BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Determination of Need for an Electrical Power Plant in Okeechobee County by Okeechobee Generating Company, L.L.C.	)	DOCKET NO. 991462-EU FILED: MARCH 3, 2000

ORIGINAL

REBUTTAL TESTIMONY

OF

GERARD J. KORDECKI

ON BEHALF OF

OKEECHOBEE GENERATING COMPANY, L.L.C.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR DETERMINATION OF NEED FOR THE OKEECHOBEE GENERATING PROJECT, FPSC DOCKET NO. 991462-EU

REBUTTAL TESTIMONY OF GERARD J. KORDECKI

Q: **Please state your name, address and occupation.**

A: My name is Gerard J. Kordecki. My business address is 10301 Orange Grove Drive, Tampa, Florida 33618. I am self-employed as an energy and regulatory consultant.

Q: **Have you previously filed testimony in this docket?**

A: Yes. I filed direct testimony on October 25, 1999 in support of the need application of Okeechobee Generating Company, L.L.C. ("OGC") for the Okeechobee Generating Project ("Okeechobee Project" or "Project").

Q: **What is the purpose of your rebuttal testimony?**

A: My testimony rebuts the testimonies of Florida Power & Light's ("FPL") witnesses Samuel S. Waters and John H. Landon on the following matters: (1) their conclusions concerning the appropriate information and evaluation methodologies necessary to evaluate the Project; (2) their contentions that the plant will be sub-optimal in reducing Florida ratepayers' electric costs; (3) Mr. Waters' belief that the Project should not be included in calculating the reserve margin for Peninsular Florida; (4) Dr. Landon's statements concerning wholesale competition, market concentration and market power; and (5) various statements by both witnesses in which they improperly characterized my direct testimony.

Q: **Mr. Kordecki, please describe how the FPL witnesses would have the Florida Public Service Commission ("Commission") evaluate the Okeechobee Generating Project.**

A: Both witnesses believe the Commission should require OGC to furnish the same data, analysis of alternatives, conservation mitigation, risk analyses, and optimal reserve margin studies that the Commission would or should require of the incumbent retail-serving utilities. In fact, it would appear that FPL proposes that this plant should be evaluated against FPL's or another retail-serving utility's building the same plant to determine the comparative revenue requirement effects on FPL and the comparative impacts on wholesale prices in the regulated Florida market.

Q: **Why isn't the approach suggested by FPL's witnesses reasonable?**

A: If FPL or other retail-serving entities were evaluating mutually exclusive alternatives to reduce their native load customers' fuel and purchased power costs, this process would seem proper. This is the type of evaluation that FPL and the other investor-owned utilities ("IOUs") in Florida typically use to evaluate alternatives once they have identified a capacity or reliability need for additional generation resources, and this methodology is appropriate for the IOUs because their analyses are conducted to choose between mutually exclusive alternatives. For example, once FPL identifies a need for an additional 1,000 MW of capacity, that's basically all it will add to its system; the choice is whether to add 1,000 MW of combined cycle capacity, 1,000 MW of coal capacity, 1,000 MW of combustion turbines, 1,000 MW of generation using some other technology, or some combination of technologies to produce approximately the 1,000 MW of needed capacity. I am sure that this is the type of evaluation that FPL used to determine the need for its current repowering projects (at its Ft. Myers and Sanford plants) even though these projects did not require need hearings to determine if other alternatives were more cost-effective. The significant difference between FPL's fuel displacement benefit analyses for its repowering projects and the Okeechobee Project is that the costs and benefits of repowering are internalized to FPL whereas this merchant plant will be selling on a Peninsula-wide basis.

Moreover, the decision for the Commission in this docket is not a mutually exclusive choice of approving the Okeechobee Generating Project at the expense of rejecting any other proposed power plant. Because no utility can be required to buy from the Project, purchases will only be made when they are cost-effective to the purchasing utility. This is true in the short term for as-available and other short-term (e.g., hour-ahead, day-ahead, or week-ahead firm or non-firm energy) purchases. It is also true for potential long-term purchases. In fact, the Okeechobee Project will only displace a plant that might be built by a retail-serving utility if the particular utility were to contract to buy firm capacity and energy from the Project instead of building its own plant, and this will only happen when the capacity and energy purchase is cost-effective to the purchasing utility--otherwise, the utility would build its own unit. Thus, mutual exclusivity--upon which Dr. Landon's whole argument depends--only applies when the utility determines that purchasing from the Project is cost-effective as compared to building its own unit, and accordingly, both Dr. Landon's analytical framework and his analysis are inappropriate and inapplicable to the decision facing the Commission in this case.

Q: **What does Mr. Waters have to say about the Commission's**

application of a statewide approach to evaluating need for a proposed power plant, such as the Commission used in the recent Duke New Smyrna need determination case?

A: Mr. Waters argues that the statewide approach won't work for the individual utility. In the following passage, Mr. Waters attempts to describe the difficulty of determining the "most" cost-effective option when applied to Peninsular Florida:

> When all these factors are combined into Peninsular Florida, there can be a mismatch between what is the most cost-effective option for Peninsular Florida's utilities in the aggregate and what is the most cost-effective option for the specific utility with the need. It was this repeated mismatch that led the Commission to abandon using a statewide avoided unit for cogeneration pricing and to quit using APH findings as a surrogate in need determination proceedings.

(Direct testimony of Samuel S. Waters at 14.)

Q: Is this an appropriate critique to the application of a statewide (or Peninsula-wide) approach to evaluating need for a merchant power plant?

A: No, although there are some problems, in certain contexts, with statewide planning. Though Mr. Waters' quote is specific to cogeneration pricing, it does reflect the problems with statewide planning. I agree with Mr. Waters that the Commission adopted individual utility-specific need criteria to be applied in determinations of need for a utility in meeting its load growth or its economic needs. However, I strongly disagree if his statement is meant to be interpreted that statewide cost-effective planning cannot be done. The most significant problems are the allocations of need (or capacity), especially in the context where a qualifying cogeneration facility can force utilities to purchase its capacity and energy, and which utility or utilities are going to pay for the resource.

However, these problems are not present in evaluating the need for a merchant power plant such as the Okeechobee Generating Project. The statewide (or Peninsula-wide) approach presented by OGC, which is effectively the same as the approach used by the Commission in the Duke New Smyrna case, helps solve the problems described by Mr. Waters--the alleged mismatch of needs, costs, existing system resource configuration, and so forth. OGC does so by assuming the construction, financial, market and operational risks associated with developing, constructing, and operating the power plant--the Project will not be in any utility's rate base, nor will it have any ability to force any captive utility customers to either pay for the plant or even to buy the plant's output. The Project will sell into the Peninsular Florida wholesale market to any willing purchasers. The purchasing utilities or entities are expected to act rationally and purchase only when their incremental costs are higher than the prices being quoted by OGC. Based on my experience in the Florida electric industry, and with the Commission's regulation, this is consistent with the Commission's expectations as to how retail-serving utilities will (and should) behave in attempting to provide service to their customers at lowest cost.

The Project becomes the most cost-effective solution to economic fuel displacement because it will operate on a Peninsula-wide basis without requiring a statewide allocation process, which Mr. Waters describes as being unmanageable. In contrast to the allocation problem posed by Qualifying Facilities ("QFs"), no utility has to buy the Project's output; the "allocation" of the Project's output will be the result of an ongoing series of economic transactions that occur only when cost-effective to the purchasing utilities.

The Okeechobee Project would not change the requirements for adequate installed and operating reserves for the load-serving utilities. Their retail service obligations remain the same. Each utility would continue to develop and pursue its least-cost plan as it has done in the past. The Project would simply become another economic resource.

Q: What, if anything, do FPL's witnesses have to say about the information required to evaluate the Okeechobee Generating Project?

A: Both Mr. Waters and Dr. Landon attempt to attribute to the Project requirements for data, studies and analyses which are used in need determination hearings for retail-serving utility petitioners, who require their native load customers to directly bear the costs of the resource.

Q: Please give some examples.

A: For instance, Mr. Waters in his testimony talks about the need for reliability analyses. He states: "The first type of reliability analysis is a reserve margin analysis. This analysis is usually done for a load serving utility. . . ." (Direct Testimony of Samuel S. Waters at 6.) In this instance, Mr. Waters says, and I agree, that the Project should not be included as part of an <u>individual utility's reserve margin</u> unless that power has been contracted for on a firm basis. After a lengthy discussion on individual utility reserve margins and their calculation, he concludes the "OGC project cannot defer or avoid a single MW of planned utility capacity." (Direct Testimony of Samuel S. Waters at

11.) Mr. Waters further opines that individual utility-specific needs cannot be ignored and that evaluation from a Peninsular Florida perspective alone is not sufficient. As far as individual utility need is concerned, I agree with Mr Waters. Until and unless its output is contracted for, the Okeechobee Generating Project should be regarded as an available, "as-needed" plant which will not be part of any individual utility's reserves without a firm contract.

