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

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			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.

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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 14

SANDRA P. MEYER
JAMES L. TURNER
JIM L. STANLEY
JOHN J. ROEBEL
PAUL K. JETT
JOHN D. SWEZ
DOUGLAS D. ESAMANN
DWIGHT L. JACOBS
CARL L. COUNCIL, JR.
JOHN J. SPANOS
DR. RICHARD G. STEVIE

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

SANDRA P. MEYER

ON BEHALF OF

DUKE ENERGY KENTUCKY

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Sandra P. Meyer, 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 President of The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("Duke Energy Ohio") and its subsidiary, The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I earned a Bachelor of Science degree in Accounting from Louisiana State University. I have completed Harvard University's Advanced Management Program. I am a certified public accountant in North Carolina and Texas. I am a member of the North Carolina Associations of Certified Public Accountants and the American Institute of Certified Public Accountants. I have served as advisory director of the Houston Chapter of the Texas Society of Certified Public Accountants. I am also a past regional director and past president of the Charlotte and Houston Chapters of Financial Executives International, a professional society of chief financial officers and other financial executives.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined Texas Eastern Corporation ("Texas Eastern") in 1976 as a junior accountant. I held positions of increasing responsibility with Texas Eastern and its successor, PanEnergy Corp. ("PanEnergy"). I was elected vice president and controller of PanEnergy in 1994, and I was named to the additional position of treasurer in 1996. Following the 1997 merger of Duke Energy Corporation ("Duke Energy") and PanEnergy, I held various financial leadership positions with Duke Energy until 2001, when I was named senior vice president of retail services. In 2003, I became group vice president of customer service, sales and marketing for Duke Power, a business unit of Duke Energy. I was named to my current position in April 2006.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS PRESIDENT OF DUKE ENERGY KENTUCKY.

A. As President of Duke Energy Kentucky, I am responsible for ensuring that our customers continue to have access to safe, reliable, and reasonably priced gas and electric service, and that these services are provided in accordance with applicable federal and state laws and regulations.

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

A. My testimony provides an overview of Duke Energy Kentucky's electric business operations. I next discuss the Company's major developments since its last retail electric base rate case in 1991, including the status of the transfer of the East Bend Generating Station ("East Bend"), Miami Fort Generating Station Unit 6 ("Miami Fort 6") and the Woodsdale Generating Station ("Woodsdale") (collectively, "the Plants").

I explain our need for an increase in electric rates. I discuss how the timely and constructive regulatory treatment we seek from the Commission will enable us to continue our high levels of customer satisfaction by providing our customers with the reasonably priced, reliable service they have come to expect from us.

I describe Duke Energy Kentucky's proposal in this proceeding relating to the Back-up Power Supply Agreement ("Back-up PSA") approved by the Commission in Case No. 2003-00252. I also discuss the resource planning that we have undertaken to identify other supply options for Duke Energy Kentucky.

I sponsor the following Filing Requirements ("FR"): FR 8(1), FR 8(2), FR 10(1)(b)(2), FR 10(1)(b)(3), FR 10(1)(b)(4), FR 10(1)(b)(5), FR 10(1)(b)(6), FR 10(9)(a), and FR 10(9)(e). Finally, I introduce the other witnesses who testify on the Company's behalf, and I provide an overview of their testimony.

II. DUKE ENERGY KENTUCKY'S ELECTRIC BUSINESS

A. OVERVIEW

Q. PLEASE GIVE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S ELECTRIC BUSINESS.

A. Duke Energy Kentucky is based in Cincinnati, Ohio, with additional electric operations locations in Newport, Erlanger, and Rabbit Hash, Kentucky, and North Bend and Trenton, Ohio, as well as local transmission and distribution facilities throughout Northern Kentucky. The Company's operations at these locations are as follows:

- Cincinnati, Ohio – the headquarters for Duke Energy Kentucky;

- Rabbit Hash, Kentucky – the East Bend Generating Station;
- North Bend, Ohio – the Miami Fort Generating Station Unit 6;
- Trenton, Ohio – the Woodsdale Generating Station;
- Newport, Kentucky – Duke Energy Kentucky's local customer service office; and
- Erlanger, Kentucky – Duke Energy Kentucky's construction and maintenance facility.

From these locations, Duke Energy Kentucky generates electricity; provides for the construction, operation and maintenance of its electric delivery system; and conducts its business operations. Duke Energy Kentucky provides electric service to approximately 131,000 customers in Boone, Campbell, Gallatin, Grant, Kenton and Pendleton counties in Northern Kentucky. Mr. Roebel discusses the Plants and Mr. Stanley discusses Duke Energy Kentucky's local transmission and distribution operations in detail.

B. ECONOMIC DEVELOPMENT

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S ECONOMIC DEVELOPMENT ACTIVITIES.

A. Duke Energy Kentucky's longstanding support for state and local economic development efforts, combined with Duke Energy Kentucky's reasonably priced rates, have resulted in a number of Kentucky economic development successes in which we have played a part.

Duke Energy Kentucky's economic development staff chaired the 2004 Annual Meeting for the Kentucky Industrial Development Council. Our economic development staff also actively participates in the Tri-County

Economic Development Foundation, consisting of Boone, Kenton and Campbell Counties.

For the last seven years, Duke Energy and/or Cinergy have been named as one of the "Top 10 Best" utility economic development programs by *Site Selection* magazine. Even more important to us, our surveys of local economic development officials indicate that they are highly satisfied (100% satisfaction rate) with Duke Energy Kentucky's economic development efforts and services.

We estimate that our cooperative efforts, along with state and local economic development officials, have contributed to the creation of nearly 22,000 Kentucky jobs and more than $1.9 billion of capital investment in Northern Kentucky since 1995.

C. <u>CHARITABLE GIVING</u>

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S CHARITABLE GIVING PHILOSOPHY.

A. Duke Energy Kentucky has made good corporate citizenship a priority by giving back to the communities we serve. Since 1994, our philanthropic affiliate, Cinergy Foundation, has contributed over $2.35 million to Northern Kentucky charitable organizations in the communities we serve. We strongly encourage a spirit of volunteerism among our employees, who contribute countless hours of volunteer time to support the many communities in which they live and work. Duke Energy Kentucky also supports heating assistance programs.

D. CUSTOMER SERVICE CHANNELS

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S CUSTOMER SERVICE ACTIVITIES.

A. Duke Energy Kentucky strives to provide customers a variety of convenient methods to do business with us. Duke Energy Kentucky strives to contain and reduce its customer service costs by using new technology and new customer service channels. Duke Energy Kentucky's customer service channels include:

- *Contact Centers* – Duke Energy Midwest (covering Kentucky, Ohio and Indiana) staffs four contact centers (two for Customer Service, one for Credit, and one for New Service Contacts) with over 300 persons. These centers handle four million customer contacts per year, including telephone calls, e-mails, on-line chats and faxes.
- *Business Service Center* – Our Business Service Center provides customer service and communications to our commercial, industrial, and governmental customers. The Business Service Center is staffed by skilled personnel with many years of quality field experience who respond to customers via telephone, e-mail, and fax. Additionally, Duke Energy Kentucky provides Customer Relationship Managers and Technical Service Engineers who meet with these customers in person as needed.
- *Pay Stations* – Pay stations are local authorized retailers or agents that accept Duke Energy Kentucky bill payments and transmit the data to our billing system on a daily basis. Our eight Duke Energy Kentucky pay

stations allow customers to pay their bills at conveniently located businesses, many of which have extended hours.

- *Automated Phone Service* – This service allows customers to access information regarding their gas and/or electric service accounts from any touchtone telephone, 24 hours a day, seven days a week. Via Automated Phone Service, customers can check the amount and due date of their current bill, verify the amount and date of their last payment, confirm the amount and due date to prevent disconnection for non-payment, pay by phone, make payment arrangements, or report a service outage. In 2005, Duke Energy Midwest's self-service Interactive Voice Response handled approximately 1.3 million customer contacts – representing 23% of total call volume.
- *Online Services* – Via our Web site, customers have the freedom to manage their gas and/or electric service accounts from any computer with Internet access – 24 hours a day, seven days a week. With our Online Services, customers can view and pay their bills, check the amount and due date of a current bill, access billing and usage history, turn on or turn off service, enroll in our Budget Billing Program, report an electric power outage, submit meter reads, view meter reading schedules, and more. Duke Energy Kentucky customers use Online Services as a way to manage their gas and/or electric accounts online. As of December 31, 2005, we have approximately 215,000 Duke Energy Kentucky and Ohio customers who have established online accounts. This represents a 125%

increase from the number of Kentucky and Ohio customers with online accounts as of December 2003. On average, Duke Energy Midwest has approximately 113,000 customers that visit Online Services on a monthly basis (a 130% increase from 2003).

- *Duke-Energy.com* – Our website provides customers with useful and timely information, such as how to manage bills during the heating and cooling seasons, how to be safe around gas and electricity, information about rate tariffs and more. Customers may also perform online energy audits; identify ways to conserve energy; view the "Storm Center" to see the locations and number of electric outages during severe weather; submit online requests for tree trimming; and report street light outages.
- *Customer Service Office* – Duke Energy Kentucky customers who wish to do business in person with a Duke Energy Kentucky representative can visit our office located at 1697 A Monmouth, Newport, Kentucky. This is a relatively new location, replacing our previous location in Covington. It provides for more open and efficient use of office space, and allows for a more effective office design, resulting in shorter wait times for customers. This new location is more accessible by car for all customers in the Duke Energy Kentucky service area, while remaining convenient to our customers, especially our low-income customers, by being located in a core area where public transportation is accessible.

E. BILL MANAGEMENT AND BILL PAYMENT OPTIONS

Q. PLEASE GIVE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S BILL MANAGEMENT AND BILL PAYMENT PROGRAMS.

A. Duke Energy Kentucky offers several optional bill management programs, designed to meet our customers' varied needs:

- *Budget Billing Program* – This program helps customers manage their monthly energy costs by setting a monthly billing amount based on an average annual cost. Under the "Quarterly" Budget Billing plan, we review the customer's account every three months and adjust the Budget Billing amount to better reflect the actual energy use. This allows customers to avoid a twelfth month bill adjustment. Under the "Annual" Budget Billing plan, the customer's monthly payments remain the same each month, and in the twelfth month, the customer is billed or credited for any difference between actual usage and the total amount paid during the Budget Billing year. During the sixth month of the Annual plan, we review the customer's account and notify them with a bill message if the current Budget Billing amount needs to be adjusted up or down. The customer can notify us if they wish to change their Budget Billing amount at any time.
- *Adjusted Due Date* – This plan allows eligible customers to extend their normal billing due date up to ten days from their original due date. This enables customers to better align their due date with the date they receive their paycheck, pension, Social Security check, *etc.*

- *Extended Payment Agreements* – Duke Energy Kentucky offers extended payment plans to eligible customers who are having difficulty paying their entire bill by the due date. Customers may be eligible for a six-month agreement, the One-Third Payment Plan, or a Combination Agreement and Budget Billing plan.
- *WinterCare* – This energy assistance program is available to eligible Duke Energy Kentucky customers who need financial assistance with their gas and/or electric bill and is independently administered by the Northern Kentucky Community Action Commission. Eligibility is based upon need and does not necessarily follow government assistance guidelines. Eligible customers can receive up to $300.00 in assistance for their utility bill. WinterCare is completely funded by Duke Energy Kentucky employees, customers, and shareholders. For 2006, Duke Energy Kentucky provided a $25,000 lump sum contribution and is matching $1.00 for every $1.00 donated, up to $25,000, providing for total funding of up to $50,000.

Duke Energy Kentucky also offers a number of bill payment options for customers, in addition to the traditional bill payment option via U.S. mail:

- *BillPayer 2000* – This program allows customers to have their bill payments automatically deducted from their checking account. A nominal transaction fee is assessed by the third-party vendor for this program.

- *Speedpay* – This program allows customers to make payments by electronic check or credit/debit card over the telephone or via the Internet. The third-party vendor charges a transaction fee for this program.
- *e-Bill* – This free online electronic payment option allows Duke Energy Kentucky customers to view and pay their gas and/or electric bills online. e-Bill offers two payment options: AutoPay (payments are automatically paid each month on the due date) and Pay Online (customers authorize bill payments online each month). All customer payments are electronically deducted from their personal checking account and/or money market account. Duke Energy Kentucky currently has approximately 15,000 customers enrolled in e-Bill.

F. <u>CUSTOMER SATISFACTION</u>

Q. HOW DOES DUKE ENERGY KENTUCKY'S PERFORMANCE MEASURE FOR PROVIDING HIGH QUALITY CUSTOMER SERVICE?

A. Duke Energy Kentucky strives to provide high quality customer service. Cinergy received the distinction by J.D. Power and Associates ("J.D. Power") in 2005 as the first utility in the nation to receive Call Center Certification. This is an outstanding achievement, given the rigorous internal audit, as well as the many detailed customer surveys which were conducted by J.D. Power. All of Duke Energy's call centers were successfully certified in 2006.

We measure our customer satisfaction performance through two primary measurement tools: the J.D. Power annual electric utility residential customer satisfaction studies and our own survey of residential customers who have recently interacted with Duke Energy Kentucky.

J.D. POWER STUDIES

J.D. Power is well known for setting the standard for measurement of consumer opinion and customer satisfaction in many key industries. J.D. Power annually surveys electric utilities' residential customer satisfaction. Duke Energy Midwest participates in these annual studies. The results indicate that Duke Energy consistently provides high quality customer service.

The J.D. Power electric utility residential customer satisfaction study, established in 1999, calculates overall customer satisfaction based on five performance areas: (1) power quality and reliability; (2) company image; (3) price and value; (4) billing and payment; and (5) customer service. For 2005, the most recent study for which results are available, J.D. Power measured residential customer satisfaction for the country's 78 largest electric utilities, serving over 91 million customers. Since 1999, Duke Energy Midwest's scores in overall satisfaction have outperformed the industry average and the Midwest region average scores.

DUKE ENERGY KENTUCKY – SPECIFIC CUSTOMER SURVEYS

In addition to the independent J.D. Power studies, our internal customer satisfaction measurements continue to reflect strong performance in meeting the needs of Duke Energy Kentucky customers. We regularly survey residential customers who have had a recent service contact with Duke Energy Kentucky. These surveys are conducted throughout the year by an independent research firm.

Five key processes are measured by these surveys, reflecting the majority of interactions customers have with Duke Energy Kentucky: (1) billing issues (billing inquiries, billing complaints, *etc.*); (2) office bill payments (payments made over the counter at a Duke Energy Kentucky customer service office); (3) turn on/turn off requests (requests for initiation, transfer, or termination of service); (4) service failure (outages and emergency situations); and (5) miscellaneous service requests (service requests of a non-emergency nature).

Customers who had a recent contact in one of these five process areas are randomly sampled, by means of a mail survey within ten days of their contact with Duke Energy Kentucky. Since 1999, we have accumulated over 4,300 Duke Energy Kentucky survey responses. These responses represent the "voice" of our Duke Energy Kentucky customers and enable us to continue to improve customer satisfaction in each of the key processes included in the survey.

Duke Energy Kentucky's customer satisfaction scores indicate that overall customer satisfaction is high – in 2005, customers provided the following ratings:

- billing issues: 82% of responding customers were "satisfied" or "very satisfied;"
- office bill payments: 96% of responding customers were "satisfied" or "very satisfied;"
- turn on/turn off requests: 93% of responding customers were "satisfied" or "very satisfied;"
- service failure: 90% of responding customers were "satisfied" or "very satisfied;" and

- miscellaneous service requests: 84% of responding customers were "satisfied" or "very satisfied."

III. MAJOR DEVELOPMENTS SINCE 1991

Q. WHAT MAJOR DEVELOPMENTS IN DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC BUSINESS HAVE OCCURRED SINCE ITS LAST RETAIL ELECTRIC BASE RATE CASE IN 1991?

A. In 1994, The Cincinnati Gas & Electric Company, the Company's parent company, merged with PSI Energy, Inc. to form Cinergy Corp. ("Cinergy"). In 2006, Cinergy merged with Duke Energy. Duke Energy Kentucky has realized operational efficiencies from the 1994 merger and, as Mr. Turner discusses, will realize additional operational efficiencies from the 2006 merger with Duke Energy, while continuing to provide reliable, cost-effective service.

Duke Energy Kentucky obtained approximately 1,100 megawatts of capacity when Duke Energy Ohio transferred the Plants to Duke Energy Kentucky at the beginning of 2006. Duke Energy Kentucky has joined the Midwest Independent System Operator, Inc. as a transmission provider; however, as explained by Mr. Stanley, Duke Energy Kentucky only owns local transmission facilities. The bulk transmission system in Northern Kentucky is owned by Duke Energy Ohio.

The Company has initiated several initiatives since 1991 to more efficiently operate its business and provide better service for customers. I discuss the cost savings programs later in my testimony. Our current initiatives include deploying Advanced Metering Infrastructure ("AMI") and introducing a Personalized Energy Report.

Q. PLEASE EXPLAIN THE COMPANY'S PLAN TO INTRODUCE AMI.

A. AMI consists of the communications hardware and software, advanced metering and all data management systems necessary to store, process and transmit the data being collected by using two-way communication through advanced metering. There are various types of automated meter reading ("AMR") technologies and we have installed approximately 9,700 drive-by AMR devices for safety or inaccessibility reasons.

We have explored various technologies and concluded that the technologies that offer the most promise are Power Line Communications ("PLC") technology and Broadband over Power Lines ("BPL") technology. We conducted a competitive bidding process and selected a vendor to install AMI equipment using PLC technology beginning later this year. We plan to install the equipment for electric and gas customers, involving approximately 230,000 meters, which will take a few years to completely deploy. We will continue to evaluate BPL technology during this time and we will keep our options open for deploying BPL technology in conjunction with PLC technology during the roll-out process.

The AMI system will enable us to provide two-way meter communications. The AMI technology should improve our customer usage information, avoid meter inaccessibility issues, provide for time-based rates, and enhance outage restoration. Mr. Stanley discusses our AMI plans in greater detail.

Q. PLEASE EXPLAIN THE COMPANY'S PLAN TO INTRODUCE PERSONALIZED ENERGY REPORTS.

A. The Personalized Energy Report is part of Duke Energy Kentucky's Demand Side Management programs. The program targets single family residential customers. After completing a mailed survey, participants will receive a personalized report containing facts about their energy usage and energy saving tips. Some survey respondents will also receive an "Efficiency Starter Kit," containing nine easily installed energy saving devices to show how easily home energy usage can be made more efficient. We started rolling out the program in May 2006. We will mail out approximately 43,000 surveys and 12,500 starter kits. The Personalized Energy Report will help customers better manage rising energy costs.

IV. COMPANY'S NEED FOR PROPOSED RATE INCREASE

Q. PLEASE EXPLAIN WHY DUKE ENERGY KENTUCKY PROPOSES TO INCREASE ITS RETAIL ELECTRIC RATES.

A. The Company proposes new rates to comply with the Commission's directive in Case No. 2003-00252 to file its next general rate case such that the new rates will become effective on January 1, 2007. We also seek new rates because our present base rates reflect our cost of service from 1991, and our present fuel rate has been frozen since 2001. Duke Energy Kentucky also needs to reflect the costs related to the Plants in its retail rates, including current costs for fuel and emission allowances, which have increased significantly in recent years. Finally, Duke

Energy Kentucky also seeks to include in rates the costs for its continued investment in distribution and local transmission facilities needed to provide reliable service for Kentucky customers. The load growth on Duke Energy Kentucky's system has been relatively slow, and has not significantly offset these increased costs. These factors compel the Company to propose new rates in this proceeding.

Q. PLEASE GENERALLY DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED RATE INCREASE.

A. Duke Energy Kentucky proposes to increase its non-fuel electric base rates so as to increase its annual revenues for its electric business by approximately $46.5 million. We also propose to increase the fuel cost recovery by approximately $20 million over the amount currently reflected in our base fuel rate and our current frozen rate in the Fuel Adjustment Clause, which has been frozen since 2001. In sum, the increase over current rates is approximately $66.6 million. This represents an average aggregate base rate increase of approximately 26.7% over the average electric base rates currently in effect. This rate increase is necessary in order to allow Duke Energy Kentucky to recover its costs for providing reliable electric service, plus a fair return on its investment in electric generation, local transmission and distribution facilities.

Duke Energy Kentucky used a forecasted test period starting with projected 2006 budget information and made certain adjustments as a basis for the forecasted test period ending December 2007, as discussed by Mr. Davey. The Company selected a forecasted test period because it continues to invest heavily in its electric business and the forecasted test period will enable Duke Energy Kentucky to avoid some degree of lag in recovery of these costs, and gain more certainty in recovery of its capital investment and fuel costs, as these expenditures will be reflected in base rates through the end of the forecasted test period.

Q. HOW DO DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC RATES COMPARE TO THE RATES FOR OTHER ELECTRIC UTILITIES?

A. Duke Energy Kentucky's average electric rates compare favorably to the national average rates, but are higher than Kentucky investor-owned utility average electric rates. According to the Typical Bills and Average Rates Report for Winter 2006 published by the Edison Electric Institute, the national average electric delivery rate for residential customers was 45% higher than Duke Energy Kentucky's current residential electric rates. For commercial and industrial customers, the national average rates were approximately 45% and 8% higher than Duke Energy Kentucky's, respectively. Based on the most recently published data, Duke Energy Kentucky's electric rates are higher than other Kentucky investor-owned utilities; however, our higher overall rates partially result from our different customer mix. Other Kentucky electric utilities have a higher proportion of commercial and industrial customers, which typically have lower average rates, while Duke Energy Kentucky has a higher concentration of residential customers.

Q. HOW HAVE DUKE ENERGY KENTUCKY'S COSTS INCREASED AS COMPARED TO THE AMOUNTS CURRENTLY REFLECTED IN RATES?

A. Since its last general electric rate case, Duke Energy Ohio has transferred the Plants to Duke Energy Kentucky, and the Companies have terminated the wholesale power contract through which Duke Energy Kentucky formerly obtained its wholesale power supply. Duke Energy Kentucky has invested approximately $399 million for these facilities. The Company has also made substantial capital investments to its local transmission and distribution systems since its last electric rate case. The valuation date in that case was July 31, 1991. From that date through December 31, 2007, these system investments are projected to total approximately $170 million above the level currently reflected in rates. Additionally, Duke Energy Kentucky's Fuel Adjustment Clause has been frozen since 2001, but the costs for fuel and purchased power have increased significantly since then. Other costs, such as emission allowances, have also increased significantly. Mr. Smith discusses in greater detail the drivers for the Company's proposed rates.

V. STATUS OF ASSET TRANSFER AND RESOURCE PLANNING

Q. WHAT IS THE STATUS OF THE PLANT TRANSFER THAT THE COMMISSION APPROVED IN CASE NO. 2003-00252?

A. The closing for Duke Energy Ohio's transfer of the Plants to Duke Energy Kentucky occurred effective January 1, 2006. These are quality generating assets that will provide value for our customers for many years to come. Mr. Roebel describes the Plants' characteristics in more detail.

Q. ARE THERE ANY OPEN ISSUES RELATING TO THE PLANT TRANSFER THAT THE COMPANY ASKS THE COMMISSION TO RESOLVE IN THIS PROCEEDING?

A. Yes. In Case No. 2003-00252, the Commission approved a Back-up Supply Agreement ("Back-up PSA") for the Plants. Under the terms of the Back-up PSA, Duke Energy Ohio agreed to provide back-up power for East Bend and Miami Fort 6 for planned and unplanned outages through the end of 2009. The Companies have not obtained approval for the Back-up PSA from the Federal Energy Regulatory Commission ("FERC") for this affiliate contract. We are in the process of putting various supply options out for competitive bidding before seeking FERC approval, as I discuss later in my testimony.

Q. WHAT DOES THE COMPANY PROPOSE RELATING TO THE BACK-UP PSA?

A. Duke Energy Kentucky requests Commission approval to refresh the pricing of the capacity payments in the Back-up PSA to reflect current market pricing. Mr. Esamann discusses this proposal in more detail.

Q. WHAT RESOURCE PLANS HAVE YOU MADE, GIVEN THAT THE BACK-UP PSA IS NOT IN EFFECT?

A. I have discussed various supply options with Mr. Esamann and I ultimately authorized him to purchase 100 megawatts of firm capacity for July and August 2006. I also directed him to begin a competitive bidding process to explore other supply options. We are seeking bids on a number of different products and for a variety of short- and long-term time periods. The bids from the competitive bidding process are expected in July 2006. We will evaluate the supply options at that time and we will notify the Commission of the results of the competitive bidding process. Mr. Esamann discusses the various supply options and the competitive bidding process in more detail.

Q. WHAT IMPACT WOULD IT HAVE ON DUKE ENERGY KENTUCKY IF THE COMMISSION APPROVES THE COMPANY'S REQUEST TO REFRESH THE PRICING UNDER THE BACK-UP PSA?

A. If the Commission approves our request, the pricing for the Back-up PSA would increase because market prices have risen since 2003. The Back-up PSA, however, as approved by the Commission in Case No. 2003-00252, is a somewhat risky option for the Company to rely upon because the prospects for approval by the FERC are uncertain. Additionally, any delay involving the FERC approval process will make resource planning more difficult.

We would prefer to take a fresh look at all available supply options and select the optimal supply plan. This open bidding process will improve the likelihood of timely FERC approval. This would provide reasonable assurance that Duke Energy Kentucky could obtain the best portfolio of supply options and the least amount of regulatory risk to reliably serve our Kentucky customers. Mr. Esamann explains the reasons for our proposal in more detail.

VI. <u>FILING REQUIREMENTS SPONSORED BY WITNESS</u>

Q. PLEASE DESCRIBE FR 8(1) AND FR 8(2).

A. These filing requirements provide for the Company to seek proposed new rates through a written application addressing various matters, and to file a prescribed number of copies with the Commission. This was done at my direction.

Q. PLEASE DESCRIBE FR 10(1)(B)(2).

A. FR 10(1)(b)(2) certifies that Duke Energy Kentucky's annual reports are on file with the Commission, including the annual report for the most recent calendar year. These reports are filed by March 31 annually, and we filed the current report due by March 31, 2006, as required by the Commission's rules.

Q. PLEASE DESCRIBE FR 10(1)(B)(3).

A. FR 10(1)(b)(3) is a certified copy of the Company's articles of incorporation, or a statement that the articles of incorporation were filed in a recent Commission proceeding. The current articles of incorporation and amendments for Duke Energy Kentucky were filed in our recent gas rate case, Case No. 2005-00042, and we reference this in our current filing.

Q. PLEASE DESCRIBE FR 10(1)(B)(4).

A. FR 10(1)(b)(4) applies to utilities that are limited partnerships; therefore, it does not apply to Duke Energy Kentucky, which is a corporation.

Q. PLEASE DESCRIBE FR 10(1)(B)(5).

A. FR 10(1)(b)(5) is a certificate of good standing or authorization, which we provide with our filing.

Q. PLEASE DESCRIBE FR 10(1)(B)(6).

A. FR 10(1)(b)(6) is a certificate of assumed name. Duke Energy Kentucky's actual legal name is "The Union Light, Heat and Power Company." The Company has filed for the assumed names of "Duke Energy Kentucky, Inc." and "Duke Energy." These certificates of assumed name are provided with our filing.

Q. PLEASE DESCRIBE FR 10(1)(B)(9).

A. FR 10(1)(b)(9) is a statement verifying that customer notice has been provided in accordance with the Commission's rules.

Q. PLEASE DESCRIBE FR 10(4).

A. FR 10(4) is a description of how the customer notice of the rate proposal was provided pursuant to the Commission's rules.

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

A. FR 10(9)(a) requires testimony from me, as the Company's chief officer in charge of Kentucky operations, about Duke Energy Kentucky's existing programs to achieve improvements in efficiency and productivity and the purpose of each program. These programs are discussed below.

- Duke/Cinergy merger: In April 2006, Duke Energy and Cinergy closed their merger. Duke Energy Kentucky will benefit from the operational efficiencies arising from the merger, as discussed more fully by Mr. Turner. The Commission's November 29, 2005 Order in Case No. 2005-00228 provides that, for the present case, these savings are already being reflected through the merger savings sharing mechanism. Duke Energy Kentucky will credit customers with approximately $7.6 million in net merger savings through this sharing mechanism. In future general rate cases with proposed rates effective on or after January 1, 2008, the actual savings will be reflected in base rates.

- Service outage management systems: we manage electric outages using the following systems designed to enhance efficiency and productivity: Supervisory Control and Data Acquisition ("SCADA"), the Trouble Call Outage Management System ("TCOMS"), the Electric Trouble data mart and the Outage Information System. Mr. Stanley describes our outage management process and systems in more detail.
- Electric distribution system maintenance programs: our major programs to achieve efficiency and productivity in maintaining our distribution system are the substation inspection program, the line inspection program, the vegetation management program, the underground replacement program, the capacitor installation maintenance program, infrared scanning of equipment and dissolved gas analysis. These programs are all designed to keep our distribution systems in good working order through efficient use of our resources. These programs are part of our distribution maintenance practices, which Mr. Stanley discusses.
- AMI technology: Duke Energy Kentucky will begin installing AMI technology later this year, as I discussed earlier in my testimony. We expect this to ultimately improve customer service and reduce our costs related to meter reading, customer service calls and call center operations. The cost savings related to the AMI initiative are reflected in the forecasted test period.
- Plant maintenance and pollution control improvements: Mr. Roebel discusses various maintenance programs and capital improvement

programs to install pollution control equipment, which are designed to enhance the efficiency and productivity of the Plants.

The cost savings impacts of these programs are reflected in the forecasted test period, except that merger savings are already being reflected in our rates through the merger savings sharing mechanism, as I discussed above.

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

A. FR 10(9)(e) is the management attestation of the reasonableness of the financial data for the forecasted test period. In preparing this document, I reviewed the testimony of Duke Energy Kentucky's witnesses, including Mr. Davey, regarding how the forecasted test period data was developed. I also discussed this matter with Mr. Davey. I can attest that the forecasted test period data submitted in this proceeding is reasonable, reliable, and made in good faith; that the assumptions have been identified and justified; that the assumptions and methodologies are the same used by management; and that productivity and efficiency gains are included in the forecast. I signed the statement of attestation to this effect, which is provided with the filing requirements submitted by the Company.

VII. INTRODUCTION OF WITNESSES

Q. PLEASE INTRODUCE THE OTHER DUKE ENERGY KENTUCKY WITNESSES IN THIS PROCEEDING, AND EXPLAIN THE SUBJECT MATTER OF THEIR TESTIMONY.

A. Duke Energy Kentucky will present testimony from the following witnesses:

- James L. Turner, Chief Commercial Officer, explains Duke Energy's corporate and business structure, and discusses the beneficial impacts of the Duke/Cinergy merger on our Kentucky customers;
- Jim L. Stanley, Vice President, Field Operations – Midwest, provides additional testimony regarding the operation of Duke Energy Kentucky's electric business. He also supports the operation and maintenance budget and the capital expenditure budget for local transmission and distribution facilities used for the forecasted financial data;
- John J. Roebel, Group Vice President, Engineering and Technical Services, describes the Plants. He also supports the operation and maintenance budget and the capital expenditure budget for the Plants used for the forecasted financial data;
- Paul K. Jett, Director, RTO Activities, describes the Midwest ISO's Day 1 and Day 2 operations and supports the estimate of certain transmission-related charges used for the forecasted financial data;
- John D. Swez, Manager, Asset Management, discusses the Midwest ISO's Day 2 energy markets in additional detail, and supports the estimate of the remaining transmission charges used for the forecasted financial data;
- Douglas F Esamann, Vice President, Strategy and Planning, describes the Company's proposal relating to the Back-up PSA. He also supports the costs for fuel, emission allowance and wholesale power used for the forecasted financial data;

- Dwight L. Jacobs, Controller, discusses Duke Energy Kentucky's accounting processes and will sponsor certain information related to Duke Energy Kentucky's accounting for the Plants used for the forecasted financial data;
- Carl J. Council, Jr., Director, Asset Accounting, explains the remaining net plant in service and construction work in progress contained in rate base and other plant-related items used for the forecasted financial data;
- John J. Spanos, of Gannett Fleming, Inc., sponsors Duke Energy Kentucky's latest depreciation study;
- Dr. Richard G. Stevie, Head of the Market Analysis Department, explains the forecasting methodologies and supports the Duke Energy Kentucky gas and electric sales used in the forecasted test period data;
- C. James O'Connor, Vice President, Human Resources, provides Duke Energy Kentucky's employee base and the Company's compensation and benefit programs, including the wage and salary and loading rate assumptions used for the forecasted financial data;
- Keith G. Butler, Vice President of Corporate Taxation, provides testimony on the various tax matters affecting this proceeding.
- Lynn J. Good, Vice President and Treasurer, discusses Duke Energy Kentucky's credit ratings, financial objectives, cash requirements, and capital structure.
- Carol E. Shrum, Vice President of Financial Shared Services, provides testimony regarding service company cost assignments.

- Brian P. Davey, General Manager for Financial Planning and Analysis, will discuss Duke Energy Kentucky's budgeting process and sponsor the forecasted financial data.
- Dr. Roger A. Morin, an independent consultant, provides testimony on Duke Energy Kentucky's requested return on equity.
- Paul F. Ochsner, Rates Coordinator, sponsors Duke Energy Kentucky's cost of service study.
- Jeffrey R. Bailey, Manager of Pricing, provides testimony regarding rate design and changes to Duke Energy Kentucky rate schedules and other electric tariff provisions.
- William Don Wathen, Jr., Manager of Revenue Requirements, sponsors Duke Energy Kentucky's revenue requirements and certain adjustments to the forecasted test period financial data; and
- Paul G. Smith, Vice President, Ohio/Kentucky Rates, discusses the Company's compliance with and requests for relief relating to the Commission's orders in the Company's last electric base rate case and the Plant transfer case. He will also discuss the drivers for the Company's proposed rates.

VIII. CONCLUSION

Q. WERE FR 8(1), FR 8(2), FR 10(1)(B)(2), FR 10(1)(B)(3), FR 10(1)(B)(4), FR 10(1)(B)(5), FR 10(1)(B)(6), FR 10(1)(B)(9), FR 10(4), FR 10(9)(A), AND FR 10(9)(E) PREPARED UNDER YOUR SUPERVISION AND DIRECTION?

A. Yes.

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

A. Yes.

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, Sandra P. Meyer, being duly sworn, states 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.

Sandra P. Meyer, Affiant

Subscribed and sworn to before me by Sandra P. Meyer on this 18TH day of May, 2006.

NOTARY PUBLIC

My Commission Expires:

JOHN J. FINNIGAN, JR. Attorney at Law
NOTARY PUBLIC, STATE OF OHIO
My commission has no expiration
date. Section 147.03 O.R.C.

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

JAMES L. TURNER

ON BEHALF OF

DUKE ENERGY KENTUCKY

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James L. Turner. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. WHAT IS YOUR CURRENT POSITION?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as Group Executive and Chief Commercial Officer of the U.S. Franchised Electric & Gas ("Franchised Electric & Gas") business unit.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I received a B.S. degree from Ball State University, Indiana, in 1981 and a J.D. degree, *cum laude*, from the Indiana University School of Law in 1984. I was admitted to the Indiana bar in June 1984. I completed the Advanced Management Program at Harvard Business School in 2001.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. From June 1984 through January 1991, I practiced law with the Indianapolis law firm of Bingham Summers Welsh & Spilman (now called Bingham McHale), where I was elected to partnership in October 1990.

In late 1990, Governor (now U.S. Senator) Evan Bayh appointed me as Indiana's Utility Consumer Counselor. In this position, I led a state agency of about 65 employees with responsibility for representing the interests of electric, gas, telephone, water and sewer utility consumers in proceedings before the Indiana Utility Regulatory Commission and in state and federal court. During my tenure, I served on the Executive Committee of the National Association of State Utility Consumer Advocates. In 1993, I returned to the private practice of law, joining the Indianapolis law firm of Lewis & Kappes, PC, where I represented large industrial energy consumers before the Indiana Utility Regulatory Commission, the Indiana General Assembly and in court proceedings.

I joined Cinergy Corp. ("Cinergy") in 1995 as senior counsel, and I moved through a series of positions with increasing responsibilities. In 1997, I was named vice president of Cinergy Services, Inc. (now "Duke Energy Shared Services, Inc.") responsible for government and regulatory affairs and customer service. In 1999, I was promoted to president of Cinergy's Ohio utility subsidiary, The Cincinnati Gas & Electric Company (now "Duke Energy Ohio"). In 2001, I was elected as an Executive Vice President of Cinergy and became Chief Executive Officer of Cinergy's Regulated Business Unit. In 2004, I was named as Cinergy's Chief Financial Officer. In mid-2005, I was promoted to the position of president of Cinergy. Finally, in November 2005, I was named to my current position and was formally elected to the position in April 2006 when the Duke Energy/Cinergy merger closed.

Q. PLEASE DESCRIBE YOUR DUTIES AS CHIEF COMMERCIAL OFFICER OF DUKE ENERGY'S FRANCHISED ELECTRIC & GAS BUSINESS UNIT.

A. I am responsible for all commercial functions within Duke Energy's utility operating companies in Kentucky, Ohio, Indiana, North Carolina and South Carolina. I directly oversee the strategic planning, finance, legal and human resources functions. I also supervise the presidents of these operating companies, who are directly responsible for each operating company's regulatory, rates, economic development, and government and community affairs functions.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISISON?

A. Yes, in Case Number 2003-00252, I supported the transfer from Duke Energy Ohio to The Union Light, Heat and Power Company (now "Duke Energy Kentucky") of the East Bend Generating Station ("East Bend"), the Miami Fort Generating Station Unit 6 ("Miami Fort"), and the Woodsdale Generating Station ("Woodsdale") (collectively, "the Plants").

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

A. I provide an overview of Duke Energy's corporate and business structure. I also discuss how the merger better enables Duke Energy Kentucky to provide safe, reliable and reasonably priced gas and electric service to its customers.

II. OVERVIEW OF DUKE ENERGY'S CORPORATE AND BUSINESS STRUCTURE

Q. YOU HAVE REFERRED TO BOTH A CORPORATE STRUCTURE AND A BUSINESS STRUCTURE. HOW DO YOU DISTINGUISH THE TWO?

A. Corporate structure refers to specific legal entities through which Duke Energy conducts and transacts business and makes regulatory filings with the U.S. Securities and Exchange Commission and other regulatory agencies. Business structure refers to the way in which Duke Energy is organized, managed, and makes decisions regarding the day-to-day operation of the business.

Q. PLEASE GENERALLY DESCRIBE DUKE ENERGY'S CORPORATE STRUCTURE.

A. Duke Energy is a holding company, formerly named Duke Energy Holding Corp., and was formed in connection with the merger of the former Duke Energy Corporation and Cinergy, which closed in April 2006.

Duke Energy is a Delaware corporation and, following the merger, is organized into three principal subsidiaries, as described below.

The first is Duke Power LLC, formerly known as Duke Energy Corporation, which converted into a limited liability company and does business as Duke Energy Carolinas. It provides regulated electric service in North Carolina and South Carolina.

Second, Duke Energy holds Duke Capital, which was transferred from Duke Power, post-merger, to be a direct subsidiary of Duke Energy. Duke Capital includes: (1) Duke Energy Gas Transmission, which owns and operates over 17,500 miles of gas transmission pipelines and 250 billion cubic feet of natural gas storage, gathering and processing assets, a natural gas liquids processing operation and a local distribution company serving over 1.2 million customers in Canada; (2) Duke Energy Field Services ("DEFS"), a joint venture with ConocoPhillips, which produces, transports, markets and sells natural gas liquids; Duke Energy International, which operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U.S. and Canada, and (4) Crescent Resources, which manages and develops high quality commercial, residential and multi-family real estate projects primarily in the Southeastern and Southwestern U.S.

Duke Energy's third major corporate holding is Cinergy, which continues to hold the former Cinergy businesses, including Duke Energy Kentucky, Duke Energy Ohio and PSI Energy, Inc. d/b/a Duke Energy Indiana. The latter three companies are regulated public utility operating companies providing gas and/or electric utility service in Kentucky, Ohio and Indiana, except that retail electric generation service is deregulated in Ohio.

Q. WHICH CORPORATE ENTITIES PROVIDE SERVICES FOR DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC CUSTOMERS?

A. Our customers in Kentucky receive services from several Duke Energy companies. In addition to services they receive from Duke Energy Kentucky employees, our customers benefit from services provided by other Duke Energy affiliates that have signed a services agreement to perform services for Duke Energy Kentucky. The Commission approved these services agreements in Case No. 2005-00228, involving the Duke/Cinergy merger. Duke Energy Shared Services, Inc. is the services company located in the Midwest that provides administrative and operational services for Duke Energy Kentucky. Duke Energy Business Services, LLC is a services company located in North Carolina that provides administrative and operational services for Duke Energy Kentucky. Ms. Shrum describes these business arrangements and the service agreements in more detail in her testimony.

Q. HOW WILL DUKE ENERGY KENTUCKY'S CUSTOMERS KNOW WHICH LEGAL ENTITY IS PROVIDING SERVICE?

A. The legal entity structure and relationships that I have described (and that Ms. Shrum describes in more detail in her testimony) should be essentially invisible and seamless to our retail electric customers in Kentucky. In other words, our Kentucky customers should expect to receive reliable, adequate, and reasonably priced electric service from Duke Energy Kentucky without regard to how the company is structured or organized to provide those services.

Q. PLEASE DESCRIBE DUKE ENERGY'S BUSINESS STRUCTURE.

A. Duke Energy is organized into five business units through which it manages and makes decisions regarding the operation of the business. These business units are:

- Franchised Electric & Gas, which consists of the regulated public utility operating companies in Kentucky, Ohio, Indiana, North Carolina and South Carolina, and their related electric generation, transmission, distribution and customer service operations as well as our natural gas distribution operations in Kentucky and Ohio, We have organized the management of the Franchised Electric & Gas business into three groups—commercial, operations, and nuclear;
- Duke Energy Americas, consisting of Duke Energy's non-regulated electric generation (including Duke Energy Ohio's deregulated electric generation portfolio), international energy, trading and marketing, and energy services businesses;

- Duke Energy Gas, consisting of the Duke Energy Gas Transmission and DEFS businesses I described earlier;
- Corporate, consisting of the enterprise wide finance, legal, corporate development, human resources and communications functions; and
- Crescent Resources, consisting of the real estate development business I discussed earlier.

Q. WHERE ARE DECISIONS MADE REGARDING THE OPERATION OF DUKE ENERGY KENTUCKY?

A. Decisions regarding the operation of Duke Energy Kentucky are made principally within the leadership team of the Franchised Electric & Gas business unit, including Sandra P. Meyer, the President of Duke Energy Kentucky.

III. BENEFITS OF THE DUKE/CINERGY MERGER FOR DUKE ENERGY KENTUCKY'S CUSTOMERS

Q. HOW WILL THE DUKE/CINERGY MERGER BENEFIT DUKE ENERGY KENTUCKY'S CUSTOMERS?

A. This merger combined two outstanding companies with a strong track record of reasonable rates, high customer satisfaction, and safe and reliable services. The merged entity will build on the combined foundation of these two companies and better enable Duke Energy Kentucky to provide safe, reliable and reasonably priced gas and electric service to its customers. Duke Energy Kentucky will benefit from Duke Energy's strong financial and generation profile, as shown below:

Table 1 – Duke Energy Company Facts*

Total Assets:	$76 Billion
Revenues:	$12.3 Billion
Net Income:	$1.5 Billion
Customers:	3.8 Million Electric 1.7 Million Gas
Generation:	40,000 Net MW

*(Financial data is from the combined Duke/Cinergy proxy statement as of September 30, 2005. Customer data is as of December 31, 2005).

The increased scale and scope of operations resulting from the merger has strengthened new Duke Energy's balance sheet and financial flexibility, compared with the balance sheet and financial resources of the former Duke Energy or Cinergy. The merger synergies will lower the combined companies' cost structure. These synergies will reduce costs from eliminating overlapping functions, avoiding duplicative expenditures, consolidating operations and increasing purchasing power. The new Duke Energy will have higher productivity and lower costs than the former companies had, which will result in a financially sound company.

Customers immediately benefited from the merger via the merger savings sharing mechanism, approved by the Commission's November 29, 2005 Order in Case No. 2005-00228. Customers will receive additional benefits in future rate proceedings, because the merger will enable us to keep Duke Energy Kentucky's costs lower, and enable us to provide gas and electric utility service at reasonable prices.

