Florida Power & Light Company, 215 S. Monroe St., Suite 810, Tallahassee, FL 32301

FPL

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October 15, 2008

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COMMISSION CLERK

-VIA HAND DELIVERY -

Ms. Ann Cole
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 080001-EI

Dear Ms. Cole:

I am enclosing for filing in the above docket the original and fifteen (15) copies of the following documents on behalf of Florida Power & Light Company ("FPL"):

- The pre-filed testimony of K.M. Dubin concerning the Nuclear Power Plant Cost Recovery amount to be recovered through FPL's 2009 Capacity Cost Recovery ("CCR") factors, together with Exhibit KMD-8 that contains the revised CCR schedules and a revised Schedule E-10. Ms. Dubin's testimony also addresses revisions to the CCR factors to reflect an increase in the Turkey Point Unit 5 GBRA credit that is being returned to customers via the CCR factors.

- The revised affidavit of R.B. Deaton and accompanying Exhibit RDB-5, which were originally filed on September 2, 2008 and have been revised to include a Commercial Industrial Demand Reduction Rider adjustment of approximately $11,000 that was inadvertently omitted from the original calculation of the Turkey Point Unit 5 GBRA credit and to correct the effective date of the credit (these revisions support the increase in the credit that is addressed in Ms. Dubin's testimony described above).

- Revised pages 10-12 of the pre-filed testimony of FPL witness T.O. Jones, which was originally filed on September 2, 2008. The revision updates the discussion of actions that are being taken to address the RCP seal cavity line failures at St. Lucie Unit 1, based on information that was not available when the testimony was originally filed. The revision does not affect FPL's cost recovery request.

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RCP 1
SSC ___
SGA 1
ADM ___
CLK ___

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- Revised Schedule E-3, which was originally filed on August 4, 2008, to correct errors identified to FPL by the Commission Staff. This revision does not affect FPL's cost recovery request.

If there are any questions regarding this transmittal, please contact me at 561-304-5639.

Sincerely,

Nanci Nesmith

for John T. Butler

Enclosures
cc: Counsel for parties of record (w/enclosures)

CERTIFICATE OF SERVICE
Docket No. 080001-EI

I HEREBY CERTIFY that a true and correct copy of (1) the pre-filed testimony of K.M. Dubin and accompanying Exhibit KMD-8, (2) the revised affidavit of R.B. Deaton and accompanying Exhibit RDB-5, (3) revised pages 10-13 of the September 2, 2008 pre-filed testimony of FPL witness T.O. Jones, and (4) revised Schedule E-3, which was originally filed on August 4, 2008, have been furnished by overnight delivery (*) or United States mail on October 15th, 2008 to the following:

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By: Nancy R. Smith
for John T. Butler

OCTOBER 15, 2008

TESTIMONY OF K.M. DUBIN

AND EXHIBIT KMD-8

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 080001-EI

October 15, 2008

Q. Please state your name and address.

A. My name is Korel M. Dubin and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Senior Manager of Purchased Power in the Resource Assessment and Planning Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval revised Capacity Cost Recovery (CCR) factors for the period January 2009 through December 2009 that reflect (1) the Nuclear Power Plant Cost Recovery (NPPCR) amount approved by the Commission on October 14, 2008; and (2) a revised credit amount for the true-up of Turkey Point Unit 5 Generation Base Rate Adjustment (GBRA) costs.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes, I have. KMD-8 provides the revised CCR schedules as well as a revised E-10 Schedule reflecting the impact of those revisions on a 1,000 kWh residential bill.

Q. What is the NPPCR amount that the Commission approved for recovery through the CCR during the January 2009 through December 2009 period?

A. At the October 14, 2008 agenda conference the Commission authorized FPL to recover $220,529,243 through the CCR during that period.

Q. Is this the same amount that FPL included in the 2009 CCR Factors at the time of FPL's September 2, 2008 projection filing?

A. No. In its September 2, 2008 filing in this docket, FPL included $258,406,183 for the NPPCR in the calculation of its 2009 CCR Factors, which was the amount that FPL had originally requested in its August 6, 2008 filing in Docket No. 080009-EI. However, at the cost recovery hearing held on September 11 and 12, 2008, FPL witness Steven Scroggs presented an adjustment to the 2008 actual/estimated pre-construction costs, which eliminated the long lead procurement line item from the October, November and December 2008 estimate. This adjustment reduced the requested NPPCR from $258,406,183 to $220,529,243. As I noted previously, the Commission approved recovery of this revised amount at its October 14, 2008 agenda conference.

Q. Has FPL included any other revisions to its CCR factors for the period January through December 2009?

A. Yes. FPL has revised the credit of $9,296,089, including interest, for the true-up of Turkey Point Unit 5 costs for the period May 1, 2007 through December 31, 2008, which was included as a reduction to the 2009 CCR factors in the September 2, 2008 filing. As presented in the revised affidavit and exhibits of Renae B. Deaton that is being filed in conjunction with this testimony, this credit has been increased from $9,296,089 to $9,307,126, in order to include the Commercial Industrial Demand Reduction Rider adjustment of approximately $11,000 that was inadvertently omitted from the original calculation of the credit.

Q. What will be the revised charge for a Residential customer using 1,000 kWh effective January 2009?

A. As shown on the revised Schedule E-10 that is part of my Exhibit KMD-8, the "typical" Residential 1,000 kWh bill will be $118.99 instead of $119.41 as shown on the Schedule E-10 that was filed on September 2, 2008. Of this amount, the revised Capacity Cost Recovery charge is $8.16, instead of $8.55 as originally filed.

As a result of these revisions, the “typical” 1,000 kWh Residential Bill will now increase by 7.42% in January 2009 instead of 7.80% as originally filed.