If, however, Mr. Waters means there is no reliability value, I disagree. Although the Project never claimed it was deferring any individual utility capacity, at least not at the present time when it has not entered into any firm capacity and energy contracts, Mr. Waters' categorical statement is at best overly broad. The presence of the Project will enhance the reliability of bulk power supply in Peninsular Florida and should be treated as any other unit in the calculation of potential assistance in meeting load. I will discuss Peninsular Florida reliability in more detail later in my rebuttal testimony.

Q: Are there other examples of FPL's witnesses arguing that the statewide or Peninsula-wide approach applied by the Commission in the Duke New Smyrna case is inappropriate?

A: Yes. Mr. Waters maintains that "[a]ttempting to address the need criteria solely from a Peninsular Florida basis rather than from a utility specific basis risks substantial error and confusion." (Direct Testimony of Samuel S. Waters at 13.) Mr. Waters further states: "There cannot be a Peninsular Florida need, either due to reliability or economics, unless there is a utility specific need of one or more utilities. However, there can be a utility specific need for a power plant when there is not a Peninsular Florida need." (Direct Testimony of Samuel S. Waters at 13.) I agree with the last statement as it pertains to need for reliability. This situation occurs because each individual load serving entity is responsible to meet its own load and energy requirements with its own least cost plan. There is no requirement for Peninsular Florida to have an overall most cost-effective plan. When each utility does its planning studies and expansion plans, mismatches on a statewide basis can occur.

Q: **What is your response to this argument?**

A: I believe that Mr. Waters is wrong in his contention that there cannot be an economic need on a statewide basis. First there is the potential for mismatches caused by the individual utilities expanding their systems independent of each other. Compounding the problem is the fact that a number of megawatts of combustion turbine capacity, small fossil steam plants (probably not a factor) and repowering of existing units do not require a need hearing or any type of cost effectiveness determination. In fact, using FPL's most recent 10-year site plan plus recent announcements, it was calculated that 60 percent of FPL's net capacity additions over the next nine years will come from units not requiring a need hearing.

The most important reason that there may be--and apparently is--the potential for additional power plants justified on the basis that they will provide statewide economic benefits are changes associated with combined cycle technology and significantly improved heat rates on gas turbines. Load serving utilities built the types of units which were the most economical at the time of construction. Many of those units use oil and gas. Many are still running today, although some are running at relatively low capacity factors, and contributing to meeting native load requirements. Most are not sitting on ready in order to make off-system sales when the opportunity arises. Most of the repowering projects are probably devoted to displacing these less efficient plants coupled with some increases in capacity in most instances as an added benefit. Not all of the older and less efficient units are being displaced through repowering. Many of the IOUs have these older units running on their systems. Plants like the Okeechobee Generating Project operating on a non-firm basis can take advantage of diversity of needs among the various utility systems. An individual load serving utility in its least cost planning may not capture these non-firm off-system purchase potentials as part of its most cost-effective analysis. OGC is willing to accept the risk to serve this economic potential.

Q: **How about Dr. Landon's approach?**

A: Dr. Landon apparently wants the Okeechobee Project to be dealt with on some comparative basis. For example, he asserts that OGC does not present a comparative analysis of the impact on customers of alternate generation projects. He describes what he feels the Commission should require in its "comparative analysis": OGC apparently should compare the effects of its plant with alternative plants which the incumbent utilities have not identified and may not be willing to build. Dr. Landon also goes through a litany of what he calls defects in information submitted regarding construction costs, he questions availability factors, and the like. His plan apparently would be to compare the Project with a theoretical plant on FPL's system. He states similar analyses would be done for other utilities. I do not believe that Dr. Landon's example proves that the Project should not be built. What Dr. Landon's theoretical example proves is that FPL should be building a plant to displace less efficient plant on its system.

This cost effectiveness on FPL's system is, I am sure, the basis of its repowering projects. If FPL had already done this analysis for its system and it showed that no more cost-effective fuel substitution is available, FPL should have presented such a study in this docket.

Dr. Landon answers the question of why FPL might not build such a project--in his view it is the potential for uneconomic duplication. But if the new FPL unit had positive economic benefits to its customers, then there can be no "uneconomic duplication." What better party than FPL, who, one might reasonably assume, is examining its system very frequently, to submit to the Commission that there are no economic fuel displacements left on FPL's system. The key question that still may be left unanswered is: Are there fuel displacement benefits which are available on a statewide basis which are not, or cannot be, captured by an evaluation of an individual utility system?

Another interesting question is: If a new unit would be cost-effective to all electric customers in Peninsular Florida, but not an individual utility, should that project be deemed not to be cost-effective? This is essentially the argument that FPL and its witnesses are making in opposition to the Okeechobee Generating Project. (Of course, it is fairly obvious that such a project should be recognized as being cost-effective.)

Q: **Mr Kordecki, Mr. Waters admits that the Okeechobee Project will add to reliability but argues that it may not be needed to meet the Peninsular Florida reliability criterion. What is your response?**

A: My basic response is that Mr. Waters is correct that the Project will enhance reliability of the Peninsula's bulk power supply system, and that his apparent criticism--that the Project may not be needed to meet the Peninsular Florida reliability criterion--is meaningless. The real point is that the State, and the electric customers in the Peninsula, will be better off with the Project than without it, and they will not have to bear any of the typical risks associated with retail-serving utility-built power plants. I understand that the Peninsular Florida reliability criterion was being met with a 15 percent reserve margin as late as last fall. Since that time three utilities have signed a stipulation that they will increase their reserve margins to 20 percent. This is to be accomplished by 2004. Apparently there were a number of industrial customers and the Commission Staff who felt that a larger reserve margin would give more comfort even if it was not the optimal reliability level. The addition of the Okeechobee Project should help to improve even more customers' comfort levels. This plant will also provide an additional alternative for third party "buy-through" purchases (where customers' retail-serving utilities buy power from other sources and re-sell it to those customers at cost plus an administrative fee of approximately $2 or $3 per MWH) for those large commercial and industrial customers who are on interruptible rates or load management tariffs. If purchases from the Okeechobee Project were made for this purpose, this would enhance these customers' reliability in a cost-effective manner. In fact, there may be a number of other innovative arrangements for the use of this non-firm power.

Q: Mr. Waters states "I hardly think that a resource that is available under circumstances that have never occurred [capacity emergency declared by the Governor and the Cabinet] is reasonably characterized as a firm resource properly available for inclusion in a reserve margin." (Direct Testimony of Samuel S. Waters at 31.) What is your response?

A: First, the reason that Florida has adopted the capacity emergency plan was because the Florida Peninsular utilities couldn't serve their firm customers during the Christmas of 1989. Second, much of the pressure recently brought to bear on the utilities to increase their reserve margins was predicated on the fear of more potential occurrences similar to Christmas of 1989.

Mr. Waters' rationale, that you should not count the Okeechobee Project in the reserve margin because emergency conditions are the only time the Project can be forced to sell in the grid, reminds me of something that happened to me recently when looking at a piece of property near the Gulf of Mexico. I knew getting insurance had become difficult so I asked the realtor if there was going to be a problem procuring insurance. She said she could get a homeowners policy from someone she knew and I shouldn't worry about flood insurance because the area in question hadn't been hit by a hurricane since 1961.

Practically speaking, the Project can be considered as free insurance that Florida electric customers will not be required to pay for in their base rates. This makes it very cost-effective insurance.

It is my belief that OGC would not be in this hearing if they were not considered to be a proper applicant by this Commission. As a Florida utility, if the Governor issues an emergency order, OGC would be required to generate into the grid. It is my opinion that if capacity situations were in effect which would warrant even an inkling of some level of capacity shortfall in Florida, any merchant plant that has generation available would be selling. I believe that these are the situations that the merchant plant builders were anticipating when they made commitments to construct generating units.

Q: **In your direct testimony did you state that OGC would only sell in the State of Florida as indicated by Mr. Waters and Dr. Landon in their testimonies?**

A: No, I did not state that output from the Project would only be sold in Florida. I stated that "I do not believe that any significant amount of merchant power would be sold outside of Florida . . . ." (Direct Testimony of Gerard J. Kordecki at 17.) The context of my direct testimony was to indicate that, contrary to the testimonies of FPL's witnesses, the economics of the Project are not based on out-of-state sales. My rationale was based on the fact that average production costs are higher in Florida than in SERC and other adjoining regions. Second, OGC would have to purchase transmission service from FPL (which significantly adds to cost) and reserve service across the Georgia/Florida Interface, the rights to which are contractually owned by four utilities. If FPL were exercising all of its entitlement, OGC would have to purchase from one of the other three utilities (if available) which further increases OGC's costs. Third, most of the transactions across the interface appear to be driven by short-term capacity shortages in other regions of the country. If OGC's financial motivation is to serve these short term fluctuations, it would make more economic sense to construct a peaking unit (with combustion turbines only) in the SERC region.