New Duke Energy combined two companies dedicated to safe and reliable service. The merger will enable new Duke Energy to draw upon the best safety and reliability practices of both companies. The merger creates a broader base of employees over a larger geographic area. This will better enable new Duke Energy's operating companies to provide mutual assistance to each other during severe weather conditions. Duke Energy Kentucky made various merger commitments relating to maintaining reliable service, such as regular reporting of reliability performance. Duke Energy Kentucky's customers will continue to enjoy safe and reliable service following the merger.

Q. DOES DUKE ENERGY KENTUCKY'S PROPOSED ELECTRIC RATE INCREASE RESULT FROM THE DUKE/CINERGY MERGER?

A. Absolutely not. We have anticipated for some time—certainly before the merger—that this rate case would occur. Duke Energy Kentucky's base electric rates have not increased since 1992 and its Fuel Adjustment Clause rate has been frozen since 2001.

This proposed rate increase was anticipated in connection with the Commission's December 5, 2003 Order in Case No. 2003-00252. In that case, the Commission approved Duke Energy Ohio's transfer of the Plants to Duke Energy Kentucky, and ordered Duke Energy Kentucky to file a new general electric rate case with new rates effective January 1, 2007. This case will enable Duke Energy Kentucky to move the Plants into rate base, and to recover higher operating costs and fuel costs, which have increased significantly since the Commission approved the Company's present rates.

IV. <u>CONCLUSION</u>

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

A. Yes.

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, James L. Turner, 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.

James L. Turner, Affiant

Subscribed and sworn to before me by James L. Turner on this 26th day of May, 2006.

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

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

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

JIM L. STANLEY

ON BEHALF OF

DUKE ENERGY KENTUCKY

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ATTACHMENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jim L. Stanley, 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, Field Operations – Midwest.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS VICE PRESIDENT, FIELD OPERATIONS – MIDWEST OF DUKE ENERGY.

A. I am responsible for transmission and distribution construction and maintenance, substation construction and maintenance, premise services, meter reading, customer service engineering, and electric outage response for the Duke Energy Midwest service area in Kentucky, Ohio and Indiana.

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

A. I hold a Bachelor of Science degree in Accounting from Ball State University. I joined PSI Energy, Inc. as Staff Accountant/Corporate Accounting Analyst in the Accounting Department. I progressed through assignments of increasing responsibility in accounting, human resources and field operations. I have served as district manager and regional manager for field operations. I have also served as general manager of employee and union relations, general manager of transmission and distribution projects, and vice president of transmission and distribution construction and maintenance. I was named to my current position April 1, 2006.

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

A. The purpose of my testimony is: (1) to describe Duke Energy Kentucky's electric delivery system; (2) to explain Duke Energy Kentucky's overall policies relating to the design, construction, operation and maintenance of the Company's electric delivery facilities; and (3) to explain the need for continued investment in the electric delivery system in order to maintain system reliability. I also sponsor part of the information in Schedule B-4.1 and the capital budget relating to the Company's local transmission and distribution facilities contained in Filing Requirements ("FR") 10(9)(b), FR 10(9)(f) and FR 10(9)(g), which I provided to Mr. Davey for the forecasted financial data. Finally, I discuss the Company's program to introduce Advanced Metering Infrastructure ("AMI"), and I sponsor Attachment JLS-1, an illustration of how the technology will work and Attachment JLS-2, which provides the costs and benefits for the AMI program for the forecasted test period.

II. DUKE ENERGY KENTUCKY'S ELECTRIC DISTRIBUTION SYSTEM FACILITIES AND POLICIES RELATING TO DESIGN, CONSTRUCTION, OPERATION AND MAINTENANCE OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM

Q. PLEASE GENERALLY DESCRIBE THE DUKE ENERGY KENTUCKY ELECTRIC DELIVERY SYSTEM.

A. The Duke Energy Kentucky electric delivery system is used, among other things, to deliver retail electric service to approximately 131,028 customers located throughout our service area in the Commonwealth of Kentucky, and is spread throughout 6 counties in the northern part of the Commonwealth. As of December 31, 2005, Duke Energy Kentucky owns and operates all of its electric distribution and local transmission facilities. Its parent, The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("Duke Energy Ohio"), owns and operates, subject to the functional control of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), the bulk transmission facilities located in Duke Energy Kentucky's service territory. The Duke Energy Kentucky's electric delivery system is used, among other things, to deliver retail electric to 131,028 customers located in all or portions of six counties in northern Kentucky. Duke Energy Kentucky's electric delivery system includes approximately 106 circuit miles of transmission lines operating at 69 kV. It also includes 2,130 miles of primary distribution circuits operating at 34.5 kV or lower and approximately 813 miles of secondary distribution circuits operating at 480 volts or below. The delivery system also includes approximately 31 distribution substations, and 2 combined transmission and distribution substations with a combined capacity of approximately 1,400,000 kVA and various other equipment and facilities. While the Duke Energy Kentucky electric system is not directly interconnected with any other control areas, it is served by transmission facilities within the Duke Energy Midwest control area which, in turn, is directly interconnected with a total of 11 control areas.

The Duke Energy Kentucky's electric delivery system includes various other equipment and facilities such as control rooms, computers, capacitors, street lights, meters, and protective, relay and telecommunications equipment and facilities.

The Duke Energy Kentucky electric delivery system provides considerable flexibility for Duke Energy Kentucky to operate in a manner that provides reliable and economical power to our customers.

Q. PLEASE GENERALLY DESCRIBE HOW DUKE ENERGY KENTUCKY'S ELECTRIC DELIVERY SYSTEM HAS GROWN BETWEEN JULY 31, 1991, (*I.E.*, THE GENERAL RATE BASE CUTOFF DATE IN DUKE ENERGY KENTUCKY'S LAST RETAIL ELECTRIC RATE CASE) AND DECEMBER 31, 2005.

A. Duke Energy Kentucky's electric delivery system has grown substantially. On July 31, 1991, Duke Energy Kentucky's original cost electric delivery system plant in service was $152 million. By December 31, 2005, Duke Energy Kentucky's original cost electric delivery system plant in service had increased by 97% to $299 million. As a further example, since December 31, 1991, Duke Energy Kentucky has installed over 500 circuit-miles of distribution circuits, and 335,406 kVA of distribution substation transformer capacity. Investments like these have been necessary to maintain safe, reliable, efficient and economical electric delivery service for our existing customers as well as serve approximately 24,758 new retail electric customers added to the Duke Energy Kentucky system since 1991.

Q. IN YOUR OPINION, ARE DUKE ENERGY KENTUCKY'S ELECTRIC DELIVERY SYSTEM FACILITIES USED AND USEFUL IN PROVIDING SERVICE TO DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC CUSTOMERS?

A. In my opinion, they are. They are used daily to provide safe, reliable, efficient and economical electric delivery service to our customers.

Q. PLEASE GENERALLY DESCRIBE HOW THE TRANSMISSION AND DISTRIBUTION SYSTEM IS DESIGNED, CONSTRUCTED AND OPERATED.

A. The electric transmission system is designed to deliver bulk electric power from local generating plants and other resources to regional substations, or to interconnect with other systems in order to enhance system reliability. The transmission voltage used by Duke Energy Kentucky is 69 kV. As I previously mentioned, Duke Energy Ohio owns the bulk transmission system in Northern Kentucky, consisting of 138kV and above. There are two 69 kV circuits in Kentucky owned by Duke Energy Ohio. The system generally consists of steel tower or wood pole transmission lines and substations with power transformers, switches, circuit breakers and associated equipment. The physical design of the system is generally governed by the National Electrical Safety Code ("NESC"), adopted in KRS § 278.042. The system is operated in accordance with guidelines issued by Reliability*First*, which is a regional reliability council that is the successor organization to the East Central Area Reliability Council ("ECAR") and the North American Electric Reliability Council ("NERC"). The system is under the control of the Midwest ISO, a regional transmission organization approved by the Federal Energy Regulatory Commission ("FERC").

The electric distribution system is designed to receive bulk power at transmission voltages, reduce the voltage to 34.5 kV, 12.5 kV, or 4 kV, and deliver power to customers' premises. The distribution system generally consists of substation power transformers, switches, circuit breakers, wood pole lines, underground cables, distribution transformers, and associated equipment. The physical design of the distribution system is also generally governed by the NESC.

Duke Energy Kentucky operates the transmission and distribution facilities it owns in accordance with good utility practice. Duke Energy Kentucky continuously runs the system with a workforce that works to provide customer service 24 hours per day, seven days per week, 365 days per year, including trouble response crews. Duke Energy Kentucky regulates equipment loading in accordance with good utility practice. The Company monitors outages with various systems such as Supervisory Control and Data Acquisition ("SCADA"), Trouble Call Outage Management System ("TCOMS"), Electric Trouble data mart, and Outage Information System.

Customers typically report outages by telephone through Duke Energy's call center. The call center creates an outage call through a telephone software application that interfaces with TCOMS, a state-of-the-art outage management software application that Duke Energy Kentucky adopted in 2001 to improve its ability to monitor and respond to outages. TCOMS analyzes the calls and identifies to Duke Energy's dispatchers the piece of equipment (circuit breaker, recloser, fuse, transformer, *etc.*) that is the probable location of the outage. The dispatcher contacts the field trouble response person through the radio system to direct him/her to the probable equipment location to make repairs and restore electric service to the customers. Generally, the field trouble response person inspects the circuit or segment of line in question to identify and report the cause of the outage. The dispatcher records the date, time, duration and cause of the outage in TCOMS.

Dispatchers continuously monitor weather conditions. When lightning, wind or ice storms hit Duke Energy Kentucky's service territory, line crews are paged, called or held over to respond. Duke Energy Kentucky will often call in several hundred employees to respond to severe storms, including Duke Energy Franchised Electric and Gas employees stationed in Ohio, Indiana, North Carolina and South Carolina. If necessary, Duke Energy Kentucky will contact other utilities for additional line crews through a mutual assistance program. These rigorous operating practices have enabled Duke Energy Kentucky to provide reliable electric service to its customers.

Q. PLEASE GENERALLY DESCRIBE HOW DUKE ENERGY KENTUCKY'S DISTRIBUTION SYSTEM IS MAINTAINED.

A. Duke Energy Kentucky maintains its distribution system in accordance with good utility practice by following several inspection, monitoring, testing, and periodic maintenance programs. Examples of these programs include: substation inspection program, line inspection program, vegetation management program, underground replacement program, capacitor installation maintenance program, infrared scanning of equipment and dissolved gas analysis. Duke Energy Kentucky uses various reliability indices to measure the effectiveness of its maintenance programs and system reliability.

Q. WHAT ARE THE COMPANY'S OBJECTIVES IN DESIGNING, CONSTRUCTING, OPERATING AND MAINTAINING ITS DISTRIBUTION FACILITIES?

A. In designing, constructing, operating and maintaining its facilities, the Company strives to provide safe, cost-effective and reliable electric service.

Q. PLEASE DESCRIBE SOME OF THE FACTORS THAT THE COMPANY MUST CONSIDER IN ATTEMPTING TO ACHIEVE THESE OBJECTIVES.

A. In providing electric service to its customers, the Company must provide safe and reliable service while at the same time prudently and responsibly managing the costs of providing such service. The Company weighs various factors in selecting the electric delivery system projects in which to invest, including the Company's planning criteria, any requirements mandated either by regulatory authorities or reliability councils, and project cost versus customer benefits, to name a few.

Q. HOW DOES THE COMPANY BALANCE ALL OF THESE FACTORS?

A. Annually, electric system studies are performed to determine where and when system modifications are needed to ensure load is adequately served. When these needs are identified, multiple solutions are developed, addressing not only the capacity need, but also providing opportunities to maintain or improve reliability and operating flexibility. Recommendations are made and discussed with the operations staff to ensure a balanced, workable plan has been developed. To support and improve this effort Duke Energy Kentucky purchased and implemented a new distribution system planning software tool that allows for quicker, more detailed analysis of the system.

In the course of maintaining and operating the electric system, equipment and hardware is identified that requires repair or replacement. Blanket budgets have been established to cover small items, but specific projects are developed for larger expenditure items. These items are triggered as a result of operating issues, new load growth, or as a result of the various inspection, monitoring, and testing programs I described above.

III. MEASURING THE RELIABILITY OF DUKE ENERGY KENTUCKY'S ELECTRIC DELIVERY SYSTEM

Q. YOU STATED THAT DUKE ENERGY KENTUCKY USES VARIOUS INDICES TO MEASURE THE EFFECTIVENESS OF ITS MAINTENANCE PROGRAMS AND SYSTEM RELIABILITY. PLEASE EXPLAIN THESE RELIABILITY INDICES.

A. These reliability indices are generally recognized standards for measuring the number, scope and duration of outages. These indices are defined as follows.

Customer Average Interruption Duration Index ("CAIDI") is the average interruption duration or average time to restore service per interrupted customer, and is expressed by the sum of the customer interruption durations divided by the total number of customer interruptions.

System Average Interruption Duration Index ("SAIDI") is the average time each customer is interrupted, and is expressed by the sum of customer interruption durations divided by the total number of customers served.

System Average Interruption Frequency Index ("SAIFI") is the system average interruption frequency index, and represents the average number of interruptions per customer. SAIFI is expressed by the total number of customer interruptions divided by the total number of customers served.

Q. HOW HAS DUKE ENERGY KENTUCKY'S SYSTEM PERFORMED AS MEASURED BY THESE RELIABILITY INDICES?

A. Duke Energy Kentucky's system has performed well, even after installing the TCOMS system in 2001. Electric distribution utilities that install a modern TCOMS system generally see reliability scores decline, even though the TCOMS system improves reliability, because new TCOMS systems detect more outages than the old monitoring systems they replaced. Duke Energy Kentucky's reliability scores have exceeded industry average reliability scores. The latest reliability index scores available are for calendar year 2005, and are reported below.

Table 1 – Reliability Indexes

Reliability Index	Duke Energy KY 2005 Actual	EEI 2004 Quartile
CAIDI	84.6	2nd
SAIFI	1.03	2nd
SAIDI	87.5	2nd

IV. DUKE ENERGY KENTUCKY'S INVESTMENT IN ITS TRANSMISSION AND DISTRIBUTION FACILITIES

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S INVESTMENT RELATING TO ITS TRANSMISSION AND DISTRIBUTION FACILITIES DURING THE PAST FEW YEARS AND ITS PROJECTED FUTURE INVESTMENT.

A. The table below summarizes Duke Energy Kentucky's capital expenditures for its transmission and distribution facilities for the period from 1998 through 2007.

Table 2 – Capital Expenditures 1998 - 2007

Capital Expenditures($)	1998	1999	2000	2001	2002
Transmission	382,818	1,249,095	1,472,361	1,808,949	1,159,169
Distribution	11,017,752	10,624,945	12,258,769	15,007,595	11,181,542
Total	11,400,570	11,874,040	13,731,130	16,816,544	12,340,711

Capital Expenditures($)				Forecast	
	2003	2004	2005	2006	2007
Transmission	875,043	754,103	1,822,429	2,572,866	998,090
Distribution	14,885,538	12,812,429	15,622,805	16,398,460	16,251,291
Total	15,760,581	13,566,532	17,445,234	18,971,326	17,249,382

V. MAJOR CHALLENGES FACING DUKE ENERGY KENTUCKY'S ELECTRIC DELIVERY SYSTEM

Q. WHAT ARE THE MAJOR CHALLENGES FACING DUKE ENERGY KENTUCKY'S TRANSMISSION AND DISTRIBUTION SYSTEM?

A. The aging of the transmission and distribution system is a major challenge. Much of this equipment is over 30 years old. This equipment typically will last from 30–50 years. We expect to incur substantial expenditures to replace this equipment during the next several years. The charts below show the age distribution for Duke Energy Kentucky's poles, distribution circuit breakers, and transmission and distribution transformers.

Figure 1 – Duke Energy Kentucky Distribution Poles Age Distribution

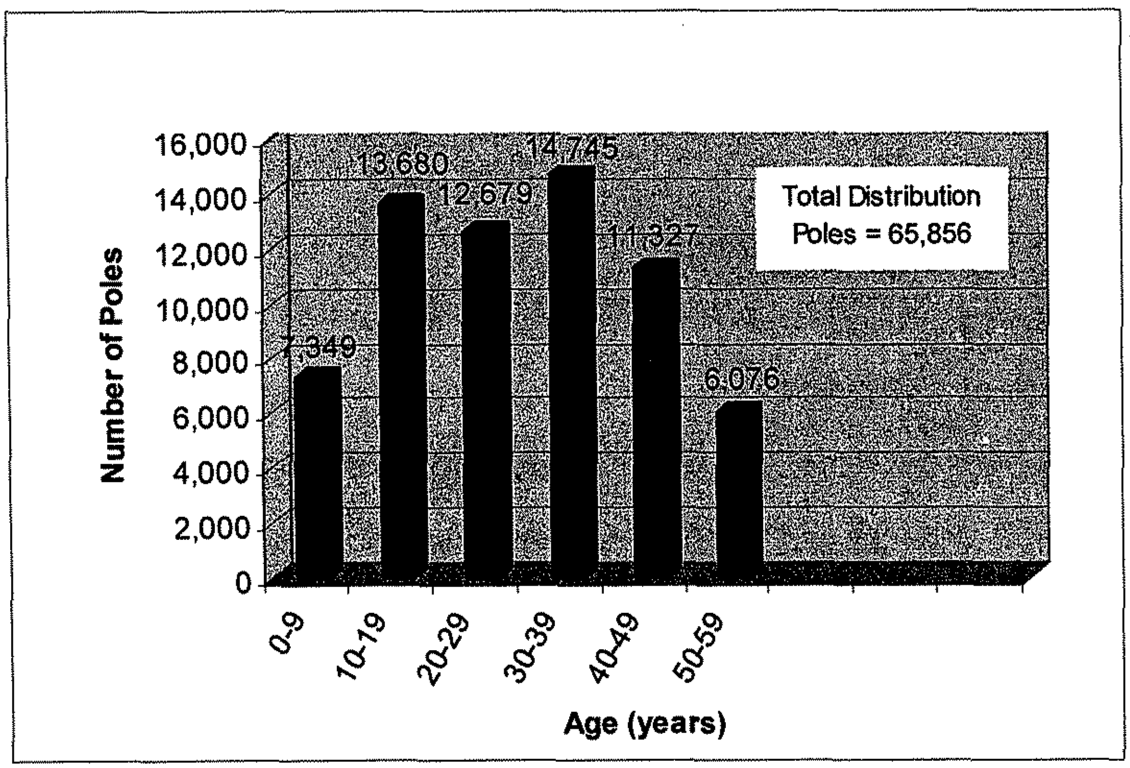


Figure 2 – Duke Energy Kentucky
Distribution Circuit Breakers Age Distribution As Of
Spring 2006

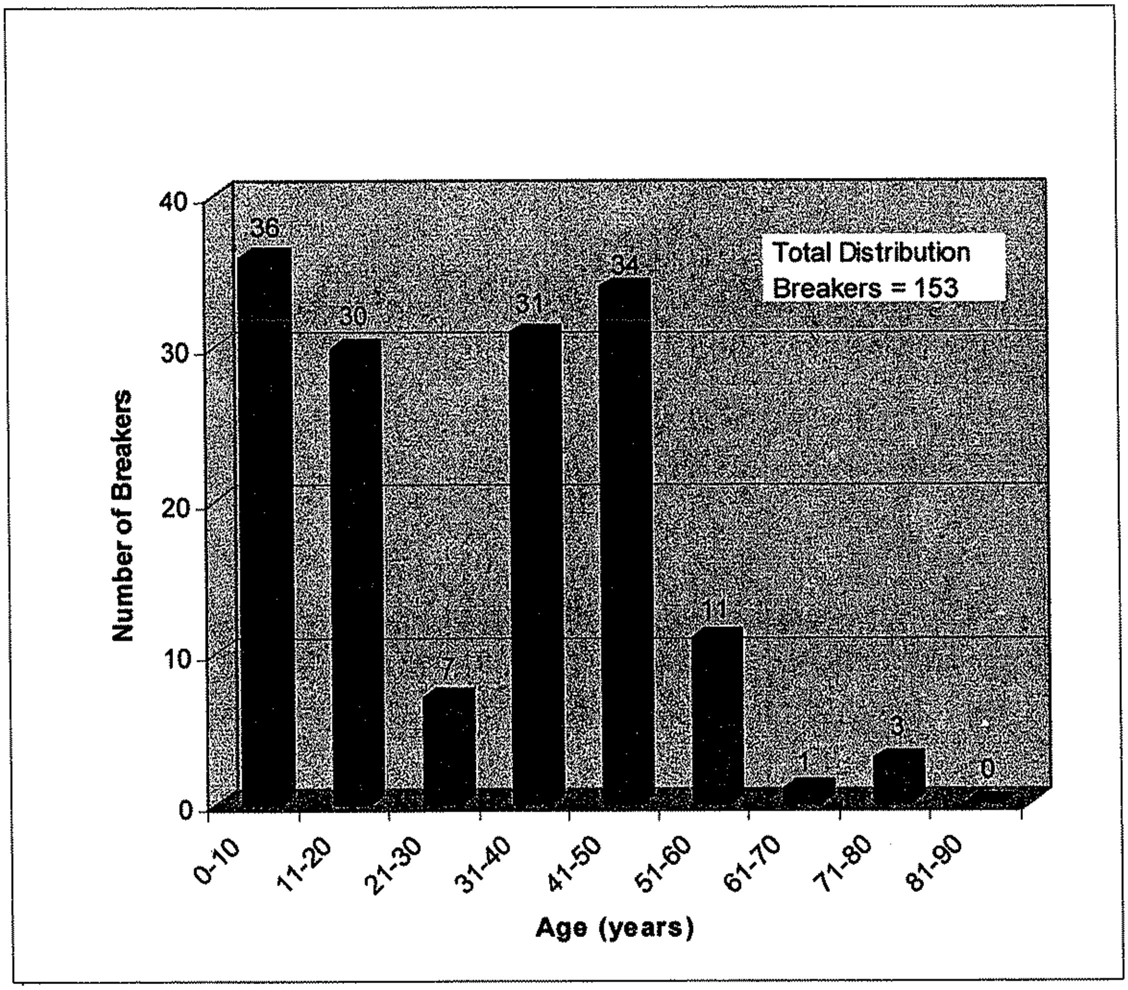
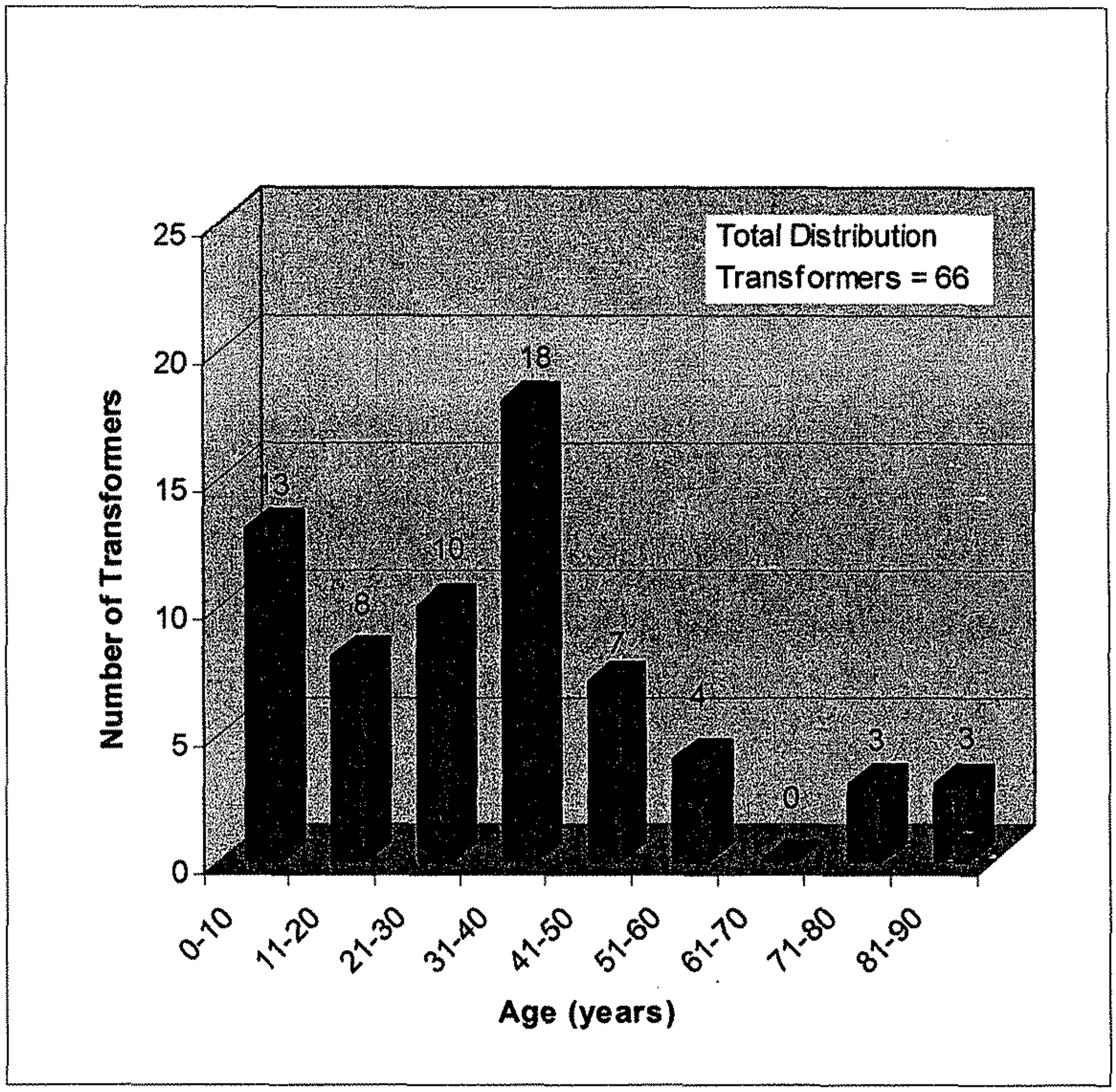


Figure 3 – Duke Energy Kentucky Distribution Transformer Age Distribution as of Spring of 2006



Q. DO CUSTOMERS' EXPECTATIONS PRESENT A CHALLENGE?

A. Yes. Customers are increasingly using equipment that is highly sensitive to voltage fluctuations; therefore, customers are demanding highly reliable service that minimizes the number of voltage fluctuations. This presents a challenge for Duke Energy Kentucky to strike the correct balance between reliable and economic service.

Q. DOES THE INCREASING AMOUNT OF REGULATION PRESENT A CHALLENGE?

A. Yes. As our scores on the reliability indices demonstrate, Duke Energy Kentucky has delivered reliable service under the current regulatory environment. Additional reliability regulations may be imposed that could impose additional compliance costs on CG&E. For example, Reliability*First* could issue mandatory reliability rules. Duke Energy Kentucky supports efforts to maintain and improve distribution system reliability, however, there will certainly be increased costs associated with such improvements.

VI. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULE B-4.1.

A. Schedule B-4.1 is a list of projects that are projected in Construction Work in Progress ("CWIP") as of December 31, 2007. This schedule presents the percent complete for each project as of December 31, 2007 based on both elapsed time and total expenditures. I supplied the information on this schedule relating to local transmission and distribution facilities.

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

A. FR 10(9)(b) consists of the most recent capital construction budget containing the forecasted construction expenditures for a minimum of three years. I provided the forecasted capital construction budget for the local transmission and distribution facilities contained in FR 10(9)(b) and for Mr. Davey's use for the forecasted financial data.

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

A. FR 10(9)(f) includes the following information for major projects constituting five percent or more of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the local transmission and distribution facilities contained in FR 10(9)(f).

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

A. FR 10(9)(g) includes the following information for projects constituting less than five percent of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the local transmission and distribution facilities contained in FR 10(9)(g).

VII. AMI PROGRAM

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S AMI PROGRAM.

A. Duke Energy Kentucky has decided to deploy an AMI solution based on Power Line Communications ("PLC") technology. PLC technology uses the electrical distribution system as the communication medium between the meter and the controlling software. Attachment JLS–1 is an illustration of the PLC technology. AMI is more than automated and advanced metering, more commonly referred to as automated meter reading ("AMR"). AMI's objectives are to: (1) measure energy either in real-time or other time-measured increments; (2) record details and values (voltage, reactive measurements); (3) accept commands (to turn on service or poll for data for outage confirmation or demand response); and (4) provide a centralized system to validate, edit, and estimate the data. There is strategic and tactical value in having daily and/or hourly information regarding our distribution system beyond the monthly read for billing purposes. To achieve these objectives, it is important to use a technology or a blend of technologies to install advanced metering capabilities that include two-way communication systems between the meter and the utility.

Initially, Duke Energy Kentucky will deploy Two-Way Automatic Communication System ("TWACS") technology beginning later this year. Duke Energy Kentucky will continue to evaluate technology advances as well as the cost-effectiveness of other technologies such as Broadband Over Power Line ("BPL"). Regardless of the two-way communication technology used, AMI will include a complete hardware and software system utilizing new advanced metering technology, and new computer systems to collect, validate, store, and perform advanced analytics with this meter data to enhance Duke Energy Kentucky's business processes and customer interactions. We expect the AMI program to provide significant customer benefits.

Q. **WHAT BENEFITS DO YOU EXPECT TO RECEIVE FROM THE AMI PROGRAM?**

A. AMI will enable automatic meter reading that can provide hourly data on a daily basis for all customers. After full deployment of AMI, Duke Energy Kentucky will realize savings due to fewer monthly meter reads and costs associated with succession orders that our meter readers currently perform. We expect to have fewer billing estimates due to improved accessibility. The Call Center will resolve more billing inquiries on a first-call basis, by having the customer's hourly/daily data and by reviewing the customer's load profile and usage activity.

By providing advanced metering, the communication infrastructure, and a meter data management system, Duke Energy Kentucky can isolate metering from data storage, which makes it easier and less risky to change meter functions, such as switching between standard and daylight saving time or changing the times when peak rates will be charged. In addition, AMI enables innovative demand response options, providing customers the ability to respond to volatility reduction.

After AMI is fully deployed, we will be able to explore offering innovative time-based pricing options that enable customers to manage their energy usage during times of rising costs. The AMI system will provide enhanced detection of tampering and theft of energy service. We will be able to design better preventive maintenance programs, because the data will identify which assets are overloaded or under-utilized. We will be able to obtain more accurate voltage readings, allowing better power quality monitoring. This will allow us to monitor and notify customers of sags in the system as a value-added service.

Additionally, we will be able to monitor our vegetation management practices, because the AMI equipment will enable us to detect and classify pockets of vegetation-induced service problems by feeder. AMI will also provide outage confirmation information that will allow the Company to understand the severity of an outage, identify nested outages, and validate restoration efforts without unnecessary trips to a customer's premises. This additional capability and information should enhance customer satisfaction.

Q. HOW AND WHEN DOES THE COMPANY PLAN TO DEPLOY THE AMI SYSTEM?

A. Duke Energy Kentucky expects to begin deploying the system later this year. The deployment will occur over approximately a three-year time span. We will begin installing AMI equipment in phases so that we can continue to perform the economic analysis, business requirement definition and planning, monitoring of the maturity of AMR technologies and defining and understanding customer needs and behaviors.

For the first phase, we plan to focus on areas in Northern Kentucky that will provide a good mix of gas, electric, and combination accounts as well as inside and outside meter locations. This first phase is to demonstrate the strategic and tactical value of AMI to the customer, utility, and Commission. We plan to install advanced metering capabilities for a minimum of 40,500 electric meters and 28,100 gas meters during 2007.

Q. WHAT COSTS AND COST SAVINGS DOES DUKE ENERGY KENTUCKY EXPECT TO REALIZE?

A. We expect to invest approximately $24 million in capital expenditures for this entire AMI project. The expenditures will chiefly consist of the automated meter reading equipment, electric meters, gas meters, project management costs, substation equipment, vendor costs and computer hardware and software. These costs do not include the hardware and software costs associated with the energy data management system.

The rate case includes the investment related to the electric meter installation that will occur during the forecasted test period, which is approximately $6.5 million. An additional investment that is not included in this rate case will cover the costs to include the gas meters as part of the AMI project. We expect to realize savings primarily through meter reading and associated workers' compensation expenses. However, we also expect to incur some additional operational and maintenance expenses related to purchased power, meter base and weatherhead repairs, equipment and battery failures, meter inspections, and information technology maintenance. We project that the AMI system will allow us to realize approximately $34 million in savings through 2020.

Q. HAVE YOU CALCULATED THE EXPECTED COSTS AND COST SAVINGS FOR THE FORECASTED TEST PERIOD?

A. Yes, I calculated the costs and cost savings for the first six years of the program, including the forecasted test period, as shown on Attachment JLS-2. I provided this information to Mr. Wathen for his use in calculating the revenue requirements. As can be seen, the costs of AMI deployment will outweigh the revenues and synergies for the early stages of the program, while we are in the process of deploying the equipment.

Q. WHAT APPROVALS DOES THE COMPANY SEEK FOR ITS AMI PROGRAM?

A. The Company requests that the Commission grant a certificate of public convenience and necessity ("CPCN") for the program or, in the alternative, a finding that no CPCN is required. Duke Energy Kentucky also requests that the Commission include the AMI costs and offsetting cost savings in calculating new rates for the Company.

VIII. CONCLUSION

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

A. Yes, I provided Mr. Davey with the cost of building out the Erlanger construction and maintenance building for the forecasted financial data. I also provided him with the operation and maintenance cost estimates for the Erlanger building for the base period and the forecasted test period.

Q. WAS THE INFORMATION YOU PROVIDED TO MR. DAVEY, AND FOR FR10(9)(B), 10(9)(F) AND 10(9)(G), AND ATTACHMENTS JLS-1 AND JLS-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, Jim L. Stanley, 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.

Jim L. Stanley, Affiant

Subscribed and sworn to before me by Jim L. Stanley on this 22nd day of May, 2006.

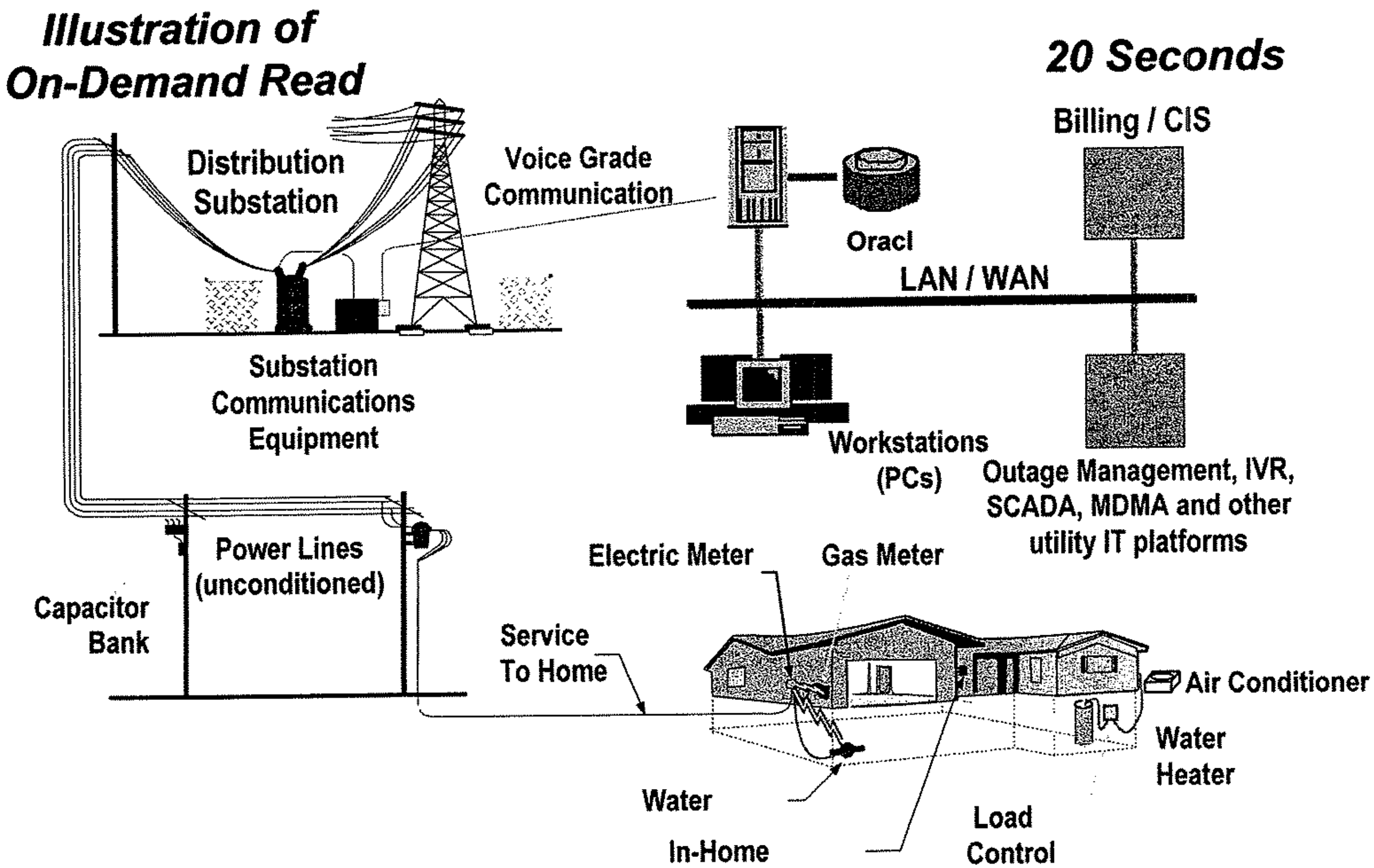
Anita M. Schafer
NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

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

How does PLC Work?



Duke Energy Kentucky
Summary of AMI Investment on Net Savings

Electric Program

Year	2006	2007	2008	2009	2010	2011
Gross Plant	$ 888,885	$ 6,763,857	$ 13,586,550	$ 13,982,451	$ 13,953,114	$ 13,914,495
Accumulated Depreciation	(29,630)	(256,116)	(842,577)	(1,635,676)	(2,442,153)	(3,247,086)
Net Plant	$ 859,256	$ 6,507,741	$ 12,743,973	$ 12,346,775	$ 11,510,961	$ 10,667,410
Accumulated deferred income taxes	(49,075)	(423,637)	(1,263,292)	(2,044,571)	(2,429,052)	(2,637,746)
Rate base	$ 810,180	$ 6,084,103	$ 11,480,681	$ 10,302,204	$ 9,081,910	$ 8,029,663
O&M Savings/Costs						
Cin Common						
Meter Data Management analysts	-	37,889	58,538	73,693	75,903	78,181
Substation equipment failures	-	-	-	-	84	6,086
Software maintenance	-	61,720	63,571	65,478	67,443	69,466
T&D Operations "OK on arrival" savings	-	(10,422)	(34,591)	(49,143)	(50,617)	(52,135)
KY Common						
Meter Reading savings	-	(236,383)	(784,530)	(1,114,574)	(1,148,011)	(1,182,451)
Service Delivery off-cycle reads savings	-	(10,338)	(34,312)	(48,746)	(50,209)	(51,715)
Workers' compensation savings	-	(2,289)	(7,598)	(10,795)	(11,118)	(11,452)
Severance costs	-	211,612	266,396	-	-	-
Meter inspections	-	-	-	-	119,496	123,081
KY Electric						-
Meter Operations savings	-	(9,746)	(32,344)	(45,951)	(2,712)	(2,794)
Meter base and weatherhead repairs	-	194,630	245,018	-		-
AMR module failures	-				32,762	62,487
Net O&M Savings	$ -	$ 236,673	$ (259,852)	$ (1,130,038)	$ (966,979)	$ (961,246)
Other Savings/Costs						
Depreciation expense	$ 29,630	$ 226,487	$ 586,447	$ 792,955	$ 806,202	$ 804,933
Property tax expense	12,459	94,362	184,788	179,028	166,909	154,677
Purchased power expense	-	9,566	30,824	42,516	42,516	42,516
Benefit of Billing Cycle Time Reduction	-	(203,535)	(655,836)	(904,601)	(904,601)	(904,601)
Net Other Savings/Costs	$ 42,089	$ 363,553	$ (113,630)	$ (1,020,141)	$ (855,953)	$ (863,721)

Duke Energy Kentucky
Summary of AMI Investment on Net Savings

Gas Program

Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Gross Plant	$ 622,639	$ 4,812,583	$ 9,653,173	$ 10,101,588	$ 10,101,588	$ 10,101,588
Accumulated Depreciation	(20,755)	(200,986)	(680,142)	(1,334,446)	(2,003,697)	(2,672,949)
Net Plant	$ 601,884	$ 4,611,597	$ 8,973,030	$ 8,767,142	$ 8,097,891	$ 7,428,640
Accumulated deferred income taxes	(34,376)	(366,572)	(1,140,435)	(1,864,031)	(2,211,460)	(2,390,180)
Rate base	$ 567,508	$ 4,245,025	$ 7,832,596	$ 6,903,111	$ 5,886,431	$ 5,038,460
O&M Savings/Costs						
Cin Common						
Meter Data Management analysts	-	26,540	41,004	51,620	53,168	54,763
Substation equipment failures	-	-	-	-	59	4,263
Software maintenance	-	43,233	44,530	45,866	47,242	48,659
Off-network gas meter reads	-	7,546	25,045	35,582	36,649	37,749
KY Common						
Meter Reading savings	-	(165,580)	(549,541)	(780,727)	(804,149)	(828,274)
Service Delivery off-cycle reads savings	-	(7,242)	(24,034)	(34,145)	(35,170)	(36,225)
Workers' compensation savings	-	(1,604)	(5,322)	(7,561)	(7,788)	(8,022)
Severance costs	-	148,228	186,603	-	-	-
Meter inspections	-	-	-	-	83,703	86,215
KY Electric						-
Meter Operations savings	-	(1,158)	(3,842)	(5,458)	(5,622)	(5,791)
Meter base and weatherhead repairs	-	-	-	-		-
AMR module failures	-				56,325	88,307
Net O&M Savings	$ -	$ 49,964	$ (285,558)	$ (694,825)	$ (575,583)	$ (558,356)
Other Savings/Costs						
Depreciation expense	$ 20,755	$ 180,232	$ 479,156	$ 654,304	$ 669,251	$ 669,251
Property tax expense	8,727	66,868	130,109	127,124	117,419	107,715
Purchased power expense	-	-	-	-	-	-
Benefit of Billing Cycle Time Reduction	-	(127,728)	(411,569)	(567,682)	(567,682)	(567,682)
Net Other Savings/Costs	$ 29,482	$ 169,336	$ (87,863)	$ (481,079)	$ (356,594)	$ (349,071)

Duke Energy Kentucky
Summary of AMI Investment on Net Savings

Combined Program

Year	2006	2007	2008	2009	2010	2011
Gross Plant	$ 1,511,524	$ 11,576,440	$ 23,239,722	$ 24,084,039	$ 24,054,702	$ 24,016,083
Accumulated Depreciation	(50,384)	(457,103)	(1,522,719)	(2,970,123)	(4,445,850)	(5,920,034)
Net Plant	*$ 1,461,140*	*$ 11,119,337*	*$ 21,717,003*	*$ 21,113,917*	*$ 19,608,852*	*$ 18,096,049*
Accumulated deferred income taxes	(83,451)	(790,210)	(2,403,726)	(3,908,601)	(4,640,512)	(5,027,926)
Rate base	$ 1,377,689	$ 10,329,128	$ 19,313,277	$ 17,205,316	$ 14,968,340	$ 13,068,123
O&M Savings/Costs						
Cin Common						
Meter Data Management analysts	-	64,429	99,542	125,313	129,071	132,944
Substation equipment failures	-	-	-	-	143	10,349
Software maintenance	-	104,953	108,101	111,344	114,685	118,125
T&D Operations "OK on arrival" savings	-	*(2,876)*	*(9,545)*	*(13,561)*	*(13,968)*	*(14,387)*
KY Common						
Meter Reading savings	-	(401,963)	(1,334,071)	(1,895,301)	(1,952,160)	(2,010,725)
Service Delivery off-cycle reads savings	-	(17,580)	(58,346)	(82,892)	(85,378)	(87,940)
Workers' compensation savings	-	(3,893)	(12,920)	(18,356)	(18,906)	(19,474)
Severance costs	-	359,840	452,999	-	-	-
Meter inspections	-	-	-	-	203,199	209,296
KY Electric						
Meter Operations savings	-	(10,903)	(36,186)	(51,410)	(8,334)	(8,584)
Meter base and weatherhead repairs	-	194,630	245,018	-	-	-
AMR module failures	-	-	-	-	89,087	150,794
Net O&M Savings	$ -	$ 286,637	$ (545,410)	$ (1,824,863)	$ (1,542,561)	$ (1,519,602)
Other Savings/Costs						
Depreciation expense	$ 50,384	$ 406,719	$ 1,065,602	$ 1,447,259	$ 1,475,453	$ 1,474,184
Property tax expense	21,187	161,230	314,897	306,152	284,328	262,393
Purchased power expense	-	9,566	30,824	42,516	42,516	42,516
Benefit of Billing Cycle Time Reduction	-	(331,264)	(1,067,405)	(1,472,283)	(1,472,283)	(1,472,283)
Net Other Savings/Costs	$ 71,571	$ 532,889	$ (201,492)	$ (1,501,220)	$ (1,212,547)	$ (1,212,792)

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

JOHN J. ROEBEL

ON BEHALF OF

DUKE ENERGY KENTUCKY

183673

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Roebel. My business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. WHAT IS YOUR CURRENT POSITION?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as Group Vice President, Engineering and Technical Services.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received a bachelor's degree in Mechanical Engineering from the University of Cincinnati Engineering College in 1980. I have also taken graduate courses, primarily in business administration, at the University of Cincinnati and Xavier University. I am also a registered Professional Engineer in Ohio and Kentucky.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I worked for The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("CG&E" or "Duke Energy Ohio") as a co-op student in the engineering area during undergraduate school, and became a full-time employee after graduation in 1980. Since joining CG&E, and later Cinergy Services, Inc. after the merger of CG&E and PSI Energy, Inc. d/b/a Duke Energy Indiana ("Duke Energy Indiana"), I have held positions of increasing responsibility in the engineering and construction management areas, including mechanical project engineer for a new coal-fired unit, project manager on the conversion of CG&E's Zimmer Generating Station from nuclear to coal, and manager of the design and construction of

CG&E's Woodsdale Generating Station ("Woodsdale"). I was promoted to Vice President, Generation Resource Group in October 1998. I was named to my current position as Group Vice President, Engineering and Technical Services in April 2006.