Q. Does this conclude your testimony?

A. Yes, it does.

KMD-8

DOCKET NO. 080001-EI
EXHIBIT ___________
PAGES 1-5

OCTOBER 15, 2008

REVISED 10/15/08

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2009 THROUGH DECEMBER 2009

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$18,644,336	$223,732,036
2. SHORT TERM CAPACITY PAYMENTS	3,933,560	4,117,810	3,490,284	3,643,864	3,495,364	4,454,740	4,454,740	4,454,740	4,454,740	3,495,364	3,495,364	3,829,060	$47,319,630
3. CAPACITY PAYMENTS TO COGENERATORS	$27,667,653	$27,667,653	$27,667,653	$27,667,653	$27,667,653	$27,667,653	$27,667,653	$25,419,531	$25,419,531	$25,419,531	$25,419,531	$25,419,531	$320,771,227
4. SJRPP SUSPENSION ACCRUAL	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$200,486	$2,405,832
5. RETURN REQUIREMENTS ON SJRPP SUSPENSION LIABILITY	($463,915)	($465,769)	($467,623)	($469,477)	($471,331)	($473,186)	($475,040)	($476,894)	($478,748)	($480,602)	($482,456)	($484,310)	($5,689,352)
6. INCREMENTAL PLANT SECURITY COSTS	$ 2,615,962	$ 2,618,791	$ 2,622,187	$ 2,619,644	$ 2,616,826	$ 2,617,190	$ 2,616,746	$ 2,617,210	$ 2,622,330	$ 2,617,683	$ 2,618,111	$ 2,636,580	$31,439,262
7. TRANSMISSION OF ELECTRICITY BY OTHERS	207,880	219,338	206,670	192,819	599,562	600,275	590,775	591,986	584,863	177,681	185,181	197,626	$4,354,655
8. TRANSMISSION REVENUES FROM CAPACITY SALES	(542,427)	(530,874)	(345,258)	(298,850)	(139,908)	(153,726)	(116,647)	(282,532)	(84,560)	(104,287)	(206,499)	(390,816)	($3,196,384)
9. SYSTEM TOTAL	$52,263,536	$52,471,771	$52,018,735	$52,200,475	$52,612,988	$53,557,770	$53,583,049	$51,168,863	$51,362,979	$49,970,193	$49,874,054	$50,052,493	$621,136,906
10. JURISDICTIONAL % *													98.76729%
11. JURISDICTIONALIZED CAPACITY PAYMENTS													$613,480,089
12. SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
13. 2007 FINAL TRUE-UP – overrecovery/(underrecovery) ($3,707,455)			2008 EST \ ACT TRUE-UP – overrecovery/(underrecovery) ($26,832,716)										($30,540,170)
14. NUCLEAR COST RECOVERY - TOTAL COST													$220,529,243
15. Turkey Point Unit 5 GBRA True-Up													($9,307,126)
16. TOTAL (Lines 10+11+12+13+14)													$798,296,784
17. REVENUE TAX MULTIPLIER													1.00072
18. TOTAL RECOVERABLE CAPACITY PAYMENTS													$798,871,558

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN.(MW)	%
FPSC	18,436	98.76729%
FERC	230	1.23271%
TOTAL	18,666	100.00000%

* BASED ON 2007 ACTUAL DATA

REVISED 10/15/08

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2009 THROUGH DECEMBER 2009

Rate Schedule	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1/RST1	65.077%	55,403,306,419	9,718,567	1.08663620	1.06901375	59,226,896,463	10,560,547	52.33820%	56.97040%
GS1/GST1	64.480%	6,219,248,803	1,101,055	1.08663620	1.06901375	6,648,462,497	1,196,446	5.87518%	6.45440%
GSD1/GSDT1/HLFT1 (21-499 kW)	76.435%	24,942,068,687	3,725,073	1.08655195	1.06894858	26,661,788,803	4,047,485	23.56075%	21.83474%
OS2	95.627%	18,498,130	2,208	1.05506701	1.04443473	19,320,090	2,330	0.01707%	0.01257%
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	81.083%	11,220,287,833	1,579,680	1.08535318	1.06805030	11,983,831,786	1,714,511	10.58999%	9.24918%
GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	89.478%	2,133,689,890	272,215	1.07696203	1.06151341	2,264,940,431	293,165	2.00150%	1.58152%
GSLD3/GSLDT3/CS3/CST3	93.476%	261,545,665	31,941	1.02836156	1.02355239	267,705,691	32,847	0.23657%	0.17720%
ISST1D	111.786%	0	0	1.05506701	1.04443473	0	0	0.00000%	0.00000%
ISST1T	111.422%	0	0	1.02836156	1.02355239	0	0	0.00000%	0.00000%
SST1T	111.422%	87,048,226	8,918	1.02836156	1.02355239	89,098,420	9,171	0.07874%	0.04947%
SST1D1/SST1D2/SST1D3	111.786%	5,382,413	550	1.05506701	1.04443473	5,621,580	580	0.00497%	0.00313%
CILC D/CILC G	92.489%	3,419,610,773	422,070	1.07580614	1.06089603	3,627,851,508	454,065	3.20589%	2.44952%
CILC T	93.565%	1,493,300,492	182,193	1.02836156	1.02355239	1,528,471,292	187,360	1.35069%	1.01074%
MET	72.366%	91,941,054	14,503	1.05506701	1.04443473	96,026,431	15,302	0.08486%	0.08255%
OL1/SL1/PL1	653.334%	584,472,455	10,212	1.08663620	1.06901375	624,809,092	11,097	0.55214%	0.05986%
SL2, GSCU1	113.244%	109,513,160	11,039	1.08663620	1.06901375	117,071,074	11,995	0.10345%	0.06471%
TOTAL		105,989,914,000	17,080,224			113,161,895,158	18,536,901	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2009 through December 2009.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2007 demand losses.
(5) Based on 2007 energy losses.
(6) Col(2) * Col(5).
(7) Col(3) * Col(4).
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

REVISED 10/15/08

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
JANUARY 2009 THROUGH DECEMBER 2009

