invoice caused the Other O&M category lead days to be understated by 0.47 days (1.45 x 0.3259). A loss of 0.47 lead days for this Other O&M category that has a $233,838 average daily balance increases rate base by $109,904 ($233,838 x 0.47). Using a 12% grossed-up overall cost of capital for illustrative purposes yields a $13,188 increase in revenue requirements. In other words, the Company saved customers $883.33 by taking a discount, but wants to charge them $13,188 for its efforts. This is not appropriate.

An example of Mr. Gallagher's failure to capture the correct service period can be seen on sample item 13 in the $25,000 to $50,000 stratum. This particular invoice clearly identifies the service period by stating "for services from 5/31/2008 to 6/27/2008."[276] Unfortunately, Mr. Gallagher relied on a July 2, 2008 date as the service period.[277]

Q. WHAT IS THE IMPACT OF THE VARIOUS CORRECTIONS THAT YOU RECOMMEND TO THE OTHER O&M LEAD DAYS PROPOSED BY MR. GALLAGHER?

A. As set forth on Schedule (JP-5), the numerous recommended corrections to the Other O&M category increase the Company proposed 28.55 lead days to 44.07 lead days.

SECTION VII: RIVER BEND DECOMMISSIONING REVENUE REQUIREMENT

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses the Company's request for decommissioning expense revenue requirements associated with River Bend. To the extent the Commission has authority to address this issue, I recommend that the Company's request for a $2.8 million decommissioning expense annual revenue requirement be reversed and the existing $0-level of decommissioning expense be retained.

[276] Company Workpaper WP/E-4 page 1026.
[277] Id., at page 972 for sample number 13.

Q. WHY DO YOU STATE THAT THE COMMISSION MAY NOT HAVE AUTHORITY TO RULE ON DECOMMISSIONING REVENUE REQUIREMENT MATTERS?

A. It is my understanding that Cities' witness Mr. Brazell will be addressing this issue as to whether the Commission has authority to impact a FERC established tariff. However, to the extent that the Commission believes it has authority to address this issue, I recommend the retention of the $0-level of decommissioning expense revenue requirements.

Q. WHAT DOES THE COMPANY REQUEST REGARDING DECOMMISSIONING REVENUE REQUIREMENTS?

A. Mr. Gillam states that the Company is requesting $2.8 million of annual decommissioning expense.[278] This represents a $2.8 million increase from the existing $0-level of expense.

Q. WHAT IS THE COMPANY'S BASIS FOR REQUESTING A $2.8 MILLION REVENUE REQUIREMENT FOR DECOMMISSIONING ACTIVITIES?

A. The existing $0-level of decommissioning expense is predicated on Item 9 of the Settlement Term sheet in Docket No. 34800. Item 9 states that nuclear depreciation and decommissioning amounts reflect the life extension of River Bend. In other words, while the Company has not formally received the 20-year life extension from the NRC for River Bend, it did recognize the impact of such extension for ratemaking purposes in its settlement of Docket No. 34800. Now in this case, Mr. Gillam bases his analysis for decommissioning revenue requirements on the initial 40-year life span versus a 60-year life span for River Bend.[279]

Q. IS THE COMPANY'S REVERSAL OF POSITION APPROPRIATE?

A. No. The industry as a whole has embarked on and received approval for 20-year license extensions for various nuclear power plants. Indeed, Entergy Corporation has already

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[278] Direct Testimony of Mr. Gillam at page 3.
[279] Gillam Exhibit PEG-3.

received 20-year license extensions for nuclear units and is in the process of seeking 20-year license extensions for several other nuclear generating facilities. In addition, the NRC has been given a formal notice that a license extension will be requested for the River Bend station. Thus, the industry, the Company's parent, and the Company all recognize the change in life expectancy for nuclear generating facilities such as River Bend.

Q. HOW DID MR. GILLAM DEVELOP HIS $2.8 MILLION ESTIMATE?

A. Mr. Gillam developed an analysis that reflected estimation of future decommissioning costs, earning rates for different types of external funds, cost escalation rates, management fee levels, as well as other variables. Mr. Gillam estimated these variables through the year 2034, or approximately 25 years into the future.[280]

Q. HOW DOES THE 20-YEAR LIFE EXTENSION AFFECT THE CALCULATION EMPLOYED BY MR. GILLAM?

A. Given that the Company's earnings rate for its trust funds are higher than its estimated cost escalation rates yields the straightforward conclusion that a 20-year life extension will reduce the need for additional customer funding of the external trust funds requirements. In other words, estimated earning rates of 4.51% and higher are greater than the assured 4.25% cost escalation rate. Therefore, the further out into the future the decommissioning process is moved the lesser is the need for further customer contribution to the external funds.

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[280] Direct Testimony of Mr. Gillam at pages 4-6, and Exhibit PBG-3.

Q. ARE THERE PROBLEMS WITH MR. GILLAM'S ANALYSES PRIOR TO RECOGNITION OF A 20-YEAR LIFE EXTENSION FOR RIVER BEND?

A. Yes. Mr. Gillam relies on an excessive Texas retail allocation factor (i.e., 42.73% versus 42.5%).[281] Mr. Gillam's analysis also understates the starting balance of both external funds by millions of dollars.[282] In addition, Mr. Gillam only addresses future assumed cost escalation for decommissioning activities and fails to address productivity gains or other cost reduction factors.

Q. HAVE YOU ANALYZED THE IMPACT ON THE EXPECTED DECOMMISSIONING REVENUE REQUIREMENT FUNDS FOR A 20-YEAR LIFE EXTENSION?

A. Yes. Recognition of a 20-year life extension for the River Bend station would eliminate the Company's $2.8 million requested revenue requirements for decommissioning. Recognition of the 20-year life extension in conjunction with the correction noted above would further result in the fact that Texas retail customers have already overpaid their annual decommissioning funding requirements.

Q. HAVE TEXAS CUSTOMERS BEEN TREATED FAIRLY IN THE DECOMMISSIONING FUNDING PROCESS?

A. No. Even though ETI is responsible for approximately 42.5% of River Bend and EGSL is responsible for approximately 57.5%, the same situation does not exist for the decommissioning fund balance. As of December 31, 2009, Texas retail customers' trust fund balance was $101 million out of the total $153.5 million balance.[283] Thus, while Texas retail customers have only 42.5% of the plant they have contributed 66% of the total decommissioning fund balance. In other words, Texas retail customers have historically done what was thought to be the "right thing" and contributed to the fund in a responsible, but excessive, manner.

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[281] Id., at Exhibit PBG-3.
[282] Response to Rose City 10-3.
[283] Response to Rose City 10-3 and 10-2.

Q. HAVE TEXAS RETAIL CUSTOMERS BEEN REWARDED FOR DOING THE "RIGHT THING"?

A. No. As stated elsewhere in my testimony, the nation as well as the world experienced a financial meltdown in the second half of 2008. Due to the dramatic declines in the equity markets Texas retail customers lost more money than their counterparts in Louisiana. Indeed, Company witness Mr. Caruso stated that "the jurisdiction that has accumulated the most balance [Texas retail customers] is going to have a bigger share of the gain or loss."[284] Mr. Caruso was right, Texas retail customers have suffered to date much more than their counterparts in Louisiana. First they paid more, then lost more in the worldwide financial meltdown in 2008, and now are being asked to make up for those losses. The Company's decommissioning trust fund treatment of Texas retail customers has not been equitable compared to Louisiana customers.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the retention of the current $0-level of decommissioning expense. The 20-year life extension and correction of certain errors would eliminate the Company's request. Additional factors must also be considered. First, even slight increase in the earnings rates or slight decline in the cost escalation factor would further eliminate the need for any current contribution. Indeed, EGSL employs a 2.5% decommissioning cost escalation factor in Louisiana and a 5.7% earnings growth rate.[285] If either of these factors were employed in Texas, the result would be further support for a $0-level of decommissioning accrual. Next, any recognition of gains in productivity would also reduce the need for any further decommissioning contributions. This concept is significant given the decommissioning cost estimate have a built in contingency factor. The only necessary contingency factor is time itself. As more time passes, and there is more than 35 years until the 20-year life extension expires, costs, productivity, earnings and other factors will be known with greater certainty. Another consideration for totally eliminating the requested revenue requirements is the fact that if the actual decommissioning process were delayed for a short period, after retirement, it would result

[284] Deposition of Mr. Caruso on April 29, 2010 at TR 54.

[285] Entergy Corporation August 13, 2009 letter to the NRC regarding the "Decommissioning Funding Assurance Plans."

in the current fund levels being even more excessive. Therefore, there is no reason to change the current contribution level at this time.

SECTION VIII: RIVER BEND DEPRECIATION RATES

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. The Company has included a River Bend depreciation analysis in its filing. City witness Mr. Brazell will address whether the Commission has authority to set a depreciation rate for the River Bend station. However, to the extent the Commission does set depreciation rate, the rate proposed by the Company must be reduced to reflect the elimination of interim retirements and a 20-year license extension.

Q. WHAT DEPRECIATION RATE DOES THE COMPANY REQUEST FOR RIVER BEND?

A. As set forth in Company witness Mr. Spanos' Exhibit JJS-2, the Company seeks a composite depreciation rate for its nuclear plant investment of 3.6%. This rate is comprised of individual rates for the individual plant accounts and reflects the recognition of interim retirements, an ELG calculation procedure, and a 40-year life span rather than a 60-year life span.

Q. ARE THE RATES PROPOSED BY THE COMPANY APPROPRIATE AND REASONABLE?

A. No. As previously noted under the depreciation section of my testimony, the Commission has historically denied the inclusion of interim retirements. The current rates for River Bend do not reflect the impact of interim retirements. In addition, also discussed in the depreciation section of my testimony, the use of the ELG depreciation procedure is inappropriate. Finally, the life span proposed by the Company is artificially short based on the available facts.

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RIVER BEND DEPRECIATION RATES

Account	ETI	Cities
321	2.99%	1.33%
322	3.67%	1.53%
323	4.24%	1.66%
324	3.14%	1.32%
325	5.03%	2.10%
Total	3.36%	1.42%

As can be seen in the table above, the 20-year life extension and elimination of interim retirements significantly reduces the necessary depreciation rates and depreciation expense requested by the Company by $26,671,803 for the Texas jurisdiction based on plant as of December 31, 2008.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes. However to the extent I have not addressed an issue, method, procedure, etc., that should not be construed that I am in agreement with the Company's issue, method, procedure, etc.

