050317-EI

DIRECT TESTIMONY

OF

GEORGE BACHMAN

CHERYL MARTIN

MARK CUTSHAW

ROBERT CAMFIELD

IN

FLORIDA PUBLIC UTITITIES COMPANY

PETITION OF
FLORIDA PUBLIC UTILITIES COMPANY

FUEL COST RECOVERY AND PHASE-IN PLAN

Q. Please state your name, title, and business address.

A. Witness Bachman. My name is George Bachman. I am the Chief Financial Officer and Treasurer of Florida Public Utilities Company. My business address is 401 South Dixie Highway, West Palm Beach, Florida, 33401.

Witness Martin. My name is Cheryl Martin. I am Controller for Florida Public Utilities Company. My business address is 401 South Dixie Highway, West Palm Beach, Florida, 33401.

Witness Cutshaw. My name is Mark Cutshaw. I am the Director of the Northwest Florida Division for Florida Public Utilities Company. My business address is 2825 Pennsylvania Avenue, Marianna, Florida 32447.

Witness Camfield. My name is Robert Camfield. I am a Vice President with Christensen Associates Energy Consulting LLC (CAEC). My business address is Suite 700, 4610 University Avenue, Madison, Wisconsin, 53705.

Q. What is the scope of your testimony?

A. The scope of our testimony is twofold. First, we provide evidence in support of the costs of power supply (generation and transmission services) of Florida Public Utilities Company (FPU or Company), for use in determining the retail price of the Company's fuel cost recovery mechanism. Second, our testimony presents the Company's proposed phase-in of costs associated with sharply higher power supply costs beginning in January 2008, as anticipated. In the course of presenting the proposed phase-in plan, we review current conditions of wholesale power markets and the implications for power procurement; and we present the Company's overall procurement strategy.

Q. Please review your professional background and experience that qualifies you to provide such recommendations.

A. Witness Bachman. I have Bachelor of Science Degree in Business Administration from Indiana University in 1981, with a concentration in Accounting. I subsequently joined Southeastern Public Service Company, and served as the Assistant Controller at the time of my departure in January 1985, when I joined Florida Public Utilities Company. My positions through 1998 included General Accounting Office Manager, Accounting Manager, and Controller.

In 1999 I was appointed to my current position, Chief Financial Officer and Treasurer of Florida Public Utilities Company. As the senior financial and accounting official of the Company I have overall fiduciary responsibility and oversee the accounting and finance department with all related functions. The accounting and finance staff maintains the accounting systems and carries out day-to-day functions such as revenue accounting, cost accounting, cash management, tax accounting, and payroll. Our area maintains the financial records of the Company and reports financial results. The accounting and finance department is also responsible for various studies in support of accounting activities, such as determination of depreciation rates. As Chief Financial Officer, I represent the Company before the investment community including investment and commercial banks. Finally, I am responsible to the Chief Executive Officer for the development of financial policy, and I am involved in determination of overall business strategy at the highest level.

I have been an expert witness in numerous fuel, purchased gas, and rate relief proceedings before the Florida Public Service Commission for electric, gas, and water.

<u>Witness Martin</u>. I have been employed by FPU since 1985 and I have worked within numerous accounting functions Company. I assumed the position of Corporate Accounting Manager in 1995. In this position, I managed the Corporate Accounting Department including regulatory accounting (Fuel, PGA, conservation, rate cases, surveillance reporting, and general regulatory reporting), tax accounting, external reports, and various special projects. In January 2002, I assumed the position of Controller of the Company where, in addition to the above duties, I also have responsibilities in purchasing, general accounting, and Securities and Exchange Commission (SEC) reporting. I have been an expert witness in numerous proceedings on behalf of FPU before the

Florida Public Service Commission (FPSC), including rate relief in Docket Numbers 881056-EI, 930400-EI, and 030438-EI for retail electricity service, and 900151-GU and 940620-GU for retail natural gas service. I graduated from Florida State University in 1984 with a Bachelor of Science degree in Accounting. I am a Certified Public Accountant in the State of Florida.

Witness Cutshaw. I joined FPUC in May 1991 as Division Manager in the Marianna Division. In 2001, my title was changed to Director, Northwest Florida. My work experience and responsibilities at FPUC include all aspects of budgeting, customer service, and operations and maintenance in the Marianna/Northwest Florida Division. In 2003 – 2004, I testified before the Florida Public Service Commission in Docket 030438-El on rate design and related matters. In 1993, I participated in the Cost of Service study for the Marianna Division Rate Case Filing and testified during the proceeding. I have also been involved with numerous proceedings and matters of Florida Public Utilities Company before the Commission, including filings, audits, and data requests for the FPSC. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began work with Mississippi Power Company in June 1982. I left Mississippi Power Company in May, 1991 while in the position of Supervisor, Electric Operations. While at MPC, I was involved in the budgeting, operations and maintenance activities in the Hattiesburg, Laurel and Pascagoula Districts.

Witness Camfield. I am a graduate of Interlochen Arts Academy, and hold a Bachelor of Science Degree in Business Administration from Ferris State

University with an emphasis in Management, graduating in 1969. I earned a Master of Arts Degree in Economics at Western Michigan University in 1975, with a concentration in Monetary Theory and Policy. I joined the Michigan Public Service Commission in 1976 as a staff economist. During my tenure with the Michigan Commission, I was involved in several retail electricity and natural gas pricing issues, and I testified in several rate case proceedings regarding cost of capital and retail gas prices. I joined the New Hampshire Public Service Commission in 1979 as the senior economist, and held the position of chief economist beginning in 1981. In these positions, I was responsible for the development, administration, and training of the economics staff. I oversaw economic analysis and the development and delivery of testimony, and provided policy advice to the Commission on a variety issues such as construction work in progress, financial planning, and the determination of PURPA Section 133 rates. I joined Southern Company in 1983, and held positions in several departments including Pricing and Economic Analysis at Georgia Power Company, Costing Analysis at Southern Company Services, and Southern Company's Strategic Planning Group. In 1994, I joined Laurits R. Christensen Associates, Inc. as senior economist, and currently hold the position of Vice President. My experience covers a gamut of issues facing regulated industries. I have represented agency staff, consumer advocates, independent generation companies, utilities, and transmission companies before nine regulatory agencies regarding cost of capital, cost benchmarking, forecasts of electricity demand, retail rates, cost of service allocation, generation planning, and transmission issues. I have been involved in the negotiation of power supply contracts and the terms for franchise licenses. My overseas assignments are several, and I recently managed a large market restructuring project in Central Europe. I have served on national and regional advisory panels, and I have advised electric companies on numerous policy and technical issues. Innovations include two-part tariffs for transmission services, web-based self-designing retail electric products, marginal cost-based cost-of-service methods, and efficient pricing of distribution services. I have published chapters in books, reports, and articles in noted journals such as *The Electricity Journal, CIGRE,* and *IEEE Transactions on Power Systems*. Currently, I am the Program Director of EEI's Market Design and Transmission Pricing School. My resume, including the list of formal appearances before regulatory agencies, is attached.

Q. Can you please review the market context and situation of Florida Public Utilities Company?

A. Yes. The electricity business unit of Florida Public Utilities Company is a distribution utility that serves two retail markets of northern Florida. These markets are referred to as the Northeast and Northwest divisions. During 2004, the Northeast division, also known as Fernandina Beach, served 15,100 customers with gross electricity sales of 449,464 MWh. The Northwest division, also known as Marianna served 15,000 customers with gross electricity sales of 316,884 MWh.

The Northeast division distribution system is interconnected with JEA (formerly the Jacksonville Electric Authority) transmission network at one delivery point with 150,000 kVA of transformer capability and 138 kV primary feeders. The Northwest division interconnects with Southern Company's transmission network at five delivery points with 130,000 kVA of capability and 12.5 kV primary feeders.

Q. What are the Company's current arrangements for the power supply?

A. Both divisions of the Company are wholly dependent upon external purchases of generation and transmission (G&T) services to satisfy the needs of the Company's retail markets. Accordingly, FPU has, for a number of years, engaged in full requirements contracts for G&T services with suppliers in the southeast region. Full requirements refers to an umbrella or package of services covering the total loads of FPU, and includes energy (balancing or spot energy), reserve service categories of regulation, spin, non-spin, and backup, ancillary services of voltage support and black start, and the transmission services of network transport services and transaction scheduling. Full requirements services have been and are currently provided to FPU under long-term contracts with JEA in the case of the Northeast division, and with Gulf Power Southern Company (Gulf/SoCo) in the case of the Northwest division. Both contracts date to 1997 and expire in December 2007. The Company is currently implementing its strategy for power supply for 2008 and beyond. This involves the recent release of the Company's all-source RFP.

