CINERGY

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John J. Finnigan, Jr.
Senior Counsel

VIA HAND DELIVERY

August 9, 2005

RECEIVED
AUG 0 9 2005
PUBLIC SERVICE COMMISSION

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: In the Matter of an Adjustment of Gas Rates of The Union Light, Heat and Power Company
Case No. 2005-00042

Dear Ms. O'Donnell:

Enclosed please find an original and ten copies of ULH&P's responses to the Staff's Fourth Set of data requests and the Attorney General's Third Set of data requests in the above-referenced case.

Please note that the information for the responses to the Attorney General's data requests numbers 23, 24, 33g, and 37-50 is not currently available. ULH&P requests an extension of time until tomorrow to provide this information. These data requests were all assigned to Mr. Spanos, along with several other data requests. Mr. Spanos was out of the office on a previously-scheduled vacation last week. He returned to the office yesterday and attempted to answer all of the data requests, but was unable to complete them all. We expect to receive his remaining responses by the end of the day today, and we expect to be able to file them by tomorrow. We will also e-mail these responses to the attorneys for the Staff and the Attorney General as soon as the information becomes available.

Please file-stamp and return the two extra copies of this letter in the enclosed over-night envelope.

If you have any questions, please call me at (513) 287-3601.

Sincerely,

John J. Finnigan

John J. Finnigan, Jr.
Senior Counsel

JJF/sew
cc: Hon. Elizabeth Blackford (via hand-delivery with encl.)

KyPSC Staff Fourth Set Data Requests
ULH&P Case No. 2005-00042
Date Received: July 29, 2005
Response Due Date: August 09, 2005

KyPSC-DR-04-001

REQUEST:

1. ULH&P is a combined electric and gas utility. In this proceeding, ULH&P is seeking an increase in its gas revenues and is utilizing a forecasted test period. Consistent with the approach followed in previous ULH&P rate cases, ULH&P has calculated a jurisdictional rate base ratio based upon the gas and total company rate bases. In this case, the "Slippage Factor" for the gas construction projects has been an issue. In order to have the information available to accurately calculate the jurisdictional rate base ratio, provide the following information relating to ULH&P's electric construction projects:

   a. For each electric construction project begun during the last 10 calendar years, provide the information requested in the format contained in Schedule 1, attached to this data request. For each project, include the amount of any cost variance and delay encountered, and explain in detail the reason(s) for such variances and delays.
   b. Using the data included in Schedule 1, calculate the annual "Slippage Factor" associated with ULH&P's electric construction projects. The slippage Factor should be calculated using the format shown on Schedule 2, attached to this data request.

RESPONSE:

a. The information as requested is not available. Approximately two-thirds of the Company's annual construction budget is for "blanket" items. This means that the budget covers general categories of work rather than specific projects. Blanket projects include such things as replacement of existing property, plant and equipment, upgrades of existing plant and new construction for service area expansion. Also, some of the specific projects budgeted may span several calendar years for completion. The budget for this type of project is re-determined each year during the budget process. Finally, the budget dollars at the requested level of detail for prior years is no longer available. The annual construction budget and actual construction expenditures requested in KyPSC-DR-04-001(b) is available and is provided in response to that sub-part.

b. See Attachment KyPSC-DR-04-001(b).

WITNESS RESPONSIBLE: Gary J. Hebbeler

CASE NO. 2005-00042
THE UNION LIGHT, HEAT ANT POWER COMPANY
Calculation of Capital Construction Project Slippage Factor - Electric Operations

Source: Schedule 1 - Construction Projects - Electric Operations

Years	Annual Actual Cost	Annual Original Budget	Variance in Dollars	Variance as Percent	Slippage Factor
2004	$ 13,566,532	$ 15,740,155	$ (2,173,622)	-13.8%	0.862
2003	$ 15,979,490	$ 15,492,276	$ 487,214	3.1%	1.031
2002	$ 12,318,166	$ 16,971,715	$ (4,653,549)	-27.4%	0.726
2001	$ 16,816,544	$ 14,912,635	$ 1,903,909	12.8%	1.128
2000	$ 13,731,130	$ 15,350,116	$ (1,618,986)	-10.5%	0.895
1999	$ 11,874,040	$ 9,156,337	$ 2,717,703	29.7%	1.297
1998	$ 11,400,571	$ 10,089,364	$ 1,311,207	13.0%	1.130
1997	$ 8,966,326	$ 8,562,864	$ 403,462	4.7%	1.047
1996	$ 8,551,795	$ 10,651,452	$ (2,099,657)	-19.7%	0.803
1995	$ 11,881,751	$ 10,365,400	$ 1,516,351	14.6%	1.146
Total	$ 125,086,344	$ 127,292,313	$ (2,205,969)	-1.7%	0.983
10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factor)					1.006

The Annual Actual Cost, Annual original Budget, Variance in Dollars, and Variance as Percent are to be taken from Schedule 1. Total all projects for a given year.
The Slippage Factor is calculated by dividing the Annual Actual Cost by the Annual Original Budget. Calculate a Slippage Factor for each year and the Totals line. Carry Slippage Factor percentages to 3 decimal places.

KyPSC Staff Fourth Set Data Requests
ULH&P Case No. 2005-00042
Date Received: July 29, 2005
Response Due Date: August 09, 2005

KyPSC-DR-04-002

REQUEST:

2. Refer to the Rebuttal Testimony of William Don Wathen, Jr. ("Wathen Rebuttal"), page 4. Provide an analysis of the governmental affairs expenses recorded during the base period, the 12 months ended May 31, 2005. This analysis should include the vendor or recipient name, the amount of the total transaction, the amount charged to gas operations, and a complete description of each transaction.

RESPONSE:

ULH&P is unable to prepare this detailed analysis of these expenses within the time allotted. ULH&P withdraws its request for recovery of Governmental Affairs expenses in this proceeding; however, ULH&P reserves the right to seek recovery of Governmental Affairs expenses in future base rate proceedings.

WITNESS RESPONSIBLE: William Don Wathen, Jr.

KyPSC-DR-04-003

REQUEST:

3. Refer to the Wathen Rebuttal, page 7.

   a. Since ULH&P is billed for and must pay the PSC Assessment during the month of JULY each year, is it correct that ULH&P incurs the PSC Assessment in July?

   b. On line 14 Mr. Wathen states, "The payment for the service the Company receives from the Commission for the twelve months following payment of the invoice." Specifically identify the "services" the Commission provides to ULH&P.

RESPONSE:

a. Each July, ULH&P is billed for and makes its payment for the PSC Assessment. At the time of the payment, the accounting entry is to credit Cash and debit Prepayments. Since July is the first month of the period over which the prepayment is related, a journal entry is also prepared to credit Prepayments and debit Regulatory Commission expense for one-twelfth of the Prepayment amount.

   To the extent that a cash payment is made in July, then ULH&P does incur that payment in July; however, as illustrated above, only the portion attributable to that July is accrued in that month.

b. Services provided to ULH&P by the Commission include:

   - Hearing rate cases and establishing rates for gas and electric service;
   - Establishing and maintaining service territories and settling disputes;
   - Meter testing;
   - Monitoring and resolving consumer complaints;
   - Approving issuances or assumptions of securities by utilities;
   - Conducting financial audits of utility books and records, and management audits of utility practices (including gas purchasing practices);
   - Determining valuations for utility property and approving sale or transfer of utility property valued in excess of $1 million;
   - Investigating operating conditions of utilities; and
   - Monitoring compliance with service and safety regulations.

WITNESS RESPONSIBLE: William Don Wathen, Jr.

KyPSC-DR-04-004

REQUEST:

4. Refer to the Rebuttal Testimony of Jeffrey R. Bailey, pages 3 and 4, where he states that the amount of the proposed bad check charge is a "level consistent with that of many retail establishments."

   a. Provide the results of any studies, surveys, etc. that ULH&P relied upon to develop its proposed bad check charge.

   b. Provide the amount that ULH&P is charged by its bank(s) for a returned check that has been deposited.

   c. Provide, along with workpapers showing its calculation, the internal administrative cost that ULH&P incurs to process a bad check.

   d. Would ULH&P agree that the charge by the bank(s) plus its internal administrative cost would be an appropriate cost basis for determining a bad check charge? If no, explain why.

RESPONSE:

a. ULH&P did not perform any studies or conduct any surveys in the development of its bad check charge.

b. ULH&P is currently charged $1.35 for checks returned due to insufficient funds.

c. As indicated in response to KyPSC-DR-04-004(a), ULH&P did not perform any studies for this case related to the costs incurred to process a bad check. ULH&P's affiliate, PSI Energy, Inc., conducted a study used during its recent rate case which should be reasonably representative of the costs to process a bad check. This case had a test year of the year ended September 30, 2002. See Attachment KyPSC-DR-04-004(c).

d. ULH&P does not agree that bank charges and internal administrative costs alone are appropriate costs for determining a bad check charge. The function of a bad check charge is to serve as a deterrent, in order to prevent customers from using an inordinate amount of the time of ULH&P's employees to process these bad checks. ULH&P believes the current market price of approximately $20 is more reflective of a reasonable deterrent. Furthermore, ULH&P does not wish to be penalized, relative to the market, for being efficient processors of bad checks. ULH&P's resources and efforts are better spent providing essential and necessary utility services.

WITNESS RESPONSIBLE: Jeffrey R. Bailey

PSI Energy, Inc.
Cause No. 42359
Standard Minumim Filing Requirements
170 IAC 1-5-16(c)

PSI ENERGY
EXPENSE/REVENUE ANALYSIS FOR HANDLING A RETURNED CHECK
TWELVE MONTHS ENDED SEPTEMBER 30, 2002

	Number of Returned Checks	Time Per check	Average Hourly Rate of Pay	Direct Labor	Other Expense	Total Expense	Revenue	Revenue Excess of Cost
CURRENT EXPENSES:								
	8,016	20 minutes	$16.34	$43,617	$30,381	$73,997		
CURRENT REVENUE:								
	8,016	$15.00					$120,240	$46,243
PROPOSED REVENUE :								
	8,016	$20.00					$160,320	$86,323

Time spent:	Rate		Other Expenses
Approximately 20 minutes per return check in Billing Services, Treasury, Corp. Accounting and Others	$16.34		
Material/Bank charge	$1.75		$14,028
Benefits	30%	$5.44	$13,082
Taxes	7.5%	$5.44	$3,271
			$30,381

KyPSC-DR-04-005

REQUEST:

5. Refer to the Rebuttal Testimony of Gary J. Hebbeler ("Hebbeler Rebuttal"), pages 2 through 4 and Attachment GJH-Rebuttal-1.

   a. Explain what period of time Mr. Hebbeler is referring to when he says "past several years" on page 2, line 9.

   b. Explain why budget cuts at the Kentucky Transportation Cabinet resulted in ULH&P not being able to spend a portion of the amount it had allocated for main replacements.

   c. Were the budget cuts at the Kentucky Transportation Cabinet the only reason ULH&P did not spend the full budgeted amount for construction projects in 2003 and 2004? If not, describe the other reasons.

   d. Explain in detail why the Slippage Factor shown on Attachment GJH-Rebuttal-1 is reasonable, since it does not reflect the most recent calendar years prior to the beginning of the forecasted period.

   e. On page 4 of the Hebbeler Rebuttal he states that if the Commission decides to use a Slippage Factor that includes 2003 and 2004 in the calculation, the appropriate factor to use would be based on all construction projects during the last 10 years. Explain why it would not be reasonable to apply the 4-year Slippage Factor for the Accelerated Main Replacement Program ("AMRP") to the AMRP forecasted test period projects and the 10-year, non-AMRP Slippage Factor to the non-AMRP forecasted test period projects.

RESPONSE:

a. The years 2001 through 2004.

b. As discussed in Mr. Hebbeler's testimony, government-mandated projects consist of street improvement projects and other construction projects ULH&P is required to undertake. The budget for these government-mandated projects is developed through a qualitative review of historical data. As discussed in Mr. Hebbeler's rebuttal testimony, during the years ULH&P did not expend its full budget, the Kentucky Department of

Transportation ("KDOT") notified ULH&P late in ULH&P's construction cycle that KDOT's budget had been cut by the Commonwealth of Kentucky. As a result of this budget cut by the Commonwealth of Kentucky, KDOT's level of construction was reduced, thus reducing ULH&P's construction expenditures below what had been budgeted.

c. During 2003, approximately 91% ($2,166,936) of the variance in dollars ($2,381,248) is attributable to KDOT's reduced level of construction activity in Northern Kentucky. The remaining 9% was due to under-runs in blanket projects.

During 2004, approximately 83% ($1,642,712) of the variance in dollars ($1,979,171) is attributable to KDOT's reduced level of construction activity in Northern Kentucky. The remaining 17% was due to under-runs in blanket projects.

d. As discussed in Mr. Hebbeler's rebuttal testimony, years 2003 and 2004 were eliminated from GJH-Rebuttal-1 because these years' "Variance in Dollars" resulted primarily from KDOT's reduced level of construction activity in Northern Kentucky as a result of budget cuts by the Commonwealth of Kentucky. Removing 2003 and 2004 from the "Slippage Factor Calculation" eliminates this extraordinary circumstance.

e. ULH&P agrees with the Staff's approach to apply the 4-year AMRP Slippage Factor to AMRP expenditures and the 10-year non-AMRP Slippage Factor to the non-AMRP forecasted test period projects if the positive AMRP Slippage Factor (100.932%) is applied to the AMRP forecasted test period projects. If the Staff is not in agreement with this portion of the calculation, ULH&P supports applying the All Capital Construction Projects Slippage Factor to the combined total forecasted test period projects.

WITNESS RESPONSIBLE: Gary J. Hebbeler

KyPSC-DR-04-006

REQUEST:

6. Refer to the Rebuttal Testimony of Roger A. Morin ("Morin Rebuttal"), pages 23 and 24. Dr. Morin refers to "sea changes in the energy industry" and that historical growth rates are downward biased by the sluggish earnings performance in the last decade, due to the structural transformation on the energy utility business from a regulated monopoly to a competitive environment. Since ULH&P is a relatively small regulated gas local distribution company, provide an explanation of how these changes cause ULH&P's earnings to suffer.

RESPONSE:

See ULH&P's response to KyPSC-DR-04-007, and the tables provided for small-cap company growth rates and for Dr. Morin's sample companies. The average historical growth rates in earnings and dividends for small cap companies over the past five and ten years have been negative. Clearly, historical earnings growth has been negatively affected by volatile fuel prices, mergers and acquisitions, dwindling margins, write-offs, intense fuel competition, declining usage per customer and restructuring.

WITNESS RESPONSIBLE: Roger A. Morin

KyPSC-DR-04-007

REQUEST:

7. Refer to the Morin Rebuttal, page 68. Provide supporting documentation, including copies of analysts' reports, for the contention that "energy utilities are expected to lower their dividend payout ratio over the next several years in response to the gradual penetration of competition in the revenue stream." Explain whether these analysts are referring to small gas local distribution companies.

RESPONSE:

The table at Attachment KyPSC-DR-04-007, Page 1 of 2, displays the historical and projected growth rates for both earnings per share and dividends per share for all the natural gas distribution utilities covered in the Value Line survey. It is clear from the averages at the bottom of the table that earnings have grown, and are expected to continue to do so, at a much faster rate than dividends. The same is true for the companies included in Dr. Morin's sample, as shown in the table at Attachment KyPSC-DR-04-007, Page 2 of 2.

The same is true for small-cap companies. The market capitalization for each company is shown on the table at Attachment KyPSC-DR-04-007, Page 1 of 2. Projected growth in earnings for small-cap companies well exceeds the projected growth in dividends.

