The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
Table of Contents

RECEIVED
MAY 3 1 2006
PUBLIC SERVICE COMMISSION

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
1	1	KRS 278.180	30 days' notice of rates to PSC.	Sandra P. Meyer
1	2	807 KAR 5:001 Section 8 (1)	Full name and P.O. address of applicant and reference to the particular provision of law requiring PSC approval.	Sandra P. Meyer
1	3	807 KAR 5:001 Section 8 (2)	The original and 10 copies of application plus copy for anyone named as interested party.	Sandra P. Meyer
1	4	807 KAR 5:001 Section 10 (1)(b)(1)	Reason adjustment is required.	Paul G. Smith
1	5	807 KAR 5:001 Section 10 (1)(b)(2)	Statement that utility's annual reports, including the most recent calendar year, are filed with PSC. 807 KAR 5:006, Section 3 (1).	Dwight L. Jacobs
1	6	807 KAR 5:001 Section 10 (1)(b)(3) and (5)	If utility is incorporated, certified copy of articles of incorporation and amendments or out of state documents of similar import. If they have already been filed with PSC refer to the style and case number of the prior proceeding and file a certificate of good standing or authorization dated within 60 days of date application filed.	Sandra P. Meyer
1	7	807 KAR 5:001 Section 10 (1)(b)(4)	If applicant is limited partnership, certified copy of limited partnership agreement. If agreement filed with PSC refer to style and case number of prior proceeding and file a certificate of good standing or authorization dated within 60 days of date application filed.	Sandra P. Meyer
1	8	807 KAR 5:001 Section 10 (1)(b)(6)	Certified copy of certificate of assumed name required by KRS 365.015 or statement that certificate not necessary.	Sandra P. Meyer
1	9	807 KAR 5:001 Section 10 (1)(b)(7)	Proposed tariff in form complying with 807 KAR 5:011 effective not less than 30 days from date application filed.	Jeffrey R. Bailey
1	10	807 KAR 5:001 Section 10 (1)(b)(8)	Proposed tariff changes shown by present and proposed tariffs in comparative form or by indicating additions in italics or by underscoring and striking over deletions in current tariff.	Jeffrey R. Bailey
1	11	807 KAR 5:001 Section 10 (1)(b)(9)	Statement that notice given, see subsections (3) and (4) of 807 KAR 5:001, Section 10 with copy.	Sandra P. Meyer
1	12	807 KAR 5:001 Section 10 (2)	If gross annual revenues exceed $1,000,000, written notice of intent filed at least 4 weeks prior to application. Notice shall state whether application will be supported by historical or fully forecasted test period.	Sandra P. Meyer
1	13	807 KAR 5:001 Section 10 (4) (a)	Sewer utilities shall give the required typewritten notice by mail to all of their customers pursuant to KRS 278.185.	Sandra P. Meyer
1	14	807 KAR 5:001 Section 10 (4)(b)	Applicants with twenty (20) or fewer customers affected by the proposed general rate adjustment shall mail the required typewritten notice to each customer no later than the date the application is	Sandra P. Meyer

The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
			filed with the commission.	
1	15	807 KAR 5:001 Section 10 (4)(c)	Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by one (1) of the following methods: 1. A typewritten notice mailed to all customers no later than the date the application is filed with the commission; 2. Publishing the notice in a trade publication or newsletter which is mailed to all customers no later than the date on which the application is filed with the commission; or 3. Publishing the notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made within seven (7) days of the filing of the application with the commission.	Sandra P. Meyer
1	16	807 KAR 5:001 Section 10 (4)(d)	If notice is published, an affidavit from the publisher verifying that the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the Commission no later than forty-five (45) days of the filed date of the application.	Sandra P. Meyer
1	17	807 KAR 5:001 Section 10 (4)(e)	If notice is mailed, a written statement signed by the utility's chief officer in charge of Kentucky operations verifying the notice was mailed shall be filed with the Commission no later than thirty (30) days of the filed date of the application.	Sandra P. Meyer
1	18	807 KAR 5:001 Section 10 (4)(f)	All utilities, in addition to the above notification, shall post a sample copy of the required notification at their place of business no later than the date on which the application is filed which shall remain posted until the commission has finally determined the utility's rates.	Sandra P. Meyer
1	19	807 KAR 5:001 Section 10 (5)	Notice of hearing scheduled by the commission upon application by a utility for a general adjustment in rates shall be advertised by the utility by newspaper publication in the areas that will be affected in compliance with KRS 424.300.	Sandra P. Meyer
1	20	807 KAR 5:001 Section 10 (8)(a)	Financial data for forecasted period presented as pro forma adjustments to base period.	William Don Wathen, Jr.
1	21	807 KAR 5:001 Section 10 (8)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	William Don Wathen, Jr.
1	22	807 KAR 5:001 Section 10 (8)(c)	Capitalization and net investment rate base shall be based on a 13 month average for the forecasted period.	William Don Wathen, Jr.

The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
1	23	807 KAR 5:001 Section 10 (8)(d)	After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless such revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within thirty (30) days of a scheduled hearing on the rate application.	William Don Wathen, Jr.
1	24	807 KAR 5:001 Section 10 (8)(e)	The commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.	William Don Wathen, Jr.
1	25	807 KAR 5:001 Section 10 (8)(f)	Reconciliation of rate base and capital used to determine revenue requirements.	William Don Wathen, Jr.
1	26	807 KAR 5:001 Section 10 (9)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.	All witnesses
1	27	807 KAR 5:001 Section 10 (9)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures.	Jim L. Stanley John J. Roebel
1	28	807 KAR 5:001 Section 10 (9)(c)	Complete description, which may be in prefiled testimony form, of all factors used to prepare forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.	Brian P. Davey
1	29	807 KAR 5:001 Section 10 (9)(d)	Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period.	Brian P. Davey
1	30	807 KAR 5:001 Section 10 (9)(e)	Attestation signed by utility's chief officer in charge of Kentucky operations providing: 1. That forecast is reasonable, reliable, made in good faith and that all basic assumptions used have been identified and justified; and 2. That forecast contains same assumptions and methodologies used in forecast prepared for use by management, or an identification and explanation for any differences; and 3. That productivity and efficiency gains are included in the forecast.	Sandra P. Meyer
1	31	807 KAR 5:001 Section 10 (9)(f)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed: 1. Date project began or estimated starting date;	Jim L. Stanley John J. Roebel

The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
			2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During construction ("AFUDC") or Interest During construction Credit; and 4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit.	
1	32	807 KAR 5:001 Section 10 (9)(g)	For all construction projects constituting less than 5% of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection.	Jim L. Stanley John J. Roebel
1	33	807 KAR 5:001 Section 10 (9)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: 1. Operating income statement (exclusive of dividends per share or earnings per share); 2. Balance sheet; 3. Statement of cash flows; 4. Revenue requirements necessary to support the forecasted rate of return; 5. Load forecast including energy and demand (electric); 6. Access line forecast (telephone); 7. Mix of generation (electric); 8. Mix of gas supply (gas); 9. Employee level; 10. Labor cost changes; 11. Capital structure requirements; 12. Rate base; 13. Gallons of water projected to be sold (water); 14. Customer forecast (gas, water); 15. MCF sales forecasts (gas); 16. Toll and access forecast of number of calls and number of minutes (telephone); and 17. A detailed explanation of any other information provided.	Brian P. Davey Lynn J. Good #6, #13, #16 & #17 Not applicable
1	34	807 KAR 5:001 Section 10 (9)(i)	Most recent FERC or FCC audit reports.	Dwight L. Jacobs
1	35	807 KAR 5:001 Section 10 (9)(j)	Prospectuses of most recent stock or bond offerings.	Lynn J. Good
1	36	807 KAR 5:001 Section 10 (9)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or the Automated Reporting Management Information System Report (telephone) and PSC Form T (telephone).	Dwight L. Jacobs
2	37	807 KAR 5:001 Section 10 (9)(l)	Annual report to shareholders or members and statistical supplements for the most recent 5 years prior to application filing date.	Dwight L. Jacobs

The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
3	38	807 KAR 5:001 Section 10 (9)(m)	Current chart of accounts if more detailed than Uniform System of Accounts charts.	Dwight L. Jacobs
3	39	807 KAR 5:001 Section 10 (9)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast.	Brian P. Davey
3	40	807 KAR 5:001 Section 10 (9)(o)	Complete monthly budget variance reports, with narrative explanations, for the 12 months prior to base period, each month of base period, and subsequent months, as available.	Brian P. Davey
4-7	41	807 KAR 5:001 Section 10 (9)(p)	SEC's annual report for most recent 2 years, Form 10-Ks and any Form 8-Ks issued during prior 2 years and any Form 10-Qs issued during past 6 quarters.	Dwight L. Jacobs
8	42	807 KAR 5:001 Section 10 (9)(q)	Independent auditor's annual opinion report, with any written communication which indicates the existence of a material weakness in internal controls.	Dwight L. Jacobs
8	43	807 KAR 5:001 Section 10 (9)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	Dwight L. Jacobs
8	44	807 KAR 5:001 Section 10 (9)(s)	Summary of latest depreciation study with schedules itemized by major plant accounts, except that telecommunications utilities adopting PSC's average depreciation rates shall identify current and base period depreciation rates used by major plant accounts. If information has been filed in another PSC case, refer to that case's number and style.	John J. Spanos
8	45	807 KAR 5:001 Section 10 (9)(t)	List all commercial or in-house computer software, programs, and models used to develop schedules and work papers associated with application. Include each software, program, or model; its use; identify the supplier of each; briefly describe software, program, or model; specifications for computer hardware and operating system required to run program	William Don Wathen, Jr.

The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
8	46	807 KAR 5:001 Section 10 (9)(u)	If utility had any amounts charged or allocated to it by affiliate or general or home office or paid any monies to affiliate or general or home office during the base period or during previous 3 calendar years, file: 1. Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment; 2. method and amounts allocated during base period and method and estimated amounts to be allocated during forecasted test period; 3. Explain how allocator for both base and forecasted test period was determined; and 4. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable.	Carol E. Shrum
9	47	807 KAR 5:001 Section 10 (9)(v)	If gas, electric or water utility with annual gross revenues greater than $5,000,000, cost of service study based on methodology generally accepted in industry and based on current and reliable data from single time period.	Paul F. Ochsner
10	48	807 KAR 5:001 Section 10 (9)(w)	Local exchange carriers with fewer than 50,000 access lines need not file cost of service studies, except as specifically directed by PSC. Local exchange carriers with more than 50,000 access lines shall file: 1. Jurisdictional separations study consistent with Part 36 of the FCC's rules and regulations; and 2. Service specific cost studies supporting pricing of services generating annual revenue greater than $1,000,000 except local exchange access: a. Based on current and reliable data from single time period; and b. Using generally recognized fully allocated, embedded, or incremental cost principles.	Not applicable
10	49	807 KAR 5:001 Section 10 (10)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase.	William Don Wathen, Jr.
10	50	807 KAR 5:001 Section 10 (10)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of the rate base.	William Don Wathen, Jr.
10	51	807 KAR 5:001 Section 10 (10)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and by individual account.	William Don Wathen, Jr.

The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
10	52	807 KAR 5:001 Section 10 (10)(d)	Summary of jurisdictional adjustments to operating income by major account with supporting schedules for individual adjustments and jurisdictional factors.	William Don Wathen, Jr.
10	53	807 KAR 5:001 Section 10 (10)(e)	Jurisdictional federal and state income tax summary for both base and forecasted periods with all supporting schedules of the various components of jurisdictional income taxes.	Keith G. Butler
10	54	807 KAR 5:001 Section 10 (10)(f)	Summary schedules for both base and forecasted periods (utility may also provide summary segregating items it proposes to recover in rates) of organization membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases.	William Don Wathen, Jr.
10	55	807 KAR 5:001 Section 10 (10)(g)	Analyses of payroll costs including schedules for wages and salaries, employee benefits, payroll taxes, straight time and overtime hours, and executive compensation by title.	William Don Wathen, Jr.
10	56	807 KAR 5:001 Section 10 (10)(h)	Computation of gross revenue conversion factor for forecasted period.	William Don Wathen, Jr.
10	57	807 KAR 5:001 Section 10 (10)(i)	Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for 5 calendar years prior to application filing date, base period, forecasted period, and 2 calendar years beyond forecast period.	Brian P. Davey
10	58	807 KAR 5:001 Section 10 (10)(j)	Cost of capital summary for both base and forecasted periods with supporting schedules providing details on each component of the capital structure.	Lynn J. Good
10	59	807 KAR 5:001 Section 10 (10)(k)	Comparative financial data and earnings measures for the 10 most recent calendar years, base period, and forecast period.	Brian P. Davey
10	60	807 KAR 5:001 Section 10 (10)(l)	Narrative description and explanation of all proposed tariff changes.	Jeffrey R. Bailey
10	61	807 KAR 5:001 Section 10 (10)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes.	Jeffrey R. Bailey
10	62	807 KAR 5:001 Section 10 (10)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Jeffrey R. Bailey

The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
10	63	807 KAR 5:001 Section (10)(3)	Amount of change requested in dollar amounts and percentage for each customer classification to which change will apply. a. Present and proposed rates for each customer class to which change would apply. b. Electric, gas, water and sewer utilities-the effect upon average bill for each customer class to which change would apply. c. Local exchange companies-include effect upon average bill for each customer class for change in basic local service.	Jeffrey R. Bailey
10	64	807 KAR 5:001 Section 10 (4)(c)(d)(e)(f)	If copy of public notice included, did it meet requirements?	Sandra P. Meyer
10	65	807 KAR 5:001 Section 6(1)	Amount and kinds of stock authorized.	Lynn J. Good
10	66	807 KAR 5:001 Section 6(2)	Amount and kinds of stock issued and outstanding.	Lynn J. Good
10	67	807 KAR 5:001 Section 6(3)	Terms of preference of preferred stock whether cumulative or participating, or on dividends or assets or otherwise.	Lynn J. Good
10	68	807 KAR 5:001 Section 6(4)	Brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee, or trustee, amount of indebtedness authorized to be secured thereby, and the amount of indebtedness actually secured, together with any sinking fund provisions.	Lynn J. Good
10	69	807 KAR 5:001 Section 6(5)	Amount of bonds authorized, and amount issued, giving the name of the public utility which issued the same, describing each class separately, and giving date of issue, face value, rate of interest, date of maturity and how secured, together with amount of interest paid thereon during the last fiscal year.	Lynn J. Good
10	70	807 KAR 5:001 Section 6(6)	Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid thereon during the last fiscal year.	Lynn J. Good
10	71	807 KAR 5:001 Section 6(7)	Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of any portion of such indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid thereon during the last fiscal year.	Lynn J. Good
10	72	807 KAR 5:001 Section 6(8)	Rate and amount of dividends paid during the five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.	Lynn J. Good
10	73	807 KAR 5:001 Section 6(9)	Detailed income statement and balance sheet.	William Don Wathen, Jr.

The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
11	-	807 KAR 5:001 Sction 10(10) (a) through (k)	Schedule Book (Schedules A-K)	Various
12	-	807 KAR 5:001 Sction 10(10) (l) through (n)	Schedule Book (Schedules L-N)	Various
13	-	-	Work papers	Various
14	-	807 KAR 5:001 Section 10(9)(a)	Testimony (Volume 1 of 2)	-
15	-	807 KAR 5:001 Section 10(9)(a)	Testimony (Volume 2 of 2)	-
16	-	KRS 278.2205(6)	Cost Allocation Manual	-
17	-	807 KAR 5:056 Section 1(7)	Coal Contracts	-

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT
OF ELECTRIC RATES OF THE UNION
LIGHT, HEAT AND POWER COMPANY
D/B/A DUKE ENERGY KENTUCKY

CASE NO. 2006- 00172

FILING REQUIREMENTS

VOLUME 15

C.JAMES O'CONNOR
KEITH G. BUTLER
LYNN J. GOOD
CAROL E. SHRUM
BRIAN J. DAVEY
DR. ROGER A. MORIN
PAUL F. OCHSNER
JEFFREY R. BAILEY
WILLIAM DON WATHEN, JR.
PAUL G. SMITH

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

C. JAMES O'CONNOR

ON BEHALF OF

DUKE ENERGY KENTUCKY

183689

TABLE OF CONTENTS

		PAGE
I.	INTRODUCTION AND PURPOSE	1
II.	COMPANIES' EMPLOYMENT CHARACTERISTICS	3
III.	COMPENSATION PHILOSOPHY	5
IV.	BASE PAY PROGRAMS	7
V.	INCENTIVE PAY PROGRAMS	8
VI.	PROPOSAL FOR SHARING INCENTIVE PAY EXPENSE	13
VII.	COMPETITIVE MARKET ANALYSES – COMPENSATION	19
VIII.	REASONABLENESS OF COMPENSATION PROGRAMS	19
IX.	BENEFIT PLAN DESIGN	20
X.	COST MANAGEMENT CONTROLS	21
XI.	REASONABLENESS OF BENEFITS PROGRAM	22
XII.	WAGE AND BENEFIT COST ESTIMATES	23
XIII.	CONCLUSION	24

ATTACHMENTS

Attachment CJO-1 – Regulated Businesses' 2005 Annual Incentive Plan Goals and Actual Results

Attachment CJO-2 – Mr. Stanley's 2005 Annual Incentive Plan Goals and Actual Results

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is C. James O'Connor, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as Vice President, Human Resources.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I graduated from Indiana University with a Bachelor of Science degree in business management. I also earned a Master of Art degree in Executive Development from Ball State University. I have also had further education at Purdue University in management studies, at the University of Wisconsin in labor studies and from Ball State University in economic development.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined PSI Energy, Inc. in 1976 as an Energy Consultant in Field Operations, Transmission and Distribution, Electric Operations. I advanced through various positions of increasing responsibility in sales, economic development, labor relations, safety, district management in field operations, transmission and distribution, and human resources. I was named to my current position of Vice President, Human Resources in April 2006.

Q. PLEASE DESCRIBE YOUR DUTIES AS VICE PRESIDENT, HUMAN RESOURCES.

A. I am responsible for the Human Resources function for Duke Energy's U.S. Franchised Electric & Gas ("Franchised Electric & Gas") Commercial Business Unit. My responsibilities generally include accountability to the business unit for the delivery of all Human Resource functions. To this end, Duke has three Human Resource organizations that partner to provide an end product. The three departments and their responsibilities are Corporate Human Resources, which performs the strategic design of Human Resource programs; Human Resources Operations, which oversees all administrative functions across the enterprise; and Human Resources Business Partners, which represents the business unit human resources needs to the other two Human Resources organizations. Working with these other Human Resources organizations, I am responsible for the following services: compensation and benefits, employee and labor relations, staffing and recruiting, training and organizational development, inclusion strategies and diversity programs, workforce planning and measurement, succession planning, leadership development and employee and retiree communications relating to the Franchised Electric & Gas Commercial Business Unit.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I support the reasonableness of the Company's compensation and benefit programs. I also support the Company's proposal to share the costs of incentive compensation programs between shareholders and customers, using the same method approved in the Commission's February 2, 2006 Order on Rehearing in

Case No. 2005-00042, with one exception that I will discuss later. I also provided Mr. Davey with certain labor costs for the forecasted test period.

II. COMPANIES' EMPLOYMENT CHARACTERISTICS

Q. WHERE DO THESE EMPLOYEES WORK WHEN PERFORMING SERVICES FOR DUKE ENERGY KENTUCKY CUSTOMERS?

A. Duke Energy Kentucky's customers receive services from employees of Duke Energy Kentucky and affiliated companies. The employees work at the East Bend Generating Station ("East Bend"), the Miami Fort Unit 6 Generating Station ("Miami Fort 6") and the Woodsdale Generating Station ("Woodsdale") (collectively, "the Plants). They also work at our customer service center at 1697 A Monmouth Street in Newport, and at our 19th and Augustine facility in Covington, which is dedicated to gas operations, and at our Erlanger construction and maintenance center. They also work in our Cincinnati, Ohio headquarters and in the Duke Energy headquarters in Charlotte, North Carolina.

Q. WHAT TYPE OF SPECIAL SKILLS OR KNOWLEDGE IS REQUIRED IN ORDER TO OPERATE AN ELECTRIC UTILITY SUCH AS DUKE ENERGY KENTUCKY?

A. The operation and maintenance of electric generating plants, transmission substations and transmission and distribution equipment requires specialized technical skills. Employees must have the requisite knowledge and technical skills to plan, design, operate and maintain electric generating plants and high voltage equipment in a manner that provides safe, adequate and reliable service. The operation and maintenance of a field office and a customer call center requires a detailed knowledge of all aspects of customer service. Field office and call center employees must understand the characteristics of the electric generating and delivery service provided by Duke Energy Kentucky, the metering, billing and collection processes and various other customer service matters. At the corporate level, highly skilled managers, engineers, accountants, computer hardware and software experts, computer programmers and other highly-trained professionals are needed to support the employees who are directly responsible for generating and delivering electricity to Duke Energy Kentucky's customers.

Q. HOW IMPORTANT IS THE RECRUITMENT AND RETENTION OF SUCH EMPLOYEES TO THE COMPANIES' SUCCESS?

A. The recruitment and retention of such employees is critical to the Companies' success. The skills needed for employees to render high-quality, utility service takes several years to develop. For example, electric plant operators and control technicians are highly-skilled positions that require experience and knowledge which is acquired over several years. If we were to lose such employees, we would incur additional costs to train replacements for these positions. Consequently, we strive to be an "employer of choice" that attracts qualified employees and retains such employees, which benefits customers by providing a more highly skilled work force at a lower overall cost.

Q. WHAT FACTORS AFFECT THE RECRUITMENT AND RETENTION OF SUCH EMPLOYEES?

A. The recruitment and retention of such employees is directly related to their compensation, benefits, and career development opportunities, as well as management values, opportunities for a balanced lifestyle, and the nature of the work itself. Industry and market conditions also impact the Companies' ability to recruit and retain employees.

Q. WHERE DO THE COMPANIES OBTAIN APPLICANTS FOR VACANT POSITIONS?

A. We draw applicants from various geographic areas, depending on the job we need to fill. As a general rule, the more highly skilled the job position being filled, the broader the scope of the Companies' recruitment efforts. We generally recruit executives on a national level; exempt employees locally and regionally; and non-exempt employees locally. The Companies employ applicants drawn from other utilities and from diverse employment backgrounds in other industries.

III. COMPENSATION PHILOSOPHY

Q. PLEASE DESCRIBE THE COMPANIES' BASIC COMPENSATION PHILOSOPHY.

A. The Companies' basic compensation philosophy is to design a compensation program consisting of base salary and annual incentives that provides employees with an opportunity to earn total compensation competitive with the market. This philosophy supports the Companies' goal to attract, retain and motivate the caliber of employees with the education, experience, judgment and skills necessary to carry out the responsibilities of the positions that the employees are hired to fill. The Companies' compensation strategy for executive employees is to provide a compensation package consisting of a combination of fixed and variable pay, using base salary, short-term incentives and long-term incentives; these components, in the aggregate, are targeted to deliver total compensation at the 50th percentile of the applicable peer group. However, if Duke Energy delivers superior performance, our compensation program is designed to provide total compensation above market median based on performance, and conversely, if Duke Energy's performance should decline, its executives' total compensation is designed to decline to a level commensurate with such performance.

The Companies adopted this executive compensation strategy in order to attract, retain and motivate the executive talent required to deliver superior performance. This strategy emphasizes performance-based compensation that balances rewards for both short-term and long-term results and which aligns the executives' interests with the long-term success of Duke Energy and its subsidiaries, including Duke Energy Kentucky.

Q. PLEASE DESCRIBE HOW THE COMPANIES STRUCTURE THEIR COMPENSATION PROGRAMS.

A. The Companies' compensation programs consist of a base pay component and an incentive pay component. The base pay component is a set amount, reviewed by management at least annually, and established at a level that: (1) provides competitive compensation based on the nature and responsibilities of the employee's position; and (2) is fair relative to the pay for other similarly situated positions in the organization. The incentive pay component is variable and is at risk to the employees. Incentive pay is generally linked to the accomplishment of specific goals established in advance for the individual employee, his or her business unit, and/or the corporation. The purpose of incentive pay is: (1) to encourage employees to perform at a high level in order to accomplish specific objectives intended to ensure safe, reliable and economical utility service to our customers and to ensure their business unit's and the corporation's overall success; and (2) to constitute a component of a compensation package that is competitive with the market.

IV. BASE PAY PROGRAMS

Q. *PLEASE DESCRIBE THE COMPANIES' BASE PAY PROGRAMS.*

A. Every employee receives base pay in the form of semi-monthly earnings (for exempt employees) or weekly wages (for non-exempt and union employees).

Q. HOW DOES THE COMPANIES' BASE PAY IN RECENT YEARS COMPARE WITH THE MARKET TREND?

A. The Companies have adjusted their base pay in recent years to stay within the target range. For example, prior to the Duke Energy/Cinergy Corp. ("Cinergy") merger, the Cinergy Companies increased their base pay in recent years; however, these increases were at lower rates than the market trend, in order to align base pay provided by the Companies to a level equivalent to the 50^{th} percentile of base pay of comparably sized utility companies. In the aggregate, the Cinergy Companies increased their base pay for executives, exempt, and non-union, non-exempt employees by 2.5% in 2003, which was 1.3 % below the market trend, by 3.0% in 2004, which was 0.5% below the market trend, by 3.5% in 2005, which was comparable to the market trend and by 3.5% in 2006, which was equivalent to the market trend for exempt and non-exempt, non-union employees but .2% lower than the market trend for executives. It should be noted that employees' individual increases may vary relative to the base pay budget, to allow for individual differentiators based on performance and current pay levels relative to the market.

Duke Energy Kentucky and the International Brotherhood of Electrical Workers ("IBEW") Local No. 1347 entered into a new three-year collective bargaining agreement on April 12, 2006. The collective bargaining agreement provides for a 3.0% wage increase for each of the first two years of the contract and a 4.0% wage increase for the third year of the contract, with increased employee health care costs. Duke Energy Kentucky and the United Steelworkers of America ("USWA") Local No. 12049 entered into a five-year collective bargaining agreement in 2002 which expires on May 15, 2007. The collective bargaining agreement provides for a 3.0% wage increase each year for the term of the contract.

We are currently evaluating each job position in the Franchised Electric & Gas Commercial Business Unit to determine the proper market job equivalent for salary benchmarking purposes. When this process is completed, we will take appropriate action to ensure that we maintain our industry target range for base compensation.

V. INCENTIVE PAY PROGRAMS

Q. PLEASE DESCRIBE THE COMPANIES' INCENTIVE PAY PROGRAMS.

A. Duke Energy and Cinergy had various incentive pay programs prior to the merger. We have designed the incentive plans for Duke Energy that will be in place post-merger. The Companies' major incentive pay programs are: (1) the Cinergy Corp. Annual Incentive plans (AIP)/Duke Energy Corporation Annual Incentive Plan (referred to for convenience as "Short-Term Incentive Plan" or "STI"); (2) the Cinergy Corp. Union Employees' Incentive Plan ("UEIP"); and (3) the Cinergy Corp. 1996 Long-Term Incentive Compensation Plan ("LTIP")/Duke Energy Corp. 1998 Long-Term Incentive Plan ("LTI").

Q. PLEASE DESCRIBE THE AIP AND STI PLANS.

A. The AIP/STI plans are short-term incentive plans that allow employees to receive cash payments if certain pre-determined performance goals are attained during the relevant calendar year. The AIP plans are available to exempt and certain non-exempt, non-union employees of Duke Energy Kentucky and the service companies who do not participate in another incentive plan. The purpose of the annual incentive plans is to attract, retain and motivate employees; enhance teamwork and high levels of achievement; and to facilitate the accomplishment of specific corporate, business unit and individual goals.

At the beginning of each calendar year, corporate, business unit and individual performance goals are established for the annual plans, and a thorough review is performed at the end of the calendar year to determine the achievement levels for each performance goal. The Compensation Committee of the Duke Energy Board of Directors ("Compensation Committee") approves the corporate performance goal at the beginning of each calendar year and certifies the payout level achieved for such goal at the end of the calendar year.

The performance goals are the objectives that the corporation, business unit and individual employees must attain in order for the employees to receive payment under the annual incentive plans. The performance goals may consist of a combination of corporate, business unit and individual goals. The corporate performance goal must be an objective measure of the corporation's performance, efficiency or profitability. Business unit goals are related to specific financial and operational objectives of the unit such as safety, reliability and cost of service. Individual goals are set cascading down from and supporting the business unit and corporate goals so that everyone works towards common goals and objectives. The Company's objective is to balance corporate goals and individual goals appropriately so employees can have a direct impact relative to their goals.

All applicable goals are weighted, with a possible range of scores from zero to 3.0. Once an achievement level is determined, the achievement level is multiplied by the weighting assigned to each respective goal to determine an overall payout level.

Q. WHAT WERE THE RESULTS OF THE AIP FOR 2005?

A. For 2005, the AIP provided for the following weightings for employees in the Franchised Electric & Gas Business Unit, which was then part of the Company's Regulated Businesses Business Unit ("Regulated Businesses" or "RBU"): 50% corporate performance goal, 25% business unit goals and 25% individual performance goals.

The 2005 corporate performance goal was based on Cinergy's net income. The payout with respect to the 2005 corporate performance goal was a level 2.1 achievement for all employees.

In 2005, the business unit goals of the Regulated Businesses (of which Electric Operations was a part) were based on the following factors: (1) Electric System Average Interruption Frequency Index ("SAIFI") – the average number of customer interruptions excluding Level 3 and higher storms; (2) Electric Customer Average Interruption Duration Index ("CAIDI") – the average number of hours to restore service excluding Level 3 and higher storms; (3) Gas CAIDI – the average duration of customer outages, excluding outages due to certain extraordinary causes; (4) lost-time accident rate; (5) number of traffic accidents; (6) customer satisfaction score results; (7) operation and maintenance ("O&M") expense levels; and (8) capital expenditure levels. The aggregate payout with respect to the Regulated Businesses business unit performance goals corresponded to a 2.2 achievement level.

A total of 2,161 employees participated in the AIP plans in 2005.

Q. WHAT INFORMATION IS USED TO CALCULATE THE CUSTOMER SATISFACTION COMPONENT OF THE AIP FOR RBU EMPLOYEES?

A. We use the Duke Energy Kentucky-specific customer satisfaction survey scores discussed in more detail in Ms. Meyer's testimony.

Q. PLEASE DESCRIBE THE UEIP.

A. The UEIP is available to union employees of Duke Energy Kentucky, and the service companies who do not participate in another incentive plan. The UEIP is a short-term incentive plan that allows union employees to receive cash payments if the Company attains certain corporate performance goals or if their group attains certain performance goals during a calendar year. The purpose of the UEIP is to attract, retain and motivate employees, enhance teamwork and high levels of achievement, and to facilitate the accomplishment of specific corporate and business unit goals.

The UEIP award levels consist of a percentage of the employee's base and overtime earnings, based on the following corporate and business unit achievement levels:

REGULATED BUSINESS UNIT	**UEIP Award Levels (expressed as a percentage of earnings)**		
	1	**2**	**3**
Corporate Measure	0.50%	0.75%	1.00%
Safety	If a union achieves the applicable safety goal, .5% is added to its members' incentive payouts; if a union fails to achieve this goal, 0% is added to its members' incentive payout.		
Customer Satisfaction/Peak Equivalency	If a union achieves the applicable customer satisfaction goal or peak equivalency goal, .5% is added to its members' incentive payouts; if the union fails to achieve these goals, 0% is added to its members' incentive payouts.		
Total Incentive Opportunity	**1.5%**	**1.75%**	**2.00%**

As with the AIP/STI plan(s), the Compensation Committee of the Board of Directors approves the corporate performance goal and the level of corporate performance that will be associated with particular payout levels. At the end of the year, the Compensation Committee certifies the actual performance and payout level with respect to such corporate performance goal.

Q. WHAT WERE THE RESULTS OF THE UEIP FOR 2005?

A. For 2005, the corporate measure was based on the same corporate net income performance goal used for the AIP and, as mentioned earlier in my testimony, the payout for this corporate measure corresponded to a 2.1 achievement level. All goals were met by the unions for 2005.

Q. PLEASE DESCRIBE THE LTIP AND LTI PLANS.

A. These plans pay equity-based compensation to executive employees and non-employee directors in a manner that aligns their interests with the long-term interests of Duke Energy and its affiliates, including Duke Energy Kentucky. The purpose of the long-term incentive plan(s) is: (1) to assist in attracting, retaining and motivating executives by keeping the Companies' compensation package competitive; and (2) to align a portion of executive compensation with stakeholder interests by encouraging and enabling executives to acquire Duke Energy stock.

VI. PROPOSAL FOR SHARING INCENTIVE PAY EXPENSE

Q. WHAT INCENTIVE PAY EXPENSE DOES DUKE ENERGY COMPANY PROPOSE TO RECOVER IN THIS PROCEEDING?

A. Duke Energy Kentucky proposes to share its incentive plan expense between shareholders and customers in the same manner the Commission approved in Case No. 2005-00042. In that case, the Commission approved recovery of incentive pay expense related to performance objectives that directly benefit customers, such as reliability, customer satisfaction and individual performance objectives. The Commission disallowed recovery of incentive pay expense related to performance objectives based on corporate financial goals. Accordingly, Duke Energy Kentucky proposes to recover the following amount of incentive compensation costs in its revenue requirement calculation, based on the following allocations and assuming the following achievement levels:

Table 1 – <u>Incentive Pay Sharing Proposal</u>

Incentive Plan	Incentive Plan Components	Budgeted Achievement Level	Percentage Of Total Plan	Percentage to Shareholders	Percentage to Customers	Percentage of Total Shared by Customers
STI – Leadership	Corporate goals	2.0	40%	100%	0%	0%
	Franchised Electric & Gas EBIT	2.0	40%	100%	0%	0%
	RBU operational goals	2.0	20%	0%	100%	20%
STI – Non-Leadership	Corporate goals	2.0	25%	100%	0%	0%
	Franchised Electric & Gas EBIT	2.0	25%	100%	0%	0%
	RBU operational goals	2.0	50%	0%	100%	50%
LTIP	Total shareholder return	at target	100%	100%	0%	0%
UEIP	0.75% of pay based on corporate financial measure; 1% of pay based on operational goals *i.e.,* customer satisfaction and safety	2.0	100%	0%	57%	43%

Q. WHY DOES THE COMPANY'S PROPOSAL FOR INCENTIVE COMPENSATION USE THE ACHIEVEMENT LEVELS IDENTIFIED ABOVE?

A. These are the budgeted achievement levels for the performance goals for the AIP and the UEIP. The 2.0 achievement level is used for the budget because this is equivalent with a target achievement level, which is what the Company expects to achieve on average over time. Over the past five years, the Company's performance has consistently been higher than the budgeted amounts.

Q. PLEASE EXPLAIN HOW THE COSTS RELATED TO THE AIP'S AND STI'S CORPORATE PERFORMANCE OBJECTIVE ARE DIVIDED BETWEEN CUSTOMERS AND SHAREHOLDERS.

A. The AIP and STI have three separate components: corporate goal, individual goals, and business unit operational goals. We propose that the expense attributable to the corporate performance goal be allocated 100% to the shareholders with nothing allocated directly to customer.

Q. PLEASE EXPLAIN HOW THE COSTS RELATED TO THE AIP'S AND STI'S INDIVIDUAL AND RBU OPERATIONAL PERFORMANCE OBJECTIVES ARE DIVIDED BETWEEN CUSTOMERS AND SHAREHOLDERS.

A. Duke Energy Kentucky's rates should reflect 100% of the costs of individual and business unit incentive goals. These goals are operationally focused and directly benefit the customer. The individuals measured by these goals and included in the rate base are employed directly by Duke Energy Kentucky or allocate their time to Duke Energy Kentucky, and they work on Duke Energy Kentucky matters which directly benefit customers. As a result, customers should bear the full cost of this portion of employees' incentive pay.

Finally, the AIP's and STI's business unit operational goals for employees directly benefit customers because the goals are tied to outage frequency, time required to restore service, lost-time accidents, customer satisfaction scores, O&M expense levels and capital expenditures. Superior performance relating to these goals directly benefits Duke Energy Kentucky customers through safe and reliable service, customer service quality, and low energy costs.

Q. PLEASE EXPLAIN HOW THE COSTS FOR THE UEIP PLAN ARE REFLECTED IN DUKE ENERGY KENTUCKY'S PROPOSAL.

A. The UEIP is an incentive plan for union employees not eligible for any other incentive compensation plans. These union employees include many of our back office personnel, including administrative and clerical as well as meter readers, and employees who construct and maintain the Company's gas distribution system. All are functions that are critical to reliable customer service. At the 2.0 achievement level, which we use in our budget, the UEIP performance objectives are based 43% (*e.g.*, .75% of pay) on corporate financial performance and 57% (*e.g.*, 1.0% of pay) customer-oriented objectives, namely safety, customer satisfaction and reliability. We propose allocation of the costs of this plan 43% to shareholders and 57% to customers.

Q. ARE THE AIP AND STI BUSINESS UNIT AND INDIVIDUAL GOALS DIRECTED MORE TOWARD SHAREHOLDER BENEFITS OR CUSTOMER BENEFITS?

A. The Regulated Businesses' 2005 goals and actual results are at Attachment CJO-1. These goals clearly incent behavior that furthers the customers' interest. As I previously discussed, the goals are based on items such as: (1) keeping capital expenditures and operation and maintenance expense at reasonable levels, which tends to produce lower rates; (2) operational excellence, which produces more reliable service for customers; and (3) providing high quality customer service.

The individual annual incentive goals of Mr. Stanley, the Vice President of Field Operations Midwest, are presented at Attachment CJO-2 and clearly further customers' interests by incenting behavior in the same manner, because his goals roll up into the Business Unit goals. The individual goals of the other employees in Franchised Electric & Gas Field Operations-Midwest do as well, because they are designed to roll up into Mr. Stanley's goals and the Business Units goals, such that the employees' individual goal achievement would help Mr. Stanley and the Business Unit achieve their goals.

As can be seen, these Business Unit and individual goals are closely tied to metrics, such as safety, reliability, cost control and customer satisfaction, which provide customer benefits. Thus I believe that Duke Energy Kentucky's rates should reflect these incentive compensation costs, consistent with the treatment approved by the Commission in Case No. 2005-00042.

Q. BASED ON ALL OF THE ABOVE-MENTIONED ALLOCATIONS TO CUSTOMERS AND SHAREHOLDERS, HOW MUCH OF DUKE ENERGY KENTUCKY'S TOTAL INCENTIVE COMPENSATION EXPENSE WOULD BE REFLECTED IN ITS EXPENSES FOR THE FORECASTED TEST PERIOD?

A. Duke Energy Kentucky proposes to recover $870,178 of the $3,380,211 Electric Operations incentive compensation costs originally included in the forecasted test period. This represents approximately 26% of the total Duke Energy Kentucky incentive compensation expense originally included as an expense in the forecasted test period.

Q. DO YOU HAVE AN OPINION AS TO THE REASONABLENESS OF DUKE ENERGY KENTUCKY'S PROPOSED TREATMENT FOR INCENTIVE COMPENSATION COSTS?

A. Yes. In my opinion, all of Duke Energy Kentucky's incentive compensation costs are properly recoverable. Nevertheless, Duke Energy Kentucky's proposal allocates the costs of its incentive compensation plans between shareholders and customers consistent with the Commission's February 2, 2006 Order on Rehearing in Case No. 2005-00042.

VII. COMPETITIVE MARKET ANALYSES – COMPENSATION

Q. WERE ANY STUDIES CONDUCTED IN 2005 REGARDING THE COMPETITIVENESS OF THESE COMPENSATION PROGRAMS?

A. Yes, Hewitt and Associates ("Hewitt"), Mercer Consulting ("Mercer") and Towers Perrin Co. ("Towers") performed such studies. All three firms are worldwide human resources consulting firms. More information about each is available at http://was4.hewitt.com/hewitt.com/hewitt, www.mercer.com and www.towers.com.

Q. PLEASE DESCRIBE THESE COMPENSATION STUDIES.

A. The studies generally reported that Cinergy's compensation program is competitive within the industry.

VIII. REASONABLENESS OF COMPENSATION PROGRAMS

Q. DO YOU HAVE AN OPINION AS TO WHETHER THE COMPANIES' EMPLOYEE COMPENSATION PROGRAMS ARE REASONABLE AND NECESSARY TO ATTRACT, RETAIN, AND MOTIVATE THE

QUALIFIED EMPLOYEES NEEDED TO PROVIDE SAFE, RELIABLE, EFFICIENT AND ECONOMICAL SERVICE TO DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC CUSTOMERS?

A. Yes. In my opinion, the Companies' base pay, short-term and long-term incentive compensation programs are, indeed, competitive, reasonable, and necessary to attract, retain, and motivate qualified employees that the Companies need to provide safe, reliable, effective, efficient and economical electric service to Duke Energy Kentucky's retail customers.

IX. BENEFIT PLAN DESIGN

Q. HOW DO BENEFITS TIE INTO THE COMPANIES' OVERALL COMPENSATION PHILOSOPHY?

A. Benefits are the non-pay portion of the overall compensation picture. Generally, benefits are provided through one of two vehicles: retirement plans and welfare benefit plans. Retirement plans include pension and 401(k) plans. Welfare benefit plans include medical, dental, life insurance, and disability plans.

Q. WHAT IS THE COMPANIES' BENEFITS PHILOSOPHY?

A. We offer a competitive, comprehensive benefits program in order to establish ourselves as an employer of choice. In order to attract, retain and motivate a high caliber work force, a company must offer a competitive benefits program as well as a competitive compensation program. Benefits also play an important role in retaining employees, which is important for us as our business involves complex processes such that employees must receive long-term training to perform their jobs well. Our benefits program is designed not only to attract qualified employees but also to retain employees, thus the Companies are able to maintain a highly trained, experienced work force that is capable of rendering excellent utility service.

X. COST MANAGEMENT CONTROLS

Q. HOW HAVE THE COMPANIES MANAGED HEALTH CARE COSTS?

A. The Companies are self-insured on most of their medical and dental benefits options. This avoids a risk premium that the Companies would otherwise have to pay to a third party for underwriting the plans. Employees and retirees must order maintenance prescriptions through the mail order program and specialty biotech drugs through the specialty prescription drug program. These programs help employees, retirees, and the Companies to lower total prescription costs. The medical plans have utilization management programs in place to help eliminate unnecessary or inappropriate medical treatment or hospitalization. These programs are designed to help employees receive quality care while preventing unnecessary expenses for the employee and the Companies, and include hospital pre-certification and hospital stay review. We also apply usual and customary reimbursement guidelines on health and dental claims. The Company offers incentives to employees to opt out of the medical and dental plans, or to reduce the level of coverage in the medical plan. The Company has comprehensive Disease Management and Wellness Programs which encourage employees to adopt healthier lifestyles as well as to manage chronic illnesses that are associated with increased expense. In early 2005, the Company was awarded the Cincinnati Business Courier "Healthy Heroes Award" in recognition for its comprehensive wellness program.

Q. HAVE ANY OTHER COST REDUCTIONS BEEN IMPLEMENTED WITH REGARD TO RETIREE BENEFITS?

A. As with active employees, we have a retail discount drug network for retirees, three tiers of prescription co-pays requiring greater employee/retiree cost sharing and mandatory mail order. The Company continues to pass along normal premium increases to retirees on an annual basis. The new Health Reimbursement Account program also will allow the Company to better control and predict future retiree medical costs. In 2005, the Company began unblending active employee claims experience from retiree claims experience resulting in retirees' premiums reflecting the true cost of retiree coverage. In 2006, the Company elected to maintain retiree prescription drug coverage and apply for the Medicare Part D retiree drug subsidy.

Q. IN YOUR OPINION, WILL THE COMPANIES ELIMINATE MEDICAL AND DENTAL BENEFITS FOR RETIREES?

A. In my opinion, medical and dental benefits for retirees are necessary to attract and retain the qualified employees necessary to provide quality service to our customers. I believe that it is unlikely that these retiree benefits would be eliminated without providing some other form of benefits to offset the effect of elimination.

XI. <u>REASONABLENESS OF BENEFITS PROGRAM</u>

Q. DO YOU HAVE AN OPINION REGARDING THE REASONABLENESS AND NECESSITY OF THE COMPANIES' EMPLOYEE BENEFITS

PROGRAMS TO ATTRACT, RETAIN AND MOTIVATE QUALIFIED EMPLOYEES TO PROVIDE SAFE, RELIABLE, EFFICIENT, AND ECONOMICAL SERVICE TO DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC CUSTOMERS?

A. Yes. In my opinion, the Companies' employee benefits programs are both reasonable and necessary to attract, retain and motivate qualified employees to provide quality service to our retail electric customers in a safe, reliable, efficient and economical manner.

Q. WHY DO YOU HOLD THAT OPINION?

A. As work force diversity has evolved, employees have become increasingly concerned about the level of financial protection and pay. Based on my experience and day-to-day contact with employees, I believe that in numerous cases, the employee's ultimate employment decision is heavily based on benefits. Therefore, our benefit levels must be competitive and reflect current benefit trends.

XII. <u>WAGE AND BENEFIT COST ESTIMATES</u>

Q. DID YOU PROVIDE ANY COST ESTIMATES TO MR. DAVEY FOR HIS USE IN PREPARING THE FORECASTED FINANCIAL DATA?

A. Yes, I provided Mr. Davey with certain compensation and fringe benefit costs for his use in preparing the forecasted financial data.

Q. HOW DID YOU ESTIMATE THESE LABOR AND BENEFIT COST CHANGES FOR THE FORECASTED PERIOD?

A. I made reasonable estimates based on recent trends, current conditions, the market studies by independent consultants that I discussed previously in my testimony, and my previous experience with compensation and benefits matters. Based on these considerations, I provided Mr. Davey with the following estimates for the forecasted test period consisting of the twelve months ending December 31, 2007: the union and non-union labor rate increases; the fringe benefit loading rates, payroll tax, and indirect labor loading rates for union and non-union labor.

XIII. CONCLUSION

Q. ARE ATTACHMENTS CJO-1 AND CJO-2 TRUE AND ACCURATE COPIES OF THE DOCUMENTS THEY PURPORT TO REPRESENT?

A. Yes.

Q. IS THE INFORMATION YOU PROVIDED TO MR. DAVEY ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, C. James O'Connor, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

C James O'Connor

C. James O'Connor, Affiant

Subscribed and sworn to before me by C. James O'Connor on this 22nd day of May, 2006.

Anita M. Schafer

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2009

2005 RBU KPI's – YEAR END RESULTS

Key Performance Indicator	Tracking	Weight %	Standards 1	2	3	2005 Year End Results	Achievement Level
MAXIMIZE NET INCOME Operation and Maintenance Expense	Actual versus budget (excluding DSM, PIPP and sale of A/R)	15%	Budget	2% under budget	4% under budget	Budget - $301.9 Actual - $290.8 Variance - $11.1	Level 2.85
Capital Expenditures	Actual versus budget (Non-AMRP)	10%	Budget	2% under budget	4% under budget	Budget – $299.3M Actual - $283.4M Variance - $15.6 5.32% under	Level 3
	Hit AMRP Rate Targets – Gas	5%	Within +2% to -4% of budget	Within +2% to -1% of budget	Within +1% to -1% of budget	Target – $62.4M Actual - $62.7M Variance – $.3M .5% over	Level 3
DRIVE CONTINUOUS OPERATIONAL IMPROVEMENT Electric System Average Interruption Frequency Index (SAIFI) – average number of customer interruptions (excludes Level 3 and higher storms)	12 month rolling average of total number of customer interruptions / total number of electric customers	5%	Maintain service level 1.52	Current service level 1.39	Best service level 1.26	1.47	Level 1.42
CEMI (Sustained Customer Outage)	Percent of customers having more than five outages per year	5%	6%	5%	3%	3.5%	Level 2.74
Electric Customer Average Interruption Duration Index	12 month rolling average of total number of electric customer hours out of service /	5%	Maintain service level	Current service level	Best service level 82 minutes	92.6	Level 1.48

Key Performance Indicator	Tracking	Weight %	1	Standards 2	3	2005 Year End Results	Achievement Level
(CAIDI) – average number of hours to restore service (excludes Level 3 and higher storms)	total number of electric customer outages		96 minutes	89 minutes			
Gas Customer Average Interruption Duration Index (CAIDI) – average number of hours to restore service (excludes certain unusual outages)	Annual average of total number of gas customer hours out of service / total number of gas customer outages	5%	Maintain service level 4.3 hours	Current service level 3.8 hours	Best service level 3.3 hours	4.0 hours through 12/31/05	Level 1.6
PROVIDE OUTSTANDING CUSTOMER SERVICE							
Customer Contact Satisfaction (maintain current satisfaction levels in the face of high natural gas costs and rate case filings)	Survey of approximately 50,000 residential customers that have contacted Cinergy	10%	86% satisfied and very satisfied	87% satisfied and very satisfied	88% satisfied and very satisfied	87%	Level 2
Public Safety Awareness	Percent of customers aware of public safety ads	5%	40%	42%	44%	44.4%	Level 3
PROMOTE SUPERIOR EMPLOYEE PERFORMANCE							
Lost-Time Incident Rate	Total lost-time accidents x 200,000 / total hours worked	15%	Average of last 3 years 0.50	Midpoint between levels 1 and 3 0.46	Better than best year 0.42	.51	Level 1
Traffic Accidents	Number of traffic accidents	10%	Average of last 3 years 87	Midpoint between levels 1 and 3 77	Better than best year 67	88	Level 1
Face-to-face Meetings	Percent of employees participating in face-to-face meetings with RBU executives	5%	85%	90%	95%	2nd qtr = 40%	Level 1

Key Performance Indicator	Tracking	Weight %	Standards 1	2	3	2005 Year End Results	Achievement Level
RECEIVE CONSTRUCTIVE REGULATORY TREATMENT ULH&P Gas Distribution Case and CG&E Electric Distribution Case	Based upon outcomes of current proceedings	10%	Subjective	Subjective	Subjective	Subjective	3.0

ACHIEVEMENT LEVEL RESULTS: 2.17

Cinergy Performance Management - 2005
Planning and Appraisal Worksheet

Rating
0 - Did not meet
1 - Meets expectations
2 - Exceeds expectations
3 - Exceptional performance

Name: **Jim Stanley**
Date: **March, 2005**

Culture Initiatives	Requirements	Results

KPI KEY PERFORMANCE INDICATORS	Tracking	Standards 1	Standards 2	Standards 3	Weight %	Actual Results	Rating
Operation and Maintenance Expense	R.B.U. Actual versus Budget	Budget	2.0% below budget	4% below budget	15%	$11.1M under	2.85
Capital Expenditures	T&D C&M Actual versus Budget	Budget	2% below budget	4% below budget	15%	4.9% below	3.00
Customer Average Interruption Duration Index (CAIDI) - average number of hours to restore service (excludes level 3 and higher storms)	12 month rolling average of total electric customer hours out of service/total number of electric customer outages	96 minutes	89 minutes	82 minutes	9%	92.6	1.48
System Average Interruption Frequency Index - (SAIFI) - average number of customer interruptions (excludes level 3 and higher storms)	12 month rolling average of total number of customer interruptions/total number of electric customers	1.52 outages	1.39 outages	1.26 outages	8%	1.47	1.42
CEMI (sustained customer outage)	Percent of customers having more than five outages per year	6%	5%	3%	8%	3.5	2.74

Cinergy erformance Management - 2005

Planning and Appraisal Worksheet

Rating
0 - Did not meet
1 - Meets expectations
2 - Exceeds expectations
3 - Exceptional performance

Name: Jim Stanley
Date: March, 2005

Culture Initiatives	Requirements	Results

KPI KEY PERFORMANCE INDICATORS	Tracking	Standards			Weight %	Actual Results	Rating
		1	2	3			
Customer Contact Satisfaction	Survey of customers receiving service contact	86% satisfied and very satisfied	87% satisfied and very satisfied	88% satisfied and very satisfied	10%	87%	2.00
Safety - Lost Time Incidents	Total Lost time incidents - T&D C&M -	Average of last 3 years (4)	Midpoint between levels 1 and 3 (3)	Better than best year (1)	5%	5 incidents	0.00
Safety - Total Incidents	Total OSHA recordable incidents - T&D C&M -	Average of last 3 years (59)	Midpoint between levels 1 and 3 (56)	Better than best year (52)	5%	50 incidents	2.00
Safety - Traffic Accidents	Number of Traffic Accidents - T&D C&M -	Average of last 3 years (33)	Midpoint between levels 1 and 3 (30)	Better than best year (27)	5%	41 accidents	0.00
Journey Toward Inclusion	Percentage of T&D C&M Employees attending meetings	15%	20%	35%	5%	84%	3.00

Cinergy Performance Management - 2005
Planning and Appraisal Worksheet

Rating
0 - Did not meet
1 - Meets expectations
2 - Exceeds expectations
3 - Exceptional performance

Name: Jim Stanley
Date: March, 2005

Culture Initiatives	Requirements	Results

KPI KEY PERFORMANCE INDICATORS	Tracking	Standards			Weight %	Actual Results	Rating
		1	2	3			
Face to Face Employee Meetings	Percentage of T&D C&M Employees in meetings with V.P.	20%	35%	50%	5%	62%	3.00
R.B.U. spend savings thru sourcing initiatives	Total RBU savings resulting from sourcing initiatives	$14M	$17.5M	$21M	5%	$4.78M savings - 7.8% of spend impacted - target = 5%	2.50
Continued Improvement Process	Progress of CIN10 initiative implementation	subjective	subjective	subjective	5%	subjective	3.00

Achievement Level Results = 2.2185

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

KEITH G. BUTLER

ON BEHALF OF

DUKE ENERGY KENTUCKY

183623

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE .... - 1 -

II. SCHEDULES SPONSORED BY WITNESS .... - 3 -

III. INCOME TAX EXPENSE .... - 5 -

IV. PROPERTY TAX EXPENSE .... - 9 -

V. ADITC AND DEFERRED INCOME TAX BALANCES RELATING TO THE THREE GENERATING PLANTS .... - 10 -

VI. CONCLUSION .... - 11 -

ATTACHMENTS

ATTACHMENT KGB-1 – Calculation of Composite Federal and State Statutory Income Tax Rates

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Keith G. Butler, and my business address is 400 South Tryon Street, Charlotte, NC 28285.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as Vice President Corporate Tax.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Science degree in Business Administration, with a concentration in accounting from the University of North Carolina at Chapel Hill. I am a Certified Public Accountant in the State of North Carolina, a member of the American Institute of Certified Public Accountants, a member of the North Carolina Association of Certified Public Accountants and a member of the Tax Executives Institute.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined Duke Energy in January 1984 in the Controller's Department and have worked in various leadership positions in accounting, finance, independent power development and energy services. I was appointed to the position of Vice President & Corporate Controller in August 2001 and was responsible for the accounting functions of Duke Energy. In June 2005, I was appointed to the position of Vice President Corporate Tax.

Q. PLEASE DESCRIBE YOUR DUTIES AS VICE PRESIDENT CORPORATE TAX.

A. As Vice President Corporate Tax, I have overall responsibility for corporate tax compliance, planning, and accounting for Duke Energy. The Duke Energy tax department prepares and files federal, state and local income, sales and use, excise, and property tax returns for Duke Energy. We also file tax returns for various joint ventures if Duke Energy is the designated tax matters partner.

The tax department maintains and reconciles Duke Energy's tax accounts and manages audits with the Internal Revenue Service and state and local tax authorities. Finally, the tax department is responsible for the reporting and disclosure of tax related matters, to the extent required.

I serve on the Duke Energy Transaction Review Committee. This committee will recommend significant transactions to the CEO and board of directors for review and approval. The other members consist of leaders of the following departments: Finance, General Counsel, Corporate Development, Risk Management and Treasury. This committee will meet on an as-needed basis.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky's ("Duke Energy Kentucky") income tax expense presented in this filing and certain other tax matters. I sponsor part of the information in Schedule B-6, the *pro forma* income tax adjustment on Schedule D-2.29, and Schedules E-1 and E-2. I also provided certain additional tax information to other witnesses for their use in certain calculations for the base period and the forecasted period. Finally, I support Duke Energy Kentucky's calculation of income tax expense and property tax expense, and the recommended treatment for accumulated deferred investment tax credits ("ADITC") and accumulated deferred income tax ("ADIT") balances relating to The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio's ("Duke Energy Ohio") transfer of generating plants to Duke Energy Kentucky.

II. <u>SCHEDULES SPONSORED BY WITNESS</u>

Q. WHAT INFORMATION DID YOU PROVIDE FOR SCHEDULE B-6?

A. I provided Accumulated Deferred Investment Tax Credit and Accumulated Deferred Income Tax balance information to Mr. Wathen for both the base period and the forecasted period for Schedule B-6.

Q. PLEASE DESCRIBE SCHEDULE D-2.29.

A. Schedule D-2.29 is a pro-forma adjustment to the income tax calculation on Schedule E-1 for the "domestic production deduction" of the Company. I will describe this deduction in more detail later in my testimony. This deduction was allowed as part of the American Jobs Creation Act of 2004 and is a permanent deduction to both state and federal income taxes which results in a decrease in income tax expense.

Q. PLEASE DESCRIBE SCHEDULE E-1.

A. Schedule E-1 is the calculation of adjusted jurisdictional federal and state taxable income and federal and state income tax expense for the base period under current income tax rates and for the forecasted period at income tax rates in effect for that period.

Q. PLEASE DESCRIBE SCHEDULE E-2.

A. Schedule E-2 is for the calculation of jurisdictional federal and state taxable income and federal and state income tax expense. Since the utility taxes are 100% jurisdictional, this schedule is not applicable.

Q. WHAT TAX INFORMATION DID YOU PROVIDE TO OTHER WITNESSES?

A. I provided Mr. Davey with the property tax expense for the forecasted financial data. These expenses are based on projected property tax rates applied to the most recent valuations as approved by the Kentucky Department of Revenue ("KDR"), updated for projected additions including the recent Plant transfers, retirements, and additional depreciation.

I also provided Mr. Davey with the income tax rates and the amortization of the investment tax credit for both the forecasted portion of the base period consisting of the six months ending August 31, 2006, and the forecasted test period.

I reviewed Mr. Davey's calculation of deferred income taxes for the base period and the forecasted period, I provided the amount of tax depreciation he used for this calculation, and I support the methodology he used for calculating deferred income taxes. I also provided Ms. Good with the accumulated deferred investment tax credit balance for her use on Schedules J-1, J-1.1 and J-1.2.

III. INCOME TAX EXPENSE

Q. WHAT TAX RATE DID THE COMPANY USE TO CALCULATE ITS TEST PERIOD FEDERAL INCOME TAX EXPENSE?

A. The Company used the statutory Federal corporate income tax rate of 35% for both the base period and forecasted period.

Q. WHAT TAX RATE DID THE COMPANY USE TO CALCULATE ITS TEST PERIOD STATE INCOME TAX EXPENSE?

A. The Company used the statutory Kentucky corporate income tax rate of 7% for the base period. For the forecasted period, the Company used the statutory Kentucky corporate income tax rate of 6%, as this is the Kentucky corporate income tax rate that will be in effect beginning in 2007. The Company used the Ohio statutory corporate income tax rate of 8.5% for both the base period and the forecasted period. Due to the transfer of two generating plants in Ohio as of January 1, 2006, from Duke Energy Ohio to the Company, the Company's apportionment calculation for state income taxes results in a composite state statutory tax rate of 5.8%. This is the rate that was used to determine state income tax expense for the forecasted period.

Q. WHAT IS THE COMBINED FEDERAL AND STATE STATUTORY INCOME TAX RATE APPLICABLE DURING THE TEST PERIOD?

A. The combined statutory Federal and state statutory income tax rate for Duke Energy Kentucky, which is expected to be in effect during the base period is 39.55% and for the forecasted period is 38.77%. This rate includes the corporate statutory federal income tax rate of 35% and the statutory Kentucky corporate income tax rate of 7% for the base period and the composite state statutory income tax rate of 5.8% for the forecasted period. The calculation of these composite federal and state statutory income tax rates are shown on Attachment KGB-1. State income taxes are deductible in computing the federal tax liability and this deduction is considered in computing the overall effective tax liability. I provided this information to Mr. Wathen for his use in calculating the revenue requirement. I also provided him with the amount of income tax expense for the base period and the forecasted test period, based on these income tax rates.

Q. WHY DID YOU USE THE STATUTORY KENTUCKY INCOME TAX RATE INSTEAD OF THE EFFECTIVE KENTUCKY INCOME TAX RATE TO CALCULATE DUKE ENERGY KENTUCKY'S INCOME TAX EXPENSE?

A. In my opinion, Duke Energy Kentucky should use the income tax rate that most accurately reflects the actual state income tax for its business on a stand-alone basis, which for the base period is the statutory rate of 7% and for the forecasted period is the composite statutory tax rate of 5.8%. These are the proper tax rates to apply to Duke Energy Kentucky's electric business operations and this treatment is consistent with the Kentucky income tax rate approved by the Commission for the Company's 2005 gas rate case. This treatment is also consistent with the Commission's most recent ruling on the subject because, in its March 31, 2006 Order in Case No. 2003-00433, the Commission issued an Order on rehearing, rejecting the Attorney General's request that the effective Kentucky income tax rate should be used to calculate the revenue requirement for Louisville Gas & Electric Company's electric operations.

Q. YOU REFERRED EARLIER TO THE AMERICAN JOBS CREATION ACT OF 2004. PLEASE EXPLAIN THE BACKGROUND OF THIS LAW.

A. President Bush signed the American Jobs Creation Act of 2004 into law on October 22, 2004. In passing this law, Congress intended to reduce the tax burden on domestic manufacturers and to enhance the competitiveness of American manufacturers in the global economy. The law provides a phased-in income tax deduction of 9% on the lesser of the taxpayer's income from qualified production activities or taxable income. The law defines "qualified production activities" to include the production of electric energy. The tax deduction is phased-in as follows:

Year	Amount of Deduction
2005 and 2006	deduction equals 3% of qualified production activity taxable income
2007 through 2009	deduction equals 6% of qualified production activity taxable income
2010 and beyond	deduction equals 9% of qualified production activity taxable income

Q. HOW DOES THE AMERICAN JOBS CREATION ACT OF 2004 AFFECT THE CALCULATION OF DUKE ENERGY KENTUCKY'S FEDERAL INCOME TAXES?

A. The deduction applies to taxable income from generating and other electric production activities, so it applies to Duke Energy Kentucky's generation of electric energy from its generating plants. The deduction is calculated, however, at the consolidated level; therefore, any losses from Duke Energy's non-regulated operations may prevent Duke Energy from realizing any benefit from this deduction in its consolidated federal tax filing. Nevertheless, for ratemaking purposes we calculated this deduction on the income from Duke Energy Kentucky's generating activities on a stand-alone basis. This is consistent with our use of the composite statutory income tax rate that I discussed earlier in my testimony, because both situations use the utility's stand-alone income tax expense rather than the consolidated holding company tax impact.

Q. WHAT RATE DID THE COMPANY USE TO CALCULATE THESE DEDUCTIONS?

A. We used the deduction rate of 6% of qualified production activity taxable income, because this is the level of the phased-in deduction that will be in effect when Duke Energy Kentucky's new retail electric base rates are put in effect and for two years thereafter.

Q. DOES KENTUCKY HAVE A SIMILAR DEDUCTION FOR STATE INCOME TAXES?

A. Yes, but it has slightly different limits. The Kentucky Legislature enacted House Bill 272 in 2005, and the Department of Revenue has proposed a new emergency regulation, 103 KAR 16:310E. The new law adopts a deduction from Kentucky corporate income taxes for domestic production activity equal to the federal deduction, but the proposed emergency regulation limits the deduction to the lesser of the Company's Kentucky income tax or consolidated income tax, capped by the amount of wages paid to Kentucky residents.

Q. DID THE AMERICAN JOBS CREATION ACT OF 2004 HAVE ANY OTHER IMPACTS ON DUKE ENERGY KENTUCKY'S INCOME TAXES?

A. No.

IV. PROPERTY TAX EXPENSE

Q. HOW DID DUKE ENERGY KENTUCKY CALCULATE THE PROPERTY TAX EXPENSE FOR THE FORECASTED TEST PERIOD?

A. We calculated the property tax expense based on the assessed value of Duke Energy Kentucky's property located in Kentucky and Ohio with adjustments for anticipated property tax rate increases, additions including the power plant transfers, retirements and additional depreciation. As in past years, Duke Energy Kentucky will attempt to negotiate proper assessment values with the KDR. The Company will notify the Commission of the result of its negotiations with the KDR for the 2006 tax year so the Commission can determine whether to adjust Duke Energy Kentucky's property tax expense for the forecasted test period. The Ohio property is assessed on a triennial basis, with the next re-assessment expected to occur in 2008.

V. ADITC AND DEFERRED INCOME TAX BALANCES RELATING TO THE THREE GENERATING PLANTS

Q. WHAT TREATMENT DOES DUKE ENERGY KENTUCKY REQUEST FOR THE ADITC AND ADIT BALANCES RELATING TO THE THREE GENERATING PLANTS TRANSFERRED FROM DUKE ENERGY OHIO TO DUKE ENERGY KENTUCKY?

A. Duke Energy Kentucky proposes that these items should be reflected as non-jurisdictional balances on its books as of January 1, 2006, the effective date of Duke Energy Ohio's transfer of the plants to Duke Energy Kentucky, and excluded from the calculation of its electric revenue requirement. Duke Energy Kentucky will continue to amortize these balances below-the-line over the remaining lives of the generating plants.

Duke Energy Kentucky has recorded above-the-line all deferred income taxes generated after January 1, 2006 and through the end of the forecasted test period, and has reflected such deferred income tax activity and ADITs in calculating its revenue requirements.

This treatment of the ADITC and ADIT balances relating to the generating plants is consistent with: (1) the treatment prescribed by the FERC Uniform System of Accounts; (2) accepted principles of tax normalization; (3) the accounting treatment applied in similar transactions in other jurisdictions; and (4) the Commission's ruling at pages 15-18 of its December 5, 2003 Order in Case No. 2003-00252 approving the transfer of the generating plants.

