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March 2, 2002

Via Federal Express

Ms. Blanca S. Bayo, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: *Review of the Retail Rates of Florida Power & Light Company, Docket No. 001148-EI*

Dear Ms. Bayo:

On behalf of the South Florida Hospital and Healthcare Association ("SFHHA"), enclosed please find:

(1) an original and 15 copies of the Prepared Direct Testimony and Exhibits of Stephen J. Baron; and 02471-02

(2) an original and 15 copies of the Public Version of the Prepared Direct Testimony and Exhibits of Lane Kollen. 02472-02

Please acknowledge receipt and filing of the above by stamping the duplicate copy and returning same in the enclosed self-addressed stamped envelope to the undersigned.

Additionally, in a separate overnight package, we have served you with a Confidential version of Lane Kollen's Prepared Direct Testimony, a copy of which also is being served upon FPL.

Thank you for your assistance in connection with this matter.

Very truly yours,

Mark F. Sundback

Mark F. Sundback
Kenneth L. Wiseman
Attorneys For the Hospitals

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Re: Review of the Retail Rates of Florida Power & Light Company	))	Docket No. 001148-EI

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2002

PUBLIC VERSION

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Re:	**Review of the Retail Rates of Florida Power & Light Company**	**))**	**Docket No. 001148-EI**

TABLE OF CONTENTS

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree from the University of Toledo. I also earned a Master of Business Administration degree from the University of Toledo. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than twenty years, both as an employee and as a consultant. Since 1986, I have been a consultant with Kennedy and Associates, providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1978 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions.

I have appeared as an expert witness on accounting, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on more than one hundred occasions. I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. I have testified before the Florida Public Service Commission in Docket Nos. 870220-EI (Florida Power Corp.), 8800355-EI (Florida Power & Light), 881602-EU and 890326-EU (City of Tallahassee), 890319-EI (Florida Power & Light), 910840-PU (Generic Proceeding Re SFAS 106), 910890-EI (Florida Power Corp.), and 920324-EI (Tampa Electric

Company). My qualifications and regulatory appearances are further detailed in my Exh.___(LK-1)).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the South Florida Hospital and Healthcare Association ("SFHHA")

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address several revenue requirement issues, including the revenue refund included by the Company in the test year relating to the effects of the Rate Agreement in prior years; the special depreciation allowed pursuant to the Commission's Order in Docket 990067-EI; further depreciation effects on the Company's nuclear units of license renewals (life extensions) of 20 years; deferred pension debit included by the Company in working capital; storm damage expense, reserve, and funding; projected growth in operation and maintenance expense; capitalization structure. I also discuss matters associated with FPL's capital additions.

Q. Please summarize your testimony.

A. I recommend that the Commission reduce the Company's revenue requirement by at least $475 million based upon the following adjustments.

Remove the revenue refund due to the effects of the 1999 Rate Agreement. ($34.086 million reduction).

Reduce depreciation expense to reflect Turkey Point 3 and 4 and St. Lucie 1 and 2 20-year service life extensions. ($77.485 million reduction).

Amortize the special nuclear and fossil depreciation allowed pursuant to 1999 Rate Agreement over three years. ($53.574 million reduction).

Remove the deferred pension debit included by the Company in working capital. ($62.873 million reduction).

Eliminate increase in storm damage expense. ($30.315 million reduction)

Reflect rate of return based upon internal funding of storm damage reserve treated as rate base reduction. ($31.099 million reduction).

Reduce projected growth in operation and maintenance expense, excluding the proposed increase in storm damage expense from 9.2% to 4.6%. ($47.432 million reduction).

Adjust overall return for accumulated deferred income tax effects of rate base adjustments. ($34.140 million increase)

Limit the common equity in the capitalization structure to 50%, quantified on a traditional basis. ($172.545 million reduction).

II. REFUND DUE TO RATE AGREEMENT

Q. Please describe how the Company has reflected its projection of the refund in the 2002 test year related to the 1999 Rate Agreement.

A. The Company has reflected a $34.086 million projection of the refund for prior years pursuant to the 1999 Rate Agreement as a permanent adjustment (reduction) to existing and ongoing base rate tariff levels.

Q. Should the Commission make an adjustment to remove this refund amount from test year operating income?

A. Yes. This refund amount does not reflect a permanent adjustment to existing and ongoing base rate tariff levels. Test year operating income should reflect the existing and ongoing base rate tariff levels without refunds related to prior periods. As such, the projected $34.086 million refund should be taken out of operating income on a pro forma basis.

Q. Why is the refund not a permanent feature?

A. The arrangement under the 1999 Rate Agreement expires in the spring of 2002. Thus the revenue-sharing threshold under which the refund will arise will not apply to revenue levels once the 1999 Rate Agreement is no longer effective.

III. DEPRECIATION AND AMORTIZATION

<u>Depreciation on Turkey Point 3 & 4 and St. Lucie 1 & 2</u>

Q. What service life is reflected currently in the depreciation rates for the Turkey Point 3 and 4 and St. Lucie 1 and 2 nuclear units?

A. The depreciation rates most recently authorized by the Commission for these nuclear units reflect service lives of 40 years. These service lives were based upon the 40-year terms of the initial NRC operating licenses for the units.

Q. Have there been recent changes in the expected service lives of the nuclear units?

A. Yes. FPL has applied for 20 year operating license extensions for the two Turkey Point units and the two St. Lucie units.

Q. Has the NRC ever refused to extend the operating license for any nuclear unit to date?

A. No.

Q. Why should the Commission reflect the additional 20-year service lives of the units for depreciation expense purposes in this proceeding?

A. First, absent any reliable documentation to the contrary, the Company clearly plans to operate these nuclear units for as long as it is physically and economically possible to do so. In fact, the Company cited such economic benefits to ratepayers as the rationale for applying for license extensions on the Turkey Point units. The Company stated in its 2000 Annual Report to Shareholders the following:

> To ensure that customers continue to receive the economic and environmental benefits provided by Turkey Point, FPL in 2000 submitted an application to the Nuclear Regulatory Commission to extend the plant's operating license an additional 20 years until 2033.

The Company has also prepared studies that demonstrate life extension is economic and will provide benefits to ratepayers.

If the Company did not believe that extending the units' lives through the license renewal process was physically possible and economically viable, based upon the facts currently known and knowable, then it would have been imprudent for it to incur the significant costs to extend the operating licenses. Thus, the best evidence of the service lives of these units is the Company's current intent to continue to operate them for an additional 20 years beyond the initial license terms.

Second, the existing depreciation rates are excessive because they provide for rate recovery of the capital costs of the units over 40 year service lives rather than the expected 60-year service lives. The mismatch between service lives and recovery creates intergenerational inequities among ratepayers. The existing depreciation rates and the ratemaking process provide for current and future recovery of plant additions, including those that may be necessary to assure the continued operation of the plants throughout their initial 40 years service lives as well as the additional 20 years.

Third, changing the depreciation rates will have a direct and immediate effect on the rates otherwise charged to ratepayers as the result of this proceeding. If the depreciation rates are changed subsequent to this proceeding, then the reduced expense will redound to the benefit of FPL's parent company, FPL Group, unless and until base rates are again reset. If the Commission waits until the Company files another depreciation study, even assuming FPL reflects the service life extensions in that depreciation study, it is unlikely ratepayers will receive a direct and immediate rate reduction coinciding with the Commission's adoption of new depreciation rates.

Q. **Is there another reason to act on this issue in this rate case?**

A. Yes. If power prices are deregulated and the electric industry in Florida is restructured without fixing this problem, FPL will experience a windfall – in essence, twenty years' use of large generating units with effectively no capital investment left. This will distort competition and means that ratepayers will have subsidized FPL unnecessarily.

Q. Did the Georgia Public Service Commission recently approve a reduction in the depreciation rates for Hatch 1 and 2 and Vogtle 1 and 2 based upon Georgia Power Company's application to extend the operating licenses for the Hatch units and its intent to do so for the Vogtle units?

A. Yes. In December 2001, that Commission approved significantly lower depreciation rates for the Hatch 1 and 2 nuclear units reflecting 20-year operating life extensions. The decision was based upon then pending Georgia Power Company applications before the NRC for 20-year license renewals. In January 2002, the NRC approved the applications for Hatch 1 and 2, thereby renewing their operating licenses for an additional 20 years.

In addition, the Georgia Public Service Commission approved depreciation rates that reflected 10-year service life extensions for the Vogtle 1 and 2 nuclear units. That decision was based upon Georgia Power Company's stated intent to apply for 20-year license renewals on those units as soon as possible in accordance with the NRC's procedural schedule for such license renewals.

Q. Have you quantified the effect of extending the service lives by 20 years for Turkey Point 3 and 4 and St. Lucie 1 and 2?

A. Yes. The effect is to reduce the Company's MFR revenue requirement by $77.485 million. This quantification reflects a reduction in depreciation expense of $83.000 million and a related reduction in accumulated depreciation for the test year of $41.500 million, but excluding the offsetting deferred tax effect reflected in the overall return applied to rate base.

Amortization of Special Depreciation

Q. Please describe the special depreciation authorized by the Commission in conjunction with its approval of a Stipulation and Settlement in Docket No. 990067-EI.

A. FPL was authorized to record up to an additional $100 million annually, over a three-year period, in special depreciation to reduce its nuclear and/or fossil production plant in service. The Company has recorded $170.250 million in such special depreciation.

Q. How has the Company reflected the special depreciation in its filing in this proceeding?

A. The Company has reflected this special depreciation as a reduction to rate base in this proceeding, but has reflected no amortization of this amount in operating income.

Q. Should the Commission amortize the special depreciation amount to the benefit of ratepayers in this proceeding?

A. Yes. There is no valid reason for the Commission simply to perpetuate this temporary overrecovery only as a rate base reduction, and with no amortization, going forward. The Company was allowed to accumulate the special depreciation in lieu of rate reductions for excess earnings during the effective period of the 1999 Rate Agreement. The Company has reflected the full amount of this special depreciation as a rate base reduction in its filing in this proceeding. As such, there is no dispute as to whether the special depreciation is attributable to, and thus belongs to, the ratepayers. However, the Company's filing provides for no return of this overrecovery to ratepayers. The Commission ultimately will have to make a determination as to the disposition of this overrecovery, preferably in this docket. Unless the Commission acts to amortize this amount, then the special depreciation will result in an accumulated depreciation reserve that exceeds the cost of the Company's existing plant and projected dismantlement costs. Perhaps recognizing the inequities of a similar situation in a previous docket, the Commission authorized the amortization of another special depreciation amount over the remaining life of the underlying nuclear assets.

Q. What amortization period should the Commission utilize to return the special depreciation to ratepayers?

A. A three-year amortization period would be appropriate. The special depreciation was recovered from ratepayers over the three-year term of the 1999 Rate Agreement. It should be returned over a comparable period. In this manner, it is more likely that the those ratepayers that paid the excess revenues for the special depreciation will be the beneficiaries of the return of those revenues.

Q. Have you quantified the effect on the revenue requirement of a three-year amortization of the special depreciation?

A. Yes. A three-year amortization would reduce the revenue requirement by $53.574 million. The amortization expense would be negative $56.750 million and rate base would increase by $28.375 million, assuming a uniform amortization throughout the test year, and excluding the offsetting deferred tax effect reflected in the overall return applied to rate base.

IV. DEFERRED PENSION DEBIT

Q. Please describe the deferred pension debit included by the Company in its cash working capital computation.

A. The Company has included a deferred pension debit in working capital. This asset represents the cumulative effect of the Company's net pension income (negative pension expense) since 1994 as detailed in its response to SFHHA Interrogatory #42, which I have replicated as my Exh.___(LK-2).

Q. Should the deferred pension debit be included in cash working capital as a conceptual matter?

A. No. The inclusion of this asset in rate base would require ratepayers to pay a carrying charge on an asset representing the cumulative effect of pension income amounts recognized and retained by FPL during the years 1994-2001. The benefits of the pension income during those years was not provided to ratepayers in the form of rate reductions. Instead, the rates in effect during those years, but for the limited reductions due to the 1999 Rate Agreement, reflected the recovery from ratepayers of positive pension expense based upon the test year levels in Docket No. 830465-EI. Thus, the elimination of the pension expense and the recognition of pension income were "savings" benefits retained by the Company's shareholder, FPL Group. As such, any carrying costs on the deferred pension debit amount accumulated through 2001, assuming there are any, should be attributed to FPL and its shareholder, and not to ratepayers.

Q. To the extent that pension income actually is flowed through to ratepayers, is it appropriate to reflect the related deferred pension debit in rate base?

A. Yes. In the test year, the Company has reflected pension income in operating income. Thus, the average balance of the test year pension income should be reflected in rate base.

Q. Have you quantified the effect of removing the deferred pension debit from rate base?

A. Yes. The removal of the deferred pension debit from rate base for the 1994-2001 period results in a revenue requirement reduction of $62.873 million, excluding the offsetting deferred tax effect reflected in the overall return applied to rate base.

V. STORM DAMAGE EXPENSE, RESERVE, AND FUNDING

Q. Please describe the Company's request for storm damage expense and funding treatment.

A. The Company has requested an increase in storm damage expense from the currently authorized level of $20.3 million to $50.3 million in conjunction with its request for an increase in the reserve level from $234 million to a target of $500 million. The Company has funded the storm damage reserve, which is managed by an FPL Group affiliate. As such, the large amount of reserve balance has not been utilized to reduce rate base in the Company's filing, unlike the Company's other reserve balances that are not funded and instead are utilized to reduce rate base.

Q. If the storm damage reserve balance is not utilized to reduce rate base, then how are ratepayers compensated for the use of their money?

A. Unfortunately, the Company's filing reflects no compensation to ratepayers for the use of their money. There not only is no rate base reduction, there also is no reduction in the requested $50.3 million annual expense to reflect earnings on the trust fund the Company has established.

Q. Under the traditional regulatory cost recovery model, are ratepayers compensated for their money either through a return offset on trust fund earnings or through a rate base reduction?

A. Yes. The failure to reflect an earnings offset of any sort to the requested accrual is unlike the return (earnings) offset recognized in the quantifications of pension expense, postretirement benefits other than pensions expense, and decommissioning expense, all of which accumulate amounts in dedicated trust funds similar to the funded reserve approach employed by FPL for storm damage expense. Other advances by ratepayers not included in trust funds are reflected as rate base reductions, including accumulated deferred income taxes.

Q. Should the Commission increase the storm damage expense amount?

A. No. First, increasing the storm damage expense will only exacerbate the disconnect between expense accruals and actual costs. By virtue of the fact that there is already a substantial storm reserve balance, the Company has been provided excessive storm damage expense recovery in prior years. Expense accruals have exceeded actual costs.

Second, the Commission should reject the Company's conclusory rationale that it is necessary to prepay storm damage costs in anticipation of a possible catastrophic loss exceeding the existing reserve level, and allow FPL to deprive ratepayers of time value of their substantial funds. In effect, this rationale is no different than if the Company had requested that ratepayers prepay the costs of the various generating plant repowerings in which it is engaged. While such prepayments may result in lower financing costs for FPL, they result in higher costs to ratepayers through current rates and intergenerational inequities.

In fact, the inequity of the intergenerational affect is driven home by information FPL produced in response to SFHHA in discovery. FPL's response to SFHHA Interrogatory No. 123 shows that for FPL's Southeastern region, the number of years between expected occurrences of hurricanes ranges from a low of 16 years for hurricanes at the SSI 3 level to 250 years for hurricanes at the SSI 5 level. For FPL's western region, the number of years between expected occurrences of hurricanes ranges from a low of 30 years for SSI 1 hurricanes to over 500 years for SSI 5 hurricanes. For FPL's Northeastern region, the number of years between expected occurrences of hurricanes ranges from a low of 36 years for SSI 1 hurricanes to 500 years for SSI 5 hurricanes. FPL's interrogatory response providing this information is reproduced as my Exh.___ (LK- 3). Thus, the information FPL provided shows an expectation that if FPL's proposal is approved, today's ratepayers will be paying for storm damages that may not be suffered for generations to come.

Q. But what are the expected annual damages for hurricanes at each of the storm intensity levels (*i.e.*, SSI 1 through SSI 5)?

A. FPL has no analysis on that issue. *See* Exh. ___ (LK- 4) (FPL Interrogatory Response No. 124).

Q. Are there other reasons why the requested increase in the storm fund should be rejected?

A. Yes. The request for the additional $30 million in storm fund amounts seems to ignore federal and state funds available in the event of natural disasters and catastrophic losses. Such funds would serve to reduce the costs associated with catastrophic losses.

Additionally, there is no indication that the Company could not finance and subsequently recover from ratepayers any costs related to a catastrophic loss above and beyond existing reserve levels and government emergency assistance. To the contrary, the Company does have plans in place to finance such costs if such a catastrophic loss should occur. In addition, the Company historically has been able to recover its storm damages costs from ratepayers, even if the reserve temporarily is depleted or negative.

Further, the Company's request fails to incorporate earnings on the trust fund and is overstated for that reason alone. The Commission should incorporate earnings on the trust fund in order to determine the net accrual necessary. For example, if the Commission believes that a $40 million annual accrual is appropriate, then that amount should be reduced for the earnings on the trust fund. At a 10% rate of return, applied to the existing $234 million balance, the net expense requirement would be only $17 million ($40 million less $23 million).

Q. Is the Company's approach to fund the storm damage reserve the most economic from the perspective of the ratepayers?

A. No. First, the earnings of the trust fund apparently inure to the benefit of the Company, not ratepayers. Although the earnings on the trust fund are added to the trust fund balance, the existing and proposed expense accruals have not been reduced for trust fund earnings.

Second, the trust fund earnings historically have been significantly below the Company's last authorized and requested rates of return. In other words, ratepayers would be far better off if the Company utilized these prepayments to invest in plant and equipment by displacing other required financing and reflected the prepayments as a reduction to rate base similar to the Company's other reserves. The trust fund has averaged an after tax return of only 4.5% over the last 5 years compared to its last authorized rate of return of 10.40% and its test year MFR rate of return in this proceeding of 8.97%. The average return earned by the Company on the storm damage trust fund over the last 5 years is detailed in the Company's response to SFHHA Interrogatory # IV-38, a copy of which I have replicated as my Exh.___(LK-5) along with my computations of the average return over the last 5 years.

Q. What would be the impact if the trust fund had earned an after tax rate of return comparable to that reflected in the MFR filing in this proceeding rather than the 4.5% it actually earned?