Q. PLEASE SUMMARIZE YOUR DUTIES AS GROUP VICE PRESIDENT, ENGINEERING AND TECHNICAL SERVICES.

A. I supervise and am responsible for the professional group that provides the engineering and technical support to the electric generating plants operated by Duke Energy's U.S. Franchised Electric & Gas ("Franchised Electric & Gas") Operations Business Unit for both regulated and non-regulated assets, Environmental Health and Safety ("EH&S") for the entire company and engineering for Power Delivery (Transmission and Distribution). The Franchised Electric & Gas Operations Business Unit's generating plants consists of the plants operated by Duke Energy's regulated operating companies, including The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky"). The services we provide includes engineering, construction management, safety, operation and maintenance support services.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I testified before the Commission in Case No. 2003-00252, involving Duke Energy Kentucky's request to approve the transfer of the Plants from Duke Energy Ohio.

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

A. I describe the East Bend Generating Station ("East Bend"), the Miami Fort Generating Station Unit No. 6 ("Miami Fort 6") and Woodsdale (collectively "the Plants") that Duke Energy Ohio transferred to Duke Energy Kentucky effective January 1, 2006. I support Duke Energy Kentucky's request that the Plants be added to Duke Energy Kentucky's rate base at net book value. I also discuss certain information of future plant outages that I provided to other witnesses for their testimony. I also sponsor part of the information in Schedule B-4.1 and the capital budget relating to the Plants contained in Filing Requirements ("FR") 10(9)(b), FR 10(9)(f) and FR 10(9)(g), which I provided to Mr. Davey for the forecasted financial data.

II. GENERAL DESCRIPTION OF THE PLANTS

Q. PLEASE DESCRIBE EAST BEND.

A. East Bend is a 648 megawatt ("MW") (nameplate rating) coal-fired base load unit located along the Ohio River in Boone County, Kentucky, that was commissioned in 1981. Duke Energy Kentucky (447 MW, or 69%) and The Dayton Power and Light Company ("DP&L") (201 MW, or 31%) jointly own it. The 447 MW or 69% ownership share represents 100% of Duke Energy Kentucky's ownership share in the Plant.

I discuss the Plants' nameplate ratings and net ratings in my testimony. The nameplate ratings are the ratings provided by the manufacturer of the generating equipment, and these ratings are actually engraved on a nameplate that is affixed to the equipment. The net ratings represent the net amount of power that we can dispatch from the Plants after some portion of the gross power output is used to power the Plant machinery. The net rating for Duke Energy Kentucky's share of East Bend is 414 MW.

East Bend was originally planned for up to four coal-fired units but only one unit (Unit 2) was constructed. The station has river facilities to allow barge deliveries of coal and lime. East Bend is designed to burn low- to high-sulfur eastern bituminous coal and achieved a net plant heat rate for 2005 of 10,181 Btu/kWh and through March 2006 year-to-date is 10,237 Btu/kWh. The major pollution control features are: a mechanical draft cooling tower, a high-efficiency hot side electrostatic precipitator, a lime-based flue gas desulfurization ("FGD") system and a selective catalytic reduction control ("SCR") system designed to reduce nitrogen oxide ("NO_x") emissions by 85%. The FGD system was upgraded in 2005 to increase the sulfur dioxide ("SO_2") emissions removal to an average of 97%. The station electrical output is directly connected to the Duke Energy Midwest (consisting of Kentucky, Ohio and Indiana) 345 kilovolt (kV) transmission system

Q. PLEASE DESCRIBE MIAMI FORT 6.

A. Miami Fort 6 is a 168 MW (nameplate rating) coal-fired base/intermediate load unit located at Miami Fort Station along the Ohio River in Hamilton County, Ohio, that was commissioned in 1960. The net rating is 163 MW.

Unit 6 is one of four coal-fired units at the Miami Fort Generating Station. The nameplate ratings for Units 5, 7 and 8 are 100 MW, 512 MW and 512 MW, respectively. Duke Energy Ohio wholly owns Unit 5. Duke Energy Kentucky wholly owns Unit 6, while Units 7 and 8 are jointly owned by Duke Energy Ohio

(64%) and DP&L (36%). The station has river facilities to allow for barge delivery of coal. Unit 6 is designed to burn low- to high-sulfur eastern bituminous coal and achieved a net unit heat rate for 2005 of 10,295 Btu/kWh. Through March 2006 year-to-date the net heat rate is 10,225 Btu/kWh. The major pollution control feature is a high-efficiency electrostatic precipitator. The unit had a temporary Selective Non-Catalytic Reduction System for NO_x reduction, which did not perform as well as anticipated, and therefore was replaced earlier this year by second-generation low NO_x burners to reduce NO_x emissions. This unit is directly connected to the Duke Energy Midwest high voltage transmission system.

Q. PLEASE DESCRIBE WOODSDALE.

A. Woodsdale is a six-unit combustion turbine ("CT") station located in Butler County, Ohio, just north of Cincinnati, with a collective nameplate rating of 490 MW. Woodsdale's net summer capacity is 500 MW (including inlet cooling), because the inlet cooling of the air temperatures increases Woodsdale's capacity. Woodsdale is designed for peaking service, and it has dual fuel capability (natural gas and propane) and black start capability. Black start capability means that the station has the ability to initiate a recovery of a substantial portion of load without relying on energy from outside sources if the regional grid experiences a blackout. The black start capability is initiated by an Allison 501-KB gas turbine that serves as a back-up power source and allows the station to start generating energy without power from the electric grid.

Woodsdale is connected to two separate gas transmission companies, Texas Eastern Transmission Company ("TETCO") and Texas Gas Transmission Company, that transport the natural gas to supply the station. The propane is stored at the Todhunter propane cavern. The first five units were commissioned in 1992, with the sixth added in 1993. NO_x emissions are controlled by water injection. The station electrical output is directly connected to the Duke Energy Midwest 345 kV transmission system.

III. EMISSION CONTROL LIMITS

Q. ARE THE PLANTS SUBJECT TO ANY EMISSION CONTROL LIMITS?

A. Yes. Miami Fort 6 has an air permit that limits SO_2 emissions to 5.0 lbs/MMBTU, which does not impose a significant operating restriction because the unit receives a lower sulfur coal content than what is permitted. East Bend has an SO_2 emission limit of 1.2 lbs/MMBTU, which is not a significant operating restriction because the FGD system is designed to meet this emission limit. Woodsdale is a peaking station that by permit cannot exceed a combined total of 17,844 operating hours for twelve units, which is not a significant operating restriction because this limit was imposed when the Plant was designed for twelve CT units, and only six CT units were constructed.

IV. FUTURE MAJOR CAPITAL PROJECT COST ESTIMATES

Q. DO YOU ANTICIPATE PERFORMING ANY MAJOR CAPITAL PROJECTS AT THE PLANTS IN THE FORSEEABLE FUTURE?

A. Yes. The major capital projects currently planned at the Plants over the next few years includes completion of the combustion turbine overhaul program at

Woodsdale and also evaluating whether to make additional environmental improvements at Miami Fort 6. A successful generator rewind project was conducted at East Bend in 2005.

Q. PLEASE DESCRIBE THESE CAPITAL PROJECTS AND EXPLAIN WHY THESE CAPITAL PROJECTS ARE NECESSARY.

A. The East Bend Generator Rewind consisted of rewinding both the generator stator and rotor. The stator was converted to a water-cooled system. The rotor had both the zone rings and retaining rings replaced. This work was necessary because East Bend was one of only three of this model of generators manufactured by Westinghouse not to be re-wound out of a total population of 35. The rewind addressed a problem that, if not corrected, could have resulted in a catastrophic failure and associated long outage. The cost to repair or replace the East Bend generator following a catastrophic event, and the associated impacts of a long-term outage, likely would have greatly exceeded the cost of the generator rewind.

Any additional environmental improvements at Miami Fort 6 will depend on the extent of new emission limits imposed under the U.S. Environmental Protection Agency's Clean Air Interstate and Clean Air Mercury rules. Each state has until September, 2006 to adopt the new federal rules and submit the revisions for incorporation into the state implementation plan. If reduced emission limits are imposed for Miami Fort 6 and if the SO_2 emissions allowance trading market continues to be volatile, we will implement appropriate measures, such as burning only low sulfur fuel, installing precipitator upgrades or installing a SO_3 injection system.

The Woodsdale Overhauls consist of required periodic maintenance to maintain high unit availability. The primary overhaul activities involve replacing the compressor and turbine blades, hot gas path parts and generator maintenance of the CT units. Each CT unit has several hundred blades, which turn a generator (as the blades are propelled by the hot gas/air mixture resulting from the combustion process) to produce electricity. The CT units will not function reliably unless the blades are replaced as they become worn, and the process of removing the old blades and installing the new ones is very time-consuming. Procurements of parts for the overhaul of CT#1 will begin in 2007 with the work performed in 2008.

V. BENEFITS TO DUKE ENERGY KENTUCKY FROM OWNING THE PLANTS AND REQUEST TO ADD PLANTS TO RATE BASE AT NET BOOK VALUE

Q. HAS DUKE ENERGY KENTUCKY BENEFITTED FROM OWNING THE PLANTS?

A: Yes. Duke Energy Ohio supervised the construction of the Plants; therefore, we know that the Plants are well-constructed. Cinergy personnel operated and maintained the Plants prior to the transfer to Duke Energy Kentucky, so we know that the Plants have been well-maintained and are in good working order. Since these are existing facilities, Duke Energy Kentucky did not need to face any uncertainty as to any real property acquisition, siting, permitting, construction, or operational issues.

Q. ARE THE PLANTS USED AND USEFUL FOR SERVING DUKE ENERGY KENTUCKY'S NATIVE LOAD CUSTOMERS?

A. Yes. The Plants have performed well and are high quality generating assets relative to the age and condition of comparable generating plants. One useful measure of the quality of a coal-fired generating station is the equivalent availability factor, which measures the percentage of time that the station is available for operations after planned and unplanned outages and derates (which result from operational conditions) are taken into account. The annual average equivalent availability factor ratings from 2000 through 2005 for East Bend were between 59.57% and 93.94%, for Miami Fort 6 were between 78.89% and 89.6% and for Woodsdale were between 81.97% and 95.15%. The average equivalent availability for coal-fired plants in the North American Electric Reliability Council ("NERC") from 2000 through 2004, which is the most recent data available for 600 MW units is 84.2% and for 160 MW units is 84.92%. The 2005 data will become available in October 2006. The average equivalent availability for Gas Turbine and Jet Engines in NERC for the same period was 88.46%.

The Plants have been well maintained and are in good working order. Coal supplies are readily available. There are no known environmental considerations that could lead to significant derates. There are no transmission constraints. The Plants have provided excellent service for customers of the Cinergy system in the past, and will continue to do so for Duke Energy Kentucky's customers for many years to come.

Q. WHAT RATEMAKING TREATMENT DOES DUKE ENERGY KENTUCKY SEEK FOR THE PLANTS IN THIS PROCEEDING?

A. We request that the Plants be reflected in Duke Energy Kentucky's rate base at net book value as of January 1, 2006, the effective date of the Plants' transfer from Duke Energy Ohio to Duke Energy Kentucky, less accumulated depreciation through the end of the forecasted test period. The Commission stated in Finding No. 7 of its December 5, 2003 Order in Case No. 2003-00252 that it could see no reason why the Plants' net book value should not be used as the appropriate valuation for the Plants for future rate-making purposes. As this is Duke Energy Kentucky's first retail electric base rate case since the Plants were transferred, we have used this method, and we ask the Commission to confirm that this is the appropriate method for valuing the Plants in this proceeding.

VI. INFORMATION ON PLANT OUTAGES PROVIDED TO OTHER WITNESSES

Q. WHAT INFORMATION DID YOU SUPPLY TO OTHER WITNESSES ON PLANT OUTAGES?

A. I provided Mr. Esamann with an estimate of the number of days/weeks of planned outages and the rates of forced outages for the Plants from 2006 to 2009. I also provided Mr. Davey with the operation and maintenance costs for planned outages at the Plants for the forecasted test period.

Q. HOW DID YOU ESTIMATE THE NUMBER OF DAYS OF PLANNED OUTAGES?

A. I used the definition for certain types of forced outages contained in the Commission's Fuel Adjustment Clause regulation, 807 KAR 5:056, as follows: (1) nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours; and (2) which result from faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance. I reviewed the Plants' outages meeting these criteria for 2000 through 2005 and I estimated the number of days of planned outages during the relevant time period, as follows:

Table 1 - Planned Outages for the Plants

Planned Outages	2006	2007	2008	2009
WOODSDALE 1	5Weeks	1Week	1Week	3Weeks
WOODSDALE 2		1Week	1Week	3Weeks
WOODSDALE 3	5 Days	1Week	1Week	3Weeks
WOODSDALE 4		1Week	17Weeks	3Weeks
WOODSDALE 5	8 Days	1Week	1Week	3Weeks
WOODSDALE 6		1Week	1Week	3Weeks
EAST BEND 2	1Week	7Weeks	1Week	3Weeks
MIAMI FORT 6	4Weeks		3Weeks	

Q. WHAT INFORMATION DID YOU SUPPLY TO MR. ESAMANN ON FORCED OUTAGES?

A. I provided Mr. Esamann with an estimate of the equivalent forced outage rate for the Plants. I provided a five-year average of the equivalent forced outage rate ("EFOR") which is a measurement that takes the number of forced outage hours and equivalent forced derate hours relative to the number of service hours and forced outage hours. I used the EFOR for the Plants for the period of 2000 through 2005. The annual average EFOR from 2000 through 2005 for East Bend were between 6.02% and 16.69%; for Miami Fort 6 were between 3.38% and

9.42%; and for Woodsdale were between 1.25% and 21.37%. The average EFOR for coal-fired plants in NERC from 2000 through 2004 for 600 MW units was 7.03% and for 160 MW units was 6.35%. The average EFOR for Gas Turbines and Jet Engines for the same period was 30.25%. I provided an estimate to Mr. Esamann of the average equivalent forced outage rates for East Bend and Miami Fort 6 during the time period of 2007 through 2009 of 7% and 10.5%, respectively.

VI. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DECRIBE SCHEDULE B-4.1.

A. Schedule B-4.1 is a list of projects that are projected in Construction Work in Progress ("CWIP") as of December 31, 2007. This schedule presents the percent complete for each project as of December 31, 2007 based on both elapsed time and total expenditures. I supplied the information on this schedule relating to generation plant.

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

A. FR 10(9)(b) consists of the most recent capital construction budget containing the forecasted construction expenditures for a minimum of three years. I provided the forecasted capital construction budget for the Plants contained in FR 10(9)(b) and for Mr. Davey's use for the forecasted financial data.

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

A. FR 10(9)(f) includes the following information for major projects constituting five percent or more of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the Plants contained in FR 10(9)(f).

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

A. FR 10(9)(g) includes the following information for projects constituting less than five percent of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the Plants contained in FR 10(9)(g).

VII. <u>CONCLUSION</u>

Q. IS THE INFORMATION ON PLANT OUTAGES YOU PROVIDED TO OTHER WITNESSES ACCURATE, TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. WAS THE INFORMATION YOU PROVIDED FOR SCHEDULE B-4.1, FR10(9)(B), 10(9)(F) AND 10(9)(G) 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, John J. Roebel, being duly sworn, deposes and says that he is Group Vice President, Engineering and Technical Services for Duke Energy Shared Services, LLC, 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.

John J. Roebel, Affiant

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

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC
STATE OF OHIO

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

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 K. JETT

ON BEHALF OF

DUKE ENERGY KENTUCKY

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ATTACHMENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul K. Jett. 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 Director, RTO Activities.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I earned an Associate Degree of Applied Science in Electrical Engineering Technology from the University of Cincinnati in 1991. I earned a Bachelor of Science Degree in Electrical Engineering Technology from the University of Cincinnati in 1998. I earned a Masters of Business Administration Degree from Thomas More College in 2000.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined The Cincinnati Gas & Electric Company ("CG&E") in March 1987 as a substation operator. I then progressed through a variety of positions of increasing responsibility. In 2001, I served as Cinergy Corp.'s ("Cinergy") project manager to prepare for the transfer of functional control of the operation of Cinergy's transmission systems to the Midwest ISO. In February 2002, the Midwest ISO began providing services as a "Day 1" RTO under its own Open Access Transmission Tariff ("OATT"). As Cinergy's Day 1 project manager, I oversaw the establishment of Cinergy's business practices, systems, and interfaces necessary to do business with the Midwest ISO following the Day 1 startup in February 2002.

In March 2003, I was promoted to Director, Federal Regulatory Policy. Among other duties, my responsibilities in that position included helping Cinergy analyze and prepare for the Midwest ISO's launch of its Day 2 Markets, which established a centralized security-constrained economic dispatch platform supported by a day-ahead and real-time energy market design, including locational marginal pricing (sometimes referred to as "LMP") and financial transmission rights (sometimes referred to as "FTRs") throughout the Midwest ISO region. In February 2005, I assumed my current position of Director, RTO Activities.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, RTO ACTIVITIES.

A. As Director, RTO Activities, I am primarily responsible for the execution and support of initiatives carried out by Duke Energy's transmission function in connection with the activities of Regional Transmission Organizations ("RTOs"), including Duke Energy's participation in the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") and the day-ahead and real-time electric energy markets operated by the Midwest ISO (sometimes referred to as the "Day 2 Markets"). My key responsibilities include: (i) serving as Duke Energy's representative for an supporting the efforts of the Midwest ISO's Transmission Owners; (ii) monitoring the Midwest ISO's and other parties' filings with the Federal Energy Regulatory Commission ("FERC") concerning the Midwest ISO's Open Access Transmission and Energy Markets Tariff ("TEMT") and business practices; (iii) providing input into Duke Energy's internal business practices related to its participation in the Midwest ISO; and (iv) monitoring other regulatory and RTO developments.

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

A. The purpose of my testimony is to describe generally the Midwest ISO's Day 1 and Day 2 operations, which the Midwest ISO implemented on February 1, 2002 and April 1, 2005, respectively, including an overview of the types of charges Duke Energy Kentucky incurs on behalf of its retail electric customers. I also describe certain forecasted transmission cost information that I provided to Mr. Davey for the forecasted financial data.

II. DUKE ENERGY KENTUCKY'S MEMBERSHIP IN THE MIDWEST ISO

Q. WHO OWNS AND OPERATES THE BULK TRANSMISSION FACILITIES USED FOR PROVIDING RETAIL ELECTRIC SERVICE FOR DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC CUSTOMERS?

A. As discussed by Mr. Stanley, the bulk transmission system (consisting of transmission facilities 69 kilovolts ("kV") and above) located in Northern Kentucky is owned by CG&E d/b/a Duke Energy Ohio. Duke Energy Ohio transferred functional control of all of its transmission facilities, including facilities owned in Northern Kentucky, to the Midwest ISO in February 2002. Duke Energy Kentucky owns some local transmission facilities below 69kV, which it transferred to the Midwest ISO in February 2002. PSI Energy, Inc. d/b/a

Duke Energy Indiana also transferred its transmission facilities to the Midwest ISO at that time. The transmission owners have operational control over these transmission facilities, and the Midwest ISO has functional control.

III. THE MIDWEST ISO'S DAY 1 OPERATIONS

Q. PLEASE DESCRIBE THE SERVICES THE MIDWEST ISO BEGAN PERFORMING WHEN IT COMMENCED DAY 1 OPERATIONS.

A. When the Midwest ISO began Day 1 operations, it assumed responsibility for certain functions that were formerly performed by transmission owners in the Midwest ISO region. That responsibility included the determination of transfer capability, processing of requests for transmission service, OASIS (*i.e.*, Open Access Same-Time Information System) administration and scheduling of transmission transactions. The Midwest ISO also assumed responsibility for evaluating regional security conditions to determine whether requests for transmission service can be accommodated on the transmission system and whether transactions actually scheduled result in power flows that remain within or violate security limits designed to ensure reliable operation of the interconnected transmission grid. Consistent with that role, the Midwest ISO is responsible for determining whether transmission schedules should be curtailed to maintain power flows within security limits. Thus, while the Midwest ISO had some redispatch and transmission system reconfiguration authority in MISO Day 1, the Midwest ISO's primary means of managing congestion on the transmission system in MISO Day 1 was essentially limited to screening and denying requests for transmission service that would violate security limits and ordering the curtailment of scheduled transactions when necessary.

Q. IS DUKE ENERGY KENTUCKY OBLIGATED TO PURCHASE TRANSMISSION SERVICE FROM THE MIDWEST ISO?

A. Yes. The Midwest ISO is the exclusive transmission provider of all transmission service requested and scheduled on the transmission facilities under its functional control. The Federal Energy Regulatory Commission ("FERC") has mandated that all transmission customers must take transmission service from the Midwest ISO for service over the transmission facilities under the Midwest ISO's functional control. Thus, Duke Energy Kentucky, on behalf of its retail electric customers in Kentucky, is a transmission customer under the Midwest ISO Open Access Transmission and Energy Market Tariff ("TEMT") with respect to transmission service required to serve Duke Energy Kentucky's retail electric customers, including the transmission of electricity produced at generating facilities owned and operated by Duke Energy Kentucky and transmitted across transmission facilities owned by Duke Energy Kentucky and its affiliate, Duke Energy Ohio, but under the functional control of the Midwest ISO.

Q. WHAT MIDWEST ISO CHARGES ARE TRANSMISSION CUSTOMERS REQUIRED TO PAY RELATED TO DAY 1 OPERATIONS FOR TRANSMISSION SERVICE TAKEN TO SERVE THEIR RETAIL ELECTRIC CUSTOMERS?

A. The Midwest ISO is a not-for-profit entity. Accordingly, the Midwest ISO TEMT contains a variety of scheduled charges designed to ensure that the Midwest ISO remains revenue neutral. Under Schedule 1 of its TEMT, the Midwest ISO recovers the costs it incurs for providing transaction scheduling and system dispatch associated with real-time control of the transmission system. Under Schedule 10, the Midwest ISO imposes an administrative adder to recover its operating costs. Transmission customers are required to pay this fee for the transmission service they take on behalf of their retail electric customers. Under Schedule 10-FERC, the Midwest ISO collects revenues to pay the annual charge assessed by the FERC on the Midwest ISO based on the megawatt-hours of electric energy it transmits in interstate commerce as reported on FERC Form 582. Transmission customers are allocated a portion of that fee based on the megawatt-hours of network transmission service taken to serve their retail electric customers.

Schedules 2, 3, 5 and 6 of the Midwest ISO TEMT also contain a number of pass-through charges for ancillary services that the Midwest ISO procures from generators in the Midwest ISO region. Transmission customers that are vertically integrated utilities, such as Duke Energy Kentucky, typically self-supply those ancillary services, so the Midwest ISO does not invoice self-supplying transmission customers for those charges. For example, Schedule 5 of the Midwest ISO TEMT imposes a charge for spinning reserve service that must be provided or procured by the transmission provider (*i.e.*, the Midwest ISO) to ensure online reserves are available in the event of a system contingency. Note, however, that Duke Energy Kentucky procures Schedule 2 Reactive Supply and Voltage Control, and Schedule 3 Regulation and Frequency Response Service from Duke Energy Ohio. The Midwest ISO procures Schedule 5 spinning reserve service from Duke Energy Kentucky for its own load, so Duke Energy Kentucky is not subject to that charge. The same is true for Schedule 6 supplemental reserve service. Finally, Duke Energy Kentucky, as a transmission owning member of the Midwest ISO, is entitled to certain revenues collected by the Midwest ISO under its TEMT.

Q. IS IT APPROPRIATE FOR DUKE ENERGY KENTUCKY TO RECOVER THROUGH ITS RETAIL RATES THE CHARGES IMPOSED UNDER THE MIDWEST ISO TEMT?

A. Yes. Duke Energy Kentucky taking transmission service under the Midwest ISO TEMT to serve its retail electric customers is comparable to a Kentucky retail gas utility taking gas transportation service from an interstate gas pipeline to serve its Kentucky retail gas customers. In both situations, a Kentucky utility incurs costs to serve its Kentucky retail customers based upon FERC-approved rates set forth in a FERC-approved tariff. Just as a Kentucky gas utility is permitted by the Commission to recover from its Kentucky retail gas customers the utility's gas transportation costs incurred under a FERC-approved tariff to serve those customers, Duke Energy Kentucky, to the extent it is not already been authorized to do so, should be permitted to recover from its Kentucky retail electric customers the transmission costs incurred to serve those customers.

IV. THE MIDWEST ISO'S DAY 2 ENERGY MARKETS

Q. ARE YOU FAMILIAR WITH THE MIDWEST ISO'S DAY 2 ENERGY MARKETS?

A. Yes. As explained above, my responsibilities include monitoring federal regulatory policy and related matters. Consequently, I was substantially involved in the Company's efforts to prepare for the startup of the Midwest ISO's energy markets.

Q. WHY DID THE MIDWEST ISO IMPLEMENT DAY-AHEAD AND REAL-TIME ENERGY MARKETS?

A. The Midwest ISO's Day 2 energy markets initiative arose out of the Midwest ISO's efforts to comply with the FERC's directive in Order No. 2000 that required regional transmission organizations to provide transmission customers access to a market-based mechanism for congestion management and a real-time balancing market. For several reasons, the Midwest ISO decided to base its market design on the day-ahead and real-time energy markets that have been operated by PJM Interconnection since April 1998. A standard market design approach that results in a common market across the Midwest ISO and PJM regions is expected to result in substantial costs savings for market participants. Indeed, in a July 2002 order, the FERC mandated the implementation of a common market by the Midwest ISO and PJM. In that order the FERC stated:

> [W]e cannot ignore the substantial costs savings associated with having a common market across both regions. The transition period must be as short as absolutely possible. Therefore, in order to hasten these benefits, as well as to ensure as short a transition period as possible, we will require Midwest ISO and PJM to form a functional common market across the two organizations by October 1, 2004. This is consistent with Midwest ISO's commitment to have an LMP-based market in place by the end of 2003 for its region.

Alliance Companies et al., 100 FERC P61,137, ¶ 40 (July 31, 2002).

Q. PLEASE GENERALLY DESCRIBE THE MIDWEST ISO'S DAY 2 ENERGY MARKETS.

A. The principal document governing the operation of the Midwest ISO's energy markets is the Midwest ISO's TEMT, which was conditionally accepted by the FERC on August 6, 2004. The TEMT replaced the Midwest ISO's currently effective Open Access Transmission Tariff. The Midwest ISO launched its Day 2 Energy Markets on April 1, 2005. Effective January 1, 2006, Duke Energy Ohio transferred the East Bend No. 2, Miami Fort No. 6 and Woodsdale Generating Station Plants ("the Plants") to Duke Energy Kentucky. Since that time, Duke Energy Kentucky has arranged for and purchased transmission service on behalf of its retail customers pursuant to the TEMT.

Under the TEMT, the Midwest ISO administers both real-time and day-ahead markets for electric energy utilizing locational marginal pricing and financial transmission rights. The real-time energy market functions as the real-time balancing market required by Order No. 2000. The day-ahead market provides a means for market participants to mitigate their exposure to price risk in the real-time markets. It also provides meaningful information to the Midwest ISO regarding expected real-time operating conditions for the next day, which enhances the Midwest ISO's ability to ensure reliable operation of the transmission system. Additionally, locational marginal pricing, which is described in more detail by Mr. Swez, provides a market-based solution to managing congestion in the Midwest ISO region.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY CONGESTION.

A. All energy transactions on the transmission system can potentially result in congestion - that is, a transaction may cause one or more transmission elements to exceed its capability. Such congestion can either be resolved through methodologies, such as the North American Electric Reliability Council's ("NERC") Transmission Loading Relief ("TLR") procedures, or through market-based mechanisms, such as the use of locational marginal pricing.

Q. WHAT ARE FINANCIAL TRANSMISSION RIGHTS, OR FTRS?

A. FTRs, which are described in more detail in the testimony of Mr. Swez, are financial instruments that provide market participants a means to manage the risk of congestion costs they may incur as a result of scheduling energy transactions in the day-ahead energy market. FTRs were proposed by the FERC as part of its standard market design initiative and are currently a feature of several of the centrally dispatched energy markets operating in the U.S., including the energy markets operated by PJM, the New York ISO and ISO New England.

Q. PLEASE EXPLAIN THE BENEFITS OF LOCATIONAL MARGINAL PRICING OVER THE UTILIZATION OF THE NERC'S TLR PROCEDURES AS A MEANS TO MANAGE CONGESTION.

A. The Midwest ISO only had authority under Day 1 operations to order redispatch under emergency conditions. Since economic redispatch is not available to accommodate a given transmission transaction, the Midwest ISO's only recourse when a previously approved transmission request would lead to a violation of operating security limits was to curtail one or more transactions using TLR procedures that are based on uneconomic, inefficient criteria. Physical rationing of access to the transmission system in the Midwest ISO region through the use of TLR curtailments, however, led to inefficient use of the transmission grid, because TLRs take little account of the relative economic value of competing transactions. Regular and persistent use of TLR procedures in a region can indicate that congestion may exist in the area. If TLRs are used as the primary means to manage congestion, a party that values transmission capacity through a particular constraint higher than another party may not have an effective recourse to take advantage of this differential. Using TLRs as the primary congestion management tool also led to an underutilization of the transmission system. This is because a transmission provider, in order to avoid the excessive use of TLRs, would likely be overly conservative in approving requests for access to the transmission system in the first instance.

Moreover, utilizing a TLR often would not result in the desired outcome. Relieving congestion by calling a TLR was based on imprecise flow estimates that might not have accurately predicted the amount of congestion relief actually realized by calling the TLR. Additionally, the time needed to implement a requested curtailment could have been unacceptable depending on the nature of the constraint to be relieved.

In contrast, locational marginal pricing, which is the pricing methodology recommended by the FERC in Order No. 2000 and in use by PJM, the New York ISO and ISO New England, is a market-based pricing methodology that aligns the physics of redispatch caused by transmission congestion with the economic consequences. A security-constrained dispatch that prevents security violations before the fact is a significant improvement to reliability over the former congestion management system, which, as explained above, relied in large part on unpredictable and cumbersome TLR procedures to relieve transmission congestion after the fact.

Q. ARE THERE OTHER BENEFITS FROM THE MIDWEST ISO'S ENERGY MARKETS?

A. Yes. In addition to the reliability benefits described above, the Midwest ISO has projected that significant economic benefits will be realized from implementing the Day 2 energy markets.

Q. DID THE IMPLEMENTATION OF THE MIDWEST ISO'S DAY 2 ENERGY MARKETS RESULT IN NEW CHARGES THAT TRANSMISSION CUSTOMERS WERE REQUIRED TO PAY ON BEHALF OF THEIR RETAIL CUSTOMERS?

A. Yes. As noted above, the Midwest ISO is a not-for-profit entity. Like the Midwest ISO OATT it replaces, the Midwest ISO TEMT contains schedules and charges designed to ensure the Midwest ISO's continued revenue neutrality. Additionally, transmission customers became entitled to receive certain payments from the Midwest ISO as a result of their participation in the Day 2 energy markets. The new charges and credits that the Midwest ISO imposes under the TEMT (*i.e.*, charges and credits not included in the existing OATT) essentially fall into one of the following categories: (1) LMP charges related to energy purchase and sale transactions in the Midwest ISO's day-ahead and real-time energy markets; (2) charges and credits related to the settlement of FTRs held by market participants; (3) charges and credits related to certain uplift costs that the Midwest ISO will socialize and collect from all or a certain group of market participants; (4) administrative charges designed to ensure that the Midwest ISO will recover its costs of administering the energy markets and FTRs; and (5) other miscellaneous charges, costs and credits.

Q. PLEASE GENERALLY DECRIBE THE LMP CHARGES IMPOSED UNDER THE TEMT.

A. All purchases and sales of energy in the day-ahead and real-time energy markets are made at locational marginal prices, which reflect the market clearing price to serve the next increment of load at a given location. The locational marginal price of energy for a given market interval reflects: (1) the energy clearing price for that interval, which is the same for all locations in the Midwest ISO region; (2) the congestion costs incurred to deliver the energy to the withdrawal location; and (3) a marginal electricity loss component.

Every transaction scheduled through the Midwest ISO market is subject to locational marginal pricing. Each generator owned or operated by Duke Energy Kentucky is paid for all the megawatt-hours it supplies to the markets at its locational marginal price. Duke Energy Kentucky also designates a load zone as the withdrawal location for withdrawals from the energy markets made to serve its retail customers. The locational marginal price at that load zone represents the purchase price of energy for the load within that load zone. Since the energy clearing price is the same at every location for a given market interval, to the extent that Duke Energy Kentucky's own generators are serving its retail customers, the difference between the credit to Duke Energy Kentucky for that generation and the charge to Duke Energy Kentucky to serve that load will equal the congestion and losses incurred to deliver the energy.

Q. ARE BILATERAL PURCHASES SUBJECT TO LOCATIONAL MARGINAL PRICING?

A. Yes. The Midwest ISO imposes a charge for congestion and losses between the source and sink for bilateral purchases that are scheduled in the day-ahead or real-time energy market. Thus, to the extent Duke Energy Kentucky makes a bilateral purchase to serve its retail customers, in addition to the purchase price paid to the seller, that purchase will be subject to a charge for congestion and losses to deliver the energy to Duke Energy Kentucky's load zone.

Q. PLEASE DESCRIBE HOW FTRS ARE SETTLED IN THE DAY-AHEAD ENERGY MARKET.

A. Duke Energy Kentucky receives a separate FTR settlement statement for each operating day. After the day-ahead market is cleared, the Midwest ISO calculates the hourly financial value of each FTR using day-ahead locational marginal prices. FTR holders receive either credits or charges based upon the type of FTRs and the amount of congestion along the defined path of those FTRs.

Q. PLEASE DESCRIBE THE NEW ADMINISTRATIVE CHARGES IMPOSED UNDER SCHEDULE 16 AND SCHEDULE 17 OF THE TEMT.

A. Under Schedule 16, the Midwest ISO recovers all the costs it incurs related to providing FTR Administrative Service. Such costs include, but are not limited to, costs associated with: (1) coordination of FTR bilateral trading; (2)

administration of FTRs through allocation, assignment, auction or any other process accepted by the FERC; (3) support of the Midwest ISO's on-line internet-based FTR tool; (4) "simultaneous feasibility" analyses to determine the total combination of FTRs that can be outstanding and accommodated by the transmission system under the functional control of the Midwest ISO at a given point in time; and (5) the administration of FTRs and revenue distribution.

Schedule 17 provides for the recovery of all costs incurred by the Midwest ISO to provide Energy Market Support Administrative Service. Such costs include, but are not limited to, costs associated with: (1) market modeling and scheduling functions; (2) market bidding support; (3) LMP support; (4) market settlements and billing; (5) market monitoring functions; and (6) enabling the least-cost, security-constrained commitment and dispatch of generating resources to serve load in the Midwest ISO control areas while also establishing a spot energy market.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY UPLIFT COSTS.

A. Under its TEMT, the Midwest ISO has imposed a number of charges that it socializes and collects from all market participants or a certain group of market participants. For example, the Midwest ISO imposes a "Real-Time Revenue Sufficiency Guarantee Charge" on most market participants to ensure generators recover certain unit commitment costs for generators committed to be available during real-time operations for reliability purposes. Similarly, a charge or credit is allocated to market participants for inadvertent energy surpluses or shortages resulting from inadvertent energy between control areas and seams with other markets.

Q. HOW DOES DUKE ENERGY KENTUCKY PROPOSE TO RECOVER THE SCHEDULED CHARGES AND UPLIFT CHARGES IT PAYS THE MIDWEST ISO ON BEHALF OF ITS RETAIL ELECTRIC CUSTOMERS?

A. Duke Energy Kentucky proposes to recover through base rates the Midwest ISO's scheduled charges and uplift charges. These charges consist of the following Midwest ISO charges, as allocated by the Midwest ISO to Duke Energy Kentucky's retail electric customers: (i) Midwest ISO management costs billed to Duke Energy Kentucky by the Midwest ISO under Schedule 10 (ISO Cost Recovery Adder, including Schedule 10-FERC) of the TEMT; (ii) Midwest ISO management costs billed to Duke Energy Kentucky by the Midwest ISO under Schedule 16 (Financial Transmission Rights) (Administrative Service Cost Recovery Adder) of the Midwest ISO TEMT; (iii) Midwest ISO management costs billed to Duke Energy Kentucky by the Midwest ISO under Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder); (iv) costs billed to Duke Energy Kentucky by the Midwest ISO under the Midwest ISO TEMT for standard market design; (v) other government-mandated transmission costs Duke Energy Kentucky is required to pay on behalf of its retail electric customers; and (vi) certain Midwest ISO transmission revenues assigned to Duke Energy Kentucky, collected by the Midwest ISO under the Midwest ISO TEMT.

Q. DID YOU PROVIDE MR. DAVEY WITH A PORTION OF DUKE ENERGY KENTUCKY'S FORECASTED TRANSMISSION COSTS?

A. Yes, I provided Mr. Davey with a portion of Duke Energy Kentucky's forecasted transmission costs, and Mr. Swez supplied the remaining forecasted transmission costs.

I provided Mr. Davey with the forecasted transmission costs for Schedules 1 through 3 and Schedule 9 for the forecasted portion of the base period and for the forecasted test period, which I calculated by applying the tariffed rates to Dr. Stevie's load forecast.

I also provided Mr. Davey with projected MISO Schedule 10-FERC, Schedules 10, 16 and 17 charges for Duke Energy of Kentucky. I also calculated these charges by using the load forecast obtained from Dr. Stevie. The forecast of Midwest ISO rates was obtained from the Midwest ISO and provided to Midwest ISO stakeholders at the Midwest ISO Advisory Committee Meeting on January 18, 2006. A copy of the Midwest ISO's forecasted rates is at Attachment PKJ-1.

Schedule 10-FERC is \$0.05 per MWh of projected energy.

Under Schedule 16, the Midwest ISO recovers all the costs it incurs related to providing FTR Administrative Service. Schedule 16 is 100% demand based. The monthly charges are derived by multiplying the monthly rate with the forecasted demand.

Schedule 17 provides for the recovery of all costs incurred by the Midwest ISO to provide Energy Support Administrative Service. Schedule 17 is 100%

energy based. The monthly charges are derived by multiplying per MWh rate with the forecasted monthly energy.

The cost associated with operating the Midwest ISO exclusive of those costs recovered pursuant to Schedules 1, 16 or 17 shall be recovered through Schedule 10 charges. The Midwest ISO costs recovered under Schedule 10 shall include the Midwest ISO's deferred pre-operating costs; the costs associated with building and operating the Security Center, including capital cost and operating expenses; and costs associated with administering the Tariff. Sixty percent of the Schedule 10 charges are based on forecasted demand and 40% of the charges are based on forecasted energy. I provided this cost information to Mr. Davey for the forecasted portion of the base period (*e.g.*, *the six months ending August 31*, 2006), and for the forecasted test period (*e.g.*, the twelve months ending December 31, 2007).

I supplied forecasted transmission cost information for the transmission costs listed in Section IV of Attachment PKJ-2, which lists all of the Midwest ISO's TEMT charges. Mr. Swez supports the forecasted costs listed in Sections I through III of Attachment PKJ-2.

Q. DOES DUKE ENERGY KENTUCKY PROPOSE TO RECOVER TRANSMISSION COSTS THROUGH ANY OTHER COST RECOVERY MECHANISMS IN ADDITION TO THE BASE RATE RECOVERY SUPPORTED BY MR. DAVEY?

A. Yes. Duke Energy Kentucky proposes to recover economy purchases costs through the Day 2 energy markets, through its Fuel Adjustment Clause, as discussed by Mr. Wathen. These economy purchases costs will include congestion and losses costs reflected in the locational marginal price. Duke Energy Kentucky proposes to apply all incremental credits and recover the remaining charges not reflected in base rates through a tracking mechanism known as Rider TCRM – Transmission Cost Recovery Mechanism. Attachment PKJ-2 lists all of the charges and credits under the TEMT, all of which Duke Energy Kentucky proposes to recover in base rates and track under Rider TCRM for the period on and after January 1, 2007. Duke Energy Kentucky proposes that credits received under the TEMT should generally be an offset to corresponding costs imposed under the TEMT. For example, revenues received pursuant to the Excess Congestion Charge Fund Credit that are allocable to retail customers will offset congestion costs incurred by Duke Energy Kentucky that are allocable to retail customers.

V. CONCLUSION

Q. ARE THE CALCULATIONS OF TRANSMISSION COSTS THAT YOU PROVIDED TO MR. DAVEY ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. IS ATTACHMENT PKJ-1 A TRUE AND ACCURATE COPY OF THE FORECASTED COSTS YOU RECEIVED FROM THE MIDWEST ISO?

A. Yes.

Q. IS ATTACHMENT PKJ-2 A TRUE AND ACCURATE SUMMARY OF THE MIDWEST ISO'S TEMT CREDITS AND CHARGES, AND THE COMPANY'S PROPOSED TREATMENT OF THESE CREDITS AND CHARGES?

A. Yes.

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

A. Yes.

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, Paul K. Jett, 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 K. Jett

Paul K. Jett, Affiant

Subscribed and sworn to before me by Paul K. Jett on this 22nd day of May, 2006.

John J. Finnigan Jr.

NOTARY PUBLIC

My Commission Expires:

JOHN J. FINNIGAN, JR. Attorney at Law
NOTARY PUBLIC, STATE OF OHIO
My commission has [illegible] expiration
date. Section 147.03 O.R.

Item C11

Midwest ISO Annual Revenue Requirement - 2006 Budget
($ in thousands, except Billing Rates)

	2006	2007	2008	2009	2010
Revenue:					
Cost Adder Revenue	$ 245,365	$ 252,082	$ 250,999	$ 245,653	$ 252,066
Other Revenue	$ 12,010	$ 14,493	$ 15,051	$ 15,632	$ 14,671
Total Revenue	$ 257,375	$ 266,575	$ 266,050	$ 261,285	$ 266,737
Expenses:					
Operating Expenses	$ 158,605	$ 166,529	$ 171,571	$ 176,764	$ 182,113
Interest Expenses	$ 19,645	$ 18,283	$ 16,010	$ 13,995	$ 12,144
Depreciation and Amortization	$ 79,125	$ 81,764	$ 78,469	$ 70,526	$ 72,480
Total Expenses	$ 257,375	$ 266,576	$ 266,050	$ 261,285	$ 266,737
Billing Determinants					
Schedule 10 MWhs - Demand Based (000)	924,752	943,247	962,112	981,354	1,000,981
Schedule 10 Adder MWhs - Energy (000)	689,961	703,760	717,835	732,192	746,836
Schedule 16 - FTR MW Volume (000)	729,887	744,485	759,375	774,562	790,053
Schedule 17 - MWh (Load+Generation+Virtuals) (000)	1,659,441	1,692,630	1,726,482	1,761,012	1,796,232
Billing Rates					
Schedule 10 - Demand Based- $ per MWh	$ 0.073	$ 0.073	$ 0.070	$ 0.063	$ 0.063
Schedule 10 - Energy- $ per MWh	$ 0.065	$ 0.065	$ 0.062	$ 0.057	$ 0.056
Schedule 10 - Total- $ per composite MWh	$ 0.137	$ 0.138	$ 0.132	$ 0.120	$ 0.119
Portion of Sch 10 - Demand Based	60%	60%	60%	60%	60%
Portion of Sch 10 - Energy	40%	40%	40%	40%	40%
Schedule 16 - $ per FTR MW Volume	$ 0.026	$ 0.025	$ 0.025	$ 0.025	$ 0.025
Schedule 17 - $ per MWh (Load+Generation+Virtuals)	$ 0.069	$ 0.070	$ 0.070	$ 0.070	$ 0.071
Capital Expenditures	$ 43,724	$ 24,000	$ 24,000	$ 24,000	$ 24,000

NOTES:

1) 2006 forecast of capital expenditures includes 2005 carry forward amount of $8.6 million.