Interestingly, Dr. Landon adds two "additional factors" which I believe, would support OGC looking for locations outside of the Florida Reliability Coordinating Council ("FRCC") Region, if, in fact, OGC was targeting making sales in that region. First, there is the opportunity to sell ancillary services at market-based rates which is not generally available in the FRCC Region and cannot be easily or practically exported from the Peninsular Florida region. Second, Dr. Landon states that some of Florida's neighboring utilities may experience environmental plant emission problems in the near future which could increase the prices relative to their historic levels and relative to those in Florida. If this is true, or if OGC thought it probable, plant locations in the SERC region would be more attractive to OGC and its affiliates since competing costs would be higher and transmission costs would be lower. Under such a hypothetical situation, OGC could still export into Florida even though there may be reduced transmission capacity available traveling north to south across the Georgia/Florida Interface.

Q: **Dr. Landon and Mr. Waters lament over the possibility that the OGC plant will reduce the level of out-of-state, off-system sales that could be made by FPL. Do you believe that the OGC plant will affect FPL's out-of-state sales significantly?**

A: As I stated earlier, I do not believe there will be a significant effect. Most reductions in FPL's off-system sales will not be because of the construction of the OGC plant. Dr. Landon's and Mr. Waters' concerns ignore the fact that utilities will contract with OGC.

In fact, the presence of the Okeechobee Project has the potential to increase FPL's off-system sales. For example, if FPL had a medium or long-term power purchase contract with OGC, it would then have more economic resources to use in pursuing off-system sales. Essentially, OGC may thus provide the opportunity for FPL both to reduce the cost of serving its native load and to increase FPL's ability to make off-system sales.

Q: **Please explain.**

A: FPL's out-of-state sales to marketers have increased significantly from 1995 through 1998. In 1995, FPL sold to two out-of-state utilities and three power marketers only. The total sales were approximately 339,000 MWH. In 1998, FPL sold to 13 out-of-state utilities and 14 power marketers. Total sales reached approximately

1,713,000 MWH or an increase of over 500 percent.

I'm sure that some of this increase can be attributed to FPL's expanded trading activities, which I understand include most or all of the trading of power from the FPL Energy plants all across the country.

Some of this increase is due to the increase in the number of potential buyers, particularly power marketers buying for resale or to cover previous sales. The primary reason for the increase in sales is there are more shortages of capacity particularly on a spot basis in areas of the midwest and southeast.

Will these off-system sales levels continue for FPL? Probably not. FPL should shift its focus on OGC as a competitor for resales outside the Florida market to new competitors building in the SERC Region. Three announcements of new wholesale only plants located in Georgia and Alabama have been made official since testimony was filed in this docket. Two units are proposed by Calpine (one wholesale only, the other will be a QF with most of the output going into the wholesale market). These two plants total 1400 megawatts. The third plant will be built by Georgia Power (Southern). It will total 500 megawatts and will be for wholesale only sales. All three of these plants will be using similar technology (natural gas-fired combined cycle plants) and all are located closer to out-of-Florida markets than OGC. It appears obvious that these new wholesale additions will compete with FPL substantially and significantly more effectively for out-of-state sales than the Okeechobee Project.

Thus, the continuation of profits and ratepayer gains from off-system sales is speculative anyway because of the development of these new power plants in Georgia and Alabama that will reduce prospective out-of-state sales by FPL and other Florida utilities, including OGC. These developments will also reduce the profits from such sales as may be made. Also, as discussed elsewhere in my rebuttal testimony, FPL's (and the other utilities') requests for increased incentives for their shareholders would further reduce these likely-diminishing off-system sales gains.

Q: **Mr. Kordecki, at pages 31-32 and 48 of his testimony, Dr. Landon has testified that FPL's off-system sales produce benefits to FPL's ratepayers because the profits from such sales are "passed through the fuel clause to customers." Are there any additional factors that the Commission should consider in evaluating this assertion?**

A: Yes. The Commission should note that all four of Florida's major investor-owned utilities, including FPL, have filed testimony asking the Commission to expand the range of off-system sales for which their respective shareholders will receive part of the gains. Some, including FPL, have also advocated increasing the percentage of gains that flow to the utilities' shareholders as an incentive. This testimony has been submitted in Docket No. 991779-EI, <u>In Re: Review of the Appropriate Application of Incentives to Wholesale Power Sales by Investor-Owned Electric Utilities</u>, by Korel M. Dubin and Joseph P. Stepenovitch on behalf of FPL; by M.W. Howell on behalf of Gulf Power Company; by Karl H. Wieland on behalf of Florida Power Corporation; and by W. Lynn Brown and Deirdre A. Brown on behalf of Tampa Electric Company. For example, at pages 1-2 of Mr. Dubin's testimony, he states "The purpose of my testimony is to request Commission approval to extend the shareholder incentive set forth in Order No. 12923, issued January 24, 1984 in Docket No. 830001-EU-B to other opportunity sales. Additionally, my testimony requests that consideration be given to increasing the percentage for shareholder incentives to provide further encouragement to utilities." The other witnesses advocate similar changes. I have included all six witnesses' testimonies as Composite Exhibit _____(GJK-R-1) to my rebuttal testimony.

The point here is that while FPL's witness Landon is touting these benefits in this docket, two other FPL witnesses are advocating reducing these ratepayer benefits to the benefit of FPL's shareholders. In other words, if the Commission gives FPL what it requests in

Docket No. 991779-EI, it will reduce ratepayer gains that FPL is proclaiming proudly in this need determination proceeding.

Q: **Dr. Landon states that "[I]t seems unlikely" that Florida utilities can exercise market power in the Florida wholesale market. (Direct Testimony of John H. Landon at 58.) Do you agree?**

A: The question of market power potential for the larger Florida utilities has not been decided. It is evident, however, that resource ownership in Florida is highly concentrated with the two largest generating utilities combining for approximately 65 percent of the resources, with the larger having 44 percent. Dr. Landon does agree that the addition of merchant plants such as the Project will reduce concentration.

Both FPL and FPC have market-based rate authority <u>outside</u> of Peninsular Florida and cost-based caps on their wholesale sales in Florida. These cost-based caps are significantly higher than their average system cost, so there is room for significant profits on Florida sales. The one remaining Peninsular Florida investor-owned utility (Tampa Electric Company) and its sister company, Hardee Power Partners, both have market-based rate authority both inside and outside of Florida. The municipals and the generation and transmission organizations have the ability to sell at market level rates. Only FPL and FPC cannot. FPL and FPC claim they are "required" to sell at regulated, cost-based prices. Actually FPL and FPC volunteered to sell at cost-based rates. In FPC's initial filing to FERC for market-based rates, it requested market-based rate authority for all areas including Florida. After interventions, protests of market power and settlement discussions, FPC withdrew its request for market-based rates in Florida and limited the authority to out-of-state. FPL's request followed FPC's. After interventions and protests, FPL limited their market-based rate authority to sales outside of Peninsular Florida. These two companies have the largest geographical exclusion of market-based rate authority that I have encountered. They cannot sell at market-based rates in their most natural markets, namely in the Florida Reliability Coordinating Council Region. I know of no such restrictive limitation(s) placed on other utilities in the country.

By opposing new entrants into the Peninsular Florida market, FPL and others are maintaining this highly concentrated market in Peninsular Florida at a minimum.

Q: **Mr Kordecki, do you have any other comments to Dr. Landon's or Mr Waters' testimonies?**

A: Yes, Mr. Waters concludes that customers will pay more because there is a higher risk with the OGC plant than with a plant built by FPL or another utility. Mr. Waters is wrong. The risks might be the same if FPL were to build this unit independent of their rate base and absorb all risks and have no obligated customer base, as OGC is doing. Then, of course, I would expect that FPL's shareholders would want a higher return than the protected return of the regulated utility.

OGC's returns on capital may or may not be higher than FPL's regulated return. Since purchases from OGC will only be made when the purchase price of OGC's power is lower than the purchaser's incremental cost of other resource options, it matters not if OGC's return is higher or lower or the same as a regulated utility, because the kilowatt-hour costs will be lower to customers.

Q: Mr Kordecki, does this conclude your rebuttal testimony?

A: Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Determination of Need for an Electrical Power Plant in Okeechobee County by Okeechobee Generating Company, L.L.C.	)	DOCKET NO. 991462-EU FILED: MARCH 3, 2000

REBUTTAL EXHIBITS

OF

GERARD J. KORDECKI

ON BEHALF OF

OKEECHOBEE GENERATING COMPANY, L.L.C.