A. The trust fund balance would be in excess of $300 million for the test year, compared to the existing $234 million balance cited by the Company in its testimony.

Q. What would the trust fund's balance be three years from now if that MFR-level return continued along with the historic pattern of withdrawals?

A. Nearly $400 million.

Q. What is your recommendation regarding the Company's funding of the storm damage reserve?

A. I recommend that the Commission reflect the storm damage reserve as a rate base reduction in the same manner as it reflects other reserve amounts representing prepayments by ratepayers. This is the least cost financing option for ratepayers. If the Company dissolves the trust fund, then presumably it could utilize the funds to displace existing or future financing consistent with its overall rate of return requirements.

Q. Should the Commission ensure that ratepayers are provided a return on their money provided to the Company for storm damage expenses in advance of the Company's payments for such expenses, regardless of the level of storm damage expense authorized by the Commission in this proceeding?

A. Yes. I recommend that the Commission reflect the return effects directly by utilizing the reserve balance as a reduction to rate base. Alternatively, the Commission could reflect the return as a reduction to the expense accrual that it otherwise finds to be appropriate.

Q. Have you quantified the effect of your recommendations on storm damage expense, reserve, and funding?

A. Yes. The effects of my recommendations are to reduce the revenue requirement by $61.414 million. The revenue requirement effect includes a reduction in storm damage expense of $30.000 million, the increase sought by the Company, and reflects a rate base reduction for the Company's $234 million reserve balance.

VI. OPERATION AND MAINTENANCE EXPENSE

Q. Please describe the increase in O&M expense sought by the Company in this proceeding.

A. The Company's revenue requirement projection for 2002 includes an increase of $123.879 million (jurisdictional) in O&M expense for the test year over the MFR estimate of $1,021.911 million (jurisdictional) for 2001. The increase is $30.000 million less once the Company's requested increase in storm damage expense is removed. Nevertheless, the increase sought by the Company exceeds 12.12% including the increase to storm damage expense and 9.19% excluding the increase to storm damage expense.

Q. How does the Company's request compare to the actual growth in O&M expense in prior years?

A. The Company's request is excessive compared to its actual experience. The following table provides a history of the Company's O&M expenses and the annual percentage increase or decrease.

FLORIDA POWER & LIGHT COMPANY
NON-FUEL O&M EXPENSE

	$Million	% Change
1995	1,138	na
1996	1,127	-0.99%
1997	1,132	0.44%
1998	1,163	2.74%
1999	1,089	-6.36%
2000	1,062	-2.48%
	Average % Change	-1.33%

In addition to reducing its O&M expense in absolute dollars, the Company has reduced its O&M expense on a cents per kWh basis for the last 11 consecutive years, a fact that it cites in support of its claim that it is focused on controlling its costs and improving its efficiencies.

Q. **Historically, how does the Company's actual O&M expense compare to its budget amounts?**

A. Historically, the Company's actual O&M expense has been less than its budget amounts. In 2000, the Company's actual O&M expense was $999 million compared to budget (plan) of $1,034 million. In 1999, the Company's actual O&M expense was $1,026 million compared to budget of $1,072 million. In 1998, the Company's O&M expense was $1,088 million compared to budget of $1,090 million. The Company provided these comparisons in response to SFHHA Interrogatory # V-57, which I have replicated as my Exh.___(LK- 6).

Q. Did the Company revise its O&M expense downward in conjunction with its revision downward of revenues?

A. No. Instead of a reduction in O&M compared to the Company's budget for 2002, relied upon for its initial MFR filing, the Company claimed an increase in O&M of $22.640 million when it subsequently revised certain MFR schedules.

Once again, the failure to reduce downward its O&M expense is a complete disconnect from reality, not only based upon FPL's history, but also based upon business requirements in the unregulated world. First, FPL is focused on reducing its O&M expense per kWh, a statistic it cites in public forums as evidence of its excellent management. If projected sales are reduced and O&M expense is not, then the projected O&M expense per kWh will rise compared to the 11 prior years of reductions.

Second, FPL should not be held to a lower standard of cost control in response to projected lower sales, but rather to a higher standard. It is only logical that if revenues are lower for purposes of the rate filing compared to the Company's budget, then it also should be required to reflect commensurate reductions in its O&M expense for purposes of the rate filing compared to its budget.

Q. Please respond to the claim by Company witness Mr. Shearman that the Company will not be able to sustain its enviable historic reductions in O&M expense into 2002 and 2003 due to "inflation, aging assets, customer growth, and load growth.

A. There is not a shred of logical support for such an assertion. First, inflation currently is nearly nonexistent. Second, the Company's capital expenditures for new and replacement plant approximate 15% of its asset base every year. This is evidence of relatively new, and more likely, lower maintenance plant. Some of those capital expenditures undoubtedly were incurred to reduce O&M expense and are reflected in rate base. Ratepayers should be provided the full benefit of the related expense reductions.

Third, customer growth and load growth obviously overlap quite a bit. As noted earlier, to the extent that such growth is projected to be lower, as reflected in the Company's revised revenue forecast, then O&M expense should have been reduced as well, not increased. Finally, it should be noted that the Company voluntarily determined to increase its reserve margin from the Commission's mandated 15% to 20% and to accelerate its scheduled capacity additions and repowerings. Thus, at least to some extent, the related O&M expense also is discretionary. Presumably, the Company should recover such discretionary increased costs through higher interchange revenues, particularly given its projection of little or no growth in its customer base.

Finally, the FPL Group 2000 Annual Report to Shareholders directly rebuts the substance of Mr. Shearman's arguments in favor of higher O&M expense growth. The Company cites its ability actually to reduce O&M expense in the face of customer and load growth and describes the addition of significant generation capacity (new plant compared to the aging plant cited by Mr. Shearman). The relevant excerpt from that Annual Report follows.

> Since 1990, when the company was restructured, FPL has driven down costs while achieving continuous improvements in virtually every area of its operations. At the same time, it has taken steps to meet the sharply increasing energy demands of a service area that continues to grow at a rapid pace.
>
> FPL's customer base grew by 2.5% in 2000 to more than 3.8 million. More new customers, 92,000, were added than in any year since 1990. In addition, energy usage per customer increased by nearly 2% over the previous year.
>
> In 2000, FPL reduced its operations and maintenance costs per kilowatt-hour for the tenth consecutive year. Since 1990, O&M costs have declined 40% - from 1.82 cents per kilowatt-hour to 1.09 cents. During this time the company added more than 700,000 new customer accounts and increased its generating capacity by 24%.
>
> FPL's cost reduction efforts have resulted in a more efficient and productive organization and enabled the company to hold down the price of its electricity to below the national average.
>
> FPL continues to achieve major improvements in such critical success areas as plant performance, electric reliability, and customer service.

Thus, it appears that FPL does not share Mr. Shearman's views regarding its ability to reduce O&M expense given the same factors cited in his testimony.

Q. Did Mr. Shearman investigate whether FPL's efforts to reduce costs during 1999-2001 caused costs to increase following 2001?

A. No. Apparently he made no effort to determine whether that had occurred. Of course, during the 1999-2001 period, FPL might retain all of the savings resulting from deferring costs. Mr. Shearman also did not investigate how FPL's profits may have been increased during 1999-2001, due to such cost reductions. See my Exh.___ (LK-7).

In contrast, FPL had no assurance that it would retain any cost savings following March 31, 2002, and any costs that could be deferred into that period could help justify higher rates.

Q. Are Mr. Shearman's comparisons meaningful?

A. Not really. He ignored many different variables between utilities that tend to affect costs and thus he is unable to make apples to apples comparisons.

Q. Did his various exhibits take into account varying ages of generation fleets, which would affect outage levels and O&M cost levels?

A. No. Exh.____ (LK-8).

Q. Did his various exhibits take into account the differences in types of generators, since (for instance) different types of nuclear reactors have different maintenance issues?

A. No. Exh.___ (LK-9).

Q. What reasonably can be concluded regarding the Company's projected growth in O&M expense given its historic O&M expense growth and its public statements regarding controlling costs and improving efficiencies?

A. The Company's O&M expense projected for the test year is excessive. The Commission should look to history as a guide to the reasonable and necessary level of O&M expense and the Company's ability to control the actual level of expense compared to the amounts reflected in its filing in this proceeding.

Q. What is your recommendation?

A. Absent more definitive data or a more conclusive showing of actual O&M levels, I recommend that the Commission limit the growth in O&M expense for the test year to at most half of the Company's projection, excluding the increase due to storm damage expense. This recommendation reflects a 4.60% increase in O&M expense compared to 2001, excluding the proposed increase in storm damage expense, still an exceptionally high level compared to recent experience of negative growth.

VII. CAPITALIZATION STRUCTURE

Q. Please describe the Company's proposed capitalization structure.

A. The Company has proposed the following capitalization structure computed on a financial statement basis, excluding accumulated deferred income taxes, which are included in capitalization only as a ratemaking convention in lieu of subtraction from rate base.

FLORIDA POWER & LIGHT COMPANY
CAPITALIZATION STRUCTURE

	$Million	%Capital
Long Term Debt	2,809	32.7%
Short Term Debt	52	0.6%
Preferred Stock	227	2.6%
Common Equity	5,505	64.1%
Total	8,593	100.0%

Q. Is the level of common equity included in the Company's proposed capitalization structure excessive?

A. Yes. It is excessive for an A rated utility coupled with the lower level of risk experienced by FPL as a regulated utility compared to FPL Group and its unregulated business activities. FPL's bond ratings and investor risk perceptions are strongly influenced by FPL Group's extensive unregulated business activities. This higher level of unregulated risk results in higher costs that should not burden FPL's ratepayers.

Q. What has Standard and Poor's stated regarding the FPL Group unregulated activities risk and the effect on FPL?

A. First, S&P rates utility debt on the basis of the parent company's consolidated fundamentals, not solely on the utility company's business and financial risk. S&P stated in a recent commentary posted on its website the following:

> [U]tilities that merge with other companies and invest outside the traditional regulated businesses will be rated on the basis of the qualitative and quantitative fundamentals of their consolidated entities.

Second, prior to the downrating of FPL from AA- to A, S&P issued its rationale for the its negative creditwatch and stated the following in the wake of the announcement of the proposed FPL-Entergy merger.

> The ratings on Florida Power & Light Co., the utility operating company of FPL Group Inc., are on CreditWatch with negative implications, reflecting FPL Group's announced merger with lower-rated Entergy Corp.
>
> * * * *
>
> Despite the utility's stellar financials, the consolidated entity is challenged to improve consolidated credit-protection measures as the firm expands its portfolio of independent power projects.
>
> Florida Power & Light's corporate credit rating is based on the financial and business risk profile analysis of the consolidated enterprise, derived by analyzing each individual core-operating unit. There are insufficient prescriptive regulatory measures to restrict cash flow from the utility to the parent.
>
> Florida Power & Light's first mortgage bonds are rated the same as the firm's corporate credit rating.

In reviewing FPL and its affiliates, Standard & Poor's noted FPL's "buoyant cash flow" and "strong business profile" "tempered by the growing portfolio of higher-risk nonregulated investments, principally in independent power projects . . . ." Particularly, in reviewing the growth plans of the FPL Group, the report stated that "Standard & Poor's views the business risk profile of independent power producers at the high end of the risk spectrum . . . ." FPL Group's energy marketing and trading operation was characterized as a "high-risk business segment."

More recently, Standard and Poor's reiterated its concerns regarding the effect of the unregulated business activities on the entire FPL Group "family" of companies, which includes FPL.

> The IPP financing strategy and the amount of risk mitigation undertaken will be important to sustaining current ratings for the entire FPL family . . . Resolution of the CreditWatch listing is expected in the near future. Notably, FPL Group's commitment to expand its nonregulated businesses, including its portfolio of IPPs, will challenge the firm to strengthen consolidated credit-protection measures to maintain the existing ratings profile.

The Credit Watch listing was resolved in September 2001, and the effects of FPL's nonutility spending were clear.

> Credit quality for Florida Power & Light Co., the utility operating company of FPL Group Inc., reflects the unit's steady and reliable cash flow attributes, tempered by the parent's growing portfolio of higher-risk, nonregulated investments, principally in independent power projects.
>
> Current ratings for FPL Group and its affiliates incorporate increasing business risk for the consolidated enterprise attributable to the growing nonregulated independent power producer (IPP)

> portfolio, regulatory challenges in Florida, an aggressive financing plan, and declining credit protection measures . . .
>
> Florida Power & Light's credit profile reflects an above-average business position . . . .
>
> Parent FPL Group's portfolio of nonregulated electric power generation holdings is in several regions, ... The potential for an economic downturn and the possibility of additional capacity coming on line in some of the regions that FPL Group has targeted highlight some of Standard & Poor's concerns . . . about this high-risk business line.

Similarly, Moody's also tied its concerns regarding the debt ratings for the FPL Group companies, including FPL, to the risk associated with FPL Group's unregulated business activities.

> [G]rowth strategies implemented by FPL Energy, an unregulated subsidiary of FPL Group, also increase pressure on the consolidated company's credit profile. FPL Energy intends to finance and build 6,000 mw of unregulated merchant generation by 2003. While most of these projects will eventually be financed with non-recourse debt, FPL Group Capital provides interim financing. The parent company guarantees the debt issued by FPL Capital which in turn creates pressure for all the rated entities within the consolidated group.

Q. What are the Standard and Poor's debt to total capitalization guidelines for an A rating on utility debt?

A. Standard and Poor's guidelines for an A rating and a company business risk profile of 4 (FPL's rankings) range from 46% to 50% debt to total capitalization.

Q. What is the average capitalization structure of the comparison group of A rated utilities utilized by Company witness Dr. Avera to develop his return on equity recommendation?

A. Dr. Avera computed the following average capitalization structure based upon his comparison group as of September 30, 2001.

CAPITALIZATION STRUCTURE DR. AVERA COMPARISON GROUP	
Short Term Debt	**2.1%**
Long Term Debt	**42.5%**
Preferred Securities	**5.4%**
Common Equity	**50.0%**
Total	**100.0%**

Dr. Avera noted that the individual common equity ratios embodied in the average ranged from a low of 42.9% to a high of 59.9%.

Q. **What is Mr. Avera's opinion of credit-rating agencies, such as those quoted above?**

A. "[P]erhaps the most objective guide to a utility's overall investment is its bond rating" assigned by "independent rating agencies." (Avera Direct, p. 47: 11-13).

Q. Is that similar to the opinion held by FPL's Mr. Dewhurst?

A. Yes. "Rating agencies, acting as independent risk assessors on behalf of investors generally, are an important source of evidence" of investors' sentiments. Dewhurst Direct Testimony, p. 19:18-22.

Q. What do the rating agencies think will be the outcome of this proceeding?

A. "[T]he market is expecting a rate cut" according to Justin McCann of Standard & Poor's (Miami Herald, February 24, 2002).

Q. Should ratepayers be required to subsidize FPL Group's nonregulated business activities through a capitalization structure that reflects a "bulked-up" common equity level so that FPL Group, on a consolidated basis, had adequate credit protection?

A. No. The unregulated business entities should provide the consolidated entity the necessary credit protections. It is inappropriate for the ratepayers to subsidize the FPL Group unregulated business activities through an excessive common equity level.

Q. Are there other factors that should be taken into account when assessing the appropriate level of equity capitalization for FPL?

A. Yes. Approximately 45% of FPL's total jurisdictional revenues are recovered by trackers, rather than through base rates.

Q. Is there another factor warranting consideration?

A. Yes. The timing, and perhaps to a lesser extent the scope, of FPL's present ambitious construction program are in part within FPL's control. FPL's determination to agree to a 20% (in lieu of a 15%) reserve margin, and its desire to build its own generation capacity, obviously influence its capital needs.

Q. What is your recommendation regarding the appropriate capitalization structure for FPL as a regulated utility?

A. I recommend the Commission adopt a capitalization structure of no more than 50% common equity and up to 50% debt, computed on a financial statement basis, excluding accumulated deferred income taxes and other Commission ratemaking adjustments. Once the determination is made regarding an appropriate financial statement capitalization structure, the Commission should adjust that structure for its various historic ratemaking adjustments, the largest of which is accumulated deferred income taxes.

Q. Have you quantified the return effects of the accumulated deferred income tax adjustments to capitalization and capitalization structure necessitated by your rate base adjustments?

A. Yes. The return effects of the prior rate base recommendations, excluding the effects of any further modifications to the capitalization structure quantified below, results in an increase to the revenue requirement of $34.140 million

Q. Have you quantified the effect of your recommendation on the capitalization structure for FPL?

A. Yes. This recommendation results in a reduction to the revenue requirement of $173.545 million. I have quantified this reduction to the revenue requirement as the difference between the Company's proposed grossed up overall rate of return and that corresponding to my recommendation (based upon the averages cited in Dr. Avera's testimony) times the rate base adjusted for the effects of the other adjustments that I have proposed. This adjustment is incremental to the previous adjustment for the return effects of the accumulated deferred income taxes.

VIII. SANFORD REPOWERING

Q. Please describe the Sanford Repowering Project (the "Sanford Project" or the "project").

A. The Sanford Project involved *inter alia* converting two previously oil- and gas-fired units, at the Sanford site, to gas fired combined cycle units.

Q. Did FPL originally project that the project would be in-service by 2002?

A. No. Originally FPL had scheduled the Sanford Project to be in-service after 2002.

Q. How did FPL evaluate the alternatives to repowering Sanford?

A. When we asked that question, FPL initially provided a generic description of criteria it claims it evaluated in determining whether to repower Sanford. Subsequently, FPL provided additional information.

Q. Did FPL compare the Sanford Repowering Project to a specific independent entity's project?

A. No.

Q. Did FPL's review of the Sanford Repowering Project use the cost which will be incurred to complete the project?

A. No.

Q. Did FPL conduct an RFP or open season to solicit bids in lieu of building its own capacity?

A. No.

Q. Mr. Waters discusses the Sanford Project in the context of the 1998 Ten Year Site Plan. What were the estimates of cost in 1998 for repowering Sanford Project?

A. FPL furnished a March 1998 "Summary of Alternatives" involving repowering Sanford in 2002 or 2004. The analysis, stated in 1998 dollars, estimated that repowering two units would cost $441 million (including $48 million for transmission expansion).

Moreover, the analysis showed that net per-KW costs would be reduced if re-powering was completed in 2004 rather than 2002. (Exh.___ (LK –10)).

