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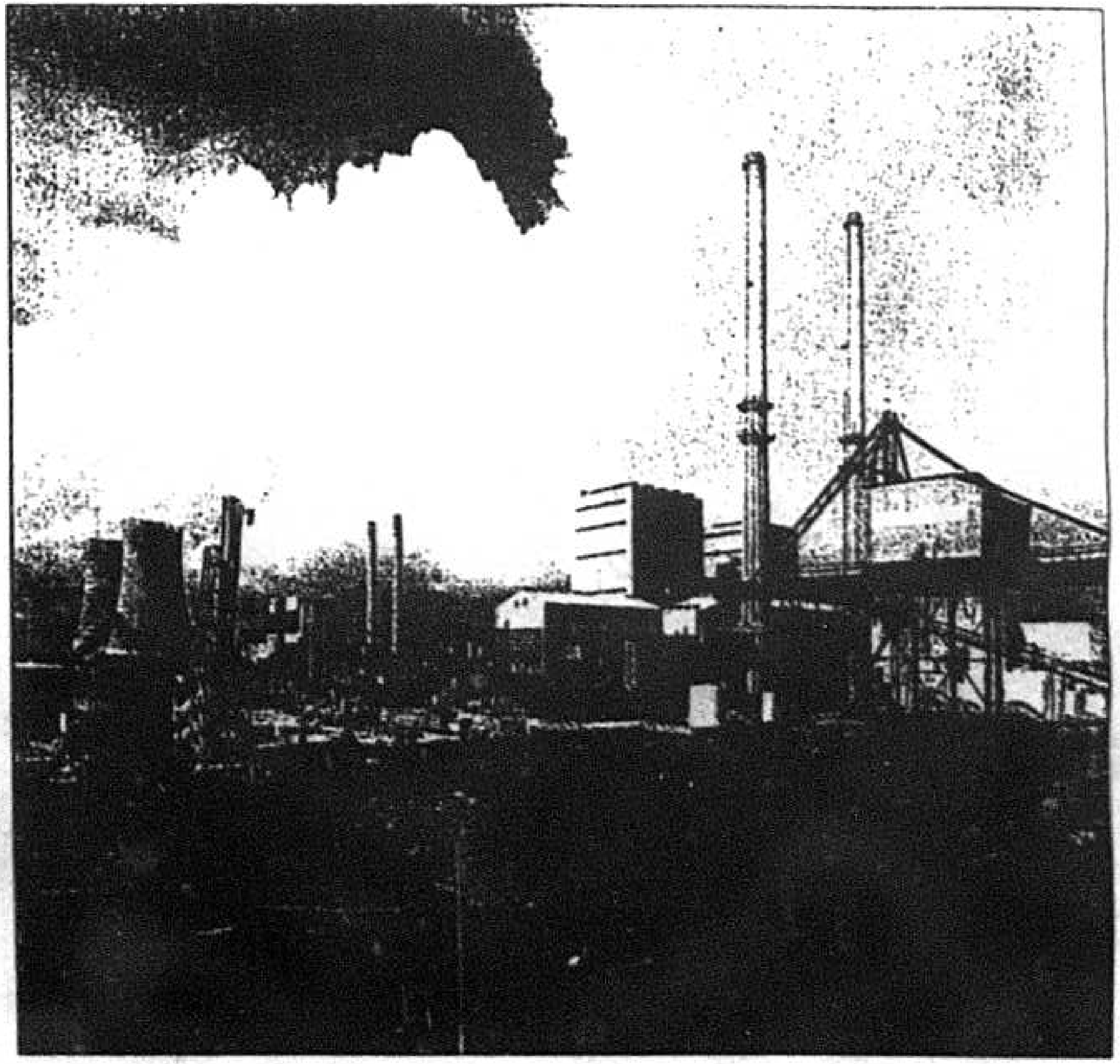
CHASE

Capital Markets Presentation to

Florida Power Corporation

April 9, 1996



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I. EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

- For the Florida Power Corporation ("FPC"), preferred stock is high cost debt rather than low cost equity.
- Replacing preferred stock with debt will not change FPC's credit quality or credit outlook, but will reduce FPC's weighted average cost of capital ("WACC"). The optimal capital structure is the debt-mezzanine capital-equity ratio that minimizes the Company's WACC.
- FPC's capital structure and cash flow can support more variable rate, short term debt to further reduce the WACC by taking advantage of historically upward sloping yield curves.
- FPC's 7.40% and 7.76% preferred issues are in the money to be called and refinanced, on a matched maturity, preferred for preferred basis. FPC's 7.08% preferred issue is in the money to be called and refinanced on a matched maturity, preferred for debt basis.
- Therefore, FPC should call these two preferred issues and refinance this high cost debt with commercial paper. Additionally, FPC should take advantage of opportunities in the fixed income markets to realize the value of the embedded option in the 8 5/8% bond.

FLORIDA POWER CORP.
Preferred Stock Portfolio
Summary Statistics

Number of Issues		7
Average Size	$	19,785,713
Weighted Average Dividend Rate		6.79%
Amount Outstanding	$	138,500,000
Percentage of Capital Structure		3.60%

PREFERRED STOCK

ADVANTAGES	DISADVANTAGES
• Capital with no default risk	• Preferred dividends are not tax deductible
• Cash flow flexibility - dividends can be omitted and the stock can be retired	• Preferred dividends must be paid before common dividends and may be cumulative
✓ • Viewed as equity by rating agencies	• An expensive form of 'debt' financing if viewed as debt
• Preservation of stockholder control	• Unsecured debt can have many of the features that preferred stock has - at a much lower after-tax cost

DEBT

ADVANTAGES	DISADVANTAGES
• Lowest cost form of financing	• Default risk increases as debt is added
• Interest is tax deductible	✓ • Rating agency issues

CAPITAL STRUCTURE/RATING AGENCY ISSUES

The following traditional corporate finance "rationales" for issuing preferred do not apply to Florida Power Corp.:

Preferred securities provide a means to raise low cost equity (without surrendering control) for issuers with marginal investment grade or non investment grade credit ratings.

Corporations with accumulated tax losses often consider preferred when there is no tax advantage for issuing debt.

The preferred covenants are no more onerous than the issuer's other debt covenants.

The historical tax advantages of issuing preferred are diminishing:

80-70% ↓

The changes to the cap on the dividend received deductions for corporations moved the corporate investor market from fixed rate to adjustable rate preferred (either through an auction or remarketing agent). 6.45%

The specialized tax deductible preferred vehicles -- MIPS, QUIPS, QUICS, TOPRS, etc. -- are likely to be attacked by the Joint Committee on Taxation and are being challenged by the executive branch.

Refinancing preferred with debt will not change Florida Power's or Florida Progress' credit rating or credit outlook due to the companies' low percentage of preferred stock in their strong capital structures.

FLORIDA POWER CORP.'S PREFERRED STOCK PORTFOLIO

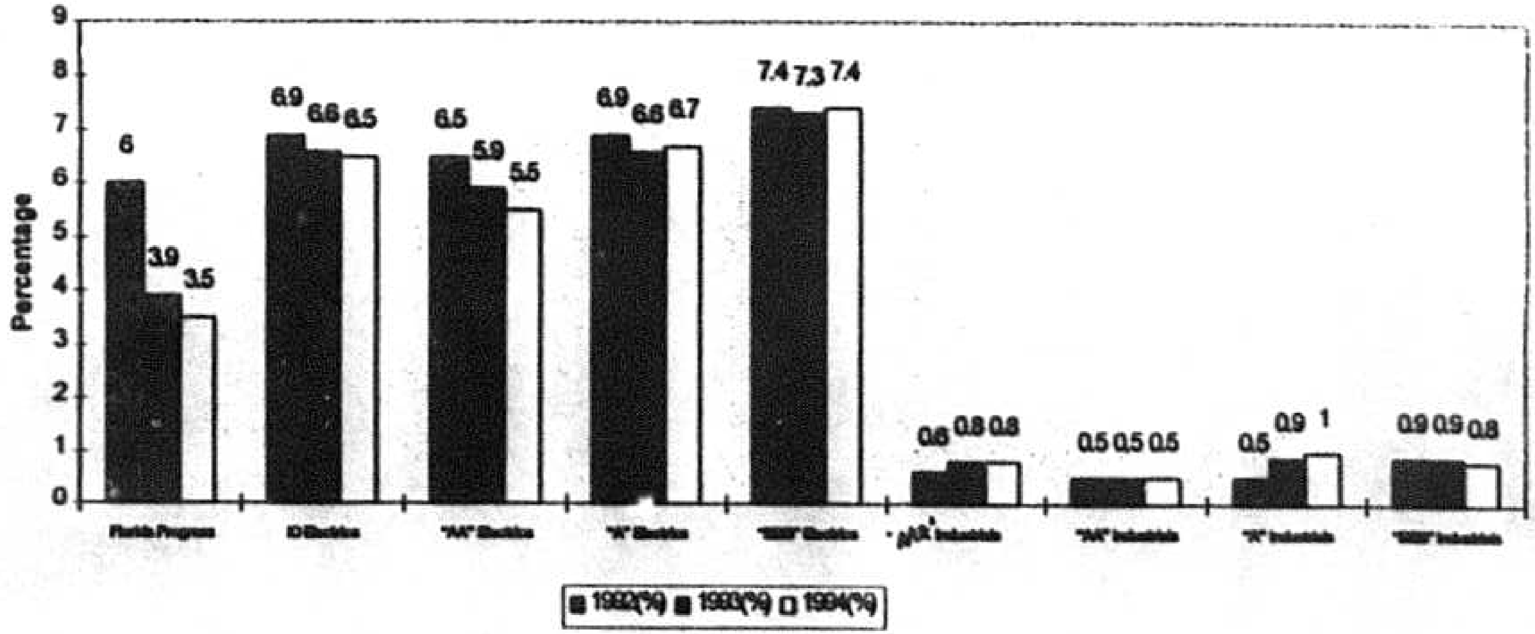
Annual Dividend Rate	Outstanding ($MM)	Current Redemption Price	Next Call Date
4.00%	4.0	$104.25	3/29/96
4.40%	7.5	102.00	3/29/96
4.58%	10.0	101.00	3/29/96
4.60%	4.0	103.25	3/29/96
4.75%	8.0	102.00	3/29/96
7.08%	25.0	104.72*	3/29/96
7.40%	30.0	102.48	3/29/96
7.76%	50.0	102.21	3/29/96

6 1/8 Perpetual

* Call price at 11/15/96 drops to 102.36.

II. RATING AGENCY AND CAPITAL STRUCTURE ANALYSIS

PREFERRED STOCK AS A PERCENTAGE OF TOTAL CAPITAL



UTILITY COMPARABLES
CAPITALIZATION ANALYSIS
Year-End 1995

	Florida Power	%	FPL Corp.	%	Alabama Power	%	Georgia Power	%	Tampa Electric	%	Duke Power	%
Short Term Debt	0	0	178.5	2.1	390.0	6.5	400.3	4.5	144.5	8.7	12.1	0.1
Current Portion LTD	30.6	1.0	100.0	2.5	84.6	1.4	150.4	1.7	26.0	1.6	155.3	1.7
Long Term Debt	1,279.1	39.9	3,094.1	37.3	2,374.9	39.7	3,315.5	37.5	583.1	35.1	3,711.4	39.7
Preferred Stock	138.5	4.3	339.0	4.1	440.4	7.4	692.8	7.8	55.0	3.3	684.0	7.3
Common Stock	1,754.0	54.8	4,473.8	54.0	2,690.4	45.0	4,299.0	48.5	851.9	51.3	4,785.2	52.2
TOTAL CAPITALIZATION	3,202.2	100.0	8,289.4	100.0	5,980.3	100.0%	8,858.0	100.0%	1,660.5	100.0%	9,348.0	100.0%
Current Portion LTD	30.6		100.0		84.6		150.4		26.0		12.1	
Short Term Debt	0		178.5		390.0		222.3		144.5		155.3	
Taxable LTD	1,044.2		2,546.7		1,909.9		1,715.4		255.0		3,294.3	
Tax-Exempt LTD	240.9		547.4		476.1		1,678.0		358.1		172.0	
Other LTD	0		17.7		9.0		87.4		0		318.7	
Unamortized Debt	-6.0		-30.4		-25.3		-14.9		-4.0		-61.7	
Current Portion LTD	-30.6		-100.0		-84.6		-150.4		-26.0		-12.1	
TOTAL LONG TERM DEBT	1,279.1		3,094.1		2,374.9		3,315.5		583.1		3,711.2	
Weighted Ave. Interest Cost	7.20%		7.97%		7.39%		7.14%		6.91%		7.94%	
LT Debt Carrying Value	1,279.1		3,194.1		2,451.0		3,378.0		583.1		3,777.7	
Estimated Fair Value	NA		3,285.9		2,577.0		3,487.0		638.6		3,879.0	
% Capital Structure - Variable Debt	0.0% → 4.5		2.2%		12.7%		10.1%		21.3%		5.0%	
% Capital Structure - Fixed Debt	39.9		39.7%		33.5%		31.9%		25.8%		37.2%	

CREDIT RATING ANALYSIS FOR U.S. INDUSTRIAL COMPANIES (a)

	Florida Power Corp. LTM 12/31/95	AAA	AA	A	BBB
Pre-tax Interest Coverage	4.32x	19.93x	8.89x	4.73x	2.50x
EBITDA Interest Coverage	7.47x	29.17x	13.44x	7.40x	4.30x
Funds from Operations/Total Debt	40.5%	136.8%	75.1%	44.3%	29.3%
Operating Income to Revenue	20.1%	21.6%	16.1%	13.9%	11.4%
Total Debt/Capitalization incl. short-term debt	40.9%	21.3%	26.4%	37.4%	47.0%
Total Debt/EBITDA	1.68x				

(a) Indicative criteria based on statistics published in the October 1994 Standard & Poor's Global Sector Review (Creditstats)

PRO FORMA CREDIT RATING ANALYSIS FOR U.S. INDUSTRIAL COMPANIES (a)

	Florida Power Corp. *Pro Forma* LTM 12/31/95	AAA	AA	A	BBB
Pre-tax Interest Coverage	4.20x	19.93x	8.89x	4.73x	2.50x
EBITDA Interest Coverage	7.23x	29.17x	13.44x	7.40x	4.30x
Funds from Operations/Total Debt	38.3%	136.8%	75.1%	44.3%	29.3%
Operating Income to Revenue	20.1%	21.8%	16.1%	13.9%	11.4%
Total Debt/Capitalization incl. short-term debt	43.4%	21.3%	28.4%	37.4%	47.0%
Total Debt/EBITDA	1.77x				

(a) Indicative criteria based on statistics published in the October 1994 Standard & Poor's Global Sector Review (Creditstats)

CREDIT RATING ANALYSIS FOR U.S. UTILITIES COMPANIES (a)

	Florida Power Corp. LTM 12/31/95	AAA	AA	A	BBB
Pre-tax Interest Coverage	4.32x	7.05x	4.64x	3.40x	2.74x
Funds from Operations/Interest	5.07x	9.94x	5.87x	4.30x	3.90x
Funds from Operations/Total Debt	40.5%	62.1%	32.2%	25.8%	22.4%
Total Debt/Capitalization incl. short-term debt	40.9%	51.8%	45.8%	48.6%	52.7%
Total Debt/EBITDA	1.68x				

(a) Indicative criteria based on statistics published in the October 1995 Standard & Poor's Global Sector Review (Creditstats)

PRO FORMA CREDIT RATING ANALYSIS FOR U.S. UTILITIES COMPANIES (a)

	Florida Power Corp. *Pro Forma* LTM 12/31/95	AAA	AA	A	BBB
Pre-tax Interest Coverage	4.20x	7.05x	4.54x	3.40x	2.74x
Funds from Operations/Interest Coverage	4.88x	9.94x	5.37x	4.30x	3.90x
Funds from Operations/Total Debt	38.6%	62.1%	32.2%	25.8%	22.4%
Total Debt/Capitalization incl. short-term debt	43.4%	51.8%	45.9%	48.6%	52.7%
Total Debt/EBITDA	1.77x				

(a) Indicative criteria based on statistics published in the October 1995 Standard & Poor's Global Sector Review (Creditstats)

FLORIDA POWER CORP.
CAPITALIZATION AND CREDIT STATISTICS

	Actual 12/31/95		Commercial Paper* Pro Forma 12/31/95		30 year Debenture* Pro Forma 12/31/95	
	$ (mm)	%	$ (mm)	%	$(mm)	%
Capitalization						
Current Portion LTD & P.S.	$ 30.6	1.0%	$ 30.6	1.0%	30.6	1.0%
Short Term Debt	-0-	0.0	80.0	2.5	-0-	0.0
Long Term Debt	1,279.1	39.9	1,279.1	39.9	1,359.1	42.4
Total Debt	1,309.7	40.9	1,388.3	43.4	1,388.3	43.4
Common Stock & R.E.	1,754.0	54.8	1,754.0	54.5	1,754.0	54.5
Preferred Stock	138.5	4.3	58.5	1.8	58.5	1.8
Total Capitalization	$3,202.2	100.0%	$3,202.2	100.0%	3,180.6	100.0%

Operating Data	Actual 12/31/95	Pro Forma 12/31/95	Pro Forma 12/31/95
Revenue	$2,271.7	$2,271.7	$2,271.7
EBITDA	781.0	781.0	781.0
Preferred Dividends	9.7	3.6	3.6
Interest Expense	104.5	108.9**	110.5***
Capital Expenditures	283.4	283.4	283.4
Financial Ratios			
EBITDA/Interest Expense	7.47x	7.23x	7.11x
(EBITDA-CapEx)/Interest Expense	4.76x	4.57x	4.50x
Total Debt/EBITDA	1.68x	1.77x	1.77x
Total Debt/Capitalization	40.9%	43.4%	43.4%

*Assumes refinancing of $30MM of 7.40% pfd and $50MM of 7.76% pfd.
**Borrowing rate on Commercial Paper set at 5.5%.
***Borrowing rate on 30 year debenture set at 7.5%.

CONCLUSIONS

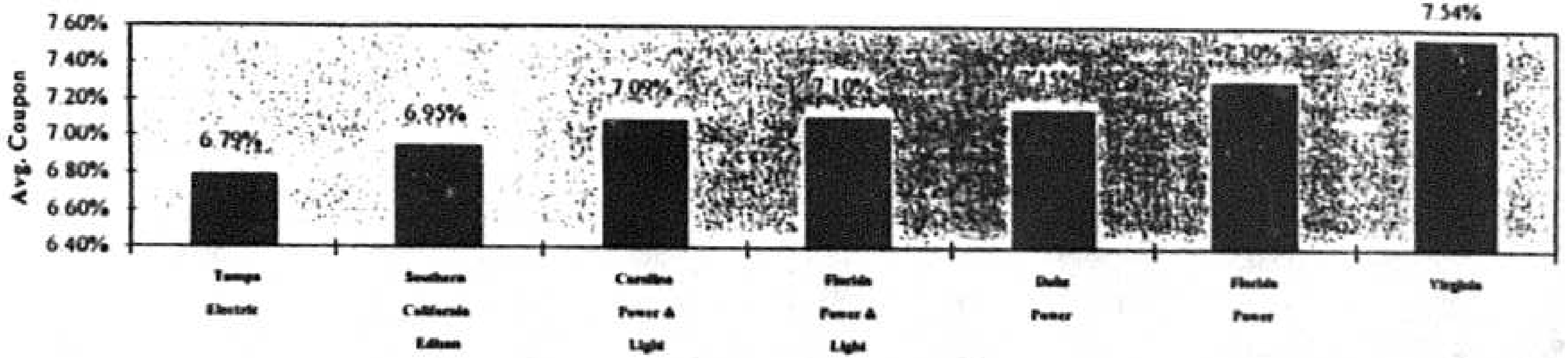
- The replacement of $80MM of preferred stock should not impair the ratings of Florida Power. Pro forma numbers show no material deterioration in credit quality.
- Pro forma total debt to capitalization of 43.4% remains in line with other Southeastern utilities' debt ratios such as Florida Power & Light, 41.9%, Alabama Power, 47.6%, Georgia Power, 43.7%, Tampa Electric, 45.4% and Duke Power, 41.5.
- Although existing coverage ratios lie slightly below the median for AA Rated Electrics, pro forma coverage ratios remain within acceptable limits for AA Rated Electric Utilities. Pre-tax interest coverage drops from 4.32x to 4.20x while funds from operations to total interest falls from 5.07x to 4.88x.
- Several other Southeastern Electric Utilities including Tampa Electric, Florida Power and Light, and Duke Power have replaced significant amounts of preferred stock with debt.
- Given Florida Power's strong capital structure and the lack of variable-rate financing, Chase Securities recommends the replacement of $30MM of 7.40% preferred and $50MM of 7.76% preferred with commercial paper.

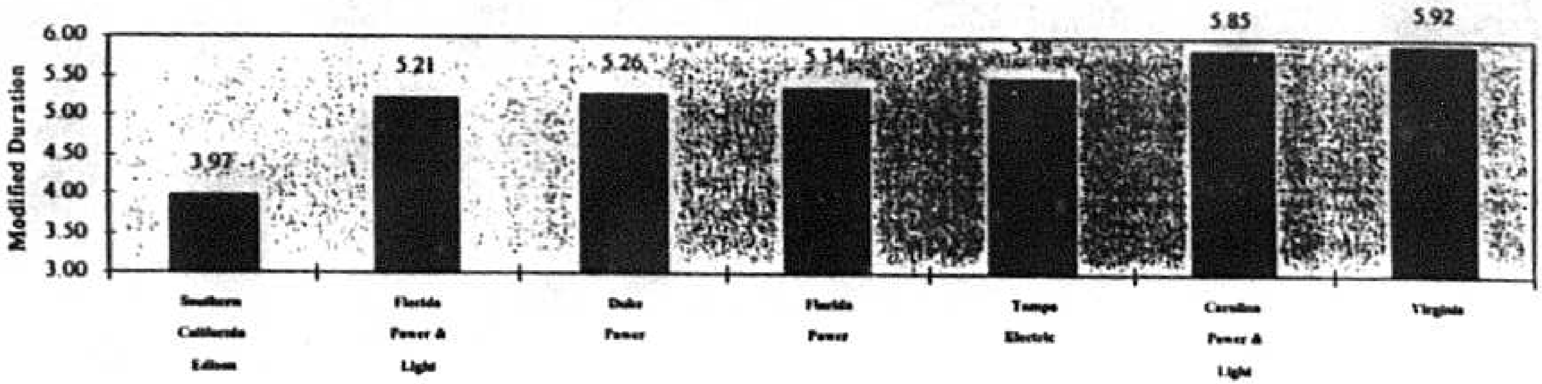
Debt Portfolio Analysis

(Updated from January 24, 1996 presentation)

Portfolio Analysis Update

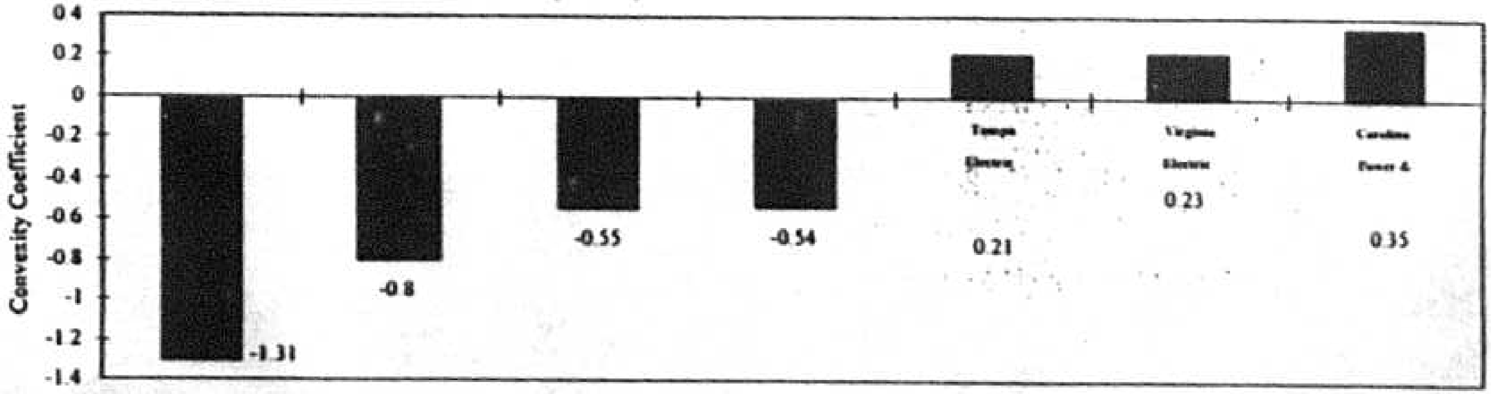
Assuming that each company has a developed corporate credit curve, the average coupon of a portfolio will be a factor of a company's credit rating, the optionality in their portfolio, and when the company borrowed. Relative to this peer group, FPC has a high average coupon, an average amount of callable paper, an average duration, and superior convexity.

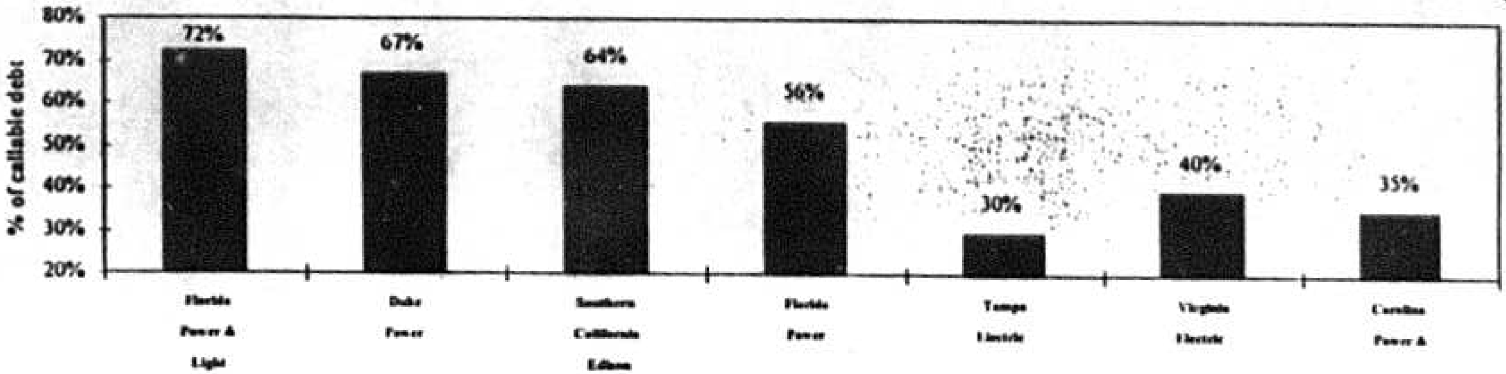




Portfolio Analysis Update

Convexity is a reflection of both the amount of callable paper in a corporation's portfolio as well as the value of those call options. Thus, there should be a strong correlation between a portfolio's convexity, the amount of callable paper in the portfolio, and the average coupon of the portfolio (an indication of the value of those options).



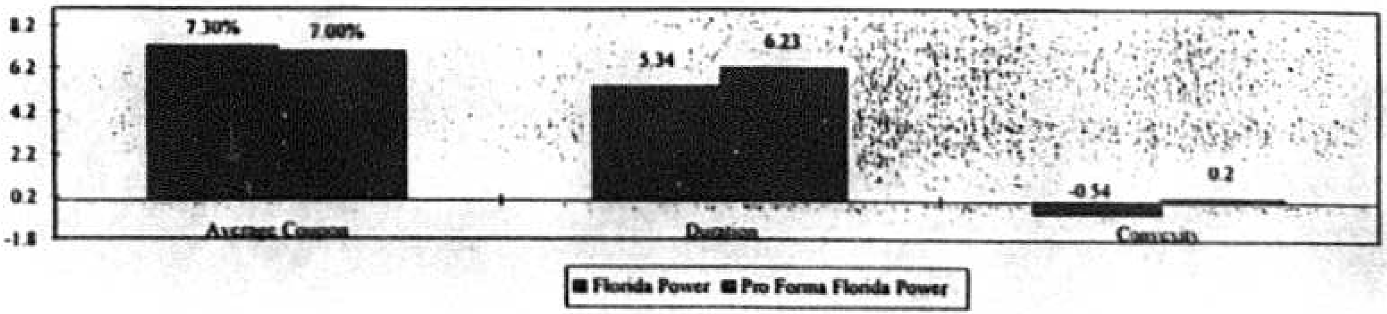


Conclusion: FPC's portfolio has enough convexity relative to its peer group that it can afford to give up some of that callability by monetizing those options and/or issuing non-call debt at lower coupons.

Debt Portfolio Analysis Update Summary

Company	Ratings	Reported LTD	Public LTD ($mm)	Market Value	Average Price	Average Coupon	Mod. Duration	% of callable debt	Convexity	BPV ($)
Florida Power & Light	A1/AA-	3376.6	2,620	2,644	100.90%	7.10%	5.21	72%	-1.31	1,316
Duke Power	Aa2/AA-	3711.4	3,155	3,164	100.30%	7.15%	5.26	67%	-0.8	1,535
Southern California Edison	A2/A+	7195.2	3,594	3,618	100.68%	6.95%	3.97	64%	-0.55	1,662
Virginia Electric	A2/A	4611.9	2,966	3,042	102.57%	7.54%	5.92	40%	0.23	1,807
Carolina Power & Light	A2/A	2684.4	1,376	1,404	102.10%	7.09%	5.85	35%	0.35	823
Tampa Electric (TECO)	Aa2/AA	995.8	252	257	102.03%	6.79%	5.48	30%	0.21	141
Florida Power	Aa3/AA-	1685.2	929	953	102.54%	7.30%	5.34	56%	-0.54	511
Pro Forma FPC			678	692	102.08%	7.00%	6.23	39%	0.20	433

Pro Forma Portfolio Results



High coupon callable paper (7.25%, 7.375%, 8.625%) is called and not refinanced with long term debt, increasing convexity and reducing average coupon. Duration increases due to the fact that paper being called had its duration calculated to the call date.

Exhibit I

Refunding Analysis

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 3/8s of 6/1/2002
Assumptions For Financial Analysis

The Outstanding Issue		The Refunding Issue	
Type of Security	DEBT		
		Redemption Method	CALL
Issue Date	6/1/72	Redemption/Refunding Date	6/1/96
Amount Outstanding (000)	$50,000	Current Market Value	100.68%
		Current Yield to Call	12.820%
Coupon Rate	7.375%	Yield to Maturity	7.236%
Initial Offer Price	101.52%	Tender or Call Price	101.54%
Yield to Maturity	7.250%	Yield to Next Call	#NUM!
		Yield to Maturity	7.056%
Maturity	6/1/02		
Years to Maturity	6.00	Cost of Tender or Call	0.000%
Mandatory Sinking Fund	No	Type of Security	DEBT
Next Payment (date)	6/1/00		
Annual Payment (%)	22.50%	Maturity	6/1/02
		Years to Maturity	6.00
Next Call Date	6/1/96		
Next Call Price	101.54%	Mandatory Sinking Fund	NO
		Starting (date)	
Expenses of Issue (000)		Annual Payment (%)	
Underwriting Commission	$438		
Estimated Expenses	250	Interest Rate of Refunding Issue	6.750%
Total	$688		
		Underwriting Commission	0.600%
Unamortized Expenses	$137	At Next Call	0.600%
		Expenses of Issue (000)	
Discount (Premium) Upon Issue	($760)	Underwriting Commission	$300
Unamortized Amount	($152)	Estimated Expenses	100
		Total	$400

Other

Marginal Tax Rate	35.00%	After-tax Cost of Capital for PV Calculations	
		Low Rate	4.23%
Common Shares Outstanding	96,150	Base Case	4.39%
		High Rate	4.55%

Finance Redemption Premium NO

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 3/8s of 6/1/2002

Upfront Costs Associated With Redemption and Refunding

Costs (000):	Non-cash Book Entries	Pre-tax Cash Costs	Tax Savings	After-tax Cash Cost
Call/Tender Premium		$770	$270	$501
Expense of Redemption Issue		0	0	0
Underwriting Commission - New Issue		300		300
Expenses - New Issue		100		100
Unamortized Discount (Premium) - Old Issue	(152)		(53)	53
Unamortized Expense - Old Issue	137		48	(48)
Accrued Interest/ Dividends - Old Issue			0	0
Totals	($14)	$1,170	$264	$906

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 3/8s of 6/1/2002

Redemption/Refunding Sensitivity Analysis

Breakeven Refunding Coupon Using Varying Retirement Prices And Discount Rates to Achieve ar

Retirement Price	Discount Rate After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)
	4.23%	6.50%	4.39%	6.75%	4.55%	7.00%
100.54%	7.30%		7.30%		7.29%	
101.54%	7.24%		$\boxed{7.23\%}$		7.23%	
102.54%	7.18%		7.17%		7.17%	

Net Present Value Using Varying Refinancing and Discount Rates and a Retirement 101.54%

Refunding Issue Coupon Rate	Discount Rate After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)
	4.23%	6.50%	4.39%	6.75%	4.55%	7.00%
6.50%	$4,153		$4,153		$4,050	
6.75%	2,837		$\boxed{2,684}$		2,611	
7.00%	1,366		1,271		1,226	

Breakeven Refunding Coupon (Versus NPV's Above) at the Next Call I 6/1/96
Using Varying Refinancing and Discount Rates and a Retirement Price 101.54%

Refunding Issue Coupon Rate	Discount Rate After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)
	4.23%	6.50%	4.39%	6.75%	4.55%	7.00%
6.50%	6.52%		6.52%		6.52%	
6.75%	6.76%		$\boxed{6.76\%}$		6.77%	
7.00%	7.01%		7.01%		7.01%	

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 3/8s of 6/1/2002

Impact of Retirement & Refunding on Net Income

Calculation of Redemption Costs		
Call/Tender Premium - After-tax		$501
Expense of Call/Tender - After-tax		0
Plus: Unamort. Discount (Premium) Old Issue - After-tax		(99)
Unamort. Costs Old Issue - After-tax		89
Total Redemption/Tender Costs		$491
Annual Amortization (over	6 years)	$82

		Period Ended			
	12/30/96	12/30/97	12/30/98	12/31/99	12/30/00
After-tax Cost of Outstanding Issue					
Interest/Dividend	$2,143	$3,688	$3,688	$3,688	$3,688
Amort.: Discount (Premium)	0	0	0	0	0
Expenses	13	23	23	23	23
Total Pre-tax Cost	2,156	3,710	3,710	3,710	3,710
Income Tax Effect @	35.00%	35.00%	35.00%	35.00%	35.00%
After-tax Cost	$1,402	$2,412	$2,412	$2,412	$2,412
After-tax Cost of Refunding Issue					
Interest/Dividend	$1,961	$3,375	$3,375	$3,375	$3,375
Cost of Premium @ New Issue Rate	30	52	52	52	52
Amort.: Issuance Costs	39	67	67	67	67
Total Pre-tax Cost	2,030	3,494	3,494	3,494	3,494
Income Tax Effect @	35.00%	35.00%	35.00%	35.00%	35.00%
After-tax Cost	$1,320	$2,271	$2,271	$2,271	$2,271
Impact on Net Income					
Plus: Cost of Outstanding Issue	$1,402	$2,412	$2,412	$2,412	$2,412
Less: Cost of Refunding Issue	1,320	2,271	2,271	2,271	2,271
Less: Cost of Redemption	48	82	82	82	82
Impact on Net Income	$34	$59	$59	$59	$59
Impact Per Share (96,150 shares)	$0.0004	$0.0006	$0.0006	$0.0006	$0.0006

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 3/8s of 6/1/2002
Impact of Redemption/Tender & Refunding on Revenue Requirements

	Period Ended				
	12/30/96	12/30/97	12/30/98	12/31/99	12/30/00
Pre-tax Cost of Outstanding Issue					
Interest/Dividend	$2,143	$3,688	$3,688	$3,688	$3,688
Amort.: Discount (Premium)	0	0	0	0	0
Expenses	13	23	23	23	23
Total Pre-tax Cost	$2,156	$3,710	$3,710	$3,710	$3,710
Pre-tax Cost of Refunding Issue					
Interest/Dividend	$1,961	$3,375	$3,375	$3,375	$3,375
Amort.: Issuance Costs	39	67	67	67	67
Total Pre-tax Cost	$2,000	$3,442	$3,442	$3,442	$3,442
Impact on Revenue Requirements					
Less: Cost of Outstanding Issue	$2,156	$3,710	$3,710	$3,710	$3,710
Plus: Cost of Refunding Issue	2,000	3,442	3,442	3,442	3,442
Plus: Recovery of Redemption Costs	122	170	162	154	146
Impact on Revenue Requirements	($34)	($98)	($107)	($115)	($123)
Summary of Redemption Cost Recovery					
Beginning Balance Redemption Costs	756	682	556	430	304
Cost of Carry	49	44	36	28	20
Amortization	73	126	126	126	126
Total Recovery	122	170	162	154	146
Ending Balance	682	556	430	304	179

Note: Recovery of Redemption Costs assumed over 6 years with a pre-tax rate of return of 6.50% .

NPV Savings of Revenue Requirements($000) $2,293

Florida Power Corporation

Preferred Retirement and Replacement Analysis
8 5/8s of 11/1/21
Assumptions For Financial Analysis

The Outstanding Issue	
Type of Security	DEBT
Issue Date	10/30/91
Amount Outstanding (000)	$150,000
Coupon Rate	8.625%
Initial Offer Price	98.75%
Yield to Maturity	8.743%
Maturity	11/1/21
Years to Maturity	25.00
Mandatory Sinking Fund	No
Next Payment (date)	6/1/00
Annual Payment (%)	22.50%
Next Call Date	11/1/96
Next Call Price	105.54%
Expenses of Issue (000)	
Underwriting Commission	$1,313
Estimated Expenses	250
Total	$1,563
Unamortized Expenses	$1,302
Discount (Premium) Upon Issue	$1,875
Unamortized Amount	$1,562

The Refunding Issue	
Redemption Method	CALL
Redemption/Refunding Date	11/1/96
Current Market Value	106.99%
Current Yield to Call	5.721%
Yield to Maturity	7.980%
Tender or Call Price	**105.54%**
Yield to Next Call	#NUM!
Yield to Maturity	8.105%
Cost of Tender or Call	0.000%
Type of Security	DEBT
Maturity	11/1/21
Years to Maturity	25.00
Mandatory Sinking Fund	NO
Starting (date)	
Annual Payment (%)	
Interest Rate of Refunding Issue	**7.600%**
Underwriting Commission	0.875%
At Next Call	0.875%
Expenses of Issue (000)	
Underwriting Commission	$1,313
Estimated Expenses	100
Total	$1,413

Other

Marginal Tax Rate	35.00%	After-tax Cost of Capital for PV Calculations	
		Low Rate	4.78%
Common Shares Outstanding	96,150	Base Case	4.94%
		High Rate	5.10%

Finance Redemption Premium NO

Florida Power Corporation

Preferred Retirement and Replacement Analysis
8 5/8s of 11/1/21

Upfront Costs Associated With Redemption and Refunding

Costs (000):	Non-cash Book Entries	Pre-tax Cash Costs	Tax Savings	After-tax Cash Cost
Call/Tender Premium		$8,310	$2,908	$5,401
Expense of Redemption Issue		0	0	0
Underwriting Commission - New Issue		1,313		1,313
Expenses - New Issue		100		100
Unamortized Discount (Premium) - Old Issue	1,562		547	(547)
Unamortized Expense - Old Issue	1,302		456	(456)
Accrued Interest/ Dividends - Old Issue			0	0
Totals	$2,864	$9,722	$3,911	$5,812

Florida Power Corporation

Preferred Retirement and Replacement Analysis
8 5/8s of 11/1/21

Redemption/Refunding Sensitivity Analysis

Breakeven Refunding Coupon Using Varying Retirement Prices And Discount Rates to Achieve ar

	Discount Rate					
	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)
Retirement Price	4.78%	7.35%	4.94%	7.60%	5.10%	7.85%
104.54%	7.30%		7.30%		7.29%	
105.54%	7.24%		$\boxed{7.23\%}$		7.23%	
106.54%	7.18%		7.17%		7.17%	

Net Present Value Using Varying Refinancing and Discount Rates and a Retirement 105.54%

	Discount Rate					
	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)
Refunding Issue Coupon Rate	4.78%	7.35%	4.94%	7.60%	5.10%	7.85%
7.35%	$4,153		$4,153		$4,050	
7.60%	2,837		$\boxed{2,684}$		2,611	
7.85%	1,366		1,271		1,226	

Breakeven Refunding Coupon (Versus NPV's Above) at the Next Call I 11/1/96
Using Varying Refinancing and Discount Rates and a Retirement Price 105.54%

	Discount Rate					
	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)
Refunding Issue Coupon Rate	4.78%	7.35%	4.94%	7.60%	5.10%	7.85%
7.35%	6.52%		6.52%		6.52%	
7.60%	6.76%		$\boxed{6.76\%}$		6.77%	
7.85%	7.01%		7.01%		7.01%	

Florida Power Corporation

Preferred Retirement and Replacement Analysis
8 5/8s of 11/1/21

Impact of Retirement & Refunding on Net Income

Calculation of Redemption Costs		
Call/Tender Premium - After-tax		$5,401
Expense of Call/Tender - After-tax		0
Plus: Unamort. Discount (Premium) Old Issue - After-tax		1,015
Unamort. Costs Old Issue - After-tax		846
Total Redemption/Tender Costs		$7,263
Annual Amortization (over	25 years)	$291

	Period Ended				
	12/30/96	12/30/97	12/30/98	12/31/99	12/30/00
After-tax Cost of Outstanding Issue					
Interest/Dividend	$2,099	$12,938	$12,938	$12,938	$12,938
Amort.: Discount (Premium)	0	0	0	0	0
Expenses	8	52	52	52	52
Total Pre-tax Cost	2,107	12,990	12,990	12,990	12,990
Income Tax Effect @	35.00%	35.00%	35.00%	35.00%	35.00%
After-tax Cost	$1,370	$8,443	$8,443	$8,443	$8,443
After-tax Cost of Refunding Issue					
Interest/Dividend	$1,849	$11,400	$11,400	$11,400	$11,400
Cost of Premium @ New Issue Rate	102	632	632	632	632
Amort.: Issuance Costs	9	57	57	57	57
Total Pre-tax Cost	1,961	12,088	12,088	12,088	12,088
Income Tax Effect @	35.00%	35.00%	35.00%	35.00%	35.00%
After-tax Cost	$1,275	$7,857	$7,857	$7,857	$7,857
Impact on Net Income					
Plus: Cost of Outstanding Issue	$1,370	$8,443	$8,443	$8,443	$8,443
Less: Cost of Refunding Issue	1,275	7,857	7,857	7,857	7,857
Less: Cost of Redemption	47	291	291	291	291
Impact on Net Income	$48	$295	$295	$295	$295
Impact Per Share (96,150 shares)	$0.0005	$0.0031	$0.0031	$0.0031	$0.0031

Florida Power Corporation

Preferred Retirement and Replacement Analysis
8 5/8s of 11/1/21
Impact of Redemption/Tender & Refunding on Revenue Requirements

	Period Ended				
	12/30/96	12/30/97	12/30/98	12/31/99	12/30/00
Pre-tax Cost of Outstanding Issue					
Interest/Dividend	$2,099	$12,938	$12,938	$12,938	$12,938
Amort.: Discount (Premium)	0	0	0	0	0
Expenses	8	52	52	52	52
Total Pre-tax Cost	$2,107	$12,990	$12,990	$12,990	$12,990
Pre-tax Cost of Refunding Issue					
Interest/Dividend	$1,849	$11,400	$11,400	$11,400	$11,400
Amort.: Issuance Costs	9	57	57	57	57
Total Pre-tax Cost	$1,858	$11,457	$11,457	$11,457	$11,457
Impact on Revenue Requirements					
Less: Cost of Outstanding Issue	$2,107	$12,990	$12,990	$12,990	$12,990
Plus: Cost of Refunding Issue	1,858	11,457	11,457	11,457	11,457
Plus: Recovery of Redemption Costs	894	1,263	1,230	1,197	1,164
Impact on Revenue Requirements	$645	($270)	($303)	($336)	($369)
Summary of Redemption Cost Recovery					
Beginning Balance Redemption Costs	11,174	11,101	10,654	10,207	9,760
Cost of Carry	821	816	783	750	717
Amortizaton	73	447	447	447	447
Total Recovery	894	1,263	1,230	1,197	1,164
Ending Balance	11,101	10,654	10,207	9,760	9,313

Note: Recovery of Redemption Costs assumed over 25 years with a pre-tax rate of return of 7.35%.