2) Forecast of capital expenditures includes capitalized labor and capitalized interest.

3) Costs to implement and operate: (i) ancillary services, (ii) control area consolidation, and (iii) resource adequacy are not included in this forecast

	2006	2007	2008	2009	2010
Cost per MWH of Energy					
Schedule 10	$ 0.162	$ 0.162	$ 0.155	$ 0.141	$ 0.141
Schedule 16	$ 0.027	$ 0.027	$ 0.026	$ 0.026	$ 0.027
Schedule 17	$ 0.167	$ 0.169	$ 0.168	$ 0.168	$ 0.170
Total Cost / MWh of Schedule 10 Energy	$ 0.356	$ 0.358	$ 0.350	$ 0.336	$ 0.338
Forecast of Cost per MWh made in December 2004	$ 0.385	$ 0.380	$ 0.368	$ 0.354	n/a

Forecast as of January 10, 2006.

Midwest ISO Annual Revenue Requirement - 2006 Budget
($ in thousands, except Billing Rates) (LGE/KU Exits)

Item C11

	2006	2007	2008	2009	2010
Revenue:					
Cost Adder Revenue	$ 245,365	$ 247,082	$ 245,999	$ 240,653	$ 247,066
LGE/KU Exit Fee	$ -	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Other Revenue	$ 12,010	$ 14,493	$ 15,061	$ 15,632	$ 14,671
Total Revenue	$ 257,375	$ 266,575	$ 266,060	$ 261,285	$ 266,737
Expenses:					
Operating Expenses	$ 158,605	$ 166,529	$ 171,571	$ 176,764	$ 182,113
Interest Expenses	$ 19,645	$ 18,283	$ 16,010	$ 13,995	$ 12,144
Depreciation and Amortization	$ 79,125	$ 81,764	$ 78,469	$ 70,526	$ 72,480
Total Expenses	$ 257,375	$ 266,576	$ 266,060	$ 261,285	$ 266,737
Billing Determinants					
Schedule 10 MWhs - Demand Based (000)	904,752	886,652	904,385	922,473	940,922
Schedule 10 Adder MWhs - Energy (000)	689,961	661,534	674,765	688,260	702,026
Schedule 16 - FTR MW Volume (000)	729,887	699,816	713,812	728,088	742,650
Schedule 17 - MWh (Load+Generation+Virtuals) (000)	1,659,441	1,591,072	1,622,894	1,655,352	1,688,459
Billing Rates					
Schedule 10 - Demand Based - $ per MWh	$ 0.073	$ 0.076	$ 0.072	$ 0.066	$ 0.065
Schedule 10 - Energy - $ per MWh	$ 0.065	$ 0.068	$ 0.065	$ 0.059	$ 0.058
Schedule 10 - Total - $ per composite MWh	$ 0.137	$ 0.143	$ 0.137	$ 0.124	$ 0.124
Portion of Sch 10 - Demand Based	60%	60%	60%	60%	60%
Portion of Sch 10 - Energy	40%	40%	40%	40%	40%
Schedule 16 - $ per FTR MW Volume	$ 0.025	$ 0.026	$ 0.026	$ 0.026	$ 0.026
Schedule 17 - $ per MWh (Load+Generation+Virtuals)	$ 0.069	$ 0.074	$ 0.073	$ 0.073	$ 0.074
Capital Expenditures	$ 43,724	$ 24,000	$ 24,000	$ 24,000	$ 24,000

NOTES:
1) 2006 forecast of capital expenditures includes 2005 carry forward amount of $8.6 million.
2) Forecast of capital expenditures includes capitalized labor and capitalized interest.
3) Costs to implement and operate: (i) ancillary services, (ii) control area consolidation, and (iii) resource adequacy are <u>not</u> included in this forecast.

	2006	2007	2008	2009	2010
Cost per MWH of Energy					
Schedule 10	$ 0.162	$ 0.169	$ 0.162	$ 0.147	$ 0.146
Schedule 16	$ 0.027	$ 0.028	$ 0.027	$ 0.027	$ 0.028
Schedule 17	$ 0.167	$ 0.177	$ 0.176	$ 0.176	$ 0.178
Total Cost / MWh of Schedule 10 Energy	$ 0.356	$ 0.373	$ 0.365	$ 0.350	$ 0.352
Forecast of Cost per MWh with LGE/KU	$ 0.336	$ 0.358	$ 0.350	$ 0.336	$ 0.338

Forecast as of January 10, 2006.

MIDWEST ISO CHARGES AND CREDITS

I. Charges and Credits Settled in the Day-Ahead Energy Market

A. Charge: Purchases From MISO in the Day-Ahead Energy Market

1. TEMT reference (Module C): 39.3.1(a-b)

2. Description: Charge for all energy scheduled to be withdrawn from load nodes in the Day-Ahead market.

B. Charge: Bilateral Purchases Scheduled Day-Ahead

1. TEMT reference (Module C): 39.3.3(a-d)

2. Description: Charge for losses and congestion between the source and sink for bilateral purchases that are financially scheduled in the Day-Ahead market. The amount to be paid to the seller for such bilateral purchases (i.e., the energy component) is settled outside the MISO market.

C. Credit: FTR congestion revenues

1. TEMT reference (Module C): 39.3.4(a-b)

2. Description: Revenues received for congestion costs from an FTR receipt point to an FTR delivery point to the holder of such FTR. Value is pro-rated if congestion revenues are not sufficient to fully fund all FTRs.

D. Charge: FTR congestion costs

1. TEMT reference (Module C): 39.3.4(a-b)

2. Description: Charge for all negative congestion costs from an FTR receipt point to an FTR delivery point to the holder of such FTR (FTR Obligations only).

E. Charge and Credit: FTR Auction Settlement

1. TEMT reference (Module C): 44.6, 45.6

2. Description: Charges and payments to FTR holders for purchases and sales of FTRs through MISO auctions or secondary markets.

F. Charges and Credits: Virtual Bids and Offers in the Day-Ahead Market

1. TEMT reference (Module C): 39.3.2(a)

2. Description: Charges and credits for virtual resource offers and virtual demand bids in the Day-Ahead market.

G. Credit: Day-Ahead Recovery of Unit Commitment Costs

1. TEMT reference (Module C): 39.3.2(b)

2. Description: Credit to generators for generation committed by MISO to recover start up and no load costs if those costs are not otherwise recovered in the Day-Ahead market.

H. Credit: Excess Congestion Charge Fund Credit

1. TEMT reference (Module C): 39.3.4(c)

2. Description: Excess congestion charges collected are distributed at the end of each month to FTR holders and the end of each year to network and firm point-to-point transmission customers.

I. Charge: Day-Ahead Revenue Sufficiency Charge

1. TEMT reference (Module C): 39.3.1(c)

2. Description: Charge to collect revenue necessary to ensure generators recover startup and no load costs for units committed by MISO in the Day-Ahead market.

II. Charges And Credits Settled In The Real-Time Markets

A. Charge: Purchases From MISO in the Real-Time Energy Market

1. TEMT reference (Module C): 40.3.3(a)(i)

2. Description: Charge for all energy withdrawn from load nodes in the Real-Time market that exceeds amounts scheduled in the Day-Ahead market at those nodes.

B. Charge: Bilateral Purchases Scheduled Real-Time

1. TEMT reference (Module C): 40.4.1(d)(i), 40.4.2

2. Description: Charge for losses and congestion between the source and sink for bilateral purchases that are financially scheduled in the Real-Time

market. The amount to be paid to the seller for such bilateral purchases is settled outside the MISO market.

C. Charge: Uninstructed Deviation Penalty

1. TEMT reference (Module C): 40.3.4(a-d)

2. Description: Charge to generators that do not follow MISO dispatch basepoints within tolerance band.

D. Credit: RAC Recovery of Unit Commitment Costs

1. TEMT reference (Module C): 40.3.3(b)(ii)

2. Description: Credit to generators for generation committed by MISO to recover start up and no load costs if those costs are not otherwise recovered in the Real-Time market (credit supported through revenue collected from the Real-Time Revenue Sufficiency Guarantee Charge).

E. Credit: Marginal Losses Surplus Credit

1. TEMT reference (Module C): 39.3.5(a-b); 40.5

2. Description: Payments distributed to market participants for excess loss amounts collected through LMP charges imposed in the Day-Ahead and Real-Time markets.

F. Charge and Credit: Inadvertent Energy Charge or Credit

1. TEMT reference (Module C): 40.7

2. Description: A charge or credit allocated to market participants for all inadvertent energy value surplus or shortage due to inadvertent energy between control areas and seams with other markets.

G. Charge: Real-Time Revenue Sufficiency Guarantee Charge

1. TEMT reference (Module C): 40.3.3(a)(ii)

2. Description: Charge to market participants to socialize the revenue required to ensure generators recover the startup and no load costs for units committed in the RAC process.

H. Charge and Credit: Other Uplifted Charges and Credits

1. TEMT reference (Module C): various

2. Description: Charges and credits for other costs and revenues uplifted to market participants.

III. Other Day 2 Costs

A. Cost: Costs for Rescheduled Planned Generator Outages

1. TEMT reference (Module C): 38.2.5(h)(iii)

2. Description: Unreimbursed costs incurred as a result of outages rescheduled by the Midwest ISO.

B. Cost: Control Area Operations Costs

1. TEMT reference: none

2. Description: Unreimbursed control area costs incurred by CG&E under the Balancing Authority Agreement.

C. Cost: Other Internal Costs

1. TEMT reference: none

2. Description: Other internal costs, including software, hardware and labor costs, incurred as a result of MISO Day 2.

D. Charge and Credit: Miscellaneous Penalty Amounts

1. TEMT reference (Module C): 65.3

2. Description: Charges and credits for miscellaneous penalties.

IV. TEMT Scheduled Charges

A. Schedule 1: Scheduling, System Control and Dispatch Service

1. TEMT Reference: Schedule 1

2. Description: Charge for providing transaction scheduling and system dispatch associated with real-time control of the transmission system.

B. Schedule 2: Reactive Supply And Voltage Control From Generation Sources Service

1. TEMT Reference: Schedule 2

2. Description: Charge for providing reactive power support necessary to maintain transmission voltages on the transmission system.

C. Schedule 3: Regulation and Frequency Response Service

1. TEMT Reference: Schedule 3

2. Description: Charge for providing for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz).

D. Schedule 5: Operating Reserve - Spinning Reserve Service

1. TEMT Reference: Schedule 5

2. Description: Charge for serving load during an emergency contingency by providing generating units that are on-line and loaded at less than maximum output, ready to serve additional demand and which can be fully applied in ten (10) minutes.

E. Schedule 6: Operating Reserve - Supplemental Reserve Service

1. TEMT Reference: Schedule 6

2. Description: Charge for serving load in an emergency contingency by providing generating units that are on-line but unloaded which can be fully applied in 10 minutes, by quick-start generation capable of serving demand within 10 minutes, or by interruptible load that can be removed within 10 minutes.

G. Schedule 9: Network Integration Transmission Service

1. TEMT Reference: Schedule 9

2. Description: Charge for providing transmission service.

H. Schedule 10: Administrative Service Cost Recovery Adder

1. TEMT Reference: Schedule 10

2. Description: Charge imposed to recover administrative and overhead costs not recovered under Schedules 1, 10-FERC, 16 or 17.

I. Schedule 10-FERC: FERC annual charge

1. TEMT Reference: Schedule 10-FERC

2. Description: Charge imposed to recover FERC annual charge that Midwest ISO is required to pay as a transmission provider.

J. Schedule 16: FTR Administrative Service Cost Recovery Adder

1. TEMT reference: Schedule 16

2. Description: Charge imposed to recover costs incurred by MISO to administer FTRs.

K. Schedule 17: Energy Market Support Administrative Service Cost Recovery Adder

1. TEMT reference: Schedule 17

2. Description: Charge imposed to recover costs incurred by MISO to administer the day-ahead and real-time energy markets.

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

JOHN D. SWEZ

ON BEHALF OF

DUKE ENERGY KENTUCKY

183239

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Swez, 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 Manager, Regulated Real-Time Operations.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Mechanical Engineering from Purdue University in 1992. I received a Masters of Business Administration degree from the University of Indianapolis in 1995.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined PSI in 1992 and have held various engineering positions in the Power Services and Power Trading departments. In 2003, I assumed the position of Manager, Regulated Operations. I assumed my current position on January 1, 2006. In addition, I am a registered licensed professional engineer in the State of Ohio.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS MANAGER, REGULATED REAL-TIME OPERATIONS, AS THEY RELATE TO DUKE ENERGY KENTUCKY.

A. As Manager, Regulated Real-Time Operations, I am responsible for submitting The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky's

"Duke Energy Kentucky") demand bids and supply offers to the Midwest Independent System Operator, Inc.'s ("Midwest ISO") day-ahead and real-time electric energy markets (sometimes referred to as the "Day 2 Markets") as well as managing Duke Energy Kentucky's short-term supply position to ensure Duke Energy Kentucky has adequate resources committed to serve its retail customers' electricity needs in the most cost-effective manner.

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

A. The purpose of my testimony is to describe the effect the Midwest ISO's Day 2 energy markets have had on economic dispatch in the Midwest region and the supply resources used to serve Duke Energy Kentucky's retail customers' electricity needs. I will begin by generally describing a traditional economic dispatch and commitment process, including wholesale power purchases. I will then discuss the Day 2 energy markets that the Midwest ISO implemented on April 1, 2005, including an overview of the Midwest ISO's day-ahead and real-time energy markets, the principles of locational marginal pricing, the purpose of financial transmission rights ("FTRs"), and wholesale power purchases today as part of this process. I support the Company's recovery of incremental transmission costs incurred on and after January 1, 2007 through a tracking mechanism. I also discuss cost estimates I provided to other witnesses. Finally, I will discuss the delivery points for energy under the Back-up Power Sale Agreement ("Back-up PSA").

II. TRADITIONAL ECONOMIC DISPATCH AND COMMITMENT

Q. ARE YOU PERSONALLY INVOLVED IN DAY-TO-DAY DECISIONS REGARDING THE DISPATCHING AND COMMITMENT OF RESOURCES USED TO SERVE DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC CUSTOMERS?

A. Yes, I am. As explained above, my responsibilities include managing Duke Energy Kentucky's short-term supply position to ensure adequate resources are committed to meet Duke Energy Kentucky's retail customers' electricity needs in the most cost-effective manner.

Q. PLEASE EXPLAIN THE MEANING OF THE TERM "ECONOMIC DISPATCH AND UNIT COMMITMENT."

A. Economic dispatch and unit commitment is an operating procedure used by utilities to supply electricity to their customers using the most cost-effective resources available. Utilities serve their retail customers using the least cost combination of their own generation and purchased power resources available. The cost-differential employed in making the determination of the most economical resources available are the incremental costs incurred to supply retail customers' electricity needs with self-generation or equivalent wholesale purchases of energy.

Q. PLEASE EXPLAIN HOW UTILITIES USED WHOLESALE PURCHASES TO SUPPLEMENT THEIR OWN GENERATION RESOURCES PRIOR TO THE START OF THE MISO DAY 2 MARKET.

A. Prior to April 1, 2005, Midwest utilities used energy transactions in the forward or real-time markets to balance their systems, ensuring that the most cost-effective combination of resources were committed and dispatched appropriately to meet customer demand. Utilities made decisions related to unit commitment, unit dispatch, and wholesale transactions among other factors.

III. OVERVIEW OF THE MIDWEST ISO'S DAY 2 ENERGY MARKETS

Q. PLEASE GENERALLY DESCRIBE THE MIDWEST ISO'S DAY 2 ENERGY MARKETS.

A. On April 1, 2005, the Midwest ISO began to independently administer day-ahead and real-time markets for electric energy. The real-time energy market functions as a real-time balancing market. Through the day-ahead market, market participants are able to mitigate their exposure to price risk in the real-time markets, as I will describe later in my testimony. Both markets are based on supply offers and demand bids (or actual demand in the case of the real-time market) submitted to the Midwest ISO by market participants, including both generator owners (as sellers) and load serving entities (as buyers). Thus, Duke Energy Kentucky functions as both a seller and buyer in the markets to serve its retail electric customers in Kentucky.

The Midwest ISO uses the generation offers and demand bids (or actual metered demand as in the case of the real-time market) to arrange a security-constrained, economic dispatch for the entire Midwest ISO region for each market interval. The market interval for the day-ahead market is hourly; for the real-time market, the dispatch interval is every five minutes. Once the Midwest ISO defines a security-constrained economic dispatch solution for a given market dispatch interval, it determines market clearing prices in each market using the principles of locational marginal pricing. Finally, the Midwest ISO administers a system of FTRs based upon the use of locational marginal pricing for pricing energy to allow parties to hedge their exposure to congestion costs.

Q. PLEASE EXPLAIN THE TERMS "SELF-SCHEDULING" AND "MUST-RUN UNITS."

A. Duke Energy Kentucky can "self-schedule" or make "must-run" certain resources to ensure that those resources are committed in the most cost-effective manner to supply the electricity needs of its retail customers. A must-run offer would allow the generator owner to have the option to commit a unit to operate at a minimum specific megawatt level for any hour. For instance, a coal unit that takes 24 hours to start up would typically be committed by the market participant and made a must-run unit in the day-ahead market. A self-scheduled unit would have a generator offer that would specify an exact operating level. The Midwest ISO then sends a set-point back to the generator to run at the specified level. For instance, a unit that is brought on for testing could be offered as a self-schedule unit.

Q. PLEASE EXPLAIN LOCATIONAL MARGINAL PRICING.

A. Locational marginal pricing defines the marginal cost of energy serving the next increment (*i.e.*, one megawatt "MW") of load at each location, based on generation dispatch, transmission constraints binding the dispatch, and the offers and bids of sellers and buyers participating in the energy markets. Because the locational marginal price is based on the marginal cost of energy to serve the next increment of load, the energy clearing price is the same at each location supplying energy to or withdrawing energy from the market for a given market interval. Additionally, the locational marginal price paid for energy withdrawn at a load zone (*i.e.,* energy withdrawn to serve retail customers) includes costs for congestion in any market interval when the transmission system is constrained and the lowest price generator available cannot serve the next increment of load at that load zone because of such congestion. The locational marginal price also includes a component to reflect the marginal losses incurred to deliver the energy to the load zone.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY CONGESTION.

All energy transactions on the transmission system can potentially result in congestion – that is, a transaction may cause one or more transmission elements to exceed its capability. Congestion in the Day 2 markets is resolved primarily through the use of locational marginal pricing.

Q. WHAT ARE FTRS?

FTRs are financial instruments that provide market participants a means to manage the risk of congestion costs they may incur as a result of energy transactions in the day-ahead energy market. Market participants who own FTRs are provided revenues as an offset to congestion costs for scheduling injections (*e.g.*, generation, bilateral sales, *etc.*) at one location, and withdrawals (*e.g.*, load, bilateral purchases) at a different location in the day-ahead energy market. FTRs do not protect market participants from congestion costs that result from scheduling power in the real-time energy market or from deviations between transactions scheduled in the day-ahead energy market and real-time operations.

IV. ECONOMIC DISPATCH IN DAY 2 MARKETS

Q. HOW HAS THE MIDWEST ISO'S IMPLEMENTATION OF ITS DAY 2 ENERGY MARKETS AFFECTED UTILITIES' TRADITIONAL ECONOMIC DISPATCH AND UNIT COMMITMENT?

A. The fundamentals of economic dispatch and hedging price risk have not changed. A utility's retail customers continue to enjoy the benefits of the operating costs of the utility's own generation. When lower cost power is available in the wholesale market, the utility's higher cost generation is displaced with purchases of the lower cost power. In the Day 2 markets, Duke Energy Kentucky has the option to purchase energy from the Midwest ISO's day-ahead and real-time energy markets. Participation in those markets, however, will involve a number of considerations that will affect the resources used and the costs incurred to serve retail customers. Those considerations include decisions regarding the preparation and submission of generator offer curves in the day-ahead and real-time markets, the amount of retail load bid into the day-ahead market, and the acquisition of FTRs.

Q. WILL DUKE ENERGY KENTUCKY EVER MAKE BILATERAL PURCHASES OF ENERGY?

A. Yes. If Duke Energy Kentucky lacks sufficient generation to serve its load forecast or it is otherwise economic, Duke Energy Kentucky may attempt to enter into bilateral forward transactions.

Q. PLEASE EXPLAIN HOW UTILITIES USE WHOLESALE PURCHASES TODAY TO SUPPLEMENT THEIR OWN GENERATION RESOURCES.

A. Although most utilities' generating plants supply the bulk of the energy used to meet their retail customers' electricity needs, utilities typically do not rely solely on their own production of electricity. Forward reliability purchases from the wholesale market in the form of bilateral energy, capacity contracts, or options may be used to ensure that adequate capacity or reserves are available during periods when demand is expected to be high or as a financial hedge.

For next-day bilateral transactions, preparation begins with a 6:30 a.m. internal conference call each morning. During this call, weather, load, market, generation output, unit production costs, and generation availability forecasts are discussed in detail with dispatchers, traders, asset managers, and power plant personnel. At the same time, the final load forecast for each hour of the next day is generated. A short-term optimization model is then used, taking into account all inputs, to determine the level of purchases or sales and a resulting optimum position for next day transactions.

The market for day-ahead bilateral purchases and sales typically occurs between 7:30 a.m. and noon the day prior to the operating day. Duke Energy Kentucky makes day-ahead transactions and sales primarily through brokers or via the Web-based platform operated by IntercontinentalExchange, Inc. ("ICE"). Day-ahead on-peak power transactions are available in standard 50 MW blocks for a set 16-hour period. Day-ahead off-peak power transactions are available in standard 50 MW blocks for a set eight-hour period. These purchases and sales are financial hedges that reduce risk for the native load customer.

A similar process to the above is employed for the rest of the week, weekend, and next week purchases and sales. However, for longer term transactions, since key inputs such as weather are more uncertain, a model that uses a more scenario driven approach is employed.

Forward capacity purchases could also be entered into by Duke Energy Kentucky for the purpose of meeting certain requirements such as for the Midwest ISO Module E Resource Adequacy.

Q. HOW ARE THE RESPONSIBILITIES FOR DISPATCH IN DAY 2 DIVIDED BETWEEN THE MIDWEST ISO AND DUKE ENERGY KENTUCKY?

A. The Midwest ISO directs the dispatch of all generation connected to the transmission system under its functional control. Duke Energy Kentucky submits offer curves for its generation resources. These offer curves define the offer prices for a range of outputs, taking into account physical limits. As described above, Duke Energy Kentucky may also choose to operate a unit at a selected output level by self-scheduling or offering a unit with a must-run status. The Midwest ISO accepts all the self-scheduled and must-run generation offers and then performs an incremental dispatch to meet the remaining demand requirement.

The Midwest ISO sends a five-minute base point to each generating unit connected to the transmission system under its functional control to direct the dispatch. Duke Energy Kentucky provides regulation and frequency response service within its area through the intra-five-minute dispatch of its generating units. As part of a larger balancing authority, Duke Energy Kentucky is responsible for maintaining its respective reliability criteria.

Q. HOW DOES THE DAY-AHEAD MARKET ALLOW DUKE ENERGY KENTUCKY TO MITIGATE ITS RETAIL CUSTOMERS' EXPOSURE TO PRICE RISK IN THE REAL-TIME MARKETS?

A. Transactions that are scheduled in the day-ahead market, including offers to supply generation and bids to purchase energy, that are cleared by the Midwest ISO, create financially binding obligations to sell or purchase energy at the day-ahead locational marginal prices. Real-time transactions that do not deviate from corresponding transactions that are scheduled in the day-ahead market do not incur additional charges. So, for example, if a utility bids its load forecast in the day-ahead market, the utility pays the day-ahead locational marginal price at the utility's load zone. If the real-time load exceeds the amount bid in the day-ahead market, the amount underbid pays real-time locational marginal prices. Conversely, if the real-time load is less than the amount bid in the day-ahead market, the amount overbid is sold back to the real-time market at real-time locational marginal prices. Prices paid to suppliers in the real-time market are handled similarly. In other words, only deviations from day-ahead schedules (injections or withdrawals) are exposed to real-time locational marginal prices.

Moreover, congestion costs can only be hedged in the day-ahead markets. FTRs are not available to offset congestion costs incurred in the real-time markets. Thus, to the extent congestion costs are anticipated as a result of scheduling a transaction from a resource to a load zone, that transaction would typically be scheduled in the day-ahead market in order to take advantage of any FTRs that may be available.

Finally, virtual offers and bids can also be submitted in the day-ahead market as a means of hedging certain real-time operations risks.

Q. DOES DUKE ENERGY KENTUCKY USE THE MIDWEST ISO'S DAY-AHEAD MARKETS TO MITIGATE ITS RETAIL CUSTOMERS' EXPOSURE TO REAL-TIME PRICES?

A. Yes. Duke Energy Kentucky submits demand bids in the day-ahead market based on its day-ahead load forecasts. Likewise, Duke Energy Kentucky submits resource offers in the day-ahead markets as allowed under the Midwest ISO's Transmission and Energy Markets Tariff ("TEMT").

Q. DOES DUKE ENERGY KENTUCKY NEED TO SELF-SCHEDULE ITS GENERATION RESOURCES TO ENSURE RETAIL CUSTOMERS GET THE BENEFIT OF THE LOWEST COST DISPATCH?

A. Not typically. In fact, self-scheduling all resources would deny retail customers an opportunity to purchase energy from lower cost resources that may be offered to the day-ahead or real-time markets. Generally, Duke Energy Kentucky makes its resources available to the Midwest ISO energy markets via the submission of generator offers.

Nevertheless, Duke Energy Kentucky may self-schedule certain resources or submit them as a must-run unit offer. Examples of situations include, but are not limited to:

- units that are being tested and must operate at a constant output for the duration of the testing;
- units whose output is restricted to a certain level for environmental or operational reasons; and
- unit startups where the Midwest ISO day-ahead commitment process will not capture the full economics of unit commitment.

Additionally, Duke Energy Kentucky anticipates that its baseload coal units will be sometimes offered as must-run units to obtain the most cost-effective commitment for the Midwest ISO. The Midwest ISO unit commitment process associated with the day-ahead and real-time market is best suited for mid-merit and short-run units. For those units that must be committed for several days or even weeks at a time, submitting a unit as a must-run unit guarantees reliable and predictable operation and the optimum economic commitment of the unit. The remainder of energy available from those units between minimum and maximum operating range is offered in the day-ahead and real-time markets for economic dispatch.

Q. WHAT IS A GENERATOR OFFER CURVE?

A. A generator offer curve is a series of megawatt-price pairs that represent the offer prices for the generator to operate at various load levels within the generator's operating range. The curve, in essence, defines the offer of a market participant to dispatch a generator at a megawatt output level for the associated price of the megawatt-price pair or higher.

A startup and no load offer price is included with the submission of offer curves for resources offered in the day-ahead and real-time markets. A resource offer that clears the day-ahead or real-time market is guaranteed recovery of the startup and no load offer price submitted along with its offer curve. The Midwest ISO does not guarantee startup and no load cost recovery for self-scheduled resources.

Q. UNDER WHAT CIRCUMSTANCES DOES DUKE ENERGY KENTUCKY SUBMIT GENERATOR OFFER CURVES?

A. Duke Energy Kentucky is required by the Midwest ISO to submit offers for designated network resources in the day-ahead market to meet its next day forecasted load plus the operating reserve requirement. Additionally, after the day-ahead market clears, the Midwest ISO employs a reliability assessment commitment ("RAC") process to ensure sufficient resources have been committed to serve the regional load forecast. Duke Energy Kentucky's designated network resources must also be made available during the RAC process. All of the generation resources owned by Duke Energy Kentucky and used to serve its retail customers are designated network resources in the Day 2 energy markets. Consequently, at a minimum, Duke Energy Kentucky must submit offer curves for all of its designated network resources for consideration in the RAC process.

Q. DOES DUKE ENERGY KENTUCKY CONSIDER THE IMPACT OF OPERATING CONSTRAINTS IN ITS GENERATOR OFFER CURVES?

A. Yes. Constraints that can be expressed as a real-time cost, such as the consideration of certain emission costs, can be reflected in offer curves. Indirect costs can also be reflected in the offer curves. For example, a gas-fired peaking unit may need a system overhaul after a fixed number of starts or a certain number of hours of operation. The incremental maintenance costs could be allocated over the unit starts, operating hours or some combination of the two to reflect the incremental maintenance costs.

Q. WHAT ARE VIRTUAL OFFERS AND BIDS?

A. A virtual supply bid is a bid to purchase energy that is not backed by physical load. A virtual supply offer is an offer to sell energy in the day-ahead energy market that is not supported by a physical injection or reduction in withdrawals in commitment by a resource.

Q. ARE THERE ANY CIRCUMSTANCES WHERE DUKE ENERGY KENTUCKY MIGHT USE VIRTUAL OFFERS AND BIDS FOR THE BENEFIT OF RETAIL CUSTOMERS?

A. Yes, there are ways that virtual offers and bids could be used to benefit retail customers. For example, a virtual bid could be submitted for a unit that is expected to come back from an outage the following day. This would mitigate some of the risk associated with a delay in unit startup while allowing the generator and load to settle day-ahead and lock in the value of any FTR hedges available for that unit. In addition, virtual bids could be used as a hedge against unexpected losses in generation or to reduce risk around units that could have extreme volatility in the real-time markets.

Q. PLEASE EXPLAIN HOW FTRS WERE ALLOCATED BY THE MIDWEST ISO AND ACQUIRED BY DUKE ENERGY KENTUCKY.

A. The Midwest ISO's FTRs allocation process is a multi-tiered nomination approach. FTRs are allocated annually for both peak and non-peak periods for each of the four seasons from June 1 to May 31 of the following year. The initial allocations were conducted more frequently.

In each tier, a market participant is given an opportunity to nominate FTRs for its designated network resources based on the market participant's total forecast peak load. FTRs are allocated to the extent the Midwest ISO determines that the candidate FTRs comport with a Simultaneous Feasibility Test ("SFT"). The Midwest ISO also has a means by which FTRs requested but not received can be restored. Specifically, the Midwest ISO may restore certain candidate FTRs that were curtailed in the first two allocation tiers. The Midwest ISO can restore the FTRs, partially or totally, to the nominated quantity.

After the initial FTR distribution, a market participant can attempt to obtain additional FTRs. For each of the upcoming seasons, a market participant can bid to buy, or offer to sell, FTRs in an annual auction. Additionally, if transmission capacity is forecasted to be available, then a market participant may be allocated FTRs during a monthly allocation. Monthly auctions, for the upcoming month, afford market participants an opportunity to buy or sell FTRs. Additionally, market participants can engage in bilateral trading of FTRs independently from the Midwest ISO in order to improve their congestion hedge position.

Q. DID THE MIDWEST ISO ALLOCATE SUFFICIENT FTRS TO ENABLE DUKE ENERGY KENTUCKY TO COMPLETELY ELIMINATE THE RISK OF INCURRING CONGESTIONS COSTS?

A. No. The Midwest ISO cannot allocate sufficient FTRs so that Duke Energy Kentucky will never have to pay congestion costs that exceed the revenues received as a result of the FTRs it owns in each of the 8,760 hours of the day-ahead energy market over the course of a year. Moreover, it is not likely an FTR holder would schedule energy transactions that exactly match its FTRs in each hour. The goal will be to attempt to obtain sufficient FTRs so that the total amount of FTR revenues received in the day-ahead market over the period of time the FTRs are effective is approximately equal to the congestion costs incurred as a result of the energy transactions scheduled during that period.

Q. WHAT FACTORS DOES DUKE ENERGY KENTUCKY TAKE INTO CONSIDERATION WHEN ATTEMPTING TO OPTIMIZE ITS HEDGE AGAINST CONGESTION COSTS THROUGH THE ACQUISITION OF FTRS?

A. In the initial allocation process, an important consideration is to attempt to obtain FTRs for resources that have the greatest amount of projected congestion costs between the resource and the load zone. FTRs that have negative congestion that would incur an additional expense will generally be avoided. When evaluating potential FTR hedges for congestion, unit capacity factor and counterflow are the most important considerations. A unit's capacity factor is a measure of the energy the unit actually produces over a period of time relative to its total capacity to produce energy. To be properly hedged, the energy flow along the potential FTR path from the source to the sink should match as closely as possible the megawatt amount of the FTR. Therefore, units with high capacity factors are generally good candidates for sources of FTRs. Peaking units that seldom run and therefore have low capacity factors are generally less desirable sources for FTRs.

A unit located at the end of a frequently constrained line that actually tends to alleviate congestion when dispatched is said to provide counterflow. These units would be paid a premium when producing energy for relieving the constraint. The premium paid to the unit through the congestion component of the locational marginal price, however, would have to be paid back to the Midwest ISO through the settlement of the FTR. Therefore requests for FTRs for counterflow units should be limited. However, certain counterflow obligations may be unavoidable based on the Midwest ISO's FTR allocation process.

Q. WILL FTRS FOR NATIVE LOAD AND FTRS FOR OFF SYSTEM SALES BE SEPARATELY ACCOUNTED FOR?

A. Yes. Any credits or charges related to FTRs procured to serve Duke Energy Kentucky's load will be assigned to retail customers.

Q. DOES DUKE ENERGY KENTUCKY PARTICIPATE IN THE FTR AUCTIONS AND SECONDARY MARKETS FOR FTRS?

A. Yes. Duke Energy Kentucky believes that if it can improve retail customers' hedge against congestion costs, then it should do so. However, Duke Energy Kentucky does not engage in speculative trading of the FTRs assigned to retail customers.

Q. **HOW DOES DUKE ENERGY KENTUCKY PROPOSE TO RECOVER THESE TRANSMISSION COSTS ON A GOING FORWARD BASIS?**

A. Transmission costs will be recovered in base rates through the end of the forecasted test period. Mr. Wathen supports the incremental transmission cost recovery via Rider TCRM – Transmission Cost Recovery Mechanism. This is a tracking mechanism of all incremental transmission costs incurred on and after January 1, 2007.

Q. **DO YOU HAVE AN OPINION AS TO WHETHER IT IS JUST AND REASONABLE FOR THE COMPANY TO RECOVER ITS INCREMENTAL TRANSMISSION COSTS INCURRED ON AND AFTER JANUARY 1, 2007 THROUGH A TRACKING MECHANISM?**

A. Yes.

Q. **PLEASE STATE YOUR OPINION.**

A. In my opinion, it would be just and reasonable for Duke Energy Kentucky to recover incremental transmission costs incurred on and after January 1, 2007 through Rider TCRM. These transmission costs are generally volatile, outside the Company's control and can involve significant amounts of costs. These factors all weigh in favor of recovering such costs through a tracking mechanism.

V. <u>COST ESTIMATES PROVIDED BY WITNESS</u>

Q. **DID YOU CALCULATE CERTAIN FORECASTED TRANSMISSION COSTS AND PROVIDE THIS INFORMATION TO MR. DAVEY FOR HIS USE IN PREPARING THE FORECASTED FINANCIAL DATA?**

A. Yes.

Q. PLEASE EXPLAIN HOW YOU MADE THIS CALCULATION.

A. I calculated the amounts of revenues and charges for the items listed in Sections I through III of Attachment PKJ-2. This attachment lists the various revenues and charges under the Midwest ISO's TEMT tariff for the Day 2 energy markets.

I estimated these revenues and charges using Duke Energy Ohio's historical information for the months of April 2005 through November 2005, and allocating these revenues and charges to Duke Energy Kentucky using Duke Energy Kentucky's load ratio. No Midwest ISO charge specifically provides Congestion or Losses. I estimated congestion and losses by comparing the prices at the generator pricing node and the load pricing node. The difference in price between the generator and the load is the combined Congestion and Losses. I used a monthly average for the period and added this amount to the budget for each month of 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 calculated the revenues and charges for the remaining items in Sections I through III of Attachment PKJ-2 by applying the April through November 2005 data, in the same manner as I described above. I applied the revenues against the charges to obtain the net cost for these items. I supplied this information to Mr. Davey for his use in preparing the forecasted portion of the base period and the forecasted test period financial data.

VI. CHANGES TO BACK-UP PSA

Q. ARE YOU FAMILIAR WITH THE DUKE ENERGY KENTUCKY BACK-UP PSA APPROVED BY THE COMMISSION IN CASE NO. 2003-00252?

A. Yes, I have reviewed the Back-up PSA.

Q. WHAT DELIVERY POINTS DID THE BACK-UP PSA ORIGINALLY USE?

A. The agreement specified that back-up power would be delivered as an "Into-Cinergy" product, that is, providing for Duke Energy Ohio to deliver the back-up energy at the busbars of Duke Energy Ohio's generating plants and at interconnection points between the Cinergy transmission system and generating or transmission facilities within the Cinergy control area owned by third parties. This agreement was originally proposed prior to the definition of the Midwest ISO Day 2 markets implementation or design.

Q. DO THE DELIVERY POINTS NEED TO BE CHANGED DUE TO THE MIDWEST ISO DAY 2 MARKETS?

A. Yes. Under the Midwest ISO Day 2 market, if the original Back-up PSA delivery points remained intact, the seller could choose from a large number of different delivery points, exposing Duke Energy Kentucky to potentially significant congestion costs. In proposing a new delivery point, three choices were evaluated: (1) delivery to the unit or units that are off-line; (2) delivery to the Duke Energy Kentucky load zone; or (3) delivery to the Cinergy.Hub.

Delivery to the generating unit(s) that is/are off-line would subject Duke Energy Kentucky to congestion and losses between the unit(s) and the Duke

Energy Kentucky load zone, although FTRs could be used to hedge some of this congestion. Delivery to the Duke Energy Kentucky load zone would allow congestion and loss charges to be avoided by Duke Energy Kentucky. However, delivery to either the generating unit(s) or delivery to the Duke Energy Kentucky load zone is not a liquid point and would reduce or possibly eliminate any potential offers related to backup power for Duke Energy Kentucky.

Delivery to the Cinergy.Hub, since it is a liquid bilateral market that counterparties could use to hedge their exposure, would be the best overall delivery point for Duke Energy Kentucky. With delivery to the Cinergy.Hub, Duke Energy Kentucky would pay for congestion and losses between Cinergy.Hub and the Duke Energy Kentucky load zone, but this delivery point would still represent the most economic option for Duke Energy Kentucky due to the additional offers that would be available from the more liquid, transparent Cinergy.Hub. In addition, Cinergy.Hub best represents the price of the Duke Energy Kentucky load zone as opposed to other hubs.

VII. CONCLUSION

Q. ARE THE CALCULATIONS 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, John D. Swez, 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.

John D. Swez, Affiant

Subscribed and sworn to before me by John D. Swez on this 22nd day of May, 2006.

NOTARY PUBLIC

My Commission Expires: September 25, 2010

NOTARY PUBLIC STATE OF OHIO

SUSAN M. GROSSER
Notary Public, State of Ohio
My Commission Expires
September 25, 2010

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

DOUGLAS F ESAMANN

ON BEHALF OF

DUKE ENERGY KENTUCKY

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ATTACHMENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Douglas F Esamann, and 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 Group Vice President, Strategy and Planning.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I am a graduate of Indiana University with a Bachelor of Science Degree in Accounting.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined PSI Energy, Inc. ("PSI Energy," now known as "Duke Energy Indiana") in 1979 and have held various positions in the Accounting, Tax, and Corporate Development areas, and various financial positions within the Cinergy Corp.'s ("Cinergy") Commercial Business Unit. From 1999 until 2001, I was Vice President and Chief Financial Officer of Cinergy's Commercial Business Unit. I was named as President of PSI Energy in 2001. I became Senior Vice President, Energy Portfolio Strategy and Management for Cinergy in 2004. I was named to my current position effective in April 2006 with the closing of the Duke/Cinergy merger.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS GROUP VICE PRESIDENT, STRATEGY AND PLANNING.

A. I am a member of the executive management team for the U.S. Franchised Electric & Gas ("Franchised Electric & Gas") Business Unit, and along with that team, I am responsible for the overall direction and strategy of this business unit, long-term resource and environmental planning, business development and business service center. The Franchised Electric & Gas Business Unit consists of Duke Energy's regulated utility operating companies in Kentucky, Ohio, Indiana, North Carolina and South Carolina. I share responsibility with other members of the management team for the planning for these companies, including the planning necessary to ensure that our customers continue to have access to safe, reliable, and reasonably priced gas and electric service.

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

A. I discuss the background of the proposed Back-up Power Sale Agreement ("Back-up PSA") approved by the Commission in Case No. 2003-00252, including the purpose of the Back-up PSA and how the pricing for the Back-up PSA was determined.

I explain Duke Energy Kentucky's proposal in this proceeding relating to the Back-up PSA, and the reasons supporting this proposal. I discuss the changes in the wholesale power market that have occurred since 2003, including changes relating to the Midwest Independent System Operator, Inc.'s ("Midwest ISO") Day 2 energy markets. I quantify the increase in wholesale market prices that has occurred since 2003, including the drivers for these price increases. I also explain how I calculated the increase in the Back-up PSA capacity charges to reflect current market pricing.

I also discuss the long-term competitive bidding process that Duke Energy Kentucky has underway to procure additional and long-term back-up supply options. Finally, I sponsor Filing Requirement ("FR") 10(9)(h)(7) and certain forecasted financial data that I provided to Mr. Davey.

II. BACKGROUND OF BACK-UP PSA

Q. ARE YOU FAMILIAR WTH THE PROPOSED BACK-UP PSA THAT THE COMMISSION APPROVED IN CASE NO. 2003-00252?

A. Yes, I have reviewed the Back-up PSA and related testimony sponsored by Mr. McCarthy, whose testimony was adopted at the hearing by Mr. Harkness. I also reviewed the Commission's orders and the Company's filings relating to the Back-up PSA.

Q. PLEASE EXPLAIN THE PURPOSE OF THE BACK-UP PSA.

A. The purpose of the Back-up PSA was to supply Duke Energy Kentucky with a firm supply of back-up power for the East Bend Generating Station ("East Bend") and the Miami Fort Generating Station Unit 6 ("Miami Fort 6"). As Mr. McCarthy's pre-filed testimony discusses, one benefit from using Duke Energy Ohio as the supplier at that time was that Duke Energy Kentucky could gain access to a firm power supply from an affiliate provider with a diverse mix of generating assets and an adequate reserve margin. Mr. McCarthy also discusses the then-existing lack of availability of long-term wholesale power contracts, and the risks related to wholesale power contracts with unaffiliated third parties, as follows:

> **Q. WHAT ABOUT PURCHASED POWER AS AN ALTERNATIVE TO BUYING GENERATING ASSETS?**
>
> A. To approach the reliability and economic benefits of plant ownership, a purchased power arrangement would have to be long-term. Yet in recent years, various factors have caused the market for long-term power purchases to greatly diminish. These factors include the California energy crisis, the Enron debacle, bankruptcy filings by certain energy companies and the credit downgrades of other energy companies by investment ratings agencies, attempts to cancel long-term purchase power deals as a result of bankruptcy filings and litigation, the economic downturn, the continued uncertainty in the transmission market, and the crisis regarding manipulation by certain energy traders of industry market price indices. These factors have made the long-term power market risky for buyers. As a result of such factors, new long-term purchase power agreements currently tend to run no longer than five years from the date of execution. If ULH&P were to issue an RFP for its full wholesale power requirements for the long-term, the inception date for the new wholesale contract would be January 1, 2007. And if the contract would run for the remaining useful life of the Plants, potential bidders would have to agree to provide a fixed price for power through an equivalent date. The market for such contracts is relatively illiquid. While it is possible that some owner of a sizeable merchant fleet might offer such an agreement against current market trends, I could not recommend such a solution to ULH&P, given the credit problems, bankruptcy, and efforts at contract cancellation that are prevalent among merchants now, particularly not as an alternative to ULH&P's ownership of its own high quality generating assets, to be operated with all the benefits of joint economic dispatch.

