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FMPA
Florida Municipal Power Agency

Jody Lamar Finklea
Associate General Counsel

VIA HAND DELIVERY

May 14, 2004

Ms. Blanca S. Bayó, Director
Division of Commission Clerk and
Administrative Services
FLORIDA PUBLIC SERVICE COMMISSION
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

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Dear Ms. Bayó:

Re: Docket No. 020233-EI
Pre-Workshop Comments of Seminole Electric Cooperative, Inc., and Florida Municipal Power Agency Regarding GridFlorida Applicants Matrix on Market Design Issues

Enclosed please find one (1) original and fifteen (15) copies of the written comments of Seminole Electric Cooperative, Inc., and Florida Municipal Power Agency (the Comments), in anticipation of the GridFlorida Market Design Issues Workshop, May 19-21, 2004. The Comments are submitted for filing in the above referenced docket. They have also been distributed to all stakeholders via the GridFlorida E-mail Exploder List.

Please acknowledge receipt of these documents by time/date stamping the enclosed additional copy of this filing, as indicated.

Very truly yours,

Jody Lamar Finklea
Associate General Counsel

Enclosures

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Docket No. 020233-EI

Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency Pre-Workshop Comments Regarding GridFlorida Applicants Matrix on Market Design Issues

On April 29, 2004, the GridFlorida Applicants distributed a brief discussion paper and an accompanying matrix regarding market design issues to be discussed at the May 19-21, 2004 Florida Public Service Commission ("FPSC") staff workshop on market design issues. In sharp contrast to their earlier workshop presentations on pricing issues, the Applicants' market design presentation simply "identif[ies] the major issues and options associated with developing a market design structure for the unique GridFlorida footprint," (Applicants' draft Issues for May 19-21 Market Design Workshop at 5) , without indicating what positions the GridFlorida Applicants are suggesting for adoption. This approach does not seem to comport with FPSC staff's April 6, 2004, notice herein, which indicates that "[t]he Applicants will provide a draft position for each of these identified [market design] issues by April 29, 2004; other parties are to provide their responses to the Applicants' draft positions by May 13, 2004." Seminole Electric Cooperative, Inc. ("Seminole") and the Florida Municipal Power Agency ("FMPA") cannot effectively respond to positions that the Applicants have not yet put forth, but Seminole and FMPA will be prepared to discuss the issues identified by Applicants and other parties as they are developed in the workshop.

Seminole and FMPA believe that the matrix supplied by the Applicants, in addition to being non-responsive to the FPSC staff's April 6 notice, is incomplete. The purpose of this response will be to discuss the deficiencies of the Applicants' matrix (as well as to provide a supplemental matrix for use at the May 19-21 workshop). In addition, Seminole/FMPA are appending to these comments a paper by Dr. Laurence D. Kirsch, entitled "Criteria for Establishing an RTO in Florida" ("Kirsch Paper"). The Kirsch Paper addresses, among other things, the serious market power impediments in Florida to implementation in Florida of an RTO that creates and operates organized markets ("Full RTO") versus an RTO that performs all of the same functions as a Full RTO (e.g., oversees a transmission operation with centralized planning, no pancaking, and the like) *except* refrains from implementation of organized markets ("Basic RTO").

The main deficiency in the Applicants' matrix is that it omits from consideration certain threshold issues that are implicit in both Issues 1 and 2 set forth in the FPSC staff memorandum of April 6, 2004. Those issues and others are set forth below (and where appropriate reflected in the supplemental matrix submitted herewith):

- The first issue is whether the market power/market entry situation in Florida is such that an RTO with markets cannot be reasonably expected to operate in the best interests of Florida electric consumers. (See Kirsch Paper at section 3.)

- Assuming that the market power/market entry problems in Florida are such that it is reasonable to conclude that consumers would not be well served at this time by being subject to an RTO with organized markets, is Florida ready for a Day 1 RTO (Basic RTO) without organized markets? (See Kirsch Paper at section 5.)

- What are the functions that a Basic RTO should perform? What are the likely benefits of instituting a Basic RTO? What are the costs anticipated to achieve an operational Basic RTO? (Will the ICF study address these issues?) (See Kirsch Paper at section 2.2.)

- What structural changes would have to occur in order for Florida to be in position to implement a Day 2 RTO with organized markets (Full RTO) in a manner likely to yield significant net benefits to Florida consumers? (See Kirsch Paper at sections 3.2 and 3.3.)

- What are the likely benefits of instituting a Full RTO? What would be the anticipated costs to achieve an operational Full RTO? (Will the ICF study address this issue?) (See Kirsch Paper at section 2.2.)

- When will all participants have access to information showing where transmission constraints exist in the system today, where such constraints are anticipated to exist over the next decade, and what upgrades (if any) are planned to alleviate them and to ensure that the grid is sufficiently robust to support simultaneously feasible FTRs for at least all existing firm uses (plus that required for reasonably anticipated load growth)?

- What specific behavioral remedies will be required to effectively mitigate market power in organized GridFlorida markets? The Applicants use the term "cost-based" throughout – what should that term mean in the context of bid caps in an RTO with organized markets? (See Kirsch Paper at section 3.3.1.)

- The Applicants raise the issue of average versus marginal losses – what would be the cost shifts caused by a change from average to marginal losses?

Regarding the threshold market power issue, Seminole/FMPA do *not* believe that Florida is ready for an RTO with organized markets due to the extremely serious market power/market entry problems plaguing Florida. This has been made abundantly clear in prior submissions by Seminole/FMPA,[1] and is discussed in detail by their economist, Dr. Kirsch, in the attached Kirsch Paper. Specifically, Dr. Kirsch concludes (section 5):

1 *See, e.g.*, "Remarks of Tim Woodbury, September 15, 2003 Technical Conference," filed herein on September 25, 2003.

a. Florida is ready for implementation of a Basic RTO that would manage congestion using traditional cost-based methods. A Basic RTO would provide Florida with efficiency benefits arising from non-discriminatory transmission access, elimination of pancaked rates, and independent centralized planning.

b. Florida is not ready for implementation of a Full RTO that would manage congestion through bid-based LMP methods. Before a Full RTO can provide net benefits to Florida's consumers, the State's significant market power problems must be adequately addressed.