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 991779-EI

REVIEW OF THE APPROPRIATE APPLICATION OF WHOLESALE POWER SALES BY INVESTOR-OWNED UTILTIES

MARCH 1, 2000

TESTIMONY OF K. M. DUBIN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 991779-EI

March 1, 2000

Q. Please state your name, business address, employer and position.

A. My name is Korel M. Dubin, and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Rates and Tariffs Department.

Q. Have you previously testified in this docket or a related docket?

A. Yes, I have testified in Docket No. 990001-EI, the Fuel and Purchase Power Cost Recovery Docket. Docket No. 991779-EI is a spin off from the Fuel Docket.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to request Commission approval to extend the shareholder incentive set forth in Order No. 12923, issued January 24, 1984 in Docket No. 830001-EU-B to other opportunity sales. Additionally, my testimony requests that consideration be given to increasing the percentage for shareholder incentives to provide further encouragement to utilities.

Q. Please describe the 20 percent shareholder incentive set forth in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B?

A. In Order 12923 the Commission established an incentive to share the gains on broker sales between the retail customers and the utility shareholders. The objective of establishing this incentive was to maximize economy sales and provide a net benefit to customers.

Q. Should the Commission eliminate the 20 percent shareholder incentive set forth in Order No. 12923?

A. No. The objective of this order to maximize economy sales and provide a net benefit to customers continues to be and may even be more valid today. As stated in the testimony of FPL witness J. Stepenovitch, the market has changed significantly since 1984; there is more competition. And, since there is more competition, on the surface it may appear that incentives are no longer needed but just the opposite is true. Competition affects each end of the transaction in different ways. It may be easier to buy if there is more competition but it is also harder to sell. In this more competitive environment, when it is harder to make sales, it does not make sense to eliminate shareholder incentives. On the contrary, when it is harder to make sales, utilities should be encouraged to make them. Although utilities are motivated to make these sales to keep rates as low as possible, a shareholder incentive compensates the utility for the disincentives (such as increased O & M and wear and tear on the generating assets) associated with making these sales.

Q. **Should the Commission extend the 20 percent shareholder incentive set forth in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B to other types of sales?**

A. Yes. As described in the testimony of FPL witness J. Stepenovitch, the broker system is being used much less than in the past and utilities are now making the majority of sales outside of the broker network, particularly outside of the state. Therefore, the shareholder incentive should be extended to these non-broker opportunity sales to provide an incentive for utilities to maximize these off system sales, which will benefit customers even more. Consideration should also be given to increasing the percentage for shareholder incentives to provide further encouragement to the utilities and to compensate for the associated disincentives.

Q. **What types of economy energy sales should be eligible for a shareholder incentive?**

A. In addition to the current treatment of Schedule C, Broker Sales, FPL believes that sales transactions made pursuant to Tariff No. 1 and the Market Based Rates Tariff should also be eligible for a shareholder incentive. Both of these types of transactions are commonly referred to as opportunity sales. Although FPL recommends that the shareholder incentive should be extended to other opportunity sales, FPL believes that the shareholder incentive should not be applied to Emergency Sales such as Schedules AF and DF.

Q. How should the incentive be structured?

A. FPL believes that consideration should be given to increasing the percentage for shareholder incentives. For example, a sliding scale could be used where the shareholder incentive on the first $20 million in gains on sales could be shared 80% to retail customers and 20% to shareholders. The next $20 million could be shared 60% to retail customers and 40% to shareholders, and any gains over $40 million could be shared 50%/50%. By using a sliding scale, the utility is compensated and the customer benefits by a lower fuel charge.

Q. Does this conclude your testimony?

A. Yes, it does.

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 991779-EI

REVIEW OF THE APPROPRIATE APPLICATION OF WHOLESALE POWER SALES BY INVESTOR-OWNED UTILTIES

MARCH 1, 2000

TESTIMONY OF J. P. STEPENOVITCH

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities.	DOCKET NO. 991779-EI FILED: March 1, 2000

PREPARED DIRECT TESTIMONY OF JOSEPH P. STEPENOVITCH

Q. Please state your name and business address.

A. My name is Joseph P. Stepenovitch. My business address is 11770 U.S. Highway One, North Palm Beach, Florida 33408.

Q. Please state your position and the nature of your responsibilities at FPL.

A. I am the Director of Wholesale Operations in FPL's Energy Marketing & Trading Division. My primary function in that position is to oversee the overall generation asset optimization. This function oversees fuel purchases/sales, power purchase/sales, and transportation for fuel and power.

Q. Please describe your educational background, and work experience.

A. I received a Bachelor of Science degree in Business Administration in 1989 from Barry University in Miami, Florida. I have been employed by FPL since 1980. In that time, I have held various positions within FPL's Power Supply Department; (1) System Operation Senior Specialist from October 1980 through February 1982; (2) Interchange Coordinator from February 1982 through February 1986; (3) Operational Planning Supervisor from February 1986 through May 1991; (4)

Manager of Interchange Operations from May 1991 through April 1997; and (5) my current position since April 1997. Prior to my employment with FPL, I worked for New England Power Service Company for twelve years in a variety of positions in power delivery and systems operations areas.

Q. **In addition to your position at FPL, do you participate in any related organizations?**

A. Yes. I am currently FPL's representative to the Florida Energy Broker Network, Inc., FRCC Market Interface Committee, and the Board of Directors for NESA (National Energy Services Association).

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to describe why incentives are appropriate and how incentives benefit both the customers and the stockholders. I will describe the dramatic changes which have taken place in the wholesale energy market over the past several years and also describe how FPL's wholesale operations are changing in order to be a well equipped participant in this new and evolving market.

Q. **Why should the Commission approve a stockholder incentive?**

A. In Order 12923, the objective of establishing the incentive was to maximize economy sales and provide a net benefit to customers. This objective to maximize economy sales, which could provide significant benefits to customers, continues to be valid today. However, due to the changes in the market, as described later in my testimony, the economy sales which were the subject of Order 12923 are practically non-existent.

Utilities are now making more opportunity sales outside of the broker network, particularly outside of the state. This increases FPL's costs. Therefore, the shareholder incentive should be extended to all opportunity sales to provide adequate incentive for utilities to maximize these off-system sales which will benefit customers to a greater extent. FPL believes incentives would also apply to capacity sales made with a utility's "temporary" excess generating capability. These opportunity sales allow Florida utilities to reduce overall costs through greater asset utilization. The more efficient use of capacity will help minimize retail rates for all Florida customers. Applying incentives to all opportunity sales also will protect against disincentives such as increased O & M costs, which includes the wear and tear on generation assets required to make these sales.

To maximize opportunity sales, additional effort is required on the part of the utility to utilize additional manpower and equipment. Therefore, a sharing of non-fuel revenues between retail customers and stockholders is fair, and would provide an incentive for utilities to pursue these sales even further. This will allow the retail customers to more fully realize the benefits of existing generating resources in Florida. Structured properly, incentives will motivate a utility to pursue the maximum amount of savings possible. Incentives will serve to promote management's willingness to allocate additional resources and funds to its energy marketing and trading functions. This in turn will serve to increase the market publications. In order to transact in different regions and with new parties, we have had to become members of various power pools. FPL also added a new phone system to handle the increased volume of transactions and expanded its trading floor. All of these changes have added to FPL's cost structure. However, customers have received a more than commensurate benefit from these investments as gains on off-system sales have increased from \$5.5 million in 1996 to approximately \$59.1 million in 1999.

Q. Please summarize your testimony.

A. The Commission's objective of establishing the incentive was to maximize economy sales and provide a net benefit to customers. This objective continues to be valid today. Utilities are now making more opportunity sales outside of the broker network, particularly outside of the state. The wholesale market has become more complex, making wholesale sales transactions more competitive, difficult, and challenging to make. Therefore, the shareholder incentive should be extended to all opportunity sales to provide an incentive for utilities to maximize these off-system sales which will benefit customers.

Q. Does that conclude your testimony?

A. Yes it does.

ORIGINAL

FLORIDA POWER CORPORATION

DOCKET NO. 991779-EI

DIRECT TESTIMONY OF
KARL H. WIELAND

Q. Please state your name and business address.

A. My name is Karl H. Wieland. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power Corporation as Manager of Financial Analysis.

Q. Please state your educational background and professional experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of South Florida in 1968 and a Master's Degree in Engineering Administration, also from the University of South Florida, in 1975. I have also attended the Management Development Program at Georgia State University and the Public Utility Financial Seminar sponsored by the Irving Trust Company in New York. I am a registered Professional Engineer in the state of Florida and I have been employed by Florida Power Corporation on a full time basis since 1972. During the first seven years of my career, I worked as a Transmission Planning Engineer in the System

Planning Department and as an Economic Research Analyst in the Economic Research Department. I became Manager of Generation Planning in 1979, Manager of Economic Research in 1983, and Director of Business Planning in 1990. I assumed my present position in 1998.

