BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including Effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.	Docket No. 000824-EI Dated March 7, 2003

PROGRESS ENERGY'S OPPOSITION TO OPC'S MOTION TO ENFORCE SETTLEMENT AGREEMENT

Progress Energy Florida, Inc., formerly Florida Power Corporation, Inc. ("Progress Energy" or "the Company") files this response in opposition to the Motion to Enforce Settlement Agreement filed by the Office of Public Counsel ("OPC") on its own behalf and on behalf of the Florida Industrial Power Users Group, Florida Retail Federation, Buddy Hansen/Sugarmill Woods Civic Association, and Publix Super Markets, Inc. (hereinafter collectively referred to as the "Movants").

The Movants' Motion is in the nature of a motion for summary judgment, asking for affirmative relief (a determination that Progress Energy owes a refund) based ostensibly on the plain language of the Settlement Agreement and without any supporting affidavits. In this response, Progress Energy opposes Movants' request for relief and asks the Commission for a definitive ruling on the merits of this dispute in Progress Energy's favor, based on the undisputed evidence, including the Commission's Order approving the proposed rate stipulation, all attachments and exhibits to that Order, and the Affidavit of Mr. Javier Portuondo, submitted herewith.

We believe that this matter will be in a posture after oral argument for the Commission to rule in Progress Energy's favor, based on the absence of any factual dispute, without an evidentiary hearing. If, however, the Commission believes that it does not have a sufficient record to decide the merits in the Company's favor at this time, then in the alternative we would request an evidentiary hearing to resolve this dispute.

I. **Introduction**

Traditionally, the Commission has used an authorized Return on Equity ("ROE") to limit earnings levels. When the utility earns above the top of the range, the Commission or OPC might initiate a rate review to reduce the utility's rates. In their Settlement Agreement in this case, however, the parties agreed to a revenue sharing plan in lieu of a traditional limit on ROE as a means to limit earnings levels. Under this revenue sharing plan, when Progress Energy receives more revenues than projected, the excess revenues are shared on a 1/3 – 2/3 basis between shareholders and customers.

The key to the plan is that expected – i.e., projected – base rate revenues must be compared on an apples-to-apples basis with actual base rate revenues for the periods in which revenue sharing is in effect in order to identify excess revenues that should be shared. The parties are in a dispute about how to treat the transition year, 2002. The dispute arises from the fact that the revenue sharing plan commences part way through that year, on May 1, 2002. Although the fact that the revenue sharing plan commences part way through the year may necessitate some adjustments, the basic premise of the plan remains unchanged: the object is still to identify whether there are any excess revenues over those projected. When the parties' Settlement Agreement and this Commission's Order approving that agreement are applied in a sensible manner, consistent with both the language and explicit intent of those documents, it becomes clear that a refund of excess revenues in the amount $4,998,489 is called for in the year 2002.

By their Motion, the Movants are attempting to turn the revenue sharing feature of the Settlement Agreement on its head. The Movants ask that Progress Energy be required to refund over $18 million of revenues that it had always projected it would receive, as can be readily deduced from the forecasted information in the Company's Minimum Filing Requirements ("MFRs") submitted in this case. They argue for this result by insisting, among other things, that $41.6 million in 2002 revenues that the Company had always projected it would receive must be deemed excess revenues subject to revenue sharing because these revenues would have exceeded the forecast if the Commission had applied the agreed-upon 9.25 percent rate reduction (totaling $125 million per year) prior to May 1, 2002, the effective date of the rate reduction.

The net effect of the Movants' interpretation is to achieve indirectly what the Movants could not achieve directly: namely, to obtain a retroactive rate reduction for the first part of 2002, even though neither the Company, the Commission, nor any of the parties ever stated or agreed that rates would be reduced prior to May 1, 2002. To the contrary, the Settlement Agreement explicitly directs that Progress Energy would "begin applying the lower base rate charges required by this Stipulation and Settlement to meter readings made on and after the Implementation Date," namely, May 1, 2002. (Para. 2) (emphasis added).

The Movants' argument contravenes the language and the intent of the Settlement Agreement and this Commission's Order approving that agreement.

II. Background, Stipulation, and Order

Overview

The parties to this docket entered into a stipulation and settlement on March 27, 2002 (the "Settlement Agreement"), to resolve all disputed issues in Progress Energy's then-pending rate case. The Settlement Agreement was approved by the Commission by Order PSC-02-655-AS-

EI, dated May 14, 2002, which includes and incorporates the Settlement Agreement (Exh. A hereto). The Settlement Agreement included an innovative revenue sharing feature to prevent excessive returns from unanticipated revenue increases.

By way of background, the Commission had previously established a regulated rate of return for Progress Energy. Under that traditional rate making approach, Progress Energy did not have the opportunity to benefit from better-than-projected revenues that might push earnings above the permissible range. Under revenue sharing, however, utility shareholders and customers alike stand to benefit from better-than-projected revenues.

The essence of the revenue sharing feature is to compare expected — i.e., projected — base rate revenues against actual base rate revenues for the periods in which revenue sharing is in effect. If the Company achieves only the revenues it had projected, then the Company will use those revenues to cover costs and return requirements just as it normally would. If, however, the Company realizes greater-than-projected revenues, it will share the majority of those "excess" revenues with its customers.

In this regard, the parties provided in their Settlement Agreement that, "Commencing on the Implementation Date and for the remainder of 2002 and for calendar years 2003, 2004 and 2005, and for each calendar year thereafter until terminated by the Commission, FPC will be under a Revenue Sharing Incentive Plan as set forth [in the Settlement Agreement]." (Para. 6). The Settlement Agreement provides that Progress Energy's shareholders would be entitled to receive a "1/3 share" of extraordinary revenues, and Progress Energy's retail customers would receive the remaining "2/3 share." (Para. 6, I).

The parties agreed to this mechanism in lieu of a capped return on equity. Specifically, the Settlement Agreement provides that "FPC will no longer have an authorized Return on

Equity (ROE) range for the purpose of addressing earnings levels, and the revenue sharing mechanism herein described will be the appropriate and exclusive mechanism to address earnings levels." (Para. 3) (emphasis added). By this provision, the parties explicitly recognized that their intent was to use revenue sharing to operate as a substitute for, and a functional equivalent of an authorized ROE – namely, to prevent the Company from obtaining the full benefit of excessive revenues, i.e., base rate revenues that might otherwise trigger a rate review if they were to exceed the level necessary to enable the Company to recover its costs and return requirements.

Evaluation of Revenues

As a starting point for evaluating revenues, the parties established a "threshold" for each year covered by the Settlement Agreement, beginning with 2002. Although the parties agreed that revenue sharing would apply only from May 1, 2002 forward, the Settlement Agreement specifies an annualized threshold that extrapolated the $125 million rate reduction for all 12 months of 2002, even though that rate reduction also commenced on May 1, 2002. Specifically, for 2002, the parties agreed that the threshold would be $1,296 million, and that this amount would be increased in lock-step fashion each year thereafter by $37 million. (Para. 6).

The 2002 sharing threshold of $1,296 million corresponds to the 2002 base rate revenues projected in the Company's MFRs less the permanent annual rate reduction of $125 million. The $37 million increase in the sharing threshold for each of the subsequent years corresponds to the anticipated increase in revenues associated with projected sales and customer growth.

The Settlement Agreement provides that, for each year of the agreement, the threshold set forth in the Settlement Agreement will be compared to "base rate revenues" to determine that amount of revenues subject to revenue sharing. (Para. 6). The term "base rate revenues" is not defined in the Settlement Agreement. It is apparent, however, that in order to arrive at "base rate revenues," it is necessary to take into account all rate reductions, increases, and refunds called for by the Settlement Agreement itself. Without making adjustments for such changes in base rates, it would be impossible either to express "base rate revenues" and the sharing threshold on comparable terms or to ensure the internal integrity of all the terms of the Settlement Agreement.

Because the Settlement Agreement itself does not provide clear direction about how to calculate "base rate revenues," we must look at the substance and significance of all the terms that <u>are</u> set forth in the Settlement Agreement. The Commission, itself, recognized this in its Order approving the Settlement Agreement. In addition to the permanent rate reduction of $125 million annually, the Settlement Agreement provided for a $35 million refund of interim rates in 2002, which obviously would have a direct impact on the <u>net</u> base revenues available for revenue sharing.

<u>Commission Order</u>

In its Order, the Commission recognized and called attention to the fact that "[t]he Stipulation . . . is silent regarding the apportionment of the refund during the interim period." (Order, p. 5). The Commission went on to state:

> Unless there is specific evidence to the contrary, it is normally assumed that the amount to be refunded has been accumulated on an even monthly basis during the interim period. <u>This is an important consideration in determining the appropriate level of revenue that will be subject to the revenue threshold and cap for 2002</u>. We find that only $10,370,000 of the total refund of $35 million ($35,000,000 ÷ 13.5 x 4) is attributable to revenues collected subject to refund during the January 1, 2002, through April 30, 2002 period.

(Order, pp. 5-6) (emphasis added).

Significantly, the Commission took as a <u>given</u> that the Company would have to make appropriate adjustments to "base rate revenues" in "<u>determining the appropriate level of revenue that will be subject to the revenue threshold and cap for 2002</u>." That was never in doubt. The only issue the Commission felt compelled to address was how the Company might allocate the impact of one of the terms of the Settlement Agreement between different years where this was not apparent on the face of the Settlement Agreement.

In accordance with the Commission's Order, it is apparent that Progress Energy must adjust "base rate revenues" for 2002 by increasing those revenues by some or all of the amount the Company was ordered to refund to its customers in 2002. That is true because the forecasted revenues in the Company's MFRs did not anticipate or project that the refund would take place. Therefore, if the refund out of revenues collected subject to refund were not added back into "base rate revenues," it would appear that Progress Energy had not met its MFR forecast at the end of 2002 even if the Company experienced perfectly "normal" weather conditions and had otherwise achieved exactly the level of revenues projected. As a practical matter, absent an adjustment, the payment of the refund would thus operate to insulate Progress Energy from any further refunds to customers through revenue sharing, even if 2002 revenues far exceeded the Company's projections.

As discussed, the Commission authorized Progress Energy to add back to 2002 revenues approximately $25 million of the total refund amount that was determined to be attributable to the prior year. After consultation with Staff, Progress Energy has concluded that adding back the full $35 million in the year the refund was paid (2002) would better accomplish the objective of the adjustment authorized by the Commission. The basis for this conclusion is explained in the affidavit of Mr. Javier Portuondo, attached hereto as Exhibit B.

Lighting and Service Charges

The Commission's Order further recognizes that, although the "proposed Stipulation provides for a 9.25% reduction in base rates for all rate classes, . . . certain Lighting Service (LS-

1) lighting fixture and pole charges will be <u>increased</u>, as will FPC's Service Charges." (Order, p. 4) (emphasis added). The increases in lighting and service charges are reflected in the exhibit to the Settlement Agreement. In discussing these individual items, the Commission noted that new service charges "will result in an annual <u>increase</u> in revenues to FPC of approximately $11 million" and that the "revised fixture charges will result in an annual revenue <u>increase</u> to FPC of approximately $3 million," for a total rate <u>increase</u> of $14 million. (Order, p. 8) (emphasis added). This rate increase is an offset to the $125 million rate increase called for in another provision of the Settlement Agreement.

The total $14 million figure is an <u>annual</u> amount, occurring in each year until such time as the Commission changes the tariff. Therefore, an adjustment to reflect this increase must be made each year. The amount allocable to the period after May 1, 2002 is $9,338 million.

The exhibit to the Settlement Agreement that identifies these rate increases is an integral part of that agreement, as the Commission recognized. OPC and Florida Retail Federation took no position on the particular matters addressed in the exhibit. Yet, they were present and supported approval of the entire agreement when it was brought before the Commission. If the increases reflected in the exhibit were to be treated as falling outside the revenue sharing plan contained in the main body of the Settlement Agreement, then, by the same token, the <u>revenues</u> themselves generated by the increases during 2002 would have to be excluded from the base rate revenues to which the revenue sharing plan applies. If the increases fall outside the Settlement Agreement, then they should fall outside the agreement for all purposes. If, on the other hand, the increases specified in the exhibit are to be taken into account in determining how to apply the revenue sharing plan, it is still necessary to make an adjustment to "base rate revenues" to exclude the enhanced revenues attributable to this decrease because they may not be deemed "excessive" revenues due to extreme weather conditions, etc. Rather, they are explicitly authorized by the Commission as a normal, recurring revenue item that should not give rise to an automatic refund each year the Settlement Agreement is in effect, even if only the forecasted level of sales are achieved. Otherwise, there would have been no point in granting the specific rate increase for the two items.[1]

Annual Rate Reduction

In addition to providing for a refund of $35 million out of revenues collected subject to refund and an increase in lighting and service charges, the Settlement Agreement calls for a reduction in base rate revenues in the annual amount of $125 million. It is critical that this additional adjustment to Progress Energy's revenues be taken into account for purposes of determining "base rate revenues" subject to sharing. In order to determine how to do so, it is critical to understand how the sharing "threshold" set forth in the Settlement Agreement was established.

As noted, the "threshold" in the Settlement Agreement for 2002 – $1,296 million – refers to revenues for the entire year and is thus an annualized number. The starting point for setting this threshold was Progress Energy's MFRs for the year 2002. Specifically, for the year 2002, the Company's MFRs projected that its then-current rates would produce revenues of $1,421 million, based on normal weather. Thereafter, as part of the Settlement Agreement, Progress Energy agreed to an annual rate reduction of $125 million. This amounted to a percentage base rate reduction of 9.25 percent. (Para. 2). The parties then subtracted the entire amount of this annual reduction from the 2002 revenues projected in the MFRs in order to arrive at an annualized sharing threshold of $1,296 million. The effect of this would be to re-set rates to

[1] Because this is a recurring issue, the Company must make an adjustment to "base rate revenues" for this increase in 2003 and subsequent years.

produce revenues of $1,296 million for the entire year, as if the rate reduction has been in effect since January 1, 2002.

It is evident on the face of the Settlement Agreement, however, the 9.25 percent agreed-upon rate reduction was scheduled to commence on May 1, 2002, not January 1, 2002. (Para. 6). This means that the amount of the annual $125 million rate reduction that actually occurred in 2002, on and after May 1, 2002, was $83.4 million, not $125 million. In other words, absent an adjustment in "base rate revenues" for purposes of revenue sharing, the annualized threshold would cause projected 2002 revenues of $41.6 million received before the May 1 rate reduction to be inaccurately classified as "excess" revenues and therefore subject to sharing.[2]

Thus, to allocate the impact of all rate refunds, increases, and decreases called for by the Settlement Agreement so as to arrive at an accurate depiction of better-than-projected revenues, the Company had to make one final adjustment to "base rate revenues" for 2002 – namely, subtracting $41.6 million from unadjusted "base rate revenues."

Summary of Adjustments

The effect of all three adjustments is as follows:

2002 unadj. actual revenues	**$1,323,003,903**
Interim refund	**35,000,000**
Service fee/lighting increase	**(9,338,000)**
Rate reduction not in effect	**(41,625,000)**
Adjusted "base rate revenues"	**$1,307,069,903**

[2] If the Company were to add back to 2002 revenues only $25 million of the $35 million refund, as authorized by the Commission, then the annualized threshold would overstate revenues by only $31 million, in which case the Company would need to make an adjustment of only that amount (instead of a $41 million adjustment) to account for the impact of the $125 million rate reduction.