Q. Was this estimate consistent with for the project's ultimate cost?

A. No. Neither were subsequent estimates. According to FPL, the project in October 1998 was forecast to cost $437 million; by August, 1999, that forecast had risen by over $100 million, to $546 million (Exh.___ (LK-11)). This reflected at least in part changing the identity of the two units to be repowered. Additionally, in October, 1998, the power delivery department estimated related costs of about $55 million (Exh.___ (LK-12)).

Q. Was $546 million the ultimate cost of the Sanford Project?

A. Far from it. The project budget authorized by FPL (excluding financing) reached $622 million by the summer of 2000 (Exh.___ (LK-13)).

Q. What is the most current forecast of the capital cost of the Project?

A. According to Mr. Waters, it is now approximately $697 million, or $75 million above the $622 million authorized project budget and almost $100 million above the August 1999 estimate. This includes at least $76 million for transmission interconnection work (*id.*).

Q. Has the Sanford Project been successful from the FPL perspective?

A. Evidently not. Even using FPL's "Sanford Repowering Success Criteria," which reflects the $622 million estimate, the project is $75 million over budget. (Exh.___ LK-14)).

Q. Can you identify major causes of the cost overrun?

CONFIDENTIAL INFORMATION FOLLOWS

[Confidential Information Intentionally Omitted]

[Confidential Information Intentionally Omitted]

END OF CONFIDENTIAL INFORMATION

Q. **Has FPL changed when it anticipated incurring charges in connection with Sanford?**

A. Yes. In a document dated May 9, 2001 (Exh.____ (LK-15)), FPL compared its "current approved 5-year forecasts" of expenditures for the Sanford (and Fort Myers) project(s) to its most up-to-date forecast. The comparison showed that the May 2001 forecast projects an increase in 2002 expenditures of $15 million, over what the then-current approved 5-year forecast had estimated, with reductions in expenditures shown in pre- and post-2002 periods.

Q. **Prior to the construction report described above, and following changes in its original schedule, when did FPL project that the Sanford Project would be placed in-service?**

A. In 2002.

Q. **What is the impact of FPL's post-September 11, 2001 estimates of consumption upon the need for capacity?**

A. FPL's "2002 Alt. Forecast," a post-September 11, 2001 projection, reflects a decrease of about 3% in the projected 2005 total consumption by jurisdictional customers compared to the pre-September 11, 2002 FPL 2002 Budget Forecast (Exh.____ LK-16)).

IX. AFFILIATE RELATIONSHIPS

Q. Do you have concerns with FPL's interrelations with its affiliates?

A. Yes. FPL is engaged in numerous transactions with its affiliates, including those involving millions of dollars but which are not subject to a written contract. *See* Exh.__ (LK-17). Unfortunately, FPL has resisted providing responsive information. Therefore, I reserve the opportunity to supplement this testimony when FPL has furnished adequate data.

Q. Does this complete your direct testimony?

A. For now.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Re:	**Review of the Retail Rates of Florida Power & Light Company**	**))**	**Docket No. 001148-EI**

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2002

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than twenty-five years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Consumers
Kimberly-Clark

Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co	Premature retirements, interest expense.
10/88	88-170- EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171- EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial Considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87)
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No 87), Part 32, income tax normalization.

Expert Testimony Appearances
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As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements , detailed investigation

Expert Testimony Appearances
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Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co	Recovery of CAAA costs, least cost financing
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp	Merger
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.

**Expert Testimony Appearances
of
Lane Kollen
As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co	Incentive rate plan, earnings review
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co	Alternative regulation, cost allocation.

**Expert Testimony Appearances
of
Lane Kollen
As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.

**Expert Testimony Appearances
of
Lane Kollen
As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers mechanisms	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery
4/99	99-02-05	CT	Connecticut Industrial Utility Customers mechanisms.	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative regulation.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement Stipulation
7/99	97-596 (Surrebuttal)	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 (Surrebuttal)	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
8/99	98-474 98-083 (Rebuttal)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative forms of regulation.
8/99	98-0452-E-GI (Rebuttal)	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

**Expert Testimony Appearances
of
Lane Kollen
As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	U-24182 (Supplemental Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements In projected test year.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
11/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 (Affidavit)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009		Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs
12/00	U-21453, U-20925, U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 (Direct)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925 and U-22092 (Subdocket B) (Surrebuttal)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc,.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy	Merger, savings, reliability.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm Staff	Entergy Gulf States, Inc	Business separation plan: settlement agreement on overall plan structure
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution (Rebuttal)	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan. agreements, hold harmless conditions, Separations methodology
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Review requirements, Rate Plan, fuel clause recovery
11/01	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.

Florida Power & Light Company
Docket No. 001148-EI
SFHA Fourth Set Interrogatories
Interrogatory No. 42
Page 1 of 1

Q.

Refer to MFR Schedule B-26 page 1 lines 15-27 regarding the adoption and changes in accounting for pension expense. Please provide a schedule detailing the history of the prepaid pension asset included in account 186.190, including any offsetting accumulated deferred income tax amounts by FERC account. For each year, commencing with 1993, cited as the year in which this change was implemented, through 2002, provide the beginning balance of the prepaid pension asset, increases or decreases for the year, and the ending balance. Reconcile the increases or decreases for each year to the Company's pension expense for that same year.

A.

See attached schedule.

South Florida Hospital Healthcare
Interrogatory #42
History of Acct. 186.190 - Prepaid Pension Asset
Years ending 1993 through 2002 (1)

[redacted]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002 (1)
Beginning balance	19,542	(329)	11,637	25,069	43,354	112,110	173,331	262,799	371,180	473,902
Pension expense	14,592	11,966	18,726	18,285	68,757	79,626	89,469	108,381	101,895	109,798
Adjustments	(34,463) (2)		(5,294) (2)			(18,405) (2)				
Ending balance	(329)	11,637	25,069	43,354	112,110	173,331	262,799	371,180	473,075	583,700
Deferred Tax Balances Accounts 282 and 283	127	(4,489)	(9,670)	(16,724)	(43,247)	(66,862)	(101,375)	(143,182)	(182,468)	(225,142)

Notes:

(1) - Actual amounts for 1993 through 2001 and projected test year amounts for 2002.

(2) - These amounts relate to special retirement plans resulting from FPL's cost reduction programs.

Docket No. 001148-EI
L. Kollen Exhibit No.__ (LK-2)
History of Account 186.190 - Prepaid Pension Asset
Page 2 of 2

Q.

Re: Testimony and Exhibits of Steven E. Harris

With respect to hurricanes at levels SS 1 through SS 5, please state the probability of each occurring during the year. Please also state the number of years between expected occurrences at each hurricane level.

A.

Refer to Document SPH-1 Section 11, Reference 1. The following table of likelihood of landfall is provided:

Table 2

ANNUAL PROBABILITY OF LANDFALLING STORMS

Region	SSI 1	SSI 2	SSI 3	SSI 4	SSI 5
Western (Manatee through Collier)	3.3%	2.0%	2.1%	0.4%	negligible
Southeastern (Dade/Broward/Palm Beach)	4.8%	5.3%	6.3%	2.4%	0.4%
Northeastern (Martin and north)	2.8%	2.8%	1.6%	0.5%	0.2%

The recurrence interval for the storm landfall probabilities provided in Table 2 above is:

Annual Probability	Recurrence Interval (years)
0.2%	500
0.4%	250
0.5%	200
1.6%	63
2.0%	50
2.1%	48
2.4%	42
2.8%	36
3.3%	30
4.8%	21
6.3%	16

Q.
Re: Testimony and Exhibits of Steven E. Harris

Separately for hurricane levels SS 1 through SS 5, please calculate exceedence probabilities in the form of Table 9-2.

A.
These analyses were not performed as part of the study.

Florida Power & Light Company
Docket No. 001148-EI
SFHA Fourth Set Interrogatories
Interrogatory No. 38

Q.

Please provide a 6 year history of the storm damage fund reserve, consisting of actual amounts for 1997-2001 and projected amounts for the 2002 test year. Separately show for each year the beginning balance of the reserve, expense accruals, write-offs (charges), and ending balance of the reserve. Provide the requested amounts on a jurisdictional basis.

A.

Year	(1) Contributions/ Expense	(2) Fund arnings	(3) Storm Costs harged to Reserve	(7) Ending Reserve Balance	(8) Mark-to-Market djustment (FAS 115)	(9) Adjusted Ending Reserve Balance
Actual						
1996				221,244	1,333	222,577
1997	20,300	10,840	1,117	251,267	1,177	252,445
1998	20,300	12,459	27,554	256,472	2,116	258,588
1999	20,300	9,451	67,824	218,399	(2,820)	215,579
2000	20,300	9,075	17,566	230,208	(1,076)	229,132
2001	20,300	11,388	27,208	234,687	640	235,328
Projected						
000 (actual)				230,208	(1,076)	229,132
2001 (a)	20,300	9,596	(b)	260,104	1,399	261,504
2002	50,300	10,221	(b)	320,625	1,399	322,025

(a) five months actual, seven months projected

(b) the number and costs of storms are too unpredictable to predict.

See MFR C-9 (account 924) for the jurisdictional factor applicable to the annual expense accrual. See MFR B-7 for the jurisdictional factor applicable to the reserve balance. Note- the storm and property damage reserve is a funded reserve which is excluded from rate base (see MFR B-4).

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-6)
Operating Expenses - Budgeted and Actual

Florida Power & Light Company
Docket No. 001148-EI
SFHA Fifth Set of Interrogatories
Interrogatory No. 57
Page 1 of 1

Q.
Please compare your operating budget by year established in advance for fiscal years 1998, 1999, 2000 and 2001 with the actual results of operations experienced during such respective periods.

A.

($ in millions)

	1998		1999		2000		2001	
Expenses:	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan
Fuel and Purchased Power	$ 2,175	$ 2,244	$ 2,232	$ 2,191	$ 2,511	$ 2,253	$ [redacted]	$ [redacted]
Base O&M	1,088	1,090	1,026	1,072	999	1,034	[redacted]	[redacted]
Depreciation and Amortization	1,249	1,078	989	1,263	975	924	[redacted]	[redacted]
Taxes	952	945	959	928	975	968	[redacted]	[redacted]
Other, primarily interest	286	293	233	246	256	255	[redacted]	[redacted]
	$ 5,750	$ 5,650	$ 5,439	$ 5,700	$ 5,716	$ 5,434	$ [redacted]	$ [redacted]

(Actuals - Babka)
(Plan - Beilhart)

The information requested for 2001 is confidential and will be made available for inspection at FPL's General Offices at 9250 West Flager Street, Miami, Florida 33174 during normal business hours pursuant to a mutually satisfactory confidentiality agreement or protective order.

Q.

Re: Testimony and Exhibits of John G. Shearman

Please discuss and describe in detail and provide all documents related to, Mr. Shearman's investigation concerning whether, or the extent to which, FPL's efforts to reduce costs during the period 1999 - 2001, will cause or could cause costs in any category to increase for any period following 2001. If Mr. Shearman did not investigate that topic please so state.

A.

Mr. Shearman did not specifically investigate, or testify on this exact topic. However, FPL's track record of consistent year-on-year cost reductions began well in advance of the 1999-2001 time period referenced and therefore implies no history of such decision-making. Please see pages 22 through 23 of Mr. Shearman's testimony for a complete description of his opinions on FPL's future O&M expenses.

Q.

Re: Testimony and Exhibits of John G. Shearman

Please quantify in Mr. Shearman's opinion the amount of increase in net profits that FPL enjoyed during the period 1999- April 1, 2002 as a result of FPL's lower costs and efficiency enhancements. Please provide your workpapers and supporting documents and describe how you went about calculating the amount.

A.

FPL objects to this interrogatory as it seeks analyses that have not been performed, or data that have not been collected with the preparation of the FPL witnesses' testimony.

Q.

Re: Testimony and Exhibits of John G. Shearman

With respect to Mr. Shearman's testimony and exhibits please compare the weighted average age of the FPL generation fleet with that of the various samples that are used for comparison purposes in Mr. Shearman's materials.

A.

FPL objects to this interrogatory as it seeks analyses that have not been performed, or data that have not been collected with the preparation of the FPL witnesses' testimony.

Q.

Re: Testimony and Exhibits of John G. Shearman

With respect to Document JMS-3, please indicate the size of the sample (a) within the United States and (b) outside the United States. Please indicate the type(s) of reactor operated by FPL, and the proportion of reactors of that type in the sample population, broken out as between those in the United States and those outside of the United States. Please identify the other type(s) of reactors that are contained in the sample population and the relative percentages that each represents of the sample population. Please provide a comparable set of data for Documents JMS-4 and JMS-5. In the witness' opinion, what is the cause of the significant decrease in forced outage rates for the sample group from 1997 through 2000.

A.

FPL objects to this interrogatory as it seeks analyses that have not been performed, or data that have not been collected, in connection with the preparation of the FPL witnesses' testimony.

SUMMARY OF GENERATION ALTERNATIVES
NEW PLANT ENTRY PRICE

	Alternatives:	RePower PFM Unit 1&2	3 Escalation Notes
	I. CONSTRUCTION (1000) 1997 $		
A	Permit/Eng/Fab (months)	24	
B	Construction Phase (months)	30	
C	Project Total (months)	54	
D	Land	($1,881)	1
E	Materials	$281,802	2
F	Labor & Equipment	$75,450	
G	Total Direct Cost	$355,571	
H	Construction Indirects	$0	
I	Licensing	$5,000	
J	Project Support	$5,000	
K	Contingency	$20,000	
L	Total Indirect Cost	$30,000	
M	$/KW Net Summer	$275	
N	$/KW Net Winter	$256	
O	Fuel Expansion	$6,000	
P	Transmission Expansion	$23,000	
Q	Railroad & Cars	$0	
R	Total Other Cost	$29,000	
S	Grand Total Cost	$414,571	
T	$/KW Net Summer	$296	
U	$/KW Net Winter	$275	
	II. PLANT CHARACTERISTICS		
V	Net Sum 95F Capability (mw)	1,400	
W	Net 75F Capability (mw)	1,508	
	Net 59F Capability (mw)	1,541	
X	Heat Rate btu/kwh 95F 100% Load HHV	6,959	
Y	Heat Rate btu/kwh 75F 100% Load HHV	6,815	
Y1	Heat Rate btu/kwh 75F 75% Load HHV	6,990	
Y2	Heat Rate btu/kwh 75F 50% Load HHV	7,630	
Z	Heat Rate btu/kwh 59F 100% Load HHV	6,783	
AA	Equiv. Avail. %	96%	
BB	Sched Outage (wks/yr)	1.5	
CC	Equiv Forced Outage	1.0%	
	III. OPERATION		
DD	Total O&M (mm/yr)	$8	
EE	(remove 6MM for existing fleet cost		
FF	for Repower only)		
GG	Capital Replace ($mm/yr)	$6	
	IV. SPENDING CURVES		
HH	Year 6	$0	
II	Year 5	$0	
JJ	Year 4	$1,658	
KK	Year 3	$2,902	
LL	Year 2	$193,190	
MM	Year 1	$216,821	
	V. NOTES:		
NN		New NSC	
	Fuel	Natural Gas	
	AFUDC Adder		
OO	Equipment	"7F ++" 6CT & 6HRSG	
PP	Cooling	Intake/Discharge	
QQ	SCR's	no	
RR			

1 $4MM Sale Price minus $519k Site Demo and $1.6MM Book Value (1996 $$)

2 $150MM to be issued in 1997 PO's

3 All other numbers have not been escalated

IRP_Repower PFM 11296ESC

SUMMARY OF GENERATION ALTERNATIVES
COST AND COMPETITION TEAM
IRP 1998

	New Generation Alternatives				
		16	17	18	19
	Alternatives:	400 PC Greenfield	400 PC Martin	200 SC Exist Site - "G"	500 CC - F++ Greenfield
	I. CONSTRUCTION (1000) 1998 $				
A	Permit/Eng/Fab (months)	36	30	9	24
B	Construction Phase (months)	30	27	6	24
[redacted]					
D	Land	$ 1,210	$ -	$ -	$ 1,200
E	Materials	$ 226,000	$ 224,000	$ 42,069	$ 120,000
F	Labor & Equipment	$ 104,000	$ 104,000	$ 6,333	$ 44,000
G	Total Direct Cost	$ 331,210	$ 328,000	$ 48,402	$ 165,200
H	Construction Indirects	$ -	$ -	$ -	$ -
I	Licensing	$ 6,000	$ 5,500	$ 400	$ 3,200
J	Project Support	$ 4,220	$ 3,616	$ 1,090	$ 2,700
K	Contingency	$ 10,657	$ 8,799	$ 249	$ 6,844
L	Total Indirect Cost	$ 20,877	$ 17,915	$ 1,739	$ 12,744
M	$/KW Net Summer	$ 880	$ 865	$ 251	$ 374
N	$/KW Net Winter	$ 873	$ 860	$ 218	$ 346
O	Fuel Expansion	$ -	$ -	$ 200	$ 4,000
P	Transmission Expansion				$ 13,000
Q	Railroad & Cars	$ 8,000	$ 8,000	$ -	$ -
R	Total Other Cost	$ 8,000	$ 8,000	$ 200	$ 17,000
[redacted]					
U	$/KW Net Winter	$ 896	$ 880	$ 219	$ 379
	II. PLANT CHARACTERISTICS				
[redacted]					
v	Net Win 75F Capability (mw)	401	401	215	496
W	Net Win 59F Capability (mw)	402	402	230	514
[redacted]					
Y	Heat Rate btu/kwh 75F 75%	9,600	9,600	10,801	6,816
Z	Heat Rate btu/kwh 75F 50%	10,100	10,100	12,344	6,773
AA	Equiv. Avail. %	97%	97%	98%	96%
BB	Sched Outage (wks/yr)	1.0	1.0	0.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%
	III. OPERATION				
[redacted]					
EE	Fixed ($/kw - yr)	18.66	13.96	0.51	4.31
FF	Variable (excl. fuel) ($/mwh)	1.603	1.603	0.295	0.405
GG	Capital Replace ($mm/yr)	3.00	3.00	1.50	2.30
	IV. SPENDING CURVES				
HH	Year 6	$ 1,440	$ -	$ -	$ -
II	Year 5	$ 7,202	$ 6,724	$ -	$ -
JJ	Year 4	$ 8,642	$ 8,494	$ -	$ 780
KK	Year 3	$ 61,935	$ 62,643	$ -	$ 1,365
LL	Year 2	$ 97,944	$ 96,265	$ 17,620	$ 90,844
MM	Year 1	$ 182,924	$ 179,789	$ 32,722	$ 101,956
	V. NOTES:	$ 360,087	$ 353,915	$ 50,341	$ 194,944
NN	Net MW change (summer)	+400 New NSC	+400 New NSC	+200 New NSC	+476 New NSC
	Equipment Available				
OO	Equipment	PC	PC	1-CT - "G"	7F++* 2CT&2HRSG&1ST
PP	Cooling	Tower	Reservoir	Existing	Tower
QQ	SCR's	yes - SCR	yes - SCR	no	no
RR	Back-Up Fuel Adder	$ [illegible]	$ 3,000	$ 2,500	$ 3,500