My current responsibilities include financial planning and forecasting, financial analysis of projects and proposals, cost benefit analyses, fuel adjustment filings and other fuel-related regulatory activities. I have testified before this Commission on numerous occasions regarding a variety of regulatory policy issues, including the role of utility incentives as a ratemaking tool -- most recently at the fuel adjustment hearings in November 1999 which led to the establishment of this "spin-off" docket.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to urge that the Commission update its long standing practice of providing utilities with an incentive for short-term economy sales made on the Florida energy broker by applying the incentive to short-term (non-separated) off-broker sales as well, in recognition of current market conditions that have led to a drastic reduction in the use of the broker as the vehicle for conducting the beneficial sales.

Q. Do the reasons for the Commission's initial establishment of a shareholder incentive in 1984 remain valid today?

A. Yes. In Order No. 12923 issued January 24, 1984, the Commission acknowledged that, in moving the treatment of economy sales out of base rates where utilities retained 100% of the gain, establishment of an incentive through the fuel adjustment clause was desirable to preserve the then-current level of economy sales and that such an incentive would provide a net benefit to ratepayers. Faced with the current level of competition in the wholesale power market, the case for positive incentives is stronger today than in 1984, when the Commission instituted the 80/20 sharing of gains on economy sales.

Q. Why do you believe there is a greater need for incentives today than there was in 1984 despite the fact that the industry has become more competitive?

A. The need for incentives is greater today than it was 10 to 20 years ago *because of* the fact that the industry has become more competitive. During the early 1980s, wholesale markets for economy sales were simple. The Florida broker system *was* the market, and the participants were the Florida utilities. Each utility entered its hourly incremental and decremental production costs into a computer that matched offers, notified buyers and seller, and established transaction prices.

Today's markets are much more complex and take significantly more effort and resources in order to participate successfully. Transmission paths and payments must be arranged by the seller in accordance with complex FERC rules. Sales are no longer limited to hourly split-the-savings transactions, rather, the transactions can span days, weeks, or even months. Pricing is at the market and all deals are negotiated rather than determined by set formula. The seller must manage additional risks associated with transactions that take place at future times when costs are not known with certainty. Finally, participants are more numerous and sophisticated. They compete for a significant share of the market value that historically has stayed within Florida, to the benefit of the retail customer.

For all these reasons, today's marketing operations have grown from a part-time activity for dispatchers to departments staffed with experienced traders, risk managers, and sophisticated computer equipment. Current marketing operations take significantly more effort and resources in order to participate successfully. Incentives provide the Commission with the most effective and efficient tool for ensuring that utilities extract the maximum value from the market for the benefit of the customer.

Q. Florida Power has significantly reduced the level of sales made through the Florida broker, for which a shareholder incentive is provided, and instead makes most of its non-separated sales through tariffs that do not provide an incentive. Doesn't that indicate that incentives are no longer needed to encourage these sales?

A. No. One reason that Florida Power participates in the non-broker market is to help reduce rates to its customers. That clearly is the obligation of any utility. It is also true, however, that while 100% of the generation-related gains on sales have been returned to customers through the fuel or Capacity Cost Recovery (CCR) clauses, Florida Power has been retaining 100% of transmission revenues from such sales. Except for sales made through the broker, a separate transmission charge based on the Company's open access tariff is added to the sales transaction. For the current year, Florida Power projects $2.7 million in additional transmission revenues for non-separated sales. By comparison, 20% of projected generation-related gains would yield an additional $2.1 million. Prior to January 2000, transmission revenues were credited to other operating revenues in surveillance reports, thus benefiting customers in the long term, but providing a strong shareholder incentive to increase sales in the short term. At the November 1999 fuel adjustment hearings, however, the Commission ordered 100% of these revenues to be flowed back to customers via the CCR clause, thereby eliminating this incentive. Therefore, like the situation in 1984 when the Commission eliminated the base rate incentive for economy sales, a replacement incentive is needed to encourage these sales for the benefit of ratepayers.

Q. If the Commission approves an incentive, how should it be structured?

A. I recommend that the Commission apply the existing 80/20 sharing to all non-separated economy transactions. Doing so would continue to apply the incentive provision in the manner intended by Order 12923 which stated "...economy energy sales profits are to be divided between ratepayers and the shareholders on a 80% - 20% basis, respectively."

Q. How you would define economy sales for purposes of applying an incentive?

A. In order to qualify for an incentive, a sale should meet three simple tests:

1. The sale is not separated, *i.e*, less than one year in duration.
2. The sale is profitable (revenues exceed incremental fuel costs), *i.e.*, provides a net benefit to ratepayers.
3. The seller must be able to influence whether or not the sale takes place and the transaction price.

Q. How would your proposed incentive mechanism treat "unprofitable" sales?

A. An unprofitable sale, *i.e.*, when incremental fuel costs exceed revenues, can arise in many ways. A sale during the peak or off-peak hours of a day could show a loss for an hour or two, or a sale for a week could contain one or more unprofitable days. The risk of a sale turning out to be unprofitable is inherent in any transaction whose profitability is based on estimates of future costs.

Florida Power proposes a symmetrical treatment for both profitable and unprofitable sales. In the same way that shareholders receive 20% of the gain when sales are profitable, they would absorb 20% of the loss when sales are unprofitable. For example, if incremental fuel costs exceed revenues by $10 per MWH during 2 hours of an 8-hour sale for 50 MWs, the loss over this two-hour period would be $1,000 and result in recoverable fuel costs being reduced by $200. In this manner, utilities would be encouraged to aggressively seek out sales that produce the greatest benefit to ratepayers by providing shareholders with a reward commensurate with a sale's profit and a penalty commensurate with a sale's loss.

Q. Which of Florida Power's interchange schedules would qualify under your definition of economy sales?

A. With the exception of Schedule A (emergency), and Schedule B (short-term firm), all sales reported on Fuel Adjustment Schedule A-6 should qualify. Schedules A and B meet criteria 1 and 2 above, but are made upon request by a buyer, not marketed by the seller.

Q. Could your definition include firm sales?

A. Yes, it could. The vast majority of non-separated sales Florida Power makes are as-available or recallable. By including all sales, the Commission eliminates having to define exactly what a firm sale is or risk inconsistent interpretation and application. As long as a utility expects to have adequate reserves over the period of the sale and the criteria advocated above are met, there is no reason to exclude a sale from an incentive provision simply because it is firm. Since firm sales generally have more value and thus a higher price than non-firm sales, excluding such sales would encourage a utility to engage in transactions that brings less value to customers only because they qualify for an incentive.

Q. How should the shareholder incentive be treated for regulatory accounting purposes?

A. The incentive should continue to be recorded below-the-line for ratemaking and surveillance purposes, as it is today.

Q. Does this conclude your direct testimony?

A. Yes.

TECO
TAMPA ELECTRIC

ORIGINAL

TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 991779-EI

TESTIMONY
AND EXHIBIT OF

W. LYNN BROWN

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

W. LYNN BROWN

Q. Please state your name, address and occupation.

A. My name is Lynn Brown. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Wholesale Marketing and Sales.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor's degree in Electrical Engineering from Louisiana State University in 1972 and subsequently joined Tampa Electric. I held various engineering, operations and managerial positions in Energy Delivery from 1973 through March 1997. I became Manager of Short-Term Wholesale Trading in April 1997 and was promoted to my present position in August 1998. I am responsible for short-term and long-term wholesale power purchases and sales, including non-firm energy sales that are made both on and off the Energy Broker Network ("broker").

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe Tampa Electric's wholesale marketing activities, provide an overview of the wholesale market within and external to Florida, and explain the significance of company incentives for non-separated, non-firm wholesale sales.

Q. Have you prepared an exhibit supporting your testimony in this proceeding?

A. Yes. My Exhibit No. 1 (WLB-1) consists of one document entitled "Glossary to Wholesale Schedules and Terms."

Q. Please describe Tampa Electric's Wholesale Marketing and Sales Department.

A. Tampa Electric's Wholesale Marketing and Sales Department ("Wholesale Marketing and Sales" or "department") is comprised of 13 full-time employees and one part-time employee. The department's general responsibilities include monitoring the wholesale market, preparing analyses and forecasts, and negotiating short-term and long-term sales and purchases. The department is also responsible for the consummation of all wholesale transactions including negotiations of terms and conditions, energy scheduling, OASIS reservation, transaction tagging, transaction monitoring, and deal documentation for billing and auditing.

Wholesale Marketing and Sales operates a trading floor 24 hours a day, seven days a week and has contractual relationships with numerous utilities and power marketers for sales and purchases of power. The department's annual budget is approximately $1.3 million.

Q. Please describe the types of wholesale transactions Tampa Electric enters.

A. Tampa Electric enters into many types of wholesale transactions depending on the needs of its wholesale customers and Tampa Electric's available capacity and energy. The company utilizes several types of wholesale sales schedules as described in detail in my exhibit.