NPV Savings of Revenue Requirements($000) $6,047

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 1/4s of 11/1/2002
Assumptions For Financial Analysis

The Outstanding Issue

Type of Security	DEBT
Issue Date	11/14/72
Amount Outstanding (000)	$50,000
Coupon Rate	7.250%
Initial Offer Price	101.00%
Yield to Maturity	7.168%
Maturity	11/1/02
Years to Maturity	6.42
Mandatory Sinking Fund	No
Next Payment (date)	6/1/00
Annual Payment (%)	22.50%
Next Call Date	6/1/96
Next Call Price	101.43%
Expenses of Issue (000)	
Underwriting Commission	$438
Estimated Expenses	250
Total	$688
Unamortized Expenses	$147
Discount (Premium) Upon Issue	($500)
Unamortized Amount	($107)

The Refunding Issue

Redemption Method	CALL
Redemption/Refunding Date	6/1/96
Current Market Value	100.08%
Current Yield to Call	15.946%
Yield to Maturity	7.234%
Tender or Call Price	101.43%
Yield to Next Call	#NUM!
Yield to Maturity	6.970%
Cost of Tender or Call	0.000%
Type of Security	DEBT
Maturity	6/1/02
Years to Maturity	6.00
Mandatory Sinking Fund	NO
Starting (date)	
Annual Payment (%)	
Interest Rate of Refunding Issue	6.750%
Underwriting Commission	0.600%
At Next Call	0.600%
Expenses of Issue (000)	
Underwriting Commission	$300
Estimated Expenses	100
Total	$400

Other

Marginal Tax Rate	35.00%	After-tax Cost of Capital for PV Calculations	
		Low Rate	4.23%
Common Shares Outstanding	96,150	Base Case	4.39%
		High Rate	4.55%

Finance Redemption Premium NO

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 1/4s of 11/1/2002

Upfront Costs Associated With Redemption and Refunding

Costs (000):	Non-cash Book Entries	Pre-tax Cash Costs	Tax Savings	After-tax Cash Cost
Call/Tender Premium		$715	$250	$465
Expense of Redemption Issue		0	0	0
Underwriting Commission - New Issue		300		300
Expenses - New Issue		100		100
Unamortized Discount (Premium) - Old Issue	(107)		(37)	37
Unamortized Expense - Old Issue	147		52	(52)
Accrued Interest/ Dividends - Old Issue			0	0
Totals	$40	$1,115	$264	$851

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 1/4s of 11/1/2002

Redemption/Refunding Sensitivity Analysis

Breakeven Refunding Coupon Using Varying Retirement Prices And Discount Rates to Achieve ar

	Discount Rate					
	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)
Retirement Price	4.23%	6.50%	4.39%	6.75%	4.55%	7.00%
100.43%	7.30%		7.30%		7.29%	
101.43%	7.24%		7.23%		7.23%	
102.43%	7.18%		7.17%		7.17%	

Net Present Value Using Varying Refinancing and Discount Rates and a Retirement 101.43%

	Discount Rate					
	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)
Refunding Issue Coupon Rate	4.23%	6.50%	4.39%	6.75%	4.55%	7.00%
6.50%	$4,153		$4,153		$4,050	
6.75%	2,837		2,684		2,611	
7.00%	1,366		1,271		1,226	

Breakeven Refunding Coupon (Versus NPV's Above) at the Next Call I 6/1/96
Using Varying Refinancing and Discount Rates and a Retirement Price 101.43%

	Discount Rate					
	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)	After-Tax	(Pre-Tax)
Refunding Issue Coupon Rate	4.23%	6.50%	4.39%	6.75%	4.55%	7.00%
6.50%	6.52%		6.52%		6.52%	
6.75%	6.76%		6.76%		6.77%	
7.00%	7.01%		7.01%		7.01%	

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 1/4s of 11/1/2002

Impact of Retirement & Refunding on Net Income

Calculation of Redemption Costs		
Call/Tender Premium - After-tax		$465
Expense of Call/Tender - After-tax		0
Plus: Unamort. Discount (Premium) Old Issue - After-tax		(70)
Unamort. Costs Old Issue - After-tax		96
Total Redemption/Tender Costs		$491
Annual Amortization (over	6 years)	$82

	Period Ended				
	12/30/96	12/30/97	12/30/98	12/31/99	12/30/00
After-tax Cost of Outstanding Issue					
Interest/Dividend	$2,107	$3,625	$3,625	$3,625	$3,625
Amort.: Discount (Premium)	(15)	(35)	(37)	(40)	(43)
Expenses	13	23	23	23	23
Total Pre-tax Cost	2,105	3,613	3,611	3,608	3,605
Income Tax Effect @	35.00%	35.00%	35.00%	35.00%	35.00%
After-tax Cost	$1,368	$2,349	$2,347	$2,345	$2,343
After-tax Cost of Refunding Issue					
Interest/Dividend	$1,961	$3,375	$3,375	$3,375	$3,375
Cost of Premium @ New Issue Rate	28	48	48	48	48
Amort.: Issuance Costs	39	67	67	67	67
Total Pre-tax Cost	2,028	3,490	3,490	3,490	3,490
Income Tax Effect @	35.00%	35.00%	35.00%	35.00%	35.00%
After-tax Cost	$1,318	$2,268	$2,268	$2,268	$2,268
Impact on Net Income					
Plus: Cost of Outstanding Issue	$1,368	$2,349	$2,347	$2,345	$2,343
Less: Cost of Refunding Issue	1,318	2,268	2,268	2,268	2,268
Less: Cost of Redemption	48	82	82	82	82
Impact on Net Income	$2	($2)	($3)	($5)	($7)
Impact Per Share (96,150 shares)	$0.0000	($0.0000)	($0.0000)	($0.0001)	($0.0001)

Florida Power Corporation

Preferred Retirement and Replacement Analysis
7 1/4s of 11/1 2002
Impact of Redemption/Tender & Refunding on Revenue Requirements

	Period Ended				
	12/30/96	12/30/97	12/30/98	12/31/99	12/30/00
Pre-tax Cost of Outstanding Issue					
Interest/Dividend	$2,107	$3,625	$3,625	$3,625	$3,625
Amort.: Discount (Premium)	(15)	(35)	(37)	(40)	(43)
Expenses	13	23	23	23	23
Total Pre-tax Cost	$2,105	$3,613	$3,611	$3,608	$3,605
Pre-tax Cost of Refunding Issue					
Interest/Dividend	$1,961	$3,375	$3,375	$3,375	$3,375
Amort.: Issuance Costs	39	67	67	67	67
Total Pre-tax Cost	$2,000	$3,442	$3,442	$3,442	$3,442
Impact on Revenue Requirements					
Less: Cost of Outstanding Issue	$2,105	$3,613	$3,611	$3,608	$3,605
Plus: Cost of Refunding Issue	2,000	3,442	3,442	3,442	3,442
Plus: Recovery of Redemption Costs	122	170	162	154	146
Impact on Revenue Requirements	$17	($1)	($7)	($12)	($18)
Summary of Redemption Cost Recovery					
Beginning Balance Redemption Costs	755	682	556	430	304
Cost of Carry	49	44	36	28	20
Amortizaton	73	126	126	126	126
Total Recovery	122	170	162	154	146
Ending Balance	682	556	430	304	178

Note: Recovery of Redemption Costs assumed over 6 years with a pre-tax rate of return of 6.50% .

NPV Savings of Revenue Requirements($000) $424

Exhibit II

Call Monetization Strategies

Call Monetization of 8.625% due 11/1/21

High Coupon Debt Profile

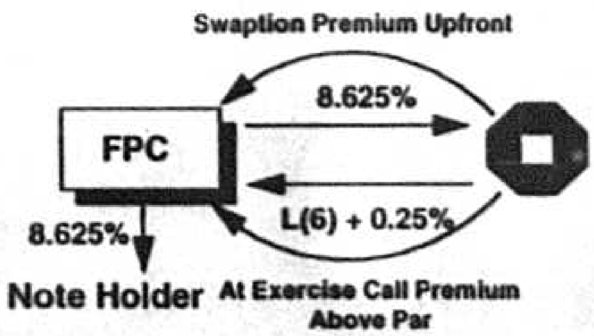
The Florida Power Corp. ("FPC") currently has $150,000,000 of its 8.625% notes due 11/1/21 outstanding. These notes are callable starting 11/1/96 on a sliding premium scale until 11/1/11 when it is callable at par.

Embedded Option

Upon issuing the note FPC bought a call option from the note holders. The value of this call option is greater when rates are low relative to the coupon on the note. FPC is therefore exposed to an erosion in the value of its call option in an increasing interest rate environment.

Construction

The tactical construction to protect the value of the call involves executing a swaption that commences on the call date of the note and has a maturity tailored to the issuer's call-period preference.



Call Monetization

This strategy will generate an upfront cash receipt for FPC that allows them to capture the current high value of their call option. When applied over the life of the swaption or issue this receipt will significantly lower FPC' financing costs.

Call Monetization of 8.625% due 11/1/21

Advantageu

FPC receives a significant premium upfront.

FPC will not have to pay a premium to call the bonds in the future.

The intrinsic value of the call is protected against market fluctuations (i.e. rising interest rates).

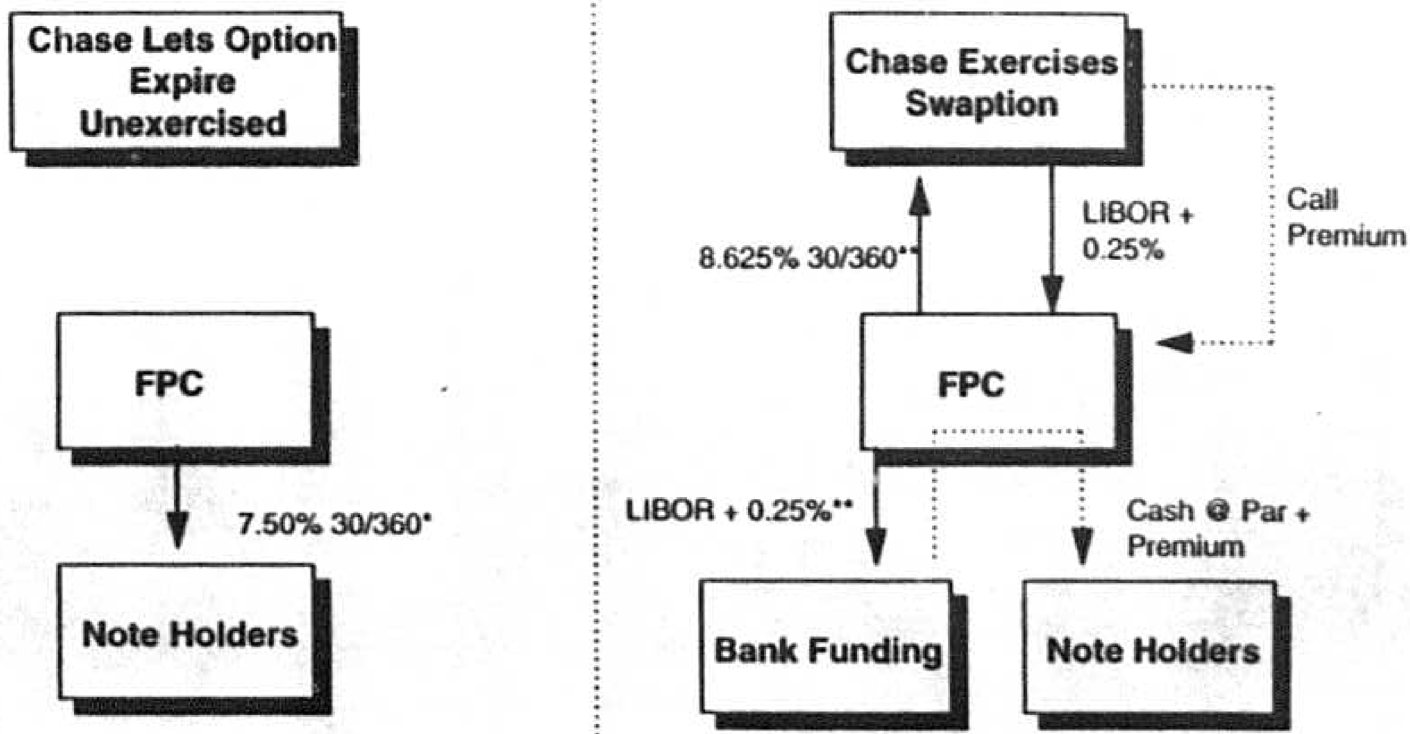
The premium effectively reduces FPC' cost of funding by 112 bps for 25 yrs.

Disadvantages

FPC' right to call its bonds is subject to exercise of the swaption by Chase. Assuming the current market yield curve and option pricing parameters remain constant, Chase would be inclined to exercise on 11/1/96 if the 25 **year swap rate would be at or lower than 7.14%.**

Call Monetization of 8.625% due 11/1/21

High Interest Rates | *After Call Date* | **Low Interest Rates**



* - Assumes $19MM premium amortized over the remaining life of the issue (8.6255%-1.12%).

** - 7.50% assuming amortization of premium over the remaining life of the issue

Call Monetization of 8.625% due 11/1/21

Accounting issues

One method of accounting for this structure:

The initial cash premium is accounted for as a debit to the Cash account. This is offset by a credit to the Other Liabilities account.

Dr Cash
Cr Other Liabilities

Going forward, the swaption is marked to market and the Other Liabilities account is debited or credited accordingly against the Other Inc/Exp ledger.

Dr Other Liabilities
Cr Other Income (P/L)

OR

Dr Other Expenses (P/L)
Cr Other Liabilities

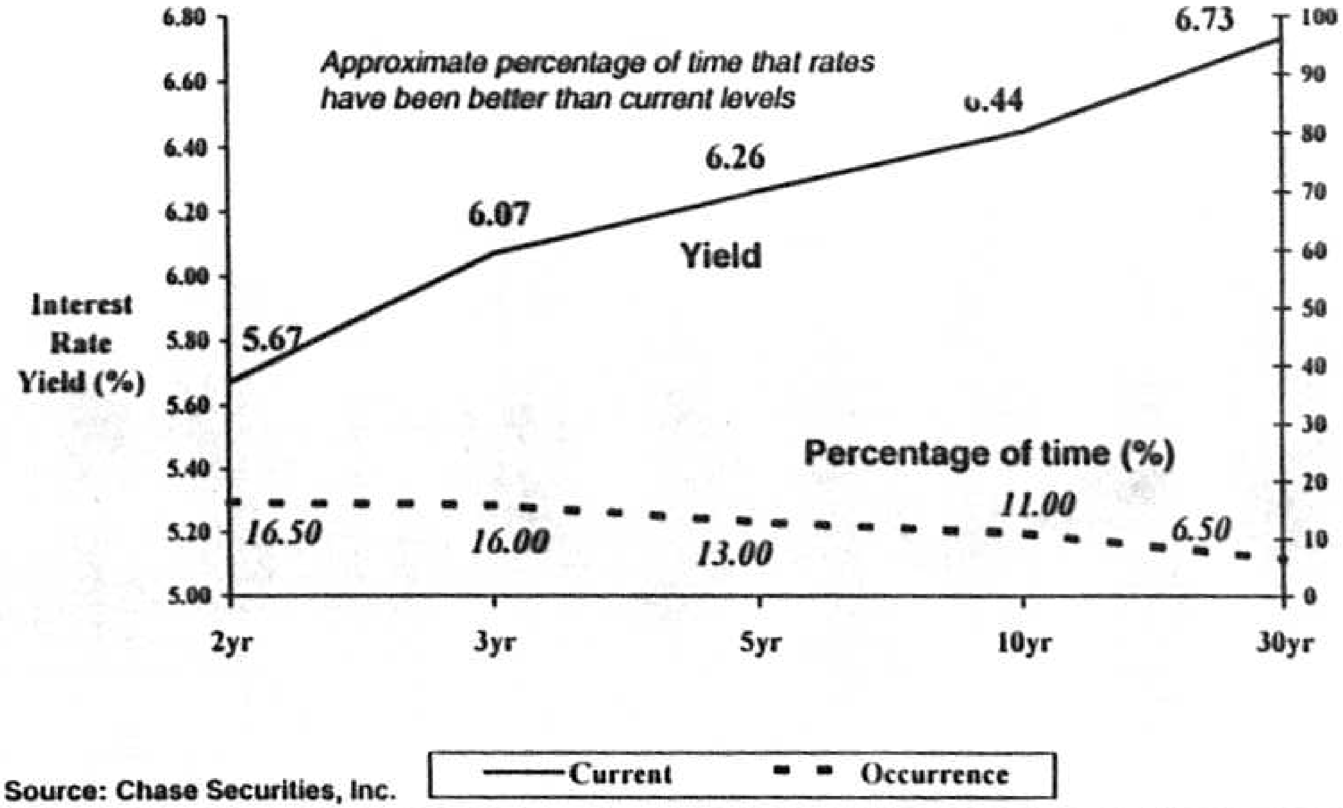
If the swaption is exercised, the swap is eligible for hedge accounting if it can offset bank debt. If no bank debt exists, the mark to market on the swap will continue to be accounted for as shown above. Unwinding the swap or swaption before expiry will result in the realization of gains or losses accordingly.

** Chase has determined this accounting treatment solely on its own methodology. Chase is providing the information as an accommodation and makes no representation or warranty regarding it. Please check with your own accountants.*

Exhibit III

Chase Medium Term Economic Outlook

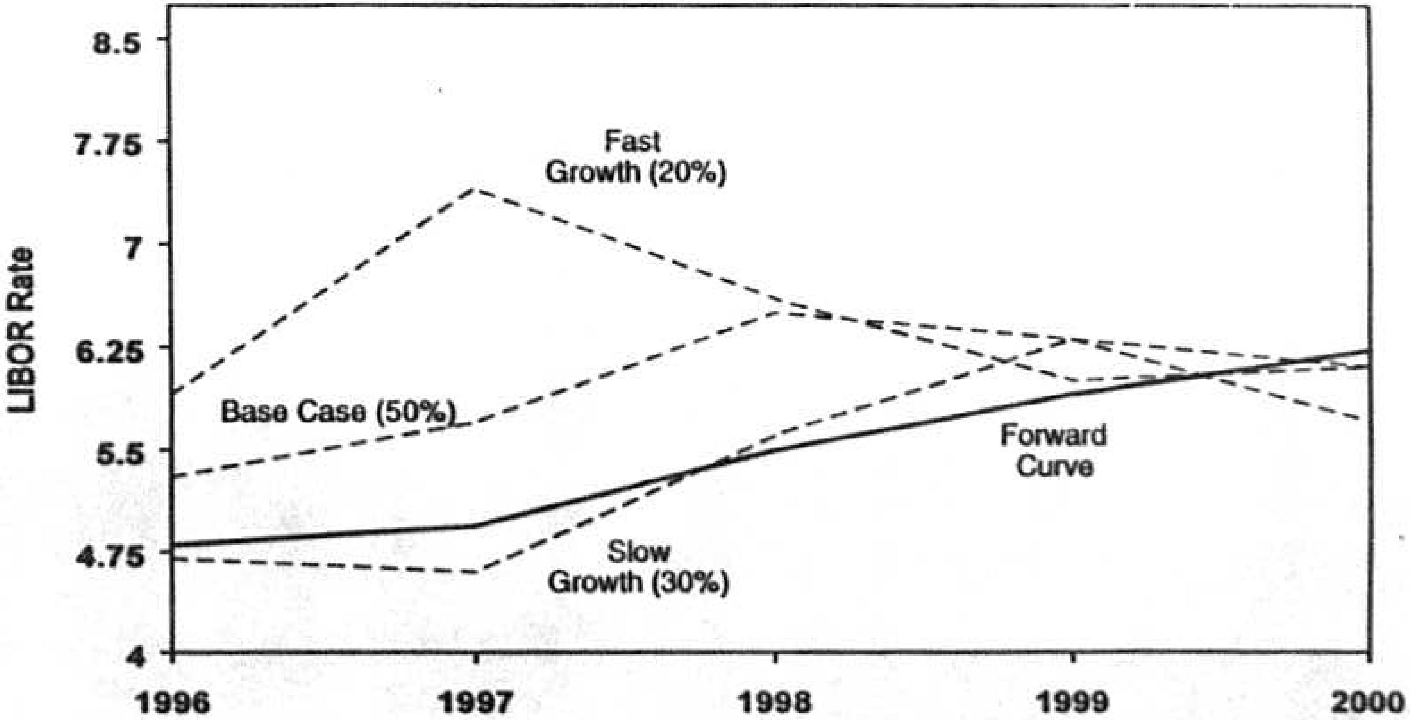
Treasury Yield Curve



Source: Chase Securities, Inc.

Chase Economics Group April 1996

3-MONTH LIBOR Scenarios



- The Chase Economic Group forecasts where 3-month LIBOR will average each year in different economic scenarios over the next five years.
- The forward curve shows where the market implied mid-year 3-month LIBOR is over each of the next five years.

MEDIUM TERM U.S. ECONOMIC OUTLOOK : 1996-2000

Base Case Scenario (50% Probability)

	1996	1997	1998	1999	2000
Real GDP	2.1	2.6	1.5	1.5	3.5
CPI	3.2	3.4	3.8	3.6	3.2
Fed Funds	5.1	5.5	6.2	6.0	5.5
LIBOR, 3-Mo.	5.3	5.7	6.5	6.3	5.7
T-Bond, 10-Yr	5.8	6.3	7.2	7.2	6.9

- This is a successful "soft-landing scenario" in which the tightening implemented in 1994 and 1995 turns out to be enough to slow the economy to its potential growth rate in 1996.
- Since the unemployment rate is relatively low, inflation will accelerate slightly.
- The Fed holds policy steady in the second half of 1996, given moderate growth and inflation.
- This scenario is most likely to be achieved if growth overseas isn't too strong and the federal budget deficit is gradually reduced, but not quite balanced over the next five years.

Note: The GDP forecast is now using the BEA's chain-weighted GDP series. GDP and CPI forecasts are Q4 over Q4 growth rates. Interest rate forecasts are annual averages.

MEDIUM TERM U.S. ECONOMIC OUTLOOK : 1996-2000

Slow Growth Alternative (30% Probability)

	1996	1997	1998	1999	2000
Real GDP	1.4	2.0	2.8	2.8	1.5
CPI	2.8	2.8	2.8	3.2	3.2
Fed Funds	4.5	4.4	5.3	6.0	5.8
LIBOR, 3-Mo.	4.7	4.6	5.6	6.3	6.1
T-Bond, 10-Yr	5.5	5.3	6.5	7.3	7.2

- Growth falls to the 1.0-1.5% range in 1996, mostly because of the lagged effects of the Fed tightening implemented in 1994 and early 1995. In addition, exports are weak because of poor growth in the U.S.'s key trading partners.
- The Fed cuts the fed funds rate to 4.0% by the second half of 1996.
- By 1997, the lagged effects of the monetary tightening implemented in 1994 wear off and the easing implemented in 1995 and 1996 start to drive growth up. The Fed starts tightening again.
- Fiscal policy is mildly contractionary in the 1996-98 period.
- Oil prices are assumed to remain stable in the $15-20 per barrel range throughout the forecast period.

MEDIUM TERM U.S. ECONOMIC OUTLOOK : 1996-2000

Fast Growth Alternative (20% Probability)

	1996	1997	1998	1999	2000
Real GDP	2.8	2.0	0.0	2.5	3.0
CPI	3.6	4.0	4.2	3.8	3.6
Fed Funds	5.6	7.0	6.5	5.8	5.8
LIBOR, 3-Mo.	5.9	7.4	6.6	6.0	6.1
T-Bond, 10-Yr	6.8	7.8	7.5	6.9	7.5

- In this scenario, a combination of factors leads to stronger growth in 1996. These factors would include stronger growth overseas and a weak dollar, which would stimulate exports. Another possible contributing factor would be the lack of an agreement on cutting the deficit. The housing market would also respond to the strong bond rally of 1995.

- Such a confluence of events would lead to 2.5-3.0% growth in 1996. The unemployment rate would drop below 5.5% in 1996, making the labor market about as tight as in the late 1980s. Inflation would accelerate sharply, exacerbated by a rise in oil prices to $30 per barrel by 1996 in reaction to strong worldwide demand.

- By mid 1996, the Fed would resume tightening. By early 1998, this would produce a fairly severe recession.

- Concerns about inflation and lack of progress in reducing the federal budget deficit would probably push bond yields to 8.0% or higher in 1997.

Exhibit IV

Duration and Convexity Explained

Duration & Convexity Summary

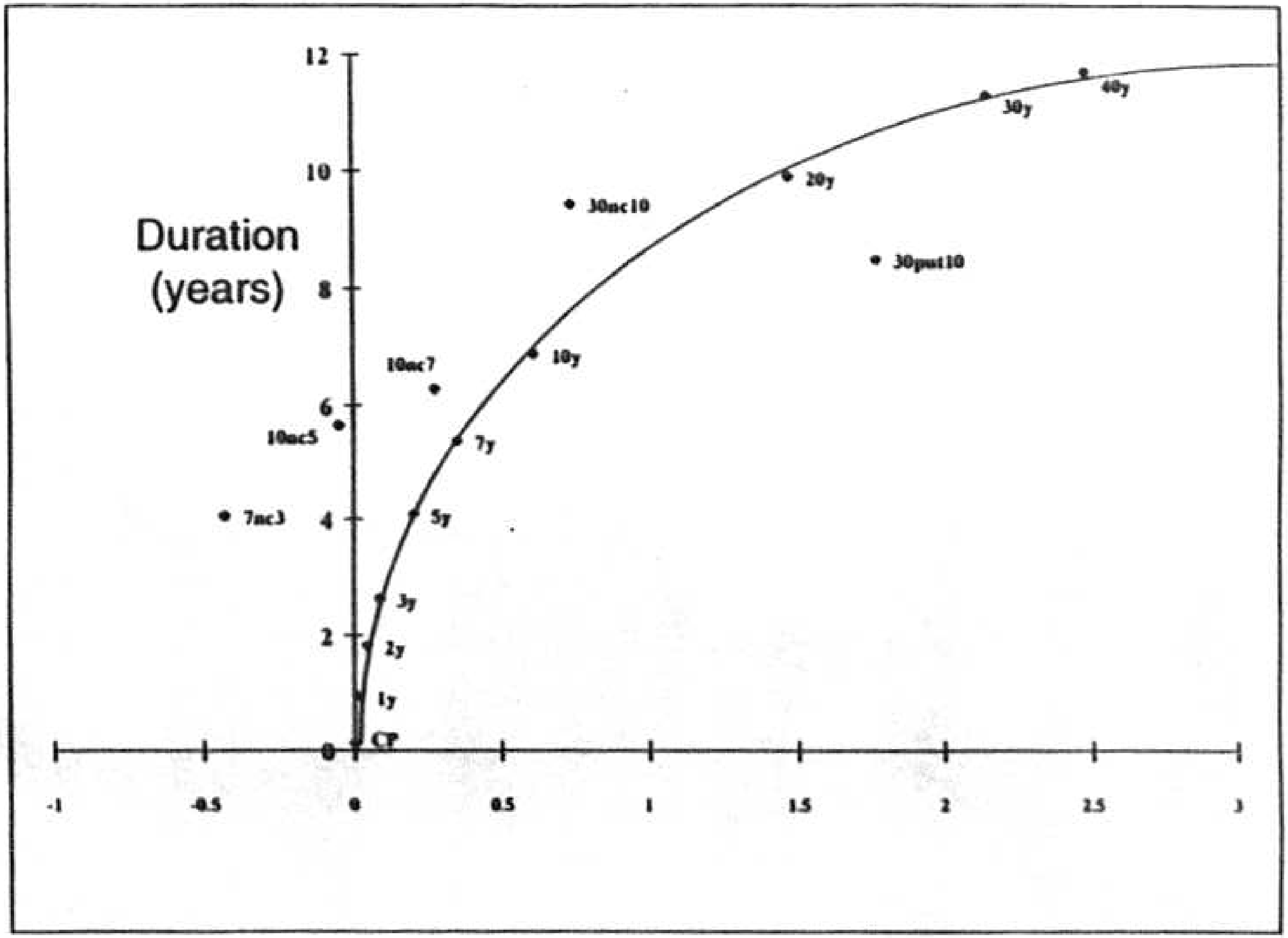
•When rates move significantly, duration becomes an inadequate measure of price movements for bullet paper. In order to estimate the true price sensitivity of a bond, convexity should be considered. Positive convexity dictates that, regardless of which direction rates move, a bond's price performance is better than just the duration term would imply.

•All other things being equal, investors want higher convexity (better price performance in volatile markets) and issuers want lower convexity. Investors look at duration and convexity as indicators of how their investments will perform.

•Convexity is often an indication of call flexibility. A company with a lower overall portfolio convexity is likely to have more call flexibility in that portfolio.

•Treasurers should have an understanding of how the market value of their liabilities will be affected by changes in interest rates. Duration and convexity are useful in this regard. They also provide a convenient way to compare corporate debt portfolios on both a sector and industry basis.

Bond Duration and Convexity



Duration & Convexity

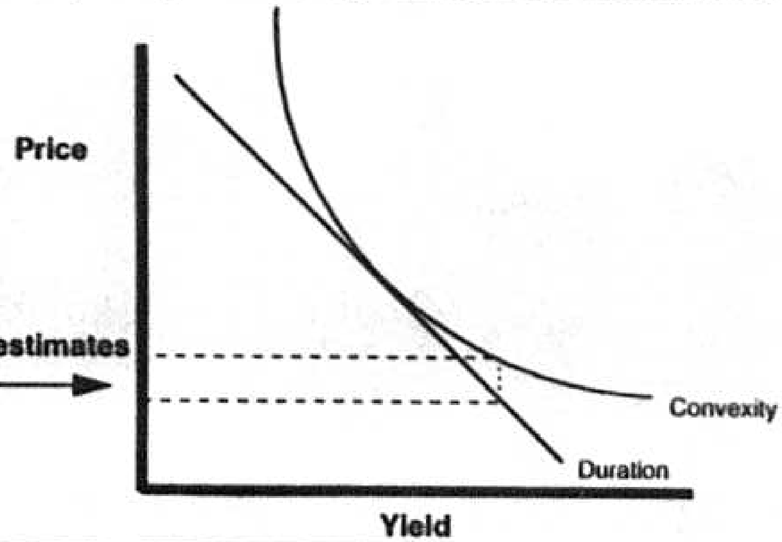
Duration and convexity are two concepts used in measuring the interest rate sensitivity of bond prices. Besides giving us the present value weighted average life of a particular bond's cash flows, modified duration also provides a reasonable estimate of the percentage change in the price of a bond for a change in its yield. For example, if we wanted to determine how much the price of a bond with a modified duration of 9.9 would change for a 1% change in yield, we could use the formula...

Percentage Change in Price = - Modified Duration x Percentage Change in Yield or...

9.9 x 1% = 9.9%

However, true price performance is not linear but convex. So, while small price changes can be estimated by modified duration, convexity dictates that estimates for large changes in price will overstate the amount of price declines in rising yield environments and understate price appreciation when yields fall. The more convex a bond is, the better a bond will perform in volatile markets (when yields move significantly in one direction or the other). This is why investors focus on convexity.

Amount of error in price change estimates due to convexity



Duration & Convexity

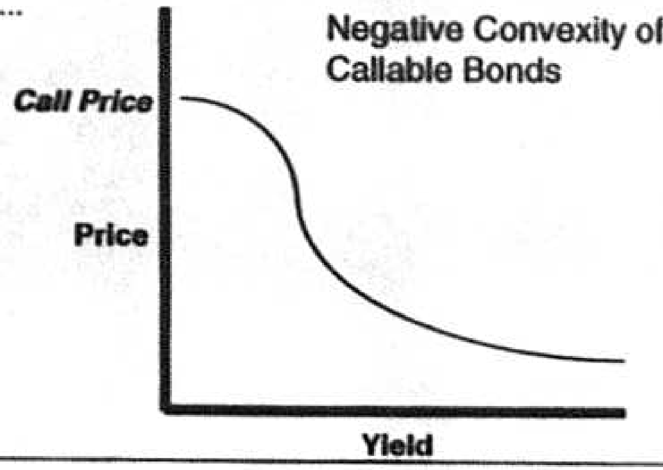
Thus, the true change in price is...

Change in Price = - Modified Duration x Change in Yield + 0.5 x Convexity x (Change in Yield $)^2$

Note that because the convexity term is multiplied by the change in yield squared, it is always additive for bonds with positive convexity, giving the price/yield curve its convex slope. For small changes in yield, the convexity term is immaterial. For larger changes in yield it is more significant.

Example:
•For an 8% 30 year bond priced at par, modified duration is 11.3, convexity is 2.14.
•If yields drop to 7.99%, the bond price rises to 100.113% (convexity term immaterial).
•If yields drop by 0.5% to 7.5%, the bond price rises to 105.93%.
•Duration increases the price by 5.65% (11.3% x .5).
•Convexity increases the price by an additional .27% (.5 x 2.14 x $.5^2$)

Convexity becomes even more important for callable bonds. A callable bond will drop in price if rates rise, but will only rise a certain amount when rates fall (due to the call option). This is because the likelihood of a bond being called increases as rates fall, causing the market to begin pricing an issue "to the call". This is when we see one of the effects of negative convexity. See below...



Formulae

Macaulay duration (in years) $= \sum_{t=1}^{n} \frac{t \times PVCF_t}{k \times PVTCF_t}$

Modified duration $= \frac{\text{Macaulay duration}}{1 + (\text{Yield}/k)}$

Percentage change = **- Modified duration x Yield change x 100**

Convexity (in years) $= \frac{1}{[1 + (y/k)]^2} \sum_{t=1}^{n} \frac{t \times (t+1) PVCF_t}{k^2 \times PVTCF}$

Approximate percentage price change due to convexity = **0.5 x Convexity x (Yield change)^2 x 100**

Estimated percentage price change = **- Modified Duration x Yield change x 100 + .5 x Convexity x (Yield change)^2 x 100**

Where

k = Number of periods (payments) per year (e.g., $k = 2$ for semiannual bonds).
n = Number of periods until maturity (years to maturity x k).
t = Period in which the cash flow is expected to be received ($t = 1,\dots,n$)
$PVCF_t$ = Present value of cash flow in period t discounted at the YTM.
PVTCF = Total present value of the cash flow of the bond where the present value is determined using the YTM.

RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO FLORIDA POWER CORPORATION

ATTACHMENT TO NUMBERS TWO & THREE

STANDARD & POOR'S
Utilities Rating Service

CORPORATE CREDIT RATING	AA-
OUTLOOK	STABLE

FLORIDA POWER CORP.

Analyst: Barbara A. Eiseman (212) 208-1656; Company contact: James Smallwood (813) 866-5647

OUTSTANDING RATINGS

Florida Power Corp.	
Commercial paper	A-1+
Senior secured debt	AA-
Senior unsecured debt	A+
Preferred stock	A+
Progress Capital Holdings Inc.	
Commercial paper	A-1
Senior unsecured debt	A

DEBT RATING HISTORY

SENIOR DEBT	1996	AA-
	1995	AA-
	1994	AA-
	1993	AA-
	1992	AA-
	1991	AA-

OUTLOOK: STABLE
ELECTRIC BUSINESS POSITION: Above average (1)

RATIONALE

Florida Power Corp.'s ratings reflect an above average business position and healthy financial condition. Florida Power's business profile is supported by a healthy service area with above-average growth prospects, responsive Florida regulation, a diversified fuel mix, nominal Clean Air Act spending, and credit-conscious management. Furthermore, a small industrial load (about 9% of revenues) limits exposure to the possibility of retail wheeling, while the utility's geographical location gives near-term protection from competition. Rates and total energy costs are competitive within peninsular Florida but are slightly higher than the regional average. Florida Power supplements owned capacity with power purchases from neighboring utilities and from cogenerators; purchased power will provide some 27% of generation for the foreseeable future. These costs are passed through as a capacity cost recovery factor and fuel charge. Notwithstanding the likelihood for about 1.0% annual price increases to recover purchased power costs, the company's competitive position will not be noticeably affected. Florida Power will avoid any base rate relief requests for many years. Operations at the Crystal River 3 nuclear station continue to improve, with a 1995 capacity factor of 100%.

Debt leverage, including off-balance-sheet purchased power obligations, will remain high for current ratings, hovering around 51%. Yet, internal funding, funds from operations interest coverage, and funds from operations to total debt should remain healthy even throughout the construction of two gas-fired combined cycle units to become operational in 1998 and 1999. Continued strong kilowatt-hour (kWh) sales growth and aggressive cost controls should allow Florida Power to maintain pretax interest coverage, adjusted for purchased power, at levels over 3.2 times (x). Plans for nonutility activities include growing the energy-related businesses while divesting real estate and leasing assets.

OUTLOOK

A period of ratings stability for Florida Power is based on above-average sales growth, rate flexibility, limitations on rate increases, little wholesale and industrial

Financial summary (Mil. $)	1995*	1994	1993	1992	1991
Gross revenues	2,231.7	2,080.5	1,957.6	1,774.1	1,718.8
Net income from continuing operations	227.8	200.8	194.9	186.9	180.9
Funds from operations (FFO)	535.7	513.9	445.0	416.2	385.9
Net cash flow	345.6	328.1	268.1	244.1	227.0
Capital expenditures	274.2	308.6	426.4	472.9	345.9
Total capital	3,180.6	3,266.4	3,240.4	3,029.2	2,882.2
Adjusted ratios					
Pretax interest coverage (x)	3.37	3.02	2.96	2.98	N.A.
Total debt/total capital (%)	48.1	50.9	54.0	50.9	N.A.
FFO interest coverage (x)	4.56	4.36	3.99	3.99	N.A.
FFO/avg. total debt (%)	29.6	28.8	24.2	25.8	N.A.

*For 12 months ended Sept. 30 (unaudited). N.A.—Not available.

Operating summary	1994	1993	1992	1991	1990
Growth (%)					
Retail (MWh)	4.3	4.4	0.9	1.2	3.1
Retail (customers)	2.4	2.7	2.0	2.1	3.1
Capacity (MW)	7,457	6,711	6,912	6,971	6,827
Reserve margin (%)	7.2	(0.3)	(1.0)	15.1	16.5
Rates (cents/kWh)					
Residential	8.24	7.92	7.24	7.33	7.27
Commercial	5.86	5.81	5.51	5.69	5.68
Industrial	4.84	4.79	4.25	4.38	4.41

MW—Megawatts. MWh—Megawatt-hours. kWh—Kilowatt-hours.

FLORIDA POWER CORP.

exposure, aggressive cost controls, efficient operations, and healthy cash flow. However, the parent's support of riskier affiliates and large purchased power commitments restrain upside credit potential.

RECENT DEVELOPMENTS

January 1996. Allen J. Keesler, Jr., president and chief executive officer of Florida Power since 1988, announced that he will retire on April 1, 1996. To begin an orderly succession of top management for Florida Progress Corp. and Florida Power, other management changes were announced (*see Management*).

December 1995. Florida Power and the city of Clearwater signed a new 30-year franchise agreement. Clearwater is the company's second-largest franchise customer and accounts for approximately 5% of annual revenues. No franchise agreement representing significant revenues are due to expire for the next several years. Including a $12.5 million contribution made in December, Florida Progress contributed $50 million in 1995 to Florida Power from the proceeds of the holding company's public stock offerings and the Progress Plus Stock Plan.

November 1995. The Florida Public Service Commission (PSC) approved its staff's recommendation for higher estimated total future decommissioning costs ($2.0 billion, or $404.6 million in 1995 dollars) than that presented in Florida Power's filing. Florida Power is already establishing a funded reserve to pay for decommissioning, which is $165 million at Dec. 31, 1995.

October 1995. Florida Power announced an agreement with Seminole Electric Cooperative to provide an additional 455 megawatts (MW) of wholesale power. The contract begins in 1999 for a three-year period. Also in October, the Nuclear Regulatory Commission (NRC) issued its Systematic Assessment of Licensee Performance (SALP) report on the Crystal River nuclear station. The SALP that covered the Feb. 20, 1994 through Sept. 16, 1995 period was satisfactory despite some slippage in engineering. The overall score fell to a "1.75" from a "1.5", with plant support achieving a superior grade of "1.0" and the categories of engineering, maintenance, and operations receiving acceptable marks of "2.0".

September 1995. The Florida PSC approved Florida Power's petition for the amortization of some $23 million in costs for the canceled, 500 kilovolt Lake Tarpon-Kathleen transmission line. The costs are being amortized over four years, retroactive to Jan. 1, 1995. In the third quarter, Florida Power absorbed a $6.9 million pretax charge to begin the amortization.

MAJOR STRENGTHS AND RISKS

Major strengths:

- Healthy and growing service area.
- Small dependence on the industrial sector.
- Florida's geographical location and peninsular shape reduce competition from out-of-state power sources.
- Supportive Florida regulatory environment.
- Florida PSC and state legislature have adopted a cautious approach toward retail wheeling.
- Diversified fuel mix.
- Proactive management team.
- Effective cost containment efforts.
- Nominal Clean Air Act exposure.
- Base rate stability.
- Rates are competitive within Florida.

Major risks:

- Challenge associated with ownership of a nuclear station.
- Large off-balance-sheet purchased power obligations.
- Capacity needs to meet growing demand.
- Credit risk heightened by Florida Progress' diversified activities.

CORPORATE STRUCTURE

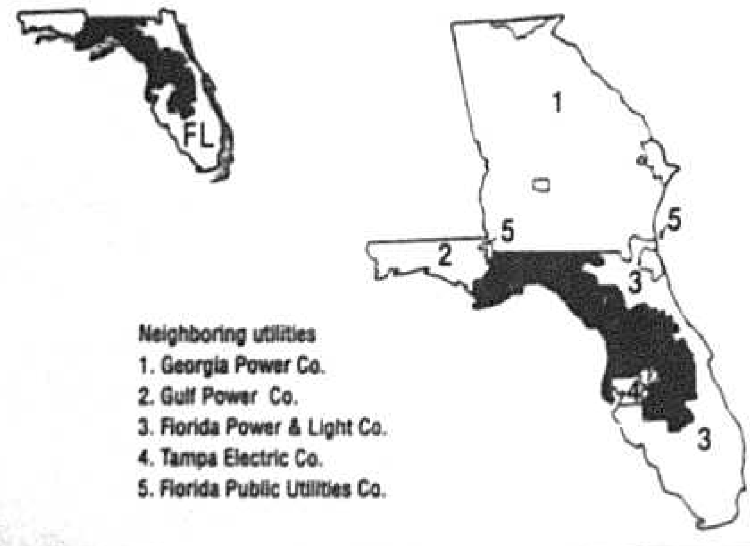
Florida Progress was formed in 1982 and is a diversified holding company. Headquartered in St. Petersburg, Fla., its principal subsidiary, Florida Power (75% of consolidated assets, 90% of earnings, and 75% of revenues) was incorporated in 1899, and is engaged in the generation, purchase, transmission, distribution, and sale of electricity. In August 1988, Progress Capital Holdings Inc. (PCH) was formed to become the downstream holding company for Florida Progress' diversified operations and to consolidate financing of the nonutility businesses. Diversified activities include an energy and transportation company, a life insurance firm, and a commercial lending, leasing, and real estate operation.

Florida Progress' ratings largely reflect the creditworthiness of Florida Power, adjusted for higher-risk nonutility operations. PCH's ratings reflect the implicit support of parent, Florida Progress. The support is evidenced by a net worth maintenance agreement between the two companies.

Electric Fuels Corp., established in 1976, is an energy and transportation company that serves electric utilities, including Florida Power, and industrial companies. Its major businesses include coal mining, procurement, and transportation; bulk commodities transportation; railcar repair and railcar parts manufacturing and reconditioning, and rail and trackworks components.

Mid-Continent Life Insurance Co., founded in 1909 and acquired by Florida Progress in 1986, is a life insurance firm, whose principal product is a low-premium death benefit policy that is sold through independent agents.

FLORIDA POWER CORP.



Progress Credit Corp., formed in 1983, is a financial services and real estate company with lending and leasing transactions (mainly involving commercial aircraft and real estate) and real estate projects. The company plans to continue with its orderly liquidation of these assets.

Advanced Separation Technologies (AST) and Progress Energy Corp. are two very small subsidiaries. AST is an R&D company whose principal product is a patented adsorption technology. Progress Energy was reactivated in 1994 to pursue independent power production opportunities, primarily in the Southeast U.S.

SERVICE AREA Florida Power, the state's second-largest investor-owned electric utility, provides electricity to more than 1.2 million customers. Service is rendered in 32 of the state's 67 counties, covering approximately 20,000 square miles with a total population of about 4.5 million in central and north central Florida and along the west coast of the state. The service territory includes St. Petersburg and Clearwater, as well as the areas surrounding Walt Disney World, Orlando, Ocala, and Tallahassee.

Florida utilities have certain retail service territorial rights granted by the Florida PSC. Florida Power holds negotiated franchise agreements with varying expiration terms extending to 2030 with virtually all of the municipalities in which it distributes energy. Of the company's 110 franchises, only one (Mexico Beach) will expire before the year 2000; it represents less than 1% of total utility revenues. Although mounting competition may affect new franchise deals, Florida Power's

Service area economics* (% chg.)

	1993	1994	1995	1996-1999¶	1996-2006¶
Manufacturing employment					
Service territory	1.7	1.1	1.1	(0.5)	(0.3)
SERC region	1.1	0.8	0.6	(1.0)	(0.9)
National	(0.2)	1.3	0.2	(0.7)	(0.5)
Nonmanufacturing employment					
Service territory	4.3	4.4	4.8	3.6	3.2
SERC region	3.8	3.5	3.2	2.5	2.2
National	2.4	3.3	2.6	2.1	1.8
Total employment					
Service territory	4.0	4.1	4.3	3.2	2.9
SERC region	3.3	3.0	2.8	2.0	1.8
National	2.0	3.0	2.2	1.6	1.5
Population					
Service territory	1.4	1.8	2.2	2.0	1.8
SERC region	1.5	1.5	1.5	1.3	1.2
National	1.0	1.0	1.0	0.9	0.9
Private housing starts					
Service territory§	5.2	18.7	(3.1)	(0.4)	2.0
SERC region	13.2	9.7	(7.0)	(1.6)	0.8
National	19.1	7.9	11.5	(4.6)	0.4
Unemployment rate					
Service territory§	6.4	5.6	4.3	4.4	4.3
SERC region	6.1	5.5	5.0	5.4	5.5
National	6.8	6.1	5.6	6.0	5.9
Real per capita income (1987 $)					
Service territory§	15,822	16,452	16,964	17,926	20,271
SERC region	15,408	15,885	16,325	17,198	19,070
National	16,429	16,892	17,333	17,968	19,872

*Economic variables determined by the aggregation of metropolitan statistical areas provided by the company. ¶Employment, population, and housing start estimates represent compound annual growth rates for the period. Unemployment and real per capita income estimates represent forecasts for the last year in the period. §Data represent the largest metropolitan area(s) in the service territory. SERC—Southeastern Electric Reliability Council. *Source:* DRI/McGraw-Hill

Industries served
(1994)

Industry type	Sales (%)	Revenue (%)
Nonmetal mining	33.6	25.6
Electrical machinery	12.6	12.3
Food and kindred	11.9	11.3
Stone, clay, glass, and concrete	6.5	5.1
Meas. and analyzing instruments	5.8	5.8
Chemicals	5.6	4.7
Rubber and misc. plastic products	5.0	5.0
Fabricated metal	4.1	4.4
Printing and publishing	3.6	4.0
Paper	3.1	3.1
Total (GWh/mil. $)	3,580	173.