Q. Have the current contracts been favorable overall, and in the general interest of the Company's retail customers?

A. Yes. The current full requirements power supply arrangements have been wholly successful. Both suppliers, JEA and Gulf/SoCo, have served Florida Public Utilities Company and its retail electricity customers well from a broad perspective including reliability, counterparty risk, and commercial terms of sale. The contract terms and prices of the current contracts were negotiated in good faith by the contracting parties within an environment of increasing contestability in wholesale markets. The negotiation process resulted in commercial terms that have been fair to the contracting parties including JEA, Gulf/SoCo initially. However, wholesale prices rose substantially during 1998 and 1999, and with the exception of 2002, the terms have been generally favorable to the Company in all years thereafter. It is useful to reference Exhibit BMCC-5, which shows compiled day-ahead spot prices for energy for the relevant regions of the North American Reliability Council regions include the Southeastern Electric Reliability Council (SERC) and the Florida Reliability Coordinating Council for individual months of the years 2000 – 2004. As observed, these prices range from \$33 to \$49 for SERC and from \$43 to \$52 for the FRCC over these years. A similar story is revealed for the early contract years, in part due to a large and unanticipated run-up in short-term prices during 1998 and 1999. However, it is important to recognize that *ex post* comparisons of spot prices with respect to contract prices agreed to at the start of a period simply describe the outcome of events beyond the contracting parties' control or influence. Ex post prices can reside outside the range of expectations held by the counter parties at the time that the contracts were agreed to.

The Company's successful arrangements for power supply coupled with its cost efficiency in distribution services mean that the retail customers of FPU have enjoyed and continue to enjoy low-cost and reliable retail power services. Indeed, Exhibit BMCC-6 shows that customers of Florida Public Utilities Company currently enjoy about a 20% cost advantage with respect to peer groups.

Q. What is Florida Public Utilities Company's strategy for power supply beyond December 2007?

A. The Company has issued a *Request for Proposals for Wholesale Power Supply* (RFP), and is in the midst of receiving and assessing offers to provide wholesale power supply including generation and transmission services. The anticipated offers by bidders will be assessed according to the dual objective of minimizing prices and overall risks to retail consumers, where risks include price volatility, delivery, and counterparty risks.

The Company is pursuing all possible avenues and measures to obtain the lowest possible prices in order to sustain its competitive price advantage in retail markets. The RFP is the first major step in the Company's transparent and open procurement process. The procurement process is geared to building contestability by facilitating the maximum level of bidder participation. Accordingly, the Company's RFP has been delivered to a fairly large number of suppliers that have expressed interest in responding to the RFP.

The procurement strategy is set up in a manner that provides the basis to diversify risks by building a contract portfolio that includes multiple suppliers and contract laddering for the two divisions. To this end, the RFP seeks to obtain three types of offers to supply: Full Requirements, Partial Requirements, and Energy Service (block energy). Bids will be assessed according to objective, value-based criteria. Nonetheless, the full success of the RFP is somewhat dependent upon the level of participation of bidders, and the offers themselves.

The Company has been remarkably successful as a low-cost service provider, particularly in view of the absence of potential scale economies at all levels and areas of its operations. From the perspective of the RFP and power supply, the Company is mindful of possible limits occasioned by its comparatively small-sized electricity operations in terms of risk diversification. Also, the Company remains concerned about the timing of the release of the RFP, which is taking place at a time of high cost wholesale market prices. Thus, it is essential that the term and the structure of the commercial terms of the resulting contract match up with the overall market outlook at the time that power supply contracts with winning bidders are finalized, and do so in a way that captures benefits in the form of lower prices should wholesale prices subsequently decline.

Q. What are the likely results of the Company's power procurement process?

A. It is likely that the contemporary conditions of electricity markets will translate into sharply higher prices for generation and transmission services beginning in

2008. As we mentioned, wholesale electricity prices have risen to exceptionally high levels since 2004. This contemporary experience affects expectations of the future; that is, forward prices reflect commitments conditional upon expectations of the future. In turn, expectations of future spot prices reflect recent price experience of wholesale markets.

As with all forward markets including commodities, currencies, and financial markets, expected electricity market conditions and spot prices are implicit in market participants' willingness to supply (sell) and willingness to pay (purchase) over future periods. That is, bids and offers reflect the expected future short-run marginal costs/spot prices of the region as such costs/prices reflect opportunity cost – essentially, the highest-valued use of resources, otherwise known as market worth. As observed, prices of New York Mercantile Exchange (NYMEX) futures (standardized forward contracts) for delivery at various locations across the Eastern Interconnection as well as in the West over the ensuing two or three years, are trading within the range of roughly $58 to $75 per MWh. Not surprising, futures prices are lower during off-peak months than during peak months. Also, futures contracts for off-peak hours trade lower, ranging around $40 per MWh. Of particular concern are the high prices of off-peak periods, which are driven largely by exceptionally high costs of primary fuels, the major input to the process of producing and generating electricity, and to a lesser extent by the increased frequency that gas-fired generators are on the margin.

Q. What are the implications of high forward wholesale prices for retail consumers?

A. The implications for retail consumers are twofold. First, customers of Florida Public Utilities Company face substantial likelihood of sharply higher retail prices for power supply. While the Company is committed to obtaining the best outcome from its procurement process, the resulting prices reflect the realities of wholesale markets, and are properly incurred costs and wholly prudent in all aspects. The higher prices of the succeeding contracts for power, as expected, will bring the retail prices of the Company to an overall level that approaches that of other service providers in the region. Nonetheless, the Company believes that, through its efficient power procurement process and ongoing business operations, it will remain the price leader within the Florida region over the foreseeable future, particularly in view of the significant upward pressure that higher primary fuel prices will have on all utilities within the region and at the national level.

Second, under the current regulatory framework, retail prices will rise abruptly when the new wholesale supply contracts come into force in January 2008. The abrupt transition to the higher price level constitutes a needless and burdensome shock to customers that can be eased with mitigating policy and action. Transitioning to the high prices is an issue of vital importance to retail consumers, and Florida Public Utilities Company wishes to enlist the assistance of the Florida Public Service Commission. Through appropriate regulatory policy, the Commission and the Company can help retail consumers to bridge the ensuing and difficult timeframe.

Q. What strategies are available to mitigate the abrupt change in wholesale power costs on retail customers?

A. As commonly recognized, sudden abrupt bill changes and volatility (variation) is costly to consumers. While high prices are evidence of the contemporary markets that we face, the Florida Public Service Commission and the Company can take progressive action to largely mitigate what is likely to otherwise be a clear-cut case of rate shock. To this end, the Company proposes to phase in the impact of higher expected wholesale power costs to retail customers over the 2006 – 2010 timeframe. The effect of the phase-in plan is to soften the impact of the large price rise on customer bills, as anticipated. In so doing, the overall welfare of customers will be improved.

Q. What are the design principles that underlie Florida Public Utilities phase-in plan?

A. The proposed phase-in plan and framework is premised on a central design principle. That is, the recommended plan should improve welfare while also satisfying a *"hold harmless"* constraint. In the immediate context, hold harmless means that the retail customers of the Company are left indifferent in money flows, regardless of the approach taken. That is, the plan is bill neutral in terms of discounted money flows for customers as a whole. The proposed phase in plan obtains improvements in overall welfare by mitigation/ elimination of rate shock while also satisfying hold harmless criteria.

Q. What are the main elements of the proposed phase-in plan?

A. The Company's proposed plan has several key features. First, the proposed plan incorporates a *surcharge*, a special and temporary charge to retail customers on fuel costs during the two years previous to the effective date of the new contracts. The surcharge amount would be implemented in two steps during these two years, 2006 and 2007. The second step, 2007, is somewhat higher in absolute terms than the first step, 2006, as the surcharge ramps up and approaches the anticipated contract prices, which are effective in early 2008.