CITIES RECOMMENED DEPRECIATION RATES
FOR ENTERGY TEXAS, INC.
PERIOD ENDED 12/31/2008

Account	Balance 12/31/2008	Net Salvage %	Net Salvage $	Reserve 12/31/2008	Net Depreciable 12/31/2008	Remaining Life	Annual Depreciation Accrual	Annual Depreciation Rate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
311								
Sabine 1	$1,652,593	0%	$0	$877,366	$775,227	20.50	$37,816	2.29%
Sabine 2	$575,219	0%	$0	$495,312	$79,907	20.50	$3,898	0.68%
Sabine 3	$1,322,129	0%	$0	$1,008,618	$313,511	23.50	$13,341	1.01%
Sabine 4	$6,495,531	0%	$0	$5,384,358	$1,111,173	30.50	$36,432	0.56%
Sabine 5	$8,542,692	0%	$0	$5,919,890	$2,622,802	35.50	$73,882	0.86%
Sabine Com	$23,517,615	0%	$0	$17,243,072	$6,274,543	35.50	$176,748	0.75%
Lewis Ck 1	$1,634,945	0%	$0	$1,534,232	$100,713	26.50	$3,800	0.23%
Lewis Ck 2	$1,422,372	0%	$0	$1,326,357	$96,015	27.50	$3,491	0.25%
Lewis Ck Cm	$10,968,849	0%	$0	$9,088,724	$1,880,125	27.50	$68,368	0.62%
Big Cajun Cm	$62,906	0%	$0	$9,661	$53,245	34.50	$1,543	2.45%
Big Cajun 3	$19,485,264	0%	$0	$13,648,410	$5,836,854	34.50	$169,184	0.87%
Nelson O&G	$2,764,789	0%	$0	$566,421	$2,198,368	33.50	$65,623	2.37%
Nelson 6	$28,689,319	0%	$0	$19,992,817	$8,696,502	33.50	$259,597	0.90%
System	$568,326	0%	$0	$582,658	($14,332)	27.50	($521)	-0.09%
Spindle Top	$1,647,952	0%	$0	$314,519	$1,333,433	35.50	$37,561	2.28%
Total 311	$109,350,501		$0	$77,992,415	$31,358,086		$950,764	0.87%
312								
Sabine 1	$12,972,582	0%	$0	$8,985,739	$3,986,843	20.50	$194,480	1.50%
Sabine 2	$12,123,162	0%	$0	$7,404,198	$4,718,964	20.50	$230,193	1.90%
Sabine 3	$28,490,652	0%	$0	$11,665,900	$16,824,752	23.50	$715,947	2.51%
Sabine 4	$39,330,618	0%	$0	$18,326,712	$21,003,906	30.50	$688,653	1.75%
Sabine 5	$74,944,061	0%	$0	$51,337,824	$23,606,237	35.50	$664,964	0.89%
Sabine Com	$23,959,157	0%	$0	$16,533,521	$7,425,636	35.50	$209,173	0.87%
Lewis Ck 1	$18,811,295	0%	$0	$8,905,273	$9,906,022	26.50	$373,812	1.99%

CITIES RECOMMENED DEPRECIATION RATES
FOR ENTERGY TEXAS, INC.
PERIOD ENDED 12/31/2008

Account	Balance 12/31/2008	Net Salvage %	Net Salvage $	Reserve 12/31/2008	Net Depreciable 12/31/2008	Remaining Life	Annual Depreciation Accrual	Annual Depreciation Rate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Lewis Ck 2	$18,842,014	0%	$0	$8,626,408	$10,215,606	27.50	$371,477	1.97%
Lewis Ck Cm	$3,272,856	0%	$0	$2,253,139	$1,019,717	27.50	$37,081	1.13%
Big Cajun Cm	$1,049,284	0%	$0	$159,412	$889,872	34.50	$25,793	2.46%
Big Cajun 3	$51,685,966	0%	$0	$30,912,603	$20,773,363	34.50	$602,126	1.16%
Nelson O&G	$2,659,983	0%	$0	$427,959	$2,232,024	33.50	$66,628	2.50%
Nelson 6	$98,643,166	0%	$0	$65,695,199	$32,947,967	33.50	$983,521	1.00%
System	$0	0%	$0	$0	$0	-	$0	0.00%
Spindle Top	$0	0%	$0	$0	$0	-	$0	0.00%
Total 312	$386,824,609		$0	$231,273,700	$155,590,722		$5,163,849	
314								
Sabine 1	$13,707,313	0%	$0	$13,082,946	$624,367	20.50	$30,457	0.22%
Sabine 2	$10,850,111	0%	$0	$9,700,343	$1,149,768	20.50	$56,086	0.52%
Sabine 3	$20,220,328	0%	$0	$11,642,354	$8,577,974	23.50	$365,020	1.81%
Sabine 4	$24,962,805	0%	$0	$20,061,252	$4,901,553	30.50	$160,707	0.64%
Sabine 5	$50,422,827	0%	$0	$34,099,660	$16,323,167	35.50	$459,808	0.91%
Sabine Com	$986,164	0%	$0	$280,221	$705,943	35.50	$19,886	2.02%
Lewis Ck 1	$12,834,153	0%	$0	$7,659,987	$5,174,166	26.50	$195,252	1.52%
Lewis Ck 2	$10,433,812	0%	$0	$7,425,026	$3,008,786	27.50	$109,410	1.05%
Lewis Ck Cm	$279,718	0%	$0	$79,112	$200,606	27.50	$7,295	2.61%
Big Cajun Cm	$2,861	0%	$0	$151	$2,710	34.50	$79	2.75%
Big Cajun 3	$15,547,062	0%	$0	$8,928,937	$6,618,125	34.50	$191,830	1.23%
Nelson O&G	$51,653	0%	$0	$20,569	$31,084	33.50	$928	1.80%
Nelson 6	$22,162,454	0%	$0	$13,784,805	$8,377,649	33.50	$250,079	1.13%
System	$0	0%	$0	$0	$0	-	$0	0.00%
Spindle Top	$0	0%	$0	$0	$0	-	$0	0.00%
Total 314	$182,461,261		$0	$126,765,363	$55,695,898		$1,846,835	

CITIES RECOMMENED DEPRECIATION RATES
FOR ENTERGY TEXAS, INC.
PERIOD ENDED 12/31/2008

Account	Balance 12/31/2008 (a)	Net Salvage % (b)	Net Salvage $ (c)	Reserve 12/31/2008 (d)	Net Depreciable 12/31/2008 (e)	Remaining Life (f)	Annual Depreciation Accrual (g)	Annual Depreciation Rate (h)
315								
Sabine 1	$6,010,506	0%	$0	$3,583,458	$2,427,048	20.50	$118,393	1.97%
Sabine 2	$3,485,293	0%	$0	$3,101,443	$383,850	20.50	$18,724	0.54%
Sabine 3	$5,514,680	0%	$0	$4,444,718	$1,069,962	23.50	$45,530	0.83%
Sabine 4	$7,102,089	0%	$0	$5,351,261	$1,750,828	30.50	$57,404	0.81%
Sabine 5	$21,664,124	0%	$0	$13,629,033	$8,035,091	35.50	$226,341	1.04%
Sabine Com	$6,412,363	0%	$0	$2,023,282	$4,389,081	35.50	$123,636	1.93%
Lewis Ck 1	$4,921,864	0%	$0	$2,663,601	$2,258,263	26.50	$85,217	1.73%
Lewis Ck 2	$3,706,543	0%	$0	$1,874,495	$1,832,048	27.50	$66,620	1.80%
Lewis Ck Cm	$3,602,726	0%	$0	$1,636,296	$1,966,430	27.50	$71,507	1.98%
Big Cajun Cm	$86,091	0%	$0	$16,372	$69,719	34.50	$2,021	2.35%
Big Cajun 3	$11,594,684	0%	$0	$7,769,777	$3,824,907	34.50	$110,867	0.96%
Nelson O&G	$261,813	0%	$0	$55,034	$206,779	33.50	$6,173	2.36%
Nelson 6	$20,136,487	0%	$0	$13,122,443	$7,014,044	33.50	$209,374	1.04%
System	$95,188	0%	$0	$65,834	$29,354	27.50	$1,067	1.12%
Spindle Top	$0	0%	$0	$0	$0	-	$0	0.00%
Total 315	$94,594,451		$0	$59,337,047	$35,257,404		$1,142,874	1.21%
316								
Sabine 1	$0	0%	$0	$0	$0	20.50	$0	0.00%
Sabine 2	$130,127	0%	$0	$10,082	$120,045	20.50	$5,856	4.50%
Sabine 3	$0	0%	$0	$0	$0	23.50	$0	0.00%
Sabine 4	$21,805	0%	$0	$1,096	$20,709	30.50	$679	3.11%
Sabine 5	$0	0%	$0	$0	$0	35.50	$0	0.00%
Sabine Com	$3,985,871	0%	$0	$1,831,188	$2,154,683	35.50	$60,695	1.52%
Lewis Ck 1	$0	0%	$0	$0	$0	26.50	$0	0.00%
Lewis Ck 2	$0	0%	$0	$0	$0	27.50	$0	0.00%
Lewis Ck Cm	$937,205	0%	$0	$794,000	$143,205	27.50	$5,207	0.56%

CITIES RECOMMENED DEPRECIATION RATES
FOR ENTERGY TEXAS, INC.
PERIOD ENDED 12/31/2008

Account		Balance 12/31/2008	Net Salvage %	Net Salvage $	Reserve 12/31/2008	Net Depreciable 12/31/2008	Remaining Life	Annual Depreciation Accrual	Annual Depreciation Rate
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Big Cajun Cm		$273,453	0%	$0	$78,705	$194,748	34.50	$5,645	2.06%
Big Cajun 3		$738,631	0%	$0	$445,314	$293,317	34.50	$8,502	1.15%
Nelson O&G		$164,664	0%	$0	$21,048	$143,616	33.50	$4,287	2.60%
Nelson 6		$1,356,200	0%	$0	$868,266	$487,934	33.50	$14,565	1.07%
System		$3,115,785	0%	$0	$2,226,946	$888,839	25.54	$34,802	1.12%
Spindle Top		$0	0%	$0	$0	$0	-	$0	0.00%
Total 316		$10,763,554		$0	$6,316,458	$4,486,909		$140,238	
Total Steam		$783,994,376		$0	$501,684,983	$282,389,019		$9,244,560	1.18%
Hydor Prod.		$255,807	0%	$0	$251,591	$4,216	9.70	$435	0.17%
Transmission									
	350	$31,234,089	0%	$0	$14,025,676	$17,208,413	69.69	$246,928	0.79%
	352	$21,520,152	-5%	($1,076,008)	$6,610,622	$15,985,537	37.94	$421,337	1.96%
	353	$337,948,070	5%	$16,897,403	$114,009,798	$207,040,868	37.69	$5,493,257	1.63%
	354	$25,429,920	-5%	($1,271,496)	$20,643,860	$6,057,556	34.25	$176,863	0.70%
	355	$171,934,688	-25%	($42,983,672)	$38,668,500	$176,249,860	48.08	$3,665,762	2.13%
	356	$164,622,565	-20%	($32,924,513)	$38,506,382	$159,040,696	43.01	$3,697,761	2.25%
	358	$321,998	0%	$0	$39,478	$282,520	36.72	$7,694	2.39%
	359	$202,758	0%	$0	$124,702	$78,056	39.66	$1,968	0.97%
Total Trans.		$753,214,239		($61,358,285)	$232,629,018	$581,943,506		$13,711,571	