VI. CONCLUSION

Q. WAS THE TAX INFORMATION YOU SUPPLIED FOR SCHEDULE B-6, AND WERE SCHEDULE D-2.29, SCHEDULES E-1 AND E-2, THE TAX INFORMATION YOU SUPPLIED TO OTHER WITNESSES, AND ATTACHMENT KGB-1 PREPARED UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

State of North Carolina)
) SS:
County of Mecklenburg)

The undersigned, Keith G. Butler, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Keith G. Butler, Affiant

Subscribed and sworn to before me by Keith G. Butler on this 17 day of May, 2006.

Angela M Bick
NOTARY PUBLIC

My Commission Expires: 8 - 10 - 2008

DUKE ENERGY KENTUCKY

Calculation of Combined Statutory Federal and State Income Tax Rate

BASE PERIOD

Line No.			
1	State Taxable Income	$ 100.00	
2	Statutory State Income Tax Rate	7.0%	
3	State Income Tax		$ 7.00
4	Federal Taxable Income	$ 93.00	
5	Statutory Federal Income Tax Rate	35.00%	
6	Federal Income Tax		32.55
7	Total Income Tax		$ 39.55
8	Combined Statutory Federal and State Income Tax Rate (line 7 / line 1)		39.55%

FORCASTED PERIOD

Line No.			
1	State Taxable Income	$ 100.00	
2	Statutory State Income Tax Rate	5.8%	
3	State Income Tax		$ 5.80
4	Federal Taxable Income	$ 94.20	
5	Statutory Federal Income Tax Rate	35.00%	
6	Federal Income Tax		32.97
7	Total Income Tax		$ 38.77
8	Combined Statutory Federal and State Income Tax Rate (line 7 / line 1)		38.77%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

LYNN J. GOOD

ON BEHALF OF

DUKE ENERGY KENTUCKY

183227

TABLE OF CONTENTS

PAGE

I.	INTRODUCTION AND PURPOSE	- 1 -
II.	DUKE ENERGY KENTUCKY'S CURRENT CREDIT RATINGS	- 4 -
III.	DUKE ENERGY KENTUCKY'S FINANCIAL OBJECTIVES	- 6 -
IV.	DUKE ENERGY KENTUCKY'S CASH REQUIREMENTS	- 7 -
VI.	DUKE ENERGY KENTUCKY'S COST OF DEBT	- 10 -
VII.	SCHEDULES SPONSORED BY WITNESS	- 11 -
X.	CONCLUSION	- 16 -

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lynn J. Good, and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Duke Energy Corporation ("Duke Energy') affiliated companies as Vice President and Treasurer.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Science Degree in Systems Analysis and Accounting from Miami University, Oxford, Ohio, and I am a Certified Public Accountant in the State of Ohio.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. From July 1981 to May 2002, I worked in various levels of senior management with Arthur & Andersen Co. ("Arthur Andersen"), certified public accountants. While at Arthur Andersen, I had regional energy industry responsibilities for risk consulting and internal audit practices. From May 2002 to May 2003, I was a partner with the international accounting firm Deloitte & Touche LLP. I joined Cinergy Corp. in May 2003, as Vice President, Financial Project Strategy and Oversight for Cinergy Services, Inc., responsible for improving financial and accounting management reporting and organizational effectiveness, as well as addressing compliance with the Sarbanes – Oxley Act of 2002. I was appointed to the position of Vice President and Controller in November 2003, and in

January 2005, after assuming responsibility for budgets, forecasts and tax, I was appointed to Vice President Finance and Controller. In August 2005, I was appointed CFO of Cinergy. I was appointed to my current position of Vice President and Treasurer of Duke Energy effective with the closing of the merger between the former Duke Energy Corporation and Cinergy Corp. on April 3, 2006.

Q. PLEASE DESCRIBE YOUR DUTIES AS VICE PRESIDENT AND TREASURER.

A. As Vice President and Treasurer, I am responsible for financing the operations of the Duke Energy companies. This includes managing the existing portfolio of securities, as well as the issuance of new taxable and tax-exempt debt securities and common and preferred equity securities, and obtaining other sources of external funds, including securitization, lease financing and short-term debt facilities. My responsibilities also encompass financial risk management of the companies' interest rate and foreign currency risk exposure. I am also responsible for oversight and administration of the pension and other non-qualified benefit investments, and daily cash management. My duties also include managing Duke Energy's and its subsidiaries' relationships with the major credit rating agencies and with the commercial banks and debt capital markets. In addition, I am responsible for the financial planning and analysis activities within the company.

I serve on Duke Energy's Performance Review Committee. The other members consist of Mr. Jim Rogers, Duke Energy's President and CEO, and the leaders of the following departments: Finance, General Counsel, Corporate

Development, Communications, Corporate Secretary/Ethics & Compliance, and Controller. The Performance Review Committee will meet quarterly with each of the following three Duke Energy businesses: U.S. Franchised Electric & Gas, Duke Energy Gas Transmission and Duke Energy Americas. The meetings will concentrate on financial performance and other matters, including strategic direction, operational, safety and environmental performance, and Sarbanes-Oxley and other compliance requirements. I also serve on the Duke Energy Transaction Review Committee. This committee will recommend significant transactions to the CEO and board of directors for review and approval. The other members consist of the leaders of the following departments: Finance, General Counsel, Corporate Development, Risk Management and Tax. This committee will meet on an as-needed basis.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. I previously filed testimony in Case No. 2005-00228, involving the merger of Duke Energy and Cinergy Corp.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses Duke Energy Kentucky's current credit ratings, its financial objectives and the cash requirements facing Duke Energy Kentucky. Additionally, my testimony addresses the capital structure of Duke Energy Kentucky and its cost of debt included in Schedules J-1, J-1.1, J-1.2, J-2, and J-3, which I support. I also sponsor the percentage of construction expenditures financed internally, fixed coverage ratios and the ratings agencies ratings in

Schedule K. I reviewed and approved the financing plan included in both the base and forecasted test periods in this proceeding. Additionally, I provided the following information to Mr. Davey for his use in preparing the forecasts: Duke Energy's dividend policy; Duke Energy Kentucky's debt rate assumptions; existing short-term and long-term debt balances; sales of accounts receivable; capital lease and equipment lease information; and information relating to the long-term debt financing for the Plants in March 2006. I also sponsor Filing Requirements ("FR") FR 6(1), FR 6(2), FR 6(3), FR 6(4), FR 6(5), FR 6(6), FR 6(7), FR 6(8), FR 10(9)(h)(11) and FR 10(9)(j).

II. DUKE ENERGY KENTUCKY'S CURRENT CREDIT RATINGS

Q. HOW ARE DUKE ENERGY KENTUCKY'S OUTSTANDING SECURITIES CURRENTLY RATED BY THE THREE MAJOR CREDIT RATING AGENCIES?

A. As of the date of this testimony, Duke Energy Kentucky's outstanding securities are rated by the three major credit rating agencies as follows:

	Fitch	Moody's	Standard & Poor's
Senior Unsecured Debt	BBB+	Baa1	BBB

The ratings outlook from S&P and Fitch is stable; the ratings outlook from Moody's is positive.

Q. PLEASE EXPLAIN WHAT IS MEANT BY THESE CREDIT RATINGS FOR DUKE ENERGY KENTUCKY'S SENIOR UNSECURED DEBT AND WHY DO SOME RATINGS CARRY A "+"?

A. Obligations carrying the "BBB" rating from Standard & Poor's or Fitch are considered medium grade investment securities. They are described as having adequate protection for the investor. "BBB" rated debt is presumed to be more susceptible to changes in economic conditions than those issuers rated "A." Moody's "Baa2" rating is comparable to the "BBB" from Standard and Poor's and Fitch.

Ratings may also be modified by the addition of a plus or minus sign to indicate relative standing within the major rating category. A "BBB+" credit rating is at the higher end of the "BBB" credit rating category and a "BBB-" credit rating is at the lower end of the "BBB" credit rating category. The "1" in a Moody's rating is the same as a "+" and a "3" is equivalent to a "-".

Q. WHEN WERE DUKE ENERGY KENTUCKY'S CURRENT CREDIT RATINGS ESTABLISHED?

A. Duke Energy Kentucky's current credit ratings were established by Moody's in November 1995, by Standard & Poor's in June 2002, and by Fitch in April 2004. These ratings were all affirmed by the respective agencies in April 2006.

Q. HAS THE MERGER AFFECTED DUKE ENERGY KENTUCKY'S CREDIT RATINGS?

A. The senior unsecured ratings of Duke Energy Kentucky have remained unchanged. The ratings outlook at Moody's has changed to "Positive", and is "Stable" at Fitch and S&P.

Q. HAVE THE MAJOR CREDIT RATING AGENCIES RAISED ANY OTHER CONCERNS ABOUT DUKE ENERGY KENTUCKY?

A. In past reports, the ratings agencies have expressed concerns about the potential for stricter environmental regulations, which could lead to large capital expenditure requirements for Duke Energy Kentucky, given the transfer of the generating plants from Duke Energy Ohio to Duke Energy Kentucky. However, as we incur environmental capital expenditures, we intend to seek timely rate relief.

III. DUKE ENERGY KENTUCKY'S FINANCIAL OBJECTIVES

Q. WHAT ARE DUKE ENERGY KENTUCKY'S FINANCIAL OBJECTIVES?

A. Duke Energy Kentucky's general financial objective is to achieve the fundamentals necessary to provide assured and reasonable access to the capital markets in order to continue to provide cost effective, safe, adequate, environmentally-compliant and reliable service to our customers. Specific financial objectives necessary to enhance or maintain the desired financial strength include: (a) maintaining at least a 50% common equity ratio for Duke Energy Kentucky on a financial capitalization basis; and (b) achieving and maintaining at least a "BBB+" credit rating for Duke Energy Kentucky's senior unsecured debt, and ultimately to improve the credit rating for Duke Energy Kentucky's senior unsecured debt to an "A-" credit rating. If Duke Energy Kentucky were to issue senior secured debt, it is anticipated that these would be rated one notch higher than the senior unsecured debt.

Q. DO YOU BELIEVE THAT DUKE ENERGY KENTUCKY'S CUSTOMERS WILL BENEFIT IF DUKE ENERGY KENTUCKY IS ABLE TO ACHIEVE ITS CREDIT RATING OBJECTIVES?

A. Yes, I do.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY'S CUSTOMERS WILL BENEFIT FROM DUKE ENERGY KENTUCKY ACHIEVING ITS CREDIT RATING OBJECTIVES.

A. There are many reasons why our customers will benefit from the credit rating objectives that we have established. The benefits of achieving and maintaining an "A" credit rating or higher are discussed in the pre-filed testimony of Duke Energy Kentucky witness Dr. Roger A. Morin. These benefits include not only lower overall financing costs, but also greater assurance of access to the capital markets, thus improving Duke Energy Kentucky's ability to maintain a safe, reliable, and low cost level of customer service.

IV. <u>DUKE ENERGY KENTUCKY'S CASH REQUIREMENTS</u>

Q. WHAT ARE DUKE ENERGY KENTUCKY'S CAPITAL NEEDS DURING THE 2006-2007 TIME PERIOD?

A. For the years 2006 and 2007, Duke Energy Kentucky projects expenditures for electric and gas construction projects of approximately $123 million. In connection with the transfer of the Plants from Duke Energy Ohio, Duke Energy Kentucky assumed approximately $167 million in debt. Duke Energy Kentucky subsequently re-financed $90 million of this debt in March 2006 with two issuances of senior notes, totaling $115 million. We are currently reviewing a refinancing of the tax-exempt debt that Duke Energy Kentucky assumed from Duke Energy Ohio as part of the Plant transfer. Duke Energy Kentucky has no long-term debt maturing in 2006 and 2007, excluding any capital lease maturities.

V. DUKE ENERGY KENTUCKY'S CAPITAL STRUCTURE

Q. HOW DID DUKE ENERGY KENTUCKY FINANCE THE THREE GENERATING PLANTS TRANSFERRED FROM DUKE ENERGY OHIO?

A. Duke Energy Ohio transferred the East Bend Generating Station, the Miami Fort Generating Station Unit 6 and the Woodsdale Generating Station (collectively, "the Plants") to Duke Energy Kentucky effective January 1, 2006. At closing, Duke Energy Kentucky financed the Plants by an equity contribution of $139,855,099 from Duke Energy Ohio, and by Duke Energy Kentucky assuming the following debt from Duke Energy Ohio:

Table 1 – Outstanding Debt

Description	Amount
Floating Rate Monthly Demand Pollution Control Revenue Refunding Bonds, 1985 Series A (The Cincinnati Gas & Electric Company Project)	$16,000,000
5½% Collateralized Pollution Control Revenue Refunding Bonds, 1994 Series A (The Cincinnati Gas & Electric Company	$48,000,000
Assignment and Assumption Agreement between The Cincinnati Gas & Electric Company and The Dayton Power and Light Company dated September dated September 30, 2005, related to the 6.5% Collateralized Pollution Control Revenue Refunding Bonds, 1992 Series A (The Dayton Power and Light Company Project)	$12,720,000
Assumption of Accounts Payable from Duke Energy Ohio	$90,280,000
Total:	$167,000,000

Q. DID DUKE ENERGY KENTUCKY SUBSEQUENTLY RE-FINANCE SOME OF THIS DEBT?

A. Yes. On March 10, 2006, Duke Energy Kentucky executed a closing for the sale of $115 million in a private placement of senior unsecured notes, pursuant to a bond purchase agreement executed March 7, 2006. The notes were issued in two series: $50 million of 10-year debentures due 2016, bearing a fixed interest rate of 5.75% and $65 million of 30-year debentures, bearing a fixed interest rate of 6.20%. The proceeds of this debt issuance were primarily used to repay $90,280,000 in accounts payable assumed from Duke Energy Ohio in connection with the Plant transfer. In addition, the proceeds were used to re-finance $15 million of existing higher coupon debt and for general corporate purposes.

Q. WHAT WAS DUKE ENERGY KENTUCKY'S CAPITAL STRUCTURE ON A FINANCIAL REPORTING BASIS AS OF MARCH 31, 2006?

A. Duke Energy Kentucky's corporate capital structure at March 31, 2006, was 49.1% debt (both short-term (including the balance of proceeds from the sale of Accounts Receivable) and long-term), and 50.9% common equity. In the present case, Duke Energy Kentucky's capital structure is based on the projected thirteen-month average for Duke Energy Kentucky as of December 31, 2007, of 49.1% debt (short-term (including the balance of proceeds from sale of Accounts Receivable) and long-term), and 50.9% common equity as detailed on Schedule J-1.1.

VI. DUKE ENERGY KENTUCKY'S COST OF DEBT

Q. DID DUKE ENERGY COMPANY TAKE ANY STEPS SINCE ITS LAST ELECTRIC BASE RATE CASE IN 1991 TO MANAGE ITS FINANCING COSTS, THUS MITIGATING THE RATE INCREASE PROPOSED IN THIS CASE?

A. Yes. Duke Energy Kentucky has aggressively managed its financing costs and was able to reduce the cost of long-term debt from 9.375% at July 31, 1991 (the end of the test period in Case No. 91-370), to 6.845% at December 31, 2005, and projected to be 6.090% for the thirteen-month average forecasted test period ending December 31, 2007.

Q. WHAT IS DUKE ENERGY KENTUCKY'S PROJECTED AVERAGE COST OF SHORT-TERM DEBT FOR THE THIRTEEN MONTHS ENDING DECEMBER 31, 2007?

A. At December 31, 2007, Duke Energy Kentucky's average corporate cost of short-term debt (including cost of proceeds from sale of Accounts Receivable) for the prior thirteen-month period is projected to be 5.138%. The projected short-term interest rates of the notes payable to associated companies were based on Bloomberg's Implied Forwards Curve for one month London Interbank Offered Rate (LIBOR) plus the anticipated fees of Cinergy Corp.'s revolving credit facilities. For the sale of Accounts Receivable, the assumed rate of interest was also based on Bloomberg's Implied Forwards Curve for one month LIBOR plus a credit spread of 20 basis points, which is based on the credit worthiness of banks involved in Duke Energy Kentucky's sale of its retail receivables. The details of this calculation are shown in Schedule J-2, Page 2 of 2.

Q. WHAT IS DUKE ENERGY KENTUCKY'S PROJECTED AVERAGE COST OF LONG-TERM DEBT FOR THE THIRTEEN MONTHS ENDING DECEMBER 31, 2007?

A. Duke Energy Kentucky's corporate cost of long-term debt for the forecasted test period is projected to be 6.090%. The details of this calculation are shown in Schedule J-3, Page 2 of 2.

VII. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULES J-1, J-1.1 AND J-1.2.

A. Schedule J-1, entitled "Cost of Capital Summary" sets forth the projected capital structure and capitalization ratios of Duke Energy Kentucky at August 31, 2006 and the average of the projected balances and rates for the thirteen-month period ending December 31, 2007. The cost of the long-term and short-term debt capitalization components are developed on Schedules J-2 and J-3. The weighted cost of the various capital components is computed by multiplying the respective capitalization ratio by the computed annualized cost rate. The overall weighted cost of capital is reflected in the rate of return requested for the thirteen-month period ending December 31, 2007.

Schedules J-1.1 and J-1.2 entitled "Average Forecasted Period Capital Structure - Current Rates" and "Average Forecasted Period Capital Structure - Proposed Rates," respectively, sets forth Duke Energy Kentucky's projected weighted cost of capital based on the average of the projected balances and rates for the thirteen-month period ending December 31, 2007. Schedule J-1.1 assumes no rate increase and Schedule J-1.2 reflects the balances assuming the proposed rates are in effect.

Mr. Butler supports the accumulated deferred investment tax credit related portions of Schedules J-1, J-1.1 and J-1.2.

Q. PLEASE DESCRIBE SCHEDULES J-2 AND J-3.

A. Schedule J-2, entitled "Embedded Cost of Short-Term Debt," and Schedule J-3, entitled "Embedded Cost of Long-Term Debt," set forth the calculations of the cost of short-term debt and long-term debt, respectively, of Duke Energy Kentucky. The information on page 1 of these schedules was computed at the date of the base period, August 31, 2006. On page 2, the balances and interest rates are based on the average of the projected balances and rates for the thirteen-month period ending December 31, 2007.

Q. WHY IS SCHEDULE J-4 NOT INCLUDED?

A. Schedule J-4 is designed to provide the embedded cost of preferred stock for Duke Energy Kentucky. Since Duke Energy Kentucky has no preferred stock, this schedule has not been filed.

Q. DO YOU SPONSOR ANY OF THE INFORMATION CONTAINED IN ANY OTHER SCHEDULES?

A. Yes. I sponsor the percentage of construction expenditures financed internally, fixed coverage ratios and the ratings agencies ratings in Schedule K.

VIII. FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 6(1).

A. FR 6(1) provides the amount and kinds of stock authorized.

Q. PLEASE DESCRIBE FR 6(2).

A. FR 6(2) provides the amount and kinds of stock issued and outstanding.

Q. PLEASE DESCRIBE FR 6(3).

A. FR 6(3) is a requirement to provide certain terms and conditions for any preferred stock. Since Duke Energy Kentucky has no preferred stock, there is no information to provide.

Q. PLEASE DESCRIBE FR 6(4).

A. FR 6(4) provides a description of certain terms and conditions for any mortgages. Since Duke Energy Kentucky has no mortgages, there is no information to provide.

Q. PLEASE DESCRIBE FR 6(5).

A. FR 6(5) provides certain terms and conditions for any bonds authorized and issued.

Q. PLEASE DESCRIBE FR 6(6).

A. FR 6(6) provides certain terms and conditions for any notes issued.

Q. PLEASE DESCRIBE FR 6(7).

A. FR 6(7) is a requirement to provide certain terms and conditions for other indebtedness.

Q. PLEASE DESCRIBE FR 6(8).

A. FR 6(8) provides certain information regarding dividend payments by Duke Energy Kentucky during the past five years.

Q. PLEASE DESCRIBE FR 10(9)(H)(11).

A. FR 10(9)(h)(11) provides Duke Energy Kentucky's capital structure requirements.

Q. PLEASE DESCRIBE FR 10(9)(J).

A. FR 10(9)(j) is a requirement to provide copies of the prospectuses of the most recent stock or bond offerings.

IX. INFORMATION SUPPLIED TO OTHER WITNESSES

Q. DID YOU SUPPLY ANY INFORMATION TO OTHER WITNESSES FOR THEIR USE IN THIS PROCEEDING?

A. Yes. I supplied Mr. Davey with certain information for the forecasted portion of the base period, consisting of the six months ending August 31, 2006 and the forecasted test period, consisting of the twelve months ending December 31, 2007. I also reviewed the results of the financial forecasts Mr. Davey sponsors to determine whether any changes needed to be made for the financing plan.

Q. WHAT FINANCIAL INFORMATION DID YOU PROVIDE TO MR. DAVEY?

A. I provided the short- and long-term debt interest rates and balances; the planned new issuances of long-term debt and associated expenses; the balances on the sale of accounts receivable; and the capital lease data, including the payment schedules for these leases. I also provided him with the principal and interest payments to convert the Erlanger facility from an operating lease to a capital lease. All of this data was developed in the normal course of developing the original and the revised 2006 annual budget and the 2007 forecast.

Q. **YOU STATED THAT YOU REVIEWED THE FORECASTS TO DETERMINE WHETHER ANY CHANGES NEEDED TO BE MADE FOR THE FINANCING PLAN. WHAT FINANCIAL INFORMATION DO YOU NORMALLY REVIEW FOR THE FORECASTING PROCESS?**

A. I typically review the results of the financial forecasts for the annual budget and for any other forecast work such as the two periods in this proceeding. I review the financing plan, including the dividend levels. For example, I review to see if there are appropriate levels of short-term and long-term debt. If the short-term debt levels have grown too large, I will provide instructions to fund the short-term debt by issuing long-term debt with the specific parameters that should be assumed with that debt issuance. I reviewed these factors for the forecast prepared by Mr. Davey and provided him with the financial plan for the forecast.

Q. **WHAT INSTRUCTIONS DID YOU GIVE REGARDING THE DIVIDEND LEVELS?**

A. I instructed Mr. Davey to follow the Duke Energy dividend policy, which states that the operating companies' dividend amounts will be consistent with the respective operating company maintaining a reasonable capital structure, providing reasonable and adequate service, and maintaining an adequate cash position. In addition, as a matter of normal practice, the dividend payout ratios of the operating companies will represent approximately equal percentages over time of their respective income available for common dividends. The target is a 70%

payout ratio based on net income available, which is in line with general electric utility industry practice. On occasion, an operating company may participate to a greater or lesser extent in the furnishing of cash for Duke Energy's common stock dividends in order to address the unique needs of the operating companies (*e.g.*, construction, operating cash needs, *etc.*) at that time. Based on this policy, and the cash flows and capital structure in the current forecast, the dividend was eliminated in 2006, and is 35% of net income in 2007.

X. CONCLUSION

Q. HOW WAS THE RATE OF RETURN FOR COMMON EQUITY DETERMINED?

A. The return on Common Equity, as contained on Schedules J-1, J-1.1 and J-1.2, reflects the recommendation of Duke Energy Kentucky witness Dr. Roger A. Morin, supported by his testimony in this case.

Q. WERE SCHEDULES J-1, J-1.1, J-1.2, J-2, J-3, AND THE INFORMATION YOU SPONSOR IN SCHEDULE K, FR 6(1), FR 6(2), FR 6(3), FR 6(4), FR 6(5), FR 6(6), FR 6(7), FR 6(8), FR 10(9)(H)(11) FR10(9)(J) AND THE INFORMATION YOU SUPPLIED TO MR. DAVEY PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

State of North Carolina)
) SS:
County of Mecklenburg)

The undersigned, Lynn J. Good, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Lynn Good

Lynn J. Good, Affiant

Subscribed and sworn to before me by Lynn J. Good on this 18th day of May, 2006.

Bonnie B. Williams

NOTARY PUBLIC

My Commission Expires: 11-06-07

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

CAROL E. SHRUM

ON BEHALF OF

DUKE ENERGY KENTUCKY

183681

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE .... -1-

II. COST ALLOCATIONS FOR COMMON COSTS SHARED BY DUKE ENERGY KENTUCKY AND DUKE ENERGY OHIO .... -12-

III. A&G COST ALLOCATIONS BETWEEN DUKE ENERGY KENTUCKY'S GAS AND ELECTRIC OPERATIONS .... -13-

IV. NEW ALLOCATION PROCESSES .... -16-

V. CONCLUSION .... -17-

ATTACHMENTS

ATTACHMENT CES-1 – Service Company Utility Service Agreement

ATTACHMENT CES-2 – Operating Company/Non-Utility Companies Service Agreement

ATTACHMENT CES-3 – Operating Companies Service Agreement

ATTACHMENT CES-4 – Service Company Non-Utility Service Agreement

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Carol E. Shrum, and my business address is 400 South Tyron Street, Charlotte, North Carolina 28201.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as Vice President, Financial Shared Services.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS VICE PRESIDENT OF FINANCIAL SHARED SERVICES.

A. I am responsible for various accounting activities, including the cost allocation processes for service company costs utilized for Duke Energy and its affiliates, including allocations to The Union Light Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A I received a Bachelor of Science degree in Business Administration from the University of North Carolina at Chapel Hill in 1980. I received a Master of Business Administration degree from Queens College in 1986. I am a Certified Public Accountant licensed in the state of North Carolina and I am a Certified Management Accountant.

I was initially employed by Duke Power Company in 1980 as a staff accountant and have since held various accounting or finance related positions in Duke Power Financial Accounting and Analysis, Duke Power Financial

Forecasting, Duke Power Asset Accounting, Duke Energy Corporate Accounting, and Duke Energy Business Services Financial Accounting and Analysis. I also served as the Duke Power Vice President of Planning and Finance from September 2001 through March 2003 and the Duke Power Vice President and Controller from March 2003 through June 2004. I assumed my current position and responsibilities in April 2006 as Vice President of Financial Shared Services for the U.S. Franchised Electric & Gas Business Unit.

Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A I discuss the three service agreements used by Duke Energy Kentucky to assign costs, and which the Commission approved in Case No. 2005-00228, involving the business combination between Duke Energy and Cinergy Corp. ("Cinergy"): the Service Company Utility Service Agreement ("Utility Service Agreement"), the Operating Company/Non-Utility Companies Service Agreement ("Operating Company/Non-Utility Service Agreement"), and the Operating Companies Service Agreement. I also describe the processes to be used to assign costs to the various parties to the proposed Utility Service Agreement. I also sponsor Filing Requirement ("FR") 10(9)(u). Finally, I sponsor certain information that I supplied to Mr. Davey for his use in developing the forecasted financial data.

Q. **PLEASE DESCRIBE THE DUKE ENERGY SERVICES COMPANY.**

A. Duke Energy Shared Services, Inc. ("DESS"), formerly Cinergy Services, Inc., and Duke Energy Business Services, LLC ("DEBS") are wholly-owned subsidiary service companies of Duke Energy. DESS and DEBS provide a variety of administrative, management, and support services (Functions), such as accounting and human resources, to Duke Energy and its affiliates pursuant to two agreements: the Utility Service Agreement and the Non-Utility Service Agreement. Under the Utility Service Agreement, DESS and DEBS provide services to and on behalf of Duke Energy's utility operating companies, including Duke Energy Kentucky. Under the Non-Utility Service Agreement, DESS and DEBS provide services to and on behalf of Duke Energy's non-utility companies. These affiliate companies receiving services from DESS and DEBS are referred to as "Client Companies."

Q. WHAT IS COST ALLOCATION?

A. Cost allocation is the process of assigning the costs incurred in providing certain services to the appropriate affiliates or companies.

Q. PLEASE DESCRIBE WHAT IS MEANT BY THE TERM "COST."

A. "Cost," or "fully embedded cost," refers to all components of costs including salaries and wages, office supplies and expenses, outside services employed, property insurance, injuries and damages, employee pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and cost of capital.

Q. WHAT ARE THE CATEGORIES OF COST ALLOCATIONS IMPACTING DUKE ENERGY KENTUCKY AND ITS AFFILIATES?

A. In general, there are three categories of cost allocations that affect Duke Energy Kentucky and its affiliates: (1) cost allocations from DESS and DEBS, the two affiliate service companies of Duke Energy; (2) cost allocations between Duke

Energy Kentucky and Duke Energy Ohio for common costs shared by Duke Energy Ohio and Duke Energy Kentucky; and (3) A&G cost allocations between gas and electric operations.

Q. PLEASE DESCRIBE THE UTILITY AND NON-UTILITY SERVICE AGREEMENTS.

A. The Utility Service Agreement (Attachment CES-1), the Operating Company/Non-Utility Service Agreement (Attachment CES-2) and the Operating Companies Service Agreement (Attachment CES-3) were entered into and approved in connection with the Duke/Cinergy merger by the Kentucky Public Service Commission, the Public Utilities Commission of Ohio, and the Indiana Utility Regulatory Commission. Approval of the agreements by the North Carolina Utilities Commission is pending. Additionally, DESS and DEBS are parties to the Non-Utility Service Agreement (Attachment CES-4), though Duke Energy Kentucky is not a party to this agreement.

The Utility Service Agreement and the Non-Utility Service Agreement describe the types of services that DESS and DEBS provide and how the costs of such services are determined, including the methods of assigning costs among Duke Energy Kentucky and other Client Companies. The Operating Company/Non-Utility Service Agreement describes the terms for services to be provided between Duke Energy Kentucky and certain non-utility affiliates. The Operating Companies Service Agreement describes the terms for services to be provided between Duke Energy Kentucky and its utility affiliates.

Q. PLEASE DESCRIBE HOW COSTS OF DESS AND DEBS ARE ACCOUNTED FOR UNDER THE UTILITY SERVICE AGREEMENT AND THE NON-UTILITY SERVICE AGREEMENTS.

A. DESS and DEBS maintain an accounting system in which all of their costs are accumulated. These costs are charged to the appropriate Client Companies monthly, using one of the three approved methods of assignment contained in the Utility and/or Non-Utility Service Agreements.

Q. WHAT ARE THE APPROVED METHODS OF ASSIGNMENT?

A. The approved methods of assignment are: (1) directly assignable; (2) distributable; and (3) allocable.

Q. PLEASE DESCRIBE EACH METHOD OF ASSIGNMENT.

A. The direct assignment method is utilized to direct charge costs for services specifically performed for a single Client Company. The distributable cost assignment method is used to assign costs for services rendered specifically for two or more Client Companies. The allocable method of assignment is used to allocate costs for services of a general nature, which are applicable to more than one of the Client Companies.

Q. WHAT TYPES OF EXPENDITURES ARE DIRECTLY ASSIGNED FROM DESS OR DEBS TO DUKE ENERGY KENTUCKY?

A. DESS or DEBS employees who work on a project specifically for Duke Energy Kentucky, charge their labor and expenses directly to Duke Energy Kentucky. For example, the legal services Function will charge Duke Energy Kentucky directly for work performed specifically for Duke Energy Kentucky.

Q PLEASE EXPLAIN THE DISTRIBUTABLE CHARGES FROM DESS OR DEBS TO DUKE ENERGY KENTUCKY.

A. DESS or DEBS employees who work on a project specifically for Duke Energy Kentucky and one or more other Client Companies, will distribute those costs to those companies directly benefiting from the services based on a logical and reasonable basis.

Q. PLEASE EXPLAIN THE ALLOCABLE CHARGES FROM DESS OR DEBS TO DUKE ENERGY KENTUCKY.

A. Allocable charges to Duke Energy Kentucky are for a portion of expenditures originating on DESS or DEBS books that are applicable to both Duke Energy Kentucky and one or more other Client Companies, but which cannot be charged directly to Duke Energy Kentucky. These charges are allocated to Duke Energy Kentucky based on allocation methods set forth in Appendix A of the Utility Service Agreement. For example, costs related to Investor Relations activities are applicable to all Duke Energy affiliates but cannot be direct charged to any one affiliate. Those costs are allocated to all affiliates using the allocation factor described for the Investor Relations Function in Appendix A of the Utility Service Agreement.

Q. UNDER WHAT CIRCUMSTANCES ARE THE ALLOCATION METHODS SET FORTH IN APPENDIX A OF THE UTILITY SERVICE AGREEMENT USED TO DETERMINE CHARGES TO DUKE ENERGY KENTUCKY?

A. The allocation methods provided in Appendix A of the Utility Service Agreement are used by DESS or DEBS to assign charges to Client Companies, including Duke Energy Kentucky, for activities that cannot be charged directly or distributed. For example, costs associated with the human resources' payroll Function are allocated to the Client Companies, including Duke Energy Kentucky, using the Number of Employees Ratio as provided in the Utility Service Agreement.

Q. WHAT ARE THE ALLOCATION METHODS SPECIFIED IN APPENDIX A OF THE UTILITY SERVICE AGREEMENT?

A. Eighteen allocation ratios are specified in the Utility Service Agreement. These ratios are the: (1) Sales Ratio; (2) Electric Peak Load Ratio; (3) Number of Customers Ratio; (4) Number of Employees Ratio; (5) Construction-Expenditures Ratio; (6); Circuit Miles of Electric Distribution Lines Ratio; (7) Circuit Miles of Electric Transmission Lines Ratio; (8) Number of Central Processing Unit Seconds Ratio; (9) Revenues Ratio; (10) Inventory Ratio; (11) Procurement Spending Ratio; (12) Square Footage Ratio; (13) Gross Margin Ratio; (14) Labor Dollars Ratio; (15) Number of Personal Computer Work Stations Ratio; (16) Number of Information Systems Servers Ratio; (17) Total Property, Plant and Equipment Ratio; and (18) Generating Unit MW Capability Ratio.

Q. WHAT WAS THE RATIONALE BEHIND THE SELECTION OF THESE RATIOS?

A. Consistent with traditional cost causation principles, the ratios represent "cost drivers" for a particular Function (*i.e.*, those factors which are the greatest contributors to costs). For example, costs related to human resources are allocated based on the Number of Employees Ratio. Costs related to support of personal computers are allocated based on the Number of Personal Computer Workstations Ratio. Costs related to meter reading and to customer billing and payment processing in the Marketing and Customer Relations Function, are allocated based on the Number of Customers Ratio. For some Functions, costs of a general nature are allocated based on a weighted-average of more than one ratio. The Utility Service Agreement describes how the weighted-average ratios are calculated.

Q. HOW IS THE DESS AND DEBS NON-UTILITY COST ASSIGNMENT PROCESS DIFFERENT FROM THE UTILITY COST ASSIGNMENT PROCESS?

A. The non-utility cost assignment process is virtually identical to the utility cost assignment process.

Q. HOW ARE COSTS INCURRED BY DESS AND DEBS ON BEHALF OF BOTH UTILITY AND NON-UTILITY COMPANIES ALLOCATED TO THESE COMPANIES?

A. Where DESS or DEBS performs a Function that serves both utility and non-utility affiliate companies, the costs are allocated between the utility companies and the non-utility companies using the appropriate allocation method as described in Appendix A. For instance, costs incurred by DESS for human resource Functions are to be allocated, under both the Utility and Non-Utility Service Agreements, based on the Number of Employees ratio. Thus, common human resources costs are allocated based on the respective number of employees each company employs.

Q. WHAT PROCESSES DO DESS AND DEBS EMPLOYEES FOLLOW IN ALLOCATING THEIR TIME AND EXPENSES UNDER THE UTILITY AND NON-UTILITY SERVICE AGREEMENTS?

A. All source documents (*e.g.*, timesheets, expense reports, invoices, and journal entries) applicable to DESS and DEBS require appropriate accounting coding to be used, which identifies the affiliate or affiliates to be assigned the costs. The initiating department determines the appropriate coding for each transaction. The coding indicates whether the cost should be assigned directly, distributed, or allocated, and it also determines the appropriate allocation method to be used. Using this coding, the accounting system will process each transaction and assign the appropriate costs to each respective Client Company. The allocation percentages for each allocation method are updated periodically, at a minimum annually.

Q. PLEASE DESCRIBE FURTHER THE PROCESS USED TO UPDATE THE ALLOCATION PERCENTAGES.

A. On a periodic basis, and at a minimum, annually, the Financial Shared Services organization will review allocation methods. This review will include updating source data used to develop the allocation percentages. For example, annually, the allocator based on the number of employees, which is primarily utilized to allocate costs associated with the human resources Function, is updated to reflect the number of employees of each Duke Energy affiliate company.

Q. PLEASE DESCRIBE FR 10(9)(U), PAGE 1 OF 4.

A. FR 10(9)(u), page 1 of 4 outlines the methods used, prior to the merger in April 2006 and according to the Utility Service and Non-Utility Service Agreements as amended in February 1997, to allocate costs that could not be charged directly by DESS to the regulated and non-regulated Duke Energy affiliates, including Duke Energy Kentucky. FR 10(9)(u), page 1(a) of 4 summarizes the total amount of expenditures charged from DESS to Duke Energy Kentucky for the three years ended December 31, 2003, 2004 and 2005 and for the base period and the forecasted test period which include the twelve month periods ending August 31, 2006 and December 31, 2007, respectively.

Q. ARE THE ALLOCATION METHODS LISTED IN FR 10(9)(U), PAGE 1 OF 4 THE SAME COST ALLOCATION METHODS CONTAINED IN THE UTILITY SERVICE AGREEMENT APPROVED FOR USE BEGINNING IN APRIL 2006?

A. The allocation methods listed in FR 10(9)(u) page 1 of 4 are similar to the allocation methods contained in the Utility Service Agreement. The allocation methods listed in FR 10(9)(u) page 1 of 4 are 7 of the 18 methods included in the Utility Service Agreement.

Q. DID THE U.S. SECURITIES AND EXCHANGE COMMISSION ("SEC") CONDUCT ANY AUDITS OF DESS SUBSEQUENT TO THE SEC'S APPROVAL OF THE PREDECESSOR UTILITY SERVICE AGREEMENT?

A. Yes. In 1996, the SEC conducted a field audit of Cinergy Services, Inc. ("Cinergy Services") (now known as "DESS") under the predecessor to the Utility Service Agreement, which was substantially similar to the current agreement except that it had fewer allocation ratios. The FERC participated in that audit, and also conducted its own field audits of Duke Energy Indiana and Duke Energy Ohio in 1996 and 1997, respectively. The SEC and the FERC both concluded that the pricing and cost allocation methods used by Cinergy Services complied with the then applicable rules and regulations of the SEC.

Q. DID CINERGY CONDUCT ANY AUDITS OF CINERGY SERVICES?

A. Yes. Cinergy conducted an internal audit of Cinergy Services biennially. Cinergy conducted these internal audits in 2000, 2002 and 2004. These audits, which were shared with the SEC, concluded that the pricing and cost allocation methods used by Cinergy Services complied with the SEC's rules and regulations.

Q. WERE ANY AUDITS CONDUCTED OF DEBS?

A. Yes. Duke Energy has conducted an internal audit of DEBS cost allocations on an annual basis. These audits, which were shared with the North Carolina Public Staff, concluded that the pricing and cost allocation methods used by DEBS complied with the cost allocation manual filed with the North Carolina Utilities Commission.

II. COST ALLOCATIONS FOR COMMON COSTS SHARED BY DUKE ENERGY KENTUCKY AND DUKE ENERGY OHIO

Q. DO ALL CHARGES FOR DUKE ENERGY KENTUCKY ORIGINATE ON DUKE ENERGY KENTUCKY'S BOOKS?

A. No. Charges can originate either on Duke Energy Kentucky's books for its own operations or can originate from its parent company, Duke Energy Ohio, and/or other affiliated companies.

Q. PLEASE EXPLAIN THE DIRECT CHARGES FROM DUKE ENERGY OHIO TO DUKE ENERGY KENTUCKY?

A. Direct charges from Duke Energy Ohio to Duke Energy Kentucky are for costs such as employee labor, employee expenses, and inventory (material) transactions which are specifically incurred for Duke Energy Kentucky's gas and/or electric operations.

Q. WHAT TYPES OF CHARGES ARE ALLOCATED TO DUKE ENERGY KENTUCKY FROM DUKE ENERGY OHIO?

A. Charges allocated to Duke Energy Kentucky from Duke Energy Ohio represent a portion of costs originating on Duke Energy Ohio's books that apply to gas and/or electric activities which cannot be charged directly and which apply to both Duke Energy Kentucky and Duke Energy Ohio.

Q. WHAT TYPES OF EXPENDITURES ARE CHARGED DIRECTLY VERSUS ALLOCATED TO DUKE ENERGY KENTUCKY?

A. The majority of common costs for Duke Energy Kentucky and Duke Energy Ohio are direct charged to the appropriate affiliate. Expenditures incurred directly for a specific project can be charged directly to Duke Energy Kentucky. A small portion of common costs may be allocated to Duke Energy Kentucky from Duke Energy Ohio. These costs include certain metering and customer related costs.

Q. PLEASE BRIEFLY DESCRIBE FR 10(9)(U), PAGES 2 OF 4 AND 2(A) OF 4.

A. FR 10(9)(u), page 2 of 4 provides the bases used to allocate charges between Duke Energy Ohio and Duke Energy Kentucky which originate on Duke Energy Ohio's books and are allocated to Duke Energy Kentucky. Page FR 10(9)(u), page 2 of 4 also provides the bases used to allocate these charges. FR 10(9)(u), page 2(a) of 4 provides the amount of these costs allocated to Duke Energy Kentucky for the three years ended December 31, 2003, 2004 and 2005 and for the base period and for the forecasted test period ended August 31, 2006 and December 31, 2007, respectively.

III. A&G COST ALLOCATIONS BETWEEN DUKE ENERGY KENTUCKY'S GAS AND ELECTRIC OPERATIONS

Q. WHAT TYPES OF EXPENDITURES ARE CHARGED DIRECTLY VERSUS ALLOCATED TO GAS OR ELECTRIC?

A. Most expenditures incurred directly for a specific project can be charged directly to a gas or an electric account. Certain administrative costs for general support functions, such as Accounts Payable and Accounting, are common to both gas and electric operations, and must be allocated. In addition, a portion of those costs is also capitalized.

Q. HOW HAVE THE ALLOCATION BASES FOR A&G EXPENDITURES BEEN DETERMINED?

A. A study of A&G departments performing common activities (gas and electric operations and capital and expense activities) has been prepared annually. Department managers are asked to describe the services provided by their departments, as well as to indicate the operational function (gas and/or electric) they have supported in the previous twelve months. They are also asked to indicate the time they have spent in support of capital and/or operation or maintenance activities for both gas and electric operations.

Q. **HOW IS THIS INFORMATION USED TO DETERMINE ASSIGNMENT OF COMMON A&G COSTS?**

A. The cost allocation process for common A&G expenditures allocates costs based on statistical data that best relates to the specific activity to be allocated. For example, Accounts Payable activities are allocated to capital and expense accounts for both gas and electric operations based on the actual accounting distribution for the Accounts Payable transactions performed during the period of the study.

Q. **PLEASE BRIEFLY DESCRIBE FR 10(9)(U), PAGES 3 AND 4.**

A. FR 10(9)(u), page 3 of 4 provides the bases used to allocate A&G charges between gas and electric operations for those items that cannot be directly charged. FR 10(9)(u), page 3(a) of 4, summarizes the total amount of A&G expenditures allocated between gas and electric A&G expense accounts for the three years ended December 31, 2003, 2004 and 2005 and for the base period and the forecasted test period ended August 31, 2006 and December 31, 2007, respectively. FR 10(9)(u), page 4 of 4 provides the bases used to allocate A&G

charges between capital and expense for those items that cannot be directly charged. FR 10(9)(u), page 4 of 4 also provides the amount of A&G costs allocated to capital accounts for the three years ended December 31, 2003, 2004 and 2005 and for the base period and the forecasted test period ended August 31, 2006 and December 31, 2007, respectively.

Q. ARE THE ALLOCATIONS INDICATED ON FR 10(9)(U), PAGES 3 AND 4 USED TO DETERMINE ALL CHARGES THAT SHOULD BE RECORDED TO GAS AND ELECTRIC OPERATIONS FOR BOTH CAPITAL AND EXPENSE ACCOUNTS?

A. No. Expenditures applicable to gas or electric operations are charged directly whenever possible. For example, employees performing work on a specific project will charge direct to the appropriate gas and/or electric expense or capital account.

Q. UNDER WHAT CIRCUMSTANCES ARE THE ALLOCATIONS INDICATED ON FR 10(9)(U), PAGES 3 AND 4 USED?

A. The allocation bases on these schedules are used to allocate charges for activities which cannot be charged directly, such as costs applicable to both gas and electric expense and/or to capital accounts. The allocation processes in the financial system combine the DESS and DEBS allocation factors and the gas and electric allocation factors into composite allocation factors.

Q. DID YOU PROVIDE ANY INFORMATION TO OTHER WITNESSES FOR THEIR USE IN THIS PROCEEDING?

A. Yes, I supplied Mr. Davey with the allocation factors in effect immediately prior to the merger, for his use in developing the forecasted financial data.

IV. NEW ALLOCATION PROCESSES

Q. ARE THE COST ALLOCATION METHODS THAT DESS AND DEBS UTILIZE DIFFERENT FROM THE COST ALLOCATION PROCESSES USED BY DUKE ENERGY KENTUCKY PRIOR TO THE MERGER?

A. The basic methodologies utilized are similar, but there has been some updating of factors used in the process.

Q. WERE THE NEW ALLOCATION PROCESSES REFLECTED IN THE FORECASTED TEST PERIOD OF THIS CASE?

A. No. The forecasted test period is based on the budgeting process and cost allocation methods used by Duke Energy Kentucky prior to the merger.

Q. DO YOU ANTICIPATE THE NEW COST ALLOCATION PROCESSES TO HAVE A MATERIAL IMPACT TO THE AMOUNT OF EXPENDITURES ALLOCATED TO DUKE ENERGY KENTUCKY'S ELECTRIC OPERATIONS ON AN ONGOING BASIS?

A. No. Many of the new allocation factors are the same as the previous allocation factors. All of the allocation factors have been developed with the intent of assigning costs consistent with cost causation. Given that objective, I do not anticipate a material impact to the amount of expenditures allocated to Duke Energy Kentucky's electric operations.

V. CONCLUSION

Q. WAS THE INFORMATION YOU PREPARED FOR MR. DAVEY AND WAS FR 10(9)(U) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

State of North Carolina)
) SS:
County of Mecklenburg)

The undersigned, Carol E. Shrum, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Carol E. Shrum

Carol E. Shrum, Affiant

Subscribed and sworn to before me by Carol E. Shrum on this 24th day of May, 2006.

Kathy S. Moraleda

NOTARY PUBLIC

My Commission Expires: December 13, 2008

DUKE ENERGY KENTUCKY

Basis for Allocating Cinergy Services, Inc.'s Costs Between Affiliates
For Those Items Which Cannot Be Charged Direct

Cinergy Services Inc. (Services), a wholly-owned subsidiary service company of Cinergy Corp. and an affiliate of Duke Energy Kentucky, was created to provide a variety of administrative, management and support services to both utility and non-utility affiliates under the terms of the Utility Service Agreement and the Non-Utility Service Agreement, as amended, dated March 1994 and February 1997, respectively.

Under the provisions of these agreements, Services may provide the following services to utility and non-utility affiliates: Information Systems, Meters and Transportation, Electric System Maintenance, Marketing and Customer Relations, Electric Transmission and Distribution Engineering and Construction, Power Engineering and Construction, Human Resources, Materials Management, Facilities, Accounting, Power Planning, Public Affairs, Legal, Rates, Finance, Right of Way, Internal Auditing, Environmental Affairs, Fuels, Investor Relations, Planning and Executive.

The above mentioned service agreements provide the basis for how costs for services will be assigned, distributed or allocated between companies. To the extent costs are allocated, these agreements specify the appropriate allocation methodologies (factors) for each of the above mentioned services. The allocation methodologies (factors) in these agreements include:

Utility Service Agreement	Non-Utility Service Agreement
Sales Ratio	Revenues Ratio
Electric Peak Load Ratio	Number of Customers Ratio
Number of Customers Ratio	Number of Employees Ratio
Number of Employees Ratio	Construction Expenditures Ratio
Construction Expenditures Ratio	Number of Central Processing Unit Seconds Ratio
Circuit Miles of Electric Distribution Lines Ratio	Direct Cost Ratio
Number of Central Processing Unit Seconds Ratio	

The Service Agreements require all allocation methodologies to be reviewed and updated periodically (not less than annually). Pursuant to an SEC request, the Internal Auditing department conducts an independent review of all Service Company bills monthly.

Amounts assigned to Duke Energy Kentucky from Services during the years ended December 31, 2005, 2004, 2003, the base period, and forecasted test period are provided by method of assignment in the attached schedule.

In April 2006, the merger between Cinergy Corp. and Duke Energy was consummated. Effective with that merger, Cinergy Services Inc. was renamed to Duke Energy Shared Services, Inc. Also effective with the merger, new Utility Service and Non-Utility Service Agreements were approved. These agreements included certain new allocation factors. These new cost allocation processes are not expected to have a material effect on Duke Energy Kentucky allocated amounts. The base period and forecasted test period data reflected herein is based upon the budgeting process and cost allocation methods used by Duke Energy Kentucky prior to the merger.

Duke Energy Kentucky

Analysis of Amounts Assigned to Duke Energy Kentucky from Cinergy Services, Inc.
Summarized by Allocation Basis
For the Years Ended December 31, 2003, 2004 and 2005, Base Period, and Forecasted Test Period

Allocation Basis	Years Ended December 31, 2003	Years Ended December 31, 2004	Years Ended December 31, 2005	Base Period (1)	Forecasted Test Period (2)
Circuit Miles	$ 1,080	$ 755	$ 163	$ -	$ -
Construction	$ 1,390,648	$ 1,025,001	$ 649,348	$ 396,523	$ 329,787
CPU Seconds	$ 540,064	$ 605,326	$ 109,429	$ 21,612	$ 17,975
Customers	$ 3,544,182	$ 3,562,990	$ 3,735,205	$ 4,326,072	$ 3,597,979
Direct	$ 6,455,877	$ 5,150,019	$ 7,392,711	$ 10,952,132	$ 9,108,850
Employees	$ 2,842,829	$ 2,999,254	$ 5,103,991	$ 6,514,836	$ 5,418,366
Employees, Customers, and Construction	$ 675,574	$ 865,652	$ 647,537	$ 692,539	$ 575,982
Indirect	$ 1,238,466	$ 1,474,754	$ 1,407,336	$ 3,295,118	$ 2,740,539
Revenues and Sales	$ 864,591	$ 1,432,492	$ 2,465,467	$ 612,311	$ 509,257
Revenues, Sales and Construction	$ 2,404,908	$ 2,708,685	$ 8,294,821	$ 16,296,505	$ 13,553,747
Sales	$ 2,084,882	$ 1,471,508	$ 861,237	$ 606,529	$ 504,448
Peakload	$ -	$ -	$ 32,753	$ 364,480	$ 303,136
Grand Total	$ 22,043,101	$ 21,296,436	$ 30,699,998	$ 44,078,657	$ 36,660,066

(1) Base period represents September 2005 - February 2006 Actual and March 2006 - August 2006 Budget
(2) Forecasted test period represents January 2007 - December 2007 Budget

Note: Amounts reflect all costs (operations, maintenance and construction) assigned to Duke Energy Kentucky.

THE UNION LIGHT, HEAT AND POWER COMPANY

Basis for Allocating Charges Between The Cincinnati Gas & Electric Company
And The Union Light, Heat and Power Company for Those Items Which Cannot Be Charged Direct

Certain of CG&E departments provide services to CG&E and ULH&P. To the extent that the charges from those departments cannot be direct charged to a particular company, they are allocated. The bases for such allocations are determined by a review of the work activities performed by each department. The costs associated with each activity are distributed to the appropriate company based on a quantitative measure related to the work being performed. The primary quantitative measures utilized prior to April 2005 include:

1. Number of Retail Gas and Electric Customers.
2. Number of Retail Gas Customers.
3. Number of Retail Electric Customers.
4. Number of Retail Gas and Electric Meters.
5. Number of Retail Gas Meters.
6. Number of Retail Electric Meters.

Various departments of CG&E provide services to CG&E and ULH&P. Whenever possible, the costs of these services are charged direct to the company for which the services were performed. In some cases, however, there is no reasonable basis for direct charging an expense to either CG&E or ULH&P, so the expense must be allocated between the two companies. Examples of such expenses are the Marketing Department's expense for preparing bill inserts for both CG&E and ULH&P customers and the Customer Services Department's expense for credit and collection activity provided to both CG&E and ULH&P. These are activities that benefit both CG&E and ULH&P, but cannot be directly charged to either, so the cost of these activities is allocated between the companies.

Most costs can be directly charged, such that the need to allocate costs only arises for a small percentage of ULH&P's total costs. When costs must be allocated, the company utilizes cost causation principles, matching each item of expense with an activity that most reasonably applies to the function nature of the expense being allocated. The amounts allocated by CG&E to ULH&P during the years ended December 31, 2005, 2004 and 2003 are provided by allocation code in the attached Schedule FR9(u)2(a) of 4. For budgeting purposes, these costs have been direct charged.

The allocation codes provided in the attached Schedule FR9(u)2(a) of 4 that were utilized prior to April 2005 were based on fixed percentage distributions between CG&E and ULH&P. The "C" in the location code designates the portion of the costs allocated to CG&E, with the remainder allocated to ULH&P. For example, allocation code "C50" indicates that the costs were allocated 50% to CG&E and 50% to ULH&P; allocation code "C76" indicates that the costs were allocated 76% to CG&E and 24% to ULH&P, etc.

Beginning in April 2005, with the implementation of a new Finance and Accounting system, an increased emphasis was placed on charging direct to the appropriate affiliate company whenever feasible. This resulted in a reduction in the number of allocation bases available for use to only include the following three methods:

1. Number of Retail Gas and Electric Customers (CCU)
2. Number of Gas Meters (MCU)
3. Total Gas Sales (SCU)

Each department is responsible for periodically reviewing the activities it performs and for determining an appropriate mechanism for allocating its common costs, based on the nature of the work being performed. In so doing, the goal is to select the quantitative measure that most closely relates to the nature of the work performed, such that the quantitative measure used to allocate common costs is reasonable.

For the majority of costs, CG&E department general managers select the Number of Retail Gas and Electric Customers as the method for allocating common costs, which as of December 31, 2005 was split approximately 83% - CG&E and 17% ULH&P.

The Union Light, Heat and Power Company

Analysis of Amounts Assigned to ULH&P from CG&E
For the Years Ended December 31, 2003, 2004, 2005, Base Period, and Forecasted Test Period

	Years Ended December 31,				
Allocation Code (1)	2003	2004	2005	Base Period (3)	Forecasted Test Period (4)
C50	$ 1,421	$ 181	$ 55	$ -	$ -
C80	$ 182,794	$ 137,881	$ 55,905	$ -	$ -
C84	$ 651,781	$ 884,821	$ 183,284	$ -	$ -
C85	$ 12	$ -	$ -	$ -	$ -
C87	$ 153,048	$ 169,928	$ 37,108	$ -	$ -
C88	$ 5,378	$ 1,197	$ 55	$ -	$ -
C90	$ 17,186	$ 17,150	$ 295	$ -	$ -
C94	$ -	$ -	$ 3	$ -	$ -
CCU (2)	$ -	$ -	$ 1,265,145	$ 911,429	$ -
MCU (2)	$ -	$ -	$ 318,808	$ 206,439	$ -
SCU (2)	$ -	$ -	$ 472	$ 160	$ -
Total	$ 1,011,620	$ 1,211,159	$ 1,861,130	$ 1,118,028	$ -

(1) Allocation Code represents a fixed percentage split between CG&E and ULH&P. For example, "C84" would allocate the common cost between CG&E and ULH&P in the following proportions: CG&E 84%, ULH&P 16%. Amounts presented represent amounts allocated to ULH&P.

(2) Effective in April 2005, use of the fixed percentage allocation codes was discontinued. These codes were replaced by CCU, MCU and SCU codes which allocate between CG&E and ULH&P based on number of gas & electric customers, number of gas mains and total gas sales, respectively.

(3) Base period represents September 2005 - February 2006 Actual and March 2006 - August 2006 Budget. Budget period amounts have been directly charged to ULH&P.

(4) Forecasted test period represents January 2007 - December 2007 Budget. Budget period amounts have been directly charged to ULH&P.

DUKE ENERGY KENTUCKY

Basis for Allocating Administrative and General Charges Between Gas and Electric Expense
For Those Items Which Cannot Be Charged Direct

To the extent that Duke Energy Kentucky's A&G costs cannot be directly charged to gas and/or electric expense, they are allocated using the results of an annual study. The annual study consists of a general review of the activities performed by each department charging A&G accounts. Departmental costs are then distributed based on quantitative measures associated with the activity performed. The allocation methods utilized during the year ended December 31, 2005 are as follows:

1. Labor Dollars Charged by Operating Department.

2. Number of Retail Customers.

3. Number of General Ledger Journal Entry Transaction Lines.

4. Number of Accounts Payable Transaction Lines.

5. Inventory Levels by Operating Department.

6. Number of Miscellaneous Accounts Receivable Journal Entry Transaction Lines.

7. Revenue Dollars.

The amount of A&G costs allocated between gas and electric during the years ended December 31, 2005, 2004, 2003, the base period, and forecasted test period are provided by A&G account number in the attached Schedule FR9-u-2(a) of 3.

The annual study referred to above is completed during the fourth quarter of each calendar year. The study includes a review of the departments charging A&G accounts during the year. The review consists of a survey questionnaire and / or interview and focuses on the services provided for the current year and significant changes forecasted for the upcoming year. The focus of the study is to determine what administrative functions provide support to the company's gas and electric operations and how these administrative functions benefit gas and electric operations. The study also contains a review of the seven categories of statistical data listed above, which is used to allocate A&G costs between gas and electric expense. These statistics are computed using various company sources (i.e., accounting and payroll systems, etc.) and represent the gas/electric splits for the current year.

Under cost causation principles, the functional activities of each department are matched with the allocation method that most closely relates to the nature of the work performed. Departments are assigned a gas / electric percentage (%) split allocation for their departments' predominant activity. In April 2005, effective with the implementation of the new Finance &Accounting system, Cinergy combined certain of its cost allocation processes into one process. Cinergy's combined cost allocation process, as it relates to Duke Energy Kentucky's electric operation, primarily reflects the combination of the old gas and electric cost allocation process and the Cinergy Services or new DESS cost allocation process. The results of these two independent studies have been linked, resulting in a combined allocation percentage for each specific transaction.

Duke Energy Kentucky

Administrative and General Charges Allocated between Gas and Electric Expense Accounts
For the Years Ended December 31, 2003, 2004, 2005, Base Period and Forecasted Test Period

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	12/31/2003			12/31/2004			12/31/2005 (3)			Base Period (1) (3)			Forecasted Test Period (2) (3)		
		Electric	Gas	Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas	Total
920000	A&G Salaries	$2,606,325		$ 2,606,325	$3,153,752		$ 3,153,752	$ 2,981,638	2,441,205	$ 5,422,843	$ 7,226,751	$ 2,533,524	$ 9,760,274	$ 8,524,059	$ 1,801,201	$10,325,260
920090	A&G Salaries		2,467,668	2,467,668		2,826,897	2,826,897									
921000	A&G Expense	710,946		710,946	785,557		785,557	1,127,521	970,375	2,097,896	1,966,547	1,154,516	3,121,062	2,646,281	953,981	3,600,262
921090	A&G Expense		729,373	729,373		661,857	661,857									
923000	Outside Services	542,503		542,503	779,234		779,234	1,018,193	1,053,262	2,071,455	1,052,644	584,148	1,636,792	1,894,369	645,169	2,539,538
923090	Outside Services		558,206	558,206		683,186	683,186									
924000	Property Insurance	24,184		24,184	24,742		24,742	470,171	13,691	483,862	294,000	-	294,000	-	-	-
924090	Property Insurance		24,281	24,281		23,115	23,115									
925000	Injuries and Damages	148,509		148,509	92,343		92,343	431,046	454,147	885,194	675,880	262,719	938,598	680,060	63,394	743,454
925090	Injuries and Damages		149,100	149,100		87,556	87,556									
926000	Employee Pensions and Benefits	(349,766)		(349,766)	(315,262)		(315,262)	(253,635)	497,147	243,512	(106,010)	(84,715)	(190,725)	-	-	-
926090	Employee Pensions and Benefits		(105,639)	(105,639)		(131,653)	(131,653)									
930000	General Advertising Expense	80,982		80,982	101,963		101,963	34,208	30,252	64,460	14,498	9,458	23,957	16,851	10,406	27,257
930090	General Advertising Expense		104,819	104,819		108,348	108,348									
930200	General Miscellaneous Expense	275,887		275,887	25,283		25,283	267,669	208,774	476,443	408,864	225,628	634,493	602,873	123,494	726,367
930202	General Miscellaneous Expense						-			-						
930290	General Miscellaneous Expense		276,903	276,903		22,362	22,362									
931000	Rents	1,038,644		1,038,644	953,975		953,975	1,410,436	1,151,658	2,562,094	1,660,873	784,527	2,445,401	1,680,071	511,850	2,191,921
931090	Rents		974,465	974,465		940,946	940,946									
935000	Maintenance of General Plant	227,756		227,756	310,340		310,340	254,432	131,591	386,023	313,398	51,308	364,706	498,372	13,814	512,186
935090	Maintenance of General Plant		218,229	218,229		238,813	238,813									
		$5,305,970	$ 5,397,405	$10,703,375	$5,911,927	$5,461,427	$11,373,354	$ 7,741,679	$6,952,102	$14,693,781	$13,507,445	$ 5,521,113	$19,028,558	$16,542,936	$ 4,123,309	$20,666,245

(1) Base Period represents September 2005 - February 2006 Actual and March 2006 - August 2006 Budget.
(2) Forecasted test period represents January 2007 - December 2007 Budget.
(3) Effective in 2005 with the new Finance and Accounting system implementation, Duke Energy Kentucky's chart of accounts has been modified to combine the gas and electric specific accounts.

DUKE ENERGY KENTUCKY

Basis for Allocating Administrative and General Charges Between Capital and Expense
For Those Items Which Cannot Be Charged Direct

To the extent that Duke Energy Kentucky's Administrative and General (A&G) costs cannot be direct charged to construction activities, they are allocated using the results of an annual study. The annual study consists of a general review of the activities performed by each department charging A&G accounts. Once it is determined that an A&G departmental activity is in support of construction and cannot be charged direct, those applicable costs are then distributed based on quantitative measures associated with the activity performed. The allocation methods utilized during the year ended December 31, 2005 are as follows:

1. Number of General Ledger Journal Entry Transaction Lines

2. Number of Accounts Payable Transaction Lines

3. Number of Miscellaneous Accounts Receivable Journal Entry Transaction Lines

4. Study of the Fixed Assets Department's Activities Performed in Support of Capital

5. Study of the Legal Department's Activities Performed in Support of Capital

6. Labor Dollars Charged by Operating Department

The amount of the A&G costs capitalized for Duke Energy Kentucky during the years ended December 31, 2005, 2004 and 2003, were $620,399, $588,208, $864,691, respectively.

Under cost causation principles, each department providing support to the capital program is matched with the allocation method that most reasonably applies to the functional nature of the A&G costs being capitalized. Based upon the allocation method, each department is provided with an A&G capital/expense percentage (%) split. A monthly journal entry is created to allocate costs identified to support capital.

The annual study referred to above is completed during the fourth quarter of each calendar year. The study includes a review of the departments charging A&G accounts during the year. The review consists of a survey questionnaire and/or interview and focuses on the services provided for the current year and significant changes forecasted for future periods. The focus of the study is to determine what administrative functions provide support to the company's construction program. The study also contains a review of the six categories of statistical information listed above, which is used to apportion A&G costs between expense and capital accounts. These statistics are computed using various company sources (i.e., accounting and payroll systems, etc.) and represent the O&M/capital splits for the current year.

Examples of A&G departments supporting the company's capital program include: Accounts Payable, Fixed Asset Accounting, and Purchasing.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

BRIAN P. DAVEY

ON BEHALF OF

DUKE ENERGY KENTUCKY

183625

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE ..... - 1 -

II. THE BUDGETING AND FORECASTING PROCESS ..... - 2 -

III. METHODOLOGY FOR THE FORECASTED DATA ..... - 5 -

A. INCOME STATEMENT ..... - 5 -

B. BALANCE SHEET STATEMENT ..... - 12 -

C. CASH FLOW STATEMENT ..... - 13 -

IV. REASONABLENESS OF THE FORECASTED TEST PERIOD DATA ..... - 13 -

V. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS ..... - 14 -

VI. CONCLUSION ..... - 16 -

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brian P. Davey. My business address is 1000 East Main Street, Plainfield, Indiana, 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as General Manager, Financial Planning and Analysis.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor's Degree in Accounting from Indiana University of Indianapolis in 1981. I am also a Certified Public Accountant licensed in the State of Indiana.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I became employed by Public Service of Indiana, Inc. in 1982 as a Staff Accountant. I held various positions in the Rate, Corporate Accounting and Financial Forecasting departments. In 1994, I was promoted to Financial Forecasting manager and subsequently held various accounting and forecasting manager and director positions in the Commercial Business Unit. In 2003, I was promoted to Assistant Controller. In 2005, I became General Manager, Budgeting and Forecasting. In April 2006, I was named to my current position.

Q. PLEASE DESCRIBE YOUR DUTIES AS GENERAL MANAGER, FINANCIAL PLANNING AND ANALYSIS.

A. I am responsible for preparing the budgets and forecasts and performing financial analysis for Duke Energy's U.S. Franchised Electric & Gas Business Unit, which consists of Duke Energy's public utility operating companies in Kentucky, Ohio, Indiana, North Carolina and South Carolina.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I describe the budgeting and forecasting processes used by the Company in developing the base and forecasted test periods. I sponsor and support the forecasted operating revenues and expenses prior to the *pro forma* adjustments, and the long-term financial forecast, which were prepared under my direction and control. I sponsor Schedules I-1 through I-5; a portion of Schedule K and Filing Requirements ("FR") 10(9)(c), 10(9)(d), 10(9)(h), 10(9)(n), and 10(9)(o).