The second feature is *interest accrual*. That is, the surcharge amounts accrue interest monthly at 2.8 per cent interest, which is the current cost of commercial paper. The total accrual amount including principal and interest accumulate in an escrow account. The accumulated surcharge and interest should also be excluded from the company's working capital for purposes of surveillance and base rate making in order to hold the company harmless as well as customers.

The third feature of the plan is referred to as *flow-back credits*, where the escrow balance at year-end 2007 is flowed back as credits (reductions) to the retail charges for the new contracts, in three steps over the years 2008, 2009, and 2010. The flow back credits diminish over time, with the amount of the credit for 2008 greater than that of 2009, and with 2009 greater than that for 2010. The surcharge amounts, escrow accrual, and flow-back amounts are subject to full accounting audits and checks, and review by the Florida Public Service Commission.

The fourth feature of the Company's proposed plan is referred to as *within-process adjustment and reconciliation*. That is, the surcharge amounts will be adjusted as market expectations change, as actual energy sales deviate from forecast sales, as offers are received, and as contracts for new power supply are reached. Finally, we wish to mention that the baseline point used to determine the surcharge amounts are, by design, out-of-market in order to preserve incentive compatibility.

Q. Given current expectations of the Company, please describe the surcharge amounts and the implied revenue and escrow amounts obtained with the proposed phase-in plan.

A. The proposed surcharge amounts for 2006 and 2007 and the resulting revenues and escrow balances are shown on pages 1 and 2 of Exhibit BMCC-1, for the Northeast and Northwest divisions of FPU respectively. As shown for the Northeast division (page 1), the 2006 surcharge is 0.644 cents per kWh, while the surcharge for 2007 is 1.418 cents per kWh. These surcharge values are applied to energy sales during the months of January – December of 2006 and 2007.

For the Northeast division, the surcharges revenues resulting from the implementation of the phase-in plan are expected to be $3,147,560 and $7,191,467 for 2006 and 2007, respectively, stated in nominal terms. With the inclusion of the accrual of interest, the resulting escrow balance at December 2007 is expected to be $10,560,025. As proposed, interest is compounded monthly.

As mentioned above, the escrow amount is flowed back as a credit to customer bills during 2008 – 2010. The flow back credit amounts received by customers are equal to $5,586,226 during 2008, $3,338,752 during 2009, and $1,995,523 in 2010. Escrow balances accrue interest over the course of the flow back period, 2008 – 2010.

The surcharge and flow back credits are less for the Northwest division because of lower sales quantities and higher contract prices for power supply currently, than for the Northeast division. Specifically, the 2006 surcharge is 0.321 cents per kWh, while the surcharge for 2007 is 0.676 cents per kWh. The expected surcharge revenues obtained by the phase in plan in the Northwest are $1,024,210 and $2,196,775 for 2006 and 2007, respectively, stated in nominal terms. With the inclusion of the accrual of interest, the resulting escrow balance at December 2007 is expected to be $3,291,077.

The escrow amount flowed back as credits to customers in the Northwest division during 2008 – 2010 are equal to $1,711,652 during 2008, $1,049,566 during 2009, and $643,623 in 2010.

Q. Please describe the size the rate shock impacts facing customers absent the phase in plan.

A. As mentioned, the increases in prices are large without the implementation of the phase in plan. Exhibit BMCC-1 page 3 shows the anticipated rate impacts on customer bills beginning in the year 2008 without the presence of the plan. As can be seen, the percentage change in the customer bills of residential, commercial, and industrial consumers range from 22 to 78%. Abrupt change in customer bills of these magnitudes are of major concern, and evidence of the substantial burden placed on retail consumers in the absence of the phase in plan.

In addition, the bill impacts differ significantly among customers and it is useful to review the differential impacts. Without the phase in plan, customers of the northeast division face significantly larger increases than customers of the northwest division. This is because the current contract prices for wholesale power supply for the northwest division are higher than the corresponding prices for the northeast division. As observed, the percentage change in customer bills range from 22% to 45% for the northwest division, whereas the impacts for the northeast division are larger still, ranging from 35% to 78%. As a general rule, the change in the electricity bills facing customers rises progressively with an increasing share of the current bill composed of costs of wholesale power. For this reason, the larger customers of the northeast division in particular face very large bill impacts.

The bill impacts clearly demonstrate the need to phase in the costs of the Company's new contracts.

Q. Can you please elaborate on and briefly discuss fairness and efficiency aspects of the proposed phase in plan?

A. Yes. The proposed plan has both fairness and market efficiency aspects. From a social efficiency perspective, the path of the phase in prices more closely matches wholesale prices, which reflect societal marginal costs of power, over the years of the surcharge, 2006 and 2007. Overall efficiency is improved and the level of retail sales will be somewhat less than otherwise during these years. Conversely, phase in prices experienced by consumers depart from wholesale prices during the period of the flow back credits. Accordingly, retail sales levels will be somewhat greater than otherwise during these latter years.

The first order welfare impacts of the proposed plan, measured as consumer surplus and as reflected in expected electricity sales impacts, are significant for individual years but small overall for the several years over which the plan is in effect. However, our main concern and the purpose of the proposed phase in plan is the benefits obtained by introducing a degree of gradualness in price changes – essentially, second order benefits realized through of stability of prices. By attenuating rate shock, a form of risk, the proposed plan reduces harm caused by a sudden increase in prices. It is predominantly this reason rather than market efficiency that underlies the Company's petition to the Commission to implement the phase in plan as proposed.

Q. Do customers prefer reduced risk, and does the phase-in plan add value?

A. Yes. Cursory observation, intuition and common sense, and formal empirical evidence across a broad range of markets suggest that risk and uncertainty are costly and that economic agents, both firms and households, prefer less risk all other factors constant. A large number of examples of risk aversion in the behavior of agents are readily available:

1. The comparatively large-scale participation and steady growth of futures markets and over-the-counter forward contracts for wholesale commodities including energy, agriculture, and metals, as well as the steady expansion of the products that are traded forward.

2. The longstanding presence of comparatively long-term debt instruments in financial markets, the growth in financial options including complicated compound features.

3. The appearance of weather-related insurance to mitigate financial losses attributable to crop damage, and insurance to guard against damaged goods and cargo while in transit.

4. The growth in the volume of transactions in forward currency markets.

5. The expansion of consumer insurance markets beyond life, auto, and home insurance categories and products. Insurance coverage is commonly available for health, consumer electronics, boats, automobile repair and service, tires, theft, and appliances. In addition, the range of coverage of insurance menus and options has expanded vastly.

6. The appearance of forward retail contracts for home heating oil and propane gas.

7. The vast expansion of specialized insurance products for business that cover a broad range of contingency events such as physician malpractice, and disability and physical incapacity for athletes and artists, as well as insurance for highly valued art and musical instruments.

8. Strong consumer preferences for fixed-price open-quantity tariff design for regular telephone service in lieu of measured service.

9. Equity share prices, as traded on major financial exchanges worldwide, are ordered according to perceptions of risks. If equity A has equivalent expected cash returns to capital but higher perceived risks vis-à-vis the cash returns and risks of equity B, A will trade at market prices lower than that of B. The lower prices of A provide the means for the realization of higher expected market returns to shareholders of A than to the shareholders of B, thus compensating for the higher risks implicit in holding the shares of A.

Risk management mechanisms and insurance tools are the vehicles of markets to mitigate risks and the costly effects of uncertain events associated with the many aspects of business and life. In so doing, a broad spectrum of markets are made more complete. A window to the expanding opportunities to hedge risk is Robert Shiller's recent book entitled "The New Financial Order: Risk in the 21st Century" published in 2003. The range of possible products and applications of risk management principles is vast. The essential point is that there exists a broad base of market experience to affirm the intuitive notion that risk is costly and that economic agents are willing to compensate third parties willing to assume the costly burden of and responsibility for risk. In short, agents prefer less risk to more, and market processes can be expected to implement many new innovations to mitigate risk.

Q. What about retail electricity markets? Is there explicit evidence and examples of risk aversion in the choices of consumers?