Under the Settlement Agreement, this adjusted revenue figure must be compared to the revenue threshold specified in the Settlement Agreement to identify excess revenues subject to refund, as follows:

Total adjusted revenues	**$1,307,069,903**
Threshold for 2002	**1,296,000,000**
Excess revenues	**$ 11,069,903**

After making these adjustments, we have identified "excess" revenues for the entire year 2002. This is because we started with annual projected revenues for the entire year and made adjustments necessary to determine the amount of revenues the Company actually achieved for the full year, taking into account the impact of the rate decrease, increase, and refund called for by the Settlement Agreement. Then we compared this to the amount of "base rate revenues" originally projected for the entire year, yielding a delta between projected and actual revenues for the entire year, attributable, by definition, to unprojected revenue-enhancing conditions external to the Settlement Agreement itself. This is the whole focus of revenue sharing.

Because the delta is an annual figure, however, a further calculation must be made to take into account the fact that the revenue sharing plan explicitly applies only to the period beginning on and after May 1, 2002. The Settlement Agreement provides for such a calculation, as follows: "For 2002 only, the refund to the customers will be limited to 67.1% (May 1 through December 31) of the 2/3 customer share." (Para. 6 II). Implementing this provision (and adding interest), we obtain the following result:

Excess revenues	**$11,069,903**
67.1% May-Dec. multiplier	**7,427,905**
2/3 customer share	**4,954,413**
Interest	**44,077**
Customer sharing amount	**$ 4,998,489**

In essence, we must make the adjustments we have described to "base rate revenues" to obtain an accurate difference between revenues projected for the entire year 2002 based on normal weather conditions and rate refunds, reductions, and increases occurring during any part of that year. The result of those adjustments, though, is simply to create an accurate picture of "excess" revenues over the entire year, including periods when rate changes were in effect and periods when they were not in effect. Having thus gotten the annual "pot" right, we must then apply the 67.1 percent multiplier to that pot to recognize the fact that the customers are entitled to share in only part of those annual "excess" revenues because the revenue sharing plan commences on May 1, 2002, the fifth month of the year. The percentage specified in the Settlement Agreement – 67.1 percent – corresponds to that part of the year comprising May 1, 2002 through December 30, 2002.

This approach faithfully implements all parts of the Settlement Agreement and Order and adheres to the parties' underlying intent, as manifested in the language of the Settlement Agreement itself, which makes clear that the overarching aim of the revenue sharing plan is to limit revenues in lieu of a Commission established ROE.

Movants' Calculation

In reaching a different result – contemplating a $23,034,004 refund to customers – the Movants argue for an application of the revenue sharing mechanism that focuses on only parts of the Settlement Agreement and Order, but disregards other crucial components of both the Settlement Agreement and Order. In the process, the Movants argue for an interpretation that would subvert the intent of the parties and the Commission.

Specifically, the Movants argue that no adjustment may be made to 2002 calendar year revenues to reflect the fact that the Commission-approved rate reduction did not actually commence until May 1, 2002. Of course, without such an adjustment, customers could seek a refund from revenues that Progress Energy had projected to achieve from the outset of the rate case, in the Company's MFRs, by arguing that the Company enjoyed excessive revenues for the first part of the year, when revenue sharing did not even apply, due to the simple fact that no rate reduction was imposed on rates from January 1, 2002 through April 30, 2002.

This is because the Movants seek to disregard the fact that the $1,296 million threshold set forth in the Settlement Agreement is an annual figure that assumes for the purpose of creating an annualized number that the parties were agreeing to a total rate reduction of $125 million for 2002. That this is an annualized figure that artificially assumes the full impact of the agreed-upon general rate reduction on a calendar-year basis is made clear in the Settlement Agreement, which increases this figure in a lock-step fashion each year by the amount of $37 million, for use in each subsequent full calendar year. (Para. 6).

The net effect of the Movants' interpretation is to achieve indirectly what the Movants could not achieve directly: namely, to obtain an automatic rate reduction for the first part of 2002, even though neither the Company, the Commission, nor any of the parties ever stated or agreed that rates would be reduced prior to May 1, 2002. To the contrary, the Settlement Agreement explicitly directs that Progress Energy would "begin applying the lower base rate charges required by this Stipulation and Settlement to meter readings made on and after the Implementation Date," namely, May 1, 2002. (Para. 2) (emphasis added).[3]

By the same token, by their interpretation, the Movants would force Progress Energy to increase substantially the $35 million refund the Company agreed to pay from revenues collected subject to refund prior to the effective date of the Settlement Agreement. In this regard, the Settlement Agreement explicitly provides that Progress Energy would "refund to customers $35 million of the interim revenues collected" and that "[n]o other interim revenues collected by FPC during this period will continue to be held subject to refund." (Para. 14) (emphasis added). Yet, the Movants' interpretation would necessitate a refund for the sole reason that revenues "exceed" a threshold that reflects a rate cut that never took place during the interim period simply because it is an annualized number.

Plain Language Argument

The Movants seek to justify this interpretation by arguing that the plain language of the Settlement Agreement forecloses any adjustment to base rate revenues. This argument is meritless for at least two dispositive reasons.

First, if we were to apply the Settlement Agreement literally, customers would get absolutely no refund under the revenue sharing agreement for 2002. That is because the Settlement Agreement literally provides that "Commencing on the Implementation Date and for the remainder of 2002 and for calendar years 2003, 2004 and 2005, and for each calendar year thereafter until terminated by the Commission, FPC will be under a Revenue Sharing Incentive Plan as set forth below." (Para. 6). Read literally, this provision (and others like it in the

---

[3] This not only contradicts the intent of the Settlement Agreement and Order but would constitute an illegal retroactive rate cut. See City of Miami v. Florida Public Service Commission, 208 SO. 2d 249, 260 (Fla. 1968) (prohibiting the Commission from imposing retroactive rate changes).

Settlement Agreement) makes clear that there should be no sharing of revenues realized before May 1, 2002. Applying the Settlement Agreement literally, we should mechanically compare "base rate revenues" taken in by the Company on and after the Implementation Date with the threshold set forth in the Agreement to determine if there is a surfeit or deficiency of revenues. Progress Energy's revenues on and after May 1, 2002, total $928 million. The threshold is set at $1,296 million. Accordingly, there is a deficiency of revenues, as compared with the threshold, after the Implementation Date. Thus, under a literal interpretation of the Settlement Agreement, the Company has no excess revenues to share.

Second, the Movants' argument that the Settlement Agreement should be read literally to preclude any adjustments not expressly provided for in the document is undercut by the fact that the Commission itself recognized in its Order approving the Settlement Agreement that appropriate adjustments must be made "in determining the appropriate level of revenues that will be subject to the revenue threshold and cap for 2002." (Order, p. 6). In reaching this result, the Commission specifically noted that, far from foreclosing the need for interpretation, the Settlement Agreement was "silent" on this issue. The Commission took as a given that such adjustments were contemplated by the Settlement Agreement and had to be made consistent with the evident intent of the agreement.

The only issue the Commission saw a need to address was how Progress Energy might allocate one such adjustment (the interim refund that had been collected over two different calendar years) where the method of allocation was not self-evident. There was simply no need for the Commission to address the issue of allocation for other similar adjustments because the sums involved were attributable exclusively to 2002 and thus required no multi-year allocation.[4]

The Commission's Order in this regard plainly refutes Movants' mechanical construction of the Settlement Agreement and makes clear that (1) the Settlement Agreement contemplates that adjustments must be made to 2002 "base rate revenues" to effectuate the parties' obvious intent, and (2) in this regard, it is critical to account for the effect of the rate adjustments called for in the Settlement Agreement in order to arrive at a true picture of whether the Company derived "excess" revenues (i.e., revenues that exceeded the amounts projected) due to factors external to the Settlement Agreement itself.

The Percentage Multiplier

In further support of their position, the Movants have suggested that the percentage multiplier (67.1 percent) is the sole mechanism established by the parties to deal with the fact that the rate settlement went into effect part way through the first year, namely, on May 1, 2002.

---

[4] If the Settlement Agreement were to be applied mechanically, even the adjustment specifically discussed by the Commission should not be made. If no adjustments were made, and the lighting and service charges were treated as falling outside the Settlement Agreement, as Movants appear to believe they should, then Movants' construction would produce a much smaller refund than the one they now seek. This may be shown as follows:

2002 Revenues	**$1,323,003,903**
Lighting/service charges	**(9,338,000)**
	1,313,665,903
2002 Sharing Threshold	**(1,296,000,000)**
Difference	**17,665,903**
67.1% multiplier	**11,853,820**
2/3 customer share	**$ 7,906,498**

It is not reasonable to assume that the Commission meant to authorize only one step down the road of making logically necessary adjustments to account for the impact of rate refunds, decreases, and increases called for by the Settlement Agreement in order to calculate "base rate revenues." Conceptually, the Commission's discussion necessitates that all such adjustments of like kind be made to avoid internal inconsistencies.

As we have explained, however, the percentage multiplier addresses only part of the problem but not the whole problem. The percentage multiplier operates to set aside (or divide up) for revenue sharing a part of the "pot" of annual 2002 revenues. But the question remains what should go into the "pot" in the first place, before part of it is set aside for sharing on a 1/3 – 2/3 basis. In order to answer that initial question, we must recognize that the whole point of the revenue sharing program is to identify excess revenues – i.e., revenues that exceed projections in the MFRs – which might have triggered a rate review under traditional ROE ratemaking. As we have discussed, this can be accomplished by recognizing that, in 2002, not only did the revenue sharing plan commence part way through the year, but so did the $35 million rate refund, the $125 million rate reduction, and the $14 million increase in lighting and service charges. We cannot determine the size of the annual 2002 pot in the first place without making proper adjustments to reflect these facts, as the Commission recognized in its Order. Only after we have made the necessary adjustments to ensure that we have the right "pot" of revenues for 2002, are we in a position to apply the 67.1 percent multiplier to set aside the right portion of that annual pot for purposes of revenue sharing.

III. Controlling Legal Principles

Overview

At the outset, it is important to recognize that we are not dealing in this matter merely with a stipulation among private parties. We are dealing also with a Commission Order, approving a proposed stipulation in a rate case, where the Commission's power is paramount. The Commission, therefore, has the authority and the responsibility to ensure that the revenue sharing mechanism at issue is applied in a manner that effectuates the Commission's own understanding in approving the proposed stipulation and that does not do violence to well-understood regulatory policies and principles. See Miami Bridge Co. v. Railroad Commission, 20 So. 2d 356 (Fla. 1943) (state's powers over rates are paramount over contractual agreements); City of Tampa Waterworks Co., 34 So. 631 (Fla. 1903) (contracts are subject to regulatory authority).

In this case, the Movants call upon this Commission to apply its Order and the Settlement Agreement mechanically and with a blind eye to any consideration of the true purpose or logic of the revenue sharing agreement, or the background against which it was adopted, precisely because the interpretation the Movants urge conflicts with the considerations taken into account by the parties in developing the agreement and does violence to the whole concept of revenue sharing, which was explicitly intended to serve as a mechanism to limit excess revenues, in lieu of an authorized ROE. The Commission should reject the Movants' strained interpretation of the Settlement Agreement and Order.

Taking into consideration traditional principles of judicial contract construction, the Commission should reject the Movants' position and deny their Motion. It is well settled that, in construing a contract, a court must construe the contract as a whole, with due regard to all of its terms. See City of Homestead v. Johnson, 760 So. 2d 80, 84 (Fla. 2000) ("Courts [should] . . . read provisions of a contract harmoniously in order to give effect to all portions thereof."). It is inappropriate to construe any term in isolation from the remainder of the agreement. See Sugar Cane Growers Cooperative of Florida, Inc. v. Pinnock, 735 So. 2d 530, 535 (Fla. 4th DCA 1999) (holding that trial court erred in failing to give effect to all provisions of the agreement); see also Macaw v. Gross, 452 So. 2d 1126, 1127 (Fla. 3d DCA 1984) ("To ascertain the intention of the parties to a contract, the trial court must examine the whole instrument, not just particular portions, and reach an interpretation consistent with reason, probability, and the practical aspects of the transaction between the parties.") (emphasis added). The court must interpret the contract so as to give meaning to all of its terms. See Inter-Active Servs., Inc. v. Heathrow Master Assoc., Inc., 721 So. 2d 433, 435 (Fla. 5th DCA 1998) ("When possible, courts should give effect to each provision of a written instrument in order to ascertain the true meaning of the instrument."); see Coral Gables Police Benev. Ass'n v. Just, 179 So. 2d 390, 392 (Fla. 1965) ("Intention of parties to a contract must be determined by an examination of entire instrument.").

The overarching aim in construing the provisions of the agreement is to discern and effectuate the parties' intent. See American Home Assur. Co. v. Larkin General Hosp., Ltd., 593 So. 2d 195, 196 (Fla. 1992) ("The intent of the parties to the contract should govern the construction of a contract . . . . To determine the intent of the parties, a court should consider the language in the contract, the subject matter of the contract, and the object and purpose of the contract.") (emphasis added). The court should avoid any interpretation of a contract that is absurd or appears to contravene the true intent of the parties in entering into the agreement. See World Vacation Travel, S.A., de C.V. v. Brooker, 799 So. 2d 410, 412 (Fla. 3d DCA 2001) ("Looking to the other provisions of a contract and to its general scope, if one construction would lead to an absurd conclusion, such interpretation must be abandoned and that adopted which will be more consistent with reason and probability.").

Natural Reading of the Settlement Agreement and Order

Progress Energy believes that the "contract" (i.e., the Settlement Agreement), on its face, can and should be interpreted to produce a logical, fair result that is consistent with the parties' intent and the Commission's Order. The Commission should reject Movants' inappropriate interpretation of the Commission's Order and the parties' Settlement Agreement. As we have described, the most natural reading of all the terms of the Settlement Agreement and Order leads to one inescapable conclusion: the revenue sharing mechanism was intended to limit excessive revenues in lieu of an authorized ROE. In this context, it is plain that excess revenues are revenues that might be inflated due to unanticipated factors external to the Settlement Agreement itself, such as extreme weather conditions, and that might otherwise trigger a rate review by the Commission. The Settlement Agreement calls for a comparison of "base rate revenues" and the annualized sharing threshold. This comparison may be made properly only by determining "base rate revenues" in a manner that takes into account the annualized effect of all rate reductions, increases, and refunds authorized elsewhere in the Order and Settlement Agreement. Absent adjustments for these effects, the comparison simply cannot be made on a meaningful, apples-to-apples basis.

In the Event of an Ambiguity

If the Commission doubts Progress Energy's interpretation in considering the terms of the Settlement Agreement itself, at a minimum the Commission must conclude that the Settlement Agreement is ambiguous. Indeed, this Commission in its own Order recognized that the Settlement Agreement "was silent," i.e., was not explicit or unambiguous, on whether and how the parties were to take into account all necessary adjustments to 2002 "revenues that will be subject to the revenue threshold and cap." (Order, p. 6).

Of course, "If a contract is clear, complete and unambiguous, there is no need for judicial construction. . . . But even the most cautious drafting, and the most exhaustive imagination, rarely covers every possible contingency." Centennial Mortgage, Inc. v. SG/SC, Ltd., 772 So.2d 564, 565 (1st DCA 2000). "[W]here the contract is susceptible to two different interpretations, each one of which is reasonably inferred from the terms of the contract, the agreement is ambiguous." Miller v. Kase, 789 So. 2d 1095, 1097-98 (4th DCA 2001). It is not unusual for each side in a contract dispute to claim "that the contract is clear and unambiguous, but each ascribes a different meaning to the 'unambiguous' language of the contract." Id. at 1098. This may be indicative of the fact that the contract is, in fact, ambiguous. Id.