(Pre-filed Testimony of Robert C. McCarthy in Case No. 2003-00252 at page 16, line 10 through page 17, line 11.)

Q. DO THESE CONCERNS STILL EXIST?

A. No, not to the magnitude experienced at the time Mr. McCarthy pre-filed his testimony. Industry conditions have substantially changed since 2003, as I discuss later in my testimony.

Q. PLEASE EXPLAIN THE TERMS OF THE BACK-UP PSA.

A. The Back-up PSA was scheduled to commence upon the transfer date for the Plants, and scheduled to end on December 31, 2009. The Back-up PSA provided the following terms:

- Back-up capacity and firm energy for East Bend and Miami Fort No. 6 for scheduled and non-scheduled outages. The contract contemplated that Duke Energy Kentucky and Duke Energy Ohio would jointly plan their scheduled outages such that Duke Energy Ohio could supply back-up power in an economical manner.

- The back-up power was intended to be priced at market rates. The contract provided for an energy charge and monthly capacity charges of $359,729 for East Bend and $61,866 for Miami Fort No. 6. The energy charge was priced at the average variable cost per MWH of energy produced during the prior calendar month at the Plant for which back-up power is required.

- The contract was an "Into Cinergy" product, providing for Duke Energy Ohio to deliver the back-up energy at the busbars of the Plants and at interconnection points between the Cinergy transmission system and generating or transmission facilities owned by third parties.

Q. PLEASE EXPLAIN HOW THE PRICING FOR THE BACK-UP PSA WAS DETERMINED.

A. As I mentioned, the capacity charge was based on the market price and an estimate of how often Duke Energy Kentucky would require back-up power for East Bend and Miami Fort 6. The market price was estimated by using the forward market prices quoted from the Megawatt Daily and off-peak prices quoted from the North American Power 10x Report.

III. DUKE ENERGY KENTUCKY'S PROPOSAL RELATING TO BACK-UP PSA

Q. WHAT DOES DUKE ENERGY KENTUCKY PROPOSE FOR THE BACK-UP PSA IN THIS PROCEEDING?

A. We propose that the capacity charges reflected in the 2003 Back-up PSA be updated to reflect current wholesale power market pricing. Additionally, we are in the process of conducting a competitive bidding process for a variety of supply options. This competitive bidding process should be completed in July 2006. We propose to share the results of the competitive bidding process with the Commission and the parties to this proceeding, and to obtain approval for retail rate recovery of the lowest cost and best supply option that addresses Duke Energy Kentucky's long-term supply needs.

Q. WHY DOES DUKE ENERGY KENTUCKY PROPOSE TO REFRESH THE CAPACITY CHARGES IN THE BACK-UP PSA TO REFLECT CURRENT MARKET PRICING?

A. The pricing in the Back-up PSA was intended to reflect current market pricing. The prices currently reflected in the Back-up PSA reflect the wholesale market pricing in effect during mid-2003, because Duke Energy Kentucky filed its initial application and testimony with the Commission in Case No. 2003-00252 in July 2003. Duke Energy Kentucky was unable to close on the transfer of the Plants until January 2006 due to delays in the regulatory approval process. The environment at the FERC was in a state of flux and we experienced delay at the U.S. Securities and Exchange Commission due to an unexpected intervention by the Ohio Consumers' Counsel. Approval from these agencies was required before the Plants could be transferred. Once the transfer was approved, we proceeded expeditiously to issue a request for proposals for back-up supply. The change in market conditions that has occurred over the course of these regulatory delays should not be borne by the shareholders of Duke Energy.

Updating the Back-up PSA to reflect the current market may eliminate regulatory risk relating to approval of the Back-up PSA. My understanding is that approval from the Federal Energy Regulatory Commission ("FERC") for the Back-up PSA is required under §205 of the Federal Power Act. I also understand that FERC generally requires that a competitive bidding process be used in order to obtain FERC approval for a wholesale power contract between affiliates.

In the present case, Duke Energy Kentucky and Duke Energy Ohio did not use a competitive bidding process prior to agreeing upon the prices reflected in the Back-up PSA. If Duke Energy Ohio were to bid to match the prices reflected in the Back-up PSA, my understanding is that it would be uncertain whether the FERC would approve a competitive bidding process with this type of preordained bid by an affiliate at a price that is well below current market pricing.

Additionally, the Back-up PSA requires that Duke Energy Kentucky share confidential wholesale market competitive information with the counterparty, that is, the exact dates for planned outages during the duration of the Back-up PSA. If Duke Energy Ohio were the counterparty, my understanding is that this type of information sharing would require FERC approval, and that the prospects for FERC approval are uncertain.

Even if Duke Energy Kentucky were fortunate enough to obtain these FERC approvals, my understanding is that the approval process could be quite lengthy.

Finally, updating the Back-up PSA to reflect current market pricing would enable Duke Energy Kentucky to consider all available supply options and to select the lowest cost and best available supply option to address its long-term supply needs.

IV. INCREASE IN WHOLESALE MARKET PRICES

Q. YOU STATED THAT THE BACK-UP PSA WAS PRICED AT THE MARKET PRICE AS OF 2003. WHAT MARKET PRICE DOES THE BACK-UP PSA REFLECT?

A. The Back-up PSA reflects an average around-the-clock market price of $28.00 per megawatt-hour, as stated in Mr. Harkness' testimony at page 25, line 1 of the hearing transcript in Case No. 2003-00252.

Q. HOW MUCH HAVE WHOLESALE MARKET PRICES INCREASED SINCE 2003?

A. The current around-the-clock market price of power as of March 3, 2006, the date of the model run used in our forecast, is approximately $46 per megawatt-hour.

Q. HOW DID YOU DETERMINE THE CURRENT WHOLESALE MARKET PRICE?

A. The current wholesale market price is based on actual wholesale market transactions entered into by the operating companies in the Franchised Electric & Gas Business Unit, quotes and actual transactions observed by our traders, observations of Day 2 energy prices, and price quotes in industry publications such as *Megawatt Daily.*

Q. WHAT ARE THE DRIVERS OF THE WHOLESALE MARKET PRICE INCREASES?

A. The primary drivers for the higher wholesale market prices are the higher costs for the inputs: fuel and emission allowances. These costs have increased significantly in recent years, as shown by the following table:

Table 1 – Commodity Price Increases*

Commodity	2003	2004	2005	% Change 2005 vs. 2003
WTI Crude Oil Price ($/bl)	31.1	41.5	56.6	+82%
Natural Gas – Henry Hub ($/MMBtu)	5.46	5.90	8.50	+56%
Central Appalachia Compliance Coal ($/Ton)	35.7	57.0	64.8	+82%
Illinois Basin High Sulfur Coal ($/Ton)	23.7	31.7	37.5	+58%
Wyoming Powder River Basin High Btu Coal ($/Ton)	6.3	6.3	9.7	+55%
SO2 Allowance ($/Ton)	174.3	437.9	906.0	+420%
NOx Allowance ($/Ton)	4,516.2	2,258.1	2,907.8	-36%

*ICF Consulting Group, Inc.

V. CALCULATION OF INCREASED CAPACITY CHARGES TO BE REFLECTED IN RATES

Q. DID YOU CALCULATE THE CURRENT WHOLESALE MARKET PRICE FOR PROVIDING SERVICE UNDER THE BACK-UP PSA?

A. Yes, I estimated future wholesale market prices from January 1, 2007 through December 31, 2009, the end of the contract term for the Back-up PSA. I prepared this estimate using the Franchised Electric & Gas Business Unit's Commercial Business Model. This is an in-house, proprietary software tool. We use this tool to develop our forecasts, as discussed by Mr. Davey. We load the Commercial Business Model with observed data, such as fuel and emission allowances costs, and wholesale market price observations, as I described earlier. The Commercial Business Model uses this data to develop energy production-related costs, prices, revenues and profits related to energy. This software tool was used to estimate the wholesale market prices for providing service under the Back-up PSA from January 1, 2007 through December 31, 2009.

Q. WHY DID YOU USE JANUARY 1, 2007 AS THE BEGINNING DATE FOR YOUR CALCULATION?

A. The effective date of the Plant transfer to Duke Energy Kentucky was January 1, 2006. Under the Commission's prior orders, however, Duke Energy Kentucky's retail electric rates for power supply were frozen until December 31, 2006. I therefore used January 1, 2007 as the starting date for my calculation.

Q. WHAT IS THE DIFFERENCE IN THE COST FOR PROVIDING SERVICE UNDER THE BACK-UP PSA AT CURRENT MARKET PRICES VERSUS THE 2003 ESTIMATED MARKET PRICES REFLECTED IN THE BACK-UP PSA ITSELF?

A. The current market price for providing service under the Back-up PSA, less the revenues received under the pricing reflected in Back-up PSA, is $31.3 million for 2007 through 2009. My calculation is shown at Attachment DFE-1. My calculation is based on the current hourly wholesale market prices from the Commercial Business Model as shown on Attachment DFE-2.

Q. PLEASE EXPLAIN HOW YOU MADE THIS CALCULATION.

A. I started with the pricing reflected in the Back-up PSA itself, which I discussed earlier in my testimony. I then obtained an estimate from Mr. Roebel of the number of days and the expected dates for planned outages during each year. Mr. Roebel also provided me historical information regarding the number of days and the level of forced outages annually.

The energy cost for the Back-up PSA is based on the previous month's average variable cost for the unit being backed up. I determined these energy costs by estimating the fuel cost, market price of SO_2 and NO_x emission allowances, the variable operation and maintenance cost and the Midwest ISO Day 2 real-time energy market congestion and losses costs. These costs were developed from the forecast based on the Commercial Business Model performed on March 3, 2006. I applied these amounts to the outage data I described earlier to obtain the contract price for energy under the Back-up PSA.

I next calculated the price for obtaining back-up power at current market prices. I used the same outage data I described above. The Commercial Business Model was used to calculate the hourly market prices for purchases necessary to cover the planned and forced outages. For each hour when the market price was greater than the prior month's average variable cost for each unit, we adjusted the purchase price to this contract price for energy reflected in the Back-up PSA. The sum of the difference in back-up pricing and the market price for back-up power was then averaged over the remaining three-year term of the Back-up PSA after the current rate freeze expires. The Back-up PSA capacity charge was then subtracted from these market prices to obtain the difference in cost for serving the Back-up PSA at today's market prices. I supplied this information to Ms. Meyer. I also supplied this calculation to Mr. Wathen to use in his *pro forma* adjustment shown in Schedule D-2.25.

VI. CHANGES IN WHOLESALE POWER MARKET CONDITIONS

Q. ONE REASON CITED IN 2003 FOR ENTERING INTO THE BACK-UP PSA WITH DUKE ENERGY OHIO AT A NEGOTIATED PRICE WAS THAT THE MARKET FOR LONG-TERM WHOLESALE POWER CONTRACTS WAS ALMOST NON-EXISTENT AT THAT TIME. HAVE CONDITIONS IN THE WHOLESALE POWER MARKET CHANGED SINCE 2003?

A. Yes, conditions have substantially changed. The market has stabilized since 2003, when the conditions discussed by Mr. McCarthy's testimony – such as the

California power crisis, the Enron debacle, and tight credit conditions – caused a corresponding contraction in the wholesale power market and restricted the availability of long-term contracts. However, wholesale market prices have significantly increased.

Q. HAS THE MIDWEST ISO'S DAY 2 ENERGY MARKETS AFFECTED THE WHOLESALE POWER MARKET?

A. Yes. The Midwest ISO has launched its Day 2 energy markets on April 1, 2005. This created day-ahead and real-time energy markets based on locational marginal pricing principles. Prior to the Day 2 markets, bilateral wholesale power contracts in transmission-congested areas were often subject to frequent interruptions caused by transmission loading relief procedures ("TLR"), which were used to relieve the transmission congestion.

The frequency of TLRs has greatly diminished with the introduction of the Day 2 markets. Additionally, the Day 2 markets provide a ready source of energy, at a transparent price, across a broad region served by many participating generators. This has also made the wholesale power market more liquid, and has also led to a much greater frequency of long-term wholesale power contracts.

There is a greater availability of well-financed companies available as wholesale power providers. The market conditions existing in 2003, which restricted the availability of long-term wholesale power contracts, have substantially changed.

VII. DUKE ENERGY'S CURRENT RESOURCE PLANNING

Q. ARE YOU FAMILIAR WITH THE INTEGRATED RESOURCE PLAN FOR DUKE ENERGY KENTUCKY?

A. Yes, the Integrated Resource Plan ("IRP") is developed under my supervision and control for each regulated operating company. The IRP is filed periodically with the state commissions. Duke Energy Kentucky filed its last IRP with the Commission on April 2, 2004 in Case No. 2004-00014, and the Commission issued an Order on January 14, 2005 approving the IRP. Although this IRP provided a snapshot of Duke Energy Kentucky's resource planning at that point in time, IRP planning is a dynamic process that is periodically updated.

Q. PLEASE GENERALLY DESCRIBE THE IRP PLANNING PROCESS.

A. The IRP planning process assesses various supply-side, demand-side and emission compliance alternatives to develop a long-term, cost-effective portfolio to provide customers with reliable service at reasonable costs. The IRP planning process involves various assumptions such as future energy prices, future environmental compliance requirements and reliability constraints.

Q. WHAT RELIABILITY CONSTRAINT ASSUMPTIONS ARE NECESSARY TO DEVELOP AN IRP?

A. We must determine a minimum reserve margin, an annual estimate of the number of loss of load hours and an annual estimate of the expected unserved energy.

Q. WHAT PLANNING RESERVE MARGIN WAS USED FOR THE COMPANY'S LAST IRP?

A. The Company used a planning reserve margin of 16.2%, based on then-current North American Electric Reliability Council ("NERC") standards, based on operating the Plants, assuming the Back-up PSA would be in effect, and reserving for the loss of the largest unit (with the Back-up PSA, the largest unit would be one of the Woodsdale units).

Q. HAVE ANY CHANGES OCCURRED SINCE 2004 THAT HAVE CAUSED THE COMPANY TO USE A DIFFERENT PLANNING RESERVE MARGIN?

A. Yes. The reliability standards formerly established by NERC are now established by Reliability*First*, which NERC approved under the Energy Policy Act of 2005 as one of eight Regional Reliability Councils in North America. Reliability*First*, which encompasses the former ECAR, MAAC and MAIN regions, began operations on January 1, 2006. As of April 1, 2005, the Midwest ISO began its security-constrained economic dispatch of wholesale electricity ("MISO Day 2"). In conjunction with MISO Day 2, the MISO members formerly within ECAR were required to meet a day-ahead offer requirement consistent with the member's forecasted load and a 4% operating reserve requirement (after outages and derates) from physical capacity, because ECAR did not have a standard for planning reserve requirements. This is a much higher standard than an installed reserve margin requirement because compliance with the standard is affected by outages and derates. With the formation of Reliability*First*, the operating reserve requirement still translates into approximately 4%. For the summer of 2006, sufficient purchases were made to meet an adequate reserve margin to ensure compliance with the standard.

For the longer term, Duke Energy Kentucky's reserve requirements will be impacted by Reliability*First*. Reliability*First* has adopted a Resource Planning Reserve Requirement Standard that the Loss of Load Expectation ("LOLE") due to resource inadequacy cannot exceed one day in ten years (0.1 days per year). However, until analyses are performed by the Planned Reserve-Sharing Group ("PRSG") that Duke Energy Kentucky will join (which has not been determined yet), it is too soon to know exactly what the impact on Duke Energy Kentucky's required reserve criteria might be. It is anticipated that the planning year starting January 1, 2008, will be the first year in which this standard will be in effect. Assuming the Back-up PSA is in place, the Company's actual summer reserve margin during this period is estimated at 20.4% for 2007, 20.2% for 2008 and 20% for 2009.

Q. HOW DOES THE BACK-UP PSA AFFECT THE COMPANY'S RESOURCE PLANNING?

A. In Case No. 2003-00252, Duke Energy Kentucky and The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("Duke Energy Ohio") proposed that Duke Energy Ohio would supply power under the Back-up PSA. Duke Energy Kentucky's IRP planning has assumed that the Back-up PSA would be in effect. However, the contract must be approved by the Federal Energy Regulatory Commission ("FERC"). Yet the FERC might not approve the Back-up PSA.

Another possibility is that the FERC might approve the Back-up PSA, but only after a lengthy delay.

The fact that the Back-up PSA has not yet been approved, and the possibility that the Back-up PSA might not be approved, effectively requires Duke Energy Kentucky to consider only short-term solutions assuming that the Back-up PSA will be approved in some form. This restricts Duke Energy Kentucky from considering other more comprehensive resource plans that would be in effect through 2009 and possibly beyond, such as capacity swaps with other utilities or long-term wholesale power contracts. These other options might present better long-term supply options.

Q. HAS THE COMPANY TAKEN ANY STEPS TO OBTAIN ADDITIONAL CAPACITY FOR 2006?

A. Yes, Ms. Meyer approved the purchase of firm capacity for 100 megawatts, which can be exercised at an energy cost of the then-current market price, for July and August 2006.

Q. HAS THE COMPANY TAKEN ANY STEPS TO EVALUATE FUTURE SUPPLY OPTIONS?

A. Yes. At Ms. Meyer's direction, we have solicited competitive bids for a number of supply options. We retained Burns & McDonnell Engineering Co., Inc. ("Burns & McDonnell"), an independent consulting firm, to oversee the competitive bidding process. Burns & McDonnell is in the process of issuing the Request for Proposals ("RFP"). The RFP describes the different supply options for which we have solicited bids.

We will consider these supply options and determine how these options compare with the Back-up PSA. We will provide the Commission with the results of this bidding process when we obtain them. We expect that the bidding will close in July 2006.

VIII. INFORMATION SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 10(9)(H)(7).

A. FR 10(9)(h)(7) provides Duke Energy Kentucky's generation mix, which is approximately 99% coal and 1% gas/oil.

Q. DID YOU PROVIDE ANY INFORMATION TO MR. DAVEY FOR HIS USE IN DEVELOPING THE FORECASTED FINANCIAL DATA?

A. Yes. I supplied Mr. Davey with the following information for the forecasted portion of the base period, consisting of the six months ending August 31, 2006 and for the forecasted test period, consisting of the twelve months ending December 31, 2007. I provided the cost for inter-company rent paid by Duke Energy Kentucky to Duke Energy Ohio for use of the Miami Fort 6 step-up transformer. I derived this information from the lease agreement.

I provided Mr. Davey with certain production costs and revenues such as fuel costs, emission allowances costs and purchased power costs, and revenue derived from off-system sales, after applying the off-system sales sharing mechanism approved by the Commission in Case No. 2003-00252. I obtained this information from the March 3, 2006 Commercial Business Model run.

I also provided Mr. Davey with the projected account balances, for his use in preparing the balance sheet, as of December 31, 2006 and for the forecasted test period for the following items: emission allowances, coal, oil, gas and materials and supplies. I obtained this information from historic trends and adjustments for expected changes forecasted within the March 3, 2006 Commercial Business Model run.

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

A. Yes, I supplied Ms. Meyer and Mr. Wathen with the value of the difference in price between current market prices and the prices reflected in the agreement itself for providing service under the Back-up PSA.

IX. CONCLUSION

Q. WAS FR 10(9)(H)(7), THE INFORMATION SUPPLIED TO MS. MEYER, MR. WATHEN, AND MR. DAVEY, AND WERE ATTACHMENTS DFE-1 AND DFE-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, Douglas F Esamann, 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.

Douglas F Esamann, Affiant

Subscribed and sworn to before me by Douglas F Esamann on this 25th day of May, 2006.

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC
STATE OF OHIO

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

Summary of Adjustments to Model for Back-up PSA

2007	
Planned Outage Purchases	
Base Case Purchase Cost	$ 15,633,016.00
Adjustment for Price Cap in Backup Agreement	$ (8,399,044.49)
New Planned Outage Cost	$ 7,233,971.51
Forced Outage Purchases	
Base Case Purchase Cost	$ 9,770,528.00
Adjustment for Price Cap for East Bend	$ (4,531,840.49)
Adjustment for Price Cap for Miami Fort 6	$ (1,365,049.60)
New Forced Outage Cost	$ 3,873,637.90
2008	
Planned Outage Purchases	
Base Case Purchase Cost	$ 3,891,550.00
Adjustment for Price Cap in Backup Agreement	$ (1,704,338.82)
New Planned Outage Cost	$ 2,187,211.18
Forced Outage Purchases	
Base Case Purchase Cost	$ 10,580,808.00
Adjustment for Price Cap for East Bend	$ (4,665,802.58)
Adjustment for Price Cap for Miami Fort 6	$ (1,239,319.05)
New Forced Outage Cost	$ 4,675,686.38
2009	
Planned Outage Purchases	
Base Case Purchase Cost	$ 7,007,507.00
Adjustment for Price Cap in Backup Agreement	$ (3,623,934.39)
New Planned Outage Cost	$ 3,383,572.61
Forced Outage Purchases	
Base Case Purchase Cost	$ 10,649,737.00
Adjustment for Price Cap for East Bend	$ (4,424,530.07)
Adjustment for Price Cap for Miami Fort 6	$ (1,341,910.22)
New Forced Outage Cost	$ 4,883,296.71
Total Adjustments for Backup Power Agreement Pricing	
Forced	$(17,568,452.01)
Planned	$(13,727,317.70)
	$(31,295,769.70)

Note: These values represent the difference in cost to serve for backup power between the value of purchases at Market Price and the sales to ULH&P under the Backup Agreement.

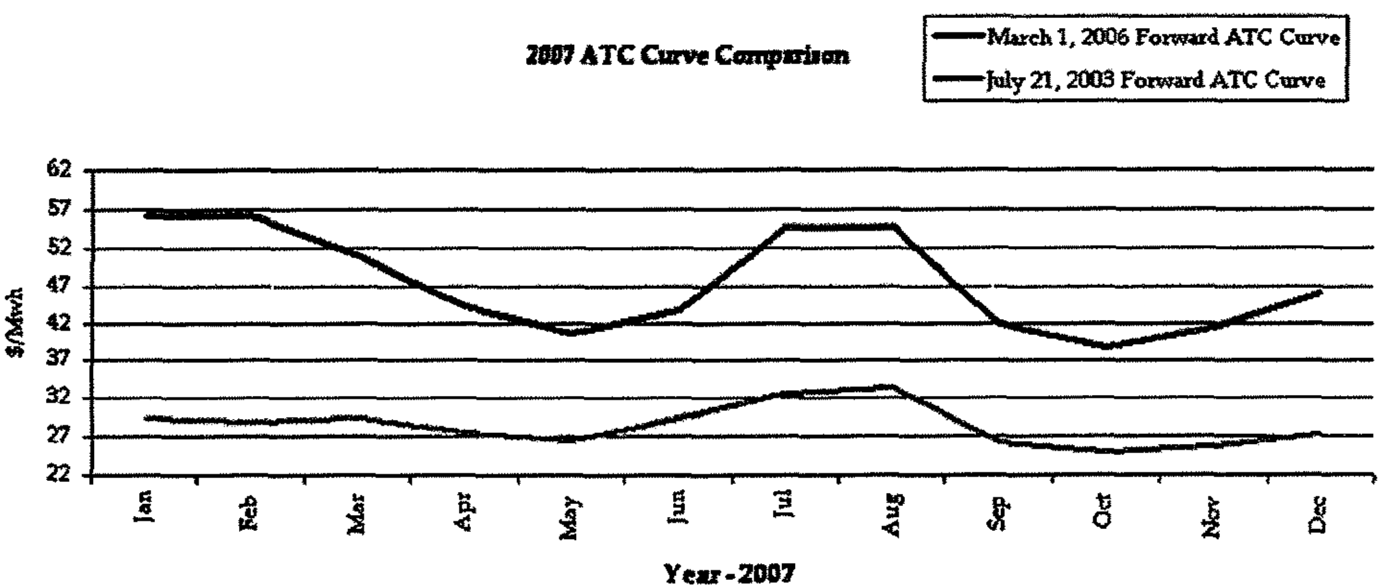
Commercial Business Model

Price Curve Comparison - Power ATC

March 1, 2006 vs July 21, 2003

	March 1, 2006 Forward ATC Curve			July 21, 2003 Forward ATC Curve		
Month	**2007**	**2008**	**2009**	**2007**	**2008**	**2009**
Jan	$56.21	$55.42	$55.57	$29.44	$29.67	$29.59
Feb	$56.21	$55.39	$55.46	$28.80	$29.13	$29.30
Mar	$50.76	$50.76	$50.71	$29.42	$29.43	$29.86
Apr	$44.28	$44.22	$44.44	$27.68	$28.20	$28.46
May	$40.54	$40.89	$41.26	$26.43	$26.52	$26.59
Jun	$43.69	$43.83	$43.86	$29.39	$29.61	$30.06
Jul	$54.50	$53.99	$53.90	$32.68	$33.13	$33.64
Aug	$54.50	$54.53	$54.65	$33.41	$32.93	$33.10
Sep	$41.75	$41.62	$41.84	$26.20	$26.82	$27.10
Oct	$38.66	$38.67	$38.97	$24.87	$25.23	$25.40
Nov	$41.43	$41.59	$41.68	$25.64	$25.57	$26.06
Dec	$46.19	$45.79	$45.94	$27.32	$27.99	$28.24
Annual Avg.	**$47.39**	**$47.22**	**$47.36**	**$28.44**	**$28.69**	**$28.95**
Summer Avg.	**$48.61**	**$48.49**	**$48.56**	**$30.42**	**$30.62**	**$30.97**

Note: Prices are Into-Cinergy forward price curves.



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

DWIGHT L. JACOBS

ON BEHALF OF

DUKE ENERGY KENTUCKY

183627

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ATTACHMENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dwight L. Jacobs and my business address is 526 South Church Street, Charlotte, North Carolina, 28202-1803.

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 Controller.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from the University of North Carolina with a Bachelor of Science in Business Administration. I am a certified public accountant. I am a member of the American Institute of Certified Public Accountants ("CPAs") and the North Carolina Association of CPAs.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE

A. I practiced accounting for 14 years with Arthur Andersen, where I was promoted to Audit Manager in 1992 and promoted to Audit Partner in 2000. I joined Duke Energy in 2002 as Managing Director of Corporate Accounting and Reporting. I became Vice President and Controller of Duke Power in 2004. I was promoted to my current position as Vice President and Controller of Duke Energy's U.S. Franchised Electric & Gas ("Franchised Electric & Gas") Commercial Business Unit earlier this year. I am also the business unit's accounting representative with Edison Electric Institute, a trade association of electric utility companies.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS VICE PRESIDENT AND CONTROLLER.

A. As Vice President and Controller, I have overall responsibility for the accounting functions of the Company's Franchised Electric & Gas Commercial Business Unit, which comprises Duke Energy's regulated utility businesses in Kentucky, Ohio, Indiana, North Carolina and South Carolina. I am responsible for the books of account, accounting records, and financial statements for these regulated utility businesses.

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

A. I explain the accounting treatment for The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio's ("Duke Energy Ohio") transfer 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") from Duke Energy Ohio to The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky"). I discuss the journal entries used to record the transfer of the Plants on Duke Energy Kentucky's books, including the journal entries related to Duke Energy Kentucky's financing for the Plants.

I discuss certain accounting entries which Duke Energy Kentucky recorded below-the-line related to the Plant transfer. I discuss the accounting treatment used for the Plants after January 1, 2006. I also sponsor Schedule B-2.4 and the following Filing Requirements ("FR"): 10(9)(i), 10(9)(k), 10(9)(l), 10(9)(m), 10(9)(p), 10(9)(q) and 10(9)(r). Finally, I describe certain accounting information relating to the transfer of the Plants, which my team provided to Mr. Davey for his use in preparing the forecasted test year financial data.

II. ACCOUNTING ENTRIES AND ACCOUNTING TREATMENT RELATED TO TRANSFER OF PLANTS

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING ENTRIES RELATED TO DUKE ENERGY OHIO'S TRANSFER OF THE PLANTS TO DUKE ENERGY KENTUCKY?

A. Yes.

Q. HAVE YOU REVIEWED THE COMMISSION'S ORDERS RELATING TO THE TRANSFER OF THE PLANTS?

A. Yes, I have reviewed the Commission's Orders dated December 5, 2003 and June 17, 2005 in Case No. 2003-00252.

Q. PLEASE IDENTIFY ATTACHMENT DLJ-1.

A. Attachment DLJ-1 is a summary of the transfer accounting used by Duke Energy Kentucky to record the transfer of the Plants, including the journal entries related to Duke Energy Kentucky's financing for the Plants.

Q. PLEASE EXPLAIN THESE ACCOUNTING ENTRIES.

A. The accounting entries record the transfer of the Plants from Duke Energy Ohio to Duke Energy Kentucky, which occurred effective January 1, 2006, at Duke Energy Ohio's net book value as of January 1, 2006. The Plants were transferred at net book value, including fuel, material and supplies, emission allowances, and prepayments, which was approximately $399 million. Duke Energy Kentucky recorded below-the-line Duke Energy Ohio's accumulated deferred income tax liabilities and accumulated deferred investment tax credits for the Plants through December 31, 2005. Duke Energy Kentucky proposes that these amounts should not be deducted from rate base, in accordance with the Commission's December 5, 2003 Order in Case No. 2003-00252. Going forward, Duke Energy Kentucky will record, above-the-line, any deferred income tax expense related to operating the Plants on and after January 1, 2006. The accounting entries also reflect Duke Energy Kentucky's financing for the Plants, which consisted of assuming various liabilities from Duke Energy Ohio, including approximately $77 million in notes payable and approximately $90 million in accounts payable, plus an equity contribution by Duke Energy Ohio of approximately $140 million.

Q. UNDER GENERALLY ACCEPTED ACCOUNTING PRINCIPLES, WAS DUKE ENERGY KENTUCKY REQUIRED TO RECOGNIZE ANY STEP-UP OR STEP-DOWN IN BASIS FOR THESE PLANTS AT THE TIME OF TRANSFER?

A. No. Financial Accounting Standard ("FAS") 141 provides at paragraph D12 that when a transfer of assets or liabilities occurs between two entities under common control, the entity receiving the assets shall record the assets and liabilities at the transferring entity's net book value as of the transfer date.

Q. THE ACCOUNTING ENTRIES SHOW AN INCREASE OF APPROXIMATELY $7.5 MILLION FOR THE DEFERRED TAX LIABILITIES RECORDED BY DUKE ENERGY KENTUCKY VERSUS THE DEFERRED TAX LIABILITIES RECORDED BY DUKE ENERGY OHIO AS OF THE TRANSFER DATE. PLEASE EXPLAIN WHY THE

COMPANIES RECORDED DIFFERENT BALANCES FOR THIS ACCOUNT.

A. Ohio enacted new tax reform legislation in 2005. The new law phased out the corporate state income tax applicable to the Plants and implemented a gross receipts tax. This resulted in a significant decrease in the state income tax rate previously used to calculate the income tax impacts of temporary differences between Duke Energy Ohio's financial books versus tax liabilities. This significantly decreased Duke Energy Ohio's deferred income tax liabilities.

Cinergy Corp. followed the "separate company return" method for calculating the amount of taxable income on the financial statements of its subsidiaries. Accordingly, Duke Energy Kentucky had to record the deferred tax liabilities based on its stand-alone tax rates, which are higher than Duke Energy Ohio's tax rates. This resulted in the $7.5 million increase in the deferred tax liabilities for Duke Energy Kentucky. These deferred tax liabilities were recorded above-the-line and are treated as such in the revenue requirement calculation.

Q. **PLEASE EXPLAIN FINANCIAL ACCOUNTING STANDARD 71 AND WHETHER DUKE ENERGY KENTUCKY WILL ACCOUNT FOR THE PLANTS UNDER FAS 71 ON A GOING FORWARD BASIS.**

A. Financial Accounting Standard ("FAS") 71 provides for an entity to capitalize certain costs if the entity charges rates for its services that are subject to review and approval by an independent agency, and the entity reasonably expects that the rates will be set at a level to allow the entity an opportunity to recover its costs of providing service. Duke Energy Kentucky concluded that the Plants would be subject to FAS 71 beginning January 1, 2006. Accordingly, Duke Energy Kentucky began accounting for the Plants under FAS 71, including accruing Allowance for Funds Used During Construction on the Construction Work in Progress transferred with the Plants.

Q. HOW HAS DUKE ENERGY KENTUCKY TREATED ITS TRANSACTION COSTS RELATED TO THE PLANT TRANSFER?

A. The Commission approved creation of a deferral account for the transaction costs up to $2.45 million, to be amortized over five years. The transaction costs are not expected to exceed this $2.45 million limit. The Company established a deferral account for these costs and Duke Energy proposes to amortize the account over a five-year period, without carrying charges.

Q. HAS DUKE ENERGY KENTUCKY ACCOUNTED FOR THE PLANTS IN A MANNER CONSISTENT WITH THE COMMISSION'S ORDERS IN CASE NO. 2003-00252?

A. Yes. The Commission's December 5, 2003 Order approved the transfer of the Plants at net book value. The Commission also approved the below-the-line treatment of accumulated deferred investment tax credits and accumulated deferred income taxes.

III. SCHEDULE AND FILING REQUIREMENTS SPONSORED BY WITNESS AND INFORMATION PROVIDED TO MR. DAVEY

Q. PLEASE DESCRIBE SCHEDULE B-2.4.

A. Schedule B-2.4 is entitled "Property Merged or Acquired" for the base period and the forecast period. This schedule lists the Plants that were transferred to Duke Energy Kentucky during the base period. Other than this property, Duke Energy Kentucky projects that no property will be merged or acquired for the forecast period, so no other items appear on this schedule.

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

A. FR 10(9)(i) is a copy of the most recent Federal Energy Regulatory Commission ("FERC") audit report for Duke Energy Kentucky, reporting on the results of the Company's last FERC audit.

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

A. FR 10(9)(k) provides the most recent FERC Form 1 report for Duke Energy Kentucky.

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

A. FR 10(9)(l) consists of the most recent annual reports to shareholders for the five years prior to the application. Duke Energy Kentucky does not provide a formal annual report because Duke Energy Ohio owns 100% of Duke Energy Kentucky's shares. We have provided the annual reports for Duke Energy and for Cinergy Corp. ("Cinergy") because the companies merged on April 3, 2006.

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

A. FR 10(9)(m) is a copy of the current chart of accounts for Duke Energy Kentucky.

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

A. FR 10(9)(p) consists of Duke Energy Kentucky's last two years' Form 10-Ks and Form 8-Ks filed with the U.S. Securities and Exchange Commission, as well as the Form 10-Qs filed during the past six quarters.

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

A. FR 10(9)(q) is the independent auditor's annual opinion report for Duke Energy Kentucky. The auditor did not note any material weaknesses in internal controls.

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

A. FR 10(9)(r) requires the Company to provide quarterly reports to stockholders for the most recent five quarters. Duke Energy Kentucky does not provide quarterly reports to Duke Energy Ohio, and has not prepared quarterly reports to Duke Energy Ohio since 2002. In response to this filing requirement, we are providing copies of the last five quarterly reports to stockholders of Cinergy through the second quarter of 2002.

Q. DID YOU SUPPLY ANY INFORMATION TO MR. DAVEY RELATED TO THE TRANSFER OF THE PLANTS FROM DUKE ENERGY OHIO TO DUKE ENERGY KENTUCKY FOR HIS USE IN PREPARING THE FORECASTED TEST YEAR FINANCIAL DATA?

A. As I previously mentioned, Duke Energy Ohio transferred the Plants to Duke Energy Kentucky effective January 1, 2006. My team supplied the following information to Mr. Davey for his use in preparing the forecasted test year financial data relating to this transfer: (1) the depreciation accrual rates for the generation plant (these rates do not reflect Mr. Spanos' proposed new depreciation rates); and (2) 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.

IV. CONCLUSION

Q. WAS SCHEDULE B-2.4 PREPARED BY YOU OR UNDER YOUR SUPERVISION AND CONTROL?

A. Yes.

Q. ARE FR 10(9)(I), 10(9)(K), 10(9)(L), 10(9)(M), 10(9)(P), 10(9)(Q) AND 10(9)(R) AND ATTACHMENT DLJ-1 TRUE AND ACCURATE COPIES OF THE DOCUMENTS THEY PURPORT TO REPRESENT?

A. Yes.

Q. IS THE INFORMATION YOU PROVIDED TO MR. DAVEY TRUE AND 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 North Carolina)
) SS:
County of Mecklenburg)

The undersigned, Dwight L. Jacobs, being duly sworn, deposes and says that he is Controller for U.S. Franchised Electric & Gas (a business unit within Duke Energy Corporation), 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.

DJacobs

Dwight L. Jacobs, Affiant

Subscribed and sworn to before me by Dwight L. Jacobs on this 11 day of May, 2006.

Janice Bumgardner

NOTARY PUBLIC

My Commission Expires:

OFFICIAL SEAL
Notary Public, North Carolina
County of Mecklenburg
JANICE BUMGARDNER
My Commission Expires August 17, 2009

Transfer of The Cincinnati Gas & Electric Company Electric Production Plants
East Bend, Woodsdale, and Miami Fort Unit 6
to The Union Light, Heat & Power Company

The Cincinnati Gas & Electric Company

Account	Account Description	12/31/2005 Balance	East Bend	Woodsdale	MF#6
Net Book Value of Plant in Service					
101/106	Electric Plant in Service / Completed Construction Not Classified	$ 748,943,254.56	$ 416,647,131.54	$ 261,846,162.14	$ 68,449,940.88
108	Accumulated Provision for Depreciation of Electric Utility Plant	$ (381,838,863.62)	$ (205,250,465.15)	$ (121,450,477.54)	$ (55,137,920.93)
	Total	$ 365,104,390.94	$ 211,396,666.39	$ 140,395,704.60	$ 13,312,019.95
Construction Work In Progress/Retirement Work in Progress (Salvage)					
107	Constuction Work in Progress	$ 10,486,553.58	$ 574,830.45	$ 9,122,177.58	$ 789,545.55
108	Retirement Work in Progress	$ (102,239.13)	$ (102,239.13)	$ -	$ -
	Total	$ 10,384,314.45	$ 472,591.32	$ 9,122,177.58	$ 789,545.55
Asset Retirement Obligation					
230	Asset Retirement Obligation	$ (1,736,392.95)	$ (1,280,199.70)	$ -	$ (456,193.25)
Material and Supplies Inventory					
154	Plant Materials and Operating Supplies	$ 9,480,077.20	$ 6,134,499.12	$ 2,229,843.60	$ 1,115,934.48
154	Plant Materials and Operating Supplies (DP&L Portion of Other M&S)	$ (1,901,694.71)	$ (1,901,694.71)		
163	Stores Expense Undistributed	$ 439,567.18	$ 228,181.89	$ 140,876.86	$ 70,508.63
154	Plant Materials and Operating Supplies (Reserve for Loss on Parts)	$ (181,325.71)		$ (181,325.71)	
	Total	$ 7,836,623.96	$ 4,460,986.30	$ 2,189,194.55	$ 1,186,443.11
Fuel Inventory (Coal, Oil, Lime, Propane) and Prepaid Synfuel					
151	Fuel Stock	$ 8,362,735.52	$ 4,014,483.39	$ 2,526,223.52	$ 1,822,028.61
154	Plant Materials and Operating Supplies	$ 480,676.58	$ 480,676.58	$ -	$ -
165	Prepayments	$ 5,903,620.44	$ 5,903,620.44	$ -	$ -
	Total	$ 14,747,032.54	$ 10,398,780.41	$ 2,526,223.52	$ 1,822,028.61
Emission Allowance Inventory					
158	Allowance Inventory	$ 771,504.25			
Tax					
190	Accumulated Deferred Income Taxes	$ 3,263,782.00			
255	Accumulated Deferred Investment Tax Credit	$ (5,342,874.00)			
282	Accumulated Deferred Income Taxes	$ (83,391,917.00)			
283	Accumulated Deferred Income Taxes	$ 645,938.00			
	Total	$ (84,825,071.00)			
Grand Total - Net Decrease in Asset for CG&E		$ 312,282,402.19			

Transfer of The Cincinnati Gas & Electric Company Electric Production Plants
East Bend, Woodsdale, and Miami Fort Unit 6
to The Union Light, Heat & Power Company

The Union Light Heat & Power Company

Account	Account Description	12/31/2005 Balance	East Bend	Woodsdale	MF#6
Net Book Value of Plant in Service					
101/106	Electric Plant in Service / Completed Construction Not Classified	$ 746,943,254.56	$ 416,647,131.54	$ 261,846,182.14	$ 68,449,940.88
108	Accumulated Provision for Depreciation of Electric Utility Plant	$ (381,838,863.62)	$ (205,250,465.15)	$ (121,450,477.54)	$ (55,137,920.93)
	Total	$ 365,104,390.94	$ 211,396,666.39	$ 140,395,704.60	$ 13,312,019.95
Construction Work in Progress/Retirement Work in Progress (Salvage)					
107	Constuction Work in Progress	$ 10,486,553.58	$ 574,830.45	$ 9,122,177.58	$ 789,545.55
108	Retirement Work in Progress	$ (102,239.13)	$ (102,239.13)	$ -	$ -
	Total	$ 10,384,314.45	$ 472,591.32	$ 9,122,177.58	$ 789,545.55
Asset Retirement Obligation					
230	Asset Retirement Obligation	$ (1,736,392.95)	$ (1,280,199.70)	$ -	$ (456,193.25)
Material and Supplies Inventory					
154	Plant Materials and Operating Supplies	$ 9,460,077.20	$ 6,134,499.12	$ 2,229,643.60	$ 1,115,934.48
154	Plant Materials and Operating Supplies (DP&L Portion of Other M&S)	$ (1,901,694.71)	$ (1,901,694.71)		
163	Stores Expense Undistributed	$ 439,567.18	$ 228,181.89	$ 140,876.66	$ 70,508.63
154	Plant Materials and Operating Supplies (Reserve for Loss on Parts)	$ (181,325.71)		$ (181,325.71)	
	Total	$ 7,836,623.96	$ 4,460,986.30	$ 2,189,194.55	$ 1,186,443.11
Fuel Inventory (Coal, Oil, Lime, Propane) and Prepaid Synfuel					
151	Fuel Stock	$ 8,362,735.52	$ 4,014,483.39	$ 2,526,223.52	$ 1,822,028.61
154	Plant Materials and Operating Supplies	$ 480,676.58	$ 480,676.58	$ -	$ -
165	Prepayments	$ 5,903,620.44	$ 5,903,620.44	$ -	$ -
	Total	$ 14,747,032.54	$ 10,398,780.41	$ 2,526,223.52	$ 1,822,028.61
Emission Allowance Inventory					
158	Allowance Inventory	$ 771,504.25			
Tax					
190	Accumulated Deferred Income Taxes	$ 3,474,349.00			
255	Accumulated Deferred Investment Tax Credit	$ (5,342,874.00)			
282	Accumulated Deferred Income Taxes	$ (91,112,980.00)			
283	Accumulated Deferred Income Taxes	$ 687,611.00			
	Total	$ (92,293,894.00)			
Grand Total - Net Increase in Asset for ULH&P		$ 304,813,579.19			

Subsequent Adjustment Related to the
Transfer of The Cincinnati Gas & Electric Company Electric Production Plants
East Bend, Woodsdale, and Miami Fort Unit 6
to The Union Light, Heat & Power Company

The Cincinnati Gas & Electric Company

Account	Account Description	12/31/2005 Balance	East Bend	Woodsdale	MF#6
Net Book Value of Plant In Service					
101/106	Electric Plant In Service / Completed Construction Not Classified	$ 326,944.72	$ 230,066.44	$ -	$ 96,878.28
108	Accumulated Provision for Depreciation of Electric Utility Plant	$ (146.85)	$ -	$ (146.85)	$ -
	Total	$ 326,797.87	$ 230,066.44	$ (146.85)	$ -
Construction Work In Progress/Retirement Work In Progress (Salvage)					
107	Constuction Work In Progress	$ (4,370.62)	$ (4,370.62)	$ -	$ -
108	Retirement Work in Progress	$ -	$ -	$ -	$ -
	Total	$ (4,370.62)	$ (4,370.62)	$ -	$ -
Fuel Inventory (Coal, Oil, Lime, Propane) and Prepaid Synfuel					
131	Cash	$ 224,075.01	$ 224,075.01	$ -	$ -
253	Other Deferred Credits	$ (224,075.01)	$ (224,075.01)	$ -	$ -
	Total	$ -	$ -	$ -	$ -
Tax					
190	Accumulated Deferred Income Taxes	$ 1,719,092.00			
	Total	$ 1,719,092.00			
Grand Total - Net Decrease in Asset for CG&E		$ 2,041,519.25			