Seminole/FMPA believe that a Basic RTO (which would perform all of the non-market related functions of a Full RTO) should be effectuated with all due speed so that the obvious drawbacks of the current system (namely, pancaked rates, lack of centralized planning, and the like) can be promptly addressed. At the same time a concerted effort should be made to address the structural market power/market entry problems that render markets unworkable in the current environment.

Seminole and FMPA will be prepared to discuss these issues at the May 19-21 workshop.

CRITERIA FOR ESTABLISHING AN RTO IN FLORIDA

prepared by

Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.

prepared for

Florida Municipal Power Agency
Seminole Electric Cooperative, Inc.

May 13, 2004

TABLE OF CONTENTS

CRITERIA FOR ESTABLISHING AN RTO IN FLORIDA

Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.[1]

1. INTRODUCTION

I am a Ph.D. economist who has spent the past two decades specializing in economic analysis of the electric power industry. My particular interest has been the efficient pricing of electricity services at both the wholesale and retail levels as well as the efficient design of wholesale electricity markets. In the course of my work, I have been involved in analyses of wholesale pricing practices and wholesale market design, with a focus on power pool operations, utility cost structures, unbundled service pricing, and market power. I have published articles in the *Electricity Journal* and *Public Utilities Fortnightly* on the pricing of transmission and ancillary services in FERC-regulated Independent System Operators and Regional Transmission Organizations. I have presented oral and/or written testimony before FERC and before state regulatory commissions, including those of California and New York.

I have worked extensively with electricity unbundling issues since 1983 when, at the Pacific Gas and Electric Company, I examined the mathematics of locational pricing (known as "locational marginal pricing" or "LMP") while helping PG&E develop the nation's second retail real-time pricing program. In 1989, I wrote my first report on the mathematics of unbundling operating reserves. In 1993, I presented to the New York Power Pool a plan for the adoption of LMP in place of their then-failing split-the-savings trading system.

The foregoing history is summarized by my resume, which is presented in Attachment 1.

In short, I have been an enthusiastic proponent of power industry restructuring, unbundling, and competition. Events over the past few years, however, have made me concerned about the costs of the restructuring process and especially about major problems that have never been solved. The most infamous of these problems is market power, which I address in this paper. Other major unsolved problems are centered on transmission investment issues, including the determination of when transmission gets built, who pays for transmission, and how transmission and generation investments are coordinated to provide electricity to consumers at least cost. The benefits of competition have been substantially reduced, and perhaps even made negative in certain regions, by these restructuring costs and unsolved problems.

The purpose of this paper is to identify qualitatively the potential benefits and costs of competition in electricity, and to explain what needs to be done to improve the chances of Florida consumers enjoying net benefits from restructuring. To achieve this purpose, this paper is organized as follows. Section 2 describes the benefits and costs of wholesale electric market restructuring, first in general and then for those benefits and costs likely to be seen in Florida specifically. Section 3 discusses the market power problems that are likely to hinder competition in Florida and the possible remedies for market power problems. Section 4 describes

[1] 4610 University Avenue, Madison, WI 53705-2164. Email: LKIRSCH@LRCA.COM.

considerations relevant to managing transmission congestion in Florida. Finally, Section 5 provides a summary of findings and recommendations.

2. THE BENEFITS AND COSTS OF ELECTRICITY RESTRUCTURING

The popular discussion of electricity restructuring – and even some discussion in the power industry press – vaguely talks about the "benefits of competition" as if competition itself is a benefit. But competition is beneficial – in electricity or in any other industry – only if it brings lower-cost and/or better products to consumers.

Therefore, as Florida considers whether and how to restructure its wholesale power industry, it should not merely presume that opening some service to competition is automatically a good thing. Instead, Florida needs to examine how each element of reform is likely to affect the cost and/or quality of electric service.

To facilitate such an examination, the first part of this section discusses the generic benefits and cost of wholesale electricity market restructuring. The second part discusses the benefits and costs that Florida should anticipate experiencing.

2.1. Benefits and Costs in General

The benefits of restructuring may include the following:

A. *Lower-cost commitment and dispatch.* Restructuring may lower commitment and dispatch costs in several ways. First, the elimination of pancaked rates can create new cost-lowering opportunities for trade. Second, independently administered non-discriminatory transmission access can allow market participants to engage in cost-lowering trades that would not otherwise be possible. Third, if restructuring includes centralized commitment and dispatch, this centralization may facilitate additional cost-lowering trades.

B. *Faster adaptation of improvements in generation technologies and management.* Restructuring can give firms stronger profit incentives than they had previously, thus inducing them to find ways to reduce costs and improve generator performance.

C. *Greater consumer choice.* In theory, restructuring can encourage load-serving entities (LSEs) to provide consumers with new products, some of which create benefits by better communicating efficient wholesale price signals to consumers, and others of which provide direct conveniences to consumers.

D. *Better timing and location of generation investments.* In theory, restructuring's profit incentives may induce better timing of generation investments. If restructuring includes LMP, there could also be better incentives for efficient location of generation. If restructuring includes a regional planning process, it can facilitate both better timing and location of generation investments.

E. *Better timing and location of transmission investments.* In theory, restructuring that includes LMP could produce efficient price signals for investment in transmission. Restructuring that includes a regional planning process can also facilitate more efficient, effective, and equitable transmission investments.

F. *Less regulatory intervention.* In theory, restructuring could allow regulators to play a minimal role in generation investment and cost-recovery issues.

Having watched the evolution of the power industry over the past two decades, and having shared in many of the hopes and disappointments, my sense is that some of the foregoing benefits are real while others are mere hopes. In particular, I believe that items A ("Lower-cost commitment and dispatch") and B ("Faster adaptation of improvements in generation technologies and management") are real: we have actually seen substantial growth in the volume of cost-lowering trades; and although it is difficult to separate the technological and management improvements that are due to restructuring from those that would have occurred anyway, I have seen at least anecdotal evidence of many power firms improving their management out of fear of competition.