GWh—Gigawatt-hours. *Source:* Edison Electric Institute.

rates appear to be low enough that municipalization will be difficult to justify economically.

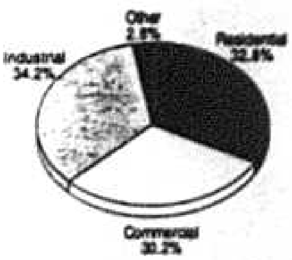
In late 1995, the city of Clearwater signed a new 30-year franchise agreement with Florida Power. Clearwater, the second-largest city in the company's service area, accounts for some 5% of total annual revenue. The franchise was set to expire in summer 1996.

In late 1994, the company entered into a new 10-year territorial agreement with the Orlando Utilities Commission (OUC), a municipal utility. The pact marked the end of a long controversy over which the utility would serve an expanding area near Orlando airport, annexed by the city of Orlando. This contract replaces the previous 20-year agreement that expired in July 1994. OUC will add the area of land to its service area and will buy the distribution assets from Florida Power. The agreement prohibits the OUC from taking over any customers because of annexation. Loss of this territory will not harm Florida Power's financial condition.

Economic support centers on phosphate and rock mining and processing, electronics design and manufacturing, health care-related manufacturing, and citrus and other food processing. Other important commercial activities are tourism, health care, construction, and agriculture.

Florida Power does not rely heavily on the industrial sector, with industrial customers constituting only 8.5% of electric revenues and 11.9% of kWh sales, limiting its exposure to the possibility of retail wheeling. IMC Agrico Co., AT&T Microelectronics, and Florida Crushed Stone Co. are among the utility's largest customers. With the bulk of the company's customer base derived from the residential class (56% of electric revenues and 46% of sales), Florida Power is amply insulated from the effects of cyclical volatility.

Industry Retail Sales (MWh)
1994



Source: Edison Electric Institute.

The economy of the service area, like Florida in general, is expected to remain strong, driven by growth in population, tourism, and trade. The state's population is forecasted to grow by about 1.65 million people by the year 2000 to a total of 15.5 million. Florida Power's service area is projected to expand to about 5.1 million people by the year 2000. The state unemployment rate was lower than the national average for the first three quarters of 1995, after being higher in 1994. In the near term, the state is projected to be the second in the nation in employment growth and fifth in the nation in population growth. In recent years, Florida's per capita personal income tracked closely to the national averages. Total personal income is growing at a faster rate for Florida than for the U.S. This trend is probably due more to the state's faster-growing population than to increasing per capita income. Florida's residential housing starts led the nation in 1994. However, residential housing starts were down in the first three quarters of 1995 compared to 1994. In terms of value of nonresidential construction contracts, Florida ranked as the third-highest state in 1994.

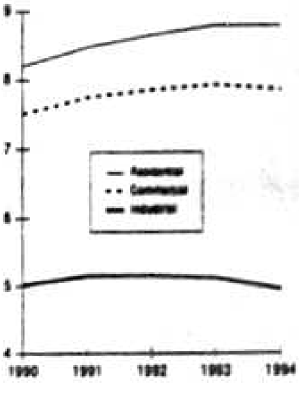
SALES

During the five years ended 1995, annual retail kWh sales growth averaged a relatively healthy 3.6%. In 1995, these sales advanced 6.6% over 1994, with increases for the residential sector of 7.8%, commercial 4.4%, and industrial 8.0%. Strong customer growth, higher average customer usage, and a healthy economy contributed to the improved energy sales.

The steady influx of new residents into Florida, as well as increased customer usage, will result in higher electric sales for the company. The five-year average annual growth rate for sales to retail customers is forecasted at a strong 3.9%, including the effects of demand-side management programs. Wholesale sales are expected to advance a bit more slowly at roughly 3.0%. Peak demand is expected to grow at about 2% during the same period. The company's annual customer growth rate remains about twice the national average at around 2.5%.

COMPETITIVE POSITION

Industry Rates
(cents/kWh)



All three of the Florida peninsular investor-owned electric utilities have above average business positions primarily because of the strong state economy, low exposure to industrial retail competition, lack of excess capacity in the state, geographical characteristics, and cross-state border transmission capacity limitations that, for now, provide a degree of protection for the state's peninsular utilities from out-of-state competition. The competitive relationship among the three Florida investor-owned utilities is removed from Gulf Power Co.—a Southern Co. subsidiary located in the panhandle of Florida—since Gulf Power does not provide a direct conduit for Southern Co. into the Florida peninsula. Power sales from the Southern Co. system are transmitted through the state of Georgia. Because Southern Co. dispatches as a system based on economics, in its entirety, the company is the closest source of out-of-state competition to the Florida utilities. All but some 1,000MW in interstate transmission capacity are tied up by contracts.

Florida Power's total cost of production and purchased power at 4.22 cents per kWh is approximately 13% higher than the 1994 Southeastern Reliability Council (SERC) regional average of 3.73 cents. However, the company's costs are competitive within Florida. Florida Power's residential realization at 8.24 cents per kWh is above the SERC group average, about 9% higher than Florida Power & Light Co. and some 3% below Tampa Electric Co. Florida Power's rate design provides competitive rates to large commercial and industrial customers. Its average commercial rate of 5.86 cents per kWh is very competitive; the tariff is 5.6% below Florida Power & Light, nearly 18% less expensive than Tampa Electric's, and 9%

Market segments

	1994	1993	1992	1991	1990
Sales					
Total retail (GWh)	27,675	26,528	25,414	25,179	24,879
Residential (%)	50.1	50.4	50.5	50.1	49.9
Commercial (%)	29.8	29.7	29.7	29.7	29.5
Industrial (%)	12.9	12.7	12.8	13.1	13.9
Other (%)	7.2	7.1	7.0	7.0	6.7
Wholesale (GWh)	2,339	2,120	1,962	2,171	2,265
Total sales (GWh)	30,015	28,648	27,376	27,350	27,144
Revenue					
Total retail (mil. $)	1,908	1,781	1,578	1,592	1,562
Residential (%)	59.8	59.5	58.9	58.2	57.8
Commercial (%)	25.4	25.7	26.4	26.8	26.7
Industrial (%)	9.1	9.1	8.8	9.1	9.7
Other (%)	5.7	5.7	5.9	6.0	5.8
Wholesale (mil. $)	125	127	100	104	104
Total revenue (mil. $)	2,033	1,907	1,678	1,696	1,666
Annual sales growth (%)					
Residential	3.7	4.3	1.6	1.7	5.3
Commercial	4.7	4.5	0.7	2.2	4.8
Industrial	5.9	3.9	(1.5)	(4.4)	(8.2)
Total retail	4.3	4.4	0.9	1.2	3.1
Standard & Poor's retail avg.	2.6	3.6	0.3	2.0	1.9
Wholesale	10.4	8.1	(9.7)	(4.2)	(5.1)
Total sales growth	4.8	4.6	0.1	0.8	2.4
Retail customer growth	2.4	2.7	2.0	2.1	3.1

GWh—Gigawatt-hours. *Source:* UDI/McGraw-Hill below the SERC group average. Although Florida Power's industrial rate at 4.84 cents per kWh is a bit higher than the region, it is in line with the state average. Moreover, Florida Power's industrial base accounts for a very manageable 11.9% of electric sales and only 8.5% of revenues thereby limiting exposure to the possibility of retail wheeling.

Currently, the company does not have long-term contracts with its industrial customers. The industrial customer rates are covered by tariffs approved by the Florida PSC. However, Florida Power recognizes the value of securing future long-term sales arrangements and has several initiatives established for that purpose.

Despite energy and capacity cost increases based on certain escalators in purchased power contacts, Florida Power's rates should remain competitive in years to come. These costs are passed through as a capacity cost-recovery factor and fuel charge. Notwithstanding the likelihood for about 1.0% annual retail rate increases to recover purchased power costs, the company's competitive position will not be noticeably affected. Florida Power will avoid any base rate relief requests for many years.

Florida Power continues to develop long-range business strategies to respond to an increasingly free market, with emphasis on customer satisfaction, cost cutting, productivity and efficiency enhancements, and increasing off-peak sales. To secure closer customer relationships, the company is establishing teams of account executives who are trained to be energy experts in specific types of businesses. The company is essentially becoming a full-service energy provider. On the cost control front, Florida Power has restructured with workforce reductions and consolidation. The company has managed to hold its nonfuel operations and maintenance (O&M) expenses level steady since 1992 while absorbing higher costs for customer growth, inflation, other post-retirement benefits, and increasing environmental and insurance costs.

Given Florida Power's relatively small wholesale load, the company has little immediate threat from economic bypass. Florida Power has 14 wholesale customers that consists of 12 municipal customers. The wholesale customers constitute about 7% of electric revenues and are under long-term contractual arrangements.

Energy costs and rates
(cents/kWh) for 1994

Utility	Fuel	Total variable production	Total fixed production	Purchased power	Production and purchased power	Total energy cost	Residential rate	Commercial rate	Industrial rate
Florida Power Co.	1.87	2.60	1.60	4.28	4.22	5.90	8.24	5.86	4.84
Alabama Power Co.	1.50	2.02	1.08	2.78	3.05	4.09	6.93	6.71	4.13
Carolina Power & Light Co.	1.22	2.35	1.48	5.88	4.15	5.14	8.22	6.85	5.29
Duke Power Co.	0.88	1.56	0.71	N.M.	3.43	4.59	7.31	5.96	4.24
Florida Power & Light Co.	1.69	2.45	1.71	4.28	4.19	5.81	7.54	6.19	4.91
Georgia Power Co.	1.46	2.10	1.31	3.13	3.36	4.61	7.53	7.30	4.52
Gulf Power Co.	1.78	2.82	1.11	2.33	3.54	4.72	6.73	5.74	4.45
Mississippi Power & Light Co.	2.21	2.79	0.74	4.87	4.07	5.73	8.25	8.12	6.14
Mississippi Power Co.	1.48	2.28	1.30	1.90	2.99	4.00	6.48	5.94	3.70
Savannah Electric & Power Co.	3.92	6.40	4.69	1.91	3.39	4.98	7.01	6.93	4.23
South Carolina Electric & Gas Co.	1.42	2.13	1.52	2.46	3.33	4.51	7.51	5.94	4.01
Tampa Electric Co.	2.39	3.05	1.25	5.82	4.34	5.82	8.50	6.91	4.75
Virginia Electric & Power Co.	1.19	1.90	1.44	6.45	4.09	5.35	8.21	5.83	4.24
SERC region average	1.41	2.13	1.28	5.66	3.73	5.02	7.68	6.39	4.47
Standard & Poor's average	1.48	2.29	1.90	4.31	4.22	5.68	8.84	7.85	5.04

N.M.—Not meaningful. SERC—Southeastern Electric Reliability Council. kWh—Kilowatt-hour. Source: UDI/McGraw-Hill.

Exposure to municipalization in the near term is minimized by the terms of the various franchise agreements that typically extend for 20 or 30 years and the costs associated with municipalization. These costs to the municipality would include loss of franchise fees, acquisition of distribution assets, and loss of property taxes relating to these assets. The relatively competitive Florida Power residential rate helps to mitigate the potential for municipalization.

FUEL AND POWER SUPPLY

Florida Power has adequate fuel diversity, with coal providing 45% of electricity produced in 1994, and nuclear, oil, gas, and purchased power contributing 17%, 16%, 1%, and 21%, respectively. Minor deviation is expected in the fuel mix; purchased power will rise to about 27% of generation.

Most of the coal for the company's facilities is expected to be supplied from the Appalachian coal fields. Some two-thirds of the coal is expected to be delivered by rail and the remainder by barge. The coal is being supplied by Florida Progress' subsidiary, Electric Fuels, based on contracts between Florida Power and Electric Fuels. Electric Fuels has long-term contracts with various sources for 75% of the coal requirements for Florida Power's coal units. Electric Fuels acquires the remainder in the spot market and under short-term contracts. The long-term contracts have price adjustment provisions. Oil is purchased under contracts with several suppliers. The cost of oil is tied by contracts to certain posted market prices. Management believes that the company has contracts for an adequate supply of oil for the foreseeable future. Natural gas is purchased on the spot market under firm and interruptible contracts. Florida Power has contracts for the supply of uranium concentrates (Stage I) and the conversion of uranium concentrates (Stage II) through 1997, and the enrichment of uranium (Stage III) and the fabrication of uranium into fuel assemblies (Stage IV) through 2004.

Fuel and power supply

	1994	1993	1992	1991	1990
Generating capacity					
Owned (MW)	7,207	6,428	6,512	6,571	6,041
Firm purchased (MW)	250	283	400	400	886
Peak demand (MW-winter)	6,955	6,729*	6,982	6,056	5,948
Reserve margin (%)	9.1	3.2	0.8	15.1	16.5
Peak growth (%)	3.4	(3.6)	15.3	1.8	(12.8)
Annual load factor (%)	51.2	51.3	46.8	53.5	53.0
SERC regional reserve margin (%-summer)	16.8	16.8	16.8	16.8	16.8
Generation by fuel source (%)					
Coal	44.0	44.7	53.4	50.5	73.7
Oil	16.1	21.0	27.6	22.5	0.0
Gas	0.0	0.2	0.2	0.0	0.0
Nuclear	18.0	17.8	18.8	17.4	14.1
Purchased	21.9	16.3	0.0	9.6	12.2

SERC—Southeastern Electric Reliability Council. MW—Megawatts. *Summer peak. *Source*: Edison Electric Institute.

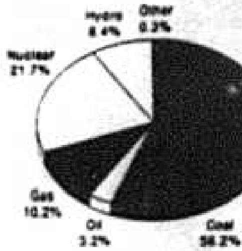
Nuclear operating statistics (1994)

Unit	% owned	Forced outage rate (%)	Last SALP period	Operations	Maintenance	Engineering	Plant support	Avg.
Crystal River 3	90.0	0.0	8/92 - 2/94	2	2	1	1	1.50

Unit	Book value (mil. $)	Decomm. basis	Est. decomm. cost (mil. $)	Date of estimate	Total amt. funded (mil. $)	Annual amt. funded (mil. $)	Funding sufficiency (%)
Crystal River 3	352.0	Decontamination	221.3	12/93	110.0	11.0	96.4

SALP—Systematic Assessment of Licensee Performance. *Source*: Nuclear Regulatory Commission.

Industry Fuel Mix
1994



Source: Edison Electric Institute.

Summary nuclear statistics
(1994)

Total gener. cap. (MW)	7,457
Total nuclear cap. (MW)	801
Nuc. cap. as a % of total cap.	11
BV of nuclear invest. (mil. $)	352
BV as a % of net plant	10
BV as a % of common equity	21
Avg. capacity factor for all units (%)	
Past three years	60
Lifetime	82
Units on NRC watch list	None
Decomm. est. (mil. 1994 $)	221
Total amt. funded (mil. 1994 $)	110
Funding sufficiency (%)	96

BV—Book value. MW—Megawatts. NRC—Nuclear Regulatory Commission.

Florida Power supplements its owned capacity with power purchases from neighboring utilities and cogenerators. It has a take-or-pay arrangement for purchases of 400MW of coal-fired capacity (two separate contracts of about 200MW each) with Southern Co. through 2010. Florida Power has an option to decrease these purchases to 200MW annually, beginning in 2000, with a three-year termination notice. The purchases are made from specific generating units with a capacity of some 3,500MW and are guaranteed by Southern Co.'s entire system, which totals more than 30,000MW. The capacity and energy charges are based on the actual costs to operate the units. If lower-cost power is available on Southern Co.'s system, Florida Power pays the lower amount. Florida Power's total cost is calculated using Southern Co.'s Federal Energy Regulatory Commission (FERC) rates of return and includes a transmission charge. Over time, these contracts are expected to become more economic—capacity payments are likely to decline as the units are depreciated and energy costs should fall, given the recent termination of an unfavorable coal contract.

Florida Power also has a purchased power contract with Tampa Electric that was absorbed by Florida Power as part of the acquisition of the Sebring electrical distribution system. The arrangement ends after Feb. 28, 2011, upon one-year notice of either party. Capacity payments increase as projected growth in Sebring's load increases—50MW through 1998, 60MW from 1999 to 2004, and 70MW from 2005 to 2011. The capacity payments are based on Tampa Electric's total system embedded costs as approved by FERC. The energy component is based on Tampa Electric's system average plus a variable O&M charge, adjusted to actual every six months.

To analyze the financial impact of purchased power, Standard & Poor's employs the following financial methodology. The net present value of future annual capacity payments (discounted at 10%) represents a potential debt equivalent—the off-balance-sheet obligation that a utility incurs when it enters into a long-term purchased power contract. However, Standard & Poor's adds to the utility's balance sheet only a portion of this amount, recognizing that such a contractual arrangement is not entirely the equivalent of debt. What percentage is added (the risk factor) is a function of Standard & Poor's qualitative analysis of the specific contract and the extent to which market, operating, and regulatory risks are borne by the utility. Since Florida Power recovers substantially all fuel and purchased power costs through fuel and capacity adjustment clauses, and given the fully dispatchable nature of the contracts and need for the power, Standard & Poor's has assigned relatively low-risk factors of 40% to Florida Power's take-or-pay purchased power obligations.

The company has contracts with qualifying facility (QF) suppliers for 1,164MW of capacity with terms ranging from six to 29 years. Of the 1,164MW under contract, 1,049MW are currently available. The contracts were negotiated when market players believed that natural gas prices would be higher and more volatile than coal. Thus, these contracts are based on the costs of a pulverized coal-fired plant and are priced higher than Florida Power's system average generating cost. In 1994, the company developed a curtailment program for its QF contracts to address system reliability during minimum load conditions; on Sept. 11, 1995, the Florida PSC approved the plan. In addition, the company negotiated with its QF suppliers to reduce voluntarily their output during low-load periods. In accordance with certain contract provisions, Florida Power began paying "as available" prices for purchased power during certain periods. The revised pricing reduces payments to cogenerators by some $15 million annually. Three cogenerators filed or amended lawsuits to challenge this pricing methodology. Going forward, the company will strive to improve QF contracts through negotiation and optimize the use of purchased power by administering them in the most cost-effective manner. Since Florida Power is able to recover virtually all capacity and fuel costs through regulatory adjustment mechanisms, Standard & Poor's has assigned a risk factor of only 10% to Florida Power's take and pay obligations.

The company's future capacity plans include 470MW of gas-fired combined-cycle generating units to be built in Polk County, Fla. This facility is scheduled to become operational in late 1998. The installed cost for the units is projected to be competitive with independent power producer costs. Florida Power and Georgia Power are building a jointly owned 165MW peaking facility that will come on line later this year. Florida Power will own two-thirds of the station, operate and maintain it, and have full use of it eight months each year. By using advanced technology and sharing construction costs, the installed cost per kW will be less than 60% of what it previously cost for a peaker. In a separate arrangement, Florida Power has agreed to sell between 200MW and 500MW of summer peaking capacity annually to Georgia Power from 1996 through 1999. Since Florida Power is a winter peaker and Georgia Power is a summer-peaking utility, this transaction is advantageous to both parties. Florida Power's generation strategy includes continuing efforts to sign similar agreements with other utilities. Revenues from these sales will help to offset some of the company's annual production costs and better utilize its facilities year-round.

OPERATIONS Historically, management has run a fairly efficient and lean organization. Florida Power's operating proficiency, as defined by customers per employee, remains well above the industry average with the most significant progress made during 1994. During the past several years, management has instituted various workforce reductions through attrition and early retirement programs. Since December 1993, Florida Power eliminated approximately 1,150 positions (20% of the workforce). The total revenue to total kWh ratio is a bit better than the industry average owing to the company's reasonable embedded cost of production plant. Florida Power

Efficiency statistics
Operating efficiency (electric-retail)

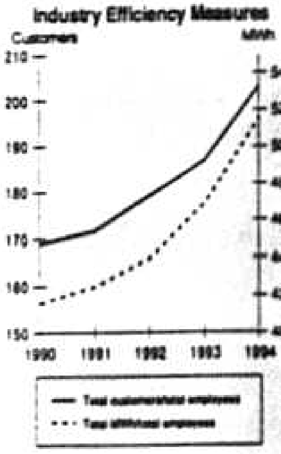
	1994	1993	1992	1991	1990
Total customers/employee	225	193	189	182	185
Industry avg.	204	188	180	172	169
Total MWh/total employee	5,005	4,214	4,084	3,948	4,055
Industry avg.	5,148	4,881	4,368	4,224	4,136
Total revenue/total kWh (cents)	6.89	6.71	6.20	6.32	6.28
Industry avg.	7.19	7.24	7.14	7.08	6.85

kWh—Kilowatt-hours. MWh—Megawatt-hours. *Source:* UDI/McGraw-Hill.

Base load statistics
Year-end 1994

Plant	Units	% of ownership	Fuel	Alt. fuel	Gross capacity (MW)	Net generation (GWh)	Heat rate (Btu)	Capacity factor (%)	Installed cost/kW ($)	Fuel exp./kWh (cents)	Total var prod. exp./kWh (cents)
Crystal River 3	3	90.0	Uranium	None	891	5,969	10,353	76.5	816	0.57	2.09

MW—Megawatts. GWh—Gigawatt-hours. kWh—Kilowatt-hours. Btu—British thermal units. *Source:* UDI/McGraw-Hill.



has been a national leader in fossil plant efficiency; its units have placed the company in the top 10 nationally in terms of steam unit efficiency for 10 consecutive years.

Florida Power has the second-largest transmission network in Florida. The company plans to expand its transmission grid by pursuing investment opportunities beyond traditional access requests across its grid. Florida Power is interconnected with the electric systems of Florida Power & Light; Georgia Power; Tampa Electric; Gulf Power; the cities of Gainesville, Kissimmee, Lakeland, Smyrna Beach, St. Cloud, and Tallahassee; the OUC; Reedy Creek Energy Services; Seminole Electric Cooperative Inc.; and the Southeastern Power Administration. Transmission interface with Georgia Power is limited with 3,600MW capacity north to south and 1,300MW capacity south to north. Most of the capacity is already contracted. Only some 1,000MW of north to south capacity is currently available. Import capability from other utilities is from north only due to Florida Power's peninsular shape. This differs from inland utilities that are entirely surrounded by the transmission grids.

Nuclear. The utility owns 90.4% (755MW) of the 835MW Crystal River 3 nuclear station that commenced commercial operation in 1977 at a total cost of $723.2 million or $654.1 million for Florida Power's ownership interest. Crystal River 3, a pressurized water reactor with Babcock and Wilcox-designed turbine generators, is the company's single largest base load facility, accounting for about 19% of kWh available for sale. Since its initial operation, Crystal River 3 had experienced several years of inferior operations due to extended refueling and maintenance outages. However, since the early 1990s, the plant has been performing very well in terms of plant statistics, duration and costs of refueling outages, O&M expenses, and nuclear industry reports.

In early 1994, the station completed its scheduled refueling outage in a record 57 days. Crystal River 3 is on a 24-month refueling cycle; the next major outage is slated to begin in the first quarter of 1996. Management is targeting a 47-day refueling and maintenance outage, which will include performing the 10-year, in-service inspection program, and replacement of both low pressure turbines and the reactor cooler pump motor. The outage is expected to cost about $25 million.

The station's recent statistical measures have been impressive, with a year-to-date capacity factor of 100% through Dec. 31, 1995. Over the 1992 to 1994 period, Crystal River 3's capacity averaged 80%—the best three-year performance ever.

The last Crystal River SALP, which covered the period Feb. 20, 1994 through Sept. 16, 1995, was satisfactory despite some slippage in engineering. The overall score fell to a "1.75" from a "1.5" (based on a range of "1.0" to "3.0," with "1.0" being the highest possible grade), with plant support achieving a superior grade of "1.0" and the categories of engineering, maintenance, and operations receiving acceptable marks of "2.0."

Florida Power is working with the NRC to resolve concerns over a fire retardant material, called Thermo-Lag, which is used as a fire barrier around electrical conduit and cables. The company believes that there are more effective ways to address the problem than to replace all the Thermo-Lag at Crystal River 3. Management projects total costs to be about $5 million.

In late 1995, the Florida PSC approved a new site-specific study that estimated future decommissioning costs for Crystal River 3 to be approximately $2 billion, which corresponds to $404.6 million in 1995 dollars. Florida Power increased its share of the retail portion of annual decommissioning expense to the Florida PSC approved level of $20.5 million annually, beginning in January 1995. The company also has adjusted the wholesale portion of this expense in a comparable manner, increasing it to $1.2 million annually.

Environmental. Florida Power is not materially affected by the Clean Air Act. Compliance coal is burned at Crystal River Units 4 and 5 and low-sulfur coal is burned at Crystal River Units 1 and 2. Additionally, using natural gas at the proposed Polk County power plant complex in the late 1990s will assist Florida Power in meeting tighter emission standards. Continuous emissions monitors were installed on most of the company's plants by the end of 1994 at a total cost of about $11 million. To meet Phase II, Florida Power is implementing a strategy based primarily on burning cleaner fuels. Compliance with nitrogen oxide limitations will require the installation of low nitrogen burners on some facilities. These costs will be around $8 million and will be incurred through 2000.

ASSET CONCENTRATION

Asset concentration risk is not excessive, with the single greatest concentration primarily centered on the investment in the Crystal River 3 nuclear station. Depreciated book value is approximately $347 million, which represents a manageable 20% of common equity, 10% of net electric plant in service, and 11% of total capitalization. Crystal River 3 is Florida Power's single largest base load facility, and accounted for 9% of total capacity (including purchased power) and 19% of generation (including purchased power) in 1995.

The coal-fired Crystal River units 4 and 5, completed in 1984 are also major generating stations for Florida Power. The two facilities consist of 1,434MW and accounted for about 17% of total capacity (including purchased power) and 27% of total generation (including purchased power) in 1995. Net book value of the two plants is about $490 million. These units have been excellent performers with lifetime availability factors of close to 90%.

NONREGULATED BUSINESS

Florida Progress' ratings largely reflect the creditworthiness of Florida Power, adjusted for higher-risk nonutility operations. Diversified activities account for approximately 25% of consolidated assets, 10% of earnings, and 25% of revenues. The company's strategy is to retain and expand those businesses that have the most promise for stability and profitability. This approach has led the company to focus on Electric Fuels (about $600 million in assets) and Mid-Continent Life insurance (approximately $570 million in assets). Meanwhile, most other operations are either being sold or restructured. Included in this group are lending and leasing assets of some $405 million relating to commercial aircraft and real estate as well as its real estate operation with investments of about $130 million in office buildings and undeveloped land.

PCH, which provides funding for the diversified operations, was established in 1988. PCH has a senior unsecured debt rating of 'A' and a commercial paper rating of 'A-1'. The ratings reflect the implicit support of its parent, Florida Progress. The support is evidenced by a net worth maintenance agreement between the two companies. The outlook is stable, mirroring the credit trend of Florida Power, the system's primary source of cash flow. At the end of 1995, PCH had about $500 million of debt outstanding.

Electric Fuels is an energy and transportation company that serves electric utilities, including Florida Power, and industrial companies. Formed in 1976, Electric Fuels has operations in 15 states and is involved in the mining, procurement and transportation of coal; bulk commodities transportation; and railcar services. Electric Fuels plans to increase its market share of existing operations and make new investments in markets that expand its products and services. Electric Fuels has earned an average return on equity (ROE) of about 13.3% during the last three years.

Mid-Continent Life Insurance, acquired in 1986, serves 37 states and sells its policies through some 9,000 independent agents. Its principal product is a low-premium death benefit policy. The company has almost $14 billion of life insurance policies outstanding. Nearly all of the company's financial portfolio is in investment-grade securities. Mid-Continent has held an average ROE of about 11.5% during the last four years. Florida Progress plans to maintain a conservative growth strategy for Mid-Continent through the development of a regional office network.

AST and Progress Energy are two very small subsidiaries. AST is an R&D company whose principal product is a patented adsorption technology. The product, called an Ion Separation machine, removes dissolved impurities and makes chemical separations in continuous process rather than conducting the separation in batches. The company has net income of about $1.8 million. Despite its small size, it has earned very high ROEs. Progress Energy was reactivated in 1994 to pursue independent power production opportunities, primarily in the Southeast U.S.

REGULATION Florida Power's retail rates are subject to the jurisdiction of the five member appointed Florida PSC. The commission is considered to be supportive of strong credit quality for the electric utilities in the state. Authorized ROEs are in line with industry averages, forecasted test periods are utilized, incentive ratemaking mechanisms for efficient operations are in place, and companies can recover

Regulation

Regulatory agency	Florida Public Service Commission	
State	Florida	
Case period	Eight months.	
Interim procedures	Selectively.	
Authorized returns (Last 12 to 18 months)		
Return on equity (electric)	11.35	
Return on equity (gas)	13.0	
Return on equity (telephone)	12.2	
Rate base	Average original cost.	
Test period	Forecasted.	
CWIP	Some CWIP included in rate base for a partial cash return.	
Adjustment mechanisms	Fuel and purchased power adjustment clauses (semiautomatic), both the capacity and energy components of purchased power are reflected through the fuel adjustment clause; demand-side management related expenses can be recovered without filing a base rate case; an oil backout cost adjustment allows accelerated recovery of investments in projects designed to displace oil-generated capacity	
Incentive ratemaking	Demand-side management; plant performance; rate of return and price cap/index; oil backout cost recovery factor rule.	
Commissioners	Party	Term
Susan Clark, Chair	Democrat	January 1999
Julia Johnson	Democrat	January 1997
Diane Kiesling	Democrat	January 1998
Joe Garcia	Independent	January 1998
J. Terry Deason	Democrat	January 1999

Source: Regulatory Research Associates Inc.

without a full-blown general rate proceeding fuel adjustment and purchased power capacity costs and costs associated with energy conservation projects. Importantly, the commission has been receptive to rate design and pricing flexibility.

The Florida PSC is monitoring developments nationwide surrounding retail competition. The position of the commission's is that legislation is required for PSC to authorize retail wheeling. The Florida state legislature tabled a proposal requiring the Florida PSC to study retail wheeling in the state. Instead, the legislature has assigned a committee to study competition in the electric utility industry in Florida and to report the results to the legislature in early 1996. The Florida PSC staff is expected to participate in the study as required by the legislative committee.

Effective Jan. 1, 1995, Florida Power adopted a three-year test of residential revenue decoupling. The revenue decoupling essentially eliminates the linkage between sales and revenues. The company is using a mechanism that is established by dividing its revenue requirements by the number of customers during a test year. The difference between actual and target revenues is trued-up annually. Under the experiment, abnormal weather patterns will no longer impact earnings with respect to residential revenues. This ratemaking concept is not expected to have a long-term material financial impact on the company.

In late 1993, the company implemented an $18.1 million electric rate hike, the third and final step of a three-year, $85.8 million phase-in plan granted by the commission in September 1992. The order provided the company with the opportunity to earn a regulatory ROE of 12%, with an allowed range between 11% and 13%. Although rates will rise a bit due to purchased power cost recovery, Florida Power will avoid seeking base rate relief for many years.

MANAGEMENT

On Jan. 17, 1996, Allen J. Keesler, Jr., president and chief executive officer of Florida Power since 1988 announced his retirement, effective April 1, 1996. To begin an orderly succession of top management for Florida Progress and Florida Power, Florida Progress Chairman and CEO Jack B. Critchfield will relinquish his position as chairman of Florida Power. This responsibility will be assumed by Richard Korpan, who will become chairman and CEO of Florida Power as part of a transition period of up to one year. Mr. Korpan will also retain his executive responsibilities at Florida Progress as president and chief operating officer.

Joe Richardson will be promoted to president and chief operating office of Florida Power, effective April 1, 1996. Mr. Richardson is currently senior vice president, Energy Distribution. He has nearly 20 years experience with the company and a diverse work background.

Florida Power is a well-run, customer-driven, efficient, and financially sound electric utility. Importantly, management has traditionally been supportive of strong utility credit quality. Management continues to concentrate on cutting expenses, new marketing strategies to increase off-peak sales, strengthening customer satisfaction, and reengineering to achieve business excellence in its response to mounting competition in the electric utility industry. Regarding diversification, the company plans to continue with its orderly liquidation of risky lending and leasing and real estate assets. Prospectively, any new activities will be funded through redeployment; equity invested in diversified operations will likely remain less than 20% of total equity.

On the cost front, management has held nonfuel O&M expenses steady since 1992 while absorbing higher costs for new customers, inflation, and other increasing expenses. Going forward, management's goal is to run the business at the lowest, prudent O&M level possible, allocating a portion of the budget for strategic spending to help the utility position itself for an increasingly free market. In addition, the company has refinanced some $576 million of higher cost securities, reducing its embedded cost of long-term debt to a relatively low 7.2%. Because the company's common dividend payout ratio to shareholders was on the high side, the board of directors lowered the divided growth rate the last two years to about 2%. The payout ratio is now around the industry average but management's goal is to achieve and maintain lower levels ranging from 75% to 70%.

EARNINGS ANALYSIS

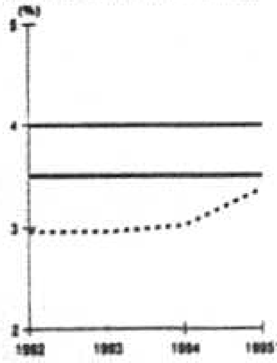
Florida Progress announced that earnings per share for 1995 rose 9.6%. Earnings for the year were $238.9 million or $2.50 per share, compared with $212 million or $2.28 per share for the same period in 1994. The higher earnings reflect an increase in retail kWh sales due to a stronger economy, more extremes in summer and winter weather, customer growth of 2.2%, and cost cutting measures at Florida Power.

Since 1991, Florida Power has refinanced about $576 million of long-term debt, including scheduled maturities, lowering the embedded cost of debt to a relatively low 7.2%. This activity in conjunction with operating cost reductions has helped to lift adjusted pretax interest coverage and ROE to 3.37x and 12.7%, respectively. Healthy cash flow, manageable new money needs, ambitious cost containment initiatives, strong kWh sales growth, ongoing emphasis on customer service, and continued favorable nuclear performance should help to keep pretax interest coverage at levels above 3.2x, commensurate with 'AA-' utility with an above average business position.

CASH FLOW ANALYSIS

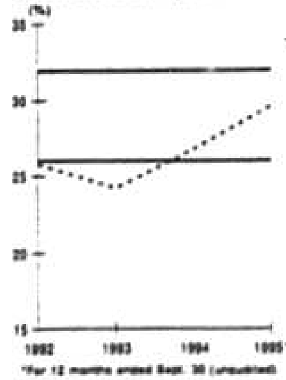
Florida Power budgeted $330 million, excluding allowance for funds used during construction but including nuclear fuel expenditures, for its 1995 construction program. Actual outlays were $283 million or 16.6% below budget. Last year, the company slashed its prospective five-year construction forecast by some $200 million due to the cancellations of the Lake Tarpon-Kathleen line project and Anclote power plant gas conversion project, and a decrease in the estimated cost

Adjusted Pretax Interest Coverage Vs. 'AA' Electric Utility Benchmark



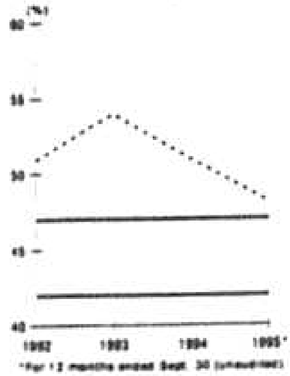
*For 12 months ended Sept. 30 (unaudited).

Adjusted FFO/Avg. Total Debt Vs. 'AA' Electric Utility Benchmark



*For 12 months ended Sept. 30 (unaudited).

Adjusted Total Debt/Total Capital Vs. 'AA' Electric Utility Benchmark



*For 12 months ended Sept. 30 (unaudited).

to construct the planned generating units at the Polk County site.

Electric construction expenditures, including nuclear fuel, for the five years through 2000, are projected to total approximately $1.38 billion, of which some $265 million is budgeted for this year. Depreciation and amortization during the same period are forecasted at approximately $1.38 billion. The depreciation rate was a high 4.8% during 1994. Florida Power's construction program will average a relatively high 9% of total capitalization and will concentrate primarily on improvements and additions to electric production, distribution, and transmission facilities.

Internal cash flow should continue to cover the bulk of construction outlays. Funds from operations interest coverage and funds from operations to total debt, adjusted for purchased power obligations, are expected to remain strong, at levels over 4.2x and 25%, respectively.

BALANCE SHEET ANALYSIS

The company has historically utilized conservative financing practices. Management has been committed to maintaining capital structure balance at the utility, infusing sufficient amounts of equity over the last several years. The company has no long-term floating-rate debt, and asset quality is high with few regulatory or deferred assets. In recent years, Florida Power's balance sheet characteristics have displayed modest improvement. Reported debt leverage is about 41%, common equity close to 55%, and preferred stock approximately 4%. When factoring in off-balance-sheet purchased power commitments using a weighted average risk factor of about 15%, debt leverage is expected to hover around 51% through the balance of the century. Other than the purchased power contracts and a nominal amount of operating leases, Florida Power has no other off-balance-sheet obligations.

Full equity treatment is given to Florida Power's $138.5 million preferred stock layer, which is all fixed-rate perpetual and accounts for a very reasonable 4.4% of total capitalization; little deviation is expected from the current level. Florida Power's embedded cost of preferred stock was a relatively low 6.8% in 1995.

FINANCING FLEXIBILITY

The company has strong financing flexibility to meet its needs, as demonstrated by a market-to-book ratio of about 165% as well as consolidated lines of credit totaling $800 million. Florida Power has a 364-day and five-year revolving bank credit facilities, $200 million each, which are used to back up commercial paper. PCH has a private $400 million medium-term note program and two revolving bank credit facilities: a 364-day $100 million facility and a five-year $300 million facility. These facilities are used to back up PCH's commercial paper program.

During 1995, Florida Progress contributed $50 million of new equity into Florida Power primarily from the sale of common stock through the parent's dividend reinvestment and stock purchase plan; no additional infusions are expected though the balance of the decade. The funds were used to repay commercial paper and for general corporate purposes. Florida Progress expects to convert the plan from original issue to open market purchase during 1996.

Florida Power has a very manageable debt maturity schedule, with a total of $148.5 million coming due over 1996 through 2000. Some $200 million of first mortgage bond financing is anticipated during the same period. The company's current first mortgage bond shelf capacity is $370. Although medium-term notes are not expected to be issued during the next five years. Florida Power has an undrawn $169 million medium-term note shelf in place for flexibility.

Financing flexibility

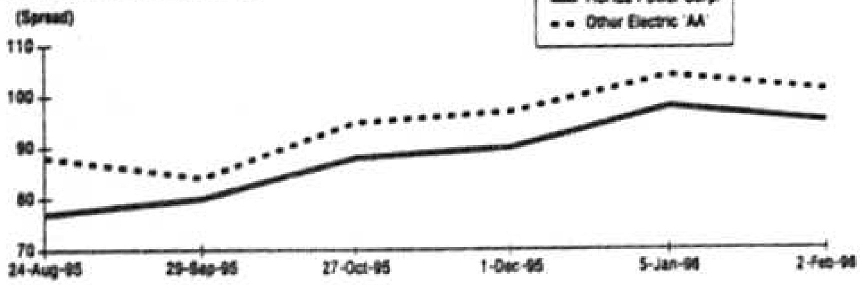
Common equity characteristics as of Nov. 30, 1995	
Ticker symbol	FPC
Stock price ($)	35 3/8
PE ratio (x)	14.3
Dividend yield (%)	5.7
Market to book (%)	165.9
Dividend to book (%)	9.5
Debt characteristics at fiscal year ended 1995	
Secured debt (%)	73
Unsecured debt (%)	27
Subordinated debt (%)	0
Fixed-rate debt (%)	100
Variable-rate debt (%)	0
Avg. life of long-term debt (years)	17
Embedded cost of long-term debt (%)	7.2
Debt maturing in five years (mil. $)	148.5

Short-term financing
As of Dec. 31, 1995

Short-term debt (mil. $)	Arranged	Outstanding	Expiration date	Same-day availability	MAC clause
Commercial paper	400.0	145.2			
Bank lines					
Contracted committed lines	400.0	0.0	N.A.	N.A.	N.A.
Avg. cost of short-term debt (%)	N.A.				

MAC—Material adverse change. N.A.—Not available.

Spread Over 30-Year Treasury



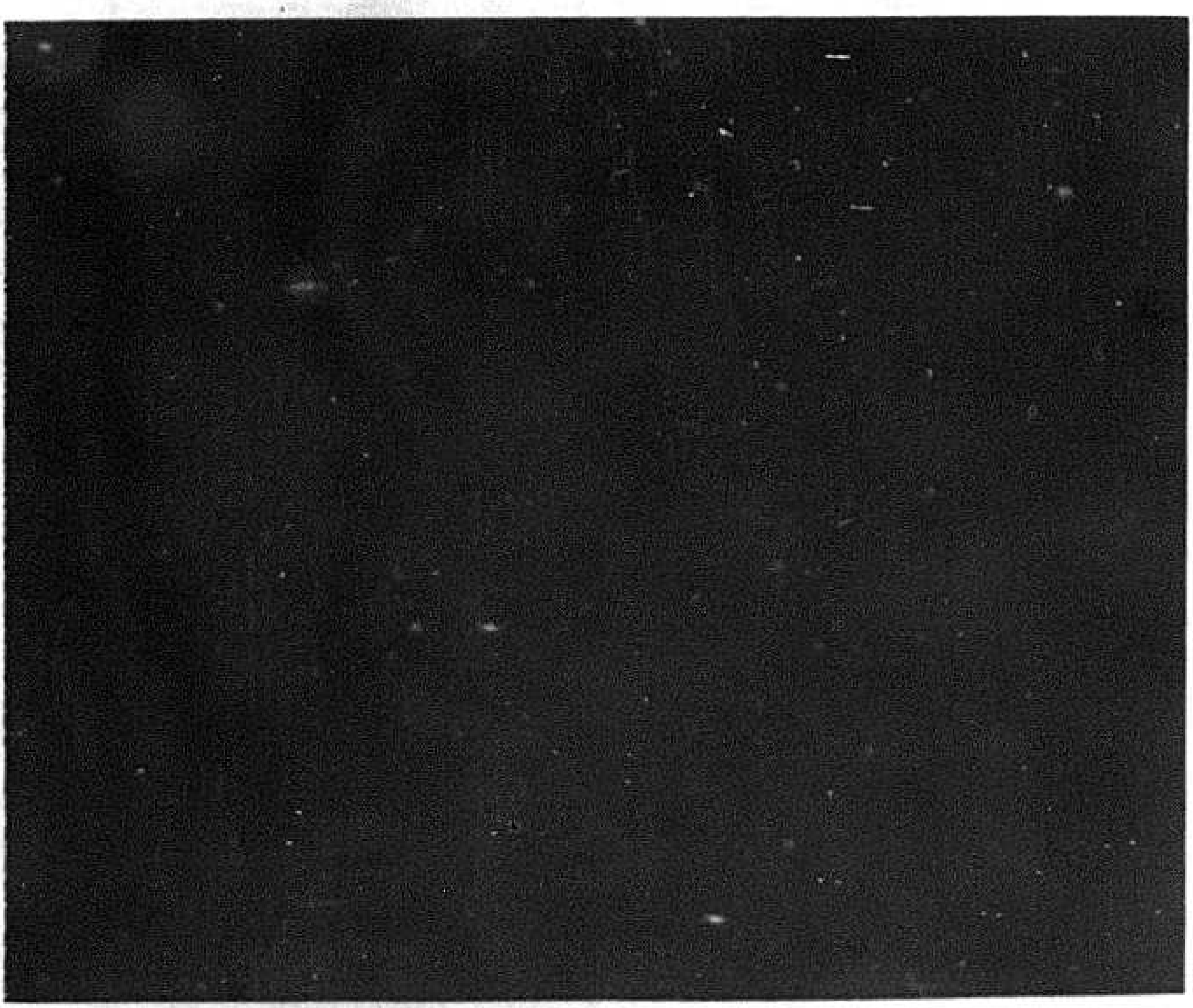
Financial statistics

Florida Power Co.	—Year ended Dec. 31—				
	1995*	1994	1993	1992	1991
Income statement (mil. $)					
Gross revenues	2,231.7	2,080.5	1,957.6	1,774.1	1,718.8
Operating expenses (excl. DD&A)	1,490.2	1,399.5	1,325.9	1,197.5	1,152.7
Depreciation and amortization	283.9	261.5	240.2	209.5	206.3
Pretax operating income	457.6	419.5	391.5	367.1	359.8
Gross interest expense	106.1	108.4	105.8	100.2	95.2
Pretax income	360.1	315.5	299.2	284.4	273.6
AFUDC and deferrals	8.2	10.9	15.6	18.7	9.4
Income taxes	132.3	114.7	104.3	97.5	92.7
Net income from continuing operations	227.8	200.8	194.9	186.9	180.9
Earnings protection					
Pretax interest coverage (x)	4.32	3.81	3.68	3.66	3.78
Adjusted pretax interest coverage (x)	3.37	3.02	2.98	2.96	N.A.
Preferred dividend coverage (x)	3.79	3.34	3.10	2.92	2.99
AFUDC and deferred income/earnings (%)	3.6	5.4	8.0	10.0	5.2
Return on common equity (nominal) (%)	12.8	12.0	12.2	12.4	12.5
Common dividend payout (%)	82.7	92.1	90.1	91.3	86.6
Annual O&M growth (%)	(8.8)	(0.6)	14.2	8.1	N.A.
Annual expense growth (excl. DD&A) (%)	6.5	5.6	10.7	3.9	N.A.
O&M/revenues (%)	20.9	24.6	26.3	25.4	24.2
Total operating expenses (excl. DD&A)/revenues (%)	66.8	67.3	67.7	67.5	67.1
Balance sheet (mil. $)					
Cash and equivalents	4.7	0.0	0.0	0.0	0.0
Gross plant	6,324.8	6,201.2	5,974.3	5,525.5	5,098.2
Net plant	3,588.7	3,869.2	3,641.4	3,442.0	3,193.3
Total assets	4,308.9	4,284.5	4,259.5	3,980.6	3,643.2
Short-term debt	51.3	90.7	170.9	132.5	37.1
Long-term debt	1,257.0	1,363.8	1,398.6	1,235.8	1,115.6
Preferred stock	138.5	143.5	148.5	218.0	231.0
Common equity	1,733.8	1,667.4	1,522.4	1,444.9	1,308.5
Total capitalization	3,180.6	3,265.4	3,240.4	3,029.2	2,692.2
Total off-balance-sheet obligations	428.0	428.0	389.3	354.9	N.A.
Balance sheet ratios (%)					
Short-term debt/total capital	1.6	2.8	5.3	4.4	1.4
Long-term debt/total capital	39.5	41.8	43.2	40.8	41.4
Preferred stock/total capital	4.4	4.4	4.6	7.1	8.6
Common equity/total capital	54.5	51.1	47.0	47.7	48.6
Adjusted total debt/total capital	48.1	50.9	54.0	50.9	N.A.
Cash flow (mil. $)					
Net income	227.8	200.8	194.9	186.9	180.9
Depreciation	320.1	294.8	278.5	243.4	241.9
Deferred taxes and ITC	(21.8)	(0.9)	(25.0)	8.8	(35.2)
AFUDC and deferrals	(8.2)	(10.9)	(15.6)	(18.7)	(9.4)
Other FFO adjustments	17.8	30.1	14.2	(4.0)	7.7
Funds from operations (FFO)	535.7	513.9	445.0	416.2	385.9
Preferred dividends	(9.8)	(10.1)	(13.4)	(16.7)	(16.8)
Common dividends	(180.3)	(175.7)	(163.5)	(155.4)	(142.1)
Net cash flow (NCF)	345.6	328.1	268.1	244.1	227.0
Working capital changes	45.3	(20.4)	28.0	(86.0)	81.1
Capital expenditures (capex)	(274.2)	(308.6)	(426.4)	(472.9)	(345.9)
Discretionary cash flow	116.7	(0.9)	(130.3)	(314.8)	(37.8)
Cash flow adequacy					
Capex/avg. total capital (%)	8.5	9.5	13.6	16.5	12.8
NCF/capex (%)	126.0	106.3	62.9	51.6	65.6
FFO/avg. total debt (%)	38.8	34.0	30.3	33.0	33.5
Adjusted FFO/avg. total debt (%)	29.8	26.6	24.2	25.8	N.A.
FFO interest coverage (x)	5.99	5.88	5.09	5.05	4.96
Adjusted FFO interest coverage (x)	4.56	4.36	3.99	3.99	N.A.