It is well settled that, "[i]n the absence of clear and unambiguous language, the court must engage in judicial interpretation. To that end, the court must attempt to ascertain the intention of the parties and may accept parol evidence, not to vary the terms of the contract but to explain ambiguous terms." Id. (emphasis added). It is equally well established that, "[i]n construing a contract, the court should try to place itself in the situation of the parties, including the surrounding circumstances, to determine the meaning and intent of the language used." Id. (emphasis added). When a court is called upon to construe a contract, "[e]xtrinsic evidence is not only admissible . . . but is frequently required where the instrument itself does not provide sufficient insight into intent." Centennial Mortgage, Inc. v. SG/SC, Ltd., 772 So. 2d at 565.); see Berry v. Teves, 752 So. 2d 112, 114 (2d DCA 2000) (when contract contains a latent ambiguity "parole evidence is admissible to determine the parties' intent").

Certainly, the Commission has ample grounds here to reject the Movants' exhortation to take an ostrich-like approach to resolving this dispute, ignoring all "matters lying outside of the agreement" that may bear on the parties' true intent. (Motion to Enforce, p. 5). It serves neither the interests of the parties, the Commission, nor the ratepayers to ignore, for example, the content of the very MFRs that were the focus of the rate case and that served as the basis for the most fundamental projections and calculations in the Settlement Agreement. When the Commission considers the language of its own Order, all the terms of the Settlement Agreement read in harmony with each other, and the surrounding circumstances in which the Settlement

Agreement was entered into, the Commission will readily conclude that Progress Energy's interpretation is correct and the Movants' interpretation is wrong.

IV. Conclusion

For the foregoing reasons, and based on the Affidavit of Mr. Javier Portuondo submitted herewith, the Commission should deny the Movants' Motion to Enforce Settlement Agreement and enter an order determining that the Movants are not entitled to the refund they seek. We believe that, on the current record, the Commission may enter an order in favor of Progress Energy in this matter after oral argument without further proceedings. If, however, the Commission believes that it does not have a sufficient record to decide the merits in the Company's favor at this time, then in the alternative we would request an evidentiary hearing to resolve this dispute.

Respectfully submitted,

James A. McGee
PROGRESS ENERGY SERVICE COMPANY, LLC
Post Office Box 14042
St. Petersburg, FL 33733-4042
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

Gary L. Sasso
Jill H. Bowman
W. Douglas Hall
CARLTON FIELDS, P.A.
Post Office Box 2861
St. Petersburg, FL 33731
Telephone: (727) 821-7000
Facsimile: (727) 822-3768
Attorneys for Progress Energy Florida, Inc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of foregoing has been furnished via U.S. Mail to the following this 7th day of March, 2003.

Mary Anne Helton, Esquire
Adrienne Vining, Esquire
Bureau Chief, Electric and Gas
Division of Legal Services
Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
Phone: (850) 413-6096
Fax: (850) 413-6250
Email: mhelton@psc.state.fl.us

Jack Shreve, Esquire
Public Counsel
John Roger Howe, Esquire
Charles J. Beck, Esquire
Deputy Public Counsel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison St., Room 812
Tallahassee, FL 32399-1400
Phone: (850) 488-9330
Attorneys for the Citizens of the State of Florida

Ron LaFace, Esquire
Greenberg Traurig, P.A.
101 E. College Ave.
Tallahassee, FL 32301
Phone: 850-222-6891
Attorneys for Florida Retail Federation

Vicki Kaufman, Esquire
Joseph McGlothlin, Jr., Esquire
McWhirter Law Firm
117 S. Gadsden St.
Tallahassee, FL 32301
Phone: 850-222-2525
Attorneys for Florida Industrial Power Users Group

Thomas A. Cloud, Esquire
Gray, Harris & Robinson, P.A.
301 East Pine Street, Ste. 1400
P.O. Box 3068
Orlando, FL 32801
Phone: (407) 244-5624
Fax: (407) 244-5690
Attorneys for Publix Super Markets, Inc.

Michael Twomey, Esquire
Post Office Box 5256
Tallahassee, FL 32314-5256
Phone: 850-421-9530
Attorneys for Buddy Hansen and Sugarmill Woods Civil Association

Attorney

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.	DOCKET NO. 000824-EI
In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 020001-EI ORDER NO. PSC-02-0655-AS-EI ISSUED: May 14, 2002

The following Commissioners participated in the disposition of this matter:

LILA A. JABER, Chairman
J. TERRY DEASON
BRAULIO L. BAEZ
MICHAEL A. PALECKI
RUDOLPH "RUDY" BRADLEY

ORDER APPROVING SETTLEMENT, AUTHORIZING MIDCOURSE CORRECTION, AND REQUIRING RATE REDUCTIONS

BY THE COMMISSION:

I. BACKGROUND

Docket No. 000824-EI was opened on July 7, 2000, to review the earnings of Florida Power Corporation (FPC, utility, or company) and the effects of the acquisition of FPC by Carolina Power & Light Company (CPL). The acquisition was consummated on November 30, 2000. By Order No. PSC-01-1348-PCO-EI, issued June 20, 2001, in Docket No. 000824-EI, we directed FPC to file Minimum Filing Requirements (MFRs) to provide this Commission and all other interested parties with the data necessary to begin an evaluation of FPC's level of earnings on a going-forward basis. In addition, FPC was ordered to hold $113.9 million subject to refund pending a final disposition in Docket No. 000824-EI. We subsequently reduced

EXHIBIT A

DOCUMENT NUMBER-DATE
05132 MAY 14 8
FPSC-COMMISSION CLERK

the amount held subject to refund to $98 million by Order No. PSC-01-2313-PCO-EI, issued November 26, 2001.

FPC filed its initial set of MFRs and testimony on September 14, 2001, with subsequent filings on October 15, 2001, and November 15, 2001, and rebuttal testimony on February 11, 2002, and March 4, 2002. The intervenors began filing testimony on January 17, 2002, and our staff prefiled testimony on January 28, 2002. Discovery ended on March 13, 2002. The hearing was scheduled to begin on March 20, 2002. On that date, however, the parties filed a Joint Motion To Postpone Scheduled Hearings to afford the parties the opportunity to finalize the terms of a settlement and stipulation. The motion was granted by Order No. PSC-02-0411-PCO-EI, issued March 26, 2002. By Order No. PSC-02-0412-PCO-EI, issued March 26, 2002, the hearing schedule was suspended.

On March 27, 2002, FPC, the Office of Public Counsel (OPC), the Florida Industrial Power Users Group, the Florida Retail Federation, Publix Super Markets, Inc., and Buddy Hansen and Sugarmill Woods Civic Association, filed a Joint Motion for Approval of Stipulation and Settlement and Further Postponement of Hearings and a Stipulation and Settlement. The Stipulation and Settlement, including Exhibit A attached thereto, is attached to this Order as Attachment 1 and is incorporated herein by reference. FPC subsequently filed a Petition to Reduce its Fuel Adjustment Factors on April 8, 2002. This Order addresses both of these filings.

II. <u>STIPULATION AND SETTLEMENT</u>

All parties to Docket No. 000824-EI proffered the Stipulation and Settlement as a complete resolution of all matters pending in that docket. The Stipulation and Settlement was signed by all parties to the proceeding. However, OPC and the Florida Retail Federation have taken no position on the cost of service and rate design matters discussed in Section 16 of the Stipulation. The major elements contained in the Stipulation are as follow:

- $125 million permanent base rate reduction effective May 1, 2002 (9.25% base rate reduction). (Paragraph 2)

- $35 million in interim revenues to be refunded through the Fuel and Purchased Power Cost Recovery Clause. (Paragraph 14)

- Implementation of a revenue cap and revenue sharing plan for the remainder of 2002 and calendar years 2003, 2004, and 2005. (Paragraph 6)

- Recovery of the Hines Unit 2 depreciation expense and return on capital, up to the level of fuel savings associated with Hines Unit 2, through the fuel adjustment clause until December 31, 2005. (Paragraph 9)

- Suspension of the accruals for nuclear decommissioning and fossil dismantlement, an annual $62.5 million reduction of depreciation expense and the discretionary ability to reverse all, or part of, the $62.5 million annual depreciation expense reduction. (Paragraph 10)

- Discretionary ability to accelerate the amortization of certain specified regulatory assets. (Paragraph 11)

- In the event FPC does not achieve a 20 percent improvement in System Average Interruption Duration Index (SAIDI) during 2004 and 2005, the utility will refund $3 million for both years in equal amounts to the ten percent of FPC customers served by FPC's worst performing distribution feeder lines. (Paragraph 13)

- Revisions to certain cost of service and rate design matters. (Paragraph 16 and Exhibit A)

As part of the Stipulation, FPC has filed a petition for an $85 million ($83.7 million retail) mid-course correction to reduce its fuel cost recovery factors for the remainder of 2002, effective with May Cycle 1 billings. The mid-course correction consists of a $50 million ($48.7 million retail) reduction due to decreased fuel costs and the $35 million interim refund. We address that petition in Section III of this Order.

The proposed Stipulation consists of 18 paragraphs, most of which are self-explanatory. Those provisions which merit comment or clarification are as follow:

Paragraph 2: The proposed Stipulation provides for a 9.25% reduction in base rates for all rate classes. As further discussed in Paragraph 16, certain Lighting Service (LS-1) lighting fixture and pole charges will be increased, as will FPC's Service Charges.

The proposed percentage reduction in all base rate charges differs from previous rate stipulations that allocated the reduction on an energy (per kilowatt-hour) basis. We find that the percentage reduction in base rates is a better method of allocating a decrease in this case because all classes are treated equally. Under an energy allocation, a larger percentage of the total reduction is allocated to large commercial and industrial customers at the expense of residential and small commercial customers.

Order No. PSC-01-1348-PCO-EI, requiring FPC to file MFRs, states that one of the reasons for requiring MFRs was to ensure proper ratemaking and cost allocations among the rate classes to reflect changes that have occurred since the company's last rate case. FPC's most recent fully allocated cost of service study was filed in 1991, and utilized a projected 1993 test year. Since that time, significant changes have taken place in the company's operations, and cost shifting among the rate classes has occurred.

This Commission has historically sought to establish rates that recover the cost to serve each rate class. Stated differently, this Commission has attempted to set the rate of return for each rate class as close as practicable to the system-wide rate of return. We recognize, however, that a Stipulation is a negotiated document, and all participants have made concessions. While the proposed across-the-board percentage reduction does not improve FPC's rate structure, it does not worsen it. Accordingly, we find that the across-the-board reduction is reasonable.

Paragraph 3: Per the terms of this provision, FPC will no longer have an authorized Return on Equity (ROE) range for the purpose of addressing earnings levels. However, FPC will still have a currently authorized ROE range of 11.00% to 13.00%, with a 12.00% midpoint, for all other purposes, such as cost recovery clauses and AFUDC.

Paragraph 6: This provision addresses the revenue sharing plan. The following delineate the sharing threshold and revenue cap points by year:

YEAR	THRESHOLD (millions)	CAP (millions)
2002	$1,296	$1,356
2003	$1,333	$1,393
2004	$1,370	$1,430
2005	$1,407	$1,467

Paragraph 9: This provision permits the recovery of the return on capital and the depreciation expense, up to the level of fuel savings, associated with Hines Unit 2 through the fuel adjustment clause. However, the Stipulation is silent on the methodology to be utilized to estimate the fuel savings. Although we approve the recovery mechanism set forth in Paragraph 9, the resolution of the definition of "fuel savings" is an issue that will be more appropriately addressed in Docket No. 020001-EI.

Paragraph 13: This provision provides that FPC will refund $3 million to customers in the event that the utility's SAIDI improvement is not achieved for calendar years 2004 and 2005. OPC has since clarified, and the other parties have agreed, that the proposed $3 million refund to customers in the event that FPC does not achieve its distribution reliability objective during the years 2004 and 2005 applies separately to those years. FPC's objective is to achieve a 20% improvement (decrease) compared to its 2000 SAIDI in each of those years. Thus, if the objective were not achieved in 2004, FPC would refund $3 million to customers in 2005; and if the objective were not achieved in 2005, FPC would refund $3 million to customers in 2006.

Paragraph 14: This provision provides for a $35 million refund of the interim revenues collected subject to refund since March 13, 2001. This represents a 13 ½ month period from the beginning of the interim until its conclusion on April 30, 2002. The Stipulation, however, is silent regarding the apportionment of the refund during the interim period. Unless there is specific evidence to the contrary, it is normally assumed that the amount to be refunded has been accumulated on an even monthly basis during the interim period. This is an important consideration in determining the appropriate level of revenues that will be subject to the revenue threshold and cap for 2002. We find that only $10,370,000 of the total refund of $35 million ($35,000,000 ÷ 13.5 x 4) is attributable to revenues collected subject to refund during the January 1, 2002, through April 30, 2002 period.

Paragraph 15: This provision states that FPC's IS-1 and IST-1 Interruptible rates, and its CS-1 and CST-1 Curtailable rates will remain open to existing customers and retain their current demand credits until reviewed in a general rate case. These demand credits are given to non-firm customers to compensate them for allowing FPC to interrupt at times of capacity shortfall, and are recovered through the Conservation Cost Recovery Clause. The rates will continue to remain closed to new customers, as they have been since April 1996.

In its MFR filing, FPC had proposed to close the rates and require the existing customers to transfer to the IS-2, IST-2, CS-2 and CST-2 non-firm rates because the company did not believe that the current IS-1, IST-1, CS-1 and CST-1 credits were cost effective.

Paragraph 16: This provision addresses certain rate design and cost of service matters that were agreed to as a part of the proposed Stipulation. These matters are discussed in Exhibit A to the Stipulation containing nine numbered paragraphs, which is attached hereto as part of Attachment 1. OPC and the Florida Retail Federation took no position on these matters, and thus they do not oppose or support them.

Initial Levelized Residential Rate

The Stipulation includes a reduction in the base rate charges for all rate classes of 9.25%. For the residential class, this results in a reduction in the monthly customer charge from $8.85 to $8.03, and a reduction in the non-fuel energy charge from 4.020 cents per kwh to 3.648 cents per kwh. In addition, the residential fuel factor will decrease from 2.692 cents per kwh to 2.367 cents per kwh due to the fuel mid-course correction. The mid-course correction includes a $48.7 million ($50 million system) reduction due to decreased fuel costs, and a $35 million reduction that represents the stipulated interim refund.

As shown on page 1 of Impact of Proposed Stipulation and Settlement on Monthly 1,000 kwh Residential Bill, attached hereto as Attachment 2 and incorporated herein by reference, these reductions will result in a $7.99 decrease in the 1,000 kwh residential bill, from the current $91.65 to $83.66. These rates will be in effect beginning with the first billing cycle in May 2002 through the end of June 2002.

Inverted Residential Rate

Pursuant to paragraph 1 of Exhibit A, attached hereto as part of Attachment 1, all residential customers will be billed under an inverted rate that will be implemented in July 2002. Under this rate, the non-fuel energy charge will be 3.315 cents per kwh for usage up to 1,000 kilowatt hours per month, and 4.315 cents per kwh for all usage above 1,000 kilowatt hours.

The Stipulation states that the inverted rate is to be designed to be revenue neutral to the levelized rate. This means that it should recover on an annual basis the same revenues as the new levelized rate effective in May 2002. Our review of the rate design workpapers confirms that the proposed inverted rate achieves this goal.

