DOCKET NO. 041272-EI
COMPOSITE FIPUG STIPULATED EXHIBIT NO. 2
(CONFIDENTIAL)
HEARING EXHIBIT NO. 48

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Document #	Description
1	Excerpts from PEF's Response to OPC's First Request for Production of Documents, No. 5 (Bates PEF-SR-00729 to 00737)
2	Excerpts from PEF's Response to OPC's Second Request for Production of Documents, No. 20 (Bates PEF-SR-10051 to 10093; PEF-SR-10113 to 10148)

(entire DN) 8.29.05 (See DN08247-05)

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 041272-EI EXHIBIT NO. 48
COMPANY/ WITNESS: FIPUG
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FPSC-COMMISSION CLERK

DOCKET NO. 041272-EI
COMPOSITE FIPUG STIPULATED EXHIBIT NO. 2
(CONFIDENTIAL)
HEARING EXHIBIT NO. _____

DOCUMENT NO. 1

Progress Energy Florida
Budget v. Actual Income Statement Reconciliation - October 2004

MTD Budgeted Net Income				$ 25.6	
Variances	Actual	Budget	*Pre-tax*	*After-tax*	*EPS*
Margin					
Retail Margin					
Weather	$ 0.5	$ -	0.5	$ 0.3	$ 0.00
Growth/Usage	114.5	106.8	7.7	4.7	0.02
Provision for Rate Refund	(4.8)	(1.3)	(3.5)	(2.1)	(0.01)
Other Retail Margin	9.3	12.1	(2.8)	(1.7)	(0.01)
TOTAL Retail Margin	119.5	117.6	1.9	1.2	0.00
Wholesale Margin					
Wholesale Base	7.2	4.9	2.3	1.4	0.01
Transmission Revenue	3.7	3.4	0.3	0.2	0.00
Non-recoverable Purchased Power	(1.6)	(1.1)	(0.5)	(0.3)	(0.00)
TOTAL Wholesale Margin	9.3	7.2	2.1	1.3	0.01
Total Margin	128.8	124.8	4.0	2.5	0.01
O&M					
Energy Supply - Nuclear	6.3	7.9	1.6	1.0	0.00
PEF Energy Delivery	7.2	10.9	3.7	2.3	0.01
O&M Challenge	0.0	(0.7)	(0.7)	(0.4)	(0.00)
Corporate Staff/Affiliate Costs-Service Co	9.8	10.7	0.9	0.6	0.00
Other Affiliate Costs - Corp	6.4	3.7	(2.7)	(1.7)	0.00
Pension Expense/Credit	(1.0)	(0.3)	0.7	0.4	0.00
Other	13.6	12.6	(1.0)	(0.6)	(0.00)
	42.3	44.8	2.5	1.5	0.01
Depreciation	23.6	23.3	(0.3)	(0.2)	(0.00)
Other Income/(Expense)					
AFUDC equity	0.6	0.8	(0.2)	(0.1)	(0.00)
Contributions/Donations/Pol Act	(0.5)	(1.0)	0.5	0.3	0.00
COLI	0.3	0.1	0.2	0.1	0.00
Gain (Loss) on disposition of property	0.8	0.0	0.8	0.5	0.00
Other Non regulated businesses	0.7	0.2	0.5	0.3	0.00
Other income/(expense) - net	(0.3)	(0.1)	(0.2)	(0.1)	(0.00)
Interest expense	(10.2)	(9.7)	(0.5)	(0.3)	(0.00)
AFUDC debt	0.4	0.6	(0.2)	(0.1)	(0.00)
	(8.2)	(9.1)	0.9	0.6	0.00
Income and Other Taxes					
Taxes Other than Income	4.1	8.9	4.8	2.9	0.01
Income Taxes @ Effective Tax Rate	17.7	13.1	(4.6)	0.0	0.00
Income Tax Adjustments (ITC/Permanent Differences)	(0.5)	0.0	0.5	0.5	0.00
	21.3	22.0	0.7	3.4	0.01
Net Income	$ 33.4	$ 25.6	$ 7.8	$ 7.8	$ 0.03
Variance Summary					
Known Timing Variances			(2.0)	(1.2)	(0.01)
Other Variances			14.7	9.0	0.04
Budget Variance			12.7	7.8	0.03
MTD Actual Net Income				$ 33.4	

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Progress Energy Florida
Budget v. Actual Income Statement Reconciliation - October 2004

YTD Budgeted Net Income				$ 278.0	
Variances	Actual	Budget	*Pre-tax*	*After-tax*	*EPS*
Margin					
Retail Margin					
Weather	$ (8.0)	$ -	$ (8.0)	$ (4.9)	$ (0.02)
Hurricane Charley, Frances and Jeanne	(11.8)	-	(11.8)	(7.2)	(0.03)
Growth/Usage	1,117.1	1,118.9	(1.8)	(1.1)	(0.01)
Provision for Rate Refund	(7.0)	(13.7)	6.7	4.1	0.02
Other Retail Margin	113.4	111.1	2.4	1.4	0.00
TOTAL Retail Margin	1,203.7	1,216.3	(12.6)	(7.6)	(0.03)
Wholesale Margin					
Wholesale Base	84.4	68.9	15.6	9.6	0.04
Transmission Revenue	36.9	33.6	3.4	2.1	0.01
Non-recoverable Purchased Power	(14.3)	(11.1)	(3.2)	(2.0)	(0.01)
TOTAL Wholesale Margin	107.0	91.3	15.7	9.7	0.04
Total Margin	1,310.7	1,307.6	3.1	2.1	0.01
O&M					
Energy Supply - Nuclear	69.0	75.6	6.6	4.1	0.02
Energy Supply - Power Ops	121.9	123.9	2.0	1.2	0.01
PEF Customer Service Center	32.6	36.1	3.5	2.1	0.01
PEF Energy Delivery	111.7	122.7	11.0	6.8	0.03
Corporate Staff/Affiliate Costs-Service Co	97.5	106.2	8.7	5.3	0.02
Other Affiliate Costs - Corp	22.3	27.6	5.3	3.3	0.01
Pension Expense/Credit	(9.4)	(1.8)	7.6	4.7	0.02
Other	(17.5)	(27.8)	(10.3)	(6.3)	(0.03)
	428.1	462.5	34.4	21.1	0.09
Depreciation	232.9	238.8	5.9	3.6	0.01
Other Income/(Expense)					
AFUDC equity	4.5	6.1	(1.6)	(1.0)	(0.00)
Contributions/Donations/Pol Act	(7.1)	(5.1)	(2.0)	(1.2)	(0.01)
COLI	0.7	2.2	(1.5)	(0.9)	(0.00)
Gain (Loss) on disposition of property	1.2	0.0	1.2	0.7	0.00
Other Non regulated businesses	3.5	1.5	2.0	1.2	0.01
Other Income/(expense) - net	(2.3)	(2.9)	0.6	0.3	0.00
Interest expense	(96.5)	(97.8)	1.3	0.8	0.00
AFUDC debt	3.7	5.0	(1.3)	(0.8)	(0.00)
	(92.3)	(91.0)	(1.4)	(0.8)	(0.00)
Income and Other Taxes					
Taxes Other than Income	86.7	91.0	4.3	2.6	0.01
Income Taxes @ Effective Tax Rate	164.2	146.3	(17.9)	(0.3)	0.00
Income Tax Adjustments (ITC/Permanent Differences)	0.0	0.0	0.0	0.0	(0.00)
	250.9	237.3	(13.8)	2.3	0.01
Net Income	$ 306.4	$ 278.0	$ 28.4	$ 28.4	$ 0.12
Variance Summary					
Known Timing Variances			(3.5)	(2.1)	(0.01)
Other Variances			49.7	30.5	0.13
Budget Variance			46.2	28.4	0.12
YTD Actual Net Income				$ 306.4	

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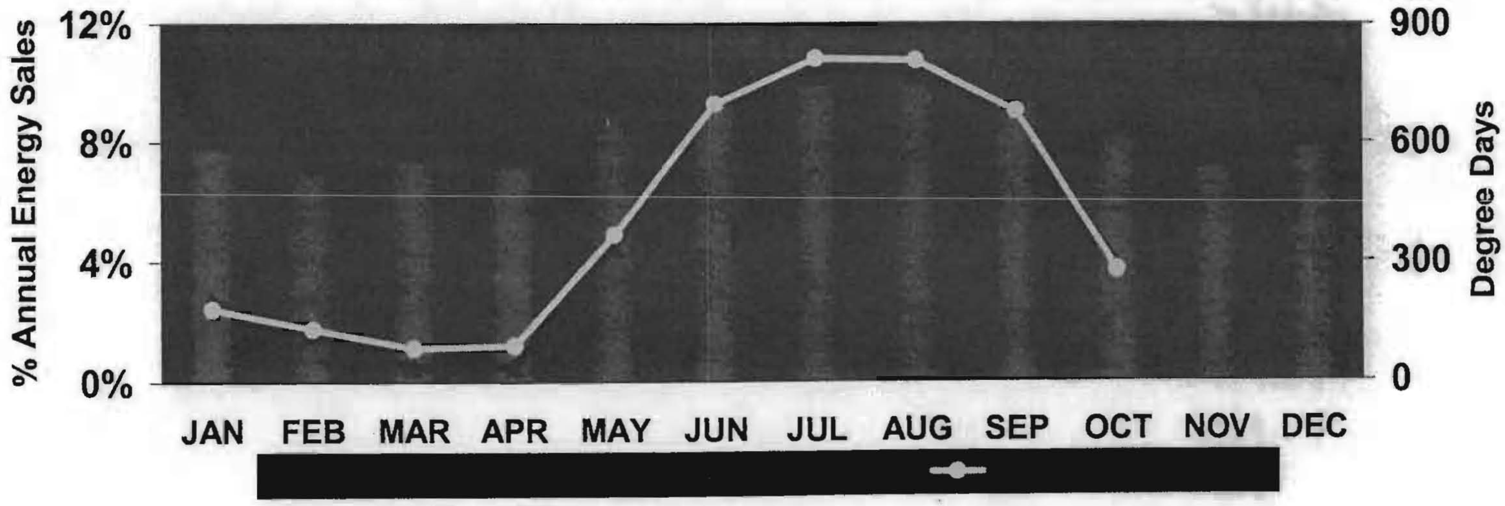
PEF-SR-00730

PEF 2004 Energy Sales and Degree Days

Year-to-Date October: -139 Degree Days / $-19.8* million

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT
Dollars / Degree Day ($ thousands)	61	75	67	49	47	47	53	41**	20***	50
Degree Day Difference	21	(8)	(49)	(54)	(31)	39	(31)	(44)	7	11
Cumulative Weather Impact ($ millions)	1.3	0.7	(2.6)	(5.2)	(6.7)	(4.8)	(6.5)	(13.5)	(20.3)*	(19.8)*



* $11.8 million of retail unfavorability is due to customer outages associated with 3 Hurricanes
** Excludes outages associated with Hurricane Charley
*** Excludes outages associated with Hurricanes Frances & Jeanne

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PEF-SR-00731

Progress Energy Florida
Budget v. Actual Income Statement Reconciliation - October 2004
Speaker Notes

MONTH TO DATE

RETAIL MARGIN VARIANCE ANALYSIS

		Actual		Budget		Budget Variance	
Retail MWH		3,343,508		3,203,008		140,500	
Retail Revenue	$	273.8	$	260.7	$	13.1	Excluding fuel and other passthrough revenues, retail base revenues were $4.2M favorable primarily due to retail customer growth/usage ($7.7M) and favorable weather ($0.6M), partially offset by the provision for rate refund due to higher than budgeted revenues ($3.5M).
Retail Fuel and Capacity Expense		(138.9)		(130.3)		(8.6)	
Other Passthrough Expenses		(26.0)		(23.8)		(2.2)	
Hines 2 Recovery		3.0		4.1		(1.1)	Hines 2 return (including recoverable depreciation) is unfavorable primarily due to lower than budgeted initial investment ($0.7M) and longer depreciation life ($0.4M).
Other Operating Revenues		7.6		6.9		0.7	Favorable primarily due higher than anticipated service revenues ($0.8M).
RETAIL GROSS MARGIN	$	119.5	$	117.6	$	1.9	

WHOLESALE MARGIN VARIANCE ANALYSIS

		Actual		Budget		Budget Variance	
SECI MWH		73,207		55,380		17,827	
SECI Base Revenues	$	1.3	$	1.7	$	(0.4)	
FPL MWH		129,262		37,182		92,080	
FPL Base Revenues	$	2.0	$	0.8	$	1.2	Favorable primarily due to the extension of the 150MW contract which was not budgeted ($1.2M).
TECO MWH		92,063		-		92,063	
TECO Base Revenues	$	1.3	$	-	$	1.3	Favorable due to the new TECO contract which began in June and was not budgeted ($1.3M).
Other Wholesale MWH		114,833		88,613		26,220	Favorable primarily due to higher revenues from New Smyrna Beach due to an additional contract which began
Other Wholesale Base Revenues	$	2.6	$	2.4	$	0.2	in March, which was not budgeted ($0.3M).
Total Wholesale MWH		409,365		181,175		228,190	
Total Wholesale Base Revenue	$	7.2	$	4.9	$	2.3	
Wheeling and Transmission Revenues	$	3.7	$	3.4	$	0.3	
Non-recoverable Purchased Power	$	(1.6)	$	(1.1)	$	(0.5)	
WHOLESALE GROSS MARGIN	$	9.3	$	7.2	$	2.1	

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MONTH TO DATE

O&M		Pre-tax		After-tax		EPS	Explanations
Energy Supply - Nuclear	$	1.6	$	1.0	$	0.00	Favorable primarily due to lower labor and maintenance costs due to storm preparation and restoration (storm costs are charged to the storm reserve).
PEF Energy Delivery	$	3.7	$	2.3	$	0.01	Delivery is favorable primarily due to storm restoration costs associated with Hurricanes Charley, Frances and Jeanne (storm costs charged to storm reserve). Major drivers include tree trimming ($1.3M), payroll ($0.8), safety and training ($0.5M) and CTE projects ($0.4M).
O&M Challenge	$	(0.7)	$	(0.4)	$	0.00	Current CMR projection shows that all of the O&M Challenge ($9M by year-end) will be met by year-end.
Corporate Staff/Affiliate Costs-Service Co	$	0.9	$	0.6	$	0.00	Favorable primarily due to lower payroll primarily due to vacancies ($0.7M), corporate communications expenses ($0.3M; due to corporate sponsorships which are budgeted here while actuals are recorded in donations) and IT&T infrastructure costs due to restructuring ($0.4M), partially offset by higher legal expenses ($0.3M; due to settlements).
Other Affiliate Costs - Corp	$	(2.7)	$	(1.7)	$	0.00	Unfavorable due to the timing of payroll accruals ($2.0M) and ECIP/MICP ($1.5M; primarily due to a true-up of the accrual based on a new estimate).
Pension Expense/Credit	$	0.7	$	0.4	$	0.00	Favorable pension due to true-up to updated actuarial studies, which reflect lower pension costs.

Depreciation		Pre-tax		After-tax		EPS	Explanations
Depreciation	$	(0.3)	$	(0.2)	$	(0.00)	

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MONTH TO DATE

Other		Pre-tax		After-tax		EPS	Explanations
AFUDC equity	$	(0.2)	$	(0.1)	$	(0.00)	
Contributions/Donations/Pol Act	$	0.5	$	0.3	$	0.00	
COLI	$	0.2	$	0.1	$	0.00	Gains on COLI due to favorable market returns.
Other income/(expense) - net	$	1.1	$	0.7	$	0.0	Favorable primarily due to a gain recognized from the sale of land ($0.8M).
Interest expense	$	(0.5)	$	(0.3)	$	(0.00)	Unfavorable primarily due to higher interest on commercial paper ($0.4M).
AFUDC debt	$	(0.2)	$	(0.1)	$	(0.00)	Projects not qualified for AFUDC were included in the budget.

Income and Other Taxes		Pre-tax		After-tax		EPS	Explanations
Taxes Other than Income	$	4.8	$	2.9	$	0.01	Primarily due to a $4.5M favorable adjustment to the property tax accrual (property taxes are estimated each year then trued-up when notices from taxing authorities are received).
Income Taxes @ Effective Tax Rate	$	(4.6)	$	-	$	-	Due to higher net income before tax.
Income Tax Adjustments (ITC/Permanent Differences)	$	-	$	-	$	-	

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Progress Energy Florida
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Speaker Notes

YEAR TO DATE

RETAIL MARGIN VARIANCE ANALYSIS

		Actual		Budget		Budget Variance	
Retail MWH		32,552,136		33,237,405		(685,269)	
Retail Revenue	$	2,645.8	$	2,717.4	$	(71.6)	Excluding fuel and other passthrough revenues, retail base revenues were $16.0M unfavorable primarily due to the estimated impact of Hurricanes Charley, Frances and Jeanne ($11.6M), mild weather ($8.0 million) and lower retail customer growth/usage ($1.8M), partially offset by the provision for rate refund ($6.7M) which was favorable due to lower than expected revenues and the impact of hurricanes.
Retail Fuel and Capacity Expense		(1,318.3)		(1,365.1)		46.8	
Other Passthrough Expenses		(230.7)		(246.9)		16.2	
Hines 2 Recovery		30.4		41.2		(10.8)	Hines 2 return (including recoverable depreciation) is unfavorable primarily due to lower than budgeted initial investment ($7.0M) and longer depreciation life ($3.8M).
Other Operating Revenues		76.6		69.8		6.8	Favorable primarily due to the GPIF award ($2.1M) and higher than anticipated service revenues ($4.4M).
RETAIL GROSS MARGIN	$	1,203.7	$	1,216.3	$	(12.6)	

WHOLESALE MARGIN VARIANCE ANALYSIS

		Actual		Budget		Budget Variance	
SECI MWH		955,039		796,978		156,061	Energy was favorable while base revenues were unfavorable primarily due to lower than budgeted coincident peak demand charges on the '83 contract ($2.0M). In addition, energy on the '95 contract was favorable while base revenues were unfavorable ($1.4M) due to the budget for the '95 contract which includes transmission revenues (actual transmission revenues are recorded to transmission and wheeling).
SECI Base Revenues	$	27.8	$	31.1	$	(3.3)	
FPL MWH		1,157,201		603,690		553,511	
FPL Base Revenues	$	22.5	$	12.6	$	9.9	Favorable primarily due to the extension of the 150MW contract which was not budgeted ($9.1M).
TECO MWH		451,631		-		451,631	
TECO Base Revenues	$	6.4	$	-	$	6.4	Favorable due to the new TECO contract which began in June and was not budgeted ($6.4M).
Other Wholesale MWH		1,100,250		919,097		181,153	Favorable primarily due to higher revenues from New Smyrna Beach due to an additional contract which began in March, which was not budgeted ($2.3M).
Other Wholesale Base Revenues	$	27.7	$	25.2	$	2.5	
Total Wholesale MWH		3,664,121		2,321,765		1,342,356	
Total Wholesale Base Revenue	$	84.4	$	68.9	$	15.5	
Wheeling and Transmission Revenues	$	36.9	$	33.6	$	3.4	Favorable primarily due to an adjusted transmission billing to Georgia Power for prior service not previously billed ($1.0M; which was subsequently paid in full) and unbudgeted transmission revenues.
Non-recoverable Purchased Power	$	(14.3)	$	(11.1)	$	(3.2)	
WHOLESALE GROSS MARGIN	$	107.0	$	91.3	$	15.7	

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Progress Energy Florida
Budget v. Actual Income Statement Reconciliation - October 2004
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YEAR TO DATE

O&M		Pre-tax		After-tax		EPS	Explanations
Energy Supply - Nuclear	$	6.6	$	4.1	$	0.02	Favorable primarily due to lower labor and maintenance material expenses, of which $2.6M (pre-tax) is expected to reverse by year-end.
Energy Supply - Power Ops	$	2.0	$	1.2	$	0.01	CT is $1.4M favorable primarily due to a lower allocation of costs from RCO ($0.8M; primarily due to lower benefits) and the timing of outage related expenses. Fossil Ops is $0.6M favorable primarily due to the timing of outages (favorability at Anclote and Suwannee, partially offset by unfavorability at Crystal River).
PEF Customer Service Center	$	3.5	$	2.1	$	0.01	Primarily due to lower labor at the Customer Support Center due to vacancies and storm support ($1.7M), property management expenses and IT&T applications related expenses.
PEF Energy Delivery	$	11.0	$	6.8	$	0.03	Delivery is favorable primarily due to storm restoration costs associated with Hurricanes Charley, Frances and Jeanne (storm costs charged to storm reserve). Major drivers include tree trimming ($3.9M), CTE projects ($1.5M), and safety and training ($1.2M), partially offset by bargaining unit overtime ($1.7M) and the ECIP/MICP payout ($1.1M).
O&M Challenge	$	(7.4)	$	(4.5)	$	0.02	Current CMR projection shows that all of the O&M Challenge ($9M by year-end) will be met by year-end.
Corporate Staff/Affiliate Costs-Service Co	$	8.7	$	5.3	$	0.02	Favorable primarily due to lower executive benefits ($3.4M primarily due to a true up of the PSSP plan, lower stock prices and forfeitures of restricted stock), lower payroll primarily due to vacancies ($3.5M), corporate communications expenses ($2.3M; primarily due to sponsorships which are budgeted here while the actuals are recorded in donations - $1.3M), IT&T infrastructure costs due to restructuring ($2.0M) and lower insurance ($1.2M; primarily due to nuclear premiums - $0.5M and lower property insurance and lower workers' comp claims of $0.7M), partially offset by higher depreciation expenses related to an adjusted life of software ($2.2M) and the labor accrual which is unbudgeted ($1.6M).
Other Affiliate Costs - Corp	$	5.3	$	3.3	$	0.01	Favorable due to a $4.6M adjustment to benefits expensed through the burden process (primarily due to lower health insurance costs), a $2.7M actuarial adjustment to benefits (primarily OPEB), favorable AR adjustments related to the reversal of prior year write-offs ($3.0M), lower executive benefits ($1.0M; primarily due to a true up of the PSSP Plan due to lower stock prices - $0.7M) and Bayboro exit costs ($1.0M favorable; exit costs budgeted for the second quarter but not yet incurred), partially offset by service company accrued vacation which was reclassified from a regulatory asset to expense ($2.8M), the timing of payroll accruals ($2.9M), MICP/ECIP ($2.1M unfavorable; primarily due to true-up of new estimate in October) and AR charge-offs related to uncollectibles ($0.8M).
Pension Expense/Credit	$	7.6	$	4.7	$	0.02	Includes a $4.2M actuarial adjustment recorded in September.

Depreciation		Pre-tax		After-tax		EPS	Explanations
Depreciation	$	5.9	$	3.6	$	0.01	Includes $3.8M of favorable Hines 2 depreciation expense due to a longer life and less investment than budgeted, a depreciation adjustment related to retirements ($1.3M) and an adjustment related to the transfer of parts that should have been inventoried ($1.3M).

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Speaker Notes

YEAR TO DATE

Other		Pre-tax		After-tax		EPS	Explanations
AFUDC equity	$	(1.6)	$	(1.0)	$	(0.00)	Projects not qualified for AFUDC were included in the budget.
Contributions/Donations/Pol Act	$	(2.0)	$	(1.2)	$	(0.01)	Unfavorable primarily due to the timing of the contribution to the Progress Energy Foundation ($0.0M; entire annual contribution made in March versus a budget of quarterly contributions) and corporate sponsorships being recorded here while the budget is included in O&M (Other Affiliate Costs Corporate) - $1.3M.
COLI	$	(1.5)	$	(0.9)	$	(0.00)	Losses on COLI, based on market returns.
Other income/(expense) - net	$	3.9	$	2.4	$	0.01	Primarily due to gains on the disposition of property ($1.1M; from the sale of land) and non-regulated energy and delivery services income ($2.0M).
Interest expense	$	1.3	$	0.8	$	0.00	Favorable primarily due to interest benefit on income tax deficiency ($3.5M; due to resolved IRS tax matters), partially offset by higher debt costs primarily due to new debt issued during 2003 ($1.4M). In addition, interest income for deferred fuel is budgeted here, but actuals are recorded in deferred fuel ($1.5M unfavorable).
AFUDC debt	$	(1.3)	$	(0.8)	$	(0.00)	Projects not qualified for AFUDC were included in the budget.

Income and Other Taxes		Pre-tax		After-tax		EPS	Explanations
Taxes Other than Income	$	4.3	$	2.6	$	0.01	Primarily due to property taxes ($4.5M; due to a $4.5M adjustment to the property tax accrual in October) and the Florida Regulatory Assessment Fee ($1.9M) which was not budgeted for, partially offset by payroll taxes ($1.9M).
Income Taxes @ Effective Tax Rate	$	(17.9)	$	(0.3)	$	(0.00)	Due to higher net income before tax.

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DOCKET NO. 041272-EI
COMPOSITE FIPUG STIPULATED EXHIBIT NO. 2
(CONFIDENTIAL)
HEARING EXHIBIT NO. _____

DOCUMENT NO. 2

Progress Energy Florida, Inc.

Monthly Financial Review Meeting

November 2004

Progress Energy

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Attendees: *N/A*

PEF-SR-10052

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Net Income Analysis

(Dollars in Millions - After tax)

Current Month

Budget	$ 15.0
Variances:	
Base Revenues	1.2
Other Operating Revenues	0.6
Other, Net	(0.1)
Interest Expense	(0.7)
O&M	(1.0)
Actual	$ 15.0

Prior Year	$ 8.4
Variances:	
Base Revenues	4.5
O&M	3.8
Hines 2 Return	1.8
Other Income and Expense	(0.4)
Interest Expense	(1.0)
Depreciation & Amortization	(1.0)
Other, Net	(1.1)
Actual	$ 15.0

Key Points:

Net income was flat to budget primarily due to base revenues and other operating revenues (primarily service revenues), offset by O&M and interest expense (due to higher debt balances). Base revenues were favorable primarily due to wholesale base revenues ($1.8M) and the provision for rate refund ($0.7M), partially offset by the impact of mild weather ($1.7M). O&M was unfavorable primarily due to Other Affiliate Costs ($1.8M) and Corporate Staff and Affiliate Costs from Service Company ($0.6M), partially offset by Energy Supply ($1.6M).

Key Points:

Net income was $6.6 million favorable to the prior year primarily due to base revenues, O&M and the return on Hines 2, partially offset by other, net, depreciation and amortization (including Hines 2 - $0.4M) and interest expense (higher debt balances). Base revenues were higher primarily due to retail customer growth/usage ($5.4M) and wholesale base revenues ($1.5M), partially offset by the impact of milder weather in the current year ($2.5M). O&M was lower primarily due to Energy Supply ($2.1M) and Other Affiliate Costs ($1.0).

Net Income Analysis

(Dollars in Millions - After tax)

Year-to-Date

Budget	$ 293.0	**Prior Year**	$ 275.2
Variances:		Variances:	
Base Revenues	0.9	Base Revenues	30.1
O&M	20.1	O&M	21.4
Other Operating Revenues	6.9	Hines 2 Return	20.5
Depreciation & Amortization	3.4	Other Operating Revenues	3.9
Interest Expense	(0.7)	Other, Net	(4.2)
Other Income and Expense	(1.0)	Depreciation & Amortization	(11.2)
Other, Net	(1.2)	Interest Expense	(14.3)
Actual	$ 321.4	**Actual**	$ 321.4
		Regulatory ROE (Note 1)	13.39%

Key Points:

Net income was $28.4 million favorable to budget year-to-date primarily due to O&M, other operating revenues (primarily service revenues $3.6M and GPIF award $1.3M) and depreciation and amortization (includes $2.6M of favorable Hines 2 depreciation and $1.6M of depreciation adjustments), partially offset by other, net and other income and expense. O&M was lower primarily due to Energy Supply ($6.9M), Energy Delivery ($6.4M), Corporate Staff and Affiliate Costs from Service Co ($4.8M) and the pension credit ($5.1M). Base revenues include wholesale base revenues ($11.4M) and the provision for rate refund ($4.8M), partially offset by the impact of Hurricanes ($7.2M) and mild weather ($6.6M).

Key Points:

Net income was $46.2 million favorable to the prior year-to-date primarily due to higher base revenues, O&M (Energy Supply - $12.3M, the pension credit - $7.7M and Energy Delivery - $3.3M, partially offset by Corporate Staff and Affiliate Costs from Service Co - $3.2M) and the Return on Hines 2, partially offset by interest expense (primarily the interest on income tax deficiency - $10.1M) and depreciation and amortization (due to property additions, including Hines 2 - $4.9M, and distribution equipment due to CTE capital projects - $3.5M). Base revenues were higher primarily due to retail customer growth/usage ($21.5M), the provision for rate refund ($14.5M; which includes a prior year $11.2M adjustment to the 2002 revenue sharing accrual) and wholesale base revenues ($7.3M), partially offset by the impact of hurricanes ($7.2M) and the impact of milder weather in the current year ($6.7M).

Note 1 - Regulatory ROE reported on a one-month lag

Electric Margin Analysis

(Base Revenues only)

(Dollars in Millions - Presented on a Pre-tax Basis)

Current Month

Budget	$ 95.4
Variances:	
Wholesale Base	3.0
Provision for rate refund	1.1
Retail Customer Growth	0.9
Retail Customer Usage	(0.1)
Industrial	(0.2)
Weather	(2.8)
Actual	$ 97.3

Prior Year	$ 89.9
Variances:	
Retail Customer Usage	6.8
Wholesale Base	2.4
Retail Customer Growth	2.0
Provision for rate refund	0.7
Industrial	(0.4)
Weather	(4.1)
Actual	$ 97.3

Key Points:

Electric margin was $1.9 million favorable to budget primarily due to wholesale base revenues, the provision for rate refund (favorable due to lower than anticipated revenues) and retail customer growth, partially offset by the impact of mild weather. Wholesale base revenues were favorable primarily due to the FPL 150MW contract extension ($1.2 million) and the new TECO contract that began in June ($1.2 million).

Key Points:

Electric margin was $7.4 million favorable to prior year primarily due to retail customer usage, wholesale base revenues and retail customer growth, partially offset by the impact of milder weather in the current year. Wholesale base revenues were higher primarily due to the new TECO contract which began in June 2004 ($1.2 million).

Electric Margin Analysis

(Base Revenues only)

(Dollars in Millions - Presented on a Pre-tax Basis)

Year-to-Date

Budget	$ 1,269.4
Variances:	
Wholesale Base	18.5
Provision for rate refund - 2004	9.5
Retail Customer Growth	7.8
Industrial	(1.4)
Provision for rate refund - 2003	(1.7)
Retail Customer Usage	(8.7)
Weather	(10.8)
Impact of Hurricanes	(11.8)
Actual	$ 1,270.8

Key Points:

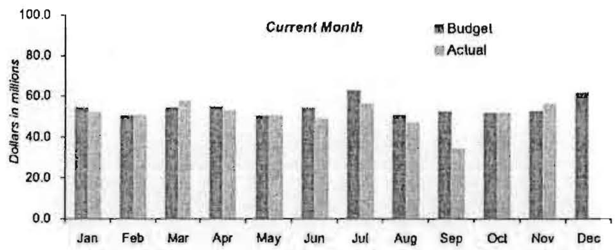
Electric margin was $1.4 million favorable to budget year-to-date primarily due to wholesale base revenues, a favorable 2004 rate refund provision (due to lower retail revenues) and retail customer growth, partially offset by the impact of Hurricanes Charley, Frances and Jeanne, the impact of mild weather and retail customer usage. Wholesale base revenues were favorable primarily due to the FPL 150 MW contract extension ($10.3 million), the new TECO contract that began in June 2004 ($7.3 million), higher New Smyrna Beach revenues due to an additional contract which began in March 2004 ($2.5 million), partially offset by lower demand charges on the SECI '83 contract ($2.1 million).

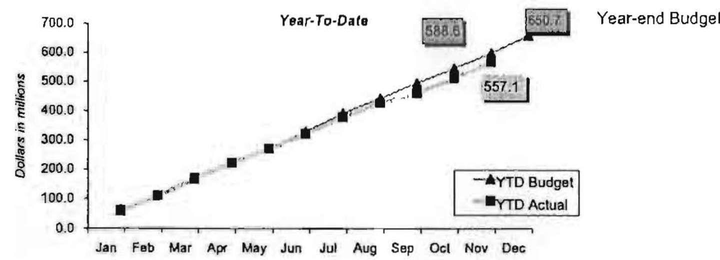
Prior Year	$ 1,221.8
Variances:	
Retail Customer Growth	28.6
Provision for rate refund	23.6
Wholesale Base	11.9
Retail Customer Usage	6.5
Industrial	1.1
Weather	(10.9)
Impact of Hurricanes	(11.8)
Actual	$ 1,270.8

Key Points:

Electric margin was $49.0 million favorable to prior year-to-date primarily due to retail customer growth, the provision for rate refund (in the prior year there was an $18.2 million adjustment to the 2002 revenue sharing accrual) and wholesale base revenues, partially offset by the impact of Hurricanes Charley, Frances and Jeanne and the impact of milder weather in the current year. Wholesale base revenues were higher primarily due to the extension of the 150MW FPL contract ($4.2 million), higher SECI revenues ($1.6 million; due to new contract which began in April 2003 and higher demand charges on the '83 contract), higher New Smyrna Beach revenues ($2.3 million; due to additional contract which began in March 2004), higher TECO revenues ($3.4 million; due to new contract which began in June 2004 versus previous contract which expired in April 2003) and higher Tallahassee revenues ($2.8 million; due to an additional contract which began in June 2004), partially offset by lower FMPA revenues ($2.4 million; due to lower contractual demand).

Progress Energy Florida Legal Entity - O&M Budget Target Summary





Organization	November 2004 Month-to-date ($ 000's)		Fav/(Unfav)		November 2004 Year-to-date ($ 000's)		Fav/(Unfav)		Year-end ($ 000's)		Fav/(Unfav)	
	Budget	Actual	Var	Var %	Budget	Actual	Var	Var %	Budget	Projection	Var	Var %
Energy Supply - Nuclear Generation	6,235	5,972	263	4%	81,807	74,981	6,826	8%	90,202	85,799	4,403	5%
Energy Supply - Power Operations	14,245	11,928	2,317	16%	138,109	133,829	4,280	3%	153,381	150,357	3,024	2%
Carolinas ED - PEF Customer Service	3,352	2,939	413	12%	39,477	35,517	3,960	10%	43,425	40,119	3,306	8%
PEF Energy Delivery	11,302	11,933	(631)	(6%)	134,067	123,667	10,400	8%	148,428	141,423	7,005	5%
Progress Ventures	282	204	78	28%	3,186	2,786	400	13%	3,523	3,138	385	11%
Committed O&M Challenge and Incentives	(750)	-	(750)	NM	(8,114)	-	(8,114)	NM	(9,000)	-	(9,000)	NM
CMR O&M Total	34,666	32,976	1,690	5%	388,532	370,780	17,752	5%	429,959	420,836	9,123	2%
Corporate Staff from Service Co	7,637	8,364	(727)	(10%)	90,743	83,186	7,557	8%	98,771	93,280	5,491	6%
CMR Regulated O&M Total	42,303	41,340	963	2%	479,275	453,966	25,309	5%	528,730	514,116	14,614	3%
Pension Credit	(271)	(942)	671	218%	(2,051)	(10,360)	8,309	391%	(2,127)	(11,302)	9,175	(391%)
Other Affiliate Costs - Svc. Co.	2,862	2,992	(130)	(5%)	26,000	25,740	260	1%	29,427	27,533	1,894	6%
Other Affiliate Costs - Corp.	3,747	6,674	(2,927)	(76%)	31,378	29,019	2,359	8%	36,627	31,656	4,971	16%
ECCR	4,860	4,759	101	2%	63,180	55,706	7,474	12%	68,525	68,189	336	0%
ECRC	1,294	1,662	(368)	(28%)	16,412	18,909	(2,497)	(15%)	17,829	17,827	2	0%
Recoverable Non-Fuel Expenses	-	1,231	(1,231)	NM	-	6,074	(6,074)	NM	-	-	-	NM
Joint Owner Expenses/Other	(723)	(604)	(119)	21%	(8,528)	(6,887)	(1,641)	11%	(9,391)	(9,391)	-	0%
Less Payroll Taxes	(1,334)	(1,161)	(173)	(13%)	(17,063)	(15,037)	(2,026)	(12%)	(18,915)	(18,377)	(538)	3%
Net O&M Legal Entity Total	52,738	55,951	(3,213)	(6%)	588,603	557,130	31,473	5%	650,705	620,251	30,454	5%
Florida Adjustments (Recovery Clause Items):												
ECCR & ECRC	(6,154)	(6,421)	(267)	(4%)	(79,591)	(74,615)	4,976	6%	(86,354)	(86,016)	338	0%
Other (Including Emissions Allowances)	-	(1,231)	(1,231)	NM	-	(6,073)	(6,073)	NM	-	-	-	NM
Progress Energy Florida O&M Total (Base Recoverable)	46,584	48,299	(1,715)	(4%)	509,012	476,442	32,570	6%	564,351	534,235	30,116	5%

Note: "Less Payroll Taxes" variances are defined as Unfavorable/(Favorable). The "Less Payroll Taxes" line offsets the impact of payroll taxes reflected in the various line items above it, in order to calculate Net Regulated O&M. Payroll taxes are reported in the Other Taxes line of the Income Statement.

NM = not meaningful

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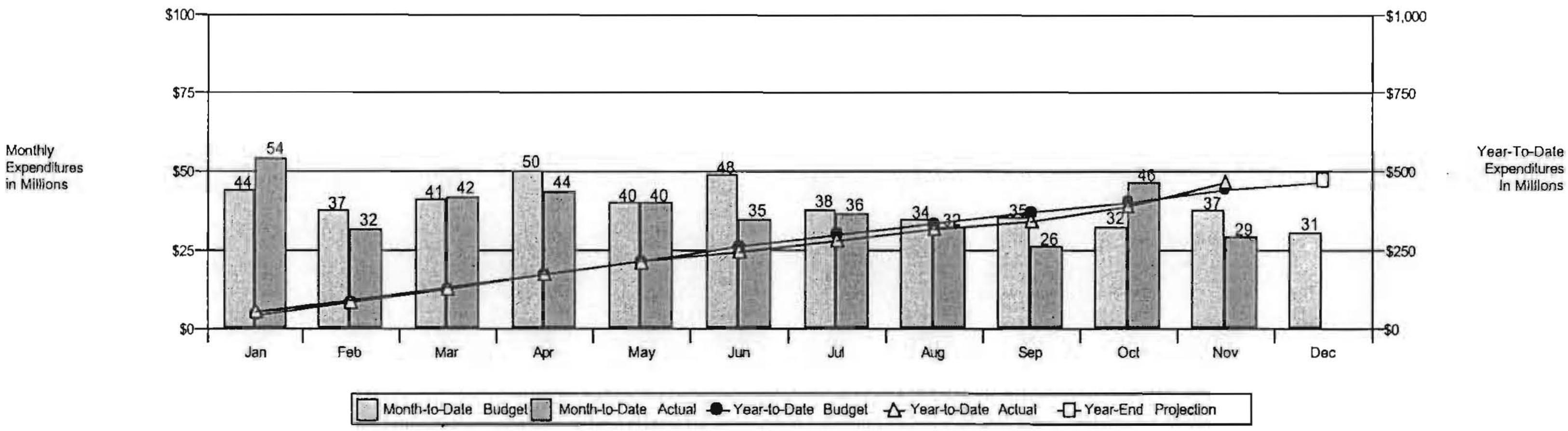
PEF-SR-10057

Progress Energy Florida (60)
Capital
November 2004



November ($ 000's)				Year-To-Date ($ 000's)					Year-End ($ 000's)				Variance Gap ($ 000's)		
Budget	Actual	Var Fav/(Unfav)	Var% Fav/(Unfav)	Budget	Actual	YTD Var Fav/(Unfav)	Var% Fav/(Unfav)	Charge To Organization	Budget	Projection	YE Var Fav/(Unfav)	Var% Fav/(Unfav)	YTD Var Fav/(Unfav)	YE Var Fav/(Unfav)	Gap
879	1,883	(1,004)	(114 %)	12,618	10,315	2,303	18 %	Energy Supply - Nuclear Generation	13,466	12,929	537	4 %	2,303	537	(1,766)
6,393	6,173	221	3 %	44,648	40,656	3,992	9 %	Energy Supply - Power Operations	47,125	46,669	456	1 %	3,992	456	(3,536)
147	1	146	100 %	861	39	822	95 %	Energy Delivery Carolinas	1,010	35	975	97 %	822	975	154
18,502	22,463	(3,961)	(21 %)	243,905	224,719	19,186	8 %	Energy Delivery Florida	263,079	252,078	11,000	4 %	19,186	11,000	(8,186)
7,367	3,927	3,440	47 %	111,221	106,250	4,971	4 %	Regulated Future Generation	116,243	116,263	(21)	(0 %)	4,971	(21)	(4,992)
33,288	**34,447**	**(1,159)**	**(3 %)**	**413,254**	**381,979**	**31,275**	**8 %**	**Regulated Capital**	**440,922**	**427,974**	**12,948**	**3 %**	**31,275**	**12,948**	**(18,327)**
0	67	(67)	(100 %)	0	54,887	(54,887)	(100 %)	Major Storm	0	54,400	(54,400)	(100 %)	(54,887)	(54,400)	487
693	132	561	81 %	3,692	(25,391)	29,084	788 %	Regulated Capital Corporate	4,386	(18,663)	23,049	526 %	29,084	23,049	(6,034)
(72)	(115)	43	(59 %)	(1,033)	69	(1,102)	107 %	Joint Owner Expenses	(1,103)	(1,103)	0	0 %	(1,102)	0	1,102
0	0	0	0 %	0	660	(660)	(100 %)	Capital - Recoverable Environmental Cost Recovery	0	(39)	39	100 %	(660)	39	698
195	8	187	96 %	2,282	384	1,899	83 %	Pension (Less Cost Recovery)	2,524	54	2,470	98 %	1,899	2,470	571
1,774	1,111	663	37 %	15,832	9,412	6,420	41 %	AFUDC	17,657	6,323	11,334	64 %	6,420	11,334	4,913
35,878	**35,649**	**228**	**1 %**	**434,027**	**421,999**	**12,028**	**3 %**	**Net Regulated Capital Legal Entity**	**464,386**	**468,947**	**(4,561)**	**(1 %)**	**12,028**	**(4,561)**	**(16,590)**
161	42	119	74 %	1,365	(41)	1,405	103 %	Non-Regulated	1,518	521	997	66 %	1,405	997	(408)
36,039	**35,691**	**348**	**1 %**	**435,392**	**421,958**	**13,434**	**3 %**	**Net Capital Legal Entity**	**465,904**	**469,468**	**(3,564)**	**(1 %)**	**13,434**	**(3,564)**	**(16,997)**

NOTE:

1. Energy Delivery Florida Budgets include an adjustment for Revenue Construction.

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Capital Expenditures

November 30, 2004 - Actual vs. Budget

- Energy Supply is $11.3 million favorable primarily due to Regulated Future Generation, which was favorable $5.0M due to the spending on major equipment at Hines 3 (budget was based on estimates of contracts; however, final contracts were more favorable than budgeted). Power Operations was $4.0 million favorable due to the return of Tiger Bay parts to inventory from CWIP, the timing of the Hines 1 outage and favorable fossil generation spending (primarily due to the timing of projects at Anclote and Bartow, partially offset by unbudgeted maintenance, regulatory and safety projects at the Crystal River fossil plant, net $0.6M favorable). Nuclear Generation was $2.3 million favorable due to the timing of fire protection spending, alternate AC power source projects, and various steam generator projects.