WITNESS RESPONSIBLE: Roger A. Morin

NATURAL GAS DISTRIBUTION INDUSTRY
HISTORICAL AND PROJECTED GROWTH RATES

Company	Industry	Hist EPS Gth 5-Y (1)	Hist EPS Gth 10-Y (2)	Hist Divid Gth 5-Y (3)	Hist Divid Gth 10-Y (4)	Projected EPS Gth (5)	Projected Divid Gth (6)	Market Cap $M
1 AGL Resources	GASDISTR	11.0	6.0	0.5	0.5	5.0	3.5	$3,009
2 AmeriGas Partners	GASDISTR	14.5				4.0		$1,776
3 Atmos Energy	GASDISTR	3.5	4.0	2.5	3.5	6.5	2.0	$2,333
4 Canadian Utilities 'B'	GASDISTR	7.5	7.5	16.0	9.0			$3,519
5 Cascade Natural Gas	GASDISTR	1.0	3.5			7.0	0.5	$247
6 Chesapeake Utilities Cor	GASDISTR	3.5	3.0	2.0	2.5			$180
7 Corning Natural Gas Cor	GASDISTR							$8
8 Energy West Inc.	GASDISTR	-30.0	-15.0	-6.5	-0.5			$27
9 EnergySouth Inc	GASDISTR	5.0	6.0	6.0	5.5			$219
10 Ferrellgas Partners L P	GASDISTR	18.0				3.2		$1,167
11 KeySpan Corp.	GASDISTR	30.5	6.5	2.5	3.0	1.0	2.0	$6,549
12 Laclede Group	GASDISTR	-0.5	1.5	0.5	1.0	6.0	1.0	$686
13 Markwest Hydrocarbon	GASDISTR							$235
14 NATURAL GAS DISTRIE	GASDISTR							$41,367
15 NICOR Inc.	GASDISTR	-0.5	2.0	4.5	4.5	1.0	1.5	$1,826
16 New Jersey Resources	GASDISTR	8.5	7.0	2.5	2.0	5.5	3.5	$1,337
17 Northwest Nat. Gas	GASDISTR	3.0	2.5	1.0	1.0	7.5	2.5	$1,069
18 Pacific Northern Gas Ltd	GASDISTR	-7.0	-2.0	-24.5	-11.0			$69
19 Penn Octane Corp	GASDISTR							$6
20 Peoples Energy	GASDISTR	1.0	2.5	2.0	1.5	3.5	1.5	$1,700
21 Piedmont Natural Gas	GASDISTR	3.0	4.5	5.0	5.5	6.5	5.0	$1,898
22 RGC Resources Inc	GASDISTR	-3.0		1.5				$56
23 SEMCO Energy	GASDISTR	-20.0	-11.0	-15.0	-5.5	14.5		$173
24 South Jersey Inds.	GASDISTR	10.5	6.5	1.5	1.0	6.5	6.5	$833
25 Southern Union	GASDISTR	18.5	14.0			15.0		$2,102
26 Southwest Gas	GASDISTR	1.5	4.0		1.0	10.0		$983
27 Streicher Mobile Fueling	GASDISTR							$21
28 Suburban Propane Partn	GASDISTR					4.2		$1,095
29 Terasen Inc.	GASDISTR	8.5	10.5	7.5	5.5	6.5		$3,181
30 UGI Corp.	GASDISTR	19.5	13.5	3.5	3.5	9.5	5.5	$3,283
31 WGL Holdings Inc.	GASDISTR	2.0	3.0	1.5	1.5	6.5	1.5	$1,680
AVERAGE		**4.4**	**3.6**	**0.7**	**1.8**	**6.5**	**2.8**	**$2,666**

Source: Value Line Investment Analyzer 7/2005

	Company	Industry	EPS Gth 5-Y	EPS Gth 10-Y	Divid Gth 5-Y	Divid Gth 10-Y	Proj EPS Gth	Proj Divid Gth	Zacks Proj Gth
1	AGL Resources	GASDISTI	11.0	6.0	0.5	0.5	5.0	3.5	4.8
2	Atmos Energy	GASDISTI	3.5	4.0	2.5	3.5	6.5	2.0	5.3
3	KeySpan Corp.	GASDISTI	30.5	6.5	2.5	3.0	1.0	2.0	2.8
4	Laclede Group	GASDISTI	-0.5	1.5	0.5	1.0	6.0	1.0	5.0
5	New Jersey Resourc	GASDISTI	8.5	7.0	2.5	2.0	5.5	3.5	6.0
6	NICOR Inc.	GASDISTI	-0.5	2.0	4.5	4.5	1.0	1.5	2.3
7	Northwest Nat. Gas	GASDISTI	3.0	2.5	1.0	1.0	7.5	2.5	5.5
8	Peoples Energy	GASDISTI	1.0	2.5	2.0	1.5	3.5	1.5	4.0
9	Piedmont Natural Ga	GASDISTI	3.0	4.5	5.0	5.5	6.5	5.0	5.1
10	South Jersey Inds.	GASDISTI	10.5	6.5	1.5	1.0	6.5	6.5	6.0
11	Southwest Gas	GASDISTI	1.5	4.0		1.0	10.0		6.0
12	UGI Corp.	GASDISTI	19.5	13.5	3.5	3.5	9.5	5.5	7.3
13	WGL Holdings Inc.	GASDISTI	2.0	3.0	1.5	1.5	6.5	1.5	4.0
	AVERAGE		**7.2**	**4.9**	**2.3**	**2.3**	**5.8**	**3.0**	**4.9**

Source: VLIA July 2005

KyPSC-DR-04-008

REQUEST:

8. Refer to the Rebuttal Testimony of Robert C. Lesuer. As part of the preparation of his rebuttal testimony, did Mr. Lesuer review the Commission's previous Orders in ULH&P rate cases addressing the rate-making treatment of incentive compensation expenses? Explain the response.

RESPONSE:

No. ULH&P did not ask me to research prior Commission decisions.

WITNESS RESPONSIBLE: Robert C. Lesuer

KyPSC-DR-04-009

REQUEST:

9. Refer to the Rebuttal Testimony of James A. Riddle ("Riddle Rebuttal"), pages 2 through 5, the Attachment JAR-Rebuttal-1, and ULH&P's response to the Commission Staff's Third Data Request dated May 10, 2005 ("Staff's Third Request"), Item 30(b).

   a. Based on the annual heating degree days ("HDD") of 5,054 for the period 1980-2004 shown in the response to Item 30(b) of Staff's Third Request, provide a graphical representation using the same methodology as in JAR-Rebuttal-1.

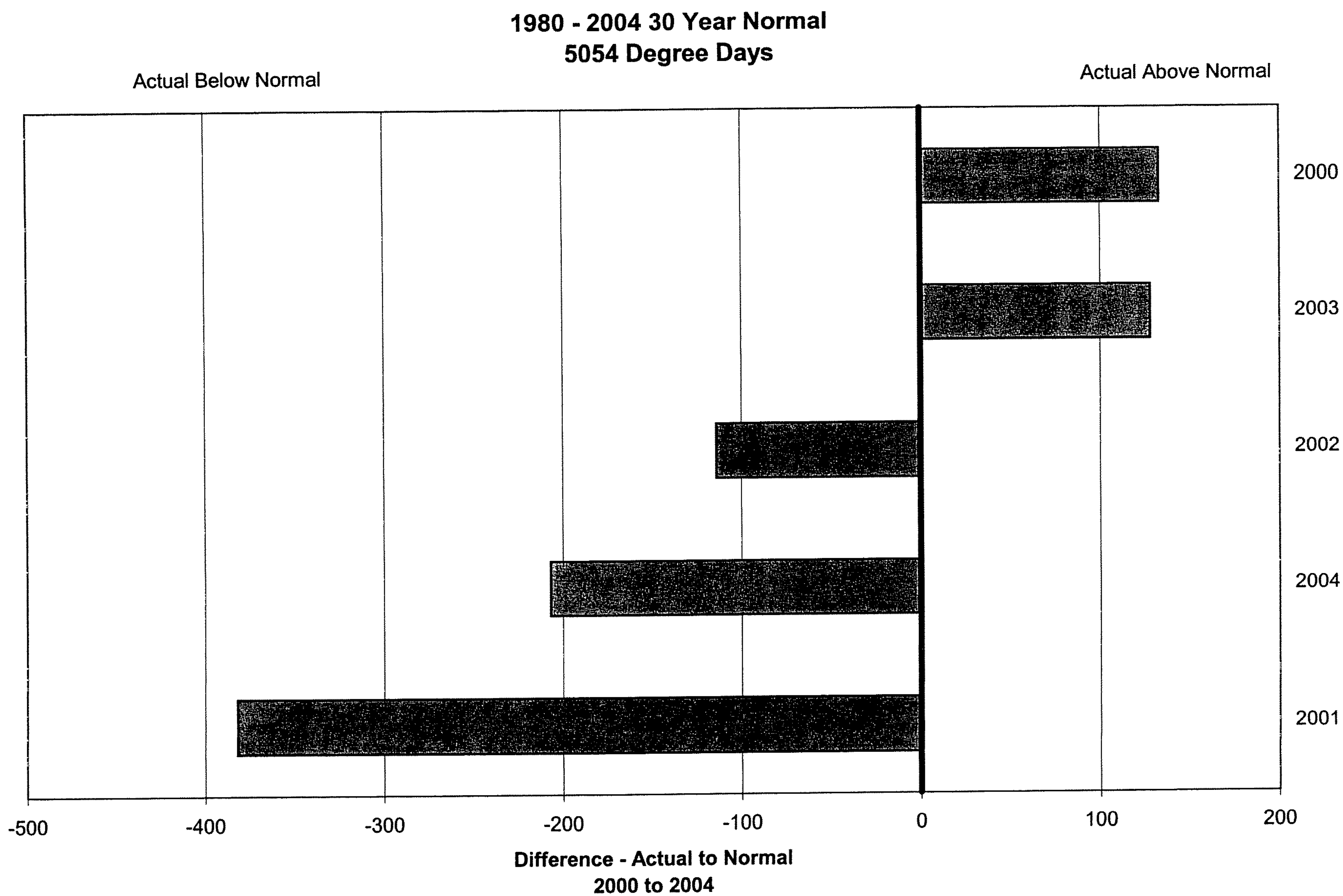
   b. The sentence beginning on line 23 of page 4 of the Riddle Rebuttal, which continues on page 5, indicates that it is Mr. Riddle's conclusion, based on his review of weather data, that the 10-year normal HDDs used by ULH&P are "a more accurate representation of reasonable weather for gas load forecasting." State Mr. Riddle's education and work experience in the field of meteorology.

RESPONSE:

a. See Attachment KyPSC-DR-04-009(a).

b. Mr. Riddle is not a meteorologist and has no formal education in this field. Mr. Riddle's educational background is in statistics, probability, economics, and data analysis. He also has nearly 20 years of experience in utility load forecasting and the drivers of energy usage, including weather. He is able to analyze trends in data and make informed decisions based on that analysis.

WITNESS RESPONSIBLE: James A. Riddle


1980 - 2004 30 Year Normal
5054 Degree Days
Actual Below Normal
Actual Above Normal
2000
2003
2002
2004
2001
-500
-400
-300
-200
-100
0
100
200
Difference - Actual to Normal
2000 to 2004

KyPSC Staff Fourth Set Data Requests
ULH&P Case No. 2005-00042
Date Received: July 29, 2005
Response Due Date: August 09, 2005

KyPSC-DR-04-010

REQUEST:

10. Refer to the Riddle Rebuttal, pages 17 through 21, regarding the forecast of Firm Transportation ("FT") volumes, Attachment JAR-Rebuttal-2, and the response to Item 30(a) of the Staff's Third Request.

    a. Provide the level of FT volumes for the forecasted test period that is derived using the average annual growth rate of 2.90 percent shown in the attachment.

    b. A second revision to Schedule M reflecting the weather data for the 1980-2004 period was provided in response to Item 30(a) of the Staff's Third Request. Provide a third revision to Schedule M, which in addition to reflecting the same weather data as the second revision, incorporates the FT volumes contained in the response to part (a) of this request.

RESPONSE:

a. 1,364,565 Mcf.

b. See Attachment KyPSC-DR-04-010(b).

WITNESS RESPONSIBLE: (a) James A. Riddle
(b) Jeffrey R. Bailey

THE UNION LIGHT HEAT & POWER COMPANY
CASE NO. 2005- 00042
REVENUES AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2006
(GAS SERVICE)

DATA: ___ BASE PERIOD X FORECASTED PERIOD — Ky Staff-4th DR-010(B)
TYPE OF FILING: ___ORIGINAL ___UPDATED _X__ REVISED
WORK PAPER REFERENCE NO(S).: — SCHEDULE M
25 Year Normalized Volumes with Adjustments — PAGE 1 OF 1

LINE NO.	RATE CLASSIFICATION (A)	REVENUE AT PRESENT RATES (B)	REVENUE AT PROPOSED RATES (C)	REVENUE CHANGE (AMOUNT) (D=C-B)	% OF REVENUE CHANGE (E=D / B)
1	SALES SERVICE:				
2	RS RESIDENTIAL	86,522,374	98,369,754	11,847,380	13.69%
3	TOTAL RS	86,522,374	98,369,754	11,847,380	13.69%
4	GS COMMERCIAL	31,908,258	33,644,772	1,736,514	5.44%
5	GS INDUSTRIAL	4,966,016	5,039,233	73,217	1.47%
6	GS OTHER PUB AUTH	5,573,993	5,686,707	112,714	2.02%
7	TOTAL GS	42,448,267	44,370,712	1,922,445	4.53%
8	TOTAL SALES SERVICE	128,970,641	142,740,466	13,769,825	10.68%
9	TRANSPORTATION:				
10	FT LARGE	2,539,834	2,803,236	263,402	10.37%
11	IT	1,001,561	1,178,299	176,738	17.65%
12	TOTAL TRANSPORTATION	3,541,395	3,981,535	440,140	12.43%
13	TOTAL THROUGHPUT	132,512,036	146,722,001	14,209,965	10.72%
14	MISCELLANEOUS REVENUES:				
15	LATE PAYMENT CHARGES	0	0	0	0.00%
16	BAD CHECK CHARGES	10,000	18,182	8,182	81.82%
17	RECONNECTION CHARGES	7,000	11,667	4,667	66.67%
18	RENTS	0	0	0	0.00%
19	INTERDEPARTMENTAL	87,941	88,007	66	0.08%
20	SPECIAL CONTRACTS	0	0	0	0.00%
21	REVENUE TRANSP OF GAS-ASSOC COS	657,936	657,936	0	0.00%
22	OTHER MISC	19,000	19,000	0	0.00%
23	TOTAL MISCELLANEOUS	781,877	794,791	12,914	1.65%
24	TOTAL COMPANY REVENUE	133,293,913	147,516,792	14,222,879	10.67%

8/5/2005 7:52

KyPSC Staff Fourth Set Data Requests
ULH&P Case No. 2005-00042
Date Received: July 29, 2005
Response Due Date: August 09, 2005

KyPSC-DR-04-011

REQUEST:

11. Refer to the Rebuttal Testimony of John J. Spanos ("Spanos Rebuttal"), pages 5 and 6. Provide documentation supporting Mr. Spanos's contention that nearly all jurisdictional public utility depreciation rates incorporate net salvage factors and that nearly all utilities include net salvage in the depreciation rate calculation.

RESPONSE:

With the exception of studies presented to the Pennsylvania Public Utility Commission since 1962, all depreciation rates are determined with a component of net salvage. This contention is supported by reviewing all rate cases across the United States which establish life and salvage parameters in determining depreciation rates. Each of the studies performed by Gannett Fleming over the last 50-plus years will show the net salvage percent in the depreciation rate. This is also the case of all other depreciation studies performed by others with the exception of Pennsylvania and a few instances in a couple of other states over the last couple of years.

WITNESS RESPONSIBLE: John J. Spanos

KyPSC-DR-04-012

REQUEST:

12. Refer to the Spanos Rebuttal, page 34. Indicate where in Mr. Spanos's depreciation study the average cost of retiring mains and the average gross salvage percentage for mains, as stated on lines 15 through 22, are shown.

RESPONSE:

The average cost of retiring mains and the average gross salvage percentage for mains is shown on page III-95 of the depreciation study.

WITNESS RESPONSIBLE: John J. Spanos

REQUEST:

13. Refer to the Rebuttal Testimony of Alexander J. Torok ("Torok Rebuttal"), page 2 and Attachment AJT-Rebuttal-1.

    a. Provide a schedule comparing ULH&P's tentative assessment and final assessed values for 2000 through 2004. Include a calculation showing the difference between the tentative assessment and the final assessment for each year and state the percentage difference.

    b. Has ULH&P protested the tentative assessment for 2005? If yes, provide a copy of the written protest sent to the Department of Revenue

RESPONSE:

a. See Attachment KyPSC-DR-04-013.

b. The Company has not protested the tentative assessment to date. The deadline for protesting is August 19, 2005.

WITNESS RESPONSIBLE: Alex J. Torok

Union Light Heat and Power
Case No. 2005-00042
Tentative vs. Final Property Tax Assesments
2000-2004 Tax Years

Tax Year	Tentative Assessments	Final	Difference	% Difference
2000	336,233,206	260,000,000	76,233,206	-22.67%
2001	371,584,360	266,500,000	105,084,360	-28.28%
2002	372,327,350	282,000,000	90,327,350	-24.26%
2003	322,680,030	272,000,000	50,680,030	-15.71%
2004	400,551,451	298,000,000	102,551,451	-25.60%
2005 (1)	543,548,261			

(1) 2005 final assessments are currently undetermined at this point (8/1/2005)

KyPSC-DR-04-014

REQUEST:

14. Refer to the Torok Rebuttal, page 4.

    a. Explain why the unprotected accumulated deferred income taxes are a deferred tax asset rather than a deferred tax liability.

    b. If the unprotected accumulated deferred income taxes were reflected on ULH&P's books by May 31, 2005, indicate where this deferred tax asset is shown in the schedules filed on July 15, 2005.

RESPONSE:

a. The unprotected tax item referred to is an asset because it is associated with expenses that have been deducted for book purposes, which are not yet deductible for tax purposes. Examples of these expenses are Pension and Post-Retirement Benefits.

b. Excess deferred taxes are reported on Schedule B-6 (and WPB-6a) in their respective ADIT account, with an offset in a FAS 109 account for the excess deferred taxes, including gross-up.