A. Yes, examples of risk aversion behavior by participants in electricity markets are readily at hand. For example, the fast expansion of fixed bill products at the retail level, and the wide scale participation in financial and physical transmission rights at the wholesale level are immediate examples. The fact that fixed bill products, which hedge quantity risks, are typically offered at premium prices suggests that many consumers are willing to pay higher *expected* prices for the risk hedging features of fixed bill products. In essence, consumers make value-improving choices, and by selection of premium-priced fixed bill options, retail consumers can improve welfare. This means that, for those customers that self select fixed bill products, the inherent quantity risks of the standard offer tariff, as perceived, is more costly the price premium attending the risk management feature of the option.

A second example of the costly nature of risk is the selection behavior of retail customers that are confronted with bill-neutral time-of-day options. To a substantial degree, customers prefer conventional non-varying price open quantity tariffs, which are common and prevalent among retail tariffs of service providers, to the TOU option. Generally, the TOU option is selected only when customers are capable of substantially shifting load to the lower-priced off peak periods – thus reducing the total electric bill – *or* where the customer bill on the TOU option is somewhat below that of the conventional tariff, holding quantities constant.

A third example is the self-selection of curtailable service load control options. To a large extent, customers will only chose such options when they are attended by rather substantial discounts in comparison with the firm service of standard offer tariffs. Essentially, the uncertainty associated with non-firm supply is costly, and sufficient discounts are necessary to obtain customer participation in non-firm power supply.

Q. What are the policy lessons and principles that we can draw from market experience and the behavior of agents regarding risks?

A. First, it is quite clear that risk is costly, and that the Commission and Florida Public Utilities Company should take the necessary action to reduce risks in a cost effective manner where possible. Second, the Commission should support the Company's plan to phase in the anticipated higher prices for power supply. In so doing, the Commission mitigates the costly impacts of rate shock, thus improving the welfare of the retail customers of Florida Public Utilities Company.

Q. Is there precedent for the phase-in of sharply rising costs for power supply?

A. While the reasons, situation, and market context were unique to the earlier era, a number of incumbent utilities phased in large-scale and costly base load power plants during the 1980s. Utility sponsors and regulators allowed and fully supported the phase-in of prudently incurred costs over several years in order to ease the burden of what would have otherwise been serious rate shock events.

It is useful to mention that the situation during this previous timeframe is in sharp contrast to that of the Florida Public Utilities Company in several important respects. Back then, large-scale base load plants were the primary cause of rate shock, and their utility sponsors had in several cases breached the confidence of retail customers and regulators, as manifest in costly overruns of construction budgets. As a result, the plants and their sponsors sometimes faced serious regulatory issues related to the need for additional resources, technology choice, and plant costs that were significantly out-of-market.

In contrast, the situation of the Company contains none of these issues. Rather, Florida Public Utilities Company faces higher costs simply because of the contemporary realities of wholesale markets.

Q. Would you please describe the workings of power markets in the Southeast, and the implications for power procurement?

A. Wholesale power markets were opened to new entrants with the passage of the national Energy Policy Act of 1992. Provisions of the Act called for incumbent transmission service providers, most of which were and continue to be vertically integrated electric companies, to allow access to transmission networks to buyers and sellers of wholesale power. Authority for implementation, oversight, and enforcement of the wholesale electricity market provisions of the Energy Policy Act was assigned to the Federal Energy Regulatory Commission (FERC).

The market mechanisms and procedures for obtaining access to power networks and scheduling wholesale transactions were not formalized, and the process was encumbered by burdensome scheduling, procedural, and institutional inefficiency. Arguably, accessibility to networks was effectively denied by procedural burdens for several years. A defining moment in the organization of wholesale markets was the Open Access Transmission Tariff as established in 1996. In April of that year, the FERC issued two landmark orders:

- Order 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities;* and,
- Order 889, *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct.*

In addition to functionally separating the generation and transmission functions and activities of incumbent utilities, these two companion orders define categories of wholesale services, define the basis for determining the prices for wholesale services, and set forth fairly definitive procedures regarding the scheduling of wholesale transactions among control areas of the Nation's transmission grid using web based services (OASIS).

While the FERC has authorized the further unbundling of wholesale markets with the formation of ISOs and RTOs in California and the northern regions of the Eastern Interconnection, FERC Orders 888 and 889 constitute the authority for the conduct of power markets in much of the U.S. and under which a large volume of short- and long-term power transactions occur.

The growth in wholesale market transactions has precipitated the implementation of OASIS sites by service providers in order to facilitate the scheduling of wholesale transactions. Also, regional markets have formed commercial hubs at various locations and interfaces throughout the U.S. Hubs play an important role in price discovery.

These various procedural mechanisms and market provisions serve to facilitate and enable market processes. Buyers and sellers can engage in a variety of near-term transactions using more-or-less standard market products such as energy service and bundled packages of energy and transmission (including reserves) for same-day and day-ahead hourly and 16-hour periods, as well as for weekly and monthly peak-period and all-hours supply. Furthermore, market participants can schedule long-term transactions across seasons and years. In most regions, wholesale market participants are numerous and include rural cooperatives, local distribution companies, power trading subsidiaries of investor-owned utilities, trading authorities and merchant traders, merchant generators, and municipalities. While nettlesome impediments to competition remain wholesale electricity markets are reasonably contestable in most regions and within most timeframes.

This wholesale market environment is quite suitable for competitive power procurement, although serious challenges may be present in some areas and locales because of accessibility to transmission and so-called "pancaked" pricing of transmission services across multiple control areas. While these issues are encumbering and are not to be minimized, buyers including local distribution companies such as Florida Public Utilities Company, can organize well-structured procurement processes and often obtain competitively priced power supply.

Q. What are your expectations regarding future electricity prices and the reasons that underlie future price levels?

A. The U.S. electricity industry has entered an era of sharply higher wholesale prices for electricity beginning in late 2003. The contemporary high power prices are a national phenomenon, and are a result of three main factors. First, primary fuel prices including coal, natural gas, and oil have all risen to very high levels. Current fuel prices are largely a result of a sudden and seemingly sustained tightening of supply-demand balance for fuels; supply margins are fairly tight and inventories are exceptionally low from time to time over recent years in the case of natural gas and oil.

Second, transmission networks have experiencing substantially higher levels of congestion in recent years, which is manifest as increased frequency in transmission load relief (TLR) calls, and expanded differences in locational and zonal prices for power. Third, the aggregate demand for electricity service, as reflected in observed peak loads and energy consumption, has advanced over the past three years to levels that better balance with and more fully utilize generation supply. Fourth, and to a lesser extent, concerns about global warming and other environmental considerations have caused the electricity industry to increasingly embrace renewable resources, as evidenced by the adoption of Resource Portfolio Standards policy in several regions of the U.S. While renewable resources may reduce total emissions including sulfur dioxide (SO2), mercury (including elemental, vapor, and particulate bound components), nitrogen oxides (NOX), particulate matter, and carbon dioxide (CO2), such resources will raise the total costs of power supply, as far as the internal and direct resource costs are concerned.

Q. Please provide projections of future prices.

A. Exhibit BMCC-2 presents a projection of spot power prices for the Southeast region over the 2005 – 2012 timeframe. We include tables of average spot prices for three timeframes including all-hours, peak periods, and off-peak periods. These prices are a result of market simulations developed by CAEC and used regularly to prepare forecasts of regional prices. The prices reflect simulations of a range of possible market outcomes for energy, and the implicit reserve services of regulation, spin, non-spin, and backup reserve categories. The composite power prices are marginal cost-based prices for regions and incorporate scarcity rents. However, the prices do not include black start or reactive power, nor do they reflect the marginal cost of delivery services including transmission network service, connections services, and scheduling.

While we have also developed prices for Florida, the North American Electric Reliability Council (NERC) region known as the Florida Reliability Coordinating Council (FRCC), we believe that the more relevant region for the purposes herein is the NERC region known as the Southeast Electric Reliability Council (SERC), which encompasses the states of Alabama, Georgia, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia, as well as the southern and northeastern areas of Louisiana.