- Energy Delivery is $19.2 million favorable due to lower installation costs for new customers and street lights ($7.1M) primarily due to the timing of CIAC (contribution in aid of construction) payments of $4.6M, favorable volume adjustment due to new customer growth ($6.4M) and the timing of various projects such as load growth, CTE, meters & transformers purchases and delay of base programs due to storms ($11.1 million), partially offset by DOT relocation projects and replace/refurbish costs ($5.2 million) and the ECIP/MICP payout ($1.7 million). Favorability is significantly driven by costs shifting to major storm duty related to Hurricanes Charley, Frances, Jeanne and Ivan and Tropical Storm Bonnie.

- Major Storm is $54.9 million unfavorable primarily due to the accrual of estimated capital storm costs related to Hurricanes Charley ($37.5M), Frances ($9.4M), Jeanne ($7.4M) and Ivan ($0.1M).

- Florida Other is $36.5 million favorable primarily due to regulated capital corporate spending ($29.1M, primarily due to the gas turbine loaned to GE) and favorable AFUDC ($6.4 million), which is currently only applicable to Hines 3 (the budget included other projects).

- Florida Energy Services consists of non-utility purchases and did not vary significantly from budget.

Reconciliation between Capital CMR and Cash Flow
2004

J:\Control\variance analysis\2004\November 2004\[Recon Cap CMR to CF Nov.xls]2004

(000's)	Nov-04	YD
Net capital per Capital CMR - Net Regulated Capital	35,649	421,999
Gross property additions per cash flow	35,173	408,512
Add back transfers to 108 if included in Gross additions (COR/salvage transfers - not included on the CMR)		8,255
Add back storm reserve (on CMR, non-cash on cash flow)		54,400
Subtract turbine loaned to GE (on CMR, non-cash on cash flow)		(29,584)
Subtract change in presentation of COR/Salvage (Jan-Jun;transfers not on CMR)		(8,337)
Transfer of assets from inventory (on CMR, non-cash on cash flow)		(6,200)
Transfer of assets to inventory (reversed from CMR in Oct, non-cash on cash flow in Sept)		0
Add back transfers to non-utility if included in Gross additions (subtracted for CF additions, on CMR)		1,191
Intercompany transfer of property not on CMR		(11,861)
	35,173	416,376
Difference	476	5,623
less:AFDC equity (included in Operating Activity on CF)	(607)	(5,145)
Remaining Difference	(131)	478
	-0.4%	0.1%
Capex flow through CWIP		
Beginning CW balance	410,481	328,268
Add: Capital expenditures (from cash flow)	35,173	408,512
AFDC equity (Cap expen per cash flow only includes AFDC debt)	607	5,145
Transfers to non-utility	0	62
	35,780	413,719
less:		
Storm accrual (non-cash)		54,400
loan of turbine to GE (non-cash)		(29,584)
Settlement of PTC transfer (from 2003;included as gross addition at time of settlement)		(9,203)
Transfers to 108 - salvage and removal	(1,110)	(4,486)
COR/Salvage (Jan-Jun) shown as Gross Additions in Investing vs. Operating		(8,337)
Transfer of assets to inventory (non-cash)		(19,018)
land sales	(114)	(146)
Transfers to utility plant in-service	(26,330)	(306,903)
	(27,554)	(323,277)
Subtotal	418,707	418,710
Ending CW balance per balance sheet	418,708	418,708
Variance	(1)	2
	0.0%	0.0%

Business Update

Energy Delivery - Florida

1. Cost Status as of November 2004

Class	Period	Variance	Major Drivers
O&M	November 2004 YTD	$10.4 M favorable	• Payroll, Safety, and Training favorable due to storm $6.9 M • Tree Trimming favorable $3.2 M due to work backlog from storms
	YE Projection	$7.0 M favorable	
Capital	November 2004 YTD	$19.2 favorable	• New Customer unit cost/CIAC $7.1 M favorable • Base programs and CTE behind schedule due to storms $5.9 M favorable • Load Growth Feeder work behind schedule $3.2 M favorable (timing and storms)
	YE Projection	$11 M favorable (to be carried forward into 2005 due to capital backlog of customer requested work)	

Key ED-FL Initiatives

- SAIDI 80
- Preparation for 2005 rate case
- Franchise Agreements

Cost Status (as of November)

Class	Period	Variance	Explanation
O&M	YTD	$6.8 M Under	- $4.7 M - Facility contractor, materials, and mod reductions; security under runs; higher staff vacancy than budgeted due to overall NGG cost issues. - $0.4 M – Storm charges to PEF considered base (of the total $1.1M charged). - $1.7 M – Primarily severance under runs.
	Projection	$4.4 M Under	- Continuing to evaluate projection. Anticipate another $1M in savings is probable.
Capital	YTD	$ 2.3 M Under	- Steam Generator, Fire Protection, and AC power source contracts awarded later than anticipated.
	Projection	$0.5 M Under	- Some roof repair work due to Hurricane Jeanne to be done in 2004 (and remaining in 2005).

Key Items Of Interest

- Hurricanes
  - Charley – no major issues
  - Frances – automatic scram due to loss of off site power of 230Kv lines; some rainwater intrusion into Auxiliary Building
  - Ivan – no major issues
  - Jeanne – roof damage to 4 buildings estimated to be approximately $1.1M (Capital) plus other minor damage < $100k (O&M – excludes storm preps and extra shifts required to be on site for shift changes)

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PEF-SR-10063

Power Operations Group Update

Progress Energy

RCO Update

Progress Energy

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PEF-SR-10065

Regulatory Update

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Property and Plant Accounting Update

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Cost Status (as of November)

Classification	Period	Variance	Explanation
O&M-Corp Staff Regulated	YTD	$7.6M Under (8%)	• Corp Comm - advertising campaign shifted to latter part of the year • IT&T - infrastructure • Svc Co Group Managed Acct - delay in settlement of workers comp claims • Miscellaneous under runs in labor and related costs, contract labor, meals/travel/other throughout the Svc Co • Offset by increased costs for Sarbanes-Oxley compliance
	YE	$5.5M Under (6%)	• Corp Comm - advertising favorability offset by unfavorability in non-regulated O&M (not reported on CMR) • IT&T - infrastructure • Miscellaneous under runs in labor and related costs, contract labor, meals/travel/other throughout the Svc Co • Offset by increased costs expected for Sarbox compliance • True year end favorability approx $3.5M
O&M-Affiliate Costs	YTD	$0.3M Under	• Favorability in executive benefits and insurance • Offset by unfavorability in depreciation, facility exit costs, income taxes and labor accrual (that reverses in subsequent month)
	YE	$1.9M Under (6%)	• Favorability in executive benefits and insurance • Offset by unfavorability in depreciation, income tax and workers compensation

Other Business Issues

- Portion of YTD under runs expected to be consumed for advertising, Sarbox work, claim settlements, fees and strategic initiatives; however, it is expected that not all will be consumed

PEF-SR-10068

Treasury Update

Tom Sullivan

Progress Energy

Projection Rollforward

($ millions)

YTD Actual Net Income (Through November 2004)	$ 321.4
December Budget	17.5
Actual Net Income + Balance 2004 Budget	$ 338.9
Variances	*After-tax*
Margin	
Retail Margin	
Provision for Rate Refund	0.7
Other Retail Margin	(2.5)
TOTAL Retail Margin	(1.8)
Wholesale Margin	
Wholesale Base Revenue	0.8
Unrecovered Capacity Purchases	(0.3)
TOTAL Wholesale Margin	0.5
Total Margin	(1.2)
O&M	
Energy Supply	(2.2)
Energy Delivery	(2.0)
PEF Customer Service Center	(0.4)
Corporate Staff/Affiliate Costs - Service Co	0.7
Other Affiliate Costs - Corp	0.5
Pension Expense / Credit	0.2
Other	1.8
	(1.5)
Depreciation	(0.3)
Other	
Interest	(0.8)
AFUDC	(0.5)
Other	0.0
	(1.3)
Income and Other Taxes	(0.7)
Projection Variance	(5.1)
2004 Projected (11+1) Net Income	$ 333.8

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PEF-SR-10070

Emerging Issues and Areas of Focus

Significant and Unusual Transactions

Entity:	**Progress Energy Florida**
Date:	**11/18/2004**
Preparer:	**Marcia Olivier**
Reviewer:	**Lori Cross**

($ in millions)

Reference Number ____________

Detailed Description of Transaction:

An adjustment will be made in November to decrease the line loss multiplier charged to retail customers through the fuel adjustment clause for the period 1/04-9/04 from 1.00357 to 1.00097. Fuel expense charged to retail customers is grossed up by the loss multiplier to compenstate for retail line losses which are higher than system average line losses. The multiplier is being adjusted to exclude stratified sales from the calculation, because the dollars to which the multiplier is applied already exclude stratified sales. This change in methodology more accurately allocates costs between retail and wholesale average cost customers.

Accounting Guidance:

Include discussion of accounting guidance governing transaction, if applicable and the "why" it was accounted for as it is reflected herein.

Journal Entry Recorded (Include Tax Impacts):

G/L Account	New Account ?	Account Description	Financial Statement Line	Amount Recorded		Impact to Cash Flow	
				Debit	*Credit*	*(Use) /Source*	*Line Item*
1861922	no	Def Fuel Exp 1/04-12/04	Misc Def Debits (BS)		2,762,852	non cash accrual	
5572002	no	FL Def Fuel Expense	Fuel (IS)	2,762,852		non cash accrual	

Transaction Recording Checklist:

Does the entry require a regulatory to GAAP adjustment?	No
Did the entry relate to or impact prior years' operations? If yes, has restatement been considered?	No
Is a prior year reclass required in order to reflect current year presentation?	No
Does the accounting involve significant management estimates and subjectivity?	No
Was Accounting Policy & Research consulted on Accounting Treatment?	No
Is D&T sign-off requested prior to close?	No

Transaction Reporting Checklist:

What GAAP disclosure, if any, is required?	N/A
What SEC disclosure, if any, is required?	N/A
Was Financial Reporting Consulted on Financial Statement Presentation?	No.
Was D&T consulted regarding the accounting or financial statement presentation?	No.

APPENDIX

INCOME STATEMENT VARIANCE ANALYSIS
(Dollars in Thousands)

	Month To Date					Year To Date				
	November	Variance Fav(Unfav)					Variance Fav(Unfav)			
	2004	vs. Budget		vs. P/Y Actual		2004	vs. Budget		vs. P/Y Actual	
Operating Revenues										
Base Revenues	$ 97,370	$ 1,935	*A*	$ 7,444	*E*	$ 1,270,824	$ 1,417	*L*	$ 49,030	*T*
Fuel & PP Revenues - Recovery Clause	141,352	13,229	*(1)*	20,541	*(1)*	1,636,512	(13,006)	*(1)*	262,822	*(1)*
Other Operating Revenues	29,555	3,028	*B*	1,750	*F*	342,261	13,720	*M*	34,455	*U*
Total Operating Revenues - *Schedule A*	268,277	18,192		29,735		3,249,597	2,131		346,307	
Operating Expenses										
Fuel used in electric generation - *Schedule B*	97,843	(11,857)	*(1)*	(26,837)	*(1)*	1,084,485	41,201	*(1)*	(276,662)	*(1)*
Purchased Power - *Schedule B*	40,756	(2,140)	*(1)*	7,101	*(1)*	524,346	(41,416)	*(1)*	(917)	*(1)*
Operations and maintenance - *Schedule C*	55,951	(3,213)	*C*	6,788	*G*	557,130	31,473	*N*	20,219	*V*
Depreciation & Amortization	23,568	(272)		(1,574)	*H*	256,446	5,632	*O*	28,455	*W*
Taxes other than on income	20,424	(532)		(1,988)	*I*	234,471	8,767	*P*	(15,901)	*X*
Total Operating Expenses	238,542	(18,014)		(16,510)		2,656,878	45,657		(244,806)	
Pretax Operating Income	29,735	178		13,225		592,719	47,788		101,501	
Other Income (Expense)										
Interest income	7	(17)		1		48	(139)		(179)	
Other, net	740	(144)		(779)		2,297	(1,286)	*Q*	(220)	
Total Other Income (Expense)	747	(161)		(778)		2,345	(1,425)		(399)	
Interest Charges										
Interest charges	10,403	(870)		(1,334)	*J*	106,859	298		(20,175)	*Y*
Allowance for borrowed funds used during construction	(504)	(151)		(316)		(4,266)	(1,442)	*R*	(3,126)	*Z*
Total Interest Charges, net	9,899	(1,021)		(1,650)		102,593	(1,144)		(23,301)	
Income before Income Taxes	20,583	(1,004)		10,798		492,471	45,219		77,801	
Income Tax Expense	5,459	1,015	*D*	(4,166)	*K*	169,658	(16,819)	*S*	(31,569)	*AA*
Net Income	15,124	11		6,632		322,813	28,400		46,232	
Dividends on Preferred Stock	126	-		-		1,386	-		-	
Earnings for Common Stock	$ 14,998	$ 11		$ 6,632		$ 321,427	$ 28,400		$ 46,232	

(1) = These items are passed through to the rate payer and therefore do not impact earnings.

INCOME STATEMENT VARIANCE ANALYSIS

Month to date vs. Budget

A. Base revenues were $1.9 million favorable due to wholesale base revenues ($3.0 million), a favorable provision for rate refund due to lower than budgeted revenues ($1.1 million) and retail customer growth/usage ($0.8 million), partially offset by mild weather ($2.8 million) and industrial revenues ($0.2 million). Wholesale base revenues were favorable primarily due to the extension of the 150 MW FPL contract ($1.2 million) and the new TECO contract ($1.3 million), which were not budgeted.

B. Other operating revenues were $3.0 million favorable due to higher ECCR/ECRC revenues ($1.1 million), franchise and gross receipt tax revenues ($0.9 million) and miscellaneous service revenues ($1.4 million). Franchise and gross receipts tax revenues are passed through to the applicable taxing authority and therefore do not impact earnings. ECCR/ECRC revenues are collected from the ratepayer and offset expenses specifically incurred on ECCR/ECRC projects, and therefore do not impact earnings.

C. O&M was $3.2 million unfavorable primarily due to Other Affiliate Costs ($2.9 million) and a higher allocation of Corporate Staff and Affiliate Costs from Service Company ($0.9 million; due to the fall corporate advertising campaign that had been budgeted for earlier in the year), partially offset by lower business unit spending in Energy Supply ($2.6 million; primarily due to Fossil Ops which was $1.9 million favorable due to projects at Crystal River which were canceled or delayed until 2005). Other Affiliate Costs were unfavorable due to the timing of payroll accruals ($1.4 million), A/R chargeoffs related to uncollectibles ($0.6 million) and monthly benefit adjustments ($0.9 million; related to a true-up of ESIP based on updated projections).

D. Income tax expense was $1.0 million favorable primarily due to lower pre-tax income.

Month to date vs. Prior Year

E. Base revenues were $7.4 million favorable primarily due to the retail customer growth/usage ($8.8 million), wholesale base revenues ($2.4 million) and the provision for rate refund ($0.7 million; due to a higher threshold than prior year), partially offset by the impact of milder weather in the current year ($4.1 million) and lower industrial revenues ($0.4 million). Wholesale base revenues were higher primarily due to the new TECO contract, which began in June 2004 ($1.3 million) and higher Tallahassee revenues due to an additional contract which began in June 2004 ($2.0 million).

F. Other operating revenues were $1.8 million favorable primarily due to franchise and gross receipts tax revenues ($1.3 million) and higher ECCR/ECRC revenues ($1.3 million), partially offset by lower wheeling and transmission revenues ($0.8 million; due to a $1.1 million billing adjustment on the Reliant contract in the current year). Franchise and gross receipts tax revenues are passed through to the applicable taxing authority and therefore do not impact earnings. ECCR/ECRC revenues are collected from the ratepayer and offset expenses specifically incurred on ECCR/ECRC projects, and therefore do not impact earnings.

G. O&M was $6.8 million favorable primarily due to lower business unit spending in Energy Supply ($3.5 million; primarily due to the timing of outages and maintenance projects), Other Affiliate Costs ($1.7 million; due to a true-up of the ECIP accrual in the prior year based on projected payouts - $3.3 million, partially offset by A/R charge-offs related to uncollectibles - $1.2 million) and the pension credit ($1.1 million), partially offset by Corporate Staff and Affiliate Costs from Service Company ($1.3 million; primarily due to higher depreciation expense due to an adjusted life of software - $0.7 million, nuclear premiums and credits - $0.3 million, and corporate advertising - $0.3 million).

H. Depreciation and amortization expense was $1.6 million unfavorable primarily due to higher depreciation expense in the current year due to property additions (including $0.7 million related to Hines 2).

I. Taxes other than on income were $2.0 million unfavorable primarily due to gross receipts taxes ($1.0 million) and franchise taxes ($0.7 million). Franchise and gross receipts taxes are pass throughs and do not impact earnings.

J. Interest charges were $1.3 million unfavorable primarily due to interest on commercial paper and revolving credit agreements ($0.7 million; due to higher borrowings in the current year).

K. Income tax expense was $4.2 million unfavorable primarily due to higher pre-tax income.

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INCOME STATEMENT VARIANCE ANALYSIS

Year to date vs. Budget

L. Base revenues were $1.4 million favorable primarily due to wholesale base revenues ($18.5 million) and the provision for rate refund ($7.8 million favorable; due to lower than expected revenues and the impact of the hurricanes), partially offset by the impact of Hurricanes Charley, Frances and Jeanne ($11.8 million) and the impact of mild weather ($10.8 million). Wholesale base revenues were higher due to the 150MW FPL contract extension ($10.3 million), the new TECO contract which began in June ($7.5 million) and higher New Smyrna Beach revenues due to an additional contract which began in March ($2.5 million), partially offset by lower SECI revenues ($3.5 million; primarily due to lower coincident peak demand charges on the '83 contract - $2.1 million).

M. Other operating revenues were $13.7 million favorable primarily due to ECCR/ECRC revenues ($6.3 million), miscellaneous service revenues ($5.8 million), higher wheeling and transmission revenues ($2.9 million) and the GPIF award ($2.1 million), partially offset by lower franchise and gross receipts tax revenues ($3.8 million). ECCR/ECRC revenues are collected from the ratepayer and offset expenses specifically incurred on ECCR/ECRC projects, and therefore, do not impact earnings. Franchise and gross receipts tax revenues are collected from the ratepayer and passed on to the applicable taxing authority, and therefore do not impact earnings. Wheeling and transmission revenues were favorable primarily due to an adjusted transmission billing to Georgia Power for service not previously billed ($1.0 million; which was subsequently paid in full) and transmission revenues on new contracts which were not budgeted.

N. O&M was $31.5 million favorable primarily due to lower business unit spending in Energy Supply ($11.2 million; primarily due to nuclear labor and maintenance material expenses, as well as the timing of CT and fossil outage expenses) and Energy Delivery ($10.4 million; primarily due storm restoration costs associated with Hurricanes Charley, Frances and Jeanne as storm costs are charged to the storm reserve), the pension credit ($8.3 million; which includes a $4.2 million favorable actuarial adjustment), a lower allocation of Corporate Staff and Affiliate Costs from Service Company ($7.8 million), PEF Customer Service ($3.9 million; due to lower labor at the Customer Service Center due to vacancies and storm support as storm costs are charged to the storm reserve - $1.7 million, lower lease expenses due to the purchase of the Customer Service Center building and IT&T application related expenses) and Other Affiliate Costs ($2.4 million). Corporate Staff and Affiliate Costs from Service Company were lower primarily due to lower executive benefits ($3.5 million; due to a true-up of the PSSP plan due to lower stock prices, and forfeitures of restricted stock), lower payroll primarily due to vacancies ($3.7 million), corporate communications expenses ($1.5 million; primarily to corporate sponsorships being budgeted here while actuals are recorded to donations - $1.3 million), IT&T infrastructure costs due to restructuring ($2.1 million) and lower insurance ($1.7 million; due to lower nuclear premiums of $0.5 million, lower property insurance - $0.5 million, and worker's comp claims of $0.8 million), partially offset by higher depreciation expenses related to an adjusted life of software ($2.5 million) and the labor accrual which is unbudgeted ($1.8 million). Other Affiliate Costs were favorable due to a $4.6 million favorable adjustment to benefits expensed through the burdening process (primarily due to lower health insurance costs), a $2.7 million favorable actuarial adjustment to benefits (primarily OPEB), favorable A/R adjustments related to the reversal of prior year write-offs ($3.0 million), lower executive benefits ($1.0 million; primarily due to a true-up of the PSSP Plan due to lower stock prices - $0.7 million) and Bayboro exit costs ($1.0 million favorable; exit costs budgeted for the second quarter but not yet incurred), partially offset by service company accrued vacation which was reclassified from a regulatory asset to expense ($2.8 million), the timing of payroll accruals ($4.2 million), MICP/ECIP ($2.4 million unfavorable; primarily due to true-up of new estimate in October) and A/R charge-offs related to uncollectibles ($1.4 million).

O. Depreciation and amortization was $5.6 million favorable primarily due to lower than budgeted depreciation on Hines 2 due to a longer life than budgeted ($4.2 million), a depreciation adjustment related to retirements ($1.3 million) and an adjustment related to the transfer of parts that should have been inventoried ($1.3 million).

P. Taxes other than on income were $8.8 million favorable primarily due to property taxes ($5.0 million; due to a $4.5 million true-up of the accrual based on actual notices received from taxing authorities), franchise taxes ($3.4 million) and payroll taxes ($2.0 million), partially offset by the Florida regulatory assessment fee which was not budgeted for ($2.1 million). Franchise taxes are pass throughs and do not impact earnings.

Q. Other, net was $1.3 million unfavorable primarily due to corporate contributions/donations ($2.3 million), AFUDC equity ($1.8 million; projects not qualified for AFUDC were included in the budget) and lower gains than budgeted on COLI based on market returns ($1.4 million), partially offset by non-regulated energy and delivery services income ($2.0 million) and gains on the disposition of property ($1.1 million; primarily from the sale of land). Corporate contributions/donations were unfavorable due to corporate sponsorships being recorded here while the budget is included in O&M ($1.4 million) and the timing of the contribution to the Progress Energy Foundation ($0.6 million; entire annual donation made in March versus a budget of quarterly contributions.

R. Allowance for funds used during construction – debt was $1.4 million unfavorable due to the budget including projects that are not qualified for AFUDC.

S. Income taxes were $16.8 million unfavorable due to higher pre-tax income.

INCOME STATEMENT VARIANCE ANALYSIS

Year to date vs. Prior Year

T. Base revenues were $49.0 million favorable primarily due to retail customer growth/usage ($35.1 million), the rate refund provision ($23.6 million; in the prior year there was an unfavorable adjustment of $18.2 million to the 2002 revenue sharing accrual) and wholesale base revenues ($11.9 million), partially offset by the $11.8 million unfavorable impact of Hurricanes Charley, Frances and Jeanne) and the impact of milder weather in the current year ($10.9 million). Wholesale base revenues were higher primarily due to the extension of the 150MW FPL contract ($4.2 million), the new TECO contract which began in June 2004 ($3.4 million; prior contract expired in April 2003), higher SECI revenues ($1.6 million; due to new contract which began in April 2003 and higher demand charges on the '83 contract), higher New Smyrna Beach revenues ($2.3 million; due to additional contract which began in March 2004) and higher Tallahassee revenues ($2.8 million; due to an additional contract which began in June 2004), partially offset by lower FMPA revenues ($2.4 million; due to lower demand on the contract).

U. Other operating revenues were $34.5 million favorable primarily due to ECCR/ECRC ($14.6 million), franchise and gross receipts tax revenues ($13.6 million), miscellaneous service revenues ($4.2 million) and wheeling and transmission revenues ($2.6 million). ECCR/ECRC revenues are collected from the ratepayer and offset expenses specifically incurred on ECCR/ECRC projects, and therefore, do not impact earnings. Franchise and gross receipts tax revenues are collected from the ratepayer and passed on to the applicable taxing authority, and therefore do not impact earnings.

V. O&M was $20.2 million favorable primarily due to lower business unit spending in Energy Supply ($20.0 million) and Energy Delivery ($5.3 million; due to storm restoration costs associated with Hurricanes Charley, Frances and Jeanne - storm costs are charged to the storm reserve), the pension credit ($12.5 million; which includes the impact of actuarial adjustments - a $4.2 million credit in the current year compared to a $2.7 million expense in the prior year) and PEF Customer Service ($5.2 million), partially offset by Other Affiliate Costs ($1.3 million) and a higher allocation of Corporate Staff and Affiliate Costs from Service Company ($5.2 million; due to a prior year reallocation of service company charges - $1.8 million, higher depreciation expense due to an adjustment to the life of software - $3.2 million, and labor accruals - $1.1 million, partially offset by favorable benefits of $4.8 million, due to PSSP adjustments as a result of lower stock prices and forfeitures of restricted stock). Included in Energy Supply in the prior year are the costs related to the nuclear outage, of which $16.1 million of costs were offset at the corporate level as the reserve was reversed. After adjusting for the nuclear outage accrual in the prior year, Energy Supply was $3.9 million favorable and Other Affiliate Costs were $14.8 million favorable primarily due to favorable net A/R adjustments to correct prior year write-offs ($5.6 million), favorable payroll taxes of $3.4 million (payroll taxes are offset in other), burden adjustments related to benefits ($4.6 million credit in the current year versus a $1.1 million expense in the prior year), a $2.7 million actuarial adjustment (primarily related to OPEB), an inventory obsolescence charge in the prior year ($2.4 million), lower MICP/ECIP expense of $1.7 million and favorable executive benefits ($0.7 million; due to PSSP due to lower stock prices), partially offset by accounts receivable charge offs of $4.5 million and the reclassification of the service company vacation accrual from a regulatory asset to expense ($2.8 million). AR charge-offs were recorded in PEF Customer Service in the prior year.

W. Depreciation and amortization expense was $28.5 million favorable due to the amortization of the Tiger Bay purchased power contract ($46.6 million), which was fully amortized in September 2003, partially offset by higher depreciation due to property additions (including depreciation of $7.9 million on Hines 2 and distribution equipment ($5.7 million) primarily due to CTE capital projects. The amortization of the purchased power contract was passed through to the ratepayer and therefore did not impact earnings.

X. Taxes other than on income were $15.9 million unfavorable primarily due to gross receipt taxes ($7.4 million), franchise taxes ($6.3 million) and property taxes ($3.6 million), partially offset by payroll taxes ($1.5 million). Franchise and gross receipts taxes are pass throughs and therefore, have no impact on earnings. Property taxes were higher due to Hines 2, asset transfers from PTC, normal property additions and tax millage rate increases.

Y. Interest charges were $20.2 million unfavorable primarily due to the amortization of interest on income tax deficiency ($16.4 million; in the prior year, amortization of the interest benefit was accelerated and realized completely in September, 2003 - $17.1 million vs. $3.7 million in the current year) and higher interest due to additional debt issued in December 2003 ($3.5 million).

Z. AFUDC-debt was $3.1 million unfavorable due to Hines 2 being placed into service in December 2003.

AA. Income tax expense was $31.6 million unfavorable due to higher pre-tax income.

Progress Energy Florida, Inc.
BALANCE SHEETS
November 30, 2004 vs. December 31, 2003

(in thousands)	November 2004	December 2003	Variance	%	Reference #
ASSETS					
Utility Plant					
Electric utility plant in service	$ 8,329,952	$ 8,149,681	$ 180,271	2.2%	
Accumulated depreciation	(2,944,975)	(2,870,905)	(74,070)	2.6%	
Utility plant in service, net	5,384,977	5,278,776	106,201	2.0%	
Held for future use	7,921	7,921	-	0.0%	
Construction work in progress	418,708	328,268	90,440	27.6%	
Nuclear fuel, net of amortization	47,400	69,108	(21,708)	-31.4%	
Total Utility Plant, Net	5,859,006	5,684,073	174,933	3.1%	1
Current Assets					
Cash and cash equivalents	18,689	10,253	8,436	82.3%	
Accounts receivable	201,691	190,621	11,070	5.8%	2
Unbilled accounts receivable	57,726	58,686	(960)	-1.6%	
Receivable from affiliates	12,848	7,391	5,457	73.8%	3
Taxes receivable	152,886	-	152,886	-	15
Deferred income taxes	-	39,049	(39,049)	-100.0%	
Inventory	297,188	230,499	66,689	28.9%	4
Deferred fuel cost	167,150	204,314	(37,164)	-18.2%	5
Prepayments and other current assets	19,427	5,310	14,117	265.9%	6
Total Current Assets	927,605	746,123	181,482	24.3%	
Deferred Debits and Other Assets					
Regulatory assets	394,592	125,789	268,803	213.7%	7
Unamortized debt expense	21,573	24,634	(3,061)	-12.4%	
Nuclear decommissioning trust funds	450,555	433,482	17,073	3.9%	
Miscellaneous other property and investments	45,452	39,541	5,911	14.9%	8
Prepaid pension cost	230,547	220,187	10,360	4.7%	
Other assets and deferred debits	37,599	5,881	31,718	539.4%	9
Total Deferred Debits and Other Assets	1,180,318	849,514	330,804	38.9%	
Total Assets	**$ 7,966,929**	**$ 7,279,710**	**$ 687,219**	9.4%	

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Progress Energy Florida, Inc.
BALANCE SHEETS
November 30, 2004 vs. December 31, 2003

(in thousands)	November 2004	December 2003	Variance	%	Reference #
CAPITALIZATION AND LIABILITIES					
Capitalization					
Common stock equity	$ 1,081,318	$ 1,081,257	$ 61	0.0%	
Retained Earnings	1,227,792	1,061,365	166,427	15.7%	
Comprehensive income	(3,776)	(3,784)	8	-0.2%	
Total common stock equity	2,305,334	2,138,838	166,496	7.8%	
Preferred stock of subsidiary - redemption not required	33,497	33,497	-	0.0%	
Long-term debt, net	1,856,526	1,903,800	(47,274)	-2.5%	10
Total Capitalization	4,195,357	4,076,135	119,222	2.9%	
Current Liabilities					
Current portion of long-term debt	48,000	42,700	5,300	12.4%	11
Accounts payable	278,355	160,634	117,721	73.3%	12
Payable to affiliates	104,697	75,231	29,466	39.2%	13
Notes payable to affiliates	117,469	362,976	(245,507)	-67.6%	14
Taxes accrued	-	19,781	(19,781)	-100.0%	15
Interest accrued	45,074	42,063	3,011	7.2%	
Short-term Obligations	368,270	-	368,270	100%	16
Customer deposits	135,195	126,765	8,430	6.7%	17
Accrued taxes other than income	6,929	10,372	(3,443)	-33.2%	
Other current liabilities	98,327	75,133	23,194	30.9%	18
Total Current Liabilities	1,202,316	915,655	286,661	31.3%	
Deferred Credits and Other Liabilities					
Accumulated deferred income taxes	584,032	363,321	220,711	60.7%	19
Accumulated deferred investment tax credits	35,872	41,352	(5,480)	-13.3%	
Regulatory liabilities	1,350,366	1,322,431	27,935	2.1%	20
Asset Retirement Obligation	335,163	319,277	15,886	5.0%	21
Other liabilities and deferred credits	263,823	241,539	22,284	9.2%	22
Total Deferred Credits and Other Liabilities	2,569,256	2,287,920	281,336	12.3%	
Total Capitalization and Liabilities	**$ 7,966,929**	**$ 7,279,710**	**$ 687,219**	9.4%	

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Balance Sheet Variance Analysis
November 30, 2004 vs. December 31, 2003

Assets

1. **Net Utility Plant** – Increase of $174.9 million is primarily due to property additions of $458.9M offset by depreciation and retirements. Property additions include Transmission projects $44.3M, Steam Production $26.2M and Distribution Ops and Support projects $183.7M, Nuclear Production $5.6M, Hines 3 $94.4M and Hines 2 $12.5M. Retirements include the turbine loaned to GE ($29.6M). The decrease in nuclear fuel relates to amortization.

2. **Accounts receivable** – Increase of $11.1 million is primarily due to higher billed electric revenues in the current month versus December 2003 (billed electric energy sales were approximately 16% higher) primarily due to higher fuel revenues and the timing of billing cycles.

3. **Receivables from affiliates** – Increase of $5.5 million is due to the timing of intercompany settlements through the pay agent funding services.

4. **Inventory** - Increase of $66.7 million is primarily due to the transfer of Tiger Bay equipment from CWIP to inventory ($6.2M), return of materials to inventory associated with the Tiger Bay March 2004 outage ($10.9M), the transfer of fully paid equipment related to Hines from prepaids ($6.3M), the transfer to inventory related to a portion of the turbine that was not transferred to GE and was in CWIP ($12.8M), and an increase in fuel inventory ($24.3M, primarily due to higher fuel prices in the current year versus prior year).

5. **Deferred fuel costs** – Decrease of $37.2M is due to the collection of approximately $186.9M of prior years' under recovered fuel costs as approved by the Public Service Commission and $149.7M under-recovery of current year fuel costs due to rising fuel prices.

6. **Prepayments and other current assets** – Increase of $14.1 million is primarily due to the SO2 allowances ($14.7M, due to allowance purchases at a significantly higher price than in the prior year). Higher prices are driven by higher demand in the market (higher fuel prices have caused some companies to use coal with higher SO2 content, which requires more allowances) and lower supply (pending Clean Air legislation has caused many companies with surplus allowances to keep these allowances versus selling them until legislation is final).

7. **Regulatory assets** – Increase of $268.8M is primarily due to the reclassification of the storm reserve ($263.9M, which includes $310.3M of incurred hurricane costs partially offset by $46.4M of existing storm reserve) from Regulatory Liabilities to Regulatory Assets. This reclassification was due to the accrued and incurred storm costs for Hurricanes Charley, Frances, Jeanne and Ivan that caused the storm reserve balance to result in a net deficit balance.

8. **Miscellaneous other property and investments** – Increase of $5.9 million is due to a $4.3M increase in net non-utility property (primarily due to the reclass of the PTC assets in March 2004 of $3.1M net of accumulated depreciation) and $1.7M due to an increase in the Rabbi Trust, which is used to fund the Supplemental Executive Retirement Plan (SERP), due to a $1.5M cash contribution in July 2004.

9. **Other assets and deferred debits** – Increase of $31.7 million is primarily due to the turbine loaned to GE ($29.6M).

Balance Sheet Variance Analysis
November 30, 2004 vs. December 31, 2003

Liabilities and Stockholder's Equity

10. **Long-term debt, net** – Decrease of $47.3 million is primarily due to the reclassification of the $45.0 million bonds due 7/1/05 to current.

11. **Current portion of long-term debt** – Increase of $5.3 million is due to the payment of the $40.0M bonds due 7/1/04 and the reclassification of the $45.0M bonds due 7/1/05 to current in July 2004.

12. **Accounts payable** - Increase of $117.7 million is due primarily to the accrual of estimated costs related to Hurricanes Charley ($37.9M), Frances ($35.0M), and Jeanne ($47.9M).

13. **Payable to affiliates** – Increase of $29.5 million is primarily attributable to the timing of pay agent funding services and their intercompany settlements.

14. **Notes payable to affiliates** – Decrease of $245.5 million is due to proceeds received from commercial paper were used to reduce the money pool balance. PEF's borrowing changed from intercompany to external funding based on total company cash availability (see explanation #16).

15. **Taxes accrued / Taxes receivable** – Decrease of $172.7 million is due to the 2004 current tax benefit of $99.1 million and payments (net of refunds) of $76.8 million, partially offset by the PGN tax benefit allocation of $3.6 million. The year to date current provision was reduced by approximately $232.5M as a result of deferring casualty losses associated with Hurricanes Charley, Frances, Jeanne, and Ivan (see explanation #18).

16. **Short-term obligations** – Increase of $368.3 million is due to commercial paper borrowings ($143.3M) and draws on the revolving line of credit ($225.0M). External funds (versus intercompany borrowings) were accessed due to the decrease in available cash at a consolidated PGN level (funds that were previously available were used to pay a $500M medium term note which was retired in March 2004 at the holding company). The revolving line of credit was utilized in place of additional commercial paper as a strategy to transition into a lower tiered commercial paper market due to the reduction in PEF's credit rating.

17. **Customer deposits** – Increase of $8.4 million is due to new residential and commercial customers and an additional deposit required from a large commercial customer due to a decrease in their credit rating.

18. **Other current liabilities** – Increase of $23.2 million is primarily due to the current year MICP/ECIP accrual ($21.9M), current deferred income taxes ($18.5M, primarily due to under recoveries of fuel partially offset by unbilled fuel) and negative cash balances at November 30, 2004 ($18.7M; the transfer funds between accounts did not happen until December 1st), partially offset by the payment of the 2003 retail rate refund which was accrued for in 2003 ($18.5M), the reversal of MICP/ECIP awards accrued for in 2003 ($22.1M; actual payouts were charged directly to applicable business units) and the timing of payroll funding ($9M - at 12/31/03, the payroll was processed but not paid until 1/2/04).

19. **Accumulated deferred income taxes** – Increase of $220.7 million is due primarily to casualty losses associated with Hurricanes Charley ($79.5M), Frances ($90.7M), Jeanne ($57.9M), and Ivan ($4.3M). Casualty losses are deducted for tax versus applied against the storm reserve for book, creating a deferred tax liability.

20. **Regulatory liabilities** – Increase of $27.9 million is primarily due to an increase in property cost of removal ($55.1M) which is now classified as a regulatory liability vs. accumulated depreciation due to an SEC ruling effective December 2003 and the nuclear outage accrual for the 2005 outage ($9.5M), partially offset by the reclassification of the storm reserve balance ($46.4M) to regulatory assets (see explanation #6 above).

21. **Asset retirement obligation** – Increase of $15.9 million is due to monthly accretion (approximately $1.4M per month).

22. **Other liabilities and deferred credits** – Increase of $22.3 million is primarily due to an additional environmental accrual for expenses identified for ECRC remediation ($8.4M), an increase in advance wholesale billings ($7.0M) primarily due to a $6.0M deposit received in August related to a wholesale customer (Mirant, received in lieu of letter of credit), a derivative liability related to oil derivatives in a loss position at November 30, 2005 ($5.7M) and current year accruals to record the unfunded retail liability associated with medical benefits for retired employees ($5.4M).

Progress Energy Florida, Inc.