WITNESS RESPONSIBLE: Alexander J. Torok

KyPSC-DR-04-015

REQUEST:

15. Refer to the Rebuttal Testimony of Timothy J. Verhagen ("Verhagen Rebuttal"), page 3.

    a. Explain why ULH&P is proposing that the regulated business unit component of the Annual Incentive Plan be allocated 100 percent to ratepayers.

    b. Explain why ULH&P is proposing that the Long-Term Incentive Compensation Plan be shared on a 50-50 basis, when the plan component is "total shareholder return."

RESPONSE:

a. Such an allocation is reasonable, given that the goals of the Annual Incentive Plans for those in the Regulated Businesses Unit directly support reliability, safety, customer satisfaction and other operational goals, which directly benefit ULH&P's customers. This incentive compensation is a necessary cost of doing business, in order to attract and retain talented employees. Additionally, this type of incentive compensation is necessary for ULH&P to have pay levels which are at market levels. If ULH&P did not pay this type of compensation, customers would incur higher costs because ULH&P would need to spend more money on hiring and training new employees, due to existing employees migrating to other jobs where companies do pay such incentive compensation.

b. Such an allocation is reasonable, given that the total shareholder return is impacted by earnings growth and sustained stock prices. These factors enable Cinergy and its subsidiaries, such as ULH&P, to borrow and maintain debt at low costs. These low debt costs help ULH&P maintain competitive rates, which directly benefits our customers.

WITNESS RESPONSIBLE: Timothy J. Verhagen

KyPSC Staff Fourth Set Data Requests
ULH&P Case No. 2005-00042
Date Received: July 29, 2005
Response Due Date: August 09, 2005

KyPSC-DR-04-016

REQUEST:

16. Refer to the Verhagen Rebuttal, page 8. Provide copies of the portions of the cited decision from the Indiana Utility Regulatory Commission that discuss the rate-making treatment for incentive compensation costs.

RESPONSE:

See Attachment KyPSC-DR-04-016. The relevant discussion on incentive compensation begins at page 72 of 122 of the Commission's order.

WITNESS RESPONSIBLE: Timothy J. Verhagen

*2004 Ind. PUC LEXIS 150, *; 234 P.U.R.4th 1*

PETITION OF PSI ENERGY, INC. FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE; FOR APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND OF RULES AND REGULATIONS APPLICABLE TO SUCH RATES AND CHARGES; FOR THE AUTHORITY TO REFLECT ITS QUALIFIED POLLUTION CONTROL PROPERTY AND OTHER NEW PLANT AND EQUIPMENT IN ITS RATES AND CHARGES; FOR APPROVAL OF ITS IMPLEMENTATION OF THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN-FACTOR TEST; FOR APPROVAL OF VARIOUS RATE TRACKING MECHANISMS, INCLUDING A PROPOSED MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR MANAGEMENT COST ADJUSTMENT RIDER AND CONTINUED USE OF A PURCHASED POWER TRACKING MECHANISM; AND FOR APPROVAL OF RELATED ACCOUNTING TREATMENT AND DEPRECIATION RATES AND OTHER ACCOUNTING RELIEF RELATIVE TO ITS BUSINESS

CAUSE NO. 42359

Indiana Utility Regulatory Commission

2004 Ind. PUC LEXIS 150; 234 P.U.R.4th 1

May 18, 2004, Approved

CORE TERMS: customer, electric, estimate, off-system, dividend, plant, beta, depreciation, tracker, net salvage, load, flotation, retail, risk premium, annual, tracking, allowance, long-term, investor, recommended, reduction, proxy, fuel, transmission, utilized, calculation, estimated, staff, generation, trading

PANEL: **[*1]** BY THE COMMISSION: David E. Ziegner, Commissioner; Scott R. Storms, Chief Administrative Law Judge; HADLEY, RIPLEY AND ZIEGNER CONCUR; McCARTY AND LANDIS ABSENT

OPINIONBY: ZIEGNER; STORMS

OPINION: On December 30, 2002, PSI Energy, Inc. ("PSI," "Petitioner," or "Company") filed its Petition for authority to increase rates and charges for retail electric utility service and approval of revised rules and regulations applicable to such service. PSI's Petition also sought approval of other items related to rates identified in the caption above, and indicated PSI's intent to comply with and utilize the provisions of the Commission's Minimum Standard Filing Requirements ("MSFRs"). Participants in this Cause included the Indiana Office of Utility Consumer Counselor ("OUCC"), and several parties that intervened in this proceeding including: the Citizens Action Coalition of Indiana, Inc. ("CAC"); Indiana and Purdue Universities; an *ad hoc* group of PSI industrial customers known as the PSI-Industrial Group ("PSI-IG"); the International Brotherhood of Electrical Workers, Local Union No. 1393 ("IBEW Local 1393"); The Kroger Co. ("Kroger"); Steel Dynamics, Inc. -- Pittsboro Division ("SDI"); and Nucor Corporation **[*2]** ("Nucor") (collectively, the "Intervenors"). On January 21, 2003, this Commission designated from its staff Bradley K. Borum, Laura Cvengros and Matthew Inman, as testimonial staff in this Cause ("Testimonial Staff" or "Staff"). On April 1, 2003, this Commission designated Kristina Kern-Wheeler and Andrea Brandes as Counsel to the Testimonial Staff.

On February 11, 2003, this Commission conducted a Prehearing Conference and thereafter issued its Prehearing Conference Order, which established the 12 months ended September 30, 2002, as the test year in this Cause, with adjustments allowed for changes thereafter that are fixed, known and measurable and occur within 12 months following the end of the test year. May 31, 2003 was established as the cut-off date for rate base determination and for updating Petitioner's actual number of employees, salaries and wages, benefits, payroll taxes and property taxes. Petitioner was ordered to file schedules to support such updates by July 15, 2003. August 31, 2003 was established as the cut-off date for updating Petitioner's major projects as defined in this Commission's MSFRs, Petitioner's construction-work-in-progress ("CWIP") balances, any amounts **[*3]** deferred by Petitioner pursuant to Commission orders, the actual number of customers and the average customer usage. Petitioner identified in its Petition the following projects as major projects eligible for a special later cutoff date: its Noblesville Repowering Project, Madison Generating Station, Henry County Generating Station and Gibson Generating Station Unit 4 selective catalytic reduction equipment ("SCR"). Petitioner was required to support these August 31, 2003 updates by its rebuttal testimony filing date of October 6, 2003. PSI reserved the right to update its major project amounts up to 10 days before the final set of hearings in this Cause.

On March 28 and April 11, 2003, PSI prefiled its case-in-chief testimony and exhibits in this Cause. A hearing on PSI's evidence commenced June 9, 2003. On July 15, 2003 PSI filed its May 31, 2003 Cut-Off Date Update Filing as required by the Prehearing Conference Order. On August 19, 2003, the Intervenors and the OUCC prefiled testimony and exhibits constituting their respective cases-in-chief. The Intervenors filing evidence included the CAC, PSI-IG, Purdue University, and Kroger. The Testimonial Staff filed its report, testimony **[*4]** and exhibits, on September 3, 2003. Petitioner prefiled its August 31, 2003, Cut-Off Date Update Filing, and its rebuttal and update testimony and exhibits, on October 6, 2003. PSI filed a final update to its major projects on October 20, 2003, as provided in the Prehearing Conference Order. The OUCC filed updated and corrected Public's Exhibit ("Pub. Ex.") No. 8U and Revised Pub. Ex. No. 3 on October 31, 2003. PSI filed Petitioner's Exhibit ("Pet. Ex.") X-32 and OO-3, both as corrected, on October 31, 2003. A hearing on the prefiled testimony and exhibits of the Intervenors and Testimonial Staff commenced on November 3, 2003, followed by a hearing on Petitioner's update and rebuttal evidence. On October 22, 2003, a Field Hearing in this Cause was held in Kokomo, Indiana, and on October 27, 2003, a Field Hearing was held in Bloomington, Indiana as required by Ind. Code § 8-1-2-61(b).

At the close of the record, the parties were authorized to file proposed orders and briefs in support, as well as exceptions to proposed orders and reply briefs, in accordance with an agreed upon procedural schedule. The Presiding Commissioner and Chief Administrative Law Judge attended all of the Evidentiary **[*5]** Hearings in this proceeding, and have thus observed the demeanor and credibility of the witnesses. All proposed findings of the parties not specifically determined in this Order are hereby rejected. This Commission, having examined the evidence and being duly advised in the premises, now finds that:

1. Notice and Jurisdiction. Due, legal and timely notice of the filing of the Petition was given and published by PSI, as required by law. Proper and timely notice was given by PSI, as required by law, to its customers summarizing the manner and extent of the proposed changes in its retail rates and charges. Due, legal and timely notice of the public hearings herein was given and published by this Commission. PSI is a public utility as defined in Ind. Code § 8-1-2-1 and is subject to regulation by this Commission in the manner and to the extent provided for in the Public Service Commission Act, Ind. Code § 8-1-2. This Commission has jurisdiction over PSI and the subject matter of this Cause.

2. Petitioner's Characteristics. PSI is an Indiana corporation with its principal office in the Town of Plainfield, Hendricks County, Indiana. PSI is engaged in the business **[*6]** of generating and supplying electric utility service to over 740,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. PSI is a wholly-owned subsidiary of Cinergy Corp. ("Cinergy"), a publicly-held corporation, and an affiliate of The Cincinnati Gas & Electric Company ("CG&E"), also wholly owned by Cinergy.

PSI provides electric utility service to the public by means of electric utility plant, properties, equipment and facilities owned, operated, managed and controlled by it, which are used and useful for the convenience of the public in the production, transmission, distribution and furnishing of electric utility service to retail customers in the State of Indiana. PSI also engages in sales for resale of electric energy to municipal utilities, rural electric membership corporations, Wabash Valley Power Association, Inc. ("WVPA"), Indiana Municipal Power Agency ("IMPA"), and other utilities, which in turn supply electric utility service to customers in areas not served directly by PSI.

3. Current Rates and Relief Requested. Petitioner's current base retail electric rates and charges were approved by Order entered **[*7]** by this Commission, on September 27, 1996, in Cause No. 40003 ("1996 Order" or "Cause No. 40003"). By its Petition here, PSI requests this Commission's approval to increase those rates and charges. Petitioner originally requested that this Commission approve an increase in the amount of $ 200,420,000. However, after the updates made in accordance with the Prehearing Conference Order, and with certain compromise positions set forth in Petitioner's rebuttal testimony, Petitioner reduced the requested increase in its basic retail electric rates to $ 178,303,000, which would represent an approximately 11.2% increase over Petitioner's current average retail rates. Pet. Ex. OO-3; Pet. Ex. DD, p. 3.

4. Petitioner's Rate Base.

A. Used and Useful Determinations. In determining Petitioner's rate base, we have been charged with making basic determinations in connection with our ultimate conclusion as to the fair value of Petitioner's utility plant actually used and useful in rendering retail electric utility service to the public. The following findings underlie these determinations.

(1) Petitioner's Generating Facilities. The evidence in this Cause shows that PSI owns and **[*8]** operates 11 generating stations, which are capable of producing approximately 6,800 megawatts ("MW") of electric generating capacity (summer-rated). Approximately 76% of PSI's generating capacity is coal-fired, 20% is natural-gas or synthetic gas-fired, 3.5% is oil-fired and approximately 0.7% is hydro-powered. Pet. Ex. O-1. PSI's Gibson Unit 5 is jointly owned, with PSI owning 50.05% of the unit and WVPA and IMPA owning 25% and 24.95%, respectively. Pursuant to a 2002 Joint Generation Dispatch Agreement ("JGDA"), PSI jointly dispatches its generating plants with CG&E's generating plants. Pet. Ex. B, pp. 7-8.

PSI's electric generating properties consist of five primarily coal-fired stations (Cayuga, Edwardsport (one oil-fired unit), Gallagher, Gibson, and Wabash River), having a total of 20 individual generating units, one hydroelectric generating station (three units), and 27 rapid-start peaking units, including peaking units at PSI's Madison Generating Station and at PSI's Henry County Generating Station. The Madison and Henry County Stations were acquired by PSI, February 5, 2003, after this Commission approved their purchase by PSI in Cause No. 42145. PSI also owns and operates **[*9]** two generating units at its Noblesville Repowering Project, near Noblesville, Indiana, approved by this Commission in Cause No. 41924 and completed in June 2003. Pet. Ex. O, pp. 2-3.

PSI's coal-fired stations use primarily Illinois Basin coal from mines located in Indiana. PSI owns and operates various pollution control equipment located at its generating stations, including flue gas desulfurization equipment ("scrubbers") at its Gibson Units 4 and 5, SCRs at Gibson Units 2, 3 and 4, and modular cooling towers at PSI's Cayuga Station. Pet. Ex. B, p. 9. PSI's witness John J. Roebel, Vice President of the Generating Resources Group, described the status and costs of the Company's evolving plan to comply with federal NO[X] reduction requirements ("Compliance Plan"). At the time of PSI's case-in-chief filing, the active NO[X] Compliance Plan included SCRs, Boiler Optimization Programs, low-NO[X] burners, and new precipitators, at various units at PSI's Gibson, Cayuga, Gallagher, and

Wabash River Stations. Several additional projects have been deferred due to the receipt of early reduction credits. Mr. Roebel explained that the following NO[X] Compliance Plan projects are in-service or **[*10]** were expected to be in-service by the summer of 2003: Boiler Optimization Programs at Cayuga Units 1 and 2, Gallagher Units 1 and 2, Wabash River Unit 2, and Gibson Unit 3; Low NO[X] Burners at Gallagher Unit 4 and Wabash River Unit 6; and SCRs at Gibson Units 2, 3 and 4. Mr. Roebel testified that all of PSI's electric generating and related facilities are used and useful by PSI in the provision of utility service to its retail electric customers. Pet. Ex. O, p. 5.

No party took issue with the used and useful nature of PSI's generating facilities. We find that, as of the applicable cut-off date, updated as permitted by the Prehearing Conference Order, the above-described properties were used and useful and reasonably necessary for the convenience of the public and should be included in PSI's rate base.

(2) Petitioner's Transmission and Distribution Facilities. The evidence presented in this Cause demonstrates that PSI owns and/or operates over 5,800 circuit miles of transmission lines, over 130 transmission substations, approximately 20,500 miles of distribution lines, approximately 440 distribution substations and various other distribution equipment, such as capacitors, line **[*11]** transformers, street lights and meters. PSI's transmission system is jointly owned with WVPA and IMPA. PSI is interconnected with nine other utility control areas, and the Cinergy transmission system is interconnected with twelve other utility control areas. Pet. Ex. B, p. 10.

Approximately one year ago, PSI and CG&E transferred functional control of the operation of the Cinergy transmission system to the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO"). PSI and CG&E are also parties to the East Central Area Reliability Council Agreement ("ECAR Agreement"), which coordinates the planning and operation of generation and transmission facilities and provides for maximum reliability of the regional bulk power supply. In the opinion of PSI's witness Ronald R. Jackups, Vice President, Electric System Operations, PSI's transmission facilities are used and useful in providing service to PSI's retail electric customers. Pet. Ex. M, p. 8. No party took issue with the used and useful nature of PSI's transmission and distribution ("T&D") facilities. We find that, as of the applicable cut-off date, such facilities were used and useful and reasonably necessary for **[*12]** the convenience of the public and should be included in PSI's rate base.

(3) Petitioner's Office and General Facilities. The evidence shows that PSI's office facilities generally consist of the Company's corporate offices in Plainfield and numerous field offices located throughout PSI's service territory. These office facilities are used to provide customer service, sales, economic development, billing, payment, engineering, financial, accounting, service dispatch, construction, maintenance, service restoration, and other services necessary in the conduct of the electric utility business. In addition, PSI's 24-hour Call Center, garage and storeroom are located at its corporate offices. Pet. Ex. M, pp. 8-9. No party took issue with the used and useful nature of PSI's office and general facilities. We find that Petitioner's office and general facilities were, as of the applicable cut-off date, used and useful and reasonably necessary for the convenience of the public and should be included in PSI's rate base.

B. Original Cost of PSI's Electric Property. PSI's proposed jurisdictional net original cost of its electric utility plant in service, including plant in service net of **[*13]** accumulated depreciation, fuel stock, emission allowances, and materials and supplies ("M&S"), was $ 3,662,350,000, as of the appropriate cut-off date in this case. Pet. Ex. OO-3. No party took issue with Petitioner's jurisdictional net original cost rate base, and we find that the jurisdictional net original cost of PSI's electric utility property used and useful for the benefit of the public is $ 3,662,350,000, comprised of the following elements:

Net Electric Utility Plant in Service	$ 3,463,726,000

Fuel Stock	$ 67,925,000
Emission Allowances	$ 14,651,000
AFUDC Continuation/Deferred Depreciation	$ 75,202,000
Materials and Supplies	$ 40,846,000
Net Utility Rate Base	$ 3,662,350,000

Pet. Ex. X-1, as updated as of October 6, 2003, and as adjusted per Pet. Ex. OO-3.

