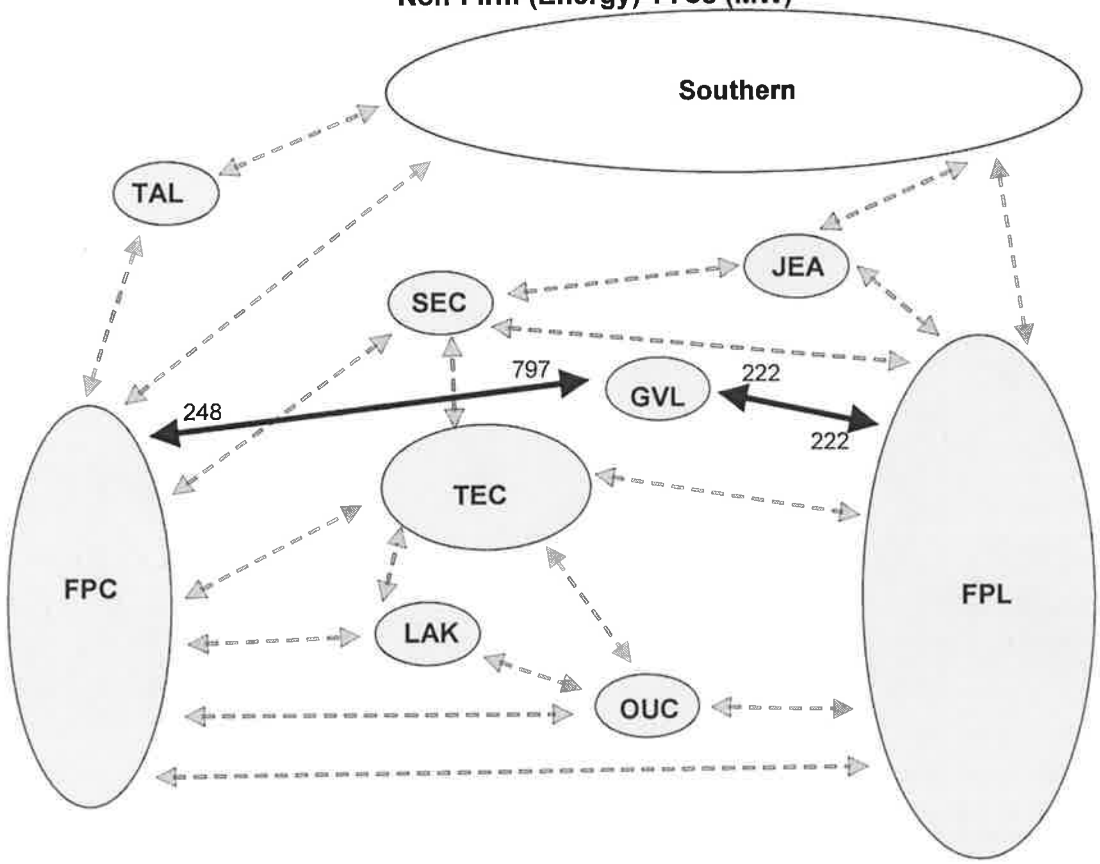


**Figure 1-10**
**Non-Firm (Energy) TTCs (MW)**

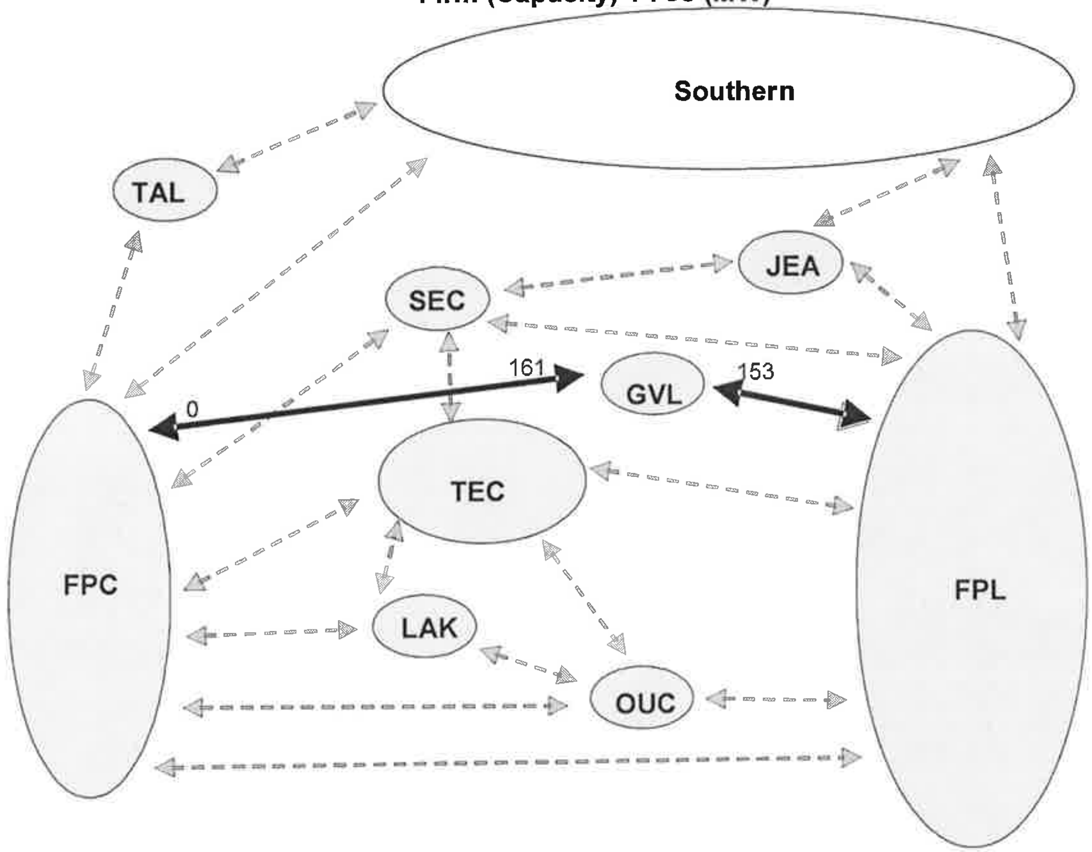



GVL Non-Firm Simultaneous TTCs: Imports = 260 MW; Exports = 490 MW[14]

[14] Subject to on-going review.

# DRAFT

**Figure 1-11**
**Firm (Capacity) TTCs (MW)**




GVL Firm Simultaneous TTCs: Imports = 30 MW; Exports = 0

# CHAPTER TWO
# DEMAND GROWTH BEFORE ADDITIONAL DEMAND SIDE MANAGEMENT PROGRAM IMPLEMENTATION

The demand growth forecast before additional DSM is very important. If electricity demand is less than expected, costly investments can and should be deferred. On the other hand, if demand is greater than expected, the City could be exposed to a higher than expected reliance on purchasing power from a few sellers in the wholesale power market and the need to quickly make decisions regarding the imperative of meeting reserve requirements.

This chapter discusses demand growth projections before additional DSM beyond the levels already planned by GRU. The next chapter separately addresses DSM. This chapter is organized into four sections. The first discusses historical electricity demand growth. The second briefly discusses electricity demand forecasting accuracy. The third presents the forecast demand growth rates used in this study. The fourth discusses GRU's supply and demand balance.

## DEMAND GROWTH BEFORE ADDITIONAL DSM

Electricity demand growth for GRU has been 3.3 percent per year on a ten year rolling average basis through 2004. The ten year average including 2005 for which only limited demand data is available is 3.2 percent. These rates are above the U.S. average of approximately 2.5 percent per year for peak demand. GRU's growth is also very close to the FRCC average (Florida Regional Coordinating Council) which covers most of the state. Florida's electricity demand growth rate is the fastest among large states.