STATEMENTS OF CASH FLOWS
(In thousands)

	Month November 2004	Month November 2003	Variance	%	Reference
Operating Activities					
Net income	$ 15,124	$ 8,492	$ 6,632	78.1	
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	24,702	23,351	1,351	5.8	
Deferred income taxes and investment tax credits, net	(5,130)	17,602	(22,732)	(129.1)	
Deferred fuel cost	25,313	6,363	18,950	297.8	1
Net decrease (increase) in accounts receivable	38,540	(22,001)	60,541	275.2	2
Net (increase) decrease in inventories	(15,370)	3,548	(18,918)	(533.2)	3
Net increase in prepaids and other current assets	(1,223)	(1,651)	428	25.9	
Net (decrease) increase in accounts payable	(32,416)	12,136	(44,552)	(367.1)	4
Net increase (decrease) in customer deposits	3,043	(2,392)	5,435	227.2	5
Change in income taxes, net	10,589	(4,459)	15,048	337.5	6
Net decrease in other current liabilities	(63,751)	(49,315)	(14,436)	(29.3)	7
Other	(60,123)	411	(60,534)	(14,728.5)	8
Net Cash Used in Operating Activities	**(60,702)**	**(7,915)**	**(52,787)**	**(666.9)**	
Investing Activities					
Property additions	(35,173)	(32,638)	(2,535)	(7.8)	
Nuclear fuel additions	(418)	(59)	(359)	(608.5)	
Other investing activities	(38)	(15)	(23)	(153.3)	
Net Cash Used in Investing Activities	**(35,629)**	**(32,712)**	**(2,917)**	**(8.9)**	
Financing Activities					
Proceeds from issuance of long-term debt, net of fees	-	297,367	(297,367)	(100.0)	9
Net increase in short-term indebtedness, net of fees	15,270	-	15,270	-	10
Net decrease (increase) in intercompany notes	108,615	(264,666)	373,281	141.0	11
Dividends paid to parent	(38,750)	-	(38,750)	-	12
Dividends paid on preferred stock	(126)	(126)	-	-	
Other financing activities	17,128	(241)	17,369	7,207.1	13
Net Cash Provided by Financing Activities	**102,137**	**32,334**	**69,803**	**215.9**	
Net Increase (Decrease) in Cash and Cash Equivalents	**5,806**	**(8,293)**	**14,099**	**170.0**	
Cash and Cash Equivalents at Beginning of the Period	**12,883**	**11,520**	**1,363**	**11.8**	
Cash and Cash Equivalents at End of the Period	**$ 18,689**	**$ 3,227**	**$ 15,462**	**479.1**	

Progress Energy Florida, Inc.
STATEMENTS OF CASH FLOWS
(In thousands)

	YTD November 2004	YTD November 2003	Variance	%	Reference
Operating Activities					
Net income	$ 322,813	$ 276,581	$ 46,232	16.7	
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	290,953	291,317	(364)	(0.1)	
Deferred income taxes and investment tax credits, net	268,724	(17,567)	286,291	1,629.7	1
Deferred fuel cost	37,164	(156,139)	193,303	123.8	2
Net (increase) decrease in accounts receivable	(14,543)	8,586	(23,129)	(269.4)	3
Net (increase) decrease in inventories	(39,264)	15,220	(54,484)	(358.0)	4
Net increase in prepaids and other current assets	(14,117)	(46)	(14,071)	(30,589.1)	5
Net (decrease) increase in accounts payable	30,867	37,276	(6,409)	(17.2)	6
Net increase in customer deposits	8,430	4,675	3,755	80.3	7
Change in income taxes, net	(178,317)	57,779	(236,096)	(408.6)	8
Net (decrease) increase in other current liabilities	(13,170)	18,168	(31,338)	(172.5)	9
Other	(220,342)	(2,318)	(218,024)	(9,405.7)	10
Net Cash Provided by Operating Activities	**479,198**	**533,532**	**(54,334)**	**(10.2)**	
Investing Activities					
Property additions	(408,512)	(496,172)	87,660	17.7	11
Nuclear fuel additions	(418)	(50,433)	50,015	99.2	12
Other investing activities	(3,440)	(1,734)	(1,706)	(98.4)	13
Net Cash Used in Investing Activities	**(412,370)**	**(548,339)**	**135,969**	**24.8**	
Financing Activities					
Proceeds from issuance of long-term debt, net of fees	1,053	936,121	(935,068)	(99.9)	14
Net increase (decrease) in short-term indebtedness, net of fees	368,270	(258,149)	626,419	242.7	15
Retirement of long-term debt	(42,700)	(373,025)	330,325	88.6	16
Net decrease in intercompany notes	(245,507)	(99,894)	(145,613)	(145.8)	17
Dividends paid to parent	(155,000)	(203,273)	48,273	23.7	18
Dividends paid on preferred stock	(1,386)	(1,386)	-	-	
Other financing activities	16,878	2,004	14,874	742.2	19
Net Cash (Used In) Provided by Financing Activities	**(58,392)**	**2,398**	**(60,790)**	**2,535.0**	
Net Increase (Decrease) in Cash and Cash Equivalents	**8,436**	**(12,409)**	**20,845**	**168.0**	
Cash and Cash Equivalents at Beginning of the Period	**10,253**	**15,636**	**(5,383)**	**(34.4)**	
Cash and Cash Equivalents at End of the Period	**$ 18,689**	**$ 3,227**	**$ 15,462**	**479.1**	

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Cash Flow Variance Analysis - Month
November 30, 2004 vs. November 30, 2003

1. **Net decrease in deferred fuel cost** – Decrease of $19.0 million is due primarily to the collection in the current month of the prior years' under recovered fuel costs of approximately $18 million and $7 million over-recovery of current year's fuel costs, versus an over recovered position of $6.4 million in the prior year.
2. **Net decrease in accounts receivable** – Decrease of $60.5 million is primarily due to the timing of cash receipts and a decrease in sales of electric in November 2003 vs. October 2003 of approximately 7% versus a decrease in the current month versus October 2004 of approximately 12%.
3. **Net increase in inventories** – Increase of $18.9M is due primarily to an increase in fuel stock in the current month ($17M) versus a decrease in fuel stock in the prior year ($5M). In the prior year there was a nuclear outage, which increased the burns of fuel stock, as compared to no nuclear outage in the current month. In the current month, inventory increased primarily due to the increase in fuel prices and delays of fuel shipments in the prior months due to the storms.
4. **Net decrease in accounts payable** – Decrease of $44.6 million is due primarily to a reduction in the accrual for storm costs as actual costs were incurred ($46M) and the timing of intercompany settlements.
5. **Net increase in customer deposits** – Increase of $5.4M is due to new residential and commercial customer deposits (including an additional deposit required from a large commercial customer in the current month due to a decreased credit rating versus a reduction in the deposit required from this customer in November of the prior year).
6. **Net increase in income taxes** – Increase of $15.0 million is due to favorable pre-tax income compared to prior year, as well as timing differences.
7. **Net decrease in other current liabilities** – Decrease of $14.4 million is primarily due to higher property tax payments in the current month versus prior year ($4.4M), timing of gross receipts tax payments ($6.0M) and a higher MICP/ECIP accrual in the prior year primarily due to a true-up of the estimated payout ($5.8M).
8. **Other** – Decrease of $60.5 million is primarily due to costs incurred related to storm restoration in the current month (excluding storm cost accruals) of approximately $54M and the timing of the capital portion of the labor accrual ($2.2M).
9. **Proceeds from issuance of long-term debt, net of fees** – Decrease of $297.4 million is due to the issuance of $300 million 5.10% Series bonds due 2015, net of discount and debt costs, in the prior year versus no issuances in the current month.
10. **Net increase in short-term indebtedness, net of fees** – Increase of $15.3 million is primarily due to a $55M increase of draws on the revolving credit agreement, partially offset by a decrease in commercial paper borrowings of $40M in the current month versus proceeds from issuance of bonds in the prior year. The revolving credit agreement was used in place of commercial paper as a strategy to transition into a lower tiered commercial paper market due to the reduction in PEF's credit rating.
11. **Net increase in intercompany notes** - Increase of $373.3 million is primarily due to the reduction of money pool borrowings using the proceeds from the bond issuance (noted in #9 above) in the prior year and an increase in money pool borrowings in the current month. The method by which PEF obtains financing (external vs. internal) is based on total company cash availability and needs.
12. **Dividends paid to parent**- Increase of $38.8 million is due to timing of dividend requirements to the parent.
13. **Other financing activities** – Increase of $17.4 million is due to the change in cash provided by checks drawn in excess of bank balances (due to transfer of funds between cash accounts did not occur until December 1, 2004).

Cash Flow Variance Analysis - YTD
November 30, 2004 vs. November 30, 2003

1. **Deferred income taxes and investment tax credits, net** – Increase of $286.3 million is primarily due to an increase in accumulated deferred income taxes in the current year of $233M as a result of casualty losses related to Hurricanes Charley ($80M), Frances ($91M), Jeanne ($58M), and Ivan ($4M) and temporary timing differences related to the under recovery of fuel in the current year ($64M).
2. **Net decrease in deferred fuel cost** – Decrease of $193.3 million is due to the collection in the current year of prior years' under recovered fuel costs of approximately $187 million and $150 million under-recovery of current year's fuel costs, versus an under-recovered position of approximately $156 million in the prior year.
3. **Net increase in accounts receivable** – Increase of $23.1 million is due primarily to an increase in electric sales from December 2003 to November 2004 of 16% versus an increase in electric sales from December 2002 to November 2003 of 8% and the timing off intercompany settlements through the pay agent funding services.
4. **Net increase in inventories** – Increase of $54.5 million is due primarily to the return of materials to inventory associated with the Tiger Bay March outage ($10.9M), the transfer of fully paid equipment from prepaids ($6.3M - related to Hines), partially offset by issuances of inventory for use in service. Fuel stock increased $27M in the current year versus a decrease of $26M in the prior year (net change $53M) primarily due to the nuclear outage in the prior year which increased burns of other fuel. In addition, December 2002 fuel levels were higher in anticipation of a bargaining unit strike, which caused a decrease in 2003 inventory.
5. **Net increase in prepaids and other current assets** – Increase of $14.1 million is due to an increase in the SO2 allowances balances of $14.7M (primarily due to significant increases in the price of allowances) versus lower purchases in the prior year.
6. **Net increase in accounts payable** – Increase of $6.4 million is due primarily to the timing of payagent funding services and their related intercompany settlements and purchases, partially offset by payments to outside vendors.
7. **Increase in customer deposits** – Increase of $3.8M is primarily due to customer growth (approximately 36k new customers in the current year versus prior year at November 30, 2004.
8. **Change in income taxes, net** – Decrease of $236.1 million is primarily due to timing differences related to casualty losses due to Hurricanes Charley, Frances, Jeanne and Ivan (see explanation #1 above).
9. **Net decrease in other current liabilities** – Decrease of $31.3 million is due primarily to the payment of a portion of the 2002 retail rate refund in the prior year ($16M) and higher negative cash balances versus prior year ($17M higher, due to transfer of funds between accounts did not occur until December 1, 2004).
10. **Other** – Decrease of $218.0 million is primarily due to costs incurred related to storm restoration in the current year ($244M) and higher pension credits of $10M (as a result of actuarial adjustments), partially offset by an increase in the nuclear outage reserve of $9M in the current year versus a reduction in the reserve of $10M in prior year due to the October 2003 CR3 outage, an increase in environmental liabilities due to additional costs related to ECRC ($8M) and an MGP site ($3M) and an increase of $6M related to a deposit received in August 2004 related to a wholesale customer (Mirant, received in lieu of a letter of credit).
11. **Property additions** – Cash used decreased by $87.7 million due primarily to lower expenditures in the current year as compared to the prior year for the Hines 2 complex ($77M - Hines 2 was placed in service December 2003), Nuclear projects ($28M, primarily due to the reactor vessel head replacement project at CR3 in the prior year), and various Distribution projects ($18M), partially offset by higher expenditures in the current year for Hines 3 ($48M).
12. **Nuclear Fuel** – Cash used decreased by $50.0 million due to nuclear fuel purchases in 2003 related to the October 2003 nuclear outage.
13. **Other investing activities** – Increase of $1.7 million is primarily due to the contribution of $1.5M to the company-owned life insurance plan in the current year versus no contribution in the prior year.
14. **Proceeds from issuance of long-term debt, net of fees** – Decrease of $935.1 million is due to two bond issuances in February 2003 and one in November 2003 versus no issuances in 2004.
15. **Net increase in short-term indebtedness, net of fees** – Increase of $626.4 million is due to additional commercial paper and revolving credit borrowing in 2004 (vs. intercompany borrowing based on fund availability at a consolidated level) as compared to bond issuances and proceeds from the sale of NCNG (which were borrowed through the money pool) in the prior year which were used to pay down commercial paper.
16. **Retirement of long-term debt** - Decrease of $330.3 million is due to retirement of the $150 million 8% bonds due 12/22 and the maturity of the $70 million 6 1/8% bonds due 3/03, the $110 million 6% bonds due 7/03 and the $35 million 6.6% notes due 7/03 versus maturity of the $40 million 6.69% notes due 7/04.
17. **Net decrease in intercompany notes** - Decrease of $145.6 million is primarily due to the repayment of money pool borrowings in the prior year using the proceeds from the bond issuances (as indicated above) and the use of external funding through commercial paper and the revolving credit agreement in the current year (due to total company cash availability).
18. **Dividends paid to parent** – Decrease of $48.3 million is due to lower dividend requirements from the parent.
19. **Other financing activities** – Increase of $14.5 million is due to the change in cash provided by checks drawn in excess of bank balances (primarily due to transfers of funds between cash accounts in the current month did not occur until December 1, 2004).

Progress Energy Florida, Inc.

STATEMENTS OF CASH FLOWS
(In thousands)

	CM Actual November 2004	CM Budget November 2004	Variance	%	
Operating Activities					
Net income	$ 15,124	$ 15,113	$ 11	0.1	
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	24,702	25,528	(826)	(3.2)	
Deferred income taxes and investment tax credits, net	(5,130)	(2,724)	(2,406)	(88.3)	
Deferred fuel cost	25,313	15,159	10,154	67.0	
Net decrease in accounts receivable	38,540	863	37,677	4,365.8	
Net (increase) decrease in inventories	(15,370)	4,700	(20,070)	(427.0)	
Net (increase) decrease in prepaids and other current assets	(1,223)	322	(1,545)	(479.8)	
Net (decrease) increase in accounts payable	(32,416)	1,417	(33,833)	(2,387.6)	
Net increase in customer deposits	3,043	-	3,043	NM	
Change in income taxes, net	10,589	9,198	1,391	15.1	
Net (decrease) increase in other current liabilities	(63,751)	(73,450)	9,699	13.2	
Other	(60,123)	1,156	(61,279)	(5,301.0)	
Net Cash Used in Operating Activities	**(60,702)**	**(2,718)**	**(57,984)**	**(2,133.3)**	**1**
Investing Activities					
Property additions	(35,173)	(34,016)	(1,157)	(3.4)	
Nuclear fuel additions	(418)	-	(418)	-	
Other investing activities	(38)	-	(38)	-	
Net Cash Used in Investing Activities	**(35,629)**	**(34,016)**	**(1,613)**	(4.7)	
Financing Activities					
Net increase in short-term indebtedness, net of fees	15,270	75,862	(60,592)	(79.9)	
Net increase in intercompany notes	108,615	-	108,615	-	
Dividends paid to parent	(38,750)	(38,750)	-	-	
Dividends paid on preferred stock	(126)	(378)	252	66.7	
Other financing activities	17,128	-	17,128	-	
Net Cash Provided by Financing Activities	**102,137**	**36,734**	**65,403**	**178.0**	**2**
Net Increase in Cash and Cash Equivalents	**5,806**	**-**	**5,806**	**NM**	
Cash and Cash Equivalents at Beginning of the Period	**12,883**	**13,002**	**(119)**	**(0.9)**	
Cash and Cash Equivalents at End of the Period	**$ 18,689**	**$ 13,002**	**$ 5,687**	43.7	

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Progress Energy Florida, Inc.

STATEMENTS OF CASH FLOWS
(In thousands)

	YTD Actual November 2004	YTD Budget November 2004	Variance	%	
Operating Activities					
Net income	$ 322,813	$ 294,413	$ 28,400	9.6	
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	290,953	288,670	2,283	0.8	
Deferred income taxes and investment tax credits, net	268,724	(35,718)	304,442	852.3	
Deferred fuel credit	37,164	176,388	(139,224)	(78.9)	
Net increase in accounts receivable	(14,543)	(3,363)	(11,180)	(332.4)	
Net increase in inventories	(39,264)	(1,300)	(37,964)	(2,920.3)	
Net (increase) decrease in prepaids and other current assets	(14,117)	3,016	(17,133)	(568.1)	
Net (decrease) increase in accounts payable	30,867	6,343	24,524	386.6	
Net increase in customer deposits	8,430	-	8,430	-	
Change in income taxes, net	(178,317)	64,383	(242,700)	(377.0)	
Net (decrease) increase in other current liabilities	(13,170)	(11,121)	(2,049)	(18.4)	
Other	(220,342)	24,501	(244,843)	(999.3)	
Net Cash Provided by Operating Activities	**479,198**	**806,212**	**(327,014)**	**(40.6)**	1
Investing Activities					
Property additions	(408,512)	(416,241)	7,729	1.9	
Nuclear fuel additions	(418)	(265)	(153)	(57.7)	
Other investing activities	(3,440)	-	(3,440)	-	
Net Cash Used in Investing Activities	**(412,370)**	**(416,506)**	**4,136**	**1.0**	2
Financing Activities					
Proceeds from issuance of long-term debt	1,053	-	1,053	-	
Net increase (decrease) in short-term indebtedness, net of fees	368,270	(55,362)	423,632	765.2	
Retirement of long-term debt	(42,700)	(42,700)	-	-	
Net decrease in intercompany notes	(245,507)	(135,132)	(110,375)	(81.7)	
Dividends paid to parent	(155,000)	(155,000)	-	-	
Dividends paid on preferred stock	(1,386)	(1,512)	126	8.3	
Other financing activities	16,878	-	16,878	-	
Net Cash Used in Financing Activities	**(58,392)**	**(389,706)**	**331,314**	**85.0**	3
Net Increase in Cash and Cash Equivalents	**8,436**	**-**	**8,436**	**-**	
Cash and Cash Equivalents at Beginning of the Period	**10,253**	**13,002**	**(2,749)**	**(21.1)**	
Cash and Cash Equivalents at End of the Period	**$ 18,689**	**$ 13,002**	**$ 5,687**	**43.7**	

Cash Flow Variance Analysis - Month

November 30, 2004 Actual vs. November 30, 2004 Budget

1 **Net cash used in operating activities** - Increase in cash used of $58 million is primarily due to costs incurred related to storm restoration (excluding storm cost accruals).

2 **Net cash provided by financing activities** - Increase in cash provided of $65 million is due to an increase in financing needs as a result of a decrease in cash provided from operations.

Cash Flow Variance Analysis - YTD

November 30, 2004 Actual vs. November 30, 2004 Budget

1 **Net cash provided by operating activities** - Decrease in cash provided of $327M is primarily due to the lower than budgeted recovery of deferred fuel due to increased fuel costs and costs incurred related to storm restoration (excluding storm cost accruals). The decrease in income taxes is due to timing differences related to casualty losses associated with the storms, and therefore these decreases are offset in deferred income taxes.

2 **Net cash used by investing activities** - Decrease in cash used of $4M is primarily due to the timing of spending at Hines 3.

3 **Net cash used by financing activities** - Decrease in cash used of $331M is primarily due to an increase in financing needs as a result of a decrease in cash provided from operations.

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Sales (mWh) and Revenues (000's) Schedule A

	MONTH					YEAR-TO-DATE				
	Actual	vs. Prior	%	vs. Budget	%	Actual	vs. Prior	%	vs. Budget	%
SALES OF ENERGY (mWh)										
Residential	1,423,770	22,309	1.6	208,636	17.2	17,974,929	(34,782)	(0.2)	(277,175)	(1.5)
Commercial	991,681	33,718	3.5	2,682	0.3	10,793,112	121,083	1.1	(378,854)	(3.4)
Industrial	345,734	(30,660)	(8.2)	(1,790)	(0.5)	3,718,512	12,576	0.3	(57,107)	(1.5)
Governmental	269,740	10,537	4.1	10,216	3.9	2,790,151	55,561	2.0	(58,746)	(2.1)
Unbilled Sales - Retail - note 1	(275,606)	137,837	NM	(275,606)	NM	30,751	72,416	NM	30,751	NM
Retail Subtotal	2,755,319	173,741	6.7	(55,862)	(2.0)	35,307,455	226,854	0.7	(741,131)	(2.1)
Sales for Resale - Non - Assoc	33,042	(51,126)	(60.7)	(29,250)	(47.0)	982,355	89,974	10.1	121,280	14.1
Sales for Resale - Mun - Pub - Other	342,062	114,556	50.4	225,760	194.1	2,927,191	710,450	32.1	1,287,907	78.6
Sales for Resale - Interchange Power	24,037	(73,358)	(75.3)	(75,963)	(76.0)	758,523	(46,696)	(5.8)	(278,477)	(26.9)
Unbilled Sales - Wholesale - note 1	(25,939)	9,061	NM	(25,939)	NM	103,738	37,626	NM	103,738	NM
Wholesale Subtotal	373,202	(867)	(0.2)	94,608	34.0	4,771,807	791,354	19.9	1,234,448	34.9
Total Energy Sales	3,128,521	172,874	5.9	38,746	1.3	40,079,262	1,018,208	2.6	493,317	1.3
ENERGY REVENUES (000's)										
Residential	$ 133,752	$ 9,938	8.0	$ 19,217	16.8	$ 1,676,906	$ 111,101	7.1	$ (25,939)	(1.5)
Commercial	72,338	10,133	16.3	57	0.1	785,581	102,211	15.0	(28,830)	(3.5)
Industrial	21,648	697	4.3	(656)	(2.9)	232,263	29,896	14.8	(9,496)	(3.9)
Governmental	18,721	2,727	17.1	515	2.8	193,191	27,336	16.5	(6,291)	(3.2)
Unbilled Revenues - Retail (1)	(10,887)	2,606	NM	(10,887)	NM	449	9,648	NM	449	NM
Provision for Retail Revenue Cap - 2004	(39)	(39)	NM	1,102	NM	(5,413)	(5,413)	NM	9,491	NM
Provision for Retail Revenue Cap - 2003	-	751	NM	-	NM	(1,658)	29,093	NM	(1,658)	NM
Retail Subtotal	$ 235,533	$ 27,013	13.0	$ 9,348	4.1	$ 2,881,319	$ 303,872	11.8	$ (62,274)	(2.1)
Sales for Resale - Non - Assoc	3,042	(2,435)	(44.5)	(1,563)	(33.9)	73,328	7,643	11.6	1,097	1.5
Sales for Resale - Mun - Pub - Other	17,765	7,174	67.7	11,787	197.2	142,247	31,481	28.4	60,972	75.0
Sales for Resale - Inter Pwr	1,150	(2,263)	(66.3)	(2,423)	(67.8)	31,158	(1,717)	(5.2)	(8,143)	(20.7)
Unbilled Revenues - Wholesale (1)	60	1,430	NM	60	NM	(1,410)	1,537	NM	(1,410)	NM
Wholesale Subtotal	$ 22,017	$ 3,906	21.6	$ 7,861	55.5	$ 245,323	$ 38,944	18.9	$ 52,516	27.2
Total Sales of Electric Energy	$ 257,550	$ 30,919	13.6	$ 17,209	7.2	$ 3,126,642	$ 342,816	12.3	$ (9,758)	(0.3)
Miscellaneous Revenues (2)	10,727	(1,183)	(9.9)	983	10.1	122,955	3,490	2.9	11,889	10.7
Total GAAP Electric Revenue	268,277	29,736	12.5	18,192	7.3	3,249,597	346,306	11.9	2,131	0.1
Deferred Fuel Revenues	2,412	4,852	NM	2,412	NM	(4,629)	5,438	(54.0)	(4,629)	NM
Total Electric Revenues per MOR	$ 270,689	$ 34,588	14.7	$ 20,604	8.2	$ 3,244,968	$ 351,744	12.2	$ (2,498)	(0.1)

NM = Not meaningful

(1) Budgeted numbers included unbilled by class.

(2) Includes wheeling revenues which pass through the capacity cost recovery clause and GPIF amortization.

Base Revenue Analysis (In '000's)

	MONTH					YEAR-TO-DATE				
	Actual	vs. Prior	%	vs. Budget	%	Actual	vs. Prior	%	vs. Budget	%
Base Revenue*	$ 97,370	$ 7,444	8%	$ 1,935	2%	$ 1,270,824	$ 49,030	4%	$ 1,417	0%
Fuel and Capacity Revenues	141,325	20,639	17%	13,202	10%	1,635,521	263,612	19%	(13,997)	-1%
Other Pass-through Revenues	18,623	2,655	17%	2,040	12%	217,750	28,183	15%	2,475	1%
Other Operating Revenues	10,960	(1,001)	-8%	1,015	10%	125,502	5,481	5%	12,236	11%
Total GAAP Revenue	$ 268,277	$ 29,736	12%	$ 18,192	7%	$ 3,249,597	$ 346,306	12%	$ 2,131	0%

* Includes unbilled revenues

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PEF-SR-10089

Wholesale Revenue Analysis

(Includes unbilled revenues)

(Base Revenues in thousands)

Month

	Actual		vs. Budget		vs. Prior Year	
	MWh	Base Rev.	MWh	Base Rev.	MWh	Base Rev.
SECI	49,498	$ 1,581	(12,811)	$ (226)	(23,422)	$ 4
FPL	123,880	$ 2,484	88,366	$ 1,618	9,976	$ 397
TECO	71,035	$ 1,150	71,035	$ 1,150	71,035	$ 1,150
Other	104,750	$ 2,771	23,979	$ 506	14,900	$ 822
Wholesale Rate Refund	-	$ (60)	-	$ (60)	-	$ 25
Total	349,163	$ 7,926	170,569	$ 2,988	72,489	$ 2,398

Year-to-Date

	Actual		vs. Budget		vs. Prior Year	
	MWh	Base Rev.	MWh	Base Rev.	MWh	Base Rev.
SECI	1,004,537	$ 29,371	143,250	$ (3,492)	81,632	$ 1,607
FPL	1,281,081	$ 24,986	641,877	$ 11,544	315,456	$ 4,366
TECO	517,843	$ 7,542	517,843	$ 7,542	325,415	$ 3,398
Other	1,209,823	$ 30,702	209,955	$ 3,210	115,547	$ 2,075
Wholesale Rate Refund	-	$ (301)	-	$ (301)	-	$ 468
Total	4,013,284	$ 92,300	1,512,925	$ 18,503	838,050	$ 11,914

Wholesale Revenue Analysis

Key Points vs. Budget:

Month

FPL - favorable due to 150 MW contract extended from April 2004 through March 2005 ($1.2 million; contract extension is not included in the budget).

TECO - favorable due to new contract which began in June (not budgeted).

Year-to-date

SECI - unfavorable primarily due to lower than budgeted coincident peak demand charges on the SECI '83 contract ($2.1 million) and the budget for the '95 contract, which includes transmission revenues ($1.5 million; actual transmission revenues are recorded to wheeling and transmission revenues).

FPL - favorable primarily due to 150MW contract extension ($10.3 million).

TECO - favorable due to new contract which began in June.

Other - favorable primarily due to higher New Smyrna Beach revenues due to an additional contract which began in March ($2.5 million) and higher Tallahassee revenues due to an additional contract which began in June 2004 ($2.0 million).

Key Points vs. Prior Year:

Month

TECO - favorable due to the new contract which began in June 2004. TECO contract in the prior year expired on April 30, 2003.

Year-to-date

SECI - favorable due to higher coincident peak demand charges on the '83 contract ($1.4M) and a new SECI contract which began in April 2003 ($0.6M).

FPL - 150 MW contract began in March 2003 ($4.2M)

TECO - favorable due to a new contract which began in June 2004. TECO contract in the prior year expired on April 30, 2003.

Other - favorable primarily due to higher New Smyrna Beach revenues due to an additional contract which began in March 2004 ($2.3M) and higher Tallahassee revenues due to an additional contract which began in June 2004 ($2.8M), partially offset by lower FMPA revenues due to lower contracted demand in the current year ($2.4M).

O&M BASE RECOVERABLE VARIANCE ANALYSIS *
(Dollars in Thousands)

	MONTH			Year-to-Date		
	Amount	vs. Budget	vs. Prior Year	Amount	vs. Budget	vs. Prior Year
Energy Supply	$17,900	$2,580	$3,496	208,810	11,106	$19,976
PEF Customer Service	2,939	413	982	35,517	3,960	5,116
PEF Energy Delivery	11,933	(631)	(148)	123,667	10,400	5,291
Progress Ventures	204	78	196	2,786	400	591
Corporate Staff and Affiliate Costs from Service Co	11,356	(857)	(1,282)	108,926	7,817	(5,160)
Pension Expense (Credit)	(942)	671	1,138	(10,360)	8,309	12,520
Other Affiliate Costs	6,674	(2,927)	1,671	29,019	2,359	(1,320)
O&M Challenge and Incentives	-	(750)	-	-	(8,114)	-
Other, Net	(1,765)	(292)	122	(21,923)	(3,667)	(2,182)
Total O&M Base Recoverable	$ 48,299	($1,715)	$6,175	$ 476,442	$32,570	$34,832

* *Excludes ECCR, ECRC, Base Recoverable Fuel & Purchased Power and Recoverable Non-fuel expenses*

Variance - Current Month vs. Budget:
O&M expenses were $1.7 million unfavorable primarily due to Other Affiliate Costs ($2.9 million) and a higher allocation of Corporate Staff and Affiliate Costs from Service Company ($0.9 million; due to the fall corporate advertising campaign that had been budgeted for earlier in the year), partially offset by lower business unit spending in Energy Supply ($2.6 million; primarily due to Fossil Ops which was $1.9 million favorable due to projects at Crystal River which were canceled or delayed until 2005). Other Affiliate Costs were unfavorable due to the timing of payroll accruals ($1.4 million), A/R chargeoffs related to uncollectibles ($0.6 million) and monthly benefit adjustments ($0.9 million; related to a true-up of ESIP based on updated projections).

Variance - Current Month vs. Prior Year:
O&M expenses were $6.2 million favorable primarily due to lower business unit spending in Energy Supply ($3.5 million; primarily due to the timing of outages and maintenance projects), Other Affiliate Costs ($1.7 million; due to a true-up of the ECIP accrual in the prior year based on projected payouts - $3.3 million, partially offset by A/R charge-offs related to uncollectibles - $1.2 million) and the pension credit ($1.1 million), partially offset by Corporate Staff and Affiliate Costs from Service Company ($1.3 million; primarily due to higher depreciation expense due to an adjusted life of software - $0.7 million, nuclear premiums and credits - $0.3 million, and corporate advertising - $0.3 million).

Schedule C

O&M BASE RECOVERABLE VARIANCE ANALYSIS (con't)

Variance - Year-to-Date vs. Budget:

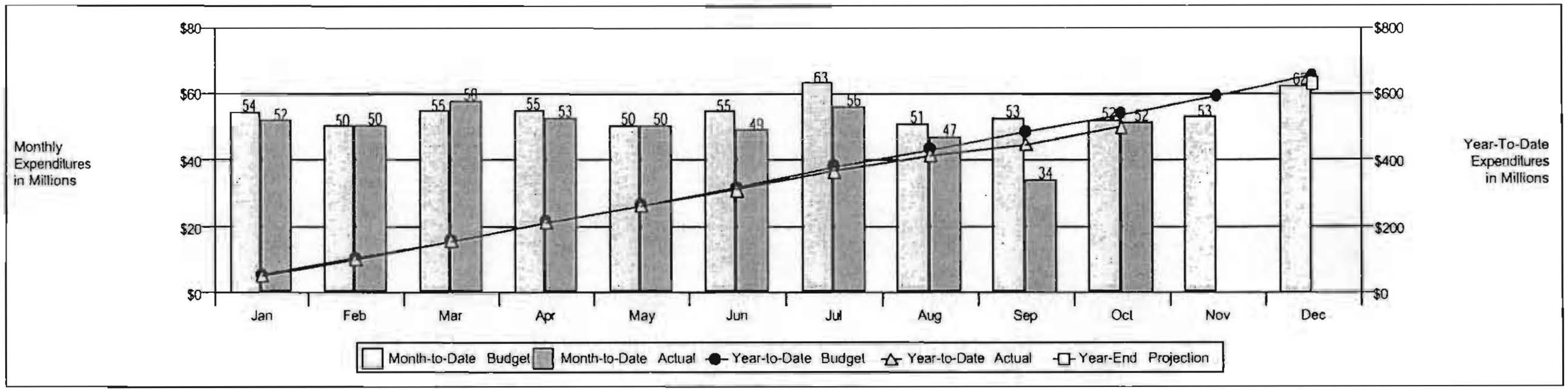
O&M expenses were $32.7 million favorable primarily due to lower business unit spending in Energy Supply ($11.1 million; primarily due to nuclear labor and maintenance material expenses, as well as the timing of CT and fossil outage expenses) and Energy Delivery ($10.4 million; primarily due storm restoration costs associated with Hurricanes Charley, Frances and Jeanne as storm costs are charged to the storm reserve, partially offset by bargaining unit overtime - $1.9 million and a higher than budgeted ECIP/MICP payout - $1.1 million), the pension credit ($8.3 million; which includes a $4.2 million favorable actuarial adjustment), a lower allocation of Corporate Staff and Affiliate Costs from Service Company ($7.8 million), PEF Customer Service ($3.9 million; due to lower labor at the Customer Service Center due to vacancies and storm support as storm costs are charged to the storm reserve -$1.7 million lower lease expenses due to the purchase of the Customer Service Center building and IT&T application related expenses) and Other Affiliate Costs ($2.4 million). Corporate Staff and Affiliate Costs from Service Company were lower primarily due to lower executive benefits ($3.5 million; due to a true-up of the PSSP plan due to lower stock prices, and forfeitures of restricted stock), lower payroll primarily due to vacancies ($3.7 million), corporate communications expenses ($1.5 million; primarily to corporate sponsorships being budgeted here while actuals are recorded to donations - $1.3 million), IT&T infrastructure costs due to restructuring ($2.1 million) and lower insurance ($1.7 million; due to lower nuclear premiums of $0.5 million, lower property insurance - $0.5 million, and lower property insurance and worker's comp claims of $0.8 million), partially offset by higher depreciation expenses related to an adjusted life of software ($2.5 million) and the labor accrual which is unbudgeted ($1.8 million). Other Affiliate Costs were favorable due to a $4.6 million favorable adjustment to benefit expensed through the burdening process (primarily due to lower health insurance costs), a $2.7 million favorable actuarial adjustment to benefits (primarily OPEB), favorable A/R adjustments related to the reversal of prior year write-offs ($3.0 million), lower executive benefits ($1.0 million; primarily due to a true-up of the PSSP Plan due to lower stock prices - $0.7 million) and Bayboro exit costs ($1.0 million favorable; exit costs budgeted for the second quarter but not yet incurred), partially offset by service company accrued vacation which was reclassified from a regulatory asset to expense ($2.8 million), the timing of payroll accruals ($4.2 million), MICP/ECIP ($2.4 million unfavorable; primarily due to true-up of new estimate in October) and A/R charge-offs related to uncollectibles ($1.4 million).

Variance - Year-to-Date vs. Prior Year:

O&M expenses were $34.8 million favorable primarily due to lower business unit spending in Energy Supply ($20.0 million) and Energy Delivery ($5.3 million; due to storm restoration costs associated with Hurricanes Charley, Frances and Jeanne - storm costs are charged to the storm reserve), the pension credit ($12.5 million; which includes the impact of actuarial adjustments - a $4.2 million credit in the current year compared to a $2.7 million expense in the prior year) and PEF Customer Service ($5.1 million), partially offset by Other Affiliate Costs ($1.3 million) and a higher allocation of Corporate Staff and Affiliate Costs from Service Company ($5.2 million; due to a prior year reallocation of service company charges - $1.8 million, higher depreciation expense due to an adjustment to the life of software - $3.2 million, and labor accruals - $1.1 million, partially offset by favorable benefits of $4.8 million, due to PSSP adjustments as a result of lower stock prices and forfeitures of restricted stock). Included in Energy Supply in the prior year are the costs related to the nuclear outage, of which $16.1 million of costs were offset at the corporate level as the reserve was reversed. After adjusting for the nuclear outage accrual in the prior year, Energy Supply was $3.9 million favorable and Other Affiliate Costs were $14.8 million favorable primarily due to favorable net A/R adjustments to correct prior year write-offs ($5.6 million), favorable payroll taxes of $3.4 million (payroll taxes are offset in other), burden adjustments related to benefits ($4.6 million credit in the current year versus a $1.1 million expense in the prior year), a $2.7 million actuarial adjustment (primarily related to OPEB), an inventory obsolescence charge in the prior year ($2.4 million), lower MICP/ECIP expense of $1.7 million and favorable executive benefits ($0.7 million; due to PSSP due to lower stock prices), partially offset by accounts receivable charge offs of $4.5 million and the reclassification of the service company vacation accrual from a regulatory asset to expense ($2.8 million).

PEF-SR-10093

O&M Reconciliation of CMR to Legal Entity
Florida (60)
October
2004



October ($ 000's)				Year-To-Date ($ 000's)					Year-End ($ 000's)				Variance Gap ($ 000's)		
Budget	Actual	Var Fav/(Unfav)	Var % Fav/(Unfav)	Budget	Actual	YTD Var Fav/(Unfav)	Var % Fav/(Unfav)	FUNCTION GROUP	Budget	Projection	YE Var Fav/(Unfav)	Var % Fav/(Unfav)	YTD Var Fav/(Unfav)	YE Var Fav/(Unfav)	Gap
7,889	6,304	1,586	20 %	75,571	69,009	6,562	9 %	Energy Supply - Nuclear Generation	90,202	86,311	3,892	4 %	6,562	3,892	(2,670)
11,093	11,315	(221)	(2 %)	123,864	121,901	1,962	2 %	Energy Supply - Power Operations	153,381	150,649	2,732	2 %	1,962	2,732	770
3,329	3,428	(99)	(3 %)	36,125	32,578	3,546	10 %	Energy Delivery Carolinas	43,425	40,119	3,306	8 %	3,546	3,306	(240)
10,948	7,217	3,731	34 %	122,765	111,733	11,032	9 %	Energy Delivery Florida	148,428	142,761	5,668	4 %	11,032	5,668	(5,364)
266	251	15	6 %	2,904	2,582	322	11 %	Progress Ventures	3,523	3,404	119	3 %	322	119	(203)
(716)	0	(716)	100 %	(7,364)	0	(7,364)	100 %	Committed O&M Challenge	(9,000)	0	(9,000)	100 %	(7,364)	(9,000)	(1,636)
32,810	**28,515**	**4,295**	**13 %**	**353,865**	**337,804**	**16,061**	**5 %**	**CMR O&M Total**	**429,960**	**423,244**	**6,717**	**2 %**	**16,061**	**6,717**	**(9,344)**
7,840	6,918	922	12 %	83,106	74,822	8,284	10 %	Service Co Corporate Staff Reg	98,771	93,747	5,024	5 %	8,284	5,024	(3,260)
40,650	**35,433**	**5,217**	**13 %**	**436,971**	**412,626**	**24,345**	**6 %**	**Regulated O&M Total**	**528,731**	**516,990**	**11,741**	**2 %**	**24,345**	**11,741**	**(12,604)**
3,695	6,321	(2,626)	(71 %)	27,631	22,134	5,497	20 %	Affiliate Costs - Corp.	36,627	31,615	5,012	14 %	5,497	5,012	(486)
(644)	(619)	(25)	4 %	(5,804)	(6,375)	570	(10 %)	Joint Owner Expenses	(6,991)	(6,991)	0	0 %	570	0	(570)
(259)	(864)	605	(234 %)	(1,780)	(9,207)	7,427	(417 %)	Pension (Less Cost Recovery & Joint Owner)	(2,127)	(10,459)	8,332	(392 %)	7,427	8,332	905
2,869	2,845	24	1 %	23,141	22,748	393	2 %	Affiliate Costs - Svc. Co.	29,427	28,459	968	3 %	393	968	575
(1,365)	(854)	(511)	(37 %)	(15,730)	(13,876)	(1,854)	(12 %)	Payroll Taxes	(18,915)	(18,459)	(456)	(2 %)	(1,854)	(456)	1,398
44,946	**42,269**	**2,677**	**6 %**	**464,428**	**428,076**	**36,353**	**8 %**	**Base Recoverable O&M**	**566,752**	**541,156**	**25,596**	**5 %**	**36,353**	**25,596**	**(10,756)**
0	1,588	(1,588)	(100 %)	0	2,607	(2,607)	(100 %)	Non-Fuel Expenses - Recoverable	0	0	0	0 %	(2,607)	0	2,607
5,604	5,339	265	5 %	58,320	50,947	7,373	13 %	Energy Conservation Clause	68,525	68,189	336	0 %	7,373	336	(7,037)
1,430	1,985	(555)	(39 %)	15,117	17,246	(2,129)	(14 %)	Environmental Cost Recovery	17,829	17,827	1	0 %	(2,129)	1	2,130
0	489	(489)	(100 %)	0	2,329	(2,329)	(100 %)	Recoverable Cost Maritime Security	0	0	0	0 %	(2,329)	0	2,329
7,034	**9,401**	**(2,366)**	**(34 %)**	**73,437**	**73,129**	**308**	**0 %**	**Pass Through Expenses**	**86,354**	**86,017**	**337**	**0 %**	**308**	**337**	**29**
51,980	**51,662**	**318**	**1 %**	**537,865**	**501,179**	**36,686**	**7 %**	**Net Regulated O&M Legal Entity Total**	**653,106**	**627,173**	**25,933**	**4 %**	**36,686**	**25,933**	**(10,753)**

NOTES:
1. Service Co Corporate Staff Reg represents portion of Service Company costs that are allocated to regulated utilities. Does not include Service Co Corporate Staff Utility Non Reg.
2. "Less Payroll Taxes" variances are defined as Unfavorable/(Favorable). The "Less Payroll Taxes" line offsets the impact of payroll taxes reflected in the various line items above it in order to calculate Net Regulated O&M. Payroll Taxes are reported in the Other Taxes line of the Income Statement.