C. Fair Value of PSI's Electric Property.

(1) Legal Requirements. Ind. Code § 8-1-2-6 requires this Commission to value a public utility's property at its "fair value." In *Indianapolis Water Co. v. Public Service Comm'n*, 484 N.E.2d 635 (Ind. Ct. App., 1985), the Indiana Court of Appeals confirmed that a utility should be entitled to earn a fair rate of return on the **[*14]** fair value of its utility property used and useful in serving the public. The Court gave this Commission the following four basic directives regarding the application of the concept of "fair value:"

> (a) It is upon the statutory "fair value" of its used and useful property that a utility should be allowed to earn a return.
>
> (b) "Fair value" is not an either/or situation as to original cost or reproduction cost new. It is a conclusion or final figure, drawn from all the various values or factors to be weighed in accordance with the statute by this Commission.
>
> (c) In its determination of "fair value", this Commission may not ignore the commonly known and recognized fact of inflation.
>
> (d) While original cost is one of the factors that this Commission should consider in arriving at a "fair value" figure, it is not necessarily, in and of itself, an accurate reflection of the "fair value" of the utility's property.

In the *Indianapolis Water Co.* case, the Court of Appeals referred to the Supreme Court's holding in *Public Service Comm'n v. City of Indianapolis*, 235 Ind. 70, 131 N.E.2d 308, 325 (1956), that "reproduction cost new **[*15]** less depreciation cannot be disregarded in fixing a valuation for rate making purposes." The Court of Appeals went on to indicate that these observations "are as pertinent today as they were in 1956." *Indianapolis Water*, 484 N.E. 2d at 640. The Court of Appeals reiterated that this Commission must authorize rates that provide the utility with the opportunity to earn a fair rate of return on the fair value of its property in *Gary-Hobart Water Corp. v. Indiana Utility Regulatory Comm'n*, 591 N.E.2d 649, 653-54 (Ind. Ct. App., 1992), *reh'g denied*.

(2) Reproduction Cost New Less Depreciation. A valuation of PSI's electric utility plant as of September 30, 2002, was made by PSI witness John J. Spanos. This study was based on the reproduction cost new of such property, less depreciation. The total appraised value at that date was determined to be not less than $ 5,269,844,632. The valuation was determined by applying cost trend factors to the original cost of the various types of PSI's utility property. Reductions for depreciation were based on physical inspection, analysis of PSI's mortality experience with respect to **[*16]** its property history and past retirements of property and judgment based upon Mr. Spanos' experience. Pet. Ex. T, p 15. No party took issue with Mr. Spanos' valuation. After adjustments for major projects, fuel stock, emission allowances, M&S and jurisdictional separation, PSI's evidence showed, and we find, that the reproduction

cost new less depreciation value of PSI's utility property is not less than $ 5,799,973,000. Pet. Ex. Z-8.

(3) Fair Value Determination. The fair value of Petitioner's used and useful property at August 31, 1995, found in Petitioner's last rate case was $ 2,838,569,000 (excluding M&S, fuel stockpile and *pro forma* fuel). Adjusting this value for inflation since the cut-off date in the 1996 Order produces a Consumer Price Index ("CPI") adjusted value of $ 3,438,471,000. To this value must be added PSI's property additions, net of retirements, since the 1996 Order, of $ 1,215,055,000, and M&S, fuel stock and emission allowances of $ 203,006,000. Such a calculation results in a valuation of Petitioner's total jurisdictional plant in service and used and useful in the provision of retail electric service to the public of $ 4,856,532,000. Pet. Ex. C-6. We **[*17]** find that the fair value of Petitioner's total jurisdictional plant in service and used and useful in the provision of retail electric service to the public is $ 4,856,532,000.

5. Fair Rate of Return. Having determined the fair value of Petitioner's used and useful property for the provision of retail electric utility service in Indiana, we turn now to a determination of a level of net operating income that represents a reasonable return on that property. This determination requires balancing the interests of the investors and consumers through the exercise of a fair and enlightened judgment, having regard to all relevant facts. *See, Bethlehem Steel Corp. v. Northern Ind. Public Serv. Co.*, 397 N.E.2d 623, 630 (Ind. Ct. App., 1979).

In the case of *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692-693 (1923), the Court set the standard against which a determination of a fair rate of return is measured:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to **[*18]** all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

262 U.S. at 692-693.

In the case of *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), the Court expanded on the guidelines **[*19]** to be used to assess the reasonableness of the allowed return, and recognized that revenues must cover capital costs:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . by that standard the return to the equity owner should be commensurate with

> returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

320 U.S. at 603.

One widely accepted method for evaluating the reasonableness of a public utility's return involves a consideration of capital structure and development of an overall weighted cost of capital. However, this Commission utilizes cost of capital estimation evidence as only one factor in determining the fair rate of return for a public utility. Cost of capital testimony, while relevant evidence in the determination of a fair rate of return, is clearly not the only consideration. We **[*20]** have repeatedly found:

> Cost of capital is an important element of the ratemaking process. However, we have pointed out many times that cost of capital is not synonymous with the fair rate of return. Ultimately, the determination of a fair rate of return is the prerogative of the Commission, taking into consideration all the relevant evidence. The objective is to determine the return which is reasonably sufficient to assure confidence in and financial soundness of the utility and adequate, under efficient and economical management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties. *Columbus Gas Light Co. v. Public Serv. Comm'n of Ind.,* 193 Ind. 399,404-406,140 N.E. 538, 540 (1923); *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n,* 262 U.S. 679, 692-693 (1923). These goals go well beyond the use of formulas and mathematical calculations which may imply a level of precision which does not really exist. . . . Rather, we are to exercise the flexibility afforded us by statute and the Indiana Supreme Court.

See, PSI **[*21]** *Energy, Inc.* Cause No. 40003, (Ind. Util. Reg. Comm'n, September 27, 1996), at 34-35.

The Indiana courts have supported this view and have held that, in determining an appropriate rate of return, it is not necessary for this Commission to determine the cost of capital, and that the Commission may consider evidence regarding the cost of capital in conjunction with other evidence presented in the proceeding. *Bethlehem Steel Corp. v. Northern Ind. Public Serv. Co.,* 397 N.E.2d 623, 630 (Ind. Ct. App., 1979); *Office of Utility Consumer Counselor v. Public Serv. Co.,* 449 N.E.2d 604, 607 (Ind. Ct. App., 1983). Determining a fair rate of return is the prerogative of this Commission after giving weight to all material evidence. The Indiana Court of Appeals has recognized that it is appropriate for this Commission to utilize the rate of return as a "balance wheel" to provide a limited margin of error for the resolution of other issues. The Commission's primary objective is to reach an overall result that is equitable and that will permit continuity of utility services on a sound financial basis. *L. S. Ayres & Co. v. Indianapolis Power & Light Co.,* 351 N.E.2d 814, 821 **[*22]** (Ind. Ct. App., 1976). The determination of a utility's revenue requirement is primarily an exercise of informed regulatory judgment. If the judgment is to be exercised properly, the Commission must examine every aspect of the utility's operation, and the economic environment in which the utility functions, to ensure that the data it has received is representative of operating conditions that will, or should, prevail in future years. *City of Evansville v. Southern Ind. Gas & Electric Co.,* 339 N.E.2d 562, 568 (Ind. Ct. App., 1975).

With this background in mind, we now turn our attention to the evidence submitted in this proceeding concerning Petitioner's capital structure, cost of capital, and other matters relevant to the determination of a fair return for Petitioner, including: the relative risks facing the energy industry and PSI; PSI's financial condition, financing requirements and financial objectives; PSI's credit quality; and PSI's performance in rendering retail electric utility service in Indiana.

A. Capital Structure. The Prehearing Conference Order provided that the economic and financial data used in determining Petitioner's cost of capital **[*23]** and capital structure shall not be restricted as to the time or method of adjustment used for financial and accounting exhibits, but should be as current as possible and updated as of the prefiling dates set forth in that order. Pursuant to this provision, Petitioner's October 6, 2003 filing updated its actual capital structure as of August 31, 2003, with certain updates for events that occurred in September 2003. Pet. Ex. X-32, Corrected; Pet. Ex. VV-1.

Intervenor Kroger took issue with PSI's regulatory capital structure and argued that short-term debt should be included in PSI's capital structure for ratemaking purposes. Kroger Ex. No. 1, p. 16. Additionally, PSI-IG witness Michael Gorman expressed concern about the $ 200 million equity infusion to PSI from its parent company, Cinergy Corp. PSI-IG Ex. No. 3, p. 8. PSI witnesses Stephen M. Farmer and Ronald R. Reising addressed these arguments and concerns relative to the capital structure to be utilized in this case for ratemaking purposes.

(1) Short-Term Debt in the Regulatory Capital Structure. Mr. Stephen Farmer, PSI's Revenue Requirements Manager, opposed the inclusion of short-term debt in PSI's capital structure for regulatory **[*24]** purposes, explaining that short-term debt is used to finance items that are not in rate base, such as certain regulatory assets and cash working capital needs and CWIP. Pet. Ex. QQ, p. 2. Mr. Farmer pointed out that this Commission, in excluding short-term debt from PSI's regulatory capital structure in Cause No. 40003, rejected the OUCC's argument in that case -- and not repeated by the OUCC here -- that the portion of PSI's short-term debt that exceeded PSI's CWIP balance should be included in PSI's capital structure for ratemaking purposes. *Id*.

Mr. Farmer further noted that in Cause No. 40003, the OUCC witness Matthew Kahal testified that it would be appropriate to exclude short-term debt from the capital structure only if short-term debt balances are comparable to (or less than) CWIP balances. Mr. Farmer pointed out that the balance of PSI's short-term debt outstanding at August 31, 2003, was $ 112,333,000, while its CWIP balance was $ 154,456,000. While acknowledging that a portion of PSI's CWIP is eligible for CWIP ratemaking treatment (*i.e.*, qualified pollution control expenditures), Mr. Farmer pointed out that short-term debt is also used to finance working capital **[*25]** needs and costs of assets that are not recovered in rates. Pet. Ex. QQ, p. 3. As for a suggestion that short-term debt may have become a permanent component of PSI's capital structure, Mr. Farmer observed that PSI's investment in plant in service has increased significantly since the end of the test period in this case -- yet during this same period PSI's short-term debt balance has not increased appreciably.

In support of Kroger's position, Mr. Kevin Higgins quoted from Standard and Poor's 2001 publication, "Corporate Ratings Criteria" that states:

> Traditional measures focusing on long-term debt have lost much of their significance, since companies rely increasingly on short-term borrowings. It is now commonplace to find permanent layers of short-term debt, which finance not only seasonal working capital but also an ongoing portion of the asset base.

Mr. Farmer responded that financial analysts do not make a regulatory distinction between used and useful plant included in rate base and other assets. Pet. Ex. QQ, p. 5. Financial analysts, he said, include short-term debt as part of company capitalization because the "asset base" of a company would include investments in plant **[*26]** not receiving rate treatment (*e.g.*, non-qualified pollution control property CWIP investments and regulatory assets). During cross-examination, Mr. Farmer also pointed out that the same Standard and Poor's publication quoted by Mr. Higgins also states that "Flexibility can be jeopardized when a firm is overly reliant on bank borrowings or commercial paper." Tr. at Y88.

As additional support for its position that short-term debt should be included in PSI's capital structure, Kroger emphasized the difference between PSI's capitalization and PSI's original cost depreciated rate base, arguing that a utility's rate base should approximate its capitalization. Kroger Ex. No. 1, pp. 10-11.

In response, Mr. Farmer indicated that that balance between capitalization and rate base is simply a theory that presumes "perfect ratemaking" -- that is, perfect and perfectly timed recovery of the utility's costs, and consistently fair returns earned by the utility, year in and year out. In reality, ratemaking and recovery of costs are not perfect. The utility may or may not earn consistently fair returns year in and year out. Tr. at Y56-61 and Y89-90. Mr. Farmer presented a number of explanations **[*27]** for the difference between PSI's rate base and its capitalization. These explanations include: changes in accounts receivables balances; changes in accounts payable balances; different rate case cut-off dates for rate base on the one hand, and capital structure on the other; PSI's use of its sale of accounts receivables proceeds to redeem outstanding first mortgage bonds and preferred stock; impacts on capital structure and retained earnings produced by various accounting requirements; and less than reasonable returns earned by PSI at various times, effectively shrinking investors' capital investments. Tr. at Y56-61. With regard to this latter reason -- investors' capital investments effectively diminishing over time to the extent that the utility earns less than a reasonable return -- Mr. Farmer emphasized that utility investors expect and demand a reasonable return over time of their principal actually invested, not a return on a diminished capital investment. Tr. at Y60.

The evidence indicates that Petitioner's short-term debt balances have been used to finance construction-work-in-progress and other capital items, such as regulatory assets, not in PSI's rate base. If short-term **[*28]** debt had been financing plant additions in Petitioner's rate base, the short-term debt would have been increasing appreciably as substantial plant was added. Moreover, as Mr. Farmer pointed out, the cost of short-term debt is reflected in the application of Allowance for Funds Used During Construction ("AFUDC") to CWIP expenditures. Consequently, customers regularly receive the benefit of Petitioner's lower-cost short-term debt through lower capitalized AFUDC rates. Accordingly, based on our review of the evidence presented in this Cause, we conclude -- as we did in Cause No. 40003-that PSI's short-term debt should not be included in its capital structure for ratemaking purposes.

(2) Cinergy's $ 200 Million Equity Infusion to PSI. PSI-IG witness Michael Gorman expressed concern over PSI's receipt of a $ 200 million equity infusion from its parent company, Cinergy Corp., and recommended that certain assurances be made by PSI in order to support its claim that the equity infusion will positively enhance its credit rating. PSI-IG Ex. No. 3, p. 8. The assurance Mr. Gorman wanted was that such equity infusion will occur without increasing Cinergy's overall debt level. *Id.* Mr. Gorman **[*29]** argued that if Cinergy is making an equity infusion in PSI by issuing additional debt, the higher debt level of Cinergy could have as much negative credit rating impact on PSI as the positive impact credited from the increase in PSI's common equity and the decrease in its debt leverage. *Id.* Mr. Gorman noted that PSI's bond rating is heavily tied to Cinergy's bond rating and he said that analysts were concerned with Cinergy's highly leveraged capital structure. *Id.* at 9.

In response to Mr. Gorman's concern, PSI witness Ronald R. Reising, Cinergy's Vice President of Finance, noted that Cinergy has raised over $ 900 million in additional equity since December 2001, and that the funds raised by Cinergy's equity issuances supported the funding of the $ 200 million infusion to PSI. Pet. Ex. EE, p. 15. Similarly, in earlier testimony, PSI witness Mr. James E. Rogers, Chairman and CEO of both Cinergy and PSI, explained that Cinergy made the $ 200 million equity infusion in order to strengthen PSI's balance sheet and maintain PSI's credit ratings. Pet. Ex. A, p. 29.

Regarding the $ 200 million equity infusion from PSI's parent, we conclude that PSI adequately explained both the source **[*30]** of the funds (from the $ 900 million in equity issuance funds raised by Cinergy since December 2001) and, more importantly, the use of the funds to strengthen PSI's balance sheet and preserve PSI's credit quality.

(3) Commission's Ultimate Finding Regarding PSI's Regulatory Capital Structure. Based on the foregoing, we find that the PSI capital structure to be used in this case is:

Description	**Capitalization**
Common Equity	$ 1,603,374,000
Preferred Stock	42,333,000
Long Term Debt	1,402,254,000
Deferred Income Taxes	519,273,000
Unamortized ITC -- 1970 & Earlier	193,000
Unamortized ITC -- 1971 & Later	30,571,000
Customer Deposits	9,741,000
Total Capitalization	$ 3,607,739,000

B. Cost of Capital. It was undisputed that PSI's evidence demonstrated that its embedded cost of long-term debt was 6.37%, preferred stock 6.11%, and customer deposits 6%, or that post-1970 unamortized investment tax credits should have the weighted cost of long-term debt, preferred stock and common equity capital. Pet. Ex. X-32 Corrected; Pet. Ex. VV-1. There was disagreement only concerning Petitioner's current cost of common equity capital. Petitioner, OUCC, and PSI-IG submitted testimony **[*31]** sponsoring the results of their respective cost of common equity capital studies. Staff submitted testimony concerning the results of these three studies. CAC submitted testimony addressing certain aspects of Petitioner's risk profile.

(1) Petitioner's Cost of Common Equity Evidence. In his testimony filed on March 28, 2003, Petitioner's witness Dr. Roger A. Morin recommended that PSI be allowed to earn an 11.5% return on its common equity capital, based on studies he performed using the Capital Asset Pricing Model ("CAPM"), the Risk Premium ("RP"), and Discounted Cash Flow ("DCF") methods of determining the cost of such capital. Pet. Ex. G, p. 4. During his oral testimony on June 12, 2003, Dr. Morin indicated that there had been a slight decrease in long-term interest rates and some slight changes in dividend yields from the time of his March 2003 prefiled testimony, resulting in a slight decrease in his recommended return on common equity from 11.5% to in the vicinity of 11.2% to 11.3%. Dr. Morin noted in his oral update that he would be submitting a full-fledged update before the final phase of hearings. Tr. at G109-G110. In his testimony filed as a part of PSI's August 31, **[*32]** 2003 Update, Dr. Morin reduced his recommended cost of common equity to 11.2%, based on more recent data. Pet. Ex. TT, pp. 2-3. Use of Dr. Morin's cost of common equity in PSI's proposed regulatory capital structure produced an overall, weighted cost of capital of 7.63%. Pet. Ex. X-32, Corrected; Pet. Ex. VV-1.