*For 12 months ended Sept. 30 (unaudited). N.A.—Not available. AFUDC—Allowance for funds used during construction. O&M—Operations and maintenance. DD&A—Depreciation, depletion, and amortization. ITC—Investment tax credits.

STANDARD & POOR'S

CORPORATE RATINGS CRITERIA



Utilities

The utilities rating methodology encompasses two basic components: business risk analysis and financial analysis. Evaluation of industry characteristics, the utility's position within that industry, its regulation, and its management provides the context for assessing a firm's financial condition.

Historical analysis is a tool for identifying strengths and weaknesses, and provides a starting point for evaluating financial condition. Business position assessment is the qualitative measure of a utility's fundamental creditworthiness. It focuses on the forces that will shape the utilities' future.

Utilities credit analysis factors

Business risk	Financial risk
• Markets and service area economy	• Earnings protection
• Competitive position	• Capital structure
• Operations	• Cash flow adequacy
• Regulation	• Financial flexibility/capital attraction
• Management	
• Fuel, power, and water supply	
• Asset concentration	

The credit analysis of utilities is quickly evolving, as utilities are treated less as regulated monopolies and more as entities faced with a host of challengers in a competitive environment. Marketplace dynamics are supplanting the power of regulation, making it critically important to reduce costs and/or market new services in order to thwart competitors' inroads.

Markets and service area economy

Assessing service territory begins with the economic and demographic evaluation of the area in which the utility has its franchise. Strength of long-term demand for the product is examined from a macroeconomic perspective. This enables Standard & Poor's to evaluate the affordability of rates and the staying power of demand.

Standard & Poor's tries to discern any secular consumption trends and, more importantly, the reasons for them. Specific items examined include the size and growth rate of the market, strength of the franchise, historical and projected sales growth, income levels and trends in population, employment, and per capita income. A utility with a healthy economy and customer base—as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment—will have a greater capacity to support its operations.

For electric and gas utilities, distribution by customer class is scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed cautiously, since a utility may have significant exposure to cyclical volatility. Alternatively, a large residential component yields a stable and more predictable revenue stream. The largest utility customers are identified to determine their importance to the bottom line and assess the risk of their loss and potential adverse effect on the utility's financial position. Credit concerns arise when individual customers represent more than 5% of revenues. The company or industry may play a significant role in the overall economic base of the service area. Moreover, large customers may turn to cogeneration or alternative power supplies to meet their energy needs, potentially leading to reduced cash flow for the utility (even in cases where a large customer pays discounted rates and is not a profitable account for the utility). Customer concentration is less significant for water and telecommunication utilities.

Competitive position

As competitive pressures have intensified in the utilities industry, Standard & Poor's analysis has deepened to include a more thorough review of competitive position.

Electric utility competition

For electric utilities, competitive factors examined include: percentage of firm wholesale revenues that are most vulnerable to competition; industrial load concentration; exposure of key customers to alternative suppliers; commercial concentrations; rates for various customer classes; rate design and flexibility; production costs, both marginal and fixed; the regional capacity situation; and transmission constraints. A regional focus is evident, but high costs and rates relative to national averages are also of significant concern because of the potential for electricity substitutes over time.

Mounting competition in the electric utility industry derives from excess generating capacity, lower barriers to entering the electric generating business, and marginal costs that are below embedded costs. Standard & Poor's has already witnessed declining prices in wholesale markets, as *de facto* retail competition is already being seen in several parts of the country. Standard & Poor's believes that over the coming years more and more customers will want and demand lower prices. Initial concerns focus on the largest industrial loads, but other customer classes will be increasingly vulnerable. Competition will not necessarily be driven by legislation. Other pressures will arise from global competition and improving technologies, whether it be the declining cost of incremental generation or advances in transmission capacity or substitute energy sources like the fuel cell. It is impossible to say precisely when wide-open retail competition will occur; this will be evolutionary. However, significantly greater competition in retail markets is inevitable.

Gas utility competition

Similarly, gas utilities are analyzed with regard to their competitive standing in the three major areas of demand: residential, commercial, and industrial. Although regulated as holders of monopoly power, natural gas utilities have for some time been actively competing for energy market share with fuel oil, electricity, coal, solar, wood, etc. The long-term staying power of market demand for natural gas cannot be taken for granted. In fact, as the electric utility industry restructures and reduces costs, electric power will become more cost competitive and threaten certain gas markets. In addition, independent gas marketers have made greater inroads behind the city gate and are competing for large gas users. Moreover, the recent trend by state regulators to unbundle utility services is creating opportunities for outsiders to market niche products. Distributors still have the upper hand, but those who do not reduce and control costs, and thus rates, could find competition even more difficult.

Natural gas pipelines are judged to carry a somewhat higher business risk than distribution companies because they face competition in every one of their markets. To the extent a pipeline serves utilities versus industrial end users, its stability is greater. Over the next five years, pipeline competition will heat up since many service contracts with customers are expiring. Most distributor or end-use customers are looking to reduce pipeline costs and are working to improve their load factor to do so. Thus, pipelines will likely find it difficult to recontract all capacity in coming years. Being the pipeline of choice is a function of attractive transportation rates, diversity and quality of services provided, and capacity available in each particular market. In all cases though, periodic discounting of rates to retain customers will occur and put pressure on profitability.

Water utility competition

As the last true utility monopoly, water utilities face very little competition and there is currently no challenge to the continuation of franchise areas. The only exceptions have been cases where investor-owned water companies have been subject to condemnation and municipalization because of poor service or political motivations. In that regard, Standard & Poor's pays close attention to costs and rates in relation to neighboring utilities and national averages. (In contrast, the privatization of public water facilities has begun, albeit at a slower pace than anticipated. This is occurring mostly in the form of operating contracts and public/private partnerships, and not in asset transfers. This trend should continue as cities look for ways to balance their tight budgets.) Also, water utilities are not fully immune to the forces of competition; in a few instances wholesale customers can access more than one supplier.

Telephone competition

The Telecommunications Act of 1996 accelerates the continuing challenge to the local exchange companies' (LECs) century-old monopoly in the local loop. Competitive access providers (CAPs), both facilities-based and resellers, are aggressively pursuing customers, generally targeting metropolitan areas, and promising lower rates and better service.

Most long-distance calls are still originated and terminated on the local telephone company network. To complete such a call, the long-distance provider (including AT&T, MCI, Sprint and a host of smaller interexchange carriers or "IXCs") must pay the local telephone company a steep "access" fee to compensate the local phone company for the use of its local network. CAPs, in contrast, build or lease facilities that directly connect customers to their long-distance carrier, bypassing the local telephone company and avoiding access fees, and thereby can offer lower long-distance rates. But the LECs are not standing still; they are combating the loss of business to CAPs by lowering access fees, thereby reducing the economic incentive for a high usage long-distance customer to use a CAP. LECs are attempting to make up for the loss of revenues from lower access fees by increasing basic local service rates (or at least not lowering them), since basic service is far less subject to competition. LECs are improving operating efficiency and marketing high margin, value-added new services. Additionally, in the wake of the Telecommunications Act, LECs will capture at least some of the inter-LATA long-distance market. As a result of these initiatives, LECs continue to rebuild themselves—from the traditional utility monopoly to leaner, more marketing oriented organizations.

While LECs, and indeed all segments of the telecommunications sector, face increasing competition, there are favorable industry factors that tend to offset heightened business risk and auger for overall ratings stability for most LECs. Importantly, telecommunications is a declining-cost business. With increased deployment of fiber optics, the cost of transport has fallen dramatically and digital switching hardware and software have yielded more capable, trouble-free and cost-efficient networks. As a result, the cost of network maintenance has dropped sharply, as illustrated by the ratio of employees per 10,000 access lines, an oft cited measurement of efficiency. Ratios as low as 25 employees per 10,000 lines are being seen, down from the typical 40 or more employees per 10,000 ratio of only a few years ago.

In addition, networks are far more capable. They are increasingly digitally switched and able to accommodate high-speed communications. The infrastructure needed to accommodate switched broadband services will be built into telephone networks over the next few years. These advanced networks will enable telephone companies to look to a greater variety of high-margin, value-added services. In addition to those current services such as call waiting or caller ID, the delivery of hundreds of broadcast and interactive video channels will be possible. While these services offer the potential of new revenue streams, they will simultaneously present a formidable challenge. LECs will be entering the new (to them) arena of multimedia entertainment and will have to develop expertise in marketing and entertainment programming acumen; such skills stand in sharp contrast to LECs' traditional strengths in engineering and customer service.

Operations

Standard & Poor's focuses on the nature of operations from the perspective of cost, reliability, and quality of service. Here, emphasis is placed on those areas that require management attention in terms of time or money and which, if unresolved, may lead to political, regulatory, or competitive problems.

Operations of electric utilities

For electrics, the status of utility plant investment is reviewed with regard to generating plant availability and utilization, and also for compliance with existing and contemplated environmental and other regulatory standards. The record of plant outages, equivalent availability, load factors, heat rates, and capacity factors are examined. Also important is efficiency, as defined by total megawatt hour per employee and customers per employee. Transmission interconnections are evaluated in terms of the number of utilities to which the utility in question has access, the cost structures and available generating capacity of these other utilities, and the price paid for wholesale power.

Because of mounting competition and the substantial escalation in decommissioning estimates, significant weight is given to the operation of nuclear facilities. Nuclear plants are becoming more vulnerable to high production costs that make their rates uneconomic. Significant asset concentration may expose the utility to poor performance, unscheduled outages or premature shutdowns, and large deferrals or regulatory assets that may need to be written off for the utility to remain competitive. Also, nuclear facilities tend to represent significant portions of their operators' generating capability and assets. The loss of a productive nuclear unit from both power supply and rate base can interrupt the revenue stream and create substantial additional costs for repairs and improvements and replacement power. The ability to keep these stations running smoothly and economically directly influences the ability to meet electric demand, the stability of revenues and costs, and, by extension, the ability to maintain adequate creditworthiness. Thus, economic operation, safe operation, and long-term operation are examined in depth. Specifically, emphasis is placed on operation and maintenance costs, busbar costs, fuel costs, refueling outages, forced outages, plant statistics, NRC evaluations, the potential need for repairs, operating licenses, decommissioning estimates and amounts held in external trusts, spent fuel storage capacity, and management's nuclear experience. In essence, favorable nuclear operations offer significant opportunities but, if a nuclear unit runs poorly or not at all, the attendant risks can be great.

Operations of gas utilities

For gas pipeline and distribution companies, the degree of plant utilization, the physical condition of the mains and lines, adequacy of storage to meet seasonal needs, "lost and unaccounted for" gas levels, and per-unit nongas operating and construction costs are important factors. Efficiency statistics such as load factor, operating costs per customer, and operating income per employee are also evaluated in comparison to other utilities and the industry as a whole.

Operations of water utilities

As a group, water utilities are continually upgrading their physical plant to satisfy regulations and to develop additional supply. Over the next decade, water systems will increasingly face the task of maintaining compliance, as drinking water regulations change and infrastructure ages. Given that the Safe Drinking Water Act was authorized in 1974, the first generation of treatment plants built to conform with these rules are almost 20 years old. Additionally, because the focus during this period was on satisfying environmental standards, deferred maintenance of distribution systems has been common, especially in older urban areas. The increasing cost of supplying treated water argues against the high level of unaccounted for water witnessed in the industry. Consequently, Standard & Poor's anticipates capital plans for rebuilding distribution lines and major renewal and replacement efforts aimed at treatment plants.

Operations of telephone companies

For telephone companies, cost-of-service analysis focuses on plant capability and measures of efficiency and quality of service. Plant capability is ascertained by looking at such parameters as percentage of digitally switched lines; fiber optic deployment, in particular in those portions of the plant key to network survival; and the degree of broadband capacity fiber and coaxial deployment and broadband switching capacity. Efficiency measures include operating margins, the ratio of employees per 10,000 access lines, and the extent of network and operations consolidation. Quality of service encompasses examination of quantitative measures, such as trouble reports and repeat service calls, as well as an assessment of qualitative factors, that may include service quality goals mandated by regulators.

Regulation

Regulatory rate-setting actions are reviewed on a case-by-case basis with regard to the potential effect on creditworthiness. Regulators' authorizing high rates of return is of little value unless the returns are earnable. Furthermore, allowing high returns based on noncash items does not benefit bondholders. Also, to be viewed positively, regulatory treatment should allow consistent performance from period to period, given the importance of financial stability as a rating consideration.

The utility group meets frequently with commission and staff members, both at Standard & Poor's offices and at commission headquarters, demonstrating the importance Standard & Poor's places on the regulatory arena for credit quality evaluation. Input from these meetings and from review of rate orders and their impact weigh heavily in Standard & Poor's analysis.

Standard & Poor's does not "rate" regulatory commissions. State commissions typically regulate a number of diverse industries, and regulatory approaches to different types of companies often differ within a single regulatory jurisdiction. This makes it all but impossible to develop inclusive "ratings" for regulators.

Standard & Poor's evaluation of regulation also encompasses the administrative, judicial, and legislative processes involved in state and federal regulation. These can affect rate-setting activities and other aspects of the business, such as competitive entry, environmental and safety rules, facility siting, and securities sales.

As the utility industry faces an increasingly deregulated environment, alternatives to traditional rate-making are becoming more critical to the ability of utilities to effectively compete, maintain earnings power, and sustain creditor protection. Thus, Standard & Poor's focuses on whether regulators, both state and federal, will help or hinder utilities as they are exposed to greater competition. There is much that regulators can do, from allocating costs to more captive customers to allowing pricing flexibility—and sometimes just stepping out of the way.

Under traditional rate-making, rates and earnings are tied to the amount of invested capital and the cost of capital. This can sometimes reward companies more for justifying costs than for containing them. Moreover, most current regulatory policies do not permit utilities to be flexible when responding to competitive pressures of a deregulated market. Lack of flexible tariffs for electric utilities may lure large customers to wheel cheaper power from other sources.

In general, a regulatory jurisdiction is viewed favorably if it permits earning a return based on the ability to sustain rates at competitive levels. In addition to performance-based rewards or penalties, flexible plans could include market-based rates, price caps, index-based prices, and rates premised on the value of customer service. Such rates more closely mirror the competitive environment that utilities are confronting.

Electric industry regulation

The ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract is also important in the electric industry. (While contracting at reduced rates constrains financial performance, it lessens the potential adverse impact in the event of retail wheeling. Since revenue losses associated with this strategy are not likely to be recovered from ratepayers, utilities must control costs well enough to remain competitive if they are to sustain current levels of bondholder protection.)

Natural gas industry regulation

In the gas industry, too, several state commission policies weigh heavily in the evaluation of regulatory support. Examples include stabilization mechanisms to adjust revenues for changes in weather or the economy, rate and service unbundling decisions, revenue and cost allocation between sales and transportation customers, flexible industrial rates, and the general supportiveness of construction costs and gas purchases.

Water industry regulation

In all water utility activities, federal and state environmental regulations continue to play a critical role. The legislative timetable to effect the 1986 amendments to the Safe Drinking Water Act of 1974 was quite aggressive. But environmental standards-setting has actually slowed over the past couple of years due largely to increasing sentiment that the stringent, costly standards have not been justified on the basis of public health. A moratorium on the promulgation of significant new environmental rules is anticipated.

Telecommunications industry regulation

Despite the advances in telecommunications deregulation, analysis of regulation of telephone operators will continue to be a key rating determinant for the foreseeable future. The method of regulation may be either classic rate-based rate of return or some form of price cap mechanism. The most important factor is to assess whether the regulatory framework—no matter which type—provides sufficient financial incentive to encourage the rated company to maintain its quality of service and to upgrade its plant to accommodate new services while facing increasing competition from wireless operators and cable television companies.

Where regulators do still set tariffs based on an authorized return, Standard & Poor's strives to explore with regulators their view of the rate-of-return components that can materially impact reported versus regulatory earnings. Specifically these include the allowable base upon which the authorized return can be earned, allowable expenses, and the authorized return. Since regulatory oversight runs the gamut from strict, adversarial relationships with the regulated operating companies to highly supportive postures, Standard & Poor's probes beyond the apparent regulatory environment to ascertain the actual impact of regulation on the rated company.

Management

Evaluating the management of a utility is of paramount importance to the analytical process since management's abilities and decisions affect all areas of a company's operations. While regulation, the economy, and other outside factors can influence results, it is ultimately the quality of management that determines the success of a company.

With emerging competition, utility management will be more closely scrutinized by Standard & Poor's and will become an increasingly critical component of the credit evaluation. Management strategies can be the key determinant in differentiating utilities and in establishing where companies lie on the business position spectrum. It is imperative that managements be adaptable, aggressive, and proactive if their utilities are to be viable in the future; this is especially important for utilities that are currently uncompetitive.

The assessment of management is accomplished through meetings, conversations, and reviews of company plans. It is based on such factors as tenure, industry experience, grasp of industry issues, knowledge of customers and their needs, knowledge of competitors, accounting and financing practices, and commitment to credit quality. Management's ability and willingness to develop workable strategies to address their systems' needs, to deal with the competitive pressures of free market, to execute reasonable and effective long-term plans, and to be proactive in leading their utilities into the future are assessed. Management quality is also indicated by thoughtful balancing of public and private priorities, a record of credibility, and effective communication with the public, regulatory bodies, and the financial community. Boards of directors will receive ever more attention with respect to their role in setting appropriate management incentives.

With competition the watchword, Standard & Poor's also focuses on management's efforts to enhance financial condition. Management can bolster bondholder protection by taking any number of discretionary actions, such as selling common equity, lowering the common dividend payout, and paying down debt. Also important for the electric industry will be creativity in entering into strategic alliances and working partnerships that improve efficiency, such as central dispatching for a number of utilities or locking up at-risk customers through long-term contracts or expanded flexible pricing agreements. Proactive management teams will also seek alternatives to traditional rate-base, rate-of-return rate-making, move to adopt higher depreciation rates for generating facilities, segment customers by individual market preferences, and attempt to create superior service organizations.

In general, management's ability to respond to mounting competition and changes in the utility industry in a swift and appropriate manner will be necessary to maintain credit health.

Fuel, power, and water supply

Assessment of present and prospective fuel and power supply is critical to every electric utility analysis, while gauging the long-term natural gas supply position for gas pipeline and distribution companies and the water resources of a water utility is equally important. There is no similar analytical category for telephone utilities.

Electric utilities

For electric utilities emphasis is placed on generating reserve margins, fuel mix, fuel contract terms, demand-side management techniques, and purchased power arrangements. The adequacy of generating margins is examined nationally, regionally, and for each individual company. However, the reserve margin picture is muddied by the imprecise nature of peak-load growth forecasting, and also supply uncertainty relating to such things as Canadian capacity availability and potential plant shutdowns due to age, new NRC rules, acid rain remedies, fuel shortages, problems associated with nontraditional technologies, and so forth. Even apparently ample reserves may not be what they seem. Moreover, the quality of capacity is just as important as the size of reserves. Companies' reserve requirements differ, depending upon individual operating characteristics.

Fuel diversity provides flexibility in a changing environment. Supply disruptions and price hikes can raise rates and ignite political and regulatory pressures that ultimately lead to erosion in financial performance. Thus, the ability to alter generating sources and take advantage of lower cost fuels is viewed favorably.

Dependence on any single fuel means exposure to that fuel's problems: electric utilities that rely on oil or gas face the potential for shortages and rapid price increases; utilities that own nuclear generating facilities face escalating costs for decommissioning; and coal-fired capacity entails environmental problems stemming from concerns over acid rain and the "greenhouse effect."

Buying power from neighboring utilities, qualifying facility projects, or independent power producers may be the best choice for a utility that faces increasing electricity demand. There has been a growing reliance on purchased power arrangements as an alternative to new plant construction. This can be an important advantage, since the purchasing utility avoids potential construction cost overruns as well as risking substantial capital. Also, utilities can avoid the financial risks typical of a multiyear construction program that are caused by regulatory lag and prudence reviews. Furthermore, purchased power may enhance supply flexibility, fuel resource diversity, and maximize load factors. Utilities that plan to meet demand projections with a portfolio of supply-side options also may be better able to adapt to future growth uncertainties. Notwithstanding the benefits of purchasing, such a strategy has risks associated with it. By entering into a firm long-term purchased power contract that contains a fixed-cost component, utilities can incur substantial market, operating, regulatory, and financial risks. Moreover, regulatory treatment of purchased power removes any upside potential that might help offset the risks. Utilities are not compensated through incentive rate-making; rather, purchased power is recovered dollar-for-dollar as an operating expense.

To analyze the financial impact of purchased power, Standard & Poor's first calculates the net present value of future annual capacity payments (discounted at 10%). This represents a potential debt equivalent—the off-balance-sheet obligation that a utility incurs when it enters into a long-term purchased power contract. However, Standard & Poor's adds to the utility's balance sheet only a portion of this amount, recognizing that such a contractual arrangement is not entirely the equivalent of debt. What percentage is added is a function of Standard & Poor's qualitative analysis of the specific contract and the extent to which market, operating, and regulatory risks are borne by the utility (the risk factor). For unconditional, take-or-pay contracts, the risk factor range is from 40%-80%, with the average hovering around 60%. A lower risk factor is typically assigned for system purchases from coal-fired utilities and a higher risk factor is usually designated for unit-specific nuclear purchases. The range for take-and-pay performance obligations is between 10%-50%.

Gas utilities

For gas distribution utilities, long-term supply adequacy obviously is critical, but the supply role has become even more important in credit analysis since the Federal Energy Regulatory Commission's Order 636 eliminated the interstate pipeline merchant business. This thrust gas supply responsibilities squarely on local gas distributors. Standard & Poor's has always believed distributor management has the expertise and wherewithal to perform the job well, but the risks are significant since gas costs are such a large percentage of total utility costs. In that regard, it is important for utilities to get preapprovals of supply plans by state regulators or at least keep the staff and commissioners well informed. To minimize risks, a well-run program would diversify gas sources among different producers or marketers, different gas basins in the U.S. and Canada, and different pipeline routes. Also, purchase contracts should be firm, with minimal take-or-pay provisions, and have prices tied to an industry index. A modest percentage of fixed-price gas is not unreasonable. Contracts, whether of gas purchases or pipeline capacity, should be intermediate term. Staggering contract expirations (preferably annually) provides an opportunity to be an active market player. A modest degree of reliance on spot purchases provides flexibility, as does the use of market-based storage. Gas storage and on-property gas resources such as liquefied natural gas or propane air are effective peak-day and peak-season supply management tools.

Since pipeline companies no longer buy and sell natural gas and are just common carriers, connections with varied reserve basins and many wells within those basins are of great importance. Diversity of sources helps offset the risks arising from the natural production declines eventually experienced by all reserve basins and individual wells. Moreover, such diversity can enhance a pipeline's attractiveness as a transporter of natural gas to distributors and end users seeking to buy the most economical gas available for their needs.

Water utilities

Nearly all water systems throughout the U.S. have ample long-term water supplies. Yet to gain comfort, Standard & Poor's assesses the production capability of treatment plants and the ability to pump water from underground aquifers in relation to the usage demands from consumers. Having adequate treated water storage facilities has become important in recent years and has helped many systems meet demands during peak summer periods. Of interest is whether the resources are owned by the utility or purchased from other utilities or local authorities. Owning properties with water rights provides more supply security. This is especially so in states like California where water allocations are being reduced, particularly since recent droughts and environmental issues have created alarm. Since the primary cost for water companies is treatment, it makes little difference whether raw water is owned or bought. In fact, compliance with federal and state water regulations is very high, and the overall cost to deliver treated water to consumers remains relatively affordable.

Asset concentration in the electric utility industry

In the electric industry, Standard & Poor's follows the operations of major generating facilities to assess if they are well managed or troubled. Significant dependence on one generating facility or a large financial investment in a single asset suggests high risk. The size or magnitude of a particular asset relative to total generation, net plant in service, and common equity is evaluated. Where substantial asset concentration exists, the financial profile of a company may experience wide swings depending on the asset's performance. Heavy asset concentration is most prevalent among utilities with costly nuclear units.

Earnings protection

In this category, pretax cash income coverage of all interest charges is the primary ratio. For this calculation, allowance for funds used during construction (AFUDC) is removed from income and interest expense. AFUDC and other such noncash items do not provide any protection for bondholders. To identify total interest expense, the analyst reclassifies certain operating expenses. The interest component of various off-balance-sheet obligations, such as leases and some purchased-power contracts, is included in interest expense. This provides the most direct indication of a utility's ability to service its debt burden.

While considerable emphasis in assessing credit protection is placed on coverage ratios, this measure does not provide the entire earnings protection picture. Also important are a company's earned returns on both equity and capital, measures that highlight a firm's earnings performance. Consideration is given to the interaction of embedded costs, financial leverage, and pretax return on capital.

Capital structure

Analyzing debt leverage goes beyond the balance sheet and covers quasi-debt items and elements of hidden financial leverage. Noncapitalized leases (including sale/leaseback obligations), debt guarantees, receivables financing, and purchased-power contracts are all considered debt equivalents and are reflected as debt in calculating capital structure ratios. By making debt level adjustments, the analyst can compare the degree of leverage used by each utility company.

Furthermore, assets are examined to identify undervalued or overvalued items. Assets of questionable value are discounted to more accurately evaluate asset protection.

Some firms use short-term debt as a permanent piece of their capital structure. Short-term debt also is considered part of permanent capital when it is used as a bridge to permanent financing. Seasonal, self-liquidating debt is excluded from the permanent debt amount, but this situation is rare—with the exception of certain gas utilities. Given the long life of almost all utility assets, short-term debt may expose these companies to interest-rate volatility, remarketing risk, bank line backup risk, and regulatory exposure that cannot be readily offset. The lower cost of shorter-term obligations (assuming a positively sloped yield curve) is a positive factor that partially mitigates the risk of interest-rate variability. As a rule of thumb, a level of short-term debt that exceeds 10% of total capital is cause for concern.

Similarly, if floating-rate debt and preferred stock constitute over one-third of total debt plus preferred stock, this level is viewed as unusually high and may be cause for concern. It might also indicate that management is aggressive in its financial policies.

A layer of preferred stock in the capital structure is usually viewed as equity—since dividends are discretionary and the subordinated claim on assets provides a cushion for providers of debt capital. A preferred component of up to 10% is typically viewed as a permanent wedge in the capital structure of utilities. However, as rate-of-return regulation is phased out, preferred stock may be viewed by utilities—as many industrial firms would—as a temporary option for companies that are not current taxpayers that do not benefit from the tax deductibility of interest. Even now, floating-rate preferred and money market perpetual preferred are problematic; a rise in the rate due to deteriorating credit quality tends to induce a company to take out such preferred stock with debt. Structures that convey tax deductibility to preferred stock have become very popular and do generally afford such financings with equity treatment.

Cash flow adequacy

Cash flow adequacy relates to a company's ability to generate funds internally relative to its needs. It is a basic component of credit analysis because it takes cash to pay expenses, fund capital spending, pay dividends, and make interest and principal payments. Since both common and preferred dividend payments are important to maintain capital market access, Standard & Poor's looks at cash flow measures both before and after dividends are paid.

To determine cash flow adequacy, several quantitative relationships are examined. Emphasis is placed on cash flow relative to debt, debt service requirements, and capital spending. Cash flow adequacy is evaluated with respect to a firm's ability to meet all fixed charges, including capacity payments under purchased-power contracts. Despite the conditional nature of some contracts, the purchaser is obligated to pay a minimum capacity charge. The ratio used is funds from operations plus interest and capacity payments divided by interest plus capacity payments.

Financial flexibility/capital attraction

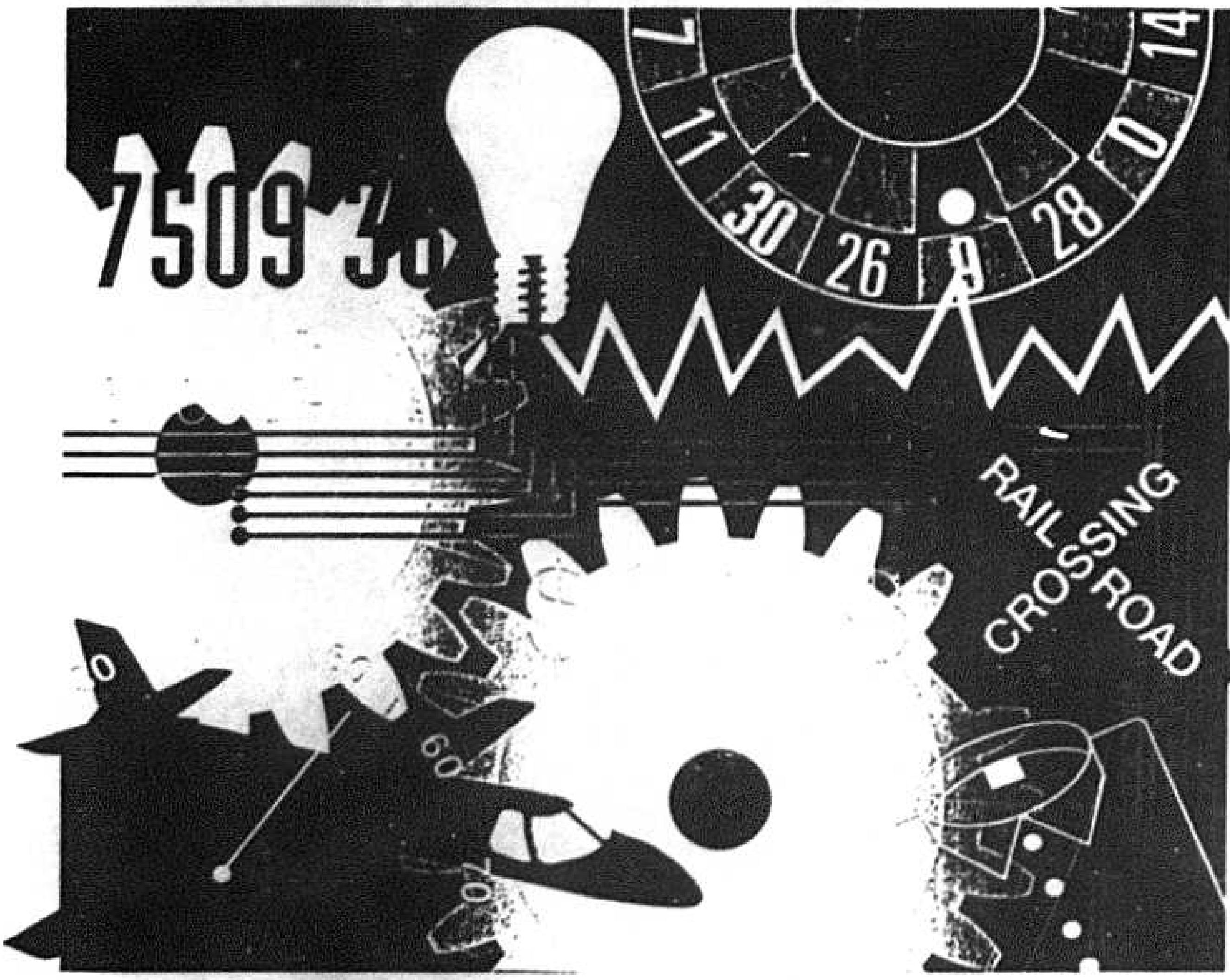
Financing flexibility incorporates a utility's financing needs, plans, and alternatives, as well as its flexibility to accomplish its financing program under stress without damaging creditworthiness. External funding capability complements internal cash flow. Especially since utilities are so capital intensive, a firm's ability to tap capital markets on an ongoing basis must be considered. Debt capacity reflects all the earlier elements: earnings protection, debt leverage, and cash flow adequacy. Market access at reasonable rates is restricted if a reasonable capital structure is not maintained and the company's financial prospects dim. The analyst also reviews indenture restrictions and the impact of additional debt on covenant tests.

Standard & Poor's assesses a company's capacity and willingness to issue common equity. This is affected by various factors, including the market-to-book ratio, dividend policy, and any regulatory restrictions regarding the composition of the capital structure.

STANDARD & POOR'S

GLOBAL SECTOR REVIEW

UTILITIES



NOVEMBER 1996

FLORIDA POWER CORP.

Analyst: Mary Ellen Olson, New York (1) 212-208-8947

RATING(S) AFFIRMED

OUTLOOK: STABLE

SENIOR DEBT HISTORY

1995	AA-
1994	AA-
1993	AA-
1992	AA-
1991	AA-

OUTSTANDING RATING(S)	
Senior secured debt	AA-
Senior unsecured debt	A+
Preferred stock	A+
Commercial paper	A-1+

RATIONALE The ratings reflect Florida Power Corp.'s above average business position and a healthy financial condition. Florida Power's business profile is supported by a healthy service area with above-average growth prospects, responsive Florida regulation, a diversified fuel mix, minimal Clean Air Act spending, and a credit-conscious management. A small industrial load (about 9% of revenues) limits exposure to the possibility of retail wheeling, while the utility's geographical location gives near-term protection from competition.

Rates and total energy costs are competitive in peninsular Florida, but are slightly higher than the regional average. Florida Power supplements owned capacity with power purchases from neighboring utilities and from cogenerators; purchased power will provide about 27% of generation for the foreseeable future. The costs are passed through as a capacity cost recovery factor and fuel charge. Notwithstanding the likelihood for about 1.0% annual price increases to recover purchased power costs, the company's competitive position will not be affected noticeably. Florida Power will avoid any base rate relief requests for many years. Operations at the Crystal River 3 nuclear station continue to improve, with a 1995 capacity factor of 100%. Debt leverage, including off-balance-sheet purchased power obligations, will remain high for current ratings, at about 51%. But internal funding, funds from operation interest coverage, and funds from operations to total debt should remain healthy even throughout the construction of two gas-fired combined cycle units, which will become operational in 1998 and 1999. Continued strong kilowatt-hour sales growth and aggressive cost controls should allow Florida Power to maintain pretax interest coverage, adjusted for purchased power, at levels over 3.2 times.

OUTLOOK A period of ratings stability for Florida Power is based on above-average sales growth, rate flexibility, limitations on rate increases, little wholesale and industrial exposure, aggressive cost controls, efficient operations, and healthy cash flow.

Florida Power Co. financial statistics

			—Year ended Dec. 31—		
(Mil. $)	1996*	1995	1994	1993	1992
Gross revenues	2,303.1	2,271.7	2,080.5	1,957.6	1,774.1
Net income from continuing operations	228.9	227.0	200.8	194.9	186.9
Funds from operations (FFO)	541.1	524.3	502.0	432.5	416.2
Net cash flow (NCF)	348.1	333.9	316.2	255.6	244.1
Capital expenditures (capex)	282.8	283.4	319.3	426.4	472.9
Pretax interest coverage (x)	4.14	4.33	3.81	3.68	3.65
Preferred dividend coverage (x)	3.63	3.80	3.34	3.10	2.92
FFO interest coverage (x)	6.20	5.95	5.57	4.97	5.05
Capex/avg. total capital (%)	8.9	8.8	9.8	13.6	15.6
NCF/capex (%)	123.1	117.8	99.0	59.9	51.6
FFO/avg. total debt (%)	42.6	37.9	33.2	29.4	30.4
Return on common equity (nominal) (%)	12.5	12.7	12.0	12.2	11.8
Total capitalization	3,130.5	3,202.2	3,265.4	3,240.4	3,029.2
Short-term debt (%)	1.6	1.0	2.8	5.3	4.4
Long-term debt (%)	37.7	39.9	41.8	43.2	40.8
Preferred stock (%)	4.4	4.3	4.4	4.6	7.1
Common equity (%)	56.3	54.8	51.1	47.0	47.7

*For 12 months ended March 31 (unaudited).

Florida Power Co. operating statistics

			—Year ended Dec. 31—		
	1995	1994	1993	1992	1991
Total sales (GWh)	32,403	30,015	28,648	27,376	27,350
Residential (%)	46.1	46.2	46.7	46.9	46.2
Commercial (%)	26.6	27.5	27.5	27.6	27.4
Industrial (%)	11.9	11.9	11.8	11.9	12.1
Wholesale (%)	9.0	7.8	7.4	7.2	7.9
Other (%)	6.4	6.6	6.6	6.5	6.4
Avg. retail revenue (cents/kWh)	7.03	6.89	6.71	6.20	6.32
Retail sales growth (%)	6.59	4.32	4.38	0.93	1.21
Capacity at time of peak (MW)	7,721	7,457	6,711	6,912	6,971
Reserve margin (%)	N.A.	7.2	(0.3)	(1.0)	13.1

MW—Megawatts. MWh—Megawatt-hours. kWh—Kilowatt-hours. GWh—Gigawatt-hours.

Florida Power Corporation

August 1996

Ratings

Category	Moody's Rating
First Mortgage Bonds	Aa3
Senior Unsecured Debt	A1
Counterparty Rating	A1
Preferred Stock	"a1"
Commercial Paper	P-1

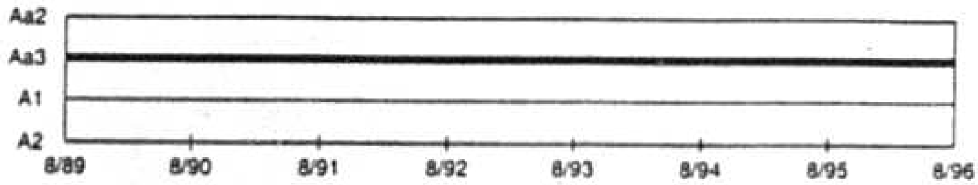
Contacts

Analyst	Phone
A. Tucker Hackett	(212) 553-1653
Susan D. Abbott	

Florida Progress Corp.

Senior Unsecured Medium-Term Notes	A2
Commercial Paper	P-1

Rating History



Operating Statistics

Florida Power Corporation (Statistics in bold type)
Peer Group Median (Statistics in light type)

	[1]1996	1995		1994		1993		1992		[2]5-Yr.Avg.	
Revenue (US$ bil.)	**2.3**	1.0	**2.3**	1.0	**2.1**	1.0	**2.0**	0.9	**1.8**	[3]1.9	**[3]5.9**
Assets (US$ bil.)	**4.3**	2.7	**4.3**	2.7	**4.3**	2.6	**4.3**	2.4	**4.0**	[3]4.0	**[3]4.0**
Com. Equity (US$ bil.)	**1.8**	0.9	**1.8**	0.8	**1.7**	0.7	**1.5**	0.7	**1.4**	[3]5.4	**[3]8.1**
Op. Margin (%)	**19.9**	21.9	**20.1**	21.5	**20.2**	20.7	**20.0**	21.4	**20.7**	21.3	**20.4**
ROA (avg.)(%)	**5.1**	3.8	**5.1**	3.5	**4.5**	3.7	**4.4**	3.8	**4.5**	3.7	**4.6**
ROE (avg.)(%)	**12.8**	12.6	**12.7**	11.7	**12.0**	12.0	**12.2**	11.9	**12.4**	12.1	**12.5**
Div. Payout (%)	**83.5**	79.5	**83.2**	83.5	**92.1**	81.3	**90.1**	81.9	**91.3**	81.2	**88.6**
Pretax Int. Cov. (X)	**4.4**	3.4	**4.3**	3.3	**3.8**	3.2	**3.7**	2.9	**3.7**	3.1	**3.9**
Fxd. Chg. Cov. (X)	**4.0**	3.0	**3.9**	2.7	**3.5**	2.6	**3.2**	2.4	**3.0**	2.6	**3.3**
RCF % TD	**29.6**	15.1	**26.3**	14.3	**22.6**	13.1	**16.2**	12.8	**19.3**	13.7	**21.1**
RCF % Gross CAPEX	**128.5**	112.7	**121.6**	89.5	**101.3**	90.6	**56.6**	87.2	**53.7**	94.2	**79.0**
Total Cap. (US$ bil.)	**3.1**	1.9	**3.2**	1.8	**3.3**	1.8	**3.2**	1.7	**3.0**	[3]3.8	**[3]4.0**
TD % Cap.	**39.3**	49.5	**40.9**	50.0	**44.5**	50.4	**48.4**	50.0	**45.2**	50.1	**43.9**
Pfd. Stk. % Cap.	**4.4**	5.7	**4.3**	6.3	**4.4**	6.2	**4.6**	6.6	**7.1**	6.3	**5.9**
Common % Cap.	**56.3**	45.0	**54.8**	44.3	**51.1**	44.3	**47.0**	43.2	**47.7**	43.9	**50.3**
Adj. TD % Adj. Cap.	**57.4**	52.3	**57.5**	55.2	**54.8**	54.9	**55.0**	57.8	**51.3**	55.7	**53.6**

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale
Revenue (US$ mil.)	1,252.7	515.3	189.3	153.4
Kwh(mil.)	14938	8612	3864	2903
¢/Kwh	8.4	6.0	4.9	5.3
Industry Avg. (¢/Kwh)	8.3	7.2	5.1	3.2
Competitive Position	**Break-even Price($)**	**Regional Avg.($)**	**Stranded Cost($mil.)**	**Stranded Cost % Eq.**
	35.20	34.89	339	20

[1] For the 12 months ended March 31, 1996. Balance sheet items are as of March 31, 1996. [2] Five year average 1995-1991. [3] Five year compound annual growth rate.

Opinion

Rating Rationale

Florida Power Corporation (FPC) maintains its Aa3 senior secured bond rating by virtue of its reasonable production costs, effective management strategies, the favorable composition of its growing customer base, supportive regulation, and the protection from competition afforded by Florida's geographic isolation. However, the company has entered a construction cycle which, combined with sizable power purchase contracts at above market prices, will pressure generating costs. Nuclear operating risk, and the parent's guarantee of the debt of diversified businesses, contribute further risk for the bondholder.

The company derives a small portion (9%) of revenues from the industrial sector and a large portion from residential sales (56%.) Few industrial customers support deregulation and all customer classes continue to grow. As a result, neither Florida's utility regulatory commission nor its legislature have strongly supported initiatives to open the state's retail market for electric power to competition.

The slow pace of deregulation provides the company with time to streamline operations and to reduce costs. Central to this strategy are negotiations to exchange up-front payments for lower capacity charges from non-utility power suppliers. We expect formal commission approval this fall of management's intent to use $18 million for this purpose in lieu of returning it to customers.