CITIES RECOMMENED DEPRECIATION RATES
FOR ENTERGY TEXAS, INC.
PERIOD ENDED 12/31/2008

Account		Balance 12/31/2008	Net Salvage %	Net Salvage $	Reserve 12/31/2008	Net Depreciable 12/31/2008	Remaining Life	Annual Depreciation Accrual	Annual Depreciation Rate
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Distribution									
	360	$11,377,010	0%	$0	$5,801,450	$5,575,560	59.50	$93,707	0.82%
	361	$7,428,830	-5%	($371,442)	$3,074,442	$4,725,830	34.16	$138,344	1.86%
	362	$154,769,835	15%	$23,215,475	$54,170,584	$77,383,775	35.44	$2,183,515	1.41%
	364	$168,927,973	-30%	($50,678,392)	$75,498,362	$144,108,003	26.09	$5,523,496	3.27%
	365	$167,287,943	10%	$16,728,794	$25,262,851	$125,296,298	29.34	$4,270,494	2.55%
	366	$47,246,249	0%	$0	$5,776,558	$41,469,691	49.66	$835,072	1.77%
	367	$102,506,210	-5%	($5,125,310)	$27,457,164	$80,174,356	25.93	$3,091,954	3.02%
	368	$230,541,197	0%	$0	$17,001,471	$213,539,726	25.46	$8,387,263	3.64%
	369.1	$58,239,825	-10%	($5,823,982)	$9,347,098	$54,716,709	23.17	$2,361,533	4.05%
	369.2	$56,596,295	-10%	($5,659,629)	$17,012,935	$45,242,989	21.65	$2,089,745	3.69%
	370	$57,739,294	0%	$0	$15,542,202	$42,197,092	19.06	$2,213,908	3.83%
	371	$41,613,855	0%	$0	$13,961,610	$27,652,245	27.21	$1,016,253	2.44%
	373	$21,416,138	0%	$0	$2,072,005	$19,344,133	39.79	$486,156	2.27%
	373.2	$129,765	-20%	($25,953)	$101,713	$54,005	39.20	$1,378	1.06%
Total Dist.		$1,125,820,419		($27,740,440)	$272,080,445	$881,480,413		$32,692,818	
General									
	390	$53,758,161	0%	$0	$19,199,694	$34,558,467	40.13	$861,163	1.60%
	391.1	$766,637	5%	$38,332	$492,980	$235,325	5.35	$43,986	5.74%
	391.2	$69,726	0%	$0	$69,726	$0	-	$0	0.00%
	391.2	$11,573,956	0%	$0	$4,132,011	$7,441,945	8.35	$891,251	7.70%
	391.3	$796,103	0%	$0	$587,950	$208,153	3.92	$53,100	6.67%
	392	$91,988	0%	$0	$28,829	$63,159	4.16	$15,182	16.50%
	393	$3,214,625	0%	$0	$1,672,977	$1,541,648	7.19	$214,416	6.67%
	394	$7,328,378	0%	$0	$2,699,030	$4,629,348	15.35	$301,586	4.12%
	395	$451,090	0%	$0	$315,573	$135,517	3.00	$45,172	10.01%

CITIES RECOMMENED DEPRECIATION RATES
FOR ENTERGY TEXAS, INC.
PERIOD ENDED 12/31/2008

Account	Balance 12/31/2008	Net Salvage %	Net Salvage $	Reserve 12/31/2008	Net Depreciable 12/31/2008	Remaining Life	Annual Depreciation Accrual	Annual Depreciation Rate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
396	$526,899	0%	$0	$388,360	$138,539	4.28	$32,369	6.14%
397.1	$3,921,189	0%	$0	$1,050,003	$2,871,186	12.81	$224,136	5.72%
397.2	$12,850,720	0%	$0	$12,850,720	$0	-	$0	0.00%
397.2	$26,810,758	0%	$0	$21,649,980	$5,160,778	7.79	$662,488	2.47%
398	$727,915	0%	$0	$333,504	$394,411	5.42	$72,770	10.00%
Total General	$122,888,146		$38,332	$65,471,337	$57,378,477		$3,417,619	
Total Plant	$2,786,172,987		($89,060,393)	$1,072,117,374	$1,803,195,631		$59,067,003	
ETI Request							$116,029,481	
Cities Adjustment							($56,962,478)	

SOURCES AND REFERENCES

Columns (a & d)	: Exhibit JJS-1 at pages 51-54.
Columns (b & f)	: Cities' recommended adjustments as discussed in Mr. Pous' testimony.
Column (c)	: Column (a) times Column (b).
Column (e)	: Column (a) less Column (c) less Column (d).
Column (g)	: Column (e) divided by Column (f).
Column (h)	: Column (g) divided by Column (a).

CITIES RECOMMENDED CORRECTION FOR
ENTERGY TEXAS INC.'S
FULLY ACCRUED DEPRECIATION ERROR

Account	Description	Plant Balance (a)	Depreciation Rate (b)	Depreciation Expense (c)	Missing Years (d)	Missing Expense (e)
316.192	Misc. Equip. - Syst Repair Shop	$56,275	2.278%	$1,282	5.58	$7,157
334.19	Acces.Equip. Toledo Bend	$218,538	3.131%	$6,842	2.83	$19,387
391.3	Data Handling Equipment	$1,752,737	62.681%	$1,098,633	5.58	$6,134,034
	Total			$1,106,757		$6,160,578
	Decrease in Rate Base					**$6,160,578**
	Annual Amortization Expense With 4 Year Amortization					**$1,540,145**

SOURCES AND REFERENCES

Column (a)	: Response to Rose City 13-32 Attachment.
Column (b) 316 & 334	: Response to Rose City 13-32 Attachment.
Column (b) 391	: Attachment CFG-I, Staff's proposed rate, as adopted in Docket No. 16705.
Column (c)	: Column (a) times Column (b).
Column (d)	: December 2003 through June 2009 for accounts 316 and 391. September 2006 through June 2009 for account 334. Starting dates from response to Rose City 13-32 Attachment. Ending date as of the end of the test year.
Column (e)	: Column (c) times Column (d).

SCHEDULE (JP-3)

CITIES RECOMMENDED ADJUSTMENTS TO ENTERGY TEXAS, INC.'S SPINDLETOP GAS STORAGE FACILITY TEST YEAR ENDED JUNE 30, 2009

Line No.	Description	Current Value Adjustment (a)	Initial Capital Adjustment (b)	Net Adjustment (c)
1	Net Salvage Value	$100,000,000		
2	Initial Capital Cost		$40,000,000	
3	Texas Retail Factor	42.50%	42.50%	
4	Texas Retail Value	$42,500,000	$17,000,000	
5	Remaining Life (Yr)	35.5		
6	Amortization Period (Yr)		4	
7	Annual Credit	$1,197,183	$4,250,000	
8	Remaining Life (Yr)		35.5	
9	Depreciation Expense		$478,873	
10	Net Adjustment	$1,197,183	$3,771,127	$4,968,310

SOURCES AND REFERENCES

Line 1	: October 18, 2004 appraisal by Hadco International.
Line 4	: Line 1 or 2 times Line 3.
Lines 5 & 8	: Reflects 65 year life span for Sabine 5.
Line 7	: Line 4 divided by Line 5 or 6.
Line 9	: Line 7 divided by Line 8.
Line 10	: Line 7 less Line 9.

CITIES RECOMMENDED ADJUSTMENT TO CASH WORKING CAPITAL
FOR ENTERGY TEXAS, INC.
FOR THE TWELVE MONTHS ENDED JUNE 30, 2009

	DESCRIPTION	ETI PROPOSAL ($'s)	CITIES ADJUSTMENT ($'s)	CITIES ADJUSTED ($'s)	AVERAGE DAILY AMOUNT ($'s)	REVENUE LAG DAYS	EXPENSE LEAD DAYS	NET LAG DAYS	WORKING CASH ($'s)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	O & M								
2	PAYROLL								
3	GSU	35,210,377	(7,531,403)	27,678,974	75,833	37.12	14 55	22.57	1,711,546
4	VACATION	-	3,842,535	3,842,535	10,527	37 12	210.67	(173 55)	(1,827,046)
5	INCENTIVE COMPENSATION	-	3,688,868	3,688,868	10,106	37.12	253.5	(216 38)	(2,186,842)
6	FUEL								
7	COAL	45,001,972		45,001,972	123,293	37 12	47.72	(10 60)	(1,306,907)
8	OIL	709,889		709,889	1,945	37.12	14 93	22 19	43,157
9	GAS	425,244,643		425,244,643	1,165,054	37 12	41.28	(4 16)	(4,846,624)
10	RECOVERABLE ALLOWANCES (A/C 509)	44,509		44,509	122	37.12	37 94	(0.82)	(100)
11	ELIGIBLE PURCHASED POWER	553,436,302		553,436,302	1,516,264	37.12	37 94	(0.82)	(1,243,336)
12	3RD PARTY CAPACITY CONTRACTS	32,605,482		32,605,482	89,330	37.12	37.94	(0 82)	(73,251)
13	AFFILIATE CAPACITY CONTRACTS	184,084,272		184,084,272	504,340	37.12	60 04	(22 92)	(11,559,484)
14	RESERVE EQUALIZATION	35,137,338		35,137,338	96,267	37.12	37 94	(0.82)	(78,939)
15	ENTERGY SERVICES, INC.	68,997,263	(9,481,590)	59,515,673	163,057	37.12	39.3	(2.18)	(355,463)
16	ESI INCENTIVE COMPENSATION	-	9,481,590	9,481,590	25,977	37.12	253.5	(216.38)	(5,620,894)
17	FAS 106	-	2,522,308	2,522,308	6,910	37 12	312 55	(275 43)	(1,903,341)
18	OTHER O & M	85,350,863	(2,522,308)	82,828,555	226,928	37.12	44.07	(6.95)	(1,577,146)
19	TOTAL O & M	1,465,822,911	-	1,465,822,911	4,015,953				(30,824,669)
20	TAXES OTHER THAN INCOME TAXES								
21	408 110 EMPLOYMENT TAXES	2,383,333			6,530	37.12	17 19	19 93	130,137
22	408 110 EMPLOYMENT TAXES - ESI	1,886,426			5,168	37.12	39.3	(2 18)	(11,267)
23	408 165 CITY OCCUPATION TAX - ESI	190			1	37 12	39.3	(2 18)	(1)
24	408 152 FRANCHISE TAX-STATE (TX TAX)	4,223,537			11,571	37 12	317 5	(280 38)	(3,244,371)
25	408 152 FRANCHISE TAX-STATE (LA TAX)	75,000			205	37 12	110.86	(73.74)	(15,152)
26	408.152 FRANCHISE TAX-STATE - ESI	(16,603)			(45)	37.12	39.3	(2 18)	99
27	408.154 FRANCHISE TAX-LOCAL	1,943,697			5,325	37.12	89 12	(52 00)	(276,910)
28	408 163 STREET RENTAL	-			-	0	0	-	-
29	408 164 GROSS RECEIPTS & SALES TAX	322,910			885	0	0	-	-
30	408 172 REGULATORY COMMISSION	2,209,514			6,053	37 12	228.5	(191.38)	(1,158,512)
31	408 180 SALES & USE TAX	0			0	0	0	-	-
32	408.100 SALES & USE TAX - ESI	(2,659)			(7)	37 12	39 3	(2 18)	16
33	408.142 AD VALOREM TAX	20,169,425			55,259	37.12	217.29	(180.17)	(9,955,960)
34	408.142 AD VALOREM TAX - ESI	176,293			483	37.12	39 3	(2 18)	(1,053)
35	TOTAL TAXES OTHER THAN INC TAX	33,371,064			91,428				(14,532,974)

CITIES RECOMMENDED ADJUSTMENT TO CASH WORKING CAPITAL
FOR ENTERGY TEXAS, INC.
FOR THE TWELVE MONTHS ENDED JUNE 30, 2009

DESCRIPTION	ETI PROPOSAL ($'s)	CITIES ADJUSTMENT ($'s)	CITIES ADJUSTED ($'s)	AVERAGE DAILY AMOUNT ($'s)	REVENUE LAG DAYS	EXPENSE LEAD DAYS	NET LAG DAYS	WORKING CASH ($'s)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
33 FEDERAL	79,366,318			217,442	37 12	38 5	(1 38)	(300,070)
34 STATE	48,918			134	37 12	39 3	(2 18)	(292)
35 TOTAL CURRENT INCOME TAXES	79,415,236			217,576				(300,362)
36 TOTAL WORKING CASH (5)	1,578,609,211			4,324,957				(45,658,005)
37 ETI REQUEST								(1,979,613)
38 CITIES RECOMMENDED ADJUSTMENT								**(43,678,392)**

Column (a) Company Schdule E-4
Column (b) Response to Rose City 9-16, 7-1(E), 6-4 through 6-101, and 24-55
Coulumn (c) : Column (a) less Column (b)
Column (d) : Column (c) divided by 365
Columns (e&f) : Company Schdule E-4, and Mr Pous' testimony.