Dr. Morin performed two CAPM analyses, one using what he characterized as the "plain vanilla" CAPM and another using an empirical approximation of the CAPM ("ECAPM"). He also performed six RP analyses: (i) a historical RP analysis of the electric utility industry using Treasury bond yields; (ii) a historical RP analysis of the electric industry using A-rated utility bond yields; (iii) a historical RP analysis of the natural gas utility industry using Treasury bond yields; (iv) a historical RP analysis of the natural gas industry using A-rated utility bond yields; (v) a study of the risk premiums allowed in the electric utility industry relative to Treasury bond yields; and (vi) a study of the risk premiums allowed in the electric utility industry relative to A-rated utility bond yields. He performed DCF analyses, using both Zacks Investment Research, Inc. ("Zacks") and Value **[*33]** Line Investors' Service ("Value Line") dividend growth estimates, on three surrogates for the Company: (i) a group of electric utilities that make up Moody's Electric Utility Index; (ii) a group of investment-grade, vertically integrated electric utilities; and (iii) a group of natural gas distribution utilities. Pet. Ex. G, pp. 4 and 46; and Pet. Ex. TT, p. 3. His revised cost of common equity capital results ranged from 10.3% to 12.5%, averaging 11.2%. Pet. Ex. TT, p. 3.

In his testimony, Dr. Morin indicated that he believes that all of the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the current electric utility industry. Dr. Morin indicated that he believes that past earnings and dividends of electric utilities are simply not indicative of the future, as historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including structural transformation to a more competitive environment. As a result, Dr. Morin testified that he believes that these historical data are not representative of the future long-term earning power of these **[*34]** companies. Moreover, Dr. Morin indicated that he believes that historical growth rates are not representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available. Pet. Ex. G, pp. 13-14. Dr. Morin indicated that a similar conclusion applies to historical risk premiums. He testified that historical measures of risk, such as beta, are necessarily downward-biased in assessing the present fluid circumstances of the electric utility industry. Current changes in the fundamentals of electric utilities are not yet fully reflected in historical data. Pet. Ex. G, p. 14.

Dr. Morin stated that the return allowed for a public utility must necessarily reflect the investors' return requirements and be commensurate with returns on investments in other firms having corresponding risks. The allowed return, he said, should be sufficient to assure confidence in the financial integrity or strength of the firm, in order to maintain its creditworthiness and the ability to attract capital on reasonable terms. The attraction of capital standard focuses, he testified, on investors' **[*35]** return requirements that are generally determined using market value methods, such as the RP, CAPM or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternatives of comparable risk. Pet. Ex. G, pp. 6-8.

Dr. Morin testified that the heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return, and concluded that the end result of this Commission's decision in this proceeding should be to allow PSI the opportunity to earn a return on common equity capital that is: (i) commensurate with returns on investments in other firms having corresponding risks; (ii) sufficient to assure confidence in PSI's financial integrity; and (iii) sufficient to maintain PSI's creditworthiness and ability to attract capital on reasonable terms. Pet. Ex. G, p. 10.

(a) Dr. Morin's CAPM and Risk Premium Results. Dr. Morin testified that the fundamental **[*36]** concept underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. Denoting the risk-free rate by "R[F]" and the return on the market as a whole by "R[M]", he stated the formula for the "plain vanilla" CAPM is as follows:

K = R[F] + beta (R[M] - R[F])

Dr. Morin testified that under this formula the return required by investors (K) is made up of a risk-free component (R[F]), plus a risk premium given by [beta] (R[M] - R[F]). To derive the CAPM risk premium estimate, three inputs are required: the risk-free rate (RF), the beta ([beta]) and the market risk premium (R[M] - R[F]). For the risk-free rate, Dr. Morin used 5.0%. For the beta, he used 0.72, and for the market risk premium, he used 6.8%. Pet. Ex. G, p. 15.

Dr. Morin explained that the basis for his 5% risk-free rate was the actual yield on long-term Treasury bonds, **[*37]** in February 2003, shortly before he filed his initial testimony in March of 2003. Pet. Ex. G, p. 16. Dr. Morin's market risk premium of 6.8%, was based on the results of both forward-looking and historical studies of long-term risk premiums, as shown in the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2002 Yearbook*. Pet. Ex. G, p. 20. This study, he said, compiles security returns from 1926 to 2001 and shows that a broad market sample of common stocks outperformed the income component of long-term U.S. government bonds by approximately 7.5%. Pet. Ex. G, p. 20.

To determine an appropriate beta for PSI, whose common stock is not publicly traded, Dr. Morin used two proxies -- the average beta for the electric utility industry, as reported by Value Line, and the average beta of a group of natural gas distribution utilities that he selected. Pet. Ex. G, p. 17. The average beta for the electric utility industry, he said, was 0.71 as of January 2003, and the average beta for the group of natural gas distribution utilities was 0.72 as of January 2003. Pet. Ex. G, pp. 17-18; Pet. Ex. G-2; and Pet. Ex. G-3. He observed that ongoing changes in risk fundamentals are not **[*38]** yet fully reflected in historical beta estimates for electric utilities and, as a result, the historic beta estimates are downward biased. Pet. Ex. G, p. 19. Given the dramatic changes occurring in the electric utility operating environment, Dr. Morin stressed the need to be forward-looking because investors consider prospective long-term risks when making investment decisions. Pet. Ex. G, p. 18. In his "plain vanilla" CAPM study, Dr. Morin used a beta of 0.72, for what he characterized as a conservative estimate, of the beta applicable to PSI's electric utility operations. Pet. Ex. G, p. 20. Use of that beta, together with a risk-free rate of 5.0% and a market risk premium of 6.8%, produced in Dr. Morin's initial testimony a CAPM-based estimate of PSI's cost of common equity of 9.9% (5.0% + 0.72 x 6.8%), and 10.2% with flotation costs. Pet. Ex. G, p. 23.

Dr. Morin testified that because the CAPM produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00, expanded CAPMs have been developed, which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias and thereby enrich its conceptual validity. Pet. **[*39]** Ex. G, p. 23. Using this "empirical" version of the CAPM, he said that the formula becomes:

K = R[F] + 0.25 (R[M] - R[F]) + 0.75 beta (R[M] - R[F])

Utilization of this formula produced a return on common equity of 10.4% without flotation cost, and 10.7% with flotation costs, using 5.0% for RF, a market risk premium of 6.8% and a beta of 0.72. Pet. Ex. G, p. 23.

For his RP approach to cost of common equity, Dr. Morin examined historical risk premiums for the electric utility industry from 1931 to 2001 using Moody's Electric Utility Index as an industry proxy. Pet. Ex. G, p. 24; and Pet Ex. G-4. A risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1931 to 2001, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. The resulting average risk premium over the period was 5.6% over long-term Treasury bonds. Given that long-term Treasury bonds were yielding 5.0% shortly before Dr. Morin's March 2003 filing, he determined the implied cost of equity for the average electric utility using this method to be 5.0% + 5.6% = 10.6% without flotation cost, **[*40]** and 10.9% with flotation costs. Pet. Ex. G, p. 24.

Dr. Morin testified that he did not adjust his risk premium results to account for PSI's risk relative to the industry because PSI's total investment risks are currently comparable to those of the electric utility industry. He noted that PSI's bonds are currently rated "A3", which is close to the industry average. Because the historical risk premium estimate from the Moody's electric utility industry group reflects the risk of the average electric utility and because PSI's total investment risks are currently comparable to those of the industry, Dr. Morin concluded that the expected equity return from the Moody's group is applicable to PSI. Pet. Ex. G, p. 24.

Using the same historical analysis described above, but substituting the yield on A-rated electric utility bonds for the yield on U.S. Treasury bonds, produced an average risk premium of 4.5% in Dr. Morin's initial testimony. Pet. Ex. G, pp. 25-26; and Pet. Ex. G-5. Adding this premium to the current yield on A-rated bonds of 7.0% produced an implied cost of equity for the average electric utility of 11.5% without flotation cost, and 11.8% with flotation costs, he said. Pet. Ex. **[*41]** G, p. 26.

Applying the same risk premium analysis to the natural gas utility industry produced an implied cost of equity for the average electric utility of 10.7% without flotation cost, and 11.0% with flotation costs, using long-term Treasury bonds for the risk free rate, in Dr. Morin's initial testimony. Pet. Ex. G, p. 26; and Pet Ex. G-6, Substituting the long-term bond yield for A-rated utilities for the yield on Treasury bonds produced an average risk premium of 5.0%, which, when added to the yield on A-rated bonds of 7.0% at the time of his initial testimony, produced an implied cost of equity of 12% (7.0% + 5.0%) without flotation cost, and 12.3% with flotation costs. n1 Pet. Ex. G, pp. 26-27; and Pet Ex. G-7.

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n1 Dr. Morin stated that all of his market-based estimates (CAPM, RP and DCF) include an adjustment for flotation costs, as these costs are incurred but not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. Pet. Ex. G, p. 42. Flotation costs include a direct component in the form of compensation to the security underwriter for its marketing/consulting services, for risks involved in distributing the issue, and for operating expenses associated with the issue. Flotation costs also include an indirect component in the form of downward pressure on the stock price as a result of the increased supply of stock from the new issue, the latter frequently referred to as market pressure. Pet. Ex. G, p. 42, and Pet. Ex. G, Appendix A.

- - - - - - - - - - - - End Footnotes- - - - - - - - - - - - - **[*42]**

Dr. Morin also examined the historical risk premiums implied in the returns on common equity ("ROE") allowed by regulatory commissions over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. Pet. Ex. G, p. 27. This allowed risk premium approach produced an average ROE spread over long-term Treasury yields of 5.1% for the 1993-2002 period. Dr. Morin's data showed that there has been a rising trend of the risk premium in response to lower interest rates and rising competition and restructuring. Pet. Ex. G, pp. 27-28. These studies produced costs of common equity of

11.3% and 11.4% at the time of Dr. Morin's initial testimony, depending on whether long term Treasury bonds or A-rated utility bonds were used. Pet. Ex. G, pp. 27-30. Dr. Morin updated the CAPM and RP results of his study in October 2003, using data as of the end of August. He indicated that, as of the end of August 2003, the yield on long-term Treasury bonds was 5.3%, compared to 5.0% in February when he prepared his initial study. The following table summarizes Dr. Morin's ROE estimates obtained from his CAPM and RP studies, updated as of August 31, 2003:

Risk Premium Methods	**%ROE**
CAPM	10.9%
ECAPM	11.4%
Risk Premium Electric Utility Treasury Bonds	11.2%
Risk Premium Electric Utility "A"-Rated Bonds	12.1%
Risk Premium Natural Gas Treasury Bonds	11.3%
Risk Premium Natural Gas "A"-Rated Bonds	12.5%
Allowed Risk Premium Treasury Bonds	11.3%
Allowed Risk Premium "A"-Rated Bonds	11.4%

[*43]
Pet. Ex. TT, p. 3.

(b) Dr. Morin's DCF Results. Dr. Morin observed that according to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. Pet. Ex. G, p. 30. One widely used method to measure these anticipated benefits in the case of a non-static company, he said, is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process, he said, can be represented by the following formula, for the traditional DCF model:

K[e] = D[1]/P[0] + g

K[e]=investors' expected return on equity

D[1]=expected dividend during the coming year

P[0]=current stock price

g=expected growth rate of future dividends, earnings, book value

Pet. Ex. G, pp. 30-31. The idea of this market value approach, is to infer K[e] from the observed share price, dividend, and from an estimate of investors' expected future growth. Pet. Ex. G, p. 31.

Dr. Morin applied the DCF model to three proxy groups for PSI: (i) Moody's electric utilities; (ii) a group of vertically integrated electric utilities that he selected; and (iii) a group consisting of widely-traded dividend-paying **[*44]** natural gas distribution companies, drawn from the Value Line edition of the Value Line Gas Distribution Group. Dr. Morin used the spot dividend yields reported in the January 2003 edition of Value Line. Pet. Ex. G, pp. 31-32. Because dividends are paid quarterly in practice, Dr. Morin observed, the investors' required return must be determined with a DCF model that reflects the quarterly nature of dividends payments. Pet. Ex. G, p. 33; see also, Pet. Ex. G, pp. 33-36; and Pet. Ex. G-8.

Dr. Morin explained that, as a proxy for expected growth, he examined growth estimates developed by professional analysts employed by large investment brokerage institutions. These forecasts, he said, are made by large reputable organizations, and the data are readily available to investors and representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Dr. Morin used analysts' long-term growth forecasts contained **[*45]** in Zacks as proxies for investors' growth expectations in applying the DCF model. He also used Value Line's growth forecast as an additional proxy. Pet. Ex. G, p. 37.

Dr. Morin did not use historical growth rates in his DCF approach because he believes that they have little relevance as proxies for future long-term growth. Pet. Ex. G, p. 38. They are downward-biased by the sluggish earnings performance in the last five years, due to the structural transformation of the electric utility industry from a regulated monopoly to a more competitive environment. Pet. Ex. G, p. 38. He illustrated this point by adding the historical growth rates over the past five years of 2.1%, -1.3%, and 3.5% for the electric utility companies that make up Value Line's Electric Utility composite group to the average 5.0% dividend yield prevailing in February of 2003 for the companies he examined; this produced cost of equity estimates of 7.1%, 3.7%, and 8.5%, using earnings, dividends, and book value growth rates, respectively. He observed that such estimates of common equity costs are less than, or close to, the cost of debt for these companies. Pet. Ex. G, p. 38.

Dr. Morin, in his initial testimony, stated **[*46]** that for the electric utilities that make up Moody's Electric Utility Index (Column 2 of page 1 of Pet. Ex. G-10), the average long-term growth forecast obtained from Zacks was 5.2% and, adding this growth rate to the average expected dividend yield of 5.8% (Column 3), produced an estimate of equity costs of 11.0% for the group, unadjusted for flotation costs or quarterly timing. Providing for the quarterly timing of dividends and adding an allowance for flotation costs to these results brings the cost of equity estimate to 11.5%, shown in Column 5 of Pet. Ex. G-10. Pet. Ex. G, p. 39. Using Value Line's long-term earnings growth forecast of 5.4%, instead of the Zacks consensus forecast, the cost of equity for the Moody's group is 11.1%, and, after provision for quarterly timing and allowance for flotation costs, the cost of equity estimate is 11.6%, as shown on page 2 of Pet. Ex. G-10. Pet. Ex. G, p. 39.

Using a group of 13 vertically integrated electric utilities (*i.e.*, publicly listed parent companies whose electric utility operating subsidiaries include both transmission and distribution ("T&D") and generation activities), and the average long-term growth forecast obtained **[*47]** from Zacks of 6.6% for this group, and adding this growth rate to the average expected dividend yield of 5.6%, produced an estimate of equity costs of 12.2% for the group. Pet. Ex. G, pp. 39-40; and Pet. Ex. G-11. Providing for quarterly timing of dividends and adding an allowance for flotation costs to the results of Column 4 of Pet. Ex. G-11 brings the cost of equity estimate to 12.7%. Pet. Ex. G, p. 40. Removing the impact of significant outliers from the result, to produce a truncated average, resulted in a 12.0% cost of common equity. Pet. Ex. G, p. 40.

Using Value Line's long-term earnings growth forecast of 6.5%, instead of the Zacks consensus forecast, Dr. Morin produced a cost of equity for the vertically integrated electrics of 12.0%. Pet. Ex. G, p. 40. Allowance for quarterly timing and flotation costs brought that cost of equity to 12.5%. The truncated average was 12.0%. Pet. Ex. G, p. 40.

Dr. Morin testified that using the average long-term growth forecast obtained from the Zacks corporate earnings database for the gas distribution group of 5.5%, and adding that growth rate to the average expected dividend yield of 4.7%, produced an estimate of equity costs of 10.2% for **[*48]** the gas distribution group. Pet. Ex. G, p. 41, and Pet. Ex. G-12. Dr. Morin added that providing for quarterly timing of dividends and flotation costs to this result brings the cost of equity estimate to 10.7%. Pet. Ex. G, p. 41. Repeating the same procedure, but using Value Line's long-term earnings growth forecast of 8.7%, instead of the Zacks consensus growth forecast, produced a cost of common equity for the gas distribution group of 13.6%, unadjusted for flotation costs. Pet. Ex. G, p. 41. Adding an allowance for flotation costs and allowing for quarterly dividend payments brought this cost of equity estimate to 13.8%, while the truncated average result was 13.6%. Pet. Ex. G, p. 41; and Pet. Ex. G-12.