As a result of the inverted rate design, the 1,000 kwh residential bill will decrease by an additional $3.41 in July 2002, to $80.25, as shown on page 1 of Attachment 2. We note that this change is an artifact of the inverted rate design, and does not represent an additional overall rate reduction. Under the inverted rate, customers who use less than 1,500 kwh per month will see a reduction in their bill relative to the levelized rate, while those who use above that level will see an increase.

Interruptible and Curtailable Rate Schedules

Pursuant to paragraph 2 of Exhibit A, attached hereto as part of Attachment 1, the billing demand credits for FPC's IS-2 and IST-2 Interruptible rates will be raised from their current level of $2.82 to $3.08 per kw. The credits for its CS-2 and CST-2 Curtailable rates will be raised from $1.50 to $2.31 per kw.

These credits are given to non-firm customers to compensate them for allowing FPC to interrupt at times of capacity shortfall, and are recovered through the Conservation Cost Recovery Clause. The revised credits represent the cost-effective level proposed by FPC in its MFR filing.

Paragraph 3 of Exhibit A, attached hereto as part of Attachment 1, states that a 500 kw minimum billing demand provision will be added to the IS-2, IST-2, CS-2 and CST-2 rate schedules. This means that customers will be billed for a minimum of 500 kw of demand, even if their actual measured demand falls below that level. for the month.

The Stipulation states that for existing customers whose billing demands have been below 500 kw in any of the 12 billing periods prior to May 1, 2002, the minimum billing provision will not apply if they give the required 36 months' notice for returning to firm service. FPC has indicated that there are three existing customers who will be affected by the new minimum billing demand provision.

<u>Service Charges</u>

Paragraph 8 of Exhibit A, attached hereto as part of Attachment 1, states that the Service Charges proposed by FPC in its filing will be adopted. Service Charges recover the costs of activities such as the initial connection or reconnection of service, and temporary service. The new charges will result in an annual increase in revenues to FPC of approximately $11 million.

<u>Lighting Service (LS-1) Rate Schedule</u>

As noted above, all rate classes will receive a 9.25% base rate reduction, including the non-fuel energy and customer charges under the Lighting Service (LS-1) rate schedule. The Stipulation provides, however, in paragraph 9 of Exhibit A, that certain of the lighting fixture and pole charges will be increased. These charges are monthly rental fees that recover the cost of optional FPC-provided lighting fixtures and poles. The revised fixture charges will result in an annual revenue increase to FPC of approximately $3 million.

The maintenance charges, which recover the cost of maintaining the lighting fixtures, will remain unchanged from their current levels. The addition and deletion of certain lighting fixture offerings proposed by FPC in its initial filing are also incorporated as part of the stipulation.

City of Sebring Capacity Charges

Paragraph 5 of Exhibit A, attached hereto as part of Attachment 1, states that the base rate charges to which the parties have stipulated do not reflect the recovery of any purchased power capacity costs. Consequently, the credit currently reflected in FPC's Capacity Cost Recovery clause (CCRC) for base rate production capacity costs associated with sales to FPC's customers in the territory formerly served by the Sebring Utilities Commission (Sebring) will be discontinued.

The CCRC credit was established in 1993 following FPC's acquisition of the electric distribution assets of Sebring. As a result of that transaction, FPC began serving those electric customers who were formerly served by Sebring. (See Order No. PSC-92-1468-FOF-EU, issued December 17, 1992, in Docket No. 920949-EU.)

The credit is made to avoid the double recovery through base rates of production capacity costs associated with the former customers of Sebring that are now served by FPC. The Stipulation specifies that FPC's revised base rates do not include any purchased power costs, and it therefore proposes to eliminate the credit now included in FPC's CCRC effective May 1, 2002. The elimination of this credit will result in an approximate $4.4 million annual increase in the level of costs recovered by FPC through the CCRC.

Conclusion

We have reviewed the terms of the Stipulation. The proposed $125 million base rate reduction and $35 million refund afford FPC's ratepayers immediate relief. The Stipulation also implements a revenue sharing plan that could result in future refunds to FPC's ratepayers. Moreover, there is the potential for an additional $3 million refund for calendar years 2004 and/or 2005 if FPC fails to achieve certain performance levels during those years. In addition, FPC's ratepayers will not be subject to an increase in base rates when Hines Unit 2 is placed into service in late 2003. The major costs of Hines Unit 2 will be recovered by offsetting the fuel savings associated with that unit. Based upon all of the foregoing, we find that the proposed Stipulation and Settlement provides a reasonable resolution of the issues regarding FPC's level of earnings and base rates, and it is therefore approved in its entirety.

III. PETITION FOR ADJUSTMENT TO REDUCE FUEL AND PURCHASED POWER COST RECOVERY FACTORS

On April 8, 2002, FPC filed a petition to reduce its collections through the Fuel and Purchased Power Cost Recovery Clause (Fuel Clause) by $85 million during the last 8 months of 2002. This $85 million reduction is comprised of two parts: 1) $50 million to reflect lower than expected fuel costs, and 2) $35 million to refund interim revenues held subject to refund in Docket No. 000824-EI as set forth in Section 14 of the Settlement and Stipulation. We find that the fuel clause is a reasonable mechanism for returning the $35 million interim refund to FPC's ratepayers. FPC proposes to reduce its levelized fuel adjustment factor to 2.363 cents per kwh, effective with the May Cycle 1 billings. In conjunction with the change in FPC's base rates, the monthly bill of a residential ratepayer who uses 1,000 kwh per month will decrease to $83.66 (see Attachment 2). The proposed factors by FPC rate schedule are shown on Attachment 3, Fuel and Purchased Power Cost Recovery Factors, which is attached hereto and incorporated herein by reference.

Absent the $50 million reduction, FPC would experience an end-of-period (December 2002) net over-recovery amount of approximately $58.9 million. This amount represents six percent of FPC's total fuel and net power transactions costs as forecasted in its projection testimony in Docket No. 010001-EI. Since FPC filed its projection testimony in Docket No. 010001-EI, its forecasted 2002 fuel cost of system net generation has decreased by $59.3 million. We attribute this reduction primarily to a 21.9 percent drop in the projected natural gas price and secondarily to a 7.1 percent drop in the projected coal price. Although total costs were reduced by $50 million, it should be noted that FPC is allocating $48.7 million of that reduction to the retail ratepayers.

In the interest of matching fuel revenues with fuel costs, we support FPC's proposal to return part of its over-recovery balance to its ratepayers sooner rather than later. However, we have not yet analyzed the prudence of FPC's actual or projected 2002 fuel costs. We shall determine the prudence of FPC's 2002 fuel costs at the evidentiary hearing scheduled in Docket No. 020001-EI, commencing November 20, 2002.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Joint Stipulation and Settlement filed on March 27, 2002, attached hereto as Attachment 1, is approved in its entirety, subject to the clarifications discussed in the body of this Order. It is further

ORDERED that each of the findings made in the body of this Order is hereby approved in every respect. It is further

ORDERED that the attachments and exhibit attached hereto are incorporated herein by reference. It is further

ORDERED that Florida Power Corporation's petition for an adjustment to reduce its fuel and purchased power cost recovery factors is granted. It is further

ORDERED that Docket No. 000824-EI shall be closed. It is further

ORDERED that Docket No. 020001-EI shall remain open.

By ORDER of the Florida Public Service Commission this 14th day of May, 2002.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records and Hearing
Services

(S E A L)

RG

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW
APPLICABLE TO SECTION II OF THIS ORDER

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW APPLICABLE TO SECTION III OF THIS ORDER

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

Any party adversely affected by Section III of this order, which is preliminary, procedural or intermediate in nature, may request: (1) reconsideration within 10 days pursuant to Rule 25-22.0376, Florida Administrative Code, if issued by a Prehearing Officer; (2) reconsideration within 15 days pursuant to Rule 25-22.060, Florida Administrative Code, if issued by the Commission; or (3) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Director, Division of the Commission Clerk and Administrative Services, in the form prescribed by Rule 25-22.060, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

ATTACHMENT 1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.	Docket No. 000824-EI

STIPULATION AND SETTLEMENT

Florida Power Corporation, the Office of Public Counsel, the Florida Industrial Power Users Group, the Florida Retail Federation, Publix Super Markets, Inc., and Buddy Hansen and Sugarmill Woods Civic Association (collectively, the Stipulating Parties), hereby enter into this Stipulation and Settlement for the purpose of reaching an informal resolution of all outstanding issues in Docket No. 000824-EI pending before the Florida Public Service Commission (the Commission) and, accordingly, stipulate and agree as follows:

1. Upon approval and final order of the Commission, this Stipulation and Settlement will become effective on May 1, 2002 (the "Implementation Date"), and continue through December 31, 2005, except as otherwise provided in Sections 6, 7 and 15 hereof.

2. Florida Power Corporation (FPC) will reduce its revenues from the Sale of Electricity by a permanent annual amount of $125 million. This reduction will be reflected on FPC's customer bills by reducing all base rate charges for each rate schedule by 9.25%. All other cost of service and rate design matters will be determined in accordance with Section 16. FPC will begin applying the lower base rate charges required by this Stipulation and Settlement to meter readings made on and after the Implementation Date.

3. Effective on the Implementation Date, FPC will no longer have an authorized Return on Equity (ROE) range for the purpose of addressing earnings

levels, and the revenue sharing mechanism herein described will be the appropriate and exclusive mechanism to address earnings levels.

4. No Stipulating Party will request, support, or seek to impose a change in the application of any provision hereof. The Stipulating Parties other than FPC will neither seek nor support any additional reduction in FPC's base rates and charges, including interim rate decreases, that would take effect prior to December 31, 2005 unless such reduction is initiated by FPC. FPC will not petition for an increase in its base rates and charges, including interim rate increases, that would take effect prior to December 31, 2005, except as provided in Section 7.

5. During the term of this Stipulation and Settlement, revenues which are above the levels stated herein will be shared between FPC and its retail electric utility customers -- it being expressly understood and agreed that the mechanism for revenue sharing herein established is not intended to be a vehicle for "rate case" type inquiry concerning expenses, investment, and financial results of operations.

6. Commencing on the Implementation Date and for the remainder of 2002 and for calendar years 2003, 2004 and 2005, and for each calendar year thereafter until terminated by the Commission, FPC will be under a Revenue Sharing Incentive Plan as set forth below. For purposes of this Revenue Sharing Incentive Plan, the following retail base rate revenue threshold amounts are established:

I. Revenue Cap - All retail base rate revenues above the retail base rate revenue cap will be refunded to retail customers on an annual basis. The retail base rate revenue cap for 2002 will be $1,356 million. For 2002 only, the refund to customers will be limited to 67.1% (May 1 through December 31) of the retail base rate revenues exceeding the cap. The retail base rate revenue caps for calendar year 2003 and for each calendar year thereafter in which this Plan is in effect will be increased by $37 million over the prior year's revenue cap. Section 8 explains how refunds will be paid to customers.

II. Sharing Threshold - Retail base rate revenues between the sharing threshold amount and the retail base rate revenue cap will be divided into two shares on a 1/3, 2/3 basis. FPC's shareholders shall receive the 1/3 share. The 2/3 share will be refunded to retail customers. The sharing threshold for 2002 will be $1,296 million in retail base rate revenues. For 2002 only, the refund to the customers will be limited to 67.1% (May 1 through December 31) of the 2/3 customer share. The retail base rate revenue sharing threshold amounts for calendar year 2003 and for each calendar year thereafter in which this Plan is in effect will be increased by $37 million over the prior year's revenue sharing threshold. Section 8 explains how refunds will be paid to customers.

7. If FPC's retail base rate earnings fall below a 10% ROE as reported on an FPSC adjusted or pro-forma basis on an FPC monthly earnings surveillance report during the term of this Stipulation and Settlement, FPC may petition the Commission to amend its base rates notwithstanding the provisions of Section 4. The other Stipulating Parties are not precluded from participating in such a

proceeding. This Stipulation and Settlement shall terminate upon the effective date of any Final Order issued in such proceeding that changes FPC's base rates.

8. All revenue sharing refunds will be paid with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, Florida Administrative Code, to retail customers of record during the last three months of each applicable refund period based on their proportionate share of base rate revenues for the refund period. For purposes of calculating interest only, it will be assumed that revenues to be refunded were collected evenly throughout the preceding refund period at the rate of one-twelfth per month. All refunds with interest will be in the form of a credit on the customers' bills beginning with the first day of the first billing cycle of the third month after the end of the applicable refund period. Refunds to former customers will be completed as expeditiously as reasonably possible.

9. Beginning with the in-service date of Hines Unit 2 through December 31, 2005, FPC will be allowed to recover through the fuel cost recovery clause a return on average investment and straight-line depreciation expense (but no other non-fuel expense) for Hines Unit 2, to the extent such costs do not exceed the unit's cumulative fuel savings over the recovery period. All costs associated with Hines Unit 2, including those described in this section, are subject to Commission review for prudence and reasonableness as a condition for recovery through the fuel cost recovery clause. The investment for Hines Unit 2 upon which a return is recovered under this section will be excluded from rate base for surveillance reporting purposes during the recovery period.

10. Beginning with the Implementation Date through December 31, 2005, FPC will suspend accruals to its reserves for nuclear decommissioning and fossil

dismantlement. For each calendar year during this period, FPC will also record \$62.5 million as a credit to depreciation expense and a debit to the bottom line depreciation reserve and may, at its option, record up to an equal annual amount as an offsetting accelerated depreciation expense and a credit to the bottom line depreciation reserve. Any such reserve amount will be applied first to reduce any reserve excesses by account, as determined in FPC's depreciation studies filed after the term of this Stipulation and Settlement, and thereafter will result in reserve deficiencies. Any such reserve deficiencies will be allocated to individual reserve balances based on the ratio of the net book value of each plant account to total net book value of all plant. The amounts allocated to the reserves will be included in the remaining life depreciation rate and recovered over the remaining lives of the various assets. Additionally, depreciation rates as addressed in Order No. PSC-98-1723-FOF-EI, Docket No. 971570-EI, will not be changed for the term of this Stipulation and Settlement.

11. FPC will be authorized, at its discretion, to accelerate the amortization of the regulatory assets for FAS 109 Deferred Tax Benefits Previously Flowed Through, Unamortized Loss on Reacquired Debt, and Interest on Income Tax Deficiency over the term of this Stipulation and Settlement.

12. Beginning with meter readings made on and after the Implementation Date, FPC shall effect a mid-course correction of its fuel cost recovery clause to reduce the fuel clause factor based on projected over-recoveries, in the amount of \$50 million, for the remainder of calendar year 2002. The fuel cost recovery clause shall continue to operate as normal, including but not limited to, any additional mid-course adjustments that may become necessary and the calculation of true-ups to

actual fuel clause expenses. FPC will not use the various cost recovery clauses to recover new capital items which traditionally and historically would be recoverable through base rates, except as provided in Section 9.

13. FPC will continue the implementation of its four-year Commitment to Excellence Reliability Plan, including its objective of a 20% improvement in FPC's System Average Interruption Duration Index (SAIDI), measured on a calendar-year basis, by no later than 2004. FPC will provide a $3 million refund to customers in the event this SAIDI improvement is not achieved for calendar years 2004 and 2005. Any such refunds will be paid in equal amounts to the 10% of FPC's total retail customers served by FPC's worst performing distribution feeder lines based on each feeder line's SAIDI performance. SAIDI levels will be calculated consistent with the Commission's reliability reporting procedures, but SAIDI performance levels during 2004 and 2005 will be adjusted for extraordinary weather conditions that may occur during those years. Any disputes concerning the existence or extent of extraordinary weather conditions will be resolved by the Commission.