60005014

SUMMARY OF GENERATION ALTERNATIVES
COST AND COMPETITION TEAM
IRP 1998

	New Generation Alternatives	9	10	11	12	13	14	15
	Alternatives:	Repower PSN 3	Repower PFM-1	Repower PCU-5	400 Orl Martin	800 Orl Martin	400 CFB Greenfield	400 CFB Martin
	I. CONSTRUCTION (1000) 1998 $							
A	Permit/Eng/Fab (months)	24	30	30	30	30	33	30
B	Construcion Phase (months)	21	24	21	30	30	30	27
[redacted]								
D	Land	$ -	$ -	$ -	$ -	$ -	$ 1,210	$ -
E	Materials	$ 95,151	$ 100,735	$ 45,934	$ 202,000	$ 400,000	$ 224,210	$ 224,210
F	Labor & Equipment	$ 18,132	$ 29,853	$ 18,193	$ 106,000	$ 180,000	$ 95,586	$ 95,586
G	Total Direct Cost	$ 113,283	$ 130,588	$ 64,127	$ 308,000	$ 580,000	$ 321,006	$ 319,796
H	Construction Indirects	$ 2,973	$ 3,265	$ 1,603	$ -	$ -	$ -	$ -
I	Licensing	$ 3,000	$ 3,000	$ 4,000	$ 8,500	$ 8,500	$ 6,000	$ 5,500
J	Project Support	$ 5,830	$ 4,000	$ 4,000	$ 3,548	$ 3,836	$ 4,100	$ 3,608
K	Contingency	$ 13,759	$ 8,451	$ 4,424	$ 9,482	$ 20,693	$ 10,244	$ 8,512
L	Total Indirect Cost	$ 25,562	$ 18,716	$ 14,027	$ 21,530	$ 33,029	$ 20,344	$ 17,620
M	$/KW Net Summer	$ 503	$ 541	$ 662	$ 824	$ 766	$ 853	$ 844
N	$/KW Net Winter	$ 422	$ 454	$ 579	$ 820	$ 762	$ 849	$ 839
O	Fuel Expansion	$ -	$ 95,000	$ -	$ 16,000	$ 16,000	$ -	$ -
P	Transmission Expansion							
Q	Railroad & Cars	$ -	$ -	$ -	$ -	$ -	$ 8,000	$ 8,000
R	Total Other Cost	$ -	$ 95,000	$	$ 16,000	$ 16,000	$ 8,000	$ 8,000
[redacted]								
U	$/KW Net Winter	$ 422	$ 743	$ 579	$ 860	$ 782	$ 869	$ 859
	II. PLANT CHARACTERISTICS							
[redacted]								
V	Net Win 75F Capability (mw)	316	316	130	401	802	401	401
W	Net Win 59F Capability (mw)	329	329	135	402	804	402	402
[redacted]								
Y	Heat Rate btu/kwh 75F 75%	7,619	7,619	7,820	10,004	10,004	9,700	9,700
Z	Heat Rate btu/kwh 75F 50%	7,429	7,429	8,580	10,384	10,384	10,200	10,200
AA	Equiv. Avail. %	96%	95%	95%	97%	97%	97%	97%
BB	Sched Outage (wks/yr)	1.3	1.6	1.6	1.0	1.0	1.0	1.0
CC	Equiv Forced Outage	1.5%	2.0%	2.0%	1.0%	1.0%	1.0%	1.0%
	III. OPERATION							
[redacted]								
EE	Fixed ($/kw - yr)	5.37	5.58	9.92	10.62	6.89	15.40	10.70
FF	Variable (excl. fuel) ($/mwh)	0.585	0.620	1.064	1.671	1.585	1.497	1.497
GG	Capital Replace ($mm/yr)	2.10	2.10	1.00	2.00	3.00	2.00	2.00
	IV. SPENDING CURVES							
HH	Year 6	$ -	$ -	$ -	$ -	$ -	$ 1,397	$ -
II	Year 5	$ -	$ -	$ -	$ 5,874	$ 10,694	$ 6,987	$ 5,872
JJ	Year 4	$ 2,638	$ 4,642	$ 1,485	$ 8,293	$ 15,097	$ 8,284	$ 8,290
KK	Year 3	$ 17,356	$ 30,538	$ 9,769	$ 61,850	$ 112,596	$ 60,088	$ 61,829
LL	Year 2	$ 59,148	$ 104,073	$ 33,294	$ 93,984	$ 171,096	$ 95,023	$ 93,953
MM	Year 1	$ 59,704	$ 105,051	$ 33,606	$ 175,529	$ 319,547	$ 177,470	$ 175,471
	V. NOTES:	$ 138,845	$ 244,304	$ 78,154	$ 345,530	$ 629,029	$ 349,350	$ 345,416
NN	Net MW change (summer)	+276 From NSC Incremental	+276 From NSC Incremental	+118 From NSC Incremental	+400 New NSC	+800 New NSC	+400 New NSC	+400 New NSC
	Equipment Available							
OO	Equipment	"F" 2CT&2HRSG	"F" 2CT&2HRSG	V84.3 1CT &1HRSG	N/A	N/A	1CFB	1CFB
PP	Cooling	Existing	Existing	Existing	Reservoir	Reservoir	Tower	Reservoir
QQ	SCR's	no	no	no	no	no	yes - SNCR	yes - SNCR
RR	Backup Fuel Adder	$ 2,500	$ [illegible]	$ 1,500	$ 3,000	$ 3,000	$ [illegible]	[illegible]

60005015

SUMMARY OF GENERATION ALTERNATIVES
COST AND COMPETITION TEAM
IRP 1998

	New Generation Alternatives						
		1	1A	2	3	3A	4
	Alternatives:	400 CC - ATS Greenfield	400 CC - ATS Greenfield	300 CC - G Greenfield	400 CC - ATS Martin	400 CC - ATS Martin	300 CC - G Martin
	I. CONSTRUCTION (1000) 1998 $						
A	Permit/Eng/Fab (months)	30	30	30	20	20	20
B	Construction Phase (months)	22	22	22	19	19	19
[redacted]							
D	Land	$ 1,298	$ 1,298	$ 1,298	$ -	$ -	$ -
E	Materials	$ 125,000	$ 125,000	$ 88,747	$ 123,000	$ 123,000	$ 88,747
F	Labor & Equipment	$ 35,000	$ 35,000	$ 25,253	$ 35,000	$ 35,000	$ 25,253
G	Total Direct Cost	$ 161,298	$ 161,298	$ 115,298	$ 158,000	$ 158,000	$ 114,000
H	Construction Indirects	$ -	$ -	$ -	$ -	$ -	$ -
I	Licensing	$ 4,000	$ 4,000	$ 4,000	$ 3,200	$ 3,200	$ 3,200
J	Project Support	$ 3,476	$ 3,476	$ 3,476	$ 2,700	$ 2,700	$ 2,700
K	Contingency	$ 8,439	$ 8,439	$ 6,139	$ 6,556	$ 6,556	$ 4,560
L	Total Indirect Cost	$ 15,915	$ 15,915	$ 13,615	$ 12,456	$ 12,456	$ 10,460
M	$/KW Net Summer	$ 423	$ 423	$ 416	$ 407	$ 407	$ 402
N	$/KW Net Winter	$ 396	$ 396	$ 373	$ 380	$ 380	$ 360
O	Fuel Expansion				$ 12,000	$ 12,000	$ 10,000
P	Transmission Expansion						
Q	Railroad & Cars	$ -	$ -	$ -	$ -	$ -	$ -
R	Total Other Cost	$ -	$ -	$ -	$ 12,000	$ 12,000	$ 10,000
[redacted]							
[redacted]							
U	$/KW Net Winter	$ 396	$ 396	$ 373	$ 407	$ 407	$ 389
	II. PLANT CHARACTERISTICS						
[redacted]							
v	Net Win 75F Capability (mw)	430	430	332	430	430	332
W	Net Win 59F Capability (mw)	448	448	346	448	448	346
[redacted]							
Y	Heat Rate btu/kwh 75F 75%	6,470	6,245	6,768	6,470	6,245	6,768
Z	Heat Rate btu/kwh 75F 50%	6,970	6,729	7,389	6,970	6,729	7,389
AA	Equiv. Avail. %	96%	96%	96%	96%	96%	96%
BB	Sched Outage (wks/yr)	1.5	1.5	1.5	1.5	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
	III. OPERATION						
[redacted]							
EE	Fixed ($/kw - yr)	7.69	7.69	7.69	4.31	4.31	4.31
FF	Variable (excl. fuel) ($/mwh)	0.405	0.405	0.602	0.405	0.405	0.602
GG	Capital Replace ($mm/yr)	2.30	2.30	2.30	2.30	2.30	2.30
	IV. SPENDING CURVES						
HH	Year 6	$ -	$ -	$ -	$ -	$ -	$ -
II	Year 5	$ 709	$ 709	$ 516	$ -	$ -	$ -
JJ	Year 4	$ 1,418	$ 1,418	$ 1,031	$ 730	$ 730	$ 538
KK	Year 3	$ 30,126	$ 30,126	$ 21,915	$ 1,277	$ 1,277	$ 941
LL	Year 2	$ 56,708	$ 56,708	$ 41,252	$ 85,024	$ 85,024	$ 62,658
MM	Year 1	$ 88,252	$ 88,252	$ 64,199	$ 95,424	$ 95,424	$ 70,323
	V. NOTES:	$ 177,213	$ 177,213	$ 128,913	$ 182,456	$ 182,456	$ 134,460
NN	Net MW change (summer)	+419 New NSC	+419 New NSC	+310 New NSC	+419 New NSC	+419 New NSC	+310 New NSC
	Equipment Available	2003-2005	2006+	2000+	2003-2005	2006+	2000+
OO	Equipment	ATS - "H" 1CT & 1HRSG	ATS - "H" 1CT & 1HRSG	"G" 1CT & 1HRSG	ATS - "H" 1CT & 1HRSG	ATS - "H" 1CT & 1HRSG	"G" 1CT & 1HRSG
PP	Cooling	Tower	Tower	Tower	Reservoir	Reservoir	Reservoir
QQ	SCR's	no	no	no	no	no	no
RR	Dual Fuel Adder	$ 3,500	$ [illegible]	$ 3,500	$ 3,500	$ 3,5[illegible]	[illegible]

60005016

SUMMARY OF GENERATION ALTERNATIVES
COST AND COMPETITION TEAM
IRP 1998

	New Generation Alternatives	5	5A	6	6A	7	8
	Alternatives:	800 CC - ATS Greenfield	800 CC - ATS Greenfield	800 CC - ATS Martin	800 CC - ATS Martin	Repower HotWind Box PTF-1	Repower PRV 2
	I. CONSTRUCTION (1000) 1998 $						
A	Permit/Eng/Fab (months)	30	30	20	20	24	24
B	Construction Phase (months)	27	27	22	22	22	17
C	Project Total (months)	57	57	42	42	46	41
D	Land	$ 2,596	$ 2,596	$ -	$ -	$ -	$ -
E	Materials	$ 241,250	$ 241,250	$ 237,250	$ 237,250	$ .58,735	$ 52,923
F	Labor & Equipment	$ 67,550	$ 67,550	$ 67,550	$ 67,550	$ 17,696	$ 10,110
G	Total Direct Cost	$ 311,396	$ 311,396	$ 304,800	$ 304,800	$ 76,431	$ 63,033
H	Construction Indirects	$ -	$ -	$ -	$ -	$ 1,911	$ 2,043
I	Licensing	$ 4,000	$ 4,000	$ 3,200	$ 3,200	$ 3,000	$ 3,000
J	Project Support	$ 4,418	$ 4,418	$ 3,646	$ 3,646	$ 4,000	$ 5,788
K	Contingency	$ 15,991	$ 15,991	$ 14,024	$ 14,024	$ 6,827	$ 8,125
L	Total Indirect Cost	$ 24,409	$ 24,409	$ 20,870	$ 20,870	$ 15,738	$ 18,956
M	$/KW Net Summer	$ 401	$ 401	$ 389	$ 389	$ 683	$ 410
N	$/KW Net Winter	$ 375	$ 375	$ 363	$ 363	$ 580	$ 363
O	Fuel Expansion			$ 16,000	$ 16,000	$ -	$ -
P	Transmission Expansion						
Q	Railroad & Cars	$ -	$ -	$ -	$ -		$ -
R	Total Other Cost	$ -	$ -	$ 16,000	$ 16,000	$ -	$ -
S	Grand Total Cost	$ 335,805	$ 335,805	$ 341,670	$ 341,670	$ 92,169	$ 81,989
T	$/KW Net Summer	$ 401	$ 401	$ 408	$ 408	$ 683	$ 410
U	$/KW Net Winter	$ 375	$ 375	$ 381	$ 381	$ 580	$ 363
	II. PLANT CHARACTERISTICS						
V	Net Sum 95F Capability (mw)	838	838	838	838	135	200
v	Net Win 75F Capability (mw)	860	860	860	860	153	217
W	Net Win 59F Capability (mw)	896	896	895	896	159	226
X	Heat Rate btu/kwh 75F 100% Load HHV	6,300	6,081	6,300	6,081	8,368	7,615
Y	Heat Rate btu/kwh 75F 75%	6,470	6,245	·6,470	6,245	8,272	7,911
Z	Heat Rate btu/kwh 75F 50%	6,970	6,729	6,970	6,729	8,417	8,512
AA	Equiv. Avail. %	96%	96%	96%	96%	95%	96%
BB	Sched Outage (wks/yr)	1.5	1.5	1.5	1.5	1.6	1.3
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	2.0%	1.5%
	III. OPERATION						
DD	Total O&M (mm/yr)	7.01	7.01	5.80	5.80	1.99	2.7[illegible]
EE	Fixed ($/kw - yr)	5.15	5.15	3.82	3.82	9.58	6.82
FF	Variable (excl. fuel) ($/mwh)	0.382	0.382	0.382	0.382	0.623	0.819
GG	Capital Replace ($mm/yr)	4.60	4.60	4.60	4.60	1.00	1.00
	IV. SPENDING CURVES						
HH	Year 6	$ -	$ -	$ -	$ -	$ -	$ -
II	Year 5	$ 1,679	$ 1,679	$ -	$ -	$ 1,567	$ -
JJ	Year 4	$ 18,805	$ 18,805	$ 2,733	$ 2,733	$ 2,212	$ 1,558
KK	Year 3	$ 43,990	$ 43,990	$ 4,783	$ 4,783	$ 16,498	$ 10,249
LL	Year 2	$ 119,882	$ 119,882	$ 157,510	$ 157,510	$ 25,070	$ 34,927
MM	Year 1	$ 151,448	$ 151,448	$ 176,643	$ 176,643	$ 46,822	$ 35,255
	V. NOTES:	$ 335,805	$ 335,805	$ 341,670	$ 341,670	$ 92,169	$ 81,989
NN	Net MW change (summer)	+838 New NSC	+838 New NSC	+838 New NSC	+838 New NSC	+135 From NSC Incremental	+200 New NSC
	Equipment Available	2003-2005	2006+	2003-2005	2006+		
OO	Equipment	ATS - "H" 2CT & 2HRSG	ATS - "H" 2CT & 2HRSG	ATS - "H" 2CT & 2HRSG	ATS - "H" 2CT & 2HRSG	V84.3 1CT	"F" 1CT & 1HRSG
PP	Cooling	Tower	Tower	Reservoir	Reservoir	Existing	Existing
QQ	SCR's	no	no	no	no	no	no
RR	Dual Fuel Adder	$ 7,000	$ [illegible]	$ 7,000	$ 7,000	$ 1,[illegible]	[illegible]

60005017

	Alternatives:	500 MW Combined Cycle	RePower PFM Unit 1&2
	I. CONSTRUCTION (1000) 1997 $		
A	Permit/Eng/Fab (months)	24	24
B	Construction Phase (months)	24	30
C	Project Total (months)	48	54
D	Land	$1,200	($1,681)
E	Materials	$120,000	$276,802
F	Labor & Equipment	$44,000	$75,450
G	Total Direct Cost	$165,200	$350,571
H	Construction Indirects	$0	$0
I	Licensing	$3,200	$5,000
J	Project Support	$2,700	$5,000
K	Contingency	$6,844	$20,000
L	Total Indirect Cost	$12,744	$30,000
M	$/KW Net Summer	$374	$269
N	$/KW Net Winter	$359	$258
O	Fuel Expansion	$4,000	$6,000
P	Transmission Expansion	$13,000	$23,000
Q	Railroad & Cars	$0	$0
R	Total Other Cost	$17,000	$29,000
S	Grand Total Cost	$194,944	$409,571
T	$/KW Net Summer	$410	$290
U	$/KW Net Winter	$393	$278
	II. PLANT CHARACTERISTICS		
V	Net Sum 95FCapability (mw)	476	1,413
W	Net 75F Capability (mw)	496	1,473
	Net 59F Capability (mw)	514	1,525
X	Heat Rate btu/kwh 95F100% Load HHV	6,870	6,940
Y	Heat Rate btu/kwh 75F100% Load HHV	6,816	6,885
Z	Heat Rate btu/kwh 59F100% Load HHV	6,773	6,840
AA	Equiv. Avail. %	96%	96%
BB	Sched Outage (wks/yr)	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%
	III. OPERATION		
DD	Total O&M (mm/yr)	$3.67	$8
EE	(remove 6MM for existing fleet cost		
FF	for Repower only)		
GG	Capital Replace ($mm/yr)	2.30	$6
	IV. SPENDING CURVES		
HH	Year 6	$0	$0
II	Year 5	$0	$0
JJ	Year 4	$780	$1,638
KK	Year 3	$1,365	$2,867
LL	Year 2	$90,844	$190,860
MM	Year 1	$101,956	$214,206
	V. NOTES:		
NN		New NSC	New NSC
	Fuel	Natural Gas	Natural Gas
	AFUDC Adder		
OO	Equipment	"7F ++" 2CT & 2HRSG&1ST	"7F ++" 6CT & 6HRSG
PP	Cooling	Mech Draft	Intake/Discharge
QQ	SCR's	no	no
RR			