The regional price projections are developed by applying a structural analysis approach to the markets represented by a so-called compressed SERC region. The development of projected wholesale price involves projections in regional economic activity, hourly loads for the region, the region's generation portfolio including units under construction as well as possible new generators in the future, and a range of possible future primary fuel prices. Exhibit BMCC-3, pages 1 – 3, shows supporting details that underlie the wholesale market price projections. Page 1 shows summer demand and generation capacity over the 2005 – 2012 timeframe for the compressed SERC region for low, moderate, and high demand growth scenarios. Of particular interest are the capacity reserve margins, where reserves stay tightly bundled around fifteen percent. These reserve levels reflect expected reserves for the surrounding regions of the Eastern Interconnection, and are not specific to SERC. Imposing non-SERC specific reserves on the simulations for the SERC region is necessary in order to reflect the natural behavior of power markets. Namely, regions that are a little long in capacity or otherwise have cost advantages – and thus have comparatively low marginal costs – will export power to regions that are relatively short. Hence, it is appropriate to utilize non-SERC specific reserve margins in the determination of the projections of regional power prices.

Exhibit BMCC-3 pages 2 – 3 contain the three scenarios of primary fuel prices and generation expansion for the moderate demand case, respectively. Page 2 presents a plausible set of alternative long-term paths for primary fuel prices in the Southeast over the 2008 – 2012 timeframe. These primary fuel price paths are obtained through a combination of analysis and intuition, and represent a combination of current forward prices converted to spot, as well as long-term trends. The fuel prices are utilized to project future electricity prices, also for the Southeast, and incorporate transportation costs as well as, in the case of coal, the costs of environmental compliance for sulfur dioxide. It is worthwhile to mention that SO2 allowance prices have risen fourfold over the most recent eighteen month period.

As observed, we expect that price pressure for primary fuels will ease somewhat, before assuming the long-term path that roughly follows general inflation. The scenarios of fuel prices reflect possible long-term paths of prices and do not reveal the full range of short-term uncertainty and volatility inherent to primary fuels.

The modeling approach develops hourly prices (marginal costs) for six day-types for the months of each forecast year. The approach uses Monte Carlo methods to determine generator downtime for maintenance and unit availability. The approach obtains numerous realizations of prices/marginal costs for each hour of the various day types. The day-type analyses are then mapped to the various days of a weather normalized year, where the days of the year have been categorized according to day type and month. The result is a range of possible hourly prices. The prices embody implicit rents for scarcity, market power, and various market inefficiencies and friction that cannot be otherwise explicitly accounted for.

The modeling approach obtains prices for reserve services using optimization techniques (linear programming methods), based upon assumed operating parameters of generating units within the region.

As noted above, Page 1 of Exhibit BMCC-2 presents the expected value of wholesale electricity prices over all hours, while page 2 presents the expected prices for peak and off-peak hours. The projected prices are shown by month and year. As can be seen, the analysis suggests that wholesale electricity prices will generally recede from the current highs to levels of about $55.00 per MWh, and to then rise as primary fuel prices assume trajectories that conform with the respective long-term historical path roughly equivalent to overall expected inflation. Also, the long-term path reflects the gradual evolution in the generator unit portfolio of the region. Model simulations suggest, and market experience confirms, that as a general rule wholesale electricity prices are higher during summer months than non-summary periods. Although not shown, simulated and observed wholesale prices reveal higher variation (volatility) and risk during summer periods than non-summer periods. This result follows from the generally tighter supply margins of the summer, where unexpected demandside events (such as weather) and supply-side events (such as generating unit and transmission line outages) translate into comparatively larger upside risk than during non-summer periods. Also, summer wholesale market prices for electricity can reveal distinct up-side skewness in the underlying statistical distributions.

Q. Please discuss the primary fuel prices and the outlook for fuels, as utilized in the projected wholesale prices.

A. In the case of coal, supplies are plentiful although rising demand for coal has been precipitated by high natural gas prices. Essentially, coal and gas are substitutes, with fairly substantial substitution elasticity. This means that generation companies – mainly electric utilities – will tend to utilize coal-based generation more intensively with rising prices for gas relative to coal. In addition, the costs of transportation of coal from locations where it is extracted to locations where it is consumed as fuel (coal-fired generators) has been recently constrained as a result of bottlenecks in railroad lines in key locations, of (as reported) some shortages of locomotives and coal cars and, we suspect, the exercise of market power by major railroads in key areas of the U.S. Also, there are reports that expanded U.S. coal exports are being used to produce steel worldwide.

Natural gas supply in the U.S. is constrained in the short run because of limits of economically viable wells and fields at market prices of less than \$3 – \$4 dollars per MCF (MMBTU) within the continental U.S. Second, inventories at various locations in the U.S. have been limited such that, when coupled with limited extraction capability, wholesale prices of natural gas can show high sensitivity to short-run changes in demand and expectations of future weather patterns and forecasts.

Unlike the difficult years of the 1970s, oil plays a rather insignificant role in electricity supply currently, particularly in the Southeast, and thus need not be considered in the context of the immediate issues at hand. Nonetheless, we wish to mention in passing that oil prices are currently driven by steadily increasing demand for transportation worldwide, mainly automobiles. Second, the retail prices of oil-derived products such as fuel oil for heating are affected by the apparent limits of refinery capacity in the U.S.

Pages 1 – 4 of Exhibit BMCC-4 present forward contracts for primary fuels for deliveries over future months, as reported by NYMEX during late 2004. It is important to recognize that *forwards* represent composite expectations of traders, both hedgers and speculators, regarding future spot prices for fuels. In essence, these forward prices suggest that traders in late '04 implicitly expected high primary fuel prices to be present over the ensuing months. Page 4 of Exhibit BMCC-4 presents coal price futures for deliveries during 2005 and 2006, as of February '05. As can be seen, the more current expectations reveal somewhat lower coal prices prospectively, than that of late 2004.

It is useful to view the current high levels of primary fuel prices within the context of long-term history. Accordingly, we present on pages 1 – 2 of Exhibit BMCC-7 primary fuel prices for crude oil, coal, and natural gas for 1973 – 2004 period for the consideration of the Commission. As can be seen, while primary prices are exceptionally high currently, such prices are not unprecedented. Specifically, primary fuel prices reached current levels during the 1980 – 1984 timeframe, stated in real terms.

Q. Please describe transmission congestion and the impact of congestion on wholesale prices.

A. Congested network facilities, including specific flowgates and key interfaces among control areas, separate markets. Congestion raises prices for some areas and lowers prices for others. Congestion is a particular issue for load centers that are downstream from constrained flowgates and interfaces, such as the various load centers of the Florida peninsula, as they now face higher costs for wholesale services. Congestion along key flowgates and interfaces leads to the realization of higher profits by downstream generators (constrained on) and lower profits by upstream merchant generators (constrained off).

Q. Please discuss supply-demand balance, reserve margins, and the effects of reserve margins on wholesale prices.

A. Supply-demand balance in the U.S. and Southeast is shown on page 2 of Exhibit BMCC-5. As mentioned earlier, supply-demand balance has tightened somewhat. In the case of electricity markets, changes in supply margins operate together with the characteristic of non-storability to produce instances in which small changes in supply margin often translate into fairly sizable impacts on power prices. Overall for the Eastern Interconnection, we would guess that the brief excess supply bubble of 2002 – 2003 is largely exhausted. And while the current large-scale volume of wholesale transactions is not altogether new, it is not as if the electricity industry has decades of experience; learning is a key element of market experience and it is reasonable to opine that the bubble of recent years is an infrequent phenomenon that will not be revisited often.

In summary, the supply-demand balance of markets is currently in approximate long-run equilibrium with capacity reserve levels near 16%, perhaps a little higher. For the present, we have no reason to expect overall capacity reserves in the future to deviate much from this level over the long run, aside from periodic variations largely attributable to random weather phenomena. One thing that could change long-term optimal capacity reserve margins is a rise in customer participation in reserve markets (curtailment programs) and other demand response programs such as real-time pricing.

Q. Please summarize your testimony and recommendations for the consideration of the Commission.

A. Florida Public Utilities Company takes very seriously, at the highest level, its duty to provide continued and uninterrupted power supply to its retail customers at reasonable cost. To this end, the Company is in the process of implementing a least cost long-term procurement strategy for power supply beginning in 2008. However, contemporary wholesale markets and market prices, in the Southeast and nationally, reveal sharply higher costs for power as a direct result of a roughly twofold increase in the costs of primary fuels, of increasingly constrained networks, of a steady tightening of supply-demand balance and reduced supply margins, and of environmental considerations being increasingly manifest in policy at the regional and national level.

These market conditions are affecting expectations of market participants over future years and, at this time, the Company and retail customers in all likelihood will face and be burdened with sharply higher prices for power beginning in 2008.