On the other hand, I believe that items C ("Greater consumer choice") and D ("Better timing and location of generation investments") reflect hope more than experience. Consumer participation in innovative programs has been limited. And because a variety of institutional and technical factors hamper generation investment, it is debatable whether competition or regulation lead to a better generation investment outcome. Perhaps it is still too early to judge the prospects for these two items.

Finally, I believe that Items E ("Better timing and location of transmission investments") and F ("Less regulatory intervention") might have seemed plausible once upon a time, but experience (so far) has proved them false. The only market-based transmission investments have been a handful of DC lines; and even in restructured markets where there have been clear net benefits of transmission investment, such investments have almost always been undertaken only under the umbrella of regulated cost-based recovery because the market has not responded to the need. To the extent that restructuring *does* succeed in encouraging transmission investment, it will be because of the successes of regional planning processes fostered by RTOs rather than because of free market responses to investment needs. As for lower regulatory costs, it is apparent that regulators will continue to be heavily involved in the implementation and operation of restructured markets in general and in generation investment decisions in particular.

The *costs* of restructuring, on the other hand, are more definite. They include at least the following:

A. *RTO/ISO creation and implementation.* It costs hundreds of millions of dollars to create an RTO/ISO-administered market, and it costs at least tens of millions of dollars per year to operate the RTO/ISO that runs one.[2] This stands in stark contrast to the substantially lower capital and operating costs involved in establishing and running an RTO/ISO without organized markets beyond the bilateral markets that already exist.

B. *Financial instability.* Under regulation, costs are averaged over time and space in a way that spreads risks among market participants; and cost-of-service ratemaking insulates consumers from the inevitable major shifts over time in the values of generation services. The result is that consumer prices are fairly stable under regulation. If restructuring includes a move toward market-based pricing of generation, both generators and consumers will be exposed to financial risks that they do not face under cost-of-service

[2] See the statistics in Section 2.2, Table 1.

ratemaking. The financial risks faced by generators can lead (and have led) many of them to lose money and some of them to go bankrupt, thus diminishing potential competitive benefits and increasing the cost of capital that must ultimately be recovered from consumers. The financial risks faced by consumers can lead to unstable electricity bills that harm consumers directly.

C. *Market power.* In restructured electricity markets with market-based pricing, there is the possibility that some suppliers will manipulate market prices for the purpose of increasing their profits. This is particularly problematic in load pockets, in areas experiencing generation dominance, and in areas where there are significant barriers to entry.

The foregoing benefits and costs are region-specific. In particular, the benefits and costs depend upon a host of regional factors, including fuel availability, generation characteristics and ownership, transmission infrastructure, geography, environmental limitations, and local laws.

2.2. Benefits and Costs in Florida

For Florida, the benefits and costs of restructuring will depend upon the extent of restructuring. We consider two scenarios:

- *Basic RTO.* In this scenario, the RTO would perform the same functions as in a Full RTO except that there would be no organized markets, and congestion would be managed through traditional methods that include cost-based redispatch pursuant to FERC's open access transmission tariff and transmission loading relief procedures (TLRs). The costs of redispatch would be socialized either among all market participants or by zones.
- *Full RTO.* In this scenario, the RTO would create and operate markets, and would manage congestion through bid-based LMP methods. The energy price at each location would equal the marginal as-bid cost of serving that location. Use of congested interfaces would be priced according to the differences in LMPs at resource and load locations. The lowest-valued transmission uses would be implicitly curtailed. The costs of redispatch would generally be borne by generators in relatively low-price locations and consumers in relatively high-price locations or zones. Financial transmission rights (FTRs) would partly hedge market participants against uncertain differences in the LMPs at their resource and load locations.[3]

For the Basic RTO scenario, Florida is likely to enjoy two areas of benefit. First, there is likely to be improved commitment and dispatch through greater opportunities for trade arising from

[3] In some regions of the U.S., the transition to an LMP market has been made difficult by the transmission system's inability to support the full funding of the FTRs that would cover all existing firm uses of the grid. In such cases, significant controversy has arisen as to how LSEs can continue to obtain power from their existing generation resources without exposure to significant unhedged congestion costs. FERC's White Paper promises to support the existing rights through uplift charges. Some parties are seeking (over significant opposition) to pro rate the FTRs assigned to LSEs when the grid cannot support the full funding of the FTRs that are equivalent to existing rights; but such pro ration could leave some LSEs (and their customers) unhedged against large congestion charges under the new LMP regime, even when merely using what had been long-established firm transmission rights. To avoid such problems in any transition to LMP, the ability of the grid to support, through FTRs, all existing firm uses needs to be examined, with cost-effective upgrades installed *before* market implementation is considered.

non-discriminatory transmission access and from elimination of pancaked rates. Second, there are likely to be enhanced efficiencies from the RTO's provision of independent, centralized planning that evaluates Peninsular Florida as a whole and meets the needs of all LSEs and consumers on a non-discriminatory basis.

For the Full RTO scenario, Florida is likely to enjoy the preceding benefits plus, if market power problems are adequately addressed, commitment and dispatch are likely to be incrementally more efficient. This extra efficiency would occur because of centralization of the commitment and dispatch process and possibly also because of the better profit incentives that should accompany LMP.

For the Basic RTO scenario, Florida would incur some RTO creation and operation costs. These would include costs for an operations center and for an independent tariff administration and planning staff.

For the Full RTO scenario, Florida would incur the foregoing costs, plus some other very significant costs. The costs of Full RTO creation and operation would be much higher because they would include the considerable expenses associated with implementing LMP, running markets, and monitoring markets. Table 1 shows what annual operating costs have been for existing ISOs.[4] It is particularly expensive to create RTOs/ISOs in regions, like Florida, that do not already have a tight power pool. The Full RTO scenario would also involve the costs associated with financial instability and market power, the latter of which are discussed at length in the following section.