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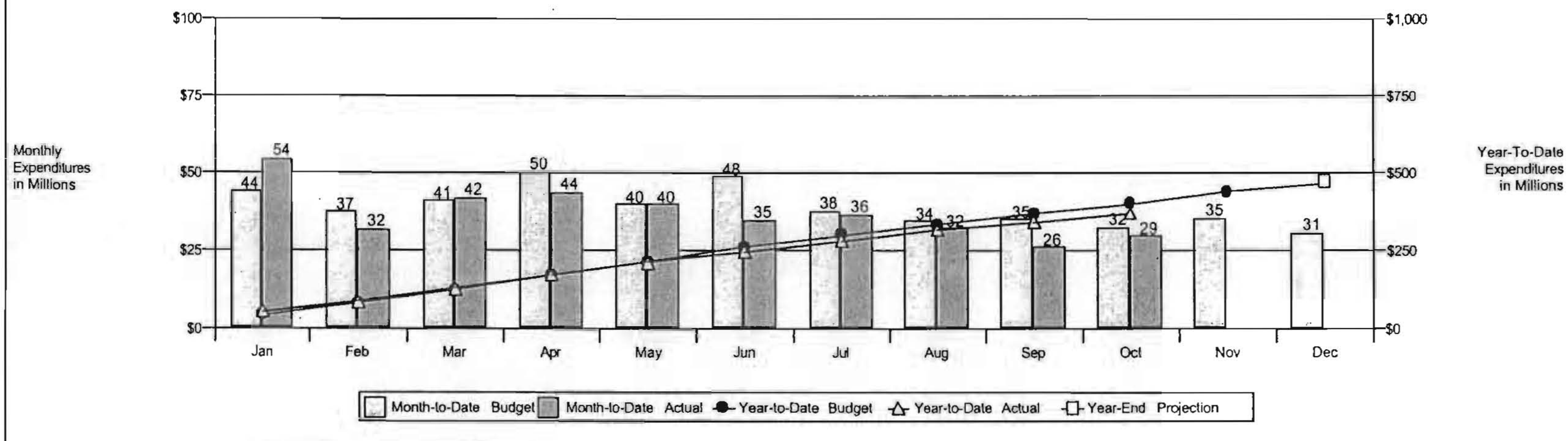
PEF-SR-10113

Progress Energy Florida (60)
Capital
October 2004



October ($ 000's)				Year-To-Date ($ 000's)					Year-End ($ 000's)				Variance Gap ($ 000's)		
Budget	Actual	Var Fav/(Unfav)	Var% Fav/(Unfav)	Budget	Actual	YTD Var Fav/(Unfav)	Var% Fav/(Unfav)	Charge To Organization	Budget	Projection	YE Var Fav/(Unfav)	Var% Fav/(Unfav)	YTD Var Fav/(Unfav)	YE Var Fav/(Unfav)	Gap
1,123	1,603	(480)	(43 %)	11,740	8,432	3,308	28 %	Energy Supply - Nuclear Generation	13,466	12,926	539	4 %	3,308	539	(2,768)
2,396	2,095	301	13 %	38,255	34,483	3,772	10 %	Energy Supply - Power Operations	47,125	46,228	898	2 %	3,772	898	(2,874)
90	2	88	97 %	715	39	676	95 %	Energy Delivery Carolinas	1,010	35	975	97 %	676	975	299
19,937	15,259	4,678	23 %	225,403	202,256	23,147	10 %	Energy Delivery Florida	262,187	255,477	6,710	3 %	23,147	6,710	(16,438)
6,032	12,272	(6,240)	(103 %)	103,854	102,322	1,531	1 %	Regulated Future Generation	116,243	116,263	(21)	(0 %)	1,531	(21)	(1,552)
29,579	**31,231**	**(1,652)**	**(6 %)**	**379,966**	**347,532**	**32,434**	**9 %**	**Regulated Capital**	**440,030**	**430,929**	**9,101**	**2 %**	**32,434**	**9,101**	**(23,333)**
0	420	(420)	(100 %)	0	54,820	(54,820)	(100 %)	Major Storm	0	54,400	(54,400)	(100 %)	(54,820)	(54,400)	420
698	(3,800)	4,498	644 %	2,999	(42,225)	45,223	1508 %	Regulated Capital Corporate	4,386	(18,663)	23,049	526 %	45,223	23,049	(22,174)
(92)	553	(646)	699 %	(961)	184	(1,145)	119 %	Joint Owner Expenses	(1,103)	(1,103)	0	0 %	(1,145)	0	1,145
0	(5)	5	100 %	0	660	(660)	(100 %)	Capital - Recoverable Environmental Cost Recovery	0	(39)	39	100 %	(660)	39	698
192	5	188	98 %	2,088	376	1,712	82 %	Pension (Less Cost Recovery)	2,524	54	2,470	98 %	1,712	2,470	758
1,721	1,059	662	38 %	14,058	8,301	5,757	41 %	AFUDC	17,657	6,323	11,334	64 %	5,757	11,334	5,577
32,098	**29,463**	**2,634**	**8 %**	**398,150**	**369,648**	**28,501**	**7 %**	**Net Regulated Capital Legal Entity**	**463,494**	**471,902**	**(8,408)**	**(2 %)**	**28,501**	**(8,408)**	**(36,909)**
133	0	133	100 %	1,204	(82)	1,286	107 %	Non-Regulated	1,518	521	997	66 %	1,286	997	(289)
32,231	**29,463**	**2,767**	**9 %**	**399,353**	**369,566**	**29,787**	**7 %**	**Net Capital Legal Entity**	**465,012**	**472,423**	**(7,411)**	**(2 %)**	**29,787**	**(7,411)**	**(37,198)**

NOTE:

1. Energy Delivery Florida Budgets Include an adjustment for Revenue Construction.

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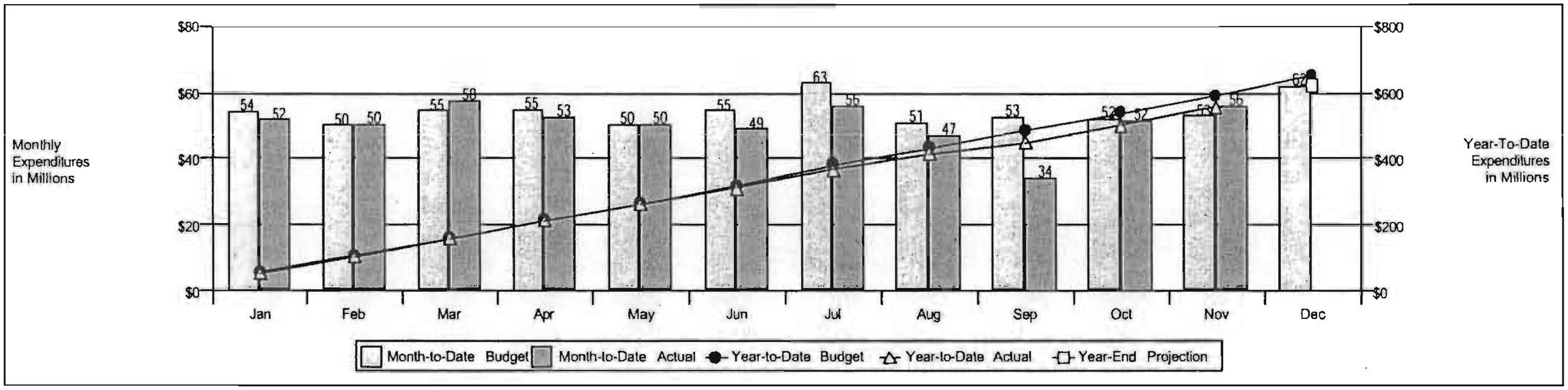
PEF-SR-10114

O&M Reconciliation of CMR to Legal Entity
Florida (60)
November
2004



November ($ 000's)				Year-To-Date ($ 000's)					Year-End ($ 000's)				Variance Gap ($ 000's)		
Budget	Actual	Var Fav/(Unfav)	Var % Fav/(Unfav)	Budget	Actual	YTD Var Fav/(Unfav)	Var % Fav/(Unfav)	FUNCTION GROUP	Budget	Projection	YE Var Fav/(Unfav)	Var % Fav/(Unfav)	YTD Var Fav/(Unfav)	YE Var Fav/(Unfav)	Gap
6,235	5,972	263	4 %	81,807	74,981	6,826	8 %	Energy Supply - Nuclear Generation	90,202	85,799	4,403	5 %	6,826	4,403	(2,422)
14,245	11,928	2,317	16 %	138,109	133,829	4,279	3 %	Energy Supply - Power Operations	153,381	150,357	3,024	2 %	4,279	3,024	(1,255)
3,352	2,939	414	12 %	39,477	35,517	3,960	10 %	Energy Delivery Carolinas	43,425	40,119	3,306	8 %	3,960	3,306	(654)
11,302	11,933	(632)	(6 %)	134,067	123,667	10,400	8 %	Energy Delivery Florida	148,428	141,423	7,005	5 %	10,400	7,005	(3,395)
282	204	77	27 %	3,186	2,786	400	13 %	Progress Ventures	3,523	3,138	385	11 %	400	385	(15)
(750)	0	(750)	100 %	(8,114)	0	(8,114)	100 %	Committed O&M Challenge	(9,000)	0	(9,000)	100 %	(8,114)	(9,000)	(886)
34,667	**32,977**	**1,690**	**5 %**	**388,532**	**370,781**	**17,751**	**5 %**	**CMR O&M Total**	**429,960**	**420,836**	**9,124**	**2 %**	**17,751**	**9,124**	**(8,627)**
7,637	8,364	(727)	(10 %)	90,743	83,186	7,557	8 %	Service Co Corporate Staff Reg	98,771	93,280	5,491	6 %	7,557	5,491	(2,066)
42,304	**41,341**	**963**	**2 %**	**479,274**	**453,967**	**25,307**	**5 %**	**Regulated O&M Total**	**528,731**	**514,116**	**14,615**	**3 %**	**25,307**	**14,615**	**(10,692)**
0	0	0	0 %	0	0	0	0 %	Major Storm	0	11	(11)	(100 %)	0	(11)	(11)
3,747	6,594	(2,848)	(76 %)	31,378	28,728	2,650	8 %	Affiliate Costs - Corp.	36,627	30,808	5,819	16 %	2,650	5,819	3,169
(522)	(630)	108	(21 %)	(6,326)	(7,004)	678	(11 %)	Joint Owner Expenses	(6,991)	(6,991)	0	0 %	678	0	(678)
(271)	(862)	591	(218 %)	(2,051)	(10,069)	8,018	(391 %)	Pension (Less Cost Recovery & Joint Owner)	(2,127)	(10,454)	8,327	(392 %)	8,018	8,327	309
2,860	2,992	(133)	(5 %)	26,000	25,740	260	1 %	Affiliate Costs - Svc. Co.	29,427	27,533	1,894	6 %	260	1,894	1,634
(1,334)	(1,161)	(172)	(13 %)	(17,063)	(15,037)	(2,026)	(12 %)	Payroll Taxes	(18,915)	(18,388)	(527)	(3 %)	(2,026)	(527)	1,500
46,784	**48,282**	**(1,499)**	**(3 %)**	**511,212**	**476,358**	**34,854**	**7 %**	**Base Recoverable O&M**	**566,752**	**536,636**	**30,117**	**5 %**	**34,854**	**30,117**	**(4,737)**
0	0	0	0 %	0	2,607	(2,607)	(100 %)	Non-Fuel Expenses - Recoverable	0	0	0	0 %	(2,607)	0	2,607
4,860	4,759	101	2 %	63,180	55,706	7,474	12 %	Energy Conservation Clause	68,525	68,189	336	0 %	7,474	336	(7,138)
1,294	1,662	(368)	(28 %)	16,412	18,909	(2,497)	(15 %)	Environmental Cost Recovery	17,829	17,827	1	0 %	(2,497)	1	2,498
0	1,256	(1,256)	(100 %)	0	3,584	(3,584)	(100 %)	Recoverable Cost Maritime Security	0	0	0	0 %	(3,584)	0	3,584
6,154	**7,677**	**(1,523)**	**(25 %)**	**79,591**	**80,805**	**(1,214)**	**(2 %)**	**Pass Through Expenses**	**86,354**	**86,017**	**337**	**0 %**	**(1,214)**	**337**	**1,551**
52,938	**55,951**	**(3,013)**	**(6 %)**	**590,803**	**557,130**	**33,673**	**6 %**	**Net Regulated O&M Legal Entity Total**	**653,106**	**622,652**	**30,454**	**5 %**	**33,673**	**30,454**	**(3,219)**

NOTES:
1. Service Co Corporate Staff Reg represents portion of Service Company costs that are allocated to regulated utilities. Does not include Service Co Corporate Staff Utility Non Reg.
2. "Less Payroll Taxes" variances are defined as Unfavorable/(Favorable). The "Less Payroll Taxes" line offsets the impact of payroll taxes reflected in the various line items above it in order to calculate Net Regulated O&M. Payroll Taxes are reported in the Other Taxes line of the Income Statement.
3. Projection is system data. As requested by Financial Planning, business units provided the following off-system projection updates on December 3rd: Service Co Corp Staff Reg $91M, decrease of $2M; Affiliate Costs - Corp $35M, increase of $4M; Joint Owner Expenses (8M), decrease of $1M.

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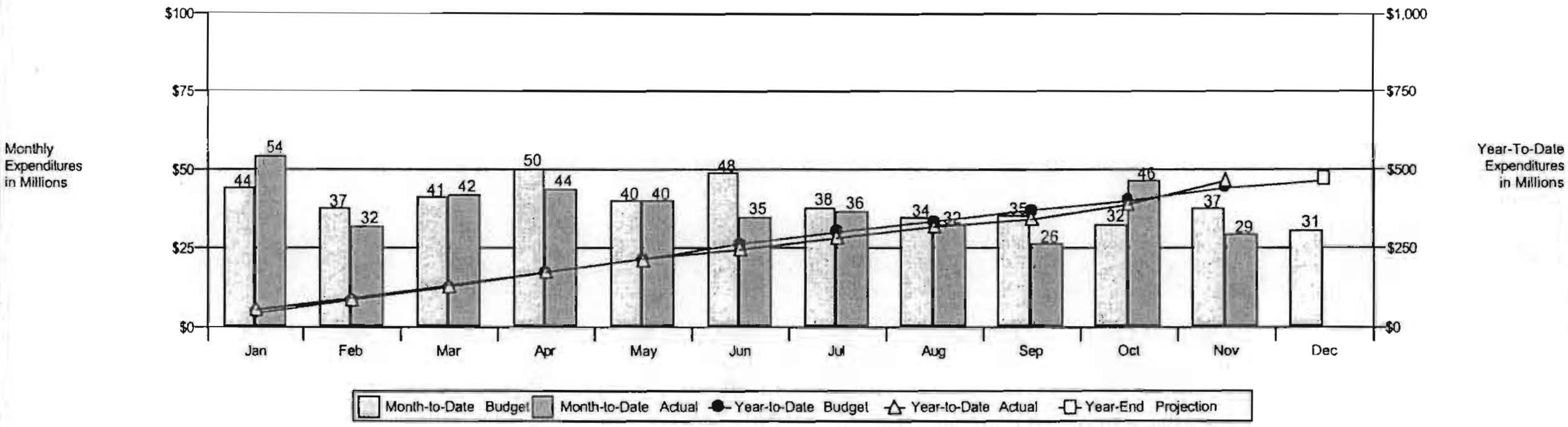
Progress Energy Florida (60)
Capital
November 2004



November ($ 000's)				Year-To-Date ($ 000's)					Year-End ($ 000's)				Variance Gap ($ 000's)		
Budget	Actual	Var Fav/(Unfav)	Var% Fav/(Unfav)	Budget	Actual	YTD Var Fav/(Unfav)	Var% Fav/(Unfav)	Charge To Organization	Budget	Projection	YE Var Fav/(Unfav)	Var% Fav/(Unfav)	YTD Var Fav/(Unfav)	YE Var Fav/(Unfav)	Gap
879	1,883	(1,004)	(114 %)	12,618	10,315	2,303	18 %	Energy Supply - Nuclear Generation	13,466	12,929	537	4 %	2,303	537	(1,766)
6,393	6,173	221	3 %	44,648	40,656	3,992	9 %	Energy Supply - Power Operations	47,125	46,669	456	1 %	3,992	456	(3,536)
147	1	146	100 %	861	39	822	95 %	Energy Delivery Carolinas	1,010	35	975	97 %	822	975	154
18,502	22,463	(3,961)	(21 %)	243,905	224,719	19,186	8 %	Energy Delivery Florida	263,079	252,078	11,000	4 %	19,186	11,000	(8,186)
7,367	3,927	3,440	47 %	111,221	106,250	4,971	4 %	Regulated Future Generation	116,243	116,263	(21)	(0 %)	4,971	(21)	(4,992)
33,288	34,447	(1,159)	(3 %)	413,254	381,979	31,275	8 %	Regulated Capital	440,922	427,974	12,948	3 %	31,275	12,948	(18,327)
0	67	(67)	(100 %)	0	54,887	(54,887)	(100 %)	Major Storm	0	54,400	(54,400)	(100 %)	(54,887)	(54,400)	487
693	132	561	81 %	3,692	(25,391)	29,084	788 %	Regulated Capital Corporate	4,386	(18,663)	23,049	526 %	29,084	23,049	(6,034)
(72)	(115)	43	(59 %)	(1,033)	69	(1,102)	107 %	Joint Owner Expenses	(1,103)	(1,103)	0	0 %	(1,102)	0	1,102
0	0	0	0 %	0	660	(660)	(100 %)	Capital - Recoverable Environmental Cost Recovery	0	(39)	39	100 %	(660)	39	698
195	8	187	96 %	2,282	384	1,899	83 %	Pension (Less Cost Recovery)	2,524	54	2,470	98 %	1,899	2,470	571
1,774	1,111	663	37 %	15,832	9,412	6,420	41 %	AFUDC	17,657	6,323	11,334	64 %	6,420	11,334	4,913
35,878	35,649	228	1 %	434,027	421,999	12,028	3 %	Net Regulated Capital Legal Entity	464,386	468,947	(4,561)	(1 %)	12,028	(4,561)	(16,590)
161	42	119	74 %	1,365	(41)	1,405	103 %	Non-Regulated	1,518	521	997	66 %	1,405	997	(408)
36,039	35,691	348	1 %	435,392	421,958	13,434	3 %	Net Capital Legal Entity	465,904	469,468	(3,564)	(1 %)	13,434	(3,564)	(16,997)

NOTE:

1. Energy Delivery Florida Budgets include an adjustment for Revenue Construction.

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Progress Energy Florida
Energy Delivery Monthly Financial Summary
2004 - October

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	Regulated O&M	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
Line #	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
1	NORTH CENTRAL REGION	$ 620	$ 327	$ 293	$ 6,648	$ 5,736	$ 912	$ 619	$ 574	$ 8,082	$ 7,475	$ 607	$ 869	$ 1,738	52%
2	SOUTH CENTRAL REGION	649	277	371	7,066	5,837	1,229	856	584	8,536	7,467	1,069	815	1,631	40%
3	NORTH COASTAL REGION	396	481	(85)	4,134	4,135	(0)	85	413	5,113	5,184	(71)	524	1,049	27%
4	SOUTH COASTAL REGION	862	741	121	9,476	9,228	248	127	923	11,466	11,089	377	931	1,861	1%
5	COASTAL REGION COMBINED	1,258	1,222	36	13,610	13,363	248	212	1,336	16,579	16,273	306	1,455	2,910	9%
6	DIST OPS & SUPPORT	4,947	2,877	2,070	52,507	48,447	4,060	1,990	4,845	63,590	61,416	2,174	6,485	12,970	34%
7	Distribution Total	$ 7,473	$ 4,703	$ 2,770	$ 79,831	$ 73,383	$ 6,449	$ 3,679	$ 7,338	$ 96,787	$ 92,631	$ 4,155	$ 9,624	$ 19,249	31%
8	TRANSMISSION	$ 1,899	$ 1,298	$ 601	$ 21,085	$ 19,041	$ 2,044	$ 1,443	$ 1,904	$ 26,115	$ 25,429	$ 686	$ 3,194	$ 6,388	68%
9	CTE PROJECT MANAGEMENT	475	76	399	9,303	7,781	1,521	1,122	778	10,274	9,226	1,048	722	1,444	-7%
10	ENERGY DELIVERY ADMIN	488	786	(297)	5,567	5,516	51	348	552	6,709	6,466	243	475	951	-14%
11	ENERGY DELIVERY SERVICES	316	206	110	3,548	3,170	378	268	317	4,391	4,189	202	510	1,019	61%
12	ED MANAGER BUSINESS OPERATIONS	184	116	68	2,034	1,696	338	270	170	2,489	2,134	355	219	438	29%
13	FPC - ED	19	9	10	196	193	3	(8)	19	239	220	19	13	27	-30%
14	PROGRESS ENERGY FLORIDA PRESIDE	93	20	73	1,202	945	257	183	95	1,425	1,128	297	91	183	-3%
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
16		$ 10,948	$ 7,213	$ 3,735	$ 122,765	$ 111,724	$ 11,041	$ 7,306	$ 11,172	$ 148,428	$ 141,423	$ 7,005	$ 14,850	$ 29,699	33%

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KEY YTD POINTS:

19 1 - ECIP / MICP Payout - ($1.1m) Unfav - Budgeted ECIP at 5% & 7% payout - Actual 6.675% & 9.65%. Safety Incentives and Performance awards - ($0.4m) Unfav - The safety award program is main driver.

20 2 - CTE - $1.0m Fav YTD - Major Driver is Veg Mgmt which was cut back to meet mitigation efforts, prior to the impact of the Major Storms.

21 3 - Bargaining Unit OT - Unfavorable ($1.7m) - Dispatch - ($1.0m) and Meter Reading ($0.3m) driving variance. These variances are offset by $1.2m favorable in Safety & Training, $2.3m fav in Payroll related burdens and $3.4m in payroll (other than safety & training).

22 4 - Tree Trimming - $3.9m favorable YTD (excludes CTE - Only Transmission and DOS). CTE is favorable YTD due to mitigation plan and DOS is favorable due to Bonnie, Charley, Frances and Ivan Storm Impact

23 5 - The Year-end Projection reflects the impact of the Major Storms and managements efforts to address backlog work offset by $1.5m increase for R&D Business Case.

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	Regulated Capital	Current Month - (000's)			Year-to-Date - (000's)						Year-End - (000's)					
29	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance with Price Included	Burn Rate	Prior Month YTD Var	Variance with Price Excluded	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
30	NORTH CENTRAL REGION	$ 2,162	$ 2,259	$ (96)	$ 24,137	$ 21,523	$ 2,614	$ 2,152	2,711	$ 1,563	$ 29,187	$ 28,790	$ 397	$ 3,633	$ 7,267	69%
31	SOUTH CENTRAL REGION	2,327	1,712	615	30,711	29,147	1,563	2,915	949	(1,371)	36,582	36,133	448	3,493	6,986	20%
32	NORTH COASTAL REGION	1,120	1,569	(449)	13,853	14,446	(592)	1,445	(143)	(971)	16,554	15,930	624	742	1,484	-49%
33	SOUTH COASTAL REGION	1,989	1,965	24	27,499	26,931	568	2,693	544	(2,034)	32,834	33,372	(538)	3,221	6,441	20%
32	COASTAL REGION COMBINED	3,108	3,534	(426)	41,352	41,376	(24)	4,138	402	$ (3,005)	49,388	49,302	86	3,963	7,925	-4%
33	DIST OPS & SUPPORT	5,033	3,883	1,150	50,372	43,432	6,940	4,343	5,790	6,940	59,190	59,752	(562)	8,160	16,320	88%
34	Distribution Total	$ 12,630	$ 11,388	$ 1,242	$ 146,572	$ 135,479	$ 11,093	$ 13,548	$ 9,851	$ 4,127	$ 174,347	$ 173,977	$ 371	$ 19,249	$ 38,498	42%
35	Note: Current Month does not have Price Impact included				Rev Construction PRICE impact applied against YTD Variance		-		-	6,402			-			
36					S/L PRICE impact applied against YTD Variance		-		-	565			-			
37					Total Distribution Variance		$ 11,093		$ -	$ 11,093			$ -			
38																
39	TRANSMISSION	$ 6,187	$ 3,464	$ 2,724	$ 52,986	$ 46,010	$ 6,976	$ 4,601	$ 4,252	$ 6,976	$ 62,006	$ 60,507	$ 1,500	$ 7,248	$ 14,496	58%
40	CTE PROJECT MANAGEMENT	421	273	148	14,490	11,112	3,378	1,111	3,230	3,378	15,182	13,887	1,295	1,388	2,776	25%
41	ENERGY DELIVERY ADMIN	753	134	618	11,270	9,593	1,677	959	1,058	8,643	12,403	10,971	1,432	689	1,377	-28%
42	ENERGY DELIVERY SERVICES	15	-	15	154	62	92	6	77	92	185	185	-	62	123	901%
43	ED MANAGER BUSINESS OPERATIONS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
44	FPC - ED	-	-	-	-	-	-	-	-		-	-	-	-	-	0%
45	Total Regulated Capital	$ 20,006	$ 15,259	$ 4,747	$ 225,472	$ 202,256	$ 23,216	$ 20,226	$ 18,469	$ 23,216	$ 264,123	$ 259,526	$ 4,597	$ 28,635	$ 57,270	42%

46 NOTE: Due to the impact of Price and the way it is calculated; it is not reflected in the current month. Therefore, you cannot take Prior Month Variance and add Current Month Variance to tie to current YTD variance.

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KEY YTD POINTS:

50 1 - The Price Variances for New Customer & Streetlight work are favorable YTD -$6.9 m. This is due to CIAC $4.3m above budget in collections in NCW. Volume Adjustment YTD is $5.5m favorable (NCW $7.7m less S/L $2.2m).

51 2 - Load Growth Projects $3.4m, CTE $3.4m, Meters & Transformer Purchases $1.9m, Facilities $0.4m, Fleet $0.2m & Base Programs $2.4m all favorable due to impact from Storms

52 3 - DOT & Replace / Refurbish continue to exceed budget - YTD Unfavorable Variance - ($4.2m) DOT - ($3.9m) & R/R ($0.3m)

53 4 - ECIP / MICP Payout - ($1.7m) Unfav - Budgeted ECIP at 5% & 7% payout - Actual 6.875% & 9.65%

54 5 - The Year-end Projection reflects the base labor reductions due to the Major Storms and Operational managements estimate of backlog work that can be accomplished before year-end.

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Progress Energy Florida
Energy Delivery Monthly Financial Summary - O&M
2004 - October

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Line #	Regulated O&M Description - Charge To	Current Month - (000's) Budget	Actual	Variance	Year-to-Date - (000's) Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Year-End - (000's) Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
1	NORTH CENTRAL REGION	$ 620	$ 327	$ 293	$ 6,648	$ 5,736	$ 912	$ 619	$ 574	$ 8,082	$ 7,475	$ 607	$ 869	$ 1,738	52%
2	SOUTH CENTRAL REGION	649	277	371	7,066	5,837	1,229	858	584	8,536	7,467	1,069	815	1,631	40%
3	NORTH COASTAL REGION	396	481	(85)	4,134	4,135	(0)	85	413	5,113	5,184	(71)	524	1,049	27%
4	SOUTH COASTAL REGION	862	741	121	9,476	9,228	248	127	923	11,466	11,089	377	931	1,861	1%
5	COASTAL REGION COMBINED	1,258	1,222	36	13,610	13,363	248	212	1,336	16,579	16,273	306	1,455	2,910	9%
6	DIST OPS & SUPPORT	4,947	2,877	2,070	52,507	48,447	4,060	1,990	4,845	63,590	61,416	2,174	6,485	12,970	34%
7	**Distribution Total**	**$ 7,473**	**$ 4,703**	**$ 2,770**	**$ 79,831**	**$ 73,383**	**$ 6,449**	**$ 3,679**	**$ 7,338**	**$ 96,787**	**$ 92,631**	**$ 4,155**	**$ 9,624**	**$ 19,249**	**31%**
8	TRANSMISSION	$ 1,899	$ 1,298	$ 601	$ 21,085	$ 19,041	$ 2,044	$ 1,443	$ 1,904	$ 26,115	$ 25,429	$ 686	$ 3,194	$ 6,388	68%
9	CTE PROJECT MANAGEMENT	475	76	399	9,303	7,781	1,521	1,122	778	10,274	9,226	1,048	722	1,444	-7%
10	ENERGY DELIVERY ADMIN	488	786	(297)	5,567	5,516	51	348	552	6,709	6,466	243	475	951	-14%
11	ENERGY DELIVERY SERVICES	316	206	110	3,548	3,170	378	268	317	4,391	4,189	202	510	1,019	61%
12	ED MANAGER BUSINESS OPERATIONS	184	116	68	2,034	1,696	338	270	170	2,489	2,134	355	219	438	29%
13	FPC - ED	19	9	10	196	193	3	(8)	19	239	220	19	13	27	-30%
14	PROGRESS ENERGY FLORIDA PRESIDEN	93	20	73	1,202	945	257	183	95	1,425	1,128	297	91	183	-3%
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
16		**$ 10,948**	**$ 7,213**	**$ 3,735**	**$ 122,765**	**$ 111,724**	**$ 11,041**	**$ 7,306**	**$ 11,172**	**$ 148,428**	**$ 141,423**	**$ 7,005**	**$ 14,850**	**$ 29,699**	**33%**
17															

Line #	CTE Programs Description - Charge By	Current Month - (000's) Budget	Actual	Variance	Year-to-Date - (000's) Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Year-End - (000's) Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
1															
2	NORTH CENTRAL REGION	$ -	$ -	$ -	$ -	$ 4	$ (4)	$ (4)	$ 0	$ -	$ -	$ -	$ (2)	$ (4)	-600%
3	SOUTH CENTRAL REGION	-	-	-	-	6	(6)	(6)	1	-	-	-	(3)	(6)	-600%
4	NORTH COASTAL REGION	-	1	(1)	-	9	(9)	(8)	1	-	-	-	(5)	(9)	-600%
5	SOUTH COASTAL REGION	-	-	-	-	4	(4)	(4)	0	-	-	-	(2)	(4)	-600%
7	DIST OPS & SUPPORT	55	16	39	2,050	1,669	381	342	167	2,170	2,120	50	225	451	35%
8	TRANSMISSION	400	29	371	7,000	5,325	1,675	1,304	533	7,800	6,603	1,197	639	1,277	20%
9	Other Charge By Org	20	30	(10)	253	764	(511)	(501)	76	304	503	(199)	(130)	(261)	-271%
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
12	**Total CTE Programs**	$ 475	$ 76	$ 399	$ 9,303	$ 7,781	$ 1,521	$ 1,122	$ 778	$ 10,274	$ 9,226	$ 1,048	$ 722	$ 1,444	-7%
13															

Line #	Base Programs Description - Charge By	Current Month - (000's) Budget	Actual	Variance	Year-to-Date - (000's) Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Year-End - (000's) Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
14															
15															
16	NORTH CENTRAL REGION	$ 55	$ 0	$ 55	$ 282	$ 311	$ (29)	$ (84)	$ 31	$ 371	$ 274	$ 97	$ (18)	$ (37)	-160%
17	SOUTH CENTRAL REGION	30	2	28	245	347	(102)	(130)	35	294	311	(17)	(18)	(36)	-152%
18	NORTH COASTAL REGION	31	61	(30)	196	194	2	32	19	230	172	58	(11)	(22)	-156%
19	SOUTH COASTAL REGION	38	6	32	313	332	(19)	(51)	33	375	248	127	(42)	(84)	-227%
21	DIST OPS & SUPPORT	-	0	(0)	-	7	(7)	(6)	1	-	-	-	(3)	(7)	-600%
22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
25	**Total Base Programs**	$ 154	$ 70	$ 84	$ 1,035	$ 1,190	$ (155)	$ (239)	$ 119	$ 1,270	$ 1,005	$ 266	$ (93)	$ (185)	-178%
26															

Line #	Tree Trimming Description - Charge To	Current Month - (000's) Budget	Actual	Variance	Year-to-Date - (000's) Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Year-End - (000's) Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
27															
28															
29	CTE	$ 395	$ (13)	$ 408	$ 5,444	$ 3,976	$ 1,468	$ 1,059	$ 398	$ 6,234	$ 5,237	$ 997	$ 631	$ 1,261	59%
30	DISTRIBUTION	1,132	(159)	1,290	13,128	8,816	4,312	3,022	882	15,453	13,139	2,314	2,161	4,322	145%
31	TRANSMISSION	4	33	(29)	42	437	(395)	(365)	44	52	52	-	(192)	(385)	-540%
32	**Total Tree Trimming**	$ 1,531	$ (138)	$ 1,670	$ 18,614	$ 13,229	$ 5,385	$ 3,716	$ 1,323	$ 21,738	$ 18,427	$ 3,311	$ 2,599	$ 5,199	96%
33															

Line #	R&D - Business Case	Current Month - (000's)	Year-to-Date - (000's)	Year-End - (000's)
34				

PEF-SR-10118

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Progress Energy Florida
Energy Delivery Monthly Financial Summary - O&M
2004 - October

Row	Description - Charge To DOS	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
36	R&D Revenue	88	-	88	790	178	612	524	18	$ 940	-	940	(89)	(178)	-600%
37	R&D Expenses	96	95	1	987	670	317	315	67	1,224	1,010	214	170	340	153%
38	Income Tax	(3)	(38)	35	(79)	(197)	118	83	(20)	114	-	114	98	197	-600%
39	**Net R&D Business Case Impact**	$ (5)	$ (57)	$ 52	$ (118)	$ (295)	$ 177	$ 125	$ (30)	$ (398)	$ (1,010)	$ 613	$ (357)	$ (715)	1111%

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41 NOTE - R&D's Budget is not reflected in ED-FL. The budget was based on a business case prepared supporting this program.

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Row	R&D Region Work - excludes Bus Case	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
44	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
45	NORTH CENTRAL REGION	$ 25	$ 5	$ 20	$ 262	$ 106	$ 156	$ 135	$ 11	$ 323	$ 323	$ -	$ 108	$ 216	921%
46	SOUTH CENTRAL REGION	18	6	12	192	167	25	14	17	237	237	-	35	70	109%
47	NORTH COASTAL REGION	85	47	38	892	549	343	305	55	1,104	1,019	85	235	470	328%
48	SOUTH COASTAL REGION	53	20	33	556	394	162	129	39	685	770	(85)	188	376	377%
50	DIST OPS & SUPPORT	-	0	(0)	-	4	(4)	(4)	0	-	-	-	(2)	(4)	-600%
51	**Total R&D Region Work**	$ 181	$ 78	$ 103	$ 1,901	$ 1,220	$ 681	$ 578	$ 122	$ 2,349	$ 2,349	$ -	$ 564	$ 1,128	362%

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Row	Streetlight Maintenance - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
54	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
55	NORTH CENTRAL REGION	$ 66	$ 31	$ 35	$ 685	$ 574	$ 112	$ 76	$ 57	$ 842	$ 746	$ 96	$ 86	$ 172	50%
56	SOUTH CENTRAL REGION	94	13	82	1,051	626	424	343	63	1,270	858	411	116	232	85%
57	NORTH COASTAL REGION	36	19	17	380	246	134	117	25	470	470	-	112	224	356%
58	SOUTH COASTAL REGION	113	64	48	1,184	994	191	143	99	1,455	1,455	-	231	462	132%
60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
61	**Total Streetlight Maintenance**	$ 310	$ 128	$ 182	$ 3,301	$ 2,440	$ 861	$ 679	$ 244	$ 4,036	$ 3,530	$ 507	$ 545	$ 1,090	123%

Row	Line Ops - Troubleman - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)						Year-End - (000's)					
64	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Cost Per Outage	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
65	NORTH CENTRAL REGION	$ 26	$ 8	$ 18	$ 267	$ 195	$ 73	$ 55	$ 19	$ 22.81	$ 329	$ 127	$ 202	$ (34)	$ (67)	-273%
66	NORTH CENTRAL REGION	26	8	18	267	195	73	55	19	$ 27.33	329	127	202	(34)	(67)	-273%
67	NORTH COASTAL REGION	24	18	6	250	269	(19)	(24)	27	$ 42.96	309	258	51	(5)	(11)	-120%
68	SOUTH COASTAL REGION	35	22	13	368	447	(80)	(93)	45	$ 42.25	450	229	221	(109)	(219)	-345%
70	-	-	-	-	-	-	-	-	-		-	-	-	-	-	0%
71	**Total Line Ops - Troubleman**	$ 110	$ 56	$ 54	$ 1,152	$ 1,105	$ 47	$ (7)	$ 111	$ 34.02	$ 1,417	$ 741	$ 676	$ (182)	$ (364)	-265%

Row	Dispatch - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)						Year-End - (000's)					
75	Description - Charge To DOS	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Cost Per Outage	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
76	Bargaining Unit OT	$ 80	$ 85	$ (5)	$ 769	$ 1,731	$ (962)	$ (956)	$ 173	$ 53.28	$ 999	$ 999	$ -	$ (366)	$ (732)	-311%
78	**Total Dispatch Direct Costs**	269	196	73	2,747	3,019	(271)	(345)	302	$ 92.91	3,451	3,496	(45)	239	478	-21%

Row	Meter Reading - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)						Year-End - (000's)					
82	Description - Charge To DOS	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Cost Per Customer	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
83	Bargaining Unit OT	$ 40	$ 69	$ (29)	$ 361	$ 701	$ (340)	$ (311)	$ 70	$ 0.46	$ 453	$ 453	$ -	$ (124)	$ (248)	-277%
85	**Total Meter Reading Direct Costs**	583	519	64	5,624	6,040	(416)	(480)	604	$ 3.94	6,923	7,022	(98)	491	982	-19%

Row	Safety & Training - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)						Year-End - (000's)					
88	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Cost Per Employee	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
89	NORTH CENTRAL REGION	$ 126	$ 31	$ 95	$ 1,302	$ 849	$ 452	$ 357	$ 85	$ 3,023	$ 1,602	$ 1,489	$ 113	$ 320	$ 640	277%
90	SOUTH CENTRAL REGION	124	32	92	1,246	764	482	390	76	2,456	1,527	1,241	286	238	477	212%
91	NORTH COASTAL REGION	79	22	57	825	597	228	171	60	3,032	1,022	1,022	-	212	424	255%
92	SOUTH COASTAL REGION	101	40	61	1,067	1,090	(23)	(85)	109	3,417	1,304	1,181	123	46	91	-58%
94	DIST OPS & SUPPORT	147	102	45	1,530	1,274	256	211	127	2,512	1,885	1,661	224	193	387	52%
95	TRANSMISSION	156	126	30	1,624	1,864	(240)	(270)	186	4,830	2,014	2,014	-	75	150	-60%
96	ENERGY DELIVERY SERVICES	4	1	3	30	15	15	12	2		39	39	-	12	24	676%
97	-	-	-	-	-	-	-	-	-		-	-	-	-	-	0%
98	**Total Safety & Training**	$ 737	$ 353	$ 384	$ 7,624	$ 6,454	$ 1,170	$ 786	$ 645	$ 3,225	$ 9,393	$ 8,647	$ 746	$ 1,096	$ 2,193	70%

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Progress Energy

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Energy Delivery Monthly Financial Summary - O&M
2004 - October

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100 NON REGULATED O&M INFORMATION:

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Row	EDS Strategic Areas	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
102	Description	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
104	Payroll & Related Burdens	$ 657	$ 612	$ 45	$ 6,846	$ 5,657	$ 1,189	$ 1,143	$ 566	$ 8,483	$ 8,483	$ -	$ 1,413	$ 2,825	150%
105	Advertising	60	49	11	3,265	2,008	1,256	1,245	201	4,186	4,186	-	1,089	2,178	442%
106	Customer Incentives	3,715	3,236	479	41,196	36,534	4,662	4,183	3,653	49,703	49,703	-	6,585	13,169	80%
107	Other Costs	898	433	466	6,449	3,920	2,529	2,064	392	6,638	6,638	-	1,359	2,718	247%
108	**Total Costs**	5,331	4,329	1,002	57,756	48,120	9,636	8,635	4,812	69,011	69,011	-	10,445	20,891	117%
109															
110	**Customer & Program Incentives Detail Breakout:**														
111	Interruptible	1,572	1,388	184	16,113	15,661	452	268	1,566	19,454	19,454	-	1,896	3,793	21%
112	Residential Energy Mgmt	1,640	1,437	204	19,217	16,251	2,966	2,762	1,625	23,201	23,201	-	3,475	6,950	114%
113	Other Program Incentives	303	189	115	3,633	2,625	1,008	893	262	4,358	4,358	-	867	1,734	230%
114	Other Customer Incentives	199	223	(23)	2,234	1,998	236	260	200	2,691	2,691	-	347	693	73%
115	**Total Incentives**	$ 3,715	$ 3,236	$ 479	$ 41,196	$ 36,534	$ 4,662	$ 4,183	$ 3,653	$ 49,703	$ 49,703	$ -	$ 6,585	$ 13,169	80%

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Energy Delivery Monthly Financial Summary - Capital

2004 - October

Regulated Capital

Current Month - (000's)

Line #	Description - Charge To	Budget	Actual	Variance	
1	NORTH CENTRAL REGION	$ 2,162	$ 2,259	$ (96)	
2	SOUTH CENTRAL REGION	2,327	1,712	615	
3	NORTH COASTAL REGION	1,120	1,569	(449)	
4	SOUTH COASTAL REGION	1,989	1,965	24	
5	COASTAL REGION COMBINED	3,108	3,534	(426)	
6	DIST OPS & SUPPORT	5,033	3,883	1,150	
7	Distribution Total	$ 12,630	$ 11,388	$ 1,242	#N/A
8	Note: Current Month does not have Price Impact included				
9					
10					
11					
12	TRANSMISSION	$ 6,187	$ 3,464	$ 2,724	
13	CTE PROJECT MANAGEMENT	421	273	148	
14	ENERGY DELIVERY ADMIN	753	134	618	
15	ENERGY DELIVERY SERVICES	15	-	15	
16	ED MANAGER BUSINESS OPERATIONS	-	-	-	
17	FPC - ED	-	-	-	
18	Total Regulated Capital	$ 20,006	$ 15,259	$ 4,747	
19	NOTE: Due to the impact of Price and the way it is calculated; it is not reflected in the current month. Therefore, you can not take Prior Month Variance and add Current Month Variance to tie to current YTD variance.				