Rate Schedule	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor ($/kw)	(10) Capacity Recovery Factor ($/kwh)
RS1/RST1	52.33820%	56.97040%	$32,162,690	$420,111,081	$452,273,771	55,403,306,419	-	-	-	0.00816
GS1/GST1/WIES1	5.87518%	6.45440%	$3,610,394	$47,596,040	$51,206,434	6,219,248,803	-	-	-	0.00823
GSD1/GSDT1/HLFT1 (21-499 kW)	23.56075%	21.83474%	$14,478,470	$161,013,752	$175,492,222	24,942,068,687	47.36064%	72,142,643	2.43	-
OS2	0.01707%	0.01257%	$10,492	$92,690	$103,182	18,498,130	-	-	-	0.00558
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	10.58999%	9.24918%	$6,507,724	$68,205,280	$74,713,004	11,220,287,833	62.66433%	24,527,921	3.05	-
GSLD2/GSLDT2/CS2/CST2/HLFT3 (2,000+ kW)	2.00150%	1.58152%	$1,229,958	$11,662,451	$12,892,409	2,133,689,890	68.48888%	4,267,646	3.02	-
GSLD3/GSLDT3/CS3/CST3	0.23657%	0.17720%	$145,375	$1,306,693	$1,452,068	261,545,665	76.00256%	471,407	3.08	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	41.32527%	0	**	-
ISST1T	0.00000%	0.00000%	$0	$0	$0	0	11.39886%	0	**	-
SST1T	0.07874%	0.04947%	$48,384	$364,833	$413,217	87,048,226	11.39886%	1,046,106	**	-
SST1D1/SST1D2/SST1D3	0.00497%	0.00313%	$3,053	$23,073	$26,126	5,382,413	41.32527%	17,842	**	-
CILC D/CILC G	3.20589%	2.44952%	$1,970,076	$18,063,244	$20,033,320	3,419,610,773	74.45869%	6,291,271	3.18	-
CILC T	1.35069%	1.01074%	$830,024	$7,453,403	$8,283,427	1,493,300,492	75.82759%	2,697,721	3.07	-
MET	0.08486%	0.08255%	$52,146	$608,732	$660,878	91,941,054	60.06395%	209,688	3.15	-
OL1/SL1/PL1	0.55214%	0.05986%	$339,298	$441,452	$780,750	584,472,455	-	-	-	0.00134
SL2/GSCU1	0.10345%	0.06471%	$63,575	$477,175	$540,750	109,513,160	-	-	-	0.00494
TOTAL			$61,451,659	$737,419,899	$798,871,558	105,989,914,000		111,672,245		

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(3) (Total Capacity Costs/13) * Col (1)
(4) (Total Capacity Costs/13 * 12) * Col (2)
(5) Col (3) + Col (4)
(6) Projected kwh sales for the period January 2009 through December 2009
(7) (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730)
(9) Col (5) / (8)
(10) Col (5) / (6)

Totals may not add due to rounding.

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1D	$0.38	$0.18
ISST1T	$0.37	$0.18
SST1T	$0.37	$0.18
SST1D1/SST1D2/SST1D3	$0.38	$0.18

REVISED 10-15-08

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	CURRENT AUG 08 - DEC 08	PRELIMINARY JAN 09 - MAY 09	DIFFERENCE $	DIFFERENCE %	PRELIMINARY JUNE 09 - OCT 09	DIFFERENCE $	DIFFERENCE %	PRELIMINARY NOV 09 - DEC 09	DIFFERENCE $	DIFFERENCE %
BASE	$39.37	$39.31	($0.06)	-0.15%	$40.72	$1.41	3.59%	$42.00	$1.28	3.14%
FUEL	$60.21	$64.13	$3.92	6.51%	$62.72	($1.41)	-2.20%	$61.44	($1.28)	-2.04%
CONSERVATION	$1.45	$2.03	$0.58	40.00%	$2.03	$0.00	0.00%	$2.03	$0.00	0.00%
CAPACITY PAYMENT	$5.46	$8.16	$2.70	49.45%	$8.16	$0.00	0.00%	$8.16	$0.00	0.00%
ENVIRONMENTAL	$0.40	$0.94	$0.54	135.00%	$0.94	$0.00	0.00%	$0.94	$0.00	0.00%
STORM RESTORATION SURCHARGE	$1.11	$1.45 *	$0.34	30.63%	$1.45	$0.00	0.00%	$1.45	$0.00	0.00%
SUBTOTAL	$108.00	$116.02	$8.02	7.43%	$116.02	$0.00	0.00%	$116.02	$0.00	0.00%
GROSS RECEIPTS TAX	$2.77	$2.97	$0.20	7.22%	$2.97	$0.00	0.00%	$2.97	$0.00	0.00%
TOTAL	**$110.77**	**$118.99**	$8.22	7.42%	**$118.99**	$0.00	0.00%	**$118.99**	$0.00	0.00%

* Storm Charge effective November 1, 2008

OCTOBER 15, 2008

REVISED AFFIDAVIT OF RENAE B. DEATON

AND REVISED EXHIBIT RBD-5

FILED SEPTEMBER 2, 2008

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased power Cost Recovery Clause and Generating Performance Incentive Factor	))))	DOCKET NO. 080001-EI FILED: September 2, 2008

AFFIDAVIT

STATE OF FLORIDA
COUNTY OF MIAMI-DADE

BEFORE ME, the undersigned authority, personally appeared Renae B. Deaton, who being first duly sworn deposes and says:

1. My name is Renae B. Deaton. I am employed by Florida Power & Light Company ("FPL"). My business address is 9250 West Flagler St., Miami, Florida, 33174.

2. I hold a Bachelor of Science in business administration and a Masters of Business Administration from Charleston Southern University. Since joining FPL in 1998 I have held positions in the rates and regulatory areas. Prior to joining FPL, I was employed at the South Carolina Public Service Authority (d/b/a Santee Cooper) for fourteen years where I held a variety of positions in the Corporate Forecasting, Rates, and Marketing Department and in generation plant operations.