14. Effective on the Implementation Date, FPC will refund to customers $35 million of the interim revenues collected subject to refund since March 13, 2001, through a credit to the fuel cost recovery clause in conjunction with the mid-course correction provided in Section 12. No other interim revenues collected by FPC during this period will continue to be held subject to refund.

15. The billing demand credits for Interruptible and Curtailable customers currently receiving service under FPC's IS-1, IST-1, CS-1 and CST-1 rate schedules shall remain in effect for the term of this Stipulation and Settlement, and thereafter until these rate schedules are reviewed in a general rate case, provided,

however, that these rate schedules shall continue to be closed to new customers, as defined in the stipulation approved by the Commission in Docket No. 950645-EI.

16. The cost of service and rate design matters identified in Exhibit A to this Stipulation and Settlement will be treated in the manner described therein. The Office of Public Counsel and the Florida Retail Federation have taken no position on the cost of service and rate design issues in this proceeding and, therefore, neither support nor oppose the cost of service and rate design provisions set forth in Exhibit A.

17. The provisions of Sections 1 through 15 of this Stipulation and Settlement are contingent on approval of these sections in their entirety by the Commission. The treatment of the cost of service and rate design matters identified in Exhibit A in accordance with Section 16 of this Stipulation and Settlement is contingent on approval of these matters in their entirety by the Commission. Approval of this Stipulation and Settlement in its entirety will resolve all matters in this Docket pursuant to and in accordance with Section 120.57(4), Florida Statutes (2001). This Docket will be closed effective on the date the Commission Order approving this Stipulation and Settlement is final.

18. This Stipulation and Settlement dated as of March 27, 2002 may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

In Witness Whereof, the Stipulating Parties evidence their acceptance and agreement with the provisions of this Stipulation and Settlement by their signature.

Florida Power Corporation

By ______________________

James A. McGee, Esquire
Post Office Box 14042
St. Petersburg, Florida 33733

Office of Public Counsel

By ______________________

Jack Shreve, Esquire
111 W. Madison St., Room 812
Tallahassee, Florida 32399

Florida Industrial Power Users Group

By ______________________

John W. McWhirter, Jr., Esquire
McWhirter, Reeves, McGlothlin,
Davidson, Decker, Kaufman
Arnold & Steen, P.A.
Post Office Box 3350
Tampa, Florida 33601

Florida Retail Federation

By ______________________

Ronald C. LaFace, Esquire
Greenberg Traurig, P.A.
Post Office Drawer 1838
Tallahassee, Florida 32302

Publix Super Markets, Inc.

By ______________________

Thomas A. Cloud, Esquire
Gray, Harris & Robinson, P.A.
301 East Pine Street, Suite 1400
Orlando, Florida 32802

Buddy Hansen and Sugarmill Woods Civic Association

By ______________________

Michael B. Twomey, Esquire
Post Office Box 5256
Tallahassee, Florida 32314

DOCUMENT NUMBER-DATE
04530 APR 24 8
FPSC-COMMISSION CLERK

EXHIBIT A
Stipulation and Settlement

Cost of Service and Rate Design Matters[1]

1. The current flat-rate energy charge for Rate Schedules RS-1, RSS-1, RSL-1, and RSL-2 shall be redesigned using an inverted rate design. Such inverted rate design shall provide: (a) two rate blocks consisting of a unit charge for the first 1000 kWh and a unit charge for all additional kWh, (b) the second rate block shall have a unit charge of one cent per kWh more than the first rate block, (c) the first rate block shall reflect 66.7% and the second block shall reflect 33.3% of the annual energy sales of these rate schedules for the test period, and (d) the total revenues produced shall be the same amount as that which would have been produced by a flat rate energy charge for the test period as applied to the annual energy sales of these rate schedules. Because of implementation time requirements, the inverted residential rate schedules described above will be effective beginning with cycle 1 meter readings for July 2002.

2. The billing demand credits for Rate Schedule CS-2, Curtailable General Service, and Rate Schedule CST-2, Curtailable General Service Optional Time of Use Rate, are $2.31 per kW of load factor adjusted demand. The billing demand credits for Rate Schedule IS-2, Interruptible General Service, and Rate Schedule IST-2, Interruptible General Service Optional Time of Use Rate, are $3.08 per kW of load factor adjusted demand.

3. A 500 kW minimum billing demand provision shall be added to Rate Schedules IS-2, IST-2, CS-2, and CST-2. Any existing customer under any of these rate schedules who established a billing demand of less than 500 kW in any of the 12 billing months preceding the implementation of this provision shall be advised by FPC that the minimum demand of 500 kW would not apply in the event the customer gives FPC written notice requesting to transfer to a firm rate schedule.

4. The CIAC payment option for the additional installed cost of a time of use meter shall be $132 for Rate Schedules RST-1 and GST-1. No CIAC payment is required for any other time of use rate schedule.

5. FPC's revised base rate charges do not reflect any cost recovery for purchased power capacity costs. Therefore, the credit in the present Capacity

---

[1] The Office of Public Counsel and the Florida Retail Federation neither support nor oppose the cost of service and rate design provisions set forth in this exhibit.

Cost Recovery clause that recognizes a base rate contribution for production capacity costs associated with sales resulting from the acquisition of retail customers in and near the City of Sebring shall terminate effective with the Implementation Date.

6. The 12 Coincident Peak and 1/13 Average Demand (12 CP & 1/13 AD) methodology will continue to be used for the allocation of FPC's production capacity costs to its retail customer classes during the term of this Stipulation and Settlement.

7. The monthly charge for additional equipment that the Company may optionally provide to a customer under its general service rate schedules is not subject to the base rate reduction and shall remain at the rate of 1.67% per month of the installed cost.

8. The service charges for Rate Schedules SC-1 and TS-1 are as follows:

Initial Service	$61.00
Re-establishment of service	$28.00
Re-establishment of service for customers with a Leave Service Active agreement	$10.00
Reconnection after disconnection for non-pay during normal business hours	$40.00
Reconnection after disconnection for non-pay outside of normal business hours	$50.00
Temporary service extension	$104.00

9. The charges for lighting fixtures, maintenance, and poles, as well as the additions, deletions, and restrictions of certain fixture and pole types, shall be those set forth in FPC's proposed Rate Schedule LS-1, Lighting Service (attached).

Florida Power
A Progress Energy Company

RATE SCHEDULE LS-1
LIGHTING SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer for the sole purpose of lighting roadways or other outdoor land use areas; served from either Company or Customer owned fixtures of the type available under this rate schedule.

Character of Service:

Continuous dusk to dawn automatically controlled lighting service (i.e., photoelectric cell); alternating current, 60 cycle, single phase, at the Company's standard voltage available.

Limitation of Service:

Availability of certain fixture or pole types at a location may be restricted due to accessibility.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Unmetered:	$1.20 per line of billing
Metered:	$3.45 per line of billing

Energy and Demand Charge:

Non-Fuel Energy Charge:	1.746¢ per kWh
plus Energy Conservation Cost Recovery Factor:	See Sheet No. 6.105
plus Capacity Cost Recovery Factor:	See Sheet No. 6.106

Per Unit Charges:

I. **Fixtures:**

BILLING TYPE	DESCRIPTION	LAMP SIZE LUMENS	WATTS[2]	kWh	CHARGES PER UNIT FIXTURE	MAINTENANCE	NON-FUEL ENERGY[3]	TOTAL
	Incandescent:[1]							
110	Roadway	1,000	92	32	$0.94	$3.29	$0.56	$4.79
115	Roadway	2,500	189	66	1.48	3.33	1.15	5.96
170	Post Top	2,500	206	72	18.69	1.21	1.26	21.16
	Mercury Vapor:[1]							
205	Open Bottom	4,000	125	44	2.34	0.93	0.77	4.04
210	Roadway	4,000	125	44	2.70	0.93	0.77	4.40
215	Post Top	4,000	125	44	3.18	0.93	0.77	4.88
220	Roadway	8,000	203	71	3.06	0.92	1.24	5.22
225	Open Bottom	8,000	203	71	2.29	0.93	1.24	4.46
235	Roadway	21,000	450	158	3.70	0.95	2.76	7.41
240	Roadway	62,000	1,102	386	4.85	1.10	6.74	12.69
245	Flood	21,000	450	158	4.85	0.95	2.76	8.56
250	Flood	62,000	1,102	386	5.68	1.10	6.74	13.52

(Continued on Page No. 2)

Florida Power
A Progress Energy Company

SECTION NO. VI
SEVENTEENTH REVISED SHEET NO. 6.281
CANCELS SIXTEENTH REVISED SHEET NO. 6.281

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 1)

I. Fixture: (Continued)

		LAMP SIZE			CHARGES PER UNIT			
BILLING TYPE	DESCRIPTION	LUMENS	WATTS[2]	kWh	FIXTURE	MAINTENANCE	NON-FUEL ENERGY[3]	TOTAL
	Sodium Vapor:							
305	Open Bottom1	4,000	60	21	2.33	$1.28	$0.0.37	3.98
310	Roadway1	4,000	60	21	2.86	1.28	0.37	4.51
313	Open Bottom1	6,500	82	29	3.64	1.74	0.51	5.82
314	Hometown II	9,500	121	42	3.73	1.47	0.73	5.93
315	Post Top - Colonial/Contemp1	4,000	60	21	4.35	1.28	0.37	6.00
316	Colonial Post Top1	4,000	97	34	3.71	1.28	0.59	5.58
318	Post Top1	9,500	121	42	2.29	1.28	0.73	4.30
320	Roadway-Overhead Only	9,500	121	42	2.90	1.28	0.73	4.91
321	Deco Post Top - Monticello	9,500	140	49	10.89	1.47	0.86	13.22
322	Deco Post Top - Flagler	9,500	140	49	14.86	1.47	0.86	17.19
323	Roadway-Turtle OH Only	9,500	121	42	3.96	1.47	0.73	6.16
325	Roadway-Overhead Only	16,000	185	65	3.01	1.30	1.13	5.44
326	Deco Post Top – Sanibel	9,500	140	49	15.13	1.47	0.86	17.46
330	Roadway-Overhead Only	22,000	249	87	3.34	1.32	1.52	6.18
335	Roadway	27,500	297	104	3.31	1.32	1.82	6.45
336	Roadway-Bridge1	27,500	297	104	6.18	1.32	1.82	9.32
337	Roadway-DOT1	27,500	297	104	5.38	1.32	1.82	8.52
338	Deco Roadway–Maitland	27,500	297	104	8.70	1.47	1.82	11.99
339	Deco Roadway-Maitland	50,000	482	169	9.36	1.47	2.95	13.78
340	Roadway-Overhead Only	50,000	482	169	4.01	1.33	2.95	8.29
341	HPS Flood-Sebring1	16,000	185	65	3.72	1.32	1.13	6.17
342	Roadway-Turnpike1	50,000	479	168	7.57	1.27	2.93	11.77
343	Roadway-Turnpike1	27,500	309	108	7.42	1.22	1.89	10.53
345	Flood-Overhead Only	27,500	293	103	4.28	1.32	1.80	7.40
346	Deco Post Top-Ocala II	9,500	140	49	8.74	1.47	0.86	11.07
350	Flood-Overhead Only	50,000	485	170	4.47	1.33	2.97	8.77
351	Underground Roadway	9,500	121	42	4.96	1.28	0.73	6.97
352	Underground Roadway	16,000	185	65	6.95	1.30	1.13	9.38
353	Underground Roadway	22,000	249	87	7.44	1.32	1.52	10.28
354	Underground Roadway	27,500	309	108	7.42	1.32	1.89	10.63
356	Underground Roadway	50,000	479	168	7.81	1.33	2.93	12.07
357	Underground Flood	27,500	309	108	8.09	1.32	1.89	11.30
358	Underground Flood	50,000	479	168	8.19	1.33	2.93	12.45
359	Underground Turtle Rwy	9,500	121	42	5.58	1.47	0.73	7.78
360	Deco Roadway Rect1	9,500	134	47	9.98	1.28	0.82	12.08
365	Deco Roadway Rectangular	27,500	309	108	9.98	1.32	1.89	13.19
366	Deco Roadway Rect	50,000	479	168	9.98	1.32	2.93	14.23
370	Deco Roadway Round	27,500	309	108	12.28	1.32	1.89	15.49
375	Deco Roadway Round	50,000	479	168	12.29	1.33	2.93	16.55
380	Deco Post Top – Acorn1	9,500	141	49	7.00	1.28	0.86	9.14
381	Deco Post Top1	9,500	140	49	3.71	1.28	0.86	5.85
383	Deco Post Top-Biscayne	9,500	140	49	12.76	1.28	0.86	14.90
385	Deco Post Top – Salem	9,500	141	49	5.96	1.28	0.86	8.10
393	Deco Post Top1	4,000	60	21	7.00	1.28	0.37	8.65
394	Deco Post Top1	9,500	140	49	16.64	1.40	0.86	18.90
	Metal Halide							
327	Deco Post Top-MH Sanibel	12,000	211	74	15.34	1.47	1.29	18.10
371	MH Deco Rectangular	38,000	454	159	12.78	3.08	2.78	18.64
372	MH Deco Circular	38,000	454	159	15.12	3.08	2.78	20.98
373	MH Deco Rectular5	110,000	1080	378	12.73	4.75	6.60	24.08
386	MH Flood 5	110,000	1080	378	11.86	4.75	6.60	23.21
389	MH Flood-Sportslighter5	110,000	1080	378	11.92	4.75	6.60	23.27
390	MH Deco Cube	38,000	454	159	15.04	3.08	2.78	20.90
396	Deco PT MH Sanibel Dual5	24,000	423	148	29.97	6.14	2.58	38.69
397	MH Post Top-Biscayne	12,000	211	74	12.85	3.07	1.29	17.21
398	MH Deco Cube5	110,000	1080	378	18.28	4.75	6.60	29.63
399	MH Flood	38,000	454	159	9.89	3.08	2.78	15.75

(Continued on Page 3)

ISSUED BY: Mark A. ers, Myers, Vice President, Finance
EFFECTIVE:

Florida Power
A Progress Energy Company

SECTION NO. VI
TWELFTH REVISED SHEET NO. 6.282
CANCELS ELEVENTH REVISED SHEET NO. 6.282

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 2)