Year-to-Date - (000's)

Line #	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var
1	$ 24,137	$ 21,523	$ 2,614	$ 2,152	$ 2,711
2	30,711	29,147	1,563	2,915	949
3	13,853	14,446	(592)	1,445	(143)
4	27,499	26,931	568	2,693	544
5	41,352	41,376	(24)	4,138	402
6	50,372	43,432	6,940	4,343	5,790
7	$ 146,572	$ 135,479	$ 11,093	$ 13,548	$ 9,851
8			-		-
9			-		-
10			$ -		$ -
12	$ 52,988	$ 46,010	$ 6,976	$ 4,601	$ 4,252
13	14,490	11,112	3,378	1,111	3,230
14	11,270	9,593	1,677	959	1,056
15	154	62	92	6	77
16	-	-	-	-	-
17	-	-	-	-	-
18	$ 225,472	$ 202,256	$ 23,216	$ 20,226	$ 18,469

Year-End - (000's)

Line #	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
1	$ 29,187	$ 28,790	$ 397	$ 3,633	$ 7,267	69%
2	36,582	36,133	448	3,493	6,988	20%
3	16,554	15,930	624	742	1,484	-49%
4	32,834	33,372	(538)	3,221	6,441	20%
5	49,388	49,302	86	3,963	7,925	-4%
6	59,190	59,752	(562)	8,160	16,320	88%
7	$ 174,347	$ 173,977	$ 371	$ 19,249	$ 38,498	42%
8			-			
9			-			
10			$ -			
12	$ 62,006	$ 60,507	$ 1,500	$ 7,248	$ 14,496	56%
13	15,182	13,887	1,295	1,388	2,776	25%
14	12,403	10,971	1,432	689	1,377	-28%
15	185	185	-	62	123	901%
16	-	-	-	-	-	0%
17	-	-	-	-	-	0%
18	$ 264,123	$ 259,528	$ 4,597	$ 28,835	$ 57,270	42%

Revenue Construction

Current Month

Line #	Description - Charge By	Budget Units	Actual Units	Unit Variance	Volume Variance $ (000's)	Prior Year Units
1	Volume Adjustment					
2	NORTH CENTRAL REGION	530	702	(172)	$ (94)	828
3	SOUTH CENTRAL REGION	1,192	1,216	(24)	(4)	1,307
4	NORTH COASTAL REGION	421	494	(73)	(57)	569
5	SOUTH COASTAL REGION	675	703	(28)	23	325
6	COASTAL REGION AVERAGE	1,096	1,197	(101)	(34)	894
7	Total Distribution Vol Adj	2,818	3,115	(297)	$ (131)	3,029
8						
9	DOS	2,818	3,115	(297)	(161)	3,029
10	Total Dist & DOS Volume Adjustment				$ (291)	
11						

Year-to-Date

Line #	Budget Units	Actual Units	Variance Units	Volume Variance $ (000's)	Prior Month YTD Volume Variance $ (000's)
2	5,671	6,246	(575)	$ (444)	(350)
3	12,798	15,114	(2,316)	(1,871)	(1,867)
4	4,167	4,921	(754)	(837)	(761)
5	6,406	8,340	(1,934)	(1,543)	(1,586)
6	10,572	13,261	(2,689)	(2,380)	(2,347)
7	29,041	34,621	(5,580)	$ (4,694)	$ (4,564)
9	29,041	34,621	(5,580)	(3,013)	(2,853)
10				$ (7,708)	$ (7,418)

Year-End

Line #	Budget Units	Projection Units	Var Units	Volume Variance $ (000's)	2003 Actual Units
2	6,776	7,823	$ (1,045)	$ (817)	10,252
3	14,956	18,296	(3,340)	(2,675)	17,275
4	5,021	6,121	(1,100)	(1,198)	6,687
5	7,746	9,824	(2,078)	(1,604)	4,258
6	12,767	15,945	(3,178)	(2,602)	10,945
7	34,501	42,064	(7,563)	$ (6,293)	38,472
9	34,501	42,064	(7,563)	(4,084)	38,472
10				$ (10,378)	

Current Month

Line #	Description - Charge By	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance Impact (000's)
12					
13	Price Adjustment				
14	NORTH CENTRAL REGION	$ 925	$ 952	$ (28)	$ (85)
15	SOUTH CENTRAL REGION	740	607	134	148
16	NORTH COASTAL REGION	978	1,610	(631)	(326)
17	SOUTH COASTAL REGION	966	830	336	186
18	COASTAL REGION AVERAGE	971	1,034	(64)	(140)
19	DOS	-	-	-	-
20	Total Price Adjustment	$ 865	$ 849	$ 16	$ (77)
21					

Year-to-Date

Line #	Budget Price	Actual Price	Unit Price Variance $	Price Variance Impact (000's)	Prior Month YTD Price Variance $ (000's)
14	$ 924	$ 753	$ 172	$ 985	1,070
15	735	581	154	2,498	2,350
16	980	913	68	431	292
17	964	627	337	2,488	3,236
18	970	733	237	2,920	3,528
19	-	-	-	-	-
20	$ 858	$ 670	$ 188	$ 6,402	$ 6,947

Year-End

Line #	Budget Price	Projection Price	Price Variance $	Price Variance Impact (000's)
14	$ 925	$ 801	$ 124	$ 966
15	737	606	131	2,399
16	980	804	176	1,078
17	964	760	204	2,004
18	971	777	193	3,082
19	-	-	-	-
20	$ 860	$ 707	$ 153	$ 8,447

Line #		Budget	Actual	Variance	YTD Budget	YTD Actual	YTD Variance	Prior Month YTD Var	Year-End Budget	Year-End Projection	Year-End Variance
22	LRC Projects Not Budgeted										
23		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24											

Meters & Transformer Purchases

Current Month - (000's)

Line #	Description - Charge To DOS	Budget	Actual	Variance
25				
26				
27	METERS	$ 226	$ 461	$ (235)
28	TRANSFORMERS-OH	418	(959)	1,377
29	TRANSFORMERS-UG	1,038	948	90
30	Total Meters & Transformers	$ 1,682	$ 450	$ 1,232
31				
32				

Year-to-Date (000's)

Line #	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var
27	$ 3,535	$ 3,395	$ 141	$ 339	$ 376
28	3,950	4,557	(607)	456	(1,984)
29	9,819	7,420	2,399	742	2,310
30	$ 17,305	$ 15,372	$ 1,933	$ 1,537	$ 701

Year-End - (000's)

Line #	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
27	$ 3,930	$ 3,930	$ -	$ 268	$ 535	-21%
28	4,642	5,326	(684)	384	766	-16%
29	11,540	10,058	1,482	1,319	2,639	78%
30	$ 20,112	$ 19,314	$ 798	$ 1,971	$ 3,942	28%

Streetlight Construction

Current Month

Line #	Description - Charge To	Budget Units	Actual Units	Unit Variance	Volume Variance $ ($000's)
33					
34					
35	Volume Adjustment				
36	NORTH CENTRAL REGION	329	217	112	$ 86
37	SOUTH CENTRAL REGION	637	167	470	447
38	NORTH COASTAL REGION	193	101	92	52
39	SOUTH COASTAL REGION	454	224	230	184
40	COASTAL REGION COMBINED	647	325	322	237
41	Total Dist Regions Vol Adj	1,613	709	904	$ 769
42					

Year-to-Date

Line #	Budget Units	Actual Units	Unit Variance	Volume Variance $ ($000's)	Prior Month YTD Volume Variance $: ($000's)
36	3,377	2,405	972	$ 752	$ 666
37	6,524	5,137	1,387	1,318	871
38	1,889	1,183	706	401	349
39	4,184	4,613	(429)	(343)	(527)
40	6,073	5,796	277	58	(179)
41	15,974	13,338	2,636	$ 2,128	$ 1,358

Year-End

Line #	Budget Units	Projection Units	Variance	Volume Variance $ ($000's)	2003 Actual Units:
36	4,125	2,806	$ 1,319	$ 1,020	4,241
37	7,709	5,908	1,801	1,711	6,106
38	2,298	1,442	856	486	3,646
39	5,102	5,462	(360)	(288)	2,294
40	7,400	6,904	496	198	5,942
41	19,235	15,618	3,617	$ 2,930	16,289

Current Month

Line #	Description - Charge To	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance $ Impact ($000's)
43					
44	Price Adjustment				
45	NORTH CENTRAL REGION	$ 773	$ 1,408	$ (634)	$ (138)
46	SOUTH CENTRAL REGION	950	1,328	(378)	(63)
47	NORTH COASTAL REGION	568	758	(190)	(19)
48	SOUTH COASTAL REGION	800	621	179	40
49	COASTAL REGION COMBINED	731	664	67	21
50	Total Price Adjustment	$ 826	$ 1,048	$ (222)	$ (180)
51					

Year-to-Date

Line #	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance $ Impact ($000's)	Prior Month YTD Price Variance $: ($000's)
45	$ 773	$ 746	$ 28	$ 87	$ 204
46	950	865	85	437	500
47	568	612	(44)	(53)	(33)
48	800	775	25	114	74
49	728	742	(14)	61	40
50	$ 828	$ 790	$ 38	$ 565	$ 745

Year-End

Line #	Budget Price	Projection Price	Unit Price Variance $: Fav/(Unfav)	Price Variance Impact: ($000's)
45	$ 773	$ 1,137	$ (364)	$ (1,020)
46	950	1,240	(290)	(1,711)
47	568	905	(337)	(486)
48	800	747	53	288
49	728	780	(52)	(198)
50	$ 827	$ 1,018	$ (191)	$ (2,930)

Line #				
52	Streetlight Construction $	Current Month - (000's)	Year-to-Date (000's)	Year-End - (000's)

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Progress Energy

Progress Energy Florida

Energy Delivery Monthly Financial Summary - Capital

2004 - October

	Description - Charge To	Budget	Actual	Variance
53				
54	NORTH CENTRAL REGION	$ 254	$ 305	$ (51)
55	SOUTH CENTRAL REGION	605	222	383
56	NORTH COASTAL REGION	110	77	33
57	SOUTH COASTAL REGION	363	139	224
58	COASTAL REGION COMBINED	$ 473	$ 216	$ 257
59	-	-	-	-
60	Total Streetlight Construction	$ 1,333	$ 527	$ 332
61				
62	Revenue Adjustment Included -	Volume & LRC		

	Description - Charge To	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var
54	NORTH CENTRAL REGION	$ 2,612	$ 1,793	$ 819	$ 179	$ 870
55	SOUTH CENTRAL REGION	6,198	4,443	1,754	444	1,371
56	NORTH COASTAL REGION	1,073	724	348	72	315
57	SOUTH COASTAL REGION	3,347	3,577	(229)	358	(454)
58	COASTAL REGION COMBINED	$ 4,420	$ 4,301	$ 119	$ 430	$ (138)
59		-	-	-	-	-
60	Total Streetlight Construction	$ 13,230	$ 10,538	$ 2,692	$ 1,054	$ 2,103

	Description - Charge To	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
54	NORTH CENTRAL REGION	$ 3,190	$ 3,190	$ -	$ 898	$ 1,397	289%
55	SOUTH CENTRAL REGION	7,324	7,324	-	1,440	2,880	224%
56	NORTH COASTAL REGION	1,306	1,306	-	291	581	301%
57	SOUTH COASTAL REGION	4,082	4,082	-	252	505	-29%
58	COASTAL REGION COMBINED	$ 5,387	$ 5,387	$ -	$ 543	$ 1,086	28%
59		-	-	-	-	-	0%
60	Total Streetlight Construction	$ 15,901	$ 15,901	$ -	$ 2,682	$ 5,363	154%

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Progress Energy

Progress Energy Florida
Energy Delivery Monthly Financial Summary - Capital
2004 - October

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Row	Merchant Plant Construction - Vandolah: Description - Charge To	Current Month - (000's) Budget	Current Month Actual	Current Month Variance	Year-to-Date (000's) Budget	YTD Actual	YTD Variance	YTD Burn Rate	Prior Month YTD Var	Year-End - (000's) Budget	YE Projection	YE Variance	YE Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
66	TRANSMISSION	$ 453	$ 656	$ (202)	$ 13,033	$ 10,716	$ 2,317	$ 1,072	$ 2,520	$ 13,283	$ 11,305	$ 1,978	$ 295	$ 589	-73%

67

Row	CTE Programs: Description - Charge By	Current Month - (000's) Budget	Current Month Actual	Current Month Variance	Year-to-Date (000's) Budget	YTD Actual	YTD Variance	YTD Burn Rate	Prior Month YTD Var	Year-End - (000's) Budget	YE Projection	YE Variance	YE Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
70	NORTH CENTRAL REGION	149	72	76	5,170	3,244	$ 1,926	$ 324	1,850	$ 5,318	$ 3,906	$ 1,413	$ 331	$ 662	2%
71	SOUTH CENTRAL REGION	4	53	(49)	2,594	2,293	301	229	350	2,603	2,787	(184)	247	494	8%
72	NORTH COASTAL REGION	21	(3)	24	1,918	1,736	183	174	159	1,961	2,222	(261)	243	486	40%
73	SOUTH COASTAL REGION	55	73	(19)	1,691	1,100	590	110	609	1,800	1,463	337	181	362	65%
73	DIST OPS & SUPPORT	-	1	(1)	-	30	(30)	3	(28)	-	-	-	(15)	(30)	-600%
74	TRANSMISSION	192	41	151	3,117	2,063	1,054	208	903	3,500	3,500	-	719	1,437	248%
75	ENERGY DELIVERY SERVICES	-	-	-	-	1	(1)	0	(1)	-	-	-	(1)	(1)	-600%
76	Other Charge By Org	-	34	(34)	-	645	(645)	65	(611)	-	10	(10)	(317)	(635)	-592%
77	Total CTE Programs	$ 421	$ 273	$ 148	$ 14,490	$ 11,112	$ 3,378	$ 1,111	$ 3,230	$ 15,182	$ 13,887	$ 1,295	$ 1,388	$ 2,776	25%

78

Row	Base Programs: Description - Charge By	Current Month - (000's) Budget	Current Month Actual	Current Month Variance	Year-to-Date (000's) Budget	YTD Actual	YTD Variance	YTD Burn Rate	Prior Month YTD Var	Year-End - (000's) Budget	YE Projection	YE Variance	YE Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
81	NORTH CENTRAL REGION	390	80	309	2,008	1,075	$ 933	$ 108	$ 624	$ 2,651	$ 1,662	$ 989	$ 293	$ 587	173%
82	SOUTH CENTRAL REGION	177	74	103	1,484	1,155	329	115	226	1,781	1,440	341	143	265	23%
83	NORTH COASTAL REGION	173	10	163	1,083	597	485	60	323	1,274	1,012	261	207	415	247%
84	SOUTH COASTAL REGION	342	492	(150)	2,968	2,691	277	269	427	3,567	3,308	259	309	617	15%
86	DIST OPS & SUPPORT	78	22	55	806	442	364	44	308	999	931	69	244	488	452%
87	TRANSMISSION	-	-	-	-	5	(5)	1	(5)	-	-	-	(3)	(5)	-600%
88	Other Charge By Org	-	(3)	3	-	(41)	41	(4)	38	-	-	-	21	41	-600%
89	Total Base Programs	$ 1,160	$ 676	$ 483	$ 8,349	$ 5,925	$ 2,424	$ 592	$ 1,941	$ 10,273	$ 8,353	$ 1,920	$ 1,214	$ 2,428	105%

90

Row	Load Growth Projects: Description - Charge By	Current Month - (000's) Budget	Current Month Actual	Current Month Variance	Year-to-Date (000's) Budget	YTD Actual	YTD Variance	YTD Burn Rate	Prior Month YTD Var	Year-End - (000's) Budget	YE Projection	YE Variance	YE Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
93	NORTH CENTRAL REGION	$ 16	$ 102	$ (86)	$ 422	$ 468	$ (46)	$ 47	$ 41	$ 436	$ 467	$ (31)	$ (0)	$ (1)	-101%
94	SOUTH CENTRAL REGION	-	(29)	29	1,009	680	330	68	301	1,009	545	465	(68)	(135)	-199%
95	NORTH COASTAL REGION	22	122	(100)	354	206	146	21	248	367	258	110	26	51	24%
96	SOUTH COASTAL REGION	214	92	122	3,066	912	2,174	91	2,052	3,400	2,459	941	774	1,547	748%
98	DIST OPS & SUPPORT	-	0	(0)	-	2	(2)	0	(2)	-	-	-	(1)	(2)	-600%
99	TRANSMISSION	973	694	280	6,441	5,188	1,253	519	973	7,569	7,569	-	1,191	2,381	129%
100	Other Charge By Org	-	47	(47)	-	503	(503)	50	(456)	-	53	(53)	(225)	(450)	-547%
101	Total Load Growth Projects	$ 1,226	$ 1,028	$ 197	$ 11,313	$ 7,959	$ 3,354	$ 796	$ 3,157	$ 12,782	$ 11,351	$ 1,431	$ 1,696	$ 3,392	113%

102

Row	DOT Projects: Description - Charge By	Current Month - (000's) Budget	Current Month Actual	Current Month Variance	Year-to-Date (000's) Budget	YTD Actual	YTD Variance	YTD Burn Rate	Prior Month YTD Var	Year-End - (000's) Budget	YE Projection	YE Variance	YE Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
105	NORTH CENTRAL REGION	$ 117	$ (13)	$ 130	$ 1,167	$ 953	$ 213	$ 95	$ 84	$ 1,400	$ 1,800	$ (400)	$ 423	$ 847	344%
106	SOUTH CENTRAL REGION	183	253	(70)	3,225	3,623	(398)	362	(328)	3,500	4,400	(900)	389	777	7%
107	NORTH COASTAL REGION	49	847	(598)	987	1,914	(927)	191	(329)	1,051	2,127	(1,076)	107	213	-44%
108	SOUTH COASTAL REGION	88	294	(206)	875	2,729	(1,854)	273	(1,648)	1,050	3,000	(1,950)	135	271	-50%
110	DIST OPS & SUPPORT	-	49	(49)	-	506	(506)	51	(457)	-	147	(147)	(180)	(359)	-455%
111	TRANSMISSION	-	-	-	-	34	(34)	3	(34)	-	-	-	(17)	(34)	-600%
112	Other Charge By Org	-	-	-	-	407	(407)	41	(407)	-	-	-	(204)	(407)	-600%
113	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
114	Total DOT Projects	$ 436	$ 1,230	$ (794)	$ 6,254	$ 10,167	$ (3,913)	$ 1,017	$ (3,119)	$ 7,001	$ 11,474	$ (4,473)	$ 654	$ 1,307	-36%

115

Row	Replace / Refurbish: Description - Charge To	Current Month - (000's) Budget	Current Month Actual	Current Month Variance	Year-to-Date (000's) Budget	YTD Actual	YTD Variance	YTD Burn Rate	Prior Month YTD Var	Year-End - (000's) Budget	YE Projection	YE Variance	YE Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
118	NORTH CENTRAL REGION	$ 494	$ 501	$ (7)	$ 6,114	$ 5,891	$ 223	$ 569	$ 229	$ 7,335	$ 6,849	$ 486	$ 479	$ 958	-19%
119	SOUTH CENTRAL REGION	403	171	232	4,605	4,547	59	455	(173)	5,438	4,882	556	167	335	-63%
120	NORTH COASTAL REGION	122	248	(125)	2,763	2,710	52	271	178	3,066	2,751	315	20	41	-93%
121	SOUTH COASTAL REGION	363	542	(179)	6,211	6,696	(485)	670	(307)	7,508	7,869	(361)	586	1,173	-12%
123	DIST OPS & SUPPORT	38	138	(101)	279	459	(180)	46	(80)	343	343	-	(58)	(117)	-227%
124	CTE PROJECT MANAGEMENT	-	1	(1)	-	10	(10)	1	(8)	-	-	-	(5)	(10)	-600%
125	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
126	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
127	Total Storm Restoration	$ 1,420	$ 1,601	$ (181)	$ 19,972	$ 20,314	$ (342)	$ 2,031	$ (161)	$ 23,889	$ 22,693	$ 996	$ 1,190	$ 2,379	-41%

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PEF-SR-10124

Progress Energy

Progress Energy Florida
Energy Delivery Monthly Financial Summary - Capital
2004 - October

128	Grow	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
129	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
130	NORTH CENTRAL REGION	$ 1,148	$ 1,247	$ (100)	$ 12,098	$ 11,786	$ 310	$ 1,179	410	$ 14,656	$ 14,926	$ (271)	$ 1,569	$ 3,139	33%
131	SOUTH CENTRAL REGION	1,618	1,419	199	22,839	20,693	1,945	2,069	1,746	26,998	27,480	(482)	3,393	6,787	64%
132	NORTH COASTAL REGION	851	1,160	(309)	9,085	9,704	(619)	970	(310)	11,147	10,744	404	520	1,039	-46%
133	SOUTH COASTAL REGION	1,293	1,055	237	16,152	16,423	(271)	1,642	(508)	19,109	20,494	(1,385)	2,035	4,071	24%
135	DIST OPS & SUPPORT	3,247	1,678	1,570	33,145	24,893	8,252	2,489	8,682	38,833	38,573	2,260	5,840	11,680	135%
136	TRANSMISSION	4,251	1,767	2,484	21,202	15,507	5,695	1,551	3,211	27,132	28,672	460	5,583	11,165	260%
137	CTE PROJECT MANAGEMENT	-	-	-	-	2	(2)	0	(2)	-	-	-	(1)	(2)	-600%
138	ENERGY DELIVERY ADMIN	-	-	-	-	(66)	66	(7)	66	-	-	-	33	66	-600%
139	ENERGY DELIVERY SERVICES	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
140	ED MANAGER BUSINESS OPERATIONS	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
141	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
142	**Total Grow Capital Category**	$ 12,408	$ 8,326	$ 4,082	$ 114,320	$ 98,944	$ 15,377	$ 9,894	$ 11,295	$ 137,876	$ 136,889	$ 987	$ 18,973	$ 37,945	92%
143															

144	Maintain	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
145	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
146	NORTH CENTRAL REGION	$ 1,014	$ 1,011	$ 3	$ 12,039	$ 9,735	$ 2,304	$ 974	$ 2,301	$ 14,531	$ 13,863	$ 668	$ 2,064	$ 4,128	112%
147	SOUTH CENTRAL REGION	708	293	415	8,072	8,454	(382)	845	(797)	9,583	8,653	930	100	199	-88%
148	NORTH COASTAL REGION	269	409	(140)	4,768	4,741	27	474	167	5,407	5,186	220	222	445	-53%
149	SOUTH COASTAL REGION	696	910	(213)	11,347	10,506	839	1,051	1,053	13,725	12,876	847	1,185	2,370	13%
149	DIST OPS & SUPPORT	1,786	2,206	(420)	17,226	18,539	(1,313)	1,854	(892)	20,357	23,179	(2,822)	2,320	4,640	25%
150	TRANSMISSION	1,936	1,697	239	31,784	30,503	1,281	3,050	1,041	34,874	33,834	1,040	1,665	3,331	-45%
151	CTE PROJECT MANAGEMENT	421	273	148	14,490	11,110	3,380	1,111	3,232	15,182	13,887	1,295	1,389	2,777	25%
152	ENERGY DELIVERY ADMIN	753	134	616	11,270	9,659	1,611	966	992	12,403	10,971	1,432	656	1,311	-32%
153	ENERGY DELIVERY SERVICES	15	-	15	154	62	92	6	77	185	185	-	62	123	901%
154	FPC - ED	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
155	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
156	**Total Maintain Capital Category**	$ 7,598	$ 6,933	$ 665	$ 111,152	$ 103,312	$ 7,840	$ 10,331	$ 7,174	$ 126,248	$ 122,637	$ 3,610	$ 9,663	$ 19,325	-8%
157															
158	**Total Capital**	$ 20,006	$ 15,259	$ 4,747	$ 225,472	$ 202,256	$ 23,216	$ 20,226	$ 18,469	$ 264,123	$ 259,526	$ 4,597	$ 28,635	$ 57,270	42%

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PEF-SR-10125

Progress Energy

Progress Energy Florida

Energy Delivery Monthly Financial Summary - Revenue Construction

2004 - October

Revenue Construction - Volume

Current Month

Line #	Description - Charge To	Budget Units	Actual Units	Unit Variance	Volume Variance $	Prior Year Units:
1	Residential				($000's)	
2	NORTH CENTRAL REGION	442	635	(193)	$ (137)	560
3	SOUTH CENTRAL REGION	1,066	1,101	(35)	(22)	1,158
4	NORTH COASTAL REGION	365	440	(75)	(61)	353
5	SOUTH COASTAL REGION	513	600	(87)	(68)	455
6	Total Dist Regions Res Vol Adj	2,386	2,776	(390)	$ (288)	2,526
7						
8	DOS - Meters & Transformers Vol Adj	2,386	2,776	(390)	(211)	2,526
9	Total Residential Volume Adj				$ (499)	
10						
11	Commercial & Industrial					
12	NORTH CENTRAL REGION	88	67	21	$ 43	100
13	SOUTH CENTRAL REGION	126	115	11	19	148
14	NORTH COASTAL REGION	56	54	2	4	80
15	SOUTH COASTAL REGION	162	103	59	91	157
16	Total Dist Regions C&I Vol Adj	432	339	93	$ 157	485
17						
18	DOS - Meters & Transformers	432	339	93	50	485
19	Total C&I Volume Adj				$ 207	
20						
21	Combined Residential and C&I					
22	NORTH CENTRAL REGION	530	702	(172)	$ (94)	828
23	SOUTH CENTRAL REGION	1,192	1,216	(24)	(4)	1,307
24	NORTH COASTAL REGION	421	494	(73)	(57)	569
25	SOUTH COASTAL REGION	675	703	(28)	23	325
26	Total Dist Regions Vol Adj	2,818	3,115	(297)	$ (131)	3,029
27						
28	DOS - Meters & Transformers Vol Adj	2,818	3,115	(297)	(161)	3,029
29	Total Volume Adjustment				$ (291)	
30						

Year-to-Date

Line #	Description - Charge To	Budget Units	Actual Units	Unit Variance	Volume Variance $	Prior Month YTD Volume Variance $:
1	Residential				($000's)	($000's)
2	NORTH CENTRAL REGION	4,728	5,275	(547)	$ (387)	$ (250)
3	SOUTH CENTRAL REGION	11,502	13,425	(1,923)	(1,208)	(1,185)
4	NORTH COASTAL REGION	3,607	4,181	(574)	(467)	(406)
5	SOUTH COASTAL REGION	4,885	6,780	(1,895)	(1,482)	(1,414)
6	Total Dist Regions Res Vol Adj	24,721	29,661	(4,940)	$ (3,544)	$ (3,256)
7						
8	DOS - Meters & Transformers Vol Adj	24,721	29,661	(4,940)	(2,668)	(2,457)
9	Total Residential Volume Adj				$ (6,211)	$ (5,713)
10						
11	Commercial & Industrial					
12	NORTH CENTRAL REGION	943	971	(28)	$ (57)	$ (100)
13	SOUTH CENTRAL REGION	1,297	1,689	(392)	(663)	(682)
14	NORTH COASTAL REGION	560	740	(180)	(371)	(375)
15	SOUTH COASTAL REGION	1,521	1,560	(39)	(61)	(152)
16	Total Dist Regions C&I Vol Adj	4,320	4,960	(640)	$ (1,151)	$ (1,308)
17						
18	DOS - Meters & Transformers	4,320	4,960	(640)	(346)	(396)
19	Total C&I Volume Adj				$ (1,496)	$ (1,703)
20						
21	Combined Residential and C&I					
22	NORTH CENTRAL REGION	5,671	6,246	(575)	$ (444)	$ (350)
23	SOUTH CENTRAL REGION	12,798	15,114	(2,316)	(1,871)	(1,867)
24	NORTH COASTAL REGION	4,167	4,921	(754)	(837)	(781)
25	SOUTH COASTAL REGION	6,406	8,340	(1,934)	(1,543)	(1,566)
26	Total Dist Regions Vol Adj	29,041	34,621	(5,580)	$ (4,694)	$ (4,564)
27						
28	DOS - Meters & Transformers Vol Adj	29,041	34,621	(5,580)	(3,013)	(2,853)
29	Total Volume Adjustment				$ (7,708)	$ (7,416)
30						

Year-End

Line #	Description - Charge To	Budget Units	Projection Units	Variance	Volume Variance $	2003 Actual Units:
1	Residential				($000's)	
2	NORTH CENTRAL REGION	5,650	6,635	$ (985)	$ (696)	6,862
3	SOUTH CENTRAL REGION	13,423	16,220	(2,797)	(1,756)	15,329
4	NORTH COASTAL REGION	4,347	5,203	(856)	(696)	4,215
5	SOUTH COASTAL REGION	5,905	8,011	(2,106)	(1,647)	5,768
6	Total Dist Regions Res Vol Adj	29,325	36,069	(6,744)	$ (4,795)	32,174
7						
8	DOS - Meters & Transformers Vol Adj	29,325	36,069	(6,744)	(3,642)	32,174
9	Total Residential Volume Adj				$ (8,437)	
10						
11	Commercial & Industrial					
12	NORTH CENTRAL REGION	1,128	1,188	$ (60)	$ (121)	1,408
13	SOUTH CENTRAL REGION	1,532	2,076	(544)	(918)	1,896
14	NORTH COASTAL REGION	674	918	(244)	(502)	851
15	SOUTH COASTAL REGION	1,841	1,813	28	43	1,930
16	Total Dist Regions C&I Vol Adj	5,175	5,995	(820)	$ (1,498)	6,085
17						
18	DOS - Meters & Transformers	5,175	5,995	(820)	(443)	6,085
19	Total C&I Volume Adj				$ (1,941)	
20						
21	Combined Residential and C&I					
22	NORTH CENTRAL REGION	6,778	7,823	$ (1,045)	$ (817)	10,252
23	SOUTH CENTRAL REGION	14,956	18,296	(3,340)	(2,675)	17,275
24	NORTH COASTAL REGION	5,021	6,121	(1,100)	(1,198)	6,687
25	SOUTH COASTAL REGION	7,746	9,824	(2,078)	(1,604)	4,258
26	Total Dist Regions Vol Adj	34,501	42,064	(7,563)	$ (6,293)	38,472
27						
28	DOS - Meters & Transformers Vol Adj	34,501	42,064	(7,563)	(4,084)	38,472
29	Total Volume Adjustment				$ (10,378)	
30						

31 Revenue Construction - Price

Current Month

Line #	Description - Charge To	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance $ Impact
32					
33	Residential				($000's)
34	NORTH CENTRAL REGION	$ 707	$ 1,033	$ (326)	$ (207)
35	SOUTH CENTRAL REGION	628	653	(25)	(28)
36	NORTH COASTAL REGION	813	1,409	(596)	(262)
37	SOUTH COASTAL REGION	782	524	258	155
39	DOS	-	-	-	-
40	Total Price Adjustment	$ 704	$ 832	$ (128)	$ (343)
41					
42	Commercial & Industrial				
43	NORTH CENTRAL REGION	$ 2,015	$ 187	$ 1,828	$ 122
44	SOUTH CENTRAL REGION	1,689	161	1,528	176
45	NORTH COASTAL REGION	2,058	3,240	(1,182)	(64)
46	SOUTH COASTAL REGION	1,549	1,245	304	31
48	DOS	-	-	-	-
49	Total Price Adjustment	$ 1,751	$ 986	$ 765	$ 266
50					
51	Combined				
52	NORTH CENTRAL REGION	$ 925	$ 952	$ (28)	$ (85)
53	SOUTH CENTRAL REGION	740	607	134	148
54	NORTH COASTAL REGION	978	1,610	(631)	(326)
55	SOUTH COASTAL REGION	966	630	336	186
57	DOS	-	-	-	-
58	Total Price Adjustment	$ 865	$ 849	$ 16	$ (77)
59					

Year-to-Date

Line #	Description - Charge To	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance $ Impact	Prior Month YTD Price Variance $:
32						
33	Residential				($000's)	($000's)
34	NORTH CENTRAL REGION	$ 707	$ 721	$ (14)	$ (75)	$ 132
35	SOUTH CENTRAL REGION	628	503	125	1,678	1,706
36	NORTH COASTAL REGION	813	778	35	147	294
37	SOUTH COASTAL REGION	782	535	247	1,678	1,715
39	DOS	-	-	-	-	-
40	Total Price Adjustment	$ 701	$ 588	$ 113	$ 3,428	$ 3,846
41						
42	Commercial & Industrial					
43	NORTH CENTRAL REGION	$ 2,015	$ 923	$ 1,092	$ 1,060	$ 938
44	SOUTH CENTRAL REGION	1,689	1,204	485	820	644
45	NORTH COASTAL REGION	2,058	1,674	384	284	(1)
46	SOUTH COASTAL REGION	1,549	1,029	520	811	1,521
48	DOS	-	-	-	-	-
49	Total Price Adjustment	$ 1,759	$ 1,164	$ 595	$ 2,974	$ 3,101
50						
51	Combined					
52	NORTH CENTRAL REGION	$ 924	$ 753	$ 172	$ 985	$ 1,070
53	SOUTH CENTRAL REGION	735	581	154	2,498	2,350
54	NORTH COASTAL REGION	980	913	68	431	292
55	SOUTH COASTAL REGION	964	627	337	2,488	3,236
57	DOS	-	-	-	-	-
58	Total Price Adjustment	$ 858	$ 670	$ 188	$ 6,402	$ 6,947
59						

Year-End

Line #	Description - Charge To	Budget Price	Projection Price	Unit Price Variance $: Fav/(Unfav)	Price Variance Impact:
32					
33	Residential				($000's)
34	NORTH CENTRAL REGION	$ 707	$ 602	$ 105	$ 696
35	SOUTH CENTRAL REGION	628	520	108	1,756
36	NORTH COASTAL REGION	813	679	134	696
37	SOUTH COASTAL REGION	782	576	206	1,647
39	DOS	-	-	-	-
40	Total Price Adjustment	$ 702	$ 570	$ 131	$ 4,795
41					
42	Commercial & Industrial				
43	NORTH CENTRAL REGION	$ 2,015	$ 1,913	$ 102	$ 121
44	SOUTH CENTRAL REGION	1,689	1,276	413	857
45	NORTH COASTAL REGION	2,058	1,511	547	502
46	SOUTH COASTAL REGION	1,549	1,573	(24)	(43)
48	DOS	-	-	-	-
49	Total Price Adjustment	$ 1,758	$ 1,528	$ 230	$ 1,436
50					
51	Combined				
52	NORTH CENTRAL REGION	$ 925	$ 801	$ 124	$ 966
53	SOUTH CENTRAL REGION	737	606	131	2,399
54	NORTH COASTAL REGION	980	804	176	1,078
55	SOUTH COASTAL REGION	964	760	204	2,004
57	DOS	-	-	-	-
58	Total Price Adjustment	$ 860	$ 707	$ 153	$ 6,447
59					

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Progress Energy

Progress Energy Florida

Energy Delivery Monthly Financial Summary - Revenue Construction

2004 - October

Revenue Construction - CIAC — Current Month

60	Revenue Construction - CIAC	Budget	Actual	Unit CIAC Variance $: Fav/(Unfav)	CIAC Variance $: Fav/(Unfav) ($000's)
61	Description - Charge To				
62	Residential				
63	NORTH CENTRAL REGION	$ (436)	$ (661)	$ 225	$ 99
64	SOUTH CENTRAL REGION	(529)	(316)	(213)	(227)
65	NORTH COASTAL REGION	(409)	(137)	(272)	(99)
66	SOUTH COASTAL REGION	(406)	(399)	(6)	(3)
68	Total Residential CIAC	$ (467)	$ (371)	$ (97)	$ (230)
69					
70	Commercial & Industrial				
71	NORTH CENTRAL REGION	$ (792)	$ (705)	$ (87)	$ (8)
72	SOUTH CENTRAL REGION	(1,226)	(1,482)	256	32
73	NORTH COASTAL REGION	(568)	(389)	(179)	(10)
74	SOUTH COASTAL REGION	(278)	(150)	(128)	(21)
76	Total C&I CIAC	$ (697)	$ (871)	$ 174	$ (6)
77					
78	Combined				
79	NORTH CENTRAL REGION	$ (495)	$ (668)	$ 173	$ 92
80	SOUTH CENTRAL REGION	(603)	(440)	(164)	(195)
81	NORTH COASTAL REGION	(430)	(171)	(259)	(109)
82	SOUTH COASTAL REGION	(375)	(340)	(35)	(24)
84	Total Combined CIAC	$ (502)	$ (418)	$ (84)	$ (236)

Year-to-Date

	Description - Charge To	Budget	Actual	Unit CIAC Variance $: Fav/(Unfav)	CIAC Variance $: Fav/(Unfav) ($000's)	Prior Month YTD CIAC Variance $: ($000's)
62	Residential					
63	NORTH CENTRAL REGION	$ (423)	$ (701)	$ 278	$ 1,315	$ 1,210
64	SOUTH CENTRAL REGION	(491)	(606)	115	1,324	1,106
65	NORTH COASTAL REGION	(396)	(679)	282	1,018	1,072
66	SOUTH COASTAL REGION	(390)	(434)	44	217	141
68	Total Residential CIAC	$ (444)	$ (48)	$ (396)	$ 3,873	$ 3,529
70	Commercial & Industrial					
71	NORTH CENTRAL REGION	$ (770)	$ (764)	$ (7)	$ (6)	$ (19)
72	SOUTH CENTRAL REGION	(1,193)	(1,595)	403	522	446
73	NORTH COASTAL REGION	(562)	(133)	(429)	(240)	(234)
74	SOUTH COASTAL REGION	(271)	(379)	109	165	175
76	Total C&I CIAC	$ (694)	$ (796)	$ 102	$ 441	$ 369
78	Combined					
79	NORTH CENTRAL REGION	$ (481)	$ (712)	$ 231	$ 1,308	$ 1,135
80	SOUTH CENTRAL REGION	(562)	(706)	144	1,846	1,512
81	NORTH COASTAL REGION	(419)	(605)	187	777	840
82	SOUTH COASTAL REGION	(361)	(421)	60	382	318
84	Total Combined CIAC	$ (481)	$ (630)	$ 149	$ 4,314	$ 3,805

Year-End

	Description - Charge To	Budget	Projection	CIAC Variance $: Fav/(Unfav)	CIAC Variance Impact: ($000's)
62	Residential				
63	NORTH CENTRAL REGION	$ (429)	$ (662)	$ 233	$ 1,318
64	SOUTH CENTRAL REGION	(505)	(610)	106	1,421
65	NORTH COASTAL REGION	(400)	(679)	279	1,211
66	SOUTH COASTAL REGION	(392)	(404)	13	76
68	Total Residential CIAC	$ (452)	$ (589)	$ 137	$ 4,026
70	Commercial & Industrial				
71	NORTH CENTRAL REGION	$ (780)	$ (838)	$ 57	$ 65
72	SOUTH CENTRAL REGION	(1,211)	(1,850)	640	980
73	NORTH COASTAL REGION	(567)	(152)	(414)	(279)
74	SOUTH COASTAL REGION	(272)	(389)	117	216
76	Total C&I CIAC	$ (350)	$ (549)	$ 199	$ 982
78	Combined				
79	NORTH CENTRAL REGION	$ (488)	$ (692)	$ 204	$ 1,383
80	SOUTH CENTRAL REGION	(577)	(738)	161	2,401
81	NORTH COASTAL REGION	(423)	(608)	186	932
82	SOUTH COASTAL REGION	(363)	(401)	38	292
84	Total Combined CIAC	$ (489)	$ (634)	$ 145	$ 5,008

85

86	Revenue Construction - LRC	Current Month			Year-to-Date			Prior Month	Year-End		
87	Description - Charge By	Budget:	Actual:	Variance: Fav/(Unfav)	Budget:	Actual:	Variance: Fav/(Unfav)	YTD Var	Budget:	Projection:	Variance: Fav/(Unfav)
88	NORTH CENTRAL REGION	$ 29	$ 65	$ (36)	$ 292	$ 321	$ (29)	$ 7	$ 350	$ 350	$ -
89	SOUTH CENTRAL REGION	12	5	7	127	44	83	76	150	150	-
93	Total LRC	$ 42	$ 70	$ (29)	$ 418	$ 364	$ 54	$ 83	$ 500	$ 500	$ -

NOTE: The favorable YTD price variance of $ 6.4 million is driven by the above budget collection of CIAC of $ 4.3 million.