FPU's retail prices will change abruptly under standard ratemaking mechanisms of the current regulatory framework, and absent needed policy intervention by the Florida Public Service Commission. Accordingly, it is both necessary and appropriate for the Company, with the approval and full support of the Commission, to phase in the much higher prices for power as anticipated. The phase-in plan, as presented herein, has been designed in a manner that improves consumer welfare by mitigating the rate shock that would otherwise occur. Our phase-in plan contains important safeguards and features including interest accruals, accounting audits, regulator checks, and the provision for changes as market expectations evolve. Thus, the plan as proposed is in the general interest of retail consumers and provides the Commission with the necessary level of confidence that facilitates its approval and support.

Q. Does this conclude your Direct Testimony?

A. Yes.

Florida Public Utilities Company

PHASE IN PLAN SUMMARY

Eastern Division

Price Impacts (cents/kWh)

Year	Retail Fuel Prices: Current ('06, '07) and Future ('08 - '10) Contracts	Surcharge	Flow-Back Credits	Net Retail Fuel Charge	Average Non-Fuel Charge*	Average Net Retail Prices
2006	3.200	0.644		3.844	1.670	5.514
2007	3.200	1.418		4.618	1.670	6.288
2008	6.036		1.061	4.975	1.670	6.645
2009	6.080		0.611	5.469	1.670	7.139
2010	6.121		0.352	5.769	1.670	7.439

Surcharge Revenues, Nominal:	2006	$3,147,560
	2007	$7,191,467
	Total	$10,339,027
Surcharge Revenues, w/Interest:	2006	$3,187,516
	2007	$7,372,509
	Total	$10,560,025
Nominal Flow Credits:	2008	$5,586,226
	2009	$3,338,752
	2010	$1,995,523
	Total	$10,920,501

* Base rate charges are held unchanged from current leve for purposes of model simulation only.
Depending upon the costs of delivery services, however, base rate may change over the 2006 - 2010 timeframe.

Florida Public Utilies Company

PHASE IN PLAN SUMMARY

Western Division

Price Impacts (cents/kWh)

Year	Retail Fuel Prices: Current ('06, '07) and Future ('08 - '10) Contracts	Surcharge	Flow-Back Credits	Net Retail Fuel Charge	Average Non-Fuel Charge*	Average Net Retail Prices
2006	4.062	0.321		4.383	2.265	6.648
2007	4.170	0.676		4.846	2.265	7.111
2008	6.036		0.518	5.518	2.265	7.783
2009	6.080		0.312	5.768	2.265	8.033
2010	6.121		0.188	5.933	2.265	8.198

Surcharge Revenues, Nominal:	2006	$1,024,210
	2007	$2,196,775
	Total	$3,220,985
Surcharge Revenues, w/Interest:	2006	$1,037,211
	2007	$2,253,866
	Total	$3,291,077
Nominal Flow Credits:	2008	$1,711,652
	2009	$1,049,566
	2010	$643,623
	Total	$3,404,841

* Base rate charges are held unchanged from current leve for purposes of model simulation only.
Depending upon the costs of delivery services, however, base rate may change over the 2006 - 2010 timeframe.

Florida Public Utilities Company

ANTICIPATED RATE SHOCK IMPACTS, 2008

WESTERN DIVISION

	Monthly Usage Level			
	250 kWh		1,000 kWh	
Residential Customers	$ Change In Bill	% Change In Bill	$ Change In Bill	% Change In Bill
	$5.43	22.2%	$21.70	32.0%

	Monthly Usage Level			
	1,000 kWh		15,000 kWh	
Commercial and Industrial Customers	$ Change In Bill	% Change In Bill	$ Change In Bill	% Change In Bill
	$21.70	30.0%	$372.75	45.0%

EASTERN DIVISION

	Monthly Usage Level			
	250 kWh		1,000 kWh	
Residential Customers	$ Change In Bill	% Change In Bill	$ Change In Bill	% Change In Bill
	$7.98	35.2%	$31.91	52.6%

	Monthly Usage Level			
	1,000 kWh		15,000 kWh	
Commercial and Industrial Customers	$ Change In Bill	% Change In Bill	$ Change In Bill	% Change In Bill
	$31.02	48.1%	$561.88	77.9%

Docket No. ______________
Witnesses: Bachman, Martin, Cutshaw and Camfield
Exhibit ________ (BMCC-2)

Florida Public Utilities Company

PROJECTIONS OF WHOLESALE ELECTRICITY PRICES

Southeast Region

Expected Prices for All Hours ($/MWh)

	2005		2006		2007		2008		2009		2010		2011		2012	
Month	Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range	
January	48	60	45	59	41	57	38	55	40	55	42	54	43	56	44	58
February	44	55	42	55	39	54	36	52	38	52	40	51	41	53	42	55
March	43	53	41	53	38	52	35	51	37	50	39	50	40	52	41	54
April	47	59	43	58	39	55	36	53	38	53	40	52	41	54	42	56
May	56	70	51	67	46	64	42	62	44	61	47	60	48	62	49	65
June	66	86	59	80	52	74	47	71	50	69	53	68	54	71	55	73
July	73	94	65	88	58	81	53	78	56	77	59	75	60	77	61	80
August	75	97	68	90	60	84	55	80	58	79	61	77	62	80	63	83
September	61	79	54	74	48	68	44	66	46	64	49	63	50	65	51	68
October	60	80	53	73	47	68	42	65	45	63	47	62	48	64	49	66
November	56	75	50	70	45	65	40	62	42	60	45	59	46	61	47	63
December	46	58	43	57	40	55	37	54	39	53	41	52	42	54	43	56
Annual	57	74	52	70	47	66	43	63	45	62	48	61	49	63	50	66

Florida Public Utilities Company

PROJECTIONS OF WHOLESALE ELECTRICITY PRICES

Southeast Region

Expected Prices for Peak Hours ($/MWh)

	2005		2006		2007		2008		2009		2010		2011		2012	
Month	Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range	
January	51	64	48	62	44	60	40	58	42	58	45	57	46	59	47	61
February	46	58	44	58	40	56	37	54	39	54	41	53	42	55	43	57
March	45	58	43	57	40	55	37	54	39	53	41	52	42	54	42	56
April	51	66	47	63	42	60	39	57	41	56	43	55	44	57	45	60
May	64	80	58	76	51	71	47	68	49	67	52	66	54	69	55	72
June	76	98	68	91	60	84	54	81	58	78	61	77	62	80	63	83
July	85	109	76	101	68	93	62	90	65	88	69	86	70	89	71	92
August	87	111	78	104	70	96	64	92	67	90	71	88	71	91	73	95
September	69	90	62	83	54	77	49	74	53	72	55	70	56	73	57	76
October	65	87	57	79	50	73	45	69	48	67	50	65	51	67	53	70
November	59	80	52	73	47	68	42	64	44	63	47	61	48	63	48	65
December	48	60	45	59	41	57	38	55	40	55	42	54	43	56	44	58
Annual	64	82	58	77	52	72	47	70	50	68	53	67	54	69	55	72

Expected Prices for Off Peak Hours ($/MWh)

	2005		2006		2007		2008								2012	
Month	Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range		Plausible Range	
January	45	57	42	56	39	54	36	53							42	56
February	43	52	40	53	37	51	34	50							40	54
March	41	48	38	49	36	48	33	47							39	52
April	43	53	40	52	36	51	33	49							39	53
May	46	58	43	57	39	55	36	53							42	56
June	54	71	48	66	43	61	39	59							46	61
July	60	79	54	73	48	68	43	66							50	67
August	60	79	54	74	48	69	44	66							51	68
September	51	67	46	63	41	59	37	57							44	59
October	54	72	48	67	43	63	39	60							45	62
November	53	70	47	66	42	62	38	59							44	60
December	44	55	42	55	38	53	35	52							41	55
Annual	50	64	46	61	41	58	38	56	40	55	42	54	43	57	44	59

Docket No. ______________
Witnesses: Bachman, Martin, Cutshaw and Camfield
Exhibit _______ (BMCC-3)