3. I currently hold the position of Rate Development Manager with responsibilities for rate development and tariff administration.

4. The purpose of my affidavit is to submit for the Commission's confirmation the revisions to FPL's rates and charges resulting from application of the revised Generation Base Rate Adjustment ("GBRA") Factor for true-up of Turkey Point Unit 5 costs to be applied to meter readings made on and after December 31, 2008, and application of the initial GBRA factors resulting from the commercial operation of WCEC Units 1 and 2 to be applied to meter readings made on and after June 1 and November 1, 2009, respectively. Also, I provide the amount to be refunded through the Capacity Cost Recovery Clause ("CCRC") in order to adjust base revenues for the difference between the cumulative base revenues that have been or will have been collected since the implementation of the initial GBRA Factor on May 1, 2007 through December 30, 2008 and the cumulative base revenues that would have resulted if the revised GBRA Factor had been implemented on May 1, 2007.

Revised GBRA for True-up of Turkey Point Unit 5 costs

5. The Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-05-0902-S-EI, issued September 14, 2005 in Docket 050045-EI ("Settlement Agreement"), provided for a GBRA factor to be applied to FPL's rates upon the commercial in-service date of any power plant that is approved pursuant to the Florida Power Plant Siting Act ("PPSA") within the term of the Settlement Agreement. In Order No. PSC-06-1057-FOF-EI, the Commission approved the initial GBRA Factor for Turkey Point Unit 5 of 3.271%. This initial GBRA Factor was determined using the estimate of capital cost from the Turkey Point Unit 5 need determination.

6. As discussed in the affidavit of Dr. Morley dated September 1, 2006 in Docket No. 060001-EI ("Dr. Morley Affidavit") and pursuant to the Settlement

Agreement, once the actual capital costs of Turkey Point Unit 5 are known, a revised GBRA Factor is to be computed using the same data and methodology incorporated in the initial GBRA Factor, with the exception that Turkey Point Unit 5's actual capital costs will be used in lieu of the capital cost upon which the need determination was based.

7. Pursuant to the Settlement Agreement, the GBRA is to be implemented by adjusting base charges and non-clause recoverable credits (e.g. the transformer rider credits and the curtailable service credits) by an equal percentage. The calculation of this percentage change in rates is based on the ratio of Turkey Point Unit 5's jurisdictional annual revenue requirement and the forecasted retail base revenues from the sales of electricity during the first twelve months of the unit's operation. This ratio is the GBRA Factor. The revised GBRA Factor is applied to FPL's current base charges and non-clause recoverable credits, adjusted to remove the initial GBRA Factor, to produce the revised base rate charges. I describe below in more detail the computation of the revised GBRA Factor.

8. The base revenue requirement revised for Turkey Point Unit 5's actual capital costs for the first twelve months of Turkey Point Unit 5's operation of $123.22 million was provided by the accounting department based on FPL's books and records. The Jurisdictional Separation Factors consistent with the separation of costs incorporated in Docket 050045-EI are applied to this figure. As shown in Document No. RBD-1, the resulting jurisdictional revenue requirement is $121.31 million.

9. Except for the revenue requirements associated with the actual capital costs, the revised GBRA Factor is computed using the same data used in the computation

of the initial GBRA Factor. This data includes billed retail base revenues from the sales of electricity and unbilled retail base revenues in the amount of $3,876.80 million. This data is shown in Document No. RBD-2 and is the same as that shown in Dr. Morley's Affidavit.

10. The revised GBRA Factor is calculated based on the ratio of Turkey Point Unit 5's jurisdictional annual revenue requirement and the total retail base revenues from the sales of electricity over the first twelve months of Turkey Point Unit 5's commercial operation. The computation and resulting GBRA Factor is provided in Document No. RBD-3. Document No. RBD-4 shows the revised charges that result from removing the initial GBRA factor of 3.271%, and applying the revised GBRA Factor of 3.129% to FPL's current base charges and non-clause recoverable credits. These new charges will be applied to meter readings made on and after December 31, 2008.

11. Pursuant to the settlement agreement and consistent with the Dr. Morley Affidavit, once Turkey Point Unit 5's actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the initial GBRA Factor, a one-time credit is to be made through the capacity clause. The difference between the cumulative base revenues that have been or will have been collected since the implementation of the initial GBRA Factor on May 1, 2007 through December 30, 2008 and the cumulative base revenues that would have resulted if the revised GBRA Factor had been implemented on May 1, 2007 will be credited to customers through the CCRC with interest at the 30-day commercial paper rate as specified in Rule 25-6.109. The amount of the refund with interest is $9.31 million and is shown on Document No. RBD-5.

WCEC Unit 1

12. As presented in Dr. Sim's affidavit, the projected base revenue requirement for the first twelve months of WCEC Unit 1's operation is $140.70 million. The Jurisdictional Separation Factors consistent with the separation of costs incorporated in Docket 050045-E1 are applied to this figure. As shown in Document No. RBD-6, the resulting jurisdictional revenue requirement is $138.52 million.

13. The GBRA Factor also requires computation of the retail base revenues from the sales of electricity during the first twelve months of WCEC Unit 1's commercial operation. Billed retail base revenues from the sales of electricity have been projected using the same load forecast incorporated in the Company's current capacity clause filing. Document No. RBD-7 shows the billed retail base revenues from the sales of electricity for the period June 2009 through May 2010 for all customer classes. Billed retail base revenues from the sales of electricity include customer, demand and energy charge revenues and non-clause recoverable credits. Thus, all the charges subject to the GBRA Factor are included in this revenue figure. In addition, unbilled retail base revenues are included in total retail base revenues from the sales of electricity in order to account for the collection lag resulting from the billing cycle. As shown in Document No. RBD-7, the total retail base revenues from the sales of electricity over the first twelve months of WCEC Unit 1's commercial operation are projected be $3,866.34 million.