II. THE BUDGETING AND FORECASTING PROCESS

Q. DESCRIBE THE SOURCE OF THE FORECASTED FINANCIAL DATA USED IN THIS CASE.

A. The forecasted data used in this proceeding is based on the annual budget for The Union Light, Heat and Power Company (now known as "Duke Energy Kentucky") as contained in Cinergy Corp.'s ("Cinergy") 2006 Annual Budget developed prior to Cinergy's merger with Duke. I supervised the coordination and development of this budget and it was reviewed and approved by the Company's upper management and Board of Directors.

Q. HOW DID YOU USE THE 2006 ANNUAL BUDGET RESULTS FOR THE BASE AND FORECASTED PERIODS IN THIS PROCEEDING?

A. The base period is the twelve months ending August 31, 2006 and consists of six months of actual data through February 28, 2006 and the remaining six months of forecasted data. The forecasted test period is the twelve months ending December 31, 2007. The Company's 2006 budget was the starting point for the preparation of both the base and forecasted periods. A simplistic high level summary of that approach is as follows. First, I revised the 2006 Annual Budget for a limited number of updated assumptions, as I describe in detail later in my testimony. Next, I extended the revised 2006 numbers to 2007 using the Company's standard forecasting methodology, which I also describe later in my testimony when I explain how I prepared the financial forecasts. Finally, I updated the revised budget and the forecasted test period with actual data through February 2006.

Q. DESCRIBE THE BUDGETING AND FORECASTING PROCESSES THAT YOU USED TO DEVELOP THE BASE AND TEST PERIODS IN THIS PROCEEDING.

A. Budgeting is done at levels known as the "responsibility and construction centers." The centers use the guidelines provided by the Company's Budgets and Forecasts Department. The centers prepare detailed responsibility budgets consisting of expense items, certain types of revenues, and construction budgets for capital projects. The information from all of the responsibility and construction centers is consolidated into a corporate budget and reviewed by executive management. One or more iterations of the annual budget are typically required before final approval by executive management and the Board of

Directors. This "bottom-up" approach has been an effective process for managing costs.

Q. DESCRIBE THE GUIDELINES PROVIDED BY THE BUDGETS AND FORECASTS DEPARTMENT IN DEVELOPING CINERGY'S ANNUAL RESPONSIBILITY (OPERATION AND MAINTENANCE) BUDGET.

A. These guidelines provide a detailed set of instructions for creating a center budget. For example, there are detailed instructions for budgeting employee labor data, such as the escalation rates for non-union labor expenses, indirect labor and fringe benefit loading rates, and how to handle staff additions or deletions. Individual employees and certain associated costs of the employees are included or excluded in any given center's budget according to the expected future reporting assignment for that employee. Detailed instructions for non-labor related expenses, such as transportation and information technology expenses, are included. There are instructions for handling contract labor and supplies, and guidelines for identifying a capital versus expense item. Budget coordinators are required to use these assumptions and/or instructions in projecting their future departmental expenses. These operation and maintenance ("O&M") budgeting guidelines are reflected in the budgets and forecasts that are submitted to the Company's upper management and Board of Directors for approval, and are also reflected in the forecasted financial data in this proceeding.

Q. WHAT OTHER STEPS ARE INVOLVED IN DEVELOPING THE CORPORATE BUDGET?

A. In addition to the O&M expenses and capital data provided by the budgeting process, other forecasted information is required as follows:

1. Operating revenues;
2. Projected fuel, purchased power, emission allowance, other production costs and off-system sales;
3. Depreciation;
4. Property taxes;
5. Financing assumptions, including short- and long-term debt rates, dividend policy, issuances and redemptions, accounts receivable sales and capital leases; and
6. Tax rates and tax depreciation.

III. METHODOLOGY FOR THE FORECASTED DATA

Q. PLEASE DESCRIBE HOW THIS FORECASTED INFORMATION WAS USED FOR THE CORPORATE BUDGET AND LATER REVISED AND/OR EXTENDED THROUGH THE BASE AND FORECAST PERIODS.

A. I will do so by describing the three primary financial statements beginning with the income statement.

A. INCOME STATEMENT

Q. PLEASE DESCRIBE HOW THE OPERATING REVENUES WERE FORECASTED.

A. The first step in preparing the operating revenues for the 2006 annual budget was to obtain a forecast of the projected gas MCF and electric kWh sales from Dr. Stevie. Dr. Stevie, Head of the Market Analysis Department, prepared the load forecasts on a monthly basis for each customer class over a ten-year period. The forecasts are updated at least annually. The Market Analysis Department also provides the number of customers for each customer class by rate schedule. The projected revenues for the annual budget and the long-range forecast for MCF and kWh sales were calculated by applying the tariff charges to these sales forecast numbers for all gas customers and for residential electric customers. The projected revenue for electric non-residential customers was calculated by applying average realizations to their respective kWh sales forecasts.

Q. ARE THE REVENUE PROJECTIONS BASED ON WEATHER NORMALIZED LOAD FORECASTS?

A. Yes. As described by Dr. Stevie, a ten-year period was used as the basis for calculating normal weather. This is the same methodology that management relies on for preparing its budgets and forecasts, and for financial presentations to the Board of Directors, credit rating agencies, and the investment community.

Q. WERE ANY ADJUSTMENTS MADE TO THESE BUDGETED OPERATING REVENUES FOR THE BASE AND FORECASTED PERIODS?

A. Yes, an adjustment was made to reflect the Merger Savings Credit Rider approved by the Commission in Case No. 2005-00228 beginning May 2006. We also made an adjustment to reflect full recovery of fuel costs through an assumed Fuel Adjustment Clause beginning January 1, 2007.

Q. HOW WERE OTHER REVENUES PROJECTED?

A. The budget centers provide information for the 2006 annual budget for the other revenue categories, such as reconnection charges, late payment fees, *etc.* The other revenues for periods after 2006 were obtained by using a 1.5% escalation factor. Additionally, Mr. Esamann used the Commercial Business Model to provide me with forecasts of the power production costs, such as fuel, emission allowances and purchase power costs, and revenues, such as off-system sales, after applying the off-system sales sharing mechanism approved by the Commission in Case No. 2003-00252.

Q. HOW WERE PRODUCTION COSTS SUCH AS FUEL, EMISSION ALLOWANCES, PURCHASED POWER, AND REVENUES SUCH AS OFF-SYSTEM SALES PROJECTED?

A. The Commercial Business Model is a proprietary production cost model developed in-house. The model uses Monte Carlo simulation techniques. Among other things, the model includes a function to relate weather to load, planned and unplanned outages, contract and estimated market prices. It allows for purchases and sales from the wholesale market, and it includes any constraints (*e.g.*, must-run status) that would be appropriate to simulate the operations of the generating units.

The output of the model is a mathematical average of over 500 simulated cases. This model was used for Cinergy's 2006 Annual Budget and then updated for new market pricing, fuel costs, emission allowance and purchased power costs and a new outage schedule to provide a 2007 forecast, including revenues from off-system sales.

Q. DESCRIBE HOW DEPRECIATION EXPENSE IS INCLUDED IN THE FORECAST.

A. The forecasted depreciation for existing and projected gas and electric plant is calculated by multiplying the depreciable plant by appropriate composite depreciation rates. These composite rates for transmission, distribution, common and general plant are based on rates currently in effect and approved by this Commission in Case No. 91-370. The depreciation rates used for the East Bend Generating Station ("East Bend"), the Miami Fort Generating Station Unit 6 ("Miami Fort 6") and the Woodsdale Generating Station ("Woodsdale") (collectively, "the Plants") are the same as the depreciation rates used prior to the transfer.

The projected gas and electric capital budget data was prepared by the construction centers for a five-year period at the time of the 2006 Annual Budget preparation per Cinergy's capital budgeting process, which I discussed earlier. The capital budget was obtained from Mr. Stanley for the local transmission and distribution areas and from Mr. Roebel for the Plants. These numbers were revised to reflect the addition of capital expenditures for a build-out project associated with the Erlanger construction and maintenance facility, provided by Mr. Stanley.

Q. DESCRIBE HOW OPERATION AND MAINTENANCE EXPENSES ARE INCLUDED IN THE FORECAST.

A. The O&M expenses, including fringe benefits, payroll taxes and indirect labor loadings were obtained from the 2006 Annual Budget by the various responsibility centers, using the bottom-up approach that I described above. Duke Energy Kentucky's proportionate share of the shared services expenses and the corporate center O&M expenses are assigned and/or allocated from the Service Companies to Duke Energy Kentucky are also derived using the same bottom-up approach. The allocated share is derived by the application of appropriate allocations based on the pre-merger service company allocation factors, as discussed in Ms. Shrum's testimony.

Q. HOW WAS THE O&M REVISED AND EXTENDED THROUGH THE FORECASTED PERIOD?

A. I made revisions for charges from the Midwest Independent System Operator, Inc. ("Midwest ISO"), inter-company expenses, removal costs, Florence and Erlanger facility expenses, and the amortization expense relating to regulatory assets for the gas business. The primary reasons for these revisions was either too little information was known at the time of the preparation of the budget to develop any supportable charges to be included or, in the case of inter-company transactions, nothing was budgeted as it was not the Company's practice to budget certain inter-company transactions.

Mr. Swez and Mr. Jett calculated the costs for the Midwest ISO for both the base and the forecasted periods. Mr. Esamann provided the cost for the inter-company rent for the Miami Fort 6 step-up transformer for both the base and the forecasted periods. Mr. Stanley provided the costs for the Erlanger facility for the base and the forecasted periods. Mr. Roebel provided the O&M costs for scheduled outages for the plants for the forecasted test period. Ms. Good provided the principal and interest payments to convert the Erlanger facility from an operating lease to a capital lease. Mr. Jacobs supports applying Statement of Financial Accounting Standards No. 71 for the costs of removal relating to the Plants. Mr. Jacobs provided the amortization expense relating to all regulatory assets, including an adjustment to reflect the amortization of rate case expenses approved by the Commission in Case No. 2005-00042, for 2006 and 2007.

Q. PLEASE DESCRIBE HOW YOU EXTENDED THE O&M TO 2007.

A. I took the following steps to extend the O&M to 2007. First, I applied certain assumptions to the 2006 revised budget data to determine the financial forecasted data for the period. For labor-related expenses, I applied the projected labor cost rate increases provided by Mr. O'Connor to the budgeted 2006 union and non-union employee labor expense, which was 3.3% and 4.0%, respectively. I also used the fringe benefit (42%) and payroll tax (7.5%) loadings as well as the indirect labor loadings for union (32%) and non–union (21%) employees that Mr. O'Connor provided.

For non-labor expenses I used a 1.5% increase to escalate the 2006 budgeted amounts to 2007 levels because this escalation rate is typically used to provide an incentive for management to control these costs.

Q. WERE ALL OF THE O&M EXPENSES FOR 2007 ESCALATED AS YOU JUST PREVIOUSLY DESCRIBED?

A. No. Amortizations of regulatory assets are per the Commission's orders. Rents, Midwest ISO and other production expenses such as emission allowances (classified in the Cost of Goods Sold section on the income statement) and the O&M costs for scheduled outages were supplied by other witnesses as previously explained.

Q. HOW DID YOU OBTAIN THE PROPERTY TAX EXPENSE?

A. The property tax expense was obtained from the 2006 Annual Budget and was prepared as described by Mr. Butler. Mr. Butler supplied the property tax expenses for the forecasted financial test period data, based on the capital projections supported by Mr. Stanley and Mr. Roebel.

Q. HOW DID YOU OBTAIN THE "OTHER INCOME AND EXPENSE?"

A. The "other income and expense" is a below-the-line item, and is derived from a combination of sources. The amount of funds for the Allowance for Funds Used During Construction ("AFUDC") was obtained from the gas and electric capital forecasts prepared for the 2006 annual budget. These capital forecasts were supplied by Mr. Stanley for the local transmission and distribution business and by Mr. Roebel for the Plants. Miscellaneous revenues and expenses, such as gas jobbing revenues and expenses, and rent on non-utility property, were obtained from the 2006 annual budget prepared by the responsibility centers, and escalated at 1.5% for the 2007 forecasted test period.

Q. HOW DID YOU OBTAIN THE INTEREST EXPENSE?

A. Ms. Good provided the long-term debt balances and long- and short-term interest rates for the revised 2006 annual budget and the 2007 forecast. The amount of short-term debt balances and associated interest expense were derived using the Company's proprietary Hyperion forecasting software tools.

Q. HOW DID YOU OBTAIN THE INCOME TAX EXPENSE?

A. Mr. Butler provided the appropriate income tax rates and the amortization of investment tax credit ("ITC"). The income tax expense was derived using the same Hyperion forecasting software tools previously mentioned for each month of the revised 2006 annual budget period and the 2007 forecast, by applying statutory income tax rates to applicable taxable book income and adjusting the resulting applicable income taxes by the ITC amortization amounts.

B. BALANCE SHEET STATEMENT

Q. HOW WERE INITIAL BALANCES ESTABLISHED FOR THE BALANCE SHEET?

A. The final month of actual data for the base period was the February 28, 2006 balances. Mr. Council supplied the net book value for the existing gas, electric and common plant and construction work in progress for the period ending February 28, 2006 for the local transmission and distribution property. I used the Powerplant software to calculate the depreciation expense and net gas, electric, and common plant and construction work in progress balances for the forecasted period.

Q. HOW WAS THE TRANSFER OF THE PLANTS REFLECTED IN THE FORECAST?

A. Since the transfer of the Plants took place effective January 1, 2006, the forecast software tools captured this transfer via the update with actual data through February 2006 business. The long-term debt financing for this transfer occurred in March 2006, so the 2006 annual budget was revised to reflect this fact. Ms. Good supplied the information on the long-term debt financing for the Plants.

Q. WHAT OTHER INFORMATION WAS USED TO ESTABLISH THE BASE AND FORECASTED BALANCE SHEETS?

A. Mr. Roebel and Mr. Stanley provided the capital expenditures for the forecasted portion of the base period and for the forecasted test period. All of the forecasted capital data was prepared for the 2006 Annual Budget and was completed for a five-year period as typically done. The data was modified for the Erlanger build-out project I previously discussed.

The other assumptions were the dividend policy, the projected changes in long-term debt, the amount of capital lease and equipment lease payments, and the sale of accounts receivable, as provided by Ms. Good for both the revised 2006 annual budget and the 2007 forecast. In addition, Mr. Esamann supplied the Plant inventories for emission allowances, coal, oil and gas and materials and supplies.

C. CASH FLOW STATEMENT

Q. HOW DID YOU PREPARE THE CASH FLOW STATEMENT FOR THE 2006 ANNUAL BUDGET?

A. The cash flow statement is generated by the Hyperion forecasting software forecasting tools. It is derived from corresponding inputs from the income statement and changes in the balance sheet.

IV. REASONABLENESS OF THE FORECASTED TEST PERIOD DATA

Q. DO YOU HAVE AN OPINION AS TO WHETHER THE FORECASTED TEST PERIOD FINANCIAL DATA IS REASONABLE, RELIABLE, MADE IN GOOD FAITH, AND THAT ALL BASIC ASSUMPTIONS USED IN THE FORECAST HAVE BEEN IDENTIFIED AND JUSTIFIED?

A. Yes, the forecasted test period financial data is reasonable, reliable and made in good faith, based on all the information available as of the time of this filing. In my opinion, as General Manager, Financial Planning and Analysis, the budgeting and forecasting processes are adequate, reasonable, and reliable. My testimony has identified all the basic assumptions in the forecast. These assumptions are justified by my testimony and the testimony of the other witnesses I have identified.

Q. DOES THE FORECAST CONTAIN THE SAME ASSUMPTIONS AND METHODOLOGIES USED IN FORECASTED DATA PREPARED FOR USE BY MANAGEMENT?

A. Yes.

Q. DOES THE FORECASTED TEST PERIOD REFLECT ANY EXPECTED PRODUCTIVITY AND EFFICIENCY GAINS?

A. Yes. The forecasted data reflects all expected productivity and efficiency gains, except the merger savings, which are reflected in all the forecasted periods beginning May 2006 by using the merger credit approved by the Commission in Case No. 2005-00228, as I explained earlier.

V. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULES I-1 THROUGH I-5.

A. Schedule I-1 contains comparative income statements for the Company. Schedules I-2.1 through I-5 contain comparative revenue and sales statistical information as required by the Commission's filing requirements.

Q. PLEASE DESCRIBE SCHEDULE K.

A. Schedule K contains comparative financial and statistical information, as required by the Commission's filing requirements. I provided the condensed income statement, on page 2, and the mix of sales and fuel on page 5, for the base period and the forecasted test period.

Q. PLEASE DESCRIBE FR 10(9)(C).

A. FR 10(9)(c) is a summary of the assumptions used to prepare the forecasted test period data. Our assumptions and methodologies have also been described in my testimony and the testimony of other witnesses I identified earlier.

Q. PLEASE DESCRIBE FR 10(9)(D).

A. FR 10(9)(d) is Duke Energy Kentucky's annual and monthly twelve-month budget preceding the filing date, for the base period and forecasted period.

Q. PLEASE DESCRIBE FR 10(9)(H).

A. FR 10(9)(h) is Duke Energy Kentucky's financial forecast corresponding to the three-year capital budget. This includes an income statement, a balance sheet, a statement of cash flow, and certain other required financial and statistical information. Dr. Stevie sponsors FR10(9)(h)(5), Mr. Esamann sponsors FR10(9)(h)(7), and Ms. Good sponsors FR10(9)(h)(11).

Q. PLEASE DESCRIBE FR 10(9)(N).

A. FR 10(9)(n) consists of monthly summary income statements comparing the Company's actual results to budget from March 2005 through August 2005. In the present case, Duke Energy Kentucky has provided the quarterly financial statements it files with the Commission.

Q. PLEASE DESCRIBE FR 10(9)(O).

A. FR 10(9)(o) consists of management's monthly variance reports. Cinergy issued such reports on the basis of its Regulated Business Unit and these reports have been provided as part of this filing. These reports are self-explanatory narrative comments on the variances.

VI. CONCLUSION

Q. WERE SCHEDULES I-1 THORUGH I-5, THE INFORMATION YOU SPONSOR IN SCHEDULE K, AND FR 10(9)(C), FR 10(9)(D), FR 10(9)(H), FR 10(9)(N), AND FR 10(9)(O) PREPARED BY OR SPONSORED AND SUPPORTED BY YOU?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

State of Indiana)
) SS:
County of Hendricks)

The undersigned, Brian P. Davey, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Brian P. Davey
Brian P. Davey, Affiant

Subscribed and sworn to before me by Brian P. Davey on this 19th day of May, 2006.

Patty L. Sullivan
NOTARY PUBLIC

My Commission Expires: 11-02-2012

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF

DUKE ENERGY KENTUCKY

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE .... - 1 -

II. REGULATORY FRAMEWORK AND RATE OF RETURN .... - 5 -

III. COST OF EQUITY CAPITAL ESTIMATES .... - 13 -

A. CAPM Estimates .... - 21 -

B. Risk Premium Estimates .... - 34 -

C. Allowed Risk Premiums .... - 35 -

D. DCF Estimates .... - 37 -

E. Need For Flotation Cost Adjustment .... - 50 -

IV. SUMMARY AND RECOMMENDATION ON COST OF EQUITY .... - 54 -

APPENDICES

APPENDIX A – CAPM, Empirical CAPM

APPENDIX B – Flotation Cost Allowance

EXHIBITS

EXHIBIT RAM-1 – Resume of Roger A. Morin

EXHIBIT RAM-2 – Vertically Integrated Electric Utilities Beta Estimates

EXHIBIT RAM-3 – Moody's Electric Utility Common Stocks
Over Long-Term Treasury Bonds
Annual Long-Term Risk Premium Analysis

EXHIBIT RAM-4 – Electric Utilities Historical Growth Rates

EXHIBIT RAM-5 – Integrated Electric, Gas, and Combination Utilities

EXHIBIT RAM-6 – S&P's Vertically Integrated Electric Utilities
DCF Analysis: Value Line Growth Projections

EXHIBIT RAM-7 – S&P's Vertically Integrated Electric Utilities
DCF Analysis: Analysts' Growth Forecasts

EXHIBIT RAM-8 – Moody's Electric Utilities
DCF Analysis: Value Line Growth Projections

EXHIBIT RAM-9 – Moody's Electric Utilities

EXHIBIT RAM-10 – Vertically Integrated Electric Utilities Common Equity Ratios

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet, Inc., where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty five years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and on "Utility Capital

Allocation," which I have developed on behalf of The Management Exchange Inc. and Exnet in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including *The Journal of Finance*, *The Journal of Business Administration*, *International Management Review*, and *Public Utility Fortnightly*. I published a widely-used treatise on regulatory finance, *Utilities' Cost of Capital*, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released *Regulatory Finance*, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book was scheduled for publication at the time of this writing. I have engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. Exhibit RAM-1 describes my professional credentials in more detail.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before nearly fifty (50) regulatory bodies in North America, including the Kentucky Public Service Commission ("KPSC" or "Commission"), the Federal Energy Regulatory Commission, and the Federal Communications Commission. I have also testified before the following state, provincial, and other local regulatory commissions:

Alabama	Hawaii	Nevada	Oregon
Alaska	Illinois	New Brunswick	Pennsylvania
Alberta	Indiana	New Hampshire	Quebec
Arizona	Iowa	New Jersey	South Carolina
Arkansas	Kentucky	New York	South Dakota
British Columbia	Louisiana	Newfoundland	Tennessee
California	Manitoba	North Carolina	Texas
Colorado	Michigan	North Dakota	Utah
Delaware	Minnesota	Nova Scotia	Vermont
District of Columbia	Mississippi	Ohio	Virginia
Florida	Missouri	Oklahoma	Washington
Georgia	Montana	Ontario	West Virginia

The details of my participation in regulatory proceedings are provided in Exhibit RAM-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on the electric utility operations of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("DEK," or "Company") in the Commonwealth of Kentucky with particular emphasis on the fair return on Duke Energy Kentucky's common equity capital committed to that business. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion. I have also been asked to comment on the adequacy of the Company's capital structure.

Q. PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDIX ACCOMPANYING YOUR TESTIMONY.

A. I have attached to my testimony Exhibits RAM-1 through RAM-10 and Appendices A and B. These Exhibits and Appendices relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. WERE THESE EXHIBITS AND APPENDICES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING DEK'S COST OF COMMON EQUITY.

A. I recommend that a rate of return on common equity capital in a range of 11.25% to 11.50% be used for ratemaking purposes on DEK's common equity capital. My recommended range is derived from studies I performed using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies. I performed two CAPM analyses, one using the traditional CAPM and another using an empirical approximation of the CAPM ("ECAPM"). I performed two risk premium analyses: a historical risk premium analysis on the electric utility industry using Treasury bond yields and a study of the risk premiums allowed in the electric utility industry. I also performed DCF analyses on three surrogates for the Company. They are: DEK's ultimate parent company, Duke Energy Corporation ("Duke"), a group of investment-grade vertically integrated electric utilities, and a group of electric utilities that make up

Moody's Electric Utility Index.

My recommended rate of return on common equity reflects the application of my professional judgment to the indicated returns from my CAPM, Risk Premium, and DCF analyses. Moreover, my recommended return is predicated on the assumption that the Commission will approve the Company's capital structure for ratemaking purposes, which consists of 50.9% common equity capital.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into three (3) sections:

(i) Regulatory Framework and Rate of Return;

(ii) Cost of Equity Estimates; and

(iii) Summary and Recommendation.

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. In the third section, the results from the various approaches used in determining a fair return are summarized.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF THE COMPANY'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk. On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. HOW DOES DEK'S COST OF CAPITAL RELATE TO THAT OF ITS PARENT COMPANY?

A. I am treating DEK as a separate stand-alone entity, distinct from the parent company Duke, because it is the cost of capital for DEK that we are attempting to measure and not the cost of capital for Duke's consolidated activities. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the investor, in this case, Duke. The true cost of capital depends on the use to which the capital is put, in this case DEK's electric utility operations in the Commonwealth of Kentucky. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on DEK is the return foregone in comparable risk electricity utility operations, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations should behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Therefore, the cost of investing funds in an operating utility subsidiary such as DEK is the return foregone on investments of similar risk and is unrelated to the identity of the investor.

Q. PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET UNDER TRADITIONAL COST OF SERVICE REGULATION.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate DEK's cost of common equity capital.

Q. DR. MORIN, WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR RETURN ON COMMON EQUITY?

A. The allowable return on equity should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, 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. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. 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 alternative investments of comparable risk.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE RATE OF RETURN ON COMMON EQUITY?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1) *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

2) *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S.391 (1944).

The *Bluefield* case set the standard against which just and reasonable rates of return are measured:

> *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 <u>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</u> ... The <u>return should be reasonable</u>, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to <u>maintain and support its credit and enable it to raise money</u> necessary for the proper discharge of its public duties.* (Emphasis added)

The *Hope* case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the *Bluefield* case and recognized that revenues must cover "capital costs." The Court stated:

> *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 attract capital.* (Emphasis added)

The United States Supreme Court reiterated the criteria set forth in *Hope* in *Federal Power Commission v. Memphis Light, Gas & Water Division*, 411 U.S. 458 (1973), in *Permian Basin Rate Cases*, 390 U.S. 747 (1968), and most recently in *Duquesne Light Co. vs. Barasch*, 488 U.S. 299 (1989). In the *Permian* cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

> *...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed...*

Therefore, the "end result" of this Commission's decision should be to allow DEK the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the company's financial integrity, and (3) sufficient to maintain the company's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the Company. It is the composite weighted cost of the various classes of capital (*e.g.,* bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service.

While utilities like DEK enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on equity.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into differences in required return, in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the required return on capital is set by supply and demand, and is influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. HOW DOES THE COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by the Company are obtained in two general forms, debt capital and common equity capital. The cost of debt funds can be ascertained easily from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt, based on the utility's capital structure, in order to arrive at the overall cost of capital.

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

III. <u>COST OF EQUITY CAPITAL ESTIMATES</u>

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR RATE OF RETURN ON COMMON EQUITY FOR DEK?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF methodologies. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to DEK.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of capital.

Q. ARE THERE ANY DIFFICULTIES IN APPLYING COST OF CAPITAL METHODOLOGIES IN THE CURRENT ENVIRONMENT OF CHANGE?

A. Yes, there are. All the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the electric and natural gas utility industry. This is because utility company historical data have become less meaningful for an industry in a state of profound change. Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including corporate structural transformation and the transition to a more competitive environment. As a result, these historical indicators are not representative of the future long-term earning power of these companies. Moreover, historical growth rates are not representative of future trends for utilities involved in mergers and acquisitions, as these companies going forward would not be the same companies for which historical data are available.

Q. DR. MORIN, ARE YOU AWARE THAT SOME REGULATORY COMMISSIONS AND SOME ANALYSTS HAVE PLACED PRINCIPAL RELIANCE ON DCF-BASED ANALYSES TO DETERMINE THE COST OF EQUITY FOR PUBLIC UTILITIES?

A. Yes, I am.

Q. DO YOU AGREE WITH THIS APPROACH?

A. While I agree that it is certainly appropriate to consider the results of the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. There are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All of these methodologies are accepted and used by the financial community and supported in the financial literature.

When measuring the cost of common equity, which is essentially the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component are vivid examples of the potential shortcomings of the DCF model. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. Absent any hard evidence, which does not exist as far as I am concerned, as to which method outperforms the other, all relevant evidence should be used, in order to minimize judgmental error, measurement error, and conceptual infirmities. A regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. It is unwarranted to conclude that the DCF model standing alone is necessarily the ideal or best predictor of the stock price and of the cost of equity reflected in that price, just as it should not be concluded that the CAPM or Risk Premium models standing alone produce the perfect or best explanation of that stock price or the cost of equity. As a result, all the various methodologies to estimate the cost of equity should be considered.

Q. DOES THE FINANCIAL LITERATURE SUPPORT THE USE OF MORE THAN A SINGLE METHOD?

A. Yes. Authoritative financial literature strongly supports the use of multiple methods. For example, Professor Eugene F. Brigham, a widely respected scholar and finance academician, asserts:

In practical work, it is often best to use all three methods - CAPM, bond yield plus risk premium, and DCF - and then apply judgment when the methods produce different results. People experienced in estimating capital costs recognize that both careful analysis and some very fine judgments are required. It would be nice to pretend that these judgments are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible.[1]

In a subsequent edition of his best-selling corporate finance textbook, Dr. Brigham discusses the various methods used in estimating the cost of common equity capital, and states:

However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive - no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods...[2]

Another prominent finance scholar, Professor Stewart Myers, in his best selling corporate finance textbook, points out:

The constant growth [DCF] formula and the capital asset pricing model are two different ways of getting a handle on the same problem.[3]

In an earlier article, Professor Myers explains:

Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.[4]

---

[1] E. F. Brigham and L. C. Gapenski, *Financial Management Theory and Practice*, p. 256 (4th ed., Dryden Press, Chicago, 1985).
[2] *Id.* at p. 348.
[3] R. A. Brealey and S. C. Myers, *Principles of Corporate Finance*, p. 182 (3rd ed., McGraw Hill, New York, 1988).
[4] S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," *Financial Management*, p. 67 (Autumn 1978).

Q. DOES THE BROAD USAGE OF THE DCF METHODOLOGY IN PAST REGULATORY PROCEEDINGS INDICATE THAT IT IS SUPERIOR TO OTHER METHODS?

A. No, it does not. Uncritical acceptance of the standard DCF equation vests the model with a degree of reliability that is simply not justified. One of the leading experts on regulation, Dr. Charles F. Phillips discusses the dangers of relying solely on the DCF model:

> *[U]se of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investors' capitalization rate and the cost of equity capital to a utility for application to book value (i.e. an original cost rate base) are identical only when market price is equal to book value. Indeed, DCF advocates assume that if the market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered; and vice versa. Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.*
>
> *[T]here remains the circularity problem: Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. For all of these reasons, the DCF model suggests a degree of precision which is in fact not present and leaves wide room for controversy about the level of k [cost of equity].*[5]

Dr. Charles F. Phillips also discusses the dangers of relying solely on the CAPM model because of the lack of realism of certain of its stringent assumptions, as is the case for any model in the social sciences.

Sole reliance on any one model, whether it is DCF, CAPM, or Risk

Premium, simply ignores the capital market evidence and investors' use of the other theoretical frameworks. The DCF model is only one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology that should supplant other financial theory and market evidence. The same is true of the CAPM.

Q. DO THE ASSUMPTIONS UNDERLYING THE DCF MODEL REQUIRE THAT THE MODEL BE TREATED WITH CAUTION?

A. Yes, particularly in today's rapidly changing utility industry. Even ignoring the fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, the DCF methodology, as those familiar with the industry and the accepted norms for estimating the cost of equity are aware, is problematic for use in estimating cost of equity at this time.

Several fundamental structural changes have transformed the energy utility industry since the standard DCF model and its assumptions were developed. For example, deregulation, increased wholesale competition triggered by national policy, accounting rule changes, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, improvements in generation efficiencies, and mergers-acquisitions have all influenced stock prices in ways that have deviated substantially from the assumptions of the DCF model. These changes suggest that some of the fundamental assumptions underlying the standard DCF model, particularly that of constant growth and constant relative market valuation, for example

---

[5] C. F. Phillips, *The Regulation of Public Utilities Theory and Practice* (Public Utilities Reports, Inc., 1988) pp. 376-77. [Footnotes omitted].

price/earnings ratios and market-to-book ratios, are problematic at this point in time for utility stocks, and that, therefore, alternate methodologies to estimate the cost of common equity should be accorded at least as much weight as the DCF method.

Q. IS THE CONSTANT RELATIVE MARKET VALUATION ASSUMPTION INHERENT IN THE DCF MODEL ALWAYS REASONABLE?

A. No, not always. Caution must be exercised when implementing the standard DCF model in a mechanistic fashion, for it may fail to recognize changes in relative market valuations over time. The traditional DCF model is not equipped to deal with surges in market-to-book ("M/B") and price-earnings ("P/E") ratios. The standard DCF model assumes a *constant* market valuation multiple, that is, a constant P/E ratio and a constant M/B ratio. Stated another way, the model assumes that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current ratio of market price to dividend (or earnings), and that the stock price will grow at the same rate as the book value. This is a necessary result of the infinite growth assumption. This assumption is unrealistic under current conditions. The DCF model is not equipped to deal with sudden surges in M/B and P/E ratios, as was experienced by a number of utility stocks in recent years.

In short, caution and judgment are required in interpreting the results of the DCF model because of: (1) the effect of changes in risk and growth on electric utilities, (2) the disconnect between the tenets of the DCF model and the characteristics of utility stocks in the current capital market environment, and (3) the practical difficulties associated with the growth component of the DCF model. Hence, there is a clear need to go beyond the DCF results and take into account the results produced by alternate methodologies in arriving at a return on equity ("ROE") recommendation.

Q. DO THE ASSUMPTIONS UNDERLYING THE CAPM REQUIRE THAT THE MODEL BE TREATED WITH CAUTION?

A. Yes, as was the case with the DCF model, the assumptions underlying the CAPM are stringent. Moreover, the empirical validity of the CAPM has been the subject of intense research in recent years. Although the CAPM provides useful evidence, it must be complemented by other methodologies.

A. <u>CAPM Estimates</u>

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM ("ECAPM"). The CAPM is a fundamental paradigm of finance. The fundamental idea 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. According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium given by β times $(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, $(R_M - R_F)$. For the risk-free rate, I used 5.0%, based on current interest rates on long-term U.S. Treasury bonds. For beta, I used 0.85 and for the market risk premium I used 7.8%. These respective inputs to the CAPM are explained below.

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM AND RISK PREMIUM ANALYSES?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the actual and forecast yields on 30-year Treasury bonds.

The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term or intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

Another reason for utilizing the longest maturity Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return will therefore be equal to the inflation rate anticipated to prevail over the very long-term. The same expectation should be embodied in the risk free rate used in applying the CAPM model. It stands to reason that the actual yields on 30-year Treasury bonds will more closely incorporate within their yield the inflation expectations that influence the prices of common stocks than do short-term or intermediate-term

U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yield on such securities should be used as proxies for the risk-free rate in applying the CAPM, provided there are no anomalous conditions existing in the 30-year Treasury market. In the absence of such conditions, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. DR. MORIN, WHY DID YOU REJECT SHORT-TERM INTEREST RATES AS A PROXIES FOR THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?

A. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. WHAT IS YOUR ESTIMATE OF THE RISK-FREE RATE IN APPLYING THE CAPM?

A. The level of U.S. Treasury 30-year long-term bond yields prevailing in April 2006 as reported in the Value Line Investment Analyzer ("VLIA") April 2006 edition was 5.0%. I also examined the long-term interest rate forecasts contained in the April 2006 edition of the Blue Chip Financial Forecasts. The consensus forecast reported in that publication for the yield on 30-year Treasury bonds was 5.1%, virtually identical to the current level of 5.0%. I therefore used 5.0% as my estimate of the risk-free rate component of the CAPM.

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta," or "systematic risk." The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. The beta coefficient indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

As a wholly-owned subsidiary of Duke, DEK is not publicly traded, and therefore, proxies must be used for DEK. I examined the betas of a sample of widely-traded investment-grade vertically integrated electric utilities covered by Standard & Poor's with at least 50% of their revenues from regulated utility operations. This group is examined in more detail later in my testimony, in connection with the DCF estimates of the cost of common equity. In order to minimize the well-known thin trading bias in measuring beta, I only considered those companies whose market capitalization exceeded $500 million. As displayed on page 1 of Exhibit RAM-2, the average beta for the group is 0.85.

As a check on the beta estimate, I examined the average beta for the electric utility industry, as represented by the electric utilities that make up Moody's Electric Utility Index. As displayed on page 2 of Exhibit RAM-2, the average beta for the group is 0.88 and becomes 0.85 with the two outliers (Duke Energy, American Electric Power) removed from the group. These two estimates are nearly identical to the previous estimates. Based on these results, I shall use 0.85 as a reasonable estimate for the beta applicable to DEK.

Q. WHAT MARKET RISK PREMIUM ESTIMATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the market risk premium, I used 7.5%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. First, the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2006 Yearbook,* compiling historical returns from 1926 to 2005, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.5%. The historical market risk premium over the income component of long-term Treasury bonds rather than over the total return is 7.1%[6]. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical market risk premium, and I concur with this viewpoint. The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected market risk premium. The more accurate way to estimate the market risk premium from historic data is to use the <u>income</u> return, not <u>total</u> returns on government bonds, as explained at page 66 of *Ibbotson Associates, Stocks, Bonds, Bills, and Inflation: Valuation Edition, 2005 Yearbook.* This is because the income component of total bond return (*i.e.* the coupon rate) is a far better estimate of expected return than the total return (*i.e.* the coupon rate + capital gain), as realized capital gains/losses are largely unanticipated by bond investors. The long-horizon (1926-2005) market risk premium (based on income returns, as required) is specifically calculated to be

[6] Because 30-year bonds were not always traded or even available throughout the entire 1926-2005 long period covered in the Ibbotson Associate Study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. To the extent that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Ibbotson study, the difference in yield is not material. In fact, the difference in yield between 30-year and 20-year bonds is actually negative. The average difference in yield over the 1977-2006 period is 13 basis points, that is, the yield on 20-year bonds is slightly higher than the yield on 30-year bonds.

7.1% rather than 6.5%.

Second, a DCF analysis applied to the aggregate equity market using Value Line's aggregate stock market index and growth forecasts indicates a prospective market risk premium of 7.9%. The average of the historical (7.1%) and prospective estimates (7.9%), which is 7.5%, provides a reasonable estimate of the market risk premium.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MARKET RISK PREMIUM ESTIMATE?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the market risk premium with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. Since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. PLEASE DESCRIBE YOUR PROSPECTIVE APPROACH IN DERIVING THE MARKET RISK PREMIUM IN THE CAPM ANALYSIS.

A. For my prospective estimate of the market risk premium, I applied a DCF analysis to the aggregate equity market using Value Line's VLIA software. The dividend yield on the dividend-paying stocks that make up the Value Line Composite index made up of some 1800 stocks is currently 1.2% (VLIA 04/2006 edition), and the average projected dividend growth rate is 11.3%. Adding the dividend yield to the growth component produces an expected return on the aggregate equity market of 12.5%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 12.7%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the market risk premium estimate to approximately 12.9%. Subtracting the risk-free rate of 5.0% from the latter, the implied risk premium is 7.9% over long-term U.S.

Treasury bonds. The average of the historical (7.1%) and prospective market risk premium (7.9%) estimates is 7.5%.

As a check on my market risk premium estimate, I examined a recent 2003 comprehensive article published in *Financial Management*, Harris, Marston, Mishra, and O'Brien ("HMMO") that provides estimates of the ex ante expected returns for S&P 500 companies over the period 1983-1998[7]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the market risk premium for that year. The table below, drawn from HMMO Table 2, displays the average prospective risk premium estimate for each year from 1983 to 1998. The average market risk premium estimate for the overall period is 7.2%, which is reasonably close to my own estimate of 7.5%.

Year	DCF Market Risk Premium
1983	6.6%
1984	5.3%
1985	5.7%
1986	7.4%
1987	6.1%
1988	6.4%
1989	6.6%
1990	7.1%
1991	7.5%
1992	7.8%
1993	8.2%
1994	7.3%
1995	7.7%
1996	7.8%
1997	8.2%
1998	9.2%
MEAN	**7.2%**

[7] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," *Financial Management*, Autumn 2003, pp. 51-66.

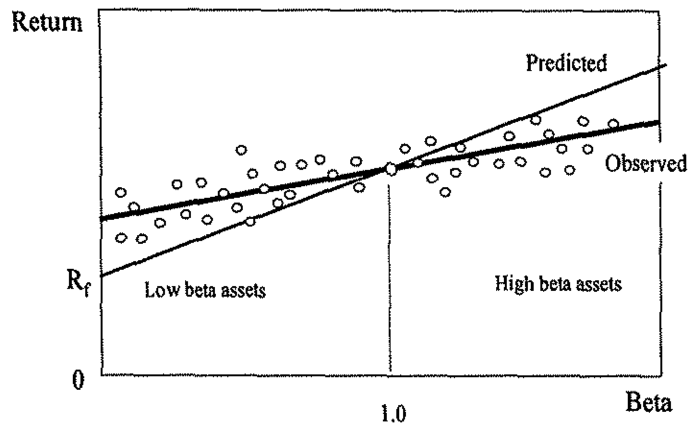
Q. WHAT IS YOUR RISK PREMIUM ESTIMATE OF THE COMPANY'S COST OF EQUITY USING THE CAPM APPROACH?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 5.0%, a beta of 0.85, and a market risk premium of 7.5%, the CAPM estimate of the cost of common equity is: 5.0% + 0.85 x 7.5% = 11.4%. This estimate becomes 11.7% with flotation costs, discussed later in my testimony.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE EMPIRICAL VERSION OF THE CAPM?

A. With respect to the empirical validity of the plain vanilla CAPM, there have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 13 of my book, *Regulatory Finance* and in Chapter 6 of my latest book, *The New Regulatory Finance*, published by Public Utilities Report Inc. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \alpha + \beta \times (MRP - \alpha)$$

where α is the "alpha" of the risk-return line, a constant, MRP is the market risk premium ($R_M - R_F$), and the other symbols are defined as usual. Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following ECAPM expression:

$$K = RF + 0.25\,(RM - RF) + 0.75\,\beta(RM - RF)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than raw betas also incorporate some of the desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha adjustment.

Q. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED BETAS?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on a myriad of empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated.

Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

Appendix A contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings. In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\ \beta\,(R_M - R_F)$$

Inserting 5.0% for the risk-free rate R_F, a market risk premium of 7.5% for $(R_M - R_F)$ and a beta of 0.85 in the above equation, the return on common equity is 11.7% without flotation costs and 12.0% with flotation costs.

B. <u>Risk Premium Estimates</u>

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE ELECTRIC UTILITY INDUSTRY.

A. As a proxy for the risk premium applicable to DEK, I estimated the historical risk premium for the electric utility industry with an annual time series analysis applied to the electric utility industry as a whole, using Moody's Electric Utility Index as an industry proxy. The analysis is depicted on Exhibit RAM-3. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year.

The average risk premium over the period was 5.6% over long-term

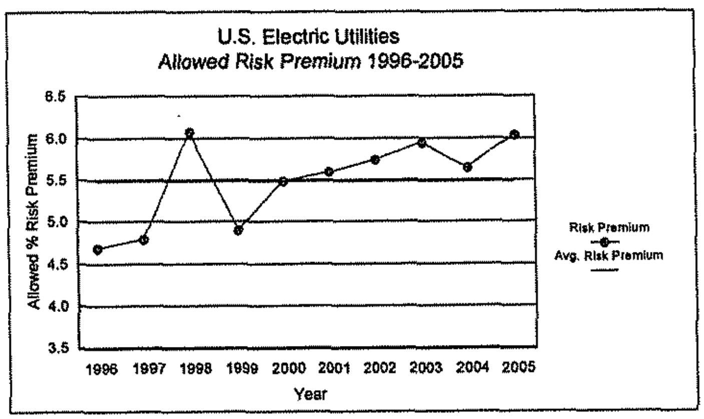
Treasury bonds. Given that long-term Treasury bonds are currently yielding 5.0%, the implied cost of equity for the average risk electric utility from this particular method is 5.0% + 5.6% = 10.6% without flotation costs and 10.9% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony. I note that over most of this lengthy historical period, both the T&D and generation businesses were indistinguishable in risk, that is, were fully integrated regulated monopolies subject to the regulatory compact.

The historical risk premium analysis for the electric utility industry stops in 2001 because the annual Moody's Public Utility Manual from which the data were drawn was discontinued following the acquisition of Moody's by Mergent in 2002. In view of the rising risk premium allowed by regulators documented in the next section of my testimony, it would not be unreasonable to expect that the current utility risk premium exceeds the historical average. I did examine some more recent historical bond return and equity return data based on the S&P Utility Index instead of Moody's Electric Utility Index. The addition of 2002-2005 data actually raises the historical risk premium slightly. This is not surprising in view of the rising utility equity market during the 2003-3005 period.

C. <u>Allowed Risk Premiums</u>

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE ELECTRIC UTILITY INDUSTRY.

A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the returns on equity allowed by regulatory commissions for electric utilities over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. The allowed equity returns are reported on a quarterly basis by Regulatory Research Associates. The average common equity return spread over long-term Treasury yields was 5.5% for the 1996-2005 time period, as shown by the horizontal line in the graph below. The graph also shows the year-by-year allowed risk premium. As indicated by the rising arrow on the graph, the escalating trend of the risk premium in response to lower interest rates and rising competition and restructuring is noteworthy.

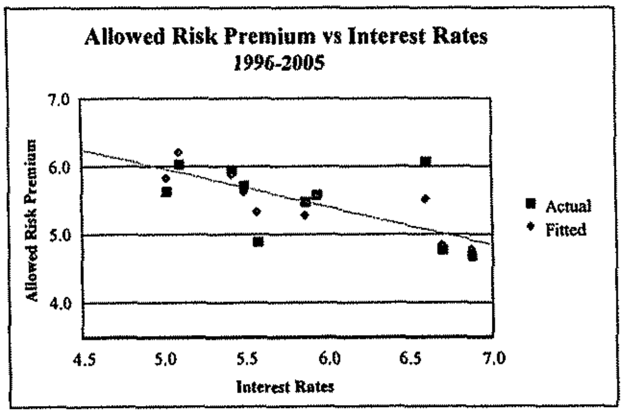


A careful review of these common equity decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the last decade:

$$RP = 9.1508 - 0.6505\ YIELD \qquad R^2 = 0.74$$

$(t = 4.7)$

The relationship is highly statistically significant[8] as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The figure below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past common equity decisions.



Inserting the current long-term Treasury bond yield of 5.0% in the above equation suggests that a risk premium estimate of 5.9% should be allowed for the average risk electric utility, implying a cost of equity of 10.9% for the average risk utility.

D. DCF Estimates

[8] The coefficient of determination R^2, sometimes called the "goodness of fit measure" is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample rata. The t-statistic is a standard measure of the statistical significance of an independent variable in a regression relationship. A t-value above 2.0 is considered highly significant.

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. 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. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, book value, stock price

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, *Regulatory Finance*. The traditional DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The traditional DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. IS THE CONSTANT GROWTH DCF MODEL APPLICABLE UNDER ALL CIRCUMSTANCES?

A. No, it is not, as I discussed earlier in my testimony. For companies in a mature industry, such as the electric utility industry had been until recent years, a constant growth rate is a reasonable assumption. For companies in a more dynamic evolving industry, such as the electric utility business, this assumption may not be reasonable; the dividend growth rate may be expected to converge only over time toward a steady-state long-run level.

Q. HOW DID YOU ESTIMATE DEK'S COST OF EQUITY WITH THE DCF MODEL?

A. I applied the DCF model to three proxies for DEK: the parent company Duke, a group of vertically integrated electric utilities, and a group consisting of the electric utilities that make up Moody's electric utilities index.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/Po) and the expected long-term growth (g). The expected dividend D_1 in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. The reason is that current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the dividend yields reported in the April 2006 edition of Value Line's VLIA. Basing dividend yields on average results from a large group of companies reduces the concern that vagaries of individual company stock prices will result in an unrepresentative dividend yield.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are 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. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecast as an additional proxy.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO ELECTRIC UTILITIES?

A. Columns 1, 2, and 3 of Exhibit RAM-4 display the historical growth in earnings, dividends, and book value per share over the last five years for the electric utility companies that make up Value Line's Electric Utility composite group. The average historical growth rates in earnings, dividends, and book value for the group are 2.1%, 0.0%, and 3.2% over the past 5 years, respectively. Several companies have experienced a negative earnings growth rate, as evidenced by the numerous historical growth rates reported on the table that are negative.

These historical growth rates have little relevance as proxies for future long-term growth at this time. 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. Several electric utility companies have experienced earnings growth rate. The industry as a whole has experienced zero dividend growth over the past five years. These anemic historical growth rates are certainly not representative of these companies' long-term earning power, and produce unreasonably low DCF estimates, well outside reasonable limits of probability and common sense. To illustrate, adding the historical growth rates of 2.1%, 0.0%, and 3.2% to the average dividend yield of approximately 4.0% prevailing currently for those same companies, produces preposterous cost of equity estimates of 6.1%, 4.0%, and 7.2%, using earnings, dividends, and book value growth rates, respectively. Of course, these estimates of equity costs are outlandish as they are less than the cost of long-term debt for these companies.

I have therefore rejected historical growth rates as proxies for expected growth in the DCF calculation. In any event, historical growth rates are somewhat redundant because such historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model.

Q. DID YOU CONSIDER DIVIDEND GROWTH PROXIES IN APPLYING THE DCF MODEL?

A. No, I did not. This is because it is widely expected that electric utilities will continue to lower their dividend payout ratio over the next several years in response to the gradual penetration of competition and its potential impact on the revenue stream. In other words, earnings and dividends are not expected to grow at the same rate in the future. According to the latest edition of Value Line, the expected dividend growth of 2.7% for the electric utility industry, as proxied by Moody's Electric Utility Index companies, is significantly less than the expected earnings growth of 5.4% over the next few years.

Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must adjust to the changing payout ratio. The assumptions of constant perpetual growth and constant payout ratio are clearly not met. The implementation of the standard DCF model is of questionable relevance in this circumstance.

Dividend growth rates are unlikely to provide a meaningful guide to investors' growth expectations for electric utilities in general. This is because electric utilities' dividend policies have become increasing conservative as business risks in the industry have intensified steadily. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks. To wit, the dividend payout ratios of energy utilities has steadily decreased from about 80% ten years ago to the 60% level today. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. After all, it is growth in earnings that will support future dividends and share prices.

Q. IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS IN THE INVESTMENT COMMUNITY?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Zacks Investment, First Call Thompson, Yahoo Finance, and Multex provide comprehensive compilations of investors' earnings forecasts, to name some. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends. Third, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, accounting for 65% of the ranking.

Q. PLEASE DESCRIBE YOUR FIRST PROXY GROUP FOR THE COMPANY'S VERTICALLY INTEGRATED ELECTRIC UTILITY BUSINESS?

A. As a first proxy for the Company's vertically integrated electric utility business, I examined a group of investment-grade utilities designated as "integrated" utilities by S&P in a recent comprehensive analysis of utility business risks. The original group is shown on Pages 1 - 3 of Exhibit RAM-5, and includes electricity and natural gas utility operating companies engaged in predominantly integrated utility activities. Foreign companies, private partnerships, private companies, and companies below investment-grade, that is, companies with a bond rating below Baa3, were eliminated as well as those companies without Value Line coverage. Page 4 of Exhibit RAM-5 narrows the group down to include only the parent companies of investment-grade vertically integrated electric utilities. Two companies whose market capitalization was less than $500 million (Central Vermont, Green Mountain Power) were also eliminated in order to minimize any stock price anomalies due to thin trading. The remaining sample of 38 companies is made up of the parent company of these electric utility companies as shown on Page 5 of Exhibit RAM-5. The final group of 26 companies only includes those companies with at least 50% of their revenues from regulated electric utility operations. The same group was discussed earlier in connection with beta estimates and is retained for the DCF analysis.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE VERTICALLY INTEGRATED ELECTRIC UTILITY GROUP USING VALUE LINE GROWTH PROJECTIONS?

A. For purposes of conducting the DCF analysis, as shown on Page 1 of Exhibit RAM-6, two companies (Allete, and Progress Energy) for which no growth forecast was available were discarded. One non-dividend paying company, El Paso Electric, was discarded also. PG&E was eliminated on account of its extraordinary outlying growth rate.

As shown on Column 2 of page 2 of Exhibit RAM-6, the average long-term growth forecast obtained from Value Line is 5.7% for this group. Adding this growth rate to the average expected dividend yield of 4.3% shown in Column 3 produces an estimate of equity costs of 10.0% for the group. Recognition of flotation costs brings the cost of equity estimate to 10.2%, shown in Column 5.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE VERTICALLY INTEGRATED ELECTRIC UTILITY UTILITIES GROUP USING THE ANALYSTS' CONSENSUS GROWTH FORECAST?

A. From the original sample of 26 companies shown on page 1 of Exhibit RAM-7, Empire District and MGE Energy were eliminated as no analysts' growth forecasts were available from Zacks. One non-dividend paying company, El Paso Electric, was discarded also. For the remaining 22 companies shown on page 2 of Exhibit RAM-7, using the consensus analysts' earnings growth forecast published by Zacks of 5.8% instead of the Value Line forecast, the cost of equity for the group is 10.1% unadjusted for flotation cost. Recognition of flotation costs brings the cost of equity estimate to 10.3%, shown in Column 5, virtually the same result obtained using the Value Line growth forecasts.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR DEK'S PARENT COMPANY?

A. The DCF results for DEK's parent company can be gleaned from Exhibits RAM-6 and RAM-7. As shown at the bottom of Exhibit RAM-7 Page 2, Column 2, the long-term growth forecast obtained from the Zacks corporate earnings database is 6.0% for Duke. Combining this growth rate with the expected dividend yield of

4.6% shown in Column 3 produces an estimate of equity costs of 10.6%. Recognition of flotation costs brings the cost of equity estimate to 10.8%, shown in Column 5.

Repeating the exact same procedure, only this time using Value Line's long-term earnings growth forecast of 8.5% instead of the Zacks consensus growth forecast, the cost of equity for Duke is 13.2%, unadjusted for flotation costs. Adding an allowance for flotation costs brings the cost of equity estimate to 13.4%. This analysis is displayed at the bottom of Exhibit RAM-6, Page 2. The average of the two Duke-specific DCF estimates is 12.1%.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR MOODY'S ELECTRIC UTILITIES GROUP?

A. Page 1 of Exhibit RAM-8 displays the electric utilities that make up Moody's Electric Utility Index. Progress Energy for which no growth forecast was available was eliminated from the group, along with DPL Inc on account of its outlying DCF estimate which was far less than the cost of debt. Public Service Enterprise Group and Cinergy were discarded on account of ongoing merger activity. As shown on Column 2 of page 3 of Exhibit RAM-8, the average long-term growth forecast obtained from Value Line is 5.9% for this group. Adding this growth rate to the average expected dividend yield of 4.4% shown in Column 3 produces an estimate of equity costs of 10.4% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 10.6%, shown in Column 5.

Using the consensus analysts' growth forecast from Zacks instead of the

Value Line growth forecast, the cost of equity for the Moody's group is 10.4%. This analysis is displayed on Pages 1 and 2 of Exhibit RAM-9. No growth projections were available for CH Energy and Duquesne Light, and those companies were therefore eliminated from the group. Public Service Enterprise and Cinergy were also discarded on account of ongoing merger activity.

Q. DO DCF RESULTS GENERALLY UNDERSTATE THE COST OF EQUITY?

A. Yes, they do. Application of the standard DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock prices and book values are reasonably similar, that is, when the M/B ratio is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds unity. This is particularly relevant in the current capital market environment where electric utility stocks are trading at M/B ratios well above unity and have been for two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.

Q. CAN YOU ILLUSTRATE THE EFFECT OF THE M/B RATIO ON THE DCF MODEL BY MEANS OF A SIMPLE EXAMPLE?

A. Yes. The simple numerical illustration shown in the table below demonstrates the result of applying a market value cost rate to a book value rate base under three different M/B scenarios. The three columns correspond to three M/B situations: the stock trades below, equal to, and above book value, respectively. The last situation (bolded portion of the table) is noteworthy and representative of the current capital market environment. The DCF cost rate of 10%, made up of a 5% dividend yield and a 5% growth rate, is applied to the book value rate base of $50 to produce $5.00 of earnings. Of the $5.00 of earnings, the full $5.00 is required for dividends to produce a dividend yield of 5% on a stock price of $100.00, and no dollars are available for growth. The investor's return is therefore only 5% versus his required return of 10%. A DCF cost rate of 10%, which implies $10.00 of earnings, translates to only $5.00 of earnings on book value, a 5% return.

The situation is reversed in the first column when the stock trades below book value. The $5.00 of earnings is more than enough to satisfy the investor's dividend requirements of $1.25, leaving $3.75 for growth, for a total return of 20%. This is because the DCF cost rate is applied to a book value rate base well above the market price.

Therefore, the DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently and has been for several years, and understates the cost of common equity capital.

Effect of M/B Ratio on Market Return

		CASE 1	CASE 2	CASE 3
1	Initial purchase price	$25.00	$50.00	$100.00
2	Initial book value	$50.00	$50.00	$50.00
3	Initial M/B	0.50	1.00	2.00
4	DCF Return 10% = 5% + 5%	10.00%	10.00%	10.00%
5	Dollar Return	$5.00	$5.00	$5.00
6	Dollar Dividends 5% Yield	$1.25	$4.00	$4.00
7	Dollar Growth 5% Growth	$3.75	$1.00	$1.00
8	**Market Return**	**20.00%**	**10.00%**	**5.00%**

E. <u>Need For Flotation Cost Adjustment</u>

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, *etc.*). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are

5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Appendix B, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE DEK THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its ultimate parent, in this case, Duke. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

IV. SUMMARY AND RECOMMENDATION ON COST OF EQUITY

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final recommendation, I performed four risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from electric utility industry aggregate data, using the current and forecast yields on long-term Treasury bonds. I also performed DCF analyses on three surrogates for DEK: the parent company, a group of vertically integrated electric utilities, and a group of companies that make up Moody's Electric Utility Index. The results are summarized in the table below.

STUDY	ROE
CAPM	11.7%
Empirical CAPM	12.0%
Risk Premium Electric Utility	10.9%
Allowed Risk Premium	10.9%
DCF Integrated Elec Utility Zacks Growth	10.1%
DCF Integrated Elec Utility Value Line Growth	10.1%
DCF Duke Energy	12.1%
DCF Moody's Electrics Zacks Growth	10.4%
DCF Moody's Electrics Value Line Growth	10.6%

The results range from a low of 10.2% to a high of 12.1%, with a midpoint of 11.2%. Yet another way of presenting the results is on a methodological basis. The average result from the three principal methodologies is as follows:

CAPM	11.9%
Risk Premium	10.9%
DCF	10.7%
AVERAGE	11.2%

The overall average result is 11.2%, and the various results are closely clustered around 11.2%. Placing slightly less weight on the DCF results, the central result is 11.25%. I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in the above table must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from the summary table and infer DEK's equity costs from that number alone.

Q. DID YOU CONSIDER ANY OTHER FACTORS IN MAKING YOUR COST OF EQUITY CAPITAL RECOMMENDATION?

A. Yes, I did. I considered the fact that the yields on 30-year Treasury bonds have been rising since I performed my studies and are forecast to continue rising. The level of 30-year long term bond yields forecast by Value Line in its quarterly economic forecast dated May 2006 edition is 5.2%, slightly higher than the 5.0% rate reported in the April 2006 edition of this report, which I used to determine the risk-free rate of return.

I also considered several risk factors relating to DEK's electric operations. I reviewed the testimony of Mr. Roebel and Mr. Esamann, and I reviewed Kentucky's Fuel Adjustment Clause regulation at 807 KAR 5:056. As Mr. Roebel discusses, DEK's generating assets are highly concentrated. To illustrate, the baseload East Bend plant is a very large component of DEK's total capacity.

My understanding of Kentucky's Fuel Adjustment Clause regulation is that the Company cannot recover through the Fuel Adjustment Clause for the costs of back-up supply occasioned by forced outages from causes such as faulty equipment, manufacture, or design. If a given plant has a sustained forced outage and if DEK is forced to obtain replacement power at spot market prices for a prolonged period, then DEK's inability to timely recover these costs through the Fuel Adjustment Clause increases financial risk. There is uncertainty as to whether the Commission will allow DEK retail rate recovery for back-up supply costs at current market prices. There is also uncertainty surrounding DEK's prospects for securing a long-term back-up supply, especially given the high degree of concentration in a few generating plants.

In reaching my recommended return of a range of 11.25% to 11.50%, I considered all of these factors, in addition to the results of my cost of equity capital studies discussed above.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING DEK'S COST OF EQUITY CAPITAL?

A. Based on the results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable return on common equity lies in a range of 11.25% to 11.50%.

Q. IS THERE A RELATIONSHIP BETWEEN FINANCIAL RISK AND THE AUTHORIZED RETURN ON EQUITY?

A. There certainly is. A low authorized return on equity increases the likelihood the utility will have to rely increasingly on debt financing for its capital needs. This creates the specter of a spiraling cycle that further increases risks to both equity and debt investors; the resulting increase in financing costs is ultimately borne by the utility's customers through higher capital costs and rates of returns.

Q. WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON DEK'S COMMON EQUITY CAPITAL?

A. My recommended return on common equity for DEK is predicated on the adoption of the Company's test year capital structure consisting of 50.9% common equity capital.

Q. DID YOU EXAMINE THE REASONABLENESS OF THE COMPANY'S TEST YEAR CAPITAL STRUCTURE?

A. Yes, I did. I have compared DEK's test year capital structure with the capital structures of comparable risk investor-owned vertically integrated electric utilities. As shown on Exhibit RAM-10, the average and median common equity ratio of comparable risk investment-grade integrated electric utilities, the same group of companies used earlier in my testimony when applying the DCF model, are 49% and 51%, respectively, nearly identical to the Company's test year capital structure.

I have also compared the Company's test year common equity ratio of

50.9% to the capital structure benchmark contained in Standard and Poor's ("S&P") Rating Criteria for electric utilities. DEK is assigned a Business Risk Position of 5.0 by S&P on a scale of 1.0 to 10.0, with 1.0 being the least risky and 10.0 the most risky. For a utility with a Business Risk Position of 5.0, the debt ratio benchmark for a single "A" bond rating, which I consider optimal for both ratepayers and utility investors, is 42% – 50%, that is, an equity benchmark of 50% - 58% versus the Company's 50.9% common equity. The Company's common equity ratio barely lies within the range for a single "A" bond rating. The benchmark for a BBB bond rating is 50% – 60%, that is, an equity benchmark of 40% - 50% versus the Company's 50.9% common equity. For a BBB bond rating, the Company's common equity ratio lies within the upper portion of the range.

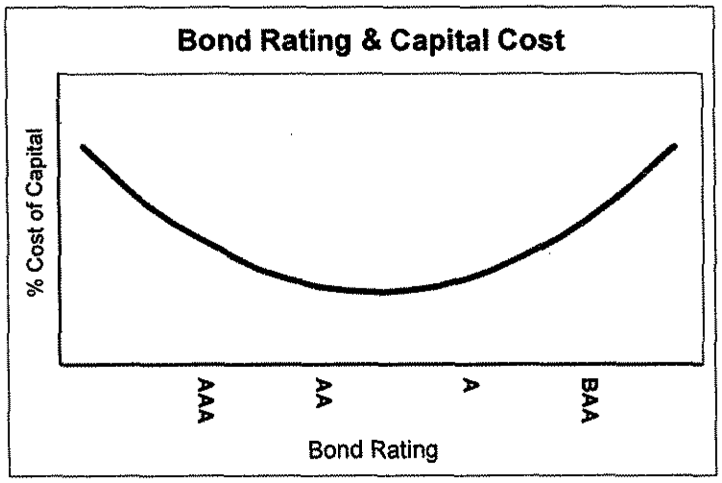
If the Commission imputes a capital structure consisting of substantially more (less) debt than the test year capital structure, the higher (lower) common equity cost rate related to a changed common equity ratio should be reflected in the approach. If the Commission ascribes a capital structure different from the test year capital structure, which imputes a higher debt amount for example, the repercussions on equity costs must be recognized. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, the greater the debt ratio, the greater is the return required by equity investors. Both the cost of incremental debt and the cost of equity must be adjusted to reflect the additional risk associated with the more debt-heavy capital structure. Lower common equity ratios imply greater risk and higher capital cost, and conversely.

Q. DR. MORIN, YOU MENTIONED EARLIER THE NEED FOR AN OPTIMAL BOND RATING OF SINGLE A. COULD YOU ELABORATE ON THAT POINT?

A. Yes, certainly. It is in both ratepayers' and investors' interest that a regulated utility be financially sound and have the credit rating and financial flexibility needed to (1) cope with the increased operational challenges in today's much more volatile industry environment; (2) pursue initiatives to further increase performance, and (3) finance in a timely and cost effective fashion the significant infrastructure investment needs faced in DEK's service territory.

In the utility regulation context, the idea of an optimal strong "A" bond rating for a utility's senior securities is widely supported. That is why the vast majority of utilities in North America migrate to such a bond rating.

I have performed several studies and I have frequently testified on the optimal capital structure for various utilities. One common theme in these studies and testimonies is the desirability of a strong "A" bond rating from both the ratepayers' and investors' standpoint. Chapter 19 of my book *Regulatory Finance* describes a capital structure simulation model for electric utilities using market data prior to industry restructuring. The graph below illustrates the major finding of the model, and demonstrates how the cost of capital changes as the debt ratio increases and the bond rating declines.



The horizontal axis shows that as the company substitutes debt for equity, the bond rating progressively deteriorates from "AAA" all the way down to "BAA" and beyond. The vertical axis shows what happens to overall capital costs, hence to rates, as the company continues to substitute debt for equity and its bond rating deteriorates. With each successive substitution of lower-cost debt for higher-cost equity, the average cost of capital declines as the weight of low-cost debt in the weighted average cost of capital increases. An optimal point is reached where the cost advantage of debt is exactly offset by the increased cost of equity. This is the optimal capital structure point. Beyond that point, the cost disadvantage of equity outweighs the cost advantage of debt, and the weighted cost of capital rises accordingly. The message from the graph is clear: over the long run, a strong "A" bond rating will minimize the cost of capital to ratepayers.

Several intangible costs and distress costs associated with a low bond rating cannot be readily accommodated into a mathematical simulation model without the model becoming computationally prohibitive. Thus, the case for a strong "A" bond rating is understated in these studies. Several examples of such costs follow.

The need to maintain borrowing capacity is well known. During normal times, a utility company should conserve enough unused borrowing capacity so that during adverse capital market periods it can use this capacity to avoid foregoing investment opportunities, selling stock at confiscatory prices, or jeopardizing its mandated obligation to serve. The yield advantage of a higher bond rating increases dramatically in adverse capital market conditions.