CITIES ADJUSTMENT TO CASH WORKING CAPITAL
FOR THE OTHER O&M EXPENSE CATEGORY
ENTERGY TEXAS, INC.
TEST YEAR ENDED JUNE 30, 2009

Stratum	Dollar Amount %	ETI Lead Days	ETI Weighted Lead Days	Cities Lead Days	Cities Weighted Lead Days	Cities Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)
>$100,000	32.59%	24.43	7.96	53.77	17.52	9.56
$50,000-$100,000	7.23%	51.56	3.73	51.56	3.73	0.00
$25,000-$50,000	8.63%	23.74	2.05	44.2	3.82	1.77
$10,000-$25,000	21.03%	23.58	4.96	32.51	6.84	1.88
$2,500-$10,000	17.51%	37.48	6.56	39.65	6.94	0.38
$250-$2,500	11.88%	24.65	2.93	40.89	4.86	1.93
<$250	1.13%	32.09	0.36	32.09	0.36	0.00
Total	100.00%		28.55		44.07	15.52

SOURCES AND REFERENCES

Columns (a-c) : Company Workpaper WP/E-4 page 826.
Column (d) : Schedule (JP-5) pages 2-6.
Column (e) : Column (a) times Column (d).
Column (f) : Column (d) less Column (b).

CITIES ADJUSTMENT TO CASH WORKING CAPITAL
FOR THE OTHER O&M EXPENSE CATEGORY
ENTERGY TEXAS, INC.
TEST YEAR ENDED JUNE 30, 2009
>$100,000 Stratum

Item	Page	Amount	Adjusted Amount	Lead Days	Adjusted Lead Days	Reason	Weighted Lead Days	Adj. Wght. Lead Days
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		$103,898	$103,898	40	40		1.6	1.77
2		$134,702	$134,702	40	40		2.07	2.29
3		$117,983	$117,983	60	60		2.72	3.01
3		$3,001	$3,001	91	91		0.11	0.12
3		$5,071	$5,071	122	122		0.24	0.26
4		$108,398	$108,398	65	65		2.71	2.99
5		$111,085	$111,085	40	40		1.71	1.89
6		$241,574	$241,574	40	40		3.72	4.11
7		$149,314	$149,314	40	40		2.3	2.54
8	880	$142,214	$0	-99	0	Prepayment	-5.42	0
9	881	$119,657	$120,500	30	60.5	45 Net	1.38	3.1
9	881	$3,207	$3,230	59.5	89.5	45 Net	0.07	0.12
9	881	$2,443	$2,460	91	121	45 Net	0.09	0.13
10	882	$117,200	$118,026	29.5	60	45 Net	1.33	3.01
10	882	$993	$1,000	60	90	45 Net	0.02	0.04
11		$147,040	$147,040	39.5	39.5		2.23	2.47
12	884	$119,657	$120,500	46	76	45 Net	2.12	3.89
12	884	$1,092	$1,100	76	106	45 Net	0.03	0.05
13	885	$119,657	$120,500	29.5	59.5	45 Net	1.36	3.05
13	885	$1,986	$2,000	60	90	45 Net	0.05	0.08
14	886	$99,017	$99,715	29.5	59.5	45 Net	1.12	2.52
14	886	$4,429	$4,460	60	90	45 Net	0.1	0.17
15		$141,655	$141,655	40	40		2.18	2.41
16		$104,300	$104,300	39.5	39.5		1.58	1.75
17	889	$112,000	$0	-169.5	0	Prepayment	-7.3	0
18	892	$119,657	$120,500	31.5	61.5	45 Net	1.45	3.15
18	892	$1,986	$2,000	62	92	45 Net	0.05	0.08
19	893	$128,594	$129,500	29.5	59.5	45 Net	1.46	3.28
19	893	$1,986	$2,000	60	90	45 Net	0.05	0.08
20	894	$128,594	$129,500	60	90	45 Net	2.97	4.95
20	894	$1,986	$2,000	91	121	45 Net	0.07	0.1
20	894	$5,601	$5,640	122	152	45 Net	0.26	0.36
Total		$2,599,977	$2,352,652				24.43	53.77

SOURCES AND REFERENCES

Columns (a, b, d, g)	: Company Workpaper WP/E-4 page 828.
Column (c)	: Total after reversal of discount or removal of prepayments.
Column (d)	: Reflects 45 days rather than 15 days, or 0 days for prepayments.
Column (f)	: Direct testimony of Mr. Pous.
Column (h)	: Column (c) divided by total for Column (c) times Column (e).

**CITIES ADJUSTMENT TO CASH WORKING CAPITAL
FOR THE OTHER O&M EXPENSE CATEGORY
ENTERGY TEXAS, INC.
TEST YEAR ENDED JUNE 30, 2009
$25,000-$50,000 Stratum**

Item	Page	Amount	Adjusted Amount	Lead Days	Adjusted Lead Days	Reason	Weighted Lead Days	Adj. Wght. Lead Days
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		$36,148	$36,148	44	44		2.13	2.4
1		$314	$314	75	75		0.03	0.04
2		$45,673	$45,673	40.5	40.5		2.48	2.79
3		$26,796	$26,796	127	127		4.56	5.13
4		$32,661	$32,661	21	21		0.92	1.03
5		$27,318	$27,318	57	57		2.09	2.35
6		$33,355	$33,355	-8	-8		-0.36	-0.4
7		$40,799	$40,799	45.5	45.5		2.49	2.8
7		$595	$595	76	76		0.06	0.07
8		$28,296	$28,296	133	133		5.04	5.67
9		$25,830	$25,830	19	19		0.66	0.74
10		$38,485	$38,485	-8	-8		-0.41	-0.46
11		$48,438	$48,438	40.5	40.5		2.63	2.96
12	1025	$37,589	$0	-175.5	0	Prepayment	-8.83	0
13	1026	$28,638	$28,638	40	57	Service Prd.	1.53	2.46
14		$44,535	$44,535	13	13		0.78	0.87
15		$44,570	$44,570	39.5	39.5		2.36	2.65
16	1029	$45,583	$0	-99	0	Prepayment	-6.04	0
17		$32,897	$32,897	90	90		3.96	4.46
18		$49,340	$49,340	40.5	40.5		2.68	3.01
19		$32,590	$32,590	46	46		2.01	2.26
19		$269	$269	77	77		0.03	0.03
20		$45,730	$45,730	48	48		2.94	3.31
20		$356	$356	64	64		0.03	0.03
Total		$746,805	$663,633				23.77	44.2

SOURCES AND REFERENCES

Columns (a, b, d, g) : Company Workpaper WP/E-4 page 972.
Column (c) : Total after reversal of discount or removal of prepayments.
Column (d) : Reflects corrected service period, or 0 days for prepayments.
Columns (e & f) : Direct testimony of Mr. Pous.
Column (h) : Column (c) divided by total for Column (c) times Column (e).

CITIES ADJUSTMENT TO CASH WORKING CAPITAL
FOR THE OTHER O&M EXPENSE CATEGORY
ENTERGY TEXAS, INC.
TEST YEAR ENDED JUNE 30, 2009
$10,000-$25,000 Stratum

Item	Page	Amount	Adjusted Amount	Lead Days	Adjusted Lead Days	Reason	Weighted Lead Days	Adj. Wght. Lead Days
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		$12,854	$12,854	46	46		2.15	2.23
2	1080	$11,957	$11,957	48	62	Service Prd.	2.08	2.79
3		$22,772	$22,772	19	19		1.57	1.63
4		$12,110	$12,110	55.5	55.5		2.44	2.53
5		$13,771	$13,771	21	21		1.05	1.09
6		$12,603	$12,603	96.5	96.5		4.41	4.58
7		$13,431	$13,431	15	15		0.73	0.76
8		$13,965	$13,965	28	28		1.42	1.47
9		$17,220	$17,220	20	20		1.25	1.3
10		$11,133	$11,133	41	41		1.66	1.72
11		$13,431	$13,431	32	32		1.56	1.62
12		$24,593	$24,593	-2	-2		-0.18	-0.19
13		$10,002	$10,002	50.5	50.5		1.83	1.9
14		$12,455	$12,455	26	26		1.18	1.22
15		$10,000	$0	-197	0	Prepayment	-7.15	0
16		$14,543	$14,543	36.5	36.5		1.93	2
17		$10,359	$10,359	47	47		1.77	1.83
18		$13,515	$13,515	21	21		1.03	1.07
19		$13,564	$13,564	43	43		2.12	2.2
20		$11,282	$11,282	18	18		0.74	0.76
Total		$275,560	$265,560				23.59	32.51

SOURCES AND REFERENCES

Columns (a, b, d, g)	: Company Workpaper WP/E-4 page 1075.
Column (c)	: Total after reversal of discount or removal of prepayments.
Column (d)	: Reflects corrected service period, or 0 days for prepayments.
Columns (e & f)	: Direct testimony of Mr. Pous.
Column (h)	: Column (c) divided by total for Column (c) times Column (e).

**CITIES ADJUSTMENT TO CASH WORKING CAPITAL
FOR THE OTHER O&M EXPENSE CATEGORY
ENTERGY TEXAS, INC.
TEST YEAR ENDED JUNE 30, 2009
$2,500-$10,000 Stratum**

Item	Page	Amount	Adjusted Amount	Lead Days	Adjusted Lead Days	Reason	Weighted Lead Days	Adj. Wght. Lead Days
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		5862	5862	50.5	50.5		2.79	2.79
2		4209	4209	65	65		2.58	2.58
3		4610	4610	34	34		1.48	1.48
4		3800	3800	54	54		1.93	1.93
5		4845	4845	15	15		0.68	0.68
6		2542	2542	-2	-2		-0.05	-0.05
7		8893	8893	30	30		2.51	2.51
8	1120	5804	5804	32.5	57	Service Prd.	1.78	3.12
9		8310	8310	63	63		4.93	4.93
10	1123	$5,337	$5,337	39	55.5	Service Prd.	1.96	2.79
11		$7,011	$7,011	35	35		2.31	2.31
12		$6,471	$6,471	48	48		2.93	2.93
13		$3,208	$3,208	13	13		0.39	0.39
14		$5,641	$5,641	25	25		1.33	1.33
15		$2,524	$2,524	42	42		1	1
16		$5,915	$5,915	22	22		1.23	1.23
17		$4,636	$4,636	35	35		1.53	1.53
18		$6,059	$6,059	40	40		2.28	2.28
19		$4,729	$4,729	47	47		2.09	2.09
20		$5,777	$5,777	33	33		1.8	1.8
Total		$106,183	$106,183				37.48	39.65

SOURCES AND REFERENCES

Columns (a, b, d, g)	: Company Workpaper WP/E-4 page 1103.
Column (c)	: Total after reversal of discount or removal of prepayments.
Column (d)	: Reflects corrected service period.
Columns (e & f)	: Direct testimony of Mr. Pous.
Column (h)	: Column (c) divided by total for Column (c) times Column (e).