14. The GBRA Factor is calculated based on the ratio of WCEC Unit 1's jurisdictional annual revenue requirement and the total retail base revenues from the sales of electricity over the first twelve months of WCEC Unit 1's commercial operation. The computation and resulting GBRA Factor of 3.583%, is provided in Document No. RBD-

8. Document No. RBD-9 shows the revised charges that result from applying the GBRA Factor to FPL's current base charges and non-clause recoverable credits. Pursuant to the Settlement Agreement, these new charges will be applied to meter readings made on and after the commercial in service date of WCEC Unit 1, currently projected to occur in June 2009. FPL will submit for the FPSC staffs administrative approval revised tariff sheets reflecting these new charges prior to the actual commercial in service date.

15. Once WCEC Unit 1's actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the initial GBRA Factor for WCEC Unit 1, a one-time credit will be made through the capacity clause. In order to determine the amount of this credit a revised GBRA Factor will be computed using the same data and methodology incorporated into the initial GBRA Factor, with the exception that WCEC Unit 1's actual capital costs will be used in lieu of the capital cost the need determination was based on. On a going forward basis, base rates will be adjusted to reflect the revised GBRA Factor for WCEC Unit 1. The difference between the cumulative base revenues since the implementation of the initial GBRA Factor and the cumulative base revenues that would have resulted if the revised GBRA Factor had been implemented during the same time period will be credited to customers through the capacity clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109.

WCEC Unit 2

16. As presented in Dr. Sim's affidavit, the base revenue requirement for the first twelve months of WCEC Unit 2's operation is $129.10 million. The Jurisdictional Separation Factors consistent with the separation of costs incorporated in Docket 050045-

El are applied to this figure. As shown in Document No. RBD-10, the resulting jurisdictional revenue requirement is $127.10 million.

17. The GBRA Factor also requires computation of the retail base revenues from the sales of electricity during the first twelve months of WCEC Unit 2's commercial operation. Billed retail base revenues from the sales of electricity have been projected using the same load forecast incorporated in the Company's current capacity clause filing. Document No. RBD-11 shows the billed retail base revenues from the sales of electricity for the period November 2009 through October 2010 for all customer classes. Billed retail base revenues from the sales of electricity include customer, demand and energy charge revenues and non-clause recoverable credits. Thus, all the charges subject to the GBRA Factor are included in this revenue figure. In addition, unbilled retail base revenues are included in total retail base revenues from the sales of electricity in order to account for the collection lag resulting from the billing cycle. As shown in Document No. RBD-11, the total retail base revenues from the sales of electricity over the first twelve months of WCEC Unit 2's commercial operation are projected be $4,030.30 million.

18. The GBRA Factor is calculated based on the ratio of WCEC Unit 2's jurisdictional annual revenue requirement and the total retail base revenues from the sales of electricity over the first twelve months of WCEC Unit 2's commercial operation. The computation and resulting GBRA Factor, 3.154%, is provided in Document No. RBD-12. Document No. RBD-13 shows the revised charges that result from applying the GBRA Factor to FPL's current base charges and non-clause recoverable credits. Pursuant to the Settlement Agreement, these new charges will be applied to meter readings made on and after the commercial in service date of WCEC Unit 2, currently projected to occur in

November 2009. FPL will submit for the FPSC staffs administrative approval revised tariff sheets reflecting these new charges prior to the actual commercial in service date.

19. Once WCEC Unit 2's actual capital costs are known, if the unit's actual capital costs are less than the projected costs used to develop the initial GBRA Factor for WCEC Unit 2, a one-time credit will be made through the capacity clause. In order to determine the amount of this credit a revised GBRA Factor will be computed using the same data and methodology incorporated into the initial GBRA Factor, with the exception that WCEC Unit 2's actual capital costs will be used in lieu of the capital cost the need determination was based on. On a going forward basis, base rates will be adjusted to reflect the revised GBRA Factor for WCEC Unit 2. The difference between the cumulative base revenues since the implementation of the initial GBRA Factor and the cumulative base revenues that would have resulted if the revised GBRA Factor had been implemented during the same time period will be credited to customers through the capacity clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109.

Renae B. Deaton

Renae B. Deaton

I hereby certify that on this 19 day of Sept, 2008 before me, an officer duly authorized in the State and County aforesaid to take acknowledgements, personally appeared Renae B. Deaton who is personally known to me, and she acknowledge before me that she executed this certification of signature as her free act and deed who did not take an oath.

I witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as this 19 day of Sept.2008.

Notary Public

State of Florida

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA

Notary Public State of Florida
Janet Hopkins
My Commission DD539404
Expires 06/27/2010

Revised October 15, 2008

Docket No. 080001-EI
R. Deaton, Exhibit No. ________
Document No. RBD-5 Page 1 of 2
True-up Calculation for Turkey Point Unit 5