Q. For what types of wholesale sales is Tampa Electric currently receiving an incentive?

A. Tampa Electric currently applies the 20 percent company incentive on gains from all economy energy sales made under FERC-approved Schedule C and Schedule X. This includes sales made on and off the broker. The company has consistently applied the incentive since April 1984 upon approval by the Florida Public Service Commission ("Commission") in Docket No. 830001-EU-B.

Q. Please describe the types of wholesale sales to which Tampa Electric believes an incentive should apply.

A. It is appropriate to retain an incentive for <u>all</u> non-separated, non-firm wholesale sales. This should not only include Schedules C and X sales, but it should also include Service Schedule J and G sales and all non-firm, market-priced wholesale sales.

Q. Why should the company be incented to make non-separated, non-firm wholesale sales?

A. It has been proven that incentives work. Incentives provide a motivation to behave a certain way and to achieve a desirable result. Tampa Electric's ratepayers have benefited from the company making economy sales through rate offsets from gains on these sales. Over the last 16 years, the company has also benefited by being able to retain 20 percent of the net gains.

The incentive has encouraged Tampa Electric to be aggressive regarding the production and sale of economy energy. The company has optimized generating unit maintenance, operated generating units to make sales, optimized economic generation dispatch, and devoted time, effort and resources to consummating transactions. This has resulted in a win-win for the company and its retail ratepayers.

Conditions, however, have changed. The wholesale market, especially the short-term energy market, has changed considerably since 1984. Because of these changes, it is appropriate for the Commission to extend a company incentive to <u>all</u> non-separated, non-firm sales.

Q. Please describe the changes in the non-firm energy market in Florida.

A. Florida's energy market has changed considerably in recent years. Prior to 1997, most non-firm transactions were cost-based, next-hour sales and purchases involving two Florida utilities. Most transactions were accomplished on the broker and the power was retained in the state to benefit all Florida ratepayers. These transactions were mostly "split-the-savings" transactions providing equal economic benefits to the buyer and seller.

Since 1997 the players and trading methods have changed. FERC Orders 888 and 889 opened the wholesale power market by requiring transmission owners to provide standardized open access. This brought about new market participants, including power marketers. Power marketers are now party to many non-firm wholesale transactions nationwide. These entities have market-based pricing freedom and use it extensively to take advantage of supply and demand imbalances.

Until recently, the broker facilitated only cost-based transactions which marketers found to be too limiting. Most transactions today are made via market-based power exchanges and off-broker deals that are consummated via telephone. Furthermore, the market has become volatile due to regional generation shortages and transmission constraints. The Florida market is influenced by a transmission constraint at the Georgia border that limits both purchases and sales across the state line and can result in high in-state prices. Additionally, market spikes in other regions of the country can place a high demand on available power in Florida, which can result in higher volumes of high-priced power exported from the state or higher in-state prices. The combination of new market participants, commodity-demand fluctuations, transmission constraints and price volatility has resulted in a very different non-firm wholesale market.

Q. What incentive structure is Tampa Electric proposing?

A. Tampa Electric is proposing that a company incentive of 40 percent be applied for all non-separated, non-firm sales made within the state. A lower company incentive of 20 percent should be applied for all non-separated, non-firm sales made outside the state.

Q. What effect would this proposed company incentive have on retail ratepayers?

A. This incentive will continue to lower rates to retail ratepayers with enhanced system reliability. Eighty percent of the margins for all non-separated, non-firm sales made outside Florida and 60 percent of the margins for all non-separated, non-firm sales made inside Florida would be credited directly to retail ratepayers. The company incentive will encourage selling utilities to maximize transactions especially within the state.

Utilities that are willing to provide generation resources to serve the needs of its ratepayers and the Florida market due to changes in supply-side resources and/or customer demand should receive a greater incentive. Larger volumes of non-firm energy on the wholesale market will result in a more robust and competitive Florida market. Purchasers of energy benefit by having more resource options that provide competitively priced energy and increased reliability for firm and non-firm retail customers. Therefore, all Florida retail ratepayers (buyers and sellers) benefit by these types of transactions.

Q. Would Tampa Electric continue making non-firm sales absent an incentive?

A. Of course. Tampa Electric has always strived to provide its retail ratepayers with reasonably priced, highly reliable electric service and off-system sales have helped achieve this goal. By having an incentive in place, however, utilities are motivated to go above and beyond the norm in transacting non-firm sales. The incentive provides additional justification and encouragement to maintain a professional staff that understands and can track the highly competitive wholesale market, and that knows how to optimize transactions and maximize sales revenues.

Q. Please summarize your testimony.

A. Tampa Electric's Wholesale Marketing and Sales Department is responsible for monitoring the wholesale market, analyzing and forecasting the company's needs for purchased power and ability to sell energy, and making short-term and long-term sales and purchases. Because of recent changes in the Florida wholesale market, it is even more important to incent utilities to make off-system sales.

Tampa Electric proposes that the Commission extends company incentives to <u>all</u> non-separated, non-firm wholesale sales. A higher company incentive of 40 percent should be applied to all non-separated, non-firm sales made within the state and a lower incentive of 20 percent should be applied for all non-separated, non-firm sales made outside the state. The incentive will encourage utilities to retain knowledgeable marketers of wholesale energy, maintain competitive and reliable generation, and aggressively market excess non-firm energy. Incentives benefit ratepayers by encouraging wholesale sales and then sharing with retail ratepayers the majority of profits from these off-system sales. Purchasing utilities also benefit by obtaining competitively priced energy for their customers at a cost lower than other supply-side resources.

Q. Does this conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 991779-EI
WITNESS: W. LYNN BROWN
EXHIBIT NO.____ (WLB-1)

TAMPA ELECTRIC COMPANY

EXHIBIT OF W. LYNN BROWN

INDEX

Glossary of Wholesale Schedules and Terms

Schedule or Term	Description
Schedule A Emergency	Used to replace generation due to an unplanned deficiency (forced outage). Price is based on fuel plus an hourly adder from the highest cost on-line generating unit at the time of the sale. The sale is limited to a 72-hour period, and is and non-separated.
Schedule B Scheduled/ Short – Term	Scheduled for short-term use to cover capacity deficiencies due to a unit outage. Is often used after the 72-hour time limitation has expired for Schedule A. The price for capacity and non-fuel energy is based on the embedded cost of the unit(s) most likely to provide the service.
Schedule C Economy	Sold to buyers wanting to avoid use of their own higher cost generation. Is offered on an hourly basis and priced based on the mid-point between the seller's and buyer's cost for generation for incremental system energy. Buyer must have its own back-up generation available. Sales are non-separated.
Schedule D	Normally a one-year or longer commitment to provide a specified amount of capacity and energy at a forecasted level of availability. Price typically carries a non-negotiable capacity charge and an incremental energy charge. The most common types of Schedule D power sales are unit power sales, station power sales or system power sales. Sales are typically separated.
Schedule G Back-up	Allows the buyer to provide required reserve capacity margin by contracting for it rather than building it. The buyer pays a negotiated reservation fee for this service plus a negotiated capacity and incremental energy charge when capacity is actually called upon. Sales are typically short-term, non-separated.
Schedule J Negotiated	Normally a short-term commitment to provide a specified amount of capacity and energy at a forecasted level of availability. Price may include a negotiable capacity charge and negotiable energy charge. Energy charges are typically based on the type of generating resource used to serve the sale. Normally offered with less availability than Schedule D. Sales may be firm or non-firm and are typically non-separated.
Schedule X Extended Economy	Similar to Schedule C, but commitment is longer than one hour. A majority of Schedule X sales are packaged within one-hour blocks totaling up to 7 days. Sales are not separated.
Market-Based Sales	Market-based price rather than cost-based sale that is typically executed similar to Schedules J and G. Sales can be firm or non-firm for varying terms and are typically short-term and non-separated.
Schedule AR or PR All or Partial Requirements	All or a portion of the total buyer's load is served at the same availability level as the seller's firm retail load. Pricing is based on the seller's net embedded cost of providing the requirement service to the customer. Fuel is billed at the seller's system average fuel cost. These agreements are normally long-term, separated contracts.
Broker or EBN	Florida Energy Broker Network which utilizes hardware and software to match buyers and sellers. Transactions have historically been cost-based and "split the savings" in nature, however on October 7, 1999, broker members approved the use of for market-based pricing.
Economy Sales	Schedule C and X sales made on or off the broker.
Non-firm Sales	Sales that can be interrupted to serve firm and non-firm retail customers.
Non-separated Sales	Sales that are made and supported by the utility's retail jurisdictional assets.