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2003

	New Generation Alternatives							13
	Alternatives:	Repower HotWind Box PTF-1	Repower PRV 2	Repower PSN 3	Repower PFM-1	Repower PCU-5	400 On Martin	800 On Martin
	I. CONSTRUCTION (1000) 1996 $							
A	Permit/Eng/Fab (months)	24	24	24	30	30	30	30
B	Construction Phase (months)	22	17	21	24	21	30	30
C	Project Total (months)	46	41	45	54	51	60	60
D	Land	$ -	$ -	$ -	$ -	$ -	$ -	$
E	Materials	$ 58,735	$ 52,923	$ 95,151	$ 100,735	$ 45,934	$ 202,000	$ 400,000
F	Labor & Equipment	$ 17,696	$ 10,110	$ 18,132	$ 29,853	$ 18,193	$ 106,000	$ 180,000
G	Total Direct Cost	$ 76,431	$ 63,033	$ 113,283	$ 130,588	$ 64,127	$ 308,000	$ 580,000
H	Construction Indirects	$ 1,911	$ 2,043	$ 2,973	$ 3,265	$ 1,603	$ -	$ -
I	Licensing	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 4,000	$ 8,500	$ 8,500
J	Project Support	$ 4,000	$ 5,788	$ 5,830	$ 4,000	$ 4,000	$ 3,548	$ 3,836
K	Contingency	$ 6,827	$ 8,125	$ 13,759	$ 8,451	$ 4,424	$ 9,482	$ 20,693
L	Total Indirect Cost	$ 15,738	$ 18,956	$ 25,562	$ 18,716	$ 14,027	$ 21,530	$ 33,029
M	$/KW Net Summer	$ 683	$ 410	$ 503	$ 541	$ 662	$ 824	$ 766
N	$/KW Net Winter	$ 580	$ 363	$ 422	$ 454	$ 579	$ 820	$ 762
O	Fuel Expansion	$ -	$ -	$ -	$ 95,000	$ -	$ 16,000	$ 16,000
P	Transmission Expansion							
Q	Railroad & Cars		$ -	$ -	$ -	$ -	$ -	$ -
R	Total Other Cost	$ -	$ -	$ -	$ 95,000	$ -	$ 16,000	$ 16,000
S	Grand Total Cost	$ 92,169	$ 81,989	$ 138,845	$ 244,304	$ 78,154	$ 345,530	$ 629,029
T	$/KW Net Summer	$ 683	$ 410	$ 503	$ 885	$ 662	$ 864	$ 786
U	$/KW Net Winter	$ 580	$ 363	$ 422	$ 743	$ 579	$ 860	$ 782
	II. PLANT CHARACTERISTICS							
V	Net Sum 95F Capability (mw)	135	200	276	276	118	400	800
W	Net Win 59F Capability (mw)	159	226	329	329	135	402	804
X	Heat Rate btu/kwh 75F 100% Load HHV	8,368	7,615	7,379	7,379	7,570	9,683	9,683
Y	Heat Rate btu/kwh 75F 75%	8,272	7,911	7,619	7,619	7,820	10,004	10,004
Z	Heat Rate btu/kwh 75F 50%	8 417	8,512	7,429	7,429	8,580	10,384	10,384
AA	Equiv. Avail. %	95%	96%	96%	95%	95%	97%	97%
BB	Sched Outage (wks/yr)	1.6	1.3	1.3	1.6	1.6	1.0	1.0
CC	Equiv Forced Outage	2.0%	1.5%	1.5%	2.0%	2.0%	1.0%	1.0%
	III. OPERATION							
DD	Total O&M (mm/yr)	1.99	2.74	2.84	2.97	2.22	9.93	16.29
EE	Fixed ($/kw - yr)	9.58	6.82	5.37	5.58	9.92	10.62	6.89
FF	Variable (excl. fuel) ($/mwh)	0.623	0.819	0 585	0.620	1.064	1.671	1.585
GG	Capital Replace ($mm/yr)	1.00	1.00	2 10	2.10	1.00	2.00	3.00
	IV. SPENDING CURVES							
HH	Year 6							$ -
II	Year 5	$ 1,567	$ -	$ -	$ -	$ -	$ 5,874	$ 10,694
JJ	Year 4	$ 2,212	$ 1,558	$ 2,638	$ 4,642	$ 1,485	$ 8,293	$ 15,097
KK	Year 3	$ 16,498	$ 10,249	$ 17,356	$ 30,538	$ 9,769	$ 61,850	$ 112,596
LL	Year 2	$ 25,070	$ 34,927	$ 59,148	$ 104,073	$ 33,294	$ 93,984	$ 171,096
MM	Year 1	$ 46,822	$ 35,255	$ 59,704	$ 105,051	$ 33,606	$ 175,529	$ 319,547
	V. NOTES:	$ 92,169	$ 81,989	$ 138,845	$ 244,304	$ 78,154	$ 345,530	$ 629,029
NN	Net MW change (summer)	+135 From NSC Incremental	+200 New NSC	+276 From NSC Incremental	+276 From NSC Incremental	+118 From NSC Incremental	+400 New NSC	+800 New NSC
OO	Equipment	V84.3 1CT	"F" 1CT &1HRSG	"F" 2CT&2HRSG	"F" 2CT&2HRSG	V84.3 1CT & 1HRSG	N/A	N/A
PP	Cooling	Existing	Existing	Existing	Existing	Existing	Reservoir	Reservoir
QQ	SCR's	no	no	no	no	no	no	no
RR	Back-Up Fuel Adder	$ 1,500	$ 2,500	$ 2,500	$ 3,000	$ 1,500	$ 3,000	$ 3,000

60005019

Repower Sanford
2002 and 2004

		2002	2004
	Alternatives:	RePower PSN Units 3&4	RePower PSN Units 3&4
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)	24	24
B	Construction Phase (months)	24	24
C	Project Total (months)	48	48
D	Land	$0	$0
E	Materials	$279,521	$279,521
F	Labor & Equipment	$77,075	$77,075
G	Total Direct Cost	$356,596	$356,596
H	Construction Indirects	$0	$0
I	Licensing	$5,000	$5,000
J	Project Support	$5,000	$5,000
K	Contingency	$25,000	$25,000
L	Total Indirect Cost	$35,000	$35,000
M	$/kW Net Summer	$280	$269
N	$/kW Net Winter	$260	$252
O	Fuel Expansion	$2,000	$2,000
P	Transmission Expansion	$48,000	$48,000
Q	Railroad & Cars	$0	$0
R	Total Other Cost	$50,000	$50,000
S	Grand Total Cost	$441,596	$441,596
T	$/KW Net Summer	$315	$303
U	$/KW Net Winter	$293	$284
	II. PLANT CHARACTERISTICS		
V	Net Sum 95FCapability (mw)	1,400	1,457
W	Net 75F Capability (mw)	1,506	1,555
	Net 59F Capability (mw)	1,541	1,623
X	Heat Rate btu/kwh 95F100% Load HHV	6,959	6,845
Y	Heat Rate btu/kwh 75F100% Load HHV	6,815	6,777
Y1	Heat Rate btu/kwh 75F 75% Load HHV	6,990	6,951
Y2	Heat Rate btu/kwh 75F 50% Load HHV	7,630	7,587
Z	Heat Rate btu/kwh 59F100% Load HHV	6,783	6,718
AA	Equiv. Avail. %	96%	96%
BB	Sched Outage (wks/yr)	1 5	1.5
CC	Equiv Forced Outage	1.0%	1.0%
	III. OPERATION		
DD	Total O&M (mm/yr)	$8	$8
EE	(remove 6MM for existing fleet cost		
FF	for Repower only)		
GG	Capital Replace ($mm/yr)	$6	$6
	IV. SPENDING CURVES		
HH	Year 6	$0	$0
II	Year 5	$0	$0
JJ	Year 4	$1,766	$1,766
KK	Year 3	$3,091	$3,091
LL	Year 2	$205,784	$205,784
MM	Year 1	$230,955	$230,955
	V. NOTES:		
NN			
	Fuel	New NSC Natural Gas	New NSC Natural Gas
	AFUDC Adder		
OO	Equipment	"7F ++" 6CT & 6HRSG	"7F +++" 6CT & 6HRSG
PP	Cooling	Intake/Discharge	Intake/Discharge
QQ	SCR's	no	no
RR		non-escalated	non-escalated

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-10)
Sanford Comparisons
Page 9 of 17

	New Generation Alternatives		
		20	21
	Alternatives:	Repower	Repower
		PFM Unit 1&2	PSN Unit 3&4
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)	22	24
B	Construction Phase (months)	25	24
C	Project Total (months)	47	48
D	Land	$ (681)	$ -
E	Materials	$ 291,802	$ 279,521
F	Labor & Equipment	$ 85,450	$ 77,075
G	Total Direct Cost	$ 376,571	$ 356,596
H	Construction Indirects	$ -	$ -
I	Licensing	$ 5,000	$ 5,000
J	Project Support	$ 5,000	$ 5,000
K	Contingency	$ -	$ 25,000
L	Total Indirect Cost	$ 10,000	$ 35,000
M	$/KW Net Summer	$ 263	$ 266
N	$/KW Net Winter	$ 241	$ 244
O	Fuel Expansion	$ 6,000	$ 2,000
P	Transmission Expansion	$ 26,000	$ 48,000
Q	Railroad & Cars	$ -	$ -
R	Total Other Cost	$ 32,000	$ 50,000
S	Grand Total Cost	$ 418,571	$ 441,596
T	$/KW Net Summer	$ 285	$ 300
U	$/KW Net Winter	$ 261	$ 275
	II. PLANT CHARACTERISTICS		
V	Net Sum 95F Capability (mw)	1,470	1,470
v	Net Win 75F Capability (mw)	1,535	1,535
W	Net Win 59F Capability (mw)	1,605	1,605
X	Heat Rate btu/kwh 75F 100% Load HHV	6,795	6,795
Y	Heat Rate btu/kwh 75F 75%	6,830	6,830
Z	Heat Rate btu/kwh 75F 50%	7,450	7,450
AA	Equiv. Avail. %	96%	96%
BB	Sched Outage (wks/yr)	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%
	III. OPERATION		
DD	Total O&M (mm/yr)	-	6.172
EE	Fixed ($/kw - yr)	0.00	1.087
FF	Variable (excl. fuel) ($/mwh)	-	0.370
GG	Capital Replace ($mm/yr)	0.00	12.67
	IV. SPENDING CURVES		
HH	Year 6	$ -	$ -
II	Year 5	$ 5,450	$ -
JJ	Year 4	$ 31,042	$ 38,499
KK	Year 3	$ 227,471	$ 239,984
LL	Year 2	$ 116,227	$ 122,620
MM	Year 1	$ 38,381	$ 40,492
	V. NOTES:	$ 418,571	$ 441,596
NN	Net MW change (summer)	+953	+953
		New NSC	New NSC
		Incremental O&M	Incremental O&M
	Equipment Available		2002
OO	Equipment	7F++"	7F++"
		6CT&6HRSG	6CT&6HRSG
PP	Cooling	Existing	Existing
QQ	SCR's	no	no
RR	Back-Up Fuel Adder	$ -	$ -

9/14/98
re Bob Burgess

at 35° 1650 mw

6745 at 35° F.

60005021

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-10)
Sanford Comparisons
Page 10 of 17

	New Generation Alternatives		
		20	21
	Alternatives:	Repower Simple Cycle PFM 1 CT SC	Repower Simple Cycle PSN 1CT SC
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)		
B	Construction Phase (months)		
C	Project Total (months)		
D	Land		
E	Materials		
F	Labor & Equipment		
G	Total Direct Cost	$ -	$ -
H	Construction Indirects		
I	Licensing		
J	Project Support		
K	Contingency		
L	Total Indirect Cost	$ -	$ -
M	$/KW Net Summer	$ -	$ -
N	$/KW Net Winter	$ -	$ -
O	Fuel Expansion		
P	Transmission Expansion		
Q	Railroad & Cars		
R	Total Other Cost	$ -	$ -
S	Grand Total Cost	$ -	$ -
T	$/KW Net Summer	$ -	$ -
U	$/KW Net Winter	$ -	$ -
	II. PLANT CHARACTERISTICS		
V	Net Sum 95F Capability (mw)	149	149
v	Net Win 75F Capability (mw)	163	163
W	Net Win 59F Capability (mw)	172	172
X	Heat Rate btu/kwh 75F 100% Load HHV	10,450	10,450
Y	Heat Rate btu/kwh 75F 75%	11,280	11,280
Z	Heat Rate btu/kwh 75F 50%	13,500	13,500
AA	Equiv. Avail. %		
BB	Sched Outage (wks/yr)		
CC	Equiv Forced Outage		
	III. OPERATION		
DD	Total O&M (mm/yr)	-	-
EE	Fixed ($/kw - yr)		
FF	Variable (excl. fuel) ($/mwh)		
GG	Capital Replace ($mm/yr)		
	IV. SPENDING CURVES		
HH	Year 6	$ -	$ -
II	Year 5	$ -	$ -
JJ	Year 4	$ -	$ -
KK	Year 3	$ -	$ -
LL	Year 2	$ -	$ -
MM	Year 1	$ -	$ -
	V. NOTES:	$ -	$ -
NN	Net MW change (summer)	New NSC	New NSC
	Equipment Available	2002	2002
OO	Equipment	7F++" Simple Cycle	7F++" Simple Cycle
PP	Cooling	N/A	N/A
QQ	SCR's	no	no
RR	Back-Up Fuel Adder	$ -	$ -

9/14/98 ~~from~~ Bob Burgess

mw
182 at 35° F.

10,220 at 35° F.

60005022

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-10)
Sanford Comparisons
Page 11 of 17

	New Generation Alternatives		
		20	21
	Alternatives:	Repower	Repower
		PFM Unit 1&2	PSN Unit 3&4
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)	22	24
B	Construction Phase (months)	25	24
[redacted]			
D	Land	$ (681)	$
E	Materials	$ 291,802	$ 279,521
F	Labor & Equipment	$ 85,450	$ 77,075
G	Total Direct Cost	$ 376,571	$ 356,596
H	Construction Indirects	$ -	$ -
I	Licensing	$ 5,000	$ 5,000
J	Project Support	$ 5,000	$ 5,000
K	Contingency	$ -	$ 25,000
L	Total Indirect Cost	$ 10,000	$ 35,000
M	$/KW Net Summer	$ 263	$ 266
N	$/KW Net Winter	$ 241	$ 244
O	Fuel Expansion	$ 6,000	$ 2,000
P	Transmission Expansion	$ 26,000	$ 48,000
Q	Railroad & Cars	$ -	$ -
R	Total Other Cost	$ 32,000	$ 50,000
[redacted]			
U	$/KW Net Winter	$ 261	$ 275
	II. PLANT CHARACTERISTICS		
[redacted]			
V	Net Win 75F Capability (mw)	1,535	1,535
W	Net Win 59F Capability (mw)	1,605	1,605
[redacted]			
Y	Heat Rate btu/kwh 75F 75%	6,830	6,830
Z	Heat Rate btu/kwh 75F 50%	7,450	7,450
AA	Equiv Avail %	96%	96%
BB	Sched Outage (wks/yr)	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%
	III. OPERATION		
[redacted]			
EE	Fixed ($/kw - yr)	0.00	1.067
FF	Variable (excl fuel) ($/mwh)		0.370
GG	Capital Replace ($mm/yr)	0.00	12.67
	IV. SPENDING CURVES		
HH	Year 6	$ -	$ -
II	Year 5	$ 5,450	$ -
JJ	Year 4	$ 31,042	$ 38,499
KK	Year 3	$ 227,471	$ 239,984
LL	Year 2	$ 116,227	$ 122,620
MM	Year 1	$ 38,381	$ 40,492
	V. NOTES:	$ 418,571	$ 441,596
NN	Net MW change (summer)	+953	+953
		New NSC	New NSC
		Incremental O&M	Incremental O&M
	Equipment Available		2002
OO	Equipment	7F++*	7F++*
		6CT&6HRSG	6CT&6HRSG
PP	Cooling	Existing	Existing
QQ	SCR's	no	no
RR	Back-Up Fuel Adder	$	$

60005023

9/14/98 1:29 PM

	New Generation Alternatives		
		20	21
	Alternatives:	Repower Simple Cycle PFM 1 CT SC	Repower Simple Cycle PSN 1CT SC
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)		
B	Construction Phase (months)		
C	Project Total (months)		
D	Land		
E	Materials		
F	Labor & Equipment		
G	Total Direct Cost	$ -	$ -
H	Construction Indirects		
I	Licensing		
J	Project Support		
K	Contingency		
L	Total Indirect Cost	$ -	$
M	$/KW Net Summer	$ -	$ -
N	$/KW Net Winter	$ -	$ -
O	Fuel Expansion		
P	Transmission Expansion		
Q	Railroad & Cars		
R	Total Other Cost	$ -	$ -
S	Grand Total Cost	$	$
T	$/KW Net Summer	$	$
U	$/KW Net Winter	$ -	$ -
	II. PLANT CHARACTERISTICS		
V	Net Sum 95F Capability (mw)	149	149
v	Net Win 75F Capability (mw)	163	163
W	Net Win 59F Capability (mw)	172	172
X	Heat Rate btu/kwh 75F 100% Load HHV	10,450	10,450
Y	Heat Rate btu/kwh 75F 75%	11,280	11,280
Z	Heat Rate btu/kwh 75F 50%	13,500	13,500
AA	Equiv Avail. %		
BB	Sched Outage (wks/yr)		
CC	Equiv Forced Outage		
	III. OPERATION		
DD	Total O&M (mm/yr)		
[illegible]	[illegible]		
[illegible]	[illegible]		
	[illegible]		
		$ -	$ -
		$ -	$ -
		$ -	$ -
		$ -	$ -
		$ -	$ -
		$ -	$ -
		$ -	$ -
NN	Net MW change (summer)	New NSC	New NSC
	Equipment Available	2002	2002
OO	Equipment	7F++* Simple Cycle N/A no	7F++* Simple Cycle N/A no
RR	Back-Up Fuel Adder	$	$