TURKEY POINT 5 REVENUE - GBRA PROVISION FOR REFUND CALCULATION

	UNBILLED REV - FPSC	GBRA UNBILLED REV	BILLED GBRA BASE REV	BILLED + UNBILLED GBRA BASE REV	REVISED BILLED + UNBILLED GBRA REV	REFUND
Jan-07	0	0	0	0	0	0
Feb-07	0	0	0	0	0	0
Mar-07	0	0	0	0	0	0
Apr-07	115,222.107	3,649.539	0.000	3,649.539	3,491.106	158.433
May-07	126,157.534	346.368	9,521.889	9,868.257	9,439.858	428.399
Jun-07	151,250.020	794.778	10,456.765	11,251.543	10,763.093	488.450
Jul-07	146,207.109	-159.729	11,814.109	11,654.380	11,148.443	505.938
Aug-07	178,178.949	1,012.674	11,868.555	12,881.230	12,322.032	559.197
Sep-07	164,028.952	-448.186	12,365.091	11,916.904	11,399.570	517.334
Oct-07	158,544.328	-173.720	10,985.244	10,811.525	10,342.177	469.348
Nov-07	134,476.725	-762.316	9,725.609	8,963.293	8,574.180	389.113
Dec-07	117,975.987	-522.643	9,267.827	8,745.184	8,365.539	379.644
Jan-08	93,219.020	-784.151	9,558.203	8,774.052	8,393.155	380.897
Feb-08	88,187.932	-159.354	8,525.780	8,366.425	8,003.224	363.202
Mar-08	99,919.066	371.571	8,537.599	8,909.171	8,522.408	386.763
Apr-08	119,423.193	617.773	8,820.118	9,437.891	9,028.175	409.716
May-08	144,144.534	783.022	9,656.638	10,439.661	9,986.456	453.204
Jun-08	152,589.862	267.497	11,252.973	11,520.470	11,020.346	500.124
Jul-08	163,480.405	344.946	11,719.193	12,064.139	11,540.413	523.726
Aug-08	172,908.702	298.631	12,109.953	12,408.584	11,869.905	538.679
Sep-08	179,559.700	210.663	11,793.886	12,004.549	11,483.410	521.139
Oct-08	159,029.270	-650.280	11,185.169	10,534.889	10,077.551	457.339
Nov-08	147,480.191	-365.805	9,915.458	9,549.653	9,135.086	414.568
Dec-08	0.000	-4,671.279	9,491.332	4,820.053	4,610.805	209.247
TOTAL		0.000	208,571.392	208,571.392	199,516.932	9,054.460

Note: Actual revenues through June 2008

Revised October 15, 2008

True-up Calculation for Turkey Point Unit 5

PROVISION FOR REFUND INTEREST

	REFUND ACCRUAL	CUMULATIVE REFUND	INTEREST RATE	CUM. REFUND WITH INTEREST	MONTHLY INTEREST	CUMULATIVE INTEREST
Jan-07	0	0	0.0043875	0	0	0
Feb-07	0	0	0.0043875	0	0	0
Mar-07	0	0	0.0043917	0	0	0
Apr-07	158	158	0.0043875	159	0	0
May-07	428	587	0.0043833	589	2	2
Jun-07	488	1,075	0.0043875	1,081	4	6
Jul-07	506	1,581	0.0043792	1,593	6	11
Aug-07	559	2,140	0.0045375	2,160	8	20
Sep-07	517	2,658	0.0044458	2,688	11	31
Oct-07	469	3,127	0.0040708	3,170	12	43
Nov-07	389	3,516	0.0039458	3,572	13	56
Dec-07	380	3,896	0.0040542	3,967	15	71
Jan-08	381	4,277	0.0033583	4,362	14	85
Feb-08	363	4,640	0.0025708	4,737	12	97
Mar-08	387	5,027	0.0023833	5,135	12	109
Apr-08	410	5,436	0.0022792	5,557	12	121
May-08	453	5,890	0.0020333	6,022	12	132
Jun-08	500	6,390	0.0021958	6,536	14	146
Jul-08	524	6,913	0.0021958	7,075	15	161
Aug-08	539	7,452	0.0021958	7,629	16	177
Sep-08	521	7,973	0.0021958	8,168	17	195
Oct-08	457	8,431	0.0021958	8,644	18	213
Nov-08	415	8,845	0.0021958	9,078	19	233
Dec-08	209	9,054	0.0021958	9,307	20	253
TOTAL	9,054.460				252.666	

TOTAL REFUND	$9,307,126

OCTOBER 15, 2008

TESTIMONY OF TERRY O. JONES
FILED SEPTEMBER 2, 2008

REVISED PAGES 10 THROUGH 12

cavity piping. The leakage occurred on a Reactor Coolant Pump seal upper cavity pipe. FPL determined the crack was due to water chemistry and the piping design. The January 2008 outage duration was approximately 11 days.

Q. What corrective actions did FPL take at St. Lucie Unit 2 to avoid recurrence of this problem?

A. During the January 2008 Unit 2 outage, the maintenance strategy employed for the repairs on the failed seal line was a complete replacement of all the associated seal line piping on all RCPs. This approach was dictated by the lack of sufficient time during the outage to collect forensics data and thoroughly evaluate that data to determine the root cause for the failures. We did not want to extend the outage, so complete line replacement was the most prudent strategy in the short run.

Q. Did FPL continue to investigate the cause of the RCP seal line failures after St. Lucie Unit 2 returned to service?

A. Yes. FPL conducted several evaluations that resulted in a much better understanding of the mechanisms that created the line failures. These evaluations led us to conclude that vibration was a major contributor to the failures. Vibration of the lines resulted from vibration of the RCPs themselves, and we determined that the extent of the line vibration depended upon how closely a line's resonant frequency matched the vibration frequency of the RCPs.

Q. Has FPL experienced RCP seal line failures at St. Lucie Unit 1?

A. No. However, with the assistance of an outside firm specializing in piping analysis, FPL has risk-ranked the Unit 1 RCP seal lines based on piping geometry and the potential for vibration fatigue cracking. Each of the 16 lines was assigned a risk of either low, moderate or high. The results of this analysis were reviewed and accepted by FPL's Site Design Engineering organization. As a preventive measure, FPL plans to replace four seal lines during Unit 1's Fall 2008 refueling outage that have been identified as high risk. FPL will continue to monitor the medium and low-risk lines for further deterioration but does not believe that replacing them is warranted at this time.

Q. Has FPL experienced any other unplanned outages at its St. Lucie plant in 2008?

A. In June 2008 St Lucie Unit 2 was manually shut down due to a secondary side transient. This transient occurred during maintenance activities to replace a feedwater heater level detector. The outage duration for this event was approximately 2 days.

Also in June 2008, St Lucie Unit 2 was manually shut down due to a trip of a main condensate pump when the motor leads associated with this pump electrically faulted. The outage duration for this event was approximately 2 days.

In August 2008, St. Lucie Unit 1 shut down due to flooding associated with the unprecedented amount of rainfall from Tropical Storm Fay. The outage duration was approximately 5 days.

FPL is in the process of investigating and evaluating these recent outages.