CITIES ADJUSTMENT TO CASH WORKING CAPITAL
FOR THE OTHER O&M EXPENSE CATEGORY
ENTERGY TEXAS, INC.
TEST YEAR ENDED JUNE 30, 2009
$250-$2,500 Stratum

Item	Page	Amount	Adjusted Amount	Lead Days	Adjusted Lead Days	Reason	Weighted Lead Days	Adj. Wght. Lead Days
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		315	315	100	100		1.81	1.94
2		253	253	29.5	29.5		0.43	0.46
3		300	300	18	18		0.31	0.33
4		90	90	159.5	159.5		0.82	0.88
4		174	174	137	137		1.37	1.47
5		500	500	36	36		1.03	1.11
6		1883	1883	41	41		4.43	4.75
7		390	390	14	14		0.31	0.34
8		282	282	30	30		0.49	0.52
9		$2,125	$2,125	32	32		3.9	4.18
10		$850	$850	40	40		1.95	2.09
11		$831	$831	41	41		1.95	2.09
12		$1,620	$1,620	52.5	52.5		4.88	5.23
13		$1,267	$1,267	36	36		2.62	2.8
14		$500	$500	34	34		0.98	1.05
15		$393	$393	30	30		0.68	0.72
16		$460	$460	37	37		0.98	1.05
17	1164	$1,170	$0	-201	0	Prepayment	-13.49	0
18		$1,623	$1,623	37	37		3.44	3.69
19		$1,761	$1,761	52	52		5.25	5.63
20		$648	$648	14	14		0.52	0.56
Total		$17,435	$16,265				24.66	40.89

SOURCES AND REFERENCES

Columns (a, b, d, g)	: Company Workpaper WP/E-4 page 1138.
Column (c)	: Total after reversal of discount or removal of prepayments.
Column (d)	: Reflects 0 days for prepayments.
Columns (e & f)	: Direct testimony of Mr. Pous.
Column (h)	: Column (c) divided by total for Column (c) times Column (e).

JACOB POUS, P.E.

PRESIDENT, DIVERSIFIED UTILITY CONSULTANTS, INC.

B.S. INDUSTRIAL ENGINEERING M.S. MANAGEMENT

I graduated from the University of Missouri in 1972, receiving a Bachelor of Science Degree in Engineering, and I graduated with a Master of Science in Management from Rollins College in 1980. I have also completed a series of depreciation programs sponsored by Western Michigan University, and have attended numerous other utility related seminars.

Since my graduation from college, I have been continuously employed in various aspects of the utility business. I started with Kansas City Power & Light Co., working in the Rate Department, Corporate Planning and Economic Controls Department, and for a short time in a power plant. My responsibilities included preparation of testimony and exhibits for retail and wholesale rate cases. I participated in cost of service studies, a loss of load probability study, fixed charge analysis, and economic comparison studies. I was also a principal member of project teams that wrote, installed, maintained, and operated both a computerized series of depreciation programs and a computerized financial corporate model.

I joined the firm of R. W. Beck and Associates, an international consulting engineering firm with over 500 employees performing predominantly utility related work, in 1976 as an Engineer in the Rate Department of its Southeastern Regional Office. While employed with that firm, I prepared and presented rate studies for various electric, gas, water, and sewer systems, prepared and assisted in the preparation of cost of service studies, prepared depreciation and decommissioning analyses for wholesale and retail rate proceedings, and assisted in the development of power supply studies for electric systems. I resigned from that firm in November 1986 in order to co-found Diversified Utility Consultants, Inc. At the time of my resignation, I held the titles of Executive Engineer, Associate and Supervisor of Rates in the Austin office of R. W. Beck and Associates. I later founded P&L Concepts, Inc.

As a principal of the firm of Diversified Utility Consultants, Inc., I have presented and prepared numerous electric, gas, and water analyses in both retail and wholesale proceedings. These analyses have been performed on behalf of clients, including public utility commissions, throughout the United States and Canada. As president of P&L Concepts, Inc., I perform the same type of services as performed under Diversified Utility Consultants, Inc.

I have been involved in over 400 different utility rate proceedings, many of which have resulted in settlements prior to the presentation of testimony before regulatory bodies.

I am registered to practice as a Professional Engineer in the states of Florida, Texas, Mississippi, North Carolina, Arizona, New Mexico, Arkansas, and Oklahoma.

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY JACOB POUS

ALASKA		
ALASKA REGULATORY COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Beluga Pipe Line Co.	P-04-81	Refundable Rates
Kenai Nikiski Pipeline	U-04-81	Rate Base
Beluga Pipe Line Co.	U-07-141	Depreciation
ARIZONA		
ARIZONA CORPORATION COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Citizens Utilities Co.	E-1032-93-111	Depreciation
ARKANSAS		
ARKANSAS PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Reliant Energy ARKLA	01-0243-U	Depreciation
CALIFORNIA		
CALIFORNIA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Pacific Gas & Electric Co.	Application No. 97-12-020	Depreciation, Net Salvage, and Amortization of True Up
Pacific Gas & Electric Co.	Application No. 02-11-017	Mass Property Salvage, Net Salvage, Mass Property Life, Life Analysis, Remaining Life, Depreciation
San Diego Gas & Electric Co.		Value of Power Plants
Southern California Edison Co.	Application 02-05-004	Depreciation, Net Salvage
CANADA		
ALBERTA ENERGY AND UTILITIES BOARD		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
AltaLink Management/ Transalta Utilities Corp	App. Nos. 1279345 and 1279347	Depreciation
Epcor Distribution, Inc.	App No. 1306821	Depreciation
Enmax Corporation	App No. 1306818	Depreciation
Transalta Utilities Corporation	TFO Tariff Appl. 1287507	Depreciation
UtiliCorp Networks Canada	App. No.	Depreciation

(Alberta) Ltd.	1250392	
Atco Electric	App. No. 1275494	Depreciation
ALBERTA PUBLIC UTILITIES BOARD		
Alberta Power Limited	E 91095	Depreciation
Alberta Power Limited	E 97065	Depreciation
Canadian Western Natural Gas Co. Limited		Depreciation
Centra Gas Alberta Inc.		Depreciation
Edmonton Power Co.	E 97065	Depreciation
Edmonton Power Generation, Inc.	1999/2000	GUR Compliance, Depreciation
Northwestern Utilities Limited	E 91044	Depreciation
NOVA Gas Transmission Ltd.	RE95006	Depreciation
TransAlta Utilities Corporation	E 91093	Depreciation
TransAlta Utilities Corporation	E 97065	Depreciation
TransAlta Utilities Corporation	App No. 200051	Gain on Sale
NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Northwest Territories Power Corporation	1995/96 and 1996-97	Depreciation
Northwest Territories Power Corporation	2001	Depreciation
COURTS		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
112th Judicial District Court of Texas	5093	Ratemaking principles, Calculation of damages
253rd Judicial District Court of Texas	45,615	Ratemaking principles, Level of Bond
126th Judicial District Court of Texas	91-1519	Ratemaking principles, Level of Bond
172 Judicial District Court of Texas		Franchise Fees
United States Bankruptcy Court Eastern District of Texas	93-10408S	Level of Harm, Ratemaking, Equity for Creditors
3rd Judicial District Court of Texas		Adequacy of Notice
DISTRICT OF COLUMBIA		
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Washington Gas Light Co.	768	Depreciation

FLORIDA		
FLORIDA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Progress Energy Florida, Inc.	090079-EI	Depreciation, Excess Reserve
Progress Energy Florida, Inc.	050078-EL	Depreciation, Excess Reserve
Florida Power & Light Co.	790380-EU	Territorial Dispute
Florida Power & Light Co.	080677-EI 090130-EI	Depreciation, Excess Reserve
FEDERAL ENERGY REGULATORY COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Alabama Power Co.	ER83-369	Depreciation
Connecticut Municipal Elect. Energy Coop v Connecticut Light & Power Co.	EL83-14	Decommissioning
Florida Power & Light Co.	ER84-379	Depreciation, Decommissioning
Florida Power & Light Co.	ER93-327-000	Transmission access
Georgia Power Co.	ER76-587	Rate Base
Georgia Power Co.	ER79-88	Depreciation
Georgia Power Co.	ER81-730	Coal Fuel Stock Inventory, Depreciation
ISO New England, Inc.	ER07-166-000	Depreciation
Maine Yankee Atomic Power Co.	ER84-344-001	Depreciation, Decommissioning
Maine Yankee Atomic Power Co.	ER88-202	Decommissioning
Pacific Gas & Electric	ER80-214	Depreciation
Public Service of Indiana	ER95-625-000, ER95-626-000 & ER95-039-000	Depreciation, Dismantlement
Southern California Edison Co.	ER81-177	Depreciation
Southern California Edison Co.	ER82-427	Depreciation, Decommissioning
Southern California Edison Co.	ER84-75	Depreciation, Decommissioning
Southwestern Public Service Co.	EL 89-50	Depreciation, Decommissioning
System Energy Resource, Inc.	ER95-1042-000	Depreciation, Decommissioning
Vermont Electric Power Co.	ER83 342000 & 343000	Decommissioning
Virginia Electric and Power Co.	ER78-522	Depreciation, Rate Base
INDIANA		
INDIANA UTILITY REGULATORY COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Indianapolis Water Co.	39128	Depreciation

Indiana Michigan Power Co.	39314	Depreciation, Decommissioning
KANSAS		
KANSAS CORPORATION COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Arkansas Louisiana Gas Co.	181,200-U	Depreciation
United Cities Gas Co.	181,940-U	Depreciation
LOUISIANA		
LOUISIANA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Louisiana Power & Light Co.	U-16945	Nuclear Prudence, Depreciation
CITY OF NEW ORLEANS		
Entergy New Orleans, Inc.	UD-00-2	Rate Base, Depreciation
MASSACHUSETTS		
MASSACHUSETTS TELECOMMUNICATIONS AND ENERGY		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Bay State Gas	D.T.E.-0527	Depreciation
National Grid/KeySpan	07-30	Quality of Service
MISSISSIPPI		
MISSISSIPPI PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Mississippi Power Co.	U-3739	Cost of Service, Rate Base, Depreciation
MONTANA		
MONTANA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Montana Power Co. (Gas)	90.6.39	Depreciation
Montana Power Co. (Electric)	90.3.17	Depreciation, Decommissioning
Montana Power Co. (Electric and Gas)	95.9.128	Depreciation
Montana-Dakota Utilities	D2007.7.79	Depreciation
NEVADA		
NEVADA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Nevada Power Co.	81-602, 81-685 Cons.	Depreciation
Nevada Power Co.	83-667, Consolidated	Depreciation
Nevada Power Co.	91-5032	Depreciation, Decommissioning
Nevada Power Co.	03-10002	Depreciation
Nevada Power Company	08-12002	Depreciation & CWC
Nevada Power Company	06-06051	Depreciation, Life Spans,

		Decommissioning Costs, Deferred Accounting
Nevada Power Company	06-11022	General Rate Case
Nevada Power Company	10-02009	Production Life Spans
Sierra Pacific Power Co.	83-955	Depreciation (Electric, Gas, Water, Common)
Sierra Pacific Power Co.	86-557	Depreciation, Decommissioning
Sierra Pacific Power Co.	89-516, 517, 518	Depreciation, Decommissioning (Elec., Gas, Water, Common)
Sierra Pacific Power Co.	91-7079, 80, 81	Depreciation, Decommissioning (Elec., Gas, Water, Common)
Sierra Pacific Power Co.	03-12002	Allowable level of plant in service
Sierra Pacific Power Co.	05-10004	Depreciation
Sierra Pacific Power Co.	05-10006	Depreciation
Sierra Pacific Gas Company	06-07010	Depreciation, Generating Plant Life Spans, Decommissioning Costs, Carrying Costs
Sierra Pacific Power Co.	07-12001	Depreciation, CWC
Southwest Gas Corporation	93-3025 & 93-3005	Depreciation
Southwest Gas Corporation	04-3011	Depreciation
Southwest Gas Company	07-09030	Depreciation
NORTH CAROLINA		
NORTH CAROLINA UTILITIES COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
North Carolina Natural Gas	G-21, Sub 177	Cost of Service, Rate Design, Depreciation
OKLAHOMA		
OKLAHOMA CORPORATION COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Arkansas Oklahoma Gas Corporation	PUD 200300088	CWC, Legal expenses, Factoring, Cost Allocation, Depreciation
Oklahoma Natural Gas Co.	PUD 980000683	Depreciation, Calculation Procedure, Depreciation on CWIP
Public Service Co. of Oklahoma	PUD 960000214	Depr., Interim Activity, Net Salvage, Mass Prop., Rate Calc. Technique
Reliant Energy ARKLA	PUD 200200166	Depreciation, Net Salvage, Software Amortization
Public Service Company of Oklahoma	PUD 200600285	Depreciation
Public Service Company of	PUD	Depreciation