II. Poles:

BILLING TYPE	DESCRIPTION	CHARGES PER UNIT
425	Wood, 14' Laminated 1	1.82
420	Wood, 30/35'	1.66
480	Wood, 40/45'	4.28
415	Concrete, Curved1	4.37
450	Concrete, 1/2 Special	1.60
410	Concrete, 15' 1	2.12
405	Concrete, 30/35'	3.86
406	16' Deco Conc – Single Sanibel	8.93
407	16' Decon Conc – Double Sanibel	9.63
408	26' Aluminum DOT Style Pole	38.10
409	36' Aluminum DOT Style Pole	48.25
411	16' Octagonal Conc1	2.00
412	32' Octagonal Deco Conc	12.44
413	25' Tenon Top Concrete	8.09
466	16' Deco Con Vic II – Dual Mount	13.79
467	16' Deco Conc Washington – Dual	20.73
468	16' Deco Conc Colonial – Dual Mt	10.19
471	22' Deco Conc	11.45
472	22' Deco Conc Single Sanibel	12.24
473	22' Deco Conc Double Sanibel	13.18
474	22' Deco Conc Double Mount	14.31
476	25' Tenon Top Bronze Concrete	13.39
477	30' Tenon Top Bronze Concrete	14.52
478	35' Tenon Top Bronze Concrete	16.06
479	41' Tenon Top Bronze Concrete	19.40
485	Concrete, 40/45'	8.82
435	Aluminum, Type A1	6.04
439	Black Fiberglass 16'	18.13
440	Aluminum, Type B1	6.72
445	Aluminum, Type C1	13.13
455	Steel, Type A1	3.77
460	Steel, Type B1	4.04
465	Steel, Type C1	5.65
430	Fiberglass, 14', Black1	1.92
437	Fiberglass, 16', Black, Fluted, Dual Mount1	20.11
449	Deco Fiberglass, 16', Black, Fluted, Anchor Base1	15.90
436	Deco Fiberglass, 16', Black, Fluted1	17.87
438	Deco Fiberglass, 20', Black1	5.36
434	Deco Fiberglass, 20', Black, Deco Base 1	11.22
446	Deco Fiberglass, 30', Bronze1	10.60
433	Deco Fiberglass, 35', Bronze1	10.84
432	Deco Fiberglass, 35', Bronze, Anchor Base1	25.19
428	Deco Fiberglass, 35', Bronze, Reinforced1	17.51
447	Deco Fiberglass, 35', Silver, Anchor Base1	19.61
431	Deco Fiberglass, 41', Bronze1	14.32
429	Deco Fiberglass, 41', Bronze, Reinforced1	24.08
448	Deco Fiberglass, 41', Silver1	16.50
469	35' Tenon Top Quad Floor Mount	12.23
481	30' Tenon Top Concrete, Single Flood Mount	7.76
482	30' Tenon Top Conc, Double Flood Mount/inc Bracket	10.77
483	46' Tenon Top Conc, Triple Flood Mount/Includes Bracket	14.96
484	46' Tenon Top Conc Double Flood Mount/Includes Bracket	14.70
486	Tenon Style Concrete 46' Single Flood Mount	11.69
487	35' Tenon Top Conc, Triple Flood Mount/Includes Bracket	$12.08
488	35' Tenon Top Conc, Double Flood Mount/Includes Bracket	11.81
489	35' Tenon Top Concrete, Single Flood Mount	8.80
490	Special Concrete 13' 1	15.94
491	30' Tenon Top Conc, Triple Flood Mount/Includes Bracket	11.04
492	16' Smooth Decorative Concrete/The Colonial	6.87
493	19' White Aluminum 1	23.71

(Continued on Page 4)

Florida Power
A Progress Energy Company

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 3)

494	46' Tenon Top Concrete/Non-Flood Mount/1-4 Fixtures	12.68
496	30' Tenon Top Concrete/Non-Flood Mount/1-4 Fixtures	9.81
497	16' Decorative Concrete w/decorative base/The Washington	16.92
498	35' Tenon Top Concrete/Non-Flood Mount/1-4 Fixtures	10.26
499	16' Decorative Concrete-Vic II	9.98

III. Additional Facilities

Electrical Pole Receptacle4 2.32

Notes:

(1) Restricted to existing installations.
(2) Includes ballast losses.
(3) Shown for information only. Energy charges are billed by applying the foregoing energy and demand charges to the total monthly kWh.
(4) Available only on certain decorative poles. Electric use allowed only from Oct. through Jan. Energy charged separately.
(5) Special applications only.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the sum of the Customer Charge and applicable Fixture and Maintenance Charges.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Except as provided in Special Provision No. 14, service under this rate schedule shall be for a minimum initial term of six (6) years from the commencement of service and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination. Upon early termination of service under this schedule, the Customer shall pay an amount equal to the remaining monthly lease amount for the term of contract, applicable Customer Charges and removable cost of the facilities.

Special Provisions:

1. The Company will require a written contract from the Customer for service under this rate upon the Company's standard form.

2. Where the Company provides a fixture or pole type other than those listed above, the monthly charges, as applicable shall be computed as follows:

   I. Fixture
      (a) Fixture Charge: 1.46% of the Company's average installed cost.
      (b) Maintenance Charge: The Company's estimated cost of maintaining fixture.

   II. Pole
      Pole Charge: *1.67% of installed cost*

3. The Customer shall be responsible for the cost incurred to repair or replace any fixture or pole which has been willfully damaged. The Company shall not be required to make such repair or replacement prior to payment by the Customer for damage.

(Continued on Page 5)

ISSUED BY: Mark A. Myers, Vice President, Finance
EFFECTIVE:

Florida Power
A Progress Energy Company

SECTION NO. VI
ORIGINAL SHEET NO. 6.284

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 4)

4. Maintenance Service for Customer-owned fixtures at charges stated hereunder shall be restricted to fixtures being maintained as of November 1, 1992. For additional requests of the Company to perform maintenance of Customer-owned fixtures, the Company may consider providing such service and bill the Customer in accordance with the Company's policy related to "Work Performed for the Public."

5. kWh consumption for Company-owned fixtures shall be estimated in lieu of installing meters. kWh estimates will be made using the following formula:

$$kWh = \frac{\text{Unit Wattage (including ballast losses) x 350 hours per month}}{1{,}000}$$

6. kWh consumption for Customer-owned fixtures shall be metered. Installation of Customer-owned lighting facilities shall be provided for by the Customer. The Company may consider installing customer owned lighting facilities and will bill the Customer in accordance with the Company's policy related to "Work Performed for the Public." Any costs incurred by the Company to provide for consolidation of existing lighting facilities for the purpose of metering shall be at the Customer's expense.

6. No Pole Charge shall be applicable for a fixture installed on a Company-owned pole which is utilized for other general distribution purposes.

7. Replacement of lamps of Company maintained fixtures will be made by the Company within three (3) business days after the Customer notifies the Company that the lamp is burned out.

8. For a fixture type restricted to existing installations and requiring major renovation or replacement, the fixture shall be replaced by an available sodium vapor fixture of the Customer's choosing and the Customer shall commence being billed at its appropriate rate. Where the Customer requests the continued use of the same fixture type for appearance reasons, the Company will attempt to provide such fixture and the Customer shall commence being billed at a rate determined in accordance with Special Provision No. 2 for the cost of the renovated or replaced fixture.

9. The Customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities.

10. After December 31, 1998, all new leased lighting shall be installed on poles owned by the Company.

11 Alterations to leased lighting facilities requested by Customer after date of installation, (i.e. redirect, install shields, etc.), will be billed to the Customer in accordance with the Company's policy related to "Work Performed for the Public".

12. Service for street or area lighting is normally provided from existing distribution facilities. Where suitable distribution facilities do not exist, it will be the Customer's responsibility to pay for necessary additional facilities. Refer to section IV, paragraph 3.01 of the Company's General Rules and Regulations Governing Electric Service to determine the Contribution in Aid of Construction owed by the Customer.

13. The Customer shall have the option to make an up-front lump sum payment in lieu of paying the otherwise applicable monthly charges specified in this rate schedule, for those premium lighting fixtures and poles designated by the Company, subject to the following conditions:

   A. The Customer must execute the Company's standard form Up-Front Lease Agreement (UFLA) with an initial term of ten (10) years, after the initial term the then effective monthly fixture and pole charges will be applicable.

   B. The up-front lump sum payment shall be calculated based on the present value of the otherwise applicable monthly fixture and pole charges over the initial ten-year term of the UFLA, discounted at a rate equal to the interest rate paid on ten (10) ten-year Treasury Notes at the end of the month prior to execution of the UFLA, and shall be adjusted for Federal and State tax impacts from the receipt of a lump sum payment instead of monthly payments over a ten-year period.

   C. The minimum up-front lump sum payment is $50,000.

   D. A processing fee of $700 shall be paid upon execution of the UFLA to defray the costs of contract administration over the term of the UFLA.

   E. If the Customer requests multiple engineering estimates to determine the up-front lump sum payment that would be required under alternative lighting configurations, the Company may charge a fee to cover its reasonable costs to perform such estimates.

ISSUED BY: Mark A. Myers, Vice President, Finance
EFFECTIVE:

Attachment 2
Page 1 of 3

Impact of Proposed Stipulation and Settlement on Monthly 1,000 kwh Residential Bill
Florida Power Corporation
Docket No. 000824-EI

	Current	Effective May 2002		Effective July 2002		Difference July 2002 vs. Current
Customer Charge	$8.85	$8.03		$8.03		($0.82)
Non-Fuel Energy Charge	$40.20	$36.48	(1)	$33.15	(2)	($7.05)
Fuel Charge	$26.92	$23.67	(3)	$23.67		($3.25)
Energy Conservation Charge	$2.07	$2.07		$2.07		$0.00
Capacity Cost Recovery Charge	$11.32	$11.32		$11.32		$0.00
Gross Receipts Tax	$2.29	$2.09		$2.01		($0.28)
Total Bill	**$91.65**	**$83.66**		**$80.25**		**($11.40)**

(1) Proposed levelized residential non-fuel energy charge effective May - June 2002.

(2) Proposed inverted residential non-fuel energy charge, effective July 2002.

(3) Proposed fuel mid-course correction reduction of $83.7 million, including interim refund of $35 million.

RESIDENTIAL FUEL COST RECOVERY FACTORS FOR THE PERIOD: **May 2002 - June 2002**

Attachment 2
Page 2 of 3

NOTE: **This schedule reflects a midcourse correction to Florida Power Corporation's fuel factors and a reduction to FPC's base rate charges resulting from a proposed stipulation and settlement in Docket No. 000824-EI. The settlement provides that residential customers will be billed a levelized non-fuel energy charge for the period May - June 2002, and an inverted non-fuel energy charge starting July 2002.**

		Florida Power & Light Co.	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Present (cents per kwh):	April 15, 2002 - April 30, 2002	2.635	2.692	3.313	2.239	4.060	3.983
Proposed (cents per kwh):	May 2002 - June 2002	**2.635**	**2.367**	**3.313**	**2.239**	**4.060**	**3.983**
	Increase/Decrease:	0.000	-0.325	0.000	0.000	0.000	0.000

TOTAL MONTHLY BILL - RESIDENTIAL SERVICE - 1,000 KILOWATT HOURS

PRESENT April 15, 2002 - April 30, 2002	Florida Power & Light Co.	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Base Rate Charges	40.22	49.05	51.92	42.20	20.43	19.20
Fuel and Purchased Power Cost Recovery Clause	26.35	26.92	33.13	22.39	40.60	39.83
Energy Conservation Cost Recovery Clause	1.87	2.07	1.16	0.64	0.83	0.58
Environmental Cost Recovery Clause	0.00	N/A	1.59	1.02	N/A	N/A
Capacity Cost Recovery Clause	7.01	11.32	3.79	0.27	N/A	N/A
Gross Receipts Tax (1)	0.77	2.29	2.35	0.68	1.59	0.61
Total	**$76.22**	**$91.65**	**$93.94**	**$67.20**	**$63.45**	**$60.22**

PROPOSED May 2002 - June 2002	Florida Power & Light Co.	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Base Rate Charges	40.22	44.51	51.92	42.20	20.43	19.20
Fuel and Purchased Power Cost Recovery Clause	26.35	23.67	33.13	22.39	40.60	39.83
Energy Conservation Cost Recovery Clause	1.87	2.07	1.16	0.64	0.83	0.58
Environmental Cost Recovery Clause	0.00	N/A	1.59	1.02	N/A	N/A
Capacity Cost Recovery Clause	7.01	11.32	3.79	0.27	N/A	N/A
Gross Receipts Tax (1)	0.77	2.09	2.35	0.68	1.59	0.61
Total	**$76.22**	**$83.66**	**$93.94**	**$67.20**	**$63.45**	**$60.22**

PROPOSED INCREASE / (DECREASE)	Florida Power & Light Co.	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Base Rate Charges	0.00	-4.54	0.00	0.00	0.00	0.00
Fuel and Purchased Power Cost Recovery Clause	0.00	-3.25	0.00	0.00	0.00	0.00
Energy Conservation Cost Recovery Clause	0.00	0.00	0 00	0.00	0.00	0 00
Environmental Cost Recovery Clause	0.00	0.00	0.00	0.00	0.00	0.00
Capacity Cost Recovery Clause	0.00	0.00	0.00	0.00	0.00	0.00
Gross Receipts Tax (1)	0.00	-0.20	0.00	0.00	0.00	0.00
Total	$0.00	($7.99)	$0.00	$0.00	$0.00	$0.00

(1) Additional gross receipts tax is 1% for Gulf, FPL and FPUC-Fernandina Beach. FPC, TECO and FPUC-Marianna have removed all GRT from their rates, and thus entire 2.5% is shown separately. (2) Fuel costs include purchased power demand costs of 1.726 for Marianna and 1 888 cents/KWH for Fernandina allocated to the residential class.

RESIDENTIAL FUEL COST REC 'ERY FACTORS FOR THE PERIOD: **July 2002 - :cember 2002**

Attachment 2
Page 3 of 3

NOTE: This schedule reflects the 1,000 kwh re: ·ntial bill under Florida Power Corporation's inverted non-fuel energy cha The inverted non-fuel energy charge i: oposed in a stipulation and settlement in Docket No. 000824-EI, effective May 1, 2002. For the period l y - June residential customers will be billed a levelized non-fuel energy cha

		Florida Power & Light Co.	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Present (cents per kwh):	May 2002 - June 20	2.635	2.367	3.313	2.239	4.060	3.983
Proposed (cents per kwh):	July 2002 - Decemb 2002	2.635	2.367	3.313	2.239	4.060	3.983
	Incr :/Decrease:	0.000	0.000	0.000	0.000	0.000	0.000

TO L MONTHLY BILL - RESIDENTIAL SERVICE - 1,000 KILOWATT I URS

PRESENT May 2002 - June 2002	Florida Power & Light Co.	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Base Rate Charges	40.22	44.51	51.92	42.20	20.43	19.20
Fuel and Purchased Power Cost Recovery Clause	26.35	23.67	33.13	22.39	40.60	39.83
Energy Conservation Cost Recovery Clause	1.87	2.07	1.16	0.64	0.83	0.58
Environmental Cost Recovery Clause	0.00	N/A	1.59	1.02	N/A	N/A
Capacity Cost Recovery Clause	7.01	11.32	3.79	0 27	N/A	N/A
Gross Receipts Tax (1)	0.77	2.09	2.35	0.68	1.59	0.61
Total	$76.22	$83.66	$93.94	$67.20	$63.45	$60.22

PROPOSED July 2002 - December 2002	Florida Power & Light Co.	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Base Rate Charges	40.22	41.18	51.92	42.20	20.43	19.20
Fuel and Purchased Power Cost Recovery Clause	26.35	23.67	33.13	22.39	40.60	39.83
Energy Conservation Cost Recovery Clause	1 87	2.07	1.16	0.64	0.83	0.58
Environmental Cost Recovery Clause	0.00	N/A	1.59	1.02	N/A	N/A
Capacity Cost Recovery Clause	7.01	11.32	3.79	0.27	N/A	N/A
Gross Receipts Tax (1)	0.77	2.01	2.35	0.68	1.59	0.61
Total	$76.22	$80.25	$93.94	$67.20	$63.45	$60.22

PROPOSED INCREASE / (DECREASE)	Florida Power & Light Co.	Florida Power Corporation	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. (2) Marianna	Florida Public Utilities Co. (2) Fernandina Beach
Base Rate Charges	0.00	-3.33	0.00	0.00	0.00	0.00
Fuel and Purchased Power Cost Recovery Clause	0.00	0.00	0.00	0.00	0.00	0.00
Energy Conservation Cost Recovery Clause	0.00	0.00	0.00	0.00	0.00	0.00
Environmental Cost Recovery Clause	0.00	0.00	0.00	0.00	0.00	0.00
Capacity Cost Recovery Clause	0.00	0.00	0.00	0.00	0.00	0.00
Gross Receipts Tax (1)	0.00	-0.08	0.00	0.00	0.00	0.00
Total	$0.00	($3.41)	$0.00	$0.00	$0.00	$0.00

(1) Additional gross receipts tax is 1% for Gulf, FPI ıd FPUC-Fernandina Beach. FPC, TECO and FPUC-Marianna have removed all ꓤT from their rates, and thus entire 2.5% is shown separately. (2) Fuel costs include pu ısed power demand costs of 1.726 for Marianna and 1.888 cents/KWH for Ferna na allocated to the residential class.