Q. Does this conclude your testimony?

A. Yes it does.

OCTOBER 15, 2008

REVISED SCHEDULE E-3
FOR 2008 ESTIMATED/ACTUAL PERIOD
FILED ON AUGUST 4, 2008

Generating System Comparative Data by Fuel Type

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
Fuel Cost of System Net Generation ($)	**ACTUALS**	**ACTUALS**	**ACTUALS**	**ACTUALS**	**ACTUALS**	**ACTUALS**
1 Heavy Oil	16,993,995	22,902,013	31,759,248	71,514,487	68,056,247	103,668,024
2 Light Oil	180,704	840,820	139,380	416,488	344,757	131,733
3 Coal	12,578,611	12,010,604	3,773,346	8,674,732	13,585,911	13,308,745
4 Gas	303,046,588	308,188,667	344,950,595	384,166,506	476,978,063	512,803,656
5 Nuclear	9,152,181	8,430,238	9,098,382	7,903,098	8,640,774	9,958,783
6 ***Total***	341,952,079	$352,372,341	$389,720,951	$472,675,312	$567,605,752	$639,870,942
System Net Generation (MWH)						
7 Heavy Oil	163,557	222,625	313,262	647,957	631,555	884,962
8 Light Oil	1,136	4,699	628	1,892	1,612	660
9 Coal	585,814	517,794	162,259	376,843	615,341	579,432
10 Gas	4,237,624	4,052,626	4,401,718	4,918,502	5,279,024	5,753,192
11 Nuclear	2,116,671	1,898,820	2,066,766	1,731,527	1,903,380	2,130,176
12 ***Total***	7,104,802	6,696,564	6,944,633	7,676,720	8,430,912	9,348,422
Units of Fuel Burned						
13 Heavy Oil (BBLS)	274,981	372,726	511,796	1,065,296	1,037,763	1,441,436
14 Light Oil (BBLS)	2,031	10,802	1,242	3,952	4,039	1,107
15 Coal (TONS)	69,532	54,878	28,300	45,596	74,023	70,918
16 Gas (MCF)	31,482,018	31,083,782	33,876,559	37,100,978	42,357,715	43,351,190
17 Nuclear (MBTU)	22,842,856	20,573,934	22,363,822	18,714,867	20,776,737	23,372,380
BTU Burned (MMBTU)						
18 Heavy Oil	1,764,587	2,390,622	3,285,880	6,840,564	6,660,685	9,253,504
19 Light Oil	11,767	62,454	7,169	22,926	22,967	6,371
20 Coal	5,836,604	5,644,265	1,665,794	4,022,082	6,260,090	5,991,246
21 Gas	32,287,423	31,886,896	34,784,589	38,103,754	43,654,776	44,626,093
22 Nuclear	22,842,856	20,573,934	22,363,822	18,714,867	20,776,737	23,372,380
23 ***Total***	62,743,237	60,558,171	62,107,254	67,704,193	77,375,255	83,247,891

Generating System Comparative Data by Fuel Type

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
Generation Mix (%MWH)						
24 Heavy Oil	2.30	3.32	4.51	8.44	7.49	9.47
25 Light Oil	0.02	0.07	0.01	0.02	0.02	0.01
26 Coal	8.25	7.73	2.34	4.91	7.30	6.20
27 Gas	59.64	60.52	63.38	64.07	62.62	61.54
28 Nuclear	29.79	28.36	29.76	22.56	22.58	22.79
29 ***Total***	100.00	100.00	100.00	100.00	100.00	100.00
Fuel Cost per Unit						
30 Heavy Oil ($/BBL)	61.8006	61.4446	62.0545	67.1311	65.5798	71.9200
31 Light Oil ($/BBL)	88.9897	77.8409	112.2431	105.3985	85.3663	118.9977
32 Coal ($/ton)	53.8285	52.4570	51.9429	51.2237	52.5920	52.7251
33 Gas ($/MCF)	9.6260	9.9148	10.1826	10.3546	11.2607	11.8291
34 Nuclear ($/MBTU)	0.4007	0.4098	0.4068	0.4223	0.4159	0.4261
Fuel Cost per MMBTU ($/MMBTU)						
35 Heavy Oil	9.6306	9.5799	9.6654	10.4545	10.2176	11.2031
36 Light Oil	15.3569	13.4630	19.4420	18.1666	15.0110	28.2205
37 Coal	2.1551	2.1279	2.2652	2.1568	2.1702	2.2214
38 Gas	9.3859	9.6651	9.9168	10.0821	10.9261	11.4911
39 Nuclear	0.4007	0.4098	0.4068	0.4223	0.4159	0.4261
BTU burned per KWH (BTU/KWH)						
40 Heavy Oil	10,789	10,738	10,489	10,557	10,546	10,456
41 Light Oil	10,354	13,291	11,419	12,121	14,248	7,075
42 Coal	9,963	10,901	10,266	10,673	10,173	10,340
43 Gas	7,619	7,868	7,903	7,747	8,269	7,757
44 Nuclear	10,792	10,835	10,821	10,808	10,916	10,972
Generated Fuel Cost per KWH (cents/KWH)						
45 Heavy Oil	10.3903	10.2873	10.1382	11.0369	10.7760	11.7144
46 Light Oil	15.9001	17.8943	22.2013	22.0189	21.3882	19.9656
47 Coal	2.1472	2.3196	2.3255	2.3020	2.2079	2.2969
48 Gas	7.1513	7.6047	7.8367	7.8106	9.0353	8.9134
49 Nuclear	0.4324	0.4440	0.4402	0.4564	0.4540	0.4675
50 ***Total***	4.8130	5.2620	5.6118	6.1573	6.7324	6.8447