[4] Data for startup costs are more difficult to determine because they have not necessarily been incurred at a single moment in time. Startups generally occur over a period of years. Furthermore some markets (e.g., California and New England) had startup costs associated with their original market designs, and then incurred (and will incur) further startup costs for their new market designs. We do know that the California ISO and the Midwest ISO respectively borrowed \$310 million and \$200 million around the times of their startups. The New York ISO, by contrast, seems to have borrowed only \$55 million. See California Independent System Operator, *Issuance Resolution (1998-03-Xx) Of The Board Of Governors Of The California Independent System Operator Corporation Authorizing \$310,000,000 Aggregate Principal Amount Outstanding At Any Time Of The Corporation's Commercial Paper Notes*, March 1998, http://www.caiso.com/docs/1998/12/15/1998121518l2593997.rtf; Midwest Independent Transmission System Operator, *Application of the Midwest Independent Transmission System Operator Under Section 204 of the Federal Power Act to Issue Securities*, April 17, 2000, http://www.midwestiso.org/documents/long_term_financing_filing.pdf; and New York ISO, *Monthly Report*, August 2000, p. 12, www.nyiso.com/services/documents/mthly-reports/pdf/august_monthly_report.pdf.

Table 1
Costs of Creating and Operating ISOs[5]
(millions of dollars)

ISO	Annual Operating Costs	Previous Tight Pool?
California ISO	209.3	no
ISO New England	112.2	yes
Midwest ISO	193.0	no
New York ISO	118.2	yes
PJM	187.0	yes

In short, the potential benefits of the Full RTO are greater than the benefits of the Basic RTO, but the costs are also much greater. In deciding whether to pause or stop at the Basic RTO or move on to the Full RTO, a key question is whether the potential extra benefits are sufficient to more than cover the extra costs. A large part of the answer to this question hinges on the issue of market power.

3. MARKET POWER

In considering whether and how electricity markets in Florida should be restructured, we need to first consider the extent to which these markets are likely to be competitive. When markets are competitive, prices approximate the market's marginal cost of supply, which is the cost of the next unit of production (including legitimate and verifiable opportunity costs). When markets are not competitive, one or more suppliers can use their market power to raise prices significantly above the market's marginal costs. These elevated market prices cause losses to consumers in the forms of higher bills and reduced consumption.

To consider market power issues in Florida, this section is divided into three parts. The first part explains the factors that determine the geographic scope of electricity markets. Identifying geographic markets is necessary to identifying the firms that can compete to serve consumers in those markets. The second part examines evidence concerning the extent of actual and potential electricity competition in Florida. The third part describes means by which market power may be addressed.

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[5] For operating costs, which include fixed-cost amortization, sources are: California ISO, *Monthly Financial Report, December 2003*, January 22, 2004, p. 3, Operating Expenses plus Interest and Other Expenses, http://www.caiso.com/docs/09003a6080/2c/25/09003a60802c25d1.pdf; ISO New England, *2003 Budget*, presentation, undated, p. 7, www.iso-ne.com/about_the_iso/Annual_Reports/2003_Budget.ppt; Midwest Independent Transmission System Operator, *2004 Budget*, Advisory Committee Presentation, p. 3, http://www.midwestiso.org/documents/financial_docs/Advisory%20Comm%20Presentation%20on%202004%20Budget%20(12-10-03)(REVISED)%20%5BRead-Only%5D.pdf; New York ISO, *2004 Budget Overview*, Budget, Standards & Performance Subcommittee, September 26, 2003, p. 6; PJM, *Approved 2003 Budget and Service Category Rates*, posted March 3, 2004, p. 4, http://www.pjm.com/markets/ancillary/downloads/2003-budget.pdf.

3.1. Determining the Geographic Scope of Electricity Markets

For any good or service, the geographic scopes of markets are determined by physical, institutional, and cost barriers. Physical barriers can include mountains and oceans that make trade difficult or impossible. Institutional barriers can include industry practices or laws that constrain allowable transactions. Cost barriers can include factors related to distance that limit the profitability of trades. The distinction between physical, institutional, and cost barriers is not always clearcut.

For electricity, the geographic scopes of markets are determined by transmission constraints, system operations practices, and transmission pricing. Transmission constraints physically limit the trades in energy and operating reserves that can occur between entities on opposite sides of the constraints. Control area boundaries can limit the trades in regulation service (frequency control) that can occur between entities on either side of the boundaries.[6] Transmission pricing (e.g., pancaked rates) can influence trading patterns by creating artificial cost advantages for some trades over other trades.

In considering a GridFlorida electricity market, Peninsular Florida is the relevant geographic scope of potential energy and operating reserve markets. Transmission constraints over the limited ties between Florida and Georgia often separate Peninsular Florida's energy and operating reserve markets from those of the rest of the nation. With the establishment of an RTO, the elimination of rate pancaking within GridFlorida will remove this significant artificial cost barrier to trade *within* Peninsular Florida (though it will not affect Florida's electrical isolation from the rest of the nation). Furthermore, Florida's unique reserve-sharing arrangements indicate that Peninsular Florida is a single market, as it meets some of the NERC control area requirements on a peninsular basis rather than on an individual utility basis.

On the other hand, transmission constraints within Florida may sometimes divide Peninsular Florida's energy market into geographic submarkets. In some cases, these submarkets can be smaller than control areas. This is a matter that requires FPSC investigation before moving to serious consideration of reliance on markets in Florida.

Regarding the geographic scope of regulation service, one of the key purposes of control areas is to maintain power balance within control area boundaries, and regulation service is an important means of achieving this purpose. Therefore, control areas are generally the relevant starting points for determining the geographic scopes of potential regulation service markets. Nonetheless, through long-term dynamic scheduling arrangements, some Florida control areas provide regulation service to utilities outside of their control areas.

3.2. Assessing Competition in Florida

Competition in Florida depends upon present patterns of generation ownership and upon barriers to new competition.

[6] Advanced technologies like dynamic scheduling can partly overcome this particular barrier.