Subsequent Adjustment Related to the
Transfer of The Cincinnati Gas & Electric Company Electric Production Plants
East Bend, Woodsdale, and Miami Fort Unit 6
to The Union Light, Heat & Power Company

The Union Light Heat & Power Company

Account	Account Description	12/31/2005 Balance	East Bend	Woodsdale	MF#6
Net Book Value of Plant in Service					
101/106	Electric Plant in Service / Completed Construction Not Classified	$ 326,944.72	$ 230,066.44	$ -	$ 96,878.28
108	Accumulated Provision for Depreciation of Electric Utility Plant	$ (146.85)	$ -	$ (146.85)	$ -
	Total	$ 326,797.87	$ 230,066.44	$ (146.85)	$ -
Construction Work in Progress/Retirement Work in Progress (Salvage)					
107	Constuction Work in Progress	$ (4,370.62)	$ (4,370.62)	$ -	$ -
108	Retirement Work in Progress	$ -	$ -	$ -	$ -
	Total	$ (4,370.62)	$ (4,370.62)	$ -	$ -
Fuel Inventory (Coal, Oil, Lime, Propane) and Prepaid Synfuel					
131	Cash	$ 224,075.01	$ 224,075.01	$ -	$ -
253	Other Deferred Credits	$ (224,075.01)	$ (224,075.01)	$ -	$ -
	Total	$ -	$ -	$ -	$ -
Tax					
190	Accumulated Deferred Income Taxes	$ 1,719,092.00			
	Total	$ 1,719,092.00			
Grand Total - Net Increase in Asset for ULH&P		$ 2,041,519.25			

THE UNION LIGHT, HEAT AND POWER COMPANY

Asset Transfer Financing Analysis
For the Transfer of The Cincinnati Gas & Electric Company Electric Production Plants
East Bend, Woodsdale, and Miami Fort Unit 6
to The Union Light, Heat & Power Company

As of January 1, 2006

Debt/Equity Detail

Total Available for Debt Assumption	$	167,000,000
Total Equity Contribution	$	139,855,099

Debt Assumption Detail

CG&E Boone County Series 1985A due 2013	$	16,000,000
CG&E Boone County Series 1994A due 2024	$	48,000,000
CG&E Boone County 6.5% due 2015	$	12,720,000
Total Tax Exempt Debt Assumption	$	76,720,000
Total Accounts Payable to Affiliates Assumption	$	90,280,000
	$	167,000,000

Accounts Payable Assumption Detail

Cinergy Corp.	$	65,285,472
Cinergy Services	$	24,994,528
	$	90,280,000

**Transfer of The Cincinnati Gas & Electric Company Electric Production Plants
East Bend, Woodsdale, and Miami Fort Unit 6
to The Union Light, Heat & Power Company**

**The Cincinnati Gas & Electric Company
January 1, 2006**

Entry #	Account	Account Title	Debit	Credit
1	102	Electric Plant Purchased or Sold		375,811,133
	123	Investment in ULH&P	147,323,921	
	145	Notes Receivable from Affiliated Companies	76,720,000	
	131	Cash		224,075
	151	Fuels		8,362,736
	154	Plant Materials and Operating Supplies		7,877,733
	158	Allowance Inventory		771,504
	163	Stores Expense Undistributed		439,567
	165	Prepayments		5,903,620
	190	Accumulated Deferred Income Taxes		4,982,874
	230	Asset Retirement Obligation	1,736,393	
	234	Accounts Payable to Affiliated Companies	90,280,000	
	253	Other Deferred Credits	224,075	
	255	Accumulated Deferred Investment Tax Credit	5,342,874	
	282	Accumulated Deferred Income Taxes	83,391,917	
	283	Accumulated Deferred Income Taxes		645,938
	To record CG&E's transfer of the production plants, fuel, inventory, and related deferred income taxes.			
2	102	Electric Plant Purchased or Sold	757,752,382	
	101/106	Electric Plant in Service / Completed Construction Not Classified		747,270,199
	107	Construction Work in Progress		10,482,183
	To transfer the original cost of production plants out of accounts 101, 106 and 107.			
3	108	Accumulated Provision for Depreciation of Electric Utility Plant	381,941,250	
	102	Electric Plant Purchased or Sold		381,941,250
	To transfer accumulated provision for depreciation of production plant out of account 108.			
4	123	Investment in ULH&P		7,468,823
	190	Accumulated Deferred Income Taxes		210,567
	282	Accumulated Deferred Income Taxes	7,721,063	
	283	Accumulated Deferred Income Taxes		41,673
	To record additional "above the line" deferred income taxes related to ULH&P's acquisition of the production plants, fuel, and related inventory.			
			1,552,433,875	1,552,433,875

**Transfer of The Cincinnati Gas & Electric Company Electric Production Plants
East Bend, Woodsdale, and Miami Fort Unit 6
to The Union Light, Heat & Power Company**

**The Union Light, Heat & Power Company Entries
January 1, 2006**

Entry #	Account	Account Title	Debit	Credit
1	102	Electric Plant Purchased or Sold	375,811,133	
	208	Donations Received from Stockholders		147,323,921
	233	Notes Payable to Affiliated Companies		76,720,000
	131	Cash	224,075	
	151	Fuels	8,362,736	
	154	Plant Materials and Operating Supplies	7,877,733	
	158	Allowance Inventory	771,504	
	163	Stores Expense Undistributed	439,567	
	165	Prepayments	5,903,620	
	190	Accumulated Deferred Income Taxes	4,982,874	
	230	Asset Retirement Obligation		1,736,393
	234	Accounts Payable to Affiliated Companies		90,280,000
	253	Other Deferred Credits		224,075
	255	Accumulated Deferred Investment Tax Credit		5,342,874
	282	Accumulated Deferred Income Taxes		83,391,917
	283	Accumulated Deferred Income Taxes	645,938	
	To record ULH&P's acquisition of the production plants, fuel, inventory, and related "below the line" deferred income taxes.			
2	102	Electric Plant Purchased or Sold		757,752,382
	101/106	Electric Plant in Service / Completed Construction Not Classified	747,270,199	
	107	Construction Work in Progress	10,482,183	
	To transfer the original cost of production plants out of accounts 101, 106 and 107.			
3	108	Accumulated Provision for Depreciation of Electric Utility Plant		381,941,250
	102	Electric Plant Purchased or Sold	381,941,250	
	To transfer accumulated provision for depreciation of production plant out of account 108.			
4	208	Donations Received from Stockholders	7,468,823	
	190	Accumulated Deferred Income Taxes	210,567	
	282	Accumulated Deferred Income Taxes		7,721,063
	283	Accumulated Deferred Income Taxes	41,673	
	To record additional "above the line" deferred income taxes related to ULH&P's acquisition of the production plants, fuel, and related inventory.			
			1,552,433,875	1,552,433,875

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

CARL J. COUNCIL, JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY

183585

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Carl J. Council, Jr. and my business address is 526 South Church Street, Charlotte, North Carolina, 28202-1803.

Q. WHAT IS YOUR PRESENT POSITION?

A. I am employed by the Duke Energy Corporation ("Duke Energy") affiliated companies as Director, Asset Accounting.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I am a graduate of the University of North Carolina at Charlotte with a Bachelor of Science degree in Accounting. I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants. I am also a member of the Edison Electric Institute Property Accounting and Valuation Committee.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I began my employment with Duke Energy in the Controller's Department in September, 1982 as a Financial and Accounting Assistant. In 1989, I moved to the Internal Audit Department as an Internal Auditor. In 1992, I moved to the Treasury Department as an assistant to the Treasurer. I became a Financial Analyst in the Corporate Finance Department in 1994, and a Senior Financial Analyst in 1997, specializing in economic analysis/business unit valuation, cost of capital calculations and issues, and capital markets issuances. In 1999, I moved to the Rates & Regulatory Affairs Department as Manager, Regulatory Accounting, focusing on affiliate code of conduct and electric restructuring issues, as well as the monthly and annual fuel clause reporting. In 2001, I was named Director of Asset Accounting for Duke Power. In April, 2006 I assumed my current position as Director of Asset Accounting for the Duke Energy affiliated companies.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, ASSET ACCOUNTING.

A. As Director of Asset Accounting, I have responsibility for the accounting activities within the Company's U.S. Franchised Electric & Gas Commercial Business Unit related to fixed assets, including depreciation and nuclear decommissioning, materials and supplies inventory, fuel, including both inventory and payment of fuel invoices, emission allowances, joint owner billings for fixed assets, and sales and use tax return preparation.

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

A. I am responsible for actual net plant in service and construction work in progress contained in rate base and other actual plant-related items that Mr. Davey uses in his testimony, except for Schedule B-2.4 - Property Merged or Acquired, which Mr. Jacobs sponsors. In particular, I sponsor the following Schedules: B-2, B-2.1, B-2.2, B-2.3, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, the actual plant data on Schedule K, page 1, and the composite depreciation rates on Schedule K. The source and sponsor of the budgeted and projected data as shown on these schedules is Mr. Davey. The source and sponsor of the proposed depreciation and amortization accrual rates used in these schedules, including the supporting depreciation study, is Mr. Spanos.

II. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE THE INFORMATION CONTAINED IN THE SECTION B SCHEDULES.

A. The Section B schedules develop the Jurisdictional Net Plant In Service. The schedules are based on the Company's budget records as of the end of the base period (August 31, 2006) and the end of the forecast period (December 31, 2007).

Q. PLEASE DESCRIBE SCHEDULE B-2.

A. Schedule B-2 shows the plant in service including allocated common plant by major property grouping for the base period and the 13-month average as of the plant valuation date of December 31, 2007. The amount shown in the column labeled "Adjusted Jurisdiction" on page 1 of 2, and "13-Month Average Adjusted Jurisdiction" on page 2 of 2, represents plant in service that is deemed used and useful in providing electric service to our Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.1.

A. Schedule B-2.1 consists of a further breakdown of Schedule B-2 by the Federal Energy Regulatory Commission ("FERC") and Company Account for each major property grouping for the base period and the forecast period. The plant in service investment shown in the column labeled "Adjusted Jurisdiction" on pages 1 through 6, and "13-Month Average Adjusted Jurisdiction" on pages 7 through 12, represents electric plant in service including allocated common plant that is deemed used and useful in providing electric service to the Company's Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.2.

A. Schedule B-2.2 shows proposed adjustments to plant in service for the base period and the forecast period. An adjustment has been made for the forecast period to exclude the Florence service building, which is being replaced by the Cox Road facility in Erlanger that we leased in 2005. We have moved the Florence building to non-utility property in this proceeding because the facility will no longer be used and useful in providing electric service to our Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.3.

A. Schedule B-2.3 shows gross additions, retirements and transfers by FERC and Company Account for each major property grouping for the base period and the forecast period.

Q. PLEASE DESCRIBE SCHEDULE B-2.5.

A. Schedule B-2.5 is entitled "Leased Property" and provides data for the base period and the forecast period. Duke Energy Kentucky began leasing new electric meters in 1999. Duke Energy Kentucky also entered into a lease for a building on Cox Road in Erlanger, Kentucky in 2005 to house its gas and electric construction and maintenance operations. Schedule B-2.5 contains the cost of electric meters and the cost associated with the building lease prior to allocation.

Q. PLEASE DESCRIBE SCHEDULE B-2.6.

A. Schedule B-2.6 shows the property held for future use included in rate base for the base period and forecast period. The Company has not included any property held for future use in rate base.

Q. PLEASE DESCRIBE SCHEDULE B-2.7.

A. Schedule B-2.7 contains data on utility property excluded from rate base for the base period and forecast period. There are no exclusions of utility property from rate base.

Q. PLEASE DESCRIBE SCHEDULE B-3.

A. Schedule B-3 shows the total plant investment and Reserve for Accumulated Depreciation and Amortization by FERC and Company Account grouping for the base period and the forecast period. The amounts for the forecast period on pages 7 through 12 are 13-month averages. The adjusted jurisdictional reserve in the last column is applicable to the jurisdictional plant shown on Schedule B-2, "Adjusted Jurisdiction" and "13-Month Average Adjusted Jurisdiction."

Q. PLEASE DESCRIBE SCHEDULE B-3.1.

A. Schedule B-3.1 shows adjustments to Accumulated Depreciation and Amortization for the base period and the forecast period. Since the Company has adjusted Plant in Service to reflect transferring the Florence Service Building to non-utility property for the forecast period, the related Accumulated Depreciation and Amortization is adjusted on this schedule.

Q. PLEASE DESCRIBE SCHEDULE B-3.2.

A. Schedule B-3.2 lists the 13-month average jurisdictional plant investment and reserve balance as of December 31, 2007 for each FERC and Company Account within each major property grouping. It also shows the proposed depreciation and amortization accrual rate, calculated annual depreciation and amortization expense, percentage of net salvage value, average service life and curve form, as applicable for each account. The calculated annual depreciation and amortization was determined by multiplying the 13-month average adjusted jurisdictional plant investment for the forecast period by the proposed depreciation and amortization accrual rates.

With this filing, the Company filed with the Commission proposed depreciation and amortization accrual rates prepared in 2006 and sponsored by Mr. Spanos of Gannett Fleming, Inc., who prepared the depreciation study. The account numbers referred to in the depreciation study were those in effect in 2006 for Duke Energy Kentucky. The Company requests that the Commission approve these new depreciation and amortization accrual rates included in this filing and that the depreciation and amortization accrual rates be effective January 1, 2007, corresponding with the effective date of the electric rates established in this case.

Q. PLEASE DESCRIBE SCHEDULE B-4.

A. Schedule B-4 is a list of construction work in progress by major property grouping for the base period and the forecast period. Construction Work in Progress ("CWIP") is broken down by amounts subject to Allowance for Funds Used During Construction ("AFUDC") and amounts not subject to AFUDC. No CWIP has been eliminated since the electric plant is 100% jurisdictional.

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN SCHEDULE K.

A. I sponsor the actual plant data submitted on page 1 of Schedule K. This information includes Plant in Service by major property grouping and Reserve for Accumulated Depreciation and Amortization by utility service for the 13-month average forecast period, for the base period and as of December 31 for each of the last ten years. Plant held for future use and construction work in progress have also been provided for the same periods. I also sponsor the composite depreciation rates shown on Schedule K.

III. INFORMATION PROVIDED TO OTHER WITNESSES

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

A. Yes, I provided Mr. Davey with the actual net book value for the existing gas, electric and common plant for the period ending February 28, 2006, for his use in calculating the forecasted financial data.

IV. CONCLUSION

Q. WERE SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, THE INFORMATION YOU PROVIDED ON SCHEDULE K, AND THE INFORMATION YOU PROVIDED TO MR. DAVEY, (EXCLUDING THE BUDGET AND FORECAST NUMBERS PREPARED BY MR. DAVEY AND THE PROPOSED DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND SUPPORTING DEPRECIATION STUDY PREPARED BY MR. SPANOS) 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 North Carolina)
) SS:
County of Mecklenburg)

The undersigned, Carl J. Council, 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 knowledge, information and belief.

Carl J. Council Jr., Affiant

Subscribed and sworn to before me by Carl J. Council Jr., on this 22 day of May, 2006.

Janice Bumgardner
NOTARY PUBLIC

My Commission Expires:

OFFICIAL SEAL
Notary Public, North Carolina
County of Mecklenburg
JANICE BUMGARDNER
My Commission Expires August 17, 2009

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

JOHN J. SPANOS

ON BEHALF OF

DUKE ENERGY KENTUCKY

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming, Inc.

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING, INC.?

A. I have been associated with the firm since college graduation in June 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am a Vice President.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member of the Society of Depreciation Professionals and the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003.

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas

Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state Public Utility Commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December 2000, I was promoted to my present position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc. and I became responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Hampton Water Works Company, Omaha Public Power District, Enbridge Pipe Line Company, Inc., Columbia Gas of Virginia, Inc., Virginia Natural Gas Company, National Fuel Gas Distribution

Corporation - New York and Pennsylvania Divisions, The City of Bethlehem - Bureau of Water, The City of Coatesville Authority, The City of Lancaster - Bureau of Water, Peoples Energy Corporation, The York Water Company, Public Service Company of Colorado, Enbridge Pipelines, Enbridge Gas Distribution, Inc., Reliant Energy-HLP, Massachusetts-American Water Company, St. Louis County Water Company, Missouri-American Water Company, Chugach Electric Association, Alliant Energy, Oklahoma Gas & Electric Company, Nevada Power Company, Dominion Virginia Power, NUI-Virginia Gas Companies, Pacific Gas & Electric Company, PSI Energy, NUI - Elizabethtown Gas Company, Cinergy Corporation – CG&E, Cinergy Corporation – ULH&P, Columbia Gas of Kentucky, SCANA, Inc., Idaho Power Company, El Paso Electric Company, Central Hudson Gas & Electric, Centennial Pipeline Company, CenterPoint Energy-Arkansas, CenterPoint Energy – Oklahoma, CenterPoint Energy – Entex, CenterPoint Energy - Louisiana, NSTAR – Boston Edison Company, Westar Energy, Inc., South Jersey Gas Company, Duquesne Light Company, MidAmerican Energy Company, Laclede Gas, Duke Energy Company, Bonneville Power Administration, NSTAR Electric and Gas Company, EPCOR Distribution, Inc. and B. C. Gas Utility, Ltd. My additional duties include determining final life and salvage estimates, conducting field reviews and presenting recommended depreciation rates to management for their consideration.

Q. **HAVE YOU SUBMITTED TESTIMONY TO ANY STATE UTILITY COMMISSION ON THE SUBJECT OF UTILITY PLANT DEPRECIATION?**

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission, the Commonwealth of Kentucky Public Service Commission, the Public Utilities

Commission of Ohio, the Nevada Public Utility Commission, the Public Utilities Board of New Jersey, the Missouri Public Service Commission and the Massachusetts Department of Telecommunications and Energy, the Alberta Energy & Utility Board, the Idaho Public Utility Commission, the Louisiana Public Service Commission, the State Corporation Commission of Kansas, the Oklahoma Corporate Commission, The Public Service Commission of South Carolina, Railroad Commission of Texas – Gas Services Division, the New York Public Service Commission, Illinois Commerce Commission, and the Indiana Utility Regulatory Commission.

Q. HAVE YOU HAD ANY ADDITIONAL EDUCATION RELATING TO UTILITY PLANT DEPRECIATION?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

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

A. I sponsor the depreciation study performed for Duke Energy Kentucky, which is included in the filing as Filing Requirement ("FR") 10(9)(S).

II. DEPRECIATION STUDY

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which can be reasonably anticipated or contemplated, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. DID YOU PREPARE THE DEPRECIATION STUDY FILED BY DUKE ENERGY KENTUCKY IN THIS PROCEEDING?

A. Yes. I prepared the depreciation study submitted by Duke Energy with its filing in this proceeding. My report is entitled: "Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric and Common Plant as of December 31, 2005." This report sets forth the results of my depreciation study for Duke Energy Kentucky.

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. ARE THE METHODS AND PROCEDURES OF THIS DEPRECIATION STUDY CONSISTENT WITH PAST PRACTICES?

A. Yes. The methods and procedures of this study are the same as those utilized in past studies of this company as well as many others before this Commission. The prior study for Duke Energy Kentucky's gas operations used the same general methods and procedures, and was approved by this Commission in Case No. 2005-00042. The prior study for Duke Energy Kentucky's electric operations used the same general methods and procedures, and was approved by this Commission in Case No. 91-370.

Q. PLEASE DESCRIBE THE CONTENTS OF YOUR REPORT.

A. My report is presented in three parts. Part I, Introduction, presents the scope and basis for the depreciation study. Part II, Methods Used in Study, includes descriptions of the basis of the study, the estimation of survivor curves and net salvage and the calculation of annual and accrued depreciation. Part III, Results of Study, presents a description of the results, summaries of the depreciation calculations, graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations.

The table on pages III-4 through III-6 presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2005, the book reserve and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page III-7 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page III-138 presents the results of the salvage analysis. The section beginning on page III-163 presents the depreciation calculations related to surviving original cost as of December 31, 2005.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line remaining life method of depreciation, with the equal life group procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and reasonable manner.

For General Plant Accounts 1910, 1930, 1940, 1970, 1980 in common plant and 3910, 3940 and 3970 in electric plant, I used the straight line remaining life method of amortization. The account numbers identified throughout my testimony represent those in effect as of December 31, 2005. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historical data from records related to Duke Energy Kentucky's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1956 through 2005. The transactions included additions, retirements, transfers, sales and the related balances. The Company records included surviving dollar value by year installed for each plant account as of December 31, 2005.

Q. WHAT METHOD DID YOU USE TO ANALYZE THIS SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available, because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the depreciation study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE DUKE ENERGY KENTUCKY'S SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa type survivor curves were used to perform these interpretations.

Q. WHAT IS AN "IOWA-TYPE SURVIVOR CURVE" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 44-R1 indicates an average service life of forty-five years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a relatively low height, 1, for the mode (possible modes for R type curves range from 1 to 5).

Q. DID YOU PHYSICALLY OBSERVE DUKE ENERGY KENTUCKY'S PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDY?

A. Yes. I made a field review of Duke Energy Kentucky's property on August 15, 2005 to observe representative portions of plant. The field review in 2005 included visits to the East Bend and Woodsdale facilities. Prior studies also included to these facilities as well as the Miami Fort facility. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge as well as information from other discussions with management was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1990 through 2005 and considered estimates for other electric companies. I also used the demolition cost estimates prepared by Sargent & Lundy for the production facilities at Miami Fort, East Bend and Woodsdale.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED

COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line remaining life method, and using remaining lives weighted consistent with the equal life group procedure.

Q. **PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.**

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. **PLEASE DESCRIBE THE EQUAL LIFE GROUP PROCEDURE.**

A. The equal life group procedure is a method for determining the remaining life annual accrual for each vintage property group. Under this procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. The vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals.

Q. **PLEASE DESCRIBE AMORTIZATION ACCOUNTING.**

A. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. Amortization accounting is used for accounts with a large number of units, but small asset values, therefore, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life which the asset will render full benefit. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off the Company books, but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. AMORTIZATION ACCOUNTING IS BEING IMPLEMENTED TO WHICH PLANT ACCOUNTS?

A. Amortization accounting is only appropriate for certain Common and General Plant accounts. These accounts are 1910, 1930, 1940, 1970, 1980 for Common Plant; and 3910, 3940 and 3970 for Electric Plant which represent less than one percent of depreciable plant.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDY.

A. I will use Account 3640, Poles, Towers and Fixtures, as an example because it is one of the largest depreciable mass accounts and represents over 4% of depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1956 through 2005 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1956-2005 and 1975-2005 experience bands are presented on pages III-69 through III-74 of the report. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page III-69 shows $312,320 retired at age 0.5 with $45,133,474 exposed to retirement. Consequently, the retirement ratio is 0.0069 and the surviving ratio is 0.9931. These life tables, or original survivor curve, are plotted along with the estimated smooth survivor curve, the 44-R0.5 on page III-68.

My calculation of the annual depreciation related to the original cost at December 31, 2005, of utility plant is presented on pages III-208 through III-210. The calculation is based on the 44-R0.5 survivor curve, 15% negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page III-5.

III. CONCLUSION

Q. WAS THE DEPRECIATION STUDY FILED BY DUKE ENERGY KENTUCKY IN THIS PROCEEDING, FR 10(9)(S), 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 Pennsylvania	)	
	)	**SS:**
County of Cumberland	)	

The undersigned, John J. Spanos, being duly sworn, deposes and says that he is a Vice President associated with the firm of Gannett Fleming, Inc., and 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.

John J. Spanos

John J. Spanos, Affiant

Subscribed and sworn to before me by John J. Spanos on this 15th day of MAY, 2006.

NOTARY PUBLIC

My Commission Expires:

NOTARIAL SEAL
CHERYL ANN RUTTER, Notary Public
Camp Hill Boro, Cumberland County
My Commission Expires Feb. 20, 2007

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

DR. RICHARD G. STEVIE

ON BEHALF OF

DUKE ENERGY KENTUCKY

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ATTACHMENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Richard G. Stevie, and my business address is 139 E. 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 General Manager of the Market Analysis Department.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATION

A. I received an A.B. in Economics from Thomas More College in May 1971. In June 1973, I was awarded a Master of Arts degree in Economics from the University of Cincinnati. In August 1977, I received a Ph.D. in Economics from the University of Cincinnati.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. Past employers include the Cincinnati Water Works where I was involved in developing a new rate schedule and forecasting revenues, the United States Environmental Protection Agency's Water Supply Research Division where I was involved in the research and development of a water utility simulation model and analysis of the economic impact of new drinking water standards, and the Economic Research Division of the Public Staff of the North Carolina Utilities Commission where I presented testimony in numerous utility rate cases involving natural gas, electric, telephone, and water and sewer utilities on several issues including rate of return, capital structure, and rate design. In addition, I was involved in the Public Staff's research effort and presentation of testimony regarding electric utility load forecasting. This included the development of electric load forecasts for the major electric utilities in North Carolina. I was also involved in research concerning cost curve estimation for electricity generation, rate setting and separation procedures in the telephone industry, and the implications of financial theory for capital structures, bond ratings, and dividend policy. In July 1981, I became the Director of the Economic Research Division of the Public Staff with the responsibility for the development and presentation of all testimony of the Division.

In November 1982, I joined the Load Forecast Section of The Cincinnati Gas & Electric Company. My primary responsibility involved directing the development of the company's Electric and Gas Load Forecasts. I also participated in the economic evaluation of alternate load management plans and was involved in the development of the Company's Integrated Resource Plan ("IRP"), which integrated the load forecast with generation options and demand-side options.

With the reorganization after the merger of CG&E and PSI in late 1994, I became Manager of Retail Market Analysis in the Corporate Planning Department of Cinergy Services with responsibility for the load forecasting, load research, DSM impact evaluation, and market research functions of the Company. Currently, I am the General Manager of the Market Analysis Department with responsibility for several areas including load forecasting, load research, market research, Demand Side Management ("DSM") strategy and analysis, load management development and business development analytics.

In addition, since 1990 I have chaired the Economic Advisory Committee for the Greater Cincinnati Chamber of Commerce. I have been a part-time faculty member of Thomas More College located in Northern Kentucky and the University of Cincinnati teaching undergraduate courses in economics. And, most recently, I have become an outside adviser to the Applied Economics Research Institute in the Department of Economics at the University of Cincinnati, as well as a member of an advisory committee to the Economics Department at Northern Kentucky University.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes, I am a member of the American Economic Association and the National Association of Business Economists.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS GENERAL MANAGER OF THE MARKET ANALYSIS DEPARTMENT.

A. I have responsibility for several functional areas including load forecasting, load research, DSM analysis, market research, load management development, and business development analytics for Duke Energy's U.S. Franchised Electric & Gas Commercial Business Unit.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I provided testimony on behalf of the Company in Case No. 2003-00252 involving the transfer of generating assets from The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("Duke Energy Ohio") to The Union Light Heat & Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky"). My testimony explained Duke Energy Kentucky's long-term energy and demand forecast and described the company's regulated demand-side management and load management programs.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE ANY OTHER REGULATORY AGENCIES?

A. Yes. I have presented testimony on several occasions before the Indiana Utility Regulatory Commission, the North Carolina Utilities Commission, and the Public Utilities Commission of Ohio.

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

A. My testimony presents and explains Duke Energy Kentucky's long-term energy and demand forecast prepared in 2005 and utilized in the Company's rate case filing. This includes a discussion of the level of normal weather utilized in the preparation of the forecast. In addition, I describe Duke Energy Kentucky's current and historical regulated DSM and load management programs and review how these programs help Duke Energy Kentucky meet its energy and peak demand requirements. I sponsor Filing Requirement ("FR") 10(9)(h)(5). I also discuss certain information that I supplied to Mr. Davey for his use in preparing the forecasted financial data.

II. LOAD FORECAST

Q. DID YOU PARTICIPATE IN THE PREPARATION OF THE COMPANY'S 2005 LOAD FORECAST?

A. Yes, I did.

Q. HOW IS DUKE ENERGY KENTUCKY'S LOAD FORECAST DEVELOPED?

A. Generally speaking, the Load Forecast is developed in three steps: first, a service area economic forecast is obtained; next, an energy forecast is prepared; and finally, using the energy forecast, summer and winter peak demand forecasts are developed.

The forecast methodology is essentially the same as that presented in past Integrated Resource Plans filed with the Kentucky Public Service Commission ("Commission"). The only difference would be that the models have been updated to include more recent data.

Q. PLEASE DESCRIBE HOW THE SERVICE AREA ECONOMIC FORECAST IS OBTAINED.

A. The economic forecast for Northern Kentucky and the Greater Cincinnati region is obtained from Moody's Economy.com, a nationally recognized economic forecasting firm. Based upon its forecast of the national economy, Moody's Economy.com prepares a forecast of key economic concepts specific to the greater Cincinnati area, including Northern Kentucky. This forecast provides detailed projections of employment, income, wages, industrial production, inflation, prices, and population. This information serves as input into the energy forecast models.

The Duke Energy Kentucky service area is located in Northern Kentucky adjacent to the city of Cincinnati which is contained within the service area of Duke Energy Ohio, another subsidiary of Duke Energy. The economy of

Northern Kentucky is contained within the Cincinnati Primary Metropolitan Statistical Area ("PMSA") and is an integral part of the regional economy.

Q. HOW IS THE ENERGY FORECAST DEVELOPED?

A. The energy forecast projects the load required to serve Duke Energy Kentucky's retail customer classes - residential, commercial, industrial, government or other public authority ("OPA"), and street lighting. The projected energy requirements for Duke Energy Kentucky's retail electric customers are determined through econometric analysis. Econometric models are a means of representing economic behavior through the use of statistical methods, such as regression analysis.

Q. WHAT ARE THE PRIMARY FACTORS AFFECTING ENERGY USAGE?

A. Some of the major factors are the number of residential customers, weather, and economic activity measures such as employment, industrial production, income and price. For the residential sector, the key factors are real per capita income, real energy price, weather, appliance saturations, and appliance efficiencies. For the commercial and governmental sectors, the key factors include the weather, employment, and real energy prices. In the industrial sector, the key factors include industrial production, real energy prices, and the weather. Finally, for the street lighting sector, the key factors include the number of residential customers and the saturation of new efficient lighting.

Generally, energy use increases with higher industrial and commercial activity along with the increased saturation of residential appliances, including space heating and cooling equipment. As energy prices increase, energy usage tends to decrease due to customers' conservation activities.

Q. ARE THESE FACTORS RECOGNIZED IN THE EQUATIONS USED TO PROJECT THE ENERGY REQUIREMENTS OF DUKE ENERGY KENTUCKY'S RETAIL CUSTOMERS?

A. Yes, they are. By including these variables in the forecasting process, we can project future energy consumption based on forecasts of these economic and weather factors.

Q. HOW IS THE FORECAST OF ENERGY REQUIREMENTS FOR DUKE ENERGY KENTUCKY'S RETAIL CUSTOMERS PREPARED?

A. The Duke Energy Kentucky forecast of energy requirements is included within the overall forecast of energy requirements for the Greater Cincinnati and Northern Kentucky region. The Duke Energy Kentucky sales forecast is developed by allocating percentages of the total regional forecast for each customer group. These percentages provide Duke Energy Kentucky forecasts for sales to the residential, commercial, industrial, government or OPA, and street lighting sectors. Forecasts are also prepared for three minor categories: interdepartmental use (Gas Department), Company (Duke Energy Kentucky) use, and losses. In a similar fashion, the Duke Energy Kentucky peak load forecast is developed by allocating a share from the regional total. Historical percentages and judgment are used to develop the allocations of sales and peak demands.

Q. ARE THERE ANY ADJUSTMENTS MADE TO THE ALLOCATED FORECASTS DERIVED FROM THE ECONOMETRIC MODELS?

A. The Company may adjust the forecast for anticipated increases in load due to a major new customer or a significant expansion at a current customer's site.

However, for the 2005 Load Forecast there were no adjustments for new customer loads or expansion at a current customer's site.

Q. PLEASE EXPLAIN HOW THE PEAK FORECASTS ARE DEVELOPED.

A. The Company projects both a winter and a summer peak for the total region using econometric equations where peak demand is a function of economic growth, as measured by energy sales, and several key weather factors. As previously discussed, the Duke Energy Kentucky peak load forecast is developed by allocating a share from the regional total.

For the summer peak, the weather factors are temperature and humidity around the time of the peak, the morning low temperature, and the high temperature for the day before the peak. For the winter peak, the weather factors are the temperature and wind speed around the time of the peak, and the low temperature from the evening before when the peak occurs in the morning. If the winter peak occurs in the evening, the morning low temperature for the day is used instead of the evening low from the day before.

The set of key weather factors were determined through an analysis of the effects of weather on energy demand. The weather conditions used to forecast the summer peak are 93.4° Fahrenheit with a relative humidity of 50.2% on the day of the peak, a morning low temperature of 72.3° Fahrenheit on the day of the peak, and a high temperature of 92.9° Fahrenheit on the day before the peak.

Q. DOES DUKE ENERGY KENTUCKY'S ENERGY AND PEAK LOAD FORECAST ALREADY INCLUDE THE IMPACT OF HISTORICAL DSM PROGRAMS?

A. Yes, the impact of the historical DSM programs that have been implemented in the Duke Energy Kentucky service area are already reflected in these forecasts. The historical data used to develop the 2005 Load Forecast incorporate the historical impact of those existing programs.

Q. DOES DUKE ENERGY KENTUCKY'S LOAD FORECAST INCLUDE THE IMPACT FROM THE INSTALLATION OF ADDITIONAL MEASURES THROUGH ONGOING DSM PROGRAMS?

A. No. Incremental DSM peak load reductions due to current and future programs are not reflected in the historical data used to create the 2005 Load Forecast. The projected incremental impact of existing programs through the end of the current Commission approved time horizon (2006 through 2009) is an additional reduction of almost 38 million kWh and 17 MW. The load forecast provided here does not reflect those projected energy efficiency impacts, though they would be incorporated into an IRP.

Q. ARE THERE OTHER PEAK LOAD REDUCTIONS THAT ARE NOT INCLUDED IN DUKE ENERGY KENTUCKY'S LOAD FORECAST?

A. Yes. The load forecast has not been reduced for the impact of load reductions due to the Company's special contract interruptible customers. Rather, the load forecast portrays the level of expected internal peak demand. Currently, the expected summer peak load reduction from the only interruptible customer is estimated to be 2 to 3 MW.

In addition, the peak load reduction attributable to the PowerShare® CallOption program is not included in Duke Energy Kentucky's load forecast.

Currently, no customers have signed up to participate in the PowerShare® CallOption program. However, under the PowerShare® QuoteOption program, 54 customers have signed up with a potential for a 10 MW demand reduction. In 2005, on the peak day, this program provided 9 MW of load reduction.

Finally, Duke Energy Kentucky's load forecast has not been reduced for peak load reductions attributable to the Real-Time Pricing ("RTP") program. The expected load reduction is 2 MW. These two programs are discussed later in my testimony.

Q. IS DUKE ENERGY KENTUCKY'S LOAD FORECASTING METHODOLOGY SIMILAR TO THAT EMPLOYED PRIOR TO THE CREATION OF DUKE ENERGY IN 2006?

A. Yes, the econometric forecasting methodology used to create the 2005 Load Forecast is basically the same as that used by the Company prior to the merger.

Q. ARE YOU FAMILIAR WITH OTHER ELECTRIC UTILITIES' LONG-TERM LOAD FORECASTS?

A. Yes, I am.

Q. ARE THE FACTORS THAT ARE USED BY DUKE ENERGY KENTUCKY IN FORMULATING ITS LOAD FORECASTS SIMILAR TO THE FACTORS USED BY OTHER UTILITIES IN THEIR LOAD FORECASTS?

A. Yes. While other utilities might use a variety of load forecasting approaches, such as econometric, end-use, trend analysis, or time series analysis, nearly all of the utilities I am familiar with use the same factors considered by Duke Energy

Kentucky, to varying degrees. These commonly used factors include: population, weather data, income forecasts, industrial production measures, employment, and price information. In addition, price forecasts for alternate fuels including natural gas and fuel oil are used as well.

Q. HOW DOES MANAGEMENT JUDGMENT FIT INTO THE LOAD FORECASTS?

A. Under any approach to load forecasting, judgment is an essential element. Each utility must use the approach that, in its judgment, best suits its particular situation, taking into account the various factors.

Q. PLEASE DESCRIBE ATTACHMENT RGS-1.

A. Attachment RGS-1 is a summary of Duke Energy Kentucky's energy and peak load forecast. The projected rate of growth in total retail sales for the five-year period 2006 to 2011 is 0.86 % and for the ten-year period 2006 to 2016 is 0.81 % per year.

Q. DID YOU PROVIDE THIS LOAD FORECAST TO DUKE ENERGY KENTUCKY WITNESSES JETT AND SWEZ?

A. Yes. I provided the load forecast to Mr. Jett and Mr. Swez for their calculation of forecasted transmission charges.

III. <u>DEGREE DAY DATA USED IN THE FORECAST</u>

Q. HOW IS WEATHER MEASURED FOR PURPOSES OF THE ELECTRIC FORECAST?

A. Weather is expressed in terms of Heating Degree Days and Cooling Degree Days.

Q. WHAT IS A HEATING DEGREE DAY AND A COOLING DEGREE DAY?

A. A Heating Degree Day (HDD) is calculated using a base temperature measured on the Fahrenheit scale and occurs when the daily average temperature is below the base. HDD measure the difference of the daily average temperature and the base temperature. The formula is:

Heating Degree Days = Base Temperature – Daily Average Temperature

A Cooling Degree Day (CDD) is also calculated using a base temperature measured on the Fahrenheit scale. However, it occurs when the daily average temperature is above the base. CDD measure the difference of the daily average temperature and the base temperature. The formula is:

Cooling Degree Days = Daily Average Temperature – Base Temperature

Q. PLEASE EXPLAIN "NORMAL" WEATHER.

A. The electric forecast projects Duke Energy Kentucky's electric sales for the test period. In order to project this, one must make a judgment about the weather conditions expected to occur during the test period. This is known as "normal" weather. The electric forecast is based on such expected weather conditions.

Q. DOES THE NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION (NOAA) PROVIDE NORMAL WEATHER DATA FOR DUKE ENERGY KENTUCKY'S SERVICE AREA?

A. Yes. NOAA is responsible for monitoring climate conditions in the United States. Additional information about NOAA is available at their web site at www.noaa.gov. The standard time period prescribed by the United Nations

World Meteorological Organization for measuring climate conditions is 30 years, and NOAA updates its calculations for the United States for these 30-year periods at the end of each decade. The most current 30-year period used by NOAA is 1971-2000. NOAA's next 30-year normal weather period will be 1981-2010.

NOAA provides estimates of "normal" HDD and CDD using daily measurements obtained from the weather station located at the Northern Kentucky and Greater Cincinnati International Airport. These data are provided on a daily, monthly and annual basis. Attachment RGS-2 provides the NOAA normal degree days for Covington, Kentucky, based upon the 30-year period from 1971 through 2000.

Q. WHAT ARE THE NOAA ANNUAL NORMAL CDD AND HDD FOR COVINGTON, KENTUCKY, FOR 1960 THROUGH 1990 AND FOR 1971 THROUGH 2000?

A. The NOAA normal annual level of HDD for the years 1961 through 1990 is 5,248. The annual level of HDD for the years 1971 through 2000 is 5,148. The annual level of NOAA normal CDD for the years 1961 through 1990 is 996. The annual level of NOAA normal CDD for the years 1971 through 2000 is 1,064.

Q. DID YOU USE NOAA WEATHER NORMALS TO PREPARE THE ELECTRIC FORECAST?

A. No. After initially consulting the normal weather data prepared by NOAA, in particular, the 30-year normal level of degree days, and comparing them to more recent actual NOAA weather data, it makes better sense from a forecasting perspective to use a more recent period as the basis for estimating a normal level of degree days. I ultimately determined that it would be more appropriate to use NOAA weather data for a recent 10-year period to prepare the electric forecast.

Q. WHY DID YOU USE 10-YEAR WEATHER NORMALS INSTEAD OF NOAA WEATHER NORMALS FOR THE FORECAST?

A. Importantly, the "normal" weather used in the forecast must be representative of current weather trends. Experience during the past several years indicates that the NOAA normal level based on 1961 through 1990 and the level based on 1971 through 2000 are not representative of current weather for the Duke Energy Kentucky service area, especially for HDD. There is evidence of a long-term downward trend in HDD. Also, during the past several years, actual HDD were well below the NOAA 30-year normal HDD levels. Therefore, I have to conclude that the 30-year level normal HDD was no longer representative as an estimate of the weather useful for producing a forecast. I concluded that it would be reasonable to forecast Duke Energy Kentucky's sales for the test period using normal HDD derived from the actual weather experienced over a recent 10-year period.

Q. WHAT ANNUAL LEVEL OF NORMAL DEGREE DAYS DID YOU USE FOR THE FORECASTS?

A. I used 5,018 HDD and 1,048 CDD as the basis of normal weather in developing the forecast. This is derived using weather data from a ten-year period ending 2004. In my opinion, this measure of normal weather more accurately represents reasonable weather conditions for forecasting purposes, as compared to the

NOAA 30-year normal level of degree days based on the years 1961 through 1990 or the years 1971 through 2000.

Q. WHAT HAS BEEN THE LONG-TERM TREND IN HDD AND CDD FOR COVINGTON, KENTUCKY?

A. For the years 1971 through 2005, the 30-year average of HDD for Covington, Kentucky, has experienced a significant downward trend. The graph at Attachment RGS-3 provides visual evidence of this trend, as well as trend lines for 25-year and 10-year averages. In Duke Energy Kentucky's most recent natural gas rate case, the Commission ruled that a twenty-five year average should be used to establish the level of normal weather for HDD. As a result, Attachment RGS-3 also provides the trend in the 25-year average for HDD.

The declining trend in HDD is also evidenced by the fact that the NOAA normal level of heating degree days based on the 30-year period from 1971 through 2000 is lower than the one based on 1961 through 1990 (5,148 vs. 5,248). Interestingly, the 25 year average, as utilized by the Kentucky Public Service Commission in the Company's recent natural gas rate case, has recently trended sharply down and is very close to the ten-year average.

For CDD, the 10-year average is very close to the NOAA 30-year normal (1,048 vs. 1,064). The graph at Attachment RGS-4, page 1 of 2 provides a visual comparison of the current 30-year NOAA normal CDD with the 10-year and 25-year averages. The level of historical CDD shows a downward trend based upon the 10-year averages, but the 25-year average does not show an apparent upward or downward trend. The graph at Attachment RGS-4, page 2 of 2 provides a clearer visual comparison of the current 30-year NOAA normal CDD with the 10-year average, indicating how close the current 10-year average is to the NOAA level of normal degree days.

Q. WHAT HAS BEEN THE TREND IN HDD AND CDD FOR COVINGTON, KENTUCKY, OVER THE LAST TEN YEARS?

A. For the years 1995 through 2004, the trend in HDD for Covington, Kentucky, has continued slightly downward, as can be seen from the graph at Attachment RGS-5. For CDD, there is also a slight trend downward as can be seen from the graph at Attachment RGS-6.

Q. HOW DO THE ACTUAL ANNUAL HDD AND CDD FOR THE LAST TEN YEARS FOR COVINGTON, KENTUCKY, COMPARE TO 30-YEAR NORMALS?

A. For 1995 through 2004, Duke Energy experienced five out of ten years where actual annual HDD were below the 30-year normal HDD level of 5,148. In fact for five of the last seven years, actual HDD have fallen below the NOAA normal level. See Attachment RGS-7. This illustrates that over the last seven years, the NOAA heating degree day normal is too high.

For 1995 through 2004, Duke Energy experienced six out of ten years where actual annual CDD were below the 30-year normal CDD level of 1,064. See Attachment RGS-7. While CDD have been low more years in the last ten than above, there has not been a consistent pattern as with HDD.

Q. HOW DO THE ACTUAL ANNUAL HDD AND CDD FOR THE LAST TEN YEARS FOR COVINGTON, KENTUCKY, COMPARE TO THE 25-YEAR NORMALS RECENTLY USED BY THE COMMISSION?

A. For 1995 through 2004, Duke Energy experienced five years where actual annual HDD were below and five years above the 25-year normal HDD level of 5,047. See Attachment RGS-8. This is consistent with the recent trend that shows the 25-year average approximating the ten-year average.