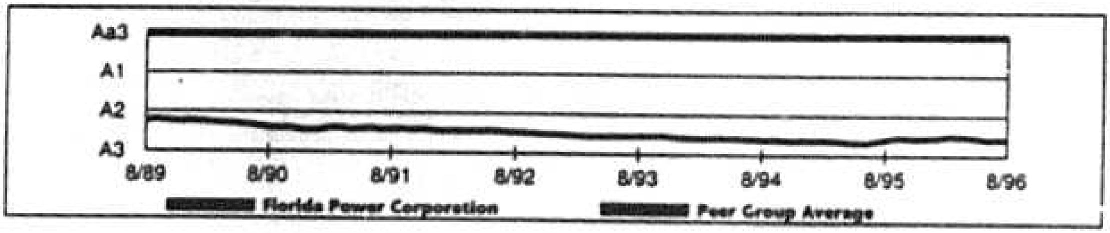
Rating Outlook

The rating outlook is stable. Although FPC does not intend to seek rate relief for $281 million in construction costs for the new combined cycled baseload plant, we believe that the company will be able to offset these expenditures with cost control and sales growth.

Coupon	Type of Debt	Maturity	Moody's Rating
Florida Power Corporation			
7.000%	First Mortgage Bonds	2023	Aa3
8.000%	First Mortgage Bonds	2022	Aa3
8.625%	First Mortgage Bonds	2021	Aa3
6.875%	First Mortgage Bonds	2008	Aa3
6.000%	First Mortgage Bonds	2003	Aa3
6.125%	First Mortgage Bonds	2003	Aa3
7.250%	First Mortgage Bonds	2002	Aa3
7.375%	First Mortgage Bonds	2002	Aa3
6.500%	First Mortgage Bonds	1999	Aa3
6.125%	First Mortgage Bonds	1997	Aa3
	Medium-Term Notes Program	1997	A1
	Medium-Term Notes Program		A1
	Medium-Term Notes Program		A1
	Counterparty Rating		A1
4%	Cum. Pfd. Stk.		"a1"
4.60%	Cum. Pfd. Stk.		"a1"
4.40%	Cum. Pfd. Stk.		"a1"

(Continued on page 8)

Rating History with Peer Group



The peer group on the front page includes 126 electric utilities. Members of the peer group may change from year to year, which may slightly alter peer group data.

Company Fundamentals

Business Fundamentals and Competitive Position

Florida Power Corporation (FPC), Florida's second-largest investor-owned utility, serves central and northern Florida and the west coast of the state with economic plants fueled by coal (39% of total generating capacity), nuclear power from its 90% ownership interest in Crystal River 3 (19%), and oil and gas (16%.) Although company owned generation is economic, several expensive power purchase contracts (26%) detract from the company's cost position. Furthermore, the company has entered a construction cycle to complete in 1998 a combined cycle, 507-mw baseload plant in Polk county. At $555/kw, this new, undepreciated plant will pressure FPC's total production costs.

FPC offers rates that are competitive within Florida. The preponderance of FPC's sales are to residential customers, which contributed 56% of the company's 1995 revenues, followed by sales to the commercial sector, which comprised 23% of 1995 sales. The industrial sector contributed 9% of the company's sales in 1995; other retail customers contributed 5%; and 7% of sales were to 16 wholesale customers, the largest of which is Seminole Electric Cooperative.

We expect growth in the residential and commercial sectors to drive a 4% compound annual increase in FPC's sales. Commercial activities in the service territory include tourism, health care, construction, and agriculture; industries include phosphate and rock mining and processing, electronics design and manufacturing, and citrus and other food processing. Only one phosphate producer, IMC Agrico, is pressing publicly for consumer choice among suppliers of electric power. Others are negotiating more quietly, opting for interruptible service contracts, which offer discounts in return for letting the utility cut off electricity during periods of high demand, or for new real-time pricing tariffs.

FPC's short-term competitive position is protected by growing demand, area assignment laws, the isolation afforded by the Florida peninsula, and a lack of transmission access to the state. The legislature adjourned in May without acting on a retail wheeling bill that had been introduced in the House for the second year in a row. (Retail wheeling is a plan to allow retail customers to contract to purchase power directly from any provider without regard to currently existing service areas.)

FPC has 111 franchise agreements, which contribute about 40% of its revenues. In December, it signed a new 30-year agreement with its second-largest franchise customer, the City of Clearwater, which accounts for approximately 5% of total revenue. The seven additional franchises that expire before 2000 do not contribute a significant percentage of revenue.

Management Strategy

With the retirement in April 1996 of Allen Kessler, President and Chief Executive Officer of Florida Power Corporation, the company began a reorganization of its senior management that could take up to a year to complete. Although many key executives have assumed different responsibilities, the company's strategy to position itself to compete successfully appears unchanged. This strategy includes enhancing marketing and customer service, streamlining operations, workforce reengineering, functional unbundling of generation from transmission and distribution, and growing wholesale sales. Efficiencies realized through these mechanisms will offset costs incurred to construct a new baseload facility and enable the company to avoid filing for rate relief upon their completion. Management is also actively negotiating to reduce capacity payments made to non-utility generators to purchase power, and is amortizing regulatory assets to clean up the balance sheet.

FPC has reduced its workforce by 20% since 1993. Also, effective July 1, the company reorganized into three functional areas: Energy Solutions, to focus on customer service, and marketing, technology, and new produce development; Energy Delivery, to handle bulk transmission and distribution of electric power to customers; and Energy Supply, to oversee fossil and nuclear generation. Going forward, FPC intends to limit increases in operation and maintenance expenses to less than the national inflation rate.

The company has entered a baseload construction cycle to complete in 1998 a combined cycle, gas-fired, 5· mw baseload unit in Polk county. In October 1995, the company announced an agreement with Seminole Electric Cooperative to provide 455 mw of wholesale power for three years, beginning in 1999. This agreement will increase wholesale sales by more than 40%, to 8% of total kwh sales. To complement demand for FPC's power which peaks during the winter, the company has entered into an arrangement with Georgia Power, whose demand peaks in the summer. The two utilities will share the utilization of a 165-mw combustion turbine, scheduled to enter commercial operation this year. Separately, FPC agreed to sell between 150 and 400 mw of peaking capacity to Georgia Power from 1996 through 1999.

The strategy for the nuclear unit includes maintaining high capacity factors and cooperating with seven other nuclear utilities to pool equipment purchases and other costs. In 1995, the nuclear unit achieved a 100% capacity factor; a refueling outage in 1996 will preclude a repeat performance this year. FPC's safety ratings from the Nuclear Regulatory Commission (NRC) average 1.75 on a scale of 1 to 3, with 1 being the highest. The NRC recently levied a $500,000 fine on the company for unauthorized testing and the commission has moved up the company's next review to September, 1996 from March, 1997.

The company remains one of the industry's largest purchasers of power, much of which is above market prices in Florida. FPC contracted to purchase 1,110 mw of non-utility generated power, to come gradually on line by 1997. In addition, it purchases up to 407 mw from the Southern Company under an expensive contract that runs through 2010 (with an option to reduce purchases to 200 mw in 2000 upon three years notice), and 50 mw from Tampa Electric. The company is actively negotiating with non-utility generators to reduce the payments made to them.

FPC is the principal operating subsidiary of the Florida Progress Corporation, a diversified utility holding company. Medium-term notes (rated A2) and commercial paper (P-1) issued by Progress Capital Holdings (PCH), a subholding company, finance the non-utility businesses. Management recently announced its intention to divest the Progress Credit Corporation, its leasing and real estate business unit through a corporate spin-off to existing shareholders later this year. The spin-off will result in a $25 million after-tax charge to earnings, primarily to write down certain Progress Credit assets, and an approximate $175 million reduction to net worth pursuant to the dividend. Moody's confirmed the PCH ratings based upon the reduction in risk and improved cash flow in the remaining businesses.

Florida Progress' remaining diversified businesses after the spin-off include Electric Fuels Corporation, the transportation and coal subsidiary, which it continues to expand, and the Mid-Continent Life Insurance Company, both of which are profitable. In August the parent replaced its net worth support agreement of PCH businesses with a guarantee of PCH debt. The parent's support of non-utility businesses increases risk for the bondholder at the utility level. However, Florida Progress's strategic decision to concentrate on domestic opportunities shields bondholders from risks inherent in international diversification.

Regulation and Rates

The Florida legislature is in session annually between March and May. For the second year in a row, the House failed to act on a bill that had been introduced in support of retail wheeling. During the eight month recess, an Oversight and Investigation Subcommittee of the House Committee on Utilities and Telecommunication examined the issue of competition in the electric industry, but produced no recommendations for the legislature.

The Florida Public Service Commission (FPSC) continues to express prudency and caution toward retail wheeling, and has yet to take any action to foster it. The commission recently approved FPC's real-time pricing tariff, which enables the company to offer incremental hourly pricing to large customers that can not take advantage of the interruptible rate option.

FPC has not requested rate relief since the October 1992 order that authorized a 12% midpoint for the equity return, in line with other Florida utilities. Prior approvals enable the company to add Polk to rate base upon its completion. It intends to construct the Polk plant without seeking increases, opting instead to offset construction expense with cost control. We expect the company to be able to contain retail rate increases to 1% over the next five years despite growing power purchase expenses.

At the request of the FPSC, FPC initiated a three-year test, effective January 1995, of revenue decoupling for residential customers. Under the test, kilowatt-hour (kwh) sales and revenues are decoupled, eliminating the disincentive for utilities to urge customers to conserve energy. The company plans to present to the commission a proposal to exchange future cogenerator capacity payments for up-front payments, as part of a commission approved deferral of the disposition of the company's $18 million liability from the over-recovery of revenues under the residential revenue decoupling test during 1995. A final decision is expected this fall from the commission.

The Federal Energy Regulatory Commission (FERC) governs wholesale rates, which account for about 6% of FPC's revenues. FPC filed an open access tariff with FERC pursuant to Rule 888, promulgated in March. The Florida broker system already operates as a competitive bulk power market.

Risks/Weaknesses

- Expensive purchased power contracts.
- Nuclear operating risk.
- New Polk baseload plant will pressure generating costs upon completion in 1998.
- Parent guarantee of non-regulated subsidiary debt.

Opportunities/Strengths

- Cost control, renegotiation of above-market power purchase contracts, and other initiatives by management to improve the company's competitive position..
- Reasonable generating costs and minimal deferred assets.
- Economically vibrant service territory.
- Little support from customers or the legislature for competition in retail market for electric power.
- Geography provides a natural barrier to competition.
- Reasonable regulation by the FPSC.

Financial Analysis

We expect that growth in the number of customers and increased usage per customer will drive kwh sales growth of 4% per year through 2000. Sales growth, cost savings, and debt reduction will enable pretax interest coverage to average 4.8 times despite growing fuel and purchased power expenses. For 1995, FPC posted a 12.7% equity return on a GAAP basis.

Aided by amortization of the $23 million expense incurred in connection with the canceled Lake Tarpon transmission line, cash flow coverage of interest expense remains above 6 times throughout the forecast period. During the second quarter of the year, it expensed the remaining $12 million of Turner and Higgins power plants previously placed in extended cold shutdown. We expect the company to continue to clean up the balance sheet going forward. The company could amortize an additional $18 million in regulatory assets this year.

FPC's construction program totals $1.4 billion for the 1996-2000 forecast period. It peaks in 1997 at $332 million due to construction of the Polk units; otherwise, it averages $275 million per year. After dividends, cash flow from operations covers capital expenditures by over 100% . For this reason, the company plans no additional debt or equity offerings. Debt and preferred stock repayments will continue despite heightened construction spending. The company will cover any shortfall with commercial paper.

The parent intends to grow common equity toward 60% over the next few years. However, expensive capacity payments associated with purchased power contracts will limit this improvement. In addition, although risk has diminished in diversified businesses pursuant to the corporate spin-off of the real estate and leasing business unit, Moody's views the parent's guarantee of debt of non-utility businesses as risky from a bondholder perspective.

	1995	1994	1993	1992	1991
Coverage Analysis (Excl. AFUDC and Other Allowances)					
Pretax interest coverage	4.34	3.80	3.68	3.66	3.77
SEC interest coverage	4.41	3.90	3.78	3.78	3.81
SEC fixed-charge coverage	3.86	3.41	3.17	3.03	3.02
Funds from oper. %interest exp.	6.12	5.74	5.07	5.36	4.97
Funds from oper. %net CAPEX (%)	193.79	164.[illegible]	99.46	92.24	109.33
Funds from oper. %net CAPEX + pref. div.	187.21	158.96	96.48	89.09	104.26
Funds from oper. %total debt (%)	40.85	35.35	27.45	31.88	36.45
Deferred charges as % of common equity	6.36	6.05	6.65	4.35	9.66
Earnings Analysis					
Return on avg.					
Common equity	12.70	11.96	12.23	12.37	13.15
Total assets	5.07	4.46	4.41	4.47	4.58
Total capital	8.58	7.91	7.85	8.13	8.35
AFUDC as % net income	3.22	5.43	8.00	9.98	5.21
Asset Composition					
Total assets	4,284.9	4,284.5	4,259.5	3,980.6	3,643.2
As % total assets					
Net utility plant	84.2	85.6	85.5	86.5	87.7
Investments	4.3	3.4	3.2	3.0	0.6
Current assets	8.9	8.6	9.0	9.0	8.2
Deferred charges	2.6	2.4	2.4	1.6	3.5
As % gross electric plant					
Electric plant in prod. (gross)					
Fossil	25.1	25.4	25.5	27.2	29.1
Nuclear	10.2	10.5	10.4	10.6	11.1
Gas turbine	6.1	4.5	4.8	3.4	3.6
Total electric plant in prod.	41.5	40.4	40.7	41.2	43.8
Other electric plant (gross)					
Transmission	12.0	11.8	11.3	11.1	11.8
Distribution	29.4	28.3	27.4	27.1	27.6
Common plant	8.7	9.7	9.8	8.4	6.0
Construction in process	2.1	3.6	4.8	6.0	4.7
Nuclear fuel	6.4	6.1	6.2	6.1	6.1
Acquisition adj.	0.0	0.1	0.0	0.0	0.0
Total other electric plant	58.5	59.6	59.3	58.8	56.2
Construction					
Construction expenditures (excl. AFUDC)	276	313	433	473	346
CWIP % common equity	7.5	13.3	18.8	23.1	18.5
CWIP % gross plant	2.1	3.6	4.8	6.0	4.7
Constr. exp. % prior year cap.	8.5	9.7	14.3	18.4	13.1
Constr. exp. % prior yr. gross plant	4.5	5.2	7.8	9.3	7.2

	1995	1994	1993	1992	1991
Market Analysis					
Total operating revenue	2,271.7	2,080.5	1,957.6	1,774.1	1,718.8
As % total oper. revenue					
Electric	100.0	100.0	100.0	100.0	100.0
As % total electric revenue					
Residential	55.1	54.9	54.1	52.4	53.9
Commercial	22.7	23.3	23.4	23.4	24.8
Industrial	8.3	8.3	8.3	7.8	8.4
Public authority	5.1	5.2	5.2	5.2	5.5
Wholesale	6.8	6.0	6.5	5.7	6.0
Other	2.0	2.3	2.6	5.5	1.4
KWH Sales	32,403	30,015	28,748	27,376	27,350
As % total KWH sales					
Residential	46.1	46.2	46.5	46.9	46.2
Commercial	26.6	27.5	27.4	27.6	27.4
Industrial	11.9	11.9	11.8	11.9	12.1
Other	6.4	6.6	6.9	6.5	6.4
Wholesale	9.0	7.8	7.4	7.2	7.9
Average revenue per KWH (cents)					
Residential	8.39	8.24	7.92	7.24	7.33
Commercial	5.98	5.86	5.81	5.51	5.69
Industrial	4.90	4.84	4.79	4.25	4.38
Wholesale	5.28	5.34	5.97	5.12	4.79
Peak Load Analysis					
Summer (MW)					
Generating capacity	6,771	6,771	6,659	6,236	6,102
Firm purchases	457	417	283	600	387
Less sales	245	209	231	228	0
Peak load	7,128	6,681	6,729	6,357	5,925
Summer excess capacity	-145	298	-18	251	564
Winter (MW)					
Generating capacity	7,347	7,337	7,563	6,623	6,571
Purchases	457	250	50	400	400
Less sales	83	130	228	111	0
Peak load	7,722	6,955	6,653	6,982	6,056
Winter excess capacity	-1	502	732	-70	915
Reserve margins					
Summer	-2	4	-0	4	10
Winter	-0	7	11	-1	15

Electric

F

Florida Power Corporation

(Continued from page 2)

Coupon	Type of Debt	Maturity	Moody's Rating
Florida Power Corporation			
4.58%	Cum. Pfd. Stk.		"a1"
7.40%	Cum. Pfd. Stk.		"a1"
7.76%	Cum. Pfd. Stk.		"a1"
$7.08	Cum. Pfd. Stk.		"a1"
4.75%	Pfd. Stk.		"a1"
	Commercial Paper		P-1
Prospective Debt Under Registration			
	415 Shelf Registration		(P)Aa3

In-Depth Analysis

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Moody's Special Comment

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Contacts

Analyst	Phone
Thomas J. Marsnella Susan Abbott Christopher L. Baldwin Robert W. Burke	(212) 553-1653

THE RISKS OF PURCHASED POWER CAN IMPAIR ELECTRIC UTILITY CREDIT QUALITY

• Moody's believes there are inherent risks in a utility meeting its franchise generating needs regardless of whether it pursues a company-owned or a purchased-power strategy to meet those needs. The build versus buy decision is not a choice between risk and absence of risk. There is no free lunch. The industry is replete with examples of the risks which accrue to electric utilities from the use of purchased power.

• The risks of purchased power as well as other off-balance-sheet obligations can be conceptualized on a risk continuum. At one extreme, the financial commitments associated with purchased-power agreements are fully capitalized on a utility's balance sheet and added dollar for dollar to its reported debt, with traditional debt-protection measurements adjusted accordingly. At the other end of the continuum, financial ratios are calculated using the liabilities as reported under GAAP. To indicate this continuum, we specify electric utility debt-protection measurement figures both on a GAAP "as reported" basis and on an adjusted basis in our published research.

• Which of the two sets of statistical debt-protection measurements best reflects economic reality is a function of the nature of the contractual arrangements between a utility and its power providers and the degree to which economic risks have been transferred from the utility to the power provider. Moody's believes that in most cases reality lies somewhere in between the two extremes. We will assess each electric utility on a case-by-case basis to determine the degree of risk transfer. However, we will do so with a cautious eye in considering whether or not a real transfer of economic risk has occurred.

• A concern for utility investors is that electric utilities remain largely uncompensated by economic regulators for the risks associated with purchased power. If regulatory treatment continues as is, most new purchased-power commitments that utilities enter into will result in an incremental diminution in utility credit strength. To preserve existing credit quality, utility regulators must recognize that utility managements need to offset the risks of purchased power by either earning a profit margin on the business or a higher return on rate-based assets. Moody's recent downgradings of the debt ratings of Consumers Power Company, Virginia Power Company, Orange and Rockland Utilities, and Southern California Edison were in part a reflection of these industry forces.

EFFECTS OF DEREGULATION ON CAPACITY PLANNING

The breaking of the regulatory compact -- under which the interests of both utility shareholders and ratepayers were recognined -- has made the building of large, new, base-load generating stations an uneasy proposition at best. At the same time, an alternative solution -- purchasing power -- has raised concerns as to the reliability and economic viability of the power providers as well as the extent to which economic risk has really been shifted from the power purchaser. Concerns about where risk actually resides grow heavier as the industry continues to deregulate.

As the industry has evolved, so has Moody's analytical emphasis. Historically, it has been common for utilities to supplement or displace owned generation with purchases, mostly from neighboring utilities and, depending on transmission, from more distant points. However, there has been an increasing amount and variety of nonutility -- or not traditionally regulated -- power generation available to meet utilities' load requirements. Initially, these power sources were developed in response to the passage of the 1978 Public Utility Regulatory Policies Act (PURPA), which was designed to encourage the use of renewable energy resources and the more efficient use of nonrenewable resources. Additional momentum followed from efforts at the federal level to develop a more competitive environment in all utility businesses -- initially gas and telephone, and more recently electric. PURPA gave rise to the NUG or nonutility generator. Thus the business of generating power, once the exclusive domain of investor-owned, public, and cooperative utilities, was opened to a more diverse group of participants.

Purchased power can be provided by two basic types of NUGs: qualifying facilities (QFs) and non-qualifying facilities of independent power producers (IPPs). A non-qualifying facility differs from a QF in that the non-QF does not have to meet PURPA requirements for a qualifying facility. utilities are therefore not obligated to buy power from a non-QF facility and utilities would only buy power by negotiating a purchased power arrangement. In recent years, the relative size of NUG plants and the absolute volume of power that they provide have steadily increased, and both are projected to rise dramatically during the remainder of this decade. The North American Electric Reliability Council projects that NUGs will account for 20% (17,700 mw) of planned capacity additions over the 1990s. From a bondholder's perspective, this growth has signaled the advent of a new era in assessing contract risk and resulted in our heavier scrutiny of off-balance-sheet, purchased-power transactions.

THE RISKS AND BENEFITS OF PURCHASING POWER

As utilities have increased power purchases, Moody's has acknowledged both the benefits and the risks associated with such contractual obligations.

The benefits of purchasing power vary, depending largely on the type of contractual arrangements made between a utility and its supplier. Where non-firm contracts are utilized, economy or emergency purchases of energy may be made, improving the overall operating flexibility and profitability of the utility. Where firm and near-firm purchased power contracts are utilized, access to less expensive, competitively priced power may at times be gained on a long-term or short-term basis. Moody's considers this to be one of the greatest benefits to pursuing a purchased power strategy. We also acknowledge that by purc power a utility can reduce many of the construction risks associated with c generating additions. Purchases may both complement a utility's existing cap or fuel mix and be sized to match the utility's expected growth in demand, ma the purchases less likely to result in excess capacity -- not an uncommon re after large base-load units are placed into commercial service. Rate shock as ciated with rate-basing plants, as well as with the associated prudence/exces capacity/used-and-useful issues surrounding capital recovery, can also be mit gated. We also note that competitive bidding and integrated resource planning, o which purchases are one supply option, have at times resulted in diminished regulatory volatility.

Moody's emphasizes, however, that significant risks typically accrue to a utility that pursues the purchased-power option. Moody's scrutiny of these risks begins with an assessment of the terms of a utility's portfolio of power contracts. Many purchased-power contracts embody debt-like characteristics. The riskiest of these require a high level of unconditional, fixed payments over a long time frame. In addition, many seemingly conditional agreements may effectively be unconditional if specified performance benchmarks for the NUG are easily achievable. Under either a build or buy scenario, a significant issue for Moody's is that demand risk is a responsibility retained by the utility. Other issues that we focus on include the cost of and need for power, as well as the diversity or concentration of power purchases. Above-market rates run the risk of being disallowed at some point by regulatory commissions. Likewise, costs incurred for power not needed to serve demand on either a current or prospective basis have an increased likelihood of not being recovered. Finally, a broad portfolio of small contracts may ultimately present less risk to a utility than concentration in just one or two purchase power agreements.

MOODY'S PHILOSOPHICAL APPROACH TO ANALYZING CONTRACT RISK

Purchased power is not a new phenomenon and our approach toward analyzing its effects has been and continues to be rooted in basic principles of corporate finance. First and foremost, we believe that all assets critical to running a company's business should be reflected on its balance sheet. Similarly, the corresponding liabilities that are associated with these assets should also be reflected on the company's books. The degree to which the company's financial flexibility is adversely impacted is a function of the inherent risks that have been assumed. It is of particular concern if, when entering into a financial commitment, the company does not at the same time increase its equity base to compensate for these risks. This longstanding principle of corporate finance is one that Moody's has applied to assessing the contract risks associated with any off-balance-sheet financing, whether it be purchased power, a sale/leaseback financing, nuclear fuel trust, or accounts-receivable sale.

In assessing the risks which accrue to a utility's portfolio of purchased-power contracts, Moody's employs a variety of analytic approaches, including one which is used to help dimension or "box in" the credit ramifications of contract risk for off-balance-sheet obligations. This approach involves identifying the extreme positions, calculating debt-protection measurements based upon those extremes, and then recognizing that reality lies somewhere on a continuum in between the extremes. We then identify the critical issues that need to be qualitatively assessed in order to determine just where on that continuum reality lies. The degree to which a company's financial flexibility is affected by a portfolio of purchased-power commitments is therefore determined by a qualitative assessment of the inherent risks in the portfolio.

Moody's assesses the effects of purchased power on this risk continuum. At one extreme, the financial commitment associated with a portfolio of purchased-power agreements is fully capitalized on a company's balance sheet and then added dollar for dollar to its reported debt. At the other end of the continuum, we assess the company's financial commitments as reported under GAAP. Determining where on this continuum reality lies depends on a qualitative consideration of the degree that a real transfer of economic risk has occurred from the utility to the power provider.

Moody's has decided that it will publish on a broader and more consistent basis than it has in the past some of the adjusted debt-protection measurements that we have long used to dimension the full capitalization end of the continuum. As the industry continues to deregulate and the role of nonutility generators grows, the proper assessment of contract risk becomes increasingly important. In general, we believe that financial parameters that capitalize all of a company's financial commitments may be a truer reflection of economic substance and therefore a more accurate gauge of credit risk.

What follows is a discussion of the qualitative and quantitative risks of purchased power, including a description of the attributes which would cause us to conclude that a company has more or less exposure to these various risks. Moody's has discussed these risks in previous publications, specifically "Purchased Power Commitments and Their Impact on Investor-Owned Utility Credit Quality" (August 1990, reprinted in August 1992), and "Purchased Power As An Asset" (June 1992).

ASSESSING FINANCIAL RISK

The broad conceptual risks associated with purchased-power agreements encompass financial, demand, supply, construction, operating, rate-base and regulatory risks.

Clearly, the most significant concern about purchased power commitments from Moody's perspective is the financial risk associated with the fixed-payment stream which purchased-power contracts require utilities to service. A brief discussion of contracts will help dimension our sensitivities.

There are three basic types of purchased-power arrangements — take-or-pay or TOP contracts, take-and-pay or TAP contracts, and spot power purchases. We believe that, regardless of how the accounting profession treats purchased power for financial statement purposes, all purchased-power arrangements — from TOP contracts to spot power purchases — involve a decrease in financial flexibility. The degree of erosion depends on the specific contract terms.

TOP or "hell-or-high water" contracts imply an unconditional obligation to either take power, regardless of the utility's need and irrespective of the power provider's operating performance, or to not take the power but nevertheless pay for it. TOP contracts entail both demand risk (risk that the power is not needed) and operating risk (risk that the facility has performance problems). In Moody's opinion, these types of contracts often entail a significant use of financial flexibility.

understanding between neighboring utilities and take place only if both parties agree to the transaction. While a reliance on spot purchases of power does admittedly imply supply risk (risk that the power is not available when required), Moody's nevertheless views such contracts as typically involving a minimal use of financial flexibility.

In between these extremes lie TAP contracts, which provide that the utility must pay for power as long as the power is available to be delivered. Performance-based or conditional TAP contracts are hybrid TAP contracts and represent the majority of TAP contracts executed today between IOUs and NUGs. Under these arrangements, a utility is obligated to take and pay for power as long as certain conditions are met -- for example, the unit must typically meet certain availability standards. Although operating risk at first may appear to be reduced under performance-based TAP contracts, Moody's believes that the motivation of the NUG operators in terms of structuring the contracts, high reliability of the majority of NUG plants and relatively low levels at which performance standards are typically set, all result in these power purchases effectively functioning as a part of a utility's core capacity. In addition, the purchasing utility loses significant flexibility in managing its resource mix. This loss of operating flexibility may be mitigated if dispatchability is a contract feature within the TAP arrangement. In general, Moody's views most TAP contracts as having a level of risk between that of TOP obligations and spot power purchases.

DIMENSIONING THE EXTREMES

Moody's believes that it is a utility's assumption of demand risk and the effect of locking into a long-term firm or near-firm contract with an explicit or implicit fixed-cost component which represents the most significant drain on the utility's financial flexibility. One of the ways that Moody's quantifies the extent to which financial flexibility may have been eroded is by capitalizing the fixed-demand or capacity component of all purchased-power obligations on a utility's balance sheet and imputing an effective interest cost for coverage calculations.

These adjusted numbers provide a framework upon which we layer analysis of various qualitative factors. We believe that it is the rare exception when GAAP reported financials accurately represent the real financial risk of an electric utility, that there are several instances where reality is much closer to, if not at, the full capitalization end of the continuum, and that in the majority of cases reality is somewhere between the two extremes.

As an example that aptly demonstrates the hidden risks and debt-like nature that purchased-power commitments can take, we readily point to the financial problems of Tucson Electric Power Company. Tucson Electric is at the tail end of a complex financial restructuring with its creditors. When that process began, the company had $1.4 billion of debt reported on its GAAP-based financial statements. However, Tucson Electric has been dealing with creditor groups totaling nearly $2.7 billion --almost two times its reported obligations. The largest single component of this discrepancy is a purchased-power contract valued by Tucson Electric at $715 million. That $715 million figure represents the present value of minimum capacity payments over the life of the contract. It is not risk adjusted. All $2.7 billion of creditors are being dealt with, not 10%, 20% or 80% of them. In cases like that of Tucson Electric, where a purchased-power commitment is with a single power source and where the terms of the contract are relatively inflexible from the utility's perspective, Moody's has traditionally and will continue to view with a very skeptical eye claims that a real transfer of economic risk has transpired. In such cases, we believe that the full capitalization approach is a more useful approach for credit analysts to use as a proxy with which to gauge true financial flexibility.

As a second example that demonstrates the hidden risks and debt-like nature that purchased-power commitments can take, we point to the well-publicized breach-of-contract litigation concerning Gulf States Utilities' contract to purchase capacity and energy from the Southern Company. Notwithstanding the executory nature of purchased-power contracts and how they may be treated in a court of law, it is clear that Gulf States is aware of the legal, enforceable and potentially deleterious consequences of purchased-power obligations on a utility's financial position. The breach-of-contract litigation between Gulf States and the Southern Company was ultimately settled by Gulf States' paying the Southern Company approximately $300 million, an amount roughly equal to the present value of non-fuel charges over the life of the contract.

Also of interest is the SEC's recent reclassification of a Nevada Power Company purchased-power contract as a capital lease. This decision constitutes further evidence that the financial community is increasingly aware of the debt-like nature that purchased-power contracts may represent.

A final example of the tangible risks to utilities that purchased power represents is readily witnessed by looking within the sector of the financial community that lends to the independent power industry. Discussions with the finance companies and commercial banks who have the greatest expertise in this area have made it clear to Moody's that the credit quality of a power purchaser, as well as the strength of the contract that binds the power purchaser closely to the repayment of project debt, are both critical elements of a well-structured loan. Indeed, Moody's itself has assessed over 25 power projects and in each case the credit quality of the power purchaser and strength of the contracts have been critical variables in a high bond rating. For example, Moody's average A3 rating for the 10 generation and transmission rural electric cooperative utilities that we publicly rate is heavily based on the fact that the industry's all-requirements contracts with its power purchaser members significantly mitigate the typically high, 80%–95% G&T cooperative debt-to-capital ratios. Similarly, the real financial risk at the distribution cooperative level is significantly understated if one only looks at reported financials, since it is the distribution cooperatives who are fundamentally responsible for repaying G&T cooperative debt. Whether it involves G&T cooperatives or NUGs, it is clear that the financial community perceives a clear subsidization taking place whereby the power purchaser's equity is basically being lent to support project debt.

While most purchased power agreements that are in place today are not in the same venue as a Tucson Electric or Nevada Power Company situation, Moody's nevertheless firmly believes that taking the opposite approach of ignoring the financial commitment associated with a purchased power agreement is equally misleading.

MOODY'S CAPITALIZATION APPROACH

Moody's has historically calculated many debt-protection measurements on a GAAP-reported or unadjusted basis as well as on an adjusted basis in order to incorporate sale/leaseback financings, accounts receivables sales, and other off-balance-sheet transactions into a company's asset and debt profile. In the case of purchased power, we do the same in an attempt to dimension the high end of the risk continuum. The adjusted and unadjusted numbers serve as starting points to help us assess the real impact upon financial flexibility that purchased power represents.

To "box in" the purchased power risk continuum, we first make several assumptions regarding the relationship of fixed and variable purchased-power payments, average contract length, and applicable interest rates. These assumptions have been derived and refined through the scrutiny of much financial and operating data provided to us by both power purchasers and power producers. Our capitalization methodology primarily relies on publicly available financial data in order to maximize comparability across the industry. However, where more detailed information is available, it is of course used within the rating process.

Our first assumption is that 60% of annual purchased-power payments are demand or capacity related, with the remaining 40% energy or fuel charges. Secondly, we assume that outstanding contracts average a term of 25 years. We then calculate the approximate purchased-power liability that those fixed charges represent today by computing the net present value of future capacity payments discounted at an annual interest rate of 10%. Assuming 25-year contracts, equal annual payments, and a 10% discount rate, the capitalization factor equals 6.5 times for each $1 of capacity payment. The interest component is then simply calculated at 10% of the capitalized liability and used to develop adjusted coverages. On this basis, interest expense equates to approximately 65% of the annual capacity payments or 39% of total annual purchased-power expense.

A reality check on our purchased-power capitalization approach was taken from three different perspectives. First, we compared the results as predicted under our methodology with actuals as provided to us by the industry. For example, a series of power projects that the rating agency recently evaluated for debt-rating purposes had an actual average capacity to purchased-power revenue ratio of 60.18% —almost exactly equal to our 60% assumption. In addition, the portfolio of projects had an average interest-expense to capacity revenue ratio of 52.25%. While this is well below the 65% derived by our capitalization approach, the difference is easily understandable. From the power purchaser's perspective, the capitalization of its liability has little direct bearing on the power seller's actual capital structure. Whether the power seller financed its underlying assets with 100% equity or 100% debt is irrelevant. To the power purchaser, the relevant issue is that it has locked into a financial commitment that has a fixed payment stream associated with it, and therefore the capitalization of its fixed, demand charge is in essence 100% debt financed. If the portfolio of actual power projects is analyzed on the basis of an assumed 100% debt structure, then the portfolio's average interest-expense to capacity revenue ratio increases from 52.25% to approximately 60%, much closer to the 65% derived by our capitalization approach. The 5% shortfall is based upon the fact that power providers do actually rely on some explicit equity as part of their actual capital structure, that equity is more expensive than debt, and that capacity payments embody both a return on debt and a return on equity. Were the portfolio of power projects to be analyzed on the basis of a 100% debt structure and a cost of debt equal to the power project's weighted average cost of capital, then the portfolio's average interest expense-to-capacity revenue ratio would increase to the 65% derived by our capitalization methodology.

As a second reality check, we specifically focused on Tucson Electric's purchased-power agreement with Century Power and compared what Moody's approach would capitalize the liability at with what Tucson Electric publicly valued it at. As stated, Tucson Electric had $1.4 billion of reported debt on its books when it began discussions with creditors representing $2.7 billion of financial commitments. The largest single component of the difference was a purchased-power agreement that Tucson Electric valued at $715 million. The annual capacity charge for power under that contract was $88 million. This equates to a capitalization factor of 8.1 times ($715 million divided by $88 million) versus the 6.5 times capitalization factor derived by Moody's methodology. In the case of Tucson Electric, Moody's capitalization approach would be less conservative than reality. The major reason is because Tucson restructured its purchased-power agreement in 1987 to preserve company cash flows that resulted in reducing the upfront payments by $22 million per year for the first 10 years and backloading the savings in the later years. Based on an annual capacity payment of $110 million instead of $88 million, the imbedded capitalization factor would be exactly 6.5 times.

As a third reality check, we also compared the logic underpinning our purchased-power capitalization approach to the longstanding approach that Moody's has used to capitalize operating leases. The logic is identical. However, one difference is that Moody's general operating lease capitalization approach assumes that operating leases have an average eight-year life, which, assuming a 10% discount rate, results in the well known rule-of-thumb that on average one-third of operating lease rentals represents interest expense and two-thirds represent depreciation. Under a much longer, 25-year contract assumption typical with purchased-power agreements, interest expense on average represents 65% of annual fixed payments and depreciation represents 35%.

Moody's capitalization approach, as well as the associated adjusted financial statistics, are illustrated in the following example:

	FINANCIALS
	(Thousands)
Annual Purchased Power Expense	$5,000
Earnings Before Interest & Taxes	40,000
Interest Expense	10,000
Total Debt	50,000
Total Capitalization	100,000

CALCULATIONS

Capacity Charge	$5,000 X 60%	=	$ 3,000
Debt Component	3,000 X 6.5	=	19,500
Interest Component	19,500 X 10%	=	1,950

	UNADJUSTED			ADJUSTED		
Coverage Ratio:	$40,000/	$10,000 =	4.0 X	$41,950/	$11,950	= 3.5X
Leverage Ratio:	50,000/	100,000 =	50 %	69,950/	119,500	= 59%

Although adjusting financial statements for off-balance-sheet commitments has traditionally played an important role in Moody's rating analyses, we have only on rare occasions published a broad range of adjusted numbers. The capitalization of operating leases and unfunded pension liabilities are cases in point. Because of the growing importance to the electric utility industry of purchased power and its associated risks, we believe that it is of significant value to investors to specify debt-protection measurements on both an unadjusted and adjusted basis in our publications.

Selected electric utility unadjusted and adjusted debt-protection measurements for a Moody's industry peer group of 50 major investor-owned electric utilities appears at the end of this text. Two important points are critical to a full appreciation of this information. First, where more precise data is available, Moody's has and will continue to factor that information into its rating process. Secondly, in cases where unadjusted and adjusted debt-protection measurements of financial risk differ significantly, our present ratings already capture to the best extent possible our current assessment of the utility's true financial strength.

A QUALITATIVE ASSESSMENT: DETERMINING WHERE ON THE RISK CONTINUUM REALITY LIES

Determining whether reality lies closer to the full capitalization end of the spectrum or the other extreme requires a careful qualitative analysis of the nature of the terms of the contracts, the reliability and economic viability of the power providers, and the regulatory environment in which the utility operates. This involves understanding on a broad basis a company's portfolio of power contracts and assessing a host of qualitative concerns. Accordingly, this section is divided into two parts. The first part is dedicated to the broad conceptual issues that we believe a utility faces in selecting the purchased-power option. These issues are often common to either a buy or build scenario. We discuss six broad risks: demand, supply, construction, operating, rate-base and regulatory risks. The second part highlights the specific qualitative issues that are critical to assessing a given utility's portfolio of purchased-power agreements, and defines some of the attributes which might present more or less risk for the fixed-income investor.

DEMAND RISK

We define demand risk as the risk that contracted power will either not be required or will be uneconomical relative to other supply options. Factors which must be analyzed in properly assessing demand risk include:

-regulatory mechanisms to pass through such costs (disallowance of such costs is the extreme risk)
-unconditional take-and-pay contracts
-accurate demand forecasting, possibly as a result of regulator-approved intgrated resource planning
-dispatchability of power
-market renegotiation provisions
-termination payment provisions

Contracts which are effectively take-or-pay exacerbate demand risk.

SUPPLY RISK

Supply risk is the risk of power not being available when needed. For utilities with TAP contracts, this is not an unlikely scenario. For companies with conditional TAP contracts, provisions such as availability levels need to be scrutinized. The degree to which a utility could be harmed is a function of how badly the power is needed. Concentration in one type of fuel, technology, or asset is given considerable attention, especially as the industry migrates towards more capacity per contract. The absolute level of contracted power is also gauged.

Other issues examined include:

-reliability of the provider
-type of plant technology: unproven versus standardized/mature
-supply position of utility power pool
- ability to pass replacement power costs through to ratepayers via adjustment clauses

Supply risk is sometimes offset, although this practice can be a two-edged sword, by accepting more bids for power than a utility actually needs. This assumes that, via attrition, some projects will not be built. Regulatory response to such actions is key.

CONSTRUCTION RISK

What happens if plant construction is delayed or if the plant is not built at all? Relative to company sponsored programs, construction risk for a buying utility remains minimal under most purchased-power contracts. Risks that could accrue to the utility include lack of completion guarantees and inability to influence construction schedules, i.e., lack of control over the process. Offsets to these risks include turnkey contract provisions, progress payments, and performance incentives.

OPERATING RISK

Operating risk has two key dimensions. The first is really the flip side of supply risk: what happens if the plant does not operate reliably? A consideration critical to the analysis of this risk is that the utility retains its obligation to serve, yet--via contracts--it may lose significant control over its purchased-power supply relative to the control it exercised over its own generation. Reliability, maintenance, redundancies, even some of the things independent power producers (IPPs) may refer to as "gold plating", may or may not be influenced by the utility.

The second dimension is related to the question of how unexpected costs, both fuel and nonfuel, are dealt with. These could be passed through, and possibly accounted for in escalators. When such costs can be passed through, who absorbs any regulatory lag? Again, contract provisions are key.

An analysis of operating risk offsets would focus on:

- operating conditions specified in TAP contracts
- utility rights to intervene in failing projects
- the composition of the utility's "portfolio" of purchased power in relation to its total existing and target capacity mix

RATE-BASE RISK

An important issue that affects utilities that rely on purchased power involves the effects of purchased power on a company's rate base. Unlike a company-owned generating project, rate-base additions and the opportunity to earn a return on a contract are precluded for a utility adding purchased capacity to its generating mix. Heavy reliance on purchased power by a utility may result in a static or declining rate base, which could weaken the utility's viability in the financial and negotiating market places over time. Despite the annual replacement of lower capital cost transmission and distribution facilities at current prices, the aggregate influence on declining rate base should be marginal, at best.

A utility that has a material reliance on purchases could experience the erosion of its traditional earning asset base. Consequently, it may have limited cash flow to finance construction needs if its purchase contracts expire and are not renewed. As bond analysts, we believe that monitoring cash flow relative to outstanding debt and fixed charges is the greatest concern as rate base shrinks. Another concern of particular importance to companies in a capital intensive industry is capital attraction. As it applies here, the question is whether a company's use of purchased power and its impact on rate base could have an adverse impact on its ability to raise capital in the financial markets. Management strategies to enhance slow-growing, flat, or decreasing earnings, such as business diversification, could be a concern. "Build some, buy some, save some" capacity planning strategies which include moderate reliance on purchased power may constructively address this issue while avoiding excessive financing needs.

REGULATORY RISK

How insulated is a purchasing utility from regulatory disallowances? An analysis of this risk includes an examination of the following factors:

- Economics: A lesson learned from the deregulation of other industries is that good economics win. Economic "market- based" power seems less susceptible to regulatory scrutiny. Some QFs may be high priced now in relation to market prices, but some (not all) regulatory commissions at present do not appear to be focusing closely on this for these PURPA facilities.
- Regulatory involvement in a utility's generation supply decisions: some states preapprove contracts. Competitive bidding also connotes a strong perception of prudency.
- Recovery of purchased-power costs: the ability to pass along capacity payments through an automatic adjustment clause offers protection against nonrecovery risk. However, such passed-through costs may eventually be subject to review.
- Regulatory "out" clauses: where they exist, these could possibly offer a significant offset to regulatory risk. However, these clauses may only allow a future commission to lower amounts paid for power, not necessarily to void the contract. If the contract were to be abrogated, the power might have to be replaced; and it is also safe to assume that the contract would be subject to litigation at that point.

In general, prudent regulation can be extremely useful in mitigating the risks of purchased power. However, Moody's underscores the word "mitigated" rather than "eliminated". In either a "build" or "buy" scenario, certain risks may seldom, if ever, be regulated away.

PORTFOLIO-SPECIFIC QUALITATIVE ISSUES

A qualitative assessment of a specific portfolio of power contracts focuses on two questions. First, to what extent has the particular utility really transferred economic risk to a third party? Second, to what degree are there benefits that might partially mitigate the associated risks? In attempting to answer these questions, we consider such issues as the terms of the contracts, the viability and reliability of the power providers, the diversity of power sources, the regulatory environment in which the utility operates, potential prudency review of power contracts, a company's declining rate base in the absence of new plant, supply availability, and fuel diversity. The chart below highlights some of the more significant qualitative considerations in this risk assessment process. Ascertaining where reality lies on the credit risk continuum between the full capitalization and GAAP reported extremes is largely a function of an intensive analysis of a utility's portfolio of power contracts relative to these qualitative issues.

THE PURCHASED POWER RISK CONTINUUM

Risk Consideration	Higher Risk	Lower Risk
1. Contract Structure		
- Tenor	Long-term/Firm	Short-term/Spot
- Obligation to Pay	Unconditional SLOB;TOP	No commitments/Based on mutual understanding
2. Project Rationale & Economics		
- Purpose of Purchases	Base-load capacity	Seasonal exchange/Peaking
- Cost of Power	Above-market rates/avoided costs	Below-market rates/avoided costs
- Need for Power	Power not needed to serve demand on either a current or prospective basis	Purchases are integral to supply
- Control over Availability/Scheduling	No control	Fully dispatchable
- Service Area Demand	Volatile/Strong cyclicality	Stable
- Alternative Sources of Power	Operates in capacity-short region	Operates in capacity long region
- Status of Project	In development/construction	Completed/ on line
3. Portfolio Effect		
- Diversity of Sources	One large contract	Many contracts/ No concentration
- Source of Power	Dedicated units	Slice of system
- Technology Utilized	New/Untested	Established
- Fuel Utilized	Nuclear	Hydro
4. Strength of Power Providers		
- Credit Quality	Low rated/Speculative grade	Highly rated/Investment grade
- Reliability	Inexperienced operator	Solid operating profile

Risk Consideration	Higher Risk	Lower Risk
5. Competitive Impact		
- Effect on Rates & Competitive Position	Large rate increases required to absorb costs; weakens competitive position	Small increases needed to absorb costs; positive or minimal effect on competitive position
6. Regulatory Impact		
- Regulatory Involvement/ Support for Purchases as a Utility Supply Option	Low involvement/Support	High involvement/Support
- Recovery of Purchased-Power Costs	Delayed or disallowed cost recovery	Costs automatically included in rates; utility encouraged to to build equity to offset purchased power risks

THE CHALLENGE OF FUTURE CAPACITY PLANNING

Moody's believes the build versus buy decision is not a choice between risk and absence of risk. There is no free lunch. Admittedly, the issue is divisive within the industry. Some utility managements have used the buy option only to a limited degree while others have suggested that build versus buy may be a choice between losing money and not making money. We are firm in our belief that purchased power contracts involve risk for all the reasons previously mentioned.