Bond flotation costs, which must be borne by ratepayers, increase also as bond ratings decline, particularly in years of difficult financial markets. Not only is lower bond quality associated with higher yields, but lower-rated utility bonds also carry shorter maturities, especially in poor years. The result is a maturity mismatch between the firm's long-term capital assets and its liabilities. Moreover, lower bond quality is associated with more years of call protection, particularly during difficult financial markets; since bonds are frequently called after a decrease in interest rates, bonds which carry call protection for a greater number of years are more costly to utility companies. Finally, as bond ratings decline, the probability that a company will reduce the dollar amount or shorten the maturity of their bond issues increases dramatically; this in turn reduces the marketability of a bond issue, and hence increases its yield. Any reasonable quantification of such implicit costs reinforces the case for a strong "A" rating.

The implication for DEK is very clear. Long-term achievement and maintenance of a strong "A" rating is in investors' and ratepayers' best interests. Capital structure targets should be therefore set so as to achieve such ratings.

Q. DR. MORIN, IN LIGHT OF YOUR DISCUSSION OF AN OPTIMAL BOND RATING, PLEASE COMMENT ON DEK'S CAPITAL STRUCTURE.

A. Long-term achievement and maintenance of a strong "A" rating is in investors' and ratepayers' best interests. Capital structure targets should be therefore set so as to achieve such ratings. In addition, although the legal definition of investment grade is "BBB", the actual practical definition of investment grade is "A". This is because a large majority of institutional investors are precluded from investing in bonds rated below "A". For all these reasons, sound public policy requires that the Commission establish rates so as to create financial conditions conducive to an optimal bond rating of at least single "A".

As discussed earlier, the Company's financial condition is not consistent with a single "A" credit rating. In light of DEK's capital expenditure requirements and the critical importance of preserving access to capital markets, DEK's long-term goal is to achieve strong single "A" credit ratings. Consequently, DEK's credit profile with the two major credit rating agencies needs to improve in order to support an upgrade from its current unsecured rating levels to a Single "A" rated level. This goal implies continued improvement in reducing debt, reducing interest expense and increasing cash flows.

The existence of a strong equity base favorably impacts the cost of debt by virtue of superior credit ratings, allows the company to absorb operating deficits without violating debt servicing obligations, and provides flexibility and freedom in timing new debt issues, in that capital can be raised with discretion under favorable capital market conditions.

Q. DR. MORIN, HOW DOES THE MERGER BETWEEN THE FORMER DUKE ENERGY CORPORATION AND CINERGY CORP. AFFECT YOUR RATE OF RETURN RECOMMENDATION?

A. The merger between the former Duke Energy Corporation and Cinergy Corp. has no discernible impact on the rate of return on equity than would have been sought if the merger had not occurred. In my view, the Company's proposed cost of equity is not higher than it would have been absent the merger. The senior unsecured ratings of Duke Energy Kentucky have remained unchanged. The rating agency actions in response to the merger announcement were relatively positive. Moody's made no changes to the Cinergy and Duke Energy Kentucky ratings, and noted potential positive impacts from the merger. The ratings outlook at Moody's has changed to "Positive", and is "Stable" at Fitch and S&P.

The economies of scale, synergies, and greater fuel diversity that will result from the merger, coupled with the complementary capacity need and supply profiles within the larger company resulting from the merger, will maintain and may enhance the creditworthiness of the Company's securities so as to counteract any near-term negative rating effects of the merger, to the extent that there are any. I discuss the demand synergies, cost synergies and managerial economies that can arise from a merger in my treatise on value creation, *Driving Shareholder Value,* McGraw-Hill, 2001.

Q. FINALLY, DR. MORIN, IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PRE-FILED TESTIMONY AND THE DATE YOUR ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

<u>AFFIDAVIT</u>

STATE OF GEORGIA)

COUNTY OF GLYNN)

BEFORE ME, the undersigned authority, on this day personally appeared Roger A. Morin, who, having been placed under oath by me, did depose as follows:

"My name is Roger A. Morin. I am of legal age and a resident of the State of Georgia. The foregoing testimony offered by me on behalf of Duke Energy Kentucky is true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true, and correct."

Roger A. Morin

SUBSCRIBED AND SWORN TO BEFORE ME by the said Roger A. Morin this 22ND day of MAY, 2006.

Notary Public in and for the

State of Georgia

Colin T. Jefferies
NOTARY PUBLIC
Glynn Co., Georgia
My Commission Expires March 29, 2009

APPENDIX A

CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea 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. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

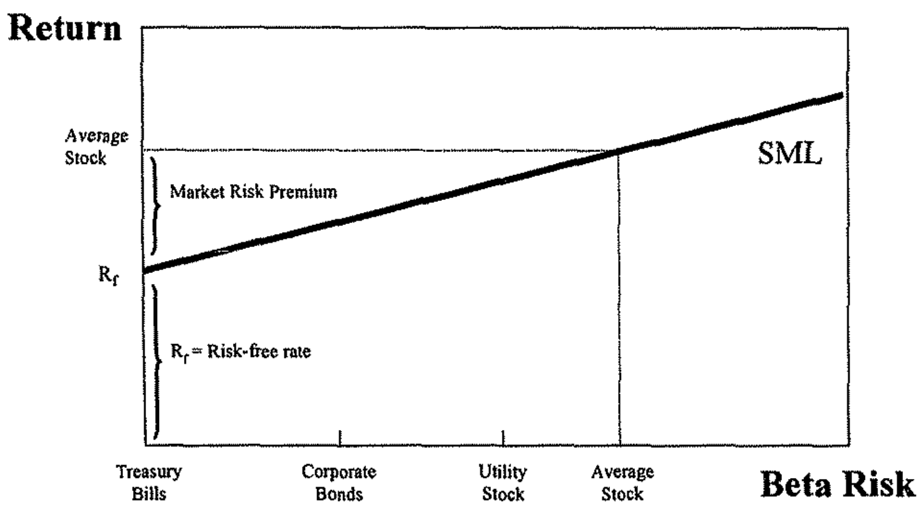
$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β, and the market risk premium, $(R_M - R_F)$, where R_M is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

$$K = R_F + \beta \times MRP \qquad (2)$$

The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.

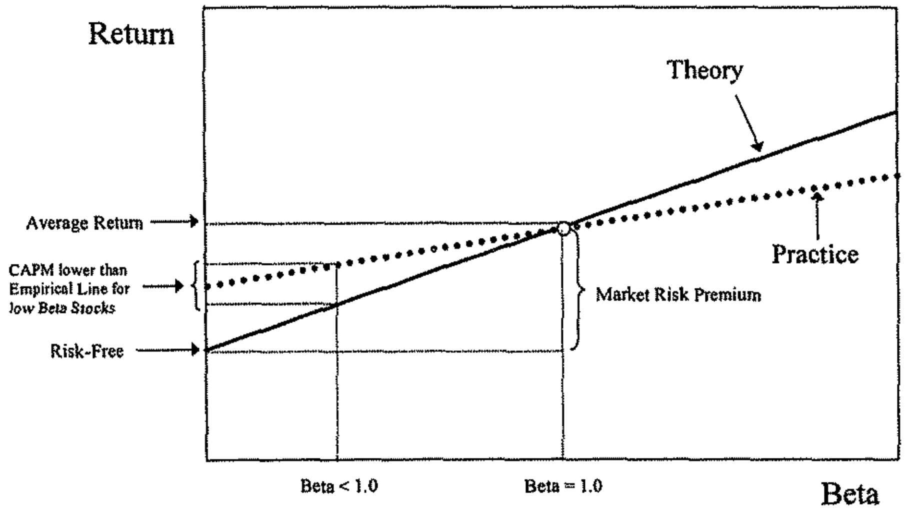
CAPM and Risk - Return
in Capital Markets



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \qquad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of "alpha" in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979), Litzenberger et al. (1980) and Rosenberg and Marathe (1975) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	**Range of alpha**	**Period relied upon**
Fischer (1993)	-3.6% to 3.6%	1931-1991
Fischer, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien	2.0%	1983-1998

Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1994) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

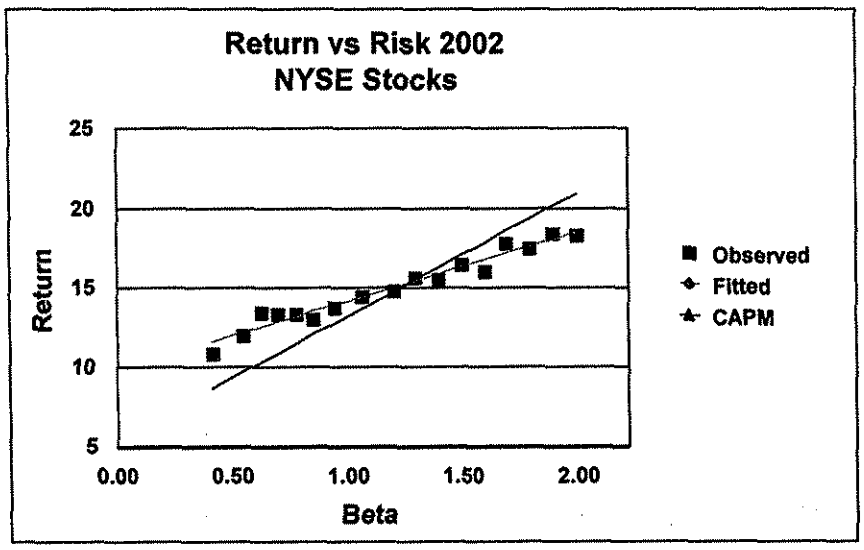
$$K = .0829 + .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6%, this relationship implies that the intercept of the risk-return relationship is higher than the 6% risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0% in that period, that is, the market risk premium $(R_M - R_F) = 8\%$, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, suggesting an alpha factor of 2%.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table

6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

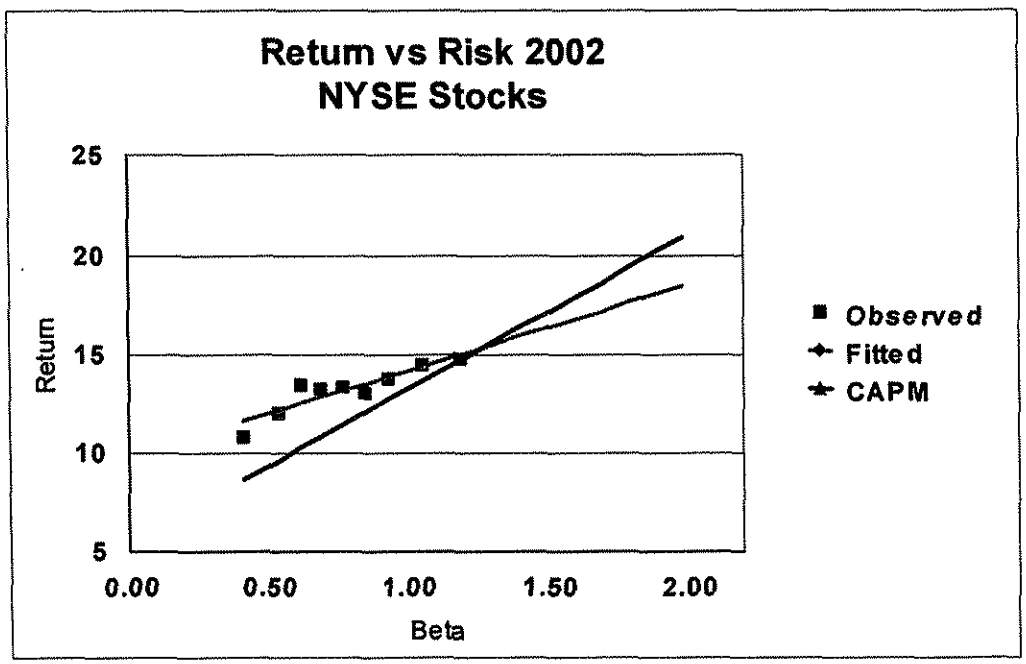
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7% while the slope is less than equal to the market risk premium of 7.7% predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-

1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year Treasury bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

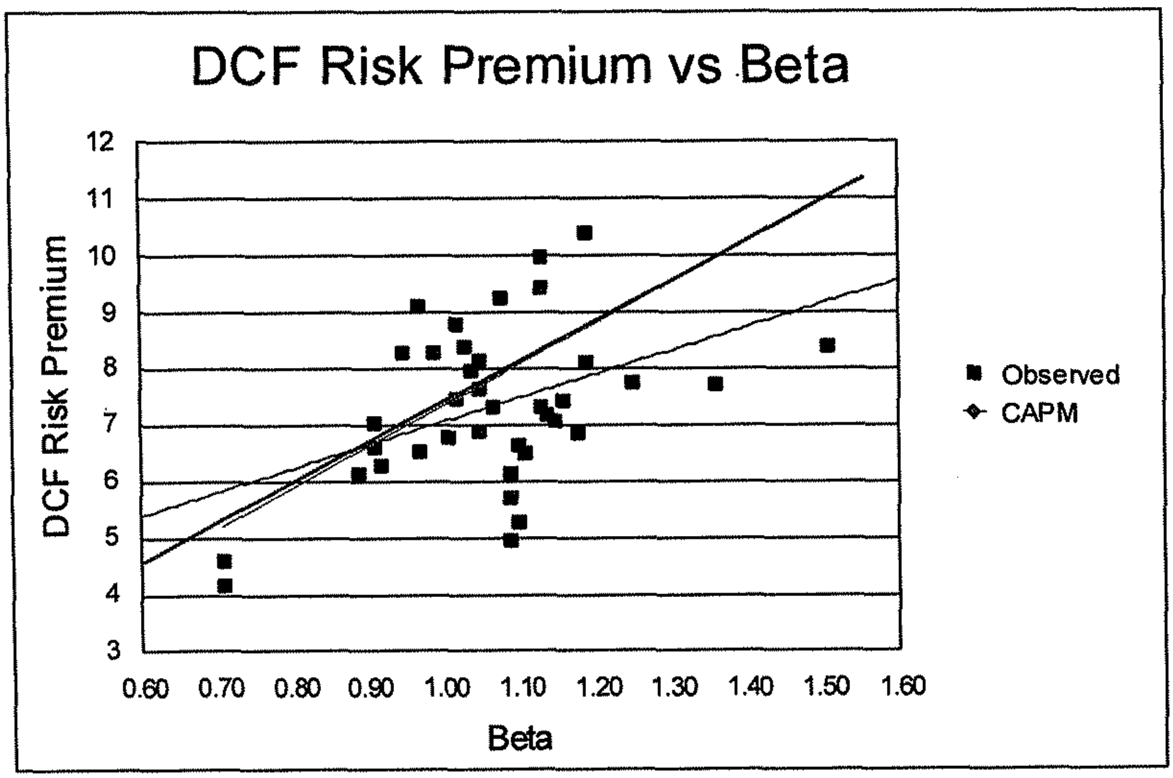
Table A-1 Risk Premium and Beta Estimates by Industry

	Industry (1)	DCF Risk Premium (2)	Raw Industry Beta (3)	Adjusted Industry Beta (4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14
4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51
18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15
32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09
34	Telc	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
	MEAN	**7.19**		

The observed *statistical* relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2%, that is approximately equal to 25% of the expected market risk premium of 7.2% shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2%. Instead, the observed slope of close to 5% is approximately equal to 75% of the expected market risk premium of 7.2%, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \qquad (6)$$

The empirical findings support values of α from approximately 2% to 7%. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2% - 3% is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[2]. An alpha in the range of 1% - 2% is therefore reasonable.

[2] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5%, the MRP is 7%, and the alpha factor is 2%. The cost of capital is determined as follows:

$$K = R_F + \alpha + \beta\ (MRP - \alpha)$$

$$K = 5\% + 2\% + 0.80(7\% - 2\%)$$

$$= 11\%$$

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1\text{-}a)\ \beta\ MRP$$

With an alpha of 2%, a MRP in the 6% - 8% range, the 'a" coefficient is 0.25, and the ECAPM becomes[3]:

$$K = R_F + 0.25\ MRP + 0.75\ \beta\ MRP$$

Returning to the numerical example, the utility's cost of capital is:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$

$$= 11\%$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[4].

---

[3] Recall that alpha equals 'a' times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is 2%, then a = 0.25

[4] In the Morin (1994) study, the value of "a" was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\ \beta$$

The value of a that best explained the observed relationship was 0.25.

REFERENCES

Black, Fischer, "Beta and Return," The Journal of Portfolio Management, Fall 1993, 8-18.

Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests, from Studies in the theory of Capital Markets," in

Jensen, M. (ed.) Studies in the Theory of Capital Markets, Praeger, New York, 1972,79-121.

Breenan, M. (1973) "Taxes, Market Valuation, and Corporate Financial Policy," National Tax Journal, 23, 417-427.

Fama, Eugene F. and James D. MacBeth, "Risk, Returns and Equilibrium: Empirical Tests," Journal of Political Economy, September 1972, pp. 607-636.

Fama, Eugene F. and Kenneth R. French, "The Cross-Section of Expected Stock Returns," Journal of Finance, Vol. 47, June 1992, pp. 427-465.

Friend, I., Westerfield, R., and Granito, M. (1978) "New Evidence on the Capital Asset Pricing Model, Journal of Finance, 23, 903-916.

Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

Kraus, A. and Litzenberger, R.H. (1976) "Skewness Preference and the Valuation of Risk Assets, Journal of Finance, 31, 1085-99.

Litzenberger, R. H. and Ramaswamy, K. "The Effect of Personal Taxes and Dividends on Capital Asset Prices: Theory and Empirical Evidence." Journal of Financial Economics, June 1979, 163-196.

Litzenberger, R. H., Ramaswamy, K. and Sosin, H. (1980) "On the CAPM Approach to the Estimation of a Public Utility's Cost of Equity Capital, Journal of Finance, 35, May 1980, 369-83.

Merton, R.C. (1973) "An Intertemporal Capital Asset Pricing Model", Econometrica, 41, 867-887.

Morin, R.A. (1981) "Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

Pettengill, Glenn N., Sridhar Sundaram and Ike Mathur, "The Conditional Relation between Beta and Returns," Journal of Financial and Quantitative Analysis, Vol. 30,No. 1, March 1995, pp. 101-116.

Rosenberg, V. and Marathe, V. (1975) "The Prediction of Investment Risk: Systematic and Residual Risk," Proceedings of the Seminar on the Analysis of Security Prices, Univ. of Chicago, 20, Nov. 1975.

Rubinstein, M.E. (1973) "A Mean-Variance Synthesis of Corporate Financial Theory, Journal of Financial Economics, March 1973, 167-82.

APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75%

for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL
(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9.99	13.28%	4.39%
10 - 19.99	8.72	2.76
20 - 39.99	6.93	2.42
40 - 59.99	5.87	1.32
60 - 79.99	5.18	2.34
80 - 99.99	4.73	2.16
100 - 199.99	4.22	2.31
200 - 499.99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 6. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1\text{-}f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are \$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at \$2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from \$26.25 to \$26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN = (D/P + g)	**14.00%**
ALLOWED RETURN ON EQUITY = (D/P(1-f) + g)	**14.47%**

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
--------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	**5.00%**		**5.00%**	**5.00%**	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	4.53%		4.53%	4.53%	

RESUME OF ROGER A. MORIN

(Spring 2006)

NAME: Roger A. Morin

ADDRESS: 9 King Ave.
Jekyll Island, GA 31527, USA

TELEPHONE: (912) 635-3233 business office
(912) 635-3233 business fax
(404) 229-2857 cellular
(404) 651-2674 office-university

E-MAIL ADDRESS: profmorin@msn.com

DATE OF BIRTH: 3/5/1945

PRESENT EMPLOYER: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Professor of Finance

HONORS: Professor of Finance for Regulated Industry
Director Center for the Study of Regulated Industry,
College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.

- Master of Business Administration, McGill University, Montreal, Canada, 1969.

- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pa., 1972-3

- Assistant Professor, University of Montreal School of Business, 1973-1976.

- Associate Professor, University of Montreal School of Business, 1976-1979.

- Professor of Finance, Georgia State University, 1979-2005

- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, College of Business, Georgia State University, 1985-2005

- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Executive Visions Inc., Board of Directors, Member
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991

PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Ameren

American Water Works Company

Ameritech

Arkansas Western Gas

Baltimore Gas & Electric – Constellation Energy

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Cascade Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co.

Central Telephone

Central & South West Corp.

Chattanoogee Gas Company

Cincinnati Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Natural Gas

Constellation Energy

Delmarva Power & Light Co.

Deerpath Group

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy New Orleans, Inc.

First Energy

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California - Verizon

GTE Northwest Inc. - Verizon

GTE Service Corp. - Verizon

GTE Southwest Incorporated - Verizon

Gulf Power Company

Havasu Water Inc.

Hawaiian Electric Company

Heater Utilities – Aqua - America

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Manitoba Hydro

Maritime Telephone

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

Mountain Bell

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Tel Enterprises Ltd.

New York Telephone Co.

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power – Emera Inc.

Nova Scotia Utility and Review Board

NUI Corp.

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Puget Sound Electric Co.

Quebec Telephone

Regie de l'Energie du Quebec

Rochester Telephone

San Diego Gas & Electric

SaskPower

Sierra Pacific Power Company

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar

- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2006
  National Seminars:

  Risk and Return on Capital Projects
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Real Options in Utility Capital Investments
  Fundamentals of Utility Finance in a Restructured Environment
  Contemporary Issues in Utility Finance

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Rate of Return

Capital Structure

Generic Cost of Capital

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES

Federal Communications Commission

Federal Energy Regulatory Commission

Georgia Public Service Commission

South Carolina Public Service Commission

North Carolina Utilities Commission

Pennsylvania Public Service Commission

Ontario Telephone Service Commission

Quebec Telephone Service Commission

Newfoundland Board of Commissioners of Public Utilities

Georgia Senate Committee on Regulated Industries

Alberta Public Service Board

Tennessee Regulatory Authority

Oklahoma State Board of Equalization

Mississippi Public Service Commission

Minnesota Public Utilities Commission

Canadian Radio-Television & Telecommunications Comm.

New Brunswick Board of Public Commissioners

Alaska Public Utility Commission

National Energy Board of Canada

Florida Public Service Commission

Montana Public Service Commission

Arizona Corporation Commission

Quebec Natural Gas Board

Quebec Regie de l'Energie

New York Public Service Commission

Washington Utilities & Transportation Commission

Manitoba Board of Public Utilities

New Jersey Board of Public Utilities

Alabama Public Service Commission

Utah Public Service Commission

Nevada Public Service Commission

Louisiana Public Service Commission

Colorado Public Utilities Board

West Virginia Public Service Commission

Ohio Public Utilities Commission

California Public Service Commission

Hawaii Public Service Commission

Illinois Commerce Commission

British Columbia Board of Public Utilities

Indiana Utility Regulatory Commission

Minnesota Public Utilities Commission

Texas Public Utility Commission

Michigan Public Service Commission

Iowa Board of Public Utilities

Missouri Public Service Commission

Arkansas Public Service Commission

Hawaii Public Utility Commission

New Hampshire Public Utility Commission

Delaware Public Utility Commission

Washington Utilities & Transportation Commission

Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC,Docket#R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Northern Telephone, Ontario PSC

GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

Newtel., Nfld. Brd of Public Commission PU 11-87

CN-CP Telecommunications, CRTC

Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., D # U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, #P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, 1989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

Cincinnati Gas & Electric 1994, 1996, 1999, 2004

Southern States Utilities, 1995

CILCO 1995, 1999, 2001

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003

Detroit Edison, 1999, 2003

Entergy Gulf States, Texas, 2000, 2004

Hydro Quebec TransEnergie, 2001, 2004

Sierra Pacific Company, 2000, 2001, 2002

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002, 2004

Mississippi Power Company, 2001, 2002

Oklahoma Gas & Electric Company, 2002 - 2003

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002

NB Power, 2002

Entergy New Orleans, 2002

Hydro-Quebec Distribution 2002

PSI Energy 2003

Fortis – Newfoundland Power & Light 2002

Emera – Nova Scotia Power 2004

Hydro-Quebec TransEnergie 2004

Hawaiian Electric 2004

Missouri Gas Energy 2004

AGL Resources 2004

Arkansas Western Gas 2004

Public Service of New Hampshire 2005

Hawaiian Electric Company 2005

Delmarva Power & Light Company 2005

Union Heat Power & Light 2005

Puget Sound Electric Co 2006-01-16

Cascade Natural Gas 2006

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982
- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982
- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983
- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.
- Committee on New Product Development, FMA, 1985
- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986
- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986
- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation
"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, 1978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

  Financial Management
  Financial Review
  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994.

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, forthcoming February 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities
Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.
Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

"An Economic & Financial Profile of the Canadian Cablevision Industry," Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

"Operational Risk Analysis: California Water Utilities," Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company, 1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique",CRTC,1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry", International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities", Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

UNIVERSITY SERVICE

- University Senate, elected departmental senator 1987-1989, 1998-2002
- Faculty Affairs Committee, elected departmental representative
- Professional Continuing Education Committee member
- Director Master in Science (Finance) Program
- Course Coordinator, Corporate Finance, MBA program
- Chairman, Corporate Finance Curriculum Committee
- Executive Education: Departmental Coordinator 2000

VERTICALLY INTEGRATED ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Industry	Beta
1	ALLETE	UTILCENT	
2	Alliant Energy	UTILCENT	0.85
3	Ameren Corp.	UTILCENT	0.75
4	Amer. Elec. Power	UTILCENT	1.20
5	Cen. Vermont Pub. Serv.	UTILEAST	0.60
6	Cleco Corp.	UTILCENT	1.20
7	Edison Int'l	UTILWEST	1.10
8	El Paso Electric	UTILWEST	0.70
9	Empire Dist. Elec.	UTILCENT	0.75
10	Energy East Corp.	UTILEAST	0.85
11	Entergy Corp.	UTILCENT	0.85
12	FirstEnergy Corp.	UTILEAST	0.75
13	FPL Group	UTILEAST	0.80
14	Green Mountain Pwr.	UTILEAST	0.60
15	Hawaiian Elec.	UTILWEST	0.70
16	IDACORP Inc.	UTILWEST	0.95
17	MGE Energy	UTILCENT	0.70
18	Northeast Utilities	UTILEAST	0.80
19	PG&E Corp.	UTILWEST	1.15
20	Pinnacle West Capital	UTILWEST	0.95
21	PNM Resources	UTILWEST	0.95
22	Progress Energy	UTILEAST	0.80
23	Puget Energy Inc.	UTILWEST	0.80
24	Southern Co.	UTILEAST	0.65
25	TECO Energy	UTILEAST	1.00
26	Wisconsin Energy	UTILCENT	0.75
27	Xcel Energy Inc.	UTILWEST	0.85
	AVERAGE		**0.85**

Source: VLIA
03/2006

MOODY'S ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Beta
1	Amer. Elec. Power	1.20
2	CH Energy Group	0.80
3	Consol. Edison	0.65
4	Constellation Energy	0.95
5	Dominion Resources	0.95
6	DPL Inc.	0.95
7	Duquesne Light Hldgs	0.85
8	Duke Energy	1.20
9	Energy East Corp.	0.85
10	Exelon Corp.	0.80
11	FirstEnergy Corp.	0.75
12	IDACORP Inc.	0.95
13	NiSource Inc.	0.80
14	OGE Energy	0.75
15	PPL Corp.	1.00
16	Progress Energy	0.80
17	Public Serv. Enterprise	0.90
18	Southern Co.	0.65
19	TECO Energy	1.00
20	Xcel Energy Inc.	0.85
	AVERAGE	0.88
	AVERAGE w/o AEP, Duke	0.85

Source: VLIA 4/2006

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	*Long-Term* Government Bond Yield	*20 year* Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's *Electric* Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10	-11
1931	4.07%	1,000.00				43.23					
1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.63	-8.81%	6.08%	-2.73%	-20.37%
1933	3.36%	969.60	-30.40	31.50	0.11%	28.73	1.95	-27.12%	4.95%	-22.17%	-22.28%
1934	2.93%	1,064.73	64.73	33.60	9.83%	21.06	1.60	-26.70%	5.57%	-21.13%	-30.96%
1935	2.76%	1,025.99	25.99	29.30	5.53%	36.06	1.32	71.23%	6.27%	77.49%	71.96%
1936	2.55%	1,032.74	32.74	27.60	6.03%	41.60	1.48	15.36%	4.10%	19.47%	13.43%
1937	2.73%	972.40	-27.60	25.50	-0.21%	24.24	1.74	-41.73%	4.18%	-37.55%	-37.34%
1938	2.52%	1,032.83	32.83	27.30	6.01%	27.56	1.50	13.68%	6.19%	19.84%	13.83%
1939	2.26%	1,041.65	41.65	25.20	6.68%	28.85	1.48	4.72%	5.37%	10.09%	3.41%
1940	1.94%	1,052.84	52.84	22.60	7.54%	22.22	1.54	-22.98%	5.34%	-17.64%	-25.19%
1941	2.04%	983.64	-16.36	19.40	0.30%	13.45	1.44	-39.47%	6.48%	-32.99%	-33.29%
1942	2.46%	933.97	-66.03	20.40	-4.56%	14.29	1.26	6.25%	9.37%	15.61%	20.18%
1943	2.48%	996.86	-3.14	24.60	2.15%	21.01	1.28	47.03%	8.96%	55.98%	53.84%
1944	2.46%	1,003.14	3.14	24.80	2.79%	21.09	1.31	0.38%	6.24%	6.62%	3.82%
1945	1.99%	1,077.23	77.23	24.60	10.18%	31.14	1.30	47.65%	6.16%	53.82%	43.63%
1946	2.12%	978.90	-21.10	19.90	-0.12%	32.71	1.43	5.04%	4.59%	9.63%	9.75%
1947	2.43%	951.13	-48.87	21.20	-2.77%	25.60	1.56	-21.74%	4.77%	-16.97%	-14.20%
1948	2.37%	1,009.51	9.51	24.30	3.38%	26.20	1.60	2.34%	6.25%	8.59%	5.21%
1949	2.09%	1,045.58	45.58	23.70	6.93%	30.57	1.66	16.68%	6.34%	23.02%	16.09%
1950	2.24%	975.93	-24.07	20.90	-0.32%	30.81	1.76	0.79%	5.76%	6.54%	6.86%
1951	2.69%	930.75	-69.25	22.40	-4.69%	33.85	1.88	9.87%	6.10%	15.97%	20.65%
1952	2.79%	984.75	-15.25	26.90	1.17%	37.85	1.91	11.82%	5.64%	17.46%	16.29%
1953	2.74%	1,007.66	7.66	27.90	3.56%	39.61	2.01	4.65%	5.31%	9.96%	6.40%
1954	2.72%	1,003.07	3.07	27.40	3.05%	47.56	2.13	20.07%	5.38%	25.45%	22.40%
1955	2.95%	965.44	-34.56	27.20	-0.74%	49.35	2.21	3.76%	4.65%	8.41%	9.15%
1956	3.45%	928.19	-71.81	29.50	-4.23%	48.96	2.32	-0.79%	4.70%	3.91%	8.14%
1957	3.23%	1,032.23	32.23	34.50	6.67%	50.30	2.43	2.74%	4.96%	7.70%	1.03%
1958	3.82%	918.01	-81.99	32.30	-4.97%	66.37	2.50	31.95%	4.97%	36.92%	41.89%
1959	4.47%	914.65	-85.35	38.20	-4.71%	65.77	2.61	-0.90%	3.93%	3.03%	7.74%
1960	3.80%	1,093.27	93.27	44.70	13.80%	76.82	2.68	16.80%	4.07%	20.88%	7.08%
1961	4.15%	952.75	-47.25	38.00	-0.92%	99.32	2.81	29.29%	3.66%	32.95%	33.87%
1962	3.95%	1,027.48	27.48	41.50	6.90%	96.49	2.97	-2.85%	2.99%	0.14%	-6.76%
1963	4.17%	970.35	-29.65	39.50	0.99%	102.31	3.21	6.03%	3.33%	9.36%	8.37%
1964	4.23%	991.96	-8.04	41.70	3.37%	116.54	3.43	12.93%	3.35%	16.28%	12.92%
1965	4.50%	964.64	-35.36	42.30	0.69%	114.86	3.86	-0.59%	3.34%	2.75%	2.06%

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10	-11
1931	4.07%	1,000.00				43 23					
1932	3.15%	1,135.75	135 75	40.70	17.64%	39.42	2.63	-8.81%	6.08%	-2.73%	-20.37%
1966	4.55%	993.48	-6.52	45.00	3.85%	105.99	4.11	-7.72%	3.58%	-4.14%	-7.99%
1967	5.56%	879.01	-120.99	45.50	-7.55%	98.19	4.34	-7.36%	4.09%	-3.26%	4.29%
1968	5.98%	951.38	-48.62	55.60	0.70%	104.04	4.50	5.96%	4.58%	10.54%	9.84%
1969	6.87%	904.00	-96.00	59.80	-3.62%	84.62	4.61	-18.67%	4.43%	-14.23%	-10.62%
1970	6.48%	1,043.38	43.38	68.70	11.21%	88.59	4.70	4.69%	5.55%	10.25%	-0.96%
1971	5.97%	1,059.09	59.09	64.80	12.39%	85.56	4.77	-3.42%	5.38%	1.96%	-10.42%
1972	5.99%	997.69	-2.31	59.70	5.74%	83.61	4.87	-2.28%	5.69%	3.41%	-2.33%
1973	7.26%	867.09	-132.91	59.90	-7.30%	60.87	5.01	-27.20%	5.99%	-21.21%	-13.90%
1974	7.60%	965.33	-34.67	72.60	3.79%	41.17	4.83	-32.36%	7.93%	-24.43%	-28.22%
1975	8.05%	955.63	-44.37	76.00	3.16%	55.66	4.97	35.20%	12.07%	47.27%	44.10%
1976	7.21%	1,088.25	88.25	80.50	16.87%	66.29	5.18	19.10%	9.31%	28.40%	11.53%
1977	8.03%	919.03	-80.97	72.10	-0.89%	68.19	5.54	2.87%	8.36%	11 22%	12.11%
1978	8.98%	912.47	-87.53	80.30	-0.72%	59.75	5.81	-12.38%	8.52%	-3.86%	-3.13%
1979	10.12%	902.99	-97.01	89.80	-0.72%	56.41	6.22	-5.59%	10.41%	4.82%	5.54%
1980	11.99%	859.23	-140.77	101.20	-3.96%	54.42	6.58	-3.53%	11.66%	8.14%	12.09%
1981	13.34%	906.45	-93.55	119.90	2.63%	57.20	6.99	5.11%	12.84%	17.95%	15.32%
1982	10.95%	1,192.38	192.38	133.40	32.58%	70.26	7.43	22.83%	12.99%	35.82%	3.24%
1983	11.97%	923.12	-76.88	109.50	3.26%	72.03	7.67	2.52%	11.20%	13.72%	10.46%
1984	11.70%	1,020.70	20.70	119.70	14.04%	80.16	8.26	11.29%	11.47%	22.75%	8.71%
1985	9.56%	1,189.27	189.27	117.00	30.63%	94.98	8.61	18.49%	10.74%	29.23%	-1.40%
1986	7.89%	1,166.63	166.63	95.60	26.22%	113.66	8.89	19.67%	9.36%	29.03%	2.80%
1987	9.20%	881.17	-118.83	78.90	-3.99%	94.24	9.12	-17.09%	8.02%	-9.06%	-5.07%
1988	9.18%	1,001.82	1.82	92.00	9.38%	100.94	8.87	7.11%	9.41%	16.52%	7.14%
1989	8.16%	1,099.75	99.75	91.80	19.16%	122.52	8.82	21.38%	8.74%	30.12%	10.96%
1990	8.44%	973.17	-26.83	81.60	5.48%	117.77	8.79	-3.88%	7.17%	3.30%	-2.18%
1991	7.30%	1,118.94	118.94	84.40	20.33%	144.02	8.95	22.29%	7.60%	29.89%	9.55%
1992	7.26%	1,004.19	4.19	73.00	7.72%	141.06	9.05	-2.06%	6.28%	4.23%	-3.49%
1993	6.54%	1,079.70	79.70	72.60	15.23%	146.70	8.99	4.00%	6.37%	10.37%	-4.86%
1994	7.99%	856.40	-143.60	65.40	-7.82%	115.50	8.96	-21.27%	6.11%	-15.16%	-7.34%
1995	6.03%	1,225.98	225.98	79.90	30.59%	142.90	9.06	23.72%	7.84%	31.57%	0.98%
1996	6.73%	923.67	-76.33	60.30	-1.60%	136.00	9.06	-4.83%	6.34%	1.51%	3.11%
1997	6.02%	1,081.92	81.92	67.30	14.92%	155.73	9.06	14.51%	6.66%	21.17%	6.25%
1998	5.42%	1,072.71	72.71	60.20	13.29%	181.44	8.01	16.51%	5.14%	21.65%	8.36%
1999	6.82%	848.41	-151.59	54.20	-9.74%	137.30	8.06	-24.33%	4.44%	-19.89%	-10.15%
2000	5.58%	1,148.30	148.30	68.20	21.65%	227.09	8.71	65.40%	6.34%	71.74%	50.09%
2001	5.75%	879.95	-20.05	55.60	3.57%	214.06	8.56	-5.73%	3.77%	-1.96%	-5.54%

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10	-11
1931	4.07%	1,000.00				43.23					
1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.63	-8.81%	6.08%	-2.73%	-20.37%
Mean											6.55%

Source: Mergent's (Moody's) Public Utility Manual 2002 December stock prices and dividends
Dec. Bond yields from Ibbotson Associates 2002 Yearbook Table B-9 Long-Term Government Bonds Yields

December stock price, dividends from Moody's Public Utility Manual

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

	Company Name	Industry	Earnings Growth 5-Year	Dividend Growth 5-Year	Book Value Growth 5-Year
1	ALLETE	UTILCENT			
2	Alliant Energy	UTILCENT	-3.0	-7.5	-1.5
3	Amer. Elec. Power	UTILCENT	3.5	-9.0	-3.5
4	Ameren Corp.	UTILCENT	1.5		4.0
5	Avista Corp.	UTILWEST	-3.5	-5.0	4.5
6	Black Hills	UTILWEST	4.5	4.0	17.0
7	Cen. Vermont Pub. Serv.	UTILEAST	8.5	0.5	2.0
8	CH Energy Group	UTILEAST	-1.5		2.0
9	Cinergy Corp.	UTILCENT	1.5	0.5	5.0
10	Cleco Corp.	UTILCENT	1.0	2.0	4.0
11	Consol. Edison	UTILEAST	-2.0	1.0	2.5
12	Constellation Energy	UTILEAST	6.0	-9.0	4.5
13	Dominion Resources	UTILEAST	11.0		4.5
14	DPL Inc.	UTILCENT	-1.0	0.5	-3.5
15	DTE Energy	UTILCENT	-2.0		3.5
16	Duke Energy	UTILEAST	-4.5		7.5
17	Duquesne Light Hldgs	UTILEAST	-14.5	-5.5	-17.5
18	Edison Int'l	UTILWEST		-9.0	8.5
19	Empire Dist. Elec.	UTILCENT	-5.0		2.0
20	Energy East Corp.	UTILEAST	-0.5	5.5	5.5
21	Entergy Corp.	UTILCENT	11.0	1.5	5.5
22	Exelon Corp.	UTILEAST	6.5		
23	FirstEnergy Corp.	UTILEAST	1.0	2.0	6.0
24	Florida Public Utilities	UTILEAST	-0.5	4.5	8.0
25	FPL Group	UTILEAST	3.5	4.5	6.0
26	Green Mountain Pwr.	UTILEAST	37.5	-6.5	-0.5
27	Hawaiian Elec.	UTILWEST	1.0		2.5
28	IDACORP Inc.	UTILWEST	-3.0	-0.5	4.0
29	Maine & Maritimes Corp	UTILEAST	20.0	6.5	6.0
30	MDU Resources	UTILWEST	10.5	5.0	13.0
31	MGE Energy	UTILCENT	4.0	1.0	5.0
32	NiSource Inc.	UTILCENT		1.0	7.0
33	Northeast Utilities	UTILEAST		37.5	2.0
34	NSTAR	UTILEAST	4.0	1.0	2.0
35	OGE Energy	UTILCENT	-2.0		1.5

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

36	Otter Tail Corp.	UTILCENT	2.0	2.0	7.5
37	Pepco Holdings	UTILEAST			
38	PG&E Corp.	UTILWEST	-20.5		-8.0
39	Pinnacle West Capital	UTILWEST	-3.0	7.0	4.0
40	PNM Resources	UTILWEST	-2.0	4.5	5.0
41	PPL Corp.	UTILEAST	8.5	8.5	12.0
42	Progress Energy	UTILEAST	5.5	3.0	8.5
43	Public Serv. Enterprise	UTILEAST	5.0		0.5
44	Puget Energy Inc.	UTILWEST	-5.5	-10.5	0.5
45	SCANA Corp.	UTILEAST	7.0	2.0	3.0
46	Sempra Energy	UTILWEST	14.0	-8.5	6.0
47	Southern Co.	UTILEAST	2.5	1.0	-1.5
48	TECO Energy	UTILEAST	-11.0	-3.5	-2.0
49	UniSource Energy	UTILWEST	5.0		12.0
50	UNITIL Corp.	UTILEAST	-1.5		0.5
51	Vectren Corp.	UTILCENT	1.0	3.0	3.5
52	Westar Energy	UTILCENT	-1.5	-14.5	-11.0
53	Wisconsin Energy	UTILCENT	9.5	-12.0	3.5
54	WPS Resources	UTILCENT	11.0	2.0	8.5
55	Xcel Energy Inc.	UTILWEST	-9.5	-9.0	-5.0
	AVERAGE		**2.2**	**0.0**	**3.2**

Source: Value Line Investment
Analyzer 4/2006

Integrated Electric, Gas, and Combination Utilities

	Company	Parent
1	AGL Resources Inc	AGL Resources Inc
2	Allete Inc.	Allete Inc.
3	Wisconsin Power & Light Co.	Alliant
4	Interstate Power & Light Co.	Alliant
5	Central Illinois Light Co.	Ameren Corp
6	CILCORP	Ameren Corp
7	Union Electric Co.	Ameren Corp
8	Ameren Corp.	Ameren Corp
9	Kentucky Power Co.	American Electric Power
10	Appalachian Power Co.	American Electric Power
11	Public Service Co. of Oklahoma	American Electric Power
12	Southwestern Electric Power Co.	American Electric Power
13	Atmos Energy Corp.	Atmos
14	Black Hills Power Inc.	Black Hills
15	Central Vermont Public Service	Central Vermont
16	Cincinnati Gas & Electric Co.	Cinergy Corp.
17	PSI Energy Inc.	Cinergy Corp.
18	Union Light Heat & Power Co.	Cinergy Corp.
19	Cleco Power LLC	CLECO
20	Virginia Electric& Power Co	Dominion Resources
21	Detroit Edison Co	DTE Energy Company
22	Michigan Consolidated Gas Co.	DTE Energy Company
23	Duke Energy Field Services LLC	Duke Energy
24	Southern California Edison Co.	Edison International
25	El Paso Electric Co.	El Paso Corp
26	Empire District Electric Co.	Empire District Electric Co.
27	Energen Corp	Energen Corp
28	RGS Energy Group Inc.□	Energy East Corporation
29	Rochester Gas & Electric Corp.	Energy East Corp.
30	Energy East Corp.	Energy East Corp.
31	Entergy Gulf States Inc.	Entergy Corporation
32	Entergy New Orleans Inc.	Entergy Corporation
33	Entergy Mississippi Inc.	Entergy Corporation
34	Entergy Louisiana Inc,	Entergy Corporation
35	Entergy Arkansas Inc.	Entergy Corporation
36	System Energy Resources Inc.	Entergy Corporation
37	Equitable Resources Inc.	Equitable Resources Inc.
38	Ohio Edison Co	FirstEnergy
39	Toledo Edison Co.	FirstEnergy
40	Cleveland Electric Illuminating Co.	FirstEnergy
41	Pennsylvania Power Co.	FirstEnergy
42	Florida Power & Light Co.	FPL Group Inc

Integrated Electric, Gas, and Combination Utilities

43	Kansas City Power & Light Co.	Great Plains Energy
44	Green Mountain Power Corp.	Green Mountain Power
45	Hawaiian Electric Co. Inc.	Hawaiian Electric Industries Inc
46	Idaho Power Co.	IDACORP
47	IDACORP Inc.	IDACORP Inc.
48	Kaneb Pipe Line OperPartnership L.P.	Kaneb Pipe Line LP
49	Kentucky Utilities Co.	LG&E Energy Corp
50	Montana-Dakota Utilities Co.	MDU Resources
51	Madison Gas & Electric Co.	MGE Energy
52	MidAmerican Energy Co	MidAmerican Energy Holding Co
53	National Fuel Gas Co.□	National Fuel Gas Co
54	Northern Indiana Public Service Co.	NiSource
55	Columbia Energy Group	NiSource
56	NiSource Inc.	NiSource Inc.
57	Public Service Co. of New Hampshire	Northeast Utilities System
58	Northern Border Partners L.P.	Northern Plains
59	Enogex Inc.	OGE Energy
60	Oklahoma Gas & Electric Co.	OGE Energy Corp
61	Portland General Electric Co.	Oregon Electric Utility Co
62	Pacific Gas & Electric Co.	PG&E National Energy Group Inc
63	Arizona Public Service Co.	Pinnacle West Capital Corp.
64	Pinnacle West Capital Corp.	Pinnacle West Capital Corp.
65	Public Service Co. of New Mexico	PNM Resources
66	PNM Resources Inc.	PNM Resources Inc.
67	Louisville Gas & Electric Co.	Powergen Plc
68	Progress Energy Carolinas Inc.	Progress Energy Inc
69	Progress Energy Florida	Progress Energy Inc
70	Puget Energy Inc.	Puget Energy
71	Puget Sound Energy Inc.	Puget Energy
72	Questar Market Resources Inc.	Questar Corp
73	Questar Corp	Questar Corp
74	SCANA Corp.	SCANA Corp.
75	South Carolina Electric & Gas Co.	SCANA Corp.
76	PacifiCorp	Scottish Power Group
77	San Diego Gas & Electric Co	Sempra Energy
78	Southern Co.	Southern Company
79	Alabama Power Co	Southern Company
80	Georgia Power Co	Southern Company
81	Savannah Electric & Power Co	Southern Company
82	Gulf Power Co.	Southern Company
83	Mississippi Power Co	Southern Company
84	Tampa Electric Co.	TECO Energy Inc
85	TXU U.S. Holdings Co.	TXU
86	Vectren Utility Holdings Inc.	Vectren Corporation
87	Southern Indiana Gas & Electric Co.	Vectren Corporation

Integrated Electric, Gas, and Combination Utilities

88	Wisconsin Electric Power Co.	Wisconsin Energy Corp.
89	Wisconsin Energy Corp.	Wisconsin Energy Corp.
90	Wisconsin Public Service Corp.	WPS Resources
91	Southwestern Public Service Co.	XCEL Energy Inc
92	Public Service Co. of Colorado	XCEL Energy Inc
93	Northern States Power Wisconsin	XCEL Energy Inc
94	Northern States Power Co.	XCEL Energy Inc
95	Xcel Energy Inc.	XCEL Energy Inc

S&P'S VERTICALLY INTEGRATED ELECTRIC UTILITIES

DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	ALLETE	3.2	
2	Alliant Energy	3.6	6.0
3	Ameren Corp.	5.0	2.5
4	Amer. Elec. Power	4.4	2.5
5	Cleco Corp.	4.0	4.5
6	Edison Int'l	2.7	10.5
7	El Paso Electric	0.0	18.5
8	Empire Dist. Elec.	5.8	6.5
9	Energy East Corp.	4.8	4.0
10	Entergy Corp.	3.1	5.0
11	FirstEnergy Corp.	3.6	8.5
12	FPL Group	3.8	6.5
13	Green Mountain Pwr.	4.0	3.5
14	Hawaiian Elec.	4.6	2.5
15	IDACORP Inc.	3.7	4.5
16	MGE Energy	4.2	5.0
17	Northeast Utilities	3.5	9.0
18	PG&E Corp.	3.4	26.5
19	Pinnacle West Capital	5.1	5.5
20	PNM Resources	3.6	7.0
21	Progress Energy	5.5	
22	Puget Energy Inc.	4.7	5.5
23	Southern Co.	4.7	5.0
24	TECO Energy	4.6	8.5
25	Wisconsin Energy	2.3	5.0
26	Xcel Energy Inc.	4.8	7.5
	AVERAGE	3.9	7.1

Notes:
Column 1, 2: Value Line Investment Analyzer, 4/2006

S&P'S VERTICALLY INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	3.6	6.0	3.8	9.8	10.0
2	Ameren Corp.	5.0	2.5	5.1	7.6	7.9
3	Amer. Elec. Power	4.4	2.5	4.5	7.0	7.2
4	Cleco Corp.	4.0	4.5	4.2	8.7	8.9
5	Edison Int'l	2.7	10.5	3.0	13.5	13.6
6	Empire Dist. Elec.	5.8	6.5	6.1	12.6	13.0
7	Energy East Corp.	4.8	4.0	5.0	9.0	9.3
8	Entergy Corp.	3.1	5.0	3.3	8.3	8.5
9	FirstEnergy Corp.	3.6	8.5	3.9	12.4	12.6
10	FPL Group	3.8	6.5	4.0	10.5	10.7
11	Green Mountain Pwr.	4.0	3.5	4.1	7.6	7.8
12	Hawaiian Elec.	4.6	2.5	4.7	7.2	7.4
13	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
14	MGE Energy	4.2	5.0	4.4	9.4	9.6
15	Northeast Utilities	3.5	9.0	3.8	12.8	13.0
16	Pinnacle West Capital	5.1	5.5	5.3	10.8	11.1
17	PNM Resources	3.6	7.0	3.9	10.9	11.1
18	Puget Energy Inc.	4.7	5.5	5.0	10.5	10.7
19	Southern Co.	4.7	5.0	4.9	9.9	10.2
20	TECO Energy	4.6	8.5	5.0	13.5	13.8
21	Wisconsin Energy	2.3	5.0	2.4	7.4	7.5
22	Xcel Energy Inc.	4.8	7.5	5.2	12.7	12.9
	AVERAGE	4.1	5.7	4.3	10.0	10.2
	DTE Energy	5.0	6.5	5.3	11.8	12.1

Notes:
Column 1, 2: Value Line Investment Analyzer, 4/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

S&P'S VERTICALLY INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1	ALLETE	3.2	6.8
2	Alliant Energy	3.6	4.0
3	Ameren Corp.	5.0	6.0
4	Amer. Elec. Power	4.4	3.0
5	Cleco Corp.	4.0	4.0
6	Edison Int'l	2.7	7.8
7	El Paso Electric	0.0	15.0
8	Empire Dist. Elec.	5.8	
9	Energy East Corp.	4.8	4.5
10	Entergy Corp.	3.1	7.4
11	FirstEnergy Corp.	3.6	4.8
12	FPL Group	3.8	6.5
14	Hawaiian Elec.	4.6	5.2
15	IDACORP Inc.	3.7	4.5
16	MGE Energy	4.2	
17	Northeast Utilities	3.5	8.7
18	PG&E Corp.	3.4	7.0
19	Pinnacle West Capital	5.1	6.8
20	PNM Resources	3.6	8.3
21	Progress Energy	5.5	3.8
22	Puget Energy Inc.	4.7	7.0
23	Southern Co.	4.7	4.8
24	TECO Energy	4.6	5.7
25	Wisconsin Energy	2.3	7.2
26	Xcel Energy Inc.	4.8	4.2

Notes:
Column 1: Value Line Investment Analyzer, 4/2006
Column 2: Zacks long-term earnings growth forecast, 4/2006

S&P'S VERTICALLY INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	ALLETE	3.2	6.8	3.4	10.1	10.3
2	Alliant Energy	3.6	4.0	3.7	7.7	7.9
3	Ameren Corp.	5.0	6.0	5.3	11.3	11.6
4	Amer. Elec. Power	4.4	3.0	4.5	7.5	7.7
5	Cleco Corp.	4.0	4.0	4.1	8.1	8.4
6	Edison Int'l	2.7	7.8	2.9	10.7	10.9
7	Energy East Corp.	4.8	4.5	5.0	9.5	9.8
8	Entergy Corp.	3.1	7.4	3.4	10.8	11.0
9	FirstEnergy Corp.	3.6	4.8	3.8	8.6	8.8
10	FPL Group	3.8	6.5	4.0	10.4	10.7
11	Hawaiian Elec.	4.6	5.2	4.8	10.0	10.2
12	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
13	Northeast Utilities	3.5	8.7	3.8	12.5	12.7
14	PG&E Corp.	3.4	7.0	3.6	10.6	10.8
15	Pinnacle West Capital	5.1	6.8	5.4	12.2	12.4
16	PNM Resources	3.6	8.3	3.9	12.2	12.4
17	Progress Energy	5.5	3.8	5.7	9.4	9.7
18	Puget Energy Inc.	4.7	7.0	5.1	12.1	12.3
19	Southern Co.	4.7	4.8	4.9	9.6	9.9
20	TECO Energy	4.6	5.7	4.9	10.6	10.8
21	Wisconsin Energy	2.3	7.2	2.5	9.7	9.8
22	Xcel Energy Inc.	4.8	4.2	5.0	9.2	9.4
	AVERAGE	4.0	5.8	4.3	10.1	10.3
	DTE Energy	5.0	5.5	5.3	10.8	11.1

Notes:
Column 1: Value Line Investment Analyzer, 4/2006
Column 2: Zacks long-term earnings growth forecast, 4/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Amer. Elec. Power	4.1	2.0
2	CH Energy Group	4.4	3.5
3	Cinergy Corp.	4.5	4.0
4	Consol. Edison	5.0	2.5
5	Constellation Energy	2.6	13.5
6	Dominion Resources	3.7	8.0
7	DPL Inc.	3.7	1.0
8	Duquesne Light Hldgs	5.8	4.0
9	Duke Energy	4.5	8.5
10	Energy East Corp.	4.8	4.0
11	Exelon Corp.	3.0	7.0
12	FirstEnergy Corp.	3.6	8.5
13	IDACORP Inc.	3.7	4.5
14	NiSource Inc.	4.5	0.5
15	OGE Energy	4.7	5.5
16	PPL Corp.	3.5	8.0
17	Progress Energy	5.5	
18	Public Serv. Enterprise	3.3	1.5
19	Southern Co.	4.5	5.0
20	TECO Energy	4.5	8.5
21	Xcel Energy Inc.	4.8	7.5

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 3/2006
No Value Line growth forecasts
available for Progress Energy

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	4.1	2.0	4.1	6.1	6.3
2	CH Energy Group	4.4	3.5	4.5	8.0	8.3
3	Consol. Edison	5.0	2.5	5.2	7.7	7.9
4	Constellation Energy	2.6	13.5	2.9	16.4	16.6
5	Dominion Resources	3.7	8.0	4.0	12.0	12.2
6	Duquesne Light Hldgs	5.8	4.0	6.0	10.0	10.3
7	Duke Energy	4.5	8.5	4.9	13.4	13.6
8	Energy East Corp.	4.8	4.0	5.0	9.0	9.2
9	Exelon Corp.	3.0	7.0	3.2	10.2	10.3
10	FirstEnergy Corp.	3.6	8.5	3.9	12.4	12.6
11	IDACORP Inc.	3.7	4.5	3.8	8.3	8.5
12	NiSource Inc.	4.5	0.5	4.5	5.0	5.3
13	OGE Energy	4.7	5.5	4.9	10.4	10.7
14	PPL Corp.	3.5	8.0	3.8	11.8	12.0
15	Southern Co.	4.5	5.0	4.7	9.7	10.0
16	TECO Energy	4.5	8.5	4.9	13.4	13.6
17	Xcel Energy Inc.	4.8	7.5	5.1	12.6	12.9

AVERAGE	5.9	4.4	10.4	10.6

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 3/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No Value Line growth forecasts available for Progress Energy
DPL Inc estimate less than cost of debt
Public Service Enterprise in merger activity

MOODY'S ELECTRIC UTILITIES

DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1	Amer. Elec. Power	4.4	3.0
2	CH Energy Group	4.4	
3	Cinergy Corp.	4.5	4.0
4	Consol. Edison	5.2	4.2
5	Constellation Energy	2.7	11.0
6	Dominion Resources	4.0	9.0
7	DPL Inc.	3.6	7.0
8	Duquesne Light Hldgs	5.9	
9	Duke Energy	4.3	6.0
10	Energy East Corp.	4.8	4.5
11	Exelon Corp.	3.1	9.4
12	FirstEnergy Corp.	3.6	4.8
13	IDACORP Inc.	3.7	4.5
14	NiSource Inc.	4.5	3.4
15	OGE Energy	4.5	3.0
16	PPL Corp.	3.7	8.3
17	Progress Energy	5.5	3.8
18	Public Serv. Enterprise	3.5	7.8

19	Southern Co.	4.7	4.8
20	TECO Energy	4.6	5.7
21	Xcel Energy Inc.	4.8	4.2

Notes:
Column 1: Value Line Investment Analyzer, 4/2006
Column 2: Zacks long-term earnings growth forecast, 4/2006
No growth forecast available for CH Energy Group, Duquesne Light
Public Serv Enterprise and Cinergy in merger

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	4.4	3.0	4.5	7.5	7.7
2	Consol. Edison	5.2	4.2	5.4	9.6	9.9
3	Constellation Energy	2.7	11.0	3.0	14.0	14.2
4	Dominion Resources	4.0	9.0	4.3	13.3	13.5
5	DPL Inc.	3.6	7.0	3.9	10.9	11.1
6	Duke Energy	4.3	6.0	4.6	10.6	10.8
7	Energy East Corp.	4.8	4.5	5.0	9.5	9.8
8	Exelon Corp.	3.1	9.4	3.4	12.8	13.0
9	FirstEnergy Corp.	3.6	4.8	3.8	8.6	8.8
10	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
11	NiSource Inc.	4.5	3.4	4.6	8.1	8.3
12	OGE Energy	4.5	3.0	4.6	7.6	7.9
13	PPL Corp.	3.7	8.3	4.0	12.3	12.5
14	Progress Energy	5.5	3.8	5.7	9.4	9.7
15	Southern Co.	4.7	4.8	4.9	9.6	9.9
16	TECO Energy	4.6	5.7	4.9	10.6	10.8
17	Xcel Energy Inc.	4.8	4.2	5.0	9.2	9.4
	AVERAGE	**4.2**	**5.7**	**4.4**	**10.1**	**10.4**

Notes:

Column 1: Value Line Investment Analyzer,
4/2006
Column 2: Zacks long-term earnings growth forecast, 4/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No growth forecast available for CH Energy Group, Duquesne
Lt.
Public Serv Enterprise and Cinergy in merger

VERTICALLY INTEGRATED ELECTRIC UTILITIES
COMMON EQUITY RATIOS

	Company	Industry	% Common Equity
1	ALLETE	UTILCENT	60.9
2	Alliant Energy	UTILCENT	50.2
3	Ameren Corp.	UTILCENT	52.6
4	Amer. Elec. Power	UTILCENT	44.9
5	Cen. Vermont Pub. S(	UTILEAST	60.4
6	Cleco Corp.	UTILCENT	52.0
7	Edison Int'l	UTILWEST	40.9
8	El Paso Electric	UTILWEST	58.4
9	Empire Dist. Elec.	UTILCENT	49.0
10	Energy East Corp.	UTILEAST	40.6
11	Entergy Corp.	UTILCENT	52.9
12	FirstEnergy Corp.	UTILEAST	45.4
13	FPL Group	UTILEAST	51.4
14	Green Mountain Pwr.	UTILEAST	52.9
15	Hawaiian Elec.	UTILWEST	51.0
16	IDACORP Inc.	UTILWEST	50.7
17	MGE Energy	UTILCENT	62.6
18	Northeast Utilities	UTILEAST	34.0
19	PG&E Corp.	UTILWEST	53.2
20	Pinnacle West Capita	UTILWEST	53.3
21	PNM Resources	UTILWEST	52.4
22	Progress Energy	UTILEAST	44.3
23	Puget Energy Inc.	UTILWEST	39.4
24	Southern Co.	UTILEAST	44.1
25	TECO Energy	UTILEAST	24.9
26	Wisconsin Energy	UTILCENT	43.3
27	Xcel Energy Inc.	UTILWEST	44.1
	AVERAGE		**48.7**

Source: Value Line Investment Analyzer 4/2006.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

PAUL F. OCHSNER

ON BEHALF OF

DUKE ENERGY KENTUCKY

182798

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE .... - 1 -

II. PRIOR COMMISSION DIRECTIVES .... - 2 -

III. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS .... - 3 -

IV. COST OF SERVICE STUDIES .... - 4 -

V. CONCLUSION .... - 21 -

ATTACHMENTS

ATTACHMENT PFO-1 – Summary of Demand Peak Allocation Factor Methodologies Capacity Cost Reallocation Percentages Forecasted Test Year 2007

ATTACHMENT PFO-2 – Summary of Class Rate Increase Ratio Percentages By Demand Allocation Method Reflecting Proposed Subsidy/Excess and Change in Base Rate Fuel Costs

ATTACHMENT PFO-3 – Cost of Service Results

ATTACHMENT PFO-4 – Proposed Base Revenue Increase Including Fuel

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul F. Ochsner. My business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as a Rate Coordinator.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I graduated from Northern Kentucky University in 1978 with a Bachelor of Science in Business. I completed the Edison Electric Institute's Electric Fundamental and Advanced Rate Courses conducted by the Graduate School of Business at Indiana University; the American Gas Association's Gas Fundamental Rate Seminar conducted by The University of Wisconsin's Graduate School of Business; and the Association of Edison Illuminating Company's Fundamental Load Research Seminar.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("Duke Energy Ohio") in 1971 and I progressed through various positions in the Customer Accounting and General Accounting Departments. In 1979, I became Staff Assistant in the Rate Department and I have progressed through various job levels within the Rate Department to my current position of Rate Coordinator.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS RATE COORDINATOR?

A. I prepare the gas and electric cost of service studies that support Duke Energy's regulated operating companies' revenue distribution and rate design proposals in base rate proceedings.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. In Case No. 91-370, I provided testimony supporting the Company's existing and proposed electric rates and revenues. In Case No. 2001-00092 and Case No. 2005-00042, I provided testimony supporting the Company's gas cost of service studies and jurisdictional allocation procedures and the proposed distribution of the gas rate increases.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I discuss the Commission's directives from the Company's last retail electric base rate case relating to cost of service studies. I sponsor Schedules B-7, B-7.1, B-7.2, D-3, D-4, and D-5. I also support the electric cost of service studies identified as Filing Requirement ("FR") FR 10(9)v-1 through FR 10(9)v-18.

II. <u>PRIOR COMMISSION DIRECTIVES</u>

Q. DID THE COMMISSION ISSUE ANY DIRECTIVES IN CASE NO. 91-370 RELATING TO THE COST OF SERVICE STUDIES FOR THE COMPANY'S FUTURE RATE CASES?

A. Yes. The Commission recommended that, in future rate cases, the Company should separate out distribution plant into primary and secondary components for its Cost of Service Study. If not feasible, then the Commission directed the Company to explain in testimony the reasons why it could not do so. The

Commission also directed the Company to file multiple cost of service studies that use, among other things, demand allocation methods from each of the peak demand, energy weighting, and time-differentiated families of production plant allocation methodologies.

Q. HAS THE COMPANY ADDRESSED THOSE RECOMMENDATIONS IN PREPARING THE COST OF SERVICE STUDIES FOR THIS PROCEEDING?

A. Yes. I will discuss the Company's responses in more detail later in my testimony.

III. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULES B-7 AND D-3.

A. These schedules report the allocation factors used to determine the jurisdictional percentages of electric plant, expenses, *etc*., necessary to allocate the amount of the proposed new electric rates between jurisdictional and non-jurisdictional customers. These schedules indicate that 100% of the costs are jurisdictional, because The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky") does not provide service to any non-jurisdictional electric customers.

Q. PLEASE DESCRIBE SCHEDULES B-7.1 AND D-4.

A. These schedules are the support for Schedules B-7 and D-3 described above. They provide the basis for the actual jurisdictional allocation factors.

Q. PLEASE DESCRIBE SCHEDULES B-7.2 AND D-5.

A. These schedules explain changes made to the jurisdictional allocation from the Company's prior electric rate proceeding in Case No. 91-370. In that case, the company had a firm FERC-jurisdictional wholesale power agreement with the City of Williamstown. The Company no longer has the Williamstown agreement, so no Commission jurisdictional allocation of costs is required.

Q. PLEASE DESCRIBE FR 10(9)V-1 THROUGH FR 10(9)V-18

A. FR10 (9)v-1, 2 and 3 are fully allocated, embedded cost of service studies by rate class. FR 10(9)v-4 through FR 10(9)v-18 are functionalized cost of service studies for each rate class based on the results from FR10 (9)v-1.

IV. COST OF SERVICE STUDIES

Q. WHAT INFORMATION DID THE COMPANY USE TO DEVELOP THE COST ALLOCATION FACTORS FOR THE COST OF SERVICE STUDIES USED IN THIS PROCEEDING?

A. The test year for this proceeding is the twelve months ending December 31, 2007, which is comprised of forecasted test period data. The development of the test year allocation factors is primarily based on historical data for the twelve months ended December 2005. Otherwise, forecasted test year information was used as appropriate. I will discuss the actual development of the various allocation factors used in this proceeding later in my testimony.

Q. HOW DID THE COMPANY IDENTIFY THE APPROPRIATE DISTRIBUTION PLANT AS PRIMARY AND SECONDARY VOLTAGE FOR THE ALLOCATION FACTORS?

A. The Engineering Standards Group analyzed the Overhead and Underground Conductor and Devices Accounts, Accounts 3650 and 3670, and made engineering estimates for the facilities that provide service at the primary and secondary voltages. The results of this study were used to develop the factors used to allocate the cost of these facilities to the primary and secondary voltage customer classes. Pages 46 through 50 of work paper WPFR-9v, provide the results of the engineering study, which was used in part to develop the allocation factor K205.

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. The purpose of a Cost of Service Study is to allocate a utility company's costs to the different customer classes which are responsible for causing these costs. After the costs are assigned to the appropriate customer classes, rates are designed to provide the Company with an opportunity to generate a stream of revenues to recover these costs.