60005024

9/14/98 1:30 PM

	New Generation Alternatives					
		18	19	20	21	21A
	Alternatives:	200 SC	500 CC - F++	Repower	Repower	Repower
		Exist Site - "G"	Greenfield	PFM Unit 1&2	PSN Unit 3&4	PSN Unit 3&4
	I. CONSTRUCTION (1000) 1998 $					
A	Permit/Eng/Fab (months)	9	24	22	24	24
B	Construction Phase (months)	6	24	25	24	24
C	Project Total (months)	15	48	47	48	48
			$ 1,200	$ (681)	$ -	$ -
E	Materials	$ 42 069	$ 120,000	$ 291,802	$ 279 521	$ 279 521
F	Labor & Equipment	$ 6 333	$ 44,000	$ 85,450	$ 77,075	$ 77 075
G	Total Direct Cost	$ 48 402	$ 165,200	$ 376,571	$ 356,596	$ 356,596
H	Construction Indirects	$ -	-	$ -	$ -	$
I	Licensing	$ 400	$ 3,200	$ 5 000	$ 5,000	$ 5,000
J	Project Support	$ 1,090	$ 2,700	$ 5,000	$ 5 000	$ 5,000
K	Contingency	$ 249	$ 6,844	$ -	$ 25 000	$ 25,000
L	Total Indirect Cost	$ 1 739	$ 12,744	$ 10,000	$ 35,000	$ 35,000
			378	$ 278	$ 281	$
			350	$ 252	$ 255	$
O	Fuel Expansion	$ 200	$ 4,000	$ 6,000	$ 2,000	$ 2,000
P	Transmission Expansion	By Others	$ 13,000	$ 26,000	$ 48,000	$ 48,000
Q	Railroad & Cars	$	$ -	$ -	$ -	$ -
R	Total Other Cost	$ 200	$ 17,000	$ 32,000	$ 50,000	$ 50,000
S	Grand Total Cost	$ 50,341	$ 194,944	$ 418,571	$ 441,596	$ 441,596
T	$/KW Net Summer	$ 241	$ 414	$ 300	$ 317	$ 314
U	$/KW Net Winter	$ 212	$ 383	$ 273	$ 288	$ 285
	II. PLANT CHARACTERISTICS					
V	Net Sum 95F Capability (mw)	209	471	1,393	1,393	1,407
V	Net Win 75F Capability (mw)	224	491	1,499	1,499	1,514
W	Net Win 59F Capability (mw)	237	509	1,534	1,534	1,549
X	Heat Rate btu/kwh 75F 100% Load HHV	10,010	6,802	6,802	6,802	6,768
Y	Heat Rate btu/kwh 75F 75%	10,915	6,832	6,832	6,832	6,798
Z	Heat Rate btu/kwh 75F 50%	11,875	7,458	7,458	7,458	7,421
AA	Equiv Avail %	98%	96%	96%	96%	96%
BB	Sched Outage (wks/yr)	0.5	1.5	1.5	1.5	1.5
CC	Equiv Forced Outage	1 0%	1 0%	1.0%	1 0%	1.0%
	III. OPERATION					
DD	Total O&M (mm/yr)	0.64	[illegible]	[illegible]	5.849	5.924
EE	Fixed ($/kw - yr)	0.51	4.95	0 00	1.087	1.065
FF	Variable (excl fuel) ($/mwh)	0.295	0.598	-	0.370	0.374
GG	Capital Replace ($mm/yr)	1.50	4 44	0 00	12 67	12.73
	IV. SPENDING CURVES					
HH	Year 6	$ -	$ -	$ -	$ -	$ -
II	Year 5	$ -	$ -	$ 5,450	$ -	$ -
JJ	Year 4	$ -	$ 780	$ 31,042	$ 38,499	$ 38,499
KK	Year 3	$ -	$ 1,365	$ 227,471	$ 239,984	$ 239,984
LL	Year 2	$ 17,620	$ 90,844	$ 116,227	$ 122,620	$ 122,620
MM	Year 1	$ 32,722	$ 101,956	$ 38,381	$ 40,492	$ 40,492
	V. NOTES:	$ 50,341	$ 194,944	$ 418,571	$ 441,596	$ 441,596
NN	Net MW change (summer)	+209 New NSC	+471 New NSC	+953 New NSC Incremental O&M	+953 New NSC Incremental O&M	+967 New NSC Incremental O&M
	Equipment Available				2002	2004
OO	Equipment	1-CT - "G"	7F++" 2CT&2HRSG&1ST	7F++" 6CT&6HRSG	7F++" 6CT&6HRSG	7F+++" 6CT&6HRSG
PP	Cooling	Existing	Tower	Existing	Existing	Existing
QQ	SCR's	no	no	no	no	no
RR	Back-Up Fuel Adder	$ 2,500	$ 3,500	$ -	$	$

APRIL 9, 1999

SUMMARY OF GENERATION ALTERNATIVES
IRP 1999

	New Generation Alternatives						
		14	15	16	17	18	19
	Alternatives:	400 CFB Greenfield	400 CFB Martin	400 PC Greenfield	400 PC Martin	150 SC - F Simple Cycle Existing Site	500 CC - F 7241 Greenfield
	I. CONSTRUCTION (1000) 1999 $						
A	Permit/Eng/Fab (months)	33	30	36	30	9	24
B	Construction Phase (months)	30	27	30	27	6	24
C	Project Total (months)	63	57	66	57	15	49
D	Land	$ 1,210	$ -	$ 1,210	$ -	$ -	$ 1,200
E	Materials	$ 224,210	$ 224,210	$ 226,000	$ 224,000	$ 32,000	$ 120,000
F	Labor & Equipment	$ 95,586	$ 95,586	$ 104,000	$ 104,000	$ 10,000	$ 44,000
G	Total Direct Cost	$ 321,006	$ 319,796	$ 331,210	$ 328,000	$ 42,000	$ 165,200
H	Construction Indirects	$ -	$ -	$ -	$ -	$ -	$ -
I	Licensing	$ 6,000	$ 5,500	$ 6,000	$ 5,500	$ 400	$ 3,200
J	Project Support	$ 4,100	$ 3,608	$ 4,220	$ 3,616	$ 250	$ 2,700
K	Contingency	$ 10,244	$ 8,512	$ 10,657	$ 8,799	$ 500	$ 6,844
L	Total Indirect Cost	$ 20,344	$ 17,620	$ 20,877	$ 17,915	$ 1,150	$ 12,744
M	$/KW Net Summer	$ 853	$ 844	$ 880	$ 865	$ 290	$ 363
N	$/KW Net Winter	$ 849	$ 839	$ 876	$ 860	$ 251	$ 335
O	Fuel Expansion	$ -	$ -	$ -	$ -	By Others	$ -
P	Transmission Expansion	By Others	By Others	By Others	By Others	By Others	By Others
Q	Railroad & Cars	$ 8,000	$ 8,000	$ 8,000	$ 8,000		$ -
R	Total Other Cost	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ -	$ -
S	Grand Total Cost	$ 349,350	$ 345,416	$ 360,087	$ 353,915	$ 43,150	$ 177,944
T	$/KW Net Summer	$ 873	$ 864	$ 900	$ 885	$ 290	$ 363
U	$/KW Net Winter	$ 869	$ 859	$ 896	$ 880	$ 251	$ 335
	II. PLANT CHARACTERISTICS						
V	Net Sum 95F Capability (mw)	400	400	400	400	149	490
v	Net Win 75F Capability (mw)	401	401	401	401	163	510
W	Net Win 59F Capability (mw)	402	402	402	402	172	532
X	Heat Rate btu/kwh 75F 100% Load HHV	9,600	9,600	9,500	9,500	10,450	6,830
Y	Heat Rate btu/kwh 75F 75%	9,700	9,700	9,600	9,600	11,280	7,171
Z	Heat Rate btu/kwh 75F 50%	10,200	10,200	10,100	10,100	13,500	7,718
AA	Equiv. Avail. %	97%	97%	97%	97%	98%	96%
BB	Sched Outage (wks/yr)	1.0	1.0	1.0	1.0	0.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
	III. OPERATION					10% Capacity Cap	
DD	Total O&M (mm/yr)	11.25	9.37	12.91	11.03	0.18	4.59
EE	Fixed ($/kw - yr)	15.40	10.70	18.66	13.96	0.72	5.18
FF	Variable (excl fuel) ($/mwh)	1 497	1 497	1 603	1.603	0.59	0.50
GG	Capital Replace ($mm/yr)	2.00	2.00	3 00	3 00	0.00	3.32
	IV. SPENDING CURVES						
HH	Year 6	$ 1,397	$ -	$ 1,440	$ -	$ -	$ -
II	Year 5	$ 6,987	$ 5,872	$ 7,202	$ 6,724	$ -	$ -
JJ	Year 4	$ 8,384	$ 8,290	$ 8,642	$ 8,494	$ -	$ 712
KK	Year 3	$ 60,088	$ 61,829	$ 61,935	$ 62,643	$ -	$ 1,246
LL	Year 2	$ 95,023	$ 93,953	$ 97,944	$ 96,265	$ 15,103	$ 82,922
MM	Year 1	$ 177,470	$ 175,471	$ 182,924	$ 179,789	$ 28,048	$ 93,065
	V. NOTES:	$ 349,350	$ 345,416	$ 360,087	$ 353,915	$ 43,150	$ 177,944
NN	Net MW change (summer)	+400 New NSC	+400 New NSC	+400 New NSC	+400 New NSC	+149 New NSC	+490 New NSC
	Equipment Available					2002	
OO	Equipment	1CFB	1CFB	PC	PC	7F 7241 Simple Cycle	7F 7241 Foggers 2CT&2HRSG&1ST
PP	Cooling	Tower	Reservoir	Tower	Reservoir	N/A	Tower
QQ	SCR's	yes - SNCR	yes - SNCR	yes - SCR	yes - SCR	no	no
RR	Back-Up Fuel Adder	$ 3,000	$ 3,000	$ 3,000	$ 3,000	Included	$ 3,500

ok

60005026

SUMMARY OF GENERATION ALTERNATIVES
IRP 1999

	New Generation Alternatives					
		20	21A	21B	22	[illegible]
	Alternatives:	Repower PFM Unit 1&2	Repower PSN Unit 4	Repower PSN Unit 5	400 CC - ATS Ft Myers	[illegible] G Ft Myers
	I. CONSTRUCTION (1000) 1999 $					
A	Permit/Eng/Fab (months)	5	10	10	22	22
B	Construction Phase (months)	28	28	28	19	19
C	Project Total (months)	33	38	38	[illegible]	[illegible]
D	Land	$ -			$ -	$ -
E	Materials	$ 285,148	$ 175,231	$ 175,231	$ 123,000	$ 88,747
F	Labor & Equipment	$ 111,342	$ 68,866	$ 68,866	$ 35,000	$ 25,253
G	Total Direct Cost	$ 396,489	$ 244,097	$ 244,097	$ 159,000	$ 114,000
H	Construction Indirects	$ -	$ -	$ -	$ -	$ -
I	Licensing	$ 5,282	$ 2,605	$ 2,605	$ 3,600	$ 3,600
J	Project Support	$ 5,865	$ 3,079	$ 3,079	$ 2,700	$ 2,700
K	Contingency	$ 5,284	$ 11,118	$ 11,118	$ 6,572	$ 4,560
L	Total Indirect Cost	$ 16,432	$ 16,802	$ 16,802	$ 12,872	$ 10,860
M	$/KW Net Summer	$ 281	$ 268	$ 268	$ 434	$ 400
N	$/KW Net Winter	$ 259	$ 251	$ 251	$ 398	$ 352
O	Fuel Expansion	$ -	$ -	$ -	By Others	By Others
P	Transmission Expansion	$ 27,906	$ 39,832	$ 39,832	By Others	By Others
Q	Railroad & Cars	$ -	$ -	$ -	$ -	$ -
R	Total Other Cost	$ 27,906	$ 39,832	$ 39,832	$ -	$
S	Grand Total Cost	$ 440,827	$ 300,731	$ 300,731	$ 170,872	$ 124,860
T	$/KW Net Summer	$ 300	$ 308	$ 308	$ 434	$ 400
U	$/KW Net Winter	$ 276	$ 290	$ 290	$ 398	$ 352
	II. PLANT CHARACTERISTICS					
V	Net Sum 95F Capability (mw)	1,470	975	975	394	312
v	Net Win 75F Capability (mw)	1,530	1,017	1,017	410	336
W	Net Win 59F Capability (mw)	1,595	1,038	1,038	429	355
X	Heat Rate btu/kwh 75F 100% Load HHV	6,830	6,860	6,860	6,346	6,675
Y	Heat Rate btu/kwh 75F 75%	7,171	7,203	7,203	6,599	7,010
Z	Heat Rate btu/kwh 75F 50%	7,718	7,752	7,752	7,297	7,710
AA	Equiv Avail %	96%	96%	96%	96%	96%
BB	Sched Outage (wks/yr)	1.5	1.5	1.5	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	1.0%
	III. OPERATION					
DD	Total O&M (mm/yr)	9.55	6.21	6.21	3.89	3.37
EE	Fixed ($/kw - yr)	3.40	3.08	3.08	3.87	4.89
FF	Variable (excl. fuel) ($/mwh)	0.368	0.39	0.39	0.71	0.70
GG	Capital Replace ($mm/yr)	9.20	6.33	6.33	3.51	2.59
	IV. SPENDING CURVES					
HH	Year 6	$ -	$ -	$ -	$ -	$ -
II	Year 5	$ 10,304	$ 31,400	$ 31,400	$ -	$ -
JJ	Year 4	$ 148,505	$ 119,450	$ 119,450	$ 683	$ 499
KK	Year 3	$ 138,864	$ 91,714	$ 91,714	$ 1,196	$ 874
LL	Year 2	$ 117,147	$ 42,096	$ 42,096	$ 79,626	$ 58,185
MM	Year 1	$ 26,007	$ 16,004	$ 16,004	$ 89,366	$ 65,302
	V. NOTES:	$ 440,827	$ 300,663	$ 300,663	$ 170,872	$ 124,860
NN	Net MW change (summer)	+953 New NSC	+607 New NSC	+607 New NSC	+394 New NSC	+312 New NSC
	Equipment Available				2003-2005	2000+
OO	Equipment	7F 7241 Foggers 6CT&6HRSG	7F 7241 Foggers 4CT&4HRSG	7F 7241 Foggers 4CT&4HRSG	ATS - "H" 1CT & 1HRSG	"G" 1CT & 1HRSG
PP	Cooling	Existing	Existing	Existing	Towers	Towers
QQ	SCR's	no	no	no	no	no
RR	Back-Up Fuel Adder	$ -	$ -	$ -	$ 3,500	$ 3,500

Is the winter capacity 1625 MW?

60005027

	New Generation Alternatives	7	8	9	10	11	12	13
	Alternatives:	600 CC - G	600 CC - G	500 CC - F 7241	500 CC - F 7241	150 SC - F Simple Cycle	400 CFB	400 CFB
		Greenfield	Existing Site	Greenfield	Existing Site	Existing Site	Greenfield	M[illegible]
	I. CONSTRUCTION (1000) 2000 $							
A	Permit/Eng/Fab (months)	24	20	24	24	12	33	30
B	Construction Phase (months)	24	24	24	24	11	30	27
C	Project Total (months)	48	44	48	48	23	63	57
D	Land	$1,200	$0	$1,200	$0	$0	$1,200	$0
E	Materials	$245,218	$242,548	$135,000	$130,500	$38,313	$257,000	$257,000
F	Labor & Equipment	$51,403	$47,667	$41,017	$32,817	$8,635	$117,460	$117,380
G	Total Direct Cost	$297,821	$290,215	$177,217	$163,317	$46,951	$375,660	$374,380
H	Construction Indirects	$0	$0	$0	$0	$0	$0	$0
I	Licensing	$2,500	$2,000	$2,500	$2,000	$600	$6,000	$5,500
J	Project Support	$20,500	$19,900	$12,628	$12,028	$2,777	$4,100	$3,600
K	Contingency	$16,041	$12,485	$7,694	$7,094	$503	$10,244	$8,512
L	Total Indirect Cost	$39,041	$34,385	$22,822	$21,122	$3,880	$20,344	$17,620
M	$/KW Net Summer	$545	$525	$416	$383	$330	$990	$980
N	$/KW Net Winter	$485	$468	$378	$349	$296	$985	$975
O	Fuel Expansion	By Fuels	By Fuels	By Fuels	By Fuels	By Fuels	$0	$0
P	Transmission Expansion	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv
Q	Railroad & Cars	$0	$0	$0	$0		$8,000	$8,000
R	Total Other Cost	$0	$0	$0	$0	$0	$8,000	$8,000
S	Grand Total Cost	$336,862	$324,600	$200,039	$184,439	$50,831	$404,004	$400,000
T	$/KW Net Summer	$545	$525	$416	$383	$330	$1,010	$1,000
U	$/KW Net Winter	$485	$468	$378	$349	$296	$1,005	$995
	II. PLANT CHARACTERISTICS							
V	Net Sum 95F Capability (mw)	618	618	481	481	154	400	400
V	Net Win 75F Capability (mw)	663	663	512	512	165	401	401
W	Net Win 59F Capability (mw)	694	694	529	529	172	402	402
	Heat Rate btu/kwh 75F 100% Load HHV	6,773	6,773	6,773	6,773	10,430	9,700	9,700
Y	Heat Rate btu/kwh 75F 75%	6,964	6,964	6,964	6,964	11,390	9,800	9,800
Z	Heat Rate btu/kwh 75F 50%	7,464	7,464	7,464	7,464	13,720	10,300	10,300
AA	Equiv. Avail. %	96%	96%	96%	96%	98%	89%	89%
BB	Sched Outage (wks/yr)	1.5	1.5	1.5	1.5	0.5	4.0	4.0
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%	3.0%
	III. OPERATION					10% Capacity Cap		
DD	Total O&M (mm/yr)	7.80	6.45	4.69	3.44	20.22	10.83	8.95
EE	Fixed ($/kw - yr)		2.14	5.12	2.54	0.68	15.40	10.70
		59% / 41%	26% / 74%	59% / 41%	26% / 74%	0% / 100%	80% / 20%	74% / 26%
		0.99		0.55	0.55	0.86	1.50	1.50
				33% / 67%	33% / 67%	0% / 100%	11% / 89%	11% / 89%
				3.86	3.86	0.00	2.00	2.00
HH	Year 6	$0	$0	$0	$0	$0	$1,397	$0
II	Year 5	$0	$0	$0	$0	$0	$11,637	$10,456
JJ	Year 4	$4,379	$4,220	$2,601	$2,398	$0	$13,384	$13,290
KK	Year 3	$110,491	$106,469	$65,613	$60,496	$0	$70,088	$71,829
LL	Year 2	$181,906	$175,284	$108,021	$99,597	$25,924	$110,023	$108,953
MM	Year 1	$40,087	$38,627	$23,805	$21,948	$24,907	$197,471	$195,472
	V. NOTES:							
NN	Net MW change (summer)	+618	+618	+481	+481	+154	+400	+400
		New NSC	New NSC	New NSC	New NSC	New NSC	New NSC	New NSC
	Plant Life Years	30	30	30	30	30	30	30
	Equipment Available	2000+	2000+			2002		
OO	Equipment	"G"	"G"	7F 7241 Foggers	7F 7241 Foggers	7F 7241	1CFB	1CFB
		2CT & 2HRSG	2CT & 2HRSG	2CT&2HRSG&1ST	2CT&2HRSG&1ST	Simple Cycle		
PP	Cooling	Tower	Tower	Tower	Tower	N/A	Tower	Reservoir
		YES	YES	no	no	no	yes - SNCR	yes - SNCR
		$7,000	$7,000	$5,500	$5,500	Included	$3,000	$3,000