As for the future of capacity planning, Moody's believes that just as the risks of meeting the nation's power requirements have not disappeared, neither has the utility's obligation to serve. The risks are just being allocated somewhat differently. Further deregulation will exacerbate this risk shift. Many important questions remain to be answered. Will traditional utilities become dinosaurs? Will any utility ever begin building base-load plant again for its own service territory? Will the market evolve to the point where all incremental electricity is fungible, readily available, and priced as just another commodity? Perhaps the most critical question is whether utility customers and investors will receive compensation for any risks they continue to bear under any form the industry finally takes. Over time, purchasing utilities might ultimately lower their risk profiles by skewing asset and revenue mixes towards what may be less risky transmission and distribution businesses. However, over the transition period, navigating through the treacherous waters associated with deregulation will require both keen management skill and regulatory understanding.

Deregulation provides an immediate challenge that could affect utility credit quality in the near term. That challenge is a regulatory one. Currently, all profits from a utility's rate-based assets are dedicated to paying dividends and to growing the equity that supports the company's core facilities. Moody's believes that if regulatory treatment continues as currently configured, every new purchased-power commitment that a utility enters into will result in an incremental diminution in the industry's credit strength. We believe that the industry's credit quality will generally suffer unless utility managements are more aggressive in seeking either a higher authorized return on rate-based assets or a pass-through plus mechanism in order to build an equity base that supports both their traditional, on-balance-sheet financial commitments and the growing portion of off-balance-sheet obligations. Recent downgrades to Virginia Power Company, Consumers Power Company, Orange and Rockland Utilities, and Southern California Edison, are in part a reflection of these industry forces. These rating actions may only be the beginning of a more serious industry issue if regulators remain unchanged in their behavior and if purchased power continues to be the preferred choice to meet the large additions to base-load capacity that face the industry in this decade.

Florida Power Corporation

St. Petersburg, Florida, USA

October 1, 1996

Ratings

Category	Moody's Rating
First Mortgage Bonds	Aa3
Senior Unsecured Debt	A1
Counterparty Rating	A1
Preferred Stock	"a1"
Commercial Paper	P-1

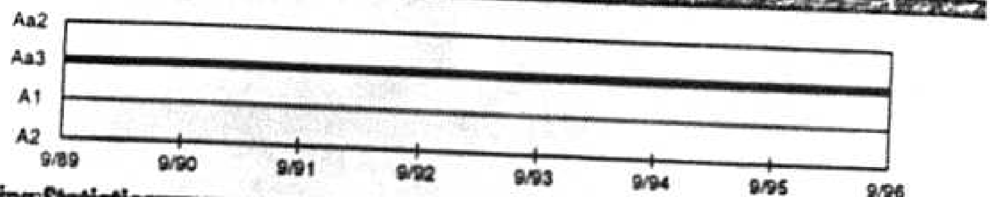
Contacts

Analyst	Phone
A. Tucker Hackett	(212) 553-1653
Susan D. Abbott	

Florida Progress Corp.

Senior Unsecured Medium-Term Notes	A2
Commercial Paper	P-1

Rating History



Operating Statistics

Florida Power Corporation (Statistics in bold type)
Peer Group Median (Statistics in light type)

	[1]1996	1995	1995	1994	1994	1993	1993	1992	1992	[2]5-Yr.Avg.	[2]5-Yr.Avg.
Revenue (US$ bil.)	**2.3**	1.0	**2.3**	1.0	**2.1**	1.0	**2.0**	0.9	**1.8**	[3]4.1	**[3]5.9**
Assets (US$ bil.)	**4.3**	2.8	**4.3**	2.7	**4.3**	2.6	**4.3**	2.4	**4.0**	[3]4.4	**[3]4.0**
Com. Equity (US$ bil.)	**1.8**	0.9	**1.8**	0.8	**1.7**	0.7	**1.5**	0.7	**1.4**	[3]5.5	**[3]8.1**
Op. Margin (%)	**19.7**	21.9	**20.1**	21.5	**20.2**	20.7	**20.0**	21.4	**20.7**	21.5	**20.4**
ROA (avg.)(%)	**5.2**	3.8	**5.1**	3.5	**4.5**	3.7	**4.4**	3.8	**4.5**	3.8	**4.6**
ROE (avg.)(%)	**12.9**	12.7	**12.7**	11.7	**12.0**	12.0	**12.2**	11.9	**12.4**	12.1	**12.5**
Div. Payout (%)	**75.9**	79.3	**83.2**	83.5	**92.1**	81.5	**90.1**	81.9	**91.3**	81.2	**88.6**
Pretax Int. Cov. (X)	**4.5**	3.4	**4.3**	3.3	**3.8**	3.2	**3.7**	2.9	**3.7**	3.1	**3.9**
Fxd. Chg. Cov. (X)	**4.1**	2.9	**3.9**	2.7	**3.5**	2.6	**3.2**	2.4	**3.0**	2.6	**3.3**
RCF % TD	**29.3**	15.0	**26.3**	14.3	**22.6**	13.1	**16.2**	12.8	**19.3**	13.7	**21.1**
RCF % Gross CAPEX	**145.6**	113.6	**121.6**	89.5	**101.3**	90.6	**56.6**	87.2	**53.7**	94.4	**79.0**
Total Cap. (US$ bil.)	**3.2**	1.9	**3.2**	1.8	**3.3**	1.8	**3.2**	1.7	**3.0**	[3]3.9	**[3]4.0**
TD % Cap.	**42.1**	49.5	**40.9**	50.0	**44.5**	50.4	**48.4**	50.0	**45.2**	50.1	**43.9**
Pfd. Stk. % Cap.	**1.8**	5.7	**4.3**	6.3	**4.4**	6.2	**4.6**	6.6	**7.1**	6.3	**5.9**
Common % Cap.	**56.0**	45.0	**54.8**	44.3	**51.1**	44.3	**47.0**	43.2	**47.7**	43.9	**50.3**
Adj. TD % Adj. Cap.	**51.0**	53.7	**57.5**	55.2	**54.8**	54.9	**55.0**	57.8	**51.3**	56.0	**53.6**

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale
Revenue (US$ mil.)	1,252.7	515.3	189.3	153.4
Kwh(mil.)	14,938	8,612	3,864	2,903
c/Kwh	8.4	6.0	4.9	5.3
Industry Avg. (c/Kwh)	8.6	7.4	5.2	3.3

Competitive Position	Break-even Price($)	Regional Avg.($)	Stranded Cost($mil.)	Stranded Cost % Eq.
	43.61	34.82	789	45

[1] For the 12 months ended June 30; Balance sheet items are as of June 30. [2] Five year average 1995-1991. [3] Five year compound annual growth rate.

Opinion

Rating Rationale

Florida Power Corporation (FPC) maintains its Aa3 senior secured bond rating by virtue of its reasonable production costs, effective management strategies, the favorable composition of its growing customer base, supportive regulation, and the protection from competition afforded by Florida's geographic isolation. However, the company has entered a construction cycle which, combined with sizable power purchase contracts at above-market prices, will elevate generating costs. Nuclear operating risk and the parent's guarantee of the debt of diversified businesses contribute further risk for the bondholder.

The company derives the bulk of its revenues (56%) from residential sales. Few of the company's industrial customers, which account for only 9% of total retail sales, support deregulation. As a result, neither Florida's utility regulatory commission nor its legislature have strongly supported initiatives to open the state's retail market for electric power to competition.

The slow pace of deregulation provides the company with time to streamline its operations and to reduce costs. Central to this strategy are negotiations to exchange upfront payments for lower capacity charges from non-utility power suppliers. We expect that the commission will approve management's request to use $18 million for such payments in lieu of returning these funds to customers.

Rating Outlook

The rating outlook is stable. Although FPC does not intend to seek rate relief for $281 million in construction costs for the new combined cycled baseload plant, we believe that the company will be able to offset these expenditures with cost control and sales growth.

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PRESENTATION
TO
STANDARD & POOR'S
MOODY'S INVESTORS SERVICE
DUFF & PHELPS

JUNE 1996

FLORIDA PROGRESS CORPORATION

PRESENTATION

TO

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JUNE 1996

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Presentation
to
Moody's Investors Service

June 1996

FLORIDA
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OCTOBER 1995

Note: For each agency, the presentation booklet will be customized by substituting the appropriate pages.

FLORIDA PROGRESS CORPORATION

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RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO FLORIDA POWER CORPORATION

ATTACHMENT TO NUMBER FOUR

Florida Power CORPORATION

January 30, 1997

VIA TELECOPY

Ms. A. Tucker Hackett
Analyst
Moody's Investors Service
99 Church Street
New York, NY 10007

Dear Tucker:

Attached are the following items pertaining to Florida Power Corporation's proposed acquisition of the Tiger Bay cogeneration facility:

1. Key facts and issues summary;
2. Projected five-year income statements, balance sheets and statements of cash flows;
3. Moody's ratio analyses (2) unadjusted and adjusted for purchased power imputed debt;
4. Moody's ratio analyses (2) reflecting the acquisition of the Tiger Bay facility, both unadjusted and adjusted for purchased power imputed debt;
5. 1990 through 1995 historical Moody's ratio analyses (2) unadjusted and adjusted for purchased power imputed debt.

Should you have any questions or comments regarding this information, please do not hesitate to call either Jim Smallwood or me.

Joseph E. Orfano
Manager of Finance
(813) 866-4113

cc: James V. Smallwood

FLORIDA POWER CORPORATION
ACQUISITION OF TIGER BAY COGENERATION FACILITY

KEY FACTS AND ISSUES SUMMARY

Plant Size 220 MW
Represents 5 of Florida Power's existing purchased power contracts
These 5 contracts are among Florida Power's highest cost contracts

Facility is a gas-fired, combined-cycle "F" technology
Well engineered and in good condition
Close to Florida Power's Polk County site
- represents key opportunity for cost savings

$445 million purchase price
- Requested FPSC approval, slated for hearing in April 1997
- Plan is to recover the retail portion ($421.4 million) over 5 years, beginning 10/97
  - $23.6 million wholesale portion will be booked to electric plant in service and depreciated ove 30 years.
- Retail impact to ratepayers:
  - increase of $2.37 per 1000 kWh in first year
  - increase of $1.65 per 1000 kWh by fifth year

  - decrease of $2.00 per 1000 kWh by sixth year
  - rate decrease increases each year thereafter

The retail portion of the acquisition price will be financed with a series of 5 medium-term notes, with maturities ranging from one to five years.

See attached financial ratio analysis

FLORIDA POWER CORPORATION
FIVE-YEAR FORECAST
PROJECTED INCOME STATEMENTS

(Dollars in millions except per share amounts)

	Actual 1996
OPERATING REVENUES	$2,393.6
OPERATING EXPENSES	
Fuel and purchased power	941.3
Other operation expenses	356.2
	1,297.5
Maintenance	119.8
Depreciation	324.2
Taxes other than income taxes	183.6
	1,925.1
INCOME FROM OPERATIONS	468.5
INTEREST EXPENSE AND OTHER	
Interest expense	98.4
Allowance for funds used during construction	(7.5)
Preferred dividends	5.8
Other	3.4
	100.1
INCOME BEFORE INCOME TAXES	368.4
INCOME TAXES	135.8
NET INCOME	$232.6
EARNINGS PER AVERAGE SHARE	$2.40
EPS Annual Growth Rates	-
EPS Average Annual Growth Rate 1996-2001	

FLORIDA POWER CORPORATION
FIVE-YEAR FORECAST
PROJECTED BALANCE SHEETS

(Dollars in millions)

	Actual 1996
ASSETS	
Net property, plant & equipment	$3,530.4
Current assets	441.7
Other assets	291.9
	$4,264.0
CAPITALIZATION AND LIABILITIES	
Common equity	$1,825.5
Preferred stock	33.5
Long-term commercial paper	200.0
Long-term debt	1,096.4
	3,155.4
Short-term debt & other current maturities	25.4
Other current liabilities	320.9
Deferred income taxes, etc.	762.3
	$4,264.0

FLORIDA POWER CORPORATION
FIVE-YEAR FORECAST
PROJECTED STATEMENTS OF CASH FLOWS

(Dollars in millions)

	Actual 1996
OPERATING ACTIVITIES	
Net income	$232.6
Adjustment for non-cash items:	
Depreciation, amortization & depletion	341.1
Deferred income taxes and ITC, net	(32.8)
Change in OPEB reserve	14.9
Allowance for equity funds used during construction	(4.6)
Decrease (increase) in working capital	(57.3)
Other operating activities	7.9
	501.8
INVESTING ACTIVITIES	
Utility plant additions	(220.2)
Other property additions	(2.7)
Proceeds from sale of properties	5.5
Other investing activities	(31.7)
	(249.1)
FINANCING ACTIVITIES	
Issuance of long-term debt	
Repayment of long-term debt	(47.3)
Incr./(decr.) in long-term commercial paper	54.8
Redemption of preferred stock	(106.4)
Dividends paid to parent	(171.2)
Equity contributions from parent	12.5
Increase (decrease) in short-term debt	4.1
Other financing activities	
	(253.5)
NET CHANGE IN CASH	(.8)
Beginning cash and equivalents	0.8
ENDING CASH AND EQUIVALENTS	$.0

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
MOODY'S RATIO ANALYSIS
($ IN MILLIONS)

	Actual 1996
ROE (avg.):	
Earnings applicable to common	232.6
Beginning common equity	1,754.0
Ending common equity	1,825.5
Average common equity	1,789.8
ROE (avg.)	13.0%
Interest coverage incl. AFUDC:	
Net income	238.4
Add: Income taxes	135.8
Add: Gross interest charges	98.4
EBIT	472.6
Divide by: gross interest charges	98.4
Interest coverage incl. AFUDC	4.80
Interest coverage excl. AFUDC:	
Net income	238.4
Add: Income taxes	135.8
Add: Gross interest charges	98.4
Deduct: AFUDC	(7.5)
EBIT	465.1
Divide by: gross interest charges	98.4
Interest coverage excl. AFUDC	4.73

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
MOODY'S RATIO ANALYSIS
($ IN MILLIONS)

	Actual 1996
Internal funds to net construction:	
Net income	238.4
Depreciation & amortization	341.1
Deferred taxes & ITCs	(32.8)
Other operating activities	22.8
Deduct: AFUDC	(7.5)
Funds from operations	562.0
Deduct: common dividends	(171.2)
Deduct: preferred dividends	(5.8)
Internal funds	385.0
Net construction	217.3
Internal funds to net construction	177.2%
Net construction to prior year cap.:	
Net construction	217.3
Prior year capitalization	3,202.2
Net construction to prior year cap.	6.8%
Capitalization:	
Current portion - ltd & pfd	25.4
Long-term commercial paper	200.0
Long-term debt	1,096.4
Total debt	1,321.8
Preferred stock	33.5
Common equity	1,825.5
Total capitalization	3,180.8
Capitalization percentages:	
Total debt	41.6%
Preferred stock	1.0%
Common equity	57.4%
Total capitalization	100.0%

Treasury Department
30-Jan-97
10:10 AM

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
MOODY'S RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER
($ IN MILLIONS)

	Actual 1996
ROE (avg.):	
Earnings applicable to common	232.6
Beginning common equity	1,754.0
Ending common equity	1,825.5
Average common equity	1,789.8
ROE (avg.)	13.0%
Interest coverage incl. AFUDC:	
Net income	238.4
Add: Income taxes	135.8
Add: Gross interest charges	98.4
Add: imputed interest expense	207.3
EBIT	679.9
Divide by: gross interest charges	98.4
Add: imputed interest expense	207.3
	305.7
Interest coverage incl. AFUDC	2.22
Interest coverage excl. AFUDC:	
Net income	238.4
Add: Income taxes	135.8
Add: Gross interest charges	98.4
Add: imputed interest expense	207.3
Deduct: AFUDC	(7.5)
EBIT	672.4
Divide by: gross interest charges	98.4
Add: imputed interest expense	207.3
	305.7
Interest coverage excl. AFUDC	2.20

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
MOODY'S RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER
($ IN MILLIONS)

	Actual 1996
Internal funds to net construction:	
Net income	238.4
Depreciation & amortization	341.1
Deferred taxes & ITCs	(32.8)
Other operating activities	22.8
Deduct: AFUDC	(7.5)
Funds from operations	562.0
Deduct: common dividends	(171.2)
Deduct: preferred dividends	(5.8)
Internal funds	385.0
Net construction	217.3
Internal funds to net construction	177.2%
Net construction to prior year cap.:	
Net construction	217.3
Prior year capitalization	4,920.9
Net construction to prior year cap.	4.4%
Capitalization:	
Current portion - ltd & pfd	25.4
Long-term commercial paper	200.0
Long-term debt	1,096.4
Imputed debt	2,073.4
Total debt	3,395.2
Preferred stock	33.5
Common equity	1,825.5
Total capitalization	5,254.2
Capitalization percentages:	
Total debt	64.6%
Preferred stock	0.6%
Common equity	34.8%
Total capitalization	100.0%

Treasury Department
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FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
MOODY'S RATIO ANALYSIS
ADJUSTED FOR TIGER BAY ACQUISITION
($ IN MILLIONS)

	Actual 1996
ROE (avg.):	
Earnings applicable to common	232.6
Beginning common equity	1,754.0
Ending common equity	1,825.5
Average common equity	1,789.8
ROE (avg.)	13.0%
Interest coverage incl. AFUDC:	
Net income	238.4
Add: Income taxes	135.8
Add: Gross interest charges	98.4
Add: Tiger Bay interest expense	
EBIT	472.6
Divide by: gross interest charges	98.4
Interest coverage incl. AFUDC	4.80
Interest coverage excl. AFUDC:	
Net income	238.4
Add: Income taxes	135.8
Add: Gross interest charges	98.4
Add: Tiger Bay interest expense	
Deduct: AFUDC	(7.5)
EBIT	465.1
Divide by: gross interest charges	98.4
Interest coverage excl. AFUDC	4.73

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
MOODY'S RATIO ANALYSIS
ADJUSTED FOR TIGER BAY ACQUISITION
($ IN MILLIONS)

	Actual	Plan				
	1996	1997	1998	1999	2000	2001
Internal funds to net construction:						
Net income	238.4					
Depreciation & amortization	341.1					
Tiger Bay depreciation/amortization	0.0					
Deferred taxes & ITCs	(32.8)					
Tiger Bay deferred taxes	0.0					
Other operating activities	22.8					
Deduct: AFUDC	(7.5)					
Funds from operations	562.0					
Deduct: common dividends	(171.2)					
Deduct: preferred dividends	(5.8)					
Internal funds	385.0					
Net construction	217.3					
Internal funds to net construction	177.2%					
Net construction to prior year cap.:						
Net construction	217.3					
Prior year capitalization	3,202.2					
Net construction to prior year cap.	6.8%					
Capitalization:						
Current portion - ltd & pfd	25.4					
Long-term commercial paper	200.0					
Tiger Bay - retail [MTNs]						
Tiger Bay - wholesale/def. tax						
Long-term debt	1,096.4					
Total debt	1,321.8					
Preferred stock	33.5					
Common equity	1,825.5					
Total capitalization	3,180.8					
Capitalization percentages:						
Total debt	41.6%					
Preferred stock	1.0%					
Common equity	57.4%					
Total capitalization	100.0%					

Treasury Department
30-Jan-97
10:31 AM

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
MOODY'S RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER/TIGER BAY ACQUISITION
($ IN MILLIONS)

	Actual	Plan				
	1996	1997	1998	1999	2000	2001
ROE (avg.):						
Earnings applicable to common	232.6					
Beginning common equity	1,754.0					
Ending common equity	1,825.5					
Average common equity	1,789.8					
ROE (avg.)	13.0%					
Interest coverage incl. AFUDC:						
Net income	238.4					
Add: Income taxes	135.8					
Add: Gross interest charges	98.4					
Add: Tiger Bay interest expense						
Add: Imputed interest expense	207.3					
EBIT	679.9					
Divide by: gross interest charges	98.4					
Add: Imputed interest expense	207.3					
	305.7					
Interest coverage incl. AFUDC	2.22					
Interest coverage excl. AFUDC:						
Net income	238.4					
Add: Income taxes	135.8					
Add: Gross interest charges	98.4					
Add: Tiger Bay interest expense						
Add: Imputed interest expense	207.3					
Deduct: AFUDC	(7.5)					
EBIT	672.4					
Divide by: gross interest charges	98.4					
Add: Imputed interest expense	207.3					
	305.7					
Interest coverage excl. AFUDC	2.20					

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
MOODY'S RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER/TIGER BAY ACQUISITION
($ IN MILLIONS)

	Actual	Plan				
	1996	1997	1998	1999	2000	2001
Internal funds to net construction:						
Net income	238.4					
Depreciation & amortization	341.1					
Tiger Bay depreciation/amortization	0.0	0.4	85.1	85.1	85.1	85.1
Deferred taxes & ITCs	(32.8)					
Tiger Bay deferred taxes	0.0					
Other operating activities	22.8					
Deduct: AFUDC	(7.5)					
Funds from operations	562.0					
Deduct: common dividends	(171.2)					
Deduct: preferred dividends	(5.8)					
Internal funds	385.0					
Net construction	217.3					
Internal funds to net construction	177.2%					
Net construction to prior year cap.:						
Net construction	217.3					
Prior year capitalization	4,920.9					
Net construction to prior year cap.	4.4%					
Capitalization:						
Current portion - ltd & pfd	25.4					
Long-term commercial paper	200.0					
Tiger Bay - retail [MTNs]						
Tiger Bay - wholesale/def. tax						
Long-term debt	1,096.4					
Imputed debt	2,073.4					
Total debt	3,395.2					
Preferred stock	33.5					
Common equity	1,825.5					
Total capitalization	5,254.2					
Capitalization percentages:						
Total debt	64.6%					
Preferred stock	0.6%					
Common equity	34.8%					
Total capitalization	100.0%					

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10:50 AM

FLORIDA POWER CORPORATION
MOODY'S HISTORICAL RATIO ANALYSIS
($ IN MILLIONS)

	1990	1991	1992	1993	1994	1995
ROE (avg.):						
Earnings applicable to common	165.5	164.1	170.2	181.5	190.7	217.3
Beginning common equity	1,130.0	1,186.5	1,308.5	1,444.9	1,522.4	1,667.4
Ending common equity	1,186.5	1,308.5	1,444.9	1,522.4	1,667.4	1,754.0
Average common equity	1,158.3	1,247.5	1,376.7	1,483.7	1,594.9	1,710.7
ROE (avg.)	14.3%	13.2%	12.4%	12.2%	12.0%	12.7%
Interest coverage incl. AFUDC:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Add: Income taxes	102.0	92.8	97.7	104.5	114.7	129.5
Add: Gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
EBIT	383.1	368.9	384.8	405.2	423.9	461.0
Divide by: gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Interest coverage incl. AFUDC	3.88	3.88	3.84	3.83	3.91	4.41
Interest coverage excl. AFUDC:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Add: Income taxes	102.0	92.8	97.7	104.5	114.7	129.5
Add: Gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Deduct: AFUDC	(4.2)	(9.4)	(18.7)	(15.6)	(10.9)	(7.3)
EBIT	378.9	359.5	366.1	389.6	413.0	453.7
Divide by: gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Interest coverage excl. AFUDC	3.84	3.78	3.65	3.68	3.81	4.34

FLORIDA POWER CORPORATION
MOODY'S HISTORICAL RATIO ANALYSIS
($ IN MILLIONS)

	1990	1991	1992	1993	1994	1995
Internal funds to net construction:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Depreciation & amortization	190.4	241.9	243.4	276.5	294.8	329.7
Deferred taxes & ITCs	(27.5)	(35.2)	8.6	(25.0)	(0.9)	(29.3)
Other operating activities	(10.2)	7.7	(4.0)	14.2	30.1	24.7
Deduct: AFUDC	(4.2)	(9.4)	(18.7)	(15.6)	(10.9)	(7.3)
Funds from operations	330.8	385.9	416.2	445.0	513.9	544.8
Deduct: common dividends	(129.0)	(142.1)	(155.4)	(163.5)	(175.7)	(180.7)
Deduct: preferred dividends	(16.8)	(16.8)	(16.7)	(13.4)	(10.1)	(9.7)
Internal funds	185.0	227.0	244.1	268.1	328.1	354.4
Net construction	265.3	345.9	472.9	426.4	319.5	283.4
Internal funds to net construction	69.7%	65.6%	51.6%	62.9%	102.7%	125.1%
Net construction to prior year cap.:						
Net construction	265.3	345.9	472.9	426.4	319.5	283.4
Prior year capitalization	2,473.9	2,633.4	2,692.2	3,029.2	3,240.4	3,265.4
Net construction to prior year cap.	10.7%	13.1%	17.6%	14.1%	9.9%	8.7%
Capitalization:						
Current portion - ltd & pfd	15.1	37.1	132.5	45.9	35.4	30.6
Short-term commercial paper	178.5	0.0	0.0	125.0	55.3	0.0
Long-term commercial paper	0.0	78.0	96.0	200.0	200.0	145.2
Long-term debt	1,019.8	1,037.6	1,139.8	1,198.6	1,163.8	1,133.9
Total debt	1,213.4	1,152.7	1,368.3	1,569.5	1,454.5	1,309.7
Preferred stock	233.5	231.0	216.0	148.5	143.5	138.5
Common equity	1,186.5	1,308.5	1,444.9	1,522.4	1,667.4	1,754.0
Total capitalization	2,633.4	2,692.2	3,029.2	3,240.4	3,265.4	3,202.2
Capitalization percentages:						
Total debt	46.1%	42.8%	45.2%	48.4%	44.5%	40.9%
Preferred stock	8.9%	8.6%	7.1%	4.6%	4.4%	4.3%
Common equity	45.0%	48.6%	47.7%	47.0%	51.1%	54.8%
Total capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Treasury Department
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FLORIDA POWER CORPORATION
MOODY'S RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER
($ IN MILLIONS)

	1990	1991	1992	1993	1994	1995
ROE (avg.):						
Earnings applicable to common	165.5	164.1	170.2	181.5	190.7	217.3
Beginning common equity	1,130.0	1,186.5	1,308.5	1,444.9	1,522.4	1,667.4
Ending common equity	1,186.5	1,308.5	1,444.9	1,522.4	1,667.4	1,754.0
Average common equity	1,158.3	1,247.5	1,376.7	1,483.7	1,594.9	1,710.7
ROE (avg.)	14.3%	13.2%	12.4%	12.2%	12.0%	12.7%
Interest coverage incl. AFUDC:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Add: Income taxes	102.0	92.8	97.7	104.5	114.7	129.5
Add: Gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Add: imputed interest expense				81.7	114.9	171.9
EBIT	383.1	368.9	384.8	486.9	538.8	632.9
Divide by: gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Add: imputed interest expense				81.7	114.9	171.9
	98.8	95.2	100.2	187.5	223.3	276.4
Interest coverage incl. AFUDC	3.88	3.88	3.84	2.60	2.41	2.29
Interest coverage excl. AFUDC:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Add: Income taxes	102.0	92.8	97.7	104.5	114.7	129.5
Add: Gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Add: imputed interest expense				81.7	114.9	171.9
Deduct: AFUDC	(4.2)	(9.4)	(18.7)	(15.6)	(10.9)	(7.3)
EBIT	378.9	359.5	366.1	471.3	527.9	625.6
Divide by: gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Add: imputed interest expense				81.7	114.9	171.9
	98.8	95.2	100.2	187.5	223.3	276.4
Interest coverage excl. AFUDC	3.84	3.78	3.65	2.51	2.36	2.26

FLORIDA POWER CORPORATION
MOODY'S RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER
($ IN MILLIONS)

	1990	1991	1992	1993	1994	1995
Internal funds to net construction:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Depreciation & amortization	190.4	241.9	243.4	276.5	294.8	329.7
Deferred taxes & ITCs	(27.5)	(35.2)	8.6	(25.0)	(0.9)	(29.3)
Other operating activities	(10.2)	7.7	(4.0)	14.2	30.1	24.7
Deduct: AFUDC	(4.2)	(9.4)	(18.7)	(15.6)	(10.9)	(7.3)
Funds from operations	330.8	385.9	416.2	445.0	513.9	544.8
Deduct: common dividends	(129.0)	(142.1)	(155.4)	(163.5)	(175.7)	(180.7)
Deduct: preferred dividends	(16.8)	(16.8)	(16.7)	(13.4)	(10.1)	(9.7)
Internal funds	185.0	227.0	244.1	268.1	328.1	354.4
Net construction	265.3	345.9	472.9	426.4	319.5	283.4
Internal funds to net construction	69.7%	65.6%	51.6%	62.9%	102.7%	125.1%
Net construction to prior year cap.:						
Net construction	265.3	345.9	472.9	426.4	319.5	283.4
Prior year capitalization	2,473.9	2,633.4	2,692.2	3,029.2	4,057.5	4,414.3
Net construction to prior year cap.	10.7%	13.1%	17.6%	14.1%	7.9%	6.4%
Capitalization:						
Current portion - ltd & pfd	15.1	37.1	132.5	45.9	35.4	30.6
Short-term commercial paper	178.5	0.0	0.0	125.0	55.3	0.0
Long-term commercial paper	0.0	78.0	96.0	200.0	200.0	145.2
Long-term debt	1,019.8	1,037.6	1,139.8	1,198.6	1,163.8	1,133.9
Imputed debt				817.1	1,148.9	1,718.7
Total debt	1,213.4	1,152.7	1,368.3	2,386.6	2,603.4	3,028.4
Preferred stock	233.5	231.0	216.0	148.5	143.5	138.5
Common equity	1,186.5	1,308.5	1,444.9	1,522.4	1,667.4	1,754.0
Total capitalization	2,633.4	2,692.2	3,029.2	4,057.5	4,414.3	4,920.9
Capitalization percentages:						
Total debt	46.1%	42.8%	45.2%	58.8%	59.0%	61.5%
Preferred stock	8.9%	8.6%	7.1%	3.7%	3.2%	2.8%
Common equity	45.0%	48.6%	47.7%	37.5%	37.8%	35.7%
Total capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Treasury Department
30-Jan-97
1:39 PM

Florida Power
CORPORATION

January 30, 1997

VIA TELECOPY

Ms. Mary Ellen Olson
Associate Director
Standard & Poor's
25 Broadway
New York, NY 10004-1064

Dear Mary Ellen:

Attached are the following items pertaining to Florida Power Corporation's proposed acquisition of the Tiger Bay cogeneration facility:

1. Key facts and issues summary;
2. Projected five-year income statements, balance sheets and statements of cash flows;
3. Standard & Poor's ratio analyses (2) unadjusted and adjusted for purchased power imputed debt;
4. Projected purchased power (QF and utility) capacity payments through life of contracts;
5. Standard & Poor's ratio analyses (2) reflecting the acquisition of the Tiger Bay facility, both unadjusted and adjusted for purchased power imputed debt;
6. Revised projected purchased power (QF and utility) capacity payments, adjusted to eliminate Tiger Bay payments;
7. 1990 through 1995 historical Standard & Poor's ratio analyses (2) unadjusted and adjusted for purchased power imputed debt.

Should you have any questions or comments regarding this information, please do not hesitate to call either Jim Smallwood or me.

Joseph E. Orfano
Manager of Finance
(813) 866-4113

cc: James V. Smallwood

FLORIDA POWER CORPORATION
FIVE-YEAR FORECAST
PROJECTED INCOME STATEMENTS

(Dollars in millions except per share amounts)

	Actual 1996
OPERATING REVENUES	$2,393.6
OPERATING EXPENSES	
Fuel and purchased power	941.3
Other operation expenses	356.2
	1,297.5
Maintenance	119.8
Depreciation	324.2
Taxes other than income taxes	183.6
	1,925.1
INCOME FROM OPERATIONS	468.5
INTEREST EXPENSE AND OTHER	
Interest expense	98.4
Allowance for funds used during construction	(7.5)
Preferred dividends	5.8
Other	3.4
	100.1
INCOME BEFORE INCOME TAXES	368.4
INCOME TAXES	135.8
NET INCOME	$232.6
EARNINGS PER AVERAGE SHARE	$2.40
EPS Annual Growth Rates	

EPS Average Annual Growth Rate 1996-2001 3.0%

FLORIDA POWER CORPORATION
FIVE-YEAR FORECAST
PROJECTED BALANCE SHEETS

(Dollars in millions)

	Actual 1996
ASSETS	
Net property, plant & equipment	$3,530.4
Current assets	441.7
Other assets	291.9
	$4,264.0
CAPITALIZATION AND LIABILITIES	
Common equity	$1,825.5
Preferred stock	33.5
Long-term commercial paper	200.0
Long-term debt	1,096.4
	3,155.4
Short-term debt & other current maturities	25.4
Other current liabilities	320.9
Deferred income taxes, etc.	762.3
	$4,264.0

FLORIDA POWER CORPORATION
FIVE-YEAR FORECAST
PROJECTED STATEMENTS OF CASH FLOWS

(Dollars in millions)

	Actual 1996
OPERATING ACTIVITIES	
Net income	$232.6
Adjustment for non-cash items:	
Depreciation, amortization & depletion	341.1
Deferred income taxes and ITC, net	(32.8)
Change in OPEB reserve	14.9
Allowance for equity funds used during construction	(4.6)
Decrease (increase) in working capital	(57.3)
Other operating activities	7.9
	501.8
INVESTING ACTIVITIES	
Utility plant additions	(220.2)
Other property additions	(2.7)
Proceeds from sale of properties	5.5
Other investing activities	(31.7)
	(249.1)
FINANCING ACTIVITIES	
Issuance of long-term debt	
Repayment of long-term debt	(47.3)
Incr./(decr.) in long-term commercial paper	54.8
Redemption of preferred stock	(106.4)
Dividends paid to parent	(171.2)
Equity contributions from parent	12.5
Increase (decrease) in short-term debt	4.1
Other financing activities	
	(253.5)
NET CHANGE IN CASH	(.8)
Beginning cash and equivalents	0.8
ENDING CASH AND EQUIVALENTS	$.0

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
S & P RATIO ANALYSIS
($ IN MILLIONS)

	Actual 1996
Capitalization:	
Current portion - ltd & pfd	25.4
Long-term commercial paper	200.0
Long-term debt	1,096.4
Total debt	1,321.8
Preferred stock	33.5
Common equity	1,825.5
Total capitalization	3,180.8
Capitalization percentages:	
Total debt	41.6%
Preferred stock	1.0%
Common equity	57.4%
Total capitalization	100.0%

Pre-tax interest coverage:	
Net income	238.4
Add: Income taxes	135.8
Add: Interest expense	98.4
Deduct: AFUDC	(7.5)
EBIT	465.1
Divide by: gross interest charges	98.4
Pre-tax interest coverage	4.73
AA rating > 3.50	
Funds from operations interest coverage:	
Net income	238.4
Depreciation & amortization	341.1
Deferred taxes & ITCs	(32.8)
Other operating activities	22.8
Deduct: AFUDC	(7.5)
Funds from operations	562.0
Cash interest paid	98.4
	660.4
Divide by: gross interest charges	98.4
Funds from operations interest cov.	6.71
AA rating > 4.00	

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
S & P RATIO ANALYSIS
($ IN MILLIONS)

	Actual 1996
Funds from operations average total debt:	
Funds from operations	562.0
Divide by: average total debt	1,315.8
Funds from oper. avg. total debt	42.7%
AA rating > 26%	
Net cash flow/capital expenditures:	
Funds from operations	562.0
Less: common dividends	(171.2)
Less: preferred dividends	(5.8)
Net cash flow	385.0
Capital expenditures	217.3
Net cash flow/capital expenditures	177.2%
AA rating > 90%	

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FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
S & P RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER
($ IN MILLIONS)

	Actual 1996
Capitalization:	
Current portion - ltd & pfd	25.4
Long-term commercial paper	200.0
Long-term debt	1,096.4
Imputed debt	**435.6**
Total debt	1,757.4
Preferred stock	33.5
Common equity	1,825.5
Total capitalization	3,616.4
Capitalization percentages:	
Total debt	48.6%
Preferred stock	0.9%
Common equity	50.5%
Total capitalization	100.0%
Pre-tax interest coverage:	
Net income	238.4
Add: Income taxes	135.8
Add: Interest expense	98.4
Add: Imputed interest expense	**43.6**
Deduct: AFUDC	(7.5)
EBIT	508.7
Divide by: gross interest charges	98.4
Add: Imputed interest expense	**43.6**
	142.0
Pre-tax interest coverage	3.58
AA rating > 3.50	

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
S & P RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER
($ IN MILLIONS)

	Actual 1996
Funds from operations interest coverage:	
Net income	238.4
Depreciation & amortization	341.1
Deferred taxes & ITCs	(32.8)
Other operating activities	22.8
Deduct: AFUDC	(7.5)
Funds from operations	562.0
Cash interest paid	98.4
Imputed interest expense	43.6
	704.0
Divide by: gross interest charges	98.4
Add: Imputed interest expense	43.6
	142.0
Funds from operations interest cov.	4.96
AA rating > 4.00	
Funds from operations average total debt:	
Funds from operations	562.0
Divide by: average total debt	1,757.4
Funds from oper. avg. total debt	32.0%
AA rating > 26%	
Net cash flow/capital expenditures:	
Funds from operations	562.0
Less: common dividends	(171.2)
Less: preferred dividends	(5.8)
Net cash flow	385.0
Capital expenditures	217.3
Net cash flow/capital expenditures	177.2%
AA rating > 90%	

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STANDARD & POOR'S APPROACH:

Utility Capacity Payments	NPV @ 10.00%	Multiply by Risk Factor of 40%	QF Expected Capacity Payments	NPV @ 10.00%	Multiply by Risk Factor of 10%	Total Capacity Payments	Imputed Debt Component	Multiply by Interest Rate of 10%

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
S & P RATIO ANALYSIS
ADJUSTED FOR TIGER BAY ACQUISITION
($ IN MILLIONS)

	Actual 1996
Capitalization:	
Short-term debt & CMLTD	25.4
Long-term commercial paper	200.0
Tiger Bay debt - retail	
Tiger Bay debt - wholesale/def. tax	
Long-term debt	1,096.4
Total debt	1,321.8
Preferred stock	33.5
Common equity	1,825.5
Total capitalization	3,180.8
Capitalization percentages:	
Total debt	41.6%
Preferred stock	1.0%
Common equity	57.4%
Total capitalization	100.0%
Pre-tax interest coverage:	
Net income	238.4
Add: Income taxes	135.8
Add: Interest expense	98.4
Add: Tiger Bay interest expense	
Deduct: AFUDC	(7.5)
EBIT	465.1
Divide by: gross interest charges	98.4
Pre-tax interest coverage	4.73
AA rating > 3.50	

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
S & P RATIO ANALYSIS
ADJUSTED FOR TIGER BAY ACQUISITION
($ IN MILLIONS)

	Actual	Plan				
	1996	1997	1998	1999	2000	2001
Funds from operations interest coverage:						
Net income	238.4					
Depreciation & amortization	341.1					
Tiger Bay depreciation/amortization						
Deferred taxes & ITCs	(32.8)					
Tiger Bay deferred taxes						
Other operating activities	22.8					
Deduct: AFUDC	(7.5)					
Funds from operations	562.0					
Cash interest paid	98.4					
	660.4					
Divide by: gross interest charges	98.4					
Funds from operations interest cov.	6.71					
AA rating > 4.00						
Funds from operations average total debt:						
Funds from operations	562.0					
Divide by: average total debt	1,315.8					
Funds from oper. avg. total debt	42.7%					
AA rating > 26%						
Net cash flow/capital expenditures:						
Funds from operations	562.0					
Less: common dividends	(171.2)					
Less: preferred dividends	(5.8)					
Net cash flow	385.0					
Capital expenditures	217.3					
Net cash flow/capital expenditures	177.2%					
AA rating > 90%						

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FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
S & P RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER/TIGER BAY ACQUISITION
($ IN MILLIONS)

	Actual			Plan		
	1996	1997	1998	1999	2000	2001
Capitalization:						
Short-term debt & CMLTD	25.4					
Long-term commercial paper	200.0					
Tiger Bay debt - retail						
Tiger Bay debt - wholesale/def. tax						
Long-term debt	1,096.4					
Imputed debt	435.6					
Total debt	1,757.4					
Preferred stock	33.5					
Common equity	1,825.5					
Total capitalization	3,616.4					
Capitalization percentages:						
Total debt	48.6%					
Preferred stock	0.9%					
Common equity	50.5%					
Total capitalization	100.0%					
Pre-tax interest coverage:						
Net income	238.4					
Add: Income taxes	135.8					
Add: Interest expense	98.4					
Add: Tiger Bay interest expense						
Add: Imputed interest expense	43.6					
Deduct: AFUDC	(7.5)					
EBIT	508.7					
Divide by: gross interest charges	98.4					
Add: Imputed interest expense	43.6					
	142.0					
Pre-tax interest coverage	3.58					
AA rating > 3.50						

FLORIDA POWER CORPORATION
1997 ANNUAL PROFIT PLAN & FINANCIAL FORECAST
S & P RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER/TIGER BAY ACQUISITION
($ IN MILLIONS)

	Actual	Plan				
	1996	1997	1998	1999	2000	2001
Funds from operations interest coverage:						
Net income	238.4					
Depreciation & amortization	341.1					
Tiger Bay depreciation/amortization						
Deferred taxes & ITCs	(32.8)					
Tiger Bay deferred taxes						
Other operating activities	22.8					
Deduct: AFUDC	(7.5)					
Funds from operations	562.0					
Cash interest paid	98.4					
Imputed interest expense	43.6					
	704.0					
Divide by: gross interest charges	98.4					
Add: Imputed interest expense	43.6					
	142.0					
Funds from operations interest cov.	4.96					
AA rating > 4.00						
Funds from operations average total debt:						
Funds from operations	562.0					
Divide by: average total debt	1,757.4					
Funds from oper. avg. total debt	32.0%					
AA rating > 26%						
Net cash flow/capital expenditures:						
Funds from operations	562.0					
Less: common dividends	(171.2)					
Less: preferred dividends	(5.8)					
Net cash flow	385.0					
Capital expenditures	217.3					
Net cash flow/capital expenditures	177.2%					
AA rating > 90%						

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STANDARD & POOR'S APPROACH:

Utility Capacity Payments	NPV @ 10.00%	Multiply by Risk Factor of 40%	QF Expected Capacity Payments	NPV @ 10.00%	Multiply by Risk Factor of 10%	Total Capacity Payments	Imputed Debt Component	Multiply by Interest Rate of 10%

FLORIDA POWER CORPORATION
S & P HISTORICAL RATIO ANALYSIS
($ IN MILLIONS)

	1990	1991	1992	1993	1994	1995
Capitalization:						
Current portion - ltd & pfd	15.1	37.1	132.5	45.9	35.4	30.6
Short-term commercial paper	178.5	0.0	0.0	125.0	55.3	0.0
Long-term commercial paper	0.0	78.0	96.0	200.0	200.0	145.2
Long-term debt	1,019.8	1,037.6	1,139.8	1,198.6	1,163.8	1,133.9
Total debt	1,213.4	1,152.7	1,368.3	1,569.5	1,454.5	1,309.7
Preferred stock	233.5	231:0	216.0	148.5	143.5	138.5
Common equity	1,186.5	1,308.5	1,444.9	1,522.4	1,667.4	1,754.0
Total capitalization	2,633.4	2,692.2	3,029.2	3,240.4	3,265.4	3,202.2
Capitalization percentages:						
Total debt	46.1%	42.8%	45.2%	48.4%	44.5%	40.9%
Preferred stock	8.9%	8.6%	7.1%	4.6%	4.4%	4.3%
Common equity	45.0%	48.6%	47.7%	47.0%	51.1%	54.8%
Total capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Pre-tax interest coverage:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Add: Income taxes	102.0	92.8	97.7	104.5	114.7	129.5
Add: Interest expense	98.8	95.2	100.2	105.8	108.4	104.5
Deduct: AFUDC	(4.2)	(9.4)	(18.7)	(15.6)	(10.9)	(7.3)
EBIT	378.9	359.5	366.1	389.6	413.0	453.7
Divide by: gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Pre-tax interest coverage	3.84	3.78	3.65	3.68	3.81	4.34
AA rating > 3.50						
Funds from operations interest coverage:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Depreciation & amortization	190.4	241.9	243.4	276.5	294.8	329.7
Deferred taxes & ITCs	(27.5)	(35.2)	8.6	(25.0)	(0.9)	(29.3)
Other operating activities	(10.2)	7.7	(4.0)	14.2	30.1	24.7
Deduct: AFUDC	(4.2)	(9.4)	(18.7)	(15.6)	(10.9)	(7.3)
Funds from operations	330.8	385.9	416.2	445.0	513.9	544.8
Cash interest paid	96.4	86.7	89.7	93.8	101.5	97.9
	427.2	472.6	505.9	538.8	615.4	642.7
Divide by: gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Funds from operations interest cov.	4.32	4.96	5.05	5.09	5.68	6.15
AA rating > 4.00						

FLORIDA POWER CORPORATION
S & P HISTORICAL RATIO ANALYSIS
($ IN MILLIONS)

	1990	1991	1992	1993	1994	1995
Funds from operations average total debt:						
Funds from operations	330.8	385.9	416.2	445.0	513.9	544.8
Divide by: average total debt	1,161.9	1,183.1	1,260.5	1,468.9	1,512.0	1,382.1
Funds from oper. avg. total debt	28.5%	32.6%	33.0%	30.3%	34.0%	39.4%
AA rating > 26%						

	1990	1991	1992	1993	1994	1995
Net cash flow/capital expenditures:						
Funds from operations	330.8	385.9	416.2	445.0	513.9	544.8
Less: common dividends	(129.0)	(142.1)	(155.4)	(163.5)	(175.7)	(180.7)
Less: preferred dividends	(16.8)	(16.8)	(16.7)	(13.4)	(10.1)	(9.7)
Net cash flow	185.0	227.0	244.1	268.1	328.1	354.4
Capital expenditures	265.3	345.9	472.9	426.4	319.5	283.4
Net cash flow/capital expenditures	69.7%	65.6%	51.6%	62.9%	102.7%	125.1%
AA rating > 90%						

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FLORIDA POWER CORPORATION
S & P HISTORICAL RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER
($ IN MILLIONS)

	1990	1991	1992	1993	1994	1995
Capitalization:						
Current portion - ltd & pfd	15.1	37.1	132.5	45.9	35.4	30.6
Short-term commercial paper	178.5	0.0	0.0	125.0	55.3	0.0
Long-term commercial paper	0.0	78.0	96.0	200.0	200.0	145.2
Long-term debt	1,019.8	1,037.6	1,139.8	1,198.6	1,163.8	1,133.9
Imputed debt				**434.3**	**448.1**	**447.6**
Total debt	1,213.4	1,152.7	1,368.3	2,003.8	1,902.6	1,757.3
Preferred stock	233.5	231.0	216.0	148.5	143.5	138.5
Common equity	1,186.5	1,308.5	1,444.9	1,522.4	1,667.4	1,754.0
Total capitalization	2,633.4	2,692.2	3,029.2	3,674.7	3,7[illegible]3.5	3,649.8
Capitalization percentages:						
Total debt	46.1%	42.8%	45.2%	54.5%	51.2%	48.1%
Preferred stock	8.9%	8.6%	7.1%	4.1%	3.9%	3.8%
Common equity	45.0%	48.6%	47.7%	41.4%	44.9%	48.1%
Total capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

	1990	1991	1992	1993	1994	1995
Pre-tax interest coverage:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Add: Income taxes	102.0	92.8	97.7	104.5	114.7	129.5
Add: Interest expense	98.8	95.2	100.2	105.8	108.4	104.5
Add: Imputed interest expense				**43.4**	**44.8**	**44.8**
Deduct: AFUDC	(4.2)	(9.4)	(18.7)	(15.6)	(10.9)	(7.3)
EBIT	378.9	359.5	366.1	[illegible]	457.8	498.5
Divide by: gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Add: Imputed interest expense				**43.4**	**44.8**	**44.8**
	98.8	95.2	100.2	149.2	153.2	149.3
Pre-tax interest coverage	3.84	3.78	3.65	2.90	2.99	3.34

AA rating > 3.50

FLORIDA POWER CORPORATION
S & P HISTORICAL RATIO ANALYSIS
ADJUSTED FOR PURCHASED POWER
($ IN MILLIONS)

	1990	1991	1992	1993	1994	1995
Funds from operations interest coverage:						
Net income	182.3	180.9	186.9	194.9	200.8	227.0
Depreciation & amortization	190.4	241.9	243.4	276.5	294.8	329.7
Deferred taxes & ITCs	(27.5)	(35.2)	8.6	(25.0)	(0.9)	(29.3)
Other operating activities	(10.2)	7.7	(4.0)	14.2	30.1	24.7
Deduct: AFUDC	(4.2)	(9.4)	(18.7)	(15.6)	(10.9)	(7.3)
Funds from operations	330.8	385.9	416.2	445.0	513.9	544.8
Cash interest paid	96.4	86.7	89.7	93.8	101.5	97.9
Imputed interest expense				43.4	44.8	44.8
	427.2	472.6	505.9	582.2	660.2	687.5
Divide by: gross interest charges	98.8	95.2	100.2	105.8	108.4	104.5
Add: Imputed interest expense				43.4	44.8	44.8
	98.8	95.2	100.2	149.2	153.2	149.3
Funds from operations interest cov.	4.32	4.96	5.05	3.90	4.31	4.60
AA rating > 4.00						
Funds from operations average total debt:						
Funds from operations	330.8	385.9	416.2	445.0	513.9	544.8
Divide by: average total debt	1,161.9	1,183.1	1,260.5	1,686.1	1,953.2	1,830.0
Funds from oper. avg. total debt	28.5%	32.6%	33.0%	26.4%	26.3%	29.8%
AA rating > 26%						
Net cash flow/capital expenditures:						
Funds from operations	330.8	385.9	416.2	445.0	513.9	544.8
Less: common dividends	(129.0)	(142.1)	(155.4)	(163.5)	(175.7)	(180.7)
Less: preferred dividends	(16.8)	(16.8)	(16.7)	(13.4)	(10.1)	(9.7)
Net cash flow	185.0	227.0	244.1	268.1	328.1	354.4
Capital expenditures	265.3	345.9	472.9	426.4	319.5	283.4
Net cash flow/capital expenditures	69.7%	65.6%	51.6%	62.9%	102.7%	125.1%
AA rating > 90%						

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RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO FLORIDA POWER CORPORATION

ATTACHMENT TO NUMBER FIVE

5. Provide a copy of the O&M agreement dated July 15, 1993 between Tiger Bay and Destec Operating Company, including all amendments or revisions to date.