Dr. Morin updated the DCF results of his study in October 2003, using data as of the end of August. He indicated that the DCF results for the vertically integrated electric and natural gas distribution utilities had decreased significantly from February when he prepared his initial study, in part due to the substantial revision in dividend taxation which lowered dividend yields (increased stock prices) and in part due to the lowering of utility growth forecast by analysts. The table **[*49]** below summarizes Dr. Morin's DCF estimates of the costs of common equity to PSI, updated as of August 31, 2003:

DCF Study	%ROE
Moody's Electrics Zacks Growth	10.3%
Moody's Electrics Value Line Growth	10.3%
Vertically Integrated Electrics Zacks Growth	10.6%
Vertically Integrated Electrics Value Line Growth	10.8%
Natural Gas Distribution Zacks Growth	10.4%
Natural Gas Distribution Value Line Growth	12.1%

Pet. Ex. TT, p. 3.

(2) OUCC's Cost of Common Equity Evidence. Edward R. Kaufman, OUCC's Lead Financial Analyst testified regarding PSI's financial condition, overall capital market conditions, and conducted analyses resulting in an initial recommended cost of equity of 9.15%. Mr. Kaufman subsequently updated his recommended cost of equity in October 2003 ("October Update") to 9.25%. Pub. Ex. No. 8U, p. 2. To estimate PSI's cost of equity, Mr. Kaufman employed DCF analyses as well as CAPM methodologies, using two proxy groups of electric companies as well as PSI's parent company, Cinergy. Pub. Ex. No. 8, p. 4. Mr. Kaufman's cost of equity estimates from these analyses ranged from 7.94% to 10.12% in his initial prefiled testimony, and 8.02% to 9.67% in his October **[*50]** Update. Pub. Ex. No. 8, p. 4; and Pub. Ex. No. 8U, Schedule 1, p. 2.

Mr. Steven C. Carver, a principal in the firm Utilitech, Inc., also testified on behalf of the OUCC, and sponsored a weighted overall cost of capital of 6.86%, based upon Mr. Kaufman's initial 9.15% recommendation. Both were later updated to 6.74% and 9.25%, respectively. Pub. Ex. No. 8, p. 4. and Pub. Ex. 3 Revised at Schedule D. OUCC witnesses Mr. Timothy Geswein and Dr. Peter M. Boerger also testified regarding PSI risk levels and required ROE in light of such risks.

Mr. Kaufman characterized Petitioner's financial condition as strong, with a common equity ratio of 47.9% (using a "traditional" securities rating capital structure) that is higher than the 24 electric utilities covered in the C.A. Turner Utility Reports ("'Turner Reports"). Pub. Ex. No. 8, p. 5. His testimony quoted from Cinergy's presentations to analysts and the testimony of its CEO, Mr. Rogers, to illustrate how the Company believes it has solid liquidity, recently affirmed investment grade credit ratings, increasing cash flow based on reduced environmental capital requirements and rate increases, and substantially reduced risk due to regulatory **[*51]** and legislative relief as well as improvements in system reliability. Pub. Ex. No. 8, p.6.

Mr. Kaufman observed that the interest rates for US Treasury Bonds are currently at their lowest point in 30-40 years, and indicated that the year-end 2002 yield on long-term government bonds was 4.55% -- the lowest year-end yield since 1966. He also identified the fact that the yield on "A" rated utility bonds as of August 5, 2003 was 6.64% and that their annual average yield had not been below 7% since 1968. Pub. Ex. No. 8, p. 7. Mr. Kaufman added that the current 4% prime rate is the lowest since April of 1959. These low costs of debt, he explained, should translate into lower costs of equity as well. Pub. Ex. No. 8, p. 7. Mr. Kaufman noted that the Petitioner recognized a 130 basis point decline in the long term risk free rate of return since Petitioner's last rate case (as demonstrated comparing of Dr. Morin's CAPM risk free rate of return in the last case (6.3%) and the CAPM risk free rate of return he used in the current proceeding (5.0%)).

Mr. Kaufman stated that because PSI's common stock was not publicly traded, one could not apply the DCF or CAPM model directly to PSI. Rather, PSI's **[*52]** cost of equity could be estimated only through the use of a proxy group. Pub. Ex. No. 8, p. 8. He first applied the DCF and CAPM analysis to Dr. Morin's selection of vertically integrated electric utilities as a proxy group. Pub. Ex. No. 8, p. 11. He also examined his own proxy group of electric utilities, using a set of screening criteria that yielded a similar but not identical selection to that used by Dr. Morin. Mr. Kaufman also used Cinergy as a proxy for PSI. Pub. Ex. No. 8, p. 11. The main difference between the criteria Mr. Kaufman used to form his proxy group and that which Dr. Morin used was that Mr. Kaufman included a combination of electric and gas companies in his proxy group and required companies he used in his proxy group to derive at least 75% of revenues from electric operations (instead of 50%, as used by Dr. Morin). Pub. Ex. No. 8, p. 11. Mr. Kaufman explained that he believes that all three of the selected proxy groups in his analysis are notably riskier than PSI because of the group members exposure to power market trading and foreign operations. Pub. Ex. No. 8, p. 13.

In doing his DCF analyses, Mr. Kaufman used the Turner Reports for current dividend yields **[*53]** of large publicly held utilities, converting the current yield to a forward yield by multiplying the current yield by 1 + 1/2 of the Company's expected growth rate. He noted that this conversion methodology has been regularly accepted by the Commission in prior rate proceedings. Pub. Ex. No. 8, pp. 16-17. To estimate the growth rate, Mr. Kaufman employed both historical and forecasted growth rates of earnings, dividends and book value per share, using Value Line as the primary source of growth data. The estimated growth rates that he used were 4.35% for his primary proxy group, 4.18% for Dr. Morin's vertically integrated electric utility proxy, and 2.90% for Cinergy. Pub. Ex. No. 8, p. 18. In an effort to ensure that his analysis was conservative Mr. Kaufman did not include any negative or very low positive growth figures in his analysis. Pub. Ex. No. 8, p. 18. Mr. Kaufman reviewed his estimate of long run growth rates by reference to Reuters Multex.com and CA Turner's Quarterly Dividend Monitor reported data. Pub. Ex. No. 8, p. 19.

Mr. Kaufman prepared multiple DCF analyses intended to allow him to cross check results and examine the impacts of alternative data sources. He summarized **[*54]** these alternative analyses in a chart within his testimony that reflects 3 and 6 month average dividend yields:

	3-month	**6-month**
Value Line (Primary Proxy)	9.09%	9.31%
Multex (Primary Proxy)	9.80%	10.02%
Value Line (Dr. Morin's Proxy)	9.12%	9.43%
Multex (Dr. Morin's Proxy)	9.81%	10.12%
Cinergy (Value Line)	7.94%	8.24%
Cinergy (Multex)	9.71%	10.02%

Mr. Kaufman's initial prefiled range of common equity costs for his DCF methodology ranged from 7.94% to 10.12%. Pub. Ex. No. 8, p. 21. His October Update reflected a narrower range of DCF results from 8.02% to 9.62%. Pub. Ex. No. 8U, Schedule 1, p. 1.

	3-month	6-month
Value Line (Primary Proxy)	9.15%	9.11%
Multex (Primary Proxy)	9.53%	9.49%
Value Line (Dr. Morin's Proxy)	9.17%	9.19%
Multex (Dr. Morin's Proxy)	9.59%	9.62%
Cinergy (Value Line)	8.02%	8.21%
Cinergy (Multex)	9.48%	9.67%

Mr. Kaufman employed the same proxy groups that he used in his DCF analysis and explained that he believes that the CAPM is typically less reliable than the DCF model because of challenges associated with estimating the market risk premium; issues concerning the application of arithmetic versus geometric means; and, controversies **[*55]** surrounding the basis selected for the risk-free return rate. Pub. Ex. No. 8, pp. 23-25.

For his CAPM risk-free rate, Mr. Kaufman reviewed short term, intermediate term and long term interest rates, ultimately using 30-year Treasury securities as an estimate of long-term yields, and giving virtually no weight to short term and intermediate term interest rates. Pub. Ex. No. 8, p. 26. In an effort to produce a result that is more consistent with the long term perspective needed for cost of equity, Mr. Kaufman used both 3-month and 6-month average yields, rather than a spot yield that might subject his results to unreasonable variability. Pub. Ex. No. 8, p. 26.

Mr. Kaufman's CAPM calculations relied primarily upon Value Line's published betas, but he also reviewed and presented two other sources of beta, derived from Security Risk Evaluation by Merrill Lynch and SmartMoney.com. Pub. Ex. No.8, p. 27. A review of the other betas presented by Mr. Kaufman demonstrates that the betas he relied upon were the largest betas from the three sources that he reviewed. Mr. Kaufman calculated both a geometric mean risk premium and an arithmetic mean risk premium, then averaged the risk premiums, multiplied **[*56]** the average by beta, and combined the product with the risk-free interest rates of long term Treasury securities, producing three CAPM results. Mr. Kaufman supported his use of both the geometric and arithmetic mean risk premium by quoting from a 1982 edition of *Stocks Bonds Bills and Inflation*, by Dr. Roger Ibbotson and from two final orders of this Commission, *People's Gas and Power*, Cause No. 39315, (*Ind. Util. Reg. Comm'n*, October 21, 1992) and *Indiana American Water*, Cause No. 40103, (*Ind. Util. Reg. Comm'n*, May 30, 1996). OUCC Exhibit 8, Kaufman Direct, page 24 line 17 through page 25 line 18. Mr. Kaufman's primary CAPM proxy group relied upon a beta of 0.610, as compared with the average beta for Dr. Morin's proxy group of 0.642 and Cinergy's beta of 0.70. Pub. Ex. No. 8, p. 27.

Mr. Kaufman's CAPM study results are summarized in the following table:

	3 month	6 month
Primary proxy group	7.98%	8.09%
Dr. Morin's proxy	8.15%	8.26%
Cinergy	8.48%	8.59%

Mr. Kaufman's October Update to his CAPM analysis showed the following increases from the results of his direct testimony:

	3 month	6 month
Primary proxy group	8.81%	8.50%

Dr. Morin's proxy	8.79%	8.48%
Cinergy	9.09%	8.78%

[*57]

Mr. Kaufman's cost of equity ("COE") results in his initial prefiled testimony ranged from 7.94% to 10.12%, with the midpoint of his range at 9.03%. Pub. Ex. No. 8, p. 29. Giving more weight to his DCF results, Mr. Kaufman concluded in his initial prefiled testimony that Petitioner's cost of equity was 9.15%. In his October Update he concluded that cost of equity had increased 10 basis points to 9.25%. Pub. Ex. No. 8U, p. 6, and Pub. Ex. No. 8, p. 29.

Mr. Kaufman indicated on cross-examination that, while his updated recommended cost of equity for PSI increased, the bottom-end of his updated range increased (from 7.94% to 8.02%) and the top-end of his updated range came down significantly (from 10.12% to 9.67%). Tr. at Q86-Q88. Mr. Kaufman also acknowledged that there was no specific numerical weighting assigned by him to arrive at his estimate of cost of equity for PSI. Tr. at Q88. Mr. Kaufman further acknowledged that he basically combined them and reached his ultimate conclusion concerning his recommended cost of equity for PSI. Tr. at Q88.

Mr. Kaufman testified on cross-examination that he believes that his 9.25% cost of equity for PSI should be reduced if this Commission approves **[*58]** PSI's proposed trackers in this proceeding, as trackers serve to reduce risk. Mr. Kaufman explained that he was not independently testifying to that conclusion; but instead was merely summarizing the testimony of other OUCC witnesses who address the risk mitigation effects of such trackers. Tr. at Q92-Q93 and Q98. Mr. Kaufman clarified on cross-examination that his reference to PSI's proposed trackers that reduce risk, and therefore require a reduction in PSI's cost of equity, do not include PSI's existing: (i) Fuel Cost Charge tracker; (ii) Demand-Side Management tracker; (iii) Construction Work In Progress tracker; or (iv) Sulfur Dioxide Emission Allowance tracker. Tr. at Q93-Q97. Instead, Mr. Kaufman testified that he was only referring to PSI's newly proposed: (i) Nitrogen Oxide Emission Allowance tracker; (ii) Midwest ISO Management Cost and Revenue Adjustment tracker; and (iii) Purchased Power tracker. Tr. at Q97-Q98. n2

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n2 Mr. Kaufman stated that he had not quantified a specific basis point adjustment to his recommended 9.25% cost of equity for PSI if this Commission approved any combination of those three proposed trackers. Tr. at Q98-Q100. Mr. Kaufman also stated during cross examination that he had asked PSI to quantify the value of PSI's proposed trackers in a data request and that PSI had failed to provide him with a response on that issue. Tr. at Q98.

- - - - - - - - - - - - End Footnotes- - - - - - - - - - - - - - **[*59]**

Mr. Kaufman noted that Dr. Morin's proxy groups contain some electric utilities that were not comparable to PSI. Pub. Ex. No. 8, pp. 36-37. Mr. Kaufman also explained how Dr. Morin's exclusive reliance on forecasted earnings per share in arriving at a growth rate for the DCF method, while ignoring actual growth in dividends per share and book value per share tended to overstate the cost of equity. Pub. Ex. No. 8, pp. 37-38. Mr. Kaufman was also critical of Dr. Morin's method for increasing the actual current dividend yield to a future yield by multiplying the current yield by one plus the Company's expected growth rate, rather than one plus one-half the expected growth rate. Mr. Kaufman supported his one plus one-half growth position by quoting from prior Commission orders and argued that Dr. Morin's full year growth adjustment inappropriately assumes a full year's worth of growth, while a half-year growth adjustment for converting a current yield into a forward annual yield for the DCF model is more appropriate. Pub. Ex. No. 8, pp. 37-39. He was further critical of the fact Dr. Morin's growth rate forecasts were applicable to the next 5-7 years, rather than in perpetuity. Pub. Ex. **[*60]** No.8, p. 39.

Mr. Kaufman also responded to Dr. Morin's argument that many electric utilities have experienced low or negative growth over the last several years, and criticized Dr. Morin's use of Green Mountain Power's forecasted earnings rate of 19.5% per year. Mr. Kaufman explained that historical data can be used in determining a growth rate for a DCF analysis only if such dramatic "outliers" are removed from the analysis. Pub. Ex. No. 8, pp. 40-42. Mr. Kaufman defended the use of historical data and criticized Dr. Morin's analysis in exhibit RAM-9 which purportedly demonstrates that it is inappropriate to use historical growth rates. Mr. Kaufman noted that many of the companies used by Dr. Morin in RAM-9 are not used by Dr. Morin in his DCF analysis, and contends that if one removes outliers and uses reasonable judgment any concerns about using historical growth rates can be alleviated. Mr. Kaufman added that at the current retention ratios employed by most utilities, the dividend growth rates predicted by Dr. Morin's DCF models are not supportable. Pub. Ex. No. 8, pp. 46-47.

Mr. Kaufman further criticized Dr. Morin for: (a) relying exclusively on intermediate-term forecasts in **[*61]** earnings per share to estimate the growth rate in dividends for his DCF model; (b) his failure to use historical growth data; and (c) adjusting his DCF models by 20 basis points to account for the quarterly timing of dividends. n3 Mr. Kaufman also disagreed with the market risk premium used by Dr. Morin in his CAPM analysis, as well as Dr. Morin's exclusive reliance on the arithmetic mean return to estimate his historic risk premium. Pub. Ex. No. 8, pp. 51 and 53. Mr. Kaufman noted that Dr. Morin's reliance on income returns, rather than total returns, overstates the market risk premium in his CAPM analysis. Mr. Kaufman explained that, while Dr. Morin relies on Ibbotson Associates ("Ibbotson") to support his use of income returns versus total returns, Mr. Kaufman believes that Ibbotson's conclusion is illogical on this point and actually supports a lower, rather than higher, risk premium. Pub. Ex. No. 8, pp. 53-55.

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n3 Mr. Kaufman noted that the Commission has accepted the quarterly dividend adjustment in prior cases, but indicated that he believes that if this approach is utilized a corresponding downward adjustment should be made to account for the timing of how a utility earns its profits (and invests them during the year). Pub. Ex, No. 8, pp. 48-49.

- - - - - - - - - - - - End Footnotes- - - - - - - - - - - - - - **[*62]**

Mr. Kaufman further testified in response to Dr. Morin's estimate of a prospective market risk premium, and explained that Dr. Morin's analysis was based on a DCF model, adjusted to capture a full year's future growth, which overstates the forward yield. Mr. Kaufman indicated that Dr. Morin's model compounds that error by inappropriately adjusting for quarterly timing of dividends. He added that Dr. Morin's aggregate market data produces an unusually high dividend yield of 2.5%, particularly in relation to Value Line's calculated averages of 2.1%. Pub. Ex. No. 8, pp. 55-57. He was further skeptical of Dr. Morin's 2.5% figure because his calculation included non-dividend paying companies, whereas Mr. Kaufman's Value Line data excluded those companies, logically meaning Dr. Morin's results should be lower, not higher, than Mr. Kaufman's. Mr. Kaufman questioned Dr. Morin's exclusive reliance on long-term government yields, as a proxy for his risk-free rate of return, claiming that it is also appropriate to consider other maturities as a proxy for the risk free rate of return. Pub. Ex. No. 8, p. 57.