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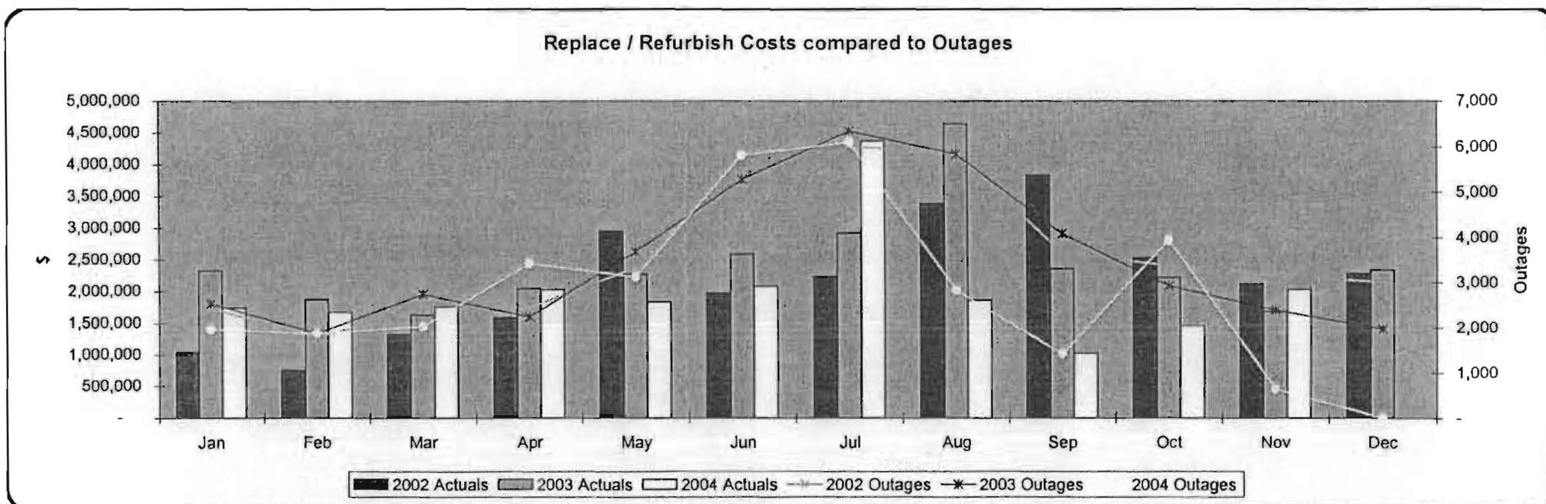
Progress Energy Florida
Energy Delivery Monthly Financial Summary - Performance - Replace / Refurbish
2004 - YTD October CAPITAL

Line #	Region	Customers Served - YTD 2003	Restoration Funds Spent YTD 2003	Restoration Budget YTD 2003	Restoration Fav / (Unfav) Variance	Customers Affected - YTD 2003	Cost Per Affected Customer	YTD CMI	Cost Per CMI	YTD SAIDI	Cost Per SAIDI Minute	YTD Outages	Cost Per Outage	YTD Lightning Strikes	Cost Per Lightning Strike
1	NORTH CENTRAL REGION	357,916	$ 7,475,064	$ 7,261,207	$ (213,857)	464,670	$ 16.09	32,014,989	$ 0.23	89.4	$ 83,568	9,569	$ 781	40,149	$ 186
2	SOUTH CENTRAL REGION	342,879	5,904,678	4,911,881	(992,797)	327,092	18.05	24,250,395	0.24	70.7	83,487	7,876	750	57,504	103
3	NORTH COASTAL REGION	171,369	$ 2,954,389	$ 1,984,072	$ (970,317)	279,696	$ 10.56	22,213,320	$ 0.13	129.6	$ 22,792	6,718	$ 440	35,857	$ 82
4	SOUTH COASTAL REGION	628,694	8,555,370	6,444,720	(2,110,650)	609,118	14.05	36,777,820	0.23	58.5	146,249	12,530	683	12,785	669
5	COASTAL REGION	800,063	$ 11,509,759	$ 8,428,792	$ (3,080,967)	888,814	$ 12.95	58,991,140	$ 0.20	73.7	$ 156,100	19,248	$ 598	48,642	$ 237
6															
7	SYSTEM	1,500,858	$ 24,889,501	$ 20,601,880	$ (4,287,621)	1,680,576	$ 14.81	115,256,524	$ 0.22	76.8	$ 324,108	36,693	$ 678	146,295	$ 170
8															
9															
10															
11	Region	Customers Served - YTD 2004	Restoration Funds Spent YTD 2004	Restoration Budget YTD 2004	Restoration Fav / (Unfav) Variance	Customers Affected - YTD 2004	Cost Per Affected Customer	YTD CMI	Cost Per CMI	YTD SAIDI	Cost Per SAIDI Minute	YTD Outages	Cost Per Outage	YTD Lightning Strikes	Cost Per Lightning Strike
12															
13	NORTH CENTRAL REGION	364,881	$ 5,891,249	$ 6,113,975	$ 222,726	386,862	$ 15.23	24,984,830	$ 0.24	68.5	$ 86,036	8,527	$ 691	35,605	$ 165
14	SOUTH CENTRAL REGION	357,548	4,546,705	4,605,373	58,668	341,974	13.30	20,966,679	0.22	58.6	77,536	7,118	639	68,411	66
15	NORTH COASTAL REGION	176,057	$ 2,710,345	$ 2,762,618	$ 52,273	255,226	$ 10.62	19,784,027	$ 0.14	112.4	$ 24,119	6,252	$ 434	42,226	$ 64
16	SOUTH COASTAL REGION	636,162	6,696,346	6,211,018	(485,328)	571,821	11.71	32,926,476	0.20	51.8	129,378	10,591	632	15,069	444
17	COASTAL REGION	812,219	$ 9,406,691	$ 8,973,636	$ (433,055)	827,047	$ 11.37	52,710,503	$ 0.18	64.9	$ 153,497	16,843	$ 558	57,295	$ 164
18															
19	SYSTEM	1,534,648	$ 19,844,645	$ 19,692,984	$ (151,661)	1,555,883	$ 12.75	98,662,012	$ 0.20	64.3	$ 308,675	32,488	$ 611	161,311	$ 123
20															
21												NOTE: Lightning Strikes includes all Major Storm days.			
22															
23	PERCENTAGE INCREASE / (DECREASE) OVER 2003														
27	NORTH CENTRAL REGION	1.9%	-21.2%	-15.8%	-204.1%	-16.7%	-5.3%	-22.0%	1.0%	-23.4%	3.0%	-10.9%	-11.6%	-11.3%	-11.1%
28	SOUTH CENTRAL REGION	4.3%	-23.0%	-6.2%	-105.9%	4.5%	-26.3%	-13.5%	-10.9%	-17.1%	-7.1%	-9.6%	-14.8%	19.0%	-35.3%
24	NORTH COASTAL REGION	2.7%	-8.3%	39.2%	-105.4%	-8.7%	0.5%	-10.9%	3.0%	-13.3%	5.8%	-6.9%	-1.4%	17.8%	-22.1%
25	SOUTH COASTAL REGION	1.2%	-21.7%	-3.6%	-77.0%	-6.1%	-16.6%	-10.5%	-12.6%	-11.5%	-11.5%	-15.5%	-7.4%	17.9%	-33.6%
26	COASTAL REGION	1.5%	-18.3%	6.5%	-85.9%	-6.9%	-12.2%	-10.6%	-8.5%	-12.0%	-1.7%	-12.5%	-6.6%	17.8%	-30.6%
29	SYSTEM	2.3%	-20.3%	-4.4%	-96.5%	-7.4%	-13.9%	-14.4%	-6.9%	-16.3%	-4.8%	-11.5%	-9.9%	10.3%	-27.7%



PEF-SR-10128

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Progress Energy Florida
Energy Delivery Monthly Financial Summary - DOT
2004 - YTD October CAPITAL

DOT 2003 Actuals

Line #	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Budget	Projection
1	NORTH CENTRAL REGION	$ 182,191	$ 270,886	$ 230,902	$ 220,337	$ 393,345	$ 375,197	$ 481,530	$ 270,882	$ 151,096	$ 150,184	$ 176,189	$ (78,157)	$ 2,824,582	$ 2,284,889	$ 2,444,889
2	SOUTH CENTRAL REGION	156,494	373,030	366,454	568,829	235,799	344,500	240,976	345,398	296,518	295,039	224,925	397,673	3,845,635	2,187,432	3,860,432
3	NORTH COASTAL REGION	47,924	73,503	226,295	15,711	87,483	153,417	(17,937)	44,060	122,706	81,070	49,483	(105,158)	778,557	1,172,565	1,172,565
4	SOUTH COASTAL REGION	251,125	246,044	788,673	381,727	343,410	816,140	589,433	529,496	352,690	471,489	304,388	261,248	5,335,863	3,345,173	5,287,173
5	COASTAL REGION COMBINED	299,049	319,547	1,014,968	397,438	430,893	969,557	571,496	573,556	475,396	552,559	353,871	156,090	6,114,420	4,517,738	6,459,738
6	2003 Total	$ 637,734	$ 963,463	$ 1,612,324	$ 1,186,604	$ 1,060,037	$ 1,689,254	$ 1,294,002	$ 1,189,836	$ 923,010	$ 997,782	$ 754,985	$ 475,606	$ 12,784,637	$ 8,990,059	$ 12,765,059

DOT 2003 Budget

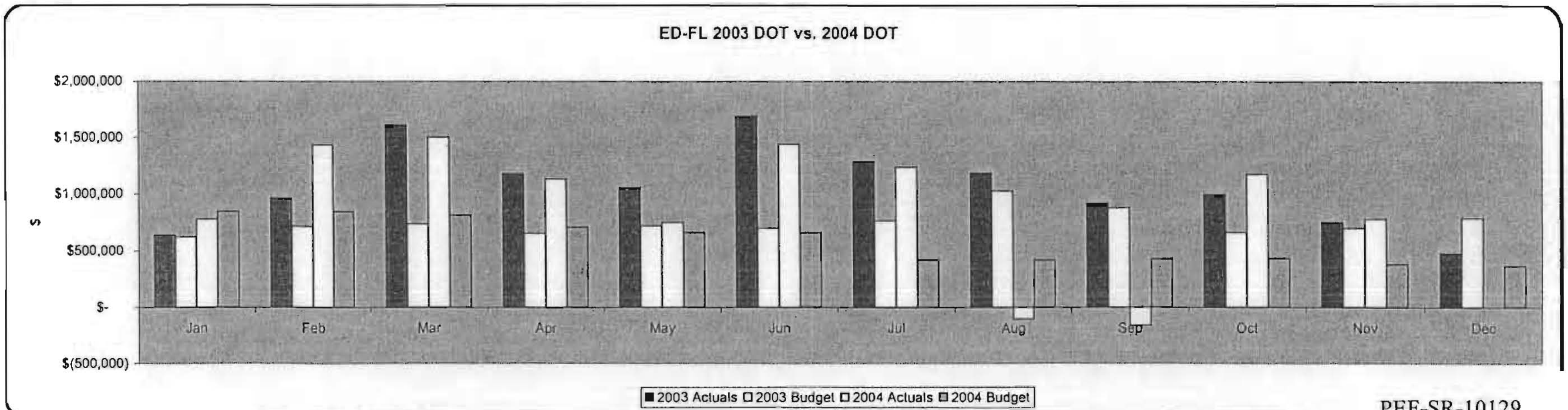
Line #	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Budget	Projection
7	NORTH CENTRAL REGION	$ 165,325	$ 190,910	$ 250,611	$ 148,943	$ 208,644	$ 166,001	$ 166,001	$ 262,255	$ 251,288	$ 131,886	$ 166,001	$ 177,024	$ 2,284,889	$ 2,284,889	$ 2,444,889
8	SOUTH CENTRAL REGION	147,421	159,195	159,195	172,462	172,462	184,236	196,010	245,358	207,783	184,236	184,236	174,837	2,187,431	2,187,432	3,860,432
9	NORTH COASTAL REGION	87,225	90,655	95,021	89,649	94,015	92,455	94,014	130,425	101,810	89,961	92,455	114,880	1,172,565	1,172,565	1,172,565
10	SOUTH COASTAL REGION	221,828	275,216	233,465	246,180	246,180	257,854	311,205	392,251	322,841	257,817	257,817	322,517	3,345,171	3,345,173	5,287,173
11	COASTAL REGION COMBINED	309,053	365,871	328,486	335,829	340,195	350,309	405,219	522,678	424,651	347,778	350,272	437,397	4,517,736	4,517,738	6,459,738
12	2003 Total	$ 621,799	$ 715,976	$ 738,292	$ 657,234	$ 721,301	$ 700,546	$ 767,230	$ 1,030,289	$ 883,722	$ 663,900	$ 700,509	$ 789,258	$ 8,990,056	$ 8,990,059	$ 12,765,059

DOT 2004 Actuals

Line #	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Budget	Projection
13	NORTH CENTRAL REGION	$ 237,278	$ 209,332	$ 175,305	$ 118,689	$ (151,089)	$ 185,450	$ 145,862	$ 72,404	$ (27,044)	$ (12,927)	$ 83,954	$ -	$ 1,037,214	$ 1,399,991	$ 1,799,991
14	SOUTH CENTRAL REGION	219,236	675,307	888,806	523,763	248,972	456,285	448,276	79,440	(170,277)	253,100	197,117	-	3,820,025	3,500,011	4,400,011
15	NORTH COASTAL REGION	181,274	198,300	172,718	146,696	304,183	300,659	300,790	(274,068)	(62,990)	646,784	98,668	-	2,013,014	1,051,427	2,127,427
16	SOUTH COASTAL REGION	141,516	355,675	270,709	348,065	350,314	503,067	347,352	17,847	100,678	293,793	403,017	-	3,132,033	1,049,998	2,999,998
17	COASTAL REGION COMBINED	322,790	553,975	443,427	494,761	654,497	803,726	648,142	(256,221)	37,688	940,577	501,685	-	5,145,047	2,101,425	5,127,425
18	2004 Total	$ 779,304	$ 1,438,614	$ 1,507,538	$ 1,137,213	$ 752,380	$ 1,445,461	$ 1,242,280	$ (104,377)	$ (159,633)	$ 1,180,750	$ 782,756	$ -	$ 10,002,286	$ 7,001,427	$ 11,327,427

DOT 2004 Budget

Line #	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Budget	Projection
19	NORTH CENTRAL REGION	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 1,399,992	$ 1,399,991	$ 1,799,991
20	SOUTH CENTRAL REGION	503,049	503,049	476,050	379,411	332,413	332,413	167,909	167,909	179,659	183,183	143,633	131,333	3,500,011	3,500,011	4,400,011
21	NORTH COASTAL REGION	138,142	138,142	138,142	126,172	126,172	126,172	48,581	48,581	48,581	48,581	34,077	30,087	1,051,430	1,051,427	2,127,427
22	SOUTH COASTAL REGION	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	1,050,000	1,049,998	2,999,998
23	COASTAL REGION COMBINED	225,642	225,642	225,642	213,672	213,672	213,672	136,081	136,081	136,081	136,081	121,577	117,587	2,101,430	2,101,425	5,127,425
24	2004 Total	$ 845,357	$ 845,357	$ 818,358	$ 709,749	$ 662,751	$ 662,751	$ 420,656	$ 420,656	$ 432,406	$ 435,930	$ 381,876	$ 365,586	$ 7,001,433	$ 7,001,427	$ 11,327,427



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PEF-SR-10129

Progress Energy

Progress Energy Florida
Energy Delivery Monthly Overtime & Headcount Summary on a Charge By Basis
October - EXCLUDES MAJOR STORM HOURS & DOLLARS
$ Costs include only Regulated Capital and O&M amounts

Current Month

Line #	Bargaining Unit	OT Hours	OT Dollars - $ (000's)	Double Time Hours	Double Time Dollars - $ (000's)	Regular Hours	Regular Dollars - $ (000's)	Overtime & Double Time Hours as % of Regular Hours	Overtime & Doubletime Dollars as % of Regular Dollars
1	NORTH CENTRAL REGION	5,291	$ 189	1,030	$ 51	18,339	$ 461	34%	52%
2	SOUTH CENTRAL REGION	3,814	138	389	20	14,552	368	29%	43%
3	NORTH COASTAL REGION	3,426	$ 125	188	10	13,315	349	27%	39%
4	SOUTH COASTAL REGION	4,731	$ 164	1,393	68	20,771	511	29%	45%
5	COASTAL REGION COMBINED	8,157	290	1,581	$ 77	34,086	$ 859	29%	43%
6	DIST OPS & SUPPORT	7,159	216	1,027	62	43,627	889	19%	31%
7	TRANSMISSION	3,161	118	461	23	19,571	487	19%	29%
8		27,582	$ 950	4,488	$ 233	130,175	$ 3,064	25%	39%
9									
10	Exempt & Non-exempt								
11	NORTH CENTRAL REGION	355	$ 6	-	$ -	9,046	$ 273	4%	2%
12	SOUTH CENTRAL REGION	466	12	-	-	9,636	272	5%	5%
13	NORTH COASTAL REGION	141	$ 4	-	$ -	6,449	194	2%	2%
14	SOUTH COASTAL REGION	273	$ 7	-	$ -	9,700	297	3%	2%
15	COASTAL REGION COMBINED	414	11	-	-	16,149	$ 491	3%	2%
16	DIST OPS & SUPPORT	394	10	-	-	16,805	512	2%	2%
17	TRANSMISSION	179	5	-	-	17,646	592	1%	1%
18	CTE PROJECT MANAGEMENT	2	0	-	-	514	28	0%	0%
19	ENERGY DELIVERY SERVICES	512	13	27	1	17,431	472	3%	3%
20	ED MANAGER BUSINESS OPERATION	12	0	-	-	2,132	70	1%	0%
21		2,334	$ 57	27	$ 1	89,359	$ 2,709	3%	2%

Year - to - Date

Line #	Bargaining Unit	OT Hours	OT Dollars - $ (000's)	Double Time Hours	Double Time Dollars - $ (000's)	Regular Hours	Regular Dollars - $ (000's)	Overtime & Double Time Hours as % of Regular Hours	Overtime & Doubletime Dollars as % of Regular Dollars
1	NORTH CENTRAL REGION	60,314	$ 2,123	7,100	$ 347	280,956	$ 6,704	24%	37%
2	SOUTH CENTRAL REGION	70,913	2,521	5,635	277	284,603	6,939	27%	40%
3	NORTH COASTAL REGION	41,464	$ 1,498	1,915	$ 94	198,671	$ 4,793	22%	33%
4	SOUTH COASTAL REGION	68,381	$ 2,372	12,834	$ 632	327,358	$ 7,827	25%	38%
5	COASTAL REGION COMBINED	109,845	3,870	14,749	726	526,029	12,620	24%	36%
6	DIST OPS & SUPPORT	79,854	2,575	17,126	1,012	533,153	10,835	18%	33%
7	TRANSMISSION	61,681	2,272	3,982	193	325,812	7,933	20%	31%
8		382,607	$ 13,361	48,592	$ 2,554	1,950,553	$ 45,031	22%	35%
9									
10	Exempt & Non-exempt								
11	NORTH CENTRAL REGION	3,332	$ 86	-	$ -	127,089	$ 3,637	3%	2%
12	SOUTH CENTRAL REGION	4,488	116	-	-	150,527	4,269	3%	3%
13	NORTH COASTAL REGION	1,684	42	-	$ -	86,174	$ 2,540	2%	2%
14	SOUTH COASTAL REGION	2,984	75	-	$ -	142,268	$ 4,155	2%	2%
15	COASTAL REGION COMBINED	4,668	$ 117	-	-	228,442	6,695	2%	2%
16	DIST OPS & SUPPORT	4,304	106	-	-	232,998	7,116	2%	1%
17	TRANSMISSION	1,983	58	1	0	253,602	8,195	1%	1%
18	CTE PROJECT MANAGEMENT	30	1	-	-	7,515	340	0%	0%
19	ENERGY DELIVERY SERVICES	3,368	88	27	1	222,293	5,873	2%	2%
20	ED MANAGER BUSINESS OPERATION	89	2	-	-	30,503	990	0%	0%
21		22,262	$ 573	28	$ 1	1,252,969	$ 37,114	2%	2%

22 Note: OT Hours Include Extended Pay hours for Exempt Employees

Line #	Headcount Data - Bargaining Unit	Approved Positions Per Org Chart	Estimated Budgeted Positions	Actual Filled Positions	Vacancy: Fav / (Unfav)	Current Month Average # of Paid OT & DT Hours Per Employee	YTD Average # of Paid OT & DT Hours Per Employee	2003 Average # of Paid OT & DT Hours Per Employee (Est)
24	NORTH CENTRAL REGION	208	199	193	6	33	35	43
25	SOUTH CENTRAL REGION	209	202	207	(5)	20	37	51
26	NORTH COASTAL REGION	137	130	138	(8)	26	31	40
27	SOUTH COASTAL REGION	231	231	224	7	27	36	30
28	COASTAL REGION COMBINED	368	361	362	(1)	27	34	54
29	DIST OPS & SUPPORT	318	322	350	(28)	23	28	46
30	TRANSMISSION	237	219	220	(1)	16	30	36
32		1,340	1,303	1,332	(29)	24	32	40

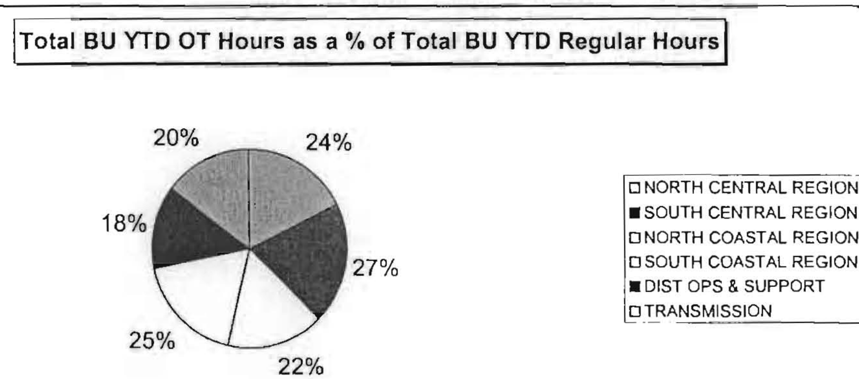
Line #	Headcount Data - Bargaining Unit	YTD Budget - Bargaining Unit OT ($ 000's)	YTD Actual - Bargaining Unit OT ($ 000's)	YTD Variance	Estimated YTD Budgeted OT & Double Time Hours	Actual YTD OT & Double Time Hours	Variance
24	NORTH CENTRAL REGION	$ 2,402	$ 2,498	$ (97)	61,205	67,414	(6,209)
25	SOUTH CENTRAL REGION	2,300	2,793	(493)	58,623	76,548	(17,925)
26	NORTH COASTAL REGION	1,969	1,586	383	50,171	43,379	6,792
27	SOUTH COASTAL REGION	2,542	2,879	(337)	64,780	81,215	(16,435)
28	COASTAL REGION COMBINED	4,511	4,465	46	114,951	124,594	(9,643)
29	DIST OPS & SUPPORT	1,628	3,454	(1,827)	41,484	96,980	(55,496)
30	TRANSMISSION	1,317	2,210	(893)	33,562	65,663	(32,101)
32		$ 12,158	$ 15,420	$ (3,263)	309,824	431,199	(121,375)

Note: YTD Actual BU OT $'s excludes Major Storm, Non-regulated & Environmental work

Line #	Exempt & Non-exempt	Approved Positions Per Org Chart	Estimated Budgeted Positions	Actual Filled Positions	Vacancy: Fav / (Unfav)
33					
35	NORTH CENTRAL REGION	96	98	88	10
36	SOUTH CENTRAL REGION	108	105	104	1
	NORTH COASTAL REGION	68	68	59	9
	SOUTH COASTAL REGION	92	92	95	(3)
37	COASTAL REGION COMBINED	160	160	154	6
38	DIST OPS & SUPPORT	151	145	157	(12)
39	TRANSMISSION	174	171	166	5
40	CTE PROJECT MANAGEMENT	6	6	3	3
41	ENERGY DELIVERY SERVICES	158	158	149	9
42	ED MANAGER BUSINESS OPERATION	23	23	18	5
43	ENERGY DELIVERY ADMIN	4	4	4	-
44		880	870	843	27
45					
46	Total Energy Delivery Florida Employees	2,220	2,173	2,175	(2)

Note: Energy Delivery Services represents CIG, Environmental, Energy Efficiency, Delivery Support Services

Goal Metrics:	
Outstanding	18%
Target	20%
Threshold	22%



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PEF-SR-10130

Progress Energy

Progress Energy Florida
Variance Explanations - O&M
2004 - October

Line #	Business Unit	Key Drivers - YTD	($ millions) YTD Variance - Fav / (Unfav)	Year-end Projected Variance
1	NORTH CENTRAL REGION	Training - $.2m Fav in Payroll Labor, Line Ops &RD - $.2m Fav in BU/BU OT Labor, Safety - $.2m Fav in Payroll/BU Labor, Environmental - $.1m Fav in BU/Materials and Fleet, Office Admin ($.1m) Unfav in Payroll/Other, Street Light Maint - $.1m Fav in Materials w/Burdens/Other, Other - ($.1m) Unfav in misc. Incentitives (ECIP&MCIP) - ($.1m) Unfav Budget at Corporate Rate 5% vs Payout of 7%	$ 0.9	$ 0.6
2				
3	SOUTH CENTRAL REGION	Favorability driven by Streetlight Maintenance $0.42m, Training $0.4m, offset by unfavorability in Office Admin & Support ($0.1m) unfavorable.	1.2	1.1
4				
5	NORTH COASTAL REGION	YTD, the Region has no O&M variance. Within the net $0m variance, there are some significant offsetting variances. The primary unfavorable drivers are associated with General Distribution Support ($0.20m), Office Services Support ($0.14), unbudgeted Relocation Expenses ($0.13m) and unbudgeted IT&T costs ($0.11). The increase in unfavorability to Gen'l Distr. Suppt from October was driven primarily by an ADJ, which reclassified costs of power purchased from SECO for resale to PEF customers. Unfavorability in Office Services Support is driven by material costs. Favorable variances within O&M include R&D work at $0.34m, followed by Training at $0.15m, SL Maint at $0.13m and payroll burdens at $0.12.	(0.0)	(0.1)
6				
7	SOUTH COASTAL REGION	Favorability driven by Payroll Burdens $0.4, Streetlight Repair $0.2, and General Distribution Support $0.2, partially offset by unfavorability in Incentives ($0.3), Line Operations ($0.1), and Small Tools ($0.1).	0.2	0.4
8				
9	DIST OPS & SUPPORT	Tree Trimming Contractor favorability $4.3M due to resources being utiltized for Hurricane Restoration, offset by Base Programs $(.2m) due to Contractor Labor being utilitzed for Pole Maint and TRIP work; Metering Svcs OT Labor $(.7m), Dispatch OT - $(1.0m) due to training, holiday, vacation and sick time taken; ECIP payout unfavorable $(.6m), Moving Expenses unbudgeted for Dispatchers $(.2).	4.1	2.2
10				
11	TRANSMISSION	Favorable variance obtained by shifting resources to Jeanne storm restoration. O&M spending expected to resume in November and December.	2.0	0.7
12				
13	CTE PROJECT MANAGEMENT	Main drivers of YTD favorable variance is due to Dist Veg Mgmt - $0.4m. and Trans Veg Mgmt - $1.2m. Offset by carryover of 2003 work into 2004 ($0.2m).	1.5	1.0
14				
15	ENERGY DELIVERY ADMIN		0.1	0.2
16				
17	ENERGY DELIVERY SERVICES	Favorability due to storm charging.	0.4	0.2
18				
19	ED MANAGER BUSINESS OPERATIONS	Vacancies driving favorable variance	0.3	0.4
20				
21	FPC - ED		0.0	0.0
22				
23	PROGRESS ENERGY FLORIDA PRESIDENT		0.3	0.3
24				
25	TOTAL ENERGY DELIVERY		$ 11.0	$ 7.0

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PEF-SR-10131

Progress Energy

Progress Energy Florida
Variance Explanations - Capital
2004 - October

Line #	Business Unit		Key Drivers - YTD	($ millions) YTD Variance - Fav / (Unfav)	Year-end Projected Variance
1	NORTH CENTRAL REGION	Grow	Unfav Var Drivers: Buggy Stock - ($.7m) unfav since actuals are in Grow while budget is in Maintain. Incentitives - ($.4m) unfav since Corp Budgeted rate of 5% while payout is at 7%. Gen Dist Indirect - $.1m Fav in Labor resources, Maj Con - $.1m Fav in Grown while all actuals charged to Maintain.	$ 0.31	$ (0.27)
2					
3		Maintain	Drivers: CIAC Reimbursement: $1m Fav - Reimbursement check from WP Franchise posted to regulatory project # Buggy Stock - $.7m fav - Budget in Maintain while actuals are in Grow due to budgeting to Replace/Ref project number instead of indirect. Outage Restoration - $.2m Fav-All labor resources/Materials/Fleet offset by Contractors/CIAC - Result of Hurricane work. Street Light Maint (Like for Like) - $.2m Fav in all resource types again due to Hurricane Work for 2 months.	2.30	0.67
4				$ 2.61	$ 0.40
5	SOUTH CENTRAL REGION	Grow	Favorability driven primarily by New Customer related CIAC $2.0 m favorable YTD, offset by Materials ($0.8m) and BU OT ($.3m) unfavorable.	$ 1.95	$ (0.48)
6					
7		Maintain	Unfavorability driven by Outage Restoration ($0.2m) unfavorable including $.3m for Conway storm, Major Conversion ($0.2m) unfavorable driven primarily by non-CIAC covered customer requests, and ($0.2m) unfavorable in System Improvement.	(0.38)	0.93
8				$ 1.56	$ 0.45
9	NORTH COASTAL REGION	Grow	After the net $0.43m favorable budget impact of the volume adjustment for NCW and NSL activities, the balance of the Region's unfavorable Grow variance ($0.62m) is driven by Buggy Stock ($0.95m), Material Burdens ($0.32m), Gen Dist Support ($0.28m), Payroll Burdens ($0.21m), Labor Incentives ($0.19m) end Customer Requested work ($0.10). Favorable offset of $1m comes from Allocations. Grow Buggy Stock unfavorability is driven, in part, by the fact that 74% of the Region's annual Buggy Stock budget is associated with Maintain, where none of the actuals reside.	$ (0.62)	$ 0.40
10					
11		Maintain	Only 4.7% of the annual Maintain budget was allocated to October and October finished with an unfavorable variance of $0.14m. However YTD, the region is still slightly favorable driven by storm response activity occuring in the same months where the region had 15% and 11% of its annual Maintain budget.	0.03	0.22
12				$ (0.59)	$ 0.62
13	SOUTH COASTAL REGION	Grow	Primary drivers of unfavorability are PEF Eng&Sup-OH Line burdens ($2.4m), Gen Dist Support ($0.3m), Incentives ($0.2), materials burdens ($0.3m), partially offset by NCW and NSL volume adjustment of $1.9m.	$ (0.27)	$ (1.38)
14					
15		Maintain	Primary driver of YTD favorability is PEF Eng&Sup-OH Line burdens $2.2m, partially offset by unfavorability in Customer Requests and Conversions ($1.0m) and OH/UG R&R ($0.5m).	0.84	0.65
16				$ 0.57	$ (0.54)
17	DIST OPS & SUPPORT	Grow	Transformers $1.8m favorable due to TRIP transformer forgiveness and storm usage; Meter purchases .5m favorable due to timing; Load Growth projects behind schedule due to storm restoration- $3.3m- Payroll and Materials driving variance.	$ 8.25	$ 2.26
18					
19		Maintain	DOT spending unfavorable $(4.0m) - Payroll, Contractors and Materials driving variance. Base Programs behind schedule - $2.4m due mainly to Payroll for Cable Replacement due to contractors being utilized.	(1.31)	(2.82)
20				$ 6.94	$ (0.56)
21	TRANSMISSION	Grow	Favorable variance obtained by shifting resources to Charley, Frances and Jeanne storm restoration. Capital work to resume during November and December.	$ 5.69	$ 0.48
22					
23		Maintain	Favorable variance obtained by shifting resources to Charley, Frances and Jeanne storm restoration. Capital work to resume during November and December.	1.28	1.04
24				$ 6.98	$ 1.50
25	CTE PROJECT MANAGEMENT	Grow		$ (0.00)	$ -
26					
27		Maintain	Favorable variances in Branch line Spacer Cable - $0.5m, Fuse Coordination - $0.8m, Cable replacement - $0.6m, Trans Line Inspection - $0.8m, Trans Lightning Mitigation - $0.3m. Unfavorable variances in carryover of Transmission 2003 Programs - ($0.2m)	3.38	1.29
28				$ 3.38	$ 1.29
29	ENERGY DELIVERY ADMIN	Grow		$ 0.07	$ -
30					
31		Maintain	0	1.61	1.43
32				$ 1.68	$ 1.43
33	ENERGY DELIVERY SERVICES	Grow		$ -	$ -
34					
35		Maintain	Timing of Purchases. Expect to use the entire budget by year-end.	0.09	-
36				$ 0.09	$ -
37				15.38	0.99
38				7.84	3.61
39	TOTAL ENERGY DELIVERY			$ 23.22	$ 4.60

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PEF-SR-10132

Progress Energy

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Progress Energy Florida
Energy Delivery Monthly Financial Summary
2004 - November

1/11/2005, 11:33 AM

Line #	Regulated O&M Description - Charge To	Current Month - (000's) Budget	Actual	Variance	Year-to-Date - (000's) Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Year-End - (000's) Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
1	NORTH CENTRAL REGION	$ 647	$ 571	$ 76	$ 7,295	$ 6,308	$ 988	$ 912	$ 573	$ 8,082	$ 7,475	$ 607	$ 1,167	$ 1,167	104%
2	SOUTH CENTRAL REGION	650	510	140	7,716	6,346	1,370	1,229	577	8,536	7,467	1,069	1,121	1,121	94%
3	NORTH COASTAL REGION	400	557	(156)	4,534	4,691	(157)	(0)	426	5,113	5,184	(71)	492	492	15%
4	SOUTH COASTAL REGION	858	712	146	10,334	9,941	394	248	904	11,466	11,089	377	1,149	1,149	27%
5	COASTAL REGION COMBINED	1,258	1,269	(11)	14,869	14,632	237	248	1,330	16,579	16,273	306	1,641	1,641	23%
6	DIST OPS & SUPPORT	4,861	5,606	(744)	57,368	54,052	3,315	4,060	4,914	63,590	61,416	2,174	7,364	7,364	50%
7	Distribution Total	$ 7,416	$ 7,956	$ (539)	$ 87,248	$ 81,338	$ 5,910	$ 6,449	$ 7,394	$ 96,787	$ 92,631	$ 4,155	$ 11,293	$ 11,293	53%
8	TRANSMISSION	$ 2,221	$ 1,937	$ 283	$ 23,306	$ 20,978	$ 2,328	$ 2,044	$ 1,907	$ 26,115	$ 25,429	$ 686	$ 4,451	$ 4,451	133%
9	CTE PROJECT MANAGEMENT	475	966	(490)	9,778	8,747	1,031	1,521	795	10,274	9,226	1,048	479	479	-40%
10	ENERGY DELIVERY ADMIN	512	506	5	6,078	6,022	56	51	547	6,709	6,466	243	444	444	-19%
11	ENERGY DELIVERY SERVICES	374	360	14	3,922	3,530	392	378	321	4,391	4,189	202	659	659	105%
12	ED MANAGER BUSINESS OPERATIONS	186	146	40	2,220	1,842	378	338	167	2,489	2,134	355	292	292	74%
13	FPC - ED	19	9	10	215	202	13	3	18	239	220	19	18	18	-2%
14	PROGRESS ENERGY FLORIDA PRESIDE	98	54	44	1,300	999	301	257	91	1,425	1,128	297	129	129	42%
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
16		$ 11,302	$ 11,934	$ (632)	$ 134,067	$ 123,658	$ 10,409	$ 11,041	$ 11,242	$ 148,428	$ 141,423	$ 7,005	$ 17,765	$ 17,765	58%

KEY YTD POINTS:

1 - ECIP / MICP Payout - ($1.1m) Unfav - Budgeted ECIP at 5% & 7% payout - Actual 6.875% & 9.65%. Safety Incentives and Performance awards - ($0.4m) Unfav - The safety award program is main driver.

2 - CTE - $1.0m Fav YTD - Major Driver is Veg Mgmt which was cut back to meet mitigation efforts, prior to the impact of the Major Storms.

3 - Bargaining Unit OT - Unfavorable ($1.9m) - Dispatch - ($1.0m) and Meter Reading ($0.4m) driving variance. These variances are offset by $1.4m favorable in Safety & Training, $2.0m fav in Payroll related burdens and $3.5m in payroll (other than safety & training).

4 - Tree Trimming - $3.2m favorable YTD (excludes CTE - Only Transmission and DOS). DOS is favorable due to Bonnie, Charley, Frances and Ivan Storm Impact

5 - The Year-end Projection reflects the impact of the Major Storms and managements efforts to address backlog work offset by $1.0m increase for R&D Business Case.

Line #	Regulated Capital Description - Charge To	Current Month - (000's) Budget	Actual	Variance	Year-to-Date - (000's) Budget	Actual	Variance with Price Included	Burn Rate	Prior Month YTD Var	Variance with Price Excluded	Year-End - (000's) Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
30	NORTH CENTRAL REGION	$ 2,315	$ 3,229	$ (915)	$ 26,452	$ 24,752	$ 1,700	$ 2,250	2,614	$ 553	$ 29,187	$ 28,790	$ 397	$ 4,037	$ 4,037	79%
31	SOUTH CENTRAL REGION	2,922	2,604	318	33,633	31,751	1,882	2,888	1,563	(1,375)	36,582	36,133	448	4,382	4,382	52%
32	NORTH COASTAL REGION	1,220	2,158	(938)	15,073	16,604	(1,530)	1,509	(592)	(1,683)	16,554	15,930	624	(674)	(674)	-145%
33	SOUTH COASTAL REGION	2,577	2,952	(375)	30,076	29,883	193	2,717	568	(2,505)	32,834	33,372	(538)	3,489	3,489	28%
32	COASTAL REGION COMBINED	3,798	5,110	(1,313)	45,150	46,486	(1,337)	4,226	(24)	$ (4,188)	49,388	49,302	86	2,815	2,815	-33%
33	DIST OPS & SUPPORT	4,449	3,823	627	54,821	47,255	7,566	4,296	6,940	7,566	59,190	59,752	(562)	12,497	12,497	191%
34	Distribution Total	$ 13,484	$ 14,766	$ (1,283)	$ 160,056	$ 150,245	$ 9,811	$ 13,659	$ 11,093	$ 2,556	$ 174,347	$ 173,977	$ 371	$ 23,732	$ 23,732	74%
35	Note: Current Month does not have Price Impact included				Rev Construction PRICE impact applied against YTD Variance		-		-	6,447			-			
36					S/L PRICE impact applied against YTD Variance		-		-	808			-			
37					Total Distribution Variance		$ 9,811		$ -	$ 9,811			$ -			
38																
39	TRANSMISSION	$ 4,087	$ 6,559	$ (2,492)	$ 57,053	$ 52,569	$ 4,484	$ 4,779	$ 6,976	$ 4,484	$ 62,006	$ 60,507	$ 1,500	$ 7,937	$ 7,937	66%
40	CTE PROJECT MANAGEMENT	345	546	(200)	14,835	11,658	3,178	1,060	3,378	3,178	15,182	13,887	1,295	2,230	2,230	110%
41	ENERGY DELIVERY ADMIN	597	592	5	11,867	10,185	1,682	926	1,677	8,937	12,403	10,971	1,432	785	785	-15%
42	ENERGY DELIVERY SERVICES	15	1	15	169	62	107	6	92	107	185	185	-	123	123	2073%
43	ED MANAGER BUSINESS OPERATIONS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
44	FPC - ED	-	-	-	-	-	-	-	-		-	-	-	-	-	0%
45	Total Regulated Capital	$ 18,509	$ 22,463	$ (3,955)	$ 243,981	$ 224,719	$ 19,261	$ 20,429	$ 23,216	$ 19,261	$ 264,123	$ 259,526	$ 4,597	$ 34,807	$ 34,807	70%
46	NOTE: Due to the impact of Price and the way it is calculated; it is not reflected in the current month. Therefore, you cannot take Prior Month Variance and add Current Month Variance to tie to current YTD variance.															

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KEY YTD POINTS:

1 - The Price Variances for New Customer & Streetlight work are favorable YTD -$7.1 m. This is due to CIAC $4.6m above budget in collections in NCW. Volume Adjustment YTD is $6.4m favorable (NCW $9.0m less S/L $2.6m).

2 - Load Growth Projects $3.2m, CTE $3.2m, Meters & Transformer Purchases $2.0m, Facilities $0.4m, Fleet $0.2m & Base Programs $2.7m all favorable due to impact from Storms

3 - DOT & Replace / Refurbish continue to exceed budget - YTD Unfavorable Variance - ($5.2m) DOT - ($4.4m) & R/R ($0.8m)

4 - ECIP / MICP Payout - ($1.7m) Unfav - Budgeted ECIP at 5% & 7% payout - Actual 6.875% & 9.65%

5 - The Year-end Projection reflects the base labor reductions due to the Major Storms and Operational managements estimate of backlog work that can be accomplished before year-end.

PEF-SR-10133

Progress Energy

1/11/2005, 11:33 AM

Progress Energy Florida
Energy Delivery Monthly Financial Summary - O&M
2004 - November

Line #	Regulated O&M	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
Line #	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
1	NORTH CENTRAL REGION	$ 647	$ 571	$ 76	$ 7,295	$ 6,308	$ 988	$ 912	$ 573	$ 8,082	$ 7,475	$ 607	$ 1,167	$ 1,167	104%
2	SOUTH CENTRAL REGION	650	510	140	7,716	6,346	1,370	1,229	577	6,536	7,467	1,069	1,121	1,121	94%
3	NORTH COASTAL REGION	400	557	(156)	4,534	4,691	(157)	(0)	426	5,113	5,184	(71)	492	492	15%
4	SOUTH COASTAL REGION	858	712	146	10,334	9,941	394	248	904	11,466	11,089	377	1,149	1,149	27%
5	COASTAL REGION COMBINED	1,258	1,269	(11)	14,869	14,632	237	248	1,330	16,579	16,273	306	1,641	1,641	23%
6	DIST OPS & SUPPORT	4,861	5,606	(744)	57,368	54,052	3,315	4,060	4,914	63,590	61,416	2,174	7,364	7,364	50%
7	**Distribution Total**	**$ 7,416**	**$ 7,956**	**$ (539)**	**$ 87,248**	**$ 81,338**	**$ 5,910**	**$ 6,449**	**$ 7,394**	**$ 96,787**	**$ 92,631**	**$ 4,155**	**$ 11,293**	**$ 11,293**	**53%**
8	TRANSMISSION	$ 2,221	$ 1,937	$ 283	$ 23,306	$ 20,978	$ 2,328	$ 2,044	$ 1,907	$ 26,115	$ 25,429	$ 686	$ 4,451	$ 4,451	133%
9	CTE PROJECT MANAGEMENT	475	966	(490)	9,778	8,747	1,031	1,521	795	10,274	9,226	1,048	479	479	-40%
10	ENERGY DELIVERY ADMIN	512	506	5	6,078	6,022	56	51	547	6,709	6,466	243	444	444	-19%
11	ENERGY DELIVERY SERVICES	374	360	14	3,922	3,530	392	378	321	4,391	4,189	202	659	659	105%
12	ED MANAGER BUSINESS OPERATIONS	186	146	40	2,220	1,842	378	338	167	2,489	2,134	355	292	292	74%
13	FPC - ED	19	9	10	215	202	13	3	18	239	220	19	18	18	-2%
14	PROGRESS ENERGY FLORIDA PRESIDEN	98	54	44	1,300	999	301	257	91	1,425	1,128	297	129	129	42%
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
16		$ 11,302	$ 11,934	$ (632)	$ 134,067	$ 123,658	$ 10,409	$ 11,041	$ 11,242	$ 148,428	$ 141,423	$ 7,005	$ 17,765	$ 17,765	58%
17															
Line #	CTE Programs	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
1	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
2	NORTH CENTRAL REGION	$ -	$ -	$ -	$ -	$ 4	$ (4)	$ (4)	$ 0	$ -	$ -	$ -	$ (4)	$ (4)	-1200%
3	SOUTH CENTRAL REGION	-	-	-	-	6	(6)	(6)	1	-	-	-	(6)	(6)	-1200%
4	NORTH COASTAL REGION	-	(2)	2	-	7	(7)	(9)	1	-	-	-	(7)	(7)	-1200%
5	SOUTH COASTAL REGION	-	-	-	-	4	(4)	(4)	0	-	-	-	(4)	(4)	-1200%
7	DIST OPS & SUPPORT	55	289	(234)	2,105	1,958	147	381	178	2,170	2,120	50	162	162	-9%
8	TRANSMISSION	400	660	(260)	7,400	5,985	1,415	1,675	544	7,800	6,603	1,197	618	618	13%
9	Other Charge By Org	20	19	2	273	783	(509)	(511)	71	304	503	(199)	(280)	(280)	-493%
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
12	**Total CTE Programs**	$ 475	$ 966	$ (490)	$ 9,778	$ 8,747	$ 1,031	$ 1,521	$ 795	$ 10,274	$ 9,226	$ 1,048	$ 479	$ 479	-40%
13															
14	Base Programs	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
15	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
16	NORTH CENTRAL REGION	$ 54	$ 10	$ 44	$ 336	$ 321	$ 15	$ (29)	$ 29	$ 371	$ 274	$ 97	$ (47)	$ (47)	-261%
17	SOUTH CENTRAL REGION	28	(1)	28	273	346	(74)	(102)	31	294	311	(17)	(35)	(35)	-213%
18	NORTH COASTAL REGION	25	-	25	220	194	26	2	18	230	172	58	(22)	(22)	-222%
19	SOUTH COASTAL REGION	35	63	(28)	348	395	(47)	(19)	36	375	248	127	(147)	(147)	-510%
21	DIST OPS & SUPPORT	-	1	(1)	-	7	(7)	(7)	1	-	-	-	(7)	(7)	-1200%
22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
25	**Total Base Programs**	$ 141	$ 73	$ 68	$ 1,177	$ 1,263	$ (86)	$ (155)	$ 115	$ 1,270	$ 1,005	$ 266	$ (258)	$ (258)	-325%
26															
27	Tree Trimming	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
28	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
29	CTE	$ 395	$ 920	$ (525)	$ 5,839	$ 4,896	$ 943	$ 1,468	$ 445	$ 6,234	$ 5,237	$ 997	$ 341	$ 341	-23%
30	DISTRIBUTION	1,132	1,774	(642)	14,260	10,590	3,670	4,312	963	15,453	13,139	2,314	2,548	2,548	165%
31	TRANSMISSION	4	39	(35)	46	475	(429)	(395)	43	52	52	-	(423)	(423)	-1080%
32	**Total Tree Trimming**	$ 1,531	$ 2,733	$ (1,202)	$ 20,145	$ 15,961	$ 4,184	$ 5,385	$ 1,451	$ 21,738	$ 18,427	$ 3,311	$ 2,466	$ 2,466	70%
33															
34	R&D - Business Case	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					

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Progress Energy

Progress Energy Florida
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Row	Description - Charge To DOS	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
36	R&D Revenue	86	-	86	877	178	698	612	16	$ 940	-	940	(178)	(178)	-1200%
37	R&D Expenses	96	142	(46)	1,083	813	271	317	74	1,224	1,010	214	197	197	167%
38	Income Tax	(4)	(57)	53	(83)	(254)	171	118	(23)	114	-	114	254	254	-1200%
39	**Net R&D Business Case Impact**	$ (6)	$ (85)	$ 79	$ (124)	$ (381)	$ 257	$ 177	$ (35)	$ (398)	$ (1,010)	$ 613	$ (630)	$ (630)	1720%

40

41 NOTE - R&D's Budget is not reflected in ED-FL. The budget was based on a business case prepared supporting this program.