Q. HAS THE COMPANY PREPARED AND FILED MULTIPLE COST OF SERVICE STUDIES AS DIRECTED BY THE COMMISSION IN THE COMPANY'S LAST ELECTRIC BASE RATE CASE?

A. Yes. The Company has filed three Class Cost of Service Studies that contain essentially the same data, except that different methodologies were used to develop the allocation factors for the demand component of Production and Transmission plant and other functionally-related costs. The demand allocation methods are as follows: (1) the Average of the Twelve (12) Coincident Peaks ("12 CP") method; (2) the Average and Excess ("A&E") method; and (3) the Summer / Non-Summer ("S/NS") method. These cost of service studies can be found as FR 10(9)v-1, 2 and 3, respectively.

Q. PLEASE DESCRIBE THE DEMAND METHODOLOGIES USED IN THESE COST OF SERVICE STUDIES.

A. The 12 CP method is designed to allocate capacity related costs to the customer classes using the system during maximum system load. The allocation of capacity costs to each customer class is based on the class load contribution to the maximum peak, at the time of peak, regardless of what their respective loads were at other times of the day.

The A&E method, also referred to as the "used and unused capacity method," recognizes both the class average use of the system capacity and the class contribution to the capacity required to meet the maximum system load. The allocation of capacity costs are allocated in a two part formula.

The "class-used" capacity component is the proportion of the class's respective average hourly kilowatt-hour ("kWh") sales to the total average hourly sales. The "class-unused" capacity is the class excess hourly peak demand contribution ratio, which is the difference between the class average hourly demands and the hourly class peak demands. The used and unused capacity factors for each class are combined to allocate capacity costs to the respective rate classes.

The S/NS method is a time-differentiated method designed to allocate capacity costs based on the weighted class average coincident peak demand contributions during the maximum system load for the summer and non-summer months. The S/NS demand ratios allocate 38.38% of capacity costs using the class average coincident peaks for the four summer months, June, July, August and September, and the remaining 61.62 % of capacity costs using average of the 12 monthly class coincident peaks for each rate group. The summer / non-summer capacity cost split was determined by the ratio of the annual energy delivered during the on and off-peak periods for each month.

Q. DID YOU COMPARE THE CLASS DEMAND RATIOS FOR EACH OF THE DEMAND METHODOLOGIES?

A. Yes. I compared the class demand ratios for the 12 CP and S/NS methods, which showed the S/NS method results in minimal increases in capacity cost responsibility for Rates RS, DS and DP. Rates EH, GS-FL, DT, TT and Lighting receive the decrease in capacity cost responsibility. The total class capacity cost switching between these two methods is approximately 1.1%.

I then compared the 12 CP and the A&E methods, which showed the A&E method results in a total class capacity cost switching percentage of approximately 7.6%, with Rate RS absorbing approximately 7% of the total. Attachment PFO-1 compares the results of the three demand methodologies.

Q. BASED UPON YOUR COMPARISON OF THE 12 CP, A&E AND S/NS METHODOLOGIES, WHICH DO YOU RECOMMEND THE COMMISSION APPROVE IN THIS PROCEEDING?

A. I recommend using the Average 12 CP methodology for three reasons. First, the 12 CP method is generally accepted in the utility industry and was approved by the Commission in the Company's last electric base rate case. The 12 CP demand methodology is used in other jurisdictions including Duke Energy Ohio's and Duke Energy Indiana's rate proceedings. Second, this methodology recognizes that Duke Energy Kentucky's current generating facilities are in place precisely to meet the monthly maximum peak loads of customers. Third, there was no compelling reason to adopt a new methodology. Rate subsidies will generally occur among customer classes, regardless of the cost of service methodology used. Changing to either the A&E or S/NS methodology will not change this fact. The Company believes that the use of the 12 CP methodology is the appropriate means to align capacity costs with the customer classes that are imposing the costs.

Q. PLEASE DESCRIBE THE TYPE OF COST OF SERVICE STUDY USED FOR THIS PROCEEDING.

A. The Cost of Service Study is an embedded fully allocated study by rate class for the forecasted test period ending December 31, 2007, as adjusted. The Cost of Service Study allocates Total Company functional cost items such as plant, operating expenses, and taxes to the various customer classes based demand- energy- and customer related allocation factors and calculates the revenue responsibility of each class. This study is identified as FR 10(9)v-1.

Q. HOW IS THE COST OF SERVICE STUDY IN SCHEDULE FR 10(9)v-1 ORGANIZED?

A. Schedule 1 of the Cost of Service Study contains a summary of the cost of service. Schedules 2 through 10 and Schedule 12 show the complete detail of all the elements of the Cost of Service Study. Schedules 11 and 13 list the allocation factors, tax rates, and rate of return data that were utilized in the cost of service program. The detailed calculation and derivation of the allocation factors used in the Cost of Service Study are included in the work papers filed in this case.

Q. DID YOU PREPARE ANY ADDITIONAL COST OF SERVICE STUDIES?

A. Yes. I used the results of the Cost of Service Study by rate class, FR 10(9)v-1, to prepare functionalized Cost of Service Studies for each rate class. These studies provide support for the customer, demand and energy charges proposed by Mr. Bailey. The functionalized studies use the allocated cost column by rate class, and then classify each line item into production, transmission or distribution functions. The production function was then classified into demand and energy functions. The transmission function was classified as demand and the distribution function was classified as demand or customer. I then allocated Duke Energy Kentucky's revenues under proposed rates into these functional categories, based on the results of the functional Cost of Service Study. This provides the revenue requirement by functional group. The functionalized Cost of Service Studies for each rate class are at FR 10(9)v-4 through FR 10(9)v-18.

Q. WHAT JURISDICTIONAL CUSTOMER CLASSES WERE USED IN THE COST OF SERVICE STUDIES?

A. The jurisdictional customer classes are as follows:

Residential – Rate RS

Secondary Distribution Small – Rates DS and DS-RTP

Secondary Distribution Small – Rate GS-FL

Secondary Distribution Small – Rate EH

Secondary Distribution Small – Rate SP

Secondary Distribution Large – Rates DT-Primary, DT-Secondary, DT-Primary-RTP and DT-Secondary-RTP

Primary Distribution – Rate DP

Transmission – Rates TT and TT-RTP

Lighting – Rates NSU, NSP, OL, SC, SE, SL, TL and UOLS

Other.

Q. PLEASE LIST EACH ELEMENT OF THE COST OF SERVICE STUDIES THAT YOU PREPARED.

A. The elements of a Cost of Service Study are the following:

Operating & Maintenance Expense
\+ Depreciation
\+ Other Taxes
\+ Federal Income Tax
\+ State Income Tax
\+ Return
\- <u>Revenue Credits</u>
= Revenue Requirement or Cost of Service

Q. HOW DID YOU DEVELOP THE BASIC COST OF SERVICE STUDY THAT YOU USED TO ALLOCATE COSTS TO THE DIFFERENT CUSTOMER CLASSES?

A. I used Coincident Peak, Non-coincident Peak, Diversified Class Peak demand data to develop demand statistics. Allocation factors were developed from customer, energy or demand statistics associated with the forecasted test period. Next, I classified costs into the specific utility functions, *i.e.,* production, transmission and distribution, and then I classified the costs as customer-, energy- or demand-related. I then allocated the costs to the various rate classes following the cost causation guidelines published in the National Association of Regulatory Utility Commissioners' "Electric Utility Cost Allocation Manual" and based on my experience with cost of service studies.

Q. HOW DID YOU DERIVE THE CUSTOMER, ENERGY AND DEMAND STATISTICS FOR EACH RATE CLASS?

A. The customer, energy and demand statistics by rate class were developed using forecasted test period data contained in work papers WPFR-9v pages 63 and 64, and the load research data shown reflected on work papers WPFR-9v 38 through 45, which is taken from actual customer data for the twelve month period ended December 31, 2005.

Q. WHAT METHOD WAS USED TO ALLOCATE PRODUCTION DEMAND RELATED COST?

I used the 12 CP method to allocate these costs. The allocation of capacity costs to each class is based on their load contribution to the maximum peak at the time of peak regardless of what their respective loads were at other times of the day.

Q. DO YOU BELIEVE THE 12 CP METHOD IS A REASONABLE ALLOCATION METHOD TO USE IN THIS PROCEEDING?

A. Yes. As I stated previously, the 12 CP method is widely accepted in the utility industry, and Duke Energy Kentucky's current base rates were established using the 12 CP method. Duke Energy Kentucky's generating facilities, a major portion of the Company's costs, are in place to meet customers' monthly maximum peak loads. The 12 CP method allocates capacity-related costs to the customer classes that use the system during the monthly maximum system peaks.

Q. HOW WERE THE DEMAND VALUES DEVELOPED FROM COMPANY CUSTOMER LOAD RESEARCH DATA?

A. Load research data for the twelve months ended December 31, 2005, and kWh sales levels for the twelve months ended December 31, 2007, were used to determine monthly peak day demand data. This monthly demand information is included on pages 11 through 30 of work paper WPFR-9v. The following is an example of how the class group demand was calculated for rate RS for the month of January 2007.

Step 1 – Determine the average demand by dividing the total kWh by the number of hours in the month.

158,621,000 kWh ÷ 744 hours =213,200 kW

Step 2 – Determine the coincident peak demand by dividing the average demand from Step 1 by the coincident peak load factor (from load research data).

- 213,200 kW ÷ 63.97% = 333,281 kW

Step 3 – Add line losses by multiplying the loss factor.

- 333,281 x 1.04452 = 348,119 kW (with losses)

I followed this process for all customer classes for the twelve months of the forecasted test year to determine each class's monthly peak coincident with Duke Energy Kentucky's monthly system peak. I used a similar procedure to develop each class's diversified class peak and highest (single) non-coincident peak demands.

Q. PLEASE DESCRIBE HOW THE 12 CP DEMAND ALLOCATOR WAS USED TO ALLOCATE COSTS.

A. The 12 CP demand allocator was used to allocate Production and Transmission capacity related costs to rate groups.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE DISTRIBUTION PLANT COSTS TO THE VARIOUS CUSTOMER CLASSES.

A. Several different allocation factors are used to allocate distribution plant costs to the customer classes.

Substations are allocated using the average demand ratio developed from the diversified class peak demand ratios for the twelve months ended December 31, 2007. *See* allocation factor K215.

Poles, Towers, & Fixtures and Conductors are allocated using the weighted distribution line allocation factor, K205. This factor allocates these costs to customers based on the diversified class peak demand ratio weighted for the primary/secondary service voltage calculation.

Line Transformers are allocated to secondary voltage customers based on class maximum non-coincident peak demand ratio. Line Transformers are sized to meet the maximum demand of the customer and are located in close proximity to the customer, so there is little or no customer load diversity. As a result, the maximum non-coincident peak demand allocation factor is appropriate. *See* allocation factor K203.

Services are allocated to secondary voltage customers based on a weighted-average number of customers' ratio. The weighting is determined by an engineering analysis which prices various service drop costs according to demand. For example, it is three times as costly for a service drop at 51 kilovolts ("kVA") versus a service drop of 5 kVA. (*See* allocation factor K217.)

Meter costs are allocated to customer classes based on a meter cost study. *See* allocation factor K407.

Lighting costs are directly assigned to Lighting Class.

Q. WHAT METHOD DID YOU USE TO ALLOCATE ADMINISTRATIVE AND GENERAL EXPENSES?

A. I used a two step approach. First, I functionalized Administrative and General ("A&G") expenses based on the specific groupings of employee salaries and wages for the forecasted test period. These groupings include Production Demand and Energy, Transmission, Distribution, Customer Accounting, Customer Service and Information and Sales. I then allocated these expenses to each rate class based on operating and maintenance ("O&M") expense allocation factors. For example, I allocated the A&G expense as production demand plant to each rate class based on the demand-related production O&M expense. I used the same procedure to allocate the other A&G expenses to each rate class. I used the A315 allocation factor for adjustments to all A&G costs throughout the basic Cost of Service Study. The A315 allocation factor simply consists of the sum of the weighted functionalized A&G expenses by class. This is the same procedure used in Case Nos. 2001-00092 and 2005-00042. The functional salary and wage amounts are on page 65 of WFPR-9v. The calculation of allocation factor A 315 is at FR 10(9)v-1, Schedule 6.

Q. HOW DID YOU ALLOCATE THE COSTS FOR COMMON AND GENERAL PLANT?

A. I functionalized common and general plant based on the functionalization of salaries and wages used in the A&G factor. I then used the A&G expenses to allocate each function to customer classes.

Q. HOW DID YOU ALLOCATE CONSTRUCTION WORK IN PROGRESS COSTS?

A. Production, transmission, distribution, common and general plant Construction Work In Progress costs were allocated based on the class weighted gross plant ratios by function.

Q. HOW DID YOU ALLOCATE THE ADJUSTMENTS THAT WERE SUBTRACTED FROM RATE BASE?

A. I used allocation factor NP29, Net Plant Ratio to allocate the balances in the accumulated deferred income taxes in Accounts 282, 283, and 284 to each rate class.

Q. HOW DID YOU ALLOCATE ADJUSTMENTS THAT WERE ADDED TO RATE BASE?

A. I used the A&G expense cost factor, A315, to allocate the amounts reflected in the Accumulated Deferred Income Tax Account 190. Items included in this account relate to post-retirement and pension benefits, vacation pay accruals, deferred compensation benefits, and miscellaneous deferrals.

Q. HOW DID YOU ALLOCATE WORKING CAPITAL?

A. Working capital consists of the following items: fuel inventories, materials and supplies, prepayments, cash, and other miscellaneous items. Fuel Inventories were allocated to rate groups based on K301, class kWh ratios; materials and supplies were allocated using NP29, class net plant ratios; prepaid insurance was allocated to rate groups using A315, A&G expense; and prepayment for fuel and fuel related expenses were allocated to rate groups based on K301, class kWh ratios.

Q. HOW DID YOU ALLOCATE PRODUCTION AND TRANSMISSION DISTRIBUTION RELATED OPERATION & MAINTENANCE EXPENSES?

A. I allocated O&M expenses associated with production, transmission and distribution facilities to class based on the customer- demand- and energy-related allocation factors.

Q. HOW DID YOU ALLOCATE CUSTOMER ACCOUNTING, UNCOLLECTIBLE ACCOUNTS, CUSTOMER SERVICE AND INFORMATION, AND SALES EXPENSES?

A. I developed four allocation factors based on an analysis performed on the specific customer activity that occurred during the year 2005. The four factors are K409, K411, 413 and K419. K409 was used to allocate the Customer Accounting Expenses in Accounts 901, 902, 903 and 905. K411 was used to allocate Account 904. K413 was used to allocate expenses in the Customer Service and Information Accounts 908, 909 and 910. K419 was used to allocate Sales Expense, which is included in Accounts 911, 912 and 913. Except for Accounts 902 and 904, specific account activities for each account were determined to be either, residential and/or non-residential or applicable to all classes. I allocated these amounts to classes based on the appropriate customer ratio analysis. The allocation of Account 902 expense is based on meter reading cost estimates by meter type for the year 2005.

Expenses in Account 904 were allocated to rate classes based on a customer class charge-off analysis for the year 2005. The support for these allocation factors can be found on page 52 of WPFR-9v.

Q. HOW DID YOU ALLOCATE DEPRECIATION EXPENSES?

A. I allocated depreciation expenses to rate class based on the functional class net-depreciated plant ratios.

Q. HOW DID YOU ALLOCATE REAL ESTATE AND PROPERTY TAXES?

A. I allocated real estate and property taxes to rate class based on the functional class net-depreciated plant ratios.

Q. HOW DID YOU ALLOCATE PAYROLL AND HIGHWAY TAXES, THE PSC ASSESSMENT AND OTHER MISCELLANEOUS TAXES?

A. I allocated the PSC Maintenance Taxes to class based on each rate class present revenue ratio. I allocated Payroll, Highway and Other Miscellaneous Taxes to rate class based the class-weighted A&G expense ratio.

Q. HOW DID YOU ALLOCATE FEDERAL AND STATE INCOME TAX ADJUSTMENTS AND DEDUCTIONS?

A. I reviewed each income tax adjustment and deduction to determine the functional cause of the adjustment and deduction, then selected the appropriate allocation factor. For example: an Other Tax Deduction item, Depreciation in Excess of Book Depreciation, was allocated to the rate classes based on the class depreciation expense ratio.

Q. HOW DID YOU ALLOCATE OTHER OPERATING REVENUES?

A. I evaluated each other operating revenue item to determine source of the revenue, then selected the appropriate allocation factor. The class ratio of present revenues was the primary allocation factor used to allocate the revenue credits to the respective rate groups.

Q. WHERE CAN THE VARIOUS ELEMENTS OF A COST OF SERVICE STUDY BE FOUND IN THE COMPANY'S COST OF SERVICE STUDY?

A. A summary of each item is listed on Schedule 1 of the Cost of Service Study. Schedules 2, 3, 4 and 5 contain detailed information on Rate Base; Schedule 6, Operation and Maintenance expenses; Schedule 7, Depreciation; Schedule 8, Other Taxes; Schedules 9 and 12 Federal and State Income Tax; Schedule 10, the Cost of Service Computation; Schedule 11, Capitalization Dollars, Rate of Return, Revenue and Income Tax Rates; and Schedule 13, Allocation Factors.

Q. PLEASE DESCRIBE THE RESULTS OF THE COMPANY'S PROPOSED COST OF SERVICE STUDY.

A. The class Cost of Service Study, FR10(9)v-1, which includes the 12 CP capacity allocation method, the incremental increase in base rate fuel costs and the rate of return of 8.761% requested in this proceeding, supports the Company's overall proposed increase of approximately $66.5 million for the test period ending December 31, 2007, as adjusted for known and measurable changes.

Q. HOW DO THE RESULTS OF THE 12 CP DEMAND COST OF SERVICE STUDY COMPARE WITH THE A&E, FR10(9)V-2, AND S/NS, FR10(9)V-3, DEMAND COST OF SERVICE STUDIES?

A. The 12 CP, A&E and S/NS studies all support the Company's proposed revenue increase of approximately $66.5 million. The comparative results of the revenue deficiency distributions follow the same pattern as the demand allocation methodology comparison shown in Attachment PFO-1. Attachment PFO-2 has been prepared to show interclass switching percentages of the revenue increases justified by rate group.

Q. HOW DID YOU DETERMINE THE PROPOSED REVENUE DISTRIBUTION FOR THIS PROCEEDING?

A. First, I reviewed the present rates of return earned, justified increase amounts and associated percentage increase for each rate group from the 12 CP Class Cost of Service Study. From this review, I determined that the justified base rate increases were significant and varied by rate group because of the magnitude of the Company's proposed increase. I evaluated the revenue subsidy/excess positions for each rate group. I found that significant changes in the current revenue distribution would be required to move each class to the requested rate of return. As a result, I determined that the base revenue distribution proposal should reflect the elimination of 25% of the revenue subsidy/excess that currently exists between customer classes. I then allocated the proposed rate increase to customer classes based on the class allocation of Capitalization Costs allocated to electric operations.

Q. WHY DID YOU USE THIS METHOD IN DETERMINING THE PROPOSED REVENUE DISTIRBUTION FOR THIS PROCEEDING?

A. The amount of the proposed increase is derived from a revenue stream based on a requested rate of return on the Company's Electric Capitalization Dollars. The Company's goal is to move toward earning the same rate of return on all customer classes, based on equitable considerations and on the principle of cost causation.

Attachment PFO-3 is Schedule 1, Summary of Results of the 12 CP Cost of Service Study prior to the subsidy/excess revenue calculation and development of proposed revenues. Rather than eliminating the subsidy/excess issue in this proceeding, the Company is proposing to use the principle of gradualism to mitigate the revenue subsidy/excess issue over time. This methodology minimizes the rate shock that would occur if 100% of the subsidy/excess amounts at issue were remedied in a single case. This base revenue distribution methodology was also used in Case No. 2005-00042.

Q. DOES THE COMPANY PROPOSE TO ESTABLISH A NEW BASE RATE FUEL AMOUNT IN THIS PROCEEDING?

A. Yes. The Company proposes to increase the base rate fuel amount to 2.1619 cents per kWh, as Mr. Wathen discusses in his testimony.

Q WHAT IS THE COMPANY'S CURRENT FUEL RATE?

A The current fuel rate is 1.6566 cents per kWh. This rate consists of a base fuel component of 1.9091 cents per kWh and an incremental fuel adjustment clause rate of a negative 0.2525 cents per kWh.

Q DOES YOUR PROPOSED REVENUE DISTRIBUTION INCLUDE THE INCREASE IN THE PROPOSED BASE RATE FUEL COST AMOUNT?

A. Yes. The change in the proposed base fuel cost rate results in approximately $20.0 million in additional revenues to cover the increase in projected fuel costs for the forecasted test period.

Q WHERE ARE THE REVENUE IMPACTS OF THE BASE RATE INCREASE OF $46.5 MILLION AND THE INCREMENTAL INCREASE

OF $20.0 MILLION IN BASE RATE FUEL COSTS FOUND?

A Attachment PFO-4 provides the results of the Company's proposed base revenue increase including fuel. This attachment also supports the Company's proposed 25% reduction of the revenue subsidy/excess positions that currently exist.

Q. HOW WERE THE RESULTS OF YOUR COST OF SERVICE STUDIES AND THE IMPACT OF THE PROPOSED BASE FUEL RATE CHANGE REVENUE USED IN THIS PROCEEDING?

A. I provided the results of the fully allocated Cost of Service Study by rate class and function, including the incremental increases in base fuel revenue, to Mr. Bailey to develop the proposed revenue distribution and rate design for this proceeding.

V. CONCLUSION

Q. WERE SCHEDULES B-7, B-7.1, B-7.2, D-3, D-4, AND D-5, FR 10(9)V-1 THROUGH FR 10(9)V-18, AND ATTACHMENTS PFO-1 THROUGH PFO-4 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, Paul F. Ochsner, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Paul F. Ochsner

Paul F. Ochsner, Affiant

Subscribed and sworn to before me by Paul F. Ochsner on this 19th day of May, 2006.

Anita M. Schafer

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2009

Duke Energy Kentucky
Summary of Demand Peak Allocation Factor Methodologies
Capacity Cost Reallocation Percentages
Forecasted Test Year 2007

Rate Group	(1) 12 CP Demand Ratio %	(2) S / NS Demand Ratio %	(3) Capacity Cost Switch %	(4) Average & Excess Demand Ratio %	(5) Capacity Cost Switch %
			(Col. 2 - Col. 1)		(Col 4 - Col 1)
Residential	44.71%	45.28%	0.57%	51.71%	6.99%
Dist Secondary - DS	26.59%	27.15%	0.56%	22.23%	-4.36%
Dist Secondary - DS RTP	0.02%	0.02%	0.00%	0.02%	0.00%
Dist Secondary - GS-FL	0.12%	0.11%	-0.01%	0.09%	-0.03%
Dist Secondary - EH	0.34%	0.20%	-0.14%	0.43%	0.09%
Dist Secondary - SP	0.01%	0.01%	0.00%	0.01%	0.00%
Dist Secondary - DT	14.80%	14.54%	-0.26%	12.28%	-2.53%
Dist Secondary - DT RTP	0.16%	0.15%	-0.01%	0.18%	0.02%
Dist Primary - DT	8.30%	8.04%	-0.26%	7.88%	-0.42%
Dist Primary - DT RTP	0.38%	0.38%	-0.01%	0.38%	0.00%
Dist Primary - DP	0.81%	0.81%	0.01%	0.59%	-0.22%
Transmission - TT	3.23%	2.93%	-0.30%	3.48%	0.25%
Transmission - TT RTP	0.20%	0.19%	-0.01%	0.20%	0.00%
Lighting	0.32%	0.18%	-0.13%	0.52%	0.20%
Other	0.01%	0.01%	0.00%	0.02%	0.01%
Total Retail	100.00%	100.00%	0.00%	100.00%	0.00%

Duke Energy Kentucky
Summary of Class Rate Increase Ratio Percentages By Demand Allcoation Method
Changes Reflecting Subsidy Excess and Increase in Base Rate Fuel Costs
Case No. 2006-00172

Rate Class	(1) 12 CP Percent of Total	(2) S /NS Percent of Total	(3) Interclass Switching %	(4) A&E Percent of Total	(5) Interclass Switching %
			Col 2- Col 1		Col 4 - Col 1
Rate RS	49.04%	49.54%	0.50%	55.50%	6.46%
Rate DS	23.65%	24.18%	0.53%	19.61%	-4.04%
Rate DS-RTP	0.01%	0.01%	0.00%	0.01%	0.00%
Rate GS-FL	0.05%	0.05%	0.00%	0.03%	-0.02%
Rate EH	0.39%	0.26%	-0.13%	0.47%	0.08%
Rate SP	0.01%	0.01%	0.00%	0.01%	0.00%
Rate DT - Secondary	14.44%	14.20%	-0.24%	12.10%	-2.34%
Rate DT RTP-Sec.	0.12%	0.11%	-0.01%	0.14%	0.02%
Rate DT-Primary	8.46%	8.22%	-0.24%	8.07%	-0.39%
Rate DT RTP-Primary	0.27%	0.26%	-0.01%	0.27%	0.00%
Rate DP	0.75%	0.76%	0.01%	0.55%	-0.20%
Rate TT	2.12%	1.84%	-0.28%	2.35%	0.23%
Rate TT-RTP	0.09%	0.08%	-0.01%	0.09%	0.00%
Lighting	0.59%	0.47%	-0.12%	0.78%	0.19%
Other	0.01%	0.01%	0.00%	0.02%	0.01%
Total	100.00%	100.00%	0.00%	100.00%	0.00%

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
FR-9v-1 KW (12 COIN PEAK)

Prior to SUBSIDY EXCESS

ELECTRIC CASE NO: 2006-00172	ITEM	ALLO	TOTAL ELECTRIC	RS RESIDENTIAL	DS SECONDARY DISTRIBUTION	DS_RTP INCR. SEC. DISTR.	GSFL SECONDARY DISTRIBUTION	EH SECONDARY DISTRIBUTION	SP SECONDARY DISTRIBUTION	DT_SEC SECONDARY DISTRIBUTION	DT_SEC_RTP INCR. SEC. DIST
SUMMARY OF RESULTS	Schedule 1										
NET INCOME COMPUTATION											
GROSS ELECTRIC PLANT IN SERVICE	GP19		$1,122,822,000	$525,502,483	$290,575,522	$244,115	$1,236,650	$3,895,718	$123,048	$161,351,823	$1,808,678
TOTAL DEPRECIATION RESERVE	DR19		(540,093,766)	(251,204,608)	(139,382,371)	(116,405)	(600,203)	(1,861,549)	(58,475)	(77,237,576)	(865,961)
TOTAL RATE BASE ADJUSTMENTS	RB71		8,213,167	2,289,340	1,804,851	2,347	19,881	26,324	783	1,902,083	20,147
TOTAL RATE BASE	RB99		590,941,401	276,587,215	152,998,002	130,057	656,328	2,060,493	65,356	86,016,330	962,864
CAPITALIZATION ALLOC TO ELECTRIC OPER	ECAP		557,080,702	260,738,880	144,231,279	122,605	618,721	1,942,428	61,611	81,087,630	907,692
OPERATING EXPENSES											
TOTAL O&M EXPENSE	OM39		197,699,516	84,777,855	50,298,708	23,989	276,379	665,421	21,181	32,226,154	176,817
TOTAL DEPRECIATION EXPENSE	DE49		33,172,220	15,567,749	8,619,041	7,262	36,406	115,549	3,665	4,794,986	53,663
TOTAL OTHER TAX & MISC EXPENSE	L591		7,634,509	3,752,832	1,924,521	1,606	8,254	26,108	888	1,061,419	11,495
TOTAL OP EXP EXC INC & R TAX	OP69		238,506,245	104,098,436	60,842,270	32,857	321,039	807,078	25,734	38,082,559	241,975
NET FED INCOME TAX ALLOWABLE	I879		16,566,971	7,553,733	4,346,741	3,745	19,078	57,664	1,756	2,481,660	27,777
NET STATE INCOME TAX ALLOWABLE	J979		2,930,903	1,336,780	768,901	662	3,374	10,202	312	438,898	4,913
AFUDC OFFSET	LO33	CW29	(373,481)	(208,413)	(85,362)	(83)	(285)	(1,457)	(46)	(46,953)	(587)
TOTAL OPERATING EXPENSE	OPEX		257,630,638	112,780,536	65,872,550	37,181	343,206	873,487	27,756	40,956,164	274,078
RETURN ON CAPITALIZATION	R751		48,805,840	22,843,334	12,636,102	10,741	54,206	170,176	5,398	7,104,087	79,523
TOTAL OTHER OPERATING REVENUES			(1,978,260)	(902,661)	(523,189)	(470)	(2,582)	(6,636)	(236)	(293,587)	(3,119)
TOTAL ELECTRIC COST OF SERVICE	CS09		304,458,218	134,721,209	77,985,463	47,452	394,830	1,037,027	32,918	47,766,664	350,482
PROPOSED REVENUES	R602		237,897,726	97,639,085	66,709,383	70,100	471,911	694,501	35,117	38,378,456	343,715
EXCESS REVENUES	XREV		(66,560,492)	(37,082,124)	(11,276,080)	22,648	77,081	(342,526)	2,199	(9,388,208)	(6,767)
TOTAL RETURN EARNED	RETE		8,045,600	135,024	5,730,869	24,610	101,409	(39,580)	6,745	1,354,947	75,379
RATE OF RETURN EARNED ON CAPITALIZATION	RORE		0.014442432	0.000517851	0.039733885	0.200725908	0.163901015	(0.020376560)	0.109477204	0.016709663	0.083044689
TOTAL RATE OF RETURN ALLOWABLE	RORA		0.08761	0.08761	0.08761	0.08761	0.08761	0.08761	0.08761	0.08761	0.08761
RETURN EARNED ON COMMON EQUITY	REOE		(0.02024)	(0.04760)	0.02947	0.34587	0.27350	(0.08867)	0.16654	(0.01578)	0.11459
ALLOWED RETURN ON COMMON EQUITY	AROE		0.11499	0.11499	0.11499	0.11499	0.11499	0.11499	0.11499	0.11499	0.11499
PRESENT REVENUES	R600		237,897,726	97,639,085	66,709,383	70,100	471,911	694,501	35,117	38,378,456	343,715
REVENUE INCREASE JUSTIFIED	RIJD		66,560,492	37,082,124	11,276,080	(22,648)	(77,081)	342,526	(2,199)	9,388,208	6,767
PER UNIT PRES REV	RIJP		0.27979	0.37979	0.16903	(0.32308)	(0.16334)	0.49320	(0.06262)	0.24462	0.01969
REVENUE INCREASE REQUESTED	RIRD		0	0	0	0	0	0	0	0	0
PER UNIT PRES REV	RIRP		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
FR-9v-1 KW (12 COIN PEAK)

ELECTRIC CASE NO: 2006-00172	ITEM	ALLO	DT_PRI PRIMARY DISTRIBUTION	DT_PRI_RTP INCR. PRI. DIST	DP PRIMARY DISTRIBUTION	TT TRANSMISSION TIME OF DAY	TT_RTP INCR. TRANS TIME OF DAY	LT LIGHTING	OTHER WATER PUMPING	TOTAL AT ISSUE	ALL OTHER
			10	11	12	14	15	16	18	19	20
SUMMARY OF RESULTS	Schedule 1										
NET INCOME COMPUTATION											
GROSS ELECTRIC PLANT IN SERVICE	GP19		$85,204,777	$3,913,630	$8,074,446	$26,485,125	$1,667,763	$12,644,599	$93,623	$1,122,822,000	$0
TOTAL DEPRECIATION RESERVE	DR19		(40,969,108)	(1,882,441)	(3,905,280)	(13,585,511)	(855,956)	(7,523,065)	(45,257)	(540,093,766)	0
TOTAL RATE BASE ADJUSTMENTS	RB71		1,271,246	55,802	72,189	583,387	36,166	127,878	743	8,213,167	0
TOTAL RATE BASE	RB99		45,506,915	2,086,991	4,241,355	13,483,001	847,973	5,249,412	49,109	590,941,401	0
CAPITALIZATION ALLOC TO ELECTRIC OPER	ECAP		42,899,388	1,967,407	3,998,327	12,710,431	799,385	4,948,623	46,295	557,080,702	0
OPERATING EXPENSES											
TOTAL O&M EXPENSE	OM39		18,780,539	418,582	1,557,898	7,181,749	210,495	1,067,874	15,875	197,699,516	0
TOTAL DEPRECIATION EXPENSE	DE49		2,532,838	116,305	239,182	755,949	47,579	279,309	2,737	33,172,220	0
TOTAL OTHER TAX & MISC EXPENSE	L591		547,338	23,980	50,409	139,227	8,113	77,664	655	7,634,509	0
TOTAL OP EXP EXC INC & R TAX	OP69		21,860,715	558,867	1,847,489	8,076,925	266,187	1,424,847	19,267	238,506,245	0
NET FED INCOME TAX ALLOWABLE	I879		1,321,461	60,626	122,527	399,245	25,131	144,421	1,406	16,566,971	0
NET STATE INCOME TAX ALLOWABLE	J979		233,664	10,721	21,667	70,542	4,441	25,577	249	2,930,903	0
AFUDC OFFSET	L033	CW29	(16,319)	(745)	(1,243)	6,183	393	(18,519)	(45)	(373,481)	0
TOTAL OPERATING EXPENSE	OPEX		23,399,521	629,469	1,990,440	8,552,895	296,152	1,576,326	20,877	257,630,638	0
RETURN ON CAPITALIZATION	R751		3,758,415	172,365	350,293	1,113,561	70,034	433,549	4,056	48,805,840	0
TOTAL OTHER OPERATING REVENUES			(153,759)	(6,802)	(14,279)	(50,294)	(2,902)	(17,594)	(150)	(1,978,260)	0
TOTAL ELECTRIC COST OF SERVICE	CS09		27,004,177	795,032	2,326,454	9,616,162	363,284	1,992,281	24,783	304,458,218	0
PROPOSED REVENUES	R602		19,862,321	782,491	1,764,802	8,534,952	404,272	2,194,212	12,408	237,897,726	0
EXCESS REVENUES	XREV		(7,141,856)	(12,541)	(561,652)	(1,081,210)	40,988	201,931	(12,375)	(66,560,492)	0
TOTAL RETURN EARNED	RETE		(615,107)	164,685	6,349	451,451	95,134	557,207	(3,522)	8,045,600	0
RATE OF RETURN EARNED ON CAPITALIZATION	RORE		(0.014338363)	0.083706625	0.001587914	0.035518150	0.119008988	0.112598394	(0.076077330)	0.014442432	0.000000000
TOTAL RATE OF RETURN ALLOWABLE	RORA		0.08761	0.08761	0.08761	0.08761	0.08761	0.08761	0.08761	0.08761	0.08761
RETURN EARNED ON COMMON EQUITY	REOE		(0.07680)	0.11589	(0.04550)	0.02118	0.18527	0.17267	(0.19814)	(0.02024)	0.00000
ALLOWED RETURN ON COMMON EQUITY	AROE		0.11499	0.11499	0.11499	0.11499	0.11499	0.11499	0.11499	0.11499	0.11499
PRESENT REVENUES	R600		19,862,321	782,491	1,764,802	8,534,952	404,272	2,194,212	12,408	237,897,726	0
REVENUE INCREASE JUSTIFIED	RIJD		7,141,856	12,541	561,652	1,081,210	(40,988)	(201,931)	12,375	66,560,492	0
PER UNIT PRES REV	RIJP		0.35957	0.01603	0.31825	0.12668	(0.10139)	(0.09203)	0.99734	0.27979	0.00000
REVENUE INCREASE REQUESTED	RIRD		0	0	0	0	0	0	0	0	0
PER UNIT PRES REV	RIRP		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

DUKE ENERGY KENTUCKY

FR-9v-1 KW (12 COIN PEAK)
ELECTRIC CASE NO: 2006-00172
COMPUTATION OF THE RATE INCREASE AMOUNT BY RATE CLASS
TWELVE MONTHS ENDING DECEMBER 31, 2007

Line No.	Rate Class	Capitalization (A)	Present Revenues (1) (B)	Net Operating Income (C)	Present ROR (D)	Gross Revenues At Average ROR (E)	Subsidy () Excess (F)	25% Reduction In Subsidy () Excess (G)	Rate Increase (H)	Proposed Revenues (I)	Proposed Percent Increase (J)	ROR At Proposed Rates (K)	Proposed Increase With Subsidy/Excess (L)
					(C) / (A)			(F) * 25%		(B) - (G) + (H)			(H) - (G)
1	Rate RS	$260,738,880	$97,639,085	$135,024	0.051785%	$103,567,898	-$5,928,813	(1,482,204)	$31,153,475	$130,274,764	33.42%	7.716695%	$32,635,679
2	Rate DS	144,231,279	66,709,383	5,730,869	3.973388%	60,752,583	5,956,800	1,489,200	17,232,970	82,453,153	23.60%	10.657897%	15,743,770
3	Rate DS-RTP	122,605	70,100	24,610	20.072591%	32,804	37,296	9,324	14,649	75,425	7.60%	22.732285%	5,325
4	Rate GS-FL	618,721	471,911	101,409	16.390102%	320,905	151,006	37,752	73,926	508,085	7.67%	19.970422%	36,174
5	Rate EH	1,942,428	694,501	(39,580)	-2.037656%	804,945	(110,444)	(27,611)	232,084	954,196	37.39%	6.149610%	259,695
6	Rate SP	61,611	35,117	6,745	10.947720%	25,556	9,561	2,390	7,361	40,088	14.16%	15.888617%	4,971
7	Rate DT - Secondary	81,087,630	38,378,456	1,354,947	1.670966%	38,078,242	300,214	75,054	9,688,472	47,991,874	25.05%	8.931080%	9,613,418
8	Rate DT RTP-Sec.	907,692	343,715	75,379	8.304469%	242,030	101,685	25,421	108,452	426,746	24.16%	13.906196%	83,031
9	Rate DT-Primary	42,899,388	19,862,321	(615,107)	-1.433836%	21,878,521	(2,016,200)	(504,050)	5,125,683	25,492,054	28.34%	6.602478%	5,629,733
10	Rate DT RTP-Primary	1,967,407	782,491	164,685	8.370663%	559,964	222,527	55,632	235,069	961,928	22.93%	13.955853%	179,437
11	Rate DP	3,998,327	1,764,802	6,349	0.158791%	1,848,731	(83,929)	(20,982)	477,726	2,263,510	28.26%	7.796942%	498,708
12	Rate TT	12,710,431	8,534,952	451,451	3.551815%	8,097,508	437,444	109,361	1,518,661	9,944,252	16.51%	10.341715%	1,409,300
13	Rate TT-RTP	799,385	404,272	95,134	11.900899%	267,773	136,499	34,125	95,512	465,659	15.18%	16.603527%	61,387
14	Lighting	4,948,623	2,194,212	557,207	11.259839%	1,401,015	793,197	198,299	591,269	2,587,182	17.91%	16.122738%	392,970
15	Other	46,295	12,408	(3,522)	-7.607733%	19,251	(6,843)	(1,711)	5,531	19,650	58.37%	1.971807%	7,242
16	Total	$557,080,702	$237,897,726	$8,045,600	1.444243%	$237,897,726	0	0	$66,560,840	$304,458,566	27.98%	8.761038%	$66,560,840

Tax Complement	61.2378900%
Average ROR	1.444243%

(1) Note: Present revenues for all rates except RTP include present base and FAC revenues.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT, AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A/DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

JEFFREY R. BAILEY

ON BEHALF OF

DUKE ENERGY KENTUCKY

183225

TABLE OF CONTENTS

		PAGE
I.	INTRODUCTION AND PURPOSE	- 1 -
II.	SCHEDULES SPONSORED BY WITNESS	- 3 -
III.	FILING REQUIRMENTS SUPPORTED BY WITNESS	- 5 -
IV.	RETAIL ELECTRIC RATE SCHEDULES AND RIDERS	- 7 -
	A. RATE DESIGN AND MAJOR RETAIL ELECTRIC RATE SCHEDULES	- 7 -
	B. LIGHTING RATES	- 16 -
	C. MISCELLANEOUS NEW OR REVISED RIDERS	- 19 -
V.	OTHER TARIFF CHANGES	- 33 -
VI.	MISCELLANEOUS CHARGES	- 34 -
VII.	CHANGES TO TARIFF LANGUAGE AND SERVICE REGULATIONS	- 35 -
VIII.	CONCLUSION	- 36 -

ATTACHMENTS

ATTACHMENT JRB-1 – Customer Charge/Minimum Bill Rationale, Twelve Months Ending December 31, 2007.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey R. Bailey. My business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as Manager, Pricing.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I received Bachelor of Science degrees in Industrial Management and Engineering from Purdue University, West Lafayette, Indiana. I also received a Master of Science degree majoring in Industrial Engineering from Purdue University.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I began my employment with PSI Energy, Inc. ("PSI") in 1990 as Supervisor, Rate Engineering. I was subsequently promoted to Manager, Rate Engineering in 1991. I held several positions in the Rate, Pricing, and Market Planning areas until 1997, when I accepted the position of Manager, Sales Analysis. In 2000, I joined the Financial Operations Department, where I held the positions of Manager, Financial Projects, and Manager, Finance. I returned to the Rate Department in 2002, in my current position as Manager, Pricing.

Before joining PSI in 1990, I was employed by the Indiana Utility Regulatory Commission ("IURC"). I began my employment there in 1983 as a Staff Engineer. During my tenure with the IURC, I held several positions, progressively increasing in responsibility, the last of which was Assistant Chief

Engineer. My primary responsibility as Assistant Chief Engineer was the supervision of the gas and electric sections that investigated rate and regulatory matters pending before the IURC.

Q. WHAT ARE YOUR DUTIES AS MANAGER, PRICING?

A. As Manager, Pricing, my primary responsibility is to develop and administer the rates and charges, contained in tariffs and contracts for gas or electric service, for Duke Energy's operating companies, including Duke Energy Kentucky.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am responsible for Duke Energy Kentucky's proposed electric rate design and tariffs. My testimony will demonstrate that the rates Duke Energy Kentucky proposes are just and reasonable, that they reflect appropriate rate making principles, and that they result in an equitable basis for recovery of Duke Energy Kentucky's revenue requirements across its various customer classes and rate schedules. The purpose of my testimony in this proceeding is to: (1) sponsor Schedules D-2.34, L, L-1, L-2.1, L-2.2, M, M-2.1, M-2.2, M-2.3 and N; (2) sponsor Filing Requirements ("FR") FR10(1)(b)(7), FR10(1)(b)(8), FR10(3)(a), FR10(3)(b), FR10(3)(c), FR10(10)(l), FR10(10)(m) and FR10(10)(n); (3) describe changes that have been made to the Company's retail electric rate schedules, riders, and Service Regulations; (4) quantify the effect of these changes to our retail electric customers; and (5) discuss implementation procedures for filing the Company's tariffs after the Kentucky Public Service Commission's order in this proceeding.

II. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULE D-2.34.

A Schedule D-2.34 is an adjustment to reconcile revenue calculated on Schedule M with revenue contained in the Company's forecast and to reflect a proposed increase in Reconnection Charges.

The reconciliation adjustment is necessary because of a discrepancy between the revenue contained within the sales forecast and that calculated on Schedule M. The projected revenue for non-residential customers is calculated by customer class by applying average realizations to their respective kWh sales forecasts. The revenues calculated on Schedule M, however, take total kWh sales as determined by the sales forecast and blend that information with what we know to represent the historical relationship between demand and energy sales. This enhanced information results in additional revenue on Schedule M of $2,255,960. An adjustment has also been made on this schedule to increase previously approved Reconnection Charges by $22,965.

Q. PLEASE DESCRIBE SCHEDULE L.

A. Schedule L is my "Narrative Rationale for Tariff Changes." This schedule describes the changes to Duke Energy Kentucky's current tariffs and the reasons for those changes.

Q. PLEASE DESCRIBE SCHEDULE L-1.

A. Schedule L-1 shows the rate schedules that Duke Energy Kentucky proposes to implement.

Q. PLEASE DESCRIBE SCHEDULE L-2.1.

A. Schedule L-2.1 shows the current rate schedules that Duke Energy Kentucky proposes to revise. The changes are reflected by indicating additions by underscoring and deletions are over-stricken. Codes are also in the right-hand margin to explain the type of change being proposed.

Q. PLEASE DESCRIBE SCHEDULE L-2.2.

A. Schedule L-2.2 contains Duke Energy Kentucky's proposed rate schedules, showing the revisions that Duke Energy Kentucky proposes in this filing. Proposed changes are designated in the same way as in Schedule L-2.1

Q. PLEASE DESCRIBE SCHEDULE M.

A. Schedule M is a one page, side-by-side comparison of Duke Energy Kentucky's test period revenues at current and proposed rates. Schedule M shows that Duke Energy Kentucky is proposing a 33.4% increase in the Residential service class, a 25.0% increase in the Distribution Voltage service class, a 17.2% increase in the Transmission Voltage service class, and a 17.9% increase in the Lighting Service class. These average increases are based upon base rates which include the fuel cost adjustment expense at current rates.

Q. PLEASE DESCRIBE SCHEDULE M-2.1.

A. Schedule M-2.1 shows test period actual base revenue dollars and the percentage distribution among the various rate classes, as well as a breakdown of total revenue. Schedule M-2.1 also shows the actual base revenue average rates per kWh for each rate class.

Q. PLEASE DESCRIBE SCHEDULES M-2.2 AND M-2.3.

A. Schedule M-2.2, page 1, shows the test period bills in summary form, base revenues under current rates, current total revenues, and proposed base revenue increases, all broken down by rate and revenue class. The billing determinants used on these schedules are normalized sales for the twelve months ended December 31, 2007. Schedule M-2.2, pages 2-21, contains a detailed calculation of base period numbers, by rate and revenue class, as summarized on Schedule M-2.2, page 1. Schedule M-2.3 is almost identical to M-2.2, page 1, except that it shows the revenue summary and detailed data calculated at the rates proposed in this case.

Q. PLEASE DESCRIBE SCHEDULE N.

A. Schedule N shows monthly bill comparisons for various consumption levels under each of Duke Energy Kentucky's primary tariff schedules, Rates RS, DS, DT, DP, and TT. This schedule allows comparisons and assessment of how these changes impact customers' bills.

III. FILING REQUIRMENTS SUPPORTED BY WITNESS

Q. PLEASE DESCRIBE FR 10(1)(B)(7).

A. FR 10(1)(b)(7) shows the proposed tariffs in a form complying with 807 KAR 5:011. The effective dates of these tariffs are not less than 30 days from the date of the filing of the application in the present case.

Q. PLEASE DESCRIBE FR 10(1)(B)(8).

A. FR 10(1)(b)(8) consists of Duke Energy Kentucky's current tariffs in a comparative form showing proposed changes. The changes are reflected by italicizing additions and striking over deletions.

Q. PLEASE DESCRIBE FR 10(3)(A).

A. FR 10(3)(a) shows the amount of change requested in dollars and the resulting percentage increase for each customer classification and by each rate classification to which the change will apply. In the present case, Duke Energy Kentucky proposes an overall retail revenue increase of 28.0%, which breaks down as previously described.

Q. PLEASE DESCRIBE FR 10(3)(B).

A. FR 10(3)(b) shows the current and proposed rates for each customer class, and the rate schedule to which the change would apply.

Q. PLEASE DESCRIBE FR 10(3)(C).

A. FR 10(3)(c) shows the effect on an average electric bill for each customer class and the rate schedule to which the change will apply.

Q. PLEASE DESCRIBE FR 10(10)(L).

A. FR 10(10)(l) is a narrative description and explanation of all proposed tariff changes.

Q. PLEASE DESCRIBE FR 10(10)(M).

A. FR 10(10)(m) is a revenue summary for both the base and forecast periods with supporting schedules that provide detailed billing analysis for all customer classes.

Q. PLEASE DESCRIBE FR 10(10)(N).

A. FR 10(10)(n) is a typical bill comparison under current and proposed rates for all customer classes.

IV. RETAIL ELECTRIC RATE SCHEDULES AND RIDERS

A. RATE DESIGN AND MAJOR RETAIL ELECTRIC RATE SCHEDULES

Q. HOW DID YOU DESIGN THE VARIOUS RATE SCHEDULES IN THIS CASE?

A. I used the cost of service information provided by Mr. Ochsner as a major component for the rate design. As he describes, the cost of service information provided the allocation of costs to the various rate classes and separation of the customer and demand components of cost. Additionally, we reviewed the Company's load research data to determine relationships between energy and demand that might prove pertinent to the design of the Company's rates.

Q. WHAT ARE THE COMPANY'S MAJOR RETAIL ELECTRIC RATE SCHEDULES?

A. The Company's major retail electric rate schedules include: Rate RS - Residential Service ("Rate RS"); Rate DS – Service at Secondary Distribution Voltage ("Rate DS"); Rate DP – Service at Primary Distribution Voltage ("Rate DP"); Rate DT - Time of Day Rate for Service at Distribution Voltage ("Rate DT"); and Rate TT – Time of Day Rate for Service at Transmission Voltage ("Rate TT"). Together, these rate schedules comprise a substantial portion of the Company's retail electric revenue requirement.

Q. IN CASE NO. 91-370, THE COMMISSION ORDERED THE COMPANY TO ADDRESS THE APPROPRIATE STRUCTURE OF RESIDENTIAL RATES. HAVE YOU UNDERTAKEN AN ANALYSIS AND FORMED CONCLUSIONS FOR THAT RATE?

A. Yes, I have.

Q. PLEASE DESCRIBE THE METHODS USED TO EVALUATE THE STRUCTURE OF RATE RS.

A. We used the Company's load research data for residential customers to fully examine their usage characteristics. Our load research data consists of a sample of 210 residential customers at December 2005, which are distinguished by strata based on the annual kWh consumed by these customers. For general information, the strata and their respective annual usage brackets are as follows:

Table 1 – Residential Strata and Annual Usage

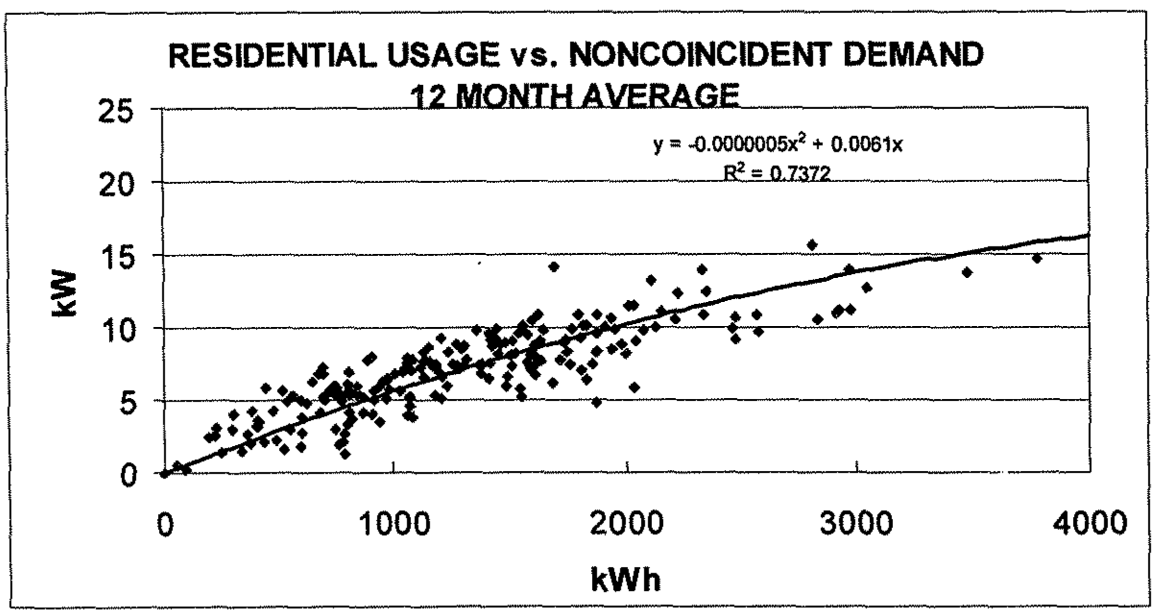
Strata	kWh
1	Less than 9,250
2	Greater than or equal to 9,250 and less than or equal to 19,250
3	Greater than 19,250

We reviewed the characteristics of these customers to examine the relationships between demand and energy use, both on a coincident and non-coincident basis, and how these load characteristics might impact operating costs during seasonal and time-of-use periods. We also used cost of service information to develop demand and energy costs in serving this class of customers.

Q. PLEASE DESCRIBE YOUR ANALYSIS.

A. We began by reviewing the relationships between demand and energy relative to the customers' monthly kWh consumption. From our load research data, we plotted individual customers' average monthly kWh usage versus their average non-coincident demand, which is the highest demand imposed by these customers during the calendar month. We found that, on average, load factor modestly improved with increased usage. This means that the per unit, or proportion, of non-coincident load imposed by these customers does not substantially change with increased usage. This is depicted in the following graph.

<u>Table 2 – Residential Usage vs. Noncoincident Demand</u>



The above graph illustrates the individual customers and the gradual improvement in load factor with additional usage. The equation contained within the graph is a polynomial expression that explains nearly 74% of the variability of the data. Using the above formula, the average calculated load factor of customers at various usage levels is shown below.

Table 3 – Load Factor at Various Usage Levels

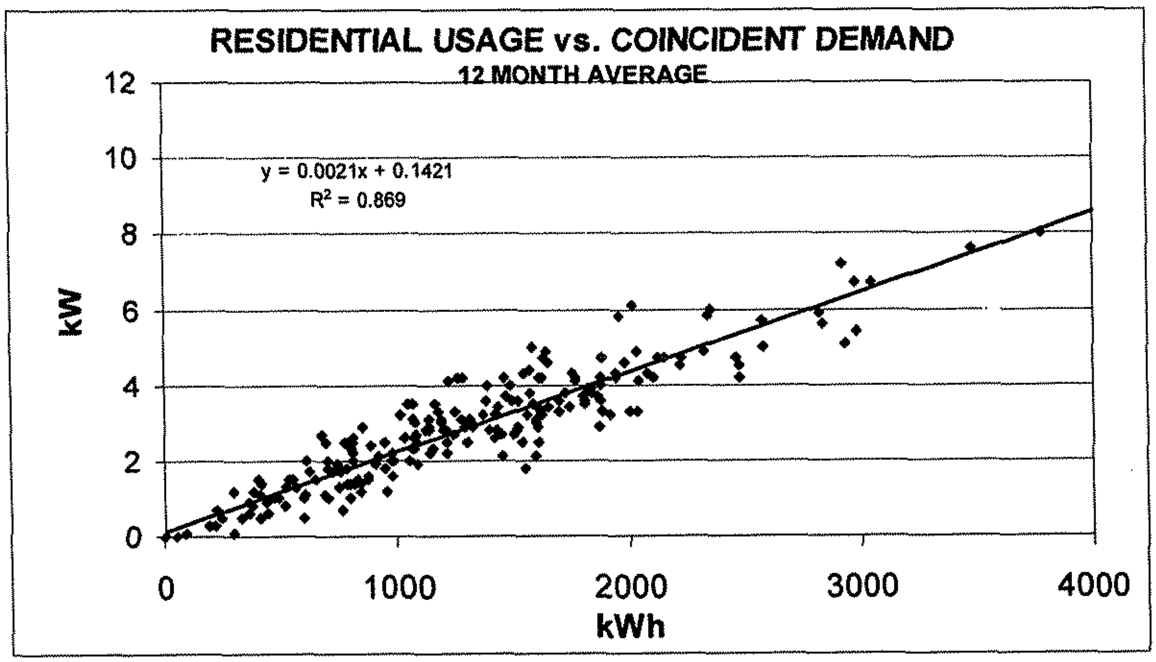
Usage	Demand	Load Factor
100	0.61	22.6%
200	1.20	22.8%
300	1.79	23.0%
400	2.36	23.2%
500	2.93	23.4%
1000	5.60	24.5%
1500	8.03	25.6%
2000	10.20	26.9%
3000	13.80	29.8%
4000	16.40	33.4%

Q. WHAT STRUCTURE FOR RATE RS DOES THIS ANALYSIS SUPPORT?

A. Improvements in load factor have typically supported a declining block structure; however, in my judgment, the improvements in load factor are not significant. As shown in the table above, the improvement in load factor between 100 and 500 kWh is less than one percent, and the improvement in load factor between 500 and 2,000 kWh is approximately three and one-half percent. So, from a usage perspective, a block between these amounts is not warranted. Also, in my opinion, even though the load factor improves more significantly beyond 2000 kWh, the number of customers that use an average of greater than 2,000 kWh per month is small, so a declining step somewhere beyond 2,000 kWh is also not warranted. By itself, though, this does not fully address what the rate structure for Rate RS should be.

For further analysis, we also plotted individual customers' average monthly kWh usage versus their average coincident demand, which is the demand imposed by these customers during the calendar month at time of system peak. We found that, on average, as consumption increases load imposed at time of system peak also increases proportionately, as demonstrated in the graph below.

<u>Table 4 – Residential Usage vs. Coincident Demand</u>



The equation within the graph explains nearly 87% of the variability of the data.

Whatever the strata, this graph convincingly demonstrates that coincident demand is proportional to usage. Since approximately 77% of the cost of serving residential customers is attributable to generation and transmission related expenditures, this graph supports the position that the overall structure of Rate RS should be a single (flat) kWh charge for all kWh consumed.

Q. WHEN ARE DECLINING BLOCK STRUCTURES WARRANTED?

A. Declining block structures can be used to recover fixed costs of the utility in the early blocks to aid the utility in revenue stability, or to recover the customer component of costs not recovered in the customer charge.

Additionally, declining block structures are justified when improving load factor with increased usage warrants a reduction in the price to be paid because these customers impose less demand as a function of usage than lower load factor customers. In essence, a customer that has a greater proportion of energy usage to their demand usage should have a lower per unit cost, otherwise these higher load factor customers would contribute excessively to the fixed costs of the utility. Our analysis has shown that improvements in load factor are not significant in most usage ranges. We therefore concluded that a declining block structure is not appropriate.

Q. BASED UPON THIS INFORMATION, DO YOU HAVE AN OPINION REGARDING WHETHER AN INVERTED BLOCK STRUCTURE IS APPROPRIATE FOR RATE RS?

A. Yes, I have. In general, an inverted block structure implies that increased usage is inefficient and lower usage is efficient. Duke Energy Kentucky's load research data has shown that higher use customers are as efficient, in terms of impacting on-peak periods and coincident peaks, as lower usage customers. In my opinion, therefore, there is no justifiable basis from a cost perspective to support an inverted block structure. However, inverted block structures may still serve various policy goals, such as "lifeline" rates. Inverted block structures have also commonly been associated with attempting to reflect marginal costs. However, without a time–differentiated rate (which would eliminate the need for an inverted structure in the first place) there is no way to determine whether the usage at any point during the monthly billing period is truly on the margin. Furthermore, without declining load factor with increased usage or proportionately increased on-peak usage with additional usage, one can conclude that an inverted block structure is not cost justifiable.

Q. DID YOU EXAMINE WHETHER OR NOT A SEPARATE SUMMER AND WINTER ENERGY RATE SHOULD BE ESTABLISHED FOR RATE RS?

A. Yes. We used a production cost simulation for all hours of the forecasted test period to determine if there was a significant cost difference between summer and winter periods. This also allowed examination of any differences in costs by strata for peak and off-peak periods. This was accomplished by establishing native load requirement and native load costs to determine a cost per kW per hour to serve customers during the forecasted test period. The results of this analysis are shown in the following table.

Table 5 – Native Load Costs and Costs to Serve

Strata 1 Cost per kWh

	On Peak	Off Peak	Average
Summer	$0.029788	$0.019166	$0.022477
Winter	$0.026095	$0.020863	$0.022407

Strata 2 Cost per kWh

	On Peak	Off Peak	Average
Summer	$0.029549	$0.019183	$0.022528
Winter	$0.026015	$0.020697	$0.022264

Strata 3 Cost per kWh

	On Peak	Off Peak	Average
Summer	$0.029461	$0.019148	$0.022436
Winter	$0.026014	$0.020619	$0.022148

From the above table, there is not a significant difference in the variable costs of providing service under Rate RS during the summer and winter periods. Thus, there is no significant justification – in terms of variable costs – to support a differential in price between the summer and winter periods. This is likely due to the large amount of baseload capacity now providing service to the Company's load. Furthermore, the information in the table demonstrates the consistency of costs across the various strata. This further confirms previous analysis that overall load shapes of customers within the various strata are similar and impose similar costs on the system.

Q. PLEASE BRIEFLY SUMMARIZE YOUR POSITION REGARDING THE STRUCTURE OF RATE RS.

A. My analysis revealed several salient points for designing Rate RS. First, greater consumption does not create a significant improvement in load factor, supporting the position that a declining block structure is inappropriate. Second, the demands imposed by customers during times of peak are proportional to the kWh used, which tends to support a flat charge for the majority of costs imposed by these customers. Both of these findings suggest that an inverted block structure is not appropriate. Finally, there does not appear to be sufficient support for a distinct summer and winter energy charge. All of these facts tend to support a flat (single) charge per kWh for all kWh consumed by residential customers without any differential between summer and winter energy charges.

Q. WHAT PROPOSAL HAS THE COMPANY MADE REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. The analysis supports a customer charge of just under $11 per month. In keeping with the concept of gradualism, Duke Energy Kentucky proposes to modestly increase the customer charge from $3.73 per month to $5.00 per month.

Q. WHAT IS THE FINAL DESIGN FOR RATE RS?

A. Based on the preceding discussion, the final rate design for Rate RS is as follows:

Customer Charge:	$5.00 per month
Energy Charge:	$0.081299 per kWh.

Q. WHAT IS THE EFFECT OF THIS RATE INCREASE ON A RESIDENTIAL CUSTOMER USING 1,000 KWH PER MONTH?

A. A residential customer using 1,000 kWh per month will experience an increase of $19.48 or 29.6% on a total bill basis. This calculation reflects all applicable riders in effect at the time of filing.

Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN OBJECTIVES FOR RATES DS, DP, DT, AND TT.

A. Given the large percentage increase, our rate design objectives for these rate schedules (hereinafter referred to as "power rate schedules" or "power rates") are to generally increase the rates to maintain a similar structure that minimizes impacts to the class of customers while collecting the total revenue requirement. Aside from this, there are no significant structural changes to the power rates. The Company performed a thorough review of the general structure of the rates. Duke Energy Kentucky reviewed the legitimacy of providing the first 15 kW at no cost to customers served under Rate DS, as well as the various caps provided under this rate. We found no significant justification for these provisions. We also reviewed power factor provisions and believe some movement toward kVAR for pricing is a means to improve price signals. However, due to the significant increase requested, we have chosen to not seek implementation of any of these specific findings in this case.

Q. WHAT ARE THE PROPOSED CUSTOMER CHARGES?

A. The customer charge for each power rate is as follows: for Rate DS, the customer charges are $7.50 for single phase service and $15.00 for three phase service; for Rate DP the customer charge is $100.00; for Rate DT, the customer charges are $7.50 for single phase service and $15.00 for three phase service; and for TT, the customer charge is $500.00. Attachment JRB-1 sets forth the customer-related costs of providing service to the various customer classes. This information was obtained from the functional cost of service study provided by Mr. Ochsner.

Q. HAVE YOU PREPARED RATE STRUCTURES FOR THE POWER RATES?

A. Yes. Again, there are no significant structural changes. The design objective of the power rates was to collect the revenue requirement while maintaining the existing structural characteristics of the rate to the greatest extent practicable. More detailed information can be found on Schedule L.

B. <u>LIGHTING RATES</u>

Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN OBJECTIVES FOR ITS LIGHTING SERVICES?

A. Our rate design objectives for these rate schedules (hereinafter referred to as "flat rate lighting schedules") are to increase the Rate/ Unit charge of the rate schedules resulting from the increase in the cost of service study, and to phase out certain street lighting atariffs.

Q. WHY DOES THE COMPANY PROPOSE TO PHASE OUT CERTAIN STREET LIGHTING TARIFFS, AND WHICH STREET LIGHTING TARIFFS WOULD BE PHASED OUT?

A. The number of lighting types and fixtures has grown considerably over the years, making the administration of our lighting programs more difficult and time consuming. We believe that our limited resources should be available for the provision of safe, adequate, and reliable electric service rather than administering discretionary ornamental lighting programs which are currently supported by these rate schedules and which could be obtained from a private contractor. The Company proposes to provide a reasonable number of essential lighting services, while limiting the variety of available lamp types and requiring customers to pay more directly for costs incurred on their behalf. Customers who desire a lighting system not offered by Duke Energy Kentucky can procure a system from any contractor and pay for the energy through Rate UOLS – Unmetered Outdoor Lighting Service ("Rate UOLS").

New customers will be offered Company standard lighting equipment and maintenance under the Company's Rate OLE – Outdoor Lighting Equipment rate schedule ("Rate OLE"), with the associated energy provided under Rate UOLS.

The Company anticipates canceling Rates Street Lighting Service ("Rate SL") Street Lighting Service – Overhead Equipment, ("Rate SE"). Street Lighting Service – Customer Owned ("Rate SC"), and Street Lighting Service for Non-

Standard Units, ("Rate NSU"), in 20 years, and Outdoor Lighting Service, ("Rate OL") and Private Outdoor Lighting for Non-Standard Units, ("NSP") in ten years. During these time periods, the existing flat rate lighting schedules customers will be migrated to the UOLS/OLE rates as their existing lighting systems reach the end of their useful life.

When the Company cancels Rates SL, SE, SC, and NSU in 20 years, and Rates OL and NSP in ten years, the remaining customers will be offered maintenance of any remaining lights under Rate OLE, and will be served under Rate UOLS for their energy service. At any time, customers can choose to have a new system installed by Duke Energy Kentucky under Rates UOLS/OLE, or they can purchase a new system from a lighting contractor.