ATTACHMENT 3

Florida Power Corporation
Fuel and Purchased Power Cost Recovery Factors
For the period: May through December 2002

	Levelized Factor (cents/kwh)	Time of Use On-Peak (cents/kwh)	Time of Use Off-Peak (cents/kwh)
Distribution Secondary	2.367	2.878	2.147
Distribution Primary	2.343	2.849	2.125
Transmission	2.319	2.820	2.103
Lighting Service	2.284	---	---

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including Effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.)	Docket No. 000824-EI Dated March 7, 2003

AFFIDAVIT OF JAVIER PORTUONDO IN SUPPORT OF PROGRESS ENERGY'S OPPOSITION TO OPC'S MOTION TO ENFORCE SETTLEMENT AGREEMENT

1. My name is Javier Portuondo, and I am employed by Progress Energy Service Company, LLC, in the capacity of Manager, Regulatory Services – Florida. In this capacity, my duties include responsibility for the regulatory accounting and reporting activities of Progress Energy Florida, Inc. ("Progress Energy" or "the Company"). My business address is Central Station, 100 Central Avenue, St. Petersburg, Florida, 33701. I participated in all aspects of the Company's recent rate case. In particular, I was actively involved in the preparation of the Company's Minimum Filing Requirements ("MFRs"), in evaluation of the negotiated proposals that led to the rate settlement ("Settlement Agreement"), and in the documentation and implementation of the Settlement Agreement. I make this Affidavit based on personal knowledge and in reliance on the business records of Progress Energy, which I prepared or which were prepared under my direction and control.

2. At the inception of the Company's recent rate case, I was responsible for preparing the Company's MFRs. Among other things, the MFRs set forth our forecast of revenues that our then-existing rates were expected to produce. Specifically, we projected that the Company would receive $1,421 million in base rate revenues for the year 2002. This set the stage for the entire rate case because the issue in the rate case was whether, or to what extent, the Company's rates (and corresponding base rate-generated revenues) should be reduced.

EXHIBIT B

3. Also at the inception of the case, the Commission ordered the Company to collect revenues subject to refund in the annual amount of $113.9 million. The Commission subsequently reduced that number to $98 million. The Company collected part of these revenues in 2001 and part in 2002 up to and including the implementation date of the rate settlement.

4. The final hearing in the case was scheduled to commence on March 20, 2002. As the hearing date approached, the parties discussed settlement intensely and ultimately agreed upon a settlement of all disputed issues, which was set forth in the Settlement Agreement. The Settlement Agreement had at least five significant features that are important to the present controversy: (1) The parties agreed upon a reduction in base rates in the amount of $125 million annually, (2) the parties agreed that the Company would provide a refund of $35 million out of the revenues collected subject to refund through the implementation date of the Settlement Agreement, and that the Company would not provide any further refund of interim revenues, (3) the parties agreed to substitute a revenue sharing plan in place of an authorized ROE as a means to limit the Company's earnings levels, (4) the parties, except the Office of Public Counsel and the Florida Retail Federation, who took no position, agreed that the Company would receive a $14 million increase in lighting and service charges in accordance with an exhibit to the Settlement Agreement, and (5) the parties agreed that these changes would be implemented on May 1, 2002, and would continue through December 31, 2005, and from year-to-year thereafter.

5. The Settlement Agreement was approved by the Commission by Order PSC-02-655-AS-EI, dated May 14, 2002, which includes the Settlement Agreement as Attachment 1.

6. Focusing on the revenue sharing feature of the Settlement Agreement, it is helpful to understand that the Commission had previously established a regulated rate of return for the Company as the means to limit earnings levels. Under that traditional ratemaking approach, the

Company did not have the opportunity to benefit from better-than-projected revenues that might push earnings above the permissible range. Under the revenue sharing plan agreed to by the parties, however, utility shareholders and customers alike stand to benefit from better-than-projected revenues.

7. The essence of the revenue sharing plan is to compare expected, or projected, base rate revenues against actual base rate revenues for the periods in which revenue sharing is in effect. If the Company achieves only the revenues it had projected, then the Company will use those revenues to cover its costs and return requirements. If, however, the Company realizes greater-than-projected revenues, it will share the majority of those "excess" revenues with its customers.

8. The parties provided in their Settlement Agreement that, "Commencing on the Implementation Date and for the remainder of 2002 and for calendar years 2003, 2004 and 2005, and for each calendar year thereafter until terminated by the Commission, FPC will be under a Revenue Sharing Incentive Plan as set forth [in the Settlement Agreement]." (Para. 6). The Settlement Agreement provides that Progress Energy's shareholders would be entitled to receive a "1/3 share" of extraordinary revenues, and Progress Energy's retail customers would receive the remaining "2/3 share." (Para. 6, I).

9. The parties agreed to this mechanism in place of a capped rate of return. Specifically, the Settlement Agreement provides that "FPC will no longer have an authorized Return on Equity (ROE) range for the purpose of addressing earnings levels, and the revenue sharing mechanism herein described will be the appropriate and exclusive mechanism <u>to address earnings levels</u>." (Para. 3) (emphasis added). By this provision, the parties explicitly recognized that their intent was to use revenue sharing to operate as a substitute for, and a functional

equivalent of, an authorized ROE – namely, to prevent the Company from obtaining the full benefit of excess revenues, i.e., base rate revenues that might otherwise trigger a rate review because they exceed what is necessary to enable the Company to recover its costs and return requirements.

10. As a starting point for evaluating revenues, the parties established a "threshold" for each year covered by the Settlement Agreement, beginning with 2002. Although the parties agreed that both revenue sharing and the $125 million rate reduction would apply only from May 1, 2002 forward, the Settlement Agreement specifies an annualized threshold that extrapolated the $125 million rate reduction for all 12 months of 2002. Thus, for 2002, the parties agreed that the threshold would be $1,296 million, and that this amount would be increased in lock-step fashion each year thereafter by $37 million. (Para. 6).

11. The 2002 sharing threshold of $1,296 million corresponds to the 2002 base rate revenues projected in the Company's MFRs less the permanent annual rate reduction of $125 million. The $37 million increase in the sharing threshold for each of the subsequent years corresponds to the anticipated increase in expenses associated with projected sales and customer growth.

12. The Settlement Agreement provides that, for each year of the agreement, the threshold set forth in the Settlement Agreement will be compared to "base rate revenues" to determine that amount of revenues subject to revenue sharing. (Para. 6). The term "base rate revenues" is not defined in the Settlement Agreement. But any proper measurement of "base rate revenues" must take into account the rate reduction, increase, and refund called for by the Settlement Agreement itself. Without making adjustments for these changes in base rates, it would be impossible either to establish a true picture of "base rate revenues" (accounting for all

Commission-directed changes thereto) and thus have an apples-to-apples comparison of the threshold and actual revenues.

13. Also, any term must be understood in the context in which it is used. As I have described, the parties' intent in establishing the revenue sharing plan was to create a substitute for an authorized ROE to limit the Company's earnings levels (by limiting the Company's revenues). To identify "excess" earnings that might have triggered a rate review if the Company had been using an authorized ROE, we have to compare actual revenues to projected revenues, accurately recognizing the authorized rate refund, increase, or decrease. For example, let's suppose we had been projecting to achieve $100 million in earnings for 2002. If our rates actually generated $110 million in revenues for the year due to extreme weather, the $10 million in "excess" earnings might trigger a rate review under traditional rate making, using an authorized ROE. Now let's suppose the Commission approved a $10 million rate increase for 2002, and we in fact generated $110 million in revenues for the year. In that case, there would be no "excess" earnings even though we realized more revenues than we were projecting at the start of the year before the Commission authorized a rate increase.

14. Why doesn't the "extra" $10 million in the second scenario trigger a rate review? Because we have to recognize that the $10 million is attributable to a Commission-authorized rate increase in base rates. Thus, when comparing the $100 million in projected revenues for the year with the $110 actual revenues, we have to <u>subtract</u> the $10 million associated with the authorized rate increase from actual revenues in order to determine "base rate revenues" for year 2002 because that amount cannot be deemed "excess" revenues for purposes of enforcing an approved ROE. That is true because the $10 million increase was <u>authorized</u> by the Commission. Therefore, it cannot be excessive. The only kind of increase in revenues that

might properly be deemed to create "excess" revenues is an increase due to factors external to the Commission's order itself.

15. The converse is also true. Let's suppose we were projecting at the beginning of the year that the Company would earn $100 million in revenues under existing rates. Then let's suppose the Commission approved a $10 million rate reduction for only half the year, resulting in a $5 million rate cut over a six-month period. This means that revenues could total $95 million without triggering a rate review. It would not be appropriate to look at the <u>annualized</u> rate cut of $10 million and say that anything over $90 million constitutes "excess" revenues. We have to look at the rate increases and decreases the Commission actually approved, and make appropriate apples-to-apples comparisons so that we distinguish true "excess" revenues from revenues that the Commission fully expected and authorized the Company to earn – which would most definitely not trigger a rate review under a traditional approved ROE approach.

16. Conceptually, we have to approach the interpretation and implementation of the term "base rate revenues" in our revenue sharing agreement in the same way. Otherwise, we might end up sharing revenues that the Commission <u>authorized</u> the Company to recover in base rates to cover its costs.

17. The Commission, itself, recognized this in its Order approving the Settlement Agreement. The Settlement Agreement provided for a $35 million refund of interim revenues to customers, which obviously would have a direct impact on the <u>net</u> base revenues available for revenue sharing.

18. In its Order, the Commission recognized and called attention to the fact that "[t]he Stipulation . . . is silent regarding the apportionment of the refund during the interim period." (Order, p. 5). The Commission went on to state:

> Unless there is specific evidence to the contrary, it is normally assumed that the amount to be refunded has been accumulated on an even monthly basis during the interim period. <u>This is an important consideration in determining the appropriate level of revenue that will be subject to the revenue threshold and cap for 2002</u>. We find that only $10,370,000 of the total refund of $35 million ($35,000,000 ÷ 13.5 x 4) is attributable to revenues collected subject to refund during the January 1, 2002, through April 30, 2002 period.

(Order, pp. 5-6) (emphasis added).

19. Significantly, the Commission took as a <u>given</u> that the Company would have to make appropriate adjustments to "base rate revenues" in "<u>determining the appropriate level of revenue that will be subject to the revenue threshold and cap for 2002</u>." That was never in doubt. The only issue the Commission felt compelled to address was how the Company might allocate the impact of one of the terms of the Settlement Agreement between different periods where this was not apparent on the face of the Settlement Agreement. By contrast, there was no need for the Commission to address the allocation of the $125 million annual rate reduction because that was an annual rate reduction occurring entirely within one year and thus required no multi-year allocation.

20. In accordance with the Commission's Order, it is apparent that Progress Energy is required to adjust "base rate revenues" for 2002 by <u>increasing</u> those revenues by some or all of the amount the Company was ordered to refund to its customers in 2002 out of interim revenues. That is true because the forecasted revenues in the Company's MFRs did not anticipate or project that the refund would take place. Therefore, if the refund out of revenues collected subject to refund were not added back into "base rate revenues," it would appear that Progress Energy had <u>not</u> met its MFR forecast at the end of 2002 even if the Company experienced perfectly "normal" weather conditions and had otherwise achieved exactly the level of revenues projected. As a practical matter, absent an adjustment, the payment of the refund would thus

operate to insulate Progress Energy from any further refunds to customers through revenue sharing even if 2002 revenues far exceeded the Company's projections.

21. As discussed, the Commission authorized Progress Energy to add back to 2002 revenues approximately $25 million of the total refund amount. After consultation with Staff, we concluded that adding back the full $35 million in the year the refund was paid (2002) would better accomplish the objective of the adjustment authorized by the Commission. This is true because we booked the entire amount of the refund against 2002 revenues. This is conventional practice for purposes of determining compliance with an authorized ROE. By contrast, for surveillance reporting purposes, we will reflect the Commission-approved allocation in our pro forma. But under traditional rate making practice, our surveillance pro formas are not used for purposes of determining compliance with an authorized ROE. If we allocated only $25 million of the refund to 2002 revenues for purposes of revenue sharing, we would thus understate the amount of "base rate revenues" for 2002, and we would have to make an offsetting adjustment elsewhere.

22. The Commission's Order further recognizes that, although the "proposed Stipulation provides for a 9.25% reduction in base rates for all rate classes, . . . certain Lighting Service (LS-1) lighting fixture and pole charges will be increased, as will FPC's Service Charges." (Order, p. 4) (emphasis added). The increases in lighting and service charges are reflected in the exhibit to the Settlement Agreement. In discussing these individual items, the Commission noted that new service charges "will result in an annual increase in revenues to FPC of approximately $11 million" and that the "revised fixture charges will result in an annual revenue increase to FPC of approximately $3 million," for a total, offsetting rate increase of $14 million. (Order, p. 8) (emphasis added).

23. The total $14 million figure is an <u>annual</u> amount. The amount allocable to the period on an after May 1, 2002 is approximately $9 million.

24. The exhibit to the Settlement Agreement that identifies these rate increases is an integral part of that agreement, as the Commission recognized. OPC and the Florida Retail Federation took no position on the matters addressed in the exhibit because they involved rate increases. If these increases were to be treated as falling outside the Settlement Agreement, then, by the same token, the <u>revenues</u> themselves generated by the increases during 2002 would have to be excluded from the base rate revenues to which the Settlement Agreement's revenue sharing plan applies. If the increases fall outside the revenue sharing plan contained in the main body of the Settlement Agreement, then they should fall outside the agreement for all purposes. If, on the other hand, the increases are to be taken into account in determining how to apply the revenue sharing plan, it is still necessary to make an adjustment to "base rate revenues" to exclude the enhanced revenues attributable to this increase because they may not be deemed "excess" revenues due to extreme weather conditions, etc., which would otherwise be precluded by an authorized ROE. Rather, they are explicitly authorized by the Commission as a <u>normal</u>, recurring revenue item that should not give rise to an automatic refund each year the Settlement Agreement is in effect, even if only the forecasted level of sales is achieved. Otherwise, there would be no point in the Commission's having granted the increases.

25. In addition to providing for a refund of $35 million in revenues collected subject to refund and an increase in lighting and service charges, the Settlement Agreement calls for a reduction in base rate revenues in the annual amount of $125 million. It is critical that this additional adjustment to Progress Energy's revenues be taken into account for purposes of determining "base rate revenues" subject to sharing. In order to determine how to take the rate

reduction into account, it is critical to understand how the sharing "threshold" set forth in the Settlement Agreement was established.