Florida Public Utilities Company

DEMAND AND SUPPLY SUMMARY

For Estimation of Regional Wholesale Prices
Compressed SERC Region*

Year	Low Demand Growth Scenario (MWs)				Moderate Demand Growth Scenario (MWs)				High Demand Growth Scenario (MWs)			
	Summer		Margin		Summer		Margin		Summer		Margin	
	Demand	Supply	MWs	%	Demand	Supply	MWs	%	Demand	Supply	MWs	%
2005	104,233	122,604	18,370	15.0%	105,510	124,104	18,594	15.0%	106,793	125,604	18,811	15.0%
2006	106,553	126,208	19,655	15.6%	108,391	127,708	19,317	15.1%	110,249	129,783	19,534	15.1%
2007	108,924	128,393	19,468	15.2%	111,350	130,993	19,642	15.0%	113,816	133,993	20,177	15.1%
2008	111,348	130,943	19,594	15.0%	114,391	134,568	20,177	15.0%	117,499	138,268	20,769	15.0%
2009	113,826	133,943	20,116	15.0%	117,515	138,243	20,728	15.0%	121,301	142,693	21,392	15.0%
2010	116,359	136,943	20,583	15.0%	120,723	142,018	21,294	15.0%	125,226	147,393	22,167	15.0%
2011	118,949	139,943	20,994	15.0%	124,020	145,893	21,873	15.0%	129,278	152,093	22,814	15.0%
2012	121,596	143,018	21,422	15.0%	127,406	149,868	22,461	15.0%	133,461	156,993	23,531	15.0%

* The projections of wholesale prices for SERC are estimated for a so-called compressed SERC region. This means that both hourly demands and the portfolio of generation capacity is scaled back from that of the entire SERC region. This scaling procedure is necessary to reduce computation time. As discussed within the documentation, the structural model approach includes iterative methods. Altogether, the modeling approach involves 225 iterations of supply by season. Demand is dimensioned as hours by day type and month. The analysis is conducted over several forecast years.

Docket No. ______________
Witnesses: Bachman, Martin, Cutshaw and Camfield
Exhibit ________ (BMCC-3)

Florida Public Utilities Company

PROJECTED PRICES OF PRIMARY FUELS

For Estimation of Regional Wholesale Prices,
SERC Region

Nominal Dollars per MMBTU

	Natural Gas			Oil			Coal		
Year	Low	Mid	High	Low	Mid	High	Low	Mid	High
2005	6.67	7.77	8.32	7.50	7.58	7.65	3.17	3.23	3.30
2006	6.24	7.16	8.05	6.09	6.23	6.98	2.88	2.96	3.14
2007	5.83	6.60	7.79	4.94	5.12	6.36	2.62	2.71	3.00
2008	5.45	6.08	7.54	4.01	4.21	5.80	2.39	2.49	2.86
2009	5.55	6.25	7.30	4.04	4.29	5.29	2.41	2.53	2.73
2010	5.66	6.41	7.07	4.08	4.37	4.82	2.43	2.58	2.61
2011	5.77	6.58	7.31	4.11	4.46	4.96	2.45	2.62	2.68
2012	5.88	6.76	7.56	4.15	4.54	5.11	2.48	2.67	2.75

Florida Public Utilities Company

PROJECTIONS OF CAPACITY ADDITIONS

For Estimation of Regional Wholesale Prices
Compressed SERC Region*

		Baseline Summer 2004			Technology Share (%) of Capacity Additions, Capacity Additions (MWs), and Total Capability (MWs)								
Generating Technology		Average Unit Size (MWs)	Average Unit Heat Rate (BTU/kWh)	Total Installed Capacity (MWs)	2004	2005	2006	2007	2008	2009	2010	2011	2012
Coal		171	10,398	47,975	0%			33%	31%	31%	30%	29%	28%
Natural Gas:	CC	386	7,046	20,442	0%	34%		22%	29%	29%	28%	27%	26%
	CT	70	11,789	23,130	100%	66%	98%	44%	39%	41%	42%	44%	45%
	Other	2	10,721	169		0%	2%	0%					
Hydro		150		10,367									
Nuclear		942	10,486	16,963									
Added Capacity (MWs)					1,700	3,358	3,604	3,285	3,575	3,675	3,775	3,875	3,975
Total Capability (MWs)				119,046	120,746	124,104	127,708	130,993	134,568	138,243	142,018	145,893	149,868

* The projections of wholesale prices for SERC are estimated for a so-called compressed SERC region. This means that both hourly demands and the portfolio of generation capacity is scaled back from that of the entire SERC region. This scaling procedure is necessary to reduce computation time. As discussed within the documentation, the structural model approach includes iterative methods. Altogether, the modeling approach involves 225 iterations of supply by season. Demand is dimensioned as hours by day type and month. The analysis is conducted over several forecast years.

Florida Public Utilities Company

CENTRAL APPALACHIAN COAL FUTURES, $/Ton

Settlement Prices Observed On NYMEX at Identified Dates, 2004-2005

Month	June 23,2004	August 10,2004	November 24,2004
July, '04	$52.80		
August	$53.00		
September	$54.30	$61.38	
October	$55.50	$64.00	
November	$55.50	$64.00	
December	$55.50	$64.00	$59.50
January, '05	$53.90	$62.00	$60.75
February	$53.90	$62.00	$61.58
March	$53.90	$62.00	$60.83
April	$51.60	$58.14	$61.00
May	$51.60	$58.14	$60.00
June	$51.60	$58.14	$59.25

Florida Public Utilities Company

NATURAL GAS FUTURES, $/MCF

Settlement Prices Observed On NYMEX at Identified Dates, 2004-2005

Month	August 10,2004	November 24,2004
September	$5.69	
October	$5.83	
November	$6.30	
December	$6.72	$7.98
January, '05	$6.95	$8.64
February	$6.91	$8.71
March	$6.79	$8.36
April	$6.21	$7.25
May	$6.09	$7.02
June	$6.11	$7.05

Florida Public Utilities Company

OIL FUTURES, $/Barrel

Settlement Prices 2004-2005, Observed On NYMEX at Identified Dates

Month	August 10,2004	November 24,2004
September	$44.84	
October	$44.44	
November	$43.96	
December	$43.38	
January, '05	$42.77	$49.44
February	$42.23	$49.45
March	$41.75	$49.37
April	$41.30	$49.04
May	$40.87	$48.56
June	$40.48	$48.06

Florida Public Utilities Company

CENTRAL APPALACHIAN COAL FUTURES, $/Ton

Settlement Prices Observed On NYMEX, Febuary 7, 2005

Month	2005	2006
January		$55.75
February		$55.50
March	$57.75	$55.50
April	$58.15	$52.50
May	$58.05	$52.50
June	$57.80	$52.50
July	$58.50	$52.50
August	$58.25	$52.50
September	$58.00	$52.50
October	$57.18	$50.90
November	$57.18	$50.90
December	$57.18	$50.90

https://www.services.nymex.com/otcsettlement/OTCSettle.jsp

Florida Public Utilities Company

DAY-AHEAD WHOLESALE PRICES*

($/MWh)

		SERC					FRCC				
Month		**2000**	**2001**	**2002**	**2003**	**2004**	**2000**	**2001**	**2002**	**2003**	**2004**
January		29.82	54.17	34.00		44.46	30.93	61.90	39.69		47.07
February		25.19	39.29	43.16		42.59	27.60	43.64	44.43		46.21
March		26.08	41.70	27.04	48.35	43.75	30.48	47.43	31.65	56.49	47.59
April		29.14	51.85	31.49	42.67	47.95	32.63	59.75	47.13	50.08	51.46
May		52.34	38.01	29.01	34.18	54.04	56.00	54.58	49.93	60.20	61.43
June		47.02	40.69	34.62	44.72	53.93	57.91	55.24	40.97	53.80	65.29
July		52.29	44.88	37.58	45.01	54.40	66.00	51.21	42.86	56.71	66.29
August		59.55	47.22	34.18	45.82	48.59	75.65	53.84	41.34	53.54	60.17
September		30.10	26.17	33.11	36.53		54.35	35.16	46.40	53.49	
October		38.58	27.50	33.39	30.68		48.60	33.58	50.44	44.23	
November		46.80	24.06	27.36	32.35		51.03	30.43	39.27	48.40	
December		79.01	21.39	29.44	39.71		75.90	28.01	36.05	45.47	
	Average:	42.99	38.08	32.86	40.00	48.71	50.59	46.23	42.51	52.24	

		DIFFERENCE				
Month		**2000**	**2001**	**2002**	**2003**	**2004**
January		1.11	7.74	5.68		2.61
February		2.41	4.36	1.27		3.61
March		4.40	5.73	4.62	8.14	3.84
April		3.49	7.90	15.64	7.41	3.52
May		3.66	16.57	20.92	26.02	7.39
June		10.89	14.55	6.34	9.08	11.36
July		13.71	6.34	5.28	11.71	11.89
August		16.10	6.62	7.16	7.72	11.58
September		24.25	8.99	13.30	16.96	
October		10.02	6.08	17.06	13.55	
November		4.23	6.37	11.90	16.05	
December		-3.11	6.62	6.61	5.75	
	Average:	7.60	8.15	9.65	12.24	

* Prices represent scheduled day-ahead deliveries to the interface of or within control areas of the relevant NERC regions. These prices largely, but not exclusively, reflect all-in generation services including energy and reserves as defined by the FERC in Order 888/889. The prices would implicitly also reflect delivery costs (transmission charges and scheduling).