Mr. Kaufman also responded to Dr. Morin's testimony regarding an upward adjustment to

[*63] beta for delayed recognition within beta of changes in risk fundamentals. Mr. Kaufman noted that Dr. Morin made a similar argument in PSI's last rate case and indicated that Cinergy's beta has declined since PSI's last rate case. Mr. Kaufman also indicated that he believes that Dr. Morin's ECAPM analysis is redundant, and notes that this type of analysis was rejected by the Commission in PSI's last rate case as the use of adjusted beta already increases beta for companies with a beta that is below 1.0. Pub. Ex. No. 8, p. 64.

With respect to Dr. Morin's RP models, Mr. Kaufman indicated that Dr. Morin's failure to include 2002 data in his risk premium analysis very likely serves to artificially overstate the historical risk premium. Pub. Ex. No. 8, pp. 65-66. He also noted that most of Dr. Morin's RP models were biased as they are based on an arithmetic mean risk premium. Pub. Ex. No. 8, p. 67. Mr. Kaufman further indicated that Dr. Morin's risk premium models do not react to changes in capital markets and should be given little if any weight.

Mr. Kaufman noted that the Commission has accepted the quarterly dividend adjustment in prior cases, but indicated that he believes that if this **[*64]** approach is utilized a corresponding downward adjustment should be made to account for the timing of how a utility earns its profits (and invests them during the year). Pub. Ex, No. 8, pp. 48-49.

Mr. Kaufman challenged Dr. Morin's proposed 30 basis point upward adjustment to the cost of equity to account for, what he believes to be, overstated flotation costs. Mr. Kaufman explained that actual flotation costs associated with Cinergy's most recent stock issuance amounted to $ 1.55 million, or less than 1% of the stock issue. Mr. Kaufman stated that while he believes that some adjustment for flotation costs is merited, he recommends the adjustment be only 5-10 basis points. Mr. Kaufman stated that the flotation cost adjustment proposed by the OUCC would increase PSI's net operating income ("NOI") by approximately $ 1.1 million per year whereas the Petitioner's proposed adjustment would increase PSI's NOI by approximately $ 5.5 million per year. Pub. Ex. No. 8, pp. 75-76. Mr. Kaufman noted that the Commission rejected Dr. Morin's overstated estimate of flotation costs in the last PSI rate, case, Cause No. 40003. Pub. Ex. No. 8, pp. 75-77.

OUCC witness Timothy Geswein testified regarding **[*65]** the general business risk levels faced by PSI and in response to observations made by PSI witness Rogers regarding industry risks. Mr. Geswein explained that, as a regulated monopoly energy provider, PSI Energy is insulated from many risks and feels few direct impacts from national economic events of the type referenced by Mr. Rogers. He characterized PSI Energy as a "low-risk regulated, franchise monopoly" for which even the Company's regulatory risks have been mitigated.

OUCC witness Dr. Peter Boerger testified in response to Mr. Reising regarding his analysis and discussion regarding PSI's risk profile, and noted that every business faces risks, but that the state's grant of a monopoly service territory to PSI causes electric utilities to be viewed as low risk enterprises despite the factors raised by Mr. Reising. Pub. Ex. No. 5, pp. 3-4. Dr. Boerger also indicated that legislation enacted since PSI's last rate Case has favorably affected the Company's risk profile. Changing the Fuel Adjustment Charge ("FAC") earnings test under IC 8-1-2-42.3 has reduced the probability that PSI would return excess earnings to ratepayers, compared to the situation that existed during the last rate **[*66]** case. In 2002, new financial incentive and cost recovery mechanisms for coal-fired investment and related environmental expenditures were enacted within IC 8-1-8.8 that may allow PSI to track increased depreciation and operation and maintenance ("O&M") for its new NO[X] investments. These legislative changes should be considered as reducing the company's cost of equity below that which would be required in the absence of such legislation. Pub. Ex. No. 5, pp. 12-13.

Dr. Boerger also explained the need to segregate the risks imposed on PSI Energy by its parent in determining the utility's cost of capital. He notes Cinergy's involvement in recent years with relatively risky merchant activities and the role of PSI to sponsor a large power trading operation, explains how Standard & Poors attributed such higher-risk nonregulated activities to both Cinergy and PSI in its publications. Pub. Ex. No. 5, p. 14. Dr. Boerger noted that a substantial share of the risk facing the company has been mitigated, and the cost of that mitigation is being paid already by Indiana consumers. Pub. Ex. No. 5, p. 15.

(3) PSI-IG's Cost of Common Equity Evidence. Michael Gorman testified for the PSI-IG and **[*67]** recommended that PSI's cost of common equity capital should be in the range of 9.7% to 10.3% and that PSI's authorized return on equity in this case not exceed 10%. PSI-IG Ex. No. 3, p. 2. He based his recommendation on a DCF analysis (10.1%), an RP analysis (9.9%-10.3%), and a CAPM model (9.7%). PSI-IG Ex. No. 3, p. 2. He stated that Cinergy's use of leveraging and entry into more risky power/gas trading and a merchant generation operation had created credit rating pressure on PSI. Mr. Gorman maintained that rates should not be set in a way that will allow PSI to contribute dividends in excess of reasonable levels to its parent company to help accelerate the pay-down of parent company debt related to failed unregulated business investments. PSI-IG Ex. No. 3, p. 3. On cross-examination Mr. Gorman acknowledged that he was not aware of any year since the formation of the Cinergy Corp. holding company structure in which the Cinergy operating companies had funneled up to Cinergy Corp. cash in excess of the Cinergy Corp. annual dividend. Tr. at T35-T36. Mr. Gorman agreed with PSI's proposed capital structure, consisting of common equity, preferred stock and long-term debt, but not short-term **[*68]** debt. PSI-IG Ex. No. 3, p. 7.

Mr. Gorman testified that the *Bluefield* and *Hope* cases have established that the return for a public utility should: (i) be sufficient to maintain financial integrity; (ii) attract capital under reasonable terms; and (iii) be commensurate with returns investors could earn by investing in other enterprises of comparable risk. PSI-IG Ex. No. 3, p. 11. Mr. Gorman also testified that the utility's cost of common equity is the return that investors expect, or require, in order to make an equity investment in the utility. PSI-IG Ex. No. 3, p. 11. Mr. Gorman also testified that it is extremely difficult, if highly impractical, to eliminate all higher equity return component premiums to compensate for deregulated market risks. PSI-IG Ex. No. 3, p. 13.

In doing his DCF analysis and RP estimates for PSI, Mr. Gorman used the group of electric utility companies that Dr. Morin selected for his analysis, agreeing that this group is reasonably comparable to PSI. PSI-IG Ex. No. 3, p. 12, and PSI-IG Ex. No. 3, Schedule 1. In his constant growth DCF analysis, Mr. Gorman relied upon the average of the weekly high and low stock prices over a 13-week period ending **[*69]** July 14, 2003. PSI-IG Ex. No. 3, p. 14. He also used the most recently paid quarterly dividend, as reported in Value Line, which he annualized and adjusted for the next year's growth to produce the adjusted dividend rate that he used. PSI-IG Ex. No. 3, p. 14.

With respect to dividend growth rates, Mr. Gorman relied on a consensus of professional security analysts as a proxy for investor consensus of future dividend growth rate expectations. Mr. Gorman testified that security analyst growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data. He used the average of three sources of growth rate estimates, including Zack's Detailed Analyst Estimates, First Call and Multex.com Investors. The consensus estimate was a simple arithmetic average or mean of surveyed analysts' earnings growth forecasts.

The result of his DCF analyses was a cost of common equity of 10.1%. PSI-IG Ex. No. 3, p. 16. He said that his comparable group average five-year growth rate of 4.65% is sustainable over an indefinite period of time, because it does not exceed the growth rate of the overall U.S. economy, which, is estimated to grow at a rate **[*70]** of 5.6%. According to Mr. Gorman, this represents a ceiling for a sustainable growth rate for a utility over an indefinite period of time. PSI-IG Ex. No. 3, p. 16.

With respect to Mr. Gorman's RP analysis, his first such model estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds over the period 1986 through 2002, using regulatory commission authorized common equity returns for electric utility companies. PSI-IG Ex. No. 3, p. 17. His second equity RP method was based on the difference between regulatory commission authorized returns on common equity and contemporary A-rated utility bond yields, over the period 1986 through July, 2003. PSI-IG Ex. No. 3, p. 17. This analysis, he said, showed an average indicated equity RP of authorized electric utility common equity returns over U.S. Treasury bonds of 4.86%. PSI-IG Ex. No. 3, p. 17 and Schedule 5. Mr. Gorman testified that his average indicated equity RP authorized electric utility common equity returns over contemporary Moody's utility bond yields was 3.43%, and, removing the two highest and lowest premium estimates, produced an equity RP in the range of 3% to 4% over that **[*71]** period. PSI-IG Ex. No. 3, p. 18 and Schedule 6. Using the long-term Treasury bond yield of 5.3% (projected by Blue Chip Financial Forecasts) and an equity risk premium of 4.4% to 5.6%, produced an estimated common equity return in the range of 9.7%-10.9%, with a midpoint estimate at 10.3%. PSI-IG Ex. No. 3, p. 18. Adding his equity risk premium of 3% to 4% over utility bond yields to the average yield on a utility bond with an A-rating for a 13-week period ending July 11, 2003 of 6.37%, produced a cost rate for common equity in the range of 9.4% to 10.4%. PSI-IG Ex. No. 3, p. 18.

With respect to his CAPM approach, Mr. Gorman started with the Blue Chip Financial Forecasts for projected long-term Treasury bond yields of 5.3% for his risk-free cost rate. PSI-IG Ex. No. 3, p. 20. He used a beta of 0.64 obtained by averaging the group betas for his comparable group of electric utilities. PSI-IG Ex. No. 3, p. 21 and Schedule 8. He derived two market based premium estimates, one forward looking and one based on long-term historical average. He estimated the expected return on the Standard & Poor's ("S&P") 500 by adding an expected inflation rate of 2.2%, to the long-term historical arithmetic **[*72]** average real return on the market. He produced an estimated return of 9.4%. PSI-IG Ex. No. 3, p. 21. The market premium is the difference, he said, between the 11.8% expected market return and his 5.3% risk-free estimate, or 6.5%. PSI-IG Ex. No. 3, p. 21. Using Ibbotson's arithmetic average of achieved total returns on the S&P 500 of 12.7% and the total return on long-term Treasury bonds of 5.7%, produced an indicated equity risk premium of 7.0%. His CAPM estimated return on common equity ranged from 9.5% to 9.8%. PSI-IG Ex. No. 3, p. 22. He concluded that PSI's cost of common equity was in a range from 9.7% to 10.3%. PSI-IG Ex. No. 3, p. 22.

Mr. Gorman was critical of Dr. Morin's original recommendation of an 11.5% cost of common equity. PSI-IG Ex. No. 3, pp. 24-25. Mr. Gorman said that in his CAPM analysis Dr. Morin used a beta of 0.72 which was considerably higher than the actual Value Line beta of 0.65 for his investment grade vertically integrated electric utility companies. His use of a beta higher than his electric utility sample increased his result. PSI-IG Ex. 3 pp. 25-26. Mr. Gorman also took issue with Dr. Morin's 30 basis point adjustment for flotation costs. *Id.* Mr. **[*73]** Gorman also did not accept Dr. Morin's ECAPM analysis. Mr. Gorman testified that that the Value Line beta Dr. Morin relied on to estimate a utility beta is already adjusted for the tendencies of betas lower than one to increase toward a market beta of one over time. Thus Dr. Morin's adjustment is redundant. PSI-IG Ex. No. 3, p. 26.

With respect to Dr. Morin's historical RP analysis, Mr. Gorman was critical of Dr. Morin's achieved return on utility stocks, compared with Treasury securities and utility bond yields. PSI-IG Ex. No. 3, p. 27. He said that the yields on Treasury securities and utility bonds have been depressed by the dramatic decrease in interest rates over the last 20 years. PSI-IG Ex. No. 3, pp. 27-28. He stated further that the achieved returns on the utility stocks and yields on utility bonds over the last several years have been driven by high expectations of large profits produced by competitive operations related to the wholesale market trading and merchant plant development. PSI-IG Ex. No. 3, p. 28. This, he said, gave the indicated equity risk premium a bias upward. PSI-IG Ex. No. 3, p. 28.

Mr. Gorman also took issue with Dr. Morin's computation of an allowed risk **[*74]** premium on electric utilities. He said that Dr. Morin arbitrarily selected the time period 1993 through 2002 to estimate the spread between regulatory-authorized returns on equity and contemporary utility bond yields and Treasury bond yields. Mr. Gorman also questioned the implication in Dr. Morin's approach, that a utility's equity risk increases with decreases in interest rates. Mr. Gorman further testified that he thought that Dr. Morin's additions of an equity risk premium to contemporary utility bond yields may overstate a fair return for regulated utility operations. PSI-IG Ex. No. 3, p. 30. He said that current bond yields are affected by the much higher risk of non-regulated energy markets, and said that the average authorized return on equity above contemporary energy industry bond yields produces a return on equity that may exceed that appropriate for lower risk regulated operations. PSI-IG Ex. No. 3, pp.30-31.

In discussing Dr. Morin's DCF analyses, Mr. Gorman claimed that the information supporting Dr. Morin's analyses was stale and needed to be updated. PSI-IG Ex. No. 3, p. 33. Mr. Gorman criticized Dr. Morin's proposal for a 30-basis point flotation cost adjustment. **[*75]** Mr. Gorman said that PSI should not be accorded flotation costs, because it is a wholly-owned subsidiary of Cinergy and does not sell its stock to the public. PSI-IG Ex. No. 3, pp. 34-35. He added, however, that if it is reasonable to allocate a portion of Cinergy's flotation expenses to PSI, PSI should be required to account for those expenses. PSI-IG Ex. No. 3, p. 35. Mr. Gorman also questioned Dr. Morin's proposal for a 20-basis point adjustment to reflect quarterly dividend compounding, claiming that it provides investors an opportunity to earn the dividend reinvestment return twice, once through the authorized return on equity and a second time when dividends are received by investors and actually reinvested by investors. PSI-IG Ex. No. 3, p. 33.

Mr. Gorman testified that he believes a commission should exercise its judgment, based on the arguments and positions taken by the expert witnesses, in determining the fair rate of return for the utility. Tr. at T27. In this regard, Mr. Gorman indicated that relevant considerations for a commission in determining a utility's fair rate of return include the utility's financial condition, the prospects for a credit rating downgrade for **[*76]** the utility, and the utility's performance in rendering utility service. Tr. at T28-T30. Mr. Gorman further testified that, in determining the fair rate of return for a utility, a commission should be forward-looking and consider business, financial, regulatory, and other issues likely to be experienced by the utility while the rates approved are expected to be in effect. Tr. at T29. Mr. Gorman acknowledged that the fair rate of return authorized for a utility could be different than the estimated cost of capital for the utility. Tr. at T30-T31.

(4) CAC Evidence on Cost of Equity. Dr. Michael F. Sheehan testified on behalf of CAC and addressed certain factors which are relevant to PSI's risk and ROE. He noted that in regulatory proceedings, risk has a significant impact on the determination of the return on equity and provided an assessment of how the industry and PSI's risks have changed, with specific reference to the many supportive and risk-reducing regulatory structures that have been adopted by this Commission. While Dr. Sheehan did not sponsor specific calculations of risk premiums or adjustments to PSI's return on equity, his testimony provides an overview of PSI's level **[*77]** of risk that is relevant to our overall consideration of the fair return for PSI.

Dr. Sheehan noted that he believes that since PSI's last rate case in Cause No. 40003, Cinergy has adopted a policy of gradually shifting risk from the holding company to PSI ratepayers. This was done through requests for preapprovals of investment expenditures; preapprovals of cost deferrals to subsequent rate cases; and, the adoption of a growing number of trackers, such that much of the revenue requirement is now governed by trackers. CAC Ex. C, p. 31. He explained that the regulatory mechanisms have shifted risks to ratepayers as, without the use of trackers, cost increases occurring between rate cases would have to be absorbed by the utility. With the use of trackers cost increases are automatically passed on to ratepayers in higher rates as they occur. These shifts in risk, according to Dr.

Sheehan, argue for elimination of some of the risk premium received by the utility in the ROE determination. CAC Ex. C, p. 33.

Mr. Bruce Biewald also testified on behalf of CAC on the subject of PSI risk exposure and return on equity. Mr. Biewald indicated that the Commission should consider, in determining **[*78]** whether the Company's requested ROE is excessive, the risk reduction effect that has occurred due to the Company's existing and proposed trackers and pre-approved costs; and, whether the approval of the Company's merchant plant acquisition acted to shift risks from Cinergy to PSI customers regarding the investment in those plants. CAC Ex. B, p.7.