TECO

TAMPA ELECTRIC

ORIGINAL

TAMPA ELECTRIC COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 991779-EI

TESTIMONY
OF
DEIRDRE A. BROWN

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DEIRDRE A. BROWN

Q. Please state your name, address and occupation.

A. My name is Deirdre A. Brown. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") and am the Director of Electric Regulatory Affairs.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Accounting in 1982 from Florida State University and a Masters of Business Administration in 1994 from the University of South Florida. In 1990 I joined TECO Energy's Audit Services Department as an Internal Auditor. I was promoted to Senior Auditor in 1991 and to Supervisor/Administrator in 1992. In 1994 I was promoted to Administrator, Health Plans where I was responsible for managing the administration of Tampa Electric's health plans, employee assistance program, and health fitness facilities. In 1995 I returned to Audit Services as Director and was responsible for auditing all functions of TECO Energy and for certain corporate compliance and code of ethics activities. In June 1998, I was promoted to my current position as Director, Electric Regulatory Affairs, where I am responsible for managing Tampa Electric's regulatory issues and policy related to base pricing, fuel, environmental, system planning, conservation, and wholesale transactions. I am a Certified Public Accountant and a Certified Internal Auditor.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the appropriateness of incentives for utilities to make certain types of wholesale sales and to describe how these incentives should be structured.

Q. Does Tampa Electric currently receive incentives to make certain wholesale sales?

A. Yes. Tampa Electric receives incentives to make certain wholesale sales as approved by the Florida Public Service

Commission ("Commission") in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B. This order authorized utilities to retain 20 percent of the gains on economy sales while flowing 80 percent of these net benefits to ratepayers. In its order the Commission agreed with Staff witness testimony that a positive incentive is desirable for the purpose of maximizing the benefits of the Energy Broker Network:

> We believe Staff's witness was correct in stating that "a positive incentive will preserve current levels of economy sales and may result in increased sales and that a 20 percent incentive is large enough to maximize the amount of economy sales and provide a net benefit to ratepayers."

The Supreme Court of Florida affirmed the Commission's position in Citizens v. Public Service Commission, 464 So 2d 1194 (Fla. 1985). It was clear then as it is now that positive incentives play an important role in maximizing economy sales to provide net benefits to ratepayers.

Q. For what types of wholesale transactions is Tampa Electric currently applying the approved incentive?

A. Tampa Electric is currently applying the incentive to economy transactions as defined in the direct testimony of the company's witness Lynn Brown.

Q. Please describe the regulatory treatment currently applied to these types of transactions.

A. For generation costs associated with economy sales, revenues sufficient to cover the incremental fuel costs are credited through the Fuel and Purchased Power Clause ("Fuel Clause") and revenues sufficient to cover the associated incremental SO_2 costs are credited to the Environmental Cost Recovery Clause ("ECRC"). Revenues attributable to operating and maintenance costs ("O&M") are credited to operating revenues. Eighty percent of the gain on the sale, which is the difference between the transaction price and the associated incremental fuel, SO_2 and O&M costs, is credited through the Fuel Clause with the remaining 20 percent being retained by the company.

Transmission revenues from economy sales are separated on an energy basis pursuant to Order No. PSC-98-0073-FOF-EI issued January 13, 1998 and reconfirmed in Order No. PSC-98-1080-FOF-EI. Specifically, 80 percent of transmission revenues are credited to retail ratepayers through the

Fuel Clause. The company retains the remaining 20 percent.

Q. Should the Commission continue to provide for company incentives to encourage non-firm wholesale sales?

A. Yes. Not only should the Commission continue to provide company incentives for economy transactions, it should include incentives for all non-separated, non-firm wholesale sales as described by witness Mr. Brown and should increase the level of these incentives for sales made within Florida.

Q. How should the incentive be designed?

A. The incentive should be designed or accounted for in a similar manner as described above for economy transactions. Generally, the Commission should include all non-separated, non-firm transactions rather than only economy transactions. Specifically, the incentive should be applied to both demand and energy components of any gains from the transaction.

Gains from the transaction should be determined by taking the overall transaction price less incremental fuel costs, which should be credited to the Fuel Clause, less incremental SO_2 costs, which should be credited to the ECRC, and less O&M costs which should be credited to operating revenues. The remaining amount is comprised of reservation charges, call premiums, and associated transmission revenues ("capacity revenues") and energy revenues. According to Order No. PSC-99-2512-FOF-EI, dated December 22, 1999 for Docket No. 990001-EI, energy revenues for non-separated, non-firm transactions should be credited to the Fuel Clause. The same order acknowledged that if these sales include an identifiable capacity component, the capacity revenue should be credited to retail ratepayers through the Capacity Cost Recovery Clause ("Capacity Clause"). Accordingly, Tampa Electric proposes to credit 80 percent of the capacity revenues to the Capacity Clause and 80 percent of the energy revenues to the Fuel Clause for all sales made outside the state. The company proposes to credit 60 percent of the capacity revenues to the Capacity Clause and 60 percent of the energy revenues to the Fuel Clause for all sales made within the state. The company will retain the remaining 20 percent or 40 percent of the capacity and energy revenues, depending on whether the sales were made to customers within Florida.

Q. Why should utilities be incented to make non-firm wholesale sales?

A. Utilities have a general obligation to make prudent decisions and to take cost-effective actions to benefit their ratepayers. Incentives serve as a means to encourage beneficial actions above and beyond that general obligation. If beneficial actions are achieved, it is appropriate to reward the utility for its performance. Not only does the utility benefit, but its ratepayers benefit by these actions.

In the instance of non-firm wholesale sales, incentives will encourage utilities to continue to enter into prudent and cost-effective transactions and will encourage increased efforts to optimize transactions. By providing a greater incentive for utilities that make non-firm sales within the state, the Commission is recognizing those utilities that have acknowledged the need for appropriate reserve margins that benefit their own customers as well as all Florida ratepayers. These transactions will be accomplished without placing retail ratepayers at risk. In fact, incentives will encourage more energy to be made available on the Florida wholesale market, thereby increasing retail reliability.

Ratepayers of the selling utility will receive benefits through lower rates by these additional efforts while the utility also benefits. Ratepayers of the purchasing utility will also benefit because more energy will be made available to the Florida wholesale market, increasing the competitiveness of the market.

Q. Is it appropriate for the Commission to establish a "bar" or minimum level for non-firm sales whereby the incentive applies only after the utility meets the minimum level?

A. No. In Order No. 12923, the Commission agreed with Staff's testimony that establishing a "bar" or minimum level is a difficult issue. Up until this time, the selling utility was allowed to retain profits only from economy sales that exceeded the level approved in the company's last rate case. The Commission agreed to remove economy sales transactions from general rate proceedings and to include them in Fuel and Purchased Power proceedings because:

> Problems with the current treatment stem from the difficulty in projecting economy sales and the potential bias of a utility to under project their economy sales profits. The difficulty in

projecting economy sales profits is due to uncertainty associated with fuel prices, weather, and forced outages of generating units and transmission lines. These variables affect not only how much a utility can sell and at what price, but also how much other utilities will buy at different prices.

For these same reasons, it is not appropriate to establish a "bar" or minimum level for non-firm sales whereby the incentive applies only after the utility meets the minimum level.

Q. Theoretically, why should gains from non-firm sales offset fuel and purchased power costs?

A. Gains from non-firm sales should offset fuel and purchased power costs because the transactions are primarily energy-based. These non-firm sales are made when the company's generation is not needed to serve retail ratepayers. If the generation were needed, the sales would be terminated or recalled. Accordingly, it is appropriate to offset fuel and purchased power costs with these energy-based revenues.

Q. If the assets used to make non-firm sales are paid for by retail ratepayers, why shouldn't 100 percent of the gains be used to offset fuel and purchased power costs?

A. As described above, the use of positive incentives will likely increase non-firm sales. Even if only 80 percent or 60 percent of the gains associated with these sales are used to offset fuel and purchased power expenses, overall retail ratepayers will earn greater benefits through increased sales.

Q. Should all Florida utilities account for these types of transactions in the same manner?

A. Yes. Although utilities use different nomenclature when differentiating between the types of wholesale transactions, the nature of the sales are essentially the same and they should be accounted for similarly among Florida utilities.

Q. Does that conclude your testimony?

A. Yes, it does.

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 991779-EI

REVIEW OF INCENTIVES FOR WHOLESALE SALES BY INVESTOR-OWNED UTILITIES

PREPARED DIRECT TESTIMONY

OF

M. W. HOWELL

MARCH 1 ,2000

GULF POWER
A SOUTHERN COMPANY

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GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 991779-EI
Date of Filing: March 1, 2000

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

A. My name is M. W. Howell, and my business address is One Energy Place, Pensacola, Florida 32520. I am Transmission and System Control Manager for Gulf Power Company.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in various rate case, cogeneration, territorial dispute, planning hearing, need determination, fuel clause adjustment, and purchased power capacity cost recovery dockets.