3.2.1. Concentration of Generation Ownership in Florida

Table 2 presents recent statistics on the ownership of Florida's generation. The largest firm owns nearly half of Florida's installed capacity, while the largest two firms together own over two-thirds of Florida's capacity. This is such a high concentration of generation ownership that there is no question that Florida's largest utilities have significant market power. Indeed, the Herfindahl-Hirschman Index (HHI), which is a conventional measure of industry concentration, is 2,753 for Florida's power industry, well above the 1,800 threshold that the U.S. government deems indicates high concentration.[7] Under antitrust economics and law, such high market concentration is regarded as correlated with a higher risk of collusive exercise of market power by two or more firms.

Table 2
Installed Capacity in Florida, Winter 2003/2004[8]

Company	Installed Capacity	Capacity Share	Share Squared
Florida Power and Light	18,749	45.9%	2,106
Progress Energy (FPC)	8,596	21.0%	443
Tampa Electric Company	3,862	9.5%	89
Jacksonville Electric	3,477	8.5%	72
Seminole Electric Cooperative	1,917	4.7%	22
Orlando	1,072	2.6%	7
Lakeland	1,039	2.5%	6
City of Tallahassee	699	1.7%	3
Florida Municipal Power Agency	652	1.6%	3
Gainesville Regional Utilities	629	1.5%	2
New Smyrna Beach	70	0.2%	0
City of Homestead	53	0.1%	0
Reedy Creek Improvement District	44	0.1%	0
Totals	40,859	100.0%	2,753

Florida's concentration statistics compare poorly with those of California just prior to its power crisis of 2000-2001. Table 3 shows the ownership statistics for California at that time. The largest firm owned about a seventh of the California's generation, while the two largest

[7] The HHI is calculated as the sum of the squares of ownership shares. In Table 2, for example, Progress Energy's 21.0% capacity share is squared, and the in the rightmost column the result (443 ≈ 21 * 21) is added to the squares of the other companies' shares. Thresholds are defined by United States Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines, April 2, 1992, *reprinted in* 4 Trade Reg. Rep. (CCH) ¶ 13,104.

[8] From R.A. Sinclair, Affidavit, Docket Nos. ER03-1389-000, ER98-651-000, ER01-2301-000, ER01-2928-000, ER01-1418-000, ER02-1238-000, ER01-1419-000, ER01-1310-000, and ER03-398-000, October 16, 2003, Exhibit RAS-6. The figures exclude a small quantity of uncontracted, independently owned merchant capacity.

generation owners together owned barely a quarter of the state's capacity. These statistics are far below the present ownership shares of Florida's utilities. As for the HHI in California, that was a mere 653.

Table 3
Installed Capacity in California, late 1999

Company	Installed Capacity	Capacity Share	Share Squared
Pacific Gas & Electric Co	6,848	14.6%	213
AES Corp	4,852	10.3%	107
HIPG	4,019	8.6%	73
Southern California Edison Co	3,412	7.3%	53
Southern Energy	3,166	6.7%	45
NRG/Dynegy	2,930	6.2%	39
Duke	2,881	6.1%	38
Bureau of Reclamation	1,792	3.8%	15
California Dept. of Water Resources	1,641	3.5%	12
FPL Energy	1,354	2.9%	8
Northern California Power Agency	875	1.9%	3
S.D. Port District (Duke)	714	1.5%	2
200+ other entities	12,482	26.6%	8
Totals	46,964	100.0%	653

In addition to its more widely dispersed generation ownership, California had one other advantage over Florida in terms of competitive access: while Florida is able to import power equal to only about 8% of its peak load, California could (and can) import power equal to about 25% of its peak load. Certainly in terms of numbers of competitors, dispersion of generation ownership, and access to supplies, California just prior to its crisis had a much more favorable situation than Florida has today.

The Florida electricity market has one other characteristic that may accentuate market power concerns, and that is that winter and summer peak demands are forecast to grow at the relatively rapid rate of 2.6% per year over the next five years. If there are significant entry barriers, such rapid demand growth can exacerbate market power problems by increasing the pivotal importance of some suppliers.

A further consideration is that in virtually all electricity markets, the ownership of resources that can provide operating reserves and regulation service is more concentrated than the ownership of resources that provide energy. In other words, market power problems in these ancillary services tend to be more difficult than for energy service. The physical reason is that only a fraction of generation capacity can provide ancillary services while all generation capacity can produce energy; and that ancillary service capability tends to be in fewer hands than the energy capability. On the other hand, because the dollar value of ancillary services is so much lower than that of energy service, the cost to consumers of market power in ancillary services will generally be much lower than that of energy service.

3.2.2. Barriers to New Competition in Florida

For Florida, there may be three relevant barriers to new competition that give incumbent firms advantages over potential new entrants. First, I am advised by counsel that Florida law has the effect of inhibiting new merchant generation. New steam plants above a certain size (75 MW) may only be built if a large percentage of the output is already committed to serving a Florida LSE's native load, which means that such plants do not get built without the cooperation of the incumbent LSEs. Such a rule, if applied to commerce in general, would stifle not only competition but also innovation. Imagine what the world would be like if one could not build an apartment building, or open a grocery store, or start manufacturing personal computers, unless customers were committed in advance to take most of the resulting service or output.

Second, the transmission connections between Florida and the rest of the world are limited to only about 8% of Florida's current peak load. With load growth, this small percentage will decline over time. Furthermore, a large share of the import capability is pre-committed to a few big Florida utilities. This limits competition from outside of Florida. Because there may also be transmission constraints within Florida, such constraints may also serve as barriers to trade and competition within the state.

Third, there may be particular inputs – like fuel supplies and generation site locations – to which incumbents have access that new entrants cannot reasonably match. If this were true, this access to inputs could also serve as a barrier to competition. I have not yet examined the extent to which such input-related barriers are material in Florida but am advised by FMPA and Seminole that they may be significant.

3.3. Addressing Market Power

Market power can be addressed through structural and/or behavioral remedies. Structural remedies address the ownership patterns and entry barriers that are the root causes of market power. Behavioral remedies address the behavior of firms that have market power that has not been alleviated by structural remedies.