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Oklahoma	200800144	
TEXAS		
TEXAS PUBLIC UTILITY COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Centerpoint Energy Houston Electric LLC	29526	Stranded Costs
Centerpoint Energy Houston Electric LLC	36918	Hurricane Cost Recovery
Central Power & Light Co.	6375	Depreciation, Rate Base, Cost of Service
Central Power & Light Co.	8439	Fuel Factor
Central Power & Light Co.	8646	Rate Base, Excess Capacity, Depreciation, Rate Design, Rate Case Expense
Central Power & Light Co.	9561	Depr., Excess Capacity, Cost of Service, Rate Base, Taxes
Central Power & Light Co.	11371	Economic Development Rate
Central Power & Light Co.	12820	Nuclear Fuel & Process, OPEB, Pension, Factoring, Depr.
Central Power & Light Co.	14965	Depr., Cash Working Capital, Pension, OPEB, Factoring, Demonstration & selling expense, non-nuclear decommissioning
Central Power & Light Co.	22352	Depreciation
Central Telephone & United Telephone Co. of Texas D/B/A Sprint	17809	Rate case expenses
City of Fredericksburg	7661	Territorial Dispute
El Paso Electric Co.	9165	Depreciation
Entergy Gulf States, Inc.	16705	Depr., Prepayments, Payroll Exp.e, Pension Exp., OPEB's, CWC, Transfer of T&D Depr.
Entergy Gulf States, Inc.	21111	Reconcilable fuel costs
Entergy Gulf States, Inc.	21384	Fuel surcharge
Entergy Gulf States, Inc.	23000	Fuel surcharge
Entergy Gulf States, Inc.	22356	Unbundling, Competition, Cost of Service
Entergy Gulf States, Inc.	23550	Reconcilable fuel costs
Entergy Gulf States, Inc.	24336	Price to Beat
Entergy Gulf States, Inc.	24460	Implement PUC Subst.R.25.41(f)(3)(D)
Entergy Gulf States, Inc.	24469	Delay of Deregulation

Entergy Gulf States, Inc.	24953	Interim Fuel Surcharge
Entergy Gulf States, Inc.	26612	Fuel Surcharge
Entergy Gulf States, Inc.	28504	Interim Fuel Surcharge
Entergy Gulf States, Inc.	28818	Cert. for Independent Organization
Entergy Gulf States, Inc.	29408	Fuel Reconciliation
Entergy Gulf States, Inc.	30163	Interim Fuel Surcharge
Entergy Gulf States, Inc.	31315	Incremental Purchase Capacity Rider
Entergy Gulf States, Inc.	31544	Transition to Competition Cost
Entergy Gulf States, Inc.	32465	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32710	River Bend 30%, Explicit Capacity, Imputed Capacity, IPCR, SGSF Operating Costs and Depreciation Recovery, Option Costs
Entergy Gulf States, Inc.	33687	Transition to Competition
Entergy Gulf States, Inc.	33966	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32907	Hurricane Reconstruction
Entergy Gulf States, Inc.	34724	IPCR
Entergy Gulf States, Inc.	34800	JSP, Depreciation, Decommissioning, Amortization, CWC, Franchise Fees, Rate Case Exp.
Gulf States Utilities Co.	5560	Depreciation, Fuel Cost Factor
Gulf States Utilities Co.	5820	Fuel Cost, Capacity Factors, Heat Rates
Gulf States Utilities Co.	6525	Depreciation, Rate Case Expenses
Gulf States Utilities Co.	7195 & 6755	Depr., Interim Cash Study, Excess Capacity, Rate Case Exp.
Gulf States Utilities Co.	8702	Rate Case Expenses, Depreciation
Gulf States Utilities Co.	10,894	Fuel Reconciliation, Rate Case Expenses
Gulf States Utilities Co. & Entergy Corporation	11292	Acquisition Adjustment Regulatory Plan, Base Rate, Rate Case Exp.
Gulf States Utilities Co. & Entergy Corporation	12423	North Star Steel Agreement
Gulf States Utilities Co. & Entergy Corporation	12852	Depreciation, OPEB, Pensions, Cash Working Capitol, Other Cost of Service, and Rate Base Items
Houston Light & Power Co.	6765	Depreciation, Production Plant, Early Retirement
Lower Colorado River Authority	8400	Rate Design
Magic Valley Electric Cooperative, Inc.	10820	Cost of Service, Financial Integrity, Rate Case Expenses

Oncor Delivery	35717	Depreciation, Self-Insurance, Payroll, Automated Meters, Regulatory Assets, PHFU
Southwestern Bell Telephone Co.	18513	Rate case expenses
Southwestern Electric Power Co.	3716	Depreciation
Southwestern Electric Power Co.	4628	Depreciation
Southwestern Electric Power Co.	5301	Depreciation, Fuel Charges, Franchise Fees
Southwestern Electric Power Co.	24449	Fuel Factor Component of Price to Beat Rates
Southwestern Electric Power Co.	24468	Delay of Deregulation
Southwestern Public Service Co.	11520	Depreciation, Cash Working Capital, Rate Case Expenses
Southwestern Public Service Co.	32766	Depreciation Expense Revenue Requirements
Southwestern Public Service Co.	35763	Depreciation
Texas-New Mexico Power Co.	9491	Avoided Cost, Rate Case Expenses
Texas-New Mexico Power Co.	10200	Jurisdictional Separation, Cost Allocation, Rate Case Expenses
Texas-New Mexico Power Co.	17751	Rate Case Expenses
Texas-New Mexico Power Co.	36025	Depreciation
Texas Utilities Electric Co.	5640	Franchise Fees
Texas Utilities Electric Co.	9300	Depreciation, Rate Base, Cost of Service, Fuel Charges, Rate Case Expenses
Texas Utilities Electric Co.	11735	Cost Allocation, Rate Design, Rate Case Expenses
Texas Utilities Electric Co.	18490	Depreciation Reclassification
West Texas Utilities Co.	7510	Depreciation, Decommissioning, Rate Base, Cost of Service, Rate Design, Rate Case Expenses
West Texas Utilities Co.	10035	Fuel Reconciliation, Rate Case Expenses
West Texas Utilities Co.	13369	Depreciation, Payroll, Pension, OPEB'S, cash working capital, fuel inventory, cost allocation, other.
West Texas Utilities Co.	22354	Depreciation
TEXAS RAILROAD COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Atmos Energy Corporation	9530	Gas Cost, Gas Purchases, Price Mitigation, Rate Case Expense
Atmos Energy Corporation	9670	CWC, Depreciation, Expenses, Shared

		Services, Taxes Other Than FIT, Excess Return
Atmos Energy Corporation	9695	Rate Case Expense
Atmos Energy Corporation	9762	Depreciation, O&M Expense
Atmos Energy Corporation	9732	Rate Case Expense
Atmos Energy Corporation	9869	Revenue Requirements
CenterPoint Energy Entex - City of Tyler	9364	Capital investment, Affiliates
CenterPoint Energy Entex- Gulf Coast Division	9791	Rate Base, Cost Allocation, Affiliate Expenses, Depreciation Net Salvage, Call Center, Litigation, Uncollectibles, Post Test Year Adjustments
CenterPoint Energy Entex- City of Houston	9902	CWC, Plant Adj., Dep., Payroll, Pensions, Cost Allocation
Energas Co.	5793	Depreciation
Energas Co. v. Westar Transmissions Co.	5168 & 4892 Cons.	Cost of Service, Refunds, Contracts, Depreciation
Energas Co.	8205	Cost of Service, Rate Base, Depreciation, Affiliate Transactions, Sale/Leaseback, Losses, Income Taxes
Energas Co.	9002-9135	Depr., Pension, Cash Working Capital, OPEB's, Rate Design
Lone Star Gas Co.	8664	Cash Working Capital, Depreciation Expense, Gain on Sale of Plant, OPEB's, Rate Case Expenses
Rio Grande Valley Gas Co.	7604	Depreciation
Southern Union Gas Co.	2738, 2958, 3002, 3018, 3019 Cons.	Cost of Service, Rate Design, Depreciation
Southern Union Gas Co.	6968 Interim & Cons.	Affiliate Transactions, Rate Base, Income Taxes, Revenues, Cost of Service, Conservation, Depreciation
Southern Union Gas Co.	8033 Consolidated	Acquisition Adj., Depr., Accumulated Provisions for Depr., Distribution Plant, Cost of Gas Clause, Rate Case Expenses
Southern Union Gas Co.	8878	Depreciation, Cash Working Capital, Gain on Sale of Building, Rate Case Expenses, Rate Design
TXU Lone Star Pipeline	8976	Depreciation, Net Salvage, Cash

		Working Capital, ALG vs. ELG
TXU Gas Distribution	9145-9147	Depreciation, Cash Working Capital, Revenues, Gain on Sale of Assets, Clearing Accounts, Over Recovery of Clearing Accounts, SFAS 106, Wages and Salaries, Merger Costs, Intra System Allocation, Zero Intercept, Customer Weighting Factor, Rate Design
TXU-Gas Distribution	9400	Depreciation, Net Salvage, Cash Working Capital, Affiliate Transactions, Software Amortization, Securitization, O&M Expenses, Safety Compliance
Westar Transmissions Co.	5787	Depreciation, Rate Base, Cost of Service, Rate Design, Contract Issues, Revenues, Losses, Income Taxes
TEXAS WATER COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
City of Harlingen-Certificate for Convenience & Necessity	8480C/8485C/ 8512C	Rate Impact for CCN
City of Round Rock	8599/8600M	Rate Discrimination, Cost of Service
Devers Canal System	8388-M	Affil. Transactions, O&M Exp., Return, Allocation, Acquisition Adj., Retroactive Ratemaking, Rate Case Exp., Depr.
Devers Canal System	30102-M	Cost of Service, Rate base, Ratemaking Principles, Affil. Trans.
Southern Utilities Co.	7371-R	Affiliate Transactions, Cost of Service
Scenic Oaks Water Supply Corporation	8097-G	Affiliate Transactions, Cost of Service, Rate base, Cost of Capital, Rate Design, Depreciation
Sharyland Water Supply vs. United Irrigation District	8293-M	Rate Discrimination, Cost of Service, Rate Case Exp.
Southern Water Corporation	2008-1811-UCR	Cost of Service
Travis County Water Control & Improv. District No. 20		Cost of Service
EL PASO PUBLIC UTILITY REGULATION BOARD		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Southern Union Gas Co.	1991	Depreciation, Calculation Procedure
Southern Union Gas Co.	1997	Depreciation, Calculation Procedure
Southern Union Gas Co.	GUD 8878 – 1998	Depreciation, Cash Working Capital, Rate Design, Rate Case Expenses

Texas Gas Services Co.	2007	Revenue Requirements
UTAH		
UTAH PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
PacifiCorp	98-2035-03	Production Plant Net Salvage, Production Life Span, Interim Additions, Mass Property, Depreciation
Rocky Mountain Power	07-035-13	Depreciation
Questar	05-057-T01	Conservation Enabling Tariff Adjustment Option and Accounting Orders
WYOMING		
WYOMING PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
PacifiCorp	20000-ER-00-162	Rate Parity

ELG VS. ALG PROCEDURE

Q. WHAT CALCULATION PROCESS HAS GANNETT FLEMING ("GF") EMPLOYED IN DEVELOPING THE ANNUAL DEPRECIATION RATES?

A. GF's proposed rates are ELG based. This approach results in over $19 million of additional depreciation expense above the remaining life depreciation expense calculated utilizing the ALG procedure for the plant in service as of December 31, 2008.