Q. Please summarize your educational and professional background.

A. I graduated from the University of Florida in 1966 with a Bachelor of Science Degree in Electrical Engineering. I received my Masters Degree in Electrical Engineering from the University of Florida in 1967, and then joined Gulf Power Company as a Distribution Engineer. I have since served as Relay Engineer, Manager of Transmission, Manager of System Planning, Manager of Fuel and System Planning, and Transmission and System Control Manager. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution systems; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

I am a member of the Engineering Committees and the Operating Committees of the Southeastern Electric Reliability Council and the Florida Reliability Coordinating Council, and have served as chairman of the Generation Subcommittee of the Edison Electric Institute System Planning Committee. I have served as chairman or member of many technical committees and task forces within the Southern electric system, the Florida Electric Power Coordinating Group, and the North American Electric Reliability Council. These have dealt with a variety of technical issues including bulk power security, system operations, bulk power contracts, generation expansion, transmission expansion, transmission interconnection requirements, central dispatch, transmission system operation, transient stability, underfrequency operation, generator underfrequency protection, and system production costing.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address the issues in this docket concerning the currently allowed 20 percent shareholder incentive for certain non-separated wholesale sales. At the November 1999 fuel hearing in Docket No. 990001-EI, the Commission decided that the incentive issues should be addressed in a separate proceeding.

Q. Should the Commission continue its present policy and provide for stockholder incentives to encourage non-separated, non-firm, wholesale sales?

A. Yes. The Commission should, at a very minimum, continue the existing direct 20% incentive to utilities for participating in the wholesale, non-firm, economy energy market. Retail customers of both a net purchasing utility and a net selling utility benefit from a vibrant economy energy market where selling utilities have both direct and indirect incentives to satisfy the market's demand for off-system economy energy. The lower cost of economy energy available from sellers allows the net purchasing utility to meet its customers' needs for energy without having to generate the energy from its higher priced units, while the 80% credit from economy sales gains allows the net selling utility to lower its retail customers' overall fuel cost.

Q. Were there any particular concerns which motivated the Commission to institute the 80/20 split that is the current incentive mechanism?

A. Definitely. In testimony filed on November 7, 1983 by the Commission Staff in Docket No. 830001-EU, their witness expressed a primary concern regarding the "potential for over-recovery or under-recovery of revenues associated with economy energy sales." Also, the Staff suggested "that a specific incentive provision be adopted to encourage utilities to maximize economy sales." In Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, the Commission adopted Staff's proposal and established the existing 20% direct shareholder incentive that recognized the need for and overall benefit to all of our customers of increased sales of economy energy.

The old system of including sales projections in base rates presented utilities an incentive to maximize economy sales by allowing them to keep 100% of the sales profits above the level included in the rate case test year. Therefore, the Commission's 1984 change in Order No. 12923 did not initiate an incentive, but rather improved the old incentive mechanism with one that also allowed the Commission to eliminate any concern that projections of economy sales might be manipulated to "game the system". This highlights the point that uncertainty regarding projections of economy sales existed in the 1980s. This uncertainty is even more pronounced in today's market. The current economy sales incentive program has produced a win-win situation for customers and stockholders of Florida's investor owned utilities and should be retained.

Q. Would utilities engage in economy sales transactions which benefit their customers but do not offer any benefits to their stockholders?

A. Yes. Utilities did this well before the existence of the 20% incentive, and they would continue to engage in these sales if the incentive were removed by this Commission. But the more important question is, "To what degree would these sales occur?" With the provision of the current shared direct incentives associated with economy sales, a net selling utility is motivated to closely monitor the wholesale power market and proactively seek out opportunities for increased economy energy sales in today's competitive wholesale power market. Therefore, if the Commission maintains its current policy and continues the direct incentive, the degree to which utilities enter into these beneficial market-based economy sales should be maximized.

Q. What happens if the Commission reverses its current incentive policy?

A. If the Commission were to reverse its current policy and remove the incentive, the current motivation for utilities to closely monitor the wholesale power market would be reduced or lost. Any decrease in this ability to track the market and know what opportunities are available would lead to a reduction in a selling utility's amount of economy energy sales, and thereby, reduce the fuel cost credit for its retail customers. Today, customers get to keep 80% of the profits of a relatively large pie. If the direct stockholder incentive is removed and the level of sales falls, that results in the customers getting 100% of a smaller pie, and the customers lose.

Q. Should this proceeding be focused exclusively on economy sales incentive issues?

A. Absolutely not. The same incentive that motivates utilities to know the market and be in a position to increase sales also results in the utilities' discovery of opportunities to purchase cheaper economy energy. All of the savings produced by these purchases go to the customer. Decreasing the incentive will also shrink the pool of available sellers, which hits the customer smack in the forehead with a double-whammy.

Q. If a stockholder incentive is maintained by the Commission, what types of non-separated, non-firm, wholesale sales should be eligible to receive the stockholder incentive?

A. In Gulf's case, all of its non-separated, non-firm, wholesale economy energy sales made under current FERC wholesale tariffs that utilize cost-based and market-based pricing should receive the stockholder incentive. It is irrelevant whether or not such sales are made on the Florida Energy Broker Network, because the benefits to the customer of economy sales are independent of whether or not they occur on the Broker. All non-firm energy that is sold at a price that results in gains above incremental production costs, regardless of whether they are labeled as "economy", should receive the incentive. In a discussion between the Commissioners and the recommendation Staff at the November 1999 fuel hearing, it was acknowledged that today's wholesale market provides utilities an opportunity to make market-based economy sales that produce higher profit margins than are produced by traditional "split-the-savings" transactions. Thus, with market-based pricing for economy sales, the retail customer receives a greater overall benefit than with the traditional "split-the-savings" type of economy sales because the customer receives 80% of these higher margins as a fuel cost reduction.

If Gulf becomes a party to any new FERC schedules that offer economy-type, non-firm energy for sale, the resulting energy sales should also receive the 20% stockholder incentive.

Q. If a stockholder incentive is maintained by the Commission, how should the incentive be structured?

A. The existing system has well served the customers of Florida's investor owned utilities for over 15 years. The Commission's establishment of this incentive mechanism has resulted in a much higher level of wholesale transactions that have produced substantial savings for Florida's electric customers. Therefore, Gulf proposes that retail customers should continue to receive 80% of the economy sales gains produced by all non-separated, non-firm, wholesale economy sales as a reduction to their overall fuel cost, while utility stockholders should continue to keep 20% of the gains as an incentive to develop and maintain the capability to aggressively participate in the economy sales market.

Q. Should there be some minimum level of sales that do not qualify for the incentive?

A. No. At the last fuel hearing, the utility witnesses, and the Commission Staff during their recommendation, made clear that the level of available sales is dependent on buyers' needs, which vary widely depending upon a number of factors, none of which can be controlled or even determined in advance by the utility. The Commission agreed with that conclusion. Setting the "bar" either too low or too high would be unfair. Even having such a "bar" ignores the unchangeable fact that the incentive mechanism does just what the Staff said seventeen years ago - it provides the motivation for utilities to maximize such sales. The laws of human behavior cannot be repealed by setting artificial standards. An incentive provides a motivation. Motivation influences behavior. If any party to this docket wants to see sales and customer benefits maximized, retaining the incentive mechanism is their correct answer.

Q. Do the changes in the wholesale market over the last few years have an effect on the investor-owned utilities' ability to make economy sales?

A. Yes. The realities of the new wholesale market and of competition have had a profound effect on the investor-owned utilities in Florida. No one can really say what level of transactions would have taken place without the incentive, because it has been in place in recent years. But everyone agrees that it would have been less. Also, a new market exists today, with more players, many of them selling out of merchant facilities, but almost all of them selling under market-based tariffs. When there were no market-based tariffs, only split-the-savings opportunities, these new players were a small part of the business. But the level of wholesale transactions has literally exploded in the last few years, because now they can maximize profit. These new players get to keep 100% of their profits, so they have quite a powerful incentive to maximize sales. Giving utilities a 20% incentive at minimum allows them the motivation to compete with the new players and at the same time share these savings with customers.

Q. Why is this true?
A. If all incentive to make sales were removed, the competition that is now provided by investor-owned utilities will be diminished. The likely result would be that prices for economy purchases will increase. Thus, the customer risks not only being deprived of his 80% share of the profits on economy sales not made, but also risks having to pay even higher prices during times of economy purchases. This dual detriment to the customer can be avoided by keeping the current incentive.

I emphasize again that there now exists a win - win situation in Florida. Any reduction in the incentive will only hurt the customer. The Commission should appropriately resist any move to send the wrong market signals by such a major policy shift as eliminating the incentive.

Q. Does this conclude your testimony?
A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 991779-EI

Before me the undersigned authority, personally appeared M. W. Howell, who being first duly sworn, deposes, and says that he is the Transmission and System Control Manager of Gulf Power Company, a Maine corporation, that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

M. W. Howell

M. W. Howell
Transmission and System Control Manager

Sworn to and subscribed before me this 28th day of February, 2000.

Jackie L. Whipple

Notary Public, State of Florida at Large

Commission No.

My Commission Expires

Jackie L Whipple
My Commission CC682964
Expires August 23, 2001