3.3.1. Structural Remedies

Structural remedies seek to increase competition by reducing entry barriers and increasing the number of suppliers. In Florida, these remedies might include:

- *Reduction of legal barriers to new entry.* Such barriers include strong legal impediments to new merchant generation.
- *Construction of new transmission capacity.* Additional transmission between Florida and Georgia would allow additional generation outside of Florida to serve Florida load. If

transmission were constrained within Florida, then additional in-state transmission would reduce barriers to competition within the state.

- *Generation divestiture.* Firms with the largest ownership shares of generation capacity might be required to sell part of their capacity to non-affiliated firms.
- *Division of large generation firms.* Firms with the largest ownership shares of generation capacity might be required to split into multiple independent firms with relatively small market shares.

Ideally, all of these structural remedies would be addressed before any consideration is given to moving to a Full RTO, since market power is anathema to functioning competitive markets (and thus to achieving consumer benefits). At a minimum, I would make two recommendations. First, to permit merchant construction of generation, Florida should consider modifying the State law that inhibits new merchant generation investment. Any such amendment should give due weight to any clear public benefits, such as environmental protection, of this law and its accompanying regulations. Second, complete information should be made available regarding transmission constraints within and into the State, along with the costs to relieve them. Cost-effective upgrades should be undertaken before serious consideration is given to moving to a Full RTO, thus ensuring that no set of Florida's customers would be subjected to disproportionate congestion charges under an LMP market.

The merits of the other structural remedies depend upon physical and institutional facts. For example, for generation divestiture and the splitting of firms, these remedies raise a host of legal, regulatory, and tax issues. These issues are beyond the scope of this paper.

3.3.2. Behavioral Remedies

Behavioral remedies are not substitutes for structural remedies. While structural remedies address the disease, behavioral remedies merely treat the symptoms. Nonetheless, when structural remedies are unavailable or insufficient, it is necessary to resort to behavioral remedies *if* market-based pricing is adopted.

The purpose of behavioral remedies is to induce healthy behavior in an inherently unhealthy situation. Specifically, behavioral remedies are designed to induce firms that have market power to behave like "price-taking" firms that do *not* have market power. The guiding principle is that, in any industry, price-taking firms will produce all of the output that they can that has a marginal cost (including legitimate and verifiable opportunity costs)[9] less than the market price. Because a firm runs a positive gross profit when its marginal costs are less than the market price, it would have no legitimate reason to withhold its available capacity from the market.

As applied to a restructured power market in Florida, behavioral remedies would therefore require firms with market power – that is, at least the two largest generation firms – to provide all of the output that they can that has a marginal cost less than the market price. As a practical

[9] For electricity generators, "marginal costs" include not only the direct fuel and labor costs of producing electricity, but can also include the legitimate and verifiable profits that the generator might make in other markets. The other markets include those for other products (i.e., ancillary services) and markets for other time periods. This time dimension is important for emissions-restricted and energy-limited generators, like hydro or emissions-restricted units, that can sell more power later if they sell less power now.

matter, these remedies are directed toward preventing both *physical withholding* and *economic withholding* of generation capacity.

To prevent physical withholding, firms with market power would be subject to a requirement that they offer for sale in short-term markets (e.g., day-ahead or same-day markets) all of their available generation capacity. To prevent disguised withholding, scheduled maintenance outages would be cleared in advance with the RTO, which will seek to accept such requests consistent with scheduling maintenance at those times when generation services have their lowest values. The RTO (or market monitor) would be responsible for auditing forced outages to confirm that they are genuine.

To prevent economic withholding, firms with market power would be subject to a requirement that they offer their available capacity at prices near the marginal costs of their respective generating units (e.g., no more than 110% of marginal costs). Generators – including those owned by firms with market power – would all receive the market-clearing price for their winning bids. Because the market-clearing price would equal the highest winning bid, all winning generators would recover their variable costs, and most winning generators would also recover some fixed costs or profit. The RTO (or market monitor) would be responsible for confirming marginal cost estimates, which would generally be easy for fossil and nuclear plants, through more difficult for emissions-restricted and energy-limited generators. Allowing bids slightly above estimated marginal costs would allow for estimation errors.

The foregoing behavioral remedies are needed only if prices are market-based (as under the Full RTO) rather than entirely cost-based (as under Basic RTO) for those entities capable of exercising market power.

4. MANAGING TRANSMISSION CONGESTION

In theory, LMP provides the most efficient way to manage transmission congestion: it encourages trades and system operation that minimize the costs of redispatch. In practice, however, the benefits of LMP are substantially reduced (or even eliminated) by two key factors. First, the exercise of market power in generation can make transmission prices inefficient because generator bids set the prices at each location, and the prices of transmission service equal the differences among locational prices. Market power can thereby undermine or eliminate the efficiency of LMP-based congestion management. Second, there are substantial costs, for both the RTO and market participants, of creating, operating, and using the information systems (e.g., computer, communications) that are required to implement LMP.

Therefore, as I suggested in Section 2.2, a two-phase approach to managing transmission congestion may be warranted:

- In Phase 1, the Basic RTO would manage congestion through traditional methods of cost-based redispatch and TLRs.
- In Phase 2, the Full RTO would manage congestion through bid-based LMP methods (following implementation of the appropriate structural and behavioral market power remedies noted above in Section 3.3).

The advantages of the two-phase approach are that the Basic RTO can be implemented promptly and at low cost, and it defers to the future the decision to undertake the costly information infrastructure development and market power mitigation that is required to implement LMP. There should not be any expectation that the Full RTO would follow the Basic RTO at a pre-determined time unrelated to structural changes that make it realistic to have competitive markets in GridFlorida. Instead, the Full RTO should be implemented only after a market power mitigation plan assures either that the market is structurally competitive or that monopolistic behavior can be controlled. The question that ultimately governs the decision to proceed to the Full RTO should be whether LMP's benefits (from lower-cost commitment and dispatch costs) are likely to exceed its implementation costs, including those of market monitoring.

5. SUMMARY OF FINDINGS AND RECOMMENDATIONS

My overall findings and recommendations are as follows:

a. Florida is ready for implementation of a Basic RTO that would manage congestion using traditional cost-based methods. A Basic RTO would provide Florida with efficiency benefits arising from non-discriminatory transmission access, elimination of pancaked rates, and independent centralized planning.

b. Florida is not ready for implementation of a Full RTO that would manage congestion through bid-based LMP methods. Before a Full RTO can provide net benefits to Florida's consumers, the State's significant market power problems must be adequately addressed.