Q. WHAT CALCULATION PROCESS IS NORMALLY UTILIZED IN THE DETERMINATION OF FINAL DEPRECIATION ACCRUAL RATES?

A. As discussed in my direct testimony, the ALG procedure is almost exclusively utilized by energy utility companies.

Q. PLEASE BRIEFLY DESCRIBE THE ELG CALCULATION PROCEDURE.

A. Once an average service life ASL with a corresponding Iowa Survivor Curve or dispersion pattern has been established, a calculation process for determining the rate must be selected. The process of calculating the depreciation rate for the plant in question depends on whether the dispersion pattern is utilized in the calculation process in a manner that recognizes projected level of retirements on an annual basis. In the case where projected annual retirement dispersion is incorporated into the calculation procedure, the method is entitled the ELG or Unit Summation Process. This process relies on the assumption that the actual future life of the various components of plant incorporated in a particular account are a precise function of the survivor curve and corresponding estimated ASL assumed.

As an example, if a 3-year ASL is assumed with a corresponding R4 Iowa Survivor Curve, it would imply that approximately 4/10 of 1% of the plant will be retired during the first year of service life. During the second year of service an additional 6.6% of the investment will retire, during the third year an additional 37.6%, during the fourth year 52.8% and during the fifth year the remaining balance of approximately 2.5% of the original plant balance. Thus, the ELG approach breaks the plant investment into 5

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separate equal life groups and attempts to recover the depreciation expense for the plant investment, not on an average basis for the account as a whole, but on an individual annual life basis for the 5 separate years the dollars of investment are anticipated to be in service.

The plant in service that is assumed to retire during the first year is assigned a 1 year life and a corresponding 100% depreciation rate. The plant in service lasting all 5 years is assigned a 5 year service life, or in effect a 20% depreciation rate for that particular equal life group. The final process is the dollar weighting of the various individual equal life groups in order to obtain a composite depreciation rate. The underlying premise is that a one to one correlation exists between estimated future occurrences and actual future occurrences.

Q. PLEASE PROVIDE A BRIEF EXPLANATION OF THE ALG RATE CALCULATION PROCEDURES.

A. The ALG rate calculation procedure follows essentially the same process as the ELG, with the exception that it does not break the plant investment into individual equal life groups. Rather, it retains the vintage data and performs the calculation procedure on individual vintage investment. Thus, the ALG procedure does not explicitly recognize in the final rate calculation that certain components of the investment in a given vintage will retire before, during, or after the assured ASL.

REAL WORLD VALIDITY OF ELG

Q. PLEASE EXPLAIN WHY ELG SHOULD NOT BE UTILIZED.

A. The ELG procedure should not be used because the real world does not mesh as nicely with the theoretical world for calculation depreciation rates as the proponents of ELG would have us believe. The fact is that depreciation calculations are simply a forecast of what may transpire in the future pertaining to the particular plant investment under investigation. As everyone should understand, almost any time a projection or forecast is made there is more than a high probability that a variance will occur between the estimation or forecast and actual results.

Q. IS THE ELG CALCULATION PROCEDURE THEORETICALLY MORE ACCURATE THAN THE ALG CALCULATION PROCEDURE?

A. No, except for one exception. That one exception is under the assumption that actual future retirements will precisely follow the pattern inherent in the selected ASL and corresponding survivor curve assumed.

Q. IS THIS A REALISTIC ASSUMPTION?

A. No, in this case, the ELG procedure, as does the ALG procedure, relies on an ASL and Iowa Survivor Curve which have been developed using an actuarial analysis in conjunction with judgment, or is some cases guess work. The actuarial approach used to derive the forecasted and the survivor curve necessary for the rate calculation, by account, relied on hundreds, if not thousands, of historical transactions which are combined into various experience bands to arrive at an historical relationship that is approximated by a single ASL and a single survivor curve. The ELG procedure takes these resulting approximations, which are predicated on a commingling of numerous historical relationships and judgment and attempts to impute precise age blocking to the existing investment for future periods.

Q. DO YOU HAVE A SPECIFIC EXAMPLE THAT ILLUSTRATES THE FALLACY OF EMPLOYING THE ELG PROCEDURE?

A. Yes. As set forth in my direct testimony, I provide an example of what an ELG procedure would have predicted for Account 353 for the past 5 years. That example demonstrated how imprecise the ELG procedure was based on actual retirements.

Q. DOES THE ALG PROCEDURE SUFFER TO THE SAME EXTENT AS THE ELG PROCEDURE SINCE IT ALSO RELIES ON THE SAME ASL AND SURVIVOR CURVE?

A. No. It does not suffer to the same extent as the ELG procedure. The ALG procedure takes the same historical approximations and recognizes that numerous historical relationships have been averaged together and approximated and, therefore, only represents a broad-brush predictor of future occurrences. This is especially true in those cases when judgment is the main or sole basis for the curve and life selection. The ALG procedure recognizes that, as with all forecasts, there will be deviations between a forecast and actual results.

While the ASL and curve may be the best overall estimator of the entire historical plant activity and the best overall estimator for future expectations, they are not <u>precise</u> on a year-to-year calculation. ASL and survivor curves are useful in the same manner under which they were developed, on an average basis.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE AVERAGE BASIS ASSUMPTION INHERENT IN THE LIFE ANALYSIS?

A. Yes. As an example, one fundamental assumption to all life analysis is that a single dispersion pattern will be representative of the dispersion pattern for each individual yearly addition. In other words, if a Company has plant additions from 1927 through 2008, it is unrealistic to assume that the life characteristics of plant placed in service in 1927 will be identical to the life characteristics of plant placed in service in 2008. However, only one ASL and one dispersion pattern is assumed to be the most representative for all plant in an account or subaccount for depreciation purposes. This is but one major area of averaging that transpires in the pyramid of depreciation assumptions that culminate in the establishment of a rate. This concept of relying on numerous averages in the development of results and then using a precise dispersion pattern in the final calculation of a depreciation rate would be the equivalent of attempting to establish a precise relationship between two entities if each one represents only an approximation of the results. An example would be if the integer value "1" was selected as the "non-precise" answer which best "approximates" an analysis, and the value "1.2" represented the "best", yet not "precise", estimator for another analysis. Mathematically, it could not reasonably be stated that the relationship of the first result to the second result was "precisely" 0.833333 (1/1.2) due to the degree of precision of the first value, which was only estimated to a whole number degree of accuracy.

Q. DOES THE ALG PROCEDURE SUFFER FROM THE SAME POTENTIAL VARIANCE BETWEEN PROJECTIONS AND ACTUAL FUTURE EVENTS AS THE ELG PROCEDURE DOES?

A. Yes, however not to the same extent. The ELG procedure magnifies the impact of the error or variance between projections and actual results.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE OF THE MAGNIFIED IMPACT DUE TO FORECASTING ERRORS WHICH RESULTS WHEN UTILIZING THE ELG CALCULATION PROCEDURE?

A. Yes. If one employs an example of a two item plant account in which each item's original cost is $100 and a zero level of net salvage is assumed. Under the initial life analysis, the two units are assumed to have a 2 year ASL based on 1 unit lasting 1 year and the second unit lasting 3 years. Table 1 sets forth the plant balances, the retirements, the depreciation expense and the depreciation reserved, by year for the ELG methodology. Table II sets forth the same information, for an ALG process. As can be seen from a comparison of these two tables the ELG methodology reflects an accelerated recovery of dollars during the first 2 years of the 3 year period involved.

TABLE I

ELG 2 YEAR AVERAGE LIFE INTIAL ASSUMPTION				
YEAR	PLANT BALANCE $	RETIREMENT $	DEPRECIATION EXPENSE $	DEPRECIATION RESERVE $
1	200	100	133	33
2	100	0	33	66
3	100	100	34	0
TOTAL		200	200	

TABLE II

ALG 2 YEAR AVERAGE LIFE INITIAL ASSUMPTION				
YEAR	PLANT BALANCE $	RETIREMENT $	DEPRECIATION EXPENSE $	DEPRECIATION RESERVE $
1	200	100	100	0
2	100	0	50	50
3	100	100	50	0
TOTAL		200	200	

Q. WHAT HAPPENS IN THE EVENT THAT AFTER THE FIRST YEAR THE DEPRECIATION ANALYST REALIZES THAT EACH ITEM OF PLANT IN SERVICE WILL ACTUALLY LAST 1 YEAR LONGER THAN ORIGINALLY ASSUMED?

A. Continuing the example, at the end of year 1 the first $100 item of plant did not retire as originally projected, and is now scheduled to retire at the end of year 2. The second item of plant, which was originally scheduled to retire at the end of year 3, now will retire at the end of year 4. The remaining life depreciation calculation now necessary to recover the undepreciated balance of plant investment over the remaining useful life of the facilities involved is set forth in Tables III and IV for the ELG procedure and ALG procedure, respectively.

TABLE III

ELG 2 YEAR INITIAL AVERAGE LIFE ASSUMPTION WITH CORRECTION AFTER FIRST YEAR				
YEAR	PLANT BALANCE $	RETIREMENT $	DEPRECIATION EXPENSE $	DEPRECIATION RESERVE $
1	200	0	133	133
2	200	100	22	55
3	100	0	22	77
4	100	100	23	0
TOTAL		200	200	

TABLE IV

ALG 2 YEAR INITIAL AVERAGE LIFE ASSUMPTION WITH CORRECTION AFTER FIRST YEAR				
YEAR	PLANT BALANCE $	RETIREMENT $	DEPRECIATION EXPENSE $	DEPRECIATION RESERVE $
1	200	0	100	100
2	200	100	50	50
3	100	0	25	75
4	100	100	25	0
TOTAL		200	200	

Q. WHAT IS THE APPROPRIATE STANDARD FOR MEASURING THE IMPACT ASSOCIATED WITH THIS 1 YEAR CHANGE IN ASSUMED ASL OF THE INVESTMENT?

A. In my opinion, if one wants to appropriately measure the impact of such a change between the ELG and the ALG process, one must rely on the theory that proponents of the ELG process use as a foundation upon which to justify the use of ELG process, that is, the matching principle. In other words, which method assigns the depreciation expense to those customers who receive the actual benefits from the plant in service being depreciated to a more accurate extent. Thus, the measurement should attempt to test how closely the matching principle is adhered to under real world circumstances in which projections are not always as precisely accurate as one might desire them to be in the theoretical world. Tables V and VI set forth a comparison for the ELG and ALG processes, respectively between:

i. The actual appropriate depreciation expense from a perfect forecasting standpoint (e.g. a 3-year average life) from the outset;
ii. The depreciation expense based upon the original assumed 2-year ASL; and
iii. The depreciation expense based upon the original assumed 2-year ASL corrected at the end of the first year to reflect the actual 3-year ASL.