Q. WILL ELIMINATING THESE RATES BENEFIT LIGHTING CUSTOMERS?

A. Yes. Rate OLE provides a one-on-one equipment contract with the customer where the customer pays the current cost of the lighting system. This locks-in the customer's equipment cost, insulates customers from future rate increases on the equipment portion of the lights, and eliminates subsidies to and from other lighting customers. Customers will have an option to pay for the physical lighting equipment up-front or over time, up to a maximum of ten years. Once the customer has fully paid-off the lighting equipment costs, they will no longer have a monthly payment for the equipment, and will be required to pay only for maintenance. In contrast, under current rates customers pay a single monthly fee, which includes an equipment charge, as long as they require electric service. If the customer's lighting system exceeds the average system life, they end up over-paying for the physical equipment since their rates remain the same.

Q. WILL ELIMINATING THESE TARIFFS RESULT IN HIGHER LIGHTING COSTS FOR CUSTOMERS?

A. Customers who install new systems will see higher lighting equipment costs in the first years relative to the current tariff, but will see only maintenance and energy costs in the later years, as discussed above.

C. MISCELLANEOUS NEW OR REVISED RIDERS

Q. PLEASE DESCRIBE PROPOSED CHANGES TO THE COMPANY'S GREEN POWER RIDER.

A. Duke Energy Kentucky's current Green Power Rider ("Rider GP"), Sheet No. 88, provides customers the opportunity to enter into a written service agreement through which the customer voluntarily contributes at least $1.00 per month to be added to the customer's normal bill for electric service. These contributions are used to purchase power from environmentally friendly sources or to help pay for the development of Green Power Energy Sources.

The new Rider GP continues to be a voluntary program for residential and small commercial customers. However, instead of merely asking customers to voluntarily contribute money to support the acquisition or development of Green Power, the customers will now be empowered to voluntarily designate a monthly kWh purchase level for Green Power. Each customer may voluntarily, at a minimum, purchase 200 kWh monthly with additional voluntary purchases to be made in 100 kWh increments. Participants will continue to be billed for electric service under their standard applicable tariffs, including all applicable riders. The voluntary increments of Green Power purchases will be billed at the applicable Green Power rate times the amount of Green Power kWh the customer has requested to purchase per month.

The customer will enter into a service agreement that specifies the amount and price of green power to be purchased monthly. Duke Energy Kentucky requests authority to adjust, up or down, the price voluntarily paid per 100 kWh of Green Power and, if necessary, adjust the size of the kWh Green Power blocks. The customers may cancel their participation in this Rider at any time after giving Duke Energy Kentucky 30 days' prior notice.

Q. PLEASE DESCRIBE HOW DUKE ENERGY KENTUCKY WILL USE THE REVENUES FROM THIS NEW RIDER GP.

A. Amounts collected above our standard applicable tariff rate plus applicable riders will be used for acquisition of Renewable Energy Certificates ("RECs") and Carbon Credits to promote the development of Green Power and to cover the costs of educational materials, marketing materials, and advertising the Green Power program.

Q. WHAT ARE RECS AND CARBON CREDITS?

A. A REC is the tradable commodity unit which represents the generation of one MWH of renewable or environmentally friendly generation. A Carbon Credit is a tradable commodity unit which represents one ton of CO_2 reduction or its equivalent. Both REC and Carbon Credits are commonly used and widely accepted industry standards.

Q. CAN LARGE COMMERCIAL AND INDUSTRIAL CUSTOMERS PARTICIPATE IN THE NEW GREEN POWER PROGRAM?

A. Yes. Duke Energy Kentucky proposes to address the needs of larger commercial and industrial customers on a customer specific special contract basis, taking into consideration their particular business objectives as they relate to Green Power and climate issues. This will require an offering of Green Power and Carbon Credits to be made available for their purchase.

Q. WILL DUKE ENERGY KENTUCKY KEEP THE COMMISSION AND STAKEHOLDERS APPRISED OF THE PROGRAM RESULTS?

A. Yes. Duke Energy Kentucky will provide annual updates on the performance of the revised Green Power Tariff Rider to stakeholders through December 31, 2009. Duke Energy Kentucky will also update the Kentucky Public Service Commission with a final report on its success.

Q. IF FEDERAL OR STATE LAWS ARE ENACTED THAT REQUIRE KENTUCKY ELECTRIC UTILITIES TO HAVE A SPECIFIC RENEWABLE PORTFOLIO STANDARD ("RPS") DURING THE THREE-YEAR TERM OF THIS PROPOSAL, SHOULD THIS PROGRAM CONTINUE?

A. If lawfully mandated to maintain an RPS, there may be no need for this voluntary, proposed program. Accordingly, Duke Energy Kentucky requests Commission approval to reserve the right to modify or withdraw this program if an RPS is enacted.

Q. YOU PREVIOUSLY STATED THAT DUKE ENERGY KENTUCKY SEEKS AUTHORIZATION TO ADJUST THE AMOUNT CHARGED MONTHLY FOR 100 KWH OF GREEN POWER DURING THE THREE YEAR TERM OF THIS PROGRAM AND TO ADJUST THE MINIMUM KWH PURCHASE AMOUNT. WHY DOES DUKE ENERGY KENTUCKY MAKE THIS REQUEST?

A. The market price for RECs fluctuates. If this Green Power Rider is approved, Duke Energy Kentucky will make a commitment to its customers to go to the marketplace and acquire the level of RECs necessary to match the Green Power commitments made voluntarily by Duke Energy Kentucky retail customers. The cost of that commitment may fluctuate with market conditions. As such, it is reasonable that Duke Energy Kentucky should reserve the right to make certain the amount it charges is sufficient to purchase a load matching level of RECs.

Additionally, the REC market is open and competitive. Duke Energy Kentucky customers do not necessarily have to participate in the Green Power Rider for RECs. Rather, they can directly purchase RECs over the internet from Green Power generators and marketers. Thus, if customers believe that Duke Energy Kentucky's Green Power Rider are unreasonably high, they can financially support Green Power through a competitor.

Just as other green power generators and marketers will base their price for RECs on prevailing market conditions, Duke Energy Kentucky requests the flexibility to adjust its price per 100 kWh of Green Power to maximize the success of this program, higher or lower. That success is maximized by growing the number of participants and an increased proliferation of the Green Power market and Green Power generation.

Thus, if the price per 100 kWh of Green Power needs to be lowered to improve voluntary participation, Duke Energy Kentucky needs the flexibility to make the downward adjustment. Conversely, if the market price of RECs increases, Duke Energy Kentucky wants the flexibility to increase the price voluntarily paid for 100 kWh of Green Power to further support for the REC market.

Q. SHOULD THE COMMISSION BE CONCERNED THAT DUKE ENERGY KENTUCKY MIGHT UNREASONABLY INCREASE THE COST OF GREEN POWER TO PARTICIPANTS IN THIS PROGRAM?

A. No. It certainly would not be in Duke Energy Kentucky's interests to compromise its own voluntary program by proposing an unreasonable price for green energy. We are proposing this tariff in order to encourage customer satisfaction and consumption of green energy; charging a higher price that would, in effect, discourage participation would make no sense. As pointed out above, RECs are openly traded in a free, competitive marketplace. So, if a customer believes that Duke Energy Kentucky's price is unreasonably high, the customer can shop elsewhere or discontinue participation in the renewable energy program altogether with appropriate notice. Also, customers will be notified 60 days in advance of any price or minimum purchase amount adjustments and may withdraw from the program upon 30 days' notice.

Q. WHAT SOURCES OF ENERGY WILL QUALIFY UNDER THE GREEN POWER STANDARD CONTRACT RIDER NO. 88?

A. Rider GP includes energy generated from renewable and environmentally friendly sources including wind, solar, photovoltaic, biomass co-firing of agricultural crops and all energy crops, hydro-as certified by the Low Impact Hydro Institute, incremental improvements in large scale hydro, coal mine methane, landfill gas, biogas digesters, biomass co-firing of all woody waste including mill residue but excluding painted or treated lumber. This is a generally accepted and supported list of environmentally-friendly generation resources.

Q. WOULD THE COMMISSION BE ACTING IN THE PUBLIC INTEREST BY ALLOWING DUKE ENERGY KENTUCKY CUSTOMERS THE OPPORTUNITY TO VOLUNTARILY PAY HIGHER THAN NORMAL RATES TO SUPPORT GREEN POWER?

A. Yes. Those who voluntarily choose to pay premium rates for Green Power improve the cost effectiveness of Green Power generation. Those volunteers also increase the market's perceived financial viability of Green Power, stimulate more Green Power investments, create more no or low emissions generating sources, and satisfy their own desire to support such a program. Given that current Green Power Generation technology is often not as cost-effective as traditional generation, it is a fair balance that those customers who most support Green Power promote it by paying its higher costs. Logically, as demand for Green Power increases, Green Power production should increase and the cost of Green Power energy should decline. This decline should stimulate interest in, participation in, and the financial viability of Green Power which is beneficial to the public.

Q. WILL DUKE ENERGY KENTUCKY PERFORM CUSTOMER EDUCATION AND MARKETING FOR THE RIDER GP?

A. Yes. Our proposed modifications to the Rider GP are intended to increase customer satisfaction and participation in the Green Power Program. Educating customers on the availability of the program and on the environmental benefits of Green Power generation is expected to increase the number of participants in the program. Increased participation results in higher demand for Green Power energy and additional financial support for Green Power technologies and for the Green Power generation market. It is reasonable to expect that as demand for Green Power energy grows, the marketplace will meet that demand with additional investment in Green Power generation and technology. But that process cannot occur without educating the public as to the benefits of Green Power energy and marketing its availability.

Q. HOW WILL DUKE ENERGY KENTUCKY INFORM CUSTOMERS ABOUT THE PROPOSED RIDER GP?

A. Duke Energy Kentucky's customer education and marketing effort will begin with a broad announcement on the customer bill to all residential and commercial customers after the Commission approves the program. Duke Energy Kentucky then proposes to start with a pilot effort of up to 10,000 customers to initially determine the success and suitability of local meetings, newspaper and radio ads, bill inserts, and direct mailing to inform and educate the public. Customer feedback on the program promotion will be incorporated into the program on a real time basis to help improve the program's efficiency and effectiveness.

Q. WHAT ACTIVITIES WILL DUKE ENERGY KENTUCKY USE IN ITS EDUCATION AND MARKETING EFFORTS?

A. Duke Energy Kentucky will use direct mailing, local meetings between Company experts and customers, radio advertising, and newspaper advertising. Additionally, Duke Energy Kentucky hopes to roll out Green Power demonstration projects that will be visible to and will help educate the public.

Q. WILL CUSTOMERS BE SOLICITED BY TELEPHONE FOR THIS PROGRAM?

A. No.

Q. IS IT IMPORTANT FOR THE PROGRAM'S SUCCESS FOR DUKE ENERGY KENTUCKY TO BE ABLE TO ADJUST THE PRICE AND THE LEVEL OF THE CONSUMPTION BLOCKS DURING THE THREE-YEAR TERM OF THIS PROGRAM?

A. Yes. Green Power and RECs are openly traded in a competitive marketplace. Thus, their prices may fluctuate and Duke Energy Kentucky's costs to obtain those commodities may vary over time. Our interaction with our customer base may demonstrate that we need to adjust the Green Power consumption blocks to satisfy customer needs and maximize participation. Similarly, we may need to lower the Green Power unit price to maximize participation. That flexibility will benefit the program and our customers. The requested flexibility satisfies two of the most important goals of this program – enhanced customer satisfaction and robust participation in, and the proliferation of, the Green Power marketplace.

Q. DOES DUKE ENERGY KENTUCKY PROPOSE CHANGES TO ITS NET METERING TARIFF?

A. Yes. The Company proposes a change to the availability section of Net Metering Rider ("Rider NM"). This change, if approved, will allow the Company, at its discretion, to provide net metering under Rider NM to customers who may not otherwise be eligible for net metering. There are no other changes to the net metering rider.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO ESTABLISH A TARIFF TO PROVIDE BACKUP CAPACITY FROM ITS DISTRIBUTION AND / OR TRANSMISSION SYSTEM(S) UNDER RIDER BDP –BACKUP DELIVERY POINT.

A. Rider BDP - Backup Delivery Point ("Rider BDP"), provides for additional access to the Company's distribution and / or transmission system(s) for customers that require enhanced reliability (but does not imply uninterrupted service). This additional access generally takes the form of an electrical tie to another distribution and / or transmission circuit to provide a redundant source of power to a customer in the event that the customer's primary service experiences interruption. Rider BDP also contemplates a fee to compensate Duke Energy Kentucky for reserving capacity on the redundant circuit.

Customer demand for this type of service has grown in recent years. Customers are demanding increasing levels of reliability. Many customers are willing to pay the additional costs of obtaining a redundant system to insulate their operations from normal outage situations. To respond to this demand, the Company has developed Rider BDP. Under this rider, customers are required to pay the Company's costs for any dedicated facilities required to provide the backup service. Customers are also required to pay for the Company reserving capacity on the facilities serving the backup facilities. This helps to ensure that the line capacity is available to the customer's backup point in the event their primary source of energy experiences an interruption. In addition, customers are charged for acceleration of capacity additions, if applicable. Appropriately charging for reserve capacity helps to cover real costs, avoid subsidization by other customers, and establish a reasonable basis to continue to provide this value added service.

Q. HOW HAVE THE CHARGES FOR RIDER BDP BEEN DEVELOPED?

A. There are two primary components to how Rider BDP will be charged. The first component is an Access Charge, and the other, if applicable, is an Acceleration Charge.

Customer characteristics determine the charges under Rider BDP, and how the service is delivered to the customer is a key component in determining those charges. Customers requesting distribution and transmission sources that are distinctly different from the sources providing the customers' primary service are charged an Access Charge. This charge is based upon the transmission and distribution components of the applicable Duke Energy Kentucky rate (*i.e.*, Rates DS, DP, DT, or TT).

The next component of Rider BDP charges depends on whether facilities must be constructed in advance of planning estimates. The advancement, in number of years, is used to determine the amount of the acceleration charge. The annual acceleration charge is the product of the capital investment, a levelized fixed charge rate ("LFCR") and the project advancement in years. Typically, the charges associated with advanced construction would be discounted to present value terms and paid in a lump sum.

Any dedicated facilities needed to provide access to the Company's distribution and / or transmission system(s) are priced under the Company's normal excess facilities agreements / arrangements.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED TRANSMISSION COST RECOVERY MECHANISM.

A. As detailed in the testimony of Mr. Wathen and Mr. Swez, this mechanism, known as the Transmission Cost Recovery Mechanism ("Rider TCRM"), will allow the Company to update its transmission rates annually for recovery of all credits, charges and revenues related to congestion and financial transmission rights assessed to Duke Energy Kentucky by the applicable regional transmission organization, currently the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), or otherwise approved by the Federal Energy Regulatory Commission ("FERC").

Q. DOES DUKE ENERGY KENTUCKY PROPOSE ANY CHANGES FOR ITS TARIFFS RELATING TO COGENERATION AND POWER SALES AND PURCHASES?

A. Yes. Duke Energy Kentucky proposes to change both of its tariffs relating to cogeneration and power sales and purchases. Both tariffs currently provide that Duke Energy Kentucky will purchase power from qualifying cogeneration facilities at Duke Energy Kentucky's avoided cost. My understanding is that this was formerly required by the Public Utility Regulatory Policies Act of 1978 ("PURPA"). I further understand that Section 1253 of the Energy Policy Act of 2005 repealed this PURPA requirement, such that, if a qualifying facility has access to a competitive wholesale market, then the utility is still required to purchase the qualifying facility's output, but at the market price instead of the utility's avoided cost. Duke Energy Kentucky's service area has access to a competitive wholesale market, that is, the Midwest ISO's Day 2 energy markets. Accordingly, we are revising these tariffs to provide for Duke Energy Kentucky to purchase the qualifying facility's output at the market price.

Q. WHAT PRICE DOES DUKE ENERGY KENTUCKY PROPOSE TO USE FOR COGENERATION AND SMALL POWER PRODUCTION SALE AND PURCHASE – OF 100 KW OR LESS?

A. Duke Energy Kentucky proposes to determine a price based upon a production cost simulation whereby a decrement of capacity is used to determine the value of the facility.

Q. WHAT MARKET PRICE DOES DUKE ENERGY KENTUCKY PROPOSE TO USE FOR COGENERATION AND SMALL POWER PRODUCTION SALE AND PURCHASE - GREATER THAN 100 KW?

A. Duke Energy Kentucky proposes that the market price for Cogeneration and Small Power Production Sale and Purchase - greater than 100 kW should be the locational marginal price for power purchased through the Midwest ISO day-ahead energy market, inclusive of the energy, congestion and losses charges, delivered to the Midwest ISO's Cinergy hub load zone.

Q. WHY IS THIS A JUST AND REASONABLE MARKET PRICE FOR PURCHASING POWER FROM QUALIFYING FACILITIES AT THE MARKET PRICE?

A. This is a just and reasonable methodology for establishing a market price because the price is determined by an independent third party based on actual supply and demand conditions as indicated by participants in the Midwest ISO day-ahead energy market. Additionally, this price is transparent and easily monitored, such that those interested in constructing qualifying facilities will have ready access to this information.

Q. WHAT CHANGES DOES DUKE ENERGY KENTUCKY PROPOSE FOR ITS POWERSHARE® PROGRAM?

A. Since inception of the program in 2000, PowerShare® has been a market-based program where the credits provided to customers for load curtailments have been based on the value of those curtailments in the short term wholesale energy market. Because market prices are highly variable, customer credits have varied dramatically from year-to-year. For instance, in 2000 and 2001, customer credits were relatively high and these credits produced excellent customer participation. However, recent low market prices have resulted in low credits for customers that have the ability to curtail load. These low credits have drastically reduced participation in the PowerShare® program, even as the Company has set new peak demand records. So, while the PowerShare® program has great potential value in providing capacity, it has been valued less by customers because of the low market-based credits.

In an effort to reinvigorate the program, and to transition it to a stable program capable of producing consistent capacity value, we propose to treat PowerShare® CallOption similar to the Company's regulated demand side management ("DSM") programs. Our DSM programs are evaluated based upon the long-term avoided costs, rather than on short-term market prices for the summer ahead. In essence, we will be giving a long-term capacity value to the CallOption customer's agreement to curtail usage. Under this new pricing methodology, which we propose on an annual basis, the credits offered to PowerShare® CallOption customers would be based upon the value of avoiding investment in a combustion turbine as opposed to the short-term, highly variable market value. This should stabilize the credits the Company can pay customers at an attractive level in exchange for an agreement to reduce their load when called upon. While this would be a material increase over current credits, the credits would not exceed the value of the annual avoided cost of a combustion turbine. Pricing at or below these levels will help to ensure the cost-effectiveness of the program overall.

Q. WHAT IS THE LEVEL OF CREDITS, OR PREMIUMS, CONTAINED IN THE TEST PERIOD AS AN OPERATING EXPENSE?

A. The test period does not contain any expenditures in the form of bill credits related to the PowerShare® CallOption program. With our transition of this program to more traditional DSM pricing, we expect increased participation in the program.

Due to the enhancement of this program, we propose to cancel the Interruptible Service Rider ("Rider IS"). There is only one customer served under this rider, and our initial calculations show the customer would benefit from greater option premiums and reduced exposure to curtailment. There is $58,320 built into base rates for credits to this customer.

Q. HOW WILL ADDITIONAL EXPENSES RELATED TO THIS PROGRAM BE RECOVERD IN RATES?

A. We propose to collect any additional expenses beyond what is built into base rates, or credit any amounts below what is built into base rates, by collecting or crediting these dollars through the Fuel Adjustment Clause ("Rider FAC").

V. OTHER TARIFF CHANGES

Q. WHAT OTHER CHANGES DO YOU PROPOSE TO IMPLEMENT?

A. The Company proposes to eliminate its Thermal Energy Storage Rider, ("Rider TES"). This rider merely refers the applicant to the, Load Management Rider ("Rider LM"), for applicable pricing. Any customer shifting load, including thermal storage, is eligible to participate in the pricing benefits of Rider LM. Therefore, we believe this rider is redundant and should be eliminated.

The Company also proposes to eliminate Rider SES, Standby or Emergency Service at Distribution Voltage Rider ("Rider SES"). This rider has also been rendered obsolete as Rider GSS, Generation Support Services, and our proposed Rider BDP, Backup Delivery Point Capacity Rider, provide more detailed, unbundled prices to render backup or standby services.

Finally, the Company proposes to eliminate the Energy Call Option Program applicable to real time pricing ("RTP") customers ("Rider EOP-RTP"). This rider sought to make call options available to RTP accounts. Full market pricing approved in 2005, and the increase in premiums sought for the PowerShare® program, would overcompensate customers for price response. Therefore, we propose to eliminate this Rider. Customers can still respond to price under the RTP program, or receive service under the standard rate and participate in the PowerShare® program.

VI. MISCELLANEOUS CHARGES

Q. WHAT CHANGES WERE MADE TO THE COMPANY'S MISCELLANEOUS CHARGES AND SERVICE REGULATIONS?

A. Reconnections at the pole where the Company was unable to gain access to the meter will be $65.

We are also implementing an after-hours reconnection charge of $50 (Sheet No. 91). This fee will apply if the Company receives notice after 12:30 p.m. that the customer wants same-day reinstatement of service. After hours reconnection at the pole will be $90.

We are also proposing a field collection fee of $15 (Sheet No. 91), whereby employees dispatched to reconnect service may accept payment from the customer.

The Company has also added a provision related to the relocation of facilities to its service regulations (Sheet No. 23). This provision requires that when a customer or private party request the relocation of facilities, the requesting party is required to pay all expenses related to the relocation. In situations where facilities are relocated at the request of a governmental entity or entities, and if the project receives public or quasi-public funding, an additional provision requires that the entity or entities pay for the relocation in proportion to the funding for the project.

Any other changes not fully described herein are minor wording changes, are clerical in nature, or were made to update the tariff to conform to Duke Energy Kentucky's current practice.

VII. CHANGES TO TARIFF LANGUAGE AND SERVICE REGULATIONS

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO THE LANGUAGE CONTAINED IN THE TARIFFS AND SERVICE REGULATIONS?

A. Yes. In the Company's Emergency Electric Procedures Tariff, the Company is deleting Section V pertaining to Transmission Emergency Rules. This language was added in 2002 after the Kentucky General Assembly enacted Senate Bill 257, which became codified as KRS 278.214. My understanding is that this law, in essence, required utilities to refrain from curtailing in-state customers' electrical service until service had been interrupted to all other customers. My further understanding is that a federal court ruled this statute unconstitutional in 2005. As a result, the Company is deleting this language from its tariff.

Q. HOW DOES THE COMPANY PROPOSE THAT THE COMPANY'S TARIFFS, INCLUDING THE PREVIOUSLY DISCUSSED RATES AND CHARGES, BE IMPLEMENTED?

A. We propose that the revised tariff, including the rates and charges complying with the Commission's order in this Case, be established effective July 1, 2006, for all customers.

VIII. CONCLUSION

Q. WERE SCHEDULES D-2.34, L, L-1, L-2.1, L-2.2, M, M-2.1, M-2.3, AND N, FRS 10(1)(B)(7), 10(1)(B)(8), 10(3)(A), 10(3)(B), 10(3)(C), 10(10)(L), 10(10)(M) AND 10(10)(N), AND ATTACHMENT JRB-1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

State of Indiana)
) SS:
County of Hendricks)

The undersigned, Jeffrey R. Bailey, being duly sworn, deposes and says that he is the Manager, Pricing, Duke Energy Shared Services, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Jeffrey R. Bailey

Jeffrey R. Bailey, Affiant

Subscribed and sworn to before me by Jeffrey R. Bailey on this 11th day of May, 2006.

Kathy L. Cobb

NOTARY PUBLIC Kathy L. Cobb

My Commission Expires: 05.01.07

Duke Energy Kentucky
Case No. 2006-00172
Residential Service
Customer Charge / Minimum Bill Rationale
Twelve Months Ending December 31, 2007

Line No.	Description	Amount
1	Capitalization allocated to Electric Operations	$33,408,833
2	Operating Expense	$13,448,166
3	Return at 7.7166946%	2,578,058
4	Operating Expense plus Return	$16,026,224
5	Less Total Other Operating Revenues	(112,538)
6	Customer Cost Component (Revenue Requirement)	$15,913,686
7	Total Residential Customers (Bills)	1,457,429
8	Monthly Revenue / Customer	$10.92
9	Annual Revenue / Customer	$131.03

Duke Energy Kentucky
Case No. 2006-00172
Service at Secondary Distribution Voltage
Customer Charge / Minimum Bill Rationale
Twelve Months Ending December 31, 2007

Line No.	Description	Amount
1	Capitalization allocated to Electric Operations	$7,993,507
2	Operating Expense	$2,838,094
3	Return at 10.6578976%	851,940
4	Operating Expense plus Return	$3,690,034
5	Less Total Other Operating Revenues	(27,331)
6	Customer Cost Component (Revenue Requirement)	$3,662,703
7	Customer Cost Component (Revenue Requirement) (Single Phase)	$1,195,056
8	Customer Cost Component (Revenue Requirement) (Three Phase)	$2,467,647
9	Total Secondary Distribution Voltage Customers (Bills) (Single Phase)	84,787
10	Total Secondary Distribution Voltage Customers (Bills) (Three Phase)	61,274
11	Monthly Revenue / Customer (Single Phase)	$14.09
12	Annual Revenue / Customer (Single Phase)	$169.14
13	Monthly Revenue / Customer (Three Phase)	$40.27
14	Annual Revenue / Customer (Three Phase)	$483.27

Duke Energy Kentucky
Case No. 2006-00172
Distribution - Time of Day Service - Secondary
Customer Charge / Minimum Bill Rationale
Twelve Months Ending December 31, 2007

Line No.	Description	Amount
1	Capitalization allocated to Electric Operations	$2,628,497
2	Operating Expense	$346,909
3	Return at 8.9310799%	234,753
4	Operating Expense plus Return	$581,662
5	Less Total Other Operating Revenues	(8,180)
6	Customer Cost Component (Revenue Requirement)	$573,482
7	Customer Cost Component (Revenue Requirement) (Single Phase)	$0
8	Customer Cost Component (Revenue Requirement) (Three Phase)	$573,482
9	Customer Cost Component (Revenue Requirement) (Primary Voltage)	$0
10	Total Distribution Time-of-Day Customers (Bills) (Single Phase)	0
11	Total Distribution Time-of-Day Customers (Bills) (Three Phase)	2,258
12	Total Distribution Time-of-Day Customers (Bills) (Primary Voltage)	0
13	Monthly Revenue / Customer (Single Phase)	$0.00
14	Annual Revenue / Customer (Single Phase)	$0.00
15	Monthly Revenue / Customer (Three Phase)	$253.98
16	Annual Revenue / Customer (Three Phase)	$3,047.74
17	Monthly Revenue / Customer (Primary Voltage)	$0.00
18	Annual Revenue / Customer (Primary Voltage)	$0.00

Duke Energy Kentucky
Case No. 2006-00172
Distribution - Time of Day Service - Primary
Customer Charge / Minimum Bill Rationale
Twelve Months Ending December 31, 2007

Line No.	Description	Amount
1	Capitalization allocated to Electric Operations	$35,532
2	Operating Expense	$9,131
3	Return at 6.6024788%	2,346
4	Operating Expense plus Return	$11,477
5	Less Total Other Operating Revenues	(114)
6	Customer Cost Component (Revenue Requirement)	$11,363
7	Customer Cost Component (Revenue Requirement) (Single Phase)	$0
8	Customer Cost Component (Revenue Requirement) (Three Phase)	$0
9	Customer Cost Component (Revenue Requirement) (Primary Voltage)	$11,363
10	Total Distribution Time-of-Day Customers (Bills) (Single Phase)	0
11	Total Distribution Time-of-Day Customers (Bills) (Three Phase)	0
12	Total Distribution Time-of-Day Customers (Bills) (Primary Voltage)	427
13	Monthly Revenue / Customer (Single Phase)	$0.00
14	Annual Revenue / Customer (Single Phase)	$0.00
15	Monthly Revenue / Customer (Three Phase)	$0.00
16	Annual Revenue / Customer (Three Phase)	$0.00
17	Monthly Revenue / Customer (Primary Voltage)	$26.61
18	Annual Revenue / Customer (Primary Voltage)	$319.33

Duke Energy Kentucky
Case No. 2006-00172
Service at Primary Distribution Voltage
Customer Charge / Minimum Bill Rationale
Twelve Months Ending December 31, 2007

Line No.	Description	Amount
1	*Capitalization allocated to Electric Operations*	$4,568
2	Operating Expense	$2,426
3	Return at 7.7969361%	356
4	Operating Expense plus Return	$2,782
5	Less Total Other Operating Revenues	(17)
6	*Customer Cost Component* (Revenue Requirement)	$2,765
7	Total Primary Distribution Voltage Customers (Bills)	127
8	Monthly Revenue / Customer	$21.77
9	Annual Revenue / Customer	$261.28

Duke Energy Kentucky
Case No. 2006-00172
Transmission - Time of Day Service
Customer Charge / Minimum Bill Rationale
Twelve Months Ending December 31, 2007

Line No.	Description	Amount
1	Capitalization allocated to Electric Operations	$28,431
2	Operating Expense	$55,805
3	Return at 10.3417185%	2,940
4	Operating Expense plus Return	$58,745
5	Less Total Other Operating Revenues	(160)
6	Customer Cost Component (Revenue Requirement)	$58,585
7	Total Transmission Time-of-Day Customers (Bills)	162
8	Monthly Revenue / Customer	$361.64
9	Annual Revenue / Customer	$4,339.65

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

WILLIAM DON WATHEN, JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY

183240

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE .... - 1 -

II. TEST PERIOD AND RATE BASE .... - 3 -

III. SCHEDULES SPONSORED BY WITNESS .... - 4 -

IV. RECOVERY OF FUEL COSTS .... - 30 -

V. TRANSMISSION COST RECOVERY MECHANISM .... - 35 -

VI. CONCLUSION .... - 37 -

ATTACHMENTS

ATTACHMENT WDW-1– Calculation of Fuel Rate to be Included in Base Rates

ATTACHMENT WDW-2a – Attachment O filing with Midwest ISO for Duke Energy Midwest Companies for 2005 and 2006

ATTACHMENT WDW-2b –Attachment O Filing with Midwest ISO FERC Electric Tariff, Third Revised Vol. No. 1

ATTACHMENT WDW-3 – Calculation of Attachment O Revenue Requirement for Duke Energy Kentucky using Dr. Morin's Recommended ROE

ATTACHMENT WDW-4 – Adjustment to Capitalization to Reflect AMI Revenue Requirements

ATTACHMENT WDW-5 – Proposed FAC – Fuel Adjustment Clause Tariff Applicable to Retail Rate Groups

ATTACHMENT WDW-6 – Rider TCRM – Transmission Cost Recovery Mechanism Applicable to Retail Rate Groups

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Don Wathen, Jr. My business address is 139 East Fourth Street, Cincinnati, Ohio 45202

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as Manager, Revenue Requirements.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I received Bachelor degrees in Business and Chemical Engineering in 1985 and 1986, respectively, and Master of Business Administration degree in 1988, all from the University of Kentucky.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. After completing graduate studies, I was employed by Kentucky Utilities Company as a planning analyst. In 1989, I began employment with the Indiana Utility Regulatory Commission ("IURC") as a senior engineer. From 1992 until mid-1998, I was employed by SVBK Consulting Group, where I held several positions as a consultant focusing primarily on utility rate matters. Since 1998, I have been employed by Cinergy Services, Inc. (now "Duke Energy Shared Services, Inc.") and have held positions in Budgets and Forecasts, Project Management, and, since 2003, as Manager, Revenue Requirements.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I previously testified in Case No. 2005-00042 in The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky's ("Duke Energy Kentucky") recent gas base rate case and in Case No. 2004-00098 in Duke Energy Kentucky's 2004 annual filing to establish new rates under Rider AMRP.

Q. HAVE YOU TESTIFIED IN ANY OTHER REGULATORY PROCEEDINGS?

A. I have previously sponsored testimony before the IURC, the Public Utilities Commission of Ohio ("PUCO"), the Federal Energy Regulatory Commission ("FERC"), and the City Council of New Orleans in various electric, gas, water, and sewer proceedings addressing rate design, revenue requirements, cost of service, and rate of return.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I describe the test period and rate base used in this proceeding. I also support the revenue requirement proposed by Duke Energy Kentucky. Toward that end, I support various adjustments to the projected data for the forecasted test period provided by Mr. Davey. I support Duke Energy Kentucky's proposal to implement its Fuel Adjustment Clause ("FAC") for costs incurred on and after January 1, 2007. I support Duke Energy Kentucky's proposal to implement a new cost recovery mechanism to pass through changes in certain transmission costs charged by the Midwest Independent System Operator, Inc. ("Midwest ISO") for transmission service rendered for Duke Energy Kentucky's retail electric customers ("Rider TCRM – Transmission Cost Recovery Mechanism").

I sponsor the following schedules: Schedules A, B-1, B-5, B-5.1, B-6, B-8, C-1 through C-2.2, D-1, D-2.1 through D-2.28, D-2.30 through D-2.33, D-2.35, F-1 through F-7, G-1 through G-3, H, and K. I sponsor Attachments WDW-1 through WDW-6 to my testimony. I also sponsor the following Filing Requirements ("FR"):

1. FR 6(9), a detailed income statement and balance sheet;
2. FR 10(8)(a), the financial data for the forecasted period in the form of *pro forma* adjustments to the base period;
3. FR 10(8)(b), the forecasted adjustments for the twelve months immediately following the suspension period;
4. FR 10(8)(c), the 13-month average capitalization and net investment rate base for the forecasted test period;
5. FR 10(8)(f), a reconciliation of the rate base and capital used to determine the revenue requirement; and
6. FR 10(9)(t), a list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and workpapers associated with the filing of the utility's application.

II. <u>TEST PERIOD AND RATE BASE</u>

Q. WHAT IS THE TEST PERIOD IN THIS PROCEEDING?

A. The Company has elected to use a forecasted test period in this proceeding. The forecasted test period reflects the twelve months ending December 31, 2007, adjusted for known and measurable changes, and a base period of twelve months ending August 31, 2006. The base period consists of six months of actual data, through February 28, 2006, and the remaining six months consist of forecasted data.

Q. HOW WERE THE RATE BASE AND CAPITALIZATION DETERMINED IN THIS PROCEEDING?

A. The Company determined rate base and capitalization using a 13-month average for the forecasted test period ending December 31, 2007. The base period rate base and capitalization represent end-of-period balances.

Q. DID THE COMPANY FOLLOW THE COMMISSION'S GUIDELINES IN DEVELOPING THE BASE AND FORECASTED TEST PERIOD DATA?

A. Yes. Per the Commission's rules, 807 KAR 5:001, Section (9)(e)(2), "the forecast contains the same assumptions and methodologies as used in the forecast period for use by management." As described by Mr. Davey, the base and forecasted test periods were developed using the same methods applied in the Company's annual budgeting process. The first six months of the base period are actual results and are taken from the Company's books and records.

III. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULE A.

A. Schedule A is the overall financial summary for both the base period and the forecasted period at present and proposed rates. Based on the filing in this proceeding, as adjusted, the Company's electric operations are projected to earn a return on capitalization of 3.68% for the forecasted test period, which is considerably less than the 8.761% return requested in this proceeding. In order to achieve the appropriate return on capitalization, Duke Energy Kentucky's non-fuel base electric revenues must increase $46,520,476, as shown in Schedule A.

Although the Company proposes to establish a level of fuel cost recovery in its base rates, the revenue requirement calculations were such that fuel and non-fuel revenue requirements could be addressed separately. The Commission's FAC regulations require that fuel cost recovery in base rates be separable from non-fuel base rates. The current rate of fuel recovery reflected in Duke Energy Kentucky's base rates is 1.9091 ¢/kWh. The FAC rate, which has been frozen since 2001, is (0.2525) ¢/kWh. The Company's net fuel recovery rate is 1.6566 ¢/kWh. At that rate, Duke Energy Kentucky would only recover $66,371,596 for its fuel expenses, compared to approximately $86,616,415 which it projects in 2007. In Attachment WDW-1, I show the calculation of the fuel rate to be included in base rates. The new fuel rate will be 2.1619 ¢/kWh. I discuss how the projection for 2007 fuel cost recovery was calculated later in my testimony. Note that Schedule A shows only the fuel cost recovery from non-RTP customers.

Q. HOW WAS TOTAL CAPITALIZATION FROM SCHEDULE J ALLOCATED TO ELECTRIC OPERATIONS ON SCHEDULE A?

A. The Company determined the amount of total capitalization allocated to electric operations using the methodology approved by the Commission in prior Duke Energy Kentucky rate proceedings. This process involves applying an electric rate base ratio, as determined on WPA-1d, to total company capitalization, as shown on Schedule J-1, page 2, adjusted for non-jurisdictional rate base.

Q. WHAT ARE THE MAJOR FACTORS THAT PREVENT DUKE ENERGY KENTUCKY FROM EARNING A FAIR RETURN ON THE CAPITAL INVESTED IN THE ELECTRIC SYSTEM?

A. In addition to the higher fuel costs I described, Mr. Smith outlines these factors in his testimony and in FR 10(1)(b)(1). In general, Duke Energy Kentucky's opportunity to earn a reasonable return is impaired due to: (1) significant increases in plant, particularly due to The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio's ("Duke Energy Ohio") transfer to Duke Energy Kentucky of the East Bend Generating Station ("East Bend"), the Miami Fort Generating Station Unit 6 ("Miami Fort 6"), and the Woodsdale Generating Station ("Woodsdale") (collectively, "the Plants"); (2) the significant increases in fuel costs during the period of frozen rates; (3) increases in transmission costs associated with Duke Energy Kentucky's membership in the Midwest ISO; and (4) normal inflationary increases in overall operation and maintenance ("O&M") expenses. These costs are partially offset by load growth and the Company's ongoing efforts to reduce costs, including savings that will accrue to Duke Energy Kentucky as a result of the recent merger between Duke Energy Corporation and Cinergy Corp.

Q. PLEASE DESCRIBE SCHEDULE B-1.

A. Schedule B-1 is the rate base summary for both the base and forecasted periods and is supported by various schedules in Section B of the Company's filing. The plant in service, reserve for accumulated depreciation and amortization, and construction work in progress for the base and forecasted periods were summarized from Schedules B-2, B-3, and B-4, as supported by Mr. Council and Mr. Jacobs. The working capital component was summarized from Schedule B-5, and other items of rate base were obtained from Schedule B-6. The jurisdictional electric rate base as contained in Schedule B-1 is $590,909,461.

Q. PLEASE DESCRIBE SCHEDULE B-5.

A. Schedule B-5 is a summary of the jurisdictional working capital calculation based on the Commission's traditional methodology. The calculation includes a cash element of working capital, material and supplies inventory, fuel inventory, emission allowance inventory, and prepayments.

Q. PLEASE DESCRIBE SCHEDULE B-5.1.

A. Schedule B-5.1 reflects the itemized miscellaneous working capital items for both the base and forecasted periods.

Q. PLEASE EXPLAIN THE MATERIALS AND SUPPLIES INVENTORY ON SCHEDULE B-5.1.

A. The materials and supplies shown on Schedule B-5.1 represent the 13-month average for the forecasted period, and the end of period balance for both the base and forecasted periods. These supplies consist primarily of supplies kept on hand in the Company's storerooms. These investments assure that adequate supplies are available to provide reliable service to customers. The 13-month average of material and supplies included in electric working capital for the forecasted test period is $8,467,889.

Q. PLEASE EXPLAIN THE FUEL AND EMISSION ALLOWANCE INVENTORIES ON SCHEDULE B-5.1.

A. The fuel and emission allowance inventories shown on Schedule B-5.1 represent the 13-month average for the forecasted period, and the end of period balance for both the base and forecasted periods. The 13-month average balances of fuel and emission allowance inventories included in electric working capital for the forecasted test period are $8,873,933 and $5,919,968, respectively.

Q. PLEASE EXPLAIN THE PREPAYMENTS ON SCHEDULE B-5.1.

A. The prepayments shown on Schedule B-5.1 represent the 13-month average for the forecasted period, and the end of period balance for both the base and forecasted periods. These prepayments are expenditures that, as required by the vendor or taxing authority, must be paid in advance prior to being charged to operations and, therefore, represent a working capital requirement. The total amount of prepayments included in the forecasted test period is $6,699,569.

Q. PLEASE EXPLAIN THE CASH WORKING CAPITAL COMPUTATION ON SCHEDULE B-5.1.

A. Cash working capital was computed for both the base and forecasted periods. It represents the financing incurred to bridge the gap between the time when expenditures are incurred to provide service and the time when payment is received for that service. The cash working capital computation is based upon the traditional methodology used by this Commission, which is one-eighth of O&M expense, as adjusted, excluding fuel and purchased power costs. For the base period, the resulting cash working capital is $9,043,344 and for the forecasted period cash working capital is $13,962,791.

Q. PLEASE DESCRIBE SCHEDULE B-6.

A. Schedule B-6 presents certain deferred credits, accumulated deferred income taxes ("ADIT"), and other items that form the adjustments to rate base as summarized on Schedule B-1. On this schedule, the first column contains balances as of the end of the base period (page 1 of 2) and the 13-month average balance for the forecasted period (page 2 of 2). The second and third columns allocate the balances to jurisdictional customers. Duke Energy Kentucky's electric operations are 100% jurisdictional, as indicated in column three. The fourth column contains adjustments to the balances and a footnote reference describing the adjustment, and the fifth column is the jurisdictional amount included in rate base. The balances shown are: Investment Tax Credits, Account 255; and Deferred Income Taxes, Account Nos. 190, 282, and 283.

Q. WHY ARE SOME OF THESE AMOUNTS EXCLUDED FROM RATE BASE?

A. There are several reasons for items to be excluded from rate base. First, with regard to the investment tax credits, certain amounts cannot be used as a cost of service reduction in accordance with the Internal Revenue Code. Second, certain amounts were eliminated to be consistent with other adjustments proposed by the Company. Third, as explained by Mr. Butler, the Company has recorded the ADIT and Accumulated Deferred Investment Tax Credit ("ADITC") transferred from Duke Energy Ohio below-the-line, and has excluded the ADIT and ADITC as of December 31, 2005, in accordance with the Commission's December 5, 2003 Order in Case No. 2003-00252.

In addition, certain of the Company's gas facilities are not used exclusively to serve Kentucky customers. Liberalized Depreciation ADIT and ADITC related to this non-jurisdictional gas plant was eliminated from jurisdictional gas rate base in determining the rate base ratio, consistent with the development of the ratio in prior proceedings. The items and corresponding amounts to be excluded from jurisdictional gas rate base are shown on WPB-6c and WPB-6d. The ratio of gas plant devoted to other than Duke Energy Kentucky's customers is based on a methodology accepted by the Commission in Case No. 2005-00042.

Q. PLEASE DESCRIBE SCHEDULE B-8.

A. Schedule B-8 contains comparative balance sheet information for the most recent five calendar years, the base period and the forecasted period.

Q. PLEASE DESCRIBE SCHEDULE C-1.

A. Schedule C-1 is a jurisdictional operating income summary for the forecasted period ended December 31, 2007. This schedule includes the operating income summary at both current and proposed rates. It assumes that the Commission allows the total amount of the requested electric revenue increase of $46,519,810. The adjusted operating results at current rates were summarized from Schedule C-2 and the proposed increase was obtained from Schedule M. The revenue at proposed rates was developed by adding the revenue increase to the operating revenues at current rates. The related expenses and taxes on the proposed increase were added to the current adjusted operating results to determine the jurisdictional *pro forma* amounts and the corresponding rate of return. The rate base as shown on this schedule is calculated on Schedule B-1. The capitalization allocated to electric operations is calculated on workpaper WPA-1c.

Q. PLEASE DESCRIBE SCHEDULE C-2.

A. Schedule C-2 is a jurisdictional operating income statement to be used for ratemaking purposes. In order to develop the forecasted test year that is appropriate for ratemaking, a two-step process was required. First, as required by 807 KAR 5:001, Section 10(8)(a), it was necessary to show the adjustments necessary to transform the financial data for the base period into the forecasted period. Second, it was necessary to adjust the forecasted period data to reflect any fixed, known and measurable adjustments required to ensure that the revenues and expenses to be recovered in rates are representative of the expected costs to serve Duke Energy Kentucky electric customers on an ongoing basis.

Schedule C-2 starts with the unadjusted base period and shows the adjustments required to extend the Company's income statement from the base period to the forecasted period. The next column on the schedule summarizes the adjustments to the unadjusted forecasted test year. These adjustments are described below. Generally, they relate to costs that were not reflected in the Company's forecasted data or were reflected in the forecasted data but not allocable to Duke Energy Kentucky's customers. The unadjusted operating results are summarized from Schedule C-2.1. The adjusted amounts include the effects of the adjustments summarized on Schedule D-1.

Q. PLEASE DESCRIBE SCHEDULE C-2.1.

A. Schedule C-2.1 sets forth the detail of total Company operating results for both the base and forecasted periods. The operating results as shown in this Schedule C-2.1 are listed by account and are summarized on Schedule C-2.

Q. PLEASE DESCRIBE SCHEDULE C-2.2.

A. Schedule C-2.2 contains a monthly comparison of revenue and expense in the base period to the 12-month period prior to the beginning of the base period. Variances from prior periods are indicated in dollars and in percent.

Q. PLEASE DESCRIBE SCHEDULE D-1.

A. Schedule D-1 is a summary of the detailed adjustments to test period operating revenues and operating expenses as set forth in Schedules D-2.1 through D-2.35. These *pro forma* adjustments to the base period data are necessary to derive the forecasted test period level which includes the fixed, known, and measurable adjustments required to ensure that revenue and expenses to be recovered in rates are set at the level required to cover the cost of providing service to Duke Energy Kentucky's electric customers.

Q. WHY ARE ADJUSTMENTS TO THE BASE AND FORECASTED PERIOD INFORMATION NECESSARY?

A. The adjustments shown in Schedules D-2.1 through D-2.14 reflect the normal budgetary changes that are expected to occur from the base period through the forecasted period. The remaining adjustments, shown in Schedules D-2.15 through D-2.35, present adjustments to the forecasted period data needed to ensure that the correct level of revenue and expense is included in rates at the proper ongoing level. Some costs, although reflected in the normal forecasting process, are not recoverable from Duke Energy Kentucky's customers. Other adjustments were made to reflect traditional ratemaking methodology (*e.g.*, amortizing a regulatory asset to reflect the Commission's prior orders). The reflection of a proper cost level is necessary in order to give the Company a reasonable opportunity to earn its authorized return and to ensure that customers are not paying for more than the cost of providing service. Ignoring appropriate adjustments to the test year used for setting rates puts the Company at risk for potentially under-recovering its ongoing costs and also puts customers at risk for overpaying for service.

Q. HOW ARE THE TAX EFFECTS OF THESE ADJUSTMENTS SHOWN ON YOUR SCHEDULES?

A. All adjustments to taxes, including taxes other than income taxes and state and federal income taxes resulting from the adjustments, described below, are shown for each individual adjustment on Schedule D-1.

Q. PLEASE DESCRIBE SCHEDULE D-2.1.

A. Schedule D-2.1 adjusts base period revenue to the level included in the forecasted test period. The adjustment results in a net revenue increase of $38,000,376. The federal and state income tax effects are shown on Schedule D-1.

Q. PLEASE DESCRIBE SCHEDULE D-2.2.

A. Schedule D-2.2 adjusts base period fuel and purchased power costs to the level included in the forecasted test period. The effect of the adjustment on Duke Energy Kentucky's electric operations is a decrease in pre-tax operating expenses of $10,242,540.

Q. PLEASE DESCRIBE SCHEDULE D-2.3.

A. Schedule D-2.3 adjusts base period other production expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $24,790,695.

Q. PLEASE DESCRIBE SCHEDULE D-2.4.

A. Schedule D-2.4 was not used in this filing.

Q. PLEASE DESCRIBE SCHEDULE D-2.5.

A. Schedule D-2.5 adjusts base period transmission expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $9,457,702.

Q. PLEASE DESCRIBE SCHEDULE D-2.6.

A. Schedule D-2.6 adjusts base period electric distribution expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $648,970.

Q. PLEASE DESCRIBE SCHEDULE D-2.7.

A. Schedule D-2.7 adjusts base period customer accounts expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $163,429.

Q. PLEASE DESCRIBE SCHEDULE D-2.8.

A. Schedule D-2.8 adjusts base period customer service and informational expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $77,858.

Q. PLEASE DESCRIBE SCHEDULE D-2.9.

A. Schedule D-2.9 adjusts base period sales expense to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $135,672.

Q. PLEASE DESCRIBE SCHEDULE D-2.10.

A. Schedule D-2.10 adjusts base period administrative and general expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase of pre-tax operating expenses of $5,590,919.

Q. PLEASE DESCRIBE SCHEDULE D-2.11.

A. Schedule D-2.11 adjusts base period other operating expenses to the level included in the forecasted test period. Since there are no other operating expenses in this case, the adjustment is $0.

Q. PLEASE DESCRIBE SCHEDULE D-2.12.

A. Schedule D-2.12 adjusts base period depreciation expense to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $9,019,894.

Q. PLEASE DESCRIBE SCHEDULE D-2.13.

A. Schedule D-2.13 adjusts base period taxes other than income taxes to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $2,119,914.

Q. PLEASE DESCRIBE SCHEDULE D-2.14.

A. Schedule D-2.14 adjusts base period income taxes to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in income tax expense of $45,782.

Q. PLEASE DESCRIBE SCHEDULE D-2.15.

A. Duke Energy Kentucky has two regulatory assets which it proposes to amortize and include for rate recovery in this case. The first regulatory asset represents costs associated with a severance program offered in 1992. The gas portion of the severance program costs and savings were reflected in gas rates by the Commission in its Order in Case No. 92-346. Since the Company has not filed an electric rate case since Case No. 91-370, it has not had an opportunity to recover these costs from ratepayers. In Case No. 92-346, the Commission ordered that downsizing costs that reflect an immediate cash outlay should be amortized over three years and costs that might require cash outlays for up to ten years should be amortized over ten years. Since it has been over ten years since the severance program was offered, the Company believes a three-year amortization period in this proceeding is appropriate.

The second regulatory asset, deferred project cost, is the balance of deferred costs, $1,291,571, as of March 31, 2006, associated with the transfer of the Plants, plus additional costs of $187,000, expected to be incurred related to issuance and approval of a Request For Proposals for the Back-up Power Supply Agreement ("Back-up PSA"), as discussed by Mr. Esamann. The Commission specifically allowed the Company to defer these costs, up to $2.45 million, for recovery in its next base electric rate case over a period of five years (*see* December 5, 2003 Order in Case No. 2003-00252). The adjustment increases amortization expenses by $806,020.

Q. PLEASE DESCRIBE SCHEDULE D-2.16.

A. The adjustment in Schedule D-2.16 is to amortize the projected cost of presenting the instant case. Duke Energy Kentucky proposes to amortize these costs over three years, which raises amortization expenses includable in revenue requirements by $78,333.

Q. PLEASE DESCRIBE SCHEDULE D-2.17.

A. Schedule D-2.17 shows the adjustment required to recognize certain affiliated company transactions that had not been included in the Company's budget and, thus, not in the forecasted test period. Including these inter-company revenues and expenses, the net effect is a pre-tax reduction of the revenue requirement of $9,707.

Q. PLEASE DESCRIBE SCHEDULE D-2.18.

A. Interest synchronization is used to ensure that the revenue requirements reflect the appropriate income tax effects for interest expense determined in the weighted-average cost of capital. Schedule D-2.18 presents the calculation of the state and federal income taxes on the interest cost included in the cost of capital. The adjustment is calculated by first determining the electric, gas, and non-jurisdictional percentages of the Company's total rate base. These percentages are then used to allocate total capitalization to electric operations as shown in WPA-1c. The capitalization allocated to electric is then multiplied by the long-term and short-term debt percentage of total capitalization. An adjustment is made to eliminate the applicable portion of Construction Work in Progress ("CWIP") subject to Allowance for Funds Used During Construction ("AFUDC") from the components of capitalization.

The result is then multiplied by the average cost of long-term and short-term debt. The sum of these results represents the annualized electric interest cost deductible for income tax purposes. From this annualized total, we subtract the forecasted test period electric book interest as described by the Commission's ratemaking guidance in Case No. 2001-00092 to determine the electric interest expense adjustment for income tax purposes. The effect of this adjustment on electric operations is to decrease federal income taxes by $1,019,112 and to decrease state income taxes by $179,280.

Q. PLEASE DESCRIBE SCHEDULE D-2.19.

A. Revenue and expenses associated with off-system sales are included in the budget and, consequently, in the forecasted test year. As I will discuss later in my testimony, Duke Energy Kentucky will be crediting customers with a share of its margins on off-system sales through its monthly FAC beginning January 1, 2007; therefore, Schedule D-2.19 is intended to completely exclude the impact of off-system sales from the calculation of the base rate revenue requirement. Other Revenue is reduced by $17,670,012 for off-system sales revenue and related expenses are reduced by $13,257,666. Related expenses include fuel, allocated emission allowance expenses, and other variable expenses.

Q. PLEASE DESCRIBE SCHEDULE D-2.20.

A. Schedule D-2.20 is an adjustment to reflect the calculation of AFUDC on the CWIP balance as of the plant valuation date. This adjustment is calculated by multiplying CWIP subject to AFUDC, as shown on Schedule B-4, page 2, times the rate of return as shown on Schedule J-1, page 2. The Company is following Commission precedent by using the overall rate of return for this calculation. An adjustment of $373,481 was made to net operating income after tax, based on the Company's use of the overall rate of return for this adjustment.

Q. PLEASE DESCRIBE SCHEDULE D-2.21.

A. The adjustment in Schedule D-2.21 eliminates the impact of Demand Side Management ("DSM") revenue, $2,018,144, and DSM expense of the same amount. In addition, as a result of eliminating the DSM revenue, uncollectible expense is reduced by $11,085 and Kentucky Public Service Commission maintenance fees are reduced by $3,370.

Q. PLEASE DESCRIBE SCHEDULE D-2.22.

A. Schedule D-2.22 is an adjustment to eliminate miscellaneous expenses such as community relations, advertising, donations, employee recognition, governmental affairs, club dues and miscellaneous events expenses from the forecasted test period. These adjustments were made in order to comply with the Commission's orders in prior rate proceedings. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $360,386.

Q. PLEASE DESCRIBE SCHEDULE D-2.23.

A. Schedule D-2.23 is an adjustment to annualize depreciation expense for the forecasted test period. Depreciation expense projected for the test year using the accrual rates proposed by Mr. Spanos and reflected in Schedule B-3.2 are compared to the depreciation expense included in the forecasted test period, Schedule C-2.1. The adjustment increases depreciation expense by $227,766.

Q. PLEASE DESCRIBE SCHEDULE D-2.24.

A. Schedule D-2.24 is an adjustment to eliminate unbilled revenue from the forecasted test period. The adjustment decreases revenue in the forecasted test period by $90,983. In addition, as a result of eliminating the unbilled revenue, uncollectible expense is reduced by $500 and Kentucky Public Service Commission maintenance fees are reduced by $152.

Q. PLEASE DESCRIBE SCHEDULE D-2.25.

A. As described by Mr. Esamann, Duke Energy Kentucky followed the methodology used in Case No. 2003-00252 to calculate the capacity payments that will be included in the Back-up PSA. These payments were not included in the budget or the forecasted test period; therefore, Schedule D-2.25 is necessary to include this cost in the forecasted test year revenue requirement. Mr. Esamann discusses the Back-up PSA in more detail. The impact of this adjustment is to increase production expenses by $10,431,923.

Q. PLEASE DESCRIBE SCHEDULE D-2.26.

A. The unadjusted budget and forecasted test year include expenses related to the provision of network integration transmission service ("NITS"). Duke Energy Kentucky relies on the transmission owned by Duke Energy Ohio and its own local transmission facilities to provide network service. The cost of this service is established using a formula rate method approved by the FERC.

The formula rate method is reflected in the Duke Energy Midwest companies' (consisting of Duke Energy Kentucky, Duke Energy Ohio and Duke Energy Indiana) annual Attachment O filing with the Midwest ISO, which aggregates the revenue requirement associated with each of the Duke Energy Midwest companies. Attachment WDW-2 includes the Attachment O filings for 2005 and 2006. The cost to Duke Energy Kentucky is based on its load ratio share of the entire Duke Energy Midwest companies' transmission system and is approved by the FERC. This cost is reflected in the Company's forecast.

Because Duke Energy Kentucky's own local transmission investment is included in the revenue requirement calculation in Attachment O and in the revenue requirement in this case, it is necessary to adjust the test year transmission expenses to ensure that retail customers are not paying twice for the same service. Of the total amount of network service transmission costs assigned to Duke Energy Kentucky, $4,187,956 is for use of its own facilities, which is included in the revenue requirements calculation. This number is slightly different than the amount shown in Attachment O because the FERC allows a 12.38% return on equity ("ROE") for transmission investment. In Attachment WDW-3, I substituted the ROE recommended by Dr. Morin of 11.50% in this case and recomputed Duke Energy Kentucky's revenue requirement. This last step is merely to recognize the retail rate of return allowed on Duke Energy Kentucky's own local transmission investment. By eliminating this amount from transmission expenses in Schedule D-2.26, customers will be paying only for the use of the Company's own local transmission system and the "incremental" transmission service provided through the Midwest ISO.

Q. PLEASE DESCRIBE SCHEDULE D-2.27.

A. Schedule D-2.27 is an adjustment to reflect a sharing of incentive compensation costs between customers and shareholders. The adjustment utilizes a methodology similar to the one adopted by the Commission in Case No. 2005-00042. Mr. O'Connor describes the incentive compensation plans and the sharing percentages that the Company proposes to use in its adjustment. The adjustment decreases incentive compensation expense in the forecasted test period by $2,510,033.

Q. PLEASE DESCRIBE SCHEDULE D-2.28.

A. As I mentioned in discussing NITS costs in Schedule D-2.26, Duke Energy recently updated its NITS rates as part of its Attachment O filing. This change, which occurred in May 2006, came after the 2006 budget and the 2007 forecasted test period were developed and, consequently, was not included in the forecasted test period revenue requirement. The only material change is the price of network service, which increased from $1.2235 per kW-month through May 31, 2006, to $1.3654 per kW-month beginning June 1, 2006.

Applying the difference in the two rates ($1.3654 - $1.2235) to the same billing demands used to develop the forecasted test period, indicates that Duke Energy Kentucky's network service costs will increase by $1,377,707 per year, as shown in Schedule D-2.28.

Q. PLEASE DESCRIBE SCHEDULE D-2.30.

A. With the transfer of the Plants from Duke Energy Ohio to Duke Energy Kentucky on January 1, 2006, related ADIT and ADITC were also transferred to Duke Energy Kentucky. As Mr. Butler discusses, these ADIT and ADITC are treated as non-jurisdictional and the amortization of these balances is recorded below-the-line. This accords with the Commission's December 5, 2003 Order in Case No. 2003-00252. The adjustment on Schedule D-2.30 reflects the below-the-line treatment of the ADIT amortization, which was not included in the Company's forecasted test year. This adjustment does not impact the overall base revenue requirements.

Q. PLEASE DESCRIBE SCHEDULE D-2.31.

A. The Company sells all of its accounts receivable to an affiliate, Cinergy Receivables, L.L.C. ("Cinergy Receivables") at a discount. The discount is based on a formula that compensates the purchasing company for the time value of money and a discount rate based on Duke Energy Kentucky's uncollectible expense.

Since the Company's capitalization includes the average balance of receivables at the interest rate being paid to Cinergy Receivables, Schedule D-2.31 ensures that there is no double recovery of the time value of money in the uncollectible expense. Consequently, the time value of money component of the discount being charged to Uncollectible Expense (Account 904) is eliminated from the forecasted test year expenses. The adjustment reduces expenses by $2,289,942. Note that the calculation of the gross revenue conversion factor ("GRCF") includes only the portion of the discount rate not associated with the time value of money.

Q. PLEASE DESCRIBE SCHEDULE D-2.32.

A. In its November 29, 2005 Order in Case No. 2005-00228, approving the Duke/Cinergy merger, the Commission approved a plan to allow the Company to share in anticipated savings that are expected to result from the merger. The revenues in the forecasted test period reflect the impact of the credit. To ensure that customers continue to receive the full value of the credit, the forecasted test year revenue must be increased to eliminate the impact of the merger credit rider. Schedule D-2.32 accomplishes this by increasing revenues in the amount of merger credits projected for the forecasted test year, $2,044,825. Increasing test year revenue lowers the rate increase request and allows customers to continue to receive the share of merger savings per the terms of the Commission's November 29, 2005 Order in the merger case.

As Mr. Davey describes in his testimony, the Company's forecast does not reflect the post-merger savings because, per the Commission's Order, the approved amount of net merger savings are passed through to customers via the Company's merger savings credit mechanism.

Q. PLEASE DESCRIBE SCHEDULE D-2.33.

A. Traditional ratemaking addresses fuel and purchased power costs separately from non-fuel base rates. Although the Company proposes to continue its practice of including a "base" level of fuel cost in its base rates, fuel and purchased power costs are addressed separately. I will discuss the derivation of the base fuel rate further below. Schedule D-2.33 eliminates fuel and purchased power costs and associated FAC revenue from the base rate revenue requirement calculation. Fuel revenue is reduced by $100,771,619 and related fuel expense is reduced by $102,961,803. The difference is attributable to off-system sales sharing credited against fuel revenue.

Q. PLEASE DESCRIBE SCHEDULE D-2.35.

A. Schedule D-2.35 is an adjustment to reflect the revenue and expense impacts of the Company's recent decision to implement the advanced metering infrastructure ("AMI"). As described further in the testimony of Mr. Stanley, the AMI program will produce savings and enhance reliability that will benefit ratepayers. In order to reflect the impact of the program in the forecasted test year, I assumed a *pro* *rata* share of the savings based on the proportion of the program expected to be completed during the forecasted test period. It is projected that 45% of the meters will be replaced during 2007. By 2011, the program will have reached a "steady state" such that all of the net savings will have leveled out. Mr. Stanley provides Attachment JLS-2 showing more detail on the costs and savings of the program.

The adjustments in Schedule D-2.35 can be broken down into four groups. The first group is the benefit of reducing billing cycle time that is expected to result from improved metering. This is identified as "revenue recovery" in JLS-2. Second, there are O&M savings that will be realized by eliminating nearly all physical meter reading. Third, there are expenses associated with owning the property such as depreciation and property taxes. Finally, there are costs to implement the program such as the severance costs associated with headcount reductions for meter readers.

For the first three items, I assumed that 2011 represented a steady-state and, thus, assumed that 45% of these savings would apply to the portion of the program being completed in 2007. In some cases, I had to discount the projected savings due to the fact that the dollars Mr. Stanley's data were in nominal value.

For implementation costs, I summed the total implementation costs and amortized the costs over five years. Again, I assumed only 45% of this cost was applicable to the forecasted test period.

The net impact on pre-tax operating income from the adjustment for the AMI program is an increase of $259,982.

Q. IS THE ADJUSTMENT SHOWN IN SCHEDULE D-2.35 THE ONLY IMPACT OF THE AMI PROGRAM REFLECTED IN THE REVENUE REQUIREMENTS?

A. No. As shown in Attachment WDW-4, the addition of the assets and capital associated with this program also affects the rate base and capitalization allocable to electric operations. In Attachment WDW-4, I calculate the additional capitalization allocable to electric by re-evaluating the rate base ratio calculation from WPA-1d including the increased rate base associated with both the electric and gas AMI program. The impact on capitalization allocable to electric is $6,195,185, which is reflected in Schedule WPA-1c and, ultimately, on Schedule A.

This methodology was used because the AMI program was only recently approved by executive management. I believe this method is a reasonable way of incorporating the rate base and capitalization impacts of the AMI program. All of the data for the adjustments was provided by Mr. Stanley.

Q. PLEASE DESCRIBE SCHEDULE F-1.

A. Schedule F-1, entitled "Social and Service Club Dues," lists social and service club dues that were incurred by the Company and charged below-the-line. As indicated on the schedule, no social or service club dues were charged to electric operating expenses during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-2.1.

A. Schedule F-2.1, entitled "Charitable Contributions," lists the charitable contributions made by the Company. As indicated on the schedule, there were no charitable contributions charged to electric operating expenses during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-2.2.

A. Schedule F-2.2, entitled "Initiation Fees/Country Club Expense," indicates that the country club expenses incurred by the Company are included on Schedule F-1. No country club expenses were charged to electric operating expenses during the forecasted test period and, thus, there are no related costs in the forecasted test period revenue requirements.

Q. PLEASE DESCRIBE SCHEDULE F-2.3.

A. Schedule F-2.3, entitled "Employee Party, Outing, & Gift Expense," indicates that there were no employee party, outing, or gift expenses projected to be included for Duke Energy Kentucky's electric operations during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-3.

A. Schedule F-3 sets forth the detail, by account, of Customer Service and Informational Sales and General Advertising Expense for both the base and forecasted test periods. Marketing/Customer Relations expenses in Account 913 and Community Relations expenses included in Account 930 have been eliminated through an adjustment on Schedule D-2.22, in order to comply with the Commission's Orders in prior rate proceedings.

Q. PLEASE DESCRIBE SCHEDULE F-4.

A. Schedule F-4, entitled "Advertising," indicates the advertising expenses projected for electric operations during the forecasted test period. These expenses have been eliminated through an adjustment on Schedule D-2.22, in accordance with regulation

807 KAR 5:016, Section 4.

Q. PLEASE DESCRIBE SCHEDULE F-5.

A. Schedule F-5, entitled "Professional Services Expenses," indicates the professional services expenses projected for electric operations during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-6.

A. Schedule F-6, entitled "Rate Case Expense," indicates the estimated expense of presenting this case. The top half of this schedule details the estimated expense of this proceeding. Also included is a comparison to the rate case expense in the Company's last two gas rate case proceedings. The bottom half of this schedule shows the amortization over a three-year period. This amount is included in expense through the adjustment contained in Schedule D-2.16.

Q. PLEASE DESCRIBE SCHEDULE F-7..

A. Schedule F-7, entitled "Civic, Political and Related Expense," indicates that there are no civic, political and related expenses projected to electric operations during the forecasted test period.