For 1995 through 2004, Duke Energy experienced six out of ten years where actual annual CDD were below the 25-year normal CDD level of 1,099. See Attachment RGS-8. Use of a 25-year average for CDD does not provide a better estimate of CDD than the NOAA normal.

Q. HOW DO THE ACTUAL ANNUAL HDD AND CDD FOR THE LAST TEN YEARS FOR COVINGTON, KENTUCKY COMPARE TO THE 10-YEAR NORMALS USED FOR THE FORECAST?

A. For 1995 through 2004, Duke Energy Kentucky experienced five out of the ten years where actual annual HDD were below the 10-year normal of 5,018 and five out of ten years where actual annual HDD were above the 10-year normal of 5,018, an even distribution around the normal as one would expect, as shown in Attachment RGS-8. For 1995 through 2004, Duke Energy Kentucky experienced six out of the ten years where actual annual CDD were below the 10-year normal of 1,048 and four out of ten years where actual annual CDD were above the 10-year normal of 1,048, a near even distribution around the normal as shown in Attachment RGS-8.

Q. DID YOU MEASURE HOW RELIABLE THE 30-YEAR AND 25-YEAR WEATHER NORMALS ARE?

A. Yes. One way to compare the relationship between the expected normal level of degree days to the actual number of degree days is to use a statistic known as the Mean Percent Error (MPE). MPE indicates whether the measure of normal degree days contains any bias to over-estimate or under-estimate the actual weather conditions. If MPE is positive, this indicates that there is a bias for the measure of normal to be higher than the actual. The formula to calculate MPE is the sum of (Normal Degree Days minus Actual Degree Days) divided by Actual Degree Days. The sum is then divided by the number of observations. Mathematically:

$$\text{MPE} = \frac{1}{\text{N}}\sum_{t=1}^{N}\frac{\hat{Y}_t - Y_t}{Y_t}$$

Where $\hat{Y}$ = Normal Annual Degree Days

and Y = Actual Annual Degree Days

I calculated the MPE for the years 1995 through 2004 comparing actual HDD to the NOAA 30-year normal degree days for the period from 1971 through 2000. The results show that the MPE is 3.2%. The MPE calculations show that using the 30-year normal period results in a bias such that the NOAA level of normal HDD will over-estimate the number of actual HDD as shown on Exhibit RGS-7.

I also calculated the MPE for CDD for the years 1995 through 2004 comparing actual CDD to the NOAA 30-year normal degree days for the period from 1971 through 2000. The results show that the MPE is 4.4%. The MPE calculations show that using the 30-year normal period results in a bias such that the NOAA level of normal CDD will over-estimate the number of actual CDD.

Q. DID YOU CALCULATE THE MPE FOR THE 25-YEAR AVERAGES OF DEGREE DAYS AND FOR THE 10-YEAR WEATHER NORMALS USED FOR THE FORECAST?

A. Yes. First, the MPE for HDD calculated for the years 1995 through 2004 comparing actual degree days to the 25-year average HDD results in an MPE of 1.1%. For CDD, the MPE is 7.8%.

Second, the MPE for HDD calculated for the years 1995 through 2004 comparing actual degree days to the 10-year average HDD used as normal for the forecast results in an MPE of 0.5%. For CDD, the MPE is 2.8%.

These results indicate that the 10-year estimate of normal degree days more closely predicted actual HDD and CDD for the years 1995 through 2004 than either the NOAA normal or the 25-five year average.

Q. DID YOU BASE YOUR DECISION TO USE 10-YEAR WEATHER NORMALS ON ANY OTHER INFORMATION?

A. Yes. Research studies have noted that shorter-term weather normal periods are more accurate predictors than 30-year periods. One is an article published in the Journal of Applied Meteorology, December 1981, Vol. 20, No. 12 entitled *On the "Best" Temperature and Precipitation Normals: The Illinois Situation* by Peter J. Lamb and Stanley A. Changnon, Jr. It is provided in Attachment RGS-9. This study arose from an inquiry by the Illinois Commerce Commission concerning the use of climatic normal in annual rate increase applications by utility companies. The authors conclude:

> Ten year normals were also found to have a high probability of being the best predictors ..., whereas, 20-year normals have a particularly low probability of such success. The standard 30-year normals were likewise found to perform poorly in this regard.

I also based my opinion on a white paper at Attachment RGS-10 entitled: "Government Development Of National Climate Products and Service" by Thomas R. Karl and James D. Laver of NOAA. This paper was delivered at the Weather, Climate, and Energy Policy Forum, October 16-17, 2001, in Washington D. C. The forum was sponsored by the American Meteorological Society (AMS) Atmospheric Policy Program in collaboration with the University of Oklahoma. In this paper, the authors discuss the weather-related needs of the energy industry in terms of products and services provided by NOAA. The authors state:

> During the past five years the energy industry has petitioned NOAA to develop more appropriate heating and cooling degree day normals. Climate Normals at the NOAA have traditionally been calculated retrospectively every ten years based on the previous 30-year period of record, *e.g.*, 1951-80, 1961-90, 1971-2000, but are often applied prospectively. Many in the energy sector use Normals to prospectively determine multi-year as well as seasonal energy requirements and operating conditions. Engineers and business decision planners have made it quite clear that the present method of providing climate normals is inadequate to support the Nation's economic competitiveness and financial decision making needs. The American Engineering Society and the American Society of Heating, Refrigeration, and

> Air Conditioning for Engineers (ASHRAE) have indicated that changes in climate are to the point where the typical 30-year Normals can no longer adequately support the planning horizons for national standards. The industry has asked that normals be available on a variety of time scales, generated dynamically, rapidly accessible, and updated on a regular basis using the most current data.
>
> * * *
>
> NOAA will overhaul the current traditional methods and procedures used to compute Normals. It will deliver the means to generate a variety of next-generation Climate Normals, such as heating and cooling degree days, freezing degree days, and other related statistics deemed important to the energy community. The normals will be calculated on a variety of time scales, *i.e.,* hourly, daily, weekly, monthly, seasonally, annually, yearly, one or more decades, *etc.* This work is expected to produce products over the next two years to enable users to generate heating and cooling degree day and other normals on demand for any reference period with appropriate data corrections. Experimental products are already developed for temperature, but more algorithms will be developed to allow for users to dynamically create tailored Normals via a Web interface. NOAA expects to provide the capability to readily combine probabilistic information with climate model scenarios of future climate for use with on-demand next-generation normals. The outcome will provide more appropriate statistics for planning purposes.

Thus, NOAA itself is encouraging organizations to use periods other than 30-year normals where other periods appear to be better predictors of the weather that will be in effect during the time period under consideration. In the present case, assuming that Duke Energy Kentucky's rates will be in effect for a period of perhaps three to five years, it would be reasonable to use 10-year weather normals for preparing the electric forecast.

IV. DUKE ENERGY KENTUCKY'S DSM / LOAD MANAGEMENT PROGRAMS

Q. PLEASE BRIEFLY DESCRIBE THE HISTORY OF DUKE ENERGY KENTUCKY'S DSM PROGRAMS.

A. On December 1, 1995, the Commission issued an Order approving the Duke Energy Kentucky and Kentucky DSM Collaborative's application for a demand-side management plan. The DSM plan was comprised of twelve programs: six for residential customers and six for commercial and industrial customers. The residential DSM programs focused on weatherization of low-income dwellings, direct load control of air conditioners, energy efficiency audits, and incentives for installation of more energy-efficient equipment. The non-residential programs provided energy audits and incentives for the installation of more energy-efficient equipment.

Over time, the content and structure of the DSM plan changed. With the apparent advent of deregulation in the region, the economic viability of DSM programs came into question. In addition, the commercial and industrial customer classes chose to end their involvement with DSM programs, partly due to the advent of deregulation and also due to a preference to rely on the marketplace for purchase of energy-efficient technologies rather than relying on a utility program. As a result of all these factors, the non-residential DSM programs were dropped and the residential program was scaled down.

The reduced set of DSM programs was approved by the Commission in an Order dated December 17, 2002, in Case No. 2002-00358, based upon an application by Duke Energy Kentucky and the Northern Kentucky Community Action Commission, on behalf of Duke Energy Kentucky's DSM Collaborative. The DSM Collaborative included the Office of the Attorney General, People Working Cooperatively, League of Women Voters, Brighton Center, Northern Kentucky Legal Aid, Kentucky NEED Project, Home Builders Association of Northern Kentucky, Campbell County Fiscal Court, United Way, Boone County Fiscal Court, and the Kentucky Division of Energy. The approved DSM programs were as follows:

- Residential Conservation and Energy Education

  Leverages state weatherization funding by reimbursing community agencies for the installation of measures that reduce energy consumed in the homes of income qualified customers. Replacement of inefficient refrigerators with Energy Star refrigerators was added to this program.

- Residential Home Energy House Call

  Offers energy audits to residential customers, provides an energy efficiency kit, and provides an opportunity to purchase energy conservation measures.

- Residential Comprehensive Energy Education

  This program promotes energy efficiency education in schools through training of teachers and through workshops for teachers and students. It was upgraded to provide energy efficiency measures to the students for installation at their homes.

- Energy Education and Bill Assistance Program (pilot).

  Provides energy efficiency and budget counseling to a limited number of income qualified customers, leverages the weatherization component of the Residential Conservation and Energy Education program above, and provides direct bill payment assistance to help participants gain control of their energy bills.

Since the Commission's Order in 2002, Duke Energy Kentucky with the involvement and support of the Residential DSM Collaborative and a newly created Commercial and Industrial Collaborative filed an application with the Commission to expand the level of effort on DSM programs. The Commission, in an Order dated February 14, 2005, in Case No. 2004-00389, approved the expansion of the DSM effort.

In addition to the previously described programs, the following programs were added to the set of DSM programs offered to customers:

- Power Manager

  The purpose of the Power Manager program is to reduce demand by controlling residential air conditioning usage during peak demand conditions in the summer months. The program is offered to residential customers with central air conditioning.

- Energy Star Products

The Energy Star Products program provides market incentives and market support through retailers to build market share and usage of Energy Star products. Special incentives to buyers and in-store support stimulate demand for the products and make it easier for store participation. The program provides incentives to customers for the purchase of compact fluorescent light bulbs and torchiere lamps.

- Energy Efficiency Web Site

  Energy Zone™ is Duke Energy Kentucky's enhanced energy efficiency web site. It provides customers with the most advanced programs, tools, and measures available to manage their energy and achieve load impacts. The website features a multi-tiered design providing the consumer the opportunity to receive quick customized energy tips and, if they choose, the ability to complete an online audit and receive ten (10) self-install energy efficiency measures.

- High Efficiency Incentive (Small to Medium Commercial & Industrial)

  Under this program, the Company provides incentives to small commercial and industrial customers to install high efficiency equipment in applications involving new construction, retrofit, and replacement of failed equipment. These incentives apply to numerous limited motor, lighting and cooling equipment types as well as additional process technologies.

Q. WHAT HAS BEEN THE IMPACT OF THE COMPANY'S DSM PROGRAMS?

A. Through 2005, the Company's DSM programs are estimated to have reached an annual savings level of over 9,000 MWh and reduced the summer peak load by 2.5 MW. Adding in the expected impact of the direct load control program brings the peak reduction total to 10 MW.

Q. PLEASE DESCRIBE THE COST-EFFECTIVENESS TEST EMPLOYED BY DUKE ENERGY KENTUCKY FOR SCREENING ITS DSM PROGRAMS.

A. Duke Energy Kentucky considers the cost-effectiveness of DSM programs when making decisions about their inclusion in the DSM agreements. The tests used are the Utility Cost Test (UCT), the Total Resource Cost Test (TRC), the Ratepayer Impact Measure Test (RIM), and the Participants Test. The UCT compares the cost (to the utility) to implement the programs with the savings (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. The TRC test compares the benefits to the utility (avoided costs) and to participants (reduced energy bills) against the cost to the utility to implement the program and the cost to participants to be involved in the program. The RIM test examines the benefits and costs to ratepayers in terms of impact on rates from implementation of the program. And the Participants Test compares the benefit to the consumer (bill reduction) against the costs to the consumer of participating in the program.

Q. PLEASE DESCRIBE HOW DUKE ENERGY KENTUCKY RECOVERS ITS DSM PROGRAM COSTS.

A. Since 1996, Duke Energy Kentucky has used the DSM Riders to recover the direct costs associated with its regulated DSM programs. In this way, Duke Energy Kentucky's customers are only charged for the costs that are actually incurred to deliver Duke Energy Kentucky's DSM programs. The rider is based on Duke Energy Kentucky's forecasted (budget) costs. Duke Energy Kentucky reconciles the rider on an annual basis and flows back any dollars that were not spent.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S CURRENT LOAD MANAGEMENT PROGRAMS.

A. Duke Energy Kentucky offers an array of voluntary customer programs designed to affect customer demand for electricity. In addition to the traditional DSM programs, Duke Energy Kentucky offers the market-based PowerShare® program and a Real-Time Pricing program. A major objective of these programs is to reduce customer demand on Duke Energy Kentucky's system at time of peak, thus helping to reduce the need to build additional generating units to serve the peak load. The DLC program, previously described, also represents an important component of Duke Energy Kentucky's load management program effort.

Q. WHAT IS THE POWERSHARE PROGRAM?

A. The PowerShare® program is offered under Duke Energy Kentucky's Rider PLM – Peak Load Management Program. This program was implemented in January 2000, following in the footsteps of a 1990's predecessor, Energy Call Options Program. The PowerShare® program is currently a market-based program that provides financial incentives in the form of bill credits to our industrial and commercial customers to reduce their electric demand during Duke Energy Kentucky's peak load times. Customers may choose to participate in either CallOption or QuoteOption.

Q. PLEASE DESCRIBE THE CALLOPTION COMPONENT OF POWERSHARE®.

A. CallOption requires customers to commit to a pre-selected load reduction, based on historic or usual demand, at a selected strike price. The strike price is selected by the customer based upon the customer's willingness and ability to comply with the call for load reduction. In return for this commitment to reduce load when called, CallOption customers receive a monthly premium payment from Duke Energy Kentucky as a credit to their bill. In addition, when customers are called to reduce load, they receive an energy credit. Our standard CallOption product may be exercised by Duke Energy Kentucky when the next day's market prices are projected to be greater than the customer's selected strike price. Duke Energy Kentucky can call the option by notifying customers by 3:00 p.m. (EST) the day ahead. The level of incentive depends upon the selected parameters: the contracted option load, the strike price, the selected duration (number of hours), the selected period (time of day) of call, and the maximum number of calls. The term of the standard CallOption program agreement is four months – June through September – with "built-in" limitations on the number of occurrences / hours the CallOption can be invoked during the time period. We have also added a year round option for customers with distributed generation that provides for higher premiums in exchange for a twelve-month term, shorter notification time and more available hours. The target market for the CallOption program includes customers with the ability to either consistently reduce load or run on-site generation to offset their normal usage. Currently, no customers have signed up to participate in the program.

Q. PLEASE DESCRIBE THE QUOTEOPTION COMPONENT OF POWERSHARE®.

A. QuoteOption allows a customer to elect whether or not to reduce its load when called upon by Duke Energy Kentucky when prices reach a minimum price. No monthly premium is paid to QuoteOption customers since they may elect not to respond when called, but an energy credit is paid for load reductions made in response to Duke Energy Kentucky's calls. Because customers have the right to elect whether or not to respond to a call, the QuoteOption essentially offers customers a no risk proposition. This election feature does give Duke Energy Kentucky less control over, and certainty of, load reductions; however, it also provides us with load reductions from a group of customers that might not participate if they had to contractually commit to mandatory load reductions.

Q. PLEASE BRIEFLY DESCRIBE HOW QUOTEOPTION LOAD REDUCTIONS ARE REPRESENTED IN DUKE ENERGY KENTUCKY'S IRP.

A. Since this is an elective program without contractual commitment, the QuoteOption load reduction is currently not represented in Duke Energy Kentucky's IRP. The program is, however, used as a hedge against the effects of extreme weather.

Q. HAS THE POWERSHARE® PROGRAM EVER BEEN USED TO REDUCE LOAD?

A. Yes. The program was activated seven times this past summer: seven CallOption events and two QuoteOption events. Under the QuoteOption program, we requested customers to provide voluntary load reductions. On July 25, 2005, Duke Midwest QuoteOption participants reduced loads by 75 MW. The Duke Energy Kentucky QuoteOption participants reduced their load by 9 MW. On July 26, 2005, total QuoteOption participants reduced load 64 MW, of which 7 MW came from Duke Energy Kentucky participants. Duke Energy Kentucky did not provide any of the CallOption load reductions.

On February 26, 2003, we experienced our first QuoteOption event. Duke Energy Kentucky customers provided approximately 1 MW of load reduction per hour. This event occurred on a non-peak winter day during the evening period with very little advance notice to our customers. Nevertheless, we obtained a fairly significant amount of load reduction at a fairly moderate price.

Overall, we are very pleased with how the process and our backroom systems have performed and especially with how our customers participated and provided load reductions.

Q. WHY HAS THE LEVEL OF THE POWERSHARE® CALLOPTION LOAD REDUCTION DIMINISHED?

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

Duke Energy®

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John J. Finnigan, Jr.
Associate General Counsel

VIA OVERNIGHT DELIVERY

RECEIVED
JUL 1 9 2006
PUBLIC SERVICE COMMISSION

July 18, 2006

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

Re: In the Matter of an Adjustment of the electric Rates of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc.
Case No. 2006-00172

Dear Ms. O'Donnell:

I am writing to correct a missing page (page 31) from the testimony of Richard G. Stevie that was inadvertently omitted from volume 14 of our May 31, 2006 filing in the above-referenced case. Enclosed is an original and ten copies for the filing.

I apologize for this inconvenience. Thank you for your consideration in this matter.

Very truly yours,

John Finnigan

John J. Finnigan, Jr.
Associate General Counsel

JJF/sew
cc: Hon. Dennis G. Howard (w/encl.)
Hon. Elizabeth E. Blackford (w/encl.)
Hon. David G. Boehm (w/encl.)
Hon. Michael L. Kurtz (w/encl.)

market. Because market prices are highly variable, customer credits have varied dramatically from year to year. In 2000 and 2001, customer credits were relatively high and these credits produced excellent customer participation. However, volatility in market prices has at times resulted in relatively low credits for customers that have the ability to curtail load. These low credits drastically reduced participation in the PowerShare® program. So, while the PowerShare® program has great potential value to Duke Energy Kentucky in providing needed capacity, it has been valued less by customers because of market-based credits could be low. This has discouraged customers willingness to invest in the equipment necessary to take advantage of the PowerShare® program.

Q. PLEASE DESCRIBE THE RTP PROGRAM.

A. Duke Energy Kentucky's RTP program (Rate RTP – Experimental Real Time Pricing Program) consists of a two-part rate: an access charge for the customer's historic load that is billed at standard tariff rates (commonly referred to as the "CBL"); and an energy charge for the customer's incremental or decremental energy usage that is billed at a real time price. Once customers receive information on the next day hourly prices, they can adjust their energy usage to either increase loads during low price times and/or decrease usage during high priced times. Currently, the Duke Energy Kentucky customer accounts that participate in RTP provide an expected peak load reduction of about 2 MWs.

Q. WHAT IS THE LOAD IMPACT OF DUKE ENERGY KENTUCKY'S LOAD MANAGEMENT PROGRAMS?

A. The load impact from the RTP program is projected to be 2 MW. Including the expected 3 MW reduction from the interruptible rate raises the total load management capability to approximately 5 MW for the 2006 summer peak. Then, adding in the potential impact of the Direct Load Control program raises the load management capability to just over 12 MW.

Q. WILL THE IMPLEMENTATION OF ADVANCED METERING INFRASTRUCTURE ("AMI") EXPAND THE CAPBILITY TO PROVIDE DEMAND-SIDE MANAGEMENT AND DEMAND RESPONSE PROGRAMS?

A. Yes, the deployment of AMI will expand our capability to offer DSM and demand response programs to the mass market. AMI would provide the capability to expand the control of appliances beyond just air-conditioners that are currently controlled through the Power Manager program. In addition, the cost of operating the program would be reduced, because we would be able to determine if the load reductions are being obtained without having to physically check the equipment. This also provides an improvement to reliability. Finally, while customer acceptance of expanded programs is unknown at this time, we expect that customers would prefer to have more options to help control their energy usage.

V. FILING REQUIREMENTS AND INFORMATION SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 10(9)(H)(5).

A. FR 10(9)(H)(5) consists of the load forecast, which I described earlier in my testimony.

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

A. Yes, I supplied Mr. Davey with the gas Mcf and electric kWh sales 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.

VI. CONCLUSION

Q. WERE FR 10(9)(H)(5), THE INFORMATION YOU PROVIDED TO MR. DAVEY, AND ATTACHMENTS RGS-1 THROOUGH RGS-10 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, Dr. Richard G. Stevie, being duly sworn, deposes and says that 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.

Dr. Richard G. Stevie, Affiant

Subscribed and sworn to before me by Dr. Richard G. Stevie on this 24th day of May, 2006.

NOTARY PUBLIC

My Commission Expires:

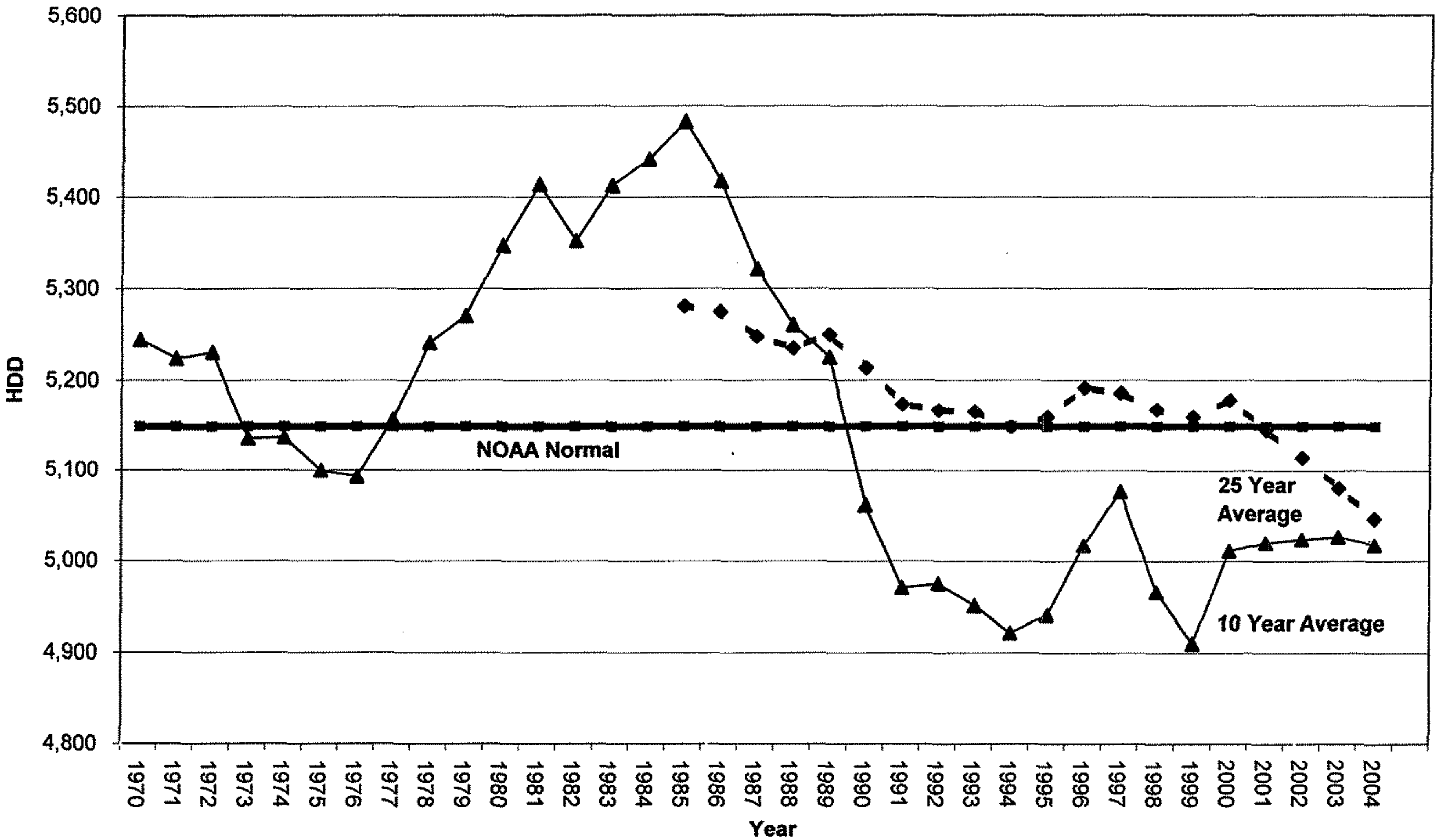
NOTARY PUBLIC STATE OF OHIO

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

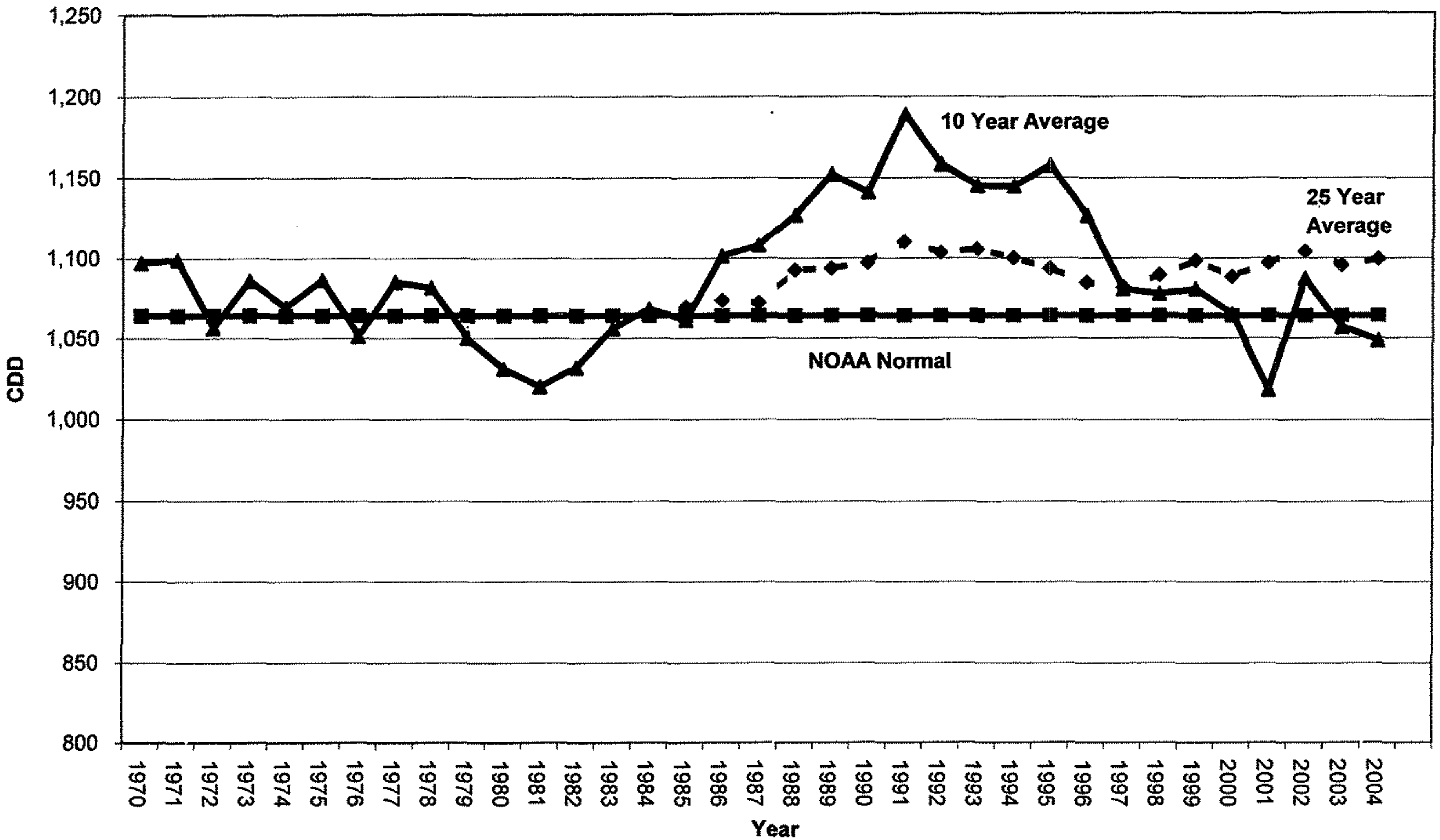
Duke Kentucky Sales (MWH) and Summer Peak (MW) Load History and Forecast								
Year	Residential	Commercial	Industrial	Governmental	Street Lighting	Total Retail Sales	Summer Peak	
1990	982,172	687,797	685,440	250,031	13,270	2,619,580		Actual History
1991	1,075,245	726,577	666,654	263,733	13,625	2,746,745		Actual History
1992	992,927	730,225	770,431	264,164	13,914	2,772,567		Actual History
1993	1,087,831	770,012	800,406	298,474	14,190	2,972,060		Actual History
1994	1,094,862	818,526	860,298	298,037	14,578	3,087,551		Actual History
1995	1,151,799	862,235	902,983	335,518	15,018	3,268,544		Actual History
1996	1,185,677	897,093	951,181	344,704	15,144	3,394,533		Actual History
1997	1,158,180	918,822	973,852	343,290	15,725	3,410,494		Actual History
1998	1,217,326	974,915	1,047,913	346,919	15,713	3,603,488		Actual History
1999	1,254,643	1,042,927	966,516	354,417	16,764	3,636,143		Actual History
2000	1,259,784	1,161,743	1,030,210	316,288	18,029	3,787,815		Actual History
2001	1,297,467	1,297,651	880,519	291,605	17,163	3,787,184		Actual History
2002	1,403,524	1,317,653	770,872	292,335	19,493	3,806,246		Actual History
2003	1,342,581	1,296,517	765,922	298,148	19,020	3,724,506		Actual History
2004	1,371,604	1,329,565	768,023	301,477	18,742	3,791,055		Actual History
2005	1,481,111	1,373,341	785,636	310,815	18,776	3,972,230		Actual History
2005	1,406,750	1,355,866	780,390	305,513	18,776	3,869,846		Actual Weather Normalized
2006	1,482,404	1,367,143	777,640	302,477	20,326	3,952,087	901	Forecast
2007	1,498,689	1,393,715	785,887	305,503	20,587	4,006,495	912	Forecast
2008	1,510,630	1,404,244	788,056	306,083	20,780	4,031,923	919	Forecast
2009	1,522,051	1,414,867	792,254	306,579	20,958	4,058,855	926	Forecast
2010	1,534,805	1,430,846	795,274	307,232	21,152	4,091,472	934	Forecast
2011	1,548,469	1,447,275	797,801	308,183	21,353	4,125,261	942	Forecast
2012	1,559,879	1,463,100	800,282	308,556	21,518	4,155,532	950	Forecast
2013	1,570,966	1,477,971	802,626	308,576	21,670	4,184,024	957	Forecast
2014	1,583,917	1,492,749	805,475	309,082	21,845	4,215,302	965	Forecast
2015	1,596,925	1,509,250	807,994	309,580	22,021	4,248,020	973	Forecast
2016	1,610,848	1,525,972	811,398	309,953	22,188	4,282,626	981	Forecast
Annual Growth Rates								
00 to 05	3.29%	3.40%	-5.28%	-0.35%	0.82%	1.0%		
06 to 11	0.88%	1.15%	0.51%	0.37%	0.99%	0.86%		
06 to 16	0.83%	1.11%	0.43%	0.24%	0.88%	0.81%		

Historical Data			Average Levels of Degree Days									
				Heating Degree Days					Cooling Degree Days			
Year	HDD	CDD	Year	10 Year	25 Year	30 Year	NOAA Normal	Year	10 Year	25 Year	30 Year	NOAA Normal
1961	5,025	1,118										
1962	5,404	1,339										
1963	5,741	750										
1964	4,944	1,068										
1965	5,077	988										
1966	5,589	1,175										
1967	5,064	895										
1968	5,184	1,103										
1969	5,377	1,162										
1970	5,037	1,373	1970	5,244			5,148	1970	1,097			1,064
1971	4,819	1,137	1971	5,224			5,148	1971	1,099			1,064
1972	5,474	912	1972	5,231			5,148	1972	1,056			1,064
1973	4,784	1,046	1973	5,135			5,148	1973	1,086			1,064
1974	4,953	900	1974	5,136			5,148	1974	1,069			1,064
1975	4,713	1,161	1975	5,099			5,148	1975	1,086			1,064
1976	5,522	822	1976	5,093			5,148	1976	1,051			1,064
1977	5,699	1,234	1977	5,156			5,148	1977	1,085			1,064
1978	6,031	1,070	1978	5,241			5,148	1978	1,082			1,064
1979	5,670	845	1979	5,270			5,148	1979	1,050			1,064
1980	5,805	1,183	1980	5,347			5,148	1980	1,031			1,064
1981	5,486	1,026	1981	5,414			5,148	1981	1,020			1,064
1982	4,854	1,031	1982	5,352			5,148	1982	1,032			1,064
1983	5,392	1,285	1983	5,413			5,148	1983	1,056			1,064
1984	5,239	1,027	1984	5,441			5,148	1984	1,068			1,064
1985	5,126	1,087	1985	5,482	5,280		5,148	1985	1,061	1,069		1,064
1986	4,867	1,225	1986	5,417	5,274		5,148	1986	1,101	1,074		1,064
1987	4,745	1,300	1987	5,322	5,248		5,148	1987	1,108	1,072		1,064
1988	5,418	1,260	1988	5,260	5,235		5,148	1988	1,127	1,093		1,064
1989	5,316	1,096	1989	5,225	5,250		5,148	1989	1,152	1,094		1,064
1990	4,171	1,070	1990	5,061	5,213	5,218	5,148	1990	1,141	1,097	1,090	1,064
1991	4,581	1,504	1991	4,971	5,173	5,203	5,148	1991	1,189	1,110	1,102	1,064
1992	4,898	725	1992	4,975	5,166	5,186	5,148	1992	1,158	1,103	1,082	1,064
1993	5,152	1,156	1993	4,951	5,165	5,166	5,148	1993	1,145	1,105	1,096	1,064
1994	4,939	1,023	1994	4,921	5,148	5,166	5,148	1994	1,145	1,100	1,094	1,064
1995	5,321	1,213	1995	4,941	5,159	5,174	5,148	1995	1,157	1,094	1,102	1,064
1996	5,632	920	1996	5,017	5,192	5,176	5,148	1996	1,127	1,085	1,093	1,064
1997	5,330	842	1997	5,076	5,186	5,185	5,148	1997	1,081	1,082	1,091	1,064
1998	4,322	1,230	1998	4,966	5,167	5,156	5,148	1998	1,078	1,089	1,096	1,064
1999	4,750	1,125	1999	4,910	5,159	5,135	5,148	1999	1,081	1,098	1,094	1,064
2000	5,187	914	2000	5,011	5,178	5,140	5,148	2000	1,065	1,089	1,079	1,064
2001	4,672	1,033	2001	5,020	5,144	5,135	5,148	2001	1,018	1,097	1,076	1,064
2002	4,938	1,417	2002	5,024	5,114	5,117	5,148	2002	1,087	1,104	1,092	1,064
2003	5,180	849	2003	5,027	5,080	5,130	5,148	2003	1,057	1,095	1,086	1,064
2004	4,847	941	2004	5,018	5,047	5,127	5,148	2004	1,048	1,099	1,087	1,064

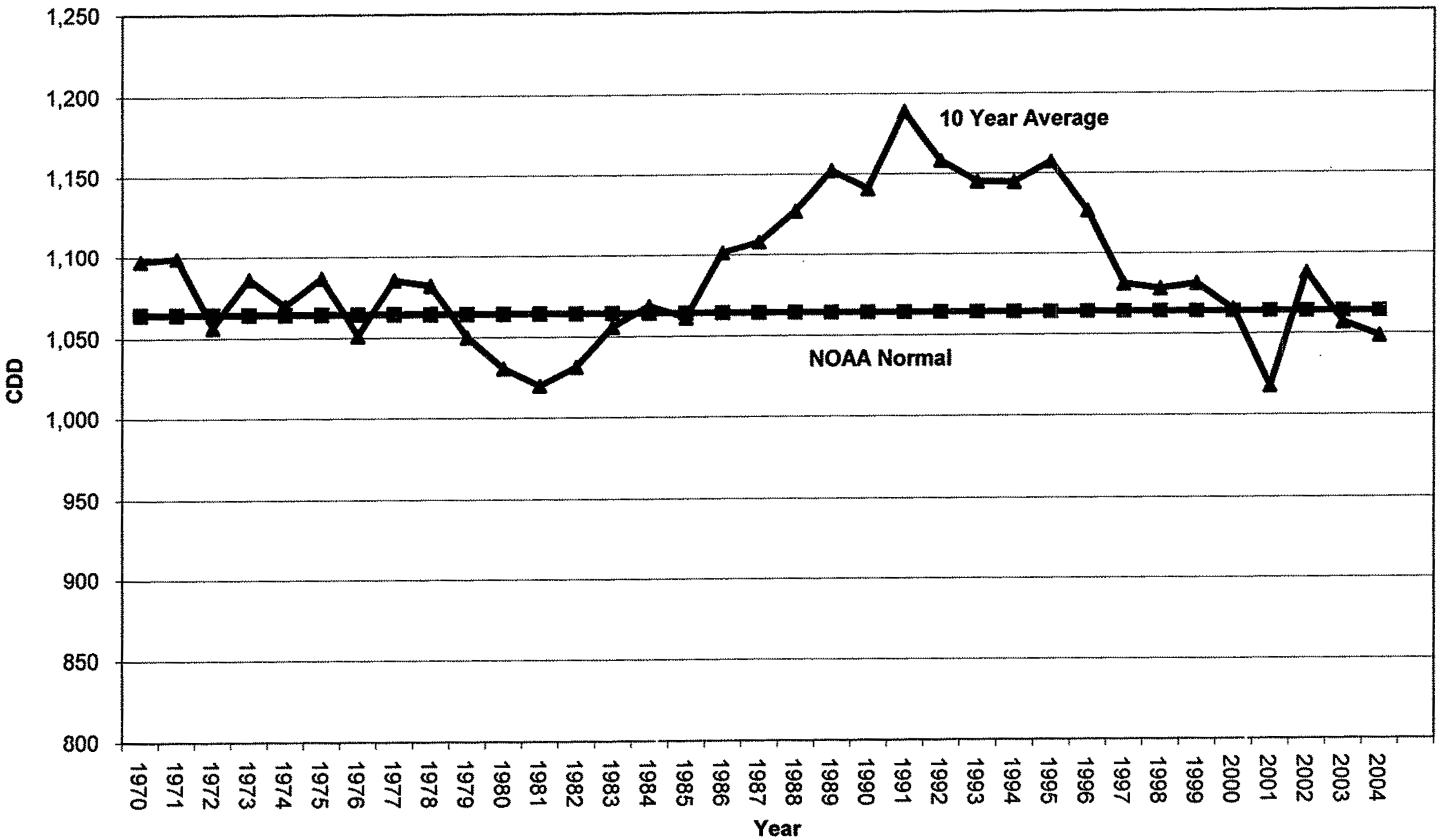
Heating Degree Days
Comparison of 10 Year and 25 Year Averages to NOAA Normal



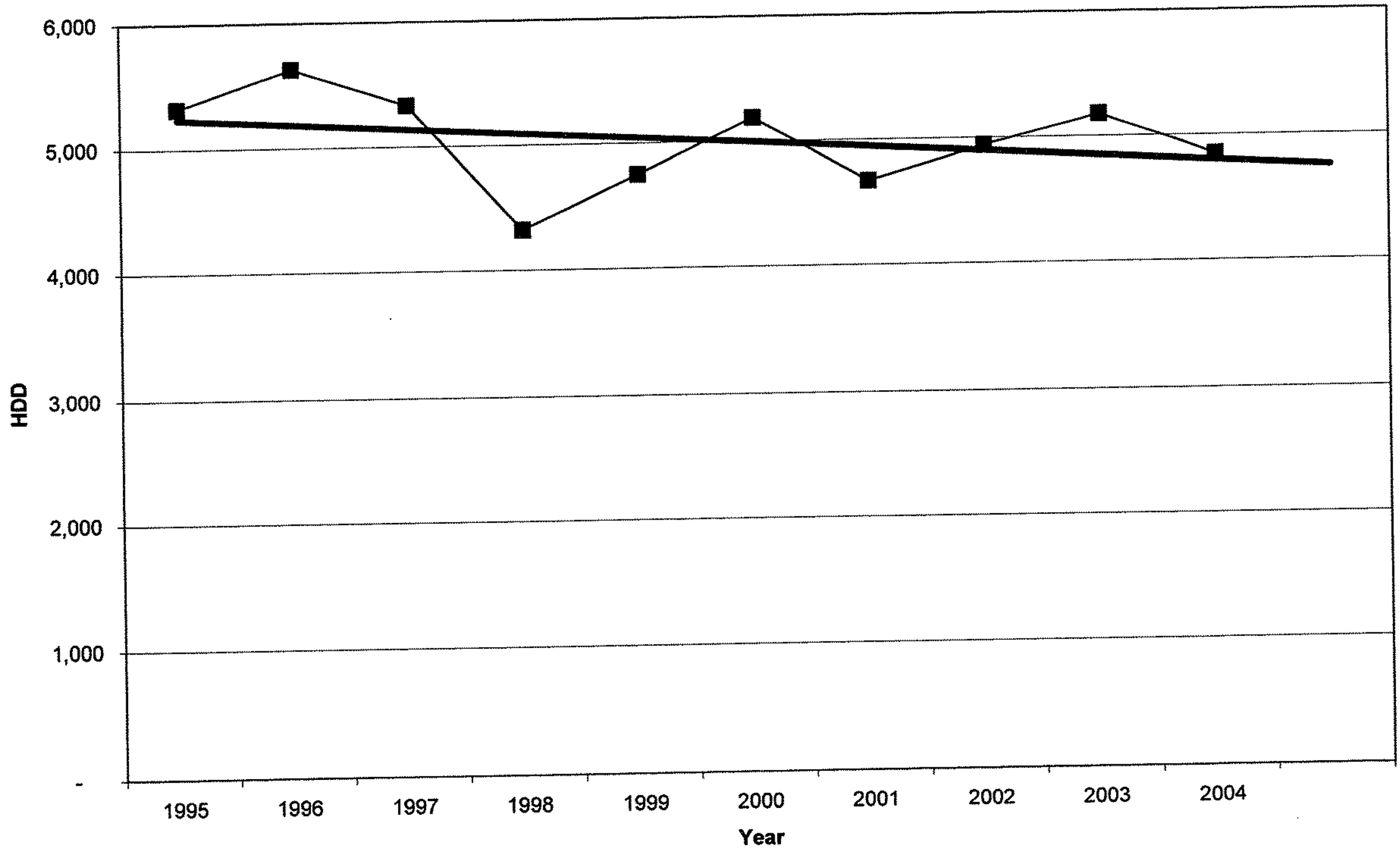
Cooling Degree Days
Comparison of 10 Year and 25 Year Averages to NOAA Normal



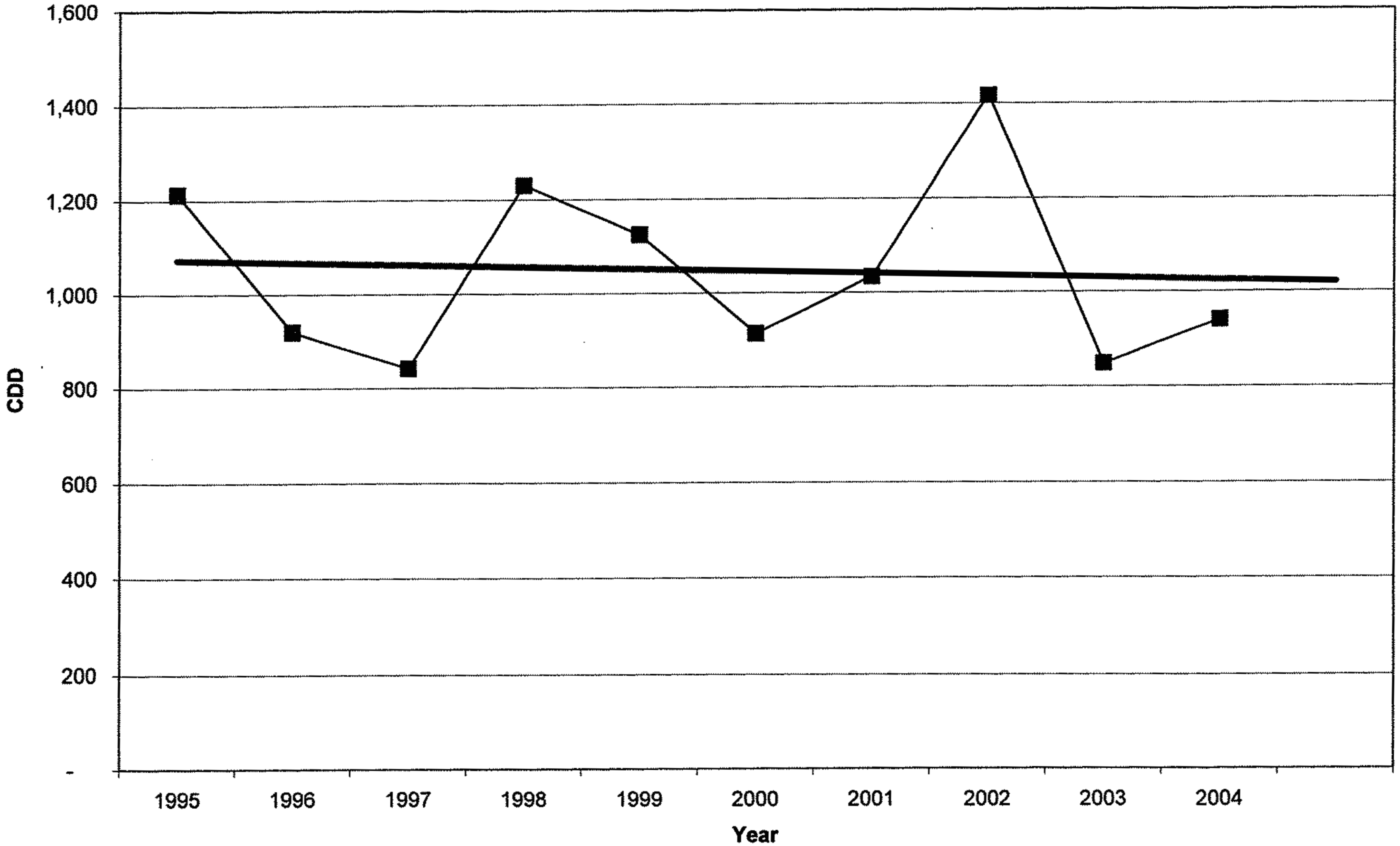
Cooling Degree Days
Comparison of 10 Year Average to NOAA Normal



HDD Trend: 1995 to 2004



CDD Trend: 1995 to 2004



Comparison of Actual HDD and CDD to NOAA Normal Levels: 1995 To 2004

Year	HDD	NOAA Normal	Actual Above NOAA	Actual Below NOAA	MPE	Year	CDD	NOAA Normal	Actual Above NOAA	Actual Below NOAA	MPE
1995	5,321	5,148	Above		-3.3%	1995	1,213	1,064	Above		-12.3%
1996	5,632	5,148	Above		-8.6%	1996	920	1,064		Below	15.7%
1997	5,330	5,148	Above		-3.4%	1997	842	1,064		Below	26.4%
1998	4,322	5,148		Below	19.1%	1998	1,230	1,064	Above		-13.5%
1999	4,750	5,148		Below	8.4%	1999	1,125	1,064	Above		-5.4%
2000	5,187	5,148	Above		-0.8%	2000	914	1,064		Below	16.4%
2001	4,672	5,148		Below	10.2%	2001	1,033	1,064		Below	3.0%
2002	4,938	5,148		Below	4.3%	2002	1,417	1,064	Above		-24.9%
2003	5,180	5,148	Above		-0.6%	2003	849	1,064		Below	25.3%
2004	4,847	5,148		Below	6.2%	2004	941	1,064		Below	13.1%
				Mean % Error	3.2%					Mean % Error	4.4%

Comparison of Actual HDD and CDD to 25 Year Average Levels: 1995 To 2004

Year	HDD	25 Year Normal	Actual Above 25 Year	Actual Below 25 Year	MPE	Year	CDD	25 Year Normal	Actual Above 25 Year	Actual Below 25 Year	MPE
1995	5,321	5,047	Above		-5.1%	1995	1,213	1,099	Above		-9.4%
1996	5,632	5,047	Above		-10.4%	1996	920	1,099		Below	19.5%
1997	5,330	5,047	Above		-5.3%	1997	842	1,099		Below	30.5%
1998	4,322	5,047		Below	16.8%	1998	1,230	1,099	Above		-10.7%
1999	4,750	5,047		Below	6.3%	1999	1,125	1,099	Above		-2.3%
2000	5,187	5,047	Above		-2.7%	2000	914	1,099		Below	20.2%
2001	4,672	5,047		Below	8.0%	2001	1,033	1,099		Below	6.4%
2002	4,938	5,047		Below	2.2%	2002	1,417	1,099	Above		-22.4%
2003	5,180	5,047	Above		-2.6%	2003	849	1,099		Below	29.4%
2004	4,847	5,047		Below	4.1%	2004	941	1,099		Below	16.8%
				Mean % Error	1.1%					Mean % Error	7.8%

Comparison of Actual HDD and CDD to 10 Year Average Levels: 1995 To 2004

Year	HDD	10 Year Normal	Actual Above 10 Year	Actual Below 10 Year	MPE	Year	CDD	10 Year Normal	Actual Above 10 Year	Actual Below 10 Year	MPE
1995	5,321	5,018	Above		-5.7%	1995	1,213	1,048	Above		-13.6%
1996	5,632	5,018	Above		-10.9%	1996	920	1,048		Below	13.9%
1997	5,330	5,018	Above		-5.9%	1997	842	1,048		Below	24.5%
1998	4,322	5,018		Below	16.1%	1998	1,230	1,048	Above		-14.8%
1999	4,750	5,018		Below	5.6%	1999	1,125	1,048	Above		-6.8%
2000	5,187	5,018	Above		-3.3%	2000	914	1,048		Below	14.7%
2001	4,672	5,018		Below	7.4%	2001	1,033	1,048		Below	1.5%
2002	4,938	5,018		Below	1.6%	2002	1,417	1,048	Above		-26.0%
2003	5,180	5,018	Above		-3.1%	2003	849	1,048		Below	23.4%
2004	4,847	5,018		Below	3.5%	2004	941	1,048		Below	11.4%
				Mean % Error	0.5%					Mean % Error	2.8%

VOL. 20, NO. 12 JOURNAL OF APPLIED METEOROLOGY DECEMBER 1981

On the "Best" Temperature and Precipitation Normals: The Illinois Situation

PETER J. LAMB AND STANLEY A. CHANGNON, JR.