SUMMARY OF GENERATION ALTERNATIVES
IRP 2000

	New Generation Alternatives	14	15	16	17	18	19
	Alternatives:	400 PC Greenfield	400 PC Martin	CC - F Repower 400mw Unit	100% Pet Coke Fuel Switch Riviera	100% Pet Coke Fuel Switch Martin	Co Fire Gas Dual Fuel Manatee
	I CONSTRUCTION (1000) 2000 $						
A	Permit/Eng/Fab (months)	36	30	10	18	30	0
B	Construction Phase (months)	30	27	28	30	34	4
C	Project Total (months)	66	57	38	48	64	4
D	Land	$1,200	$0	$0	$0	$0	$0
E	Materials	$260,038	$257,400	$212,644	$483,500	$587,500	$2,000
F	Labor & Equipment	$126,685	$126,300	$68,141	Included Above	Included Above	$1,000
G	Total Direct Cost	$387,923	$383,700	$280,785	$483,500	$587,500	$3,000
H	Construction Indirects	$0	$0	$18,746	$0	$0	$0
I	Licensing	$6,000	$5,500	$2,826	$6,000	$11,000	$0
J	Project Support	$4,220	$3,601	$8,952	$5,000	$9,000	$250
K	Contingency	$10,657	$8,799	$0	$10,000	$35,377	$114
L	Total Indirect Cost	$20,877	$17,900	$30,524	$21,000	$55,377	$364
M	$/KW Net Summer	$1,022	$1,004	$319	$864	$403	
N	$/KW Net Winter	$1,017	$999	$300	$858	$399	
O	Fuel Expansion	$0	$0	By Fuels	$0	$0	By Fuels
P	Transmission Expansion	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	$0	$0	$0
Q	Railroad & Cars	$8,000	$8,000	$0	Use Port	$0	$0
R	Total Other Cost	$8,000	$8,000	$0	$0	$0	$0
S	Grand Total Cost	$416,800	$409,600	$311,309	$504,500	$642,877	$3,364
T	$/KW Net Summer	$1,042	$1,024	$319	$864	$403	[illegible]
U	$/KW Net Winter	$1,057	$1,019	$300	$858	$399	[illegible]
	II PLANT CHARACTERISTICS						
V	Net Sum 95F Capability (mw)	400	400	975	584	1,594	[illegible]
V	Net Win 75F Capability (mw)	401	401	1,017	586	1,608	
W	Net Win 59F Capability (mw)	402	402	1,038	588	1,612	
X	Heat Rate btu/kwh 75F 100% Load HHV	9,850	9,850	6,860	9,974	9,500	10,768
Y	Heat Rate btu/kwh 75F 75%	9,950	9,950	7,203	10,054	9,600	10,707
Z	Heat Rate btu/kwh 75F 50%	10,500	10,500	7,752	10,141	10,100	10,867
AA	Equiv Avail %	89%	89%	96%	87%	94%	
BB	Sched Outage (wks/yr)	4.0	4.0	1.5	5.0	2.0	
CC	Equiv Forced Outage	3.0%	3.0%	1.0%	3.0%	2.0%	
	III OPERATION						
DD	Total O&M (mm/yr)	12.46	10.58	6.21	24.34	16.46	[illegible]
EE	Fixed ($/kw - yr)	18.66	13.96	3.08	18.13	5.93	
	% Manpower/ % Material, Equip	84% / 16%	80% / 20%	59% / 41%	80% / 20%	70% / 30%	
FF	Variable (excl fuel) ($/mwh)	1.60	1.60	0.39	3.09	0.53	
	% Manpower/ % Material, Equip	11% / 89%	11% / 89%	35% / 65%	11% / 89%	11% / 89%	
GG	Capital Replace ($mm/yr)	3.00	3.00	6.33	2.00	6.00	
	IV. SPENDING CURVES						
HH	Year 6	$1,440	$0	$44	$0	$2,572	$0
II	Year 5	$13,915	$12,409	$27,963	$0	$12,859	$0
JJ	Year 4	$13,642	$13,494	$159,042	$25,225	$15,429	$0
KK	Year 3	$71,935	$72,643	$87,266	$90,810	$110,575	$0
LL	Year 2	$112,944	$111,265	$29,377	$136,215	$174,862	$0
MM	Year 1	$202,924	$199,789	$7,617	$252,250	$328,560	$3,364
	V NOTES:						$3,364
NN	Net MW change (summer)	+400 New NSC	+400 New NSC	+607 New NSC	+0	+0	+0
	Plant Life Years	30	30	30	30	30	
	Equipment Available						
OO	Equipment	PC	PC	7F 7241 Foggers 4CT&4HRSG	2 CFB	4 Conv. Boilers Leased Bk End	Existing
PP	Cooling	Tower	Reservoir	Existing	Tower	Reservoir	Reservoir
	SCR's	yes - SCR	yes - SCR	no	yes - SNCR	yes - SCR	No
RR	Back-Up Fuel Adder	$3,000	$3,000	$0	$0	$0	$0

Ft Myers and Sanford Repowering Projects
5-YearForecast Differences ... October 1998 - August 1999

Ft Myers Repowering ... Power Generation

	5-year Forecasts October 1998	5-year Forecasts August 1999	Change
1998	$10 101,000	$10,388,000	$287,000
1999	$147 905,000	$149,015,000	$1,110,000
2000	$117.416,000	$191,624,000	$74,208,000
2001	$118.434,000	$49,151,000	($69,283,000)
2002	$27,668,000	$18,395,000	($9,273,000)
2003	$0	$5,501,000	$5.501,000
Total Forecast	**$421,524,000**	**$424,074,000**	**$2,550,000**

Sanford Repowering ... Power Generation

	5-year Forecasts October 1998	5-year Forecasts August 1999	Change
1998	$787,000	$88,000	($699,000)
1999	$62,384,000	$55,805,000	($6,579,000)
2000	$156,519,000	$271,953,000	$115,434,000
2001	$91,181,000	$144,395,000	$53,214,000
2002	$95,085,000	$58,609,000	($36,476,000)
2003	$31,451,000	$15,217,000	($16,234,000)
Total Forecast	**$437,407,000**	**$546,067,000**	**$108,660,000**

8 SA's x 692 [illegible]

10/30/98

FPL POWER GENERATION BUSINESS UNIT
SANFORD PLANT REPOWERING
(FPL BUDGET ACTIVITY # 722)
1999 Five-Year Capital Forecast
October 29, 1998
TOTAL PROJECT (BA-722)

	TOTAL	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
POWER GENERATION BUSINESS UNIT													
1998 (Prior Year)	$787,345									$5,000	$42,039	$311,090	$429,216
1999	$62,383,976	$394,924	$634,908	$4,935,741	$526,453	$867,122	$9,663,142	$523,019	$1,262,605	$11,993,815	$11,993,815	$8,680,824	$10,907,607
2000	$156,518,801	$13,296,207	$15,799,811	$11,023,210	$11,023,210	$10,926,739	$21,530,759	$12,899,560	$12,815,672	$13,308,730	$13,997,550	$9,508,999	$10,388,353
2001	$91,181,096	$7,919,951	$7,928,465	$4,379,405	$6,700,309	$8,849,559	$10,146,627	$9,179,818	$6,956,786	$7,456,786	$7,456,786	$6,780,854	$7,425,752
2002	$95,085,019	$10,864,522	$7,294,904	$6,763,037	$8,742,583	$10,590,344	$8,717,671	$10,342,731	$11,599,450	$7,275,422	$4,968,702	$3,184,228	$4,741,426
2003	$31,450,764	$3,181,536	$1,925,804	$1,484,199	$1,413,582	$1,383,062	$1,149,950	$1,163,582	$16,115,980	$1,211,023	$1,211,023	$1,211,023	$0
2004(After)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total PGBU	**$437,407,000**												
OTHER DEPTS (Power Delivery)													
1998 (Prior Year)	$0									$0	$0	$0	$0
1999	$3,500,000	$22,000	$22,000	$22,000	$22,000	$22,000	$22,000	$22,000	$22,000	$22,000	$1,522,000	$892,000	$888,000
2000	$15,200,000	$1,820,000	$1,820,000	$1,820,000	$1,820,000	$95,000	$95,000	$95,000	$95,000	$100,000	$2,500,000	$2,500,000	$2,440,000
2001	$36,153,000	$3,335,000	$3,335,000	$3,335,000	$3,335,000	$3,335,000	$2,063,000	$1,792,000	$6,900,000	$0	$600,000	$7,523,000	$600,000
2002	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2003	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2004(After)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total Other Depts	**$54,853,000**												
TOTAL PROJECT COST ***(Excluding AFUDC)***	**$492,260,000**												

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-12)
Sanford Transmission Facilities Cost
10/29/98

00421520

SANFORD REPOWERING PROJECT

CURRENT RANGE OF ESTIMATES AT COMPLETION

B&V PCR#12 - July 28, 2000

	Project Cost Est W/O Project Contingency	FPL Current Budget ("50/50 Estimate")	B&V Max Performance Estimate	B&V Worst-Case Estimate
Awarded Cost To-date (excl B&V performance Incentive)	$435,882,081	$435,882,081	$435,882,081	$435,882,081
B&V Allocated & Trended Contingencies on Awarded Cost (details attached)	$16,424,464	$16,424,464	$16,424,464	$16,424,464
Un-Awarded Major Contracts (see "major commitments listing")	$62,704,655	$62,704,655	$62,704,655	$62,704,655
Un-Spent / Un-Awarded Balance-of-Project Estimate	$15,157,321	$15,157,321	$15,157,321	$15,157,321
Project Cost Estimate (PCE) for B&V Scope	$530,168,521	$530,168,521	$530,168,521	$530,168,521
FPL - Transmission Interconnections	$75,383,000	$75,383,000	$75,383,000	$75,383,000
FPL - Demolition & Abatement	$8,000,000	$8,000,000	$8,000,000	$8,000,000
FPL - B&V Performance Incentive	$4,000,000	$4,000,000	$4,000,000	$0
FPL - Maintenance Building / Geotech / Other	$900,000	$900,000	$900,000	$900,000
FPL - FGT Fuel Gas Equipment Reimbursement	$0	$0	$0	$0
FPL - Schedule Revisions ... Pending Cost Impacts	$0	$0	$0	$0
FPL - Project Contingency	$0	$3,548,479	$18,450,957	$28,450,957
TOTAL PROJECT ESTIMATES	$618,451,521	$622,000,000	$636,902,478	$642,902,478
TOTAL CONTINGENCIES INCLUDED IN THE ESTIMATES ABOVE	*$16,424,464*	*$19,972,943*	*$34,875,421*	*$44,875,421*

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-13)
7/28/00 Sanford Cost Estimate

00421678

SANFORD REPOWERING SUCCESS CRITERIA

SAFETY

- PLANT DESIGN INCORPORATES SAFETY AND ERGONOMICS
- OSHA RECORDABLE RATE DURING CONSTRUCTION AND OPERATION - 0
- NO TRAFFIC ACCIDENTS AT BARWICK AND FORT FLORIDA ROAD INTERSECTIONS TO 17/92

ENVIRONMENTAL

- Nox - 9 ppm (30 DAY ROLLING HOURLY AVERAGE)
- CO - 12ppm (30 DAY ROLLING HOURLY AVERAGE)
- NOISE (AT "NEAREST RECEPTOR")
    - 60dB DAY (7am-10pm)
    - 55dB NIGHT (10pm-7am)
- NO NON COMPLIANCES DURING CONSTRUCTION

OPERATING*

- NET OUTPUT PER UNIT - 1009 MW (75F FOGGED)
- SINGLE EVENT LOAD LOSS
    - LESS THAN 910 MW
    - HOLD LEVEL FOR 10 MINS
    - DESIGNED TO HOLD LEVEL FOR 30 MINS
- TURNDOWN - 480 TO 1009 MW ON CONTROL
    - 280 MW MINIMUM IF CT'S CYCLE OFF
- RAMP RATE - 15 MW/MIN
- START UP DURATION TO ON-CONTROL @ 480 MW
  (30MW 1HR AFTER START, RAMPING TO 480 MW)
    - COLD - 12 HRS
    - WARM - 8 HRS
- AVAILABILITY TARGETS
    - EAF - 96%
    - POF - 2.8% (SEE O&M CRITERIA)
    - EFOR - 1.2%
- HEAT RATE - 6910 BTU/KWH HHV (75F FOGGED)
- DESIGN MUST FACILITATE PERFORMANCE TESTING AND PERFORMANCE MONITORING

FINANCIAL

- PROJECT COST - $622M
- ECONOMIC DECISION CRITERIA (LOWEST LIFE CYCLE COST)
    - NPV TERM - 5 YEARS
    - HEAT RATE VALUE - 1BTU/KWH=$128K
    - CAPACITY VALUE - 1KW=$200
    - EAF VALUE - 1%=$4M
    - O&M VALUE - $100K ANNUAL =$425K NPV

O & M*

- CT OUTAGE FREQ/DURATIONS (BREAKER TO BREAKER - PMR BASED)
    - COMBUSTION - 12 KHRS/6.5 DAYS
    - HOT GAS PATH - 24 KHRS/13 DAYS
    - MAJOR - 48 KHRS/24 DAYS
- STM TURB FREQ/DURATIONS
    - UNIT #4 - CTYR 2011/60 DAYS
    - UNIT #5 - CTYR 2010/60DAYS
- ON SITE STAFFING APPROX - 48 to 54
- ANNUAL BUDGET
    - CT OVERHAUL BUDGET - $16M
    - O&M - $5M

SCHEDULE

- STEAM UNITS OFF ON:
    - UNIT#4- 3/15/02
    - UNIT#5- 10/15/01
- GENERATION AVAILABLE BY:
    - UNIT#4- 12/31/02
    - UNIT#5- 6/30/02
- COST OF EACH DAY'S DELAY
    - $250K/DAY REPLACEMENT PWR COSTS (500 MW)
    - $2M/MO CAPACITY CONTRACT (500 MW) FOR 15% RESERVES

* PRELIMINARY ESTIMATES

1/11/00

5/9/01

POWER GENERATION DIVISION CASHFLOW RECAP

MAY 7, 2001 FIVE-YEAR FORECAST vs CURRENT APPROVED PGD PLAN

	2000 & PRIOR	2001	2002	2003 & AFTER	TOTAL PGD
MAY 7, 2001 FORECASTS					
FORT MYERS REPOWERING	$362,439,397	$71,504,449	$21,004,755	$2,353,940	$457,302,541
SANFORD REPOWERING	$316,993,939	$165,103,849	$63,468,767	$15,737,515	$561,304,070
MARTIN SIMPLE CYCLE	$77,679,471	$21,395,007	$1,320,048	$0	$100,394,526
FORT MYERS SIMPLE CYCLE	$2,239,841	$32,469,339	$78,378,858	$19,393,317	$132,481,355
PROJECTS TOTAL EXPENDITURES		$290,472,644	$164,172,428	$37,484,772	

	2001	2002	2003 & AFTER	
CURRENT APPROVED 5-YEAR FORECASTS				
FORT MYERS REPOWERING	$71,533,736	$14,943,298	$5,223,111	Demo Begins Jan 2003
SANFORD REPOWERING	$156,503,026	$57,764,805	$15,216,889	B&V Final Pmt of $4m Payable in 2003
MARTIN SIMPLE CYCLE	$28,832,157	$1,108,281	$0	
FORT MYERS SIMPLE CYCLE	$34,014,400	$75,014,402	$21,510,413*	
PROJECTS TOTAL EXPENDITURES	$290,883,319	$148,830,786	$41,950,413	* Incl $1,279 in 2004

	2001	2002	2003 & AFTER	
FORECAST DIFFERENCE TO APPROVED PLAN				
FORT MYERS REPOWERING	($29,287)	$6,061,457	($2,869,171)	Demo Begins June 2002
SANFORD REPOWERING	$8,600,823	$5,703,962	$520,626	B&V Final Pmt of $4m Payable Jan 1,2003
MARTIN SIMPLE CYCLE	($7,437,150)	$211,767	$0	
FORT MYERS SIMPLE CYCLE	($1,545,061)	$3,364,456	($2,117,096)	CTG Payments Complete on Shipment(2002)
PROJECTS TOTAL EXPENDITURES	($410,675)	$15,341,642	($4,465,641)	

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-15)
Changes in Timing of Project Costs