Q. PLEAS DESCRIBE SCHEDULE G-1.

A. Schedule G-1 contains a summary of all payroll costs and related benefits and taxes included in electric O&M expense.

Q. PLEASE DESCRIBE SCHEDULE G-2.

A. Schedule G-2 is a Total Company payroll analysis for the most recent five years, the base period and the forecasted period. Pages 1 and 2 summarize total company costs. Pages 3 through 8 show detail of payroll by employee classification including union, exempt, and non-exempt. Labor hours, labor dollars, employee benefits, payroll taxes, and the number of employees presented on Schedule G-2 represent Duke Energy Kentucky's direct amounts. Only O&M expenses include amounts allocated from Duke Energy Shared Services, Inc.

Q. PLEASE DESCRIBE SCHEDULE G-3.

A. Schedule G-3 details executive compensation and related benefits and taxes, of each of the highest paid executives as contained in Cinergy Corp's 2005 Proxy Statement that had salary and benefits allocated to Duke Energy Kentucky.

Q. PLEASE DESCRIBE SCHEDULE H.

A. Schedule H, entitled "Computation of Gross Revenue Conversion Factor," sets forth the calculation of the GRCF. This is the factor, or multiplier, used to gross-up the operating income deficiency to a revenue deficiency amount. It includes an uncollectible accounts factor which represents the portion of the average total discount rate that is related to charge-offs, collection costs and late payment charges. Also included in the GRCF are the Kentucky Public Service Commission assessment, and state and federal income taxes. The GRCF is included on Schedule A and is used to compute the calculated revenue deficiency.

Q. PLEASE DESCRIBE SCHEDULE K.

A. Schedule K contains certain financial and statistical information for Duke Energy Kentucky, as required pursuant to 807 KAR 5:001, Section 10(10)(k). Mr. Council sponsors the plant data and the composite depreciation rates contained on page 1. Ms. Good sponsors the fixed charge coverage ratios, the stock and bond ratings and the percentage of construction expenditures financed internally on page 3. I sponsor the remaining financial and statistical information.

IV. RECOVERY OF FUEL COSTS

Q. DESCRIBE THE COMPANY'S PROPOSAL FOR FUEL COST RECOVERY.

A. Projected recoverable fuel costs through the end of the forecasted test year are included in base rates. After the rate freeze period ends on December 31, 2006, Duke Energy Kentucky will begin making monthly FAC filings. These monthly FAC filings will measure Duke Energy Kentucky's actual recoverable fuel costs against the amount included in base rates. Duke Energy Kentucky will refund or recover the difference using the FAC pursuant to Commission regulation 807 KAR 5:056 and subject to certain provisions identified in Case No. 2003-00252 regarding the recoverability of replacement power during outages.

Q. WHEN WILL DUKE ENERGY KENTUCKY FILE ITS INTIAL ADJUSTMENT FOR THE FAC?

A. The first month Duke Energy Kentucky will compare actual fuel costs to the base rate amount is for January 2007, which is the first month after the rate freeze ends. Duke Energy Kentucky will not have actual data for January 2007 until February, when the January books are closed. Therefore, for at least for the first two months of 2007, the FAC will be $0. Duke Energy Kentucky expects to make a FAC filing in February for a new FAC rate effective with the beginning of the March 2007 billing cycle. This filing will be based on the actual data for January 2007 and will be the first adjustment to the FAC. The FAC rate for any period may be positive or negative depending on how Duke Energy Kentucky's projected fuel cost recovery contained in the base rates compares with its actual fuel costs.

Q. HAS DUKE ENERGY KENTUCKY PREVIOUSLY MADE FAC FILINGS?

A. Yes. Until the Commission's June 1, 2001 Order in Case No. 2001-00058 froze the FAC rate, Duke Energy Kentucky made monthly FAC filings with the Commission. These filings provided timely recovery of the fuel costs included in the power acquired from its affiliate, Duke Energy Ohio.

Q. DOES THE COMPANY PROPOSE TO CHANGE ITS FAC FILINGS, AS COMPARED TO THE FAC FILINGS THE COMPANY PREVIOUSLY MADE?

A. Yes. Importantly, Duke Energy Kentucky now owns the Plants; therefore, it must purchase fuel to generate electricity. Prior to 2001, Duke Energy Kentucky's FAC filings flowed through the fuel costs included in power acquired from Duke Energy Ohio. Now most of Duke Energy Kentucky's fuel costs will come from operating the Plants. Duke Energy Kentucky will also make purchases of power on an economic basis from the wholesale market. Subject to some of the pricing restrictions related to replacement power for outages, these wholesale power purchases will also be included in the FAC. The pricing restrictions for replacement power relate to the Back-up PSA which was proposed in Case No. 2003-00252, and is discussed by Mr. Esamann. Another change involves the Off-System Sales Sharing Mechanism that was also approved in that case.

Q. HOW WILL THE FAC REFLECT COSTS RELATED TO THE BACK-UP PSA?

A. Per the terms of the Back-up PSA described in Mr. Esamann's testimony, Duke

Energy Kentucky's monthly FAC filings will cap the recovery of replacement power for outages at East Bend and Miami Fort 6 at the prior month's variable operating cost of the unit that is being backed up.

Q. ARE THE PRICING TERMS OF THE BACK-UP PSA REFLECTED IN THE BASE FUEL RATE?

A. Yes. Attachment WDW-1 presents the Company's estimated recoverable fuel costs for the forecasted test year. The data reflects implementing the pricing terms for replacement power in the Back-up PSA, and also reflects the credit for projected margins on off-system sales. This attachment establishes a fuel rate to be incorporated into base rates representative of the Company's expectations for the forecasted test year, incorporating the special pricing provisions that were included in Case No. 2003-00252 (*i.e.*, the Back-up PSA and the sharing of margins on Off-System Sales).

Q. HOW WILL THE FAC REFLECT THE REPLACEMENT POWER PRICING LIMIT, AS PROVIDED IN THE BACK-UP PSA?

A. Duke Energy Kentucky will maintain records of all outages lasting longer than six hours to identify those outages subject to the provisions of the Back-up PSA. During those hours when an outage at East Bend or Miami Fort 6 requires the Company to replace the lost generation with economic purchases from the market or from internal resources, the cost of such power exceeding the previous month's variable cost of power from the unit experiencing the outage will be excluded.

Since the Back-up PSA extends only through 2009, Duke Energy Kentucky will thereafter revert to the Commission's statutory guidelines for fuel cost recovery in 807 KAR 5:056, with the only exception then being the sharing of margins on off-system sales.

Q. HOW DOES THE COMPANY PROPOSE TO INCORPORATE THE OFF-SYSTEM SHARING PROVISIONS INCLUDED IN THE COMMISSION'S ORDER IN CASE NO. 2003-00252?

A. As I suggest above, the margins on off-system sales will be included as part of the FAC calculation and the customer share of the margins will be credited against the fuel cost to be recovered from customers. As a result of the recent merger case, the Company implemented Rider PSM – Off-System Sales Profit Sharing Mechanism during 2006. The objective of this Rider is similar to the sharing being proposed in the FAC with slightly different thresholds. The sharing arrangement approved in the merger case ends after 2006. At that point, the provisions of the Order in Case No. 2003-00252 become effective, and we propose to eliminate Rider PSM and share the off-system sales margins through the FAC.

Q. WHY NOT JUST MODIFY THE TERMS OF RIDER PSM AND CONTINUE THIS RIDER AFTER 2006?

A. If the Commission prefers, the Company would be willing to modify and continue the Rider PSM to reflect the provisions of the sharing mechanism that will be applicable after 2006. However, since the calculation of the off-system sales margin eligible for sharing is a product of the FAC process, it seems more appropriate to simplify the process, have one less rider, and still provide the same benefit to customers by including the sharing mechanism in the FAC itself.

Q. HOW WILL THE FAC RELFECT THE OFF-SYSTEM SALES SHARING MECHANISM?

A. The Commission's December 5, 2003 Order in Case No. 2003-00252 approved a proposal for Duke Energy Kentucky to share profits from off-system sales. Under this sharing mechanism, Duke Energy Kentucky will credit customers with 100% of the annual profits on off-system sales up to $1 million. Additionally, Duke Energy Kentucky will share equally with customers the profits for each calendar year on off-system sales in excess of $1 million. Beginning with the FAC filing for January 2007, Duke Energy Kentucky will provide a schedule with its FAC filings, reflecting a credit for profits from off-system sales, consistent with the sharing mechanism. Beginning with off-system sales occurring in each subsequent January, the credit will be re-set to zero and Duke Energy Kentucky will apply the first $1 million in profits from off-system sales to customers for that year. Any over-/under-recovery from the prior year will be passed through in the form of true-ups in future FAC filings.

Q. HOW DOES DUKE ENERGY KENTUCKY PROPOSE TO DETERMINE THE COST OF FUEL ALLOCABLE TO NATIVE VERSUS NON-NATIVE SALES?

A. Duke Energy Kentucky's customers will continue to have "first call" on generation from the Plants. Duke Energy Kentucky will dispatch its resources into the Midwest ISO's Day-Ahead and Real-Time energy markets in a cost-effective manner. After each month, the Company will compare the actual hourly generation and purchased power, from least-cost to highest-cost, to load in the same hour. By "stacking" resources against native- and non-native load, the Company can incrementally assign the lowest cost generation and/or purchased power to native load subject to the reliability constraints that may be required as mentioned above. This process also allows the Company to determine the amount of profits from off-system sales to be credited to customers through the sharing mechanism.

Q. PLEASE DESCRIBE ATTACHMENT WDW-5

A. Attachment WDW-5 is a proposed tariff showing the formula we will apply to calculate the monthly FAC.

V. TRANSMISSION COST RECOVERY MECHANISM

Q. HOW DOES DUKE ENERGY KENTUCKY PROPOSE TO RECOVER TRANSMISSION COSTS?

A. The Company proposes traditional base rate recovery of its projected transmission costs for the forecasted test year. In addition, because of the volatility and magnitude of transmission costs associated with participation in the Midwest ISO Day 2 market, we propose to establish a tracker cost recovery mechanism ("Rider TCRM") to pass through to customers incremental changes in costs compared to the amounts included in base rates.

Q. WHAT TRANSMISSION COSTS ARE INCLUDED IN THE FORECASTED TEST PERIOD?

A. Mr. Swez and Mr. Jett describe the nature of the transmission costs and have provided estimates that were used in the forecast included in this case. As they have described, the Company has and will incur significant expenses as a participant in the Midwest Day 2 markets. While some of the costs are somewhat predictable and stable, certain costs can be quite volatile. For example, some of the administrative costs, such as Schedules 16 and 17, are unlikely to be substantially different than projected and are not expected to fluctuate significantly from month-to-month. Other costs, particularly congestion costs, are more volatile and difficult to forecast.

Q. WHICH COSTS WILL DUKE ENERGY KENTUCKY INCLUDE IN RIDER TCRM?

A. As I stated above, we propose to recover all incremental Midwest ISO transmission costs via a tracking mechanism.

Q. WHY SHOULD ALL INCREMENTAL MIDWEST ISO TRANSMISSION COSTS BE RECOVERED THROUGH RIDER TCRM?

A. Tracking mechanisms are often and appropriately used to pass-through to customers charges or credits for a number of reasons. These transmission costs: (1) cannot be avoided by the utility and are outside the utility's control; (2) can be substantial and (3) are volatile. Because the costs of Duke Energy Kentucky's participation in the Midwest ISO are regulated by the FERC, which has approved the Midwest ISO's rates, the Company cannot avoid these costs. As described by Mr. Swez, congestion costs can be substantial in relation to the rest of the Company's overall operating costs and, lastly, congestion costs can increase or decrease significantly from period to period.

Q. DESCRIBE HOW RIDER TCRM WOULD OPERATE.

A. Attachment WDW-6 is a draft of the tariff we propose. It is analogous to the FAC in that current costs are measured against costs included in base rates. The filing would occur annually to mitigate the volatility of the Midwest ISO's transmission rates. We will true-up the costs and revenue and we propose to establish deferral accounting to track over- and under-recovery of costs.

Q. WILL THE COMPANY PROFIT FROM IMPLEMENTATING THE TRACKER?

A. The Company does not intend to profit from implementing this tracker. Similar to the reasoning behind the FAC, the Company only intends to be made whole for the Midwest ISO's transmission costs that it incurs.

VI. CONCLUSION

Q. WERE SCHEDULES A, B-1, B-5, B-5.1, B-6, B-8, C-1 THROUGH C-2.2, D-1, D-2.1 THROUGH D-2.28, D-2.30 THROUGH D-2.33, D-2.35, F-1 THROUGH F-7, G-1 THROUGH G-3, H, AND K, FR 6(9), 10(8)(A), 10(8)(B), 10(8)(C), 10(8)(F) AND 10(9)(T), AND ATTACHMENTS WDW-1 THROUGH WDW-6 PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, William Don Wathen, Jr., being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Don Wathen

William Don Wathen, Jr., Affiant

Subscribed and sworn to before me by William Don Wathen, Jr. on this 22 day of May 2006.

Anita M. Schafer

NOTARY PUBLIC

My Commission Expires

NOTARY PUBLIC
STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2009

Duke Energy Kentucky
Calculation of Projected Test Year Fuel Cost in Base Rates [a]

	Estimated Actual Cost	Adjustment for Backup Pricing	Recoverable Cost	
Fuel Costs				
East Bend 2	$42,888,860	$0	$42,888,860	
Miami Fort 6	13,945,194	-	13,945,194	
Woodssdale	7,398,465	-	7,398,465	
Total Fossil Fuel Cost	$64,232,519	$0	$64,232,519	
Purchased Power				
Economy Purchases	13,325,740	-	13,325,740	
Cost of Replacement Power for:				
Forced Outages	9,770,528	(5,623,314)	4,147,214	
Planned Outages	15,633,016	(8,414,452)	7,218,564	
Total Purchased Power Cost	$38,729,284	($14,037,766)	$24,691,518	
Total Recoverable Cost of Fuel & Purch Power	$102,961,803	($14,037,766)	$88,924,037	
Credit for Sharing of Margin on Off-System Sales			($2,306,284)	
Estimated Net Fuel Cost for Recovery in Base Rates for Test Year			$86,617,753	
Projected Test Year Retail Sales (metered kWh)			4,006,495,000	kWh
Fuel Cost Recovery included in **base rates (¢/kWh)**			2.1619	¢/kWh

Note: [a] See testimony of Douglas F. Esamann for a detailed discussion of the Back-up Power Agreement.

Duke Energy Kentucky
Calculation of Credit for Margins on Off-System Sales [a]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Revenues	$2,115,048	$2,401,842	$1,214,222	$0	$1,767,968	$1,037,976	$1,098,032	$1,310,849	$1,319,817	$1,894,424	$1,979,954	$1,529,880	$17,670,011
Fuel Cost	1,116,129	1,221,099	648,872	-	1,153,995	781,078	731,902	828,717	961,317	1,255,182	1,261,946	970,336	10,930,572
SO_2	119,371	144,762	70,586	-	131,482	99,203	97,952	119,103	137,471	164,540	182,751	175,027	1,442,247
NO_x	-	-	-	-	16,198	14,854	16,885	23,239	29,525	-	-	-	100,701
MISO Congestion & Loss	79,030	87,745	44,922	-	87,961	56,305	52,452	60,038	70,682	89,613	89,255	66,142	784,144
Other Variable O&M	84,015	92,504	47,207	-	85,615	56,607	53,021	60,846	69,681	89,596	90,628	70,058	799,778
Gross Margin	$716,503	$855,733	$402,634	$0	$292,718	$29,929	$145,819	$218,906	$51,142	$295,493	$355,374	$248,317	$3,612,568

Note: [a] Estimate of 2007 margin on off-system sales is based on Company's production cost model as used in the forecasted test period in the case.

	$2,612,568
	1,306,284
($2,306,284)	2,306,284

KyPSC Ca: 2006-00172
Attachment WDW-2a
Page 1 of 24

Midwest ISO — First Revised Sh ., 1318
FERC Electric Tariff avised Volume No. 1 — .ent O
page 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

CINERGY

Line No.			Total	Allocator		Allocated Amount	
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 157,532,363	
	REVENUE CREDITS	(Note T)					
2	Account No. 454	(page 4, line 34)	224,547	TP	0.95212	213,796	
3	Account No. 456	(page 4, line 37)	33,769,000	TP	0.95212	32,152,246	
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.95212	0	Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	0.95212	0	Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)					32,366,042	
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 125,166,320	
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)		8,336,000	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8			(Note B)		513,000	
10	Plus 12 CP of Network Load not in line 8			(Note C)		0	
11	Less 12 CP of firm P-T-P over one year (enter negative)			(Note D)		-324,000	
12	Plus Contract Demand of firm P-T-P over one year					0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	
15	Divisor (sum lines 8-14)					8,525,000	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	14.682				
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	1.224				
			Peak Rate			Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.282			$0.282	
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.056	Capped at weekly rate		$0.040	
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	3.529	Capped at weekly and daily rates		$1.681	
21	FERC Annual Charge($/MWh)	(Note E)	$0.000 Short Term			$0.000 Short Term	Don't need. Doesn't go anywhere per Jeff Sprague
			$0.000 Long Term			$0.000 Long Term	
22							

RatesJA:\MISO\2004\Attachment WDW-2a (CIN Attachment O May 2005).xls cinergy

KyPSC Case ..o. 2006-00172
Attachment WDW-2a
Page 2 of 24

Midwest ISO
FERC Electric Tariff, T... ..evised Volume No. 1

First Revised Sl 1319

Attachment O
page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	CINERGY (3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	206.46.g	7,011,303,495	NA		
2	Transmission	206.58.g	1,268,750,758	TP	0.95212	1,208,006,933
3	Distribution	206.75.g	3,514,022,272	NA		
4	General & Intangible	206.5.g & 90.g	370,616,418	W/S	0.05687	21,077,158
5	Common	356.1	172,226,147	CE	0.05687	9,794,595
6	TOTAL GROSS PLANT (sum lines 1-5)		12,336,919,090	GP=	10.042%	1,238,878,686
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	3,126,103,088	NA		
8	Transmission	219.25.c	499,485,154	TP	0.95212	475,571,364
9	Distribution	219.26.c	1,279,661,622	NA		
10	General & Intangible	219.27.c	75,105,353	W/S	0.05687	4,271,282
11	Common	356.1	51,628,773	CE	0.05687	2,936,156
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		5,031,983,990			482,778,803
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	3,885,200,407			
14	Transmission	(line 2- line 8)	769,265,604			732,435,569
15	Distribution	(line 3 - line 9)	2,234,360,650			
16	General & Intangible	(line 4 - line 10)	295,511,065			16,805,876
17	Common	(line 5 - line 11)	120,597,374			6,858,438
18	TOTAL NET PLANT (sum lines 13-17)		7,304,935,100	NP=	10.351%	756,099,883
	ADJUSTMENTS TO RATE BASE	(Note F)				
19	Account No. 281 (enter negative)	273.8.k	-17,383,184	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	-1,446,250,898	NP	0.10351	-149,694,709
21	Account No. 283 (enter negative)	277.9.k	-346,204,857	NP	0.10351	-35,834,058
22	Account No. 190	234.8.c	254,328,861	NP	0.10351	26,324,398
23	Account No. 255 (enter negative)	267.8.h	-48,164,768	NP	0.10351	-4,985,311
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-1,603,674,846			-164,189,678
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	215,514	TP	0.95212	205,198
	WORKING CAPITAL (Note H)					
26	CWC	calculated	52,604,722			5,648,565
27	Materials & Supplies (Note G)	227.8.c & .15.c	9,441,588	TE	0.79992	7,552,486
28	Prepayments (Account 165)	110.46.d	32,535,304	GP	0.10042	3,267,209
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		94,581,614			16,468,260
30	RATE BASE (sum lines 18, 24, 25, & 29)		5,796,057,382			608,583,661

Midwest ISO
FERC Electric Tariff, Th... Revised Volume No. 1

First Revised S 1320

Attachment O
page 3 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	CINERGY (3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.100.b	71,581,678	TE	0.79992	57,259,393
2	Less Account 565	321.88.b	33,858,827		1.00000	33,858,827
3	A&G	323.168.b	391,710,202	W/S	0.05687	22,276,773
4	Less FERC Annual Fees		389,255	W/S	0.05687	22,137
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		8,206,023	W/S	0.05687	466,681
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.79992	0
6	Common	356.1	0	CE	0.05687	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		420,837,775			45,188,520
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	26,017,212	TP	0.95212	24,771,589
10	General	336.9.b	6,425,428	W/S	0.05687	365,418
11	Common	336.10.b	1,627,992	CE	0.05687	92,585
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		34,070,632			25,229,592
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	18,912,048	W/S	0.05687	1,075,538
14	Highway and vehicle	263.i	92,670	W/S	0.05687	5,270
	PLANT RELATED					
15	Property	263.i	86,782,239	GP	0.10042	8,714,710
16	Gross Receipts	263.i	20,056,418	NA	zero	0
17	Other	263.i	150,000	GP	0.10042	15,063
18	Payments in lieu of taxes		4,125	GP	0.10042	414
19	TOTAL OTHER TAXES (sum lines 13 - 19)		125,997,500			9,810,995
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.91%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		46.25%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.6641			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		232,818,345	NA		24,445,831
26	ITC adjustment (line 23 * line 24)		0	NP	0.10351	0
27	Total Income Taxes	(line 25 plus line 26)	232,818,345			24,445,831
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		503,405,993	NA		52,857,424
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		1,317,130,245			157,532,383

Midwest ISO
FERC Electric Tarif. ...evised Volume No. 1

First Revised S... 1321
...ment O
page 4 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

CINERGY
SUPPORTING CALCULATIONS AND NOTES

Line No.				
	TRANSMISSION PLANT INCLUDED IN ISO RATES			
1	Total transmission plant (page 2, line 2, column 3)			1,268,750,758
2	Less transmission plant excluded from ISO rates (Note M)			0
3	Less transmission plant included in OATT Ancillary Services (Note N)			60,743,825
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)			1,208,006,933
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)		TP=	0.95212
	TRANSMISSION EXPENSES			
6	Total transmission expenses (page 3, line 1, column 3)			71,581,678
7	Less transmission expenses included in OATT Ancillary Services (Note L)			11,443,035
8	Included transmission expenses (line 6 less line 7)			60,138,643
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)			0.84014
10	Percentage of transmission plant included in ISO Rates (line 5)		TP	0.95212
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)		TE=	0.79992

	Schedule 1 Recoverable Expenses
11,443,035	Acct 561 included in Line 13?
	Revenue Credits for Sched 1/Acct 561
1,466,433	*transactions <1 yr*
0	non-firm
0	transactions w/ load not in divisor
$1,466,433	total Revenue Credits
$9,976,602	Net Schedule 1 Expenses (Acct 561 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	*Production*	354.18.b	121,278,122	0.00	0			
13	Transmission	354.19.b	12,735,873	0.95	12,126,119			
14	Distribution	354.20.b	44,970,185	0.00	0			
15	Other	354.21,22,23.b	34,239,010	0.00	0			
16	Total *(sum lines 12-15)*		213,223,190		12,126,119	=	0.05687	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	11,016,562,978	1.00000	*	0.05687	=	0.05687
18	Gas	201.3.d	0					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		11,016,562,978					

RETURN (R)

Line		$
21	Long Term Interest (117, sum of 58c through 63c)	$195,770,834
22	Preferred Dividends (118.29c) (positive number)	$ 3,432,374
	Development of Common Stock:	
23	Proprietary Capital (112.15d)	3,855,239,780
24	Less Preferred Stock (line 28)	-62,818,000
25	Less Account 216.1 *(112.12d) (enter negative)*	-192,680,058
26	Common Stock (sum lines 23-25)	3,599,741,722

Line		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 17d through 20d)	*3,762,053,412*	*51%*	*0.0520*	0.0264	=WCLTD
28	Preferred Stock (112.3d)	62,818,000	1%	0.0548	0.0005	
29	Common Stock (line 26)	3,599,741,722	48%	0.1238	0.0600	
30	Total (sum lines 27-29)	7,424,613,134			0.0869	=R

REVENUE CREDITS

Line				Load	
	ACCOUNT 447 (SALES FOR RESALE)	*(310-311)*	*(Note Q)*		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0	
32	b. Bundled Sales for Resale included in Divisor on page 1			0	
33	Total of (a)-(b)			0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$224,547	Line 34 supported by notes in Form 1 or detailed Schedule
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)			
35	a. Transmission charges *for all transmission transactions*			$58,851,000	Line 35 supported by notes in Form 1 or detailed Schedule
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$25,082,000	Line 36 supported by *notes in Form 1 or detailed Schedule*
37	Total of (a)-(b)			$33,769,000	

Formula Rate - Non-Levelized — Rate Formula Template Utilizing FERC Form 1 Data — *For the 12 months ended 12/31/04*

CINERGY

General Note: *References to pages in this formulary rate are indicated as:* (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, *as adjusted by any amounts in contra accounts* identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of *tax credits against taxable income* as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	*Cash Working Capital assigned* to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100 line 46 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to *transmission service*, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other *assessments charged in the current year.* Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of *federal income tax deductible for state income taxes*". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that *elected to utilize amortization* of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:				
	FIT =	35.00%		
	SIT=	7.55%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax *deductible for state purposes*)	

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be *state-jurisdictional according to the seven-factor* test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included *in the development* of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up *facilities are those facilities at a generator* substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	*Debt cost rate* = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected *in* Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, *rentals and special use.*
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are *included in line 13, page 1. Grandfathered* agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	*The revenues* credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. *They do not include* revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered *under this Rate Formula Template.*

Midwest ISO
FERC Electric Tarif[illegible] [illegible]evised Volume No. 1

First Revised S[illegible] [illegible]. 1318
[illegible]ent O
[illegible] 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

PSI ENERGY, INC.

Line No.			Total	Allocator		Allocated Amount		
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 92,913,459		
	REVENUE CREDITS	(Note T)						
2	Account No. 454	(page 4, line 34)	64,000	TP	0.95483	61,109		
3	Account No. 456	(page 4, line 37)	15,182,000	TP	0.95483	14,496,272		
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.95483	0		Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	0.95483	0		Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)					14,557,382		
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 78,356,077	12CP	
							5113	
							4803	
	DIVISOR						4220	
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	4,954,000	4001	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	0	5028	
10	Plus 12 CP of Network Load not in line 8				(Note C)	0	5400	
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	-324,000	5660	
12	Plus Contract Demand of firm P-T-P over one year					0	5618	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	5030	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	3923	
15	Divisor (sum lines 8-14)					4,630,000	4204	
							4954	
							4830	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	16.924					
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	1.410					
			Peak Rate			Off-Peak Rate		
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.325			$0.325		
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.065	Capped at weekly rate		$0.046		
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	4.068	Capped at weekly and daily rates		$1.937		
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term		$0.000	Short Term	Don't need. Doesn't go anywhere per Jeff Sprague
22			$0.000	Long Term		$0.000	Long Term	

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

First Revised Sh. 1319
Attachment O
page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

PSI ENERGY, INC.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)		
	RATE BASE:							
	GROSS PLANT IN SERVICE							
1	Production	206.46.g	3,532,021,700	NA				
2	Transmission	206.58.g	771,076,088	TP	0.95483	736,248,785		
3	Distribution	206.75.g	1,794,502,961	NA				
4	General & Intangible	206.5.g & 90.g	288,792,988	W/S	0.06524	18,841,246		
5	Common	356.1	0	CE	0.06524	0		
6	TOTAL GROSS PLANT (sum lines 1-5)		6,386,393,737	GP=	11.823%	755,090,031		
	ACCUMULATED DEPRECIATION							
7	Production	219.20-24.c	1,522,638,424	NA				
8	Transmission	219.25.c	314,847,677	TP	0.95483	300,626,907		
9	Distribution	219.26.c	690,804,758	NA				
10	General & Intangible	219.27.c	63,228,367	W/S	0.06524	4,125,104		
11	Common	356.1	0	CE	0.06524	0		
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,591,519,226			304,752,012		
	NET PLANT IN SERVICE							
13	Production	(line 1- line 7)	2,009,383,276					
14	Transmission	(line 2- line 8)	456,228,411			435,621,878		
15	Distribution	(line 3 - line 9)	1,103,698,203					
16	General & Intangible	(line 4 - line 10)	225,564,621			14,716,142		
17	Common	(line 5 - line 11)	0			0		
18	TOTAL NET PLANT (sum lines 13-17)		3,794,874,511	NP=	11.867%	450,338,019		
	ADJUSTMENTS TO RATE BASE	(Note F)						
19	Account No. 281 (enter negative)	273.8.k	-17,383,184	NA	zero	0		
20	Account No. 282 (enter negative)	275.2.k	-695,722,120	NP	0.11867	-82,561,392	695,722,120	
21	Account No. 283 (enter negative)	277.9.k	-147,284,831	NP	0.11867	-17,478,301		
22	Account No. 190	234.8.c	168,894,706	NP	0.11867	20,042,746	168,894,706	
23	Account No. 255 (enter negative)	267.8.h	-26,602,998	NP	0.11867	-3,156,980		
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-718,098,427			-83,153,926		
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	89,742	TP	0.95483	85,689	151,595	
	WORKING CAPITAL (Note H)							
26	CWC	calculated	28,030,039			3,594,092		
27	Materials & Supplies (Note G)	227.8.c & .15.c	6,203,893	TE	0.70410	4,368,181	2,795,146	will change Form 1
28	Prepayments (Account 165)	~~110.46.d~~ 111.57.c	4,061,393	GP	0.11823	480,195		
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		38,295,325			8,442,468		
30	RATE BASE (sum lines 18, 24, 25, & 29)		3,115,161,151			375,712,250		

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

First Revised Sheet No. 1320
Attachment O
page 3 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

PSI ENERGY, INC.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) *Company Total*	(4) Allocator		(5) Transmission (Col 3 times Col 4)		
	O&M							
1	*Transmission*	321.100.b	27,939,460	TE	0.70410	19,672,264		
2	Less Account 565	321.88.b	3,988,552		1.00000	*3,988,552*		
3	A&G	323.168.b	204,790,884	W/S	0.06524	13,360,835		
4	Less FERC Annual Fees		484,099	W/S	0.06524	31,583	1,969,146	FERC fee paid through MISO, on line 5
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		*4,019,384*	W/S	0.06524	262,230		
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.70410	0		this is FERC assessment coming through *MISO*
6	Common	356.1	0	CE	0.06524	0		
7	*Transmission Lease Payments*		0		1.00000	0		
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		224,240,309			*28,752,733*		
	DEPRECIATION EXPENSE							
9	Transmission	336.7.b	16,530,676	TP	0.95483	15,784,224		
10	General	336.9.b	6,071,613	W/S	0.06524	396,120		
11	Common	336.10.b	0	CE	0.06524	0		
12	TOTAL DEPRECIATION *(Sum lines 9 - 11)*		22,602,489			16,180,344		
	TAXES OTHER THAN INCOME TAXES (Note J)							
	LABOR RELATED							
13	Payroll	263.i	9,690,321	W/S	0.06524	632,210	9,566,188	263.5.i Fed income contribution sounds like income tax
14	Highway and vehicle	263.i	22,794	W/S	0.06524	1,487		
15	PLANT RELATED							
16	Property	*263.i*	16,926,555	GP	0.11823	2,001,297		
17	Gross Receipts	263.i	18,828,756	NA	zero	0		
18	Other	263.i	150,000	GP	0.11823	17,735		
19	Payments in lieu of taxes		1,575	GP	0.11823	186		
20	TOTAL OTHER TAXES (sum lines 13 - 19)		45,620,001			2,652,915		
	INCOME TAXES *(Note K)*							
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.33%					
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		46.07%					
	where WCLTD=(page 4, line 27) and R= (page 4, line30)							
	and FIT, SIT & p are as given in footnote K.							
23	1 / (1 - T) = (from line 21)		1.6759					
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0					exclud this amount included in Account 255 on row 97
25	Income Tax Calculation = line 22 * line 28		118,530,228	NA		14,295,652		
26	ITC adjustment (line 23 * line 24)		0	NP	0.11867	0		
27	*Total Income Taxes*	(line 25 plus line 26)	118,530,228			14,295,652		
28	RETURN		257,295,586	NA		31,031,815		
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]							
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		668,288,614			92,913,459		

Midwest ISO
FERC Electric Tariff, ... Revised Volume No. 1

First Revised Sl... 1321
... ment O
page 4 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

PSI ENERGY, INC.
SUPPORTING CALCULATIONS AND NOTES

Line No.					
	TRANSMISSION PLANT INCLUDED IN ISO RATES				
1	Total transmission plant (page 2, line 2, column 3)			771,076,088	
2	Less transmission plant excluded from ISO rates (Note M)			0	
3	Less transmission plant included in OATT Ancillary Services (Note N)			34,827,303	
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)			736,248,785	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)		TP=	0.95483	
	TRANSMISSION EXPENSES				
6	Total transmission expenses (page 3, line 1, column 3)			27,939,460	
7	Less transmission expenses included in OATT Ancillary Services (Note L) (page 321, line 84, column (b))			7,336,625	
8	Included transmission expenses (line 6 less line 7)			20,602,835	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)			0.73741	
10	Percentage of transmission plant included in ISO Rates (line 5)		TP	0.95483	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)		TE=	0.70410	

Schedule 1 Recoverable Expenses

	7,336,625	Acct 561 included in Line 13?
		Revenue Credits for Sched 1/Acct 561
Sch. 1 CPMT & NonCPMT	511,249	transactions <1 yr
	0	non-firm
	0	transactions w/ load not in divisor
	$511,249	total Revenue Credits
	$6,825,376	Net Schedule 1 Expenses (Acct 561 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		
12	Production	354.18.b	64,299,460	0.00	0		
13	Transmission	354.19.b	7,552,667	0.95	7,211,535		W&S Allocator
14	Distribution	354.20.b	22,153,887	0.00	0		($ / Allocation)
15	Other	354.21,22,23.b	16,530,234	0.00	0		
16	Total (sum lines 12-15)		110,536,248		7,211,535	=	0.06524 = WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)	W&S Allocator (line 16)		CE
17	Electric	200.3.c	5,728,790,375	1.00000 *	0.06524	=	0.06524
18	Gas	201.3.d	0				
19	Water	201.3.e	0				
20	Total (sum lines 17 - 19)		5,728,790,375				

RETURN (R)

Line No.				$	
21	Long Term Interest (117, sum of 62c through ~~66c~~ 67c)			$98,437,979	2,131,001 Acct 430
22	Preferred Dividends (118.29c) (positive number)			$ 2,586,717	
	Development of Common Stock:				
23	Proprietary Capital (112.16c)			1,723,530,361	
24	Less Preferred Stock (line 28)			-42,333,100	
25	Less Account 216.1 (112.12d c) (enter negative)			0	
26	Common Stock	(sum lines 23-25)		1,681,197,261	

Line No.		$	%	Cost (Note P)	Weighted		
27	Long Term Debt (112, sum of ~~17d~~ 18c through ~~20d~~ 21c)	2,019,532,749	54%	0.0487	0.0263	=WCLTD	
28	Preferred Stock (112.3d)	42,333,100	1%	0.0611	0.0007		
29	Common Stock (line 26)	1,681,197,261	45%	0.1238	0.0556		12.38 ordered Cinergy Return on Equity approved by FERC will not change until a filing is made with FERC to do s
30	Total (sum lines 27-29)	3,743,063,110			0.0826	=R	

REVENUE CREDITS

Line No.				Load	
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0	
32	b. Bundled Sales for Resale included in Divisor on page 1			0	
33	Total of (a)-(b)			0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$64,000	Line 34 supported by notes in Form 1 or detailed Schedule
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)			
35	a. Transmission charges for all transmission transactions			$22,136,000	Line 35 supported by notes in Form 1 or detailed Schedule
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$6,954,000	Line 36 supported by notes in Form 1 or detailed Schedule
37	Total of (a)-(b)			$15,182,000	

Formula Rate - Non-Levelized | Rate Formula Template *Utilizing FERC Form 1 Data* | For the 12 months ended 12/31/04

PSI ENERGY, INC.

General Note: References to pages in this formulary rate are indicated as: *(page#, line#, col.#)*
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100 line 46 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:				
	FIT =	35.00%		
	SIT=	8.20%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use. (Statement AU)
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Midwest ISO
FERC Electric Tariff, ʼised Volume No. 1

KyPSC Case No. 2 00172
Attachment WDW-2a
Page 11 of 24

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

THE CINCINNATI GAS & ELECTRIC COMPANY

Line No.			Total	Allocator		Allocated Amount	12CP	
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 59,864,451		
	REVENUE CREDITS	(Note T)						
2	Account No. 454	(page 4, line 34)	127,000	TP	0.94562	120,094		
3	Account No. 456	(page 4, line 37)	18,424,000	TP	0.94562	17,422,088		Line 4 supported by schedules.
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.94562	0		Line 5 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	0.94562	0		
6	TOTAL REVENUE CREDITS (sum lines 2-5)					17,542,182		
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 42,322,269	2,860	
							2,600	
							2,457	
	DIVISOR			(Note A)			2,337	Line 8 supported with monthly CP and associated net energy.
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)		2,722,000	2,041	
9	Plus 12 CP of firm bundled sales over one year not in line 8			(Note B)		513,000	3,355	
10	Plus 12 CP of Network Load not in line 8			(Note C)		0	3,478	
11	Less 12 CP of firm P-T-P over one year (enter negative)			(Note D)		0	3,453	
12	Plus Contract Demand of firm P-T-P over one year					0	3,019	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	2,307	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	2,503	
15	Divisor (sum lines 8-14)					3,235,000	2,255	
							2,722	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	13.083					
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	1.090					
			Peak Rate			Off-Peak Rate		
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.252			$0.252		
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.050	Capped at weekly rate		$0.036		
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	3.145	Capped at weekly and daily rates		$1.498		
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term		$0.000 Short Term		
			$0.000	Long Term		$0.000 Long Term		
22								

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

0
Attachment O
page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

THE CINCINNATI GAS & ELECTRIC COMPANY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	
	RATE BASE:						
	GROSS PLANT IN SERVICE						
1	Production	206.46.g	3,479,281,795	NA			
2	Transmission	206.58.g	476,574,799	TP	0.94562	450,658,277	
3	Distribution	206.75.g	1,457,510,198	NA			
4	General & Intangible	206.5.g & 90.g	79,104,088	W/S	0.04696	3,714,997	
5	Common	356.1	156,785,840	CE	0.04696	7,363,196	
6	TOTAL GROSS PLANT (sum lines 1-5)		5,649,256,720	GP=	8.173%	461,736,470	
	ACCUMULATED DEPRECIATION						
7	Production	219.20-24.c	1,603,464,684	NA			
8	Transmission	219.25.c	175,754,459	TP	0.94562	166,196,790	
9	Distribution	219.26.c	488,602,361	NA			
10	General & Intangible	219.27.c	11,727,284	W/S	0.04696	550,754	
11	Common	356.1	45,749,087	CE	0.04696	2,148,533	
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,325,297,865			168,896,076	
	NET PLANT IN SERVICE						
13	Production	(line 1- line 7)	1,875,817,131				
14	Transmission	(line 2- line 8)	300,820,340			284,461,487	
15	Distribution	(line 3 - line 9)	968,907,837				
16	General & Intangible	(line 4 - line 10)	67,376,794			3,164,243	
17	Common	(line 5 - line 11)	111,036,753			5,214,663	
18	TOTAL NET PLANT (sum lines 13-17)		3,323,958,855	NP=	8.810%	292,840,394	
	ADJUSTMENTS TO RATE BASE	(Note F)					
19	Account No. 281 (enter negative)	273.8.k	0	NA	zero	0	
20	Account No. 282 (enter negative)	275.2.k	-729,961,269	NP	0.08810	-64,309,504	779,095,463
21	Account No. 283 (enter negative)	277.9.k	-197,733,635	NP	0.08810	-17,420,311	
22	Account No. 190	234.8.c	81,967,398	NP	0.08810	7,221,318	88,137,130
23	Account No. 255 (enter negative)	267.8.h	-20,448,702	NP	0.08810	-1,801,528	
24	TOTAL ADJUSTMENTS (sum lines 19-23)		-866,176,208			-76,310,025	
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	125,772	TP	0.94562	118,932	
	WORKING CAPITAL (Note H)						
26	CWC	calculated	23,290,560			2,005,173	
27	Materials & Supplies (Note G)	227.8.c & .15.c	3,219,100	TE	0.83900	2,700,818	3,443,847
28	Prepayments (Account 165)	111.57.c	28,189,141	GP	0.08173	2,304,012	
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		54,698,801			7,010,003	
30	RATE BASE (sum lines 18, 24, 25, & 29)		2,512,607,220			223,659,305	

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

0
Attachment O
page 3 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

THE CINCINNATI GAS & ELECTRIC COMPANY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	
	O&M						
1	Transmission	321.100.b	27,602,354	TE	0.83900	23,158,320	
2	Less Account 565	321.88.b	15,289,094		1.00000	15,289,094	
3	A&G	323.168.b	177,461,933	W/S	0.04696	8,334,216	1,249,854 Fee paid through MISO, in line 5
4	Less FERC Annual Fees		-358,241	W/S	0.04696	-16,824	
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		3,808,957	W/S	0.04696	178,882	this is FERC assessment coming through MISO
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.83900	0	
6	Common	356.1	0	CE	0.04696	0	
7	Transmission Lease Payments		0		1.00000	0	
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		186,324,477			16,041,384	
	DEPRECIATION EXPENSE						
9	Transmission	336.7.b	8,832,591	TP	0.94562	8,352,268	
10	General	336.9.b	347,150	W/S	0.04696	16,303	
11	Common	336.10.b	1,434,363	CE	0.04696	67,363	
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		10,614,104			8,435,933	
	TAXES OTHER THAN INCOME TAXES (Note J)						
	LABOR RELATED						
13	Payroll	263.i	8,806,280	W/S	0.04696	413,573	
14	Highway and vehicle	263.i	61,164	W/S	0.04696	2,872	
15	PLANT RELATED						
16	Property	263.i	68,549,510	GP	0.08173	5,602,827	70,649,278 excise tax 263.24.i (not transmission related)
17	Gross Receipts	263.i	1,227,662	NA	zero	0	499 excise tax 263.13.i
18	Other	263.i	0	GP	0.08173	0	
19	Payments in lieu of taxes		2,550	GP	0.08173	208	
20	TOTAL OTHER TAXES (sum lines 13 - 19)		78,647,166			6,019,481	
	INCOME TAXES	(Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.23%				
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		45.07%				
	where WCLTD=(page 4, line 27) and R= (page 4, line30)						
	and FIT, SIT & p are as given in footnote K.						
23	1 / (1 - T) = (from line 21)		1.6454				
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0				exclud this amount included in Account 255 on row 97
25	Income Tax Calculation = line 22 * line 28		102,501,649	NA		9,124,167	
26	ITC adjustment (line 23 * line 24)		0	NP	0.08810	0	
27	Total Income Taxes	(line 25 plus line 26)	102,501,649			9,124,167	
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		227,416,997	NA		20,243,485	
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		605,504,392			59,864,451	

Midwest ISO
FERC Electric Tariff, 1. .evised Volume No. 1

Al. .nt O
page 4 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

THE CINCINNATI GAS & ELECTRIC COMPANY
SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		476,574,799
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		25,916,522
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		450,658,277
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.94562

Year End Bulk/Common Split

Line No.	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		27,602,354
7	Less transmission expenses included in OATT Ancillary Services (Note L) (page 321, line 84, column (b))		3,112,242
8	Included transmission expenses (line 6 less line 7)		24,490,112
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.88725
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.94562
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.83900

Schedule 1 Recoverable Expenses

3,112,242	Acct 561 included in Line 13?
	Revenue Credits for Sched 1/Acct 561
955,184	transactions <1 yr
0	non-firm
0	transactions w/ load not in divisor
$955,184	total Revenue Credits
$2,157,058	Net Schedule 1 Expenses (Acct 561 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)		
12	Production	354.18.b	56,978,624	0.00	0				
13	Transmission	354.19.b	4,831,902	0.95	4,569,139				
14	Distribution	354.20.b	20,457,040	0.00	0				
15	Other	354.21,22,23.b	15,023,927	0.00	0				
16	Total (sum lines 12-15)		97,291,493		4,569,139	=	0.04696	=	WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE	
17	Electric	200.3.c	5,037,341,216	1.00000	*	0.04696	=	0.04696	680,359,814
18	Gas	201.3.d	0						
19	Water	201.3.e	0						
20	Total (sum lines 17 - 19)		5,037,341,216						

RETURN (R)

Line No.		$	
21	Long Term Interest (117, sum of 62c through ~~66c~~ 67c)	$92,667,140	2,552,559 Acct 430
22	Preferred Dividends (118.29c) (positive number)	$ 845,657	

Development of Common Stock:

Line No.			
23	Proprietary Capital (112.16c)		1,939,197,572
24	Less Preferred Stock (line 28)		-20,484,900
25	Less Account 216.1 (112.12c)	(enter negative)	-192,680,058
26	Common Stock	(sum lines 23-25)	1,726,032,614

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of ~~47c~~ 18c through ~~20c~~ 21c)	1,647,520,663	49%	0.0562	0.0273 =WCLTD	
28	Preferred Stock (112.3c)	20,484,900	1%	0.0413	0.0002	
29	Common Stock (line 26)	1,726,032,614	51%	0.1238	0.0630	12.38 ordered
30	Total (sum lines 27-29)	3,394,038,177			0.0905 =R	

REVENUE CREDITS

Line No.				Load	
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0	
32	b. Bundled Sales for Resale included in Divisor on page 1			0	
33	Total of (a)-(b)			0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	(Note R)		$127,000	Line 34 supported by notes in Form 1 or detailed Schedule
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)			
35	a. Transmission charges for all transmission transactions			$36,552,000	Line 35 supported by notes in Form 1 or detailed Schedule
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$18,128,000	Line 36 supported by notes in Form 1 or detailed Schedule
37	Total of (a)-(b)			$18,424,000	

Midwest ISO
FERC Electric Tariff, .evised Volume No. 1

0
A .nt O
page 5 of 5

Formula Rate - Non-Levelized — Rate Formula Template Utilizing FERC Form 1 Data — For the 12 months ended 12/31/04

THE CINCINNATI GAS & ELECTRIC COMPANY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 *are indicated as: #.y.x (page, line, column)*

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the *ISO coincident monthly peaks.*
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any *amounts in contra accounts identified* as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as *discussed in Note K. Account 281 is not allocated.*
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to *transmission at page 3, line 8, column 5.* Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100 line 46 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses *itemized at 351.h, and non-safety* related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the *Rate Formula Template, since they are recovered elsewhere.*
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = *"the percentage of* federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that *elected to utilize amortization of* tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by *(1/1-T) (page 3, line 26).*

Inputs Required:	FIT =	35.00%		
	SIT=	6.50%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L	Removes *dollar amount of transmission expenses included in the* OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to *reflect application of seven-factor test).*
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are *deemed to included in OATT ancillary services. For these purposes*, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original *filing and no change in ROE may be made absent* a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled *and the transmission component reflected in* Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates *have not been changed to eliminate or mitigate* pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall *include only the amounts received directly (in the case of* grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

KyPSC Case No. 2006-00172
Attachment WDW-2a
Page 16 of 24

Midwest ISO
FERC Electric Tariff, vised Volume No. 1

Att: 0
p. 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

THE UNION LIGHT HEAT AND POWER COMPANY

Line No.			Total		Allocator		Allocated Amount		12CP	
1	GROSS REVENUE REQUIREMENT	*(page 3, line 29)*					$ 3,661,243			
	REVENUE CREDITS	(Note T)								
2	Account No. 454	(page 4, line 34)	33,547		TP	1.00000	33,547			
3	Account No. 456	(page 4, line 37)	163,000		TP	1.00000	163,000			
4	Revenues from Grandfathered Interzonal Transactions		0		TP	1.00000	0			Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0		TP	1.00000	0			Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)						196,547			
									12CP	
7	*NET REVENUE REQUIREMENT*	(line 1 minus line 6)					$ 3,464,696		644	
									609	
									571	
	DIVISOR								541	
8	Average of 12 coincident system *peaks for requirements (RQ) service*					(Note A)	660,000		694	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8					(Note B)	0		762	
10	Plus 12 CP of Network Load not in line 8					(Note C)	0		814	
11	Less 12 CP of firm P-T-P over one year (enter negative)					(Note D)	0		809	
12	Plus Contract Demand of firm P-T-P over one year						0		734	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)						0		510	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)						0		558	
15	*Divisor* (sum lines 8-14)						660,000		671	
									660	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	5.250							
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	0.437							
			Peak Rate				Off-Peak Rate			
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.101				$0.101			
19	Point-To-Point Rate ($/kW/Day)	*(line 18 / 5; line 18 / 7)*	0.020	Capped at weekly rate			$0.014			
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	1.262	Capped at weekly and daily rates			$0.601			
21	FERC Annual Charge($/MWh)	(Note E)	*$0.000*	*Short Term*			$0.000	Short Term		
22			$0.000	Long Term			$0.000	Long Term		

Midwest ISO
FERC Electric Tariff, vised Volume No. 1

Atte 0
p. 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

THE UNION LIGHT HEAT AND POWER COMPANY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	
	RATE BASE:						
	GROSS PLANT IN SERVICE						
1	Production	206.46.g	0	NA			
2	Transmission	206.58.g	21,099,871	TP	1.00000	21,099,871	
3	Distribution	206.75.g	262,009,113	NA			
4	General & Intangible	206.5.g & 90.g	2,719,342	W/S	0.06511	177,060	
5	Common	356.1	15,440,307	CE	0.06511	1,005,336	
6	TOTAL GROSS PLANT (sum lines 1-5)		301,268,633	GP=	7.396%	22,282,267	
	ACCUMULATED DEPRECIATION						
7	Production	219.20-24.c	0	NA			
8	Transmission	219.25.c	8,883,018	TP	1.00000	8,883,018	
9	*Distribution*	219.26.c	100,254,503	NA			
10	General & Intangible	219.27.c	149,692	W/S	0.06511	9,747	
11	Common	356.1	5,879,686	CE	0.06511	382,833	
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		115,166,899			9,275,598	
	NET PLANT IN SERVICE						
13	Production	*(line 1- line 7)*	0				
14	Transmission	(line 2- line 8)	12,216,853			12,216,853	
15	Distribution	(line 3 - line 9)	161,754,610				
16	General & Intangible	(line 4 - line 10)	2,569,650			167,313	
17	Common	(line 5 - line 11)	9,560,621			622,503	
18	TOTAL NET PLANT (sum lines 13-17)		186,101,734	NP=	6.989%	13,006,669	
	ADJUSTMENTS TO RATE BASE	(Note F)					
19	Account No. 281 (enter negative)	273.8.k	0	NA	zero	0	
20	Account No. 282 (enter negative)	275.2.k	-20,567,509	NP	0.06989	-1,437,465	20,567,509
21	Account No. 283 (enter negative)	277.9.k	-1,186,391	NP	0.06989	-82,917	
22	*Account No. 190*	234.8.c	3,466,757	NP	0.06989	242,292	3,607,441 confirm sign of adjustment
23	Account No. 255 (enter negative)	267.8.h	-1,113,068	NP	0.06989	-77,792	
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-19,400,211			-1,355,883	
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	TP	1.00000	0	
	WORKING CAPITAL (Note H)						
26	CWC	calculated	1,284,124			129,569	
27	Materials & Supplies (Note G)	227.8.c & .15.c	18,595	TE	0.93802	17,442	
28	Prepayments (Account 165)	111.57.c	284,770	GP	0.07396	21,062	
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		1,587,489			168,074	
30	RATE BASE (sum lines 18, 24, 25, & 29)		168,289,012			11,818,860	

KyPSC Case No. . -00172
Attachment WDW-2a
Page 18 of 24

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

0
Attachment O
page 3 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

THE UNION LIGHT HEAT AND POWER COMPANY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	
	O&M						
1	Transmission	321.100.b	16,039,864	TE	0.93802	15,045,696	
2	Less Account 565	321.88.b	*14,583,181*		1.00000	14,583,181	
3	A&G	323.168.b	9,457,385	W/S	0.06511	615,781	
4	Less FERC Annual Fees		263,397	W/S	0.06511	17,150	261,561 FERC fee missing
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		377,682	W/S	0.06511	24,591	this is FERC assessment coming through MISO
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.93802	0	
6	*Common*	*356.1*	0	CE	0.06511	0	
7	Transmission Lease Payments		0		1.00000	0	
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		10,272,989			1,036,555	
	DEPRECIATION EXPENSE						
9	Transmission	336.7.b	653,745	TP	1.00000	653,745	
10	General	336.9.b	6,665	W/S	*0.06511*	434	
11	Common	336.10.b	193,629	CE	0.06511	12,607	
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		854,039			666,786	
	TAXES OTHER THAN INCOME TAXES (Note J)						
	LABOR RELATED						
13	Payroll	263.i	415,447	W/S	0.06511	27,050	
14	Highway and vehicle	263.i	8,712	W/S	0.06511	567	
15	PLANT RELATED						
16	Property	263.i	1,306,174	GP	0.07396	96,607	
17	*Gross Receipts*	*263.i*	0	NA	zero	0	
18	Other	263.i	0	GP	0.07396	0	
19	Payments in lieu of taxes		0	GP	0.07396	0	
20	TOTAL OTHER TAXES (sum lines 13 - 19)		1,730,333			124,224	
	INCOME TAXES	(Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.33%				
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		56.52%				
	where WCLTD=(page 4, line 27) and R= (page 4, line30)						
	and FIT, SIT & p are as given in footnote K.						
23	1 / (1 - T) = (from line 21)		*1.6759*				
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0				*exclud this amount included in Account 255 on row 97*
25	Income Tax Calculation = line 22 * line 28		9,428,667	NA		662,171	
26	ITC adjustment (line 23 * line 24)		0	NP	0.06989	0	
27	*Total Income Taxes*	*(line 25 plus line 26)*	9,428,667			662,171	
28	RETURN		16,681,104	NA		1,171,506	
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]						
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		38,967,132			3,661,243	

Midwest ISO | Att: O
FERC Electric Tariff ... vised Volume No. 1 | p. 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

THE UNION LIGHT HEAT AND POWER COMPANY
SUPPORTING CALCULATIONS AND NOTES

Line No.					
	TRANSMISSION PLANT INCLUDED IN ISO RATES				
1	Total transmission plant (page 2, line 2, column 3)			21,099,871	
2	Less transmission plant excluded from ISO rates (Note M)			0	
3	Less transmission plant included in OATT Ancillary Services (Note N)			0	
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)			21,099,871	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)		TP=	1.00000	
	TRANSMISSION EXPENSES				
6	Total transmission expenses (page 3, line 1, column 3)			16,039,864	
7	Less transmission expenses included in OATT Ancillary Services (Note L) (page 321, line 84, column (b))			994,168	
8	Included transmission expenses (line 6 less line 7)			15,045,696	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)			0.93802	
10	Percentage of transmission plant included in ISO Rates (line 5)		TP	1.00000	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)		TE=	0.93802	

Schedule 1 Recoverable Expenses

994,168	Acct 561 included in Line 13?
	Revenue Credits for Sched 1/Acct 561
0	transactions <1 yr
0	non-firm
0	transactions w/ load not in divisor
$0	total Revenue Credits
$994,168	Net Schedule 1 Expenses (Acct 561 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.18.b	38	0.00	0			
13	Transmission	354.19.b	351,304	1.00	351,304			
14	Distribution	354.20.b	2,359,258	0.00	0			
15	Other	354.21,22,23.b	2,684,849	0.00	0			
16	Total (sum lines 12-15)		5,395,449		351,304	=	0.06511	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	250,431,387	1.00000	*	0.06511	=	0.06511
18	Gas	201.3.d	0					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		250,431,387					

RETURN (R)

Line No.		$	
21	Long Term Interest (117, sum of 62c through ~~66c~~ 67c)	$4,665,715	267,806 Acct 430
22	Preferred Dividends (118.29c) (positive number)	0	
	Development of Common Stock:		
23	Proprietary Capital (112.16c)	192,511,847	
24	Less Preferred Stock (line 28)	0	
25	Less Account 216.1 (112.12d c) (enter negative)	0	
26	Common Stock (sum lines 23-25)	192,511,847	

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of ~~17d~~ 18c through ~~20d~~ 21c)	95,000,000	33%	0.0491	0.0162	=WCLTD
28	Preferred Stock (112.3d)	0	0%	0.0000	0.0000	
29	Common Stock (line 26)	192,511,847	67%	0.1238	0.0829	12.38 ordered
30	Total (sum lines 27-29)	287,511,847			0.0991	=R

REVENUE CREDITS

Line No.				Load	
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0	
32	b. Bundled Sales for Resale included in Divisor on page 1			0	
33	Total of (a)-(b)			0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	(Note R)		$33,547	Line 34 supported by notes in Form 1 or detailed Schedule
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)			
35	a. Transmission charges for all transmission transactions			$163,000	Line 35 supported by notes in Form 1 or detailed Schedule
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$0	Line 36 supported by notes in Form 1 or detailed Schedule
37	Total of (a)-(b)			$163,000	

Midwest ISO
FERC Electric Tariff, vised Volume No. 1

Attr 0
p 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/04

THE UNION LIGHT HEAT AND POWER COMPANY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100 line 46 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%		
	SIT=	8.20%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

KyPSC Case No. 2006-00172
Attachment WDW-2a
Page 21 of 24

	A	B	C	D	E
1		Cinergy			
2				Support for First Revised Sheet No. 1319	
3		109 Regulatory Assets & Liabilities			Attachment O
4		Accounts 190, 282 & 283			
7	Company	Account 190	Account 282	Account 283	
9	PSI				
10	Account 190060	(4,916,379)			
11	Account 190070	17,958,138			
13	Account 282490		40,379,131		
15	Account 283230			-	
19	CG&E (1)				
20	Account 190210	6,169,732			
22	Account 282250		(58,732,186)		
24	Account 283190			-	
27	(1) 73.67% of total account balance has been allocated to electric service per the Tax department and FERC Form 1.				
31	ULH&P (2)				
33	Account 190210	170,342			
35	Account 282250		(2,552,092)		
37	Account 282750		(1,072,098)		
39	Account 283190			-	
41	(2) 61.52% of total account balance has been allocated to electric service per the Tax department and FERC Form 1.				

KyPSC Case No. 2006-00172
Attachment WDW-2a
Page 22 of 24

	A	B	C	D	E	F	G
1						*Support for First Revised S*	1320
2							nt O
3	Activity_Description	(All)	FRT - v 3.00.0064				
4	*Corporation*	(All)	4/7/05 4:08 pm				
5	Activity	(All)					
6	Account_type	(All)					
7							
8	Amount					Accounting_Period	Accounting_Period
9						2003	2004
10	Corporation_Description	Account	Account_Descri	WorkCode	WorkCode_Description		
11	PSI ENERGY INC	$930,100.00	GENERAL ADV	AGENCYJ	SIGNAGE / ADVER	$15,621.05	$8,908.75
12				*EMADVERST*	Advertise name to p	$19,561.02	$22,312.57
13				SAFETYADV	SAFETY_ADVERTI	$529,719.32	$450,246.54
14	PSI ENERGY INC Total					$564,901.39	$481,467.86
15							
16							
17							
18							
19							
20	Activity_Description	(All)	FRT - v 3.00.0064				
21	Corporation	(All)	4/7/05 4:08 pm				
22	Activity	(All)					
23	Account_type	*(All)*					
24							
25	Amount					Accounting_Period	Accounting_Period
26						2003	2004
27	Corporation_Description	*Account*	*Account_Descri*	*WorkCode*	WorkCode_Description		
28	THE CINCINNATI GAS & ELECTRIC	$930,000.00	GENERAL & M	AGENCYE	SIGNAGE / ADVER	$13,619.28	$9,438.18
29				EMADVERST	Advertise name to p	$719.00	$25.00
30				SAFETYADVE	SAFETY_ADVERTI	$268,162.18	$297,875.54
31	THE CINCINNATI GAS & ELECTRIC Total					$282,500.46	$307,338.72
32							

	A	B	C	D	E	F	G
1							
2				Support for First Revised Sheet No. 1321			
3							Attachment O
4							
5	PSI						
6	Schedule 1 CPMT		$107,491.46				
7	Schedule 1 Non-CPMT		$403,757.04				
8			$511,248.50				
9							
10	CGE						
11	Schedule 1 CPMT		$109,926.55				
12	Schedule 1 Non-CPMT		$845,257.25				
13			$955,183.80				

KyPSC Case No. 2006-00172
Attachment WDW-2a
Page 24 of 24

	A	B	C	D	E
1					Support for
2					Attachment O
3	State Tax Composite				
4					
5		PSI	CG&E	ULH&P	TOTAL
6	revenue requirement	$92,913,459.04	$59,864,450.85	$3,661,242.67	$156,439,152.55
7	tax rate	8.20%	6.50%	8.20%	
8					
9	state taxes	$7,618,903.64	$3,891,189.31	$300,221.90	$11,810,314.85
10					
11	composit tax rate				7.55%
12					
13	State	Indiana	Ohio	Kentucky	

Midwest ISO
FERC Electric Tariff ...vised Volume No. 1

Second Revised S... No. 366
...ment O
... 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

CINERGY d/b/a DUKE ENERGY

Line No.			Total		Allocator	Allocated Amount	
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 173,158,995	
	REVENUE CREDITS	(Note T)	Total		Allocator		
2	Account No. 454	(page 4, line 34)	207,369	TP	0.94802	196,590	
3	Account No. 456	(page 4, line 37)	24,666,000	TP	0.94802	23,383,860	
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.94802	0	Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	0.94802	0	Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)					23,580,450	
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 149,578,545	
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	9,013,000	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	464,000	
10	Plus 12 CP of Network Load not in line 8				(Note C)	0	
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	-348,000	
12	*Plus Contract Demand of firm P-T-P over one year*					0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	
15	Divisor (sum lines 8-14)					9,129,000	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	16.385				
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	1.365				
			Peak Rate			Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.315			$0.315	
19	*Point-To-Point Rate ($/kW/Day)*	(line 18 / 5; line 18 / 7)	0.063	Capped at weekly rate		$0.045	
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	3.939	Capped at weekly and daily rates		$1.876	
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term		$0.000 Short Term	Don't need. Doesn't go anywhere per Jeff Sprague
22			$0.000	Long Term		$0.000 Long Term	

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

CINERGY d/b/a DUKE ENERGY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	207.46.g	7,411,632,739	NA		
2	Transmission	207.58.g	1,312,938,676	TP	0.94802	1,244,692,038
3	Distribution	207.75.g	3,638,905,155	NA		
4	General & Intangible	205.5.g & 207.90.g	398,611,882	W/S	0.05884	23,454,324
5	Common	356.1	185,838,392	CE	0.05884	10,934,732
6	TOTAL GROSS PLANT (sum lines 1-5)		12,947,926,844	GP=	9.879%	1,279,081,094
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	3,315,931,817	NA		
8	Transmission	219.25.c	509,166,756	TP	0.94802	482,700,235
9	Distribution	219.26.c	1,348,634,706	NA		
10	General & Intangible	219.27.c	85,245,942	W/S	0.05884	5,015,871
11	Common	356.1	61,481,811	CE	0.05884	3,617,590
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		5,320,461,032			491,333,696
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	4,095,700,922			
14	Transmission	(line 2- line 8)	803,771,920			761,991,803
15	Distribution	(line 3 - line 9)	2,290,270,449			
16	General & Intangible	(line 4 - line 10)	313,365,940			18,438,453
17	Common	(line 5 - line 11)	124,356,581			7,317,142
18	TOTAL NET PLANT (sum lines 13-17)		7,627,465,812	NP=	10.328%	787,747,398
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	-23,004,029	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	-1,415,895,911	NP	0.10328	-146,230,524
21	Account No. 283 (enter negative)	277.9.k	-284,610,095	NP	0.10328	-29,393,886
22	Account No. 190	234.8.c	196,102,041	NP	0.10328	20,252,975
23	Account No. 255 (enter negative)	267.8.h	-42,878,626	NP	0.10328	-4,428,407
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-1,570,286,620			-159,799,842
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	215,514	TP	0.94802	204,312
	WORKING CAPITAL (Note H)					
26	CWC	calculated	58,548,310			6,625,425
27	Materials & Supplies (Note G)	227.8.c & .15.c	9,578,595	TE	0.75580	7,239,507
28	Prepayments (Account 165)	111.57.c	84,768,205	GP	0.09879	8,373,959
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		152,895,110			22,238,891
30	RATE BASE (sum lines 18, 24, 25, & 29)		6,210,289,816			650,390,758

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised S[illegible] .o. 368
Attachment O
page 3 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

CINERGY d/b/a DUKE ENERGY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.100.b	77,435,420	TE	0.75580	58,525,731
2	Less Account 565	321.88.b	30,309,292		1.00000	30,309,292
3	A&G	323.168.b	432,943,700	W/S	0.05884	25,474,409
4	Less FERC Annual Fees		4,752,113	W/S	0.05884	279,614
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		6,931,232	W/S	0.05884	407,834
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.75580	0
6	Common	356.1	0	CE	0.05884	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		468,386,483			53,003,400
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	27,762,351	TP	0.94802	26,319,262
10	General	336.9.b	8,008,609	W/S	0.05884	471,227
11	Common	336.10.b	1,667,266	CE	0.05884	98,102
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		37,438,226			26,888,591
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	20,060,398	W/S	0.05884	1,180,354
14	Highway and vehicle	263.i	416,826	W/S	0.05884	24,526
15	PLANT RELATED					
16	Property	263.i	90,888,777	GP	0.09879	8,978,589
17	Gross Receipts	263.i	81,946,207	NA	zero	0
18	Other	263.i	0	GP	0.09879	0
19	Payments in lieu of taxes		6,879	GP	0.09879	680
20	TOTAL OTHER TAXES (sum lines 13 - 19)		193,319,087			10,184,149
	INCOME TAXES	(Note K)				
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.85%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		45.73%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.6625			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		248,947,479	NA		26,071,753
26	ITC adjustment (line 23 * line 24)		0	NP	0.10328	0
27	Total Income Taxes	(line 25 plus line 26)	248,947,479			26,071,753
28	RETURN		544,373,469	NA		57,011,103
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]					
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		1,492,464,744			173,158,995

KyPSC Case No. 2ᴜ06-00172
Attachment WDW-2b
Page 4 of 24

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

CINERGY d/b/a DUKE ENERGY
SUPPORTING CALCULATIONS AND NOTES

Line No.				
	TRANSMISSION PLANT INCLUDED IN ISO RATES			
1	Total transmission plant (page 2, line 2, column 3)			1,312,938,676
2	Less transmission plant excluded from ISO rates (Note M)			0
3	Less transmission plant included in OATT Ancillary Services (Note N)			68,246,638
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)			1,244,692,038
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)		TP=	0.94802
	TRANSMISSION EXPENSES			
6	Total transmission expenses (page 3, line 1, column 3)			77,435,420
7	Less transmission expenses included in OATT Ancillary Services (Note L)			15,700,715
8	Included transmission expenses (line 6 less line 7)			61,734,705
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)			0.79724
10	Percentage of transmission plant included in ISO Rates (line 5)		TP	0.94802
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)		TE=	0.75580

Schedule 1 Recoverable Expenses	
15,700,715	Acct 561 included in Line 7?
820,017	Acct 561.BA for Schedule 24
14,880,698	Acct 561 available for Schedule 1
	Revenue Credits for Sched 1/Acct 561
1,022,074	transactions <1 yr
0	non-firm
0	transactions w/ load not in divisor
$1,022,074	total Revenue Credits
$13,858,624	Net Schedule 1 Expenses (Acct 561 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.18.b	117,501,212	0.00	0			
13	Transmission	354.19.b	13,161,918	0.95	12,477,761			
14	Distribution	354.20.b	46,329,201	0.00	0			
15	Other	354.21,22,23.b	35,070,212	0.00	0			
16	Total (sum lines 12-15)		212,062,543		12,477,761	=	0.05884	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	11,279,963,855	1.00000	*	0.05884	=	0.05884
18	Gas	201.3.d	0					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		11,279,963,855					

RETURN (R)

Line No.		$
21	Long Term Interest (117, sum of 62.c through 67.c)	$219,833,465
22	Preferred Dividends (118.29c) (positive number)	$ 2,821,124
	Development of Common Stock:	
23	Proprietary Capital (112.16.c)	4,165,596,807
24	Less Preferred Stock (line 28)	-31,743,000
25	Less Account 216.1 (112.12.c) (enter negative)	-198,744,917
26	Common Stock (sum lines 23-25)	3,935,108,890

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)	4,130,887,646	51%	0.0532	0.0271	=WCLTD
28	Preferred Stock (112.3.c)	31,743,000	0%	0.0889	0.0003	
29	Common Stock (line 26)	3,935,108,890	49%	0.1238	0.0602	
30	Total (sum lines 27-29)	8,097,739,536			0.0877	=R

REVENUE CREDITS

Line No.				Load	
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0	
32	b. Bundled Sales for Resale included in Divisor on page 1			0	
33	Total of (a)-(b)			0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$207,369	Line 34 supported by notes in Form 1 or detailed Schedule
	ACCOUNT 456 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)			
35	a. Transmission charges for all transmission transactions			$52,308,000	Line 35 supported by notes in Form 1 or detailed Schedule
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$27,642,000	Line 36 supported by notes in Form 1 or detailed Schedule
37	Total of (a)-(b)			$24,666,000	

Midwest ISO
FERC Electric Tariff, vised Volume No. 1

Second Revised S No. 370
ent O
5 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

CINERGY d/b/a DUKE ENERGY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 111 line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%		
	SIT=	7.46%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	Account 456 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

Midwest ISO
FERC Electric Tariff, vised Volume No. 1

Second Revised Sheet No. 366
Attachment O
page 1 of 5

KyPSC Case .006-00172
Attachment WDW-2b
Page 6 of 24

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

PSI ENERGY, INC. d/b/a DUKE ENERGY INDIANA, INC.