Response: See attached agreement.

Preparer: L. G. Schuster

7-8-93 version

OPERATION AND MAINTENANCE AGREEMENT

BETWEEN

CENTRAL FLORIDA POWER, L.P.

And

DESTEC OPERATING COMPANY

Dated as of July 15, 1993

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OPERATION AND MAINTENANCE AGREEMENT

IN WITNESS WHEREOF, the parties have executed multiple originals of this Agreement as of the date first written above.

CENTRAL FLORIDA POWER, L.P.
a Delaware limited partnership

By: Central Florida DGE, Inc.
General Partner

By: R.O. Rogers XE
R. O. Rogers
President

DESTEC OPERATING COMPANY

By: Rod Webb XE
Rodney M. Webb
President

ATTACHMENT I

INDEPENDENT POWER PRODUCTION FACILITY
OPERATION AND MAINTENANCE AGREEMENT

ATTACHMENT II

FIRST AMENDMENT OF
OPERATION AND MAINTENANCE AGREEMENT

IN WITNESS WHEREOF, the parties have executed this Amendment, effective as of July 15, 1993.

TIGER BAY LIMITED PARTNERSHIP
(formerly Central Florida Power, L.P.)
a Delaware limited partnership

By: Central Florida DGE, Inc.
Its General Partner

By: Robert O. Rogers

Name: Robert O. Rogers

Title: President

Date: 12/20/93

KDA

DESTEC OPERATING COMPANY

By: RM Webb

Name: Rodney M. Webb

Title: President

Date: 12/28/93

OPERATION & MAINTENANCE AGREEMENT

RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO FLORIDA POWER CORPORATION

ATTACHMENT TO NUMBER SIX

Overview of the Tiger Bay Transaction

January 9, 1997

Background

Florida Power Corporation (FPC) began investigating the possibility of acquiring the Tiger Bay facility and terminating the associated purchased power agreements in June of 1996. The Tiger Bay facility is FPC's largest qualifying facility (QF) supplier. Tiger Bay delivers 220 megawatts of capacity to FPC under five purchased power agreements (PPAs). The Tiger Bay PPAs are among FPC's highest cost QF contracts, with a composite escalation rate of capacity payments and O&M expense payments included in the energy payment through 2025 of over 6% annually. As shown in Exhibit 1, the cost of power from Tiger Bay under the existing contracts is over $50/MWH currently and is projected to be as much as $188/MWH which is $131/MWH above the market price of power by 2025. As shown in Exhibit 2, the Tiger Bay transaction would eliminate approximately 27 percent of FPC's potential stranded cost liability after 2001.

In contrast to the purchased power agreements, the Tiger Bay facility itself has a number of desirable characteristics. Tiger Bay is a new gas-fired combined cycle plant using "F" technology that is well engineered and in good condition. Tiger Bay is located in close proximity to FPC's Polk County generation site which offers the potential for savings from consolidated operations. FPC's Energy Supply staff visited the Tiger Bay facility regularly during construction and after the plant assumed commercial operation. Energy Supply is very familiar with the facility, the existing plant staff and the operation of the plant. They are of the opinion that the Tiger Bay facility would fit well in to FPC's fleet of generation units.

The Proposed Transaction

On December 12, 1996 Tiger Bay and Florida Power agreed to a price of $445 million for the proposed transaction. At present, Florida Power and Tiger Bay have substantially finalized the terms of the transaction in the form of an agreement (the "Agreement") that provides for both termination of the PPAs and the purchase and sale of Tiger Bay's generation assets. An executive summary of the Agreement is contained in Exhibit 6.

The Tiger Bay transaction would save FPC customers approximately $2.4 billion in cumulative payments which represents a net present value savings of $388 million (see Exhibit 3). The recovery of the cost of the transaction from ratepayers would be spread over five years beginning in October of 1997.

FPC personnel have already begun a number of "due diligence" activities to confirm that the plant facilities are in good operating condition and all operating licenses and permits are in order before FPC assumes ownership. The Agreement includes appropriate protection for FPC regarding the operating condition of the plant and the status of licenses, permits and all environmental matters related to the operation of the plant.

Tiger Bay's existing gas supply contract with Vastar (formerly Arco Natural Gas Marketing, Inc.), which FPC will acquire under the Agreement, is a significant problem in that it is projected to be 25% to 90% above the market price of gas until it terminates at the end of 2010. If FPC cannot negotiate a buyout or modification of the Vastar contract, the proposed transaction (including the proposed regulatory treatment of the price) will not bring the cost of power from Tiger Bay down to the projected market price of power. As shown in Exhibit 1, the transaction reduces the cost of power relative to the existing contract by $23-42 per MWH between 2001 and 2010, but with the Vastar gas supply contract in place the cost of power still remains approximately $8/MWH above the projected market price during this same period. It is only after the gas supply contract terminates (after 2010) that the cost of power from the facility becomes lower than the prevailing market price (see Exhibit 1 and Exhibit 4). For this reason, after taking ownership of the facility, FPC plans to pursue a buy down or buyout of the gas supply contract.

Approvals Required

The transaction will require the approval of the Florida Progress Finance and Budget Committee as well as the Florida Power Board of Directors. For Tiger Bay, the transaction will require the approval of the Board of Directors of Destec Energy, Inc., which owns 50% of Tiger Bay, as well as clearance for sale from the six short listed bidders who are currently evaluating the acquisition of Destec. In addition, Tiger Bay will need to obtain lender consent to enter into the transaction. Finally, the transaction will require the approval of the Florida Public Service Commission (FPSC).

Financial Analysis

FPC will request that the FPSC approve cost recovery of the retail portion of the transaction price ($421.4 million) from customers over five years beginning October 1, 1997. The retail portion of the price ($421.4 million) to be recovered over five years is anticipated to be financed with a set of five medium-term notes maturing in years one through five following the transaction. A financial projection of the transaction is included as Exhibit 7.

The net rate impact of the transaction on the selected rate classes is illustrated in Exhibit 5. For all rate classes, there is an increase in rates during the five year period in which the transaction price is being recovered, followed by a permanent rate decrease. For residential customers, the rate increase in the first year would be approximately 2.5% or $2.37 per 1000 kilowatt hours, declining to $1.65 per 1000 kilowatt hours by the fifth year of cost recovery. Beginning in the sixth year, the rate increase of $1.65 per 1000 kilowatt hours is eliminated and customers will receive an additional rate reduction of approximately $2.00 per 1000 kilowatt hours. This represents a total rate reduction of approximately $3.65 per 1000 kilowatt hours.

RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO FLORIDA POWER CORPORATION

ATTACHMENT TO NUMBER SEVEN

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

	Revenue	Source	NPV	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1	FPC energy sales		349,913	27,069	27,574	27,282	27,977	30,336	30,093	30,497	31,368	32,698	28,010
2	FPC capacity sales		1,007,270	46,675	49,505	52,504	55,686	59,073	62,651	66,438	70,495	74,778	77,200
3	USAC Steam Sales		5,001	402	404	400	406	430	429	442	455	469	484
4	Total Revenue		1,362,184	74,147	77,482	80,185	84,069	89,838	93,173	97,378	102,318	107,945	105,694
5													
6	Operating Expenses												
7	Fuel commodity cost		426,456	[redacted]									
8	Fuel transportation		97,448	8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541
9	Total fuel expense		523,904	[redacted]									
10													
11	Facility O&M	TB/TM p.13	52,677	3,416	3,498	3,578	3,664	3,759	3,865	3,977	4,092	4,215	4,350
12	Major maint. accrual	TB/TM p.13	22,180	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
13	Property taxes	TB/TM p.1	31,769	2,060	2,109	2,158	2,210	2,267	2,331	2,398	2,468	2,542	2,623
14	Site lease	TB/TM p.1	8,182	531	543	556	569	584	600	618	636	655	676
15	FPC lease amort.	TB/TM p.1	11,057	828	828	828	828	828	828	828	828	828	828
16	FPC royalty payment	TB/TM p.1	22,993	280	380	511	643	777	920	1,054	1,227	1,421	1,298
17	Interconnect O&M	TB/TM p.1	2,683	174	178	182	187	191	197	203	208	215	222
18	Waste water disposal	TB/TM p.1	4,316	280	287	293	300	308	317	326	335	345	357
19	Stand-by power	TB/TM p.1	1,[illegible]54	81	83	85	87	89	92	95	97	100	104
20	Insurance	TB/TM p.1	18,220	1,181	1,210	1,238	1,267	1,300	1,337	1,376	1,415	1,458	1,505
21	Management services	TB/TM p.1	9,270	601	616	630	645	662	680	700	720	742	765
22	Admin. services	TB/TM p.1	4,626	300	307	314	322	330	339	349	359	370	382
23	Depreciation	TB/TM p.1	70,648	6,245	6,245	6,245	6,245	6,245	6,245	6,245	6,245	6,245	6,245
24	Amort. power contract	TB/TM p.14	10,355	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
25	Amort. pre-op. exp	TB/TM p.15	308	111	111	111	111	0	0	0	0	0	0
26	Gen. part. reimburse	TB/TM p.1	889	58	59	60	62	63	65	67	69	71	73
27	Accounting fees	TB/TM p.1	370	24	25	25	26	26	27	28	29	30	31
28	Banking fees	TB/TM p.1	7,598	493	504	516	528	542	557	574	590	608	627
29	Legal fees	TB/TM p.1	3,442	223	229	234	239	246	253	260	267	275	284
30	Consultants	TB/TM p.1	1,157	75	77	79	80	83	85	87	90	93	95
31	Miscellaneous	TB/TM p.1	241	21	21	21	21	21	21	21	21	21	21
32	Total operating expense		284,234	19,986	20,303	20,849	21,019	21,307	21,743	22,188	22,682	23,217	23,487
33													
34	Income before interest exp.		554,047	[redacted]									
35	Interest expense		83,517	13,079	12,948	12,783	12,521	12,159	11,666	10,845	9,783	8,741	7,880
36													
37	Net income (loss) before tax		470,529	[redacted]									

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

	Revenue	Source	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	FPC energy sales		28,776	29,305	30,251	30,148	30,990	31,489	32,694	32,794	33,377	33,789	34,274
2	FPC capacity sales		81,860	86,877	92,155	97,787	103,751	110,078	116,790	123,921	131,497	139,539	148,072
3	USAC Steam Sales		498	514	531	548	565	360	366	372	377	383	389
4	Total Revenue		111,167	116,696	122,937	128,482	135,306	141,928	149,850	157,088	165,251	173,712	182,736
5													
6	Operating Expenses												
7	Fuel commodity cost		[redacted]					29,216	29,801	30,397	31,005	31,625	32,257
8	Fuel transportation		8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,54	8,541
9	Total fuel expense		[redacted]					37,757	38,341	38,937	39,545	40,166	40,798
10													
11	Facility O&M	TB/TM p.13	4,489	4,637	4,790	4,948	5,111	5,280	5,454	5,634	5,820	6,012	6,211
12	Major maint. accrual	TB/TM p.13	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
13	Property taxes	TB/TM p.1	2,707	2,798	2,889	2,984	3,083	3,184	3,289	3,398	3,510	3,626	3,746
14	Site lease	TB/TM p.1	697	720	744	769	794	820	847	875	904	934	965
15	FPC lease amort.	TB/TM p.1	828	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
16	FPC royalty payment	TB/TM p.1	1,481	1,651	1,870	2,085	2,312	3,453	3,727	3,973	4,254	4,547	4,860
17	Interconnect O&M	TB/TM p.1	229	236	244	252	260	269	278	287	296	306	316
18	Waste water disposal	TB/TM p.1	368	380	393	406	419	433	447	462	477	493	509
19	Stand-by power	TB/TM p.1	107	110	114	118	122	126	130	134	139	143	148
20	Insurance	TB/TM p.1	1,553	1,604	1,657	1,711	1,768	1,826	1,887	1,949	2,013	2,080	2,148
21	Management services	TB/TM p.1	790	816	843	871	900	929	960	992	1,024	1,058	1,093
22	Admin. services	TB/TM p.1	394	407	421	435	449	464	479	495	511	528	545
23	Depreciation	TB/TM p.1	6,245	6,245	6,245	6,245	6,245	6,245	6,245	6,245	6,245	6,245	6,245
24	Amort. power contract	TB/TM p.14	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	0
25	Amort. pre-op. exp	TB/TM p.15	0	0	0	0	0	0	0	0	0	0	0
26	Gen. part. reimburse	TB/TM p.1	76	78	81	83	86	89	92	95	98	101	105
27	Accounting fees	TB/TM p.1	32	33	34	35	36	37	38	40	41	42	44
28	Banking fees	TB/TM p.1	647	669	691	714	737	762	787	813	839	867	896
29	Legal fees	TB/TM p.1	293	303	313	323	334	345	356	368	380	393	406
30	Consultants	TB/TM p.1	99	102	105	109	112	116	120	124	128	132	136
31	Miscellaneous	TB/TM p.1	21	21	21	21	21	21	21	21	21	21	21
32	Total operating expense		24,040	24,994	25,838	26,272	26,974	28,583	29,342	30,088	30,887	31,713	31,537
33													
34	Income before interest exp.		[redacted]					75,587	82,166	88,061	94,819	101,833	110,401
35	Interest expense		[redacted]					0	0	0	0	0	0
36													
37	Net income (loss) before tax		[redacted]					75,587	82,166	88,061	94,819	101,833	110,401

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

	Revenue	Source	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	FPC energy sales		34,764	35,260	35,760	36,267	36,778	37,265	37,818	38,347	38,881
2	FPC capacity sales		157,158	166,792	177,010	187,868	199,406	211,646	224,649	238,464	43,662
3	USAC Steam Sales		396	402	408	415	422	428	435	442	450
4	Total Revenue		192,319	202,454	213,179	224,549	236,606	249,370	262,902	277,253	82,992
5											
6	Operating Expenses										
7	Fuel commodity cost		32,902	33,560	34,232	34,916	35,615	36,327	37,053	37,794	38,550
8	Fuel transportation		8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541
9	Total fuel expense		41,443	42,101	42,772	43,457	44,155	44,868	45,594	46,335	47,091
10											
11	Facility O&M	TB/TM p.13	6,416	6,627	6,846	7,072	7,305	7,546	7,795	8,053	8,318
12	Major maint. accrual	TB/TM p.13	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
13	Property taxes	TB/TM p.1	3,869	3,997	4,129	4,265	4,406	4,551	4,701	4,856	5,017
14	Site lease	TB/TM p.1	996	1,029	1,063	1,098	1,135	1,172	1,211	1,251	1,292
15	FPC lease amort.	TB/TM p.1	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
16	FPC royalty payment	TB/TM p.1	5,195	5,550	5,928	6,331	6,759	7,214	7,699	8,215	384
17	Interconnect O&M	TB/TM p.1	327	338	349	360	372	384	397	410	424
18	Waste water disposal	TB/TM p.1	526	543	561	580	599	619	639	660	682
19	Stand-by power	TB/TM p.1	153	158	163	168	174	180	186	192	198
20	Insurance	TB/TM p.1	2,219	2,292	2,368	2,446	2,527	2,610	2,696	2,785	2,877
21	Management services	TB/TM p.1	1,129	1,166	1,205	1,245	1,286	1,328	1,372	1,417	1,464
22	Admin. services	TB/TM p.1	563	582	601	621	642	663	685	707	731
23	Depreciation	TB/TM p.1	6,245	6,245	6,245	6,245	6,245	6,245	6,245	6,245	0
24	Amort. power contract	TB/TM p.14	0	0	0	0	0	0	0	0	0
25	Amort. pre-op. exp	TB/TM p.15	0	0	0	0	0	0	0	0	0
26	Gen. part. reimburse	TB/TM p.1	108	112	115	119	123	127	131	136	140
27	Accounting fees	TB/TM p.1	45	47	48	50	51	53	55	57	58
28	Banking fees	TB/TM p.1	925	956	987	1,020	1,054	1,088	1,124	1,161	1,200
29	Legal fees	TB/TM p.1	419	433	447	462	477	493	509	526	544
30	Consultants	TB/TM p.1	141	146	150	155	160	166	171	177	183
31	Miscellaneous	TB/TM p.1	21	21	21	21	21	21	21	21	21
32	Total operating expense		32,442	33,388	34,372	35,402	36,460	37,605	38,782	40,013	26,877
33											
34	Income before interest exp.		118,433	126,967	136,034	145,689	155,971	166,897	178,526	190,905	9,224
35	Interest expense		0	0	0	0	0	0	0	0	0
36											
37	Net income (loss) before tax		118,433	126,967	136,034	145,689	155,971	166,897	178,526	190,905	9,224

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

Cash flow	Source	NPV		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Income before taxes		470,529		[redacted]									
Add: depr. & amort.		81,308		7,397	7,397	7,397	7,397	7,288	7,288	7,288	7,288	7,288	7,288
Operating Cash Flow		551,837		[redacted]									
Less: debt repayment	TB Loan	(92,583)		(1,840)	(1,840)	(2,760)	(4,600)	(5,520)	(8,280)	(14,720)	(14,720)	(14,720)	(14,720)
Debt service reserve		1,896		0	0	0	0	0	0	0	0	0	0
Partner distribution		(460,951)		[redacted]									
Net change in cash		0		4,514	0	0	0	0	0	0	0	0	0
Debt coverage ratio				0.81	1.01	1.14	1.20	1.33	1.33	1.13	1.30	1.52	1.41
Profit from sale (IRR% and cash flow)			11.8%	264,449	(7,490)	(9,504)	(10,821)	(13,128)	(13,810)	(10,565)	(14,728)	(19,300)	(16,383)

Balance Sheet Assets	Source	Start Balance 12/31/95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Gross plant	Destec Fin.	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201
Accum. depreciation	Destec Fin.	(6,246)	(13,532)	(20,817)	(28,103)	(35,388)	(42,674)	(49,960)	(57,245)	(64,531)	(71,816)	(79,102)
Net plant in service		201,955	194,669	187,384	180,098	172,812	165,527	158,241	150,956	143,670	136,384	129,099
Current assets	Destec Fin.	18,347	22,861	22,861	22,861	22,861	22,861	22,861	22,861	22,861	22,861	22,861
Debt reserve fund	Destec Fin.	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Maint. reserve fund	Destec Fin.	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868
Total current assets		25,215	29,729	29,729	29,729	29,729	29,729	29,729	29,729	29,729	29,729	29,729
Pre-operational costs	Destec Fin.	445	334	223	111	0	0	0	0	0	0	0
Misc. assets	Destec Fin.	979	979	979	979	979	979	979	979	979	979	979
Total assets		228,594	225,711	218,314	210,917	203,521	196,235	188,949	181,664	174,378	167,093	159,807

Balance Sheet Liabilities	Source	Start Balance 12/31/95	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Paid-in capital	Destec Fin.	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041
Retained earnings	Destec Fin.	752	(290)	(5,847)	(10,484)	(13,281)	(15,046)	(14,052)	(8,618)	817	8,251	15,686
Equity investment		25,793	24,751	19,194	14,557	11,760	9,995	10,989	16,423	25,858	33,292	40,727
Construct. obligation	Destec Fin.	226	226	226	226	226	226	226	226	226	226	226
Long term lease	Destec Fin.	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652
Other liab - Destec	Destec Fin.	818	818	818	818	818	818	818	818	818	818	818
Fuji Bank financing	Destec Fin.	184,000	182,160	180,320	177,560	172,960	167,440	159,160	144,440	129,720	115,000	100,280
Total capitalization		221,490	218,607	211,210	203,814	196,417	189,131	181,846	174,560	167,274	159,989	152,703
Current Liabilities	Destec Fin.	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104
Total Liabilities		228,594	225,711	218,314	210,917	203,521	196,235	188,949	181,664	174,378	167,093	159,807

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

Cash flow	Source	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Income before taxes		[redacted]					75,587	82,166	88,061	94,819	101,[illegible]33	110,401
Add: depr. & amort.		7,286	7,286	7,286	7,286	7,286	7,286	7,286	7,286	7,286	7,286	6,245
Operating Cash Flow		[redacted]					82,873	89,452	95,346	102,105	109,119	116,646
Less: debt repayment	TB Loan	(14,720)	(17,480)	(21,160)	(22,080)	(24,240)	0	0	0	0	0	0
Debt service reserve		0	0	0	0	5,000	0	0	0	0	0	0
Partner distribution		[redacted]					(82,873)	(89,452)	(95,346)	(102,105)	(109,119)	(116,646)
Net change in cash		0	0	0	0	0	0	0	0	0	0	0
Debt coverage ratio		1.63	1.65	1.65	1.82	1.91						
Profit from sale (IRR% and cash flow)		(20,833)	(22,144)	(23,722)	(27,472)	(35,655)	(82,873)	(89,452)	(95,346)	(102,105)	(109,119)	(116,646)

Balance Sheet

Assets	Source	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Gross plant	Destec Fin.	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201
Accum. depreciation	Destec Fin.	(86,387)	(93,673)	(100,959)	(108,244)	(115,530)	(122,815)	(130,101)	(137,387)	(144,672)	(151,958)	(159,203)
Net plant in service		121,813	114,528	107,242	99,957	92,671	85,385	78,100	70,814	63,529	56,243	48,998
Current assets	Destec Fin.	22,861	22,861	22,861	22,861	22,861	22,861	22,861	22,861	22,861	22,861	22,861
Debt reserve fund	Destec Fin.	5,000	5,000	5,000	5,000	0	0	0	0	0	0	0
Maint. reserve fund	Destec Fin.	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868
Total current assets		29,729	29,729	29,729	29,729	24,729	24,729	24,729	24,729	24,729	24,729	24,729
Pre-operational costs	Destec Fin.	0	0	0	0	0	0	0	0	0	0	0
Misc. assets	Destec Fin.	979	979	979	979	979	979	979	979	979	979	979
Total assets		152,521	145,236	137,950	130,665	118,379	111,094	103,808	96,522	89,237	81,951	75,706

Balance Sheet

Liabilities	Source	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Paid-in capital	Destec Fin.	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041
Retained earnings	Destec Fin.	23,120	33,315	47,189	61,983	74,538	67,252	59,967	52,681	45,395	38,110	31,865
Equity investment		48,161	58,356	72,230	87,024	99,579	92,293	85,008	77,722	70,436	63,151	56,906
Construct. obligation	Destec Fin.	228	228	228	228	228	228	228	228	228	228	228
Long term lease	Destec Fin.	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652
Other liab - Destec	Destec Fin.	818	818	818	818	818	818	818	818	818	818	818
Fuji Bank financing	Destec Fin.	85,560	68,080	46,920	24,840	0	0	0	0	0	0	0
Total capitalization		145,418	138,132	130,846	123,561	111,275	103,990	96,704	89,418	82,133	74,847	68,602
Current Liabilities	Destec Fin.	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104
Total Liabilities		152,521	145,236	137,950	130,665	118,379	111,094	103,808	96,522	89,237	81,951	75,706

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

Cash flow	Source	2017	2018	2019	2020	2021	2022	2023	2024	2025
Income before taxes		118,433	126,967	136,034	145,689	155,971	166,897	178,526	190,905	9,224
Add: depr. & amort.		6,245	6,245	6,245	6,245	6,245	6,245	6,245	6,245	0
Operating Cash Flow		124,678	133,212	142,279	151,934	162,216	173,142	184,771	197,150	9,224
Less: debt repayment	TB Loan	0	0	n	0	0	0	0	0	0
Debt service reserve		0	0	J	0	0	0	0	0	0
Partner distribution		(124,678)	(133,212)	(142,279)	(151,934)	(162,216)	(173,142)	(184,771)	(197,150)	(9,224)
Net change in cash		0	0	0	0	0	0	0	0	0
Debt coverage ratio										
Profit from sale (IRR% and cash flow)		(124,678)	(133,212)	(142,279)	(151,934)	(162,216)	(173,142)	(184,771)	(197,150)	(9,224)

Balance Sheet / Assets	Source	2017	2018	2019	2020	2021	2022	2023	2024	2025
Gross plant	Destec Fin.	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201	208,201
Accum. depreciation	Destec Fin.	(164,448)	(170,693)	(176,938)	(183,183)	(189,428)	(195,673)	(201,918)	(208,164)	(208,164)
Net plant in service		43,753	37,508	31,263	25,018	18,772	12,527	6,282	37	37
Current assets	Destec Fin.	22,861	22,861	22,861	22,861	22,861	22,861	22,861	22,861	22,861
Debt reserve fund	Destec Fin.	0	0	0	0	0	0	0	0	0
Maint. reserve fund	Destec Fin.	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868	1,868
Total current assets		24,729	24,729	24,729	24,729	24,729	24,729	24,729	24,729	24,729
Pre-operational costs	Destec Fin.	0	0	0	0	0	0	0	0	0
Misc. assets	Destec Fin.	979	979	979	979	979	979	979	979	979
Total assets		69,461	63,216	56,971	50,726	44,481	38,236	31,991	25,745	25,745

Balance Sheet / Liabilities	Source	2017	2018	2019	2020	2021	2022	2023	2024	2025
Paid-in capital	Destec Fin.	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041	25,041
Retained earnings	Destec Fin.	25,820	19,375	13,129	6,884	639	(5,606)	(11,851)	(18,096)	(18,096)
Equity investment		50,861	44,416	38,170	31,925	25,680	19,435	13,190	6,945	6,945
Construct. obligation	Destec Fin.	226	226	226	226	226	226	226	226	226
Long term lease	Destec Fin.	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652	10,652
Other liab - Destec	Destec Fin.	818	818	818	818	818	818	818	818	818
Fuji Bank financing	Destec Fin.	0	0	0	0	0	0	0	0	0
Total capitalization		62,357	56,112	49,867	43,622	37,377	31,132	24,887	18,642	18,642
Current Liabilities	Destec Fin.	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104	7,104
Total Liabilities		69,461	63,216	56,971	50,726	44,481	38,236	31,990	25,745	25,745

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

		Percent Firm	Source	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	Contract Capacity Payments		Source	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1	General Peat ($/KW-month)		Contract #1	16.04	17.06	18.14	19.29	20.51	21.81	23.19	24.65	26.22	27.88	29.65
2	EcoPeat ($/KW-month)		Contract #2	19.90	20.91	21.98	23.09	24.27	25.52	26.81	28.18	29.62	31.13	32.72
3	Timber #2 ($/KW-month)		Contract #3	16.04	17.06	18.14	19.29	20.51	21.81	23.19	24.65	26.22	27.88	0.00
4														
5	General Peat ($000)			33,030	35,130	37,354	39,722	42,234	44,911	47,753	50,759	53,992	57,410	61,055
6	EcoPeat ($000)			4,909	10,317	10,845	11,393	11,975	12,592	13,228	13,904	14,615	15,360	16,144
7	Timber #2 ($000)			1,155	1,228	1,306	1,389	1,477	1,570	1,670	1,775	1,888	2,007	0
8	Total capacity payment ($000)			39,094	46,675	49,505	52,504	55,686	59,073	62,651	66,438	70,495	74,778	77,200
9														
10	Electrical Energy Sold			1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
11	Total energy sales (GWH)			1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431
12														
13	Energy Price Assumptions		Source	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
14	Coal price ($/MMBTU)		FCP 9803	1.717	1.880	1.700	1.710	1.750	1.740	1.770	1.810	1.840	1.870	1.910
15	Natural gas price ($/MMBTU)		FCP 9803	2.340	2.500	2.158	2.108	2.050	2.050	2.100	2.150	2.150	2.200	2.250
16	Big Bend 4 coal price		TECO/BB4	2.160	2.121	2.172	2.124	2.200	2.519	2.435	2.464	2.550	2.710	2.018
17	As-avail.(fuel+O&M+startup $/MWH)		FCP 9803	17.15	17.35	17.58	17.83	17.85	17.93	18.24	18.81	19.22	19.48	19.95
18														
19	CR8C firm energy price ($/MWH)			13.50	13.21	13.37	13.45	13.60	13.68	13.92	14.23	14.47	14.71	15.02
20	BB4 firm energy price ($/MWH)			21.14	20.77	21.28	20.79	21.54	24.88	24.05	24.12	24.98	26.53	19.76
21			Source											
22	FPC delivery voltage adj (percent)		FPC/FERC #1	2.97%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
23	Performance adjustment - EcoPeat ($000)		TB/TM (4/96)	0	186	186	186	186	186	186	186	186	186	186
24														
25		Percent	Energy											
26	Energy payments	Firm	Share											
27	General Peat (BB4)	82.0%	78.81%	22,786	22,498	22,944	22,640	23,272	25,540	25,240	25,545	26,325	27,553	22,917
28	EcoPeat (CR8C)	97.0%	18.44%	3,697	3,786	3,839	3,860	3,903	3,924	3,989	4,076	4,141	4,205	4,291
29	Timber #2 (BB4)	54.0%	2.76%	784	776	790	781	802	871	864	876	902	941	802
30	Total energy payments			27,267	27,060	27,574	27,282	27,977	30,335	30,093	30,497	31,368	32,698	28,010
31														
32	Composite energy price $/MWH					19.27	19.07	19.56	21.20	21.03	21.32	21.93	22.86	19.58
33			Source											
34	Steam sales (Mlb/yr)		TB/TM (4/96)	268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203
35	Base steam price ($/Mlbs)		TB/TM (4/96)	1.50	1.50	1.51	1.49	1.51	1.60	1.60	1.65	1.70	1.75	1.81
36	Steam revenue ($000)			402	402	404	400	406	430	429	442	455	469	484

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

	Contract Capacity Payments		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	General Peat ($/KW-month)		31.53	33.53	35.65	37.92	40.33	42.89	45.61	48.51	51.59	54.87	58.36
2	EcoPeat ($/KW-month)		34.38	36.14	37.99	39.93	41.96	44.10	46.35	48.70	51.20	53.81	56.54
3	Timber #2 ($/KW-month)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4													
5	General Peat ($000)		64,927	68,045	73,410	78,085	83,048	88,319	93,920	99,892	106,234	112,988	120,175
6	EcoPeat ($000)		16,963	17,832	18,745	19,702	20,703	21,759	22,870	24,029	25,263	26,550	27,897
7	Timber #2 ($000)		0	0	0	0	0	0	0	0	0	0	0
8	Total capacity payment ($000)		81,890	85,877	92,155	97,787	103,751	110,078	116,790	123,921	131,497	139,538	148,072
9													
10	**Electrical Energy Sold**		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
11	Total energy sales (GWH)		1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431
12													
13	**Energy Price Assumptions**		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
14	Coal price ($/MMBTU)		1.940	1.970	2.000	2.030	2.060	2.091	2.123	2.155	2.187	2.220	2.253
15	Natural gas price ($/MMBTU)		2.250	2.295	2.341	2.388	2.435	2.484	2.534	2.585	2.636	2.689	2.743
16	Big Bend 4 coal price		2.087	2.153	2.256	2.214	2.302	2.343	2.481	2.467	2.519	2.547	2.585
17	As-avail (fuel+O&M+startup $/MWH)		20.25	20.38	20.66	20.98	21.28	21.58	21.88	22.18	22.48	22.78	23.08
18													
19	CR6C firm energy price ($/MWH)		15.26	15.49	15.73	15.96	16.20	16.45	16.69	16.94	17.20	17.46	17.72
20	BB4 firm energy price ($/MWH)		20.53	21.08	22.08	21.67	22.54	22.94	24.29	24.15	24.66	24.93	25.31
21													
22	FPC delivery voltage adj (percent)		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
23	Performance adjustment - EcoPeat ($000)		186	186	186	186	186	186	186	186	186	186	186
24													
25		Percent											
26	**Energy payments**	Firm											
27	General Peat (BB4)	62.0%	23,598	24,048	24,902	24,736	25,490	25,909	27,012	27,041	27,538	27,869	28,269
28	EcoPeat (CR6C)	97.0%	4,356	4,419	4,483	4,547	4,612	4,679	4,746	4,814	4,883	4,953	5,024
29	Timber #2 (BB4)	54.0%	824	839	868	863	887	902	937	939	956	967	981
30	Total energy payments		28,778	29,305	30,251	30,146	30,990	31,489	32,694	32,794	33,377	33,789	34,274
31													
32	Composite energy price $/MWH		20.12	20.48	21.15	21.07	21.66	22.01	22.85	22.92	23.33	23.62	23.96
33													
34	Steam sales (Mlb/yr)		268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203
35	Base steam price ($/Mlbs)		1.86	1.92	1.98	2.04	2.11	1.34	1.36	1.39	1.41	1.43	1.45
36	Steam revenue ($000)		498	514	531	548	565	360	366	372	377	383	389

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

		Percent Firm	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Contract Capacity Payments		2017	2018	2019	2020	2021	2022	2023	2024	2025
1	General Peat ($/KW-month)		62.08	66.03	70.23	74.70	79.46	84.52	89.90	95.63	0.00
2	EcoPeat ($/KW-month)		59.43	62.47	65.65	69.00	72.52	76.21	80.11	84.20	88.49
3	Timber #2 ($/KW-month)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4											
5	General Peat ($000)		127,835	135,969	144,618	153,822	163,624	174,044	185,122	196,921	0
6	EcoPeat ($000)		29,323	30,823	32,392	34,045	35,782	37,603	39,527	41,543	43,662
7	Timber #2 ($000)		0	0	0	0	0	0	0	0	0
8	Total capacity payment ($000)		157,158	166,792	177,010	187,868	199,406	211,646	224,649	238,464	43,662
9											
10	Electrical Energy Sold		2017	2018	2019	2020	2021	2022	2023	2024	2025
11	Total energy sales (GWH)		1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431	1,431
12											
13	Energy Price Assumptions		2017	2018	2019	2020	2021	2022	2023	2024	2025
14	Coal price ($/MMBTU)		2.287	2.321	2.356	2.391	2.427	2.464	2.500	2.538	2.576
15	Natural gas price ($/MMBTU)		2.798	2.854	2.911	2.969	3.028	3.089	3.151	3.214	3.278
16	Big Bend 4 coal price		2.624	2.663	2.703	2.744	2.785	2.827	2.869	2.912	2.956
17	As-avail.(fuel+O&M+startup $/MWH)		23.38	23.68	23.99	24.29	24.59	24.89	25.19	25.49	25.79
18											
19	CR3C firm energy price ($/MWH)		17.98	18.25	18.53	18.80	19.09	19.37	19.66	19.96	20.26
20	BB4 firm energy price ($/MWH)		25.69	26.07	26.46	26.86	27.26	27.67	28.09	28.51	28.94
21											
22	FPC delivery voltage adj (percent)		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
23	Performance adjustment - EcoPeat ($000)		186	186	186	186	186	186	186	186	186
24											
25		Percent									
26	Energy payments	Firm									
27	General Peat (BB4)	62.0%	28,673	29,081	29,494	29,910	30,331	30,756	31,185	31,619	32,058
28	EcoPeat (CR3C)	97.0%	5,096	5,169	5,244	5,319	5,395	5,473	5,552	5,631	5,712
29	Timber #2 (BB4)	54.0%	995	1,009	1,023	1,037	1,052	1,066	1,081	1,096	1,111
30	Total energy payments		34,764	35,260	35,760	36,267	36,778	37,295	37,818	38,347	38,881
31											
32	Composite energy price $/MWH		24.30	24.65	25.00	25.35	25.71	26.07	26.43	26.80	27.18
33											
34	Steam sales (Mlb/yr)		268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203	268,203
35	Base steam price ($/Mlbs)		1.48	1.50	1.52	1.55	1.57	1.60	1.62	1.65	1.68
36	Steam revenue ($000)		396	402	408	415	422	428	435	442	450

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

				1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	Natural Gas Usage (GBtu/yr):		Contract Demand											
1	FGT transportation (FTS-1)	32.0%	3,871	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633
2	FGT transportation (FTS-2)	68.0%	8,221	7,716	7,716	7,716	7,716	7,716	7,716	7,716	7,716	7,716	7,710	7,716
3	Total burnertip gas consumption			11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349
4			Source											
5	FGT shrinkage	3.50%	TB/TM p. 10	412	412	412	412	412	412	412	412	412	412	412
6	Delivered into FGT from Vastar			[redacted]										
7														
8	**Fuel and transportation rates**			1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
9	Floating gas price index ($/MWH)		(estimated)	[redacted]										
10	Contract Fixed Gas Price ($/MMBtu)		(estimated)											
11	Contract Floating Gas Price ($/MMBtu)		(estimated)											
12	Effective contract gas price ($/MMBtu)													
13														
14	Vastar commodity must-take (MMBtu/year)		Vastar contract	[redacted]										
15	Vastar demand must-take (MMBtu/year)		Vastar contract											
16	Vastar - total ($/MMBTU)													
17	Vastar - demand ($/MMBTU)		Vastar contract											
18	Vastar - commodity ($/MMBtu)													
19	Vastar - incremental commodity ($/MMBtu)													
20														
21	FTS-1 fixed cost ($/MMBTU)		TB/TM p. 11	0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434
22	FTS-1 variable cost ($/MMBtu)		TB/TM p. 11	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072
23	FTS-2 fixed cost ($/MMBTU)		TB/TM p. 11	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757
24	FTS-2 variable cost ($/MMBtu)		TB/TM p. 11	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048
25														
26	**Total Fuel Cost**		NPV	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
27	Vastar - demand		[redacted]											
28	Vastar - commodity													
29	Vastar - incremental commodity													
30	FTS-1 fixed cost		19,180	1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682
31	FTS-1 variable cost		2,985	262	262	262	262	262	262	262	262	262	262	262
32	FTS-2 fixed cost		71,034	6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226
33	FTS-2 variable cost		4,243	372	372	372	372	372	372	372	372	372	372	372
34	Total fuel cost ($000)		[redacted]											
35														
36	Generation cost ($/MWH)			29.07	29.46	29.57	29.26	29.71	31.46	31.43	32.40	33.33	34.37	35.45
37														
38	Gas commodity cost ($/MMBtu)			[redacted]										
39	Gas transportation ($/MMBTU)			0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
40	Burnertip gas cost ($/MMBtu)			[redacted]										

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

	Natural Gas Usage (GBtu/yr):		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	FGT transportation (FTS-1)	32.0%	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633
2	FGT transportation (FTS-2)	68.0%	7,716	7,716	7,716	7,716	7,716	7,716	7,716	7,716	7,716	7,716	7,716
3	Total burnertip gas consumption		11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349
4													
5	FGT shrinkage	3.50%	412	412	412	412	412	412	412	412	412	412	412
6	Delivered into FGT from Vastar		[redacted]					11,761	11,761	11,761	11,761	11,761	11,761
7													
8	Fuel and transportation rates		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
9	Floating gas price index ($/MWH)		[redacted]					21.986	22.827	22.897	23.305	23.593	23.931
10	Contract Fixed Gas Price ($/MMBtu)							0.000	0.000	0.000	0.000	0.000	0.000
11	Contract Floating Gas Price ($/MMBtu)							0.000	0.000	0.000	0.000	0.000	0.000
12	Effective contract gas price ($/MMBtu)							0.000	0.000	0.000	0.000	0.000	0.000
13													
14	Vastar commodity must-take (MMBtu/year)		[redacted]										
15	Vastar demand must-take (MMBtu/year)												
16	Vastar - total ($/MMBTU)							0.000	0.000	0.000	0.000	0.000	0.000
17	Vastar - demand ($/MMBTU)							0.000	0.000	0.000	0.000	0.000	0.000
18	Vastar - commodity ($/MMBtu)							0.000	0.000	0.000	0.000	0.000	0.000
19	Vastar - incremental commodity ($/MMBtu)							2.277	2.277	2.277	2.277	2.277	2.277
20													
21	FTS-1 fixed cost ($/MMBTU)		0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434
22	FTS-1 variable cost ($/MMBtu)		0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072
23	FTS-2 fixed cost ($/MMBTU)		0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757
24	FTS-2 variable cost ($/MMBtu)		0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048
25													
26	Total Fuel Cost		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
27	Vastar - demand		[redacted]					0	0	0	0	0	0
28	Vastar - commodity							0	0	0	0	0	0
29	Vastar - incremental commodity							29,216	29,801	30,397	31,005	31,625	32,257
30	FTS-1 fixed cost		1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682
31	FTS-1 variable cost		262	262	262	262	262	262	262	262	262	262	262
32	FTS-2 fixed cost		6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226
33	FTS-2 variable cost		372	372	372	372	372	372	372	372	372	372	372
34	Total fuel cost ($000)		[redacted]					37,757	38,341	38,937	39,545	40,168	40,798
35													
36	Generation cost ($/MWH)		38.50	37.66	38.86	40.11	41.41	26.39	26.80	27.22	27.64	28.08	28.52
37													
38	Gas commodity cost ($/MMBtu)		[redacted]					2.57	2.63	2.68	2.73	2.79	2.84
39	Gas transportation ($/MMBTU)		0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
40	Burnertip gas cost ($/MMBtu)		[redacted]					3.33	3.38	3.43	3.48	3.54	3.59