With respect to market power in a GridFlorida RTO:

c. Peninsular Florida is the relevant geographic scope of the energy and operating reserve markets.

d. Because transmission constraints within Florida may sometimes divide the energy markets into geographic submarkets, the FPSC should initiate an investigation to identify prevalent transmission constraints and load pockets in Florida.

e. The very high concentration of generation ownership in Florida creates a strong presumption that Florida's largest utilities have market power.

f. Market power problems in ancillary services tend to be more likely than in energy service, though they are probably less costly.

g. Florida should consider modifying those laws and regulations that inhibit or prohibit entry by new generation firms, and should also consider the other structural issues noted in this paper.

ATTACHMENT 1.
RESUME OF LAURENCE D. KIRSCH

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Academic Background

Ph.D., University of Wisconsin, Madison, 1982, Economics
M.S., University of Wisconsin, Madison, 1979, Economics
A.B., University of California, Berkeley, 1972, Economics

Positions

Senior Consultant, Laurits R. Christensen Associates, Inc., 1985-present
Consultant, Pacific Gas and Electric Company, San Francisco, 1982-1985
Research Assistant, Madison Consulting Group, Madison, 1981
Teaching Assistant, University of Wisconsin-Madison, 1978-1980
Staff Accountant, Clarence Rainess & Company, CPAs, Beverly Hills, CA, 1973-1974

Professional Experience

I specialize in economic analysis for the electric utility industry, including studies of bulk power markets, power pool operations, electric power system cost structures, and reliability costs. I have expertise in the pricing and operating practices of U.S. independent system operators (ISOs) and has provided comments and testimony to the Federal Energy Regulatory Commission (FERC) as well as to state commissions. I have developed and applied methods for estimating the real-time marginal energy and reserve (capacity) costs of both generation and transmission; have developed methods for costing and pricing unbundled ancillary services; have also evaluated the potential for market power in generation service markets, including the interaction of market power with transmission congestion; have participated in the development and implementation of pricing policies for independent power producers; have evaluated the merits of various schemes for auctioning wholesale power; and have assessed a wide variety of utility pricing practices.

Electricity Projects

Supply Margin Assessment and Other Market Power Metrics

Evaluation of the Net Benefits of Wisconsin's Participation in the Day Two Market of the Midwest Independent Transmission System Operator (MISO)

Major Issues Affecting Korea's Potential Separation of KEPCO's Distribution and Marketing Functions

Measuring the Performance of Regional Transmission Groups

Economics Of Operating Reserve Markets

Hedging Long-Term Transmission Price Risks Associated with Generation Investments

The Fundamentals Of Locational Marginal Pricing (LMP): Examples Of Pricing Outcomes On The PJM System

A Critique of "Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region"

Calculating Marginal Costs

Seminar on Power Industry Restructuring in the United States

Cost-Benefit Analysis of RTO Options

Evaluation of the Midwest Independent Transmission System Operator's Market Mitigation Procedures

Marginal Cost Estimation and Rate Design Policies

Survey of Literature on and Practices for Pricing Reactive Power

Commentary on FERC's Standard Market Design

Analysis of the California Independent System Operator's Grid Management Charge

Survey of Impacts and Consequences of Locational Marginal Pricing for Hydro Generation

Weather Normalization of Loads and Revenue Requirements

Opportunities for Retail Participation in Ancillary Services Markets

The Effect of Locational Prices on Retail Pricing Options

Transmission Congestion Analysis

Commentary on the Redispatch Procedures of the Midwest Independent System Operator

Curtailable Service and Self-Generation Riders

Encouraging Demand Participation in Texas' Power Markets

Seminar on Wholesale Power Markets and Prices

The Market Power Impacts of a Generation Plant Divestiture

Design of Standby, Buyback, and Interruptible Rates

Congestion Charges in the Peruvian Power System

Development of a Purchase Power Agreement Between Generation and Distribution Firms

Seminar on U.S. Power Markets for an Asian Delegation

Analysis of the Readiness for Competition of the Retail Electricity Market in Arkansas

Analysis of an Independent System Operator's Grid Management Charge

Investigation of the Benefits of Expanded Power System Metering

Quantifying the Economic Value of Ancillary Services

Development of Competitive Retail Electricity Products

New Strategies for Electricity Product Development and Wholesale Pricing

Consumer Benefits of Integrating the Generation and Transmission Assets of Municipal Utilities and Investor-Owned Utilities