42

Row	R&D Region Work - excludes Bus Case	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
44	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
45	NORTH CENTRAL REGION	$ 26	$ 11	$ 15	$ 288	$ 117	$ 171	$ 156	$ 11	$ 323	$ 323	$ -	$ 206	$ 206	1833%
46	SOUTH CENTRAL REGION	18	13	5	210	179	31	25	16	237	237	-	57	57	251%
47	NORTH COASTAL REGION	85	70	15	977	619	358	343	56	1,104	1,019	85	400	400	611%
48	SOUTH COASTAL REGION	53	42	11	609	436	173	162	40	685	770	(85)	334	334	743%
50	DIST OPS & SUPPORT	-	0	(0)	-	5	(5)	(4)	0	-	-	-	(5)	(5)	-1200%
51	**Total R&D Region Work**	$ 182	$ 136	$ 46	$ 2,083	$ 1,356	$ 727	$ 681	$ 123	$ 2,349	$ 2,349	$ -	$ 992	$ 992	705%

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Row	Streetlight Maintenance - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
54	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
55	NORTH CENTRAL REGION	$ 71	$ 109	$ (39)	$ 756	$ 683	$ 73	$ 112	$ 62	$ 842	$ 746	$ 96	$ 63	$ 63	1%
56	SOUTH CENTRAL REGION	94	52	43	1,145	678	467	424	62	1,270	858	411	180	180	192%
57	NORTH COASTAL REGION	37	42	(5)	417	288	130	134	26	470	470	-	182	182	598%
58	SOUTH COASTAL REGION	112	185	(74)	1,296	1,179	117	191	107	1,455	1,455	-	276	276	158%
60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
61	Total Streetlight Maintenance	$ 314	$ 388	$ (75)	$ 3,614	$ 2,828	$ 786	$ 861	$ 257	$ 4,036	$ 3,530	$ 507	$ 702	$ 702	173%
62															

Row	Line Ops - Troubleman - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)						Year-End - (000's)					
64	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Cost Per Outage	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
65	NORTH CENTRAL REGION	$ 27	$ 14	$ 13	$ 294	$ 208	$ 86	$ 73	$ 19	$ 23.95	$ 329	$ 127	$ 202	$ (81)	$ (81)	-529%
66	NORTH CENTRAL REGION	27	14	13	294	208	86	73	19	$ 28.53	329	127	202	(81)	(81)	-529%
67	NORTH COASTAL REGION	24	28	(3)	274	296	(22)	(19)	27	$ 46.79	309	258	51	(38)	(38)	-242%
68	SOUTH COASTAL REGION	34	41	(7)	402	489	(87)	(80)	44	$ 45.33	450	229	221	(260)	(260)	-686%
70	-	-	-	-	-	-	-	-	-		-	-	-	-	-	0%
71	Total Line Ops - Troubleman	$ 113	$ 97	$ 16	$ 1,265	$ 1,202	$ 63	$ 47	$ 109	$ 36.28	$ 1,417	$ 741	$ 676	$ (461)	$ (461)	-522%
72																
73																

Row	Dispatch - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)						Year-End - (000's)					
75	Description - Charge To DOS	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Cost Per Outage	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
76	Bargaining Unit OT	$ 80	$ 102	$ (22)	$ 849	$ 1,833	$ (984)	$ (962)	$ 167	$ 55.33	$ 999	$ 999	$ -	$ (834)	$ (834)	-600%
77																
78	Total Dispatch Direct Costs	269	266	3	3,016	3,284	(268)	(271)	299	$ 99.14	3,451	3,496	(45)	212	212	-29%
79																
80																

Row	Meter Reading - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)						Year-End - (000's)					
82	Description - Charge To DOS	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Cost Per Customer	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
83	Bargaining Unit OT	$ 40	$ 83	$ (43)	$ 400	$ 783	$ (383)	$ (340)	$ 71	$ 0.51	$ 453	$ 453	$ -	$ (331)	$ (331)	-565%
84																
85	Total Meter Reading Direct Costs	528	610	(82)	6,152	6,650	(497)	(416)	605	$ 4.31	6,923	7,022	(98)	372	372	-38%
86																

Row	Safety & Training - Direct Costs Only	Current Month - (000's)			Year-to-Date - (000's)						Year-End - (000's)					
88	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Cost Per Employee	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
89	NORTH CENTRAL REGION	$ 132	$ 62	$ 70	$ 1,434	$ 912	$ 522	$ 452	$ 83	$ 3,256	$ 1,602	$ 1,489	$ 113	$ 578	$ 578	597%
90	SOUTH CENTRAL REGION	124	63	61	1,370	827	543	482	75	2,659	1,527	1,241	286	414	414	451%
91	NORTH COASTAL REGION	80	55	24	905	653	252	228	59	3,314	1,022	1,022	-	369	369	522%
92	SOUTH COASTAL REGION	100	54	46	1,167	1,144	23	(23)	104	3,631	1,304	1,181	123	37	37	-64%
94	DIST OPS & SUPPORT	147	125	22	1,677	1,399	278	256	127	2,797	1,885	1,661	224	262	262	106%
95	TRANSMISSION	156	169	(13)	1,781	2,033	(253)	(240)	185	5,295	2,014	2,014	-	(19)	(19)	-110%
96	ENERGY DELIVERY SERVICES	4	5	(1)	34	21	14	15	2		39	39	-	19	19	894%
97	-	-	-	-	-	-	-	-	-		-	-	-	-	-	0%
98	Total Safety & Training	$ 743	$ 533	$ 210	$ 8,367	$ 6,987	$ 1,379	$ 1,170	$ 635	$ 3,517	$ 9,393	$ 8,647	$ 746	$ 1,659	$ 1,659	161%

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NON REGULATED O&M INFORMATION:

EDS Strategic Areas	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
Description	Budget	Actual	Variance	Budget	Actual	Variance	Prior Month YTD Var	Burn Rate	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
Payroll & Related Burdens	$ 656	$ 660	$ (5)	$ 7,502	$ 6,318	$ 1,184	$ 1,189	$ 574	$ 8,483	$ 8,483	$ -	$ 2,165	$ 2,165	277%
Advertising	88	1,077	(989)	3,353	3,085	268	1,256	280	4,186	4,186	-	1,101	1,101	293%
Customer Incentives	4,365	4,193	172	45,561	40,727	4,834	4,662	3,702	49,703	49,703	-	8,976	8,976	142%
Other Costs	207	423	(216)	6,657	4,343	2,313	2,529	395	6,638	6,638	-	2,295	2,295	481%
Total Costs	5,316	6,353	(1,037)	63,072	54,473	8,599	9,636	4,952	69,011	69,011	-	14,537	14,537	194%
Customer & Program Incentives Detail Breakout:														
Interruptible	1,769	1,801	(32)	17,882	17,462	420	452	1,587	19,454	19,454	-	1,992	1,992	25%
Residential Energy Mgmt	2,109	1,795	314	21,326	18,046	3,280	2,966	1,641	23,201	23,201	-	5,154	5,154	214%
Other Program Incentives	288	429	(141)	3,920	3,053	867	1,008	278	4,358	4,358	-	1,305	1,305	370%
Other Customer Incentives	199	168	31	2,433	2,166	267	236	197	2,691	2,691	-	525	525	167%
Total Incentives	$ 4,365	$ 4,193	$ 172	$ 45,561	$ 40,727	$ 4,834	$ 4,662	$ 3,702	$ 49,703	$ 49,703	$ -	$ 8,976	$ 8,976	142%

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Progress Energy Florida
Energy Delivery Monthly Financial Summary - Capital
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Regulated Capital — Current Month - (000's)

Line #	Description - Charge To	Budget	Actual	Variance	
1	NORTH CENTRAL REGION	$ 2,315	$ 3,229	$ (915)	
2	SOUTH CENTRAL REGION	2,922	2,804	318	
3	NORTH COASTAL REGION	1,220	2,158	(938)	
4	SOUTH COASTAL REGION	2,577	2,952	(375)	
5	COASTAL REGION COMBINED	3,798	5,110	(1,313)	
6	DIST OPS & SUPPORT	4,449	3,823	627	
7	Distribution Total	$ 13,484	$ 14,766	$ (1,283)	#N/A
8	Note: Current Month does not have Price Impact included				
9					
10					
11					
12	TRANSMISSION	$ 4,067	$ 6,559	$ (2,492)	
13	CTE PROJECT MANAGEMENT	345	548	(203)	
14	ENERGY DELIVERY ADMIN	597	592	5	
15	ENERGY DELIVERY SERVICES	15	1	15	
16	ED MANAGER BUSINESS OPERATIONS	-	-	-	
17	FPC - ED	-	-	-	
18	Total Regulated Capital	$ 18,509	$ 22,463	$ (3,955)	
19	NOTE: Due to the impact of Price and the way it is calculated; it is not reflected in the current month. Therefore, you can not take Prior Month Variance and add Current Month Variance to tie to current YTD variance.				

Regulated Capital — Year-to-Date - (000's)

Line #	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var
1	$ 26,452	$ 24,752	$ 1,700	$ 2,250	$ 2,614
2	33,633	31,751	1,882	2,886	1,583
3	15,073	16,804	(1,530)	1,509	(592)
4	30,076	29,883	193	2,717	568
5	45,150	46,486	(1,337)	4,226	(24)
6	54,821	47,255	7,566	4,296	6,940
7	$ 160,056	$ 150,245	$ 9,811	$ 13,659	$ 11,093
8			-		-
9			-		-
10			$ -		$ -
12	$ 57,053	$ 52,569	$ 4,484	$ 4,779	$ 6,976
13	14,835	11,658	3,178	1,060	3,378
14	11,867	10,185	1,682	926	1,877
15	169	62	107	6	92
16	-	-	-	-	-
17	-	-	-	-	-
18	$ 243,981	$ 224,719	$ 19,261	$ 20,429	$ 23,216

Regulated Capital — Year-End - (000's)

Line #	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
1	$ 29,187	$ 28,790	$ 397	$ 4,037	$ 4,037	79%
2	36,582	36,133	448	4,382	4,382	52%
3	16,554	15,930	624	(674)	(674)	-145%
4	32,834	33,372	(538)	3,489	3,489	28%
5	49,388	49,302	86	2,815	2,815	-33%
6	59,190	59,752	(562)	12,497	12,497	191%
7	$ 174,347	$ 173,977	$ 371	$ 23,732	$ 23,732	74%
8			-			
9			-			
10			$ -			
12	$ 82,006	$ 80,507	$ 1,500	$ 7,937	$ 7,937	66%
13	15,182	13,887	1,295	2,230	2,230	110%
14	12,403	10,971	1,432	785	785	-15%
15	165	185	-	123	123	2073%
16	-	-	-	-	-	0%
17	-	-	-	-	-	0%
18	$ 264,123	$ 259,526	$ 4,597	$ 34,807	$ 34,807	70%

Revenue Construction — Current Month

Line #	Description - Charge By	Budget Units	Actual Units	Unit Variance	Volume Variance $	Prior Year Units
1	Volume Adjustment				(000's)	
2	NORTH CENTRAL REGION	554	807	(253)	$ (197)	963
3	SOUTH CENTRAL REGION	1,093	1,619	(526)	(452)	1,609
4	NORTH COASTAL REGION	427	530	(103)	(106)	632
5	SOUTH COASTAL REGION	671	749	(78)	(30)	488
6	COASTAL REGION AVERAGE	1,098	1,279	(181)	(136)	1,066
7	Total Distribution Vol Adj	2,745	3,705	(960)	$ (785)	3,670
8						
9	DOS	2,745	3,705	(960)	(518)	3,670
10	Total Dist & DOS Volume Adjustment				$ (1,304)	

Revenue Construction — Year-to-Date

Line #	Budget Units	Actual Units	Variance Units	Volume Variance $	Prior Month YTD Volume Variance $
1				(000's)	(000's)
2	6,225	7,053	(828)	$ (641)	(444)
3	13,891	16,733	(2,842)	(2,323)	(1,871)
4	4,594	5,451	(857)	(943)	(837)
5	7,077	9,089	(2,012)	(1,573)	(1,543)
6	11,671	14,540	(2,869)	(2,516)	(2,380)
7	31,787	38,326	(6,539)	$ (5,480)	$ (4,694)
8					
9	31,787	38,326	(6,539)	(3,531)	(3,013)
10				$ (9,011)	$ (7,708)

Revenue Construction — Year-End

Line #	Budget Units	Projection Units	Var Units	Volume Variance $	2003 Actual Units
1				(000's)	
2	6,778	7,823	$ (1,045)	$ (817)	10,252
3	14,956	18,296	(3,340)	(2,875)	17,275
4	5,021	6,121	(1,100)	(1,198)	6,687
5	7,746	9,824	(2,078)	(1,604)	4,258
6	12,767	15,945	(3,178)	(2,802)	10,945
7	34,501	42,064	(7,563)	$ (6,293)	38,472
8					
9	34,501	42,064	(7,563)	(4,064)	38,472
10				$ (10,378)	

Price Adjustment — Current Month

Line #	Description - Charge By	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance Impact
11					
12					
13	Price Adjustment				(000's)
14	NORTH CENTRAL REGION	$ 928	$ 810	$ 116	$ 57
15	SOUTH CENTRAL REGION	743	646	97	218
16	NORTH COASTAL REGION	979	1,428	(448)	(232)
17	SOUTH COASTAL REGION	965	902	63	2
18	COASTAL REGION AVERAGE	971	1,120	(149)	(230)
19	DOS	-	-	-	-
20	Total Price Adjustment	$ 871	$ 845	$ 26	$ 45

Price Adjustment — Year-to-Date

Line #	Budget Price	Actual Price	Unit Price Variance $	Price Variance Impact	Prior Month YTD Price Variance $
13				(000's)	(000's)
14	$ 925	$ 759	$ 165	$ 1,042	985
15	736	588	149	2,716	2,496
16	980	963	18	199	(75)
17	964	650	314	2,491	3,493
18	971	767	203	2,689	3,418
19	-	-	-	-	-
20	$ 859	$ 687	$ 172	$ 6,447	$ 6,900

Price Adjustment — Year-End

Line #	Budget Price	Projection Price	Price Variance $	Price Variance Impact
13				(000's)
14	$ 925	$ 801	$ 124	$ 986
15	737	606	131	2,399
16	980	804	176	1,078
17	964	760	204	2,004
18	971	777	193	3,082
19	-	-	-	-
20	$ 860	$ 707	$ 153	$ 6,447

LRC Projects Not Budgeted

Line #		Current Month Budget	Actual	Variance	YTD Budget	Actual	Variance	Prior Month YTD Var	Year-End Budget	Projection	Variance
21											
22	LRC Projects Not Budgeted										
23		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24											

Meters & Transformer Purchases — Current Month - (000's)

Line #	Description - Charge To DOS	Budget	Actual	Variance
25	Meters & Transformer Purchases			
26				
27	METERS	$ 143	$ 403	$ (260)
28	TRANSFORMERS-OH	376	200	176
29	TRANSFORMERS-UG	935	702	233
30	Total Meters & Transformers	$ 1,454	$ 1,304	$ 150

Meters & Transformer Purchases — Year-to-Date (000's)

Line #	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var
27	$ 3,679	$ 3,798	$ (119)	$ 345	$ 141
28	4,326	4,757	(431)	432	(607)
29	10,754	8,121	2,633	738	2,399
30	$ 18,759	$ 16,676	$ 2,083	$ 1,516	$ 1,933

Meters & Transformer Purchases — Year-End - (000's)

Line #	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
27	$ 3,930	$ 3,930	$ -	$ 132	$ 132	-62%
28	4,842	5,328	(684)	569	569	32%
29	11,540	10,058	1,482	1,937	1,937	162%
30	$ 20,112	$ 19,314	$ 798	$ 2,638	$ 2,638	74%

Streetlight Construction — Current Month

Line #	Description - Charge To	Budget Units	Actual Units	Unit Variance	Volume Variance $
31					
32					
33	Streetlight Construction				
34					
35	Volume Adjustment				($000's)
36	NORTH CENTRAL REGION	366	150	216	$ 167
37	SOUTH CENTRAL REGION	574	417	157	149
38	NORTH COASTAL REGION	202	129	73	41
39	SOUTH COASTAL REGION	454	395	59	47
40	COASTAL REGION COMBINED	656	524	132	89
41	Total Dist Regions Vol Adj	1,596	1,091	505	$ 405

Streetlight Construction — Year-to-Date

Line #	Budget Units	Actual Units	Unit Variance	Volume Variance $	Prior Month YTD Volume Variance $:
35				($000's)	($000's)
36	3,743	2,555	1,188	$ 919	$ 752
37	7,098	5,554	1,544	1,487	1,318
38	2,090	1,312	778	442	401
39	4,638	5,008	(370)	(296)	(343)
40	6,729	6,320	409	146	58
41	17,570	14,429	3,141	$ 2,532	$ 2,128

Streetlight Construction — Year-End

Line #	Budget Units	Projection Units	Variance	Volume Variance $	2003 Actual Units:
35				($000's)	
36	4,125	2,806	$ 1,319	$ 1,020	4,241
37	7,709	5,908	1,801	1,711	6,106
38	2,298	1,442	856	486	3,648
39	5,102	5,462	(360)	(288)	2,294
40	7,400	6,904	496	198	5,942
41	19,235	15,618	3,617	$ 2,930	16,289

Streetlight Price Adjustment — Current Month

Line #	Description - Charge To	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance $ Impact
42					
43					
44	Price Adjustment				($000's)
45	NORTH CENTRAL REGION	$ 773	$ 516	$ 257	$ 39
46	SOUTH CENTRAL REGION	950	701	249	104
47	NORTH COASTAL REGION	568	519	49	6
48	SOUTH COASTAL REGION	800	561	239	94
49	COASTAL REGION COMBINED	729	551	178	101
50	Total Price Adjustment	$ 819	$ 603	$ 215	$ 243

Streetlight Price Adjustment — Year-to-Date

Line #	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance $ Impact	Prior Month YTD Price Variance $:
44				($000's)	($000's)
45	$ 773	$ 732	$ 41	$ 105	$ 87
46	950	853	97	540	437
47	568	603	(35)	(46)	(53)
48	800	758	42	208	114
49	728	726	2	162	61
50	$ 827	$ 776	$ 51	$ 808	$ 565

Streetlight Price Adjustment — Year-End

Line #	Budget Price	Projection Price	Unit Price Variance $: Fav/(Unfav)	Price Variance Impact:
44				($000's)
45	$ 773	$ 1,137	$ (364)	$ (1,020)
46	950	1,240	(290)	(1,711)
47	568	905	(337)	(486)
48	800	747	53	288
49	728	780	(52)	(198)
50	$ 827	$ 1,018	$ (191)	$ (2,930)

Line #				
51				
52	Streetlight Construction $	Current Month - (000's)	Year-to-Date (000's)	Year-End - (000's)

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Progress Energy

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Energy Delivery Monthly Financial Summary - Capital
2004 - November

	Description - Charge To	Budget	Actual	Variance
53				
54	NORTH CENTRAL REGION	$ 283	$ 77	$ 205
55	SOUTH CENTRAL REGION	545	292	253
56	NORTH COASTAL REGION	114	67	48
57	SOUTH COASTAL REGION	363	222	142
58	COASTAL REGION COMBINED	$ 478	$ 289	$ 189
59		-	-	-
60	Total Streetlight Construction	$ 1,306	$ 370	$ 458
61				
62	Revenue Adjustment Included -	Volume & LRC		

	Description - Charge To	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var
54	NORTH CENTRAL REGION	$ 2,895	$ 1,871	$ 1,024	$ 170	$ 819
55	SOUTH CENTRAL REGION	6,743	4,736	2,007	431	1,754
56	NORTH COASTAL REGION	1,187	791	396	72	348
57	SOUTH COASTAL REGION	3,711	3,798	(87)	345	(229)
58	COASTAL REGION COMBINED	$ 4,898	$ 4,590	$ 309	$ 417	$ 119
59		-	-	-	-	-
60	Total Streetlight Construction	$ 14,536	$ 11,198	$ 3,340	$ 1,018	$ 2,692

	Description - Charge To	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
54	NORTH CENTRAL REGION	$ 3,190	$ 3,190	$ -	$ 1,320	$ 1,320	678%
55	SOUTH CENTRAL REGION	7,324	7,324	-	2,588	2,588	501%
56	NORTH COASTAL REGION	1,308	1,306	-	514	514	615%
57	SOUTH COASTAL REGION	4,082	4,082	-	283	283	-18%
58	COASTAL REGION COMBINED	$ 5,387	$ 5,387	$ -	$ 798	$ 798	91%
59		-	-	-	-	-	0%
60	Total Streetlight Construction	$ 15,901	$ 15,901	$ -	$ 4,705	$ 4,705	362%

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Row	Merchant Plant Construction - Vandolah	Current Month - (000's)			Year-to-Date (000's)					Year-End - (000's)					
65	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
66	TRANSMISSION	$ 240	$ 711	$ (471)	$ 13,273	$ 11,427	$ 1,847	$ 1,039	$ 2,317	$ 13,283	$ 11,305	$ 1,978	$ (122)	$ (122)	-112%

Row	CTE Programs	Current Month - (000's)			Year-to-Date (000's)					Year-End - (000's)					
69	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
70	NORTH CENTRAL REGION	74	116	(43)	5,243	3,360	$ 1,883	$ 305	1,926	$ 5,318	$ 3,906	$ 1,413	$ 545	$ 545	79%
71	SOUTH CENTRAL REGION	4	90	(86)	2,599	2,383	216	217	301	2,803	2,787	(184)	404	404	86%
72	NORTH COASTAL REGION	21	(2)	23	1,940	1,734	205	158	183	1,961	2,222	(261)	488	488	209%
73	SOUTH COASTAL REGION	55	192	(137)	1,745	1,292	453	117	590	1,800	1,463	337	170	170	45%
73	DIST OPS & SUPPORT	-	0	(0)	-	30	(30)	3	(30)	-	-	-	(30)	(30)	-1200%
74	TRANSMISSION	192	102	89	3,308	2,165	1,143	197	1,054	3,500	3,500	-	1,335	1,335	578%
75	ENERGY DELIVERY SERVICES	-	-	-	-	1	(1)	0	(1)	-	-	-	(1)	(1)	-1200%
76	Other Charge By Org	-	47	(47)	-	692	(692)	63	(645)	-	10	(10)	(682)	(682)	-1184%
77	Total CTE Programs	$ 345	$ 546	$ (200)	$ 14,835	$ 11,658	$ 3,178	$ 1,060	$ 3,378	$ 15,182	$ 13,887	$ 1,295	$ 2,230	$ 2,230	110%

Row	Base Programs	Current Month - (000's)			Year-to-Date (000's)					Year-End - (000's)					
80	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
81	NORTH CENTRAL REGION	386	276	110	2,394	1,351	$ 1,043	$ 123	$ 933	$ 2,651	$ 1,662	$ 989	$ 311	$ 311	153%
82	SOUTH CENTRAL REGION	166	104	62	1,650	1,259	391	114	329	1,781	1,440	341	181	181	58%
83	NORTH COASTAL REGION	136	41	95	1,219	638	580	58	485	1,274	1,012	261	374	374	544%
84	SOUTH COASTAL REGION	328	353	(25)	3,296	3,044	252	277	277	3,567	3,308	259	264	284	-4%
88	DIST OPS & SUPPORT	78	43	34	884	486	398	44	364	999	931	69	445	445	908%
87	TRANSMISSION	-	-	-	-	5	(5)	0	(5)	-	-	-	(5)	(5)	-1200%
88	Other Charge By Org	-	(3)	3	-	(44)	44	(4)	41	-	-	-	44	44	-1200%
89	Total Base Programs	$ 1,093	$ 815	$ 279	$ 9,442	$ 6,739	$ 2,703	$ 613	$ 2,424	$ 10,273	$ 8,353	$ 1,920	$ 1,614	$ 1,614	163%

Row	Load Growth Projects	Current Month - (000's)			Year-to-Date (000's)					Year-End - (000's)					
92	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
93	NORTH CENTRAL REGION	$ 9	$ 122	$ (113)	$ 431	$ 590	$ (159)	$ 54	$ (46)	$ 436	$ 467	$ (31)	$ (123)	$ (123)	-329%
94	SOUTH CENTRAL REGION	-	204	(204)	1,009	883	126	80	330	1,009	545	465	(339)	(339)	-522%
95	NORTH COASTAL REGION	11	(3)	14	386	203	182	18	148	367	258	110	54	54	195%
96	SOUTH COASTAL REGION	173	101	72	3,258	1,013	2,246	92	2,174	3,400	2,459	941	1,448	1,446	1471%
98	DIST OPS & SUPPORT	-	2	(2)	-	4	(4)	0	(2)	-	-	-	(4)	(4)	-1200%
99	TRANSMISSION	440	341	99	6,881	5,529	1,351	503	1,253	7,569	7,569	-	2,040	2,040	306%
100	Other Charge By Org	-	18	(18)	-	522	(522)	47	(503)	-	53	(53)	(468)	(468)	-1087%
101	Total Load Growth Projects	$ 633	$ 785	$ (152)	$ 11,946	$ 8,744	$ 3,201	$ 795	$ 3,354	$ 12,782	$ 11,351	$ 1,431	$ 2,607	$ 2,607	228%

Row	DOT Projects	Current Month - (000's)			Year-to-Date (000's)					Year-End - (000's)					
104	Description - Charge By	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
105	NORTH CENTRAL REGION	$ 117	$ 84	$ 33	$ 1,283	$ 1,037	$ 246	$ 94	$ 213	$ 1,400	$ 1,800	$ (400)	$ 763	$ 763	709%
106	SOUTH CENTRAL REGION	144	197	(53)	3,369	3,820	(451)	347	(398)	3,500	4,400	(900)	580	580	67%
107	NORTH COASTAL REGION	34	99	(65)	1,021	2,013	(992)	183	(927)	1,051	2,127	(1,076)	114	114	-37%
108	SOUTH COASTAL REGION	88	403	(316)	963	3,132	(2,170)	285	(1,854)	1,050	3,000	(1,950)	(132)	(132)	-146%
110	DIST OPS & SUPPORT	-	70	(70)	-	578	(576)	52	(506)	-	147	(147)	(429)	(429)	-920%
111	TRANSMISSION	-	-	-	-	34	(34)	3	(34)	-	-	-	(34)	(34)	-1200%
112	Other Charge By Org	-	-	-	-	407	(407)	37	(407)	-	-	-	(407)	(407)	-1200%
113	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
114	Total DOT Projects	$ 382	$ 853	$ (471)	$ 6,636	$ 11,019	$ (4,383)	$ 1,002	$ (3,913)	$ 7,001	$ 11,474	$ (4,473)	$ 455	$ 455	-55%

Row	Replace / Refurbish	Current Month - (000's)			Year-to-Date (000's)					Year-End - (000's)					
117	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
118	NORTH CENTRAL REGION	$ 545	$ 675	$ (130)	$ 6,659	$ 6,566	$ 93	$ 597	$ 223	$ 7,335	$ 6,849	$ 486	$ 283	$ 283	-53%
119	SOUTH CENTRAL REGION	403	291	112	5,008	4,837	171	440	59	5,438	4,882	556	44	44	-90%
120	NORTH COASTAL REGION	148	205	(57)	2,911	2,915	(4)	265	52	3,066	2,751	315	(165)	(165)	-162%
121	SOUTH COASTAL REGION	651	859	(208)	6,862	7,555	(694)	687	(485)	7,508	7,869	(361)	314	314	-54%
123	DIST OPS & SUPPORT	36	196	(160)	315	656	(340)	60	(180)	343	343	-	(313)	(313)	-625%
124	CTE PROJECT MANAGEMENT	-	-	-	-	10	(10)	1	(10)	-	-	-	(10)	(10)	-1200%
125	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
126	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
127	Total Storm Restoration	$ 1,783	$ 2,225	$ (443)	$ 21,755	$ 22,539	$ (784)	$ 2,049	$ (342)	$ 23,689	$ 22,693	$ 996	$ 154	$ 154	-92%

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Progress Energy

Progress Energy Florida
Energy Delivery Monthly Financial Summary - Capital
2004 - November

128	Grow	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
129	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
130	NORTH CENTRAL REGION	$ 1,226	$ 1,127	$ 99	$ 13,324	$ 12,915	$ 409	$ 1,174	310	$ 14,656	$ 14,926	$ (271)	$ 2,012	$ 2,012	71%
131	SOUTH CENTRAL REGION	2,213	2,111	102	24,851	22,804	2,047	2,073	1,945	28,998	27,480	(482)	4,676	4,676	126%
132	NORTH COASTAL REGION	912	1,575	(662)	9,997	11,279	(1,282)	1,025	(619)	11,147	10,744	404	(535)	(535)	-152%
133	SOUTH COASTAL REGION	1,420	1,530	(110)	17,571	17,953	(381)	1,632	(271)	19,109	20,494	(1,385)	2,541	2,541	58%
135	DIST OPS & SUPPORT	2,777	2,275	501	35,922	27,169	8,753	2,470	8,252	38,833	36,573	2,260	9,404	9,404	281%
136	TRANSMISSION	2,805	1,582	1,223	24,007	17,089	6,918	1,554	5,695	27,132	26,872	460	9,584	9,584	517%
137	CTE PROJECT MANAGEMENT	-	6	(6)	-	8	(8)	1	(2)	-	-	-	(8)	(8)	-1200%
138	ENERGY DELIVERY ADMIN	-	(6)	6	-	(72)	72	(7)	66	-	-	-	72	72	-1200%
139	ENERGY DELIVERY SERVICES	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
140	ED MANAGER BUSINESS OPERATIONS	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
141		-	-	-	-	-	-	-	-	-	-	-	-	-	0%
142	**Total Grow Capital Category**	$ 11,352	$ 10,200	$ 1,151	$ 125,672	$ 109,144	$ 16,528	$ 9,922	$ 15,377	$ 137,876	$ 136,889	$ 987	$ 27,745	$ 27,745	100%
143															

144	Maintain	Current Month - (000's)			Year-to-Date - (000's)					Year-End - (000's)					
145	Description - Charge To	Budget	Actual	Variance	Budget	Actual	Variance	Burn Rate	Prior Month YTD Var	Budget	Projection	Variance	Burn Rate	Remaining Spending	Burn Rate % (Dec) / Inc to Meet Projection
146	NORTH CENTRAL REGION	$ 1,089	$ 2,103	$ (1,014)	$ 13,128	$ 11,838	$ 1,290	$ 1,076	$ 2,304	$ 14,531	$ 13,863	$ 668	$ 2,025	$ 2,025	88%
147	SOUTH CENTRAL REGION	710	493	217	6,782	8,947	(165)	813	(382)	9,583	8,653	930	(293)	(293)	-138%
148	NORTH COASTAL REGION	308	584	(276)	5,077	5,325	(248)	484	27	5,407	5,186	220	(139)	(139)	-129%
149	SOUTH COASTAL REGION	1,156	1,422	(264)	12,505	11,930	575	1,085	839	13,725	12,878	847	948	948	-13%
149	DIST OPS & SUPPORT	1,673	1,547	125	18,898	20,086	(1,187)	1,826	(1,313)	20,357	23,179	(2,822)	3,093	3,093	69%
150	TRANSMISSION	1,262	4,977	(3,715)	33,047	35,460	(2,434)	3,225	1,281	34,874	33,834	1,040	(1,646)	(1,646)	-151%
151	CTE PROJECT MANAGEMENT	345	540	(194)	14,835	11,650	3,185	1,059	3,380	15,182	13,887	1,295	2,238	2,238	111%
152	ENERGY DELIVERY ADMIN	597	598	(1)	11,867	10,257	1,610	932	1,611	12,403	10,971	1,432	714	714	-23%
153	ENERGY DELIVERY SERVICES	15	1	15	169	62	107	8	92	185	185	-	123	123	2073%
154	FPC - ED	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
155		-	-	-	-	-	-	-	-	-	-	-	-	-	0%
156	**Total Maintain Capital Category**	$ 7,157	$ 12,263	$ (5,106)	$ 118,309	$ 115,575	$ 2,733	$ 10,507	$ 7,840	$ 126,248	$ 122,637	$ 3,610	$ 7,062	$ 7,062	-33%
157															
158	**Total Capital**	$ 18,509	$ 22,463	$ (3,955)	$ 243,981	$ 224,719	$ 19,261	$ 20,429	$ 23,216	$ 264,123	$ 259,526	$ 4,597	$ 34,807	$ 34,807	70%

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Progress Energy

Progress Energy Florida
Energy Delivery Monthly Financial Summary - Revenue Construction
2004 - November

Revenue Construction - Volume

Current Month

Line #	Description - Charge To	Budget Units	Actual Units	Unit Variance	Volume Variance $ ($000's)	Prior Year Units:
1	Residential					
2	NORTH CENTRAL REGION	462	700	(238)	$ (169)	633
3	SOUTH CENTRAL REGION	975	1,386	(411)	(258)	1,411
4	NORTH COASTAL REGION	370	455	(85)	(69)	447
5	SOUTH COASTAL REGION	511	629	(118)	(92)	551
6	Total Dist Regions Res Vol Adj	2,317	3,170	(853)	$ (588)	3,042
7						
8	DOS - Meters & Transformers Vol Adj	2,317	3,170	(853)	(461)	3,042
9	Total Residential Volume Adj				$ (1,049)	
10						
11	Commercial & Industrial					
12	NORTH CENTRAL REGION	93	107	(14)	$ (29)	119
13	SOUTH CENTRAL REGION	118	233	(115)	(194)	194
14	NORTH COASTAL REGION	57	75	(18)	(37)	69
15	SOUTH COASTAL REGION	160	120	40	63	231
16	Total Dist Regions C&I Vol Adj	428	535	(107)	$ (197)	613
17						
18	DOS - Meters & Transformers	428	535	(107)	(58)	613
19	Total C&I Volume Adj				$ (255)	
20						
21	Combined Residential and C&I					
22	NORTH CENTRAL REGION	554	807	(253)	$ (197)	963
23	SOUTH CENTRAL REGION	1,093	1,619	(526)	(452)	1,609
24	NORTH COASTAL REGION	427	530	(103)	(106)	632
25	SOUTH COASTAL REGION	671	749	(78)	(30)	466
26	Total Dist Regions Vol Adj	2,745	3,705	(960)	$ (785)	3,670
27						
28	DOS - Meters & Transformers Vol Adj	2,745	3,705	(960)	(518)	3,670
29	Total Volume Adjustment				$ (1,304)	
30						

Year-to-Date

Line #	Description - Charge To	Budget Units	Actual Units	Unit Variance	Volume Variance $ ($000's)	Prior Month YTD Volume Variance $: ($000's)
1	Residential					
2	NORTH CENTRAL REGION	5,189	5,975	(786)	$ (556)	$ (387)
3	SOUTH CENTRAL REGION	12,477	14,811	(2,334)	(1,466)	(1,208)
4	NORTH COASTAL REGION	3,977	4,636	(659)	(536)	(467)
5	SOUTH COASTAL REGION	5,396	7,409	(2,013)	(1,575)	(1,482)
6	Total Dist Regions Res Vol Adj	27,038	32,831	(5,793)	$ (4,132)	$ (3,544)
7						
8	DOS - Meters & Transformers Vol Adj	27,038	32,831	(5,793)	(3,128)	(2,668)
9	Total Residential Volume Adj				$ (7,260)	$ (6,211)
10						
11	Commercial & Industrial					
12	NORTH CENTRAL REGION	1,035	1,078	(43)	$ (86)	$ (57)
13	SOUTH CENTRAL REGION	1,415	1,922	(507)	(857)	(663)
14	NORTH COASTAL REGION	617	815	(198)	(407)	(371)
15	SOUTH COASTAL REGION	1,681	1,680	1	2	(61)
16	Total Dist Regions C&I Vol Adj	4,749	5,495	(746)	$ (1,348)	$ (1,151)
17						
18	DOS - Meters & Transformers	4,749	5,495	(746)	(403)	(346)
19	Total C&I Volume Adj				$ (1,751)	$ (1,496)
20						
21	Combined Residential and C&I					
22	NORTH CENTRAL REGION	6,225	7,053	(828)	$ (641)	$ (444)
23	SOUTH CENTRAL REGION	13,891	16,733	(2,842)	(2,323)	(1,871)
24	NORTH COASTAL REGION	4,594	5,451	(857)	(943)	(837)
25	SOUTH COASTAL REGION	7,077	9,089	(2,012)	(1,573)	(1,543)
26	Total Dist Regions Vol Adj	31,787	38,326	(6,539)	$ (5,480)	$ (4,694)
27						
28	DOS - Meters & Transformers Vol Adj	31,787	38,326	(6,539)	(3,531)	(3,013)
29	Total Volume Adjustment				$ (9,011)	$ (7,708)
30						

Year-End

Line #	Description - Charge To	Budget Units	Projection Units	Variance	Volume Variance $ ($000's)	2003 Actual Units:
1	Residential					
2	NORTH CENTRAL REGION	5,650	6,635	$ (985)	$ (696)	6,862
3	SOUTH CENTRAL REGION	13,423	16,220	(2,797)	(1,756)	15,329
4	NORTH COASTAL REGION	4,347	5,203	(856)	(696)	4,215
5	SOUTH COASTAL REGION	5,905	8,011	(2,106)	(1,647)	5,768
6	Total Dist Regions Res Vol Adj	29,325	36,069	(6,744)	$ (4,795)	32,174
7						
8	DOS - Meters & Transformers Vol Adj	29,325	36,069	(6,744)	(3,642)	32,174
9	Total Residential Volume Adj				$ (8,437)	
10						
11	Commercial & Industrial					
12	NORTH CENTRAL REGION	1,128	1,188	$ (60)	$ (121)	1,408
13	SOUTH CENTRAL REGION	1,532	2,076	(544)	(918)	1,896
14	NORTH COASTAL REGION	674	918	(244)	(502)	851
15	SOUTH COASTAL REGION	1,841	1,813	28	43	1,930
16	Total Dist Regions C&I Vol Adj	5,175	5,995	(820)	$ (1,498)	6,085
17						
18	DOS - Meters & Transformers	5,175	5,995	(820)	(443)	6,085
19	Total C&I Volume Adj				$ (1,941)	
20						
21	Combined Residential and C&I					
22	NORTH CENTRAL REGION	6,778	7,823	$ (1,045)	$ (817)	10,252
23	SOUTH CENTRAL REGION	14,956	18,296	(3,340)	(2,675)	17,275
24	NORTH COASTAL REGION	5,021	6,121	(1,100)	(1,198)	6,687
25	SOUTH COASTAL REGION	7,746	9,824	(2,078)	(1,604)	4,258
26	Total Dist Regions Vol Adj	34,501	42,064	(7,563)	$ (6,293)	38,472
27						
28	DOS - Meters & Transformers Vol Adj	34,501	42,064	(7,563)	(4,084)	38,472
29	Total Volume Adjustment				$ (10,378)	
30						