Illinois State Water Survey, Champaign 61820

(Manuscript received 18 July 1980, in final form 11 May 1981)

ABSTRACT

Historical (1901–79) temperature and precipitation data for four Illinois stations were used to determine the frequency with which summer and winter averages for periods of various length (i.e., different climatic normals) are closest to the value for the next year, and hence its best predictor. The normal achieving the highest frequency in this regard is considered the best for characterizing the recent climate for a given point in time and assessing the abnormality of the following year.

Normals for 5, 10, 15, 20 and 25 years were investigated, along with the 30-year ones generally used. Five-year normals most frequently provided the closest estimate of the next year's value for both parameters in both seasons. Ten-year normals also have a high probability of being the best predictors, whereas 20-year normals have a particularly low probability of such success. The standard 30-year normals also perform poorly in this regard. These results contrast strongly with earlier suggestions that 15–25 year normals are "optimum" for prediction because they possess the minimum extrapolation variance when normals are employed as predictors. This difference between the two sets of results indicated that 5-year normals tend to possess larger prediction errors when they are not the best predictors, than do other normals on the greater number of occasions they are not the best predictors. The present findings were used by the Illinois Commerce Commission in evaluating weather normalization rate adjustments proposed by utility companies in 1979–80.

An investigation also is made into the nature of the climatic variation occurring when each normal is the best predictor. Five-year normals tend to attain this position for precipitation when the difference from the preceding year and the departures from longer-term averages are all moderate-to-small. When 5-year normals are the best temperature predictors, in contrast, the departures from this normal (and hence prediction errors) are very large. The frequency with which various normals were the best predictors shows no marked temporal variation during the study period.

1. Introduction

a. Background

Presently there is no firm physical basis for predicting climate. However, since economic planning and evaluation often require assumptions about future climate, alternative methods of climatic prognosis need to be investigated and the most skillful ones implemented. In this regard, there is a growing consensus that ". . . predictions of climatic variability . . . will, for the foreseeable future, be probabilistic statements based largely on the statistics of past records" (Mason 1979). For instance, research which will allow this potentially beneficial use of existing climatic information is emerging as a high priority of the U.S. National Climate Plan (National Academy of Sciences, 1980, pp. 2–3). The present study uses an interesting situation to serve as a contribution to this developing research area.

Seasonal averages of Illinois historical temperature and precipitation data are computed for moving periods of various numbers of years. These are considered to form sets of different climatic "normals" (Huschke, 1970, p. 394) that are identified by their base period length, and whose values were recomputed at yearly intervals. The basic objective is to determine the frequency with which each normal is closest to the value for the next year, and hence its best predictor. The normal achieving the highest frequency in this regard is the one most likely to minimize the departure characteristic of the year immediately following those from which it is calculated. Such a climatic normal therefore may be the most appropriate for a given point in time and the year ahead.

b. History of normals

At their introduction more than a century ago, climatic normals ". . . were considered to approximate the 'true' (stable) climate which . . . (although) . . . subject to . . . random variations from year to year . . . (was regarded as) . . . essentially invariant over the centuries" (Court, 1967–68, Part I, pp. 3–4). The longest available record was accordingly believed to provide the best normal. This principle was followed in the construction of U.S. temperature and precipitation normals until the mid-

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1950's (U.S. Weather Bureau, 1958). The first nationwide sets, issued for first-order stations in 1907, were for either 1873–1905 (temperature) or the entire record (precipitation). Their adjustment in the 1920's was largely limited to extending the base periods forward to that time. A more pronounced change occurred in the mid-1950's, with the adoption of 30-year (1921–50) temperature and precipitation normals by first-order stations (U.S. Weather Bureau, 1958) and interim 1931–55 normals by cooperative substations (U.S. Weather Bureau, 1955). The latter had previously used 1900–44 normals. Commencing in the early 1960's, the U.S. Weather Bureau adopted 30-year temperature and precipitation normals for all stations. They are computed from the data for the preceding three decades (i.e., initially 1931–60, superceded by 1941–70 in the early 1970's, and soon to be replaced by 1951–80).

This change to a moving 30-year base period conformed to a WMO recommendation aimed at reducing the influence of varying observation practices and natural climatic fluctuations on computed normals (Court, 1967–68, Part I, p. 6). It prompted Court (1967–68, Part I, pp. 5, 8) to suggest that a primary application of climatic normals now lay in the prediction of future values, and that predictive accuracy and constitutes an appropriate empirical evaluation of normals. Many users of normals treat them as the best prediction of the future, and in turn adopt them as references for the evaluation of recent weather and their pre-event decisions.

c. *Motivation for present study*

The present study is, in essence, an investigation into the predictive capability of various climatic normals. It arose from an inquiry by the Illinois Commerce Commission (ICC) about the use of normals in adjudicating rate increase applications by power companies. Decisions on rate increases are considerably affected by the degree of climatic abnormality experienced during immediately preceding years. There has been a growing tendency for Illinois utility companies to seek rate increases each year. This has increasingly necessitated an annual judgement by the ICC about the normal that best characterizes the recent climate, and hence is most appropriate for assessing the abnormality of the previous year and the preparedness of utility companies for unusual weather. This user situation reflects but one of many needs to express the climatic value most "likely" to characterize a given year.

The present research was initiated when it became apparent that the standard meteorological practice of using 30-year temperature and precipitation normals might not be the best in the foregoing contexts. Normals for 5, 10, 15, 20 and 25 years are therefore considered here, in addition to 30-year ones. This number and range of normals were believed adequate to address the broad issues identified above. Using a somewhat different criterion to that adopted in the present work, earlier studies intimated that 15–25 year normals may be better predictors for the following year than 30-year normals (e.g., Lenhard and Baum, 1954; Beaumont, 1957; Enger, 1959; Craddock and Grimmer, 1960; Court, 1967–68). Our study also examines the nature of the climatic variability occurring when each of the above normals provides the best estimate of the following season's mean value, something not previously attempted.

2. Data and methods

This study utilized data from four Illinois cooperative substations (Aurora, Urbana, Mount Vernon, Anna) aligned along a 500 km north–south axis. Their locations are depicted in Changnon (1979) and coordinates appear in Table 1. They were chosen because of their situation in each of the state's four major latitude zones, their similar elevation (~200 m), and their high-quality records (Changnon, 1979).

Basic data processing involved several steps. First, individual winter (December–February) and summer (June–August) seasonal mean temperatures and seasonal precipitation totals were computed from summer 1901 through winter 1978–79. This utilized daily maximum and minimum temperatures and daily precipitation totals. Second, the above four sets of data for individual seasons were then each converted into six time series of "running means". For an original time series of n entries X_i, running mean time series containing $(n - k + 1)$ k-year averages $\bar{X}_{k,i}$ are given by

$$\bar{X}_{k,i} = \frac{1}{k} \sum_{j=0}^{k-1} X_{i+j} \qquad (1)$$

The values of k used here were 5, 10, 15, 20, 25 and 30 years. Finally, the individual values in each running mean time series (e.g., the 1943–52 average) were then subtracted from the actual value for the year immediately following the end of their averaging period (1953 in the above example). The resulting time series of $(n - k)$ temperature or precipitation differences $\Delta X_{k,i}$, given by

$$\Delta X_{k,i} = \left[X_{i+k} - \frac{1}{k} \sum_{j=0}^{k-1} X_{i+j} \right], \qquad (2)$$

provided a range of measures of the abnormality of individual seasons. They are, in effect, time series of anomalies with respect to different reference periods. Furthermore, they also constitute expressions of the accuracy attained by the various normals in predicting the next season's mean value, as is shown below. The comparative analysis of these time series for the period summer 1931 through winter 1978–79

TABLE 1. Number of times during summer 1931 through winter 1978–79 that different climatic normals were closest to the actual value for the immediately following individual season. Values include a count for more than one normal if a tie occurred.

Climatic normal (years)	Aurora (41°45'N, 88°21'W)		Urbana (40°06'N, 88°14'W)		Mt. Vernon (38°21'N, 88°52'W)		Anna (37°28'N, 89°14'W)		All-station total	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
					Mean temperature					
5	13*	19*	15*	16*	16*	16*	15*	16*	59*	67*
10	9	6	12	7	9	12	12	12	42	37
15	9	15	9	8	9	5	8	10	35	38
20	9	8	6	12	8	10	4	9	27	39
25	9	7	6	7	10	7	6	9	31	30
30	12	8	7	11	8	7	7	5	34	31
					Total precipitation					
5	10	20*	14*	11*	10	17*	11*	14*	45*	62*
10	11*	7	6	9	12*	6	8	9	37	31
15	6	4	6	10	5	3	9	8	26	25
20	8	4	9	4	7	6	4	6	28	20
25	7	7	9	7	5	4	8	3	29	21
30	7	7	6	7	9	13	8	11	30	38

* Largest value in each column.

forms the basis of this paper. Summer 1931 was the earliest season during 1901–78/79 for which averages were available for all six of the specified preceding periods.

The previous investigations of the predictive accuracy of climatic normals referred to above were based on the evaluation of the "extrapolation variance" S_k^2 (Court, 1967–68, Part I, pp. 9–10), which resulted, where

$$S_k^2 = \frac{1}{(n-k)} \sum_{i=k}^{n-k} \left[X_{i+k} - \frac{1}{k} \sum_{j=0}^{k-1} X_{i+j} \right]^2. \quad (3)$$

Symbols are as defined earlier. It is readily apparent that S_k is simply the average of the squares of the prediction errors specified by Eq. (2), with S_k accordingly being the "standard error of extrapolation." The "mean prediction error" (Q_k) is obtained by taking the absolute value of the difference in Eq. (3), rather than its square. Previous research concentrated on identifying the value of k for which S_k^2 (or S_k^2) or Q_k was smallest. This "implicitly . . . was assumed to indicate the optimum length of record (i.e., normal) for prediction" (Court, 1967–68, Part I, p. 10). For comparative purposes, this study also will evaluate Eq. (3) for X_{i+k} values starting with summer 1931.

3. Predictive success of different climatic normals

Table 1 documents the frequency with which different climatic normals provide the closest (or closest equal) estimate of the next year's seasonal mean temperature and total precipitation in Illinois. In the notation of Eq. (2), the normal(s) providing the closest such estimate for a particular year is/are denoted by the value of k giving the minimum $|\Delta_{k,i}|$. This information is believed to provide the best *user* indication of the predictive success of various normals in cases where annual evaluations are required, more so than the relative values of the time-averaged S_k^2, S_k and Q_k indices employed in earlier studies (see Table 2 and later discussion). The outstanding feature of Table 1 is that 5-year normals are more likely to be closest to the actual value of the next year's seasonal mean temperature than normals computed for longer preceding periods. This characterizes all four stations for both winter and summer. Furthermore, for half of the cases studied, the second-shortest normal (10 years) has the second highest probability of being closest to the next year's seasonal mean temperature (Table 1). In contrast, 20-year normals are the least likely to provide the best estimate of the average temperature of the following winter. A further conspicuous temperature result is the poor performance of the standard 30-year normals in the foregoing context, particularly for the southern stations of Mount Vernon and Anna.

The precipitation results in Table 1 are generally quite similar to those for temperature. In six of the eight cases considered, 5-year normals most frequently provided the closest estimate of the next year's total seasonal precipitation. Ten-year normals attained this position in the two remaining instances, but only by a small margin over 5-year normals. Precipitation results in Table 1 also suggest that 20-

TABLE 2. Values of the extrapolation variance, S_k^2, resulting from the use of different climatic normals as predictors of the next season's actual value. Predictions were made for the period summer 1931 through winter 1978–79.

Climatic normal (years)	Aurora		Urbana		Mt. Vernon		Anna		All-station average	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
					Mean temperature (°C²)					
5	4.52	0.85	4.23	1.01	4.15	0.94*	3.58	1.12	4.12	0.98
10	4.18	0.91	4.01	1.03	4.02*	1.04	3.36*	1.20	3.89	1.05
15	4.02	0.81*	4.10	1.01	4.09	1.08	3.45	1.05	3.92	0.99
20	3.85*	0.82	3.94*	0.96*	4.03	1.14	3.36*	0.95	3.80*	0.97*
25	4.08	0.82	4.08	0.99	4.14	1.15	3.41	0.94*	3.93	0.98
30	4.24	0.88	4.10	1.08	4.27	1.18	3.56	1.00	4.04	1.04
					Total precipitation (mm²)					
5	4187	7684	6606	8000	10568	9419	14839	11619	9050	9181
10	3581	7142	5690	7355	8884	9084	13510	9903	7916	8371
15	3503	6832	5463	7116	8664	8400	13458	9994	7773	8098
20	3361	6716	5594	6942	8316	8252	12974	9284	7561	7799
25	3239*	6548*	5000*	6884*	8065*	8168	12684*	9432	7247*	7758
30	3335	6574	5135	6824*	8161	7968*	12729	9168*	7340	7649*

* Smallest values in each column.

year normals have a particularly low probability of being the best predictor of the seasonal total for the next year. The standard 30-year normals again performed poorly in this regard, though this was not as pronounced for southern Illinois as in the temperature case.

Table 2 gives the extrapolation variance S_k^2, as specified by Eq. (3), resulting from the use of each climatic normal as the predictor of the next year's seasonal mean temperature and total precipitation. As already noted, the S_k^2 statistic constituted the basis of previous investigations of the predictive accuracy of climatic normals. It therefore is evaluated here for comparative purposes. The general pattern evident in Table 2, particularly for temperature, is largely consistent with that obtained in the earlier studies. S_k^2 tends to decrease as the normal lengthens from 5 to 20 years (temperature) or 25 years (precipitation), and then increases as the normal extends to 30 years. Since the normal with the smallest S_k^2 was previously assumed to be optimum for prediction, the foregoing pattern gave rise to the earlier suggestion that *15–25 year normals may be better predictors than the standard 30-year normals*. Furthermore, it evidently precluded serious consideration of the predictive utility of very short normals. Table 2 also contains pronounced spatial variations and winter-summer contrasts which illustrate some interesting dimensions of the Illinois climate. However, they are outside the scope of the present paper.

As the above discussion suggests, the results in Tables 1 and 2 possess striking contrasts. In particular, the normal most likely to provide the best prediction for an individual season (5 years) tends to be characterized by either the highest or very high S_k^2 values for the overall study period. Furthermore, 10-year normals, which Table 1 shows to also have a high probability of predictive success in many cases, likewise possess high values of S_k^2 (Table 2). The foregoing features are particularly true of precipitation. The criterion being used in the present study to determine the predictive "success" of a climatic normal (frequency of best prediction; Table 1) thus gives a very different verdict on 5- and 10-year normals to the extrapolation variance index (Table 2) employed in earlier work to identify the so-called "optimum" predictive normal. This also is characteristic of the longer normals studied. Those for 15–25 years, previously considered optimum for prediction by virtue of small S_k^2 values such as in Table 2, have a relatively low probability of being closest to the seasonal value for the next year (Table 1). A good example is the 20-year normal/winter temperature case already referred to in the consideration of Table 1. The foregoing discussion indicates that 5-year normals tend to possess larger prediction errors [*see explanation of Eq. (3)*] when they are not the best predictors than do other normals, particularly 20- and 25-years, when they are not the best predictors.

In view of the possibly surprising nature of the foregoing results, it appeared desirable to relate those in Table 1 to the climatic variability experienced during the study period, and also to investigate whether they contain any significant temporal variations. The results are reported in succeeding sections, and yield some further insight into the aforementioned differences between Tables 1 and 2.

TABLE 3. Average anomaly magnitude relative to each normal for the years this normal was the best predictor of the next season's value. Predictions were made for the period summer 1931 through winter 1978–79.

Climatic normal (years)	Aurora		Urbana		Mt. Vernon		Anna		All-station average	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
					Mean temperature (°C)					
5	1.55	0.52	1.33	0.75	1.18	0.65	1.16	0.83	1.31	0.69
10	0.47*	0.46	0.52*	0.31	1.05	0.41	0.77	0.27	0.70	0.36*
15	1.77	0.55	1.30	0.35	0.96	0.29	1.28	0.29	1.33	0.37
20	0.60	0.17*	0.69	0.63	0.38*	0.17*	0.52*	0.74	0.55*	0.43
25	1.27	0.29	0.66	0.22*	0.74	0.40	1.34	0.35	1.00	0.37
30	1.10	0.59	0.88	0.41	1.08	0.69	1.67	0.14*	1.18	0.46
					Total precipitation (mm)					
5	26	32	43	44	60	49	75	43*	51	42
10	15*	49	43	31*	41*	29*	85	45	46	39*
15	61	31*	28	61	44	33	14*	60	37*	46
20	31	85	27*	70	41*	60	100	97	50	78
25	49	38	54	48	78	81	55	130	58	74
30	44	62	54	65	71	67	64	47	58	60

* Smallest values in each column.

4. Climatic abnormality when each normal was best predictor (or predictive accuracy of different climatic normals)

One objective in relating the results of Table 1 to the climatic variability experienced during the study period was to determine the abnormality which tended to prevail when each normal constituted the best predictor. Since the exact quantification of climatic abnormality is dependent on the reference period used in its computation, as was noted in the discussion of Eq. (2), two sets of results were obtained here. First, for the years in which each normal was the best predictor, we calculated the mean anomaly magnitude relative to that normal (Table 3). In the notation of Eq. (2), these results were obtained by averaging, as a function of k, the set of the *smallest* value (or values if a tie occurred) of $|\Delta X_{k,j}|$ for each study year. A more general indication of anomaly size, as independent of reference period as possible, was also obtained for the years each normal constituted the best predictor. This consisted of the mean anomaly magnitude relative to all normals (not shown) or, in the terminology of Section 2, the average $|\Delta X_{k,j}|$ for *all* values of k for the years each normal was the best predictor. Although these averages were of course larger than those in Table 3, both sets of results exhibited remarkably similar general patterns. In view of this, and also because the results in Table 3 have the advantage of indicating the accuracy each normal tended to attain when it was the best predictor [see discussion of Eq. (2)], only Table 3 is presented here. It actually contains values of a variant of the mean prediction error (Q_k) defined in relation to Eq. (3)—in this case they are computed from only those years in which a normal was the best predictor.

A prominent feature of Table 3 is that large temperature anomalies tend to prevail when 5-year normals constitute the best predictors for either season, and also when 15-year normals attain the best predictor position for winter. Much smaller anomalies generally characterize seasons whose mean temperatures are estimated closest by 10- and 20-year normals (winter) and 10–25 year normals (summer). Thirty-year normals tend to be the best predictors when the temperature departures are of intermediate size. Table 3 thus shows that when the best temperature prediction is provided by the normal which does this most frequently (five years, Table 1), the difference between the actual value and that predicted by the normal (i.e., the prediction error) tends to be very large. In contrast, smaller mean errors (Table 3) generally characterize the cases when the best temperature predictions are by the normals which provide this information less frequently. This is particularly true of 20-year normals. Further insight is therefore provided into why the "optimum" predictive normals for temperature suggested by Table 2 and earlier work differ from the most "successful" one identified by Table 1. The foregoing situation also suggests that the present utilization of the "statistics of past records" (Mason, 1979; see Introduction) for seasonal temperature forecasting, the simple form of which was dictated by the particular applied problem at hand, has inherent limitations. These are more pronounced for winter, when the departures are largest, than for summer when temperatures are less anomalous (Table 3).

TABLE 4. Average difference from preceding year for occasions each normal was the best predictor of the next season's value. Predictions were made for the period summer 1931 through winter 1978–79.

Climatic normal (years)	Aurora		Urbana		Mt. Vernon		Anna		All-station average	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
					Mean temperature (°C)					
5	1.94	0.76	1.76	0.92	1.41	0.80	1.64	1.13	1.69	0.90
10	1.66	0.93	1.55	0.73*	2.12	1.13	1.71	1.16	1.76	0.99
15	1.81	0.91	1.80	0.93	1.46	0.64	1.69	0.62*	1.69	0.78*
20	1.03*	0.72*	1.14	0.74	0.95*	0.95	1.43*	0.88	1.14*	0.83
25	1.64	0.82	1.05*	0.96	1.68	0.60*	1.63	1.01	1.50	0.85
30	1.88	1.36	1.46	1.06	1.83	1.21	2.01	0.64	1.80	1.67
					Total precipitation (mm)					
5	50	64*	59*	96	64*	111	85*	73*	65*	86
10	33*	90	77	90	98	49*	149	82	89	78*
15	89	74	72	99	127	96	91	84	95	88
20	54	233	100	106	71	99	187	173	103	153
25	52	88	69	61*	101	195	113	232	84	144
30	85	144	83	145	91	133	86	111	86	133

* Smallest values in each column.

Interestingly, the precipitation results in Table 3 are in considerable contrast to those for temperature. Moderate-to-small precipitation anomalies, and hence prediction errors, tend to occur when the best prediction is provided by the normals which do this most frequently (5 and 10 years, Table 1). This is especially true of summer. In contrast, large anomalies (prediction errors) generally characterize the less frequent seasons whose total precipitation is estimated closest by 20–30 year normals (Table 1). Temperature and precipitation results in Table 3 for 20-year normals are thus in particular contrast. These circumstances suggest that the prediction of Illinois seasonal precipitation using climatic normals may not have the inherent limitations apparent for temperature.

5. Difference from preceding year when each normal was best predictor

The attempt to set the results in Table 1 in the context of the climatic variability experienced during the study period also included relating them to interannual fluctuations. Results are summarized in Table 4, which gives the average difference from the preceding year for the occasions each normal was the best predictor. The general pattern of the precipitation results in Table 4 is very similar to that just described for the anomalies in Table 3. Small changes from the previous year tend to occur when the best prediction is provided by the normals which do this most frequently (5 and 10 years, Table 1). On the other hand, large differences from the preceding year generally prevail on the fewer occasions when seasonal precipitation is estimated closest by 20–30 year normals (Table 1).

Unlike the foregoing precipitation results, those for temperature in Table 4 have a slightly different general pattern to the anomalies in Table 3. The largest changes from the previous year tend to occur when the best temperature predictions are provided by 30-year normals, whereas Table 3 showed such relatively infrequent occasions (Table 1) to be characterized by only intermediate-sized anomalies. In addition, more normals attain the position of best temperature predictor when large interannual changes occur (Table 4) than when large anomalies occur (Table 3). Tables 3 and 4, however, do show that 20-year normals (winter) and 15–25 year normals (summer) are the best temperature predictors when the year-to-year changes and the anomalies are both small.

6. Temporal variation of predictive success of different normals

An investigation also was conducted into whether there was any marked temporal variation during the study period of the frequency with which individual normals provided the best predictor of the following season's value. Since no pronounced trends emerged, the results are not documented here. The occasions when 5-year normals constituted the best predictors were well-distributed across the decades studied, and not excessively concentrated in the 1970's. The frequency with which 30-year normals were the best predictors was highest in the 1950's (precipitation) and 1940's and 1970's (temperature).

7. Applications

Many users of climatic normals do so with the expectation that the published values, now having a

30-year base, provide the best prediction of the next year's conditions. Furthermore, many of these users subsequently evaluate their decision, and the ensuing economic outcomes determined by the actual weather of a given year, against the normal that was built into the decision. A typical comment might be, "last year we assumed the available 30-year normal was the best predictor of this winter. But because the winter was very extreme in comparison with the 30-year normal, we were hurt severely. . . ." Such uses of climatic normals as the best estimator of the next year's seasonal value, and in turn as the evaluator of the annual outcomes in some socioeconomic or environmental context, motivated this investigation of the predictive capability of 5-, 10-, 15-, 20-, 25- and 30-year seasonal temperature and precipitation normals for Illinois.

The present findings are now part of the evidence used by the ICC in evaluating weather normalization rate adjustments proposed by Illinois utility companies.[1] For instance, in late 1979 they were "specifically . . . used to question the value of the National Weather Service's "30-year normal" as a predictive tool for near-future weather when new rates would go into effect," in relation to adjustments proposed by three Northern Illinois utility companies.[1] These proposed adjustments, which ". . . effected revenues by a total of $153 million . . . ," were denied by the ICC.[1] This particular case was prompted by the severe 1978–79 winter, which had the lowest mean temperature this century at Aurora, the second lowest at Urbana and Anna, and the third lowest at Mount Vernon. Table 5 shows that 5-year normals provided the best prediction of this severe event; they were 1–2°C closer to the actual winter mean than the 30-year normal. The abnormality of the 1978–79 winter is thus minimized by reference to the 5-year normal. Since the beginning of 1980, our results have also ". . . been referred to (by the ICC) in rate cases involving utilities in central and southern Illinois."[1]

4. *Summary and conclusions*

This paper has analyzed Illinois historical temperature and precipitation data to determine the frequency with which different climatic normals are closest to the seasonal value for the next year, and hence its best predictor. The normal achieving the highest frequency in this regard also was considered the best for characterizing the recent climate for a given point in time and assessing the abnormality of the next year. Our investigation arose from an inquiry by the Illinois Commerce Commission (ICC) about the use of climatic normals in adjudicating annual rate increase applications by utility companies. It was initiated when it became apparent that

[1] T. L. Griffin, personal communication, 1980.

TABLE 5. Temperature departure (°C) of 1978–79 winter from various normals.

Climatic normal (years)	Aurora	Urbana	Mt. Vernon	Anna
5	−3.78	−3.33	−3.28	−3.17
10	−4.56	−3.94	−4.11	−3.44
15	−4.39	−4.06	−4.39	−3.44
20	−4.22	−3.94	−4.44	−3.50
25	−4.56	−4.33	−4.72	−3.83
30	−4.78	−4.61	−5.06	−4.22
Difference (5 years vs 30 years)	1.00	1.28	1.78	1.05

the standard meteorological practice of using 30-year normals may not be appropriate in the foregoing context.

Normals for 5, 10, 15, 20 and 25 years were considered here, in addition to 30-year ones. Five-year normals were found to most frequently provide the closest estimate of the next year's summer and winter mean temperature and total precipitation. Future research into the predictive utility of climatic normals should therefore ascertain whether 3-, 4-, 6- or 7-year normals perform better in this regard than 5-year ones. This is distinctly possible, and its investigation will require the computation of normals at one-year intervals. Ten-year normals were also found to have a high probability of being the best predictors of the parameters in question, whereas 20-year normals have a particularly low probability of such success. The standard 30-year normals were likewise found to perform poorly in this regard. These results contrast strongly with earlier suggestions that 15–25 year normals are "optimum" for prediction because they possess the minimum extrapolation variance when normals are employed as predictors. This difference between the two sets of results indicated that 5-year normals tend to possess larger prediction errors when they are not the best predictors, than do other normals on the greater number of occasions they are not the best predictors.

An investigation was made into the nature of the climatic variation occurring when each normal is the best predictor. Five-year normals were found to attain this position *for precipitation* when the difference from the preceding year and the departures from longer-term averages all tended to be moderate-to-small. When 5-year normals are the best temperature predictors, in contrast, the departures from this normal (*and hence prediction errors*) are larger than the prediction errors on the less frequent occasions the longer normals are the best predictors. This suggests that the present utilization of the "statistics of past records" (Mason, 1979; see Introduction) for seasonal temperature forecasting has inherent limitations. Since such statistical procedures are now viewed to constitute the only viable immediate basis for the development of climate forecasting schemes, there is an obvious need for long-term physically based research into the predictability of climate. Finally, the frequency with which various normals were the best predictors was found to show no marked temporal variation during the study period.

The general similarity of the results obtained along the entire 500 km north–south Illinois transect suggests that they should be reasonably transferable to other parts of the central United States.

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Government Development of National Climate Products and Services

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1. Energy-related applications of climate

Observations and Data Products Requirements

Climate and weather data and products have been requested by energy-related businesses and industry for use in planning, design and operations. It can be argued that the nation's economic competitiveness is dependent on reliable climate information expected over the lifetime of infrastructure needed to fuel the economy e.g., commercial buildings, residences, power plants, transmission lines, etc. The effective operation of many systems requires historical and real-time information about weather and climate with a high degree of accuracy and reliability. For example, the American Society of Civil Engineers and the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) use historical weather and climate data to develop standards that affect the design of energy producing and consuming systems. These data are calculated retrospectively, but used prospectively over the expected lifetime of the systems. Recently, the American Society of Civil Engineers working with the American Homebuilding Association and NOAA's National Climatic Data Center (NCDC) were responsible for the development of a new home building standard related to the depth and insulation needed to protect buildings from frost damage and loss of heat. The American Homebuilding Association estimates that the newly developed standards have saved $330M annually in energy costs or 586,000 MW hours of energy per year.

Other examples of data requirements relate to the Weather Risk Industry. Contracts between Power Companies and Re-Insurance Companies hedge against unexpected climate and weather. Climate data and products are used both to develop and settle contracts for the efficient distribution of risk, with some estimates suggesting $12 billion of annual contracts. Industry leaders have stated that recent climate variations and extremes and more demanding customer requirements, render much of the climate information they now receive inadequate to support the rapid changes associated with today's national and global business environments. When uncertainty about the data and information cannot be quantified or are unreliable, investors are unwilling to provide the capital necessary to guard against the risk of unusual weather or climate. It has also been clearly expressed by some in the industry that when data sets are not provided in a timely manner, contracts are not settled, and the industry does not operate efficiently.

During the past five years the energy industry has petitioned NOAA to develop more appropriate heating and cooling degree day normals. Climate Normals at the NCDC have traditionally been calculated retrospectively every ten years based on the previous 30-year period of record, e.g., 1951-80, 1961-90, 1971-2000, but are often applied prospectively. Many in the energy sector use Normals to prospectively determine multi-year as well as seasonal energy requirements and operating conditions. Engineers and business decision planners have made it quite clear that the present method of providing climate normals is inadequate to support the Nation's economic competitiveness and financial decision making needs. The American Engineering Society and the American Society of Heating, Refrigeration, and Air Conditioning for Engineers (ASHRAE) have indicated that changes in climate are to the point where the typical 30-year Normals can no longer adequately support the planning horizons for national standards. The industry has asked that normals be available on a variety of time scales, generated dynamically, rapidly accessible, and updated on a regular basis using the most current data.

Reliable data, where it is needed, when it is needed, is another essential component of managing long-term risk. The energy sector has identified significant shortcomings in understanding past trends and climate change over the U.S. and surrounding regions. These shortcomings include inadequate documentation of operations and changes over the life of the network, insufficient overlapping observations when new instruments are installed, and not using well-maintained, calibrated high-quality instruments. This increases the level of uncertainty for government and business decision-makers who are formulating both short term plans and longer range strategic policies and plans.

Seasonal and Interannual Energy-related Climate Outlooks

If we could routinely provide seasonal and longer climate outlooks with 100% reliability without error there would be little need for the use of past weather and climate data. We are no where close to this ideal today and, given the chaotic nature of climate, this will never be completely achieved. Nonetheless, even with the reliability of present day outlook products many users have been able to take advantage of the skill in the present-day climate outlooks. This has been especially noteworthy during the recent El Nino event. The current products produced by NOAA's Climate Prediction Center (CPC) include:

- Heating and cooling degree day weekly tables of observed degree days, departures from normal & last year (anomalies), accumulated seasonal totals, and accumulated departures - for over 360 cities, and population weighted by state, region and nation. These are available for the last calendar week by early Monday at CPC's web site.
- A heating and cooling degree days weekly forecast table. This is for the same parameters as above, based on an 8-day maximum- minimum temperature product, but only for population weighted states, regions and nation. This is available for the current calendar week by late Monday at CPC's web site.
- Heating and cooling degree day monthly (latest calendar month) table of the same parameters as above. This is available by the 3rd of the following month at CPC's web site.
- Weekly and season-to-date observed and weekly projected degree day tables and graphics for 102 U.S. climate regions (aggregated climate divisions). This includes departures from normal (anomalies). Available for previous calendar week by early Monday at CPC web site.

- A family of Excessive Heat Index Outlook products for days 3-7, 6-10, and 8-14. Included are graphics with the Maximum Heat Index and Probabilities of: 3 days • 85•F, 2 days • 90•F and 1day • 95•F for each of the three forecast ranges.

The CPC also produces a number of experimental climate outlooks which includes:

- A probability of Exceedance Experimental (mean) Temperature Forecast graphic for each 3-month season out to one year based on 102 climate regions. The graphic shows contours of normal seasonal temperature and contours of the shift in the center of the probability distribution from climatology in the form of a temperature anomaly for the season.
- Probability of Exceedance Mean Temperature Outlook curves for each 3-month season for each

of the 102 climate regions. Includes normal, observed, forecast, and error envelope curves permitting selection of any threshold probability value or range of values for a selected temperature.

- Probability of Exceedance Heating Degree Day Outlook curves for each 3-month and one 5-month season (Nov-Mar) for the same 102 climate regions and same parameters as for temperature above.
- Climate outlook tables for temperature and degree days for 65 of the largest metropolitan areas in the U.S. These are down-scaled from seasonal outlooks interpolated to102 U.S. Climate Regions. Tables give the forecast and climatological mean, and the exceedance threshold values for given probability levels (98, 95, 90, 80, 70, 60, 50, 40, 30, 20, 10, 5, and 2 percentile levels). The forecasts are for specific airport observation sites, because risk managers primarily "hedge" and verify against official airport temperature data.

2. Near-term advances anticipated in climate science and services

New Observations and Data Products

NOAA will overhaul the current traditional methods and procedures used to compute Normals. It will deliver the means to generate a variety of Next-generation Climate Normals, such as heating and cooling degree days, freezing degree days, and other related statistics deemed important to the energy community. The normals will be calculated on a variety of time scales, i.e., hourly, daily, weekly, monthly, seasonally, annually, yearly, one or more decades, etc. This work is expected to produce products over the next two years to enable users to generate heating and cooling degree day and other normals on demand for any reference period with appropriate data corrections. Experimental products are already developed for temperature, but more algorithms will be developed to allow for users to dynamically create tailored Normals via a Web interface. NOAA expects to provide the capability to readily combine probabilistic information with climate model scenarios of future climate for use with on-demand Next-generation normals. The outcome will provide more appropriate statistics for planning purposes.

Computed normals will be based on station data with the fewest time-dependent biases possible These biases arise due to station moves, instrument changes, observation practices, or exposure changes. The normals will be based on serially complete (no missing data) data so that the normals accurately reflect the average climatic conditions for any given period of record.

Indices can be used to help explain energy usages. For example, NCDC is also generating a Energy Demand Temperature Index on a routine basis. This index has been related to residential energy usage and is found to be very well correlated to energy demand in this sector. The Energy Demand Temperature Index is based on a population weighted national temperature. The population weights are based on the 2000 census and the Index can be used to assess national residential energy demand based on unusual weather. The Index uses both heating and cooling degree days based on a 65°F base.

NOAA expects to modernize its Cooperative (COOP) Observer Network and implement its new Climate Reference Network (CRN) over the next several years. NOAA is anticipating the installation of new temperature and precipitation sensors at all of its cooperative observing sites, which now totals approximately 8000 stations. The COOP network provides daily temperature and precipitation data at a density that enables resolution of the effects of local climate variability. It has the longest history of any observing network in the USA and is the backbone of all studies of temperature and precipitation variability. Although the sensors do an excellent job in capturing significant weather and climate anomalies, they were never intended to deliver real-time data, nor data with sufficient accuracy to confidently resolve long-term climate trends without substantial adjustment to the data. So, to complement this critical high density network the CRN will be a long-term observing network that will serve as the Nation's Benchmark Climate Reference Network. High quality data from CRN sites will be used to provide the best possible information about short and long-term changes in surface air temperature and precipitation, including means and extremes. Fully implemented, the network will consist of approximately 250 geographic locations (500 paired instrument suites, a primary site and a backup site) strategically selected to capture the representative climate regimes across the Nation. Coupling the CRN data with the high density COOP data and other networks will enable the energy-related business and industry to get access to highly resolved data free of time-dependent biases that have confounded many analyses of climate variability and change. The CRN data will also be used in real-time operational climate monitoring activities, research related to climate changes, input into weather forecasts, and for placing current climate anomalies into a historical perspective. These data will be transmitted hourly and accessible on-line via the Worldwide Web (WWW). Present plans call for all CRN stations to be located outside of urban areas which can be affected by local heat islands, thereby confounding the cause of changes in the climate record, but it is possible to place some additional CRN stations in major metropolitan areas to measure changes where people use energy.

Seasonal and Interannual Energy-related Climate Outlooks

NOAA's CPC has plans for improvements in existing products and the development of new products. This includes:

- Improved skill in seasonal outlooks by improved physically based climate models. (Long term goal at 5-10 years)
- Expansion of the NCDC Energy Demand Temperature Index to include an outlook through the coming winter (for the contiguous U.S., based on population weighted degree days). (Short term goal - Winter 2001-02 or 2002-03)
- Grid cell seasonal outlooks for every 3-month period out to one year. (~2003)
- Graphical displays of the tables in the experimental forecasts that provide the forecast and climatological mean, and the threshold values exceeding given probability levels (98, 95, 90, 80, 70, 60, 50, 40, 30, 20, 10, 5, and 2 percentile levels). (2002)
- Extreme Wind-Chill family of products for days 3-7, 6-10, and 8-14 based on an 8-day forecast product. (Available experimentally during Winter 2001-02.)
- Use of composites and non-normal distributions to expand the Probability of Exceeding Thresholds concept to the probabilities of conditions "off the mean" and probabilities of extreme events, e.g., cold waves. (2002-03)

Each of the operational, experimental, and planned products have been developed in response to requests from the energy community. All will be directly useful by some segment of that community, and many will have additional indirect benefits. For example, temperature and precipitation seasonal outlook probabilities for grid cells produced in a standard format are useful for verification, for comparison with other operational and experimental outlooks, and for other sectors such a water resources and hydrology for improving river and stream flow and reservoir levels. More accurate hydrological outlooks would benefit the energy community. For example, where trade- offs between water resource use for hydro-power, irrigation, and the fishing industry are necessary, e.g., the Pacific Northwest. Present plans call for increasing emphasis on probabilistic outlooks for weather and climate extremes. Increased skill in the prediction of the frequency, duration and intensity of cold outbreaks during winter, would greatly increase the value of winter outlooks to the energy community. NOAA plans to emphasize outlooks with complete probability distributions since this permits user flexibility in selecting relevant thresholds or ranges for either the probabilities or variables of interest.