Line No.			Total	Allocator		Allocated Amount	
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 96,474,294	
	REVENUE CREDITS	(Note T)					
2	Account No. 454	(page 4, line 34)	75,000	TP	0.94684	71,013	
3	Account No. 456	(page 4, line 37)	12,234,000	TP	0.94684	11,583,633	
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.94684	0	Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	0.94684	0	Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)					11,654,646	
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 84,819,648	
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)		5,199,000	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8			(Note B)		0	
10	Plus 12 CP of Network Load not in line 8			(Note C)		-348,000	
11	Less 12 CP of firm P-T-P over one year (enter negative)			(Note D)		0	
12	Plus Contract Demand of firm P-T-P over one year					0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	
15	Divisor (sum lines 8-14)					4,851,000	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	17.485				
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	1.457				

Line No.			Peak Rate		Off-Peak Rate		
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 5.	0.336		$0.336		
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.067	Capped at weekly rate	$0.048		
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 2. times 1,000)	4.203	Capped at weekly and daily rates	$2.001		
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000	Short Term	Don't need. Doesn't go anywhere per Jeff Sprague
			$0.000	Long Term	$0.000	Long Term	
22							

RatesA:\MISO\2004\Attachment WDW-2b (CIN Attachment O May 2006).XLS psl

KyPSC Case .006-00172
Attachment WDW-2b
Page 7 of 24

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised Sheet No. 367
Attachment O
page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

PSI ENERGY, INC. d/b/a DUKE ENERGY INDIANA, INC.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	207.46.g	3,877,205,041	NA		
2	Transmission	207.58.g	796,640,610	TP	0.94684	754,290,712
3	Distribution	207.75.g	1,864,915,320	NA		
4	General & Intangible	205.5.g & 207.90.g	307,824,284	W/S	0.06273	19,310,651
5	Common	356.1	0	CE	0.06273	0
6	TOTAL GROSS PLANT (sum lines 1-5)		6,846,585,255	GP=	11.299%	773,601,363
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	1,645,783,256	NA		
8	Transmission	219.25.c	327,036,610	TP	0.94684	309,651,145
9	Distribution	219.26.c	737,150,460	NA		
10	General & Intangible	219.27.c	72,369,187	W/S	0.06273	4,539,915
11	Common	356.1	0	CE	0.06273	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,782,339,513			314,191,061
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	2,231,421,785			
14	Transmission	(line 2- line 8)	469,604,000			444,639,567
15	Distribution	(line 3 - line 9)	1,127,764,860			
16	General & Intangible	(line 4 - line 10)	235,455,097			14,770,736
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		4,064,245,742	NP=	11.304%	459,410,303
	ADJUSTMENTS TO RATE BASE	(Note F)				
19	Account No. 281 (enter negative)	273.8.k	-23,004,029	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	-589,203,055	NP	0.11304	-66,601,768
21	Account No. 283 (enter negative)	277.9.k	-127,954,209	NP	0.11304	-14,463,565
22	Account No. 190	234.8.c	125,398,608	NP	0.11304	14,174,687
23	Account No. 255 (enter negative)	267.8.h	-23,623,561	NP	0.11304	-2,670,337
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-638,386,246			-69,560,983
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	89,742	TP	0.94684	84,971
	WORKING CAPITAL (Note H)					
26	CWC	calculated	29,450,890			3,534,498
27	Materials & Supplies (Note G)	227.8.c & .15.c	6,346,566	TE	0.60641	3,848,610
28	Prepayments (Account 165)	111.57.c	25,627,513	GP	0.11299	2,895,674
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		61,424,969			10,278,783
30	RATE BASE (sum lines 18, 24, 25, & 29)		3,487,374,207			400,213,073

RateJA:\MISO\2004\Attachment WDW-2b (CIN Attachment O May 2006).XLS psi

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised Sheet No. 368
Attachment O
page 3 of 5

KyPSC Case No. 2006-00172
Attachment WDW-2b
Page 8 of 24

For the 12 months ended 12/31/05

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

PSI ENERGY, INC. d/b/a DUKE ENERGY INDIANA, INC.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.100.b	28,930,121	TE	0.60641	17,543,465
2	Less Account 565	321.88.b	2,382,336		1.00000	2,382,336
3	A&G	323.168.b	213,931,986	W/S	0.06273	13,420,533
4	Less FERC Annual Fees		2,131,928	W/S	0.06273	133,742
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note		2,740,720	W/S	0.06273	171,933
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.60641	0
6	Common	356.1	0	CE	0.06273	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		235,607,123			28,275,988
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	17,926,937	TP	0.94684	16,973,930
10	General	336.9.b	7,639,409	W/S	0.06273	479,241
11	Common	336.10.b	0	CE	0.06273	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		25,566,346			17,453,171
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	9,740,283	W/S	0.06273	611,034
14	Highway and vehicle	263.i	0	W/S	0.06273	0
15	PLANT RELATED					
16	Property	263.i	18,012,225	GP	0.11299	2,035,216
17	Gross Receipts	263.i	34,018	NA	zero	0
18	Other	263.i	0	GP	0.11299	0
19	Payments in lieu of taxes		0	GP	0.11299	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		27,786,526			2,846,251
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.33%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		46.14%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.6759			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		132,329,128	NA		15,186,167
26	ITC adjustment (line 23 * line 24)		0	NP	0.11304	0
27	Total Income Taxes (line 25 plus line 26)		132,329,128			15,186,167
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		286,794,635	NA		32,912,717
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		708,083,757			96,474,294

exclude this amount (included in Account 255 on row 97)

Midwest ISO
FERC Electric Tariff, ...evised Volume No. 1

Second Revised Sheet No. 369
Attachment O
page 4 of 5

For the 12 months ended 12/31/05

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

PSI ENERGY, INC. d/b/a DUKE ENERGY INDIANA, INC.
SUPPORTING CALCULATIONS AND NOTES

Line No.			
	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		796,640,610
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		42,349,898
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		754,290,712
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.94684
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		28,930,121
7	Less transmission expenses included in OATT Ancillary Services (Note L) (page 321, line 84, column (b))		10,401,672
8	Included transmission expenses (line 6 less line 7)		18,528,449
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.64046
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.94684
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.60641

Schedule 1 Recoverable Expenses	
$10,401,672	Acct 561 included in Line 7?
426,245	Acct 561.BA for Schedule 24
9,975,427	Acct 561 available for Schedule 1
	Revenue Credits for Sched 1/Acct 561
502,990	transactions <1 yr
-	non-firm
-	transactions w/ load not in divisor
502,990	total Revenue Credits
$ 9,472,437	Net Schedule 1 Expenses (Acct 561 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.18.b	62,709,799	0.00	0			
13	Transmission	354.19.b	7,285,088	0.95	6,897,808			
14	Distribution	354.20.b	23,056,403	0.00	0			
15	Other	354.21,22,23.b	16,904,241	0.00	0			
16	Total (sum lines 12-15)		109,955,531		6,897,808	=	0.06273	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	5,866,638,877	1.00000	*	0.06273	=	0.06273
18	Gas	201.3.d	0					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		5,866,638,877					

RETURN (R)

Line No.		$
21	Long Term Interest (117, sum of 62.c through 67.c)	$ 113,821,733
22	Preferred Dividends (118.29.c) (positive number)	$ 1,975,467
	Development of Common Stock:	
23	Proprietary Capital (112.16.c)	1,973,221,207
24	Less Preferred Stock (line 28)	-11,258,100
25	Less Account 216.1 (112.12.c) (enter negative)	0
26	Common Stock (sum lines 23-25)	1,961,963,107

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)	2,388,366,983	55%	0.0477	0.0261	=WCLTD
28	Preferred Stock (112.3.c)	11,258,100	0%	0.1755	0.0005	
29	Common Stock (line 26)	1,961,963,107	45%	0.1238	0.0557	
30	Total (sum lines 27-29)	4,361,588,190			0.0822	=R

Cinergy Return on Equity approved by FERC will not change until a filing is made with FER

REVENUE CREDITS

Line No.			Load	
	ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)			
31	a. Bundled Non-RQ Sales for Resale (311.x.h)		0	
32	b. Bundled Sales for Resale included in Divisor on page 1		0	
33	Total of (a)-(b)		0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)	$	75,000	Line 34 supported by notes in Form 1 or detailed Schedule
	ACCOUNT 456 (OTHER ELECTRIC REVENUES) (Note U (330.x.n)			
35	a. Transmission charges for all transmission transactions	$	19,647,000	Line 35 supported by notes in Form 1 or detailed Schedule
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1		7,413,000	Line 36 supported by notes in Form 1 or detailed Schedule
37	Total of (a)-(b)	$	12,234,000	

Midwest ISO
FERC Electric Tariff, [illegible] Revised Volume No. 1

Second Revised Sheet No. 370
Attachment O
page 5 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

PSI ENERGY, INC. d/b/a DUKE ENERGY INDIANA, INC.

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 111 line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%		
	SIT=	8.20%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use. (Statement AU)
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	Account 456 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

Midwest ISO
FERC Electric Tariff, vised Volume No. 1

Second Revised Sh 366
of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE CINCINNATI GAS & ELECTRIC COMPANY d/b/a DUKE ENERGY OHIO

Line No.			Total	Allocator		Allocated Amount	
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 71,405,167	
	REVENUE CREDITS	(Note T)					
2	*Account No. 454*	(page 4, line 34)	98,822	TP	0.94768	93,652	
3	Account No. 456	(page 4, line 37)	12,249,000	TP	0.94768	11,608,172	
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.94768	0	Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	0.94768	0	Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)					11,701,824	
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 59,703,343	
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	3,118,000	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	464,000	
10	*Plus 12 CP of Network Load not in line 8*				(Note C)	0	
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0	
12	Plus Contract Demand of firm P-T-P over one year					0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	
15	Divisor (sum lines 8-14)					3,582,000	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	16.668				
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	1.389				

Line No.			Peak Rate		Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.321		$0.321	
19	*Point-To-Point Rate ($/kW/Day)*	*(line 18 / 5; line 18 / 7)*	0.064	Capped at weekly rate	$0.046	
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	4.007	Capped at weekly and daily rates	$1.908	
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000	Short Term
22			$0.000	Long Term	$0.000	Long Term

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised S 387
Att...ment O
page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE CINCINNATI GAS & ELECTRIC COMPANY d/b/a DUKE ENERGY OHIO

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	207.46.g	3,534,427,698	NA		
2	Transmission	207.58.g	494,999,090	TP	0.94768	469,102,350
3	Distribution	207.75.g	1,499,074,301	NA		
4	General & Intangible	205.5.g & 207.90.g	87,974,523	W/S	0.05440	4,785,513
5	Common	356.1	168,332,970	CE	0.05440	9,156,737
6	TOTAL GROSS PLANT (sum lines 1-5)		5,784,808,582	GP=	8.350%	483,044,600
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	1,670,148,581	NA		
8	Transmission	219.25.c	172,576,801	TP	0.94768	163,548,145
9	Distribution	219.26.c	506,466,657	NA		
10	General & Intangible	219.27.c	12,841,067	W/S	0.05440	698,510
11	Common	356.1	54,697,107	CE	0.05440	2,975,335
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,416,730,193			167,221,990
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	1,864,279,137			
14	Transmission	(line 2- line 8)	322,422,289			305,554,205
15	Distribution	(line 3 - line 9)	992,607,644			
16	General & Intangible	(line 4 - line 10)	75,133,456			4,087,003
17	Common	(line 5 - line 11)	113,635,863			6,181,402
18	TOTAL NET PLANT (sum lines 13-17)		3,368,078,389	NP=	9.377%	315,822,609
	ADJUSTMENTS TO RATE BASE	(Note F)				
19	Account No. 281 (enter negative)	273.8.k	0	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	-790,851,415	NP	0.09377	-74,157,644
21	Account No. 283 (enter negative)	277.9.k	-155,984,128	NP	0.09377	-14,626,534
22	Account No. 190	234.8.c	68,625,121	NP	0.09377	6,434,935
23	Account No. 255 (enter negative)	267.8.h	-18,318,445	NP	0.09377	-1,717,709
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-896,528,867			-84,066,953
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	125,772	TP	0.94768	119,192
	WORKING CAPITAL (Note H)					
26	CWC	calculated	27,441,326			2,950,642
27	Materials & Supplies (Note G)	227.8.c & .15.c	3,213,483	TE	0.81313	2,612,973
28	Prepayments (Account 165)	111.57.c	54,641,044	GP	0.08350	4,562,651
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		85,295,853			10,126,266
30	RATE BASE (sum lines 18, 24, 25, & 29)		2,556,971,147			242,001,115

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised Sh 368
Attachment O
page 3 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE CINCINNATI GAS & ELECTRIC COMPANY d/b/a DUKE ENERGY OHIO

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.100.b	29,921,163	TE	0.81313	24,329,755
2	Less Account 565	321.88.b	11,673,730		1.00000	11,673,730
3	A&G	323.168.b	207,685,017	W/S	0.05440	11,297,353
4	Less FERC Annual Fees		2,634,936	W/S	0.05440	143,331
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		3,766,926	W/S	0.05440	204,908
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.81313	0
6	Common	356.1	0	CE	0.05440	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		219,530,608			23,605,139
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	9,169,290	TP	0.94768	8,689,583
10	General	336.9.b	363,046	W/S	0.05440	19,748
11	Common	336.10.b	1,531,664	CE	0.05440	83,317
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		11,064,000			8,792,648
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	9,753,104	W/S	0.05440	530,535
14	Highway and vehicle	263.i	404,752	W/S	0.05440	22,017
15	PLANT RELATED					
16	Property	263.i	71,088,889	GP	0.08350	5,936,083
17	Gross Receipts	263.i	81,912,189	NA	zero	0
18	Other	263.i	0	GP	0.08350	0
19	Payments in lieu of taxes		0	GP	0.08350	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		163,158,934			6,488,636
	INCOME TAXES	(Note K)				
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.23%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		44.48%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.6454			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		105,781,917	NA		10,011,588
26	ITC adjustment (line 23 * line 24)		0	NP	0.09377	0
27	Total Income Taxes	(line 25 plus line 26)	105,781,917			10,011,588
28	RETURN		237,809,440	NA		22,507,156
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]					
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		737,344,898			71,405,167

exclud this amount included in Account 255 on row 97

Midwest ISO
FERC Electric Tariff, . . Revised Volume No. 1

Second Revised S 369
A. ... nt O
page 4 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE CINCINNATI GAS & ELECTRIC COMPANY d/b/a DUKE ENERGY OHIO
SUPPORTING CALCULATIONS AND NOTES

Line No.			
	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		494,999,090
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		25,896,740
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		469,102,350
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.94768
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		29,921,183
7	Less transmission expenses included in OATT Ancillary Services (Note L) (page 321, line 84, column (b))		4,248,307
8	Included transmission expenses (line 6 less line 7)		25,672,876
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.85802
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.94768
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.81313

Year End Bulk/Common Split

Schedule 1 Recoverable Expenses

$ 4,248,307	Acct 561 included in Line 7?
344,735	Acct 561.BA for Schedule 24
3,903,572	Acct 561 available for Schedule 1
	Revenue Credits for Sched 1/Acct 561
519,084	transactions <1 yr
-	non-firm
-	transactions w/ load not in divisor
519,084	total Revenue Credits
$ 3,384,488	Net Schedule 1 Expenses (Acct 561 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.18.b	54,781,559	0.00	0			
13	Transmission	354.19.b	5,507,247	0.95	5,219,126			
14	Distribution	354.20.b	20,442,215	0.00	0			
15	Other	354.21,22,23.b	15,214,833	0.00	0			
16	Total (sum lines 12-15)		95,945,854		5,219,126	=	0.05440	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	5,135,171,031	1.00000	*	0.05440	=	0.05440
18	Gas	201.3.d	0					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		5,135,171,031					

RETURN (R)

Line No.		$
21	Long Term Interest (117, sum of 62.c through 67.c)	$99,571,889
22	Preferred Dividends (118.29.c) (positive number)	$ 845,657
	Development of Common Stock:	
23	Proprietary Capital (112.16.c)	1,995,916,704
24	Less Preferred Stock (line 28)	-20,484,900
25	Less Account 216.1 (112.12.c) (enter negative)	-198,744,917
26	Common Stock (sum lines 23-25)	1,776,686,887

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)	1,647,520,663	48%	0.0604	0.0289	=WCLTD
28	Preferred Stock (112.3.c)	20,484,900	1%	0.0413	0.0002	
29	Common Stock (line 26)	1,776,686,887	52%	0.1238	0.0639	
30	Total (sum lines 27-29)	3,444,692,450			0.0930	=R

REVENUE CREDITS

Line No.				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0
32	b. Bundled Sales for Resale included in Divisor on page 1			0
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$ 98,822
	ACCOUNT 456 (OTHER ELECTRIC REVENUES) (Note U) (330.x.n)			
35	a. Transmission charges for all transmission transactions			$ 32,478,000
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			20,229,000
37	Total of (a)-(b)			$ 12,249,000

Line 34 supported by notes in Form 1 or detailed Schedule
Line 35 supported by notes in Form 1 or detailed Schedule
Line 36 supported by notes in Form 1 or detailed Schedule

Midwest ISO
FERC Electric Tariff, ... evised Volume No. 1

Second Revised Sl 370
A... ...nt O
page 5 of 5

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/05

THE CINCINNATI GAS & ELECTRIC COMPANY d/b/a DUKE ENERGY OHIO

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter

A Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.

B Labeled LF, LU, IF, IU on pages 310-311 of Form 1*at the time of the ISO coincident monthly peaks.*

C Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

D Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

E The FERC's annual charges for the year assessed the *Transmission Owner for service under this tariff.*

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize *amortization of tax credits against taxable income* as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. *Prepayments are the electric related prepayments* booked to Account No. 165 and reported on Pages 111 line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, *ISO filings, or transmission siting* itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, *since they are recovered elsewhere.*

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:				
	FIT =	35.00%		
	SIT=	6.50%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, *including all of Account No. 561.*

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of *OATT ancillary services rates and generation* step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.

R Includes income related only to transmission *facilities, such as pole attachments, rentals and special* use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate *pancaking - the revenues* are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this *Rate Formula Template.*

U Account 456 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

Midwest ISO
FERC Electric Tariff ... vised Volume No. 1

Second Revise... No. 366
...ment O
...ge 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY

Line No.			Total	Allocator		Allocated Amount	
1	*GROSS REVENUE REQUIREMENT*	*(page 3, line 29)*				$ 4,511,058	
	REVENUE CREDITS	(Note T)					
2	Account No. 454	(page 4, line 34)	33,547	TP	1.00000	33,547	
3	Account No. 456	(page 4, line 37)	183,000	TP	1.00000	183,000	
4	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0	Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	1.00000	0	Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)					216,547	
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 4,294,511	
	DIVISOR						
8	Average of 12 *coincident system peaks for requirements* (RQ) service				(Note A)	696,000	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	0	
10	Plus 12 CP of Network Load not in line 8				(Note C)	0	
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0	
12	Plus Contract Demand of firm P-T-P over one year					0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	
15	Divisor (sum lines 8-14)					696,000	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	6.170				
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	0.514				
			Peak Rate			*Off-Peak Rate*	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.119			$0.119	
19	*Point-To-Point Rate ($/kW/Day)*	*(line 18 / 5; line 18 / 7)*	0.024	Capped at weekly rate		$0.017	
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	1.483	Capped at weekly and daily rates		$0.706	
21	*FERC Annual Charge($/MWh)*	*(Note E)*	$0.000	Short Term		$0.000	Short Term
22			$0.000	Long Term		$0.000	Long Term

Midwest ISO
FERC Electric Tariff avised Volume No. 1

Second Revise ' No. 367
ment O
je 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	207.46.g	0	NA		
2	Transmission	207.58.g	21,298,976	TP	1.00000	21,298,976
3	Distribution	207.75.g	274,915,534	NA		
4	General & Intangible	205.5.g & 207.90.g	2,813,075	W/S	0.05999	168,745
5	Common	356.1	17,505,422	CE	0.05999	1,050,080
6	TOTAL GROSS PLANT (sum lines 1-5)		316,533,007	GP=	7.114%	22,517,801
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	0	NA		
8	Transmission	219.25.c	9,553,345	TP	1.00000	9,553,345
9	Distribution	219.26.c	105,017,589	NA		
10	General & Intangible	219.27.c	35,688	W/S	0.05999	2,141
11	Common	356.1	6,784,704	CE	0.05999	406,987
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		121,391,326			9,962,473
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	0			
14	Transmission	(line 2- line 8)	11,745,631			11,745,631
15	Distribution	(line 3 - line 9)	169,897,945			
16	General & Intangible	(line 4 - line 10)	2,777,387			166,604
17	Common	(line 5 - line 11)	10,720,718			643,093
18	TOTAL NET PLANT (sum lines 13-17)		195,141,681	NP=	6.434%	12,555,328
	ADJUSTMENTS TO RATE BASE	(Note F)				
19	Account No. 281 (enter negative)	273.8.k	0	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	-35,841,441	NP	0.06434	-2,306,022
21	Account No. 283 (enter negative)	277.9.k	-671,758	NP	0.06434	-43,221
22	Account No. 190	234.8.c	2,078,312	NP	0.06434	133,718
23	Account No. 255 (enter negative)	267.8.h	-936,620	NP	0.06434	-60,262
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-35,371,507			-2,275,787
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	TP	1.00000	0
	WORKING CAPITAL (Note H)					
26	CWC	calculated	1,656,094			241,884
27	Materials & Supplies (Note G)	227.8.c & .15.c	18,546	TE	0.94346	17,497
28	Prepayments (Account 165)	111.57.c	4,499,648	GP	0.07114	320,100
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		6,174,288			579,481
30	RATE BASE (sum lines 18, 24, 25, & 29)		165,944,462			10,859,022

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised ...o. 368
Attachment O
page 3 of 5

KyPSC Case No. 2006-00172
Attachment WDW-2b
Page 18 of 24

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.100.b	18,584,116	TE	0.94346	17,533,360
2	Less Account 565	321.88.b	16,253,226		1.00000	16,253,226
3	A&G	323.168.b	11,326,697	W/S	0.05999	679,443
4	Less FERC Annual Fees		-14,751	W/S	0.05999	-885
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		423,586	W/S	0.05999	25,409
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.94346	0
6	Common	356.1	0	CE	0.05999	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		13,248,752			1,935,072
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	666,124	TP	1.00000	666,124
10	General	336.9.b	6,154	W/S	0.05999	369
11	Common	336.10.b	135,602	CE	0.05999	8,134
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		807,880			674,627
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	567,011	W/S	0.05999	34,013
14	Highway and vehicle	263.i	12,074	W/S	0.05999	724
15	PLANT RELATED					
16	Property	263.i	1,787,663	GP	0.07114	127,172
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.07114	0
19	Payments in lieu of taxes		6,879	GP	0.07114	489
20	TOTAL OTHER TAXES (sum lines 13 - 19)		2,373,627			162,399
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.55%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		51.73%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.6543			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		9,059,995	NA		592,865
26	ITC adjustment (line 23 * line 24)		0	NP	0.06434	0
27	Total Income Taxes	(line 25 plus line 26)	9,059,995			592,865
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		17,514,281	NA		1,146,094
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		43,004,535			4,511,058

exclud this amount included in Account 255 on row 97

Midwest ISO
FERC Electric Tariff, vised Volume No. 1

Second Revised S' No. 369
nent O
4 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY
SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		21,298,976
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		0
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		21,298,976
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	1.00000
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		18,584,116
7	Less transmission expenses included in OATT Ancillary Services (Note L) (page 321, line 84, column (b))		1,050,736
8	Included transmission expenses (line 6 less line 7)		17,533,380
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.94346
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	1.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.94346

Schedule 1 Recoverable Expenses	
$ 1,050,736	Acct 561 included in Line 7?
49,037	Acct 561.BA for Schedule 24
1,001,699	Acct 561 available for Schedule 1
	Revenue Credits for Sched 1/Acct 561
-	transactions <1 yr
-	non-firm
-	transactions w/ load not in divisor
-	total Revenue Credits
$ 1,001,699	Net Schedule 1 Expenses (Acct 561 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.18.b	9,854	0.00	0			
13	Transmission	354.19.b	369,583	1.00	369,583			
14	Distribution	354.20.b	2,830,583	0.00	0			
15	Other	354.21,22,23.b	2,951,138	0.00	0			
16	Total (sum lines 12-15)		6,161,158		369,583	=	0.05999	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	278,153,947	1.00000	*	0.05999	=	0.05999
18	Gas	201.3.d	0					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		278,153,947					

RETURN (R)

Line No.		$
21	Long Term Interest (117, sum of 62.c through 67.c)	$6,439,843
22	Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:	
23	Proprietary Capital (112.16.c)	196,458,896
24	Less Preferred Stock (line 28)	0
25	Less Account 216.1 (112.12.c) (enter negative)	0
26	Common Stock (sum lines 23-25)	196,458,896

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)	95,000,000	33%	0.0678	0.0221	=WCLTD
28	Preferred Stock (112.3.c)	0	0%	0.0000	0.0000	
29	Common Stock (line 26)	196,458,896	67%	0.1238	0.0834	
30	Total (sum lines 27-29)	291,458,896			0.1055	=R

REVENUE CREDITS

Line No.				Load	
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0	
32	b. Bundled Sales for Resale included in Divisor on page 1			0	
33	Total of (a)-(b)			0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$ 33,547	Line 34 supported by notes in Form 1 or detailed Schedule
	ACCOUNT 456 (OTHER ELECTRIC REVENUES) (Note U) (330.x.n)				
35	a. Transmission charges for all transmission transactions			$ 183,000	Line 35 supported by notes in Form 1 or detailed Schedule
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			-	Line 36 supported by notes in Form 1 or detailed Schedule
37	Total of (a)-(b)			$ 183,000	

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | *For the 12 months ended 12/31/05*

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter

A Peak as would be reported on page *401, column d of Form 1 at the time of the ISO coincident* monthly peaks.

B Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.

C Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

D Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 *as being only transmission related.*

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 111 line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at *353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety* related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, *since they are recovered elsewhere.*

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper *showing the name of each state and how the blended or composite* SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%		
	SIT=	7.00%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.

M *Removes transmission* plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed *to included in OATT ancillary services. For these purposes*, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent *a filing with* FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.

R Includes income related only to *transmission facilities, such as pole attachments, rentals and special use.*

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are *not included in line 4, page 1 nor are the loads included in line 13, page 1.*

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues *associated with FERC annual charges, gross receipts* taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Account 456 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

	A	B	C	D	E
1		Cinergy			
2				*Support for Second Revised Sheet No. 367*	
3	F	106 Regulatory Assets & Liabilities			Attachment O
4		Accounts 190, 282 & 283			
5					
6					
7	Company	*Account 190*	*Account 282*	*Account 283*	
8					
9	PSI				
10	Account 190050	(11,856,981)			
11	Account 190053	15,880,726			
12	Account 190150	821,054			
13					
14	Account 282050		(10,617,687)		
15	Account 282150		11,108,824		
16					
17	Account 283230			-	
18					
19					
20	CG&E (1)				
21	Account 190050	(30,570,350)			
22	Account 190053	12,358,010			
23	Account 190150	21,969,110			
24					
25	Account 282050		(46,334,923)		
26	Account 282150		32,196,783		
27					
28	Account 283230			-	
29					
30					
31	(1) 74.11% of total account balance has been allocated to electric service per the Tax department and FERC Form 1.				
32					
33					
34					
35	ULH&P (2)				
36					
37	Account 190050	(1,936,423)			
38	Account 190053	1,569,473			
39	Account 190150	11,100			
40					
41	Account 282050		833,219		
42	Account 282150		5,393,908		
43					
44	Account 283230			-	
45					
46	(2) 61.87% of total account balance has been allocated to electric service per the Tax department and FERC Form 1.				

KyPSC Case No. 2006-00172
Attachment WDW-2b
Page 22 of 24

Support for Second Revised Sheet No. 368
Attachment O

Account_type (All)

Amount				Corporation	Corporation_Descri	Accounting_Period2	Accounting_Period
				010		070	
				THE CINCINNATI GAS & ELECTRIC		THE UNION LIGHT HEAT & POWER	
					QTR 1 - 2005		QTR 1 - 2005
Account	Account_Description	WorkCode	WorkCode_Description				
930000	GENERAL & MISC MEDIA - ELECTRI	AGENCYE	SIGNAGE / ADVERTISING		$5,068.76		$958.89
		SAFETYADVE	SAFETY ADVERTISING - ELECTRIC		$3,449.26		$632.24
Grand Total					$8,518.02		$1,591.13

Activity Code (All)
Activity Descripti (All)

Sum of Transaction Amount					Responsibility Corp	Responsibility Corp De	Accounting Period2	Accounting Peri
					010	070	100	Grand Total
					THE CINCINNATI GAS & ELE	UNION LIGHT HEAT & PC	PSI ENERGY INC	
					2005	2005	2005	
Account Code	Account Description	Work Code2	Work Code	Work Code Description				
930100	General Advertising Expenses	Non-Safety Advertising	AGENCYJ	SIGNAGE / ADVERTISING - JOINT	107,205.67	21,699.25	68,751.95	197,656.87
			EMADVERST	ADVERTISING	2,931.25		23,990.62	26,921.87
			TRAIN04L	2004 Train Display Labor Cost			1,041.23	1,041.23
			TRAIN04OS	2004 Train Display - Outsd Srv			10,865.59	10,865.59
		Non-Safety Advertising Total			110,136.92	21,699.25	104,649.39	236,485.56
		Safety advertising	SAFETYADV	SAFETY ADVERTISING - JOINT			2,672.02	2,672.02
		Safety advertising Total					2,672.02	2,672.02
Grand Total					110,136.92	21,699.25	107,321.41	239,157.58

Note: PSI has a full 12 months in the Hyperion Query.

	A	B	C	D	E	F	G
1							
2							Support for Second Revised Sheet No. 369
3							Attachment O
4							
5	Duke Energy Indiana						
6	Schedule 1 CPMT		$ 108,274				
7	Schedule 1 Non-CPMT		394,716				
8			$ 502,990				
9							
10	Duke Energy Ohio						
11	Schedule 1 CPMT		$ 99,532				
12	Schedule 1 Non-CPMT		419,552				
13			$ 519,084				
14							
15							
16							
17			Account				
18	Balancing Authority Costs		561.BA				
19							
20	PSI		$ 426,245				
21	CG&E		344,735				
22	ULH&P		49,037				
23	Total		$ 820,017				

	A	B	C	D	E
1					Support for Second Revised Sheet No. 370
2					Attachment O
3	State Tax Composite				
4					
5	State	Indiana	Ohio	Kentucky	
6		Duke Energy Indiana	Duke Energy Ohio	Duke Energy Kentucky	TOTAL
7	revenue requirement	$ 96,474,294.02	$ 71,405,167.29	$ 4,511,057.78	$ 172,390,519.09
8	tax rate	8.20%	6.50%	7.00%	
9					
10	state taxes	$ 7,910,892.11	$ 4,641,335.87	$ 315,774.04	$ 12,868,002.02
11					
12	composit tax rate				7.46%

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised Sheet No. 366
Attachment O
page 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY

Line No.			Total	Allocator		Allocated Amount	
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 4,404,503	
	REVENUE CREDITS	(Note T)					
2	Account No. 454	(page 4, line 34)	33,547	TP	1.00000	33,547	
3	Account No. 456	(page 4, line 37)	183,000	TP	1.00000	183,000	
4	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0	Line 4 supported by schedules.
5	Revenues from service provided by the ISO at a discount		0	TP	1.00000	0	Line 5 supported by schedules.
6	TOTAL REVENUE CREDITS (sum lines 2-5)					216,547	
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 4,187,956	Revised revenue requirement for DEK at Dr. Morin's recommended ROE.
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)		696,000	Line 8 supported with monthly CP and associated net energy.
9	Plus 12 CP of firm bundled sales over one year not in line 8			(Note B)		0	
10	Plus 12 CP of Network Load not in line 8			(Note C)		0	
11	Less 12 CP of firm P-T-P over one year (enter negative)			(Note D)		0	
12	Plus Contract Demand of firm P-T-P over one year					0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0	
15	Divisor (sum lines 8-14)					696,000	
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	6.017				
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	0.501				
			Peak Rate			Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.116			$0.116	
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.023	Capped at weekly rate		$0.017	
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	1.446	Capped at weekly and daily rates		$0.689	
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term		$0.000	Short Term
22			$0.000	Long Term		$0.000	Long Term

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised Sheet No. 367
Attachment O
page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	207.46.g	0	NA		
2	Transmission	207.58.g	21,298,976	TP	1.00000	21,298,976
3	Distribution	207.75.g	274,915,534	NA		
4	General & Intangible	205.5.g & 207.90.g	2,813,075	W/S	0.05999	168,745
5	Common	356.1	17,505,422	CE	0.05999	1,050,080
6	TOTAL GROSS PLANT (sum lines 1-5)		316,533,007	GP=	7.114%	22,517,801
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	0	NA		
8	Transmission	219.25.c	9,553,345	TP	1.00000	9,553,345
9	Distribution	219.26.c	105,017,589	NA		
10	General & Intangible	219.27.c	35,688	W/S	0.05999	2,141
11	Common	356.1	6,784,704	CE	0.05999	406,987
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		121,391,326			9,962,473
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	0			
14	Transmission	(line 2- line 8)	11,745,631			11,745,631
15	Distribution	(line 3 - line 9)	169,897,945			
16	General & Intangible	(line 4 - line 10)	2,777,387			166,604
17	Common	(line 5 - line 11)	10,720,718			643,093
18	TOTAL NET PLANT (sum lines 13-17)		195,141,681	NP=	6.434%	12,555,328
	ADJUSTMENTS TO RATE BASE	(Note F)				
19	Account No. 281 (enter negative)	273.8.k	0	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	-35,841,441	NP	0.06434	-2,306,022
21	Account No. 283 (enter negative)	277.9.k	-671,758	NP	0.06434	-43,221
22	Account No. 190	234.8.c	2,078,312	NP	0.06434	133,718
23	Account No. 255 (enter negative)	267.8.h	-936,620	NP	0.06434	-60,262
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-35,371,507			-2,275,787
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	TP	1.00000	0
	WORKING CAPITAL (Note H)					
26	CWC	calculated	1,656,094			241,884
27	Materials & Supplies (Note G)	227.8.c & .15.c	18,546	TE	0.94346	17,497
28	Prepayments (Account 165)	111.57.c	4,499,648	GP	0.07114	320,100
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		6,174,288			579,481
30	RATE BASE (sum lines 18, 24, 25, & 29)		165,944,462			10,859,022

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised Sheet No. 368
Attachment O
page 3 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.100.b	18,584,116	TE	0.94346	17,533,380
2	Less Account 565	321.88.b	16,253,226		1.00000	16,253,226
3	A&G	323.168.b	11,326,697	W/S	0.05999	679,443
4	Less FERC Annual Fees		-14,751	W/S	0.05999	-885
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		423,586	W/S	0.05999	25,409
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.94346	0
6	Common	356.1	0	CE	0.05999	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		13,248,752			1,935,072
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	666,124	TP	1.00000	666,124
10	General	336.9.b	6,154	W/S	0.05999	369
11	Common	336.10.b	135,602	CE	0.05999	8,134
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		807,880			674,627
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	567,011	W/S	0.05999	34,013
14	Highway and vehicle	263.i	12,074	W/S	0.05999	724
15	PLANT RELATED					
16	Property	263.i	1,787,663	GP	0.07114	127,172
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.07114	0
19	Payments in lieu of taxes		6,879	GP	0.07114	489
20	TOTAL OTHER TAXES (sum lines 13 - 19)		2,373,627			162,399
	INCOME TAXES	(Note K)				
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.55%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		50.91%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.6543			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		8,415,989	NA		550,723
26	ITC adjustment (line 23 * line 24)		0	NP	0.06434	0
27	Total Income Taxes	(line 25 plus line 26)	8,415,989			550,723
28	RETURN		16,529,953	NA		1,081,682
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]					
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		41,376,201			4,404,503

exclud this amount included in Account 255 on row 97

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised Sheet No. 369
Attachment O
page 4 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY
SUPPORTING CALCULATIONS AND NOTES

Line No.			
	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		21,298,976
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		0
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		21,298,976
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	1.00000
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		18,584,116
7	Less transmission expenses included in OATT Ancillary Services (Note L) (page 321, line 84, column (b))		1,050,736
8	Included transmission expenses (line 6 less line 7)		17,533,380
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.94346
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	1.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.94346

	Schedule 1 Recoverable Expenses
$ 1,050,736	Acct 561 included in Line 7?
49,037	Acct 561.BA for Schedule 24
1,001,699	Acct 561 available for Schedule 1
	Revenue Credits for Sched 1/Acct 561
-	transactions <1 yr
-	non-firm
-	transactions w/ load not in divisor
-	total Revenue Credits
$ 1,001,699	Net Schedule 1 Expenses (Acct 561 minus Credits)

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.18.b	9,854	0.00	0			
13	Transmission	354.19.b	369,583	1.00	369,583			
14	Distribution	354.20.b	2,830,583	0.00	0			
15	Other	354.21,22,23.b	2,951,138	0.00	0			
16	Total (sum lines 12-15)		6,161,158		369,583	=	0.05999	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	278,153,947	1.00000	*	0.05999	=	0.05999
18	Gas	201.3.d	0					
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		278,153,947					

RETURN (R)

Line No.		$
21	Long Term Interest (117, sum of 62.c through 67.c)	$6,439,843
22	Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:	
23	Proprietary Capital (112.16.c)	196,458,896
24	Less Preferred Stock (line 28)	0
25	Less Account 216.1 (112.12.c) (enter negative)	0
26	Common Stock (sum lines 23-25)	196,458,896

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)	95,000,000	33%	0.0678	0.0221	=WCLTD
28	Preferred Stock (112.3.c)	0	0%	0.0000	0.0000	
29	Common Stock (line 26)	196,458,896	67%	0.1150	0.0775	
30	Total (sum lines 27-29)	291,458,896			0.0996	=R

Update ROE to Dr. Morin's Recommendation

REVENUE CREDITS

Line No.				Load	
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0	
32	b. Bundled Sales for Resale included in Divisor on page 1			0	
33	Total of (a)-(b)			0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$ 33,547	Line 34 supported by notes in Form 1 or detailed Schedule
	ACCOUNT 456 (OTHER ELECTRIC REVENUES) (Note U) (330.x.n)				
35	a. Transmission charges for all transmission transactions			$ 183,000	Line 35 supported by notes in Form 1 or detailed Schedule
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			-	Line 36 supported by notes in Form 1 or detailed Schedule
37	Total of (a)-(b)			$ 183,000	

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Second Revised Sheet No. 370
Attachment O
page 5 of 5

Formula Rate - Non-Levelized | *Rate Formula Template* Utilizing FERC Form 1 Data | For the 12 months ended 12/31/05

THE UNION LIGHT HEAT AND POWER COMPANY d/b/a DUKE ENERGY KENTUCKY

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the *ISO coincident monthly peaks.*
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service *under this tariff.*
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. *Account 281 is not allocated.*
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on *Pages 111 line 57 in the Form 1.*
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. *Furthermore, a utility that* elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%		
	SIT=	7.00%	(State Income Tax Rate or Composite SIT)	SIT work papers if required
	p =	0.00%	(percent of federal income tax deductible for state purposes)	

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	Account 456 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

Duke Energy Kentucky
Adjustment to Capitalization to Reflect AMR in Revenue Requirements

		Total $	Ratio	
1	Rate Base Before Adjustment for AMI			
2	Electric	$591,137,227	74.439%	Schedule WPA-1d, line 34, 38
3	Gas	202,983,847	25.561%	Schedule WPA-1d, line 34, 38
4	Total Rate Base Before Adjustment for AMI	$794,121,074	100.000%	
5	Capitalization Before Adjustment for AMI			
6	Allocated to Electric	$550,186,484	74.439%	Schedule WPA-1c, line 9
7	Allocated to Gas	188,924,041	25.561%	*Line 8 - Line 6*
8	Total Capitalization Before Adjustment for AMI	$739,110,525	100.000%	Schedule WPA-1c, line 7
9	Additional Rate Base from AMI Project			
10	Electric	$6,084,103	58.902%	Per JLS-2 (2007 Rate Base)
11	Gas	4,245,025	41.098%	Per JLS-2 (2007 Rate Base)
12	Total Additional Rate Base from AMI Project	$10,329,128	100.000%	
13	Total Rate Base Including AMI Project			
14	Electric	$597,221,330	74.240%	Line 2 + Line 10
15	Gas	207,228,872	25.760%	Line 3 + Line 11
16	Total Rate Base Including AMI Project	$804,450,202	100.000%	
17	*Capitalization Including AMI Project*			
18	Allocated to Electric	$556,381,669	74.240%	Line 14 * Line 20
19	Allocated to Gas	193,057,983	25.760%	Line 15 * Line 20
20	Total Capitalization Including AMI	$749,439,653	100.000%	Line 8 + Line 12
21	Increase in Capitalization Allocated to Electric	$6,195,185		Line 18 - Line 6

Duke Energy Kentucky
1697-A Monmouth Street
Newport, KY 41071

RIDER FAC
FUEL ADJUSTMENT CLAUSE (C)

APPLICABLE
In all territory service.

AVAILABILITY OF SERVICE
This schedule is a mandatory rider to all electric rate schedules.

(1) The monthly amount computed under each of the rate schedules to which this fuel clause is applicable shall be increased or (decreased) at a rate per kilowatt-hour of monthly consumption in accordance with the following formula:

$$Fuel\ Cost\ Adjustment = \frac{F(m)}{S(m)} - \$0.021619\ per\ kWh$$

Where F is the expense of fuel in the second preceding month and S is the sales in the second preceding month, as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) Fossil fuel consumed in the Company's plants plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein are such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy, and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on a weighted-average inventory costing. The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of fuel itself and necessary charges for transportation of fuel from the point of acquisition to the unloading point, as listed in Account 151 of the FERC Uniform System of Accounts for Public Utilities and Licensees.

Duke Energy Kentucky
1697-A Monmouth Street
Newport, KY 41071

AVAILABILTY OF SERVICE (Contd.)

(f) As used herein, the term "*forced outages*" means all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection, or acts of the public enemy, then the Company may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment.

(3) Sales (S) shall be determined in kilowatt-hours as follows:

Add:

(a) net generation
(b) purchases
(c) interchange in

Subtract:

(d) inter-system sales including economy energy and other energy sold on an economic dispatch basis.
(e) total system losses

Duke Energy Kentucky
1697-A Monmouth Street
Newport, Kentucky 41071

RIDER TCRM
TRANSMISSION COST RECOVERY MECHANISM (N)

APPLICABILITY

Applicable to all jurisdictional retail customers in the Company's electric service area.

Whenever the average cost of transmission charged to the Company by its Regional Transmission Organization is greater or less than the average cost of this transmission included per kilowatt-hour of sales in the base period, there shall be added to or subtracted from the net monthly bill to which this Rider is applicable, an amount determined by multiplying the number of kilowatt-hours consumed by the customer during the period for which the bill is rendered by a Rider TCRM adjustment.

1. The charge per kilowatt-hour delivered under the rate schedule to which this adjustment is applicable shall be increased or decreased during each year in accordance with the following formula:

$$Adjustment\ Factor = \frac{T(y)}{S(y)} - \frac{T(b)}{S(b)}$$

where:

a. "T" is the transmission related Midwest ISO Costs billed to Duke Energy Kentucky.

b. "S" is the kilowatt-hour sales.

c. "y" is the current year.

d. "b" is the base year.

2. Eligible transmission costs (T) shall be the most recent actual annual cost of:

a. Retail share of charges billed to Duke Energy Kentucky for Schedules 10, 10-FERC, 16, 17, and 24 of the Midwest ISO's Transmission Energy Market Tariff.

b. Retail share of net charges billed to Duke Energy Kentucky for congestion and marginal losses as billed from the Midwest ISO under its Transmission Energy Market Tariff.

c. Retail share of all other charges billed to Duke Energy Kentucky for congestion and marginal losses as billed from the Midwest ISO under its Transmission Energy Market Tariff excluding Day-Ahead and Real-Time energy costs, Revenue Sufficiency Guarantee Make-whole Payments, Virtual transactions, and Disputed amounts.

d. Eligible transmission expenses, T(b), included in the base year are $12,047,693.

e. Sales, S(b), for the base year, the twelve months ending December 31, 2007, are 4,006,495,000 kWh.

Issued by authority of an Order of the Kentucky Public Service Commission dated in Case No. 2006-00172.

Issued: Effective:

Issued by Sandra P. Meyer, President

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

PAUL G. SMITH

ON BEHALF OF

DUKE ENERGY KENTUCKY

183236

TABLE OF CONTENTS

		PAGE
I.	INTRODUCTION AND PURPOSE	-1-
II.	REASONS FOR RATE INCREASE	-3-
III.	COMPLIANCE WITH COMMISSION DIRECTIVES FROM 1991 RATE CASE	-6-
IV.	REQUESTED RATEMAKING TREATMENTS RELATED TO CASE NO. 2003-00252	-8-
V.	RATEMAKING-RELATED MERGER COMMITMENTS IN CASE NO. 2005-00228	-11-
VI.	FILING REQUIREMENTS SPONSORED BY WITNESS.	-13-
VII.	CONCLUSION	-14-

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul G. Smith and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as Vice President, Rates.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Science in Industrial Management Degree from Purdue University and a Master of Business Administration Degree, with Honors, from the University of Chicago Graduate School of Business. I am a Certified Public Accountant ("CPA") in the State of Ohio and a member of the American Institute of Certified Public Accountants. I am also a member of the Edison Electric Institute's Economic Regulation and Competition Committee, and Budgeting and Financial Forecasting Committee.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. Upon graduation from Purdue University in 1982, I was employed by the CPA firm of Touche, Ross & Co. as a member of the audit staff in their Chicago office. From 1984 to 1987 I was employed by the CPA firm of Crowe, Chizek & Co. as a member of the commercial audit and tax staff in their Indianapolis office. Since 1987 I have held various positions with PSI Energy, Inc., Cinergy Services, Inc., and Duke Energy Shared Services including responsibilities in the Rates and

Regulation, Budgets and Forecasts, Investor Relations, and Corporate Development departments as well as the International Business Unit. From March 1998 to July 1999, I was assigned to and worked full-time at Midlands Electricity, the regional electric company in the United Kingdom of which Cinergy previously held a 50% equity ownership. From March 2005 to March 2006, I was assigned to evaluating and analyzing the strategic merger between Cinergy Corp. and Duke Energy, including serving as Project Manager for the merger integration process. I was appointed to my current position as Vice President, Rates in April 2006.

Q. PLEASE DESCRIBE YOUR DUTIES AS VICE PRESIDENT, RATES.

A. As Vice President, Rates, I am responsible for the regulatory accounting and filings, cost of service and rate design for The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky") and The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("Duke Energy Ohio").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I testified in Duke Energy Kentucky's 2001 gas rate case, Case No. 2001-00092.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I discuss the reasons for Duke Energy Kentucky's requested rate increase. I also address certain matters raised by the Commission in the Company's last general electric rate case, Case No. 91-370. I list the ratemaking treatment the Company seeks in the present case, related to the Commission's December 5, 2003 Order in Case No. 2003-00252 ("the Plant Transfer Order"), involving the transfer from Duke Energy Ohio to Duke Energy Kentucky of the East Bend Generating Station ("East Bend"), the Miami Fort Generating Station Unit 6 ("Miami Fort 6") and the Woodsdale Generating Station ("Woodsdale") (collectively, "the Plants"). I discuss how Duke Energy Kentucky's requested rate relief is consistent with the Company's commitments in Case No. 2005-00228 ("the Merger Order"), involving the merger of Duke Energy and Cinergy. Finally, I sponsor Filing Requirement ("FR") 10(1)(b)(1) and FR 10(2) in this proceeding, and I support the reasonableness of the Company's base rate increase request and request for certain ratemaking treatments related to the Plant transfer case.

II. REASONS FOR RATE INCREASE

Q. WHEN WERE DUKE ENERGY KENTUCKY'S PRESENT ELECTRIC RATES APPROVED BY THIS COMMISSION?

A. Duke Energy Kentucky's current electric base rates were approved by this Commission pursuant to its Order dated May 5, 1992, and its subsequent orders issued, in Case No. 91-370. The test period in that proceeding was the actual twelve months ended July 31, 1991.

In Case No. 2001-00058, the Commission approved a settlement that froze the wholesale power purchase component of Duke Energy Kentucky's retail rates through the end of 2006. The Commission re-affirmed this requirement in the Plant Transfer Order (Case No. 2003-00252).

Q. WHAT ARE THE PRIMARY REASONS FOR DUKE ENERGY KENTUCKY'S REQUESTED RATE INCREASE IN THIS PROCEEDING?

A. Duke Energy Kentucky's primary reason for filing this proceeding is to comply with the Commission's directive in the Plant Transfer Order to file its next general electric rate case such that the effective date of the new rates, following the suspension period applicable to the test period selected by Duke Energy Kentucky, will be January 1, 2007. Duke Energy Kentucky has selected a forward-looking test period for this case. The suspension period for a forward-looking test period is six months. Duke Energy Kentucky is required to give 30 days' notice before new rates go into effect. This 30 days' notice requirement and the six-month suspension period require that we file our application at this time.

Additionally, we require this relief because our present rates are based on our cost of operations in 1991 and our power supply costs have been frozen since 2001. We have incurred significant cost increases and made significant investment in generation, transmission and distribution plant since that time. Duke Energy Kentucky's electric operation is projected to earn a 3.68% return on capitalization (3.47% on rate base) during the forecasted test period ending December 31, 2007. This return is well below the 9.80% return on rate base authorized by this Commission in Case 91-370, and is below the 8.761% return on capitalization proposed in this proceeding. In order to earn a fair return, Duke Energy Kentucky's retail rates must be increased by approximately $66.6 million (including fuel and emission allowances) to satisfy a total revenue requirement of approximately $306.4 million.

Q. WHAT ARE THE PRIMARY DRIVERS OF THE PROPOSED RATE INCREASE?

A. A significant portion of Duke Energy Kentucky's revenue deficiency arises from the capital investment, operating costs, depreciation expense and taxes related to the Plants. Historically, Duke Energy Kentucky obtained all of its power supply through a full requirements wholesale power contract with its parent company, Duke Energy Ohio. In the Plant Transfer Order, the Commission approved Duke Energy Ohio's transfer of the Plants to Duke Energy Kentucky.

The transfer of the Plants occurred effective January 1, 2006. At closing, Duke Energy Kentucky recorded the Plants at their net book value, consistent with the Commission's December 5, 2003 Plant Transfer Order. The difference between the revenue requirement related to owning and operating the Plants versus the Company's previous wholesale power costs related to its wholesale power contract with Duke Energy Ohio is approximately $34 million. Included in this difference are the costs of fuel and emission allowances, which have increased significantly over the past few years, as further discussed by Mr. Esamann.

Additionally, Duke Energy Kentucky has incurred normal inflationary cost increases since 1991 for transmission, distribution and administrative costs, and increased costs associated with membership in the Midwest ISO. Finally, Duke Energy Kentucky's electric transmission and distribution rate base is projected to increase by over $100 million as compared to the rate base used in the Company's 1991 case. Offsetting these increased costs are reduced financing costs and increased revenues attributable to retail load growth.

Q. HAS DUKE ENERGY KENTUCKY TAKEN ANY ACTIONS TO MITIGATE THIS RATE INCREASE?

A. Yes. Duke Energy Kentucky has been very proactive in controlling operation and maintenance expenses and has successfully controlled its costs through a variety of initiatives, including the 2006 merger of Duke Energy and Cinergy, the 2004 CIN-10 cost reduction initiative, the 2000 early retirement program, and the 1994 merger that formed Cinergy.

The Company has also aggressively managed its financing costs, reducing its cost of long-term debt from 9.375% at July 31, 1991 to 6.845% at December 31, 2005, and projected to be 6.090% for the 13-month average forecasted period, as supported by Ms. Good.

III. COMPLIANCE WITH COMMISSION DIRECTIVES FROM 1991 RATE CASE

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S DIRECTIVES FROM THE COMPANY'S 1991 RATE CASE?

A. Yes.

Q. WHAT DIRECTIVES DID THE COMMISSION ISSUE IN THE COMPANY'S 1991 RATE CASE?

A. The Commission issued three directives relating to labor costs. The Commission directed the Company to: (1) review its process for determining the labor cost of service for rate proceedings; (2) modify its overtime labor allocation procedures;

and (3) to perform a labor study. These three directives do not apply to this proceeding because the Company has proposed a forecasted test period. The Commission also issued directives relating to the cost of service study and rate design, which I discuss below.

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S DIRECTIVE FROM THE 1991 RATE CASE RELATING TO THE COST OF SERVICE STUDY?

A. Yes. In the 1991 rate case, the Commission criticized the Company's cost of service study methodology. The Commission recommended that, in future rate cases, the Company should separate out distribution plant into primary and secondary components for its cost-of-service study. The Commission also stated that the Company should file multiple cost-of-service studies that use, among other things, demand allocation methods from each of the peak demand, energy weighting, and time-differentiated families of production plant allocation methodologies. In its June 11, 1992 Order on Rehearing, the Commission stated that the Company should study the issue of whether it is feasible to separate distribution plant into primary and secondary components for its cost-of-service study. The Commission stated that, if this is not feasible, then the Company should explain in testimony the reasons why it could not do so.

Q. HAS THE COMPANY COMPLIED WITH THIS COMMISSION DIRECTIVE?

A. Yes. Mr. Ochsner supports Duke Energy Kentucky's cost of service study, and his testimony addresses the various steps he took to comply with this Commission directive.

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S DIRECTIVE FROM THE 1991 RATE CASE RELATING TO RATE DESIGN?

A. Yes. The Commission directed the Company to address residential rate design in its next case. The Commission suggested that the Company should obtain end-use customer data to determine whether 1,000 kWh is still the appropriate break point for the declining block rate structure. The Commission also stated that it would take a moderate approach to implementing an inverted summer rate by increasing the second rate block by approximately one-and-one-half times the increase to the first block.

Q. HAS THE COMPANY COMPLIED WITH THIS COMMISSION DIRECTIVE?

A. Yes. Mr. Bailey supports Duke Energy Kentucky's rate design, and his testimony addresses the issue of the appropriate break point between the two summer rates for residential customers, including whether there should be a break point, in compliance with this Commission directive.

IV. REQUESTED RATEMAKING TREATMENTS RELATED TO CASE NO. 2003-00252

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S DECEMBER 5, 2003 ORDER IN CASE NO. 2003-00252?

A. Yes.

Q. DOES DUKE ENERGY KENTUCKY SEEK ANY RATEMAKING TREATMENT IN THE PRESENT CASE RELATING TO THE COMMISSION'S DECEMBER 5, 2003 PLANT TRANSFER ORDER?

A. Yes, Duke Energy Kentucky requests several ratemaking treatments related to the Plant Transfer Order, as follows:

- in Finding No. 7 of the Commission's December 5, 2003 Plant Transfer Order, the Commission stated that it could see no reason why the Plants should not be valued at original cost less accumulated depreciation in future ratemaking proceedings. The Company requests such treatment in this case, as supported by Mr. Jacobs;
- in Finding No. 8 of the Plant Transfer Order, the Commission authorized the Company to create an accounting deferral for its actual transaction costs related to the transfer of the Plants, up to $2.45 million. The Commission stated that it could see no reason why the Company, in its next general electric rate case, should not be permitted to recover such transaction costs, to be amortized over five years, without carrying charges. The Company requests such treatment in this case, and Mr. Wathen supports this request;
- in Finding No. 9 of the Plant Transfer Order, the Commission authorized the Company to record below-the-line the accumulated deferred investment tax credits and accumulated deferred income tax balances related to the Plants, and stated that it could see no reason why the Company should not be accorded such below-the-line treatment in future

rate proceedings. The Company requests below-the-line treatment for these balances, and Mr. Butler supports this request;

- in Finding No. 10 of the Plant Transfer Order, the Commission stated that it could see no reason why the Company should not be permitted to recover in base rates the monthly capacity charges in the Back-up Power Sale Agreement ("Back-up PSA). The Company requests an increase in these capacity charges, as explained in more detail in Mr. Turner's and Mr. Esamann's testimony. The Company requests approval to recover such increased capacity charges in base rates;
- in Finding No. 11 of the Order, the Commission approved recovery of the energy charges under the Back-up PSA in accordance with 807 KAR 5:056. The Company requests that the Commission confirm in this proceeding that the Back-up PSA energy charges will be recovered in this manner, as supported by Mr. Wathen; and
- in Finding No. 13 of the Order, the Commission stated that the Company's proposed mechanism for sharing profits from off-system sales appeared reasonable, and the Commission stated that it could see no reason why such mechanism should not be approved in the present proceeding, as I support below.

Q. WHY SHOULD THE COMMISSION APPROVE IN THIS PROCEEDING THE OFF-SYSTEM SALES SHARING MECHANISM PROPOSED BY THE COMPANY IN CASE NO. 2003-00252?

A. Under traditional ratemaking treatment, the customers receive all of the benefits from off-system sales. In Case No. 2003-00252, the Companies requested approval of an off-system sales sharing mechanism to recognize the fact that the Plants were deregulated, such that Duke Energy Ohio formerly retained all profits related to serving non-provider of last resort customers. The Commission approved an off-system sharing mechanism calling for the customers to receive the first $1 million in profits, and for 50/50 sharing of profits above $1 million. This was an integral part of the transaction in Case No. 2003-00252, and the Company submits that such treatment is just and reasonable, just as the Commission preliminarily determined in its Plant Transfer Order.

V. RATEMAKING-RELATED MERGER COMMITMENTS IN CASE NO. 2005-00228

Q. ARE YOU FAMILIAR WITH THE MERGER COMMITMENTS RELATED TO FUTURE RATEMAKING PROCEEDINGS THAT THE COMPANY MADE, AND THE COMMISSION APPROVED, IN CASE NO. 2005-00228 ("MERGER ORDER")?

A. Yes.

Q. PLEASE EXPLAIN THESE COMMITMENTS, AND EXPLAIN HOW THE COMPANY HAS HONORED THESE COMMITMENTS.

A. I will list below each merger commitment related to future ratemaking proceedings, and discuss how the Company has complied with each one:

- the settlement agreement approved in the Merger Order provided for certain rate credits, to be terminated upon the effective date of new rates in the Company's next base rate case, excluding any case resulting in new rates prior to January 1, 2008. The proposed rates in this case would take effect on January 1, 2007, following the suspension period, so the merger credits should remain in effect. The Company has satisfied this merger commitment because it proposes the continuation of the Merger Savings Credit Rider (Rider MSR-E);

- the settlement agreement contains an Attachment 2 listing 46 separate merger commitments. Merger commitments #3 and #4 relate to push-down accounting. Merger commitment #3 states that the payment for Cinergy's stock shall be excluded from Duke Energy Kentucky's books for retail ratemaking purposes. Merger commitment #4 states that any such acquisition premium would be excluded from retail ratemaking. The Company subsequently determined that it would end its voluntary reporting to the U.S. Securities and Exchange Commission, such that it would not be subject to push-down accounting. Duke Energy Kentucky did not reflect any such payment on its books; therefore, its proposed rates do not reflect any such payment or acquisition premium;
- Merger commitment #5 states that the Company would exclude change in control payments for retail ratemaking purposes. No change in control payments were allocated to Duke Energy Kentucky; therefore, its proposed rates do not reflect any change in control payments;
- Merger commitment #14 recognizes the Commission's continuing jurisdiction, for retail ratemaking purposes, over Duke Energy Kentucky's

capital structure, financing, and cost of capital. The Company continues to recognize that the Commission has such jurisdiction;

- Merger commitment #15 states that the merger will have no adverse impact on the base rates or the operation of the fuel adjustment clause, gas supply clause, and demand side management clause of Duke Energy Kentucky. The Company's proposed rates reflect continued operation of the merger credit savings sharing mechanism. This mechanism reflects a greater level of merger savings than merger costs allocated to Duke Energy Kentucky, so the Company has met this merger commitment;
- Merger commitment #16 states that Duke Energy Kentucky will not seek a higher rate of return on equity than would have been sought if the merger had not occurred. As supported by Dr. Morin, the Company's proposed cost of equity is not higher than it would have been absent the merger, so the Company has satisfied this merger commitment; and
- Merger commitment #17 states that the accounting and ratemaking treatment of the Company's excess deferred income taxes shall not be affected by the merger. The Company was not required to apply push-down accounting; therefore, the merger had no impact on the Company's excess deferred income taxes. Accordingly, the Company has honored this merger commitment.

VI. <u>FILING REQUIREMENTS SPONSORED BY WITNESS.</u>

Q. PLEASE DESCRIBE FR 10(1)(b)(1).

A. FR 10(1)(b)(1) is Duke Energy Kentucky's statement of the reasons for the proposed increase.

Q. PLEASE DESCRIBE FR 10(2).

A. FR 10(2) is a statement certifying that the Company provided four weeks' notice of its rate application, as required by the Commission's rules.

VII. CONCLUSION

Q. HAVE YOU REVIEWED DUKE ENERGY KENTUCKY'S FILING IN THIS PROCEEDING?

A. Yes, I have. I reviewed the application and supporting schedules, and the testimony and attachments of all witnesses. I believe that the costs of service are properly allocated to customer classes, and the rate design is equitable.

Q. DO YOU HAVE AN OPINION REGARDING WHETHER DUKE ENERGY KENTUCKY'S RATE REQUEST IS REASONABLE?

A. Yes.

Q. PLEASE STATE YOUR OPINION.

A. Duke Energy Kentucky's rate request is fair and reasonable. The date certain in the Company's last rate case was July 31, 1991, and the forecasted test period in this case extends through December 31, 2007. Duke Energy Kentucky has made, and plans to continue to make, significant investments in its electric system, and now owns and operates the Plants transferred as a result of the Commission's Plant Transfer Order. As stated previously, a reasonable return of, and on, these significant capital investments, along with appropriate recovery for the other increased costs I discussed earlier in my testimony, are the main drivers of this base rate case.

Q. WERE FR 10(1)(B)(1) AND 10(2) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, Paul G. Smith, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Paul G. Smith

Paul G. Smith, Affiant

Subscribed and sworn to before me by Paul G. Smith on this 24th day of May, 2006.

Anita M. Schafer

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2009