Florida Power & Light Company

Schedule E 3
Page 3 of 4
REVISED 10-15-08

Generating System Comparative Data by Fuel Type

	Jul-08 REVISED ESTIMATES	Aug-08 REVISED ESTIMATES	Sep-08 REVISED ESTIMATES	Oct-08 REVISED ESTIMATES	Nov-08 REVISED ESTIMATES	Dec-08 REVISED ESTIMATES	Total Total
Fuel Cost of System Net Generation ($)							
1 Heavy Oil	$97,283,963	$136,394,481	$53,583,756	$68,238,338	($1,401,171)	$740,373	$669,733,754
2 Light Oil	$0	$358,000	$45,000	$0	$0	$0	$2,456,882
3 Coal	$14,236,000	$14,304,000	$13,882,000	$14,416,000	$14,020,000	$14,543,000	$149,332,949
4 Gas	$586,599,425	$487,427,401	$450,791,881	$418,811,778	$362,028,863	$354,449,535	$4,990,242,957
5 Nuclear	$10,285,000	$10,250,000	$9,884,000	$9,276,000	$7,894,000	$11,186,000	$111,958,456
6 ***Total***	$708,404,388	$648,733,881	$528,186,637	$510,742,116	$382,541,692	$380,918,908	$5,923,724,999
System Net Generation (MWH)							
7 Heavy Oil	884,672	1,164,676	628,774	563,941	53,516	40,785	6,200,282
8 Light Oil	0	1,858	133	0	0	0	12,617
9 Coal	636,693	637,234	616,011	637,234	623,610	644,397	6,632,662
10 Gas	6,285,764	6,306,948	5,884,848	5,511,850	4,832,002	4,600,726	62,064,823
11 Nuclear	2,131,954	2,131,954	2,063,180	1,896,360	1,536,210	2,185,554	23,792,552
12 ***Total***	9,939,083	10,242,670	9,192,946	8,609,385	7,045,338	7,471,462	98,702,936
Units of Fuel Burned							
13 Heavy Oil (BBLS)	1,359,496	1,794,886	974,398	864,806	82,213	64,946	9,844,743
14 Light Oil (BBLS)	0	2,367	287	0	0	0	25,825
15 Coal (TONS)	350,431	350,426	338,649	350,004	338,345	349,409	2,420,510
16 Gas (MCF)	48,167,524	48,047,688	45,146,082	41,845,732	35,333,340	33,935,188	471,727,795
17 Nuclear (MBTU)	23,769,566	23,769,566	23,002,796	21,181,082	17,224,656	24,370,624	261,962,886
BTU Burned (MMBTU)							
18 Heavy Oil	8,700,771	11,487,272	6,236,145	5,534,761	526,166	415,657	63,096,614
19 Light Oil	0	13,800	1,671	0	0	0	149,125
20 Coal	6,624,824	6,629,795	6,409,716	6,629,795	6,419,872	6,633,872	68,767,955
21 Gas	48,167,524	48,047,688	45,146,082	41,845,732	35,333,340	33,935,188	477,819,085
22 Nuclear	23,769,566	23,769,566	23,002,796	21,181,082	17,224,656	24,370,624	261,962,886
23 ***Total***	87,262,685	89,948,121	80,796,410	75,191,370	59,504,034	65,355,341	871,795,665

Generating System Comparative Data by Fuel Type

	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Generation Mix (%MWH)							
24 Heavy Oil	8.93%	11.34%	6.86%	6.53%	0.80%	0.54%	6.28%
25 Light Oil	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.01%
26 Coal	6.41%	6.22%	6.70%	7.40%	8.85%	8.62%	6.72%
27 Gas	63.22%	61.62%	64.00%	64.05%	68.55%	61.58%	62.88%
28 Nuclear	21.45%	20.81%	22.44%	22.02%	21.80%	29.25%	24.11%
29 ***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Cost per Unit							
30 Heavy Oil ($/BBL)	70.8508	82.9930	57.8653	89.5207	-20.3906	13.2840	68.0296
31 Light Oil ($/BBL)	0.0000	168.7500	174.2160	0.0000	0.0000	0.0000	95.1347
32 Coal ($/ton)	46.2590	46.1210	45.9679	45.8280	45.7285	45.5855	61.6948
33 Gas ($/MCF)	12.1780	12.1705	11.8677	11.6131	11.8907	12.0445	10.5786
34 Nuclear ($/MBTU)	0.4327	0.4312	0.4297	0.4379	0.4583	0.4590	0.4274
Fuel Cost per MMBTU ($/MMBTU)							
35 Heavy Oil	11.0704	12.9677	9.0414	13.9876	-3.1860	2.0756	10.6144
36 Light Oil	0.0000	28.9492	29.9222	0.0000	0.0000	0.0000	16.4753
37 Coal	2.4469	2.4378	2.4287	2.4194	2.4100	2.4010	2.1715
38 Gas	12.1780	12.1705	11.8677	11.6131	11.8907	12.0445	10.4438
39 Nuclear	0.4327	0.4312	0.4297	0.4379	0.4583	0.4590	0.4274
BTU burned per KWH (BTU/KWH)							
40 Heavy Oil	9,837	9,858	9,911	9,816	9,824	10,177	98.27
41 Light Oil	0	7,432	12,564	0	0	0	84.61
42 Coal	10,405	10,404	10,405	10,404	10,295	10,295	96.45
43 Gas	7,665	7,614	7,667	7,585	7,305	7,378	129.89
44 Nuclear	11,149	11,149	11,149	11,169	11,212	11,151	90.82
Generated Fuel Cost per KWH (cents/KWH)							
45 Heavy Oil	10.8901	12.7833	8.9611	13.7306	-3.1301	2.1123	10.8017
46 Light Oil	0.0000	21.5139	37.5940	0.0000	0.0000	0.0000	19.4723
47 Coal	2.5460	2.5363	2.5271	2.5171	2.4810	2.4718	2.2515
48 Gas	9.3349	9.2660	9.0988	8.8088	8.6857	8.8864	8.0404
49 Nuclear	0.4824	0.4808	0.4791	0.4891	0.5139	0.5118	0.4706
50 ***Total***	7.1398	7.4184	6.7149	6.8320	6.2608	5.8466	6.0016