00422009

2002 MONTHLY FORECAST OF
BILLED SALES, CUSTOMERS AND USE BY CLASS

2002 Budget Forecast

	January	February	March	April	May	June	July	August	September	October	November	December	Total
SYSTEM SALES (mWh)													
Residential	3,874,869	3,762,017	3,257,987	3,539,325	3,629,189	4,763,609	4,990,310	5,203,464	5,237,201	4,832,118	3,720,704	3,768,114	50,578,908
Commercial	2,962,447	2,950,731	2,965,590	3,098,643	3,191,730	3,478,689	3,588,209	3,633,945	3,727,163	3,427,258	3,186,861	3,302,852	39,514,116
Industrial	337,106	336,413	340,075	339,639	339,318	338,800	338,648	338,576	338,141	338,461	338,292	338,155	4,061,622
Street & Highway	35,318	35,389	35,494	35,563	35,631	35,732	35,798	35,863	35,961	36,025	36,087	36,182	429,045
Other	4,363	4,731	4,614	4,890	5,083	5,670	5,953	5,870	5,970	5,024	5,203	4,987	62,359
Railroads & Railways	6,909	6,913	6,920	6,925	6,929	6,936	6,941	6,946	6,953	6,958	6,962	6,969	83,261
TOTAL JURISDICTIONAL SALES	7,221,012	7,096,194	6,610,681	7,024,985	7,207,881	8,629,437	8,965,860	9,224,663	9,351,388	8,645,843	7,294,109	7,457,259	94,729,311
Resale	73,587	70,890	72,529	77,589	81,987	86,753	126,064	128,697	129,962	127,335	119,843	112,054	1,207,289
TOTAL SALES	7,294,599	7,167,085	6,683,209	7,102,574	7,289,868	8,716,190	9,091,924	9,353,360	9,481,350	8,773,178	7,413,952	7,569,312	95,936,600
CUSTOMERS													
Residential	3,549,316	3,558,228	3,567,094	3,571,699	3,557,724	3,558,842	3,561,433	3,563,609	3,568,566	3,571,609	3,581,749	3,593,959	3,566,986
Commercial	431,945	433,350	433,911	434,906	436,372	434,461	434,937	435,897	437,145	437,896	438,772	440,057	435,804
Industrial	15,275	15,261	15,257	15,254	15,175	15,242	15,239	15,190	15,177	15,144	15,155	15,147	15,210
Street & Highway	2,499	2,504	2,511	2,516	2,521	2,528	2,533	2,537	2,544	2,549	2,553	2,560	2,530
Other	248	248	248	248	248	248	248	248	248	248	248	248	248
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23
TOTAL JURISDICTIONAL CUSTOMERS	3,999,307	4,009,613	4,019,043	4,024,646	4,012,063	4,011,345	4,014,413	4,017,504	4,023,704	4,027,470	4,038,499	4,051,994	4,020,800
Resale	3	3	3	3	3	4	4	4	4	4	4	4	4
TOTAL CUSTOMERS	3,999,310	4,009,616	4,019,046	4,024,649	4,012,066	4,011,349	4,014,417	4,017,508	4,023,708	4,027,474	4,038,503	4,051,998	4,020,804
USE PER CUSTOMER													
Residential	1,092	1,057	913	991	1,020	1,339	1,401	1,460	1,468	1,353	1,039	1,048	14,180
Commercial	6,858	6,809	6,835	7,125	7,314	8,007	8,250	8,337	8,526	7,827	7,263	7,506	90,669
Industrial	22,069	22,043	22,290	22,265	22,360	22,228	22,222	22,290	22,280	22,349	22,323	22,325	267,041
Street & Highway	14,134	14,13[illegible]	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	169,603
Other	17,594	19,078	18,606	19,719	20,495	22,862	24,005	23,669	24,072	20,258	20,981	20,107	251,446
Railroads & Railways	300,380	300,570	300,871	301,087	301,277	301,580	301,797	301,987	302,288	302,503	302,692	303,009	3,620,041
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,806	1,770	1,645	1,745	1,797	2,151	2,233	2,296	2,324	2,147	1,806	1,840	23,560
Resale	24,529,040	23,630,162	24,176,168	25,863,091	27,329,067	21,688,185	31,515,943	32,174,196	32,490,519	31,833,652	29,960,709	28,013,429	336,917,892
TOTAL USE PER CUSTOMER	1,824	1,787	1,663	1,765	1,817	2,173	2,265	2,328	2,356	2,178	1,836	1,868	23,860

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-16)
Pre- and Post-September 11, 2001 Sales
Estimates for 2002 and 2005
Page 2 of 4

2005 MONTHLY FORECAST OF
BILLED SALES, CUSTOMERS AND USE BY CLASS

2002 Budget Forecast

	January	February	March	April	May	June	July	August	September	October	November	December	Total
SYSTEM SALES (mWh)													
Residential	4,534,342	4,412,571	3,825,434	4,013,918	4,074,595	5,333,816	5,589,577	5,835,704	5,883,326	5,491,465	4,284,523	4,342,310	57,621,582
Commercial	3,232,659	3,255,765	3,293,143	3,477,164	3,523,384	3,817,493	3,949,330	3,960,190	4,052,804	3,695,584	3,442,604	3,594,030	43,294,149
Industrial	340,515	340,416	340,691	340,283	340,814	340,743	340,875	340,689	340,958	340,791	340,702	340,646	4,088,123
Street & Highway	37,980	38,027	38,108	38,154	38,200	38,280	38,326	38,371	38,450	38,494	38,538	38,617	459,544
Other	4,333	4,697	4,581	4,854	5,044	5,624	5,904	5,822	5,921	4,986	5,163	4,949	61,879
Railroads & Railways	7,021	7,025	7,032	7,037	7,041	7,048	7,053	7,057	7,064	7,069	7,073	7,080	84,600
TOTAL JURISDICTIONAL SALES	8,156,850	8,058,501	7,508,988	7,881,411	7,989,079	9,543,004	9,931,064	10,187,833	10,328,522	9,578,389	8,118,603	8,327,632	105,609,877
Resale	111,335	109,630	107,973	116,327	120,724	124,392	130,763	133,396	134,662	132,035	124,543	116,754	1,462,534
TOTAL SALES	8,268,185	8,168,131	7,616,962	7,997,738	8,109,804	9,667,396	10,061,827	10,321,229	10,463,183	9,710,424	8,243,146	8,444,386	107,072,411
CUSTOMERS													
Residential	3,749,897	3,758,581	3,767,194	3,767,531	3,760,293	3,761,234	3,763,769	3,765,755	3,770,567	3,773,465	3,783,668	3,795,965	3,768,160
Commercial	467,310	468,043	469,081	470,349	471,606	472,131	472,543	473,185	473,775	474,348	475,454	476,370	472,016
Industrial	15,217	15,219	15,220	15,221	15,219	15,219	15,220	15,220	15,221	15,222	15,224	15,226	15,221
Street & Highway	2,687	2,691	2,696	2,700	2,703	2,708	2,712	2,715	2,720	2,724	2,727	2,732	2,710
Other	248	248	248	248	248	248	248	248	248	248	248	248	248
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23
TOTAL JURISDICTIONAL CUSTOMERS	4,235,382	4,244,804	4,254,462	4,256,071	4,250,091	4,251,563	4,254,515	4,257,146	4,262,554	4,266,029	4,277,343	4,290,564	4,258,377
Resale	4	4	4	4	4	4	4	4	4	4	4	4	4
TOTAL CUSTOMERS	4,235,386	4,244,808	4,254,466	4,256,075	4,250,095	4,251,567	4,254,519	4,257,150	4,262,558	4,266,033	4,277,347	4,290,568	4,258,381
USE PER CUSTOMER													
Residential	1,209	1,174	1,015	1,065	1,084	1,418	1,485	1,550	1,560	1,455	1,132	1,144	15,292
Commercial	6,918	6,956	7,020	7,393	7,471	8,086	8,358	8,369	8,554	7,791	7,241	7,545	91,722
Industrial	22,377	22,368	22,384	22,357	22,394	22,389	22,397	22,384	22,401	22,389	22,380	22,372	268,592
Street & Highway	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	169,603
Other	17,473	18,940	18,473	19,573	20,339	22,678	23,807	23,475	23,873	20,105	20,819	19,956	249,511
Railroads & Railways	305,245	305,448	305,747	305,958	306,142	306,436	306,646	306,831	307,126	307,338	307,524	307,828	3,678,270
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,926	1,898	1,765	1,852	1,880	2,245	2,334	2,393	2,423	2,245	1,898	1,941	24,800
Resale	27,833,772	27,407,472	26,993,332	29,081,770	30,181,124	31,097,882	32,690,757	33,349,069	33,665,451	33,008,653	31,135,746	29,188,501	365,633,530
TOTAL USE PER CUSTOMER	1,952	1,924	1,790	1,879	1,908	2,274	2,365	2,424	2,455	2,276	1,927	1,968	25,144

10/18/01
2002 Alt Forecast

2002 MONTHLY FORECAST OF
BILLED SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	Total	
SYSTEM SALES (mWh)														
Residential	3,879,514	3,697,859	3,150,637	3,361,977	3,563,562	4,522,773	4,748,487	5,085,559	4,947,172	4,651,004	3,808,390	3,648,215	49,065,148	2.6%
Commercial	2,965,998	2,900,408	2,867,874	2,943,376	3,134,013	3,302,815	3,414,330	3,551,603	3,520,758	3,298,799	3,261,967	3,197,757	38,359,698	1.8%
Industrial	337,510	330,675	328,870	322,620	333,182	321,671	322,238	330,904	319,415	325,775	346,264	327,395	3,946,519	-3.7%
Street & Highway	35,361	34,786	34,324	33,781	34,987	33,926	34,064	35,051	33,970	34,674	36,938	35,031	416,892	-0.6%
Other	4,369	4,651	4,462	4,645	4,991	5,383	5,665	5,737	5,639	4,836	5,326	4,828	60,531	-10.1%
Railroads & Railways	6,917	6,795	6,692	6,578	6,804	6,586	6,605	6,788	6,568	6,697	7,126	6,747	80,903	-3.2%
TOTAL JURISDICTIONAL SALES	7,229,668	6,975,174	6,392,860	6,672,978	7,077,538	8,193,153	8,531,388	9,015,641	8,833,522	8,321,786	7,466,011	7,219,973	91,929,691	2.0%
Resale	73,587	70,890	72,529	77,589	81,987	86,753	126,064	128,697	129,962	127,335	119,843	112,054	1,207,289	21.9%
TOTAL SALES	7,303,255	7,046,064	6,465,388	6,750,567	7,159,525	8,279,906	8,657,451	9,144,338	8,963,484	8,449,120	7,585,854	7,332,027	93,136,980	2.2%
CUSTOMERS														
Residential	3,530,945	3,539,811	3,548,631	3,553,212	3,539,310	3,540,422	3,542,999	3,545,164	3,550,095	3,553,123	3,563,210	3,575,357	3,548,523	1.7%
Commercial	429,710	431,107	431,665	432,655	434,113	432,213	432,686	433,641	434,883	435,610	436,501	437,779	433,548	1.8%
Industrial	15,196	15,182	15,178	15,175	15,096	15,163	15,160	15,111	15,099	15,066	15,076	15,069	15,131	-2.1%
Street & Highway	2,499	2,504	2,511	2,516	2,521	2,528	2,533	2,537	2,544	2,549	2,553	2,560	2,530	3.3%
Other	248	248	248	248	248	248	248	248	248	248	248	248	248	-0.9%
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23	0.0%
TOTAL JURISDICTIONAL CUSTOMERS	3,978,621	3,988,875	3,998,256	4,003,830	3,991,311	3,990,597	3,993,649	3,996,724	4,002,892	4,006,639	4,017,611	4,031,036	4,000,003	1.7%
Resale	3	3	3	3	3	4	4	4	4	4	4	4	4	19.4%
TOTAL CUSTOMERS	3,978,624	3,988,878	3,998,259	4,003,833	3,991,314	3,990,601	3,993,653	3,996,728	4,002,896	4,006,643	4,017,615	4,031,040	4,000,007	1.7%
USE PER CUSTOMER														
Residential	1,099	1,045	888	946	1,007	1,277	1,340	1,435	1,394	1,309	1,069	1,020	13,827	0.7%
Commercial	6,902	6,728	6,644	6,803	7,219	7,642	7,891	8,190	8,096	7,572	7,473	7,304	88,478	0.0%
Industrial	22,210	21,780	21,668	21,259	22,070	21,214	21,255	21,898	21,155	21,623	22,967	21,727	260,823	1.3%
Street & Highway	14,151	13,893	13,668	13,425	13,878	13,419	13,449	13,813	13,351	13,604	14,467	13,684	164,799	-1.0%
Other	17,615	18,753	17,993	18,731	20,125	21,706	22,841	23,132	22,739	19,499	21,475	19,467	244,076	-6.6%
Railroads & Railways	300,740	295,444	290,957	286,000	295,829	286,332	287,172	295,145	285,548	291,165	309,825	293,368	3,517,525	-0.4%
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,817	1,749	1,599	1,667	1,773	2,053	2,136	2,256	2,207	2,077	1,858	1,791	22,982	0.3%
Resale	24,529,040	23,630,162	24,176,168	25,863,091	27,329,067	21,688,185	31,515,943	32,174,196	32,490,519	31,833,652	29,960,709	28,013,429	336,917,892	2.1%
TOTAL USE PER CUSTOMER	1,836	1,766	1,617	1,686	1,794	2,075	2,168	2,288	2,239	2,109	1,888	1,819	23,284	0.5%

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-16)
Pre- and Post-September 11, 2001 Sales Estimates for 2002 and 2005
Page 3 of 4

10/18/01
2002 Alt Forecast

2005 MONTHLY FORECAST OF
BILLED SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	Total	
SYSTEM SALES (mWh)														
Residential	4,496,653	4,309,366	3,675,427	3,807,797	4,016,477	5,082,099	5,337,761	5,718,379	5,563,487	5,291,009	4,391,785	4,211,306	55,901,544	4.3%
Commercial	3,205,789	3,179,616	3,164,009	3,298,606	3,473,127	3,637,335	3,771,409	3,880,571	3,812,479	3,560,684	3,528,789	3,485,600	42,018,013	2.7%
Industrial	337,685	332,454	327,331	322,809	335,953	324,662	325,518	333,840	322,422	328,351	349,231	330,369	1,970,626	0.0%
Street & Highway	37,664	37,137	36,613	36,195	37,656	36,474	36,599	37,599	36,359	37,089	39,503	37,452	446,340	2.0%
Other	4,297	4,587	4,402	4,605	4,972	5,359	5,638	5,705	5,599	4,804	5,292	4,800	60,060	-0.3%
Railroads & Railways	6,962	6,861	6,756	6,676	6,941	6,715	6,735	6,915	6,680	6,811	7,250	6,866	82,169	0.5%
TOTAL JURISDICTIONAL SALES	8,089,051	7,870,021	7,214,538	7,476,688	7,875,125	9,092,643	9,483,661	9,983,009	9,767,026	9,228,747	8,321,851	8,076,393	102,478,753	3.5%
Resale	111,335	109,630	107,973	116,327	120,724	124,392	130,763	133,396	134,662	132,035	124,543	116,754	1,462,534	1.2%
TOTAL SALES	8,200,386	7,979,651	7,322,511	7,593,015	7,995,850	9,217,035	9,614,424	10,116,406	9,901,687	9,360,782	8,446,394	8,193,147	103,941,287	3.4%
CUSTOMERS														
Residential	3,717,464	3,726,073	3,734,611	3,734,946	3,727,770	3,728,703	3,731,216	3,733,185	3,737,955	3,740,828	3,750,942	3,763,133	3,735,569	1.7%
Commercial	463,268	463,995	465,024	466,281	467,527	468,047	468,456	469,092	469,677	470,245	471,341	472,250	467,934	2.6%
Industrial	15,085	15,087	15,089	15,089	15,087	15,088	15,088	15,088	15,089	15,090	15,092	15,094	15,089	-0.3%
Street & Highway	2,687	2,691	2,696	2,700	2,703	2,708	2,712	2,715	2,720	2,724	2,727	2,732	2,710	2.0%
Other	248	248	248	248	248	248	248	248	248	248	248	248	248	0.0%
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23	0.0%
TOTAL JURISDICTIONAL CUSTOMERS	4,198,776	4,208,116	4,217,691	4,219,286	4,213,358	4,214,817	4,217,743	4,220,352	4,225,713	4,229,158	4,240,374	4,253,481	4,221,572	1.8%
Resale	4	4	4	4	4	4	4	4	4	4	4	4	4	0.0%
TOTAL CUSTOMERS	4,198,780	4,208,120	4,217,695	4,219,290	4,213,362	4,214,821	4,217,747	4,220,356	4,225,717	4,229,162	4,240,378	4,253,485	4,221,576	1.8%
USE PER CUSTOMER														
Residential	1,210	1,157	984	1,020	1,077	1,363	1,431	1,532	1,488	1,414	1,171	1,119	14,965	2.6%
Commercial	6,920	6,853	6,804	7,074	7,429	7,771	8,051	8,273	8,160	7,572	7,487	7,381	89,795	0.2%
Industrial	22,385	22,036	21,694	21,394	22,267	21,519	21,575	22,126	21,368	21,760	23,140	21,887	263,148	0.3%
Street & Highway	14,016	13,803	13,579	13,408	13,932	13,467	13,497	13,849	13,365	13,618	14,487	13,707	164,730	0.0%
Other	17,328	18,497	17,749	18,568	20,049	21,608	22,734	23,003	22,575	19,371	21,340	19,354	242,176	-0.3%
Railroads & Railways	302,708	298,304	293,758	290,247	301,776	291,974	292,832	300,662	290,429	296,119	315,223	298,541	3,572,572	0.5%
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,927	1,870	1,711	1,772	1,869	2,157	2,249	2,365	2,311	2,182	1,963	1,899	24,275	1.7%
Resale	27,833,772	27,407,472	26,993,332	29,081,770	30,181,124	31,097,882	32,690,757	33,349,069	33,665,451	33,008,653	31,135,746	29,188,501	365,633,530	1.2%
TOTAL USE PER CUSTOMER	1,953	1,896	1,736	1,800	1,898	2,187	2,280	2,397	2,343	2,213	1,992	1,926	24,621	1.6%

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-16)
Pre- and Post-September 11, 2001 Sales
Estimates for 2002 and 2005
Page 4 of 4

00100655

Florida Power & Light Company
Docket No. 001148-EI
OPC Third Request For Production of Documents
Request No. 89
Page 1 of 1

Q.

Please provide the agreement(s) between FPL and FPL FiberNet for the sale and purchase of FPL's fiber optic assets.

A.

There is no written agreement of purchase and sale for the transfer of the assets in question. The assets were transferred on the basis of two independent appraisals and pursuant to a release from the utility's mortgage and deed of trust.