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

			2017	2018	2019	2020	2021	2022	2023	2024	2025
	Natural Gas Usage (GBtu/yr):										
1	FGT transportation (FTS-1)	32.0%	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633	3,633
2	FGT transportation (FTS-2)	68.0%	7,716	7,716	7,716	7,716	7,716	7,716	7,716	7,716	7,716
3	Total burnertip gas consumption		11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349	11,349
4											
5	FGT shrinkage	3.50%	412	412	412	412	412	412	412	412	412
6	Delivered into FGT from Vastar		11,761	11,761	11,761	11,761	11,761	11,761	11,761	11,761	11,761
7											
8	Fuel and transportation rates		2017	2018	2019	2020	2021	2022	2023	2024	2025
9	Floating gas price index ($/MWH)		24.274	24.620	24.969	25.323	25.680	26.041	26.407	26.776	27.149
10	Contract Fixed Gas Price ($/MMBtu)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Contract Floating Gas Price ($/MMBtu)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	Effective contract gas price ($/MMBtu)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
13											
14	Vastar commodity must-take (MMBtu/year)										
15	Vastar demand must-take (MMBtu/year)										
16	Vastar - total ($/MMBTU)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17	Vastar - demand ($/MMBTU)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18	Vastar - commodity ($/MMBtu)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19	Vastar - incremental commodity ($/MMBtu)		2.277	2.277	2.277	2.277	2.277	2.277	2.277	2.277	2.277
20											
21	FTS-1 fixed cost ($/MMBTU)		0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434	0.434
22	FTS-1 variable cost ($/MMBtu)		0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072
23	FTS-2 fixed cost ($/MMBTU)		0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757	0.757
24	FTS-2 variable cost ($/MMBtu)		0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048
25											
26	Total Fuel Cost		2017	2018	2019	2020	2021	2022	2023	2024	2025
27	Vastar - demand		0	0	0	0	0	0	0	0	0
28	Vastar - commodity		0	0	0	0	0	0	0	0	0
29	Vastar - incremental commodity		32,902	33,560	34,232	34,916	35,615	36,327	37,053	37,794	38,550
30	FTS-1 fixed cost		1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682	1,682
31	FTS-1 variable cost		262	262	262	262	262	262	262	262	262
32	FTS-2 fixed cost		6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226	6,226
33	FTS-2 variable cost		372	372	372	372	372	372	372	372	372
34	Total fuel cost ($000)		41,443	42,101	42,772	43,457	44,155	44,868	45,594	46,335	47,091
35											
36	Generation cost ($/MWH)		28.97	29.43	29.90	30.38	30.86	31.36	31.87	32.39	32.92
37											
38	Gas commodity cost ($/MMBtu)		2.90	2.96	3.02	3.08	3.14	3.20	3.26	3.33	3.40
39	Gas transportation ($/MMBTU)		0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
40	Burnertip gas cost ($/MMBtu)		3.65	3.71	3.77	3.83	3.89	3.95	4.02	4.08	4.15

Base Case (Scardino)

FPC Financial Projection for Tiger Bay

	Summary of assumptions:	Value	Source Document
1	On-peak hours per day (hours)	11	PPA contract Appendix C, Schedule 3, page 1 of 1
2	Off-peak hours per day (hours)	13	PPA contract Appendix C, Schedule 3, page 1 of 1
3	Days per year (days)	365	(standard year)
4	Availability (percent)	75.00%	Average projected generation per FPC assumption
5			
6	Gen. Peat committed capacity (KW)	171,600	Capacity recommitment letter dated August 10, 1992
7	EcoPeat committed capacity (KW)	40,150	Capacity recommitment letter dated April 17, 1995
8	Timber #2 committed capacity (KW)	6,000	Standard Offer Contract dated July, 1989
9	Total (KW)	217,750	(computed value)
10			
11	Turbine Fuel Duty (LHV MMBtu/hr)	1554.7	Estimated fuel duty based on historical actual results
12	Total Burnertip (HHV GBtu/yr)	11,349	(computed value)
13	Fixed gas price escalator (percent)	[redacted]	[redacted]
14			
15	EcoPeat minimum capacity factor (%)	83.0%	EcoPeat contract, Appendix C, Schedule 3, page 1 of 1
16	EcoPeat elected capacity factor (%)	85.0%	EcoPeat contract, Section 7.1
17	Long-term coal price growth (percent)	1.5%	Fuel forecast FCP 9603 dated October 28, 1996
18	CR6C heat rate (BTU/KWH)	9,830	EcoPeat contract Appendix C, Schedule 3, page 1 of 1
19	BB4 heat rate (BTU/KWH)	9,790	General Peat and Timber Energy, Rate Schedule COG-2, page 3 of 9
20	CR6C fuel multiplier (factor)	0.80	EcoPeat contract Appendix C, Schedule 4, page 3 of 3
21			
22	Fuji loan interest rate (percent)	7.14%	TB/TM p.13
23	FPC lease termination cost ($000)	1,200	TB/FPC Back-up Fuel side letter agreement dated July 8, 1994
24	FPC profit interest (percent)	4.0%	FPC/TB Lease Termination Agreement dated February 22, 1993
25	Plant depreciable basis ($000)	187,353	TB/TM p.14
26			
27			

	Document abbreviation:	Source Document
29	TB/TM	Tiger Bay Transaction Model October 1996
30	TB/TM (4/96)	Tiger Bay Transaction Model April 1996
31	Destec Fin.	Destec Energy, Inc. Balance Sheet as of 12/31/95
32	TB Loan	Tiger Bay Loan Amortization Schedule for $184 million term loan
33	Contract #1	General Peat Contract for the Purchase of Firm Energy and Capacity
34	Contract #2	EcoPeat Negotiated Contract for the Purchase of Firm Capacity and Energy
35	Contract #3	Timber Energy Standard Offer Contract for the Purchase of Firm Energy and Capacity
36	FCP 9603	FPC Fuel Cost Projection 9603 dated October 28, 1996
37	TECO/BB4	Tampa Electric Company Big Bend #4 Average Charge Out Price Forecast - November 21, 1996
38	FPC/FERC #1	Florida Power's delivery voltage adjustment as filed with FERC (working papers)
39	Vastar Contract	[redacted]

RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO FLORIDA POWER CORPORATION

ATTACHMENT TO NUMBER EIGHT

Docket No. 970096-EQ
FPC's First Set of Production of Documents
Response to Document Production Request No. 8

Base Case (Scardino)

FPC Pro Forma of Tiger Bay Transaction

($000)

	Income Statement	NPV	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1	Retail CCR cost recovery	395,248	29,254	84,559	90,489	98,577	102,823	94,818	0	0	0	0
2	Unearned revenue	(51,939)	12,944	(2,601)	(12,700)	(23,622)	(40,078)	(61,451)	5,544	5,544	5,544	5,544
3	Fuel adjustment revenue	497,958	[redacted]									
5	Retail base revevenue	98,590	0	0	0	0	0	0	13,740	15,371	19,587	12,541
6	Total Electric Revenue	939,881	63,145	123,444	119,888	117,534	107,275	79,270	88,510	89,817	75,348	89,807
7												
8	Fuel Expense											
9	Gas commodity cost	409,578	[redacted]									
10	Gas transportation cost	93,178	4,270	8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541
11	Steam sales credit	(4,798)	(202)	(400)	(406)	(430)	(429)	(442)	(455)	(469)	(484)	(498)
12	Total Fuel Cost	497,958	[redacted]									
13												
14	Operating Expenses											
15	Facility O&M	44,383	1,449	2,978	3,064	3,159	3,265	3,377	3,492	3,615	3,750	3,889
16	Major maintenance	40,190	214	9,308	1,808	1,809	4,240	416	568	2,752	7,615	620
17	Property and other taxes	30,714	1,055	2,158	2,210	2,267	2,331	2,398	2,468	2,542	2,623	2,707
18	Site lease	7,910	272	556	569	584	600	618	636	655	676	697
19	Waste water disposal	4,175	143	293	300	308	317	326	335	345	357	368
20	Insurance	634	44	84	81	78	74	71	68	65	61	58
21	Total Oper. Expenses	128,005	3,176	15,378	8,033	8,206	10,827	7,206	7,588	9,973	15,082	8,339
22												
23	Depreciation expense (R)	60,482	2,772	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544
24	Amortization of PPAs (R)	215,685	26,346	52,693	52,693	52,693	52,693	26,346	0	0	0	0
25	Depreciation expense (W)	3,199	147	293	293	293	293	293	293	293	293	293
26	Amortization of goodwill (W)	12,427	1,518	3,036	3,036	3,036	3,036	1,518	0	0	0	0
27	Interest expense MTD	67,142	13,079	23,722	19,552	14,718	4,509	1,477	0	0	0	0
28	Interest expense LTD	35,983	769	1,834	2,815	3,685	5,124	6,758	7,211	6,513	5,824	5,130
29	Operating Income	(81,017)	[redacted]									
30												
31	Current income taxes	5,880	(1,243)	5,068	11,805	15,825	20,875	19,989	(10,828)	(10,647)	(10,699)	(10,543)
32	Deferred income taxes	(37,113)	(921)	(12,992)	(17,196)	(21,096)	(28,312)	(28,054)	10,315	10,103	10,069	10,069
33	Net Income to Common	(8,765)	[redacted]									

Base Case (Scardino)

FPC Pro Forma of Tiger Bay Transaction

($000)

	Income Statement	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	Retail CCR cost recovery	0	0	0	0	0	0	0	0	0	0	0	0
2	Unearned revenue	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544
3	Fuel adjustment revenue	[redacted]	[redacted]	[redacted]	[redacted]	37,397	37,975	38,566	39,168	39,782	40,409	41,048	41,699
5	Retail base reveverue	[redacted]	[redacted]	[redacted]	[redacted]	15,326	10,521	14,852	14,183	12,944	14,087	18,795	11,750
6	Total Electric Revenue	74,860	78,000	73,772	80,008	58,267	54,040	58,962	58,895	58,270	60,039	65,386	58,993
7													
8	Fuel Expense												
9	Gas commodity cost	[redacted]	[redacted]	[redacted]	[redacted]	29,216	29,801	30,397	31,005	31,625	32,257	32,902	33,560
10	Gas transportation cost	[redacted]	[redacted]	[redacted]	[redacted]	8,541	8,541	8,541	8,541	8,541	8,541	8,541	8,541
11	Steam sales credit	(514)	(531)	(548)	(565)	(360)	(366)	(372)	(377)	(383)	(389)	(396)	(402)
12	Total Fuel Cost	[redacted]	[redacted]	[redacted]	[redacted]	37,397	37,975	38,566	39,168	39,782	40,409	41,048	41,699
13													
14	Operating Expenses												
15	Facility O&M	4,037	4,190	4,348	4,511	4,680	4,854	5,034	5,220	5,412	5,611	5,816	6,027
16	Major maintenance	4,632	6,548	605	5,627	5,502	661	5,202	4,325	2,836	3,849	8,572	790
17	Property and other taxes	2,796	2,889	2,984	3,083	3,184	3,289	3,398	3,510	3,626	3,746	3,869	3,997
18	Site lease	720	744	769	794	820	847	875	904	934	965	996	1,029
19	Waste water disposal	380	393	406	419	433	447	462	477	493	509	526	543
20	Insurance	55	52	48	45	42	38	35	32	29	25	22	20
21	Total Oper. Expenses	12,620	14,815	9,159	14,479	14,661	10,137	15,006	14,469	13,329	14,704	19,802	12,406
22													
23	Depreciation expense (R)	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544	5,544
24	Amortization of PPAs (R)	0	0	0	0	0	0	0	0	0	0	0	0
25	Depreciation expense (W)	293	293	293	293	293	293	293	293	293	293	293	293
26	Amortization of goodwill (W)	0	0	0	0	0	0	0	0	0	0	0	0
27	Interest expense MTD	0	0	0	0	0	0	0	0	0	0	0	0
28	Interest expense LTD	4,448	3,760	3,073	2,385	1,697	1,135	827	646	465	284	144	90
29	Operating Income	[redacted]	[redacted]	[redacted]	[redacted]	(1,325)	(1,045)	(1,275)	(1,225)	(1,143)	(1,194)	(1,445)	(1,039)
30													
31	Current income taxes	(10,612)	(10,638)	(10,505)	(10,595)	(10,580)	(8,656)	(2,929)	(2,909)	(2,878)	(2,898)	(1,731)	(288)
32	Deferred income taxes	10,069	10,069	10,069	10,069	10,069	8,253	2,437	2,437	2,437	2,437	1,173	(113)
33	Net Income to Common	[redacted]	[redacted]	[redacted]	[redacted]	(814)	(642)	(763)	(752)	(702)	(733)	(687)	(636)

Base Case (Scardino)

FPC Pro Forma of Tiger Bay Transaction

($000)

	Income Statement	2019	2020	2021	2022	2023	2024	2025
1	Retail CCR cost recovery	0	0	0	0	0	0	0
2	Unearned revenue	5,544	5,544	5,544	5,544	5,544	5,544	5,544
3	Fuel adjustment revenue	42,384	43,042	43,734	44,439	45,159	45,893	46,642
5	Retail base reveverue	17,664	22,980	12,993	18,770	13,653	14,365	22,107
6	Total Electric Revenue	65,572	71,566	62,271	68,754	64,356	65,802	74,293
7								
8	Fuel Expense							
9	Gas commodity cost	34,232	34,916	35,615	36,327	37,053	37,794	38,550
10	Gas transportation cost	8,541	8,541	8,541	8,541	8,541	8,541	8,541
11	Steam sales credit	(408)	(415)	(422)	(428)	(435)	(442)	(450)
12	Total Fuel Cost	42,384	43,042	43,734	44,439	45,159	45,893	46,642
13								
14	Operating Expenses							
15	Facility O&M	6,246	6,472	6,705	6,946	7,195	7,453	7,718
16	Major maintenance	6,634	11,834	863	6,522	663	944	8,633
17	Property and other taxes	4,129	4,265	4,406	4,551	4,701	4,856	5,017
18	Site lease	1,063	1,098	1,135	1,172	1,211	1,251	1,292
19	Waste water disposal	561	580	599	619	639	660	682
20	Insurance	17	14	11	8	6	3	0
21	Total Oper. Expenses	18,650	24,263	13,719	19,819	14,418	15,167	23,342
22								
23	Depreciation expense (R)	5,544	5,544	5,544	5,544	5,544	5,544	5,544
24	Amortization of PPAs (R)	0	0	0	0	0	0	0
25	Depreciation expense (W)	293	293	293	293	293	293	293
26	Amortization of goodwill (W)	0	0	0	0	0	0	0
27	Interest expense MTD	0	0	0	0	0	0	0
28	Interest expense LTD	78	66	54	42	30	18	6
29	Operating Income	(1,357)	(1,942)	(1,073)	(1,383)	(1,086)	(1,113)	(1,534)
30								
31	Current income taxes	(410)	(520)	(301)	(420)	(306)	(316)	(479)
32	Deferred income taxes	(113)	(113)	(113)	(113)	(113)	(113)	(113)
33	Net Income to Common	(834)	(1,309)	(659)	(850)	(667)	(684)	(942)

Base Case (Scardino)

FPC Pro Forma of Tiger Bay Transaction

($000)

	Statement of Cash Flow	NPV	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1	Net income to common	(49,765)	[redacted]									
2	Add: depr. and amort.	743,731	17,839	64,187	74,296	85,188	101,844	95,152	293	293	293	293
3	Add: deferred taxes	(37,113)	(921)	(12,902)	(17,196)	(21,696)	(28,312)	(26,054)	10,315	10,103	10,089	10,069
4	Capital expenditures	0	0	0	0	0	0	0	0	0	0	0
5	Net dividend/(equity)	49,765	3,446	12,617	8,585	9,349	11,843	9,690	817	866	1,002	754
6	MT debt issued/(retired)	(328,106)	(16,175)	(60,838)	(70,937)	(81,859)	(98,315)	(93,341)	0	0	0	0
7	LT debt issued/(retired)	21,487	[redacted]									
8	Net change in cash	0	0	0	0	0	0	0	0	0	0	0
9												
10												
11	Balance Sheet	Initial	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
12	Gross Plant in Service	8,357	8,357	8,357	8,357	8,357	8,357	8,357	8,357	8,357	8,357	8,357
13	Accum. Depreciation	0	(147)	(440)	(733)	(1,026)	(1,319)	(1,613)	(1,906)	(2,199)	(2,492)	(2,786)
14	Net Utility Plant (W)	8,357	8,210	7,917	7,624	7,330	7,037	6,744	6,451	6,158	5,864	5,571
15												
16	Gross Plant in Service	158,000	158,000	158,000	158,000	158,000	158,000	158,000	158,000	158,000	158,000	158,000
17	Accum. Depreciation	0	(2,772)	(8,316)	(13,860)	(19,404)	(24,947)	(30,491)	(36,035)	(41,579)	(47,123)	(52,667)
18	Net Utility Plant (R)	158,000	155,228	149,684	144,140	138,596	133,053	127,509	121,965	116,421	110,877	105,333
19												
20	Goodwill (W)	15,179	13,661	10,626	7,590	4,554	1,518	0	0	0	0	0
21	PPA recovery balance (R)	263,464	237,118	184,425	131,732	79,039	26,346	(0)	(0)	(0)	(0)	(0)
22	Total Assets	445,000	414,217	352,651	291,086	229,320	167,954	134,253	128,416	122,579	116,741	110,904
23												
24												
25	Common equity	0	0	0	0	0	0	0	0	0	0	0
26	Medium term debt	421,464	405,289	344,452	273,515	191,656	93,342	0	0	0	0	0
27	Long term debt	23,536	22,793	32,456	46,323	64,690	89,673	113,915	103,307	92,911	82,548	72,186
28	Total capital	445,000	428,082	376,907	319,838	256,346	183,014	113,916	103,308	92,911	82,549	72,188
29												
30	Regulatory liability	0	(12,944)	(10,343)	2,357	25,980	66,057	127,508	121,965	116,421	110,877	105,333
31	Deferred taxes (R)	0	(595)	(12,826)	(29,444)	(50,445)	(78,047)	(103,963)	(94,083)	(84,403)	(74,755)	(65,107)
32	Deferred taxes (W)	0	(326)	(987)	(1,666)	(2,360)	(3,070)	(3,208)	(2,773)	(2,350)	(1,929)	(1,508)
33	Total Liabilities	445,000	414,217	352,651	291,086	229,320	167,954	134,253	128,416	122,579	116,741	110,904

Base Case (Scardino)

FPC Pro Forma of Tiger Bay Transaction

($000)

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Statement of Cash Flow												
1	Net income to common	[redacted]				(814)	(642)	(783)	(752)	(702)	(733)	(887)	(638)
2	Add: depr. an amort.	293	293	293	293	293	293	293	293	293	293	293	293
3	Add: deferred taxes	10,069	10,069	10,069	10,069	10,069	6,253	2,437	2,437	2,437	2,437	1,173	(113)
4	Capital expenditures	0	0	0	0	0	0	0	0	0	0	0	0
5	Net dividend/(equity)	864	906	694	837	814	642	783	752	702	733	887	638
6	MT debt issued/(retired)	0	0	0	0	0	0	0	0	0	0	0	0
7	LT debt issued/(retired)	[redacted]				(10,362)	(6,546)	(2,730)	(2,730)	(2,730)	(2,730)	(1,467)	(180)
8	Net change in cash	0	0	0	0	0	0	0	0	0	0	0	0
9													
10													
11	**Balance Sheet**	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
12	Gross Plant in Service	8,357	8,357	8,357	8,357	8,357	8,357	8,357	8,357	8,357	8,357	8,357	8,357
13	Accum. Depreciation	(3,079)	(3,372)	(3,665)	(3,958)	(4,252)	(4,545)	(4,838)	(5,131)	(5,424)	(5,718)	(6,011)	(6,304)
14	Net Utility Plant (W)	5,278	4,985	4,691	4,398	4,105	3,812	3,519	3,225	2,932	2,639	2,346	2,053
15													
16	Gross Plant in Service	158,000	158,000	158,000	158,000	158,000	158,000	158,000	158,000	158,000	158,000	158,000	158,000
17	Accum. Depreciation	(58,211)	(63,754)	(69,298)	(74,842)	(80,386)	(85,930)	(91,474)	(97,018)	(102,561)	(108,105)	(113,649)	(119,193)
18	Net Utility Plant (R)	99,789	94,246	88,702	83,158	77,614	72,070	66,526	60,982	55,439	49,895	44,351	38,807
19													
20	Goodwill (W)	0	0	0	0	0	0	0	0	0	0	0	0
21	PPA recovery balance (R)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
22	Total Assets	105,067	99,230	93,393	87,556	81,719	75,882	70,045	64,208	58,371	52,534	46,697	40,860
23													
24													
25	Common equity	0	0	0	0	0	0	0	0	0	0	0	0
26	Medium term debt	0	0	0	0	0	0	0	0	0	0	0	0
27	Long term debt	61,824	51,461	41,099	30,737	20,374	13,828	11,098	8,368	5,637	2,907	1,441	1,281
28	Total capital	61,824	51,462	41,099	30,737	20,376	13,828	11,098	8,368	5,638	2,908	1,441	1,281
29													
30	Regulatory liability	99,789	94,245	88,701	83,158	77,614	72,070	66,526	60,982	55,438	49,894	44,351	38,807
31	Deferred taxes (R)	(55,459)	(45,810)	(36,162)	(26,514)	(16,866)	(10,839)	(8,433)	(6,026)	(3,620)	(1,214)	0	0
32	Deferred taxes (W)	(1,087)	(606)	(245)	176	597	823	853	884	915	945	905	792
33	Total Liabilities	105,067	99,230	93,393	87,556	81,719	75,882	70,045	64,208	58,371	52,534	46,697	40,860

Base Case (Scardino)

FPC Pro Forma of Tiger Bay Transaction

($000)

	Statement of Cash Flow	2019	2020	2021	2022	2023	2024	2025
1	Net income to common	(834)	(1,009)	(659)	(850)	(667)	(684)	(942)
2	Add: depr. and amort.	293	293	293	293	293	293	293
3	Add: deferred taxes	(113)	(113)	(113)	(113)	(113)	(113)	(113)
4	Capital expenditures	0	0	0	0	0	0	0
5	Net dividend/(equity)	834	1,009	659	850	667	684	942
6	MT debt issued/(retired)	0	0	0	0	0	0	0
7	LT debt issued/(retired)	(180)	(180)	(180)	(180)	(180)	(180)	(180)
8	Net change in cash	0	0	0	0	0	0	0
9								
10								
11	**Balance Sheet**	2019	2020	2021	2022	2023	2024	2025
12	Gross Plant in Service	8,357	8,357	8,357	8,357	8,357	8,357	8,357
13	Accum. Depreciation	(6,597)	(6,891)	(7,184)	(7,477)	(7,770)	(8,063)	(8,357)
14	Net Utility Plant (W)	1,759	1,466	1,173	880	586	293	(0)
15								
16	Gross Plant in Service	158,000	158,000	158,000	158,000	158,000	158,000	158,000
17	Accum. Depreciation	(124,737)	(130,281)	(135,825)	(141,368)	(146,912)	(152,456)	(158,000)
18	Net Utility Plant (R)	33,263	27,719	22,175	16,632	11,088	5,544	(0)
19								
20	Goodwill (W)	0	0	0	0	0	0	0
21	PPA recovery balance (R)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
22	Total Assets	35,022	29,185	23,348	17,511	11,674	5,837	(0)
23								
24								
25	Common equity	0	0	0	0	0	0	0
26	Medium term debt	0	0	0	0	0	0	0
27	Long term debt	1,081	900	720	540	360	180	(0)
28	Total capital	1,081	901	721	541	360	180	0
29								
30	Regulatory liability	33,263	27,719	22,175	16,631	11,087	5,544	(0)
31	Deferred taxes (R)	0	0	0	0	0	0	0
32	Deferred taxes (W)	679	566	452	339	226	113	(0)
33	Total Liabilities	35,022	29,185	23,348	17,511	11,674	5,837	0

Base Case (Scardino)

FPC Pro Forma of Tiger Bay Transaction

($000)

	Cost of Service	NPV	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1	Retail rate base		298	6,761	21,185	39,945	64,246	91,005	99,023	89,243	79,579	69,931
2	Wholesale rate base		22,867	20,864	18,204	15,562	12,935	10,789	9,588	8,866	8,151	7,436
3	Average rate base		23,164	27,624	39,389	55,506	77,181	101,794	106,611	98,109	87,729	77,367
4	Pre-tax cost of capital		6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%
5	O&M expenses	97,291	2,121	13,220	5,823	5,938	8,498	4,808	5,098	7,431	12,459	5,832
6	Depreciation	15,626	1,665	3,329	3,329	3,329	3,329	1,811	297	293	293	293
7	Other Taxes	30,714	1,055	2,138	2,210	2,267	2,331	2,398	2,464	2,542	2,623	2,707
8	Return on rate base	35,983	769	1,834	2,615	3,685	5,124	6,758	7,211	6,513	5,824	5,136
9	Base revenue requirements	179,613	5,609	20,541	13,977	15,220	19,280	15,775	15,070	16,780	21,199	13,769
10												
11	Retail revenue reqmts.	150,087	3,018	15,013	9,014	10,424	14,519	12,867	13,740	15,371	19,567	12,541
12	Wholesale revenue reqmts.	29,526	2,592	5,528	4,963	4,796	4,760	2,909	1,330	1,409	1,632	1,228
13	Total revenue requirements	179,613	5,609	20,541	13,977	15,220	19,280	15,775	15,070	16,780	21,199	13,769
14												
15	Revenue requirements to summary	179,613	5,609	20,541	13,977	15,220	19,280	15,775	15,070	16,780	21,199	13,769
16												
17	Retail earnings impact		(1,854)	(9,222)	(5,537)	(6,403)	(8,918)	(7,903)	(8,440)	(9,441)	(12,019)	(7,703)
18	Wholesale earnings impact		(1,592)	(3,395)	(3,048)	(2,946)	(2,924)	(1,787)	(817)	(866)	(1,002)	(754)
19	Total earnings impact		(3,446)	(12,617)	(8,585)	(9,349)	(11,843)	(9,690)	(9,257)	(10,307)	(13,022)	(8,458)
20												
21												
22	Taxable Income	Sum/Check	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
23	Book taxable income	(120,254)	(5,609)	(20,541)	(13,977)	(15,220)	(19,280)	(15,775)	(1,330)	(1,409)	(1,632)	(1,228)
24												
25	Add retail CCR revenue (R)	498,520	29,254	84,559	90,489	96,577	102,823	94,818	0	0	0	0
26	Less MTN interest expense (R)	(77,057)	(13,079)	(23,722)	(19,552)	(14,718)	(4,509)	(1,477)	0	0	0	0
27	Less 20 year asset deprec.(R)	(139,864)	(5,245)	(10,088)	(9,343)	(8,644)	(7,986)	(7,385)	(6,839)	(6,322)	(6,238)	(6,236)
28	Less 15 year PPA amort. (R)	(281,600)	(9,387)	(18,773)	(18,773)	(18,773)	(18,773)	(18,773)	(18,773)	(18,773)	(18,773)	(18,773)
29	PPA current deduction (R)	0	0									
30												
31	Add book depr. & amort. (W)	23,536	1,665	3,329	3,329	3,329	3,329	1,811	293	293	293	293
32	Less tax depreciation (W)	(8,357)	(313)	(603)	(558)	(516)	(477)	(441)	(409)	(378)	(373)	(373)
33	Less 15 year goodwill (W)	(15,179)	(506)	(1,012)	(1,012)	(1,012)	(1,012)	(1,012)	(1,012)	(1,012)	(1,012)	(1,012)
34	Taxable income per tax	(120,254)	(3,221)	13,139	30,602	41,023	54,115	51,766	(28,070)	(27,801)	(27,736)	(27,331)
35												
36	Tax depreciation 20 yr MACRS	100.000%	3.750%	7.220%	6.680%	6.180%	5.710%	5.280%	4.890%	4.520%	4.460%	4.460%
37	GDP price index (DRI 10/96)		2.4%	2.3%	2.4%	2.6%	2.8%	2.9%	2.9%	3.0%	3.2%	3.2%

Base Case (Scardino)

FPC Pro Forma of Tiger Bay Transaction

($000)

	Cost of Service	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	Retail rate base	60,283	50,634	40,986	31,338	21,690	13,853	9,636	7,230	4,823	2,417	607	(0)
2	Wholesale rate base	6,722	6,008	5,294	4,579	3,865	3,249	2,827	2,503	2,179	1,855	1,567	1,351
3	Average rate base	67,005	56,642	46,280	35,918	25,555	17,101	12,463	9,733	7,003	4,272	2,174	1,351
4	Pre-tax cost of capital	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%
5	O&M expenses	9,824	11,926	6,175	11,397	11,477	6,848	11,809	10,959	9,703	10,958	15,933	8,409
6	Depreciation	293	293	293	293	293	293	293	293	293	293	293	293
7	Other Taxes	2,796	2,889	2,984	3,083	3,184	3,289	3,398	3,510	3,626	3,746	3,869	3,997
8	Return on rate base	4,448	3,760	3,073	2,385	1,697	1,135	827	646	465	284	144	90
9	Base revenue requirements	17,362	18,868	12,525	17,157	16,651	11,566	16,127	15,408	14,087	15,281	20,239	12,789
10													
11	Retail revenue reqmts.	15,955	17,393	11,396	15,794	15,326	10,521	14,852	14,183	12,944	14,087	18,795	11,750
12	Wholesale revenue reqmts.	1,407	1,476	1,129	1,363	1,325	1,045	1,275	1,225	1,143	1,194	1,445	1,039
13	Total revenue requirements	17,362	18,868	12,525	17,157	16,651	11,566	16,127	15,408	14,087	15,281	20,239	12,789
14													
15	Revenue requirements to summary	17,362	18,868	12,525	17,157	16,651	11,566	16,127	15,408	14,087	15,281	20,239	12,789
16													
17	Retail earnings impact	(9,800)	(10,683)	(7,000)	(9,701)	(9,414)	(6,462)	(9,123)	(8,712)	(7,951)	(8,653)	(11,545)	(7,218)
18	Wholesale earnings impact	(864)	(906)	(894)	(837)	(814)	(642)	(783)	(752)	(702)	(733)	(887)	(638)
19	Total earnings impact	(10,665)	(11,590)	(7,893)	(10,539)	(10,228)	(7,104)	(9,906)	(9,464)	(8,653)	(9,386)	(12,432)	(7,856)
20													
21													
22	Taxable Income	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
23	Book taxable income	(1,407)	(1,476)	(1,129)	(1,363)	(1,325)	(1,045)	(1,275)	(1,225)	(1,143)	(1,194)	(1,445)	(1,039)
24													
25	Add retail CCR revenue (R)	0	0	0	0	0	0	0	0	0	0	0	0
26	Less MTN interest expense (R)	0	0	0	0	0	0	0	0	0	0	0	0
27	Less 20 year asset deprec (R)	(6,238)	(6,238)	(6,238)	(6,238)	(6,238)	(6,238)	(6,238)	(6,238)	(6,238)	(6,238)	(3,147)	0
28	Less 15 year PPA amort. (R)	(18,773)	(18,773)	(18,773)	(18,773)	(18,773)	(9,387)	0	0	0	0	0	0
29	PPA current deduction (R)												
30													
31	Add book depr. & amort. (W)	293	293	293	293	293	293	293	293	293	293	293	293
32	Less tax depreciation (W)	(373)	(373)	(373)	(373)	(373)	(373)	(373)	(373)	(373)	(373)	(188)	0
33	Less 15 year goodwill (W)	(1,012)	(1,012)	(1,012)	(1,012)	(1,012)	(506)	0	0	0	0	0	0
34	Taxable income per tax	(27,510)	(27,578)	(27,232)	(27,466)	(27,428)	(17,255)	(7,582)	(7,342)	(7,460)	(7,512)	(4,486)	(746)
35													
36	Tax depreciation 20 yr MACRS	4.460%	4.460%	4.460%	4.460%	4.460%	4.460%	4.460%	4.460%	4.460%	4.460%	2.250%	
37	GDP price index (DRI 10/96)	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%

Base Case (Scardino) — FPC Pro Forma of Tiger Bay Transaction

($000)

	Cost of Service	2019	2020	2021	2022	2023	2024	2025
1	Retail rate base	(0)	(0)	(0)	(0)	(0)	(0)	(0)
2	Wholesale rate base	1,171	991	810	630	450	270	90
3	Average rate base	1,171	990	810	630	450	270	90
4	Pre-tax cost of capital	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%	6.64%
5	O&M expenses	14,521	19,998	9,313	15,268	9,714	10,311	18,325
6	Depreciation	293	293	293	293	293	293	293
7	Other Taxes	4,129	4,265	4,406	4,551	4,701	4,856	5,017
8	Return on rate base	78	66	54	42	30	18	6
9	Base revenue requirements	19,021	24,622	14,066	20,154	14,739	15,478	23,641
10								
11	Retail revenue reqmts.	17,664	22,980	12,993	18,770	13,653	14,365	22,107
12	Wholesale revenue reqmts.	1,357	1,642	1,073	1,383	1,086	1,113	1,534
13	Total revenue requirements	19,021	24,622	14,066	20,154	14,739	15,478	23,641
14								
15	Revenue requirements to summary	19,021	24,622	14,066	20,154	14,739	15,478	23,641
16								
17	Retail earnings impact	(10,850)	(14,115)	(7,981)	(11,530)	(8,386)	(8,824)	(13,579)
18	Wholesale earnings impact	(834)	(1,009)	(858)	(850)	(667)	(684)	(942)
19	Total earnings impact	(11,684)	(15,124)	(8,840)	(12,379)	(9,053)	(9,507)	(14,521)
20								
21								
22	Taxable Income	2019	2020	2021	2022	2023	2024	2025
23	Book taxable income	(1,357)	(1,642)	(1,073)	(1,383)	(1,086)	(1,113)	(1,534)
24								
25	Add retail CCR revenue (R)	0	0	0	0	0	0	0
26	Less MTN interest expense (R)	0	0	0	0	0	0	0
27	Less 20 year asset deprec.(R)	0	0	0	0	0	0	0
28	Less 15 year PPA amort. (R)	0	0	0	0	0	0	0
29	PPA current deduction (R)							
30								
31	Add book depr. & amort. (W)	293	293	293	293	293	293	293
32	Less tax depreciation (W)	0	0	0	0	0	0	0
33	Less 15 year goodwill (W)	0	0	0	0	0	0	0
34	Taxable income per tax	(1,064)	(1,349)	(779)	(1,090)	(792)	(820)	(1,241)
35								
36	Tax depreciation 20 yr MACRS							
37	GDP price index (DRI 10/96)	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%

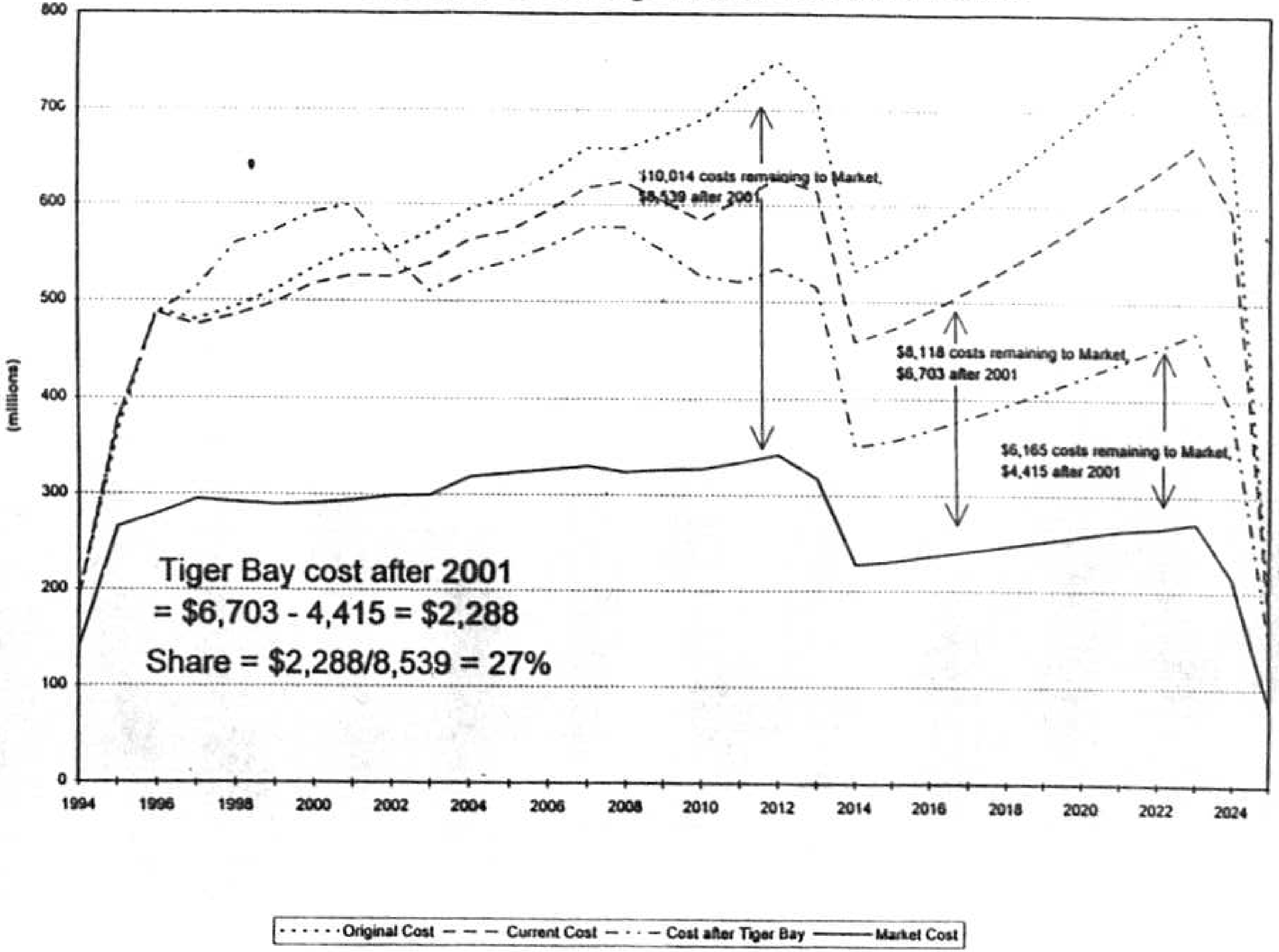
FPC Pro Forma of Tiger Bay Transaction
Base Case (Scardino)

	Key Assumptions		Source Document
1	Facility purchase price ($000)	445,000	Purchase agreement dated January 20, 1997, Section 2.02(a)
2	Price allocation to PPA ($000)	281,600	Purchase agreement dated January 20, 1997, Schedule 2.03
3			
4	Wholesale rate base ($000)	8,357	(computed)
5	Wholesale asset write-off ($000)	15,179	(computed)
6	Retail rate base ($000)	421,464	(computed)
7	Total facility purchase price ($000)	445,000	(computed)
8			
9	Gas contract buyout (0=no,1=yes)	0	Input assumption switch
10	Gas contract buyout cost ($000)	0	Input assumption value
11			
12	Leverage for acquired plant (percent)	100.0%	FPC General Economic Data Table 1, page 1 dated 11/7/95
13	Return on equity (percent)	12.00%	FPC General Economic Data Table 1, page 1 dated 11/7/95
14	Cost of long term debt (percent)	6.84%	FPC General Economic Data Table 1, page 1 dated 11/7/95
15	Composite tax rate (percent)	38.575%	FPC General Economic Data Table 1, page 1 dated 11/7/95
16	FPC discount rate (percent)	8.87%	FPC General Economic Data dated 11/7/95
17	Cost of medium term debt (percent)	6.33%	FPC memo to Karl H. Wieland dated December 13, 1996
18	Retail cost of capital for rev. rqmts.	6.84%	FPC memo to Karl H. Wieland dated December 13, 1996
19	Wholesale cost of capital for rev. rqmts.	6.84%	FPC memo to Karl H. Wieland dated December 13, 1996
20	Annual discount rate adjustment (factor)	1.0887	(computed value)
21			
22	Book life (years)	28.5	Input assumption value
23	Tiger Bay asset book value ($000)	158,000	Accounting working papers
24	Leverage for recovery balance (percent)	100.0%	Input assumption value
25	Base production jurisd. resp. (percent)	94.71%	FPC CCR filing Oct. 1996 thru march 1997 part D, Sheet 1 of 5
26	Estimated FPC O&M reduction ($000)	600	Tiger Bay Evaluation by R. W. Anderson dated 8/23/96
27	Estimated insurance cost (% of net book)	0.045%	Insurance rate per R. W. Anderson (12/30/96)
28			
29	Recovery of base rate costs	1	Input assumption switch
30	0=none 1=2002-2025 2=1997-2025		
31			
32	Effective year of purchase	1997	Input assumption value
33			
34	Effective month of purchase for revenues	10	Input assumption value
35	Portion of first year (percent)	25.0%	(computed)
36	Effective month of purchase for expenses	7	Input assumption value
37	Portion of first year (percent)	50.0%	(computed)
38			
39	Annual amortization ($000)	79,064	Input assumption value
40	Adjust amort amount to zero balance --->	0	
41			
42	Tax treatment of PPA allocation	1	Input assumption switch
43	1=15 yr s/l 2= current		

RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO FLORIDA POWER CORPORATION

ATTACHMENT TO NUMBER NINE

Exhibit 2 - FPC's Cogeneration Cost versus Market

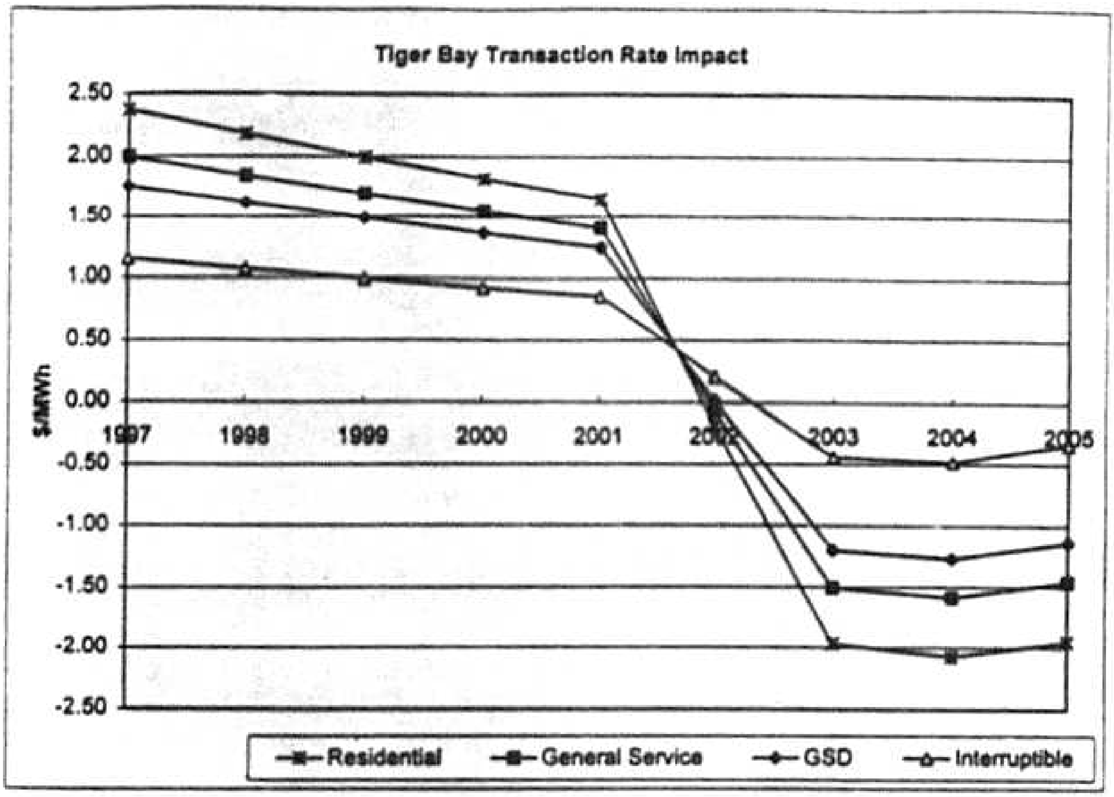


5

RESPONSE TO STAFF'S FIRST REQUEST FOR PRODUCTION OF DOCUMENTS TO FLORIDA POWER CORPORATION

ATTACHMENT TO NUMBER TEN

Exhibit 5
Rate Impact of Tiger Bay Transaction



The net rate impact of the transaction on the selected rate classes is illustrated above. For all rate classes, there is an increase in rates during the five year period in which the transaction price is being recovered, followed by a permanent rate decrease. For residential customers, the rate increase in the first year would be approximately 2.5% or $2.37 per 1000 kilowatt hours, declining to $1.65 per 1000 kilowatt hours by the fifth year of cost recovery. Beginning in the sixth year, the rate increase of $1.65 per 1000 kilowatt hours is eliminated and customers will receive an additional rate reduction of approximately $2.00 per 1000 kilowatt hours. This represents a total rate reduction of approximately $3.65 per 1000 kilowatt hours.