26. As noted, the "threshold" in the Settlement Agreement for 2002 – $1,296 million – is an annualized number. The starting point for setting this threshold was Progress Energy's MFRs for the year 2002. Specifically, for the year 2002, the Company's MFRs projected that its then-current rates would produce revenues of $1,421 million. Thereafter, as part of the Settlement Agreement, Progress Energy agreed to an annual rate reduction of $125 million. This amounted to a percentage base rate reduction of 9.25 percent. (Para. 2). The parties then subtracted the entire amount of this annual deduction from Progress Energy's 2002 projected revenues in order to arrive at the sharing threshold of $1,296 million.

27. It is evident on the face of the Settlement Agreement, however, that the 9.25 percent agreed-upon rate reduction was scheduled to commence on May 1, 2002, not January 1, 2002. (Para. 6). This means that the amount of the annual $125 million rate reduction that actually occurred in 2002, on and after May 1, 2002, was $83.4 million, not $125 million. In other words, absent an adjustment in "base rate revenues" for purposes of revenue sharing, the annualized threshold would cause projected 2002 revenues of $41.6 million received before the May 1 rate reduction to be inaccurately classified as "excess" revenues and therefore subject to sharing.[1]

28. Thus, the Company had to make one final adjustment to "base rate revenues" for 2002 – namely, subtracting $41.6 million from unadjusted "base rate revenues" – to neutralize

[1] If the Company were to add back to 2002 revenues only $25 million of the $35 million refund, as authorized by the Commission, then the annualized threshold would overstate revenues by only $31 million, in which case the Company would need to make an adjustment of only that amount (instead of a $41 million adjustment) to reflect properly the impact of the $125 million rate reduction.

the impact of all rate refunds, increases, and decreases called for by the Settlement Agreement so as to arrive at an accurate depiction of better-than-projected revenues.

29. The effect of all three adjustments is as follows:

2002 unadj. actual revenues	**$1,323,003,903**
Interim refund	**35,000,000**
Service fee/lighting increase	**(9,338,000)**
Rate reduction not in effect	**(41,625,000)**
Adjusted "base rate revenues"	**$1,307,069,903**

30. Under the Settlement Agreement, this adjusted revenue figure must be compared to the revenue threshold specified in the Settlement Agreement to identify excess revenues subject to refund, as follows:

Total adjusted revenues	**$1,307,069,903**
Threshold for 2002	**1,296,000,000**
Excess revenues	**$ 11,069,903**

31. After making these adjustments, we have identified "excess" revenues for the entire year 2002. This is because we were working with revenue numbers for the entire year, adjusted to take into account refunds, increases, and reductions that occurred during different times of the year. We compared this adjusted "base rate revenue" figure with an annualized threshold to obtain a delta between projected and actual revenues for the entire year, attributable, as a result of the adjustments, to unprojected revenue-enhancing conditions external to the Settlement Agreement itself. This is the whole focus of revenue sharing.

32. Because the delta is an <u>annual</u> figure, however, a further calculation must be made to take into account the fact that the revenue sharing plan explicitly applies only to the period beginning on and after May 1, 2002. The Settlement Agreement provides for such a calculation, as follows: "For 2002 only, the refund to the customers will be limited to 67.1% (May 1 through December 31) of the 2/3 customer share." (Para. 6 II). Implementing this provision (and adding interest), we obtain the following result:

Excess revenues	**$11,069,903**
67.1% May-Dec. multiplier	**7,427,905**
2/3 customer share	**4,954,413**
Interest	**44,077**
Customer sharing amount	**$ 4,998,489**

33. In reaching a different result – contemplating a $23,034,004 refund to customers – the Office of Public Counsel and the other parties who have filed a motion supposedly to enforce the settlement ("the Movants") argue for an application of the revenue sharing mechanism that focuses on only parts of the Settlement Agreement and Order, but disregards other crucial components of both the Settlement Agreement and Order. In the process, the Movants argue for an interpretation that would undermine the intent of the parties and, from all appearances, the intent of the Commission.

34. Specifically, the Movants argue that no adjustment may be made to 2002 calendar year revenues to reflect the fact that the Commission-approved rate reduction did not actually commence until May 1, 2002. Of course, without such an adjustment, customers could seek a refund from revenues that Progress Energy had projected to achieve from the outset of the rate

case, in the Company's MFRs, by arguing that the Company enjoyed excess revenues in relation to the annualized threshold for the first part of the year, when revenue sharing did not even apply, due to the simple fact that no rate reduction was imposed on rates from January 1, 2002 through April 30, 2002.

35. This is because the Movants want us to disregard the fact that the $1,296 million threshold set forth in the Settlement Agreement is an annualized figure that assumes for the purpose of creating an annualized number that the parties were agreeing to a total rate reduction of $125 million for 2002. That this is an annualized figure that artificially assumes the full impact of the agreed-upon general rate reduction on a calendar-year basis is made clear in the Settlement Agreement, which increases this figure in a lock-step fashion each year by the amount of $37 million, for use in each subsequent full calendar year. (Para. 6).

36. The net effect of the Movants' interpretation is to achieve indirectly what the Movants could not achieve directly: namely, to obtain an automatic rate reduction for the first part of 2002, even though neither the Company, the Commission, nor any of the parties ever stated or agreed that rates would be reduced prior to May 1, 2002. To the contrary, the Settlement Agreement explicitly directs that Progress Energy would "begin applying the lower base rate charges required by this Stipulation and Settlement to meter readings made on and after the Implementation Date," namely, May 1, 2002. (Para. 2) (emphasis added).

37. By the same token, by their interpretation, the Movants would force Progress Energy to increase the $35 million refund the Company agreed to pay from revenues collected subject to refund prior to the effective date of the Settlement Agreement. In this regard, the Settlement Agreement states that Progress Energy would "refund to customers $35 million of the interim revenues collected" and that "[n]o other interim revenues collected by FPC during this

period will continue to be held subject to refund." (Para. 14) (emphasis added). Yet, the Movants' interpretation would require a refund for the sole reason that revenues necessarily "exceed" a threshold that reflects a rate cut that never took place during the interim period simply because it is an annualized number.

38. The Movants have argued that the plain language of the Settlement Agreement forecloses any adjustment to base rate revenues. This argument is not supported by the language of the agreement that we entered into.

39. First, if we were to apply the Settlement Agreement literally, customers would get absolutely no refund under the revenue sharing agreement for 2002. That is because the Settlement Agreement literally provides that "Commencing on the Implementation Date and for the remainder of 2002 and for calendar years 2003, 2004 and 2005, and for each calendar year thereafter until terminated by the Commission, FPC will be under a Revenue Sharing Incentive Plan as set forth below." (Para. 6). Read literally, this provision (and others like it in the Settlement Agreement) makes clear that there should be no sharing of revenues taken in by the Company prior to May 1, 2002. Applying the Settlement Agreement literally, we should mechanically compare "base rate revenues" taken in by the Company on and after the Implementation Date with the threshold set forth in the Agreement to determine if there is a surplus or deficiency of revenues. Progress Energy's revenues on and after May 1, 2002, total \$928 million. The threshold is set at \$1,296 million. Accordingly, there is a deficiency of revenues, as compared with the threshold, after the Implementation Date. Thus, under a literal interpretation of the Settlement Agreement, the Company has no excess revenues to share.

40. Second, the Movants' argument that the Settlement Agreement should be read literally to preclude any adjustments not expressly provided for in the document is undercut by

the fact that the Commission itself recognized in its Order approving the Stipulation and Settlement that appropriate adjustments <u>must</u> be made "in determining the appropriate level of revenues that will be subject to the revenue threshold and cap for 2002." (Order, p. 6). In reaching this result, the Commission specifically noted that, far from foreclosing the need for interpretation, the Settlement Agreement was "silent" on this issue. The Commission took as a given that such adjustments were contemplated by the Settlement Agreement and had to be made consistent with obvious intent of the agreement.

41. As I have explained, the only issue the Commission saw a need to address was how Progress Energy might <u>allocate</u> one such adjustment (the refund of revenues collected subject to refund, over two different calendar years) where the method of allocation was not self-evident. There was simply no need for the Commission to address the issue of allocation for other similar adjustments because the sums involved were attributable exclusively to 2002 and thus required no multi-year allocation.[2]

---

[2] If the Settlement Agreement were to be applied mechanically, even the adjustment specifically discussed by the Commission should not be made. If <u>no</u> adjustments were made, and the lighting and service charges were treated as falling outside the Settlement Agreement, as Movants appear to believe they should, then Movants' construction would produce a much smaller refund than the one they now seek. This may be shown as follows:

2002 Revenues	**$1,323,003,903**
Lighting/service charges	**(9,338,000)**
	1,313,665,903
2002 Sharing Threshold	**(1,296,000,000)**
Difference	**17,665,903**
67.1% May-Dec. multiplier	**11,853,820**
Refund (2/3 share)	**$ 7,906,498**

It is not reasonable to assume that the Commission meant to authorize only one step down the road of making logically necessary adjustments to account for the impact of rate refunds, decreases, and increases called for by the Settlement Agreement in order to calculate "base rate revenues." Conceptually, the Commission's discussion necessitates that all such adjustments of like kind be made to avoid internal inconsistencies.

42. The Commission's Order accordingly contradicts Movants' mechanical misinterpretation of the Settlement Agreement and makes clear that (1) the Settlement Agreement contemplates that adjustments must be made to 2002 "base rate revenues" to honor the parties' intent, and (2) in this regard, it is critical to account for the effect of the rate adjustments called for in the Settlement Agreement in order to arrive at a true picture of whether the Company derived "excess" revenues (i.e., revenues that exceeded the amounts projected) due to factors external to the Settlement Agreement itself.

43. I understand that the Movants are suggesting that the fact that the $125 million rate reduction was in effect for only part of the year 2002 is completely taken care of by the fact that the Settlement Agreement states that 2002 revenues available for sharing are limited to only 67.1 percent of the difference between the "threshold" and "base rate revenues," where 67.1 percent corresponds to that portion of the year from May 1, 2002 through the end of December. The short answer to this argument is that this multiplier provision takes care of part of the problem but not all of the problem. Specifically, this provision does ensure that only the correct percentage of "excess" revenues (corresponding to eight months of the year, namely, May through December) are set aside for sharing (on a 1/3 – 2/3 basis), but it does <u>not</u> help determine what amount of 2002 revenues are truly "excess" in the first place. The only way we can determine that is to calculate 2002 "base rate revenues" to reflect the impact of the rate refund, increase, and decrease called for by the Settlement Agreement itself.

44. Let me illustrate this with an example. Let's suppose that we were projecting revenues for 2002 of $100 million at the start of the year based on then-existing rates. Then the Commission orders an annual rate cut of $10 million, commencing on July 1, 2002 and continuing from year-to-year thereafter. The Commission further orders that the parties shall

participate in a 1/3 – 2/3 revenue sharing plan commencing July 1, 2002. To implement this, the Commission approves an annualized threshold of $90 million, reflecting the $10 million annual rate reduction.

45. Now let's suppose the Company generates $110 million in revenues for 2002. If we compare the $90 million threshold with unadjusted revenues of $110 million, we would get a delta of $20 million. If we then multiplied that times 50 percent, representing the half-year the rate reduction was in effect, we would get an amount equal to $10 million. But that does not reflect the amount of "excess" revenues for the half-year rate reduction period that is appropriately subject to the 1/3 – 2/3 revenue sharing plan commencing on June 1, 2002.

46. The reason it does not is because we did not first derive a true picture of "excess" revenues for the entire year. So we are multiplying 50 percent by the wrong figure. In order to get a true picture of "excess" revenues for the entire year, we have to adjust "base rate revenues" to reflect the changes in base rates actually approved by the Commission. This in turn requires that we recognize that the threshold being used for comparison is an "annualized" figure derived by simply subtracting the $10 million annual rate cut from $100 million in 2002 revenues projected under pre-existing rates.

47. Because the threshold is annualized, it inaccurately reflects that rates were set at the lower level beginning January 1, 2002 through June 30, 2002, thereby generating $5 million less for that period. So if we made no corresponding adjustment to "base rate revenues," we would erroneously conclude that "base rate revenues" were $5 million over the amount projected under approved base rates in existence prior to July 1, 2002. Recognizing this, we must adjust "base rate revenues" by subtracting $5 million from base rate revenues to get an apples-to-apples comparison between actual revenues and the annualized sharing threshold. Adjusted "base rate

revenues" thus equal $105 million ($110 million less the $5 million adjustment). When the annualized threshold is compared with that amount, we get a delta equal to $15 million ($105 million less $90 million), not $20 million ($110 million less $90 million). This represents a true picture of the "excess" of actual over projected revenues for the <u>entire year</u> 2002.

48. Because the revenue sharing plan commences, however, on July 1, 2002, we must still multiply this $15 million figureby 50 percent to obtain that portion of "excess" revenues available for revenue sharing. This computation yields an amount of "excess" revenues available for sharing equal to $7.5 million, <u>not</u> $10 million. So only $7.5 million is appropriately available for sharing on a 1/3 – 2/3 basis.

49. Further confirmation that this is the way the Settlement Agreement is intended to work may be seen by looking ahead to how it will work in 2003. For 2003, the parties will use the same annualized threshold (increased by $37 million per year to reflect projected growth), but for 2003 (and subsequent calendar years), that threshold accurately states the amount of annual rate <u>reduction</u> provided for under the Settlement Agreement. Interim refunds will no longer occur, and so no adjustment for that will be required. We will have to make an adjustment for the service and lighting charges <u>increase</u> reflected in the exhibit to the Settlement Agreement since this is a recurring item, or we can adopt the Movants' view, for the sake of argument, that the service and lighting increases fall outside the Settlement Agreement for all purposes. The net result of all these circumstances is that only truly "excess" revenues available <u>during the period the revenue sharing agreement is in effect</u> will be shared for 2003 (and subsequent years), just as it is intended.

49. To explain, the threshold in 2003 will reflect the <u>actual</u> reduction that has occurred from revenues projected in the Company's MFRs for the period covered by the

threshold, namely, the calendar year 2003. That is true because an annualized number should be accurate in a full calendar year. So it will fully reflect what Progress Energy is now projecting it will receive under Commission-approved rates in effect during 2003 (putting the lighting and services charges to one side). That being the case, if the Company receives any revenues above that amount for 2003, they may properly be deemed "excess" revenues subject to sharing. That is conceptually how the revenue sharing plan was intended to operate.

50. The Movants' refusal to recognize the adjustments made necessary by the fact that 2002 is a transition year, however, results in an internal inconsistency in the way the revenue sharing plan operates in 2002 and in <u>any</u> other year. By arguing that the 67.1 percent multiplier takes care of the issue, the Movants implicitly acknowledge that there is an issue that needs to be dealt with and that it was the parties' intent to harmonize the application of the revenue sharing plan in 2002 with its application in other years. But they argue for an interpretation that undermines that intent and that would result in a windfall to the customers that no one ever expected or intended. Indeed, no matter what they now say, the Movants cannot possibly contend that they intended or expected the result that they argue for in their Motion based on a literal reading of the Settlement Agreement, if for no other reason than that the Commission Order reflects an adjustment not expressly called for in the Settlement Agreement.

51. This concludes my Affidavit.

STATE OF FLORIDA

COUNTY OF PINELLAS

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this 7th day of March, 2003 by JAVIER PORTUONDO. He is personally known to me, or has produced his ______________ driver's license, or his ______________ ______________ as identification.

(Signature)

Javier J. Portuondo
(Printed Name)

(AFFIX NOTARIAL SEAL)

NOTARY PUBLIC, STATE OF North Carolina

December 16, 2006
(Commission Expiration Date)

(Serial Number, If Any)

Mary D Todd