Florida Public Utilities Company

CAPACITY MARGINS OF U.S. REGIONS

Shown As % Reserve With Reference To Installed Capacity

NERC REGION	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
ECAR	20.4	15.4	11.4	14.5	12.5	12.5	13.3	15.6	16.9	16.4	18.0	19.5
ERCOT	20.7	27.3	22.2	22.9	21.0	15.9	14.4	17.4	18.3	19.5	21.5	21.6
FRCC	13.7	12.4	7.9	17.2	14.3	13.0	17.0	16.7	17.3	18.7	18.7	16.4
MAAC	18.7	14.7	9.3	15.4	14.7	14.2	17.1	19.6	20.5	20.8	20.1	19.8
MAIN	20.5	20.5	19.6	19.2	15.8	13.6	13.4	15.9	17.0	16.4	16.6	15.9
MAPP, U.S.	13.6	15.9	15.9	18.2	13.5	14.4	17.1	17.6	15.9	16.8	19.0	19.6
NPCC, U.S.	23.9	16.7	12.3	14.4	15.3	14.4	17.3	16.5	22.6	23.3	25.3	25.7
SERC	16.3	10.5	15.8	10.7	11.1	12.8	12.9	13.4	17.1	15.1	15.4	15.7
SPP	13.9	18.9	14.8	15.3	12.3	14.5	15.1	14.9	16.4	18.5	18.9	22.7
WECC	19.6	17.9	13.6	17.5	17.7	17.5	23.0	24.7	23.5	21.8	24.5	24.9
Contiguous U.S.	18.6	16.4	14.5	15.7	14.6	14.3	16.2	17.5	18.9	18.7	19.9	20.5

Sources: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Docket No. ______________
Witnesses: Bachman, Martin, Cutshaw and Camfield
Exhibit ______ (BMCC-6)

Florida Public Utilities Company

COMPARISON OF RETAIL ELECTRIC PRICES

SAMPLES OF ELECTRIC UTILITIES AND FLORIDA PUBLIC UTILITIES COMPANY
(Cents/kWh)

Florida Utilities	1994	1995	1996	1997	1998	1999	2000	2001	2002	Average
Residential	7.74	7.82	8.07	8.14	7.95	7.77	7.81	8.74	8.25	8.03
Commercial/Industrial	5.90	5.99	6.24	6.22	6.01	5.89	5.96	6.85	6.43	6.16

South Atlantic Utilities	1994	1995	1996	1997	1998	1999	2000	2001	2002	
Residential	7.71	7.80	7.84	7.85	7.77	7.64	7.60	7.97	7.78	7.77
Commercial/Industrial	5.49	5.55	5.54	5.48	5.40	5.33	5.32	5.58	5.38	5.45

Small Electric Companies	1994	1995	1996	1997	1998	1999	2000	2001		
Residential	8.16	7.84	7.80	8.00	7.97	7.69	7.54	7.82	7.64	7.83
Commercial/Industrial	5.29	5.37	5.34	5.35	5.27	5.22	5.30	5.68	5.32	5.35

Florida Public Utilities Company	1994	1995	1996	1997	1998	1999	2000	2001		
Residential	7.13	7.03	7.21	6.85	6.41	6.17	5.97	5.93	6.32	6.56
Commercial/Industrial	6.11	5.88	5.90	5.58	5.11	4.75	4.65	4.73	4.91	5.29

Florida Public Utilities Company

HISTORICAL VIEW OF PRIMARY FUEL PRICES

NOMINAL DOLLARS PER MMBTU

			NATURAL GAS		
Year	CRUDE OIL	COAL*	Wellhead	City Gate	Utilities
1973	0.67	0.40	0.22		0.38
1974	1.18	0.73	0.30		0.51
1975	1.32	0.90	0.44		0.77
1976	1.41	0.91	0.58		1.06
1977	1.48	0.94	0.79		1.32
1978	1.55	1.03	0.91		1.48
1979	2.18	1.24	1.18		1.81
1980	3.72	1.33	1.59		2.27
1981	5.48	1.43	1.98		2.89
1982	4.92	1.46	2.46		3.48
1983	4.52	1.41	2.59		3.58
1984	4.46	1.39	2.66	3.95	3.70
1985	4.15	1.40	2.51	3.75	3.55
1986	2.16	1.31	1.94	3.22	2.43
1987	2.66	1.28	1.67	2.87	2.32
1988	2.17	1.26	1.69	2.92	2.33
1989	2.73	1.25	1.69	3.01	2.43
1990	3.45	1.25	1.71	3.03	2.38
1991	2.85	1.25	1.64	2.90	2.18
1992	2.76	1.22	1.74	3.01	2.36
1993	2.46	1.19	2.04	3.21	2.61
1994	2.27	1.17	1.85	3.07	2.28
1995	2.52	1.16	1.55	2.78	2.02
1996	3.18	1.14	2.17	3.34	2.69
1997	2.97	1.12	2.32	3.66	2.78
1998	1.87	1.13	1.96	3.07	2.40
1999	2.68	1.09	2.19	3.10	2.62
2000	4.61	1.10	3.68	4.62	4.38
2001	3.71	1.15	4.00	5.72	4.61
2002	3.88	1.21	2.95	4.12	3.68
2003	4.75	1.49	4.88	5.85	5.54
2004	6.34	2.47	5.49	6.65	6.03

* Coal prices 2004 reflect July futures prices for August - December deliveries, and are thus overstated.

Florida Public Utilities Company

HISTORICAL VIEW OF PRIMARY FUEL PRICES

2004 DOLLARS PER MMBTU

			NATURAL GAS		
Year	CRUDE OIL	COAL	Wellhead	City Gate	Utilities
1973	2.28	1.35	0.75		1.29
1974	3.69	2.27	0.93		1.59
1975	3.77	2.56	1.25		2.19
1976	3.80	2.46	1.56		2.85
1977	3.74	2.37	2.00		3.34
1978	3.67	2.44	2.15		3.50
1979	4.76	2.71	2.58		3.95
1980	7.45	2.66	3.18		4.55
1981	10.03	2.62	3.62		5.29
1982	8.48	2.52	4.24		6.00
1983	7.50	2.35	4.30		5.94
1984	7.14	2.23	4.26	6.32	5.92
1985	6.45	2.17	3.90	5.82	5.51
1986	3.28	1.99	2.95	4.89	3.69
1987	3.93	1.89	2.47	4.24	3.43
1988	3.10	1.80	2.42	4.18	3.33
1989	3.77	1.72	2.33	4.15	3.35
1990	4.58	1.65	2.27	4.02	3.16
1991	3.66	1.60	2.10	3.72	2.79
1992	3.45	1.53	2.18	3.77	2.96
1993	3.01	1.46	2.50	3.93	3.20
1994	2.73	1.40	2.22	3.68	2.73
1995	2.96	1.37	1.82	3.27	2.37
1996	3.67	1.32	2.50	3.85	3.10
1997	3.37	1.27	2.63	4.15	3.15
1998	2.10	1.27	2.20	3.44	2.69
1999	2.97	1.20	2.42	3.43	2.90
2000	4.99	1.19	3.98	5.00	4.74
2001	3.92	1.22	4.23	6.05	4.87
2002	4.04	1.26	3.07	4.28	3.83
2003	4.85	1.52	4.98	5.97	5.66
2004	6.34	2.47	5.49	6.65	6.03