Mr. Biewald explained that he believes the Company's various special rate riders and its CWIP tracker have allowed the recovery of 8.4% of its operating income during the test year. CAC Ex. B, pp. 8-9. He noted that in addition to the existing Riders 60,62,63,66 and 67, PSI is seeking approval for new proposed trackers in the form of Rider 68 (MISO), Rider 69 (NO [X]) and Rider 70 (Purchased Power). CAC Ex. B, p. 9. According to Mr. Biewald, the Company's rate tracking mechanisms effectively reduce its shareholders' exposure to risk in that they: (1) reduce regulatory lag; (2) allow certain significant categories of costs (e.g. environmental costs) that increase to be put into rates without consideration of other, related categories of costs (e.g. cost of capital) that decrease; (3) tend to defer general rate cases with their attendant risks **[*79]** and costs; and, (4) tend to decrease the scope and detail of regulatory review of tracked costs compared to a general rate case. In addition, Mr. Biewald noted, "such riders can, in many situations, greatly reduce volatility of net earnings on a monthly, quarterly and annual basis." CAC Ex. B, p. 10.

With respect to Dr. Morin's peer group of utility companies used to calculate his ROE, Mr. Biewald noted that PSI has the highest number of trackers among the 26 utility companies, and is one of only two companies that have trackers for perhaps the four most significant cost categories that are commonly tracked: 1) fuel adjustment; 2) purchased power; 3) environmental cost recovery; and, 4) emission allowances. According to Mr. Biewald's analysis, the large number of PSI's rate adjustment trackers relative to its industry peers suggest that the Company is relatively well protected against many risks to which other utilities are often exposed. CAC Ex.B, p.11

(5) Testimonial Staff's Testimony. In his testimony Mr. Inman indicated that he did not prepare an independent cost of equity study for PSI, choosing instead to analyze the cost of equity estimates of PSI and other parties in the **[*80]** case. IURC Staff Ex. No. 1, p. 3. Mr. Inman agreed with Dr. Morin's 20-basis point quarterly dividend adjustment to reflect the fact that current stock prices, which reflect expected quarterly dividend payments, are lower than the standard DCF result suggests. IURC Staff Ex. No. 1, p. 5. Logic dictates, he said, that an upward adjustment to the standard DCF model would correct the understatement. IURC Staff Ex. No. 1, p. 5. Mr. Inman also testified that, in the DCF model, the current dividend yield must be adjusted to reflect the expected dividend yield. Mr. Inman indicated that there are two common methods which calculate the expected, or forward, dividend yield -- full-year and half-year. Citing recent Commission proceedings, Testimonial Staff recommended use of the half-year method of calculating forward dividend yield. IURC Staff Ex. No. 1, p. 5. Mr. Inman further noted that Dr. Morin's DCF results were higher in his March 2003 profiled testimony than those produced by other methods of determining the cost of common equity capital. n4 Mr. Inman stated that Staff's final DCF recommendations begin with Dr. Morin's current yield data and growth forecasts for each of his DCF calculations **[*81]** and adjust for the half-year dividend yield method, a quarterly dividend adjustment and direct flotation costs. IURC Staff Ex. No. 1, p. 7.

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n4 However, this changed in Dr. Morin's October 2003 update which showed that his October

2003 DCF results were below his October 2003 CAPM and RP results. Pet Ex. G, p. 46; and Pet. Ex. TT, p. 3.

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With respect to the CAPM model, Testimonial Staff used the February to July 2003 six-month average of 30-year Treasury bond yields to obtain a rate of 4.86%. This average was used to smooth out the recent swings in long-term bond yields. IURC Staff Ex. No. 1, p. 8. By comparison, Dr. Morin used 5.0% in his initial testimony, and 5.3% in his updated testimony. Pet. Ex. G, p. 16; and Pet. Ex. TT, p. 3. Mr. Inman anticipated the higher interest rate in Dr. Morin's update and stated in his September 2003 prefiled testimony that considering the bottoming out of interest rates and the recent upswing in long-term bond yields, it would not be surprising if Dr. Morin chooses to leave his estimate **[*82]** as it is or even revises it upward. IURC Staff Ex. No. 1, p. 8.

Mr. Inman indicated that Testimonial Staff did not dispute Dr. Morin's use of the 0.72 Value Line suggested beta in his CAPM calculations. IURC Staff Ex. No. 1, p. 9. For the market rate of return, Staff agreed with Dr. Morin's use of the period beginning 1926 and extending through the most recent available year as this takes into account nearly all economic scenarios and is most representative of all possible returns. IURC Staff Ex. No. 1, p. 9. However, while supporting this approach, Mr. Inman observed that Dr. Morin failed to include 2002 data in his calculation of the market risk premium. To adjust for this deficiency, Mr. Inman included 2002 data in his market risk premium calculation to ensure that his calculation accurately reflects data extending through this period. Mr. Inman stated that Testimonial Staff supported giving weight to both the arithmetic and geometric means of computing annual growth rates. IURC Staff Ex. No. 1, pp. 12-13.

Mr. Inman said that Testimonial Staff believes that the proper market risk premium to be used in this case should include total return on long-term Treasury bonds, and not just **[*83]** income thereon. Adjusting Dr. Morin's results for use of total return on long-term bonds, and giving equal weight to the arithmetic mean and the geometric mean market risk premiums, Testimonial Staff arrived at a market risk premium of 5.55%. IURC Staff Ex. No. 1, p. 14. Testimonial Staff used Dr. Morin's 6.1% prospective risk premium, resulting in a CAPM market risk premium input of 5.83%, which produced a CAPM estimate of PSI's cost of common equity of 9.05%. Mr. Inman said that the primary reasons for the 85 basis point difference between Staff's and Dr. Morin's original unadjusted CAPM estimates are: (i) Staff's use of then more current, lower risk-free rates; (ii) Staff's use of lower market risk premium due to inclusion of 2002 data; (iii) Staff's equal weighting of the geometric and arithmetic mean risk premiums; and (iv) Staff's use of 30-year Treasury bond total return. IURC Staff Ex. No. 1, p. 15.

With respect to flotation costs, Staff recommended allowing one-half of Dr. Morin's proposed flotation cost adjustment, which would amount to a 15 basis point adjustment to the CAPM and RP methods, and a 2.5% gross up of the dividend yield produced by the DCF method. IURC Staff **[*84]** Ex. No. 1, p. 17. Testimonial Staff recommended rejection of Dr. Morin's ECAPM calculation on the grounds that the Value Line beta already contains an adjustment of beta, therefore it was unnecessary for Dr. Morin to make a further adjustment of beta. IURC Staff Ex. No. 1, p. 17.

With respect to the RP method Mr. Inman, in conformity with previous Commission orders, adjusted Dr. Morin's RP calculations by equally weighting the arithmetic and geometric mean risk premium, using Dr. Morin's source data. IURC Staff Ex. No. 1, p. 18. Testimonial Staff then adjusted Dr. Morin's flotation costs to allow for direct costs only and updated his 30-year Treasury bond data and A-rated utility bond yields. IURC Staff Ex. No. 1, p. 18. Testimonial Staff accepted Dr. Morin's statistical analyses of hundreds of risk premiums allowed by state regulatory commissions over a 10-year period compared with long-term Treasury bond yields, but observed that Dr. Morin's results do not account for the differences in risk factors that may have been considered by the various state commissions in the hundreds of data points. IURC Staff Ex. No. 1, pp. 18-19. For that reason, Testimonial Staff said, the results of **[*85]** Dr. Morin's allowed RP calculations are questionable. IURC Staff Ex. No. 1, p. 19.

Giving somewhat less weight to the DCF results than Dr. Morin, Testimonial Staff produced lower results, concluding that a reasonable cost of common equity would be in the range of 10.25% to 10.50%, which, as Mr. Inman observed, falls in the lower end of Dr. Morin's suggested range of 10.2% to 13.6%. IURC Staff Ex. No. 1, p. 19. In his oral direct testimony, Mr. Inman updated his reasonable range of cost of equity for PSI to 10.35% to 10.55%. Tr. at T51-T52. Mr. Inman noted that Staff offered several different weighting mechanisms for consideration to provide this Commission with options based upon previous Commission orders which have given less weight to the DCF method. IURC Staff Ex. No. 1, p. 19. Staff's different weighting mechanisms included a 8%/46%/46% CAPM/RP/DCF (excluding ECAPM) weighting which produced a top-end 10.96% cost of equity, and a 40%/40%/20% CAPM/RP/DCF (excluding ECAPM) weighting which produced a low-end 10.24% cost of equity. IURC Staff Ex. No. 1, p. 20.

Mr. Inman observed that Regulatory Research Associates, Inc. ("RRA") tracks major rate case decisions by state commissions. **[*86]** Mr. Inman testified that RRA reported that the average cost of equity authorized by state commissions for the electric industry for the first six months of 2003 was 11.38%, and 11.16% for all of 2002. IURC Staff Ex. No. 1, p. 22. Mr. Inman stated on cross-examination that RRA reported that the average cost of equity authorized by state commissions for the electric industry for the first nine months of 2003 was 10.91%, which could be 11% if you excluded the 9.5% awarded to New Jersey Central Power & Light. n5 Tr. at T106-T107. Mr. Inman observed that Dr. Morin's original 11.5% recommendation falls just above the midpoint, and Staff's recommended range falls in the lower end, of the range RRA reported thus far for 2003. IURC Staff Ex. No. 1, p. 22.

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n5 We note that this August 1, 2003 decision was premised, in large part, in response to quality of service problems of the utility and that the 9.5% was only put into effect on an interim basis. *See*, 2003 N.J. PUC LEXIS 253 and 2003 N.J. PUC LEXIS 243.

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Observing that the determination of an exact investor required return on equity is impossible, Mr. Inman said that finding a range of reasonableness for ROE is more realistic. IURC Staff Ex. No. 1, p. 22. He observed that experts and non-experts alike will agree that the results of the CAPM, RP and DCF methods are driven by the inputs, of which there are countless possibilities and legitimate arguments regarding the appropriate inclusion or exclusion of various inputs. IURC Staff Ex. No. 1, pp. 22-23. Mr. Inman testified that Mr. Gorman also used DCF, RP and CAPM calculations in formulating his cost of equity recommendation of 9.7% to 10.3%, and noted that experts that use different inputs into the same formulas can arrive at different final cost of equity ("COE") estimates. IURC Staff Ex. No. 1, pp. 23-24. Mr. Inman concluded with the observation that, as the Commission has noted in other cases, the Petitioner has recommended a high COE and all opposing experts have recommended much lower COE's. The true COE most probably lies somewhere in between. IURC Staff Ex. No. 1, p. 24.

Mr. Inman stated in his prefiled testimony that PSI's credit rating downgrade risk could increase as a result [*88] of this rate case. IURC Staff Ex. No. 1, p. 24. In this regard, Mr. Inman stated that a downgrade of PSI's credit rating would lead to increased debt costs, a reduction in financing options, and ultimately higher costs to consumers. IURC Staff Ex. No. 1, p. 25. Therefore, Mr. Inman testified that it is important to PSI and to its customers that this Commission's final order in this Cause, regardless of the findings on cost of capital and rate of return, recognizes PSI's strengths and position relative to its industry peers. IURC Staff Ex. No. 1, p. 25. Mr. Inman noted that conspicuously absent from Petitioner's case-in-chief testimony was an analysis of the impact of PSI receiving something less than its requested increase, such as 50% or 75%. n6 Mr. Inman concluded that he believes that approval of a rate increase for PSI which is less than the full amount requested, but is an amount that could still be considered "substantially all" will not endanger PSI's credit rating. IURC Staff Ex. No. 1, p. 26.

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n6 The Petitioner's rebuttal evidence did include such a 75% scenario. Pet. Ex. HH, pp. 4-5; Pet. Ex. HH-1; Pet. Ex. GG, pp. 6-10; and Pet. Ex. EE, pp. 5-6.

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(6) Petitioner's Rebuttal Evidence on Cost of Equity.

(a) Rebuttal Concerning OUCC's Cost of Common Equity Evidence. Dr. Morin testified for PSI in rebuttal to the cost of common equity capital testimony submitted by other parties. Dr. Morin observed that Mr. Kaufman's recommended ROE of 9.15% (prior to being updated to 9.25%) was substantially under the average returns on common equity allowed in the electric and natural gas utility rate cases in the first six months in 2003 of 11.40% and 11.38%, respectively, as reported by RRA in its survey of regulatory decisions dated June, 2003. Pet. Ex. No. FF, p. 15. Dr. Morin also observed that it was well under the average returns of 11.6% and 11.7% allowed on common equity for the utilities in Mr. Kaufman's sample groups as reported in the Turner Reports survey for September, 2003. Pet. Ex. FF, p. 15. Dr. Morin concluded that Mr. Kaufman's recommendation was: (a) well outside the zone of currently allowed rates of return for Mr. Kaufman's comparable companies; (b) well outside the mainstream of recently authorized returns for electric and natural gas utilities allowed by state regulatory agencies throughout the country; and (c) [*90] would be among the lowest, if not the lowest, in the country if adopted. Pet. Ex. FF, p. 16.

Dr. Morin testified that he believes that Mr. Kaufman's dividend yield calculation in his DCF analysis understate flotation costs by 20-25 basis points. Pet. Ex. FF, pp. 16-17. Mr. Kaufman's flotation cost approach, Dr. Morin observed, assumes that all past flotation costs associated with past securities issues have been recovered, which he said is not the case here. Pet. Ex. FF, p. 17. Because such costs were not expensed in the past, Dr. Morin said, investors should be compensated for flotation costs for the entire time that these initial funds are retained by the firm, on an on-going basis. Pet. Ex. FF, pp. 17-18. In theory, Dr. Morin said, flotation costs could be expensed and recovered through rates as they are incurred. However, this procedure is not considered appropriate here because the common equity capital raised in a given stock issue remains in the utility's common equity account and continues to provide benefits to ratepayers indefinitely. Pet. Ex. FF, p. 18. He reiterated that unlike the case of bonds, common stock has no finite life, so that flotation costs cannot be amortized [*91] and must, therefore, be recovered via an upward adjustment to the allowed return on equity. Pet. Ex. FF, p. 18.

Dr. Morin also disagreed with Mr. Kaufman's dividend yield calculation in his DCF analysis, because Mr. Kaufman multiplied the current dividend yield by one plus one half the expected growth rate (1 + 0.5g), rather than by one plus the expected growth rate (1 + g), thereby understating the return expected by the investor. Pet. Ex. FF, p. 19. Dr. Morin explained that the fundamental assumption of the annual DCF model used by Mr. Kaufman is that dividends are received by investors annually, at the end of each year, and that the first dividend is to be received by the investor one year from now. Pet. Ex. FF, p. 19. Instead, he said, dividends are received quarterly. Because the appropriate amount of dividends to use in the annual DCF model is the prospective dividend one year from now, rather than the dividend one-half year from now, Mr. Kaufman's approach, Dr. Morin testified, understates the proper dividend yield, thereby understating PSI's cost of equity by approximately 15 basis points. Pet. Ex. FF, p. 19. Dr. Morin emphasized that because the price of a stock reflects **[*92]** the quarterly payment of dividends, it is essential that the DCF model used to estimate equity costs also reflect the compounding or quarterly dividends in the same way that bond yield calculations are routinely adjusted to reflect semiannual interest payments. Pet. Ex. FF, p. 20. By failing to recognize the quarterly nature of dividend payments in his DCF computation, Dr. Morin said that Mr. Kaufman understated PSI's cost of equity capital by about 20 basis points. Pet. Ex. FF, p. 21.

Dr. Morin also disagreed with Mr. Kaufman's use of the average stock price over the past three and six months to derive the dividend yield to use in his DCF. Pet. Ex. FF, p. 23. Dr. Morin indicated that he believes because the analyst is attempting to determine a utility's cost of equity in the future, current stock prices provide a better indication of expected future prices than any other price. Pet. Ex. FF, p. 23. Dr. Morin also took issue with Mr. Kaufman's proxies used to derive his DCF growth rate component, which was an average of all of the rates calculated, using Mr. Kaufman's proxy group. Pet. Ex. FF, p. 24. Dr. Morin reproduced those rates in the following table, based on Mr. Kaufman's Schedule **[*93]** 4:

TABLE 3

Mr. Kaufman's Growth Rates

Primary Group of Electric Utilities

	ALL	**Excl DPS**	**Forecast**	**Only DPS**
	(1)	**(2)**	**(3)**	**(4)**
Historical 10 yr. EPS	3.8%	3.8%		
Historical 5 yr. EPS	4.5%	4.5%		
Historical 10 yr. DPS	2.2%			2.2%
Historical 5 yr. DPS	3.1%			3.1%
Historical 10 yr. BPS	3.1%	3.1%		
Historical 5 yr. BPS	4.2%	4.2%		
Forecast EPS	6.2%	6.2%	6.2%	
Forecast DPS	4.7%		4.7%	4.7%
Forecast BPS	4.7%	4.7%	4.7%	
Multex Forecast EPS	4.9%	4.9%	4.9%	
Turner Forecast DPS	3.1%		3.1%	3.1%
Average	4.0%	4.5%	4.7%	3.3%

Pet. Ex. FF, p. 25.

Dr. Morin said that based on this table the overall average growth rate from all the proxies, as shown in Column 1, is 4.0%, and that the dividend growth proxies average of 3.3% shown at the bottom of Column 4 is an outlier, compared to the average of 4.5% computed by excluding the dividend proxies (Column 2) and compared to the average of 4.7% obtained