31 Revenue Construction - Price

Current Month

Line #	Description - Charge To	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance $ Impact ($000's)
33	Residential				
34	NORTH CENTRAL REGION	$ 707	$ 925	$ (218)	$ (152)
35	SOUTH CENTRAL REGION	628	849	(221)	(306)
36	NORTH COASTAL REGION	813	1,169	(356)	(162)
37	SOUTH COASTAL REGION	782	879	(97)	(61)
39	DOS	-	-	-	-
40	Total Price Adjustment	$ 707	$ 918	$ (210)	$ (662)
41					
42	Commercial & Industrial				
43	NORTH CENTRAL REGION	$ 2,015	$ 59	$ 1,956	$ 209
44	SOUTH CENTRAL REGION	1,689	(563)	2,252	525
45	NORTH COASTAL REGION	2,058	2,998	(940)	(71)
46	SOUTH COASTAL REGION	1,549	1,021	528	63
48	DOS	-	-	-	-
49	Total Price Adjustment	$ 1,756	$ 416	$ 1,341	$ 727
50					
51	Combined				
52	NORTH CENTRAL REGION	$ 926	$ 810	$ 116	$ 57
53	SOUTH CENTRAL REGION	743	646	97	218
54	NORTH COASTAL REGION	979	1,428	(448)	(232)
55	SOUTH COASTAL REGION	965	902	63	2
57	DOS	-	-	-	-
58	Total Price Adjustment	$ 871	$ 845	$ 26	$ 45
59					

Year-to-Date

Line #	Description - Charge To	Budget Price	Actual Price	Unit Price Variance $: Fav/(Unfav)	Price Variance $ Impact ($000's)	Prior Month YTD Price Variance $: ($000's)
33	Residential					
34	NORTH CENTRAL REGION	$ 707	$ 745	$ (38)	$ (228)	$ (75)
35	SOUTH CENTRAL REGION	628	535	93	1,372	1,678
36	NORTH COASTAL REGION	813	816	(3)	(15)	18
37	SOUTH COASTAL REGION	782	564	218	1,616	1,888
39	DOS	-	-	-	-	-
40	Total Price Adjustment	$ 701	$ 620	$ 81	$ 2,746	$ 3,508
41						
42	Commercial & Industrial					
43	NORTH CENTRAL REGION	$ 2,015	$ 838	$ 1,177	$ 1,269	$ 1,060
44	SOUTH CENTRAL REGION	1,689	990	699	1,344	820
45	NORTH COASTAL REGION	2,058	1,796	262	214	(93)
46	SOUTH COASTAL REGION	1,549	1,029	520	874	1,605
48	DOS	-	-	-	-	-
49	Total Price Adjustment	$ 1,758	$ 1,091	$ 667	$ 3,701	$ 3,392
50						
51	Combined					
52	NORTH CENTRAL REGION	$ 925	$ 759	$ 165	$ 1,042	$ 985
53	SOUTH CENTRAL REGION	736	588	149	2,716	2,498
54	NORTH COASTAL REGION	980	963	18	199	(75)
55	SOUTH COASTAL REGION	964	650	314	2,491	3,493
57	DOS	-	-	-	-	-
58	Total Price Adjustment	$ 859	$ 687	$ 172	$ 6,447	$ 6,900
59						

Year-End

Line #	Description - Charge To	Budget Price	Projection Price	Unit Price Variance $: Fav/(Unfav)	Price Variance Impact: ($000's)
33	Residential				
34	NORTH CENTRAL REGION	$ 707	$ 602	$ 105	$ 696
35	SOUTH CENTRAL REGION	628	520	108	1,756
36	NORTH COASTAL REGION	813	679	134	696
37	SOUTH COASTAL REGION	782	576	206	1,647
39	DOS	-	-	-	-
40	Total Price Adjustment	$ 702	$ 570	$ 131	$ 4,795
41					
42	Commercial & Industrial				
43	NORTH CENTRAL REGION	$ 2,015	$ 1,913	$ 102	$ 121
44	SOUTH CENTRAL REGION	1,689	1,276	413	857
45	NORTH COASTAL REGION	2,058	1,511	547	502
46	SOUTH COASTAL REGION	1,549	1,573	(24)	(43)
48	DOS	-	-	-	-
49	Total Price Adjustment	$ 1,758	$ 1,528	$ 230	$ 1,436
50					
51	Combined				
52	NORTH CENTRAL REGION	$ 925	$ 801	$ 124	$ 966
53	SOUTH CENTRAL REGION	737	606	131	2,399
54	NORTH COASTAL REGION	980	804	176	1,078
55	SOUTH COASTAL REGION	964	760	204	2,004
57	DOS	-	-	-	-
58	Total Price Adjustment	$ 860	$ 707	$ 153	$ 6,447
59					

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Progress Energy

Progress Energy Florida

Energy Delivery Monthly Financial Summary - Revenue Construction

2004 - November

60	Revenue Construction - CIAC	Current Month				Year-to-Date					Year-End			
61	Description - Charge To	Budget	Actual	Unit CIAC Variance $: Fav/(Unfav)	CIAC Variance $: Fav/(Unfav) ($000's)	Budget	Actual	Unit CIAC Variance $: Fav/(Unfav)	CIAC Variance $: Fav/(Unfav) ($000's)	Prior Month YTD CIAC Variance $: ($000's)	Budget	Projection	CIAC Variance $: Fav/(Unfav)	CIAC Variance Impact: ($000's)
62	**Residential**													
63	NORTH CENTRAL REGION	$ (459)	$ (250)	$ (209)	$ (97)	$ (426)	$ (661)	$ 235	$ 1,218	$ 1,299	$ (429)	$ (662)	$ 233	$ 1,318
64	SOUTH CENTRAL REGION	(579)	(557)	(22)	(21)	(498)	(602)	104	1,302	310	(505)	(610)	106	1,421
65	NORTH COASTAL REGION	(418)	(695)	276	102	(399)	(680)	282	1,120	939	(400)	(679)	279	1,211
66	SOUTH COASTAL REGION	(402)	(136)	(267)	(136)	(391)	(406)	15	81	154	(392)	(404)	13	76
68	**Total Residential CIAC**	$ (491)	$ (425)	$ (65)	$ (152)	$ (448)	$ (41)	$ (407)	$ 3,722	$ 2,703	$ (452)	$ (589)	$ 137	$ 4,026
69														
70	**Commercial & Industrial**													
71	NORTH CENTRAL REGION	$ (830)	$ (1,578)	$ 747	$ 69	$ (776)	$ (837)	$ 61	$ 63	$ (63)	$ (780)	$ (838)	$ 57	$ 65
72	SOUTH CENTRAL REGION	(1,307)	(4,490)	3,183	376	(1,202)	(1,837)	635	898	373	(1,211)	(1,850)	640	980
73	NORTH COASTAL REGION	(591)	(348)	(243)	(14)	(565)	(153)	(412)	(254)	(257)	(567)	(152)	(414)	(279)
74	SOUTH COASTAL REGION	(276)	(495)	219	35	(271)	(390)	119	200	157	(272)	(389)	117	216
76	**Total C&I CIAC**	$ (723)	$ (1,451)	$ 728	$ 467	$ (697)	$ (888)	$ 191	$ 907	$ 211	$ (350)	$ (549)	$ 199	$ 982
77														
78	**Combined**													
79	NORTH CENTRAL REGION	$ (521)	$ (472)	$ (49)	$ (27)	$ (485)	$ (690)	$ 206	$ 1,281	$ 1,079	$ (488)	$ (692)	$ 204	$ 1,383
80	SOUTH CENTRAL REGION	(658)	(982)	325	355	(569)	(728)	158	2,201	620	(577)	(738)	161	2,401
81	NORTH COASTAL REGION	(441)	(648)	207	88	(421)	(609)	188	866	683	(423)	(608)	186	932
82	SOUTH COASTAL REGION	(372)	(222)	(151)	(101)	(362)	(402)	40	281	313	(363)	(401)	38	292
84	**Total Combined CIAC**	$ (527)	$ (641)	$ 115	$ 315	$ (485)	$ (631)	$ 146	$ 4,629	$ 2,694	$ (489)	$ (634)	$ 145	$ 5,008
85														

86	Revenue Construction - LRC	Current Month			Year-to-Date				Year-End		
87	Description - Charge By	Budget:	Actual:	Variance: Fav/(Unfav)	Budget:	Actual:	Variance: Fav/(Unfav)	Prior Month YTD Var	Budget:	Projection:	Variance: Fav/(Unfav)
88	NORTH CENTRAL REGION	$ 29	$ (23)	$ 52	$ 321	$ 298	$ 23	$ (29)	$ 350	$ 350	$ -
89	SOUTH CENTRAL REGION	11	77	(66)	138	121	17	83	150	150	-
93	Total LRC	$ 40	$ 55	$ (14)	$ 459	$ 419	$ 40	$ 54	$ 500	$ 500	$ -

NOTE: The favorable YTD price variance of $ 6.4 million is driven by the above budget collection of CIAC of $ 4.6 million.

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PEF-SR-10143

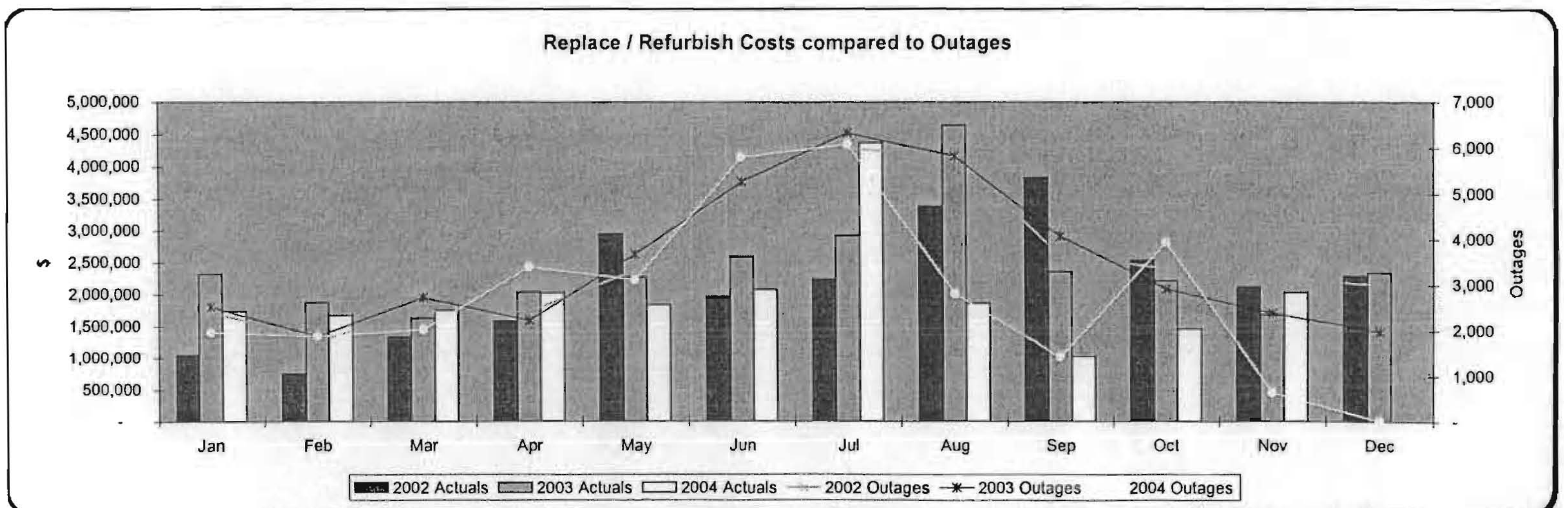
Progress Energy Florida
Energy Delivery Monthly Financial Summary - Performance - Replace / Refurbish
2004 - YTD November CAPITAL

Line #	Region	Customers Served - YTD 2003	Restoration Funds Spent YTD 2003	Restoration Budget YTD 2003	Restoration Fav / (Unfav) Variance	Customers Affected - YTD 2003	Cost Per Affected Customer	YTD CMI	Cost Per CMI	YTD SAIDI	Cost Per SAIDI Minute	YTD Outages	Cost Per Outage	YTD Lightning Strikes	Cost Per Lightning Strike
1	NORTH CENTRAL REGION	357,836	$ 7,905,701	$ 8,031,993	$ 126,292	499,210	$ 15.84	33,869,536	$ 0.23	94.7	$ 83,525	10,336	$ 765	40,466	$ 195
2	SOUTH CENTRAL REGION	342,802	6,278,387	5,406,833	(871,554)	344,609	18.22	25,364,045	0.25	74.0	84,854	8,371	750	57,704	109
3	NORTH COASTAL REGION	171,330	$ 3,153,199	$ 2,161,138	$ (992,061)	296,514	$ 10.63	23,614,306	$ 0.13	137.8	$ 22,878	7,245	$ 435	35,176	$ 87
4	SOUTH COASTAL REGION	628,554	9,235,616	6,931,090	(2,304,526)	659,972	13.99	39,584,250	0.23	63.0	146,651	13,522	683	12,830	720
5	COASTAL REGION	799,884	$ 12,388,815	$ 9,092,228	$ (3,296,587)	956,486	$ 12.95	63,198,556	$ 0.20	79.0	$ 156,801	20,767	$ 597	49,006	$ 253
6															
7	SYSTEM	1,500,522	$ 26,572,903	$ 22,531,054	$ (4,041,849)	1,800,305	$ 14.76	122,432,137	$ 0.22	81.6	$ 325,676	39,474	$ 673	147,176	$ 181
8															
9															
10															

Line #	Region	Customers Served - YTD 2004	Restoration Funds Spent YTD 2004	Restoration Budget YTD 2004	Restoration Fav / (Unfav) Variance	Customers Affected - YTD 2004	Cost Per Affected Customer	YTD CMI	Cost Per CMI	YTD SAIDI	Cost Per SAIDI Minute	YTD Outages	Cost Per Outage	YTD Lightning Strikes	Cost Per Lightning Strike
12															
13	NORTH CENTRAL REGION	366,126	$ 6,566,205	$ 6,659,108	$ 92,903	391,319	$ 16.78	25,321,827	$ 0.26	69.2	$ 94,940	8,705	$ 754	36,543	$ 180
14	SOUTH CENTRAL REGION	360,335	4,837,264	5,007,899	170,635	353,015	13.70	21,461,483	0.23	59.6	81,217	7,307	662	71,598	68
15	NORTH COASTAL REGION	176,758	$ 2,915,464	$ 2,910,969	$ (4,495)	255,589	$ 11.41	19,812,454	$ 0.15	112.1	$ 26,010	6,330	$ 461	44,169	$ 66
16	SOUTH COASTAL REGION	638,204	7,555,085	6,861,554	(693,531)	578,485	13.06	33,539,708	0.23	52.6	143,761	10,785	701	15,740	480
17	COASTAL REGION	814,962	$ 10,470,549	$ 9,772,523	$ (698,026)	834,074	$ 12.55	53,352,162	$ 0.20	65.5	$ 169,771	17,115	$ 612	59,909	$ 175
18															
19	SYSTEM	1,541,423	$ 21,874,018	$ 21,439,530	$ (434,488)	1,578,408	$ 13.86	100,135,472	$ 0.22	65.0	$ 336,715	33,127	$ 660	168,050	$ 130
20															
21															
22															

NOTE: Lightning Strikes includes all Major Storm days.

Line #	Region	PERCENTAGE INCREASE / (DECREASE) OVER 2003													
23															
27	NORTH CENTRAL REGION	2.3%	-16.9%	-17.1%	-26.4%	-21.6%	6.0%	-25.2%	11.1%	-26.9%	13.7%	-15.8%	-1.4%	-9.7%	-8.0%
28	SOUTH CENTRAL REGION	5.1%	-23.0%	-7.4%	-119.6%	2.4%	-24.8%	-15.4%	-8.9%	-19.5%	-4.3%	-12.7%	-11.7%	24.1%	-37.9%
24	NORTH COASTAL REGION	3.2%	-7.5%	34.7%	-99.5%	-13.8%	7.3%	-16.1%	10.2%	-18.7%	13.7%	-12.6%	5.8%	22.1%	-24.3%
25	SOUTH COASTAL REGION	1.5%	-18.2%	-1.0%	-69.9%	-12.3%	-6.7%	-15.3%	-3.5%	-16.6%	-2.0%	-20.2%	2.6%	22.7%	-33.3%
26	COASTAL REGION	1.9%	-15.5%	7.5%	-78.8%	-12.8%	-3.1%	-15.6%	0.1%	-17.1%	8.3%	-17.6%	2.6%	22.2%	-30.9%
29	SYSTEM	2.7%	-17.7%	-4.8%	-89.3%	-12.3%	-6.1%	-18.2%	0.6%	-20.4%	3.4%	-16.1%	-1.9%	14.2%	-27.9%



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PEF-SR-10144

Progress Energy

Progress Energy Florida
Energy Delivery Monthly Financial Summary - DOT
2004 - YTD November CAPITAL

DOT 2003 Actuals

Line #	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Budget	Projection
1	NORTH CENTRAL REGION	$ 182,191	$ 270,886	$ 230,902	$ 220,337	$ 393,345	$ 375,197	$ 481,530	$ 270,882	$ 151,096	$ 150,184	$ 176,189	$ (78,157)	$ 2,824,582	$ 2,284,889	$ 2,444,889
2	SOUTH CENTRAL REGION	156,494	373,030	366,454	568,829	235,799	344,500	240,976	345,398	296,518	295,039	224,925	397,673	3,845,635	2,187,432	3,860,432
3	NORTH COASTAL REGION	47,924	73,503	226,295	15,711	87,483	153,417	(17,937)	44,060	122,706	81,070	49,483	(105,158)	778,557	1,172,565	1,172,565
4	SOUTH COASTAL REGION	251,125	246,044	788,673	381,727	343,410	816,140	589,433	529,496	352,690	471,489	304,388	261,248	5,335,863	3,345,173	5,287,173
5	COASTAL REGION COMBINED	299,049	319,547	1,014,968	397,438	430,893	969,557	571,496	573,556	475,396	552,559	353,871	156,090	6,114,420	4,517,738	6,459,738
6	2003 Total	$ 637,734	$ 963,463	$ 1,612,324	$ 1,186,604	$ 1,060,037	$ 1,689,254	$ 1,294,002	$ 1,189,836	$ 923,010	$ 997,782	$ 754,985	$ 475,606	$ 12,784,637	$ 8,990,059	$ 12,765,059

DOT 2003 Budget

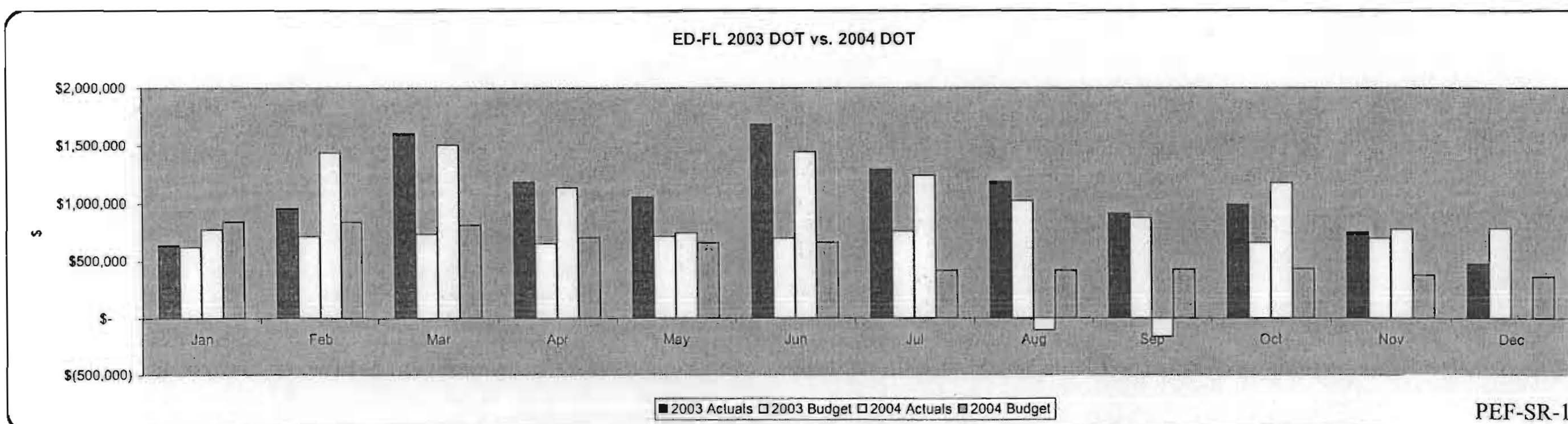
Line #	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Budget	Projection
7	NORTH CENTRAL REGION	$ 165,325	$ 190,910	$ 250,611	$ 148,943	$ 208,644	$ 166,001	$ 166,001	$ 262,255	$ 251,288	$ 131,886	$ 166,001	$ 177,024	$ 2,284,889	$ 2,284,889	$ 2,444,889
8	SOUTH CENTRAL REGION	147,421	159,195	159,195	172,462	172,462	184,236	196,010	245,358	207,783	184,236	184,236	174,837	2,187,431	2,187,432	3,860,432
9	NORTH COASTAL REGION	87,225	90,655	95,021	89,649	94,015	92,455	94,014	130,425	101,810	89,961	92,455	114,880	1,172,565	1,172,565	1,172,565
10	SOUTH COASTAL REGION	221,828	275,216	233,465	246,180	246,180	257,854	311,205	392,251	322,841	257,817	257,817	322,517	3,345,171	3,345,173	5,287,173
11	COASTAL REGION COMBINED	309,053	365,871	328,486	335,829	340,195	350,309	405,219	522,676	424,651	347,778	350,272	437,397	4,517,736	4,517,738	6,459,738
12	2003 Total	$ 621,799	$ 715,976	$ 738,292	$ 657,234	$ 721,301	$ 700,546	$ 767,230	$ 1,030,289	$ 883,722	$ 663,900	$ 700,509	$ 789,256	$ 8,990,056	$ 8,990,059	$ 12,765,059

DOT 2004 Actuals

Line #	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Budget	Projection
13	NORTH CENTRAL REGION	$ 237,278	$ 209,332	$ 175,305	$ 118,689	$ (151,089)	$ 185,450	$ 145,862	$ 72,404	$ (27,044)	$ (12,927)	$ 83,954	$ -	$ 1,037,214	$ 1,399,991	$ 1,799,991
14	SOUTH CENTRAL REGION	219,236	675,307	888,806	523,763	248,972	456,285	448,276	79,440	(170,277)	253,100	197,117	-	3,820,025	3,500,011	4,400,011
15	NORTH COASTAL REGION	181,274	198,300	172,718	146,696	304,183	300,659	300,790	(274,068)	(62,990)	646,784	98,668	-	2,013,014	1,051,427	2,127,427
16	SOUTH COASTAL REGION	141,516	355,675	270,709	348,065	350,314	503,067	347,352	17,847	100,678	293,793	403,017	-	3,132,033	1,049,998	2,999,998
17	COASTAL REGION COMBINED	322,790	553,975	443,427	494,761	654,497	803,726	648,142	(256,221)	37,688	940,577	501,685	-	5,145,047	2,101,425	5,127,425
18	2004 Total	$ 779,304	$ 1,438,614	$ 1,507,538	$ 1,137,213	$ 752,380	$ 1,445,461	$ 1,242,280	$ (104,377)	$ (159,633)	$ 1,180,750	$ 782,756	$ -	$ 10,002,286	$ 7,001,427	$ 11,327,427

DOT 2004 Budget

Line #	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Budget	Projection
19	NORTH CENTRAL REGION	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 116,666	$ 1,399,992	$ 1,399,991	$ 1,799,991
20	SOUTH CENTRAL REGION	503,049	503,049	476,050	379,411	332,413	332,413	167,909	167,909	179,659	183,183	143,633	131,333	3,500,011	3,500,011	4,400,011
21	NORTH COASTAL REGION	138,142	138,142	138,142	126,172	126,172	126,172	48,581	48,581	48,581	48,581	34,077	30,087	1,051,430	1,051,427	2,127,427
22	SOUTH COASTAL REGION	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	87,500	1,050,000	1,049,998	2,999,998
23	COASTAL REGION COMBINED	225,642	225,642	225,642	213,672	213,672	213,672	136,081	136,081	136,081	136,081	121,577	117,587	2,101,430	2,101,425	5,127,425
24	2004 Total	$ 845,357	$ 845,357	$ 818,358	$ 709,749	$ 662,751	$ 662,751	$ 420,656	$ 420,656	$ 432,406	$ 435,930	$ 381,876	$ 365,586	$ 7,001,433	$ 7,001,427	$ 11,327,427



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PEF-SR-10145

Progress Energy Florida
Energy Delivery Monthly Overtime & Headcount Summary on a Charge By Basis
November - EXCLUDES MAJOR STORM HOURS & DOLLARS
$ Costs include only Regulated Capital and O&M amounts

Current Month

Line #	Bargaining Unit	OT Hours	OT Dollars - $ (000's)	Double Time Hours	Double Time Dollars - $ (000's)	Regular Hours	Regular Dollars - $ (000's)	Overtime & Double Time Hours as % of Regular Hours	Overtime & Doubletime Dollars as % of Regular Dollars
1	NORTH CENTRAL REGION	8,533	$ 301	1,141	$ 56	28,161	$ 674	34%	53%
2	SOUTH CENTRAL REGION	7,058	256	677	35	25,246	616	31%	47%
3	NORTH COASTAL REGION	4,861	$ 177	92	5	20,487	493	24%	37%
4	SOUTH COASTAL REGION	11,010	$ 382	839	42	32,802	783	36%	54%
5	COASTAL REGION COMBINED	15,871	558	931	$ 46	53,289	$ 1,276	32%	47%
6	DIST OPS & SUPPORT	9,264	285	1,003	59	53,502	1,089	19%	32%
7	TRANSMISSION	5,500	202	808	39	30,089	742	21%	33%
8		46,226	$ 1,603	4,560	$ 236	190,287	$ 4,397	27%	42%
9									
10	Exempt & Non-exempt								
11	NORTH CENTRAL REGION	517	$ 5	-	$ -	13,644	$ 391	4%	1%
12	SOUTH CENTRAL REGION	442	12	-	-	15,231	430	3%	3%
13	NORTH COASTAL REGION	235	$ 6	-	$ -	9,425	289	2%	2%
14	SOUTH COASTAL REGION	215	$ 5	-	$ -	14,439	429	1%	1%
15	COASTAL REGION COMBINED	450	11	-	-	23,864	$ 718	2%	2%
16	DIST OPS & SUPPORT	574	13	-	-	23,586	731	2%	2%
17	TRANSMISSION	197	6	-	-	24,268	806	1%	1%
18	CTE PROJECT MANAGEMENT	-	-	-	-	640	34	0%	0%
19	ENERGY DELIVERY SERVICES	340	9	-	-	23,642	624	1%	1%
20	ED MANAGER BUSINESS OPERATION	-	-	-	-	2,563	87	0%	0%
21		2,520	$ 56	-	$ -	127,438	$ 3,821	2%	1%

Year - to - Date

Line #	Bargaining Unit	OT Hours	OT Dollars - $ (000's)	Double Time Hours	Double Time Dollars - $ (000's)	Regular Hours	Regular Dollars - $ (000's)	Overtime & Double Time Hours as % of Regular Hours	Overtime & Doubletime Dollars as % of Regular Dollars
1	NORTH CENTRAL REGION	68,847	$ 2,425	8,241	$ 403	309,117	$ 7,378	25%	38%
2	SOUTH CENTRAL REGION	77,971	2,777	6,312	312	309,849	7,555	27%	41%
3	NORTH COASTAL REGION	46,325	$ 1,675	2,007	$ 98	219,158	$ 5,286	22%	34%
4	SOUTH COASTAL REGION	79,391	$ 2,753	13,673	$ 674	360,160	$ 8,611	26%	40%
5	COASTAL REGION COMBINED	125,716	4,428	15,680	772	579,318	13,896	24%	37%
6	DIST OPS & SUPPORT	89,118	2,860	18,129	1,071	586,655	11,924	18%	33%
7	TRANSMISSION	67,181	2,474	4,790	232	355,901	8,675	20%	31%
8		428,833	$ 14,964	53,152	$ 2,790	2,140,840	$ 49,428	23%	36%
9									
10	Exempt & Non-exempt								
11	NORTH CENTRAL REGION	3,525	$ 91	-	$ -	140,733	$ 4,027	3%	2%
12	SOUTH CENTRAL REGION	4,930	127	-	-	165,758	4,699	3%	3%
13	NORTH COASTAL REGION	1,919	47	-	$ -	95,599	$ 2,828	2%	2%
14	SOUTH COASTAL REGION	3,199	81	-	$ -	156,707	$ 4,585	2%	2%
15	COASTAL REGION COMBINED	5,118	$ 128	-	-	252,306	7,413	2%	2%
16	DIST OPS & SUPPORT	4,878	119	-	-	256,584	7,847	2%	2%
17	TRANSMISSION	2,180	64	1	0	277,870	9,001	1%	1%
18	CTE PROJECT MANAGEMENT	30	1	-	-	8,155	373	0%	0%
19	ENERGY DELIVERY SERVICES	3,708	97	27	1	245,935	6,497	2%	1%
20	ED MANAGER BUSINESS OPERATION	89	2	-	-	33,066	1,077	0%	0%
21		24,458	$ 629	28	$ 1	1,380,407	$ 40,935	2%	2%

22 Note: OT Hours include Extended Pay hours for Exempt Employees

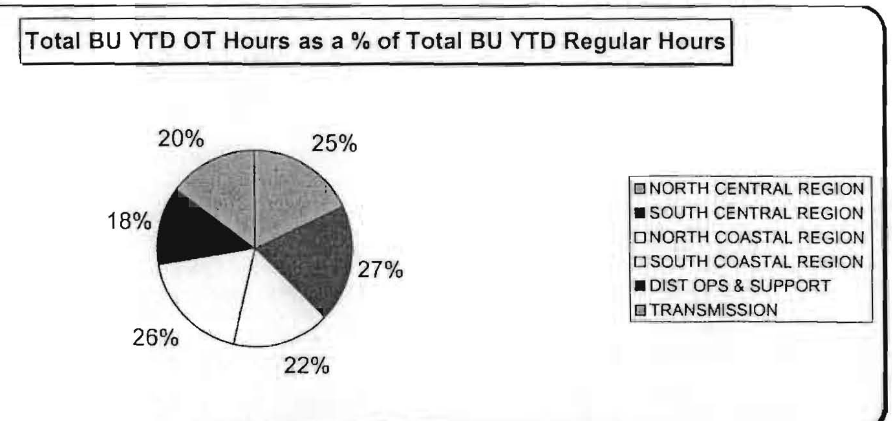
Line #	Headcount Data - Bargaining Unit	Approved Positions Per Org Chart	Estimated Budgeted Positions	Actual Filled Positions	Vacancy: Fav / (Unfav)	Current Month Average # of Paid OT & DT Hours Per Employee	YTD Average # of Paid OT & DT Hours Per Employee	2003 Average # of Paid OT & DT Hours Per Employee (Est)	YTD Budget - Bargaining Unit OT ($ 000's)	YTD Actual - Bargaining Unit OT ($ 000's)	YTD Variance	Estimated YTD Budgeted OT & Double Time Hours	Actual YTD OT & Double Time Hours	Variance
24	NORTH CENTRAL REGION	208	199	193	6	50	36	43	$ 2,613	$ 2,845	$ (231)	66,600	77,088	(10,488)
25	SOUTH CENTRAL REGION	209	202	208	(6)	37	37	51	2,464	3,084	(620)	62,785	84,283	(21,498)
26	NORTH COASTAL REGION	137	130	138	(8)	36	32	40	2,101	1,774	327	53,537	48,332	5,205
27	SOUTH COASTAL REGION	231	231	220	11	54	38	30	2,795	3,303	(508)	71,222	93,064	(21,842)
28	COASTAL REGION COMBINED	368	361	358	3	47	36	54	4,896	5,076	(181)	124,760	141,396	(16,636)
29	DIST OPS & SUPPORT	318	322	350	(28)	29	28	46	1,798	3,777	(1,979)	45,811	107,247	(61,436)
30	TRANSMISSION	237	219	221	(2)	29	30	36	1,444	2,382	(939)	36,789	71,971	(35,182)
32		1,340	1,303	1,330	(27)	38	33	40	$ 13,214	$ 17,164	$ (3,950)	336,744	481,985	(145,241)

Note: YTD Actual BU OT $'s excludes Major Storm, Non-regulated & Environmental work

Line #		Approved Positions Per Org Chart	Estimated Budgeted Positions	Actual Filled Positions	Vacancy: Fav / (Unfav)
33					
34	Exempt & Non-exempt				
35	NORTH CENTRAL REGION	98	98	87	11
36	SOUTH CENTRAL REGION	108	105	103	2
	NORTH COASTAL REGION	68	68	59	9
	SOUTH COASTAL REGION	92	92	95	(3)
37	COASTAL REGION COMBINED	160	160	154	6
38	DIST OPS & SUPPORT	151	145	150	(5)
39	TRANSMISSION	174	171	163	8
40	CTE PROJECT MANAGEMENT	6	6	3	3
41	ENERGY DELIVERY SERVICES	158	158	147	11
42	ED MANAGER BUSINESS OPERATION	23	23	18	5
43	ENERGY DELIVERY ADMIN	4	4	4	-
44		880	870	829	41
45					
46	Total Energy Delivery Florida Employees	2,220	2,173	2,159	14

Note: Energy Delivery Services represents CIG, Environmental, Energy Efficiency, Delivery Support Services

Goal Metrics:	
Outstanding	18%
Target	20%
Threshold	22%



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Progress Energy

Progress Energy Florida
Variance Explanations - O&M
2004 - November

Line #	Business Unit	Key Drivers - YTD	($ millions) YTD Variance - Fav / (Unfav)	($ millions) Year-end Projected Variance
1	NORTH CENTRAL REGION	Training - $.3m Fav in Labor resources/Materials w/Burdens, Line Ops &RD - $.3m Fav in BU/BU OT Labor/Fleet, Safety - $.2m Fav in Payroll/BU Labor/BU OT/Materials w/Burdens, Environmental - $.2m Fav in BU/Materials and Fleet, Office Admin ($.1m) Unfav in Payroll/Other, Street Light Maint - $.1m Fav in Materials w/Burdens/Other, Other - ($.1m) Unfav in misc. Incentitives (ECIP&MCIP) - ($.1m) Unfav Budget at Corporate	$ 1.0	$ 0.6
2				
3	SOUTH CENTRAL REGION	Favorability driven by Streetlight Maintenance $0.46m, Training $0.43m, offset by unfavorability in Office Admin & Support ($0.1m) unfavorable.	1.4	1.1
4				
5	NORTH COASTAL REGION	The region experienced an unfavorable variance in O&M for November resulting in a YTD unfavorable variance of ($0.16m). The primary unfavorable drivers are associated with General Distribution Support ($0.28m), unbudgeted Relocation Expenses ($0.16m), Office Services Support ($0.16), unbudgeted IT&T costs ($0.13) and unbudgeted CSM costs ($0.07m). Offsetting favorable variances within O&M include R&D work at $0.36m, followed by Training at $0.17m and SL Maint at $0.13m. Much of the unfavorability in Office Services Support driven by material costs was identified as erroneously charged Buggy Stock. An ADJ submitted during month end close was not released timely and would have reduced O&M spending by approximetly $0.1m, which would have resulted in a YTD unfavorable O&M variance of just $0.06m. This ADJ will be released during December	(0.2)	(0.1)
6				
7	SOUTH COASTAL REGION	Favorability driven by Payroll Burdens $0.5, Streetlight Repair $0.1, and Office Services Support $0.4, partially offset by unfavorability in Incentives ($0.3), Line Operations ($0.1), and UG Locates ($0.1).	0.4	0.4
8				
9	DIST OPS & SUPPORT	Tree Trimming Contractor favorability $3.5M due to resources being utiltized for Hurricane Restoration; offset by Metering Svcs OT Labor $(.9m), Dispatch OT - $(1.0m) due to training, holiday, vacation and sick time taken; ECIP payout unfavorable $(.6m), Moving Expenses unbudgeted for Dispatchers $(.2).	3.3	2.2
10				
11	TRANSMISSION	YTD favorable variance due to shirting resources to storm restoration during August and September. November favorable variance due to resources working CTE and capital	2.3	0.7
12				
13	CTE PROJECT MANAGEMENT	Main drivers of YTD favorable variance is due to Dist Veg Mgmt - $0.2m. and Trans Veg Mgmt - $0.9m. Offset by carryover of 2003 work into 2004 ($0.2m).	1.0	1.0
14				
15	ENERGY DELIVERY ADMIN	Fac, $.1m, due to timing of property management expense	0.1	0.2
16				
17	ENERGY DELIVERY SERVICES	Favorability due to storm charging.	0.4	0.2
18				
19	ED MANAGER BUSINESS OPERATIONS		0.4	0.4
20				
21	FPC - ED		0.0	0.0
22				
23	PROGRESS ENERGY FLORIDA PRESIDENT		0.3	0.3
24				
25	TOTAL ENERGY DELIVERY		$ 10.4	$ 7.0

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Progress Energy

Progress Energy Florida
Variance Explanations - Capital
2004 - November

Line #	Business Unit		Key Drivers - YTD	($ millions) YTD Variance - Fav / (Unfav)	($ millions) Year-end Projected Variance
1	NORTH CENTRAL REGION	Grow	Unfav Var Drivers: Buggy Stock - ($.8m) unfav since actuals are in Grow while budget is in Maintain. Incentitives - ($.4m) unfav since Corp Budgeted rate of 5% while payout is at 7%. Gen Dist Indirect - $.2m Fav in Labor resources, Maj Con - $.1m Fav in Grown while all actuals charged to Maintain.	$ 0.41	$ (0.27)
2					
3		Maintain	Drivers: Buggy Stock - $.8m fav - Budget in Maintain while actuals are in Grow due to budgeting to Replace/Ref project number instead of indirect. Outage Restoration - $.1m Fav-All labor resources/Materials/Fleet offset by BU OT/Contractors/CIAC - Result of Hurricane work. Street Light Maint (Like for Like) - $.2m Fav in all resource types again due to Hurricane Work for 2 months.	1.29	0.67
4				$ 1.70	$ 0.40
5	SOUTH CENTRAL REGION	Grow	Favorability driven primarily by New Customer related CIAC $2.4 m and Contractors $0.6m favorable YTD, offset by Materials ($1.2m) and BU OT ($.3m) unfavorable.	$ 2.05	$ (0.48)
6					
7		Maintain	Unfavorability driven by Outage Restoration ($0.1m) unfavorable including $.3m for Conway storm, Major Conversion ($0.2m) unfavorable driven primarily by non-CIAC covered customer requests, and ($0.2m) unfavorable in System Improvement.	(0.17)	0.93
8				$ 1.88	$ 0.45
9	NORTH COASTAL REGION	Grow	After the nat $0.49m favorable budget impact of the volume adjustment for NCW [favorable impact = $0.94m] and NSL [unfavorable impact = $0.45m] activities, the balance of the Region's total unfavorable Grow variance ($1.3m) is driven by Buggy Stock ($1.1m), Material Burdens ($0.36m), Gen Dist Support ($0.33m), Payroll Burdens ($0.27m), Labor Incentives ($0.19m) and Customer Requested work ($0.12m). Favorable offset of $1.5m comes from Allocations. Grow Buggy Stock unfavorability is driven, in part, by the fact that 74% of the Region's annual Buggy Stock budget is associated with Maintain, where none of the actuals reside. From a	$ (1.26)	$ 0.40
10					
11		Maintain	Only 5.3% of the annual Maintain budget was allocated to November and the month finished with an unfavorable variance of $0.26m. This results in a YTD unfavorable variance of ($0.25m). The unfavorability is driven by Allocations ($0.7m) and Contractors ($0.13m) partially offset by BU Labor $0.24m, Fleet $0.17m and CIAC	(0.25)	0.22
12				$ (1.53)	$ 0.62
13	SOUTH COASTAL REGION	Grow	Primary drivers of unfavorability are PEF Eng&Sup-OH Line burdens ($2.7m), Gen Dist Support ($0.3m), Incentives ($0.2), materials burdens ($0.3m), partially offset by NCW and NSL volume adjustment of $1.8m.	$ (0.38)	$ (1.38)
14					
15		Maintain	Primary driver of YTD favorability is PEF Eng&Sup-OH Line burdens $2.4m, partially offset by unfavorability in Customer Requests and Conversions ($1.2m) and OH/UG R&R ($0.7m).	0.57	0.85
16				$ 0.19	$ (0.54)
17	DIST OPS & SUPPORT	Grow	Transformers $2.02m favorable due to TRIP transformer forgiveness and storm usage; Load Growth projects behind schedule due to storm restoration- $3.2m- Payroll and Materials driving variance.	$ 8.75	$ 2.26
18					
19		Maintain	DOT spending unfavorable $(4.1m) - Payroll, Contractors and Materials driving variance. Base Programs behind schedule - $2.7m due mainly to Payroll for Cable Replacement due to contractors being utilized.	(1.19)	(2.82)
20				$ 7.57	$ (0.56)
21	TRANSMISSION	Grow	Favorable variance due to timing of construction on initiative projects. Schedule changes in part due to the storms.	$ 6.92	$ 0.46
22					
23		Maintain	Unfavorable variance due to regulatory customer requests (ie. DOT) exceeding budget and necessary purchase of spare transformers.	(2.43)	1.04
24				$ 4.48	$ 1.50
25	CTE PROJECT MANAGEMENT	Grow		$ (0.01)	$ -
26					
27		Maintain	Favorable variances in Branch line Spacer Cable - $0.5m, Fuse Coordination - $0.9m, Cable replacement - $0.4m, Trans Line Inspection - $0.8m, Trans Lightning Mitigation - $0.3m. Unfavorable variances in carryover of Transmission 2003 Programs - ($0.2m)	3.19	1.29
28				$ 3.18	$ 1.29
29	ENERGY DELIVERY ADMIN	Grow		$ 0.07	$ -
30					
31		Maintain	Facilities favorable of $0.4m, timing, fac plans to spend $ in Dec; Fleet favorable of $0.6m, timing, Fleet plans to spend 4's in Dec, Other favorable of $0.1m	1.61	1.43
32				$ 1.68	$ 1.43
33	ENERGY DELIVERY SERVICES	Grow		$ -	$ -
34					
35		Maintain	Timing of Purchases - Current projection as of the end of November is to be $50K-$60K favorable due to a change in accounting treatment for some ECCR items.	0.11	-
36				$ 0.11	$ -
37				16.53	0.99
38				2.73	3.61
39	TOTAL ENERGY DELIVERY			$ 19.26	$ 4.60

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