TABLE V

COMPARISON OF ELG CALCULATED DEPRECIATION EXPENSE OVER TIME			
YEAR	ACTUAL 3-YEAR $	ASSUMED 2-YEAR $	CORRECTED 3-YEAR $
1	75	133	100
2	75	33	22
3	25	34	22
4	25	0	23

TABLE VI

COMPARISON OF ALG CALCULATED DEPRECIATION EXPENSE OVER TIME			
YEAR	ACTUAL 3-YEAR $	ASSUMED 2-YEAR $	CORRECTED 3-YEAR $
1	67	100	100
2	67	50	50
3	33	50	25
4	33	0	25

Q. PLEASE SUMMARIZE THE DIFFERENCES IN THE EXAMPLE BETWEEN THE ELG AND THE ALG APPROACHES ASSOCIATED WITH EACH METHODOLOGY'S ABILITY TO ADHERE TO THE MATCHING PRINCIPLE AND REAL WORLD OCCURRENCES.

A. Tables VII and VIII show a side-by-side comparison of dollars and percentages of the variance imposed on ratepayers in the real world application of depreciation expense through rates due to an assumed 1-year change in the service life of each of the individual plant components. Table VII reflects a comparison of depreciation expense corrected after the first year to actual depreciation expense based on the correct ASL of 3 years, while Table VIII reflects a comparison of depreciation expense without the correction after the first year. As can be seen from Tables VII and VIII, ELG results in a greater percentage and dollar variance in charges to ratepayers through depreciation expense. This more extreme reaction is due to the ELG procedure's fundamental lack of ability to react in a just and reasonable manner under real world conditions.

TABLE VII

COMPARISON OF ASSUMED TO ACTUAL FOR ELG AND ALG WITHOUT CORRECTION AFTER FIRST YEAR				
	DOLLARS ($)		PERCENT (%)	
YEAR	ELG	ALG	ELG	ALG
1	58	33	77	49
2	-53	-17	71	25
3	-3	-8	12	24
4	-2	-8	8	24

TABLE VIII

COMPARISON OF ASSUMED TO ACTUAL FOR ELG AND ALG WITHOUT CORRECTION AFTER FIRST YEAR				
	DOLLARS ($)		PERCENT (%)	
YEAR	ELG	ALG	ELG	ALG
1	58	33	77	49
2	-42	-17	56	25
3	9	17	36	51
4	-25	-33	100	100

Q. WHAT WOULD THE RESULTS BE IF AN EXAMPLE INDICATED A SHORTENING OF SERVICE LIFE RATHER THAN A LENGTHENING OF SERVICE LIFE AS CONTAINED IN YOUR PRIOR EXAMPLE?

A. The impact on ratepayers would still result in a magnification of error in an example in which the Company's initial estimate of service life was excessive and then modified for shorter service life under the ELG method as compared to the ALG method.

Q. IS IT PRACTICAL IN THE REAL WORLD OF UTILITY RATEMAKING TO ASSUME THAT ONE WOULD RECOGNIZE THE ERROR IN A PROJECTION BEFORE THE END OF THE FIRST YEAR OF USE AND THUS, BE ABLE TO CORRECT IT FOR THE UPCOMING YEAR?

A. No. First, depreciation studies are generally performed every 3 to 5 years. Second, when depreciation studies are performed, they are based on historical test years and only after obtaining the results are they then placed into rate case test years which often are after the depreciation test period. Thus, the example in which I assumed a 1-year error in life estimation, and the correction made before the beginning of the second year, is truly an optimistic assumption in the example. In reality, an ELG rate developed at the outset of the example would be in place many years, which would result in a significantly greater over recovery of depreciation expense than exhibited in the example. Recall that it has been 15 years since the existing rates were approved by the Commission.

Q. THEN THE REAL WORLD APPLICATION OF ELG PRODUCES AN EVEN MORE SEVERE IMPACT THAN THE PROPONENTS OF ELG NORMALLY INDICATE?

A. Yes. The proponents of ELG normally talk in terms of depreciation analysis without going the additional step of integrating the depreciation analysis into the ratemaking process. Once this additional step is taken into account, it further distorts the appropriateness of the ELG methodology to function in the real world of utility ratemaking.

Q. ARE THERE ACTUAL COMPANY EXAMPLES WHICH CORROBORATE THE HYPOTHETICAL EXAMPLE YOU HAVE JUST OFFERED?

A. I have reviewed the Company's various plant accounts. These accounts contain extensive examples in which the retirements that have occurred differed, and some cases differed significantly from what the assumed ASL and corresponding dispersion curve would have indicated.

Q. IS THIS VARIANCE BETWEEN THE COMPANY'S ACTUAL HISTORICAL DATA AND THE COMPANY'S ESTIMATE OF RETIREMENTS SET FORTH IN ITS CURRENT RECOMMENDATIONS PRECISELY THE DIFFERENCE BETWEEN THEORETICAL CALCULATION AND REAL WORLD OCCURRENCES THAT YOU ARE DISCUSSING HEREIN?

A. Yes. The ELG methodology takes a theory and applies it as though it is a precise picture of the future without recognition of the impact that can transpire due to the realities of real world operations of utility systems.

SENSITIVITY TO TIME

Q. IS THE ELG PROCEDURE MORE SENSITIVE TO TIME THAN THE ALG PROCEDURE?

A. Yes, it is. As previously noted, the ELG procedure assumes precise division of the investment into annual retirement increments over the entire life of the property.

Theoretically, it further assumes that the dollar weighted ELG depreciation rate will be implemented immediately <u>and</u> will be in place for only 1 year.

Q. WHAT HAPPENS IF THE ELG DEPRECIATION RATE IS KEPT IN PLACE FOR MORE THAN 1 YEAR?

A. If an ELG depreciation rate is kept in place for more than the year for which it was developed, it <u>accelerates</u> the level of depreciation expense for the plant from which it was developed. The manner in which ELG depreciation must be developed automatically destroys the time dependent relationship between the calculation period and the application period. In other words, in order to rely on a historical test period for depreciation purposes, one has already lost the window of opportunity to implement those ELG derived depreciation rates to the appropriate plant balances without distortion. In this case, the depreciation rates are based on data through 2008. The rates in this case will not become effective until late 2010, or almost 2 years later. Thus, the precision attempted to be gained through the theoretical development of ELG rates is lost in an attempt to employ such methodology in the real world.

Q. WHAT HAPPENS IF THE ELG RATE IS NOT PLACED IN SERVICE IN A TIME PERIOD SPECIFICALLY CORRESPONDING TO THE TEST YEAR PERIOD OF THE DEPRECIATION ANALYSIS FROM WHICH IT WAS DEVELOPED?

A. If the ELG rates are implemented after the historic test year of the depreciation analysis upon which it was developed, <u>it is already out of date</u> and distorts the precise relationship upon which its calculation procedure is predicated. Therefore, if a 2008 depreciation test year is utilized and a 2011 implementation of such rate is relied upon for ratemaking purposes, then the precision upon which the ELG procedure is theoretically grounded is destroyed and additional <u>accelerated</u> depreciation impacts transpire.

Q. IS IT EVER POSSIBLE TO PERFORM A HISTORIC DEPRECIATION ANALYSIS RELYING UPON AN ELG PROCESS AND IMPLEMENT THOSE SAME RATES DURING THE TIME PERIOD APPLICABLE TO ITS DEVELOPMENT?

A. No. It is theoretically impossible and in reality cannot transpire. Thus, those who believe they have built a better mousetrap with the theoretical ELG model cannot in fact utilize it to catch a real world mouse.

CONSISTENCY BETWEEN LIFE AND SALVAGE ANALYSIS

Q. DID THE COMPANY EMPLOY A SIMILAR ELG CONCEPT IN ITS SALVAGE ANALYSIS?

A. No, it did not.

Q. HOW DOES THE CONCEPT OF ELG TRANSLATE INTO A SALVAGE RELATED ANALYSIS?

A. The ELG process, as previously noted, breaks the investment in a plant account down into individual equal life groups. If a unit of property retires in the first year of operation, the concept is to recover 100% of the investment in such item of plant during that 1 year period, which is the equivalent of assigning a 100% depreciation rate to that investment. In order to translate this same concept over to the salvage analysis, one would need to realize, in general, that when an item of plant retires in its first year of operation it will have a higher level of gross salvage than the equivalent item which would retire in the fiftieth or sixtieth year of operation.[1] Thus, a salvage analysis would need to be performed on a time differentiated basis in order to reflect potentially higher levels of gross and net salvage corresponding to the shorter lived items defined in the ELG life calculation.

[1] An example of this relationship would be a pump that fails in its first year of operations normally would have a greater salvage value to a rebuilder than a pump which fails after 40 years when no spare parts are available.

Q. DID MR. ROFF ALSO PROVIDE INFORMATION IN THAT SAME CASE WHICH WOULD INDICATE THAT HE WAS INCORRECT?

A. Yes. Mr. Roff provided a publication entitled *American Gas Association/Edison Electric Institute An Introduction to Net Salvage of Public Utility Plant.*[2] On page 6 of that publication the following statement is made:

> if age interval net salvage estimates are desirable and/or identifiable, ELG based net salvage recovery can be incorporated into the depreciation rates.

Q. WHAT WOULD BE THE IMPACT ON DEPRECIATION RATES IF THERE WAS A MATCHING OF ELG CONCEPTS BETWEEN THE LIFE AND SALVAGE ANALYSIS?

A. The net impact would be to move the ELG rate closer to the ALG rate. Thus, reducing the level of accelerated depreciation associated with the currently proposed procedure which only reflects ELG concepts for life analysis.

Q. DOES THE COMPANY MAINTAIN ITS ACCUMULATED PROVISION FOR DEPRECIATION ON AN ELG BASIS?

A. No, it does not. In fact, it doesn't even keep the information on an account basis.

Q. PLEASE EXPLAIN WHAT AN ELG BASIS IS, AND HOW IT APPLIES TO THE ACCUMULATED PROVISION FOR DEPRECIATION?

A. If one is to accept the ELG premise of absolute precision, which is required in order to utilize ELG in the life portion of a depreciation calculation, then the consistent application of precision must also be applied to the accumulated provision for depreciation. Under this arrangement, the Company would be required to maintain an additional significant level of accounting detail applicable to each individual property unit in order to accrue the depreciation expense attributable to that property unit corresponding to what was assumed to exist in the life analysis.

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[2] NPSC Docket No. 93-3005, OCA 2nd RFI, Qn. 2-13.

Q. WHAT WOULD THE ESTABLISHMENT OF INDIVIDUAL PROPERTY UNIT ACCUMULATED PROVISIONS FOR DEPRECIATION ACCOUNTS REQUIRE?

A. It would require extensive and significant expansion of the record keeping process. It would require the establishment of a separate accumulated provision for depreciation for each different ELG block within each different vintage of property for each plant account or sub-account. Thus, every single year in which an addition is made to plant in service, a new and distinct series of accumulated provision for depreciation accounts would need to be created.

As an example, if one were to carry the example previously set forth in my appendix through to the concept of an accumulated provision for depreciation, then the Company would be required to create two separate ELG accumulated provisions for depreciation for the two items of additions in that year. One provision would account for the 1 year life property and the other provision group would account for the 3 year life property. Only under this arrangement would one be able to complete the consistent accounting of the property in question under each ELG. The results would be that the assumed 1 year life property would actually be significantly over-accrued unless the Company could have reacted fast enough to realize that it had incorrectly estimated the service life of the unit. This would require extensive monitoring of all plant accounts on a vintage basis for each ELG.

Q. WOULD THIS TYPE OF ACCOUNTING BE EVEN MORE COMPLEX UNDER REAL WORLD UTILITY OPERATION?

A. Yes. Rather than assuming a simple two unit example with a 1 and a 3 year life for the two items of property, assume addition of millions of dollars corresponding to potentially thousands of different equal life groups of additions for each year. Then multiply that number of accumulated provisions for depreciation by each year into the future in which the Company adds plant in service. One can easily see the mushrooming administrative nightmare that would transpire, especially when one assumes that life characteristics