Rate Structure Optimization

A New Strategic Direction In Retail Electricity Product Development and Pricing

Market Power Study of PG&E's Proposed Divestiture Of Hydroelectric Assets

Electric Cost-of-Service and Rate Design Study

Redesigning Distribution Tariffs for Restructured Electric Power Markets

Managing Transmission Risk

Comprehensive Review and Revision of Electric Rates

Shaping of Electric Energy Tariff Policy

Software for Developing Profitable Retail Product Mixes

Software for Reserve Costing and Generation Unit Scheduling

Dynamic Pricing and the Future of Distributed Generation

Development of Market-Based Pricing Products

Pricing Issues in California's Restructured Electricity Market

Survey of Unbundled Electric Power Services

Costing and Pricing Ancillary Services

Developing New Electricity Products in a Restructured Electricity Market

Retail Pricing of Electric Power in a Competitive Market Environment

Pricing Risk

Review of Draft Ancillary Service Tariffs

The Pricing of Unbundled Electric Power Services

Ancillary Services and the Organization of Electric Power Markets

Pricing Retail Electricity Financial Services

Including Marginal Reliability Costs In Real-Time Prices
Real-Time Pricing Program Development
Costing and Pricing Transmission and Distribution Services
Market Restructuring for Retail Access
Regulatory Reform in Response to Emerging Competition
Retail Market Management and Service Design
Directions for Reactive Power Price Reform
Transmission Pricing Policy
Retail Market Management and Service Design
Transmission Pricing Strategies
Real-Time Pricing Implementation Study
Managing Electric Power Generation in a Competitive Market Environment
A Plan for Reforming the Price Structure of the New York Power Pool
Design, Implementation, and Evaluation of Real-Time Pricing
Real-Time Pricing Assessment Study
Forecasting and Measuring Hourly Marginal Costs of Electricity
The Use of Rate Design to Achieve DSM Goals
Economic Impacts of Electricity Cost Shocks
Design and Analysis of a Real-Time Pricing Program
Inclusion of Transmission Reliability Costs in Real-Time Pricing Decisions
Commercial and Industrial Market Management
Development of an External Cost Indexing Incentive Plan
Forward and Options Contracts for Electric Power
Comparative Assessment of Alternative Regulatory Reform Proposals
Dynamic Pricing of Decentralized Power Systems
Design of a Voluntary Time-of-Use Rate for Residential Customers
Design and Testing of Real-Time Pricing Structures for Supplemental Electric Service
Evaluation of Proposed Nuclear Performance Incentive Plans
A Field Test of Priority Service Pricing
Program Design and Implementation for Voluntary Interruptible Service
Design of Retail Electricity Rates for Efficiency and Profitability
Survey of Recent Developments in U.S. Curtailable Power Service Programs
Cost-Benefit Analysis of Seasonal Time-of-Use Peak-Activated and Interruptible Rates

Estimation of the Load Relief Provided by an Interruptible Service Program

Efficient Pricing of Transmission Services

Analysis of the Feasibility of Real-Time Pricing in the State of Maryland

Costs and Benefits of Alternative Wholesale Electricity Supply Strategies

Analysis of Household Load Response to Voluntary Time-of-Use Rates

Design of an Experimental Real-Time Pricing Program

The Interaction of Time-of-Use Rates and Energy-Using Technologies: The Case of Residential Heat-Pumps

Real-Time Pricing of Power Purchases from Cogenerators and Small Power Producers

Marginal Shortage Costs and Avoided Cost Payments to Qualifying Facilities

Other Projects

Price Cap Design and X Factor Estimation for Peruvian Telecommunications Regulation

Review of Pharmaceutical Economics

Commentary on FERC's Gas Rate Design Mega-NOPR

Evaluation of the Price Escalation Clauses of a Long-Term Coal Supply Contract

Bell Operating Companies' Marginal Operating Costs for Interstate Switched Access and Private Line: An Econometric Model

Oil Inventory Economics

The Marginal Cost of Gas Service

The Economic Theory of Enhanced Natural Gas Service to the Industrial Sector

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		SUPPLEMENTAL MATRIX OF SEMINOLE AND FMPA	
Issue 1: Market Design Issues	**Sub-Issues/ Options**	**Description**	**Comments**
Whether the market power/market entry situation in Florida is such that an RTO with markets cannot be reasonably expected to operate in the best interests of Florida electric consumers.		Organized markets require ample buyers and sellers unimpeded by market power/market entry problems in order to produce competitive outcomes that benefit consumers.	Characteristics such as generation dominance by a few utilities, lack of interface capability to other states (and possibly within the state), and legislation effectively precluding new merchant plants present arguably insuperable barriers to the effective functioning of competitive markets.
Assuming that the market power/market entry problems in Florida are such that it is reasonable to conclude that consumers would not be well served at this time by being subject to an RTO with organized markets, is Florida ready for a Day 1 (Basic) RTO without organized markets?		The issue here is whether there are any reasons why a Basic RTO (i.e., one without organized markets) should not be implemented in Florida pending satisfactory resolution of the market power/market entry problems.	The ICF study will apparently look at the costs/benefits of a Basic RTO (change case 1).

What are the functions that a Basic RTO should perform?		The functions of a Basic RTO would seem to include all functions of a Full RTO except those associated with establishing and operating organized day ahead and real time markets.	Seminole/FMPA are not aware that any stakeholders oppose regional planning, elimination of pancaking, reliance on an RTO OATT, etc.
What are the likely benefits of instituting a Full RTO? What would be the anticipated costs to achieve an operational Full RTO?		The ICF study is supposed to address these issues but it can only do so hypothetically due to the market power/market entry problems that would beset the markets in the current environment (and which are likely not picked up by the ICF approach).	The costs of implementing RTO markets are substantial, and given the severity of market power concerns within GridFlorida, it is not at all apparent that the assumed efficiencies and cost savings from centralized dispatch will be achieved.
When will all participants have access to information showing where transmission constraints exist in the system today, where such constraints are anticipated to exist over the next decade, and what upgrades (if any) are planned to alleviate them and to ensure that the grid is sufficiently robust to support simultaneously feasible FTRs for at least all existing firm uses (plus that required for reasonably		Congestion charges are obviously a major concern of all load serving entities, and thus it is imperative for all participants to have a sense as to where congestion is likely to occur and what steps will be taken to avoid such congestion. Only with this information can the impact of LMP be understood.	

anticipated load growth)?			
Losses	The Applicants raise the issue of average versus marginal losses – what would be the cost shifts caused by a change from average to marginal losses?	Cost shifts have been a major concern in other areas where changes from historical practices have been discussed; this area is no exception.	
Issue 2: Market Monitoring and Market Power Mitigation	**Sub-Issues/ Options**	**Description**	**Comments**
What specific behavioral remedies will be required to effectively mitigate market power in organized GridFlorida markets?		Applicants' matrix covers this important issue in a confusing manner, divided among Methods of Monitoring and Mitigation Measures.	To be consistent with the theory supporting single market clearing price markets, mitigated bids should be restricted to marginal costs (including legitimate and verifiable opportunity costs) plus 10%
The Applicants use the term "cost-based" throughout – what should that term mean in the context of bid caps in a Full RTO with organized markets?		Typically in competitive markets, the notion is that bidders are "price takers" and thus have an incentive to bid marginal costs (since if the market clearing price exceeds the bid, the bidder recovers its variable costs plus makes a profit).	Including fixed costs in mitigated bids distorts the markets and is contrary to the theory supporting single market clearing price markets.